(xvi) Any additional information, including experimental studies and tests, requested by the Commission.

(3) The Commission determines that the product meets the safety criteria in § 32.34.

(b) Notwithstanding the provisions of paragraph (a) of this section, the Commission may deny an application for a specific license under this section if the end uses of the product cannot be reasonably foreseen.

§ 32.34 Items containing byproduct material incidental to production safety criteria.

(a) An applicant for a license under § 32.33 must demonstrate that the item is designed and will be manufactured so that:

(1) In normal use, normal handling, and normal storage of the quantities of exempt items likely to accumulate in one location, including during marketing, distribution, installation, and/or servicing of the item, it is unlikely that:

(i) The external radiation dose in any one year, or the committed dose resulting from the intake of radioactive material in any one year, to a suitable sample of the group of individuals expected to be most highly exposed to radiation or radioactive material from the item will exceed 50 μSv (5 mrem); and

(ii) There will be a significant reduction in the effectiveness of the safety features of the item from wear and abuse.

(2) In disposal of quantities of exempt items likely to accumulate in the same disposal site, it is unlikely that the external radiation dose in any one year, or the committed dose resulting from the intake of radioactive material in any one year, to a suitable sample of the group of individuals expected to be most highly exposed to radiation or radioactive material, will exceed 10 μSv (1 mrem).

(3) In use, handling, storage, and disposal of the quantities of exempt products likely to accumulate in one location, including during marketing, distribution, installation, and/or servicing of the item, the probability is low that the safety features of the item would fail under such circumstances that a person would receive an external radiation dose or committed dose in excess of 5 mSv (500 mrem), and the probability is negligible that a person would receive an external radiation dose or committed dose of 100 mSv (10 rem) or greater.[1]

(b) An applicant for a license under § 32.33 must demonstrate that, even in unlikely scenarios of misuse, including those resulting in direct exposure to the item for 1,000 hours at an average distance of 1 meter and those resulting in dispersal and subsequent intake of 10^{-4} of the quantity of byproduct material (or in the case of tritium, an intake of 10 percent), a person will not receive an external radiation dose or committed dose in excess of 100 mSv (10 rem), and, if item is small enough to fit in a pocket, that the dose to localized areas of skin averaged over areas no larger than 1 square centimeter from carrying the item in a pocket for 80 hours will not exceed 2 Sv (200 rem).

§ 32.35 Conditions of licenses issued under § 32.33: Quality control, labeling, and reports of transfer.

Each person licensed under § 32.33 must:

(a) Carry out adequate control procedures in the manufacture of the item to assure that each item meets the quality control standards approved by the Commission;

(b) Label or mark each point of sale package and, if feasible, each unit. Each mark or label must contain the statement ''CONTAINS RADIOACTIVE MATERIAL'' and must identify the initial transferor of the item; and

(c) Maintain records of all transfers and file a report with the Director of the Office of Nuclear Material Safety and Safeguards by an appropriate method listed in 10 CFR 30.6(a), including in the address: ATTN: Document Control Desk/Exempt Distribution.

(1) The report must clearly identify the specific licensee submitting the report and include the license number of the specific licensee.

(2) The report must indicate that the items are transferred for use under 10 CFR 30.16 or equivalent regulations of an Agreement State.

(3) The report must include the following information on items transferred to other persons for use under 10 CFR 30.16 or equivalent regulations of an Agreement State:

(i) A description or identification of the type of each item and the model number(s); and

(ii) The number of units of each type of product transferred during the reporting period by model number.

(4)(i) The report, covering the preceding calendar year, must be filed on or before January 31 of each year. The licensee must separately include data for transfers in prior years not previously reported to the Commission.

(ii) Licensees who permanently discontinue activities authorized by the license issued under § 32.33 must file a report for the current calendar year within 30 calendar days after ceasing distribution.

(5) If no transfers of byproduct material have been made under § 32.33 during the reporting period, the report must so indicate.

(6) The licensee must maintain the record of a transfer for one year after the transfer is included in a report to the Commission.

§ 32.303 [Amended]

■ 5. In § 32.303, amend paragraph (b) by adding the references ''32.33, 32.34,'' in sequential order.

Dated June 21, 2022.

For the Nuclear Regulatory Commission.

Brooke P. Clark,

Secretary of the Commission.

[FR Doc. 2022–13599 Filed 6–24–22; 8:45 am]

BILLING CODE 7590–01–P

[1] Paragraph (a)(3) of this section assumes that as the magnitude of the potential dose increases above that permitted under normal conditions, the probability that any individual will receive such a dose must decrease. The probabilities have been expressed in general terms to emphasize the approximate nature of the estimates that are to be made. The following values may be used as guides in estimating compliance with the criteria: Low—not more than one such failure/incident per year for each 10,000 exempt units distributed. Negligible—not more than one such failure/incident per year for each one million exempt units distributed.

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM22–10–000]

Transmission System Planning Performance Requirements for Extreme Weather

AGENCY: Federal Energy Regulatory Commission, Department of Energy.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission proposes to direct that the North American Electric Reliability Corporation, the Commission-certified Electric Reliability Organization, submit to the Commission modifications to Reliability Standard TPL–001–5.1 (Transmission System Planning Performance Requirements) within one year of the effective date of a final rule in this proceeding to address reliability concerns pertaining to transmission system planning for extreme heat and cold weather events that impact the reliable operations of the Bulk-Power

System. Specifically, we propose to direct NERC to develop modifications to Reliability Standard TPL–001–5.1 to require: development of benchmark planning cases based on information such as major prior extreme heat and cold weather events or future meteorological projections; planning for extreme heat and cold events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme weather conditions, and including the broad area impacts of extreme weather; and corrective action plans that include mitigation for any instances where performance requirements for extreme heat and cold events are not met.

DATES: Comments are due August 26, 2022.

ADDRESSES: Comments, identified by docket number, may be filed in the following ways. Electronic filing through *https://www.ferc.gov,* is preferred.

- *Electronic Filing:* Documents must be filed in acceptable native applications and print-to-PDF, but not in scanned or picture format.
- For those unable to file electronically, comments may be filed by U.S. Postal Service mail or by hand (including courier) delivery.
  - Mail via U.S. Postal Service only: Addressed to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street NE, Washington, DC 20426.
  - For delivery via any other carrier (including courier): Deliver to: Federal Energy Regulatory Commission, Office of the Secretary, 12225 Wilkins Avenue, Rockville, MD 20852.

FOR FURTHER INFORMATION CONTACT:

Mahmood Mirheydar (Technical Information), Office of Electric Reliability, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, (202) 502–8034, *mahmood.mirheydar@ferc.gov*

Milena Yordanova (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, (202) 502–6194, *milena.yordanova@ferc.gov*

SUPPLEMENTARY INFORMATION:

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I. Introduction

1. Pursuant to section 215(d)(5) of the Federal Power Act (FPA),[1] the Commission proposes to direct that the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submit modifications to Reliability Standard TPL–001–5.1 (Transmission System Planning Performance Requirements)[2] that address concerns pertaining to transmission system planning for extreme heat or cold weather events that impact the reliable operation[3] of the Bulk-Power System.[4]

[1] 16 U.S.C 824o(d)(5).

[2] *Transmission Planning Reliability Standard TPL–001–5,* Order No. 867, 85 FR 8155 (Feb. 13, 2020), 170 FERC ¶ 61,030, at P 1 (2020) (approving the proposed Reliability Standard TPL–001–5 and associated implementation plan). *N. Am. Elec. Reliability Corp.,* Docket No. RD20–8–000 (June 10, 2020) (delegated order) (approving Reliability Standard TPL–001–5.1). This NOPR refers to Reliability Standard TPL–001–5.1 to reflect that the currently effective version 4 of the Reliability Standard will be soon replaced by version 5.1 and any modifications proposed in the NOPR will apply only to TPL–001–5.1.

[3] The FPA defines ''Reliable Operation'' as ''operating the elements of the Bulk-Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.'' 16 U.S.C. 824o(a)(4).

[4] The Bulk-Power System is defined in the FPA as ''facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.'' *Id.* 824o(a)(1).

2. We take this action to address planning challenges associated with extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand.[5] Extreme heat and cold weather events are occurring with greater frequency, and are projected to occur with even greater frequency in the future.[6] As such, the impact of concurrent failures of Bulk-Power System generators and transmission equipment and the potential for cascading outages [7] that may be caused by extreme heat and cold events should be studied and corrective actions should be identified and implemented.

3. At the Commission's June 1–2, 2021 technical conference on Climate Change, Extreme Weather, and Electric System Reliability, there was consensus among panelists that planners cannot simply project historical weather patterns forward to effectively forecast the future, since climate change has made the use of historical weather observations no longer representative of future conditions.[8] For example, extreme heat in summer in regions like the Pacific northwest and extreme cold in winter in regions like Texas has increased demand for electricity at times when historically demand has been low and such events will likely continue to present challenges in the future.[9] Therefore, transmission planners and planning coordinators need to reflect these new realities into their planning processes.[10]

4. Since 2011, the country has experienced at least seven major extreme heat and cold weather events,[11] all of which put stress on the Bulk-Power System, and resulted in some degree of load shed, and in some cases nearly caused system collapse and uncontrolled blackouts, which were only avoided via the actions of system operators. Of these, the four most severe occurred in 2011, 2013, 2018, and 2021. The extreme weather conditions in the February 2011 Southwest Cold Weather Event resulted in the acumulative loss of approximately thirty thousand megawatts of generation resources, causing the Electric Reliability Council of Texas (ERCOT) to shed load to prevent widespread, uncontrolled blackouts throughout the entire ERCOT Interconnection. The September Midwest and Mid-Atlantic 2013 Heatwave Event lasted over three days and at its peak required a 5,791 MW reduction in load. The PJM Interconnection, L.L.C. (PJM) analysis during the event indicated a need for pre-contingency load shed to avoid post-contingency voltage collapse and a potential cascading outage.[12] During the January 2018 South Central Cold Weather Event in the Midwest, had the grid operator lost the single largest contingency of 1,163 MW, there could have been firm load shedding to maintain system stability. In February of 2021, the extensive cold in the South Central and Texas regions required a combined total of 23,418 MW of firm load shed to maintain Bulk-Power System reliability; it was the largest controlled load shedding event in U.S. history. During this 2021 Cold Weather Event, had frequency in Texas remained under its lowest point on February 15, 2021 for an additional five minutes, approximately 17,000 MW of additional generation would have tripped, potentially blacking out the entire ERCOT Interconnection. ERCOT shed firm load in order to maintain frequency to prevent a collapse of the system.[13]

5. Given the reliability risks associated with extreme heat and cold weather events, including the potential for widespread blackouts, we believe it would be appropriate for planning of the transmission system to account for extreme heat and cold weather events' potential impact over wide geographical areas, and to consider the changing resource mix and associated planning assumptions. Reliability Standard TPL–001–4, the currently effective transmission system planning standard, was developed to establish transmission system planning performance requirements that ensure that the Bulk-Power System operates reliably over a broad spectrum of system conditions and following a wide range of probable contingencies. Reliability Standard TPL–001–4, and its successor, TPL–001–5.1, includes provisions for transmission planners and planning coordinators to study system performance under extreme events based on their experience. However, the current standards do not specifically require that a performance analysis be conducted for extreme heat and cold weather, despite the fact that such events have demonstrated a potential harm to reliable operations of the Bulk-Power System, thus leaving a gap in system planning.

6. To address this reliability gap, we propose to direct NERC to develop modifications to Reliability Standard TPL–001–5.1 to require: (1) development of benchmark planning cases based on information such as major prior extreme heat and cold weather events or future meteorological projections; (2) planning for extreme heat and cold events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the broad area impacts of extreme heat and cold

[5] Technical Conference June 1–2, 2021, *Climate Change, Extreme Weather, and Electric System Reliability,* Docket No. AD21–13–000 (June 1–2, 2021), June 1, 2021 Tr. 26: 3–7 (Derek Stenclik, Founding Partner, Telos Energy, Inc.), 31:7–8 (Judy Chang, Undersecretary of Energy, Massachusetts).

[6] Environmental Protection Agency, *Climate Change Indicators: Weather and Climate* (May 12, 2021) (EPA Climate Change Indicators), *https://www.epa.gov/climate-indicators/weather-climate* (showing an upward trend in extreme heat and cold weather events).

[7] NERC Glossary of Terms Used in Reliability Standards (Updated March 29, 2022) (NERC Glossary). NERC defines ''cascading'' as, ''The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.''

[8] June 1, 2021 Tr. 30:2–3 (Chang), 31:12–18 (Lisa Barton, Executive Vice President/Chief Operating Officer, American Electric Power).

[9] June 1, 2021 Tr. 31:1–6 (Chang); June 2, 2021 Tr. 72:8–10 (Amanda Frazier, Senior Vice President of Regulatory Policy, Vista Corp.); 9:1–5 (Wesley Yeomans, Vice President of Operations, New York Independent System Operator, Inc. (NYISO)) (noting that in New York the majority of the extreme conditions were cold weather related but that there can be heat waves in New York City, and more heat waves are expected).

[10] June 1, 2021 Tr. 35:1–6 (Chang). *See also* US News, *Blackouts in US Northwest Due to Heat Wave, Deaths Reported* (June 29, 2021), *https://www.usnews.com/news/business/articles/2021-06-29/rolling-blackouts-for-parts-of-us-northwest-amid-heat-wave*; Judah Cohen et al., *Linking Arctic Variability and Change With Extreme Winter Weather in the United States,* 373 Sci. 1116, 1120 (2021), *https://www.science.org/doi/10.1126/science.abi9167* (a study connecting the 2021 extreme cold weather event in Texas and the South-central United States to global warming-induced weather anomalies that are likely to continue to produce severe winter storm events).

[11] This NOPR references the following seven extreme heat and cold weather events experienced since 2011: (1) February 2011 Southwest Cold Weather Event; (2) September Midwest and Mid-Atlantic 2013 Heatwave Event; (3) January 2014 Polar Vortex Cold Weather Event; (4) January 2018 South Central Cold Weather Event; (5) August 2020 California Heatwave Event; (6) 2021 Cold Weather Event; (7) June 2021 the Pacific Northwest Heatwave Event. The naming of the events is based on the title of the associated reliability report for each event cited below.

[12] PJM, *Technical Analysis of Operational Events and Market Impacts during the September 2013 Heat Wave,* at 13 (Dec. 23, 2013), *https://www.yumpu.com/en/document/read/40807126/20131223-technical-analysis-of-operational-events-and-market-impacts-during-the-september-2013-heat-wave.*

[13] FERC, NERC, Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas, and the South-Central United States,* at 133 (Nov. 2021) (2021 Cold Weather Event Report).

weather; and (3) corrective action plans that include mitigation for any instances where performance requirements for extreme heat and cold events are not met. In proposing to direct NERC to modify Reliability Standard TPL–001–5.1, we are not proposing specific requirements. Instead, we identify concerns that we believe should be addressed. NERC may propose to develop new or modified Reliability Standards that address our concerns in an equally efficient and effective manner. However, NERC's proposal should explain how it addresses the Commission's concerns.[14]

7. We further propose to direct NERC to submit modifications to Reliability Standard TPL–001–5.1 within one year of the effective date of a final rule in this proceeding with compliance obligations for all proposed new or modified Reliability Standards beginning no later than 12 months from the date of Commission approval of the modified Reliability Standard. Finally, we invite comments on whether to also direct NERC to address in Reliability Standard TPL–001–5.1 other extreme weather-related events.

II. Background

A. Legal Authority

8. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[15] Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,[16] and subsequently certified NERC.[17]

9. Pursuant to section 215(d)(5) of the FPA, the Commission has the authority, upon its own motion or upon complaint, to order the ERO to submit to the Commission a proposed Reliability Standard or a modification to a Reliability Standard that addresses a specific matter if the Commission considers such a new or modified Reliability Standard appropriate to carry out section 215 of the FPA.[18] Further, pursuant to § 39.5(g) of the Commission's regulations, the Commission may order a deadline by which the ERO must submit a proposed or modified Reliability Standard, when ordering the ERO to submit to the Commission a proposed Reliability Standard that addresses a specific matter.[19]

B. Climate Change, Extreme Weather, and Electric System Reliability Technical Conference

10. On March 5, 2021, the Commission announced that staff would hold a technical conference to discuss issues surrounding the threat to electric system reliability posed by climate change and extreme weather events.[20] The Commission sought to understand, among other things, whether further action from the Commission is needed to help achieve an electric system that can withstand, respond to, and recover from extreme weather events.[21] On March 15, 2021, the Commission invited comments on a range of issues related to Bulk-Power System reliability, including how extreme weather events (*e.g.,* hurricanes, extreme heat, extreme cold, drought, storms), have impacted the electric system and whether these events would require changes to the way generation, transmission, substation, or other facilities are designed, built, sited, and operated.[22] The Commission also inquired whether there are opportunities to improve the NERC Reliability Standards to address vulnerabilities to Bulk-Power System reliability due to climate change or extreme weather events in the areas of transmission planning, Bulk-Power System operations, Bulk-Power System maintenance, and emergency operations.[23]

11. On June 1 and 2, 2021, the Commission convened a staff-led technical conference on Climate Change, Extreme Weather, and Electric System Reliability focused on: (1) ways in which planning practices might evolve to achieve outcomes that reflect consumer needs for reliable electricity in the face of patterns of climate change and extreme weather events that diverge from historical trends; (2) best practices throughout the industry for assessing the risks posed by climate change and extreme weather and developing cost-effective mitigation; (3) ways in which existing operating practices may necessitate updated techniques and approaches in light of increasing instances of extreme weather and longer-term threats posed by climate change; (4) best practices for the recovery period following an extreme weather event; and (5) the role that coordination and cooperation across jurisdictions could play in planning, operations, and recovery practices to address climate change and extreme weather events.[24]

12. Following the conference, the Commission invited comments on specific topics discussed at the conference, such as the possibility of: incorporating probabilistic methods into local transmission planning and/or regional transmission planning; coordinating transfers across the seams between Regional Transmission Organizations; the possibility of modifying transmission planning requirements established under Reliability Standard TPL–001 to better assess and mitigate the risk of extreme weather events and associated common mode failures; additional changes to the NERC Reliability Standards to address the risk of extreme weather events; and among other topics, whether target levels of interregional transfer capacity could help facilitate more effective development of interregional transmission projects to help ensure reliability and resilience during extreme weather events.[25]

C. Overview of Technical Conference Comments

13. Commenters submitted more than 50 sets of pre-conference and 20 post-conference comments on a wide range of issues, including the types of extreme weather events experienced,[26] and the range of mitigating measures that could be taken to address the specific risks of climate change in various regions of the country. Commenters expressed

[14] *See e.g., Mandatory Reliability Standards for the Bulk-Power Sys.,* Order No. 693, 72 FR 16416 (Apr. 4, 2007), 118 FERC ¶ 61,218, at PP 186, 297, *order on reh'g,* Order No. 693–A, 120 FERC ¶ 61,053 (2007) (''where the Final Rule identifies a concern and offers a specific approach to address the concern, we will consider an equivalent alternative approach provided that the ERO demonstrates that the alternative will address the Commission's underlying concern or goal as efficiently and effectively as the Commission's proposal''); *Reliability Standards for Physical Sec. Measures,* 146 FERC ¶ 61,166, at P 13 (2014).

