Statement of the North American Electric Reliability Corporation
2024 Reliability Technical Conference
Docket No. AD24-10-000
October 16, 2024

At its most basic level, the reliability challenge in North America is a simple math problem: **The supply of electricity is not growing fast enough to meet the growing demand for electricity.** The frequency of actual and near-miss reliability events is warning sign. Unless reliability is appropriately prioritized during the energy transition, North America is at risk of more frequent and more serious long duration reliability disruptions, including the possibility of national consequence events.

Over the next ten years, NERC's *2023 Long-Term Reliability Assessment* finds that electricity peak demand and energy growth forecasts are higher than at any point in the past two decades. In North America, by 2033, summer peak demand for electricity is forecast to increase 10%, while electricity generation is only expected to grow by 4%. This represents a reversal in the decades-long trend of falling or flat growth rates. While there are regional variations, decreasing energy and capacity reserve margins in much of North America are leading to higher risk of energy shortages during extreme conditions. Even as margins continue to decline, more is being asked of the electric grid. Ambitious electrification goals for transportation, homes and buildings, plus the growth in large load centers, can stress the grid beyond acceptable boundaries.

With oversight by the Federal Energy Regulatory Commission (FERC), the reliability regime led by NERC and the Regional Entities is mitigating risks that once challenged the BPS. By many conventional metrics, the electric transmission grid is highly reliable and resilient, and has grown more so. Yet the risk profile is steadily deteriorating. The following factors are contributing to this deterioration:

- Rapid, often disorderly, transformation of the generation resource base, with incomplete replacement of retiring generation products and services
- Performance and energy sufficiency issues associated with replacement resources as conventional units retire and are replaced with variable production inverter-based resources,
- Wide-area, long duration extreme weather events, which are becoming more frequent,
- Increased demand due to electrification, industrial repatriation, and data-center development,
- Slow development of new energy infrastructure needed to support grid resilience and the clean energy future,
- Persistent cybersecurity and physical threats.

Outside of cyber/physical security, three reliability priorities must be addressed:

- First, we must manage the pace of the transformation in an orderly way, which is currently not happening. Conventional generation is retiring at an unprecedented rate, a trend that is further accelerated by policy goals.
- Second, we must identify new resources to replace retiring generation that provide both sufficient energy and essential reliability services needed for stable grid operations (such as flexibility, voltage support, frequency response, and dispatchability).
- Third, we must shift focus from planning for solely "capacity on peak" to "energy 24x7" due to the changing fuel mix. Further, to maximize their potential and mitigate risk, we need to better understand the impact on the BPS from the dynamic performance associated with inverter-based resources/loads (IBR and IBL) and distributed energy resources (DER). These understandings can then be balanced against the potential for demand side management – both energy efficiency and demand response – to support reliability and resilience.
- Finally, planning for growing demand – such as electrification goals and large load center development – must be calibrated with the reliability needs of the bulk power system (BPS).

Progress is being made on each of these priorities, however more work needs to be done. The solutions are challenging due to the inherent complexity of the issues, differing jurisdictions, and the number and diversity of stakeholders. Progress depends upon engagement by myriad government agencies at the federal, state, and local levels, and continued close collaboration with industry that is growing exponentially in diversity and numbers. NERC appreciates this technical conference because it convenes the range of stakeholders necessary to drive solutions for continued reliability. NERC is optimistic that the energy transformation can be navigated in a reliable way, provided reliability is appropriately the first order of priority.

With this backdrop in mind, the following discussion covers topics in the Supplemental Notice of Technical Conference, detailing findings, recommendations, and specific actions by the ERO Enterprise.

Panel 1: Managing Reliability Risks and Challenges

NERC Priorities

To ensure the continued reliability of BPS and to remain at the forefront of the complex, dynamic environment, NERC is completing year two of a three-year work plan that aligns priority activities under four focus areas:

- **Energy:** Tackling the reliability and resilience challenges with the changing resource mix, ensuring sufficient amounts of energy and essential reliability services are available for reliable operation, and improving system performance during extreme weather;

- **Security:** Enhancing the focus on physical and cyber security risks, monitoring, mitigation, and evolution;
- **Agility:** Becoming a more nimble organization in key areas, such as standards development, internal operational processes, and technical deliverables; and
- **Sustainability:** Investing in automation, eliminating single points of failure, and strengthening the ERO Enterprise's long-term stability and success.

