Individual or group. (61 Responses)
Name (41 Responses)
Organization (41 Responses)
Group Name (20 Responses)
Lead Contact (20 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (7 Responses)
Comments (61 Responses)
Question 1 (0 Responses)
Question 1 Comments (54 Responses)
Question 2 (48 Responses)
Question 2 Comments (54 Responses)
Question 3 (41 Responses)
Question 3 Comments (54 Responses)
Question (46 Responses)
Question 4 Comments (54 Responses)

Individual
Reigh Walling
Walling Energy Systems Consulting, LLC
No
I agree that the assessments required by the stage 2 standard meet the assessments directed by the FERC. There are two specific changes in the wording of the standard that I believe will enhance the relevance and value of the assessments: 1. In Requirement 2, Clause 2.1 requires study of peak and off-peak conditions. It is a reasonable generalization that peak load conditions would be a critical condition for which study is justified. Off-peak load conditions may or may not be condition of relative criticality, depending on the characteristics of the specific system. It is suggested that Clause 2.1.2 be modified to require study of either an Off-Peak condition or an alternative condition that is diverse from the Peak condition in terms of generation dispatch, power import or export, reliance on reactive compensation, etc. for which a justifiable basis can be made that the condition might be critical in terms of susceptibility to GMD impacts. The suggested revision retains the requirement to study two different conditions, but avoids the possible waste of engineering resources to study an Off-Peak condition that may obviously be non-critical in some systems. 2. Footnote 2 of Table 1 can easily be misinterpreted to imply that the sole impact of harmonics during GMD is to cause the tripping of BES assets due to misoperation of protection systems. Extreme harmonics during GMD can cause damage to BES equipment such as capacitor units and generators from which the equipment may not be adequately protected by the existing

protection schemes. It is strongly recommended that the wording of footnote 2 be revised to state "Harmonics during GMD may result in tripping of BES transmission and generation assets due to damage to the equipment or due to misoperation of protection systems. P8 planning analysis shall consider removal of equipment that the planner determines may be susceptible."
Yes
Group
Northeast Power Coordinating Council
Guy Zito
Once a PC or TP is chosen as an applicable functional entity, it is not specified on which facilities of the system the modeling Requirement R1 and the study requirements (R2, R3 and R7) shall apply. Not all facilities should be included in the studies; only those having a significant impact.
No
The P8 event in Table 1 doesn't offer enough clarity. We would expect that the "GMD event" is not an initial condition, but is part of the event. It would be needed to explain the nature of this event: is it the increase of dc current on the system and the transformer saturation? How is an entity going to simulate this event that leads to the removal of compensating devices or Transmission Facilities? These points need to be clarified before the standard can be approved. The benchmark GMD Event is a new approach that needs to be well mastered before being adopted. Refer to our response to Question 4. It is indicated in the Purpose that the requirements are within the Near-Term Transmission Planning Horizon. However, specific requirements (R1 to R8) refer to a Long-Term Planning Horizon. Delete the Time Horizon reference in the Purpose to avoid confusion.
No
GMDs cover large geographical areas, so it’s very important to have modelling data from neighboring regions, especially in the congested Northeast, in order to identify impacts from external equipment. How does the Drafting Team envision ensuring that actions taken in one area do not negatively impact entities in adjacent areas? For example, PJM CAP negatively affecting NYISO entities. For example, a PJM CAP might result in GIC’s flowing on adjacent NYISO elements exacerbating the problem in New York. What recourse would an adjacent region have to prevent this negative impact from shifting GMD related costs to their region? There is concern with the Benchmark GMD Event proposed in Attachment 1 and the high value of the geoelectric field of 8 V/km not being based on direct measurement, but on hypothesis to deduce electric field from magnetic field. For example, according to the proposed method and the field scale, the top value would be applied to a large portion of Québec, with much higher values than those applied to most of the United States. Hydro-Québec did experience the March 1989 GMD, but the electric field deduced from that event

was much less than the proposed value of 8 V/km. It should be considered that the direct reading of electric field should be in the methodology. Historical records are most representative of the risk that entities have to face. Also, it should be considered that this is a new method of analysis and it needs to be validated before requiring compliance based on those estimated values. Parts 2.2 and 7.1 specify the Benchmark GMD event described in Attachment 1 be used in the GMD Vulnerability Assessment and assessment of thermal impact. During the Project 2013-03 Geomagnetic Disturbance Mitigation Industry Webinar on April 24, 2014 it was stated that the benchmark event does not need to be used, but if an entity used something different they had to provide an explanation/justification. Clarification is needed.
No
Throughout the standard, the acronym for alternating current should be capitalized AC. As in other standards, acronyms for terms not used in the NERC Glossary are capitalized. Geomagnetically induced current contains both AC and DC components. Are AC models adequate to capture the impact of a geomagnetic disturbance? The Rationale Box for R1 supports the importance of DC models. The Geomagnetic Disturbance Planning Guide, December 2013 discusses DC system models. If a DC model is needed, then requirement R1 should be made to read: R1. Each Planning coordinator and Transmission Planner shall maintain alternating current (AC) and direct current (DC) System models…. Regarding the Table 1 footnotes, Footnote 1 simply repeats the initial condition statement, but should be expanded to provide examples. Each category of the Implementation Plan allows a time delay of one year after completion of the preceding stage: 1) System modeling, 2) Vulnerability assessments to GMD events, 3) Assessment of thermal impact on power transformers, 4) Corrective action plan. This Implementation Plan is highly dependent on the availability of time study tools. Please make sure that sufficient delay for tool development is considered and that stages are postponed accordingly. Given the newness of the science and assumptions, it is possible that more time than four years may be needed. If models or other factors change as the science develops, latitude should be offered with respect to the four year implementation plan. The standard would be easier to understand if R5 were combined with R2. The PC/TP obligation for conducting the GMD Vulnerability Assessment and the responsibility of the PC to determine the split of responsibilities between the PC/TP for conducting the GMD Vulnerability Assessment should be in the same Requirement. As written, R2 requires each Planning Coordinator and Transmission Planner to complete a GMD Vulnerability Assessment of the Near Term Transmission Planning Horizon for its respective area once every 60 months. R5 states that “Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify the individual and joint responsibilities of entities in the Planning Coordinator’s area for performing the required studies for the GMD Vulnerability Assessment.” The standard refers to the Corrective Action Plan in R1 and M1. However, the Corrective Action Plan is described in R3. We suggest revising the reference in R1 to “the Corrective Action Plan developed under R3.” We think the benchmark GMD event is technically justified (but it must consider real life measurements [see response to Question 3]), and provides the necessary basis for conducting the assessments directed in Order No. 779. Regarding R2, why does the standard categorize it as

a “Long-term Planning” horizon? The Parts and sub-Parts state that the study conditions should include peak load “…for one year within the Near-term planning horizon”? Requirement R4 may conflict with the requirements of other TPL standards. The Rationale for Requirement R4 refers to TPL-001 and, accordingly this should be explicitly referenced in the requirement. Regarding R6 and M6, the distribution of results should be limited to other entities (TO/GO) only to the extent those TO/GOs need the specific study results. This approach limits distribution of CEII and focuses the release of study results to pertinent other parties. Recommend that distribution of the GMD Vulnerability Assessment be clarified and limited with wording such as “…shall distribute results to relevant TOs and GOs in its respective planning area and, as appropriate, adjacent PCs and TPs.” R6 requires distribution of results to “…any functional entity that has a reliability related need…” but does not specify what constitutes a reliability related need. The distribution of study results should be limited to protect CEII. R6 does not indicate what the TOs, GOs and adjacent PCs and TPs should do with the GMD Vulnerability Assessment results. Measure M6 should include reference to distribution of results to TOs and GOs. Requirement R7 should refer to the GMD Vulnerability Assessment results that were distributed to the TO and GO as specified in R6. Requirement R8 requires TOs and GOs to provide transformer assessments to PCs and TPs but does not specify what the PCs and TPs should do with the information. The SDT should consider including a requirement about what the PC and TP should do with this information.
Group
FirstEnergy Corp.
Richard Hoag
In general FirstEnergy Corp. agrees with the drafting team. The Planning Coordinator is required to keep a model and would need inputs from the Generator Owner, however, geomagnetic disturbances are a low probability impact for generators.
Yes
The drafting team assembled a good flexible standard.
Yes
Yes
The implementation timeline is realistic as written and should not be shortened.
Individual
John Seelke
Public Service Enterprise Group
While we agree that the correct functional entites have been identified, we have concerns that R3 and R6 allow a PC or TP to specifiy what a TO or GO must do in a CAP. We assume that CAP developed in R3 and commented on in R6 would assign responsibilities for mitigation to TOs and GOs, even though R3 does not explicitly assign them mitigation responsibilities. The first two bullets of R3 (shown below) could greatly impact TOs and GOs:

• Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment. • Installation, modification, or removal of Protection Systems or Special Protection Systems. We offer three points for the SDT to consider: • TOs and GOs cannot be delegated mitigation obligations by a PC/TP under the NERC framework. While "performance" can be dictated by a NERC standard, how that performance is achieved (the "what") cannot be. • A PC/TP CAP should require all impacted TOs and GOs to concur with the it. Only by such concurrence can TOs and GOs acknowledge their GMD mitigation responsibilities. o Alternatively, the PC/TP Vulneability Assessment in R2 could require location-specific performance for GMD, with the development of a CAP required by the associated TOs and GOs to meet that performance. • The requirements R2 and R3 which, in part, state "Each Planning Coordinator and the Transmission Planner shall …" would be interpreted to mean both the PC and the TP shall perform the required action. If a GO has a different PC and TP, this may result in two CAP plans. We understand that this is not the intent, but we recommend that the SDT consider this wording: "Each Planning Coordinator, or its designated Transmission Planner, shall…"
No
The sequence of events required by TPL-007-1 is not communicated in the standard. We recommend a flow diagram or a Gantt chart be provided in an attachment to the standard to indicate the sequence of requirements and the compliance timing for each requirement, along with a brief explanation of the logic of the sequence. We note that the Implementation Plan requires this order of implementation by various entities, with the cumulative time (per the Implementation Plan) for compliance with different requirements from the date pf regulatory approval of TPL-007-1: • R1 and R5 are performed first by the PC/TP. (12 mo.) • R2, R4, and R6 are performed second by the PC/TP. (24 mo.) • R7 and R8 are performed third by the TO and GO. (36 mo.) • R3 is performed last by the PC/TP. (48 mo.) It is difficult to understand how the GMD Vulnerability Assessment required in R2 can be completed without understanding whether R7 thermal impacts may result in need for temporary removal or other mitigation means for TO or GO transformer assets. In addition, R6, which allows other Transmission Planners as well as TOs and GOs to comment on Vulnerability Assessment the CAP, cannot be completed before R3 (the development of the CAP) is completed.
No
The benchmark GMD event is so severe that even new transformers specficed at locations that have experienced a prior GMD event and whose owners are aware of Order 779 will likely require mitigation under TPL-007-1.
No
The allotted time for GOs and TOs to complete the assessments specified in R7 is insufficient. Firstly, on the assumption that TOs and GOs receive the GIC information required to complete R7 on time – by 24 months after applicable authority approval - from the PC/TP, 12 months (36 – 24) to complete R7 will be inadequate. Secondly, there is no allowance in the plan for GOs and TOs in the event the PC/TP does not provide the GIC information at the 24 month milestone. The implementation plan needs revision to provide a specified amount of time to

TOs and GOs after receipt of the GIC information from the PC/TP. And the specified amount of time must be treater than 12 months; PSEG suggests 24 months.
Individual
Terry Volkmann
Volkmann Consulting, Inc
FERC Order No. 779 (P.67) requires the development of one or more standards that requires the owners and operators perform vulnerability assessments. TPL-007 falls short in meeting this FERC directive. Earlier the NREC BOT adopted EOP-010 that requires the RC & TOP to develop operating procedures with no requirements for conducting vulnerability assessments. TPL-007 is developed as a Planning Standard with: 1. no requirement for the PC and TP to communicate the vulnerability assessment results to the applicable RC and TOP. 2. no requirement for the RC and TOP to integrate the TPL-007 vulnerability assessment findings into their operating procedures under EOP-010. Secondly TPL-007 does not cover the variety of operating conditions that the RC and TOP routinely operate under. As example high transfers were demonstrated to change the voltage collapse point by 50 to 70% in the PowerWorld studies were presented at the NERC GMDTF meeting in March 2014. Since the primary operational step in many of the RC operating procedures is to reduce or maintain transfers under a certain value, it is critical for the RC and TOP to study the effects of power transfers on voltage collapse in their area during a GMD event. Either TPL-007 needs to be expanded to cover operating conditions, i.e. high transfers or a revision to EOP-010 needs to be developed in parallel to require the RC and TOP to conduct vulnerability assessments using similar tools as those developed to meet TPL-007. Finally there are numerous technical articles discussing the development of harmonics during a GMD event and the associated impact on reactive devices (capacitors) and generators. The only connection to harmonics impacts in the TPL-007 standard is the footnote on page 5 in the P8 table. This footnote requires the consideration of equipment outages from harmonics. As stated, this presents three problem areas: 1. the footnote states a requirement to the planner to remove equipment susceptible to harmonics. This should be an explicit requirement directed to the PC or TP. 2. PCs and TPs are not required to have protection system expertise in the course of performing their duties, thus have no foundation to assess protection system susceptibility. This requirement should be assigned to the GO and TO who own the protection system and equipment being protected. 3. The standard requires the TO and GO to evaluate their transformer performance during a GMD event, but not their protection systems. The TO and GO are the owners of the BES protection systems and have access to protection system expertise. It is recommended to add a requirement for the TO and GO to evaluate the vulnerability of their associated capacitor and generator protection systems to harmonics in both relay operability and settings. The TO and GO are then required to provide their assessment of which protection systems are vulnerable to tripping from harmonics during a GMD event to their RC, TOP, PC and TP. Standards C50.12 and C50.13 can provide the basis for the vulnerability assessment of the protection system settings and performance during

the stator harmonic currents that may create rotor heating. The SDT is recommended to develop a guidance document to assist in determining harmonic susceptibility.
No
FERC Order No. 779 (P.67) requires the development of one or more standards that requires the owners and operators perform vulnerability assessments. TPL-007 falls short in meeting this FERC directive. EOP-010 that requires the RC & TOP to develop operating procedures with no requirements for conducting vulnerability assessments. TPL-007 is developed as a Planning Standard with no requirement for the RC and TOP to integrate the vulnerability assessment findings into their operating procedures under EOP-010. Either TPL-007 needs to be expanded to cover operating conditions or a revision to EOP-010 needs to developed in parallel to require the RC and TOP to conduct vulnerability assessments using similar tools as those developed in TPL-007. The following changes should be made: 1. R2 needs to be run at firm transfer and at peak transfer levels in order to fully and accurately assess the vulnerability 2. R2 results need to be communicated to the RC/TOP (could be covered in R6) 3. R3.1 Operating procedures need to be demonstrated to be capable to be executed in the lead times of GMD event notifications. 4. R4 RC and TOP must use same voltage criteria for the same area of study and share limits with adjacent PCs and TPs. 5. R6 90 days is too long to provide the results.
No
FERC Order No. 779 (P.2) requires the benchmark GMD events to be "technically justified". The GMDTF has introduced a concept of spatial averaging with a minimal peak area and has not provided the technical justification of the size of this area. This concept completely ignores the impact in the peak field area of interest. Even if the concept of spatial averaging is correct, there is no basis that the peak area will be restricted to 100 km square. The use of a 30 hour period for the benchmark event is questionable when there is evidence that the Carrington event lasted much longer and may have lasted as long as 12 days. In addition the SDT has not considered that peak areas will move around. Considering the field area will move, the event maybe longer than 30 hours and the peak area of interest may be larger, it is possible that the entire BES between geomagnetic latitudes 60 and 40 degrees will witness peak fields. TPL-007 should require the studying of the area of peak field to understand the vulnerability. The technical justification for the 100km peak area needs to be provided in the Benchmark Geomagnetic Disturbance Event Description document.
Yes
Individual
Scott Knewasser
FRCC
The applicability section of the standard includes power transformers with a high side, wye-grounded winding connected at 200 kV or higher. I believe the intent of the standard is to apply to transformers connected to 200 kV or higher systems. As written, a 230 kV high side,

wye-grounded transformer would not apply since its winding is connected at 230 kV divided by the square root of 3, or 133 kV (line to ground). If the SDT intends to include these transformers, consider revising the applicability section of the standard to include power transformers with a high side, wye-grounded winding connected to 200 kV or higher systems (line to line).
Group
Foundation for Resilient Societies
Thomas Popik
No, we do not agree that applicable functional entities should be limited to “Planning Coordinators, Transmission Planners, Transmission Owners, and Generator Owners with a high-side, wye-grounded winding connected at 200 kV or greater.” First, a lower limit of 100 kV per the Bulk Electric System definition, not a limit of 200 kV, should apply. GMD impacts have been observed in equipment operating between 100 kV and 200 kV, according to the report of the Oak Ridge National Laboratory, “Geomagnetic Storms and Their Impacts on the U.S. Power Grid.” Second, Balancing Authorities and Reliability Coordinators should also be included as applicable functional entities, because these entities must manage GMD impacts and system restoration if planning and installation of hardware protective devices were to be inadequate.
No
No, we do not agree that the proposed standard meets the assessment parameters directed by FERC, principally because the Benchmark GMD Event has not been technically justified. In Order 779, FERC directed that “The benchmark GMD events must be technically justified because the benchmark GMD events will define the scope of the Second Stage GMD Reliability Standards (i.e., responsible entities should not be required to assess GMD events more severe than the benchmark GMD events).” Moreover, we do not agree that the proposed standard adequately takes into account “the potential impact of GMDs based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment” as directed by FERC. One “condition” or “technical specification” of equipment would be resistance to mechanical shock and vibration. Yet the proposed NERC standard completely ignores the potential impact of shock and vibration, despite the observation of these effects in equipment during solar storms. Importantly, there is no necessarily long time constant for damage from shock or vibration—a brief peak GIC occurring during sudden storm commencement could immediately damage transformers. The thermal models of transformers proposed for conducting assessments do not present test results and therefore are speculative. Given the opportunity to test a wide variety of transformers for thermal impact and publicly disclose the results, the electric utility industry declined to do so.

No
No, we do not agree that the proposed Benchmark GMD Event is technically justified and provides the necessary basis for conducting the assessments directed in Order No. 779. The Benchmark GMD Event suffers from the following technical deficiencies: 1. The proposed Benchmark GMD Event proposes a maximum geoelectric field of 8 V/km based on “spatially averaged geoelectric field amplitudes,” a newly contrived, unpublished, and unsupported scientific hypothesis. We took the time to read the published references where available online. Some of the published references appear to contradict the central premise of the proposed Benchmark GMD event. For example, Reference 17 states in its Abstract: “By using GIC data and corresponding geomagnetic data from north European magnetometer networks, the ionospheric drivers of large GIC during the event were identified and analyzed. Although most of the peak GICs during the storm were clearly related to sub storm intensifications, there were no common characteristics discernible in substorm behavior that could be associated with all the GIC peaks. For example, both very localized ionospheric currents structures, as well as relatively large-scale propagating structures were observed during the peaks in GIC. Only during the storm sudden commencement at the beginning of the event were large-scale GICs evident across northern Europe with coherent behaviour.” The published reference reveals that “relatively large-scale propagating structures were observed during the peaks in GIC” and sudden storm commencement has produced “large-scale GIC evident across northern Europe with coherent behaviour”—both statements in clear contradiction of the NERC “spatial averaging” hypothesis which proposes that all high amplitude effects would be localized. 2. Most of the published references used to purportedly support the NERC hypothesis of “spatial averaging” use data from Europe instead of North America. 3. The sparse and selected data used to calculate the NERC benchmark geoelectric field was recorded from 1993 to 2013, a narrow period lacking severe or even moderate solar storms. To develop probabilities for a “100 year” storm peak amplitudes, the widest possible window of prior data should be used, even if the data is from different sources; arbitrary statistical inclusions and exclusions should not trump use of all relevant data sets. 4. The sparse and selected data used to calculate the NERC benchmark geoelectric field was from “four different station groups spanning a square area of approximately 500 km in width.” The safety of the American and Canadian public should not depend on calculations based on data from only four relatively small areas. The location of the four station groups was not disclosed by NERC. 5. The Benchmark GMD Event does not incorporate safety factors, despite its reliance on an untested hypothesis and sparse data. Given the significant societal impact for an erroneous Benchmark GMD Event, (i.e., potential death of millions of Americans and Canadians), use of safety factors would be prudent and should be required. A broad “safety factor” is an essential component of the required design of a Benchmark GMD Event. Moreover, the urgency of a safety factor is elevated by the exclusion of Generator Operators (GOs) from the NERC Standard EOP-010-1 — Geomagnetic Disturbance Operations. If the Phase II Benchmark Event is set too low, it is foreseeable that most electric utilities that implement the hardware protection standard will opt out of purchase of neutral ground or other hardware to protect Generator Step Up transformers at Bulk Power System generation sites. Hence, in a geomagnetic storm comparable to the New York Central Railroad storm of

May 1921, with volts/km far in excess of the 8 V/km benchmark in the proposed standard, hundreds of GSU transformers may be both hardware-unprotected and exempted from participation in mandatory "operating procedures." The combination of jurisdictionally-defective operating procedures and an imprudently low Benchmark Event will leave these long replacement-time transformers without protection and beyond the capability of the President of the United States to order immediate de-energizing of these vulnerable transformers during a storm. Deficiencies in both the GMD operating procedure standard (now under FERC review) and the GMD Benchmark Event should not be allowed to exacerbate risks of a blackout in which over 100 million Americans are without power for 1-2 years.
No
No, we do not support the approach taken by the drafting team in the proposed Implementation Plan because the assessment procedures rely on a flawed Benchmark GMD Event and are otherwise technically deficient. We note that in June 2013 the NERC Standards Committee eliminated a standards project for equipment monitoring that could have provided near-real-time reporting of GIC events and correlation with high voltage transformer operating condition. We urge NERC to develop and make publicly available site-specific GIC data for all sites with extra high voltage transformers interconnecting to the Bulk Power System, and to commit to periodic updating of observed GIC and time sequences for all relevant transformer locations. Moreover, the proposed standard does not require periodic update of assessments based on improved GMD data, updates to the GMD Benchmark Event, and reports of equipment impacts coincident or shortly after GMD events. Because the standards project for equipment monitoring was cancelled, the proposed standard should require improved GMD monitoring by means of additional GIC monitors—GIC monitors would be cost-effective as they cost only about $15,000 per monitor.
Individual
John Bee on behalf of Exelon and its affiliates
Exelon
Agree
No
Requirement R1: GIC models will require additional data beyond what is currently provided for power-flow models, etc. Examples include dc resistance for lines and transformers, substation grounding resistance and geographic coordinates, and variation of transformer reactive power loss with respect to GIC. This data is not readily available so consideration needs to be given to the time and effort that may be required to gather this information, and that some information e.g. transformer reactive losses due to GIC may not be known. Will the TO and GO be required to provide this data? Suggest that generic data be used in the event that the data is unavailable.
Yes

While the proposed Benchmark event appears to be technically justified and provides the necessary basis for conducting assessments, the level of detail suggested for conducting transformer thermal assessments seems overly complicated and cumbersome. It is recommended that a streamlined methodology be developed, or defined by the PC or TP, to evaluate transformer thermal impacts based on high-level characteristics of the Benchmark event and the analysis performed by the PC or TP. Any real event will likely share general characteristics with the Benchmark event, but will be completely different in terms of its actual signature. A more straightforward evaluation methodology would be more efficient and possibly just as effective as detailed analysis for each transformer based on a specific signature. The Thermal Assessment whitepaper describes a technique that consists of selecting a GIC pulse representative of the GIC peak. Could one (or more) pulses be defined with a magnitude and duration that are representative of the “worst” part of the Benchmark event and used as a standard test for R7? It seems this would not be much different than the simplified analysis described in the whitepaper, except that a uniform test would be defined rather than allowing each entity to choose what they believe a representative GIC pulses may be.
No
Requirement 7: It appears that the analysis described for R7 will require that time-series GIC data corresponding to the benchmark event be simulated for each transformer subject to the requirements in the standard. Calculation of this data would essentially require the same models and study tools used by the PC and TP to meet the requirements described in R1 and R2, in addition to the ability to map these results into the corresponding time-series GIC for each transformer. Suggest that the PC or TP performing the studies described in R2 should be required to provide GIC data for each transformer sufficient for the TO or GO to perform the assessment described in R7. Requirement 7: In order to perform the assessments described in R7, accurate data is required for each transformer that describes thermal response with respect to GIC. Will manufacturers be required to provide this data? What if such data is not available, e.g., for older equipment installed in the field? The transformer manufacturers will be over whelmed which may result in a bottle neck. Is the expectation that each transformer that is in scope for the thermal assessment is analyzed individually? If the transformers are of the same design from the same manufacturer, it would be redundant to perform thermal assessment study on each transformer from that particular transformer manufacturer. It would be more practical to perform the study on just one type of the transformer from each manufacturer. Since 5-leg core and Shell form transformer designs are more susceptible to GIC, only transformers with these designs should be considered for system impact study. This study would provide worst case scenario for system impact. Suggest that similar transformer types and designs be analyzed as a group, i.e. one assessment be performed for all transformers of simular design and or type. Requirement 7: Our initial understanding was that assessment of thermal impact for all solely and jointly owned power transformers with high-side, wye-grounded windings connected at 200 kV or higher was only required for transformers that were identified as having high GIC during the PC/TP GMD planning assessment. If this was the intent suggest rewording R7 to state: Each Transmission Owner and Generator Owner shall conduct an assessment of thermal impact for all of its solely and

jointly owned power transformers with high-side, wye- grounded windings connected at 200 kV or higher that were identified as having high GIC in the GMD Vulnerability Assessment. Requirement 7: The thermal analysis described in the white-paper is somewhat detailed, requiring the ability to simulate and evaluate the thermal transformer response as a function of time, or analysis of the time-series GIC for each transformer to identify representative GIC “pulses” that can compared against manufacturer-provided capability curves. Suggest that the PC or TP define a more straightforward assessment methodology based on their simulation results; for example, possibly a single worst-case GIC pulse can be provided for each transformer to be screened. Requirement 7.3: The requirement reads “Describe suggested actions and supporting analysis to mitigate the impact of electromagnetically-induced currents, if any”. We are not sure how the TO or GO can achieve this since it would require the PC to re run the GMD Vulnerability Assessment. Is the intent that this will be an iterative process? Requirement R6: The Rational reads “Distribution of GMD Vulnerability Assessment results and Corrective Action Plans provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies and planned mitigation measures may affect neighboring systems and should be taken into account by planners. Additionally, this GIC information is essential 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”. How would a TO or GO know what the impact of mitigation efforts performed by other entities will be on our own systems? The result could be constantly changing GIC profiles which would result in re-performing studies. Requirement 7: The “Transformer Thermal Impact Assessment” white paper (Pg. 2) states that a transformer GMD impact assessment must consider the transformer condition (e.g. age, gas content, and moisture in oil). Transformer condition is inherently subjective and dynamic. For these reasons, this parameter should be considered out of scope of the impact assessment. Requirement 7: The “Transformer Thermal Impact Assessment” white paper (Pg. 3) states that in order to determine maximum hot spot temperature rise due to GIC contribution “maximum ambient and loading temperature should be used”. The base case condition should be more clearly defined. If short time emergency loading (i.e. loading beyond nameplate to the maximum temperatures permitted in IEEE C57.91) is used as the base case, the additional thermal rise due to GIC will exaggerate the actual effects of GIC to the transformer during normal operation. Note that the transformer manufacturer capability curves provided in the paper only define the GIC capability as a function of % MVA Rating without defining the what it actual is (nameplate versus capability). Suggest that normal continuous rating be used for the Thermal Impact Assessment.
Individual
Paul Rocha
CenterPoint Energy
CenterPoint Energy agrees in general that the standard drafting team has correctly identified the registered entities to perform the functions required in the draft standard. However,

