Individual or group. (85 Responses)
Name (53 Responses)
Organization (53 Responses)
Group Name (32 Responses)
Lead Contact (32 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (14 Responses)
Comments (85 Responses)
Question 1 (61 Responses)
Question 1 Comments (71 Responses)
Question 2 (61 Responses)
Question 2 Comments (71 Responses)
Question 3 (59 Responses)
Question 3 Comments (71 Responses)
Question 4 (59 Responses)
Question 4 Comments (71 Responses)
Question 5 (0 Responses)
Question 5 Comments (71 Responses)
Question 6 (46 Responses)
Question 6 Comments (71 Responses)
Question 7 (45 Responses)
Question 7 Comments (71 Responses)
Question 8 (45 Responses)
Question 8 Comments (71 Responses)
Question 9 (41 Responses)
Question 9 Comments (71 Responses)
Question 10 (0 Responses)
Question 10 Comments (71 Responses)

-
Individual
Paul Rocha
CenterPoint Energy
Yes
CenterPoint Energy agrees in general with the SDT proposal but has an alternative suggestion for the specific roles of the applicable responsible entities. Please see CenterPoint Energy’s comments regarding Requirement 1 (Question 2).
Yes
CenterPoint Energy agrees in general with proposed Requirement 1 but offers an alternative proposal on specific aspects of the Requirement. We propose that the SDT modify R1 to read as follows: Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan consisting of Operating Procedures developed by the Reliability Coordinator and coordination of GMD Operating Procedures that may be developed by individual Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. Discussion: We believe it is not necessary, beneficial, or efficient for each and every applicable Transmission Operator and Balancing Authority to try to develop GMD-related Operating Procedures and for the Reliability Coordinator to then try to harmonize multiple individual Operating Procedures in a way that benefits the region as a whole. We believe the most efficient and beneficial approach is for the Reliability Coordinator to develop an Operating Plan for the region, but allow (not require) individual Transmission Operators and Balancing Authorities to supplement the Reliability Coordinator’s Operating Plan with individual Transmission Operator or Balancing Authority Operating Procedures, as along as those individual Operating Procedures, if any, are coordinated by the Reliability Coordinator. As repeatedly and correctly noted in the FERC Order, GMD assessment and mitigation requires a wide-area view. We believe some, if not most, individual Transmission Operators and Balancing Authorities will not be in a good position to reasonably determine what GMD-related operating actions would benefit the reliable operation of the entire region. Indeed, for some individual Transmission Operators and Balancing Authorities, it is possible and we believe likely that no action by that individual party is necessary or beneficial for the reliability of the region as a whole. The Reliability Coordinator has the wide-area view and is in the best position to determine what Operating Procedures would benefit the region as a whole. However, we also recognize that some individual Transmission Operators or Balancing Authorities may have already developed and implemented Operating Procedures, or may do so in the future based on

specific concerns or vulnerabilities identified at some future time. We believe that it is beneficial to allow (but not require) individual Transmission Operators and Balancing Authorities to develop individual Operating Procedures based upon that entity’s detailed knowledge and assessment of its facilities, as long as provision is made for the Reliability Coordinator to coordinate such discretionary individual procedures that would supplement the regional procedures. If the SDT agrees with CenterPoint Energy’s proposal, the language of R1.2 would probably need to be modified by changing “…GMD Operating Procedures of all Transmission Operators and Balancing Authorities…” to “…GMD Operating Procedures of any submitted Transmission Operators and Balancing Authorities…”. Also, R3 would need to be modified. R4 and R5 would be deleted. CenterPoint Energy will discuss proposed changes to R3 in response to the next question.
No
See CenterPoint Energy’s response to the previous question. In this question, the SDT states, “The draft Standard is intended to allow each entity to develop its own procedures…”. There is a difference between allowing each entity to develop its own procedures and requiring each entity to do so. R3, as proposed, would do the latter. CenterPoint Energy’s proposed changes to R1 would allow, but not require, an individual entity to develop its own procedures that would supplement required regional procedures developed by the Reliability Coordinator. If the SDT agrees with CenterPoint Energy’s proposed change to R1, R3 would be modified to require Transmission Operators and Balancing Authorities to submit individual Operating Procedures, if any are developed, to the Reliability Coordinator so that the Reliability Coordinator could ensure coordination that would benefit the region as a whole. CenterPoint Energy also has specific concerns that R3.1 is unnecessary and unduly prescriptive. On page 24 of the FERC Order, FERC describes NERC’s concern with reliance upon the most familiar means of characterizing space weather information, the “K-Index”. On Page 30 of the Order, FERC acknowledged NERC’s concern and took no position regarding overreliance on the K-Index to trigger operational procedures. R3.3 appropriately allows the responsible entity to choose and then document for compliance what the trigger mechanism would be, which could be space weather information or some other mechanism (GIC monitoring, for example). If an individual entity concurs with NERC’s view that space weather information is an unreliable means of triggering Operating Procedures, then that entity should not be required to acquire and disseminate such information. Proposed language changes to implement CenterPoint Energy’s suggestions are as follows: R3 Each Transmission Operator and Balancing Authority that chooses to develop, maintain, and implement Operating Procedures to supplement the Reliability Coordinator’s Operating Plan described in R1 shall submit such supplemental Operating Procedures to the Reliability Coordinator for review and approval. 3.1 DELETED 3.2 DELETED (addressed by R1.1) 3.3 Moved to Requirement 1 as R1.3 R4 DELETED (addressed by R2) R5 DELETED
Yes
CenterPoint Energy is hopeful that the SDT will agree with CenterPoint Energy’s suggested changes. With CenterPoint Energy’s suggested changes, we believe this standard can be reasonably applied throughout North America. If not, we believe the proposed standard is problematic for regions that have little or no GMD-related risk and ask that the SDT consider a proposal to exclude such regions from applicability. CenterPoint Energy understands that such a proposal would be subject to the Commission’s review and approval but the FERC Order is clear that the Commission understands that there are different risks in different regions and the Commission does not endorse or order a “one-size-fits-all” approach. CenterPoint Energy believes candidate regions to exclude from these requirements would potentially include ERCOT, SERC, and FRCC. However, to re-iterate our main point, we believe this standard could be applied to all regions, even those regions with minimal GMD-related risk, if CenterPoint Energy’s proposed changes are accepted. Even for those regions that have more GMD-related risk than other regions, CenterPoint Energy believes it is problematic and, at best, inefficient, for each and every Transmission Operator and Balancing Authority in such regions to attempt to develop individual Operating Procedures intended to collectively enhance the reliability of the region as a whole.
Yes
Group
MRO NERC Standards Review Forum (NSRF)
Russel Mountjoy
No
Do not agree with the statement "includes any transformer with high side terminal voltage greater than 200kV". This would include potiential transformers with high side terminal voltage greater than 200 kV. We believe that the effects of GMD on these devices are significantly reduced because of the high impedance of these systems. Applicability should be changed to "includes power transformers with the high side terminal voltage greater than 200kV". The change from "any transformer" to "power transformer" will match the 2012 GMD Report, Chapter 5 - Power Transformers.
No
Suggest changing language in M1 for clarity and also to replace "implemented" with “coordinated”. M1 should read: M1.

Each Reliability Coordinator shall have a GMD Operating Plan meeting all the provisions of Requirement R1; and evidence such as a revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that development and maintenance of the plan was coordinated with Transmission Operators and Balancing Authorities. Rationale: The use of the word implemented implies that the actionable items within the Operating Plan were executed as designed to mitigate the effects of a GMD event. This is an “event driven” measure but the Requirement is to “coordinate” GMD Operating Plans. By using “coordinate” (vice implement) within the Measure, the measure uses the same words as the Requirement.
Yes
Yes
Would like clarification of the statement “last effective date” in the Table of Compliance Elements, Rows 2 and 4. Change the sentence to the following: “The responsible entity reviewed its GMD Operating Procedures and submitted them for approval more than 36 months, but less than 39 months, since the last effective date of the procedures”
Yes
Yes
No
Yes
MISO has business practice manuals (BPMs) that may require modifications.
If the need for mitigation is identified, it is important to coordinate the response and installation of identified mitigations between GOs and TOs.
Group
SERC OC Review Group
Stuart Goza
Yes
Yes. We feel that the focus of this standard should be at the higher voltage such as 345 kV lines where line length makes the lines more vulnerable to GIC. It is recommended that the SDT consider changing the high side terminal voltage to greater than 300 kV. In addition, if the original language (greater than 200kV), remains in the standard, there should be an exception for equipment such as transformers.
Yes
Language should be added to ensure coordination between adjacent RCs.
Yes
Yes
Yes
Yes
There is a possibility that the DP would be included because the 200 kV limit may include distribution equipment. The SDT should consider raising the “bright line” to 300 kV.
The industry is developing the necessary procedures, processes and analysis tools to support the GMD standard. As these technologies evolve the industry will make modifications to address those changes. SDT should consider and ensure that entities have adequate time to conduct analyses based on the responsible entity's assessment of entity-specific factors such as geography, geology, and system topology.
Until analysis is underway there is a possibility that Reliability Emergency Procedures and market operations may require modification.
Thank you for the opportunity to comment. Disclaimer: The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Individual
John Falsey

Invenergy LLC
Agree
Individual
Thomas Foltz
American Electric Power
Yes
No
R1, 1.2 We are concerned by requiring the RC to “coordinate” Operating Procedures, and determine their collective compatibility. Exactly what actions would demonstrate coordination, and how could compliance of it be proven or shown? The word “coordinate” is very subject to interpretation, and could be inconsistently applied in various audits. R1.2 states that the GMD Operating Plan shall include “A process for the RC to determine that the GMD Operating Procedures … are coordinated and compatible.” This could potentially result in different coordination requirements in different regions and consequently, prevent entities who are operating in multiple regions to use consistent procedures within an entity’s service territory.
Yes
No
Requirements R2 and R4 state that each applicable entity shall review its GMD Operating Plan/Procedures every 36 months from the last *effective* date while Requirement 5 states that the applicable entities shall have a copy of its GMD Operating Procedures in the control room(s) prior to its *implementation* date. AEP recommends referencing the effective date only. R5 should be changed to state “…shall have a hard or electronic copy of its GMD Operating Procedures…”
In the VSL matrix, R4 states that “the responsible entity reviewed its GMD Operating Procedures and submitted them for approval….”. Requirement 4, as stated, does not require approval for the Operating Procedures, therefore the words “and submitted them for approval” should be deleted from all four VSLs for R4.
Yes
Yes
No
Yes
The SAR indicates that there may be changes to additional standards eventually proposed as a result of Stage 2 project efforts. There is no mention of any specific modifications or additional requirements related to the sharing of GMD-related modeling information. A library of GIC models capturing various system conditions will eventually be necessary. There should be a similar coordinated effort in developing such a GIC model library as the MMWG that develops power flow and stability models on an annual basis.
AEP is voting negative on this draft, but can foresee voting in the affirmative if the issues and concerns expressed in this response are addressed in future versions of the draft.
Individual
John Bee
Exelon and its Affiliates
Yes
Yes
Yes
R3.3, font is incorrect – need the entire number to be bold.
No
Exelon believes that performing a review of GMD Plans / Operating Procedures every 36 months is contrary to the Paragraph 81 criteria whose effort was to remove truly administrative requirements that do not have an impact on electric grid reliability. We feel tha R2, M2 and R2, M4 should be removed.

Individual
Nazra Gladu
Manitoba Hydro
Yes
No
(1) R 1.1: This requirement needs clarification. It refers to a GMD Operating Plan requiring “a description of activities designed to mitigate the effects of GMD events….”. It is not clear whether the “activities” are intended to be performed by the Reliability Coordinator or refer to the Operating Procedures of the Transmission Operators / Balancing Authorities, or some other type of activity directed by the Reliability Coordinator, but performed by other entities. FERC Order 779 only referred to a possible “coordination “ of Operating Procedures and that element is captured separately in R 1.2. (2) R 1.2: The requirement for “compatibility” of Operating Procedures causes concern and should be deleted. FERC Order 779 (Par. 38) specified that GMD standards “should allow responsible entities to tailor their operational procedures based on the responsible entity’s assessment of entity-specific factors, such as geography, geology and system topology. While FERC also directed NERC to consider the “coordination” of such operational procedures, it did not require the “compatibility” of such procedures. Manitoba Hydro already has in place operating procedures to respond to GMD events. The role of Manitoba Hydro’s Reliability Coordinator is to notify Manitoba Hydro of GMD events and disseminate information on present and forecasted storm levels. This would be appropriately viewed as coordination. However, requiring a Reliability Coordinator to determine the “compatibility” of several entities’ Operating Procedures goes beyond coordination and begs the question of what happens if there is a determination that certain Operating Procedures are not compatible. Does the Reliability Coordinator have the authority to direct an entity to adopt a different procedure? If so, it is not clear how it would be determined which responsible entity must change its procedures. Most importantly, this requirement erodes the discretion that was granted to Transmission Operators and Balancing Authorities under Order 779.
(1) Background - for clarity, consider replacing the words “can lead to” with [may result in]. (2) Purpose - for clarity, consider replacing the purpose section of the standard with the following sentence: “To [ensure plans, operating procedures, and resources are maintained and available] to mitigate the effects of geomagnetic disturbance (GMD) [emergencies on the bulk electric system.]” (3) M2 - consider revising the measure as follows: “Each Reliability Coordinator shall have evidence [showing] that it has reviewed its GMD Operating Plan within the timeframe of Requirement R2. [Acceptable evidence could] include a dated review signature sheet or revision history.” (4) 3.1, 3.2 and 3.3 - for completeness, start the sentance with [A listing of the]. (5) M4 - consider revising the measure as follows: “Each Transmission Operator and Balancing Authority shall have evidence [showing] that it has reviewed its GMD Operating Procedures within the timeframe of Requirement R4. [Acceptable evidence could include] a dated review signature sheet or revision history.” (6) Table of Compliance Elements, R2, Low, Medium, High VSL - insert the word [last] before the words “effective date” for consistency with Requirement R2. (7) Some entities may reduce exports to neighbors as a mitigating strategy. This method, determined to be the ideal action, based on system studies, may be perceived as potentially impacting neighbouring entities. What level of coordination would be required or appropriate to permit the curtailment of exports?
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
No
Should only apply to transformers which are part of BES. BES definition is based upon the low side winding voltage of greater than 100 kV where as this requirement is based upon high side voltage. Thus, this goes beyond BES elements. We suggest it apply to transformer with low side winding voltage of 200 kV or greater.
Yes

No
Requirment 3.2 requires coordination with Reliability coordinator’s plan. Thus, there should be a provision that this requirement is effective only 6 months after the Reliability coordinator’s plan is available.
No
Requirement R5 is unnecessary and should be deleted altogether. This requirement is a process and not a standard and it is not necessary to have a hard copy when an electronic copy could be readily available. There is no reliability benefit to this requirement.
Implementation time for BA and TOP should have 6 additional months than the implementation time for Reliability coordinator. This is to allow coordination wiht Reliability Coordinator’s procedures affecting BA and TOP. Requirement R1, 1.2 should have the word “all” deleted. It does not serve any specific purpose and could become unnecessarily burdensome.
No
No
Group
Salt River Project
Bob Steiger
Yes
We agree that the scope is appropriate.
No
We believe that the requirement should state that the Reliability Coordinator should establish triggers that are appropriate for the given geographical and system exposure for each TO or BA. We would suggest language such as the following: R1.1 The Reliability Coordinator shall create a preliminary assessment of the exposure for each BA and TO. The plan and procedures developed by the Reliability Coordinator shall establish trigger levels for initiating and terminating these plans or procedures based on the preliminary assessment of exposure for each BA or TO.
No
Please see Comment for question 2. The requirements for the Reliability Coordinator should be the same for the Transmission Operator and Balancing Authority.
Yes
A general comment on the Solar Cycle. It seems that the timing of the peak of the solar cycle might require more frequent review of plans and procedures.
Yes
Yes
Yes
Yes
Depending on how the Reliability Coordinator writes the plan and procedures there could be an impact to elements of the BES that are jointly owned, mainly regarding contractual requirements.
We believe the standard needs to address shared elements of the BES. The exposure at one end of a shared element may be more significant than at the remote end. NERC and the Reliability Coordinator need to provide direction when this type of situation occurs.
Individual
Joe O'Brien for Ed Mackowicz
NIPSCO
No
There are geological and physical (circuit length) that correlate directly to the probability of GIC reaching levels that would harm transformers. There is also historical evidence of the presence of and correspondingly the absence of GIC in systems.

