

**NERC**

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

# PRC-024-3 Draft 1 Summary Comment Responses

Project 2018-04 Modifications to PRC-024-2

RELIABILITY | RESILIENCE | SECURITY



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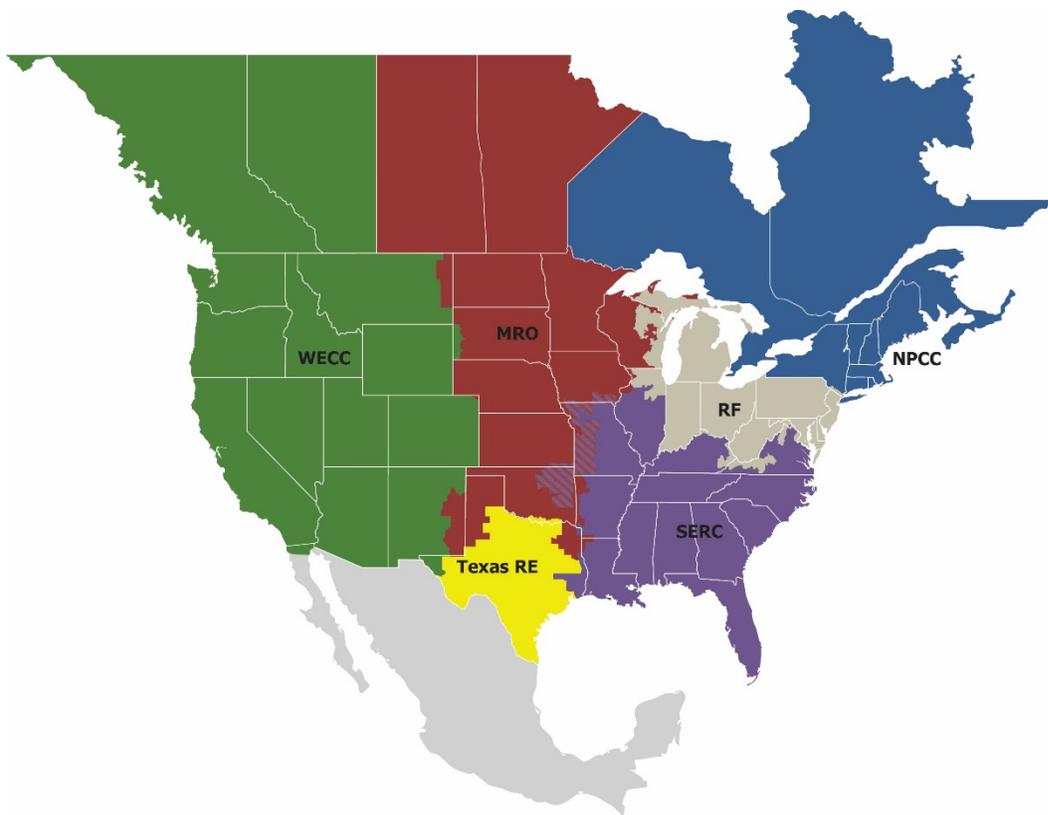
# Preface

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

Reliability | Resilience | Security  
*Because nearly 400 million citizens in North America are counting on us*

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



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

## Executive Summary

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On November 27, 2018, the NERC Operating Committee (OC) and Planning Committee (PC) submitted a Standard Authorization Request (SAR) prepared by the Inverter-Based Resource Performance Task Force (IRPTF), which reports to the OC and PC.

Based off the analyses of the [Blue Cut Fire](#) and [Canyon 2 Fire](#) disturbances in southern California along with the development of the [PRC-024-2 Gaps Whitepaper](#), the IRPTF identified potential modifications to PRC-024-2 to ensure that inverter-based generator owners, operators, developers, and equipment manufacturers understand the intent of the standard in order for their plants to respond to grid disturbances in a manner that contributes to the reliable operation of the BPS.

Reliability Standard PRC-024-3 contains a series of revisions and clarifications intended to help ensure that inverter-based resources respond to grid disturbances in a manner that contributes to the reliable operation of the Bulk-Power System.

In addition, the standard includes a Regional Variance for the Quebec Interconnection and related revisions to clarify the applicability of the standard in that Interconnection.

# Introduction

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## Background

<b>Project Name:</b>	2018-04 Modifications to PRC-024-2   PRC-024-3 (Draft 1)
<b>Comment Period Start Date:</b>	4/17/2019
<b>Comment Period End Date:</b>	5/31/2019
<b>Associated Ballots:</b>	2018-04 Modifications to PRC-024-2 PRC-024-3 IN 1 ST

There were 69 sets of responses, including comments from approximately 169 different people from approximately 125 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the [project page](#).

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact Senior Director of Engineering and Standards [Howard Gugel](#) (via email) or at (404) 446-9693.

## Chapter 1: Responses to Protection Modification

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### Question # 1

*The standard drafting team (SDT) replaced “protective relays” to “protection” throughout the standard to include relays, settings in applicable control systems, as well as other types of voltage and frequency protection devices. Do you agree with these modifications? If you do not agree, or if you agree but have comments or suggestions, provide your recommendation, explanation, and proposed modification*

### Summary

Several commenters requested an official NERC definition for a “protection”. Many commenters suggested that protection functions within control systems (e.g. excitation system, governor control system, inverter control system, etc.) should not be included within the standard. Also, we received various comments on protection systems in plant auxiliary loads indirectly tripping generation resources. Also some commented that protection should only respond to electrical signals and directly trip the generating resource.

### Response

The SDT agrees that this standard should only apply to measured electrical quantities and should exclude devices that respond to mechanical measurements. The SDT modified the Facilities section to include this exclusion. The SDT has modified the Facilities Section to adequately describe “protection” meant to be included and has added footnotes with specific language to Requirements R1 and R2 to further clarify.

### Summary

The standard’s language needs to be more generic. Various Inverter Based Resource control systems and protection systems design features (not just “protection”) have demonstrated the ability to cause curtailment of output for perturbations of frequency and voltage. The standard needs to require that none of these design features can cause Inverter Based Resource facilities to curtail output for frequency and voltage deviations within the limits specified in this standard.

