NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

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

Requested information			
SAR Title:	Transmission Planning Energy Scenarios		
Date Submitted:	October 30, 2023		
SAR Requester			
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SAR Type (Check as many as apply)			
☒ New Standard ☒ Revision to Existing Standard ☒ Add, Modify, or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☒ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	

Requested information
What is the risk to the Bulk Electric System (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):

The current transmission planning Reliability Standard TPL-001-5.1 – Transmission System Planning Performance Requirements[1] does not expressly require transmission planners and planning coordinators to consider in the long-term planning horizon (1) normal and extreme natural events,[2] (2) gas-electric interdependencies and (3) distributed energy resources (DER) events. In particular, Reliability Standard TPL–001–5.1, Table 1, provisions 3. b (steady state) and 2. j (stability) require analyses to be performed for certain events based upon operating experience but do not expressly require these three types of impacts.

Events related to these three areas have spanned the continent in recent years and demonstrate the challenges associated with planning, particularly those events that affect a wide area or that occur during periods when the Bulk-Power System (BPS) must meet unexpectedly high demand. Extreme weather events have occurred with greater frequency in recent years and are projected to occur with even greater frequency in the future. Dependency on natural gas is increasing as it is becoming a more significant share of the dispatchable resources due to large thermal plant retirements and increases in renewables. Lastly, DER has been and continues to be, an area that has been shown to create impacts on the BPS planning as well as its operation.

Events have shown that the risk of such events can pose to the reliable operation of the BPS and is accentuated by the FERC Order No. 896[3] ("Order") directing NERC to require transmission system planning for extreme heat and cold weather events that impact the Reliable Operation of the BPS. The Order emphasizes that long-term transmission planning, along with other measures, can play an important role in identifying and helping to minimize not only extreme heat and cold weather events but also the three risks noted above.

In parallel with the efforts related to the Order and in addition to the priorities identified in NERC's work plan priorities informed by the Reliability Issues Steering Committee (RISC), this project will similarly harmonize the NERC TPL-001 transmission planning Reliability Standard with the creation of one or more new Reliability Standard(s) to address (1) normal and extreme natural events, (2) gas-electric interdependencies, and (3) DER. The potential risks for cascading outages that may be caused by these three areas of risk should use benchmark events[4] and planning cases[5], have both the steady-state and stability analyses conducted, and have corrective action plans developed and implemented where BPS performance cannot be met.

[1] TPL-001-5.1 at https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.1.pdf.
[2] Normal and extreme natural events will not include extreme heat and cold as addressed in the FERC Order No. 896.
[3] Order No. 896, *Transmission System Planning Performance Requirements for Extreme Weather*, 183 FERC ¶ 61,191 (2023), available at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20230615-3100&optimized=false.
[4] The transmission planning analyses intend to target specific cases called benchmark events for which energy scenarios would be applied according to defined performance criteria.
[5] Power flow cases used in performing transmission planning studies.

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The modification of the Reliability Standard(s) will establish benchmark events related to the three risk areas[6] for required analyses and require the development of planning cases with appropriate sensitivities over a wide area. The Reliability Standard(s) must require the identification and implementation of corrective actions where system performance requirements are not met, including appropriate coordination and communication of studies.
Purpose or Goal (What are the reliability gap(s) or risk(s) to the Bulk Electric System being addressed, and how does this proposed project provide the reliability-related benefit described above?):
The purpose of this project is to address the transmission planning reliability gaps that do not expressly require transmission planners and planning coordinators to consider (1) normal and extreme weather, (2) gas-electric interdependencies, and (3) DER in their transmission planning assessments in the long-term planning horizon. Using the Transmission Planning Energy Scenarios Technical Justification Document, October 2023 ("White Paper"), the goal in revising an existing Reliability Standard(s) or creating one or more new Reliability Standard(s) is to: A. Revise the TPL Reliability Standard and/or develop one or more new Reliability Standard(s) (addressing all three risk areas). B. Develop energy scenario-based[7] benchmark events and planning cases. C. Consider defining "wide area" if needed to address defined energy scenarios.[8] D. Identify responsible functional entities for developing benchmark events and planning cases and for conducting studies over a wide area. E. Require coordination among responsible entities and the sharing of data and studies. F. Require study of concurrent/correlated generator and transmission outages. G. Conduct transmission system planning studies of all three risk areas over the long-term planning horizon, including: a. Steady state and transient stability analyses. b. Sensitivity analysis applying appropriate sensitivities based on collaboration from neighboring planners. c. Consider modification to the traditional planning approach(es). H. Require the development of corrective action plans that mitigate specified instances where performance requirements are not met. I. Establish an appropriate implementation timeline to address the risks.
Project Scope (Define the parameters of the proposed project):
The scope of the proposed project is to develop one or more new transmission planning Reliability Standard(s) or modify an existing Reliability Standard to address the issues and criteria discussed in

