U.S. Committee on Energy and Commerce
Subcommittee on Energy
"Keeping the Lights On: Examining the State of Regional Grid Reliability"
March 25, 2025
Documents for the Record

1. Letter from the American Gas Associations (AGA), addressed to Chairman Latta and Ranking Member Pallone, submitted by the Majority.
2. Letter from the SAFE Center for Grid Security, addressed to Chairman Latta, submitted by the Majority.
3. Report from the North American Reliability Cooperation (NERC) entitled "2024 Long-Term Reliability Assessment," submitted by the Majority.
4. Report from the North American Reliability Cooperation (NERC) entitled "Reliability Insights The Interconnected Gas and Electric Systems," submitted by the Majority.
5. Infographic from the North American Reliability Cooperation, submitted by the Majority.
6. Letter from the American Public Power Association (APPA), addressed to Chairman Guthrie, Chairman Latta, Ranking Member Pallone, and Ranking Member Castor, submitted by the Majority.
7. Article from Energy Wire entitled "Trump Says Coal Should Make a Comeback. At what price?," submitted by the Minority.
8. An RMI report entitled "The Business Case for New Gas is Shrinking," submitted by the Rep. DeGette.
9. An Executive Order entitled "Temporary Withdrawal of All Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects," submitted by Rep. DeGette.

The Honorable Brett Guthrie
Chairman
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

The Honorable Frank Pallone
Ranking Member
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

Re: House Committee on Energy and Commerce Subcommittee on Energy Hearing titled "Regional Grid Reliability"

Dear Chairman Guthrie and Ranking Member Pallone:

The American Gas Association ("AGA") respectfully submits this letter to the Energy and Commerce Subcommittee on Energy ("Committee") to highlight the importance of the natural gas system to the reliability and resiliency of the electric system, as well as to residential, commercial, and industrial customers that directly use natural gas. This letter also provides an overview of one of AGA's reliability and resiliency efforts to meet the growing national demand for energy while maintaining affordability for consumers. More than 189 million Americans and 5.8 million businesses use natural gas because it is affordable, reliable, and safe. Importantly, on the coldest day of the year, the natural gas system delivers 3 times more energy than the electric system delivers on the hottest day of the year. The overall goal should be to preserve and enhance reliability and affordability for all customers, both gas and electric.

AGA, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 79 million residential, commercial, and industrial natural gas customers in the U.S., of which 94 percent — more than 74 million customers — receive their gas from AGA members. AGA is an advocate for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies, and industry associates. Today, natural gas meets one-third of the United States' energy needs.[1]

A resilient energy system is essential to the operation of nearly every critical function and sector of the U.S. economy as well as the communities that depend upon its services. Disruptions to the U.S. energy system have the potential to create widespread economic and social impacts, including losses in productivity, health, and safety issues, and — in the most extreme cases — loss of life. The highest priority for a natural gas local distribution company ("LDC") is the delivery of natural gas to its customers safely, reliably, responsibly, and at just and reasonable rates.[2] LDCs across the country are obligated, in accordance with applicable state law and regulatory requirements, to distribute natural gas to retail, residential, commercial, governmental, and industrial customers — including electric generators.[3] These

[1] For more information, please visit www.aga.org.
[2] Elements of an LDC's retail services are regulated at the state level and not by the federal government. *See, e.g.,* 15 U.S.C. § 717(b) ("The provisions of this chapter . . . shall not apply . . . to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.").
[3] Most laws or regulations that govern utility service include the concept of the "obligation to serve." In short, this duty stems from the reality that when a franchise service territory is granted by a state or regulatory entity, a public interest is established in maintaining reliable service.

requirements underscore the fact that residential and business customers require uninterrupted service for human need purposes, such as home heating, and business purposes.

The natural gas and electric sectors are mutually dependent on each other and over the last several years, AGA and its members have actively engaged in a variety of forums to discuss issues related to the reliability and resilience of the energy system, as well as gas-electric coordination matters. Enhancing gas-electric coordination, particularly for winter weather preparedness remains a critical priority for AGA and its members. As electricity demand is expected to increase, the electric sector will become even more dependent on natural gas and other commodities to generate electricity. In light of this, investing in appropriate energy infrastructure will be pivotal to reliably meet demand growth.

As the power system becomes more reliant on natural gas fueled generation for reliability, pipelines and storage facilities are essential to provide that service. A robust natural gas system is critical in providing gas and electric system reliability during extreme weather events. Currently, approximately 25 percent of the natural gas used for power generation is delivered by natural gas utilities; utilities use on- and off-system storage, as well as pipeline transportation, to ensure natural gas service to customers behind the city gate. As the energy system evolves, new and updated infrastructure may be required to ensure service and meet the additional demands on the system, from residential, business, industrial, and electric generation customers.

The Committee should be aware that the National Association of Regulatory Utility Commissioners ("NARUC") Gas-Electric Alignment for Reliability ("GEAR") task force was established to address the gas-electric challenges facing the energy industry today. Late last year, the GEAR task force unanimously recommended the creation of the Natural Gas Readiness Forum — an industry-led voluntary effort aimed at improving the communication, preparation, and readiness of the energy sector, via a multi-state forum of stakeholders from the various elements of the natural gas and electric value chains, as well as federal and state regulators. The GEAR working group recommended that the Natural Gas Readiness Forum be administered by AGA.

AGA convened the first Natural Gas Readiness Forum meeting on December 16 and 17, 2024 in Atlanta, Georgia. The two-day event included representatives from across the natural gas value chain including representatives from the Federal Energy Regulatory Commission, Department of Energy, North American Electric Reliability Corporation, regional transmission operators, electric generators, energy trade associations, state regulatory utility commissions and state energy offices. AGA will continue to convene such meetings to ensure preparedness of the natural gas value chain.

The American Gas Association thanks the Energy and Commerce Subcommittee on Energy for continuing discussions on reliability and its efforts to identify solutions to the challenges facing the energy industry today. AGA offers its assistance as a resource to the Committee to achieve those solutions. If you have any questions regarding this submission, please do not hesitate to contact the undersigned.

Respectfully,

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The Honorable Bob Latta
House Committee on Energy & Commerce
Subcommittee on Energy
2123 Rayburn House Office Building
45 Independence Avenue SW
Washington, D.C. 20515

Dear Chairman Latta,

As Executive Director of the SAFE Center for Grid Security, I am writing in support of policy initiatives that consider national defense priorities and the importance of a reliable U.S. electric grid. SAFE was founded in 2004 to develop and advocate for policies to improve America's energy, economic, and national security. The men and women who comprise the Armed Forces and the installations on which they serve rely on power delivered by the grid every day. Domestic electricity that is reliable, abundant, and stable in price is not just integral to American economic competitiveness, but it is also foundational to our national security.

Ensuring National Security through Grid Reliability

The reliability of the U.S. electric grid is inextricably linked to national security. Our military installations, critical defense operations, and defense industry hubs depend on a stable and reliable power supply to maintain readiness, deterrence, and response capabilities. Yet, our aging and overstressed grid infrastructure is increasingly vulnerable to extreme weather, cyberattacks, and physical threats. In fiscal year 2021 alone, Department of Defense (DoD) installations across the United States experienced over 6,000 energy outages, leading to more than 3,000 days of lost power—an unacceptable level of risk for our national defense.[i]

Energy permitting reform is a crucial step in strengthening grid reliability and ensuring that our armed forces remain mission-ready. By streamlining the permitting process for critical energy extraction, generation, and transmission projects, permitting reform will facilitate the expansion of a reliable and modern grid capable of supporting military installations and their surrounding communities.

Grid Reliability as a National Defense Imperative

Almost all DoD installations rely on civilian power grids, which are increasingly vulnerable to disruptions.[ii] Recent hurricanes, such as Helene and Milton, have demonstrated how power outages can severely impact military readiness, with some bases left unable to operate effectively for days. Additionally, targeted attacks—such as the 2022 assault on Duke Energy substations in North Carolina, which left tens of thousands in the defense community without power—underscore the growing threat to critical defense infrastructure.

Without robust transmission expansion and permitting reform, these vulnerabilities will persist, leaving installations at risk of prolonged outages that jeopardize operations, communications, and force mobilization. Just 24 hours without power can result in mission-critical failures, loss of situational awareness, and compromised national defense capabilities.

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Grid Disruptions to National Security by the Numbers

- **5** – The number of military bases that experienced power losses that left servicemembers largely unavailable to respond to other potential threats during Hurricane Helene.[iii] Moody Air Force Base specifically suffered severe damage, including widespread outages and losses of communication capabilities.
- **700** – The number of airmen who worked to restore the installation's essential services during Hurricane Helene, with power gradually coming back online after several days.[iv]
- **36,000** – The number of individuals in the defense community surrounding Fort Liberty, North Carolina, who were affected by a significant power outage in 2022. This disruption, which lasted several days, was caused by deliberate attacks on two Duke Energy substations in Moore County.[v] Fort Liberty, home to the 82nd Airborne Division, is crucial for rapid global deployment capabilities, with the ability to mobilize within 18 hours of notification.[vi]
- **70** – The number of tenant commands, including two Nimitz-class aircraft carriers and Joint Base Lewis-McChord (JBLM), that were impacted during an attack on substations operated by Tacoma Power and Puget Sound Energy in Washington state.[vii] JBLM is home to the 62nd Airlift Wing, which operates C-17s for worldwide combat and humanitarian missions.[viii] These events highlight the vulnerability of grid infrastructure supporting key military installations and their surrounding communities.
- **More than 12** – The number of utility companies across the country that were targeted by cyber-attacks in 2019 alone.[ix]

Permitting Reform Strengthens Grid Reliability to Protect National Security

Permitting reform will enable faster development of new transmission lines that connect different grid regions, ensuring military bases have access to diverse and abundant power sources. When one region is compromised due to extreme weather or attack, a more interconnected grid allows installations to draw power from unaffected areas, mitigating risk. By streamlining the permitting process for new energy infrastructure, permitting reform ensures that critical transmission projects are built faster, reducing the likelihood of prolonged blackouts that could disrupt defense readiness. Each additional gigawatt of interregional transmission capacity can significantly reduce outages and save millions in avoided costs from power failures.[x] Permitting reform will facilitate the integration of a broader range of domestic energy resources, ensuring that military installations have access to stable and diverse energy supplies. For military installations, such improvements in reliability can mean the difference between sustained operations and catastrophic failures. More specifically, permitting reform aimed at improving grid reliability for national defense includes:

- **An "all the above" approach to expediting the development of domestic energy resources:** Reforms to simplify permitting by reducing delays and eliminating duplicative paperwork for oil, natural gas, coal, nuclear, renewable energy, energy storage, hydropower, geothermal, and liquified natural gas export projects is the most essential first step in improving grid reliability. Utilizing of all the energy resources our country has to offer would allow us to take full advantage of our domestic supply, reducing risk and securing the grid.

