RELIABILITY FIRST

February 2, 2026

The Maryland House of Delegates
6 Bladen Street, Room 412
Annapolis, MD 21401

Re: ReliabilityFirst Corporation's testimony to the Maryland House of Delegates Environment and Transportation Committee

As requested, RF respectfully provides written comments on technical considerations related to grid reliability.

RF is one of the six North American Electric Reliability Corporation[1] (NERC) Regional Entities responsible for preserving and enhancing the reliability, resilience, and security of the bulk power system (BPS, or "system").[2] Collectively, NERC and the Regional Entities comprise the ERO Enterprise. With specific authorities under the Federal Power Act and through a delegation agreement with NERC, RF's mission serves the public good by assuring BPS reliability for over 73 million customers in 13 states including the District of Columbia.[2] We audit and enforce the NERC Reliability Standards for more than 300 registered entities. We also provide outreach and education to registered entities in our footprint, and technical expertise to state public utility commissions, legislators, and other stakeholders.

RF's role with the states is to serve as an objective technical resource concerning reliability risks. While energy policy should appropriately prioritize BPS reliability, our statements are not intended and should not be interpreted as advocating for a specific policy outcome. We are independent and resource-neutral, and our expertise has been provided to stakeholders and committees across our footprint to discuss the reliability risks facing our region.

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[1] NERC is a not-for-profit international regulatory authority designated by the Federal Energy Regulatory Commission (FERC) to assure the effective and efficient reduction of risks to the reliability and security of the grid. Through delegation agreements and with oversight from FERC, NERC works with six Regional Entities (including RF) on compliance monitoring and enforcement activities.
[2] RF does not have jurisdiction over the local distribution of electricity, which is a state responsibility.

The Energy Trilemma

The latest *2025 ERO Reliability Risk Priorities Report* recommends that policymakers adopt a three-pronged principles-based approach to decision making regarding energy policy.[3] Energy policy that is volatile or misaligned can be a risk to reliability. RF refers to this as the "energy trilemma," *i.e.,* the need to balance electric reliability, affordability, and environmental sustainability. Often, prioritizing one leg of the energy trilemma has tradeoffs or detrimental impacts on one or both other legs. For example, rebuilding aging infrastructure and adding new lines and substations may benefit reliability, but at a cost to the ratepayer. Preserving an aging fossil fuel generator may be a detriment to state renewable goals. Integrating new Inverter-Based Resources (IBRs) may result in the need for new transmission, tools, training, and technology to maintain reliability, adding additional costs to the system.

RF's focus throughout this testimony will be preserving and enhancing reliability (our area of expertise), although we are mindful that policymakers and commissioners make difficult decisions regarding the tradeoffs of cost (and cost allocation) along with compliance with federal and state environmental regulations. While states may have preferences and priorities regarding affordability, economic development, and/or environmental targets, reliability (*e.g*., meeting resource adequacy requirements and maintaining essential reliability services) remains essential to prevent blackouts. Additionally, care must be taken to integrate a diverse resource mix, resilient from common mode failures, with the ability to serve load over multiple scenarios (including the lack of a particular fuel source.) The *2025 ERO Reliability Risk Priorities Report* recommends a durable "all of the above" approach that considers energy sufficiency and the full spectrum of resource options and services required to keep the BPS reliable.

Electricity Costs: Breakdown of an Electric Utility Bill

To help frame the affordability dimension of the energy trilemma, RF will begin with a brief overview of the key components of a typical electric bill. In Maryland, residential electric bills generally consist of five elements: generation supply, distribution, transmission, FERC approved riders, and applicable taxes.

1. The supply (or generation) charge covers the cost of producing the electricity consumed, which often fluctuates with market prices. PJM's market prices reflect the underlying balance of supply and demand needed to maintain grid reliability across the region. In the capacity market, prices rise when available generation tightens due to factors like retirements, limited new supply, or growing demand, signaling the need for new investment and helping ensure sufficient resources are available to meet future peak loads. These prices also incorporate updated rules that more accurately value a generator's ability to perform during extreme weather or system stress. Across PJM's energy and reserve markets, prices reflect the real-time cost of producing electricity and maintaining adequate reserves, ensuring reliability as demand fluctuates.

2. The delivery charge includes the cost of maintaining and operating the poles, wires, substations, and other grid infrastructure needed to transport electricity from power plants

[3] 2025 ERO Reliability Risk Priorities Report, page 45

to homes and businesses. This portion is regulated and does not change with customer usage choices.

3. Transmission charges cover long-distance, high-voltage transport of electricity across regional grids.

4. Many bills also include riders or surcharges for public programs, such as energy efficiency, environmental initiatives, storm recovery, vegetation management, or assistance for low-income customers.

5. Finally, taxes and fees mandated by state or local governments appear as separate line items.

Together, these components reflect both the cost of the electricity consumed and the infrastructure required to reliably deliver it to customers.[4]

Electricity Costs: Affordability

Regional Transmission Organizations (RTOs), such as PJM, aim to improve efficiency and reduce costs by coordinating participating utilities and power providers for generation and transmission across the region. If a state considers leaving PJM, it would likely pursue either a Fixed Resource Requirement (FRR) or a Vertically Integrated Utility (VIU) model to secure power. Both options can offer state regulators greater control, but some believe this may lead to higher electricity prices.[5] Alternatively, PJM estimates that its operations save consumers in the region between $3.2 and $4 billion annually.[6]

As described above, the overall cost of electricity to consumers is a combination of market design plus other factors, including state commissions regulating investments in enhancing and maintaining the reliability and security of the grid. Affordability can also hinge on factors such as geography, natural resources, load growth, and the interconnectedness of transmission systems (*i.e.,* the ability to move power both intra-regionally and inter-regionally). Both the EIA and FERC track energy prices by state to maintain transparency to consumers.[7]

PJM continues to focus on affordability within its footprint, particularly as data centers and other large loads show increasing interest in connecting to the grid. The PJM Board of Managers recently released an outline of steps for PJM and its stakeholders to maintain affordability and reliability for ratepayers while integrating large-load customers. The plan includes reviewing and reassessing PJM markets, improving load forecasting, expanding state roles, creating pathways for "bring your own new generation" (BYONG) for large-load customers, establishing an accelerated interconnection track for state-sponsored generation projects, and initiating a rapid

[4] See A Consumer's Guide to Summer 2025 Electric Rates.
[5] See PJM's Securing Resources Through the Fixed Resource Requirement and What Happens if States Leave PJM - EPSA.
[6] See PJM Fact Sheet for Policymakers 2024, p. 2.
[7] See How Much Is the Average Electric Bill in November 2025? and FERC How Affordable and Reliable is Your Power.

backstop generation procurement process.[8] These actions, represented through 12 proposals, will be filed with FERC and will modify PJM's policies and procedures. Many of the measures are intended for interim use as the region works to rebalance supply and demand. PJM has also expressed interest in ongoing stakeholder engagement as it advances development plans focused on affordability and reliability.