[6] Risk areas: (1) Normal and extreme weather, (2) gas-electric interdependencies, and (3) distributed energy resources (DER).
[7] E.g., Energy scenarios including, but not limited to traditional or normal patterns (i.e., "de-carbonization and policy", significant changes in alternative generation resources (i.e., "high renewables penetration"), and induced increases in consumption due to electrifications (i.e., "high demand").
[8] Wide Area is defined in Glossary of Terms Used in NERC Reliability Standards. The subject matter experts charged with defining "wide area" will need to consider revising the defined term of creating a different term.

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the White Paper in collaboration with those efforts to address directives from FERC Order No. 896 pertaining to the study of extreme heat and cold weather events. New or revised definitions may be required (e.g., "wide area"). This project may also need to revise Reliability Standard MOD-032-1 – Data for Power System Modeling and Analysis[9] for data sharing.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide (1) a technical justification[10] for developing a new or revised Reliability Standard or definition, which includes a discussion of the risk and impact on the reliability of the BES, and (2) a technical foundation document (*e.g.,* research paper) to guide the development of the Standard or definition):
The individuals responsible for the development of one or more new Reliability Standard(s) or the modification of a Reliability Standard shall achieve the actions listed below related to addressing the three identified risk areas pertaining to transmission system planning over the long-term planning horizon that impact the Reliable Operation of the BPS. The technical justification and foundation of the reliability-related benefits is addressed in the White Paper concerning the developing of one or more new Reliability Standard(s) and/or modifying an existing Reliability Standard, which includes the addition or modification of any term(s) used in Reliability Standards. To assist the drafting team for this project and those efforts addressing Order No. 896 directives, the following actions have been prepared in a sequence consistent with the directives in the Order. **Normal Natural Events** A. Revise to harmonize the TPL-001-5.1 Reliability Standard and/or develop one or more new Reliability Standard(s) to address normal natural events. B. Develop energy scenario-based benchmark planning event and planning cases that include addressing: a. Seasonal demand variations. b. Planned energy resource additions. c. Resource variability. d. Factors that affect the scope of energy scenarios: i. Identifying geographical regional differences in climate and weather patterns. ii. Using historical natural event meteorological data from reliable sources (e.g., national laboratories, regional transmission operators (RTO), National Oceanic

[9] See MOD-032-1 at https://www.nerc.com/pa/Stand/Reliability%20Standards/MOD-032-1.pdf.

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

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and Atmospheric Administration (NOAA), Environment Canada, and other local, state, and federal agencies and organizations.

iii. Applying a common method to follow when creating benchmark planning cases.

iv. Potential event-related coincident contingencies (e.g., concurrent/correlated generation and transmission outages, derates, etc.) and expected future conditions of the system, such as changes in load.

v. Available transfers.

vi. Generation resource mix.

vii. Identifying facilities sensitive to certain events.

C. Consider defining "wide area" if needed to address defined energy scenarios.

D. Identify responsible functional entities for developing:

a. Benchmark events.

b. Planning cases.

c. Entities to conduct studies over a wide area.

d. Corrective action plans.

