A Review of Coal-Fired Electricity Generation in the U.S.

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APRIL 27, 2023

Brattle

NOTICE

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Executive Summary

In this report, we review the recent history of changes in the U.S. coal generation fleet and assess contributing factors to the decline in coal-fired generation capacity over the past 15 years, and summarize the current state of market fundamentals and regulations. Our assessment is based on filings and announcements related to the historical, announced, planned, and anticipated coal plant retirements from utilities and merchant operators, as well as the claimed contributing factors, and observations of trends in coal-fired capacity and generation. We discuss implications for coal-fired capacity and generation over the next 20 years.

From 2005 to December 2022, the U.S. coal-fired fleet capacity decreased from 321 GW to 219 GW due to retirements that far outpaced earlier estimates and announcements. Over the same period, energy generation from coal-fired plants decreased even more dramatically from 1,886 TWh to 665 TWh. The reduction in coal capacity corresponds to about 9% of total U.S. generation capacity. About 68 GW of additional coal capacity has been announced for retirement by the end of this decade. If historical trends offer any indication, the total capacity of announced coal plant retirements is likely an underestimate of future actual retirements.

Attributing coal plant retirements to a single driver is challenging and nearly impossible, but some key factors have emerged as common contributors to historical and currently announced retirements, as articulated by owners of coal plants and other key industry participants. These factors include:

- Sustained decreases in natural gas prices, which increases the competitiveness of natural gas as an alternate fuel to coal, and decreases coal plants' wholesale market revenues through the impacts of gas prices on wholesale energy prices;
- Lower costs to build and operate wind, solar, and storage resources, which increases the competitiveness of new renewable resources as an alternative to coal;
- Very low growth in peak load and annual energy consumption, which reduce capacity and energy prices in wholesale electricity markets and contribute to avoided buildout of new firm capacity;
- Increased costs to operate coal units due to aging of the fleet; and

- Federal and state regulations and policy, which impose compliance costs that increase the cost of continuing to operate coal units and reduce the cost of replacement power that would come from renewable resources. Companies' decisions to retire coal plants are also consistent with their long-term decarbonization and sustainability plans.

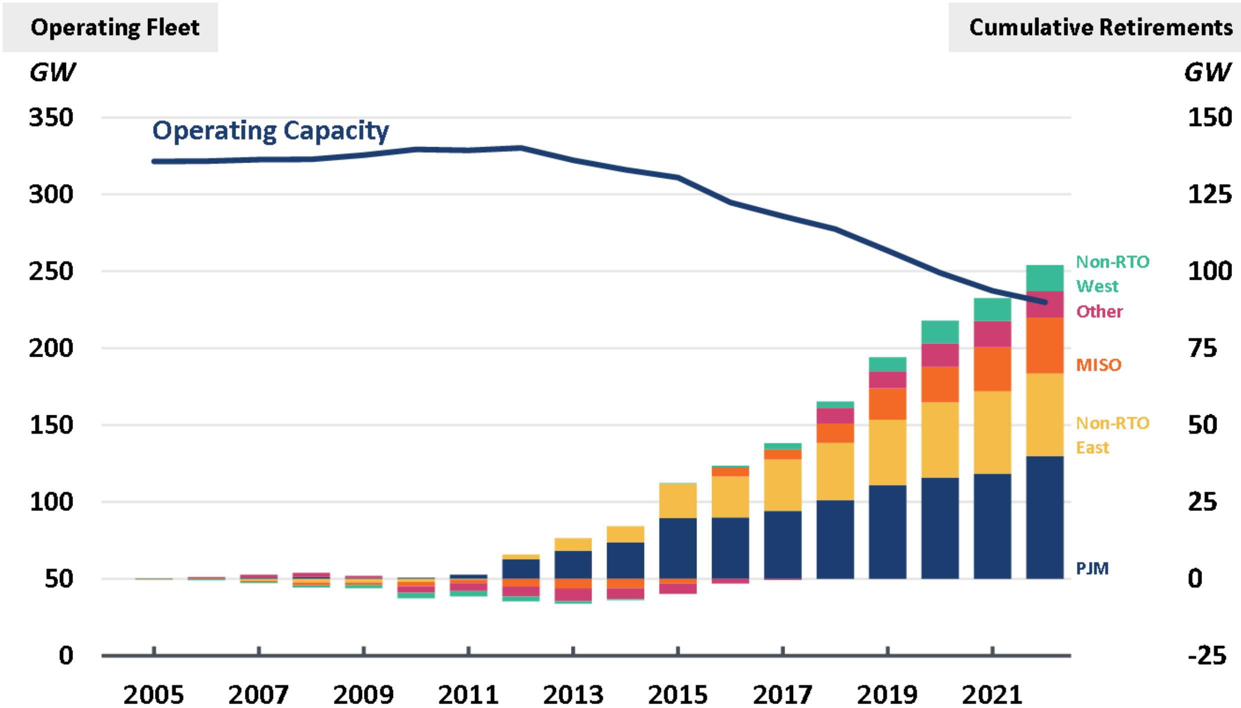
Provisions in the recently passed Inflation Reduction Act (IRA) that increase the economic attractiveness of clean energy resources have prompted some coal owners to re-examine the options for their coal fleet. The coal plant owners that have incorporated the IRA incentives into their planning find that in many cases it is now more economic to retire their coal plants and replace them with renewable resources.

I. Introduction/Overview

Coal-fired power plants in the United States have experienced dynamic shifts over the last 20 years due to increasing competitive pressures and other factors. In 2005, the operating coal capacity reached 321 GW, and electricity generation from coal plants totaled 1,886 TWh[1]. In the following years, the operating fleet capacity increased marginally to a peak of 330 GW in 2012 before beginning a steady decline thereafter. Since then, approximately 10 GW of coal capacity has retired each year, and the operating coal fleet in the U.S. decreased to 219 GW as-of December 2022, with an additional 68 GW announced and planned for retirement through 2030. Figure 1 below shows the year-over-year change and a breakdown in the cumulative net retirements by market region. Recent retirements have been concentrated in PJM, MISO, and in regions outside of organized markets including Alabama, Georgia, and Florida. Cumulatively, more than 800 units and 124 GW of capacity have been retired since 2005.

[1] For the duration of this report, metrics related to coal capacity are measured based on the nameplate capacity.

FIGURE 1: HISTORICAL DECLINE IN COAL CAPACITY ACROSS THE UNITED STATES



Notes and source: "Cumulative retirements" refer to the net total of additions and retirements in each year. Negative cumulative retirements indicates more capacity was added than the amount retired. The "Other" category includes cumulative retirements in CAISO, ERCOT, New England ISO, NYISO, and SPP. Hitachi Powergrids, Velocity Suite.

The negative cumulative retirement values in Figure 1 correspond to net additions such as new units or capacity upgrades. Almost all of the cumulative additions have been located in MISO, ERCOT, PJM, SPP, and non-RTO regions.[2] While nearly 6 GW of capacity came online as recently as 2010, annual coal capacity additions tapered in the subsequent years.[3] The owners of the last new facility (Spiritwood Energy) announced a plan in 2020 to convert its fuel source to natural gas.[4]

The reduction in coal generation output has been steeper than the reduction in capacity. Over the 2005–2022 period, annual generation declined nearly 65% to 665 TWh while the capacity declined by 29%. This pattern indicates that the remaining coal plants are dispatched less

[2] Non-RTO regions include states that do not participate in organized markets, such as Alabama and Georgia in the Eastern Interconnection, and Arizona and New Mexico in the West.

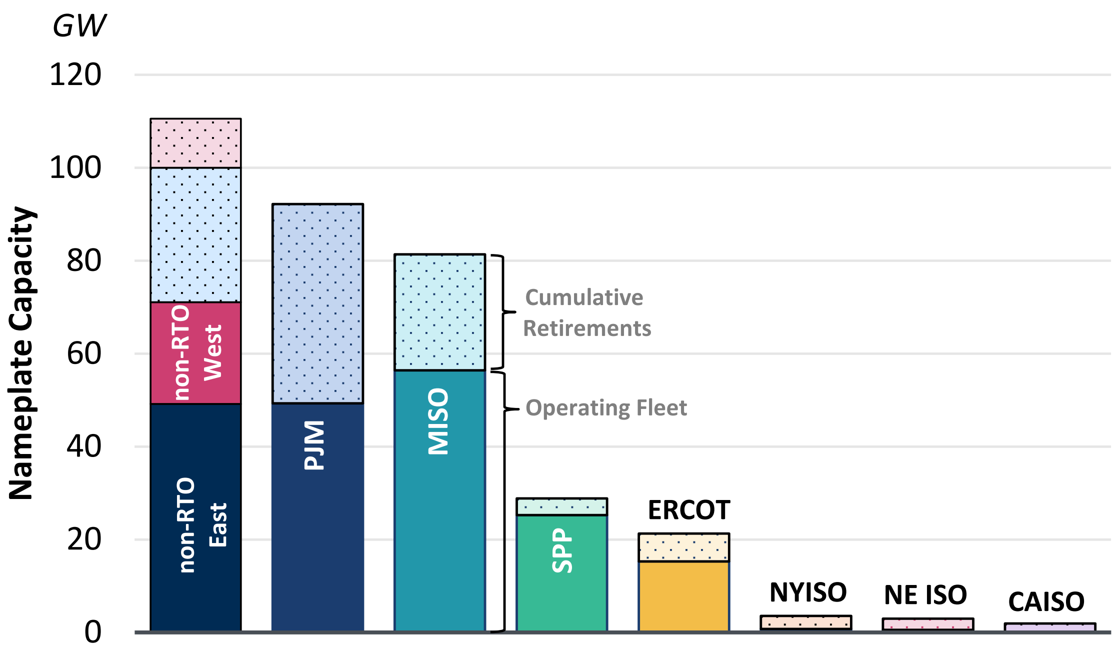
[3] The last new coal unit was built in 2019 as a 17 MW add-on to an existing coal facility. This project, built on the University of Alaska Fairbanks campus, has been directly tied to the limited natural gas infrastructure in the remote region, and a nearby coal mine. *See* A. DeMarban, "There's only one coal plant being built in the nation, and it's at UAF," *Anchorage Daily News*, September 4, 2017.

[4] Great River Energy, Company News, "Major power supply changes to reduce costs to member-owner cooperatives," May 7, 2020.

frequently. Indeed, the fleet-wide capacity factor, a measurement for how often power plants operate at full capacity, has decreased from 67% to 35% over the same time period.

Of the 219 GW of coal capacity currently online, most is concentrated in MISO (56 GW), PJM (49 GW), the non-RTO East region (49 GW), SPP (25 GW), the non-RTO West region (22 GW), and ERCOT (15 GW) (see Figure 2 below). The operating coal capacity in NYISO and NE ISO is negligible, and the last active unit in California retired in 2015.

FIGURE 2: TOTAL COAL RETIREMENTS AND CURRENT CAPACITY BY REGION (2005–2022)

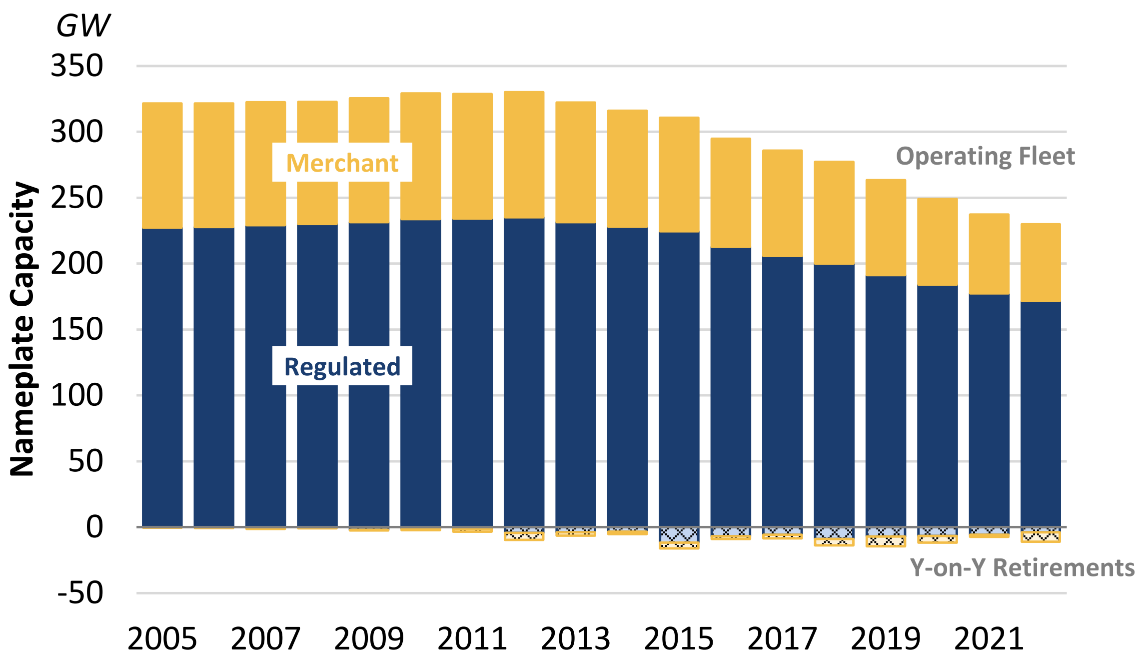


Source: Hitachi Powergrids, Velocity Suite.