ReliabilityFirst's role in this discussion is to serve as a technical resource on grid reliability, which includes information on how reliability ties in to cost. As mentioned in the Energy Trilemma, there are tradeoffs when prioritizing any of the three legs (reliability, cost, and environmental sustainability). For example, in an effort to prioritize the least cost generation coming onto the system, a state may compromise the diversity of resources needed to maintain a reliable and secure grid. Caps to market prices may remove entry of resources that can benefit reliability and/or environmental sustainability. Rate freezes may defer needed maintenance and modernization to aging infrastructure. These factors all need to be balanced to maintain a reliable grid and avoid energy poverty (i.e., the inability of consumers to afford electricity). The cost/affordability conversation also includes job creation, economic development, and the impact on the economy. Large load growth may negatively impact energy prices when adding new resources, however there may be long term economic benefits to increasing the overall supply. And finally, this applies not just to additional infrastructure, but to other "all-of-the-above" solutions such as Grid-Enhancing Technologies and load flexibility.

Resource Adequacy

Resource adequacy refers to matching supply with demand to ensure that the grid has adequate resources to supply loads 24 hours per day, 365 days per year, during all operating conditions. NERC annually assesses and reports on the adequacy of the Bulk Electric System in the United States and Canada over a 10-year period. This report, the Long-Term Reliability Assessment (LTRA),[9] projects electricity supply and demand and discusses key issues and trends that could affect reliability. It is important to note that the LTRA reports are not predictions of what will happen; but rather are projections based on information supplied through a transparent stake-holder process collecting data about resources, load forecasts, transmission system changes, and generation retirements. LTRA reports also include recommendations to address risks, such as enhanced communication, coordination, and collaboration between federal and state policymakers, regulators, owners, and operators of the BPS as well as with the needed critical infrastructure sectors.

The LTRA reports provide unique value as NERC serves as an independent reliability resource, and the assessments focus on risks over a longer timeframe to allow for mitigating action to take place. Over the past 14 years, LTRA findings show a clear deterioration in reliability margins and have identified resource adequacy risks. As early as 2012, the LTRA anticipated significant fossil-fired generator retirements over the five-year period (2012-2017) and noted that generator developers would need to make up for the shortfall in future years.[10] Although the region has

[8] PJM Board Decisional Letter on Critical Issue Fast Path - Large Load Additions.
[9] The LTRA is an annual reliability and adequacy study of the BPS, mandated by Section 215(g) of the Federal Power Act. Background information about the LTRA process including the process, assumptions, and definitions of technical terms used can be found here. The latest LTRA was published in January 2026.
[10] See 2012 LTRA, page 200.

experienced high levels of reliability, severe weather events such as the Polar Vortex (2014) and Winter Storm Elliott (2022) have underscored the trend and risks associated with shrinking reserve margins.

The 2018 LTRA was the first assessment to identify projected resource shortfalls in the RF footprint, specifically impacting the Midcontinent Independent System Operator (MISO) region adjacent to PJM.[11] This projection was based on challenges balancing supply and demand due to the changing generation mix and retirement of baseload resources, well before the emerging large load increases primarily driven by data centers. Market response to higher capacity prices resulted in new generation resources that pushed the risk out several years in subsequent LTRA assessments.

The 2019 LTRA revealed an emerging risk of energy deficiencies during off-peak periods in the MISO region. Historically, meeting summer peak load requirements was seen as sufficient for year-round reliability, but by 2019, this was no longer the case, marking a trend toward greater vulnerability and underscoring that resource adequacy could no longer be measured solely by summer peak conditions.[12] The report also called for increased coordination, communication, and outreach with state policy makers to discuss the changing resource mix which included more local generation resources added to the distribution system, commonly referred to as Distributed Energy Resources (DERs).

The 2020-2022 LTRA reports continued to show increasing resource adequacy risks across the country in the five-year horizon due to the changing generation mix and retirements of baseload units. In the 2022 LTRA, NERC introduced its first Risk Area Summary map.[13] This map was used in Congressional hearings to highlight NERC's warning that two-thirds of the country was at elevated or high risk of resource adequacy shortfalls. [14] Even if a region was at normal risk (gray area), it was often adjacent to an elevated or high risk region, indicating that the region may be relied upon for energy transfers during emergency conditions. The 2022 LTRA indicated a trend of projected load growth rates for the first time due to electrification, electric vehicles, and cryptocurrency. This was still before the recent upward demand of data center load growth that has accelerated these resource adequacy risks.

Although the PJM region remained in the normal risk category for the 2023 LTRA, the report highlighted that electricity peak demands and energy growth forecasts over the 10-year assessment period were higher than any point in the past decade, due to large industrial loads such as data centers, smelters, manufacturing centers, hydrogen electrolyzers, and charging stations. The PJM section of the report warned of increasing reliability risks "due to the potential for the timing of generator retirements to be misaligned with load growth and the arrival of new generation on the system. Trends toward higher demand, faster generation retirements, and slower resource entry could expose PJM to decreasing Planning Reserve Margins and reliability

[11] See 2018 LTRA, page 12.
[12] See 2019 LTRA, page 8.
[13] See 2022 LTRA, page 7.
[14] "The Reliability and Resilience of Electric Service in the United States in Light of Recent Reliability Assessments and Alerts," June 1, 2023, before the Committee on Energy and Natural Resources of the United States Senate. James Robb, President and CEO of NERC, provided testimony concerned about the pace of change overtaking the reliability needs of the system.

challenges from imbalanced resource composition and resource performance characteristics."[15] Around this time, PJM and MISO expressed similar concerns through the release of the PJM *Resource Retirements, Replacements and Risks* (4R) Report and the MISO *Reliability Imperative*.[16]

The previous LTRA, published in December 2024, moved both the MISO and PJM regions into the elevated risk category, largely due to resource additions not keeping pace with generator retirements with over 79 GW of national fossil-fired and nuclear generator retirements planned through 2034[17] and rapid demand growth.[18] Uncertainty around new resource additions and existing generation retirements indicated that above-normal generator outages during extreme weather could result in unserved energy or load loss. The 2024 LTRA recommended carefully managing generator deactivations, streamlining siting and permitting processes to remove barriers to resource and transmission development, and continuing to ensure essential reliability services are maintained on the grid. It also cited the need for enhanced analyses, and the importance of implementing a framework to address the operating and planning needs of the interconnected natural gas-electric energy system.[19]

In January 2025, President Trump issued Executive Order 14262 declaring a national energy emergency impacting the United States' ability to remain at the forefront of technological innovation. In July 2025, the Department of Energy released its own resource adequacy report, *Evaluating the Reliability and Security of the United States Electric Grid,*[20] which cites to resource adequacy projections found in the NERC LTRA. This led to several 202c orders in the RF footprint blocking the retirements of power plants in Pennsylvania, Michigan, and Indiana.[21] The 202c orders are 90-day orders that can be renewed by the administration; as such it is uncertain how long these resources will remain on the system available to be dispatched.

