FEBRUARY 2025

Operation of the U.S. Power Grid During the January 2025 Polar Vortex

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Executive Summary

The January 2025 Polar Vortex pushed the U.S. power grid to unprecedented limits as record-breaking low temperatures and extreme weather conditions pushed electricity demand to historic levels. Across multiple power market regions, electricity demand during the event set new single-day demand records as heating demand across sectors spiked. In response, grid operators relied heavily on dispatchable generation—primarily coal and natural gas—to ensure system reliability and stabilize supply during the extreme event.

This report analyzes and highlights how power generation across the country responded to the exceptional winter weather event in January 2025. Some of the national and regional highlights of the report include:

- **Critical Ramp-Up of Coal:** Coal-fired power plants dramatically increased their output during the Polar Vortex. In many regions, capacity factors for coal soared above 80%, far exceeding typical winter levels. This robust performance was essential, as variable renewable resources (such as wind and solar) underperformed due to adverse weather conditions. Coal's ability to increase electric output substantially ensured that approximately one-fourth of the total generation mix during peak hours came from coal-fired power plants, offsetting significant fluctuations in renewables and meeting the incremental electricity demand.

- **Role of Natural Gas and Other Fossil Fuels:** Natural gas generation also increased markedly to meet the surge in demand. However, while natural gas units ramped up production, they faced volatile fuel costs amid heightened heating and electricity demand needs. Other fossil sources like oil-fired generation, although normally minor players, were called upon to bridge shortfalls during peak periods.

- **Reduced Price Volatility via Increased Coal Dispatch:** In the PJM region, where electricity demand reached new highs (with peak demand exceeding 132 GW), coal-fired plants proved to be vital economic assets. As natural gas prices spiked—from under \$2/MMBtu in November to nearly \$30/MMBtu at the height of the event—coal's stable fuel cost (around \$2.50/MMBtu) allowed for increased coal plant dispatch and limited wholesale power price spikes. Coal plants, therefore, moved from a marginal resource in November to a primary electricity supply resource, with capacity factors increasing to nearly 70% during the event.

- **Impact on Wholesale Power Prices:** The PJM case study demonstrated that coal's dispatchability was key in containing power price spikes. PJM's average day-ahead power prices peaked at about \$225/MWh on January 21. A hypothetical analysis revealed that without coal-fired generation, prices could have soared to over \$400–\$650/MWh—potentially adding between \$500 million and \$1.4 billion in extra costs for consumers. This stark contrast underscores coal's role as a de facto price hedge in times of extreme demand.

The January 2025 Polar Vortex underscored the indispensable role of dispatchable generation in maintaining grid reliability and controlling wholesale power prices under extreme weather conditions. Coal-fired power plants, with their on-site fuel storage and stable fuel costs, proved critical in bridging the demand gap when renewable output was constrained, and natural gas prices became highly volatile. The PJM power price case study, in particular, highlights how the continued operation of coal resources can prevent massive cost escalations for electricity consumers during such events. These findings emphasize the importance of a balanced energy mix that includes resilient, dispatchable assets alongside renewables to ensure energy security and affordability in the face of future extreme weather challenges.

Table of Contents

Table of Exhibits

List of Abbreviations and Definitions

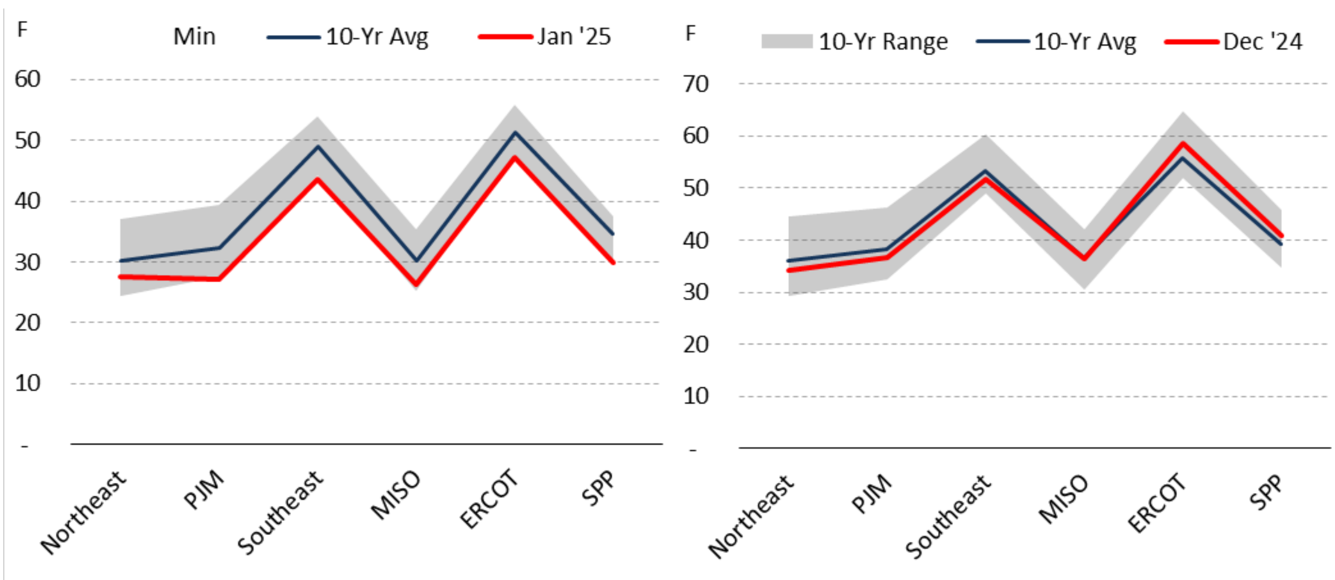
- **DAM** – Day-Ahead Market: A wholesale electricity market where prices and generation schedules are determined one day in advance.
- **EIA** – Energy Information Administration: A U.S. government agency that collects and analyzes energy data.
- **ERCOT** – Electric Reliability Council of Texas: The independent system operator managing the Texas power grid.
- **GW** – Gigawatt: A unit of power equal to one billion watts.
- **ISO** – Independent System Operator: An entity responsible for managing regional electricity markets and ensuring grid reliability.
- **MISO** – Midcontinent Independent System Operator: The system operator managing the power grid across parts of the Midwest and South.
- **MW** – Megawatt: A unit of power equal to one million watts.
- **PJM** – PJM Interconnection: The largest regional transmission organization in the U.S., covering 13 states and Washington, D.C.
- **RTO** – Regional Transmission Organization: An entity responsible for managing and coordinating electricity transmission over large geographic areas.
- **SPP** – Southwest Power Pool: An independent system operator that manages the electricity market in central U.S. states.
- **VOM** – Variable Operating and Maintenance Costs: Costs that vary based on electricity generation, including fuel and maintenance expenses.

Introduction

Arctic air rolled through many of the lower-48 states of the United States from the late hours of January 19th to January 23rd, bringing a stretch of extreme cold weather to the on-average coldest time of the year for much of the country. This extreme weather event was characterized by dramatic distortion of the upper-atmospheric circulation called the "Polar Vortex," which resulted in the widespread intrusion of frigid Arctic air into mid-latitude regions. Termed the "January 2025 Polar Vortex" for the context of this report, this event led to record-breaking low temperatures in parts of the country, stressing residential and commercial heating systems and regional power grids.

Polar vortex distortions were detected as early as the end of 2024 to early January 2025, leading to the coldest January in ten years across various power market regions in the country. Averaging at the minimum of the ten-year range of temperatures, as seen on the chart on the left in **EXHIBIT 1**, the first couple of weeks of January were characterized by escalated coal and natural gas generation. In comparison, as shown in the chart on the right in **EXHIBIT 1** below, the regional temperature averages for December 2024 largely aligned with the ten-year averages and were well within the observed temperature ranges. Subsequently, for the purpose of this report, the primary demand and generation analyses have been conducted using the December 2024 observed numbers as the baseline for a winter month with near-average weather-related electricity and fossil fuel demand.

EXHIBIT 1: JANUARY AND DECEMBER TEMPERATURE AVERAGES VS. 10-YEAR TEMPERATURE AVERAGES FOR MAJOR U.S. POWER MARKETS



Source: NOAA, Frontier Weather

This stretch of cold weather led to record-breaking highs in electricity demand in some regions of the country. Cautioned by weather forecasting models, the grid displayed a higher degree of preparedness in comparison to previous extreme weather events. As discussed within this report, dispatchable generation, i.e., coal and natural gas, were already operating with higher utilization in the early weeks of January than in December due to the sustained below-average temperatures for much of January. Daily median temperature charts for January 2025 for the regions analyzed in this report are provided in the Appendix.

Regional 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 2**.[1,2] The power market regions are presented in the order of the winter storm's impacts on their respective power systems.

EXHIBIT 2: MAP OF POWER MARKET REGIONS

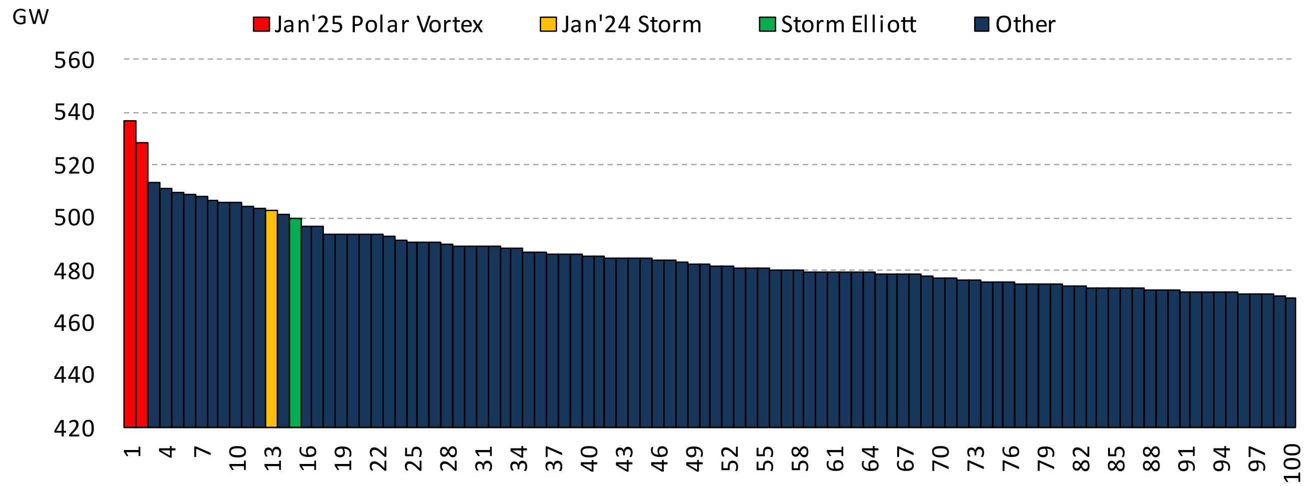
Regional Aggregate Results

Between January 20 and January 22, 2025, much of the affected Lower 48 states experienced significantly below-average temperatures, leading to a surge in electricity demand. **EXHIBIT 3** presents the top 100 electricity demand occurrences across the combined territories of SPP, ERCOT, MISO, PJM, the Southeast, and the Northeast (referred to as the "Regional Total"). The polar vortex in January 2025 resulted in the highest and second-highest electricity demand levels on record, reaching 537 GW and 528 GW, respectively—nearly 150 GW above the regional average of approximately 390 GW. These demand levels surpassed those observed during previous extreme weather events, including the Jan'24 Winter Storm and Winter Storm Elliott during December 2022, by nearly 35 GW and 37 GW, respectively.

[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 detail 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 the January 2025 polar vortex.

EXHIBIT 3: REGIONAL TOTAL - TOP 100 ELECTRICITY DEMAND DAYS

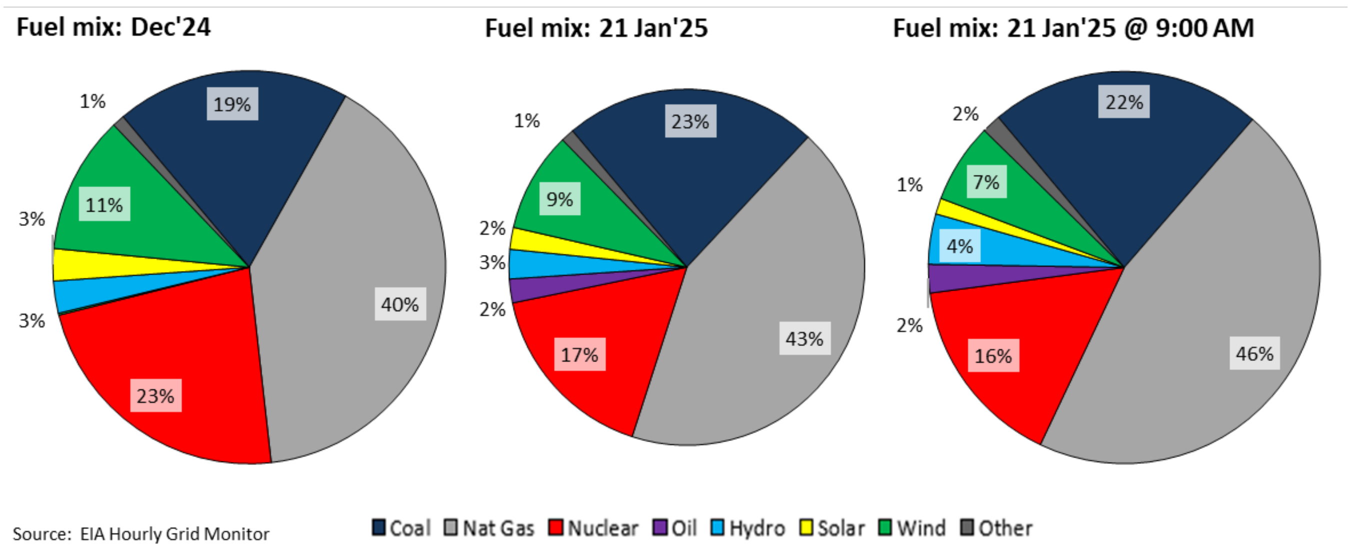


Source: EIA Hourly Grid Monitor

On a broader scale, peak electricity demand during the event occurred on January 21, reaching its apex at 9:00 AM. A comparison of the generation mix for the affected regions during the peak demand day and hour to the average hourly generation during December 2024 highlights a predominant reliance on natural gas and nuclear power, followed by coal and wind. While the overall fuel mix on January 21 remained relatively consistent with the seasonal average, there was a notable increase in coal and natural gas generation, as illustrated in **EXHIBIT 4**.

During the peak hour, coal accounted for approximately one-fourth of total generation, while wind output saw a notable decline compared to its average contribution during December 2024. Solar generation also dropped to one-third of its usual share as solar radiation during early morning hours in the winter months is minimal. In contrast, natural gas usage increased significantly, becoming the dominant source of generation with a 46% share of total electricity output.

EXHIBIT 4: REGIONAL TOTAL - GENERATION MIX

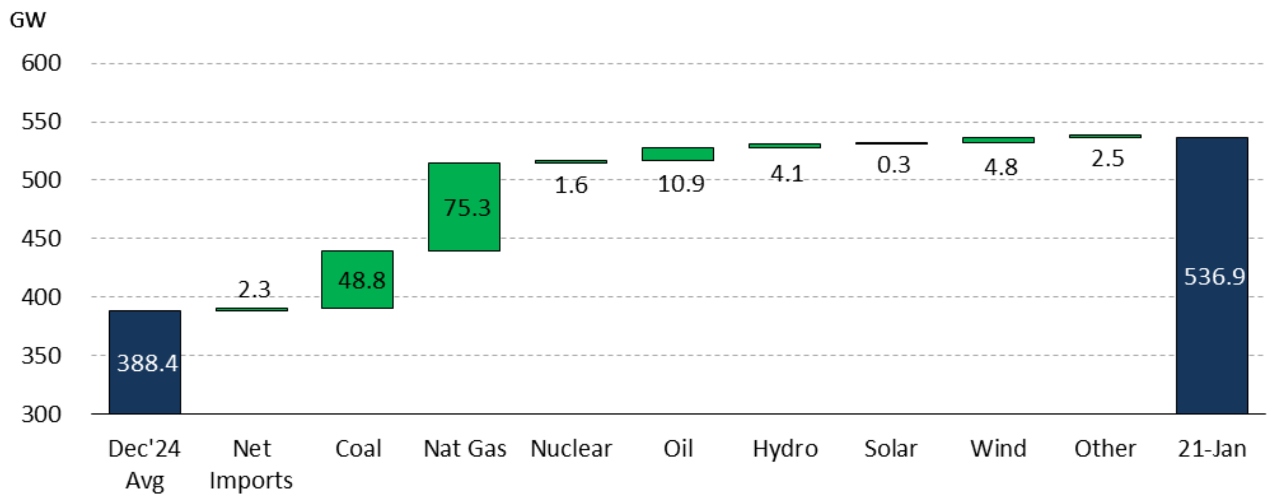


Source: EIA Hourly Grid Monitor

During the January 2025 Polar Vortex, electricity demand peaked on January 21, surging nearly 150 GW above the average hourly electricity demand in December 2024. Approximately 70% of this increased demand was met by fossil fuel generation, primarily from coal and natural gas, which contributed an additional 50 GW and 75 GW, respectively, compared to their December 2024 average hourly generation, as illustrated in **EXHIBIT 5**.

