Navajo Transitional Energy Company

March 1, 2023

The Honorable Bruce Westerman
Chairman
Committee on Natural Resources
U.S. House of Representatives
202 Cannon House Office Building
Washington, DC 20515

The Honorable Raul Grijalva
Ranking Member
Committee on Natural Resources
U.S. House of Representatives
1203 Longworth House Office Building
Washington, DC 20515

Dear Chairman Westerman and Ranking Member Grijalva:

Introduction

I appreciate the questions from the House Committee on Natural Resources. On behalf of Navajo Transitional Energy Company (NTEC), I am providing the following responses. I believe that each of these questions is an essential consideration as part of a thorough review of current energy policy for the United States and whether the policy will meet the legal requirements and energy needs of citizens moving forward. As such, each issue deserves much more attention and discussion than I am able to provide here. I am available at any time to discuss any energy or mining matter, or attend further sessions of the House Committee on Natural Resources to discuss these issues.

I also want to clearly state Navajo Transitional Energy Company's belief with regard to energy in the United States and beyond. NTEC will celebrate the day when technology and science have developed a way to power our industries, heat and cool our homes, keep incubators running in hospitals and ensure that all communities can afford cheap, dependable electricity that has zero carbon emissions, allows plants to flourish and has zero impact other than providing electricity. However, that day is not today. But NTEC remains confident that human ingenuity, resourcefulness and a results-oriented focus will allow the United States to lead the world in the search for that energy technology.

NTEC has concerns that the path we are taking as a nation is leading to an unprecedented energy crisis that will cost lives, damage the economy and risk national security. This past weekend, the Wall Street Journal, referencing an ominous report from one of the country's largest grid operators, echoed our concern that "Fossil-fuel power plants are retiring much faster than renewable sources are getting developed, which could lead to shortages and blackouts ("S.O.S for the U.S. Electric Grid", Feb. 26, 2023). The entire United States coal-generated electricity fleet accounts for one point five percent (1.5%) of global emissions. China currently has in excess of 5 times the amount of electricity generated by coal in the United States . . . and they are expected to more than double that amount in the next 6 plus years. The consequence of that action will be that China has cheap, reliable and constant energy while the United States can expect brown and blackouts by the end of the decade. While NTEC supports (and is part of) the United States leading the charge into the 'green energy future,' the ill-advised rush to decommission our existing fleet of power plants will simply lead to much higher energy costs, less reliable energy and energy shortages that will put our economy and national security at risk.

1. With the increase in wind and solar generation, why are coal companies worried about the reliability of the electrical grid?

NTEC supports development of renewable resources and is working to develop large-scale solar generation capabilities. But, wind and solar cannot replace the tens of thousands of megawatts of baseload power supplied by our coal-fired power plants. Coal provides more than one-third of the electricity generation in the world and is a critical source of baseload generation. Baseload generation is needed to keep the electricity grid stabilized and grid frequency controlled. The U.S. electricity grid operates at a frequency of 60hz and if this precise frequency is not maintained, power outages and/or significant damage can result to electricity grid infrastructure, as well as industrial equipment and consumer electronics found in most homes in the U.S. Wind and solar electricity generation do not have the attributes necessary to maintain grid frequency without support from significant baseload power.

In the past, most dialogue in electricity industry trade groups focused on the high priority of costs to consumers of electricity and what source of fuel could best provide reliable energy at a reasonable cost. In recent years, FERC, State PUC's and regional grid operators have prioritized Greenhouse Gas (GHG) reduction above any other consideration while failing to acknowledge the growing costs to consumers, the increasing risk to grid reliability and the resiliency challenges.

Wind and solar are intermittent resources, meaning they produce electricity only when weather conditions are favorable. Wind and solar are also considered non-dispatchable as opposed to coal, natural gas, and nuclear power plants which are dispatchable because their electricity output can be increased or decreased (dispatched) based on electricity demand.

The coal fleet, on the other hand, is essential for a reliable grid because (1) its high accredited capacity value contributes to resource adequacy and makes coal a highly dependable electricity resource, and (2) it provides fuel security and essential reliability services (frequency support, voltage control, and ramping/balancing). Accredited capacity is a measure of how dependable a resource is when electricity demand peaks, such as during extreme weather. MISO uses the following for accredited capacity values: nuclear 95 percent, coal and natural gas 90 percent, batteries 87.5 percent, solar 35 percent, and wind 16.6 percent. Because of its capacity value, coal is considerably more dependable than wind or solar. To illustrate the impact of accredited capacity, more than 5 megawatts of wind (90 percent divided by 16.6 percent) must be added to the grid to replace 1 megawatt of retiring coal capacity.

As grids deploy more intermittent renewables and retire dispatchable generation assets like coal, the grid becomes increasingly less reliable and resilient. This is a concern for coal producers, as well as utilities and government and quasi-government entities responsible for monitoring the nation's electrical transmission system. The North American Electric Reliability Corporation (NERC) provided subtle warnings seven years ago: "The North American Bulk Power System (BPS) is undergoing a significant change in the mix of generation resources and the subsequent transmission expansion … [T]he rate of this transformation in certain regions is impacting planning and operating of the BPS."[1] By last year, NERC's warnings had become more blunt: "… the BPS has already seen a great deal of change and more is underway. Managing this pace of change presents the greatest challenge to reliability … Energy risks emerge when variable energy resources (VER) like wind and solar are not supported by flexible resources that include sufficient dispatchable, fuel-assured, and weatherized generation."[2] To prove NERC's point about the rapid transformation, more than 100,000 MW of dispatchable, fuel-secure coal-fired generation have retired and over 128,000 MW of VER (wind and solar) nameplate capacity were added to the BPS between 2015 and 2022.

An alarming amount of coal-fired generating capacity has publicly announced plans to retire; as of December 2022, 83,000 MW have announced retirement by 2030. In addition, six EPA rules are certain to cause even more coal plant closures unless the agency takes steps to avoid causing retirements that would further jeopardize grid reliability and resilience. The announced retirements and expected impact of the EPA rules will reduce the coal electricity fleet in the United States by more than 60% in the next 7 years.

The fast pace of retirements should be deeply disturbing to the Federal Energy Regulatory Commission (FERC), the NERC, grid operators, utility commissioners and other policymakers. Limiting coal (and other thermal) retirements as well as valuing all reliability attributes would be straightforward steps to help mitigate reliability problems in the near future.

Finally, attached to my response is a new report released by Energy Ventures Analysis and America's Power that analyzed the performance of electricity resources during Storm Elliott. The analysis found that coal, natural gas, and fuel oil provided 94 percent of the additional nationwide demand for electricity caused by Elliott. In other words, fossil fuels provided almost all of the additional electricity when it was needed most, with coal providing almost 40 percent. The report further notes that because coal plants have on-site fuel storage, it makes them more dependable than natural gas plants, wind farms or solar panels. Unfortunately, the retirement of coal plants is undermining grid reliability and, therefore, should be paused.

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[1] NERC, "Essential Reliability Services Task Force Measures Framework Report," November 2015.
[2] NERC, "Long Term Reliability Assessment," December 2021.

2. Why are permitting delays important to coal producers?

Permitting delays are not just occurring in coal mining. Permit delays are being seen in the efforts to permit mines for critical minerals (e.g., cobalt, lithium, rare earth), solar and wind farms, and to develop energy storage facilities and transmission infrastructure. The byzantine regulatory structure, risk of litigation and uncertainty of permitting pathways has made developing critical energy projects – renewable resources, traditional resources, and energy infrastructure (including transmission) and efficiency projects – unpredictable and jeopardizes our economy and national security.

For coal producers, however, the regulatory interference has greater implications. The coal industry has spoken for years, perhaps decades, about the amount of coal available in the United States. Not only is the number in the billions of tons . . . it is high quality coal (cleaner burning, higher BTU) which is easily minable with today's technology and mining methods. However, the amount of coal that is currently available to be mined is a tiny fraction of that billions of tons that is available. In the Powder River Basin (Wyoming and Montana), it is estimated that there are less than 20 years left of *permitted* coal.

The vast majority of coal west of the Mississippi River is on either federal or state land. In order to obtain more permitted coal on federal or state lands, a producer must go through either the lease by application process (LBA) or the lease by modification process (LBM). Essentially, the amount of new coal to be obtained determines which process.

The overriding concern with coal permitting can be narrowed down to time, cost and risk.

TIME

Thirty years ago, it was possible for a coal company in Wyoming to acquire rights to develop a coal deposit, obtain all permitting and have revenue from the sale of the coal within 2 to 5 years. Today, due to redundancies in the regulatory process, litigation, delays by the Department of the Interior (DOI) and significant levels of judicial advocacy from judges, once a coal producer obtains the right to mine coal, it should expect at least 8-12 years to maneuver through the regulatory and legal systems before selling its first ton of coal from the property.

This is not hyperbole. The current process takes at least 8 to 12 years. I say 'at least' because there is not much evidence lately of an LBA or LBM being approved – just 2 in the last 10 years. The DOI is dealing with three coal cases in the 9th Circuit currently (Montana). Each case has been subject to extraordinary delays, inaction and almost neglect from the Department of the Interior and the Biden Administration. The actions of DOI, presumably with the consent of the Administration, have further delayed these projects immeasurably. There are thousands of jobs and hundreds of millions of dollars in state and federal revenue through royalties and taxes at stake in just these three cases.

COST

The financial implications associated with the LBA process and the LBM process are the same. The public nominates an area for the Bureau of Land Management (BLM) to sell. The BLM then reviews each application submitted by the public to make sure it complies with land-use plans. Next, a Regional Coal Team consisting of members from federal, state, local, and tribal governments reviews the application, consults the public and decides whether to continue, change or reject the application. At this point, BLM prepares an Environmental Impact Statement (EIS) or Environmental Assessment (EA) for public comment in accordance with the National Environmental Policy Act. Next, BLM prepares to sell the lease. In advance of the sale, BLM estimates the fair market value of the coal lease. BLM holds a lease sale where each bidder submits a sealed bid, and BLM opens the bids publicly. The highest bid wins, so long as it is equal to or greater than the coal tract's presale estimated fair market value, and the bidder meets all requirements (such as paying fees). Once BLM accepts a bid, the bidder must pay one-fifth of the bonus and the first year's rent.[3]

The key to point out for this discussion is the last sentence: the need to pay a large sum of money up front, prior to getting permits and many years before actually mining. The amount of coal historically obtained from the LBA process is in the hundreds of millions of tons. The 'cost' of purchasing the coal (the bonus bid) has varied over the last 23 years, but the average bonus bid per ton in Wyoming has been just over $0.86 per ton (the range is $0.30 - $1.35). Those bids were for an average of just under 271 million tons (the range is 42.8 million tons to 793 million tons).

Using these historic numbers, I would like to present an illustrative example. Assume NTEC wanted to acquire more tons on federal land in Wyoming. After the lengthy process to get the BLM to initiate the sale, we may be able to acquire 250 million tons at a bonus price of $0.85 per ton. (There would be other costs associated with the sale – such as land rents, fees, etc. – but those are being ignored for simplicity.) Under this hypothetical, NTEC would then be required to pay the federal government $212,500,000 over the next five years for the right to mine that coal. $42,500,000 would be instantly due and payable, and $42,500,000 on each of the next four anniversary dates of the sale. That expense would have to be incurred despite the now certainty under the current regulatory scheme that operations would never commence for 8-12 years, if at all.

RISK

The past decade has not been economically kind to the coal industry. Pressures from ESG investors and ESG policies at banks and insurance companies have significantly

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[3] https://revenuedata.doi.gov/how-revenue-works/coal/

reduced the amount of financing and insurance that is available to coal companies. Reduced players in the market mean that costs of capital, cost of bonding and costs of insurance have all skyrocketed over the past 7 years. Additionally, the pressures from the Biden Administration and NGOs on all fossil fuels – but especially coal – have had a drastic impact on the behaviors of utilities throughout the country. Due to economic pressures, the vast majority of coal companies filed for bankruptcy protection in the last 8 years. The economic reality for the coal industry is that margins are very thin. The future is not settled.

With these facts as background, I go back to the illustrative example above. There are less than 20 years of reserves permitted in the Powder River Basin. If NTEC acquires an ‘average’ amount of coal through an LBA, we will need to pay $42,500,000 per year starting when we win the bid. However, as stated, under current regulations and processes, after spending in excess of $212,500,000 for the new coal, NTEC will not see a penny of revenue from that purchase for at least another 8 to 12 years due to permit delays. In today’s environment, it is highly unlikely that any coal company has $212 million sitting around to float for up to 12+ years. It is highly unlikely that any of the publicly-traded companies could justify that expense to their shareholders.

As such, it is highly likely that without significant changes, the United States will be out of permitted coal well before we have developed other technologies to keep our national electricity grid stable. While this anticipated result is certain to be celebrated in many quarters, it should be a source of dire concern for the future of the U.S. energy sector and the economy as a whole.

3. **With the anticipated closure of the Four Corners Power Plant on the Navajo Nation in 2031, how is NTEC working to replace the revenue which provides an annual 39% of the Navajo Nation general fund?**

As I stated in my prior written testimony, NTEC and the Navajo Mine, in combination with the Four Corners Power Plant (FCPP), provides 39% of the revenue to Navajo Nation’s general fund on an annual basis. This is in addition to the 400+ high paying jobs on the Nation, the free coal which NTEC provides for Navajo and Hopi families to keep their dwellings warm during the winter months and the other charitable efforts and development sponsored by NTEC and our vendors.

The owners of FCPP have announced their intention to exit the plant in 2031. While NTEC is working to diversify its operations, there is no comparable opportunity for Navajo families to earn commensurate wages or learn valuable job skills. The Navajo Nation has no other comparable source of revenues. Closure will eliminate millions of dollars of revenue to the Nation while immediately putting hundreds of Navajo and Hopi out of work. Again, this is not a theoretical statement. The Navajo Nation is already experiencing the crushing consequences of the closure of the NGS generating plant and the associated Kayenta Mine. There is simply no doubt as to the inevitable results of a closure of the FCPP.

There is no commercial reason to close the FCPP, but the current owners are under extreme pressure from state energy policies, like the New Mexico Transition Act, ESG investment funds and outspoken ESG activists. These external forces are controlling the future of the FCPP without consultation with the Navajo Nation and despite the fact the FCPP and the Navajo Mine are located entirely within the boundaries of the Navajo Nation.

Ten years ago the Nation took ownership of Navajo Mine to assert self-determination, sovereignty and control over its natural resources, but forcing energy policy restrictions on the FCPP will leave the Navajo Nation again without dominion or control of its own resources. While the anticipated closure of the FCPP would have catastrophic economic impact to the Navajo Nation – it does not seem to matter to the current policy leaders.

The FCPP must not be forced to close. Period. The electricity that it provides for the southwest is desperately needed today – let alone as we transition to an electric vehicle future (with estimates of doubling the electricity demand by 2035). Further, the FCPP is simply too important to the Navajo Nation to close.

NTEC believes that carbon capture has an essential role to play to ensure that the future energy mix provides stable electricity. There are a number of power plants that are ideal for carbon capture, and the Four Corners Power Plant is one of them. We believe this plant should become a priority project to give the Navajo Nation self-determination, control over its resources, and to treat it as the sovereign nation it is.

However, there are many in opposition to the development of carbon capture. Many NGOs have stated that even though carbon capture has the ability to capture 95%+ of the CO2, the technology should not be developed. They do not want carbon capture development because it would allow coal to continue to be utilized to provide cheap, reliable energy. The unstated premise, that the NGO's "know what is best" for the Navajo, is just a continuation of decades of patronizing decisions made off the Navajo Nation without any acknowledgment of the Navajo Nation's ability to govern its own affairs.

NTEC, as an investor in and promoter of carbon capture and sequestration technology (CCS), sees an opportunity for the Navajo (and the United States) to be a global leader in decarbonization strategies that provide for the continued utilization of our nation's expansive coal resources. We would be able to take carbon capture technology to all areas of the world – especially those that are energy poor – and provide stable, reliable electricity to the 30% of the world that cannot rely on it currently. [As an added bonus of the United States exporting coal to the world, the federal government gets the revenue from the 12.5% royalty on coal from federal lands (most of the coal in the western United States).] Further, the coal will be mined in accordance with the most extensive reclamation and environmental standards on the planet. Finally, coal on the Navajo Nation and in the United States is mined by adults and in compliance with the strongest labor and safety regulation in existence.

I appreciate the opportunity to respond. Should you have questions, please contact Matthew Adams at 720.566.2933.

Sincerely,

Matthew Adams
Vice President, Senior Tax Counsel

Attachment

FEBRUARY 2023

Operation of the U.S. Power Generation Fleet During Winter Storm Elliott

Prepared for:

AMERICA'S POWER
Reliable • Secure • Resilient • Affordable

Prepared by:

ENERGY VENTURES ANALYSIS

ENERGY VENTURES ANALYSIS

8045 Leesburg Pike
Suite 200
Vienna, VA 22182

703-276-8900
www.evainc.com

Executive Summary

From December 21 to December 26, 2022, an extratropical cyclone created winter storm conditions throughout much of the United States. Frigid temperatures resulted in record-setting electricity demand for many regions, and utilities struggled to meet demand across much of the country. At some point during Winter Storm Elliott, as the event was named, more than 1.5 million customers were without electricity. In addition, sixty deaths have been attributed to the storm's effects[1].

Substantial increases in electricity generation from dispatchable fossil fuel power plants, including coal, natural gas, and oil, allowed utilities and independent system operators (ISO) across the country to meet the record-level demand for electricity during the peak of the storm. Although overall natural gas generation increased, natural gas plants also represented the largest source of unexpected power plant outages due to a lack of fuel availability, despite increased coordination efforts between the natural gas and electricity sectors, especially in the wake of the devasting and deadly Winter Storm Uri of February 2021. On the other hand, all power market regions with excess coal-fired electric generating capacity saw a significant increase in electric output from these resources, largely thanks to their significant amount of on-site fuel storage, which allows them to operate reliably without disruption due to a lack of just-in-time fuel availability.

This report analyzes and highlights how power generation across the country responded to the exceptional winter weather event in December 2022. Some of the national and regional highlights of the report include:

- Winter Storm Elliott resulted in the 24th highest single-day electricity demand on record for the U.S. Lower-48 on December 24 and the **highest single-day electricity demand on record for any day during the winter season**.
- In **ERCOT**, Elliott set the **overall single-day electricity demand record**, while electricity demand in **PJM**, **MISO**, and **SPP** all ranked in the top 20 of all time and had the highest winter demand on record.
- Natural gas production in the Appalachian basin **dropped by over 25%** during the storm due to well freeze-offs and other equipment failures. As a result, natural gas generation was limited in **PJM** and the **Northeast** due to the loss of available fuel supply, despite many plants having signed firm or uninterruptable natural gas supply contracts. Conversely, fossil fuel generation with an on-site fuel inventory of coal or oil was able to increase electric generation output to offset the loss of natural gas generation and meet the increased demand for electricity.
- Utilities in the **Southeast**, including TVA, Duke, and LG&E/KU, were required to implement rolling power outages to their customers at various points throughout the storm, as the sudden drop in temperatures and the resulting increase in natural gas heating demand caused numerous natural gas power plants to shut down as natural gas pipeline pressure was insufficient to operate these plants safely. Without the notable increase in coal-fired power generation, the power outages in these regions likely would have been longer-lasting and more widespread.
- Higher wind speeds associated with Winter Storm Elliott allowed for higher electric generation output from wind power plants in **MISO, SPP, and ERCOT** compared to previous extreme weather events. However, wind generation output can vary widely, as previous winter storm events have shown, and is not a reliable form of electricity generation during these weather events. Therefore, massive amounts of electricity from dispatchable power plants are needed to balance out the extreme variability of wind generation regions like **SPP** and **ERCOT** have experienced during the storm.
- Some regions that struggled to meet the electricity demands of Winter Storm Uri in February 2021 (**MISO**, **SPP**, and **ERCOT**) were able to meet the increased demand for electricity during Winter Storm Elliott successfully due to increased availability of natural gas, higher wind speeds, better winterization of equipment, and continued reliable performance of in-region coal plants.

[1] https://abcnews.go.com/US/20-dead-cold-weather-christmas-weekend/story?id=95809460

- However, significant natural gas plant outages due to natural gas supply issues strained the resource reserves of regions like **PJM**, **MISO**, and the **Southeast** and limited their ability to generate surplus electricity to support their neighboring regions.

