

Winter 2026 Arctic Events

A System Performance Review

Joint Staff Report: FERC, NERC, and its Regional Entities



NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Regional Entities:



ACKNOWLEDGEMENT

This report was prepared by a team that consisted of staff from the Federal Energy Regulatory Commission (FERC or the Commission), the North American Electric Reliability Corporation (NERC), and its Regional Entities: Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RF), SERC Reliability Corporation (SERC), Texas Reliability Entity, Inc. (Texas RE), and Western Electricity Coordinating Council (WECC), all of whom are named in the Appendix.

This is a joint staff report, and does not represent the views of the Commission, NERC, or any of its Regional Entities. The team acknowledges and thanks the following entities that participated in the development of this report: American Exploration and Production Council, American Gas Association (AGA), Center for Liquefied Natural Gas, Electric Reliability Council of Texas, Inc. (ERCOT), the Florida Reliability Coordinating Council, Inc. (FRCC), ISO New England, Inc. (ISO-NE), Interstate Natural Gas Association of America (INGAA), the Midcontinent Independent System Operator, Inc. (MISO), Natural Gas Council (NGC), Natural Gas Supply Association (NGSA), the New York Independent System Operator, Inc. (NYISO), the PJM Interconnection, L.L.C. (PJM), Southwest Power Pool, Inc. (SPP), Tennessee Valley Authority (TVA), and VACAR-South (VACAR South). The team appreciates the cooperation of these participants in the development of this report.

TABLE OF CONTENTS

- I. Executive Summary 1
- II. Introduction 3
- III. Process and Data4
- IV. Observations5
 - A. Electric Grid Performance5
 - 1. Weather and Season Forecast Impacts on Electric Operations5
 - 2. Generation Mix and Generator Performance7
 - 3. Load Forecast and Performance Outcomes..... 13
 - 4. Fuel Systems and Non-Fuel Consumable Management 17
 - 5. Communication, Energy Transfers, and Markets 19
 - 6. Emergency Federal Power Act Section 202(c) Orders 22
 - B. Natural Gas System Performance 26
 - 1. Natural Gas Operations, Supply, Demand, and Market Conditions..... 26
 - 2. Operational Preparedness, Communication, and Storage Management 30
 - 3. LNG 31
- V. Analysis 33
 - A. Endurance Challenge..... 33
 - B. Generator Cold Weather Operating Limitations..... 33
 - C. Energy Transfers 34
 - D. Inter-region Dynamics..... 34
 - E. Load Forecasts..... 34
 - F. Natural Gas Infrastructure 35
 - G. Logistics and Supply Chains..... 35
 - H. Backup Generation..... 35
- VI. Conclusion.....36
- VII. Appendix : Team Members List 37

EXECUTIVE SUMMARY

In March 2026, the Commission, NERC, and its Regional Entities launched a joint review of the Bulk-Power System's and natural gas system's performances¹ during the Winter 2026 Arctic Cold Period, which included Winter Storms Fern and Gianna.² This system performance review focuses on understanding what occurred during the Winter 2026 Arctic Cold Period. The review also highlights cold weather preparation improvements made prior to the Winter 2026 Arctic Cold Period that supported reliable operation of the Bulk-Power System during the period. The team engaged with numerous electric and natural gas entities across the eastern half of the United States³ and Texas to gather the information necessary to provide an overview of the performance of the Bulk-Power System and natural gas system during the Winter 2026 Arctic Cold Period.

While the electric and natural gas industries experienced significant operational constraints, electric entities did not report any manual load shed and natural gas entities did not report widespread interruption of firm customer service. Total U.S. natural gas demand peaked at 172 billion cubic feet per day (Bcf/day) on January 24, 2026⁴—one of the highest levels ever observed—while total U.S. electric demand reached 666 GW on January 27, 2026, during Winter Storm Fern.⁵ During the Winter 2026 Arctic Cold Period, generator outages peaked at 68,169 MW on January 26, 2026, across the Eastern and Texas Interconnections.⁶ The natural gas system experienced only moderate production declines and some limited short-duration *force majeure* events, both of which had insignificant effects on end users.

Building on notable operational practices that were identified in Appendix 2 of the *January 2025 Arctic Events* report,⁷ the team has observed continued improvements in generator availability and in efforts to avoid manual load shed since Winter Storm Uri in February 2021 and Winter Storm Elliott in December 2022. During Winter Storm Uri, 61,305 MW of generation was unavailable in ERCOT, SPP, and MISO South, resulting in 23,418 MW of manual load shed.⁸ Throughout Winter Storm Elliott, 90,500 MW of generation was unavailable in the Eastern Interconnection, resulting

-
- 1 For the purposes of this report, the natural gas system consists of the combination of production, processing, transportation, storage, and distribution of natural gas.
 - 2 Unless otherwise stated, this period runs from January 20 to February 10, 2026, and will be referred to as the Winter 2026 Arctic Cold Period throughout this report. For the purposes of this report: Winter Storm Fern takes place from January 24 to January 27, 2026; and Winter Storm Gianna runs from January 30 to February 2, 2026.
 - 3 Western Interconnection entities and data were not included in this report's analysis as the Winter 2026 Arctic Cold Period did not impact the Western United States. Throughout this report, references to the United States or the continental United States refer to the lower 48 states.
 - 4 Natural gas supply and demand statistics in this report are based on staff analysis of S&P Global Energy data.
 - 5 Total electric demand statistics in this report are based on U.S. Energy Information Administration (EIA) Form 930 - Hourly and Daily Balancing Authority Operations Report data.
 - 6 The 68,169 MW of generator outages excludes outages from the Southeastern Reliability Coordinator (Southeastern RC). In the January 2025 arctic events, outages in the Southeastern RC peaked at 3,049 MW. January 2025 Arctic Events Report at 11 fig. 4.
 - 7 FED. ENERGY REGUL. COMM'N ET AL., *January 2025 Arctic Events: A System Performance Review*, App. 2 (Notable Operational Practices) (Apr. 17, 2025) (January 2025 Arctic Events Report), www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional. The notable operational practices include ensuring that equipment has the proper winterization measures in place to lower the risk of generating units freezing during extreme cold weather; using annual fuel surveys and obtaining fuel procurement information that contributes to greater transparency and insight into anticipated resource availability and constraints ahead of extreme cold weather; and employing firm natural gas supply and transportation contracts, where feasible, to help reduce the risk of fuel unavailability during an extreme cold weather event.
 - 8 FED. ENERGY REGUL. COMM'N ET AL., *The February 2021 Cold Weather Outages in Texas and the South Central United States* at 9, 50 n.112 (Nov. 2021) (February 2021 Cold Weather Outages Report), www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

in 5,400 MW of manual load shed.⁹ During the January 2025 arctic events, 71,022 MW of generation was unavailable, but no manual load shed occurred.¹⁰ The Winter 2026 Arctic Cold Period also saw no manual load shed.

The Winter 2026 Arctic Cold Period had a cumulative energy demand of 138.8 TWh over an 11-day period, from January 22 to February 1, 2026.¹¹ The energy consumption over this period was greater than the cumulative demand over similar periods for each winter storm since Winter Storm Uri.

Liquefied Natural Gas (LNG) export feedgas¹² demand fell by over 40% on January 26, 2026, dropping to 11.3 Bcf/day.¹³ On January 29, 2026, Elba Island LNG Terminal in Georgia received its first LNG import since 2020, supplementing regional supplies. Total weekly natural gas storage withdrawals were 359 Bcf for the week ending January 30, 2026, matching a previous record set in January 2018.

The team's analysis shows that the Winter 2026 Arctic Cold Period was fundamentally an endurance challenge (sustained reliable operation during extended periods of system stress) that stretched electric and natural gas systems for several days, revealing how extended cold snaps amplify risks across generator performance, fuel supply chains, load forecasting, interregional energy transfers, and system operators. Electric entities reported multi-day reliability challenges driven by equipment cold weather limitations, deferred maintenance, and constrained fuel availability, while natural gas systems faced infrastructure constraints, production obstacles, and logistical barriers that affected upstream deliveries and non-fuel consumables. The Secretary of Energy issued a series of emergency orders that supported reliability by enabling system operators to dispatch generation resources that otherwise would not be available. Energy transfers across regions also played a role in supporting reliability, but their effectiveness depended on storm specific system conditions that may not occur in future events. At the same time, load forecasting errors—driven by weather uncertainty, behavioral changes, and distribution level outages—created system-wide procurement and commitment challenges. Together, these observations underscore that extreme cold events require sustained operational resilience rather than just preparation for peak conditions.

9 FED. ENERGY REGUL. COMM'N ET AL., *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott* at 5-6 (2023) (Winter Storm Elliott Report), www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022.

10 January 2025 Arctic Events Report at 1.

11 The 11-day period includes five days before and after the U.S.'s peak load hour on January 27, 2026, at 1 PM UTC. The 11-day period roughly matches the 10-day record for natural gas demand from the Winter 2026 Arctic Cold Period. See section IV.B.1, *infra*.

12 Feedgas is pipeline quality natural gas that is delivered to an LNG facility for liquefaction.

13 The cause of decline in LNG export feedgas demand by any specific LNG export terminal may differ by facility.

INTRODUCTION

Over the past fifteen years, the continental United States has experienced several extreme cold weather events that have challenged the reliability of the Bulk-Power System and the natural gas system, including the polar vortex of 2014, Winter Storm Uri in 2021, Winter Storm Elliott in 2022, Winter Storms Gerri and Heather in 2024, and Winter Storms Blair, Cora, Demi, and Enzo in 2025. Increased awareness of the impact of winter storms has reinforced the need for electric and natural gas entities to work collaboratively in preparation for such events.

The team found that during the Winter 2026 Arctic Cold Period, both the Bulk-Power and natural gas systems operated without major incident. No electric entities reported manual load shed and no natural gas entity reported widespread interruption of firm customer service. Both systems nevertheless experienced significant operational constraints. The success in maintaining system operations without major incident was in part because electric and natural gas entities communicated and coordinated in advance of and during the Winter 2026 Arctic Cold Period. Based on data and interviews, electric generators appear to have performed better during the Winter 2026 Arctic Cold Period than in many prior arctic events because of advanced generator commitments, strengthened preparedness, improved situational awareness, implementation of NERC cold weather reliability standards, and the application of other lessons learned from previous extreme cold weather events. The natural gas system also performed well overall, serving near-record levels of natural gas demand and experiencing only moderate production declines and some limited short-duration *force majeure* events, both of which had insignificant effects on end users.

The performance of the Bulk-Power and natural gas systems during the Winter 2026 Arctic Cold Period demonstrates the benefits of sustained continuing efforts to: (1) implement prior winter arctic event reports' recommendations and operational best practices; and (2) improve coordination between the electric and natural gas industries and their collaboration when responding to arctic cold periods.

PROCESS AND DATA

Staff from the Commission, NERC, and its Regional Entities collectively provided the necessary planning and operations subject matter expertise to conduct this review. The review area refers to the electric entity areas sampled within the Eastern and Texas Interconnections.¹⁴ The team issued data requests to nine electric entities across affected operating regions¹⁵ to gauge how entities within their footprint performed during the Winter 2026 Arctic Cold Period,¹⁶ and the team later met and interviewed each of the nine electric entities. Further, the team conducted interviews with representatives from natural gas trade groups across the supply chain to examine how the natural gas industry performed and collaborated with the electric industry during the Winter 2026 Arctic Cold Period. The team also reviewed relevant reports and documentation to conduct a thorough analysis of Bulk-Power System performance and natural gas system performance.

Based on this information, this report includes observations, and analysis, about the performance of the Bulk-Power System and the natural gas system during the Winter 2026 Arctic Cold Period.

14 The electric entity areas are ERCOT, FRCC, ISO-NE, MISO, NYISO, PJM, SPP, TVA, and VACAR South. Cube Hydro Carolinas, Dominion Energy South Carolina, Duke Energy Carolinas, Duke Energy Progress, and Santee Cooper are VACAR South member entities within the VACAR South reliability coordinator footprint and are referred to as “an entity(s) within VACAR South” in this report.

15 Throughout the report, the nine participating electric entities across affected operating regions will be referred to as electric entities.

16 The team based its findings on the data available at the time that this report was published.

OBSERVATIONS

Electric Grid Performance

WEATHER AND SEASON FORECAST IMPACTS ON ELECTRIC OPERATIONS

Weather Conditions

Electric entities reported varying impacts of Winter Storm Fern. ISO-NE, NYISO, PJM, ERCOT, SPP, and TVA were impacted by Winter Storm Fern but were spared significant impact from Winter Storm Gianna. In Northern states, this past winter was among the coldest in the last decade due to a multi-week arctic cold period that began with Winter Storm Fern. ISO-NE experienced 19 consecutive days of below average temperatures, while PJM reported a 10-day cold snap with forecasted peaks that could have broken historic demand records.

In the South, Winter Storm Fern brought significant precipitation, including snow and sleet in some parts of the region. TVA experienced widespread customer outages due to storm impacts on both distribution and transmission systems, including 38 transmission lines. SPP's operational risks were centered around the potential for freezing rain and icing, with temperatures approximately 18 degrees below average, that could impact generator performance.

Winter Storm Gianna moved across the Southern states three days after Winter Storm Fern. Winter Storm Gianna was localized to Southern states with the greatest impact felt in FRCC and VACAR South with historically cold temperatures and strong winds in the northern portions of Florida.

Seasonal Assessments

Electric entities conducted seasonal resource adequacy assessments in advance of the 2026 winter season. Additionally, several electric entities required generating units within their footprint to participate in a weekly survey evaluating their overall operating posture for the week ahead. During the Winter 2026 Arctic Cold Period, some electric entities increased the frequency of the survey to at least twice-a-week, and ISO-NE performed daily surveys to closely monitor available generation.

Based on data collected from the electric entities regarding seasonal assessments, the actual demand during the Winter 2026 Arctic Cold Period for each electric entity exceeded its 50/50 average peak load forecast for the seasonal assessment for winter 2025-2026.¹⁷ However, peak demand in all of the electric entities' areas, except for FRCC, was below their peak 90/10 forecasts.¹⁸

ISO-NE also noted that during the Winter 2026 Arctic Cold Period it used a 21-day energy assessment to look beyond the next peak hour and determine whether the region could maintain reliability during the extended Winter 2026 Arctic Cold Period.¹⁹ The 21-day energy assessment was important for the ISO-NE region because it experienced fuel

17 Not all entities provided this information to the team in response to the data request. A 50/50 peak load forecast is based on a 50% chance that the actual system peak load will exceed the load forecast value, while a 90/10 peak load forecast is based on a 10% chance that the actual system peak load will exceed the load forecast value. Winter Storm Elliott Report at 31 n.103.

18 FRCC exceeded its 90/10 peak forecast by 0.4% (or 206 MW).

19 ISO-NE's 21-day energy assessment is done in accordance with ISO-NE's Operating Procedure No. 21. ISO New England Operating Procedure No. 21 - Operational Surveys, Energy Forecasting & Reporting and Actions During an Energy Emergency § V (2025) (ISO-NE OP No. 21), www.iso-ne.com/static-assets/documents/rules_proceeds/operating/isone/op21/op21_rto_final.pdf.

constraints and thus there was uncertainty about whether there would be sufficient fuel after several days of high stored fuel burn rates and constrained replenishment. Typically, ISO-NE runs the 21-day energy assessment weekly, but during the Winter 2026 Arctic Cold Period, it ran the assessment daily to provide confidence that the region had sufficient fuel to satisfy its energy demand.

Winter 2026 Arctic Cold Period Forecasts

The accuracy of weather forecasts for the Winter 2026 Arctic Cold Period impacted the accuracy of electric entities' load forecasts. MISO, NYISO, PJM, and VACAR South explained that sharp temperature changes led to colder than forecasted temperatures at the front end of Winter Storm Fern and warmer than forecasted temperatures at the tail end of Winter Storm Gianna. The discrepancy between forecasted and actual temperatures can lead to load forecasts that do not reflect actual conditions. PJM and NYISO estimated that a one-degree Fahrenheit temperature difference could result in approximately a 0.5-1% variation in demand.²⁰

Electric entities are taking steps to work with weather forecasting vendors to address the challenge of weather forecasting discrepancies. During the Winter 2026 Arctic Cold Period, most electric entities used near real-time manual adjustments to their load forecasts as weather conditions evolved to try to correct for the discrepancy between forecasted and actual temperatures. An entity within VACAR South said it was working with its vendors to improve its weather forecasting method by finding historic forecasts that match present load conditions, a practice adopted in the wake of Winter Storm Elliott in 2022. Similarly, another entity within VACAR South recognized the need for improved load forecasting and initiated a dedicated internal project to update and enhance its load forecasting capabilities, embracing artificial intelligence and using probabilistic modeling scenarios.