Oil-fired generation, which usually accounts for less than 1 GW, saw a significant ramp-up, providing an additional 11 GW to help meet the record demand. On the renewable side, wind and hydro collectively added 9 GW to the grid, while solar generation on the peak day remained consistent with its output from the previous month.

EXHIBIT 5: REGIONAL TOTAL - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY

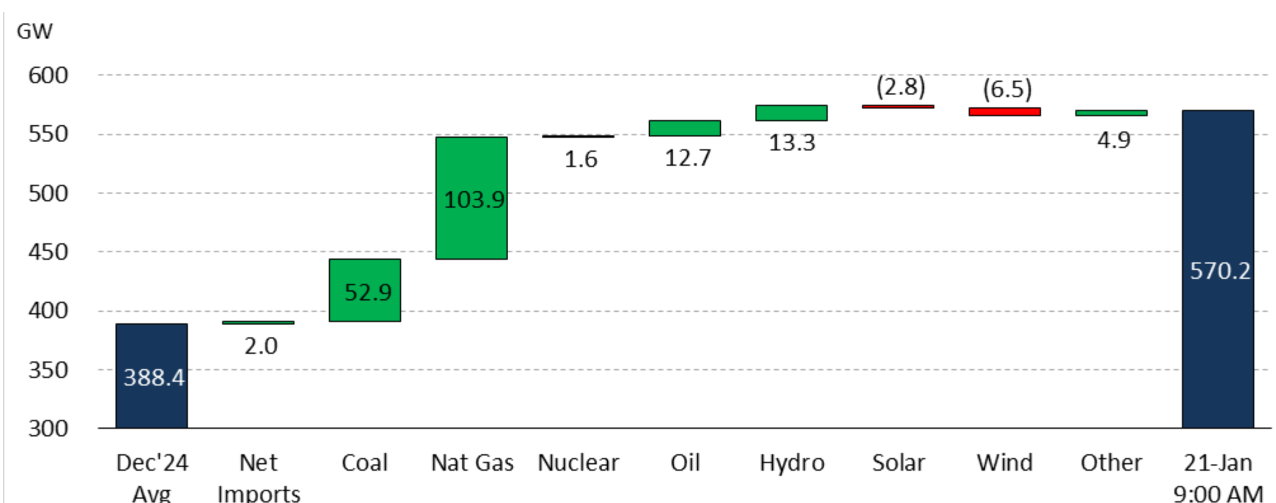


Source: EIA Hourly Grid Monitor

During the peak demand hour of the January 2025 Polar Vortex, electricity demand surged by approximately 180 GW compared to the December 2024 average hourly demand. Due to the peak occurring at 9:00 AM, solar capacity was insufficient to make a significant contribution. Both wind and solar generation experienced substantial declines, producing 6.5 GW and 2.8 GW less, respectively, than the previous month's contributions.

Fossil fuel generation supplied much of the increased demand, with natural gas providing an additional 104 GW and coal contributing another 53 GW compared to normal winter conditions, as illustrated in **EXHIBIT 6**.

EXHIBIT 6: REGIONAL TOTAL - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



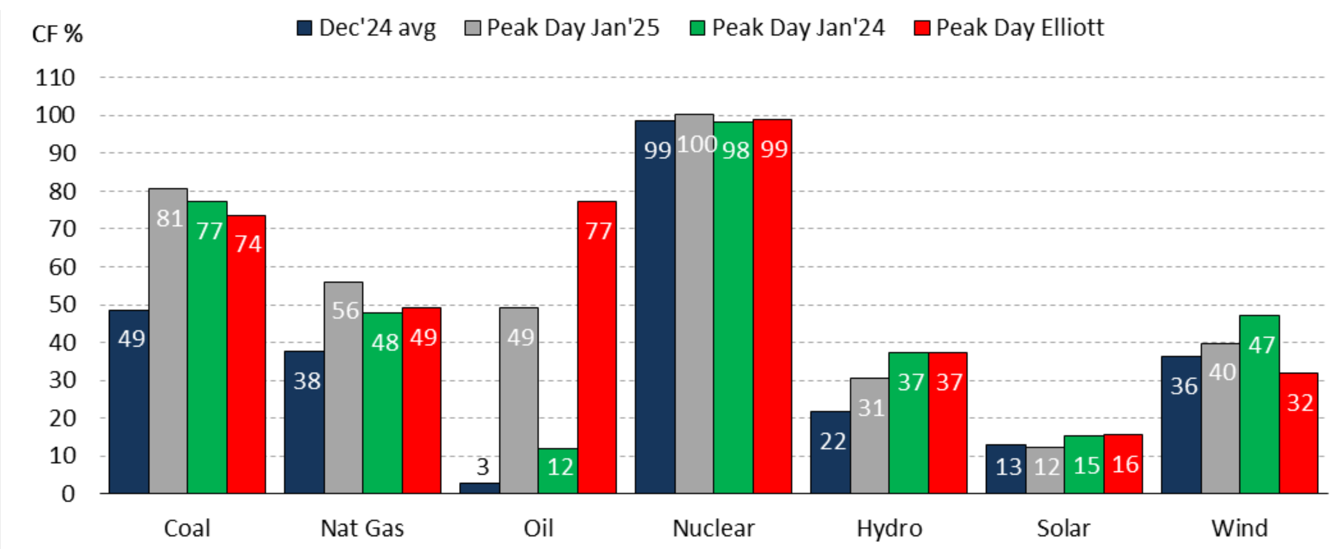
Source: EIA Hourly Grid Monitor

EXHIBIT 7 illustrates the capacity factors, or utilization rates, of various generating resources during peak demand periods compared to the average for December 2024. Capacity factors effectively capture the response and availability of different resource types for different extreme weather events like the January 2025 Polar Vortex, the January 2024 Winter Storm, and Winter Storm Elliott, independent of any resource additions or retirements that occurred between these events. Thus, it provides more equitable insights into the performance of each resource type and reflects variations in resource dispatchability during such critical situations. The capacity factors shown represent the average utilization of all operational generating resources of a given fuel type, regardless of individual unit availability during the observed periods.

Among the different resource types, coal-fired power plants exhibited the most significant increase in utilization across all three extreme weather events, excluding nuclear plants, which typically operate at nearly 100% utilization when available. During the peak demand day of the January 2025 Polar vortex, coal generation surpassed an 80% capacity factor, markedly higher than its December 2024 average and utilization levels during other extreme weather events, such as Winter Storm Elliott.

Natural gas-fired power plants also experienced a notable surge in capacity factors during peak demand days compared to December 2024, albeit at lower incremental rates than their coal-fired counterparts. In contrast, solar and wind generation contributed less significantly during these extreme weather events. Solar performance remained relatively consistent with its average generation in December 2024, while wind generation showed variability. Although wind operated at a slightly higher capacity factor during the peak demand day of the polar vortex compared to the previous month's generation, overall generation was significantly lower compared to the peak day of the January 2024 winter storm. Wind generation during the peak day of the Jan’25 Polar Vortex was 7 GW lower than during the Jan’24 storm, despite the addition of nearly 3.5 GW of wind capacity in 2024. This also highlights the intermittency of wind resources and raises questions about their reliability during extreme weather events.

EXHIBIT 7: REGIONAL TOTAL - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



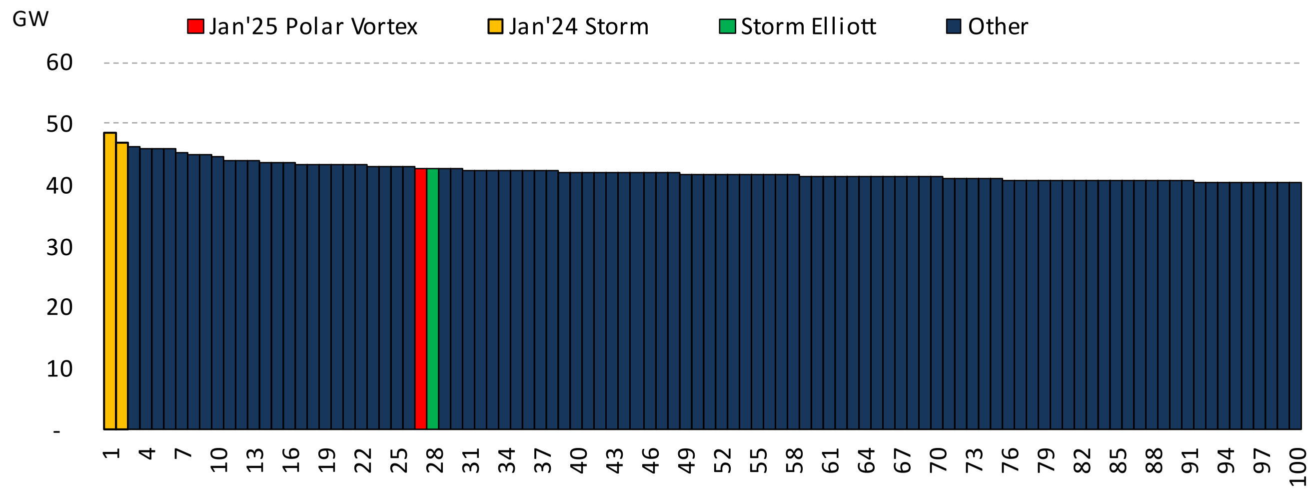
Source: EIA Hourly Grid Monitor & EIA 860 data

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.

The average demand in the region ranges between 30-35 GW. In January 2025, the Polar Vortex event resulted in one of the highest peak demands in SPP's history. On January 21, the average demand reached 42.7 GW, with a peak hourly demand of 45.3 GW. This average daily demand ranked among the top 100 demand days in history, specifically at 27th place, as illustrated in **EXHIBIT 8**. Notably, the highest electricity demand day during this Polar Vortex was comparable to and slightly exceeded the average demand on the peak day during Winter Storm Elliott.

EXHIBIT 8: SPP - TOP 100 ELECTRICITY DEMAND DAYS

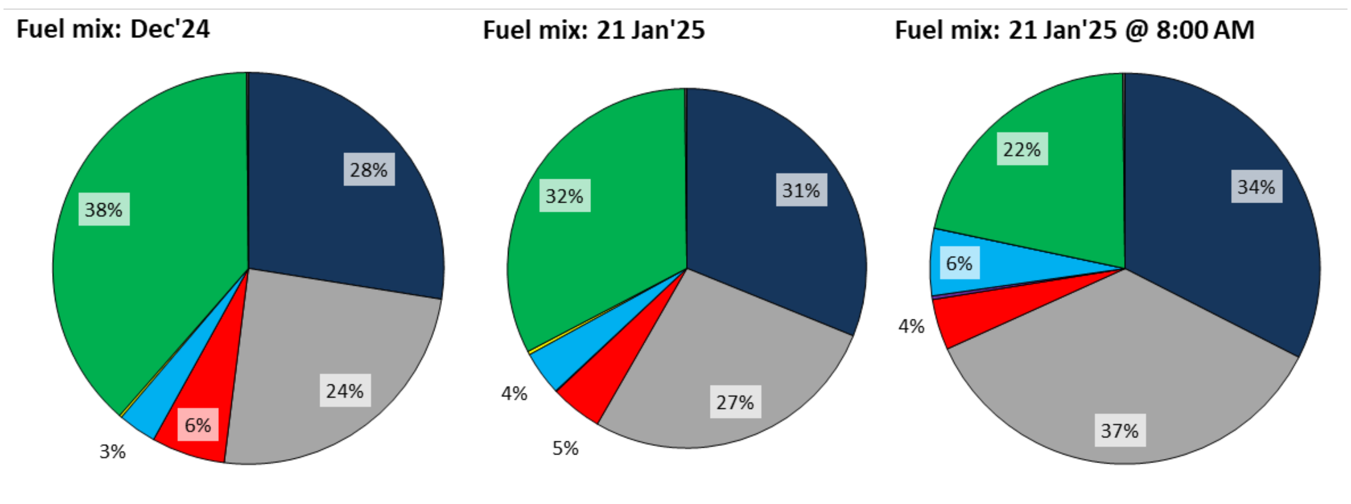


Source: EIA Hourly Grid Monitor

In December 2024, wind resources accounted for a significant portion of electricity generation in the Southwest Power Pool (SPP), making up 40% of the total. However, on January 21, when demand in the region reached its peak, the share of wind energy dropped to 32%. As demand increased, other energy sources stepped up their contributions to the grid, with coal becoming the primary source of added generation. During the peak demand hour on the morning of January 21, coal and natural gas together constituted 71% of the region's generation mix.

On January 21, wind generation averaged 14.2 GW, but it fell to 10.3 GW during the peak demand hour in the morning. This decline resulted in an increased dispatch of coal and natural gas to compensate for the shortfall, as seen in **EXHIBIT 9**.

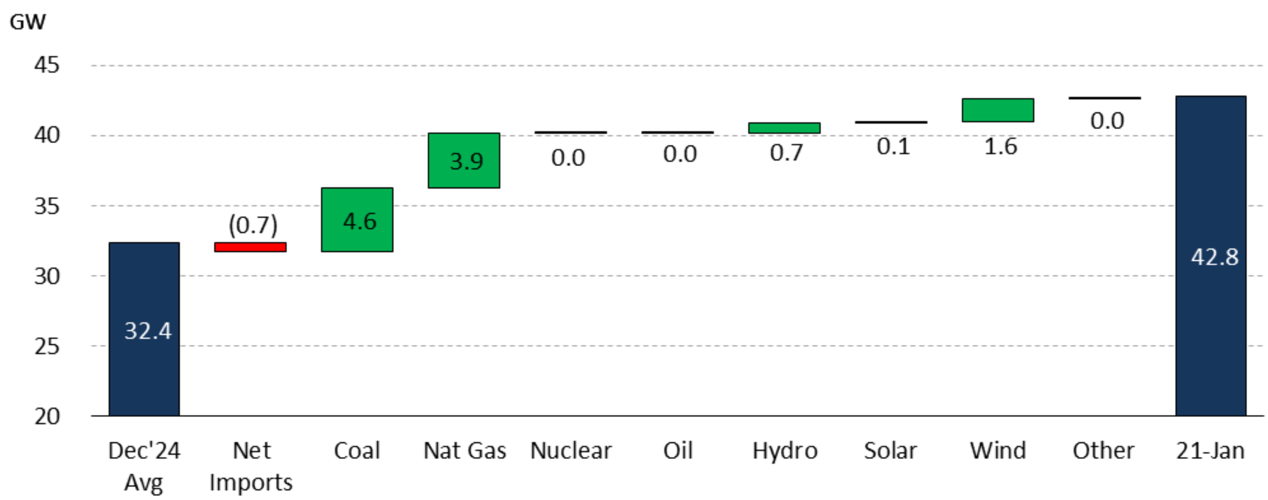
EXHIBIT 9: SPP - GENERATION MIX



Source: EIA Hourly Grid Monitor

EXHIBIT 10 displays a comparative analysis of demand and generation from various fuel sources, focusing on average hourly operations during December 2024 and the peak demand day during the Polar Vortex in January 2025. Notably, on January 21, demand increased by approximately 10 GW to 42.8 GW, leading to a significant rise in coal and gas generation—by 4.6 GW and 3.9 GW, respectively—to ensure grid stability, contributing over 87% to the additional load. While wind and hydro generation saw a slight increase, solar generation experienced a net decline compared to the previous month's output.