These two factors should be used to determine if a TOP/BA needs to develop, maintain, and implement Operating Procedures to mitigate the effects of GMD events on the reliable operation of its respective system. If the conditions for GIC do not exist and there is no history of GIC induced damage or misoperation, a RC should not be required to include those TOP/BAs in coordinating plans for GMD other than to provide assistance as required in other standards.
No
There are geological and physical (circuit length) that correlate directly to the probability of GIC reaching levels that would harm transformers. There is also historical evidence of the presence of and correspondingly the absence of GIC in systems. These two factors should be used to determine if a TOP/BA needs to develop, maintain, and implement Operating Procedures to mitigate the effects of GMD events on the reliable operation of its respective system. If the conditions for GIC do not exist and there is no history of GIC induced damage or misoperation, a RC should not be required to include those TOP/BAs in coordinating plans for GMD other than to provide assistance as required in other standards.
No
There are geological and physical (circuit length) that correlate directly to the probability of GIC reaching levels that would harm transformers. There is also historical evidence of the presence of and correspondingly the absence of GIC in systems. These two factors should be used to determine if a TOP needs to develop, maintain, and implement Operating Procedures to mitigate the effects of GMD events on the reliable operation of its respective system. If the conditions for GIC do not exist and there is no history of GIC induced damage or misoperation, the TOP should not be required to have plans specifically for GMD events.
Yes
Yes
Yes
Yes
If the geological conditions and system configuration are such that damaging magintudes of GIC do not exist and there is no history of GIC induced damage or misoperation in the TOP’s service area, it should not be required to have plans specifically for GMD events.
No
Individual
Steve Hill
Northern California Power Agency
Yes
For Stage 1 I believe the SDT has it correct; however I am concerned that there is no mention as to what will happen with IRO-005-3.1a R3 which appplies to a host of registrations. At some point EOP-010-1 will supercede IRO-005-3.1a, but no mention in the implementation plan is discussed.
No
I think there is too much latitude given. The guidance document describes GMD as more a global issue; not just a regional issue. I believe the guidance document provides a good list of activities for an RC to start with, but that these activities should be consistent between various RCs as well as the process the RCs will use to determimne if the TOP and BAs are coordinated and compatible.
No
In a perfect world this should already exist is folks are truely in compliance with IRO-005-3.1a R3. How are the RCs, TOPs and Bas curently complying with IRO-005-3a? This might provide some insight for the SDT.
Yes
Yes, but I do not see that this is any different form complying with IRO-005-3 R3 except for the 36 month review cycle.
To suumarize: I will vote no on the initial ballot per comments I have submitted; however that does not mean I am opposed to this standard. I do believe GMD is an issue that even though it is low frequency can have an reliabiilty impact on the BES or BPS. I believe the SDT needs to address the IRO-005-3 R3 concern I have discussed. If I were to guess the reason for EOP-010-1, it would be to replace a pretty loose requirement in IRO-005-3 R3. If this is the case then give more direction and guidance in the new standard per the guidance document that NERC provided
Yes
I like the SAR; too bad some of the language did not carry over into the implementation plan
Yes

No
No, but not sure I understand what you are getting at. As stated above geology and soil conditions will vary from region to region
Yes
Operating procedures that address compliance with IRO-005-3 R3 will need to be modified and new procedure to show compliance with EOP-010-1 will need to be developed.
No further comments
Individual
Melissa Kurtz
US Army Corps of Engineers
Agree
MRO NSRF
Individual
Andrew Z. Pusztai
American Transmission Company
Yes
Yes
Yes
Yes
Yes
Yes
No
No
If the need for mitigation is identified, ATC believes that it is important to coordinate the response and installation of identified mitigations between GOs and TOs.
Individual
Jonathan Appelbaum
The United Illuminating Company
Yes
No
Requirements R2 and R4 t to review the plan is purely administrative. As the scientific knowledge evelves R1 and R3 requires a plan to be designed to mitigate the effects of GMD.
Requirement R5 to make the operating plan available in the control center is administrative. Reliability requires the plan to be implemented as described in requirement R1. VRF for R1 and R3 are Medium since an entity failure to implement the GMD operating plan may lead to cascade. VRF for R2, R4, and R5 should be Low. R2, R4, and R5 are purely administrative. The entity is required to have Operating Plans that mitigate the effects of GMD a review of the operating plan is a secondary activity to developing, maintaining, and implementing an operating plan.

Individual
Michael Falvo
Independent Electricity System Operator
Yes
Yes
Yes
We agree with the proposed requirement. However, there currently exists a similar requirement in IRC-005-3.1a, R3, which says: R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans. With the introduction of the EOP-010 standard, specifically Requirement R3, the TOP and BA will have operating procedure in place and be required to monitored GMD activities on an ongoing basis. We question the need to keep R3 of IRO-005-3.1a. If the latter is deemed redundant after the adoption of the EOP-010 standard, we suggest the SDT to propose retiring R3 of IRO-005-3.1a.
Yes
Requirements R2 and R4 could easily be combined. Is there a specific reason why the Reliability Coordinator is separated from the Transmittion Operator and the Balancing Authority? The wording in these two requirements is identical.
1. Requirement R5 is not needed. The objective is that each Responsible Entity develop, maintain and implement operations plan to mitigate GMD effects. Whether or not there is a hard copy, or electronic copy for that matter, in the control room and/or the backup control centre is unimportant and irrelevant. In order that the Responsible Entities implement the plan to comply with the standard requirements, operating personnel needs to be provided and have access to the plan itself, regardless of where and how it is placed. We suggest removing R5. If Requirement R5 was to be retained, we suggest adding “Reliability Coordinator” after “Transmission Operator” and “Balancing Authority”. We believe that Reliability Coordinators should also have a copy of their GMD Operating Procedures in their primary and backup control rooms. The current Requirement R5 does not include the Reliability Coordinator. 2. The proposed Implementation Plan may conflict with Ontario regulatory practice with respect to the effective date of the standard. It is suggested that this conflict be removed by moving the last part in the effective date “,or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.” to the end of the first sentence immediately after “by applicable regulatory authorities”. The same change should be made to the first bullet under the Effective Dates Section of the Implementation Plan.
No
The Stage II assessment should be done at the interconnection level, not by a patchwork of the Planning Coordinators and Transmission Planners. If analysis shows there are potential local issues, NERC should consider regional criteria or local procedures first, rather than an overly complex standard, much of which won’t apply to most entities interonncetion-wide.
Yes
No
No
Group
Pepco Holdings Inc & Affiliates
David Thorne
No
Recommend adding “BES” as qualifier for transformer. 4.1.1 Reliability Coordinator 4.1.2 Balancing Authority with a Balancing Authority Area that includes any BES transformer with high side terminal voltage greater than 200 kV 4.1.3 Transmission Operator with a Transmission Operator Area that includes any BES transformer with high side terminal voltage greater than 200 kV
Yes
Yes

No
Requirement R5 seems administrative in nature (similar to other Paragraph 81 requirements) and seems duplicative of R3 which already requires implementation of the Operating Procedures (i.e. implementation could include making operation personnel aware of the Operating Procedure and having available). If a separate training requirement is developed, R5 would be further redundant. Recommend that R5 be removed. Requirement R2 and R4 require applicable entities to review their GMD Plans/Operating Procedures every 36-months. With solar cycles having an average duration of about 11 years and the Plan and Operating Procedure being potentially utilized 1-2 years during the peak years of the 11 year cycle, how was the 36 month review criteria reached? Recommend changing to a 48 month review period which still allows for 2-3 reviews during a 11 year solar cycle.
Yes
Suggest that any associated training requirements for System Operators be deferred to Stage 2. Based on what is learned from Stage 2 benchmark events, may want to revisited functional applicability of Stage 1 (i.e. EOP-010).
Yes
No
No
Individual
Anthony Jablonski
ReliabilityFirst
Yes
There may be cases in which a transformer with a high side terminal voltage of greater than 200 kV is not considered BES (e.g., the transformer is excluded as part of a local network). ReliabilityFirst requests clarification whether this non-BES transformer is included within the scope of the standard?
Yes
Yes
Yes
1)Requirement R2 - ReliabilityFirst recommends clarifying the term “effective date” by including the following language “of its GMD Operating Plan” at the end of the requirement. ReliabilityFirst suggests the following for the SDTs consideration: "Each Reliability Coordinator shall review its GMD Operating Plan at least once every 36 calendar months from the last effective date [of its GMD Operating Plan]." 2) Requirement R4 - ReliabilityFirst recommends clarifying the term “effective date” by including the following language “of its GMD Operating Plan.” ReliabilityFirst suggests the following for the SDTs consideration: "Each Transmission Operator and Balancing Authority shall review its GMD Operating Procedures at least once every 36 calendar months from the last effective date [of its GMD Operating Procedures]."
1) Requirement R5 - To be consistent with the language in the other requirements within the standard, ReliabilityFirst recommends changing the term “implementation date” to “effective date.” ReliabilityFirst offers the following for the SDTs consideration: "Each Transmission Operator and Balancing Authority shall have a copy of its GMD Operating Procedures in its primary control room and any applicable backup control rooms so that it is available to its operating personnel prior to its [effective] date." 2) Consideration for new Requirement R6 - ReliabilityFirst recommends including a new Requirement R6 which would require adjacent Reliability Coordinators to share their respective GMD Operating Plans. During a GMD event, it can span multiple Reliability Coordinator areas and ReliabilityFirst believes the adjacent Reliability Coordinators should be aware of each other’s GMD Operating Plans. 3) VSL Requirement R2 - The date ranges between the VSLs are not inclusive. The VSLs need to reflect "…but less than or equal to…" language. ReliabilityFirst offers the following as an example “Lower” modified VSL for the SDTs consideration: "The Reliability Coordinator reviewed its GMD Operating Plan more than 36 months, but less than [or equal to] 39 months, since the effective date." 4) VSL Requirement R4 - The date ranges between the VSLs are not inclusive. The VSLs need to reflect "…but less than or equal to…" language. ReliabilityFirst offers the following as an example “Lower” modified VSL for the SDTs consideration: "The responsible entity reviewed its GMD Operating Procedures and submitted them for approval more than 36 months, but less than [or equal to] 39 months, since the last effective date."
Yes
Yes

Yes
No
Group
Hydro One Networks Inc.
Sasa Maljukan
Yes
Yes
Yes
No
Requirement R5 is of a purely administrative nature, not contributing to reliability. Suggest to eliminate. Emphasis and focus should be in operating personnel training and awareness. If R5 is kept in the standard, request to clarify the meaning of “prior to its implementation date.” We believe it should be “prior to actions to implement the plan.” As written in could be misinterpreted as prior to the standard effective date.
There is a GMD related pre-existing requirement in IRO-005-3.1a R3. It seems, given the extensive Operating Plans proposed in EOP-010-1, that R3 in IRO-005-3.1a can be retired. This should be considered by the GMDTF. The proposed Implementation Plan may conflict with Ontario regulatory practice with respect to the effective date of the standard. It is suggested that this conflict be removed by moving the last part in the effective date “,or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.” to the end of the first sentence immediately after “by applicable regulatory authorities”.The same change should be made to the first bullet under the Effective Dates Section of the Implementation Plan.
No
Suggest adding PER-005-1, R3 in the Title of Proposed Standards(s) in this SAR. If not, how will the changes made to PER-005-1 be coordinated in conjunction with this new EOP-010-1 Standard?The disposition of IRO-005-3.1a R3 needs to be addressed in the SAR as a retirement.
Yes
Yes
The flexibility in the plan design takes into account locational differences, which are geographically and geologically based. There is no basis for differences due to regional entity boundaries.
Yes
Individual
Martyn Turner
LCRA Transmission Services Corp
No
The standard has not provided a clear reason for starting at 200 kV, which seems arbitrary. Papers on GMD do indicate the potential risk to transformer’s increases at the higher voltage levels and in particular to single phase wye connected transformers. Would propose the following: 4.1.3.1 a Transmission Operator Area that includes any BES transformer with three single phase core windings connected in a "wye" configuration of 300 kV or greater; or 4.1.3.2 a Transmission Operator Area that includes any BES transformer with at least one "wye" connected winding greater than 400 kV;
Yes
Yes
Yes

none
no comment
no comment
Yes
The standard and SAR as drafted do not address differences in geography, geology or system topology variances. For example because of its southern latitude, the ERCOT region is over 10 times less likely to be impacted by a GMD occurrence than northern regions of the country and 100 times less than regions of Canada. The cost and effort of prevention measures should be in line with the potential risks.
no comment
no comment
Individual
Michiko Sell
Public Utility District No. 2 of Grant County, WA
Yes
Yes
Yes
Yes
GCPD is concerned about the implementation period being sufficient to allow the RC to develop and implement a GMD Operating Plan AND afford adequate time to ensure that each TO and BA within its region the ability to develop, maintain and implement GMD Operating Procedures that are coordinated with the RC's GMD Operating Plan. Six (6) months is not sufficient time to allow development and coordination within the region.
Group
Dominion
Connie Lowe
Yes
Yes
Yes
No
As R2 and R4 are currently written, they are purely administrative and do nothing to improve or insure reliability. R1 requires the GMD Operating Plan be maintained which infers the need to review on a periodic basis.
Yes
Dominion suggests adding PER-005-1, R3 in the Title of Proposed Standards(s) in this SAR? If not, how will the changes made to PER-005-1 be coordinated in conjunction with this new EOP-010-1 Standard.
Yes
No
No

Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
Agree
SERC OC Review Group
Individual
Ben Li
Ben Li Associates
Yes
Yes
Yes
1. We agree with the proposed requirement. However, there currently exists a similar requirement in IRC-005-3.1a, R3, which says: R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans. With the introduction of the EOP-010 standard, specifically Requirement R3, the TOP and BA will have operating procedure in place and be required to monitored GMD activities on an ongoing basis. We question the need to keep R3 of IRO-005-3.1a. If the latter is deemed redundant after the adoption of the EOP-010 standard, we suggest the SDT to propose retiring R3 of IRO-005-3.1a. 2. It R3 is to be retained, then it does not mention “applicable” BAs and TOPs, which it should. Further, a BA or TOP should be able to adopt a template procedure developed by its Reliability Coordinator. This should be explained in an administrative appendix to the standard.
Yes
1. Requirement R5 is not needed. The objective is that each Responsible Entity develop, maintain and implement operations plan to mitigate GMD effects. Whether or not there is a hard copy, or electronic copy for that matter, in the control room and/or the backup control centre is unimportant and irrelevant. In order that the Responsible Entities implement the plan to comply with the standard requirements, operating personnel needs to be provided and have access to the plan itself, regardless of where and how it is placed. We suggest removing R5. 2. GMDs are an emerging issue. There is nothing in this standard that enables information sharing and learning. The RC plan and BA/TOP procedures should include what sensing information is in the field and the general reporting that such information gathering is done when GIC symptoms are observed. There should also be information collected following major solar events that is evaluated by the NERC technical committees. This should not be codified in the requirements, but in an administrative appendix or an activity to be included in events analysis.
No
The Stage II assessment should be done at the interconnection level, not by a patchwork of the Planning Coordinators and Transmission Planners. If analysis shows there are potential local issues, NERC should consider regional criteria or local procedures first, rather than an overly complex standard, much of which won’t apply to most entities interconnection-wide.
Yes
No
Yes
There is a possibility that the procedure of one RC could end up causing redispatch or reconfiguration in a TOP or BA area or another RC area. There is also a need to address the mechanism for cost recovery, particularly when the problem could be mitigated locally through upgrades. The cost recovery for redispatch and/or upgrades to BES facilities needamong affected entities.
Individual
Don Schmit
Nebraska Public Power District
Agree
Southwest Power Pool (SPP)
Group
seattle city light

paul haase
No
Seattle City Light supports the general concepts presented in the draft Standard and appreciates that the Standard Drafting Team affords each entity flexibility as to procedures. However, Seattle is concerned about the broad applicability of the Standard as proposed, and recommends that it only apply to BA and TOPs with Bulk Electric System (BES) transformers 200kV and above (as well as all RCs). This change would make this Standard consistent with other Standards as well as the BES definition we've worked so hard on the past several years.
Yes
Yes
Yes
Group
Northeast Power Coordinating Council
Guy Zito
Yes
The Applicability and Purpose conflict however. The Purpose says "To mitigate the effects of geomagnetic disturbances (GMD) events by implementing operating procedures." But the Standard's Purpose is not consistent with the Standard. The Standard goes into detail about the mitigation plans. Recommend the Purpose be "To establish and implement GMD mitigation operating procedures". The effectiveness of these procedures to mitigate the effects of GMD is unknown.
Yes
Yes
No
The review interval specified in R2 and R4 is 36 months. A five year review would be more appropriate given the length of the solar cycle. As R2 and R4 are currently written, they are purely administrative and do nothing to improve or ensure reliability. R1 requires the GMD Operating Plan be maintained which infers the need to review on a periodic basis. Requirement R5 also is administrative, does not contribute to reliability, and can be eliminated. Suggest to eliminate the wording "All procedures should be at the primary and backup control center as part of normal business". Emphasis and focus should be on operating personnel training and awareness. If it is decided to keep R5 in the Standard, request clarificiation of the meaning of "prior to its implementation date." It should be "prior to actions to implement the plan." As written it could be misinterpreted as prior to the Standard's effective date.
There is a GMD related pre-existing requirement in IRO-005-3.1a R3. The implementation plan is not clear regarding the retirement of the requirement. It would seem, given the extensive Operating Plans proposed in EOP-010-1, that R3 in IRO-005-3.1a can be retired. This should be considered by the GMDTF. Simpler wording would make the Standard easier to understand. Every plan will be different depending upon a wide range of factors affecting GMD mitigation; equipment types and inventory, location, system configuration and topography, latitude, ground characteristics, etc. Suggest the following simplifying wording changes to Requirement R3: R3. Each Transmission Operator and Balancing Authority shall develop, maintain, and implement GMD Operating Procedures. At a minimum, the Operating Procedures shall include: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning] 3.1. The steps or tasks for the acquisition and dissemination of space weather information to its System Operators. 3.2. The steps or tasks to be employed by System Operators that are coordinated with its Reliability Coordinator's GMD Operating Plan. 3.3 The predetermined trigger conditions for initiating and terminating steps or tasks in the Operating Procedure. To be consistent with the terminology in other standards, suggest changing the wording the Applicability Section to: 4.1.2 Balancing Authority with a Balancing Authority Area that includes transformers with high voltage terminals connected at 200kV and above. 4.1.3 Transmission Operator with a Transmission Operator Area that includes transformers with high voltage terminals connected at 200kV and above. The wording of the Purpose should be changed to "To mitigate the risk of instability, uncontrolled separation, and Cascading in the Bulk-Power System as a result of geomagnetic disturbance (GMD) events by developing, maintaining and implementing Operating Plans and Operating Procedures." The Purpose as written should state what GMD affects. It also

only addresses the implementation of the Operating Procedures but does not address the development and maintenance aspect, nor does it address the Operating Plans.
No
Suggest adding PER-005-1, R3 in the Title of Proposed Standards(s) in this SAR. If not, how will the changes made to PER-005-1 be coordinated in conjunction with this new EOP-010-1 Standard? The disposition of IRO-005-3.1a R3 needs to be addressed in the SAR as a retirement.
Yes
Yes
The flexibility in the plan design takes into account locational differences, which are geographically and geologically based. There is no basis for differences due to regional entity boundaries.
Yes
Studies, control room practices and monitoring all will be needed. These are business practice changes and have a cost which should be considered in this Standard's development. It should be.
The Standard is a reasonable response to the FERC Directives. When EOP-010-1 becomes effective IRO-005-3a Requirement R3 becomes redundant and should be removed. This information should be added to the "Related Standards" section of the SAR.
Individual
Silvia Parada Mitchell
NextEra Energy
No
NextEra Energy is pleased with the work the GMD SDT has done in a very quick period of time, with the exception of adding certain requirements that no longer fit within the paradigm under which Standards are to be drafted. NextEra suspects that these requirements were added because of the short period of time in which the SDT drafted the Standard, and, thus, NextEra is hopeful that once highlighted here that the SDT will quickly decide to delete the requirements as they are inconsistent with current Standard drafting practices. These requirements are inconsistent with both results based and P81 concepts, given that they are administrative in nature and do little to promote reliability. While some may see these requirements as good practices, adding them is no longer consistent with Standard drafting practices nor desired by stakeholders. New Standards are to be clear, high quality, technically sound and results based. Also, these requirements are similar to those that FERC recently indicated it would approve for retirement in the P81 Notice of Proposed Rulemaking. Therefore, NextEra requests that these requirements, noted below, be deleted. R2. Each Reliability Coordinator shall review its GMD Operating Plan at least once every 36 calendar months from the last effective date. R4. Each Transmission Operator and Balancing Authority shall review its GMD Operating Procedures at least once every 36 calendar months from the last effective date.
For the same reasons provided in response to question number #4 (P81 -- administrative in nature), NextEra requests that the following requirement be deleted: R5. Each Transmission Operator and Balancing Authority shall have a copy of its GMD Operating Procedures in its primary control room and any applicable backup control rooms so that it is available to its operating personnel prior to its implementation date.
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
No
Tri-State believes that Balancing Authorities should not be included as an applicable entity because there will be unnecessary duplication or conflict between the BA and the Reliability Coordinator Operating Plans.
No
Tri-State believes that the proposed standard, as written, is too vague and gives the Reliability Coordinator too much latitude to create plans as only it deems appropriate. It also does not provide for industry review of these plans beforehand. Requirement R1 appears to be a "fill in the blank" requirement, which FERC does not approve.

Yes
Tri-State agrees that R3 properly addressed FERC Order No. 779, but believes the implementation periods should be modified. A 6 month implementation period requiring the Reliability Coordinator to develop the Operating Plan and the Transmission Operator/Balancing Authority to develop the Operating Procedures is not suitable. The Transmission Operator/Balancing Authority needs time to ensure their procedures are in accordance with the Reliability Coordinator's Operating Plan so the implementation dates need to be staggered.
Yes
1. Tri-State believes a 6 month implementation period isn't appropriate for this. This implementation period requires the RC to develop the Operating Plan and the TOP/BA to develop the Operating Procedures at the same time. The TOP/BA needs time to ensure their procedures are in line with the RC's Operating Plan so the implementation dates need to be staggered. 2. Tri-State also believes Stage 1 and Stage 2 should be reversed. Developing, maintaining, and implementing a plan without first conducting assessments and determining the risk is illogical. The Operating Plans should be based on the results shown of the assessments. 3. There is a lack of evidence showing major damage and widespread outages due to a geomagnetic disturbance. There should be more studies performed before creating a Reliability Standard in order to better determine the actual necessity of one. 4. Currently, Tri-State believes that a guidance document would be a better solution to address the risk of potential geomagnetic disturbances. 5. Tri-State believes all non-BES transformers should be excluded regardless of high side voltage. In addition any transformer with a delta primary winding should be excluded regardless of the high side voltage.
Yes
Tri-State believes the SAR provides a scope to address the directives but still strongly believe that Stage 1 and Stage 2 should be in the reverse order. An assessment should be conducted to determine potential impacts from GMD events prior to developing Operating Procedures to mitigate any possible effects of GMD.
No
Tri-State believes that BAs should not be included as an applicable entity because there will be unnecessary duplication or conflict between the Balancing Authority and the Reliability Coordinator Operating Plans.
Yes
The assessments from each region will likely provide different results due to the varying geography, geology and location. A continent-wide standard will not properly or efficiently address the potential risks brought by geomagnetically induced currents. Tri-State believes that NERC should issue an alert to have the different Regional Entities review and develop regional standards, guidelines or other criteria to mitigate the possible effects of geomagnetic disturbances rather than develop a "fill in the blank" standard.
Yes
The NERC IRO-005-3.1a Requirement 3 may need to be retired and incorporated into the new standard(s). The WECC Geo-Magnetic Disturbance Reporting procedure, which meets the above NERC requirement, may also need to be modified. It is extremely difficult to determine whether internal business practices will need to be adapted prior to assessments being performed to identify potential impacts of GMD events. The final GMD Operating Plan(s) developed by the Reliability Coordinator and Balancing Authorities, which have not been developed, could also impact internal business practices.
Group
Western Area Power Administration
Lloyd A. Linke
Yes
Yes
Western Area Power Administration (WAPA) and the Bureau of Reclamation (Reclamation) believe that R1 should also require Reliability Coordinators (RCs) to be responsible for monitoring space weather information and alerting TOPs and BAs. Currently IRO-005-3.1a R3 requires RCs to ensure that TOPs and BAs are aware of GMD forecast information. . This responsibility should be enhanced in EOP-010-1 R1 and should require RCs to monitor space weather information and alert TOPs and BAs when GMD watches and warnings begin and end, and to determine what GMD responses are necessary within the RC footprint. For example, the drafting team could add sub-requirement 1.3 to require, “A process for the Reliability Coordinator to monitor space weather information and issue alerts to Transmission Operators and Balancing Authorities when GMD watches and warnings are initiated, and what GMD mitigation actions may be required in response to the GMD event.”
No
WAPA and Reclamation suggest that the drafting team remove sub-requirement R3.1. WAPA and Reclamation believe it is inappropriate to place responsibility for acquiring space weather information with the Transmission Operators (TOPs) and Balancing Authorities (BAs) because BES reliability will not be enhanced when hundreds of individual entities must determine when a GMD event begins and ends. Neighboring TOPs and BAs would likely react at different times depending

on their perception of when a GMD event begins, which could be chaotic and contribute to system instability. As discussed above in response to Question 1, WAPA and Reclamation believe that responsibility for monitoring space weather, determining when a watch or warning is appropriate, and alerting TOPs and BAs should be placed at least at the RC level and possibly with a national coordinating entity. WAPA and Reclamation believe that the drafting team should remove the current R3.1, and should renumber R3.2 and R3.3 to R3.1 and R3.2. WAPA and Reclamation also suggest that the drafting team add a new R3.3 to require TOP and BA Operating Procedures to address “The steps or tasks for receiving and disseminating space weather information to its System Operators.”
Yes
: WAPA and Reclamation also believe Generator Operators should have a role in developing Operating Procedures that will affect their equipment.
Yes
Yes
Yes
Yes
Individual
Jack Stamper
Clark Public Utilities
Agree
Snohomish County Public Utility District
Group
Western Electricity Coordinating Council
Steve Rueckert
Florida Municipal Power Agency
No
See FMPA concerns on aplicability, type of transformer, and whether or not the BA should be an applicable entity.
Yes
Requirement is acceptable, but implementaiton period is too short
Question applicability of BA and implementation period is too short
Yes
Six Month implementation period is not adequate
Yes
No
I am not aware of any regional variances that would be needed but do have concern about entities in the far south being subject to these standard prior to studies being conducted.
No
Individual
Kenn Backholm
Public Utility District No.1 of Snohomish County
No
SNPD agrees in general but believes the 200 kV voltage threshold is premature. In general, we believe that GMD should be tackled on a regional basis and already by the Reliability Coordinator (“RC”). It is our understanding that location (latitude and local geology) and the type of systems (i.e., systems with extra-high-voltage, series capacitor compensated lines, transformer configuration & grounding, and line length) are important elements in a GMD analysis. Therefore, a one-size-

fits-all approach based on voltage level would be inappropriate. SNPD believes the Reliability Coordinator ("RC") would be in the best position to identify facilities including the appropriate voltage level or other attributes that may become more apparent as research in this area matures.
Yes
Appropriate implementation time should be given so that the RC has time to develop the GMD operating plan and coordinate with neighboring RCs as well as other impacted functions. Although GMD and Geomagnetically Induced Currents ("GIC") have been well understood for many decades, how they impact various elements of the power grid are still being assessed by the electric industry and equipment manufactures. Recent work presented at the 2013 IEEE PES General meeting by Emanuel Bernabeu, Dominion "Overview of GMD Phenomena and ways to study the impact on the transmission system" and Ramsis Girgis, ABB "Equipment issues transformers, (Major Concern)'s etc. -from the transformers committee, impacts on transformer fleet and new designs" will provide more insight into appropriate actions to be taken by the RC and impacted functions. Significant discussion has taken place on this subject in many different forums; however there is very little credible analysis on how GMD can impact the BES and what level of risk does GMD pose compared to other adverse impact events. See IEEE Power & Energy article "Geomagnetic Disturbances" by IEEE Power and Energy Society Technical Council Task Force on Geomagnetic Disturbances, July/August 2013 pg. 71-78.
No
Because GMD can be a wide area event the BA and TOP efforts should focus on coordinating operations and procedures with the RC. Also GMD is a High-Impact, Low-Frequency event so overall risk to the TOP or BA area should be assessed to make certain the operations and procedures are commensurate with the risk to reliable operation of the Bulk Electric System.
Yes
Yes
Yes
No
No
Individual
Rich Salgo
NV Energy
No
The preparation and execution of operating procedures to mitigate the effects of GMD events on the power system are specific to the Reliability Coordinator and the Transmission Operator entities. We do not believe that actions are required of the Balancing Authority function at all, as this is not a balancing issue, but rather a transmission operations issue. Additionally, we believe the scope of applicability should not reach into distribution transformers, particularly radial transformers serving distribution load. Hence, we recommend that the Applicability section be modified to remove 4.1.2 (Balancing Authority) and place a limitation on 4.1.3 to restrict applicability to BES transformers of the indicated voltage range.
No
Requiring the RC to develop and maintain a plan is an appropriate requirement; however, it is unclear what the RC must do under 1.2 to "determine" that the GMD Operating Procedures in its area are coordinated and compatible. Suggest a language change to "A process for the RC to review and coordinate the GMD Operating Procedures of all TOP's in the RC Area."
No
OK, except "Balancing Authority" should be removed from R3.
Yes
Agree with the 36 month cycle of review; however, BA should be removed from R4.
No
No, as discussed in response to Q1, the BA should have no direct functional responsibility for the mitigation of GMD. This should be up to the TOP's within the BA footprint. Inclusion of the BA complicates the situation.