Operational Staffing

Local forecasts of road conditions in advance of the Winter 2026 Arctic Cold Period led several electric entities to make sure that there was sufficient operating staff to handle the prolonged cold period and maintain reliability. ERCOT, MISO, PJM, SPP, TVA, and VACAR South explained that they brought in additional operators and staff engineers to ensure their control centers were adequately staffed during what was a prolonged arctic cold period. Additionally, ERCOT, MISO, PJM, SPP, and TVA secured nearby lodging for their staff to reduce commute times and the risk of traveling on icy or snowy roads. An entity within VACAR South utilized its field crews' 4x4 vehicles to transport grid operators from their homes to the control center when road conditions were challenging.

Many entities, including MISO and an entity within VACAR South, explained that control center staff are often dual-desk certified.²¹ Dual-desk certification not only allowed operators the flexibility to cover desks experiencing staffing shortages, but also enhanced redundancy and resiliency within the control room. This capability enabled operators to seamlessly transition between roles, helping entities to maintain critical functions during unexpected disruptions or emergencies.

20 Peak electric demand statistics in this analysis are based on U.S. Energy Information Administration (EIA) Form 930 - Hourly and Daily Balancing Authority Operations Report data.

21 Dual-desk certification means that qualified operators are certified to work on multiple desks (i.e., balancing authority, generation, and interchange desks).

GENERATION MIX AND GENERATOR PERFORMANCE

Generation Mix

Table 1: Generation Mix During Winter Storms' Peak Demand Versus Typical Winter 2026 Conditions²² in the U.S.²³

	Average Hourly Generation (GW)	Generation During Hour of Peak Demand (GW)							
Generation Fuel Type	Winter 2026	Uri	Elliott ²⁴	Gerri/ Heather	Blair	Cora	Demi/ Enzo	Fern	Gianna
Natural Gas	182.0 (37.2%)	211.0 (38.2%)	265.0 (41.9%)	269.0 (41.7%)	256.0 (42.7%)	259.0 (42.7%)	289.0 (42.6%)	266.0 (40.1%)	267.0 (41.8%)
Coal	88.0 (18.0%)	161.0 (29.1%)	146.0 (23.1%)	142.0 (22.0%)	140.0 (23.3%)	130.0 (21.4%)	130.0 (19.2%)	128.0 (19.3%)	129.0 (20.2%)
Nuclear	97.0 (19.8%)	95.0 (17.2%)	94.0 (14.8%)	94.0 (14.6%)	98.0 (16.3%)	98.0 (16.1%)	97.0 (14.3%)	99.0 (14.9%)	98.0 (15.4%)
Wind	60.0 (12.3%)	24.0 (4.3%)	45.0 (7.1%)	72.0 (11.2%)	40.0 (6.7%)	50.0 (8.2%)	76.0 (11.2%)	71.0 (10.7%)	56.0 (8.8%)
Hydro + Pumped Storage	31.0 (6.3%)	47.0 (8.5%)	53.0 (8.4%)	41.0 (6.4%)	39.0 (6.5%)	40.0 (6.6%)	47.0 (6.9%)	50.0 (7.5%)	45.0 (7.1%)
Fuel Oil	1.0 (0.2%)	2.0 (0.4%)	14.0 (2.2%)	6.0 (0.9%)	4.0 (0.7%)	2.0 (0.3%)	15.0 (2.2%)	15.0 (2.3%)	12.0 (1.9%)
Other	7.0 (1.4%)	9.0 (1.6%)	15.0 (2.4%)	11.0 (1.7%)	7.0 (1.2%)	8.0 (1.3%)	9.0 (1.3%)	13.0 (2.0%)	13.0 (2.0%)
Solar	23.0 (4.7%)	2.0 (0.4%)	0.0 (0.0%)	8.0 (1.2%)	10.0 (1.7%)	12.0 (2.0%)	6.0 (0.9%)	13.0 (2.0%)	14.0 (2.2%)
Battery Storage	0.0 (0.0%)	0.0 (0.0%)	0.0 (0.0%)	0.0 (0.0%)	3.0 (0.5%)	1.0 (0.2%)	2.0 (0.3%)	8.0 (1.2%)	5.0 (0.8%)
Total Generation	489.0 (100.0%)	553.0 (100.0%)	633.0 (100.0%)	645.0 (100.0%)	600.0 (100.0%)	607.0 (100.0%)	678.0 (100.0%)	663.0 (100.0%)	638.0 (100.0%)

Source: U.S. Energy Information Administration

²² See U.S. ENERGY. INFO. ADMIN., *About the EIA-930 Data* ("In some situations, [balancing authorities] may not have detailed information about the actual fuels used to generate electricity at dual-fired or multiple-fuel generators. When the actual fuels consumed are unknown, Form EIA-930 directs [balancing authorities] to report the energy source code for the primary fuel of the generator for the entire amount of generation."), www.eia.gov/electricity/gridmonitor/about (last visited Aug. 18, 2026).

²³ Generation values during each storms' peak demand hour represent total output across the United States. Therefore, regions that were less impacted by a storm may mask localized generation changes, but system-wide shifts in generation output are still observable.

²⁴ The generation values for Winter Storms Uri and Elliott do not include load that was not able to be served or was shed. The actual demand was higher than the generation shown here but not met due to generator outages.

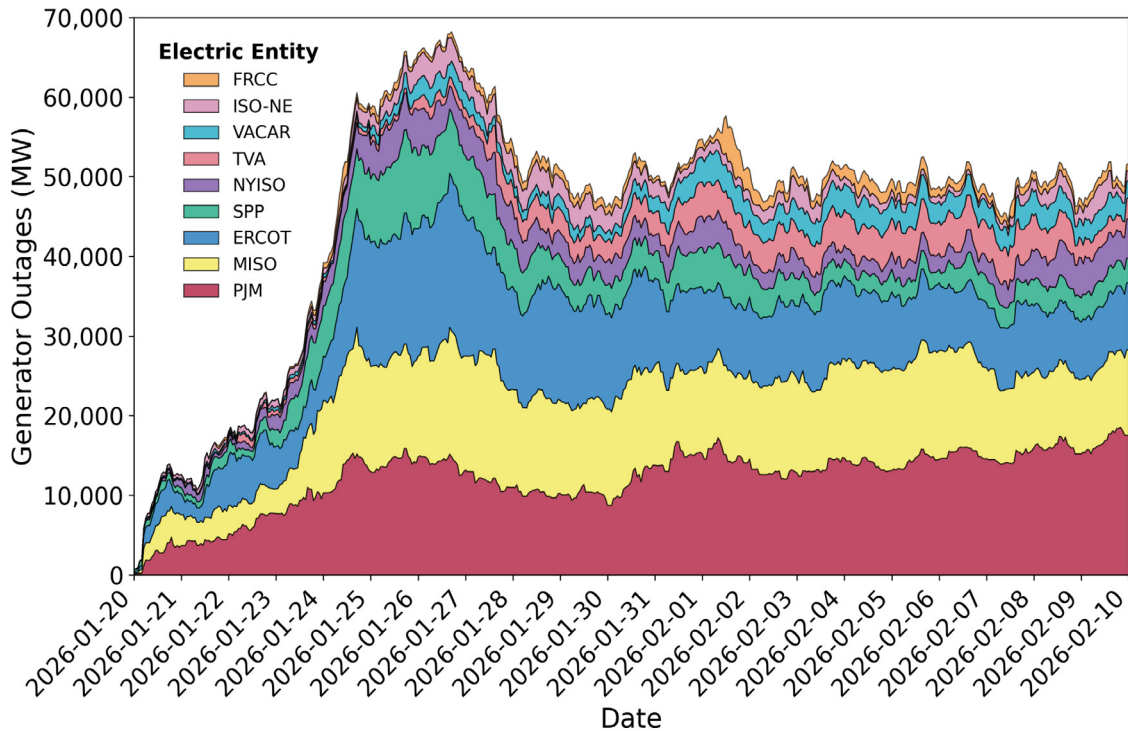
Table 1 provides a snapshot of the generation mix by fuel type in the United States at the hour of peak demand across recent winter storms. The second column of the table (Average Hourly Generation (GW) - Winter 2026) covers the baseline generation mix in the United States across non-storm hours in winter 2025-2026.²⁵ Generation is shown in GW and the percentages represent the share that each fuel type provided during each storm’s hour of peak demand. As shown in Table 1, natural gas generation produced more electricity than any other type of generation during the Winter 2026 Arctic Cold Period, as it has done for the typical winter hour and for previous winter storms. For Winter Storm Fern, natural gas provided, at the storm’s peak demand hour, an additional 84 GW above the average generation from natural gas resources across non-storm hours in winter 2025-2026 (266 GW compared to 182 GW). Coal generation at peak demand provided 40 GW above the typical winter hour output (128 GW compared to 88 GW). Fuel oil generation saw an additional 14 GW output from the typical baseline number (15 GW compared to one GW). Lastly, wind generation rose to 71 GW from 60 GW in a typical winter hour.

For Winter Storm Gianna, natural gas generation provided an additional 85 GW above its typical winter hour output (267 GW compared to 182 GW). Coal generation also provided an additional 41 GW above its typical winter hour output (129 GW compared to 88 GW). Fuel oil generation contributed 12 GW of generation, much higher than its typical output of approximately one GW. Wind generation contributed 56 GW, which is approximately four GW less than it would in a typical winter hour (56 GW compared to 60 GW).

25 A typical 2025-2026 winter hour is the average generation across all hours from December 1, 2025, through February 28, 2026, excluding hours that fall during a winter storm.

Resource Performance

Figure 1: Time Series of Coincident Incremental Unplanned Generator Outages in the Eastern and Texas Interconnections During the Winter 2026 Arctic Cold Period



Source: Winter 2026 Arctic Events Data Requests

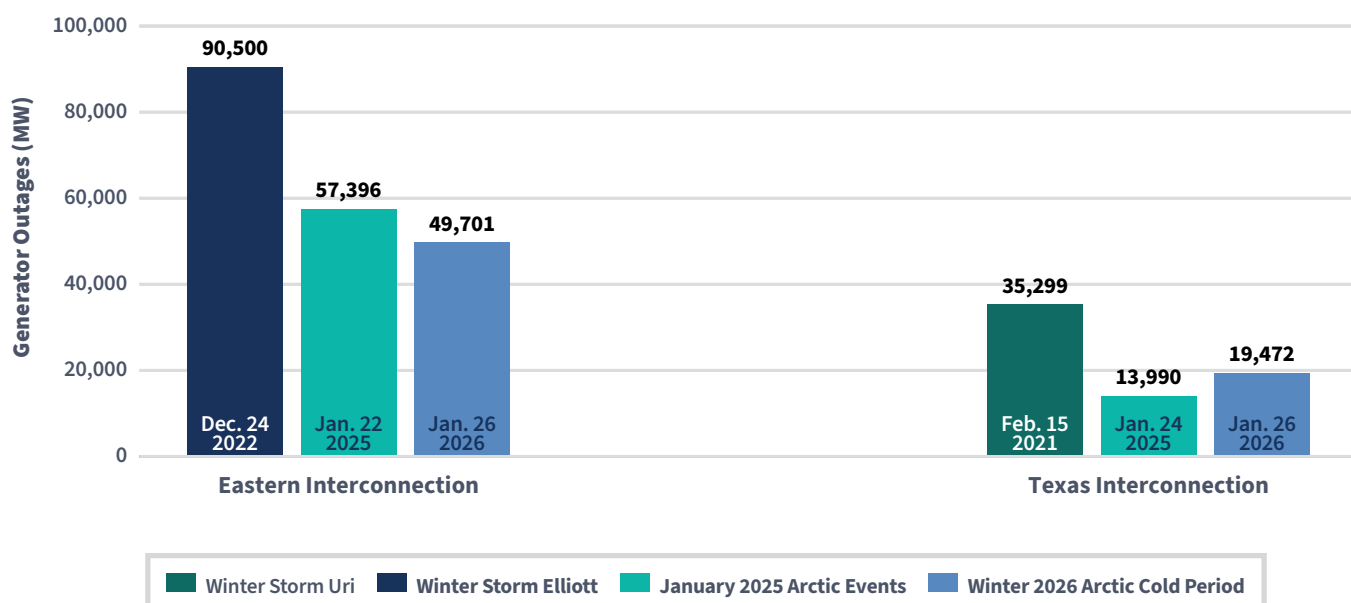
Figure 1 indicates that coincident incremental unplanned generator outages²⁶ peaked at 68,169 MW unavailable relative to nameplate capacity on January 26, 2026, at 5:15 PM Coordinated Universal Time (UTC). Data indicated that 3,099 unique generators in the review area experienced 16,953 different incremental forced outages, forced derates, or failures to start (unplanned outages)²⁷ with 11,149 and 5,804 individual unplanned outage events occurring within the Eastern Interconnection and Texas Interconnection, respectively. Despite differences in generator outages and storm impact and footprint, the magnitude of incremental unplanned generator outages in the Winter 2026 Arctic Cold Period was on par with the January 2025 arctic events' incremental unplanned generator outages of 71,022 MW.²⁸

²⁶ "Incremental" unplanned outages refer to generator events that started during the Winter 2026 Arctic Cold Period and does not include those that started before and continued into the Winter 2026 Arctic Cold Period.

²⁷ The tally of incremental unplanned generator outages counts derates that are consecutive or "related" as separate events, when reported as such in the data. Consecutive derates at a generating unit would be one derate that ends at the same time or one minute before another derate that has a different derated MW magnitude, start time, or other characteristics.

²⁸ This is not an exact comparison due to prior winter storms having different characteristics, geographic locations, duration, and resources.

Figure 2: Largest Coincident Incremental Unplanned Generator Outages by Interconnection and Winter Storm²⁹



Source: February 2021 Cold Weather Outages Report, Winter Storm Elliott Report, January 2025 Arctic Events Report, and Winter 2026 Arctic Events Data Requests

Figure 2 shows that during the Winter 2026 Arctic Cold Period, coincident incremental unplanned generator outages peaked within the Eastern Interconnection at 49,701 MW on January 26, 2026, at 1:10 AM UTC, lower than the 2022 and 2025 winter events.³⁰ In Figure 2, during the Winter 2026 Arctic Cold Period, coincident incremental unplanned generator outages peaked within the Texas Interconnection at 19,472 MW on January 26, 2026, at 8 PM UTC, lower than Winter Storm Uri, but higher than the January 2025 arctic events.³¹

Some regions with notable wind resources, such as ERCOT, saw prominent unplanned wind outages. In the Winter 2026 Arctic Cold Period, ERCOT's coincident incremental unplanned wind outages peaked at 12,896 MW, more than double ERCOT's January 2025 arctic events wind outage peak of 6,014 MW. Additionally, blackstart resources were unavailable in greater numbers than during last year's storms. In the January 2025 arctic events, 14 blackstart resources experienced unplanned generator outages that resulted in the unavailability of 116 MW in the Texas Interconnection and 98 blackstart resources experienced outages totaling 2,240 MW in the Eastern Interconnection.³² During the Winter 2026 Arctic Cold Period, 24 blackstart resources in the Texas Interconnection experienced unplanned outages with coincident unplanned incremental outages peaking at 217 MW. In the Eastern Interconnection, coincident unplanned incremental outages peaked at 3,406 MW from 154 blackstart resources.

²⁹ February 2021 Cold Weather Outages Report at 125; Winter Storm Elliott Report at 98 n.218; January 2025 Arctic Events Report at 10. Values represent coincident generator outages within the interconnection, not generator outages that are coincident across the entire review area.

³⁰ Winter Storm Elliott Report at 98 n.218; January 2025 Arctic Events Report at 10.