[15] 16 U.S.C. 824o(e).

[16] *Rules Concerning Certification of the Elec. Reliability Org. & Procedures for the Establishment, Approval, & Enf't. of Elec. Reliability Standards,* Order No. 672, 71 FR 8662 (Feb. 17, 2006), 114 FERC ¶ 61,104, *order on reh'g,* Order No. 672–A, 71 FR 19814 (Apr. 18, 2006), 114 FERC ¶ 61,328 (2006).

[17] *N. Am. Elec. Reliability Corp.,* 116 FERC ¶ 61,062, *order on reh'g and compliance,* 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc.* v. *FERC,* 564 F.3d 1342 (D.C. Cir. 2009).

[18] 16 U.S.C. 824o(d)(5).

[19] 18 CFR 39.5(g) (2021).

[20] *Climate Change, Extreme Weather, and Electric System Reliability,* Notice of Technical Conference, Docket No. AD21–13–000, at 1 (Mar. 5, 2021).

[21] *Id.* at 2.

[22] Supplemental Notice of Technical Conference, Docket No. AD21–13–000, at 1, 3 (Mar. 15, 2021).

[23] *Id.* at 5.

[24] Supplemental Notice of Technical Conference, Docket No. AD21–13–000, at 1, 3 (May 27, 2021) (attaching agenda).

[25] Notice Inviting Post-Technical Conference Comments, Docket No. AD21–13–000, at 3, 5 (Aug. 11, 2021).

[26] *See, e.g.,* California Independent System Operator Corporation (CAISO) Pre-Conference Comments at 3.

concerns that the impacts of climate change are anticipated to affect the electric system in multiple, compounding, and synergistic ways.[27] Generally, industry experts agreed that extreme weather events are likely to become more severe and frequent in the future,[28] and acknowledged the challenges associated with planning for extreme events, including shifting scheduled maintenance, canceling or recalling transmission and generation assets from scheduled maintenance to meet demand under unexpected circumstances.[29]

14. Some commenters discussed potential changes to the NERC Reliability Standards to address planning and operational preparedness for energy adequacy risks,[30] contingencies related to extreme weather events, and wide-area transmission planning and development challenges,[31] among others. In addition, participants advocated for planning that reflects the new climate-change driven conditions, as the expected impacts of climate change ''need to be baked into the rest of your planning and development activities.'' [32]

15. Pacific Gas and Electric Company states that Reliability Standard TPL–001–4 already requires transmission planners to evaluate extreme events, but could benefit from providing further clarity on the events to consider, as well as the extent to which investments can be made to the grid to mitigate the identified issues for the given event evaluated.[33]

16. Post-conference comments also addressed more directly the potential reliability gaps in the existing set of Reliability Standards, including Reliability Standard TPL–001–4. For example, MISO argues that while current Commission-approved Reliability Standards provide for the assessment of the impacts of extreme events that may include climate-driven weather events, they do not include requirements to mitigate consequences from such events.[34] Similarly, PJM states that Reliability Standard TPL–001–4 should be modified to specifically account for extreme weather events by mandating regional extreme weather design standards for transmission and generation operating criteria.[35] CAISO also states that Reliability Standard TPL–001 may not serve as the best means to assess the threat and risk of extreme weather events.[36]

17. NERC agrees that with proper planning, including consideration not only of historic temperature averages but also consideration of conditions during extreme weather events and the linkage between critical infrastructures, the risks associated with extreme weather and the changing resource mix can be mitigated.[37] NERC agrees that enhancements to the Reliability Standards could be beneficial. Some examples of potential enhancements include requiring reliability coordinators, balancing authorities, or planning coordinators to determine the temperature to which plants in their respective areas must weatherize; requiring reliability coordinators or balancing authorities to develop seasonal emergency energy management plans, to address conditions such as wildfires, extreme hot and cold temperatures, and severe storms (*i.e.,* hurricanes); requiring reliability coordinators to develop a rolling three week emergency energy management plan; and requiring balancing authorities to prepare a seasonal energy management plan based on regional extreme weather scenarios identified in NERC's seasonal assessments.[38]

D. Cold Weather Reliability Standards

18. NERC and the Commission have begun to address the effects of extreme cold weather on generating units, specifically focusing on improved performance of generating units during cold weather conditions. On August 24, 2021, the Commission approved revised Reliability Standards to address some of the reliability risks posed by extreme cold weather.[39] Effective April 2023, those Reliability Standards will, *inter alia,* require generators to implement plans for cold weather preparedness and require the balancing authority, transmission operator, and reliability coordinator to plan and operate the grid reliably during cold weather conditions by requiring the exchange of certain information related to the generator's capability to operate under such conditions.[40]

19. The proposed improvements to transmission planning discussed in this NOPR and the requirements in the Cold Weather Reliability Standards both work together to mitigate the reliability impact of extreme weather events, such as the 2021 Cold Weather Event in Texas and South-Central United States. To ensure reliability, transmission planning should be considered in the context of generators' performance and availability during extreme heat and cold events.

E. Reliability Standard TPL–001–4 (Transmission System Planning Performance Requirements)

20. Transmission system planning refers to the evaluation of future transmission system performance and creation of corrective action plans that includes mitigation for extreme heat and cold events to remedy identified deficiencies.[41] The planning horizon associated with transmission system planning covers near term (one to five years), long-term (six to 10 years), and beyond.[42]

21. Reliability Standard TPL–001–4, applicable to planning coordinators and transmission planners, establishes minimum transmission system planning performance requirements within the identified planning horizon to plan a Bulk-Power System that will operate reliably over a broad spectrum of system conditions and follow a wide range of probable contingencies.[43] Under Reliability Standard TPL–001–4, and Reliability Standard TPL–001–5.1, Requirement R2, each transmission planner and planning coordinator must prepare an annual planning assessment of its portion of the Bulk-Power System based on current or qualified past studies, document its assumptions, and document the summarized results of the

[27] Environmental Defense Fund and Columbia Law School's Sabin Center for Climate Change Law Pre-Conference Comments at 4.

[28] CAISO Pre-Conference Comments at 1–3; California Public Utilities Commission Pre-Conference Comments at 4; Oregon Public Utilities Commission Pre-Conference Comments at 2–3; NYISO Pre-Conference Comments at 4.

[29] June 2, 2021, Tr. at 21–23 (Wesley Yeomans, Vice President of Operations, NYISO).

[30] ISO-New England Inc. Pre-Conference Comments at 10.

[31] Midcontinent Independent System Operator (MISO) Pre-Conference Comments at 4–5, 14–17.

[32] June 1, 2021 Tr. 136:18–21 (Neil Millar, Vice President, Transmission Planning & Infrastructure Development, CAISO).

[33] Pacific Gas and Electric Company Pre-Conference Comments at 19–20.

[34] MISO Post-Conference Comments at 20.

[35] PJM Post-Conference Comments at 21.

[36] CAISO Post-Conference Comments at 10.

[37] NERC Pre-Conference Comments at 6.

[38] *Id.* at 15–16; NERC Post-Conference Comments at 5–7 (explaining that additional modifications to the Reliability Standards may be appropriate as the resource mix is transformed to one that is more sensitive to severe weather conditions, as some types of severe weather events or conditions could result in the loss of a substantial amount of resources due to fuel concerns).

[39] *N. Am. Elec. Reliability Corp.,* 176 FERC ¶ 61,119 (2021). The Commission approved proposed Reliability Standards EOP–011–2 (Emergency Preparedness and Operations); IRO–010–4 (Reliability Coordinator Data Specification and Collection); and TOP–003–5 (Operational Reliability Data) (collectively, the Cold Weather Reliability Standards).

[40] *Id.* P 3.

[41] NERC Glossary defines ''Planning Assessment'' as ''documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.''

[42] *Id.*

[43] Reliability Standard TPL–001–4, Purpose.

steady state analyses, short circuit analyses, and stability analyses.[44] This planning assessment is required for both near-term and long-term transmission planning horizons.[45]

22. Requirements R3 and R4 of Reliability Standard TPL–001–4 require in part that planning coordinators and transmission planners conduct steady state and stability analyses of pre-specified extreme events and evaluate possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s), if the analysis concludes that the pre-selected extreme events cause cascading outages.

23. Table 1 of Reliability Standard TPL–001–4 includes a list of examples of planning events for which specific studies may be required, generally, based on the entity's own evaluation that such an event could occur within its operating area. Section 3.a of Table-1, Steady State & Stability Performance Extreme Events, states that steady state analysis should be conducted for wide-area events affecting the transmission system based on system configuration and how it can be affected by events such as wildfires and severe weather (*e.g.,* hurricanes and tornadoes). In addition, section 3.b serves as a catch-all provision, stating that steady state analysis should be performed for ''other events based upon operating experience that may result in wide-area disturbances.''

III. The Need for Reform

A. Recent Events Show Changes in Weather Patterns Resulting in More Extreme Heat and Cold Weather Events

24. Recent extreme weather-related events that spread across large portions of the country over the past decade demonstrate the challenges to transmission planning from extreme heat and cold weather patterns. Since 2011, the country has experienced at least seven major extreme heat and cold weather events; of these, four neared system collapse (2011, 2013, 2018, and 2021 extreme cold weather events) if the operators had not acted to shed load. The remaining three events (2014, 2020, 2021 extreme heat weather events) resulted in generation loss and varying degrees of load shedding.

25. These extreme heat and cold events demonstrate a risk to reliable operation of the Bulk-Power System. Below we discuss in detail how recent extreme cold and heat events have demonstrated such risks, including resource availability, limitations of the transmission system locally and over a wide area, and limitations of interregional transfer capabilities.

26. From February 1 to February 4, 2011, the southwest region of the United States experienced unusually cold and windy weather, referred to as the February 2011 Southwest Cold Weather Event. Low temperatures during the period were in the teens for five consecutive mornings and there were many sustained hours of below freezing temperatures throughout Texas and New Mexico. Low temperatures in Albuquerque, New Mexico ranged from 7 degrees Fahrenheit to minus seven degrees Fahrenheit over the period, compared to a normal range of 51 to 26 degrees Fahrenheit. Temperatures in Dallas, Texas ranged from 19 degrees to 14 degrees Fahrenheit, compared to a normal range of 60 to mid-to-upper 30s degrees Fahrenheit. Many cities in the region did not see temperatures above freezing until February 4, 2011. In addition, sustained high winds of over 20 mph produced severe wind chill factors. The extreme weather conditions resulted in the loss of a significant number of generators which occurred almost simultaneously, causing ERCOT to shed load to prevent widespread, uncontrolled blackouts throughout the entire ERCOT Interconnection.[46] As a result, approximately 4.4 million electric customers were affected over the course of the event.[47]

27. Two years later, the Midwest and mid-Atlantic experienced unseasonably hot weather from September 9 through September 11, 2013, which led to emergency conditions in the PJM service area. During this period, temperatures ranged from the upper 80s into the 90s Fahrenheit, which in some areas like Cleveland translated into conditions of over 20 degrees above normal.[48] As a result, demand for electricity reached an all-time high for September within PJM's footprint. Transmission owners tend to schedule maintenance outages during the fall and spring, increasing the risk of system stress during periods of weather-related high energy demand, such as occurred in September 2013. PJM implemented controlled outages in a few constrained areas to prevent uncontrolled blackouts over larger areas that could have affected many more customers.[49] In preparation for another day of unseasonably high use of electricity, on September 11, PJM called for voluntary demand response [50] across much of its service area, resulting in a 6,048 MW reduction in electricity demand, the largest amount of demand response PJM had ever received. During the entire event PJM shed 157 MW of load affecting approximately 45,000 customers.[51]

28. Another extreme event occurred the following year, in early January 2014, when the Midwest, south central, and east coast regions of the country experienced an extreme cold weather event known as the polar vortex, referred to as the January 2014 Polar Vortex Cold Weather Event, where extreme cold resulted in temperatures 20 to 30 degrees Fahrenheit below normal.[52] Some areas faced days that were 35 degrees Fahrenheit or more below their normal temperatures. These extreme temperatures resulted in record high electrical demand on January 6 and again on January 7, 2014. During the January 2014 Polar Vortex Cold Weather Event, the cold weather increased demand for natural gas, which caused a significant amount of gas-fired generation to become unavailable due to unavailability of the non-firm gas purchases they relied on. The cold weather and issues from fuel combined for over 35,000 MW of generator outages during the height of the polar vortex

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[44] Reliability Standard TPL–001–4/5.1, Requirement 2. Further, steady-state analyses are a snapshot in time where load and system conditions (*e.g.,* generators, lines, facilities) are modeled as constant (not as changing over time). The analysis will either solve or diverge (not solved). *See* IEEE, *Transactions on Power Systems, Vol. 19, No. 2,* (May 2004) (power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact); *see also,* Kundur, Prabha, *Power System Stability and Control,* McGraw Hill, at 26 (1994).

[45] *See* Reliability Standard TPL–001–4, Requirement 2.1 (Near-Term Transmission Planning Horizon) and Requirement R.2.2 (Long-Term Transmission Planning Horizon).

[46] FERC and NERC Staff Report, *Outages and Curtailments During the Southwest Cold Weather Event of February 1–5, 2011,* at 7 (Aug. 2011), *https://www.ferc.gov/sites/default/files/2020-05/ReportontheSouthwestColdWeatherEventfrom February2011Report.pdf.* Load shedding may be used to reduce an overload condition (such as when thermal limits on a transmission line are exceeded), to recover from an under-frequency condition, or to return voltage to a normal level.

[47] *Id.* at 1.

[48] PJM, *Technical Analysis of Operational Events and Market Impacts during the September 2013 Heat Wave,* at 7, Figure 1, RTO Temperatures (Dec. 23, 2013) (PJM Heat Wave Analysis), *https://www.yumpu.com/en/document/read/40807126/20131223-technical-analysis-of-operational-events-and-market-impacts-during-the-september-2013-heat-wave.*

[49] *Id.* at 4.

[50] Under demand response programs, retail customers volunteer and are paid to reduce their electricity use when requested.

[51] PJM Heat Wave Analysis at 5.

[52] NERC, *Polar Vortex Review* (Sept. 2014) (Polar Vortex Review), *https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.*

weather conditions.[53] By employing communication tools, interruptible load, demand-side management tools, and voltage reduction, balancing authorities and load serving entities were mostly able to maintain their operating reserve margins and serve firm load and only one balancing authority was required to shed 300 MW of firm load. Many outages, including a number of those in the southeastern United States, were the result of temperatures that fell below a plant's design basis.[54]

29. Further, in mid-January 2018, a large area of the south-central region of the United States saw unusually cold weather, with temperatures dropping from about five degrees Fahrenheit to as much as 27 degrees Fahrenheit below the normal daily minimums. Texas, Louisiana, Arkansas, Oklahoma, Mississippi, Missouri, and other neighboring states were all affected by the extreme cold weather, which lasted from January 12 to January 19, 2018, known as the January 2018 South Central Cold Weather Event.[55] The reliability coordinators in MISO did not anticipate the numerous mitigation measures they would need to take to maintain Bulk-Power System reliability at the peak of the event (January 17, 2018), including transmission loading relief, transmission reconfiguration, and the need to be prepared to shed firm load in the event of an additional contingency in MISO South of 1,163 MW.[56] Although the system remained stable on January 17, 2018, this event represented a near miss of cascading outages.

30. Two years later, the western United States suffered another intense and prolonged heatwave affecting many areas across the Western Interconnection during a five-day period from August 14 through August 19, 2020 (August 2020 California Heatwave Event). With temperatures between 15- and 30-degrees Fahrenheit above normal, many areas in the western parts of the country broke daily heat records. Some areas in the southwest posted record temperatures: Phoenix, Arizona reached a record 115 degrees Fahrenheit. Even cities located further north had similar temperature spikes, with Portland, Oregon, registering 102 degrees Fahrenheit. Because of these high temperatures, electricity demand in the Western Interconnection reached a record high on August 18, 2020.[57] On August 14 and 15, CAISO shed firm load to maintain the operating reserves needed to maintain the reliability and security of the Bulk-Power System. Several other entities reported being one contingency away from needing to shed load as well.[58]

31. More recently, in February 2021, Texas and the South-Central United States experienced the 2021 Cold Weather Event, the fourth cold-weather-related event in the last ten years to jeopardize Bulk-Power System reliability. Temperatures began to drop below freezing in Texas and the Southwest Power Pool, Inc. (SPP) region on February 8, 2021, but temperatures dropped even lower during the week of February 14, reaching their nadir on February 15 and 16, 2021. Daily low temperatures for February 15th were as much as 40 to 50 degrees lower than average daily minimum temperatures for that day. In addition to the arctic air, the cold front brought periods of freezing precipitation and snow to large parts of Texas and the South Central region, starting February 10, and extending into the week of February 14, 2021.[59]

32. This was the most devastating cold-weather-related event in the last 10 years to impact Bulk-Power System reliability, with a combined 23,418 MW of manual firm load shed, the largest controlled firm load shed event in U.S. history.[60] The unplanned generation outages that escalated during the event, 65,622 MW, were more than four times as large as the previous largest event, in 2011 (14,702 MW).[61] ERCOT faced the greatest challenge due to the magnitude of unplanned generating unit outages in its area, coupled with its limited ability to import power to help offset generation shortfalls. Notably, the entire ERCOT Interconnection has a maximum total import limitation of only 1,220 MW, which limited ERCOT's ability to import electricity to meet demand.[62] In Texas alone, this event resulted in more than 4.5 million people losing power, cost the Texas economy between $80 to $130 billion, and caused at least 210 deaths.[63] Had frequency in Texas remained under its lowest point for an additional five minutes during the peak of the event, approximately 17,000 MW of additional generation would have tripped, potentially blacking out the entire ERCOT Interconnection. In contrast to ERCOT, some regions, such as MISO and SPP, had the ability to import power from the east, where weather conditions were less severe, to make up for a large portion of their generation shortfalls during the event. For example, PJM was exporting an unprecedented amount of electricity into MISO and SPP, reaching over 15,700 MW of interregional transfers on February 15, 2021.[64]

33. Finally, in June 2021 the Pacific Northwest experienced another record-breaking heat wave, referred to as June 2021 the Pacific Northwest Heatwave. During the event, Seattle set an all-time record high temperature of 104 degrees Fahrenheit on June 27, 2021, while Portland had two back-to-back all-time records, on June 26 and 27, 2021, where temperatures reached 108- and 112-degrees Fahrenheit, respectively.[65] While such events are still rare in today's climate, researchers believe such events are likely to become more common in the future.[66]

34. While these wide-area extreme events may not occur every year, their frequency and magnitude are expected to increase. NOAA's data and analyses show an increasing trend in extreme heat and cold events,[67] and the U.S. Environmental Protection Agency climate change indicators also show upward trends in heatwave frequency, duration, and intensity.[68] NOAA states that climate change is also driving more compound events, which are multiple extreme events occurring simultaneously or successively, such as concurrent heat waves and droughts,

[53] *Id.* at 4.