Recent and future changes in electricity supply across the country have resulted and will exacerbate the challenges ISOs and utilities experienced during Winter Storm Elliott and other recent extreme weather events. These challenges and risks include but are not limited to the following:

- While electricity demand usually peaks in the summer, the risk of electricity supply failures is most significant during winter peak events, like Winter Storms Elliott and Uri. The reason is that natural gas has grown to be the largest source of U.S. power supply (40% in 2022), and the demand for natural gas for home heating surges during cold weather at the same time as electricity demand. Even with “firm” pipeline transportation contracts (the “gold standard”), many power plants have been unable to receive enough natural gas at sufficient pipeline pressure to operate during extreme winter cold weather. Natural gas power plants do not maintain on-site gas storage (although some plants have fuel oil backup) and are not available to meet increased power demand if gas deliveries cannot increase to match increased demand.
- The only form of power generation that can increase output significantly (known as “dispatch”) to meet high electricity demand is powered by fossil fuels (coal, natural gas, and oil). The growing supply of wind and solar power can only operate when the wind blows or the sun shines. These power sources almost always operate at maximum capacity when available because of their low operating costs and, as a result, cannot increase output further when demand increases. Similarly, because of low costs, nuclear power plants are operated at maximum capacity when available. Hydropower can be managed to increase output to meet demand where there is a sufficient reservoir or pumped storage capacity, but this is a very limited supply.
- Over the last decade, the U.S. power industry has steadily replaced dispatchable fossil fuel generation capacity with on-site fuel storage (i.e., coal and oil) with non-dispatchable intermittent solar and wind resources. Driven by federal and state mandates and subsidies, this replacement will accelerate over the next decade, increasing the likelihood of system failures during extreme winter weather events. Proposed battery energy storage systems are not equipped to provide electricity for periods of time lasting longer than 4 to 8 hours, which is inadequate during extended high electricity demand events.
- The coal power fleet was a principal source of increased power generation to meet demand during Winter Storm Elliott. However, another 82 GW of coal-fired generation capacity is announced to retire before the end of the decade. In three power regions (PJM, MISO, and Southeast) analyzed in this report, the amount of announced coal retirements exceeds the increase in coal-fired electricity generation during Winter Storm Elliott. Without adequate and comparable replacement capacity, electric power system failures in these regions are more likely during similar extreme weather events.

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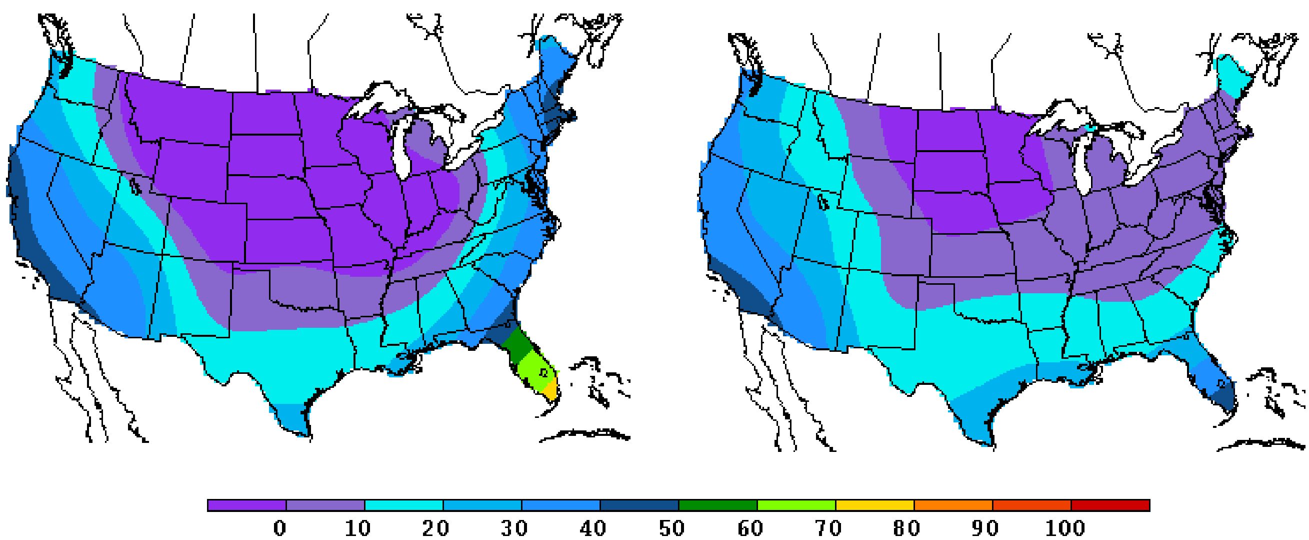
Introduction

From December 21 to 26, 2022, an extratropical cyclone (named Winter Storm Elliott) created extreme weather conditions, including record-cold temperatures, blizzards, high winds, and significant snowfall, across most of the United States and parts of Canada. During one point of Winter Storm Elliott, almost three-quarters of the U.S. population was under some form of winter weather warning or advisory from the National Weather Service[2]. Winter Storm Elliott brought record-cold temperatures for this time of year to many parts of the country, from the Pacific Northwest down to Miami, Florida, as shown in **EXHIBIT 1**.

EXHIBIT 1: DECEMBER 23, 2022 & DECEMBER 24, 2022 MINIMUM TEMPERATURES (FAHRENHEIT)



As a result of the record-cold temperatures, demand for electricity skyrocketed to meet the increased heating demand across the country, setting electricity demand records for the winter season in many parts of the country. This report shows the impacts of Winter Storm Elliott on U.S. electric power demand, how the U.S. electric generation fleet responded and performed during this record-setting cold weather event, and how upcoming changes to the U.S. electric generation fleet may increase the risk of power outages during similar events in the future.

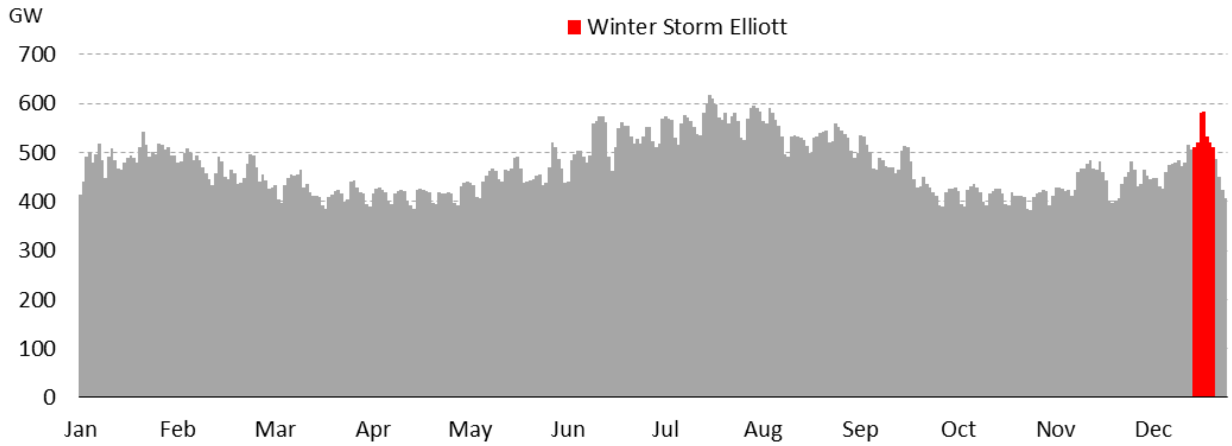
National Results

As Winter Storm Elliott moved across the country, entering the U.S. in the Pacific Northwest on December 20, 2022, and exiting the country to the East on December 25, 2022, frigid temperatures caused electricity demand to skyrocket. As shown in **EXHIBIT *2***, the average hourly electricity demand for the U.S. Lower-48 on December 24 reached its peak of 585 GW, following 582 GW the day before[3]. This was the highest demand for electricity since August 8, 2022, when demand reached 590 GW.

[2] https://www.forbes.com/sites/ericmack/2022/12/24/why-winter-storm-elliott-is-more-new-normal-than-once-in-a-generation/

[3] Unless otherwise noted, all data presented in the charts and tables shown in this report was sourced from EIA's Hourly Electric Grid Monitor, accessible at: https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48. Additionally, EVA attempted to correct all obvious data errors included in the raw EIA data. Data files associated with the report can be provided upon request.

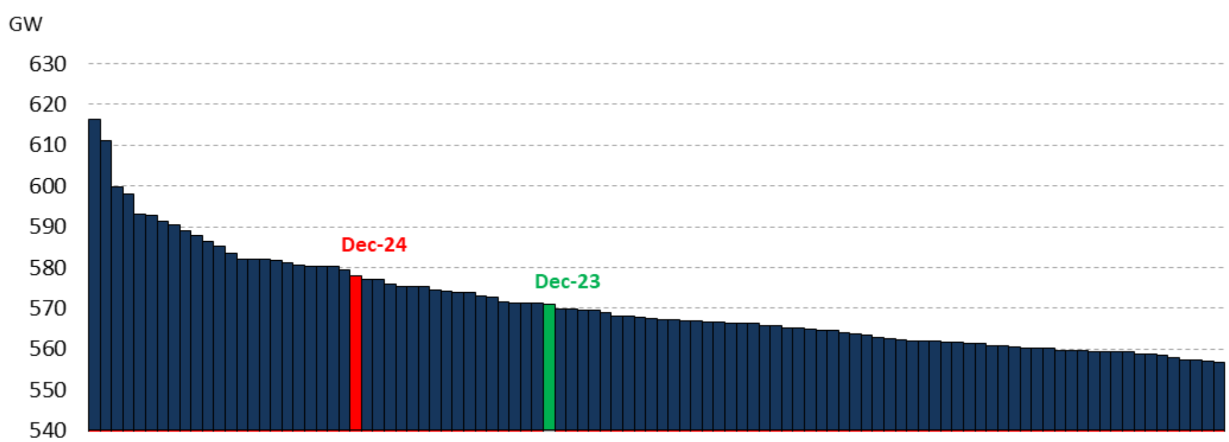
EXHIBIT 2: U.S. LOWER-48 AVERAGE HOURLY ELECTRICITY DEMAND - 2022



Source: EIA Hourly Grid Monitor

Importantly, December 23 and 24, 2022, represent the highest winter electricity demand on record (January 21, 2022, ranks 162nd as the third-highest winter electricity demand day). Further, both days rank among the top 100 average hourly electricity demand records for the U.S. Lower-48 as shown in **EXHIBIT *3*** (December 24, 2022, ranks 24th, while December 23, 2022, ranks 41st).

EXHIBIT 3: TOP 100 AVERAGE DAILY ELECTRICITY DEMAND RECORDS FOR THE U.S. L-48

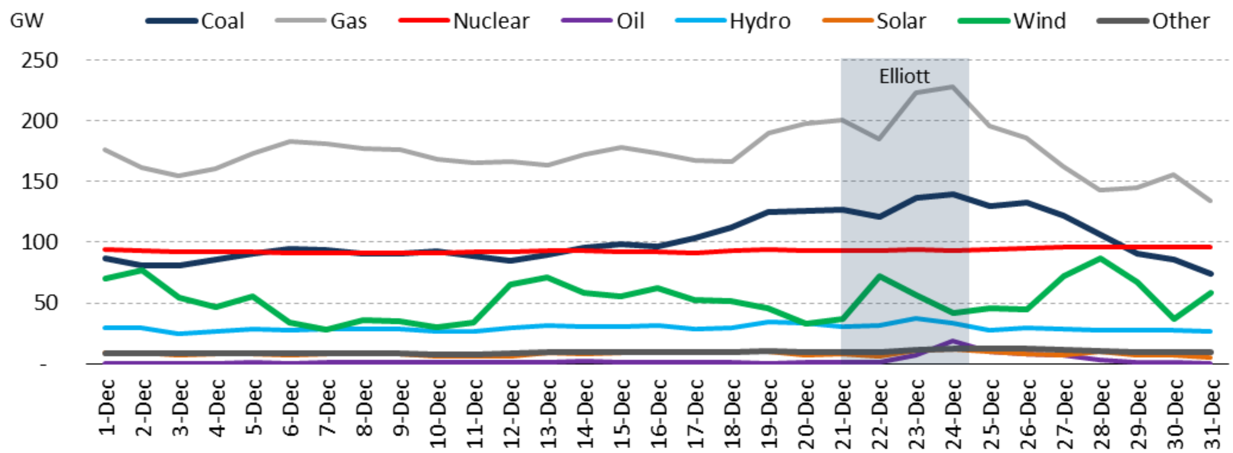


Source: EIA Hourly Grid Monitor data

Winter Storm Elliott also ranks as one of the highest electricity demand days for many regional balancing authorities (BA) and local utilities. For example, Winter Storm Elliott ranks as the highest single-day electricity demand in the Electric Reliability Council of Texas (ERCOT), the ISO encompassing most of the state of Texas, while Elliott ranks as the 4th-highest demand day in the Southwest Power Pool (SPP), the 9th-highest in PJM, and the 12th-highest in MISO. For all major U.S. ISOs (excluding CAISO in California), Elliott was the highest electricity demand during the winter season.

EXHIBIT *4* shows the average hourly electricity generation for the U.S. Lower-48 for December 2022, with the week of Winter Storm Elliott shaded in gray. As temperatures began to decline and electricity demand began to increase over the course of the month, both natural gas and coal-fired power plants increased electric generation output to meet the increased demand. The early days of the week of Winter Storm Elliott were highlighted by increased wind generation as the higher wind speeds accompanied the storm system as it moved across the country. As wind generation dropped, fossil fuel generation (natural gas, coal, and oil) increased to compensate for the drop in wind generation and meet the peak electricity demand on December 24.

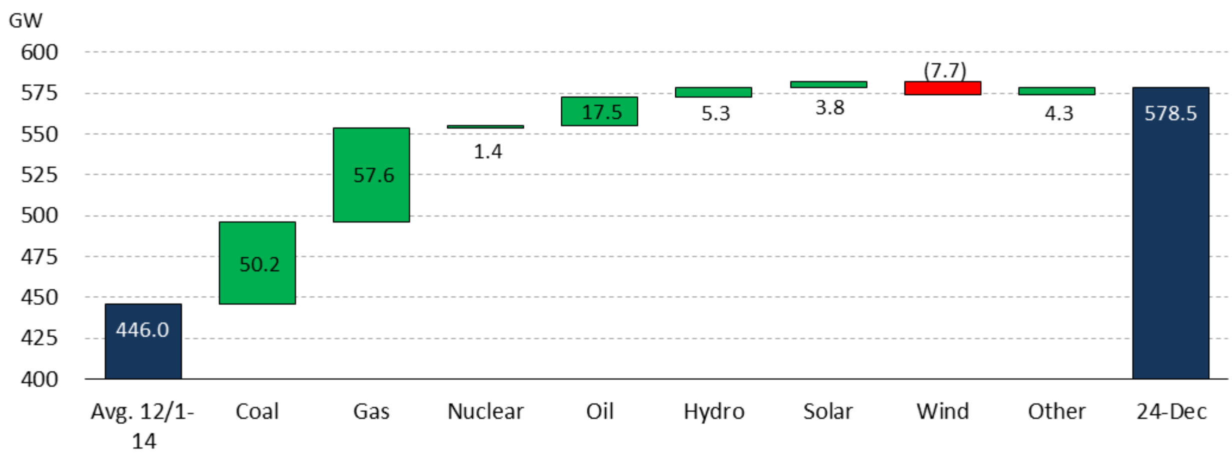
EXHIBIT 4: U.S. LOWER-48 AVERAGE DAILY NET GENERATION BY FUEL TYPE – DECEMBER 2022



Source: EIA Hourly Grid Monitor

EXHIBIT *5* quantifies how the peak electricity demand on December 24 for the U.S. Lower-48 was met by the various types of electric generating resources compared to the first two weeks of December 2022.

EXHIBIT 5: U.S. LOWER-48 CHANGE IN NET GENERATION BY FUEL TYPE DURING WINTER STORM ELLIOTT



Source: EIA Hourly Grid Monitor

Overall average hourly net electricity generation in the U.S. Lower-48 increased by roughly 132.5 GW between the first two weeks of December 2022 and December 24. Over 95% of the increase in electric generation was supplied by dispatchable fossil fuels. Natural gas-fired power plants provided an additional 57.6 GW of electricity, while coal and oil-fired power plants supplied an additional 50.2 GW and 17.5 GW of electricity, respectively. Despite the higher wind generation during the early days of Winter Storm Elliott, the average hourly wind generation on December 24, the day of peak electricity demand in the U.S. Lower-48, **declined** almost 8 GW from the first two weeks of December. While wind generation declined, all other generation types provided at least small increases in electricity output during the peak of the storm compared to the first two weeks of December 2022.

Due to the size of the storm and the regional differences in electric generation mix, the following sections explore how power supply in the different power market regions across the country fared during Winter Storm Elliott.

Regional Analysis

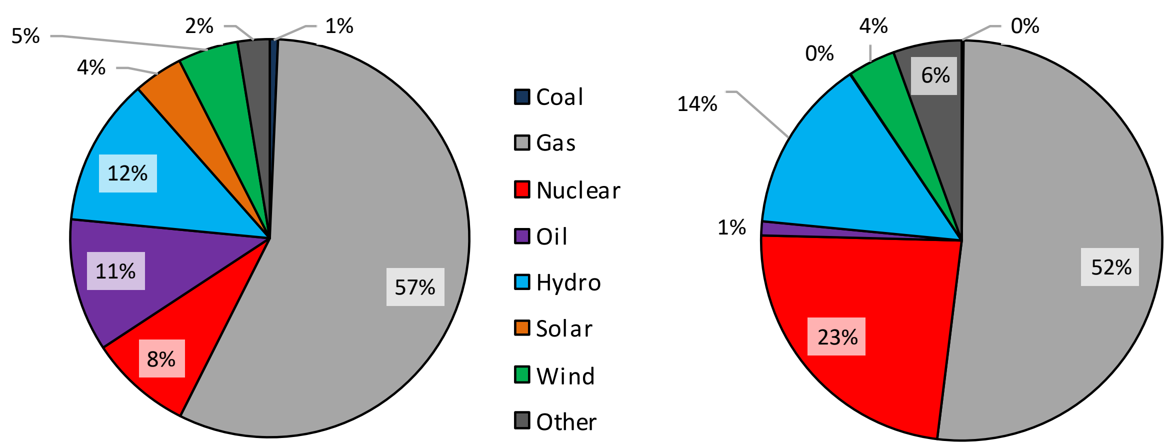
Using EIA's regional data from the Hourly Electric Grid Monitor, EVA performed analyses of the impact and performance of the power market regions shown in **EXHIBIT *6***.[4,5]

EXHIBIT 6: MAP OF POWER MARKET REGIONS

Northeast

The Northeast region is comprised of the New York and New England ISOs. **EXHIBIT *7*** shows the Northeast region's capacity mix during Winter Storm Elliott and the estimated generation mix for 2022 by fuel type.

EXHIBIT 7: NORTHEAST - 2022 END-OF-YEAR CAPACITY MIX & FULL-YEAR GENERATION MIX BY FUEL TYPE



Source: EIA Form860 data

Source: EIA Form923 & Form930 data

[4] 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

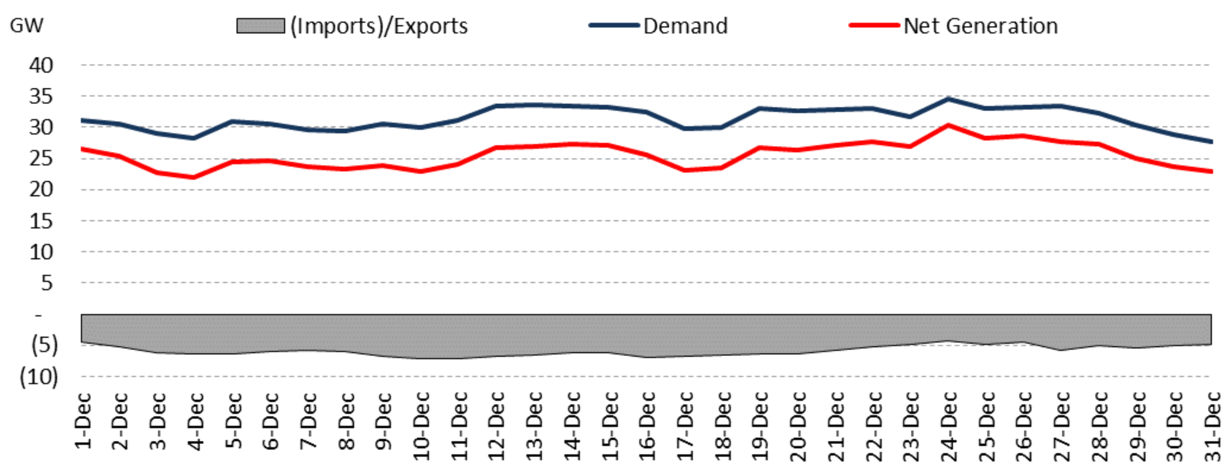
[5] WECC is excluded from the report as the data analysis showed little impact on the WECC power system during Winter Storm Elliott.

As shown in **EXHIBIT *7***, the Northeast region relies primarily on natural gas for electricity. Nuclear and hydroelectric generation also provided significant amounts of electricity in 2022.

Since no natural gas is produced within the boundary of the Northeast region, all natural gas is supplied via pipelines from surrounding areas, primarily the Mid-Atlantic (PJM power market) and Canada (and, to a small extent, via liquefied natural gas import terminals in Massachusetts). Therefore, any disruption to natural gas pipelines supplying the Northeast region would have severe adverse effects on the gas supply for power generation and home heating.

EXHIBIT *8* shows the average hourly demand, net electricity generation, and imports and exports for the Northeast region during December 2022[6].