No
No
Individual
Jen Fiegel
Oncor Electric Delivery Complany LLC
No
The draft fails to include Generator Owners and Generator Operators that have step-up and auxillary transformers with a terminal higher that 200 kV. If GMD causes unintended ground induced currents (GICs) on Transmission Owners' and Transmission Operators Transmission Transformers that are important to the grid, then it stands to reason that step-up and auxillary transformers are at risk as well. Generator Owners transformers have a great impact to the reliability of the system. Those transformers need to be included in the Standard. Additionally, it would seem imperative to include generator owner transformers that supply offsite power to nuclear generation that are above 200 kV. The Standard must include the GO and GOP in order to address the FERC Order.
No
The proposed language of R1 assumes all Regions operate the same therefore in order to support the structure of Regions across the North American utility industry, Oncor recommends R1 be revisedto: "Each Reliability Coordinator shall coordinate the development and maintain a GMD Operating Plan with its Balancing Authority, Transmission Owners, Transmission Operators, Generator Owners, and Generator Operators that coordinate GMD Operating Procedures within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include:" Oncor believes the RC should remain responsible for implementing the plan.
Yes
Yes
No
The Standard did not address all owners and operators of equipment associated with the FERC Order directing NERC to "submit for approval one or more Reliability Standards that require owners and operators to develop and implement operational procedures to mitigate the effects of GMDs." The Standard needs to also include Generation Owners and Operators of step-up transformers and auxillary transformers with at least one terminal at 200 kV or higher.
No
The Standard did not address all owners and operators of equipment associated with the FERC Order directing NERC to "submit for approval one or more Reliability Standards that require owners and operators to develop and implement operational procedures to mitigate the effects of GMDs." The Standard needs to also include Generation Owners and Operators of step-up transformers and auxillary transformers with at least one terminal at 200 kV or higher.
No
No
Individual
Oliver Burke
Entergy Services, Inc.
Yes
We feel that the focus of this standard should be at the higher voltage such as 345 kV lines where line length makes the lines more vulnerable to GIC. It is recommended that the SDT consider changing the high side terminal voltage to greater than 300 kV. One of the reasons for the change is due to the number of transmission to distribution transformers where the high side voltage is 230 kV. On the other hand, having the 200 kV cutoff has the potential to create confusion for BA. A BA with no 200 kV transformers may be intertwined with a TOP that does have the issue and likely will be exposed to issues that the TOP faces.
Yes
Language should be added to ensure coordination between adjacent RCs.

No
As mentioned in Q1, a BA with no 200 kV transformers may be intertwined with a TOP that does have the issue and likely will be exposed to issues that the TOP faces and may need to develop, maintain, and implement GMD Operating Procedures. The SDT should consider changing the high side terminal voltage to greater than 300 kV.
No
R5 is an administrative requirement for which compliance may be unprovable. This requirement (to have a copy of its GMD Operating Procedures in its Primary and Back-up Control Rooms) is also redundant to PER-005, which requires a Job Task Analysis for every task performed by System Operators. All administrative requirements should be deleted.
Yes
Yes
DP may need to be included as the 200 kV limit may include distribution equipment. The SDT should consider changing the high side terminal voltage to greater than 300 kV.
No
SDT should consider and ensure that entities have adequate time to conduct analyses based on the responsible entity's assessment of entity-specific factors such as geography, geology, and system topology.
Until analysis is underway there is a possibility that Reliability Emergency Procedures and market operations may require modification.
Group
Tennessee Valley Authority
Dennis Chastain
Agree
SERC OC Review Group
Individual
Dan Inman
Minnkota Power Cooperative, INC.
No
Do not agree with the statement "includes any transformer with high side terminal voltage greater than 200kV". This would include potiential transformers with high side terminal voltage greater than 200 kV and smaller, high impedance non-BES transformers serving load. We believe that the effects of GMD on these devices are significantly reduced because of the high impedance of these systems. Applicability should be changed to "includes power transformers with the high side terminal voltage greater than 200kV and a base rating of at least XX MVA". The change from "any transformer" to "power transformer" will match the 2012 GMD Report, Chapter 5 - Power Transformers. The addition of “XX MVA” will limit the inclusion of small 200+ kV connected transformers. It is unclear as to what that limit should be and the evidence for that limit is unknown. Alternatively, could make the statement “includes BES power transformers with a high side terminal voltage greater than 200 kV” but this could exclude large load serving transformers that do have a significant effect in relation to GMD events.
No
Comment #1) Suggest changing language in M1 for clarity and also to replace "implemented" with “coordinated”. M1 should read: M1. Each Reliability Coordinator shall have a GMD Operating Plan meeting all the provisions of Requirement R1; and evidence such as a revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that development and maintenance of the plan was coordinated with Transmission Operators and Balancing Authorities. Rationale: The use of the word implemented implies that the actionable items within the Operating Plan were executed as designed to mitigate the effects of a GMD event. This is an “event driven” measure but the Requirement is to “coordinate” GMD Operating Plans. By using “coordinate” (vice implement) within the Measure, the measure uses the same words as the Requirement. Comment #2) Suggest replacing the word “all” in R1.2 to “applicable”. Rationale: Using the word “all” could be interpreted such that TO’s and BA’s that have transformers below 200kV could be affected. Replacing “all” with “applicable” would avoid confusion, and be in alignment with the SDT intent.
Yes
Yes
See NSRF Comments
Yes

Yes
No
Yes
MISO has business practice manuals (BPMs) that may require modifications.
See NSRF's Comments
Individual
Terry Baker
PRPA
Agree
Florida Power & Light
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes
During the July 30, 2013 GMD webinar, the response to one question was that the SDT would consider whether the BA applicability is appropriate. Austin Energy (AE) would encourage the SDT to complete that effort.
Yes
No
Austin Energy (AE) believes that staggered enforcement dates between R1 and R3 are necessary for TOPs and BAs to develop Operating Procedures “that are coordinated with [their] Reliability Coordinator’s GMD Operating Plan.” The current implementation plan establishes a single date for all requirements. During the webinar, AE suggested this and the response was that NERC anticipates that TOPs' Operating Procedures will be developed first so the timing is acceptable. Given the definitions of Operating Plan and Operating Procedures in the NERC Glossary, AE understands how an Operating Plan can be built based on a series of underlying Operating Procedures, but if that is the intended order of operation, R3 should not require that Operating Procedures be coordinated with the RC’s Operating Plan.
Yes
Overall, AE has voted negative because there is an abundance of cleanup work necessary. AE asks the SDT to consider the comments above as well as the following points: (1) The SDT should more carefully consider the wording for the applicability of transformers. During the webinar, someone asked if the intent was to cover only BES tranformers and Mark Olsen answered in the affirmative. As written, the BES definition considers the low-side voltage (greater than or equal to 100 kV), whereas the Applicability section of EOP-010-1 considers only the high-side voltage. There could be transformers that are 69/230 kV that would not be BES Elements but would bring in a TOP or BA given the way 4.1.2 and 4.1.3 are currently written. Additionally, the SDT should consider transformers with high and low-side voltages greater than 100kV but excluded from the BES based on a documented exclusion or exception. (2) Given the requirement to “develop, maintain and implement” in R1 and R3, the SDT should consider adding in the same day operations time horizon to cover the "implement" action. (3) The SDT should clarify what is intended by “implement” in R1 and R3. During the webinar, the response to this question was unclear. SDTs on other recent projects (COM-003-1, for example) have gone to great lengths to define what is meant by "implement." RSAWs often state it means to include in your company’s body of operating procedures. Without explanation, a CEA might interpret implement as follow your Plan/Procedure exactly as written. The industry needs to know the SDT’s intent. (4) Change the word “all” to “applicable” before the phrase “Transmission Operators and Balancing Authorities” in R1 part 1.2. (5) The SDT should move the requirement regarding space weather (currently R3 part 3.1) to R1 so the RC can, in its coordination role, ensure that input data is consistent and applicable to its Region.
Yes
Yes
No
Not at this time. We believe, however, that due to geographic differences, entities in the ERCOT Region may request regional variances after we begin developing our approach to GMD.
No

Group
Oklahoma Gas & Electric
Terri Pyle
No
This standard should not be applicable to Balancing Authorities. FERC Order No. 779 directed the ERO to develop one or more Reliability Standards that require owners and operators of the BPS to develop and implement operational procedures to mitigate the effects of GMDs. The functions of the BA center around balancing load and generation and implementing and accounting for interchange schedules. BAs (unless they are also TOPs) do not monitor BES elements such as transformers.
Yes
No
This standard should not be applicable to the Balancing Authorities. FERC Order No. 779 directed the ERO to develop one or more Reliability Standards that require owners and operators of the BPS to develop and implement operational procedures to mitigate the effects of GMDs. The functions of the BA center around balancing load and generation and implementing and accounting for interchange schedules. BAs (unless they are also TOPs) do not monitor BES elements such as transformers.
Yes
We agree with the language of these three requirements, however, we believe that the Violation Risk Factor should be LOWER, not Medium for these documentation related requirements.
While we understand the good intentions of FERC in Order No. 779, we feel that industry’s time would be better spent pursuing Reliability initiatives that were focused on more pressing, well-documented threats to reliability, particularly as it relates to entities that are located in more southerly regions of the continent.
No
This SAR should not be applicable to Balancing Authorities. FERC Order No. 779 directed the ERO to develop one or more Reliability Standards that require owners and operators of the BPS to develop and implement operational procedures to mitigate the effects of GMDs. The functions of the BA center around balancing load and generation; and implementing and accounting for interchange schedules. BAs (unless they are also TOPs) do not monitor BES elements such as transformers.
No
This SAR should not be applicable to Balancing Authorities. FERC Order No. 779 directed the ERO to develop one or more Reliability Standards that require owners and operators of the BPS to develop and implement operational procedures to mitigate the effects of GMDs. The functions of the BA center around balancing load and generation; and implementing and accounting for interchange schedules. BAs (unless they are also TOPs) do not monitor BES elements such as transformers.
No
No
While we understand the good intentions of FERC in Order No. 779, we feel that industry’s time would be better spent pursuing Reliability initiatives that were focused on more pressing, well-documented threats to reliability, particularly as it relates to entities that are located in more southerly regions of the continent.
Individual
Texas Reliability Entity
Texas Reliability Entity
No
We agree with the RC and TOP functions. The SDT may also want to consider adding the GOP function so that large GSU’s are also monitored under this standard.
No
This wording in R1 and R3 are “fill-in-the-blank” type of requirements that NERC has been trying to move away from. We understand that Phase 2 of the GMD Standard project will provide additional details and clarification.
No
See comments for #2 above.
Yes

Many new Standards have a Guidelines and Technical Basis section as part of the Standard. Would the SDT consider creating a Guidelines and Technical Basis section?
Group
Florida Municipal Power Agency
Frank Gaffney
No
FMPA appreciates the efforts of the SDT and, in general, we believe the standard is good. However, we believe the Applicability of the standard needs improvement; and that is the primary reason we are voting Negative. The ORNL report, which FMPA believes is already unreasonably pessimistic, made several conclusions that are not reflected in the applicability that FMPA believes ought to be: 1. The applicability ought to be clear that the standard refers to only BES transformers and not step-down trasformers to distribution. 2. The winding(s) in question needs to be grounded wye connected and not delta connected for ground current to flow. The geomagnetically induced current (GIC) is ground current. Hence, the applicability ought to specify transformers with grounded wye connected winding(s) above a certain threshold voltage 3. According the the ORNL 319 report (http://web.ornl.gov/sci/ees/etsd/pes/pubs/ferc_Meta-R-319.pdf, Figure 1-17), 3 phase / 3 leg core design transformers are much less likely to saturate and result in MVAR demands about 25% of that of three single phase transformers. Hence, the applicability for > 200 kV and < 400 kV (i.e., the 230 and 345 kV transformers) ought to be limited to single phase transformers. 4. The primary concerns for GIC is for voltage collapse or relay misoperation due to increased MVAR demand of transformers that could potentially result in cascading, and potential damage to transformers (see SAR description of Industry Need); hence, the applicability should not be to BAs but only RCs and TOPs (see additional discussion in response to question 3). 5. FMPA also believes that the 200 kV threshold ought to be raised to 300 kV. Almost all 230 kV transformers are 3 phase / 3 leg core transformers with a much lower probability of becoming saturated; whereas, according to ORNL, about 15% of 345 kV transformers are single phase transformers (Figure 1-19). In addition, the resistance ot 230 kV lines is significantly higher than 345 kV lines, which will significantly reduce GIC (see Figure 1-12 noting that the chart is semi-logarithmic) for lines of similar length (see figure 1-14). This is largely due to the fact that most 345 kV lines are two conductor bundles for RFI purposes and most 230 kV lines are single conductor; hence, 230 kV lines are roughly twice the resistance of 345 kV lines for the same length of line. FMPA assumes that GSU's owned by the GO and operated by the GOP is intended to be included in the applicability (since the vast majority of GSU's are grounded wye connected on the high side), but under the interconnecting TOP's operating plan. However, the applicability does not reflect this. If the intent of the SDT is to include these GSUs, then the applicability ought to be changed accordingly. As such, FMPA suggests the following for applicability: 4.1. Functional Entities: 4.1.1 Reliability Coordinator 4.1.3 Transmission Operator with a: 4.1.3.1 Transmission Operator Area that includes any BES transformer with three single phase transformers connected in a grounded wye configuration of 300 kV or greater; or 4.1.3.2 Transmission Operator Area that includes any BES transformer with at least one grounded wye connected winding greater than 400 kV (either three single phase transformers or a three phase transformer); or 4.1.3.3 Transmission Operator Area that interconnects with any generator interconnection facilities that include a GSU that meets either criteria 4.1.3.1 or 4.1.3.2
No
Bullet 1.2 puts RC's in a position of responsibility without authority, or at least implies such. The bullet requires the RC to "determine" that the plans of the BAs and TOPs are coordinated. What happens if, through that process, the plans are determined not to be coordinated? Is the RC compliant? What would the RC do to get the plans to be coordinated? Does the RC have the authority necessary to cause this coordination? FMPA suggests looking at the EOP-006 and EOP-005 construct for guidance. And as stated in response to question 1, the BA should not be an applicable entity.
No
As stated previously, the BA should not be an applicable entity. If transmission switching is required that impacts contraints which in turn impacts dispatch, then existing procedures such as TLR and procedures regarding ancillary services should be used. If the RC or TOP needs additional generation to be commited or redispatch to occur, the RC or TOP already has the authority within the standards to require that additional unit commitment or redispatch.
Yes
Although FMPA agrees with a 3 year period, FMPA would prefer a requirement of once every 3 calendar years as opposed to 36 months to allow more flexibility in scheduling. Again, the BA should not be an applicable entity.
Yes