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

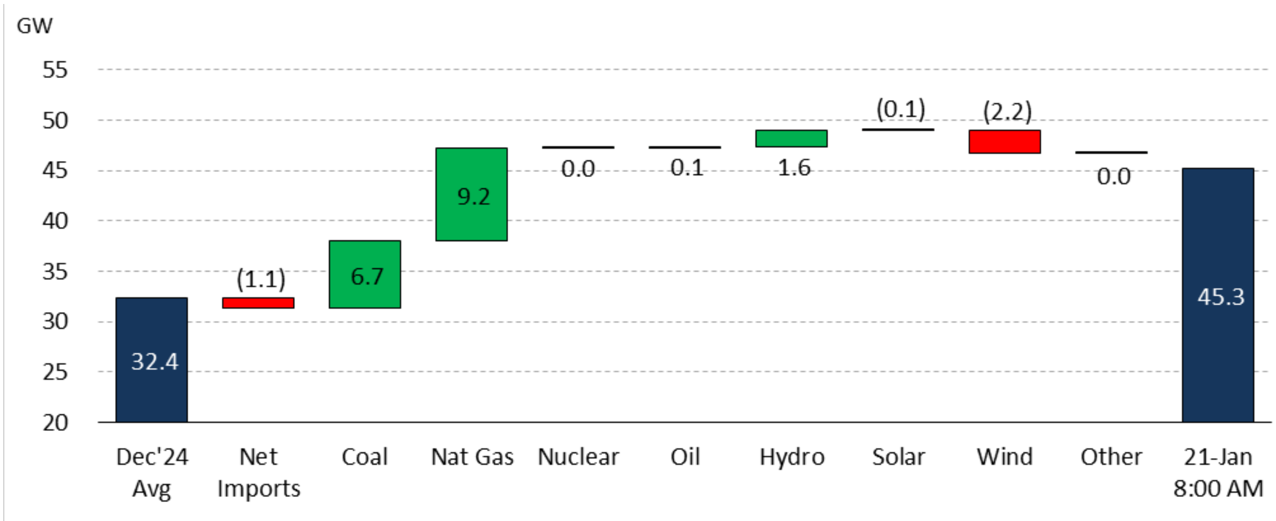


Source: EIA Hourly Grid Monitor

Similar to the previous chart, the analysis presented in **EXHIBIT 11** below offers a comparative analysis between the average hourly operations during December 2024 and the peak demand hour of the January 2025 Polar Vortex. In the SPP region, this peak occurred at 8.00 am on January 21, leading to a surge in demand of 45.3 GW.

On January 21, the daily average for wind generation was 14.2 GW; however, it decreased to 10.4 GW during the peak demand hour due to inclement weather conditions. In response, coal and natural gas generation increased substantially to meet the higher demand, rising to 15.7 GW and 17.2 GW, respectively. In comparison, during December 2024, daily coal and natural gas generation was only 9 GW and 8 GW on average, marking sharp increases of 74% and 115% in January.

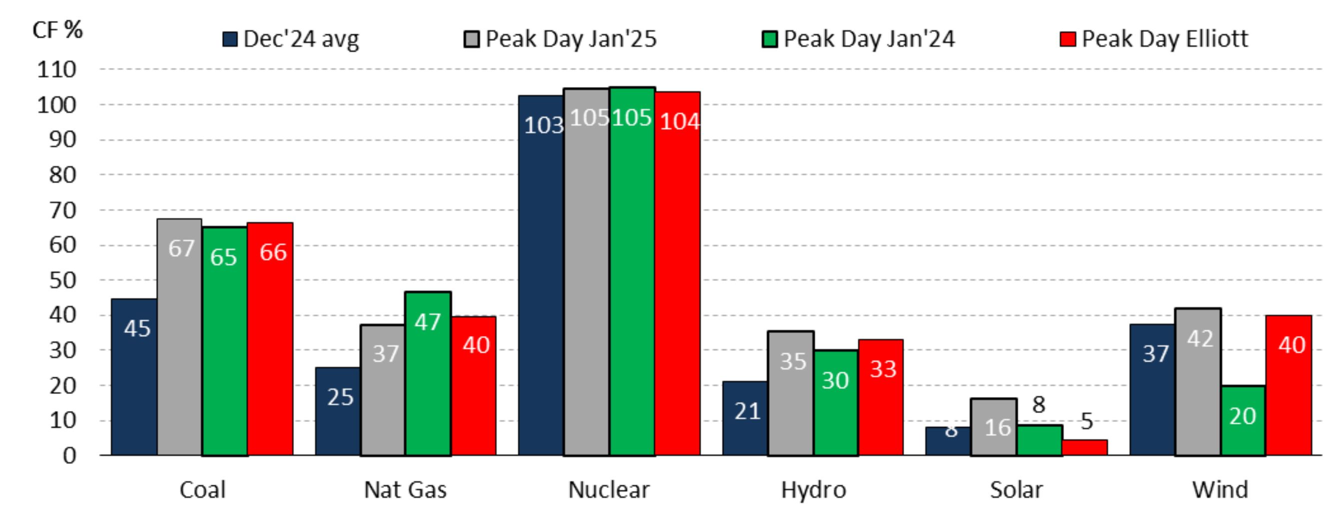
EXHIBIT 11: SPP - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



Source: EIA Hourly Grid Monitor

EXHIBIT 12 below illustrates the capacity factors of different types of generating resources during December 2024 and various periods of peak demand in comparison to January 21 in the SPP. Since absolute capacity numbers can change from year to year, capacity factors provide a more equitable metric for comparing how different fuel types respond to extreme weather events, such as the Polar Vortex and Winter Storm Elliott. As shown in **EXHIBIT 12**, coal generators significantly increased their utilization to meet the rising electricity demand. Notably, coal generation was already heightened in December, as there were anticipations of high demand due to the extreme cold. **EXHIBIT 12** also highlights the variability of solar and wind resources. Wind resources made a substantial contribution to meeting peak day demand and showed increased utilization from December averages, although they generated more electricity during non-peak hours on that day. Solar capacity factors, on the other hand, increased markedly from 8% in December 2024 to 16% on January 21, 2025, but remained low on average due to reduced solar irradiation and snow cover. In contrast, nuclear energy remained stable, while natural gas capacity factors increased from 22% to 35%.

EXHIBIT 12: SPP - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



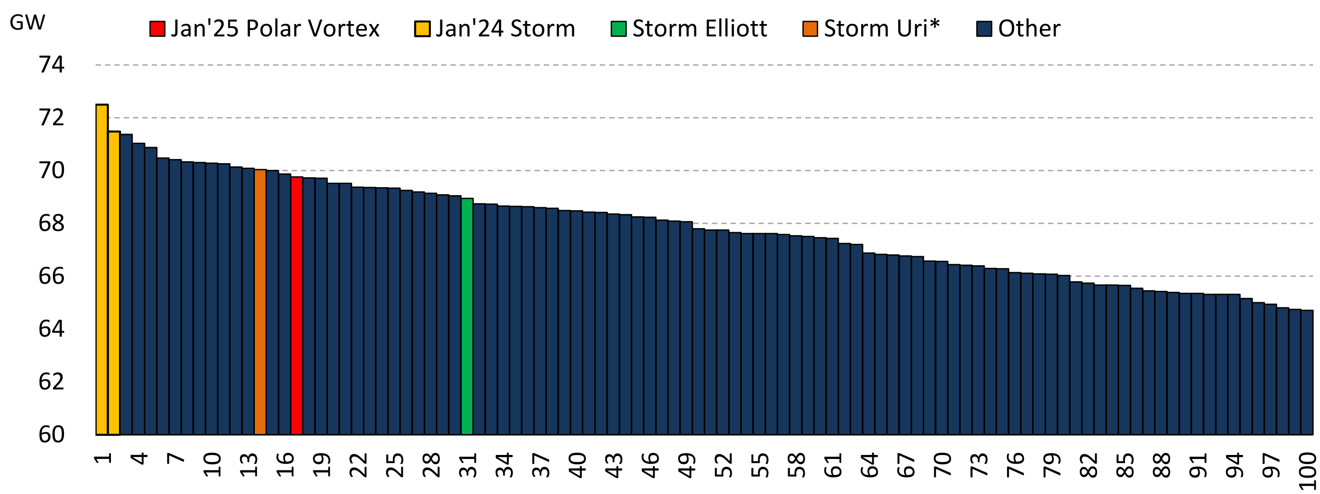
Source: EIA Hourly Grid Monitor & EIA 860 data

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.

In December 2024, ERCOT averaged a demand of about 46 GW. On January 20, the average daily demand surged to 69.7 GW, peaking at 73.7 GW during the peak hour. However, this demand was still lower than the peaks recorded during the January 2024 Winter Storm, when daily demand averaged 72.5 GW, as shown in **EXHIBIT 13**. Notably, Storm Uri and Storm Elliott registered peak demands of 70 GW and 68.9 GW, respectively.

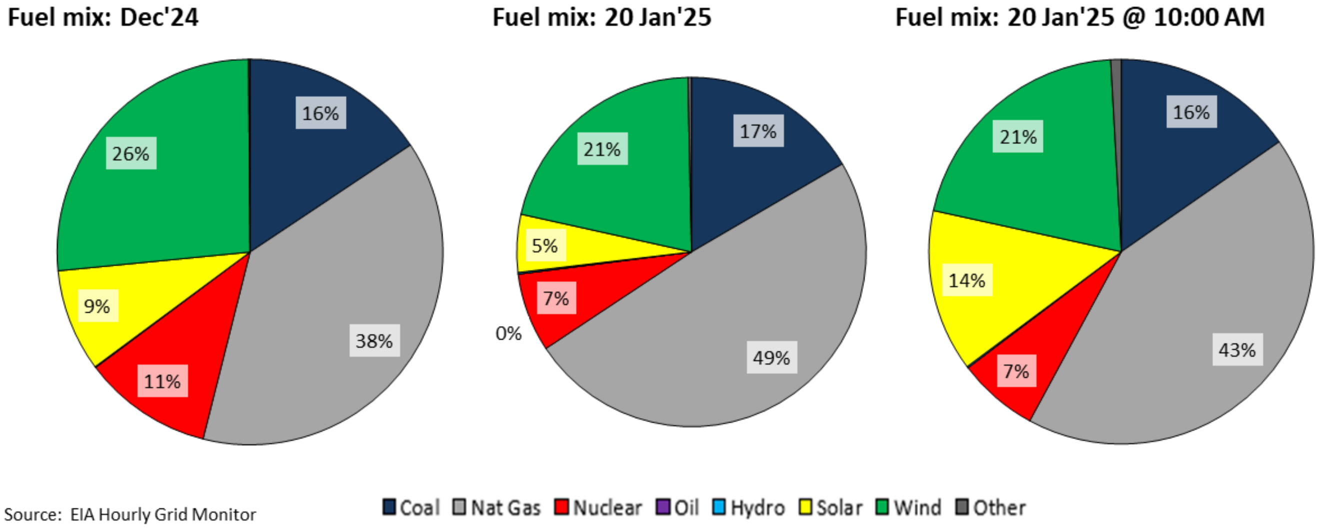
EXHIBIT 13: ERCOT - TOP 100 ELECTRICITY DEMAND DAYS



Source: EIA Hourly Grid Monitor; *Note: forecasted demand for Uri is shown. Widespread power outages caused actual demand to be much lower

Natural gas (38%) and wind (26%) are the largest contributors to the ERCOT generation mix, while coal, nuclear, and solar collectively account for the remaining third. As illustrated in **EXHIBIT 14**, the reduced solar generation during the winter months is due to decreased solar irradiation and snowfall, along with lower-than-average temperatures in January. Consequently, ERCOT was dispatching more coal and natural gas than in the previous month. However, during peak demand hours in the morning of January 20 when sunlight was available, solar generation increased by 6 GW, leading to a rise in the generation mix to 14% despite averaging at 5% for the entire day, as shown in **EXHIBIT 14**.

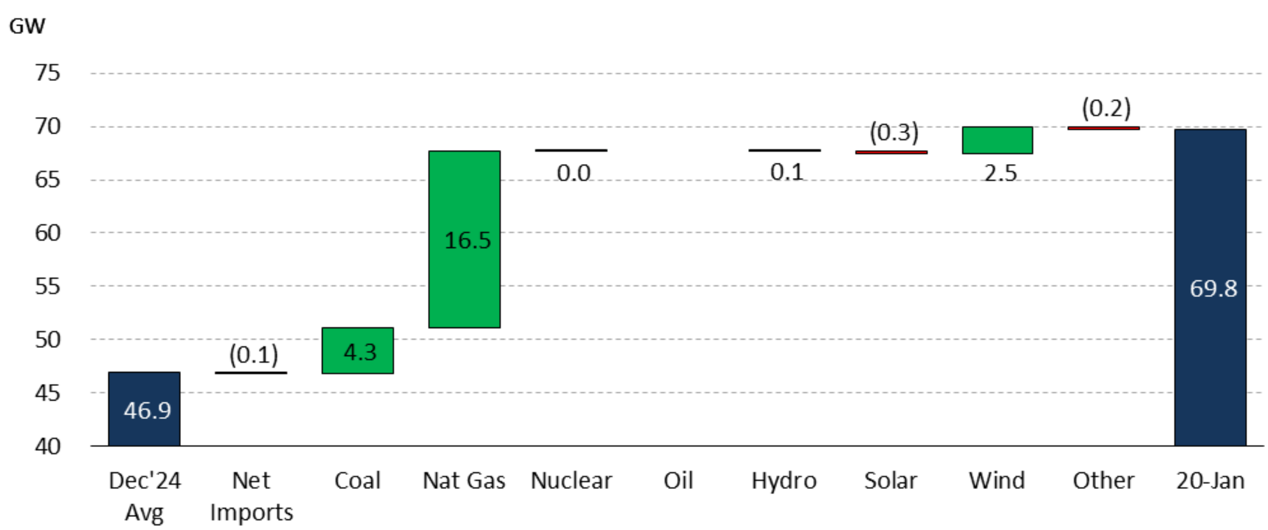
EXHIBIT 14: ERCOT - GENERATION MIX



Source: EIA Hourly Grid Monitor

The following two exhibits, **EXHIBIT 15** and **EXHIBIT 16**, provide a comparative analysis of the demand and generation response of various resource types during the peak demand day and hour of the January 2025 Polar Vortex, compared to the average demand observed in December 2024. On January 20, demand surged by over 20 GW. Consistent with patterns from previous events, such as the January 2024 Winter Storm, natural gas played a key role in meeting this shortfall during the peak demand period, contributing over 72% to the additional demand, as illustrated in **EXHIBIT 15** and **EXHIBIT 16**. Additionally, coal usage was elevated compared to December, as coal plants were operating at higher utilization due to the colder temperatures in the first few weeks of January 2025.

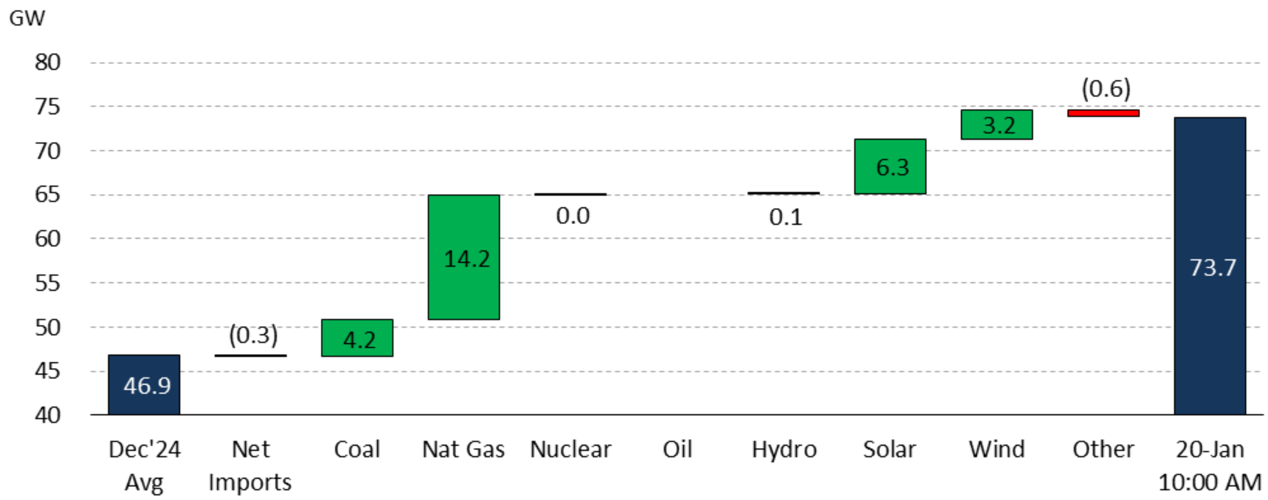
EXHIBIT 15: ERCOT - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY



Source: EIA Hourly Grid Monitor

During the January 2025 Polar Vortex, electricity demand in ERCOT peaked during the morning hours, surpassing the average daily peak demand for that day by nearly 4 GW. Compared to the previous month, peak-hour demand increased by 57%. Since this surge occurred during daylight hours, solar generation contributed an additional 6 GW to the grid relative to the prior month, as shown in **EXHIBIT 16**. Coal and natural gas collectively supplied 18.4 GW of the 27 GW increase in demand, with the remaining additional requirements met by renewable sources.