EXHIBIT 8: NORTHEAST - AVERAGE DAILY ELECTRIC DEMAND, (IMPORTS)/EXPORTS & NET GEN. – DECEMBER 2022



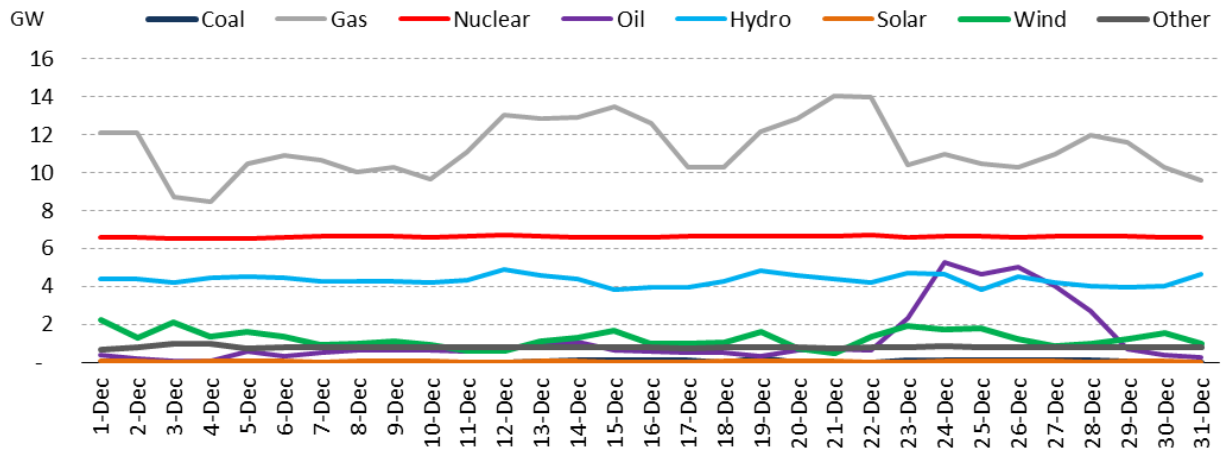
Source: EIA Hourly Grid Monitor

Most of the Northeast region had been experiencing typical cold winter weather for most of the second half of December 2022. Therefore, the impact of Winter Storm Elliott on overall electricity demand was relatively minor, reaching a peak of 34.6 GW on December 24. The average hourly demand for the first two weeks of December 2022 was 30.8 GW.

Despite the minor impact on overall electricity demand, Winter Storm Elliott significantly impacted the electric supply within the Northeast region during the week of the storm, as shown in **EXHIBIT *9*** and **EXHIBIT *10***.

[6] (Imports)/Exports below 0 means that the region imported more electricity than it exported during that time, and vice versa.

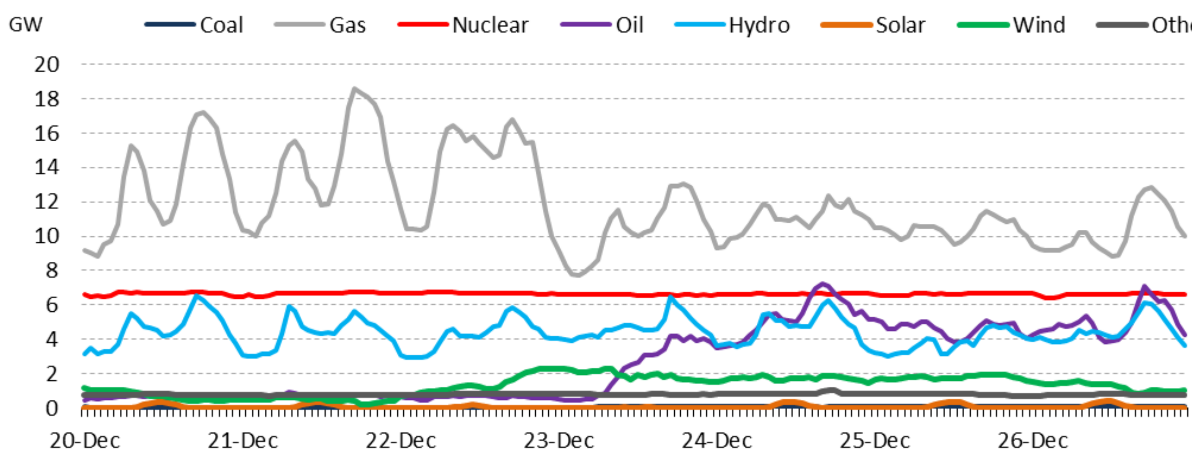
EXHIBIT 9: NORTHEAST - AVERAGE DAILY NET GENERATION BY FUEL TYPE – DECEMBER 2022



Source: EIA Hourly Grid Monitor

On December 21 & 22, hourly electricity generation from natural gas-fired power plants in the Northeast region averaged approximately 14 GW. However, between December 23 & 26, natural gas generation averaged only 10.6 GW, a drop of over 25% as plants struggled to operate amid reduced natural gas deliveries from the pipeline system supplying the region.

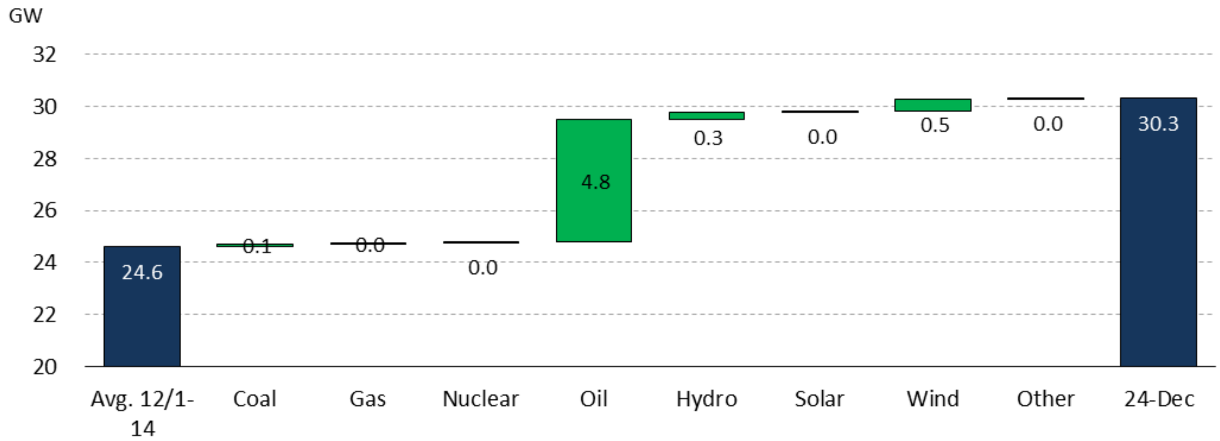
EXHIBIT 10: NORTHEAST - HOURLY GENERATION BY FUEL TYPE DURING WINTER STORM ELLIOTT



Source: EIA Hourly Grid Monitor

To compensate for the loss of available natural gas-fired generation, ISONE and NYISO called on oil-fired backup generators and dual-fueled (natural gas and fuel oil) power plants. Between December 23 & 26, hourly oil-fired generation averaged over 4.3 GW, completely offsetting the loss of natural gas generation during that period.

EXHIBIT 11: NORTHEAST - CHANGE IN NET GENERATION BY FUEL TYPE DURING WINTER STORM ELLIOTT

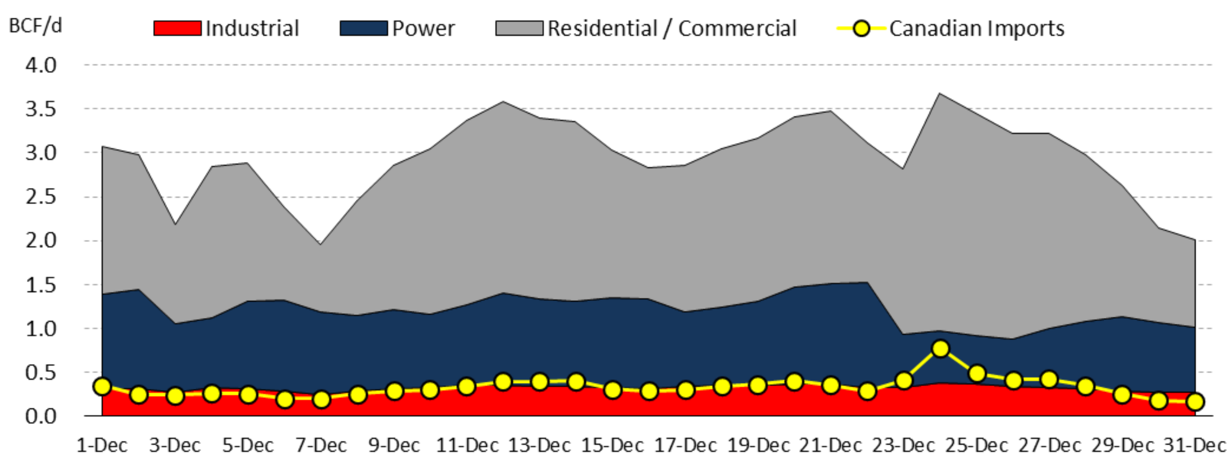


Source: EIA Hourly Grid Monitor

As shown in **EXHIBIT *11***, net electric generation in the Northeast region increased approximately 23% from the first two weeks of December 2022 to December 24, the peak electricity demand day for the Northeast region. Over 80% of the increase in generation was supplied by oil-fired power plants, which had ample fuel supply in inventory to meet the increase in electricity demand.

EXHIBIT *12* shows the natural gas demand for the Northeast region in December 2022 by end-use sector and Canadian natural gas imports. The loss of natural gas supply from the Appalachian region caused natural gas consumption in the Northeast region to drop on December 23 before Canadian natural gas imports filled most of the loss in supply the following day. While the initial loss of natural gas supply is the likely cause for most of the natural gas-fired generating fleet in the Northeast to go offline, the ensuing natural gas price increase due to the lower supply available likely also caused some economic switching from natural gas to oil-fired power plants, despite more natural gas being available potentially to allow more natural gas plants to return to service.

EXHIBIT 12: NORTHEAST - NATURAL GAS DEMAND BY END-USE SECTOR & CANADIAN IMPORTS – DECEMBER 2022

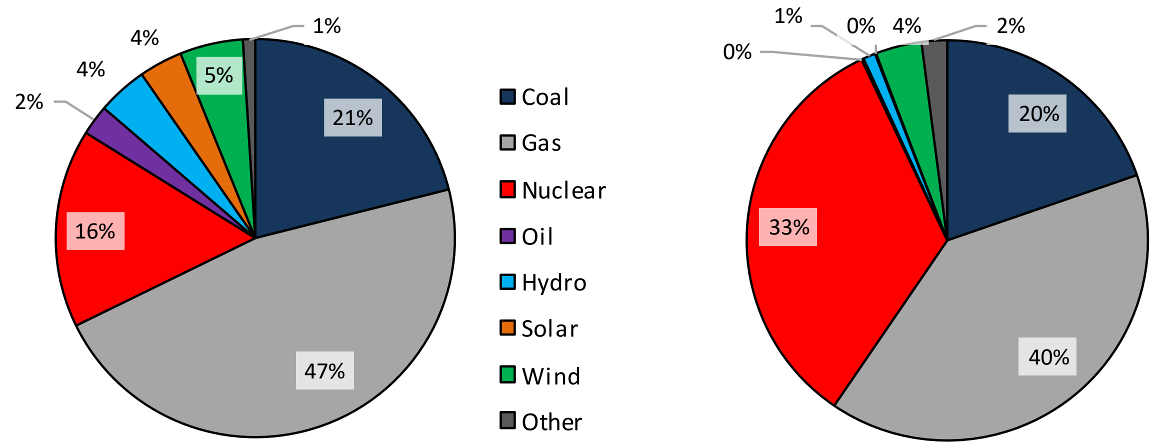


Source: Genscape

PJM

The PJM Interconnection is the country's largest ISO (by capacity), serving about 65 million customers across 13 states and D.C. PJM's 2022 end-of-year capacity mix and full-year generation mix by fuel type are shown in **EXHIBIT *13***.

EXHIBIT 13: PJM - 2022 END-OF-YEAR CAPACITY MIX & FULL-YEAR GENERATION MIX BY FUEL TYPE



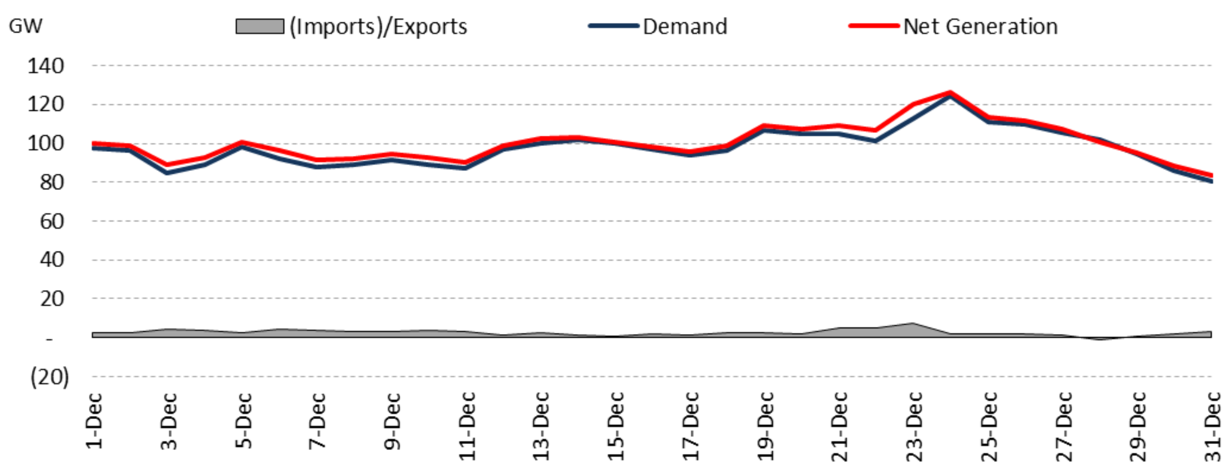
Source: EIA Form-860 data

Source: EIA Form-923 & Form-930 data

Natural gas, nuclear, and coal-fired power plants make up the majority of PJM's capacity and generation mix in 2022, accounting for 84% of PJM's total capacity and supplying 93% of PJM's electric generation in 2022.

PJM arguably experienced the most significant impact on its systemwide electricity demand across all regions during Winter Storm Elliott, when PJM's peak demand hit 124.5 GW on December 24, an increase of over 34% compared to the first two weeks of December. As mentioned previously, December 24, 2022, ranks as the highest winter demand day for PJM and the 9th-highest overall. **EXHIBIT *14*** shows the average hourly demand, net electricity generation, and imports and exports for PJM during December 2022.

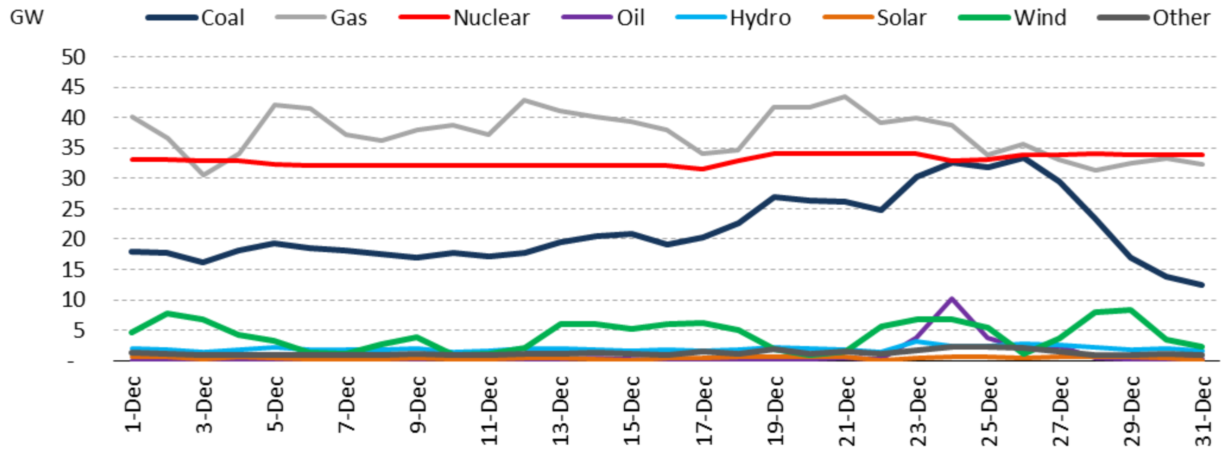
EXHIBIT 14: PJM - AVERAGE DAILY ELECTRIC DEMAND, (IMPORTS)/EXPORTS & NET GEN. – DECEMBER 2022



Source: EIA Hourly Grid Monitor

EXHIBIT *15* shows the average hourly electricity generation by fuel type in PJM for the month of December. As electricity demand continued to increase over the course of the month, PJM coal generation continued to climb to meet the increased demand while natural gas generation remained relatively constant. Nuclear generation remained relatively steady throughout the month at around 33 GW.

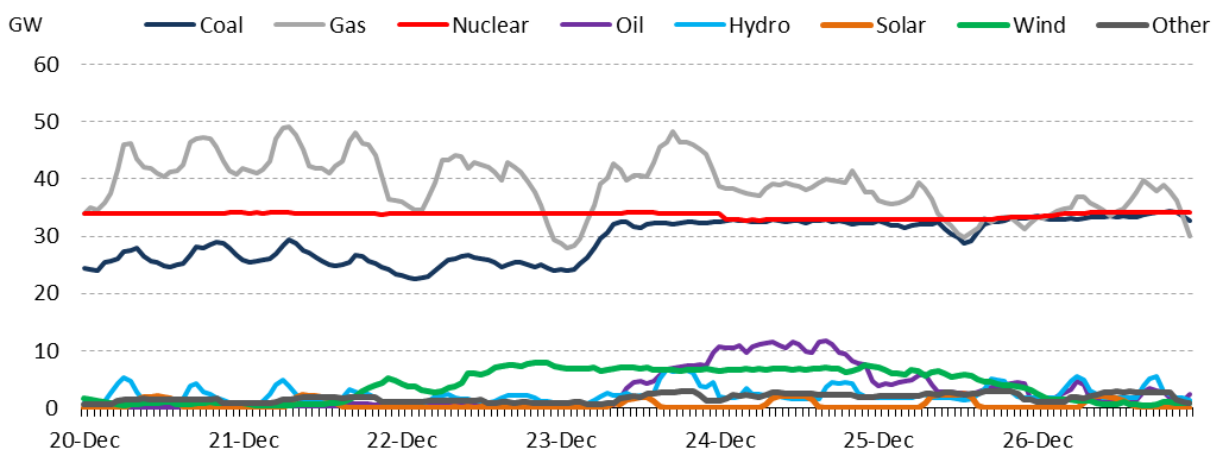
EXHIBIT 15: PJM - AVERAGE DAILY NET GENERATION BY FUEL TYPE – DECEMBER 2022



Source: EIA Hourly Grid Monitor

EXHIBIT *16* shows the hourly generation by fuel type in PJM during the week surrounding Winter Storm Elliott. As frigid temperatures moved into the region on December 23, coal-fired power plants in PJM increased their electricity output by about 6 GW to meet the increased demand. On the other hand, electric generation from natural gas-fired power plants dropped below 34 GW on December 25 after peaking at 43 GW just four days prior as reduced natural gas availability forced plants to go offline. In response, oil-fired backup generators, which relied on their on-site fuel storage, came online and provided over 10 GW of electricity on December 24 to fill the gap left by the natural gas-fired power plants.

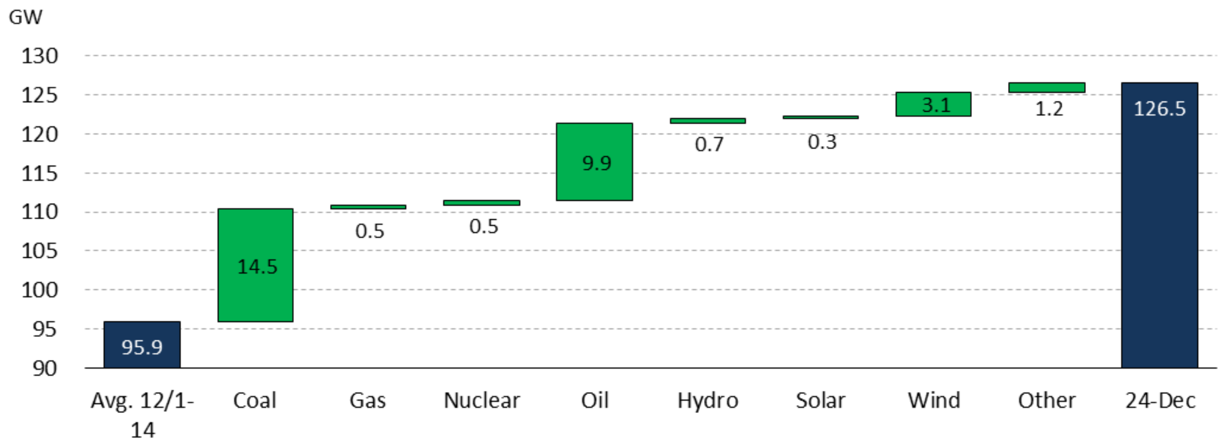
EXHIBIT 16: PJM - HOURLY GENERATION BY FUEL TYPE DURING WINTER STORM ELLIOTT



Source: EIA Hourly Grid Monitor

As shown in **EXHIBIT *17***, net electricity generation in PJM increased by over 30 GW between the first two weeks of December 2022 and the peak of the storm on December 24. Coal and oil-fired power plants, both relying on their on-site fuel inventory, accounted for 80% of the increased generation. Thanks in part to the significant increase in wind speeds that accompanied the storm, PJM's wind generation also increased by an average of about 3 GW during the storm compared to earlier in the month.