³¹ February 2021 Cold Weather Outages Report at 125; January 2025 Arctic Events Report at 10.

³² January 2025 Arctic Events Report at 23.

Weatherization and Maintenance Measures

Electric entities have embraced winterization efforts as a critical safeguard for continued system reliability. In the fall of 2025, as part of its normal practices, NYISO inspected generator sites to verify that generators were adequately weatherized for the upcoming winter. NYISO believed that these pre-winter inspections were beneficial to its system by ensuring the resources were winterized prior to and during the Winter 2026 Arctic Cold Period.

TVA noted that weatherization practices from lessons learned that it had implemented in the wake of Winter Storm Elliott in 2022 contributed to strong reliability performance during the Winter 2026 Arctic Cold Period. TVA stated that following Winter Storm Elliott, it invested approximately \$100 million in sturdier protections and physical hardening for its generators and as a result saw strong generator fleet performance during the Winter 2026 Arctic Cold Period. TVA also reported an improvement in cold weather-related generator outage duration as generator outages shrunk to a range of approximately 45 minutes to four hours, as opposed to days. The outages during the Winter 2026 Arctic Cold Period were attributable to instrumentation, valve skids, and airline valve controls. TVA has now added those components to its cold-weather critical component list, which identifies components across its fleet that could cause outages. Additionally, in the fall of 2025, TVA tested its dual-fuel units to determine that the units could run on their alternative fuel, which provided TVA with greater confidence during the Winter 2026 Arctic Cold Period that dual-fuel generators would be available.

Similarly, an entity within VACAR South winterized its generating units after Winter Storm Elliott through heat tracing, wind blocking structures, and other cold-weather measures. This entity believes that these winterization efforts helped the system perform well during Winter Storm Gianna but noted that Gianna was not comparable to Winter Storms Uri and Elliott.

Keeping generators online while balancing the need to take generators offline for maintenance was a challenge during the Winter 2026 Arctic Cold Period. ERCOT noted the difficulties around outage scheduling and deferring maintenance. During Winter Storm Fern, generators were needed to maintain reliability and delayed going offline for planned maintenance. ERCOT observed an uptick in maintenance outages as temperatures warmed, demand decreased, and the storm passed as the generators undertook the needed maintenance.

PJM also deferred generator maintenance during the storm to maintain reliability. Specifically, PJM worked with generators throughout Winter Storm Fern to identify windows to reschedule maintenance outages in a manner that reduced their potential reliability impact.

Other electric entities have engaged in similar winterization and maintenance efforts.

Generator Cold Weather Operating Limitations

Updated Reliability Standards helped electric entities to prepare for cold weather operations during the Winter 2026 Arctic Cold Period. Through Reliability Standards EOP-012-3, TOP-003, IRO-010, and TOP-002,³³ electric entities used generator cold weather operation limitations data and information collected by generator owners and operators to prepare for the Winter 2026 Arctic Cold Period. As a routine part of its generator cold weather operating limitations process, PJM in the fall of 2025 integrated a suite of cold weather generator data, including extreme cold weather

33 Reliability Standard EOP-012-3 (Extreme Cold Weather Preparedness and Operations), Reliability Standard TOP-003 (Transmission Operator and Balancing Authority Data and Information Specification and Collection), Reliability Standard IRO-010 (Reliability Coordinator Data and Information Specification and Collection), and Reliability Standard TOP-002 (Operations Planning).

temperature (ECWT)³⁴ and startup limits into their control center operations. Additionally, PJM requires generators in its footprint to update and confirm their operating limitations throughout the winter, including in advance of Winter Storm Fern. PJM provided this information to operators in the control room, allowing them to access the information across the full PJM footprint, by transmission zone, or by a specific generator. During the Winter 2026 Arctic Cold Period, PJM was thus able to identify generators at risk of being unavailable due to temperatures dropping below their ECWT and take proactive measures to avoid reliability impacts. Similarly, ISO-NE, MISO, ERCOT, and TVA integrated cold weather operating limitations data into their control room decision matrix during the arctic cold period and were equally successful in navigating the challenges posed by the Winter 2026 Arctic Cold Period.

In contrast to the experience with Winter Storm Elliott in 2022, PJM started planning for Winter Storm Fern a week before it was expected, using advanced natural gas unit commitments to ensure generators could run through the first weekend (January 24-25, 2026) of the storm. SPP employed a multi-day commitment process that allowed generators to receive notice sufficiently in advance to procure fuel for natural gas-fired units to be ready for Winter Storm Fern. SPP issued the early commitments on the evening of Thursday, January 22, 2026, and the generating resources were available to provide power as early as Saturday through Tuesday of the first weekend of the storm.

SPP relied on historical generator cold weather operating limitations data to inform operational decisions within its footprint during the Winter 2026 Arctic Cold Period. Instead of using real-time, unit-specific cold weather limitation data, SPP used aggregate historical temperature-outage relationships to identify generating units at risk of outage based on forecasted temperatures over specific time periods. During the Winter 2026 Arctic Cold Period, the approach proved adequate for addressing potential generator outages due to extreme cold weather. Similar to PJM, SPP stated that the adoption of an early commitment process following Winter Storms Uri and Elliott helped improve generator performance during the Winter 2026 Arctic Cold Period and contributed to SPP maintaining reliability.

In preparation for winter 2025-2026, FRCC reviewed generator minimum operating temperature information and identified potential cold weather-related generator risks. These risks were discussed with balancing authorities and transmission operators to support mitigation efforts in advance of expected winter conditions. During the Winter 2026 Arctic Cold Period, FRCC incorporated actual and anticipated generator dispatch, outage information and identified cold weather risks into its operational assessments and reliability studies. This approach provided a representative view of expected system conditions enhancing operators' situational awareness during the severe winter weather.

VACAR South maintains a database of unit-specific generator cold weather operating limitations data across its footprint. The individual balancing authorities within VACAR South used the database during Winter Storm Gianna to develop their daily operating plans, assess operating limitations, calculate operating reserves, and inform generator dispatch. As an outgrowth of using the database, operators communicated with generators when temperatures approached operation limitation thresholds to proactively deal with possible generator outages during Winter Storm Gianna.

TVA also used commitments in the lead-up to the storm to address generator cold weather operating limitations. TVA explained that extreme cold changes the risk profile of generation commitment—units may not be able to reliably start or may not be able to come back online after shutting down. TVA acted to reduce the risk ahead of anticipated

34 Extreme cold weather temperature is defined as: "The temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated." N. AM. RELIABILITY CORP, *Glossary of Terms*, www.nerc.com/glossary-of-terms (last visited July 26, 2026).

cold conditions by identifying cold-start and operating limits ahead of time and by starting generators early to ensure readiness when called upon.

LOAD FORECAST AND PERFORMANCE OUTCOMES

Load Forecast error

Load forecast accuracy affects reliability, although it is an indirect factor, because operators have tools available to manage conditions when forecasts and actual load diverge.³⁵ Nonetheless, understanding peak load forecast errors helps to identify (1) where load forecasting models struggle to capture rapid changes in electric system conditions; and (2) insufficient responsiveness to weather changes. By identifying the conditions that drive errors, electric entities can refine modeling assumptions and enhance data inputs to reduce load forecast error, which can reduce system stress during an extreme weather event.

Figure 3: Largest Under-forecast Percent Error by Electric Entity During the Winter 2026 Arctic Cold Period

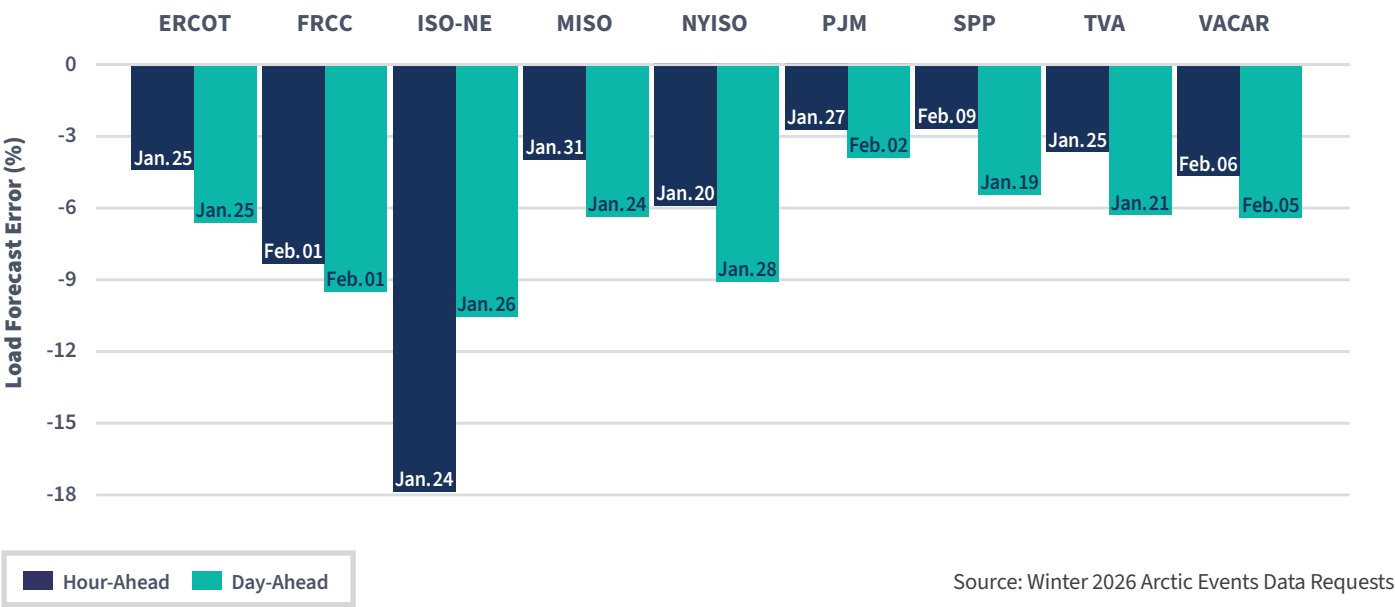


Figure 3 shows the date with the largest under-forecast percent errors for each electric entity’s hour-ahead and day-ahead load forecasts. These values represent the day at which the hour-ahead and day-ahead load forecast were each proportionately furthest below the actual load; therefore, an entity’s maximum hour-ahead and day-ahead forecast errors do not necessarily occur during the same day and/or hour.

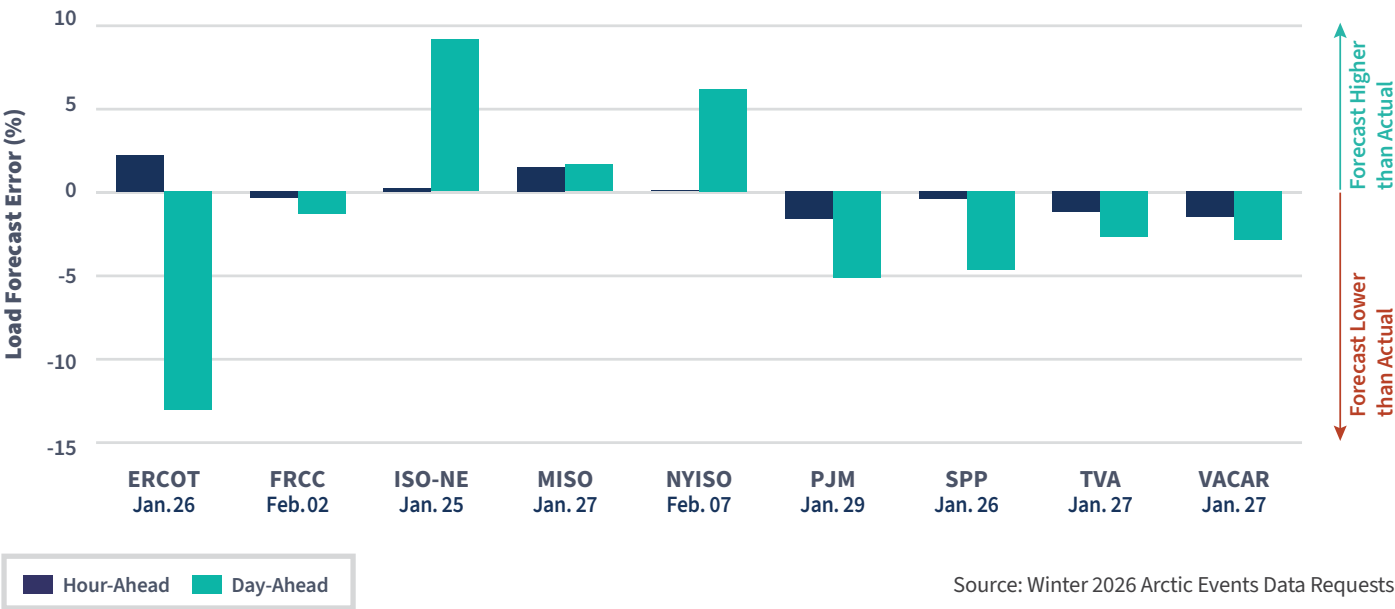
During the Winter 2026 Arctic Cold Period, the largest day-ahead load under-forecast percent error for electric entities ranged from a high of 10.5% to a low of 3.9%. Electric entities use their day-ahead load forecast to establish their plans to schedule sufficient amounts of energy to meet the next day’s demand. To provide historical context, the highest day-ahead load under-forecast percent error for balancing authorities during Winter Storm Uri, Winter Storm Elliott,

35 Load Forecasting Panel, *Increasing Market and Planning Efficiency through Improved Software Technical Conference*, Docket No. AD10-12-017, Remarks of John Moura, NERC, Director, Reliability Assessment and Performance Analysis, Day 1 Tr. 163:25-164:7 (July 7, 2026).

the January 2024 arctic storms, and the January 2025 arctic events was 11.8%, 12.5%, 14%, and 9.2%, respectively.³⁶ For reference, the average day-ahead load under-forecast throughout this period was 4.5%. Additionally, the largest hour-ahead under-forecast percent error for electric entities ranged from a high of 17.8% to a low of 2.6%, while the average hour-ahead load under-forecast error throughout the Winter 2026 Arctic Cold Period was 4.4%. Figure 3 identifies when load forecast accuracy was at its weakest in percentage terms, rather than, as shown in Figure 4 (below), the forecast error at peak demand.

As expected, the day-ahead load forecast errors were less accurate than the hour-ahead load forecast errors, except for ISO-NE at the beginning of Winter Storm Fern.³⁷ However, the magnitude of a load forecast error does not by itself indicate its operational or reliability significance. Day-ahead load forecasts have a less direct reliability impact because, at that stage, the principal decision being made is which resources to commit for the next operating day. Operators retain opportunities between day-ahead and real time to revise load expectations and adjust those commitments as additional information becomes available. Overall, whether in the day-ahead or real-time time frame, the consequences of a load forecast error depend on the timeframe and magnitude of the error, the decision informed by the load forecast, and the availability and ability of operators to respond, including adjusting resource commitments or maintaining reserves to manage load forecast uncertainty.³⁸

Figure 4: Load Forecast Percent Error at Peak Demand by Electric Entity During the Winter 2026 Arctic Cold Period



36 January 2025 Arctic Events Report at 15.

37 Some electric entities conduct 5-minute load forecasts. However, not every 5-minute forecast is always used for reliability or market purposes. For instance, only the most recent 5-minute forecast prior to each real-time unit commitment and dispatch cycle may be utilized. Therefore, a load forecast with a high forecast error may not have been used for real-time decision making. Additionally, joint staff requested hour-ahead real-time forecasts and electric entities may have provided only the single 5-minute forecast that is closest to the requested hour. As a result, this report does not analyze the forecast errors for the remaining 5-minute forecasts within each hour.

38 Load Forecasting Panel, *Increasing Market and Planning Efficiency through Improved Software Technical Conference*, Docket No. AD10-12-017, Remarks of DL Oates, MISO, Exec. Director, Market and Grid Research, Day 1 Tr. 168:21-170:4 (July 7, 2026).