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- **Establishing adaptive frameworks for transmission expansion:** As our electricity consumption continues to rise, so does the necessity of expanded transmission to adequately move power where we need it around the country. Permitting delays are a significant impediment to completing essential energy projects. Today, it takes up to 15 years to develop a new transmission line in the United States.[xi] Permitting reform designed to facilitate the construction and financing of new transmission projects while optimizing the use of current ones through line upgrades and use of grid-enhancing technologies is essential to power grid expansion that balances the need for growth with fair cost distribution and efficient resource utilization.
- **Mandating collaborative interregional planning:** The current lack of interregional transmission planning is a significant barrier to building a more resilient and efficient grid. Neighboring transmission planning regions would be required to draft joint interregional transmission plans to optimize grid reliability and affordability. By mandating collaborative planning across regions and streamlining the approval process, we facilitate the development of high-voltage, interregional transmission projects that are crucial for enhancing grid reliability and dominance.
- **Reducing the burden of unproductive lawsuits:** Delays in the courts cause costs to build up for developers and threaten the economic viability of projects, and that is on top of the inherent risk of deferring infrastructure deployments while the grid is woefully unprepared to meet future demand and respond to security challenges. While permitting reform wouldn't eliminate frivolous lawsuits, it would help reduce the risk of excessive project delays while still giving impacted communities time to address legitimate concerns.

Congressional Permitting Action Can Protect National Security

Grid security is national security. Without the ability to quickly build and deploy critical energy infrastructure, military bases and defense operations remain vulnerable to catastrophic disruptions. Permitting reform represents a necessary change that will expedite the modernization of America's energy grid, ensuring our armed forces have the reliable power they need to maintain operational dominance.

I urge you to support permitting reform to safeguard our national defense from grid failures, fortify our military installations, and uphold America's strategic readiness. I welcome the opportunity to further discuss the implications of grid reliability on national security and look forward to working together to enhance our nation's dominance.

Sincerely,

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[ii] National Defense University Press. "Realizing Energy Independence on U.S. Military Bases." *National Defense University Press*, https://ndupress.ndu.edu/Media/News/News-Article-View/Article/2808076/realizing-energy-independence-on-us-military-bases/.
[iii] National Defense University Press. "Realizing Energy Independence on U.S. Military Bases." *National Defense University Press*, https://ndupress.ndu.edu/Media/News/News-Article-View/Article/2808076/realizing-energy-independence-on-us-military-bases/.
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[v] Who shot the North Carolina power grid? - POLITICO
[vi] 82nd Airborne (army.mil)
[vii] About (navy.mil)
[viii] Units (af.mil)
[ix] Timothy Renahan, "Realizing Energy Independence on U.S. Military Bases," *Joint Force Quarterly* 103, October 14, 2021, at 63.
[x] Transmission Makes the Power System Resilient to Extreme Weather - ACORE
[xi] https://www.2035report.com/wp-content/uploads/2024/04/GridLab_2035-Reconductoring-Technical-Report.pdf

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2024 Long-Term Reliability Assessment

December 2024

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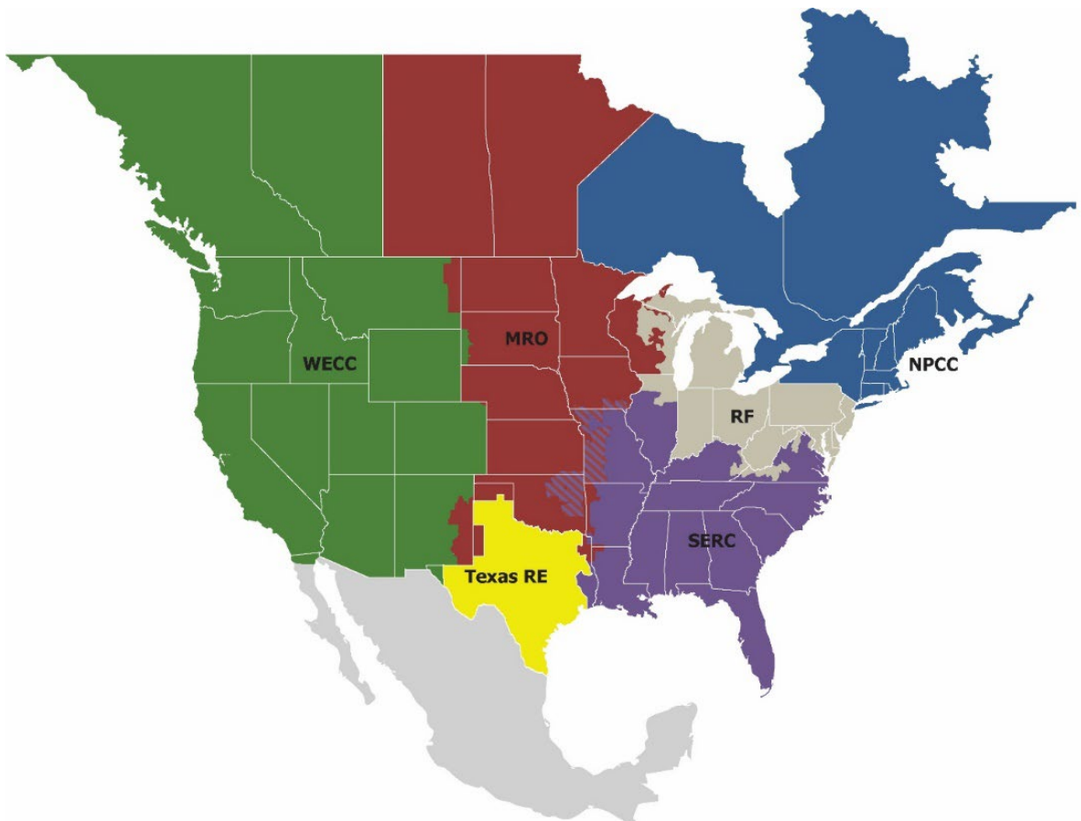
Preface

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

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area basis (see **Regional Assessments Dashboards**) to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer-review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts; this peer-review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees subsequently accepted this assessment and endorsed the key findings.

NERC develops the *Long-Term Reliability Assessment* (LTRA) annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations;[3] this is also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2024 about known system changes with updates incorporated prior to publication. This *2024 LTRA* assessment period includes projections for 2025–2034; however, some figures and tables examine data and information for the 2024 year. NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the **Demand Assumptions and Resource Categories** section of this report. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment; it is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through NERC's Electricity Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electric industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policymakers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the How NERC Defines BPS Reliability section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

[5] ERO Reliability Assessment Process Document

Assumptions

In this *2024 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2024. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading this Report

This report is compiled into two major parts:

1. **A reliability assessment of the North American BPS with the following goals:**
   a. Evaluate industry preparations that are in place to meet projections and maintain reliability
   b. Identify trends in demand, supply, reserve margins, and probabilistic resource adequacy metrics
   c. Identify emerging reliability issues
   d. Focus the industry, policymakers, and the general public's attention on BPS reliability issues
   e. Make recommendations based on an independent NERC reliability assessment process
2. **A regional reliability assessment that contains the following:**
   a. A 10-year data dashboard
   b. Summary assessments for each assessment area
   c. A focus on specific issues identified through industry data and emerging issues
   d. A description of regional planning processes and methods used to ensure reliability

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

In the *2024 LTRA*, NERC finds that most of the North American BPS faces mounting resource adequacy challenges over the next 10 years as surging demand growth continues and thermal generators announce plans for retirement. New solar PV, battery, and hybrid resources continue to flood interconnection queues, but completion rates are lagging behind the need for new generation. Furthermore, the performance of these replacement resources is more variable and weather-dependent than the generators they are replacing. As a result, less overall capacity (dispatchable capacity in particular) is being added to the system than what was projected and needed to meet future demand. **The trends point to critical reliability challenges facing the industry: satisfying escalating energy growth, managing generator retirements, and accelerating resource and transmission development.**

This *2024 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next 10 years; it also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS. The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors. Summaries of the report sections are provided below.

Capacity and Energy Risk Assessment

The **Capacity and Energy Risk Assessment** section of this report identifies potential future electricity supply shortfalls under normal and extreme weather conditions. NERC's evaluation of resource adequacy in the LTRA considers both the capacity of the resources and the capability of resources to convert inputs (e.g., fuel, wind, and solar irradiance) into electrical energy. NERC used both a probabilistic assessment and a reserve margin analysis to assess the risk of future electricity supply shortfalls. Both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development.

Areas categorized as **High Risk** fall below established resource adequacy criteria in the next five years. High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Extreme weather, producing wide-area heat waves or deep-freeze events, poses an even greater threat to reliability. **Elevated-Risk** areas meet resource adequacy criteria, but analysis indicates that extreme weather conditions are likely to cause a shortfall in area reserves. **Normal-Risk** areas are expected to have sufficient resources under a broad range of assessed conditions. The results of the risk assessment are depicted in **Figure 1**.

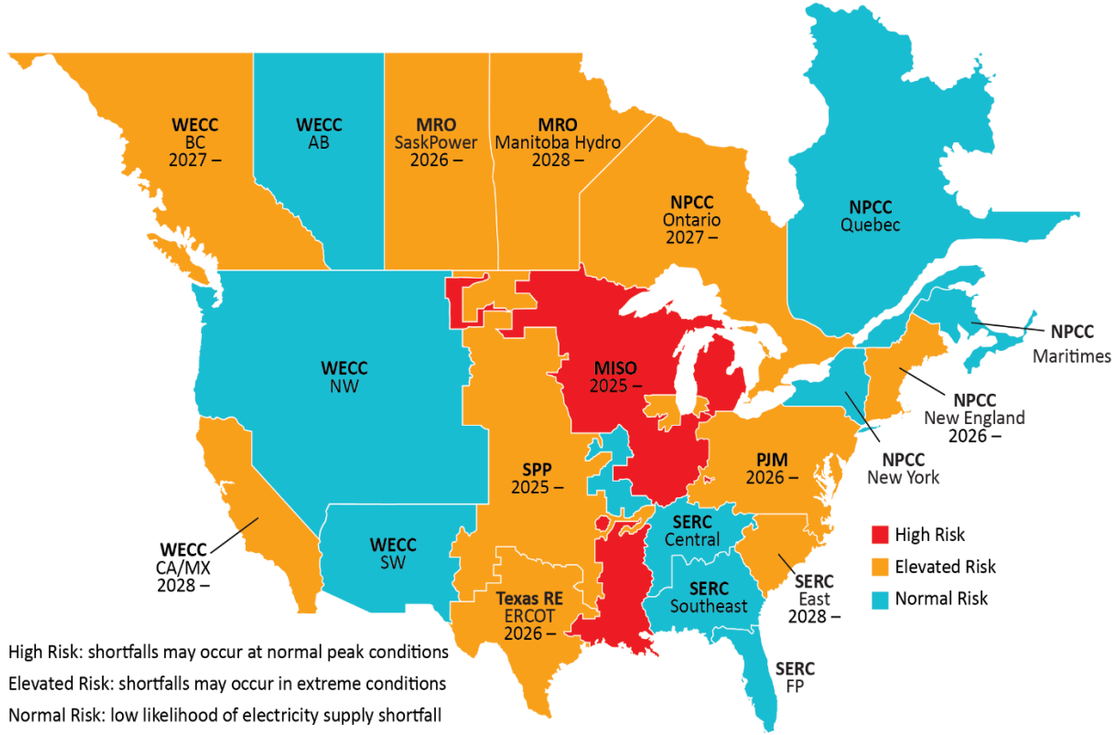


Figure 1: Risk Area Summary 2025–2029

Regional Assessments Dashboards

The **Regional Assessments Dashboards** section contains dashboards and summaries for each of the 20 assessment areas, developed from data and narrative information collected by NERC from the six Regional Entities. Probabilistic Assessments (ProbA) are presented that identify energy risk periods and describe the contributing demand and resource factors.

Table 1: Capacity and Energy Risk Assessment Area Summary			
Area	**Risk Level**	**Years**	**Risk Summary**
MISO	High	2025 -	Resource additions are not keeping up with generator retirements and demand growth. Reserve margins fall below Reference Margin Levels (RML) in winter and summer.
Manitoba	Elevated	2028 -	Potential resource shortfalls in low-hydro conditions, driven by rising demand.
SaskPower	Elevated	2026 -	Risk of insufficient generation during fall and spring when more generators are off-line for maintenance.
Southwest Power Pool (SPP)	Elevated	2025 -	Potential energy shortfalls during peak summer and winter conditions arise from low wind conditions and natural gas fuel risk.
New England	Elevated	2026 -	Strong demand growth and persistent winter natural gas infrastructure limitations pose risks of supply shortfalls in extreme winter conditions.
Ontario	Elevated	2027 -	Reserve margins fall below RMLs as nuclear units undergo refurbishment and some current resource contracts expire. Demand growth is also adding to resource procurement needs.
PJM	Elevated	2026 -	Resource additions are not keeping up with generator retirements and demand growth. Winter seasons replace summer as the higher-risk periods due to generator performance and fuel supply issues.
SERC-East	Elevated	2028 -	Demand growth and planned generator retirements contribute to growing energy risks. Load is at risk in extreme winter conditions that cause demand to soar while supplies are threatened by generator performance, fuel issues, and inability to obtain emergency transfers.
ERCOT	Elevated	2026 -	Surging load growth is driving resource adequacy concerns as the share of dispatchable resources in the mix struggles to keep pace. Extreme winter weather has the potential to cause the most severe load-loss events.
California-Mexico	Elevated	2028 -	Demand growth and planned generator retirements can result in supply shortfalls during wide-area heat events that limit the supply of energy available for import.
British Columbia	Elevated	2027 -	Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighboring areas are unable to provide excess energy.

Risk from Additional Generator Retirements

Plans for generator retirements continue at similar pace and scale to levels reported in the *2023 LTRA*. Confirmed generator retirements (52 GW by 2029 and 78 GW over the 10-year period) are accounted for in the Capacity and Energy Risk Assessment above. Economic, policy, and regulatory factors spur further fossil-fired generators to retire in the 10-year horizon. Announced retirements, which include many generators that have not begun formal deactivation processes with planning entities, total 115 GW over the 10-year period. The effect of all retirements on the assessment area Planning Reserve Margins (PRM) can be seen in **Figure 2**. On-peak reserve margins fall below RMLs; the levels required by jurisdictional resource adequacy requirements) in the next 10 years in almost every assessment area, signaling an accelerating need for more resources.

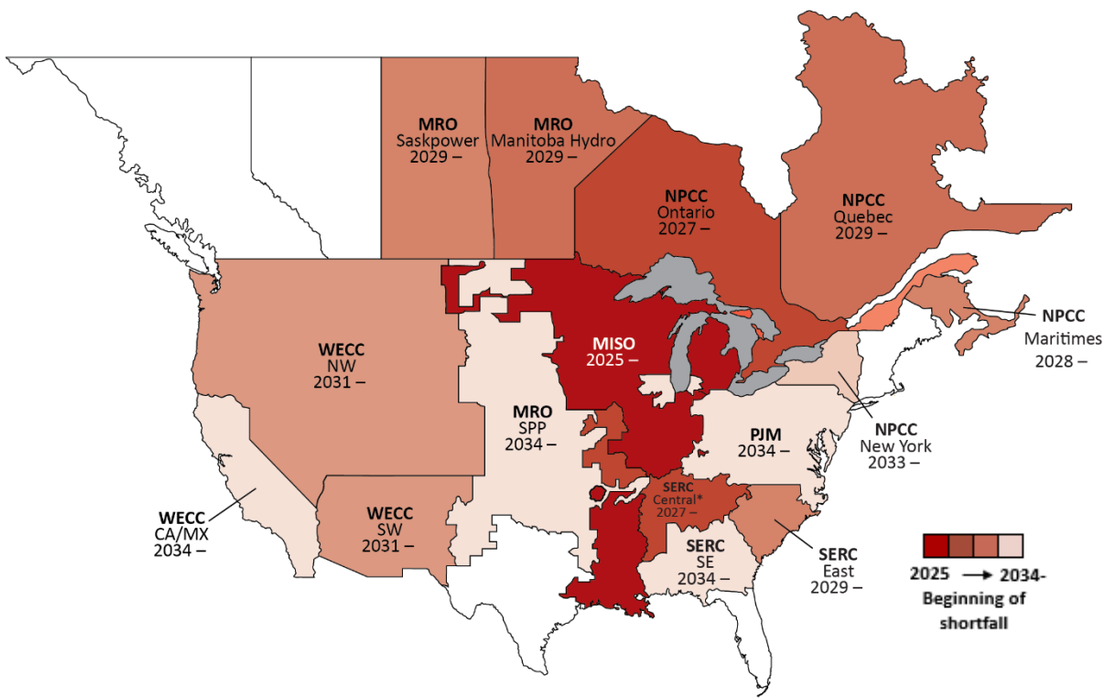


Figure 2: Projected Reserve Margin Shortfall Areas

Changing Resource Mix and Reliability Implications

New resource additions continue at a rapid pace. Solar PV remains the overwhelmingly predominant generation type being added to the BPS followed by battery and hybrid resources, natural-gas-fired generators, and wind turbines. New resource additions fell short of industry's projections from the *2023 LTRA* with the notable exception of batteries, which added more nameplate capacity than was reported in development last year.

As older fossil-fired generators retire and are replaced by more solar PV and wind resources, the resource mix is becoming increasingly variable and weather-dependent. Solar PV, wind, and other variable energy resources (VER) contribute some fraction of their nameplate capacity output to serving demand based on the energy-producing inputs (e.g., solar irradiance, wind speed). The new resources also have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. As generators are deactivated and replaced by new types of resources, ERS must still be maintained for the grid to operate reliably.

Natural-gas-fired generators are a vital BPS resource. They provide ERSs by ramping up and down to balance a more variable resource mix and are a dispatchable electricity supply for winter and times when wind and solar resources are less capable of serving demand. Natural gas pipeline capacity additions over the past seven years are trending downward, and some areas could experience insufficient pipeline capacity for electric generation during peak periods.

Trends and Reliability Implications

Demand and transmission trends affect long-term reliability and the sufficiency of electricity supplies. A summary for each is provided below and further discussed within the **Demand Trends and Implications** and **Transmission Development and Interregional Transfer Capability** sections.

Demand Trends

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. Increasing amounts of large commercial and industrial loads are connecting rapidly to the BPS. The size and speed with which data centers (including crypto and AI) can be constructed and connect to the grid presents unique challenges for demand forecasting and planning for system behavior. Additionally, the continued adoption of electric vehicles and heat pumps is a substantial driver for demand around North America. The aggregated BPS-wide projections for both winter and summer have increased massively over the 10-year period:

- The aggregated assessment area summer peak demand forecast is expected to rise by 15% for the 10-year period: 132 GW this LTRA up from over 80 GW in the *2023 LTRA*.
- The aggregated assessment area winter peak demand forecast is expected to rise over almost 18% for the 10-year period: 149 GW this LTRA up from almost 92 GW in the *2023 LTRA*.

Transmission Trends

For the first time in recent years, transmission projections reported for the LTRA reflect a significant increase in transmission development. This year's cumulative level of 28,275 miles of transmission (>100 kV) in various stages of development for the next 10 years is substantially higher than the *2023 LTRA* 10-year projections (18,675 miles) and is above the average of the past five years of NERC's LTRA reporting on average (18,900 miles of transmission planning projects in each 10-year period published in the last five LTRAs). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning stages of development.

New transmission projects are being driven to support new generation and enhance reliability. Transmission development continues to be affected by siting and permitting challenges. Of the 1,160 projects that are under construction or in planning for the next 10 years, 68 projects totaling 1,230 miles of new transmission are delayed by siting and permitting issues, according to data collected for the LTRA. Questions of cost allocation and recovery can also challenge transmission development when the benefits apply to more than one area, as often occurs with projects that enhance interregional transfer capability.

In NERC's separate Interregional Transfer Capability Study (ITCS), which was performed to meet requirements contained in the Fiscal Responsibility Act of 2023, NERC found that an additional 35 GW of transfer capability across the United States would strengthen energy adequacy under extreme conditions. Increasing transfer capability between neighboring transmission systems has the potential to alleviate energy shortfalls in some areas identified in this LTRA's **Capacity and Energy Risk Assessment**. Conversely, when resource plans are developed that address these same energy shortfalls, such as through resource additions, demand-side management initiatives, or changes to generator retirement plans, the need for increased transfer capability will also change. Planners have options for reducing energy adequacy risks from extreme weather. Selecting the best course of action will depend on weighing these options against various engineering, economic, policy, reliability, and resilience objectives.

The ITCS provides foundational insights that facilitate stakeholder analysis and actions; it is not a transmission plan. In the future, NERC will extend the study beyond the congressional mandate to include transfer capabilities from the United States to Canada and among Canadian provinces.

Emerging Issues

The **Emerging Issues** section discusses developments and trends that have the potential to substantially change future long-term demand and resource projections, resource availability, and reliable operations of the BPS. Topics include data centers and large industrial loads, battery energy storage systems, electric vehicles and load, and energy drought. NERC's RSTC has formed new task forces where needed to address emerging issues.

Recommendations

To address the energy and capacity risks identified in this LTRA, NERC recommends the following priority actions:

1. **Integrated Resource Planners, market operators, and regulators: Carefully manage generator deactivations.** Independent System Operator/Regional Transmission Organizations (ISO/RTOs) should evaluate mechanisms and process enhancements for obtaining information on expected generator retirements that would support early identification of reliability risks. State and provincial regulators and ISO/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulatory and policy-setting organizations must use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be developed and placed in service.

2. **NERC and Regional Entities: Improve the LTRA by incorporating new analysis and criteria to inform stakeholders of future reliability risks.** NERC increased the frequency of the ProbA from biennial to annual and included unserved energy and load-loss metrics as the basis for risk analysis in this year's LTRA. To be more effective in using energy criteria and outputs of probabilistic analysis, NERC must specify consistent methods and assumptions for assessment areas to follow in preparing the annual ProbA. NERC and the Regional Entities, in consultation with the RSTC, should also continue to enhance NERC's LTRA to assess ERSs in the future system and the potential impact of new and evolving electricity market practices, regulations, or legislation on resource adequacy. Finally, NERC should work with the Regional Entities to perform wide-area energy analysis with modeled interregional transfer capability. Wide-area energy analysis will support the evaluation of extreme weather and regional fuel supply issues on an interconnection level.

3. **Regulators and Policymakers: Streamline siting and permitting processes to remove barriers to resource and transmission development.** As ISO/RTOs continue looking for opportunities to speed transmission planning processes, delays from siting and permitting activities will need to be reduced. These are the most common causes for delayed transmission projects. Support from regulators and policymakers at the federal, state, and provincial levels is urgently needed.

4. **Regulators, electric industry, and gas industry member organizations: Implement a framework for addressing the operating and planning needs of the interconnected natural gas-electric energy system.** Various initiatives were launched in the past year to address the reliability needs that arise from the complexity of interconnecting natural gas and electric infrastructure. Voluntary actions taken by the natural gas industry in response to the North American Energy Standards Board (NAESB) Forum report are a positive step toward improving winter readiness. The National Association of Regulatory Utility Commissioners (NARUC) launched its Gas-Electric Alignment for Reliability (GEAR) task force this year and recently created the Natural Gas Readiness Forum. For its part, NERC continues to collaborate extensively with industry and policymakers. NERC has enhanced its Reliability Standards requiring generators to prepare for winter extremes, implement training, and establish communication protocols between generators and grid operators. Current standards projects encompass extreme weather planning and energy assurance requirements. NERC will continue to provide full support to initiatives aimed at achieving a reliable interconnected energy system and urges regulators and policymakers to support needed avenues of coordination between the two sectors.

5. **Regional transmission organizations, independent system operators, and FERC: Continue to ensure essential reliability services are maintained.** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate ERSs.[7] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to ERSs. As replacement resources are interconnected, these new resources should be capable of supporting voltage, frequency, ramping, and dispatchability. Many technologies can contribute to ERSs, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are provided and maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue.

In addition to these priorities, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. All recommendations are listed in the **Recommendations and ERO Actions Summary** section.

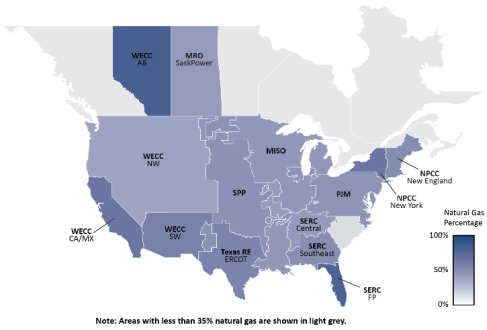
[7] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

Reliability Insights

The Interconnected Gas and Electric Systems

March 2025

North America's electric generating resources are significantly shifting due to retirements of conventional generation coupled with the growth in solar, battery, natural gas, and wind resources. Regulatory rulings and state policies are driving the development of more renewable energy resources. Meanwhile, due to the rapidly retiring coal fleet, natural-gas-fired generation has increased its share of the thermal resource mix and represents more than 80 percent of peak winter capacity in some areas of North America.



Note: Areas with less than 35% natural gas are shown in light grey.

Natural-Gas-Fired Generation	Peak Winter Capacity	Contribution to Total Winter Resource Mix
MISO	62.3 GW	45%
MRO-SaskPower	2.4 GW	43%
NPCC-New England	15.0 GW	51%
NPCC-New York	24.5 GW	66%
PJM	84.4 GW	47%
SERC-Central	22.0 GW	43%
SERC-Florida Peninsula	49.8 GW	80%
SERC-Southeast	31.9 GW	50%
SPP	29.9 GW	48%
Texas RE-ERCOT	55.3 GW	57%
WECC-AB	13.9 GW	83%
WECC-CA/MX	37.8 GW	65%
WECC-NW	33.6 GW	39%
WECC-SW	18.1 GW	58%

This growing dependence on natural gas infrastructure has created new operational and planning challenges, such as those experienced during Winter Storm Elliott in December 2022 (when extreme temperatures in the Eastern Interconnection precipitated a sharp spike in peak electricity demand, driving many grid operators to declare energy emergencies). At the same time, natural gas production in Appalachia fell by more than 6 billion cubic feet (Bcf) per day due to freeze-offs at the wellhead, other mechanical freezes, and icy roadways that delayed repairs. This loss in supply for major gas pipeline operators in the region threatened fuel delivery to power sector customers. At one point, unplanned generation outages caused by freezing generators and fuel supply issues totaled 90,500 MW, equivalent to 13 percent of the resources in the U.S. Eastern Interconnection. In the Southeast, Transmission Operators ordered more than 5,400 MW of firm load shed, the largest recorded manual load shed in the Eastern Interconnection's history. Natural gas production was also extremely impacted, leaving the Marcellus and Utica Shale formations with a production drop of 23% and 54%, respectively, at its peak. This event, and others, spotlights the wide-area challenges that winter weather can bring and energy constraints that may not be resolved by relying on assistance from neighboring areas.

The critical role of dispatchable power generation, such as coal, natural gas, and nuclear, in maintaining grid reliability (particularly during periods when weather-dependent variable resources like wind and solar are unavailable) became evident in 2016. A well leak at the Aliso Canyon natural gas storage facility in Southern California disrupted essential natural gas infrastructure, directly impacting bulk power system (BPS) reliability. This incident highlights the increasing vulnerability of the electric system as reliance on natural gas grows—any outage at a key facility can have significant consequences. Ensuring the resilience of natural gas storage, pipelines, compressor stations, and liquefied natural gas facilities is essential for the electric industry to meet its reliability obligations.

Interconnected Systems Need Coordinated Planning and Operations

The natural gas and electric systems are constituent parts of an interconnected energy delivery system. High-profile disruptions to natural gas availability in recent years have raised awareness of the interdependence between the natural gas system and the BPS infrastructure, resulting in calls for closer coordination in planning and operating these two systems to identify and mitigate risk.

Key Reliability Risks

Natural Gas Supply and Transportation Risks

- **Production Well Freeze-Offs and Winterization:** During extreme cold, natural gas wells can freeze, leading to significant reductions in supply.
- **Dependence on Electricity:** Upstream and midstream gas facilities (compressors, processing plants, and wellheads) rely on electricity from the grid to operate.
- **Pipeline Constraints:** Constrained pipeline capacity, particularly in the U.S. Mid-Atlantic and Northeast, poses challenges in delivering natural gas during peak demand, leaving little operational flexibility should any natural gas facilities be out of service.

Electric and Gas Market Harmonization

- **Scheduling:** Discrepancies between gas and electric market schedules can lead to delays in natural gas availability for power generation during peak demand.
- **Operational Coordination:** Inadequate communication between market operators and pipeline operators prevents alignment of resource availability and electricity demand.
- **Planning Coordination:** Gas and electric system planning is not integrated, and assessments of infrastructure are needed to assure the reliability and adequacy of both systems.

Resource Adequacy and Capacity to Support Large Ramps

- **Winter Peak Demand:** Extreme cold can cause sharp increases in electricity demand during the morning and evening hours, requiring generation resources to ramp up quickly.
- **Generation Preparedness and Fuel Assurance:** Natural gas power plants that are ill-prepared for rapid ramping may fail to secure fuel in real-time conditions.

Vulnerabilities in Generator Winterization

- **Implementation Challenges:** Despite recent progress, some generators still face challenges implementing comprehensive winterization measures.

Opportunities for Mitigation

- **Enhanced Winterization Requirements:** Continue monitoring of compliance with mandatory generator winterization requirements as well as voluntary pipeline and production well winterization standards.
- **Operational Preparedness:** Identification of critical gas facility loads by local grid operators and inclusion in restoration plans will speed recovery during interruptions and limit cascading effects on gas production.
- **Improved Communication Protocols:** Information-sharing practices between market operators and fuel providers should be strengthened to align generation capacity with fuel delivery timelines.
- **Market Reforms:** Market structures to better assure operational performance and fuel certainty by incentivizing and rewarding actions that promote reliability (e.g., firming fuel supply and transportation, as well as winterization investments) should be developed.
- **Cross-Market Coordination:** Policy initiatives that promote closer alignment of gas and electric market schedules during critical weather periods are necessary.
- **Capacity and Energy Planning for Ramps:** Investments in flexible generation and storage solutions are needed to support larger, more frequent ramping events.
- **Regulatory Reform:** Formalized coordination and collaboration, including the development of Standards that encompass both systems, will help assure the reliable operation of both systems.

Conclusion

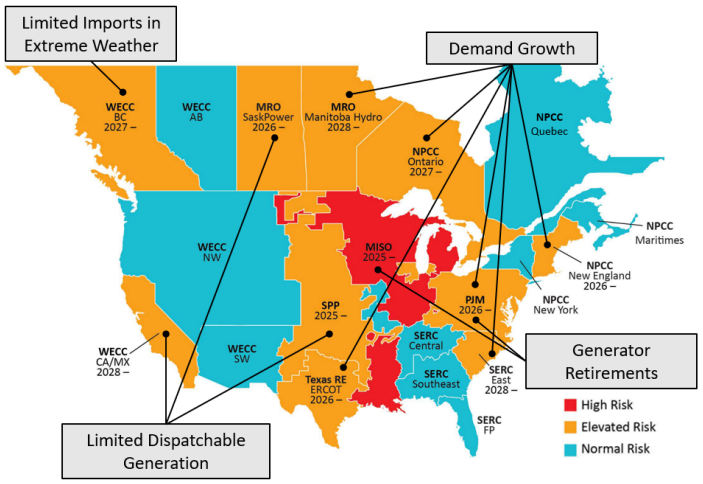
Reliable natural gas supply and electric system performance are essential to meet energy demands. The reliable delivery of energy to end users during extreme weather will be better assured by addressing risks to reliability across both systems. Immediate action is needed across the policy, market, and infrastructure domains to bolster grid resilience during winter's toughest moments.

2024 Long Term Reliablity Assessment

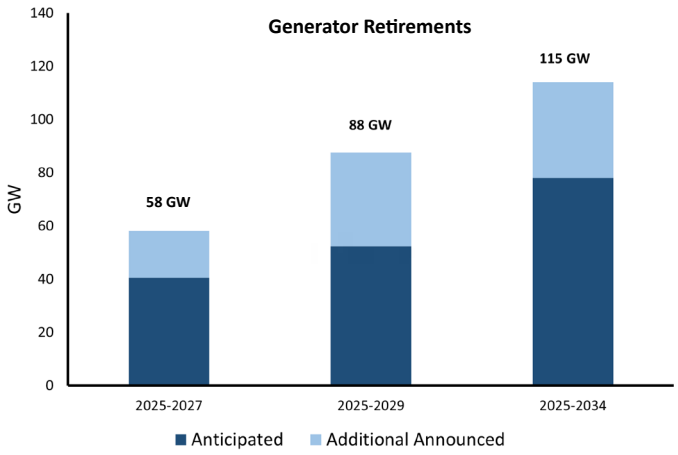
LTRA Report | LTRA Video

NERC's *2024 Long Term Reliability Assessment* (LTRA) identifies reliability trends, emerging issues and potential risks to the bulk power system over a 10-year horizon. This year's report points to the mounting reliability challenges that industry is facing — satisfying escalating energy growth, managing generator retirements and removing barriers to resource and transmission development. Recommendations to address reliability concerns include managing generator deactivations, enhancing future LTRAs with more expansive energy risks analysis, streamlining siting and permitting, promoting natural gas-electric system coordination and ensuring essential reliability services are maintained.

Resource Adequacy Risk Map
(including risk drivers and years when shortfalls begin)

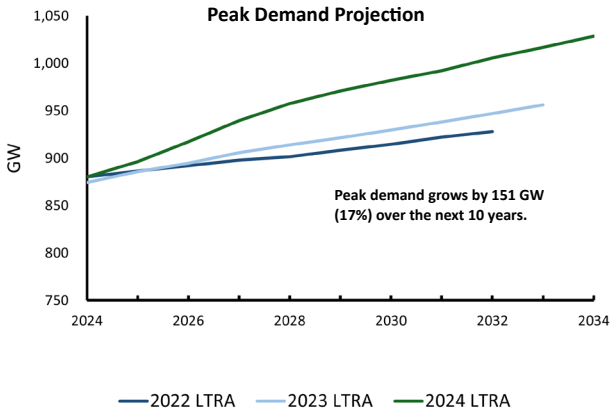


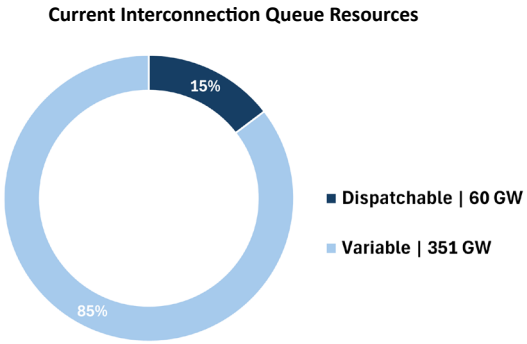
Accelerating Retirements: Resource needs to meet escalating demand growth are threatened by the current pace of generator retirements.



Escalating Demand Growth: Peak demand and energy forecasts have jumped and are at their highest levels in decades.

Declining Dispatchable Resources: Replacement resources projected over the next decade are more weather dependent and lack key reliability attributes.





March 25, 2025

The Honorable Brett Guthrie
Chairman
Energy and Commerce Committee
U.S. House of Representatives
2125 Rayburn House Office Building
Washington, D.C. 20515

The Honorable Frank Pallone
Ranking Member
Energy and Commerce Committee
U.S. House of Representatives
2125 Rayburn House Office Building
Washington, D.C. 20515

The Honorable Bob Latta
Chairman
Energy and Commerce Committee
Subcommittee on Energy
U.S. House of Representatives
2125 Rayburn House Office Building
Washington, D.C. 20515

The Honorable Kathy Castor
Ranking Member
Energy and Commerce Committee
Subcommittee on Energy
U.S. House of Representatives
2125 Rayburn House Office Building
Washington, D.C. 20515

Dear Chair Guthrie, Ranking Member Pallone, Chair Latta, and Ranking Member Castor:

The American Public Power Association (APPA) appreciates the opportunity to submit a statement for the record for the House Energy & Commerce Committee's Subcommittee on Energy hearing on, "Keeping the Lights On: Examining the State of Regional Grid Reliability."

APPA is the national trade organization representing the interests of the nation's 2,000 not-for-profit, community-owned electric utilities. Public power utilities are in every state except Hawaii. They collectively serve over 54 million people in 49 states and five U.S. territories, and account for 15 percent of all sales of electric energy (kilowatt-hours) to end-use consumers. Public power utilities are load-serving entities, with the primary goal of providing the communities they serve with safe, reliable electric service at the lowest reasonable cost, consistent with good environmental stewardship. This orientation aligns the interests of the utilities with the long-term interests of the residents and businesses in their communities. While public power utilities serve some of the nation's largest cities, nearly 1,600 of the 2,000 in operation serve rural communities. Utilities are facing unprecedented demand growth from traditional loads, data centers, and electrification at a time when traditional generation is retiring prematurely, and new, reliable generation cannot be built quickly enough. Most public power utilities are load-serving entities (LSEs) responsible for keeping the lights on. The grid operators have a critical role to play in assisting LSEs in addressing demand growth and resource adequacy issues.

Looking at the challenges of grid reliability more broadly, APPA supports efforts in Congress to enact policies that support public power utilities in providing reliable and affordable electricity to their constituents. APPA appreciates the House Energy & Commerce's work on these critical issues.

Interconnection Queues

Meeting the unprecedented load growth requires continued improvements to the process for interconnecting new, reliable generation to the grid. The Federal Energy Regulatory Commission (FERC) has approved several changes designed to speed up the interconnection process, including a recent change to PJM's interconnection queue that provides a one-time opportunity for shovel-ready, reliable resources to address near-term resource adequacy concerns. Nevertheless, in 2024 only 50 gigawatts of new capacity was added to the grid. Congress should continue to monitor the pace of resource additions in 2025 and provide oversight of FERC's continued efforts to speed up interconnection queues. Resources needed by LSEs for reliability must be considered in any efforts to streamline or prioritize interconnection queues.

Enhanced Coordination of Gas and Electric Sectors

In 2023, natural gas accounted for over 40 percent[1] of utility-scale electricity generation in the United States, with millions of Americans also relying on natural gas directly for cooking and heating their homes. To maintain current reliability and to manage the increased load from economic growth, data centers, and electrification, natural gas must continue to play an instrumental role in the electric system. While the electric and natural gas industries have long been intertwined, the relationship has become more critical in recent decades as a larger share of electricity is generated using natural gas.

For these reasons, APPA supports a readily available and affordable supply of natural gas, as well as the pipeline infrastructure necessary to ensure reliable and timely delivery where it is needed. APPA supports higher standards for delivery, notification, and transparency from the natural gas industry, whether the industry adopts and implements those standards voluntarily or through increased government oversight, including but not limited to, the establishment of a natural gas reliability organization, that carries out similar functions in the natural gas business as the North American Electric Reliability Corporation (NERC) does for electric reliability, as proposed by the 2023 North American Energy Standards Board Gas Electric Harmonization Forum Report.

Permitting Reform

APPA supports efforts in Congress to streamline the federal permitting process, eliminate excessive regulatory barriers, and ensure more predictable and timely decisions from relevant

[1] U.S. Energy Information Administration; What is U.S. electricity generation by energy source? (Feb. 2024) https://www.eia.gov/tools/faqs/faq.php?id=427&t=3

federal agencies. Despite abundant resources and potential projects to meet the rapidly growing demand for electricity, permitting red tape, needlessly burdensome regulations, and conflicts between state and federal priorities have slowed energy infrastructure development to a crawl. Utility customers ultimately pay the high cost of slow, cumbersome permitting rules.

APPA encourages Congress to prioritize infrastructure-neutral permitting reform to ensure public power utilities have the clarity and certainty to invest in required generation, distribution, and transmission infrastructure to meet rising demand and ensure grid reliability.

Supply Chain

Finally, public power utilities continue to contend with supply chain constraints for various critical grid and electric generation components. Supply chain constraints and shortages threaten the reliability of the electric grid and the nation's economy.

APPA was pleased to see the Department of Energy (DOE) take positive steps last April in its final transformer efficiency standards rule. APPA also greatly appreciates the work done by House Energy & Commerce Committee members to advocate for a balanced approach to transformer efficiency. However, despite these achievements, public power utilities still face supply chain issues, from transformers to gas turbines, making it difficult to meet rising demand and ensure grid reliability.

Congress should encourage DOE and other federal agencies to collaborate and work with public power and the broader electric sector to ensure a robust supply chain of critical components is available and accessible for electric utilities.

Conclusion

APPA commends the committee for holding today's hearing and for the ongoing focus of the House Energy & Commerce Committee and the Subcommittee on Energy to the issues impacting public power utilities, in particular, rising demand and resource adequacy, as they work to provide reliable, affordable, and sustainable power to millions of American homes and businesses.

ENERGYWIRE

Trump says coal should make a comeback. At what price?

A deal to keep two Baltimore power plants open into 2029 is the tale of repeated failures by the largest U.S. power market to plan for a future without coal.

BY: **PETER BEHR** | 03/25/2025 06:38 AM EDT

Brandon Shores power plant in Baltimore.| abriggs21/iStock

ENERGYWIRE | *First in an occasional series on PJM, the Eastern power market.*

In the tiny community of Orchard Beach on the western entrance to Baltimore Harbor, the dominant feature isn't the modern townhouses and modest bungalows or the cattails and bulrushes lining the creeks.

Looming over everything is a cluster of exhaust stacks at two large coal-fired electric power stations just to the north. "They're just ugly," said Zachary Guy, a resident of the neighborhood who took a break from working on his mother's vehicle to comment on the power units, the oldest of which has been operating for 40 years.

If federal regulators approve, utility customers in the greater Baltimore area will have to pay a $754 million surcharge to keep the plants owned by Houston-based Talen Energy cranking out more than a combined 1,500 megawatts for another four years. Brandon Shores and the smaller H.A. Wagner stations were scheduled to retire this year, adding more closures to the 15-year-long exodus from coal by U.S. power producers opting for cleaner and cheaper alternatives.

Without the plants, however, the region's shrinking power reserves would enter a dangerous place. The risk would be cascading multistate power outages, according to officials of the PJM Interconnection, which operates the grid serving Maryland and a dozen other states and the District of Columbia.

"You don't want to get anywhere near there," said Joseph Bowring, president of Monitoring Analytics, PJM's independent market monitor.

The surcharge payments will continue until 2028 or 2029 at least, when PJM hopes to complete installation of new and upgraded high-voltage transmission lines to deliver enough imported power to replace the plants. The transmission cost: an estimated $1.5 billion, more than two-thirds of it also landing on Maryland utility customers, according to state officials.

Without approval of the payments plan, now pending at the Federal Energy Regulatory Commission, Talen Energy had said it would close the plants, clean up the sites and build a waterfront development. Under its almost inscrutable operating rules, PJM is powerless to keep the plants in business.

Maryland's Office of People's Counsel, in a filing at FERC, put it more simply: Talen Energy was able to "extract a high level of compensation under threat of

shutting down the power plants."

If the PJM settlement with Talen goes through, Maryland's consumer advocate initially estimated residential electricity bills would go up by $247 a year for three or four years, with an average annual hike of $2,685 for commercial customers. While those figures will be cut down by other parts of the proposed settlement, the cost of the transmission projects will be part of customer bills for many years, said Deputy People's Counsel William Fields.

Those are all economic decisions made by powerful organizations and companies. An expanded version of that confronts President Donald Trump and his administration as they promise to bring back coal and expedite natural gas generation to power a build-out of data centers and win the race against China for artificial intelligence supremacy.

Doug Burgum, speaking as the Interior secretary and chair of Trump's new White House energy council, told Bloomberg Television that U.S. demand for more electricity through 2030 requires keeping coal plants running for longer — and could mean resurrecting coal generation that has already shut down. Most of those coal units closed because they were decades old, polluting, and less profitable than natural gas generation or bringing more wind and solar power onto the electric grids.

"Under the national energy emergency, which President Trump has declared, we've got to keep every coal plant open," Burgum said.

U.S. power producers haven't opened a large coal-fired power plant since 2013, and there have been no major plans to add more coal capacity in the future. Burgum has downplayed even the idea that companies and U.S. policies are invested in a transition to energy technology that pollutes less and emits fewer greenhouse gas emissions.

"That is one of the big lies of the climate extremists," Burgum said during the interview earlier this month at an oil and gas conference in Houston. "We're in a period of energy addition."

Trump, in announcing a national energy emergency in January, could invoke wartime authority to order any U.S. power plant to keep operating, possibly for

indefinite periods, legal scholars point out. Trump has also asserted all major actions by independent agencies that regulate the economy, including FERC, to be under the president's control. That could pull consequential decisions over wholesale power prices into the Trump White House — and potentially lead to a pricing scheme that pays premiums to the energy companies and private investors that own America's remaining coal plants.

The pending decision on a big payment to Talen Energy to keep the Baltimore plants running signals a costly return to coal, whether to ensure the lights stay on or to satisfy political promises. If Trump directs energy markets to pay for coal generation — at whatever the price — it would weigh heavily against Trump's pledge to drive down energy costs for voters.

'A very dangerous place'

Today, old fossil fuel plants are retiring faster than their power can be replaced with new generation of any kind, with the problem most severe in PJM and the Midcontinent Independent System Operator (MISO) in the central U.S., according to the 2024 Long Term Reliability Assessment by the grid's monitor, the North American Electric Reliability Corp. (NERC). And this is happening amid an unexpected surge in power demand to run new data centers with enormous energy appetites.

"We are heading toward a very dangerous place in terms of our reliability," FERC Chair Mark Christie said in an earlier interview.

"Our infrastructure is not being built fast enough to keep up with the rising demand," John Moura, NERC director of reliability assessments and performance analysis, said in releasing the long-term assessment. Within 10 years, the amounts of surplus power available to meet peak electricity needs will fall below safety levels in nearly every part of the United States, NERC concluded.

"You have a significant number of states…where it's harder and harder, or nearly impossible, to build the infrastructure necessary to produce electricity," said Kent Chandler, former chair of the Kentucky Public Service Commission and former president of the Organization of PJM States.

Grid operators weren't expecting the sudden power growth projections from data centers and new power plants that emerged in the past two years, says Scott Niemann, managing director of ESAI Energy, Massachusetts-based grid analysts. "So the need really shifted from building renewables to meet [state] mandates to getting electricity from any source you can get it from, whether it's renewable or gas fired, to meet the demand growth."

PJM could see a capacity shortage as soon as the mid-2026 delivery year, said Mark Takahashi, chair of PJM's Board of Managers.

Born nearly a century ago by utilities in Pennsylvania, New Jersey and Maryland who wanted to pool power supplies, PJM today is the largest of the seven U.S. regional power organizations. Its control room operators must maintain a moment-to-moment matching of power supply with demand in its 13-state region of 65 million people from the mid-Atlantic beaches to Chicago.

The two Baltimore plants, Brandon Shores and H.A. Wagner, are the most important power source in central Maryland. They can serve more than 1 million households. For most of their lives, the plants have also been the state's largest source of global-warming CO2 emissions, and in Brandon Shores' case, a persistent source of health-threatening sulfur dioxide exhaust from its two coal-fired steam plants.

The owner of the plants, Talon Energy, which went through a bankruptcy reorganization in 2022, has no "duty to serve" Maryland customers. The Maryland plants are part of its asset portfolio affected by profit-seeking options that include pursuing data center contracts and repurchasing its stock shares to boost their value.

Facing a lawsuit by the Sierra Club over the two plants' emissions, and emissions regulations, Talon announced in 2023 it would close the plants this year. Given a glacial decision-making process at PJM, with its more than 1,000 members, that much power was not replaced, forcing PJM to pay Talen to keep running until new power could be substituted.

"Brandon Shore's pending retirement was foreshadowed long before" the 2023 announcement, Maryland People's Counsel argued. Yet until the

announcement, “PJM does not appear to have done any pro-active review” of options for replacing the lost power, the office added.

Today, PJM has a comfortable security margin of spare capacity across its system. Its 1,408 generators of all kinds can produce a peak of 183,000 MW of power, well above the top demand forecast for this summer of 154,000 MW, PJM says. (For comparison, the 94 U.S. commercial reactors produce 97,000 MW of peak power.)

By 2030, however, PJM predicts maximum demand could rocket up to more than 180,000 MW if a predicted surge in data center demand occurs. Today’s generation capacity of 183,000 MW will drop by 40,000 MW if all the plants that say they plan to retire actually do so by 2030, PJM says. New power plants to replace the retired ones have not materialized.

Clean energy and lost opportunity

A flood of proposed power plant projects has stacked up at PJM, the vast majority of which are small solar plants. That gives PJM an opportunity to create a balance of carbon-free renewable energy, storage, nuclear power and gas-fired generation.

PJM failed to seize that opportunity, critics say.

Corporate power buyers with clean energy goals sought out solar power deals in PJM, but developers faced a costly, drawn-out process for approval to connect to the transmission grid. They waited four years or more for a go-ahead, analysts have documented.

By then, financing commitments had aged out, momentum had faded and stalled, according to analysis by the Lawrence Berkeley National Laboratory and other reviews.

PJM denied a request to interview its top executive. The regional grid, which dispatches generation and manages electric reliability, reports it had approved 37,000 MW of new projects, mostly solar, as of the end of 2023. As of last September, none had been built.

PJM has tried to catch up with the problem of the long queue of proposed generation projects. “Frankly, one of the top jobs that PJM had was running the queue," Chandler said. "That's certainly been a failure on their part.”

Natural gas projects now must deal with backlogged order books at gas turbine manufacturers and threats of shortages of imported grid components targeted by Trump’s tariffs. New gas generating plants are key to Trump’s plans, but they require building more gas pipelines, typically against local opposition.

On top of that is the damage to investor confidence stemming from the head-spinning vertigo between 2021 and now. Former President Joe Biden made a major policy drive at moving away from coal for good and making big investments in advancing this century’s energy technology. Trump has spent almost every day of his new term cutting funding for clean energy and talking up oil, gas and coal.

“It is absolutely true that uncertainty is keeping new generation from being built,” Chandler said.

PJM’s annual “capacity auction” — the strategy it uses to line up commitments for future supplies from power plant owners — has not enticed much new generation.

PJM solicits bids from generators to supply power at the generators’ chosen price, and PJM chooses the least expensive ones, with the payments ultimately passed on to power customers. Plant owners selected in the auction commit to provide power in an upcoming “delivery” year, along with the payments they receive, also face a heavy fine if they don’t deliver power when called on by PJM.

The average incentive price for the 2024-2025 year was $29 per megawatt per day in most of PJM, for a total cost to customers of $2.2 billion, a price too low to prompt owners to build new plants or maintain old ones, analysts said.

Then came the data center demand eruption. With a power shortage looming, the price in last year's auction, for the 2026-2027 delivery year shot up 900 percent to nearly $270 per MW per day in most of PJM, bringing the charge to customers to $14.7 billion. Maryland customers, cornered in the easternmost

part of PJM with the fewest power supply options, were stuck with an even higher price, $466 per MW per day.

The next auction, scheduled this June, would be under a new set of rules continuing the churn of policy changes PJM has rolled out in recent years to get the results it wants and needs, Chandler said. These changes, like the payments to Talen Energy for the Baltimore plants, require FERC approval.

For the upcoming auction Pennsylvania Gov. Josh Shapiro demanded and got PJM to agree to lower the maximum permitted bid from $500 per MW per day to about $325 per MW per day. “We believe that not moving forward with this settlement would have left us in an untenable situation,” said Stu Bresler, PJM executive vice president for market services and strategy.

“Supply and demand are not only getting tighter, but the situation is almost accelerating in that direction,” Besler said.

The dilemma is unfolding. “Everybody wants capacity, but nobody's happy to bear the costs of funding those investments, and so nothing has happened, which leaves us kind of where we are today,” Niemann said.

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BY CHRISTA MARSHALL

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The Business Case for New Gas Is Shrinking

The Inflation Reduction Act makes clean energy cheaper than more than 90 percent of proposed gas plants.

December 8, 2022

By Lauren Shwisberg

As the dust settles following the passage of the Inflation Reduction Act (IRA), the electricity industry is only beginning to understand its true impacts. One of

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those impacts is the continued erosion of the business case for new fossil gas power plants.

Over the past decade, fossil gas power plants became the default resource option for utility investment, making up a majority of capacity additions. While over the past few years the total capacity of plants built has **declined** and high **profile cancellations** have increased, the IRA's tax incentive provisions will accelerate deployment of cleaner, cheaper electricity — making gas an even less competitive choice.

New RMI analysis shows just how much the IRA changes the game.

The Analysis

We used our Clean Energy Portfolios Model — updated to include resource cost projections that reflect post-IRA levels of tax credits — to identify the lowest cost portfolio of wind, solar, battery energy storage, energy efficiency, and demand flexibility that can provide the same estimated services as a proposed fossil gas plant.

When we ran 76 GW of fossil gas plants proposed before 2035 through our Clean Energy Portfolios Model, we found that the vast majority of plants were more expensive than their respective clean energy portfolios (CEPs), shown in Exhibit 1. In a scenario where clean

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energy resources use the 30 percent Investment Tax Credit or the Production Tax Credit at $26/MWh, clean energy outcompetes 93 percent of proposed fossil gas plants — more than 20 percent more than pre-IRA.

With additional bonuses for investment in energy communities, use of domestically sourced resources, or siting in low-income communities, in nearly every instance, clean energy beats gas on cost alone. That means that when taking full advantage of the tax credits in the IRA, clean, renewable sources will be cheaper than 99 percent of proposed gas plants — plants that are contributing to price volatility in American household energy bills.

> When taking full advantage of the tax credits in the Inflation Reduction Act, clean, renewable sources will be cheaper than 99 percent of proposed gas plants.

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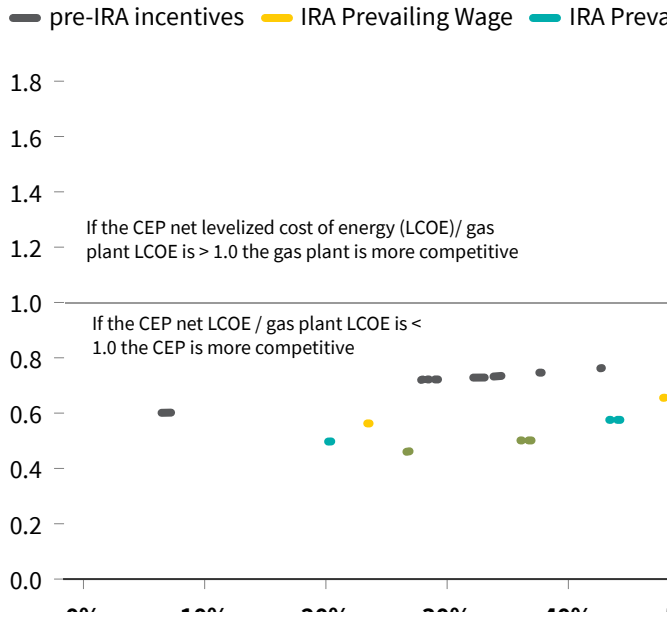
Impacts of IRA incentives on the percent cumulative capacity of competitive CEPs



IRA credit scenario assumptions and results

Credit scenario (2022$)	CEP results
Pre-IRA Incentives	72% of plants outcompeted
Prevailing wages - ITC at 30%, PTC at $26/MWh	93% of plants outcompeted
Prevailing wages +	

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The Power of Financial Incentives

One of the main reasons for this is that post-IRA solar and wind costs are expected to plummet. Analysts are projecting that renewables costs will continue to fall – with jaw-droppingly low prices for wind and solar by the end of the decade.

Credit Suisse, for example, **made headlines** when it projected $5/MWh wind and solar by 2029. S&P Global and IHS Markit **projected** numbers nearly as low — with about $10/MWh solar in 2030 falling to $5/MWh by 2035. Consulting firm ICF's **projections**, though slightly less bullish, still predict that a levelized cost of energy for solar and wind in 2030 will be 20–35 percent and 38–49 percent lower, respectively, than pre-IRA.

In most of these forecasts, renewable costs fall below the go-forward cost of a combined cycle gas plant — generally expected to be at least $30–$40/MWh. This means it will be cheaper on a per megawatt hour basis to build new wind and solar than to continue to operate existing gas.

Exhibit 3 aggregates these projections (Credit Suisse, S&P Global and IHS Markit, and ICF's low projections for 2030) into charts that show an indicative range of levelized cost of energy for wind and solar post-IRA, compared with NREL's 2022 Annual Technology Baseline pre-IRA.

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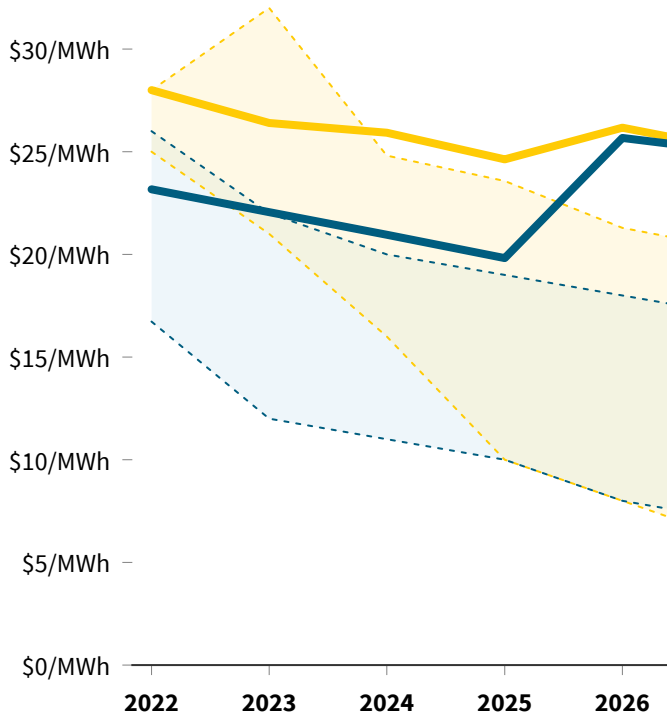
Analyst projections of solar and wind LCOE pre-IRA and post-IRA ($2021)



Source: RMI analysis of NREL 2022 Annual Technology Baseline data (Wind Class 4, Utility

While our analysis in the Clean Energy Portfolios Model only looked at battery energy storage and demand flexibility to provide firm, dispatchable energy, a host of new resource options may also be **cost-competitive** with fossil gas by the end of the decade. A range of "clean firm" technologies will increasingly compete directly with fossil gas, such as alternative energy storage technologies, geothermal, advanced nuclear, hydrogen-fired turbines, and carbon capture and storage.

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Updated Resource Plans and Procurement Processes Can Unlock $5 Billion per Year in Savings

RMI's analysis and other independent analysts are showing that the IRA can fundamentally change the math on the next right utility investment — and deliver substantial savings to customers. These aren't far-off future projections either. Cheaper, cleaner energy is the result of strong policy we passed this year.

There are actions **regulators** and utilities can take today to realize the IRA's projected **$5 billion** per year in savings for their ratepayers. New resource plans can include updated resource costs that accurately represent the new tax credits, seek to represent the full range of resources that may be commercially available within the planning horizon, and demonstrate how they will use additional IRA funding sources such as **the Energy Infrastructure Reinvestment program**. While costs remain uncertain, regulators and utilities can use **all-source procurement** — a competitive process that solicits bids from all types of resources — for near-term needs to discover the market prices and relative competitiveness across resources.

As these changes begin to make their way into utility planning and procurement, we're starting to see results:

- DTE Energy in Michigan filed its Integrated Resource Plan in early November, with a scenario that factored in IRA tax incentives. Utility executives **reported** that they expected the IRA to lower the price tag of their 20-year plan for customers about $500 million.
- The Minnesota Public Utilities Commission approved Xcel's request this week to build 460 MW of solar at a retiring coal plant site — part of a CEP that will avoid a new gas plant. Xcel **reported** that the IRA was anticipated to save ratepayers 30 percent over its initial estimate of project costs.
- **Duke Energy** in Florida is providing customers with a $56 million refund as a result of solar tax credits.
- **Ameren** is proposing to lower customer rates by 4.5 percent.

To fully realize the benefits of the IRA, now is the time for utilities and regulators to reevaluate plans for investing in new fossil gas power plants and take advantage of the opportunity to deliver ratepayer savings with cleaner options.

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The WHITE HOUSE

PRESIDENTIAL ACTIONS

Temporary Withdrawal of All Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects

The White House

January 20, 2025

January 20, 2025

MEMORANDUM FOR THE SECRETARY OF THE TREASURY
THE ATTORNEY GENERAL
THE SECRETARY OF THE INTERIOR
THE SECRETARY OF AGRICULTURE
THE SECRETARY OF ENERGY
THE ADMINISTRATOR OF THE ENVIRONMENTAL PROTECTION AGENCY

SUBJECT: Temporary Withdrawal of All Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects

Section 1. Temporary Withdrawal of Areas. Consistent with the principles of responsible public stewardship that are entrusted to this office, with due consideration for a variety of relevant factors, including the need to foster an energy economy capable of meeting the country's growing demand for reliable energy, the importance of marine life, impacts on ocean currents and wind patterns, effects on energy costs for Americans –- especially those who can least afford it –- and to ensure that the United States is able to

maintain a robust fishing industry for future generations and provide low cost energy to its citizens, I hereby direct as follows:

Under the authority granted to me in section 12(a) of the Outer Continental Shelf Lands Act, 43 U.S.C. 1341(a), I hereby withdraw from disposition for wind energy leasing all areas within the Offshore Continental Shelf (OCS) as defined in section 2 of the Outer Continental Shelf Lands Act, 43 U.S.C. 1331. This withdrawal shall go into effect beginning on January 21, 2025, and shall remain in effect until this Presidential Memorandum is revoked.

To the extent that an area is already withdrawn from disposition for wind energy leasing, the area's withdrawal is extended for a time period beginning on January 21, 2025, until this Presidential Memorandum is revoked.

This withdrawal temporarily prevents consideration of any area in the OCS for any new or renewed wind energy leasing for the purposes of generation of electricity or any other such use derived from the use of wind. This withdrawal does not apply to leasing related to any other purposes such as, but not limited to, oil, gas, minerals, and environmental conservation.

Nothing in this withdrawal affects rights under existing leases in the withdrawn areas. With respect to such existing leases, the Secretary of the Interior, in consultation with the Attorney General as needed, shall conduct a comprehensive review of the ecological, economic, and environmental necessity of terminating or amending any existing wind energy leases, identifying any legal bases for such removal, and submit a report with recommendations to the President, through the Assistant to the President for Economic Policy.

Sec. 2. Temporary Cessation and Immediate Review of Federal Wind Leasing and Permitting Practices**.** (a) In light of various alleged legal deficiencies underlying the Federal Government's leasing and permitting of onshore and offshore wind projects, the consequences of which may lead to grave harm — including negative impacts on navigational safety interests, transportation interests, national security interests, commercial interests, and marine mammals — and in light of potential inadequacies in various environmental reviews required by the National Environmental Policy Act to lease or permit wind projects, the Secretary of the Interior, the Secretary of Agriculture, the Secretary of Energy, the Administrator of the Environmental Protection Agency, and the heads of all other relevant agencies, shall not issue new or renewed approvals, rights of way, permits, leases, or loans for onshore or offshore wind projects pending the

completion of a comprehensive assessment and review of Federal wind leasing and permitting practices. The Secretary of the Interior shall lead that assessment and review in consultation with the Secretary of the Treasury, the Secretary of Agriculture, the Secretary of Commerce, through the National Oceanic and Atmospheric Administration, the Secretary of Energy, and the Administrator of the Environmental Protection Agency. The assessment shall consider the environmental impact of onshore and offshore wind projects upon wildlife, including, but not limited to, birds and marine mammals. The assessment shall also consider the economic costs associated with the intermittent generation of electricity and the effect of subsidies on the viability of the wind industry.

(b) In light of criticism that the Record of Decision (ROD) issued by the Bureau of Land Management on December 5, 2024, with respect to the Lava Ridge Wind Project Final Environmental Impact Statement (EIS), as approved by the Department of the Interior, is allegedly contrary to the public interest and suffers from legal deficiencies, the Secretary of the Interior shall, as appropriate, place a temporary moratorium on all activities and rights of Magic Valley Energy, LLC, or any other party under the ROD, including, but not limited to, any rights-of-way or rights of development or operation of any projects contemplated in the ROD. The Secretary of the Interior shall review the ROD and, as appropriate, conduct a new, comprehensive analysis of the various interests implicated by the Lava Ridge Wind Project and the potential environmental impacts.

(c) The Secretary of the Interior, the Secretary of Energy, and the Administrator of the Environmental Protection Agency shall assess the environmental impact and cost to surrounding communities of defunct and idle windmills and deliver a report to the President, through the Assistant to the President for Economic Policy, with their findings and recommended authorities to require the removal of such windmills.

(d) The Attorney General may, as appropriate and consistent with applicable law, provide notice of this order to any court with jurisdiction over pending litigation related to any aspect of the Federal leasing or permitting of onshore or offshore wind projects or the Lava Ridge Wind Project, and may, in the Attorney General's discretion, request that the court stay the litigation or otherwise delay further litigation, or seek other appropriate relief consistent with this order, pending the completion of the actions described in subsection (a) or subsection (b) of this section, as applicable.

This memorandum shall be implemented consistent with applicable law and subject to the availability of appropriations.

This memorandum is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person. You are authorized and directed to publish this memorandum in the *Federal Register.*

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