FEBRUARY 2026

Operation of the U.S. Power Grid During Winter Storm Fern

ENERGY VENTURES ANALYSIS

Prepared for:

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Executive Summary

Winter Storm Fern was a roughly week-long North American extreme cold weather event, with core impacts from January 23 to February 1, 2026, bringing sustained Arctic cold, ice, and snow from Northern Mexico through the Southern United States into the Northeast and parts of Canada. At its peak, the storm affected an estimated 230 million people and contributed to more than one million customer outages across multiple regions. Unlike a brief cold snap, Winter Storm Fern brought several consecutive days of well-below-normal temperatures, placing prolonged stress on both electric and natural gas systems. Aggregate electricity demand across impacted regions peaked at approximately 500.6 GW on January 27, the 13th-highest demand day of the past decade, and remained consistently above 450 GW from January 21 through February 2, compared with roughly 385 GW during the first half of January. What distinguishes Winter Storm Fern from prior events such as the January 2025 Polar Vortex and Winter Storm Elliott is not peak magnitude but persistence: rather than a sharp, short-lived spike, Winter Storm Fern placed sustained, multi-day reliability pressure across every major power market region simultaneously. Key findings from the report include:

- **Critical Role of Dispatchable Thermal Generation:** Roughly 79% of the incremental electricity demand on the peak demand day was met by fossil-fuel generation. Natural gas led the operational response, increasing output by approximately 51 GW relative to early-January averages, followed by coal at approximately 39 GW. At the peak demand hour — 8:00 AM on January 27 — natural gas ramped to approximately 236 GW (+83 GW) and coal to nearly 110 GW (+40 GW). Oil-fired generation, normally a minimal contributor, added approximately 16 GW during the peak hour, primarily in the Northeast, where dual-fuel units drew on on-site oil storage to compensate for tight pipeline gas availability.

- **Surge in Coal Utilization Across All Regions:** At the regional aggregate level, coal capacity factors rose from approximately 46% in the first half of January to roughly 72% during the storm, with individual regions reaching considerably higher. In SPP, coal capacity factors surged from approximately 43% to nearly 90%, and coal and natural gas output rose by roughly 96% and 116%, respectively, at the peak demand hour. In PJM, coal capacity factors rose from approximately 51% to 81%, and coal output increased by over 11 GW. In the Southeast, which set an all-time regional demand record with peak hourly load approaching 171 GW, coal capacity factors rose from 37% in early January to 71% during the storm. Nuclear units maintained approximately 100% utilization throughout the event, consistent with their baseload role, while wind and solar output remained constrained by adverse weather and early-morning winter timing.

- **Coal as a De Facto Price Hedge:** Beyond their operational contributions, coal-fired power plants served as a critical financial buffer for electricity consumers. Coal fuel costs remained largely stable throughout the storm, while natural gas prices increased 7- to 13-fold across regions, rising above $87/MMBtu in PJM at the peak. Because coal displaced higher-cost natural gas at the margin, its continued dispatch suppressed the marginal system energy price materially relative to a coal-absent scenario. Day-ahead power prices at the PJM Hub reached approximately $850/MWh on January 27, a new all-time high; without coal available, prices would have been substantially higher still.

- **Estimated Consumer Savings Exceeding $1.1 Billion:** EVA estimated the system energy price on each RTO's peak demand day under two scenarios: the actual dispatch stack and a hypothetical stack with no coal generation. In SPP, removing coal is estimated to have raised the system energy price from approximately $238/MWh to over $425/MWh, saving consumers approximately $195 million on January 24 alone. In ERCOT, the equivalent savings on January 25 are estimated at approximately $185 million. In MISO, coal suppressed system energy prices by nearly $200/MWh on January 26, saving consumers over $420 million. In PJM, the coal fleet saved consumers approximately $347 million on January 30. Across these four RTOs, the coal fleet saved consumers an estimated $1.1 billion on their respective peak demand days. These figures are conservative: they reflect only the system energy price component of wholesale prices, cover only each region's single peak day, and exclude the impact on congestion, line-loss, and scarcity pricing, all of which would have risen materially as reserve margins tightened in coal's absence.

Winter Storm Fern underscores the indispensable role of dispatchable generation, particularly coal, in maintaining grid reliability and controlling wholesale power costs during sustained extreme weather events. The storm's duration, rather than any single peak hour, defined its reliability challenge: grid operators required thermal resources capable of sustaining high output for ten or more consecutive days, not merely ramping for a brief spike. Coal-fired power plants, with their on-site fuel storage and stable delivered fuel costs, proved structurally well-suited to this challenge across every affected region. These findings reinforce the importance of a balanced resource mix that retains resilient, dispatchable assets alongside variable renewables, and highlight the substantial and ongoing financial value those assets provide to electricity consumers when extreme weather conditions arrive.

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Introduction

Winter Storm Fern was an approximately week-long North American weather event, with core impacts from January 23 to February 1, 2026, bringing sustained Arctic cold, ice, and snow from Northern Mexico through the Southern United States into the Northeast and parts of Canada. At peak impact, the storm affected an estimated 230 million people and contributed to more than one million customer outages across multiple regions. Unlike a brief cold snap, Fern delivered several consecutive days of below-normal temperatures, creating prolonged stress across both electric and natural gas systems.

The cold outbreak drove electricity demand to near-record or record winter levels across major power markets, including PJM and the broader Northeast. Aggregate demand across impacted regions peaked at roughly 500 GW on January 27th, January 31st, and again on February 1st, reflecting not only the severity but also the persistence of the event. In contrast to earlier January conditions, which largely tracked within seasonal norms, Winter Storm Fern's arrival in the latter half of the month produced sustained deviations from typical winter load patterns. Unlike prior winter events such as the January 2025 Polar Vortex and Winter Storm Elliott, Fern was characterized by elevated demand sustained over an extended period rather than a sharp, short-lived spike. This prolonged pressure tested grid flexibility and resource adequacy as system operators managed high load for multiple consecutive days.

For this report, the first half of January is treated as the baseline for typical winter operations. From the perspective of electric grid operations performance and its analysis, this report considers the core duration of the storm in late January and the cold weather that followed into early February collectively as Winter Storm Fern. The following analysis isolates the incremental impacts of Winter Storm Fern on demand, generation mix, and system performance relative to these early-January conditions, highlighting the operational response and resource contributions during a period of sustained cold-weather stress.

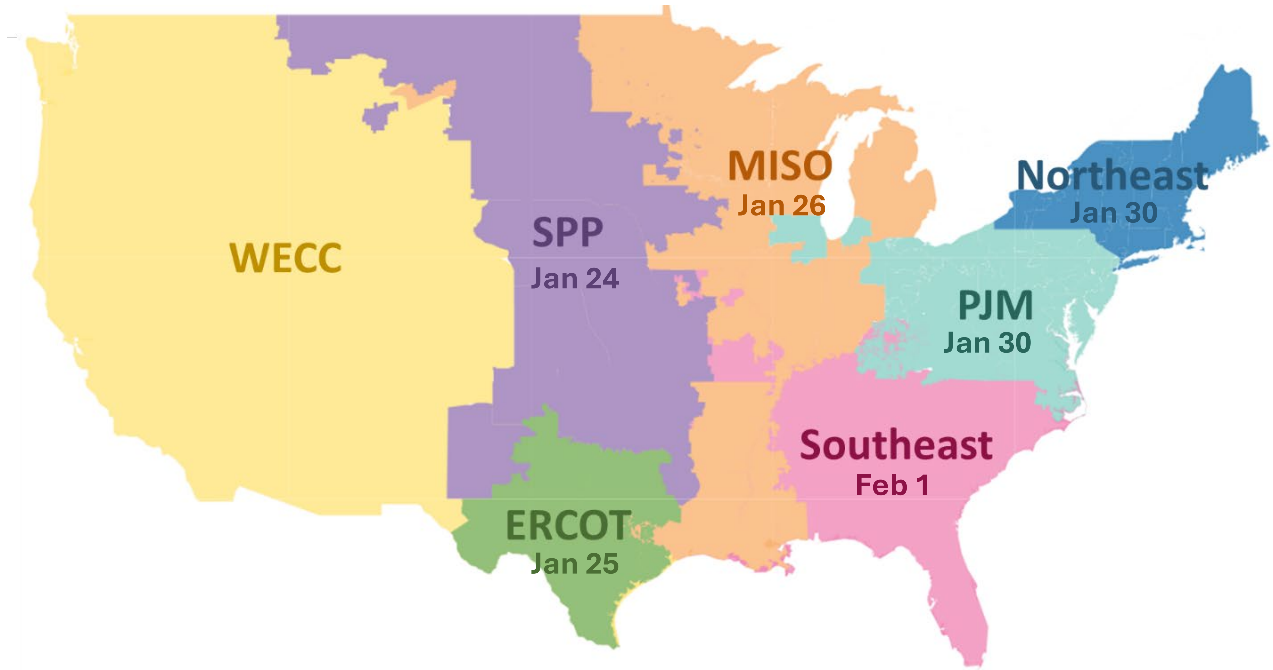
Part I: Regional Power Market Analysis

Using EIA's regional data from the Hourly Electric Grid Monitor, EVA performed analyses of the impact and performance of the power market regions shown in **EXHIBIT 1**, excluding WECC. [1,2] The power market regions are presented in the order of the winter storm's impacts on their respective power systems.

[1] Northeast = EIA Grid Monitor regions NY & NE; PJM = MIDA; Southeast = TEN, CAR, SE & FLA; MISO = MIDW; ERCOT = TRE; SPP = CENT; WECC = NW, SW & CAL. Further details on which balancing authorities make up the EIA regions can be found here: https://www.eia.gov/electricity/930-content/EIA930_Reference_Tables.xlsx

[2] WECC is excluded from the report as the data analysis showed little impact on the WECC power systems during Winter Storm Fern.

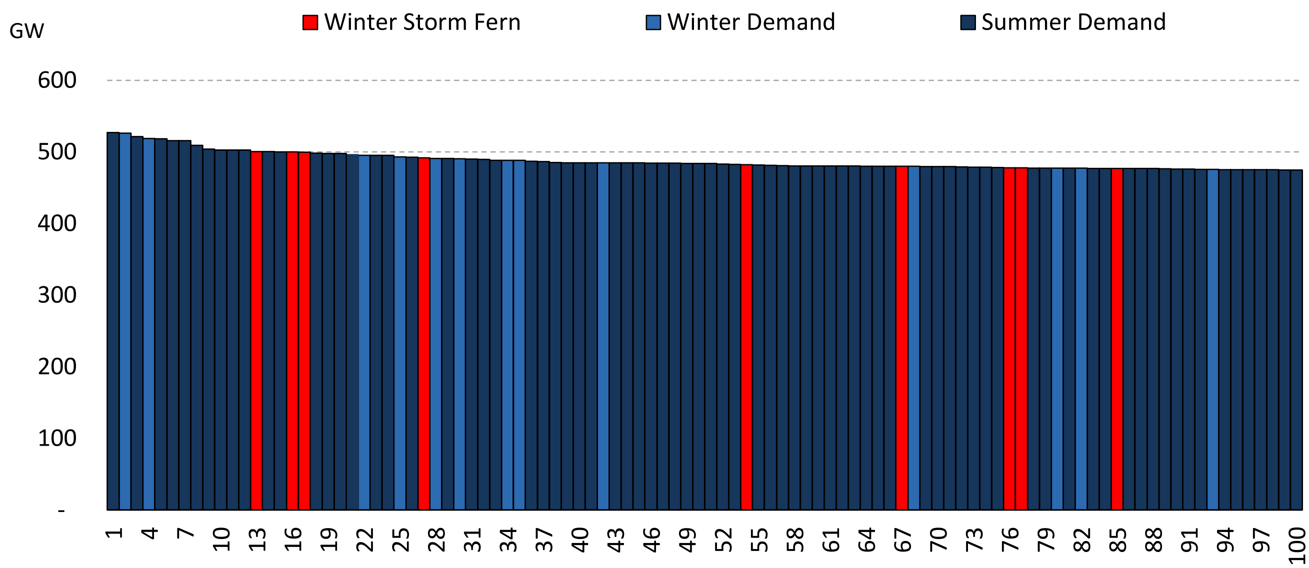
EXHIBIT 1: MAP OF POWER MARKET REGIONS & PEAK DEMAND DAY OF WINTER STORM FERN



Regional Aggregate Results

Between January 21 and February 2, much of the Lower-48 experienced temperatures well below the ten-year average, leading to sustained elevated electricity demand. **EXHIBIT 2** shows the top 100 electricity demand days across the combined footprints of SPP, ERCOT, MISO, PJM, the Northeast (NYISO and ISONE), and the Southeast. Winter Storm Fern produced the 13th-highest demand day of the past decade, with aggregate load reaching approximately 500.6 GW on January 27. Notably, demand pressures began building as early as January 15 during earlier cold spells. They remained consistently elevated, averaging well above 450 GW from January 21 through February 2, compared with roughly 385 GW during the first half of January. While higher absolute peaks were observed during the January 2025 Polar Vortex, those levels were exceeded only briefly; in contrast, Fern was characterized by a longer duration and greater persistence of elevated load, placing prolonged stress on the system across multiple regions simultaneously.

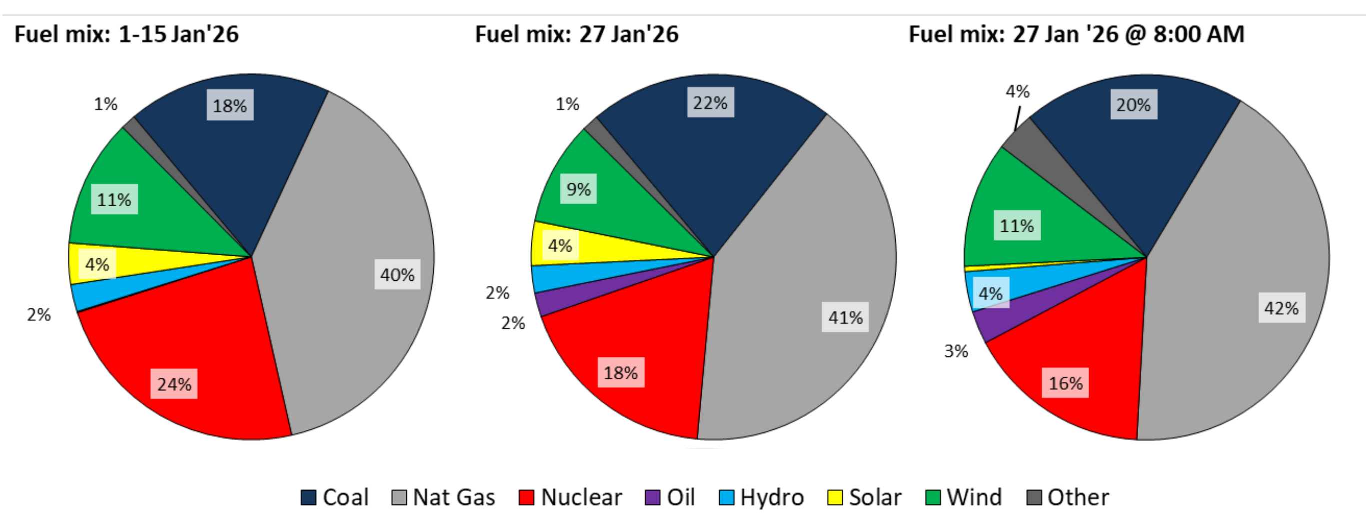
EXHIBIT 2: REGIONAL TOTAL - TOP 100 ELECTRICITY DEMAND DAYS



Source: EIA Hourly Grid Monitor

On a broader scale, the highest aggregate electricity demand during the event occurred on January 27, peaking at 8:00 AM. The storm's prolonged duration led to similarly elevated demand later in the period, with load reaching approximately 500 GW on February 1 and 499.7 GW on January 31. A comparison of the generation mix on the peak-demand day and hour with the average hourly mix from the first half of January shows continued reliance on natural gas and coal, followed by nuclear and wind. The overall fuel composition on January 27, including during the peak hour, remained broadly consistent with the seasonal baseline, suggesting that incremental demand was largely met through proportional increases in dispatchable thermal resources, particularly natural gas and coal, as shown in **EXHIBIT 3**. As expected, solar output was limited during early-morning winter hours and declined to minimal levels at the 8:00 AM peak, contributing little to system supply at the time of maximum demand.

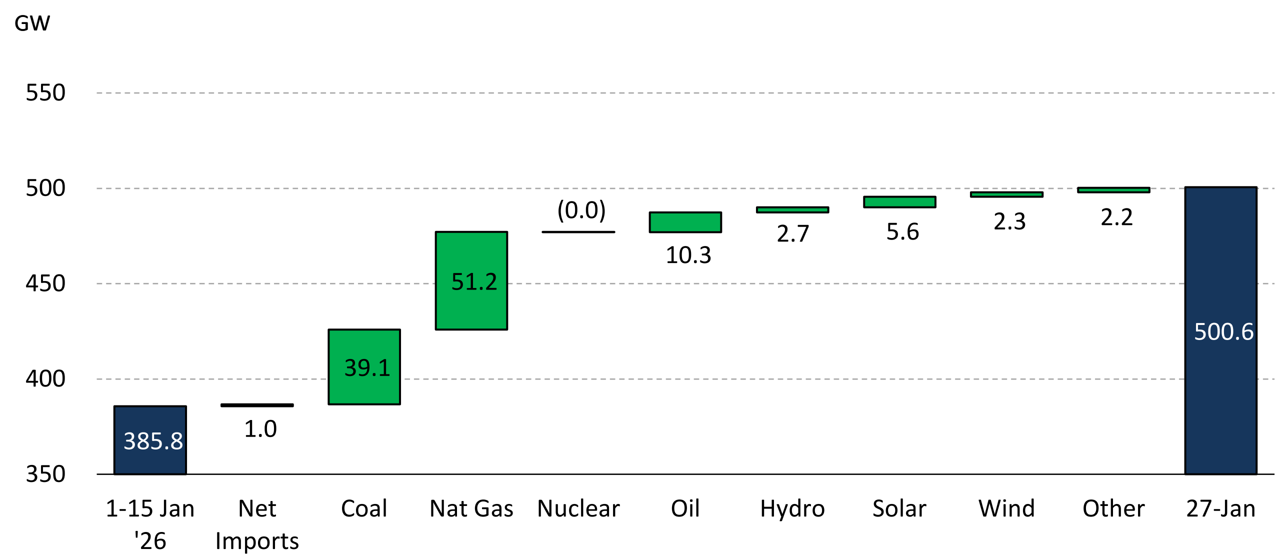
EXHIBIT 3: REGIONAL TOTAL - GENERATION MIX



Source: EIA Hourly Grid Monitor

During Winter Storm Fern, electricity demand peaked on January 27, rising nearly 115 GW above the average hourly demand observed during the first half of January. Roughly 79% of this incremental load was met by fossil fuel generation, led by natural gas and coal, which increased output by 51.2 GW and 39.1 GW, respectively, relative to their early-January hourly averages, as shown in **EXHIBIT 4**. Oil-fired generation, which typically contributes less than 1 GW, also saw a notable increase, adding more than 10 GW, primarily in the Northeast, to support system reliability during peak conditions. On the renewable side, wind and hydro together provided roughly 8 GW of additional generation, while solar contributed an incremental 2 GW, reflecting both seasonal limitations and the challenges from inclement weather.

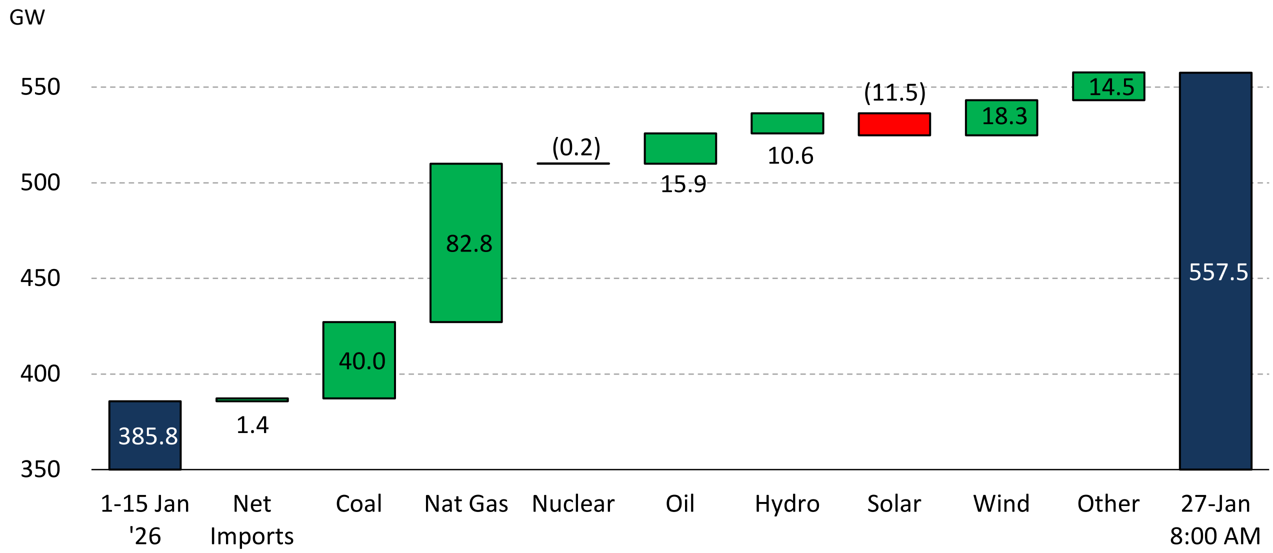
EXHIBIT 4: REGIONAL TOTAL - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY OF WINTER STORM FERN



Source: EIA Hourly Grid Monitor

At the peak demand hour on January 27 at 8:00 AM, regional electricity load rose to approximately 557.5 GW, nearly 172 GW above the average hourly demand observed during the first half of January. Similar to the daily comparison, the majority of the incremental demand was met by fossil fuel generation, with natural gas increasing by roughly 83 GW to 236.2 GW and coal by about 40 GW to 109.9 GW, as illustrated in **EXHIBIT 5**. Oil-fired generation also contributed meaningfully, adding nearly 16 GW from its early January average, reflecting its role as a reliability backstop during extreme conditions. On the renewable side, wind generation increased by approximately 18 GW and hydro by about 11 GW. In comparison, solar output declined by roughly 12 GW due to the early-morning timing of the peak and limited winter irradiance. Net imports and other resources provided modest additional support. This operational pattern indicates the system's reliance on dispatchable thermal generation to meet sharp surges and prolonged elevated demand during the peak hour.