Yes
Yes
Florida is not susceptible to high GIC due to latitude and geology. At minimum, the applicability of the stadnrd ought to change based on geography and geology, e.g., maybe Florida’s applicability is only for > 400 kV or not applicabile at all.
No
Group
Southern Company
Wayne Johnson
Yes
The currently drafted standard does not include GOPs as an applicable entity. Consideration should be made to include them as an entity for reliability purposes. For example, a GOP may decide to take a unit offline if a K7 is declared, and if so, the reliability entities would need to know that these units are not available, if needed. In addition, if GOPs are added as applicable entities, they need to have a requirement to provide their plan to the reliability entities. Although we are suggesting adding the Generator Operator as an applicable entity, we do suggest that they be allowed to develop their own GMD Operating Plan or implement the GMD Operating Plan of its Transmission Operator. We also believe, consistent with our response to Question #7 below, that the standard should not apply to BAs, as the the risks mitigated by requiring them to have Operating Procedures are things that the TOP monitors and can either take action themselves or instruct the BA to redispatch generation.
Yes
The SDT should consider creating criteria for the RC to use to ensure plans are coordinated and compatible. For example, criteria were developed for RCs to use to approve TOP restoration plans in EOP-006-2, R5, which indicates that the “Reliability Coordinator shall determine whether the Transmission Operator’s restoration plan is coordinated and compatible with the Reliability Coordinator’s restoration plan and other Transmission Operators’ restoration plans within its Reliability Coordinator Area.” Similarly, the SDT or a committee designated by the SDT should create criteria for RCs to use to ensure plans are coordinated and compatible.
Yes
An additional requirement should be added requiring BA/TOPs to send their initial plans and any revisions to the RC for review, since the RC has responsibility for ensuring plans are coordinated and compatible.
Yes
For R3.1, to address potential confidential data issues, the weather data utilized should be publicly available . We recommend changing R3.1 as follows: R3.1 The steps or tasks for the acquisition and dissemination of publicly available space weather information to its System Operators.
Yes
Yes
As stated above in our response to Question #1, we suggest that the BA should not be required to have Operating Procedures for GMD. The risks mitigated are things that the TOP monitor and can either take action themselves or instruct the BA to redispatch generation.
No
No, as long as the phase 2 standards are non-prescriptive. EOP-010-1 allows entities to account for regional differences that exist in their area through the development of their plans. This methodology of accounting for regional differences through plan development needs to be continued as the phase 2 standards or standard changes are developed.
No
Group
Emprimus LLC and Volkmann Consulting
Terry Volkmann
Yes
For the Stage 1 standard, appropriate inclusion of affected transformers is not as important as it will be in Stage 2. What is important for the Stage 1 standard to capture in its applicability section the portion of the BES most effected by a GMD and

the most influential to maintain BES reliability. In capturing RC, BA and TOP with 200kv transformers, the SDT has captured entities that have influence over the 200kv and above system. For entities the own and operate facilities between 100 and 200kv, their system reliability will be maintained by the RC and any neighboring / over-arching entities that operation 200kv and above.
No
We agree with the language of develop, maintain and implement a GMD Operating Plan. However, the requirement does not have any evaluation of whether the Operating Plan was appropriately and effectively implemented for an event. M1 should include a post-event evaluation activity and subsequent documentation of the plan implementation.
No
We agree with the language stated in R3. However, R3 should include the requirement of the TOP to communicate that they have implemented their Operating Procedures. Likewise the requirement does not have any evaluation of whether the Operating Procedures were appropriately and effectively implemented for an event. M3 should include a post-event evaluation activity and subsequent documentation of the plan implementation
Yes
R5 should be applicable to RC also.
Yes
Yes
No
Yes
GIC mitigation systems should be excluded from the SPS definition.
Group
FirstEnergy
Doug Hohlbaugh
Yes
Yes
Yes
No
Requirements R2 & R4 FirstEnergy questions the need for Requirement R2 and R4 which propose an every 3-year review of GMD operating procedures. This is an administrative task and should not be a reliability requirement subject to mandatory enforcement. The requirements do not adhere to principles identified by the Par. 81 team and now being applied across all drafting teams. Par 81 Criteria B1 Administrative which states "The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome." Additionally, an upcoming draft revision to the NUC-001 standard is proposing to remove a similar obligation in NUC-001 (R9.1.3). FERC's Order 779 did not suggest a need for the responsible entities to periodically update their GMD Operating Procedures every 3-years. Rather in paragraph 39 the Commission states "While responsible entities will develop and implement operational procedures, NERC can support their efforts, for example, by identifying and sharing operational procedures found to be the most effective. NERC should also periodically survey the responsible entities' operational procedures, offer recommendations based on lessons-learned and new research findings, and re-evaluate whether modification to the Reliability Standards is warranted." It is our understanding that it's the ERO's responsibility to reconsider whether or not more specific minimum GMD procedure expectations should be codified in the standard at some future date. This could be done for example during the 5-year review period of the standard and the NERC GMD Task Force could be tasked with providing the review required of NERC and propose changes to the GMD standard if needed. Requirements R5 Requirement R5 indicates a need for the Operating Procedures to be located at the primary and back-up control center facility. The intent of Requirement R5 is already covered in standard EOP-008-1, R2. FirstEnergy recommends that Requirement R5 be struck as a redundant obligation.
The comments are supported by the following GMD standard ballot body members representing FirstEnergy: Bill Smith, Segment 1 Transmission Owners; Cindy Stewart, Segment 3 Load Serving Entities; Doug Hohlbaugh, Segment 4 Transmission Dependent Utilities; Ken Dresner, Segment 5 Electric Generators and Kevin Querry, Segment 6 Brokers, Aggregators, and Marketers.

Yes
Yes
No
No
Individual
David Jendras
Ameren
We believe GMD is a regional issue and therefore a NERC Standard is not necessary. We believe that studies need to be completed before considering a new NERC Standard. In addition, an entity cannot develop operating plans and procedures based on unstudied GMD conditions. After the initial assessments of potential impacts of GMD on BES reliability is complete, then appropriate (if necessary) plans and procedures can then be developed and if necessary a standard could then be drafted based on results of the studies.
No
We believe that the scope should include initial assessments of potential impacts of GMD before a standard is drafted.
Individual
Catherine Wesley
PJM Interconnection, L.L.C.
Yes
PJM has also signed onto SERC's comments.
Yes
PJM has also signed onto SERC's comments.
Yes
PJM has signed onto SERC's comments. PJM also signs onto the SRC's response to Question #3.
Yes
PJM has signed onto SERC's comments.
Yes
PJM has signed onto SERC's comments.
Yes
PJM has signed onto SERC's comments.
No
PJM has signed onto SERC's comments.
No
PJM has signed onto SERC's comments.
Individual
Michael Lowman
Duke Energy

Yes
While Duke Energy agrees in principle with starting at 200kV and above for having a GMD process/procedure, we believe that 300kV and above would be a more appropriate bright-line. In addition, if the bright-line remains at 200kV and above, we recommend the SDT should consider an alternative method of including only 200kV and above BES elements. Lastly, Duke Energy believes that only transformers with wye connected winding(s) should be included because only wye connected winding(s) are affected by GIC(s).
Yes
Duke Energy believes R1.2 should be changed to “Each Reliability Coordinator shall have an Operating Process to determine that the GMD Operating Procedures of all Transmission Operators and Balancing Authorities in the Reliability Coordinator Area are coordinated and compatible.“
Yes
Yes
Duke Energy believes that “Same Day Operations” is a more appropriate time horizon for R1 and R3.
Yes
Yes
Yes
Duke Energy believes that due to regional variances, GMD procedures should vary based on GMD severity levels and kV thresholds.
Yes
If a TOP’s GMD procedure includes the curtailment of transactions to mitigate a potential GMD event, then the modification of a TOP(s)/TSP(s) business practices may be required.
Group
PacifiCorp
Ryan Millard
No
Generator Operators are listed as applicable functions within the SAR but are absent from the scope of applicability of EOP-010-1. If Generator Operators are not included under the standard they should be removed from the scope of the SAR, as this creates inherent confusion as to their explicit applicability to the standard. Additionally, PacifiCorp does not support inclusion of the BA as an applicable functional entity.
No
PacifiCorp supports Florida Municipal Power Agency’s position as it relates to Question 2. R1.2 requires the RC to "determine" that the plans of the BAs and TOPs are coordinated but it is not clear what happens if, through that process, the plans are determined not to be coordinated? Is the RC compliant? What would the RC do to get the plans to be coordinated? Does the RC have the authority necessary to cause this coordination? PacifiCorp supports FMPA’s suggestion to look at the EOP-006 and EOP-005 construct for guidance.
No
PacifiCorp supports Florida Municipal Power Agency’s position as it relates to Question 3. As stated previously, the BA should not be an applicable entity. If transmission switching is required that impacts contraints which in turn impacts dispatch, then existing procedures such as TLR and procedures regarding ancillary services should be used. If the RC or TOP needs additional generation to be commited or redispatch to occur, the RC or TOP already has the authority to require that additional unit commitment or redispatch.
No
PacifiCorp affirms that if the intent of a review of an entity’s GMD plans and procedures is to improve the scientific understanding of GMDs, a more prudent requirement would be a periodicity that is post-operative event based.In the absence of a GMD event, the 36-month requirement is arbitrary and one that would likely be performed by an entity as a best business practice.
No
PacifiCorp believes the use of the term “Bulk Power System” confuses the scope of the standard. PacifiCorp recommends replacing “Bulk Power System” with the term “Bulk Electric System” and adding the caveate that the voltage limitation be set at 200kv and above.

No
Please refer to the answer supplied for Question 1.
No
None other than those identified.
Group
Beaches Energy Services
Steve Lancaster
Agree
FMPA
Group
Bureau of Reclamation
Erika Doot
Yes
No
The Bureau of Reclamation (Reclamation) and Western Area Power Administration (WAPA) recommend that R1 should also require Reliability Coordinators (RCs) to be responsible for monitoring space weather information and alerting TOPs and BAs. Currently IRO-005-3.1a R3 requires RCs to ensure that TOPs and BAs are aware of GMD forecast information. . This responsibility should be enhanced in EOP-010-1 R1 and should require RCs to monitor space weather information and alert TOPs and BAs when GMD watches and warnings begin and end, and to determine what GMD responses are necessary within the RC footprint. For example, the drafting team could add sub-requirement 1.3 to require, “A process for the Reliability Coordinator to monitor space weather information and issue alerts to Transmission Operators and Balancing Authorities when GMD watches and warnings are initiated, and what GMD mitigation actions may be required in response to the GMD event.”
No
WAPA and Reclamation suggest that the drafting team remove sub-requirement R3.1. WAPA and Reclamation suggest that it is inappropriate to place responsibility for acquiring space weather information with the Transmission Operators (TOPs) and Balancing Authorities (BAs) because BES reliability will not be enhanced when hundreds of individual entities must determine when a GMD event begins and ends. Neighboring TOPs and BAs would likely react at different times depending on their perception of when a GMD event begins, which could be chaotic and contribute to system instability. As discussed above in response to Question 1, WAPA and Reclamation believe that responsibility for monitoring space weather, determining when a watch or warning is appropriate, and alerting TOPs and BAs should be placed at least at the RC level and possibly with a national coordinating entity. WAPA and Reclamation believe that the drafting team should remove the current R3.1, and should renumber R3.2 and R3.3 to R3.1 and R3.2 respectively. WAPA and Reclamation also suggest that the drafting team add a new R3.3 to require TOP and BA Operating Procedures to address “The steps or tasks for receiving and disseminating space weather information to its System Operators.”
Yes
WAPA and Reclamation also believe that Generator Operators should have a role in developing Operating Procedures that will affect their equipment.
Yes
Individual
Michael Brytowski
Great River Energy
No
GRE agrees with ACES recommending the drafting team provide technical justification for choosing 200 kV as the threshold. We ask that the drafting team consider increasing the voltage level on the high side of the transformer to 345 kV, or in the alternative, provide rationale for setting the limit at 200 kV. GRE agrees with ACES and does not believe that the

Balancing Authority (BA) should be listed as an applicable entity in the GMD standard. Per the NERC functional model, the BA is focused on balancing load, interchange and generation and supporting system frequency while the Transmission Operator (TOP) is focused transmission flows and, in particular, controlling voltages. It would be the TOP or RC that would identify the need to commit additional generation to mitigate loading on transformers or to increase reactive support.
No
GRE agrees with the MRO NSRF on the suggested language change in M1 for clarity and also to replace "implemented" with “coordinated”. M1 should read: M1. Each Reliability Coordinator shall have a GMD Operating Plan meeting all the provisions of Requirement R1; and evidence such as a revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that development and maintenance of the plan was coordinated with Transmission Operators and Balancing Authorities. Rationale: The use of the word implemented implies that the actionable items within the Operating Plan were executed as designed to mitigate the effects of a GMD event. This is an “event driven” measure but the Requirement is to “coordinate” GMD Operating Plans. By using “coordinate” (versus implement) within the Measure, the measure uses the same words as the Requirement. This standard is similar to cold weather preparedness, where there are geographic differences and increased risks to reliability in particular locations. GMD events should be discussed at a regional level, technical guidance documents should be issued for utilities in high risk locations, and practical solutions should be reached at each region.
Yes
Because of the wide-area nature of a GMD event, GRE is suggesting a higher level authority such as the NERC Operating Committee or a NERC technical committee consider drafting guidelines to provide details in preparing for GMD events that would include recommendations to entites in areas susceptible to GMD events.
No
With NERC’s Relaibilibity Assurance Initiative (RAI), the P81 initiative and the work performed by the Independent Expert Review Project, R2 & R4 are administrative in nature and suggest the drafting team remove these two requirements. Similarly, R5 is also in administrative and is redundant with R3 because R3 has an implementation requirement. Per the P81 NOPR, CIP-003-3, R4 which required the cyber security policy be available to all personnel with CCA responsibilities, has been approved to be retired.
GRE agrees with ACES, The Long-term Planning Time Horizon for each requirement should be removed. The Long-Term Planning Horizon covers a period of one year or longer. An operating procedure or plan will cover the Real-Time Operations horizon or Operations Planning horizon at best. By NERC Glossary definition, an operating plan, process or procedure will not cover the Long-Term Planning horizon. An operating procedure lists the specific steps that should be taken by specific operating positions. An operating process includes steps that may be selected based on “Real-time conditions”. A operating plan contains operating procedures and processes.
Yes
No
As previously stated in Q1, the Balancing Authority (BA) should not be included in the standard.
Yes
See ACES Comment for question 8.
No
The drafting team needs to consider the impacts to smaller entites. Smaller entities have limited resources especially when considering hardening transformers against GMD events. A cost benefit analysis should be considered when weighing the reliability gains versus the costs of hardening the electric system.
GMD events cover a wide area and multiple entities. Planning Coordinators (PC) are the ones that should be conducting the initial assessments with recommendations to the individual entities. The scope of these studies are much broader than individual entites.
Individual
Wryan Feil
Northeast Utilities
Yes
I agree with the applicability, however if the definition of BES changes I do not think this standard should apply down to those with transformers having high sides of 100 kV. The impact of GMDs and the magnitude of GICs is greatly reduced at these lower voltages and doesn't warrant the additional burden it would impose.
Yes
I agree that the RC should coordinate the plans for the BAs and TOPs in its area. It might be beneficial that there be coordination at the RRO level so that RC plans are coordinated as well, since GMDs/ GICs do not recognize arbitrary system borders.
Yes
The language in R3 is adequate.