### Response

Regulations of power output is geared towards a performance-based standard. PRC-024 is not a performance-based standard. Therefore, this is outside the scope of the standard.

### Summary

A comment stated that this is a Protective Relay Standard which should not include control systems. It is believed that the SAR does not recommend inclusion of control systems. It is also believed that control systems are designed by control engineers are to ensure required performance while operating within the equipment limits.

### Response

The SDT believes that portions of control systems act like protection by tripping the generating resource or causing it to cease injecting current and therefore needs to be addressed by this Standard. The PRC family of Standards apply to protection and control. These controls are already in scope via PRC-024-2, Footnote

1

### **Summary**

A comment sought clarification for requirement 4.2.1.5 “Elements utilized in aggregation of the dispersed power producing resources” of what could be an “elements” for applicability of the PRC-024 requirements. Dispersed power resources which operate in aggregate utilize a controller which has the capability to automatically trip the resources under certain high-side system frequency and voltage conditions. The settings for these controllers should also be considered as being applicable to the PRC-024 requirements regardless of their ownership.

### **Response**

The SDT agrees that the protection on the elements up to the generating resource’s connection to the BES should be included in the scope of PRC-024-3 and be set to not trip the generating resource within the “No Trip Zone”.

## Chapter 2: Point of Interconnection

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### Question # 2

*To address confusion regarding “at the point of interconnection,” the team replaced it with the phrase, “at the high side of the generator step-up or collector transformer.” Do you agree with this clarifying change? If not, please provide an alternative suggestion*

#### *Summary*

Several commenters noted that they do not consider the high side of the GSU or collector transformer to always be the correct location to consider a voltage excursion when setting voltage protection. They believe that either the generator side terminal or end of the generator tie line would be more appropriate.

#### *Response*

The SDT did not make a substantive change to the existing Standard but rather reorganized language for clarity. The previous version of the Standard stated that the voltage excursion occurred at the point of interconnection and then later defined the point of interconnection as the high side of the GSU in a footnote. The SDT does not have technical justification to change that location of the voltage excursion.

#### *Summary*

Several commenters noted that sites may have multiple stages of generator step up or collector transformers and that the way that the draft is currently written, it is unclear which transformer should be used when analyzing voltage relay settings.

#### *Response*

The SDT agrees with the comments that the way the Standard is currently written, it is unclear. The SDT has clarified that for the purposes of this standard, for generating resources with multiple stages of step up to reach interconnecting voltage, this is the high side of the transformer with a low side below 100kv and a high side 100kv or above.

#### *Summary*

Several commenters noted that it was unclear what was meant by collector transformer and generator step up transformer and if they applied to non-BES equipment identified in Applicability Section 4.2.1.5. Commenters suggested that they may benefit from an illustration.

#### *Response*

While the SDT only moved language from a footnote to the requirement language, they did agree that clarity can be added to specifically identify what transformers are meant. This can be accomplished by the same solution to the previous set of comments above about sites that have multiple stages of step up prior to interconnecting voltage.

## Chapter 3: Momentary Cessation in the No Trip Zone

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### Question # 3

*The SDT modified Requirements R1 and R2 to not allow momentary cessation, in addition to tripping, in the “no trip zone.” Do you agree that momentary cessation should not be allowed in the no trip zone? If not, please provide your rationale.*

#### Summary

Many responders recommended that the SDT define the term Momentary Cessation before using it in a Standard. Many also noted that this term is not in the NERC Glossary

#### Response

The SDT agrees that clarity is required around the term Momentary Cessation. The term has been eliminated from the standard and replaced with “or cease injecting current.”

#### Summary

One entity responded that the SDT needs to consider that momentary cessation is required for certain FACTS devices, e.g. STATCOMs or SVCs because unlike solar PV, there is no source behind the STATCOM.

#### Response

This standard is applicable to generating resources, which does not include FACTS devices such as STATCOMs, etc.

#### Summary

One entity referenced the proposed revision to footnote 5 and stated that it could preclude the exemption of legacy inverters not capable of meeting the proposed revisions to the standard.

#### Response

The SDT recognizes that this might cause confusion and has modified the footnote accordingly.

#### Summary

Several respondents expressed concern that there was no exemption for older equipment that was not able to meet the proposed new requirements. There is concern that inverters initiate momentary cessation due to voltages measured at their terminals. They initiate momentary cessation to protect the power electronics. The voltages seen at the terminals may be due to switching spikes on the low side of the GSU which may not be reflected in the voltage at the point of interconnection.

#### Response

The SDT notes that existing R3 in the standard provides for exemptions, and that this has not been eliminated in the proposed revisions.

#### Summary

Two respondents indicated that momentary cessation is a controls system response and not a protection system response, and therefore out of the scope of the proposed revisions to the standard.

### **Response**

The SDT notes that the existing footnote 1 specified that protective relaying, “ including multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals...” is within the scope of the standard. The SDT moved the requirements already imbedded in the existing footnote into the body of the standard for clarity purposes.

### **Summary**

There was a concern that requiring a generating facility to not trip due to impending loss of synchronism, actual loss of synchronism, or due to instability in power conversion control equipment may exacerbate the system condition which originated the disturbance. That is, not allowing a unit to trip when it needs to trip in those instances can make the situation worse.

### **Response**

The SDT notes that this standard is a generating resource protection setting standard and not a generating resource performance standard. Tripping or ceasing to inject current for the listed events is allowed.

### **Summary**

Several respondents indicated that the momentary cessation question is confusing because it does not address the exceptions in R1 and R2.

### **Response**

The SDT notes that existing R3 in the standard provides for exemptions, and that this has not been eliminated in the proposed revisions.

### **Summary**

One respondent commented that momentary cessation is necessary to protect the inverter power electronics.

### **Response**

The SDT notes that based on input from two inverter manufacturers, present inverter technology and control is such that the need for inverters to cease injecting current within the “No Trip Zone” is no longer a design requirement.

### **Summary**

One respondent suggested using the effective date of the generator Interconnection Agreement as the basis for determining which inverters should be subject to exemption under R3.