E. Require coordination among responsible entities and the sharing of data and studies.

F. Require the study of concurrent/correlated generator and transmission outages.

G. Conduct transmission system planning studies for normal, natural events over the long-term planning horizon for:

a. Steady-state analyses – The steady-state analyses need to assess the system performance under no contingencies (e.g., P0 under TPL-001) with all system elements in-service with the anticipated generation dispatch. Steady-state studies must:

i. Apply normal natural weather benchmark planning events to the planning case.

ii. Apply the defined energy scenarios to each benchmark planning event.

iii. Include specific defined criteria for determining concurrent and correlated outages of both generators and transmission lines.

iv. Model demand load response in benchmark planning event cases as a corrective action to meet system performance criteria.

v. Evaluate the wide area performance during such benchmark planning events and energy scenarios.

b. Transient stability analyses – The stability (i.e., dynamic) analyses need to assess the system performance under a defined contingency or set of contingencies, but not

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necessarily mirroring or to the rigor of the TPL-001 Reliability Standard planning contingencies (e.g., Categories P1-P7). Stability studies must:

i. Apply normal, natural event benchmark planning events.

ii. Apply the defined energy scenario contingencies (e.g., high demand and low resource availability) to each benchmark planning event.

iii. Include specific defined criteria for determining concurrent and correlated unplanned outages of both generators and transmission lines.

iv. Model demand load response in benchmark planning event cases as a corrective action to meet system performance criteria.

v. Evaluate the wide area performance during such benchmark planning events and energy scenarios.

c. Sensitivity analysis applying appropriate sensitivities based on collaboration from neighboring planners. The following are minimum considerations:

i. Require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case.

ii. Establish a baseline set of sensitivities that include conditions that vary with temperature, such as load, generation, and system transfers.

iii. Document sensitivity assumptions.

d. Consider modification to the traditional planning approach(es). Consider the following probabilistic approaches at a minimum:

i. Whether probabilistic techniques can be incorporated into the new or modified Reliability Standard(s) and implemented by responsible entities and

ii. If a probabilistic approach is feasible and reasonable, address factors such as:

1. A projected frequency (e.g., 1-in-50-year event), or

2. A probability distribution (95th percentile event).

H. Require the development of corrective action plans that mitigate specified instances where performance requirements are not met. Corrective action plans must:

a. Identify specified instances in benchmark event cases when performance standards are not met.

b. Establish required study contingencies and baseline sensitivities for which a corrective action plan is required.

c. Determine whether corrective action plans should be required for single or multiple sensitivity cases.

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d. Determine whether corrective action plans should be developed if a benchmark event that is not already included in benchmark planning case would result in cascading outages, uncontrolled separation, or instability.

e. Require mitigation for specified instances where performance requirements for benchmark events and energy scenarios are not met (*i.e.* when certain benchmark studies conducted under the Reliability Standard show that a benchmark event would result in cascading outages, uncontrolled separation, or instability).

f. Require certain processes to facilitate interaction and coordination with applicable regulatory authorities, including applicable governing bodies responsible for retail electric service, as appropriate in implementing a corrective action plan.

g. Require that responsible entities share their corrective action plans with applicable regulatory authorities, including applicable governing bodies responsible for retail electric service issues.

I. Establish an appropriate implementation timeline to address the risks.

J. Establish a method and interval (e.g., every 3-5 years) for periodic updates to benchmark event and planning cases, inputs, energy scenarios, assumptions, and other key data required to conduct studies.

Extreme Natural Events

A. Revise to harmonize the TPL-001-5.1 Reliability Standard and/or develop one or more new Reliability Standard(s) to address extreme natural events.

B. Develop energy scenario-based benchmark planning event and planning cases that include addressing:

a. Seasonal demand variations.

b. Planned energy resource additions.

c. Resource variability.

d. Factors that affect the scope of energy scenarios:

i. Identifying geographical regional differences in climate and weather patterns.

ii. Using extreme natural event meteorological data from reliable sources (e.g., national laboratories, regional transmission operators (RTO), National Oceanic and Atmospheric Administration (NOAA), Environment Canada, and other local, state, and federal agencies and organizations.

iii. Applying a common method to follow when creating benchmark planning cases.