In most years, a higher proportion of the merchant-owned coal capacity was retired relative to the portion of retired capacity among regulated units (3.7% versus 2% of the total, on average; see Figure 3 below). This pattern reflects in part the differences in economic criteria for retirement between merchant owners and regulated owners, who have an obligation to serve their customers. At a high level, a regulated owner would find a coal unit economic to retire if the present value of future avoidable costs to operate the unit is sufficiently higher than the present value of *future replacement power costs*.[5] In contrast, a merchant owner would find a coal unit economic to retire if the present value of future avoidable costs to operate the unit is sufficiently higher than the present value of *future market revenues*.

[5] This description of retirement criteria ignores some additional considerations such as cost of transmission upgrades that may be necessary to maintain local reliability after the retirement of the unit, or contractual obligations for fuel purchases and delivery.

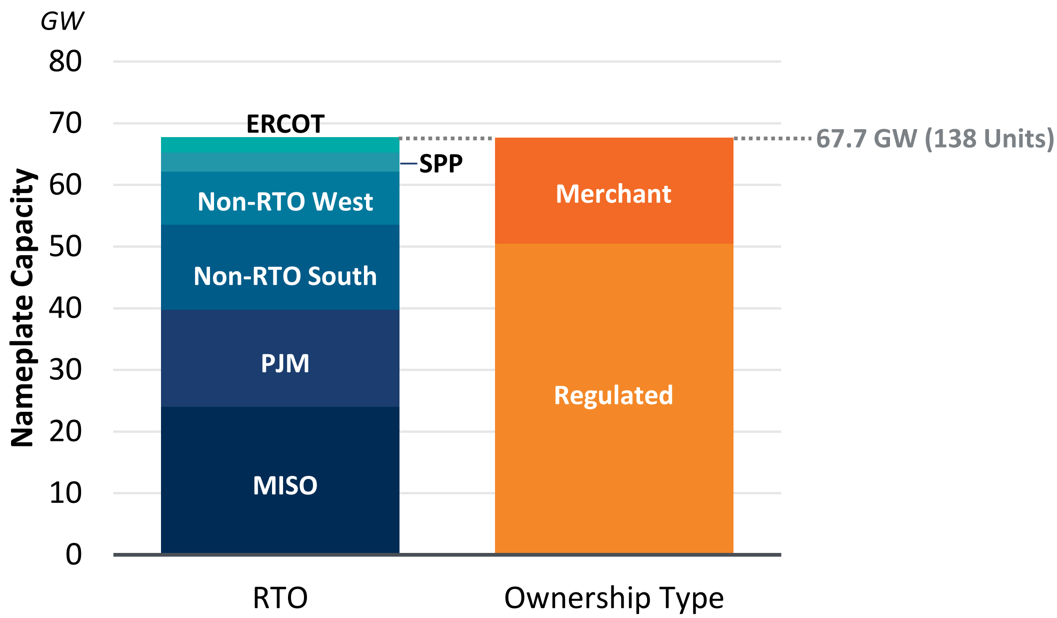
FIGURE 3: OPERATING COAL-FIRED CAPACITY BY TYPE OF OWNERSHIP



Source: Hitachi Powergrids, Velocity Suite.

Looking forward, about 68 GW of coal plant capacity (or about 8 GW per year) is slated to retire by the end of the decade based on current announced retirements as of December 2022. As shown in Figure 4, the regulated coal capacity (51 GW) accounts for most of the announced retirements.

FIGURE 4: ANNOUNCED COAL PLANT RETIREMENTS BY 2030

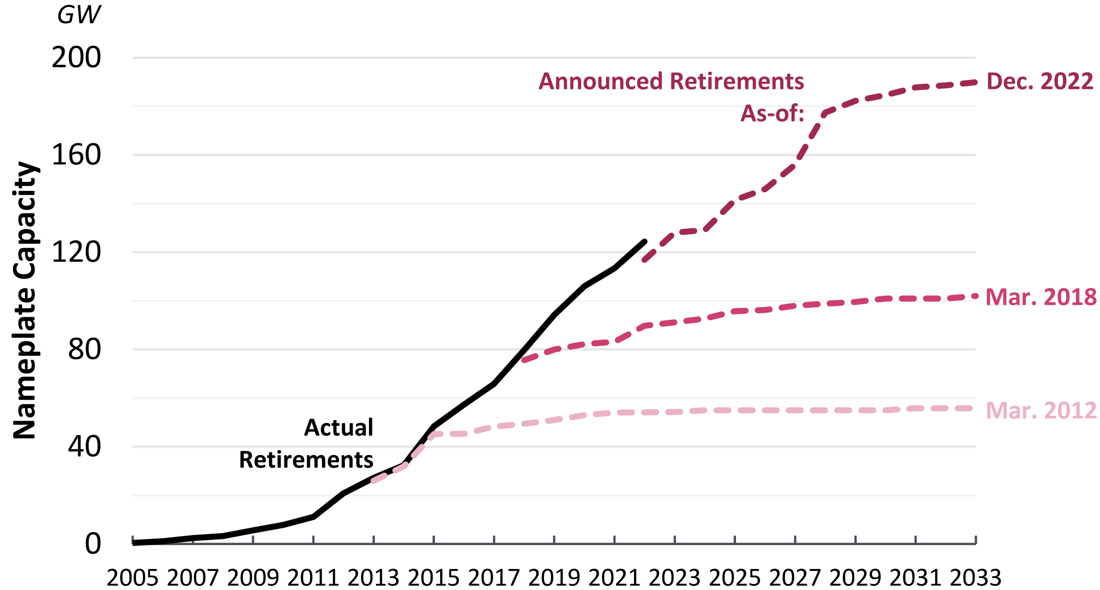


Notes and Source: NYISO and NE ISO have 0 GW of announced retirements, and CAISO has 0 GW of operating coal assets. Hitachi Powergrids, Velocity Suite.

If historical trend is of any indication, the total capacity of announced coal plant retirements is likely an underestimate of future actual retirements. Historically announced retirements tended to understate the actual retirements. While announced retirements serve as a good proxy for actual retirements in the near term, its predictive power diminishes for retirements that are farther in the future (see Figure 5 below). The retirement decision may be considered and evaluated, but may not be announced some time after the retirement decision was made in order to monitor the potential changes in market and regulatory outlook before committing to the retirement timing. However, unexpected changes in market drivers may revise the retirement schedule, or force retirement decisions to change in short order.

As an example, in 2012, the coal capacity that was announced for retirement during the 10-year period 2013–2022 was only about 33 GW. In contrast, the capacity of actual retirements during that period was about 100 GW, or about 70 GW higher. Likewise, proposed retirements as-of May 2018 for the four years between 2019 and 2022 were 16 GW short. Looking forward, we expect actual retirements by 2030 to exceed the currently announced retirements by that time due to factors such as natural gas price, renewable energy technology improvements, and tax incentives for renewable and low- and zero-carbon resources in the recently passed IRA, among other factors.

FIGURE 5: ANNOUNCED VS. ACTUAL COAL PLANT RETIREMENTS



Source: Hitachi Powergrids, Velocity Suite

II. Evolution of Market Fundamentals and Federal/State Policy

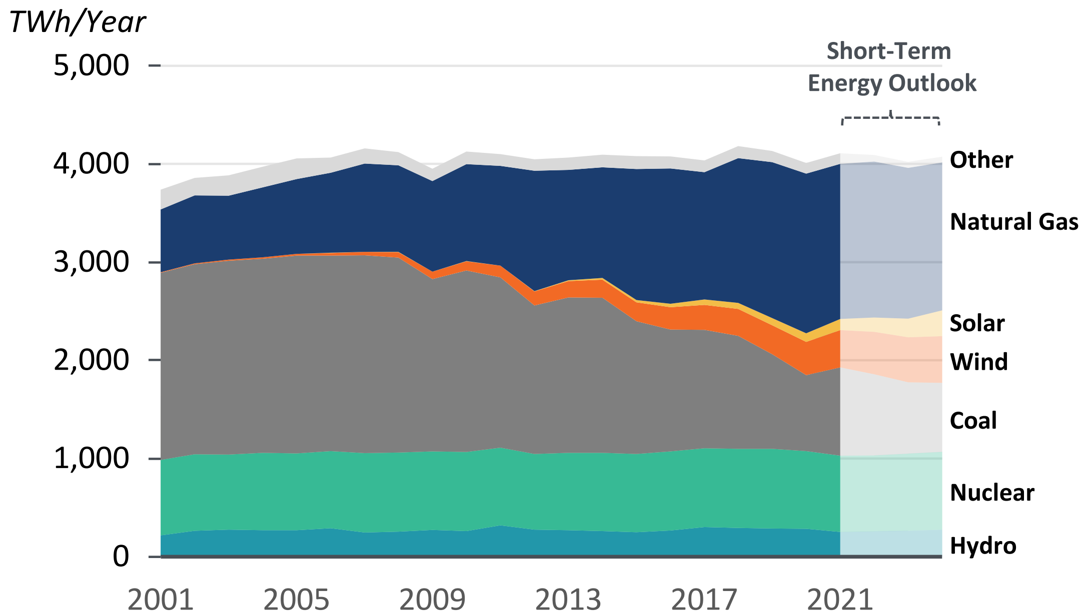
This section describes the historical market fundamentals and regulatory and policy developments that have likely contributed to coal plant retirements in the past 10 to 15 years, as well as the current market fundamentals and current regulations and policies that have likely contributed to planned and announced retirements by 2030. We note that attributing coal plant retirements to a single driver is challenging and nearly impossible due to several key reasons. First, the economic criteria for determining the timing of retiring coal units is a function of the combined effects of various market and regulatory expectations at the time the decision is made, including the future costs to operate the coal unit, future wholesale power prices, and future costs of new resources. Second, these economic variables often span many years into the future as a result of the capital-intensive nature of building generation plants that typically last for many decades, and they are highly uncertain. Third, and finally, the economics of retirement for each coal unit are unique due to differences in fuel characteristics, boiler configuration, contractual obligations, as well as different circumstances facing the unit owner with respect to costs of financing, power supply portfolio, reliability constraints, and the owner's expectations of future market and regulatory developments. Public filings and documents, when available, reveal to some extent the economic analyses behind retirement decisions, but they do not always capture the coal plant owner's private expectations of future costs and market conditions.

Over the last 10-to-15 years, the five key factors relevant to economics of coal plant retirements have been:

- Sustained decreases in natural gas prices (both as a competing fuel as an alternative to the use of coal in generating power, and due to its impact in lowering the wholesale energy prices);
- Reduction in costs of building and operating wind, solar, and storage resources (as competing technologies for generating power and due to its impact in lowering wholesale energy prices);
- Very low growth in peak load and annual energy consumption (due to its impact on reducing wholesale energy and capacity prices and due to delaying the need for adding new firm capacity);
- Increased costs of operating and maintaining coal units due to aging of the fleet; and
- Federal and state regulations and policy (due to compliance costs increasing the costs of continuing to operate coal units and reducing the cost of replacing energy from renewable resources).

Taken together, these factors lead to adverse economic effects on coal generation, resulting in in lower generation from the coal fleet over the years (see Figure 6 below).

FIGURE 6: U.S. ELECTRICITY GENERATION BY SOURCE (2005–2022)



Notes and Source: Other includes: Biomass, Coke, Geothermal, Liquids, Other, Other Biomass, Other Gases, Pumped Hydro, and Wood Fuels. EIA Electricity Data Browser, EIA Short Term Energy Outlook (2022–2024).

A. Low (And Expectation of Low) Natural Gas Prices

In many regions of the U.S. power system, gas-fired generation units tend to have higher variable costs (i.e., fuel and variable operating and maintenance costs) compared to coal-fired and other types of units. This means that gas-fired units in those regions are typically the "marginal units" in many hours by setting the price of power. Consequently, the price of natural gas can have an outsized impact on the wholesale price of electricity. Lower gas prices mean lower market-clearing prices for power and lower profits for coal plants if their fuel costs do not decrease with natural gas prices. Very low gas prices (as in 2012 when gas prices at the Henry Hub trading location were around $2/MMBtu[6]) can result in reducing the marginal costs of efficient gas-fired units below that of coal-fired units, hence pushing coal units up the supply curve and further reducing their margins. The increase in renewables in the market intensifies this effect as renewables with zero short-run marginal costs push the supply curve to the right, contributing to a lower clearing price. The dynamics between gas prices and coal plant economics have led to decreasing coal margins in the past 10 years.

6 All prices are expressed in nominal dollars unless otherwise specified.

In the 2005 to 2020 period, gas prices experienced sustained and dramatic declines, as shown in Figure 7 below. Henry Hub spot prices in that period declined from a peak level of about \$9/MMBtu to as low as \$2/MMBtu.[7] Spot prices spiked during occasional cold snaps, but mostly declined over the study period. Decreases in gas price forecasts often lag behind decreases in spot prices, but they also exhibit a downward trend as the impacts of shale gas on the market became clearer. Indeed, the rise of shale gas at the end of the last decade emerged as the biggest single factor driving lower prices for wholesale power.[8]

In 2021 and 2022, there was an uptick in natural gas spot prices due to increased LNG exports, Russia's invasion of Ukraine, and recovery from the pandemic. However, the rise in gas price does not appear likely to persist in the medium to long term, as evidenced by industry-wide expectations of lower gas prices both in projections and futures. Henry Hub futures suggest elevated price levels in 2023 that will gradually stabilize in the following years to levels seen before the pandemic.