[54] *Id.* at iii.

[55] FERC and NERC Staff Report, *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018,* at 6–8 (July 2019) (2018 Cold Weather Event Report), *https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf.*

[56] *Id.* at 12.

[57] Western Electricity Coordinating Council, *August 2020 Heatwave Event Analysis Report,* at 1–2 (Mar. 19, 2021) (2020 Heat Event Report), *https://www.wecc.org/Reliability/August%202020%20Heatwave%20Event%20Report.pdf.*

[58] *Id.* at 1.

[59] 2021 Cold Weather Event Report at 9, 12–13.

[60] *Id.* at 9.

[61] *Id.*

[62] *Id.* at 127 n.197.

[63] *Id.* at 10.

[64] PJM Post-Conference Comments at 17–18; 2021 Cold Weather Event Report at 229 n. 355. Interregional transfer capability allows an entity in one region with available energy to assist one or more entities in another region that is experiencing an energy shortfall due to the extreme weather event.

[65] Climate Signals, *Northwest Pacific Heat Wave June 2021* (Oct. 2021), *https://www.climatesignals.org/events/northwest-pacific-heat-wave-june-2021#/more.*

[66] Sjoukje Y. Philip, Sarah F. Kew et al., *Rapid attribution analysis of the extraordinary heatwave on the Pacific Coast of the US and Canada* (June 2021), at 19*, https://www.worldweather attribution.org/wp-content/uploads/NW-US-extreme-heat-2021-scientific-report-WWA.pdf.*

[67] NOAA website, *Climate Data Online* (NOAA website, Climate Data Online), *https://www.ncdc.noaa.gov/cdo-web/.*

[68] EPA Climate Change Indicators.

and more extreme heat conditions in cities.[69]

35. With respect to extreme cold, NOAA explains that accelerated arctic warming is likely contributing to the increasing frequency of Arctic polar vortex-stretching events that deliver extreme cold to the United States and Canada, including the winter 2021 Texas cold wave.[70] NOAA climate data indicates that the occurrence of significant cold weather events is trending higher nationwide.[71]

36. As discussed, the recent extreme heat and cold events have had a significant impact on the reliability of the Bulk-Power System. However, the potential impact of widespread extreme heat and cold events on the reliability of the Bulk-Power System can be modeled and studied in advance as part of near-term and long-term transmission system planning. Transmission planners could use the studies to develop transmission system operational strategies or corrective action plans with mitigation that could be deployed prior to and in preparation for extreme heat and cold events. Examples of such corrective action plans include planning for additional contingency reserves or implementing new energy efficiency programs to decrease load,[72] planning for additional interregional transfer capability, transmission switching/reconfiguration, or adjusting transmission and generation maintenance outages based on longer-lead forecasts. Therefore, given the urgency of addressing the negative impact of extreme weather on the reliability of the Bulk-Power System, the proposed directives to NERC in this NOPR aim to improve system planning specifically for extreme heat and cold weather events.

B. NERC Reliability Standards Do Not Require Planning To Minimize the Increasing Reliability Risks Associated With Anticipated Extreme Heat and Cold Weather Events

37. The currently effective Reliability Standard TPL–001–4 and the to-be-effective TPL–001–5.1, Requirements R3 and R4 require steady state and stability analyses to be performed for extreme events ''listed in Table 1 that are expected to produce more severe system impacts.'' Table 1, Steady State & Stability Performance Extreme Events, under the Steady State analysis, sections 3.a.iii and 3.a.iv lists wildfires and severe weather (*e.g.,* hurricanes and tornadoes) as potential events that could be studied. However, neither Requirements R3 or R4, nor the associated Table 1 specifically require steady state analyses for extreme heat and cold conditions to be completed as part of the transmission planner's or planning coordinator's planning assessment. Finally, Table 1, provisions 2.f (stability) and 3.b (steady state), require the responsible entities to study events based on operating experience that may result in a wide-area disturbance, but they do not specify the study of extreme heat or cold conditions.

38. System planning measures alone will not eliminate the reliability risk associated with extreme heat and cold events. However, system planning will limit the impact of such events and reduce the risk to the reliability of the Bulk-Power System, which prior events demonstrate is significant.

39. The country experienced wide-spread cold weather events in 2011, 2014, 2018, and 2021. With the exception of the January 2018 South Central Cold Weather Event, planned and unplanned generating unit outages caused energy emergencies and triggered the need for firm load shed. As evidenced by the last cold weather event in 2021, where generation loss and loss of load were the most extreme, it becomes increasingly more important to consider changes in transmission planning. Although during the January 2018 South Central Cold Weather Event the system remained stable, the 2018 Cold Weather Event Report addressing this specific event recommended that MISO and other reliability coordinators perform voltage stability analyses when under similarly constrained conditions, benchmark planning and operations models against actual events that strained the system, perform periodic impact studies to identify which elements in the adjacent reliability coordinators' systems have the most impact on their own systems, and perform drills with entities involved in load shedding to prepare to execute load-shedding for maintaining reserves while at the same time alleviating severe transmission conditions.[73]

40. Having the necessary data and performing modeling in advance of extreme cold temperatures could allow transmission planners and operators to assess the potential impact of an event to identify corrective actions that could be taken well in advance of the event. Such action could include ensuring generators have winterized their equipment, scheduling fewer planned outages of generating units and transmission lines, and endeavoring to maintain transmission ties intact to: (1) permit maximum transfers to an area experiencing a deficiency in generation; (2) minimize the possibility of cascading outages; and (3) assist in restoring operation to normal.[74] While these corrective action plans may not fully mitigate the potential impact of these events, they could minimize the impact and reduce system restoration time.

41. Past experience can inform how steady state and stability analyses should model transmission and generator outages, including availability of wind, natural gas, and other resources sensitive to extreme cold conditions. For example, the February 2021 cold weather-related outages in Texas and the south-central United States caused 4,125 outages/derates of generating units (*i.e.,* approximately 456 GW during event in total event area). Of the total generation losses, 59% were gas-fired generating units due to fuel issues[75] and a pipeline equipment failure, and 27% were wind generation due to blade icing.[76]

42. While heat events have different planning challenges, they also present a serious risk to the Bulk-Power System and often require operators to shed load to maintain system stability. The recent extreme heat events resulted in a variety of reliability issues such as controlled rolling blackouts and transmission congestion. During the August 2020 California Heatwave Event, wind production was low during the evenings, and solar generation was declining during the peak demand hours, leading to reserve shortages.

[69] NOAA website, Climate Data Online.

[70] NOAA, Climate Program Office, *Research Links Extreme Cold Weather in the United States to Arctic Warming, https://cpo.noaa.gov/Interagency-Programs/NIHHIS/ArtMID/6409/ArticleID/2369/Research-Links-Extreme-Cold-Weather-in-the-United-States-to-Arctic-Warming?msclkid=f9ad03bcc7c911ecba22ebf3e1ead5d9.*

[71] NOAA website, Climate Data Online.

[72] Contingency reserves would only contribute to a corrective action plan to the extent that they are expected to perform during the applicable modeled extreme weather event(s) and thereby contribute to meeting the applicable performance criteria. Accordingly, if for instance, extreme cold is anticipated to cause fuel unavailability for the applicable area, a corrective action plan would need to account for such limitations.

[73] 2018 Cold Weather Event Report at 12–13.

[74] ERCOT, *Nodal Operating Guide,* at 137 (Jan. 1, 2022), *https://www.ercot.com/files/docs/2021/12/21/Nodal%20Operating%20Guide.pdf.*

[75] Fuel issues included 87% natural gas fuel supply issues (decreased natural gas production, terms and conditions of natural gas commodity and transportation contracts, low pipeline pressure and other issues) and 13% other fuel issues.

[76] 2021 Cold Weather Event Report at 163.

Similar to Texas, California relies on wind and solar generation to meet normal peak day demand, but wind and solar generation were largely unavailable. Steady state and stability analyses of study cases modeled to reflect past extreme conditions as well as modeling of availability of generation resources during extreme heat conditions in the planning process could have better prepared the transmission operators for such conditions.

43. Past extreme heat and cold events discussed above demonstrate the importance of assessing resource and reserve requirements under extreme heat and cold weather conditions. Developing and using extreme heat and cold weather scenarios in planning analyses will help to identify the potential risks that extreme events may pose to the Bulk-Power System. Based on the risks identified, appropriate mitigations or corrective action plans such as requiring additional reserves and transfer capability can be developed and deployed to address the risks and specify what should be planned for the longer term to ensure the availability of electricity in real time.

44. NERC recognizes that extreme events present a reliability risk and there are opportunities to improve the transmission planning processes. Following the 2021 extreme cold weather event, NERC issued a level 2 NERC Alert to industry on cold weather preparations for extreme weather events with five recommendations to assist reliability coordinators, balancing authorities, transmission operators, and generator owners in preparing for the winter season. NERC's level 2 Alerts recommend but do not mandate registered entities to take specific actions.[77] The Alert recommended seasonal operating plans for the upcoming winter season, which would include plans to utilize additional transmission capacity, consideration of the import capability of the system and resource availability constraints on external systems, and load forecasting practices that consider extreme events, among other recommendations.[78] The NERC Alert did not include any recommendations concerning long-term transmission planning.

45. In addition, in 2021 NERC formed the Energy Reliability Assessment Task Force (ERATF) to assess risks associated with unassured energy supplies, including the inconsistent output from variable renewable energy resources, fuel location, and volatility in forecasted load, which can result in insufficient amounts of energy on the system to serve electrical demand.[79] The ERATF uses resource adequacy models to address energy availability concerns related to the operations planning horizon (*i.e.,* one day to one year) and near-term planning horizon (*i.e.,* one to five years).[80] In December of 2021, the ERATF prepared a draft Standard Authorization Request (SAR) and based on the comments to the SAR, two SARs were created: a planning SAR and an operations/operations planning SAR, aiming to create or modify NERC Reliability Standards across the operations/operational planning time horizon and the planning time horizon. To discuss this latest update with industry members, NERC held an informational Webinar on May 19, 2022, and the two SARs were scheduled for committee consideration on June 8, 2022.[81]

46. While these ongoing efforts by NERC and industry members are intended to improve system reliability, they do not directly address the gap in transmission planning related to extreme heat and cold weather. NERC acknowledges that heat and cold events have effects on the grid but at this time has not determined that modifications to TPL–001–5.1 are needed to address extreme weather events.[82]

IV. Proposed Directives

47. We preliminarily find that a reliability gap exists in Reliability Standard TPL–001–5.1 with respect to a lack of a long-term planning requirement for extreme heat and cold weather events. Accordingly, pursuant to section 215(d)(5) of the FPA, we propose to direct that NERC develop modifications to Reliability Standard TPL–001–5.1 to require: (1) development of benchmark planning cases based on information such as major prior extreme heat and cold weather events or future meteorological projections;[83] (2) planning for extreme heat and cold events using steady state and transient stability analyses expanded to consider a range of extreme heat and cold weather scenarios (*i.e.,* sensitivities to be applied to the benchmark base case(s)), including the expected resource mix's availability during extreme heat and cold weather conditions, and including the broad area impacts of extreme heat and cold weather; and (3) corrective action plans that include mitigation for any instances where performance requirements for extreme heat and cold events are not met. We further elaborate on the substance of these proposed directives below. In proposing to direct NERC to develop modifications to Reliability Standard TPL–001–5.1, we are not proposing specific requirements; we are identifying concerns that we believe should be addressed. NERC may propose to develop new or modified Reliability Standards that address these concerns in an equally efficient and effective manner as the requirements proposed in this paragraph; however, NERC must explain how its proposal addresses the Commission's concerns.[84]

48. We further propose to direct NERC to submit modifications to Reliability Standard TPL–001–5.1 within one year of the effective date of a final rule in this proceeding with compliance obligations for all proposed new or modified Reliability Standards beginning no later than 12 months from the date of Commission approval of the modified Reliability Standard. Finally, we invite comments on whether to also direct NERC to address in Reliability Standard TPL–001–5.1 other extreme weather-related events.

49. Below we provide additional context for these three proposed directives and describe reliability concerns and potential options for

[77] NERC, *About Alerts, https://www.nerc.com/pa/rrm/bpsa/Pages/About-Alerts.aspx.*

[78] NERC, *Alert R–2021–08–18–01 Extreme Cold Weather Events* (Aug. 18, 2021), *https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20R-2021-08-18-01%20Extreme%20Cold%20Weather%20Events.pdf.*

[79] NERC, *Energy Reliability Assessment Task Force website,* (ERAFT website), *https://www.nerc.com/comm/RSTC/Pages/ERATF.aspx#:~:text=%E2%80%8B%E2%80%8B%E2%80%8B%E2%80%8B%E2%80%8B,insufficient%20amounts%20of%20energy%20on.*

[80] NERC Post-Technical Conference Comments at 7.

[81] NERC, *Informational Webinar: Industry Webinar Energy Reliability Assessment Task Force Update on the Revised SARs* (May 19, 2022), *https://www.nerc.com/pa/RAPA/Lists/RAPA/DispForm.aspx?ID=480*; NERC, *Reliability and Security Technical Committee Meeting Agenda,* SAR Draft.

[82] NERC, *2021 ERO Reliability Risk Priorities Report,* Risk Profile 2, at 26 (July 2021), *https://www.nerc.com/comm/RISC/Documents/RISC%20ERO%20Priorities%20Report_Final_RISC_Approved_July_8_2021_Board_Submitted_Copy.pdf; see also* NERC Post-Conference Comments at 5 (referencing Reliability Standard TPL–001–4, NERC states that ''[w]ith respect to extreme weather more generally, NERC staff will continue to examine the Reliability Standards to determine if other modifications are needed.'').

[83] For instance, a benchmark event could be constructed based on data from a major prior extreme heat or cold event, with adjustments if necessary to account for the fact that future meteorological projections may estimate that similar events in the future are likely to be more extreme.

[84] Order No. 693, 118 FERC ¶ 61,218 at P 186; *Reliability Standards for Physical Sec. Measures,* 146 FERC ¶ 61,166 at P 13.

consideration that we believe would address these concerns.

A. Develop Benchmark Planning Cases Based on Major Prior Extreme Heat and Cold Weather Events

50. As part of its revisions to Reliability Standard TPL–001–5.1, we are proposing to direct that NERC develop requirements that address the types of extreme heat and cold scenarios the responsible entities are required to study. Reliability Standard TPL–001–5.1 does not require any specific approach to studying extreme heat and cold events and we are concerned that, without specific requirements describing the types of heat and cold scenarios that entities must study, the standard may not provide a significant improvement upon the status quo.

51. To accomplish this, the modified Reliability Standard developed by NERC should include benchmark events that responsible entities must study, as well as guidelines regarding which range of sensitivities must be applied to these benchmark event scenarios. Such benchmark events should be based on prior events (*e.g.,* February 2011 Southwest Cold Weather Event, January 2014 Polar Vortex Cold Weather Event) and/or constructed based on meteorological projections, as described above. In addition to providing valuable case study information to be applied to possible comparable future events, these events will also serve as a basis for effectively using assets and resources. Once developed, the results of the benchmark events studies could be applied to determine the limitations of the transmission system locally and over a wide-area, and to understand resource availability and potential firm load shedding requirements under stressed conditions.

52. While extreme weather risks may vary from region to region and change over time, it is important that transmission planners and planning coordinators likely to be impacted by the same types of extreme weather events use consistent benchmark events. In determining an appropriate benchmark event, NERC should consider approaches to provide a uniform framework while still recognizing regional differences. For example, NERC could define benchmark events around a projected frequency (*e.g.,* 1-in-50-year event) or probability distribution (95th percentile event),

53. We propose to provide NERC with flexibility in defining one or more appropriate benchmark events. For example, one approach could be for NERC to develop the common benchmark event or events through the standards development process and include the relevant parameters of the benchmark event or events in the modified reliability standard. Another approach could be to include in the modified standard the primary features of the benchmark event or events (*e.g.,* the expected occurrence such as one-in-50 years) while designating another set of entities, such as the Regional Entities, reliability coordinators, or even NERC itself, as responsible for periodically updating key aspects of the benchmark events based on the most up-to-date data. Such a method for developing benchmark events and scenarios could establish a common design basis across the industry while still recognizing regional differences in climate and weather patterns. We seek comment on whether, and to what extent, it may be appropriate to allow designated entities to periodically update key aspects of the benchmark events.

54. As discussed further below, establishing one or more benchmark events should form the basis for sensitivity analysis, which provide better visibility into the actual system conditions during extreme heat and cold. For example, sensitivity analysis could include analysis of simultaneously varying generation dispatch (*e.g.,* wind, solar, natural gas, and other fuel generation availability), system transfers, and load, which have been observed during prior extreme heat and cold events.

55. In addition to establishing requirements that address the extreme heat and cold scenarios that responsible entities are required to study, NERC could also establish measures of system performance (stability, voltage, thermal limits, etc.) to determine whether the responsible entities must implement a corrective action plan. Performance requirements are a corollary to study requirements—without clear performance requirements, the obligations on responsible entities to mitigate issues with system performance may be unclear. Moreover, performance requirements are an integral part of the existing Reliability Standard TPL–001–5.1.[85] Accordingly, NERC should incorporate performance requirements for extreme heat and cold conditions when modifying TPL–001–5.1.

56. In establishing any proposed performance requirements, NERC should seek to prevent system instability, uncontrolled separation, and cascading outages. While load shedding could still occur during extreme heat and cold events to prevent instability, uncontrolled separation, and cascading, it should be minimized as much as possible. Developing benchmark events and associated corrective actions to be deployed prior to and during the event, would result in better system performance in real time.

B. Transmission System Planning for Extreme Heat and Cold Weather Events

57. As discussed above, we propose to direct that NERC develop modifications to Reliability Standard TPL–001–5.1 to require planning for extreme heat and cold events using steady state and transient stability analyses expanded to consider a range of extreme heat and cold weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the broad area impacts of extreme heat and cold weather. In this section, we discuss six topics which NERC would be required to address in a modified Reliability Standard pursuant to the proposed directive: (1) steady state and transient stability analysis; (2) transmission planning studies of wide area issues; (3) concurrent generator and transmission outages; (4) sensitivity analysis; (5) consideration of modifications to the traditional planning approach; and (6) coordination among planning coordinators and transmission planners and sharing of results. We note that a range of methods/approaches could satisfy the Commission's directive with regard to issues (3) through (6). NERC would retain flexibility with regard to *how* to address these topics, so long as it incorporates them into its proposed solution. To better inform our directive to NERC in the final rule, we invite comments on these matters.