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iv. Potential event-related coincident contingencies (e.g., concurrent/correlated generation and transmission outages, derates, etc.) and expected future conditions of the system, such as changes in load.

v. Available transfers.

vi. Generation resource mix.

vii. Identifying facilities sensitive to certain events.

C. Consider defining "wide area" if needed to address defined energy scenarios.

D. Identify responsible functional entities for developing:

a. Benchmark events.

b. Planning cases.

a. Entities to conduct studies over a wide area.

c. Corrective action plans.

E. Require coordination among responsible entities and the sharing of data and studies.

F. Require the study of concurrent/correlated generator and transmission outages.

G. Conduct transmission system planning studies for extreme natural events over the long-term planning horizon for:

a. Steady-state analyses – The steady-state analyses need to assess the system performance under no contingencies (e.g., P0 under TPL-001) with all system elements in-service with the anticipated generation dispatch. Steady-state studies must:

i. Apply extreme natural weather benchmark planning events to the planning case.

ii. Apply the defined energy scenarios to each benchmark planning event.

iii. Include specific defined criteria for determining concurrent and correlated outages of both generators and transmission lines.

iv. Model demand load response in benchmark planning event cases as a corrective action to meet system performance criteria.

v. Evaluate the wide area performance during such benchmark planning events and energy scenarios.

b. Transient stability analyses – The stability (i.e., dynamic) analyses need to assess the system performance under a defined contingency or set of contingencies, but not necessarily mirroring or to the rigor of the TPL-001 Reliability Standard planning contingencies (e.g., Categories P1-P7). Stability studies must:

i. Apply extreme natural event benchmark planning events.

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ii. Apply the defined energy scenario contingencies (e.g., high demand and low resource availability) to each benchmark planning event.

iii. Include specific defined criteria for determining concurrent and correlated unplanned outages of both generators and transmission lines.

iv. Model demand load response in benchmark planning event cases as a corrective action to meet system performance criteria.

v. Evaluate the wide area performance during such benchmark planning events and energy scenarios.

c. Sensitivity analysis applying appropriate sensitivities based on collaboration from neighboring planners. The following are minimum considerations:

i. Require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case.

ii. Establish a baseline set of sensitivities that include conditions that vary with temperature, such as load, generation, and system transfers.

iii. Document sensitivity assumptions.

d. Consider modification to the traditional planning approach(es). Consider the following probabilistic approaches at a minimum:

i. Whether probabilistic techniques can be incorporated into the new or modified Reliability Standard(s) and implemented by responsible entities and

ii. If a probabilistic approach is feasible and reasonable, address factors such as:

1. A projected frequency (e.g., 1-in-50-year event), or

2. A probability distribution (95th percentile event).

H. Require the development of corrective action plans that mitigate specified instances where performance requirements are not met. Corrective action plans must:

a. Identify specified instances in benchmark event cases when performance standards are not met.

b. Establish required study contingencies and baseline sensitivities for which a corrective action plan is required.

c. Determine whether corrective action plans should be required for single or multiple sensitivity cases.

d. Determine whether corrective action plans should be developed if a benchmark event that is not already included in benchmark planning case would result in cascading outages, uncontrolled separation, or instability.

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e. Require mitigation for specified instances where performance requirements for benchmark events and energy scenarios are not met (*i.e.* when certain benchmark studies conducted under the Reliability Standard show that a benchmark event would result in cascading outages, uncontrolled separation, or instability).

f. Require certain processes to facilitate interaction and coordination with applicable regulatory authorities, including applicable governing bodies responsible for retail electric service, as appropriate in implementing a corrective action plan.

g. Require that responsible entities share their corrective action plans with applicable regulatory authorities, including applicable governing bodies responsible for retail electric service issues.