Yes
Comments on the Geomagnetic Disturbance Operating Procedure Template: Transmission Operator: Information and Indications: Triggers: External: Watch, Warning and Alert K index numbers are too low. K-index is known to be an unreliable predictor of GMD severity, however it makes no sense to activate procedures below K7. Triggers Internal: System-wide/ equipment-level: Parameters mentioned could be abnormal due to other causes. There should be corroborating evidence cause is GMD before entering procedure. Actions Available to the Operator: Should specify that the actions are not limited to those listed. Long lead-time: Safe system posturing (only if supported by study): Should specify the level of study. For example, this should mean a coordinated earth conductivity/ system study across a wide area to ensure that other entities are not negatively impacted- not just a state estimator study. Remove shunt reactors: some systems auto switch reactors. These (and capacitors) should be left in auto so that they can respond to voltage swings. Day-of-event: Increase situational awareness: These require being able to corellate the observed parameters to equipment/ system effect before taking actions Prepare for unplanned capacitor bank/SVC/HVDC tripping: Should add that multiple installations should be evaluated as a single contingency. Real-time actions: Safe system posturing (only if supported by study): Selective load shedding: No guidance is provided as to how this could help in a GMD. Manually start fans/pumps on selected transformers: Due to the hazard of potential catastrophic failure from static electrification caused when oil temperature is below 50 C, this section should not be mentioned. System reconfiguration (only if supported by study): Should specify the level of study. For example, this should mean a coordinated earth conductivity/ system study across a wide area to ensure that other entities are not negatively impacted- not just a state estimator study. Return to normal operation: Why is any time limit mentioned at all?
Yes
SAR scope is adequate.
No
I believe that due to the wide geographical impact of GMDs/ GICs the RRO should coordinate plans between their RCs and perhaps with other RROs.
No
All regional variances should be due to geographical, geological and system design factors and should be covered by developing earth and system models.
Yes
This project will require the conducting of detailed equipment analyses, and in the longer term regional earth conductivity and system modelling in order to determine impact of GMD/ GIC on equipment and systems. Monitoring and Indications Key parameters must be identified for control center monitoring (GIC, reactive reserves, harmonics, MVAR, etc.) and SCADA displays will have to be designed for operator use . Currently a project is underway to install GIC monitoring on selected transformers and to track the magnitude of GIC/ harmonics with GMD incidence (via Kp provided by SWPC). The impact on equipment of deviation from normal of these indications must be known, as well as actions recommended by the transmission owner. Once this is provided, the displays mentioned above can be designed. Procedure Development Once displays are developed as discussed above, a procedure will need to be developed to address requirements of EOP-010-1 R3. Currently in New England only the northern LCCs and ISO-NE have GMD procedures. These are of a general nature and may not be sufficient, but they will serve as a starting point for drafting operating procedures. (This presupposes that parameters for System Operator monitoring have been identified, provided to the control room, displays developed and the importance of the readings determined by the Transmission Owner.) The standard requires the RC to coordinate TOP procedures. This may result in a process similar to that for coordinating system restoration plans. Training Once a new procedure is developed and displays are created, a task analysis will need to take place to identify required changes to the company specific Reliability Related Task list and required modifications to the training program.This will involve development and delivery of additional classroom training and evaluation instruments, development and administering of Job Performance Measures for newly identified Reliability Related Tasks and development, delivery and evaluation of crew simulator scenarios.
1.) Training requirements should be added to PER-005. Any required training should be added to the applicable GMD standard(s) (e.g. EOP-010-1.) 2.) The requirement to have the stage 2 standard done and in effect within 18 months is reasonable, however there should be adequate time within the resulting standard for entities to conduct the required earth/ system studies and alalyze them. Adequate time is also important due to the need to coordinate mitigation efforts across areas to ensure other entities are not adversely impacted by your organizations actions.
Individual
Phil Anderson
Idaho Power Company
No
For stage 1, operational procedures make sense for Transmission Operations and not necessarily for Generation Operations. However, generator step-up transformers (GSUs) with a grounded wye high side can be affected by geomagnetic induced current (GIC). If the GSU is the property of and/or controlled by a generator operator, transformer information such as GIC, temperature, dissolved gas and abnormal operation may not be easily monitored by the

Transmission Operator. Any operational changes made by the Generator Operator will need to be coordinated by the Transmission Operator but the Transmission Operator may not be aware of GSU status. While System wide GMD operating procedures do not apply to Generator Operators, equipment level situational awareness and monitoring might. Idaho Power believes this standard should also apply to Generator Operators. Propose adding Generation Operator with any transformer with a high side terminal voltage greater than 200 kV to the Applicability Functional Entities Section 4.
Yes
Yes
Agree in General. Propose adding Generator Operator to R3 and M3. The Reliability Coordinator needs to coordinate their procedures with the Transmission Operator, Balancing Authority and Generator Operator.
Yes
Agree in General. Propose adding Generator Operator to R4, M4, R5 and M5. Many of the other standards are using a five year review cycle. The review requirement should also include a trigger based on system upgrades or major changes to system topology.
No
Propose adding Generation Operator with any transformer with a high side terminal voltage greater than 200 kV to the Applicability Functional Entities.
Group
Puget Sound Energy
Denise Lietz
No
The drafting team should ensure that the voltage level in the applicability statement does not include elements excluded by the Bulk Electric System definition. Specifically, it appears that the applicability statement would include equipment excluded from the BES by the language of BES Definition Inclusion I1 ("Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher..."). Also, voltage level is not the only measure of GMD influence on the BES - there are other factors that the standard should include in its assessment of applicability, including grounding method, grounding resistivity, core type and transformer (coiled equipment) connections. Leaving these factors out of the applicability section means that many entities who are unlikely to be affected by a GMD event will be unnecessarily burdened with drafting procedures that they may never need. In addition, it is not clear why the Balancing Authority is included as an applicable entity - in general, the actions available to the operators are transmission system specific. However, if the Balancing Authority is removed as a responsible entity, the drafting team should ensure that generation interconnection facilities are also assessed for applicability with respect to the interconnected TOP.
No
This requirement imposes a heavy burden on the RC. Understanding that some level of coordination is required, perhaps a lesser level of coordination will be acceptable, at least until phase 2 of the project is complete. Such coordination could be modeled after the approach in IRO-010, where the RC would set the specifications for the TOP Operating Plans and the TOP would be required to comply with those specifications.
Group
ACES Standards Collaborators
Jason Marshall
No
(1) We recommend the drafting team provide technical justification for choosing 200 kV as the threshold. We ask that the

drafting team consider increasing the voltage level on the high side of the transformer to 345 kV, or in the alternative, provide rationale for setting the limit at 200 kV. (2) We do not believe the science of how GMDs impact the electric grid is settled. This is evidenced by multiple reports with significantly varying conclusions. While the FERC order indicated that most reports agree that there is a minimum risk for voltage collapse due to excessive reactive power consumption of transformers during extremen GMD events, the reports may not emphasize the geographic risk of the problem. For example, does a utility in South Florida have the same risk as a utility in northern Maine? If the risks are different, a requirement for an operating procedure for all entities including the southern most entities is premature at this point. We understand that NERC has an obligation to respond to the FERC GMD directive and will support them in their efforts, however, we wonder if NERC should look for an equally efficient and effective alternative. We believe that such an alternative should include pointing to the existing and proposed standards requirements that require registered entities to respond to voltage emergencies. (3) Given the unsettled GMD science, we think it is premature to write a standard requiring specific GMD operating plans and procedures and may cause considerable overlap and redundancy within the standards which the P81 project was intended to remove and which FERC has already proposed to approve. For example, TOP-001-1a R2 and R8 already requires the TOP to take immediate actions to alleviate operating emergencies and to restore reactive power balance. TOP-002-2.1b R8 requires the TOP to plan to meet voltage and/or reactive limits, including the deliverability/capability for any single Contingency. TOP-004-2 R6.1 requires the TOP to have policies and procedures for monitoring and controlling voltage levels and reactive power flows. Finally, EOP-001-2 R2.2 requires the TOP to “develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system”. These standards requirements are applicable at all times including during GMD events. Thus, the proposed requirements will create an opportunity for double jeopardy due to the redundancy in the requirements. (4) The Balancing Authority (BA) should not be listed as an applicable entity in the standard. Per the NERC functional model, the BA is focused on balancing load, interchange and generation and supporting system frequency while the Transmission Operator (TOP) is focused transmission flows and, in particular, controlling voltages. The background section is focused on preventing transformer hot spot heating and voltage collapse through excessive use of reactive power which clearly aligns with the TOP tasks and not the BA tasks in the NERC functional model. While the BA might have a role if additional generation is committed, the role would be, in essence, to respond to TOP actions. It would be the TOP that would identify the need to commit additional generation to mitigate loading on transformers or to increase reactive support. The BA would commit generation in response to the TOP directions and would utilize existing operating procedures and processes it has for managing commitment of units. Its existing procedures and processes, for example, might include a minimum generation procedure. Implementing the procedure in response to excess generation that needs to be committed to respond to a GOP event would be no different than responding when load has simply decreased below the normal minimum generation limits. Thus, there is no need to add the BA because its existing procedures and processes would be sufficient to respond to the TOP actions.
No
(1) Having another duplicative “operating plan” does not improve reliability on the bulk electric system. The reliability standards already require several types of plans that could be enhanced to address GMD events. While we agree that flexibility is better than specificity, we disagree with the approach that another plan is required. The drafting team should consider enhancing existing operating plans and other approaches to respond to the FERC directive. (2) We believe that NERC should respond to the FERC directive with an equally efficient and effective alternative to developing a new reliability standard. Since the new standard will be largely redundant with with existing standards requirements, there is technical justification to support an alternate approach. The alternate approach would include relying on existing standards requirements. For example, IRO-014-1 R1 requires the RC to have operating procedures, processes or plans for activities that require notification or exchange of information with other reliability coordinators. Since the electric industry already takes an “all hazards” approach to planning the operation of the grid, the RCs in geographies with greater risks to GMD events should be able to rely on existing processes, procedures and plans to coordinate responses to GMD events. The electric industry’s excellent response to large events such as hurricanes has proven the “all hazards” approach to planning is effective. (3) A reliability standard is not always the best solution to address a reliability concern. This standard is similar to cold weather preparedness, where there are geographic differences and increased risks to reliability in particular locations. We cannot support a standard that attempts to address the issue in broad generalities. GMD events should be discussed at a regional level, technical guidance documents should be issued for utilities in high risk locations, and practical solutions should be reached at each region.
No
(1) The proposed standard is responsive to the FERC directive, but it fails to take into account existing reliability standards that overlap with the proposed draft, and creates duplicative requirements that could result in double jeopardy. For instance, TOP-004-2 R6.1 requires the TOP to have policies and procedures for monitoring and controlling voltage levels and reactive power flows. Since the electric industry has always taken an “all hazards” approach to planning and operating the electric grid, these policies and procedures will have already considered extreme operating situations such as events that might occur during a GMD event. These policies and procedures would, therefore, be sufficient to respond to a GMD event without the need to make them specific to the GMD event or without the need to create a duplicative standard. The drafting team or a NERC technical committee, such as the Operating Committee, could draft a reliability guideline to provide additional detail of how to prepare for GMD events and make recommendations for utilities in areas susceptible to GMD events to include preparations in their planning processes.
No
(1) Requirements R2, R4 and R5 meet one or more Paragraph 81 criteria and should not be written as separate

requirements that will result in a separate violation for failing to conduct the review on a timely basis or failing to have a copy of the operating plan or procedure in the control centers. A requirement is subject to retirement under P81 if the requirement fits any of the following criteria: it is administrative in nature, requires data collection/data retention, purely documentation or reporting, requires periodic updates, concerns only a commercial or business practice, is redundant with other standards, hinders the protection or reliable operation of the BES, or has little, if any, value as a reliability requirement. (2) Requirement R5 is very similar to CIP-003-3 R4 which requires the cyber security policy to be available to all personnel with access to or responsibility for Critical Cyber Assets. In the P81 NOPR, FERC recently proposed to approve retiring CIP-003-3 R4 because it is administrative and it would be not be practical to implement the cyber security policy if it was not available to personnel. Similarly, R5 would be redundant with R3 because R3 has an implementation requirement. How can the TOP or BA implement the operating procedure if it is not available to its operating personnel per R5? How would an auditor verifying that a copy of the plan in the primary and backup control rooms benefit reliability? It could be placed in these rooms with no notification to system operators and no training provided to system operators on the implementation. Obviously, this would not support reliability. Requirements R2 and R4 are similar to the NUC-001-2 R9.13 which compel the Nuclear Plant Generator Operator and Transmission Entity to review their agreement every three years. FERC also proposed to retire it. Thus, R2 and R4 should be removed. If some vestige R2 and R4 are to remain, they should be made a sub-part of R1 and R3 so that a separate violation is not recorded for failure to review in the 36 month time frame. (3) We do agree that the 36-month time frame for review is reasonable.
(1) We are concerned that implementation of an operating procedure for GMD may require the removal a number of transformers and could be viewed as causing a burden to neighboring systems contrary to TOP-001-1a R7. TOP-001-1a R7 compels the TOP and GOP to not remove facilities from service if it would burden neighboring systems unless there is not time for notification and coordination. Could the requirement to write an operating procedure for responding to GMD events be viewed as allowing time for coordination and notification particularly if the TOP documented in their plan to notify their RC? If EOP-010 persists, TOP R7.3 should be modified to clarify that a TOP and GOP may not have sufficient time during an extreme GMD event to make appropriate notifications and the requirement for the RC to have an operating plan will be viewed as this coordination. (2) The Long-term Planning Time Horizon for each requirement should be removed. The Long-Term Planning Horizon covers a period of one year or longer. An operating procedure or plan will cover the Real-Time Operations horizon or Operations Planning horizon at best. By NERC Glossary definition, an operating plan, process or procedure will not cover the Long-Term Planning horizon. An operating procedure lists the specific steps that should be taken by specific operating positions. An operating process includes steps that may be selected based on “Real-time conditions”. A operating plan contains operating procedures and processes. (3) Part 3.1 in R3 is unnecessary because NERC already designates MISO and WECC RC to monitor the space weather through the National Oceanic and Atmospheric Administration (NOAA) Space Weather Prediction Center (SWPC). MISO communicates this information to the Eastern and ERCOT Interconnections through reliability coordinator information system (RCIS) and WECC communicates it to the Western Interconnection as documented in a NERC alert. There is not a need to codify a process that is already in place and works effectively.
Yes
While we agree that the SAR does provide a plan to address the FERC directives, we continue to believe new standards with requirements to write specific operating plans or procedures is premature and that NERC should pursue and equally effective and efficient alternative. The electric industry is already required to have policies and procedures to manage emergency conditions through the requirements such as TOP-004-2 R6.1 and EOP-001-2 R2.2. Since the electric industry has always taken an “all hazards” approach to planning and operating the electric grid, these policies and procedures will have already considered extreme operating situations such as events that might occur during a GMD event. The electric industry’s excellent response to large events such as hurricanes, blizzards, and tornadoes has proven the “all hazards” approach to planning is effective.
No
As stated above in question one, the Balancing Authority (BA) should not be included in the standard. Per the NERC functional model, the BA is focused on balancing load, interchange and generation and supporting system frequency while the Transmission Operator (TOP) is focused transmission flows and, in particular, controlling voltages. While the BA might have role if additional generation is committed, the role would be, in essence, to respond to TOP actions. It would be the TOP that would identify the need to commit additional generation to mitigate loading on transformers or to increase reactive support.
Yes
(1) Because the science it unsettled at this point, it is difficult to imagine a situation with a GMD event so severe that it impacts significantly the furthest southern parts of the U.S. Thus, a regional variance is likely necessary for these areas. However, until the science is settled it is challenging to know where to draw the line for where the regional variances are needed geographically or geologically.
Yes
This standard will impact multiple business practices within the industry regarding budgetary issues. The cost of hardening transformers to withstand severe GMD events does not justify the reliability gains. This is especially true for smaller entities with limited resources.
The SAR discusses additional training requirements that ultimately will impact system operators. System operators already have a heavy training load from mandatory training required to meet the PER requirements (i.e. 32 hours of emergency operations training) to the training requirements to maintain NERC certification (i.e. 200 hours every three years for an RC).