Figure 4 represents the load forecast percent error at the hour of peak demand for both hour-ahead and day-ahead load forecasts. As seen in Figure 4, day-ahead load forecast errors again exceeded the hour-ahead load forecast errors. For hour-ahead, the load forecast error at peak demand dropped to below 2% for all electric entities. A lower hour-ahead error compared to day-ahead error is expected given that more current data and weather information are used leading up to the operating interval.

Figure 5: Source of the Largest Day-Ahead Load Forecast Error for ERCOT, PJM, ISO-NE, and NYISO³⁹

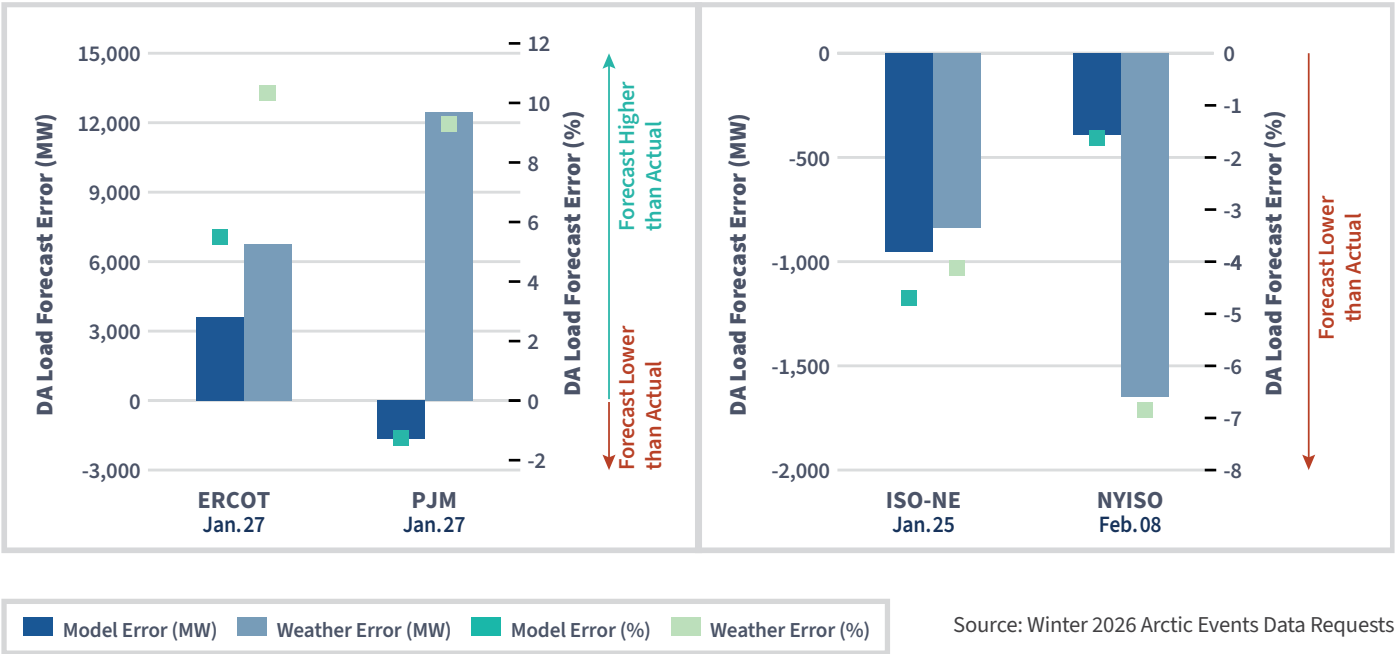


Figure 5 illustrates that the largest day-ahead load forecast MW and percent error⁴⁰ for ERCOT, PJM, ISO-NE and NYISO during the Winter 2026 Arctic Cold Period is comprised of weather error⁴¹ and load-model error⁴² components that determined the observed net load forecast error (the combination of the weather and load-model errors) at the dates indicated. The magnitude and direction of these error components varied across system operators. ERCOT, ISO-NE, and NYISO all demonstrated load-model errors and weather errors that moved in the same direction, amplifying the total load forecast error for the electric entities. In contrast, in PJM the load model error and the weather error moved in opposite directions, somewhat mitigating the net forecast error. When net forecast errors are amplified, the weather and load forecast errors compound misses on fuel procurement, generator unit commitments, and reserve positioning targets.

During the Winter 2026 Arctic Cold Period, electric entities saw day-ahead load forecast errors greater than hour-ahead load forecast errors across several metrics and electric entities' weather errors and load-model errors often,

39 Four electric entities provided weather-normalized MWs for their day-ahead load forecast, which allowed for breaking out total forecast error into its weather and load-model (non-weather) error components.

40 The percent error values are provided for the hour at which the MW difference between actual load and day-ahead load forecast was largest at each individual electric entity.

41 Weather error represents inaccuracies in the overall load forecast due to incorrect meteorological inputs from weather forecasts.

42 Load-model error, or mathematical specification error, represents inaccuracies in the overall load forecast due to structural failures, such as mathematical limitations or the use of outdated historical load data.

but not always, moving in the same direction. Load forecasting remains an area of opportunity for improving the Bulk-Power System's response to extreme weather because a load forecast error in one region can create reliability challenges interconnection-wide.

Behavioral Impacts

The majority of electric entities explained that uncertainties regarding reduced demand resulting from school and business closures (in anticipation of the adverse weather) contributed to load forecast errors during the Winter 2026 Arctic Cold Period. Closure decisions were made several hours after load forecasts were completed. ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP stated that school and business closures and other behavioral responses to the Winter 2026 Arctic Cold Period tended to lead to over-forecasting of load. For example, PJM noted that school and business closures reduced demand by 2,000 to 3,000 MW, which was between 1.4% to 2.2% of the 139,410 MW of peak demand in PJM during the Winter 2026 Arctic Cold Period.

However, electric entities insisted that they would not have experienced any failures even if schools and businesses remained open, which would have increased demand. SPP stated that demand during the weekdays of the Winter 2026 Arctic Cold Period resembled holiday load levels rather than typical weekday demand due to school and business closures. Yet, SPP was hesitant to adopt the holiday forecast because it potentially produces a lower load forecast. SPP estimates the difference between holiday and regular weekday demand is approximately 1,500 to 2,000 MW, which was roughly three to four percent of SPP's peak demand of 45,624 MW on January 26, 2026.

Some entities explained that the societal changes brought about by the COVID-19 pandemic still complicate load forecasting. ISO-NE stated that changes in hybrid work patterns after the pandemic have led to changes in the shape of its load profiles and that there are limited historical analogs that capture the COVID-induced changes.

Electric entities have embraced the lessons learned from behavioral changes to improve their load forecasting for arctic cold periods. PJM applied lessons learned from its experience with the January 2025 arctic events.⁴³ Going forward, PJM is exploring working with vendors that could provide school closure data to improve load forecasting.⁴⁴

Load Restoration

Most electric entities did not experience significant distribution customer outages; however, TVA saw notable distribution outages that impacted its load forecasts. Approximately, half-million of TVA's distribution customers lost power during the Winter 2026 Arctic Cold Period. The prolonged uncertainty around when power would be restored to customers complicated efforts to accurately forecast load. In response, TVA refined its short-term load forecast through near real-time coordination with transmission operators managing the restoration efforts. Going forward, TVA understands that outage-driven load-loss estimation provides an opportunity to improve its load forecasting.

43 January 2025 Arctic Events Report at 21.

44 PJM Interconnection, L.L.C., *January Cold Weather Operations* 37 (Feb. 5, 2026), www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2026/20260205/20260205-item-03---cold-weather-update---revised.pdf.

Demand Response

The Winter 2026 Arctic Cold Period illustrated that demand response remains a valuable reliability tool for operators. NYISO called on Special Case Resources (SCR) and its Emergency Demand Response Program (EDRP) during the prolonged cold period to reduce peak demand and manage generator fuel inventories to meet load and reserve requirements for the duration of the Winter 2026 Arctic Cold Period.⁴⁵ NYISO is working to enhance the Demand Response Information System user experience to improve system performance and support the growth and more frequent deployment of the SCR and EDRP.

PJM used demand response strategically throughout the Winter 2026 Arctic Cold Period. Instead of using all generation resources at first, PJM used demand response to maintain reliability, while keeping additional generation resources in reserve in case there were significant emergencies later in the storm sequence, preserving operational flexibility.

In the South, TVA employed its demand response portfolio, which provided approximately 1,100 MW of demand relief to promote reliability. An entity's demand response program within VACAR South covered a diverse array of assets, including streetlights and thermostats that provided small, but measurable reliability relief. This entity reported that the thermostat tranche of its portfolio resulted in 13 MW of demand reduction.

FUEL SYSTEMS AND NON-FUEL CONSUMABLE MANAGEMENT

Fuel Assurance and Availability

Fuel assurance programs and efforts were a useful tool for electric entities in maintaining reliability.⁴⁶ Noting that a natural gas-fired generator that lacks firm supply and transportation may not be a dependable energy supplier during peak winter conditions, ERCOT deployed a fuel assurance program during the Winter 2026 Arctic Cold Period to obtain sufficient fuel to maintain reliability. This program, the Firm Fuel Supply Service, developed after Winter Storm Uri, requires participating generators to procure and maintain specific levels of fuel for reliability needs.⁴⁷ This program was a useful tool for meeting reliability objectives in Texas by keeping 340 MW of generation online during the Winter 2026 Arctic Cold Period that was impacted by natural gas restrictions.

On the first weekend of Winter Storm Fern, PJM managed fuel inventory risks associated with the prolonged cold period by increasing its minimum run-time threshold for its fuel oil units from 16 to 32 hours of run-time, helping conserve fuel supplies for the anticipated peak winter demand. As the Winter 2026 Arctic Cold Period continued, PJM also directed dual-fuel units to switch from fuel oil to natural gas to further preserve limited fuel oil inventories. Additionally, the requirements for PJM's blackstart units reduce reliability risk arising from fuel limitations by requiring blackstart generators to operate independently on two or more gas pipelines.

45 NEW YORK INDEP. SYS. OPERATOR, Winter 2025-2026 Cold Weather Operations 6 (Apr. 10, 2026), www.nysrc.org/wp-content/uploads/2026/04/8.3.3-2025-2026-Cold-Weather-Ops-EC-Attachment-8.3.3.pdf.

46 Fuel assurance refers to “[p]roactively taking steps to identify fuel arrangements or other alternatives that would provide confidence such that fuel interruptions are minimized to maintain reliable [bulk-power system] performance during both normal operations and credible disruptive events.” NERC, RELIABILITY GUIDELINE, FUEL ASSURANCE AND FUEL-RELATED RELIABILITY RISK ANALYSIS FOR THE BULK POWER SYSTEM, at 1 (Sept. 2023), www.nerc.com/globalassets/who-we-are/standing-committees/rstc/egwg/fuel_assurance_and_fuel-related_reliability_risk_analysis_for_the_bulk_power_system.pdf.

47 See ELEC. RELIABILITY COUNCIL OF TX., Firm Fuel Supply Service, www.ercot.com/services/programs/firmfuelsupply/ (last visited Aug. 8, 2026).

Fuel *availability* was also a critical issue in maintaining reliability during the Winter 2026 Arctic Cold Period. Several electric entities highlighted steps that were taken throughout the Winter 2026 Arctic Cold Period to manage fuel availability. In ISO-NE, barges from Philadelphia, New York, and the Caribbean provided fuel oil needed to meet demand. In addition, in keeping with its normal winter protocols, ISO-NE tracked LNG ships to provide situational awareness on the location of LNG cargos that could meet generator demand. As the prolonged cold snap progressed, ISO-NE became increasingly dependent on fuel oil and LNG replenishment.

NYISO and PJM experienced challenges with fuel oil replenishments tied to delivery on waterways. The Hudson River in New York is a critical transitway for fuel oil in the NYISO footprint. However, at times, ice blocked the path to delivery docks. As a result, NYISO identified the need to better coordinate with the U.S. Coast Guard, who cleared the Hudson River of ice, to ensure there is a clear path for the delivery of fuel oil. PJM also noted that its footprint experienced frozen waterways and that it coordinated with the U.S. Coast Guard on clearing the waterways in its footprint for fuel oil delivery.

While fuel oil supplies generally remained available, electric entities expressed concern that severe weather conditions could increase demand for natural gas and other critical resources. Greater demand could create greater competition for available supply, particularly for electric entities that are unable to secure contractual arrangements to meet their needs in advance. Although natural gas constraints did not result in reliability issues and fuel oil shortages did not materialize, the increasing dependence on natural gas-fired generation, combined with the growing demand from other sectors, could heighten the risk of fuel oil supply constraints during future extreme weather events, particularly for those entities that rely on spot market purchases of natural gas and non-firm transportation.

TVA asserted that its vertically integrated structure provided valuable operational flexibility in ensuring that there was sufficient fuel oil supply throughout its footprint to maintain reliability. With greater visibility into the capabilities and limitations of its generating units, TVA was able to coordinate with fuel oil suppliers to dispatch fuel oil trucks early and often to critical generation units during the Winter 2026 Arctic Cold Period, which helped to mitigate the stress imposed on generators' dual fuel and on-site fuel capabilities due to the storm's length.

Non-fuel Consumables

The prolonged Winter 2026 Arctic Cold Period strained the supply of non-fuel consumables, such as demineralized water⁴⁸ and ammonia, that electric entities needed to run their units on fuel oil. Some fast-start fuel oil-burning units in ISO-NE ran for extended periods during the beginning of the Winter 2026 Arctic Cold Period as natural gas became constrained or uneconomic; typically, fast-start fuel oil units are expected to run for significantly shorter intervals.⁴⁹ In addition, some fuel oil-fired units in the region, after several days of uninterrupted operations, almost exhausted their capabilities to access the limited supplies of demineralized water, ammonia, and other non-fuel consumables required to run the units.

Generators in New York switched to fuel oil during the Winter 2026 Arctic Cold Period due to economics and limited natural gas availability. This switch and the extended runtime of fuel oil units led to increased demand for demineralized water for generators, resulting in some outages and derates. The limited supply of demineralized water was not as pronounced in New York as it was in New England.

48 Demineralized water can be used for steam production, core plant operations, or for emissions-related systems.

49 ISO – NEW ENGLAND INC., *System & Market Operations Report – March 2026*, at 35-36, 40-41 (2026), www.iso-ne.com/static-assets/documents/100033/system-and-market-ops-report-mar-2026.pdf.

Generator fuel and non-fuel consumable studies helped some electric entities incorporate limitations on the supply of non-fuel consumables during the Winter 2026 Arctic Cold Period into their operations, while other electric entities recognized the potential to improve the structure of their studies to account for the non-fuel consumable supply chain. FRCC incorporated generator limiting factors, including the availability of demineralized water, into planning studies conducted prior to Winter Storm Gianna to better reflect potential operating constraints, outages, and changes in generator availability. The insights gained from these studies helped FRCC identify potential stress points affecting fuel oil units and evaluate the reliability impacts of reductions in critical non-fuel consumables during severe winter conditions.

As discussed above, ISO-NE ran its 21-day energy assessment daily during the Winter 2026 Arctic Cold Period, which provided confidence that the area had sufficient fuel oil to satisfy demand during the cold snap. The ISO-NE Generator Fuel and Emissions Survey informs the 21-day energy assessment by asking specific and general questions related to fuels and/or emissions limitations. While the 21-day energy assessment does not explicitly ask questions about demineralized water supplies in its survey of generators, some units were reporting information about demineralized water supplies through the “additional information column” in the survey.⁵⁰ ISO-NE reported it is seeking to update the survey to formally gain insight on the availability of water supplies and other non-fuel consumables in the future.

In addition to issues with studies capturing non-fuel consumable supply chain risks, electric entities also faced transportation challenges in resupplying required non-fuel consumables during the prolonged Winter 2026 Arctic Cold Period. For ISO-NE, coordination played a critical role in replenishing exhausted non-fuel consumables for fuel oil units in the region. During the Winter 2026 Arctic Cold Period, ISO-NE worked with generators in the region and state and federal agencies to help coordinate the delivery of demineralized water trailers that came from as far away as Seattle, Washington. ISO-NE also coordinated with federal and state agencies and others, including the U.S. Department of Energy (DOE) and the National Energy Dominance Council,⁵¹ to raise awareness of the need for additional demineralized water given the uncharacteristically long period of time that some dual-fuel fired units ran on fuel oil.

