U.S. House Committee on Energy and Commerce
Subcommittee on Energy
"Winter Storm Fern Lessons: Supplying Reliable Power to Meet Peak Demand."
March 17, 2026
Documents for the Record

1. March 16, 2026, Letter from America's Power addressed to Chairman Guthrie, Chairman Latta, and Ranking Member Castor, submitted by the Majority.
2. March 2, 2026, Op-ed entitled "America's Electricity Price Shock Absorber" submitted by the Majority.
3. March 16, 2026, Letter from Industrial Energy Consumers of America (IECA) addressed to Chairman Latta and Ranking Member Castor, submitted by the Majority.
4. March 13, 2026, Letter from American Gas Association addressed to Chairman Latta and Ranking Member Castor, submitted by the Majority.
5. March 2026, Report from Always On Energy Research titled "The Financial Fallout From Winter Storm Fern: How Disappearing Wind and Solar Generation Cost Texans an Additional $766 Million, submitted by the Majority.
6. 2025, Executive Summary of a report by the National Petroleum Council titled "Reliable Energy: Delivering on the Promise of Gas-Electric Coordination," Submitted by the Majority
7. March 17, 2026, Letter from The Williams Companies, Chairman Guthrie, Chairman Latta, Ranking Member Castor and Ranking Member Pallone, submitted by the Majority.
8. February 2026, Executive Summary of a report by the Federal Energy Regulatory Commission titled "Report on the North American Electric Reliability Corporation: Interregional Transfer Capability Study," Submitted by the Majority
9. February 3, 2026, Article from RMI titled "Winter Storm Fern Highlights the Need for More Resilient Transmission," Submitted by Rep. Peters

AMERICA'S POWER
Reliable • Secure • Resilient • Affordable

March 16, 2026

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

Representative Bob Latta, Chairman
Subcommittee on Energy
U.S. House of Representatives
Washington DC 20515

Dear Chairman Guthrie and Chairman Latta:

I am writing to briefly highlight information to help inform your March 17 hearing "Winter Storm Fern Lessons: Supplying Reliable Power to Meet Peak Demand." This information is based on a report prepared by Energy Ventures Analysis (EVA).

The EVA report analyzed the performance of different electricity resources in regions of the country that were the most heavily impacted by Fern. These regions include the Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), PJM Interconnection (PJM), Electric Reliability Council of Texas (ERCOT), and the southeastern U.S. EVA found that **almost 90% of the incremental demand on the peak electricity demand day was met by dispatchable fossil-fuel generation** (coal, natural gas, and oil). Wind and solar provided 7% of the incremental demand.

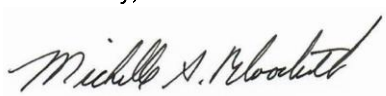
To meet the greater demand for electricity during extreme weather, power sources must increase their capacity factors if they can. EVA used EIA data to compare capacity factors during the first two weeks of January (before Fern) and during Fern, when more electricity was needed. Across the five regions that have coal power plants, the average capacity factor for the coal fleet increased from 43% to 78%, natural gas rose from 34% to 57%, wind declined from 32% to 26%, and solar remained unchanged at 13%. Nuclear plants were already running at their maximum capacity factors prior to Fern.

Coal power plants also saved consumers money during Fern. To illustrate the effect of the coal fleet on power prices, EVA assumed that the coal fleet was removed from the grid in four regions of the country – PJM, MISO, ERCOT, and SPP – when Fern peaked. Without their coal power plants, these regions, which collectively have 110,000 megawatts of coal-fired generation, would have been forced to rely more on natural gas power plants at a time when gas prices were high. Without coal, power prices were estimated to increase on the peak day of Fern by 45% ($111/MWh higher) in PJM, 54% ($108/MWh higher) in ERCOT, 79% ($187/MWh higher) in SPP, and 93% ($184/MWh higher) in MISO.

These increases in power prices that were avoided because of the coal fleet translate into savings for ratepayers of almost $1.15 billion across all four regions on the peak electricity demand day. The savings by region were estimated to be $420 million for MISO, $347 million for PJM, $195 million for SPP, and $185 million for ERCOT. It is important to note that these savings are for a single peak day in each region, not for the entire duration of the storm, which lasted for roughly one week. Thus, the coal fleet likely saved ratepayers considerably more than $1.15 billion before Fern ended.

We commend the subcommittee for holding this hearing and trust this information is helpful.

Sincerely,



Michelle Bloodworth
President and CEO

Copy to:

Representative Kathy Castor, Ranking Member
Subcommittee on Energy
U.S. House of Representatives
Washington DC 20515

DC JOURNAL

[IS] OPINION ENERGY

America's Electricity Price Shock Absorber

by Rich Nolan
March 2, 2026

Coal generation has been irreplaceable this winter. Secretary of Energy Chris Wright even called it the "MVP of the huge cold snap" the nation faced in January.

Not only has this winter's bitter cold underscored the importance of coal to the nation's power supply, it has also served as a critical reminder of the importance of sound energy policy.

If the Biden administration had gotten its way, many of the coal-fired power plants that have come to the rescue over the past two months would have been sitting dark and idle as grid operators scrambled for electricity reserves that no longer exist.

The Trump administration's efforts to prioritize the coal fleet to backstop grid reliability are already paying dividends. What's more, the data show coal is playing a key role in tempering electricity price inflation. In fact, it was an irreplaceable price-shock absorber for consumers in 2025.

According to a new economic study, increased coal generation last year shielded consumers from a 26 percent rise in natural gas prices, delivering an estimated $30 billion to $40 billion in savings. The average household saved $100 to $150 on its power and natural gas bills. In states with greater access to coal power, where there was more opportunity for fuel switching, savings were far larger.

This economic analysis underscores the importance of optionality in the electricity marketplace and the value of coal generation as a buffer against natural gas price volatility. Even a small change in natural gas prices can have an enormous impact on the economy.

The Industrial Energy Consumers of America, representing 12,000 manufacturing facilities across the country, estimates that with just a $1 rise in the Henry Hub natural gas price, consumers pay, on average, $34 billion more for natural gas and $20 billion more for electricity. The U.S. Energy Information Administration sees the Henry Hub spot price for natural gas averaging $4.30 this year, after averaging $3.50 in 2025 and just $2.21 in 2024.

Ensuring coal generation is available to relieve pressure on natural gas demand — and meet soaring electricity demand — will be critical to affordability.

Driven by the AI revolution and the rapid data center buildout, electricity demand in the U.S. is expected to jump 25 percent by 2030 and nearly 80 percent by 2050. In some regions, where data center development is concentrated, demand is growing even faster.

Peak winter power demand is expected to increase by 245 gigawatts in the next decade — the equivalent of the power needs of 150 million homes. Meeting that demand reliably and affordably requires the coal fleet. It almost certainly requires getting even more power from it.

There are few options to bring more dispatchable power to the grid immediately. Coal plants are the exception. The underutilized coal fleet represents gigawatts of needed capacity hiding in plain sight that can reliably surge power when needed while simultaneously shielding consumers from potential price shocks.

For too long, policymakers began energy policy conversations by looking beyond coal. Now, America’s energy present and future need it more than ever. Fortunately, we are seeing a return to responsible energy policy that recognizes that reality.

Industrial Energy Consumers of America (IECA)
The Voice of the Industrial Energy Consumers

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March 16, 2026

The Honorable Bob Latta
Chairman
Subcommittee on Energy
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

The Honorable Kathy Castor
Ranking Member
Subcommittee on Energy
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

Re: Hearing on "Winter Storm Fern Lessons: Supplying Reliable Power to Meet Peak Demand"

Dear Chairman Latta and Ranking Member Castor:

The manufacturing sector's economic growth has never before faced such a growing crisis as we are faced with today, due to inadequate natural gas pipeline capacity. The recent protracted cold weather has once again shown the fragility of our nation's natural gas system as 47 pipelines (see Figure 1) across the country issued operational flow orders (OFOs), restrictions, or curtailment notices to manufacturing companies to reduce demand in order to service the needs of homeowners, electricity generation, and LNG exports. Some manufacturers paid natural gas prices as high as $154 per MMBtu. Prices rose so high that some manufacturing companies shut down because it was not profitable to operate.

When there is inadequate pipeline capacity, manufacturing companies are always the first to be curtailed. Curtailment can cost tens of millions of dollars per day per facility, disrupt operations, damage equipment, and impact supply chains for consumer, industrial, and national defense products.

One hundred percent of IECA member companies are from the manufacturing sector and their competitiveness is dependent upon the affordability of natural gas and electricity. Natural gas is used as a fuel and feedstock. The U.S. manufacturing sector consumes 26 percent of the U.S. natural gas. Most manufacturing facilities operate 24/7 and require reliable supply and at affordable prices.

Pipeline warnings or notices to reduce or curtail supply are now in both winter and summer, more frequent and severe due to higher demand for electricity generation and LNG exports. Increasing electrical demand by data centers, crypto currency, and the electrification of the economy are all intensifying the problem. Pipeline capacity increases are not keeping pace with demand.

We ask Congress to take swift and decisive action to address this urgent problem and advance energy permitting legislation to expedite the expansion of our nation's natural gas pipeline network to serve our nation's growing demand.

Sincerely,

Paul N. Cicio
Paul N. Cicio
President & CEO

cc: House Committee on Energy and Commerce

FIGURE 1
Natural Gas Pipelines (interstate, intrastate, LDCs) that have issued operational flow orders (OFOs), restrictions or curtailments this winter

1.	Adelphia Gateway LLC
2.	Ameren MO
3.	ANR Pipeline Company
4.	Atlanta Gas & Light
5.	Atmos Energy:
6.	Baltimore Gas and Electric
7.	Bangor Natural Gas Company
8.	Carolina Gas Transmission
9.	Columbia Gas Transmission Company: MD, OH, VA, PA, WV
10.	Constellation
11.	Duke Energy: OH, KY, SC, NC
12.	East Tennessee Natural Gas
13.	Eastern Gas Pipeline
14.	Enable Gas Transmission, LLC
15.	Enbridge Natural Gas Company
16.	Equitrans Midstream Corp
17.	Florida Gas Transmission Company
18.	Great Lakes
19.	Liberty Utilities
20.	Louisville Gas and Electric
21.	Maritimes & Northeast Pipeline
22.	Michigan Gas Utilities
23.	Millennium Pipeline Co, LLC
24.	National Fuel Gas
25.	Natural Gas Pipeline of America (NGPL)
26.	Northern Indiana Public Service Company (NIPSO)
27.	NiSource
28.	Northern Natural Gas

29.	Northwest Pipeline
30.	Oklahoma Natural Gas
31.	Ozark Gas Transmission
32.	Panhandle Eastern Pipe Line Company
33.	Peoples Gas
34.	Piedmont Natural Gas: TN, NC, SC
35.	Portland Natural Gas Transmission System
36.	SEMCO Energy Gas Company
37.	Southern Natural Gas Company
38.	Southern Star Central Gas Pipeline
39.	Southwest Gas Corporation
40.	Spire MoGas Pipeline
41.	Summit Natural Gas of Maine
42.	Tennessee Gas Pipeline Company
43.	Texas Eastern Transmission Pipeline: TX, TN
44.	Transcontinental Gas Pipeline: VA, NC, PA, MD, NY, SC, GA Zone 4, 5, 6
45.	Trunkline Gas Company, LLC
46.	Vectren, Ohio
47.	Wisconsin Public Service

The Honorable Robert E. Latta
Chairman, Subcommittee on Energy
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

The Honorable Kathy Castor
Ranking Member, Subcommittee on Energy
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 "Winter Storm Fern Lessons: Supplying Reliable Power to Meet Peak Demand"

Dear Chairman Latta and Ranking Member Castor:

The American Gas Association ("AGA") respectfully submits this letter to the Energy and Commerce, Subcommittee on Energy ("Subcommittee") for the record for the Subcommittee on Energy hearing titled "Winter Storm Fern Lessons: Supplying Reliable Power to Meet Peak Demand."

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. AGA's Commitment to Gas-Electric Coordination

Effective gas-electric coordination is essential for maintaining the reliability and resiliency of the energy system during times of high energy demand, especially as more than 189 million Americans and 5.8 million businesses use natural gas, and natural gas accounts for 43% of power generation[2] with approximately 25% of this volume being transported to generators via natural gas utilities. High demand energy periods and weather events, like Winter Storm Fern, can test the reliability of the energy system, and can highlight healthy coordination and potential vulnerabilities of the interdependence between the gas and electric industries. When vulnerabilities occur, such events can compromise the ability of AGA's members to reliably deliver natural gas to homes, hospitals, and businesses, while also meeting the surging demand from electric power generation in recent years. Enhancing gas-electric coordination is now also critical to winning the artificial intelligence ("AI") race due to the unprecedented rise in electricity demand from AI and data centers, which adds another layer to the already existing reliability challenges. Furthermore, natural gas plays a critical role in fueling and maintaining the competitiveness of U.S. manufacturing, particularly as energy demand continues to rise.[3] AGA and its members remain committed to continuing our efforts to better ensure the reliability of both the natural gas and electric systems.

[1] For more information, please visit www.aga.org.
[2] *See* Use of Natural Gas-fired Generation Differs in the United States by Technology and Region, Today in Energy (Feb. 22, 2024), available at https://www.eia.gov/todayinenergy/detail.php?id=61444, (last visited March 12, 2026).
[3] *See* Strategic Equilibrium: The United States' Manufacturing Resurgence and the Role of Natural Gas in a Carbon-Competitive World, Centers for Strategic & International Studies (Sept. 10, 2024), available at https://www.csis.org/analysis/strategic-equilibrium-united-states-manufacturing-resurgence-and-role-natural-gas-carbon, (last visited March 12, 2026).

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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 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 utility is the delivery of natural gas to its customers safely, reliably, responsibly, and at just and reasonable rates.[4] Natural gas utilities are obligated under state law and regulatory requirements to distribute natural gas to retail, residential, commercial, governmental, and industrial customers.[5] In order to meet this statutory obligation to serve, utilities develop detailed long-term supply and transportation plans, as well as acquire firm gas supply, primarily firm upstream transportation, firm storage capacity, and may also, depending on the region, utilize firm peaking resources to ensure that they can reliably meet the physical demand for service on peak days both today and in the future. There is also extensive overlap and interdependency between the gas and electric systems, wellhead to burner tip, since parts of the value chain rely on electricity for processing and compression, as well as home natural gas furnaces that operate in tandem with an electric blower. Additionally, as stated above, the electricity sector has deepened its reliance on natural gas for power generation. Therefore, AGA's gas-electric coordination focus is on both ensuring reliability and resiliency for gas customers and supporting the electric industry.

In addition to the overall goal of gas-electric coordination being to preserve and enhance reliability for all customers, both gas and electric, harmonization and coordination efforts and discussions should include the following elements, among other things:

- Reliability efforts should be coordinated so that the reliability of one system is not achieved at the expense of the other system's customers.

- Addressing reliability will require a better understanding of both the day-to-day operations of both systems and the longer-term impacts on operations, planning, and cost to consumers.

- The gas system, particularly natural gas utility service, is reliable and resilient because natural gas utilities plan for the peak demand day (or winter peak) and use a portfolio of mechanisms to ensure that customers receive gas. This planning model helps ensure reliability and therefore should be considered and discussed in harmonization efforts.

- Harmonization should not focus narrowly on whether changes should be made to the gas industry as a solution for other reliability concerns.

- Any harmonization effort must preserve the historical quality of service received by all firm pipeline and storage customers.

[4] Elements of an LDC's retail services are regulated at the state level, not by the Commission. *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.").

[5] 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.

- Coordination efforts should draw on regional experience and expertise, stakeholders, including all relevant gas and electric interests, state commissions and agencies, *etc*.

Furthermore, enhancing communication and information sharing between both sectors is a top priority for AGA and is evidenced by AGA's engagement in various industry efforts and forums over the years. AGA and its members have been active in many forums and venues aimed at improving reliability and resiliency, as well as gas-electric coordination. This includes filings with and proceedings before the Federal Energy Regulatory Commission ("FERC") and various state regulators and agencies. Additionally, AGA and gas utilities are active participants in every level of the North American Energy Standards Board ("NAESB"), and AGA regularly participates in North American Electric Reliability Corporation ("NERC") meetings. Below is a non-exhaustive overview of activities AGA has participated in since 2018 and after Winter Storms Uri and Elliot, but please note other efforts would have predated the aforementioned time period.

1. NAESB

AGA and its members participate at NAESB via various committee activities that relate to gas-electric reliability and coordination. This includes the standards making processes and efforts to update the Base Contract for Sale and Purchase of Natural Gas ("NAESB Base Contract"). Moreover, AGA and its members were active in the NAESB Gas-Electric Harmonization ("GEH") Forum. NAESB convened the recent iteration of the GEH Forum following the July 2022 FERC/NERC report on Winter Storm Uri ("Winter Storm Uri Report"),[6] which recommended the establishment of a forum to discuss gas-electric matters. The GEH Forum started meeting in August 2022 and the final NAESB GEH Report with recommendations was issued in July 2023. AGA and various natural gas utility representatives participated in multiple meetings of the GEH Forum. AGA submitted multiple comment letters and voted via multiple surveys as part of the GEH Forum process. AGA also voted on the draft recommendations that were ultimately included in the final report.

Additionally, NAESB is positioned to respond to requests for further action concerning reliability matters, to the extent requested. As part of the 2026 annual plans for certain quadrants, NAESB included a provisional activity that provides that NAESB, upon a request or as directed by the NAESB Board or a relevant jurisdictional entity, will consider developing and/or modifying business practice standards that reflect best practices that will provide stronger operating reliability from production/supply/transport, for example, during extreme weather conditions, and more clear communications and business processes around force majeure declarations during critical operating periods.[7] This highlights that reliability and gas-electric coordination matters are still top of mind in 2026.

2. American Gas Foundation Reports on Resilience

In November 2022, the American Gas Foundation issued a report titled, "Enhancing and Maintaining Gas and Energy System Resiliency Areas of Focus and Change."[8] This study provides the technical, commercial, and regulatory analysis associated with the resilience of the U.S. gas system with the goal of identifying the necessary

[6] *See* February 2021 Cold Weather Outages in Texas and the South Central United States, A Joint Staff Report of FERC, NERC, and its Regional Entities (November 16, 2021), available at https://www ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and (last visited March 12, 2026).
[7] *See* the 2026 Annual Plans for the Wholesale Electric Quadrant and Wholesale Gas Quadrant, available at https://www.naesb.org/materials/gov.asp, (last visited March 12, 2026).
[8] *See* Enhancing and Maintaining Gas and Energy System Resiliency Areas of Focus and Change, AGA (Nov. 2022), available at https://gasfoundation.org/2022/10/14/enhancing-and-maintaining-gas-and-energy-system-resiliency/, (last visited March 12, 2026).

changes to the policy and regulatory framework for the energy industry to support gas system resilience investments. A prior report titled, "Building a Resilient Energy Future: How the Gas System Contributes to US Energy System Resilience," was issued in July 2021[9] and provides a framework for regulators, policymakers, and other stakeholders to examine energy system resilience and the role of the natural gas system.

3. AGA Report on the Value of Natural Gas Storage

In April 2025, AGA issued a report titled, "Assessing the Value of Natural Gas Storage - A Strategic Asset for Grid Reliability, System Resilience, and Operational Flexibility in a Changing Energy Landscape," ("Storage Report")[10] which highlights emerging pressures on natural gas infrastructure because of rapidly increasing demand for energy, including from data centers and a resurgence of American manufacturing. The Storage Report recommends policy considerations and strategic actions related to storage to support energy reliability, affordability, and security, including more flexible natural gas storage to preserve system reliability.

4. Natural Gas Council Report on Reliability

In April 2019, the Natural Gas Council[11] issued a report titled, "Natural Gas: Reliable and Resilient."[12] This report outlines the reliability and resilience of natural gas transportation, related regulatory authorities, and the contracting procedures necessary for large volume customers to best meet their service needs.

5. Gas-Electric Alignment for Reliability Taskforce

In November 2025, the National Association of Regulatory Utility Commissioners ("NARUC") Gas-Electric Alignment for Reliability ("GEAR") Taskforce released a final report for improving gas-electric coordination ("GEAR Report").[13] The GEAR Taskforce was a working group that brought together state regulators and industry representatives from the gas and electric industries, including a gas utility representative, to develop solutions to better align the gas and electric industries to maintain and improve the reliability of the gas and electric energy systems. GEAR gathered regulators and industry stakeholders in order to recommend solutions to better harmonize communication protocols, operations, and planning of the gas and electric systems and markets.

The GEAR Report documents the processes, results, and resolutions of GEAR. The GEAR Report states that the recommendations should serve as a backdrop and ongoing point of discussion to assist regulatory agencies

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[9] *See* Building a Resilient Energy Future: How the Gas System Contributes to US Energy System Resilience," an American Gas Foundation study prepared by Guidehouse (Jan. 2021), available at https://gasfoundation.org/wp-content/uploads/2021/01/Building-a-Resilient-Energy-Future-Full-Report_FINAL_1.13.21.pdf, (last visited March 12, 2026).

[10] *See* Assessing the Value of Natural Gas Storage - A Strategic Asset for Grid Reliability, System Resilience, and Operational Flexibility in a Changing Energy Landscape, AGA (Apr. 29, 2025), available at https://www.aga.org/research-policy/resource-library/assessing-the-value-of-natural-gas-storage/, (last visited March 12, 2026).

[11] The Natural Gas Council is comprised of five associations composed of thousands of companies that represent the industry from start to finish – from the wellhead to the burner tip. The Natural Gas Council consists of AGA, American Petroleum Institute, Independent Petroleum Association of America, Interstate Natural Gas Association of America, and Natural Gas Supply Association.

[12] *See* Natural Gas: Reliable and Resilient, Natural Gas Council (Apr. 2019), available at https://naturalgascouncil.org/wp-content/uploads/2019/04/Natural-Gas-Reliable-and-Resilient.pdf, (last visited March 12, 2026).

[13] *See* National Association of Regulatory Utility Commissioners Task Force on Gas-Electric Alignment for Reliability (GEAR) Report & Recommendations (Nov. 2025), available at https://pubs naruc.org/pub/2527936B-BEB6-767B-50BE-01BEEEB3091F, (last visited March 12, 2026).

and their partners in serving the needs of the natural gas system, the electric grid, and utility customers. The GEAR Taskforce issued several recommendations including the pertinent ones below:

- **Creation of a Natural Gas Readiness Forum -** GEAR supported the creation of a voluntary ongoing Natural Gas Readiness Forum dedicated to the enhancement of U.S. natural gas value chain reliability via the promotion of communication, peer-to-peer connections, situational awareness, and education among its participants and stakeholders to anticipate and respond to calamitous events and other issues.[14]

- **Natural Gas Pipeline Infrastructure -** With the widespread recognition that the United States needs additional natural gas pipeline infrastructure to reliably meet the United States' growing and changing demand for energy, NARUC, with the expertise and influence of its member states, should support federal permitting reform that would address infrastructure hurdles in a meaningful way such that new infrastructure may be in place in a timely manner to meet growing and changing natural gas and electricity demand.

- **Gas Storage Opportunities -** GEAR recognized the critical role of storage in supporting energy system reliability and recommended that states and organized power markets evaluate a wide array of solutions that affect the investment in, development of, and use of storage of all types, including associated infrastructure, to support the electricity grid and end use customer reliability under high energy demand conditions.

6. Natural Gas Readiness Forum

To demonstrate our commitment to the reliability of both systems and the energy system as a whole, AGA welcomed the opportunity to lead the Natural Gas Readiness Forum ("NGRF"). As noted above, NARUC launched the GEAR Taskforce to develop solutions to improve the reliability of the natural gas and electric energy systems. The GEAR Taskforce members unanimously recommended the creation of a NGRF and recommended that AGA administer the NGRF.

The NGRF is an industry-led voluntary effort aimed at improving the communication, preparation and readiness of the energy sector during winter events. The NGRF is comprised of multi-state stakeholders from the various elements of the natural gas and electric value chains, as well as federal and state regulators. The NGRF fosters operational education, situational awareness, and peer-to-peer connections across the natural gas industry, electric sector, end-users and relevant government agencies. Presentations explore the reliability of the energy system, how the natural gas system prepares for high demand periods, and cross-sector coordination with electric during extenuating circumstances.

AGA convened the first NGRF meeting in December 2024. The event included representatives from across the natural gas value chain (e.g., natural gas transportation, storage and distribution operators; natural gas producers) as well as representatives from the Commission, the Department of Energy, NERC, regional transmission operators, electric generators, energy trade associations, state regulatory utility commissions, and

[14] The Natural Gas Readiness Forum is discussed in more detail below.

state energy offices. In November 2025, AGA hosted the second annual NGRF. Energy industry stakeholders including, but not limited to, natural gas distribution operators, natural gas midstream operators, natural gas producers, state regulatory utility commissioners, regional transmission operators, and FERC representatives were in attendance to discuss industry coordination for the winter ahead.

The NGRF meeting and the agenda topics were designed to foster an environment that encouraged discussion of operational readiness across the entirety of the U.S. natural gas value chain and critical end users. The agenda included the following topics:

- Weather & Energy Outlook - National weather forecast and natural gas and electric outlooks
- Winter Preparedness of Government and Oversight Entities - Overview of winter preparedness activities of federal and state governments and oversight entities
- Winter Readiness Natural Gas Case Studies & Lessons Learned - Different parts of the natural gas value chain along with the electric sector highlight winter readiness case studies and lessons learned
- Perspectives from the Industry - Current and future trends of a specific sector regarding readiness
- Takeaways from the Regional Tabletop Exercises - Lead takeaways from the various regional meetings

The NGRF also introduced regional forums in 2025. The regional forums discuss various region-specific topics related to the reliability of the energy system. These forums include a tabletop emergency exercise to identify gaps in operations.

Importantly, on December 3, 2025, the National Petroleum Council ("NPC") issued a report titled, "Reliable Energy: Delivering on the Promise of Gas-Electric Coordination," ("NPC Gas-Electric Report").[15] The NPC Gas-Electric Report examines the risks arising from the misalignment of the natural gas and electric power sectors and outlines ten recommendations to safeguard reliability while keeping up with rising natural gas demand in the power sector. Several members of the natural gas industry were involved in drafting the study.

One of the recommendations directs NARUC to enhance dialogue and document best practices through the already established NGRF. Specifically, in Recommendation 9, the NPC recommends NARUC convene a NGRF working group to broaden stakeholder dialogue and document leading management practices across all interconnected sectors of the energy value chain. The NPC noted that the NGRF, established by NARUC and administered by AGA, is best positioned to convene diverse energy system stakeholders to document existing leading management practices and that no new entity needs to be created.

AGA is ready and committed to continue to build on the NGRF to improve the resilience of the energy system during peak demand periods. AGA looks forward to working alongside federal and state regulators and

[15] *See* Reliable Energy: Delivering on the Promise of Gas-Electric Coordination, A Report of the National Petroleum Council Committee on Gas-Electric Coordination (Dec. 3, 2025), available at https://gas-electric.npc.org/files/2025_Gas_Electric_Report.pdf, (last visited March 12, 2026).

other stakeholders to enhance coordination to ensure the energy sector can safely deliver heat to customers on the coldest day of the year. AGA is actively planning the 2026 NGRF events both on a national and regional basis.