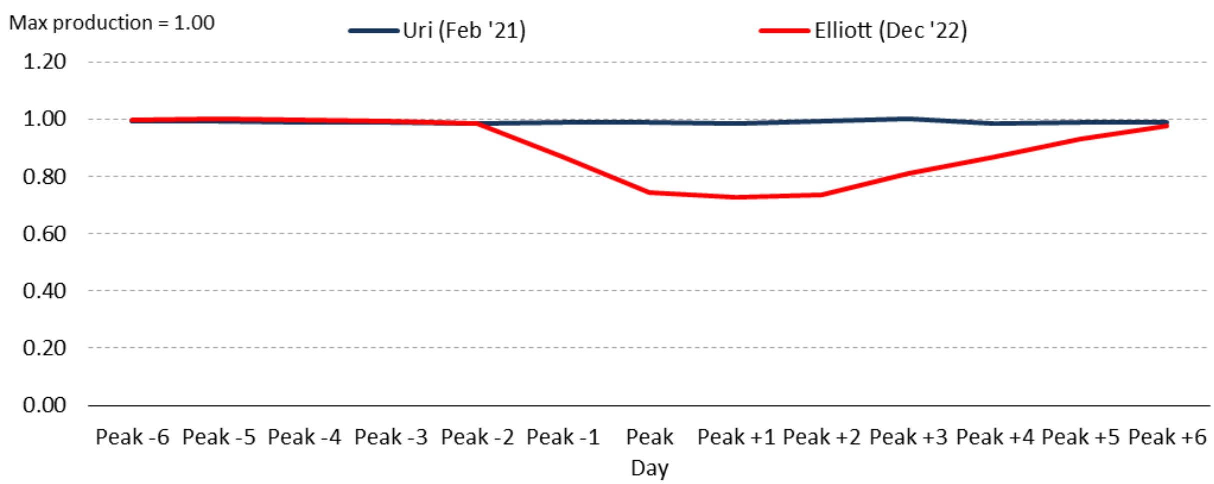
EXHIBIT 17: PJM - CHANGE IN NET GENERATION BY FUEL TYPE DURING WINTER STORM ELLIOTT



Source: EIA Hourly Grid Monitor

One of the primary reasons for the significant drop in natural gas generation during Winter Storm Elliott was the lack of available fuel supply. As temperatures dropped rapidly in the region, natural gas production in the Appalachian region dropped by 27% due to well freeze-offs[7]. **EXHIBIT *18*** shows the normalized production for the Appalachian region during winter storms Uri and Elliott six days before and after the peak demand for the respective storm system.

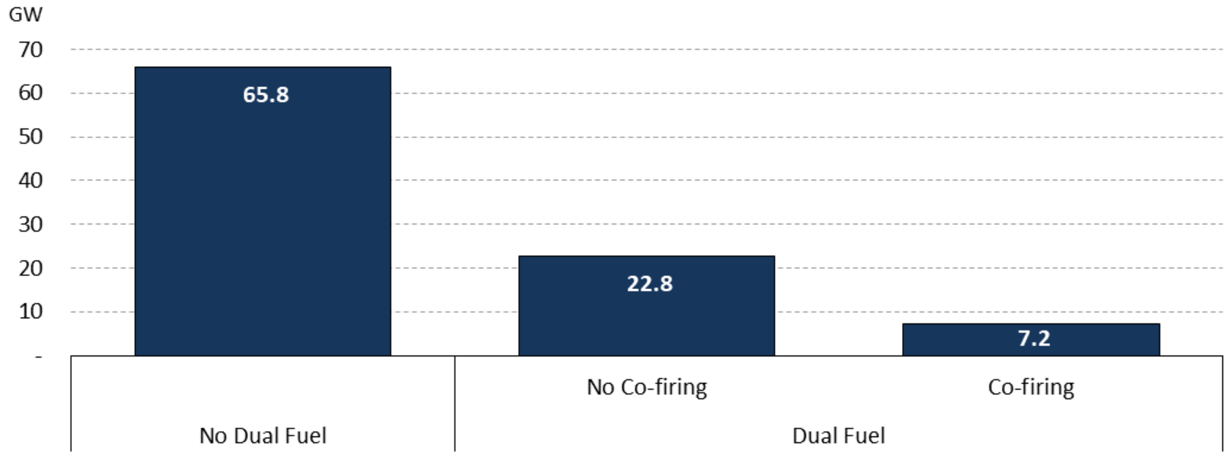
EXHIBIT 18: NORMALIZED APPALACHIAN NATURAL GAS PRODUCTION DURING WINTER STORMS URI & ELLIOTT



As natural gas supply dropped, demand for the fuel from the residential and commercial sector increased, and natural gas plants in PJM that lacked backup on-site fuel oil had to go offline until sufficient fuel supply became available once again, days after Winter Storm Elliott had moved through the region.

[7] Well freeze-offs occur when production is halted at the well because water and other liquids contained within the natural gas mixture freeze.

EXHIBIT 19: PJM - NATURAL GAS POWER PLANTS WITH DUAL-FUEL CAPABILITIES[8]



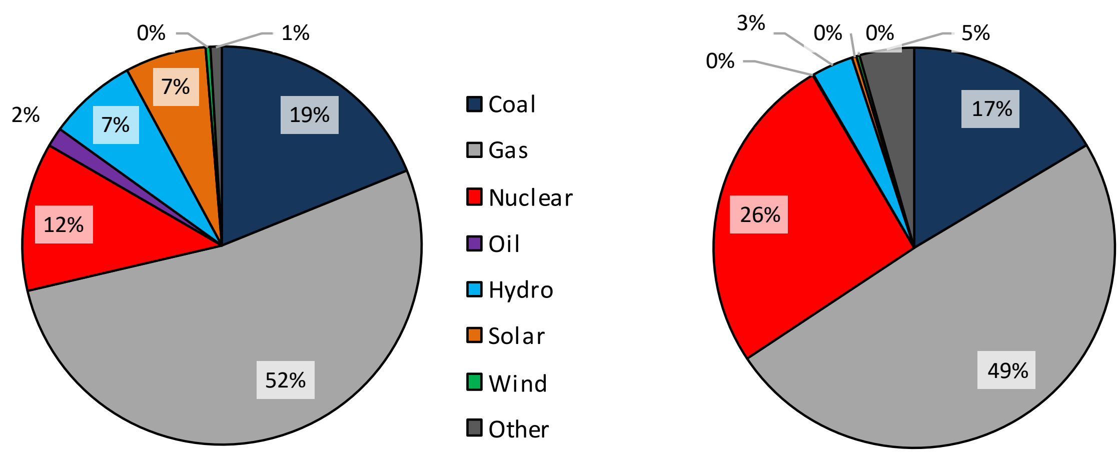
Source: EIA Form-860 2021 annual data

At the end of 2021, less than 30 GW or about one-third of all natural gas power plants in PJM had the capability to use oil as an alternative fuel source, according to EIA Form-860 data, as shown in **EXHIBIT 19**. The length of time these generators can run on fuel oil as an alternative fuel source also depends on the amount of fuel oil stored on-site. On the other hand, the average coal plant in PJM can operate at full utilization for about 30 days before running out of fuel.

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 combined end-of-year 2022 capacity mix and 2022 generation mix by fuel type for the Southeast region is shown in **EXHIBIT *20***.

EXHIBIT 20: SOUTHEAST - 2022 END-OF-YEAR CAPACITY MIX & FULL-YEAR GENERATION MIX BY FUEL TYPE



Source: EIA Form860 data

Source: EIA Form923 & Form930 data

[8] "Dual fuel" refers to power plants that can operate using two different types of fuel (excluding start-up fuel), e.g., coal and natural gas, coal and biomass, natural gas and fuel oil. "Co-firing" refers to power plants that can burn these two fuels simultaneously.

Similar to PJM, the Southeast region sources most of its electricity from natural gas, nuclear, and coal-fired power plants. Although solar generating capacity has solidly increased over the last few years, it still only accounts for less than 1% of total electricity generation in the region.

The Southeast region had the most severe operational issues during Winter Storm Elliott as three of its major utilities (Duke Energy[9], TVA[10], and LG&E/KU[11]) had to implement rolling blackouts within their systems as electricity demand increased above available generation levels.

Duke Energy experienced rapidly plunging temperatures, demand for electricity that outpaced projections, diminished generation capacity due to gas supply limits and equipment failures at some gas and coal plants, and the loss of purchased power the company was relying on that forced the company to initiate automated power outages.

On December 24, TVA's 2,600-MW coal-fired Cumberland power plant went offline due to equipment failure[12]. While the Cumberland power plant outage got the most media attention, TVA also lost about 4,400 MW of natural gas-fired generation, nearly twice as much as its coal plant outage.[13] In total, TVA lost almost 20% of its generating capacity on December 24.

As residential, commercial, and industrial natural gas demand in Kentucky spiked during Winter Storm Elliott, pressure along one of the primary natural gas supply pipelines, Texas Eastern, dropped unexpectedly. As a result of the sudden and unexpected drop in pipeline pressure, about 900 MW of LG&E/KU natural gas-fired generation suddenly came offline, resulting in rolling blackouts for over 53,000 LG&E/KU customers. This was the first time in LG&E/KU's history that the utility had to implement rolling blackouts for its customers.

As a result, almost 1 million customers were without power at one point during Winter Storm Elliott in the Southeast region, accounting for the majority of approximately 1.5 million power outages experienced across the country during the storm.

EXHIBIT *21* shows the average hourly demand, net electricity generation, and imports and exports for the Southeast region during December 2022.

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9 https://news.duke-energy.com/releases/duke-energy-updates-north-carolina-utilities-commission-on-winter-storm-elliott-emergency-outage-event

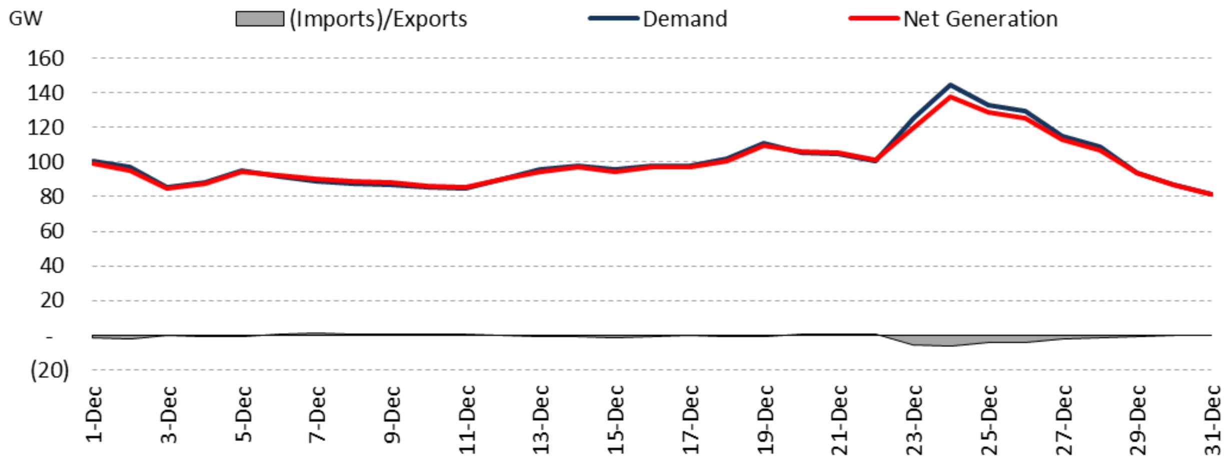
10 https://www.tva.com/newsroom/press-releases/tva-accepts-responsibility-starts-full-review

11 https://www.lpm.org/news/2023-01-26/lg-e-ku-underestimated-energy-demand-ahead-of-winter-storm-elliott

12 https://www.timesfreepress.com/news/2022/dec/23/tva-weather-tfp/

13 Legislative Archives > KET (54:45 minutes)

EXHIBIT 21: SOUTHEAST - AVERAGE DAILY ELECTRIC DEMAND, (IMPORTS)/EXPORTS & NET GEN. – DECEMBER 2022

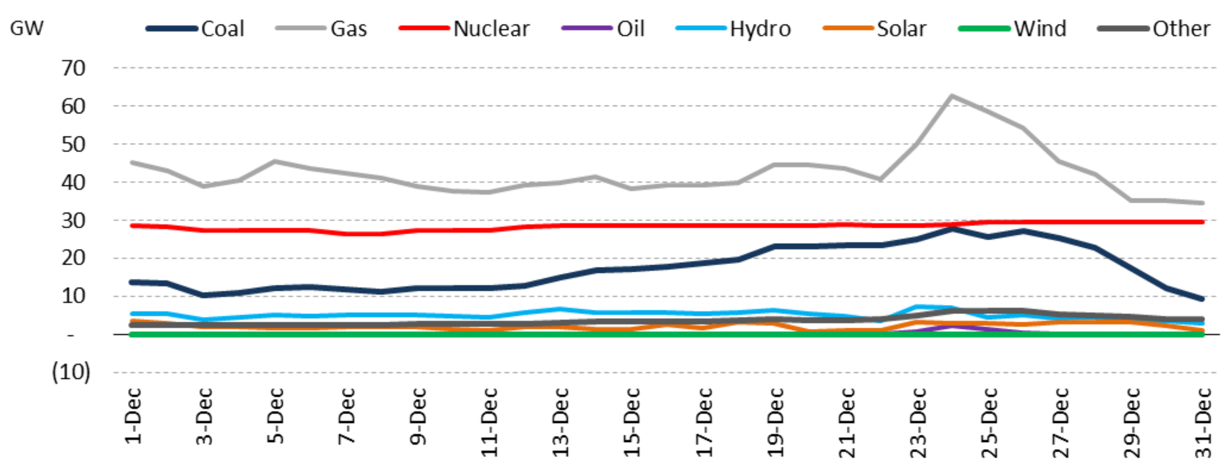


Source: EIA Hourly Grid Monitor

Despite the rolling blackouts implemented by Duke Energy and TVA, December 24 still ranked as the highest electricity demand day during the winter season and one of the highest overall for the Southeast region. Average hourly electricity demand peaked at over 144 GW, an increase of over 53 GW or 58% over the average hourly electricity demand during the first two weeks of December. Due to the lack of available power supply, the Southeast region also increased its electricity imports from surrounding regions, such as PJM and MISO, to over 6 GW on December 24.

EXHIBIT *22* and **EXHIBIT *23*** show the average hourly electricity generation by fuel type for December 2022 and the week surrounding Winter Storm Elliott, respectively.

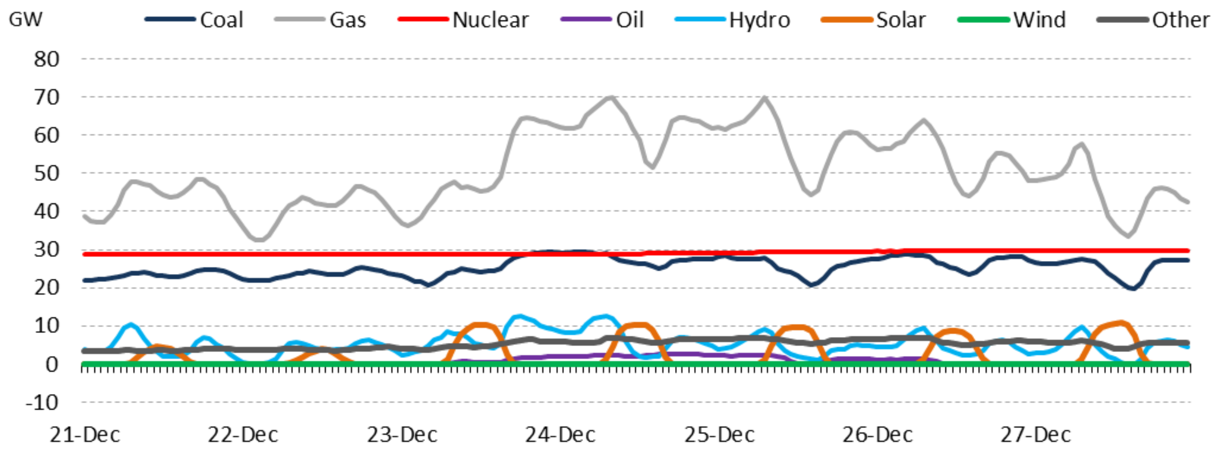
EXHIBIT 22: SOUTHEAST - AVERAGE DAILY NET GENERATION BY FUEL TYPE – DECEMBER 2022



Source: EIA Hourly Grid Monitor

Similar to PJM, as temperatures dropped and electricity demand increased over the course of the month, coal-fired power plants in the Southeast region almost **tripled** their electricity output, from 10 GW in early December to almost 30 GW on December 24.

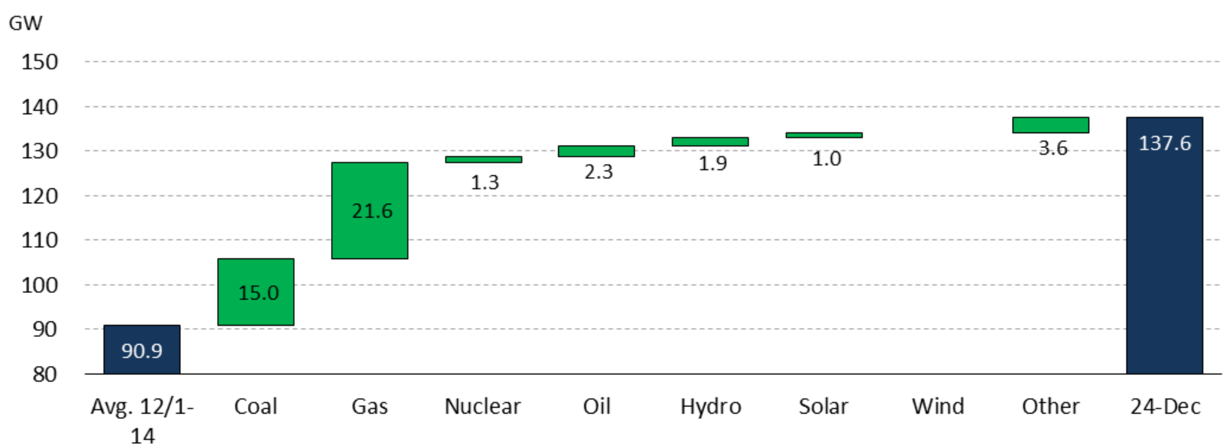
EXHIBIT 23: SOUTHEAST - HOURLY GENERATION BY FUEL TYPE DURING WINTER STORM ELLIOTT



Source: EIA Hourly Grid Monitor

Generally, while hindered by a lack of fuel supply, natural gas-fired power plants also increased their electricity output significantly during the storm, ramping from about 40 GW in the week prior to the storm to over 60 GW on December 24. However, as evidenced by the rolling blackouts implemented by TVA and Duke, the increase in coal and natural gas generation, as well as increased power imports, was not enough to fully meet the increased electricity demand of the Southeast region.

EXHIBIT 24: SOUTHEAST - CHANGE IN NET GENERATION BY FUEL TYPE DURING WINTER STORM ELLIOTT



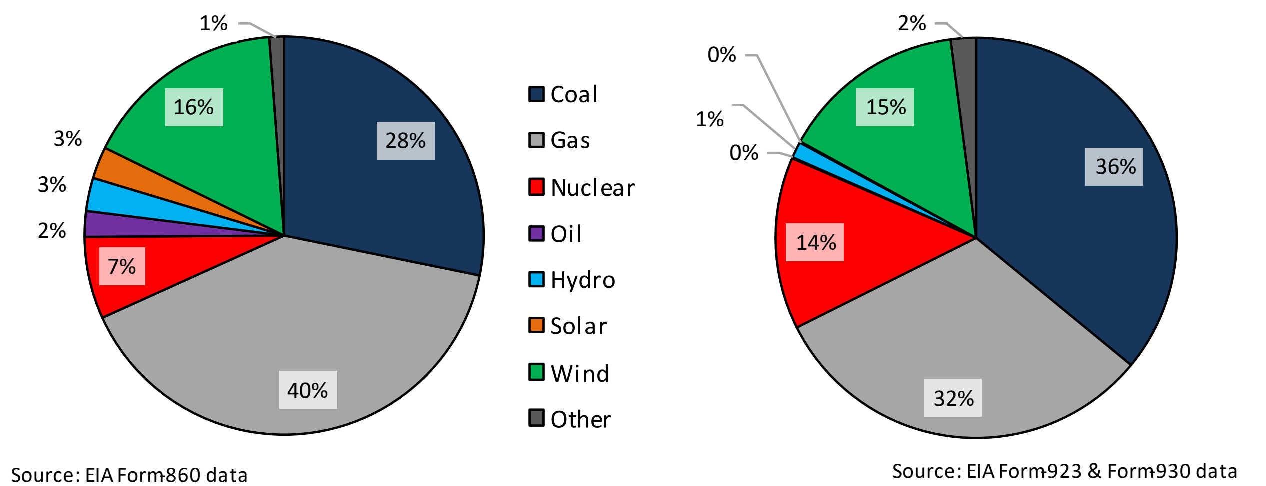
Source: EIA Hourly Grid Monitor

As shown in **EXHIBIT *24***, coal and natural gas-fired power plants once again accounted for the majority of increased electricity generation to meet the rise in demand in the Southeast region. Average hourly coal generation increased by 15 GW on December 24 compared to the first two weeks of December 2022, while natural gas increased by 21.6 GW on average over the same period.