EXHIBIT 5: REGIONAL TOTAL - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR OF WINTER STORM FERN

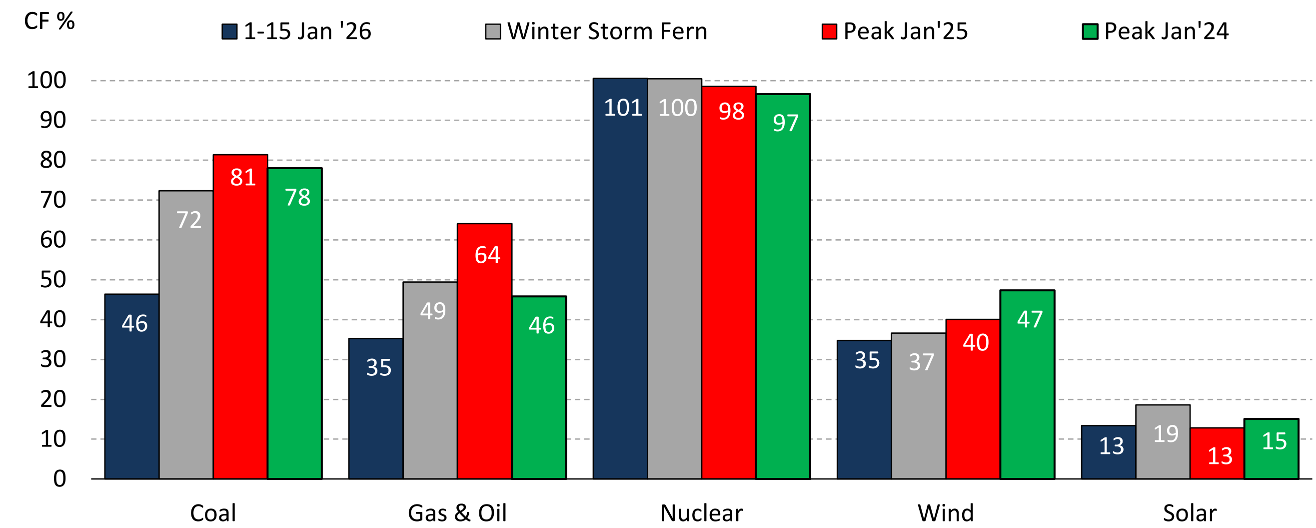


Source: EIA Hourly Grid Monitor

EXHIBIT 6 illustrates regional capacity factors by fuel type for Winter Storm Fern, compared with January 1-15, 2026, and with previous January peak events. Capacity factors effectively measure how different resources respond and remain available during extreme weather events like Winter Storm Fern, the January 2025 Polar Vortex, and the January 2024 Winter Storm, excluding any resource additions or retirements between these events. This provides a fairer view of each resource type's performance and shows how their dispatchability varies during such critical periods. The values represent the average utilization of all operational generators of each fuel type, regardless of individual unit availability during these periods. During Fern, coal capacity factors increased significantly from about 46% in early January to approximately 72%, highlighting coal's importance as a dispatchable resource in cold conditions. Gas and oil units also experienced higher utilization, with capacity factors rising from roughly 35% to nearly 49%, indicating increased thermal dispatch to meet higher demand.

Nuclear units continued to operate at or near full capacity, maintaining approximately 100% utilization during the event, consistent with prior winter peak periods and highlighting their baseload reliability. Wind capacity factors rose modestly relative to the early-January average, while solar remained comparatively limited due to seasonal and daylight constraints. Overall, the data indicate that Winter Storm Fern drove a broad-based increase in thermal unit utilization, with coal and natural gas providing the bulk of incremental reliability support, while nuclear maintained consistently high output and renewables contributed opportunistically where available.

EXHIBIT 6: REGIONAL TOTAL - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



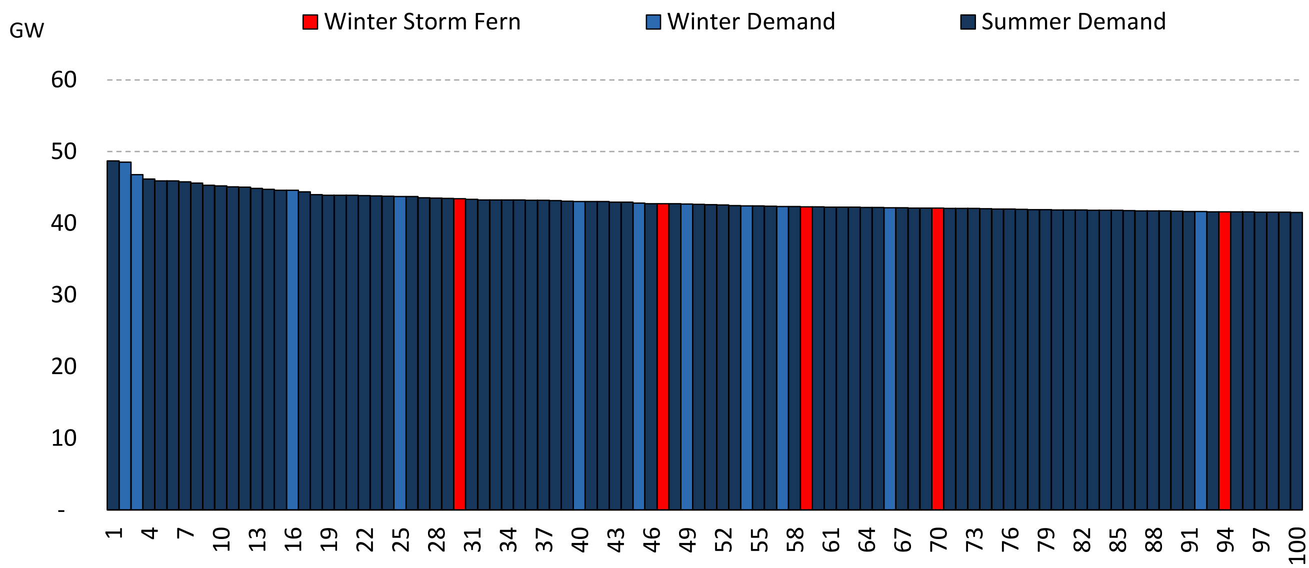
Source: EIA Hourly Grid Monitor & EIA 860 data

Southwest Power Pool

The Southwest Power Pool (SPP) is an independent system operator that manages the bulk electric grid and wholesale power market across a large area of the central United States. It serves nearly 19 million customers in 17 states, ranging from North Dakota to Louisiana.

Average winter demand in SPP typically ranges between 30 and 35 GW. On January 24, 2026, during Winter Storm Fern, demand ranked as the 30th-highest winter demand day in the past decade, placing it firmly among the region's top historical winter load events, as illustrated by **EXHIBIT 7**. While the daily peak exceeded demand during the January 2025 Polar Vortex, it remained below the more extreme peaks recorded in February 2025 and during the January 2024 winter storm. **EXHIBIT 7** also notes that multiple Fern-related days appear within SPP's top 100 winter demand rankings, indicating that the event was not limited to a single spike but instead produced several consecutive high-load days clustered in the upper half of historical observations. This sustained presence among top-ranked days reinforces that the system experienced prolonged cold-driven demand pressure rather than a short-duration surge. On the highest-demand day, load reached approximately 43.4 GW, with the hourly peak occurring two days later on January 26 at 9:00 AM, when demand rose to 45.6 GW, reflecting continued system stress even after the initial daily peak.

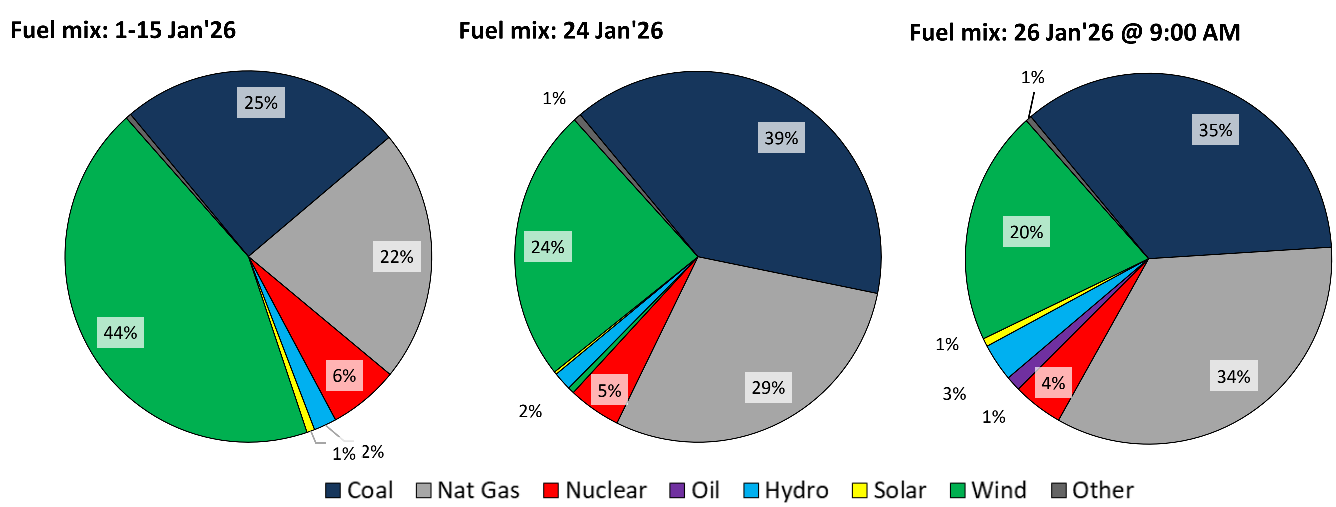
EXHIBIT 7: SPP - TOP 100 ELECTRICITY DEMAND DAYS



Source: EIA Hourly Grid Monitor

During the first half of January, wind accounted for approximately 44% of SPP generation. However, on January 24, the highest-demand day during Winter Storm Fern, wind's share fell to 24% as output moderated amid peak system stress. In response, dispatchable thermal resources increased their contribution, with coal becoming the dominant source at 39% of the mix, followed by natural gas at 29%. By the peak-demand hour on January 26 at 9:00 AM, coal and natural gas together accounted for roughly 69% of total generation, underscoring their role in maintaining reliability during extreme winter conditions. In absolute terms, wind generation averaged approximately 14.4 GW in the first half of January but declined to about 9.5 GW during the peak hour. This reduction in wind output necessitated a corresponding increase in coal and natural gas dispatch to balance the system and meet elevated demand.

EXHIBIT 8: SPP - GENERATION MIX

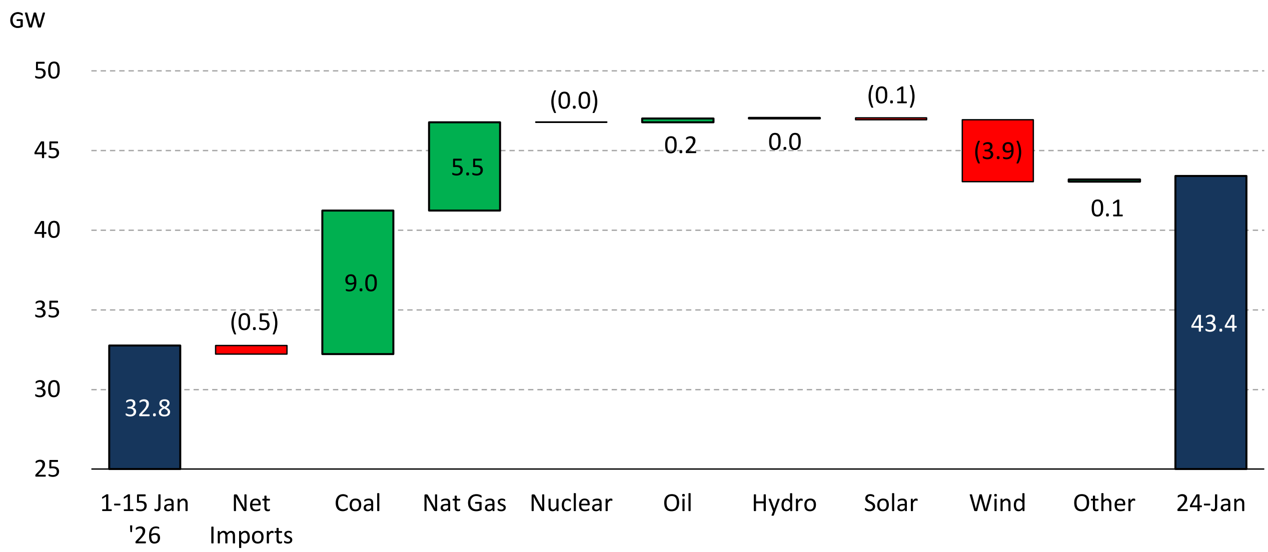


Source: EIA Hourly Grid Monitor

EXHIBIT 9 compares average hourly operations during January 1–15 with the peak-demand day of January 24 in SPP during Winter Storm Fern. Demand increased by approximately 11 GW, rising from an average of 32.8 GW in the first half of the month to 43.4 GW on the peak day. This increase was largely met by higher coal and natural gas dispatch, which rose by roughly 9 GW and 5.5 GW, respectively, relative to early-January averages.

At the same time, wind generation declined by approximately 3.9 GW due to adverse weather conditions, further widening the supply gap. As a result, the combined effect of higher demand and lower wind output was offset by additional coal and natural gas generation, underscoring the region's reliance on dispatchable thermal resources to maintain reliability during periods of extreme winter stress.

EXHIBIT 9: SPP - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY

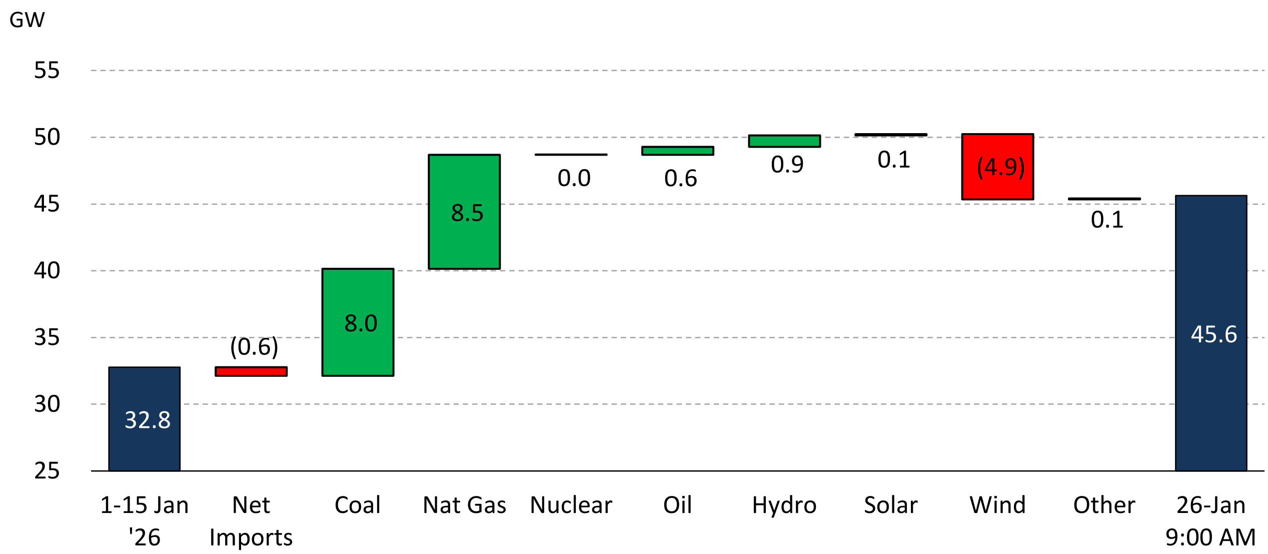


Source: EIA Hourly Grid Monitor

EXHIBIT 10 presents a comparison between average hourly operations during January 1-15 and the peak demand hour of Winter Storm Fern in SPP. The hourly system peak occurred at 9:00 AM on January 26, when demand rose to 45.6 GW, nearly 13 GW above the early-January hourly average of 32.8 GW.

During this peak hour, wind generation declined further, falling by approximately 4.9 GW from the first-half January average due to the prevailing weather conditions. In response, dispatchable thermal generation ramped up sharply. Coal and natural gas generation increased by a combined approximately 16.5 GW, more than offsetting both higher demand and the reduction in wind output. Compared to their early-January averages, coal and natural gas output rose by roughly 96% and 116%, respectively, underscoring the critical role these resources played in maintaining system balance during the most acute period of winter stress.

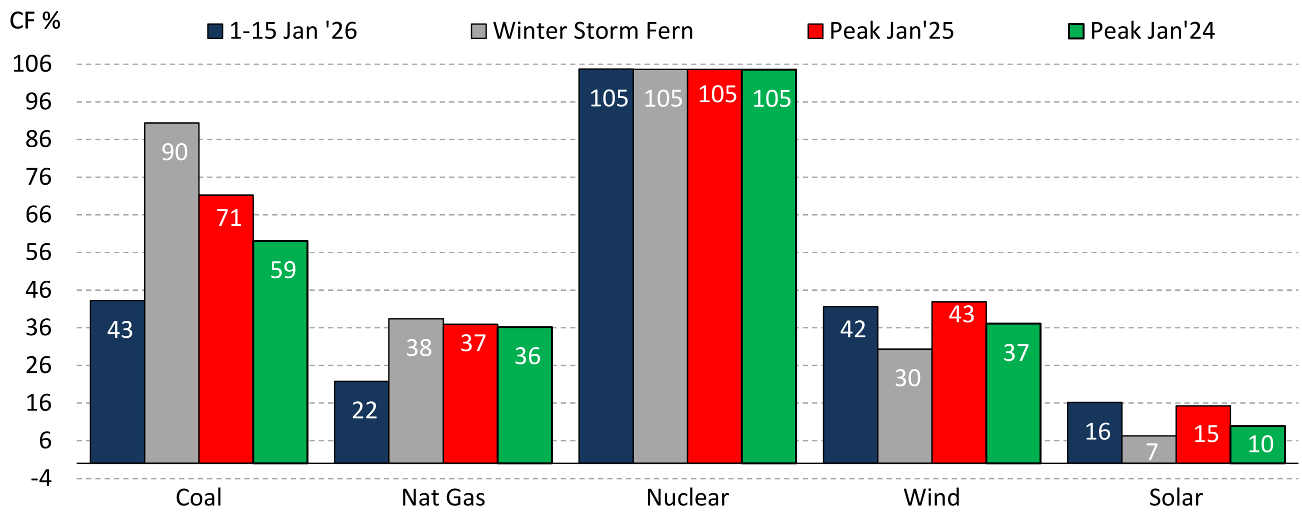
EXHIBIT 10: SPP - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



Source: EIA Hourly Grid Monitor

EXHIBIT 11 illustrates capacity factors by fuel type in SPP during January 1-15, 2026, Winter Storm Fern, and prior January peak events. Because installed capacity evolves year to year, capacity factors provide a more consistent basis for comparing how different resources respond during extreme weather conditions. During Winter Storm Fern, coal utilization rose sharply, increasing from approximately 43% in the first half of January to nearly 90%, reflecting its central role in meeting elevated demand. Coal output had already begun trending higher in the second week of January as colder temperatures increased system load ahead of the storm. Natural gas capacity factors also increased materially, rising from roughly 22% to 38%, indicating stronger thermal dispatch during peak conditions. Nuclear generation remained steady at full utilization (around 105%), consistent with its baseload role. In contrast, variable renewable resources exhibited greater volatility. Wind capacity factors declined relative to prior peak periods and were lower during the storm compared to the January 2025 peak, reflecting weather-related variability. Solar utilization also fell from approximately 16% in early January to 7% during Fern, likely due to reduced winter irradiance and snow cover. Overall, the data highlights the increased reliance on dispatchable thermal resources during sustained winter stress, while renewable output remained subject to prevailing weather conditions.

EXHIBIT 11: SPP - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



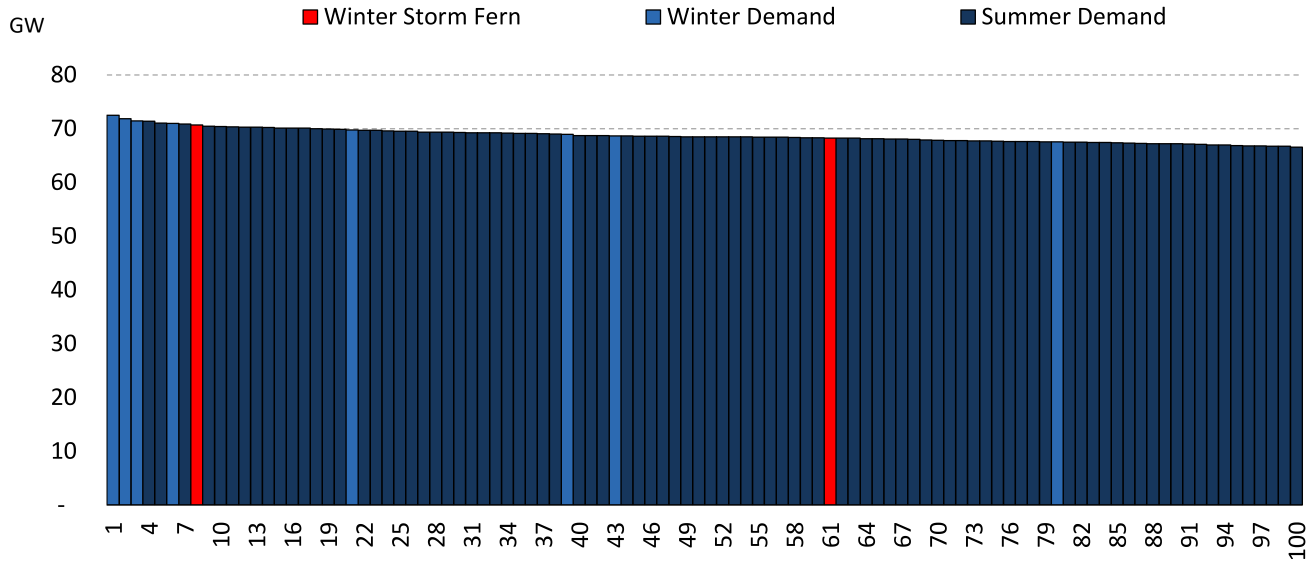
Source: EIA Hourly Grid Monitor & EIA 860 data

ERCOT

The Electric Reliability Council of Texas (ERCOT) is an independent system operator (ISO) that operates exclusively within Texas. It oversees the management of the bulk electric power grid, serving over 26 million Texans, who represent approximately 90% of the state's electric load.

During the first half of January 2026, ERCOT averaged approximately 49.2 GW of demand, with load steadily climbing as colder weather set in mid-month. As temperatures declined, natural gas generation increased proportionally, reflecting its role as the system's primary marginal fuel. By January 25, daily average demand had surged to 70.7 GW, and the hourly peak reached 75.6 GW at 9:00 AM on January 26, placing Winter Storm Fern among ERCOT's top winter demand events of the past decade, as shown in **EXHIBIT 12**. Notably, while natural gas output ramped gradually alongside rising demand throughout January, coal generation remained comparatively stable until the onset of full winter storm conditions. Only during the most acute period of cold and peak demand did coal units meaningfully increase output, providing incremental reliability support. Although Fern produced near-record winter load, it remained below the extreme peaks recorded during the January 2024 winter storm and the August 2023 heatwave. The chart shows that, while ERCOT is structurally summer-peaking, sustained Arctic conditions can drive winter demand close to historic highs and shift dispatch dynamics toward increased thermal utilization.