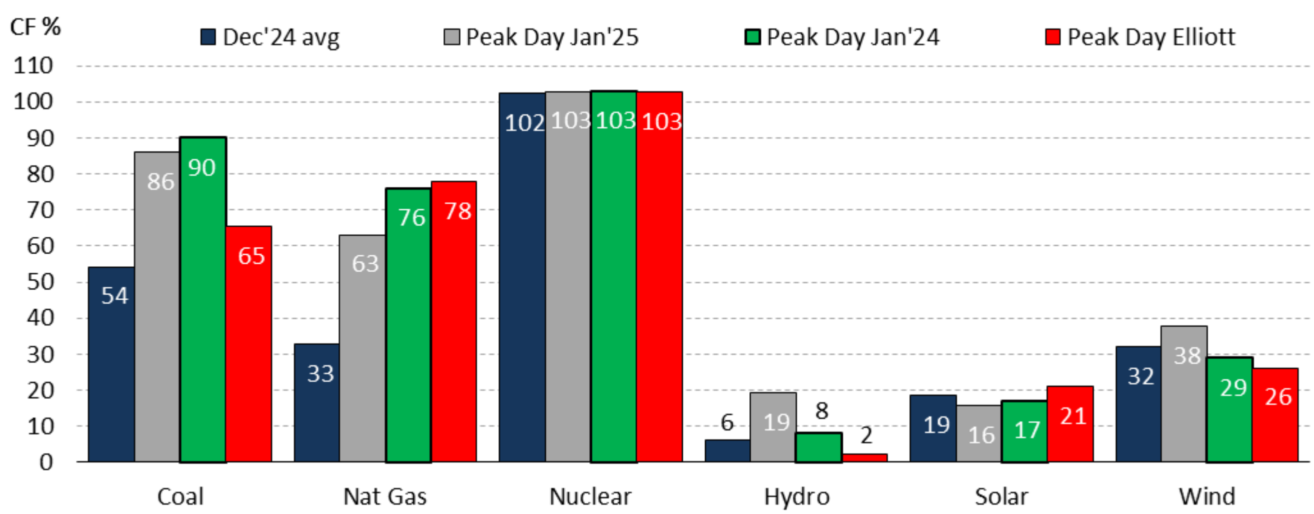
EXHIBIT 16: ERCOT - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



Source: EIA Hourly Grid Monitor

EXHIBIT 17 illustrates the capacity factors of various generating resources during peak demand periods compared to December 2024 in ERCOT. On the peak day of the January 2025 Polar Vortex, coal and natural gas units operated at average capacity factors of 86% and 63%, respectively—significantly higher than their December 2024 averages of 54% and 33%. Wind generation operated at 38%, exceeding the capacity factors observed during the January 2024 Winter Storm (29%) and Winter Storm Elliott (26%). However, due to its inherent intermittency, wind generation varied significantly depending on time and weather conditions during peak demand hours. The solar capacity factor during the Polar Vortex event decreased slightly from December 2024 due to increased cloud cover during the event.

EXHIBIT 17: ERCOT - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



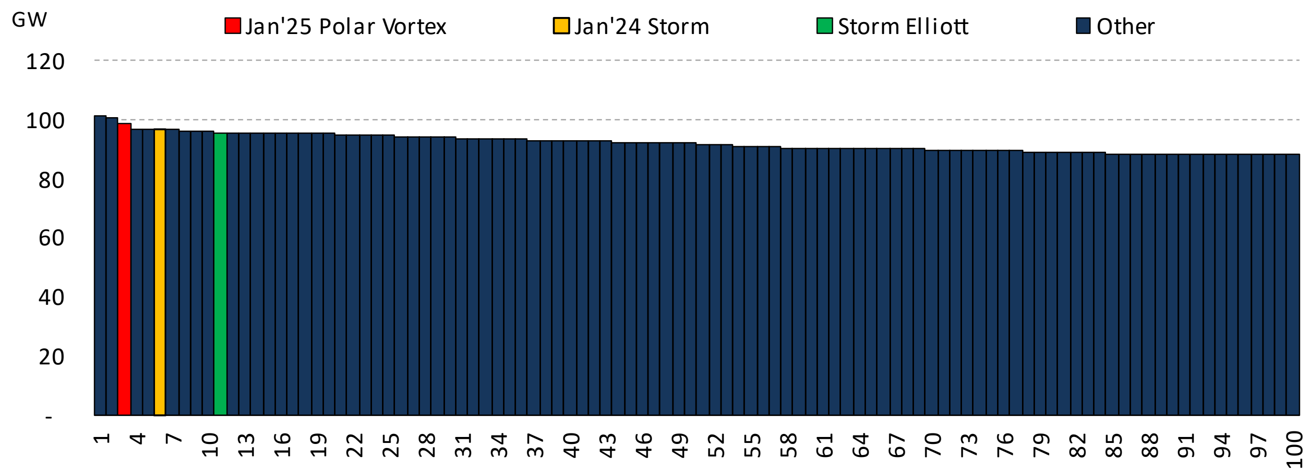
Source: EIA Hourly Grid Monitor & EIA 860 data

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 winter weeks of December, the MISO region experienced an average hourly electricity demand of 73.8 GW. The peak demand occurred on January 21, 2025, during the Polar Vortex event, with an average demand of 99 GW and a peak hourly demand of 107.1 GW in the evening. Interestingly, MISO also recorded a similar peak in hourly electricity demand of 106.8 GW during the morning hours of that same day. As shown in **EXHIBIT 18**, this day represents the third-highest demand recorded in the region's history.

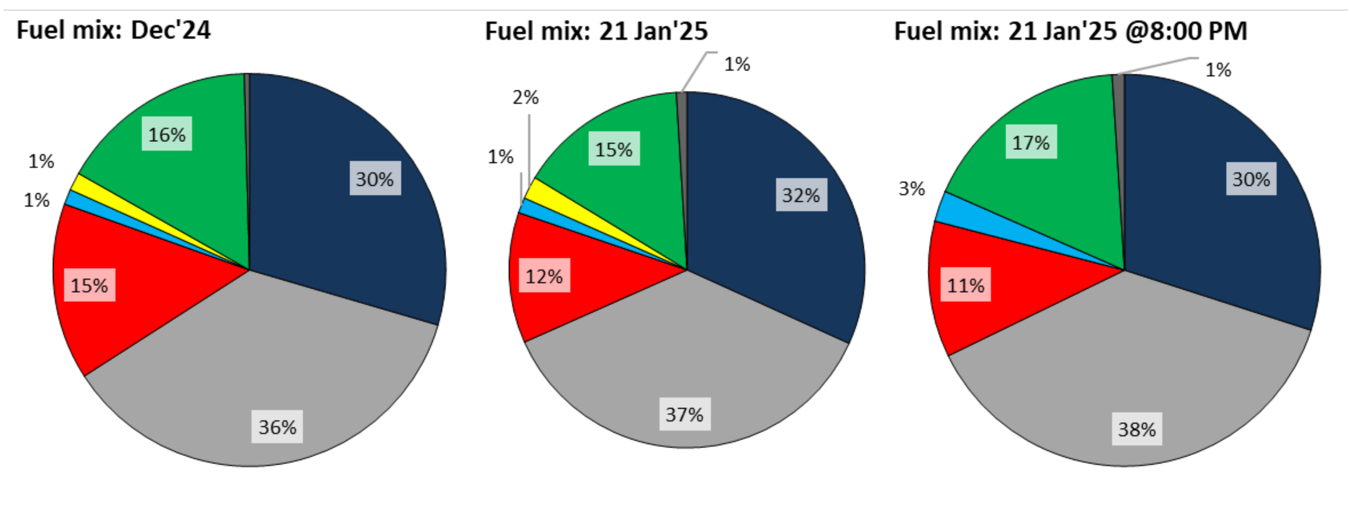
EXHIBIT 18: MISO - TOP 100 ELECTRICITY DEMAND DAYS



Source: EIA Hourly Grid Monitor

EXHIBIT 19 illustrates the average generation mix for the MISO region during December 2024, specifically on the peak demand day of the Polar Vortex, which occurred on January 21, 2025, at 8:00 PM. Typically, coal and natural gas constitute the majority of the generation mix, accounting for 66% of the total. Wind generation also plays a significant role as a renewable energy source, though solar and hydro generation contribute only small amounts. Notably, the distribution of the generation mix remained largely unchanged during this time of critical demand on January 21, indicating that the generation of natural gas, coal, and wind was proportionately heightened. Since peak demand occurred in the evening after sunset, the contribution from solar was negligible.

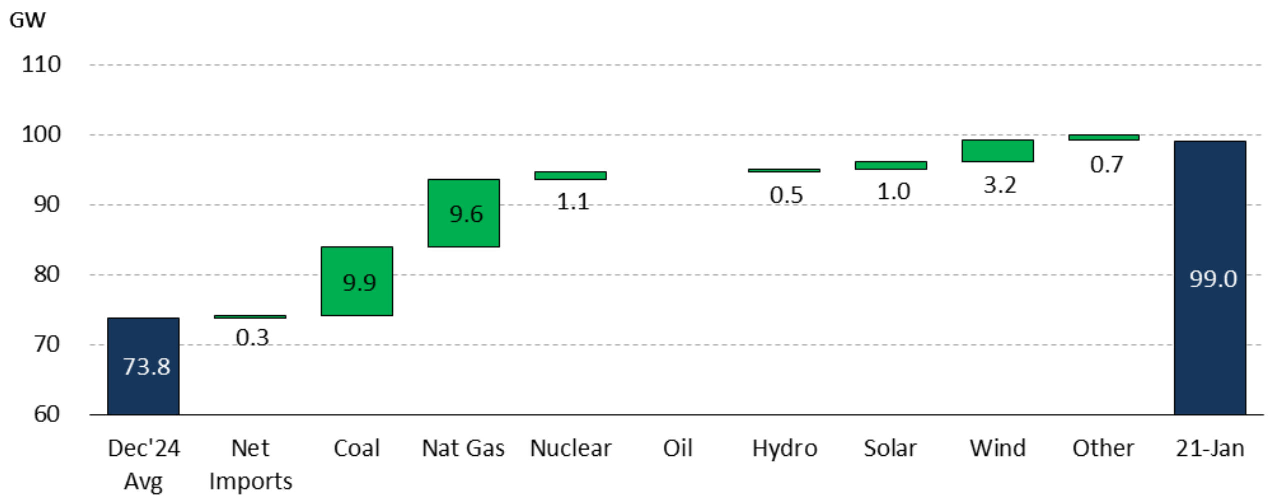
EXHIBIT 19: MISO - GENERATION MIX



Source: EIA Hourly Grid Monitor

EXHIBIT 20 compares the generation profiles between the average demand during the winter weeks of December 2024 and the peak demand day during the Polar Vortex in January 2025. On January 21, the average demand reached 99 GW, which was around 25 GW higher than the December 2024 average of 73.8 GW. As a result of the colder temperatures, coal-fired units were already generating a daily average of nearly 27.8 GW in January, compared to an average of 21.9 GW in December 2024. In response to the increased load on January 21, coal generation rose by an additional 4 GW, bringing it to 31.8 GW. Similarly, natural gas generation increased from 27 GW in December 2024 to 36.6 GW on January 21, marking a 35% increase.

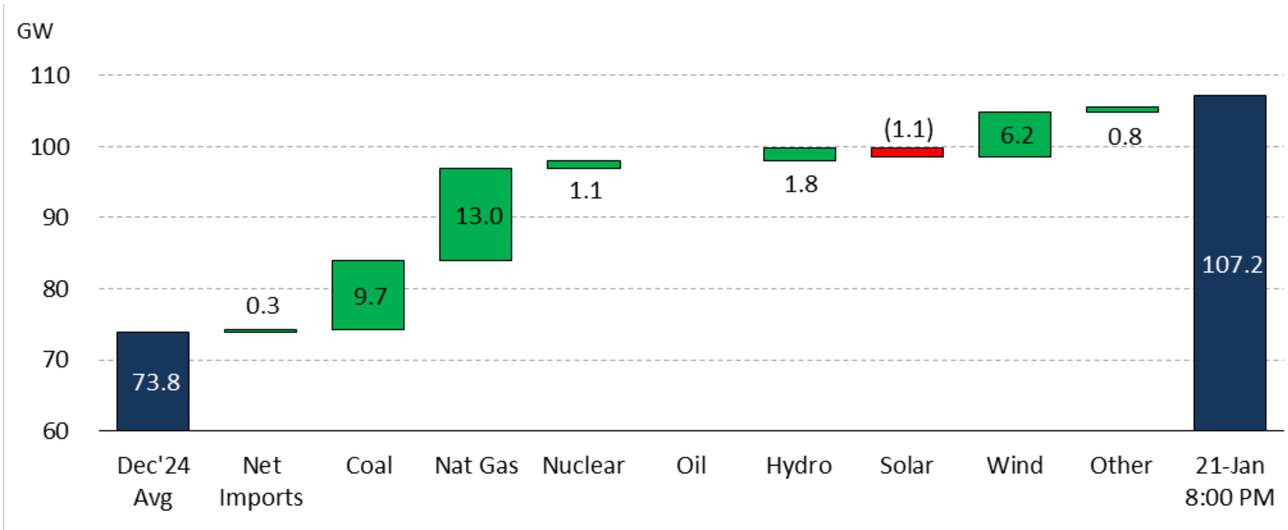
EXHIBIT 20: MISO - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY



Source: EIA Hourly Grid Monitor

EXHIBIT 21 compares the generation mix between the average demand in December 2024 and the peak hour of the highest demand experienced during the January 2025 Polar Vortex. This peak reached 107.2 GW, making it one of the highest demand peaks in MISO's history. Notably, MISO recorded two comparable periods of peak demand on January 21: in the morning at 10 AM, the demand peaked at 106.8 GW, and in the evening at 8.00 pm, it reached about 107.2 GW. The availability of solar and wind generation during these times significantly influenced the amount of coal and natural gas dispatched. In the morning, wind generation was approximately 12 GW, solar generation was 2.5 GW, natural gas generation amounted to 41 GW, and coal generation to 33 GW. In contrast, during the evening hours—when demand was slightly higher due to increased sustained winds—wind generation averaged around 18.4 GW. During this time, natural gas and coal generation were slightly lower, at 40 GW and 31.7 GW, respectively. This scenario highlights the flexibility of dispatchable resources like natural gas and coal. For instance, natural gas generation varied from 31 GW during peak solar generation hours to 42 GW at other times of the day.

EXHIBIT 21: MISO - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR

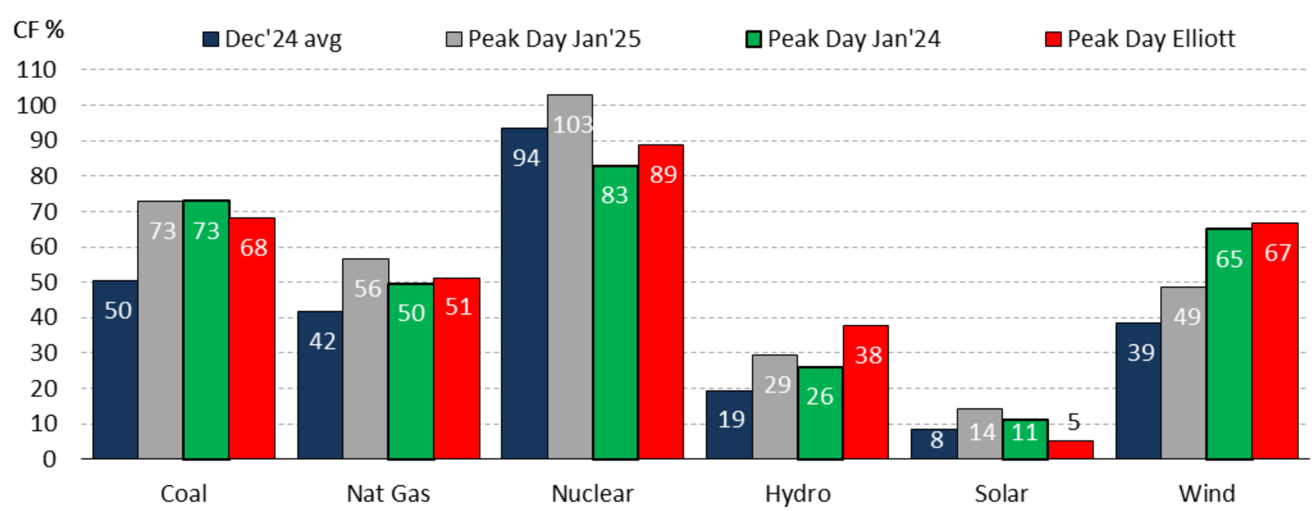


Source: EIA Hourly Grid Monitor

EXHIBIT 22 compares the capacity factors of various electricity generation resources during peak demand periods in January 2025 to those observed in December 2024, specifically referencing January 21 in the MISO region. During the Polar Vortex event, both coal and natural gas showed significantly higher capacity factors, recording 73% and 56%, respectively. In contrast, their capacity factors in December 2024 were only 50% and 42%. It is noteworthy that coal was already operating at 63.1% in January prior to this extreme weather event, which is 13 percentage points higher than in December 2024.