COMMUNICATION, ENERGY TRANSFERS, AND MARKETS

Communication

Communication within the electric industry, with federal and state agencies, and with the natural gas industry was a key factor in managing reliability risks during the Winter 2026 Arctic Cold Period. Electric entities in the Eastern Interconnection participated in daily calls with all reliability coordinators throughout the interconnection to prepare the groundwork for any anticipated support. Some of the electric entities in the Eastern Interconnection participated in a separate series of daily phone calls that involved sharing situational operation information with the balancing authorities and transmission operators within their footprints to be better prepared for the storms’ impacts for the upcoming day.

Similarly, several electric entities engaged in further coordination efforts to meet the challenges posed by the Winter 2026 Arctic Cold Period. For example, NYISO communicated with state agencies, according to its protocols, during the Winter 2026 Arctic Cold Period in preparation for the storm.

⁵⁰ See ISO-NE OP No. 21, § V.

⁵¹ The National Energy Dominance Council, among other things, is tasked with advising and assisting the President in facilitating cooperation among the federal government and domestic private sector energy partners. Exec. Order No. 14213 (Establishing the National Energy Dominance Council) § 4(b)(iv), 90 Fed. Reg. 9945, 9946 (Feb. 20, 2025).

For at least the second consecutive winter, gas-electric communication has proven essential for maintaining reliability during prolonged cold spells and electric entities have indicated that the shared information from those communications will aid their responses to future arctic cold periods. NYISO, FRCC, SPP, PJM, and ERCOT reported communicating with natural gas entities to understand the impacts the Winter 2026 Arctic Cold Period had on natural gas fuel supply and integrated that information into electric operations planning. NYISO noted that its collaboration with natural gas entities provided it with near real-time reliability information that it would not otherwise have had access to. Similarly, FRCC gathered information from natural gas entities within its footprint which provide only reliability-related information and avoid discussion of any market or competitive information.

ERCOT stated that at least one north Texas natural gas entity annually provides information about potential natural gas restrictions that could occur during the upcoming winter season, which provided useful visibility into the fuel systems throughout the Winter 2026 Arctic Cold Period. However, ERCOT stressed that its intrastate natural gas information remains limited and that operational information from additional natural gas entities would provide better situational awareness of the natural gas supply system pursuant to applicable confidentiality requirements.

Energy Transfers

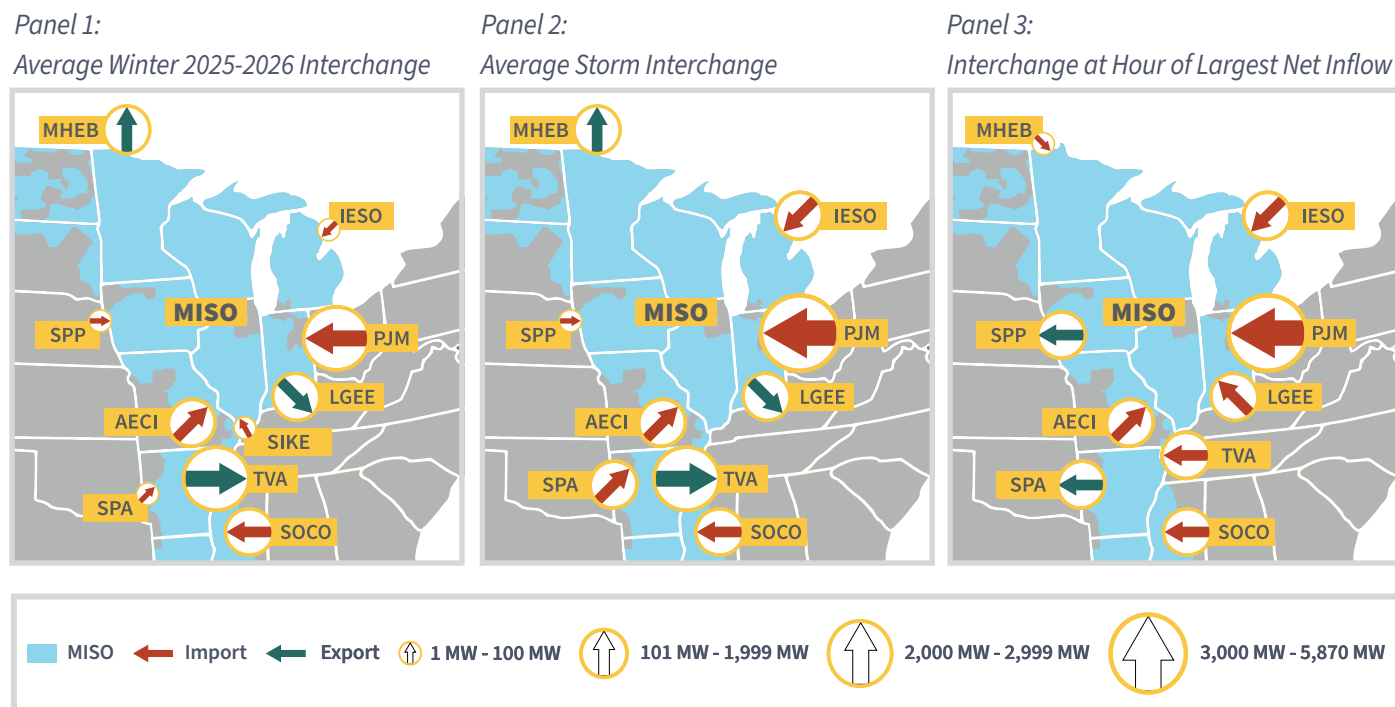
During extreme cold weather events, energy transfers among regions may assist neighboring regions in meeting energy needs. FRCC indicated that it exported energy during Winter Storm Fern, which had limited impact on Florida, but imported during Winter Storm Gianna.

SPP became a significant exporter during the Winter 2026 Arctic Cold Period because wind generation exceeded forecasted levels. SPP's resource forecast incorporated the potential for wind turbine icing and associated reductions in wind output. However, the icing conditions only partially materialized, allowing wind turbines to remain available and produce more energy than forecasted.

MISO experienced a reduction of all imports into MISO for approximately 12 hours on January 24, 2026, because a MISO market tool that publishes market prices failed for those 12 hours. MISO stated that this failure and the resulting lack of imports directly affected reliability and contributed to the need for more severe emergency declarations. To address this issue, MISO worked with TVA and several additional neighboring entities to allow the transfer of energy to the North and Central MISO regions from MISO South by increasing the Regional Directional Transfer Limit (RDTL).⁵² In particular, TVA and the neighboring entities approved the increase of the RDTL, which peaked at 4,200 MW before returning to normal limits. During this time, TVA noted that it monitored thermal and voltage limits to ensure that the system remained stable and reliable. Additionally, TVA coordinated the restoration of a critical 500 kV transmission line to allow PJM to increase export capabilities to its regional neighbors.

52 MISO limits the amount of power it transfers intra-market via its RDTL, under a joint coordination agreement with SPP, Associated Electric Cooperative, Inc., TVA, Louisiana Gas and Electric Company/Kentucky Utilities, Southern and PowerSouth, to 3,000 MW from north-to-south (1,000 MW firm and 2,000 MW non-firm, as-available) and 2,500 MW from south-to-north (1,000 MW firm and 1,500 MW non-firm, as-available). While the total AC tie line capacity, calculated by adding the total capacity of all tie lines between the balancing authorities at issue, may indicate a large transfer capacity, the actual ability to transfer power is dependent on system conditions at the time of transfer, including ambient temperatures, generation outages and dispatch, transmission outages and derates, all of which drive actual power flows on transmission lines and can limit available transfer capability. Winter Storm Elliott Report at 61 n.155.

Figure 6: MISO Interchange During the Winter 2026 Arctic Cold Period



Source: U.S. Energy Information Administration

As shown in the third panel of **Figure 6**, MISO imported approximately 9,000 MW from its neighboring balancing authorities at midnight UTC on January 24, 2026, its hour of highest net inflow during Winter Storm Fern. As expected, imports were much higher than typical during the storm. For instance, during an average hour that excluded winter storm periods in winter 2025-2026, MISO on net exported 20 MW (panel 1), and during an average hour within Winter Storm Fern, MISO on net imported just 2,000 MW (panel 2).

Gas-Electric Coordination and Markets

The Northeast and Mid-Atlantic natural gas markets relied heavily on natural gas flows from the nearby Appalachian producing region to meet natural gas demand during the Winter 2026 Arctic Cold Period. Natural gas flows from Appalachia moved east to Mid-Atlantic market areas, such as Philadelphia, and northeast to New York City. New England relied on natural gas moving south from eastern Canada and some natural gas from New York moving further north to market areas, such as Boston.

LNG was used to meet generation resources' fuel supply needs and reliability obligations during the Winter 2026 Arctic Cold Period in ISO-NE. Supply of LNG into New England relieved pressure on pipeline natural gas demand, allowing NYISO's generators to use natural gas to meet NYISO's reliability needs throughout the prolonged Winter 2026 Arctic Cold Period. The fuel dynamics between ISO-NE and NYISO demonstrate that fuel usage patterns in one region can create secondary reliability effects for neighboring regions.

While the Northeast and Mid-Atlantic were able to rely on inter-regional natural gas transfers to meet demand during

the Winter 2026 Arctic Cold Period, electric entities continue to believe that there is a misalignment in the structure of the electric and natural gas markets as it pertains to reliability in the face of arctic cold periods. MISO, NYISO, and PJM believe that there was limited liquidity in the natural gas commodity markets over the weekends of the Winter 2026 Arctic Cold Period. While there is limited liquidity in natural gas commodity markets during winter weekends, bilateral trading is still occurring and, generally, the number of trades over these periods has been increasing in recent years. Because many natural gas users tend to purchase their natural gas ahead of time, there is not as much spot-market supply available over the weekend. Additionally, it is important to note that in natural gas constrained areas, the ability to purchase natural gas does not equate to the delivery of natural gas because the natural gas transportation infrastructure may also be constrained, limiting pipelines' ability to support uncontracted deliveries.

NYISO and PJM indicated that the structural mismatch also revealed itself in the limited flexibility generators had to respond to peaks during the Winter 2026 Arctic Cold Period. Electric entities expressed concern that generators' need for flexible, hour-by-hour ramping fuel consumption to meet morning and evening electric peaks was limited due to natural gas pipelines' physical need to deliver steady ratable takes over the course of a day. Natural gas pipelines, however, report that they do offer firm and flexible, non-ratable services when possible, but generators largely elect not to subscribe to them. In the view of NYISO and PJM, the perceived mismatch required generators to procure more natural gas than they ultimately needed to preserve reliability in meeting peak demand, which left regions at the end of the pipeline (such as ISO-NE, which experienced higher natural gas prices for longer than other regions) with limited availability of natural gas. Additionally, PJM suggested that market-area storage—i.e., placing natural gas storage in reliability-constrained areas—could be a useful tool where geologically possible.

EMERGENCY FEDERAL POWER ACT SECTION 202(C) ORDERS

Federal Power Act (FPA) section 202(c) provides that when the Secretary of Energy determines that an emergency exists because of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes, the Secretary of Energy may order temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy to best meet the emergency and serve the public interest.⁵³ During the Winter 2026 Arctic Cold Period, the Secretary of Energy received numerous applications requesting emergency orders. Upon review the Secretary of Energy determined that a statutory emergency existed and issued emergency orders that: (1) directed electric entities to dispatch certain units only as needed to maintain reliability, which allowed generators to exceed Federal, State, or Local environmental limitations;⁵⁴ and (2) authorized electric entities to direct backup generation resources at data centers and other large load industrial and commercial customer sites to operate as a last resort.⁵⁵ The Secretary of Energy also directed the continued operation of certain generators slated for retirement.

The Secretary of Energy issued a total of fifteen FPA section 202(c) emergency orders and five extension orders, including to ISO-NE and PJM, over the course of the Winter 2026 Arctic Cold Period directing electric entities to dispatch units to maintain reliability that allowed generators to exceed permitted environmental emissions limitations.⁵⁶

53 16 U.S.C. § 824a(c)(1).

54 Operation under a FPA section 202(c) order allows generators to exceed Federal, State, or Local environmental limitations. *Id.* § 824a(c)(3)-(4).

55 See U.S. DEP'T OF ENERGY, 2026 DOE 202(c) Orders, www.energy.gov/ceser/2026-doe-202c-orders (last visited July 8, 2026).

56 Three emergency orders were extended on January 29, 2026, after Winter Storm Fern in anticipation of Winter Storm Gianna. See, e.g., U.S. DEP'T OF ENERGY, Order No. 202-26-3A (Jan. 30, 2026), www.energy.gov/documents/doe-order-no-202-26-03a-iso-ne.

ISO-NE stated that the Secretary of Energy’s emergency order helped ISO-NE maximize the availability of all generating resources in New England to meet expected demand for electricity during the Winter 2026 Arctic Cold Period. ISO-NE further stated that a total of 57 resources, representing approximately 11,215 MW of winter capacity, or about 39% of the region’s total winter generating capacity requested and were designated as “Specified Resources,” meaning they could exceed their emissions allowances during the emergency. Of the 57 resources, 26 reported exceedances of a specified emissions limit during the period covered by the order.

PJM also emphasized the benefits of receiving an emergency order from the Secretary of Energy.⁵⁷ PJM stated it had 39 units with a total of 5,704 MW of capacity that provided a total of 271,150 MWh of energy that would have otherwise been precluded from operating without the emergency order. The emergency order also helped to provide operational certainty necessary to purchase a multi-day block of natural gas over the first weekend of Winter Storm Fern.

Included in the total orders issued, the Secretary of Energy issued 12 emergency orders, including six orders within FRCC’s footprint, one to an investor-owned utility and five extension orders, during Winter Storm Gianna.⁵⁸ Through advanced coordination, the Secretary of Energy was able to act promptly on the requests regarding municipal facilities, helping to maintain reliable system operations during stressed system conditions. FRCC stated that the emergency orders enabled additional generation resources to remain available and provided operational flexibility that supported grid reliability.

Backup Generation

Prior to the Winter 2026 Arctic Cold Period, the Secretary of Energy issued a letter to reliability coordinators and balancing authorities, explaining that if appropriate, he would authorize reliability coordinators and balancing authorities to direct backup generation facilities to run as a last resort before declaring an Energy Emergency Alert level 3 (EEA 3), or during an EEA 3,⁵⁹ to avoid potential blackouts.⁶⁰ During the Winter 2026 Arctic Cold Period, the Secretary of Energy issued the first-ever emergency FPA section 202(c) orders for backup generation at data centers and at other large industrial and commercial customer sites (hereinafter referred to as large loads) to operate as a last resort during emergency conditions. Entities in VACAR South, PJM, and ERCOT requested emergency orders to authorize the deployment of backup generation facilities to avoid or mitigate an EEA 3 during the Winter 2026 Arctic Cold Period.⁶¹ Entities in FRCC requested emergency orders to direct the deployment of municipal and customer-

57 U.S. DEP’T OF ENERGY, Order No. 202-26-2 (Jan. 25, 2026), www.energy.gov/documents/order-no-202-26-2-pjm.

58 See, e.g., U.S. DEP’T OF ENERGY, Order No. 202-26-11 (Jan. 31, 2026), www.energy.gov/documents/doe-202c-order-no-202-26-11-orlando-utilities-commission.

59 Under an EEA 3, firm load interruption is imminent or in progress with the energy deficient balancing authority unable to meet minimum contingency reserve requirements. Reliability Standard EOP-011-4 (Emergency Operations), Att. 1 (EOP-011-4 Energy Emergency Alerts) at 14.

60 LETTER FROM U.S. SECRETARY OF ENERGY CHRIS WRIGHT RE: LEVERAGING BACKUP GENERATION FACILITIES DURING ENERGY EMERGENCIES 1 (Jan. 22, 2026), www.energy.gov/documents/leveraging-backup-generation-facilities-during-energy-emergencies.