B. Improved Coordination and Reliability Evidenced During Winter Storm Fern

There is no doubt the industry has made strides to mitigate disruptions to the energy system during severe winter weather events, such as Winter Storms Uri and Elliott. For example, during the January 2025 arctic events,[16] the electric and natural gas systems showed improved performance, in part due to lessons learned from prior storms, and better communication and coordination. Winter Storm Fern was a further example of the industry's hard work, despite the cold weather and a constrained energy system.

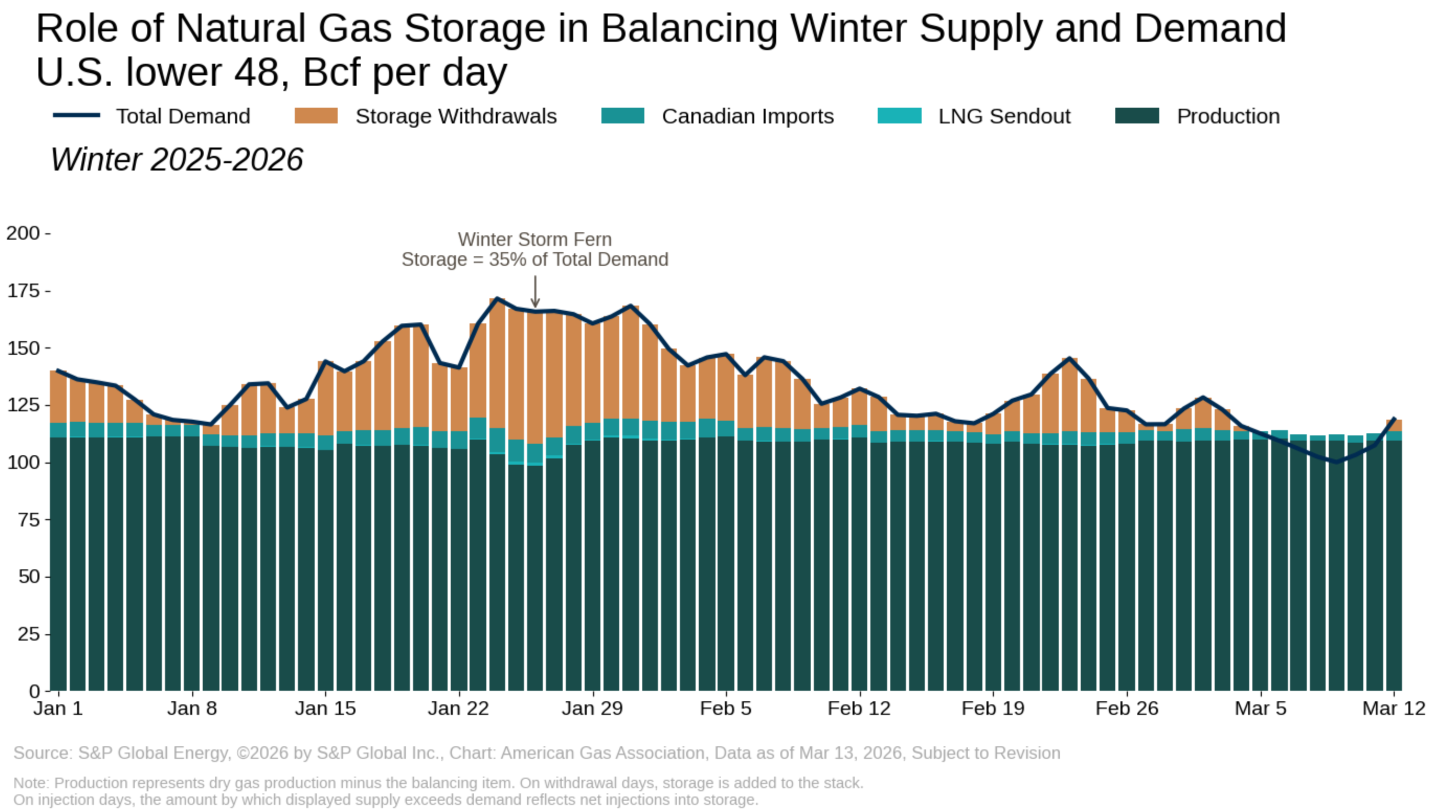
The modern U.S. natural gas system is built to meet consumer energy requirements during the coldest conditions. This inherent resilience and reliability was showcased this winter as extreme cold and multiple storms descended upon the eastern U.S. in January 2026. Winter Storm Fern produced the highest seven-day rolling average of total natural gas demand on record at 165.6 Bcf per day, starting on January 24 and ending on January 30.[17] Residential, commercial, electric power, and industrial consumption all spiked near-record daily highs. During the storm, natural gas was the primary source of electricity, with many regional grids relying on it as the primary or secondary energy source for peak hourly and daily generation.

1. Natural Gas Storage was Critical During Winter Storm Fern

One essential element that ensured reliability during Winter Storm Fern was natural gas storage. During Winter Storm Fern natural gas storage withdrawals hit a record high for the week ending January 30, 2026. Underground storage served up to 35% of demand during the event. Notably, the total natural gas demand reached 172 Bcf on January 24, 2026, just shy of the all-time high set on January 21, 2025, and remained above 160 Bcf/d for 10 days during Winter Storm Fern. The chart below illustrates the importance of natural gas storage in maintaining reliability during Winter Storm Fern.

[16] *See* January 2025 Arctic Events A System Performance Review, A Joint Staff Report of FERC, NERC, and its Regional Entities (Apr. 16, 2025), available at https://www ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional, (last visited March 12, 2026).

[17] *See* Natural Gas Market Indicators – February 5, 2026, AGA (Feb. 5, 2026), available at https://www.aga.org/research-policy/resource-library/natural-gas-market-indicators-502nd-edition/, (last visited March 12, 2026).



Natural gas storage is a critical component of the U.S. energy infrastructure, providing system reliability, stabilizing market prices, and enhancing resiliency during high-demand periods and unexpected disruptions. It helps counter historically seasonal variability of demand by serving as a physical hedge against commodity price fluctuations and changes in supply availability. The flexibility that natural gas storage offers is vital to keeping the heat and lights on during periods of high energy demand. Unfortunately, and as highlighted in the AGA Storage Report, "while LNG storage capacity, intrastate pipeline capacity, interstate pipeline capacity, production, and demand continue to grow, underground storage capacity additions remain stagnant."[18] The GEAR Taskforce tackled this matter by issuing a recommendation on natural gas storage,[19] which serves as a starting point to identify where potential investment in underground natural gas storage can improve natural gas system reliability and resiliency. This sentiment is also echoed in the recent NPC Gas-Electric Report. AGA supports continued use of and investment in natural gas storage to enhance reliability and strengthen energy security for all Americans.

2. Imports and LNG Offered Further Support

During Winter Storm Fern, the U.S. saw the highest Canadian imports in nearly two decades, a decline in LNG feedgas demand for export, and a 13 percent drop in production that reflected declines in largely oil-producing regions. Despite the drop in production, flowing gas declined less than in other major storms, notably

[18] *See* Assessing the Value of Natural Gas Storage - A Strategic Asset for Grid Reliability, System Resilience, and Operational Flexibility in a Changing Energy Landscape, AGA (Apr. 29, 2025), available at https://www.aga.org/research-policy/resource-library/assessing-the-value-of-natural-gas-storage/, (last visited March 12, 2026).

[19] *See* Gas Storage Opportunities Recommendation, GEAR Task Force (Mar. 2025), available at https://pubs.naruc.org/pub/191F5C4A-F3AA-426A-60A8-BF23226F5BA9, (last visited March 12, 2026).

Winter Storms Uri and Elliott. While production declined, it rebounded as temperatures eased, and, as of February 4, production levels are back to an output of roughly 105 to 106 Bcf per day. Moreover, LNG feedgas proved highly flexible, acting as a "relief valve" for the market during the arctic cold as LNG customers reduced demand. LNG export demand (feedgas) declined as much as 44 percent from pre-event levels (January 20-23), then quickly rebounded to 18.6 Bcf per day by January 28.[20] Finally, Canadian imports were a key incremental supply source during the winter storm, reaching 10.8 Bcf per day on January 24.[21] This level of daily Canadian imports reached the highest since 2008, underscoring the critical role that Canadian supplies still play in meeting gas demand in the U.S. market during seasonal peaks.

3. Winter Storm Fern Set Records

These successes occurred while the U.S. was experiencing sustained heating loads that were rewriting the record books. Every day from January 24 to January 31, 2026, ranked within the top 20 all-time demand days,[22] reflecting the depth and duration of the Arctic cold during and directly following Winter Storm Fern. Residential and commercial natural gas demand peaked at 72 Bcf per day on January 24, emphasizing the massive amount of energy required to sustain space-heating loads. To put this value into perspective, 70 Bcf of natural gas is equivalent to 900 GW of electricity generation capacity running for 24 hours, the same as 21.6 TWh of electricity. At that scale, the implied power output would far exceed the electricity systems of major advanced economies. In Germany, for example, total installed power generation capacity is around 270 GW, making 900 GW more than three times larger than that country's entire generation fleet.

On January 26, natural gas demand for electric power generation reached nearly 44 Bcf per day, nearing its prior winter record for gas consumption in the sector.[23] Natural gas was the number one source of electricity in ERCOT, PJM, NYISO, MISO, the Southeast, and Florida for nine days spanning January 23 through 31, and in Tennessee for eight of those nine days. Gas was similarly critical during many peak hours across these regional grids. In New England, oil was the primary generation source on five of the nine days, and natural gas was number two. In some other regions, natural gas was lower on the dispatch stack after coal, nuclear, and wind, but still within the top three sources of energy during the week. Furthermore, industrial natural gas demand climbed to 29 Bcf per day on January 24, among the highest winter-period days.

[20] *See* Natural Gas Market Indicators – February 5, 2026, AGA (Feb. 5, 2026), available at https://www.aga.org/research-policy/resource-library/natural-gas-market-indicators-502nd-edition/, (last visited March 12, 2026).
[21] *Id*.
[22] *Id*.
[23] *Id*.

C. Conclusion

The American Gas Association thanks the Energy and Commerce Subcommittee on Energy for continuing discussions on energy reliability and its efforts to identify opportunities and solutions to the challenges facing the energy industry today. While progress is encouraging, reliability is an ever-evolving challenge due to unpredictable weather events and the increasing demand for energy. Therefore, there is still more work to be done and system improvements remain necessary. AGA offers its assistance as a resource to the Subcommittee to achieve those solutions and keep the heat and lights on for millions of American families. If you have any questions regarding this submission, please do not hesitate to contact the undersigned.

Respectfully submitted,

Matthew J. Agen
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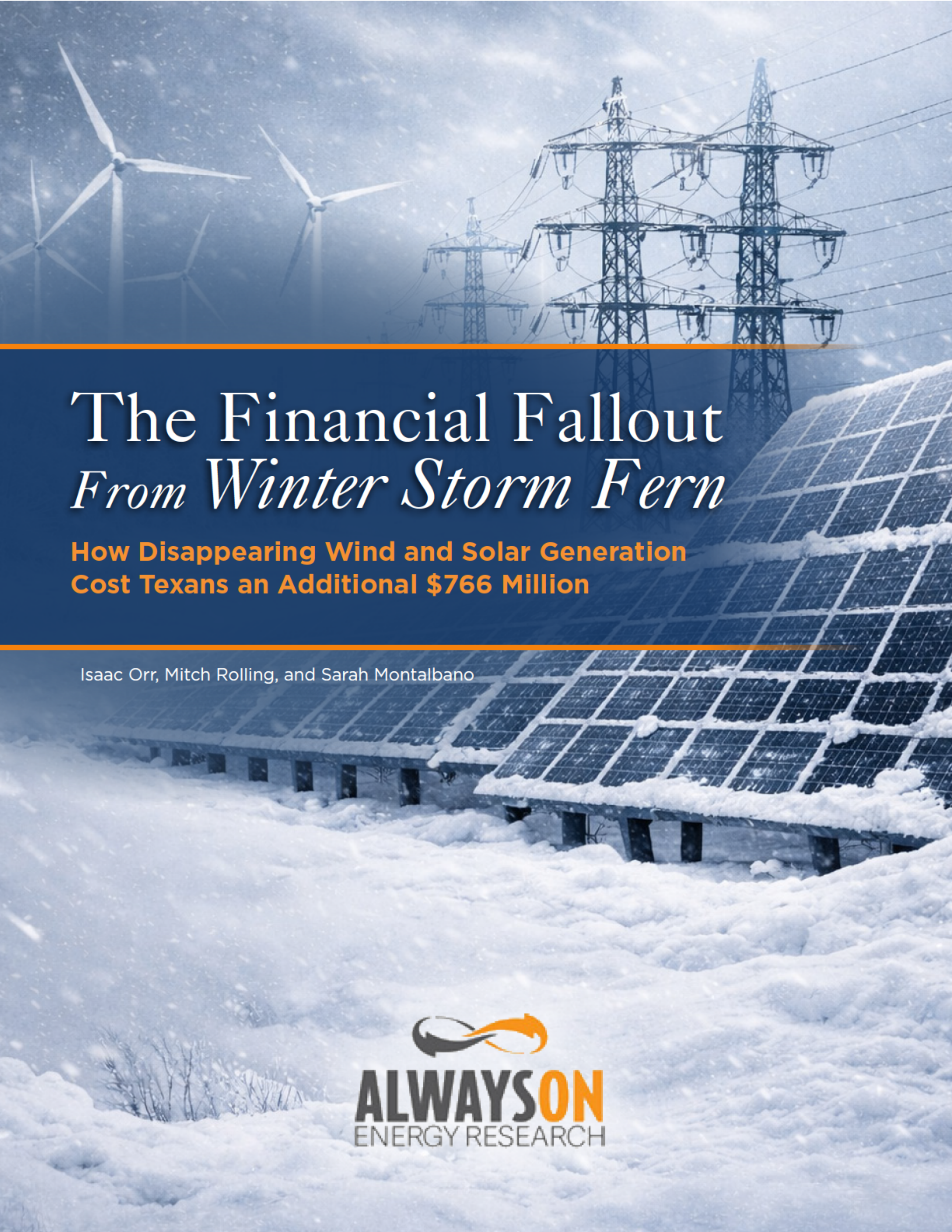
American Gas Association
400 N. Capitol Street, NW
Washington, DC 20001

Dated: March 13, 2026



The Financial Fallout *From Winter Storm Fern*

How Disappearing Wind and Solar Generation Cost Texans an Additional $766 Million

Isaac Orr, Mitch Rolling, and Sarah Montalbano

ALWAYSON
ENERGY RESEARCH

THE FINANCIAL FALLOUT FROM WINTER STORM FERN

HOW DISAPPEARING WIND AND SOLAR GENERATION COST TEXANS AN ADDITIONAL $766 MILLION

Isaac Orr, Mitch Rolling, and Sarah Montalbano

March 2026

INTRODUCTION

In the wake of Winter Storm Fern, the U.S. Department of Energy (DOE) released information demonstrating that power generation from America's thermal fleet carried the day, as coal, natural gas, nuclear, and oil, particularly in New England, provided 86 percent of the power generated during the peak of the storm.[1] In contrast, DOE's release noted that wind and solar generated just 8 percent and 2 percent of the nation's electricity, respectively, during the period of peak system stress.

This is despite the fact that U.S. Energy Information Administration (EIA) data show wind and solar constituted roughly 23 percent of the total installed capacity on the grid in January, meaning they underperformed relative to their installed capacity on the nation's power grid (see Figure 1).

The American Clean Power Association (ACP), the top lobbying arm of the wind and solar industry, has released its own narrative around the performance of wind, solar, and storage resources during Winter Storm Fern, arguing that wind and solar saved American consumers more than $2 billion during the winter weather event, including $200 million in savings in the Electric Reliability Council of Texas (ERCOT) Region.[2]

However, ACP's fact sheet did not describe the methodology used to determine these purported savings, and the organization did not respond to requests from Always On Energy Research (AOER) for more information about its calculations.

Therefore, AOER conducted its own analysis and determined that it is exceedingly unlikely that wind and solar saved Texans living in the ERCOT footprint *any money.* In fact, our analysis found low wind and solar generation during the height of the storm on January 25 likely cost Texans an additional $766 million in wholesale power costs in just 17 hours.

1 U.S. Department of Energy, "Fact Sheet: Energy Department Prevented Blackouts & Saved American Lives During Winter Storms," February 6, 2026, https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms.

2 American Clean Power Association, "Clean Energy Saved Consumers 2+ Billion During Winter Storm Fern," Accessed March 10, 2026, https://cleanpower.org/resources/clean-energy-saved-consumers-2-billion-during-winter-storm-fern/.

FIGURE 1: U.S. INSTALLED POWER PLANT CAPACITY AS OF JANUARY 2026

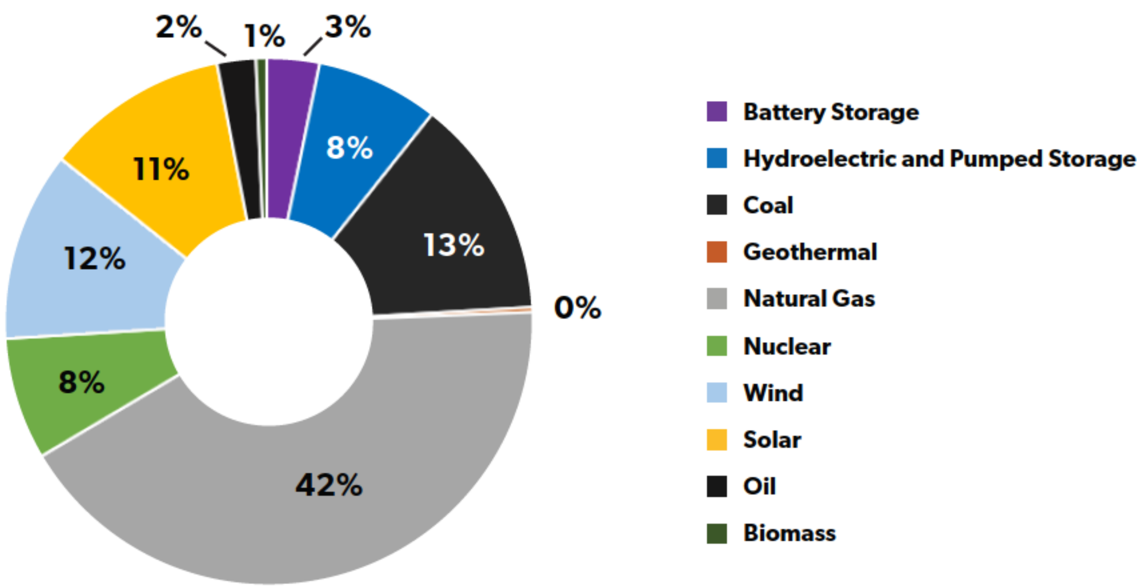


Figure 1. The thermal fleet constituted 66 percent of U.S. installed capacity but provided 86 percent of peak energy needs. In contrast, wind, solar, and batteries constituted 23 percent, and wind and solar contributed a combined 10 percent of the nation's electricity.

ERCOT'S GENERATION MIX

ERCOT has become increasingly dependent on weather-dependent resources, particularly wind energy, to meet its peak energy demand.

U.S. EIA data indicate that ERCOT has not added any net thermal capacity since 2013, as natural gas additions have been offset by coal plant closures.[3] Furthermore, the amount of thermal generation capacity on the ERCOT system has decreased since 2016, despite peak demand increasing by over 12,000 megawatts (MW), or by over 17 percent, in the last 10 years.[4]

According to the ERCOT Monthly Outlook for Resource Adequacy (MORA) report for January 2026, ERCOT had 183,709 MW of total installed capacity on its system during Winter Storm Fern, with a nameplate capacity of 87,938 MW for thermal resources and 93,828 MW for wind, solar, and battery storage.[5]

On paper, this should have been more than enough capacity to weather Winter Storm Fern, which saw a peak demand of slightly more than 75,000 MW, without a massive spike in prices. However, the ERCOT MORA data show that not all of this capacity is expected to be available during peak winter storm conditions, which occur in the mornings before

3 U.S. Energy Information Administration, "Texas Electricity Profile 2024," State Electricity Profile, November 10, 2025, https://www.eia.gov/electricity/state/texas/.

4 Ibid.

5 ERCOT, "Monthly Outlook for Resource Adequacy (MORA) Reporting Month: January 2026," Accessed March 10, 2026, https://www.ercot.com/files/docs/2025/11/07/MORA_January2026.pdf.

FIGURE 2: ERCOT INSTALLED AND EXPECTED AVAILABLE CAPACITY DURING WINTER STORM FERN HOUR ENDING 8 A.M. CST

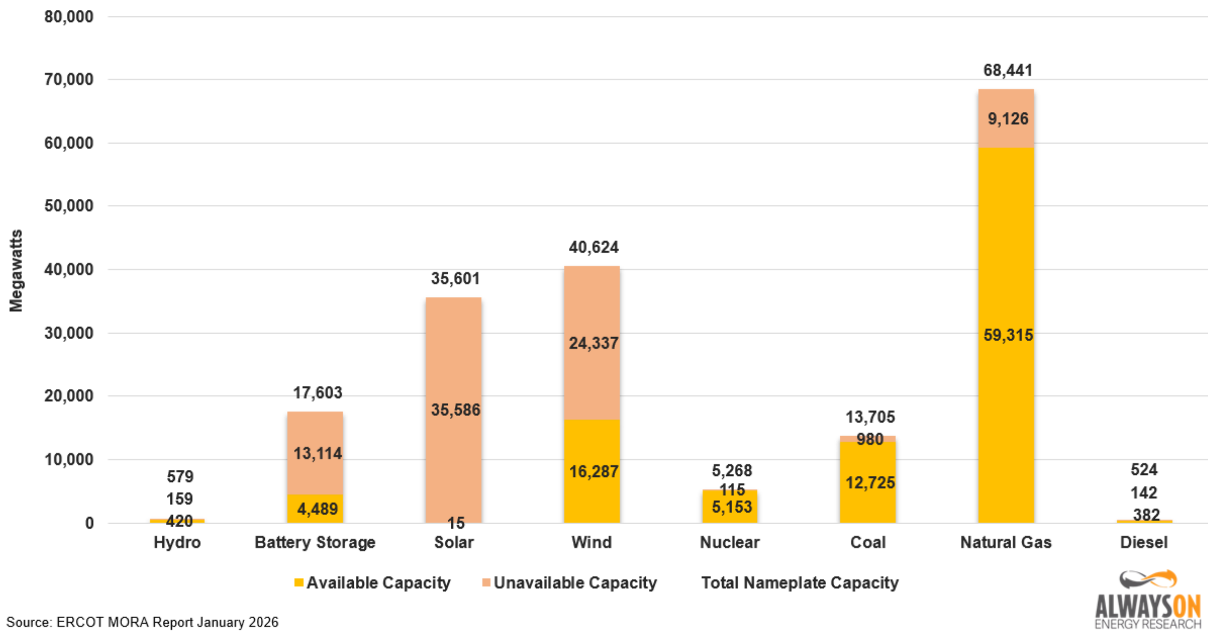


Figure 2. Expected available and expected unavailable capacity in ERCOT for January 2026. These figures include the planned resources in the MORA report.

FIGURE 3: ERCOT EXPECTED AVAILABILITY FACTORS DURING AN 8 A.M. PEAKING EVENT JANUARY 2026

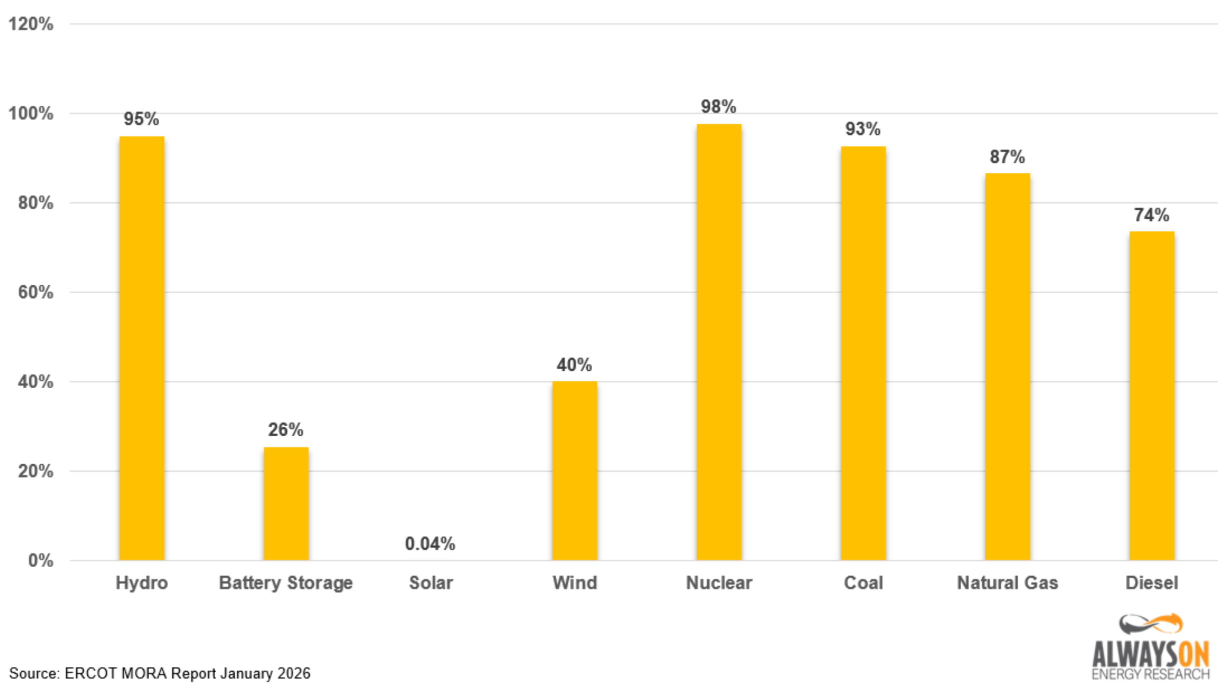


Figure 3. The availability factor for each resource was calculated as the expected available capacity divided by the total nameplate capacity. Nuclear power has the highest availability factor, while solar has the lowest.