1. Steady State and Transient Stability Analyses

58. To maintain and improve the reliability of the Bulk-Power System, it is important to conduct both steady state and stability analyses for extreme heat and cold events as part of transmission planning studies. As discussed above, steady state and stability analyses of study cases modeled to reflect past and forecasted extreme heat and cold conditions would better prepare transmission operators for such conditions. Further, this approach is consistent with Reliability Standard TPL–001–5.1, which requires both steady state and stability analyses for extreme events identified in Table 1 of the Standard. Performing these studies in the long-term planning horizon time frame (*i.e.,* five to 10 years) will provide an adequate lead time for entities to

[85] *See* Reliability Standard TPL–001–5.1 (Transmission System Planning Performance Requirements), Requirements R1 through R8.

develop and implement corrective action plans to reduce the likelihood or mitigate the consequences and adverse impacts of such events.

59. A steady-state analysis or assessment is based on a snapshot in time where bulk-electric system facilities such as generators, transmission lines, transformers, etc. are modeled as fixed and load is modeled as a constant. The steady state analysis assesses the ability of the system to deliver electricity to load within the ratings and constraints of generators and transmission lines. It also includes a contingency analysis to predict electrical system conditions when elements are removed from the base case.[86]

60. Transient stability or dynamic studies add to the steady state analyses simulate the time-varying characteristics of the system during a disturbance that occurs during an extreme heat or cold weather event. They are time-domain analyses that assess angular stability, voltage stability, and frequency excursions.[87] Transient angular stability is the ability of interconnected synchronous machines of a power system to remain in synchronism after being subjected to a disturbance (*i.e.,* fault, sudden loss of load, and generation tripping).[88] Transient voltage stability refers to the ability of a power system to maintain steady voltages at all buses in the system after being subjected to a disturbance.[89]

61. While we recognize dynamic studies can be more resource intensive to perform, we believe that the consideration of both types of studies is important to understand the potential impacts of extreme heat and cold weather events. We believe the consideration of dynamic studies is particularly important given the changing resource mix and the need to understand the dynamic behavior of both traditional generators as well as variable energy resources (VER) (mainly wind and photovoltaic solar).

62. To that end, we seek comments on whether planning coordinators and transmission planners should include contingencies based on their planning area and perform both steady state and transient stability (dynamic) analyses using extreme heat and cold cases. We are inviting comments on the following topics regarding planning for extreme heat and cold weather conditions: (1) the set of contingencies planning coordinators and transmission planners must consider; (2) required analyses to ensure system stability, frequency excursion and angular deviations caused as a result of near simultaneous outages or common mode failures of VERs; and (3) the role of demand response under such scenarios.

63. Finally, we emphasize the continued importance of ensuring that entities responsible for performing assessments under TPL–001–5.1 are able to obtain the necessary data. Currently, the data for steady-state, dynamic, and short circuit modeling can be obtained pursuant to Reliability Standard MOD–32–1, Requirement 1 (Data for Power System Modeling and Analysis), which is referenced in Reliability Standard TPL–001–5.1. Specifically, Reliability Standard MOD–32–1 allows planning coordinators and transmission planners to request data from the generator owners and transmission owners, which are obligated to provide the specified data.[90] Consistent with the existing standards, we believe it is important for NERC to ensure that registered entities responsible for performing studies of extreme weather are able to access the data necessary to complete such studies. Accordingly, we seek comment on whether the existing Reliability Standards are sufficient to ensure that responsible entities performing studies of extreme heat and cold weather conditions have the necessary data, or whether the Commission should direct additional changes pursuant to FPA 215(d)(5) to address that issue.

2. Transmission Planning Studies of Wide-Area Events

64. As discussed above, our proposed directive would include modifications to TPL–001–5.1 to require transmission planning studies that consider the broad area impacts of extreme heat and cold weather. The effects of extreme weather events on the reliable operation of the Bulk-Power System can be widespread, potentially causing simultaneous loss of generation and increased transmission constraints within and across regions. The studies required by TPL–001–5.1, however, have traditionally focused on local planning and typically do not address the issues caused by wide-area extreme heat and cold weather events on a regional or interconnection scale.[91]

65. Reliability Standard TPL–001–5.1 does not contemplate the consideration of impacts from wide-area events[92] that may impact multiple planning coordinators simultaneously; in contrast, TPL–001–5.1 only requires identifying and evaluating selected wide-area events resulting from conditions such as loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation, and does not specify studying potential issues resulting from extreme heat and cold.[93]

66. Failure to study the wide-area impact of extreme heat or extreme cold weather conditions when an entity conducts transmission planning, could result in reliability issues that simultaneously affect multiple regions to remain undetected in the long-term planning horizon. This, in turn, could lead to otherwise avoidable situations where the system is one contingency away from voltage collapse and uncontrolled blackouts.

67. Based on prior events, we preliminarily find that it is appropriate that the study criteria for extreme heat and cold events include a consideration of wide-area conditions affecting neighboring regions and their impact on one planning area's ability to rely on the resources of another region during the weather event. To identify opportunities for improved wide-area planning studies and coordination, we seek comment on: (1) whether wide-area planning studies should be defined geographically or electrically; (2) which entities should oversee and coordinate the wide-area planning models and studies (*e.g.,* reliability coordinators, regional planning groups); (3) which entities should have responsibility to address the results of the studies, and how they should communicate those results among transmission planners; and (4) how to develop corrective action plans that mitigate issues that require corrective action by, and coordination among, multiple transmission owners.

[86] NERC, *Compliance Implementation Guidance Real-time Assessment Quality of Analysis,* at 3 (May 2019), *https://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TOP-010-1(i)%2520R3%2520and%2520IRO-018-1(i)%2520R2%2520-%2520RTA%2520Quality%2520of%2520Analysis%2520(OC).pdf.*

[87] Indian Institute of Technology Patna, *Power System Dynamics and Control,* at 1, (Power System Dynamics), *https://www.iitp.ac.in/~siva/2022/ee549/Introduction_Power_System_Stability.pdf.*

[88] *Id.* at 3.

[89] *Id.* at 15.

[90] Reliability Standard MOD–032–1, Requirements R1 and R2.

[91] June 1, 2021 Tr. 153: 2–9. (Frederick Heinle, Assistant People's Counsel, Office of the People's Counsel for the District of Columbia).

[92] Reliability Standard TPL–001–5.1, Table 1, Steady State & Stability Performance Extreme Events, uses the term ''wide area events'' to refer to such things as loss of two generating stations resulting from conditions including severe weather or wildfires, distinguishing such events from ''local area events'' affecting the transmission system, which may involve the isolated loss of a transmission tower, substation, or generating station.

[93] Reliability Standard TPL–001–5.1, Table 1, Steady State & Stability Performance Extreme Events, Section 3(a)(i).

3. Study Concurrent Generator and Transmission Outages

68. Concurrent outages occur nearly simultaneously in different planning areas due to the same extreme weather events, such as the unplanned generator outages associated with the major extreme heat and cold events discussed above. Generation resources that are sensitive to severe weather conditions may cease operation during extreme heat and cold events, thus contributing to wide-area concurrent outages. In addition, the performance of power transformers, transmission lines, and other equipment degrades under extreme heat and may have to come out of service. Extreme heat could lead to significant derating, reduced lifetime, and even possible failures of power transformers, while extreme cold could lead to at least temporary facility transmission outages.[94]

69. Therefore, modeling the loss of these generators and transmission equipment during extreme heat and cold weather events would allow planners to determine the effects of potential concurrent transmission and generator outages and study the feasibility (*i.e.,* availability and deliverability) of external generation resources that could possibly be imported to serve load during such events, thereby minimizing the potential impact of extreme heat and cold events on customers.[95] Modeling concurrent generator and transmission outages would also allow planners to better identify appropriate solutions to be incorporated into corrective action plans.

70. Extreme cold effects on generators vary by generator type, cooling systems, and fuel sources.[96] Transmission planners commonly assume that the failures of individual generators are independent. This understanding, however, is inconsistent with documented historical events, that show multiple coincident outages due to the same cause. For instance, the 2021 extreme cold event demonstrated the limitations of such an assumption. Between February 8 and February 20, 2021, approximately 44% of generator outages were caused by freezing issues, 31% by fuel issues related to extreme cold weather, and another 21% were caused by mechanical/electrical failures related to cold weather.[97] Meanwhile, wind turbine generators were the second largest share of individual generating units after gas-fired generators that suffered freezing issues in the southern part of SPP and Texas, as temperatures dropped well below zero degrees Fahrenheit.[98] Transmission facilities were also affected in the short-term, as transmission operators managed to return them into service.[99] Likewise, the 2018 Cold Weather Event Report revealed that there is a high correlation between generator outages and cold temperatures, indicating that as temperatures decrease, unplanned generator outages and derates increase.[100]

71. Similarly, extreme heat impacts on generators vary by generator type, and the common implication is a reduction in the overall generation capacity throughout the wide area affected by the heat event.[101] Generally, extreme heat poses more of a threat to the functioning of a solar panel than extreme cold. As temperatures increase above 77 degrees Fahrenheit, which is a standard test condition, solar panels generate less voltage and become less efficient,[102] producing less power for a given amount of solar energy depending on the solar panel temperature coefficient.[103] For example, during the 2020 heat event in California, wind and solar generation were largely unavailable.[104] While extreme cold temperatures on clear days would not negatively impact energy output. Also, solar panels are built to be waterproof to protect the electronic components against heavy rain and to withstand hailstorms. However, snow,[105] ice accumulation, or cloud cover that commonly accompany extreme cold weather could prevent the panels from receiving as much sunlight, which would limit their power production and efficiency.

72. Requiring transmission planners and planning coordinators to study concurrent generator and transmission failures under extreme heat and cold events is one way to address the reliability gap. Accounting for concurrent outages in planning studies would provide a more realistic assessment of system conditions (*i.e.,* updated conditions based on historic benchmarked performance) during potential extreme heat and cold events and will help better assess the probability of potential occurrences of cascading outages, uncontrolled separation, or instability. Transmission planners and planning coordinators could also model the derating and possible loss of wind and solar generators, as well as natural gas generators sensitive to extreme heat and cold conditions. To identify the scope of these planning studies, we are seeking comments on: (1) the assumptions (*e.g.,* weather forecast, load forecast, transmission voltage levels, generator types, multi-day low wind, solar event, etc.) used in modeling of concurrent outages due to extreme heat and cold weather events; (2) what assumptions should be included when performing modeling and planning for generators sensitive to extreme heat and cold; (3) how the impact of loss of generators sensitive to extreme heat and cold should be factored into long-term planning; (4) the extent of neighboring systems' or planning areas' outages that should be modeled in transmission planning studies; and (5) whether a certain threshold of penetration of wind, solar generation, and natural gas generators should trigger additional analyses.

4. Sensitivity Analysis

73. As part of its revisions to TPL–001–5.1, NERC should establish a requirement for sensitivity analysis for

[94] MIT News, *Preventing the Next Blackout* (Dec. 5, 2017), *https://news.mit.edu/2017/mit-study-climate-change-effects-large-transformers-1205; see also* IEEE Standard C57.91–2011, Table 2; IEEE Standard C57.91–2011, Table 3; 2021 Cold Weather Event Report at 95.

[95] The Cold Weather Reliability Standards referenced *supra* take effect in April 2023, and are expected to improve generating unit performance and help alleviate some of the unsustainable levels of generation outages seen during extreme events. Improved transmission planning alone cannot overcome the challenges associated with generator outages during extreme events. Therefore, both the Cold Weather Reliability Standards and this proposal to improve transmission planning are necessary for the Bulk Power System to perform reliably in the face of future extreme weather events.

[96] Polar Vortex Review at 12.

[97] 2021 Cold Weather Event Report at 15–16.

[98] *Id.* at 75.

[99] *Id.* at 95.

[100] 2018 Cold Weather Event Report at 80.

[101] Department of Energy, *U.S. Energy Sector Vulnerabilities to Climate Change and Extreme Weather, Department of Energy,* at 19–22 (July 11, 2013), *https://www.energy.gov/sites/default/files/2013/07/f2/20130716-Energy%20Sector%20Vulnerabilities%20Report.pdf* (listing the impacts of increased ambient air temperature on the various types of generators).

[102] IEEEXplore, International Conference on Current Trends in Computer, Electrical, Electronics and Communication (ICCTCEEC–2017), *Effect of Temperature on Performance of Solar Panels—Analysis, https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=8455109.*

[103] Temperature coefficient describes the percentage of power output that is lost by a specific solar panel as the temperature rises above 77 degrees Fahrenheit.

[104] 2020 Heat Event Report at 11.

[105] A recent study by Sandia National Labs identified snow events as causing the largest performance reductions at solar facilities. *See* Nicole D. Jackson & Thushara Gunda, *Evaluation of Extreme Weather Impacts on Utility-Scale Photovoltaic Plant Performance in the United States,* 302, Applied Energy, 1:7 (2021), *https://www.researchgate.net/publication/353944206_Evaluation_of_extreme_weather_impacts_on_utility-scale_photovoltaic_plant_performance_in_the_United_States.*

transmission planners and planning coordinators to consider system models and sensitivity cases when assessing extreme heat and extreme cold weather. A sensitivity case is a variation from the base case that helps a transmission planner to determine if the results are sensitive to changes in the inputs. Reliability Standard TPL–001–5.1, Requirement R2.1.4 requires that sensitivity power flow cases be used to demonstrate the impact of changes to the basic assumptions used in the models for system peak load or system off-peak load. These changes include, among other things, conditions that vary with temperature; specifically, load, generation, and system transfers.[106] While requiring the variation of one of the specified conditions to demonstrate a measurable change, it does not require the simultaneous variation of load, generation and transfers necessary to model conditions that reflect extreme heat or cold weather conditions, thus potentially causing major reliability issues (*i.e.,* widespread outages, cascading, etc.) to remain overlooked and undetected in the planning horizon. To model the effect of extreme heat or cold weather, demand probability scenario cases (90/10, 80/20, 50/50),[107] generators that are affected by these events (*i.e.,* wind tripping off, solar dropping off, gas plants not operational due to gas restrictions/freeze-offs, etc.), and transfer levels need to be defined and modeled in sensitivity analyses.

74. Therefore, we seek comment on: (1) requiring transmission planners and planning coordinators to assess reliability in the planning horizon for sensitivity cases in which multiple inputs, *e.g.,* load and generator failures, change simultaneously during extreme heat and cold events; and (2) the range of factors and the number of sensitivity cases that should be considered to ensure reliable planning.

5. Modifications to the Traditional Planning Approach

75. In modifying TPL–001–5.1, we propose to direct NERC to consider planning methods and techniques that diverge from past Reliability Standard requirements.[108] Reliability Standard TPL–001–5.1 is based on a deterministic approach, which uses planned contingencies and definite performance criteria to study system response to various conditions. This approach yields accurate planning when the power supply is highly dispatchable, weather is predictable, and near-record peak demand is reached only a few days a year.[109] However, the current planning approach applied in Reliability Standard TPL–001–5.1 likely is not sufficient to accurately characterize the reliability risk from extreme heat and cold weather given the high degree of uncertainty inherent in predicting severe weather and its impact on generation resources, transmission, and load.

76. An alternative to the deterministic approach is to use probabilistic approaches in transmission planning. Probabilistic transmission planning captures random uncertainties in power system planning, including those in load forecasting, generator performance, and failures of system equipment. The probabilistic method is not intended to replace the deterministic criterion but adds one more dimension to enhance the transmission planning process.[110]

77. NERC has recognized the need to incorporate probabilistic approaches into planning activities. For example, NERC's Probabilistic Assessment Working Group develops probabilistic analysis that contributes to NERC's Long-Term Reliability Assessment every other year. NERC is also investigating the development of probabilistic methods to study resource adequacy, energy sufficiency, and transmission adequacy for reliable delivery in composite reliability studies as well as to develop enhanced reliability metrics.[111]

78. Therefore, to ensure reliable planning and operations in response to extreme heat and cold events, we believe that a new or modified approach may be beneficial to capture these events during the planning process. The new approach could include elements of both deterministic and probabilistic approaches to assess reliability outcomes. For example, the January 2018 South Central Cold Weather Event in the South Central part of the country was a near-miss where MISO would have been required to perform firm load shed if its next-worst contingency occurred (*i.e.,* outage of 1,163 MW generation in MISO South). The load shed would have been needed to alleviate low voltages at many locations that would have been significantly below their limits due to the failure of almost 200 generating units. Including scenarios in the planning process in which generator failures are probabilistically evaluated could result in a planning approach better prepared to ensure reliable outcomes compared to the existing planning requirements under Reliability Standard TPL–001–5.1.

79. One option to modify the existing planning approach would be to expand the required deterministic studies to include probabilistically developed scenarios. Therefore, we seek comments on industry's experience and opinion on combining or layering probabilistic and deterministic approaches when planning for extreme heat and cold weather conditions in the context of Reliability Standard TPL–001–5.1. Specifically, we seek comments on the use of the proposed hybrid planning approach and: (1) the assumptions from the deterministic and probabilistic approaches that should be applied to study extreme heat and cold weather events; (2) the potential planning challenges from combining the two planning approaches; (3) the costs associated with adjustments to the currently applied deterministic approach; (4) the implementation period necessary for proposed changes; and (5) the reliability benefits that could result.

6. Coordination Among Planning Coordinators and Transmission Planners and Sharing of Study Results

80. Reliability Standard TPL–001–5.1 cross-refences Reliability Standard MOD–032–1 (Data for Power System Modeling and Analysis), which establishes consistent modeling data requirements and reporting procedures

[106] To effectively model the Bulk-Power System, transmission planners need make assumptions that create scenarios that are valid, realistic, and defendable. *See* North American Transmission Forum, TPL–001–4 Reference Document, at 8–9 (Aug. 2, 2021), *https://www.natf.net/docs/natf/documents/resources/planning-and-modeling/natf-tpl-001-4-reference-document.pdf.* Specifically, appropriate assumptions and corresponding model adjustments need to be made regarding load (demand), generation (particularly that of renewables), and transfers (power flows between regions or zones). *See* National Renewable Energy Laboratory, *Report: The Evolving Role of Extreme Weather Events in the U.S. Power System with High Levels of Variable Renewable Energy* (Dec. 2021), *https://www.nrel.gov/docs/fy22osti/78394.pdf.*

[107] Demand scenario cases are given designations based on the percent probability the actual system's peak demand for the period under study will be above or below certain level. For example, for a 90/10 case, the system demand is modeled at a level that there is a 90% probability the actual system demand will be below that level and a 10% probability that the actual system demand will be above that level. Other designations follow similarly using different percentages.

[108] We are not making a proposed finding at this time that modifications to the traditional planning approach are necessary to properly plan for extreme weather. Nonetheless, there is sufficient concern such that we believe NERC should consider alternative approaches when developing a new or modified Reliability Standard in response to a final rule in this proceeding.

[109] June 1, 2021 Tr. 31 (Barton).