In the latest 2025 LTRA, results show increased risk in the RF footprint due to a combination of factors (*e.g.,* continued escalating demand forecasts from new data center loads, the pace of resource additions and uncertainty due to supply chain issues and other headwinds to development, the future resource mix capabilities for serving load over the range of seasons and hours, and mounting fuel supply issues for current and future winter generation needs).[22]

[15] See 2023 LTRA, page 76.
[16] See PJM 4R Report and MISO Reliability Imperative.
[17] See 2024 LTRA page 28. These risks may be escalated during the winter peak in the PJM region due to weather-dependent resources and fuel supply issues.
[18] See 2024 LTRA page 8.
[19] See 2024 LTRA page 10.
[20] See Evaluating the Reliability and Security of the Electric Grid report.
[21] See list of DOE 202c Orders and timeline.
[22] See 2025 LTRA.

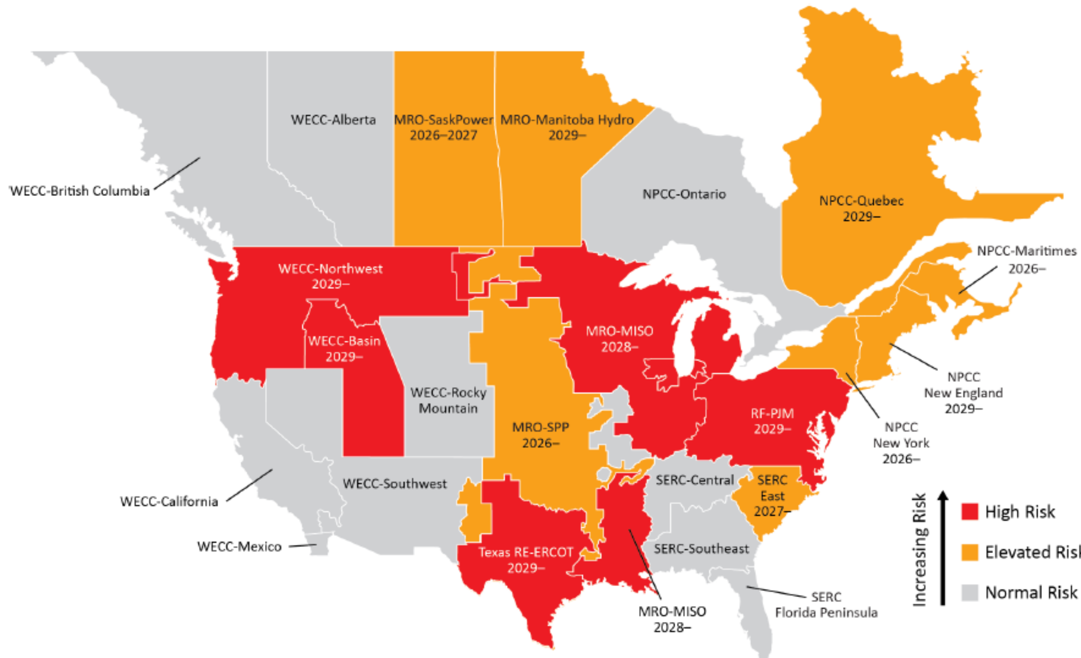

Figure 1: Risk Area Summary 2026-2030

The series of LTRA reports project significant resource shortfalls in the RF footprint as we approach the end of the decade, beginning with the changing resource mix and accelerated by data center load forecasts. While market signals have increased to incentivize additional resources (both new builds and maintaining existing resources), due to a complex landscape of environmental regulations, state policy preferences, supply chain challenges, siting and permitting delays, and federal/congressional actions, more resources are needed to combat rising energy demand forecasts. Additionally, new resources often require additional transmission buildouts to interconnect.

All of this has impacted the affordability of the BPS as the industry plans, designs, builds, and operates the grid of the future. State environmental goals have been challenged as existing fossil-fuel resources have been spared from retirement. These evolving resource adequacy challenges highlight the need to balance reliability with affordability and environmental sustainability as the Energy Trilemma suggests. While these are difficult challenges for policymakers to address, health and human services and the economy depend heavily on a reliable and secure electric grid.

For the rest of this testimony, we will further explore some of the drivers of the resource adequacy risks, along with additional risks facing the electric grid and mitigating actions.

Data Centers and Demand Growth

One of the leading resource adequacy risk drivers is demand growth. There has been a rapid increase in demand, due to the recent rise in data centers, electric vehicles, and the overall electrification of society. For example, in 2024, PJM forecasted an average 2.3% net energy load growth per year over the next 10-year period,[23] and in 2025 forecasted 4.8% growth (over double

[23] https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx, page 2.

the previous year's estimate).[24] In the 2024 LTRA, NERC states that "electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb; demand growth is now higher than at any point in the past two decades."[25] This is shown in Figure 2 on the right hand side, where the 2024 LTRA peak demand projection has dramatically grown compared to the 2023 and 2022 LTRA projections.