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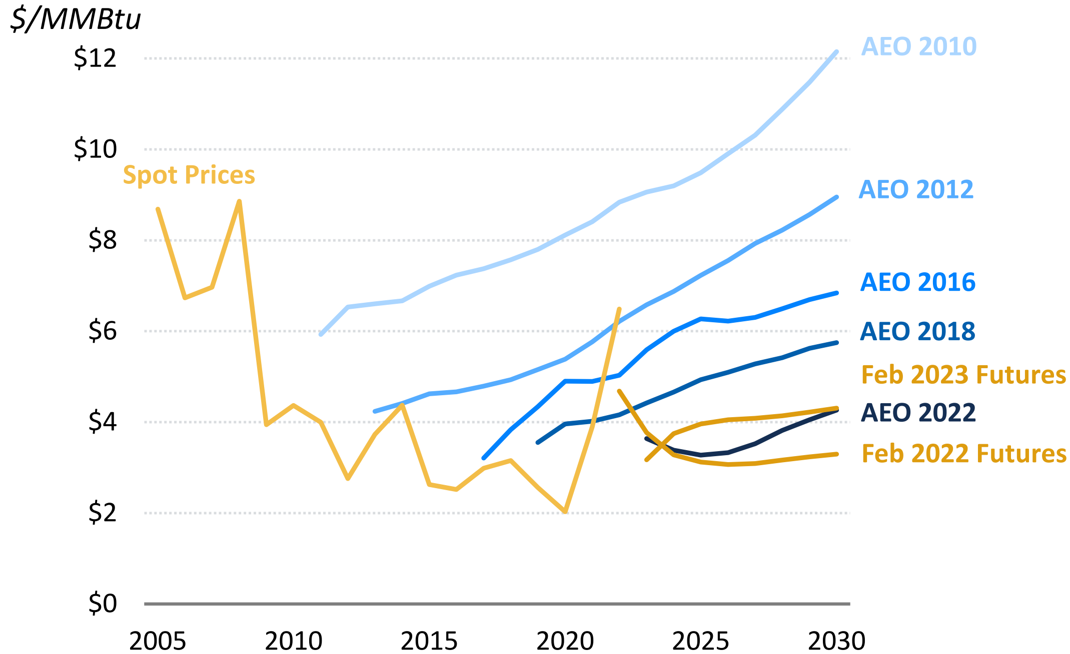
[7] EIA, *Henry Hub Natural Gas Spot Prices.*

[8] A. D. Mills, D. Millstein, R. Wiser, J. Seel, J. p. Carvallo, S. Jeong, W. Gorman, *Impact of Wind, Solar, and Other Factors on Wholesale Power Prices: An Historical Analysis—2008 through 2017*, Lawrence Berkeley National Laboratory, November 2019.

FIGURE 7: HISTORICAL AND FORECASTED HENRY HUB NATURAL GAS PRICES



Notes and Source: Historical Henry Hub data is from the EIA Natural Gas Module, forecasts are from the EIA Annual Energy Outlooks, and Henry Hub Futures are from S&P Global, Market Intelligence.

In contrast, delivered coal prices have remained relatively stable over the last 15 years (see Figure 8 below). After an increase between the 2008–2011 period, coal prices decreased slightly between 2015 and 2020 and have been below projections throughout the years. U.S. average coal prices increased from about $2/MMBtu in 2008 to $2.4/MMBtu in 2011, before gradually dropping to $1.9/MMBtu in 2020.[9] Though these price changes follow a similar trend to gas prices, their magnitudes are muted in comparison, and the 2020 price level is only slightly lower than the 2008 price.

The price of coal experienced a rebound in 2022 as demand for coal increased to compensate for the shortage of gas and heightened demand in that year, but is expected to remain at historic levels going forward. After reaching their lowest point in 2020, coal prices increased by 22% in October 2022 relative to the previous year, from $2/MMBtu to $2.5/MMBtu.[10] Prices are expected to remain high, with Central Appalachia forwards for 2024 delivery year at about $4.73/MMBtu compared to about $3.70/MMBtu in 2019.[11]

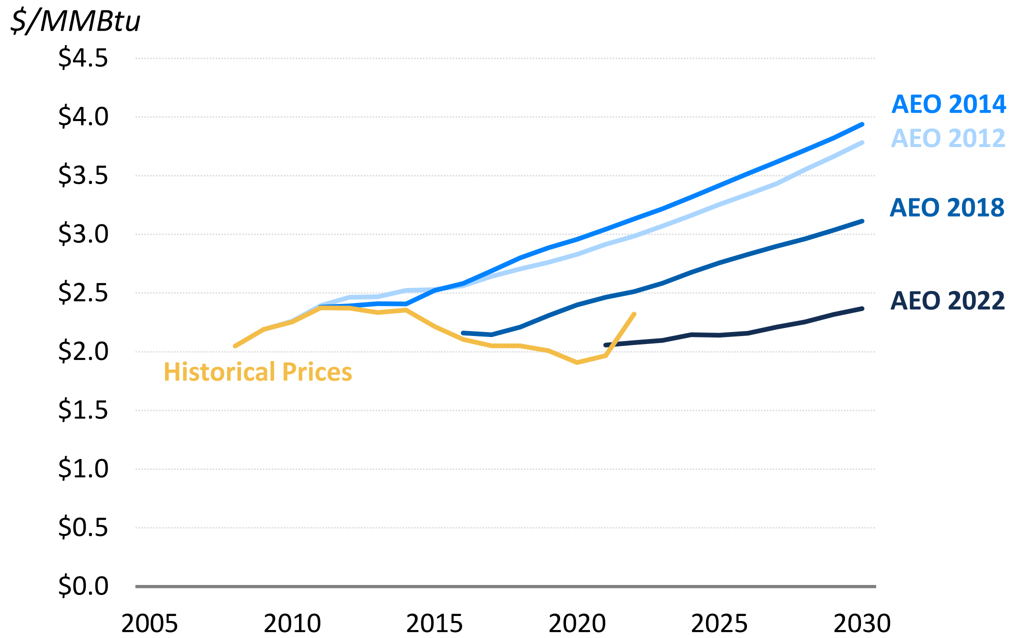
9 From the EIA Coal Data Browser.

10 From EIA Electric Power Monthly, December 2022.

11 From S&P Global Market Intelligence.

Taken together, these trends for coal and gas prices mean coal is likely to continue losing its relative competitiveness in energy markets and face the prospect of dwindling profit margins.

FIGURE 8: U.S. HISTORICAL AND FORECASTED COAL PRICES



Notes and Source: Historical data reflects prices of coal delivered to electric generators from the EIA Electricity Data Browser. Forecasts are available from the EIA Annual Energy Outlooks.

B. Significant Progress in Renewable Energy and Storage Technologies

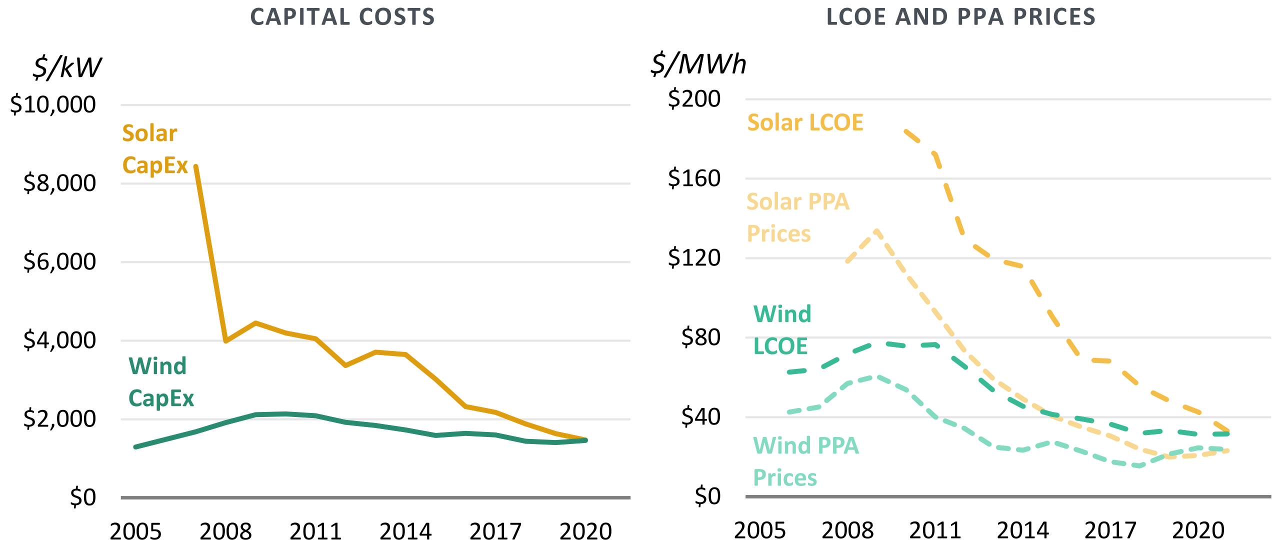
The growth of renewable energy resources has significantly impacted coal plant economics in the past 15 years. Because renewable energy resources have no short-term fuel or operating and maintenance (O&M) costs and thus a near-zero marginal cost, they tend to offer their services to the power system at zero price.[12] Subject to transmission and operational constraints, system operators always select and dispatch renewable generation for use because of their low cost relative to other energy resources.

Declines in renewable energy technology costs, improvements in technology performance, and policy incentives such as state renewable portfolio standards (RPS), net metering, and the federal investment tax credit (ITC) and production tax credit (PTC) have led to a large increase in renewable energy deployment (see Figure 10 below). Technology cost, power purchase

[12] In some markets, renewables offer price below zero to capture the relevant tax credits.

agreement (PPA), and levelized cost of electricity (LCOE) data all show substantial reduction in per-MWh costs over the past decade (see Figure 9 below). For example, the capital costs to install a new solar photovoltaic (PV) system decreased from $8,400/kW in 2007 to $1,300/kW in 2021 (in AC capacity terms).[13] Similarly, the LCOE[14] for new solar declined from $184/MWh to $33/MWh in the last decade and PPA costs declined from $112/MWh to $23/MWh.[15] Wind installed capital costs have increased slightly from $1,300/kW in 2005 to $1,500/kW in 2021, but have declined on a real dollar basis. Both PPA and LCOE costs for wind resources declined in nominal terms by 44% and 50%, over the 2006–2021 period, respectively.[16]

FIGURE 9: U.S. HISTORICAL WIND AND SOLAR CAPITAL COSTS, LCOE, AND PPA PRICES



Notes and Source: Wind and solar capital expenditure, LCOE, and PPA data is available from LBNL's Land-Based Wind Market Report and Utility-Scale Solar Market Report.

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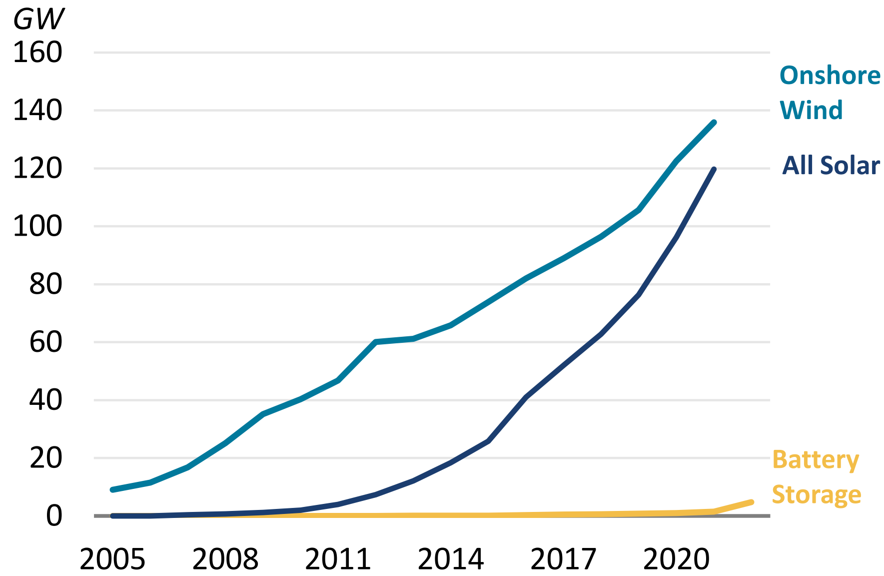
[13] Lawrence Berkeley National Laboratory, Utility-Scale Solar, 2022 Edition, 2022.

[14] LCOE measures the per unit value of the total cost of building, operating, and maintaining a power plant over an assumed financial life. LCOE represents the average revenue required to recover costs and investment returns associated with a power plant.

[15] Lawrence Berkeley National Laboratory, Utility-Scale Solar, 2022 Edition, 2022.

[16] Lawrence Berkeley National Laboratory, Land-Based Wind Market Report, 2022.

FIGURE 10: U.S. NAMEPLATE CAPACITY FOR WIND, SOLAR, AND BATTERY ENERGY STORAGE



Notes and Source: Nameplate capacity represents the AC output for wind, and DC output for solar and batteries. Wind and solar installed capacity data is available from LBNL's Land-Based Wind Market Report and Utility-Scale Solar Market Report. Installed battery storage values are extracted from EIA-860 reporting. Installed solar capacity reflects the sum of residential, commercial, and utility-scale installations.