### **Response**

The SDT believes that older legacy inverters are covered under the R3 exemption and that this is implementation provides more flexibility for the generator as opposed to imposing an effective date for the Interconnection Agreement.

## Chapter 4: Momentary Cessation – General

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### Question # 4

*Do you agree that “momentary cessation” – like “tripping” – is well understood by industry? If not, please provide your rationale*

#### Summary

Several commenters noted that momentary cessation is not a term sufficiently and consistently understood by industry. Many commenters suggested that the SDT define the term in the standard or NERC Glossary of Terms to ensure consistency in application.

Three commenters noted that momentary cessation is not well understood and are concerned how future compliance enforcement will interpret momentary cessation. Commenters suggested that the SDT draft a definition for momentary cessation in order to improve consistency in future compliance enforcement activities. Other commenters noted that momentary cessation is not the same as tripping. Tripping is associated with a mechanical action that will disconnect the generator resource from the grid via an interrupting device. Momentary cessation is an inverter “open state” of an electronic component where the inverter is not producing current and there is no interrupting device disconnecting the generator resource.

One commenter noted that momentary cessation is not well understood, and language in the standard needs to be generic enough to cover any design features that can cause facility curtailment for any reason during frequency and voltage disturbances. Another commenter noted that although the term momentary cessation may be well understood by entities that own inverter-based resources, including time parameter may provide additional clarity for those that do not currently these resources. It’s not clear if a reduction in current for any reason is considered “momentary cessation” or only when it involves blocking.

#### Response

In reviewing the comments, the SDT determined that rather than create a define term for momentary cessation, a description could be included in the requirement. For example, “...shall set its setting such that the generating resource does not trip OR cease injecting current within the No Trip Zone...” The SDT agrees that momentary cessation is illustrated as a period where an inverter ceases to inject current (no current injected), which is also referred to as “blocking”.

#### Summary

One commenter noted that momentary cessation is not the same as tripping and is much closer in comparison to a control system limiter rather than a generator protection system. Including this control system action does not fit the title and purpose of this standard, and would transform the standard from a protection setting standard to a ride-through or plant performance standard. One commenter noted that blocking is well understood term among IBR manufactures, however it seems that momentary cessation also covers the period after blocking. It’s not clear if a reduction in current for any reason is considered “momentary cessation” or only when it involves blocking.

#### Response

In reviewing the comments, the SDT believes that protection function within a control system that can potentially trip or cause a resource to cease injecting current, based on frequency and voltage excursions

does fit the purpose of this standard. Also, protective functions within a control system were in scope in the original version of the standard as part of footnote 1, and was added in the body of the standard by the SDT for clarity and to add emphasis. The SDT has modified the Facilities Section to adequately describe the “protection” meant to be included and has added footnotes with specific language to Requirements to further clarify.

## Chapter 5: Transmission Owners that Own/Apply Protection

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### Question # 5

*The SDT was apprised that, in some instances, the TO may own the GSU or collector transformers. As such, TOs were added to the applicable entity for cases where they may own a GSU or collector transformers with frequency and voltage protection enabled. Do you agree with the addition of TOs who own a GSU or collector transformer to the applicable entities? If not, please provide your rationale.*

#### *Summary*

Many commenters noted that PRC-024 was developed to ensure that protective relay settings were established such that generator resources remain connected to the grid during defined voltage and frequency transients and that mere ownership of a GSU or collector transformer does not constitute an integral part of the affected relay protection. Many commenters noted that TOs, even if they own GSUs or collector transformers, do not own generator protection relays unless they are already registered as a GO. Many commenters noted that they were unaware of any events where a BES generator failed to meet the requirements of PRC-024 because of GSU or collector transformer owned by a TO. Several other commenters similarly stated that this standard is for generator protection and questioned why protection of any transformers is included in scope. Similarly, one commenter noted that protection for TO owned GSUs or collector transformers is not intended for the protection of generators and including them in scope for this standard results in a shift of compliance burden from the GO to the TO. Finally, two commenters noted the focus should be on generator protection it is unnecessary to include TOs just because they own elements tripped by GO's protective devices.

#### *Response*

In response to these comments and the comments received during the PRC-024-3 Supplemental SAR posting, the SDT is no longer proposing to include TOs as an applicable entity in the continent-wide version of the standard. At the request of entities within the Quebec Interconnection, Transmission Owners will be included as an applicable entity for the Quebec Interconnection. The Supplemental SAR did provide for voltage, frequency and Volts/Hz applied on GSUs and UATs to be included in the scope of the standard.

#### *Summary*

One commenter stated that TOs that own asynchronous tie lines should also be included in the standard as they also exhibit momentary cessation due to voltage and frequency excursions.

#### *Response*

Asynchronous tie lines are outside the scope for applicability of PRC-024. Also, TOs have been removed from the continent-wide version of the standard.

#### *Summary*

One commenter noted that there may be instances where one entity owns the transformer and another entity owns the protection and as the standard is currently written, the transformer assets might not be within the scope of the standard.

#### *Response*

NERC writes standards to ensure reliable operation of the bulk electric system (BES), and the SDT asserts that if these situations exist, they would be rare and would not pose an impact to the BES.

## Chapter 6: Plant Auxiliary Protection Systems

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### Question # 6

*Another intent of the facilities section was to clarify that voltage and frequency protection applied to plant auxiliary equipment is not applicable to the standard. Do you agree it is clear that plant aux equipment is out of scope of PRC-024? If not, please provide your rationale and a proposal.*

#### Summary

Numerous commenters stated that the changes made to the Facilities section did not make it sufficiently clear that plant auxiliary equipment is excluded from the scope of the standard and offered alternative wording for the Facilities section or recommended the inclusion of figures to clarify the scope of equipment to be included in the standard. Numerous commenters requested that an explicit statement of the exclusion of plant auxiliary equipment be added to the Facilities section. One commenter noted that the lack of specificity regarding the inclusion of voltage, frequency, and V/Hz protective functions implemented within control systems could inadvertently include balance of plant equipment such as forced draft fans or boiler feed pumps within the scope of the standard as these components may have such protection enabled within their control system and the trip of which may result in a trip or de-rate of the plant.