CenterPoint Energy is concerned that, as currently written, the draft standard will create confusion among Planning Coordinators, Transmission Planners, Generation Owners, Transmission Owners and Regional Entities. R5 indicates that Planning Coordinators, in conjunction with Transmission Planners, will determine and identify individual and joint responsibilities for performing the required studies. However, the other requirements for performing such studies apply to all the applicable Transmission Planners and the Planning Coordinator for a region, which seems to be inconsistent with R5. CenterPoint Energy recognizes that R5 mirrors the language of TPL-001-4 R7, but an important distinction for this standard is the required communication between planning entities and owners in R6 and R8. The applicability of R6 and R8 to each planning entity results in duplicative communications. Another aspect of this standard is that due to boundary modeling considerations and emerging nature of these new requirements, it is likely that some regions would find it beneficial to consolidate modeling and analysis efforts, possibly into a single regional GMD Vulnerability Assessment. In such circumstances, the applicability to both the Planning Coordinator and each Transmission Planner would be problematic. CenterPoint Energy suggests that the SDT modify R1, R2, R3, R4, and R6 to read, "Consistent with the determination and identification of responsibilities in R5, the applicable Transmission Planner or Planning Coordinator shall…". R8 would likewise be modified such the each owner is required to provide its assessment to the applicable planning entity, as determined in R5. If the SDT agrees with this change, we further recommend that R5 be renumbered as R1 since determination of applicability is a threshold function preceding the other planning functions. CenterPoint Energy also recommends that R5 be re-written to apply to both the Planning Coordinator and Transmission Planner, as follows: "Each Planning Coordinator and each of its Transmission Planners shall mutually determine and identify the individual and joint responsibilities…".
Yes
CenterPoint Energy agrees that the proposed requirements meet the directives in Order No. 779 and are generally supported by the technical guides referenced in the standard. However, CenterPoint Energy recommends changes to some of the draft requirements, and CenterPoint Energy believes its recommended changes would also comply with the directives of Order No. 779 and would also be technically justified. In addition to the recommended changes discussed in the previous comment, CenterPoint Energy recommends the following additional changes to draft requirements: • Modify R1 to clarify that models should be developed for wye-grounded transformers with high side connections greater than 200 kV. • Add "if necessary to meet the performance requirements of Table 1"to the language in M3 to align M3 with R3. • Delete footnote 4 in Table 1. • Modify R7 to specify that an assessment of thermal impact should be conducted for power transformers that are potentially subject to peak GIC values above a certain threshold. CenterPoint Energy further proposes that the SDT set that threshold in the range of 50 to 100 amperes per phase. • Modify R6 and R8 to be consistent with our proposed changes to R7 and as discussed in the previous comment. These proposed changes are briefly explained below: • Applicable planning entities as defined in 4.1.1 and 4.1.2 of the Applicability section will typically have some transformers with high side connections below 200 kV or that do not have wye-grounded high side connections

within their system. CenterPoint Energy believes the SDT's intent in R1 is that models should only be developed for the wye-grounded transformers connected at 200 kV or higher. To clarify this intent, CenterPoint Energy recommends that R1 be revised to read that each planning entity…"shall maintain ac System models and geomagnetically-induced current (GIC) System models of the wye-grounded transformers with high side connections greater than 200 kV within its respective area…". • R3 indicates that each applicable entity "that determines..that its System does not meet the performance requirements of Table 1" is required to develop a Corrective Action Plan. However, M3 indicates that each applicable entity shall have evidence of a Corrective Action Plan, the implication being that this requirement applies regardless of whether a Corrective Action Plan is necessary to meet the performance requirements of Table 1. To align M3 with R3, CenterPoint Energy proposes that M3 be revised to indicate applicable entities "shall have evidence such as electronic or hard copies of its Corrective Action Plan if necessary to meet the performance requirements of Table 1…" • The expected occurrence of a P8 event is much less than other events defined in Table 1, such as P6 or P7. For more probable events, such as P6 and P7, Non-Consequential Load Loss can be relied upon as the primary means of compliance. Stated otherwise, footnote 4 is applied to P8, but it is not applied to more probable P6 and P7 events. CenterPoint Energy believes that if load shedding is an appropriate way to address more probable events such as P6 and P7, it is also an appropriate way to address a far less likely P8 event. Accordingly, footnote 4 should be deleted. • Regarding R7, CenterPoint Energy is concerned about the requirement to "conduct an assessment of thermal impact for all of its solely and jointly owned power transformers…" CenterPoint Energy believes the SDT and an overwhelming majority of experts would agree that an analysis using GIC capability curves, thermal response simulation, or "other technically justified means" is not necessary or beneficial for power transformers that have a peak GIC below a certain threshold value. CenterPoint Energy is further concerned about the lack of availability of GIC capability curves for most transformers and the lack of commercially available thermal response tools and modeling experts for a new type of analysis that most Transmission and Generator Owners do not perform today. The concept of a conservatively low "pass" or "fail" threshold is discussed in the Transformer Thermal Impact Assessment White Paper. The SDT may believe that peak GIC falling below a specified threshold should be considered a valid "technically justified means" of assessing a power transformer but, if so, an auditor could reasonably read the language in the draft requirement in a different way than the SDT intends. Accordingly, CenterPoint Energy proposes that the SDT modify R7 to specify that power transformers with peak GIC above a certain threshold must be assessed. CenterPoint Energy further proposes that the SDT establish that threshold between 50 to 100 amperes per phase or some other value that the SDT determines in its reasoned judgment. CenterPoint Energy believes that a threshold of 50-100 amperes per phase of peak GIC would be a conservatively low threshold above which detailed thermal impact assessments should be performed by the applicable asset owner. CenterPoint Energy proposes that the SDT establish the threshold for R7, rather than leaving the threshold to the discretion of individual entities, to ensure consistent implementation and to avoid skepticism of the GIC threshold value for entities that have low peak GIC values due to geography, geology, or other reasons. An alternative would be to set a

threshold value in the range of 50 to 100 amperes as the default, with an option to allow entities to use a value outside of that range that the planning entity technically justifies. • Regarding R6 and R8, CenterPoint Energy is concerned that the process coded in this draft version of the standard is impractical and unnecessarily cumbersome. In a region with 400-500 applicable transformers, for example, it is unnecessary and administratively burdensome to transmit GMD Vulnerability Assessments to the owners of all 400-500 transformers, regardless of GIC impact to each individual transformer. Additionally, as currently written, each owner would get at least two transmittals, one from the Planning Coordinator and one from a Transmission Planner, creating at least 800-1000 unnecessary notifications. A further complication is that each transformer owner could receive conflicting GMD Vulnerability Assessments from different planning entities. Under the R8 process, an additional 800-1,000 notifications would be provided by all the owners to the applicable Transmission Planner and Planning Coordinator. Furthermore, in a region with 10 highly interconnected planning areas, at least 100 transmittals of GMD Vulnerability Assessments would be required by Transmission Planners (10 sets of 9 transmittals to adjacent Transmission Planners and one transmittal to the Planning Coordinator). Applying CenterPoint Energy's previously discussed changes would address these concerns and make the implementation of standard more efficient. For example, under the R5 process, the planning entities might decide to perform a single region-wide GMD Vulnerability Assessment or, alternatively, create a planning coordination process modeled after the EOP-010 operational coordination process.
Yes
CenterPoint Energy commends the SDT for its work on this subject. In particular, the adjustments for latitude and soil conductivity result in a design basis event that can be applied throughout North America without the need for regional exceptions.
Yes
CenterPoint Energy generally agrees with the Implementation Plan developed by the SDT. One change that the SDT might consider is adding one year to the Implementation Plan for the parties to negotiate and determine responsibilities envisioned by R5, which CenterPoint Energy recommends be renumbered as a threshold R1 action. CenterPoint Energy's experience with similar processes, such as Coordinated Functional Registration to determine responsibility for Transmission Operator functions among multiple registered entities, causes CenterPoint Energy to believe that it will take time for multiple parties to reasonably vet and resolve this matter.
Individual
David Thorne
Pepco Holdings Inc
PC and TP seem redundent. Only need TP
Yes
Yes

Yes
Individual
Amy Casuscelli
Xcel Energy
Yes
Yes
Yes
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Do not agree. ATC supports the following comments submitted by the MRO NSRF: a. Revision to the Purpose b. Consideration of the sequence of assessments (TP/PC powerflow, then TO/GO thermal impact, then TP/PC complete assessment).
No
ATC supports the following comments as submitted by other organizations: • EEI REAC comment on inclusion “load loss” with a slight modification: Load loss for P8 should include both indirect Consequential (due to any cascading) load loss and Non-Consequential load loss. • ATC supports the MRO NSRF comments as listed below: (brief summaries only) (1) Double jeopardy with ac system model maintenance in R1 (2) Any other facilities in R3.1, (3) Other components of CAPSs in R3.2, perform R1 through R4 in R5, (4) Permission to receive assessments in R6, and (5) Have a current valid assessment in R7. Finally, ATC agrees with the MRO NSRF comment that the term, “susceptible”, in Note 3 of Table 1 needs clarification. An appropriate qualifier, or qualifiers, should be added such as “to tripping”, “to thermal damage, or “to failure”.
Yes
However, ATC believes the industry should keep trying to develop better Geoelectric Field Scaling Factors boundaries and scaling factor values.
No
ATC supports EEI REAC and MRO NSRF comments regarding factors such as the immaturity of space weather and geomagnetic sciences; the challenges of acquiring some data; and the improper sequence of analyses issue which suggest that the proposed time frame and sequencing may be unrealistic.

Individual
Michelle D'Antuono
Ingleside Cogeneration LP
Ingleside Cogeneration LP (“ICLP”) believes that it is premature to include planners and operators who control low-risk assets. As captured in the baseline GMD event white paper, there are two key factors which clearly capture those transformers and transmission systems most prone to GIC – those at higher latitudes and those grounded in high-resistive earth. A bright line could easily be drawn that would capture locales that historically have been proven to be the most threatened. Those entities have a clear and immediate self-interest in protecting their investments in equipment and systems – whereas Generator Owners located in the southern U.S. do not. After sufficient experience with GIC modeling and validation has been achieved, it may be cost effective to pursue some expansion in scope. For now, we only see an increase in compliance overhead with no commiserate reliability benefit.
No
ICLP believes that the GMD event baseline is an excellent first step approximation of geomagnectically induced currents. However, there is nothing in the standard, guidance, or white papers that indicate that the baseline will be modified over time as the industry gains experience with the phenomena. The standard may not be the appropriate place for a continual improvement process, but we would like to see NERC commit to this action. Secondly, we were unable to find a correlation between the GO/TO’s assessment of transformer vulnerability and the PC/TP’s assessment of system performance. In the generator validation standards, the link was clear – planners and owners would work together to eliminate discrepancies. ICLP is concerned that unresolved conflicts may result in a violation of TPL-007-1 – either for the planner, the equipment owner, or both.
Yes
ICLP agrees that the underlying basis of the benchmark GMD event is as technically sound as it can be at this time. We would expect that corrections to the algorithm will be made as the industry gains experience with the phenomena.
No
ICLP believes that mandatory language needs to be added in TPL-007-1 that captures the reality that real-life response to GIC will not likely reflect simulated outcomes for quite some time. We are concerned that an auditor will assess a violation for a GMD event that leads to system instability or transformer damage without clear instruction to do otherwise. Only when the correlation between models and actual performance is confirmed, can this level of expectation be accommodated. This could take years or even decades – corresponding to the incidents of such rare Disturbances.
Individual
Erika Doot
Bureau of Reclamation

The Bureau of Reclamation (Reclamation) requests that the drafting team clarify why Reliability Coordinators are not included within the scope of the standard. In the Western Interconnection, the inclusion of the Reliability Coordinator would ensure an interconnection-wide perspective on transmission planning for geomagnetic disturbance events.
No
Reclamation does not believe that the standard clearly addresses FERC's directive to consider tasking Planning Coordinators or another functional entity "to coordinate assessments across Regions… to ensure consistency and regional effectiveness." Order No. 779, ¶ 67. Reclamation does not believe that providing copies of GMD Vulnerability Assessments and Corrective Action Plans to adjacent Planning Coordinators and Transmission Planners as required by R6 amounts to coordinating assessments to ensure consistency. Reclamation suggests that the drafting team add an additional requirement to the standard to more specifically address coordination of GMD assessments among regions.
Yes
Reclamation believes that the proposed benchmark GMD event is technically justified because it is based on the best available data, and because the Quebec event provided generally conservative thermal analysis results for power transformers. Reclamation believes that based on the characteristics described in the whitepaper, Planning Coordinators and Transmission Planners will incorporate additional location-specific information to ensure that assessments are robust.
No
Reclamation suggests that the Implementation Plan for R7 be updated to allow a phased approach to compliance because entities may not be able to complete thermal impact assessments for all transformers with high-side, wye-grounded windings connected at 200kv or higher within one year of receiving geomagnetically-induced current flow models from the Planning Coordinator and Transmission Planner. For example, an entity with over 200 qualifying transformers may not be able to complete thorough studies in a compressed one-year timeframe. Reclamation suggests a phased implementation period of 30% of applicable devices assessed within 36 months of regulatory approval, 60% of devices within 48 months, and 100% of devices within 60 months. This phased implementation schedule would allow Transmission Planners and Planning Coordinators to receive all thermal impact analyses with adequate time for review before the next 60-month GMD Assessment required by R2. Reclamation has additional comments on the proposed requirements that are not covered in the questions posed by the drafting team: Reclamation suggests that R7 should include a 60-month timeframe like R2. As written, it is not clear how often Generator Owners and Transmission Owners are required to conduct thermal analyses of qualifying transformers. Reclamation also suggests that R2 should include an additional subrequirement requiring the Planning Coordinator and Transmission Planner to consider the results of thermal analysis received from Transmission Owners and Generator Owners when performing subsequent GMD Assessments. If the drafting team declines to incorporate this additional subrequirement, it should eliminate R8 as a purely administrative requirement or modify R8 to require Transmission Owners and Generator Owners to provide study results within 90

days of a request by the Planning Coordinator or Transmission Planner. Reclamation suggests that the drafting team update R5 to include the clarifying language from M5 that Planning Coordinators and Transmission Planners should demonstrate agreement has been reached with entities responsible for performing studies required for the GMD Vulnerability Assessment. Finally, Reclamation requests that the drafting team include an additional requirement requiring Planning Coordinators and Transmission Planners to demonstrate that agreement has been reached regarding proposed actions in a Corrective Action Plan that are anticipated to be completed by Transmission Owners or Generator Owners.
Individual
Venona Greaff
Occidental Chemical Corporation
Agree
Ingleside Cogeneration, LP.
Individual
Ayesha Sabouba
Hydro One
Yes
Yes
The proposed benchmark GMD event appears to be supported with reasonable technical arguments. However, we would appreciate clarity on the following points: • Why is a design basis of 1 in 100 years appropriate for a planning standard. 1 in 50 years would be closer to extreme events such as ice storms. • Why was 8 V/km selected as the reference V/km magnitude when extreme value analysis suggests that the high end should be 5.8 V/km? • Is there a geomagnetic latitude below which there is no point in carrying out detailed studies?
Yes
It is not clear why the first GMD event is labelled P8 instead of P1. This should be clarified or changed. In R3, if the Planning Coordinator and the Transmission Planner are separate entities, then they should reach agreement on the Corrective Action Plan, as well as reaching agreement on the criteria identified in R4. The skill set needed to carry out the required studies is not widely available in the industry. The proposed standard indicates in various places that certain flexibility is permitted if technical justification is provided. Who will be qualified to assess if a given technical justification is reasonable. NERC, the Planning Coordinator? In Requirement 7.3, the TO is asked to suggest mitigation plans while R3 asks TC/TP to have a Corrective Action Plan. It should be clarified that this will be an iterative process to avoid redundancy or confusion. If the TO or GO identifies a needed change as a result of the studies from the TP (e.g. a transformer must be taken out of service) then this will have an impact on the studies that will be done by the TP and which in turn will affect subsequent thermal impact studies. MOD-032, which is replacing the old MOD, should now

include the data/models required for TPL-007 studies in MOD-032 Attachment 1. These data and models are not mentioned in MOD-032 Attachment 1. Until then TPL-007 should clarify what data/model should be provided by TO.
Individual
David Jendras
Ameren
No
Is it intended that there be any other contingency events that should be applied as part of the geomagnetic disturbance assessment work? We ask for clarification on other contingencies besides adjusting the models to reflect posturing in response to warnings of a geomagnetic disturbance, and application of the effects of the geomagnetic disturbance itself, and removal of any reactive power devices and Transmission Facilities due to Protection System operation which define the contingency category P8. On Page 8, Table 1, Steady State A: We request the SDT remove possible dynamic modeling/simulation implications by considering the following change: • Current Language for Steady State A: The System shall remain stable. Cascading and uncontrolled islanding shall not occur. • Proposed Language for Steady State A: Cascading and uncontrolled islanding shall not occur. On Page 8, Table 1, Steady State Performance Footnotes #4: We request the SDT remove possible dynamic implications by considering the following change: • Current Language Footnote #4: The objective of the GMD Vulnerability Assessment is to prevent instability, uncontrolled separation, Cascading and uncontrolled islanding of the System during a GMD event. Non-Consequential Load Loss and/or curtailment of Firm Transmission Service may be needed to meet BES performance requirements during studied GMD conditions but should not be used as the primary method of achieving required performance. GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Non-Consequential Load Loss or curtailment of Firm Transmission Service is minimized during a GMD event. • Proposed Language Footnote #4: The objective of the GMD Vulnerability Assessment is to prevent uncontrolled separation and Cascading of the System during a GMD event. Non-Consequential Load Loss and/or curtailment of Firm Transmission Service may be needed to meet BES performance requirements during studied GMD conditions but should not be used as the primary method of achieving required performance. GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Non-Consequential Load Loss or curtailment of Firm Transmission Service is minimized during a GMD event. Add: Dynamic simulation is not required.
No
Because of the need to obtain additional software, become familiar with the software, and collect the necessary data needed to construct the DC models required as part of the assessment process, we request additional time for items 1), 2), and 3) as outlined above. In

addition to constructing the necessary models of one’s own system, data for adjacent systems must be obtained and shared (See page 28 of the Application Guide). Allowing 12 months to develop the models and 24 months to perform the assessments is a good start, but additional time will be needed. We would like to have 24 months to develop the models and 36 months to perform assessments. We request that the entity be able to use either calculated Rgnd (equivalent resistance from the substation ground grid to remote earth), or measured Rgnd. Both NERC Application Guides imply that Rgnd should include the effects of before transmission shield wires and/or multi-grounded neutrals being connected Some existing Rgnd values may've been measured before transmission shield wires or multi-grounded neutrals were connected, or prior to a substation addition. Rather than require potentially burdensome measurement, allow the entity to make a calculated adjustment, if appropriate.
Individual
Eric Bakie
Idaho Power Company
Yes
Yes
Idaho Power System Planning agrees that the requirements in TPL-007 address the directives of FERC Order 779.
Yes
Idaho Power System Planning agrees that the proposed benchmark GMD event is technically justified and provides the necessary basis for conducting the assessments.
No
Idaho Power System Planning feels that the proposed time frame and sequencing proposed in the Implementation Plan is unrealistic; GMD modeling data is not as commonly available as other data types reported in current MOD Standards; thus additional time will be required for entities to compile the required GMD modeling data. IPCO System Planning feels that a realistic effective dates for R1 and R5 is 24 months and 36 months for R2, R4, and R6. The proposed timeframes for R7 and R8 are unrealistic; IPCO System Planning feels that the transformer assessments should be implemented in a phased percentage of the entity's applicable equipment over a 5 year period (20% per year starting with most vulerable transformers in the first 20% block; similar to the approach used in MOD-026/MOD-027). Idaho Power System Planning feels that a realistic effective date for R3 is 60 months. Idaho Power- Power Production Engineering believes the implementation plan is too aggressive. More time for phase-in should be allowed.
Group
Arizona Public Service Company
Janet Smith

NO - AZPS would like for the drafting team to align the inclusion threshold with those elements that are considered BES elements, based on the new revised definition of the BES that goes into effect July 1, 2014. In doing so, non-BES transformers should not be included. For example – if there is a transformer with a high-side connected at 200kV or higher with a low-side connected at 69kV, it should not be included unless included based on exception.
Yes
No
AZPS requests that the benchmark GMD event be comparable to a known event, such as the 1989 event in Quebec, to ensure that the benchmark appropriately simulates actual events.
No
AZPS would like for the Drafting Team to consider extending the overall Implementation Plan to a 5-year period, rather than the proposed 4-year period as written. Rather than the proposed 12 month period that has been set aside for Requirement 1, we request for the drafting team to allow an overall 24 month period. Much of the industry has no experience with respect to modeling GIC currents and using the new tools being developed; therefore, further education and learning would be needed for those responsible for performing the required studies. This will require significant company resources and the additional 12 months would provide a more reasonable time to accomplish.
Individual
Thomas Foltz
American Electric Power
Yes
The proposed requirements are precluding the engineering which should drive them. More studies are needed before best practices can be determined. For example, are the potential system impacts and utility of available mitigation options well understood? A neutral blocking device on an autotransformer may not provide the level of mitigation expected. This is due to the fact that an autotransformer has two paths for GIC flow – through the series winding connecting primary and secondary terminals and through the common winding connecting secondary and neutral terminals. Blocking the neutral only eliminates that portion of GIC flowing in the common winding. The GIC still flows through the series winding (albeit at a possibly reduced level) which still leads to half-cycle saturation and increased reactive power losses. The magnitude of these losses may possibly be reduced by blocking devices but not eliminated. How are the system and transformer models verified, and what confidence is there that what these models are providing is accurate? AEP disagrees with requiring thermal studies for all GO/TO transformers. Rather, the PC/TP should complete their GMD vulnerability assessment and identify where the risks are. GO/TO should be required to study only those transformers in the designated high risk areas based on the vulnerability study results.

Yes
Using statistical methods to derive the parameters of an essentially random process is completely justified. Also, ignoring very localized events in the derivation process is also justified on the basis that the system we are analyzing, and the effects we are studying, are spatially very widespread.
No
While the implementation plan is adequate for the system vulnerability assessments, it would not be adequate for the transformer thermal assessments, specifically for existing transformers for which the pertinent design and performance data needed for the assessments is not available. While AEP will make every attempt to obtain the data necessary for these assessments, some vendors have inferred that not all transformers will have readily available models (nor ways of generating them) from which to derive the required data from simulation. Further consideration will be required to determine the number of transformers where obtaining design and performance data proves problematic, and determine methods to address any unavailable data. Conducting physical testing of these units as an alternate means to derive the required data, is extremely problematic if not entirely impractical. The nature of this testing precludes any type of field test, as monitoring internal hot spot temperatures requires the transformer be retrofitted with thermal sensors. This retrofit can only be accomplished at a transformer manufacturing facility, as it requires the untanking of the unit. Therefore, any physical test would require taking the unit out service, prepping and then shipping the unit to a transformer manufacturing or test facility, retrofitting the unit with thermal sensors, conducting the tests, shipping the unit back to the substation, and finally, prepping and putting the unit back in service. Even if this process could be accomplished, most facilities are not able to conduct the required tests as the electrical sources needed are not strong enough to supply the required reactive power. In the event thermal models are not available, and physical testing is not feasible, would there be a way to develop standard models for each transformer design type? Such models could then be scaled with available data to provide a reasonable estimate of thermal performance. If so, these models could be used to estimate the performance for those units in which detailed data is not available. The 36 month time frame for the transformer thermal assessments is not adequate given the level of work required to obtain the required data. Furthermore, transformer manufacturers, who will be instrumental in this process, may not be able to fulfill the high demand for this service in the required time due to very little demand diversity. AEP is also concerned with what recourses are available, if after every reasonable attempt to obtain the required data have been exhausted, the data is still not available. It is unclear how often the TO/GO must repeat their R7 required thermal assessments. Is it every time the PC/TP repeats their GMD Vulnerability Assessment? Every 5 years? Never? Since there is no benefit in repeating a study when nothing has changed, AEP recommends the standard be revised to only require the TO/GO to repeat their thermal assessment if the GIC value from the PC/TP differs more than X% for the value used in the most recent thermal assessment. It is unclear of the timing between installing a new/spare transformer and completing the thermal assessment. The standard should address the timing of the completion of the thermal assessment compared to the installation of a system spare. It should be acceptable

to complete the thermal assessment within a designated time frame (i.e. 12 months) after a spare/new transformer has been installed. Requiring the assessment be completed prior to placing a spare in service could delay returning equipment to service following a failure and result in decreased BES reliability. As proposed, the implementation plan may unintentionally shorten the TO/GO implementation period based upon the responsiveness of the PC/TP. Consider the following: If the PC/TP takes the entire 24 month period to complete their assessment (Per R2) and then takes the entire 90 days to distribute the results to the TO/GO (Per R6), the TO/GO will only have approximately 9 months to complete their thermal assessments because they spent the first 27 months waiting on data from someone else. The issue could be resolved by revising the implementation plan to require the TO/GO to be 100% compliant with R7 and R8 36 months after regulatory approval or 24 months after receiving the GMD Vulnerability Assessment from the PC/TP, whichever is longer.
Individual
Brett Holland
Kansas City Power & Light
Agree
SPP - Robert Rhodes
Group
SPP Standards Review Group
Robert Rhodes
‘High side’ is not hyphenated in Applicability sections 4.1.1 thru 4.1.4. It is hyphenated in Requirement R7 and in the Comment Form. It is not hyphenated in the Implementation Plan. We suggest the drafting team be consistent in the handling of this term, whichever it chooses to use. Generation Owner in 4.1.4 should be Generator Owner.
No
FERC Order 779 requires assessments of Bulk-Power System transformers. The proposed standard establishes a threshold of 200 kV for the applicable transformers. Question 1 references the whitepaper associated with EOP-010-1 which provided the justification for the threshold in that standard. We concur with the 200 kV threshold but suggest that the drafting team make the linkage between that whitepaper and TPL-007-1 more clear, specifically referencing the previous whitepaper. Otherwise, it appears that the proposed standard falls short of the FERC Order. Requirement R3 requires the development of a Corrective Action Plan. Current TPL standards require Corrective Action Plans for N-1 and N-2 conditions but do not require them for N-3 and beyond. If impacts from a GMD event create N-3 or beyond conditions, this standard goes beyond existing practice to require Corrective Action Plans. Shouldn’t there be consistency within the standards in this area? Requirement R6 requires the responsible entities to provide GMD assessment results to any functional entity with a reliability related need within 30 days of the request. This requirement is too broad and open-ended. How does one determine what a valid reliability related need is? What qualifies that need as valid? Without additional clarification by the drafting team this could open