We would advise the drafting team to be careful to not overburden the system operators with additional training requirements that could distract them from doing their job of maintaining system reliability.
Group
DTE Electric
Kathleen Black
No
System study of areas potentially affected by GMDs should be identified before standard is written requiring all entities to have plans and operating procedures.
No
Instead of each RC, TO and BA developing its own plan to mitigate effects of GMDs, the standard should state that each TO and BA have a plan to support its RC's GMD plan. If individually created, the plans may conflict.
No
Entities with no previous effects from GMDs should be exempted by their RX from developing a plan and entities with potential problems with GMDs should be required to develop plans to support their RC's plan and provide plan details to their RC.
No
Please see previous comments from Questions 1, 2, and 3.
Yes
Yes
No
No
Individual
Patricia Metro
National Rural Electric Cooperative Association (NRECA)
No
NRECA recommends increasing the voltage level threshold from 200 kV to 345 kV. The drafting team has not provided a technical justification for choosing the 200 kV threshold. It appears that from the limited previous experiences associated with GMD events that there was no substantive impact on equipment at voltages below 345 kV. In addition, it is important that any standard that is developed addressed regional geographic differences associated with the impacts of GMD in the requirements of the standard. Present data does not support that the potential for equipment damage resulting in a GMD event is the same for a cooperative in the Northeast and a cooperative in the Southeast. The inclusion of the Balancing Authority as an applicable entity is not necessary. If the events being addressed in this standard are solely related to preventing transformer hot spot heating and voltage collapse through excessive use of reactive power, these types of events are managed by the Transmission Operator not the Balancing Authority. The Balancing Authority will only provide generation support as directed by the Transmission Operator.
No
As explained in response to Question 1, NRECA does not believe it is necessary to include the Balancing Authority as an applicable entity in this standard.
NRECA agrees that the 36-month time frame for review is reasonable.
NRECA is does not believe that it is necessary to develop a separate GMD standard to address requiring Operating Procedures for GMD events. Criteria for addressing such events can easily be added to existing standards that require entities to have Operating Procedures. Suggesting a new standard that has similar requirements as existing standards does not adhere to the spirit of the P81 initiative to eliminate unnecessary duplicative requirements. Examples of requirements that could be revised to address GMD events are: IRO-014-1 R1 requires the RC to have operating procedures, processes or plans for activities that require notification or exchange of information with other Reliability Coordinators. TOP-004-2 R6.1 requires the TOP to have policies and procedures for monitoring and controlling voltage levels and reactive power flows. R5 - NRECA agrees that it is reasonable to require that a copy of an applicable entity’s GMD Operating Procedures is in its primary control room and any applicable backup control rooms so that it is available to its operating personnel prior to its

implementation date. In the Time Horizon designation for the requirements of this standard, the "Long Term Planning" horizon should be removed. As written, this standard addresses Operating Procedures to address Real-time events not those that meet the criteria for a "Long Term" event.
Yes
NRECA agrees that the SAR as drafted provides a scope to address the directives in Order No 779, but believes as explained in response to Question 5 the directives could be addressed by modifying existing standards as an alternative to developing a new standard.
No
As explained in response to Question 1, NRECA does not believe it is necessary to include the Balancing Authority as an applicable entity in this standard.
Yes
As explained in response to Question 1, it is important that any standard that is developed addressed regional geographic differences associated with the impacts of GMD in the requirements of the standard. Present data does not support that the potential for equipment damage resulting in a GMD event is the same for a cooperative in the Northeast and a cooperative in the Southeast.
Group
SPP Standards Review Group
Robert Rhodes
No
Please refer to our comment in Question 7 directed toward applicability in the SAR.
Yes
While we concur that R1 addresses the FERC directive, we have some reservations with the use of the word 'coordinated' in R1.2 especially along the lines of what specifically will be required by the responsible entities to show coordination. Hopefully, the Reliability Coordinator will provide those details in his processes. Additionally, we would encourage the NERC Operating Reliability Subcommittee to ensure consistency in the processes used by the Reliability Coordinators throughout NERC.
Yes
No
To address timing issues in R5, we suggest inserting the word 'current' between the 'a' and 'copy' and deleting the phrase 'so that it is available to its operating personnel prior to its implementation date'. R1 would then read Each Transmission Operator shall have a current copy of its GMD Operating Procedures in its primary control room and any applicable backup control rooms. For consistency with EOP-005, we would suggest that the VRF for R5 be reduced to Low. This is an administrative requirement and does not merit a Medium VRF. Additionally, we wonder why the Reliability Coordinator is not required to have a copy of its GMD Operating Plan in its primary and backup control centers.
Delete the phrase 'and submit(ted) them for approval' from the VSLs in R4. R4 does not require approval.
Yes
The SAR, as well as the draft standard, refer to the BPS. Given the restrictions as proposed in the standard on transformers with high-side terminals of 200 kV and above, wouldn't the reference be more appropriate to the BES?
No
The Functional Model does not assign transformer operation to the Balancing Authority yet the drafting team makes a connection between transformers and the Balancing Authority by incorporating the Balancing Authority in the Applicability Section. Why did the drafting team make this decision? Shouldn't the Balancing Authority be removed from the Applicability Section since it is concerned with balancing generation to load and not operating transformers? The Balancing Authority already has procedures to assist it whenever load or generation within its Balancing Authority Area is lost. It's reason for the loss is immaterial to the Balancing Authority, the procedures it has to cover this situation would be similar regardless of the cause. In any event, the Balancing Authority has no responsibility to mitigate issues associated with a transformer within its Balancing Authority Area. That functionality resides with the Transmission Operator.
No
While we are concerned with the intent of continent-wide requirements, if accomplished as proposed by the drafting team with flexibility provided for responsible entities to tailor their response to both stages of standard development to their risk and exposure based on their geography, geology and system topology, then regional variances may not be needed. Otherwise, regional waivers or exemptions may be appropriate.
Yes
We foresee the need for a study/modeling group similar to the MWG which would assemble the appropriate data base upon

which collaborated studies, similar to the interregional transfer capability studies being done today, would be conducted. The results of those studies would then also be made available to any responsible entity for purposes of GMD assessment.
Individual
Bill Fowler
City of Tallahassee
No
R1.2 requires the RC to determine that the GMD Operating Procedures of all Transmission Operators and Balancing Authorities are coordinated and compatible. TAL recommends replacing “all TOs and BAs” with “applicable TOs and BAs”. Additionally, the RC has to prove all the plans are “coordinated and compatible”. This was a large undertaking for the EOP-006 restoration plans, and will be equally burdensome to the RC for these plans.
Stage 1 requires an Operating Procedure to protect the BES, however, we do not have the “benchmark studies” as required in Stage 2. It would seem appropriate to have the studies first in order to write the procedures as required in Stage 1. The Stage 2 could remain with the incorporation of equipment for the mitigation of the GIC. The white paper for the 200kV threshold has not been made available as was promoted on the July 30 webinar. How can we vote when the reference is not available?
Individual
Scott Langston
City of Tallahassee
No
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Group
Bonneville Power Administration
Jamison Dye
Yes
Yes
BPA’s position is that the primary entities responding to GMD events are the TOPs and BAs. BPA believes the RC should be required to develop the criterion for their Operating Plan in direct coordination with the TOPs and BAs in their area in

order to avoid the RC developing a plan that may not be compatible with the region. Additionally, the RC should be the primary source of space/weather information and be required to disseminate that information to the TOPs and BAs in their area.
Yes
Yes
BPA agrees that operational procedures should be put in place but they will not have sufficient analysis of the full impact of certain actions due to certain technologies not being available at this point. Specifically, the reactive and thermal impacts of GMD on transformers.
Yes
Yes
No
No
Individual
Karen Webb
City of Tallahassee - Electric Utility
No
R1.2 requires the RC to determine that the GMD Operating Procedures of all Transmission Operators and Balancing Authorities are coordinated and compatible. TAL recommends replacing “all TOPs and BAs” with “applicable TOPs and BAs”. Additionally, the RC has to prove all the plans are “coordinated and compatible”. This was a large undertaking for the EOP-006 restoration plans, and will be equally burdensome to the RC for these plans.
Stage 1 requires an Operating Procedure to protect the BES, however, we do not have the “benchmark studies” as required in Stage 2. It would seem appropriate to have the studies first in order to write the procedures as required in Stage 1. The Stage 2 could remain with the incorporation of equipment for the mitigation of the GIC. The white paper for the 200kV threshold has not been made available as was promoted on the July 30 webinar. This reference is valuable to entity wishing to make an informed vote.
Individual
Bret Galbraith
Seminole Electric
No
Seminole asks the SDT to add language to the Standard that indicates that Industry and NERC intend to allow for consideration of various entity specific characteristics in developing a GMD Operating Plan. Seminole is aware that this is the intent of the SDT and therefore Seminole proposes the following language, or similar language, be added in each Requirement requiring an Entity to develop a type of GMD Operating Plan and/or set of Operating Procedures: “An Entity can take into consideration such entity-specific factors such as geography, geology, and system topology in developing a GMD Operating Plan/set of Operating Procedures.” Seminole believes that this is not clear in the Requirement and wishes that the NERC SDT specifically state the ability for an entity to tailor their plans and/or procedures to their environment. In addition, the suggested language is pulled from the SAR for this project.

Group
Colorado Springs Utilities
Kaleb Brimhall
No
• GOP should also be included. • Voltage level not a good indicator of susceptibility to ground induced currents. Possibly latitude, transmission line orientation or transmission line length a better indicator. If voltage were to be used, think higher voltage should be considered.
Yes
Yes
Yes
Comments on Requirement 1: • In need to include a requirement for the RC to acquire and disseminate space weather information to the applicable entities within their footprint. Comments on Requirement 3: • From the glossary; Operating Procedure (in part): "The steps in an Operating Procedure should be followed in the order in which they are presented"; Operating Process (in part): "An Operating Process includes steps with options that may be selected depending upon Real-time conditions." The language in the Standard will be what is audited to, notwithstanding what any individual utility may titles their documents. The actions which may be required during a GMD event are far better presented in an Operating Process (as defined) than an Operating Procedure (as defined). There is no way that a TOP could follow the exact same step-by-step procedure for all GMD eventualities, but that is what the "Operating Procedure" term demands. Comments on Requirement R3.1: • Need to eliminate the requirement to acquire space weather information in R3.1, and have it a part of the information that the RC would disseminate to ensure consistency and coordination from the RC. Comments on Implementation Plan: 1. Need to ensure that RC develops and disseminates their plan 1st with time included to incorporate RC plan into BA/TOP/GOP plans. 2. Implementation period needs to be extended from 6 months to 12 months.
Abstained from Commenting.
Yes
Yes
1. Variances are absolutely going to be necessary based on geography, geology, and system topology.
Abstained from commenting.
None
Group
JEA
Tom McElhinney
No
The applicable entities should't not include the BA but needs to include the GOs. Generator step up transformers are more critical to BES reliability than substation step down transformers. Only BES transformers should be included.
No
A vulnerability study is required before good operating procedures can be developed
No
BA should be removed
Yes
Yes

Yes
No
Individual
David Gordon
Massachusetts Municipal Wholesale Electric Company
Agree
American Public Power Association (APPA)
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC OC Review Group
Group
Santee Cooper
S. Tom Abrams
Yes
Recommend the SDT consider changing he high side terminal voltage on transformers to greater than 300 kV. The focus of the standard should be at higher voltages where the line length makes the lines more vulnerable to geomagnetically-induced currents.
Individual
Bryan Griess
Transmission Agency of Northern California
TANC appreciates the performance flexibility that has been built into the current draft of this standard, but has concerns regarding the approximately six month implementation period between its approval and effective date. Of particular concern is the ability for each Reliability Coordinator to ensure coordination and compatibility between its GMD Operating Plan and the GMD Operating Procedures for all Transmission Operators and Balancing Authorities in its footprint during such an abbreviated period. As this initiative moves forward, TANC requests that NERC continue to carefully consider the scope of entities and assets that will be subject to this and subsequent standards so that the costs borne by the industry are commensurate with the anticipated benefit to reliability.
Group

Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Agree
NRECA SERC
Group
Foundation for Resilient Societies
William R. Harris
No
Standards relating to Operating Procedures should apply to high side Transformers of 100 kV or higher. Despite higher resistance, transformers in the 100 kV to 200 kV range contribute a significant proportion of GICs that can destabilize the grid. TJ Overbye et al (2012)estimate less than 60% of total MVAR is captured in New England and Michigan if transmission under 230 kV is excluded from protection. New transformers in the 100 kV to 200 kV range are projected by the Energy Information Administration at about 20% of all new EHV transmission mileage planned for the 2012-2018 period. NERC must include generating entities, because existing studies suffice to demonstrate both vulnerability of GSU transformers operated by Generating entities and need for equipment monitoring at generator stators, and related operating procedures to protect generators in severe geomagnetic storms. GSU Generators are at greater risk than generally recognized. See studies by Legro, Abi-Samra and Tesche at ORNL (1985); Walling & Kahn (1991); J G Kappenman, Storm Analysis Report R-112, section 8 (2011); and Luis Marti, "Generator Thermal Stress during a Geomagnetic Disturbance" (2013). Of critical importance, the President of the United States has existing legal authority to order the de-energizing of electric generating facilities that are oil or gas-fired if an emergency so requires. To utilize this authority upon confirmed space warning of a severe solar geomagnetic storm, it is essential that all generating entities serving the bulk power system be included in emergency operating procedure standards; their personnel be trained to validate and confirm de-energizing orders and procedures (and re-energizing procedures), with a multi-day strategic warning but only tens of minutes for tactical order, validation, and execution. Because most of the generating facilities serving the bulk power system are not now equipped with protective equipment that would enable these facilities to "operate through" a severe solar geomagnetic storm, it is essential that generating entities be included in the Operating Procedure coverage and standards. Further, the Nuclear Regulatory Commission has existing authority to order de-energizing and safe shutdown of the 102 NRC licensed nuclear power plants in the U.S. or a subset that are especially affected by a particular GMD event. Generating entities may need to review operating procedure options for rapid shutdown of generators if GSU transformers are not equipped with protective hardware. Beyond the practical necessity of including transformers and transmission equipment in the 100 kV to 200 kV range, FERC Order 779 applies to the entire bulk power system, which is now defined as commencing at 100 kV or above and not 200 kV or above. It would be illegal for NERC to exclude a significant proportion of the transmission line mileage (for many utilities more than half total EHV transmission mileage). Even if EHV transformers above 200 kV are later protected with neutral ground blocking equipment, leakage of GICs from lower voltage equipment will add significant Mvar into regional grids. FERC intended standards to protect the entire bulk power system of 100 kV or higher; NERC's participating entities should respect and support this federal policy.
Yes
No
Reason: Earlier comments on the Operating Procedure Templates submitted by the Foundation for Resilient Societies were ignored, and not addressed on their merits by the GMD Task Force management and by the NERC Planning Committee. See our previous comments at: https://resilientsocieties.org/images/Comments Operating Procedure Template NERC GMDTF Phase 2 Rev1.pdf.
Yes
The Foundation for Resilient Societies has concerns that the NERC Planning Application Guide, developed without full public access to the related model assumptions, will mis-characterize geomagnetic latitudes with geographic latitudes; and will result in scientifically invalid assumptions that the NERC modeled "operating procedures" will suffice without need for hardware protections. For our Foundation review of the Draft NERC GMD Planning Application Guide, our review dated August 9, 2013, see: http://resilientsocieties.org/images/Resilient_Societies_Comments_on_GMD_Planning_Application_Guide _Final.pdf.
Yes
Yes
Yes
Yes