61 See, e.g., ELEC. RELIABILITY COUNCIL OF TX., *Request for Emergency Order Under Section 202(c) of the Federal Power Act for Backup Generating Facilities* (filed Jan. 24, 2026), www.energy.gov/documents/ercots-202c-application; PJM INTERCONNECTION, L.L.C., *Request for Emergency Order Under Federal Power Act Section 202(c)* (filed Jan. 26, 2026), www.energy.gov/documents/pjm-application-202c-backup-generators.

owned backup generation facilities.⁶² The Secretary of Energy issued emergency orders in response to the requests.⁶³ Ultimately, although electric entities in VACAR South, PJM, and ERCOT did not exercise the authority provided in the emergency orders for backup generation at large loads, several utilities in FRCC were able to rely on municipal and customer-owned backup generation facilities during the tightest system conditions on the evening of February 1, 2026, and on the morning of February 2, 2026.⁶⁴

Most electric entities acknowledge that backup generation, including at large loads, such as data centers, could provide potential reliability benefits during extreme weather periods. For example, ERCOT stressed that backup generation at large loads could be used to reduce demand to support reliability. Similarly, SPP acknowledged that large loads could support reliability during extreme operating conditions through their backup generation or flexible demand capabilities.

Although ERCOT⁶⁵ and PJM⁶⁶ released notices about the operation of backup generation at large loads, the electric entities stressed that critical questions about the potential use of large loads' backup generation for reliability remain unanswered. Specifically, ERCOT stated that during Winter Storm Fern, operators in its footprint did not have a pre-existing formal communication channel available or information about the capability of backup generation at large loads. Similarly, PJM noted that it lacked certainty on location, amount, duration, switching capability, communication, telemetry, and whether the exceedance of environmental limitations from an emergency order it had received applied to customer-owned backup generation at large loads under a separate emergency order it had also received.

DOE held conference calls with reliability coordinators, balancing authorities, and others prior to the winter storms. Electric entities highlighted that continued coordination between DOE and the entities, themselves, could strengthen the process around emergency orders for backup generation at large loads in the future.

Electric entities indicated that there was uncertainty around whether large loads were designed in a manner that would facilitate the use of their backup generation as a reliability mechanism under the FPA section 202(c) emergency orders. MISO understood from discussions with DOE that some large loads may need to completely disconnect from the grid to be served by their backup generation. MISO noted that large load backup generation cannot be a flexible reliability resource unless the facility is designed, interconnected, metered, modeled, protected, and operated with that in mind. PJM was concerned that in some cases, disconnecting the large loads could unintentionally disconnect additional residential, commercial, or industrial loads. PJM explained that this was the case because data centers have not been designed for an emergency reliability function at the distribution level.

62 See, e.g., ORLAND UTILS COMM'N, *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (filed Jan. 31, 2026), <https://www.energy.gov/documents/fmpa-202c-application-backup-generators>; FLA. MUN. POWER AGENCY, *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (filed Jan. 31, 2026), www.energy.gov/documents/fmpa-202c-application-backup-generators.

63 See, e.g., U.S. DEP'T OF ENERGY, Order No. 202-26-15 (Jan. 31, 2026), www.energy.gov/documents/doe-202c-order-no-202-26-15-orlando-utilities-commission-ouc (approving Orlando Utilities Commission's emergency 202(c) backup generation application); U.S. DEP'T OF ENERGY, Order No. 202-26-12 (Jan. 31, 2026), www.energy.gov/documents/doe-order-no-202-26-12-florida-municipal-power-agency-fmpa (approving Florida Municipal Power Agency's emergency 202(c) backup generation application); U.S. DEP'T OF ENERGY, Order No. 202-26-01 (Jan. 24, 2026), www.energy.gov/documents/order-no-202-26-01-ercot (approving ERCOT's emergency 202(c) application); U.S. DEP'T OF ENERGY, Order No. 202-26-06 (Jan. 26, 2026), www.energy.gov/documents/doe-order-no-202-26-06-pjm (approving PJM's emergency 202(c) application).

64 See, e.g., Cold Weather, Big Questions: Here are the Answers, OUCONNECT (Feb. 12, 2026), <https://oucblog.com/cold-weather-big-questions-here-are-the-answers/>.

65 ELEC. RELIABILITY COUNCIL OF TX., *Notice of U.S. Department of Energy Section 202(c) Order Affecting Certain Customers with Backup Generation Facilities in the ERCOT Region* (Jan. 25, 2026), www.ercot.com/services/comm/mkt_notices/M-A012526-01.

66 PJM INTERCONNECTION, L.L.C., *Notice Regarding Behind the Meter Emergency Procedure* (Jan. 29, 2026), www.pjm.com/-/media/DotCom/committees-groups/committees/oc/postings/pjm-notice-re-behind-the-meter-emergency-procedure.pdf.

Other electric entities recognized that the use of backup generation was an all or nothing proposition. For example, TVA indicated that backup generators could not run parallel with the Bulk-Power System; and large loads could not simultaneously draw power from the grid and their backup generation. Additionally, VACAR South suggested that the reliability value that large loads could provide is in load reduction, not in energy injection, as the backup generators are not designed and configured to inject energy into the Bulk-Power System.

Still, the electric entities are committed to exploring how large loads could be used for system reliability to respond to future extreme weather events and are working through the questions around large loads and backup generation. Specifically, PJM and SPP noted in interviews that they are embarking on processes with stakeholders to better integrate large loads during emergency grid conditions.

Retirements

In November and December 2025, the Secretary of Energy issued three 202(c) emergency orders to MISO and generators within MISO to ensure that three coal-fired units slated for imminent retirement would continue to operate for 90 days (i.e., throughout most or all of the 2025-2026 winter season).⁶⁷ MISO did not measure the direct impact of the three emergency orders during the Winter 2026 Arctic Cold Period because the three coal-fired units are part of the overall fleet. However, at their peak, the three coal-fired units produced 1,190 MW on February 8, 2026.

In November 2025, the Secretary of Energy issued an FPA section 202(c) order to PJM and a generator that was in effect during most of the fall and winter season.⁶⁸

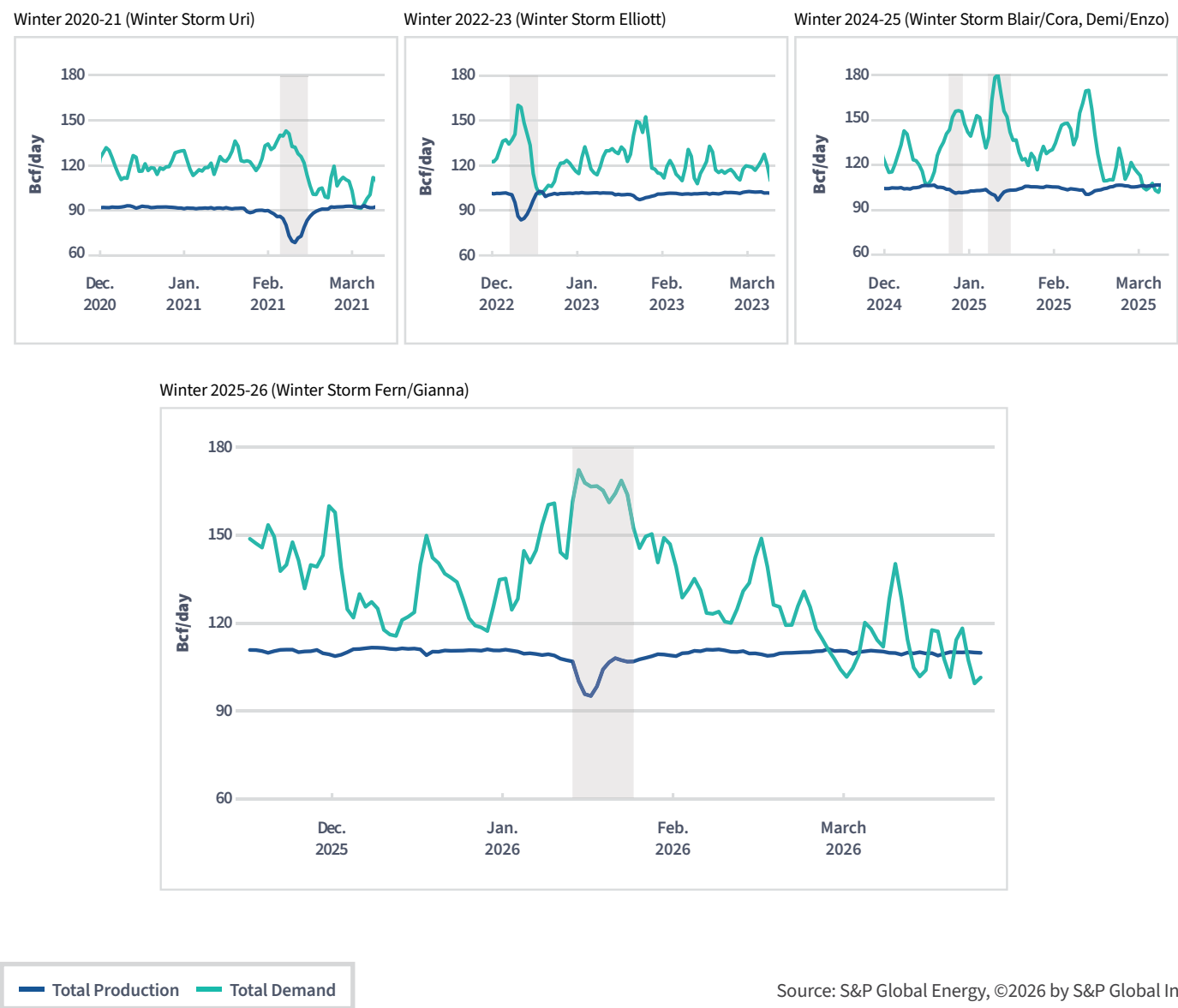
67 U.S. DEP'T OF ENERGY, Order No. 202-25-9 (Nov. 18, 2025), www.energy.gov/sites/default/files/2025-11/Order%20No%20202-25-9.pdf; U.S. DEP'T OF ENERGY, Order No. 202-25-12 (Dec. 23, 2025), www.energy.gov/documents/order-number-202-25-12-schahfer; U.S. DEP'T OF ENERGY, Order No. 202-25-13 (Dec. 23, 2025), www.energy.gov/documents/order-number-202-25-13-culley.

68 U.S. DEPT OF ENERGY, Order No. 202-25-10 (Nov. 25, 2025), www.energy.gov/sites/default/files/2025-11/Order%20No.%20202-25-10.pdf.

Natural Gas System Performance

NATURAL GAS OPERATIONS, SUPPLY, DEMAND, AND MARKET CONDITIONS

Figure 7: Total Natural Gas Demand and Production by Winter Storm

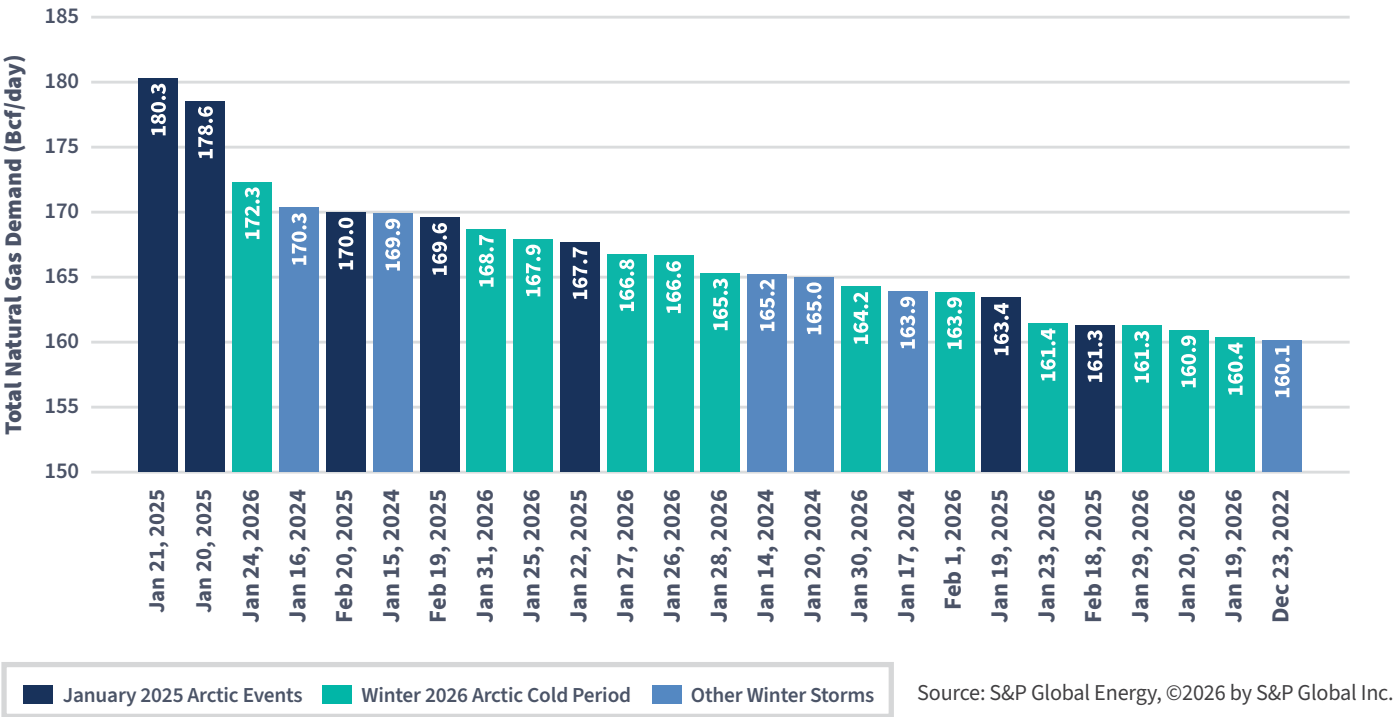


During the Winter 2026 Arctic Cold Period, total demand for natural gas rose significantly while natural gas production dropped. The graphs in **Figure 7** compare U.S. dry natural gas production with total U.S. natural gas demand over four recent winter seasons.⁶⁹ The gray shaded areas indicate severe cold weather events: Winter Storm

69 The Natural Gas Council analyzed the impacts of Winter Storm Fern on natural gas markets. Its analysis states that “the natural gas system performed well in terms of sustained flowing production, transportation and storage, and record sustained deliveries during the long-duration weather event” and that “the market-driven efforts to winterize natural gas production yielded significant dividends.” ENERGY VENTURES ANALYSIS, *Holding the Line: U.S. Natural Gas Performance During Winter Storm Fern 2* (May 2026), www.ingaa.org/wp-content/uploads/2026/06/EVA-NGC-Winter-Storm-Fern-Report-Final-1.pdf.

Uri in 2021, Winter Storm Elliott in 2022, Winter Storms Gerri and Heather in 2024, the January 2025 arctic events, and the Winter 2026 Arctic Cold Period. During each of these periods, the divergence between increasing natural gas demand and decreasing natural gas production was bridged primarily by natural gas storage, which highlights the critical role natural gas storage serves to meet natural gas demand and electric reliability. We discuss the role of storage during the Winter 2026 Arctic Cold Period further below.

Figure 8: Top 25 All-Time Natural Gas Demand Days



During the Winter 2026 Arctic Cold Period, total U.S. natural gas demand peaked at 172 Bcf/day on January 24, 2026. The prolonged Winter 2026 Arctic Cold Period resulted in consistently high demand, reaching an average of 166 Bcf/day over the 10-day period between January 23 and February 1, 2026, a new record. Although natural gas demand did not set a record for peak daily natural gas demand during the Winter 2026 Arctic Cold Period, natural gas demand remained relatively high for nearly two weeks. As shown in **Figure 8** above, 12 of the top 25 natural gas demand days from recent winters occurred during the Winter 2026 Arctic Cold Period. At the peak of the Winter 2026 Arctic Cold Period, natural gas demand exceeded natural gas production by more than 72 Bcf/day. Natural gas demand was driven primarily by increases in residential and commercial space heating and natural gas power generation, which combined to account for as much as 68% of total demand during the Winter 2026 Arctic Cold Period.