Pandora’s box. Here are some additional typo/grammatical suggestions for the proposed standard. Replace ‘New’ with ‘Newly’ in Requirement R1, Part 1.3. In multiple places throughout the requirements and in the VSLs, terms such as 30-calendar days, 90-calendar days and 60-calendar months should be hyphenated as shown. Also, in those places where the reference to ‘calendar’ has not been included, it should be included. This applies to all posted documents. In Requirement R2, the term ‘steady state’ is not hyphenated. In other places throughout the documents, the term is hyphenated. We encourage the drafting team to be consistent with the correct format throughout the posted documents. We believe the use of subparts is currently on the out at NERC. As used most recently in CIP-014-1, we suggest removing subparts 2.1.1 and 2.1.2 and replace them with bullets. In that case in the two bullets under Part 2.1, capitalize ‘Term’ in ‘…Near-term Transmisssion Planning Horizon.’ as it is a defined term in the NERC Glossary. Replace the ‘by’ in the 1st line of the Rationale Box for R4 with ‘be’. In Measure M5 ‘e-mail’ is hyphenated. In Measures M6 and M8 ‘email’ is used. We again encourage the drafting team to be consistent with the correct format whichever it may be. Replace the reference to Requirement R5 at the end of Measure M6 with Requirement R6. Delete ‘wye’ in the 4th line of Measure M8. In Table 1, insert an ‘a’ between ‘of’ and ‘P8’ in item b. under Steady State. The following are in Attachment 1: In the 3rd line of the 2nd bullet on Page 10, replace ‘geolectric’ with ‘geoelectric’. Insert a comma in the date at the top of Page 13; March 13-14, 1989. The following refer to the VSLs: Capitalize ‘Parts’ in the High and Severe VSLs for R3 and the Moderate and High VSLs for R7.
No
We believe the 2nd ‘conductivity’ in the 7th line of the last paragraph under the Statistical Considerations section on Page 9 should be deleted. In the 4th line of the 1st paragraph under the Extreme Value Analysis section on Page 12, ‘geo-electric’ is hyphenated. No where else in any of the documents is this term hyphenated. We suggest the drafting team be consistent with the use of this term throughout the documents. In the 1st paragraph under Table 1-1 on Page 13, replace’geolectric’ in the 2nd line with ‘geoelectric’. Insert a comma in the date in the last line of the paragraph under the Impact of Waveshape on Transformer Hot-spot Heating at the bottom of Page 16; March 13-14, 1989. Although this document mentions the difference between geographical and geomagnetic latitude, we suggest that the drafting team include support for the apparent 10 degree difference between the two quantities.
No
A 12 month implementation for Requirement R1 may be too short. This is for model development and it may take more than a year to research and establish the needed models. We suggest that the implementation for R1 be changed to 18 months and that it be coordinated with the MMWG effort. Since the assessments required in Requirement R2 cannot be conducted until the models have been developed, the implementation for R2 should also be extended by 6 months to 30 months and should be tied to the development of the models in R1. For consistency with the remaining requirements we suggest extending all the implementation periods by 6 months.
Individual

shirin.friedlander@ladwp.com
ladwp
Even though,LADWP's response is not addressing this specific question but we believe that the following comments are relevant to the applicability of the standard: LADWP would like to emphasize the regional differences based on geographical location due to the nature of GMD. Furthermore, LADWP believes that it is prudent to remove Registered Entities from the applicability of some requirements as long as they determine that GMD is of very low impact based on a simpler calculation (such as from the Geoelectric Field values) due to their geographical location. Attachment 1 of TPL-007-1 provides the means for calculating Geoelectric Fields for the Benchmark GMD Events. LADWP is proposing that the following language be added to the end of Sections 4.1.1 through 4.1.2 of the Applicability of TPL-007-1: “..and have determined that the Geoelectric Fields for the Benchmark GMD Events is more than XX[fill in the blank].”
Individual
Joshua Andersen
Salt River Project
SRP recommends the standard be applicable to the Reliability Coordinator(RC). SRP suggests that the RC determine which Planning Coordinators, Transmission Planners, Transmission Owners, and Generator Owners shall create and maintain GMD models per a GMD Vulnerability Assessment or a specific geomagnetic field scaling factor value. This will decrease the administrative burden on entities that are minimally affected by GMD events.
Yes
Yes
Yes
Individual
Anthony Jablonski
ReliabilityFirst
ReliabilityFirst submits the following comments for consideration: Applicability Section – ReliabilityFirst believes the Applicability language needs to be a little clearer. The white paper on applicability seems to be correct in identifying transformers, but in shortening it, some clarifying information has been lost. ReliabilityFirst recommends the following as an example

for consideration: “Planning Coordinator with a Planning Coordinator area that includes a power transformer(s) or auto-transformer(s) with a wye-grounded or wye-impedance grounded high side connected at 200 kV or higher” Applicability Section - GIC can be altered with the use of series capacitors on longer transmission lines. Thus, shouldn't applicability be expanded to include PC, TP, TO or GO with one or more "long" 200 kV and above transmission lines? Limiting applicability to transformer owners may limit available mitigation in Requirement R5. Entities serving load within one or two buses of a wye-grounded transformer may need to be involved in the study also. Otherwise, the solution of shedding load by UVLS once every 100 years may be ignored.
ReliabilityFirst submits the following comments for consideration: Requirement R1 - Requirement R1 references “supplemented by other sources as needed, including items represented in the Corrective Action Plan”. This is the first place the term “Corrective Action Plan” is referenced and it is unclear as to what “Corrective Action Plan” it is referring. If it is referring to the “Corrective Action Plan” required in Requirement R3, ReliabilityFirst recommends adding a reference to Requirement R3 in Requirement R1 such as “…including items represented in the Corrective Action Plan developed in Requirement R2 – There should be a hyphen in between the term “Near” and “Term” to be consistent with the NERC Glossary of Terms definition. Requirement R2, Part 2.1.1. – ReliabilityFirst believes the sub-part should use the NERC Defined term “On-Peak” instead of the undefined term “peak”. This would be consistent with Part 2.1.2 using the term “Off Peak”. Requirement R2 - There are Planning Coordinators and Transmission Planners in portions of the grid that have low susceptibility to GMD, due to being further south, and with low earth conductivity. The screening process outlined in: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf indicates that if voltage disturbance is less than 3% at capacitor banks, SVCs and transformers, with power flow quality data, then no further analysis needs to be required. Thus, Requirement R2 needs to be clarified. The GMD Vulnerability Assessment could consist of just the screening for 3% voltage disturbances and nothing more. Only if the 3% screening criteria is violated would it be necessary for the assessment to dig deeper into vulnerability of individual transformers, and search for violations of P-8. If the study shows no voltage disturbances over 3%, then the Planning Coordinator and Transmission Planner have no need for GMD voltage criteria (Requirement R4) or an impact analysis on each transformer (Requirement R7 and Requirement R8) Requirement R3, Part 3.1 – ReliabilityFirst recommends removing the “Examples of such actions include: “ language and modifying Part 3.1 as follows: “List System deficiencies and the associated actions needed to achieve required System performance such as, but not limited to:” Requirement R6 - ReliabilityFirst recommends clarifying the term “days” (i.e., is it calendar or business days?): “…a written request for the information within 30 [calendar] days of such a request. Requirement R8 – ReliabilityFirst recommends clarifying the term “days” (i.e., is it calendar or business days?): “…within 90 [calendar] days of completion…” Table 1 footnote 4 - In Table 1 footnote 4, ReliabilityFirst does not believe non-consequential load loss, or the curtailment of Firm Transmission Service should not be considered as the primary method of achieving required performance. This is a once in 100 year type event, and

UVLS could be the best choice for mitigation, and should not be discouraged by a TPL-007-1 standard. ReliabilityFirst recommends removing the following sentence from Table 1, note 4 “but should not be used as the primary method of achieving required performance”.
Group
Dominion
Louis Slade
Our response is that we agree.
No
Dominion is concerned with the sequence of activities that need to be followed to comply with the requirements. We suggest that all requirements be broken down, restructured, and re-organized so that they align with the actual steps of the process and have no circular dependencies. Following are examples of our concerns; • Before the applicable entity can comply with R2 (perform GMD Vulnerability Assessment), the PC and TP must comply with R5 (decide upon who does what in performing the assessmentIf Dominon understands R4 correctly (have criteria for steady-state voltage limits), it seems like something that should be done prior to or as part of R2 (perform studies). R2 requires an assessment of the Near-Term Transmission Planning Horizon, but the Time Horizon for the requirement is Long-Term Planning. We suggest the SDT make a change so that there is consistency. • By definition, a GMD Vulnerability Assessment includes consideration of localized equipment damage. The PC and TP cannot consider potential damage without the TO and GO having completed R7 (assessment of thermal impact) and R8 (provide thermal impact assessment to PC and TP). Also, the PC and TP cannot perform R3 (develop Corrective Action Plan) prior to the TO and GO completing R7 and R8 if the Corrective Action Plan is supposed to address equipment damage. However, the TO and GO cannot do R7 and R8 without the PC and TP having done R6 (distribute GMD Vulnerability Assessment and Corrective Action Plan) since the GIC studies are a pre-requisite of the thermal impact assessment. The last part of R6 includes a requirement to provide assessment results to any entity with a reliability need within 30 days of receiving a request from such an entity. Dominion suggests deleting this requirement (pursuant to P81) since it is an administrative task that does little, if anything, to benefit or protect the reliable operation of the BES.
Yes
Dominion is concerned about the website links back to the 2013-03 Project page in Attachement 1 and the Application Guidelines, how is NERC going to ensure these links will remain valid after the standard is approved? Going forward, Dominion suggests that any reference materials be included in this and other standards as attachments or appendices due to the concern mentioned above.
Yes

Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
Yes (no buttons were present in the electronic form)
No
[A] Alternating Current (AC) and Direct Current (DC) - On p. 3, Requirement R1 of the draft standard uses the phrase “maintain ac System models …” The Free Online Dictionary states that the abbreviation for alternating current is “AC” (capitalized) citing The American Heritage Dictionary. This definition makes no provision for the lower case abbreviation “ac.” alternating current, n. Abbr. AC An electric current that reverses direction in a circuit at regular intervals. The American Heritage® Dictionary of the English Language, Fourth Edition copyright ©2000 by Houghton Mifflin Company. Updated in 2009. Published by Houghton Mifflin Company. All rights reserved. See http://www.thefreedictionary.com/alternating+current Our recommendation is that the drafting team use the capitalized abbreviation “AC” in order to avoid any confusion with a potential typographical error “ac” of the two-letter word “as.” Since “AC” is not a NERC Glossary term nor is it defined in the draft standard, but is a term of art perhaps it should be spelled out and the abbreviation listed in parentheses, as with GMD and GIC. Further, it is our understanding that there are both AC and direct current (DC) components to Geomagnetically-Induced Currents (GIC’s). So, are AC models sufficient to capture the entire impact of a geomagnetic disturbance (GMD)? Assuming that both kinds of models are necessary, then Requirement R1 should read: R1. Each Planning Coordinator and Transmission Planner shall maintain [add: “alternating current (AC) and direct current (DC)”] [delete: “ac”] System models … In fact the Rationale Box on p. 4 supports this assertion where it states: “A GMD Vulnerability Assessment requires a dc GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. … The ac System model is used in conducting steady-state power flow analysis that accounts for the Reactive Power absorption of transformers due to GIC in the System.” Further support for the need for both AC and DC modelling comes from the Geomagnetic Disturbance Planning Guide, December 2013, which on p. 7 states: dc network model. The dc network consists of circuit resistances, transformer winding resistances, and station grounding resistances (see [2]). In principle, the model is straightforward, and has a high level of confidence so long as transmission line and transformer resistances are known. … And on p. 9 which states: 3.2 System Model - The dc equivalent system model is thoroughly discussed in the NERC GIC Application Guide [2]. And on p. 10, which states: • The dc network model should be consistent in size and scope with the ac model … • Equivalent circuits in the ac model are generally not directly translatable into dc equivalents. Guidance on dc network equivalent circuits is provided in the NERC GIC Application Guide. [B] Delete Requirement 2.1.2 on p. 4 Requirement R2. Peak-load conditions are all that matters. [C] Table 1 Footnotes Table 1, p. 8: Footnote 1 – The footnote simply repeats the initial condition statement, but could be expanded to provide examples.

No
GMD’s cover large regions, so it’s very important to have modelling data from neighboring regions, especially in the congested Northeast, in order to identify impacts from external equipment. How does the drafting team envision ensuring that actions taken in one area do not negatively impact entities in adjacent areas, e.g., PJM CAP negatively affecting NYISO entities. For example, a PJM CAP might result in GIC’s flowing on adjacent NYISO elements exacerbating the problem in NY. What recourse would an adjacent region have to prevent such actions from negatively impacting and shifting GMD-related costs to their region?
Yes
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC Planning Standards Subcommittee
Individual
Andrew Gallo
City of Austin dba Austin Energy
City of Austin dba Austin Energy (AE) supports CenterPoint Energy’s comments for this question.
Yes
City of Austin dba Austin Energy (AE) supports CenterPoint Energy’s comments for this question.
Yes
City of Austin dba Austin Energy (AE) supports CenterPoint Energy’s comments for this question.
Yes
City of Austin dba Austin Energy (AE) supports CenterPoint Energy’s comments for this question. Additionally, AE requests the Standard Drafting Team (SDT) provide an additional 12 months in the Implementation Plan for Requirement R1, for a total implementation time period of 24 months. As such and in combination with CenterPoint Energy’s recommendation to add one year for R5, AE recommends the SDT revise the Implementation Plan to read “Requirements R1 and R5 shall become effective on the first day of the first calendar quarter that is 24 months after the date that this standard is approved by an applicable governmental authority....” This additional time would allow entities to procure the necessary software and gather the unique inputs to the model required in R1 as well as fulfill the necessary coordination under R5. AE notes R2, R4 and R6 will be due within the same time frame (2 years), but AE believes that timeframe is still feasible.
Individual

George H. Baker
James Madison University
Agree
Foundation for Resilient Societies
Individual
Dianne Gordon
Puget Sound Energy
The language of the requirement as written does not sufficiently require the consideration of wide area effects. The Requirement states that GIC system models are to be maintained within the PC's respective area. The purview of the Planning Coordinator is too narrow for GIC studies done by individual PC's to provide meaningful results. Vulnerability assessment studies should be coordinated by the Reliability Entity at the regional level to accurately assess the Impacts GIC over wide areas. In order to produce meaningful results data must be shared among neighboring entities, not doing so could result in misleading GIC studies. Much of the data necessary to do a GIC assessment is not specifically included in required data set for Appendix 1 of MOD-032-1 standards. A sanctionable requirement holds accountable neighboring systems that may otherwise choose to withhold their data.
No
This draft standard directs applicable entities to collect data, and perform an individual GMD vulnerability assessment, develop the required mitigation plans, and share the study results with neighboring entities; it is lacking the provision that requires the entities to share the necessary modeling data to perform wide-area system impacts. Mitigation plans should be coordinated by the Reliability Entity at the regional level to avoid unintended consequences between PC areas. The standard should focus more on providing guidelines to direct entities to coordinate the resulting mitigation plans.
Yes
The benchmark GMD described from a reference peak geoelectric field as a high impact low frequency event that has been derived from statistical analysis of historical magnetometer data appears to be comparable to the more traditional TPL contingency analysis.
No
While we support the multi-phased approach to implement this standard, we still have some concerns that the 4-year period can be too short for the implementation. This standard requires an additional level of technical study using data that is not currently readily available; many entities do not have experience in conducting this type of study. The average cycle of solar maximum is 11 years, we suggest NERC to extend the implementation period of this standard beyond the 4 year timeframe referenced in the current draft.
Group
Duke Energy
Michael Lowman

Duke Energy would like to commened the SDT on the work they have done on this project and agree that the appropriate Functional Entities in the Applicablity Section of this standard were identified.
Yes
(1) Duke Energy suggests adding the flowing wording to R6 of this standard: “Each Planning Coordinator or Transmission Planner shall distribute its GMD Vulnerability Assessment results and Corrective Action Plan(s), if any, to adjacent Planning Coordinators, adjacent Transmission Planners, Transmission Owners ,Generator Owners, and Reliabity Coordinator in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 within 90 calendar days of completion, and to any other functional entity that demonstrates a reliability related need and submits a written request for the information within 30 days of such a request.” Since the RC is the responsible entity for developing, maintaining and implementing a GMD Operating Plan, we believe the RC should also be provided and made aware of the GMD Vulnerability Assesment(s) and Corrective Action Plan(s) in their respective RC area. We also believe that the decision on who will distribute the plan(s)/assessment(s) should have been identified in R5. By replacing “PC and TP” with “PC or TP”, this will remove the uncessary distiribution of the GMD Vulnerability Assesment and CAP to the same entitiy on multiple occasions and also clearly identify who is responsible for providing those assessments and plans. (2)Duke Energy suggest rewording M5 as follows: “Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that an agreement has been reached on individual and joint responsibilities for performing and distributing the required studies for the GMD Vulnerability Assessment in accordance with Requirement R5.” We believe this modification would add clarity on who is responsible for not only perfoming, but also distributing the required studies for the GMD vulnerability assesments.
Yes
Duke Energy agrees that the benchmark GMD is technically justified and addresses FERC order 779.
Yes
Duke Energy agrees with the a multi-phased approach to the Implementation Plan.
Individual
Angela P Gaines
Portland General Electric Compay
The language of the requirement as written does not sufficiently require the consideration of wide area effects. The Requirement states that GIC system models are to be maintained within the PC’s respective area. The purview of the Planning Coordinator is too narrow for GIC studies done by individual PC’s to provide meaningful results. Vulnerability assessment studies should be coordinated by the Reliability Entity at the regional level to accurately assess the Impacts GIC over wide areas. In order to produce meaningful results data must be

shared among neighboring entities, not doing so could result in misleading GIC studies. Much of the data necessary to do a GIC assessment is not specifically included in required data set for Appendix 1 of MOD-032-1 standards. A sanctionable requirement holds accountable neighboring systems that may otherwise choose to withhold their data.
No
This draft standard directs applicable entities to collect data, and perform an individual GMD vulnerability assessment, develop the required mitigation plans, and share the study results with neighboring entities; it is lacking the provision that requires the entities to share the necessary modeling data to perform wide-area system impacts. Mitigation plans should be coordinated by the Reliability Entity at the regional level to avoid unintended consequences between PC areas. The standard should focus more on providing guidelines to direct entities to coordinate the resulting mitigation plans.
Yes
The benchmark GMD described from a reference peak geoelectric field as a high impact low frequency event that has been derived from statistical analysis of historical magnetometer data appears to be comparable to the more traditional TPL contingency analysis
No
While we support the multi-phased approach to implement this standard, we still have some concerns that the 4-year period can be too short for the implementation. This standard requires an additional level of technical study using data that is not currently readily available; many entities do not have experience in conducting this type of study. The average cycle of solar maximum is 11 years, we suggest NERC to extend the implementation period of this standard beyond the 4 year timeframe referenced in the current draft.
Individual
Robert Coughlin
ISO New England Inc.
The organization of requirements is confusing. The SDT should reorganize the order in which the requirements are listed to group together requirements that cover a similar activity and that have the same “go live” dates under the implementation plan and to organize these groups in a sequence that follows a logical workflow. As illustrated below, organizing the requirements so that they read chronologically (according to Implementation Plan) makes it easier to understand. In addition, or alternatively, the SDT should include explicit language in the Requirements explaining the linkages amongst requirements. For example, until one reads the Implementation Plan, it is not obvious that information gathered pursuant to R7/R8 is meant to be an input to the work required under R3. Even though this can be understood after reading the Implementation Plan, the Standard requirements should explicitly link to each other, as applicable. Another example is R2/R5. While R2 requires completion of a GMD

Vulnerability Assessment, R5 separately requires PCs, along with each TP, to determine and identify individual and joint responsibilities for performing required studies for the GMD Vulnerability Assessment. A third example is that, although the Corrective Action Plan is referenced in in R1 and M1, it is not described in R1. Rather, it is described in R3. We suggest revising the reference in R1 to "the Corrective Action Plan developed under R3." In short, these requirements should not be divorced from each other. Listing the requirements chronologically as we propose below should help alleviate most of these issues. Requirements listed "Chronologically" Effective on the first day of the first calendar quarter that is 12 months after FERC approves: R1. Each Planning Coordinator and Transmission Planner shall maintain AC System models and geomagnetically-induced current (GIC) System models within its respective area for performing the studies needed to complete its GMD Vulnerability Assessment. The models shall use data consistent with that provided in accordance with the MOD standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P8 as the normal System condition for GMD planning in Table 1. R5. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify the individual and joint responsibilities of entities in the Planning Coordinator's area for performing the required studies for the GMD Vulnerability Assessment. Effective on the first day of the first calendar quarter that is 24 months after FERC approves R4. Each Planning Coordinator and Transmission Planner shall have criteria for acceptable System steady state voltage limits for its System during the GMD conditions described in Attachment 1 R2. Each Planning Coordinator and Transmission Planner shall complete a GMD Vulnerability Assessment of the Near Term Transmission Planning Horizon for its respective area once every 60 months. This GMD Vulnerability Assessment shall use studies, document assumptions, and document summarized results of the steady state analysis. R6. Each Planning Coordinator and Transmission Planner shall distribute its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 within 90 calendar days of completion, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. Effective on the first day of the first calendar quarter that is 36 months after FERC approves R7. Each Transmission Owner and Generator Owner shall conduct an assessment of thermal impact for all of its solely and jointly owned power transformers with high-side, wye-grounded windings connected at 200 kV or higher. R8. Each Transmission Owner and Generator Owner shall provide its assessment of thermal impact specified in Requirement R7 for all of its solely and jointly owned power transformers with high-side, wye-grounded windings connected at 200 kV or higher within 90 days of completion to the Planning Coordinator and Transmission Planner with responsibility for the area in which the associated power transformer is located. Effective on the first day of the first calendar quarter that is 48 months after FERC approves R3. Each Planning Coordinator and Transmission Planner that determines through the GMD Vulnerability Assessment conducted in Requirement R2 that its System does not meet the performance requirements of Table 1 shall develop a Corrective

Action Plan addressing how the performance requirements will be met. Also, please note the following: R6 and M6: - R6 requires distribution of the GMD Vulnerability Assessment to certain entities regardless of whether it is appropriate to do so. We recommend that distribution of the GMD Vulnerability Assessment be clarified and limited with wording such as "…each Planning Coordinator and Transmission Planner shall provide its GMD Vulnerability Assessment upon the request of a relevant Transmission Owner or Generator Owner in its respective planning area or of an adjacent Planning Coordinator or Transmission Planner." - M6 should include reference to distribution of results to relevant Transmission Owners, Generator Owners or adjacent Planning Coordinators or Transmission Planners that have requested the GMD Vulnerability Assessment. R7 – This requirement should refer to the GMD Vulnerability Assessment that was distributed to Transmission Owners and Transmission Operators as specified in R6.
Group
Bonneville Power Administration
Andrea Jessup
Yes.
Yes
BPA feels that the current state and maturity of transformer modeling does not provide modeling which is universally available for all transformers, and less available (if at all) for older transformers that are not of a current design, as would be manufactured today. Approximations may be useful in ruling out concern if the transformer sees little impact from Geomagnetically-Induced Current (GIC), even with approximate characteristics' modeling, but may leave doubt as to how impacted the transformer would be under significant GIC flow. The transformer behavior modeling still needs significant advances to be considered completely reliable. BPA also suggests consolidating language referring to Corrective Action Plans in either R1 or R3, to eliminate the possibility of violating both R1 and R3 for the same reason. Likewise, footnote 4 in Table 1 should not instruct on the content of the GMD Operating Procedures required by EOP-010-1. If this language is necessary, it should be incorporated in a future revision to the relevant reliability standard.
Yes
BPA believes that the overall concepts appear technically sound, but industry study tools are not yet configured to input the benchmark event, along with geomagnetic latitude and geographic earth resistivity parameters. Additionally, it is unknown whether the application of the benchmark model will produce results with the consistency and accuracy needed for operating decisions, and electrical system modifications to significantly mitigate GIC impact. This will require actual use and experience with the benchmark model. It should, however, inform on whether a network change significantly improves or worsens the situation.
Yes
Individual

Patrick Farrell
Southern California Edison Company
Yes. SCE agrees with the selection of functional entities by the drafting team.
Yes
Yes
Yes
Group
SERC Planning Standards Subcommittee
Jim Kelley
Yes, we agree.
No
The SDT respectfully requests the SDT to consider removing the term(s) “posture or posturing” and use language such as “changes to system configuration or configuration” to add further clarification in response to warnings of a geomagnetic disturbance, and application of the effects of the geomagnetic disturbance itself, and removal of any reactive power devices and Transmission Facilities due to Protection System operation which define the contingency category P8. Two examples of this requested change follow: Rationale for R1. Current language: The projected System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information. These adjustments could include recalling or postponing maintenance outages, for example. Language for Consideration: The projected System condition for GMD planning may include adjustments to system configuration to the System that are executable in response to space weather information. These adjustments could include recalling or postponing maintenance outages, for example. A second example can be found on page 8, Table 1, Initial Condition: Current Language: 1. System as may be postured in response to space weather information, and then Language for Consideration: 1. System as may be configured in response to space weather information, and then Further, it is requested to have SDT clarify whether it is the SDT intention that there are any other contingency events that should be applied as part of the geomagnetic disturbance assessment work? On page 8, Table 1, Steady State A: The PSS requests the SDT to consider removing possible dynamic implications by considering the following change: Current Steady State A language: The System shall remain stable. Cascading and uncontrolled islanding shall not occur. Language for Consideration: Cascading and uncontrolled islanding shall not occur. On page 8, Table 1, Steady State Performance Footnotes #4: The PSS requests the SDT to consider removing possible dynamic implications by considering the following change: Current Footnote #4 language: The objective of the GMD Vulnerability Assessment is to prevent instability,

uncontrolled separation, Cascading and uncontrolled islanding of the System during a GMD event. Non-Consequential Load Loss and/or curtailment of Firm Transmission Service may be needed to meet BES performance requirements during studied GMD conditions but should not be used as the primary method of achieving required performance. GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Non-Consequential Load Loss or curtailment of Firm Transmission Service is minimized during a GMD event. Language for Consideration: The objective of the GMD Vulnerability Assessment is to prevent uncontrolled separation and Cascading of the System during a GMD event. Non-Consequential Load Loss and/or curtailment of Firm Transmission Service may be needed to meet BES performance requirements during studied GMD conditions but should not be used as the primary method of achieving required performance. GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Non-Consequential Load Loss or curtailment of Firm Transmission Service is minimized during a GMD event. Add: Dynamic simulation is not required.
No
The SDT is requested to consider modification of the Implementation Plan for TPL-007-1 – Transmission System Planned Performance during Geomagnetic Disturbances, Effective Dates. Because of the need to obtain additional software, become familiar with the software, and collect the necessary data needed to construct the DC models required as part of the assessment process, we request additional time for items 1), 2), and 3) as outlined above. In addition to constructing the necessary models of one's own system, data for adjacent systems must be obtained and shared (See page 28 of the Application Guide). Allowing 12 months to develop the models and 24 months to perform the assessments is a good start, but additional time will be needed. We would like to have 24 months to develop the models and 36 months to perform assessments. In addition, there is concern that it will take considerable time to calculate values of Rgnd, based on location dependent earth resistivity and ground mat design at each substation. If actual measurements of Rgnd are required, we can only practically measure Rgnd at in-service substations with all neutral connections and static wires in place. Are calculated values of Rgnd sufficient? The comments expressed herein represent a consensus of the views of the above named members of the PSS only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Individual
Gul Khan
Oncor Electric Delivery Company LLC
Oncor believes that the functional entities identified in the standard have been correctly identified. R5 states "Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify the individual and joint responsibilities of entities in the Planning Coordinator's area for performing the required studies for the GMD

