

COAL COST CROSSOVER 2.0

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EXECUTIVE SUMMARY

Coal generation is at a crossroads in the United States, or more precisely at a “cost crossover.” Due to rapid recent cost declines for wind and solar, the combined fuel, maintenance, and other costs of most existing coal-fired power plants are now higher than the all-in costs of new wind or solar projects. This report compares the economics of each coal plant in the U.S. against the expected economics of potential new wind and solar plants nearby, using publicly available data.

In 2019, 239 gigawatts (GW) of coal capacity was online in the U.S. Our research finds that in 2020, 72 percent of that capacity, or 166 GW, was either uneconomic compared to local wind or solar or slated for retirement within five years. Out of the 235 plants in the U.S. coal fleet, 182 plants, or 80 percent, are uneconomic or already retiring.

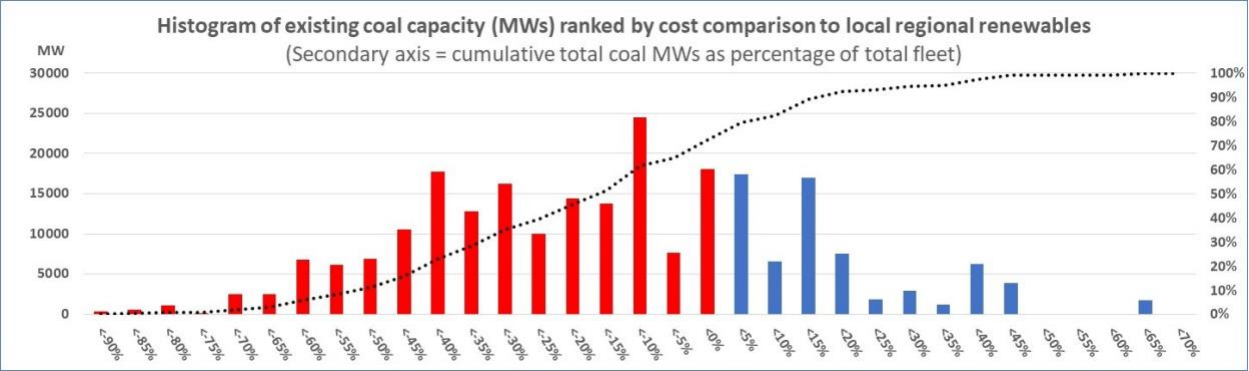


Figure 1. Aggregated plant capacity shown as percent difference between renewables LCOE and coal going-forward cost. The red bars indicate capacity where renewables are cost-competitive with coal and coal is deemed "uneconomic." The blue bars indicate capacity where coal is still cost-competitive with renewables and deemed "economic."

In the last two years, the cost of renewables has fallen even faster than the National Renewable Energy Laboratory’s forecast in its 2018 Annual Technology Baseline, and faster than predicted in the original “Coal Cost Crossover” report, which was prepared in partnership with Vibrant Clean Energy in 2019. In other words, the coal cost crossover trend continues to accelerate.

As pressure on the existing coal fleet continues to build, policymakers should seize the opportunity today to improve consumer, public health, and climate outcomes. Policies informed by cost analysis of coal and renewables and focused on competitive procurement and coal asset securitization can enable a transition that more effectively balances utility, consumer, environmental, equity, and community interests. Immense savings are available across the country, with ample opportunities to reinvest regionally in replacement clean energy portfolios.

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INTRODUCTION

Coal generation is at a crossroads in the United States, or more precisely at a “cost crossover.” Due to rapid recent cost declines for wind and solar, the combined fuel, maintenance, and other going-forward costs of existing coal-fired power plants are now higher than the all-in costs of new wind or solar projects. This cost crossover raises questions for state policymakers regarding the longevity, cost-effectiveness, and equity implications of coal plants’ continued operation. For example, what is the economic rationale for continued operation? And why shouldn’t coal plants be replaced with more cost-effective, carbon-free renewable power plants?

In 2019, Energy Innovation partnered with Vibrant Clean Energy to compile and analyze a 2018 dataset of capital, operations, and maintenance costs for coal, wind, and solar. We found that 62 percent of existing coal capacity was uneconomic compared to producing the same amount of energy locally from new wind or solar. The analysis projected that by 2025, more than 77 percent of the coal fleet would be unable to compete against new renewables.