EXHIBIT 12: ERCOT - TOP 100 ELECTRICITY DEMAND DAYS

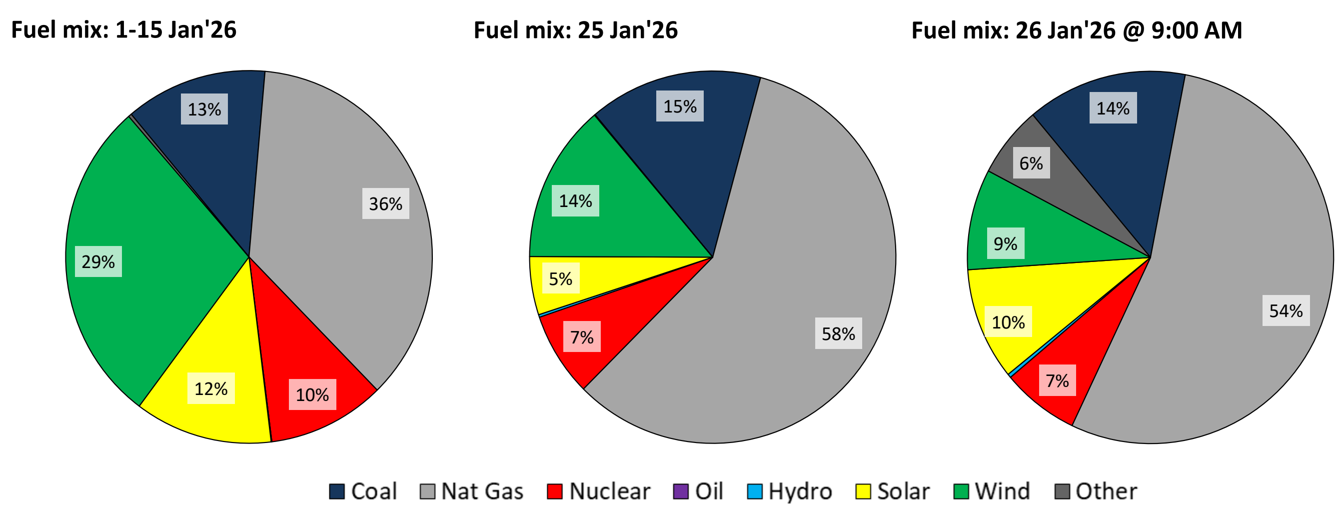


Source: EIA Hourly Grid Monitor

In the first half of January, ERCOT's generation mix was led by natural gas (36%) and wind (29%), with coal (13%), nuclear (10%), and solar (12%) accounting for the remaining share. As shown in **EXHIBIT 13**, seasonal factors limited renewable output during the winter months. Reduced solar irradiation, shorter daylight hours, and periods of snowfall constrained solar generation, while colder and more variable weather conditions affected wind output. As a result, ERCOT increasingly relied on thermal resources as demand trended upward through January.

By January 25, the event's peak daily demand, natural gas generation ramped sharply, increasing its share of the fuel mix to 58%. During the peak demand hour on January 26 at 9:00 AM, natural gas continued to supply the majority of system demand at 54%, demonstrating its role as the primary marginal and balancing resource in ERCOT during extreme winter conditions. Coal's share rose modestly from early January levels, reflecting incremental dispatch during peak stress, while wind's contribution declined materially from its early-January share. Overall, the data highlight ERCOT's dependence on natural gas to meet rapid demand increases during winter storm events, with coal providing secondary baseload reliability support.

EXHIBIT 13: ERCOT - GENERATION MIX

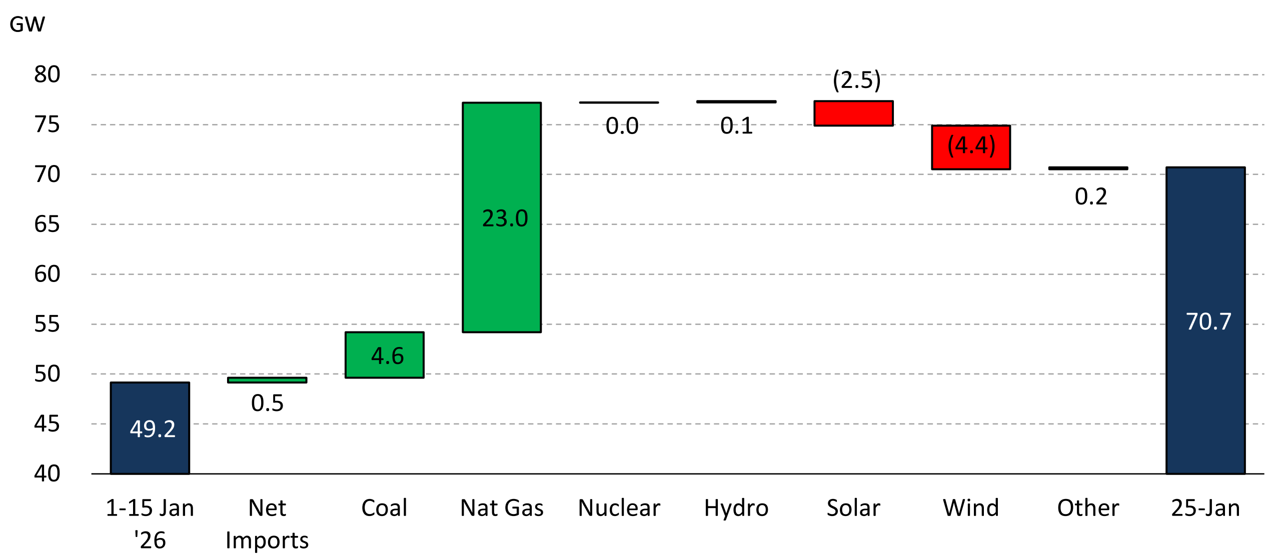


Source: EIA Hourly Grid Monitor

EXHIBIT 14 and **EXHIBIT 15** compare demand and generation by fuel type during the peak demand day and hour of Winter Storm Fern with the average hourly operations observed in the first half of January 2026. On January 25, the daily average demand increased by more than 20 GW, rising from 49.2 GW to 70.7 GW. Consistent with prior extreme winter events — including the January 2025 Polar Vortex and the January 2024 winter storm — natural gas served as the primary balancing resource. As shown in **EXHIBIT 14**, natural gas generation increased by approximately 23 GW relative to early-January averages, accounting for over 80% of the incremental demand during the peak day.

Coal generation also rose by roughly 4.6 GW compared to the first half of January, reflecting higher utilization as colder temperatures set in mid-month. In contrast, wind generation declined by about 4.4 GW on the peak day, partially offsetting renewable contributions and further reinforcing reliance on thermal dispatch. Solar output also decreased modestly, while nuclear and hydro remained largely unchanged.

EXHIBIT 14: ERCOT - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY

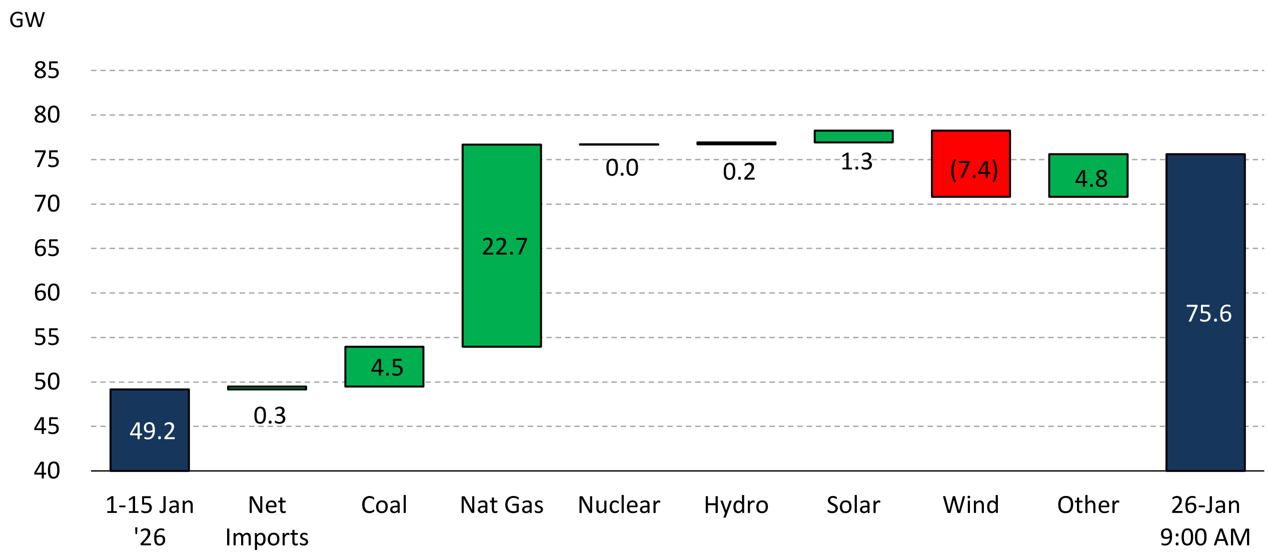


Source: EIA Hourly Grid Monitor

During Winter Storm Fern, ERCOT's system peak occurred at 9:00 AM on January 26, when demand reached 75.6 GW, nearly 5 GW higher than the previous day's average peak and approximately 26.4 GW above the average hourly demand observed during the first half of January. This sharp increase was met primarily by natural gas generation, which ramped up by 22.7 GW relative to early-January levels, supplying roughly 40.6 GW during the peak hour. Coal generation also increased by about 4.5 GW, contributing approximately 10.6 GW to the total supply.

In contrast, wind output declined materially, falling by 7.4 GW compared to the first half of January's average and producing only about 6.6 GW during the peak hour. Nuclear, hydro, and other resources remained largely stable. Overall, the data reinforce that the incremental surge in peak-hour demand, combined with reduced wind output, was predominantly offset by natural gas, with coal providing secondary support during the most acute period of winter system stress.

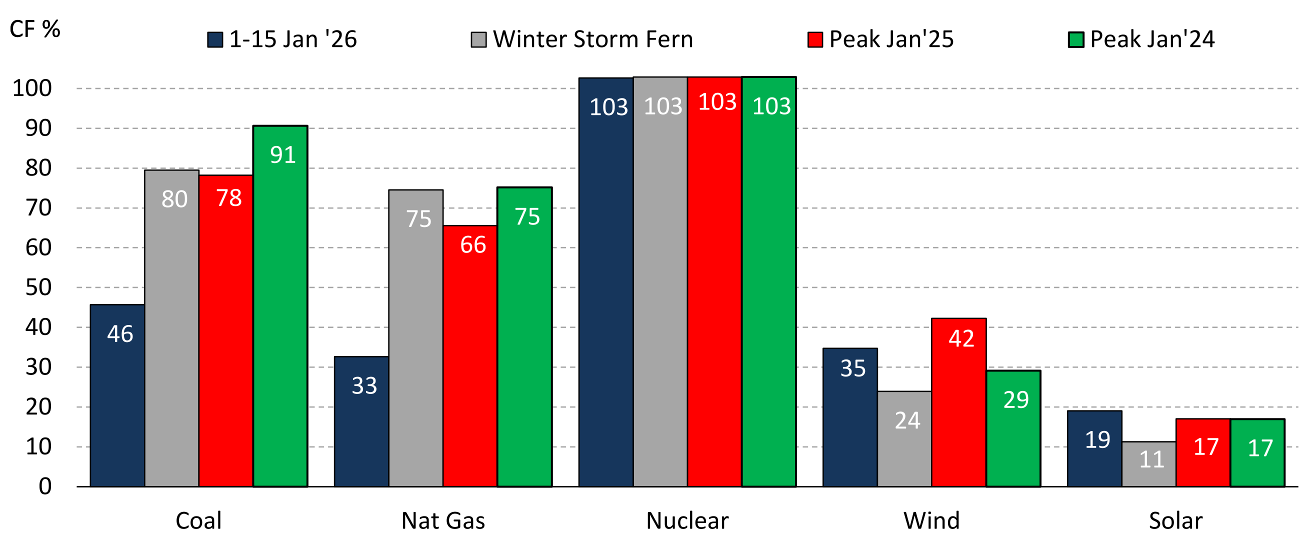
EXHIBIT 15: ERCOT - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



Source: EIA Hourly Grid Monitor

EXHIBIT 16 shows capacity factors by fuel type in ERCOT for January 1–15, Winter Storm Fern, and prior January peak events. On the peak day of Winter Storm Fern, coal and natural gas units operated at average capacity factors of approximately 80% and 75%, respectively, a substantial increase from their early-January averages of 46% and 33%. This sharp rise in utilization emphasizes the heavy reliance on thermal generation to meet elevated winter demand. Nuclear units continued operating at or near full capacity (around 103%) across all periods, reinforcing their baseload reliability. Wind capacity factors fell to roughly 24% during Fern, comparable to prior winter storm events such as January 2024 (29%) and Winter Storm Elliott (26%), though notably below the January 2025 Polar Vortex peak (42%). As expected, wind output varied with prevailing weather conditions. Solar capacity factors also declined modestly from 19% in early January to 11% during Fern, reflecting reduced winter irradiance and potential snow cover impacts.

EXHIBIT 16: ERCOT - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



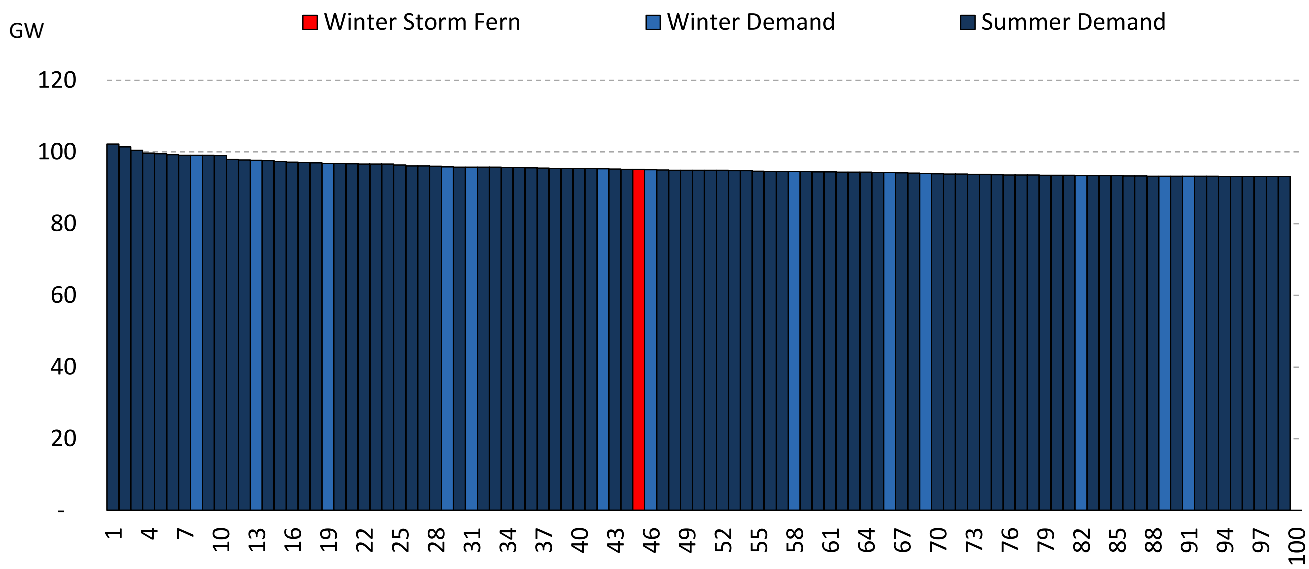
Source: EIA Hourly Grid Monitor & EIA 860 data

MISO

MISO (Midcontinent Independent System Operator) is the second-largest Independent System Operator in the U.S., responsible for managing the flow of electricity across 15 states and serving over 45 million customers.

During the first half of January, MISO averaged approximately 74.6 GW of hourly electricity demand. During Winter Storm Fern, demand increased meaningfully, with the highest storm-related day reaching roughly 95 GW. As shown in **EXHIBIT 17**, this places Fern within MISO's top 100 winter demand days, though it does not rank among the system's most extreme historical peaks, which exceed 100 GW. Unlike prior record-setting winter events, Fern's impact in MISO was characterized more by sustained elevated demand rather than a single exceptional spike. While the magnitude of the peak was moderate relative to historical highs, the persistence of higher load levels over multiple consecutive days contributed to continued operational pressure across the region during the storm.

EXHIBIT 17: MISO - TOP 100 ELECTRICITY DEMAND DAYS

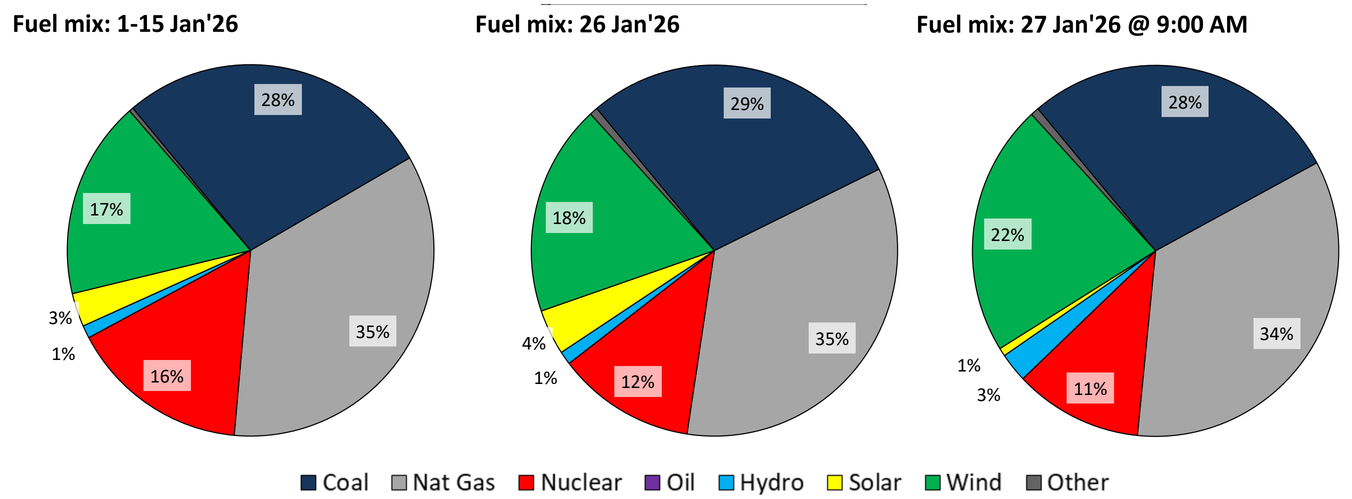


Source: EIA Hourly Grid Monitor

EXHIBIT 18 illustrates the average generation mix in MISO during January 1-15, the peak demand day of Winter Storm Fern (January 26), and the peak demand hour at 9:00 AM the following morning. Under typical early-January conditions, coal (28%) and natural gas (35%) together account for roughly 63% of total generation, with wind contributing about 17%. Nuclear provides a steady ~16%, while hydro and solar represent comparatively small shares of the mix.

During the peak demand day and the subsequent peak hour, the overall composition of the fuel mix remained broadly consistent with early-January averages. Coal and natural gas continued to supply approximately two-thirds of total generation, while wind's share increased modestly to around 18–22% during peak conditions. Nuclear output remained stable, reflecting its baseload role. Because the system peak occurred during winter morning hours, solar contribution was minimal. Overall, incremental demand during Fern was met through proportional increases across major dispatchable resources rather than a structural shift in the generation mix.

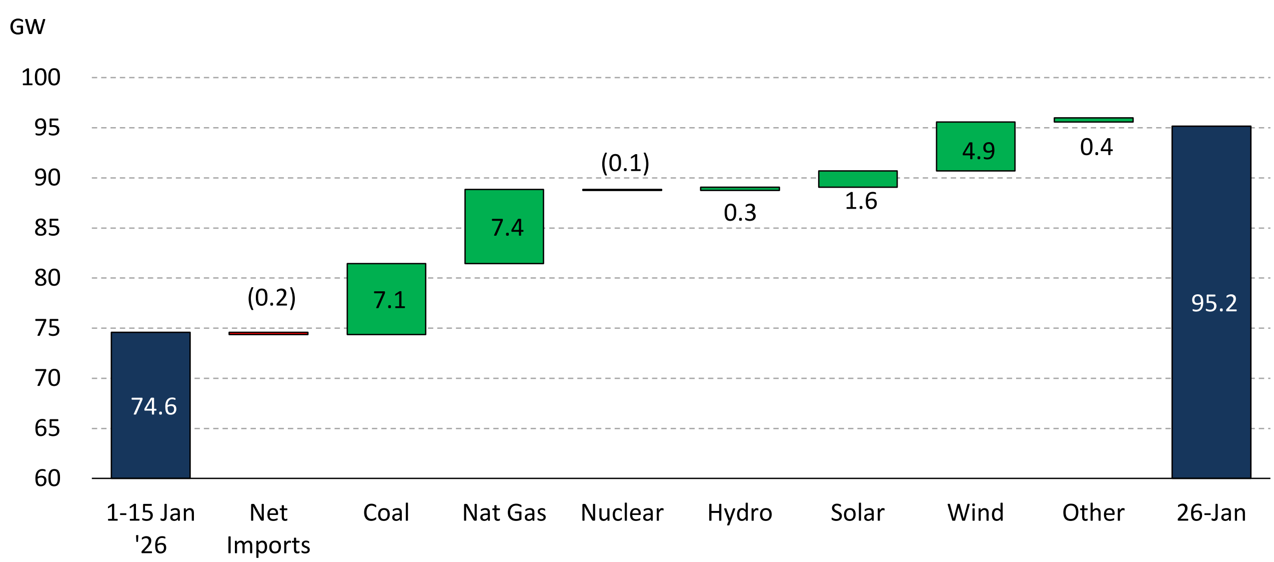
EXHIBIT 18: MISO - GENERATION MIX



Source: EIA Hourly Grid Monitor

EXHIBIT 19 compares the average generation during January 1–15 with the peak demand day of Winter Storm Fern on January 26. Daily average demand rose to 95.2 GW, approximately 20 GW above the early-January average of 74.6 GW. Coal generation, which had already been elevated due to colder mid-month temperatures, increased by an additional 7.1 GW on January 26, reaching roughly 28.1 GW. Natural gas generation similarly rose by about 7.4 GW relative to the first-half January average, increasing from approximately 26.2 GW to 33.6 GW — a gain of roughly 28%. Wind generation also contributed meaningfully on the peak day, rising by about 4.9 GW compared to early-January averages, though its output remained variable throughout the storm. For example, wind generation was closer to 14–15 GW during morning hours but increased to nearly 23–24 GW later in the evening. Nuclear and hydro output remained relatively stable, while net imports were largely unchanged. Overall, the incremental demand during Fern was met through broad-based increases in coal and natural gas dispatch, supplemented by higher wind output, rather than a structural shift in the resource mix.