On January 21, 2025, favorable weather conditions contributed to higher wind capacity factors. On that day, average wind generation reached 15.4 GW, peaking at 18.4 GW during the hour of highest electricity demand. This is an increase compared to December 2024, when the average wind generation for the month was only 12.2 GW. In past events, such as Winter Storm Elliott, sustained strong winds have allowed wind resources to achieve capacity factors exceeding 65%. This highlights how varying weather conditions significantly affect the availability of wind generation. While the solar capacity factor increased to 14% on January 21 in comparison to 8% in December, the number remains low on average due to colder weather and low solar irradiation during winter.

EXHIBIT 22: MISO - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



Source: EIA Hourly Grid Monitor & EIA 860 data

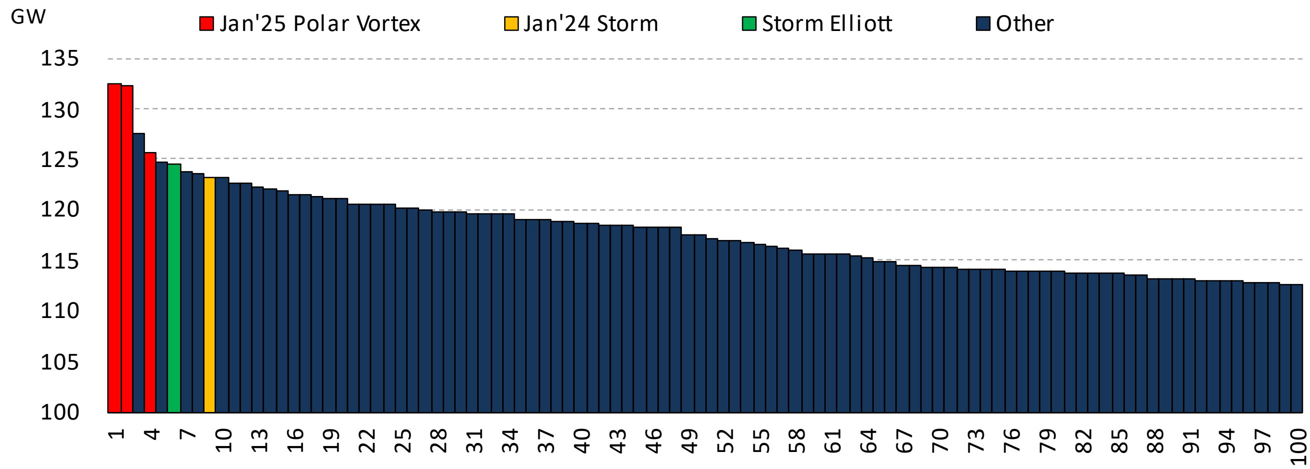
PJM

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. During the winter, PJM typically experiences an average hourly demand of approximately 95-98 GW.

The January 2025 Polar Vortex set new records for electricity demand in the PJM region, with peak demand exceeding 132 GW, marking the highest and second-highest demand days on record, as shown in

EXHIBIT 23. This exceeded all previous extreme weather events, with Storm Elliott closely following, reaching a peak demand of 124 GW. This was slightly below the levels observed during the Jan’25 Polar Vortex, while the January 2024 Winter Storm peaked just 1 GW lower than Storm Elliott.

EXHIBIT 23: PJM - TOP 100 ELECTRICITY DEMAND DAYS

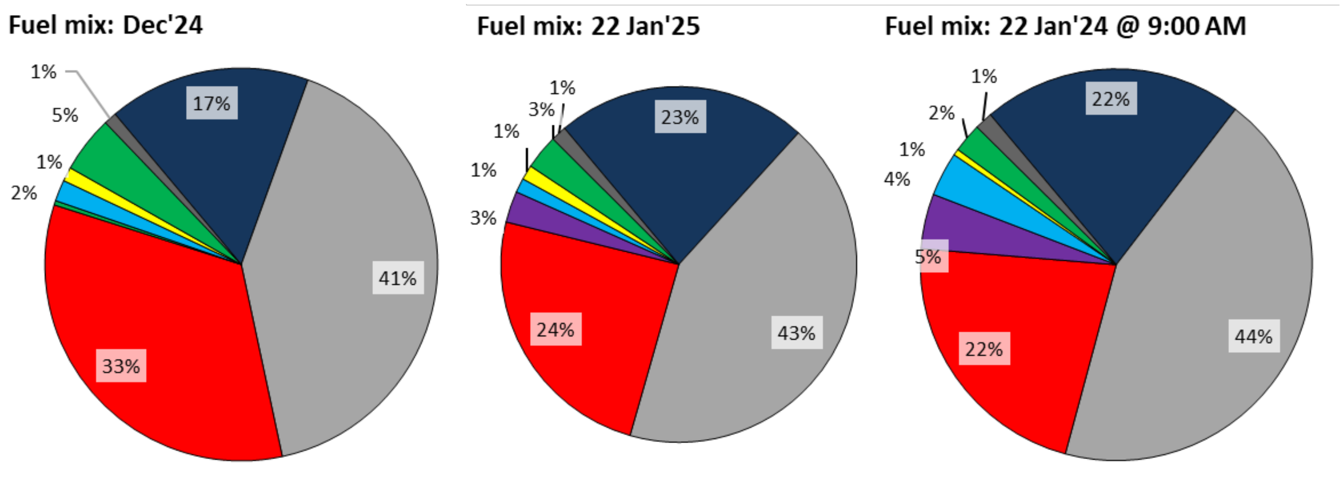


Source: EIA Hourly Grid Monitor

In PJM, nuclear power typically accounts for nearly one-third of total generation capacity. However, during the January 2025 Polar Vortex, the rapid surge in electricity demand led to a notable shift in the fuel mix, as shown in **EXHIBIT 24**. As nuclear power plants typically run at or near-maximum capacity, there was limited opportunity for an increase in generation while other resource types ramped up output, leading to a decline in nuclear power’s generation mix share. Coal generation saw a significant increase, contributing just under 25% of the fuel mix on the peak demand day, approximately 6 percentage points higher than its share in December 2024. Similarly, natural gas generation increased, maintaining a relatively consistent share of the fuel mix compared to normal winter conditions. Oil generation, which was negligible in the previous month, ramped up significantly to help meet the heightened demand.

During the peak hour of the winter storm, multiple fuel sources were mobilized to sustain grid reliability. Given that peak demand occurred in the morning, contributions from solar and wind declined compared to their December 2024 shares. Conversely, hydro generation increased during the peak hour, providing critical response support. Overall, fossil fuel resources supplied more than 70% of total generation.

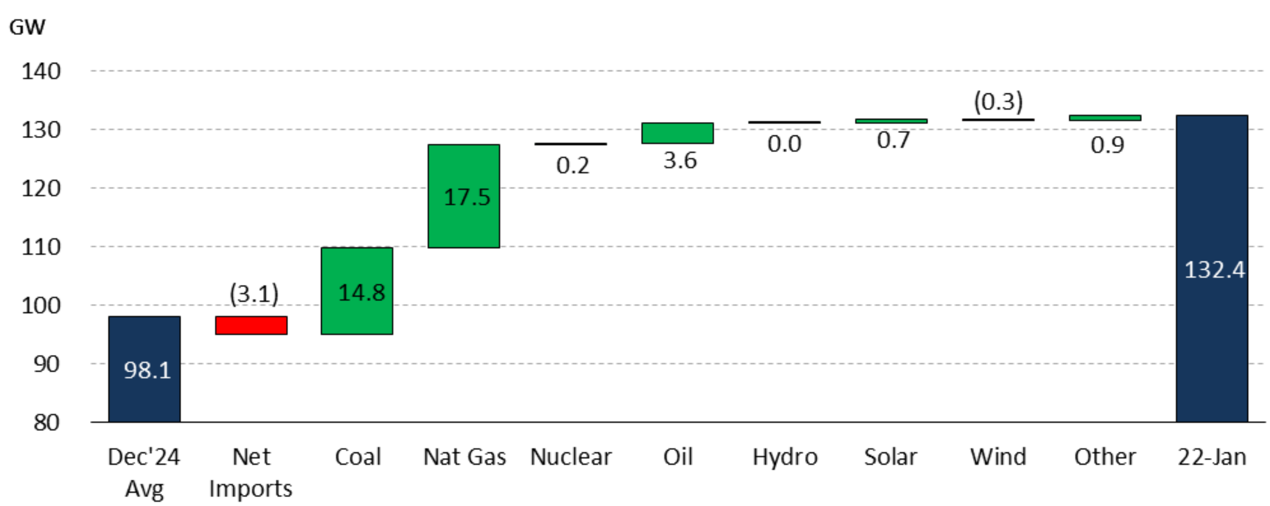
EXHIBIT 24: PJM - GENERATION MIX



Source: EIA Hourly Grid Monitor

EXHIBIT 25 compares the demand and average hourly generation across different fuel technologies between December 2024 and the peak day of the January 2025 Polar Vortex in PJM that occurred on January 22. Notably, a substantial demand disparity of 34 GW was observed between these two periods. Given the robust available generating capacity in PJM during this peak demand period, PJM demonstrated its resilience by exporting an additional 3 GW on an hourly basis to neighboring regions, primarily the Southeast, thereby bolstering their reliability. In response to the heightened demand, fossil fuels witnessed an approximate 60% increase in generation, with coal and gas generating 15 GW and 17.5 GW higher outputs, respectively, compared to the previous winter month. Additionally, wind and solar resources combined contributed only around 1% of the increased demand to the overall demand-supply equation.

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



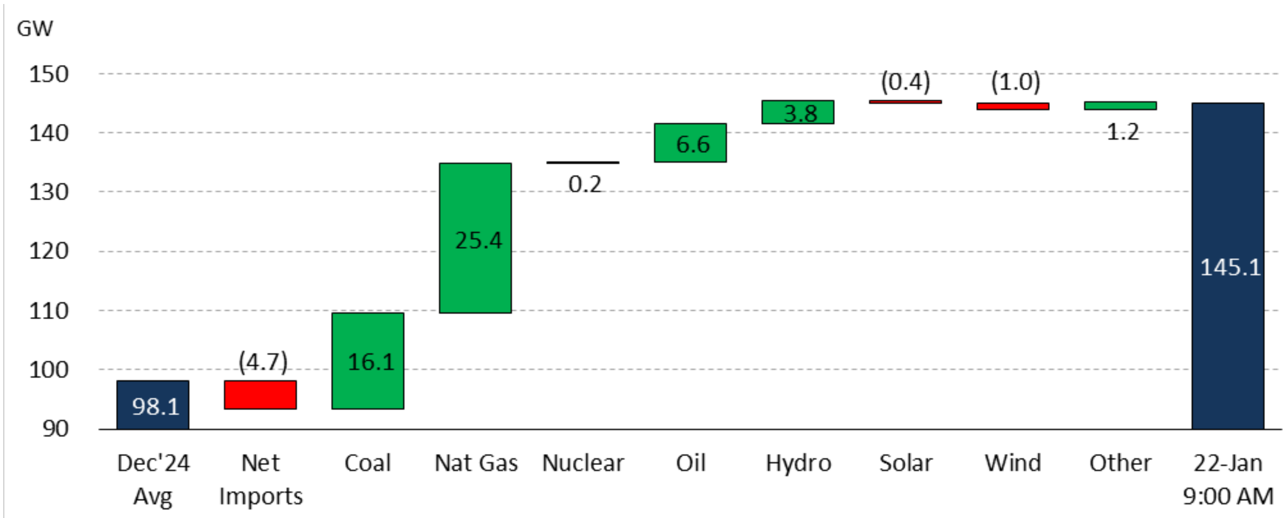
Source: EIA Hourly Grid Monitor

EXHIBIT 26, provided below, offers a detailed comparative examination of the average hourly generation across different fuel technologies between the previous winter month (Dec'24) and the peak hour of the January 2025 Polar Vortex within the PJM region. Notably, the peak hour demand surged to nearly 145 GW, prompting PJM to generate approximately 153

GW to meet this heightened demand and export surplus energy to support neighboring regions, primarily the Northeast and Southeast power market regions.

During this critical hour, coal generation reached approximately 33 GW, doubling its average generation from the previous month, which stood at 17 GW. Natural gas also ramped up production, generating 25 GW more than in the prior winter month to help meet the increased demand. Additionally, oil contributed nearly 7 GW, while combined solar and wind generation declined approximately 1.5 GW compared to the previous month's average. This reduction was primarily due to lower solar radiation and sustained winds due to the weather conditions during the morning hours, limiting their availability during this critical period.

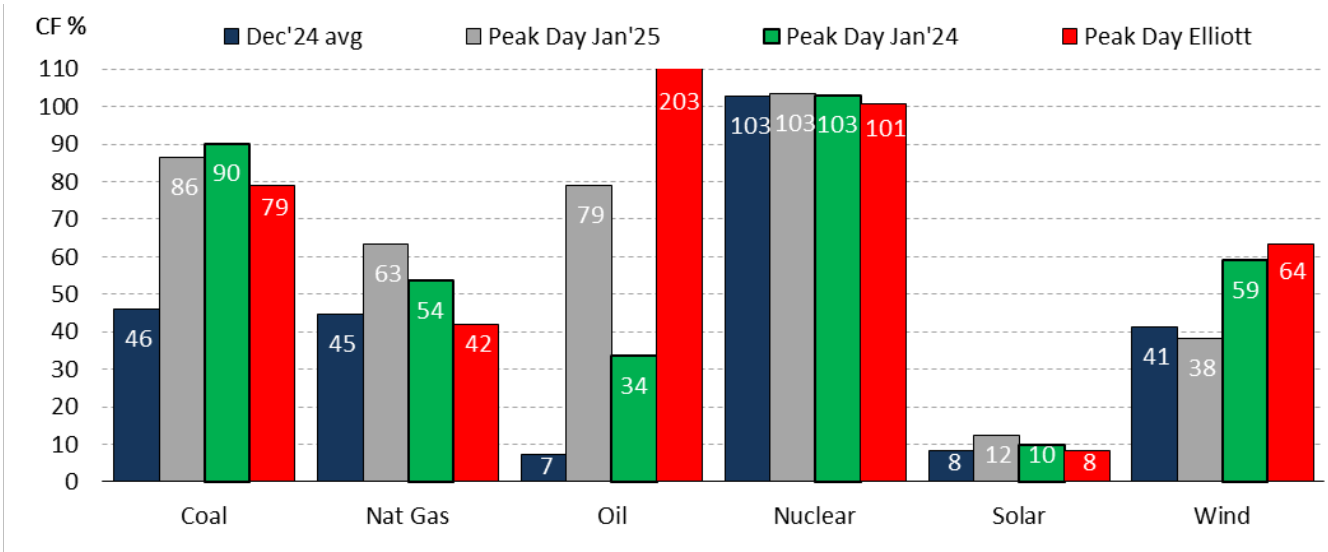
EXHIBIT 26: PJM - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



Source: EIA Hourly Grid Monitor

EXHIBIT 27 presents the capacity factors of various generating resources during periods of peak demand compared to December 2024 demand in PJM. As observed in other regions, the capacity factors of PJM coal units surged significantly, reaching nearly 86% during the peak demand day of the January 2025 Polar Vortex. Natural gas-fired power plants in PJM also demonstrated increased generation compared to the previous month and past winter storm events. In contrast, wind generation declined relative to both the prior month and previous winter storms. The January 2024 winter storm, as well as Winter Storm Elliott, benefited from strong wind generation, achieving a capacity factor of 60% or more. However, during the January 2025 Polar Vortex, the wind capacity factor dropped to 38%. Meanwhile, solar plants operated at a higher capacity factor as the peak demand day experienced increased sunshine, providing some relief compared to the previous month's average generation. Conversely, during Storm Elliott, solar generation was lower due to extensive cloud cover, which significantly limited solar output.