In the last two years, the cost of renewables has fallen even faster than the National Renewable Energy Laboratory (NREL) forecast in its 2018 Annual Technology Baseline (ATB). Additionally, the federal investment tax credit has been extended for small and large solar systems at 26 percent through 2022, 22 percent for 2023, and 10 percent indefinitely thereafter for larger systems. Wind qualifies for a production tax credit (\$15 per megawatt-hour [MWh] for 2021). Meanwhile, the capacity factor of coal-fired power plants has dropped from 53 percent in 2017 to 40 percent in 2020,¹ affecting efficiency and causing fixed operational and ongoing capital maintenance costs to be spread over fewer hours. Given these trends, it is important to reexamine the extent of the coal cost crossover.

The coal cost crossover will not in and of itself cause existing coal plants to shutter—replacing coal plants with new wind and solar energy is much more complex in practice. The purpose of this report is to serve as a primer for stakeholders and policymakers demonstrating where the math points to cheaper options that could replace annual coal electricity generation at a savings to consumers. Any decision on how to proceed will require further modeling of grid impacts and resource portfolios that provide adequate reliability services.

The following report summarizes how the coal cost crossover dataset was compiled and calculated using publicly available data. In short, we started with the levelized cost of energy (LCOE) of new wind and solar, calculated the going-forward cost of existing coal, and compared those costs within specified geographic regions on a plant-by-plant basis. The report next summarizes the topline findings with a qualitative discussion of the data. Our policy recommendations offer policymakers real-world implementation suggestions on how to realize consumer savings, local investments, and societal benefits resulting from the coal cost crossover.

To increase access and visibility of these findings, we produced an [interactive data visualization feature](#) based on this analysis. We encourage readers to visit the page and share the graphics.

DATA METHODOLOGY

WIND AND SOLAR LCOE

We reviewed onshore wind and utility-scale solar resources using outputs from the Regional Energy Deployment System (ReEDS) model, developed by NREL.² ReEDS provides a detailed look at the North American electric power sector, including generation, transmission, and end-use technologies. Using ReEDS, we generated LCOE values (which are all-in estimates of the cost of energy output in megawatt-hours, taking into account the entire capital expenditure, operations, and maintenance costs) for onshore wind and utility-scale solar.³ We also used the 2020 values from the 2020 edition of the NREL Annual Technology Baseline to gather inputs for the ReEDS model, including capital cost and performance.⁴ Our LCOE values are evaluated within ReEDS regions, which we describe in greater detail below. After providing context for the geographic regions we assessed, we lay out how we calculated LCOEs and coal going-forward cost, and how we determined whether solar or wind could entirely displace annual coal generation at a given plant cost effectively.

UNDERSTANDING WIND AND SOLAR REGIONS

Within the contiguous U.S., ReEDS defines 134 “balancing areas.”ⁱ Within those balancing areas, there are 356 further subdivided regions, called resource supply regions, which characterize the wind resource quality and supply. Balancing areas never cross state lines nor straddle multiple regional transmission operators, and they roughly (but not completely) correspond to existing utility service territories and balancing area authorities.ⁱⁱ The utility-scale photovoltaic solar resource information is available at the “balancing area” level, and the utility-scale onshore wind resource information is available at the “resource supply region” level. The differing spatial resolution of these two categories is intended to reflect the granularity of the quality and quantity differences of specific resource supplies.

ⁱ Note that this is a ReEDS-specific term and should not be confused with the balancing areas regulated by the North American Electric Reliability Corporation and the Federal Energy Regulatory Commission.

ⁱⁱ “Balancing areas” are terms of art in ReEDS, defined by the model to approximate the rough location, geography, and number of authorities that actually managed and balanced the grid when the model was developed. Many utilities are also balancing authorities. NREL defines a balancing authority as, “The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time.” See, e.g., “Balancing Area Coordination: Efficiently Integrating Renewable Energy into the Grid,” National Renewable Energy Laboratory, <https://www.nrel.gov/docs/fy15osti/63037.pdf>.