#### Response

In response to these comments, the SDT has added section 4.2.2 which provides a specific exemption of all auxiliary equipment and associated protection from the Applicability of PRC-024-3. Additionally, the SDT has changed the wording of the applicability section to note that only voltage or frequency protection that trips the generating resource directly or provides signals to trip the generating resource or cause it to cease injecting current are in scope.

#### Summary

Several commenters were confused by section 4.2.1.3 of the Facilities and asked if auxiliary transformers connected between the high side of the GSU and the point of connection to the BES are meant to be included in scope and offered suggested wording comparable to that contained in PRC-025 for clarification for auxiliary transformers to be included as in scope.

#### Response

In response to these comments the SDT has rephrased that portion of the Facilities section and added a footnote to clarify that only auxiliary transformers connected on the generator bus between the low side of the GSU and the generator terminals are in scope.

#### Summary

Several commenters questioned the use of the phrase “all or part of a generating resource” in Facilities section 4.2.1. One commenter asked if this meant that de-rates of synchronous resources now falls within the applicability of the standard. Two other commenters noted that the use of “all or part of a generating resource” in section 4.2.1 could be interpreted as including plant auxiliary systems as in scope.

#### Response

In response to these comments, the SDT rephrased the Applicability Section to eliminate the use of the phrase “all or part of a generating resource” and has added language explicitly stating that plant auxiliary systems are not in scope of PRC-024-3.

### **Summary**

One commenter stated that the proposed inclusion of the high side of unit auxiliary transformer made the exclusion of plant auxiliary equipment unclear and asked for the technical justification for including voltage and frequency protection applied on the high side of UATs within the scope of the standard.

### **Response**

The technical justification for inclusion of voltage and frequency protection provided on the high side of the UAT is that typically there is no breaker provided between the high side of the UAT and the generator bus to which it is connected. As such, any actuation of voltage or frequency protection applied on the high side of the UAT will necessitate tripping the generator and GSU to which it is connected. Most modern microprocessor based transformer protection relays are equipped with voltage, frequency, and volts/Hz elements and these could be set separately from those applied on the generator or GSU and could result in a loss of the generating resource during a voltage or frequency excursion if so applied on the high side of the UAT.

### **Summary**

Several commenters disagreed with the exclusion of plant auxiliary equipment from the scope of the standard if the loss of the specific piece of auxiliary equipment affects the P, Q or  $V_t$  output of the plant.

### **Response**

The SAR for PRC-024-3 was to clarify that auxiliary equipment is excluded from the scope of the standard and, therefore, it would be in direct conflict with the SAR to change the standard to include plant auxiliary equipment as in scope.)

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## Chapter 7: Modifications to Charts and Figures

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### Question # 7

*The SDT made several clarifying changes to the figures and tables (outlined in the SAR) to improve readability and eliminate confusion addressed in the SAR, including: (i) labeling the area outside the “No Trip Zone” as the “May Trip Zone;” (ii) removal of “ride-through” language; (iii) addition of “Minimum Time;” (iv) replacement of “instantaneous” with “0.10” seconds; and (v) clarifying modifications to the Voltage Boundary Clarifications. Do you agree with these modifications? If not, please recommend alternative solution(s)*

### Summary

Replacement of « instantaneous » with a 0.1 second minimum time - Several commenters interpreted this change as adding an intentional time delay to the protection relays and argued that it would require changing the settings of the generating resources in order to comply with the standard, which would create an unnecessary burden for the GOs.

### Response

Changes to the tables supporting the Frequency No Trip Boundary Charts were made by the SDT in order to avoid using the term « instantaneous » and ensure that a minimum time of 100ms is allowed to account for the accurate frequency measurement (especially for IBRs where frequency is derived from PLL). SDT does not intend to introduce any additional delay in where a protective relay is tasked with frequency tripping, since such a device will act on an accurate frequency measurement. The 100ms in Table will ensure such delay, whether actual latency due to relay action or allowing enough time to derive accurate frequency from PLL, is modeled explicitly on modeling world...to be discussed

### Summary

Some commenters expressed that the voltages depicted in the No-Trip Boundaries should assume positive-sequence voltage rather than RMS fundamental frequency phase-to-ground or phase-to-phase voltage.

### Response

A significant portion of protective relays measure RMS and do not measure positive sequence. The SDT contends that since this is a protection settings standard, RMS is the appropriate voltage to measure. Additionally, the values in the Attachment 2 tables were based on the analyses and studies conducted by WECC on phased quantities and not on positive sequence.

### Summary

Many commenters noted that the addition of the phrase “May Trip Zone” may cause more confusion than clarity. One commenter suggested “equipment limitation zone” Other commenters suggested shading the region on the figure. One commenter noted that the drafting team is aware of this shortcoming due to the logarithmic chart.

### Response

The SDT has removed the “May Trip” label and has added the following note to the figure: \* *The area outside the “No Trip Zone” is not a “Must Trip Zone.”* The SDT asserts that the boundaries and charts are

sufficient and that equipment limitations do not need to be addressed. The SDT believes that the for readability, the chart should remain logarithmic.

### ***Summary***

Many commenters noted that The Voltage No-Trip Boundary graph for the Eastern, Western and ERCOT Interconnections stops after 4 seconds and the corresponding table with the data points does not include a « continuous » Minimum Time like in the Frequency Boundary Data Points tables. Commenters have suggested that the graph be expanded beyond 4 seconds to clearly show continuous operation limits.

### ***Response***

For the purpose of PRC-024, the voltage curves stop at 4 seconds. PRC-024 is only intended to address voltage excursions up to 4 seconds for the Eastern, Western and ERCOT Interconnections. At that point, the voltage excursion has ended for applicability to PRC-024. Other NERC Reliability Standards address generator voltage operating requirements beyond 4 seconds.

### **Comment**

In Attachment 2, Voltage Boundary Clarifications, item 4 states that the boundary can be adjusted in proportion to frequency. Does this eliminate the possibility of leaving the boundary alone and evaluating the volts per hertz relay at 60Hz?

### **Response**

While the boundary can be adjusted, it is not required.