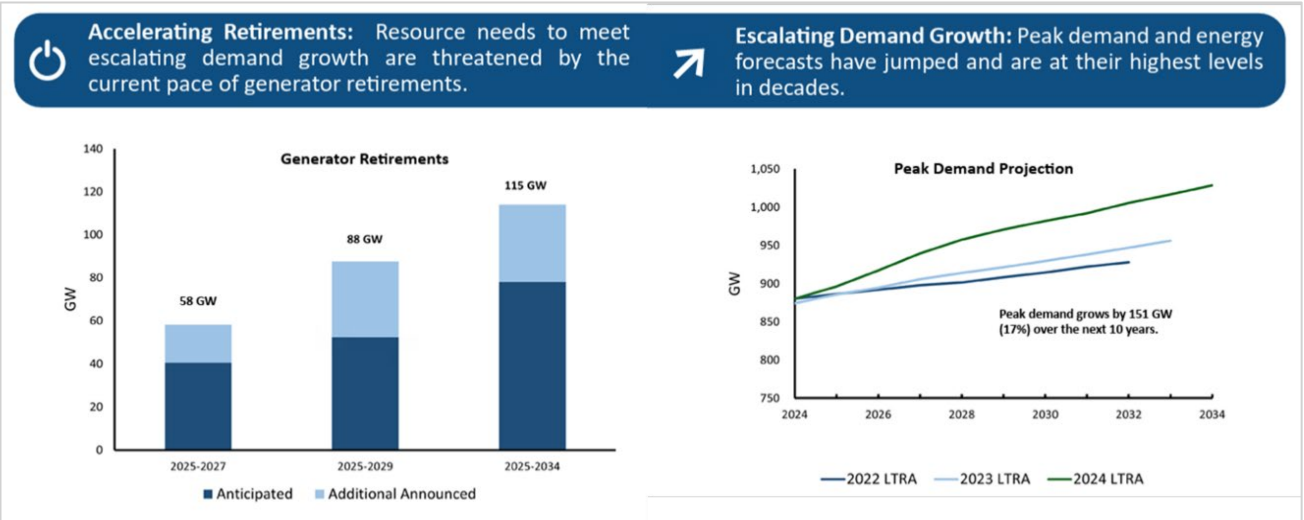

Figure 2: NERC LTRA risk drivers, published in 2024 LTRA Infographic[26]

In its 2024 United States Data Center Energy Usage Report,[27] the Lawrence Berkeley National Laboratory analyzed a range of future demand scenarios. The findings suggest that data centers could consume up to 12% of the total U.S. electricity consumption by 2028 - nearly triple their 2023 share of 4.4%, as seen in Figure 3 below.

[24] https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf, page 6.
[25]See 2024 LTRA page 8.
[26] 2024 LTRA Infographic
[27] See Lawrence Berkeley National Laboratory's 2024 United States Data Center Energy Usage Report.

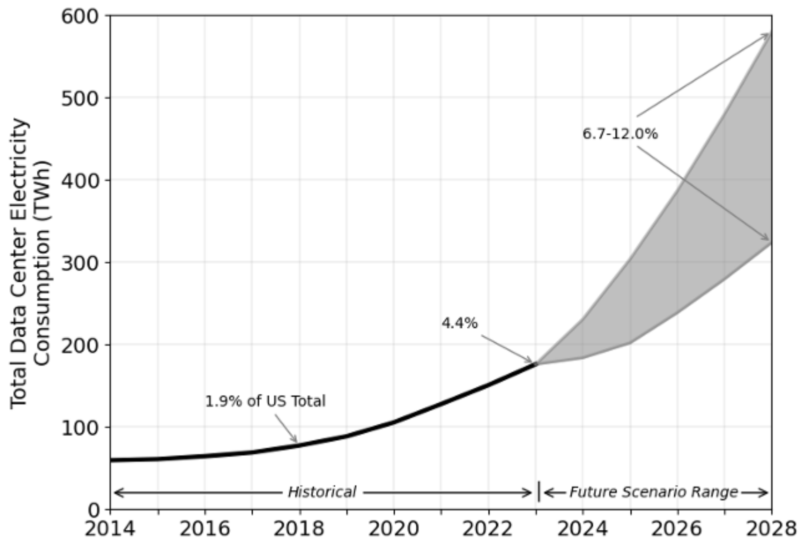

Figure 5.5. Total data center electricity use from 2014 through 2028.

Figure 3: Data center electricity use from 2014-2028, from Lawrence Berkeley National Laboratory[28]

This rapid growth in demand is not solely due to data centers, but the focus on data center load growth versus other sources is due to a variety of factors. Perhaps the largest reason for the focus is the high load density for data centers compared to other sources. While the impact of electrification and EVs is more dispersed, data centers can sit in a small area and require upwards of 300 MW. This makes data center load growth more challenging.

The map in Figure 4 from the National Renewable Energy Laboratory (now known as the National Laboratory of the Rockies) shows data center infrastructure in the US, including transmission lines, fiber optic lines, and some of the data centers by size and whether they are currently operating, under construction, or proposed. Many existing and planned data centers are sited where infrastructure can already support them, typically in areas with large existing loads or near major generation sources with established transmission lines. This concentration can further amplify demand in these already high-demand regions

[28] *Id*. at p. 52.

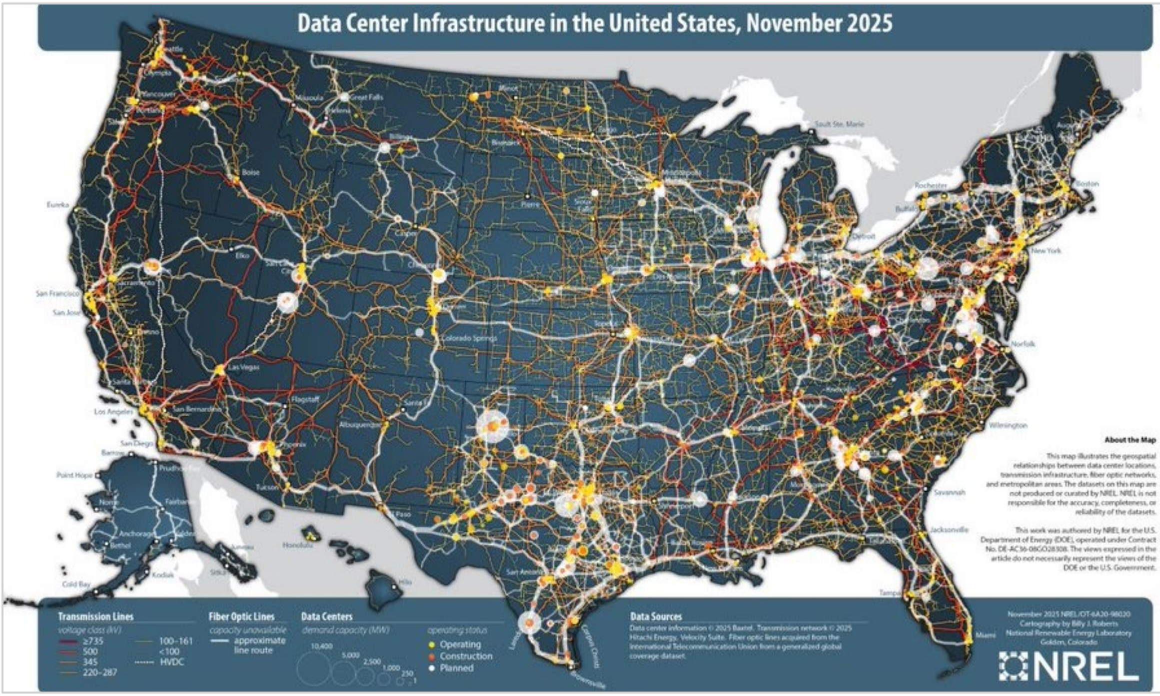

Figure 4: NREL map of data center infrastructure, released November 2025[29]