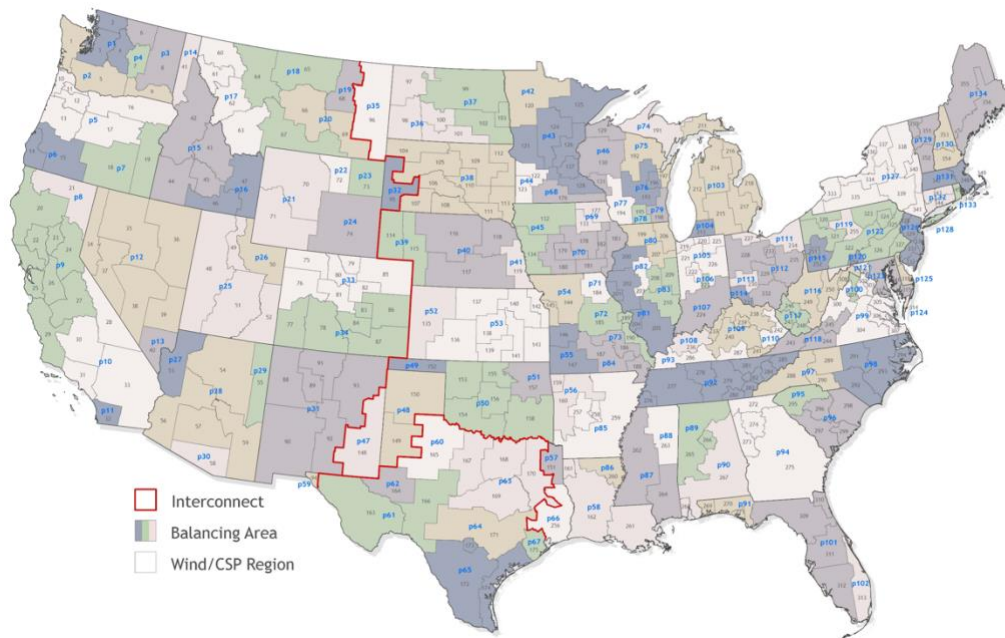


Figure 2. NREL map showing ReEDS regions, which includes 134 solar balancing areas and 356 wind resource supply regions.

The ReEDS model provides an irradiance profile for potential utility-scale solar sites for a 100 megawatt (MW) system within a balancing area. Factors that are incorporated into the potential wind evaluation include siting potential for a 100 MW system and mapping of hourly wind speeds.

We also used GIS software to match coal plants to their specific ReEDS regions for wind and solar and to calculate the approximate area of a given region, to give a sense of how “local” wind and solar resources are in this dataset. On average, the solar regions containing coal plants have an area of 28,000 square miles.ⁱⁱⁱ On average, the wind regions containing coal plants have an area of 9,500 square miles.^{iv} Assuming each region approximates a circular shape, the diameter of the largest solar region would be 360 miles (190 mile average), while the diameter of the largest wind region would be 240 miles (110 mile average). These are theoretical maximums—we do not model the exact physical location of the solar and wind resources vis-à-vis coal plants, but instead represent the LCOEs according to regional availability.

Based on our 2019 analysis with Vibrant Clean Energy, we expect that the vast majority of coal plants in the dataset have viable wind and solar resources located in close proximity. The 2019 analysis showed ample high-quality wind and solar project sites within 35 miles of every coal plant

ⁱⁱⁱ The solar regions containing coal plants have an area range of 2,000-102,000 mi², with a median of 22,000 mi².

^{iv} The wind regions containing coal plants have an area range of 1,150-45,200 mi², with a median of 6,600 mi².

in the U.S. Solar is particularly ubiquitous. Because solar irradiance does not vary widely by location,⁵ any suitable site near a coal plant will yield LCOEs close to those found in this updated dataset based on ReEDS regions. Wind capacity factors, however, vary widely within relatively small regions, making replacement with hyper-local resources particularly uncertain, especially because both large solar and wind require large expanses of available land. As such, the solar regions can be considered conservative, whereas the 110-mile average diameter for wind regions is a more accurate measure of wind proximity to coal plants.

CALCULATING LCOE

We calculated wind and solar LCOEs for comparison with each coal plant within the same ReEDS region. The LCOEs were weighted based on the resource supply in each resource class, prioritizing the highest-quality resource classes within a given ReEDS region until it completely displaced the 2019 EIA-reported annual generation for a given coal plant. So effectively, we found the weighted average LCOEs, which reflect the cost of replacing all 2019 coal generation at a specific plant based on resource cost and availability in the ReEDS region in which that plant is located.

From the ATB 2020 dataset, we used the 2022 cost inputs for solar and the 2023 inputs for wind to reflect the value of solar and wind when contracts are signed. This is the same timeline ReEDS uses to account for the impact of tax credits, for which developers can qualify by “commencing construction,” rather than finishing a given project.

Within the solar balancing areas and wind resource supply regions, ReEDS provides additional granularity on resource supply—up to 10 resource class bins for wind and seven for solar.^v The resource class bins are based on resource quality, so the respective LCOE value of each successive resource class bin scales directionally. ReEDS provides a supply curve by specifying how much wind or solar capacity might be sited in each resource bin. Regional cost estimates also include capital cost multipliers to account for different land, labor, and other project costs.

We incorporate the federal production tax credit of \$15/MWh for wind and 26 percent federal investment tax credit for 2021.^{vi}

The following charts show the resulting statistical LCOE values:

Solar (\$/MWh)		Wind(\$/MWh)	
Average	\$ 33.96	Average	\$ 36.49
Min	\$ 25.80	Min	\$ 20.95
Max	\$ 42.22	Max	\$ 70.87
Median	\$ 33.95	Median	\$ 33.58

Figure 3. The charts show the statistical solar and wind LCOE values for ReEDS regions that include coal plants, including the average, minimum, maximum, and median values.

^v Each resource class bin is further subdivided by distance from the transmission grid, to enable calculation of interconnection costs, but those were not included in this analysis.

^{vi} See the Appendix for more details on how we estimated realized wind PTC subsidy.

COAL GOING-FORWARD COSTS

We developed an estimate of the going-forward costs of running U.S. coal plants using publicly available data from the U.S. Department of Energy’s Energy Information Agency (EIA), the Federal Energy Regulatory Commission (FERC), and the U.S. Environmental Protection Agency (EPA). We compiled a list of 235 U.S. coal plants operated by utilities and independent power producers, excluding plants used for combined heat and power, with a tiered system indicating our degree of confidence in each plant’s particular estimate. The going-forward cost estimate for each coal plant in our master list is the sum of three principal components: cost of fuel, operations and maintenance costs, and going-forward costs for capital investments needed to continue operating the plant.

COMPARING RENEWABLES LCOE TO COAL GOING-FORWARD COSTS

Using the calculated plant-level weighted average LCOEs for wind and solar and plant-level going-forward coal cost, we compare the three values to determine to what extent the U.S. coal fleet is currently “uneconomic.” We use “uneconomic” in the sense that it would be more costly to continue operating existing coal plants compared to building new nearby wind or solar plants to fully displace the current annual generation from those coal plants.

More detail is available in the appendix below and the [companion dataset](#) to this report.

COAL TO RENEWABLES COST CROSSOVER FINDINGS

RENEWABLES AND COAL COST COMPARISON

Our top-level findings include:

1. Of existing U.S. coal capacity, 72 percent is more costly to operate than new nearby wind and solar, or is slated to retire by 2025.
2. Of existing U.S. coal plants, 80 percent are more costly to operate than new nearby wind and solar, or are slated to retire by 2025.

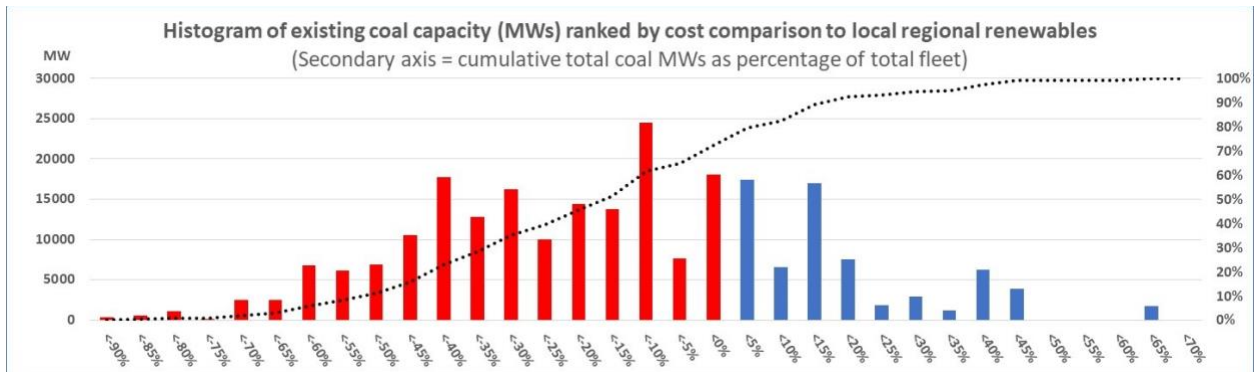


Figure 4. Aggregated plant capacity shown as percent difference between renewables LCOE and coal going-forward cost. The red bars indicate capacity where renewables are cost-competitive with coal and coal is deemed "uneconomic." The blue bars indicate capacity where coal is still cost-competitive with renewables and deemed "economic."

Our top-level findings show that the annual energy produced by a vast majority of the existing coal plants in the U.S. could be replaced by nearby wind or solar at a cost savings. U.S. coal economics have worsened substantially since our original analysis, which found that, as of 2018, 62 percent of coal capacity was uneconomic compared to local wind or solar. In addition, an estimated 16 GW of coal capacity has retired since the 2018 analysis. Our original analysis projected uneconomic coal capacity in the U.S. to be 77 percent by 2025—a pace that was almost reached in 2020.

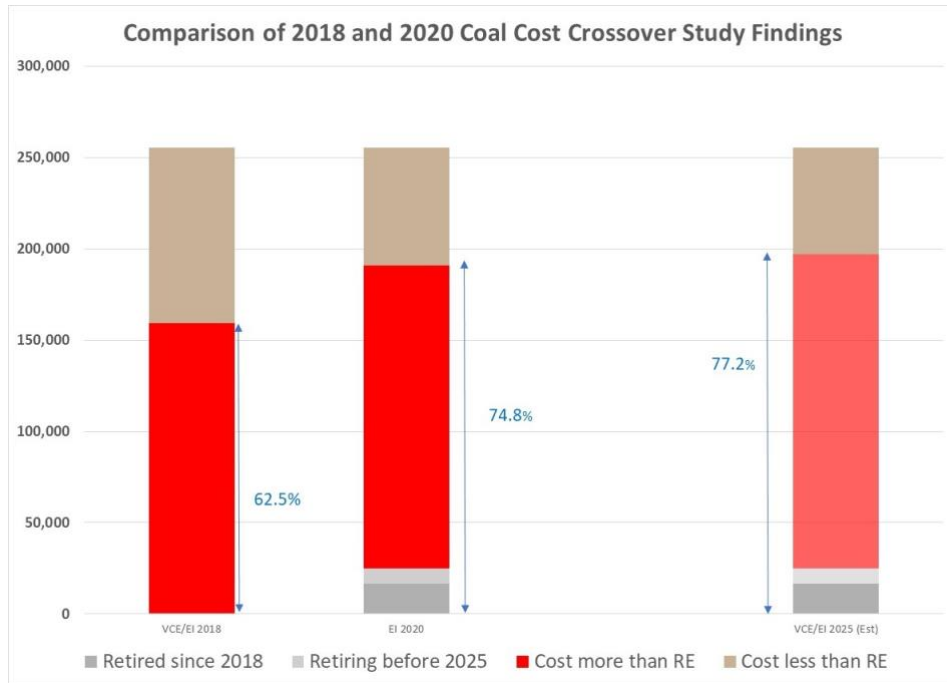


Figure 5. Comparison of our original analysis of renewables and coal cost-competitiveness, which includes a 2025 projection, to this most recent analysis. The comparison highlights that the projected 2025 coal uneconomic status was almost reached by 2020, indicating that the coal cost crossover is happening faster than we anticipated.

Our current analysis focused on whether solar or wind could entirely displace annual coal generation at a given plant cost effectively. The maps below show how, in many cases, solar and wind are both economically competitive options, although there can still be large cost differentials between the two clean resources even when they both beat coal on cost. That said, to displace uneconomic coal, policymakers should consider a portfolio of clean resources, including storage and demand-side resources, that is more varied than either entirely utility-scale solar or entirely utility-scale onshore wind projects.

Coal plants where new wind or solar are less costly

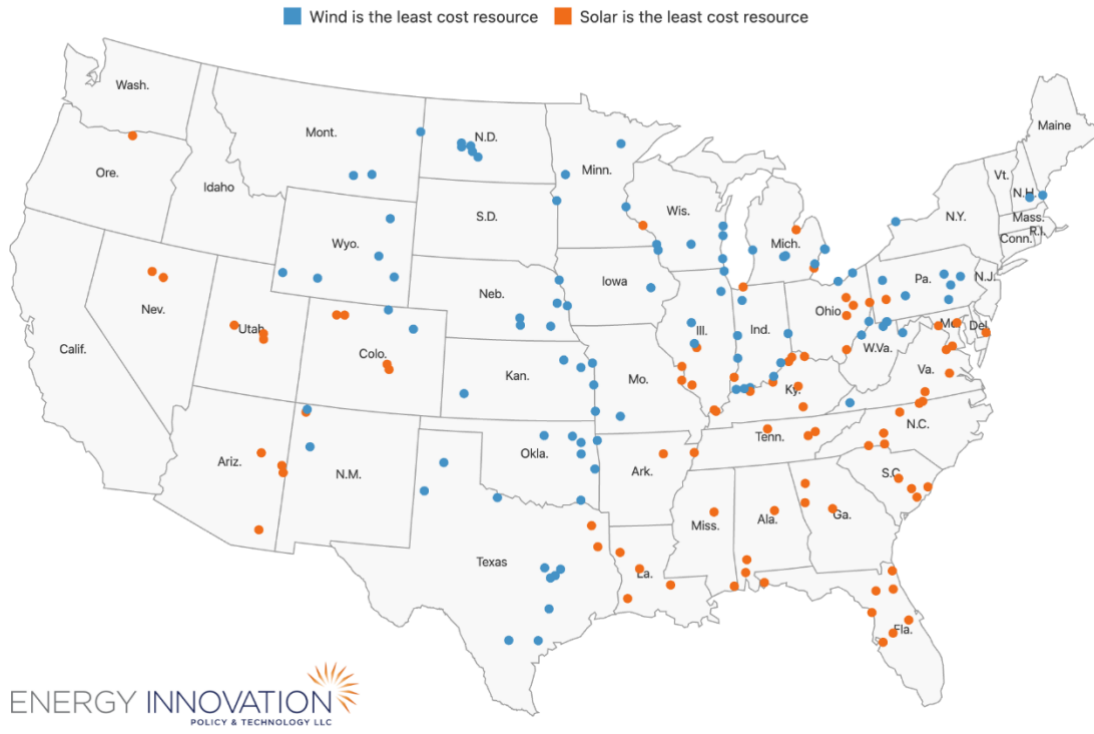


Figure 6a. These maps show how, in many cases, solar and wind are both economically competitive options compared to coal, although there can still be large cost differentials between the two clean resources even when they both beat coal on cost, especially based on geographic region. This first map shows where wind or solar are the least cost resource, the other maps show the same but also indicate plants where both wind and solar beat coal on cost.

Coal plants where new wind or solar are less costly

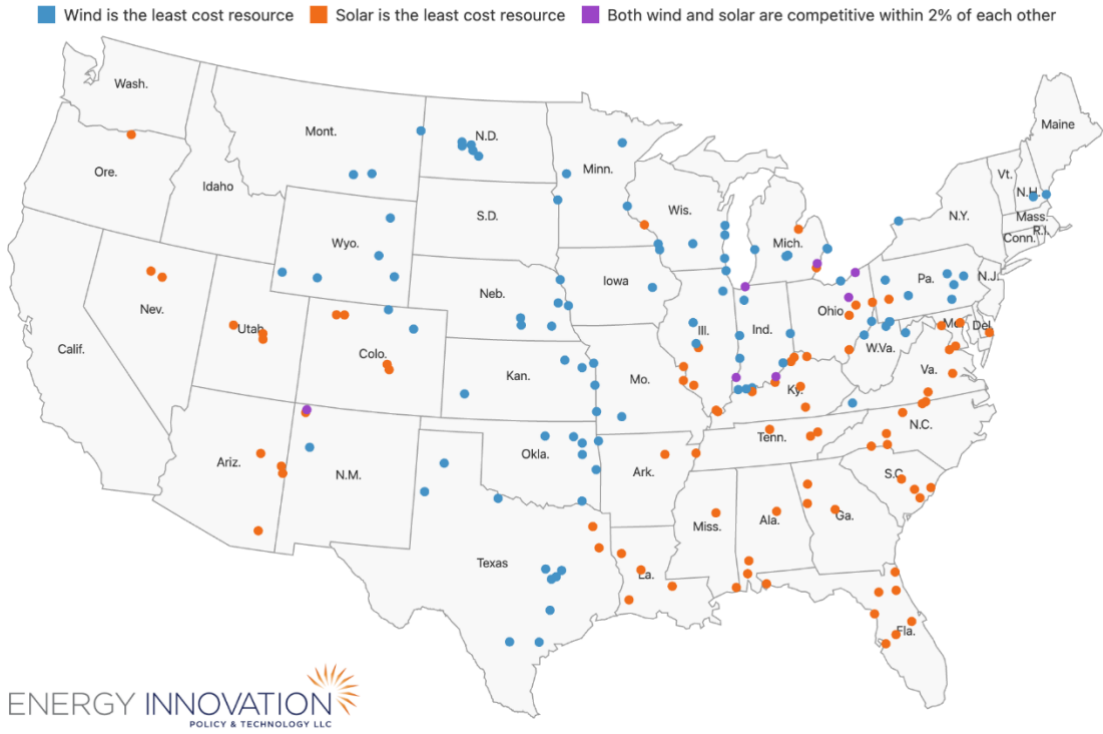


Figure 6b. This second map has purple dots where wind and solar are cheaper than coal and have a 2 percent difference in cost.

Coal plants where new wind or solar are less costly

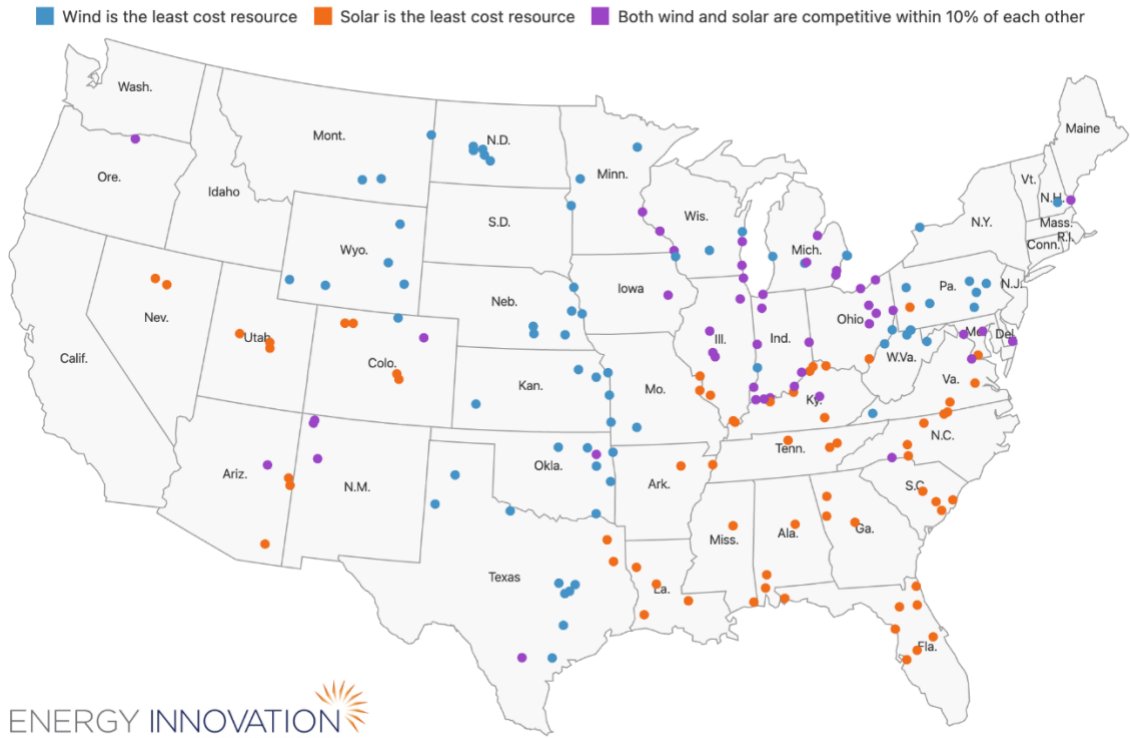


Figure 6c. The third map has purple dots where wind and solar are cheaper than coal and have a 10 percent difference in cost.