FIGURE 4: ERCOT HOURLY ELECTRICITY GENERATION BY SOURCE DURING WINTER STORM FERN

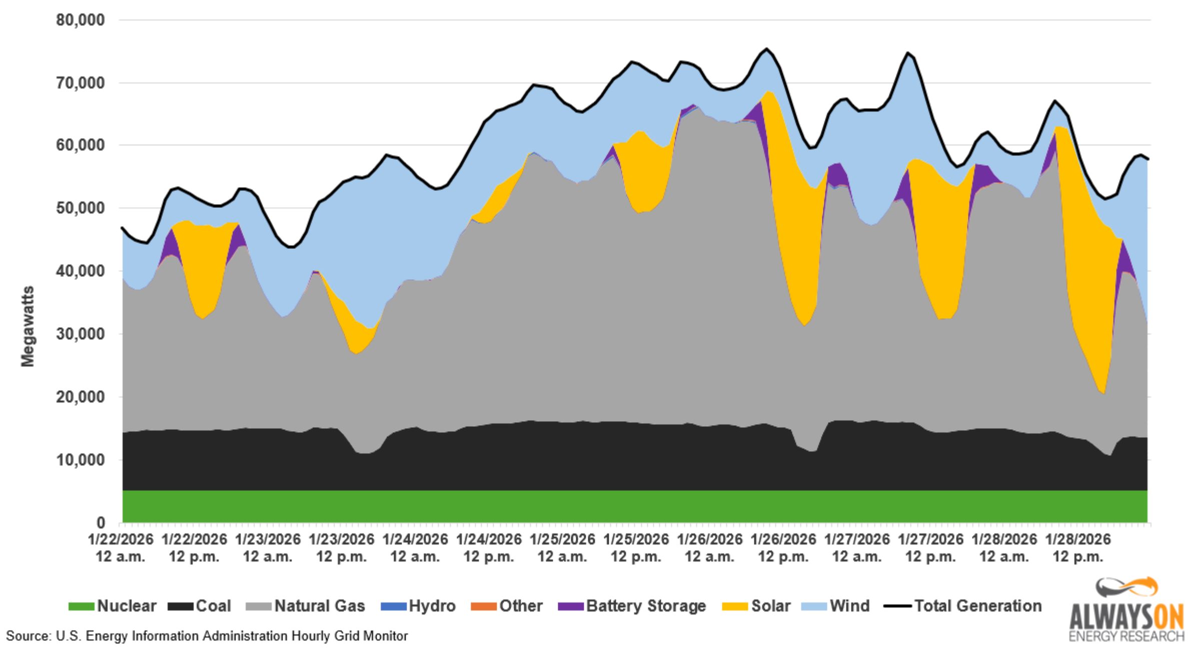


Figure 4. System conditions were tightest from January 25 at 5 p.m. through January 26 at 8 a.m. At 10 p.m., the thermal fleet was generating 66,086 MW while wind, solar, and battery storage were delivering just 5,706 MW, as batteries were consuming power at the time to recharge.

sunrise. Figure 2 shows the expected available capacity, unavailable capacity, and total installed (nameplate) capacity for each resource in ERCOT according to the MORA report.

There is a distinct difference in the expectations for performance between thermal generators, which have availability factors of 74 percent for diesel generators and 98 percent for nuclear plants, and the wind, solar, and storage fleet, which were expected to have availability factors of 40 percent, 0.04 percent, and 26 percent, respectively, during an 8 a.m. peaking event (see Figure 3).

While ERCOT expected very little contribution from solar resources during a peaking event, when demand is highest during the evening and early-morning hours, the region's wind resources underperformed their expected 40 percent availability factor, producing just 17 percent of their potential output on January 26 at 8 a.m. (see Figure 4).

WHOLESALE POWER PRICES ROSE AMID TIGHT SUPPLY CONDITIONS

Tight system conditions from the evening of January 25 through the morning of January 26 led to a substantial increase in wholesale power prices in ERCOT.

Day-ahead and real-time wholesale price data from S&P Global data show prices increased in concert with reduced wind and solar generation. Figure 5 shows day-ahead (dark green line) and real-time (light green line) increasing slightly with the overall rise in demand. However, prices did not increase substantially until electricity production from wind and solar declined.

S&P Global data show day-ahead prices reached a high of $1,832 per megawatt-hour (MWh), and real-time prices reached $871 per MWh, resulting in dramatically higher power costs for Texas families and businesses.[6]

6 S&P Global Capital IQ, HB-BUSAVE Day-Ahead and HB-BUSAVE Real-Time Price Data.

FIGURE 5: ERCOT WHOLESALE ELECTRICITY PRICES AND WIND AND SOLAR GENERATION DURING WINTER STORM FERN

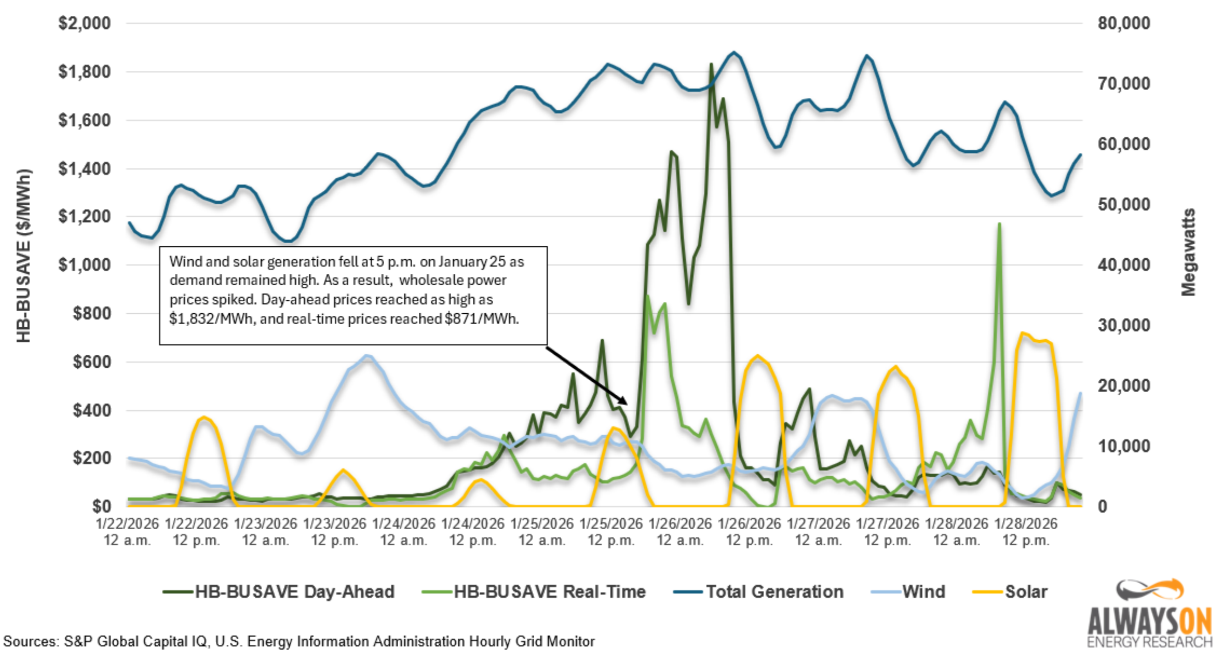


Figure 5. Wholesale power prices rose substantially due to sustained high demand and reduced generation from wind and solar facilities.

ERCOT data indicate that approximately 62.5 percent of all MWhs purchased in January 2026 were bought on the day-ahead market, and 37.25 percent on the real-time market.[7] Using this ratio, blended hourly wholesale power costs for consumers were calculated, enabling AOER to determine the additional costs to consumers compared to wholesale power costs before the reduction in energy production from variable energy sources.

Figure 6 shows the combined hourly wind and solar capacity factor and the settled energy cost in ERCOT during Winter Storm Fern.[8] It also shows the additional power costs, shaded in light red, incurred due to the drop in wind and solar generation, relative to a $20 million-per-hour power baseline cost, shown by the red line. The total additional cost of the light red areas is $766 million over 17 hours.

This analysis used an hourly baseline power cost of $20 million, which was the approximate cost of power at 4 p.m. on January 25, the hour just before wind and solar output dropped during the high-demand period.

7 ERCOT, "ERCOT Monthly Operational Overview (January 2026)," February 17, 2026, https://www.ercot.com/files/docs/2026/02/18/ERCOT-Monthly-Operational-Overview-January-2026.pdf.

8 Hourly capacity factors were obtained by dividing hourly generation from the U.S. EIA by the installed capacity listed in the ERCOT MORA report for January 2026.

FIGURE 6: ADDITIONAL ERCOT HOURLY WHOLESALE POWER COSTS DUE TO LOW WIND AND SOLAR GENERATION

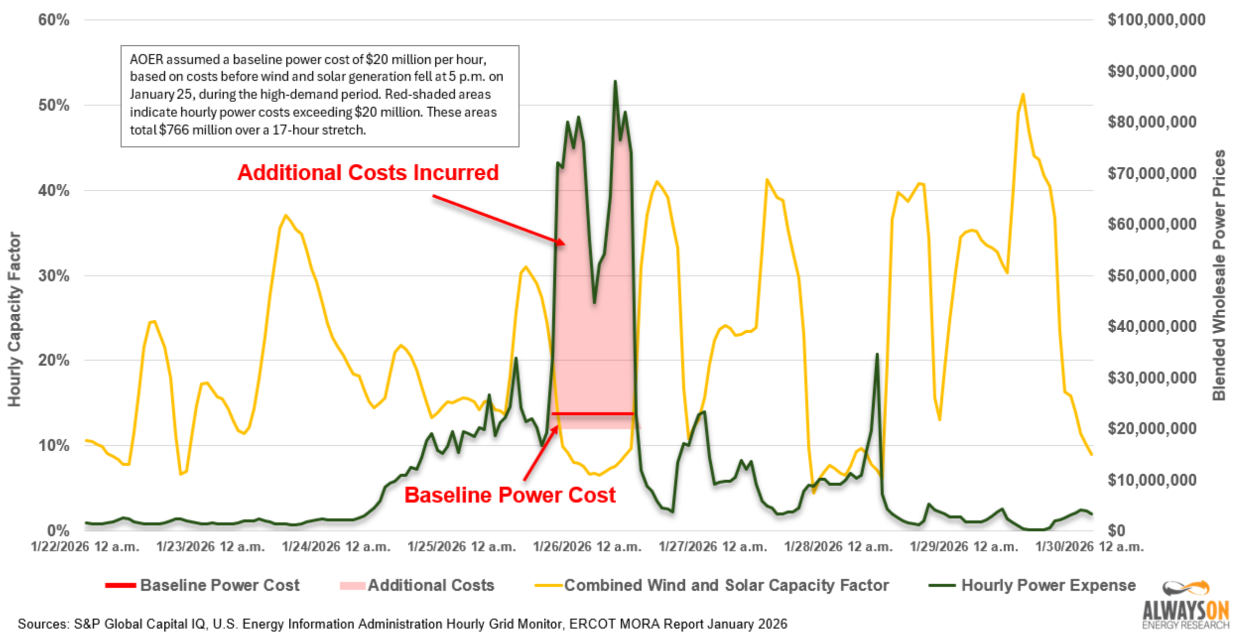


Figure 6. Wholesale power prices increased substantially as the output of the wind and solar fleets dipped below a 10 percent combined capacity factor during the height of the storm.

THE ANATOMY OF A PRICE SPIKE: WHY DID THEY RISE SO HIGH?

Ultimately, the increase in wholesale power prices resulted from high demand and inadequate supply. These dynamics were also amplified by the ERCOT demand forecast, which had estimated that peak electricity demand would be approximately 10 gigawatts (GW) higher than the actual realized peak from January 25 through January 26, putting additional upward pressure on day-ahead wholesale prices.[9]

Data from Grid Status shows outages for thermal units, wind, and solar during Winter Storm Fern (see Figure 7).[10] Wind and solar had lower initial outages, but outages increased substantially on January 24 as the cold front moved in.[11] In contrast, thermal facilities had relatively low outage rates, with availability ranging from 86 to 88 percent during the price spike event, which lasted from the evening of January 25 through the morning of January 26.

The outages reduced ERCOT's reserve margin, defined

9 U.S. Energy Information Administration, "Electric Reliability Council of Texas, Inc. (ERCOT) Electricity Overview (Demand, Forecast Demand, Net Generation, and Total Interchange) 1/22/2026-1/28/2026, Central Time," Hourly Grid Monitor, Accessed March 11, 2026, https://www.eia.gov/electricity/gridmonitor/expanded-view/custom/pending/ElectricityOverview-13/edit.

10 Grid Status, "ERCOT Thermal Generation and Outlook," January 23, 2026-January 28, 2026, https://www.gridstatus.io/charts/ercot-outages?iso=ercot&outageType=thermal&date=2026-01-23to2026-01-28.

11 Grid Status, "ERCOT Wind+Solar Generation Outages and Outlook," January 23, 2026-January 28, 2026, https://www.gridstatus.io/charts/ercot-outages?iso=ercot&outageType=irr&date=2026-01-23to2026-01-28.

FIGURE 7: ERCOT THERMAL AND WIND AND SOLAR CAPACITY OUTAGES DURING WINTER STORM FERN

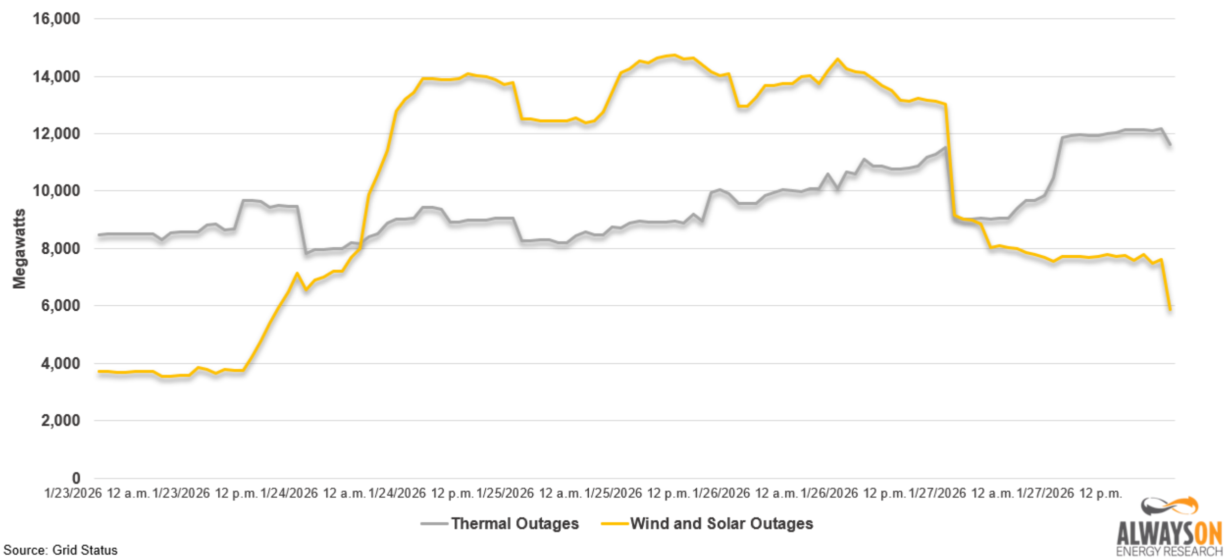


Figure 7. Thermal outage rates remained below 10 GW from January 23 through January 27. Wind outage rates increased to 14 GW on January 24 and remained elevated until January 27.

in this report as the available thermal and battery storage capacity on the system from Figure 2, minus hourly outages (Figure 7), plus real-time wind and solar generation during every hour of the storm. The reserve margin was calculated using this method because wind generation underperformed its expected output of 16,287 MW during the entirety of the price spike event.

Figure 8 shows the amount of thermal and battery storage capacity available to meet peak demand, the power provided by wind and solar, and the hourly demand on ERCOT from January 23 through January 27. The red line shows the reserve margin, which fell from over 90 percent on January 23, when demand was lower, and wind, solar, and storage were able to deliver more power to the grid, to just 6 percent at 8 a.m. on January 26.

Unsurprisingly, the falling reserve margin experienced during this period is highly correlated with rising electricity prices. In fact, in an energy-only market like ERCOT, where the grid operator does not make reliability payments to dispatchable generators to be available during periods of high stress, like winter storms, high prices are the primary mechanism for keeping reliable plants online, as they capture large portions of their annual revenue during these scarcity events.

Figure 9 shows the hourly reserve margin and blended wholesale power price from January 23 through midnight on January 27. Wholesale prices begin to rise as the reserve margin drops below 50 percent on January 24 and increase steeply as reserve margins begin their descent on January 25.

Wind, solar, and storage advocates will no doubt argue that wind and solar decreased wholesale prices when they were available. However, the question is

FIGURE 8: ERCOT HOURLY AVAILABLE RESOURCES, ELECTRICITY DEMAND, AND RESERVE MARGIN

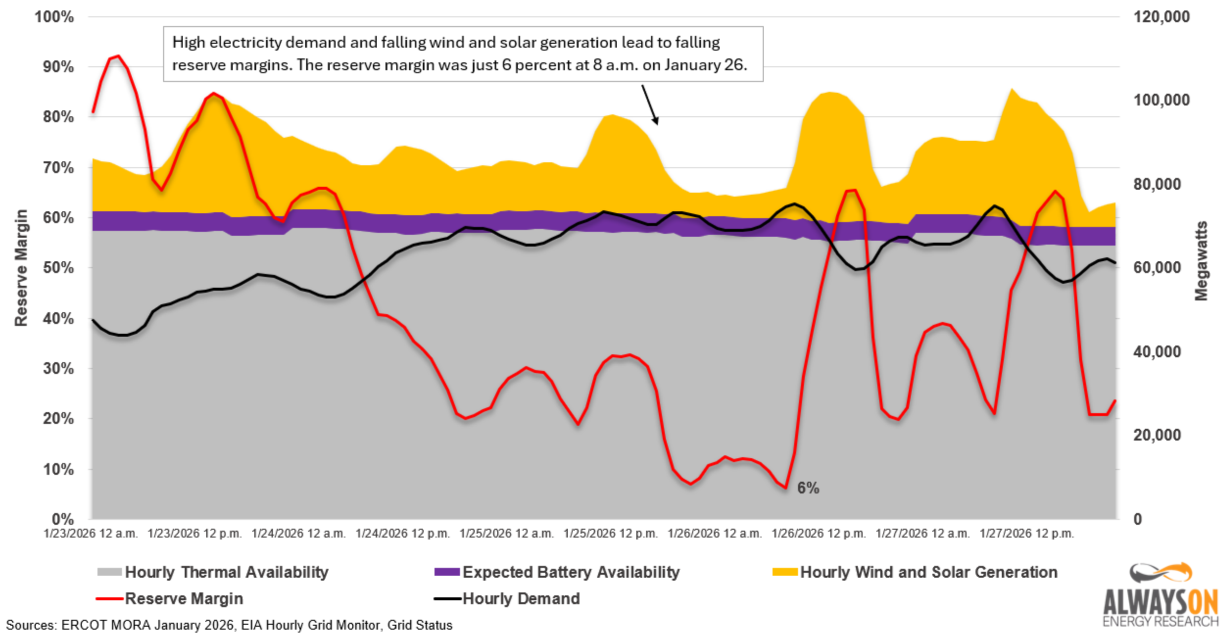


Figure 8. Reserve margins in ERCOT reached 6 percent during their lowest period.

FIGURE 9: ERCOT HOURLY RESERVE MARGIN AND WHOLESALE POWER PRICES DURING WINTER STORM FERN

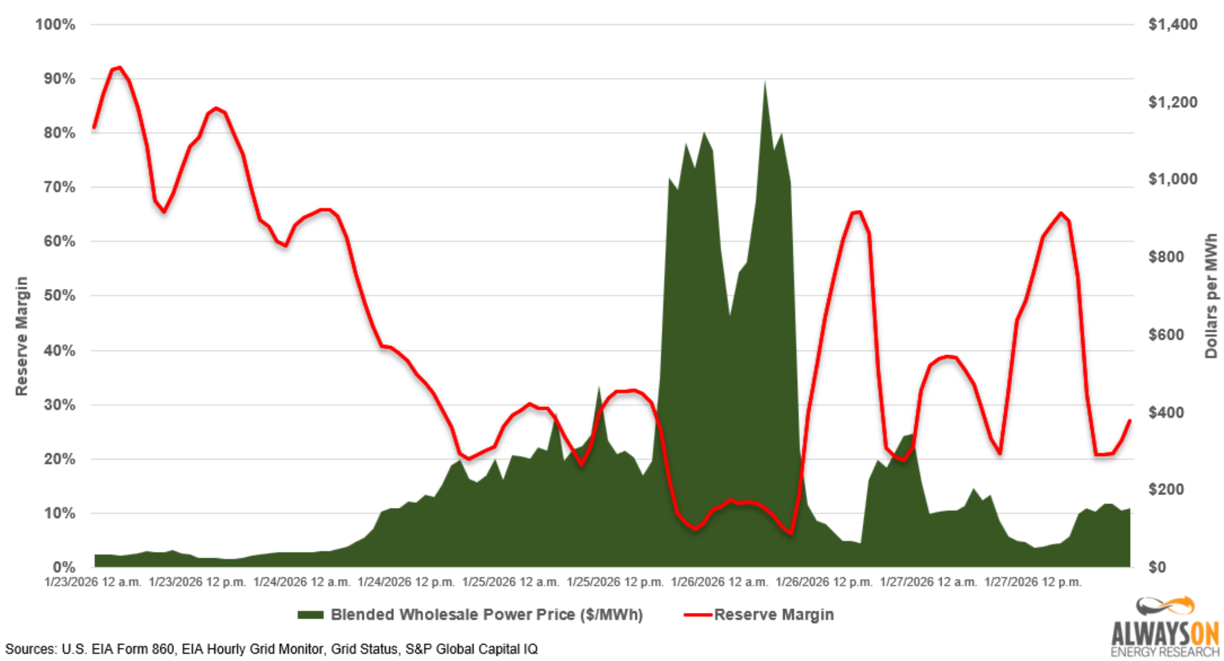


Figure 9. Wholesale power prices rose substantially as the reserve margin began to fall on January 24.

FIGURE 10: ERCOT WHOLESALE POWER PRICES BY RESERVE MARGIN DURING WINTER STORM FERN

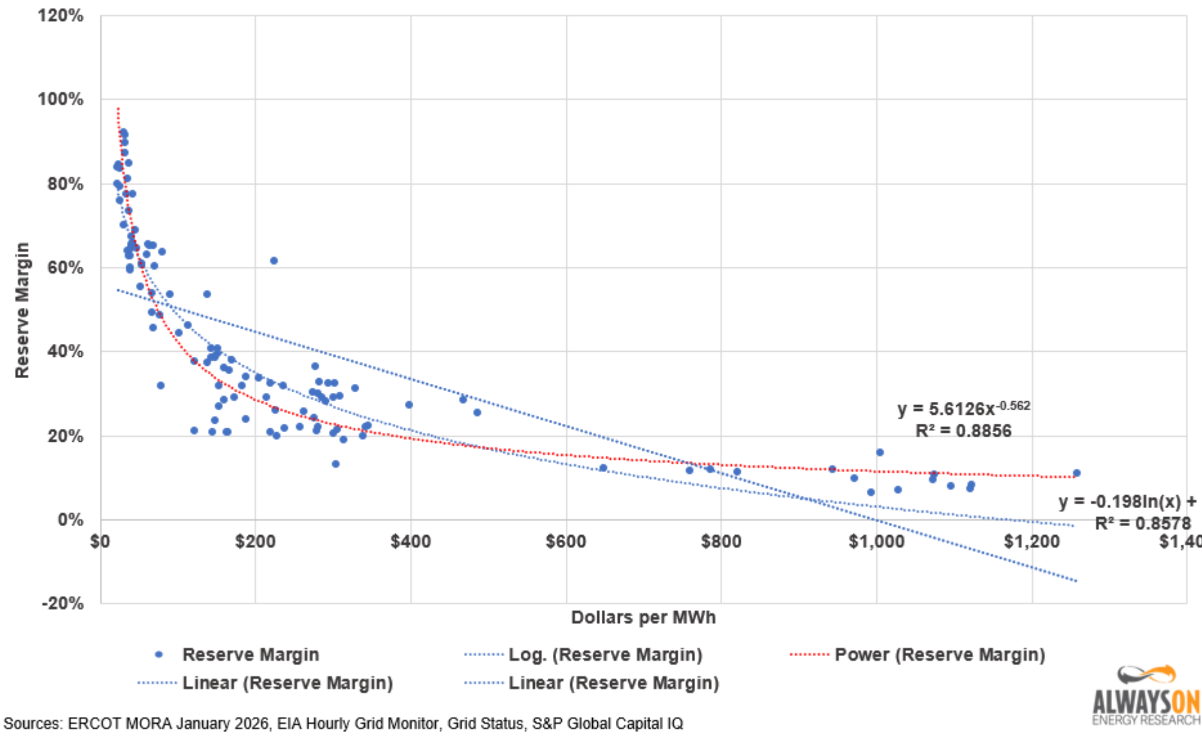


Figure 10. Wholesale power prices increased substantially as reserve margins dipped below 20 percent. An R^2 of 0.8856 is high and unusual in real-world energy market data, indicating a very strong relationship between tightening reserve margins and higher wholesale prices.

not whether these resources can reduce wholesale costs at times, because they certainly can. Instead, the questions are: Is the grid properly valuing reliable generators, is it becoming overly reliant on weather-based resources, and could Texas achieve greater price stability and reliability at a fraction of the cost by adding more natural gas instead of wind, solar, and battery storage?

Figure 10 shows the wholesale electricity price in ERCOT as a function of the available reserve margin. Based on data from Winter Storm Fern, wholesale power prices increased dramatically when reserve margins dipped below approximately 20 percent. This relationship had an R^2 of 0.8856, meaning 88.56 percent of the variation in ERCOT wholesale prices in this dataset is explained by changes in available reserve margin.

Because the high prices can be explained largely by the scarcity of the system, adding additional dispatchable capacity could have increased the reserve margin during Winter Storm Fern, reducing wholesale power prices and costs to consumers.

To assess the potential consumer benefits of more dispatchable generation, AOER added 10,000 MW of hypothetical new natural gas capacity in ERCOT to assess the impact on hourly electricity costs and reserve margins by the blended wholesale power prices at a given reserve margin percentage in the

FIGURE 11: ERCOT ESTIMATED HOURLY POWER COSTS DURING WINTER STORM FERN WITH AND WITHOUT AN ADDITIONAL 10 GW OF NATURAL GAS

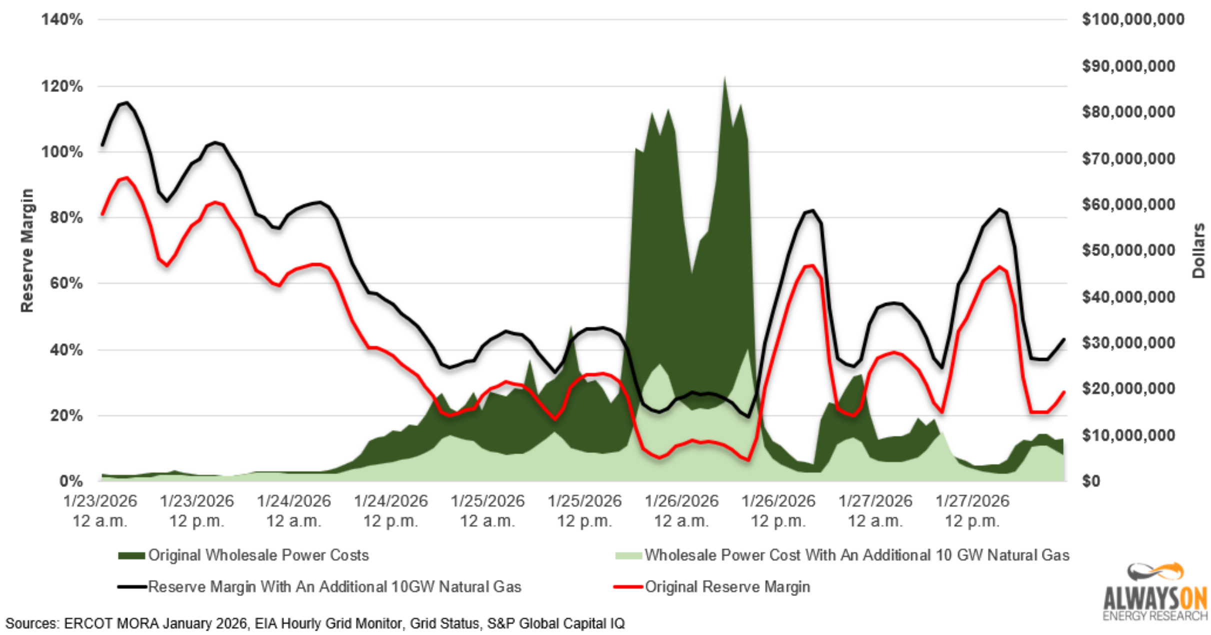


Figure 11. Adding 10,000 MW of new natural gas capacity would have increased reserve margins by 14 to 15 percent during the price spike, thereby yielding substantial savings for ERCOT residents.

original dataset, to the dollar per MWh costs after increasing the reserve margins with new natural gas capacity.