Among other activities, recent and ongoing actions in each focus area include:

- Revised the Reliability Standards development process to prepare for expeditious updates to Reliability Standards in support of the modern grid;
- Modernized the NERC Rules of Procedure and initiated Reliability Standards to support reliable integration of inverter-based resources;
- Developed critical cold weather Reliability Standards and issued urgent calls to action on best practices during extreme weather;
- Identified risks to energy security and fuel assurance, and initiated related Reliability Standards projects in support of the interconnected BPS;
- Conducted the ongoing Interregional Transfer Capability Study, leveraging existing work to analyze transmission constraints, in response to congressional directive;
- Prioritized Reliability Standard activities and technical committee work under the Reliability and Security Technical Committee;
- Engaged in outreach with stakeholders to gather data in support of assessments on potential risks to security;
- A developing communication strategy for broadened engagement that informs stakeholders about key initiatives and provides clarity and context on prioritization of NERC activities;
- Harmonized risk identification and Compliance Monitoring and Enforcement Program processing to support improved reliability and ongoing feedback loops;
- Consolidated and modernized committee structures, including the NERC Board level Regulatory Oversight Committee and Reliability and Security Technical Committee, to support strategic leadership, execution of NERC's mission, and prioritization of Reliability Standard and technical committee activities;
- Invested in infrastructure to increase automation and reduce enterprise risk through information technology applications;
- Refined the E-ISAC program to further enhance the electric industry's security posture, including activities to analyze and share security data with stakeholders, coordinate incident management, communicate mitigation strategies, and work with partners to support responses to security concerns; and revised Critical Infrastructure Protection

Standards to address supply chain and virtualization risks, and evaluated risks to physical security.

Through a collaborative process that includes engagement with stakeholders, NERC is currently updating its three-year plan to cover the 2026-2028 period. Recognizing the complexities of the energy transformation, the next update will include enhancements to NERC's analytical capabilities that will better assess complexities of the system. The updated plan will also elevate the importance of strategic engagement with stakeholders, particularly among new entrants that are critical to bulk power system reliability.

The Changing Resource Mix, Extreme Weather, and Gas-Electric Coordination

As the resources mix continues to evolve rapidly, supporting the **reliable integration of inverter-based resources** is among the highest priorities, including regulatory enhancements. Under NERC's IBR Strategy, the ERO Enterprise has undertaken activities in several areas, including risk analysis, event analysis, disturbance reports, alerts, and lessons learned; interconnection process improvements, including enhanced interconnection requirements and modeling and study improvements; best practices and industry education, including Reliability Guidelines, webinars/workshops, outreach and engagements, and identifying and addressing emerging reliability risk issues. Perhaps most importantly, NERC is also pursuing regulatory enhancements, including Reliability Standards projects and revisions to the NERC Rules of Procedure.

In June 2024, the Commission approved proposed changes to the NERC Rules of Procedure that expanded the scope of Generator Owners and Generator Operators that are registered with NERC and thereby subject to compliance with mandatory Reliability Standards. NERC also has several Reliability Standards projects underway to address more pressing reliability risks associated with the growth of IBRs on the BPS. In Order No. 901, the Commission directed NERC to develop new or revised Reliability Standards addressing IBR reliability issues as follows:

- IBR disturbance monitoring data sharing and post-event performance validation and ride-through performance requirements by November 4, 2024;
- IBR data and model validation by November 4, 2025; and
- planning and operational studies for IBRs by November 4, 2026.

In the future, NERC will undertake a comprehensive and risk-based review to determine which of the existing NERC Reliability Standards that would not apply to these entities should be modified to include them.

Over the last several years, NERC has made the development of **Reliability Standards addressing extreme cold conditions and extreme heat conditions** a high priority. From 2021 through early 2024, NERC developed a series of Reliability Standards to address preparedness and operations during extreme cold weather conditions, as recommended in the reports of the joint inquiry teams examining grid operations during the 2018 and 2021 winter storm events affecting Texas and the South Central United States.

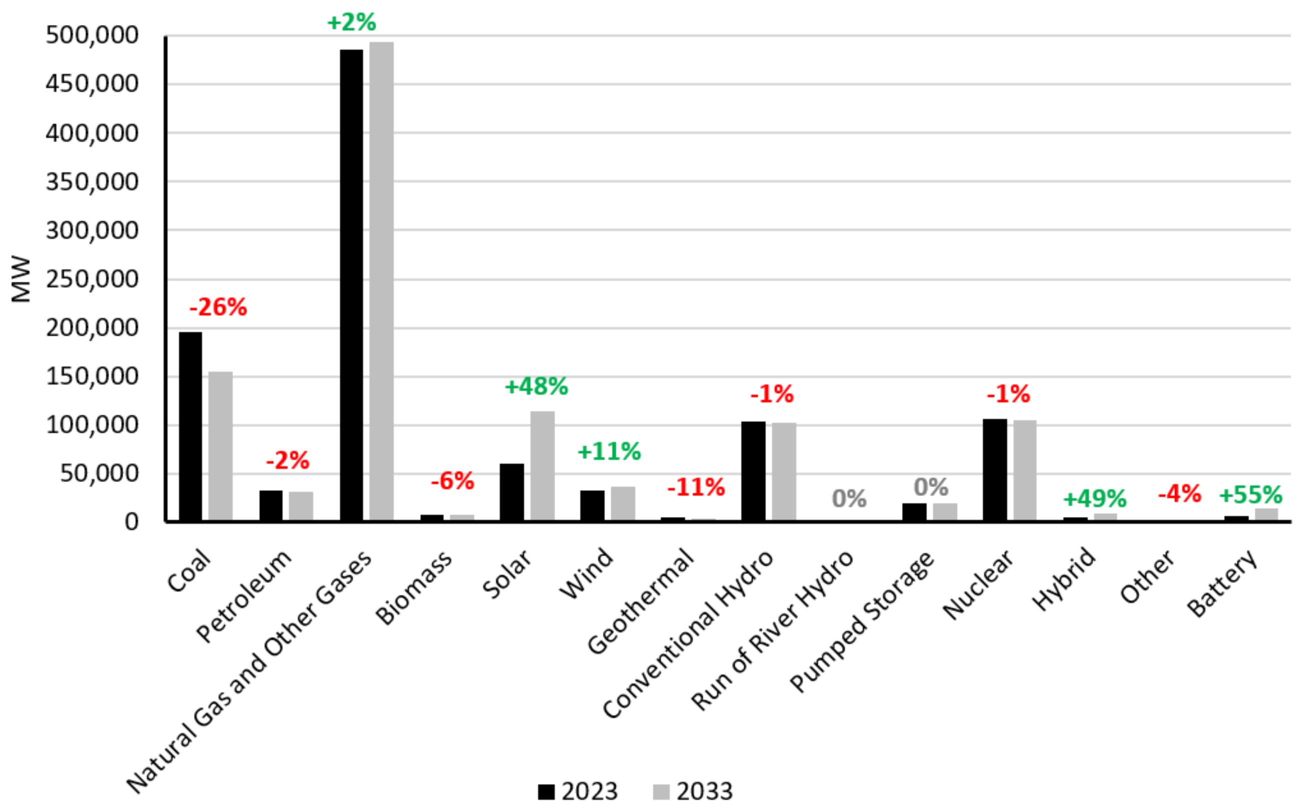
As directed by the Commission, an additional project is underway to provide further clarification of the requirements of the **generator cold weather preparedness standard** EOP-012-2 by March 2025. NERC has developed a plan to collect data on the winterization of generating units and to submit an annual informational filing on the analysis of the data starting on October 1, 2025. Additionally, NERC and the Regional Entities are preparing a strategy for performing robust compliance monitoring and enforcement of the currently effective and approved generator cold weather Reliability Standards, consistent with Recommendation 1(b) of the Winter Storm Elliott report. To the extent NERC's monitoring and analysis indicate opportunities to improve or enhance any of the cold weather Reliability Standards to better achieve their reliability goals, NERC will promptly initiate the standards development process to make the needed changes.

NERC also has a project underway to address **wide area transmission planning for extreme heat and extreme cold conditions**, as directed by the Commission in Order No. 896. Consistent with the order, the resulting Reliability Standard will require: (1) the development of benchmark planning cases based on information such as major prior extreme heat and cold weather events and/or future meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios, including expected availability of the resource mix during extreme heat and cold weather conditions, and including the broad area impacts of extreme heat and cold weather; and (3) the development of corrective action plans that mitigate specified instances where performance requirements during extreme heat and cold weather events are not met. NERC expects to file proposed Reliability Standard TPL-008-1 addressing these Order No. 896 directives by the Commission's December 2024 deadline.

While the Reliability Standards and projects described above will provide important protections for system reliability in extreme cold and extreme heat conditions, NERC has also targeted improvements to **energy assurance issues raised by extreme weather events** concurrent with the growing reliance on natural gas resources and weather-dependent variable energy resources. For NERC, energy assurance means proactively taking steps to maintain reliable BPS performance during both normal operations and credible contingency events while considering the impact of transmission, fuel assurance, emissions, and capacity analyses. NERC's focus on energy assurance seeks to shift operations and planning focus beyond capacity adequacy (the maximum level of electric power that plants can supply) and toward energy sufficiency (the amounts of energy actually available on the system to serve electrical demand and ensure reliable operation), with emphasis on cross-sector coordination between the electric and natural gas industries. For example, if capacity is available, a level of certainty in the delivery of fuel is required to ensure that the energy generated is available to support demand. The *2023 Long-Term Reliability Assessment* highlights these critical interdependencies between the electric and gas sectors. The ERO Enterprise supports these efforts to advance planning with continuous state and provincial outreach by Regional Entities, which serve as technical resources on reliability issues associated with energy assurance amidst the changing resource mix.

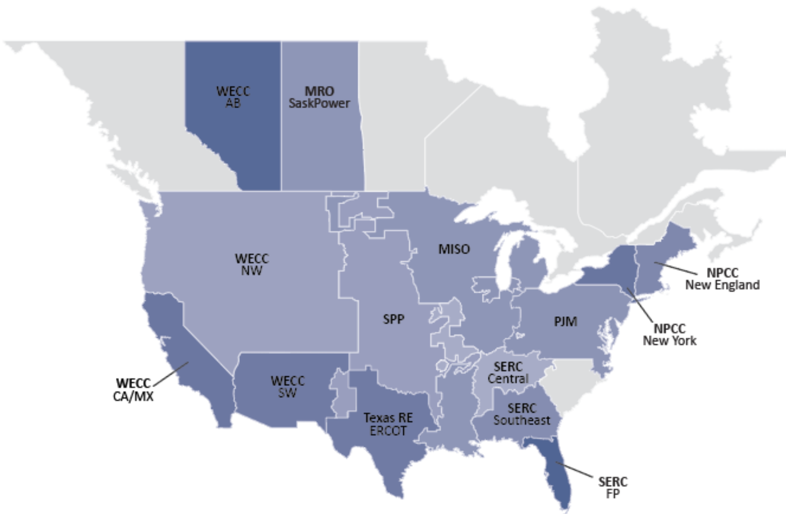
NERC has emphasized that **natural gas is essential to reliability during the grid transformation**, and reiterated NERC's commitment to working with the Commission, gas industry, and electric industry to follow up on the insights in the related report by the North American Energy Standards Board (NAESB). This graph from the *2023 Long-Term Reliability Assessment* demonstrates that generation from natural gas will remain vital to reliability over at least the next ten years to support grid transformation:

BPS Capacity by Fuel Type – 2023 and 2033



This map from the same assessment shows that most of North America is highly reliant on natural gas-fired generation during periods of peak winter demand:

Natural Gas-Fired Generation Contributions to 2023-2024 Winter Generation Mix



All other assessment areas have less than 35% natural gas fired generation contribution to winter resource mix.

	Natural-Gas-Fired Generation Peak Winter Capacity	Natural-Gas-Fired Generation Contribution to Total Winter Resource Mix
MISO	67.5 GW	46%
MRO-SaskPower	2.1 GW	46%
NPCC-New England	17.3 GW	54%
NPCC-New York	24.5 GW	66%
PJM	84.9 GW	47%
SERC-Central	22.7 GW	44%
SERC-Florida Peninsula	50.6 GW	79%
SERC-Southeast	31.5 GW	51%
SPP	27.4 GW	41%
Texas RE-ERCOT	54.2 GW	62%
WECC-AB	11.4 GW	75%
WECC-CA/MX	39.9 GW	65%
WECC-NW	31.0 GW	39%
WECC-SW	18.2 GW	62%

Continuing NERC's longstanding coordination with NAESB, NERC supported NAESB's efforts to identify solutions to the reliability challenges facing the interconnected BPS. In February 2024, NERC's Board held a technical session which included a panel on gas-electric coordination composed of representatives from NERC, the Natural Gas Supply Association, the Electric Power Supply Association, and the Interstate Natural Gas Association of America. This technical session centered around discussion of the critical interdependencies existing between the electric and gas industries, where participants acknowledged the value of greater coordination.

In addition, NERC took direct action under the Reliability and Security Technical Committee (RSTC) and as part of Reliability Standards development to tackle **energy assurance**. NERC established the Energy Reliability Assessment Task Force, which later transitioned to the Energy Reliability Assessment Working Group (ERAWG), to: (i) facilitate ongoing assessment of energy-related risks; and (ii) identify potential responsive measures to mitigate the risks associated with unassured energy supplies (such as output from variable energy resources, fuel location, and volatility in forecasted load). Based on its analyses, the ERAWG and RSTC endorsed two Standard Authorization Requests to support energy assurance. NERC created two Reliability Standards development projects, Project 2022-03 Energy Assurance with Energy-Constrained Resources and Project 2024-02 Planning Energy Assurance, to address these issues on a high priority basis. Under the project, the drafting team will develop revisions to enhance reliability by requiring entities to perform energy reliability assessments to evaluate energy assurance, and to develop corrective action plans, operating plans, or other mitigating actions to address identified risks. The ERAWG began drafting a second volume of this whitepaper and continues to serve as a resource for the drafting team. To support this work, the Electric-Gas Working Group prepared a whitepaper, *Design Basis for Natural Gas Study*.

Beyond the Reliability Standards arena, additional measures are needed to enhance reliability and extreme weather resilience. The current level of transmission development is not keeping up with the need to serve growing electricity demand and more fully reap the benefits of wind and solar resources. FERC Orders 1020 and 1977 hold considerable potential for long-term transmission planning, cost allocation, and siting.

NERC is also completing the Interregional Transfer Capability Study (ITCS). The ITCS will help inform transmission needs by identifying transfer capabilities between regions, and recommending prudent additions to capability where warranted for reliability purposes.

Finally, NERC is encouraged by the various gas-electric efforts across industry, including recent activity by the Interstate Natural Gas Association of America, the Natural Gas Supply Association, the Electric Power Supply Association, several of the independent system operators, the Gas Electric Reliability for America coalition, and NARUC's GEAR Task Force's upcoming recommendations. Even as considerable progress continues, more work is needed to fully address the challenges and risks.

Bulk Power System Cybersecurity Risks

The bulk power system is continually at risk of cyber and physical attack by criminals and nation states, notably China, Russia, Iran, North Korea, and ransomware groups. Geopolitical tensions arising from hotspot areas provide a backdrop for much of this activity, but so do the complexity and significant attack surface present in interconnected systems. Common malicious cyber activities remain **reconnaissance**, **credential harvesting and ransomware,** each becoming more difficult to detect due to increased adversary skill and emergence of generative artificial intelligence.

The "Typhoon" activity groups (Volt Typhoon, Salt Typhoon) associated with China remain the most persistent and daunting group due to their broader objectives of sowing societal chaos by attacking critical infrastructure to further their own geopolitical objectives, according to the U.S. government. Actors from Russia, Iran, and North Korea also present a threat as they offer significant cyber capabilities, and have demonstrated a willingness to use them for a variety of objectives around the world.

In addition, as the transforming grid introduces new entities on a system that is increasingly reliant on electronics and remote access software, the systems' attack surface and supply chain risk will grow even further and is a top concern. **Physical security** also remains a concern, particularly sabotage, wire cutting of critical communications, and insider risk. However, there have been no significant cyber security incidents causing BPS outages to date, and impacts from physical outages, while still concerning, have been contained to distribution level outages.

Compounding the risk landscape are threats surrounding the **2024 U.S. election process**. The E-ISAC is monitoring events around the U.S. election cycle. While there is no known threat to the BPS stemming from the election cycle at this time, the E-ISAC has conducted a number of activities in the lead-up to the election, including a special webinar for all members and partners with the FBI, DHS's Cybersecurity and Infrastructure Security Agency, and the Elections ISAC, highlighting specific election threats, and how utilities should coordinate with election officials. E-ISAC is in close contact with the intelligence community, as well as other federal partners and the Elections ISAC. Based on E-ISAC observations, threatening online discourse by extremists and misinformation by nation state adversaries could exacerbate social unrest and could lead to an increased threat to the BPS. Furthermore, it is noted that Iran, China, and Russia all have interests in promoting misinformation and influencing the election compounding the threat that we face this fall. The E-ISAC will continue to monitor, coordinate, and share updated information and analysis into January 2025 and Inauguration Day.

Grid transformation complicates the cyber risk landscape with the integration of inverter-based resources and distributed energy resources (DERs). While these technologies offer efficiency and sustainability benefits, they also introduce new cybersecurity risks, such as a greater attack surface due to the reliance on remote access. The increasing number of DER aggregators creates additional points of entry for cyber threat actors through an expanded attack surface and a concentration of resources under the control of unregistered organizations.

Supply chains provide opportunities for nation-states, terrorists, and criminals to inject vulnerabilities through the procurement of information technology, operational technology, software, firmware, hardware, and/or services. Malicious actors, especially capable nation-state actors, can conduct cyber supply chain attacks on software and hardware systems. Successful ransomware actor attacks against utility supply chains introduce additional remote access and information risks. Credible supply chain threat scenarios include outages of multiple generators, transmission stations, or substations due to the compromise of original equipment manufacturers, including but not limited to compromised services, firmware, or unauthorized remote access either interactive or programmatic which originates from the service provider.

Malicious actors, both criminals and nation states, could exploit **remote access communication pathways** to carry out coordinated attacks against the grid. While there is a growing interest in the use of cloud-based services and applications, these technologies bring new reliability and cybersecurity challenges.

As the grid architecture transforms towards increasing levels of renewable generation, these changes are most often accompanied by increased levels of autonomy and remote communications. **Artificial intelligence and machine learning** can be leveraged by threat actors to compound their efforts, thereby increasing the probability of successful attacks, though cyber security vendors will introduce similar artificial intelligence/machine learning defensive mitigations.

With regard to Reliability Standards, the ERO has three standards projects in flight to support **mitigation** of these key cyber security risks to the BPS. Balloting is currently underway to revise **CIP-003** to add controls for **low impact BES Cyber Systems** which will authenticate remote users, protect the authentication information in transit, and detect malicious communications assets containing low impact BES Cyber Systems with external routable connectivity. *(Project 2023-04)*

In Q2 2024, standards modifications were initiated which will address risk management for third-party cloud services. These modifications are intended to provide increased reliability and security to the BES by allowing the use of advanced technologies that support entities in managing grid modernization in a secure manner as well as making available to security teams additional resources that can reduce potential impact and speed recovery from security events. *(Project 2023-09)*

Reliability Standard **CIP-008** incident reporting and response planning revisions are also underway providing a minimum expectation for reporting thresholds defining an attempt to compromise which will enhance industry **threat intelligence and situational awareness**. *(Project 2022-05)*