To meet growing electricity demand from data centers, significant transmission and generation expansion will be needed to transport energy. However, the timelines for building transmission infrastructure (often a decade or more) and new generation do not align with the much shorter timelines for data center development. For example, the average time to construct a nuclear power plant is five years or more, not including siting and permitting.[30] Natural gas-fired power plants and IBRs have shorter construction periods, but predicted labor shortages, supply chain constraints, and required transmission expansion may lengthen their overall development.[31] In contrast, the average time to build a 1 GW data center facility ranges from 1 to 3.6 years,[32] creating a clear mismatch between the pace of load growth and the timelines for developing new generation and transmission needed to serve it.

This underscores a broader challenge: while projections to 2030 or 2040 carry considerable uncertainty, long-term planning is essential. FERC Order 1920 requires transmission providers to conduct long-term planning for regional transmission facilities over a 20-year time horizon to anticipate future needs.[33] To ensure reliability, efforts to ensure infrastructure is timely built and coordinated is key.

[29] Updates can be found on the National Laboratory of the Rockies website.
[30] U.S. nuclear industry - U.S. Energy Information Administration (EIA)
[31] Why 2026 will be the Year of Flexibility - RTO Insider
[32] Build times for gigawatt-scale data centers | Epoch AI
[33] https://www.ferc.gov/news-events/news/ferc-strengthens-order-no-1920-expanded-state-provisions

Recent events have shown that data center loads are unique, which we will discuss further below. Current dynamic models face challenges in capturing the unique characteristics of emerging large loads, and accurately modeling the behavior of such loads becomes increasingly critical amidst rapid development.[34] NERC's Large Loads Task Force (LLTF)[35] discusses and has started publishing documents on how data centers interact with the grid and the associated operational risks, including that many operators lack experience managing such substantial and dynamic loads.

For example, there was an incident in July 2024 where data centers tripped themselves offline during a grid-side fault as shown in Figure 5 – described as a "customer-initiated simultaneous loss of approximately 1,500 MW of voltage-sensitive load that was not anticipated by the BES [Bulk Electric System] operators."[36]

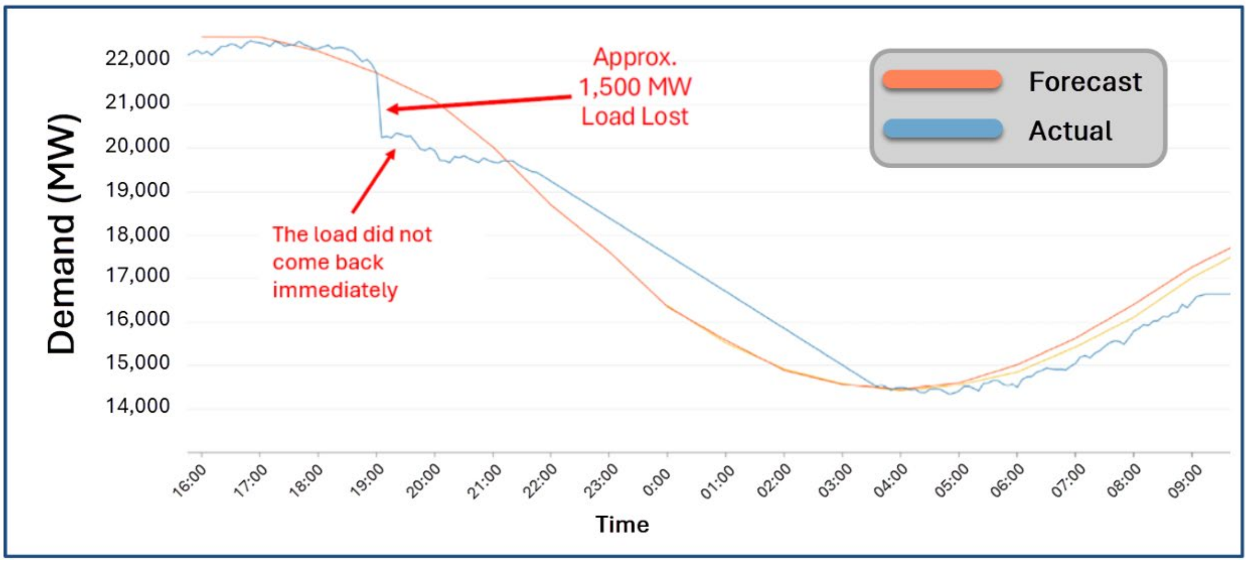

Figure 5: Demand curve showing 1,500 MW load loss event over time, from NERC Large Load Taskforce

In a report on the incident published in January 2025, NERC noted that depending on vendor supplied protection/control scheme settings, "if a certain number of voltage disturbances are seen within a certain time, the data center will transfer its load to their backup system, and it will remain there until it is manually reconnected to the grid."[37] Historically, the grid has been planned for large generation losses but not for such significant simultaneous load losses.

The heightened voltage sensitivity of data centers, coupled with rapid fluctuations in their energy consumption, present unique challenges in forecasting and planning for increased demand.[38] To

[34] See Large Loads FAQs.pdf for additional information.
[35] Information on the NERC Large Loads Task Force can be found at https://www.nerc.com/comm/RSTC/Pages/LLTF.aspx.
[36] NERC Incident Review - Considering Simultaneous Voltage-Sensitive Load Reductions, at p.1.
[37] *Id.* at p. 7.
[38] NERC Large Loads Frequently Asked Questions

raise awareness of these challenges, NERC has drafted the first of several white papers on the characteristics and risks of emerging large loads (such as data centers), the first of which was released July 2025.[39]

Another risk to consider during this period of energy transition and increased demand is the strain on supply chains. This risk is discussed in the most recent RF Regional Risk Assessment,[40] and the rapid growth of data centers can add complexity to this risk. For instance, when a utility seeks to install infrastructure to support a new data center, it is often competing with other utilities doing the same. At the same time, data center developers are often sourcing from the same limited pool of suppliers for critical equipment like backup diesel generators, battery systems, and switchgear.[41]

Forecasting data center growth remains a significant challenge. We have heard from multiple entities that developers often require utilities to sign Non-Disclosure Agreements (NDAs), limiting the ability to share information with neighboring utilities. This practice can obscure visibility and lead to potential double-counting when the same developer explores multiple sites in a region.