### **Comment**

In Attachment 2, Voltage Boundary Clarifications, how does item 2. “The boundaries apply to voltage excursions regardless of the type of initiating event” provide clarification? I understand the curves were developed based on event simulations, but for analysis, the Entity is simply plotting the relay curves using assumed loading conditions to assure these curves and thus tripping are not in the “No Trip Zone”. If this statement is attempting to tell the Entity that running a series of event simulations is not enough to ensure compliance, please add more information to the clarification.

### **Response**

The SDT has removed the statement to avoid confusion.

### ***Comment***

In Attachment 2, Voltage Boundary Clarifications, item 4 states that the boundary can be adjusted in proportion to frequency. Does this eliminate the possibility of leaving the boundary alone and evaluating the volts per hertz relay at 60Hz?

### ***Response***

The SDT has revised Boundary Detail #3 for frequency assumptions to further clarity.

### ***Comment***

In Attachment 2, Voltage Boundary Clarifications, item 6 is correct, but is redundant as Table 1 indicates no limitation in voltage setting after 4 seconds. Should item 6 be removed from the document.

### ***Response***

The SDT chose to leave the statements to clarify confusion.

## Chapter 8: Quebec Interconnection Variance

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### Question # 8

*The SDT added Quebec Interconnection-wide Variance to Requirement R2 with more stringent voltage boundaries for the No Trip Zone. Do you agree with this proposed Quebec Variance? If not, please provide your rationale*

#### *Summary*

One commenter stated that they believe that the variance language can be sufficiently and effectively handled in the Quebec Interconnect specific figure similar to the frequency "no trip zone" Quebec specific chart and that a separate variance section is not required. Other commenters noted that they did not own facilities in Quebec and therefore had no opinion on the Variance.

#### *Response*

The motivation for including the Quebec specific figure in a Regional Variance is indeed related to the different language that is used in Quebec. But it also goes beyond the language. For example, in the Quebec Interconnection, the voltage no trip boundary, in overvoltage, allows Momentary Cessation under specified conditions, which is not allowed in the continent-wide proposed requirement.

## Chapter 9: Implementation Plan

### Question # 9

*Do you agree with the proposed Implementation Plan? If not, please provide your rationale*

#### Summary

Many commenters asserted that 18 months was insufficient. More time was requested for the following reasons:

- The current lack of understanding of the behavior of existing installed equipment with regard to “momentary cessation”
- The original dates for version 1 (and 2) were phased in over a longer period.
- More time needed to (i) obtain funding for and perform an analysis to see if they have compliance gaps and, if so, (ii) obtain funding for the change(s); (iii) complete a design for the change(s); and (iv) implement the changes
- As an example, replacing "instantaneous" language with "0.10 second" requires entities to verify the existing setting to meet this requirement.
- There may be substantial retesting and replacements to comply with this proposed Standard. The NSRF recommends a 24 month implementation plan as this will give Entities planning time for maintenance outages and for budget forecasting purposes.
- More time would allow for communication with the appropriate parties to see how systems would react to the current proposed set points and maybe allow any applicable modeling that may be required. If the standard was truly just adding solar plant inverters, the current proposed implementation plan would be sufficient.
- Consider a longer implementation period than 18 months for the necessary protection scheme changes, implementation and testing of the protection systems associated with the new requirement.
- Transmission asynchronous inerties exhibit the same momentary cessation issues due to voltage and frequency excursions as solar inverters
- Nuclear generating units typically run continuously and therefore implementation would have to be done during a scheduled refueling outage (typically 2 years for a boiling water reactor and 18 months for a pressurized water reactor). The scheduling to implement design changes during refueling outages is typically scoped at least 24 months in advance.

For these reasons, commenters suggested 36, 42, 60, etc. months for the implantation dates; however, many commenters agreed that 24 months would be sufficient.

#### Response

The SDT has modified the Implementation Plan to include a 24-month compliance date for GOs. The SDT has removed the reference to TOs given the fact that TOs are no longer applicable entities in the continent-wide version of the standard. The SDT has replaced the “.1 second minimum time” value back to “instantaneous.” Also, the term momentary cessation is no longer used in the standard, and the team agrees that industry should understand “cease injecting current” to be functionally equivalent.

#### Summary

One commenter noted that changes in any protective relay function and/or voltage/frequency control functions on inverters will require additional costs to industry adjusting dynamic models to meet MOD-032 requirements. The

SDT should consider older technology that is incapable of making the changes to be grandfathered and to allow for technical exceptions in order to avoid replacement costs of some equipment.

### **Response**

These equipment limitations are covered under Requirement R3 with the exception of protective relays.

Footnote #4: *"Excludes limitations caused by the setting capability of the frequency and voltage protective relays for the generating resource(s) but does not exclude limitations originating in the equipment that the relays protect or the frequency and voltage protection imbedded in control systems."*

## **Chapter 10: Cost Effectiveness**

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### **Question # 10**

*Do you agree that the proposed modifications provide a cost-effective means of addressing issues in the SAR? If not, please provide an alternative, more cost-effective manner in which to achieve at least an equivalent level of reliability*

### **Summary**

One commenter is concerned that the term "protection" is unclear and could potentially expand the included devices and equipment beyond the intent. Several commenters believe there may be substantial cost associated with this Standard.

### **Response**

The SDT has modified the Facilities Section to adequately describe the "protection" meant to be included and has added footnotes with specific language to Requirements to further clarify. The SDT has also removed TOs from the applicability and has extended the implementation timeline from 18 to 24 months.

## Chapter 11: Miscellaneous Comments

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### Question # 11

*If you have any additional comments on themes that have NOT already been addressed in the proceeding questions on this comment form, please provide them here*

#### **Summary**

Several commenters expressed the need for diagrams like those used in other standards which shown the equipment the standard applies to.

#### **Response**

The SDT had chosen to use the BES definition to describe the equipment included in the scope of the standard and has clarified the Facilities section.

#### **Summary**

Several commenters expressed that the exclusion of plant auxiliary equipment from the standard is still not clear.