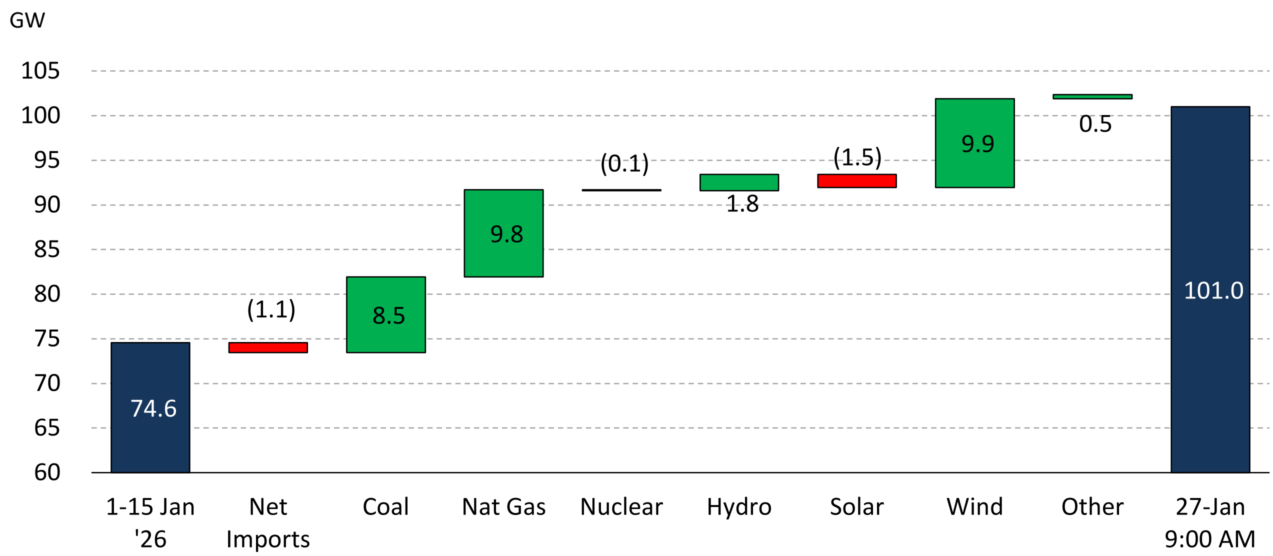
EXHIBIT 19: MISO - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY



Source: EIA Hourly Grid Monitor

EXHIBIT 20 compares the average generation profile for January 1–15 with the peak demand hour during Winter Storm Fern in MISO. The system peak reached approximately 101 GW. Wind availability played a meaningful role in shaping dispatch patterns during this period. At the 9:00 AM peak hour, wind generation was approximately 22.9 GW, while natural gas and coal generation amounted to roughly 36 GW and 29.5 GW, respectively. Although wind output was relatively strong during the morning peak, demand remained elevated above 90 GW throughout much of the day. As wind generation later declined to approximately 14 GW, coal and natural gas units increased output to maintain system balance. This intra-day variability highlights that while wind provided substantial support during the peak hour itself, dispatchable thermal resources ultimately absorbed fluctuations in renewable output and sustained reliability during prolonged high-demand conditions.

EXHIBIT 20: MISO - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR

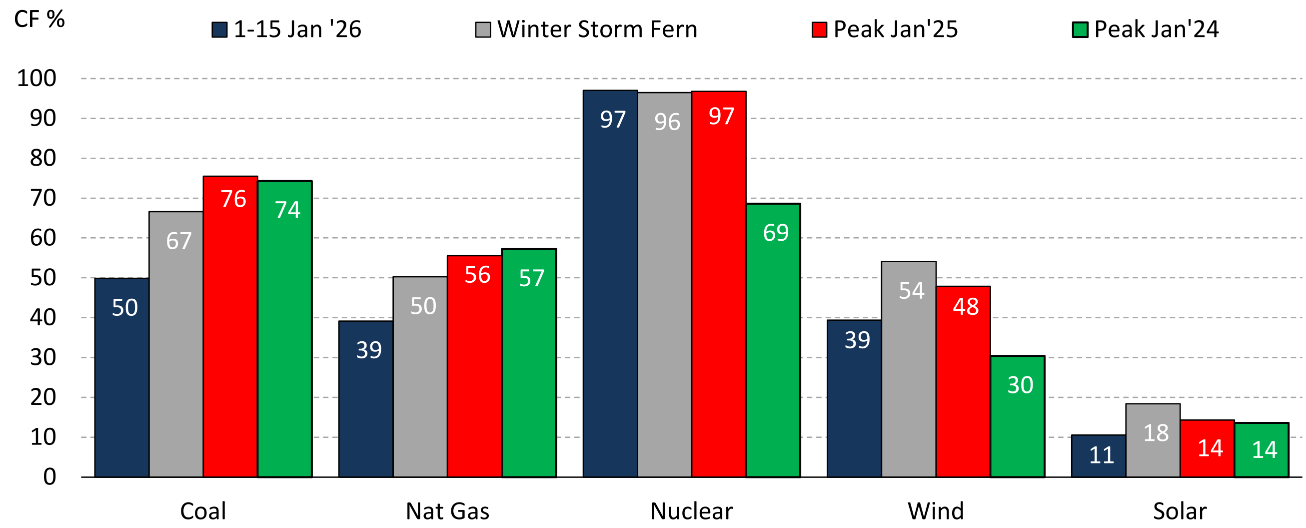


Source: EIA Hourly Grid Monitor

EXHIBIT 21 compares capacity factors by fuel type in MISO for January 1-15, Winter Storm Fern, and prior January peak events. During Winter Storm Fern, coal and natural gas operated at materially higher utilization levels relative to early-January averages. Coal capacity factors rose from roughly 50% in the first half of January to approximately 67% during the storm, while natural gas rose from about 39% to 50%. Notably, coal utilization exceeded 70% during portions of the storm outside the single peak day, reflecting sustained thermal dispatch during periods of lower wind availability. Natural gas units had already been operating at elevated utilization levels since mid-January as temperatures declined and continued to do so throughout the storm. Wind capacity factors improved during the peak day of January 26 and the peak hour on January 27, reaching roughly 54% during Fern — higher than early-January averages of about 39%. This increase reflects favorable wind conditions during the peak period itself. However, as observed in prior events, wind output remained weather-dependent and varied intra-day. While Fern saw solid wind performance, it did not reach the sustained >65% capacity factors observed during events such as Winter Storm Elliott, highlighting the variability of wind availability across extreme weather events.

Solar capacity factors increased modestly from approximately 11% in early January to around 18% in Fern, though overall contribution remained limited by winter irradiance and shorter daylight hours. Nuclear generation remained consistently near full utilization (mid- to high-90% range), reinforcing its baseload role. Overall, the data indicate that while wind provided meaningful support during peak conditions, coal and natural gas operated at significantly elevated capacity factors for a prolonged period to ensure system reliability.

EXHIBIT 21: MISO - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



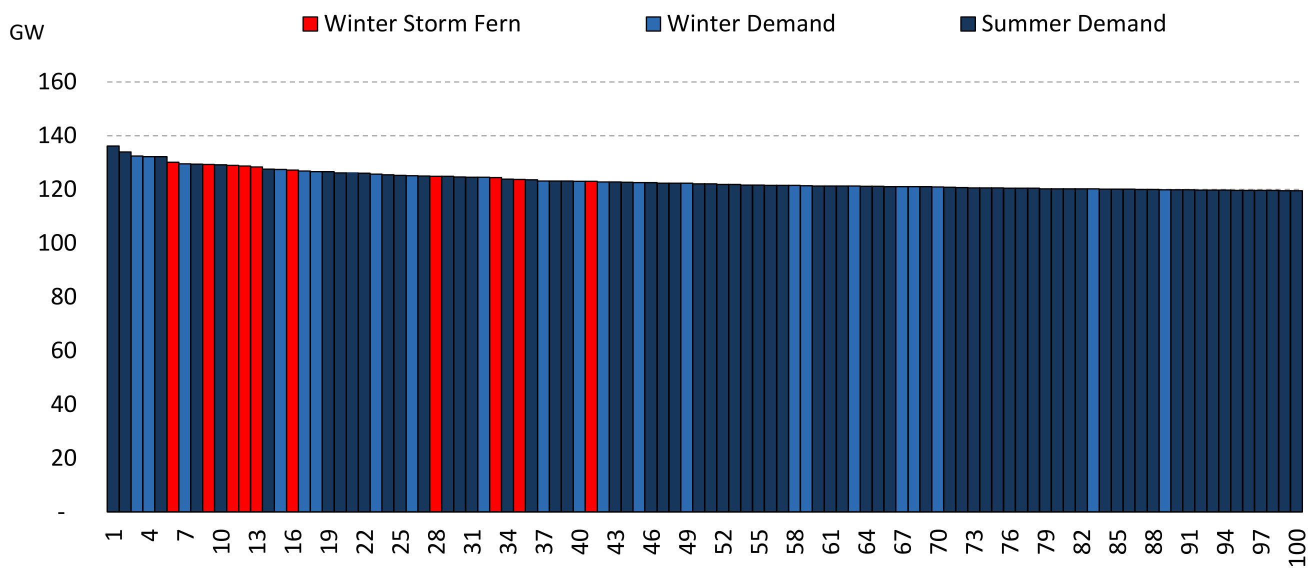
Source: EIA Hourly Grid Monitor & EIA 860 data

PJM

The PJM Interconnection, the largest Independent System Operator (ISO) in the nation by capacity, serves approximately 65 million customers across 13 states and the District of Columbia. Typically, PJM experiences an average hourly demand of approximately 95-98 GW during the winter.

In PJM, Winter Storm Fern produced multiple high-ranking electricity demand days, as shown in **EXHIBIT 22**, with several storm-related days appearing within the top 100 historical load events. While the event did not surpass PJM's all-time system peak, which remains summer-driven, it generated elevated winter loads in the 125–132 GW range. Notably, several of these days cluster within the upper tier of winter demand rankings, emphasizing the intensity of the cold spell. What distinguishes Fern is not only the magnitude of individual peak days but also the persistence of elevated demand across consecutive days. The concentration of red bars toward the higher end of the winter distribution reflects sustained system stress rather than a single short-duration spike. This pattern highlights the prolonged reliability pressure placed on PJM during the event, differentiating it from more transient cold-weather episodes.

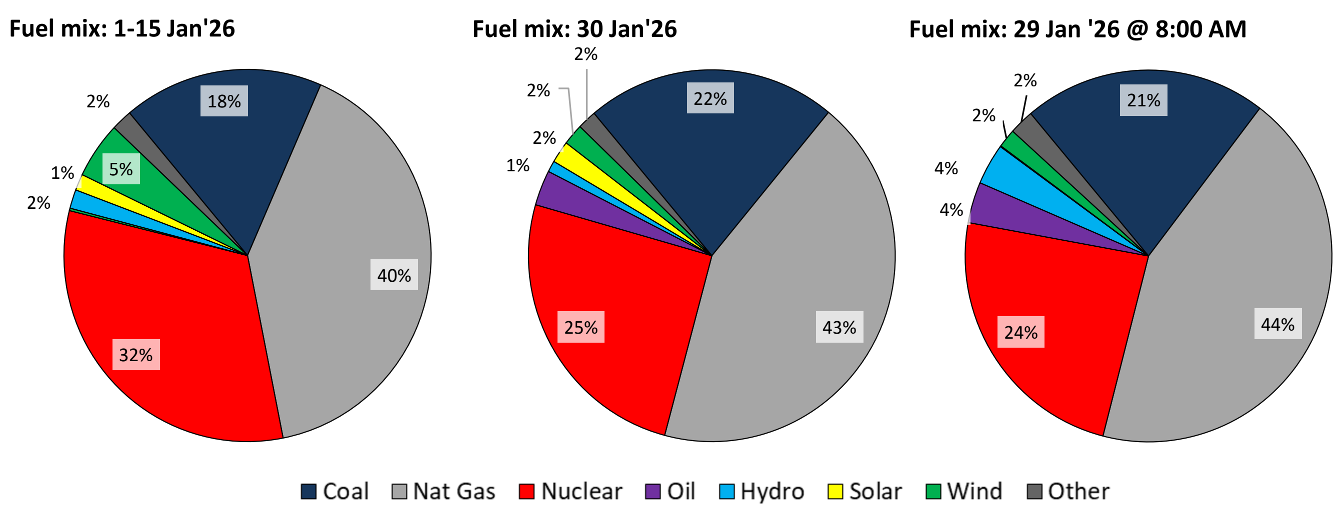
EXHIBIT 22: PJM - TOP 100 ELECTRICITY DEMAND DAYS



Source: EIA Hourly Grid Monitor

In PJM, nuclear generation typically accounts for roughly one-third of total electricity supply, with natural gas and coal comprising most of the remainder. As shown in **EXHIBIT 23**, this structure remained intact during Winter Storm Fern. Nuclear output held steady on both the peak-demand day (January 30) and the peak-demand hour (8:00 AM on January 29), remaining at consistent baseload levels. However, during these peak periods, natural gas and coal generation increased their shares of the fuel mix to meet elevated demand. On the peak day, natural gas rose to approximately 43% of total generation and coal to about 22%, while nuclear generation's share declined modestly in percentage terms due to higher overall system load rather than reduced output. During the peak hour, natural gas accounted for roughly 44% and coal for 21% of generation. Solar output was minimal during the morning peak, as expected in winter conditions, and wind's contribution remained limited. Hydro and oil generation increased modestly compared to early-January levels, providing incremental reliability support during critical demand hours.

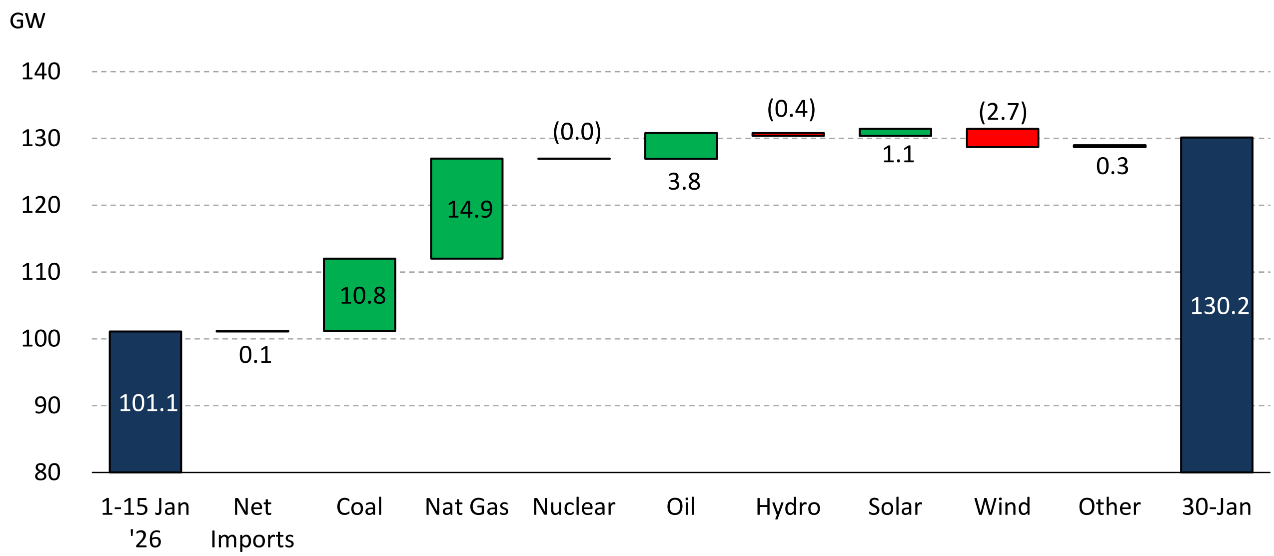
EXHIBIT 23: PJM - GENERATION MIX



Source: EIA Hourly Grid Monitor

EXHIBIT 24 analyzes average hourly demand and generation from January 1-15, comparing it to the peak demand during Winter Storm Fern in PJM on January 30. The average load grew from about 101.1 GW in early January to 130.2 GW on the peak day, an increase of roughly 29-30 GW. To accommodate this rise, fossil fuel generation notably increased: coal output went up by around 10.8 GW, and natural gas generation increased by about 14.9 GW compared to early January averages, constituting most of the additional demand. Oil-fired generation added a modest 3.8 GW, reflecting supplemental thermal dispatch during peak stress. Nuclear output stayed essentially steady, confirming its role as baseload power. Meanwhile, wind generation decreased by approximately 2.7 GW compared to early January, producing only 2.4 GW on the peak day. Solar output saw a slight rise (~1.1 GW), but its overall contribution remained limited due to seasonal conditions. In summary, the roughly 30 GW demand increase during Fern was mainly met by increased coal and natural gas use, with renewable sources providing limited support.

EXHIBIT 24: PJM - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY

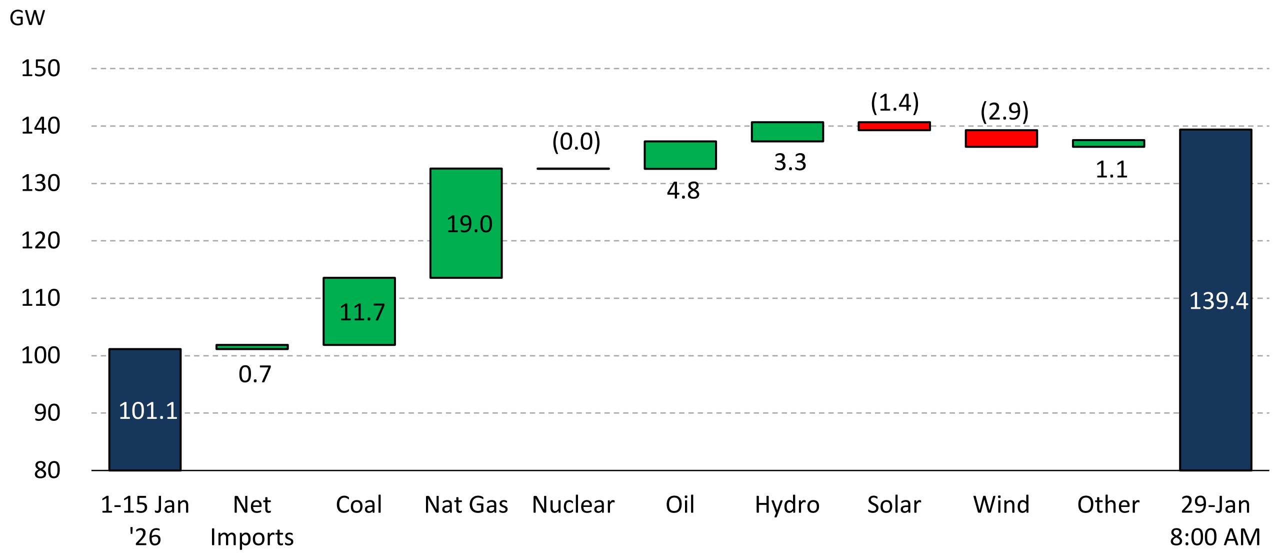


Source: EIA Hourly Grid Monitor

EXHIBIT 25 compares average hourly generation during January 1-15 with the peak demand hour of Winter Storm Fern in PJM, which occurred at 8:00 AM on January 29. System load rose to approximately 139.4 GW, nearly 38 GW above the early-January hourly average of 101.1 GW. To meet this surge, coal generation increased by roughly 11.7 GW relative to early-January levels, bringing total coal output to approximately 30 GW during the peak hour. Natural gas ramped even more materially, rising by about 19 GW compared to the first-half January average, underscoring its role as the primary marginal fuel. Oil-fired generation contributed an additional ~4.8 GW, while hydro output increased by roughly 3.3 GW, reflecting broader thermal and dispatchable resource mobilization during peak system stress.

In contrast, renewable output softened. Combined wind and solar generation declined by approximately 4-5 GW relative to early-January averages, largely due to limited winter solar irradiance and weaker wind conditions during the morning peak.

EXHIBIT 25: PJM - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR

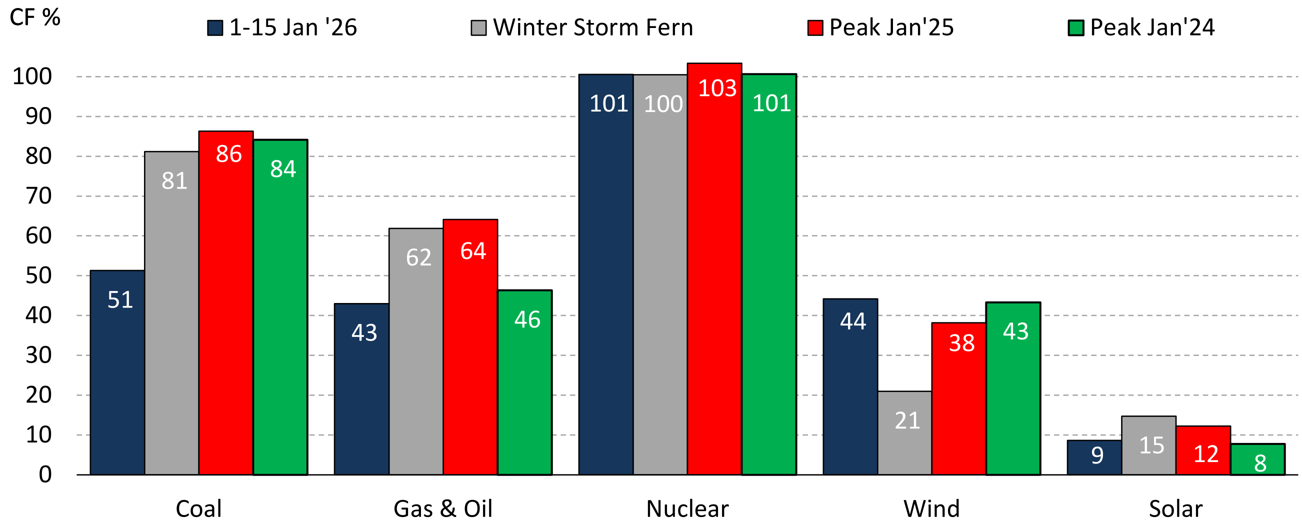


Source: EIA Hourly Grid Monitor

EXHIBIT 26 compares capacity factors by fuel type in PJM for January 1–15, Winter Storm Fern, and prior January peak events. During Winter Storm Fern, coal utilization increased materially, with capacity factors rising from roughly 51% in early January to approximately 81% on the peak demand day. This sharp increase reflects the elevated dispatch of coal units to meet sustained cold-weather load. Natural gas and oil units also operated at higher utilization, with combined capacity factors rising from about 43% in the first half of January to roughly 62% during the storm, and even higher during prior peak events. Nuclear units continued operating at or near full capacity (around 100%), reinforcing their baseload reliability during periods of system stress.

In contrast, wind capacity factors declined significantly during Fern, falling to approximately 21%, well below early-January levels (~44%) and lower than prior peak winter events. This reduction reflects less favorable wind conditions during the storm. Solar capacity factors increased modestly relative to early January, reaching about 15% during Fern, though overall contribution remained limited by seasonal daylight constraints. Overall, the data highlight PJM's increased reliance on dispatchable thermal resources during Winter Storm Fern, while renewable output remained highly weather-dependent.