These developments mean that renewables are now becoming economically competitive as replacement resources relative to natural gas plants for replacing the energy from retiring coal plants. Before tax credits, new-build renewables (both solar and wind) were estimated in a 2023 Lazard study to be lower cost on a levelized all-in cost of energy basis than new-build gas combined-cycle (CC) plants: whereas the expected LCOE for utility-scale solar and onshore wind were estimated to be between $24-$96/MWh and $24-$75/MWh, respectively, the LCOE for a new gas CC was estimated to be $39–$101/MWh. When the tax credits from the IRA are factored in, LCOE for all-in cost of renewables becomes lower by up to about $24/MWh, leading to cases where they are cheaper than the estimated cost of operating an existing gas CC ($51–$73/MWh).[17]

Accordingly, generation from renewables (hydropower, wind, solar, and others) in the U.S. increased from 358 TWh in 2005 (8.8% of total U.S. generation) to 879 TWh in 2022 (21%; see Figure 6 above). Electricity generation from wind and solar over the same period increased from 18 TWh and 0.6 TWh to 431 TWh and 146 TWh, respectively.[18]

17 Lazard, Levelized Cost of Energy Analysis—Version 16.0, 2023.

18 U.S. Energy Information Administration, Short-Term Energy Outlook Data Browser, Release Date February 7, 2023.

Recent supply constraints have resulted in some uptick in costs for new renewable energy projects in 2022, though this is likely to be a transient development. According to one industry report, median solar PPA prices increased 48% ($18/MWh)—from Q4 2021 to Q4 2022.[19] Industry analysts attribute the price increase to higher interest rates, supply chain constraints, labor costs, and high corporate buyers' demand to meet their clean energy targets.[20] Raw material costs have also risen faster in recent years than expectations, though there are signs that this trend is waning.[21,22] Looking forward, incentives in the IRA should help to reduce renewable costs as developers better understand how to meet the requirements for the full subsidy (see Section II.E for more information).

Intermittency is a challenge for renewable generation. Electricity generation from a wind turbine or a solar system depends on the wind or solar condition at any given moment. To help balance intermittent renewable generation, system operators typically rely on gas turbines. Where available, hydropower and pumped-hydro storage can also act as balancing resources, but these resources are site-limited, and have not significantly increased in the last 20 years. Increasingly energy storage assumes the short-term grid balancing function by storing excess renewable generation and sending that stored energy back to the grid in times of need. In the past few years, capital costs for energy storage have decreased from an average of $2,200/kWh[23] in 2015 to $260/kWh[24] in 2021. Accordingly, storage deployment capacity increased to 4.8 GW in 2022, from virtually none several years ago (see Figure 10 above).

19 Edison Energy Renewables Market Report, *Global Renewables Market Update*, January 2023.

20 Supply chain constraints include uncertainty surrounding the Biden Administration's tariffs on imported solar panel components from select countries, and restrictions created under the Uyghur Forced Labor Prevention Act.

Ibid.

21 The Brattle Group, PJM CONE 2026/2027 Report, 2022, p. 49.

22 Edison Energy Renewables Market Report, *Global Renewables Market Update*, January 2023.

23 EIA, *Today in Energy*, October 23, 2020.

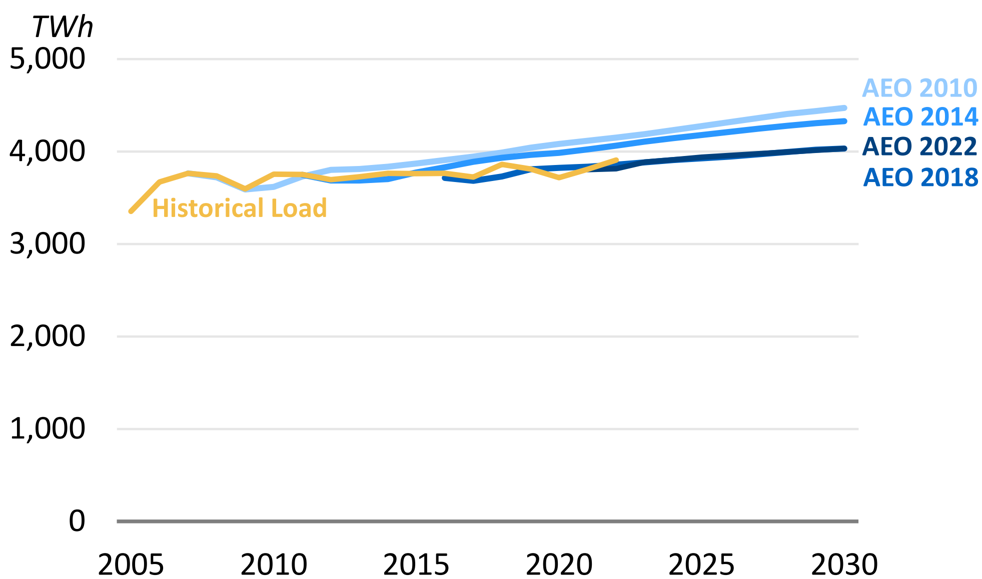
24 Lawrence Berkeley National Laboratory, Utility-Scale Solar, 2022.

C. Low Load Growth in the Last 10 Years Versus Likely Higher Load Growth Expectations Now Due to Electrification

Lower wholesale power prices due to increased deployment of resources with low marginal costs in theory can be offset by growth in demand for electricity. However, this has not been the case in the U.S. in the last 15 years, when load growth has been persistently low compared to historical growth rates.

National energy consumption has been mostly stable in the years since the Great Recession (see Figure 11 below). Compared to the historical growth rate of 5.1% per year between 1950 and 2000, the average growth rate between 2000 and 2021 was only 0.4% per year.[25] Low load growth continued well past the Great Recession to present, and the expected long-term growth rate has decreased. This lower demand for electricity means that many utilities did not have to build new resources to meet load right after retiring coal plants, making retirement an economically attractive and cost-effective approach.

FIGURE 11: U.S. HISTORICAL AND FORECASTED ELECTRIC LOAD



Notes and source: Historical data is from the Dec. 2022 EIA Short Term Energy Outlook, forecasts are from the corresponding year EIA Annual Energy Outlook.

Looking forward, load growth can exceed the base case forecasts as electrification of transportation and residential thermal needs accelerates. However, at least in the short term,

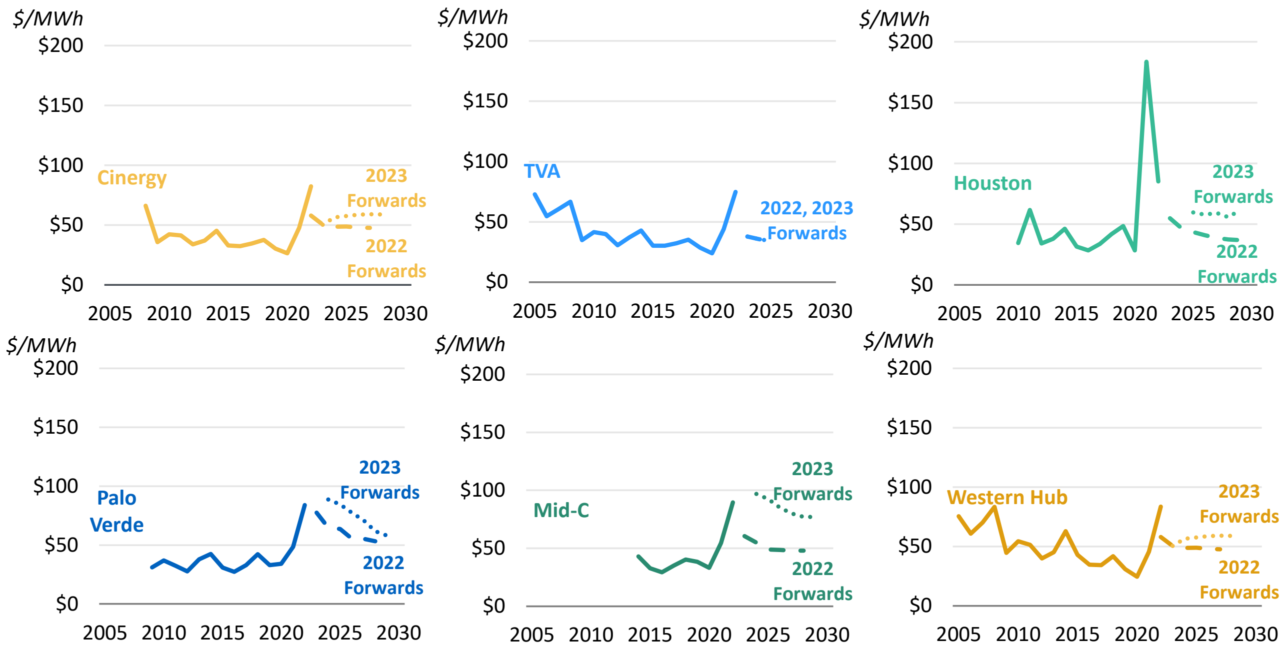
[25] U.S. Energy Information Administration, Total Energy.

these electrification shifts are likely to materialize in areas with favorable conditions for renewables rather than coal. Jurisdictions around the country pursue electrification of buildings and transportation to reduce GHG emissions and focus on deep decarbonization of the power sector through renewables. Put differently, new demand from electrification efforts will be met mostly by clean energy resources (see Section II.E).

Due to low natural gas prices, growth in renewable energy, and low load growth, power market prices on average have declined between 2005 and 2020. Figure 12 below shows that power prices remained high between 2005 and 2009, buoyed by then-high natural gas prices, but decreased thereafter and remained stable until 2021. Though natural gas prices pushed electricity prices high in the past year, prices are projected to come down from a 2022 spike and remain steady beyond 2025 (see Figure 7 above).[26] Low power prices place more pressure on the profitability of coal plants, which already face relatively high O&M costs. The slight uptick in power prices over the next few years relative to pre-pandemic levels will likely not help the long-term attractiveness of coal because coal prices are expected to increase in that window. Further, companies and states have long-term decarbonization goals. Indeed, according to EIA forecasts, the share of coal generation is expected to continue to decline in the next couple of years (see Figure 6 above).

[26] Note that power prices follow a similar shape to natural gas prices as gas units are often marginal in energy markets.

FIGURE 12: HISTORICAL WHOLESALE MARKET PRICES, ON PEAK



Sources: Historical data from Hitachi Powergrids, Velocity Suite. Forwards are as of the second Tuesday of February, available from S&P Global Market Intelligence, LLC. Forwards on the TVA subplot are for SOCO to represent prices in the Southeastern US, TVA forwards are not available.

D. Aging Coal Fleet and Higher Operating Costs

The operating coal fleet is older and larger than ever before. The average age of the current operating fleet is 47.2 years, more than 20% older than the fleet in 2005. The average nameplate capacity is 332 MW, more than 100 MW larger than in 2005.[27] Except for between 2015 and 2016, the average age of the remaining fleet has steadily increased every year since 2005 in spite of the retirement of older plants.[28,29] Aging plants often experience more frequent cycling, an increase in equipment failures, greater maintenance costs relative to the amount of

27 Hitachi Powergrids, Velocity Suite.

28 *Ibid.*

29 The trend in the median age is almost identical, with a similar short-term decline from 2015 to 2016. The age of retiring plants helps explain the two-year anomaly. From 2010 to 2017, the average age of plants retiring in each year was above 50 years. The two-year period with the most coal unit retirements across the U.S. was from 2015 to 2016, when many old units retired, leaving enough younger plants behind to minimally lower the fleet that remained.

power generated and sold, and a lower capacity factor, all of which tend to worsen plant economics as it becomes more difficult to recover the fixed costs.[30]

Age is a strong predictor of both capital expenditures and O&M costs for coal plants.[31] Each additional year of a coal plant's life corresponds to an additional $0.04/MWh of annual capital expenses. Annual O&M costs scale by $0.13/MWh for each additional year.[32] As a result, this may lead to higher short-run marginal costs, making it more expensive to operate coal plants. In fact, some coal asset owners are choosing to defer maintenance entirely to remain economical, a choice that can lead to premature retirements. Figure 12 below shows recent year-over-year increases in non-fuel related O&M costs for the operating coal fleet.[33] Non-fuel O&M costs of coal units on average (weighted by each plant's monthly generation) have increased by more than 50% in real terms, increasing from $7 per MWh in 2005 to nearly $11 per MWh in 2020 before decreasing slightly (2021 dollars).

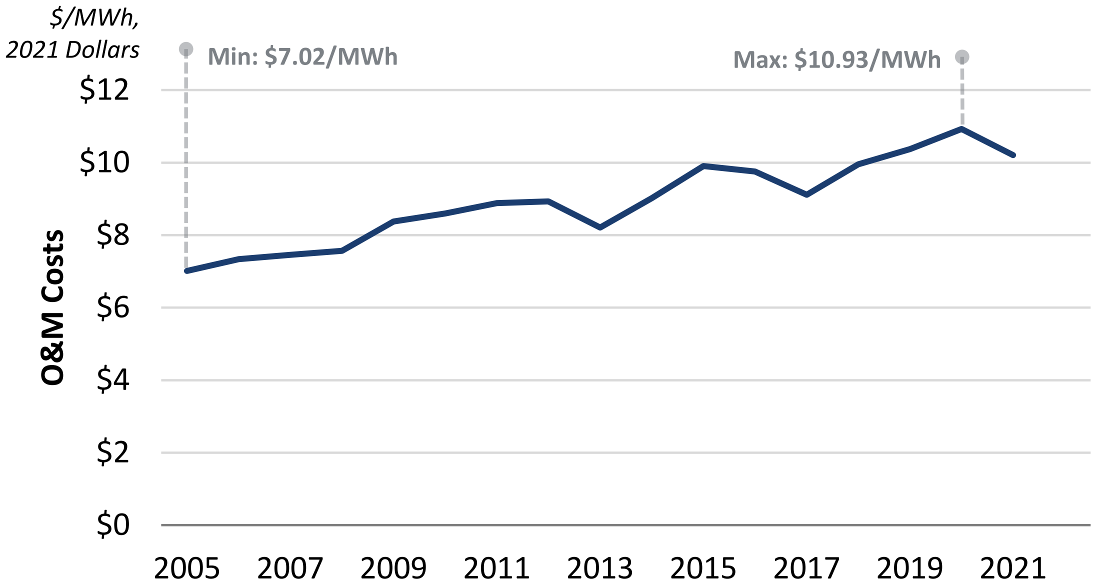
30 U.S. Energy Information Administration, Generating Unit Annual Capital and Life Extension Costs Analysis, 2019, p. 9.