This analysis found that the new gas capacity could have saved Texas families and businesses $1.34 billion in power costs. These savings are illustrated in Figure 11 by the difference between the dark-green and light-green shaded areas during the storm. These savings were driven by the fact that adding 10,000 MW of natural gas would increase the reserve margin by 14 to 15 percent during the evening of January 25 through the morning of January 26, thus reducing the scarcity prices incurred.

WHY HAS ERCOT FAILED TO ADD NEW THERMAL PLANTS?

While natural gas additions have mostly offset coal retirements, ERCOT hasn't added any net dispatchable capacity since 2003. This is largely due to the energy-only market structure, which does not properly value the differences in reliability among generators, such as gas and coal plants, and among intermittent resources, such as wind and solar.

Furthermore, Texas does not require utilities to maintain sufficient backup capacity to ensure reliable power plants are available to meet electricity demand when the wind isn't blowing or the sun isn't shining. In fact, the market structure in Texas specifically incentivizes reliable generators to exit the market.

This isn't a bug of the ERCOT market; it is a feature. In a 2018 article in PV Magazine detailing a report by the Wind Solar Alliance of Texas, the article author boasted about the parasitic effect [wind and solar] electricity generators have on the revenues of more reliable power plants.[12]

> *This is just the beginning. Texas continues to add more wind every year, and ERCOT has estimated that the state could put online 13 GW of solar by 2030.* ***This will ultimately mean more hours where coal and gas plants are not operating, and more retirements of conventional generation.*** *[Emphasis added.]*

In the case of ERCOT, the parasitic impact of wind, solar, and now battery storage has not led to retirements, but it has dissuaded new thermal generators from entering the market at a time when power demand is soaring due to population growth, industrial growth, and data centers.

CONCLUSION

Wind and solar can reduce wholesale power prices when they are producing, but their tendency to underperform during periods of peak system need can cause large spikes in wholesale prices. Our analysis suggests that the absence of wind and solar generation during the evening of January 25 through the morning of January 26 cost Texas families and businesses an additional $766 million and left the region with only a 6 percent reserve margin.

Due to tight supply conditions, adding an additional 10,000 MW of natural gas to the ERCOT system would have been an effective way to increase reserve margins to at least 20 percent during the winter storm, yielding wholesale power cost savings of $1.34 billion during the period of highest system stress.

12 Christian Roselund, "Renewables Reduced Wholesale Power Costs by $5.7 Billion in Texas," PV Magazine, November 6, 2018, https://pv-magazine-usa.com/2018/11/06/renewables-reduced-wholesale-power-costs-by-5-7-billion-in-texas/.

Reliable Energy

Delivering on the Promise of Gas-Electric Coordination

NATIONAL PETROLEUM COUNCIL | 2025

Reliable Energy

Delivering on the Promise of Gas-Electric Coordination

Committee on Gas-Electric Coordination

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National Petroleum Council 2025

NATIONAL PETROLEUM COUNCIL

U.S. DEPARTMENT OF ENERGY

The National Petroleum Council is a federal advisory committee to the Secretary of Energy.

The sole purpose of the National Petroleum Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to oil and natural gas or to the oil and gas industries.

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PREFACE

I. NATIONAL PETROLEUM COUNCIL

The National Petroleum Council (NPC) is an organization whose sole purpose is to provide advice to the federal government. After successful cooperation during World War II, President Harry Truman requested this federally chartered and privately funded advisory group to be established by the Secretary of the Interior to represent the oil and natural gas industry's views to the federal government by advising, informing, and recommending policy options. Today, the NPC is chartered by the Secretary of Energy under the Federal Advisory Committee Act of 1972, and the views represented are broader than those of the oil and natural gas industry.

NPC members, about 200 in number, are appointed by the Energy Secretary to assure well-balanced representation from all segments of the oil and natural gas industry, from all sections of the country, and from large and small companies. Members are also appointed from outside the oil and natural gas industry, representing related interests such as large consumers, states, Native Americans, and academic, financial, research, and public interest organizations and institutions. The NPC promotes informed dialogue on issues involving energy, security, the economy, and the environment of an ever-changing world.

II. STUDY REQUEST

On June 30, 2025, Secretary of Energy Chris Wright requested that the NPC undertake a *Future Energy Systems* study to provide advice on ensuring the availability of affordable, reliable, and secure energy for American consumers and allies. In his letter, the Secretary emphasized the need to address immediate priority topics—permitting and gas-electric coordination—in support of the administration's directives on energy reliability, infrastructure, and national security. The request specifically called for the delivery of this short-term study on the misalignment between the electric power and natural gas markets, and the risks this misalignment poses to the reliability of the interconnected systems. A separate short-term study is also being completed on streamlining the permitting of oil and gas infrastructure.

III. STUDY SCOPE

The Secretary asked the NPC to examine how rising natural gas and electricity demand, along with shifting load patterns, are straining natural gas pipelines in key regions of the United States. The study is also tasked with assessing the impacts of these strains on energy reliability and with providing actionable strategies to address the market misalignment. This work is to complement ongoing industry and government efforts while focusing on the reliability risks viewed through the lens of natural gas infrastructure operations and capabilities. Specifically, the study will:

- Examine the structural differences between the markets that limit incentives for long-term natural gas infrastructure investment.
- Assess how pipeline operational volatility and shifting load patterns affect gas-electric reliability.
- Review the current state of gas-electric coordination initiatives and identify remaining gaps.
- Develop policy and market recommendations to correct the misalignment and ensure long-term energy reliability and affordability.

The study places emphasis on regions identified by the North American Electric Reliability Corporation (NERC) as having elevated risks to resource adequacy, including PJM and Northeast Power Coordinating Council New England (NPCC-NE), which lie mostly within Petroleum Administration for Defense Districts Region I (PADD I), while drawing conclusions relevant to the national energy system as a whole. The study committee notes that some areas of the nation, like the territory of Puerto Rico, have significant gas-electric coordination issues but were outside the scope of this study. Additionally, coastal shipping was determined to be out of scope for this report. Finally, while various hybrid and multifuel configurations exist, dual-fuel generation is not addressed within the scope of this report.

IV. STUDY GROUP ORGANIZATION

The study was directed by a study committee composed of senior leaders from the natural gas and electric power industries, along with representatives from government, academia, and public interest organizations. The coordinating subcommittee oversaw the development of scope areas, supported by task groups focused on specific technical and policy issues. This structure is designed to ensure that a broad range of expertise and perspectives are incorporated into the analysis, deliberations, and recommendations of the NPC (Figure P-1).

Participants in this study contributed in a variety of ways, ranging from work in all study areas, to involvement in a specific topic, to reviewing proposed materials. Involvement in these activities should not be construed as a participant's or their organization's endorsement or agreement with all the statements, findings, and recommendations in this report. Additionally, while U.S. government participants provided significant assistance in the identification and compilation of data and other information, they did not take positions on the study's recommendations.

V. REPORT STRUCTURE

The report is organized into four detailed chapters:

1. Examination of the Misalignment between the Electric Power and Natural Gas Markets
2. Increasing Variable Demand on Natural Gas Pipelines and Threats to Reliability
3. Current State of Gas-Electric Coordination
4. Recommendations for Healthy Alignment between the Natural Gas and Electric Sectors

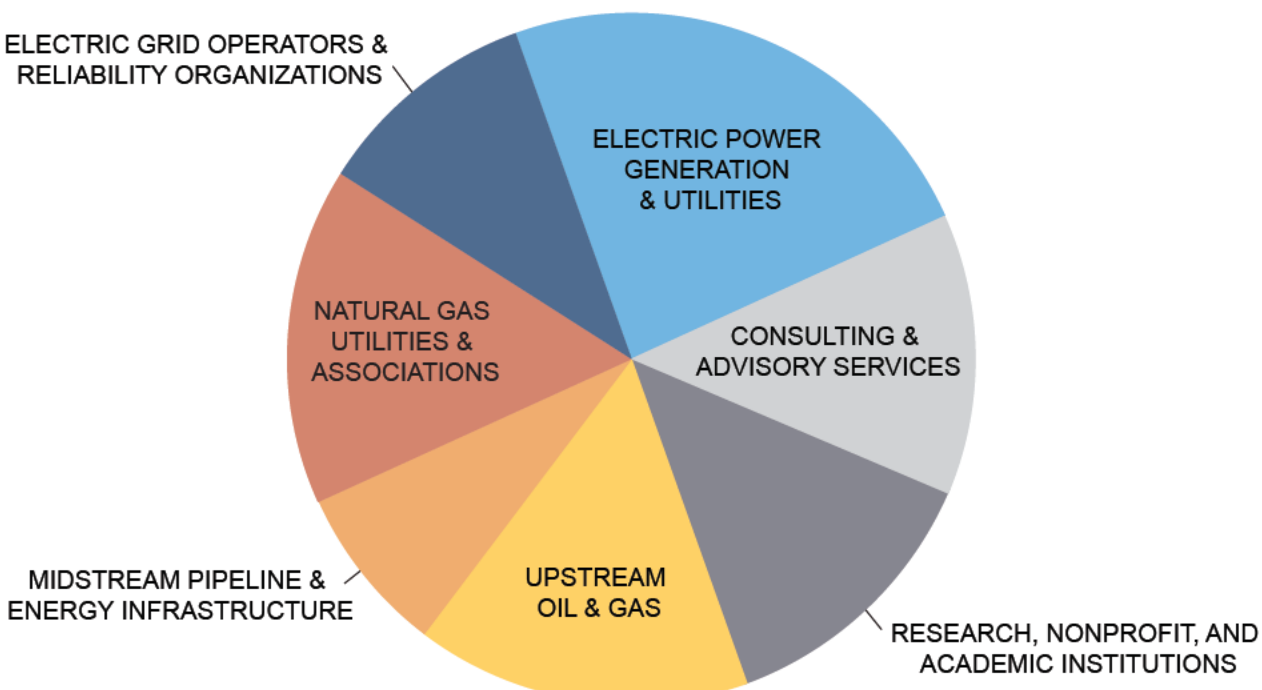
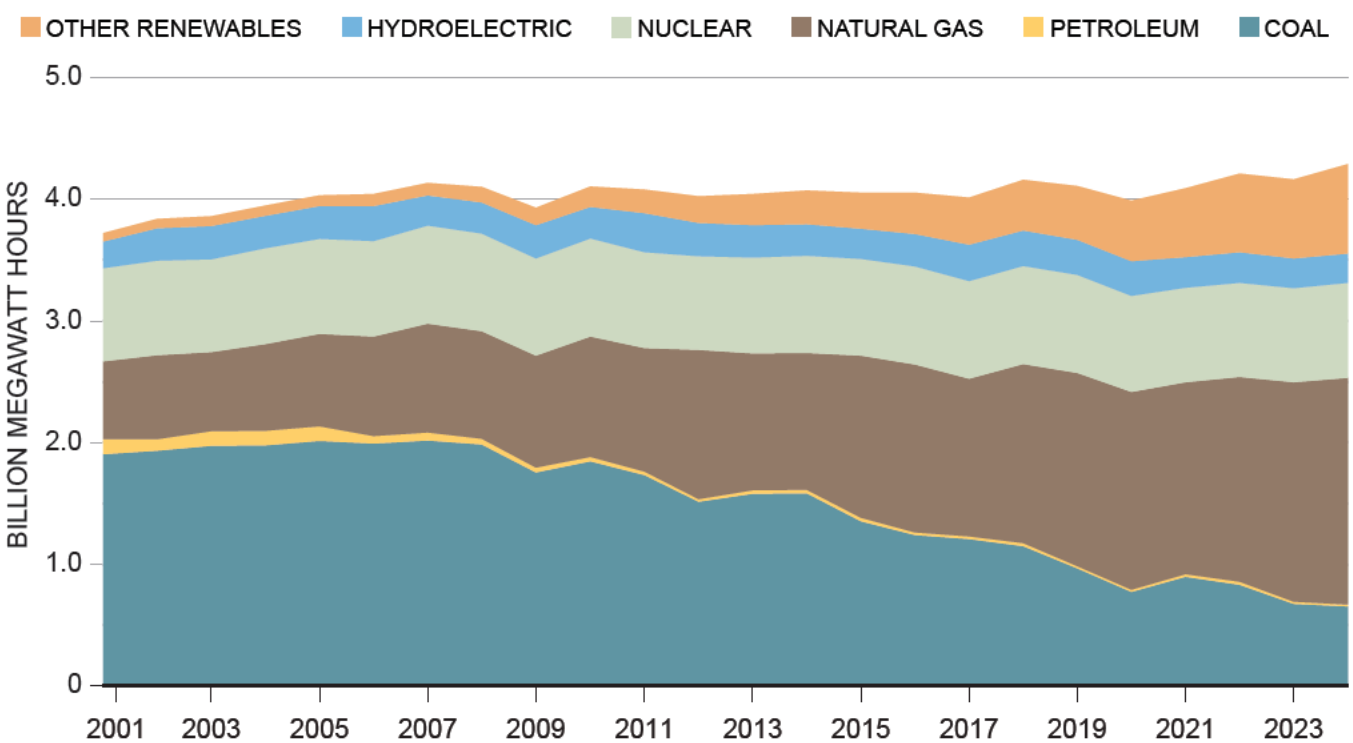


Figure P-1. *Organization Representation by Sector on the Study Committee, Coordinating Subcommittee, and Task Groups*

EXECUTIVE SUMMARY

I. INTRODUCTION

The reliability of the U.S. energy system increasingly depends on effective coordination between the natural gas and electric sectors. Natural gas is a proven, reliable fuel for electricity generation, and gas-fired electricity generation plays a central role in providing reliable baseload power, balancing intermittent energy resources like wind and solar. Development of flexible, fast-ramping gas-fired electricity generation is needed for enhanced grid reliability today and in the future. Since natural gas became the dominant fuel for U.S. electricity generation in 2016 (Figure ES-1), the interdependence between the gas and electric systems has deepened—but so have the risks of misalignment. The two systems function under fundamentally different commercial, regulatory, and operational frameworks. The gas industry is built around long-term contracts and steady demand, while the electric sector depends on real-time market dispatch and hourly price signals. These structural differences create persistent mismatches in timing and incentives, particularly during periods of high demand or extreme weather, when generators may struggle to secure fuel precisely when it is needed most. Fragmented jurisdiction further complicates coordinated planning and accountability efforts. Overcoming these challenges requires aligning market design, operational and commercial practices, and regulatory frameworks to ensure that both sectors can operate with shared situational awareness, adequate infrastructure, and



Source: Data from EIA. 2025.

Figure ES-1. *Net Annual U.S. Electricity Generation for All Sectors by Source (2001–2024)* consistent incentives for reliability. Without such integration, each system remains vulnerable to disruptions in the other, undermining overall energy security.

On June 30, 2025, Secretary of Energy Chris Wright requested the National Petroleum Council (NPC) conduct a comprehensive *Future Energy Systems* study to evaluate how the United States can maintain affordable, reliable, and secure energy while undergoing rapid transitions in demand, infrastructure, and policy. As part of this broader effort, the NPC was asked to prepare two initial priority deliverables focused specifically on the coordination between natural gas and electric power systems and permitting oil and natural gas infrastructure. This report examines the near-term risks arising from the misalignment of gas and power sectors and outlines pathways to safeguard reliability while keeping pace with growing natural gas demand in the electricity sector.

The North American Electric Reliability Corporation (NERC) has noted that roughly half of the United States is facing an elevated risk of electricity supply shortfalls over the next decade[1] due to accelerating demand, retirement of dispatchable resources, and lagging firm capacity additions such as expanding pipelines. Both the Mid-Atlantic and Northeast regions have been identified as facing increasing risks—and extreme weather events over the past five years have borne out these risks. Insights from these regions anchor the analysis, but the findings and recommendations are intended to apply across the country, in both regulated and deregulated sectors.

NPC's charge is rooted in a growing recognition that natural gas and electric power have become deeply interdependent. Pipelines, once designed primarily to serve steady ratable loads from local distribution companies (LDCs), now support a power sector that increasingly relies on gas-fired generation for both baseload and fast-ramping capacity.

The challenges are not entirely new. The gas and electric industries have examined integration since the early 1990s, beginning with efforts to reconcile operational and scheduling differences. Yet these steps were incremental as they did not resolve underlying economic and structural misalignments of the two markets. Additionally, many recommendations were only partially implemented (as noted in Chapter 3). Events such as Winter Storm Uri in 2021, Winter Storm Elliott in 2022, and even periods of growing operational volatility on pipelines in the absence of major storms demonstrate that without market reforms, operational and scheduling adjustments alone are insufficient to fully resolve reliability challenges.

Strengthening gas-electric coordination is not merely a technical exercise. It is now a public-facing reliability issue. The growing dependence of the electric grid on natural gas—and of gas infrastructure on electric power—means that disruptions in one system can now cascade into the other. Without such coordination and integration, each system remains vulnerable to disruptions in the other, undermining the resilience of the nation's evolving grid.

This challenge also represents a strategic opportunity: By improving coordination between the natural gas and electric systems, the United States can establish a benchmark for reliability and resilience, leveraging abundant North American natural gas resources to strengthen the grid. Enhanced alignment between natural gas and electric systems will maximize flexibility, reinforce infrastructure planning, and ensure performance under stress—positioning the United States to lead in the development of innovative technology and energy solutions built on a foundation of reliability. Seizing this opportunity will reinforce U.S. energy leadership and provide a model for reliability and security that others can follow.

This report 1) assesses how rising natural gas and electricity demand and shifting load patterns are straining U.S. pipeline infrastructure, 2) evaluates the reliability risks these strains pose, and 3) recommends actionable strategies to reduce misalignment between the gas and electric industries. These findings and recommendations are summarized below, with specific implementation actions associated with each recommendation discussed in detail in Chapter 4. NPC notes that many of the recommendations are interrelated and interdependent. By

1 NERC. "2024 Long-Term Reliability Assessment." December 2024. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

emphasizing natural gas infrastructure operations and capabilities, the study complements ongoing government and industry initiatives on gas-electric coordination.

II. HISTORICAL AND REGULATORY FOUNDATIONS

The natural gas and electric sectors in the United States have evolved under distinct regulatory and commercial frameworks that continue to shape their interactions today.

Historically, natural gas production and pricing were tightly regulated at the wellhead under the Natural Gas Act of 1938, with federal oversight extending through the mid-1980s. Following gradual deregulation, gas now trades at market-based prices, while interstate pipelines remain subject to Federal Energy Regulatory Commission (FERC) regulation. Because pipeline expansion depends on securing firm, long-term transportation contracts to underpin financing, the gas industry's investment and operational model remains rooted in long-term, ratable service agreements designed for predictable consumption patterns. This means that there is little to no incentive for building pipeline capacity beyond contracted firm demand.

Electricity markets followed a different trajectory. For much of the 20th century, power generation, transmission, and distribution were vertically integrated under state-regulated monopolies.[2] Beginning in the 1990s, federal and state reforms introduced wholesale competition and nonutility ownership of generation, giving rise to independent system operators (ISOs) and regional transmission organizations (RTOs) that now manage roughly two-thirds of U.S. electricity load.[3] These organized markets—originally designed to ensure nondiscriminatory dispatch of generation resources—offer real time, daily, and forward markets[4] in generation, other services, and, in many cases, reliability functions. These include procurement of adequate future supplies based on a variety of different mechanisms, depending on the jurisdiction. The coexistence of regulated and deregulated regions has created a patchwork of market designs and incentive structures across the country.

In regulated markets, vertically integrated utilities ensure reliability through long-term contracts, integrated resource plans (IRPs),[5] and cost-recovery mechanisms that allow prudent investments to be recovered from utility ratepayers, under a premise of long-term planning for resource adequacy and reliability assurance. By contrast, in deregulated markets, independent generators depend on short-term market revenues and hourly price signals, often without clear incentives or financial mechanisms to secure firm gas supply. As such, their gas procurements rely less on long-term delivery contracts and more on a variety of shorter-term commodity procurements and lower priority transportation arrangements. When the gas and electric systems are both under stress, these arrangements are the first to be curtailed. The growing variable conditions on pipelines, which are caused by inherently variable demand profiles of the electric power sector, can also endanger LDCs that serve homes and businesses. When pipeline pressures drop too low, residential and commercial gas service can be interrupted, and restoring service is a slow, labor-intensive, and costly process compared to restoring electricity.

III. CONSTRAINED INFRASTRUCTURE

The U.S. natural gas pipeline network was engineered for predictable, ratable flows rather than

2 National Bureau of Economic Research. "The U.S. Electricity Industry after 20 Years of Restructuring." April 2015. https://www.nber.org/system/files/working_papers/w21113/w21113.pdf.

3 FERC. "Energy Primer: A Handbook for Energy Market Basics." April 2020. https://www.ferc.gov/sites/default/files/2020-06/energy-primer-2020_0.pdf.

4 In organized electricity markets, the *daily* (or *day-ahead*) market schedules generation and demand for each hour of the next operating day, producing financially binding schedules and prices based on forecasted conditions. The *real-time* market balances supply and demand continuously during the operating day, settling deviations from day-ahead schedules at prices reflecting actual system conditions. *Forward* markets extend this structure over longer horizons—weeks, months, or years ahead—allowing participants to hedge price risk and secure supply through bilateral or centrally cleared contracts.

5 Integrated Resource Plans (IRPs) are long-term planning documents developed by utilities and approved by state regulators that assess future electricity demand and identify the mix of generation, transmission, and demand-side resources needed to meet reliability, cost, and policy objectives over a multiyear horizon.

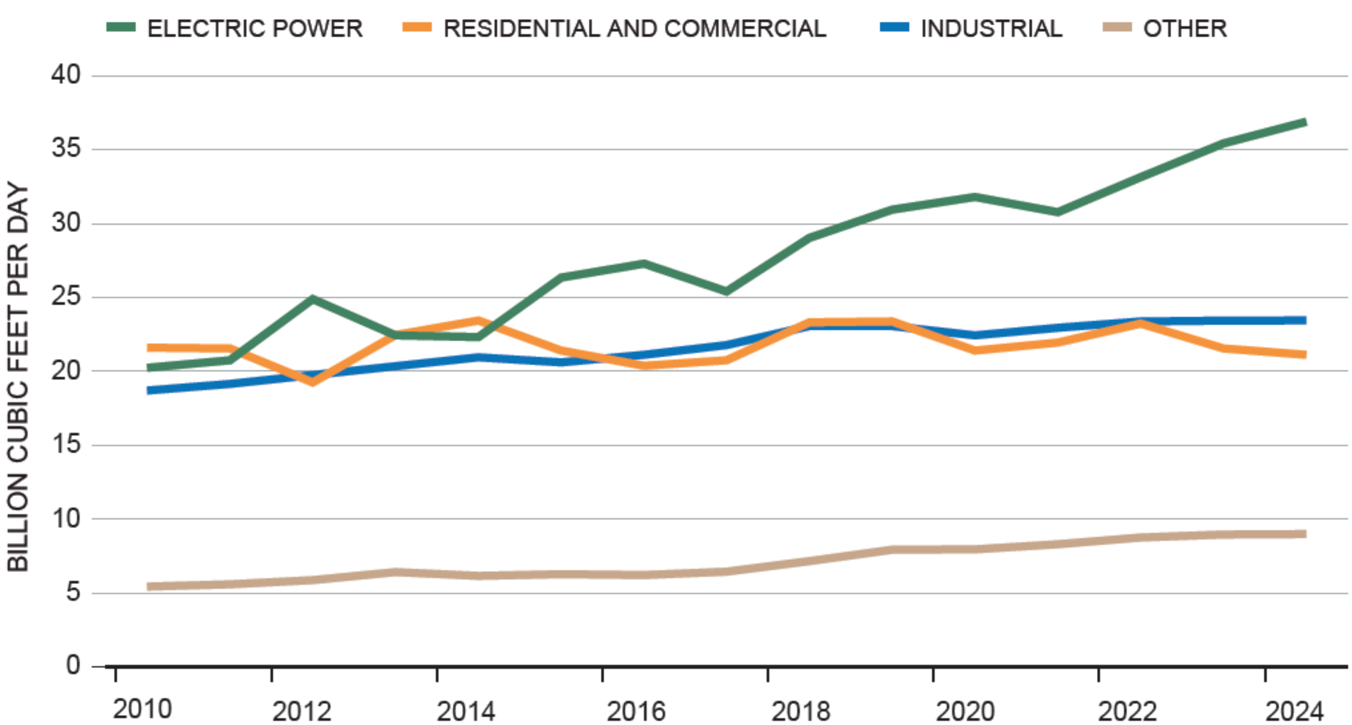
the increasingly variable demands of an electricity market with a changing generation portfolio and unexpectedly rapid growth in demand. Historically, pipelines primarily served LDCs and large industrial customers (Figure ES-2) whose consumption patterns were relatively stable and forecastable. Under this model, firm transportation contracts—long-term agreements guaranteeing delivery rights—dominated, with LDCs holding most pipeline capacity (Figure ES-3) and associated storage rights to meet heating and industrial loads. Day-to-day operational flexibility was maintained through modest use of linepack (the gas stored under pressure within the pipeline system) and limited operational storage,[6] sufficient to handle routine morning and evening demand ramps.

Over the past decade or so, the U.S. natural gas user mix has shifted dramatically as electric power generation has surpassed LDCs to become the largest gas consumer (Figure ES-2 and ES-3). This transformation has been driven by the retirement of coal plants, the widespread deployment of efficient natural gas combined cycle technology, and abundant, low-cost gas from the shale revolution. As a result, gas demand has become far more variable and dynamic, with power generators—especially in deregulated markets—often relying on secondary or interruptible pipeline capacity,[7] which amplifies intraday and seasonal fluctuations. The rapid expansion of wind and solar resources, which together account for more than 60% of new U.S. generation capacity since 2010,[8] has made gas-fired units essential for grid balancing, requiring flexible fuel supply and rapid ramping capability. At the same time, electrification of heating and transportation is shifting peak electricity demand from summer to winter, heightening competition for constrained

6 "Operational storage" refers to short-term storage—typically pipeline-connected facilities used to manage daily pressure and flow variations—distinct from long-term, high-deliverability storage such as underground salt caverns or depleted reservoirs designed for seasonal balancing.

7 "Secondary" or "interruptible" capacity refers to transportation rights that are not guaranteed and may be curtailed when firm (priority) shippers fully utilize the pipeline. These services offer flexibility and lower cost but carry higher risk of interruption during peak demand (see Chapter 2, I. A.)