#### **Response**

The SDT attempted to exclude the plant auxiliary equipment by adding the Facilities section and limiting the standard to the high side terminals of the UAT; however, an Exclusion section has be added to exclusively exclude the plant auxiliary equipment from the standard.

#### **Summary**

Several commenters stated the phrase “Elements utilized in aggregation of the dispersed power producing resources” is too broad and misunderstood. Furthermore, the mixing of this phrase and the BES I4 definition are contradictory

#### **Response**

The SDT moved footnote 2 up into the Facilities section. There is no change in the equipment covered in footnote 4 in PRC-024-2 and that described in PRC-024-3 facilities section.

#### **Summary**

Some commenters expressed that the standard applies to generator protection only and has no place for inclusion of the GSU or UAT.

#### **Response**

The SDT agrees that PRC-024-2 applies specifically to conventional synchronous generators. The inclusion of the IBR in footnote 4 clearly indicates that the generation resource is inclusive of the IBR and all equipment up to the POI (exclusive of plant auxiliary systems). It is in the opinion of the SDT that inclusion of the synchronous generator GSU and HS of the UAT better aligns with the intent of the standard and would remove any gaps where a voltage, frequency or V/Hz protection is applied exclusively to the GSU or HS of the UAT transformer. This intent is already assumed by most protection and control engineers as the damage curves for the GSU, UAT and generator are being considered when setting the V/Hz protection on the generator and coordination between independent V/Hz protection relays or control systems as in AVRs.

In most all cases, the generator is more susceptible to damage than the transformers and by default will protect the GSU and UAT.

### **Summary**

One commenter noted that the listing of voltage, frequency, and volts/hertz relays in the Facilities section is inconsistent with the NERC defined term “Facilities” which refers to “a set of electrical equipment that operates as a single Bulk Electric System Element” and stated this could cause confusion. Another commenter stated that Facilities section 4.2.1.5 expands the BES definition and should not be included. One commenter stated that Momentary Cessation is not a protection function and should not be included within the applicability of the standard.

### **Response**

The SDT does not intend to use the NERC Glossary term of Facilities. Many NERC standards have “Facilities” sections. The only reason Facilities is capitalized is due to the fact that it is a specific section of the Standard. The SDT contends that expanding the BES definition is not in scope of Project 2018-04. The SDT addressed Momentary Cessation issue in questions 3 and 4 above.

### **Summary**

The original draft of PRC-024-1 included, "shall not trip," language, which was replaced by, "set its protective relaying," after GOs pointed out that we can control our relay settings, but no one knows what might happen to take units offline for the massive disturbances of PRC-024 Att.1 and 2 (High/low drum level? High/low furnace pressure? CTG flame-out). PRC-024-3 has undone this pivotally important clarification by requiring that protection be set, "such that the generating resource does not trip." Units may trip regardless of how we set the protection for reasons that are out of scope for the standard and beyond our control. Many CTG protectives in particular are set by the OEM, and often can't be viewed by plant personnel much less adjusted. The, "set its protective relaying," language of PRC-024-2 should be retained.

### **Response**

The SDT believes that it is the entities responsibility to understand their resource’s control system and how it will react to voltage and frequency excursions. The SDT recommends that an entity contact their generator/control system OEM for information about their settings or adjustments to existing settings. Also, see Requirement R3 for more information regarding equipment limitations.

### **Comment**

If a start-up transformer can support station load during times when the unit auxiliary becomes inoperable, e.g., emergencies, is this Standard applicable to the start-up transformer?

### **Response**

The UAT is the only auxiliary transformer in the scope of the standard. Startup transformers are usually fed from the transmission system. If the startup transformer were connected to another units generator bus, it would be considered a UAT and then would be in the scope of the standard.

### **Comment**

It’s unclear in Attachments 1 and 2 whether the lines are in the No Trip Zone of the May Trip Zone. Can the Standard Drafting Team (SDT) please clarify?

**Response**

The tables specify whether inclusion or exclusion of the boundary lines.

**Comment**

Seminole reads Attachment 1, Table 1, to not apply to any protection system settings less than 0.10 seconds. For example if we had a setting at .08 sec. that was in the no trip zone, this would not be applicable to this standard, Is this correct?

**Response**

The SDT has replaced the .1 minimum time to “instantaneous,” so .08 seconds is applicable to the standard.

**Comment**

In Attachment 1, the low frequency (Hz) values are less than or equal signs until the final frequency. For Attachment 2, the low voltage (pu) points are less than signs with the final voltage being less than or equal. Why is this different? Should we be treating the boundary lines differently between attachments?

**Response**

There have been no changes from the currently enforceable standard, and the SDT does not have technical justification to make modifications at this time.

**Comment**

The “Evaluating Protection Settings” section should be modified to coincide with the operating conditions of the generator. The power factor designation should be adjusted to align with whether the generator is underexcited or overexcited. Also, the language should be modified so that it clearly states that an entity may use steady state analysis for a dynamic situation.

**Response**

The SDT has re-written the “Evaluating Protection Settings” section.

**Comment**

PRC-024-2 footnote 1 specifically instructed entities to evaluate the V/Hz protection at nominal frequency (60 Hz). In the PRC-024-3 version, this detail was lost the translation of the footnotes into the facilities/requirements section. This will create ambiguity and may cause entities to believe they have to perform dynamic simulations to show compliance with V/Hz protection schemes.

**Response**

The SDT has added this back into Attachment 2.

**Comment**

Suggest revising Purpose from “To set generator protection such that generating resource(s) remain connected, continuing to support the BES during defined frequency and voltage excursions” to instead state “To ensure generator protection \*is set\* such that generating resource(s) remain connected \*and continue to support\* the BES during defined \*durations of off-nominal frequency and voltage.\*”

**Response**

The SDT has modified the purpose statement. “To set protection such that generating resource(s) remain connected during defined frequency and voltage excursions in support of the Bulk Electric System (BES).”

**Comment**

Section Title: Change from to “Voltage Boundary Clarifications” to instead state “Voltage \*and Frequency\* Boundary Clarifications” Change from “The boundaries apply to voltage excursions regardless of the type of initiating event” to instead state “The boundaries apply to \*off-nominal\* voltage \*and frequency durations\* regardless of the type of initiating event.”