For effective operating procedures implemented through regional balancing authorities, improved near-real-time GIC monitoring will be needed for all GSU transformers, SVC equipment, and major generating equipment at risk in severe solar storms. Regional balancing authorities will require improved near-real-time monitoring to prepare and protect ready reserves. Communications must be designed to operate even during severe solar storms. Regional balancing authorities will need to be in contact with the White House Situation Room and federal command centers elsewhere.
For concerns of the Foundation for Resilient Societies, see our website at www.resilientsocieties.org. A case study of Maine and ISO-New England utilizing recently revised operating procedures documents our concern that regional "ready reserves" in a severe geomagnetic storm are likely to be inadequate due to a combination of vulnerable long distance HVDC transmission lines, a record of SVC "trips" during only moderate solar storms, and unprotected generating equipment in New England, where high GICs are recorded.
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
Yes
Yes
Yes
We agree with the proposed requirement. However, there currently exists a similar requirement in IRC-005-3.1a, R3, which says: R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans. With the introduction of the EOP-010 standard, specifically Requirement R3, the TOP and BA will have operating procedures in place and be required to monitor GMD activities on an ongoing basis. We question the need to keep R3 of IRO-005-3.1a. If the latter is deemed redundant after the adoption of the EOP-010 standard, we suggest the SDT propose retiring R3 of IRO-005-3.1a. If R3 is to be retained, then it does not mention “applicable” BAs and TOPs, which it should.
No
Requirement R5 is not needed. The objective is that each Responsible Entity develop, maintain and implement operations plan to mitigate GMD effects. Whether or not there is a hard copy, or electronic copy for that matter, in the control room and/or the backup control centre is unimportant and irrelevant. In order that the Responsible Entities implement the plan to comply with the standard requirements, operatinbg personnel needs to be provided and have access to the plan itself, regardless of where and how it is placed. We suggest removing R5.
No
If the Stage II assessment is done from a wide-area perspective, how would it work from a functional entity perspective? Other than in the ERCOT interconnection, which functional entity would be responsible at the interconnection level? No relevant functional entity has an interconnection-wide geographic scope?
Yes
No
No
Individual
Mauricio Guardado
Los Angeles Department of Water and Power
No
Reliable operation of the BES requires that GMD be responded to by all parties with equipment electrically connected to the interconnection. The NERC 2012 Special Reliability Assessment Interim report: Effects of Geomagnetic Disturbances (GMDs) on the Bulk Power System” proposes the steps outlined below for development of effective mitigation of GMDs, based on the fact that measures taken piece meal by one or more stakeholders (as opposed to those based on engineering studies and operation of the interconnection as a whole) will shift, and may concentrate, Geomagnetically Induced Currents (GICs) causing damage and possibly uncontrolled separation, or cascading failure of other system elements. Phase One – Assess and Baseline Risk Phase Two – Perform Technical and Programmatic Analysis Phase Three – Develop Integrated Solutions Phase Four – Implement Solutions and Adjust System Procedures It seems that EOP-010 is bringing requirements for operational procedures to mitigate GMDs before the relevant studies are complete, and then update them

periodically as data improves. To this end NERC has developed the “Geomagnetic Disturbance Operating Procedure Template” for Transmission Operators, which suggests a run back on equipment limits to leave headroom for the GICs. Given the above, and the fact that Generator Step Up (GSU) transformer (primaries >200kV) windings tend to have the highest currents of any BES transformer, Generator Operators should be included in stage 1 standards with the recommendation that they also have a mandatory runback to maintain D curve headroom on the generators (which will probably be called on to meet extra VAR requirements) and headroom on transformer limits to accommodate GICs.
No
Even at this early stage of standard development it is generally agreed that system wide approaches are required to prevent equipment damage and the possibility of uncontrolled separation, or cascading outages, and that partial measures are likely to relocate and or concentrate the effects of GIC’s, therefore R1 lacks a crucial element to insure grid reliability. At a minimum, the GMD operating plan should also include: R1.1.3 A process for the Reliability Coordinator to determine the need for and invoke the GMD operating procedures for a specified level response by a specified time, and a means of verifying all parties within the Reliability Coordinator Area are in compliance before that specified time. Also a process to determine and invoke an end to GMD events. Note: see R1 comment, R1.1.2 should include Generator Operators in addition to Transmission Operators and Balancing Authorities.
No
While it is agreed that BAs and TOPs and GOs should develop and maintain Operating Procedures to mitigate the effects of GMD events, doing so will protect the equipment and interest of said BA, TOP or GO, but WILL NOT insure grid reliability or the elimination of conditions which could lead to uncontrolled separation, or cascading outages. These plans must be reviewed by the RC’s technical team for their effect on other members of the interconnection, and approved or modified to meet grid reliability considerations. Such modifications must be acknowledged and agreed to by the Stakeholders, and invoked when directed by the RC (R3.3.1 and R3.3.3 are inappropriate and should be replaced by the suggested R1.1.2 above in question 2 comments).
Yes
Periodic review is important. LADWP would like to know the basis for the time period of 36 months.
Also, lacking is a clear statement that a directive from the RC (that GMD level X procedures are being invoked) needs to act as a signal that the market is suspended for the duration of the directive. During such GMD events, Grid Reliability will depend on the ability to redispatched generation to accommodate new conditions and operating limits. A means of establishing appropriate prices for power and Transmission rights should be established in advance and agreed to by all parties as a condition of GMD Operating Plan approval.
LADWP does not currently have a comment on this question.
LADWP does not currently have a comment on this question.
LADWP does not currently have a comment on this question.
LADWP does not currently have a comment on this question.
LADWP does not currently have a comment on this question.
Individual
Alice Ireland
Xcel Energy
Yes
Yes
In general, we agree with R1 & R1.1. However, we feel that R1.2 should be modified. Instead, we recommend the requirement read something like this: [1.2 A process for the Reliability Coordinator to coordinate GMD Operating Procedures and mitigating steps or tasks with Transmission Operators and Balancing Authorities in the Reliability Coordinator Area.]
No
Recommend revising R3.1. It isn’t clear as to what periodicity that an entity should be collecting and disseminating this information. Also, it is unclear as to what would qualify as a source to meet this requirement (i.e. is any ‘space weather’ source acceptable?). Suggest removing this requirement and indicate in prior requirement (R1) that RCs have the responsibility of collecting and sharing space weather information with TOPs and BAs, and RCs must subscribe to an authoritative space weather source.
Yes
The current IRO-005-3.1a R3 requires RCs to notify TOPs and BAs of certain GMD events. Consider deleting this requirement in IRO-005-3.1a as part of this implementation plan and add something in this standard (EOP-010) requiring RCs to make that notification. The pending approval of IRO-005-4 removed the explicit requirement, but development history indicates that it considers GMD to have an Adverse Reliability Impact that would require RC notification to entities.
Yes

Yes
Individual
Angela P Gaines
Portland General Electric Co
Agree
PGE supports WECC's position regarding the standard as it relates to the implementation timeframes.
Group
El Paso Electric Company
Pablo Onate
EPE generally supports stage 1 of Project 2013-03: Geomagnetic Disturbance Mitigation. EPE is concerned with the short implementation period of six calendar months following applicable regulatory approval and would like to see a 1 yearlong implementation period instead.
Individual
Rhonda Bryant
El Paso Electric Company
EPE generally supports stage 1 of Project 2013-03: Geomagnetic Disturbance Mitigation. EPE is concerned with the short implementation period of six calendar months following applicable regulatory approval and would like to see a 1 year long implementation period instead.
Individual
Joe Tarantino
Sacramento Municipal Utility District
No
~1. The applicability ought to be clear that the standard refers to only BES transformers and not step-down transformers to distribution. ~2. Referring to the Oak Ridge national Laboratory 319 report, the winding(s) in question needs to be wye connected and not delta connected for ground current to flow. The geomagnetically induced current (GIC) is ground current. Hence, the applicability ought to specify transformers with "wye" connected winding(s) above a certain threshold voltage. Three phase core transformers are much less likely to saturate and result in MVAR demands about 25% of that of three single core transformers. Hence, the applicability for > 200 kV and < 400 kV (i.e., the 230 and 345 kV transformers) ought to be limited to single phase core transformers.

No
No
Every 36 months is too short of a time-frame. It would be more appropriate to have a review of a potential plan, if indeed needed, when system configurations warrant a review. The review period should be set by the entity, IF there is even a concern.
SMUD also has concerns with the implementation period and questions whether or not six months is adequate time for the BA and TOP to develop the required GMD Operating Procedures and for the RC to develop the required Plan to coordinate those GMD Operating Procedures. SMUD also encourages the SDT to consider the GMD threshold application to be raised to 300+kV, and also encourages the Project 2013-03 Standard Drafting Team to consider the comments submitted by Florida Municipal Power Agency (FMPA) related to applicability of the standard.
No
SMUD is unaware of WECC any regional variance.
No
Individual
Laurie Williams
PNM Resources
Agree
WECC Staff
Individual
Nathan Mitchell
American Public Power Association
No
APPA appreciates the SDT's effort to limit the applicability of the proposed standard by setting a voltage threshold for TOPs and BAs. On the July 30th webinar the SDT stated that a technical whitepaper was being developed to justify the 200 kV threshold. APPA will hold any comments on the voltage threshold until after the whitepaper is released. We request that the whitepaper be provided soon so the industry has time to discuss this threshold prior to the final comment and ballot period. APPA recommends that the SDT modify the applicability section wording to replace "transformers" with "BES transformers." Including only BES transformers will make the applicability of the standard clear. Some Transmission Owners may have transformers with high side voltage above 200 kV, but they are connected radially so are not part of the BES. These transformers should be out of scope for this standard.
No
APPA suggests that the word "all" in Requirement R1.2, be replaced with the word "applicable." APPA believes using the word "all" in this context will bring into applicability TOs and BAs that have transformers below the 200 kV threshold. Replacing "all" with "applicable" will limit confusion and avoid conflict with the applicability section of the standard. APPA is also concerned with the words "coordinated and compatible" in R1.2. On the July 30th webinar the SDT stated that a full scale power flow analysis would be the ideal way for the RC to determine compatibility of various plans. APPA is concerned with the cost to TOs and BAs of meeting this "ideal" therefore we suggest that the SDT give guidance on acceptable alternatives.
Yes
Yes
Yes
Yes
No
No

Individual
Linda Jacobson-Quinn
Farmington Electric Utility System
Yes
No
Recommend rewording R1.2 ”A process for the Reliability Coordinator to coordinate GMD Operating Procedures and mitigating steps or tasks with Transmission Operators and Balancing Authorities in the Reliability Coordinator Area.“ FEUS has concerns with how the RC would ensure ALL the TOP and BA plans are coordinated and compatible. In addition, FEUS is unclear what demonstrates a plan is compatible.
No
Recommend revising 3.2. to the following, “The steps or tasks to be employed by System Operators that are coordinated with its Reliability Coordinator to mitigate the effects on the system from GMD events.” FEUS agrees it is pertinent mitigating activities are coordinated; however, we believe this level or coordination should be in line with what is expected for coordination activities during a restoration.
Yes
FEUS appreciates the work by the SDT team to allow entities flexibility when developing their operating procedures for mitigating GMD. The flexibility allows for entities to develop the plan that works with their system
Yes
Yes
No
No
Individual
Rick Terrill
Luminant Generation
Yes
Yes
Yes
Yes
Luminant has voted Negative as the posting and balloting of the GMD proposed standard did not follow the NERC Rules of Procedure. Luminant appreciates the technical work of the Ad Hoc group but believes the standard should have been posted for comments only, instead of being posted for balloting.
Individual
Scott Berry
Indiana Municipal Power Agency
Agree

IMPA supports the comments submitted by Frank Gaffney from Florida Municipal Power Agency.
Individual
Mauricio Guardado
Los Angeles Department of Water and Power
No
LADWP is making a correction to Question 1 and therefore is resubmitting its comments from yesterday. Please take these comments and regard the ones from yesterday. ____ Reliable operation of the BES requires that GMD be responded to by all parties with equipment electrically connected to the interconnection. The NERC 2012 Special Reliability Assessment Interim report: Effects of Geomagnetic Disturbances (GMDs) on the Bulk Power System" proposes the steps outlined below for development of effective mitigation of GMDs, based on the fact that measures taken piece meal by one or more stakeholders (as opposed to those based on engineering studies and operation of the interconnection as a whole) will shift, and may concentrate, Geomagnetically Induced Currents (GICs) causing damage and possibly uncontrolled separation, or cascading failure of other system elements. Phase One – Assess and Baseline Risk Phase Two – Perform Technical and Programmatic Analysis Phase Three – Develop Integrated Solutions Phase Four – Implement Solutions and Adjust System Procedures It seems that EOP-010 is bringing requirements for operational procedures to mitigate GMDs before the relevant studies are complete, and then update them periodically as data improves. To this end NERC has developed the "Geomagnetic Disturbance Operating Procedure Template" for Transmission Operators, which suggests a run back on equipment limits to leave headroom for the GICs. Given the above, and the fact that Generator Step Up (GSU) transformer (primaries >20kV) windings tend to have the highest currents of any BES transformer, Generator Operators should be included in stage 1 standards with the recommendation that they also have a mandatory runback to maintain D curve headroom on the generators (which will probably be called on to meet extra VAR requirements) and headroom on transformer limits to accommodate GICs.
No
Even at this early stage of standard development it is generally agreed that system wide approaches are required to prevent equipment damage and the possibility of uncontrolled separation, or cascading outages, and that partial measures are likely to relocate and or concentrate the effects of GIC's, therefore R1 lacks a crucial element to insure grid reliability. At a minimum, the GMD operating plan should also include: R1.1.3 A process for the Reliability Coordinator to determine the need for and invoke the GMD operating procedures for a specified level response by a specified time, and a means of verifying all parties within the Reliability Coordinator Area are in compliance before that specified time. Also a process to determine and invoke an end to GMD events. Note: see R1 comment, R1.1.2 should include Generator Operators in addition to Transmission Operators and Balancing Authorities.
No
While it is agreed that BAs and TOPs and GOs should develop and maintain Operating Procedures to mitigate the effects of GMD events, doing so will protect the equipment and interest of said BA, TOP or GO, but WILL NOT insure grid reliability or the elimination of conditions which could lead to uncontrolled separation, or cascading outages. These plans must be reviewed by the RC's technical team for their effect on other members of the interconnection, and approved or modified to meet grid reliability considerations. Such modifications must be acknowledged and agreed to by the Stakeholders, and invoked when directed by the RC (R3.3.1 and R3.3.3 are inappropriate and should be replaced by the suggested R1.1.2 above in question 2 comments).
Yes
Periodic review is important. LADWP would like to know the basis for the time period of 36 months.
Also, lacking is a clear statement that a directive from the RC (that GMD level X procedures are being invoked) needs to act as a signal that the market is suspended for the duration of the directive. During such GMD events, Grid Reliability will depend on the ability to redispatched generation to accommodate new conditions and operating limits. A means of establishing appropriate prices for power and Transmission rights should be established in advance and agreed to by all parties as a condition of GMD Operating Plan approval.
LADWP does not currently have a response for this question.
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