8 EIA. "Electric Power Annual." October 16, 2025. https://www.eia.gov/electricity/annual/.



Note: Other = natural gas consumed as transportation fuel, as lease and plant fuel, and in pipeline and distr bution use.
Source: Data from EIA. 2025.

Figure ES-2. U.S. Annual Natural Gas Consumption by Sector (2010–2024)

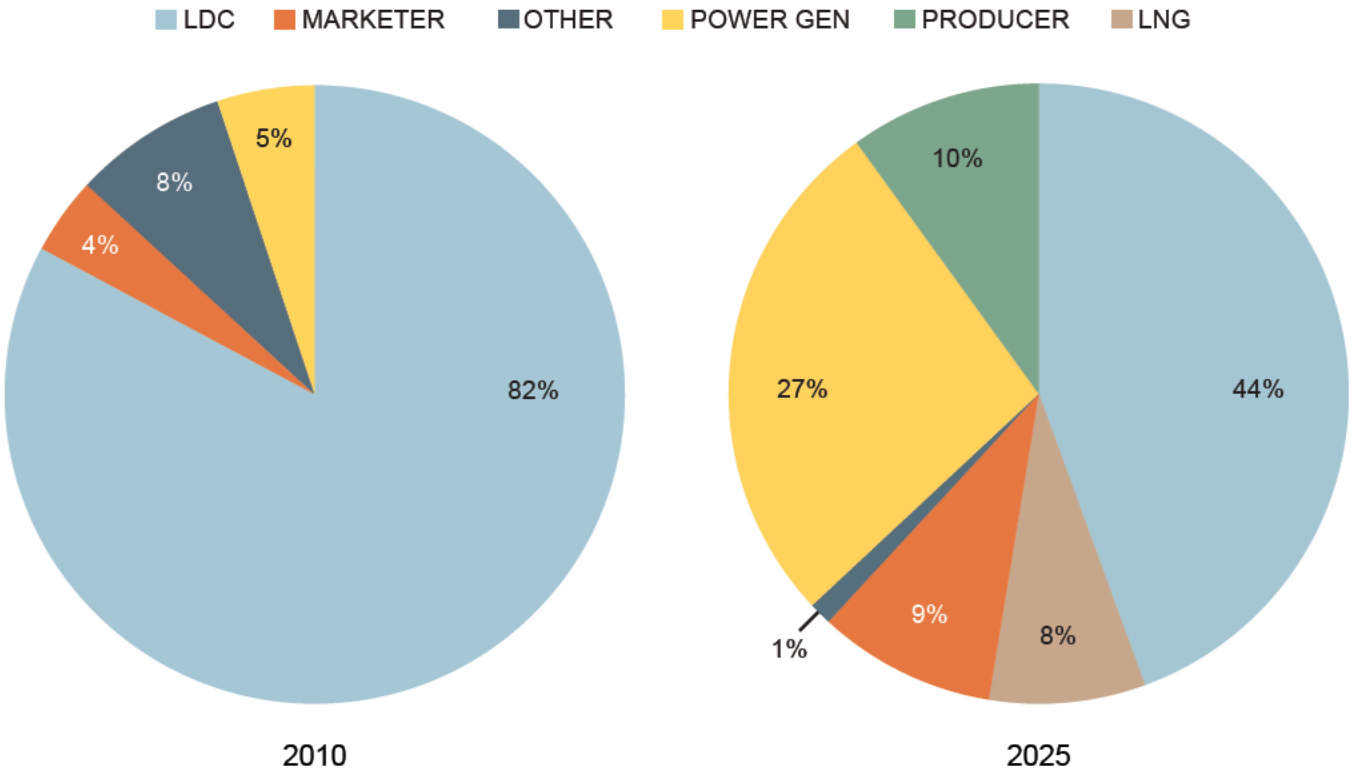


Figure ES-3. *Share of Firm Transportation Capacity on Transco Pipeline in 2010 and 2025*

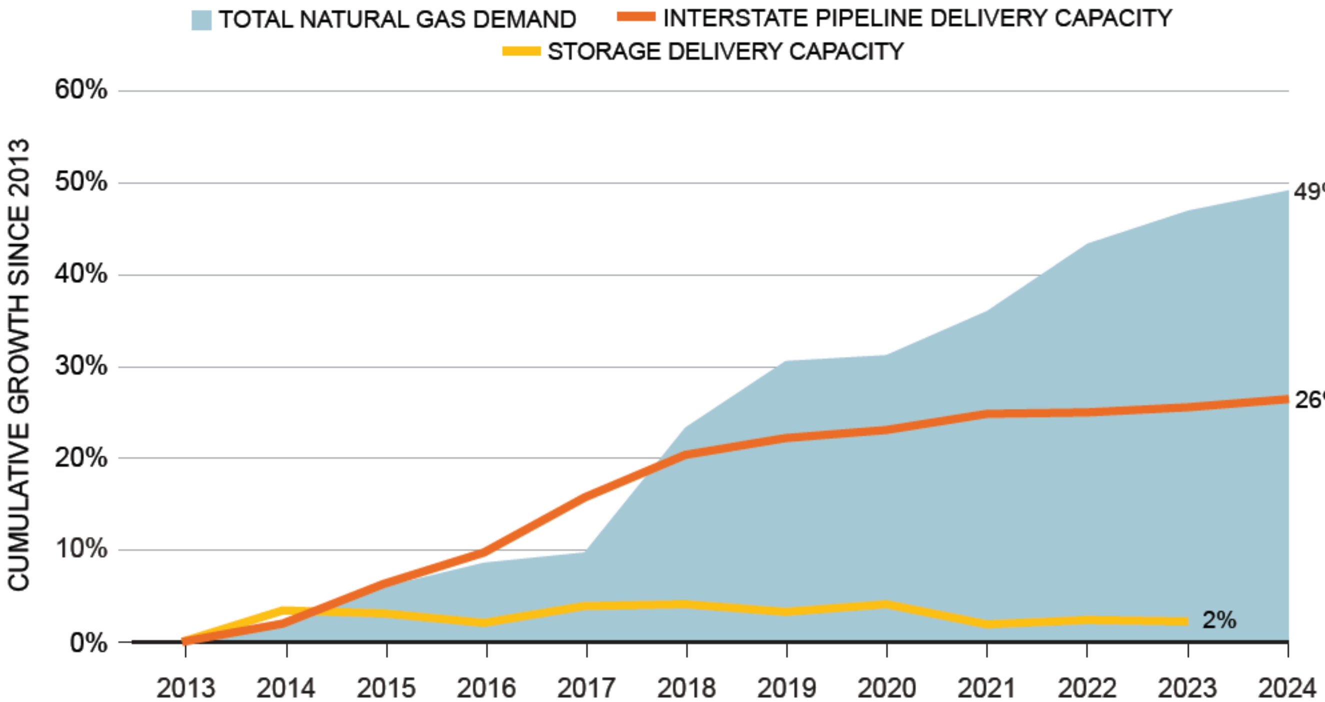
pipeline capacity precisely when both heating and power generation needs are greatest. Electricity-driven gas demand introduces sharp and often unpredictable fluctuations that pipelines were not designed to accommodate.

Pipeline operators have implemented a number of innovative solutions to accommodate these changing patterns. While some pipeline expansion has occurred over the past decade, most of this work has involved reversing flow directions and adding compressors rather than building new long-distance lines. These investments have increased volume deliverability overall, meeting aggregate demand growth for gas in general, but have led to fewer flexibilities in the system for existing users, particularly those in the electric sector who have come to rely on them.

As a result, the pipeline system's ability to adjust to increased variability demands by electric sector participants has not significantly improved nor kept pace with those evolving needs. Storing excess gas along or within pipeline systems for unexpected peaks is an option. However, the power sector users who would benefit from such additions are not yet contracting to build these facilities (Figure ES-4). Most new storage capacity has been built near liquefied natural gas export terminals to support export operations, rather than in regions where gas-fired power generation requires flexibility to manage variable loads.

FINDINGS:

- Electricity market signals prioritize short-term economic efficiencies, while natural gas infrastructure depends on long-term, firm commitments. Inadequate compensation in electricity markets often leaves generators with little incentive to secure the gas and transportation services needed to support their increasingly variable operations and peak reliability needs.
- Pipelines were built for predictable, ratable flows, but customers now require increasingly variable intraday services to meet growing demand and balance the grid as wind and solar generation expand.
- Recent pipeline expansions—implemented mainly through flow reversals and added



Note: 2023 is the most current data for storage delivery capacity.
Source: Data from EIA. 2025.

Figure ES-4. *Storage Delivery Capacity Compared to Pipeline Delivery Capacity and Gas Demand*

compression rather than new pipelines—highlight the need to address challenges between pipeline capabilities and increasingly variable demand.

RECOMMENDATIONS:

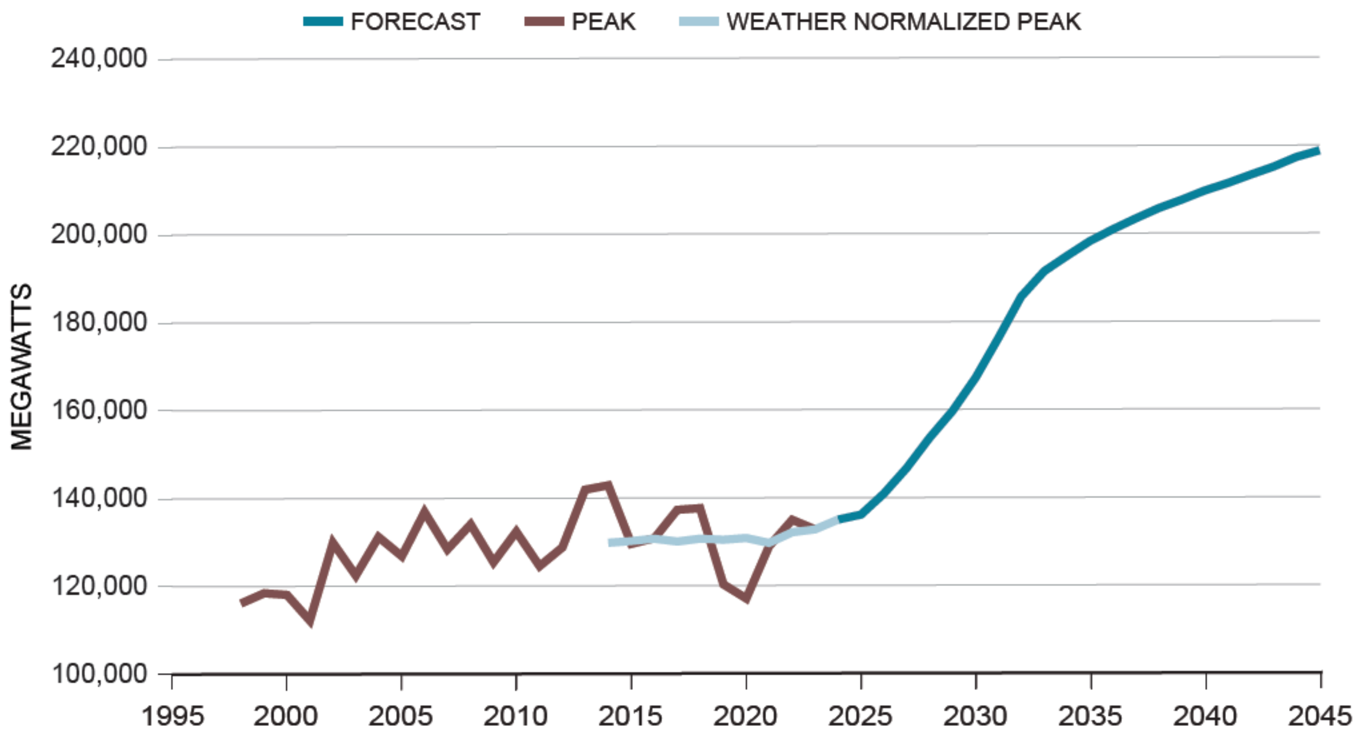
- The NPC recommends Congress and the Executive Branch take immediate legislative and administrative action to reform permitting to unlock fit-for-purpose[9] infrastructure investment.[10]
- The NPC recommends the natural gas and electric industries take urgent action to construct new fit-for-purpose energy infrastructure across the energy value chain, consistent with changing energy consumption patterns.
- The NPC recommends the natural gas and electric industries, in coordination with policymakers, prioritize actions to enhance and expand existing energy infrastructure where feasible, to manage rapidly changing flow patterns and growing demand.

IV. MAJOR COORDINATION CHALLENGES

To date, most of the gas-electric coordination debate and the studies and organized efforts to address gas-electric coordination have centered on the few days each year when the system is pushed to its limits by extreme weather. That focus risks overlooking the broader trajectory of the system. Over the next five to ten years, the rapid increase in demand for electric power, the increasing penetration of intermittent energy resources, and the emergence of a winter electricity demand peak (Figure ES-5) will drive additional absolute demand, more variation in flow patterns, and sharper peaks that extend beyond rare stress events. Preparing the system for this evolving demand profile will be just as

9 Fit-for-purpose infrastructure refers to infrastructure that is appropriately scaled and designed to meet specific functions, for example intraday variable and peak day needs.

10 See companion study: NPC. "Bottleneck to Breakthrough: A Permitting Blueprint to Build." 2025. https://permitting.npc.org/.



Source: PJM. 2025.

Figure ES-5. *Winter Peak Forecast in the PJM Interconnection LLC*

important as addressing emergency coordination during extreme conditions.

A healthy alignment between the natural gas and electric power sectors is defined by shared priorities in reliability, resiliency, and accountability. Both industries must plan for peak demand, coordinate outages, and recover quickly from disruptions, recognizing reliability as a joint responsibility that protects consumers from cascading failures. Effective alignment also acknowledges the physical limits of gas production, transport, and storage—particularly the just-in-time nature of fuel delivery—and ensures that markets and policies set realistic expectations. Robust and flexible infrastructure, clear lines of accountability, and transparent coordination—underpinned by fully understood and complementary definitions of firm service across gas and electric sectors—are essential to sustaining reliability. Finally, alignment depends on market and policy frameworks that encourage long-term investment, operational flexibility, and commercial innovation. These characteristics together form the benchmark for assessing current gaps and guiding future reforms.

The gas-electric coordination challenges can be organized into four major categories. Key findings and recommendations are presented for each category.

A. Operational Inefficiencies and Misalignments

The operational interface between the natural gas and electric power sectors is defined by different timelines, practices, and expectations. Gas flows on a fixed daily schedule, while electricity is dispatched on a rolling basis, often changing by the hour. Thus, these sectors physically move electrons and molecules across two different operating timelines. These structural differences contribute to generators making fuel commitments without certainty, which constrains their abilities to adjust to real-time shifting conditions. Various frameworks for communication exist between utility-based and competitive markets due to regulatory oversight and market integrity considerations, with a need for more coordination of planned maintenance to mitigate the risk of simultaneous outages. Electric reliability entities have made explicit measurable weatherization progress through new readiness standards and cold-weather preparedness programs through NERC. Comparable measures for the natural gas system remain voluntary, market driven, and fragmented across states; but progress has been implicitly demonstrated based on improved performance during the January 2024 Arctic storms.

FINDINGS:

- Operational improvements for electric and gas systems have been widely discussed in previous reports and forums and partially implemented. The electric sector has demonstrated more formalized progress, such as through NERC-led initiatives, while the gas sector's advancements have been primarily market driven.

RECOMMENDATIONS:

- The NPC recommends the National Association of Regulatory Utility Commissioners convene a Natural Gas Readiness Forum working group[11] to broaden stakeholder dialogue and document leading management practices across all interconnected sectors of the energy value chain.

B. Power Market Design – Economic Inefficiencies and Fuel Assurance Misalignments

At a market design level, the incentives that guide gas and electric sectors diverge. Electricity markets in competitive regions are optimized for short-term efficiency and cost minimization, while natural gas infrastructure requires firm, long-term commitments to support financing and construction. This mismatch undermines fuel assurance for power generators who often rely on an interruptible supply of gas due to cost considerations. Unlike electricity markets, which account for reserve margins to ensure reliability, natural gas markets do not provide comparable incentives for building capacity beyond contracted demand. As a result, the system lacks buffers to absorb shocks, leaving both sectors vulnerable during peak-demand and extreme weather events.

FINDINGS:

- Current market structures fail to incentivize generators to secure either long-term gas transportation or highly flexible premium products, heightening reliability risks.
- Electric and gas utilities plan for and rely on reserve margins to ensure reliability. Notwithstanding these planned utility margins, gas transportation infrastructure does not incorporate additional capacity because it is built to firm contractual needs. Therefore, there is no extra capacity on the existing pipeline system to serve the growing needs of the electric sector.

RECOMMENDATIONS:

- The NPC recommends appropriate entities (e.g., RTOs/ISOs, federal and state authorities) ensure adequate risk-based compensation for gas-fired power generators to obtain sufficient fuel and operate reliably when called upon and to be prepared to perform during stress periods.
- The NPC recommends FERC require RTO/ISOs to conduct comprehensive long-term planning that integrates resource adequacy and fuel assurance considerations, in cooperation with affected states.

C. Commercial – Gas Services Design and Power Sector Fuel Assurance Misalignments

Commercial practices in natural gas markets were not designed for today's power sector demands. Pipelines historically served local distribution companies with predictable, steady loads. Now, gas-fired generators impose sharp and unpredictable swings in demand, particularly as they balance the variability of intermittent energy resources. Yet flexible pipeline services are often inaccessible to generators, and storage development has been stagnant despite growing variability. These factors compromise the reliability of the secondary market, on which inde-

11 The Natural Gas Readiness Forum is currently coordinated by the American Gas Association.

pendent generators heavily depend, and expose local distribution companies to heightened risk.

FINDINGS:

- The emergence of a winter electricity peak that coincides with local distribution companies' design-day needs has reduced the secondary market's ability to supply independent power producers, limiting their capacity to meet electricity demand with existing infrastructure.
- Enhanced pipeline services to complement variable demand are not new, but like traditional firm transportation capacity, are typically only subscribed to by local distribution companies or vertically integrated utilities. Organized electricity markets do not appear to be adequately compensating generators to contract for such services, and additional compensation mechanisms may be required to make enhanced or flexible services commercially viable for generators.
- If solutions designed to accommodate variable demand are not developed to alleviate pipeline constraints, operational flexibility—such as the ability of shippers to utilize nonfirm or secondary delivery points—will likely become increasingly restricted, particularly in the Mid-Atlantic and Northeast regions.

RECOMMENDATIONS:

- The NPC recommends policymakers and market operators/participants work to address changing hourly gas flow patterns by developing alternative tariff structures[12] that enable enhanced gas service offerings and more flexible contracting arrangements between gas suppliers and electric generators.

12 "Tariff structures" refer to the rate designs, service categories, and terms established in pipeline or utility tariffs that define how customers pay for and access transportation, storage, or related services. These structures determine pricing, priority of service, and the flexibility available to different classes of users.

D. Fragmented Governance, Planning, and Reliability Coordination

The governance of the gas-electric interface is fragmented across multiple regulatory and operational entities. While FERC and NERC oversee parts of the system, neither has comprehensive authority to enforce alignment between the two sectors. Previous initiatives have improved communication but left deeper market misalignments unresolved. The absence of a clear accountability framework has meant that many recommendations have been implemented inconsistently, if at all. Past extreme weather events, such as Winter Storm Uri in 2021 and Winter Storm Elliott in 2022, have demonstrated how these gaps in planning and oversight translate directly into widespread consumer impacts. The NPC does not believe the creation of new oversight roles is necessary but instead submits that governance and oversight structures must be transparent for stakeholders to effectively engage.

FINDINGS:

- Clear and distinct regulatory accountability plays a critical role in advancing implementation of recommendations, largely because of authority scope.

RECOMMENDATIONS:

- The NPC recommends FERC (or RTOs/ISOs) endorse or issue an accountability framework to address the risk created by the lack of direct market commitments certain generation owners have to end-use customers.
- The NPC recommends the Federal and State Issues Collaborative publish a framework that clearly identifies and defines the roles and responsibilities for reliability, resource adequacy, and fuel assurance.
- The NPC recommends FERC enhance the Common Metrics report (FERC-922) released biennially and include an interim progress report with a focus on fuel assurance, resource adequacy, and other critical reliability metrics on a state-by-state basis.

V. THE WAY FORWARD

This NPC analysis underscores a widening structural misalignment between natural gas and electricity markets that poses increasing risks to system reliability. The alignment of these two sectors could once be characterized as a technical challenge, but with the growing need for gas-fired dispatchable resources to keep pace with demand, immediate and meaningful action is required. This report finds that the natural gas and electric systems both face reliability risks today. Neither industry—nor their customers—can afford to wait. Strengthening the system before the next crisis, not after it, is the mark of prudent risk management.

Achieving true gas-electric coordination will require more than operational adjustments. It demands structural alignment of incentives, planning processes, and accountability frameworks. Regulators, market operators, pipelines, and utilities must work toward shared reliability objectives supported by consistent standards, transparent information exchange, and clear cost-recovery mechanisms that value firm fuel assurance. Healthy alignment will depend on balancing market efficiency with reliability obligations and recognizing that neither sector can achieve resilience in isolation. Similarly, each of the recommendations presented in this study cannot effectively stand alone. They are interdependent and must be executed concurrently to provide the transformational change the U.S. energy system needs.

Coordinated action today can bridge the divide between the gas and power sectors. The recommendations developed in this study provide a roadmap for building a more reliable, resilient, and affordable energy future for the nation.

March 17, 2026

The Honorable Brett Guthrie, Chairman
Committee on Energy & Commerce
United States House of Representatives
2125 Rayburn House Office Building
Washington, D.C. 20515

The Honorable Frank Pallone, Ranking Member
Committee on Energy & Commerce
United States House of Representatives
2125 Rayburn House Office Building
Washington, D.C. 20515

The Honorable Bob Latta, Chairman
Committee on Energy & Commerce
Subcommittee on Energy
2125 Rayburn House Office Building
Washington, D.C. 20515

The Honorable Kathy Castor, Ranking Member
Committee on Energy & Commerce
Subcommittee on Energy
2125 Rayburn House Office Building
Washington, D.C. 20515

Dear Chairman Guthrie, Chairman Latta, Ranking Member Pallone, and Ranking Member Castor,

Thank you for holding today's hearing "*Winter Storm Fern Lessons: Supplying Reliable Power to Meet Peak Demand*" to highlight the critical role that energy infrastructure plays in the context of affordability and reliability.

Williams is an infrastructure company connecting American energy to local distribution companies and end-users nationwide. We are a leader in the midstream natural gas industry in scale, reach, and reliability by moving one-third of the natural gas used every day in America with over 33,000 miles of pipeline and more than 5,700 employees. Williams' operations include the Transco pipeline system, which safely and reliably delivers natural gas through a 10,000-mile interstate transmission pipeline system extending from south Texas to New York City, transporting approximately 15 percent of the nation's natural gas.

During winter storm Fern, Transco had no delivery failures and, at large, the natural gas industry performed exceptionally well. The country saw massive price spikes and pricing differentials, however, across regions due to the lack of pipeline infrastructure. Market structures and the lack of capacity from infrastructure constraints resulted in significant price spikes in areas most impacted by the winter weather event.

The Northeast United States pays some of the highest electricity prices in the nation, driven in large part by regional policies that prevent the build out of natural gas infrastructure. Every state in New England, plus New York, ranks in the top 10 nationally for most expensive retail electricity, and this is ultimately reflected in monthly bills for millions of Americans from New York to Maine. Over the past five years alone, the Northeast's average retail electricity price has increased 33 percent.[i] During severe weather events, the situation becomes extreme; spot natural gas prices have spiked to levels 17 times higher than adjacent supply regions, with prices reaching $42 to $180 per million British thermal units (MMBtu) during Winter Storm Fern[ii], compared to $8.75 to $25 per MMBtu in the Appalachian production region[iii], where pipeline infrastructure is prevalent.[iv]

The irony is acute. The Appalachian Basin, home to the Marcellus Shale formation, is the lowest-cost natural gas supply region in the United States, and it sits on the doorstep of the Northeast. Producers are capable of delivering abundant, low-cost natural gas to the region at a fraction of what Northeasterners currently pay for energy.

Yet there is not enough pipeline capacity needed to carry that gas into New England and New York, leaving the region to pay a structural premium that compounds every winter. Historical data shows that winter natural gas prices have been 230 to 250 percent higher in Massachusetts, New York, and Connecticut compared to Northeast Pennsylvania over the 2010-2025 period.[v] The gap between the energy the Northeast needs and the infrastructure available to deliver it grows wider every year, and demand-side management or renewable development is not a substitute for dispatchable, reliable, affordable fuel during peak events.

The Constitution Pipeline offers a solution to help address this affordability crisis in the Northeast. At 650 million cubic feet per day (MMcf/d) of capacity, it would represent the most significant expansion of Northeast natural gas infrastructure in a generation, delivering low-cost Appalachian gas to the Northeast. An independent analysis by S&P Global Commodity Insights quantified what this expansion would mean for families and businesses: $8.5 billion in net savings over the first 15 years the pipeline is in-service.[vi]

The Constitution Pipeline is not the entire solution to the Northeast's energy challenges, but it is the essential first step; one that Congress can support with meaningful permitting reforms for the midstream natural gas sector.

Vineyard Wind and Revolution Wind, two wind projects recently completed in the Northeast, will have a combined capacity of 1,500 MW, electricity that is not always available and that often disappears during major winter events, like Fern.[vii] On January 26, during the height of winter storm Fern, NYISO got 38.5 percent of its energy from dual fuel, 17.2 percent from natural gas, 16.6 percent from hydro, 15.2 percent from nuclear – and only 6.7 percent from wind. As of 5 pm on January 25, when it was 3 degrees in Vermont, ISO-NE was burning more oil than natural gas – a whopping 43 percent. The New England Clean Energy Connect (NECEC) transmission line from Quebec was actually exporting energy out of the Northeast. ISO-NE got 43 percent of their energy from oil and only 8 percent from renewables (that percent includes 20 percent refuse, 24 percent burning wood).

For comparison, 650 MMcf/d of natural gas (using a high-efficiency 60 percent turbine) would generate closer to 4,500 MW of electricity continuously. In other words, natural gas is more energy dense, more reliable, and more affordable – especially during peak events. The only constraint is the pipeline infrastructure needed to deliver that gas to where it is needed.

The Cost of Inaction: High Prices, Grid Constraints, and Higher Emissions

The Northeast's pipeline capacity is already running at maximum utilization during peak demand periods, creating a structural constraint that operational flexibility cannot overcome.[viii] Additional gas cannot be dispatched at peak times if infrastructure is already fully utilized.

Without adequate pipeline capacity, grid reliability is an operational reality that ISO-New England and NYISO confront every winter. Permitting and building more renewable capacity does not resolve the reliability gap that pipeline constraints impose, because more renewable capacity means more reliance on dispatchable energy to backstop intermittency.