MISO

MISO (Midcontinent Independent System Operator) is the second-largest ISO in the U.S., managing the flow of electricity across 15 U.S. states and for over 45 million customers. MISO's most recent capacity mix and generation mix by fuel type are shown in **EXHIBIT *25***.

EXHIBIT 25: MISO - 2022 END-OF-YEAR CAPACITY MIX & FULL-YEAR GENERATION MIX BY FUEL TYPE



MISO capacity and generation mix is dominated by coal, natural gas, wind, and nuclear electric generating resources, which cumulatively accounted for 91% of installed capacity at the end of 2022 and 97% of total electricity produced in 2022.

As Winter Storm Elliott brought frigid temperatures to MISO's service territory, electricity demand rose rapidly, culminating in MISO's 12th highest single-day electricity demand on December 23, 2022, at 108.6 GW. Similar to the other regions across the country, electricity demand in MISO had been steadily increasing throughout December ahead of Winter Storm Elliott, as shown in **EXHIBIT *26***. While mostly self-sufficient, MISO did increase electric power imports during the peak of the storm on December 23, when it imported an average of 3.4 GW of electric power from neighboring power markets, primarily PJM.

EXHIBIT 26: MISO - AVERAGE DAILY ELECTRIC DEMAND, (IMPORTS)/EXPORTS & NET GEN. – DECEMBER 2022

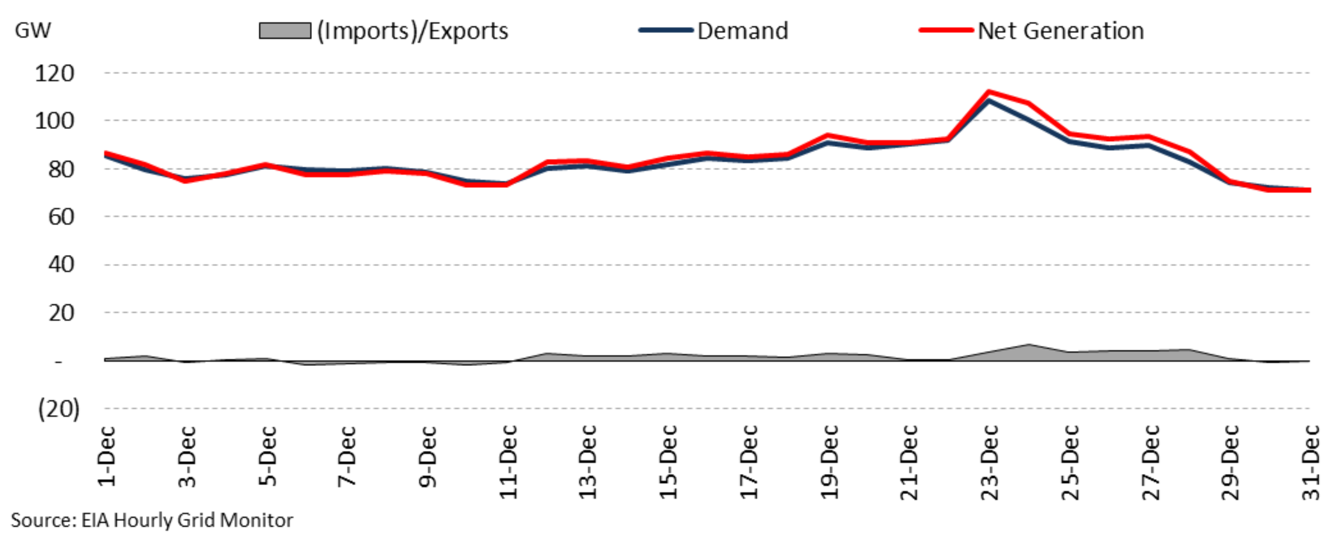
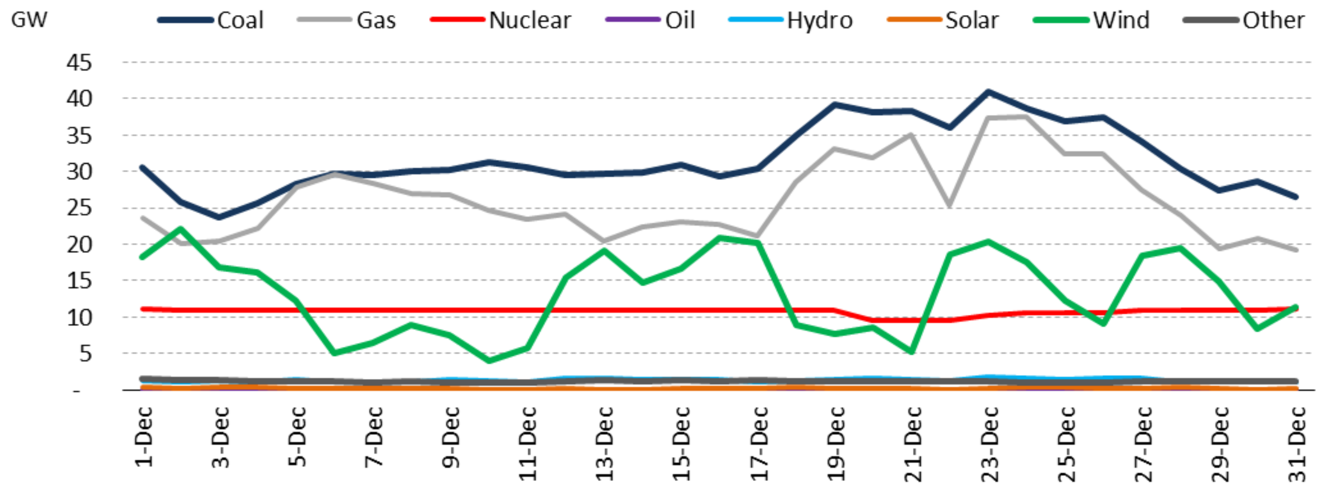


EXHIBIT *27* shows the average daily electric generation by fuel type for MISO power plants during December 2022. Coal generation continued to be the dominant fuel in December before, during, and after Winter Storm Elliott affected the region, providing relatively steady electric output day after day. On the other hand, electric output from natural gas-fired generators in MISO can vary significantly from day to day as these resources are used primarily to balance the intermittency and high variability of wind generation in MISO.

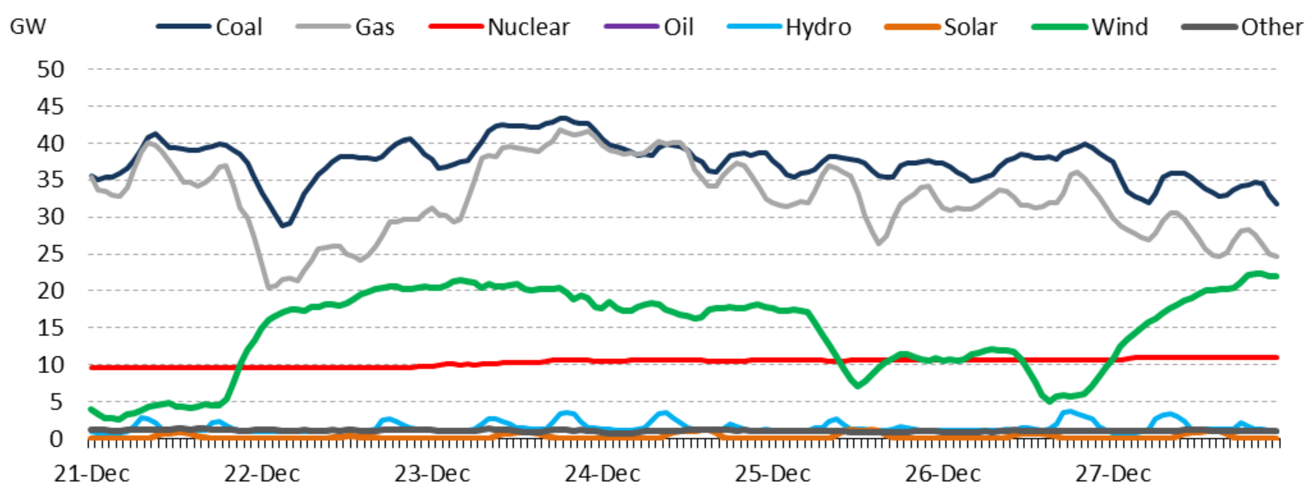
EXHIBIT 27: MISO - AVERAGE DAILY NET GENERATION BY FUEL TYPE – DECEMBER 2022



Source: EIA Hourly Grid Monitor

EXHIBIT *28* provides further detail on the hour-by-hour generation profile of the various resource types in MISO during the week of Winter Storm Elliott. Unlike other winter storms in the past, Winter Storm Elliott was accompanied by high wind speeds due to the big change in pressure as temperatures fell rapidly across the region. As a result, wind generation in MISO picked up considerably from relatively low levels on December 21 of just 5.1 GW to 20.3 GW on December 23, the peak of the storm for the MISO region. To balance the initial rapid increase of wind generation, natural gas and coal-fired power plants reduced their electric output before ramping up generation again on December 22 and 23 as electricity demand continued to climb.

EXHIBIT 28: MISO - HOURLY GENERATION BY FUEL TYPE DURING WINTER STORM ELLIOTT

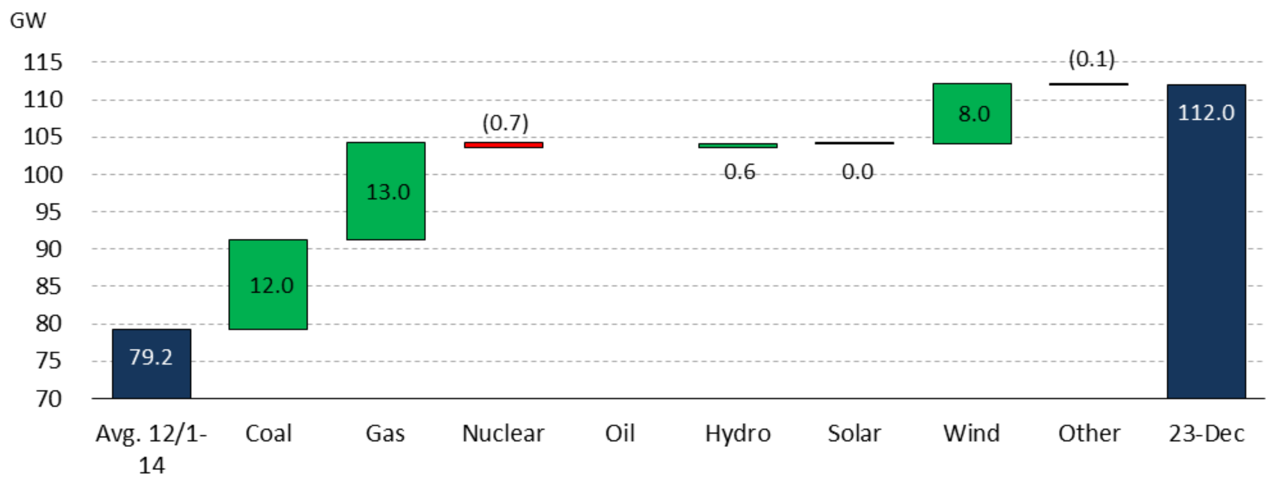


Source: EIA Hourly Grid Monitor

EXHIBIT *29* summarizes the increased generation output by fuel type during the peak day of Winter Storm Elliott and the first two weeks of December 2022. Natural gas, coal, and wind generation were significantly higher on December 23 compared to the first two weeks of December. Coal generation increased by an average of 12 GW, natural gas by 13 GW, and wind generation by 8 GW, which accounted for virtually all of the increased generation of approximately 33 GW.

However, as discussed by MISO staff during a recent Entergy Regional State Committee meeting, as much as 23 GW of natural gas-fired generation was unavailable during Winter Storm Elliott due to lack of fuel availability, which ultimately tipped the MISO energy system into emergency procedures on December 23, as the ISO tried to maintain export levels to neighboring power market regions.[14]

EXHIBIT 29: MISO - CHANGE IN NET GENERATION BY FUEL TYPE DURING WINTER STORM ELLIOTT



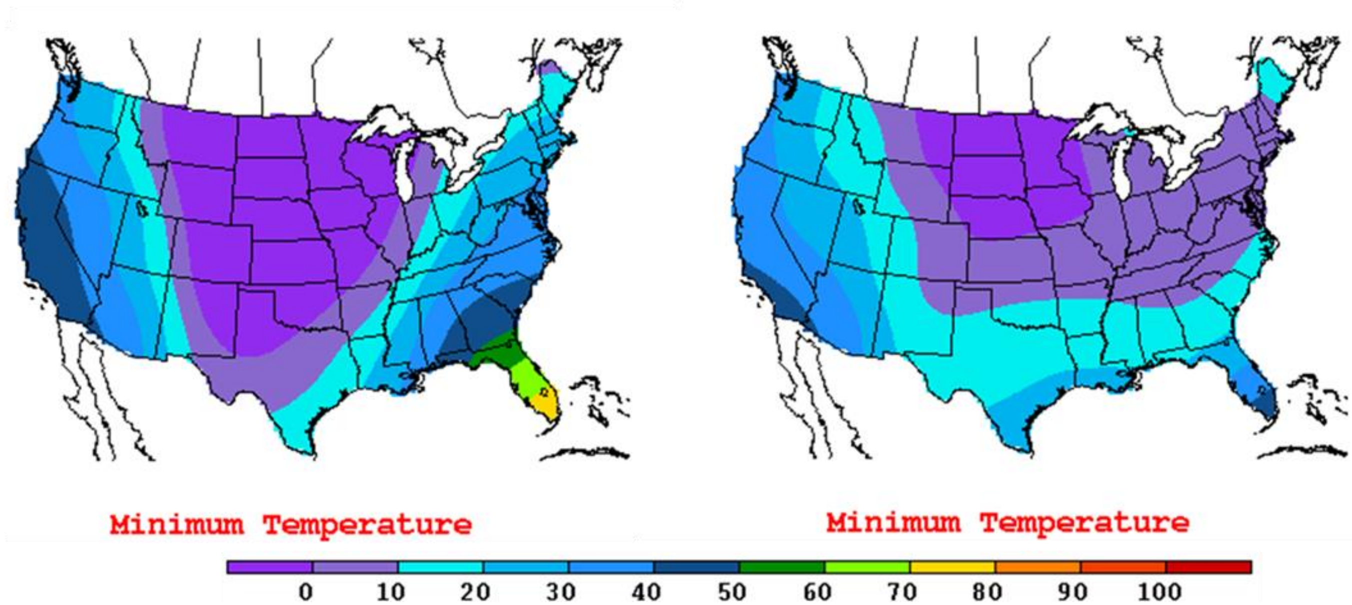
Source: EIA Hourly Grid Monitor

Comparing MISO Operations during Winter Storms Uri and Elliott

Winter Storm Elliott was the second major test during the winter season in the last three years for MISO and other power markets in the Central U.S. Around Valentine's Day 2021, another arctic blast caused temperatures to plummet and electricity demand to rise rapidly. Winter Storm Uri, as this arctic blast would later be known, severely strained the electric power grids of MISO, SPP, and ERCOT. In ERCOT, more than 4.5 million customers lost power at some point during Winter Storm Uri, and at least 57 people died. MISO and SPP were able to avoid implementing rolling blackouts thanks in large part due to increased electric power imports from neighboring power market regions like PJM and the Southeast. **EXHIBIT *30*** shows the minimum temperature differences between the two storm systems on their peak day (February 15 for Winter Storm Uri (left) and December 23 for Winter Storm Elliott (right)).

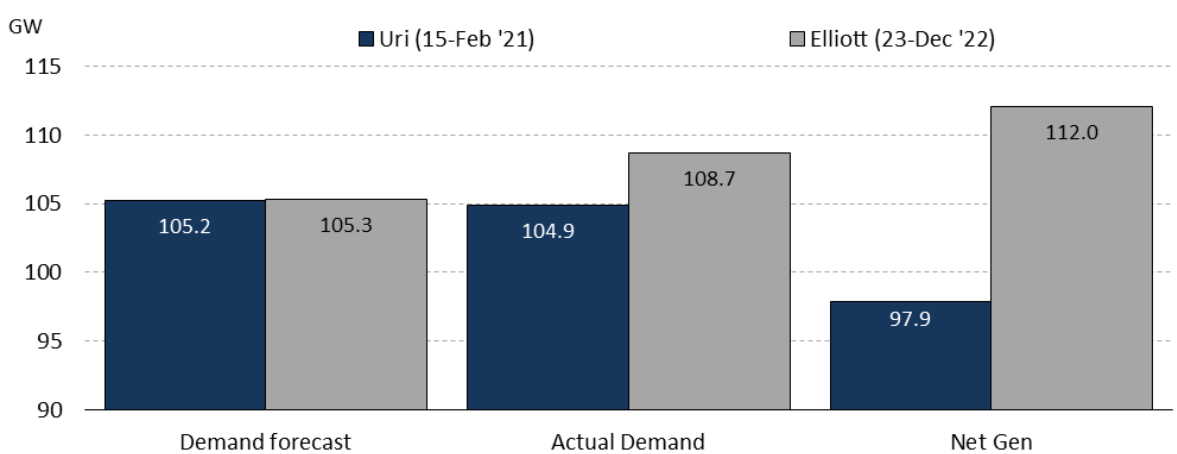
[14] https://www.rtoinsider.com/articles/31645-miso-data-show-steep-gas-fired-outages-winter-storm

EXHIBIT 30: MIN. TEMPERATURES DURING WINTER STORMS URI (FEB 15, 2021 – LEFT) & ELLIOTT (DEC 23, 2022 – RIGHT)



Although initial peak demand forecasts for the two winter storms were comparable at roughly 105 GW, MISO's actual average peak demand during Winter Storm Elliott was about 4 GW higher than during Winter Storm Uri (108.6 GW vs. 104.9 GW), as shown in **EXHIBIT *31***. Due to the higher availability of its natural gas and wind power plants, MISO was able to export electric power to its neighboring power markets and did not need to rely on electricity imports to meet its system demand as MISO did during Winter Storm Uri.

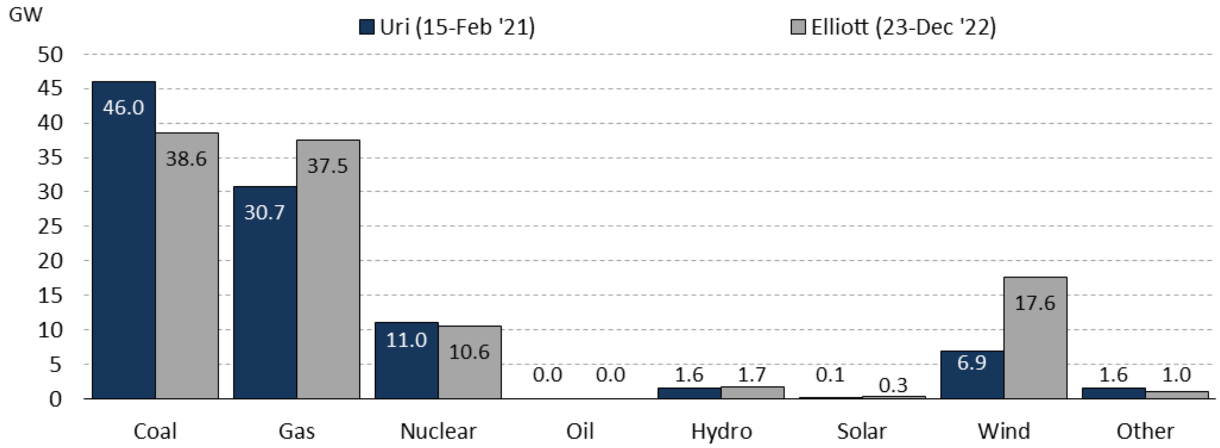
EXHIBIT 31: MISO - AVG. DAILY DEMAND FORECAST, ACTUAL DEMAND & NET GENERATION DURING WINTER STORMS URI & ELLIOTT



Source: EIA Hourly Grid Monitor

EXHIBIT *32* shows the average hourly generation by fuel type for MISO power plants during the peak of Winter Storm Uri (February 15, 2021) and Winter Storm Elliott (December 23, 2022).