**Response**

The information in the “Voltage Boundary Clarifications” does not apply to frequency. The SDT does not believe there is a need for clarification in Attachment 1 for frequency.

**Comment**

Change from “The values in the tables represent the minimum time durations allowed for specified voltage excursion thresholds” to instead state “The values in the tables represent the minimum time durations \*required\* for specified voltage thresholds.” It may still be advantageous to retain the example here because it is too easy to misconstrue the boundaries as meaning no trip for excursions that remain within the boundaries rather than no trip for time durations at the defined levels.

**Response**

The SDT believes that the language is clear.

**Comment**

Change from “The boundaries assume a system frequency of 60 Hertz” to instead state “The boundaries assume a system \*base\* frequency of 60 Hertz.” Also, please add a “the “to the second sentence to state “When evaluating volts per hertz protection, \*the\* magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.”

**Response**

The SDT has revised Boundary Detail #3 for frequency assumptions to further clarity.

**Comment**

Change “Voltages in the boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase voltage” to instead state “Voltage boundaries assume \*per unit\* RMS fundamental frequency phase-to-ground or phase-to-phase voltage.”

**Response**

The SDT has made the suggested language edits regarding the per unit voltage.

**Comment**

“In the interest of developing completely clear, unambiguous, grammatically correct Requirements, R3 could be better stated as:

Each Generator Owner or Transmission Owner shall document each known regulatory or equipment limitation<sup>1</sup> that prevents an applicable generating resource(s) (unit) with generator frequency or voltage protection from meeting the protection setting criteria in Requirements R1 or R2. Documentation includes (but is not limited to) study results, experience from an actual event, or manufacturer’s advice

The comment above can also be applied to R4. R4 is not very clear and may be providing an opportunity for entities to manipulate information to avoid complying. Recommend rewriting to clear up when and what processes allow for deviation from transmitting the setting information.”

### Response

The SDT reviewed the proposed grammatical changes and has chosen to retain the current language.

### Comment

Many commenters requested clarifying changes to the Facilities Section. Specifically, Facilities 4.2.1 includes “Frequency, voltage or volts per hertz protection including frequency or voltage protective functions within control systems”. This specifically calls out volts per hertz protection, but then assumes the reader will understand that the exciter volts per hertz protective function (tripping) is a voltage protective function. Would it be better to specifically mention the volts per hertz protective function within control systems?

Facilities 4.2.1 states “...that provide tripping or momentary cessation signals to all or part of the generating resource”. Currently only 4.2.1.1 is identified as being a generating resource. Should the statement be modified to include all or part of the dispersed power producing resources?

Facilities 4.2.1.5 makes reference to “the dispersed power producing resources”. Is it clear that this is referring to the dispersed power producing resources of Facilities 4.2.1.4? Would it be better to provide a complete description of the applicable dispersed power producing resources in 4.2.1.5?

In Attachment 2, Evaluating Protection Settings, item 1. d. includes the assumption “The automatic voltage regulator is in automatic voltage control mode”. If calculations are on the static case for steady state initial conditions, how does the automatic voltage regulator control mode come into play? Should item 1. d. be removed from the document?

Please modify Attachment 2, Evaluation Protection Settings, number 1. c. as follows, because there is no realistic scenario where the high side voltage will be 1.1 pu or higher and the generator voltage will be at 0.95 pf lagging. It is most realistic to use lagging pf for low voltage conditions and leading pf for high voltage conditions.

*For low voltage protection use Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals. For high voltage settings use Power factor is 0.95 leading (i.e. taking reactive power from the system) as measured at the generator terminals.*

Proposed requirement R4: In keeping with the intent of the current Standards Efficiency Review Project, R4 is not required within the proposed Standard as the capturing of data is redundant. The NSRF believes this can be captured under currently enforceable MOD-032-1, R2 which requests data developed by the PC and TP in R1.

Per the webinar, the SDT stated that Facilities 4.2.1.5 “Elements utilized in aggregation of the dispersed power producing resources” reads the same as PRC-025-2. The NSRF disagrees with this statement. This SDT is now expanding both PRC-025-2 and proposed PRC-024-3 to include items that make up the “collector systems”, which is directly against the FERC Approved definition of Inclusion I4. When the SDT states 4.2.1.5 is directly related to PRC-025-2 and has the same intentions, the NSRF strongly disagrees. When applying the FERC approved definition of Inclusion I4 and 4.2.1.5 of PRC-024-3 (or PRC-025-2) collector system items ARE NOT applicable to either Standard.

**Response**

The SDT has re-written the Facilities section to clarify the protection as well as on which equipment the protection applies; this includes moving, to the Facilities section, protection on equipment that was previously referenced in footnotes to PRC-024-2 requirements. The SDT's intent is that generating resource(s) (per BES Definition, 12/14) includes the generator terminal through the high side of the GSU/MPT. The Facilities Section of PRC-024-3 is consistent with footnotes #2 and #4 from PRC-024-2; the SDT has not changed the scope of the applicable facilities. The SDT has also modified Attachment 2, Evaluating Protection Settings to allow the use of most probable loading condition. The Standards Efficiency Review Phase 2 Team is tasked with addressing any additional requirements that may be redundant.

**Comment**

Footnote 5 : "Excludes limitations that are caused by the setting capability of the generator frequency and voltage protection relays themselves but does not exclude limitations originating in the equipment that they protect"

An older generator uses an electromechanical auxiliary relay for undervoltage protection. It is original equipment installed with the facility more than 30 years ago. There are no settings available on this relay. Similar to other auxiliary relays, when voltage dips below the drop out voltage, contacts would latch and trip the unit. The dropout characteristic of his relay does not meet PRC-024.

Would this case be considered an equipment limitation for PRC-024? We believe it does as it is original equipment with the plant and there is no language in the existing standard stating that new equipment needs to be installed. When new equipment is required (e.g. PRC-002 and PRC-025), a longer implementation period is accounted for.

**Response**

The SDT is not proposing substantive revisions to the PRC-024-2 language cited by the commenter. Questions regarding compliance with currently effective PRC-024-2 should be directed to ERO compliance staff.