I. Establish an appropriate implementation timeline to address the risks.

J. Establish a method and interval (e.g., every 3-5 years) for periodic updates to benchmark event and planning cases, inputs, energy scenarios, assumptions, and other key data required to conduct studies.

Natural Gas Interdependencies

A. Revise to harmonize the TPL-001-5.1 Reliability Standard and/or develop one or more new Reliability Standard(s) to address natural gas interdependencies.

B. Develop energy scenario-based benchmark planning event and planning cases that include addressing:

   a. Gas supply disruptions.

   b. Electric power supply disruptions.

   c. Fuel switching.

   d. Renewable energy integration.

C. Consider defining "wide area" if needed to address defined energy scenarios.

D. Identify responsible functional entities for developing:

   a. Benchmark events.

   b. Planning cases.

   c. Entities to conduct studies over a wide area.

   d. Corrective action plans.

E. Require coordination among responsible entities and the sharing of data and studies.

F. Require the study of concurrent/correlated generator and transmission outages.

G. Conduct transmission system planning studies for natural gas interdependencies over the long-term planning horizon for:

   a. Steady-state analyses – The steady-state analyses need to assess the system performance under no contingencies (e.g., Category P0 under TPL-001) with all system elements in-service with the anticipated generation dispatch. Steady-state studies must:

      i. Apply natural gas interdependency benchmark planning events to the planning case.

      ii. Apply the defined energy scenarios to each benchmark planning event.

      iii. Include specific criteria for determining concurrent and correlated outages of both generators and transmission lines.

      iv. Model demand load response in benchmark planning event cases as a corrective action to meet system performance criteria.

      v. Evaluate the wide area performance during such benchmark planning events and energy scenarios.

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b. Transient stability analyses – The stability (i.e., dynamic) analyses need to assess the system performance under a defined contingency or set of contingencies, but not necessarily mirroring or to the rigor of the TPL-001 Reliability Standard planning contingencies (e.g., Categories P1-P7). Stability studies must:

   i. Apply natural gas interdependency benchmark planning events.

   ii. Apply the defined energy scenario contingencies (e.g., high demand, low resource availability, fuel switching) to each benchmark planning event.

   iii. Include specific criteria for determining concurrent and correlated unplanned outages of both generators and transmission lines.

   iv. Model demand load response in benchmark planning event cases as a corrective action to meet system performance criteria.

   v. Evaluate the wide area performance during such benchmark planning events and energy scenarios.

   vi. Evaluate risks of compressor stations electric motors stalling.

c. Sensitivity analysis applying appropriate sensitivities based on collaboration from neighboring planners. The following are minimum considerations:

   i. Require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case.

   ii. Establish a baseline set of sensitivities that include conditions that vary with temperature, such as load, generation, and system transfers.

   iii. Document sensitivity assumptions.

d. Consider modification to the traditional planning approach(es). Consider the following probabilistic approaches at a minimum:

   i. Whether probabilistic techniques can be incorporated into the new or modified Reliability Standard(s) and implemented by responsible entities and

   ii. If a probabilistic approach is feasible and reasonable, address factors such as:

      1. A projected frequency (e.g., 1-in-50-year event), or

      2. A probability distribution (95th percentile event).

H. Require the development of corrective action plans that mitigate specified instances where performance requirements are not met. Corrective action plans must:

   a. Identify specified instances in benchmark event cases when performance standards are not met.