Weather-driven price volatility has become the new normal in the Northeast, with extreme pricing events becoming more frequent and more severe. During the 2016 blizzard, prices at Transco Zone 6 and Algonquin spiked above $20 per MMBtu. The 2018 cold snap strained infrastructure further. Winter storms in 2022, 2023, and 2025 each pushed heating demand to extreme levels, maxing out pipeline capacity. But Winter Storm Fern in January 2026 set new records, with gas prices in the Northeast surging to levels exceeding all previous winter storms due to prolonged extreme cold, with Iroquois Zone 2 prices reaching $179 per MMBtu, Tennessee Zone 6 North at $130 per MMBtu, and Algonquin City Gates at $85 per MMBtu, while the Appalachian supply region remained near $10 per MMBtu.[ix]

The price differentials just this winter generated costs that exceeded three years of Constitution Pipeline capacity charges. Between November 1, 2025, and February 28, 2026, Constitution could have resulted in over $900 million in savings to its shippers based on the gas price spread between Iroquois Zone 2 and Tennessee Zone 4 production region, at the pipeline's planned volume of 650,000 thousand cubic feet per day (Mcf/d).[x] This means a single winter season demonstrated an economic return that would more than justify three years' worth of expense for the project.

The reliability dimension of this problem is also accelerating. Electrification of transportation, buildings, and industrial processes is driving sustained growth in electricity demand across the Northeast. ISO-New England projects that the grid's assumed winter demand peak in the 2040s will increase 100 percent compared to today's all-time peak.[xi] New York anticipates 39 percent growth in net on-grid power demand from 18 GW in 2025 to 25 GW by 2050, driven by large load growth and electrification.

Massachusetts faces 39 percent growth (from 6.5 GW to 9.0 GW), Connecticut 58 percent growth (3.5 GW to 5.5 GW), New Hampshire 82 percent growth (1.2 GW to 2.2 GW), and Rhode Island 42 percent growth (1.3 GW to 1.8 GW). If just 50 percent of this incremental demand is met or backstopped by dispatchable natural gas generation, the essential complement to intermittent renewables, the region will need significantly more pipeline capacity that does not currently exist.

The competitive consequences of inaction compound over time. High energy costs are a primary driver of business location decisions, and the Northeast's price premium is well-documented and growing. New York residents pay 48 percent higher electricity rates than the U.S. average; Massachusetts residents pay 78 percent higher rates; Connecticut 75 percent higher; New Hampshire 42 percent higher; Rhode Island 70 percent higher; Vermont 34 percent higher; and Maine 45 percent higher. Nearly 160 Wall Street firms have moved their headquarters out of New York since the end of 2019 partly due to high energy and operating costs, taking nearly $1 trillion in assets under management with them.[xii] Connecticut made up only 0.5 percent of total non-residential construction put in place in 2024, missing out on the national manufacturing boom. Massachusetts utilities have received requests from proposed data centers for an additional 2 GW of electricity, but energy costs may be a deterrent to deployment. Every year that the region fails to address its pipeline constraints, it misses out on economic opportunity.

Notably, the Northeast continues to rely heavily on heating oil for residential and commercial heating, particularly in older housing throughout the region. In 2024, heating oil still represented 24 percent of the residential and commercial energy mix across the Constitution Pipeline impact footprint.

Increasing the natural gas share of residential and commercial demand by just one percent in Northeastern states would result in roughly 300,000 metric tons of CO_2 equivalent avoided per year, equivalent to removing 70,000 passenger vehicles from the road.[xiii]

Expanded pipeline capacity and the price stability it brings are the necessary preconditions for that switching to occur at scale. When supply is reliable and prices are structurally lower, conversion accelerates, and the environmental benefit compounds across hundreds of thousands of buildings over the life of the project.

Additionally, New York, Connecticut, Massachusetts, and New Hampshire import energy that can be both more expensive and more emissions-intensive than gas from the Appalachian Basin, when accounting for the full supply chain including liquefaction, shipping, and regasification. Replacing foreign imports with domestic Marcellus supply improves both U.S. energy security and environmental performance.

If the Northeast fails to expand pipeline capacity and winter supply shortfalls persist, grid operators will continue to rely on oil-fired backup generation during cold snaps, some of the most carbon-intensive electricity generation available in the United States, to maintain reliability.

Constraining gas infrastructure does not prevent fossil fuel use; it substitutes higher-carbon fuels in moments of crisis, while imposing large consumer costs in the process.

Connecticut Governor Ned Lamont has acknowledged pipelines as a potential vehicle for meaningful rate relief for residents already paying among the highest electricity rates in the nation.[xiv] For Massachusetts and Rhode Island, which share New England's structural gas supply constraints and their associated cost burdens, additional natural gas infrastructure offers a path to sustained price moderation.

Today's hearing highlights Winter Storm Fern in the context of affordability and reliability, showcasing the need for more natural gas pipelines.

Congress can help address the energy infrastructure constraints in the Northeast by passing meaningful permitting reforms for the midstream sector, including key measures from the strong, bipartisan permitting reform bills that passed out of the U.S. House of Representatives in December 2025 seeking to reform the Clean Water Act 401 process and the National Environmental Policy Act (NEPA) to support the buildout of energy infrastructure. [xv] We look forward to working with the U.S. Senate to incorporate these provisions into a bipartisan permitting reform package to expedite the buildout of natural gas pipelines across the United States.

With its abundant natural gas supplies, the United States is perfectly positioned to build the energy infrastructure needed to meet growing global and domestic energy demands. Bold, meaningful reforms to federal permitting and review processes will help us realize this future.

Williams appreciates the bipartisan and committed efforts of this Committee to further these policies for the benefit of the American people.

Sincerely,

THE WILLIAMS COMPANIES, INC.

Lane Wilson
Senior Vice President and General Council

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[i] 2024 Average Retail Price of Electricity per KWh analysis

[ii] 1/28/2026: Northeast Regional Average - $ 42.46, Min Settle price was AGT Receipts @ $38, Highest Traded Price - $235.42 @ IGT Z2, Highest Settle Price - $179.165 @ IGT Z2

[iii] For example, these are the Appalachia Regional averages as published by Platts during Fern: 1/30/2026 - $7.695, 1/29/2026 - $10.44, 1/28/2026 - $11.305 (low - $8.75; high - $25), 1/27/2026 - $13.31, 1/26/2026 - $68.89, 1/25/2026 - $68.89, 1/24/2026 - $68.89, 1/23/2026 - $36.995

[iv] Natural Gas Prices ($/MMBtu) at select Northeast price hubs on January 28, 2026

[v] Source: S&P Global Energy, 2010-2025 period

[vi] S&P Global Energy, 2010-2025 period https://press.spglobal.com/2025-11-04-Constitution-Pipeline-Could-Generate-Up-to-11-6-Billion-in-Total-Savings-by-Lowering-Natural-Gas-Prices-in-Energy-Tight-US-Northeast,-S-P-Global-Analysis-Finds

[vii] POLITICO Pro | Article | Vineyard Wind puts final blade on long coming project

[viii] Winter reliability analysis showing infrastructure at full utilization

[ix] Historical Daily Prices at Select Northeast Gas Hubs ($/MMBtu). regional average

[x] Winter pricing dislocations costing consumers analysis

[xi] ISO-NE Future Grid Reliability Study Phase 1

[xii] "Nearly 160 Wall Street firms have moved their headquarters out of New York since the end of 2019, taking nearly $1 trillion in assets under management with them." *Shannon Thaler, "New York loses $1 trillion in Wall Street business as firms flee the city,"* New York Post, August 21, 2023. Link: New York loses $1 trillion in Wall Street business as firms flee the city

[xiii] Source: EIA State Energy Data System, S&P Global Energy, U.S. EPA.

[xiv] WSHU Public Radio "Lamont open to controversial NY pipeline as energy prices climb" (July 2, 2025): Governor Ned Lamont said he may support construction of a natural gas pipeline as a way to bring gas into Connecticut and reduce electricity prices, noting that prices are "extremely high in Connecticut and New England, partly because natural gas pipelines are scarce." He added that expanded pipeline capacity could lower natural gas and electricity prices [wshu.org].

[xv] : the Improving Interagency Coordination for Pipeline Reviews Act (H.R. 3668), the Standardizing Permitting and Expediting Economic Development (SPEED) Act (H.R.4776), and the Promoting Efficient Review for Modern Infrastructure Today (PERMIT) Act (H.R. 3898). In the Senate, necessary Clean Water Act reforms can be achieved by incorporating language from these bills in coordination with S.1456, the SPUR Act of 2023 to advance natural gas pipelines, and the Revitalizing the Economy by Simplifying Timelines and Assuring Regulatory Transparency (RESTART) Act (S. 1449) also of 2023.

Report on the North American Electric Reliability Corporation

Interregional Transfer Capability Study

FEDERAL ENERGY REGULATORY COMMISSION

Staff Report

February 2026

Report on the North American Electric Reliability Corporation

Interregional Transfer Capability Study

A Report To Congress Pursuant
to the Fiscal Responsibility Act of 2023

FERC Docket No. AD25-4-000

FEDERAL ENERGY REGULATORY COMMISSION
Staff Report
February 2026

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EXECUTIVE SUMMARY

This executive summary (section I) provides the key highlights of this report. As detailed in section II of this report (Introduction), the Fiscal Responsibility Act of 2023 (Act) requires the North American Reliability Corporation (NERC)[1] to conduct a study of total transfer capability between transmission planning regions. The Act requires that the Interregional Transfer Capability Study (ITC Study) include the following: (1) current total transfer capability between each pair of neighboring transmission planning regions; (2) a recommendation of prudent additions to total transfer capability between each pair of neighboring transmission planning regions that would demonstrably strengthen reliability within and among such neighboring transmission planning regions; and (3) recommendations to meet and maintain total transfer capability together with such recommended prudent additions to total transfer capability between each pair of neighboring transmission planning regions.

The Act further requires: (1) NERC to submit the ITC Study to the Commission; (2) the Commission to publish the ITC Study in the *Federal Register* for public comment; and (3) the Commission to "submit a report on its conclusions to Congress and include recommendations, if any, for statutory changes." NERC conducted the ITC Study and submitted it to the Commission on November 19, 2024. The Commission published the ITC Study in the Federal Register on December 27, 2024, and public comments were due February 25, 2025. This report to Congress by the staff of the Federal Energy Regulatory Commission (Commission) is being submitted in compliance with the Act.

Section II of this report explains that the ITC Study uses the term interregional transfer capability consistent with the Commission's definition of the term total transfer capability.[2]

Section III of this report provides an overview of the ITC Study (ITC Study Overview). The ITC Study is a national assessment that identifies current energy transfers between regions, potential opportunities to strengthen connections between neighboring regions to improve energy adequacy,[3] and potential opportunities to optimize operating reserves[4] through increased transfer capability. Significantly, the ITC Study conducts this assessment using a common approach and consistent assumptions across regions in a single transmission model, allowing for a broad view of the Bulk-Power System.[5] The ITC Study is a reliability-oriented assessment, and therefore, the ITC Study focuses narrowly on the relationship between interregional transfer capability and reliability risks to make general recommendations for prudent additions. The ITC Study is clear that it did not consider any economic, siting,

1 The North American Electric Reliability Corporation (NERC) is a not-for-profit, international regulatory authority dedicated to effectively and efficiently reducing risks to the reliability and security of the bulk power system. For more information, please visit www.nerc.com/who-we-are.

2 The Commission defines total transfer capability as "the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions, or such definition as contained in Commission-approved Reliability Standards." 18 C.F.R. § 37.6(b)(1)(vi) (2025). In the context of the ITC Study, an "area" is a transmission planning region as defined in the ITC Study. *See* NERC Transmittal at 11-12

3 NERC defines energy adequacy as the ability of the Bulk-Power System to meet customer demand at all times. *See* ITC Study at 1 n.8.

4 Generally speaking, "[o]perating reserves are the electricity supplies that are not currently being used but can quickly come online in the case of an unplanned event on the system — such as a loss of generation or a transmission line — or when real-time demand is higher than forecast." See, e.g., CAISO, *Maintaining Operating Reserves Fact Sheet* (2023), www.caiso.com/documents/maintaining-operating-reserves-fact-sheet.pdf., NERC defines Operating Reserves as, "that capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve." *See*, NERC, Glossary of Terms Used in NERC Reliability Standards (Oct. 2025), https://www.nerc.com/globalassets/standards/reliability-standards/glossary_of_terms.pdf.

5 The Commission's regulations define the Bulk-Power System as "facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy." 18 C.F.R. § 39.1.

political, or environmental analyses, does not recommend specific projects to increase energy transfers and is not a transmission planning study. The ITC Study observes that transmission upgrades alone may not fully address all reliability or energy adequacy concerns.

Section III of this report also explains that, with respect to the Act's requirement to recommend "prudent additions," the ITC Study determines prudent additions to be recommendations that reduce energy deficits by transferring available excess energy from neighboring regions, and achieving three primary objectives: (1) strengthening reliability; (2) serving load under extreme conditions; and (3) not creating unintended reliability concerns. As further explained in section III of this report, the ITC Study defines a total of 30 regions (23 in the United States and 7 in Canada) for a more comprehensive and granular analysis of potential transfer capability limitations.

Lastly, section III of this report provides an overview of the ITC Study results. The following are significant results from each of the 3 parts of the study which are included in compliance with the Act's requirement that the ITC Study include three elements.

Part 1 of the ITC Study provides a summary of NERC's assessment of existing transfer capabilities between each pair of neighboring regions for two base case scenarios, 2024 Summer and 2024/2025 Winter. It makes the following findings:

- Transfer capability for 2024 Summer and 2024/25 Winter varies widely across North America, with total import capability between 1% and 92% of peak load, and transfer capability varies seasonally, regionally, and under different system conditions.

- The calculated transfer capabilities are generally higher in the West Coast, Great Lakes, and Mid-Atlantic areas, while relatively lower in the Mountain States, Great Plains, Southeast, and the Northeast regions.

- Currently there are sufficient resources and transfer capability to serve load in almost all scenarios, identifying only three regions experiencing resource deficiencies, and therefore existing infrastructure appears to be capable of maintaining energy adequacy across diverse scenarios except under especially challenging conditions.

Part 2 of the ITC Study summarizes NERC's simulation of future Bulk-Power System energy availability based on 12 years of historical hourly weather data (each of which is referred to as a "weather year"), which NERC modeled using the year 2033[6], to evaluate whether additional transfer capability (and how much) would mitigate the potential risk of energy inadequacy created by the potential resource deficiencies. It also provides NERC's determination of whether a technically prudent addition could be recommended. Part 2 of the ITC Study makes the following specific findings:

- Energy deficiencies were identified across all 12 weather years studied, with import capability during extreme conditions varying significantly across the country, indicating that a one-size-fits-all requirement for a minimum amount of interregional transfer capability may be inefficient and potentially ineffective.

- 11 out of 23 regions would experience a resource deficiency in one or more weather years, with considerable variance in the magnitude of deficiencies.

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6 For calculating technically prudent additions, NERC selected the year 2033 because interregional transmission projects typically require at least 10 years to plan and build. ITC Study at xiv.

- The ITC Study recommends a total of 35,000 MW of technically prudent additions of interregional transfer capability for 10 regions that are projected to have resource deficiencies in 2033.

- The Electric Reliability Council of Texas (ERCOT) region is shown as having the highest maximum resource deficiency (and thus the highest level of recommended prudent additions), and the Midcontinent Independent System Operator-South region (MISO-S) as having the least.

- Some identified transmission needs could be alleviated by projects already in planning, permitting, or construction phases.

- Higher than expected generation retirements without replacement capacity could lead to increased energy deficiencies and potentially more transfer capability needed than recommended.

Part 3 of the ITC Study provides recommendations to meet and maintain sufficient transfer capability. Additionally, Part 3 of the ITC Study notes that options other than increased transfer capability exist to mitigate identified energy adequacy risks, including constructing local generation, increasing demand response resources, and accepting the identified risks during extreme events (assuming other reliability thresholds are met).

Section IV of this report highlights three key themes that Commission staff identified from the public comments. The first theme, reflecting agreement from nearly all commenters, is that a process to evaluate transfer capability between neighboring regions could be beneficial. The second theme is that the ITC Study is not a recommendation for transmission development. The third theme is that solutions other than increasing transfer capability also exist to meet future reliability needs.

Next, section V of this report summarizes Commission staff's conclusions on the ITC Study (Conclusions on the NERC ITC Study). Among the conclusions, Commission staff notes that while the ITC Study has limitations, it is valuable and represents an advancement in existing transfer analysis and modeling processes. By focusing on an energy adequacy metric for every hour (i.e., the hourly energy margin), the ITC Study provides a more comprehensive understanding of energy deficiencies under extreme conditions and highlights the need for energy sufficiency on a more granular basis than conventional studies that consider only seasonal peak conditions (i.e., summer peak and winter peak).

Finally, section VI does not include any recommendations for statutory changes; and sections VII and VIII of this report include a copy of NERC's Filing to the Commission which includes the ITC Study (Appendix A) and a list of commenters that submitted comments in response to the ITC Study (Appendix B).

INTRODUCTION

The Commission is authorized by statute to ensure just and reasonable transmission rates and rates for the wholesale sale of electricity and natural gas in interstate commerce. As part of the Energy Policy Act of 2005, Congress gave the Commission additional responsibilities to protect and improve the reliability of the Bulk-Power System through the establishment of mandatory reliability standards. NERC develops and enforces these reliability standards as the Commission-certified Electric Reliability Organization.

The Fiscal Responsibility Act of 2023 (Act) was signed into law on June 3, 2023. Section 322 of the Act requires that NERC conduct a study of total transfer capability between transmission planning regions that contains the following:[7]

1. Current total transfer capability between each pair of neighboring transmission planning regions.

2. A recommendation of prudent additions to total transfer capability between each pair of neighboring transmission planning regions that would demonstrably strengthen reliability within and among such neighboring transmission planning regions.

3. Recommendations to meet and maintain total transfer capability together with such recommended prudent additions to total transfer capability between each pair of neighboring transmission planning regions.

The Act provided NERC with 18 months to complete the study and required NERC to submit the study to the Commission by December 2, 2024. NERC submitted the ITC Study to the Commission on November 19, 2024[8] and, as required by the Act, the Commission published the ITC Study in the *Federal Register* for public comment, with comments due by February 25, 2025.[9] The Act states that, no later than 12 months after the comment period ends, the Commission must "submit a report on its conclusions to Congress and include recommendations, if any, for statutory changes."[10] This report is submitted in accordance with Congress' statutory requirement.

What is Interregional Transfer Capability?

The Act requires NERC to conduct a study of "total transfer capability between transmission planning regions." Total transfer capability is defined in the Commission's regulations as "the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions, or such definition as contained in Commission-approved Reliability Standards."[11] In developing its ITC Study approach, NERC noted that the ITC Study's definition of interregional transfer capability is consistent with total transfer capability as defined in the Commission's regulations and that, in the context of interregional transfer capability, an "area" is a transmission planning region composed of public utility transmission providers.[12] Thus, the ITC Study uses the terms total transfer

7 Fiscal Responsibility Act of 2023, Pub. L. No. 118-5, § 322 (2023) (Act).

8 NERC Nov. 19 2024 Filing, app. A (ITC Study).

9 89 Fed. Reg. 95,776. *See also* Docket No. AD25-4-000.

10 Act § 322(c).

11 18 C.F.R. § 37.6(b)(1)(vi) (2025).

12 North American Electric Reliability Corporation, *Study Framework: Interregional Transfer Capability Study (ITC S[tudy])* at 7-8, www.nerc.com/pa/RAPA/Documents/ITCS_Framework_Clean.pdf.

capability, transfer capability, and interregional transfer capability interchangeably. Additionally, as the ITC Study explains, transfer capability is measured in units of electric power, generally expressed in megawatts (MW).[13] In its filing accompanying the ITC Study, NERC explains that "transfer capability is a measure of the system's ability to address energy deficiencies by relying on resources in neighboring [transmission planning] regions and is a key component of a reliable and resilient [Bulk-Power System]."[14]

The remainder of this report uses "region" to reference the transmission planning regions defined in the ITC Study. As explained below, NERC defined most of these regions as sub-regions of the Order No. 1000 transmission planning regions plus Texas.[15]

Scope of Report

This report provides an overview of the ITC Study, highlights key themes from the comments received from the public, and summarizes Commission staff's conclusions on the ITC Study. The ITC Study is included as Appendix A of this report, and a list of entities that submitted comments on the ITC Study is included as Appendix B.

13 ITC Study at 9.

14 NERC Nov. 19 2024 Filing, Transmittal at 4. (NERC Transmittal).

15 *See infra* section III.3 The ITC Study Designation of Regions.

ITC STUDY OVERVIEW

The ITC Study is a national assessment, centered on reliability, that identifies both current energy transfers between regions in the United States and potential future energy transfers that may strengthen reliability.[16] The ITC Study does this using a common approach and consistent assumptions across regions in a single transmission model, allowing for a broad view of the Bulk-Power System that can account for the weather's simultaneous effect on multiple regions across a wide area. As detailed below, the ITC Study focuses on maintaining energy adequacy as measured by the hourly energy margin.

The ITC Study is not a transmission planning study; however, the hourly energy margin could be incorporated into future transmission planning studies. The ITC Study also does not provide prescriptive solutions, assess or recommend specific transmission projects, or represent a blueprint or transmission plan to increase transfer capability.[17] Rather, following Congress's directive to NERC, the ITC Study identifies potential opportunities to strengthen connections between neighboring regions, improve energy adequacy, and optimize available reserves through increased transfer capability. In doing so, the ITC Study presents independent and informative analysis while leaving the decision to increase transfer capability, if at all, to policymakers and industry.[18]

THE ITC STUDY IS RELIABILITY FOCUSED

The ITC Study states that interregional energy transfers play an increasingly pivotal role in supporting energy adequacy, which the ITC Study defines as the ability of the Bulk-Power System to meet customer demand at all times.[19] For this reason, NERC focuses narrowly on the relationship between interregional transfer capability and reliability risks to make general recommendations for prudent additions, as required by the Act. NERC recognizes that additional transmission has more quantifiable benefits than the reliability benefits referenced in the ITC Study, and states that nothing in the ITC Study is intended to preclude the evaluation of those additional considerations.[20] NERC caveats that the ITC Study specifically does not:

- Consider any economic or cost-benefit analyses in identifying recommendations for prudent additions.[21]
- Recommend any specific projects to increase transfers between regions, including new or upgraded alternating current or direct current transmission facilities, or grid enhancing technologies.[22]
- Include a transmission planning study. NERC states that "[u]nlike the ITC [Study], [transmission] planning studies ensure that electricity is generated, transmitted, and distributed in a cost-effective, reliable, and sustainable manner, while meeting environmental and regulatory requirements."[23]

16 The ITC Study also evaluated transfer capability from Canada into the United States. ITC Study at x.
17 ITC Study at vii-viii; NERC Reply Comments at 1-2.
18 ITC Study at vii-viii.
19 ITC Study at vii.
20 ITC Study at 11.
21 ITC Study at viii.
22 ITC Study at 11.
23 ITC Study at 11.

- Evaluate operational actions that may address interregional transfer constraints.[24]

- Include recent changes to load forecasts, renewable targets, or retirement announcements into the study.[25]

- Evaluate the relative merits of additional transfer capability versus local resource additions (which could address some of the identified deficiencies).[26]

- Measure the quantified impacts of planned projects.[27]

- Use alternate modeling approaches. The ITC Study results may differ from other analyses.[28]

THE ITC STUDY DEFINITION OF "PRUDENT"

The Act requires NERC to provide a recommendation of "prudent additions to total transfer capability that would demonstrably strengthen reliability."[29] The ITC Study determines prudent additions to be recommendations based on reducing energy deficits by transferring available excess energy from neighboring regions, with three primary objectives: (1) strengthening reliability; (2) serving load under extreme conditions; and (3) not creating unintended reliability concerns.[30] The ITC Study considers Commission precedent from electric ratemaking proceedings in determining how to assess the prudence of additional transfer capability. In this context, the ITC Study notes that "FERC precedent reflects that prudence means a determination of whether a reasonable entity would have made the same decision in good faith under the same circumstances and at the relevant point in time."[31] However, the ITC Study differentiates between "prudent" as used in the utility ratemaking context, where it notes that the Commission has considered prudence in the context of specific, fact-based scenarios involving rates, and "technically prudent"[32] for reliability, which is the meaning adopted by the ITC Study.[33] The process NERC used to determine these technically prudent recommendations is described below.[34]

Importantly, the ITC Study uses the term "prudent" to describe the additions to transfer capability it recommends for reliability reasons without regard to economic considerations.[35] Noting that determining exactly how much additional capability is technically prudent can depend on the totality of factors and circumstances, NERC underscores that "nothing in the ITC [Study] should be used as justification for a particular project," and "no part of the ITC [Study] is intended as evidence regarding prudence in any ratemaking proceeding."[36] The ITC Study also plainly states that it "excludes cost-benefit assessments, meaning no economic or financial modeling was used in

24 ITC Study at xii.
25 ITC Study at vii.
26 ITC Study at 4.
27 ITC Study at vii.
28 ITC Study at vii.
29 Act § 322(a)(2).
30 ITC Study at xiv.
31 ITC Study at 11 (citing *New England Power Co.,* 31 FERC ¶ 61,047, at 61,084 (1985); Potomac-Appalachian Transmission Highline, LLC, 140 FERC ¶ 61,229, at P 82 (2012)).
32 Also referred to interchangeably as "recommended additions" or "prudent additions." *See* ITC Study at ix n.20.
33 ITC Study at 11.
34 *See infra* section III.4 Results of the ITC Study Analysis.
35 ITC Study at xiv.
36 NERC Transmittal at 15.

determining prudent recommendations."[37]

THE ITC STUDY DESIGNATION OF REGIONS

To establish regions for the purpose of the ITC Study, NERC started by recognizing the boundaries of most Order No. 1000 transmission planning regions[38] and Texas in the United States, and then adding Canadian transmission planning regions adjacent to the United States.[39] Next, NERC subdivided some of the existing Order No. 1000 transmission planning regions into smaller regions to allow for a more granular analysis of potential transfer capability limitations.[40] For example, NERC subdivided PJM Interconnection, L.L.C. (PJM), a single Order No. 1000 transmission planning region and Regional Transmission Organization, into three separate regions: PJM-West, PJM-East, and PJM-South. While the ITC Study explains that this more granular approach allows recommendations at more precise locations,[41] this approach may not reflect the nature of an Order No. 1000 transmission planning region as a whole or how the region plans for transmission.[42] The ITC Study defines a total of 30 regions (23 in the United States and 7 in Canada), as shown in Figure 1.[43]

37 ITC Study at xiv.

38 In Order No. 1000, the Commission requires, among other things, that public utility transmission providers participate in a regional transmission planning process that produces a regional transmission plan. An Order No. 1000 transmission planning region is one in which public utility transmission providers, in consultation with stakeholders and affected states, have agreed to participate for purposes of regional transmission planning and development of the regional transmission plan. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012). The Commission's Order No. 1000 transmission planning regions are available at www.ferc.gov/media/regions-map-printable-version-order-no-1000.