EXHIBIT 27: PJM - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES [3]



Source: EIA Hourly Grid Monitor & EIA 860 data

Southeast

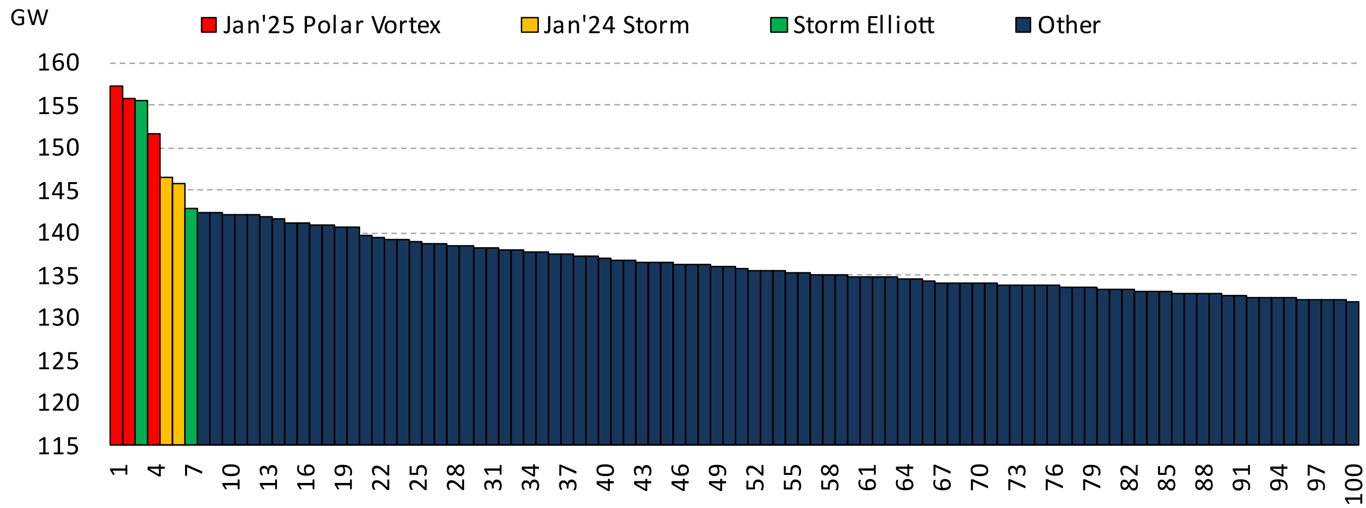
The Southeast region includes most of the states of North & South Carolina, Georgia, Florida, Alabama, Tennessee, Kentucky, and Mississippi and its major utilities, including Duke Energy, Southern Company, Dominion South Carolina, Florida Power & Light, and Tennessee Valley Authority (TVA).

The Southeast region typically experiences an average winter demand of 100–105 GW. However, extreme weather events have driven demand surges of nearly 50% beyond this baseline. Notably, the January 2025 Polar Vortex set a new record, surpassing Storm Elliott and securing three of the top five highest demand days, with peak demand reaching 157 GW, nearly 2 GW higher than the peak demand recorded during Storm Elliott, which ranks as the third highest in the region, as

[3] During this period of heightened demand, some natural gas plants used oil as a backup fuel for power generation. However, these units are not classified as oil-only capacity. As a result, the recorded oil generation exceeded the reported oil-only capacity, leading to a capacity factor of 203%.

shown in **EXHIBIT 28**. The January 2024 winter storm follows in fifth place with a peak demand of 147 GW. Overall, seven of the Southeast region's top ten highest-demand days are attributed to these three extreme weather events.

EXHIBIT 28: SOUTHEAST - TOP 100 ELECTRICITY DEMAND DAYS

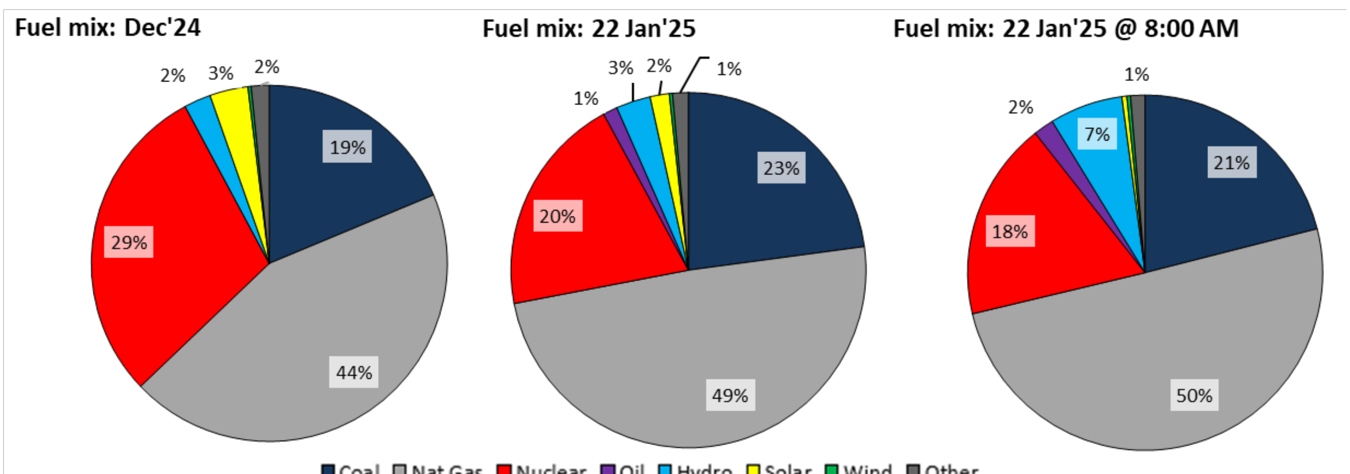


Source: EIA Hourly Grid Monitor

The Southeast region primarily relies on natural gas and nuclear power for electricity generation. During the storm, nuclear generation remained steady, leading to a decrease in its share of the generation mix. In contrast, natural gas and coal generation increased significantly compared to typical winter conditions, as shown in **EXHIBIT 29**. In December 2024, fossil fuel generation accounted for just over 60% of the total supply. However, during the peak demand day of the January 2025 Polar Vortex, fossil fuel contributions rose to 73%, with natural gas alone supplying approximately 50% of total generation.

During the peak hour of the January 2025 Polar Vortex, which occurred in the early morning, wind and solar generation contributed a negligible ~0.5% combined towards the fuel mix. However, hydro generation ramped up substantially, compensating for the decline in renewable output. Additionally, oil-fired generation, which was absent during the previous month, accounted for 2% of the generation mix.

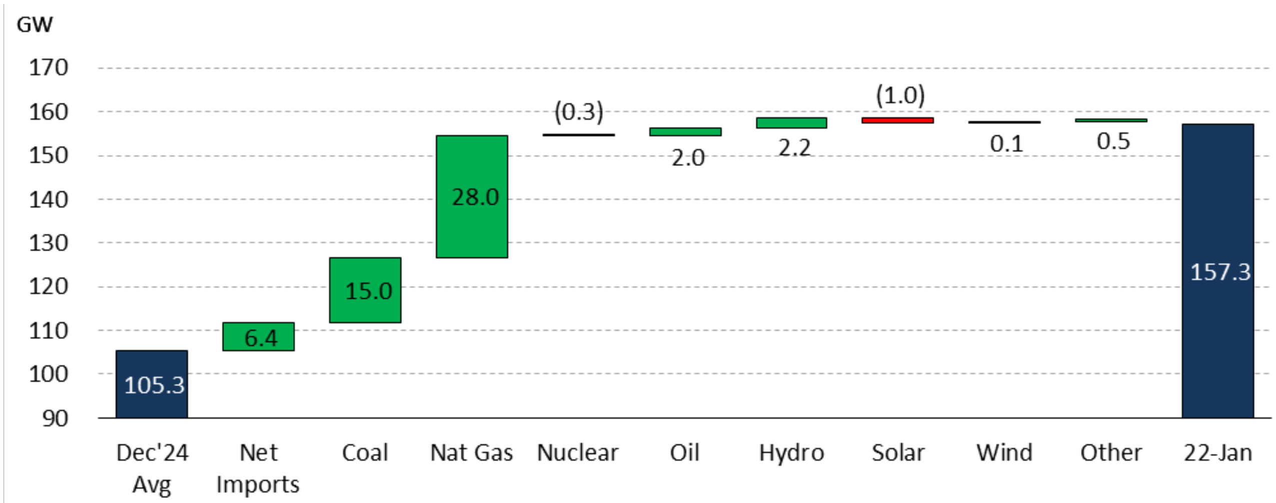
EXHIBIT 29: SOUTHEAST - GENERATION MIX



Source: EIA Hourly Grid Monitor

As hourly demand surged from 105.3 GW in December 2024 to 157.3 GW on January 22 during the Polar Vortex, coal generation played a critical role in bridging the supply gap, increasing by 15 GW—a 77% rise compared to the previous month's average generation. Natural gas generation also ramped up significantly, adding 28 GW beyond the levels observed in the prior winter month, as shown in **EXHIBIT 30**. Additionally, net imports contributed to meeting the heightened demand, supplying an extra 6.4 GW compared to the previous month's supply. While combined wind and solar generation experienced a slight decline, hydro generation increased by 2.2 GW compared to the previous month.

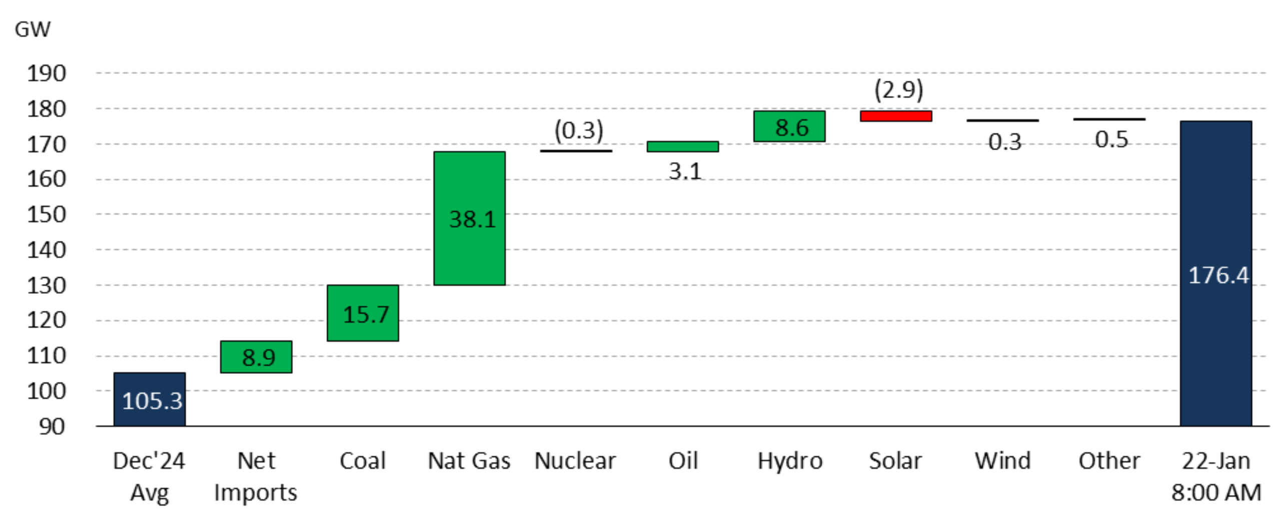
EXHIBIT 30: SOUTHEAST - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY



Source: EIA Hourly Grid Monitor

During the peak demand hour, demand surged to approximately 177 GW, a significant deviation from the average demand of around 105 GW the previous month, as shown in **EXHIBIT 31**. To meet this shortfall, natural gas played a crucial role, adding 38.1 GW, an 82% increase over the previous month's generation—bringing its total output to 84 GW. Coal generation also ramped up, increasing by 15.7 GW to reach a total of 35 GW. Additionally, imports rose sharply, contributing nearly 9 GW. While solar and wind combined generation was minimal at just 1 MW—3 GW lower than the previous month's levels, hydropower played a key role in meeting demand, supplying an additional 8.6 GW to help offset the unprecedented peak.

EXHIBIT 31: SOUTHEAST - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



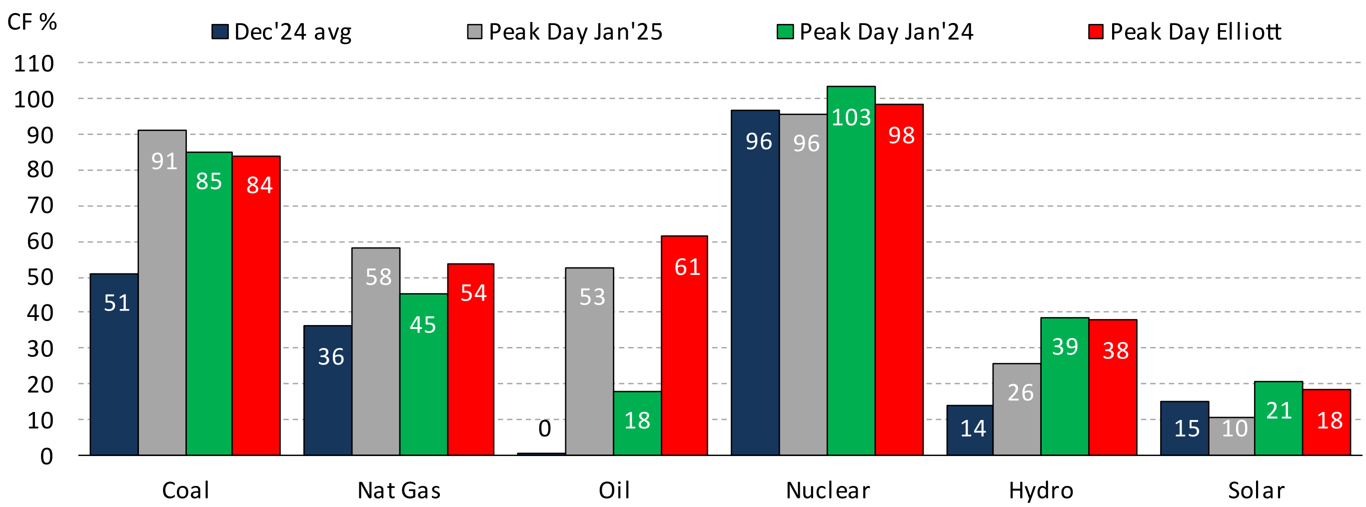
Source: EIA Hourly Grid Monitor

EXHIBIT 32 illustrates the capacity factors of various generating resources during peak demand periods compared to the average generation in December 2024 in the Southeast. Coal-fired power plants exhibited the most significant increase during the peak of the January 2025 Polar Vortex, reaching a record-high capacity factor of 91%, a 40% increase compared to the previous month's average generation. Similar spikes in capacity factors were observed for both coal and natural gas generation across all extreme weather events.

Wind is not a predominant resource in the Southeast, with a total installed capacity of under 1 GW. However, solar capacity has been expanding rapidly, with approximately 9 GW added between Storm Elliott and the January 2025 Polar Vortex, bringing total solar capacity in the region to around 25 GW.

During the January 2024 winter storm, the solar fleet operated at a capacity factor of 32%, whereas during the January 2025 Polar Vortex, it dropped to just 10%, highlighting the variability and uncertainty associated with weather-dependent generation such as wind and solar.