EXHIBIT 32: MISO - AVG. GENERATION BY FUEL TYPE DURING WINTER STORMS URI & ELLIOTT

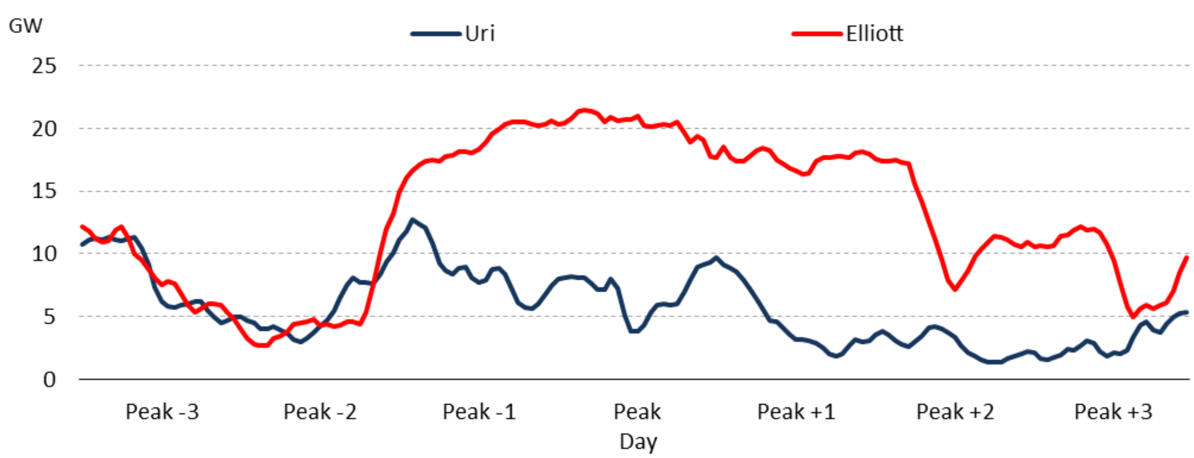


Source: EIA Hourly Grid Monitor

More specifically, due to the higher availability of natural gas supply and much higher wind generation, MISO was able to export a significant amount of electricity to its neighboring power market regions, especially the Southeast. Wind generation during Elliott was over 10 GW higher than during Uri, while natural gas generation was almost 7 GW higher during the latest storm. The drop of about 7.4 GW in average coal generation was due to coal plant retirements that occurred in MISO between winter storms Uri and Elliott.

EXHIBIT *33* shows how significant was the difference in wind generation in MISO between the two winter storms.

EXHIBIT 33: MISO - HOURLY WIND GENERATION DURING THE WEEK OF WINTER STORMS URI & ELLIOTT



Source: EIA Hourly Grid Monitor | Uri period: Feb 12-18 '21; Elliot period: Dec 20-26 '22

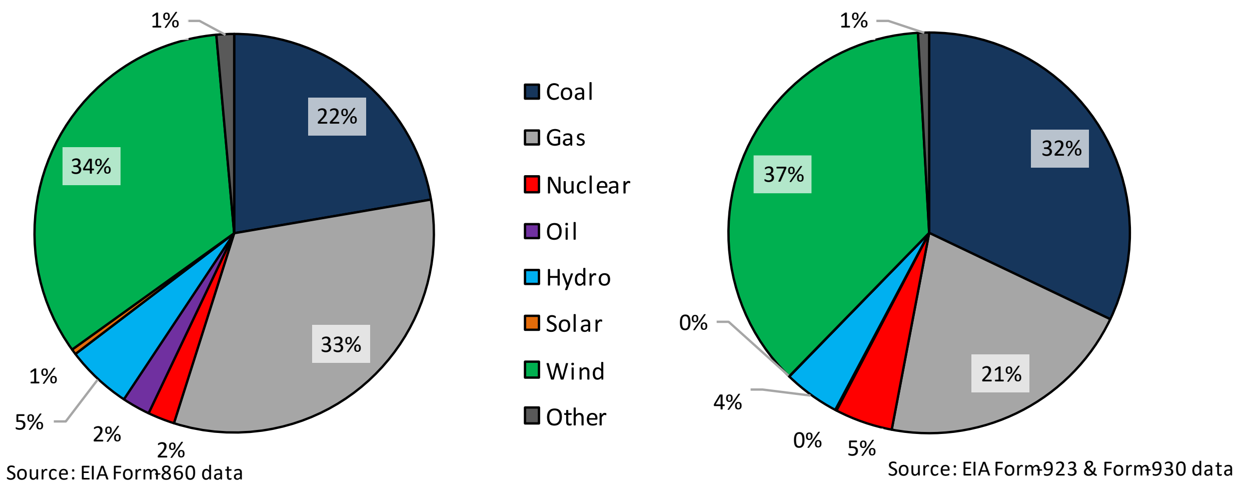
Winter Storm Elliott was accompanied by tremendous wind speeds, allowing wind generators in MISO to continue operating at high utilization rates for much of the storm. Wind generation in MISO increased by over 15 GW between December 21 and December 23 and only slowly started to taper off on December 24 as the storm system exited the region to the East. On the other hand, MISO wind generation during Uri peaked on February 13 at 12.7 GW and fell below 5 GW during the peak demand hours on February 15, 2021. For reference, between February 2021 and December 2022, MISO wind capacity grew by an estimated 3 GW and, therefore, does not explain the massive difference in wind generation output alone.

MISO's operational success during Winter Storm Elliott largely can be attributed to the massive amount of higher wind generation realized during the storm compared to Winter Storm Uri less than three years prior. However, as wind's generation share in MISO continues to displace dispatchable generation from natural gas and coal-fired power plants, MISO's future operational success during similar winter storms will increasingly depend on the wind speeds associated with such storms.

Southwest Power Pool

The Southwest Power Pool (SPP) is an independent system operator overseeing the bulk electric grid and wholesale power market in the central United States and provides electricity to almost 19 million customers across 17 states from North Dakota down to Louisiana. SPP's latest capacity and generation mix by fuel type are shown in **EXHIBIT *34***.

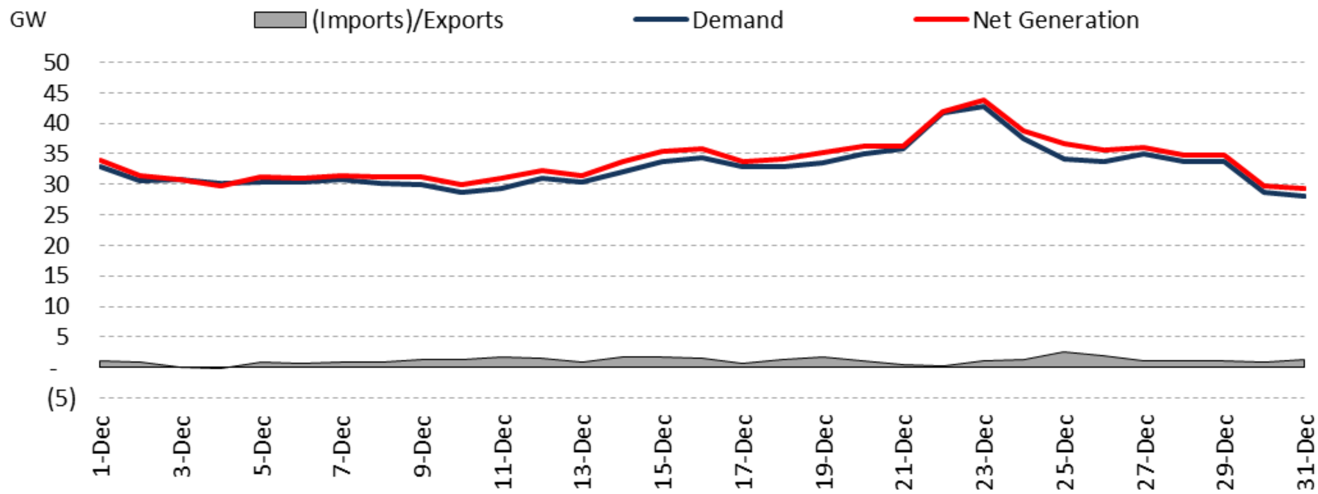
EXHIBIT 34: SPP - 2022 END-OF-YEAR CAPACITY MIX & FULL-YEAR GENERATION MIX BY FUEL TYPE



Over the last decade, SPP has seen tremendous growth in wind power generation facilities across its service territory and is now the only power market region in the U.S. where wind resources make up the largest generation share. In 2022, wind accounted for 37% of all electricity produced in SPP, followed by coal at 32% and natural gas at 21%. Hydro and nuclear generation accounted for the remaining roughly 10% of electric generation.

Similar to its power market neighbor to the East, SPP saw steadily increasing electricity demand during the middle of December 2022 before peaking on December 23, 2022, at an average of 42.6 GW, as shown in **EXHIBIT *35***.

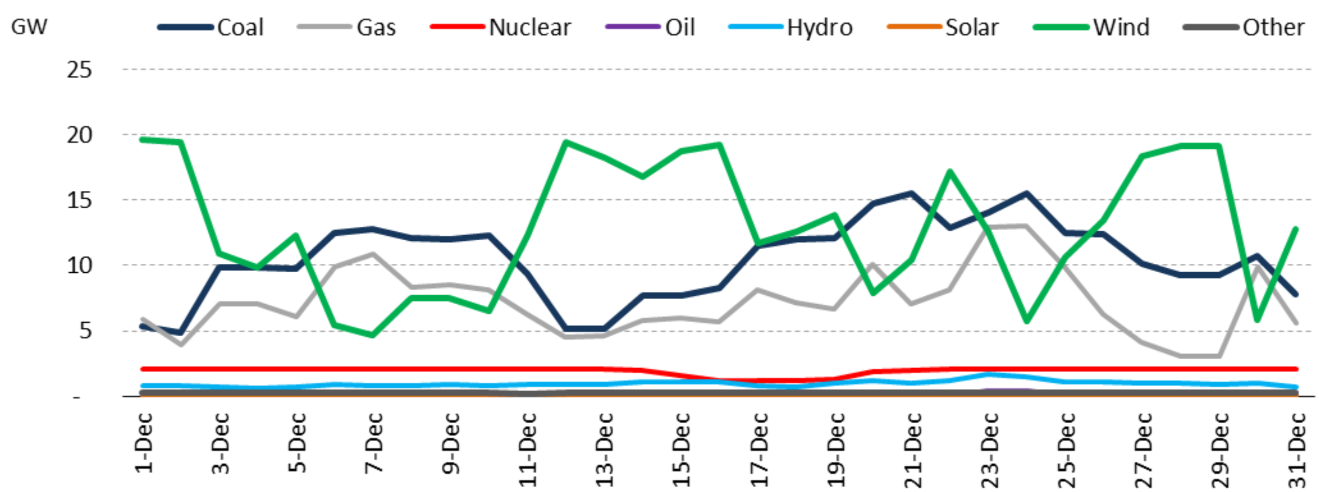
EXHIBIT 35: SPP - AVERAGE DAILY ELECTRIC DEMAND, (IMPORTS)/EXPORTS & NET GEN. – DECEMBER 2022



Source: EIA Hourly Grid Monitor

Due to the large market share and the highly variable electric output of wind power plants, coal and natural gas-fired power plants in SPP are primarily used to balance out the intermittency of wind. **EXHIBIT *36*** shows the average daily net generation by fuel type in SPP during December 2022 and highlights the complementary roles fossil fuels play to wind generation in SPP.

EXHIBIT 36: SPP - AVERAGE DAILY NET GENERATION BY FUEL TYPE – DECEMBER 2022

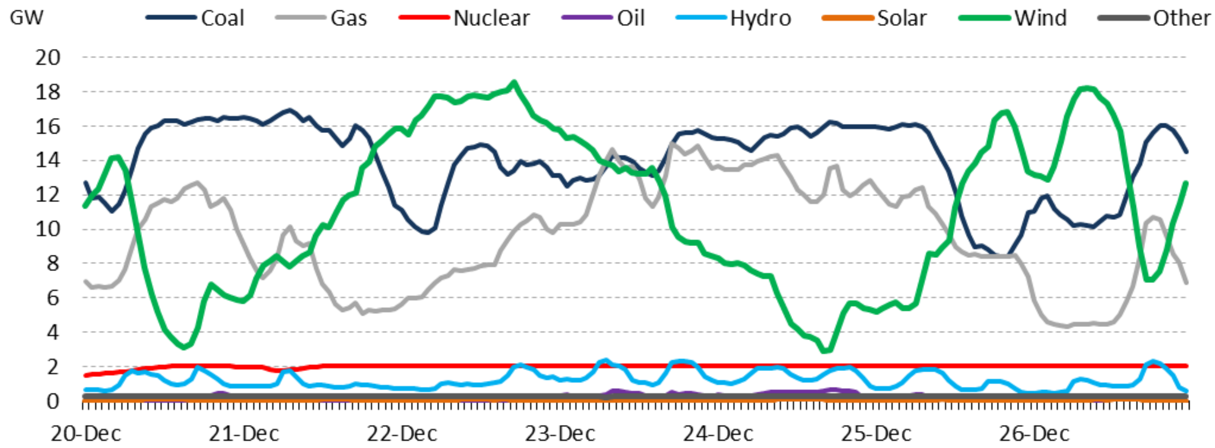


Source: EIA Hourly Grid Monitor

As electricity demand in SPP increased as Winter Storm Elliott moved into the region, average **coal generation increased from a low of around 5 GW on December 12 to just over 15 GW** on December 21, providing the majority of incremental generation as demand for electricity rose over that period.

EXHIBIT *37* highlights the interplay between the three dominant fuel types in SPP during the week of Winter Storm Elliott.

EXHIBIT 37: SPP - HOURLY GENERATION BY FUEL TYPE DURING WINTER STORM ELLIOTT

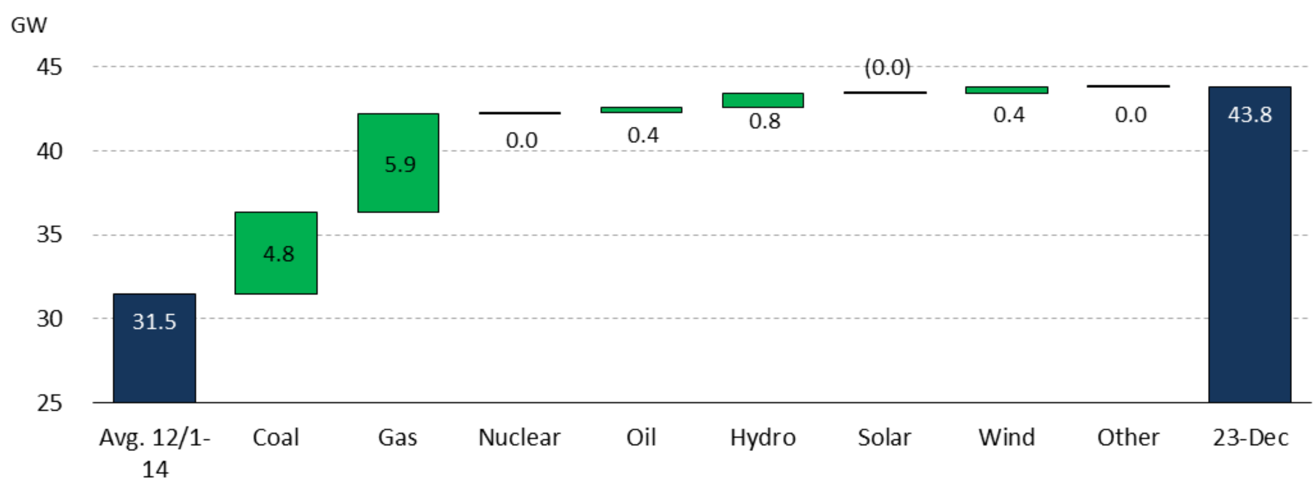


Source: EIA Hourly Grid Monitor

During the week of Winter Storm Elliott, SPP wind generation fluctuated tremendously, from a low of around 3 GW on December 20 to over 18 GW just two days later as the storm system moved into the region. Wind generation then dropped again to just 3 GW on December 24 before rising rapidly once again to over 18 GW less than 48 hours later. Both coal and natural gas-fired power plants were used to not only balance out this tremendous fluctuation in wind generation output but also to meet the increasing electricity demand as temperatures plummeted during the peak of Winter Storm Elliott on December 23.

EXHIBIT *38* summarizes the increases of the various fuels during Winter Storm Elliott on December 23 compared to their average generation output during the first two weeks of December 2022.

EXHIBIT 38: SPP - CHANGE IN NET GENERATION BY FUEL TYPE DURING WINTER STORM ELLIOTT



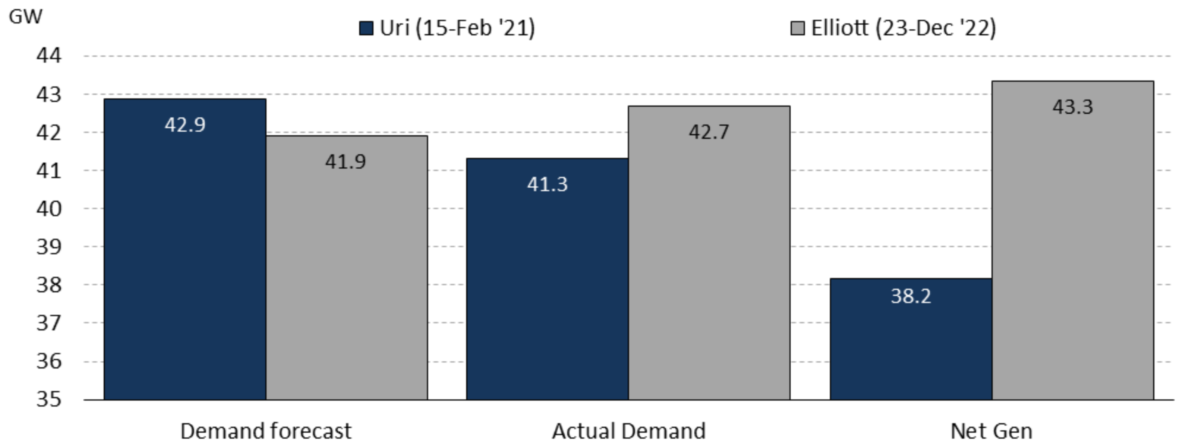
Source: EIA Hourly Grid Monitor

The total SPP system saw an increase of over 12 GW in net electric generation between the first two weeks of the month and its peak demand day on December 23. Natural gas and coal-fired power plants provided the majority of that increased generation, adding 5.9 GW and 4.8 GW of electric output, respectively. Due to the massive fluctuations in wind generation, average electric output from wind power plants was largely unchanged between the first two weeks of December 2022 and December 23.

Comparing SPP Operations during Winter Storms Uri and Elliott

Similar to its power market region to the East, Elliott represented the second significant test of the SPP electric power grid during the winter in less than three years. This section compares SPP's operations during Winter Storms Uri in February 2021 and Elliott in December 2022.

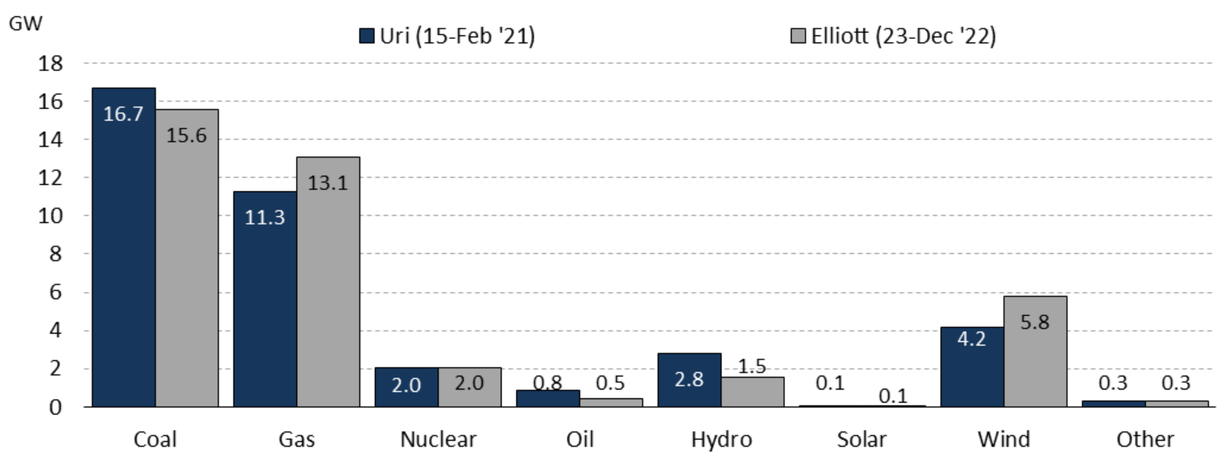
EXHIBIT 39: SPP - AVG. DAILY DEMAND FORECAST, ACTUAL DEMAND & NET GENERATION DURING WINTER STORMS URI & ELLIOTT



Source: EIA Hourly Grid Monitor

EXHIBIT *39* shows the electricity demand forecast, actual electricity demand, and net electric generation for the SPP power market during Winter Storms Uri and Elliott. Although electricity demand during Winter Storm Uri was forecasted to reach almost 43 GW, the actual demand for electricity materialized at 41.3 GW or 1.4 GW below the actual demand for electricity during Winter Storm Elliott. Due to a higher amount of wind and natural gas generation, SPP was able to meet its electricity demand with internal electric generation and did not have to rely on power imports from MISO to meet its system demand as it did during Winter Storm Uri.