EXHIBIT 26: PJM - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



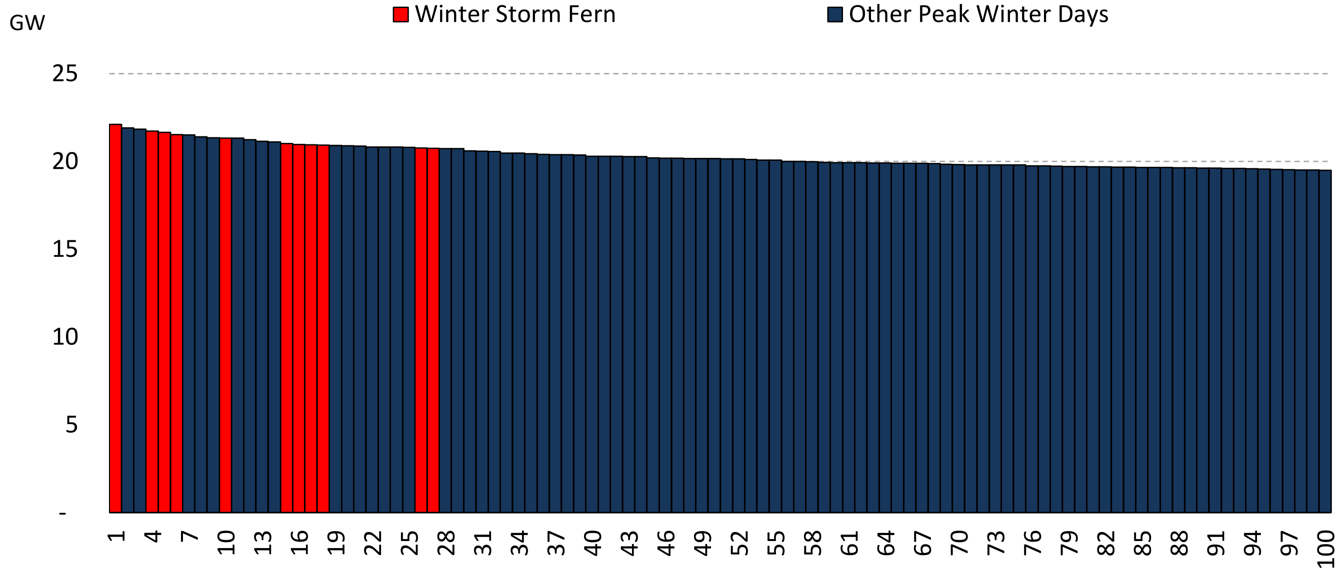
Source: EIA Hourly Grid Monitor & EIA 860 data

NYISO

The New York Independent System Operator (NYISO) operates the bulk power system across New York State, managing grid reliability and wholesale electricity markets for nearly 20 million customers. The system is characterized by strong winter heating load in downstate regions and significant transmission constraints between upstate generation and New York City demand centers.

NYISO remains a structurally summer-peaking system, as winter heating demand is still largely met by natural gas rather than electric heating. However, Winter Storm Fern stands out as a significant winter event for the region. While it did not approach NYISO's all-time system peaks, which are summer-driven, the storm produced the highest winter electricity demand on record. As shown in **EXHIBIT 27**, eleven Fern-related days rank among the top thirty winter demand days on record, highlighting the breadth of the event's impact. The prolonged sub-freezing temperatures and heavy snowfall sustained elevated load levels for more than a week. The highest demand day occurred on January 30, when the daily average load reached approximately 22.1 GW, with the peak hourly demand rising to 24.3 GW at 7:00 PM. This compares to an average of roughly 18.2 GW during the first half of January. Unlike more short-lived winter spikes observed in other regions, Fern's impact in NYISO was defined by persistence, maintaining consistently high winter demand over multiple consecutive days.

EXHIBIT 27: NYISO - TOP 100 WINTER ELECTRICITY DEMAND DAYS

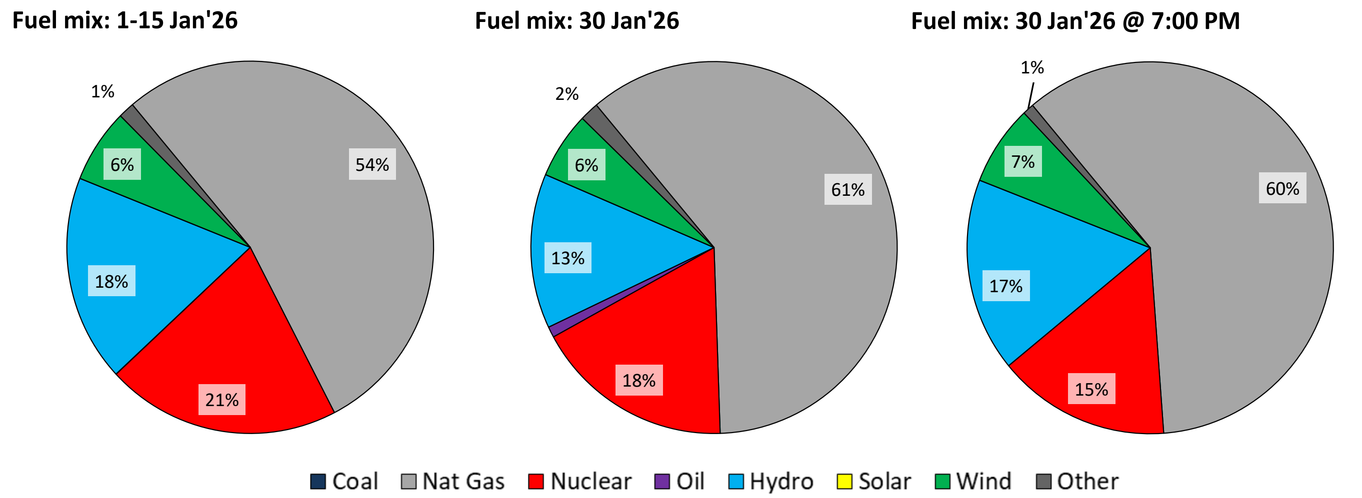


Source: EIA Hourly Grid Monitor

NYISO's generation mix is structurally dominated by natural gas and nuclear power, which together account for more than three-quarters of the total electricity supply. Hydropower provides a meaningful secondary contribution, while wind and solar represent comparatively smaller shares. Notably, NYISO does not have operational coal capacity, making the region more reliant on natural gas and nuclear during periods of elevated demand.

As shown in **EXHIBIT 28**, during Winter Storm Fern, natural gas increased its share of the generation mix from roughly 54% in the first half of January to approximately 61% on the peak demand day and 60% during the 7:00 PM peak hour. Nuclear output remained steady in absolute terms, though its percentage share declined modestly due to higher total system load. Hydropower maintained a strong contribution, accounting for about 17% of generation during the peak hour, indicating a proportional increase in output to help meet heightened demand. Wind and solar contributions remained limited during peak conditions. Overall, the fuel mix during the storm remained structurally consistent with seasonal norms, with natural gas serving as the primary balancing resource during the period of sustained winter stress.

EXHIBIT 28: NYISO - GENERATION MIX

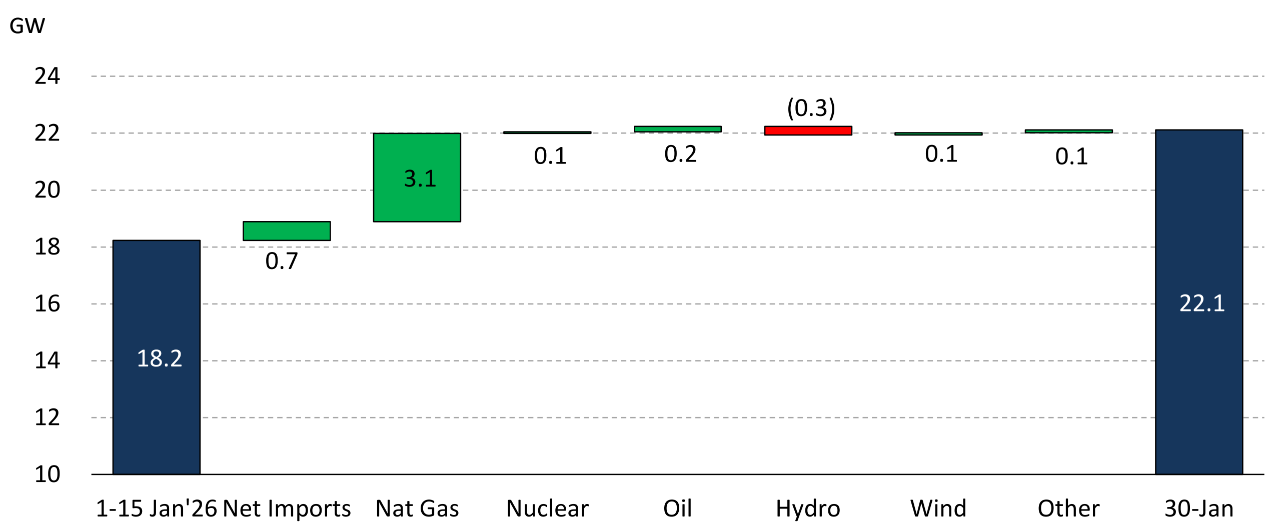


Source: EIA Hourly Grid Monitor

EXHIBIT 29 compares average operations during January 1-15 with the peak-demand day of January 30 in the NYISO. Demand increased from approximately 18.2 GW in early January to 22.1 GW on the peak day, a rise of roughly 4 GW. The majority of this incremental demand was met by higher natural gas generation, which increased by about 3.1 GW relative to early-January averages. Net imports also rose modestly, contributing an additional ~0.7 GW. Nuclear output remained effectively unchanged, while hydro, wind, oil, and other resources showed only marginal variation.

Overall, roughly 70% of the incremental load was absorbed by natural gas, with the remainder largely supported by imports, illustrating NYISO's reliance on gas-fired generation as the primary balancing resource during winter peak conditions.

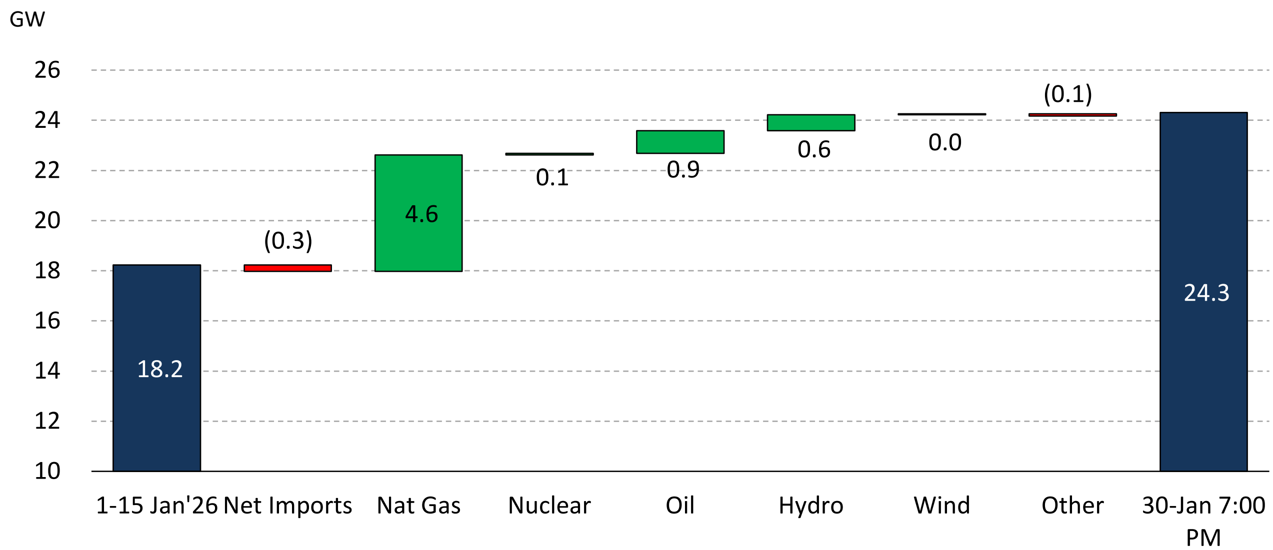
EXHIBIT 29: NYISO - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY



Source: EIA Hourly Grid Monitor

During the peak demand hour, electricity demand rose to approximately 24.3 GW, well above the early-January average of 18.2 GW, as shown in **EXHIBIT 30**. To meet this roughly 6 GW increase, natural gas served as the primary resource, increasing generation by approximately 4.7 GW, from about 8.7 GW in the first half of January to 11.8 GW during the peak hour. Hydro generation also increased by roughly 0.8 GW, while wind output rose by approximately 0.5 GW relative to early-month levels. Other resource categories, including nuclear and imports, remained largely stable.

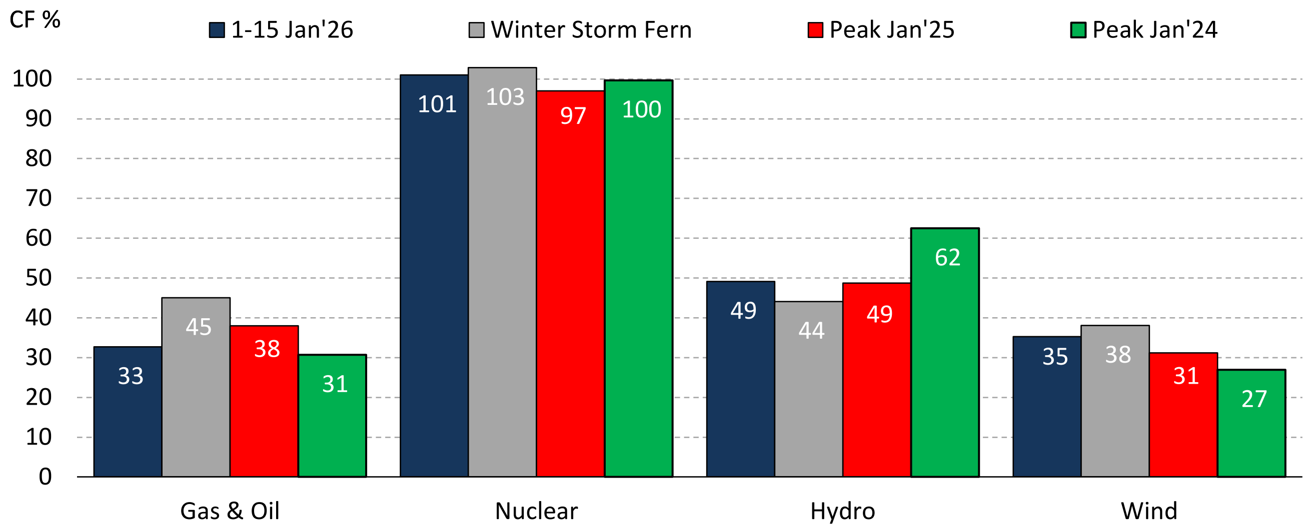
EXHIBIT 30: NYISO - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



Source: EIA Hourly Grid Monitor

EXHIBIT 31 illustrates capacity factors by fuel type in NYISO during January 1-15, Winter Storm Fern, and prior January peak events. During Winter Storm Fern, natural gas and oil units operated at higher utilization levels, with capacity factors rising from roughly 33% in the first half of January to approximately 45% during the storm. This level of utilization was also higher than that observed during the January 2025 peak event, underscoring the stronger reliance on gas-fired generation during Fern. Nuclear units continued to operate at or near full capacity (around 100%+), maintaining their consistent baseload contribution across all periods. Wind capacity factors during Fern averaged approximately 38%, modestly higher than early-January levels and above January 2024 levels, though still subject to weather-driven variability. Hydro generation is a significant source of generation in the NYISO region, while the capacity factor during the peak demand day decreased from 49% in the first half of January to 44%, hydro generation remained a notable source of electricity during Winter Storm Fern.

EXHIBIT 31: NYISO - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



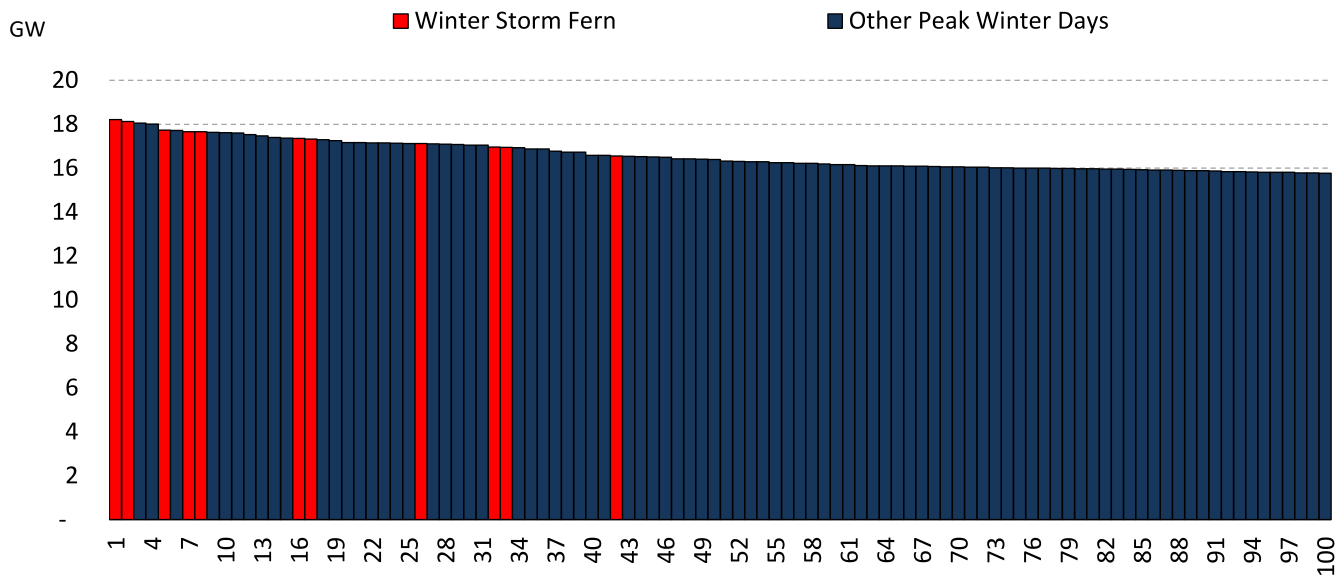
Source: EIA Hourly Grid Monitor & EIA 860 data

ISONE

ISO New England operates the bulk power grid across the six New England states, ensuring reliability and administering competitive wholesale electricity markets. The region is increasingly winter-constrained, with peak system stress often driven by summer peaks and winter natural gas supply limitations.

ISONE is structurally a summer-peaking system, with the highest historical demand days typically occurring during periods of extreme heat. During the winter months, average electricity demand in the region generally ranges around the low- to mid-30 GW level under normal conditions. However, severe cold events can drive meaningful short-term demand increases. As shown in **EXHIBIT 32**, Winter Storm Fern produced several winter days that ranked among ISONE's top 100 historical winter demand days. While these levels did not approach the region's all-time summer peaks, the storm pushed demand toward the upper end of historical winter observations. Similar to prior events such as the January 2025 Polar Vortex, winter demand increased materially relative to early-month averages, with peak-hour load rising well above typical January levels. Overall, although extreme cold events are not the dominant driver of ISONE's all-time peaks, Winter Storm Fern stands out as a notable winter reliability event due to the clustering of multiple storm-related days within the upper tier of winter demand rankings.

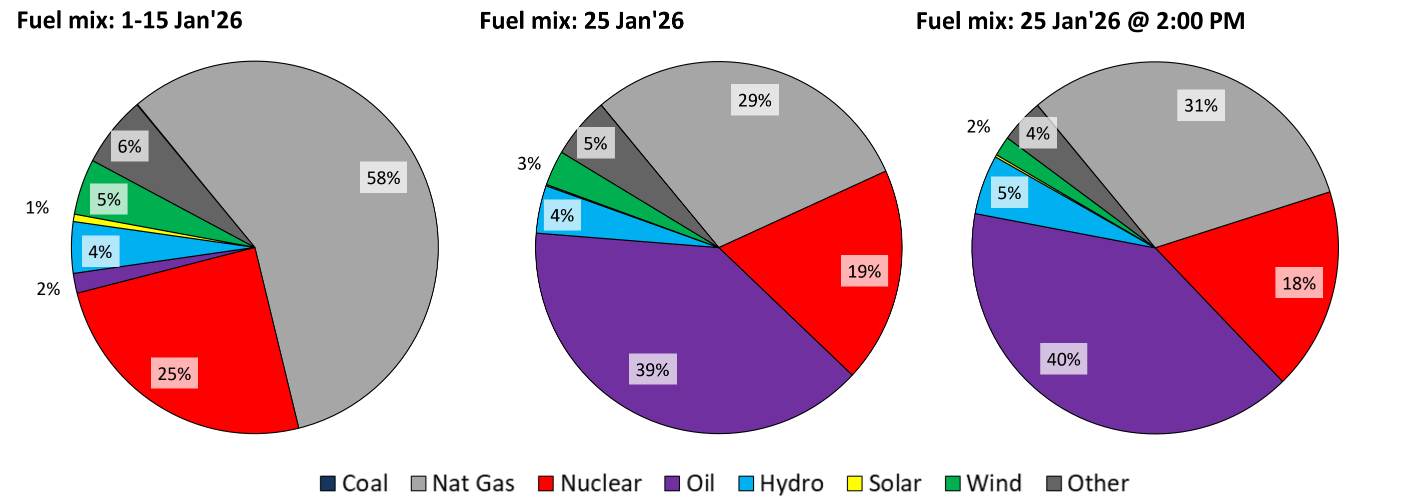
EXHIBIT 32: ISONE - TOP WINTER 100 ELECTRICITY DEMAND DAYS



Source: EIA Hourly Grid Monitor

ISONE's generation mix is typically dominated by natural gas and nuclear power, which together account for more than 80% of the total electricity supply under normal winter conditions. Hydropower and wind contribute a smaller share, while solar remains limited due to seasonal irradiation. As shown in **EXHIBIT 33**, during Winter Storm Fern, the fuel mix shifted materially. Natural gas's share declined from approximately 58% in the first half of January to 29% on the peak demand day (January 25) and 31% during the 2:00 PM peak hour. This reduction was not solely due to lower gas output in absolute terms but rather to a substantial increase in oil-fired generation. Oil, which accounted for only about 2% of the fuel mix earlier in the month, surged to roughly 39-40% on the peak day and during the 2:00 PM peak hour. This reflects ISONE's reliance on dual-fuel units switching to oil amid tight natural gas supply conditions and elevated gas prices. Nuclear generation remained steady in absolute terms but declined modestly as a percentage of the total mix due to higher overall system load and increased oil dispatch. Wind's share softened slightly relative to early January levels, while hydro remained relatively stable. Overall, the data highlight ISONE's structural winter constraint. In periods of extreme cold, when pipeline gas is limited, oil-fired generation becomes a critical reliability backstop.

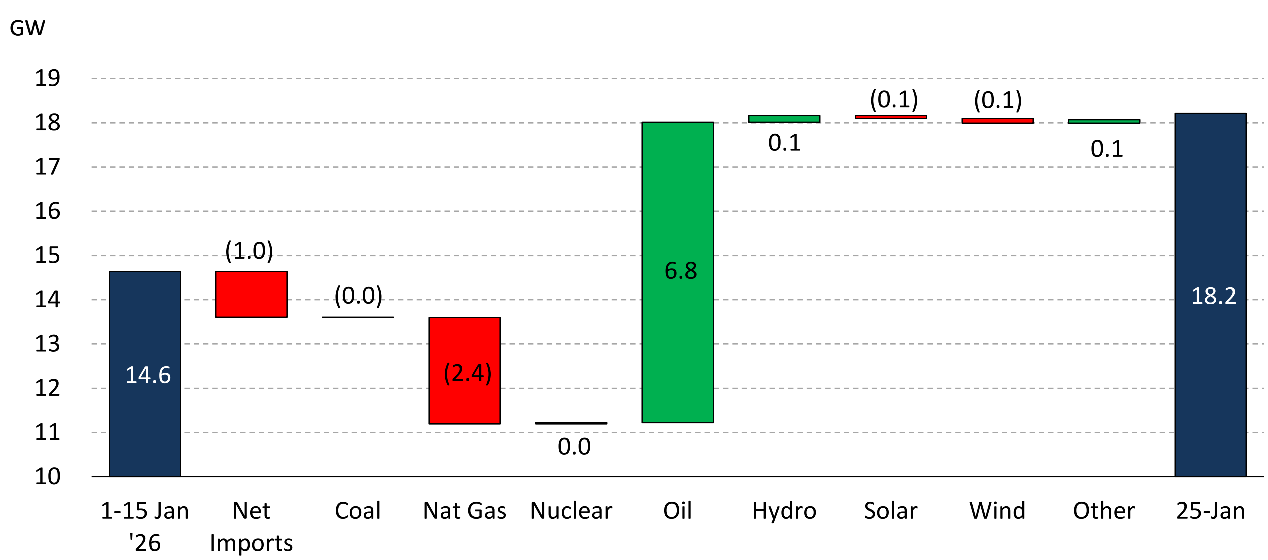
EXHIBIT 33: ISONE - GENERATION MIX



Source: EIA Hourly Grid Monitor

EXHIBIT 34 compares average operations during January 1-15 with the peak demand day of January 25 in ISONE. Demand increased from approximately 14.6 GW in early January to 18.2 GW on the peak day, a rise of roughly 3.5-4 GW. Notably, natural gas generation declined by about 2.4 GW relative to early-January levels, reflecting fuel supply constraints and higher regional gas demand for heating. The combined effect of higher electricity demand and lower gas-fired output was offset almost entirely by a sharp increase in oil-fired generation, which rose by approximately 6.8 GW. Net imports also declined modestly (~1 GW), further reinforcing the need for in-region oil dispatch. This shift demonstrates ISONE’s structural winter dynamic- oil-fired units, many of which are dual-fuel capable, can store fuel on-site ahead of extreme weather events and therefore are less exposed to real-time fuel supply volatility compared to natural gas. During Winter Storm Fern, oil effectively served as the marginal reliability resource, compensating for both elevated demand and reduced gas availability.