31 U.S. Energy Information Administration, Generating Unit Annual Capital and Life Extension Costs Analysis, 2019.

32 *Id.*, p. A-24 and A-25.

33 Non-fuel variable costs are the costs of consumables (excluding fuel) that vary directly with the MWh production of the generating unit, such as water, chemicals, and lubricants. Fixed costs are the costs that remain constant regardless of the volume of throughput. These are typically associated with capital investment, including labor, equipment maintenance, materials and contract services, among others. *Id.*, pp. 2–5.

FIGURE 12: HISTORICAL LEVEL OF NON-FUEL O&M COSTS AT U.S. COAL PLANTS



Source: Hitachi Powergrids, Velocity Suite.

At the same time, the remaining operating fleet has become more efficient on average. Since 2005, the average heat rate of the operating fleet has declined 2.1%, from 10,372 Btu/kWh to 10,157 Btu/kWh (see Figure 13 below).[34] Prior to 2015, new and more efficient plants came online, lowering the fleet's average heat rate.[35] Thereafter, the average heat rate of the operating fleet declined as inefficient plants retired. More recently, efficient coal units with low heat rates started retiring, with an average heat rate of about 10,150 Btu/kWh for the coal units that retired in 2022. The convergence of the operating fleet's average heat rate and the retiring units' average heat rate highlights the economic pressure facing the fleet, where retirement is a real prospect for many existing coal plants, and not limited to only inefficient units.

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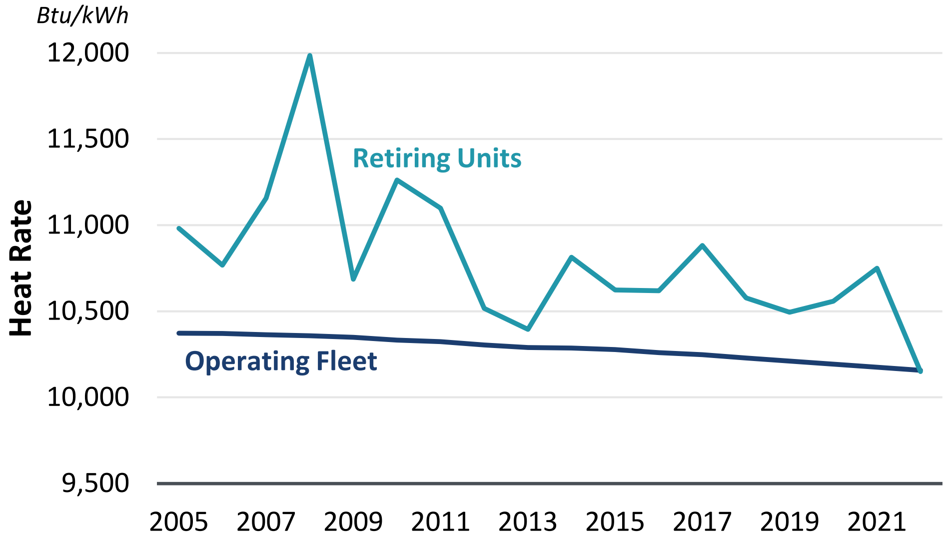
[34] The heat rate represents the amount of thermal energy that a plant requires to generate a one kWh of electricity. It is generally thought of as a measure of efficiency; plants with lower heat rates require less fuel to generate the same amount of electricity.

[35] The average heat rate of new coal units between 2005 and 2014 was 9,657 Btu/kWh.

FIGURE 13: AVERAGE HEAT RATE OF ACTIVE AND RETIRING COAL UNITS, WEIGHTED BY CAPACITY



Source and Notes: Hitachi Powergrids, Velocity Suite

E. State and Federal Policy

Policy at both the state and federal level has impacted the economics of coal plants across the country. Regulations and policies can affect the costs to continue to operate the unit, the costs of replacement power, and the expectations and future outlooks for the plant. For example, complying with environmental regulations can increase the costs of continuing to operate coal plants. At the same time, decarbonization policies signal commitments from policymakers to a clean energy future where there will be a limited role for fossil fuels (and frequently no role for coal). Financial incentives available to renewable energy resources (e.g., tax credits) both at the state and federal level help lower the cost of electricity generation from renewables and reduce the cost of replacement energy and competing resources.

To comply with various environmental laws, coal plant owners have to compare the economics of investing in environmental control equipment to keep plants online (and in some cases purchase emissions allowances) against the economics of retirement. Environmental regulations do not mandate retirement of coal plants. Rather, they induce plant owners to consider whether the profitability of the plant in the coming years justifies the investment.

Similar environmental regulations also exist at the state level with similar effects on coal plant economics, albeit some regulations are more stringent relative to the federal ones.[36]

Below are brief descriptions of some major federal regulations impacting coal plant economics and possible compliance strategies for coal plant owners. Many of the relevant regulations are at different stages of development and implementation, with several existing for more than a decade.

- The Regional Haze Rule requires states to establish goals and submit plans for achievement of visibility improvement in national parks and other wilderness areas. The plans detail emissions reduction strategies for pollutants that contribute to haze, including SO_2 and NO_x. The rule was first established in July 1999 and was most recently updated in January 2017. To comply with the Regional Haze Rule, coal plants can switch fuel to other types of coal or to natural gas, install control equipment, or retire the plant.[37]
- The Cross-State Air Pollution Rule (CSAPR) establishes a cap-and-trade program for SO_2 and NO_x to address air pollution from upwind states that impacts air quality in downwind states. To comply with this rule, coal plant owners can buy allowances in the cap-and-trade market, change the fuel used, install control equipment, or retire. CSAPR was finalized by the EPA in July of 2011 and updated in 2016 and 2021 to further reduce summertime NO_x emissions.[38] The EPA updated and expanded the program in 2023 with respect to rules to achieve the 2015 ozone standard.[39]
- The Mercury and Air Toxics Standards (MATS), issued in February 2012, sets an emissions rate standard to reduce the emissions of mercury and other hazardous air pollutants at steam generating units with a capacity more than 25 MW. To comply with MATS, coal plant

[36] For example, California's Emission Performance Standard limits long-term investments in baseload generation whose emissions rate exceeds 1,100 pounds of CO_2 per MWh, effectively forcing utilities to stop relying on generation from coal-fired power plants. *See* California Energy Commission—Tracking Progress, "California's Declining Reliance on Coal – Overview."

[37] U.S. Environmental Protection Agency, Protecting Visibility in National Parks and Scenic Areas.

[38] U.S. Environmental Protection Agency, Overview of the Cross-State Air Pollution Rule (CSAPR).

[39] On March 15, 2023, the EPA released its final rule on the Good Neighbor Plan. Included among the changes relative to the proposed rule are: i) the deferral of the timing of a backstop daily NO_x emission rate to calculate the 3-for-1 emission allowance submission determination for coal units without an existing SCR to 2030 and later years; ii) allowing large coal units to avoid paying the 3-for-1 allowance surrender up to 50 tons of NO_x above the limit; and iii) an increase to the amount of allowances states can bank to 21% through 2029 (from 10.5% in the proposal). *See* U.S. Environmental Protection Agency, Good Neighbor Plan for 2015 Ozone NAAQs, 2023.

owners were required to either install and operate control equipment, switch fuel, or retire the plant by 2015.[40]

- The Effluent Limitations Guidelines (ELG) standards limit the levels of toxic metals and other pollutants that power plants can release in their wastewater. To comply with the ELG standards, coal plants can either install control equipment, or retire the plant. The EPA is expected to revise ELG standards in 2023.[41]
- Coal Combustion Residuals (CCR) were first regulated in 2014 under the Disposal of Coal Combustion Residuals from Electric Utilities rule, which established technical requirements for the handling of coal ash for safe disposal. To comply with the CCR rule, coal plants can either install equipment for ash handling and disposal, or retire the plant. It was amended most recently in 2020.[42,43]

State-level decarbonization policies, designed to spur clean energy deployment and phase out the use of fossil fuels, also create pressure on coal plant economics. For example, Renewable Portfolio Standards (RPS) call for a certain share of state's energy production to come from renewable sources. As of November 2022, 29 states had adopted RPS, and seven others had renewable portfolio goals. Among those with an RPS enacted, 12 require 100% clean electricity by 2050.[44] Across the country, 27 states and territories have committed to reduce their GHG emissions by specific target years.[45]

The ensuing load growth from electrification of energy systems pursuant to states' clean energy policies at first glance may provide a boon to coal plants, but these state policies envision a limited or nonexistent role for coal. As an example, California aims to reach net-zero emissions by 2045. While demand for electricity is expected to double in that time frame, the state expects to supply this demand with clean energy resources, including wind, solar, hydropower, geothermal, with help from imports.[46] Similarly, renewables are key to meeting New York's

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40 U.S. Environmental Protection Agency, Mercury and Air Toxics Standards.

41 U.S. Environmental Protection Agency, Effluent Guidelines Plan. See also U.S. Environmental Protection Agency, Effluent Guidelines Plan, 2021 Supplemental Steam Electric Rulemaking.

42 U.S. Environmental Protection Agency, Disposal of Coal Combustion Residuals from Electric Utilities Rulemakings.

43 Harvard Law School Environmental and Energy Law Program, Power Plant Regulations.

44 U.S. Energy Information Administration , Renewable Energy Explained.

45 Natural Resource Defense Council (NRDC), Race to 100% Clean, December 2, 2020.

46 California Energy Commission, Docket: 19-SB-100, SB 100 Joint Agency Report: Charting a path to a 100% Clean Energy Future.

plan to reduce its economy-wide emissions by 85% relative to 1990 levels.[47] For Massachusetts to reach its net-zero goal in 2050, demand for electricity in the Commonwealth is expected to more than double compared to 2020 levels. The Commonwealth will need more than 50 GW of clean energy resources, a majority of which will include offshore wind and solar PV with energy storage.[48] Recently, New Jersey announced that the state was moving up its target for 100 percent clean electricity from 2050 to 2035. The state points to already-low impacts on energy costs and "unprecedented federal financial support" for clean energy from the IRA.[49] In the four examples, no state anticipates meeting future demand with coal. Even states with significant coal capacity historically such as Colorado, New Mexico, and North Carolina envision an extremely limited role for coal in their carbon-free future.[50]

At the same time, financial incentives for new renewable plants make them more economically attractive as replacement resources for retiring coal units. These incentives include the production tax credit (PTC) and the investment tax credit (ITC) for wind and solar energy. These tax credits have been instrumental in promoting the growth of solar and wind energy in the U.S.[51] Many states offer incentives for renewable development, including tax incentives, renewable technology rebates, renewable development funds, and more.[52] The IRA modified and expanded these tax credits (see Figure 14 below) and made it easier for entities such as energy co-operatives to monetize them to the fullest extent, prompting some coal plant owners to re-evaluate the economics of keeping versus retiring their coal assets, as discussed in the next section.

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47 R. Lueken, S. A. Newell, J. Weiss, J. Moraski, S. Ross, New York's Evolution to a Zero Emission Power System: Modeling Operations and Investment Through 2040, prepared for NYISO Stakeholders, May 18, 2020

48 Massachusetts Executive Office of Energy and Environmental Affairs, *Clean Energy and Climate Plan for 2050*, December 2022.

49 Governor Phil Murphy of the State of New Jersey, *Executive Order 315*, January 2023.

50 New Mexico's Energy Transition Act sets a standard for 50% renewable energy by 2030 and 80% by 2040 for the state's IOUs and co-operative. See Energy Transition Act, March 22, 2019; Colorado law required the elimination of carbon emissions for utility companies by 90% by the end of the decade. See HB19-1261, May 30, 2019; North Carolina set a 100% clean electricity target by 2050. See Natural Resource Defense Council (NRDC), Race to 100% Clean, December 2, 2020; and Office of Governor Roy Cooper and Energy + Environmental Economics, North Carolina Deep Decarbonization Pathways Analysis: Public Engagement Session #3, January 18, 2023.

51 T. Mai, W. Cole, E. Lantz, C. Marcy, and B. Sigrin, *Impacts of Federal Tax Credit Extensions on Renewable Deployment and Power Sector Emissions*, National Renewable Energy Laboratory Technical Report NREL/TP-6A20-65571, February 2016.

52 Database of State Incentives for Renewables and Efficiency (DSIRE), NC Clean Energy Technology Center.

FIGURE 14: FEDERAL RENEWABLE DEVELOPMENT TAX CREDITS

	Year Established	Before IRA	After IRA
Production Tax Credit (PTC)	1992	$15/MWh tax credit, unavailable for projects in service after December 2021	Base $5/MWh tax credit, up to $26/MWh for 10 years after project is in service; also available to solar projects
Investment Tax Credit (ITC)	2006	26% tax credit, phased down to 10% by 2024 for solar projects	30% tax credit

Source: Sidley Tax and Energy Update[53]

III. Findings are Broadly Consistent with Analyses and Statements from Key Stakeholders

We conducted a review of what key industry players (those with high coal capacity in their service territories) have stated on this topic. The review includes:

- 4 Investor-Owned Utilities
- 2 co-operatives
- 2 independent power producers

Our review confirms the economic challenges that coal units face, and our findings are consistent with reports from independent market monitors in organized electricity markets. For example, in PJM, as few as 5% of coal plants were able to recover their full avoidable costs in recent years.[54,55] Even in 2021 with high natural gas prices resulting in favorable market

53 Sidley, Inflation Reduction Act: Overview of Energy-Related Tax Provisions—An Energy Transition "Game Changer," August 18, 2022.