EXHIBIT 40: SPP - AVG. GENERATION BY FUEL TYPE DURING WINTER STORMS URI & ELLIOTT

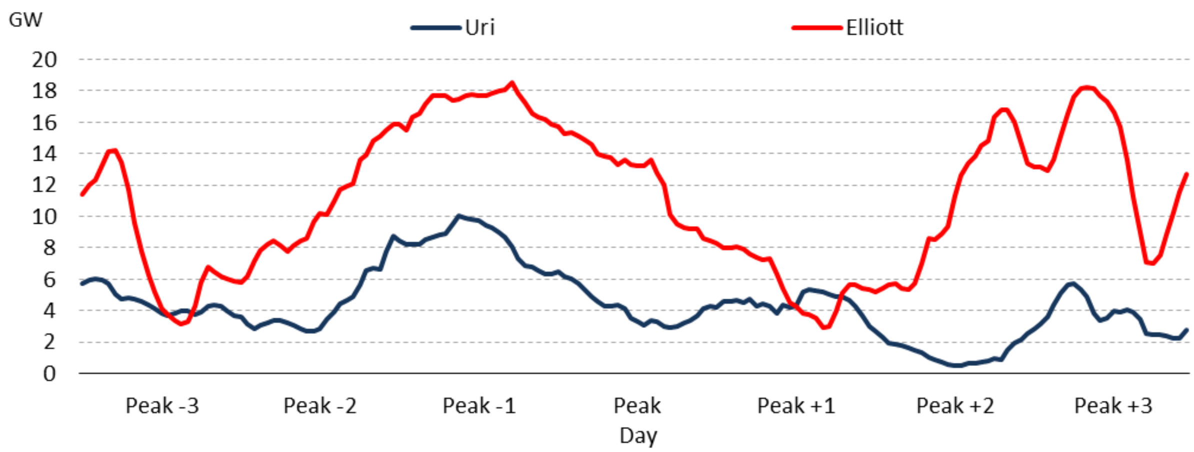


Source: EIA Hourly Grid Monitor

EXHIBIT *40* shows the difference in net generation output by fuel type in SPP during Winter Storms Uri and Elliott. Increased generation output from natural gas and wind power plants due to higher "fuel" availability allowed SPP to meet its system electricity demand with in-region generating resources and not rely on power imports. Average coal generation output declined slightly from Uri to Elliott, likely due to some unforced plant outages due to the frigid temperatures experienced in Montana and the Dakotas, where the majority of SPP coal plants are located.

It is worth highlighting once again the tremendous difference in wind generation output in SPP during the week of the two winter storm systems. During Winter Storm Uri, wind generation reached a peak of 10 GW on February 14 before dropping below 1 GW just three days later. As shown in **EXHIBIT *41***, SPP wind generation was significantly higher during Winter Storm Elliott, fluctuating between 3 GW on December 20 and over 18 GW on December 22. For reference, between February 2021 and December 2022, SPP wind capacity grew by an estimated 5.2 GW. Therefore, almost half of the increased wind generation can be explained by higher wind speeds accompanying the latest winter storm system.

EXHIBIT 41: SPP - HOURLY WIND GENERATION DURING THE WEEK OF WINTER STORMS URI & ELLIOTT



Source: EIA Hourly Grid Monitor | Uri period: Feb 12-18 '21; Elliot period: Dec 20-26 '22

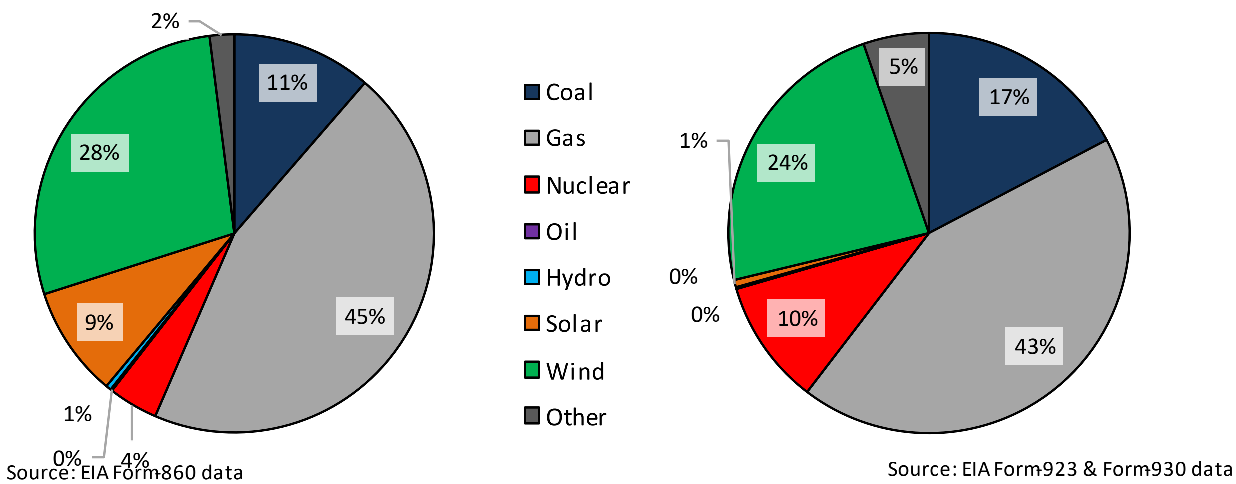
Similar to MISO, SPP's operational success during Winter Storm Elliott largely can be attributed to the higher amount of wind generation realized during the storm as well as greater fuel availability for SPP natural gas plants compared to Winter Storm Uri less than three years prior. However, as wind's generation share in SPP continues to displace dispatchable generation from natural gas and coal-fired power plants, SPP's future operational success during similar winter storms will increasingly depend on the available wind generation output during these storms.

ERCOT

The Electric Reliability Council of Texas (ERCOT) is an ISO fully contained within the state of Texas and responsible for managing the bulk electric power grid for more than 26 million Texans, representing about 90% of the state's electric load.[15] ERCOT's most recent capacity and generation mix by fuel type is shown in **EXHIBIT *42***.

[15] https://www.ercot.com/about#:~:text=The%20Electric%20Reliability%20Council%20of,of%20the%20state's%20electric%20load.

EXHIBIT 42: ERCOT - 2022 END-OF-YEAR CAPACITY MIX & FULL-YEAR GENERATION MIX BY FUEL TYPE



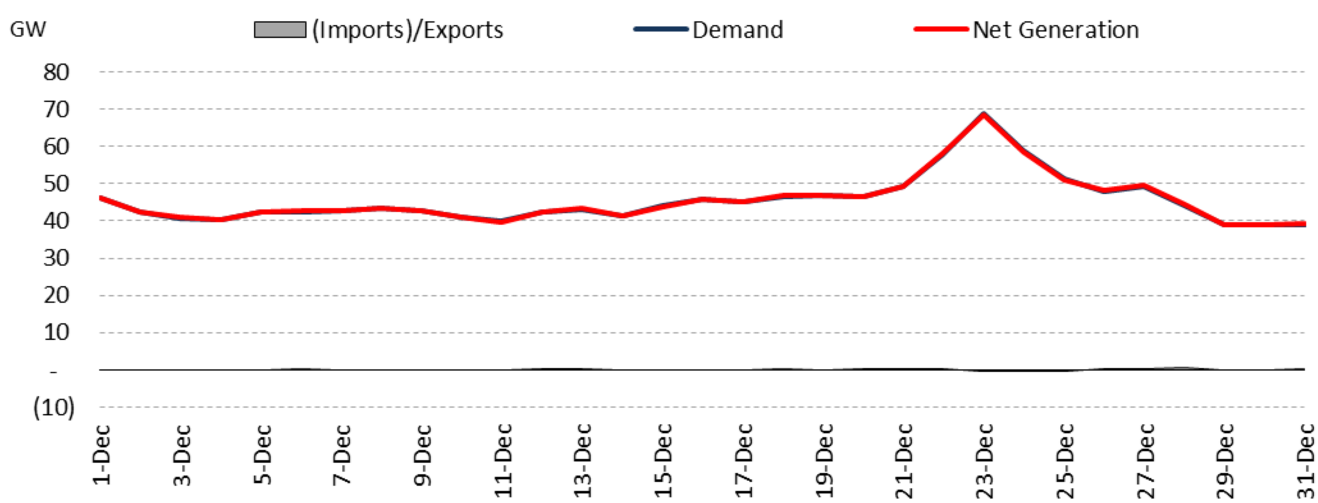
Source: EIA Form860 data

Source: EIA Form923 & Form930 data

Over the last decade, ERCOT has seen a tremendous shift away from coal-fired generation, first towards natural gas and, more recently, towards wind and solar generation. In 2022, wind accounted for almost one-quarter of all electricity produced in ERCOT, making it the second-largest fuel source after natural gas, which accounted for 43% of ERCOT's electric generation in 2022. Coal and nuclear accounted for 17% and 10%, respectively.

On December 23, 2022, Winter Storm Elliott set the record for the highest average daily electricity demand for the ERCOT power market. The record comes just less than two years after ERCOT suffered one of its most devastating system failures during Winter Storm Uri in February 2021, which is discussed later in this report. **EXHIBIT *43*** shows the rapid rise of electricity demand in ERCOT during Winter Storm Elliott.

EXHIBIT 43: ERCOT - AVERAGE DAILY ELECTRIC DEMAND, (IMPORTS)/EXPORTS & NET GEN. – DECEMBER 2022

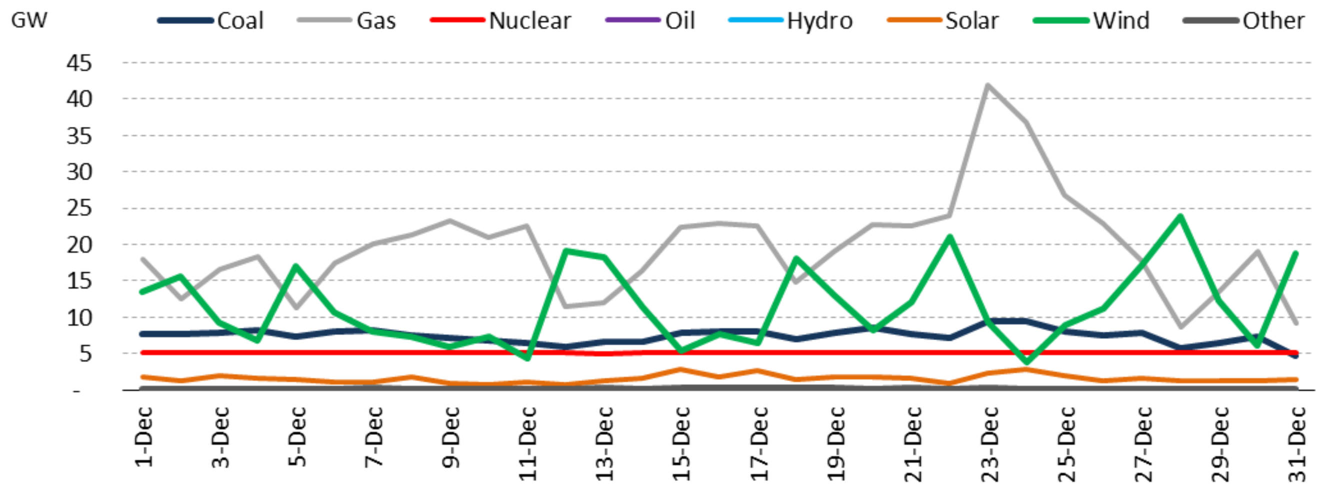


Source: EIA Hourly Grid Monitor

Electricity demand in ERCOT reached a peak of 68.9 GW on December 23, 2022, an increase of over 63% compared to the average daily demand during the first two weeks of December 2022. After the storm system exited the region, electricity demand quickly normalized at around 40 GW at the end of the month.

EXHIBIT *44* provides more detail on the average daily generation by fuel type in ERCOT during December 2022. Similar to SPP, natural gas-fired power plants in ERCOT are largely providing complementary generation to the ever-fluctuating electric output from wind power plants. During the peak of Winter Storm Elliott, generation from natural gas plants increased by almost 20 GW as the plants offset the loss in wind generation and provided the incremental electricity needed to meet the peak electricity demand during the storm.

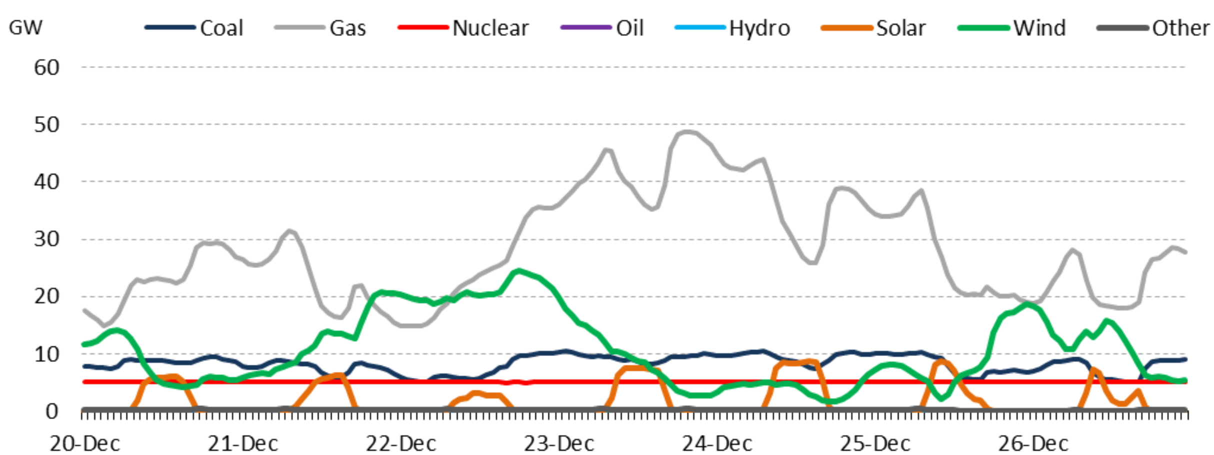
EXHIBIT 44: ERCOT - AVERAGE DAILY NET GENERATION BY FUEL TYPE – DECEMBER 2022



Source: EIA Hourly Grid Monitor

EXHIBIT *45* provides further detail on the hourly operations of the various fuels in ERCOT during the week of Winter Storm Elliott. During December 20 & 21, natural gas-fired power plants balanced out the loss in wind generation before rising rapidly on December 22 & 23 to almost 50 GW as wind generation dropped and electricity demand skyrocketed. Coal-fired power plants, which are already running at higher utilization rates in ERCOT on average, also increased generation during the peak electricity demand hours to roughly 10 GW.

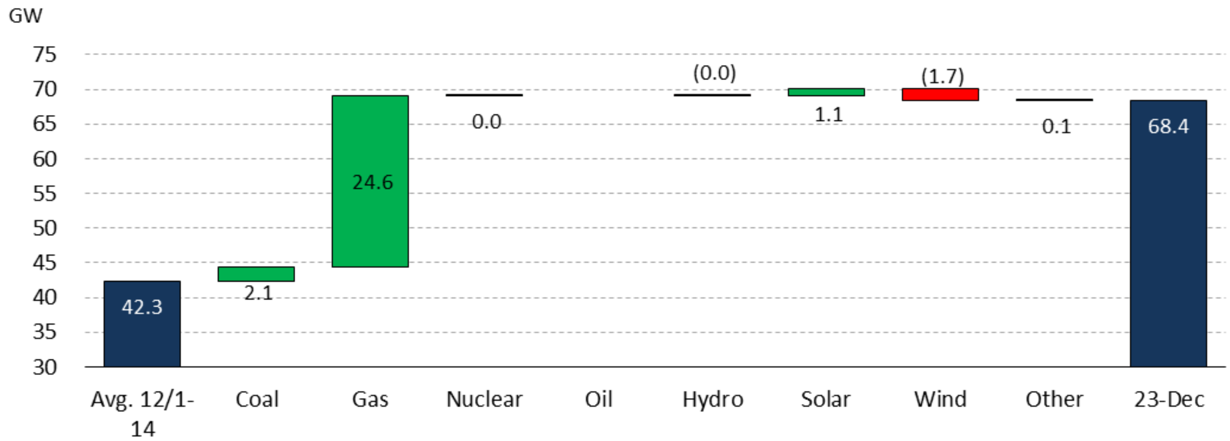
EXHIBIT 45: ERCOT - HOURLY GENERATION BY FUEL TYPE DURING WINTER STORM ELLIOTT



Source: EIA Hourly Grid Monitor

EXHIBIT *46* summarizes the increase in electric generation output in ERCOT on December 23 compared to the first two weeks of December 2022. Similar to electricity demand, net electric generation in ERCOT rose from an average of 42.3 GW during the first two weeks of the month to 68.4 GW on December 23, an increase of over 26 GW or 62%. Natural gas-fired power plants accounted for almost all of the increase. Coal and solar generation also saw minor increases, offsetting the reduced wind generation of 1.7 GW.

EXHIBIT 46: ERCOT - CHANGE IN NET GENERATION BY FUEL TYPE DURING WINTER STORM ELLIOTT



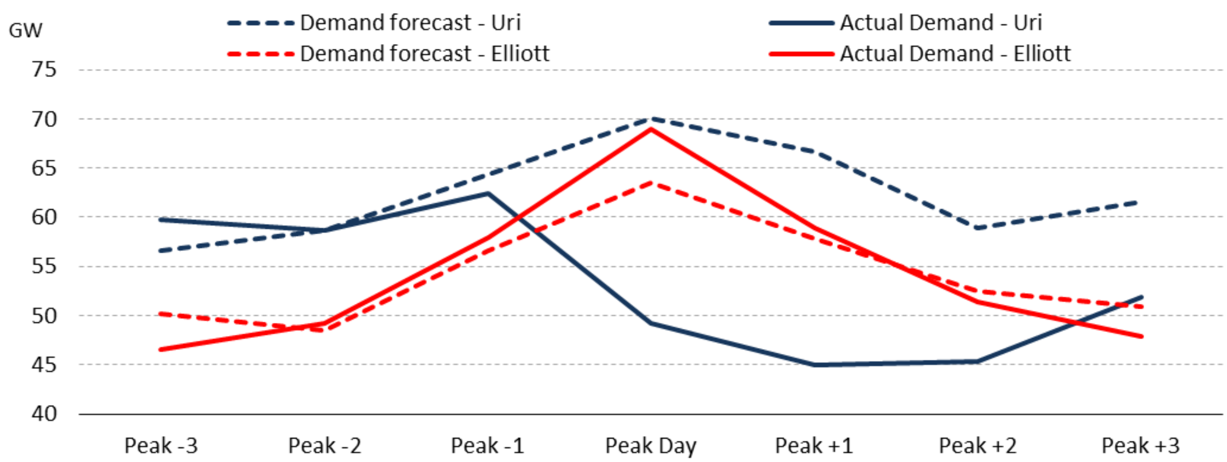
Source: EIA Hourly Grid Monitor

Comparing ERCOT Operations during Winter Storms Uri and Elliott

In February 2021, Winter Storm Uri caused a massive electricity generation failure in the ERCOT power market, which resulted in a loss of power for more than 4.5 million homes. This failure resulted in at least 57 deaths across 25 Texas counties and over $195 billion in property damage.

EXHIBIT *47* shows the demand forecast and the actual average daily demand during Winter Storms Uri and Elliott. Prior to February 15, electricity demand during Winter Storm Uri was projected to surpass 70 GW during peak hours, while electricity demand during Elliott was forecasted to peak at 63.5 GW. However, due to ERCOT having to implement rolling blackouts starting February 14 due to a lack of available electric generation resources, actual peak demand during Uri only got to 62.4 GW on February 14 before dropping to just 45 GW on February 16 as 4.5 million customers were without electricity. On the other hand, during Elliott, actual demand surpassed initial forecasts, peaking at almost 69 GW on December 23 before falling below 48 GW just three days later.

EXHIBIT 47: ERCOT - AVG. DAILY DEMAND FORECAST & ACTUAL DEMAND DURING WINTER STORMS URI & ELLIOTT

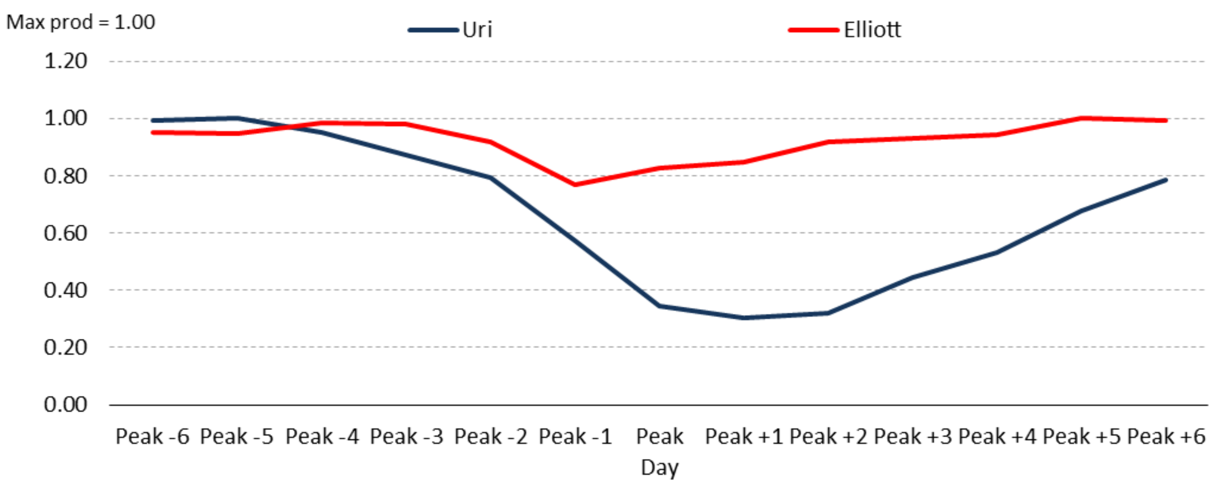


Source: EIA Hourly Grid Monitor

As cold weather moved into the ERCOT region on February 14, 2021, power plant outages rose from just under 30 GW at the end of the day to over 50 GW during the morning hours on February 15 as power plants shut down due to weatherrelated issues caused by the massive drop in temperatures, equipment failures, and fuel supply issues[16]. As a result of the sudden increase in plant outages, ERCOT initiated rolling blackouts to stabilize the grid and re-balance demand with the available supply.