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b. Establish required study contingencies and baseline sensitivities for which a corrective action plan is required. c. Determine whether corrective action plans should be required for single or multiple sensitivity cases. d. Determine whether corrective action plans should be developed if a benchmark event that is not already included in benchmark planning case would result in cascading outages, uncontrolled separation, or instability. e. Require mitigation for specified instances where performance requirements for benchmark events and energy scenarios are not met (*i.e.* when certain benchmark studies conducted under the Reliability Standard show that a benchmark event would result in cascading outages, uncontrolled separation, or instability). f. Require certain processes to facilitate interaction and coordination with applicable regulatory authorities, including applicable governing bodies responsible for retail electric service, as appropriate in implementing a corrective action plan. g. Require that responsible entities share their corrective action plans with applicable regulatory authorities, including applicable governing bodies responsible for retail electric service issues. I. Establish an appropriate implementation timeline to address the risks. J. Establish a method and interval (e.g., every 3-5 years) for periodic updates to benchmark event and planning cases, inputs, energy scenarios, assumptions, and other key data required to conduct studies.
Distributed Energy Resources A. Revise to harmonize the TPL-001-5.1 Reliability Standard and/or develop one or more new Reliability Standard(s) to address distributed energy resources (DER). B. Develop energy scenario-based benchmark planning event and planning cases that include addressing: a. High DER penetration scenarios. b. DER variability and intermittency. c. BPS support from DERs. d. DER outage scenarios. C. Consider defining “wide area” if needed to address defined energy scenarios. D. Identify responsible functional entities for developing: a. Benchmark events.

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b. Planning cases.

c. Entities to conduct studies over a wide area.

d. Corrective action plans.

E. Require coordination among responsible entities and the sharing of data and studies.

F. Require the study of concurrent/correlated generator and transmission outages.

G. Conduct transmission system planning studies for DER energy scenarios over the long-term planning horizon for:

a. Steady-state analyses – The steady-state analyses need to assess the system performance under no contingencies (e.g., P0 under TPL-001) with all system elements in-service with the anticipated generation dispatch. Steady-state studies must:

i. Apply the DER benchmark planning events to the planning case.

ii. Apply the defined energy scenarios to each benchmark planning event.

iii. Include specific criteria for determining concurrent and correlated outages of both generators and transmission lines.

iv. Model demand load response in benchmark planning event cases as a corrective action to meet system performance criteria.

v. Evaluate the wide area performance during such benchmark planning events and energy scenarios.

b. Transient stability analyses – The stability (i.e., dynamic) analyses need to assess the system performance under a defined contingency or set of contingencies, but not necessarily mirroring or to the rigor of the TPL-001 Reliability Standard planning contingencies (e.g., Categories P1-P7). Stability studies must:

i. Apply the DER benchmark planning events.

ii. Apply the defined energy scenario contingencies (e.g., high demand, low DER availability) to each benchmark planning event.

iii. Include specific criteria for determining concurrent and correlated unplanned outages of both generators and transmission lines.

iv. Model demand load response in benchmark planning event cases as a corrective action to meet system performance criteria.

v. Evaluate the wide area performance during such benchmark planning events and energy scenarios.

c. Sensitivity analysis applying appropriate sensitivities based on collaboration from neighboring planners. The following are minimum considerations:

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i. Require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case.

ii. Establish a baseline set of sensitivities that include conditions that vary with temperature, such as load, generation, and system transfers.

iii. Document sensitivity assumptions.

d. Consider modification to the traditional planning approach(es). Consider the following probabilistic approaches at a minimum:

i. Whether probabilistic techniques can be incorporated into the new or modified Reliability Standard(s) and implemented by responsible entities and

ii. If a probabilistic approach is feasible and reasonable, address factors such as:

1. A projected frequency (e.g., 1-in-50-year event), or

2. A probability distribution (95th percentile event).

H. Require the development of corrective action plans that mitigate specified instances where performance requirements are not met. Corrective action plans must:

a. Identify specified instances in benchmark event cases when performance standards are not met.

b. Establish required study contingencies and baseline sensitivities for which a corrective action plan is required.

c. Determine whether corrective action plans should be required for single or multiple sensitivity cases.

d. Determine whether corrective action plans should be developed if a benchmark event that is not already included in benchmark planning case would result in cascading outages, uncontrolled separation, or instability.

e. Require mitigation for specified instances where performance requirements for benchmark events and energy scenarios are not met (*i.e.* when certain benchmark studies conducted under the Reliability Standard show that a benchmark event would result in cascading outages, uncontrolled separation, or instability).

f. Require certain processes to facilitate interaction and coordination with applicable regulatory authorities, including applicable governing bodies responsible for retail electric service, as appropriate in implementing a corrective action plan.

g. Require that responsible entities share their corrective action plans with applicable regulatory authorities, including applicable governing bodies responsible for retail electric service issues.