Vulnerability Assessment.” It would be more feasible to perform this function prior to R2 which is when the GMD assessment is completed. Using that rationale having R4/M4 along with R5/M5 prior to R1/M1, and R2/M2 would allow for proper preparation before the completion of the assessment.
Yes
Oncor agrees that the technical guidance for the Vulnerability Assessments meet the directives of Order 779
Yes
Oncor strongly supports the proposed benchmark GMD event believing it to be technically sound reflecting good engineering practices as typically employed by electric utilities. All of these requirements have been fully addressed in a manner that we believe to be reasonable and defensible based on the current state and understanding of severe space weather and its impact on the BPS. The SDT based their Benchmark event on a 1 in 100 year event, which exceeds normal utility practices by a factor of 2 for earth based weather related catastrophic event analysis. Oncor sees great benefit in the calculation of the regional geoelectric field peak amplitude using a scaling factor to account for local geomagnetic latitude, and a scaling factor to account for the local earth conductivity structure.
Yes
Oncor supports the proposed Implementation Plan believing that it provides sufficient time for entities to effectively assess and develop Corrective Action Plans. The timeframe may appear long to outside observers but is short for the first time application by many different entities in the process.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. Comments: It is well-recognized in the industry that single-phase transformers, are generally used on 500 kV-and-up generator step-up transformers (GSUs),which are much more susceptible to geomagnetic disturbances (GMDs) than are the three-phase GSUs used at lower voltages. Susceptibility also varies with latitude, as described in NERC’s GMD publications. Before making the standard applicable at the 200 kV threshold, it would be appropriate for the SDT to perform a screening study to determine the transformer types and locations for which GMD-related analyses are justified, rather than imposing obligations relating to facilities where there may be little or no benefits.
No

NERC’s Transformer Thermal Impact Assessment White Paper states on p.9 that GOs and TOs are to analyze the impact of GMDs on applicable transformers based on manufacturer capability curves or via calculating thermal response as a function of time. We (and probably almost all entities) have no manufacturer capability curves for geomagnetically-induced current (GIC) It is not reasonable to expect that such information will become available for equipment that was designed and manufactured in most cases decades ago. Calculating thermal response as a function of time is consequently the only methodology available, and the Transformer Thermal Impact Assessment White Paper states on p.9 that one can then use measurements (i.e. the results of owner-conducted tests), manufacturer’s calculations or generic published values. No guidance is given on how to conduct GIC testing on transformers, nor is it conceivable that GOs and TOs could perform such experiments on in-service equipment, and manufacturer calculations are once again not available. This situation leaves GOs and TOs dependent on generic GIC capability curves, which NERC’s Geomagnetic Disturbance Planning Guide says on p.12, are available in reference #3, the NERC Transformer Modeling Guide. This document is shown as being “forthcoming” however, and we have been unable to obtain other sources of generic data. Thus, the tools required to fulfill requirement 7 of TPL-007-1 do not presently exist. The Transformer Modeling Guide should set forth a step-by-step calculation methodology taking one from the GIC flow inputs of TPL-007-1 requirement 7.1 to a final-product thermal response trend, using NERC-published generic thermal response curves that cover all transformer types, sizes and situations. We will comment on this document once it is published, but until then we cannot support TPL-007-1.
Yes
No
: The tools necessary to justify casting an affirmative ballot do not presently exist, as explained above. Additionally, there is more involved here than just, “studies, assessments, and procedures.” Requirement 3 of TPL-007-1 states that any deficiencies identified in the study by the PC/TP are to be addressed by a Corrective Action Plan (“CAP”), which may include calls for, “installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment,” and “installation, modification, or removal of Protection Systems or Special Protection Systems.” It is unclear in the standard as presently written whether or not the modifications listed in the CAP will constitute binding obligations; Requirement 6 says that GOs and TOs will be given this document, but not that they need to implement it. We raised this point in the 5/20/2014 webinar, and the SDT advised that the intent of the Standard was to provide for a means of creating and sharing relevant information, not to give the PC/TP the ability to require a GO to take mitigation actions (including potentially capital projects). The SDT stated that requirement 3 will be modified accordingly, and we support this action. . Requirement 5 also creates concern in saying that PCs and TPs shall, “determine and identify the individual and joint responsibilities of entities in the Planning Coordinator’s area for performing the required studies for the GMD Vulnerability Assessment.” It had seemed that the scope of GO/TO studies is covered in R7, but R5 indicates that more responsibilities for analysis may be assigned in the future, and we

have no way of presently knowing whether or not the supplemental demands made will prove feasible. R5, like R3, is too open-ended.
Group
Florida Municipal Power Agency
Frank Gaffney
It is clear the GMD does not materially impact the BES for those portions of the BES further south in latitude. Causing these entities to perform studies just to show that there is no impact is a waste of time and expense. FMPA suggests making the standard applicable to only those entities for which the furthest north portion of their system is south of a certain latitude, e.g., 32 degrees North geographic latitude (equivalent to 41.61 degrees north geomagnetic latitude). Those entities whose systems are affected are required to share the results of their analyses with their neighbors, as such, those entities below a certain latitude can develop their operating plans based on how GMD impacts their neighbors. If the SDT does not agree with this approach, then, FMPA recommends that a variance be created for FRCC, which was entirely unaffected by the Hydro-Quebec event and would have minimal impacts for even something as major as a Carrington event even in accordance with overly conservative studies performed by Oak Ridge National Labs. FMPA notes there is no valid scaling factor (β) defined by the standard in Table 1-2 for peninsular Florida. In addition, regarding the content of the statements in 4.1.1 through 4.1.4, FMPA points out that the term “power transformer”, while being defined broadly by IEEE, is understood within the transformer manufacturing industry to mean something specific. Many entities consider “power transformers” to be different from “autotransformers” and “generator step-up transformers”. FMPA suggests clarifying the intent is the IEEE definition from ANSI C57.12.80, which is an umbrella under which autotransformers and GSU transformers fall as sub-categories, “A transformer that transfers electric energy in any part of the circuit between the generator and the distribution primary circuits”. Adding on to this, because the applicability discusses wye-grounded windings, suggest that the “brightline” at 200-kV be clarified to be “system voltage” or phase-phase voltage.
No
FMPA commends the SDT for developing a good approach to performing the studies, FMPA’s comments are not major. R8 uses the phrase “solely or jointly owned” (which we know is also used in other standards like FAC-008). FMPA suggests adding to this “solely or jointly owned … transformers … for which is it registered”. If a transformer is jointly owned, only one of the owners will be registered for that transformer, i.e., the registry criteria states that the TO is: “(t)he entity that owns and maintains transmission Facilities”; hence, only the joint owner responsible for maintenance of the transformer is registered for that transformer. Adding such language will help avoid confusion. Also, on Table 1, FMPA appreciates the difficulty in trying to draw a distinction between acceptable and unacceptable system behavior during a GMD event, e.g., item b. at the top of the table and bullet 4. at the bottom of the table are good additions. FMPA wonders, however, if bullet 4. prevents UVLS as a potential mitigation by the phrase: (non-consequential load loss) “should not be used as the primary method of

achieving required performance". Transformer saturation that does not threaten the health of a transformer may still threaten voltage collapse and UVLS may be a good mitigation; however, bullet 4 seems to prevent that. FMPA also notes that bullet 3. identifies harmonic effects as the reason Protection Systems may trip. We are concerned entities will interpret this as being direction to assume this would be the only reason for such protective action. We would assert that an even more common and prevalent Protection System operation that should be modeled would be tripping for under voltage conditions (such as at power plants) and tripping of transformers due to overheating (where such tripping is utilized), as well as excessive reactive flow in the system. FMPA suggests modifying the statement to say "…due to system conditions including (but not limited to) excessive harmonic current/voltage, abnormal voltages and reactive power flow, and excessive equipment heating".
Yes
Yes
Group
SERC Planning Standards Subcommittee
Jim Kelley
Yes, we agree.
No
The SDT respectfully requests the SDT to consider removing the term(s) "posture or posturing" and use language such as "changes to system configuration or configuration" to add further clarification in response to warnings of a geomagnetic disturbance, and application of the effects of the geomagnetic disturbance itself, and removal of any reactive power devices and Transmission Facilities due to Protection System operation which define the contingency category P8. Two examples of this requested change follow: Rationale for R1. Current language: The projected System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information. These adjustments could include recalling or postponing maintenance outages, for example. Language for Consideration: The projected System condition for GMD planning may include adjustments to system configuration to the System that are executable in response to space weather information. These adjustments could include recalling or postponing maintenance outages, for example. A second example can be found on page 8, Table 1, Initial Condition: Current Language: 1. System as may be postured in response to space weather information, and then Language for Consideration: 1. System as may be configured in response to space weather information, and then Further, it is requested to have SDT clarify whether it is the SDT intention that there are any other contingency events that should be applied as part of the geomagnetic disturbance assessment work? On page 8, Table 1, Steady State A: The PSS requests the SDT to consider removing possible dynamic implications by considering the following change: Current Steady State A language: The

System shall remain stable. Cascading and uncontrolled islanding shall not occur. Language for Consideration: Cascading and uncontrolled islanding shall not occur. On page 8, Table 1, Steady State Performance Footnotes #4: The PSS requests the SDT to consider removing possible dynamic implications by considering the following change: Current Footnote #4 language: The objective of the GMD Vulnerability Assessment is to prevent instability, uncontrolled separation, Cascading and uncontrolled islanding of the System during a GMD event. Non-Consequential Load Loss and/or curtailment of Firm Transmission Service may be needed to meet BES performance requirements during studied GMD conditions but should not be used as the primary method of achieving required performance. GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Non-Consequential Load Loss or curtailment of Firm Transmission Service is minimized during a GMD event. Language for Consideration: The objective of the GMD Vulnerability Assessment is to prevent uncontrolled separation and Cascading of the System during a GMD event. Non-Consequential Load Loss and/or curtailment of Firm Transmission Service may be needed to meet BES performance requirements during studied GMD conditions but should not be used as the primary method of achieving required performance. GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Non-Consequential Load Loss or curtailment of Firm Transmission Service is minimized during a GMD event. Add: Dynamic simulation is not required.
No
The SDT is requested to consider modification of the Implementation Plan for TPL-007-1 – Transmission System Planned Performance during Geomagnetic Disturbances, Effective Dates. Because of the need to obtain additional software, become familiar with the software, and collect the necessary data needed to construct the DC models required as part of the assessment process, we request additional time for items 1), 2), and 3) as outlined above. In addition to constructing the necessary models of one's own system, data for adjacent systems must be obtained and shared (See page 28 of the Application Guide). Allowing 12 months to develop the models and 24 months to perform the assessments is a good start, but additional time will be needed. We would like to have 24 months to develop the models and 36 months to perform assessments. In addition, there is concern that it will take considerable time to calculate values of Rgnd, based on location dependent earth resistivity and ground mat design at each substation. If actual measurements of Rgnd are required, we can only practically measure Rgnd at in-service substations with all neutral connections and static wires in place. Are calculated values of Rgnd sufficient? The comments expressed herein represent a consensus of the views of the above named members of the PSS only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Individual
Paul Didsayabutra
ColumbiaGrid

: The language of the requirement as written does not sufficiently require the consideration of wide area effects. The Requirement states that GIC system models are to be maintained within the PC's respective area. The purview of the Planning Coordinator is too narrow for GIC studies done by individual PC's to provide meaningful results. Vulnerability assessment studies should be coordinated by the Reliability Entity at the regional level to accurately assess the Impacts GIC over wide areas. In order to produce meaningful results data must be shared among neighboring entities, not doing so could result in misleading GIC studies. Much of the data necessary to do a GIC assessment is not specifically included in required data set for Appendix 1 of MOD-032-1 standards. A sanctionable requirement holds accountable neighboring systems that may otherwise choose to withhold their data.
No
This draft standard directs applicable entities to collect data, and perform an individual GMD vulnerability assessment, develop the required mitigation plans, and share the study results with neighboring entities; it is lacking the provision that requires the entities to share the necessary modeling data to perform wide-area system impacts. Mitigation plans should be coordinated by the Reliability Entity at the regional level to avoid unintended consequences between PC areas. The standard should focus more on providing guidelines to direct entities to coordinate the resulting mitigation plans.
Yes
The benchmark GMD described from a reference peak geoelectric field as a high impact low frequency event that has been derived from statistical analysis of historical magnetometer data appears to be comparable to the more traditional TPL contingency analysis.
No
: While we support the multi-phased approach to implement this standard, we still have some concerns that the 4-year period can be too short for the implementation. This standard requires an additional level of technical study using data that is not currently readily available; many entities do not have experience in conducting this type of study. The average cycle of solar maximum is 11 years, we suggest NERC to extend the implementation period of this standard beyond the 4 year timeframe referenced in the current draft.
Individual
Bill Fowler
City of Tallahassee, TAL
No. 1. While TAL believes it is the intent of the standard to include autotransformers, it should be pointed out that the standard specifically specifies "power transformers", which technically are different than "autotransformers". Additionally, "power transformer" is not defined in the NERC Glossary of Terms. 2. TAL believes the intent is to include transformers with a system voltage greater than 200KV, but the current language may not always be interpreted this way. In the applicability section of EOP-010-1 (Phase 1 of the project) the language specifies a terminal voltage of greater than 200KV. In the applicability section of TPL-007-1 the language has omitted "terminal voltage", and specifies a single high side, wye-

grounded winding of greater than 200KV. This may be interpreted as a phase to ground voltage (rather than a phase to phase voltage), meaning a 115KV/230KV, 3 phase, wye grounded autotransformer could be excluded from the standard. 3. Compared to Northern geographic regions, studies (including the 2012 NERC report Effects of Geomagnetic Disturbances on the Bulk Power System) show a very low probability (less than 0.0002%) for large geomagnetic events where dB/dt > 300nT/minute for the geomagnetic latitude of FRCC utilities. TAL recommends that a path be supplied for a region as a whole to submit for a regional variance/exemption from the requirements of the standard.
No
The TPL standard should better define which "Bulk-Power System transformers" mentioned in the NOPR, are to be assessed. If the intent is include autotransformers, it should be pointed out that as it is currently written, the standard specifically specifies "power transformers", which technically are different than "autotransformers".
No
It seems that parameters involved with GMD events and associated GIC's are still being widely studied and disputed. It would be prudent to submit the "Benchmark GMD Event Data" for a peer review of experts based in the area of Space Science/Physics.
No
While TAL currently supports the phased implementation of TPL-007-1 as written, over the four year period, we believe that measures must also be taken to coordinate the phasing of the TPL-007-1 reliability standard with EOP-010, which was created during Phase one of this project. Without first receiving data from either the TPL-007-1 assessments or studies that allow for a geographic exemption to requirements in TPL-007-1, there will be no baseline from which to properly implent EOP-010. On measures: The language should be expanded to allow for posting the reports on regional websites (such as ftp sites) to fulfill the sharing requirements.
Individual
Jonathan Appelbaum
The United Illuminating Company
Yes
Yes
No
UI believes the implementation for R2 should clarify that the assessment is to be completed no later than the effective date of R2. For R3, UI does not understand why and the implementation plan does explain the reason for R3 (corrective Action Plan) to be effective 24 months later than the required R2 assessment. Many existing Standards require a CAP to be developed but none provide two years to create one. For consistency with TPL-001-4, PRC-

005-2, CIP-007, or CIP-014 the CAP for TPL-007 shoud become effective concurrent with or within 120 days of R2.
Group
MRO NERC NSRF
Joe DePoorter
The NSRF suggests the SDT revise the Purpose of TPL-007-1 to include R7 and R8 where GO and TO are required to perform assessment of thermal impact. Since the standard clearly states the TO and GO are responsible for the assessment of the impact of GIC on their transformers, the purpose of the standard should be revised to include this fact, recognizing that this is not just a TP assessment. Suggested Purpose: “Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events within the Near-Term Transmission Planning Horizon and establish requirements for assessing the thermal impacts of GIC on owned power transformers.” The standard is not clear on the proper sequencing of assessments between the TP and PC versus TO and GO. First, TP and PC should give powerflow results to TO and GO. Then TO and GO should provide their assessment of thermal impact specified in R7 to TP and PC. Next TP and PC should complete their assessments. The NSRF believes initial assessments of thermal impacts may well take more than 24 months, so to meet the sequences for all responsible entities either this timeframe needs to be expanded or provisions made for not completing thermal impacts for all transformers during the intial cycle. The NSRF also believes that some transformers have been built by manufacturers no longer in business and some transformers are old enough that manufacturers do not have sufficient information for TOs and GOs to complete thermal impact assessments. Provisions must also be made for such situations where thermal impacts cannot be completed and yet PCs and TPs need to complete their GMD Vulnerabililty Assessments within 24 months and, in some cases, at all.
Yes
: Although the NSRF agrees that the requirements in TPL-007-1 address the Order No. 779 directives for GMD Vulnerability Assessment, we recommend the SDT consider the following alternative language in requirments R1, R3, R5, R7, and Note 3: Table #1 The NSRF suggests the SDT remove the requirement to maintain ac System models in R1 to prevent the possibility of double jeopardy, as the requirement to maintain ac System models is already covered in Standard TPL-001-4 R1. The recommended wording for R1 is: “Each Planning Coordinator and Transmission Planner shall maintain (delete: ac System models and) geomagnetically-induced current (GIC) System models within its respective area for performing the studies needed to complete its GMD Vulnerability Assessment. The models shall use data consistent with that provided in accordance with the MOD standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P8 as the normal System condition for GMD planning in Table 1. The System models shall include...” The NSRF suggests the SDT revise R3.1 as there may be other facilities such as distribution facilities for customers served directly by transformation from 200 kV and up that are

appropriate fo rinclusion in a Corrective Action Plan. The revised wording is noted below: 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 (delete: associated)other facilities or equipment. • Installation, modification, or removal of Protection Systems or Special Protection Systems. • Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan. • Use of Demand-Side Management, new technologies, or other initiatives. The NSRF suggests the SDT revise R3.2 as there may be other components of Corrective Action Plans such as distribution facilities for customers served directly by transformation from 200kV and up. The revised wording is noted below: Be reviewed in subsequent GMD Vulnerability Assessments for continued validity and implementation status of identified System Facilities, Operating Procedures and other components of Corrective Action Plans. The NSRF suggests the SDT revise R5 and corresponding change to M5 because there are other responsibilities beyond the required studies in R1 through R4 that require a resolution of responsibilities. The revised wording is listed below: Each Planning Coordinator, in conjuction with each of its Transmission Planners shall determine and identify the individual and joint responsibilities of entities in the Planning Coordinator's area for performing the Requirements R1 through R4 (delete:required studies for the GMD Vulnerability Assessment). In Requirement 6 the NSRF suggests the SDT consider potential R6 conflict with Critical Energy Infrastructure Information (CEII) and CIP requirements relating to reliability issues. A recommended change is noted below: Each Planning Coordinator and Transmission Planner shall distribute its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 within 90 calendar days of completion, and to any functional entity that has a reliability related need ", permission to receive assessments," and submits a written request for the information within 30 days of such a request. The NSRF suggests the SDT consider clarifying that the thermal impact assessment may not need to be completed in each cycle for each transformer. The revised wording is listed below: Each Transmission Owner and Generator Owner shall have a current valid assessment of thermal impact for all of its solely and jointly owned power transformers with high-side, wye-grounded windings connected at 200 kV or higher. The NSRF believes there is no reasonable way to conduct the harmonics assessment required by Note 3, Table 1 at this time. We suggest the requirement be removed or the SDT describe how the harmonics assessment can be completed in the guidance document. Also, we suggest that if Note 3 to Table 1 is retained, it be changed to: Protection Systems may trip due to the effects of harmonics. P8 planning analysis shall consider removal of equipment that the planner determines may be susceptible to tripping. In the event harmonics assessment tools are not available, known or assumed values may be used, along with the assumptions utilized. The NSRF believes that the term BES should be added to R7 and R8 and read as: R7. Each Transmission Owner and Generator Owner shall conduct an assessment of thermal impact for all of its solely and jointly owned BES power transformers with high-side, wye-grounded windings connected at 200 kV or higher. The assessment shall: [Violation Risk Factor: High] [Time Horizon: Long-term

Planning] R8. Each Transmission Owner and Generator Owner shall provide its assessment of thermal impact specified in Requirement R7 for all of its solely and jointly owned BES power transformers with high-side, wye-grounded windings connected at 200 kV or higher within 90 days of completion to the Planning Coordinator and Transmission Planner with responsibility for the area in which the associated power transformer is located. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]”
Yes
The NSRF supports the proposed Benchmark GMD event, but we are concerned that data in Table II-2 (Geoelectric Field Scaling Factors) may not be accurate for all regions located in the IP1 earth model. The Benchmark GMD Event is represented by the SHIELD region on Figure II-3: Physiographic Regions of North American and the Geoelectric Field Scaling Factor is 1.0. The one reading for the IP1 earth model is measured relatively close to the SHIELD and the scaling factor is 0.94. However the IP1 model includes a very large portion of the US map. The NSRF believes that this scaling factor is inappropriate and is not representative of all the US regions included in the IP-1 earth model particularly the lower parts of the region such as the state of Iowa that exhibits low resistivity that the 0.94 scaling factor is clearly too high. We recommend that the Scaling Factors be reviewed for accuracy, compared to actual readings, etc. and be refined prior to being included as a reference.
No
The NSRF believes initial assessments of thermal impacts may well take more than the 3 years (if the revised language for Note 3 is not accepted) that are allowed for R7, so either this timeframe needs to be expanded or provisions made for not completing thermal impacts for all transformers during the intial cycle. We also believe that some transformers have been built by manufacturers no longer in business and some transformers are old enough that manufacturers do not have sufficient information for TOs and GOs to complete thermal impact assessments so provisions need to be made for that as well in R7. Also see the discussion in Question 1 above concerning sequencing issues in the implementation process.
Group
PacifiCorp
Sandra Shaffer
PacifiCorp does not agree with the proposed threshold for transformers. The requirement should be based on whether the transformer is classified as Bulk Electric System AND 200 kV or above high side connection. The threshold should result in the inclusion of only “critical Bulk-Power System facilities.” The proposed threshold would bring numerous non-critical distribution substation (230-34.5 kV and 230-12.5 kV) facilities into the analysis, as well as non-critical 230-69 kV local transmission facilities the loss of which would have no impact on the Bulk Electric System. Because a GMD event is an interconnection wide event and its impacts could be throughout the interconnection, it requires accurate modeling of the whole interconnection wide system to calculate the GIC currents. PacifiCorp believes that the responsible entity to perform the functions required in the draft standard should be the Regional Reliability Organization (RRO). By performing the study at the regional level, the

assumptions, findings and subsequent recommendations would be applied consistently across the region. Also, with the RRO performing the studies, it can be ensured that the mitigation action taken by one TP does not negatively impact the neighboring TP. As a practical matter this study can be performed by a task force of Planning Coordinators, Transmission Planners, etc. acting on behalf of the RRO.
No
Per the drafting committee webinar presentation on 05/20/2014, they would like the PCs and TPs to perform outages of transmission elements or generators that have a potential to trip during a GIC event due to harmonics as part of the GMD Vulnerability Assessment. To date, there is no commercial software available that determines the harmonics and its impacts on transmission element. Since it is therefore difficult to determine whether or not a particular transmission element will be tripped or not; the drafting committee need to provide guidelines as to what different outages a TP and/or PC needs to take as part of the GMD Vulnerability Assessment until such capabilities are developed/available in commercial software.
Yes
PacifiCorp supports the proposed Benchmark GMD event, but we are concerned that data in Table 1-2 (Geoelectric Field Scaling Factors) may not be accurate for all regions located in the earth model. We recommend that the Scaling Factors be reviewed for accuracy, compared to actual readings, etc. and be refined prior to being included as a reference.
No
PacifiCorp is concerned that the thermal impact assessment may require test information that is not available. This could include old transformers for which manufacturer records are no longer available. There needs to be a provision for these situations to ensure consistent modeling applications. Also, it is not clear whether the result of the assessment of thermal impacts would be incorporated into the study described under R2. If the thermal impacts need to be considered in the study described by R2, then the timeline for R2 needs to be expanded. As GMD is an interconnection wide event, in order to calculate the GIC, the responsible entity should be required to have a model for the whole interconnection. The draft standard should provide 18 months to the applicable entities to allow collection of the data required to produce the dc system model and ac system models (both electrical and thermal) to perform GMD Vulnerability Assessment. Requirement 1 of TPL-007 should be effective 18 months after the FERC effective date.
Group
ACES Standards Collaborators
Ben Engelby
(1) We have a concern with the responsibilities assigned to both the Planning Coordinator and Transmission Planner concurrently. The drafting team should apply a single function as responsible to maintain models, complete vulnerability assessments, and completing Corrective Action Plans. Other standards projects attempted to assign a shared responsibility

to both the PC and TP, which led to confusion regarding what roles each entity was ultimately responsible for performing. We recommend that the PC should be the entitiy responsible for maintaining the GMD models and performing GMD Vulnerability Assessment since it is the entity that has a wide area view and GICs are not bounded by transmission planning areas and it has the processes and tariff requriements in place already to coordinate with its Transmission Planners. For those areas without these tariffs and processes, the PC and TP are typically the same entity. Furthermore, by requiring a single entity such as the PC it avoids the compliance confusion of who actually is responsible and avoids the need to write requirements such as R5 that includes superfluous language such as "in conjuction with each of its Transmission Planners." This language is superfluous because the requirement apply only to the PC and cannot be enforced on the TP and should be removed. (2) Since the applicability only applies to the high side of the power transformer, this raises the question if the standard intends to expand applicability beyond the BES. As written, the standard would appear to be applicable to a 230/69 kV transformer with a wye-grounded high side. However, that transformer does not meet Inclusion I1 of the BES definition and, thus, would not be part of the BES. Is the intent to expand the definition beyond the BES? Please make clarifying changes to the standard to clear this issue up.
Yes
We believe the drafting team provided reasonable technical justification to address the directives in FERC Order No. 779. However, we have a few overarching concerns that are stated in questions 3 and 4.
No
(1) Requirements R6 and R8 meet Paragraph 81 criteria and should be removed. These requirements only deal with data requests and submittals, which is one of the criterion of Paragraph 81. Please revise or remove these requirements from the standard. (2) In Table 1 – Steady State Performance Footnotes, footnote 4 states that non-consequential load loss or curtailment of firm transmission service may be needed to meet BES performance. This may raise similar questions to the TPL footnote b. Will there be a limit on the non-consequential load loss similar to the resolution of the TPL footnote b issue?
No
(1) A four year implementation seems reasonable on paper, but the drafting team needs to take into account the other NERC standards that are going through implementation periods during this time, the significant learning curve of performing these new GMD studies, and the time to develop these new models using limited resources. The new definition of BES will bring in new assets, which will require a two-year implemetntation for all applicable standards. PRC-005-2 will be going through a multi-year implementation and the CIP version 5 standards are also being implemented during this time. There are other studies and assessments that need to be performed for physical security. Along with these high-profile standard projects, there are numerous other standards that take effect as well, which is a tremendous burden on each entity's resources. Building these new models and learning to performing these new studies is not small effort and may require additional staff and/or consultants that could have backlogged schedules due to the demand for their resources. For