Regardless of whether demand comes from data centers or other sources, the need for additional generation to meet the demand is clear. Matching this accelerating demand with new generation and transmission capacity is increasingly difficult, even with efforts to bring previously retired generation assets back online to support data center loads.

Load Flexibility and Backup Generation

One concept being widely explored is that resource adequacy challenges associated with the pace of change (primarily the long lead times required to build generation and transmission infrastructure to support load growth) can be mitigated through load flexibility.[42] This invokes the idea of using the load as a balancing resource when generation or transmission deliverability cannot provide power in the time frames data centers are seeking. Load flexibility is often raised as an opportunity to help reduce customer costs, deliver speed to data centers, and meet state environmental targets regarding reducing emissions. Load flexibility can refer to load management Demand Response (often referred to as peak shaving during times of high load or other emergency conditions) or economic Demand Response (*e.g.,* time-of-use rates or otherwise curtailing power during expensive time periods).[43] The NERC LLTF whitepaper contains a

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[39] See Characteristics and Risks of Emerging Large Loads: Large Loads Task Force White Paper.
[40] See RF Regional Risk Assessment 2023-2024, at p. 7.
[41] See Tackling operational challenges in modern data centers - DCD
[42] T. Norris, T. Profeta, D. Patino-Echeverri, and A. Cowie-Haskell, "Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems," Nicholas Institute of Energy, Environment, & Sustainability, 2025. Accessed: May 30, 2025. [Online]. Available: https://nicholasinstitute.duke.edu/sites/default/files/publications/rethinking-load-growth.pdf
[43] See PJM Demand Response Fact sheet.

section exploring the concept of flexible loads, and how it can allow operators to maintain reliability during times of high demand and/or other emergency conditions.[44]

Understanding the type and configuration of large loads is essential when assessing load flexibility opportunities. For many data centers, uptime is paramount, and their load factors are typically between 70% and 90%, which reflects a consistent demand throughout the day.[45] This consistency at all hours of the day, combined with the critical need for uninterrupted operations, limits their ability to curtail load during grid stress as most demand response programs require, unless they can switch to full load backup generation. Adding this flexibility often hinges on the facility's ability to purchase and install the necessary equipment and ensure fuel availability to support on-site backup generation when called upon.

While backup generation may provide load flexibility, it is important to study the reliability impacts of these arrangements. The 2024 data center event referenced above detailed an event where approximately 1,500 MW of data center load switched to backup power, covering approximately 25-30 substations and 60 data centers.[46] This unplanned shift (what could be termed 'accidental load flexibility') highlights the potential challenges that grid operators encounter in managing sudden, unpredictable shifts in system conditions. There are two important technical considerations to keep in mind related to the use of backup generation.

1. **Impact of losing the load or the generator**
   There are times when the generation or the load is unavailable (tripped, unavailable for maintenance, etc.) and often it is one of the two scenarios, but not both at the same time. For example, there will inevitably be times when the generation is unavailable and the load may be supported 100% by the transmission network; or conversely there may be times where the load is unavailable (e.g., trips off due to a voltage or frequency sensitivity) and the full output of the generator(s) is delivered to the grid.

   While this may not be as impactful for smaller distributed energy resources, the size and magnitude of these large loads and their associated generation may cause thermal, voltage, or stability impacts to the grid at-large. While there may be relaying or other protection systems that isolate both the load and generation together, each circumstance and location must be modeled and studied. Operators need visibility of how these configurations may react, and what operational flexibility is available at each location.[47]

[44] Characteristics and Risks of Emerging Large Loads white paper, page 21
[45] Load factor approximations can vary depending on the assumptions used by the publication, but an often cited number is 86% from the Energy and Environmental Economics (E3) whitepaper.
[46] An Assessment of Large Load Interconnection Risks in the Western Interconnection
[47] Characteristics and Risks of Emerging Large Loads white paper, pages 19-21

2. **Backup Generation Challenges**
   The generation brought by the large load may be backup generation (*i.e.,* used for load flexibility, and/or emergency backup power) or it may run continuously to offset power demanded from the grid. Regardless of how often it is needed, or the type or magnitude of the generation behind the meter, it is still subject to the same risks as traditional front-of-the-meter generation (such as supply chain issues, vulnerabilities, and emission limits). Data centers that want to bring their own generation are competing for materials from the same supply chain, which impacts supply and demand for turbines across the region. If they are using natural gas, they are competing for the same fuel supply chain. Even if the generator is not subject to NERC reliability standards (based on configuration, voltage, and magnitude), these generators still require the same maintenance (e.g., winterization, relay testing) to remain reliable. They are also subject to the same risks related to weather, security, natural disasters, and human factors such as staffing, testing, and maintenance.

These technical considerations are not meant to discourage load flexibility and other creative options to manage the pace of change when generation and/or transmission infrastructure is not available. Rather, they are shared to emphasize the importance of reliability analysis when considering these configurations.

Essential Reliability Services, Planning and Modeling, and Resource Diversity

In addition to the sharp increase in demand, we are observing that across the country, traditional baseload generation plants that were retired are being largely replaced by inverter-based resources (mostly wind and solar) that do not yet have the same operating features essential for reliability (such as ramping, voltage support, and blackstart capability, commonly referred to as Essential Reliability Services).[48] It is useful to understand the importance of Essential Reliability Services in the current risk landscape, and what levels of Essential Reliability Services are needed.[49]

The interconnection queue includes substantial sources of new generation, and integrating new resources onto the system expeditiously can help alleviate capacity shortages, provided the integration is done in a manner that ensures reliability. This includes conducting appropriate energy adequacy planning and modeling throughout all seasons.[50] This planning and modeling evaluates the impact of new generation projects coming online from the interconnection queue on overall grid reliability and resource adequacy, considering factors like variable generation from renewables and load forecasting. Additionally, a diverse fleet of generation sources that does not depend on a singular fuel source, supply chain, or common failure mechanism can

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[48] See NERC statement on Essential Reliability Services: ers-abstract-report-final.pdf
[49] See NERC Reliability Insights article, which discuss NERC's efforts to expand monitoring and analysis to perform Essential Reliability Services Assessments: https://www.nerc.com/globalassets/who-we-are/news/2025/10/2025-october-reliability-insights_final.pdf.
[50] See NERC and the National Academy of Engineering's Evolving Planning Criteria for a Sustainable Power Grid for additional information on this planning and modeling approach.

enhance reliability. Given the potential for political and economic shifts to impact certain generation types, ensuring diversity in the interconnection queue is a prudent strategy.