Overall, during the course of the Winter 2026 Arctic Cold Period, natural gas production remained relatively steady, compared to previous cold weather events. Total dry gas production dropped by as much as 14% nationwide, a smaller drop than during Winter Storms Uri and Elliott, on par with Winter Storm Gerri, but a greater drop than during Winter Storms Heather, Demi, and Enzo. Regionally, the majority of natural gas production declines occurred in the Midcontinent region, Texas, and Louisiana. While there was no single point of failure, natural gas producers reported that production declines resulted from various factors, including road access and localized power issues

due to freezing rain and snow, gathering/compression issues, midstream constraints/takeaway issues, and high line pressures. Associated natural gas production fell by as much as 27% in the Delaware Basin producing region in West Texas, while dry gas production in the Marcellus Shale in Northeast Pennsylvania saw declines of just 7% at its peak.

Associated natural gas production from oil-producing basins in West Texas experienced larger declines than dry gas production regions, largely because winter weather disrupted the management of water, a byproduct of extracting natural gas. Poor road conditions limited the ability to transport produced water from oil production sites to disposal or recycling facilities. As on-site water storage filled, some operators were required to curtail or temporarily shut in oil production, which led to a reduction in associated natural gas output at oil-producing basins.

Figure 9: Peak Daily Production Declines by Storm

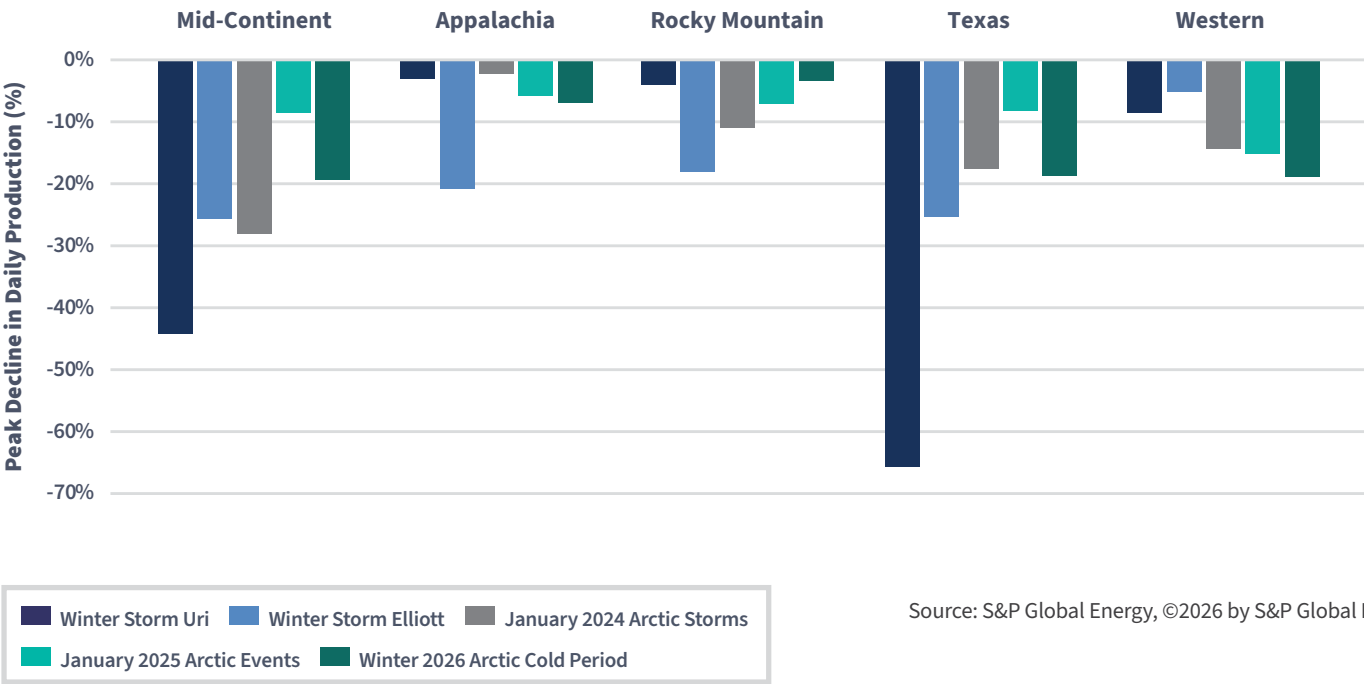


Figure 9 compares the peak daily production decline level for each recent winter storm dating back to Winter Storm Uri with the average production levels in each region during the month prior. Not every storm impacted production in every region equally, but Winter Storm Uri had a disproportionate impact on production in Texas and the Midcontinent region. In contrast, Winter Storm Elliott hit Appalachian production the hardest. As such, production performed comparatively better during the Winter 2026 Arctic Cold Period than during Winter Storms Uri and Elliott, though not as well as during the January 2025 arctic events.

Natural gas prices spiked in several areas of the country during the Winter 2026 Arctic Cold Period, particularly in Florida, New York, Pennsylvania, and New England. At some hubs new price records were set. In New England, short-lived, record high price spikes may have been a result of the fear of supply scarcity due to the potential for colder than anticipated weather leading to larger natural gas production declines, particularly in Appalachia. When weather conditions moderated and production levels stabilized, prices in New England declined from their record highs even as high levels of demand persisted.

During Winter Storm Fern, as in previous winter events, storage was called upon to meet both a sharp rise in demand and a simultaneous loss of supply. For the week ending January 30, 2026, total weekly natural gas withdrawals matched the previous record high of 359 Bcf set in January 2018. The withdrawals exceeded the five-year average for that week by 170 Bcf, or 89%, and left working natural gas storage inventory levels 1.1% below the five-year average. The South Central region accounted for 44% of the week’s lower 48 withdrawals (158 Bcf of the total 359 Bcf), with high-deliverability salt dome facilities supplying 84 Bcf of the withdrawals.⁷⁰ The significant storage withdrawals represented as much as 38% of total U.S. natural gas demand on January 26, 2026.

Figure 10: Total U.S. Storage Inventory Levels vs the Prior 5-Year Storage Range

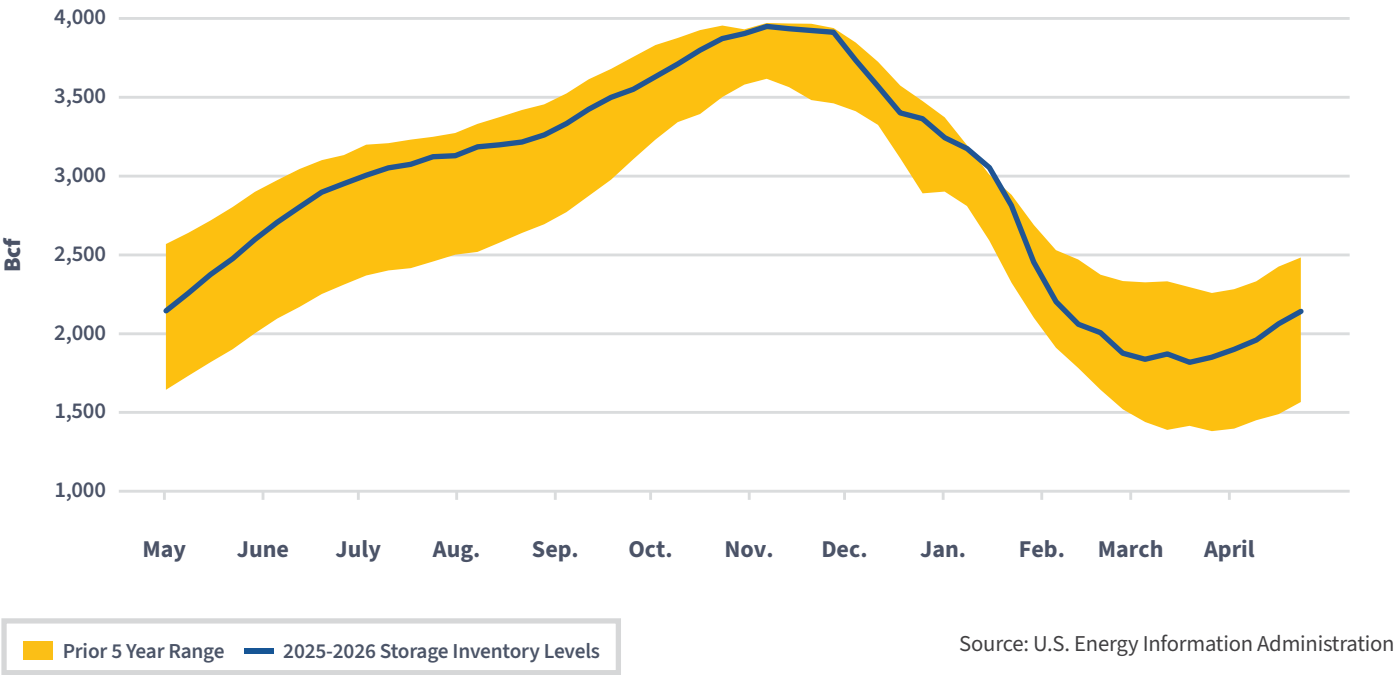


Figure 10 shows the total U.S. natural gas storage inventory level over the past year compared to the previous five-year range. During the 2025-2026 winter season, total U.S. storage inventories went from above the five-year range in mid-January to the average of the prior five-year range by early February, highlighting the substantial role storage plays in times of severe cold.

Natural gas storage will continue to be a critical element in meeting peak winter demand. However, in contrast to natural gas demand growth, natural gas storage capacity has grown only modestly in recent years. According to a recent study from the National Petroleum Council, while total natural gas demand increased by almost 50% from 2013-2024, natural gas storage capacity increased only by about 2% over that timeframe.⁷¹

70 U.S. ENERGY. INFO. ADMIN, *Weekly Underground Natural Gas Storage Report Form EIA-912*, History.xls, weekly_net_changes worksheet (accessed on June 18, 2026), available at [ir.eia.gov/ngs/ngshistory.xls](https://www.eia.gov/ngs/ngshistory.xls).

71 NAT'L PETROLEUM COUNCIL COMMITTEE ON OIL AND NATURAL GAS INFRASTRUCTURE PERMITTING, *Bottleneck to Breakthrough: A Permitting Blueprint to Build 31* (Dec. 3, 2025), www.energy.gov/sites/default/files/2025-12/NPC_Permitting_report_2025-12-3.pdf.

OPERATIONAL PREPAREDNESS, COMMUNICATION, AND STORAGE MANAGEMENT Operations

Across the natural gas supply chain, entities reported engaging in numerous activities both during and in advance of the winter season and the Winter 2026 Arctic Cold Period to improve resilience during severe cold weather. Entities reported increasing staffing, investing in winterization of facilities, improving weather forecasting, staging equipment prior to the events, and holding customer and working group/task force meetings. Pipelines and other natural gas entities frequently communicated with relevant electric entities to improve situational awareness during the event. Pipelines increased linepack to provide additional flexibility to the system in addition to issuing notices to customers warning them of impending winter weather and informing them of system conditions. Interstate natural gas pipelines also used underperformance notices to ensure that customers were injecting their gas into the pipeline commensurate with their scheduled quantities.

AGA's Natural Gas Readiness Forum⁷² also provides the industry an opportunity to periodically communicate, educate, and prepare for high natural gas demand periods throughout the year.⁷³ Natural Gas Readiness Forums are held annually with regional forums held in different regions throughout the year that emphasize the importance of communication and coordination.⁷⁴

Communication

Communication and coordination both within the natural gas system and with electric entities continued to build on improvements made in response to Winter Storm Uri. Interstate natural gas pipelines continued to issue frequent and proactive critical notices to communicate with electric entities and natural gas entities, and, importantly, entities generally continued to comply with those notices and operational flow orders (OFOs).⁷⁵

Anecdotally, various natural gas entities reported increased real-time communication with pipeline operators, customers, and electric industry stakeholders throughout the Winter 2026 Arctic Cold Period. Pipelines reported using notices, particularly OFOs and underperformance notices, more extensively since Winter Storm Elliott, which helped communicate information and set expectations regarding operational conditions on the pipelines throughout the Winter 2026 Arctic Cold Period. Pipeline shippers also continued to be more responsive to pipeline notices to take corrective action.

Pipelines reported being in regular contact with RTOs/ISOs both during and in advance of the Winter 2026 Arctic Cold Period, which in some cases resulted in modifications to generator dispatch requirements in response to pipeline OFOs. Such modifications helped reduce non-ratable takes and over-takes from natural gas generators, which benefited the natural gas system as a whole.

72 In a November 2025 report, the National Association of Regulatory Utility Commissioners' Task Force on Gas-Electric Alignment for Reliability recommended the creation of a natural gas readiness forum. NAT'L ASSOC. OF REGUL. UTIL. COMM'RS, *Task Force on Gas-Electric Alignment for Reliability: Report & Recommendations* 9 (Nov. 2025), pubs.naruc.org/pub/2527936B-BEB6-767B-50BE-01BEEEB3091F.

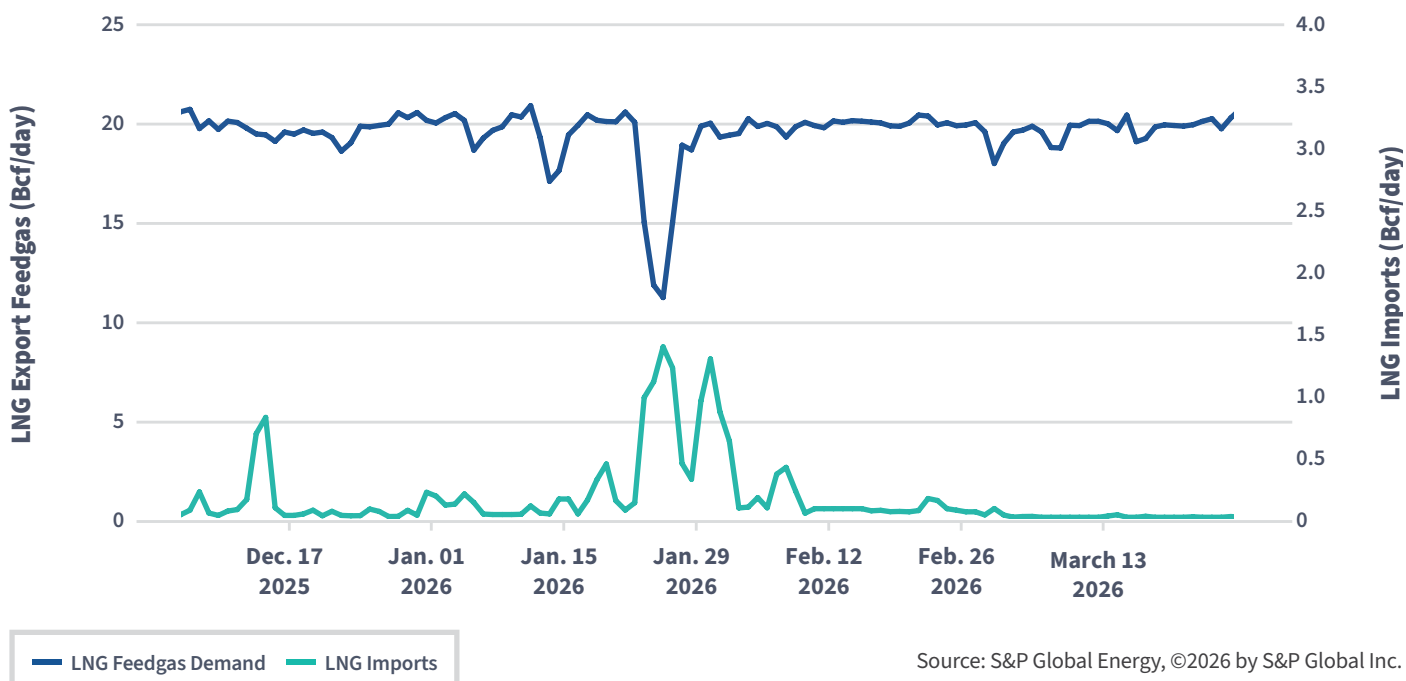
73 AM. GAS. ASSOC., *Natural Gas Readiness Forum*, www.aga.org/natural-gas/security/natural-gas-readiness-forum/ (last visited July 9, 2026).