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I. Establish an appropriate implementation timeline to address the risks. J. Establish a method and interval (e.g., every 3-5 years) for periodic updates to benchmark event and planning cases, inputs, energy scenarios, assumptions, and other key data required to conduct studies.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The cost impact is unknown and will be considered during the Reliability Standard development process. However, the SAR proposes to either create one or more new Reliability Standard(s) or modify an existing Reliability Standard that would require identified responsible entities to create corrective action plans to address risks related to transmission system planning performance for the three risk areas. The costs associated with a revised and one or more new Reliability Standard(s) are anticipated to be comparable to those associated with a responsible entity's experience in the performance of TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events for each identified risk area.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
The results of improved studies that inform mitigation needs and/or enhancements to generation and transmission based on the analyses performed by the transmission planners may uniquely impact BES facilities. For example, mitigating and corrective actions may require transmission system topology changes, including but not limited to re-evaluating load shedding plans as a safety net in response to high demand during an extreme natural weather event over a wide area. Also, if studies reveal thermal violations that could be anticipated during extreme weather, transmission facilities may need to be upgraded. Generation facilities may be impacted by having to change the way concurrent or coincident generator outages are managed and planned to reduce the likelihood of not meeting high demands over a wide area. For example, if multiple generators are disrupted due to pipeline issues and don't have dual fuel capability.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the NERC Rules of Procedure Appendix 5A:
Developing one or more new or modified Reliability Standard(s) should consider expertise from the following functional entities: Balancing Authority, Distribution Provider, Generator Owner, Planning Coordinator, Reliability Coordinator, Resource Planner, Transmission Owner, and Transmission Planner.

Requested information
Do you know of any consensus building activities[11] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
Yes, the White Paper and this SAR was developed as an ERO Enterprise collaboration, which is comprised of technical staff from NERC and NERC's six Regional Entities. Also, in Order No. 896, FERC highlighted that industry experts agreed that extreme weather events are likely to become more severe and frequent in the future, and there is a need to address them in the long-term planning horizon.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
TPL-001-5.1, MOD-032-1, and for potential coordination 2022-02 Modifications to TPL-001-5.1 and MOD-032-1,[12] Project 2022-03 Energy Assurance with Energy-Constrained Resources - Planning Horizon,[13] and Project 2022-04 EMT Modeling,[14] Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather,[15] and Project 2023-08 Modifications of MOD-031 Demand and Energy Data.[16]
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives with the benefits of using them.
None.

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

[11] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise or develop a standard or definition.
[12] See: https://www.nerc.com/pa/Stand/Pages/Project2022-02ModificationstoTPL-001-5-1andMOD-032-1.aspx
[13] See: https://www.nerc.com/pa/Stand/Pages/Project2022-03EnergyAssurancewithEnergy-ConstrainedResources.aspx
[14] See: https://www.nerc.com/pa/Stand/Pages/Project2022-04EMTModeling.aspx
[15] See: https://www.nerc.com/pa/Stand/Pages/Project-2023-07-Mod-to-TPL00151.aspx
[16] See: https://www.nerc.com/pa/Stand/Pages/Project2023-08-Modifications-of-MOD-031-Demand-and-Energy-Data.aspx

Reliability Principles	
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g., NPCC	No needed Regional or Interconnection variances were identified.

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SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR was assigned a Standards Project by NERC ☐ SAR denied or proposed as a Guidance document
Risk Tracking.	
☐ Grid Transformation ☐ Resilience/Extreme Events	☐ Energy Policy ☐ Critical Infrastructure Interdependencies
☐ Security Risks	

Version History

Version	Date	Owner	Change Tracking

1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer
5	August 14, 2023	Standards Development Staff	Updated template as part of Standards Process Stakeholder Engagement Group