EXHIBIT 32: SOUTHEAST - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



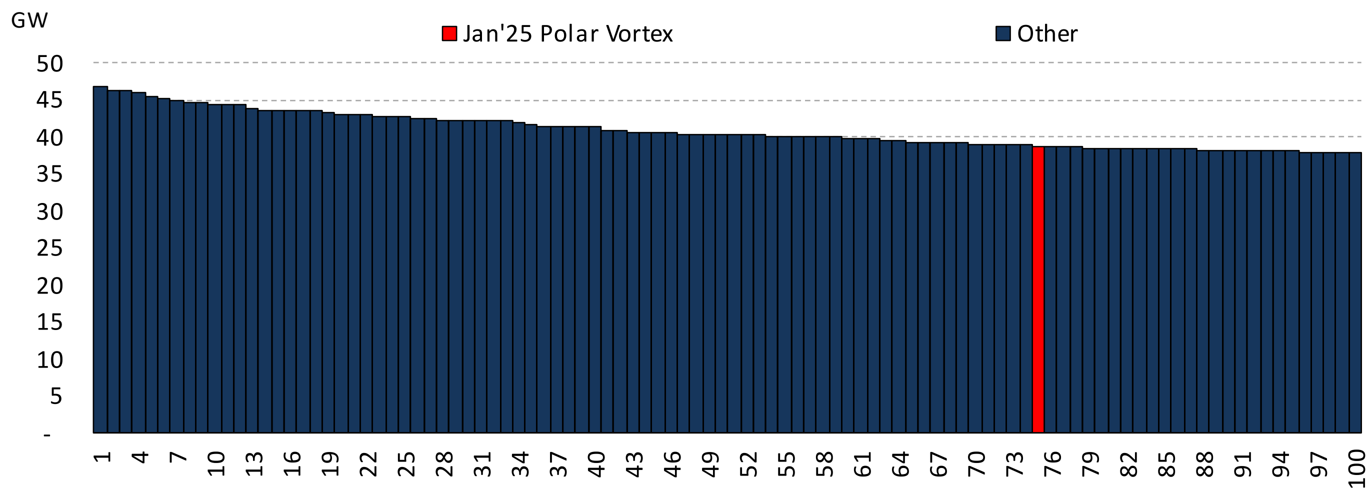
Source: EIA HourlyGrid Monitor & EIA 860 data

Northeast

The Northeast region encompasses most of Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut, and New York. Major utilities serving this region include Con Edison, National Grid, and Eversource Energy.

During the winter months, the Northeast typically experiences an average electricity demand of 30–32 GW. However, extreme weather events have occasionally driven demand surges of nearly 50% above this norm. Unlike other regions where extreme weather events have been a primary driver of peak demand, the highest demand days in the Northeast typically occur during the summer months. Nevertheless, the January 2025 Polar Vortex ranked among the top 100 highest-demand days in the region, with electricity demand increasing by nearly 20% compared to the previous month's average and peak-hour demand rising by approximately 35%, as shown in **EXHIBIT 33**.

EXHIBIT 33: NORTHEAST - TOP 100 ELECTRICITY DEMAND DAYS



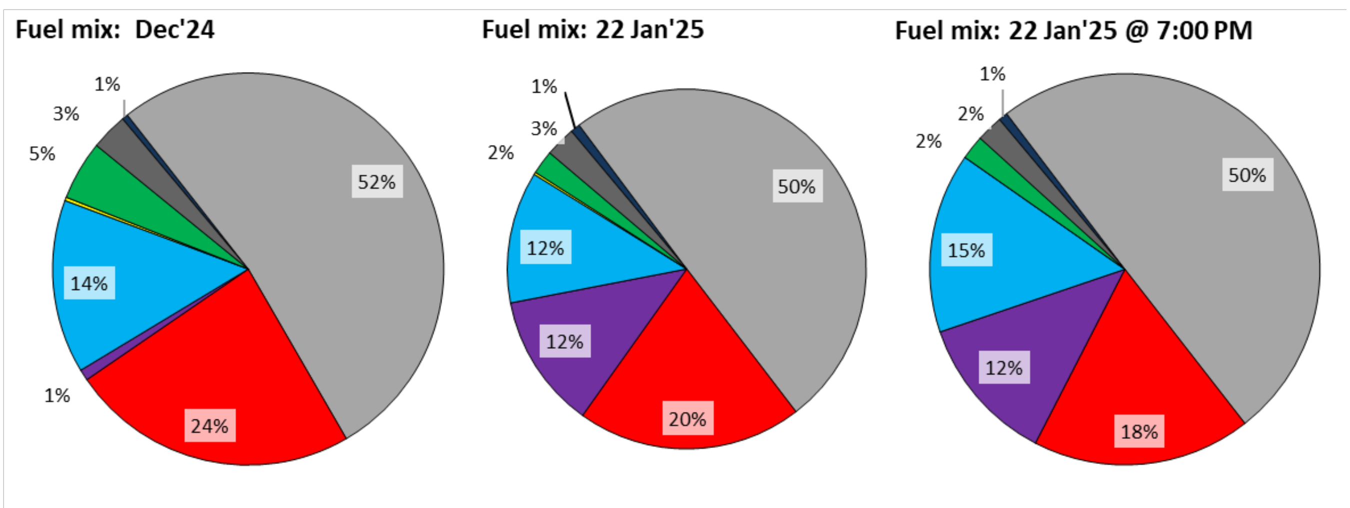
Source: EIA Hourly Grid Monitor

The Northeast region primarily relies on natural gas and nuclear power, which together account for over 75% of total electricity generation. Hydropower and wind contribute approximately 20%, while solar generation remains minimal in the region.

During the January 2025 Polar Vortex, natural gas maintained a steady share in the generation mix, striving to meet the heightened demand. However, with limited coal infrastructure and high natural gas prices, a significant portion of the additional demand was met by oil-fired power plants. Oil, which comprised just 1% of the fuel mix in December 2024, surged to 12% on the peak demand day of the January 2025 Polar Vortex.

During the peak hour of this increased demand, oil and natural gas generation remained central, maintaining a similar fuel mix to the peak demand day. Hydropower contributed 15% to the overall fuel mix during the peak hour, while wind generation declined by 3% compared to the previous month's output.

EXHIBIT 34: NORTHEAST - GENERATION MIX

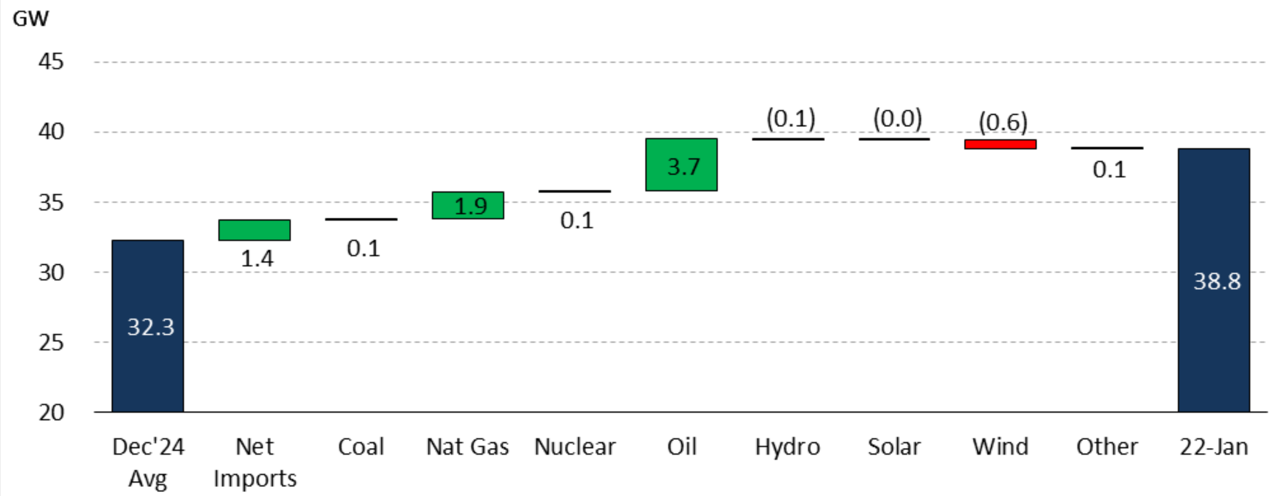


Source: EIA Hourly Grid Monitor

The January 2025 Polar Vortex led to a demand increase of approximately 6.5 GW in the Northeast region compared to the previous month's average. Most of this additional demand—around 70%—was met by natural gas and oil generation.

In contrast, wind generation declined by 0.6 GW compared to the previous month. To address the remaining supply gap, the Northeast imported approximately 1.4 GW of electricity from neighboring regions.

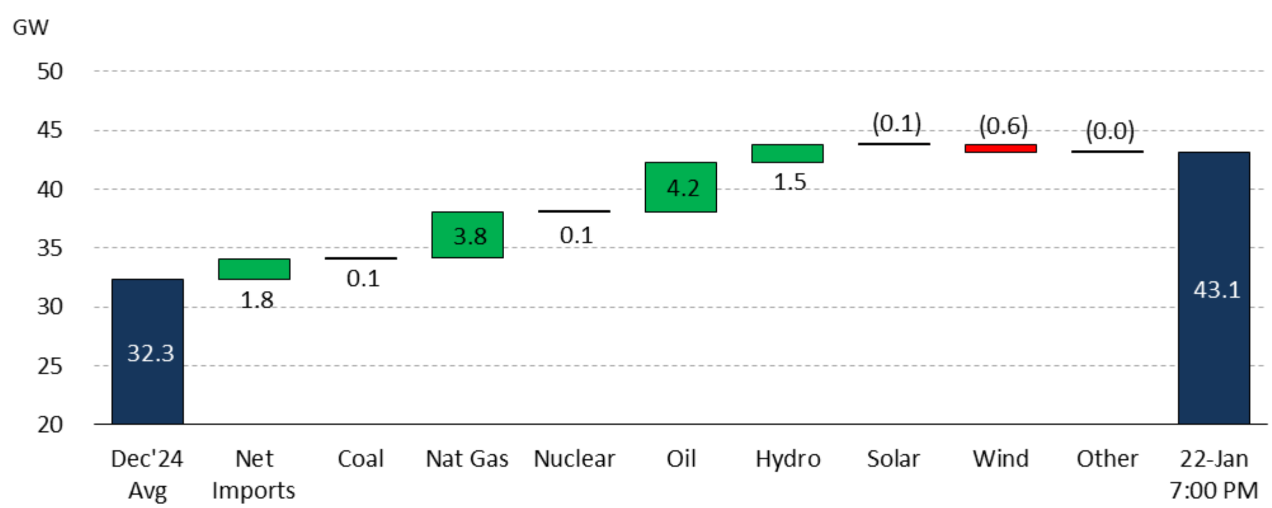
EXHIBIT 35: NORTHEAST - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY



Source: EIA Hourly Grid Monitor

During the peak demand hour, electricity demand surged to approximately 43 GW, significantly exceeding the average demand of around 32 GW, as shown in **EXHIBIT 36**. To bridge this gap, natural gas and oil generation played a crucial role, contributing an additional 3.8 GW and 4.2 GW, respectively, bringing combined generation to 23 GW. Additionally, hydro generation increased by 1.5 GW, while wind generation declined by 0.6 GW compared to the previous month's levels. Simultaneously, imports rose by nearly 1.8 GW, making a significant contribution to meeting peak demand.

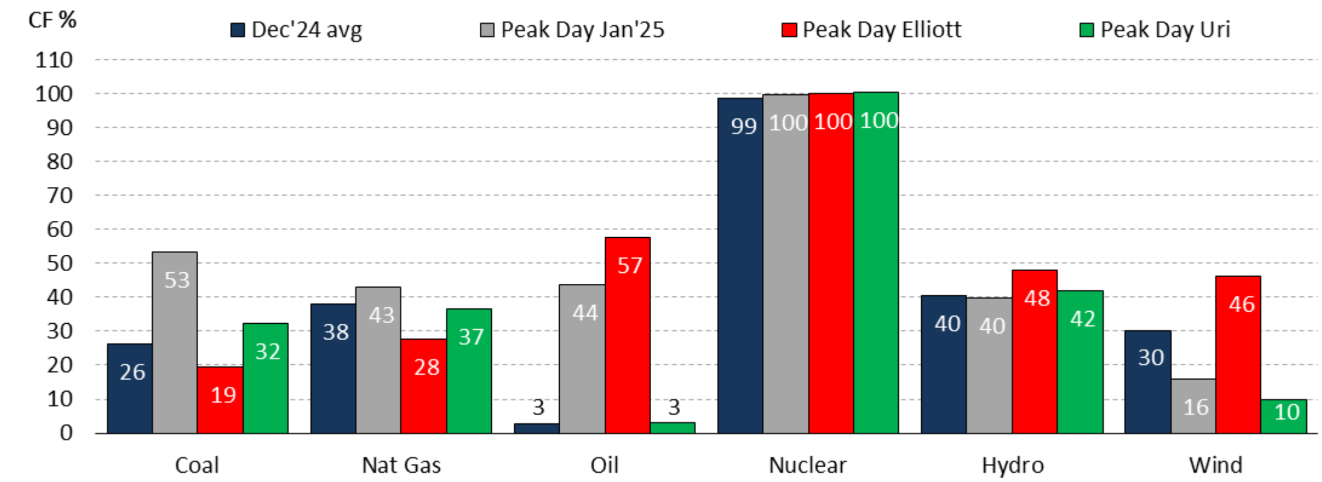
EXHIBIT 36: NORTHEAST - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



Source: EIA Hourly Grid Monitor

EXHIBIT 37 illustrates the capacity factors of various generating resources during different peak demand periods compared to the average of December 2024 in the Northeast. Like most regions, natural gas exhibited higher capacity factor utilization during the January 2025 Polar Vortex; however, the trend was different during Storm Elliott. This discrepancy was primarily due to the lack of available natural gas supply, which rendered several gas plants inoperable. Similarly, wind generation has also been inconsistent during these peak extreme weather events, with Storm Elliott reaching a 30% higher capacity factor compared to the Jan'25 Polar Vortex, mainly because Elliott brought a large amount of sustained high winds in the Northeast region that was not observed during the Jan'25 Polar Vortex. Hydro generation remained consistent across all peak demand periods analyzed. Meanwhile, oil-fired generation demonstrated reliability in the region, with the flexibility to ramp up output by approximately 4 to 4.5 GW, catering to almost 12% of the demand.

EXHIBIT 37: NORTHEAST - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES

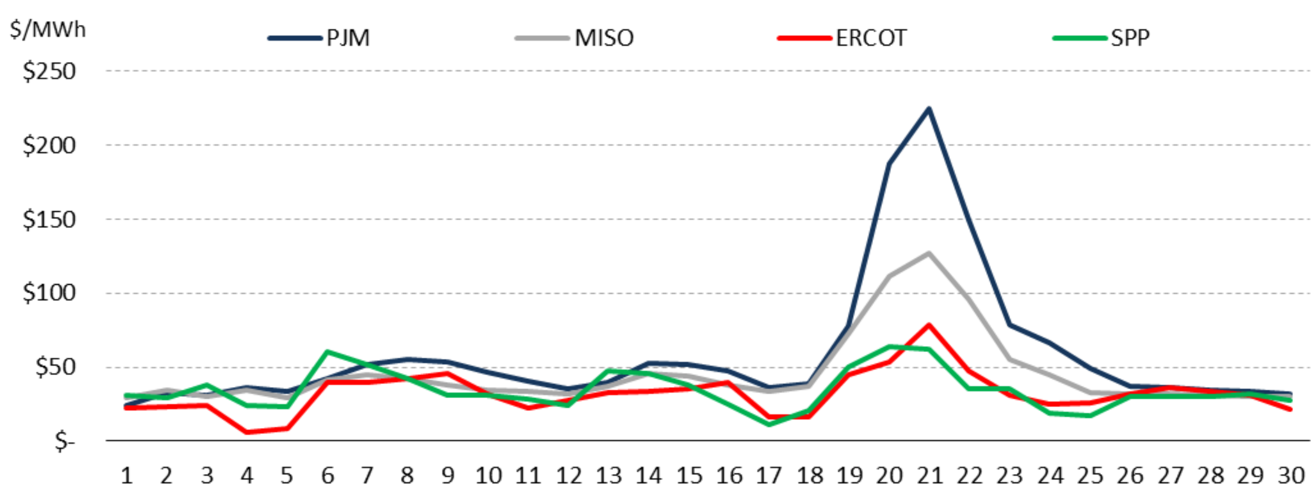


Source: EIA Hourly Grid Monitor & EIA 860 data

PJM Power Price Analysis – Case Study

Besides providing valuable incremental generation during extreme weather events like the January 2025 Polar Vortex, 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 38: DAILY AVERAGE REGIONAL AROUND-THE-CLOCK POWER PRICES DURING JANUARY 2025