74 For example, in May 2026, the AGA hosted, in conjunction with the industry advisory group, two in-person Tabletop Exercises in Providence, RI ("Northeastern Regional NGRF") on May 28, 2026, and Albuquerque, NM ("Western Regional NGRF") on May 31, 2026. The purpose of these exercises was to encourage industry-government collaboration, to engage in knowledge transfer between industry operators and state/federal government representatives in procedures and actions taken during natural gas emergencies, and to understand the policies driving incident response procedures. Each exercise was conducted as a single group, with a facilitator guiding the scenario and leading interactive discussions.

75 An operational flow order is a mechanism natural gas pipeline operators use to protect the operational integrity of the pipeline. It requires shippers to balance how much natural gas they put onto and take off of the pipeline, within a certain tolerance, or face penalties. This can impact service to interruptible shippers and can also limit firm shipper flexibility when there are large discrepancies between supply and demand.

LNG

Figure 11: LNG Export Feedgas Demand vs. LNG Imports



As LNG imports were surging on January 26, 2026, deliveries of feedgas to LNG export terminals fell to their lowest levels of the Winter 2026 Arctic Cold Period. **Figure 11** shows LNG feedgas demand and LNG imports during January and February 2026.

LNG export feedgas, which has increased significantly over the last decade, currently represents approximately 19 Bcf/day of natural gas demand. During the Winter 2026 Arctic Cold Period, LNG export feedgas demand decreased by over 40%, falling to as low as 11.3 Bcf/day on January 26, 2026.⁷⁶ Reductions in LNG feedgas demand reduced natural gas supply constraints by increasing the volume of natural gas available to domestic consumers rather than to international markets during the Winter 2026 Arctic Cold Period. Natural gas entities indicated that reductions in LNG feedgas demand may have been a result of a combination of localized supply impacts, facility-specific operational considerations, and commercial responses to rapidly changing market conditions.

On January 26, 2026, Henry Hub spot prices averaged \$30.57/million British thermal units (MMBtu), an all-time high, with individual trades as high as \$53.75/MMBtu that day.⁷⁷ These price levels exceeded LNG free-on-board prices, signaling strong economic incentives for some LNG operators to reduce feedgas receipts, allowing additional natural gas to remain in the domestic market rather than being liquefied for export. Although LNG sales contracts may

⁷⁶ AM. GAS ASSOC., *Natural Gas Market Indicators* – February 5, 2026, www.aga.org/research-policy/resource-library/natural-gas-market-indicators-502nd-edition/ (last visited July 9, 2026).

⁷⁷ Chris Newman, *Henry Hub Prices Smash All-Time Records as Winter Storm Fern, LNG Tag-Team to Tighten Balances*, NAT. GAS. INTEL. (Jan. 28, 2026), www.naturalgasintel.com/news/henry-hub-prices-smash-all-time-records-as-winter-storm-fern-lng-tag-team-to-tighten-balances/.

establish obligations for cargo delivery, LNG export facilities generally maintain operational flexibility—including onsite LNG storage—that may allow for short-term adjustments in feedgas procurement while continuing to satisfy export commitments. The degree of flexibility available varies by facility and depends on market conditions; however, the Winter 2026 Arctic Cold Period demonstrated that LNG export facilities may have commercial and operational flexibility in some circumstances, which can increase gas availability for domestic consumers, and improve overall system resilience.

In addition to LNG export feedgas declines, the domestic market received multiple LNG import shipments. The Cove Point LNG Terminal in Maryland, Elba Island LNG Terminal in Georgia and the Everett Marine Terminal in Massachusetts all received LNG imports during the Winter 2026 Arctic Cold Period. Elba Island LNG Terminal’s January 29, 2026, import was its first LNG import since 2020.⁷⁸ LNG imports during the Winter 2026 Arctic Cold Period reached as high as 1.4 Bcf/day on January 26, 2026, and totaled over 9.3 Bcf, which aided increased domestic demand.

78 Everett received an LNG delivery on January 22, 2026, and Cove Point received deliveries on January 26 and January 30, 2026. See U.S. DEP’T OF ENERGY, *U.S. Natural Gas Exports and Re-Exports Summary* (Jan 2000 – Mar. 2026), available at www.energy.gov/sites/default/files/2026-05/1.%20U.S.%20Natural%20Gas%20Imports%20Exports%20and%20Re-Exports%20Summary%20%28Jan%202000%20-%20Mar%202026%29.xlsx.

ANALYSIS

Endurance Challenge

The successive Winter Storms Fern and Gianna brought an extended Winter 2026 Arctic Cold Period to much of the eastern half of the United States and Texas. These nearly-overlapping events demonstrated that extreme cold events are not merely peak-hour reliability challenges, but instead can be multi-day events that require endurance from electric and natural gas infrastructure and operators. For example, PJM reported an extended heightened reliability risk posture that strained fuel oil systems and created uncertainty around generator availability. Similarly, ISO-NE's experience addressing nearly three weeks of far below-average temperatures underscores the need to track fuel oil inventories, non-fuel consumable logistics, and offshore fuel oil deliveries to maintain continued reliability. TVA experienced prolonged transmission and distribution outages in its footprint, highlighting that extended icing affects both energy supply and infrastructure simultaneously. Lastly, deferred generator maintenance during the Winter 2026 Arctic Cold Period increased the risk of forced outages.

To better ensure operators can prepare for extended strains on the system, the Commission approved Reliability Standard BAL-007-1, which will become effective on April 1, 2027.⁷⁹ NERC developed this Reliability Standard to improve electric entity preparedness by requiring balancing authorities to conduct multi-day Near-Term Reliability Assessments that include multi-day reliability modeling and load forecasting.

Generator Cold Weather Operating Limitations

Following Winter Storm Uri, the Commission recommended that NERC develop reliability standards that address generator winterization.⁸⁰ NERC subsequently developed Reliability Standard EOP-012-1 (Extreme Cold Weather Preparedness and Operations), which requires generator owners and operators, among other things, to identify generator performance data.⁸¹ Through Reliability Standards EOP-012-3, TOP-003, IRO-010, and TOP-002, electric entities have since incorporated extreme cold weather preparedness data into real-time operations in their control rooms.⁸² Both ERCOT and ISO-NE incorporate cold weather generator performance data into real-time operations in their control rooms. For example, ERCOT was able to use data to identify units at risk during the Winter 2026 Arctic Cold Period and to bring other generators into the resource mix to maintain reliability.

ISO-NE conducted fuel oil surveys that captured additional generators' operating limitation data and incorporated it into ISO-NE's operation decision matrix. ISO-NE's daily fuel oil surveys capture the potential for cold-weather

79 N. Am. Elec. Reliability Corp., Docket No. RD25-5-000 (Feb. 26, 2025) (delegated letter order).

80 February 2021 Cold Weather Outages Report at 184-194.

81 Reliability Standard EOP-012-1 (Extreme Cold Weather Preparedness and Operations). The Commission subsequently approved Reliability Standard EOP-012-2 in response to a directive in the order approving Reliability Standard EOP-012-1 to modify the Standard. The modified Reliability Standard EOP-012-2 requires NERC to file annual informational filings on the efficacy of, and ongoing risk posed by, the proposed technical, commercial, or operational constraint provisions in Reliability Standard EOP-012-1, to the Commission beginning 12 months after the enforceable date of Reliability Standard EOP-012-1. The Commission also subsequently approved Reliability Standard EOP-012-3 in response to a directive in the order approving Reliability Standard EOP-012-2 to modify the Standard. *Order on Clarification*, 193 FERC ¶ 61,187, at PP 2-3 (2025). Reliability Standard EOP-012-3, among other things, enhances the requirements for generator cold weather preparedness and generator cold weather constraint declarations. *Order Approving Extreme Cold Weather Reliability Standard EOP-012-3 and Directing Data Collection*, 192 FERC ¶ 61,229, at P 2 (2025), *order on clarification*, 193 FERC ¶ 61,187 (2025).

82 Reliability Standard EOP-012-3 (Extreme Cold Weather Preparedness and Operations).

derates and fuel oil supply chain constraints. The use of data by RTOs/ISOs gathered under Reliability Standard EOP-012-3 by generator owners and operators is a useful tool for situational awareness during extreme cold weather events. ISO-NE's approach highlights that the decision-making process in control rooms can be further enhanced by incorporating granular cold weather data points.

Energy Transfers

Energy transfers between neighboring regions supported reliability during the Winter 2026 Arctic Cold Period. TVA coordinated with neighboring electric entities to approve the increase in the RDTL to allow the transfer of energy into MISO, peaking at approximately 9,000 MW during the Winter 2026 Arctic Cold Period. The increase in the RDTL played an important role in helping MISO respond to the reduction of all energy imports due to the failure of a market tool on January 24, 2026, which directly affected reliability and contributed to the need for more severe emergency declarations. However, the increase in the RDTL stressed TVA's system and required TVA to actively manage stressed system conditions through the period that the transfer limit was elevated. The flow of energy to North and Central MISO during Winter Storm Fern highlights that energy transfers between regions are influenced by the specific characteristics of each arctic cold period and their effect on resource availability within a region. As such, the increased transfer limits that supported reliability during Winter Storm Fern may not be available during future arctic events.

As noted above, the import/export status of some areas, such as FRCC, varied based on prevailing system and market conditions, exporting energy during Winter Storm Fern when resources were available within Florida and importing energy during Winter Storm Gianna. This flexibility demonstrates the value of interregional transfer capability and coordination to support evolving operating needs during severe weather events.

Inter-region Dynamics

The interplay between fuel oil supply in ISO-NE and NYISO underscores the interconnected nature of reliability in the Bulk-Power System and regional fuel markets. During the Winter 2026 Arctic Cold Period, ISO-NE relied heavily on LNG and fuel oil to meet demand due to New England's natural gas pipeline deliverability constraints and economic considerations. Supply of LNG into New England relieved pressure on pipeline natural gas demand, allowing NYISO's generators to use natural gas to meet NYISO's reliability needs throughout the extended cold period New York state experienced.

Load Forecasts

Weather forecast errors and load-model errors related to school and business closures and behavioral changes, along with distribution-level outages during the Winter 2026 Arctic Cold Period, led to errors in electric entities' load forecasts. Load forecasting errors directly impact fuel procurement, generator unit commitments, and reserve positioning. Under-forecasting load in advance of storms can challenge system reliability because utilities under-procure generation, leading to electricity demand potentially exceeding energy supply. Over-forecasting load as the storm abates often leads to the tendency for electric entities in one region to over-procure natural gas, resulting in limited natural gas availability and flexibility throughout other parts of the Bulk-Power System. Load forecasting remains an area of opportunity for improving the Bulk-Power System's response to extreme weather because load forecast errors in one part of the country can pose an interconnection-wide reliability challenge.

Natural Gas Infrastructure

The challenges electric entities endured in securing natural gas to meet demand during the Winter 2026 Arctic Cold Period underscore persistent natural gas infrastructure limitations in the United States. This was particularly a challenge in ISO-NE because it is downstream of constrained natural gas pipeline corridors and thus was dependent on upstream deliveries and LNG shipments. Some generators, for a variety of reasons, may not have firm natural gas supply and transportation capacity. Such generators operate at a disadvantage during a winter event because other pipeline shippers holding firm fuel delivery on natural gas pipelines receive priority. Many of the major pipelines in the New England region were fully subscribed during the Winter 2026 Arctic Cold Period, making it difficult to obtain non-firm transportation options. While dual-fuel units in ISO-NE could avoid the need to rely on firm natural gas by switching to operating on fuel oil, that switch could place additional stress on their non-fuel consumables supply chain during a prolonged extreme cold period. Across regions, both electric entities and natural gas entities concur that building natural gas storage and pipeline capacity could improve the reliable operation of the Bulk-Power System, as additions to natural gas storage and transportation infrastructure have not kept pace with increasing natural gas demand.

Logistics and Supply Chains

Natural gas producers in primarily oil-producing regions reported experiencing challenges, due to poor road conditions from snow and ice, in securing the trucks needed to remove water, a byproduct of extracting natural gas, to continue producing natural gas. Natural gas producers also stressed the importance of pre-staging equipment and trucks within natural gas producing regions and working with snow removal crews to ensure access to their facilities to continue strong production levels during the Winter 2026 Arctic Cold Period. As seen in the response to prior cold periods and in the response to Winter Storms Fern and Gianna, maintaining natural gas production throughout the storm is necessary to cover increased natural gas demand.

The non-fuel consumables supply chain is also essential to meeting the reliability challenges for the grid posed by an extended cold period. As dual-fired generators switched to fuel oil in ISO-NE as the storm progressed, ISO-NE generators had to go to increasing lengths to secure the non-fuel consumables necessary to run the fuel oil units. ISO-NE coordinated with DOE and the National Energy Dominance Council to increase awareness of the need for additional demineralized water trailers. Mastering vendor coordination and trucking logistics to ensure the timely delivery of such non-fuel consumables is needed to maintain reliability in the face of prolonged extreme cold periods as dwindling non-fuel consumable supplies can lead to Bulk-Power System outages.

Backup Generation

Ultimately, although electric entities did not exercise the authority provided in the emergency FPA section 202(c) orders for backup generation at large loads, electrical entities in FRCC were able to rely on municipal and customer-owned backup generation facilities during the tightest system conditions. Most electric entities acknowledge that backup generation, including at large loads, could provide potential reliability benefits during extreme weather periods. However, many questions around using large loads for reliable operations remain unresolved: for example, the amount of megawatt relief the large loads can provide; communication with the appropriate staff at large loads; how large loads will be metered; telemetry and operational visibility; and isolating large loads from nearby residential, commercial, and industrial customers. PJM and ERCOT have developed procedures governing the use of backup generation.

CONCLUSION

The Winter 2026 Arctic Cold Period demonstrated that extreme cold events have the potential to impose sustained, multiday stress on the Bulk-Power System and natural gas infrastructure. Proactive actions mitigated the risks of more severe operational actions like manual load shedding. The Secretary of Energy issued a series of emergency orders that supported reliability by enabling system operators to dispatch generation resources that otherwise would not be available. Despite historic demand levels, including total U.S. natural gas demand peaking at 172 Bcf/day and electric demand reaching 666 GW, both the Bulk-Power System and natural gas infrastructure operated reliably, reflecting improvements in generator performance, fuel readiness, and cold weather operations. Near-record natural gas storage withdrawals, LNG import activity, and sharp reductions in LNG export feedgas supported electric reliability across the Eastern and Texas Interconnections during the Winter 2026 Arctic Cold Period.

The team's analysis shows that reliability challenges during prolonged cold snaps arise not only from peak conditions but stress factors that increase as an event continues, such as generator availability, fuel logistics, load forecasts, and interregional energy transfers. Sustained reliability therefore depends on a variety of factors, including coordinated system operations, continued enhanced visibility into fuel supply and deliverability risks, better integration of cold weather generator data into operational decision-making, and more accurate weather forecasting. Looking ahead, continuing to strengthen system readiness—across planning, fuel assurance, and cold weather operating practices—will be essential to enhancing reliability during future multiday arctic cold events.

APPENDIX : TEAM MEMBERS LIST

Federal Energy Regulatory Commission:

Robert Clark (Team Co-Lead)

Jeffrey Fang (Analyst Sub-team Lead)

Andrew Lerch*

Hampden T. Macbeth (Team Co-Lead)

Chase Morgan

Kent Mottice (Natural Gas Sub-team Lead)

Eric Primosch

Nicholas Snyder

Andrew Ten Eyck

Daniel Woldermarium

North American Electric Reliability Corporation:

Valerie Carter-Ridley

Suzanne Edwards

Richard Hackman

Derek Kassimer

Matthew Lewis (Team Co-Lead)

Kiel Lyons (Team Co-Lead)

Jack Norris

Donna Pratt

Tony Tatum

Midwest Reliability Organization:

Jake Bernhagen

Eric Graftaas

Northeast Power Coordinating Council, Inc.:

Ryan McSherry

Joshua Jacobi

Andrey Oks

Lacy Skinner

Quintin Lee

ReliabilityFirst:

Dwayne Fewless

Kellen Phillips

SERC Reliability Corporation:

Hassan Hamdar

Jennifer Richards

Texas Reliability Entity, Inc.:

Mark Henry

David Penney

Western Electricity Coordinating Council:

Scott Rowley

* A Former FERC employee.