EXHIBIT 34: ISONE - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY

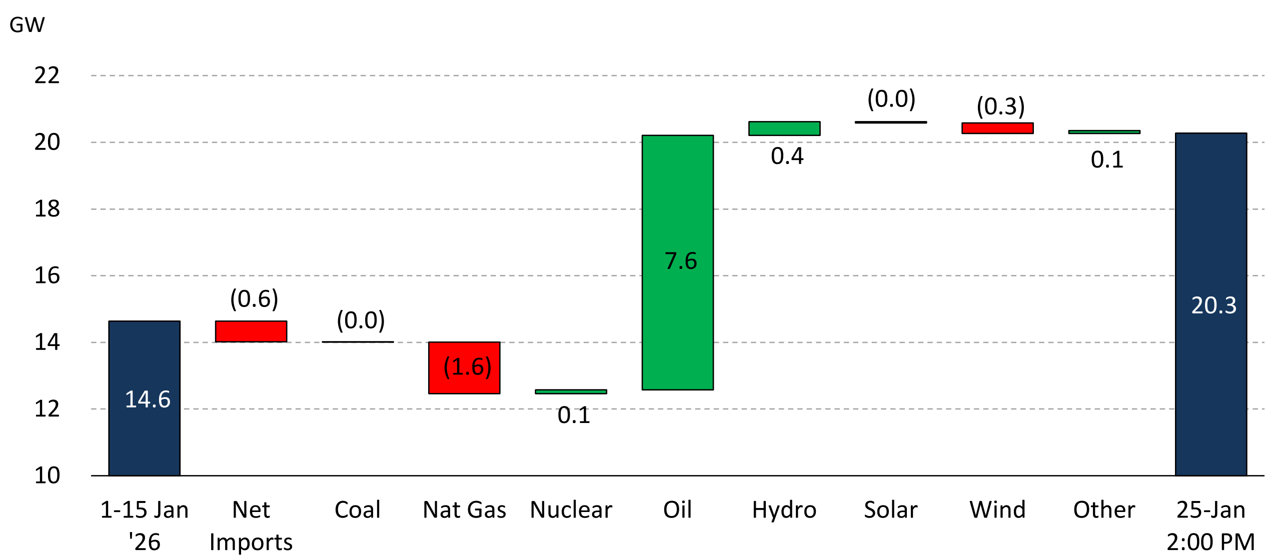


Source: EIA Hourly Grid Monitor

During the peak demand hour at 2:00 PM on January 25, electricity demand in ISO-NE rose to approximately 20.3 GW, compared to an early-January average of 14.6 GW, as shown in **EXHIBIT 35**. To meet this nearly 6 GW increase, alongside reduced natural gas output, oil-fired generation ramped significantly, increasing by approximately 7.6 GW relative to early-month levels to generate 7.8 GW. This surge reflects the activation of dual-fuel capable combined-cycle units switching to oil amid tight natural gas supply conditions and elevated gas prices.

At the same time, natural gas generation declined by roughly 1.6 GW compared to the first-half January average, reinforcing the shift toward oil during the most constrained period. Hydro provided a modest increase (~0.4 GW), while wind output softened slightly.

EXHIBIT 35: ISONE - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR

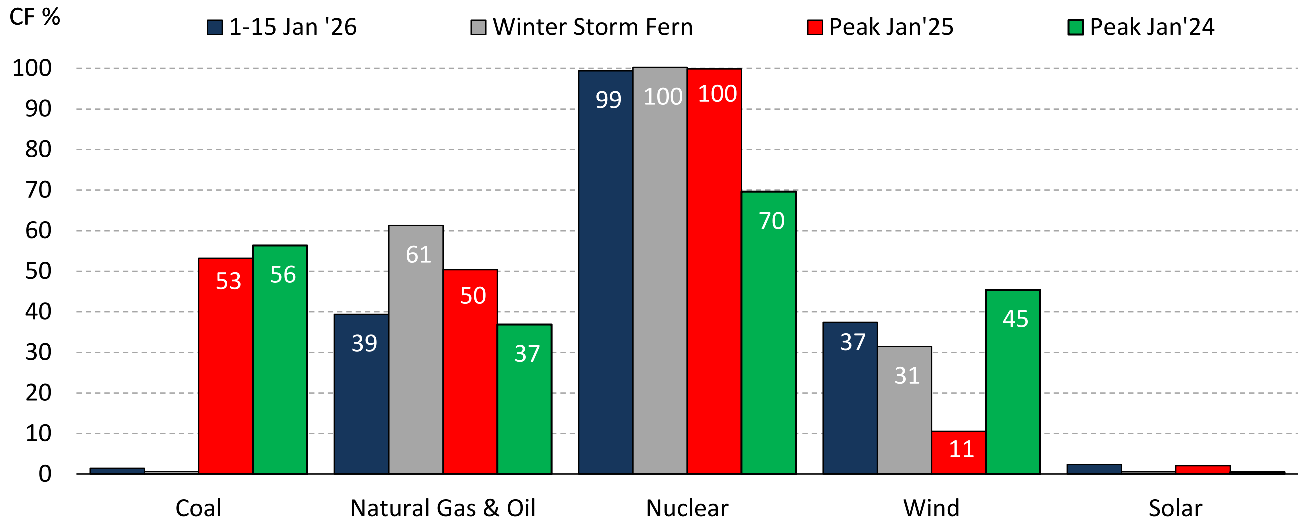


Source: EIA Hourly Grid Monitor

EXHIBIT 36 compares capacity factors by fuel type in ISO-NE during January 1-15, Winter Storm Fern, and prior January peak events. During Fern, natural gas and oil units operated at materially higher utilization levels than in the first half of January, with combined gas and oil capacity factors rising to approximately 61%, compared to roughly 39% earlier in the month. This increase was driven largely by oil-fired generation, as dual-fuel units switched fuels amid tight natural gas supply conditions.

Nuclear units continued to operate at or near full capacity (approximately 100%) during the storm, reinforcing their baseload reliability role. Wind capacity factors averaged around 31% during Fern, lower than early-January levels (~37%) and substantially below the 45% observed during January 2024, though notably higher than the 11% recorded during the January 2025 Polar Vortex event. This variability indicates the weather-dependent nature of wind generation during extreme cold events.

EXHIBIT 36: ISONE - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES[3]



Source: EIA Hourly Grid Monitor & EIA 860 data

Southeast

The Southeast region includes most of the states of North & South Carolina, Georgia, Florida, Alabama, Tennessee, Kentucky, and Mississippi and its major utilities, including Duke Energy, Southern Company, Dominion South Carolina, Florida Power & Light, and Tennessee Valley Authority (TVA).

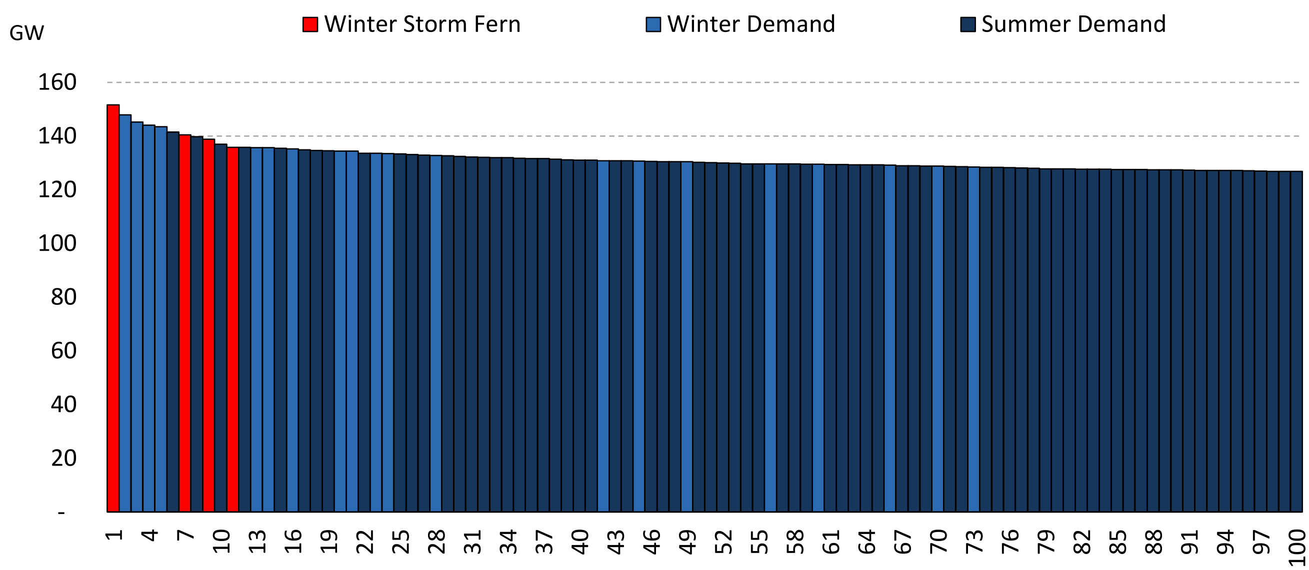
The Southeast typically records average winter demand in the range of 100-105 GW under normal seasonal conditions. However, Winter Storm Fern drove demand to unprecedented levels across the region. As shown in **EXHIBIT 37**, the storm set a new all-time regional record, surpassing prior extreme events such as the January 2025 Polar Vortex and Winter Storm Elliott. Peak daily demand reached approximately 151.6 GW on February 1, with the highest hourly load occurring the following morning at 8:00 AM, when demand surged to nearly 171 GW.

Importantly, multiple Fern-related days appear within the upper tier of the top 100 winter demand rankings, indicating that this was not a single-day spike but a sustained high-load event. The clustering of red bars near the top of the distribution highlights the prolonged nature of elevated demand over several consecutive days. While the Southeast remains structurally summer-peaking, as evidenced by the predominance of summer demand days in the broader historical dataset, recent years show a growing presence of extreme winter events among the highest load days. In fact, seven of the top ten demand days in the region have occurred during major winter weather events.

This pattern suggests that while peak system design may historically reflect summer cooling demand, winter weather events are increasingly producing system stress comparable to, and now exceeding, traditional summer peaks, with Winter Storm Fern representing the most severe winter demand event on record for the Southeast.

[3] Natural gas and oil units were combined in this analysis as most natural gas-fired power plants in ISONE are dual-fuel capable. However, as mentioned, overall natural gas generation declined, so the increase in capacity factor is due to increased oil generation, not natural gas generation.

EXHIBIT 37: SOUTHEAST - TOP 100 ELECTRICITY DEMAND DAYS

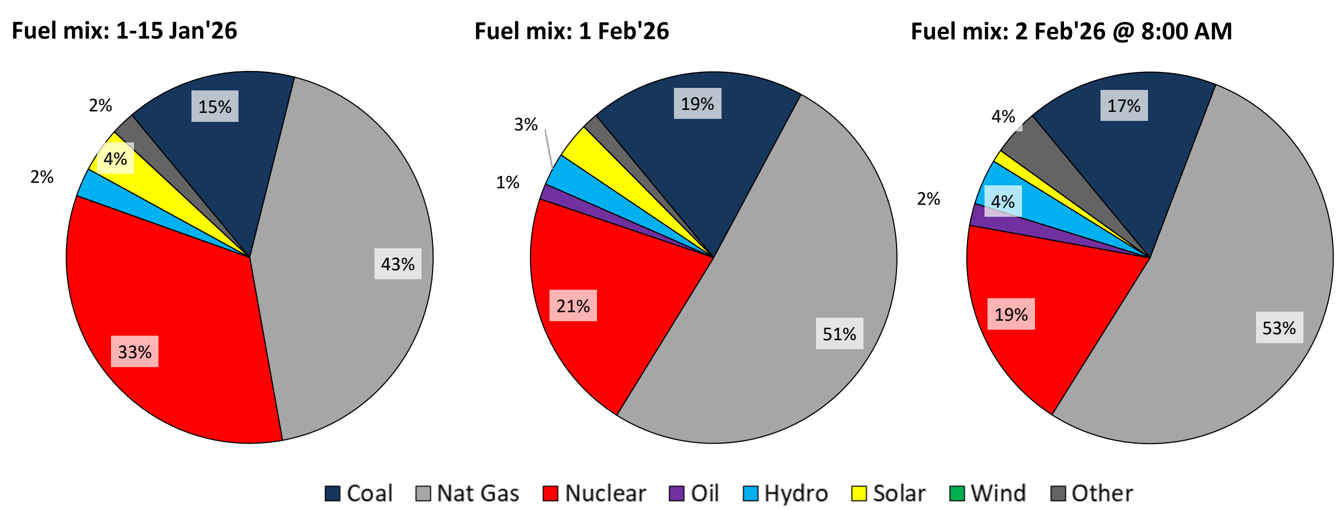


Source: EIA Hourly Grid Monitor

The Southeast region is structurally dominated by natural gas and nuclear generation, which together account for most electricity supply under typical winter conditions. As shown in **EXHIBIT 38**, during the first half of January, natural gas represented roughly 43% of the generation mix, followed by nuclear at 33% and coal at 15%, with hydro, solar, wind, and oil contributing smaller shares. During Winter Storm Fern, the fuel mix shifted meaningfully toward natural gas. On the peak demand day (February 1), natural gas rose to approximately 51% of total generation, and further to 53% during the 8:00 AM peak hour on February 2. Nuclear output remained steady in absolute terms, though its share declined modestly (to ~19–21%) due to the higher overall system load. Coal generation remained relatively stable, while oil made a small but notable appearance (~2%) during peak conditions, providing incremental reliability support.

Renewable contributions were limited during the early-morning peak hour, with solar and wind together accounting for only a marginal share of the mix due to low winter irradiance and subdued wind conditions. Hydro provided modest flexibility, increasing slightly during peak stress.

EXHIBIT 38: SOUTHEAST - GENERATION MIX

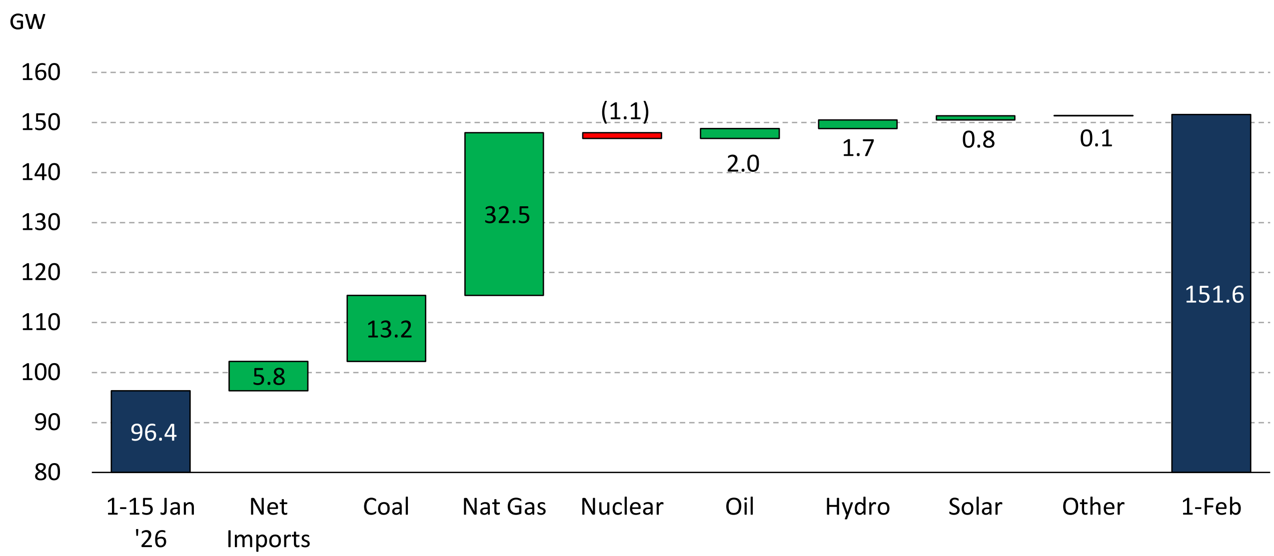


Source: EIA Hourly Grid Monitor

As average hourly demand climbed sharply from 96.4 GW in the first half of January to 151.6 GW on February 1 during Winter Storm Fern, the Southeast relied overwhelmingly on thermal generation to meet the surge. Natural gas provided the largest incremental response, increasing output by 32.5 GW, while coal generation rose by 13.2 GW. Together, these two resources accounted for the vast majority of the roughly 55 GW demand increase, underscoring their role as the region's primary dispatchable backbone during extreme cold events.

Net imports also rose by 5.8 GW, indicating strong interregional support, while oil and hydro contributed a combined additional 3.7 GW. Nuclear generation remained largely steady in absolute terms, meaning its share of the mix declined as overall demand expanded. Solar provided only a modest increase, consistent with winter seasonal limits.

EXHIBIT 39: SOUTHEAST - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY

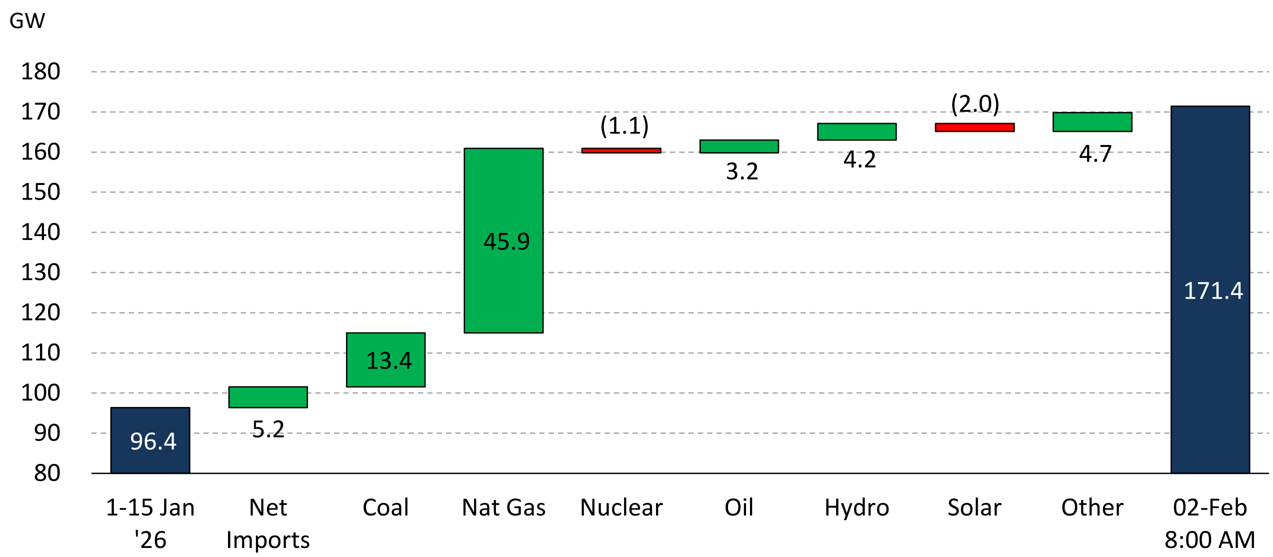


Source: EIA Hourly Grid Monitor

During the peak demand hour at 8:00 AM on February 2, load surged to 171.4 GW—nearly 75 GW higher than the 96.4 GW average observed during the first half of January. The vast majority of this incremental demand was met by natural gas, which increased output by 45.9 GW, more than doubling relative to early-January levels and reaching a total of 87.6 GW during the hour. Coal generation also rose materially, up 13.4 GW to 27.9 GW, reinforcing the role of dispatchable thermal resources in managing extreme winter peaks.

Net imports contributed an additional 5.2 GW, highlighting regional interdependence during stress conditions. Oil and hydro together added roughly 7.4 GW compared to early January, while nuclear output remained largely unchanged in absolute terms, resulting in a smaller proportional share of the fuel mix as total demand expanded. Solar output declined modestly, given the early-morning timing of the peak.

EXHIBIT 40: SOUTHEAST - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR

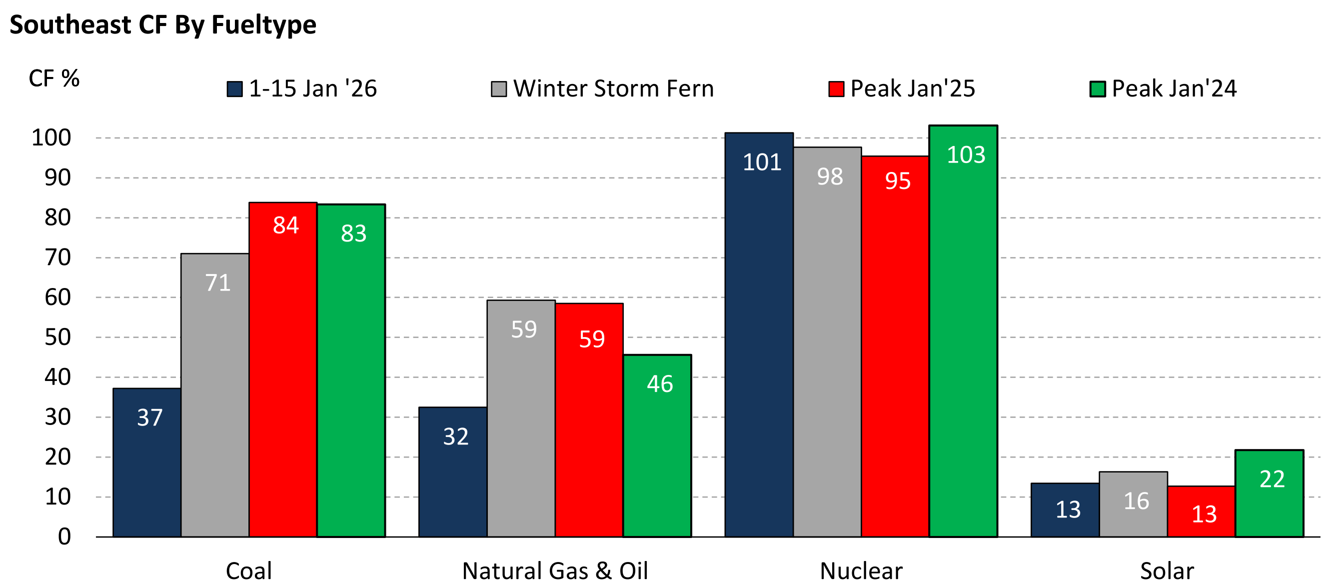


Source: EIA Hourly Grid Monitor

EXHIBIT 41 shows the capacity factors of major generating resources during Winter Storm Fern and prior peak demand events, compared with average operations in the first half of January in the Southeast. Coal units showed the most pronounced ramp in utilization, rising from 37% in early January to 71% during Winter Storm Fern and reaching the mid-80% range during prior extreme events. This reflects the region’s reliance on dispatchable thermal resources during sustained cold weather. Natural gas & oil units similarly increased from roughly 32% in early January to nearly 60% during Winter Storm Fern, reinforcing the role of gas-fired generation as the primary marginal resource.