In Q2 2024 NERC's Board of Trustees approved CIP-015 which would require internal network security monitoring for all high impact BES Cyber Systems and medium impact BES Cyber Systems with External Routable Connectivity (ERC) to ensure the detection of anomalous network activity indicative of an cyber attack. These provisions will increase the probability of early detection and allow for quicker recovery from a cyber attack. On September 19, 2024, FERC issued a Notice of Proposed Rulemaking, *Critical Infrastructure Protection Reliability Standard CIP-015-1 – Cyber Security – Internal Network Security Monitoring*, 188 FERC ¶ 61,175 (2024) (INSM NOPR). The INSM NOPR proposes to approve Reliability Standard CIP-015-1 – Cyber Security – Internal Network Security Monitoring and proposes to direct NERC to develop modifications to proposed Reliability Standard CIP-015-1 that would extend requirements for INSM to include Electronic Access Control or Monitoring Systems and Physical Access Control Systems outside the Electronic Security Perimeter. *(Project 2023-03)*

Additionally, in Q3 2023, NERC staff proposed a standards authorization request to modify CIP-013. This project would require complete and accurate assessments of supply chain security risks that reflect actual threat(s) posed to the entity. The SAR proposed to provide triggers on when the supply chain risk assessment(s) must be performed and require a response to risks identified. Subsequently, on September 19, 2024, FERC issued a Notice of Proposed Rulemaking, *Supply Chain Risk Management Reliability Standards Revisions*, 188 FERC ¶ 61,174 (2024), that proposes to direct NERC to address supply chain risk identification, assessment, and response through a new or modified Reliability Standard.

Panel 2: Resource Adequacy and Expected Load Growth

Resource Adequacy Metrics and Further Actions
Given increasing non-dispatchable resources and energy limitations within the generation fleet, resource adequacy risk cannot be sufficiently measured using traditional planning reserve margin (PRM) evaluations, which measures only peak capacity relative to demand. Energy adequacy is a critical complementary consideration of resource adequacy to ensure overall system reliability. Traditional resource adequacy models and approaches are rooted in a loss of load expectation (LOLE) criterion of 1-day-in-10 years, which is focused on peak hour conditions. However, LOLE does not adequately account for the growing risk, over all hours, arising from increased variability and uncertainty caused by the evolving resource mix and increasing demand levels. To assess resource adequacy in a changing bulk power system, the following metrics provide a more comprehensive view:

- **Energy Margin**: Measures if sufficient energy is available across various timescales, including periods of low renewable output (e.g., multi-day periods of low wind and solar). This can be done with or without interface support, to determine how much internal support is available, and quantify how much and when external support from neighboring areas is needed.
- **Loss of Load Probability (LOLP), Loss of Load Hours (LOLH), and Loss of Load Expectation (LOLE):** Evaluate the probability and frequency of supply shortfalls, accounting for variable generation resources, fuel uncertainty, and load uncertainty. LOLP/LOLH/LOLE can be used to evaluate different scenarios, such as extreme weather events, helping to inform both planning and operational decision-making.
- **Expected Unserved Energy (EUE):** This metric captures the severity and duration of potential shortfalls, complementing LOLE by providing a more detailed understanding of the impact of supply shortages. It highlights not just how often a shortfall might occur but how severe those shortfalls could be.

NERC's most recent evaluation of the EUE metric in its 2023 Long-Term Reliability Assessment (LTRA) demonstrates that using EUE identifies risk not captured using other metrics, such as reserve margins. Therefore, from an assessment perspective, additional metrics for evaluation can inform risk assessments and call attention to where risk might be unacceptable. NERC is now using a set of thresholds for future LTRAs that align with the EUE and LOLH metrics. These thresholds do not establish resource adequacy criteria; rather, they offer an approach to consistently apply energy evaluations across all assessment areas in North America to determine energy shortfall risks. Since EUE represents the amount of total energy unserved, it can be normalized over an assessment area and interconnection. In addition to using more robust metrics and criteria, a broader set of design-based scenarios must be developed to provide analyses that are technically sound and provide more insight. Adequate system performance should be ensured within a spectrum bound by defined parameters such as the outer ends of the distributions of input data, sometimes referred to as the "tails." While the tail events encompassed in these scenarios are usually averaged into an overall index, planners may want to ensure that certain tail events are fully understood and mitigated by this scenario analysis. These tail events are generally associated with extreme-condition impacts, such as a low temperature and no-wind scenario or a 99th percentile demand coupled with a pipeline outage.

Further Actions:

- **NERC and FERC Coordination:** Developing and adopting "standardized" risk-based metrics for assessment that reflect energy-limited resources, extreme weather events, and demand variability. Further, a "standardized" approach and methodology for calculating these will need to be fully detailed.
- **Promoting Scenario-Based Planning:** NERC is leading efforts to promote scenario-based resource adequacy assessments (e.g., worst-case scenarios, extreme weather events, accelerated retirements, and prolonged low renewable output periods.
- **Encouraging States to Update IRPs (Integrated Resource Plans):** States and local regulatory bodies could consider requiring utilities to incorporate these metrics and risk assessments into their IRPs.
- **Preserve Needed Resources:** As margins continue to grow smaller, states should also be encouraged to maintain generation and fuel supplies that are critical for reliability. Encouraging actions include California's extension of the Diablo Canyon nuclear plant, continued operation of the Aliso Canyon natural gas storage facility, and progress on maintaining the Everett LNG marine terminal.