Many of the natural gas-fired power plants in ERCOT had to go offline due to a lack of available fuel supply during the peak of the storm. **EXHIBIT *48*** shows the normalized daily natural gas production in the Permian Basin[17], the dominant natural gas supply source for natural gas-fired power plants in ERCOT.

EXHIBIT 48: NORMALIZED NATURAL GAS PRODUCTION IN THE PERMIAN BASIN DURING WINTER STORMS URI & ELLIOTT



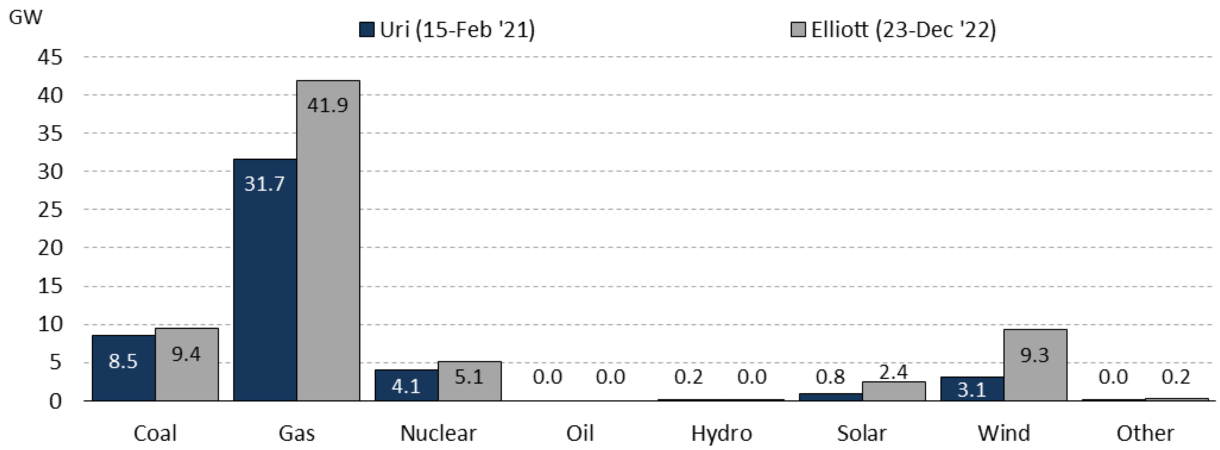
During the week of Winter Storm Uri, natural gas production in the Permian Basin dropped to just 30% of peak production levels due to well freeze-offs amid frigid temperatures. On the other hand, during Winter Storm Elliott, Permian Basin natural gas production was much less affected by well freeze-offs as the extreme cold stayed further north than during Uri, resulting in a peak production loss of just 23%. As a result, the available natural gas generating capacity during Elliott was significantly higher than during Uri, as significantly more natural gas was available to supply the increase in the power sector and residential and commercial heating demand.

EXHIBIT *49* provides greater detail on the average net electricity generation by fuel type during the peak demand days of winter storms Uri and Elliott in ERCOT.

[16] https://energy.utexas.edu/sites/default/files/UTAustin%20%282021%29%20EventsFebruary2021TexasBlackout%2020210714.pdf

[17] The Permian Basin is located in West Texas and Southeastern New Mexico.

EXHIBIT 49: ERCOT - AVG. GENERATION BY FUEL TYPE DURING WINTER STORMS URI & ELLIOTT

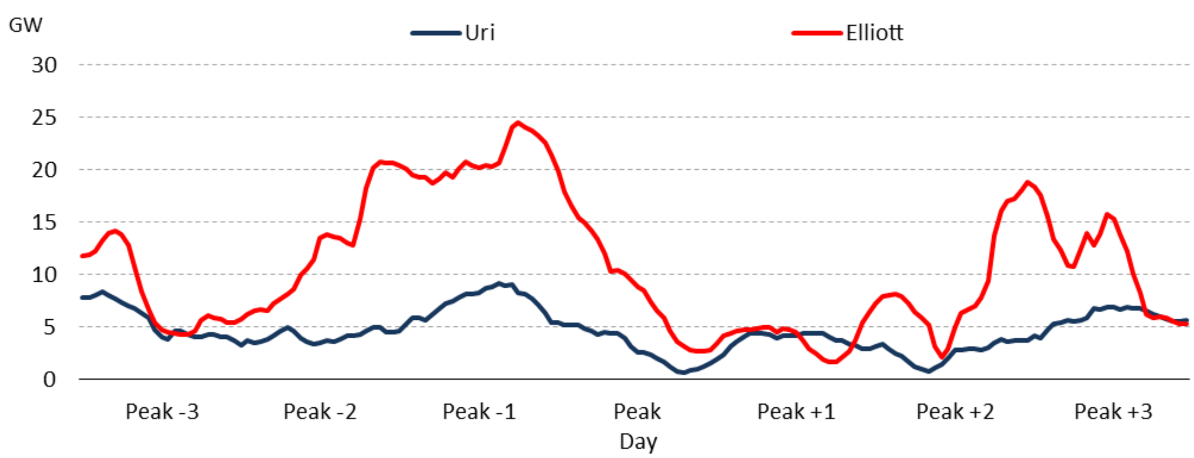


Source: EIA Hourly Grid Monitor

Due to the increased fuel supply available during Winter Storm Elliott, average natural gas generation on December 23, 2022, was over 10 GW higher than on February 15, 2021, during Winter Storm Uri. Average wind generation also increased by over 6 GW between the two storms due to higher installed capacity, higher wind speeds, and fewer equipment issues like frozen wind turbines. Average coal and nuclear generation also increased by roughly 1 GW each due to fewer equipment failures amid higher ambient temperatures during Winter Storm Elliott.

EXHIBIT *50* highlights the hourly generation profile of all wind power plants in ERCOT during the two winter storms. As mentioned previously, Winter Storm Elliott was accompanied by significantly higher wind speeds than Winter Storm Uri, especially as the storm system moved into the region on December 22, 2022.

EXHIBIT 50: ERCOT - HOURLY WIND GENERATION DURING THE WEEK OF WINTER STORMS URI & ELLIOTT

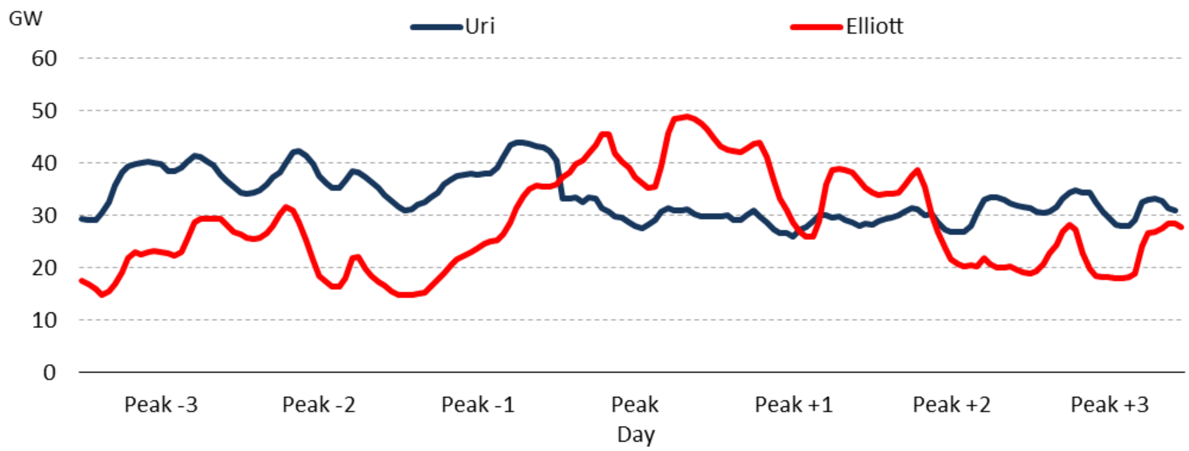


Source: EIA Hourly Grid Monitor

During the week of Winter Storm Elliott, ERCOT wind generation rose from just under 5 GW on December 20 to almost 25 GW at the end of December 22 before falling below 2 GW on December 24. Conversely, hourly wind generation during the week of Winter Storm Uri never surpassed 10 GW and averaged less than 5 GW for the week.

EXHIBIT *51* shows the hourly generation profile of natural gas-fired power plants in ERCOT during the weeks of Winter Storms Elliott and Uri. During the early morning hours on February 15, 2021, natural gas generation suddenly dropped by approximately 10 GW as fuel supply issues and equipment issues forced natural gas plants offline. On the other hand, natural gas generation during the peak hours of Winter Storm Elliott was able to increase steadily as higher ambient temperatures resulted in fewer fuel supply and equipment issues.

EXHIBIT 51: ERCOT - HOURLY NATURAL GAS GENERATION DURING THE WEEK OF WINTER STORMS URI & ELLIOTT



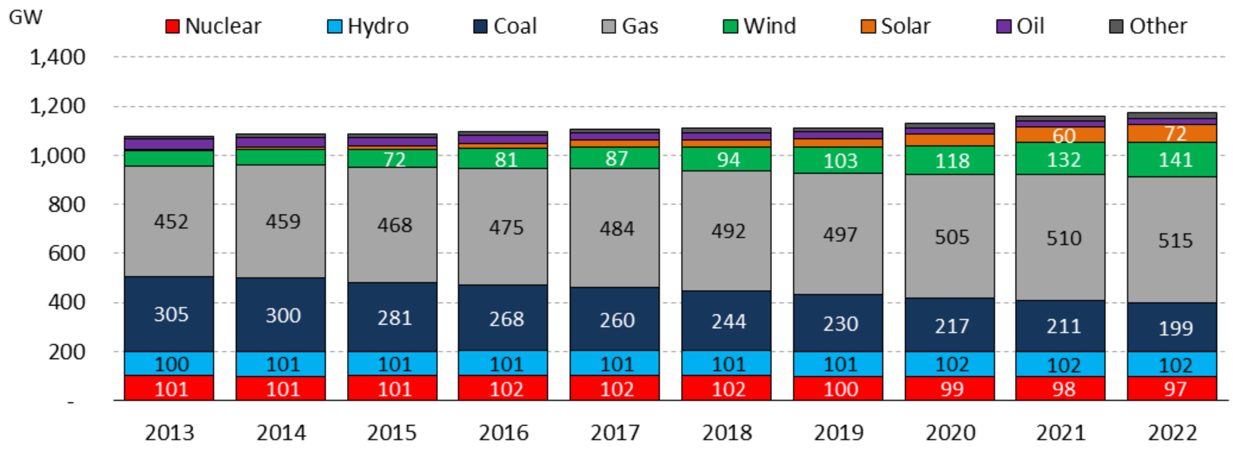
Source: EIA Hourly Grid Monitor

All in all, higher generation output from natural gas and wind power plants during Winter Storm Elliott allowed ERCOT to avoid a repeat of the power system failure it experienced during Winter Storm Uri in February 2021. However, it remains to be seen how much of the increased availability and output of these plants was due to the weatherization projects put in place in the wake of Winter Storm Uri and how much was due to the higher availability of natural gas and wind "fuel" leading up to and during Winter Storm Elliott.

Ongoing Changes in Power Generation Capacity will affect how Utilities Deal With Future Winter Storms

Over the last decade, the U.S. electric power sector has undergone massive changes. Although overall annual electricity demand has remained relatively unchanged, the capacity mix of available electric generating resources has changed considerably. **EXHIBIT *52*** shows the total operating capacity at the end of the year in the U.S. Lower-48 by fuel type for the last ten years.

EXHIBIT 52: U.S. LOWER-48 END-OF-YEAR OPERATING CAPACITY BY FUEL TYPE

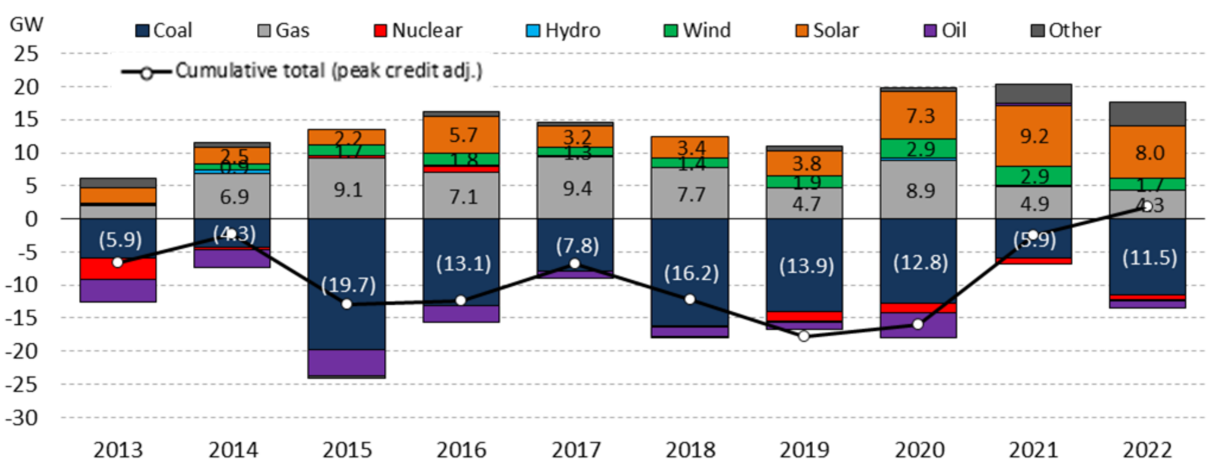


Source: EIA Form-860 data

Since 2013, over 111 GW of coal-fired electric generating capacity has closed in the U.S. Lower-48 due to higher compliance costs of updated or new environmental regulations, increased market competition from natural gas and renewable resources, and rising political pressures to replace coal with renewable resources. On the other hand, natural gas capacity increased by over 65 GW over the same period, as significantly reduced natural gas prices following the Shale Gas Revolution made natural gas more economically competitive. Wind and solar capacity also increased tremendously by a combined almost 151 GW over just the last ten years, driven primarily by federal subsidies and state policies.

However, despite the overall increase in installed capacity (ICAP) over the last decade, the cumulative amount of unforced capacity (UCAP) – the installed capacity that is adjusted for the amount it is expected to contribute during peak electricity demand hours (deducting expected forced outages) – has only recently increased above zero, as shown in **EXHIBIT *53***.

EXHIBIT 53: U.S. LOWER-48 PEAK-CREDIT ADJUSTED ANNUAL CAPACITY CHANGES BY FUEL TYPE



Source: EIA Form-860 data | Assumes peak credits of 0.2 for wind, 0.69 for solar, and 0.66 for hydro based on 2022 NERC SRA

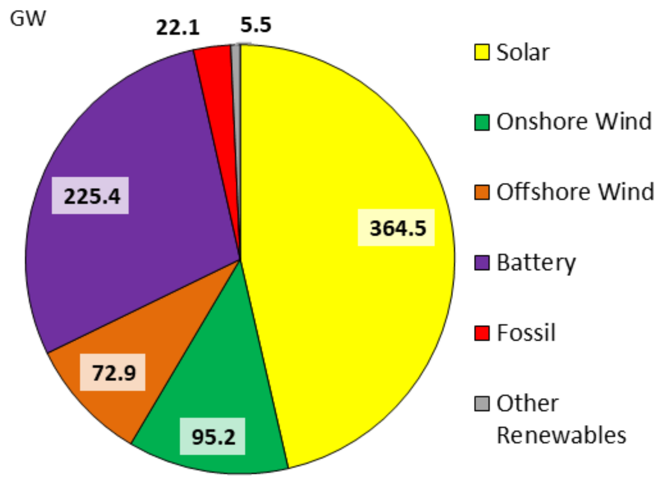
Due to the high variability of wind and solar resources, electric utilities and ISOs only count a partial amount of capacity of these resources towards their generating capacity reserve margin. Also, due to the extreme drought in the Western U.S. and the fact that its primary role is to manage the flow of rivers for environmental and agricultural purposes, hydroelectric capacity is de-rated to reflect the lower generating capacity available during peak electricity demand hours.[18] After adjusting the capacity additions over the last decade for these so-called peak credits, The U.S. electric power sector

[18] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf

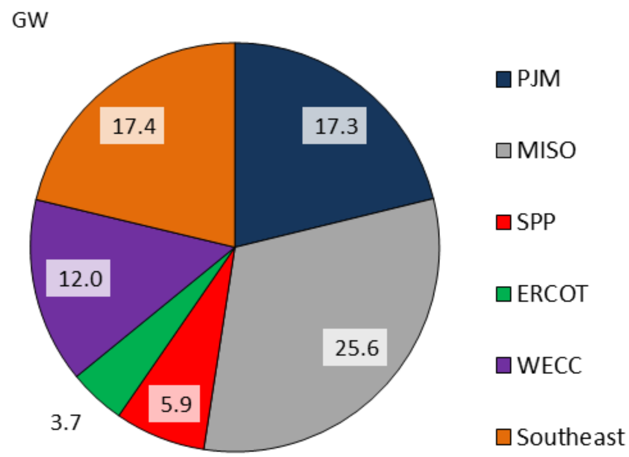
has only added less than 2 GW of capacity since 2013 as utilities have replaced dispatchable coal-fired generating capacity predominantly with partial-credit non-dispatchable renewable generating capacity like wind and solar.

This trend of replacing full peak credit dispatchable generating capacity with partial peak credit non-dispatchable capacity is projected to continue and accelerate until the end of the decade. **EXHIBIT *54*** shows the amount of active interconnection queue requests for the seven U.S. ISOs (ISO-NE, NYISO, PJM, MISO, SPP, ERCOT & CAISO) by technology type on the left and the announced coal-fired capacity retirements by power market region between 2023 and 2030 on the right.

EXHIBIT 54: ACTIVE INTERCONNECTION QUEUE REQUESTS BY FUEL TYPE (LEFT) & ANNOUNCED COAL RETIREMENTS BETWEEN 2023-30 BY POWER MARKET REGION



Source: ISO-NE, NYISO, PJM, MISO, SPP, ERCOT & CAISO interconnection queues



Source: U.S. EIA & EPA data + company announcements

Although the current combined interconnection queue contains over 780 GW of new generating capacity, almost 70% of the proposed capacity is intermittent non-dispatchable renewable energy. Less than 3% of the proposed capacity are new fossil fuel resources aimed to balance out the intermittency of existing and new renewable resources. It is also worth noting that over 75% of projects currently in the interconnection queue likely never get built, as previous analyses have shown.[19]

Even though battery storage projects make up almost 30% of new capacity in the interconnection queue, almost all of these projects are short-duration (less than eight hours of energy storage capacity) projects aimed to extend electricity production from solar power plants later into the night after the sun has set. However, this report shows that high electricity demand periods during extreme weather events such as Winter Storm Elliott can extend well beyond eight hours. Additionally, Winter Storm Elliott included relatively small amounts of snow precipitation, especially in areas with high amounts of solar capacity installed. Future possible winter storms with higher amounts of snow that can cover solar panels accompanied by lower wind speeds, like during Winter Storm Uri, can quickly render a large amount of wind and solar capacity useless to meet the substantial demand for electricity.

On the other hand, utility companies across the country have announced plans to retire 82 GW of currently operating coal-fired generating capacity by the end of the decade to advance their carbon reduction programs and avoid plant investments to comply with new or updated environmental regulations. While there exists a large amount of uncertainty around the amount and timing of new renewable capacity coming online due to supply chain, interconnection, and transmission delays, the timing of the upcoming coal retirements is all but certain due to the compliance dates associated

[19] https://emp.lbl.gov/queues

with federal environmental regulations such as the Steam-Electric Effluent Limitation Guidelines (ELG)[20] or the Good Neighbor Plan[21]. As shown in **EXHIBIT *54***, future coal retirements are spread across the country, with MISO, PJM, and the Southeast regions accounting for roughly three-quarters of all announced coal retirements. For all three regions, the amount of coal capacity announced to retire is greater than the amount of increased coal generation these regions received during Winter Storm Elliott (PJM: 17.3 GW of coal retirements vs. 14.5 GW of increased coal generation; Southeast: 17.4 GW vs. 15 GW; MISO: 25.6 GW vs. 12 GW). Retiring these power plants without replacing them with comparable long-duration dispatchable capacity will leave these regions increasingly vulnerable to more extensive and prolonged energy emergencies during extreme weather events like Winter Storms Uri and Elliott.

[20] https://www.epa.gov/eg/steam-electric-power-generating-effluent-guidelines
[21] https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs