DECEMBER 2025

ENERGY VENTURES ANALYSIS

Understanding the True Cost of Replacing Existing Coal Plants with New Renewables

Prepared for:

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ENERGY VENTURES ANALYSIS

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Executive Summary

Over the next decade, the United States faces a dual challenge of rising electricity demand and the accelerated retirement of dispatchable coal generation. This analysis by Energy Ventures Analysis (EVA) compares the **average annual ownership and operating cost** of continuing to run the retiring U.S. coal fleet (41.7 GW through the end of 2028) against the cost of replacing it with new renewable energy resources—standalone wind or solar, and hybrid configurations paired with battery storage or simple-cycle natural gas combustion turbines.

Using assumptions from the **National Renewable Energy Laboratory's (NREL) 2024 Annual Technology Baseline** and **Lazard's 2025 LCOE+** analysis, EVA evaluated the capital, operating, and fuel costs associated with each replacement scenario. The analysis also incorporated **effective load-carrying capability (ELCC)** metrics to ensure that replacement capacity provides an equivalent capacity contribution to the retiring coal fleet during periods of peak demand, especially during winter storms when renewable generation is limited by wind or solar resource availability. However, while ELCC provides a consistent measure for comparing resource adequacy across different technologies, it does not fully account for operational flexibility or dispatchability differences between coal and variable renewable resources.

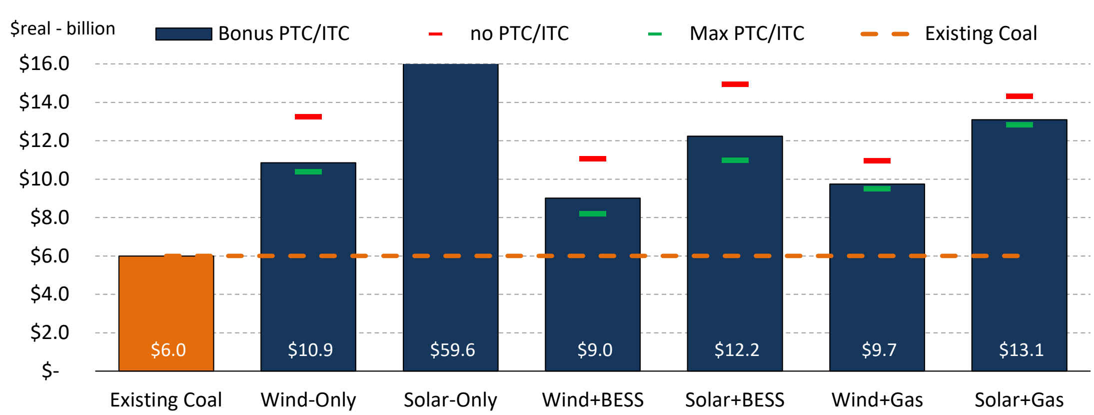
The findings indicate that while new renewable projects remain the least-cost options for new construction, **continuing to operate the existing coal fleet is far more cost-effective than replacing it** when measured on a 30-year average annual cost basis. The **average annual inflation-adjusted cost** to operate and maintain the retiring coal fleet is approximately **$6 billion**. In contrast, even under the most favorable subsidy conditions (a maximum PTC of $33/MWh and a 50% ITC), the lowest-cost replacement option—**a hybrid wind-plus-battery project**—would cost over **$8.2 billion per year**, or about **$2.2 billion (37%) more**. A standalone solar replacement, even at the same maximum PTC rate, would cost more than **$57 billion per year**, nearly **ten times higher** than continuing coal operations.

These results underscore two central findings:

- **Reliability carries a significant implicit cost**. Coal units provide stable output during winter peaks, whereas solar offers no contribution during critical hours, while wind remains highly variable.
- **Federal incentives alone cannot offset the superior reliability characteristics** associated with dispatchable resources. Despite aggressive tax credits, renewables cannot match the cost and reliability performance of existing coal units on an equivalent-service basis.

In conclusion, **retaining and operating the existing coal fleet through the 2040s remains the most cost-effective pathway for maintaining grid reliability** under current and expected market conditions. Fully replacing these plants with renewables, even under the most favorable policy incentives, would require significantly greater investment and would likely result in higher electricity costs for U.S. consumers.

EXHIBIT ES-1: ***AVERAGE ANNUAL COST – EXISTING RETIRING COAL FLEET VS. NEW RENEWABLE ENERGY***



Source: Energy Ventures Analysis, Inc. | Note: Bonus PTC/ITC = $27.50/MWh & 30%; Max PTC/ITC = $33/MWh & 50%

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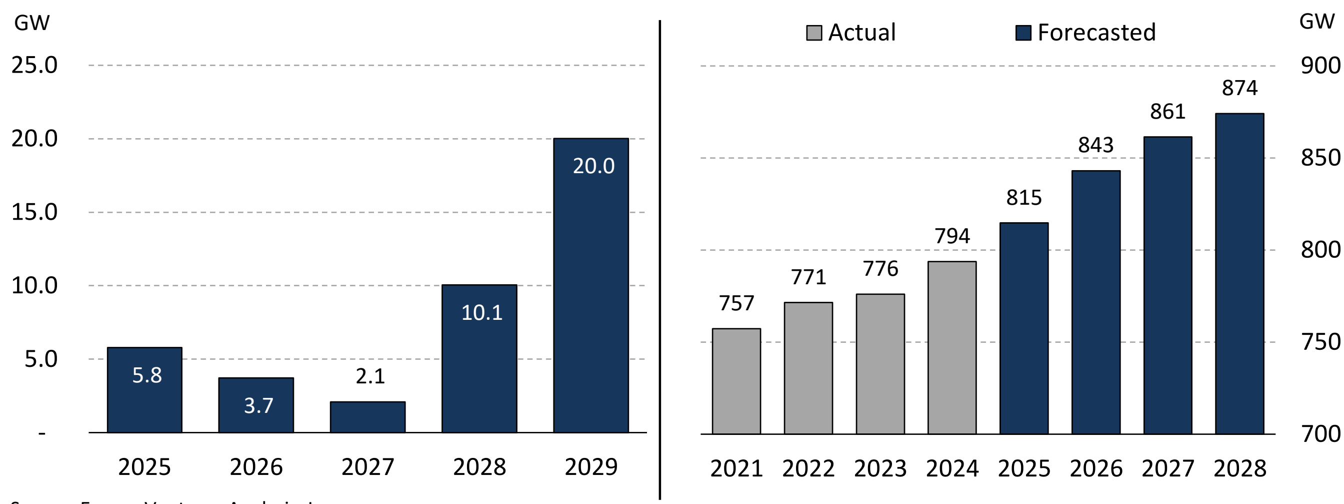
Introduction

Since taking office in January 2025, President Trump and his administration have been focused on addressing the looming energy crisis that is likely to affect the U.S. electric power sector over the next five years. By 2028, U.S. peak electricity demand is projected to increase by over 80 GW from 2024 levels to almost 875 GW. At the same time, almost 42 GW of coal plants are planned for permanent retirement, as shown in **EXHIBIT *2***.

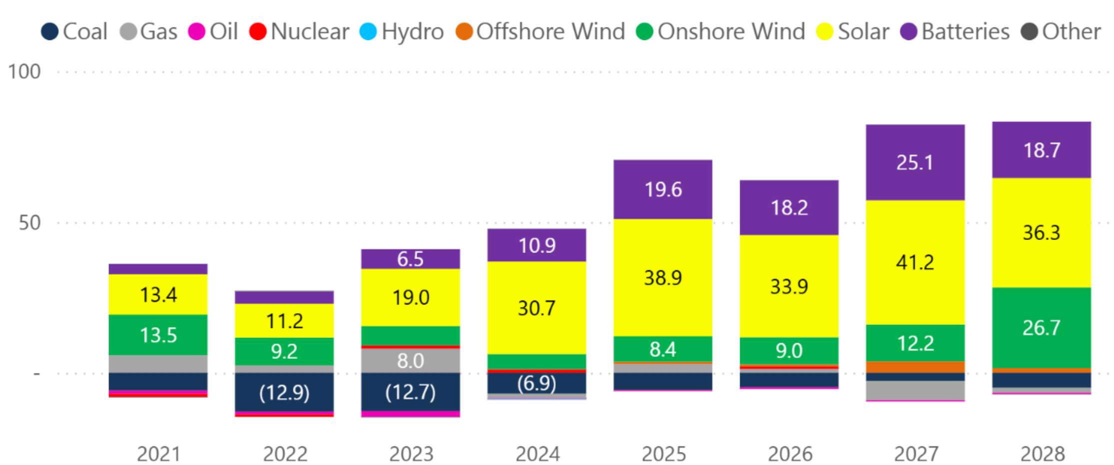
EXHIBIT 2: ANNOUNCED U.S. COAL RETIREMENTS[1] (LEFT) & FORECASTED U.S. PEAK ELECTRICITY DEMAND (RIGHT)



Source: Energy Ventures Analysis, Inc.

According to the current interconnection requests filed with the seven major U.S. independent system operators[2], as well as individual electric utility plans, the retiring coal plants are being replaced overwhelmingly with new solar, wind, and battery storage projects, as shown in **EXHIBIT *3***.

EXHIBIT 3: ANNUAL NET U.S. CAPACITY ADDITIONS/(RETIREMENTS) BY FUEL TYPE (GW)



While it is clear that new wind, solar, and battery storage projects are the most cost-effective options for new generation, primarily due to federal and state subsidies like the Production and Investment Tax Credits (PTC/ITC) and the substantial backlog of new natural gas combustion turbine orders that significantly raise costs for new turbines, the question remains

[1] Year shown refers to first full year the retiring coal capacity is offline, i.e., end-of-2028 retirements are included in 2029, the first full year of retirement

[2] Based on the September 2025 interconnection request databases of ISONE, NYISO, PJM, MISO, SPP, ERCOT, and CAISO

whether continuing to operate the coal plants scheduled for retirement or replacing them with new electric generating resources is the best financial decision for U.S. ratepayers. This analysis aims to compare the operating costs of existing coal plants with those of installing and running new generating resources to provide the same reliability and operational benefits for the U.S. electric grid. It does so by calculating the average annual ownership and operating cost of the retiring coal fleet (41.7 GW) against new standalone wind and solar projects, as well as wind and solar hybrid projects with either battery energy storage systems (BESS) or simple-cycle natural gas combustion turbines.

Methodology

When replacing existing power plants with new ones, electric utilities must ensure that the new generating resource produces at least as much electricity as the plant being retired, while also being able to meet current and projected peak demand. For this analysis, we first need to determine the amount of electricity generated by the retiring coal units and their role in meeting peak electricity demand.

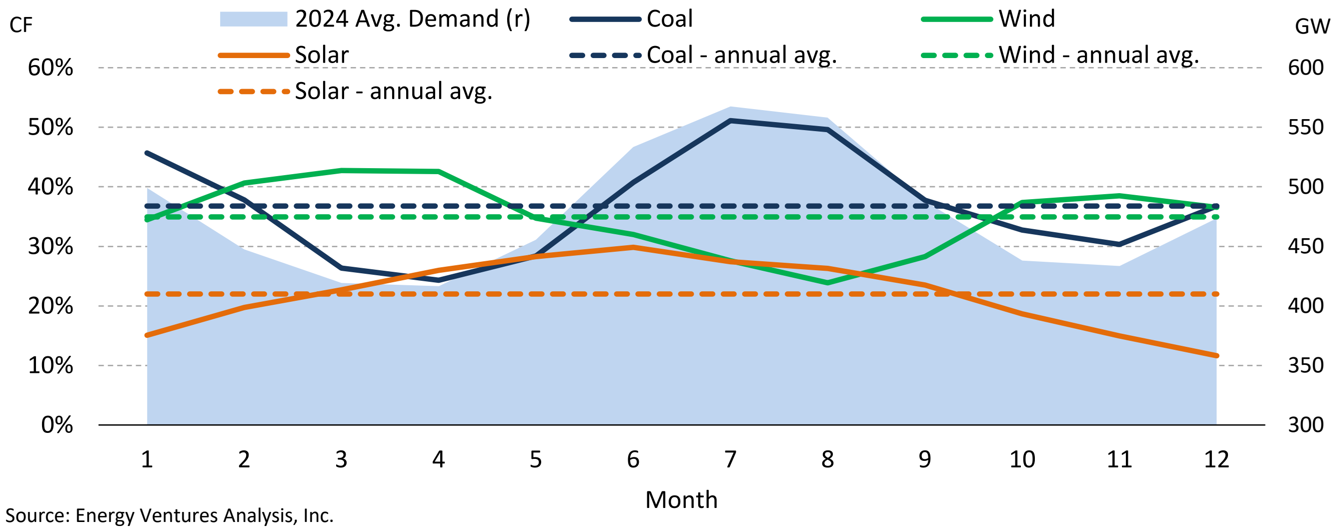
Between 2025 and 2029, 79 coal-fired electric generating units at 46 power plants have either been retired or are scheduled for permanent retirement. These 79 units range from 25 MW to 1,300 MW, totaling over 41,600 MW, with an average size of approximately 528 MW, as shown in **EXHIBIT *4***.

EXHIBIT 4: SCHEDULED COAL RETIREMENTS BY REGION

Region	No. of Units	Avg. Capacity (MW)	Total Capacity (MW)
PJM	16	819	13,108
MISO	23	495	11,377
Southeast	18	432	7,776
WECC	11	437	4,805
SPP	6	426	2,556
ERCOT	3	533	1,598
ISONE	2	230	459
U.S. Total	**79**	**528**	**41,680**

Over the last four and a half years, individual utilization rates of the 79 coal units have varied widely, from less than 1% to over 95%, while fleetwide averages ranged from a high of 43% in 2021 to a low of 31% in 2023, with an average of 37%. The primary reason for the significant variation in utilization rates among units and years is coal's growing role in balancing hourly, daily, and seasonal fluctuations in electricity demand and supply from renewable sources such as wind and solar. **EXHIBIT *5*** shows the monthly capacity factors for wind and solar compared to the retiring coal plants, along with their annual averages since 2021.

EXHIBIT 5: CAPACITY FACTORS FOR WIND, SOLAR & RETIRING COAL VS. 2024 AVG. ELECTRIC DEMAND



Source: Energy Ventures Analysis, Inc.

Although retiring coal plants and U.S. wind projects have similar fleet-wide annual capacity factors averaging around 35-37%, their monthly capacity factors have varied considerably. Wind projects produce the most electricity in spring and fall when weather fronts pass through the country. During the summer months, more stable weather patterns lead to lower wind output. In contrast, solar capacity factors depend on daylight hours, peaking in June and dropping in December. Additionally, because of their dispatchability, coal plant utilization rates match monthly electricity demand, which peaks in winter and summer due to heating and cooling needs. However, for simplicity, this analysis only replaces the average annual generation of the retiring coal fleet without matching monthly totals. Over the last four years, the annual average generation was approximately 134,357 GWh.

As mentioned, utilities also need to install sufficient new capacity to meet their peak electricity demand. Utilities and regional transmission operators use the so-called "Effective Load-Carrying Capability", which measures a resource's contribution to reliability based on the incremental quantity of load that can be satisfied by adding the resource to the grid. In other words, ELCC represents the percentage of a unit's installed capacity that can be counted on during peak electricity demand hours.

Although most electric power regions across the U.S. traditionally see peak electricity demand during the hottest days of summer, recent market developments are raising greater reliability concerns during the coldest days of winter in extreme cold weather events. A shrinking U.S. coal fleet, combined with increased reliance on natural gas and solar generation and the electrification of residential and commercial heating systems, is causing significant stress during extreme cold weather and leading to widespread power outages, as seen during Winter Storm Uri in Texas in 2021.

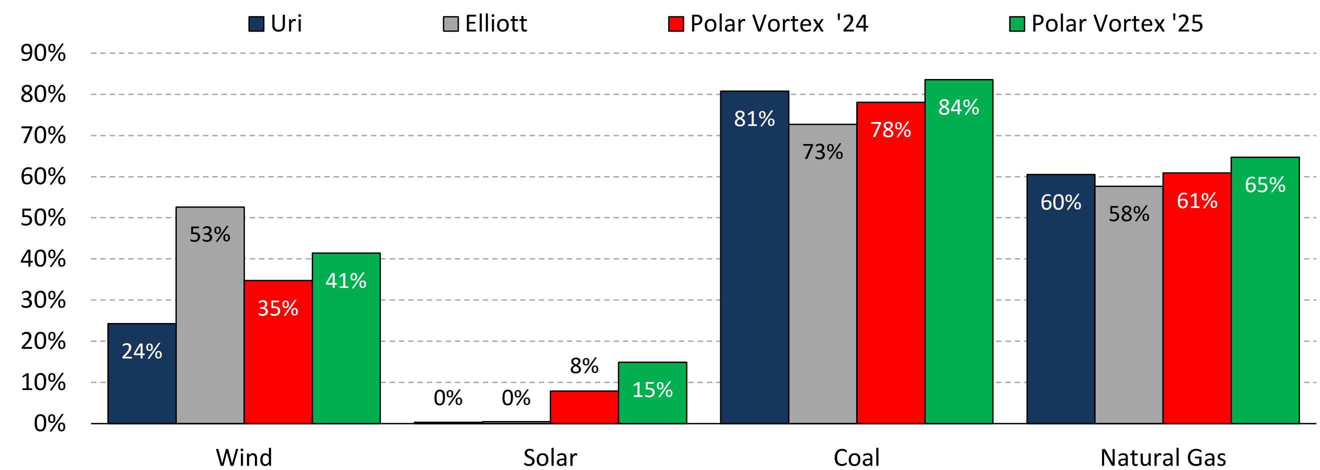
EXHIBIT *6* shows the hour of peak electricity demand during the last four major winter storms for the Eastern U.S. (excluding New York and New England).

EXHIBIT 6: PEAK ELECTRICITY DEMAND HOURS DURING THE LAST FOUR WINTER STORMS

	Uri	Elliott	Polar Vortex '24	Polar Vortex '25
PJM	n/a	8 PM *(12/23/22)*	9 AM *(1/17/24)*	9 AM *(1/22/25)*
Southeast	n/a	7 AM *(12/24/22)*	8 AM *(1/21/24)*	8 AM *(1/22/25)*
MISO	8 PM *(2/15/21)*	7 PM *(12/23/22)*	10 AM *(1/16/24)*	8 PM *(1/25/25)*
SPP	9 AM *(2/15/21)*	8 PM *(12/22/22)*	7 PM *(1/14/24)*	8 AM *(1/21/25)*
ERCOT	8 PM *(2/14/21)*	9 AM *(12/23/22)*	8 AM *(1/16/24)*	10 AM *(1/20/25)*

Unlike peak electricity demand hours during the summer, which occur primarily in the mid to late afternoon, peak demand hours during winter storms occur either late in the evening after sunset or early in the morning right around sunrise. As a result, solar output during winter peak electricity demand hours has been almost non-existent during the last four winter storms, as shown in **EXHIBIT *7***.

EXHIBIT 7: ACTUAL CAPACITY FACTOR DURING THE LAST FOUR WINTER STORMS BY FUEL TYPE



Source: Energy Ventures Analysis, Inc.

Capacity factors for wind projects have also varied significantly between winter storms, ranging from a low of 24% during Winter Storm Uri to a high of 53% during Winter Storm Elliott. Meanwhile, coal and natural gas resources have maintained relatively stable utilization rates during these events, with coal plants averaging nearly 80% of their installed capacity over the last four storms. The lower utilization of natural gas power plants during these events is mainly due to a lack of natural gas supply, as it is also heavily used for residential and commercial heating during these times.

Therefore, using the average coal plant utilization rate during the last four winter storms, the retiring coal fleet of 41,600 MW provides about 32,835 MW of reliable electricity during peak winter storms. Due to its lower capacity factor, 85,821 MW of new wind projects are needed to provide the same amount of reliable electricity. Lastly, due to its near absence during peak electricity demand hours during winter storms, almost 560,000 MW of new solar capacity is needed to provide the same amount of reliable electricity.

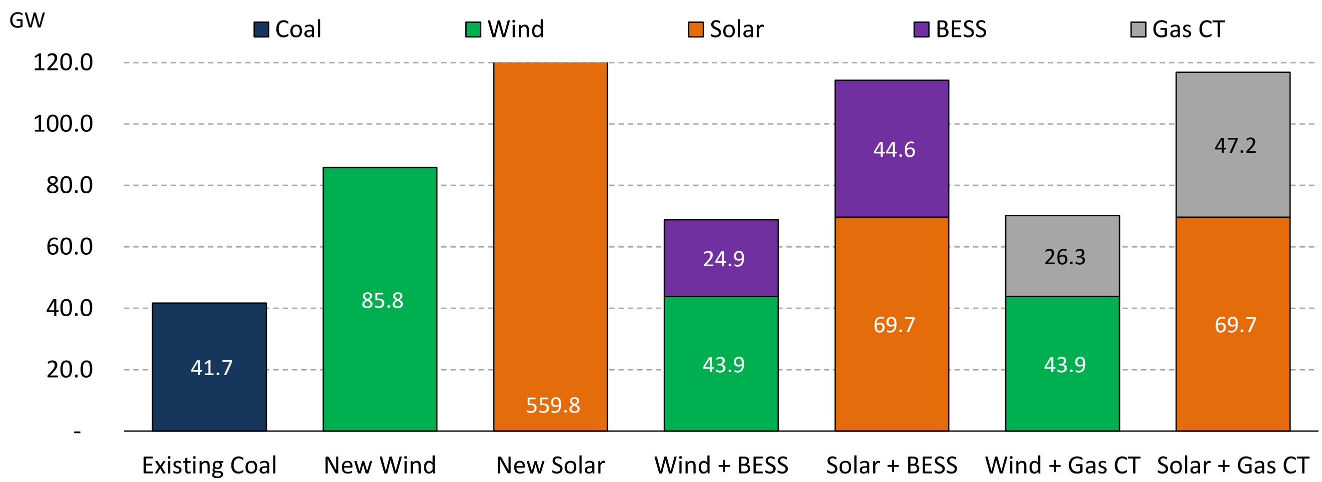
When evaluating wind and solar hybrid energy systems, this analysis assumes that the wind and solar capacity is sized to meet the annual generation of the retiring coal fleet (134,357 GWh on average over the last four years), while the backup generating capacity (i.e., battery storage or simple-cycle natural gas combustion turbine) is sized to meet the remaining capacity needed after subtracting the capacity contribution of the wind and solar projects.[3] Due to the limited availability of real-world data, this analysis assumes a 64% capacity contribution for battery storage projects, based on the most recent ELCC analyses conducted by PJM, SPP, CAISO, and Duke Energy. **EXHIBIT *8*** shows the resulting capacity requirements for each replacement category.

Notably, while ELCC provides a consistent measure for comparing resource adequacy across different technologies, it does not fully account for operational flexibility or dispatchability differences between coal and variable renewable resources. Therefore, this method likely underestimates the reliability of dispatchable generation and overstates the equivalence of renewable replacements during extreme system conditions, as it depends on prevailing wind speeds and solar radiation during the winter storm event, both of which are beyond the control of resource owners. Conversely, since coal plants

[3] For example, 43,889 MW of wind @ 35% annual CF = 134,357 GWh. 32,836 MW of peak capacity requirement – (43,889 MW * 38% wind ELCC) = 16,044 MW remaining. 24,893 MW of BESS * 64% battery ELCC = 16,044 MW.

maintain multi-week on-site fuel storage, any reliability and availability issues are almost entirely within the control of the coal plant owner.

EXHIBIT 8: REPLACEMENT CAPACITY REQUIREMENTS BY CATEGORY



Source: Energy Ventures Analysis, Inc.

After establishing the capacity needed to replace the retiring coal fleet, the following steps include calculating the financing and operating costs of the new capacity relative to continuing to operate the retiring coal fleet. This analysis leverages the capital cost, fixed and variable operating and maintenance cost assumptions published in the National Renewable Energy Laboratory's (NREL) 2024 Annual Technology Baseline (ATB) [4]and Lazard's 2025 Levelized Cost of Energy+ (LCOE+)[5] analysis. Both publications are widely referenced across the industry. The relevant cost assumptions are summarized in **EXHIBIT *9***.

EXHIBIT 9: COST ASSUMPTIONS FOR NEW REPLACEMENT CAPACITY

Company	Source	Technology	Size (MW/MWh)	Life	CapEx ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	H.R. (MMBtu/MWh)
NREL	2024 ATB	Solar	100	30	$ 1,486	$ 22.00	$ -	-
	moderate	Solar + BESS	100 + 60/240	30	$ 2,465	$ 63.00	$ -	-
		Wind	150	30	$ 1,680	$ 32.00	$ -	-
		BESS (4-hr)	60/240	30	$ 2,080	$ 48.00	$ -	-
		Gas Peaking	233	30	$ 1,228	$ 26.00	$ 7.00	9.72
Lazard	2025 LCOE+	Solar	150	35	$ 1,375	$ 12.50	$ -	-
	high-low avg.	Solar + BESS	100 + 50/200	35	n/a	n/a	n/a	n/a
		Wind	300	30	$ 2,100	$ 32.25	$ -	-
		BESS (4-hr)	50/200	20	34.5 / 217.5*	5.5*	$ -	-
		Gas Peaking	350	30	$ 1,300	$ 13.50	$ 4.25	10.70

** $/kW & $/kWh*

Additionally, this analysis assumes a $100/kW grid connection cost, consistent with assumptions included in NREL's 2024 ATB publication. However, this analysis does not include additional costs associated with regional transmission expansion, curtailment mitigation, or interconnection queue delays. These costs can vary significantly by region and project type. Excluding them provides a conservative estimate of renewable project costs relative to continued coal operation.

[4] https://atb.nrel.gov/electricity/2024/data
[5] https://www.lazard.com/media/eijnqja3/lazards-lcoeplus-june-2025.pdf

Lastly, for financing purposes, this analysis assumes a 30-year financing period for all new projects, including a 60/40 debt-to-equity ratio, an 8% cost of debt, a 12% return on equity, a 2.5% inflation rate, and a 40% combined federal and state effective tax rate, resulting in a weighted average cost of capital (WACC) of 5.64% in real terms.

For the retiring coal fleet's fixed O&M and non-fuel variable O&M costs, this analysis uses the average reported costs reported by regulated utilities to the Federal Energy Regulatory Commission (FERC) on the annual Form-1[6] for the last five years (2020-2024), adjusted for inflation. The resulting average fixed O&M and variable non-fuel O&M costs used in this analysis are $32.75/kW and $6.25/MWh, respectively. This analysis assumes no additional environmental compliance costs for continued coal operation beyond those reflected in historic O&M data. Although future regulatory changes, such as updates to EPA rules on greenhouse gas emissions, effluent limitations, or coal ash management, could affect cost outcomes, these impacts are uncertain and are therefore excluded from this analysis.

The $2.55 per MMBtu delivered coal cost is based on the five-year average delivered coal cost to the U.S. power sector based on regulated utility reporting on the Department of Energy's Energy Information Administration's (EIA) Form-923[7], also adjusted for inflation. Lastly, the fuel cost for the simple-cycle natural gas combustion turbine is based on the average natural gas price at Henry Hub during the month prior to and throughout the last four winter storms. Coal and natural gas prices are assumed to remain stable in real terms. However, it is important to note that there are significant regional differences in the prices of both delivered coal and natural gas, as well as long-term price stability for both, especially regarding future natural gas prices.

EXHIBIT *10* provides a detailed overview of the cost components used in this analysis for each category.

[6] https://www.ferc.gov/general-information-0/electric-industry-forms/form-1-electric-utility-annual-report
[7] https://www.eia.gov/electricity/data/eia923/

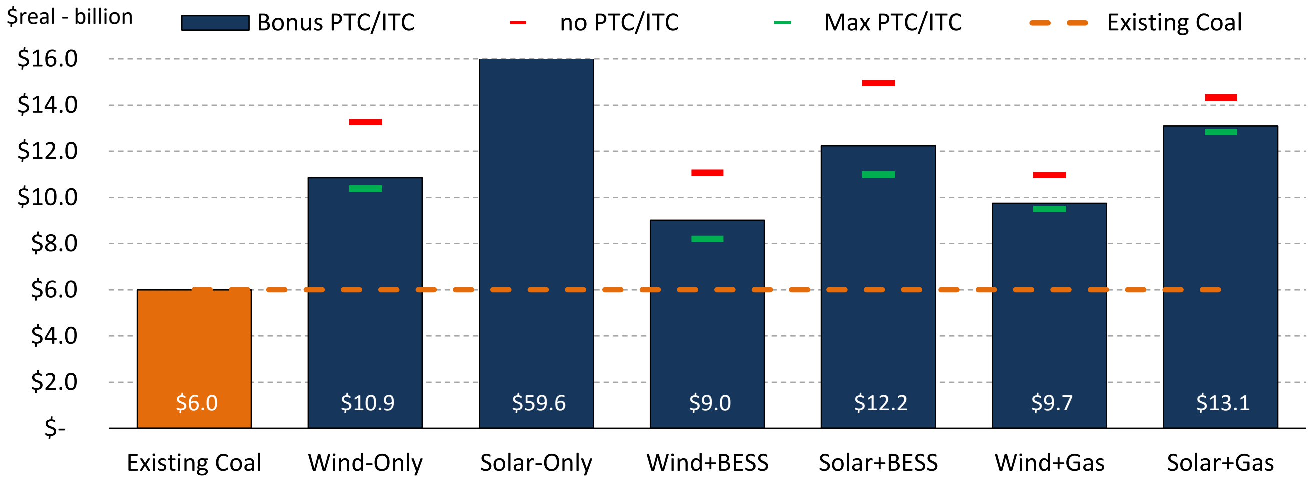
EXHIBIT 10: COST CALCULATION DETAILS

	Retiring Coal	New Wind	New Solar	Wind + BESS	Solar + BESS	Wind + Gas CT	Solar + Gas CT
Main Capacity (Cap 1 - MW)	41,680	85,821	559,806	43,889	69,673	43,889	69,673
Backup Capacity (Cap 2 - MW)	-	-	-	24,893	44,607	26,332	47,185
Annual Capacity Factor	37%	35%	22%	35%	22%	35%	22%
CT Capacity Factor						*1%*	*1%*
CT operating hours	-	-	-	-	-	*87.6*	*87.6*
Annual Generation (GWh)	**134,357**	**262,727**	**1,079,533**	**134,357**	**134,357**	**134,357**	**134,357**
ELCC Used for Cap 1	79%	38%	6%	38%	6%	38%	6%
ELCC Used for Cap 2				64%	64%	61%	*61%*
Combined Peak Capacity (MW)	**32,835.8**	**32,835.8**	**32,835.8**	**32,835.8**	**32,835.8**	**32,835.8**	**32,835.8**
Capital Cost ($mill)							
Cap 1	$ -	$ 162,202	$ 800,803	$ 82,949	$ 99,667	$ 82,949	$ 99,667
Cap 2	$ -	$ -	$ -	$ 37,147	$ 66,565	$ 33,284	$ 59,642
Grid Connect Cost ($mill)							
Cap 1		$ 8,582	$ 55,981	$ 4,389	$ 6,967	$ 4,389	$ 6,967
Cap 2				$ 2,489	$ 4,461	$ 2,633	$ 4,718
30% ITC Credit ($mill)							
Cap 1	n/a	$ -	$ -	$ -	$ -	$ -	$ -
Cap 2				$ (11,891)	$ (21,308)	n/a	n/a
Annualized Cap Cost ($mill/yr)	$ -	$ 11,932	$ 59,859	$ 8,040	$ 10,924	$ 8,611	$ 11,947
Fixed O&M ($mill/yr)							
Cap 1	$ 1,365.2	$ 1,339.0	$ 9,656.7	$ 1,339.0	$ 1,201.9	$ 1,339.0	$ 1,201.9
Cap 2				$ 871.3	$ 1,344.4	$ 823.2	$ 823.2
Heatrate (MMBtu/MWh)	11.09	n/a	n/a	n/a	n/a	10.21	10.21
Fuel Usage ('000 MMBtu)	1,489,699	n/a	n/a	n/a	n/a	23,551	42,202
Fuel Cost ($/MMBtu)	$ 2.55	n/a	n/a	n/a	n/a	$ 7.97	$ 7.97
Fuel Cost ($mill/yr)	$ 3,798.6	n/a	n/a	n/a	n/a	$ 187.7	$ 336.3
Non-Fuel VOM ($mill/yr)	$ 840.0	$ -	$ -	$ -	$ -	$ 13.0	$ 23.3
$27.50 /MWh PTC ($mill/yr)	$ -	$ (7,225.0)	$ (29,687.2)	$ (3,694.8)	$ (3,694.8)	$ (3,694.8)	$ (3,694.8)
Total Annual Cost (incl. PTC/ITC - $mill)	**$ 6,004**	**$ 6,046**	**$ 39,829**	**$ 6,556**	**$ 9,775**	**$ 7,279**	**$ 10,636**
30-yr Average Annual Cost ($mill)	**$ 6,004**	**$ 10,863**	**$ 59,620**	**$ 9,019**	**$ 12,238**	**$ 9,742**	**$ 13,100**

Results

Using the assumptions and methodology presented in the previous section, the annual inflation-adjusted cost to operate and maintain the retiring coal fleet is approximately $6 billion.

EXHIBIT 11: AVERAGE ANNUAL COST – EXISTING RETIRING COAL FLEET VS. NEW RENEWABLE ENERGY



Source: Energy Ventures Analysis, Inc. | Note: Bonus PTC/ITC = $27.50/MWh & 30%; Max PTC/ITC = $33/MWh & 50%

EXHIBIT *11* shows the 30-year average annual inflation-adjusted ownership & operating costs for the six replacement categories under different ITC and PTC assumptions. To review, the 2025 One Big Beautiful Bill Act (OBBBA)[8] significantly restricts the availability of future ITC and PTC for new wind and solar projects, while ITC applicability for new battery storage projects remains unchanged from the 2022 Inflation Reduction Act (IRA)[9]. The ITC reduces the overall project cost by a specified percentage, including construction and grid connection costs, while the PTC provides a tax credit for each megawatt-hour generated by a qualifying resource for the next 10 years following the project's commercial start date. Additionally, the IRA also includes additional ITC and PTC bonuses if the project is located in an energy community or uses a specific amount of domestically produced materials. In this analysis, the 30-year average annual ownership and operating costs are based on either no PTC or ITC, the bonus rate of $27.50/MWh for PTC and 30% ITC, or the maximum PTC and ITC rates of $33/MWh and 50%, respectively.

Because of its much higher ELCC percentage during winter storms, all categories based on wind resources as the primary energy replacement are less expensive than their solar equivalents, despite higher initial capital costs. However, all categories under all ITC and PTC assumptions are much more costly than continuing to operate the retiring coal fleet. Even with the maximum ITC and PTC values available for the next 10 years, the 30-year average annual inflation-adjusted cost of the least expensive replacement category—a hybrid wind and battery storage project—is almost $2.2 billion (37%) more costly than the continued operation of the retiring coal fleet. Conversely, replacing the energy and reliability features of the retiring coal fleet with only solar projects would cost over $57 billion, even at the maximum PTC rate of $33/MWh, which is nearly ten times the annual cost of maintaining the retiring coal fleet.

The higher annual ownership and operating costs associated with renewable replacement scenarios shown in **EXHIBIT *11*** would ultimately be passed through to electricity customers under traditional cost-of-service regulation. Utilities recovering multi-billion-dollar increases in annual revenue requirements would do so through higher retail electricity rates, either immediately through rate adjustments or gradually through future rate cases. While the precise magnitude of rate impacts depends on regional regulatory frameworks, cost allocation methodologies, and the timing of cost recovery, the direction of impact is unambiguous: replacing the retiring coal fleet with new renewable resources would result in materially higher electricity bills for residential, commercial, and industrial customers. Additional analysis is

[8] https://www.congress.gov/bill/119th-congress/house-bill/1/text
[9] https://www.congress.gov/bill/117th-congress/house-bill/5376/text

recommended to quantify the likely rate effects for each region, account for differences in customer classes, and assess the broader economic implications of higher system costs.

Overall, continuing to operate the retiring coal fleet is more cost-effective than replacing it with new renewable energy projects, whether solo or hybrid, because coal plants have better reliability characteristics during extreme winter weather events. With U.S. peak electricity demand expected to increase by over 80 GW in the next three years, maintaining the existing coal fleet benefits grid reliability, especially during winter storms, and is also a more cost-effective option compared to replacing retiring coal plants with sufficient renewable capacity.