Load Growth Drivers

Over the next ten years, NERC's *2023 Long-Term Reliability Assessment* documents that electricity peak demand and energy growth forecasts are higher than at any point in the past two decades. The aggregated 10-year summer peak demand forecast has risen by over 122 GW, and the 10-year winter peak demand forecast has risen by 119 GW (compared to current summer and winter peak demand). The growth rates of forecasted peak demand and energy continue to rise sharply since the 2022 LTRA, reversing an almost two decades trend of falling or flat growth rates. Data centers and other large commercial and industrial loads are driving the increased growth, along with electrification of transportation and heating.

- **Electrification of Transportation:** As the adoption of EVs continues, particularly in urban areas, the grid will need to support significant additional demand. This will have substantial impacts on evening peaks, as most residential EV charging occurs after work and according to local rate tariffs promoting overnight charging. Some studies estimate that by 2035, EVs could add 5-10 gigawatts of new demand in key regions such as California, contributing to steeper overnight peaks and higher system variability through the day.

- **Electrification of Buildings and Industry:** The shift from fossil fuel-based heating systems (e.g., natural gas) to electric heating (e.g., heat pumps) and industrial electrification will drive further load growth, especially in winter months. Growth in these sectors for additional products and services increases the total demand of industrial loads. In New England, electrification of the heating and transportation sectors are primary drivers of the increase in winter peak demand, which, at 3.46% compound annual growth rate, is the highest growth rate in North America.

- **Data Centers (Including Crypto and AI) and Industrial facilities:** Energy demand from data centers, artificial intelligence, and cryptocurrency operations is growing rapidly, driven by the explosion of cloud computing, artificial intelligence, and digital currency assets. Data centers are large, 24/7 consumers of electricity, with the potential to destabilize local grids if concentrated in a particular region. Their rapid build-out poses challenges for utilities, especially because many data center regions are not traditionally areas of high demand growth. Virginia data centers are driving gigawatt-scale load growth, with Virginia hosting the largest data center market in the world. And emerging energy technologies such as hydrogen production could lead to substantial new demand for power over the next few decades. For hydrogen fuel plants, installed capacity in the United States is currently at 67 MW and approximately 3.6 GW are announced or planned. Overall, several planning areas are reporting sharp increases in their 2023 load forecast compared to the 2022 load forecast, such as ERCOT (6.6%), PJM (2%), and SPP (5.2%).

Load Growth Forecasting Challenges and Uncertainties

Historically, load forecasts were primarily based on economic growth and temperature, but the current landscape of larger, more variable, and regionally specific loads requires accounting for **non-linear growth patterns** and predictions of technology adoption rates. Certain areas in North America are experiencing concentrated load growth from industrial and commercial development. Examples of large industrial loads include data centers, smelters, manufacturing centers, hydrogen electrolyzers, and future electrified mass transit or shipping charging stations. Adding large parcels of load on the system can add new uncertainties to peak and hourly load forecasting. For example, data centers have longer operating hours and require more heating and cooling than other commercial buildings. In Texas, crypto mining facilities have connected in recent years that scale their operations (and thus electricity demand) depending on electricity prices. Growth of large, concentrated loads can challenge load forecasting and localized transmission development.

EVs and other non-traditional load behaviors change the way end-use customers are consuming energy. Some programs have tried to shift these loads into lower cost portions of the day, but require extensive infrastructure, customer behavior, and systematic changes to program design to ensure reliable delivery of electricity to end-use customers. Some loads, like data centers, are also highly unpredictable and require operator coordination to ensure their consumption and system behavior during events is not adversely affecting the performance of the electric system. To compare the past to the present, traditional capacity factors were well above 50% for a given period; however, some loads are closer to 2%. This indicates our load's peak consumption is significantly higher for shorter periods than traditional profiles, creating towering peaks on the load curve.

Load growth associated with **large industrial users or data centers** can be concentrated in regions with less robust grid infrastructure, leading to local reliability concerns such as congestion. This often requires transmission upgrades or additional generation capacity to manage localized spikes in demand. Forecasting the growth and integration of these new loads is inherently uncertain due to rapidly changing technology adoption rates and policy environments. Traditional forecasting relies on economic indicators and weather trends. However, accurately predicting when and where EVs or data centers will emerge is a more complex endeavor, further complicated by varying state policies and incentives.

Electrification of transportation and buildings is largely driven by local, state, and federal policies and incentives, which can change frequently and vary regionally. For example, ambitious electrification goals in some states, such as California's ban on gasoline-powered cars by 2035, create high-demand scenarios, while other regions may have slower adoption rates. These differences increase forecasting uncertainty.

The expansive energy appetite of data centers, coupled with electrification trends, could promote a resurgence in nuclear generation, including more re-commissioning of retired units, and license extensions. The need for significant amounts of reliable, clean energy may also spur development of small modular reactors.