Increased usage of weather dependent inverter-based resources can aid in expanding the diversity of the generation fleet; however, it is important to be aware of the capabilities and limitations of these energy systems, such as their intermittent nature. Battery energy storage systems (BESS) or other storage (e.g., pumped hydro) can help to mitigate some of the risks associated with intermittency.[51] Currently the PJM interconnection queue has about 122,000 MW of solar and 50,000 MW of battery storage (the two predominant resources in the queue). While solar and battery storage generally work well in tandem, it is important to study these installations as they relate to resource adequacy, including the impact of charging the batteries.

Reliability Risks Related to Extreme Weather

Decreased reserve margins can create additional risk during extreme weather events, when power is needed the most. Winter Storm Elliott, where generation outages resulted in demand exceeding supply, was the fifth major storm with reliability impacts in the last eleven years. There were unprecedented electric generation outages coinciding with winter peak electricity demands, resulting in about 5,000 MW of load shed as rolling blackouts. FERC, NERC, and the Regions released a Joint Inquiry Report on Winter Storm Elliott with lessons learned and recommendations (which led to the creation of revised cold weather reliability standards and numerous other actions by FERC, NERC, and the industry).[52]

Retirements can also exacerbate winter performance risks, as shown in the August 2025 whitepaper[53] that used LTRA data to forecast the resource gap if events from the January 2025 cold snap repeated in the year 2029, given the projected retirements, approximate solar, wind, and battery performance, and the forced outages observed on January 22, 2025. The result was an over 18 GW resource gap, as shown in Figure 6.

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[51] In an example that RF uses, a 100 MW baseload generator that would run through an entire day would produce 2400 MWh of power. To achieve that same amount of energy, three 100 MW solar panels plus four four-hour BESS would be needed to produce the same 2400 MWh assuming 8 hours of perfect sunshine, no losses in conversion, and utilizing the battery storage during times of no solar.

[52] See https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022. FERC also released a summary of actions taken in response to the Winter Storm Elliott Joint Inquiry Report: https://www.ferc.gov/ReliabilitySpotlight#:~:text=FERC%20and%20the%20North%20American,FERC%2DNERC%20winter%20storm%20analyses.

[53] See published Reliability Insights article https://www.nerc.com/globalassets/who-we-are/news/2025/06/reliability-insights---new-approaches-needed-to-ensure-system-adequacy.pdf

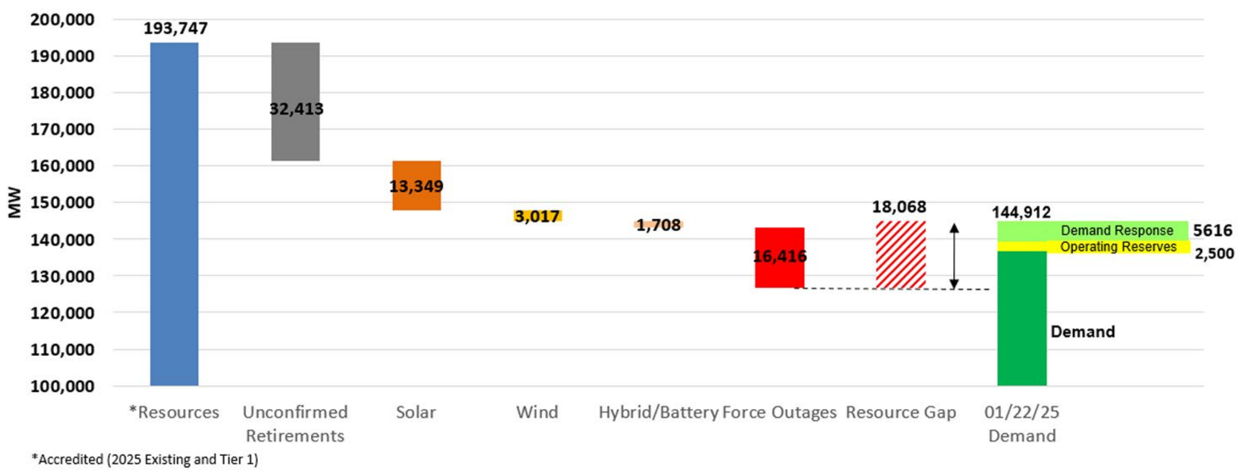

Figure 6: PJM 2029/30 Winter Risk Scenario (using Jan 2025 Peak Conditions)

Post-weather event storm damage, such as from the tornado that damaged a 500 kV line in Louisiana in March of 2025, can combine with other factors to result in emergency load shed, like the event on May 25, 2025 in Southeast Louisiana. The outage of the damaged 500 kV line, which was not yet restored, coupled with spring outage season (when many generators are out of service for maintenance and repairs, preparing for the summer season), lack of import capability, and unseasonably high temperatures, required MISO to order 600 MW of load shed to prevent broader system failure.[54]

Beyond extreme or unseasonable weather, the grid also faces more strain due to general resource availability issues (existing generation and transmission constraints). For example, the Baltimore disturbance in August 2025[55] stemmed from an unplanned outage at Brandon Shores substation (eight miles southeast of Baltimore). The loss of the single 230 kV substation cut off all transmission paths from the station to the grid in an already resource constrained area and ultimately culminated in emergency load shed.

Another metric that the ERO Enterprise tracks is the number of Energy Emergency Alerts (EEA) that are issued per year. The purpose of an EEA is to provide a real-time indication of potential and actual energy emergencies within a region. These notifications are required by NERC Standard EOP-011 and there are three levels (1, 2, & 3) that may be declared in whatever order is needed (not necessarily sequentially). An EEA-3 is the highest and most severe level because it signifies that the power grid has exhausted all other resources and may begin shedding load to prevent a cascading or widespread blackout. The NERC State of Reliability Reports[56] track these occurrences and the charts below show the overall trend of increasing EEAs across the country over the past decade.