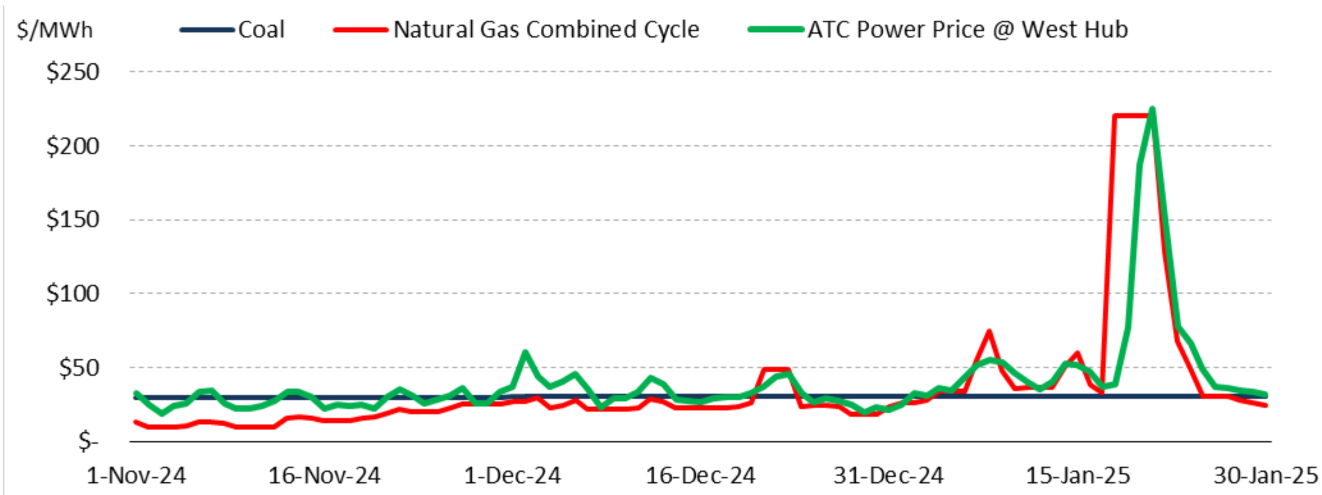


Source: S&P Global

EXHIBIT 38 shows the average daily day-ahead power prices for PJM, MISO, ERCOT, and SPP. As electricity demand increased, so did regional wholesale power prices, which encouraged additional electric generating resources not operating at full capacity yet to increase their generation output. PJM power prices saw the most significant increase of all affected power market regions, where daily average day-ahead power prices spiked to about $225/MWh on January 21 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 set by the operating cost of the last electric generating resource required to meet the electricity demand of a given hour. Operating costs include fuel costs and other non-fuel variable costs such as reagent costs for emission control equipment, emission allowance costs, or 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 since they do not use any fuel or need to budget for any emission allowance 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, wholesale power prices are set predominantly by either natural gas, coal, or oil-fired power plants. For fossil-fuel-fired power plants, fuel costs are by far the highest component of their operating cost, often accounting for more than 70% of their total operating or dispatch cost. **EXHIBIT 39** shows the estimated daily dispatch cost for illustrative coal and natural gas combined-cycle power plants in PJM from November 1, 2024, to January 30, 2025.

EXHIBIT 39: ESTIMATED DISPATCH COSTS FOR ILLUSTRATIVE COAL & NATURAL GAS COMBINED CYCLE PLANTS IN PJM

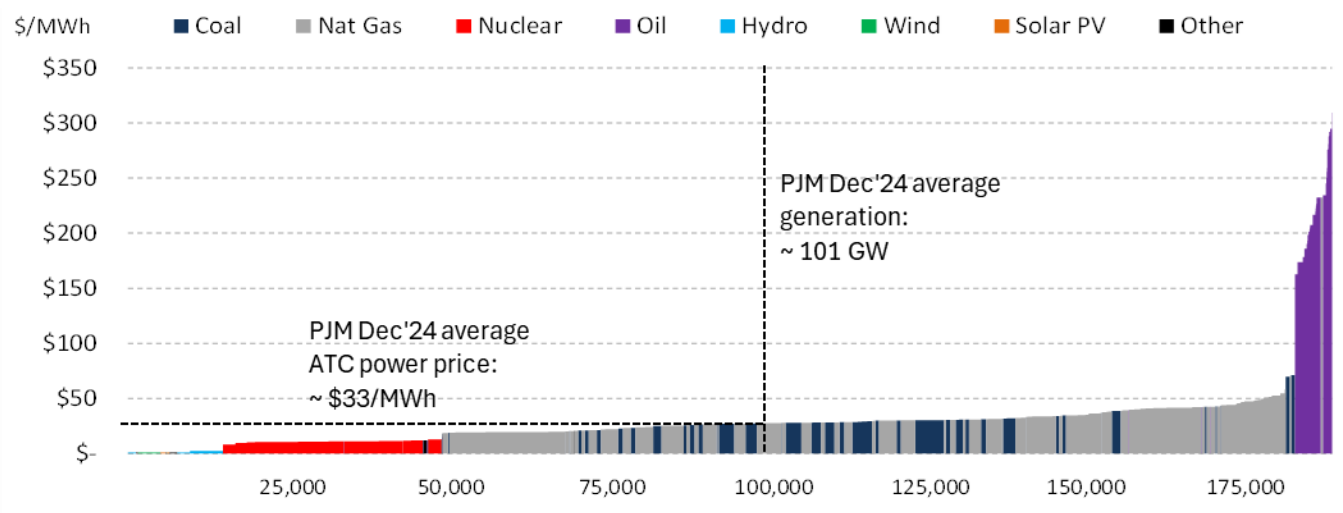


Note: Assumes 10.5 MMBtu/MWh & $4/MWh VOM for coal and 7.5 MMBtu/MWh & $2/MWh for natural gas combined cycle

As shown in **EXHIBIT 39**, there is a notable difference in dispatch cost variability between coal and natural gas power plants. At a high level, plant owners and operators use replacement cost to estimate their fuel costs used in determining their dispatch cost, i.e., what is the current market price for the fuel I am planning to consume during the plant's operation? Due to the absence of a sizeable liquid commodity trading market and the time it takes to produce and transport it, coal market prices show minimal day-to-day variability. Natural gas, on the other hand, is a highly traded energy commodity with possible large swings in market prices depending on short-term supply-demand disruptions and energy commodity trader responses.

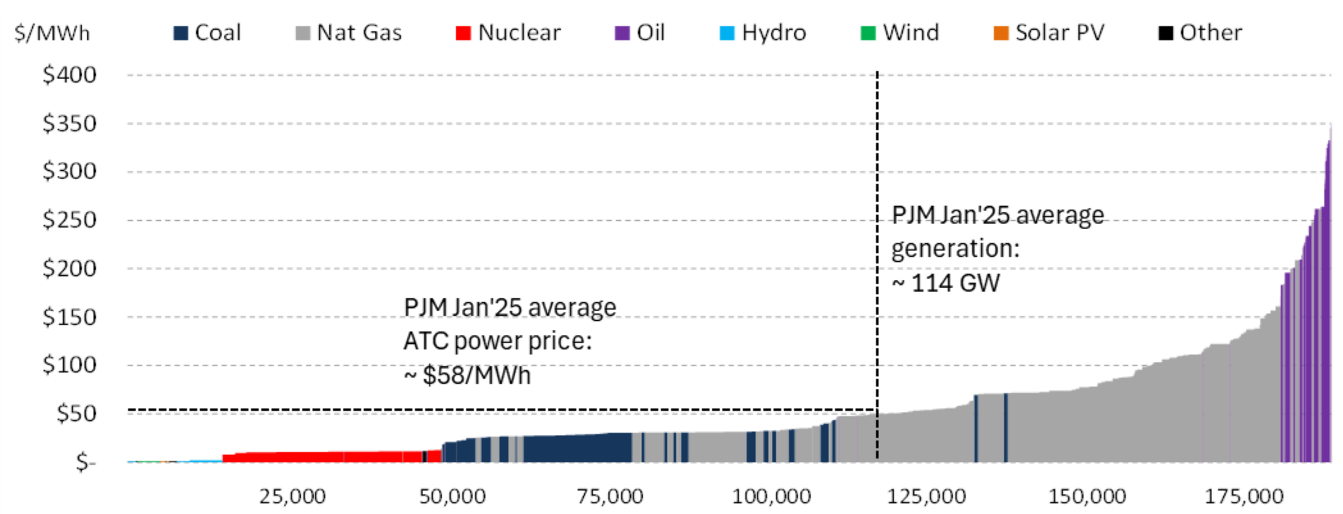
In November 2024, natural gas prices across PJM averaged less than $1.90/MMBtu, compared to coal's $2.50/MMBtu for the same period. As a result, some coal plants across PJM were more often "on the margin," setting regional power prices, while others were not operating at all. For example, capacity factors for the PJM coal fleet averaged less than 30% in November 2024, compared to natural gas' almost 40%. As the temperatures dropped in December 2024 and especially January 2025, natural gas demand for residential and commercial heating began to rise quickly, in addition to rising electricity demand, causing natural gas prices to rise. December 2024 average daily natural gas prices across PJM rose to about $3.25/MMBtu, while average delivered coal prices remained at around $2.50/MMBtu, resulting in increased natural gas-to-coal switching. For example, capacity factors for the PJM natural gas fleet averaged 44.5% in December 2024 compared to the coal fleet's 45.9%. Increasingly, PJM power prices were being set by natural gas-fired power plants instead of their coal-fired counterparts. **EXHIBIT 40** shows the estimated dispatch stack for PJM during December 2024. Notably, coal plants are highlighted in dark blue, natural gas plants in gray, and oil-fired peaking units in purple.

EXHIBIT 40: ESTIMATED PJM DISPATCH STACK DURING DECEMBER 2024



As temperatures continued to drop below the 10-year average for most of January 2025, power and non-power natural gas demand continued to climb, causing natural gas prices to rise in response. Natural gas prices across PJM averaged over $8.50/MMBtu during January 2025, including daily spikes during the peak of the Polar Vortex event to nearly $30/MMBtu. With coal prices nearly flat month-over-month, most PJM coal plants were now more economical to dispatch than their natural gas counterparts. As a result, capacity factors for the PJM coal fleet increased to nearly 70%, while the natural gas fleet showed only a modest increase from their previous month's levels to about 48%. **EXHIBIT 41** shows a notable shift of most coal plants below the dotted marginal cost line during January 2025.

EXHIBIT 41: ESTIMATED PJM DISPATCH STACK DURING JANUARY 2025



Finally, on the peak demand day (January 21, 2025) for the PJM power market during the Polar Vortex event, natural gas prices spiked to nearly $30/MMBtu, resulting in a daily average power price of about $225/MWh. In other words, it cost the PJM power market over $750 million to meet the electricity demand of 3.4 million MWh on January 21, 2025. Most notably shown by **EXHIBIT 42**, oil-fired peaking units were relied on to meet the record demand for electricity across the region and its neighbors.

EXHIBIT 42: ESTIMATED PJM DISPATCH STACK ON JANUARY 21, 2025

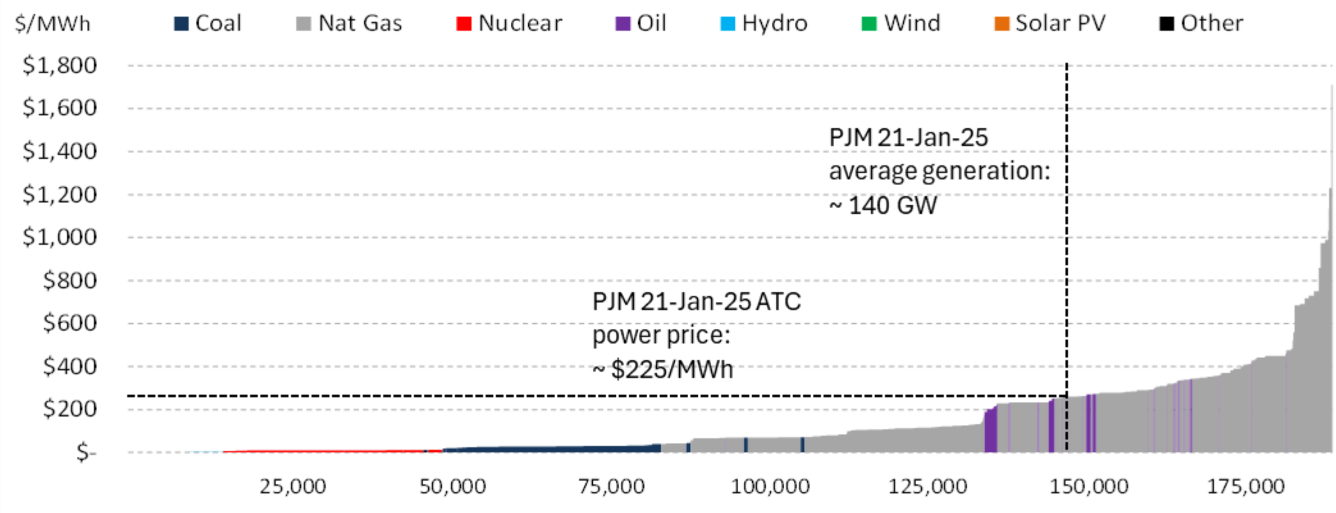
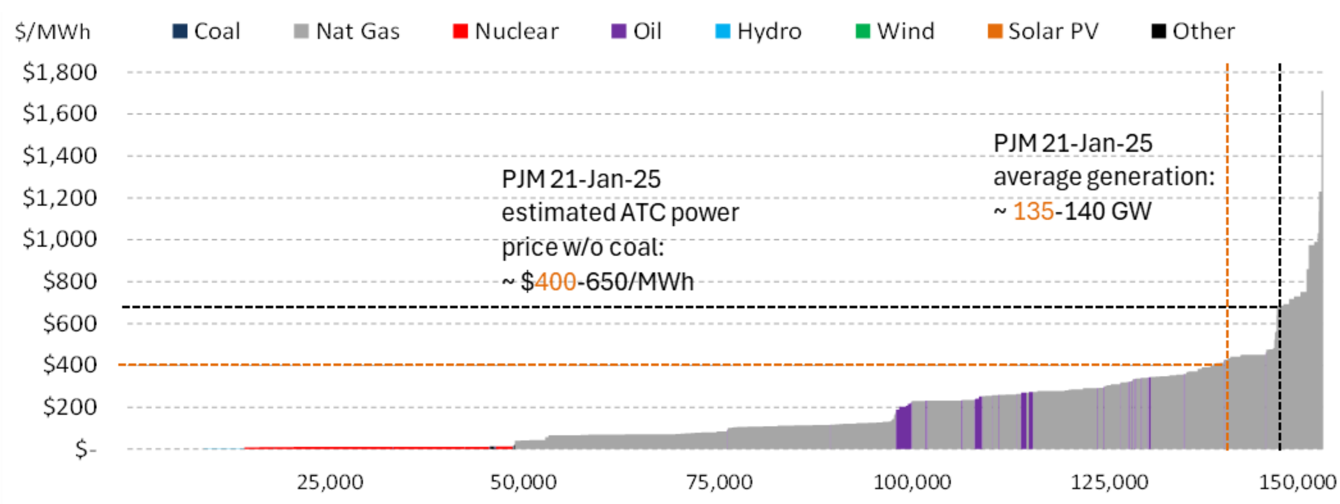


EXHIBIT 43 highlights the dramatic impact existing coal plants have on PJM wholesale power prices. The chart shows a hypothetical PJM dispatch stack on January 21, 2025, with no coal-fired power plants available to generate electricity. As the latest PJM capacity auction has shown, the PJM supply curve has limited surplus resources available to generate electricity during peak electricity demand events such as the January 2025 Polar Vortex. Assuming the same generating resources without coal-fired power plants, PJM's daily average power prices would have increased to over $400/MWh and as high as $650/MWh, more than doubling from their actual values. Accordingly, the resulting increase in power prices would have cost the PJM market an additional $500 million to $1.4 billion in electricity costs, which ultimately would be borne by electricity consumers across PJM's footprint.

EXHIBIT 43: HYPOTHETICAL PJM DISPATCH STACK ON JANUARY 21, 2025, WITHOUT COAL PLANTS



Alarmingly, about one-third of the existing PJM coal fleet is announced to retire before the end of the decade. As this extreme weather event and the others before it have shown, dispatchable, highly reliable generating resources like coal-fired power plants are paramount to ensuring reliable and affordable electricity service to electric consumers across the United States.

Appendix

EXHIBIT 44: REGIONAL DAILY TEMPERATURE IN JANUARY 2025 VS 10-YEAR AVERAGE