a small entity where the planning engineer may wear multiple hats, this will be quite a significant challenge. For these reasons, we recommend a longer implementation plan for smaller entities so applicable registered entities have enough time to focus the requisite time and resources to each of these standards implementation. Further, due to the expense of acquirinig tools and performing assessments, there should be additional time so entities are successful in executing the required tasks to mitigate GMD events. (2) Thank you for the opportunity to comment.
Group
Edison Electric Institute
Mark Gray
Yes EEI believes that the functional entities identified in the standard have been correctly identified.
Yes
Although EEI agrees that the technical guidance for the Vulnerability Assessments meet the directives of Order 779, we do have concerns that complete guidance may not have been provided in the standard for the Corrective Action Plans necessary to mitigate any BPS impacts which might be revealed by a GMD Vulnerability Assessment. For this reason, we suggest that the drafting team consider adding requirements within the standard requiring that GMD Vulnerability Assessments be issued to the responsible Reliability Coordinator in order to ensure any operational issues are properly understood and addressed. EEI further notes that in Table 1 (Steady State b), the proposed standard allows for Consequential Load Loss and generation loss as a consequence of P8 planning event. The term “load loss” should be used instead to allow for the loss of both Consequential and Non-Consequential Load. Because the P8 planning event is not fault related, we feel that use of the term “Consequential Load Loss” alone is inappropriate.
Yes
EEI strongly supports the proposed benchmark GMD event believing it to be technically sound reflecting good engineering practices as typically employed by electric utilities broadly. In FERC Order No. 779, the Commission directed NERC to “identify benchmark GMD events that specify what severity GMD events a responsible entity must assess for potential impacts on the Bulk Power System.” (See P54, Order 779) Included in that directive were requirements to include varying severity, duration, geographic footprint of the GMD, GMD intensity variations due to latitude and electric system configuration relative to magnetic field orientation. In our review of both the draft TPL-007-1 standard (Attachment 1) and the referenced Benchmark Geomagnetic Disturbance Event Description (whitepaper) dated April 21, 2014 we find all of these requirements to have been fully addressed in a manner that we believe to be reasonable and defensible based on the current state and understanding of severe space weather and its impact on the BPS. As part of our review, we found that the SDT based their Benchmark event on a 1 in 100 year event, which we agree exceeds normal utility practices by a factor of 2 for earth based weather related catastrophic event analysis. Given Industry experience with these types of events, Industry designs based on traditional engineering

analysis have been shown to be effective over time. In contrast satellite data supporting the effective observation of the sun and supported by efforts to develop a firm understanding of GMD/GIC impact on a modern power grid only spans a relatively short timeframe, in comparison (i.e., less than 30 years). This along with other limitations led the SDT to employ statistical analysis typically associated with extreme event analysis, which has been demonstrated effective in other Industries and we believe provides a useful and effective method for extrapolating a defensible Benchmark event for the Industry relative to GMD. EEI notes that one of the major enhancements to the most recently proposed Benchmark was the averaging of localized extremes. In the work conducted by the SDT, it was discovered that localized extremes during GMD events is common and supported by measured magnetometer data. Given the Benchmark is intended to address the “wide-area” effects of a GMD event, the SDT developed methods to address this issue. The result was the spatial averaging of data over a 500 km area. Although this does have the effect of lowering the projected Benchmark, we believe this to be reasonable and appropriate given the grid is resilient and designed to withstand some localized and pocketed outages which could occur during a GMD or similar extreme event. Such methods will ensure that reasonable and prudent measures are taken to protect the grid from instability and cascading failure as directed by the Commission in Order 779.
Yes
EEI supports the proposed Implementation Plan as proposed believing that it provides sufficient time for entities to effectively assess and develop Corrective Action Plans to mitigate any uncovered impacts due to GMDs. Although the timeframe does on the surface appear to be long, EEI cautions against the shortening of this Plan given the maturation expected in space weather and geomagnetic sciences, the data derived from these, and inclusion of these advancements in performing GMD vulnerability assessments.
Group
DTE Electric
Kathleen Black
Yes, we agree
No comments
No comments
No
Comments: It is not clear from the Implementation Plan for R7 and R8 if all identified mitigation work is to be completed within the 36 month time frame or only the assessment is required and any mitigation or corrective action plans are merely identified. It is not reasonable to expect mitigation work per R7.3 to be completed within the 36 month time frame. Also, it would seem prudent to coordinate mitigation measures on a regional basis. For example, shouldn’t placement of neutral GIC blocking devices be coordinated across the region by the PC and TP? It appears from R1 and R6 that the PC and TP are required to model the GIC system and provide GIC currents (as per Attachment 1) to the TO and GO for thermal

assessments. Perhaps R7.1. can be changed to clarify who is providing all the necessary GIC current information that is needed by the TO and GO.
Individual
Michael Haff
Seminole Electric Cooperative, Inc.
Agree
Yes
Note that there is a discrepancy between multiple figures throughout the proposed Standard and supporting documentation, where some illustrations depict a scaling factor (β) for the majority of the FRCC Region and other illustrations do not depict a scaling factor at all for the same Region. It appears from the USGS linked Regional Conductivity Map that is cited in the supporting documentation (see here: http://geomag.usgs.gov/conductivity/), that the maps are based off of findings from the Fernberg, et al. 2013 research paper. Reviewing the USGS conductivity maps, one is unable to select South Florida to reveal the conductivity analysis for that region based off of Fernberg, et al. 2013. Seminole suggests that the Standard should not be posted again until the SDT has determined and posted on the USGS website the conductivity(ies) for the entire FRCC region along with any scaling factor(s) for the entire FRCC region using the same methodology utilized for the rest of the Regions. In the alternative, Seminole suggests that the FRCC Region be exempt from this rulemaking until proper studies can be performed and posted that cover the FRCC Region.
Yes
It appears that the studies were based off of a 1 in 100-year event, i.e., benchmark event. In addition, it appears that the supporting documentation concludes that local GMDs do not have a wide area impact, i.e., do not directly affect wye-grounded transformers far away. If this is correct, the possibility of a local GMD occurring within the FRCC region and developing geomagnetically induced currents directly affecting a wye-grounded transformer in the FRCC Region is less than 1 in 100 years, i.e., less frequent than 1 in 100 years, correct? Further, the benchmark event for the technical basis of this Standard appears to be the 1989 Quebec event. In addition, it appears that the supporting documentation concludes that local GMDs do not have a wide area impact, i.e., do not directly affect wye-grounded transformers far away. Can the drafting team post supporting documentation in the application guidelines section of the Standard or a white paper that details GMD events as strong or stronger than the 1989 Quebec event that have occurred in the southern regions of the U.S., such as in Texas and Florida?
Yes
Individual
Jo-Anne Ross
Manitoba Hydro

Yes. Section 4 Applicability, 4.1 Functional Entities: The standard does not specifically include loads entities who may own a 200 kV or higher transformer. In Manitoba major load customers may interconnect to the transmission system at the 230 kV level and own the transformer. Such entities must also be included in the standard.
Yes
Consider amending the wording for R6 to address confidentiality concerns: "Each Planning Coordinator and Transmission Planner shall distribute its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 within 90 calendar days of completion, and to functional entities within its own planning area that has a reliability related need and submits a written request for the information within 30 days of such a request."
No
Requirements R2 and R3: The analysis proposed is not consistent with the phenomena. Transformer thermal analysis (R3) is to utilize the 12 hr benchmark waveform to determine the temperature increase in the transformer this is appropriate due to the time constants involved. It is not appropriate to take the instantaneous peak electric field magnitude for a steady state simulation (R3). The Peak electric field only occurs momentarily (figures 2 and 3). For steady state analysis it is appropriate to take some averaged or mean value for the peak electric field. If the intention of the standard is to analyse the peak instantaneous electric field values then an electromagnetic transient simulation is appropriate. Requirement R2----2.2 states that the analysis shall use the benchmark GMD event described in Attachment 1 of the standard. This is a uniform 8 V/km electric field to be scaled based on geomagnetic latitude and earth conductivity. This benchmark is not based upon sound science. The development of this benchmark event is documented in Appendix I of "Benchmark Geomagnetic Disturbance Event Description" and suppose to represent a 1 in 100 year event. The magnetometer data used for this analysis originates from the IMAGE magnetometer array located in Finland. The main purpose of this analysis is to identify 1.) The maximum peak electric field level and 2.) The reference waveshape. Technical issues with the analysis in Appendix I of "Benchmark Geomagnetic Disturbance Event Description" are: a. There is no independent peer review of the methodology or data set used develop the 1 in 100 year event, b. The data set used for the peak electric field analysis comes from the IMAGE magnetometer chain in Finland using a 21 year data set (1993 to 2013). At a minimum equivalent analysis must be completed using data from the CARISMA magnetometer chain in Canada to confirm that the data set is relevant and that the analysis is correct. c. There is no clear documentation on how IMAGE magnetometer data was manipulated to generate statistics for the 1 in 100 year event (did you simply normalize the bin counts by 21 years and then multiply it by 100?), d. Data provided does not support the proposed GMD benchmark event. Figure I-2 tells us that over a period of 100 years we would expect one 10 second interval to have a peak electric field of 3 to 8 V/km. There are 3 billion 10 second time intervals in 100 years. Thus the probability for 3 to 8 V/km to occur is 3x10-10!!! e. From the document seems that 8 V/km value was derived by visually extrapolating the curves in Figure

I-2. This is unscientific and not appropriate. Please provide a polynomial fit to the data and extrapolate using sound mathematical principles. f. Extreme value analysis does not support the 8V/km. The document argues why extreme value method (4) is preferred over (1), (2) or (3). Method (4) provides a peak electric field of 5.77 V/km! Two decimal places suggests an accuracy in the 100th's. The statistics is already in the 95% confidence sound engineering judgment would round this value to 6V/km. g. The magnetometer chain (IMAGE) used to develop the benchmark is at the same geomagnetic latitudes as Manitoba therefore the peak electric field over Winnipeg (60 degrees geomagnetic latitude) is the value found using the extreme value analysis (5.77 V/km). Instead of specifying a specific benchmark that is not supported by scientific peer review (as is the case with the proposed benchmark in "Benchmark Geomagnetic Disturbance Event Description", please rewrite R2 – 2.2 as: "2.2 Studies shall be conducted based on the approximate 1-in-100 year benchmark GMD event described in Attachment 1, a planner can substitute a technically justified 1-in-100 year benchmark GMD for its planning area where available."
Yes
Individual
Karin Schweitzer
Texas Reliability Entity
Yes
It appears that there may be a possible reliability gap with R3 and R7. If the applicable entities (PC, TP, GO or TO) have identified a corrective action plan under R3 or suggested actions under R7, there is no specific requirement for an entity to implement the corrective action plan or suggested actions. Compliance with the Standard, as currently written, may not result in reduction of an identified risk to the BPS. Consideration of adding a requirement to implement corrective actions is requested.
Group
ISO/RTO Council Standards Review Committee
Gregory Campoli
Yes
No
• Requirement R3 requires the development of a Corrective Action Plan. Current TPL standards require Corrective Action Plans for N-1 and N-2 conditions but do not require them for N-3 and beyond. If impacts from a GMD event create N-3 or beyond conditions, this standard goes beyond existing practice to require Corrective Action Plans. Shouldn't there be

consistency within the standards in the area? • It is not overly clear how to apply the proposed simulation to meet the standard. Because of this, the simulations run by various entities may not be consistently done. Since this is a new type of analysis in the planning process, it needs to be well understood by those performing the analysis. How the event is modeled, what equipment trips and the timing of this is critical to the simulation, but doesn't appear to have been fully vetted. These concerns highlight the need that more guidance on the approach is needed Also, has the GIC software that is commercially available been benchmarked against one another to ensure consistent results? If so, was the size of the system sufficiently robust to ensure similar accuracy on actual large systems? Additionally, there is contradictory language between using short-term cases, but applying for long-term horizon. • R1: The sentence: "This establishes Category P8 as the normal System condition for GMD planning in Table 1." is unnecessary. R1 requires the responsible entities to develop a system model for performing the studies needed to complete its GMD Vulnerability Assessment. Category P8 is an event or contingency to be applied, not a system model whose details are provided in Table 1. We suggest to remove this sentence to avoid confusion. • R2: The sentence: "This GMD Vulnerability Assessment shall use studies, document assumptions, and document summarized results of the steady state analysis." is unclear. The part that says: "document assumptions and document summarized results" is confusing. We are unable to clearly understand whether the requirement asks for using "documented assumptions" and "documented summarized results" (of previous studies), or to ask for "documenting assumptions" and "summarizing results". The sentence needs revision to improve clarity. Footnote 4 in Table 1: The second and third sentences are misleading. (i) The second sentence indicates that Non-Consequential Load Loss and/or curtailment of Firm Transmission Service may be needed [i.e. allowed] to meet BES performance requirements during studied GMD conditions, but it stipulates that such conditions should not be used as the primary method of achieving required performance. There is no criteria or guideline as to what constitutes "primary method" of achieving required performance. When such actions are allowed, Planning Coordinators and Transmission Planners will in their GMD Vulnerability Assessment include these actions in the studies/simulations. How would these entities determine whether or not such actions are the primary method of achieving required performance when other means are applied to meet performance targets? We suggest to remove the phrase "but should not be used as the primary method of achieving required performance" to avoid confusion. (ii) The third sentence indicates that "GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Non-Consequential Load Loss or curtailment of Firm Transmission Service is minimized during a GMD event." The condition that "Non-Consequential Load Loss or curtailment of Firm Transmission Service is minimized during a GMD event" is not specified and cannot be adequately assessed or measured. In other words, what constitutes "minimized" is a subject of debate. We therefore suggest to remove this part to avoid confusion.
No
• The event needs to be better explained as to the degree of its conservativeness and also how wide-spread the potential impacts could be. Has any research been done to determine

that if the event is conservative, how significant the Corrective Action Plans would be? And if those Corrective Action Plans are significant, is this level of conservatism appropriate. A better understanding of the benchmark GMD event needs to be provided and a better explanation of how GIC flows are calculated and used in steady state analysis is needed. Clear step-by-step calculations would be helpful to provide consistency amongst all regions.
No
• The transformer data that is needed to develop the DC transformer model is not typically provided to the TP/TO at time of delivery. Some transformers may need to be tested as the manufacturers may no longer have the necessary data due to the age of the transformers. New York has approximately 100 substations with high-side transformers at 200kV and above. Doing this testing may require an outage of the transformer and if so, it may take significant time just to get the tested information. If estimated values are used, the results of the analysis could be suspect which would be a significant concern especially considering the time and expense that would be required if Corrective Action Plans were warranted. • It is unclear what data is needed for input into the commercially available software until a demonstration is provided. If actual data is not available and estimated values are used, how can corrective action plans be proposed? These plans would have to be checked against potential risk to reliability. • The timeframe may not be realistic as it may take considerable time to get the database information from the owners of those facilities. It is extremely difficult to determine this time given the complexity it may take to get this information. Also, the software tools may not be fully understood to determine which ones can provide accurate results to the requirement simulations. Even once the software and database information has been procured, the simulation time and development of the Corrective Action Plans could easily take longer than those prescribed in the standard. • The Standard Drafting Team needs to consider moving out the implementation plan at least another 6 months, and consider rearranging the implementation order. Some regions of NERC has not fully developed a GIC model. ERCOT believes that it would take additional time to complete the GIC System model. Requirement 5 will take additional time to formulate agreements between TPs and PCs. In areas where GMDs have not historically been an operating issue, some TPs and PCs will have to secure additional expertise and tools to develop the model and complete the assessments. • The SDT needs to consider rearranging the requirements in the implementation plan in order to develop a valuable assessment. Results from requirements R7 and R8 are needed to execute R2, therefore consider switching the sequence of requirements with adjusted effective dates in the implementation plan or provide clarity otherwise.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Agree
SERC Planning Standards Subcommittee
Group
Colorad Springs Utilities

Kaleb Brimhall
Southwest Power Pool Comments
To better ensure coordination and reduce wasted software investment and resource expenditures, we suggest consideration of adding the RC or regional entity and requiring a regional model and study development. For example, WECC or the RC would develop the models and studies with the assistance of the other functional entities included in this proposed standard.
No
We still have concern that this effort is not merited based on the provided data. Especially since the peak solar flare cycle shows us starting into lower magnitude and frequency period based on historical data.
No Comments
See comments for Question 1 - Possible alternative to high investment for software and resource expenditure on a individual entity basis would be to assign requirements to the RC or regional entity to create more comprehensive studies and models which would also better utilize resources. In the corrective action plan section it references “operational procedures.” Are operational procedures going to be acceptable for long term solutions to identified vulnerabilities? Concern is that cost for mitigation could be very high with a very low probability. Thus the ability to mitigate via operational means could be effective and cost effective. The thermal studies should be required as part of the vulnerability assessments, and not be separate requirements. It appears that thermal studies are separate and distinct from vulnerability assessments, and think that thermal assessments must be a part of the vulnerability assessment for it to be complete. Requirement 6 should be by request only. We should avoid the sharing of information without a verified need and request for all parties. Making sharing of results and corrective plans by request only eliminates unnecessary paperwork burden.
Individual
Dan Inman
Minnkota Power Cooperative
MRO - NERC Standards Review Forum (NSRF)
While we support the NSRF's comments, we would also like to add: The requirement in R7 to complete a thermal impact assessment of GIC on 230 kV high-side Y-connected transformers. Removing this requirement for non-BES, radial load serving transformers would be prudent as it would reduce the number of transformers to be assessed thus reducing the iterative process between the GIC assessment and thermal impact assessments. Loss of these radial, load-serving transformers will not impact systems cascading. The following language is proposed: R7. Each Transmission Owner and Generator Owner shall conduct an assessment of thermal impact for all of its solely and jointly owned BES power transformers with high-side, wye-grounded windings connected at 200 kV or higher. The assessment shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning] R8. Each Transmission Owner and Generator Owner shall provide its assessment of thermal impact specified in Requirement R7

for all of its solely and jointly owned BES power transformers with high-side, wye-grounded windings connected at 200 kV or higher within 90 days of completion to the Planning Coordinator and Transmission Planner with responsibility for the area in which the associated power transformer is located. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]" Another methodology would be including a transformer size threshold such that radial load-serving transformers of 100 MVA or less would not be assessed.
Individual
Jay Teixeira
Electric Reliability Council of Texas, Inc.
No
It is unclear what additional items constitute "geomagnetically-induced current (GIC) System models" as compared to the "ac System models". It appears from the items in 1.1 to 1.6 that only 1.2 represents the additional items required to create a "geomagnetically-induced current (GIC) System model". Is this correct? If the corresponding "ac System model" represents a specific date/hour then are the outages included in 1.2 those outages that are in effect during the simulated date/hour that have a duration of at least six months?
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
No. Within FERC order 779 P.67 it states, "The NERC standards development process should consider tasking planning coordinators, or another functional entity with a wide-area perspective, to coordinate assessments across Regions under the Second Stage GMD Reliability Standards to ensure consistency and regional effectiveness." The logical choice for applicability, based on the FERC order, would then be PCs and RCs not TPs. Ultimately the RC has the widest range of perspective within the region and should therefor be the final entity in the chain. Tri-State would suggest that it should be the BAs/PCs responsibility to come up with initial assessments to their area and to have the PCs and RCs work together to determine the ultimate assessment for the region.
No
Tri-State does not agree. While we appreciate the documents available, we would like to see and review the "Transformer Modeling Guide" which is not yet available, before we can fully

assess this. Until then we do not believe the requirements are supported by the technical guidance.
Yes
From the technical papers that support it, Tri-State can agree with the Benchmark GMD event. However, we continue to be against having an industry standard for GMD as the Benchmark event, supported by the technical papers, is a 1 in every 100 year event and it is unreasonable to ask industry to do continual planning for such a rare event.
No
Tri-State has some older power transformers from manufacturers that are no longer around and envision great difficulty in calculating or estimating the harmonics, thus the reactive losses, and the thermal assessment. With the lack of some vital information to these assessments, Tri-State believes this will be time consuming and difficult to complete. Tri-State has a large concern associated with gathering the model data in time of the effective date. The completion of the study work within 2 years will greatly depend on how system-wide complete modeling data is obtained. Studies should be run in a coordinated manner and the RCs should play a major role in doing so.
Individual
Frederick Faxvog
Emprimus LLC
Agree
Terry Volkman and John Kappenman and Prof Dan Baker
Individual
Bill Temple
Northeast Utilities
Yes
Yes
Yes
NU would like for the SDT to provide the basis for going from 3 V/km to 8 V/km with respect to the field amplitude.
Yes
Individual
Paul Robert Hayes
CEMTACH
Agree
Agree with Foundation for Resilient Societies’ comments

Comment on Correct Characterization of Reference Geomagnetic Field Disturbance

In the May 20, 2014 NERC TPL-007-1 Technical Conference, a slide (Figure 1) was presented that attempted to characterize the dB/dt intensity of the Geomagnetic Disturbance Reference Field. The calculation of this peak dB/dt is in error and will be discussed further.

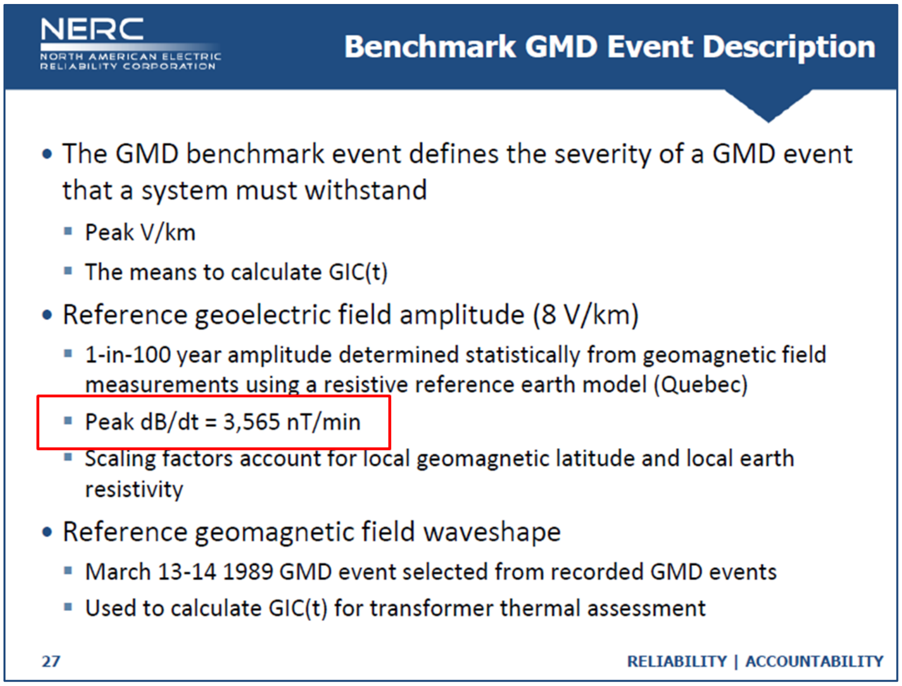

Figure 1 – Slide 27 from NERC May 20 Tech Conf noting Peak dB/dt of reference field

The NERC Geomagnetic Disturbance Reference Field was publicly provided on May 6, 2014 and has a time step cadence of 10 second time steps between data points. Figure 2 provides a plot of the total horizontal rate of change of change of the geomagnetic field (dBh/dt) in terms of nT per 10 Second time steps. As shown in this graphic summary, the peak dB/dt approaches ~600 nT/10sec (more exactly, it reaches a peak of 594 nT/10sec at time step 27,870 seconds). The NERC GMD Standards Drafting Team apparently used the simple multiplication of 6 times the 594 nT/10sec to derive the 3,565 nT/min referenced in Figure 1. This is in error and does not obey the averaging protocol used in geomagnetic observatories around the world to derive the intensity observed in nT/min. It is only possible to reach a 3,565 nT/min intensity if the actual total nT change is equal to 3,565 nT over a time span of a minute duration.

In many cases the sharp ~500 to ~600 nT/10sec changes are not sustained over a time duration of a minute, hence the simple multiplication of these values by 6 to convert to nT/min will overstate the intensity greatly in these situations. This overstatement is clearly the case in the NERC Reference Field. If we take the reference field in 10 sec time steps and average each minute the dB/dt into true nT/min rate of change, the resulting dB/dt intensity is as provided in Figure 3. As shown in this proper conversion, the peak dB/dt is only ~2000 nT/min, not the NERC claimed 3,565 nT/min. It should also be noted that this adjustment further shifts the time point of this peak to a time that is much later in the reference storm, which is also at a time consistent with the estimated peak geo-electric field. Therefore this NERC characterization is incorrect and greatly overstates the equivalent nT/min intensity of the reference waveform and is also inconsistent with the peak geo-electric field data.

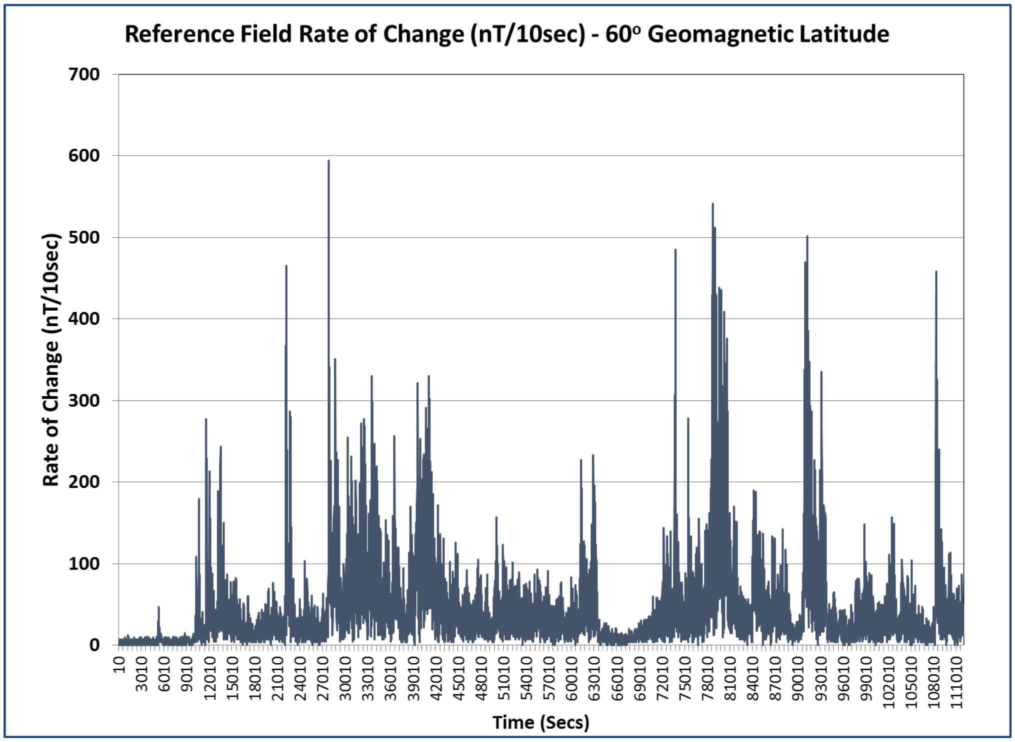

Figure 2 – Rate of Change of NERC Geomagnetic Disturbance Reference Field in nT per 10 Seconds.

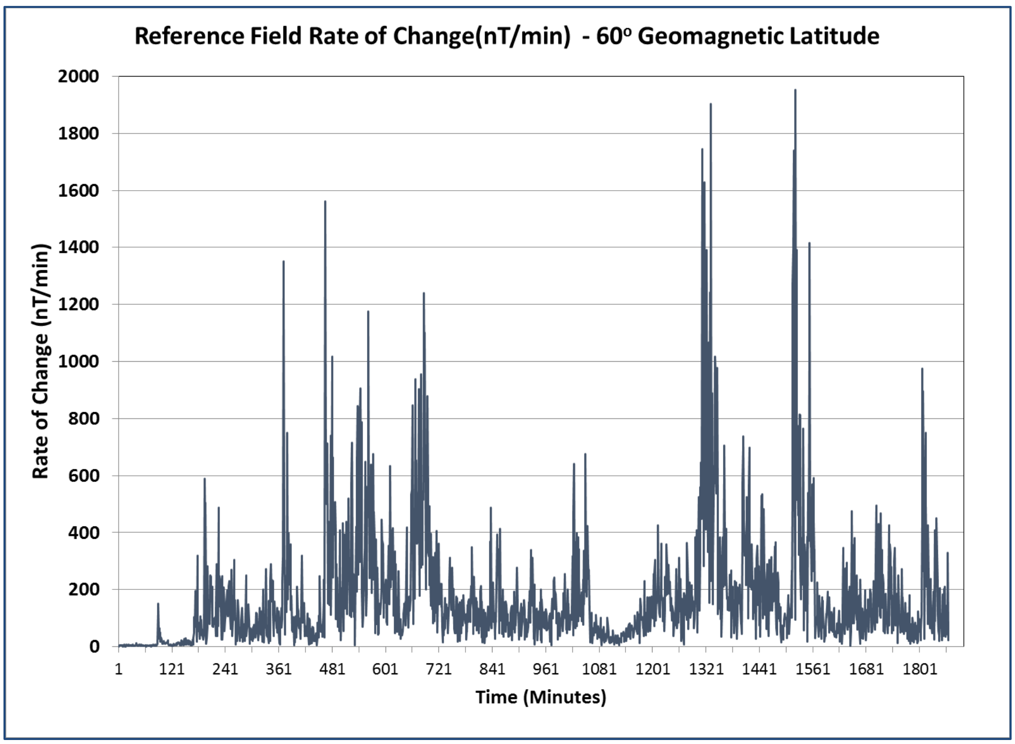

Figure 3 – Correct Rate of Change of NERC Geomagnetic Disturbance Reference Field in nT per Minute.

Comment on Instances of Observed Geo-Electric Field Intensity Greater than NERC Standards

The NERC Draft Standard TPL-007-1 provides a simplified formula based upon a Reference Geo-Electric field to derive the "Calculated Peak Geo-Electric Field" for a specific location, with their stated objective being to provide a conservative value of the peak geo-electric field for the reference storm.

To examine the merits of this "Calculated Peak Geo-Electric Field" method it is reasonable to compare the results from this method with the measurement of a known geo-electric field intensity from a moderately severe storm event (~1-in-10 year to 1-in-30 year event). On August 4, 1972 a large scale dB/dt occurred over the western half of North America. Figure 1 provides a reconstruction of this event (C. W. Anderson III, et. al. Outage of the L4 System and the Geomagnetic Disturbance of 4 August 1972).

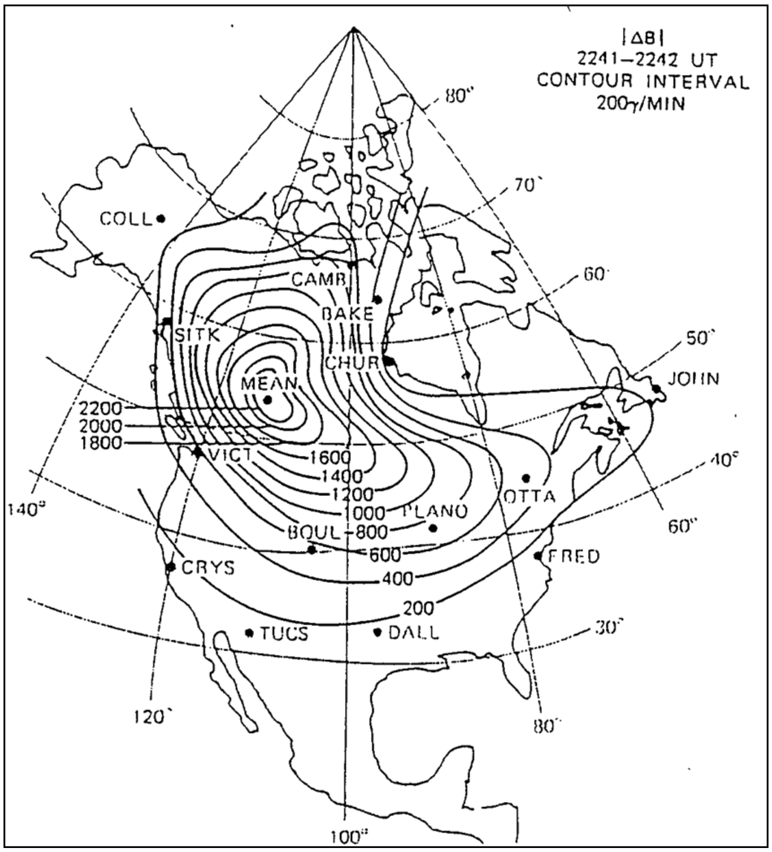

Figure 1 - Morphology of storm from ATT Analysis of Storm – Anderson, Lanzerotti, et.al.

This sudden dB/dt caused a AT&T Communication Cable failure between Plano, Illinois and Cascade Iowa due to an intense geo-electric field which affected a critical subsystem on this infrastructure. The authors of this report concluded that the geo-electric field intensity had to be at least ~7 V/km to cause this upset. Further from this reconstruction, the dB/dt intensity in the region of the L4 Cable system was estimated to be approximately 800 nT/min. The distance between Plano and Cascade is ~220 km, making this an infrastructure which is fully integrating the geo-electric field over meso-scale distances and comparable to the scale of similar infrastructures on electric power grids. Hence this is an important reference and benchmark point for this region of the US.

Using the "Calculated Peak Geo-Electric Field" method, as defined by NERC in the formula of E peak= 8 x αx β(in V/km), a peak 1-in-100 year geo-electric field can be derived for this same location in the Cascade/Plano region of the Midwest. Both Plano and Cascade are located at ~52^{o} geomagnetic latitude. This location would fix the Alpha (α) ratio as being ~0.4, the location for the Beta (β) is "Prairies" ground model with a ratio value of 0.96. Using this approach, the Peak Geo-Electric Field for the NERC 1-in-100 Year Reference Field would only be ~3 V/km, which is ~2.3 times smaller than what actually occurred during the August 4, 1972 event at this same location. As this comparison illustrates, the proposed NERC standard will significantly understate the Peak Geo-Electric for this region.

Section 1. - Analysis of Transformer Failure Rates in US and Association with Geomagnetic Storm Events

Examinations carried out using publicly available data from an IEEE GSU Transformer Failure Survey clearly show associations between prior GMD disturbances and failures of these transformers and was reported to the US FERC in a study performed by Storm Analysis Consultants. This report illustrates that the major root-cause of failures of these transformer failures over the period of 1980-1995 is likely due to specific GMD events. Further these GMD events were much smaller than the most severe GMD events that are now understood to be possible to occur across the US bulk transmission electric grid. Figure 1-1 provides a comparison plot showing Geomagnetic Storms (top as measured by Ap* index) and discrete GSU transformer failures that are reported over a period from 1980-1995. Three major storms (July 1982, Feb 1986 and March 1989) all produce increases in transformer failures in their aftermath. Further these scale in a dose/response rate to reported dB/dt levels of each storm. The highest being the 1989 storm, the next highest the 1982 storm and last being the 1986 storm.

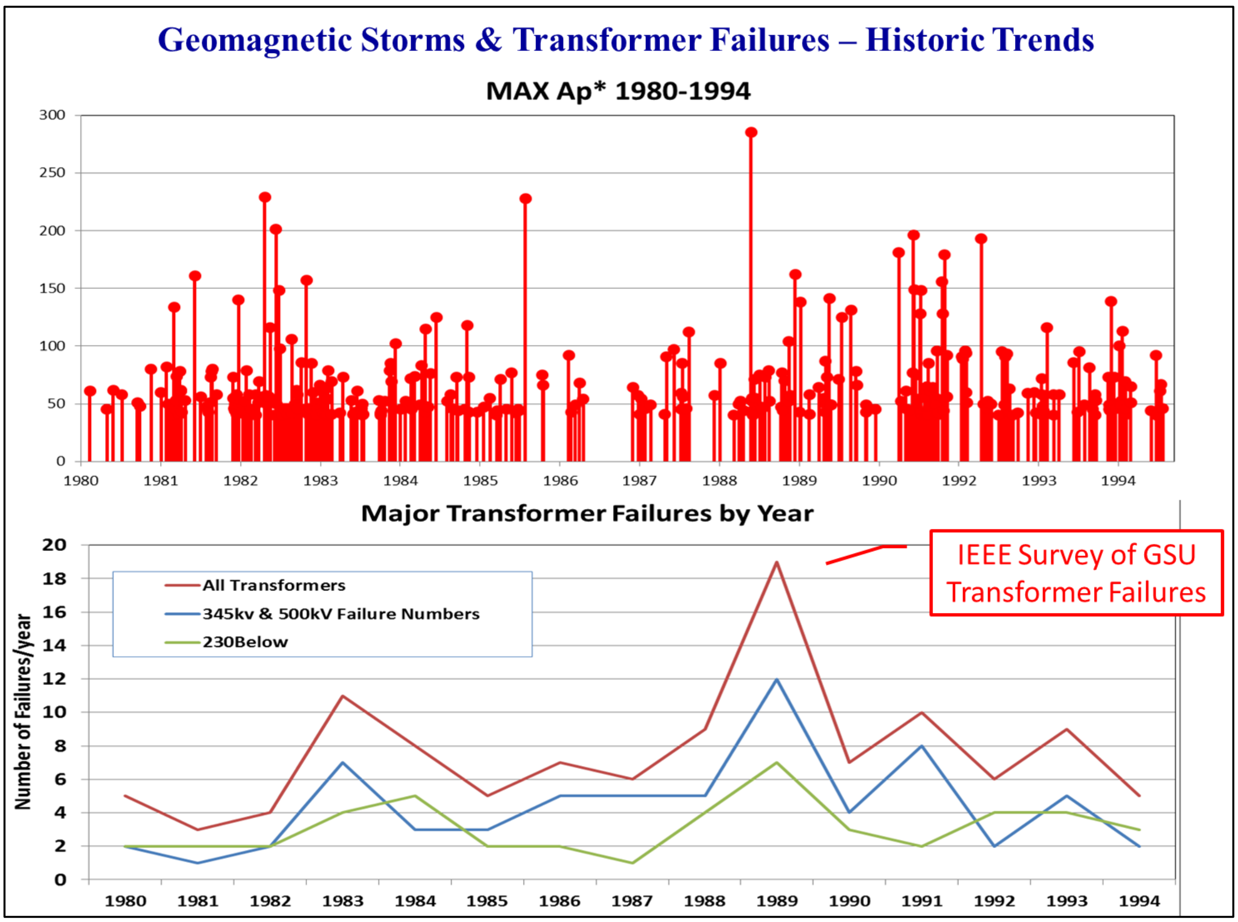

Figure 1-1 – Correlation of Geomagnetic Storms with reported GSU Transformer Failures.

Because the survey included added information on the failure events, it is possible to understand the consequential dimensions of these failures in more detail. For example all of these events Post 1989 are major failures, requiring replacement of the transformer. Further when looking at the failure, other consequential impacts where noted, the most important being that for 27% of all reported failures resulted in a major transformer/substation fire event as well. This increased the degree of consequential damage due to major catastrophic or collateral damage due to fires, tank rupture and/or oil expulsion.

In looking at the participants in this voluntary IEEE survey, the analysis showed that they constituted less than 50% of all US utilities (as measured by MWHr sales). Therefore it is likely that some failures have not been reported or included in this survey and the statistics are understating the degree of vulnerability possible from future larger storms. Other data bases do confirm this gap of reported failures as the US NRC maintains a database of Licensee Event Reports (LERs) for all nuclear power plants in the US. Over this same period of time, a number of LER reports were filed involving GSU transformer failure, that were not included in the voluntary IEEE Survey report. For example just in the few years in the aftermath of the March 1989 storm, eight (8) separate US NRC LER reports also noted GSU failures (that were not included in IEEE Survey). It is also possible that Nuclear Plant GSU failures may have also occurred that did not result in a reactor scram, which is the trigger for LER reporting under license requirements. Hence the failures reported in both of these data bases are a minimum and could be even larger due to these participation gaps. It should be emphasized that this analysis only concentrates on the GSU transformers in the BES, and as a result failure statistics on the even larger population of autotransformers in the BES is unknown. Therefore this analysis could be greatly understating the trend line of transformer failures and prior geomagnetic storms.

The NERC GMD Standards development process has not taken into consideration past failure events. In many instances various NERC reports have actually emphasized that only one transformer of a no-longer used 1970 design has failed due to GIC. There have even been well-documented instances where NERC refused to collect specific failure data reports and GIC measurements that are known to exist. Hence the ability of NERC to appropriately design forward looking standards in this vital area should be suspect.

Section 2. – Analysis of Autotransformer Tertiary Winding Vulnerability

The NERC process for determining autotransformer vulnerability has not taken into consideration the highly vulnerable tertiary windings that are common on most autotransformers in the US BES. Transformer manufacturers have also not provided public inputs on this topic area either. In a recent NERC GMD Task Force meeting, a presentation was provided on the GIC withstand estimates for a 765/345/34.5kV 750 MVA autotransformer. This presentation made no mention of the analysis of the tertiary winding heating vulnerability issues, rather it draws conclusions on winding vulnerability only from assessing the main windings of the autotransformer.

There are a number of reasons that the Tertiary winding vulnerability is more critical on autotransformers. These windings are typically much lower MVA rated than main windings. From available data, the MVA Ratings of Tertiary Windings can be as low as 4% of Main Winding MVA Rating. The tertiary winding is Delta Connected. In the case of single phase transformers, the delta connected tertiary winding will allow the flow of all Triplen (or Zero Sequence) Harmonics that are present due to GIC on the Main Windings. These Zero Sequence Currents will be present and flowing in the delta windings even when the Tertiary is unloaded. Because of this, Loading Guides for Reducing Load with Elevated GIC will be entirely ineffective, as the Tertiary Winding is already unloaded in most cases and load changes on the Main windings will not alter the production of Zero Sequence Harmonics due to GIC. Further, because the Tertiary winding is of significantly reduced MVA compared to the main winding, there is very limited capability to absorb the transformed zero sequence harmonics in the tertiary compared to the main windings. The only way to protect this vulnerable winding is taking the transformer out of service or mitigation actions to block/reduce GIC flows in the main windings.

In the recent NERC GMD TF presentation (March 2014), a transformer manufacturer assessed a 765kV transformer for a transmission owner/operator for various levels of GIC flow. Figure 2-1 provides a summary of the Harmonics due to these various levels of GIC. As shown in this graphic summary, it is estimated that there will be substantial Zero Sequence Harmonics produced at the 3rd, 6th, and 9th harmonic frequencies.

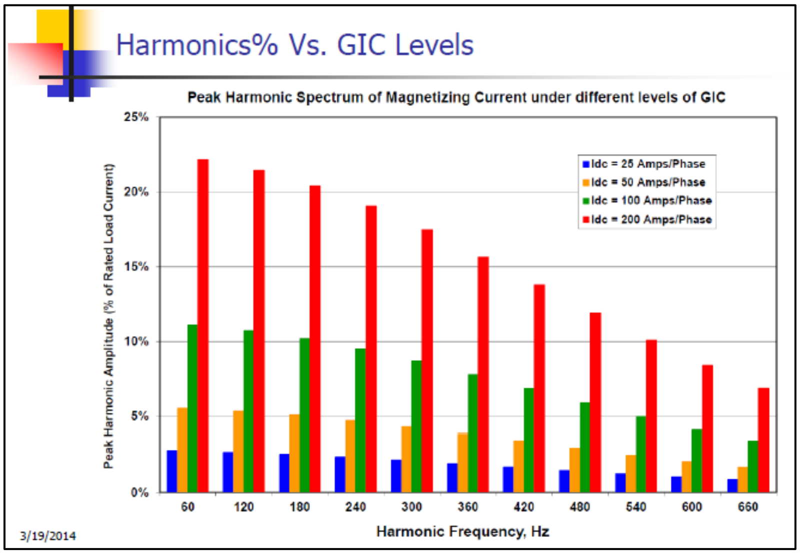

Figure 2-1 – Transformer Manufacturer Estimates of Harmonic Currents in 765kV Transformer Main Windings due to GIC

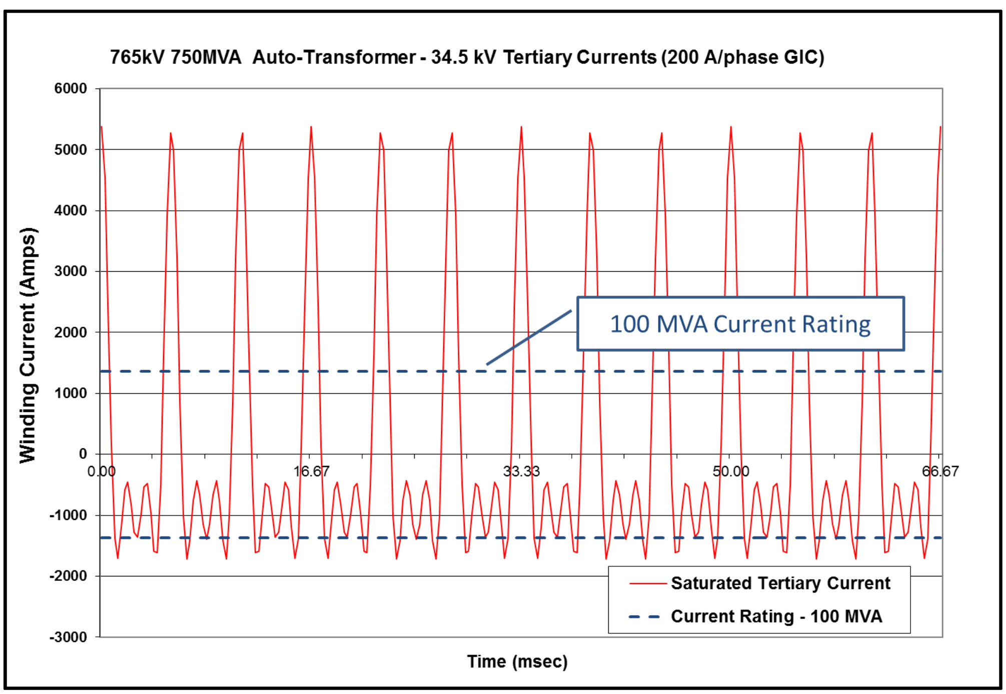

Figure 2-2 – Tertiary Winding AC Current and 100MVA Current Rating Limits for 200 A/phase GIC in Main Windings.

In the case of this particular transformer, the Main Winding has an MVA Rating of 750MVA, while the Tertiary Winding is 100MVA (i.e a 13.3% ratio, noting that ratios for even larger EHV transformers will typically be lower than 13%). In this particular case and for the 200 Amps/phase GIC level, the estimated Tertiary Winding AC Current Waveform using the harmonics from Figure 2-1 for this transformer is shown in Figure 2-2.

As this example illustrates, the waveform greatly exceeds the continuous current rating by as much as a factor of ~4. While these overloads would not be tolerable for a 60 Hz current, the reality of this case is that this example waveform consists of large components of 3rd, 6th, & 9th harmonics. Because of the harmonics this will greatly increase the winding losses (compared to same current at 60Hz), and winding heating from eddy currents and other stray loss factors. Tertiary Winding Losses can be calculated using the standard guidelines of ANSI/IEEE C57.18.10. Figure 2-3 provides a plot of the increase in Tertiary winding losses for increasing GIC levels using the inputs provided by the transformer manufacturer in Figure 2-1. As this plot illustrates, this tertiary winding will be subjected to enormous loss increases for increasing GIC. The losses will be highly concentrated in this winding accounting for more than 80% of all transformer losses. This high loss and heating concentration will greatly accelerate tertiary winding temperature increases as the rate of temperature rise is not a set "time constant", but rather is a response to the excessively high rate of energy input in these windings compared to any other location within the transformer. This is a process which can rapidly cause winding/insulation system failures. The slower time delays assumed in other locations in the transformer main windings will not be accurate for this location.

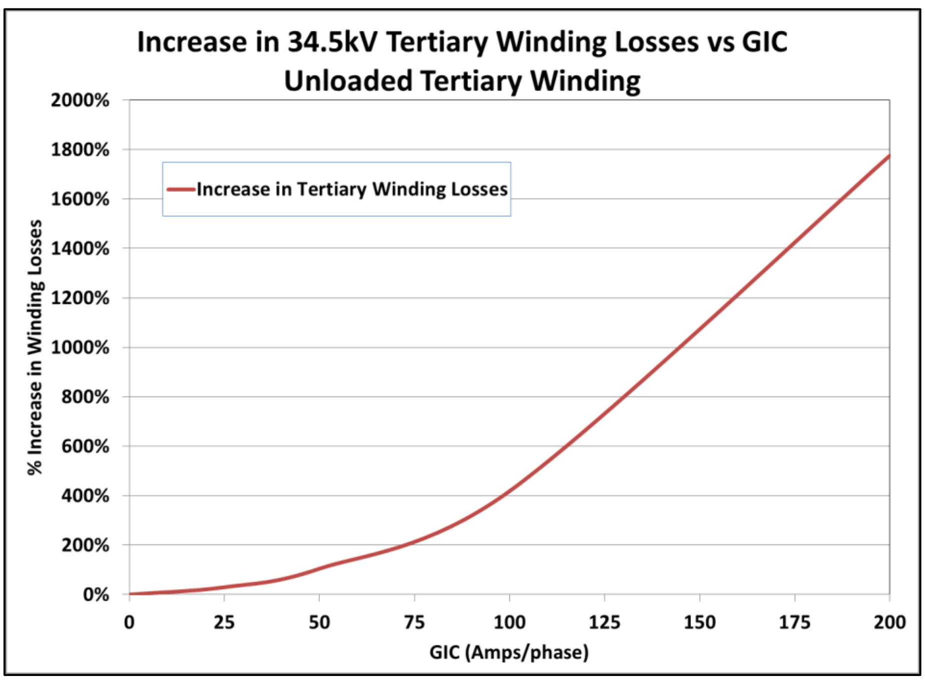

Figure 2-3 – Increase in 765kV Autotransformer Tertiary Winding Losses vs GIC levels.

In addition to losses, the same ANSI/IEEE standard can be utilized to estimate the winding hot spot levels that would occur for these GIC/harmonic exposure conditions in the tertiary windings. Figure 2-4 provides a summary of these temperature increases and also depicts the GIC and temperature limits that would normally be applied. As this analysis illustrates, the limitations of winding temperatures will be reached in the tertiary windings for very low levels of GIC flow. In the Presentation to NERC, the manufacturer had concluded that this transformer could withstand much higher GIC levels, but had based this only upon examinations of the main windings and had not included these smaller MVA tertiary windings. The transmission operator noted that these particular tertiary winding MVA ratings were relatively large in their network compared to other transformers that would have tertiary windings with lower MVA ratings. This suggests that even more severe limitations would exist in these other network transformers. As noted, this 100 MVA tertiary was rated at 13.3% of the Main Winding MVA, to examine the impact on lower rated Tertiary windings, the same set of calculations were carried out for 10% (75 MVA) and 7% (50 MVA) tertiary windings. These results are presented in Figure 2-5.

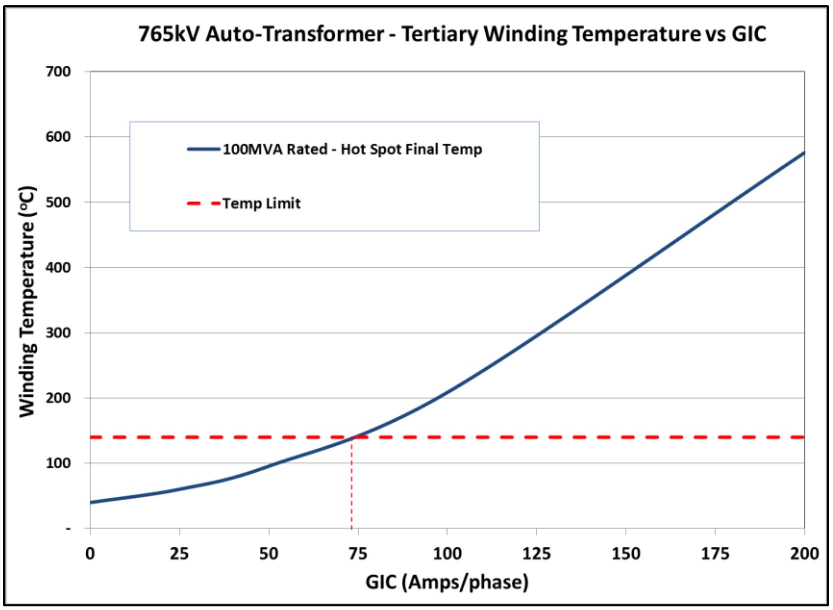

Figure 2-4 – Tertiary Winding Temperature vs GIC for 765kV Autotransformer.

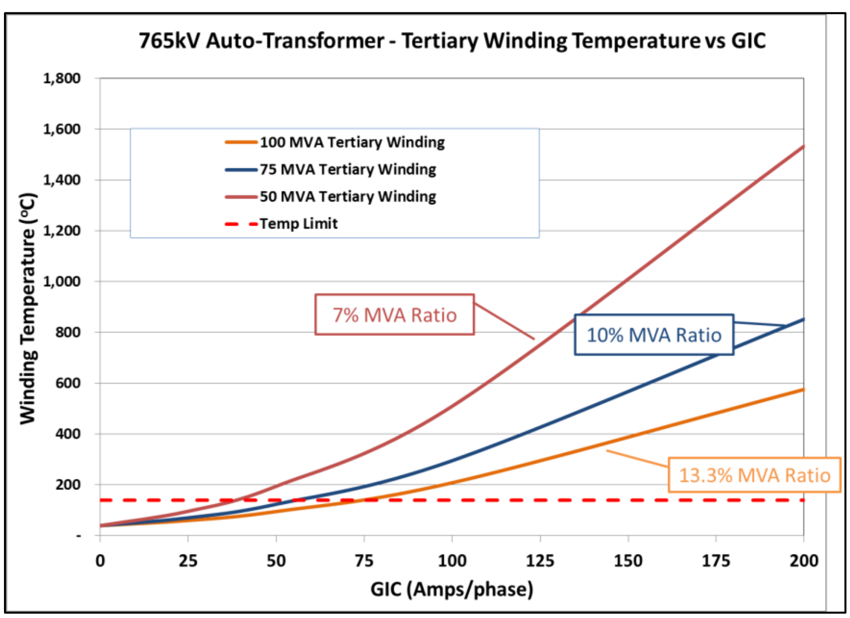

Figure 2-5 – Increase in Tertiary Winding Temperature vs GIC for 13.3%, 10% and 7% Rated Tertiary Windings

As expected, in Figure 2-5, a decreasing Tertiary MVA rating results in a proportionately higher winding temperature risk for the same level of GIC. The main windings and GIC flows of the main windings are what determine the harmonics produced by saturation. The zero sequence harmonics in the tertiary will be “fixed or controlled” based on the voltage turns ratio of the main winding to tertiary. The MVA rating of the tertiary is not a limiting factor for this transformation, but as the MVA rating of the tertiary decreases, the onset of overload and resulting over-temperature conditions will be proportionately reduced. As previously noted, the general trend in the industry is to specify a smaller % MVA rating for the tertiary winding as the MVA rating of the EHV transformer increases. In some cases the tertiary rating can be below 5% of the main winding. Unfortunately it is also these large MVA EHV autotransformers that are most likely to be exposed to high GIC flows in the network. This design trend therefore acts to heighten the risk of damage to these transformers for severe geomagnetic storm events.

The vulnerability of tertiary windings in autotransformers has not been specifically examined by any manufacturer in the course of the NERC GMD investigations. This oversight of a key vulnerability raises legitimate concerns about the adequacy of proposed NERC draft standards. The draft standards also do not comprehend other failure mechanisms which other research or experiential data indicate. There are a large number of other unexamined issues that have not been resolved. These include the role of increased vibrations caused by GIC saturation that can lead to premature failures. Data from examinations of transformer failures suggest connections in vibrations with various transformer subsystems such as core and coil clamping and with premature failures in EHV bushings. There are also failure pathologies with connected subsystems such as rigid isobus structures, internal transformer connections, other connected protection and monitoring systems. There are concerns of increased partial discharge levels that are measured with GIC caused half-cycle saturation and the pathways of deleterious impacts this could have upon transformer structures such as winding and core steels even at very low but long duration GIC exposure levels.

Section 1. GMD Standard Regarding Field Scaling- Southerly Locations

As NERC has noted in their description of the proposed GMD Standard, they have selected a reference waveform scaled from the Ottawa magnetometer data from the March 13-14, 1989 storm. The most convenient way to approximately estimate the geo-electric field and GIC in power grids is by comparing the rate of change (dB/dt) of the reference geomagnetic field. Figure 1-1 provides a summary of the rate of change of the horizontal component of this reference field located at the 60^o geomagnetic latitude.

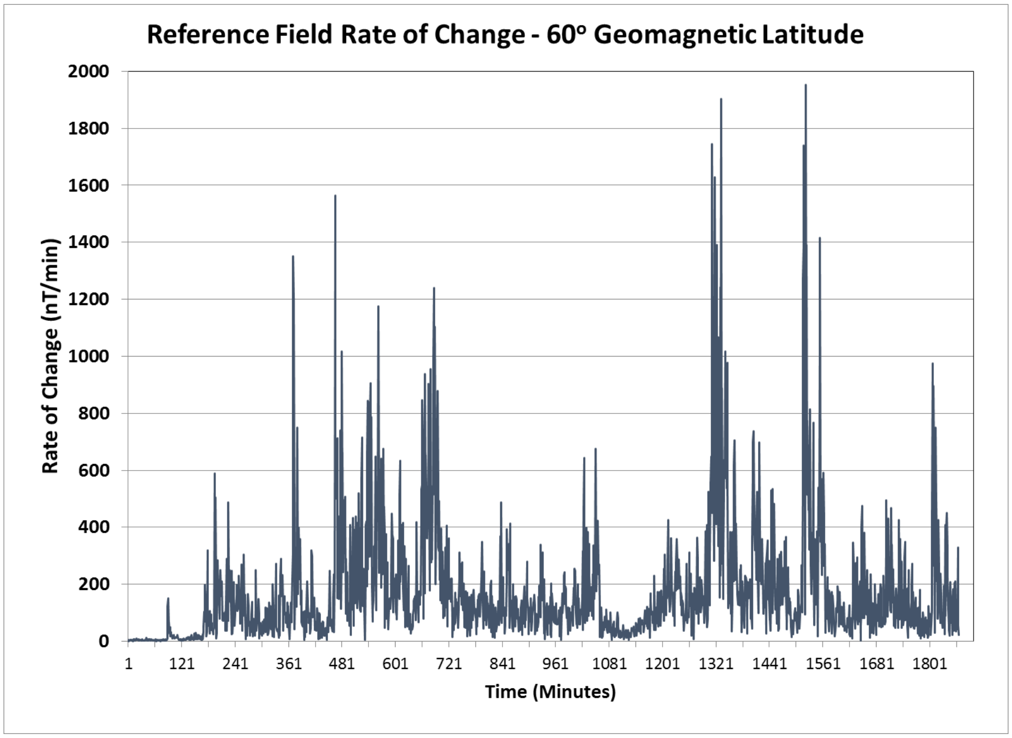

Figure 1-1 – dBh/dt (nT/min) of NERC Reference Geomagnetic Field

In the field scaling approach that NERC has recommended in their standard, they propose to use a formula to scale from the reference field defined at 60^o geomagnetic latitude to locations further south in the US. Figure 1-2 from the NERC standard overview provides the basic scaling formula. In this formula the factor alpha provides a latitude scaling factor that can be applied to the Ottawa waveform to determine scaling at all more southerly locations that can be applied. Figure 1-3 provides several example locations on what the scaling factors would be, in this figure, they note that for a location such as New York would be determined by scaling the reference field to only 30%. Further at a more southerly location like New Orleans, they would scale the reference field to only 10% levels.

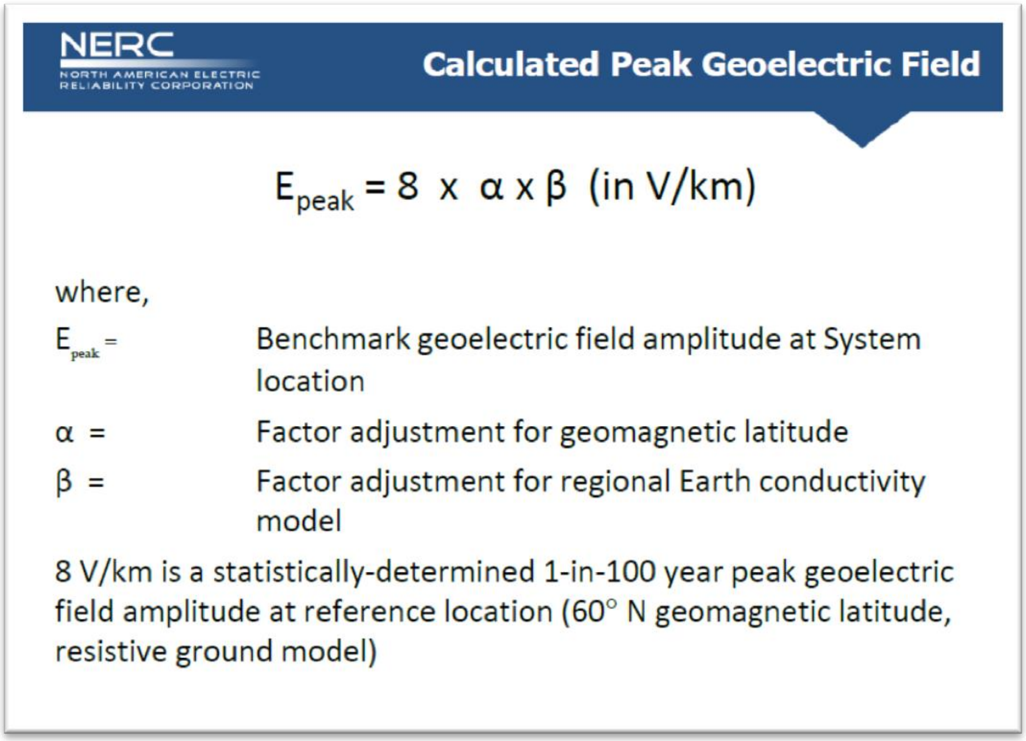

Figure 1-2 - NERC GMD Standard Location Scaling Formula

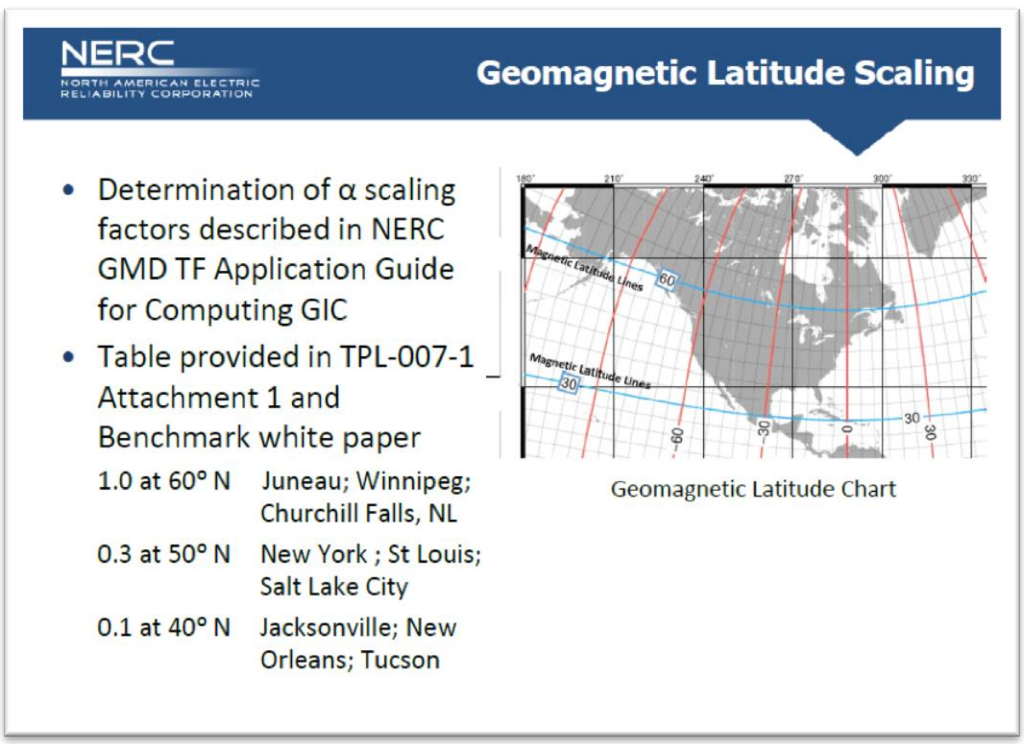

Figure1-3 – Example of 30% Scaling for NY and 10% Scaling for New Orleans

This formula approach can be readily compared to actual observations to examine if the formula provides a correct scaling factor for a 1-in-100 year scenario. In this case, we will just illustrate the scaling as applied to the reference field of dBh/dt field of Figure 1-1. To further simplify, the peak dBh/dt of this reference field was ~1950 nT/min.

In the case of latitudes at New Orleans, the peak dBh/dt would be scaled to 10% of this ~1950 nT/min peak, resulting in a peak dBh/dt of the scaled reference field of ~195 nT/min. Figure 1-4 provides a plot of the dBh/dt that was actually observed in the New Orleans region from the nearby Bay St. Louis magnetic observatory during the March 13-14, 1989 storm. As shown in this storm data, the BSL observatory experienced a peak dBh/dt of 460 nT/min. As a result, the proposed NERC scaled reference waveform would understate what was actually observed in the region by over a factor of two (2).

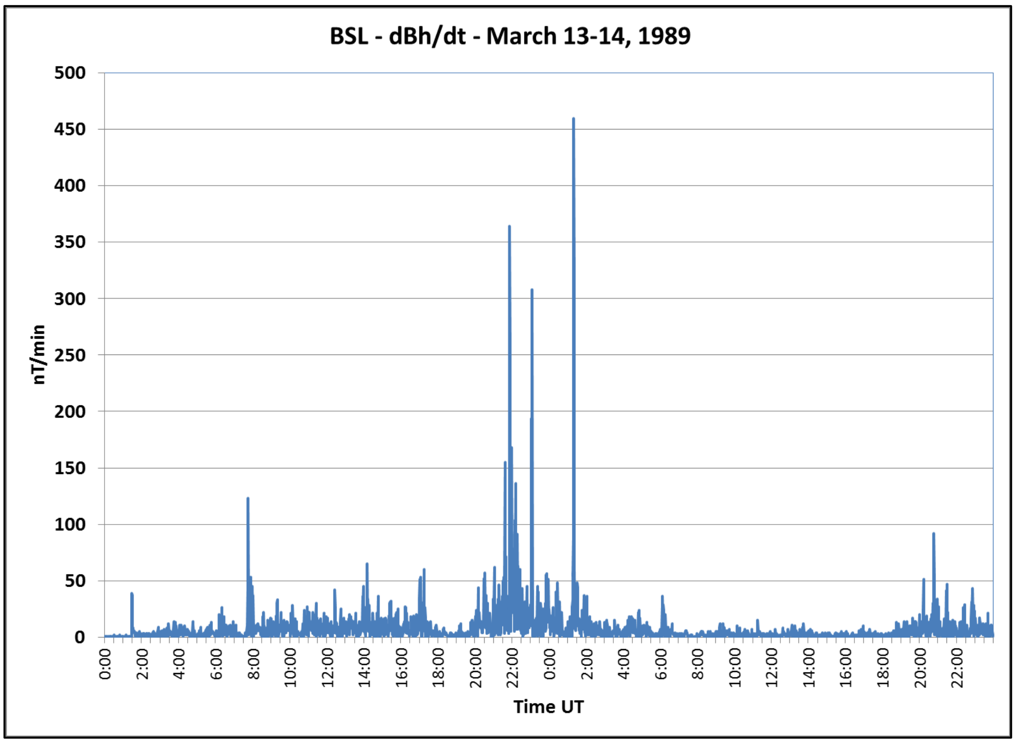

Figure 1-4 - Actual BSL Observation on March 13-14, 1989 for New Orleans location

As this comparison illustrates, the NERC Scaling formula which adjusts the reference waveform to more southerly locations is not correct for this storm and should be called into question for a much larger storm of the 1-in-100 year class. Rather than providing "conservative" characterizations of the disturbance conditions, the NERC scaled waveform formula produces unrealistically optimistic waveform intensities.

Section 2. Benchmark GMD Event – 1-in-100 Year Amplitude

From the NERC GMD Standard summary, Figure 2-1 notes that they have derived a geomagnetic referenvce field based on the March 13-14, 1989 storm. This reference field is scaled to meet their definition of a "1-in-100 year amplitude". Further as noted in Figure 2-2, they have determined that the Ottawa observatory waveforms are best suited to represent this 1-in-100 year field waveshape.

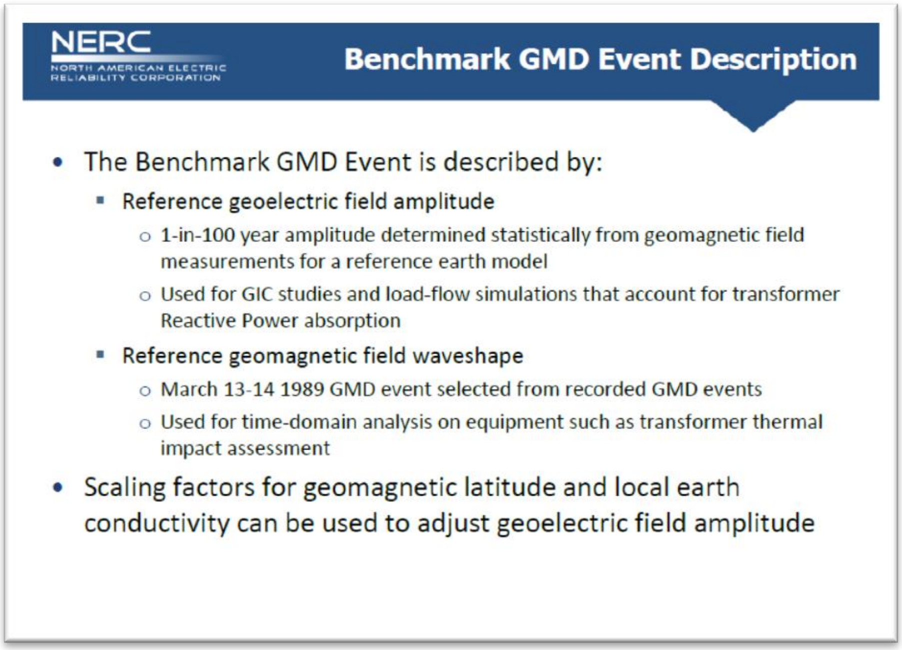

Figure 2-5 – From NERC GMD Standard Summary, March 13-14, 1989 storm as basis for GMD Standard

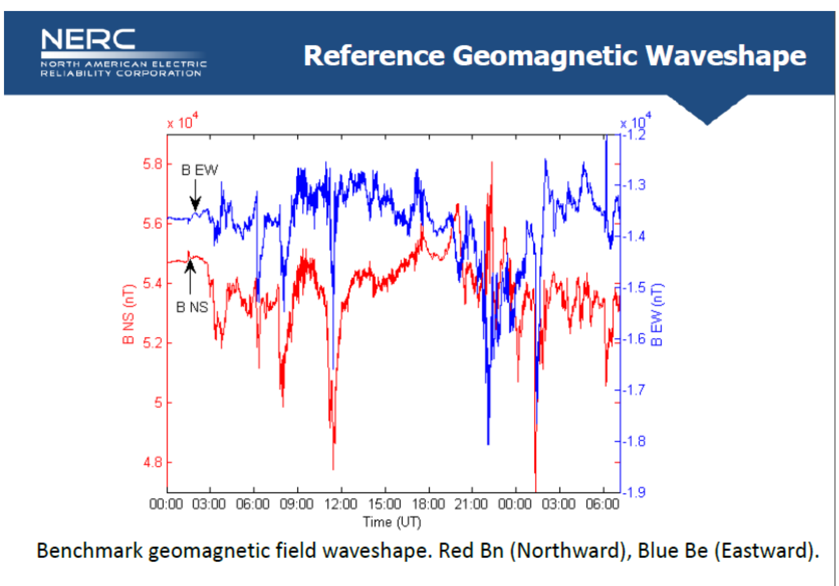

Figure 2-6 – Ottawa selected as Benchmark geomagnetic storm waveshape

The reference field is defined as being located at 60^{o} geomagnetic latitude. Figure 2-3 provides a summary of the rate of change of the horizontal field of the reference waveform. As this figure shows, the dBh/dt reached a peak of ~1950 nT/min for this location.

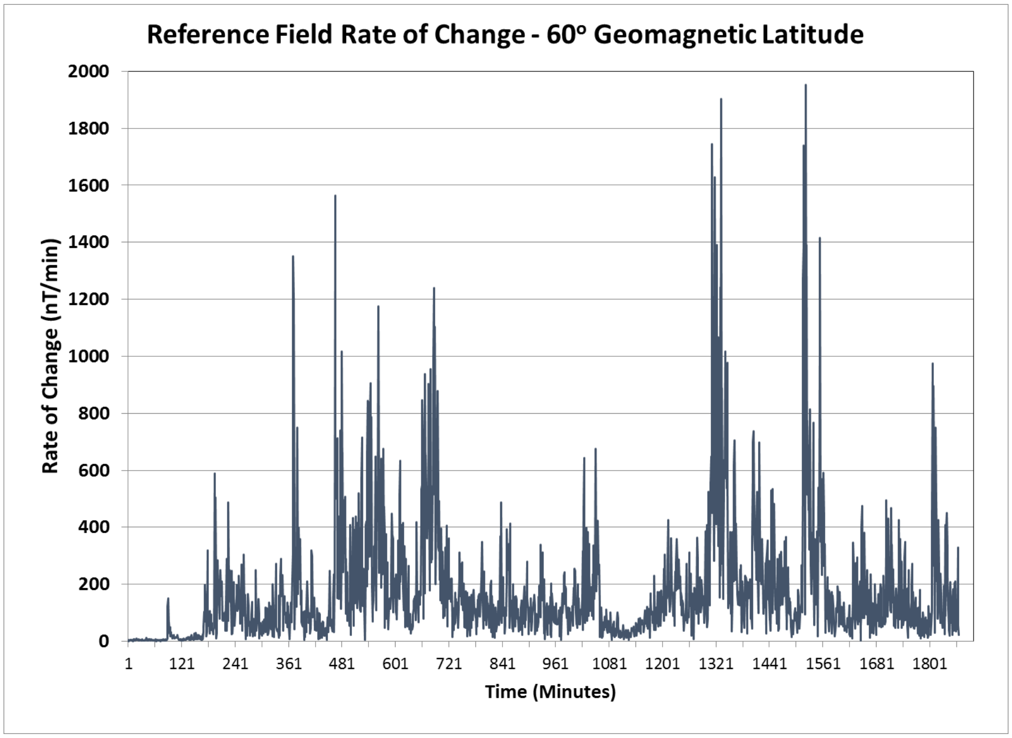

Figure 2-7 – Reference Field dBh/dt

The Ottawa observatory is located in southern Ontario Canada at the geographic latitude of 45.04°, but with a geomagnetic latitude of 56.05°. The Draft NERC Standard would reduce the above "Reference Field" to 60% for a geomagnetic latitude location of 56°. Using this scaling guide, the peak dBh/dt would be ~1170 nT/min for peak threat environment levels for electric grid infrastructures located at this latitude.

However the data available from several contemporary storms indicates that there are serious problems with these NERC threat environment conclusions. When considering geomagnetic storm climatology in North America, it is important to have a world view of the situation as well. Since a disturbance at a 50° to 56° geomagnetic latitude in Europe or any other world location would have an equal probability of also occurring in North America for future large storms. Figure 2-4 illustrates this principle for an example at 50° across the northern hemisphere. In the case of the March 13-14, 1989 storm, the largest dBh/dt was actually observed at the Brofelde observatory in Denmark (geographic latitude of 55.6° and geomagnetic latitude of 55.3°), which has a geomagnetic latitude even further southward than either Ottawa. Figure 2-5 provides a plot of the observed dBh/dt at the Brofelde magnetic observatory on March 13-14, 1989. At time 21:44UT, the peak dBh/dt at Brofelde reached 1968 nT/min, a level which is ~1.7 times larger than the proposed ~1170nT/min for this latitude for the NERC GMD Standard. The occurrence of large substorm events with a dBh/dt of 1968 nT/min at 21:44UT located at Brofelde are a consequence primarily of the randomness of the timing of the event not geographic location. Had this substorm event occurred approximately 7 hours later, this large impulsive disturbance would have been positioned over North America and arguably caused much higher geo-electric fields, GIC's and impacts to the North American power grid than envisioned by the proposed GMD standard. The substorm randomness is related to randomness of the arrival timing of the CME and the interactions in the magnetosphere that trigger these violent events. Therefore, excluding large dBh/dt events that are not over North America cannot be defensed from a point of the scientific understanding storm interactions.

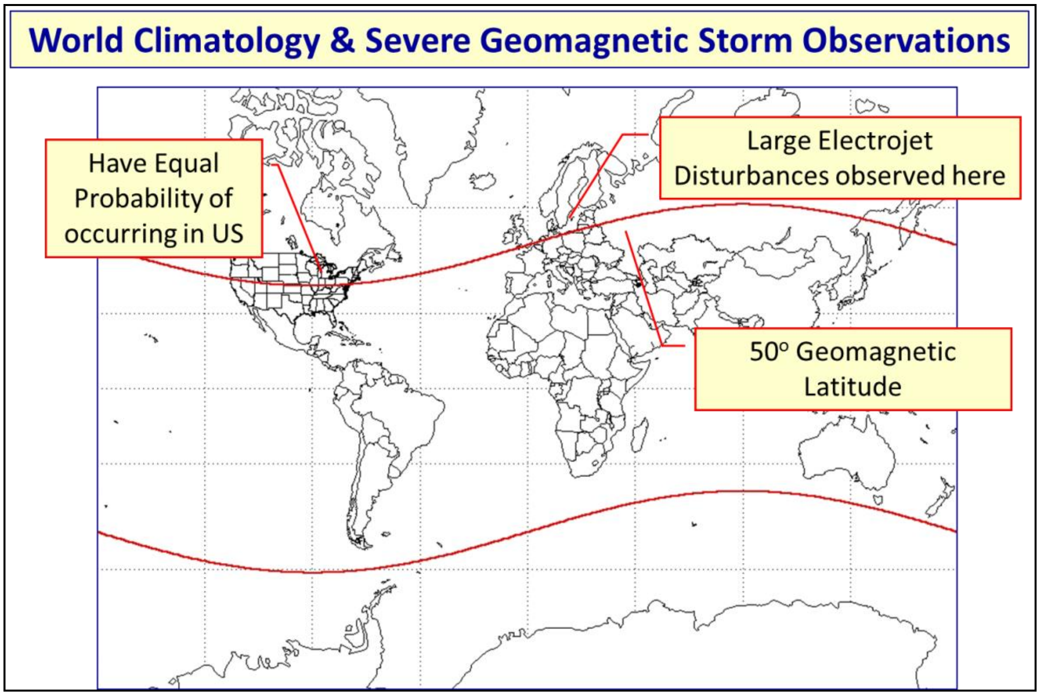

Figure 2-8 – Geomagnetic Storm Extreme Observations as a function of geomagnetic latitude worldwide

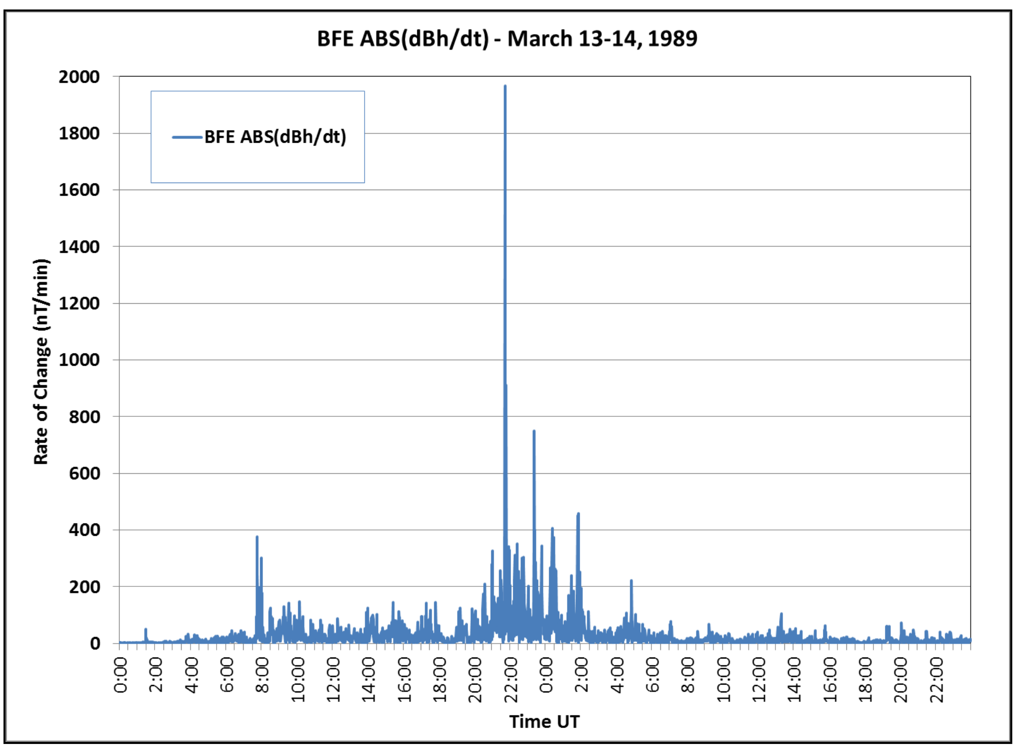

Figure 2-9 - Brofelde dBh/dt on March 13-14, 1989

In addition to the Brofelde observations from the March 13-14, 1989 storm, there are other well-known instances of large impulsive disturbances at latitudes of concern for the North American power grid. For example one of the largest dBh/dt observations occurred in the same region during the July 13-14, 1982 storm. Figure 2-6 provides a plot of the observed dBh/dt at the LOVO observatory near Stockholm. At this location (geomagnetic Latitude of 57.7^{o} which is located at similar geomagnetic latitude of Ottawa), the dBh/dt impulsive disturbance reached an intensity of 2688 nT/min. This level is ~2.3 times larger than the proposed GMD standard waveform.