Wind is not a major contributor in the Southeast, and its capacity factors have been highly event-dependent, remaining negligible during the 2025 Polar Vortex but materially higher during Winter Storm Fern and in January 2024. Solar capacity factors remained modest in winter conditions, averaging 13–16% during storm periods, compared with higher output on clearer winter days. Overall, the chart shows that extreme winter peaks in the Southeast are overwhelmingly supported by high thermal fleet utilization, with renewables providing variable, weather-dependent contributions.

EXHIBIT 41: SOUTHEAST - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES

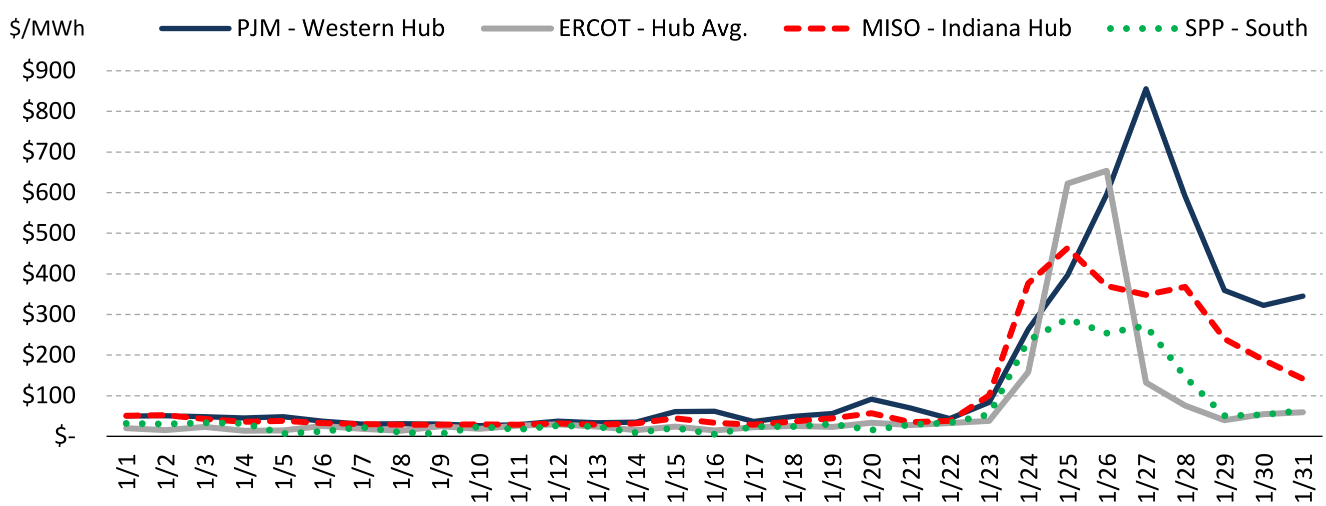


Source: EIA Hourly Grid Monitor & EIA 860 data

Part II: Price Analysis

Besides providing valuable incremental generation during extreme weather events during Winter Storm Fern, coal-fired power plants also function as a de facto price hedge for regional wholesale and, ultimately, retail power prices. The following section provides a high-level overview of the power price spikes observed across the country during the extreme weather event and the role coal-fired power plants played in limiting these power price spikes.

EXHIBIT 42: AVERAGE DAILY DAY-AHEAD POWER PRICES AT MAJOR PRICE HUBS IN JANUARY 2026



Source: S&P Global

EXHIBIT 42 shows the average daily day-ahead power prices for PJM, MISO, ERCOT, and SPP for January 2026. As electricity demand increased, so did regional wholesale power prices, which encouraged additional electric generating resources not yet operating at full capacity to increase their output. PJM power prices saw the most significant increase of all affected power market regions, with daily average day-ahead power prices spiking to about $850/MWh, a new all-time high, on

January 27 during the peak of the Polar Vortex event. Other power market regions also saw notable increases in their regional power prices.

To review, wholesale power prices are priced on a locational basis and are generally derived following the following formula:

$$Locational\ Marginal\ Pricing\ (LMP) = System\ Energy\ Price \pm Congestion \pm Line\ Loss$$

The system energy price is set by the operating cost of the last electric generating resource required to meet electricity demand in a given hour, while congestion and line-loss prices reflect the specific locations of supply and demand resources and the transmission distance required to deliver the needed electricity. Operating costs include fuel costs and other non-fuel variable costs, such as reagent costs for emission control equipment, emission allowance costs, and estimated maintenance costs that depend on the number of hours a generating resource operates in a given period. Renewable resources often have the lowest dispatch or operating costs of all electric generating resources because they do not use fuel or need to budget for emission allowances or other consumables, limiting their operating costs to estimated variable operating and maintenance costs (VOM). Nuclear plants also have very low variable operating costs compared to their fossil-fuel-based counterparts. Therefore, system energy prices, and as a result, wholesale power prices, are set predominantly by natural gas, coal, or oil-fired power plants. For fossil-fuel-fired power plants, fuel costs are by far the highest component of operating costs, often accounting for more than 70% of total operating or dispatch costs.

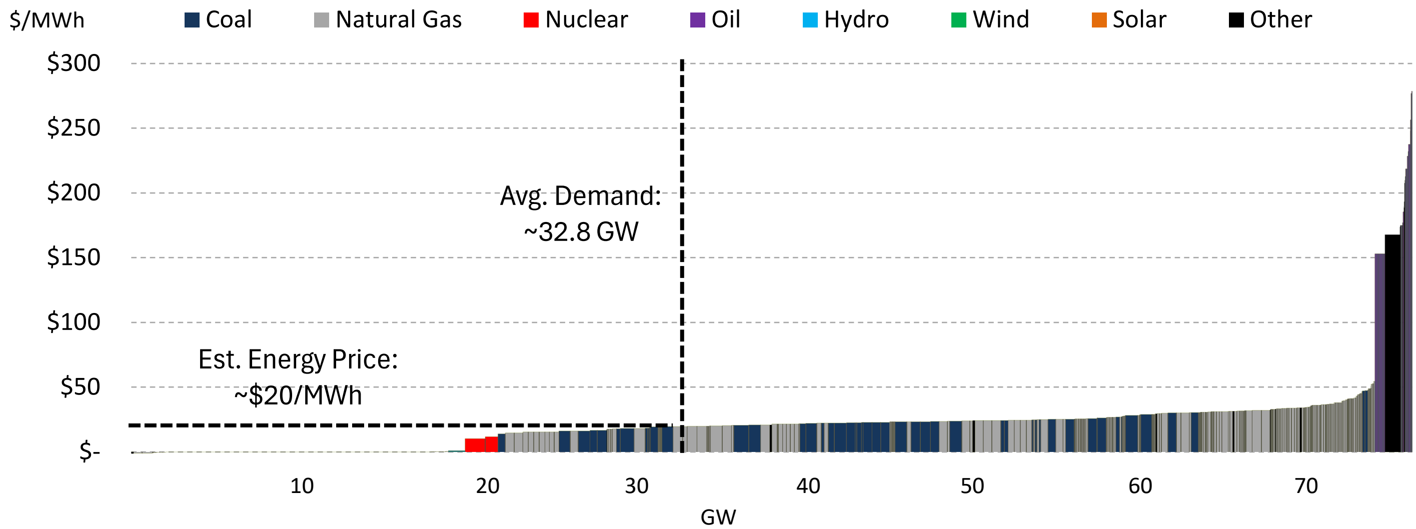
The following analysis estimates the dispatch stacks (i.e., the order of electric generating resources from lowest to highest cost available in each power market during the analyzed period) for each regional transmission operator (RTO) operating a regional day-ahead energy market affected by Winter Storm Fern. The analysis includes dispatch stacks for the first half of January 2026 (1/1-1/15), the estimated dispatch stack on each RTO's peak demand day, and a hypothetical dispatch stack on the peak demand day with no coal plants available to meet demand. The change in marginal system energy price between the estimated actual dispatch stack on the peak demand day and the hypothetical dispatch stack without coal plants is multiplied by the average hourly demand for that day to estimate the total amount of money saved due to the availability of coal plants and their ability to increase generation during peak demand events.

It is worth noting that this analysis considers only the change in the system energy price component of the LMP. As excess resources diminish, congestion and line loss costs increase because resources with more favorable congestion and line loss components are often used before less efficient ones. However, accurately estimating changes in congestion and line loss costs requires detailed nodal modeling of the RTOs. Additionally, this analysis considers only the realized savings for a single day (i.e., the peak demand day) for each RTO. As mentioned in the previous section, Winter Storm Fern affected each RTO for multiple days. Therefore, coal plants enabled additional savings on the days before and after the peak demand day in each ISO that are not included in this analysis. As a result, the savings estimate presented in this section for each RTO is likely conservative and shows only the maximum daily savings provided by the increased operations of coal plants in each RTO.

Southwest Power Pool

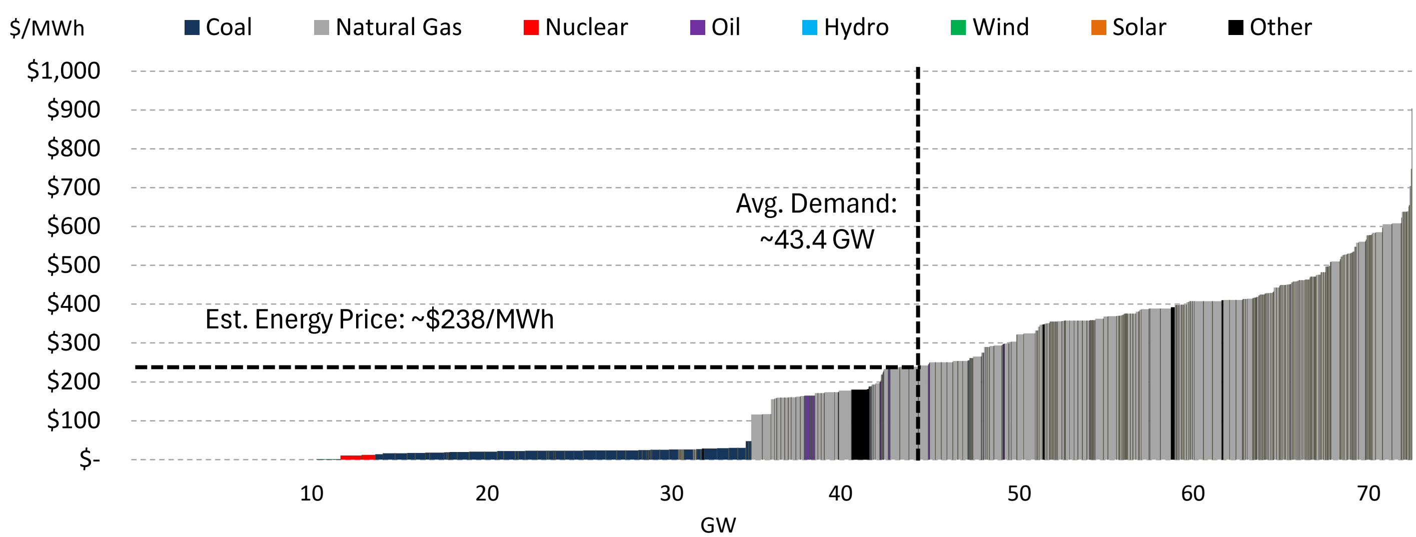
EXHIBIT 43 shows the estimated average dispatch stack for SPP during the first half of January 2026. At the beginning of the year, SPP's capacity mix was approximately 19 GW of coal, 33 GW of natural gas, 35 GW of wind, and 5 GW of hydro, with nuclear (1.9 GW), oil (1.9 GW), and solar (1.5 GW) accounting for the remaining capacity. Average delivered coal and natural gas prices to coal- and natural gas-fired power plants in SPP were \$1.94/MMBtu and \$2.26/MMBtu, respectively, during the first half of January 2026. With average hourly electricity demand of about 33 GW, the estimated average system energy price during the first half of January 2026 was approximately \$20/MWh. Due to relatively low system stress during the first half of January, the estimated system energy price was close to the average around-the-clock day-ahead LMP at SPP-South Hub during the same period (\$20.32/MWh).

EXHIBIT 43: SPP - ESTIMATED AVERAGE DISPATCH STACK - JAN 1 - JAN 15 '26



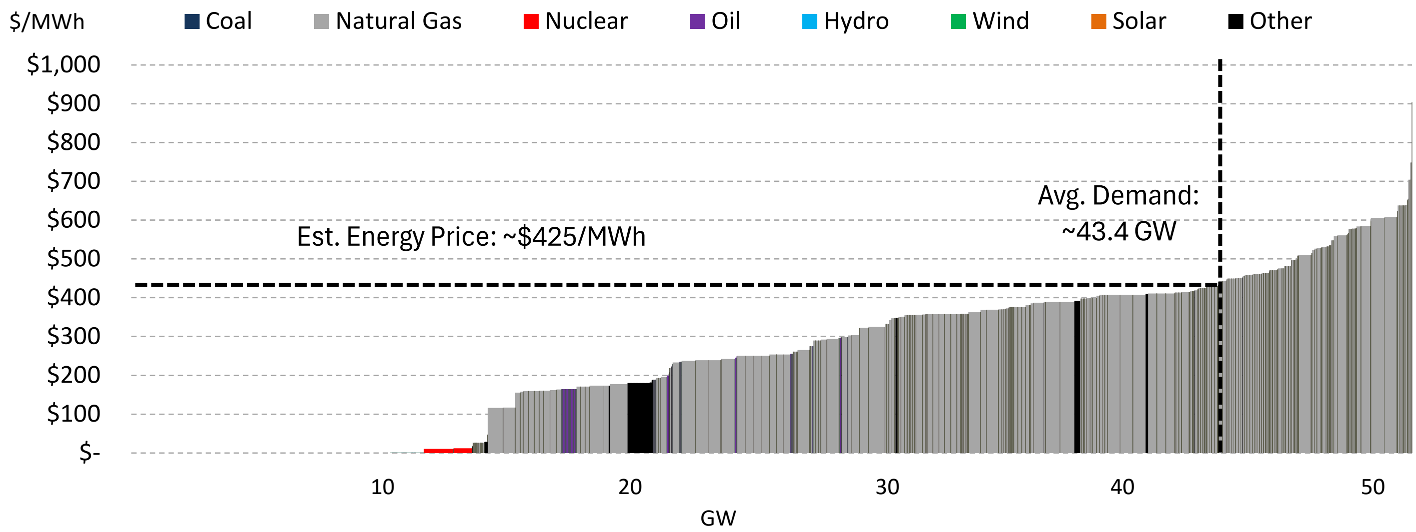
SPP experienced its peak electricity demand day on January 24, 2026, when hourly electricity demand averaged about 43.4 GW. On January 24, SPP's average wind capacity factor fell from 42% in the first half of January to 30%. At the same time, estimated delivered natural gas prices rose more than 13-fold to over $32/MMBtu, while delivered coal prices remained largely unchanged. As a result, the estimated average system energy price rose to about $238/MWh on January 24, an increase of over 10-fold compared to the first half of the month, as shown in **EXHIBIT 44**.

EXHIBIT 44: SPP - ESTIMATED DISPATCH STACK ON 24 JAN '26



At an estimated system energy price of over $238/MWh, virtually all of SPP's 19 GW of coal-fired power plants were economic and dispatched at or near their maximum available capacity, as shown by the capacity factor rising to about 90% on January 24. However, if none of the 19 GW of coal plants had been available, the average system energy price in SPP on January 24 is estimated to have increased to over $425/MWh, an increase of almost $200/MWh, as shown in **EXHIBIT 45**. At an average hourly demand of 43.4 GW, the estimated savings provided by the SPP coal fleet on January 24 alone are almost $195 million.

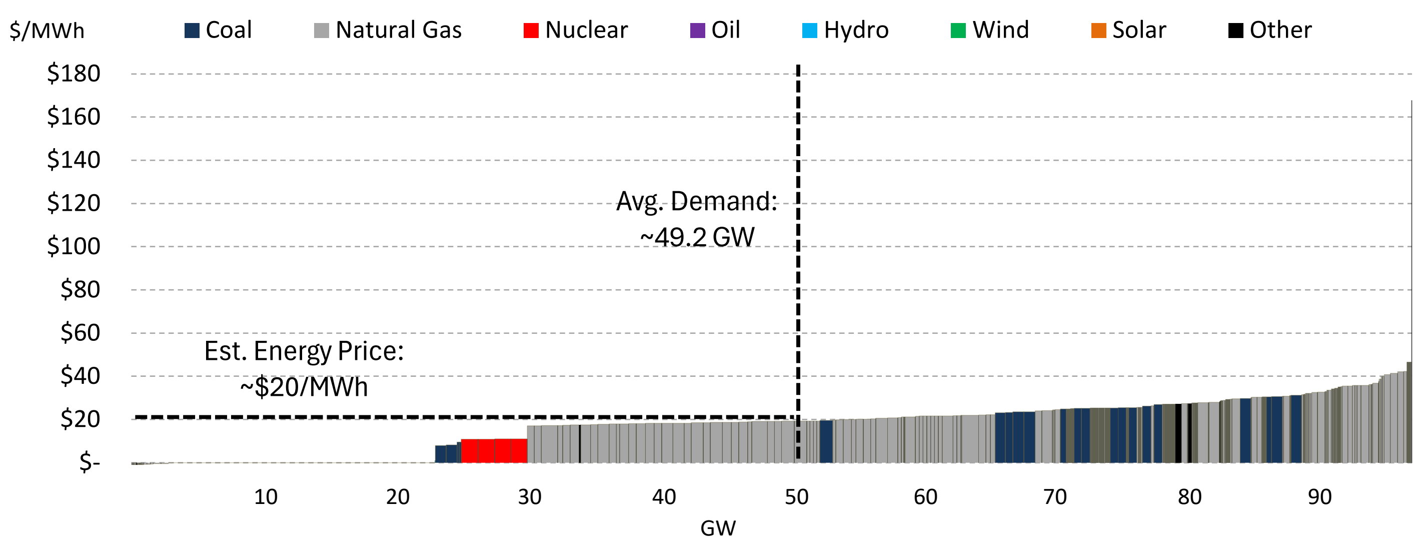
EXHIBIT 45: SPP - ESTIMATED DISPATCH STACK ON 24 JAN '26 - WITHOUT COAL



ERCOT

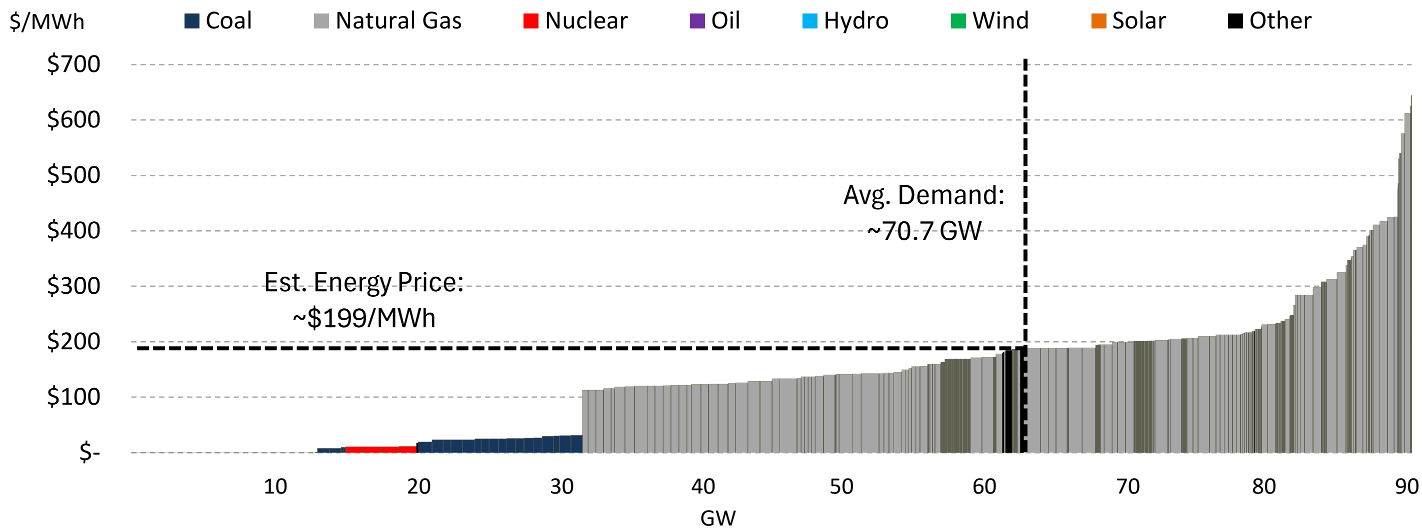
EXHIBIT 46 shows the estimated average dispatch stack for ERCOT during the first half of January 2026. At the beginning of the year, ERCOT's capacity mix was approximately 13.5 GW of coal, 55 GW of natural gas, 40 GW of wind, and 31.5 GW of solar, with nuclear (5 GW) and batteries (14 GW) accounting for the remaining capacity. Average delivered coal and natural gas prices to coal- and natural gas-fired power plants in ERCOT were $1.87/MMBtu and $2.24/MMBtu, respectively, during the first half of January 2026. With average hourly electricity demand of about 49 GW, the estimated average system energy price during the first half of January 2026 was approximately $20/MWh. Due to relatively low system stress during the first half of January, the estimated system energy price is close to the average around-the-clock day-ahead LMP at ERCOT Hub-Average during the same period ($20.42/MWh).

EXHIBIT 46: ERCOT - ESTIMATED AVERAGE DISPATCH STACK - JAN 1 - JAN 15 '26



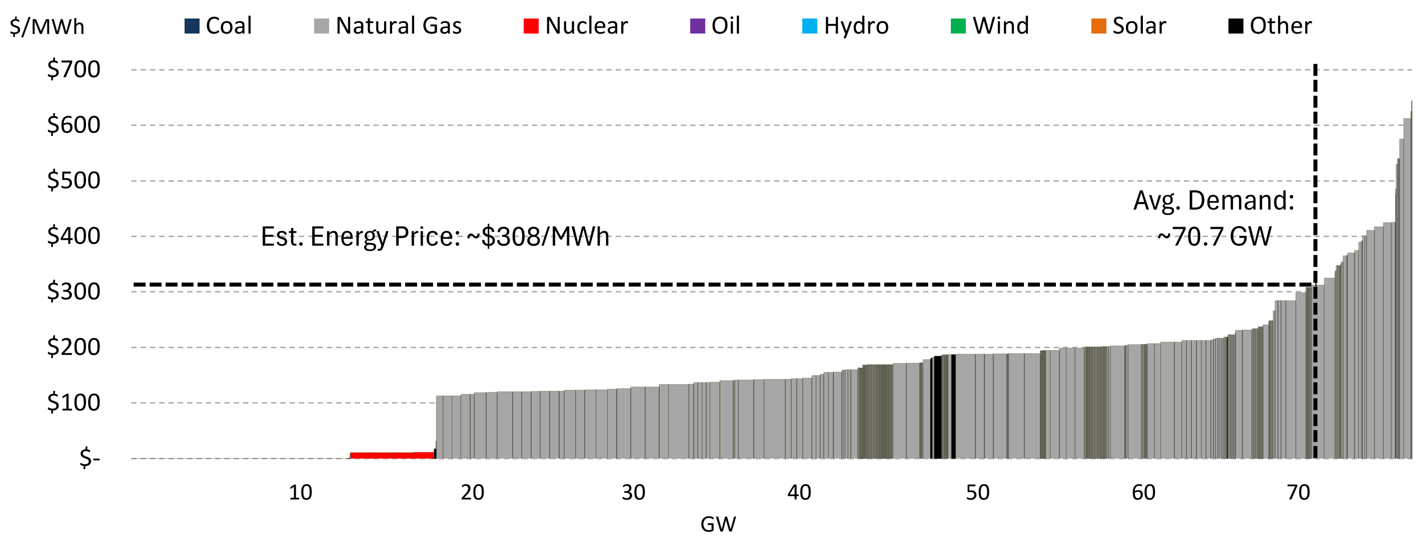
ERCOT experienced its peak electricity demand day on January 25, 2026, when hourly electricity demand averaged about 70.7 GW. On January 25, ERCOT's average wind capacity factor fell from 35% in the first half of January to 24%, while solar's capacity factor dropped from 19% to 11% over the same period. At the same time, estimated delivered natural gas prices rose more than 7-fold to almost $20/MMBtu, while delivered coal prices remained largely unchanged. As a result, the estimated average system energy price rose to about $199/MWh on January 25, a 10-fold increase compared to the first half of the month, as shown in **EXHIBIT 47**.[4]

EXHIBIT 47: ERCOT - ESTIMATED DISPATCH STACK ON 25 JAN '26



At an estimated system energy price of about $200/MWh, virtually all of ERCOT's 13 GW of coal-fired power plants were economic and dispatched at or near their maximum available capacity, as shown by the capacity factor rising to about 80% on January 25. However, if none of the 13 GW of coal plants had been available, the average system energy price in ERCOT on January 25 is estimated to have increased to about $308/MWh, an increase of over $100/MWh, as shown in **EXHIBIT 48**. At an average hourly demand of 70.7 GW, the estimated savings provided by the ERCOT coal fleet on January 25 alone are almost $185 million.

EXHIBIT 48: ERCOT - ESTIMATED DISPATCH STACK ON 25 JAN '26 - WITHOUT COAL

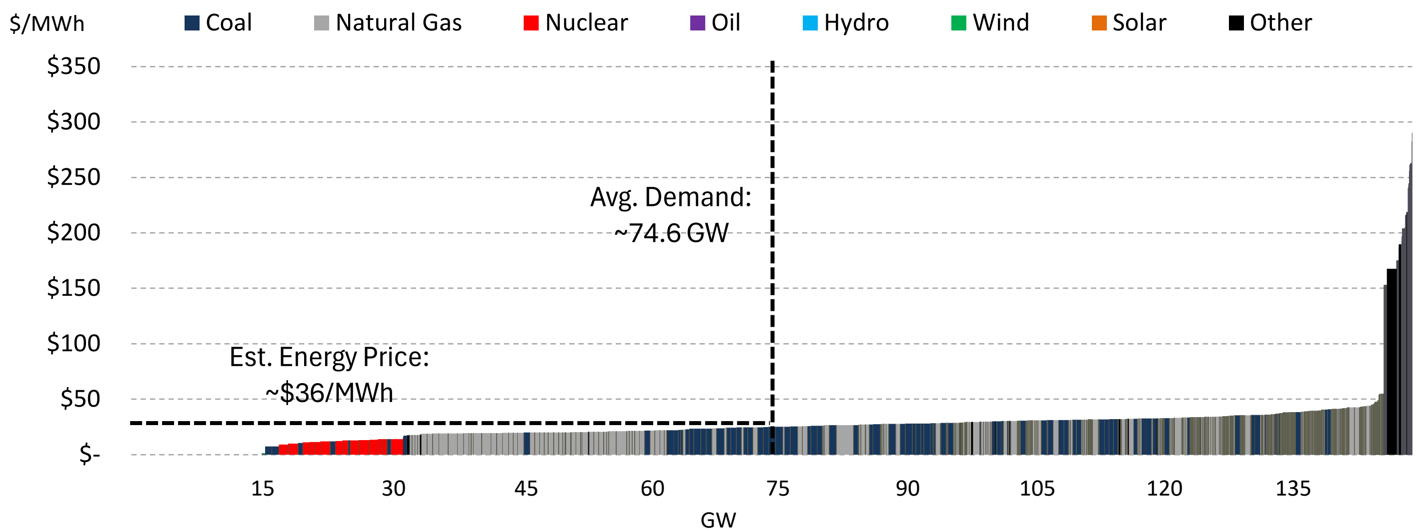


[4] Actual ATC LMP at ERCOT's Hub-Average rose to over $622/MWh in the day-ahead market as energy scarcity pricing affected marginal clearing prices. However, this analysis excludes the impact of the loss of coal plants on scarcity pricing, which, again, underscores the conservative nature of the savings estimates presented in the report.

MISO

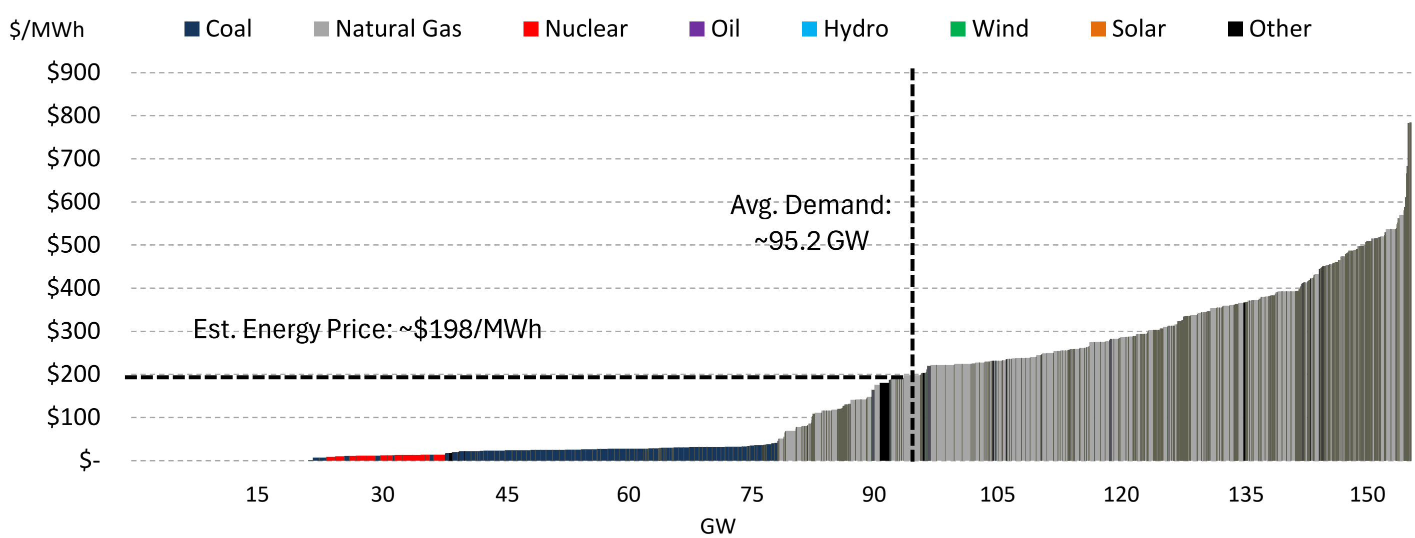
EXHIBIT 49 shows the estimated average dispatch stack for MISO during the first half of January 2026. At the beginning of the year, MISO's capacity mix was approximately 42 GW of coal, 67 GW of natural gas, 33 GW of wind, and 21 GW of solar, with nuclear (12 GW) and oil (2.9 GW) accounting for the remaining capacity. Average delivered coal and natural gas prices to coal- and natural gas-fired power plants in MISO were $2.38/MMBtu and $2.70/MMBtu, respectively, during the first half of January 2026. With an average hourly electricity demand of about 75 GW, the corresponding estimated average system energy price during the first half of January 2026 was approximately $36/MWh. Due to relatively low system stress during the first half of January, the estimated system energy price is close to the average around-the-clock day-ahead LMP at MISO Hub-Average during the same period ($35.65/MWh).

EXHIBIT 49: MISO - ESTIMATED AVERAGE DISPATCH STACK - JAN 1 - JAN 15 '26



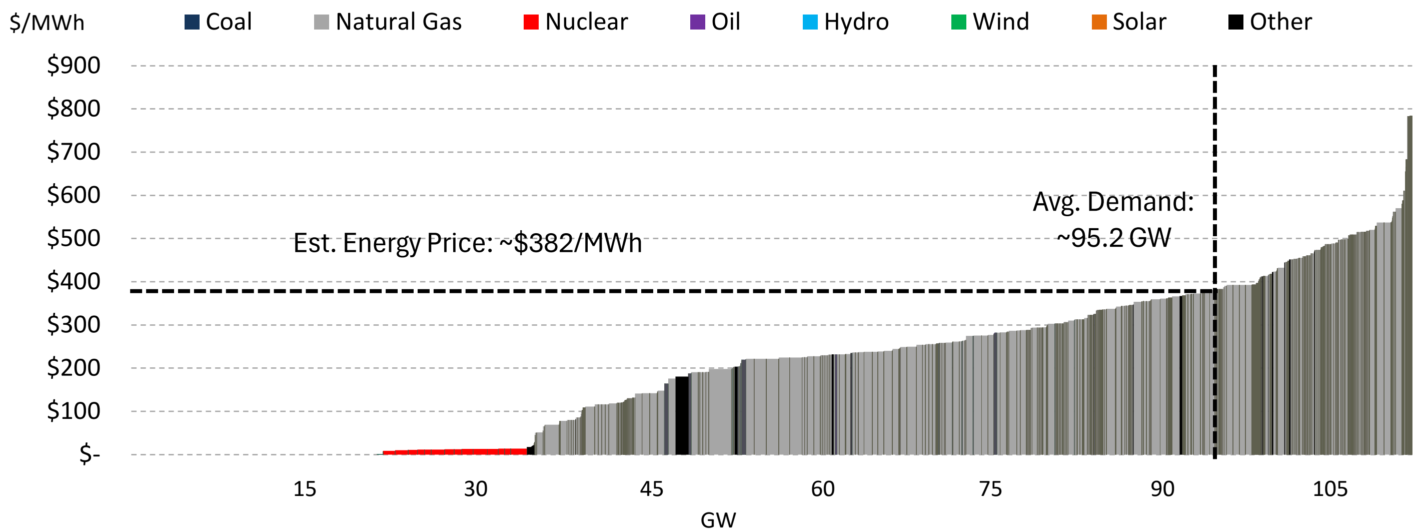
MISO experienced its peak electricity demand day on January 26, 2026, with hourly demand averaging about 95.2 GW. On January 26, estimated delivered natural gas prices rose more than 9-fold to almost $28/MMBtu, while delivered coal prices remained largely unchanged. As a result, the estimated average system energy price rose to about $198/MWh on January 26, a 5.5-fold increase compared to the first half of the month, as shown in **EXHIBIT 50**.

EXHIBIT 50: MISO - ESTIMATED DISPATCH STACK ON 26 JAN '26



At an estimated system energy price of about $200/MWh, virtually all of MISO's 42 GW of coal-fired power plants were economic and dispatched at or near their maximum available capacity, as evidenced by their output rising by over 8.5 GW on January 26 compared with the first half of the month. However, if none of the 42 GW of coal plants had been available, the average system energy price in MISO on January 26 is estimated to have increased to about $382/MWh, an increase of nearly $200/MWh, as shown in ***EXHIBIT* 48**. At an average hourly demand of 95.2 GW, the estimated savings provided by the MISO coal fleet on January 26 alone are over $420 million.

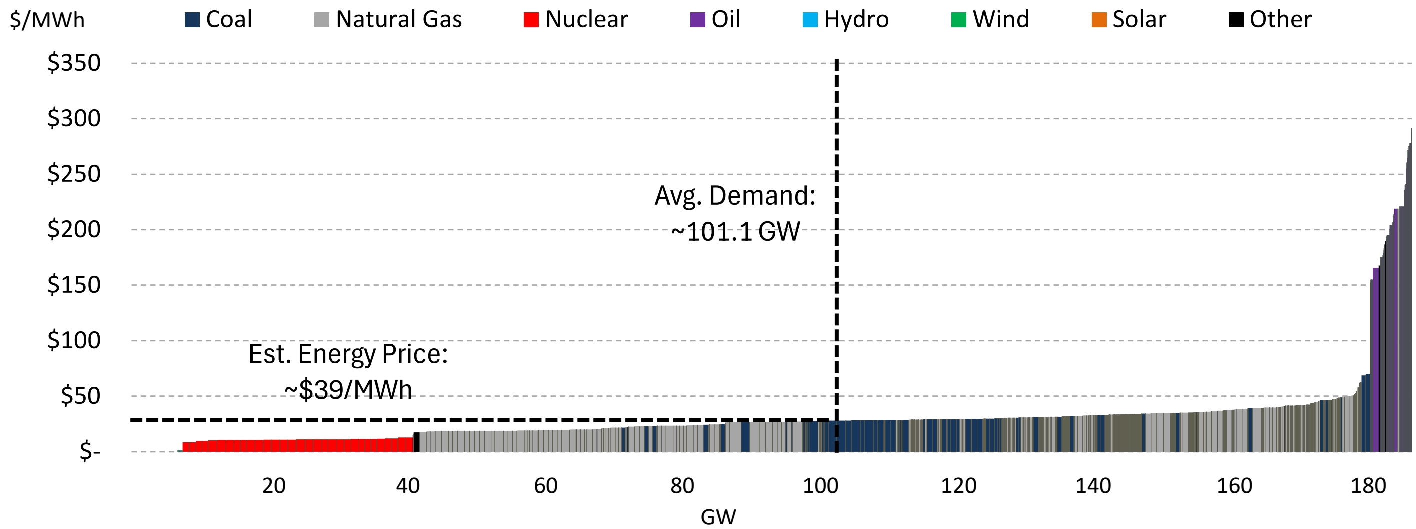
EXHIBIT 51: MISO - ESTIMATED DISPATCH STACK ON 26 JAN '26 - WITHOUT COAL



PJM

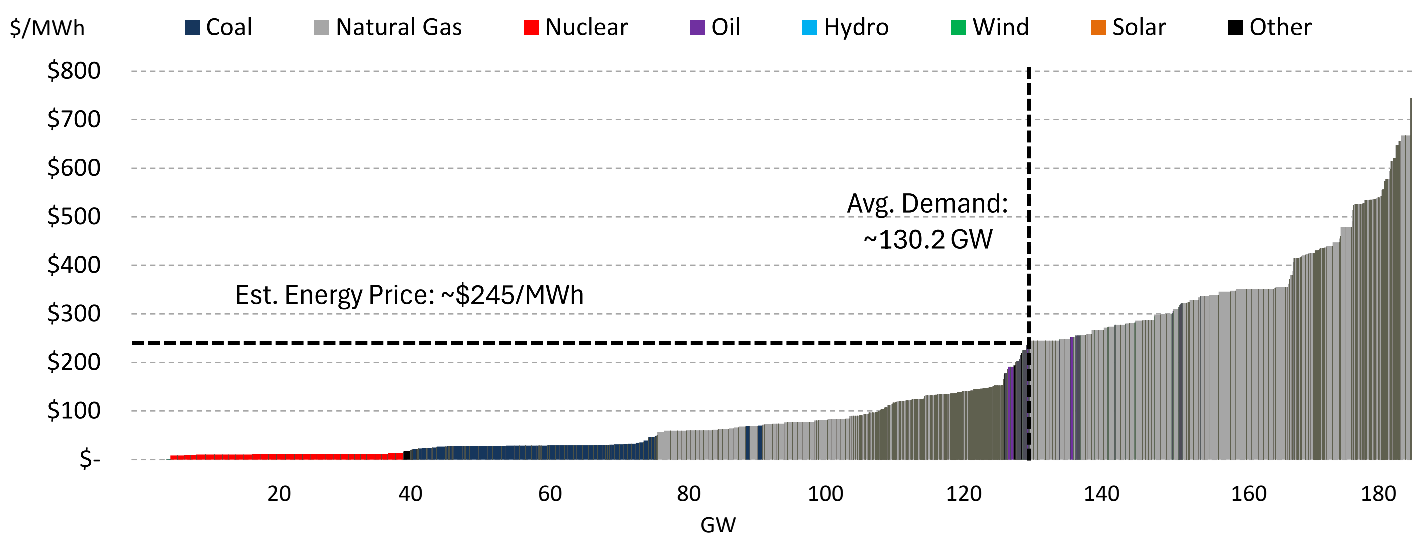
EXHIBIT 52 shows the estimated average dispatch stack for PJM during the first half of January 2026. At the beginning of the year, PJM's capacity mix was approximately 36 GW of coal, 94 GW of natural gas, 33.5 GW of nuclear, and 17.4 GW of solar, with wind (11.7 GW), hydro (8.3 GW), and oil (5 GW) accounting for the remaining capacity. Average delivered coal and natural gas prices to coal- and natural gas-fired power plants in PJM were $2.49/MMBtu and $2.98/MMBtu, respectively, during the first half of January 2026. With average hourly electricity demand of about 101 GW, the corresponding estimated average system energy price during the first half of January 2026 was approximately $39/MWh. Due to relatively low system stress during the first half of January, the estimated system energy price is close to the average around-the-clock day-ahead LMP at PJM Hub-Average during the same period ($39.48/MWh).

EXHIBIT 52: PJM - ESTIMATED AVERAGE DISPATCH STACK - JAN 1 - JAN 15 '26



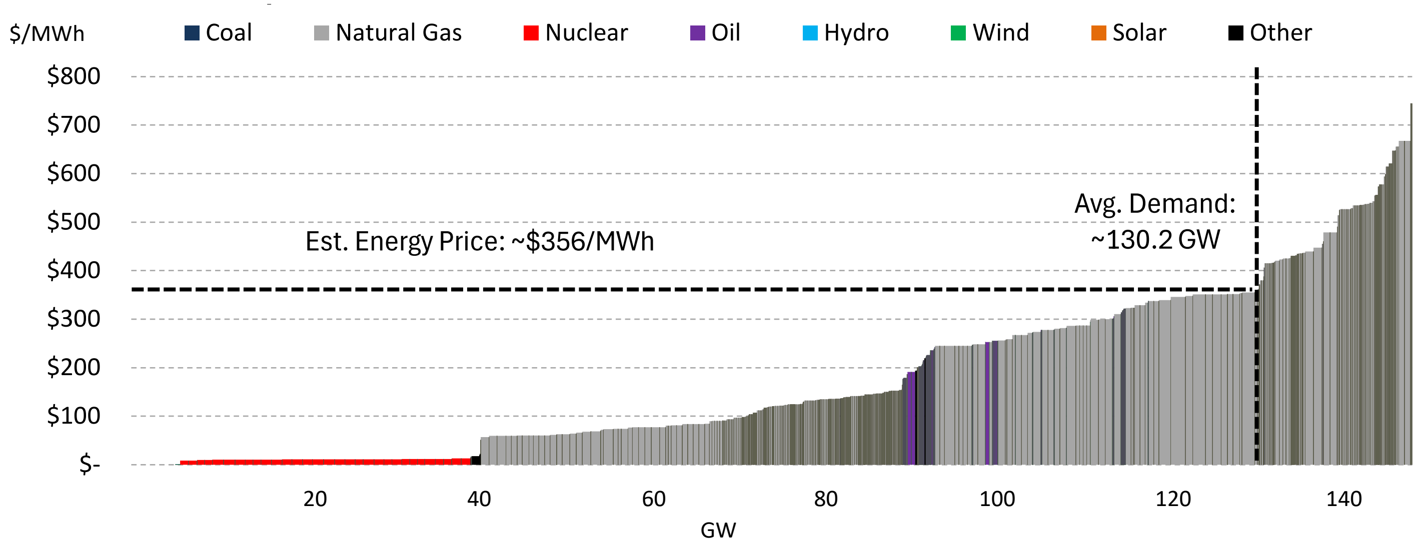
PJM experienced its peak electricity demand day on January 30, 2026, when hourly electricity demand averaged about 130.2 GW. On January 30, estimated delivered natural gas prices rose almost 7-fold to about $23/MMBtu, while delivered coal prices remained largely unchanged. Notably, natural gas prices in PJM peaked on January 27 at over $87/MMBtu due to extremely high system demand for natural gas, before prices adjusted to the heightened demand over the following days. As a result, the estimated average system energy price rose to about $245/MWh on January 30, an increase of over 6-fold compared to the first half of the month, as shown in **EXHIBIT 53**.

EXHIBIT 53: PJM - ESTIMATED DISPATCH STACK ON 30 JAN ‘26



At an estimated system energy price of about $245/MWh, virtually all of PJM’s 36 GW of coal-fired power plants were economic and dispatched at or near their maximum available capacity, as shown by the capacity factor rising to about 80% on January 30. However, if none of the 36 GW of coal plants had been available, the average system energy price in PJM on January 30 is estimated to have increased to about $356/MWh, an increase of over $100/MWh, as shown in **EXHIBIT 54**. At an average hourly demand of 130.2 GW, the estimated savings provided by the PJM coal fleet on January 30 alone are nearly $347 million.

EXHIBIT 54: PJM - ESTIMATED DISPATCH STACK ON 30 JAN '26 - WITHOUT COAL



Conclusion

Overall, the coal fleet in SPP, ERCOT, MISO, and PJM saved more than $1.1 billion on their respective peak electricity demand days during Winter Storm Fern. It is worth reiterating that these savings do not account for the total savings realized by the coal fleet over the entirety of Winter Storm Fern. As noted, natural gas prices in PJM rose to over $87/MMBtu on January 27. While electricity demand did not reach its peak until January 30, when the PJM coal fleet saved electricity consumers in PJM an estimated $347 million, the PJM coal fleet likely realized a substantial amount of savings on the days prior to and after January 30, when natural gas prices either peaked or remained elevated. Additionally, this analysis does not consider the impact on other wholesale power price components, such as congestion, line-loss, or other scarcity pricing mechanisms, which can rise substantially as excess capacity during peak demand times diminishes. Lastly, this analysis also did not investigate whether peak hourly electricity demand could have been met in the absence of coal plants during the hypothetical scenarios. More detailed analysis is necessary to estimate the full extent of savings provided by the coal fleet in SPP, ERCOT, MISO, and PJM during Winter Storm Fern.