54 2021 State of the Market Report: Volume II, Monitoring Analytics, LLC, 2022, p. 383.

55 On February 24, 2023, PJM released an assessment of historical and projected resource retirements in the market region. PJM estimated that a total of 40 GW of existing capacity will retire by 2030, and coal facilities make up 60% of the retirement capacity. PJM stated that 25 GW of the retirements are primarily driven by policy choices, including 4.4 GW of coal plant retirements due to EPA's proposed Good Neighbor rule (*See* PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks, 2023, p. 7). PJM's attribution of coal plant retirements to policy versus market fundamentals is largely based on statements from the plant owners

conditions for coal plants, the bottom quartile of coal units by net revenue (including capacity payments) recovered less than 89% of their total avoidable costs. Similarly, MISO's independent market monitor highlights that coal resources in every MISO region except for Michigan exhibited a revenue shortfall (when net revenue is less than the going forward costs).[56]

The declining demand for coal also impairs economic performance of the upstream coal mining companies. Of the two large coal mining companies, Arch Resources has switched its strategy to focus on metallurgical coal as prospects for thermal coal are dim.[57] The other mining company, Peabody, acknowledges that coal units have been under competitive pressure from a number of factors, including low natural gas price, low capital costs for gas plants, low electricity demand, and high regulatory costs for coal plants.[58] The company maintains that while coal plants have been under competitive pressure, there will be strong coal demand due to "growing caution regarding the pace of energy transition" and the increasing value of dispatchable resources increases.[59] However, we expect while the recent changes in natural gas price and disruptions in the renewable energy supply chain will have a short-term impact on coal retirement schedule, these short-term market trends do not overcome the fundamental headwinds facing coal units in the U.S. (see Section II).

Coal plant owners attribute their decisions to retire coal plants to a combination of several factors, including:

- Unfavorable market conditions due to competitive pressure from low gas prices, and low power and capacity prices;

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and a simplifying assumption that when required to make investments in pollution controls, coal units would just retire. Weeks after the release of PJM's report, EPA issued the final Good Neighbor rule in March 2023 with some significant revisions relative to the proposed rule. EPA estimated the final Good Neighbor rule would increase the total, cumulative coal plant retirements in PJM by 2030 by 1.9 GW, as compared to the baseline. *See* U.S. Environmental Protection Agency, Resource Adequacy and Reliability Analysis Technical Support Document, 2023, Table C4.

[56] Net revenue is defined as the revenue of the plant above its variable production costs had it operated during hours where its revenue from only energy and ancillary services exceeds its operating cost.

2021 State of the Market Report: Appendix, Potomac Economics, 2021, p. 118.

Going forward costs are the annual costs of keeping a unit in operation.

Id., p. 27.

[57] On a recent quarterly earnings call, the CEO of Arch Resources, Mr. Paul Lang, stated that the company observed a "pretty fast decline rate" in demand from coal-fired power plants. "[The] last coal-fired power plant was built 10 years ago in the United States and the average age is creeping up 47, 48 years. This trend is continuing. I think we'll see slowdowns in retirements over the next 2 or 3 years. But this thing is heading towards a pretty fast decline rate," said Mr. Lang. Arch Resources Earnings Call, October 27, 2022.

[58] 2021 Annual 10-K, Peabody Energy Corporation, 2022.

[59] Peabody Earnings Call, November 3, 2022.

- Cost savings for customers due to lower replacement power costs and lower portfolio costs;
- State clean energy policies and environmental regulations;
- Federal regulations; and
- Corporate decarbonization goals.

As explained earlier, while federal and state regulations prompt coal plant owners to evaluate the economics of compliance, they do not directly require coal plants to retire. Furthermore, attributing coal plant retirements to a single driver is extremely challenging, and each retirement decision depends on the plant's characteristics, the economics of the alternative options, and market drivers. More likely than not, a combination of factors (rather than a single factor) affect coal plant owners' retirement decisions.

Provisions in the IRA that increase the economic attractiveness of clean energy resources have prompted some coal owners to examine the options for their coal fleet. Those who have incorporated the IRA incentives in their planning frequently find that it is economic to retire their coal plants and replace them with renewables.

A. Investor-Owned Utilities

1. DTE

DTE Energy is an investor-owned utility in Michigan with 2.3 million electric customers and over 12,000 MW of owned generation capacity. In its 2022 integrated resource plan (IRP), the utility proposes to eventually phase out its coal generation by: [60]

- Converting the coal-fired Bell River Units 1 and 2 with combined capacity of 1,270 MW to a gas-peaking resource in 2025 and 2026, respectively; the gas peaker will be retired by 2040;
- Retiring the 1,535 MW coal-fired Monroe Units 3 and 4 in 2028 (12 years earlier than previously scheduled);
- Retiring the 1,531 MW coal-fired Monroe Units 1 and 2 in 2035 (5 years earlier than previously scheduled).

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60 DTE Application, Case No. U-21193-0014, In the matter of the Application of DTE ELECTRIC COMPANY for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief, p. 2.

DTE's capacity mix will be completely coal-free by 2036, an important step toward meeting the company's net zero by 2050 goal. To replace the retiring capacity, the utility plans to add to its system 6,500 MW of solar; 8,900 MW of wind; 1,810 MW of battery storage; and 946 MW of low or zero carbon, dispatchable resources (currently selected technology is a natural gas combined-cycle with carbon capture and sequestration). [61]

The utility's retirement decisions were informed by a resource planning analysis that compared different retirement strategies in eight market scenarios.[62] Compared to the base strategy, where the coal plants retire at the end of their book life, DTE's preferred plan reduces the net present value of revenue requirement (NPVRR) by $88 million. DTE cited the following reasons:

- The low NPVRR of the chosen retirement plan compared to the other strategies that allow the utility to exit coal prior to 2039/2040, a goal of the company;
- The Biden Administration's target for carbon-free electricity by 2035;
- Consistency with the retirement plan recommended by some stakeholders;
- The ability for the Belle River gas conversion to help with the economics and reliability impacts of the staggered retirement of units at the Monroe plant; and
- Reliability benefits from the conversion and staggered retirement to ensure renewable and storage resources are built before they are required to meet the planning reserve margin, while also providing time for clean dispatchable resources at scale to be developed and enter the market as replacement options.[63]

As part of their modeling, DTE included a "Refresh" scenario that accounts for the relevant provisions in the recently passed IRA, including changes to the resources eligible for the Production Tax Credit and the Investment Tax Credit.[64] In the Refresh scenario, with the IRA and updated fuel prices incorporated, DTE finds that the preferred strategy is $110–$705 million less expensive than the base strategy (depending on sensitivities).

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[61] *Id.*, p. JEL 16–17.

[62] The eight scenarios include four required scenarios (business-as-usual, emerging technologies, environmental policy, and carbon reduction), two company assumption scenarios (reference and high electrification), one scenario developed by DTE stakeholders, and an updated scenario that incorporates the IRA tax credits. *Id*., p. SDM 29.

[63] *Id*., p. SDM 54.

[64] *Id.*, p. RCG 10.

2. LG&E and KU

Louisville Gas and Electric (LG&E) and Kentucky Utilities Company (KU), subsidiaries of the PPL Corporation, serve a combined 1 million electric customers in Kentucky and Virginia with a resource mix that is largely comprised of coal-fired generation. Of the company's 7,702 MW of summer total net capacity, 4,867 MW (63.2%) is from coal assets.[65]

In their most recent IRP (published in October 2021), the company examined accelerating the retirement of two coal plants and two simple-cycle combustion turbine (SCCT) units. The main differences between this IRP and previous iterations include:

- Retiring the 300 MW Unit 1 at Mill Creek in 2024, compared to the previous plan for 2032 retirement, and the 297 MW Unit 2 in 2028, 6 years earlier than its planned 2034 retirement
- Retiring Brown 3 (412 MW) in 2028, 7 years earlier than its planned 2035 retirement
- Retiring Haefling 1-2 (24 MW) and Paddys Run 12 (23 MW), two SCCT units, in 2025 because of their age and inefficiency[66,67]

This replacement makeup is largely driven by cost-effectiveness, with the IRP stating that "utility-scale solar is selected beyond 2025 as a least-cost resource in almost all cases evaluated in the Companies' Long-Term Resource Planning analysis."[68] The 2021 IRP cites several analyses that led to their retirement decisions, including both utilities' 2020 Environmental Cost Recovery (ECR) compliance plan, both utilities' November 2020 applications for rate adjustments, advanced metering deployment approval, and approval of regulatory treatments, and consideration of relevant regulations.[69] The important contributing factors include:

- Comply with the amended Effluent Limit Guidelines (ELG) regulations by their 2024 compliance deadline in the most cost effective manner; [70]

[65] Based on the summer nameplate capacity. This number includes the Companies' share of Ohio Valley Electric Corporation resources. 2021 IRP Volume I, PPL Corporation, 2021, p. 5–6.

[66] 2021 IRP Volume I, PPL Corporation, 2021, pp. 5-17, 5-18.

[67] Case 2020-00349 and Case 2020-00350, Testimony of Paul W. Thompson, 2022, p. LEB-2 3.

[68] 2021 IRP Volume III, PPL Corporation, 2021, p. 1.

[69] 2021 IRP Volume I, PPL Corporation, 2021, p. 5-17.

[70] *Ibid.*

- Avoid major maintenance costs on old assets when they become uneconomic;[71]
- The inability to operate both Mill Creek 1 and 2 during ozone season because of NO_x limits;[72]
- Comply with the March 2021 revision of the Cross State Air Pollution Rule, which reduced the number of NO_x allowances issued, impacting Mill Creek 1-2 and Ghent 2 because they are not equipped with Selective Catalytic Reduction (SCR).

PPL states that these retirements will help the company reach its goal of retiring 2,000 MW of coal-fired generation by 2036, and at least 1,000 MW retired by 2028 as part of a plan to be net-zero by 2050.[73] This net zero plan has intermediate goals of a 70% reduction from 2010 emissions levels by 2035, and 80% reduction by 2040. This plan will leave LG&E and KU with only two of its currently operating combustion units still running beyond 2050: a single 550 MW coal asset at Trimble County 2 operating until 2066, and the 662 MW gas plant, Cane Run, running until 2055.[74] LG&E and KU plan to replace the retiring capacity with 1,320 MW of new gas combined-cycle plants, 1,855 MW of new solar; and 200 MW of new battery storage by 2036.[75]

In December 2022, LG&E and KU filed a joint application for Certificates of Public Convenience and Necessity (CPCN), containing an updated resource assessment analysis. In this analysis, the companies re-evaluated the coal asset retirement plan from the 2021 IRP to incorporate implications of the draft issuance of the Good Neighbor Plan by the EPA.[76] According to the companies' filing, this program will create new NO_X emissions constraints for all coal-fired generating units that are not SCR-equipped and have a capacity greater than 100 MW, affecting the Mill Creek 2 and Ghent 2 units. LG&E and KU anticipate that these units would not be able to operate during the May-September ozone season without exceeding the new rule's limits.[77]

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71 *Id.*, p. 5-18.

72 *Id.*, p. 8-38.

73 PPL Corporation, Climate Forward: PPL's 2021 Climate Assessment Report, 2021, p. 23.

74 *Ibid.*

75 2021 IRP Volume I, PPL Corporation, 2021, p. 8-1.

76 Case 2022-00402, Direct Testimony of Stuart A. Wilson, 2022, p. 4.

77 The companies found in their Certificate of Public Convenience and Necessity (CPCN) filing that savings in present value of revenue requirements associated with compliance in some cases exceed the SCR installation costs. To comply with the updated NO_x limits, the plants could install SCR equipment, which the companies estimated to cost $110 million for Mill Creek 2 and $126 million for Ghent 2. The 2021 IRP planned for a 2028 Mill Creek 2 retirement, which would fall around the time of the Good Neighbor Plan updates going into effect, so the resource assessment in the CPCN filing focused on the NPVRR impact of Ghent 2 retirement instead of

In addition to including the impacts of the Good Neighbor Plan, the new resource assessment incorporated the IRA provisions in its modeling assumptions. The 30-year load forecast in the model accounted for the impacts of the IRA, supply-side options for renewables were based on a June 2022 RFP and the IRA impacts, and IRA tax incentives were also included as model inputs.[78] In the companies' "no-regrets" resource portfolio, designed to comply with the Good Neighbor Plan and maintain reliable performance, the Ghent 2 coal unit's retirement date is moved earlier, from 2034 to 2028, and instead of retiring Mill Creek 2 and Brown 3 in 2028, the companies plan to convert both to gas facilities. The assessment identified the need to add 877 MW of solar and 125 MW of battery energy storage.[79] LG&E and KU's plan is under review for approval by the Kentucky Public Service Commission.