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[54] See MISO May 25 Load Shed Event Report.
[55] See August 2025 Baltimore Load Shed Event After Action Analysis.
[56] See the 2025 NERC State of Reliability report (page 49) and 2022 report (page 27)

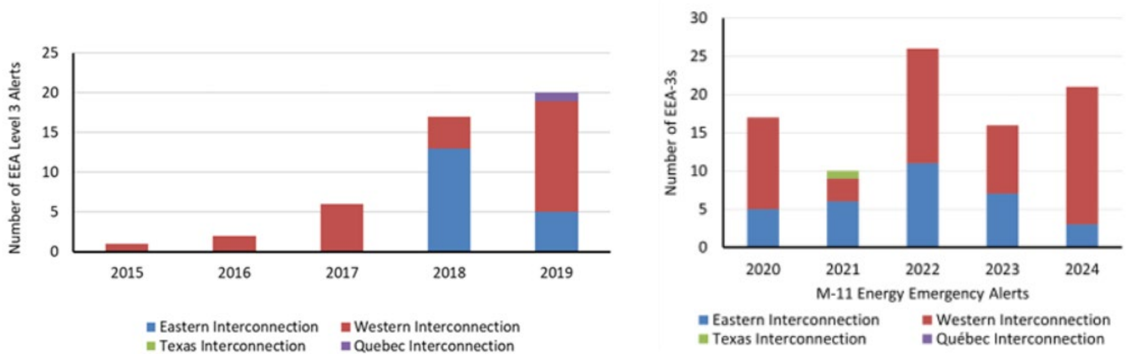

Figure 7: Number of EEA Level 3 Alerts by Interconnection 2015-2024

RF also studies events across North America and from other countries to gather insights from energy transitions in other regions and internationally. In one example, a voltage instability issue outside our region triggered a load-shedding event. During the event, severe weather (tornados and thunderstorms) resulted in line outages, combined with a large generator unexpectedly operating at lower capability, a large load forecast error, wind generation coming in lower than expected, and solar ramping off for the evening.[57]

On the global stage, the 2025 Iberian Peninsula Blackout impacted approximately 50 million people in Spain, Portugal, and a section of France when a combination of generation outages created voltage and frequency swings. While the event is still under investigation, the initial factual report notes that there was a large loss of wind and solar involved in the event.[58] Additionally, a lesser-known power outage in Sri Lanka impacted 22 million people when a transformer outage resulted in system-wide imbalances and cascading outages. During the time of the outage, a substantial portion of generation was supplied by solar PV systems.[59] This event is also still under investigation, but an initial report states that with a high penetration of IBRs, system inertia was reduced and the system was more susceptible to disturbance.[60] These three events are concerning because they did not occur during extreme hot or extreme cold weather conditions. These examples further validate the importance of NERC's work regarding implementing FERC Order 901 aimed at protecting grid reliability as intermittent power generation technologies increase penetration on the U.S. grid.[61] New and revised Standards implement and reinforce requirements regarding studies, model and data sharing, and ride-through requirements.

ERO Enterprise Efforts

Given the rapidly changing resource mix, increasing demand, and the associated reliability risks, FERC and the ERO Enterprise are working to help mitigate these emerging concerns. The *ERO Reliability Risk Priorities Report* outlines the work of the NERC Reliability Issues Steering

[57] See NERC Lesson Learned - Load Shed for Voltage Instability.
[58] Grid Incident in Spain and Portugal on 28 April 2025: ICS Investigation Expert Panel Factual Report, p. 10.
[59] Ceylon Electricity Board Report on February 2025 Sri Lanka Event, p.23.
[60] Id. at p. 45.
[61] FERC Order 901

Committee (RISC) to define and prioritize risks to the BPS.[62] The report found that, in no particular order, the top risks include grid transformation, resilience to extreme events, critical infrastructure interdependencies, security, and energy policy. Energy policy first appeared in the 2023 RISC report and remains a concern because it can amplify each of the other risks and has wide reaching impacts. The primary challenges stem from policy volatility and misalignment, as policies can shift quickly, conflict with one another, and create market uncertainty. Additionally, policies that do not align with the operational capabilities of the electric grid can create additional reliability risks. Policy decisions can significantly influence the resilience of the BPS, as well as capital investment strategies and market dynamics. Policy and implementation plans require careful consideration to avoid potential reliability issues from emerging.

Within the *ERO Risk Priorities Report*, NERC urges policymakers to adopt a three-pronged decision-making approach.[63] This framework calls for balancing three core principles: reliability, affordability, and environmental sustainability. The report also highlights the need for stronger technical education and improved coordination among state officials, utilities, RTOs/ISOs, generators, large load users, the public, and the ERO. RF serves as an independent and reputable resource, offering a range of reports that can support informed policymaking on reliability, resilience, and security of the electrical grid. We encourage policymakers to draw on these resources when applying the three-pronged approach.

The ERO Enterprise and industry are creating new and revised standards to enhance reliability, such as Project 2022-03: Energy Assurance with Energy-Constrained Resources[64] (revising several standards to require energy reliability assessments to evaluate energy assurance and Corrective Action Plans to address identified risks), and Project 2023-07: Transmission System Planning Performance Requirements for Extreme Weather.[65] There are also several ERO Enterprise working groups working on these risks, such as the LLTF.

NERC and the Regions partnered to perform the Interregional Transfer Capability Study (ITCS),[66] which analyzed total transfer capability (the amount of power that can be transferred between transmission planning regions to improve energy adequacy). It recommends prudent additions to total transfer capability that could strengthen reliability. The complete ITCS was filed with FERC in late 2024.[67]

Conclusion

There are additional risk topics and case studies that we are available to discuss at future hearings and testimonies – for example, there are cyber and physical security risks as we plan, build, operate, and defend the grid of the future. We touched on environmental factors associated with weather-dependent resources, and we can expand this discussion with case studies from Winter Storms Uri, Elliot, Gerri, Heather, and Enzo. Finally, while reliability is our area of

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[62] See 2025 ERO Reliability Risk Priorities Report.
[63] ERO Risk Priorities Report page 45
[64] See project page on NERC's website
[65] See project page on NERC's website
[66] See Interregional Transfer Capability Study Final Report at https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf.
[67] https://www.ferc.gov/sites/default/files/2024-11/20241125-3020_AD25-4-000-NERC%20ITCS%20Notice.pdf, see also FERC Docket AD25-4.

expertise and is of key importance during the energy transition, there are socio-economic considerations such as electricity costs, availability and supply of critical minerals, land usage, impacts on the economy (job growth and economic development), and environmental factors including recycling, emissions, pollution, and water usage. We can discuss case studies and events that have impacted other regions of the country, and other parts of the world.

To successfully address the complex reliability challenges emerging as the grid is transformed, NERC, the Regional Entities, and state and federal policymakers will need continued collaboration, coordination, and thoughtful action. Robust resource adequacy planning that acknowledges the benefits of a diverse resource mix and the threat of extreme weather will also help fortify the grid and electricity consumers. As states craft policies for a cleaner, more sustainable grid, we are pleased to serve as a resource to help you remain well informed regarding key reliability topics.