39 ITC Study at 7.

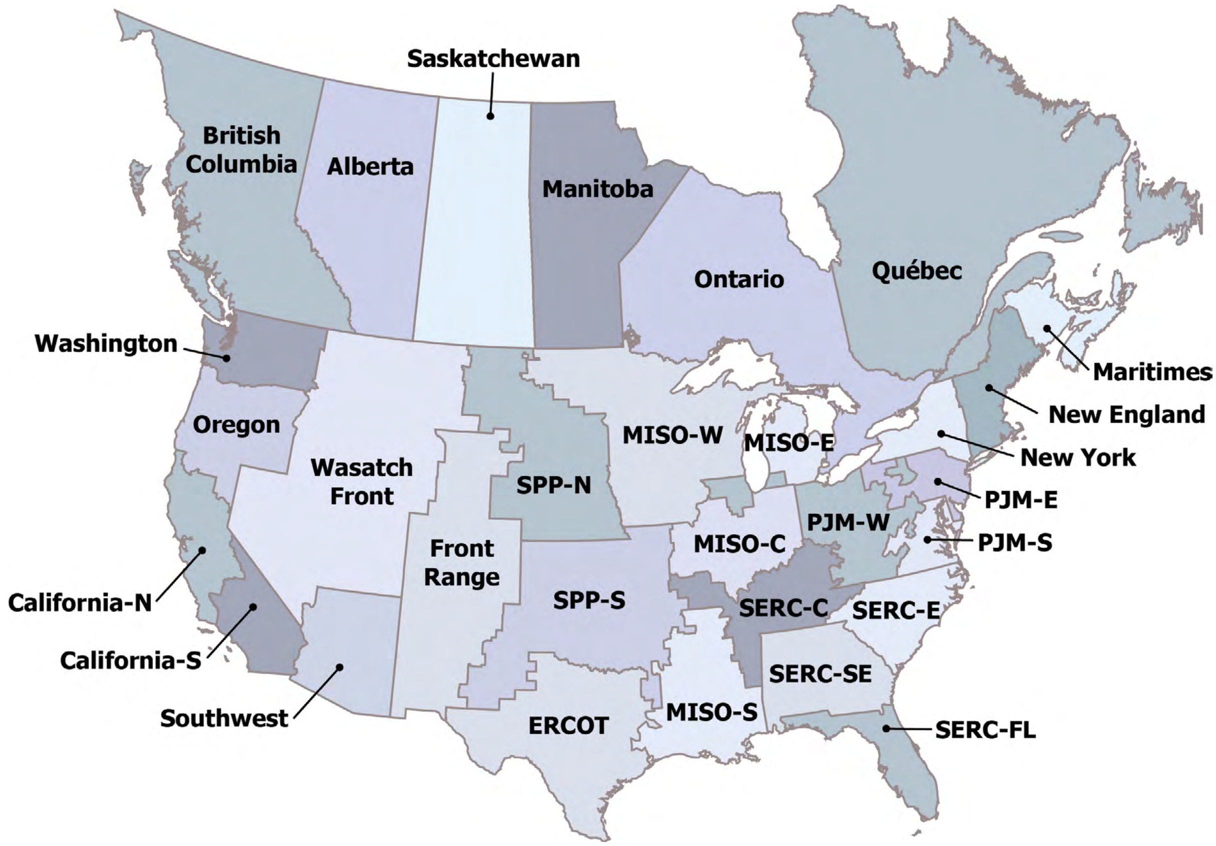
40 ITC Study at 7.

41 ITC Study at 7.

42 In the PJM example, because PJM operates as a single region for transmission planning and market operations, any recommendations by NERC regarding transfer capability in one of the NERC-defined PJM regions may not represent real-world operational and transfer capability of the full PJM transmission planning region.

43 As required by the Act, the ITC Study analyzes energy transfers between transmission planning regions in the United States. Act § 322(a). NERC optionally considered energy transfers from Canada into the United States in the ITC Study and conducted an additional study that considers energy transfers between Canadian transmission planning regions and from the United States into Canada. *See* ITC Study Canadian Analysis Final Report (Apr. 2025), www.nerc.com/globalassets/initiatives/itcs/nerc_itcs_canadian_analysis_2025.pdf.

Figure 1: NERC-Defined Transmission Planning Regions



Source: NERC, ITC Study

RESULTS OF THE ITC STUDY ANALYSIS

Results of Part 1

In Part 1, the ITC Study summarizes NERC's assessment of existing transfer capabilities between each pair of neighboring regions for two base case scenarios, 2024 Summer and 2024/2025 Winter.[44] NERC's assessment analyzes the following power flows: (1) between regions; (2) into a single region from all of its neighboring regions (total import capability);[45] and (3) between Order No. 1000 transmission planning regions (e.g., from PJM to/from Midcontinent Independent System Operator, Inc. (MISO)) (supplemental results).[46]

The ITC Study finds that transfer capability for 2024 Summer and 2024/25 Winter varies widely across North America, with total import capability between 1% and 92% of peak load, and that transfer capability varies seasonally, regionally, and under different system conditions.[47] Figure 2 shows both the transfer capabilities between neighboring regions and the total import capability of the individual region. The calculated transfer capabilities are

44 ITC Study at x, 13.

45 ITC Study at 15. The total import capability reflects simultaneous transfer limits into a region from all of its neighbors. ITC Study at 56.

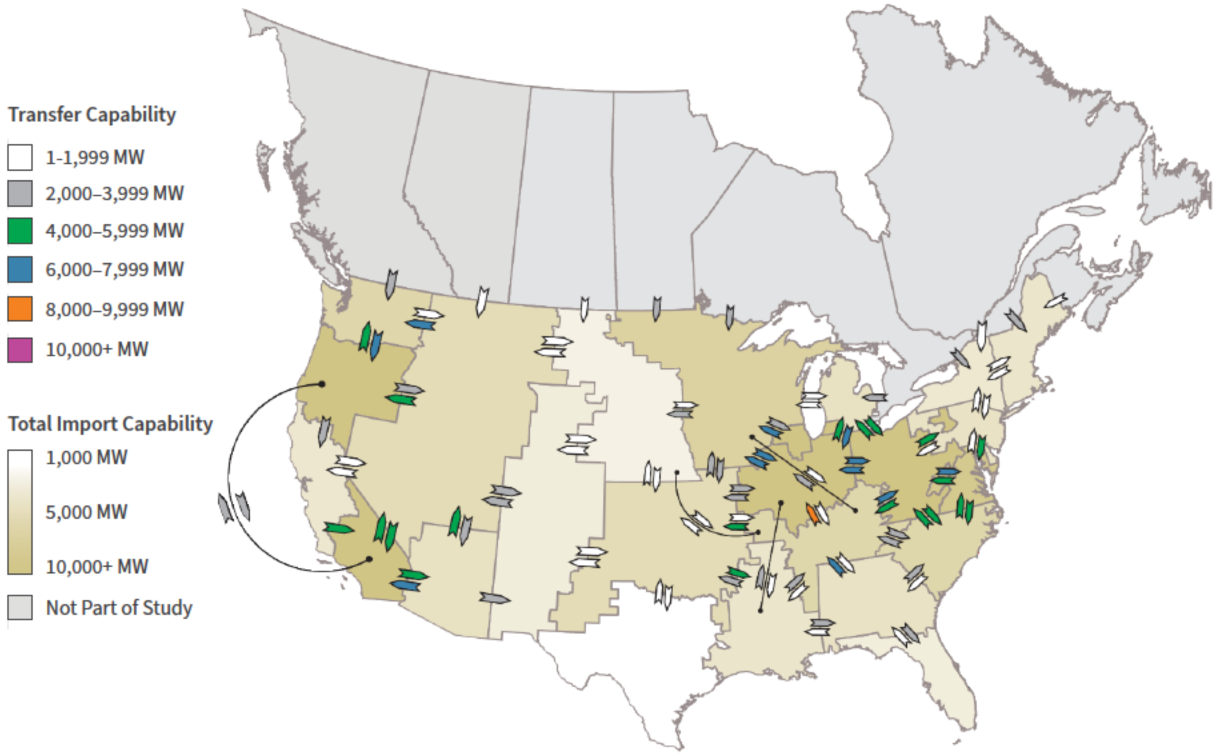
46 ITC Study at 15. The supplemental results between Order No. 1000 transmission planning regions were studied for completeness but not used to determine prudent additions in the ITC Study's next phase. ITC Study at 15, 69.

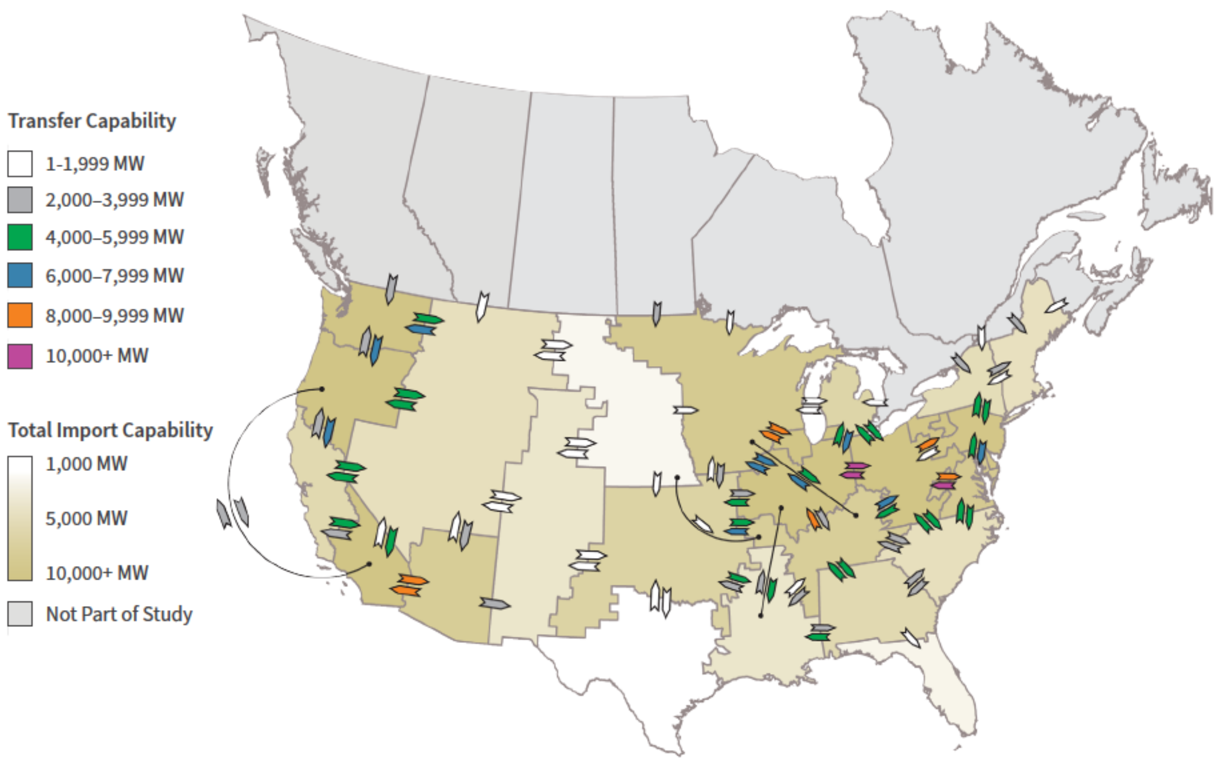
47 ITC Study at x.

generally higher in the West Coast, Great Lakes, and Mid-Atlantic areas, while relatively lower in the Mountain States, Great Plains, Southeast, and the Northeast regions. In addition, there is limited transfer capability between the four interconnections (i.e., the Eastern, Western, Texas (or ERCOT), and Québec Interconnections).[48]

48 ITC Study at x.

Figure 2: Part 1 Transfer Capabilities for Summer 2024 and Winter 2024/2025





Source: NERC, ITC Study

Results of Parts 2 and 3

In Part 2, the ITC Study summarizes NERC's simulation of future Bulk-Power System energy availability based on 12 years of historical hourly weather data, each of which is referred to as a "weather year." This approach allowed NERC to assess how an estimated future load and resource mix would respond if the historical hourly weather conditions were to occur in the future. Specifically, NERC assessed whether the energy available from resources in each region would be sufficient to meet the forecasted load in that region for each hour. The ITC Study refers to the difference between available energy and forecasted load for an hour as the hourly energy margin. NERC used the hourly energy margin analysis to determine the time-synchronized energy adequacy needs in each region, meaning the energy adequacy needs were matched to their corresponding hour.[49]

NERC defined specific margin levels to determine when a region will not have enough resources within its own region to serve its load. If a region had an hourly energy margin of 10% or less of its load, NERC assumed that region would not share surplus energy with a neighboring region and would import power from a neighboring region for that hour (tight margin level). If a region had an hourly energy margin of 3% or less of its load, NERC assumed the region would need to reduce load absent energy imports from neighboring regions or additional resources (minimum margin level).[50] When a region's hourly energy margin fell below the minimum margin level of 3%, NERC classified the region as resource deficient. If neighboring regions lacked surplus energy to export, or there was insufficient capacity on the transmission system to import power into the deficient region, NERC assumed that the deficient region must reduce load to maintain the minimum margin level.

NERC calculated the hourly energy margin and associated resource deficiencies, if any, for each region and all 12 weather years based on forecasted load and generation for the years 2024 and 2033.[51] The ITC Study explains that NERC's energy margin analysis of the 2024 model year identified only three regions—ERCOT, SERC-East, and New York—that would experience resource deficiencies (i.e., these regions had an hourly energy margin at or below the minimum margin level of 3%) that could not be addressed by resources within their region or transfers from a neighboring region using existing transfer capabilities.[52] Notably, ERCOT was the only region to experience deficiencies across multiple weather years.[53] With these few exceptions, NERC's analysis of the 2024 model year indicates that currently there are sufficient resources and transfer capability to serve load in almost all scenarios. The ITC Study finds that existing infrastructure appears to be capable of maintaining energy adequacy across diverse scenarios except under especially challenging conditions.[54]

The ITC Study explains that NERC's hourly energy margin analysis of the 2033 model year accounted for continued load growth, generation unit retirements, and expected new resource additions using data from the NERC 2023 Long

49 ITC Study at 83.

50 ITC Study at 84.

51 ITC Study at xiv.

52 ITC Study at 93, tbl. 7.1 (Maximum Resource Deficiency (MW) by TPR and Weather Year (2024 Case)).

53 The ITC Study's analysis of ERCOT's data indicates resource deficiencies from 2020 thru 2023, with the most severe deficiency occurring in 2021, a 10,699 MW resource deficiency, assuming winterization efforts. Without winterization efforts, the ITC Study indicates a resource deficiency of approximately 25,000 MW, a shortfall that mirrors the scale of the actual Winter Storm Uri event. ITC Study at 93-94.

54 ITC Study at 93.

Term Reliability Assessment.[55] The ITC Study reports the maximum resource deficiencies that NERC calculated in MW for each of the 12 historical weather years. The ITC Study finds that 11 out of 23 regions would experience a resource deficiency in one or more weather years.[56]

According to NERC's 2033 model year results, ERCOT had the largest single-year resource deficiency of 18,926 MW during conditions like the winter of 2021, and one or more resource deficiencies in seven out of the 12 weather years reviewed.[57] ERCOT had resource deficiencies that lasted for 11 hours per year on average, associated with an annual average total resource deficiency of approximately 90,000 megawatt-hours (MWh).[58]

Five other regions had one or more hours of resource deficiency per year on average: MISO-E, New York, SPP-S, PJM-S, and California North.[59] Compared to ERCOT, these five regions were much less resource deficient, ranging from 11,000 MWh of annual average resource deficiency in MISO-E to 2,000 MWh of annual average resource deficiency in California North.[60] Five remaining regions had a resource deficiency that lasted less than an hour on average per year: SERC-E, SERC-Florida, New England, MISO-S, and SPP-N.[61]

Overall, resource deficiencies were the most common in ERCOT, relatively more common and dispersed throughout the Eastern Interconnection, and relatively less common and isolated in the Western Interconnection. The ITC Study finds that regions exhibit additional resource deficiencies in the 2033 model year compared to the 2024 model year primarily because of tightening energy margins driven by load growth, the changing resource mix, and NERC's assumption that there would be no transfer capability additions during this timeframe.[62]

In the next step of Part 2, the ITC Study summarizes NERC's evaluation of whether, and specifically how much (in MWs), additional transfer capability would mitigate the potential risk of energy inadequacy created by the potential resource deficiencies in the 2033 model year. The purpose of this step is to inform the ITC Study's recommendations of technically prudent additions to total transfer capability that would demonstrably strengthen reliability. As discussed above, NERC

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55 ITC Study at 95-96. The Long Term Reliability Assessment is an annual assessment performed by NERC on the adequacy of the Bulk Electric System in the United States and Canada over a 10-year period, which projects electricity supply and demand, evaluates transmission system adequacy, and discusses key issues and trends that could affect reliability. Notably, the Long Term Reliability Assessment projects new resources in three tier levels. In general, Tier 1 resources are in the final stages for connection, while Tier 2 resources are further from completion, and Tier 3 resources are even less certain. For the 2033 resource mix in the Part 2 analysis, NERC included all existing resources, Tier 1 resource additions expected by 2033, and additions of Tier 2 and Tier 3 resources only to replace retired capacity. *See* ITC Study at 75.

56 Eight of these 11 regions had no deficiencies in the 2024 case study. ITC Study at 96, tbl. 7.4 (Maximum Resource Deficiency (MW) by TPR and Weather Year (2033 Case)).

57 ITC Study at 96, tbl. 7.4 (Maximum Resource Deficiency (MW) for Select TPRs by Weather Year (2033 Case)).

58 Total resource deficiency, reported in MWh of energy, represents the cumulative size and duration of all resource deficiencies in a region for a set period (total MW of power over time). For example, a ten MWh total resource deficiency could represent a ten MW resource deficiency for one hour, or a one MW resource deficiency for ten hours. ITC Study at 97, tbl. 7.5 (Total Resource Deficiency (GWh) by TPR and Weather Year (2033 Case)); ITC Study at 97, tbl. 7.6 (Annual Hours of Resource Deficiency by TPR and Weather Year (2033 Case)).

59 ITC Study at 97, tbl. 7.6 (Annual Hours of Resource Deficiency by TPR and Weather Year (2033 Case)). The regions are ordered from the longest to shortest annual average time of resource deficiency.

60 ITC Study at 97, tbl. 7.5 (Total Resource Deficiency (GWh) by TPR and Weather Year (2033 Case)).

61 ITC Study at 97, tbl. 7.6 (Annual Hours of Resource Deficiency by TPR and Weather Year (2033 Case)). Because each region had less than one hour of resource deficiency on average per year, the regions are ordered from the largest to smallest maximum resource deficiency. *See* ITC Study at 96, tbl. 7.4 (Maximum Resource Deficiency (MW) for Select TPRs by Weather Year (2033 Case)).

62 ITC Study at 96. The ITC Study notes that known planned projects likely to increase transfer capability are noted where applicable; while not exhaustive or an endorsement of any particular project, they illustrate that existing industry plans may be responsive to the recommended transfer capability increases. ITC Study at 98.

used the transfer capability values from Part 1, projections of future electricity supply and demand for the 2033 model year, and 12 historical weather years, to identify periods when regions would experience energy deficiencies. When this process identified a potential deficiency in any weather year, NERC assessed which neighboring region could provide electricity to alleviate the deficiency and iteratively increased transfer capability until it was resolved.[63]

Finally, NERC determined whether a technically prudent addition could be recommended in the ITC Study by generally considering two conditions:[64] (1) if a region is resource deficient (below the minimum margin level), meaning, available generation within the region and from neighbors is insufficient to meet hourly demand plus a 3% margin; and (2) if a neighboring region has surplus energy to share with the deficient region after meeting its own needs. When both these conditions are met, the ITC Study recommends technically prudent additions to transfer capability that would improve the use of surplus energy during times of system stress.

63 ITC Study at 82-92.

64 *See* ITC Study at 91-92 for the full list of criteria considered in the ITC Study when identifying prudent additions.

Figure 3: Part 2 Recommendations of Prudent Additions

Increasing Energy Deficiency Hours

Transmission Planning Region	Weather Years (WY)/ Events	Resource Deficiency Hours	Maximum Deficiency (MW)	Additional Transfer Capability (MW)	Interface Additions (MW)
ERCOT*	Winter Storm Uri (WY2021) and nine other events	135	18,926	14,100	Front Range*** (5,700) MISO-S*** (4,300) SPP-S** (4,100)w
MISO-E	WY2020 Heat Wave and two other events	58	5,715	3,000	MISO-W** (2,000) PJM-W (1,000)
New York	WY2023 Heat Wave and seven other events	52	3,729	3,700	PJM-E (1,800) Québec** (1,900)
SPP-S	Winter Storm Uri (WY2021)	34	4,137	3,700	Front Range** (1,200) ERCOT** (800) MISO-W (1,700
PJM-S	Winter Storm Elliott (WY2022)	20	4,147	2,800	PJM-E (2,800)
California North*	WY2022 Heat Wave	17	3,211	1,100	Wasatch Front (1,100)
SERC-E	Winter Storm Elliott (WY2022)	9	5,849	4,100	SERC-C (300) SERC-SE (2,200) PJM-W (1,600)
SERC-Florida	Summer WY2009 and Winter WY2010	6	1,152	1,200	SERC-SE (1,200)
New England	WY2012 Heat Wave and two other events	5	984	700	Québec** (400) Maritimes (300)
MISO-S	WY2009 and WY2011 summer events	4	629	600	ERCOT*** (300) SERC-SE (300)
TOTAL				**35,000**	

* Transfer capability additions did not fully address identified resource deficiencies | ** Existing interface is dc-only | *** Proposed new interface

Source: NERC, ITC Study

Figure 3 provides the results of Part 2. The ITC Study recommends a total of 35,000 MW of technically prudent additions of transfer capability for 10 regions that are projected to have resource deficiencies in 2033.[65] For example,

65 ITC Study at 98, tbl. 7.7 (Recommended Prudent Additions Detail). The ITC Study notes that the prudent transfer additions recommended did not fully resolve the identified resource deficiencies in California-North and ERCOT. ITC Study at 98-99.

the ITC Study identifies ERCOT as having resource deficiencies in 135 hours of the 12 historical weather years, with a maximum deficiency of 18,926 MW. The ITC Study recommends 14,100 MW in additional transfer capability to mitigate the majority of the deficiency hours in ERCOT. To accommodate the need for additional transfer capability in ERCOT, the ITC Study recommends two new interfaces with Front Range in the Western Interconnection and MISO-S in the Eastern Interconnection, and increasing the transfer capability of ERCOT's existing interface with SPP-S.[66]

The next largest technically prudent addition recommendation is for SERC-E.[67] The ITC Study recommends 4,100 MW of additional transfer capability, primarily between regions within SERC, to mitigate a limited number of hours when SERC-E was resource deficient (nine total hours across the 12 weather years).[68] The ITC Study recommends between 2,000 MW and 4,000 MW of additional transfer capability for four other regions—New York, SPP-S, MISO-E, and PJM-S.[69] The ITC Study recommends less than 2,000 MW of additional transfer capability for SERC-Florida, California-North, New England, and MISO-S.[70]

66 ITC Study at 98, tbl. 7.7 (Recommended Prudent Additions Detail).

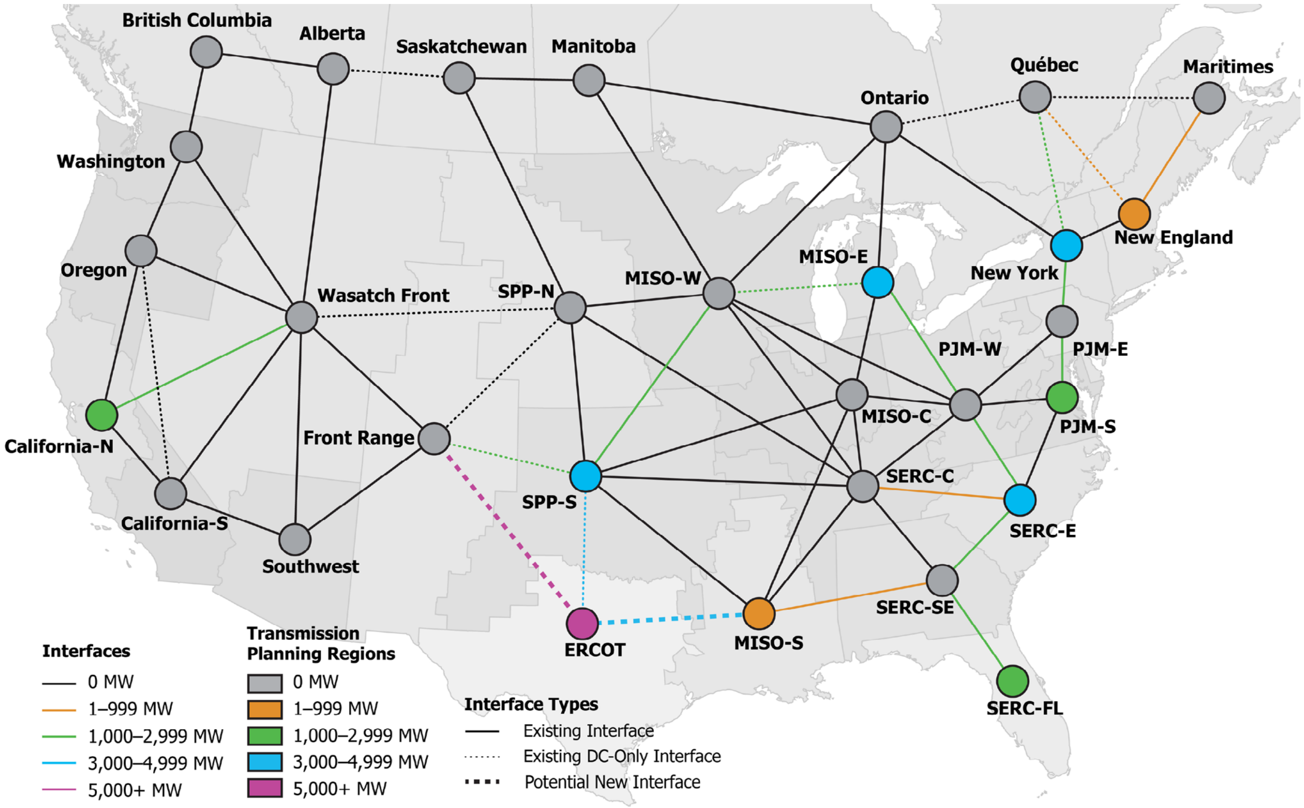
67 ITC Study at 98, tbl. 7.7 (Recommended Prudent Additions Detail).

68 ITC Study at 98, tbl. 7.7 (Recommended Prudent Additions Detail).

69 ITC Study at 98, tbl. 7.7 (Recommended Prudent Additions Detail). The regions are ordered from largest to smallest MW of recommended prudent additions.

70 ITC Study at 98, tbl. 7.7 (Recommended Prudent Additions Detail). The regions are ordered from largest to smallest MW of recommended prudent additions.