3. Minnesota Power

Minnesota Power is a division of ALLETE, Inc. that serves 145,000 electric customers in central and northern Minnesota. Minnesota Power has a higher proportion of industrial customers than most utilities, with 61% of energy sales going to retail industrial customers.[80] Founded as hydroelectric utility in the early 1900s, the utility shifted its generation capacity mix to 95% coal by 2005. Since then, Minnesota Power has transformed its generation makeup, which is now 50% renewable. Additionally, the company's EnergyForward plan set targets for 70% renewable generation in 2030 and coal-free generation by 2035.[81]

In its most recent IRP (published in February 2021), Minnesota Power proposed to further shift its generation mix away from coal by:

- Adapting coal generation at the 335 MW Boswell Energy Center (BEC) Unit 3 to economic dispatch in MISO in 2021, then retiring the plant in 2029;
- Retiring the two idle Taconite Harbor Energy Center (THEC) coal generation units in 2021 after having them idle since 2016, accelerating their retirement from the 2026 end of book life; and

SCR installation. In 23 of 24 scenarios, the retirement of Ghent 2 would lead to NPVRR savings. In 7 of the scenarios, the NPVRR savings were greater than the SCR cost for Ghent 2, indicating cost savings could be realized from retirement even without the company's cost assumption. *See* Direct Testimony of Stuart A. Wilson, Commonwealth of Kentucky, 2022, PDF pp. 46, 53, 68.

78 Case 2022-00402, Direct Testimony of Stuart A. Wilson, 2022, pp. SAW-1 4, 5, 54.

79 Case 2022-00402, Direct Testimony of Stuart A. Wilson, 2022, p. 40.

80 Minnesota Power, 2021 Integrated Resource Plan, 2021, p. 1

81 *Ibid.*

- Ceasing operations of the 468 MW Boswell Energy Center Unit 4 by 2035 and look at refuel or remission options.[82]

To replace the retired coal capacity, Minnesota Power proposed to add 200 MW of wind resources by 2025 and 200 MW of solar by 2030. The utility would pursue 100 to 200 MW of demand response for industrial customers between 2022 and 2028, and up to 50 MW of long-term demand response by 2030.[83]

In November 2022, Minnesota Public Utilities Commission approved a joint agreement between Minnesota Power and key stakeholders.[84] Per the joint agreement, Minnesota Power would:

- Increase solar capacity to 300 MW
- Increase wind capacity targets to 300–400 MW with at least 200 MW by 2026
- Implement 100-500 MWh of storage demonstration projects by 2026

Minnesota Power credited the IRA and the Infrastructure Investment and Jobs Act for "support lowering the cost of renewables and maintaining competitive rates for our customers."[85]

FIGURE 15: MINNESOTA POWER'S CAPACITY PLANS BEFORE AND AFTER IRA

	Initial 2021 IRP (Before IRA)	Approved IRP (After IRA)
Solar	• 20 MW between 2021 and 2025 • 200 MW by 2030	• 300 MW by 2026
Wind	• 200 MW by 2025	• 200 MW by 2026 • Total of 300–400 MW
Demand Response	• 100-200 MW between 2022–2028	

[82] Minnesota Power, 2021 Integrated Resource Plan, 2021, pp. 66–68.

[83] The 2021 Plan proposed by Minnesota Power, which includes the actions above, was selected because it was the least-cost option of the portfolios they considered in the study period from 2021–2035. The plan had NPVRR savings of $119 million over the base case with a 43% reduction in coal-fired generation capacity. It was consistently the lowest-cost portfolio, with the lowest NPV in 27 of 38 market sensitivity cases tested in the analysis. The plan examined converting BEC unit 3 into a gas resource, but that option was screened out due to large capital investment requirements and a long lead time to start up operations, with the company instead deciding to strengthen transmission around BEC. The study also consistently selected PTC-qualifying wind, solar located at the retired BEC sites, and transmission solutions for reliability rather than new gas resources. *See* Minnesota Power, 2021 Integrated Resource Plan, 2021, p. 37, 51, 58, and 66–68.

[84] Minnesota Power, Joint Agreement, November 7, 2022.

[85] Minnesota Power, Press Release, Minnesota Power ready to move next phase of EnergyForward following MPUC approval of resource plan, November 10, 2022.

	• 50 MW of long-term DR by 2030	
Storage	• N/A	• 100–500 MWh demo projects by 2026

4. PacifiCorp

PacifiCorp is a regulated utility that owns generation and transmission assets in the Northwest U.S. It operates as a wholly owned subsidiary of Berkshire Hathaway Energy Company. Most of PacifiCorp's electricity is sold into Utah, Oregon, and Wyoming, with smaller amounts sold to customers in Washington, Idaho, and California.

The company's resource plans have been informed primarily by economics, federal and state environmental regulations, and voluntary commitments. As part of the 2019 IRP process, an analysis showed that 60% of the coal plants at the time were uneconomic.[86] For plants subject the EPA's Regional Haze Rule,[87] PacifiCorp has the option to install new environmental control equipment, though the utility decided to retire some of its plants early. According to PacifiCorp:

> The requirement to install SCR equipment as part of a regional haze program has caused the shutdown or early closure of coal-fired units in Arizona (Cholla), New Mexico (San Juan), Oregon (Boardman), and Wyoming (Dave Johnston Unit 3), among others. At each of these plants, units were retired early or shutdown after EPA required the installation of SCR as part of a regional haze federal implementation plan or disapproval of a state implementation plan.[88]

It is important to note that economic factors likely played a role in the timing of at least one of those coal unit retirements: instead of operating Cholla 4 until 2025 as was permitted as part of the implementation plan, PacifiCorp and the other owners accelerated the retirement schedule to 2020.[89] At the time, the planned capacity to replace the 387 MW unit included wind resources, though this was later changed to solar plus storage and energy efficiency

86 PacifiCorp, 2019 IRP Public Input Meeting, December 3–4, 2018.

87 Carbon, Cholla, Craig, Dave Johnston, Hayden, Hunter, Huntington, and Wyodak.

88 EPA-HQ-OGC-2020-0717, RE: EPA Notice of Proposed Settlement Agreement; PacifiCorp's response to EPA's request for public comment, March 5, 2021.

89 In PacifiCorp's 2017 IRP, the company cites "changes in market conditions, characterized by reduced loads and wholesale power prices," as contributors to the retirement of the Cholla Power Plant. The asset had an original end-of-life in 2042. 2017 Integrated Resource Plan, PacifiCorp, 2017, p. 7.

resources.[90,91] In addition, PacifiCorp is subject to state decarbonization regulations. This includes Oregon's plan to have 100% carbon-free electricity by 2040, Washington's plan to eliminate carbon from the state's electricity supply by 2045, and Wyoming's House Bill 200 requiring coal-fired power plants to be retrofitted with carbon capture technology.[92]

In its recent 2023 IRP, PacifiCorp outlines for the first time its retirement and conversion plans for all of its coal assets, making the company's generation mix coal-free by 2039 (see Figure 16 below).[93] "Driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives," PacifiCorp proposes to retire or convert to gas 20 out of 22 coal units by 2032.[94] PacifiCorp proposes to install new environmental controls at three coal units in 2026 to comply with the EPA's Ozone Transport Rule before retiring them in the 2030s. The company's final two coal units are slated to retire by 2039. On balance, PacifiCorp will exit more coal capacity on a faster timeline under this IRP compared to previous IRPs.

FIGURE 16: PLANS FOR PACIFICORP'S COAL ASSETS

Plant Name	Units	Location	Resource Plan
Craig	1–2	Colorado	Unit 1 to retire in 2025; Unit 2 to retire in 2028
Colstrip	3–4	Montana	PacifiCorp to exit Unit 3 in 2025, with capacity share consolidated into Unit 4; Unit 4 to retire in 2029
Dave Johnston	1–4	Wyoming	Unit 3 to retire in 2027; Units 1–2 to retire in 2028; Unit 4 to retire in 2039
Hayden	1–2	Colorado	Unit 2 to retire in 2027; Unit 1 to retire in 2028
Hunter	1–3	Utah	Unit 1 to retire in 2031; Units 2–3 to retire in 2032
Huntington	1–2	Utah	Retire in 2032
Jim Bridger	1–4	Wyoming	Units 1–2 converted to gas in 2024; Units 3–4 converted to gas in 2030; retire in 2037;
Naughton	1–2	Wyoming	Units 1–2 converted to gas in 2026; retire in 2036
Wyodak	1	Wyoming	Retire in 2039

Source: 2023 Integrated Resource Plan, PacifiCorp.

90 *Id.* p. 2.

91 2019 Integrated Resource Plan, PacifiCorp, 2019, p. 258.

92 Regulators may grant a utility exemption to the mandate if the utility proves that such a retrofit is cost-prohibitive. See Bleizeffer, D., "Ratepayers to Foot $2M Bill for Coal-Power Mandate", WyoFile, Jan 3, 2023

93 *See* PacifiCorp, 2023 Integrated Resource Plan, March 31, 2023.

94 *Id.*, p. 18.

The 2023 IRP calls for more wind, solar, storage, and energy efficiency resources to replace the retiring coal assets, citing their competitive economics in no small part thanks to the IRA. According to PacifiCorp, "The notable near term impacts of the IRA are to allow all non-carbon emitting resources and energy storage resources to select either production tax credits and investment tax credits. Production tax credits are expected to provide greater benefits for wind, solar, and many other generation technologies and may contribute to suppressed market prices during periods of renewable resource oversupply as generators may be willing to accept negative [prices as an] attempt to avoid losing production tax credits."[95] In addition, PacifiCorp's participation in the regional Energy Imbalance Market enables the company to leverage low-cost electricity generated from renewable sources across the West. PacifiCorp's parent company, Berkshire Hathaway Energy, also notes that the legislation benefits the company's decarbonization goals through additional investments in non-fossil fuel technologies.[96] Furthermore, in its announcement of a joint coal-to-nuclear study to evaluate the feasibility of deploying advanced nuclear technology and integrated energy storage systems, PacifiCorp referenced the IRA as one of the drivers for this coal-to-nuclear initiative.[97]

B. Cooperatives

1. Tri-State Generation and Transmission

Tri-State Generation and Transmission Association (Tri-State) is a generation and transmission (G&T) cooperative in the western U.S., serving over 1 million customers in Colorado, Nebraska, New Mexico, and Wyoming through 42 utility member systems. Of the utility's 3,500 MW generation capacity, coal's capacity in 2019 was the highest, at 40%, followed by renewables (26%), natural gas (19%), purchases from Basin Electric (13%), and oil (2%).[98]

Tri-State's pace of transition away from coal generation assets has been a source of tension between the company and its co-operative members, who expressed concerns over Tri-State's carbon footprint and costs. To address members' concerns, and in response to Colorado's and New Mexico's clean energy goals, Tri-State introduced its Responsible Energy Plan, laying out

95 *Id.*, p. 50.

96 Berkshire Hathaway Energy, *EEI Financial Conference*, November 2022.

97 PacifiCorp, News Release, TerraPower and PacifiCorp announce efforts to expand Natrium technology deployment, October 27, 2022.

98 Tri-State, 2020 Integrated Resource Plan/Electric Resource Plan, 2020, p. 25.

priorities for the planning and operations of the utility. These priorities include eliminating emissions from coal plants in Colorado and New Mexico by 2030, increasing clean energy to 50% of Tri-State supply, and an 80% reduction in emissions from a 2005 baseline by 2030.[99] The company aims to accomplish these priorities by:

- Retiring the jointly-owned, coal-fired Craig Generating Station Unit 1 by 2025, Unit 2 by 2028, and Unit 3 by 2030 (with a total capacity of 1,285 MW);[100]
- Evaluating the retirement of Laramie River Station (LRS) Unit 3 by 2033 (27% ownership),[101] and Springerville (SPV) unit 3 by 2038 (25% ownership); both are coal-fired power plants;[102]
- Bringing 1,000 MW of wind and solar projects online by 2025.[103]

Tri-State's decision to retire LRS 3 was driven in part by Colorado's requirements to reduce the state's GHG emissions 80% by 2030 from a 2005 baseline. The company found that "continued operation of both LRS Unit 2 and Unit 3 at levels needed to satisfy and maintain an 80% CO_2 reduction in Colorado would not be economic."[104]

Tri-State has not released any analysis related to the impacts of the IRA on the company's future resource mix, but noted in a press release that the direct payment provisions in the legislation resulted in more than $15 billion in funding options and direct pay tax credits for the co-operative industry, allowing "…cooperatives that were previously excluded from these incentives to invest directly in renewable energy and energy storage, and receive benefits similar to for-profit utilities."[105] In addition, provisions in the IRA "create greater opportunities for implementation of Tri-State's Responsible Energy Plan, which includes the rapid addition of clean energy resources, steep reductions in greenhouse gas emissions, advancement of beneficial electrification technologies and participation in organized power markets in the West."[106]

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99 Tri-State, Responsible Energy Plan 2022 Progress Highlights, 2022, p. 1.

100 Craig Generating Station is jointly-owned by Tri-State, PacifiCorp, Platte River Power Authority, Salt River Project, and Xcel Energy - Colorado. *See* https://tristate.coop/craig-station-unit-2-owners-announce-retirement-date-sept-30-2028, July 2020.