[110] IEEE Explore, *Probabilistic Planning of Transmission Systems: Why, How and an Actual Example,* at 1 (July 2008), *https://ieeexplore.ieee.org/document/4596093.*

[111] NERC Post-Technical Conference Comments 3.

for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system. Reliability Standard MOD–032–1 ensures adequate means of data collection for transmission planning. It requires each balancing authority, generator owner, load serving entity, resource planner, transmission owner, and transmission service provider to provide steady-state, dynamic, and short circuit modeling data to its transmission planner(s) and planning coordinator(s). The modeling data is then shared pursuant to the data requirements and reporting procedures developed by the transmission planner and planning coordinator as set forth in Reliability Standard TPL–001–5.1, Requirement R1.

81. While balancing authorities and other entities must share system information and study results with their transmission and planning coordinator pursuant to Reliability Standards MOD–032–1 and TPL–001–5.1 as described above, there is no required sharing of such information—or required coordination—among planning coordinators and transmission planners with transmission operators, transmission owners, and generator owners, thus limiting the benefits of additional modeling. Sharing system information and study results and enhancing coordination among these entities for extreme heat and cold weather events could result in more representative planning models by better: (1) integrating and including operations concerns (*e.g.,* lessons learned from past issues including corrective actions and projected outcomes from these actions, evolving issues concerning extreme heat/cold) in planning models; and (2) conveying reliability concerns from planning studies (*e.g.,* potential widespread cascading, islanding, significant loss of load, blackout, etc.) as they pertain to extreme heat or cold.

82. Therefore, as part of its revisions, NERC should require system information and study results sharing, and coordination among planning coordinators and transmission planners with transmission operators, transmission owners, and generator owners for extreme heat and cold weather events. To better understand the benefits of the suggested actions, we are inviting comments on: (1) the parameters and timing of coordination and sharing; (2) specific protocols that may need to be established for efficient coordination practices; and (3) potential impediments to the proposed coordination efforts.

C. Implement a Corrective Action Plan If Performance Standards Are Not Met

83. Pursuant to FPA 215(d)(5), we propose to direct NERC to modify Reliability Standard TPL–001–5.1 to require corrective action plans that include mitigation for any instances where performance requirements for extreme heat and cold events are not met. Under the currently effective Reliability Standard TPL–001–4, planning coordinators and transmission planners are required to evaluate possible actions to reduce the likelihood or mitigate the consequences of extreme events but are not obligated to develop corrective action plans. Specifically, if such events are found to cause cascading outages, they need only be evaluated for possible actions designed to reduce their likelihood or mitigate their consequences and adverse impacts.[112] Accordingly, because of their potential severity, we believe that extreme heat and cold weather events should require evaluation and the development and implementation of corrective action plans to help protect against system instability, uncontrolled separation, or cascading failures as a result of a sudden disturbance or unanticipated failure of system elements.

84. Consistent with the existing requirements of TPL–001–5.1, we believe it is appropriate to provide responsible entities with the flexibility to determine the best actions to include in their corrective action plan to remedy any identified deficiencies in performance. Examples of actions that could be included in a corrective action plan are planning for additional contingency reserves or implementing new energy efficiency programs to decrease load, increasing intra- and inter-regional transfer capabilities, transmission switching, or adjusting transmission and generation maintenance outages based on longer-lead forecasts. Well planned mitigation and corrective actions that account for some of these contingencies will minimize loss of load and improve resilience during extreme heat and cold weather events.

85. In particular, increases in interregional transfer capability could be considered as one option to address potential reliability issues during extreme weather events. Such transfer capability would allow an entity in one region with available energy to assist one or more entities in another region that is experiencing an energy shortfall due to the extreme weather event. Increasing interregional transfer capability may be a particularly robust option for planning entities attempting to mitigate the risks associated with concurrent generator outages over a wide area.[113]

86. Recent events have shown that interregional transfer capability can be critical to maintaining reliability during extreme weather events. For example, during the 2021 Cold Weather Event in Texas and the South Central United States, SPP and MISO imported power from other balancing authorities to make up for their increasing load levels and generation shortfalls, because the eastern part of the Eastern Interconnection did not have the same arctic weather conditions. Specifically, MISO was able to import large amounts of power from neighbors to the east (*e.g.,* PJM), and SPP was able to transfer some of that power through MISO into its region. Those east-to-west transfers into MISO peaked at nearly 13,000 MW.[114] PJM had additional energy available to be transferred but could not facilitate the transfer due to internal congestion in neighboring systems.[115]

87. Recent events have also shown that the loss of interregional transfer capability can have significant implications for system reliability during extreme weather events. For instance, during the August 2020 California Heatwave Event, there was a reduction in the transfer capability through the Northwest AC Intertie by as much as 1,250 MW due to another extreme weather event that occurred earlier in 2020 which damaged transmission facilities in the northwest part of the Western Interconnection. The transfer capability of the intertie linking

[112] Reliability Standard TPL–001–4, Requirements R3.3.5 and R4.4.5 require computer simulation analyses of extreme events listed in Table 1 of the standard (some listed are examples and are not definitive), and if the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

[113] In this NOPR we refer to interregional transfer capability strictly in the context of improving the reliability of the Bulk-Power System through improved transmission system planning and associated modifications to NERC's Reliability Standards. As such, our proposals here are distinct from the requirements for interregional coordination and cost allocation for public utility transmission providers. *See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* Order No. 1000, 76 FR 49842 (Aug. 11, 2011), 136 FERC ¶ 61,051 (2011), *order on reh'g,* Order No. 1000–A, 77 FR 32184 (May 31, 2012), 139 FERC ¶ 61,132, *order on reh'g and clarification,* Order No. 1000–B, 77 FR 64890 (Oct. 24, 2012), 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d 41 (D.C. Cir. 2014).

[114] 2021 Cold Weather Event Report at 15.

[115] PJM Post-Conference Comments at 19–20.

Canadian and U.S. power systems was also reduced by up to 750 MW due to other planned maintenance outages, further limiting the ability to transfer energy from the north to the load centers in the south.[116]

88. Thus, we believe that there may be potential benefits in better incorporating interregional transfer capability into corrective action plans, where warranted and encourage NERC to consider establishing requirements that appropriately recognize the value of interregional transfer capability.

89. To ensure corrective action plans are developed and implemented in a timely fashion, we invite comments on the timeframe for developing such corrective action plans and sharing of the corrective actions with other interconnected planning entities.

D. Other Extreme Weather-Related Events and Issues

90. While the focus of this NOPR is on extreme heat and cold weather events, we recognize that long-term drought, particularly when occurring in conjunction with high temperatures, could also pose a serious risk to Bulk-Power System reliability over a wide geographical area.[117] In particular, we are concerned that drought may cause or contribute to conditions that affect reliable operation of transmission systems such as transmission outages, reduced plant efficiency, and reduced generation capacity.

91. Some examples of recorded events of reduced power production from drought were seen in the Midwest in 2007 forcing nuclear and coal-fired plants to shut down and curtail operations and along the Mississippi River in 2006, which affected nuclear plants in Illinois and Minnesota.[118] According to a study conducted by NOAA's drought task force, climate change has intensified the drought conditions gripping the Southwestern United States, the region's most severe on record, with precipitation at the lowest 20-month level documented since 1895.[119] The study indicates that the drought that emerged in early 2020 in California, Nevada and the ''Four Corners'' states of Arizona, Utah, Colorado and New Mexico has led to unprecedented water shortages in reservoirs across the region, while exacerbating devastating western wildfires over the past two years.[120]

In addition, NERC's 2022 Summer Reliability Assessment concludes that in 2022 drought threatens wide areas of North America, mainly in the western United States and Texas, resulting in challenges to area electricity supplies.[121]

92. Therefore, we seek comments on whether drought should be included along with extreme heat and cold weather events within the scope of Reliability Standard TPL–001–5.1 system planning requirements. These comments will assist the Commission in determining whether the final rule should direct that NERC further modify Reliability Standard TPL–001–5.1 to require transmission planners to conduct transmission planning assessments of the effects of drought conditions on transmission system operations.

93. Finally, we invite comments on whether other extreme weather events with significant impact on the reliability of the Bulk-Power System (*e.g.,* tornadoes, hurricanes) could also be considered and modeled in the future to improve system performance during these events.

V. Information Collection Statement

94. The information collection requirements contained in this Notice of Proposed Rulemaking are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[122] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[123] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to this collection of information unless the collection of information displays a valid OMB control number.

95. The proposal to direct NERC modify existing Reliability Standard TPL–001 (Transmission System Planning Performance Requirements), is covered by, and already included in, the existing OMB-approved information collection FERC–725 (Certification of Electric Reliability Organization; Procedures for Electric Reliability Standards; OMB Control No. 1902–0225),under Reliability Standards Development.[124] The reporting requirements in FERC–725 include the ERO's overall responsibility for developing Reliability Standards, such as the TPL–001 Reliability, which is designed to ensure the BES will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.[125] The Commission will submit to OMB a request for a non-substantive revision of FERC–725 in connection with this NOPR.

VI. Environmental Assessment

96. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[126] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[127] The actions proposed here fall within this categorical exclusion in the Commission's regulations.

VII. Regulatory Flexibility Act Certification

97. The Regulatory Flexibility Act of 1980 (RFA)[128] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities.

98. We are proposing only to direct NERC, the Commission-certified ERO, to develop modified Reliability Standards that require enhanced long-term system transmission planning designed to prepare for extreme heat and cold

[116] 2020 Heat Event Report at 6.

[117] DOE, *Impacts of Long-term Drought on Power Systems in the U.S. Southwest,* at 5, *https://www.energy.gov/sites/prod/files/Impacts%20of%20Long-term%20Drought%20on%20Power%20Systems%20in%20the%20US%20Southwest%20%E2%80%93%20July%202012.pdf.*

[118] *Id.* at 6.

[119] NOAA, *Assessment Report the 2020–2021 Southwestern U.S. Drought,* at 6, *https://cpo.noaa.gov/MAPP/DTF4SWReport.*

[120] Reuters, *Southwest U.S. Drought, Worst in a Century, Linked by NOAA to Climate Change* (Sept. 21, 2021), *https://www.reuters.com/business/environment/southwest-us-drought-worst-century-linked-by-noaa-climate-change-2021-09-21/#:~:text=The%20drought%20emerged%20in%20early,two%20years%2C%20the%20report%20noted.*

[121] NERC, *2022 Summer Reliability Assessment,* at 5 (May 2022), *https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf.*

[122] 44 U.S.C. 3507(d).

[123] 5 CFR 1320.11.

[124] Reliability Standards Development as described in FERC–725 covers standards development initiated by NERC, the Regional Entities, and industry, as well as standards the Commission may direct NERC to develop or modify.

[125] Reliability Standard TPL–001–4, Purpose.

[126] *Regulations Implementing the National Environmental Policy Act of 1969,* Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

[127] 18 CFR 380.4(a)(2)(ii) (2021).

[128] 5 U.S.C. 601–612.

weather conditions.[129] Therefore, this Notice of Proposed Rulemaking will not have a significant or substantial impact on entities other than NERC. Consequently, the Commission certifies that this Notice of Proposed Rulemaking will not have a significant economic impact on a substantial number of small entities.

99. Any Reliability Standards proposed by NERC in compliance with this rulemaking will be considered by the Commission in future proceedings. As part of any future proceedings, the Commission will make determinations pertaining to the Regulatory Flexibility Act based on the content of the Reliability Standards proposed by NERC.

VIII. Comment Procedures

100. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due August 26, 2022. Comments must refer to Docket No. RM22–3–000, and must include the commenter's name, the organization they represent, if applicable, and address in their comments. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

101. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's website at *http://www.ferc.gov.* The Commission accepts most standard word processing formats. Documents created electronically using word processing software must be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

102. Commenters that are not able to file comments electronically may file an original of their comment by USPS mail or by courier-or other delivery services. For submission sent via USPS only, filings should be mailed to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street NE, Washington, DC 20426. Submission of filings other than by USPS should be delivered to: Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, MD 20852.

IX. Document Availability

103. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (*http://www.ferc.gov*). At this time, the Commission has suspended access to the Commission's Public Reference Room due to the President's March 13, 2020 proclamation declaring a National Emergency concerning the Novel Coronavirus Disease (COVID–19).

104. From the Commission's Home Page on the internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

105. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202)502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov.*

By direction of the Commission. Commissioner Danly is concurring with a separate statement attached. Commissioner Clements is concurring with a separate statement attached. Commissioner Phillips is concurring with a separate statement attached.

Issued: June 16, 2022.

Debbie-Anne A. Reese,

Deputy Secretary.

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Transmission System Planning Performance Requirements for Extreme Weather

Docket No. RM22–10–000

(Issued June 16, 2022)

DANLY, Commissioner, *concurring:*

1. I concur in today's notice of proposed rulemaking directing the North American Electric Reliability Corporation (NERC) to submit modifications to Reliability Standard TPL–001–5.1 to address reliability concerns related to transmission system planning.[130] It will take over two years, at a minimum, from this notice of proposed rulemaking (NOPR) to the ultimate implementation of any such changes. Reliability Standard development is neither swift nor agile, and this NOPR will not, indeed cannot, timely address the projected risk of widespread blackouts this summer,[131] nor can they be in place quickly enough to address future summer and winter reliability challenges over the next couple of years. Yet, I agree it is an important (albeit small) step to establish mandatory and enforceable compliance obligations to promote proactive planning for weather-related events.

2. The NOPR makes use of, indeed bases our action upon, an ever-growing narrative: reliability challenges arise primarily from weather-related events.[132] But even if one were to grant that certain parts of the United States were experiencing statistically unusual weather when compared to historical baselines, that has *absolutely nothing* to do with whether the markets and regulated utilities are procuring

[129] *Cf. Cyber Sec. Incident Reporting Reliability Standards,* Notice of Proposed Rulemaking, 82 FR 61499 (Dec. 28, 2017), 161 FERC ¶ 61,291 (2017) (proposing to direct NERC to develop and submit modifications to the NERC Reliability Standards to improve mandatory reporting of Cyber Security Incidents, including incidents that might facilitate subsequent efforts to harm the reliable operation of the BES); *Internal Network Sec. Monitoring for High and Medium Impact Bulk Elec. Sys. Cyber Sys.,* 178 FERC ¶ 61,038 (2020) (proposing to direct NERC to new or modified Reliability Standards that require internal network security monitoring within a trusted Critical Infrastructure Protection networked environment for high and medium impact Bulk Electric System Cyber Systems).

[130] *Transmission Sys. Planning Performance Requirements for Extreme Weather,* 179 FERC ¶ 61,195 (2022).

[131] Chairman Glick says that I am ''prone to hyperbole'' when I warn that blackouts are the likely outcome of the majority's misguided policies to prop up renewables at the expense of competitive markets and existing fossil resources. Rich Heidorn Jr., *Summer Forecasts Spark Warnings of 'Reliability Crisis' at FERC,* RTO Insider (May 19, 2022), *https://www.rtoinsider.com/articles/30170-summer-forecasts-spark-warnings-reliability-crisis-ferc.* Chairman Glick appears to be confusing ''hyperbole'' with ''reality.'' California and Texas have already experienced blackouts. Over two-thirds of the nation faces ''elevated [reliability] risk'' this summer. Ethan Howland, *FERC commissioners respond to elevated power outage risks across two-thirds of US, Utility Dive* (May 20, 2022), *https://www.utilitydive.com/news/ferc-nerc-power-outage-risks-summer-drought/624111/* (''At its monthly meeting Thursday, Federal Energy Regulatory Commission members dissected the North American Electric Reliability Corp.'s warning that roughly two-thirds of the United States faces [sic] heightened risks of power outages this summer.'').

[132] *See* Chairman Glick (*@RichGlickFERC*), Twitter (May 19, 2022, 11:13 a.m.), *https://twitter.com/RichGlickFERC/status/1527306459263881223?s=20&t=3a4C-1cac3nmFkjZyvoUDA* (''Extreme weather may be the single most important factor impacting #grid #reliability & the impacts of expected heat, drought, wildfires, hurricanes, & other events—all pose a big threat. Keeping eye on West, ERCOT, & parts of MISO this summer.''); Benjamin Mullin, *Climate Change is Straining California's Energy System, Officials Say,* N.Y. Times (May 6, 2022), *https://www.nytimes.com/2022/05/06/business/energy-environment/california-electricity-shortage.html.*

sufficient generation of the correct type to ensure resource adequacy and system reliability. We cannot blame our problems on the weather. The problem is federal and state policies which, by mandate or subsidy, spur the development of *weather dependent* generation resources at the expense of the dispatchable resources needed for system stability and resource adequacy. This is seen in particularly stark terms in our markets in which subsidies, combined with failed market design, warp price signals. This destroys the incentives required to ensure the orderly entry, exit, and retention of the necessary quantities of the necessary types of generation. The thinner and thinner margins that result render the Bulk-Power System more and more susceptible to the caprices of weather. We have been warned by credible sources on the matter: NERC,[133] the RTOs,[134] and Commission staff.[135]

3. As more nuclear[136] and coal plants[137]—with their high capacity factors and onsite fuel—announce early retirements, the dispatchable resources that remain are predominantly natural gas generators. Backstopping weather-dependent resources with gas generators, largely dependent on just-in-time delivery of gas, raises its own set of reliability concerns, particularly in areas—like New England—with inadequate pipeline infrastructure. On top of this, the Commission has delayed the processing of pipeline certificates and cast a chill over the pipeline industry with its ''draft policy statements''[138] and orders throwing the finality of fully litigated certificates into doubt.[139] Under pressure to reduce emissions at all costs, pipelines have moved to electrify compressor stations, furthering an unhealthy co-dependency between the gas and electric systems. And the efforts of politically motivated financial institutions to cut fossil fuel producers' access to capital has added to the current supply crunch.[140] Yet, we are led to believe that extreme weather is supposed to be the culprit for the nation's looming reliability woes. Not so.

4. The question of whether the weather is getting worse is a red herring. The much more relevant question is whether current system operations and tariff and market design are adequate to maintain reliability. The present high risk of reliability failures proves that they are not. That the policies of the Commission and other government bodies are undermining reliability is far more obvious than the question of whether, and how, the weather is getting worse and what specific effects that worsening weather might have on the stability of the electric system. That question of the weather's effect on reliability is a subject that doubtless merits study and planning, but misguided government policies are the root cause of the alarming reliability issues facing the nation, not the weather.

For these reasons, I respectfully concur.

James P. Danly,
Commissioner.

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Transmission System Planning Performance Requirements for Extreme Weather
Docket No. RM22–10–000

(Issued June 16, 2022)

CLEMENTS, Commissioner, *concurring:*

1. Today's Notice of Proposed Rulemaking (NOPR) is an important step to ensure that the North American Electric Reliability Corporation (NERC) builds upon existing practices to better account for extreme weather in transmission system planning. Together with the Notice of Proposed Rulemaking proposing to direct transmission providers to submit informational reports describing their current or planned policies and processes for conducting extreme weather vulnerability assessments,[1] it will facilitate steps to enhance the reliability of the electric system.

2. NERC already addresses extreme weather in several ways. For example, Reliability Standard TPL–001–4 requires planning coordinators and transmission planners to conduct an analysis of extreme weather events and

[133] *See generally* North American Electric Reliability Corp., *2022 Summer Reliability Assessment* (May 2022), *https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments %20DL/NERC_SRA_2022.pdf.* In addition, NERC has warned that system operators in areas of significant amounts of solar photovoltaic (PV) resources should be aware of the potential for resource loss events during grid disturbances. *Id.* at 6. NERC has further warned that ''[i]ndustry experience with unexpected tripping of [Bulk-Power System]-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred as recently as Summer 2021. A common thread with these events is the lack of inverter-based resource (IBR) ride-through capability causing a minor system disturbance to become a major disturbance. The latest disturbance report reinforces that improvements to NERC Reliability Standards are needed to address systemic issues with IBRs.'' *Id.* NERC also explains that ''because the electrical output of variable energy resources (*e.g.,* wind, solar) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity.'' *Id.* at 45.

[134] *See, e.g.,* California Independent System Operator Corp., *2022 Summer Loads and Resources Assessment* (May 18, 2022), *http://www.caiso.com/Documents/2022-Summer-Loads-and-Resources-Assessment.pdf;* Midcontinent Independent System Operator (MISO), *Lack of Firm generation may necessitate increased reliance on imports and use of emergency procedures to maintain reliability* (Apr. 28, 2022), *https://www.misoenergy.org/about/media-center/miso-projects-risk-of-insufficient-firm-generation-resources-to-cover-peak-load-in-summer-months/;* PJM Interconnection, L.L.C. (PJM), *Energy Transition in PJM: Frameworks for Analysis* (Dec. 15, 2021), *https://pjm.com/-/media/committees-groups/committees/mrc/2021/20211215/20211215-item-09-energy-transition-in-pjm-whitepaper.ashx* (addressing renewable integration).

[135] *See Staff Presentation on 2022 Summer Energy Market and Reliability Assessment* (AD06–3–000), FERC, at slide 9 (May 19, 2022), *https://www.ferc.gov/news-events/news/presentation-report-2022-summer-energy-market-and-reliability-assessment* (identifying the Western U.S., Texas, MISO and Southwest Power Pool as ''[p]arts of North America are at elevated or high risk of energy shortfalls during peak summer conditions'') (emphasis in original); *id.* at slide 10 (In MISO, ''[g]eneration capacity declined 2.3% since 2021 resulting in [a] lower reserve margin'' and the ''[n]orth and central areas [are] at risk of reserve shortfall in extreme temperatures, high generation outages, or low wind'' with ''[s]ome risk of insufficient operating reserves at normal peak demand.'').

[136] U.S. Energy Information Administration, *U.S. nuclear electricity generation continues to decline as more reactors retire* (Apr. 8, 2022), *https://www.eia.gov/todayinenergy/detail.php?id=51978.*

[137] Ethan Howland, *Coal plant owners seek to shut 3.2 GW in PJM in face of economic, regulatory and market pressures,* Utility Dive (Mar. 22, 2022), *https://www.utilitydive.com/news/coal-plant-owners-seek-to-retire-power-in-pjm/620781/.*

[138] *See Certification of New Interstate Nat. Gas Facilities,* 178 FERC ¶ 61,107 (2022) (Danly and Christie, Comm'rs, dissenting)); *Consideration of Greenhouse Gas Emissions in Nat. Gas Infrastructure Project Revs.,* 178 FERC ¶ 61,108 (2022) (Danly and Christie, Comm'rs, dissenting); *see also Certification of New Interstate Nat. Gas Facilities,* 178 FERC ¶ 61,197, at P 2 (2022) (converting the two policy statements to ''draft policy statements''). It is worth noting that PJM and MISO filed comments on the draft policy statements. PJM and MISO May 25, 2022 Limited Reply Comments, Docket Nos. PL18–1–001 and PL21–3–001, at 4 (''[A]ny future Commission pipeline policy should consider the importance of ensuring that needed pipeline infrastructure can be timely sited, and ensure that the need for infrastructure to meet electric system reliability is affirmatively considered and not lost in the debate over the scope of environmental reviews to be undertaken by the Commission.'').

[139] *See, e.g., Algonquin Gas Transmission, LLC,* 174 FERC ¶ 61,126 (2021) (Danly and Christie, Comm'rs, dissenting).

[140] Matt Egan, *Energy crisis will set off social unrest, private-equity billionaire warns,* CNN Business (Oct. 26, 2021), *https://edition.cnn.com/2021/10/26/business/gas-prices-energy-crisis-schwarzman/index.html* (''Part of the problem, [Blackstone CEO Stephen Schwarzman] said, is that it's getting harder and harder for fossil fuel companies to borrow money to fund their expensive production activities, especially in the United States. And without new production, supply won't keep up.'').

[1] *One Time Informational Reports on Extreme Weather Vulnerability Assessments,* 179 FERC ¶ 61,196 (2022).

evaluate potential actions for reducing the likelihood or mitigating the consequences of the event creating adverse impacts.[2] NERC also recently adopted Cold Weather Reliability Standards, which require generators to prepare and implement plans for cold weather, and require the exchange of information between the balancing authority, transmission operator, and reliability coordinator about the generator's ability to operate under cold weather conditions to ensure grid reliability.[3] Further, NERC has prioritized improving bulk electric system resilience to wide-spread long-term extreme temperature events in its 2022 Enterprise Work Plan,[4] and is pursuing enhancements to reliability standards for the operational planning timeframe to address extreme weather via its Energy Reliability Assessment Task Force.[5] Yet even with these actions, utilities and grid operators remain underprepared for the changing climate and the increasing frequency of extreme weather it is bringing, as is evident in NERC's 2022 Summer Reliability Assessment. Therein, NERC highlights the elevated risk of an energy emergency due to the increased demand for electricity driven by above average temperatures combined with a reduced capacity because extreme drought conditions threaten the availability of hydroelectric energy for transfer.[6] Had the nation's utilities and grid operators better planned for climate change and the attendant increased likelihood of these conditions, they would be better prepared for the conditions we are likely to face this summer.

3. There is no more urgent priority for this Commission than to reform system planning so that it sufficiently contemplates and provides mechanisms to address the impact of extreme weather events on the electricity grid. Across geographies, regulatory regimes, regional resource mixes and market designs, the impact of extreme weather has vastly outpaced regulatory adaptation to it. So, I am glad to support this priority by voting for today's NOPR, which complements NERC's ongoing efforts to address the operational time frame and fills a gap by ensuring that Reliability Standards better account for extreme weather in planning. I write separately for two reasons.

4. First, while it represents an important step in tackling extreme weather's myriad impacts on the transmission system, strong follow through from NERC will be required to ensure a reliability standard that addresses extreme weather reliability challenges in a comprehensive and cost-effective manner. While the proposed rule seeks comments on whether drought should be included along with extreme heat and cold weather events within the scope of Reliability Standard TPL–001–5.1, I believe that what we already know about meteorological projections and drought's anticipated impacts on the electricity system compel the development of drought benchmark events in applicable regions of the country.[7] The question for me is not whether such events should be included, but how TPL–001–5.1 should cover the impact of drought induced reductions in supply on regions already experiencing unprecedented reductions in reservoir supply and increased wildfire risk. Further, NERC can facilitate cost effective implementation of these reliability standard modifications by requiring modeling of extreme weather events according to consistent planning rules, providing for consultation with states and other regulators in the development of corrective actions plans, and by considering of the interaction between this proposed Reliability Standard and related planning processes and rules, including the Commission's recently issued notice of proposed rulemaking regarding long-term regional transmission planning.[8] I urge stakeholders to provide recommendations to NERC as to how best to account for these considerations in commenting on this proposal.

5. Second, it is important to note that if we are to cost-effectively ensure system reliability as the frequency and intensity of extreme weather events continues to increase, further action is necessary to complement today's initial proposal. We have learned a good amount about the impact of extreme weather on the electricity system the hard way.[9] We have the opportunity to learn a great deal more from the substantial amount of important information and good ideas that stakeholders submitted in response to the Commission's inquiry into Climate Change, Extreme Weather, and Electric System Reliability in Docket No. AD21–13.

6. Themes that emerge from this collective experience and record include, at least, the need to consider: (1) establishing a process for setting explicit minimum interregional transfer capability requirements or otherwise identifying least regrets interregional solutions, (2) improved scheduling and coordination in non-RTO regions, and (3) ensuring that planning and market mechanisms appropriately reflect resource availability during extreme weather events, accounting for the possibility of common mode failures or other correlated outages.[10] As I provide in more detail below, I urge my colleagues to prioritize these complementary issues in the months to come.

A. Ensuring Cost-Effective Implementation of This NOPR

7. The effectiveness of this NOPR depends upon NERC implementing it in a manner that comprehensively addresses extreme weather threats, provides for consistency in modeling scenarios and methods to the greatest extent possible, facilitates consultation with state regulators, and appreciates its interrelation with the Commission's Regional Planning NOPR. I urge NERC and stakeholders to provide feedback on the following issues, which may facilitate strengthening the effectiveness of the eventual reliability standard.

[2] Reliability Standard TPL–001–4; *see also* Notice of Proposed Rulemaking, *Transmission System Planning Performance Requirements for Extreme Weather* (Extreme Weather NOPR), 179 FERC ¶ 61,195, at PP 20–23 (2022) (discussing the requirements set forth in TPL–001–4).

[3] *See* Extreme Weather NOPR at PP 18–19 (discussing *Cold Weather Reliability Standards,* 176 FERC ¶ 61,119, at PP 1, 3 (2021)).

[4] *See* NERC, *2022 ERO Enterprise Work Plan Priorities,* at 3 (Nov. 4, 2021), available at *nerc.com/AboutNERC/StrategicDocuments/ERO_2022_Work_Plan_Priorities_Board_Approved_Nov_4_2021.pdf.*

[5] *See* NERC, *DRAFT Energy Management Recommendations for Long Duration Extreme Winter and Summer Conditions,* available at *https://www.nerc.com/comm/RSTC/ERATF/Combined-Energy-Management-Roadmap.pdf* (last accessed June 15, 2022).

[6] NERC, *2022 Summer Reliability Assessment,* at 7, 9 (May 2022), available at *https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf.*

[7] *See* Extreme Weather NOPR at PP 90–92 (discussing the anticipated impacts of drought on the electricity system); *infra* P 8.

[8] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* 179 FERC ¶ 61,028 (2022) (Regional Planning NOPR).

[9] Severe weather events have caused significant outages in the past decade. *See* NOPR at P 26 (discussing February 2011 Southwest Cold Weather Event where low temperatures caused uncontrolled blackouts throughout ERCOT's entire region, effecting 4.4 million electric customers), P 28 (discussing January 2014 Polar Vortex Cold Weather Event where increased demand for gas and the unavailability of gas-fired generation led to 35,000 MW of generator outages, and PP 31–32 (describing how the 2021 Cold Weather Event brought the largest controlled load shed in U.S. history, with more than 4.5 million people losing power, resulting in at least 210 people dying).

[10] While this statement highlights key priority areas for further inquiry, it is not intended to be exclusive. For instance, while I do not discuss it in detail here, I support Commissioner Phillips' call for an examination of whether the Commission should require revisions to RTO/ISO generation and transmission outage scheduling practices. *See* Extreme Weather NOPR (Phillips, Comm'r, concurring) at PP 8–9.

8. Initially, in addition to benchmark cases for extreme heat and cold, it seems prudent to include drought within the scope of Reliability Standard TPL–001–5.1. It is not surprising that, as noted in comments in the extreme weather docket, the more frequent and severe droughts occurring and expected to worsen in parts of the West and Southwest portend potentially significant grid impacts via limitations on hydroelectric generating facilities as well as thermal facilities that require water for cooling.[11] These drought conditions also, of course, serve as a main driver of what the Oregon Public Utility Commission describes as ''one of the most pressing and difficult issues: the rapidly increasing risk of highly destructive wildfires.'' [12] While the need to consider a drought benchmark case does not currently arise in all regions of the country, failure to contemplate the impacts of drought in relevant regions as part of equipping transmission planning to effectively address extreme weather would hamper a final Reliability Standard's impact.

9. Further, I am pleased to see the proposal's emphasis that ''it is important that transmission planners and planning coordinators likely to be impacted by the same types of extreme weather events use consistent benchmark events.'' [13] I urge NERC and stakeholders to contemplate the benefits of consistent modeling practices and modeling assumptions, and to provide feedback on how such consistency can best be achieved within the scope of this proposed rule.[14] Consistency in the inputs and assumptions feeding these cases and scenarios will allow for neighboring transmission planners and planning coordinators to work together towards cost-effective corrective actions, like increasing transfer capability, that could otherwise be missed for lack of apples-to-apples comparisons.

10. In addition, I encourage NERC to set forth a process that provides for consultation with states in the development of corrective action plans, given that many components of such plans could be state jurisdictional. As we see in other contexts, states' jurisdiction over their resource mix and the Federal Power Act's separation of authority between FERC and states means that consideration of some of the more cost-effective options for corrective actions, including reducing demand through energy efficiency and other demand side resource development, cannot be properly facilitated without state partnership.[15] States' decisions regarding the siting of generation and transmission facilities may also be impacted by extreme weather.[16] Consulting with states will both ensure that opportunities for addressing reliability changes with state-jurisdictional solutions are not missed, and provide a path to regulatory approval of such solutions in a manner that ensures both FERC and state regulators are informed of the costs and benefits of different corrective actions.[17] High-level coordination would also allow for harmony between the extreme weather modeling methods of states and those of NERC, such as ''referring to an agreed set of climate modeling parameters or scenarios,'' where appropriate in developing their own solutions.[18]

11. Further, in considering how to address the aims of this proposal cost effectively, it is important for NERC and stakeholders to consider how this proposal to reform TPL–001–5.1 may interact with the Commission's notice of proposed rulemaking on regional transmission planning and cost allocation.[19] That NOPR proposes to require transmission planners to engage in probabilistic, scenario-based planning for longer-term system needs, including at least one extreme weather scenario, but exempts shorter-term reliability planning from this scenario planning requirement. Since efficiencies are gained when considering multiple drivers for new transmission investment and it is likely that some amount of the corrective action that may emerge from the new reliability standard involves regional or interregional transmission development, it is important to derive stakeholders' perspectives on how potential performance standards and corrective actions under a revised reliability standard interact with both shorter-term reliability and proposed longer term planning, both in terms of consistency in planning inputs and the selection of cost-effective solutions. For instance, processes may be established to prioritize finding solutions via long-term planning in the first instance wherever possible, or to incorporate multiple drivers and probabilistic benefit cost assessments into the reliability planning process, so as to leverage the benefits of multi-value planning.

B. Need for Further Actions To Ensure System Reliability

12. The Commission developed a robust record in response to the Commission's technical conference on climate change, extreme weather, and electric system reliability, and the Commission's technical conference to discuss resource adequacy developments in the Western Interconnection.[20] Today's NOPR will facilitate better planning for extreme weather events, but the record in those dockets, as well as in the Commission's inquiry into potential improvements in transmission system planning,[21] suggests action is necessary on several fronts to better facilitate cost-effective solutions. It is important to highlight three areas for which further inquiry is merited: [22] (1) increasing interregional transfer capability; (2) improving transmission scheduling and coordination in non-RTO regions; and (3) ensuring that planning and market mechanisms properly reflect resource availability during extreme weather

[11] *See, e.g.,* Comments of Environmental Defense Fund and Columbia Law School Sabin Center for Climate Change Law, Docket No. AD21–13, at 3 (filed Sept. 27, 2021) (''[C]hanges to the availability of water for cooling at thermal power plants and for hydroelectric generation will depart from historical patterns.''); Comments of the California Independent System Operator, Docket No. AD21–13 at 3 (filed April 15, 2021) (noting that drought already ''has affected the availability of hydroelectric facilitates in some years'').

[12] Comments of the Oregon Public Utility Commission, Docket No. AD21–13, at 2 (filed Apr. 14, 2021).

[13] Extreme Weather NOPR at P 52.

[14] *See* Comments of the Institute for Policy Integrity Docket No. AD21–13, at 8 (filed Apr. 14, 2021) (emphasizing potential benefits of consistent modeling practices); *see also* Pre-Technical Conference Comments of Exelon Corporation Docket No. AD21–13, at 14 (filed Apr. 15, 2021) (suggesting a process by which regulators and experts could ''define a reasonable range of scenarios describing potential climate-change related weather events and longer-term climate patters over the coming decades'').

[15] *See* Comments of PJM Interconnection, L.L.C. Docket No. AD21–13, at 9 (filed Apr. 15, 2021) (''[C]oordination with states (including state permitting agencies) on climate change and extreme weather events [is] critical.''); Comments of the R Street Institute Docket No. AD21–13, at 15 (filed Apr. 15, 2021) (''It is imperative for future reliability policy to harmonize the actions of federal and state authorities, at least to a basic degree.''); *see also* Motion to Intervene and Comments of the National Association of Regulatory Utility Commissioners Docket No. AD21–13, at 2 (filed Apr. 14, 2021) (urging the Commission to confer with the states ''where climate change and extreme weather events may implicate both federal and state issues'').

[16] *See* Comments of the National Rural Electric Cooperative Association Docket No. AD21–13, at 13 (filed Apr. 15, 2021). *See also id.* (''Most of the necessary decision-making and policy-making'' with regard to extreme weather ''will be at state and local levels.'').

[17] *See* Comments of the Institute for Policy Integrity, Docket No. AD21–13, at 8 (filed Apr. 14, 2021) (coordination would ''facilitat[e] state efforts to encourage development of flexible resources'').

[18] *Id.*

[19] Regional Planning NOPR, 179 FERC ¶ 61,028.

[20] *See* Docket Nos. AD21–13 and AD21–14.

[21] *See* Docket No RM21–17.

[22] While this statement highlights key priority areas for further inquiry, it is not intended to be exclusive. *See supra* n. 10.

events, accounting for the possibility of common mode failures or other correlated outages.

1. Increasing Interregional Transfer Capability

13. Numerous commenters have highlighted that interregional transfer capability renders the grid more resilient to extreme weather events.[23] As a recent report from The Brattle Group summarizes, ''[n]umerous studies have confirmed the significant benefits of expanding interregional transmission in North America, demonstrating that building new interregional transmission projects can lower overall costs, help diversify and integrate renewable resources more cost effectively, and reduce the risk of high-cost outcomes and power outages during extreme weather events.'' [24]

14. Yet Eversource Energy observes that ''[d]espite numerous studies suggesting the importance of increased interregional ties, most planning regions do not currently perform regular studies to assess whether increased interregional transmission capability could increase reliability during severe weather events.'' [25] This gap in planning, along with many other barriers to constructing interregional transfer capability,[26] threatens to dissuade transmission planners and planning coordinators from pursuing enhanced interregional transfer capability as a corrective action strategy, even where it is the most effective solution for customers.

15. As highlighted in section A above, consistent benchmark cases, scenarios, and other modeling practices will help to facilitate transmission planners and planning coordinators' pursuit of shared solutions, such as enhanced interregional transfer capability. Yet even with a common framework, coordination between regions is likely to prove challenging. Setting a minimum level of transfer capability could provide a unified planning goal for neighboring regions and thereby ameliorate this planning challenge.[27] American Electric Power (AEP) recommends that ''a minimum interregional transfer capability should be established through a thorough risk assessment on a nationwide, and region to region basis, using sensitivity analyses on the frequency of extreme weather events, projections of climate change impacts, and project retirements, constraints, and load changes over various timelines.'' [28] A capability requirement might vary, for instance, according to a region's generation mix, load, weather, and correlation with neighboring regions across these various attributes, and would protect system reliability by ''provid[ing] the ability to access additional generation in the event local (or even regional) generation is unable to serve customers or maintain reliability.'' [29]

16. A process for setting interregional transfer capability requirements could address a gap in existing regulation. As AEP argues, ''[b]ecause the current process evaluates transfer capability on a regional, or balancing authority-specific basis,'' it does not capture ''the efficiencies'' of connections ''between the regions.'' [30] ''[F]ailure to evaluate the grid as a whole makes the grid more susceptible to . . . the impacts of increasingly extreme weather events that impact large geographic areas,'' rendering ''the overall resilience and reliability the transmission grid less robust than it could be.'' [31]

17. As this discussion suggests, both section 215 and section 206 of the Federal Power Act are implicated by the development of interregional transfer capability. I urge stakeholders and this Commission to further explore whether section 215, section 206, or a combination thereof may serve as the basis for establishing specific minimum interregional transfer capability requirements or otherwise establishing least regrets interregional planning targets.

2. Improving Transmission Scheduling and Coordination in Non-RTO Regions

18. Enhanced transmission scheduling and coordination between balancing area authorities—in particular, RTO-to-non-RTO and non-RTO-to-non-RTO coordination—would improve grid reliability during extreme weather events, lower costs for customers, and level the regulatory playing field between RTO and non-RTO regions. Transmission scheduling and coordination can potentially be improved both via mandating a transition to flowgate methodology for determining transmission capacity in areas that continue to use path-based methodologies, and via facilitation of economic redispatch and narrowing the circumstances under which transmission curtailment procedures are permissible.

19. As leading electricity market economists have observed, ''in an electricity network, power flows along parallel paths dictated by physical laws rather than the contract path, creating widespread externalities whose complexity grows with network size.'' [32] Without ''an appropriate mechanism to allocate transmission capacity'' according to true flow, market participants ''are unlikely to take into consideration the effects of power flows that diverge from the contract path.'' [33] Despite the efficiencies of a flow-based method, however, the Reliability Standards continue to permit entities to choose either a path-based or a flow-based method of transmission method,[34] with most entities in the Western

[23] *See* Post-Conference Comments of American Electric Power, Docket No. AD21–13, at 8 (filed Sept. 27, 2021) (arguing that increased interregional transfer capability is ''an important component of meeting the challenges'' extreme weather poses for the system); Post-Conference Comments of Midcontinent Independent System Operator Inc., Docket No. AD21–13, at 23 (filed Sept. 27, 2021) (finding interregional transfer capacity improves the resilience of the power system); Comments of Americans for a Clean Energy Grid, Docket No. AD21–11 (filed Feb. 22, 2022), Attachment 1: Grid Strategies LLC, *Fleetwide Failures: How Interregional Transmission Tends to Keep the Lights On When There is a Loss of Generation* (Nov. 2021), Attachment 2: Grid Strategies LLC, *Transmission Makes the Power System Resilient to Extreme Weather* (July 2021), Attachment 3: Grid Strategies, LLC, *The One-Year Anniversary of Winter Storm Uri, Lessons learned and the Continuing Need for Large-Scale Transmission* (Feb. 13, 2022), Attachment 4: General Electric International, Inc., *Potential Customer Benefits of Interregional Transmission* (Nov. 29, 2021), and Attachment 5: Pfeifenberger et al., *A Roadmap to Improved Interregional Transmission Planning* (Nov. 30, 2021); Initial Comments of PJM Interconnection, L.L.C., Docket No. RM21–17, at 72–73 (filed Oct. 12, 2021) (''Greater interregional transfer capability has a significant reliability benefit for both adjoining regions as demonstrated . . . by the February 2021 Cold Snap and the 2014 Polar Vortex.'') (emphasis omitted).

[24] Pfeifenberger et al., *A Roadmap to Improved Interregional Transmission Planning* (Nov. 30, 2021) at iii, available at *https://www.brattle.com/wp-content/uploads/2021/11/A-Roadmap-to-Improved-Interregional-Transmission-Planning_V4.pdf; see also id.* at 2, Table 1, Summary of Select Recent Interregional Transmission Studies.

[25] Post-Conference Comments of Eversource Energy, Docket No. AD21–13, at 6–7 (filed Sept. 27, 2021).

[26] *See* Pfeifenberger et al. at 4–5 (summarizing barriers to interregional transmission planning and development).

[27] *See, e.g.,* Post-Conference Comments of PJM Interconnection, L.L.C., Docket No. AD21–13, at 19–20 (filed Apr. 15, 2021) (noting that a ''national standard or recommended planning driver for bi-directional transfer capability'' would facilitate ''interregional coordination'').

[28] Post-Conference Comments of American Electric Power, Docket No. AD21–13, at 10 (filed Sept. 27, 2021).

[29] *Id.* at 9–10.

[30] *Id.* at 9.

[31] *Id.*

[32] Chao et al., *Flow-based Transmission Rights and Congestion Management,* Electricity Journal at 39 (2000), available at *https://oren.ieor.berkeley.edu/pubs/flowbase.pdf.*

[33] *Id.*

[34] NERC Reliability Standard MOD–29 sets forth requirements for path-based transmission management, while Reliability Standard MOD–30 sets forth the requirements for a flow-based method.

Interconnection continuing to use the less efficient path-based method.[35]

20. Arizona Public Service and Public Service Company of Colorado argue that ''the path based approach results in less efficient transmission system use and could hamper the contracting and delivery of capacity resources across the Western Interconnection.'' [36] By contrast, ''a flow-based methodology, through its more realistic assessment of impacts to the entirety of the transmission system, in general enables greater utilization of the system as a whole.'' [37] As the West faces increased frequency and duration of extreme weather events, achieving maximum reliability value from all existing infrastructure is imperative.[38] This raises the question whether the Reliability Standards should require all applicable entities to transition to a flow-based methodology.

21. Beyond ensuring that transmission capacity is measured and scheduled in a manner that better matches the reality of the system, the Commission should explore complementary action to improve the ability of non-RTO system operators to provide transmission service when the grid is constrained. Transmission Loading Relief (TLR) procedures and Qualified Path Unscheduled Flow Relief (USF) procedures, the default methods of managing transmission congestion between balancing areas outside of RTO/ISO markets, are blunt instruments that in some cases fail to facilitate power transfers that would aid system reliability during extreme weather, and in other cases impose higher overall costs than appropriate redispatch of generation. As MISO highlights in its post-technical conference comments in Docket No. AD21–13, TLR fails to ''assure reliable service'' because it ''reli[es] on curtailment of interchange transactions.'' [39] TLR and USF procedures curtail transactions in a pre-set priority order, without locational marginal pricing or another adequate mechanism to guide them toward redispatching generation to facilitate optimal transmission flows. By contrast, economic ''[r]edispatch offers a way, in the vast majority of circumstances, to ensure that all transactions continue to be served despite transmission congestion.'' [40] RTO and ISOs generally utilize TLRs to mitigate an overload only where they have ''exhausted all other means available, short of load shedding.'' [41]

22. While the existing pro-forma Open Access Transmission Tariff (OATT) currently permits a transmission provider to use redispatch to maintain reliability during transmission constraints,[42] David Patton of Potomac Economics, the independent market monitor for NYISO, MISO, ISO–NE, and ERCOT, testified at the extreme weather technical conference that he was ''unaware in non-market areas of any redispatch that's actually being provided in order to supply transmission service.'' [43] The Commission should investigate how it may be able to facilitate economic redispatch in non-RTOs and reduce usage of TLRs and USFs in these areas. I am not aware of any systematic examination of the magnitude of potential benefits to improved coordination practices, but they are likely significant. During winter storm Uri, sophisticated RTO transmission scheduling practices facilitated the flow of between 10,000 and 14,000 MW from PJM to support operations in MISO and beyond.[44] Yet the use of such practices is not universal. TLRs were invoked on average over 200 times per year in the Eastern Interconnection across the past four years.[45] Public data for USFs, used across the Western Interconnection where economic redispatch is less prevalent, is not available.

23. I encourage non-RTO system operators to take action to improve their transmission scheduling practices, to highlight for the Commission challenges that they face in doing so, and to identify potential solutions to those challenges. Absent voluntary improvements by non-RTO system operators, I believe it would be appropriate for the Commission to consider requiring changes to the *pro forma* OATT to mandate transmission scheduling improvements. As MISO argues, ''greater grid connectedness that has developed since Order No. 890, emerging reliability needs not met by the status quo, including the TLR process, and the inflexibility of the TLR process in responding to extreme weather . . . have potentially created conditions that may make the lack of reliability redispatch to bordering utilities potentially unjust and unreasonable.'' [46]

24. While some commenters endorsed the general idea of improving transmission scheduling practices,[47] MISO was the only entity to provide detailed recommendations and factual support for doing so.[48] MISO provides several suggestions to the Commission, including (1) encouraging seams agreements that require non-RTOs/ISOs to compensate RTOs/ISOs for redispatch provided through market flows and for RTOs/ISOs to compensate non-RTOs/ISOs for reliability redispatch, when the market flows or the reliability redispatch are the more economical solution to a congestion problem at their seam, (2) allowing an RTO/ISO to file a presumptively just and reasonable unexecuted joint operating agreement or other agreement incorporating such redispatch provisions in cases where an RTO/ISO cannot reach agreement with a neighboring non-RTO/ISO transmission provider on joint redispatch,[49] (3) clarifying that the reliability redispatch provided under OATT section 33.2 is

[35] *See* Joint Comments of Arizona Public Service Company and Public Service Company of Colorado, Docket No. AD21–14, at 5–6 (filed Jan. 31, 2022).

[36] *Id.* at 5.

[37] *Id.* at 6.

[38] *See* Technical Conference Tr., June 24, 2021, Docket No. AD21–14–000, at 301:14 (Chairman Glick: ''I'm wondering if there are things we can do in the near term . . . that would help facilitate and improve [the] resource adequacy situation or at least improve [the] reliability situation.''); 307:2 (Amanda Ormond, in response: ''I want to just talk about efficiency of the existing transmission system because we certainly need to get more out of what we have, and Alice Jackson from [X]cel mentioned the flow-based [methodology] as you did. I think that's really important that we move to a flow[-based methodology] because [that would facilitate] know[ing] more about what's on the system where.'').

[39] Post-Conference Comments of Midcontinent Independent System Operator, Docket No. AD21–13, at 10 (filed Sept. 27, 2021).

[40] *Id.*

[41] *See, e.g.,* PJM Manual 37, Reliability Coordination § 4.1; Southwest Power Pool, *Congestion Management & Communication Processes,* 5, 12–13 (2013).

[42] *See pro forma* OATT § 33.2 (providing that network and native load resources will be redispatched without regard to ownership on a least cost basis to provide the amount of congestion relief assigned to all network and native load customers, and that the costs of such redispatch will be allocated on a load ratio share basis).

[43] *See* Technical Conference Tr., June 2, 2021, Docket No. AD21–13–000, at 67:21–23 (filed July 22, 2021).

[44] *See* Technical Conference Tr., Docket No. AD21–13, at 64:5–7 (Renuka Chatterjee) (filed July 22, 2021) (stating that PJM sent 10,000 to 14,000 MW to MISO and areas west of MISO during the February event).

[45] *See* NERC, TLR Logs, available at *https://www.nerc.com/pa/rrm/TLR/Pages/TLR-Logs.aspx* (last accessed June 14, 2022).

[46] Post-Conference Comments of Midcontinent Independent System Operator, Docket No. AD21–13, at 11 (filed Sept. 27, 2021).

[47] *See, e.g.,* Post-Conference Comments of Natural Resources Defense Council, Sierra Club, Sustainable FERC Project, and Union of Concerned Scientists, Docket No. AD21–13, at 13 (filed Sept. 27, 2017) (arguing that improved coordination of exports and imports between RTOs/ISOs and non-RTO/ISO regions will enhance system resilience); Post-Conference Comments of the Michigan Public Service Commission, Docket No. AD21–13, at 10 (filed Sept. 24, 2021) (strongly supporting improved coordination and management at market seams).

[48] *See* Post-Conference Comments of Midcontinent Independent System Operator, Docket No. AD21–13, at 10 (filed Sept. 27, 2021).

[49] *Id.* at 9, 14–15.

available sub-hourly,[50] and (4) modifying OATT section 33.2 to permit redispatch not just by network resources of the transmission provider and its network transmission customers, but also from other generators including merchants.[51] It also more broadly recommends ''[m]odifying the *pro forma* OATT to require least cost dispatch of a transmission provider's resources and to require network resources to manage seam congestion'' such ''that, in addition to requiring reliability redispatch when feasible to relieve constraints within the transmission provider's own system, the transmission provider is also required to provide such service to each of its directly-connected public utility neighbors (or non-jurisdictional transmission providers that provide reliability redispatch) prior to implementing TLR procedures.'' [52]

25. These recommendations warrant serious consideration. A more robust record is necessary to examine these ideas and other potential actions to improve transmission system scheduling, management, and coordination. I encourage stakeholders to bring forth proposals to the Commission on this topic, and to provide comments and information pertinent to the ideas discussed herein. I further recommend that the Commission take action to gather more information on these issues, such as by issuing a notice of inquiry, an order directing reports from NERC and the relevant Balancing Authorities, or a combination thereof, in order to gather more information on the use of path based management as well as USFs and TLRs,[53] the potential benefits of improved transmission scheduling, management, and coordination practices, and how such improvements could be achieved. Such proceedings could gather data on the extent to which additional transmission capacity could be freed up via a transition to flowgate methodologies, and the extent to which TLR and USF procedures are unnecessarily curtailing transmission that could have otherwise been facilitated by economic redispatch. They could also examine how non-RTO market operators could implement economic redispatch in the absence of organized markets setting locational marginal prices.

3. Properly Accounting for Resource Availability During Extreme Weather

26. As many commenters stressed in response to the Commission's technical conference examining extreme weather, another pressing issue is the need to ensure that planning procedures, resource adequacy mechanisms, and reserves markets appropriately reflect the availability of resources during extreme weather events, properly accounting for common mode outages or other correlated outages.[54]

27. Resource adequacy methodologies, in particular, are an area where accurately assessing anticipated availability of resources is critical so as to ensure that applicable planning and market design achieves the desired target level of system reliability. Commenters at the extreme weather technical conference generally agreed that existing methods are outdated and do not appropriately reflect extreme weather.[55] Failure to appropriately account for resource availability jeopardizes the reliability of grid systems in extreme weather, so doing the hard work of updating these methodologies is an urgent concern.

28. NYISO and PJM have made significant strides recently in establishing processes to ensure that their capacity markets better account for correlated availability of resources,[56] but more work is needed to implement these mechanisms, and to ensure that they are fairly assessing the contributions of different resource types. While NYISO's approved proposal explicitly contemplates extending this methodology to all resource types (albeit while providing very limited detail on *how* it will do so),[57] PJM's approved method is confined to wind, solar, storage, and hybrid resources.[58] ISO–NE's external market monitor has argued that applying ELCC to thermal resources would better reflect their value.[59]

29. Further inquiry is necessary to investigate appropriate methodologies for accounting for correlated outages of resources during extreme weather, including common mode outages related to unavailable fuel supply such as gas-fired resources without fuel during winter events or hydro-electric resources experiencing drought conditions, and correlated de-rates that may occur in relation to extreme weather such as difficulty cooling thermal facilities. I urge stakeholders, grid operators, and my colleagues at the Commission to work expeditiously to address these questions and facilitate appropriate market reforms.

C. Conclusion

30. As the Extreme Weather NOPR highlights, climate change poses a severe reliability threat to the bulk electric system. Addressing that threat is

[50] *Id.* at 11–12.

[51] *Id.* at 13.

[52] *Id.* at 11.

[53] NERC publishes data on TLR events on its website, but does not provide easily accessible information regarding the circumstances necessitating TLR usage. *See https://www.nerc.com/pa/rrm/TLR/Pages/TLR-Logs.aspx* (last accessed June 13, 2022). I am not aware of public data on the use of USFs in the Western Interconnection.

[54] *See, e.g.,* Comments of Buckeye Power, Inc., Docket No. AD21–13 at 7 (filed Apr. 15, 2021) (''[N]ew planning criteria for resource adequacy should be developed that expressly address extreme weather events and other unusual scenarios that can threaten reliability.''); Comments of Tabors Caramanis Rudkevich, Docket No. AD21–13, at 10–11, 21–24 (filed Apr. 15, 2021) (stating that seasonal resource adequacy assessments ''do not . . . adequately account for either common mode events or extreme events perceived to have a low probability,'' and advocating for ''the adoption of advanced resource adequacy methodologies and technologies that are capable of evaluation of large numbers of stochastically generated scenarios that incorporate and quantify both common mode events and the probability of extreme events''); Comments of Dominion Energy Services, Inc., Docket No. AD21–13, at 5 (filed Apr. 15, 2021) (''Constraints arising on natural gas pipelines during extreme weather may also impact the viability of operating reserves relied upon by the Regional Transmission Organizations,'' potentially leaving them ''with a false sense of security that [they have] a sufficient amount of operating reserves'' when that is not the case.); Comments of LS Power Development, LLC, Docket No. AD21–13, at 4 (filed Apr. 15, 2021) (''[P]lanning procedures must recognize and account for common mode failure among various resource classes with respect to particular weather events and require protections and redundancies to prevent catastrophic failures like those that occurred in Texas.'').

[55] *See, e.g.,* June 1, 2021 Tr. at 31:15 (Lisa Barton) (''[T]he current deterministic planning methodology that we have used today [ ] works when supply is highly dispatchable[,] when weather is predictable[, and] when peak demand is reached only a few days a year,'' and ''fundamentally needs to change'' to address current conditions); 112–113, 127–128 (Mark Lauby) (highlighting the outdated nature of 1-in-10 LOLE, and noting that it was developed on the assumption that generator forced outages are independent, an unrealistic assumption given the likelihood of common mode events caused by extreme weather); at 118 (Richard Tabors) (''Our resource adequacy metrics and planning methods systematically understate the probability, the depth, and economic health and safety costs of high impact events.'').

[56] *See PJM Interconnection, L.L.C.,* 176 FERC ¶ 61,056, at P 3 (2021) (approving a proposal by PJM to implement an ELCC methodology for crediting variable and limited duration resources); *New York Independent System Operator,* 179 FERC ¶ 61,102, at PP 75–82 (2022) (approving NYISO's proposal to implement a marginal capacity accreditation design via either ELCC or a similar Marginal Reliability Improvement technique).