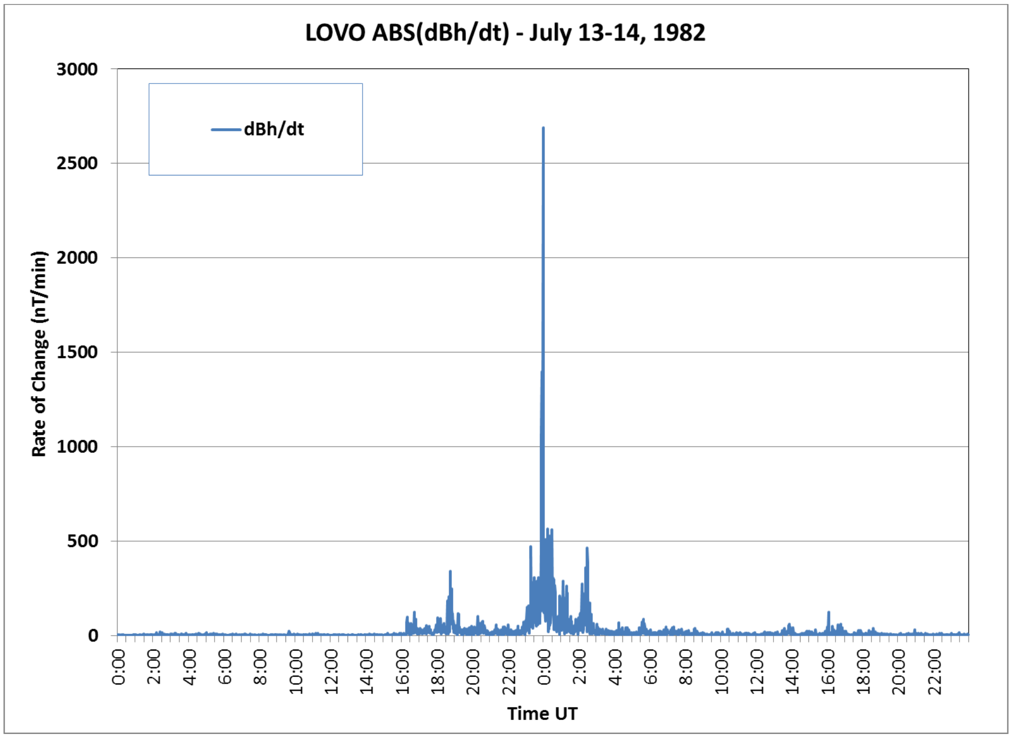

Figure 2-10 - LOVO dBh/dt on July 13-14, 1982

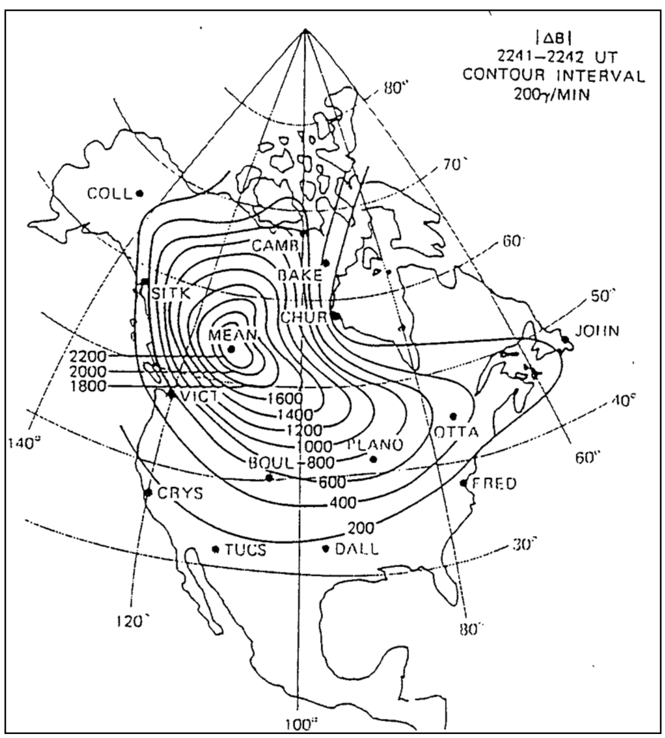

Figure 2-11 – Observed 2200 nT/min impulsive disturbance over North America on August 4, 1972 (from Anderson, Lanzerotti, et. al.).

Historically, it is known that large impulsive events have occurred over North America. Figure 2-7 provides a map of the morphology of a large ~2370 nT/min event at 22:41UT on August 4, 1972 which was positioned over the western half of North America. This is a level that is over 20% higher than the proposed NERC reference field rate of change intensity at 60^{o} geomagnetic latitude.

These are three specific events that have occurred over just the past ~40 years, this suggests that a 1-in-100 year impulsive disturbance could be even higher in intensity. Various researchers have examined available data from storm events on May 1921 and Sept 1859 and suggest that impulsive disturbance intensity levels could be as much as ~5000 nT/min. These would be intensity levels over 10 times larger than presently proposed for the NERC GMD Standard waveform. This analysis and overview calls into question the appropriateness of the NERC GMD waveform and whether it can be classified as a conservative threat environment or a 1-in-100 year threat environment.

Section 3. Benchmark GMD Event – Geographic Footprint

From the NERC GMD Standard summary, Figure 3-1 notes that NERC has determined that impulsive disturbances during benchmark storms will have relatively small regions (~100km). We question the extent that this position is reliable or can be relied upon in standard setting based upon known large storms events over just the past few decades. Such determinations of small spatial averaging would not follow from analysis of the storm large impulsive disturbance environments itself, nor are we aware of any comprehensive assessment of US ground conductivity behaviors that would support such conclusions at this time.

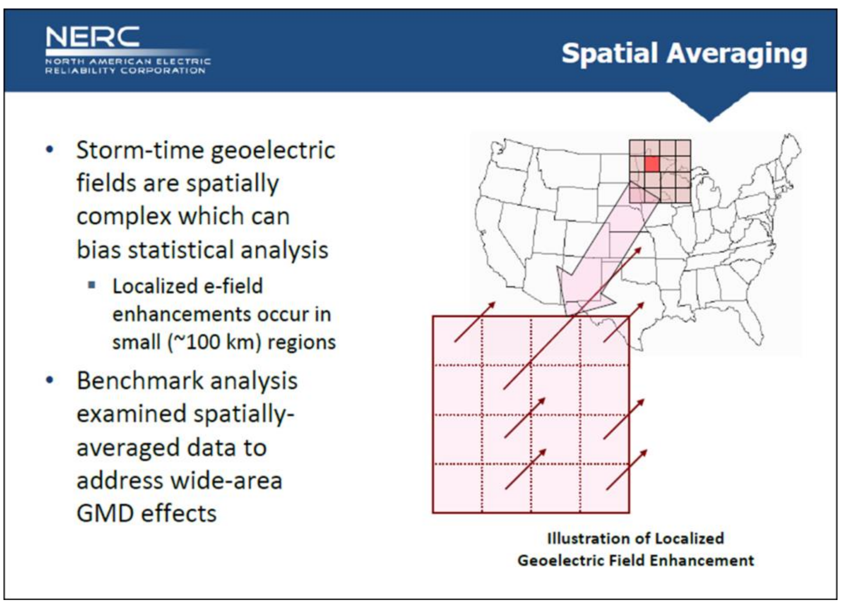

Figure 3-12 – From NERC GMD Standard Summary, Spatial averaging

As was previously noted in Figure 2-7 on August 4, 1972, the geographic footprint of a large impulsive disturbance can be enormous. Data on the geographic extent of these large dB/dt disturbances can also be extracted from the March 13-14, 1989 and July 13-14, 1982 events also discussed in Section 2 of these comments. In the case of the March 1989 storm, the large dBh/dt disturbance of 1968 nT/min at 21:44UT at Brofelde was also accompanied by the simultaneous observation of a dBh/dt intensity at Eskdalemuir observatory in Scotland of 978 nT/min at 21:44 and 1092 nT/min at 21:45UT. This observatory is ~935 km east of Brofelde and the closest observatory in that direction from Brofelde. The simultaneous observations of large impulsive disturbances at both locations suggest a single upper atmospheric current system in an east-west direction that is the driver of both observations.

In the case of the July 13-14, 1982 impulsive event, a north-south chain of magnetometers extending from Sodankyla in Northern Finland, to Lovo in Central Sweden to Brofelde in Denmark all simultaneously observed at 23:59-0:00 UT large impulsive disturbances. As previously noted in Section 2, the intensity observed at Lovo was 2688 nT/min. To the north and east at Sodankyla, the intensity reached 1905 nT/min, while at the southerly location of Brofelde, the dB/dt intensity was 1005 nT/min. For this storm there are only a limited number of observatories in operation, yet this small sample confirms a large geographic laydown. The distance from Sodankyla to Lovo to Brofelde spans an East-to-West coverage of ~600 km and a North-to-South coverage of ~1300 km. Even this limited example has a coverage area ~80 times larger than what is recommended in the NERC draft standard.

Respectfully Submitted by:

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www.DeltaStar.com

May 21, 2014

N.E.R.C.

Re: Mobile Electrical Recovery Systems for G.I.C.
Delta Star, Inc.

Dear Sirs:

INTRODUCTION:

Our Company, Delta Star, Inc. was originally founded in 1908 in Chicago Illinois. In the 1950's we began manufacturing medium power transformers at our two current locations, San Carlos, California, and Lynchburg, Virginia. In 1988 Delta Star, Inc. became an ESOP and we currently employee approximately 600 persons.

In 1976 we produced our first Mobile Substation and we are virtually the sole manufacturer of mobiles in the United States. We have manufactured more mobiles than the entire world and are supplying mobiles to nearly every major utility in the United States and Canada. For example, American Electric Power (AEP) has purchased over 120 Mobile Substations over the years and we have also supplied mobiles to many investor owned utilities (I.O.U's), electric coops, and many major cities.

The following briefly explains the ways that Mobile Substations have been used and how they may be used in the future for GIC. Also, given the fact that F.E.R.C. will soon enter into rulemaking for other substation security issues we have included a summary of additional uses for a mobile.

USAGE:

I. Initially, mobile functions were confined to three uses:

1) the failure of a substation, and
2) the regular maintenance of a substation, and
3) the ability to distribute electricity at a commercial or residential building site prior to the completion of a substation. (see Governmental Study for the utilization of mobile substation by Oak Ridge Laboratories)

Mobile for GIC:

GIC's (Geomagnetically Induced Current). These solar flare events are mostly unpredictable. If a Mobile Substation is used only in emergency situations, at idle they are not connected to the grid, and thusly not affected by GIC's.

Mobiles for Additional Emergency Usage:

1) Terrorism: As we have done in the past, a mobile can be manufactured to be enclosed in metal. Having no visual identification as a mobile, an additional layer of Kevlar like material can be shaped inside the mobiles.

2) EMP's: At their extreme (high attitude nuclear explosions, causing EMP's to travel at the speed of light, within the line of sight) its effect of "frying electronics" results in a catastrophic event reducing civilization to a pre-colonial era society. Mobile Substations can be manufactured in two different ways. When done in an electro-mechanical design the mobile is immune to EMP's.

3) Natural Disasters: When used in coordinated planning the mobile substation can be utilized as a method to create a reverse cascading electrification to a large geographical area, while providing the ability to prioritize segments requiring electricity at an earlier stage, e.g., communications, military, hospitals, financial services, etc.

II. Conclusion: Having survived acts of terrorism, GIC's, EMP's, and natural disasters, the question becomes of what use is a mobile if the rest of the electrical infrastructure is "fried" or totally disabled?

The answer has already been partially accomplished. After the 2003 blackout on the east coast, a navy nuclear submarine was used to start up a power station in New York City, by cabling the nuclear engine directly to the power station.

In the scenarios described herein, the nuclear cable from a nuclear ship would run to a step-up transformer and then to a Mobile Substation to distribute the power directly to the prioritized site.

We have enclosed materials you might find helpful from our perspective. Myself, our vice presidents, engineering experts, and planners, would appreciate the opportunity to expound on any of these matters and respond to any questions you have.

Sincerely,

Ivan H. Tepper
President & CEO

Enclosures

EIS Council Comments on Benchmark GMD Event

For NERC GMD Task Force Consideration

Submitted on May 21, 2014

Introduction

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

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

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

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

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

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

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

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

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

Spatial Averaging and Model Validation

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

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

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

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

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

1989 Quebec Storm as the Benchmark Event

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

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

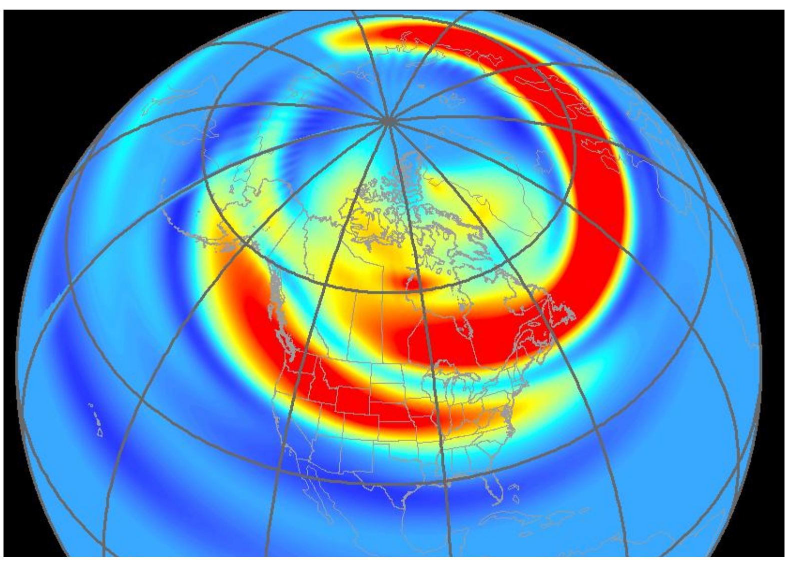

Figure 1: Snapshot of Geoelectric Fields of 1989 Quebec GMD event (Source: Storm Analysis Consultants).

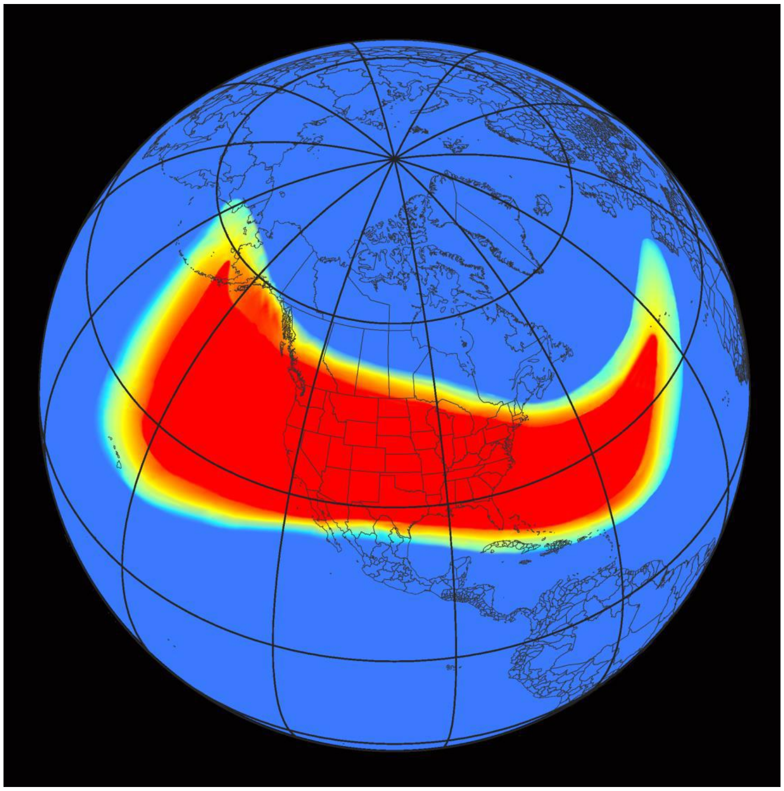

Figure 2: Snapshot of Geoelectric Fields of 1921 Railroad Storm GMD event (Source: Storm Analysis Consultants).

60 Degrees Geomagnetic Latitude Storm Center, and Latitudinal Scaling Factors

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

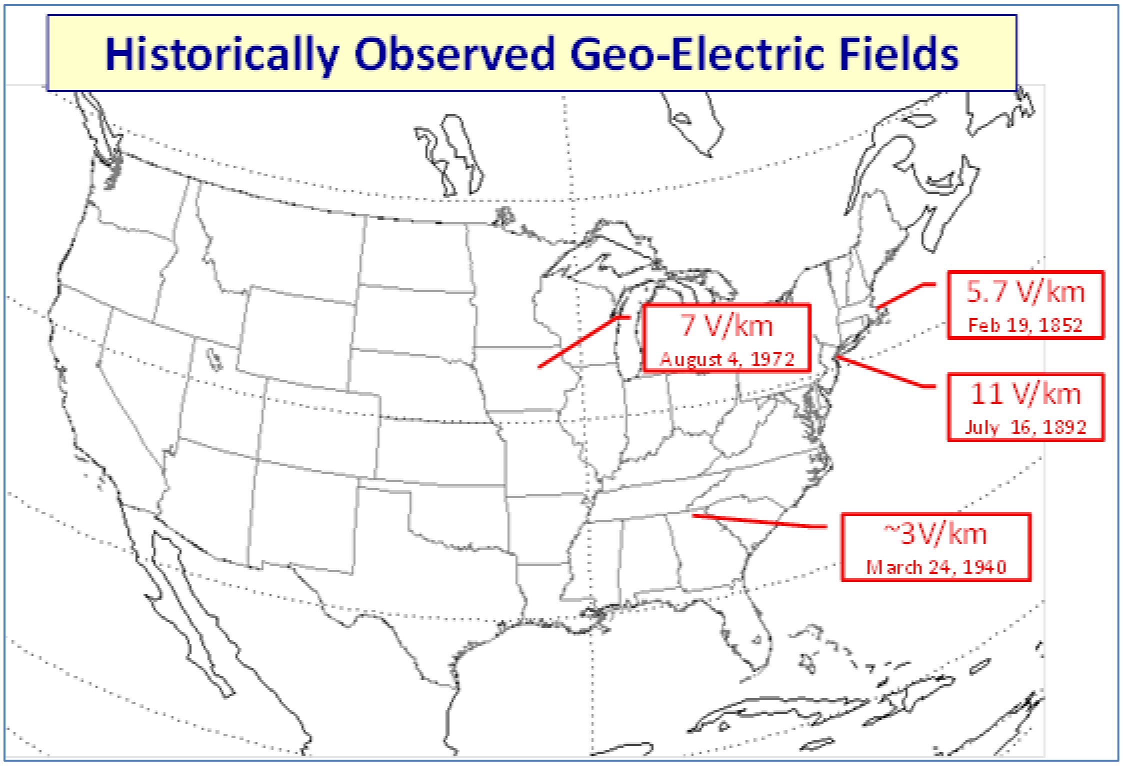

Figure 3: Historically observed geo-electric fields (Source: Storm Analysis Consultants).

Figure 3 shows a small number of measured geoelectric field intensities, indicating date and location. As can be seen, the observed values of these storm intensities (which could represent "hot spots"), are near or above 8 V/km. Given that such field intensities have been measured previously, it is recommended that a larger benchmark event be used for evaluation of system resilience for GMD events, and it must be demonstrated that the benchmark event represents a reasonable "worst-case" scenario, and captures the geoelectric field intensities of known historical storms.

Conclusion

EIS Council understands that the timetable for implementation of FERC Order 779 has placed tremendous pressure on the NERC GMDTF to recommend a credible GMD Benchmark Event on a compressed timeframe. We are sympathetic to the practical concerns of setting a reasonable benchmark for the industry in order to achieve a high level of industry buy-in and compliance. For this reason, however, we feel that the introduction of the new concept of spatial averaging has not had the proper time and peer-reviewed discussion to be widely accepted, and may in fact hinder the process by lowering confidence, while also introducing an as-yet unproven methodology into the discussion. Further, there remain obvious scientific shortcomings in using a benchmark storm centered at a designated geomagnetic latitude, when the location of such a storm is at best unknown, and could very well be at a more southward location, which would therefore invalidate the proposed latitudinal scaling factor. We recommend, therefore, a more cautious engineering approach, using a larger benchmark storm magnitude, without the use of the scaling factor, as the benchmark event against which the individual electric power companies can analyze their system resilience.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form

Project 2013-03 Geomagnetic Disturbance Mitigation

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by **May 21, 2014**.

If you have questions please contact Mark Olson at mark.olson@nerc.net or by telephone at 404-446-9760.

All documents for this project are available on the project page.

Background Information

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

- Stage 1 standard(s) that require applicable entities to develop and implement Operating Procedures were filed in November, 2013.
- Stage 2 standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or Cascading. Stage 2 standards must be filed by January 2015.

This posting is soliciting informal comments on the draft standard, TPL-007-1 – Transmission System Planned Performance During Geomagnetic Disturbances, being developed to address the stage 2 directives. TPL-007-1 includes requirements for Planning Coordinators, Transmission Planners, Transmission Owners, and Generation Owners with planning areas or transformers connected at 200 kV or higher.

Paragraph numbers in the following questions refer to Order No. 779.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions on Draft 1 of TPL-007-1

1. **Applicability**. The draft TPL-007-1 standard applies to Planning Coordinators, Transmission Planners, Transmission Owners, and Generator Owners with a high-side, wye-grounded winding connected at 200 kV or greater. The drafting team believes these are the correct functional entities to meet the directives in Order No. 779 to evaluate the effects of GICs on Bulk-Power System transformers and other equipment (P.67), consider wide-area effects and coordinate across regions (P.67), and develop plans to address potential impacts (P. 79). Justification for the 200 kV voltage threshold may be found in the whitepaper that was developed by the drafting team for the stage 1 standard, EOP-010-1 – Geomagnetic Disturbance Operations. Do you agree that these are the correct functional entities to perform the functions required in the draft standard? If you do not agree, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes
X☐ No

Comments: The TPL- 007 does not directly address the issue of harmonics that are generated during a GMD event which can damage generators as well as customer equipment. GMD generated harmonics can be a significant issue therefore the standard should be explicit in addressing an approach for assessing vulnerability and developing mitigation.
The standard should require both the development of vulnerability assessments and integration of these findings into the operating procedures.

2. **Technical basis**. Directives in Order No. 779 specify that the assessments required by the stage 2 standard should account for several parameters including the use of studies and simulations to evaluate the effects of GIC on the Bulk-Power System transformers (P. 59). The drafting team believes that the studies and analysis required by the standard meet the assessment parameters directed by FERC and are supported by the technical guides referenced in the standard. Do you agree that the requirements in TPL-007-1 address the Order No. 779 directives for GMD Vulnerability Assessment and are supported by the technical guidance? If you do not agree, or you recommend alternative language in these requirements or additional technical material, please provide specific suggestions in your comments.

☐ Yes
X☐ No

Comments: The standard should require both the development of vulnerability assessments and integration of these findings into the operating procedures.

3. **Benchmark GMD Event**. In Order No. 779, FERC directed that NERC specify the benchmark GMD event to be used by entities for assessing potential impact on the Bulk-Power System through the standards development process (P.54). Accordingly, the drafting team has posted the proposed Benchmark GMD Event Description whitepaper on the project page along with the standard for comment during this comment period. The drafting team believes the proposed benchmark GMD event is consistent with existing utility best practices, provides the consistent assessment criteria required by the FERC order, and supports assessment of the parameters specified by the directives.

   Do you agree that the proposed benchmark GMD event is technically justified and provides the necessary basis for conducting the assessments directed in Order No. 779? If you do not agree, please provide specific technically justified alternatives or suggestions for the drafting team to consider.

   ☐ Yes
   X☐ No

Comments: The geoelectric field proposed in the draft GMD standard lacks a peer review by a group of space weather experts nor has it been published in a reviewed journal. Additionally, there exists numerous available recorded sets of data that is in direct contradiction of the assumptions underlying the spatial averaging approach taken. Furthermore, there is no physical phenomena that supports an extremely huge aurora to cause an enhanced or focused geoelectric field in to a size on the order of 100km by 100km. An important standard such as this one which potentially could have a very high impact should not be based on a new spatial averaging theory for which there is violent disagreement by experts in the space weather community.
This project is identified as a Low Frequency of occurrence by potentially High Impact event. As such the GMD Task Force team should spend some time analyzing the consequences of a High Impact event. If in fact this analyzes suggests that there is a possibility of consequences that are intolerable, this would demand a more serious development of the GMD standard that is completely vetted and reviewed by an independent group of Space Weather experts before the standard can be approved.
Detailed comments from Emprimus LLC were submitted to the NERC Drafting team on Friday, May 16, 2014, and should be considered as part of these comments.

4. **Implementation**. Order No. 779 does not direct a specific Implementation Plan, but sets an expectation for a multi-phased approach and consideration for the availability of tools, models, and data that are necessary for responsible entities to perform the required GMD vulnerability assessments. The drafting team is proposing a phased implementation of TPL-007-1 over a 4-year

period. The Implementation Plan provides 1) time for entities to develop the required models; 2) proper sequencing of assessments; and 3) time for development of viable Corrective Action Plans, which may require entities to develop, perform, and validate studies, assessments, and procedures. Do you support the approach taken by the drafting team in the proposed Implementation Plan, and if you are an applicable entity in the proposed standard is the proposed time frame and sequencing realistic?

☐ Yes
X☐ No

Comments: The geoelectric field proposed in the draft GMD standard lacks a peer review by a group of space weather experts nor has it been published in a reviewed journal. Additionally, there exists numerous available recorded sets of data that is in direct contradiction of the assumptions underlying the spatial averaging approach taken. Furthermore, there is no physical phenomena that supports an extremely huge aurora to cause an enhanced or focused geoelectric field in to a size on the order of 100km by 100km. An important standard such as this one which potentially could have a very high impact should not be based on a new spatial averaging theory for which there is violent disagreement by experts in the space weather community.
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