Resource Adequacy Mechanisms

As mentioned before, historically, analysis of BPS resource adequacy focused on capacity over peak time periods. Assessment of resource adequacy centered on capacity reserve levels compared to peak demand because resources were generally dispatchable and available when needed. Reserve margins were planned so that deficiency in capacity to meet daily peak demand occurred no more than one-day-in-ten-years. Transitioning from coal and nuclear resources to wind, solar, natural gas, and hybrid resources creates a more complex scenario in which fuel assurance and forward energy supply planning become increasingly important. Generating capacity alone is not sufficient to ensure the reliable operation of the BPS.

Increased reliance on **variable resources** creates a particular challenge for assessing resource adequacy that must be fully understood. Centralized capacity markets are designed for conventional generation technologies, such as natural gas or coal, that can provide consistent and predictable output. However, with an increasing share of wind, solar, and other variable resources, the mismatch between the timing of renewable generation and peak demand may lead to shortfalls in firm capacity.

Broader deployment of **energy-limited resources** is an additional trend that raises similar challenges. Storage technologies, like lithium-ion batteries, have finite discharge durations and are often optimized for shorter-duration needs. Capacity markets need to better incentivize not only peak capacity but also multi-day reliability, which is necessary for a grid that relies heavily on energy-constrained resources. Without properly valuing energy duration and availability, these markets may fail to ensure adequate resources during prolonged low-output periods.

To accommodate the transforming generation resource mix characterized by increasing reliance on variable and energy-limited resources, regulators may consider prioritizing the following measures that recognize and value the attributes of these resources:

- **Valuing Flexibility:** Updates in capacity markets that reward both total capacity and the **flexibility** of resources — particularly those capable of ramping up quickly in response to fluctuations in demand or renewable generation. Flexibility is critical for balancing the variability of renewables, particularly wind and solar, and ensuring grid stability.
- **Locational Resource Adequacy:** The abundance of renewable resources varies regionally, and transmission constraints limit the delivery of energy needed to ensure reliability. Locational signals in the markets could help ensure procurement of resources in regions where they are most needed.
- **Incentivizing Long-Duration Storage and Demand Response:** Current market designs often do not adequately compensate long-duration energy storage or dispatchable demand response, both of which are key to maintaining grid reliability. Enhancing market mechanisms to reward these resources can help support deployment at a scale necessary to balance variable resources.

Collaboration Among the Commission and States on Resource Adequacy

The need for extensive, close collaboration between the Commission and state regulators cannot be overstated. While the states have exclusive jurisdiction over resource adequacy, the Commission's oversight of wholesale markets, interstate transmission, and other energy infrastructure significantly impacts energy capacity and deliverability, which is critical to reliability. The critical issues collaborative between FERC and the National Association of Regulatory Utility Commissions is an important engagement to foster meaningful dialogue. NERC is eager to support the collaborative in every way possible, including through technical input on reliability risk and NERC's ITCS. As the only study of its kind that is uniquely focused on grid reliability needs, the ITCS will provide valuable insights for state and federal regulators. Other recommendations to identify and proactively mitigate resource adequacy risks include:

- **Joint Planning Processes:** FERC and states can establish joint planning efforts that include interconnection-wide resource adequacy assessments, focusing on areas of rapid renewable build-out and high electrification goals. These joint efforts would help identify vulnerabilities (e.g., transmission bottlenecks, potential capacity shortfalls) and ensure that mitigation strategies are coordinated across the interconnection.

- **Harmonizing Policy Goals:** State-level decarbonization policies (e.g., renewable portfolio standards or electrification mandates) can sometimes create misalignment with resource adequacy requirements. By working together, FERC and states can align policies that encourage renewable energy development while assuring reliability. For example, they could ensure that state policies incentivize flexible, dispatchable resources alongside renewable generation until such a time that new balancing resources (such as energy storage) are deployed at scale.

- **Data and Information Sharing:** By promoting data transparency, FERC and state regulatory commissions can share insights into risk scenarios and grid stressors, enabling a more holistic view of resource adequacy and enable studies that have internally consistent assumptions. States can also adopt more granular data sharing requirements for load-serving entities (LSEs) and distributed energy resource (DER) providers to improve forecasting and planning.

- **Supporting Market Evolution:** FERC can encourage states to support market-based solutions for resource adequacy (e.g., capacity auctions, demand-side participation) that leverage price signals to procure the necessary resources. Capacity-only incentives are not sufficient when focused solely on meeting peak needs of the system. Rather, identifying periods where system stress/net peak margins are the lowest will help focus on reliability and energy needs. States can assist by ensuring that regional transmission organizations (RTOs) and independent system operators (ISOs) are adequately valuing the reliability attributes of all resources, including demand response and distributed generation.

- **Incentivizing Infrastructure Investments:** Both FERC and states could coordinate incentives for investments in grid modernization, including transmission expansions, enhanced DER integration, and storage deployment. Adequate transmission infrastructure is especially critical to ensure that renewable energy generated in remote areas can be delivered to load centers. This is particularly important as local solutions may not be sufficient for the energy constraints expected for those areas.