101 S&P Global, Market Intelligence LLC., Laramie River Station Power Plant Profile.

102 S&P Global, Market Intelligence LLC., Springerville Power Plant Profile.

103 Tri-State, 2020 Integrated Resource Plan/Electric Resource Plan, Volume II, 2020, p. 81.

104 Tri-State, 2020 Integrated Resource Plan/Electric Resource Plan, Volume I, 2020, p. 139.

105 Tri-State, Responsible Energy Plan 2022 Progress Highlights, 2022, p. 2.

106 *Ibid.*

2. Basin Electric Power Cooperative

Basin Electric Power Cooperative (Basin Electric) is a generation and transmission (G&T) cooperative that serves 3 million electric customers through 131 member rural cooperatives across 9 western states.[107] As of 2021, Basin Electric owned 4,279 MW of generation.[108]

Coal is Basin Electric's largest resource type by capacity, providing 2,859 MW (39% of the portfolio), following by wind (1,776 MW, 24%) and natural gas (1,494 MW, 21%).[109] Though still the primary fuel, coal-fired generation has decreased from 85% of Basin Electric's capability in 2000 to 39% in 2021.[110] This is a significant shift, though it is driven by Basin Electric's expanding generation portfolio (instead of reductions in coal plant capacity).[111]

Recently, Basin Electric announced that they will own 30% of Nemadji Trail Energy Center (NTEC), a gas combined-cycle plant. In the supplemental environmental analysis submitted for NTEC, the plant is described as "displacing coal generation and requiring less frequent operation of less efficient fossil fuel units," leading to a reduction in emissions of over 1 million tons per year.[112] Basin Electric also has plans to bring on more than 300 MW of solar from the Custer River project and other resources planned to be operational by 2025.[113]

Though Basin Electric is expanding its gas and renewable generation, it has not announced a plan to retire any of the four coal units. In the Basin Electric 2020 Annual Report, the then-CEO Paul Sukut wrote:

> Many of our coal-based power plants have a lot of undepreciated value on the books. We're evaluating the role these plants will play in the transition to a low-carbon

[107] Colorado, Iowa, Minnesota, Montana, Nebraska, New Mexico, North Dakota, South Dakota, and Wyoming.

[108] Basin Electric, About Us: Resource Profile, 2022.

[109] The rest of Basin Electric's mix consists of market purchases, hydro, oil/diesel/jet fuel, and recovered energy.

[110] Including Basin Electric's owned generation and purchased generation capability.

[111] Basin Electric's coal-fired capacity actually increased in that window from 2,400 MW to 2,859 MW, with the startup of the 405 MW Dry Fork Station in Wyoming in 2011.This growth was outpaced by wind and gas resources that previously did not exist. The utility did not add any more coal capacity since 2011. *See* 2021 Annual Report, Basin Electric Power Cooperative, p. 9.

[112] Dairyland Power Cooperative, Supplemental Environmental Assessment for the Nemadji Trail Energy Center Project, p. 3–25.

[113] Basin Electric Power Cooperative, 2021 Annual Report, p. 12.

> environment and how best to efficiently and effectively recover their undepreciated value over their remaining useful lives as we become less reliant upon them.[114]

At its 2022 Annual Meeting, Basin Electric's Vice President for Government Relations Tyler Hamman highlighted the benefits of the IRA for Basin Electric and other cooperatives.[115] Specifically, Mr. Hamman highlighted the importance of IRA provisions related to direct pay for renewable energy credits in allowing Basin Electric to fully take advantage of the tax credits, a "game changer" for renewable energy development.

C. Independent Power Producers

1. Vistra

Vistra is an independent power producer with 39 GW of generation assets including gas, nuclear, coal, solar, and battery storage. Active in the ERCOT, PJM, and MISO markets, Vistra's generation portfolio historically consisted of a large share of coal-fired power plants. In 2020, the company launched Vistra Zero, an initiative to transition away from fossil fuels and expand its zero-carbon generation portfolio, which includes nuclear, solar, and storage. The company aims to achieve 60% CO_2 equivalent reduction by 2030 compared to 2010 level, and net zero emissions by 2050.[116] Vistra plans to retire most of its coal facilities by 2027. The initiative continues a wider trend: since 2010, Vistra and its subsidiaries have retired or are planning to retire more than 19 GW of coal and natural gas plants.[117] The company cites the following factors that influenced its decisions to retire its coal assets (see Figure 14 below):

- Sustained low wholesale power prices;
- Oversupplied renewable generation market;
- Low natural gas prices;
- Low capacity prices;
- Grid operators' market rules;

[114] POWER, Three Coal-Heavy Utilities Team Up on New Gas-Fired Power Plant, September 30, 2021.

[115] Government Relations Report, Basin Electric 2022 Annual Meeting, 2022.

[116] Vistra, Climate Action 2030-2050, 2020.

[117] Vistra Corp., Vistra Accelerates Pivot to Invest in Clean Energy and Combat Climate Change, September 29, 2020.

- States' environmental regulations (e.g., Illinois Pollution Control Board's Multi-Pollutant Standard rule); and
- Federal regulations.

Due to worsening economic conditions for coal-fired plants, Vistra accelerated the retirement schedule for some of its coal plants in recent years. For example, the 1,300 MW Zimmer Power Plant located in Ohio was "economically challenged" and was slated to retire no later than 2027.[118] However, after the plant failed to clear PJM's capacity market auction in 2021, Vistra decided to shutter the plant in the same year.[119]

Vistra attributes the economic decline of its coal fleet to state subsidies for renewable energy and nuclear power, existing and future environmental regulations and "regulatory and political headwinds."[120] However, Vistra's former president and CEO Curt Morgan previously noted that the pressure facing the company's coal fleet was almost entirely markets-based. "The one key about coal plants is that they're closing naturally because natural gas prices are low, which then turns power prices low," said Mr. Morgan in 2020. "Even though the States are anti-coal, what is interesting is that's not why coal plants are shutting down."[121,122]

Looking forward, Vistra anticipates the IRA to provide support for the company's renewables and energy storage portfolio.[123]

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118 "These plants, especially those operating in the irreparably dysfunctional MISO market, remain economically challenged. Today's retirement announcements are also prompted by upcoming Environmental Protection Agency filing deadlines, which require either significant capital expenditures for compliance or retirement declarations." *See* Vistra Corp. News Release, Vistra Accelerates Pivot to Invest in Clean Energy and Combat Climate Change, September 29, 2020.

119 Vistra Corp., News Release, Vistra Accelerates Closure of Ohio Coal Plant to Mid-2022, Years Earlier Than Planned Company Continues its Transition Away from Coal with Retirement of Zimmer Power Plant, July 19, 2021.

120 UtilityDive, Vistra to retire 6.8 GW coal, blaming 'irreparably dysfunctional MISO market', September 30, 2020.

121 *Ibid.*

122 Vistra also reported a lower Earnings Before Interests, Taxes, Depreciation, and Amortization (EBITDA) owing to lower coal generation volumes stemming from "industry-wide fuel delivery challenges, lower capacity revenue, and higher-than-expected migration of customers to default service providers, partially offset by strong operational performance during periods of higher pricing and higher margin from Vistra Zero renewable sites." Vistra Corp., News Release, Vistra Reports Third Quarter 2022 Results; Initiates 2023 Ongoing Operations Adjusted EBITDA Guidance, November 4, 2022.

123 *Ibid.*

FIGURE 17: VISTRA'S RETIRED AND RETIRING COAL PLANTS[124]

Plant Name	Nameplate Capacity (MW)	State (RTO)	Retirement Year	Drivers/Quotes
Big Brown	1,200	PA (PJM)	2018	Challenging economics, including low natural gas prices[125]
Sandow	1,100	TX (ERCOT)	2018	Challenging economics, including low natural gas prices
Monticello	1,800	TX (ERCOT)	2018	
Northeastern Power Company	51	PA (PJM)	2018	"Uneconomic operations and negative financial outlook"[126]
J.M. Stuart	1,755	Ohio (PJM)	2018	"In response to declining market conditions"[127]
Killen Stations	618	Ohio (PJM)	2018	
Coffeen Power Plant	915	IL (MISO)	2019	Compliance with Illinois Pollution Control Board's Multi-Pollutant Standard rule, plant economics, federal regulations and the grid operator's market rules;[128] unfavorable economic conditions in the MISO market[129]
Duck Creek Power Plant	425	IL (MISO)	2019	
Havana Power Plant	434	IL (MISO)	2019	
Hennepin Power Plant	294	IL (MISO)	2019	
Zimmer Power Plant	1,300	OH (PJM)	2022	Plant economics[130]

[124] Vistra Corp. News Release, Vistra Accelerates Pivot to Invest in Clean Energy and Combat Climate Change, September 29, 2020.

[125] Vistra stated that both the Big Brown and Sandow coal plants were "economically challenged in the competitive ERCOT market." "Sustained low wholesale power prices, an oversupplied renewable generation market, and low natural gas prices, along with other factors" contributed to the retirement decision. According to the company, "the economics of operating Big Brown [did] not make it a sustainable option for [their] fleet…" and "the standalone economics of the Sandow complex no longer support continued investment in the site in this low wholesale power price environment." *See* Vistra Corp. Press Release, Luminant to Close Two Texas Power Plants: Decision a Result of Challenging Plant and Market Economics, October 17, 2017.

[126] Luminant News Release, Luminant to Close 51-Megawatt Power Facility in PJM Electric Market, August 24, 2018.

[127] AES Ohio, "DPL Inc. announces the retirement of the J.M. Stuart and Killen Station power plants," May 31, 2018.

[128] Vistra Energy News Release, Vistra Energy to Close Four Illinois Power Plants, August 21, 2019.

[129] EnergyCentral, Vistra Energy to close Hennepin Power Plant, August 25, 2019.

2. NRG Energy

NRG Energy (NRG) is an independent power producer with 18 GW of generation capacity across 25 facilities, serving 5.5 million customers. NRG's U.S. assets are located in Texas, Illinois, Maryland, California, Delaware, and New York. The company's capacity mix includes natural gas (46%), coal (44%), nuclear (6%), and renewables (1%).[131]

In 2019, NRG introduced a target to reduce emissions by 50% from 2014 levels by 2025 and to be net-zero by 2050.[132] A key element of the company's decarbonization strategy involves using carbon capture and storage (CCS) to reduce emissions from coal, which the company considers a "reliable, abundant, and inexpensive source of energy." In fact, NRG invested $1 billion, with government funding support, to build Petra Nova. However, Petra Nova operated for three years before suspending operations because of high costs and challenging economic conditions.[133,134] The economics of CCS can change depending on policy. As an example, the IRA provides additional incentives for CCS under tax credit 45Q.

At its 2022 Shareholder Meeting, NRG announced a plan to retire 1.6 GW of PJM coal and 6 GW of fossil generation across the portfolio.[135,136] Their retirement decision in PJM was tied closely to results of PJM's Base Residual Auction in June 2021 for the 2022/2023 delivery year, which cleared around half the price of the previous auction.[137]

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130 "The early retirement decision comes after the plant failed to secure any capacity revenues in the latest auction held in May by the grid operator, PJM… The Zimmer coal-fueled power plant has recently struggled economically due to its configuration, costs, and performance. The PJM capacity revenues are critical to Zimmer, and unfortunately, without them, the plant simply doesn't make money." *See* Vistra Corp. News Releases, Vistra Accelerates Closure of Ohio Coal Plant to Mid-2022, Years Earlier Than Planned: Company Continues its Transition Away from Coal with Retirement of Zimmer Power Plant, July 19, 2021.

131 NRG Energy, 2021 Sustainability Report, p. 50.

132 *Id.*, p. 10.

133 NRG completed the Petra Nova carbon capture project in 2016 at the WA Parish Generating Station. While operating, NRG sold the carbon captured at Petra Nova for use in enhanced oil recovery. Petra Nova suspended operations in May of 2020 because the decline in oil prices and the resulting decrease in revenues from sales of captured carbon. Petro Nova remains the only completed large-scale carbon capture project in the US.

134 NRG Energy, Coal: Examining how we use Earth's oldest resource.

135 S&P Global, Market Intelligence, LLC., NRG Announces retirement of about 1,600 MW of coal capacity in PJM, 2021.

136 NRG Energy, 2022 Annual Meeting of Stockholders and Proxy Statement, 2022, p. 49.

137 The retirement plan included the 410 MW Indian River Unit 4 (scheduled to retire in May of 2022). Shortly after the retirement announcement, PJM responded saying that it identified reliability violations associated with the deactivation. As of the 2022 10-Q filing, NRG was in settlement negotiations contesting the reliability must-run (RMR) rate schedule that NRG filed in response to PJM. *See* NRG Energy, Form 10-Q, 2022, pp. 28, 41

NRG is planning to retire its coal assets located outside of Texas by 2028 and installing the necessary control equipment at its two Texas-based coal-fired units, purportedly in anticipating the release of the EPA's proposal to revise the Effluent Limitations Guidelines (ELG) rule in early 2023.[138]

The company has stated that the Illinois Climate and Equitable Jobs Act (CEJA), passed in September 2021, and the IRA have also affected the company's resource plan. Targeting 100% clean energy by 2050, CEJA provides incentives to transition coal plants in to clean energy through the Coal-to-Solar Energy Storage Grant Program. NRG was notified by the Illinois Department of Commerce and Economic Opportunity that if it developed battery storage at the retired Waukegan and Will County sites outside of Chicago, it would be eligible for just under $160 million in grants.[139] According to NRG, the increased and extended clean energy tax credits in the IRA "should push solar, wind and battery development across all markets in the U.S."[140] The company expresses similar sentiments in its public report, which emphasizes the role the IRA plays in providing more certainty on the investment decisions for renewable energy. As a result of more renewables coming online, there are likely to be technological and efficiency advances that further improve the cost-effectiveness of renewables.[141]

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[138] NRG Energy, Form 10-Q, 2022, p. 37.

[139] *Id.*, p. 39.

[140] NRG Energy, NRG Energy, Inc. (NRG) Q3 2022 Earnings Call Transcript, November 7, 2022.

[141] NRG Energy, Form 10-Q, 2022, p. 39.