Figure 4: Map of Part 2 Recommendations of Prudent Additions



Source: NERC, ITC Study

Geographically, as shown in Figure 4, the ITC Study recommends technically prudent additions that would increase the transfer capability:

- Between regions along the East Coast and Piedmont (e.g., New England, New York, PJM-S, and SERC-E);
- Across the Gulf Coast from Florida to Texas (e.g., SERC-FL, MISO-S, and ERCOT);
- From the Northern Midwest to the Great Plains (e.g., MISO-E and SPP-S); and
- From California to the Inter-Mountain West (e.g., California N).[71]

In Part 3, the ITC Study provides recommendations to meet and maintain sufficient transfer capability. In addition to increasing transfer capability, the ITC Study notes that other options to mitigate identified energy adequacy risks include constructing local generation, increasing demand response resources, and accepting the identified risks during extreme events (assuming other reliability thresholds are met).[72] The ITC Study identifies several paths to

71 ITC Study at xvi, fig. ES.5 (Prudent Additions to Transfer Capability).

72 ITC Study at 134.

achieve greater transfer capability if transmission planners and planning coordinators elect to pursue that goal, including upgraded or new transmission infrastructure, grid enhancing technologies (such as dynamic line ratings, power flow control devices, and advanced conductors), and remedial action schemes.[73]

73 ITC Study at 135. Remedial Action Schemes automatically respond to unplanned equipment outages when necessary to maintain operation within reliability criteria. Remedial Action Schemes are used by system operators to apply automatic mitigation actions for sensed contingencies without operator intervention and can prevent conditions from escalating into major system disturbances.

KEY THEMES FROM THE RECEIVED ITC STUDY COMMENTS

The Commission received a total of 50 sets of comments from various stakeholders and one set of reply comments from NERC.[74] Commission staff has distilled the various issues raised by commenters into key themes.

A PROCESS TO EVALUATE THE NEED FOR ADDITIONAL INTERREGIONAL TRANSFER CAPABILITY COULD BE BENEFICIAL

Nearly all commenters agree that a process to evaluate transfer capability between neighboring regions could be beneficial. Of these commenters, a slight majority recommend that the Commission take action to establish such a process.[75] Commenters recommending Commission action have differing ideas of what Commission-initiated action on interregional transfer capability should accomplish, however. For example, some commenters recommend that the Commission provide guidance or generally consider action to enhance interregional transmission development.[76] Other commenters recommend that the Commission expand regional transmission planning and interregional transmission coordination requirements, as established in Order Nos. 1000[77] and 1920,[78] to also consider interregional transfer capability.[79] Further, some commenters recommend that the Commission go beyond establishing a process to evaluate the need for interregional transfer capability and instead recommend that the Commission establish an interregional transmission planning requirement, and/or a minimum interregional transfer capability requirement.[80]

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74 A list of commenters is available in Appendix B: List of Commenters. This report refers to individual commenters using their "Commenter Short Name" detailed in Appendix B.

75 *See, e.g.*, ACORE Comments, ACEG Comments, Advanced Energy United Comments, CCEBA Comments, Clean Grid Alliance Comments, CTEI Comments, Converge Comments, EFI Foundation Comments, emPower Rural America Comments, ENGIE North America Comments, Grid United Comments, International Transmission Company Comments, Interwest Energy Alliance Comments, Invenergy Comments, Large Consumers Comments, NASUCA Comments, National Grid Comments, Niskanen Center Comments, Northeast States Comments, Power from the Prairie Comments, Public Interest Organizations Comments, R Street Institute Comments, Southern Environmental Law Center Comments, The Western Way Comments, TAPS Comments, and WIRES Comments.

76 *See, e.g.*, CCEBA Comments, emPower Rural America Comments, ENGIE North America Comments, Grid United Comments, International Transmission Company Comments, Interwest Energy Alliance Comments, NASUCA Comments, The Western Way Comments, and WIRES Comments.

77 Order No. 1000 requires, among other things, that (1) public utility transmission providers participate in a regional transmission planning process that produces a regional transmission plan and (2) public utility transmission providers in each pair of neighboring transmission planning regions coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs (i.e., interregional transmission coordination). *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g & clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC, 762 F.3d 41 (D.C. Cir. 2014).

78 Order No. 1920 builds upon electric transmission planning and cost allocation requirements developed over the last several decades. In large part, Order No. 1920 directs transmission providers to improve long-term assessments of transmission needs and adopt reforms to cost allocation processes to adequately prepare for the future of the electric grid. Order No. 1920 requires, among other things, that (1) transmission providers in each Order No. 1000 transmission planning region conduct long-term regional transmission planning; and (2) transmission providers in neighboring Order No. 1000 transmission planning regions modify their existing interregional transmission coordination procedures to align with the long-term transmission planning reforms. *See* Federal Energy Regulatory Commission, *Explainer on the Transmission Planning and Cost Allocation Final Rule*, (May 1, 2025), www.ferc.gov/media/explainer-transmission-planning-and-cost-allocation-final-rule. Regarding interregional transfer capability, Order No. 1920 requires transmission providers, when assessing the benefits of proposed transmission facilities, to measure the benefit of reduced production costs and reduced loss of load during extreme weather events and unexpected system conditions due to increased interregional transfer capability. *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068, at P 800, *order on reh'g*, Order No. 1920-A, 189 FERC ¶ 61,126 (2024), *order on reh'g*, Order No. 1920-B, 191 FERC ¶ 61,026 (2025).

79 *See, e.g.*, ACEG Comments, Advanced Energy United Comments, ENGIE North America Comments, and TAPS Comments.

80 *See, e.g.*, ACORE Comments, Converge Comments, EFI Foundation Comments, Invenergy Comments, Large Consumers Comments, National Grid Comments, Niskanen Center Comments, Northeast States Comments, Power from the Prairie Comments, Public Interest Organizations Comments, and Southern Environmental Law Center Comments.

While the majority of commenters are not opposed to Commission action establishing a process to evaluate transfer capability, some commenters assert that the Commission need not establish a separate process to require interregional transfer capability.[81] For example, NYISO encourages the Commission to continue relying on regional transmission planning processes that require the consent of the regions, and the input of member states, utilities, and stakeholders when determining how the costs of interregional transmission projects will be allocated.[82] In addition, APPA states that, given the significant variation in regions, "any national mandate would be counterproductive and potentially trigger unintended consequences as to the most efficient combination of resources."[83]

THE ITC STUDY IS NOT A RECOMMENDATION FOR TRANSMISSION DEVELOPMENT

Many commenters argue that the ITC Study is not an accurate tool for transmission development.[84] Specifically, commenters identified several shortcomings of the ITC Study that make it an unsuitable resource to identify future transmission development, including its reliance on outdated load growth assumptions and not evaluating costs and benefits of transmission development.

According to the Niskanen Center, although the ITC Study combines historical and synthetic load to capture hourly variability, the United States is no longer experiencing a steady load growth as it did in the past decade, but rather accelerating load growth, and as a result the ITC Study results are already outdated.[85] Similarly, Interwest Energy Alliance asserts that, because the ITC Study does not include the latest load projections, the ITC Study's recommendations for increases to the transfer capability between regions is likely an underestimate and does not account for the recent significant increase in load projections.[86] EIPC notes that large transfer capability studies, such as the ITC Study, are inherently limited, representing a snapshot in time that is unlikely to occur in real time.[87]

Some commenters recommend that additional analysis to determine the costs and benefits for each region is needed before investing in transmission projects, generation facilities, or other upgrades to achieve NERC's recommended prudent additions. For example, EIPC, Large Consumers, MISO, and R Street Institute assert that the ITC Study is only a first step, and that additional analysis, including more detailed economic analysis, is necessary to justify expanded transmission infrastructure development (consistent with NERC's position in the ITC Study).[88] Several commenters specifically note that the costs related to transmission enhancements are one of several necessary details that must be considered before justifying transmission infrastructure.[89] Further, EPSA argues that failure to prioritize cost-effective and market appropriate approaches could lead to inefficient infrastructure deployment, incurrence of avoidable costs, and cost-shifting between regions that may not bring the intended benefits from transfer capability.[90] Further, Large Consumers state that it is imperative that the Commission conduct economic analyses to determine the potential

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81 *See, e.g.*, APPA Comments, CAISO Comments, EEI Comments, ERCOT Comments, FRCC Comments, MISO Comments, and NYISO Comments.

82 NYISO Comments at 13.

83 APPA Comments at 7.

84 ACEG Comments at 3; Conservative Energy Network Comments at 2; EPSA Comments at 6-7; ENGIE North America Comments at 2-3; CCEBA Comments at 7; NRG Comments at 14; Public Interest Organizations Comments at 40-41.

85 Niskanen Center Comments at 2-3.

86 Interwest Energy Alliance Comments at 2.

87 EIPC Comments at 4-5.

88 EIPC Comments at 6-7; Large Consumers Comments at 8; MISO Comments at 1; R Street Institute Comments at 1-2. *See also*, NERC Transmittal at 21 ("While the ITC [Study] recommends increased transfer capability on particular interfaces, NERC does not endorse projects or particular approaches. This is intentional because planners must evaluate potential downstream impacts of increased transfer capability.").

89 EIPC Comments at 6-7; EPSA Comments at 5; Large Consumers Comments at 9-10; MISO Comments at 3.

90 EPSA Comments at 5.

financial impacts for consumers of building NERC's recommended prudent additions.[91] Large Consumers assert that, in addition, the Commission must assess how transmission constraints contribute to inefficiencies in energy markets—including price volatility and congestion costs—and prioritize addressing those constraints.[92]

OTHER SOLUTIONS EXIST TO MEET FUTURE RELIABILITY NEEDS

Some commenters argue that existing processes are already addressing the energy deficiencies identified in the ITC Study. For example, NYISO contends that the Northeastern ISO/RTO Planning Coordination Protocol through which NYISO collaborates with its regional neighbors, PJM, ISO-NE, and Canada on interregional transmission planning issues, as well as other existing reliability and interregional transmission planning processes already facilitate the identification of prudent additions and will continue to do so in accordance with Order Nos. 1920 and 1920-A.[93] Similarly, CAISO and MISO emphasize the value of established regional transmission planning processes, advocating instead for focusing on the specific needs of each individual region and its neighboring regions.[94]

Other commenters suggest that transmission may not be the only way to address the deficiencies identified in the ITC Study. APPA states that the ITC Study correctly finds that increased transfer capability is one of many options for addressing energy deficiencies including: (1) internal resource development (e.g., generation and storage); (2) transmission enhancements; (3) demand side management; (4) demand shifting; (5) energy efficiency; (6) targeted demand response; and (7) enhanced storage development.[95] APPA adds that since the ITC Study does not consider economics or evaluate the implementation timelines for increasing transfer capability, the necessary conclusion is that increasing transfer capability may or may not be the most cost-effective or feasible option for addressing energy deficiencies.[96] Similarly, EPSA asserts that a diverse approach to ensuring reliability that allows for a host of solutions—including adding new generation—represents the best path to efficiently preserve the reliability of the Bulk-Power System.[97]

DOE avers that the nation's transfer capability needs cannot be met by increasing the transfer capability of existing transmission infrastructure alone, arguing that co-optimized studies can evaluate the interactions between generation, energy markets, and transmission/transfer capability and provide insights into the tradeoffs between generation and transmission, especially related to the costs of maintaining the same level of system reliability using different infrastructure solution options.[98]

91 Large Consumers Comments at 10.

92 Large Consumers Comments at 10.

93 NYISO Comments at 5-6, 12.

94 CAISO Comments at 3; MISO Comments at 4.

95 APPA Comments at 6.

96 APPA Comments at 6.

97 EPSA Comments at 2.

98 DOE Comments at 20-21.

CONCLUSIONS ON THE NERC ITC STUDY

Below, Commission staff offers its conclusions on the value of the ITC Study and both the current and future state of interregional transfer capability.

THE VALUE OF THE ITC STUDY

Commission staff recognizes the challenge of completing the ITC Study and the effort NERC put forth to do so. While the ITC Study has limitations, recognized by NERC, it is nonetheless valuable and represents an advancement in existing transfer analysis and modeling processes. By focusing on an energy adequacy metric for every hour (i.e., the hourly energy margin), the ITC Study provides a more comprehensive understanding of energy deficiencies under extreme conditions and highlights the need for energy sufficiency on a more granular basis than conventional studies that consider only seasonal peak conditions (i.e., summer peak and winter peak).[99] Unlike conventional regional transmission or reliability studies, NERC's analysis in the ITC Study provides a broader, more nuanced assessment of transfer capabilities across the North American Bulk-Power System.[100] This analysis enables the identification of potential bottlenecks and areas of concern that may not be apparent through existing regional studies such as NERC's Long-Term Reliability Assessment.[101] NERC's development of the ITC Study enables it to conduct large-scale interregional studies using a single model, common case development, common data sets, and common assumptions. This advancement could facilitate the development of similarly comprehensive studies that incorporate more sensitivities (e.g., additional scenarios that incorporate higher load growth or additional generation and transmission investments).[102] As part of the ITC Study, NERC also developed a new metric, the hourly energy margin, to assess the need for interregional transfer capability that focuses on energy adequacy in every hour, which could be used by transmission planners.

This said, it is important to consider what the ITC Study does not address. As NERC acknowledges, the ITC Study is not intended to be an exhaustive study of transmission limitations that may occur during real-time operations or under simultaneous transfers across regions.[103] Further, although NERC states that additional transfer capability may reduce the risk of energy inadequacy, it is important to recognize that transmission upgrades and additions alone may not fully address all reliability or energy adequacy risks, and that incremental transfer capability additions may not result in a proportional reduction to reliability risks or energy inadequacy. For example, if two adjacent regions are energy inadequate at the same time, additional transfer capability will not improve reliability because no surplus generation would be available to flow on that capability. Moreover, market-to-market coordination and seams issues

99 ITC Study at x, xii.

100 NERC's analysis includes the U.S. Bulk-Power System and interconnected portions of the Canadian power system. Specifically, the Western Interconnection includes the Canadian provinces of Alberta and British Columbia, while the Eastern Interconnection contains numerous transmission lines between the United States and Manitoba, New Brunswick, Ontario, and Saskatchewan, plus direct current connections with Québec. ITC Study at 3.

101 Notably, the 2024 Long Term Reliability Assessment primarily focuses on regional resource adequacy necessary to meet projected annual peak demand over the 10-year period 2025-2034, in contrast to the ITC Study, which assesses the need for interregional transfer capability by evaluating the hourly energy margin for two years - 2024 and 2033. Since the ITC Study models import/export capability on a much more granular scale compared to the snapshot approach of the LTRA, the two studies are not readily comparable. *See* North American Reliability Corporation, *2024 Long-Term Reliability Assessment (LTRA)*(Dec. 2024; corrected Jul. 2025), www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

102 As stated at the April 9, 2025 Canadian ITC Study Advisory Group meeting, NERC intends to use the methods developed in the ITC Study process to conduct future LTRAs. *See* North American Reliability Corporation, *Agenda ITCS Canadian Advisory Group Meeting*, (Apr. 2025), www.nerc.com/globalassets/initiatives/itcs/ca-itcs-ag/itcs_canadian_ag_agenda_20250409.pdf.

103 ITC Study at 11.

may present barriers to energy transfers between regions even when sufficient surplus generation and transfer capability is available to support such transfers. As such, while the ITC Study is useful in evaluating the energy adequacy benefits of additions to transfer capability, such additions are only one tool to help mitigate future risks to Bulk-Power System reliability.

Moreover, the ITC Study focuses on additional transfer capability to strengthen reliability, consistent with the Congressional directive to recommend "prudent additions to total transfer capability… that would demonstrably strengthen reliability." The use of a reliability dispatch method (considering first the ability of internal generation resources to serve the load within a given region) allows the ITC Study to squarely focus on identifying reliability or energy adequacy needs. It does not, however, reflect the methods that transmission planners use in *economic* transmission planning that simulate the least-cost dispatch of expected available resources to identify transmission needs.[104] Nor does it reflect the methods that transmission providers use to evaluate the economic viability of potential transmission facilities to meet those needs. Additionally, the ITC Study is based on available data as of November 2023 that does not reflect subsequent, relevant information regarding, among other things, updated load forecasts, or actual generator deactivations and additions.[105] Thus, the ITC Study serves only as a first step that could lead to additional, more specific transmission planning studies whose scope extends beyond focusing on energy adequacy, instead focusing on issues related to reliably and economically serving load during all hours of the year, including during extreme weather events. In addition, as NERC acknowledges, identifying economically efficient solutions to eliminate transfer bottlenecks requires analysis beyond the scope of the ITC Study.[106] Thus, any future transmission planning studies conducted as a next step to the ITC Study could also consider economic factors, such as the costs of any incremental transfer capability, and a wide range of possible solutions, including additional interregional transfer capability, intra-regional transmission, generation additions, storage, improved gas-electric coordination, demand-side management, and operational practices and controls.

EVALUATION OF TRANSFER CAPABILITY

The ITC Study answers some of the concerns raised by stakeholders that North American transmission infrastructure may become insufficient to maintain energy adequacy when considering the changing resource mix, extreme weather events, and increasing demand. While the ITC Study finds that existing infrastructure is generally sufficient at this time to maintain energy adequacy under most scenarios, a 10-year forward-look at 2033 projects energy deficiencies of varying degrees in 11 of the 23 regions studied.

While the ITC Study provides insight into the reliability benefits of additional transfer capability in certain areas, it also concludes that a one-size-fits-all solution to increase transfer capability, such as requiring a minimum interregional transfer capability requirement as a specified percentage of peak load, may be inefficient and potentially ineffective. For example, the ITC Study does not show a consistent correlation between needed

104 As an example of the methods a regional transmission planner may use, see Whitepaper (MISO, MISO Economic Planning Whitepaper (Oct. 2024)) at 3-15, https://cdn.misoenergy.org/MISO%20Economic%20Planning%20Whitepaper651689.pdf.

105 On January 29, 2026, NERC issued its 2025 LTRA, which assumes higher load forecasts (driven by the anticipated "massive build-out of data centers") than those assumed for the 2023 LTRA, whose data the ITC Study was based upon. The report also notes that, in many parts of the country, generator deactivation continues to outpace new additions, although the pace of retirements has slowed. *See* North American Reliability Corporation, *2025 Long-Term Reliability Assessment (LTRA)*(Jan. 2026), www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

106 ITC Study at viii.

transfer capability and existing transfer capability as a percentage of peak load of a region.[107] Thus, NERC does not recommend an across-the-board requirement for all pairs of regions to maintain an amount of interregional transfer capability based on a specified percentage of peak load.

The ITC Study also demonstrates that the value of interregional transfer capability is not immediately intuitive.[108] For example, in certain circumstances, a 1,000 MW increase in interregional transfer capability can reduce resource deficiencies by more than 1,000 MW.[109] However, if neighboring regions lack resources, additional transfer capability will provide limited help because there is not enough surplus energy to share.[110] These results suggest that using a heuristic approach to establish interregional transfer capability requirements—such as setting a target to achieve interregional transfer capability to match a fixed percent of peak load or historical outages—can inaccurately value interregional transfer capability compared to an approach that accounts for the complexity of the transmission system. As is true with setting a planning reserve margin, an intuitive or informal approach is unlikely to set the right target compared to a more systematic approach that includes thorough analysis to support decision making.

Finally, the ITC Study finds that transfer capability alone is not sufficient without excess generation to transfer;[111] thus, any recommendation to add transfer capability between regions should examine more closely, for both a region and its neighboring region(s), the combined load, internal generation, and existing transfer capability under a variety of conditions including extreme weather.

107 "[S]ome [regions] with relatively low transfer capability did not show resource deficiencies, such as SERC-SE and SERC-C with transfer capabilities of 11%-18% of peak load. In contrast, other [regions] with relatively high transfer capability did show resource deficiencies. Examples include MISO-E and PJM-S, with transfer capabilities of 25%-44% of peak load." ITC Study at 11.

108 ITC Study at 101.

109 ITC Study at 101. NERC attributes this "multiplier effect" of interregional transfer capability to storage resource optimization, shortened deficiency windows, and interactive effects. ITC Study at 101-102.

110 ITC Study at 102. NERC states this "saturation effect" highlights the need for a more comprehensive approach to addressing resource deficiencies. ITC Study at 102.

111 ITC Study at xiii, xviii, and 102-103.

OTHER: CONGRESS' INVITATION FOR THE COMMISSION TO PROVIDE RECOMMENDATIONS, IF ANY, FOR STATUTORY CHANGES

The Act states that, no later than 12 months after the comment period ends, the Commission must "submit a report on its conclusions to Congress and include recommendations, if any, for statutory changes."

The Commission has jurisdiction over interstate transmission service and transmission facilities under the Federal Power Act (FPA), including jurisdiction over transmission planning and cost allocation under FPA sections 205 and 206, as well as oversight of Reliability Standards under FPA section 215. Section 205 requires that the rates charged by any public utility in connection with such transmission service—as well as the rules and regulations affecting such rates—be just and reasonable, and further requires that public utilities file with the Commission the practices affecting such rates.[112] Section 206 provides the Commission with the authority to determine whether the Commission's jurisdictional rates, terms, and conditions are unjust, unreasonable, unduly discriminatory or preferential and to establish the just and reasonable rates, terms, and conditions.[113]

The Commission performs its oversight of grid reliability through approval and enforcement of mandatory Reliability Standards.[114] Under Section 215, the Commission has the authority to review and approve proposed Reliability Standards, or modifications to existing Reliability Standards, including those related to transmission or transmission planning, if the Commission determines that they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Although section 215(i)(2) states that the Commission (and the electric reliability organization, NERC) are not authorized to order the construction of additional generation or transmission capacity as part of a Reliability Standard,[115] it does not bar a utility from electing to construct additional transmission capacity to achieve compliance with a Reliability Standard.[116]

Commission staff makes no recommendation regarding potential statutory changes in response to the ITC Study.

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112 Section 205 requires that "[a]ll rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful." 16 U.S.C. § 824d

113 Under section 206, when the Commission finds "that any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order." 18 U.S.C. § 824e.

114 Section 215 requires NERC as the Commission-certified "Electric Reliability Organization to file each reliability standard or modification to a reliability standard or modification to a reliability standard that it proposes to be made effective under this section with the Commission." The Electric Reliability organization is certified by the Commission under section 215(c) to establish and enforce reliability standards for the Bulk Power System, subject to Commission review. 16 U.S.C. § 824o. Section 215 further authorizes the Commission to "approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest."

115 16 U.S.C. 824o(i)(2).

116 *See*, e.g., Order No. 896, Transmission Planning Performance Requirements for Extreme Weather, PP 154-55.

Winter Storm Fern Highlights the Need for More Resilient Transmission

How stronger transmission and modernizing the grid could reduce outages, lower costs, and protect communities during extreme weather.

February 3, 2026

By Sarah Toth Kotwis, Ashtin Massie, Laurie Stone

Winter Storm Fern swept across the United States this past week dumping snow and ice and wreaking havoc from Arizona to Washington, D.C. In addition to the tragic loss of life, almost 1 million people lost power, some of whom are still without power, creating difficult and dangerous living conditions, and costing families, utilities, and states a lot of money. During a particularly strained hour on the afternoon of January 25th, prices in one zone topped $1,800 per megawatt-hour — an order of magnitude higher than average prices during the weeks before the storm. Unfortunately, extreme weather events are becoming more common (and more extreme).

How can we better prepare for the next big storm? In a few ways. Strengthening electricity infrastructure and enabling more interconnected transmission infrastructure could have helped reduce both outages and costs. And, on the customer side, improving the efficiency of housing can relieve both grid *and* cost stress. Updating homes to just a 2009 building code can keep them above 40 degrees Fahrenheit for nearly two days in sub-zero temperatures.

Below, we dive into how our grid can evolve to make the next “Fern” less impactful.

What RMI is doing

RMI provides utilities and regulators with the tools they need to make smart investment decisions on both large- and small-scale solutions, from transmission lines and utility-scale renewables to efficiency and distributed energy resources. Our resources include *The State Regulator’s Role in Transmission*, a handbook for US state regulators on how to advance proactive transmission buildout to reduce costs for ratepayers; our Transmission Resource Library, a downloadable spreadsheet with a list of all major reports on transmission going back to 2004; and a webinar that brought utilities, grid operators, and regulators together to discuss how to deploy advanced transmission technologies to boost capacity, improve flexibility, and speed new energy integration.

Sharing electricity across regions

The US grid is made up of geographically distinct transmission planning regions that share power with each other when necessary. For example, if there is low energy availability or high-priced electricity in one region, it can be supplemented with lower-priced available energy from a neighboring region.

During Fern, neighboring regions supported each other wherever possible. When one area had excess electricity, it sent power to other regions facing shortages — but only up to a point.

Power sharing is limited by contractual and infrastructure constraints. Transmission lines, like water pipes, restrict how much electricity can move between regions. So even if one area has surplus power, insufficient transmission capacity often keeps it from reaching places in need.

Research shows that just increasing the efficiency with which we utilize existing lines can save hundreds of millions of dollars per year. Beyond that, more interregional transmission planning and buildout is necessary to increase system-wide reliability while meeting needs more cost-effectively.

Transmission constraints drive huge price differences

When transmission is constrained and regions cannot share power, electricity prices can vary drastically, even within the same grid.

For example, MISO, the transmission organization that covers parts of 15 states in the Midwest and South, is made up of three different regions: north, central, and south. In the beginning of Fern, cold temperatures and low wind speeds in the northern states made wind power production plummet and constrained gas availability. Meanwhile, their southern MISO counterparts and neighbors in SPP were flush with higher wind generation than expected and a less constrained gas system. As a result, MISO north customers were left paying much higher prices (2 to 15 times as much at times) than their neighbors.

More transmission capacity between these regions could have allowed lower-cost power to serve more customers, providing relief for ratepayers. Similarly, in PJM, which primarily covers states in the Mid-Atlantic region, the limits on transmission availability meant that some customers were paying much higher prices than others. And in Texas, on January 25, average electricity prices between the northern and southern parts of the state differed by more than $700 per megawatt-hour in the real-time market.

More interregional and intraregional transmission availability could have helped keep prices down for customers. To increase the ability to share power across regions, we need to increase transmission capability on existing lines and plan and build new interregional lines to enable more power sharing.

Strengthening electricity infrastructure

The ice that Fern brought damaged and downed some power lines as well. Initial damage assessments show over 470 miles of affected transmission lines, leaving hundreds of thousands of people without power. This was especially damaging in southern states, where the cold temperatures pushed the electricity infrastructure past its limits.

Hardening transmission and distribution infrastructure, for example by using advanced conductors with anti-icing coatings and real-time monitoring sensors, not only protects lines from extreme cold but also boosts grid capacity overall. These upgrades help reroute power and ensure reliable power delivery during increasingly severe and prolonged storms, reducing the need for repeated fixes (as experienced by crews working through ongoing hazards to restore power in Middle Tennessee Electric territory). Finally, strategic undergrounding, though more costly up-front, can further safeguard lines from extreme weather and limit recurring repair expenditures on the same infrastructure.

A grid that works better — in calm and crisis

Winter Storm Fern made one thing clear: the power system we rely on every day is being pushed beyond the conditions it was designed to handle. As extreme weather becomes more frequent, more intense, and more geographically widespread, the costs of outages — in lost power, lost lives, and lost economic activity — will only grow.

A more resilient grid requires both stronger transmission and smarter planning. Regulators play a central role in making this possible by supporting both planned and new transmission expansion and upgrades that deliver broad reliability and cost benefits, including projects that improve interregional power sharing. Legislators can also encourage grid modernization technologies that increase capacity on existing lines as well as threat awareness and responsiveness. And it's important to take a long-term view of costs, recognizing that investments that reduce outages and price spikes can save customers and utilities money over time.

Likewise, improving home energy efficiency can reduce overall demand on the grid, lower customer bills, and help homes maintain safe indoor temperatures for longer during outages.

Inaction has a cost. Investing now in stronger, more interconnected, and more resilient transmission can help ensure the power system works not just on clear days — but when communities need it most.