**Comment**

Reclamation requests clarification of the rationale in allowing the Transmission Planner to make less stringent voltage settings than those required by Attachment 2.

**Response**

That rationale was determined by the drafting team for version 1 of PRC-024. Please see NERC's petition to FERC for approval of PRC-024-1, Exhibit E. This drafting team has made no changes to the standard regarding this matter.

**Summary**

Some commenters asserted that the issues being addressed in PRC-024-3 were taken care of by the NERC Alert and IRPTF and, therefore, PRC-024-2 does not need to be modified.

**Response**

The Standards Committee accepted the SARs to modify PRC-024-2, and the SDT is bound by the scope as outlined in the SAR.

**Comment**

Section 4.2.1.5 as currently proposed is sufficiently broad to potentially include rooftop solar and other similar distribution systems resources. Exelon suggests the more narrow statement based on BES Definition I4 to avoid confusion.

**Response**

The SDT has clarified Section 4.2.1.5 by referencing the BES Definition, I4

**Comment**

Regarding embedded frequency protection, it is not clear if generator speed signals that result in the trip of a unit are included. TAL believes this question should be addressed in the standard given that speed is directly related to frequency.

**Response**

Although it is possible to derive the mechanical rotational speed of the turbine/generator with an AC waveform from the generator bus instrument potential transformer, turbine/generator mechanical over/under speed protection is not in the scope of PRC-024-3 from a BES reliability perspective. The primary protection for turbine overspeed resides in the turbine controls and is extremely secure.

**Comment**

The elimination of footnote 1 implies that GOs are required to activate frequency and voltage protective relaying or protection systems where they currently may not be doing so. The footnote made it clear that the standard did not require these elements to be installed or activated on the generating unit. Another commenter asked about the associated documents and whether they are necessary.

**Response**

Footnote 1 has been reinstated in draft 2 of PRC-024-3. The SDT reviewed the associated documents and has determined that the references are not necessary; as such, they have been removed from the standard.

**Comment**

Texas RE requests clarification on Footnote 5 question regarding equipment limitations for wind turbines: do wind turbines equipment limitations include “smart crowbar” equipment limitations, UPS for the turbine control system, and tower vibration limits?

**Response**

Compliance determinations are facts-specific and should be reviewed on a case by case basis.

**Comment**

Including the phrase “experience from an actual event” as allowable evidence in Measure M3 for a regulatory or equipment limitation could imply that the limitation could occur during the event. The intent of the standards is that limitations shall be documented prior to an event occurring.

**Response**

The SDT discussed this matter and contends that the intent of the Measure and the Requirement is clear. No changes made.

### **Comment**

Regarding VSLs - Although the wording is clear, this reviewer is uncertain how the Severe VSL for R3 can be enforced: "...failed to document any known non-protection system equipment limitation..." There would have to be documentation to demonstrate that the entity knows about the limitation.

### **Response**

The SDT asserts that the Requirement R3 Severe VSL reflects the requirement language and is effective as written. For example, the Severe VSL could come into consideration for determining a penalty in the following scenario: During a compliance engagement, it is determined that an entity should have followed Requirement R1 for a particular setting. The entity verbally responds that it did not violate Requirement R1 because it relied on an equipment limitation. This reply indicates the entity knew about the limitation but this knowledge was indicated verbally. In this scenario, the entity was mentioning the knowledge of the equipment limitation to show that the entity did not need to comply with Requirement R1 for that setting. If it was determined that the entity did not violate Requirement R1 but did violate Requirement R3 because the entity did not document the known equipment limitation, then the Requirement R3 Severe VSL could be considered in the penalty calculation.

### **Comment**

The Facilities section can be consolidated. There are currently redundancies in section 4.2.1. The following Facilities can be struck:

4.2.1.2 BES GSU transformer(s). This is part of the BES Generating resource so it is captured in 4.2.1.1.

4.2.1.4. Individual dispersed power producing resources identified in the BES Definition, Inclusion I4. This is a BES generating resource so it is captured in 4.2.1.1.

4.2.1.6 Collector transformer of resources identified in the BES Definition, Inclusion I4. This is part of the BES generating resource in Inclusion I4, so for the same reasons as striking, 4.2.1.2 and 4.2.1.4., it is captured in 4.2.1.1

We suggest that the Facilities section could be simplified. We do not believe that it is necessary to include the BES applicability language within the standard, since the standard should only be applicable to the BES.

### **Response**

The BES definition includes equipment that would not be considered applicable under PRC-024-3. Therefore, to be clear, the exact equipment under the scope of PRC-024-3 has been intentionally called out in this manner.

### **Summary**

Several commenters stated that there is a potential conflict between PRC-024 and PRC-006-NPCC-1

### **Response**

Revising the regional standard is beyond the scope of this project. NERC will ensure the appropriate entities are made aware of the possible conflict so that any required changes to the regional standard may be pursued through the regional standard development process.

### **Comment**

It is unclear whether the Evaluating Protection Settings section on page 21 of the redline proposed Standard

constitutes one or more requirements in connection with the evaluation of voltage protection settings. Are these additional compliance requirements that should therefore be referred to in or made a part of the main body of the proposed Standard? Is a study being required in connection with Requirement R2? If so, the SDT should incorporate a specific requirement in the proposed standard in order to eliminate confusion and ambiguity. The specific requirement should articulate (1) Responsible Entities shall perform a study and (2) the mandatory components of the study.

***Response***

The SDT has modified Evaluating Protection Settings and Requirement R2 for clarity.

**Summary**

Several commenters stated that the term “generating resources” should not be used and suggested using the term “generator” or “generating Facility”

**Response**

"Generating resource" is terminology consistently used in the BES Definition.

**Summary**

Several commenters stated that the equipment limitation exception to Requirements R1 and R2 that is contained in Requirement R3 is too broad and can be misapplied. We suggest adding an implementation period to allow all facilities to meet the protection setting criteria.

**Response**

There has been no change from the currently enforceable version of the standard. NERC writes standards to ensure reliable operation of the BES, and the SDT asserts that if these situations exist, they would be rare and would not pose an impact to the BES.