[57] 179 FERC ¶ 61,102 at PP 79, 90.

[58] 176 FERC ¶ 61,056 at P 7.

[59] *See* Potomac Economics, *2020 Assessment of the ISO New England Electricity Markets,* June 2021 at 92 (''EFORd alone does not accurately describe'' the reliability value of ''intermittent renewables, energy-limited resources, long lead time or very large conventional generators, and generators that can experience a common loss of a limited fuel supply'' because ''these resource types pose the risk of correlated outage or limited availability of a large amount of capacity under peak conditions''), and 84 (arguing that the availability of these resource types is overestimated in GE–MARS, ISO–NE's resource adequacy model).

a multi-faceted challenge posing complex issues for which there is no single answer. However, if implemented in a comprehensive and cost-effective manner, today's NOPR promises to be an important and prudent step forward in protecting customers against the effects of extreme weather. By taking complementary actions in the future that build on this step, the Commission will continue to fulfill its responsibility of ensuring bulk electric system reliability.

For these reasons, I respectfully concur.

Allison Clements,

Commissioner.

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Transmission System Planning Performance Requirements for Extreme Weather

Docket No. RM22–10–000

(Issued June 16, 2022)

PHILLIPS, Commissioner, *concurring:*

1. I concur in today's Notice of Proposed Rulemaking [1] to emphasize the critical importance of ensuring that the Bulk-Power System is prepared for extreme weather events in both the near-term and long-term. While this NOPR has the potential to reduce the threat to the reliability of the electric system, I note that we must remain vigilant as much work remains to ensure reliable delivery of power to consumers during times of stress and to resolve resilience concerns on the transmission system.

2. Climate change and extreme weather are, of course, complex issues of enormous importance to the United States. In my view, this NOPR is another step on the path to mitigating the long-term effects of extreme weather; however, I remain concerned about the grid's near-term reliability, particularly during the upcoming summer and winter seasons.[2] Still, with that in mind, I am voting in favor of issuing this NOPR because it is needed as an incremental improvement to Reliability Standard TPL–001–5.1 (Transmission System Planning Performance Requirements), which I believe currently contains a reliability gap.[3]

3. The NOPR proposes to direct NERC to modify Reliability Standard TPL–001–5.1 to require the development of benchmark planning cases based on past extreme heat and cold weather events.[4] Currently, Reliability Standard TPL–001–5.1 does not prescribe specific benchmarks, and I believe determining and using the appropriate benchmark will lead to better planning. While extreme weather can be unpredictable, applying a suitable benchmark study should lead to understanding resource availability and load shedding requirements under harsh conditions. Indeed, using benchmarks may also improve interregional coordination when load shedding and cascading outages occur.[5]

4. The NOPR also proposes to direct NERC to modify Reliability Standard TPL–001–5.1 to require corrective action plans when performance requirements for extreme heat and cold weather events are not met.[6] Currently, the reliability standards require that responsible entities evaluate possible actions to reduce the likelihood or mitigate the consequences of such events. These entities, however, are not obligated to take corrective actions to ensure such failures do not happen again.[7] I believe this NOPR rightly identifies this gap and assures that transmission planners rigorously address uncertainties surrounding extreme weather events in the planning process.

5. Looking forward, and beyond the important charge we have proposed here, I believe the Commission should next consider further interregional reliability planning reforms. When we issued a NOPR on regional transmission planning and cost allocation in April, I said in my concurrence:

As we continue to examine those issues, I urge the Commission to act expeditiously to propose interregional reliability planning reforms. Looking beyond regional boundaries is important so that cost-efficient regional and interregional projects can be considered and studied together. We should consider whether neighboring regions should adopt common planning assumptions and methods that allow for region-specific inputs. Additionally, I believe we must consider whether to adopt a requirement for a minimum amount of interregional transfer capacity to protect against shortfalls, especially during extreme weather events.[8]

I note we will continue to develop the record in our proceeding on regional transmission planning and cost allocation, and in response to today's NOPR. We should examine these and other records closely to determine the best course of further action on this ripe issue.

6. The regional nature of extreme weather highlights the difficulties facing our industry in addressing highly variable risks. The challenges facing California are very different from the challenges facing Texas. I believe a minimum transfer capability requirement is needed, because enhanced transfer capability may be the best way to take advantage of the diversity of energy sources and the many ways in which we can support the grid. Order No. 1000 was intended to encourage more interregional planning and development,[9] but, simply put, interregional projects are not being constructed,[10] and transfer capacity in

[1] *Transmission System Planning Performance Requirements for Extreme Weather,* 179 FERC ¶ 61,195 (2022) (NOPR).

[2] On August 24, 2021, the Commission approved revised Reliability Standards to address certain reliability risks posed by extreme cold weather. *Cold Weather Reliability Standards,* 176 FERC ¶ 61,119, at P 1 (2021).

[3] To its credit, in the wake of Winter Storm Uri, the North Electric Reliability Corporation (NERC) issued a level 2 NERC Alert to industry on cold weather preparations for extreme weather events, which acknowledged the reliability risks associated with more frequent extreme weather conditions. NERC, *Alert R–2021–08–18–01 Extreme Cold Weather Events* (Aug. 18, 2021) (''The recent extreme cold weather events across large portions of North America have highlighted the need to assess current operating practices and identify some recommended improvements, so that system operations personnel are better prepared to address these challenges. The events have caused major interruptions to resources, transmission paths and ultimately, end-use customers.'').

[4] NOPR at PP 51–56.

[5] *See infra* at PP 6–8.

[6] NOPR at PP 6, 83.

[7] *Id.* at P 83 (''[P]lanning coordinators and transmission planners are required to evaluate possible actions to reduce the likelihood or mitigate the consequences of extreme events but are not obligated to developed corrective action plans. Specifically, if such events are found to cause cascading outages, they need only be evaluated for possible actions designed to reduce their likelihood or mitigate their consequences and adverse impacts [citation removed]. Accordingly, because of their potential severity, we believe that extreme heat and cold weather events should require evaluation and the development and implementation of corrective action plans to help protect against system instability, uncontrolled separation, or cascading failures as a result of a sudden disturbance or unanticipated failure of system elements.'').

[8] *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* 179 FERC ¶ 61,028 (2022) (Phillips, Comm'r, concurring, at P 7).

[9] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g,* Order No. 1000–A, 139 FERC ¶ 61,132 (2012), *order on reh'g and clarification,* Order No. 1000–B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. D.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d 41 (D.C. Cir. 2014).

[10] *See* Americans for a Clean Energy Grid, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure, https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG_Planning-for-the-*

effect has been limited. Many commenters also point out the importance of adopting a minimum level of interregional transfer capability.[11]

7. Indeed, Winter Storm Uri highlighted the need for establishing a minimum level of interregional transfer capability. Almost half of the Electric Reliability Council of Texas (ERCOT) was forced out during the storm, which prompted cascading outages in Texas.[12] The Midcontinent Independent System Operator, Inc. (MISO) and the Southwest Power Pool (SPP) also experienced generation loss during the winter storm, but were able to request assistance from each other and from PJM Interconnection, L.L.C. (PJM) through their transmission interconnections.[13] As such, SPP maintained service for most of its load, except for a small portion of its customers over two of its areas.[14] Conversely, ERCOT was unable to avail itself of sufficient mutual assistance during Uri because of its limited transfer capabilities.[15] Therefore, I believe it is important that we consider proposing a minimum level of interregional capacity to aid in times of severe stress. I urge stakeholders to comment on the steps the Commission can take to facilitate a minimum level of interregional transfer capability, and whether there are ways to support existing interregional coordination methods.

8. I also encourage stakeholders to comment on whether the Commission should require revisions to RTO/ISO generation and transmission outage scheduling practices. Planned generation and transmission outages are critical for facilitating needed equipment maintenance. Failure to perform such maintenance in a timely fashion can lead to increased risks of failure of such facilities, including the potential for unscheduled, forced outages—outages that could negatively affect the reliability of the grid. Therefore, my preference is to develop a further record regarding whether RTOs/ISOs should have wider discretion to coordinate planned outages to make sure all resources and equipment are available at the time of a reliability event, which sometimes can be incredibly hard to predict.

9. By way of example, not all RTOs/ISOs are able to delay or cancel planned outages for economic reasons, even though the estimated economic impact of the outage could signal a vulnerability to a reliability issue if there is another outage in the same area.[16] Given our growing need to rely on these facilities during the shoulder months, I believe that planned generation and transmission outages could increasingly be a driver of reliability concerns, especially should an extreme weather event occur. Therefore, I urge stakeholders to comment on the provisions in RTO/ISO tariffs regarding the authority to recall or cancel planned outages, and whether those practices ensure that all possible resources can be called upon to assist during extreme weather events. I am also interested in whether rules requiring replacement capacity in the event of extended outages would address these scheduling issues.

10. Further, I would support a FERC/NERC joint effort to consult with state and local regulators on these complex issues, especially as more states are taking increasingly ambitious actions throughout the country to stem the effects of climate change and extreme weather. I believe it is beneficial to increase coordination with states and state regulators because climate change and extreme weather issues raise difficult challenges that will be novel to all relevant jurisdictions.[17] State and federal regulators must endeavor to pursue reliability solutions that are in accord with one another. In addition, while state and local action is vital to preventing the worst effects of extreme weather, federal leadership is also critical. State regulators may not have visibility into how the Bulk-Power System may respond to reliability events, so greater coordination with federal authorities would allow them to answer local stakeholders as to how the entire system is performing country-wide.[18] I encourage stakeholders to comment on whether and to what extent FERC, NERC, and state and local regulators can better coordinate on extreme weather reliability matters.

11. Finally, I note that this NOPR is not set in stone and only asks for comments in response to proposed directives to NERC. There is much good in this NOPR, and there is much more

Future1.pdf (''For all of the best efforts of the Commission and regional planning authorities, the current set of transmission regulations have resulted in inadequate levels of infrastructure that have burdened the interconnection process with the task of planning new network facilities—a task that should instead take place in the planning process. Further, existing regulations have created a system that disproportionally yields projects that address only local needs, that address reliability without more broadly assessing other benefits, or that simply replace old retiring transmission assets with the same type and design despite the potential for larger projects to more cost effectively meet the same needs.'').

[11] *See, e.g.,* AEP Post-Conference Comments, Docket No. AD21–13–000, at 8–12 (filed Sept. 27, 2021) (''The need for regions to assist each other in extreme weather events has become more frequent over the past decade, thus highlighting the value, and limitations, of current interregional transmission capabilities.''); Michigan Public Service Commission Post-Conference Comments, Docket No. AD21–13–000, at 12–13 (filed Sept. 24, 2021) (stating that it supports improving existing interregional coordination methods, such as a target level of interregional transfer capacity a target level of regional transfer capacity, to prepare for extreme weather events); PJM Interconnection, L.L.C. Post-Conference Comments, Docket No. AD21–13–000, at 19–20 (filed Sept. 27, 2021) (stating that a DOE National Labs study can identify transfer metrics to evaluate an appropriate level of import/export capability by balancing authority in terms of percentage of load); Public Interest Organizations Post-Conference Comments, Docket No. AD21–13–000, at 22–23 (filed Sept. 27, 2021) (discussing different methodologies for achieving a minimum level of interregional transfer capacity).

[12] *See* Testimony of James Robb, NERC President and Chief Executive Officer, before the Subcommittee on Oversight and Investigations Committee on Energy and Commerce, United States House of Representatives, ''Power Struggle: Examining the 2021 Texas Grid Failure,'' Mar. 24, 2021, *https://energycommerce.house.gov/sites/democrats.energycommerce.house.gov/files/documents/Witness%20Testimony_Robb_OI_2021.03.24.pdf.*

[13] FERC–NERC Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas, and the South-Central United States,* at 14, 66, 127, 141, 167 (Nov. 2021) (2021 Cold Weather Report).

[14] 2021 Cold Weather Report at 10–11.

[15] 2021 Cold Weather Report at 183 (''ERCOT, unlike MISO and SPP, . . . did not have the ability to import many thousands of MW from the Eastern Interconnection, and thus needed to shed the greatest quantity of firm load to balance electricity demands with the generating units that were able to remain online.'').

[16] *See* Eversource Post-Conference Comments, Docket No. AD21–13–000, at 5 (filed Sept. 27, 2021) (''As noted by the Commission, ISO–NE already has the ability to deny outages based on economic impact.''); *but see* MISO Post-Conference Comments, Docket No. AD21–13–000, at 19 (filed Sept. 27, 2021) (explaining that when reliability concerns are present, MISO works with generators to explore rescheduling outages).

[17] *See, e.g.,* PJM Pre-Conference Comments, Docket No. AD21–13–000, at 9 (filed Apr. 15, 2021) (explaining that coordination with states on climate change and extreme weather events is of utmost importance in the role of retail regulators and other federal agencies); Speaker Materials of Devin Hartman, R Street Institute, at the Technical Conference to Discuss Climate Change, Extreme Weather and Electric System Reliability, Docket No. AD21–13–000, at 1 (filed June 3, 2021) (discussing many reliability deficiencies, which include disjointed state-federal coordination and siloed reliability institutions); *see also* Motion to Intervene and Comments of the National Association of Regulatory Utility Commissioners, Docket No. AD21–13–000, at 2 (filed Apr. 15, 2021) (''The Commission most certainly should confer with the states . . . where climate change and extreme weather events may implicate both federal and state issues.'').

[18] *See* Technical Conference Tr., June 2, 2021, Docket No. AD21–13–000, at 130–131:1–25 (Letha Tawney) (''I would ask FERC to think of the state regulators in our role, in our states, as sort of the face of electricity and natural gas . . . [W]e don't have good visibility into how the bulk system is going to respond . . . And without good visibility into how the transmission system is adopting to these risks, [then we are] in a difficult position with our local stakeholders.'').

work to be done.[19] I look forward to examining all the comments as we seek to issue a final rule around these topics.

For these reasons, I respectfully concur.

Willie L. Phillips,

Commissioner.

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BILLING CODE 6717–01–P

[19] For instance, Commissioner Clements is right in pointing out that we must also take a close look at existing resource adequacy mechanisms and ancillary service markets. *See* NOPR (Clements, comm'r, concurring) at PP 26–27.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R03–OAR–2021–0944; FRL–9174–01–R3]

Air Plan Approval; Delaware; Control of Volatile Organic Compounds Emissions From Solvent Cleaning and Drying

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing to approve a state implementation plan (SIP) revision submitted by the State of Delaware. This revision pertains to the reduction of volatile organic compounds (VOC) emissions from cold solvent cleaning operations. This action is being taken under the Clean Air Act (CAA).

DATES: Written comments must be received on or before July 27, 2022.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R03–OAR–2021–0944 at *https://www.regulations.gov,* or via email to *gordon.mike@epa.gov.* For comments submitted at *Regulations.gov*, follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *Regulations.gov*. For either manner of submission, EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). For additional submission methods, please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section. For the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www.epa.gov/dockets/commenting-epa-dockets.*

FOR FURTHER INFORMATION CONTACT: Mallory Moser, Planning & Implementation Branch (3AD30), Air & Radiation Division, U.S. Environmental Protection Agency, Region III, 1650 Arch Street, Philadelphia, Pennsylvania 19103. The telephone number is (215) 814–2030. Ms. Moser can also be reached via electronic mail at *Moser.Mallory@epa.gov.*

SUPPLEMENTARY INFORMATION: On October 13, 2021, the Delaware Department of Natural Resources and Environmental Control (DNREC) submitted a revision to its SIP which comprises revisions to Title 7 of Delaware's Administrative Code (7 DE Admin. Code) 1124 Section 33.0—Solvent Cleaning and Drying. The revision to 7 DE Admin. Code 1124 Section 33.0 will reduce emissions of VOCs from cold solvent cleaning operations, thus reducing the formation of ground-level ozone.

I. Background

The revision consists of an amendment to 7 DE Admin. Code 1124, Control of Volatile Organic Compound Emissions, Section 33—Solvent Cleaning and Drying. Specifically, the amendment updates the solvent cleaning control requirements based upon the 2012 Ozone Transport Commission (OTC) Model Rule.

The OTC, of which Delaware is a member, is an organization established by Congress under the CAA. Among other things, the OTC develops model rules for the member states to use to reduce the emissions of ground level ozone precursors. In 2001, the OTC released the 2001 Model Rule for Solvent Cleaning (2001 Model Rule). The 2001 Model Rule is the basis for the version of 7 DE Admin. Code 1124, Control of Volatile Organic Compound Emissions, Section 33—Solvent Cleaning and Drying currently in the approved Delaware SIP.[1] After a release of the control techniques guideline (CTG): Industrial Cleaning Solvents by the EPA in 2006, proposing new VOC limits for solvent cleaning, the OTC convened a group of experts that suggested a more stringent model rule than what is provided in the CTG and the 2001 Model Rule. The OTC then developed the 2012 Model Rule for Solvent Degreasing (2012 Model Rule). The provisions set forth in the 2012 Model Rule are more stringent than those currently included in the Delaware SIP and form the basis of the Delaware SIP revision we are proposing to approve in this rulemaking. This revision eliminates an existing exemption by adding provisions that apply to owners or operators of a solvent cleaning machine that uses any volume of solvent containing VOC. This revision also reduces the solvent VOC concentration from 100 percent to 25 grams per liter of non-VOC solution for most applications.

Certain areas of Delaware are designated as nonattainment for ground-level ozone. Ground-level ozone is formed through the reaction of VOCs and other compounds in the air in the presence of sunlight. High levels of ground-level ozone can cause or worsen difficulty in breathing, asthma and other serious respiratory problems. In addition to improving public health and the environment, decreased emissions of VOCs, and therefore subsequently ground-level ozone, will contribute to the attainment of the ozone national ambient air quality standard (NAAQS).

By removing an applicability exemption and decreasing the allowable solvent VOC concentration, the 2012 Model Rule is expected to decrease emissions of VOCs. This reduction of VOC emissions from solvent cleaning operations will further reduce the formation of ground-ozone. Therefore, Delaware is amending their SIP to implement the updated 2012 Model Rule.

II. Summary of SIP Revision and EPA Analysis

This SIP revision, submitted by the State of Delaware on October 13, 2021, amends 7 DE Admin. Code 1124 section 33.0, Solvent Cleaning and Drying. The amendments to section 33.1 (Applicability) add provisions that apply to owners or operators of a solvent cleaning machine that uses any volume of solvent containing VOC. Therefore, the amendments eliminate the previous exemption for cold cleaning machines containing less than one liter of solvent and 5% by weight VOC. Section 33.1 also clarifies that it does not cover solvent cleaning machines that use the following hazardous air pollutants (HAPs): methylene chloride, perchloroethylene or 1,1,1-trichloroethane. Additionally,

[1] See 67 FR 70315 (November 22, 2002).