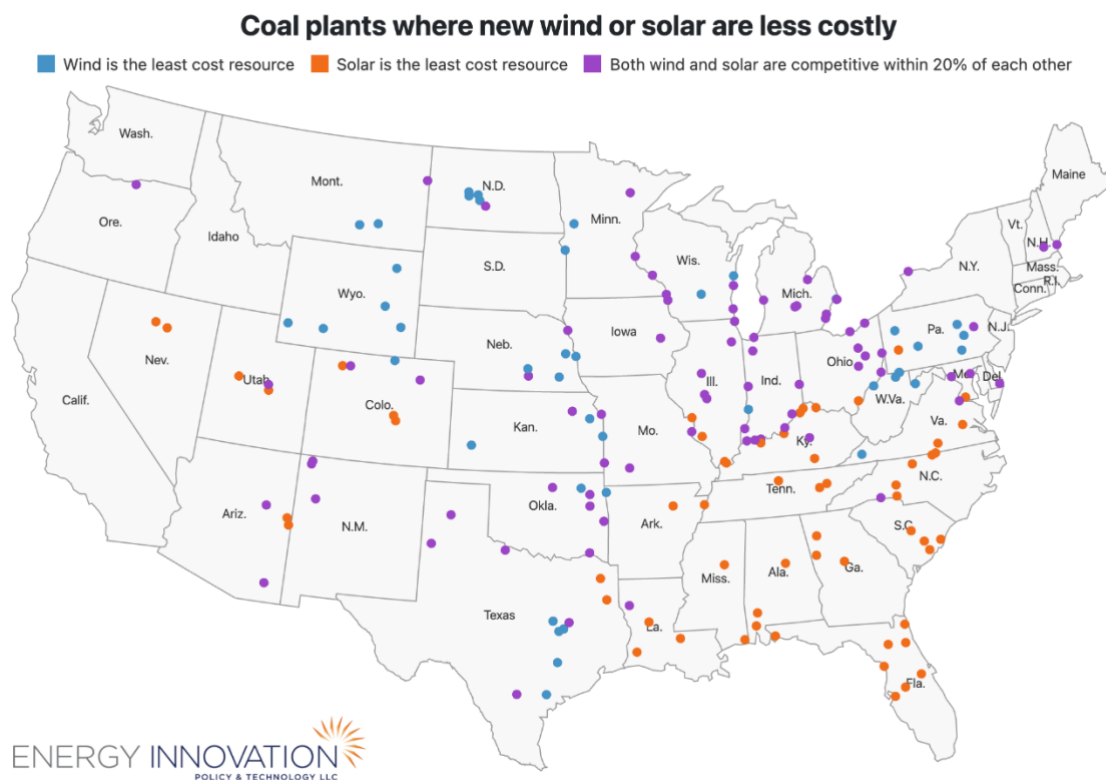


Figure 6d. The fourth map has purple dots where wind and solar are cheaper than coal and have a 20 percent difference in cost.

Our analysis is intended to give both a high-level view of the existing U.S. coal fleet and a plant-by-plant look at how each is doing economically. As with any modeling exercise, we made general, simplifying assumptions. The specific “uneconomic” status topline is likely not exact. Of the roughly 239 GW of coal plants analyzed, roughly 50 GW (~20 percent) are within a plus or minus 10 percent buffer of our economic viability criterion. Many large coal plants are just barely economic, based on our analysis, and will likely become uneconomic if renewable costs keep declining or coal capacity factors decrease.

PUBLIC HEALTH & CLIMATE IMPACTS

Coal plants emit a host of emissions. We collaborated with the Catalyst Cooperative to match plant boilers with the coal plant generators included in each coal plant in our dataset. We then collected emissions data from EPA’s 2019 eGRID database for each boiler and aggregated these figures at the coal fleet level.⁶ The database isn’t comprehensive, but it does provide detailed information on carbon dioxide (CO₂), nitrogen oxides (NO_x), and sulfur dioxide (SO₂) emissions.

CO₂ is a powerful greenhouse gas that accumulates over long time horizons in the atmosphere and contributes strongly to climate change. NO_x are a family of poisonous gases that form when coal and other fossil fuels are burned at high temperatures. SO₂ is a toxic gas that is emitted when burning fossil fuels, including coal, in power plants and other industrial facilities. Both NO_x and SO₂ exposure can lead to respiratory distress and disease, and are particularly dangerous for vulnerable populations, including children, pregnant women, the elderly, and those with pre-existing conditions.

We found the following fleet-level pollution figures:

- 1,044,635,828 tons of CO₂ per year
- 677,253 tons of NO_x per year
- 937,012 tons of SO₂ per year

The pollution findings we present are a sliver of the full range of public health risks that coal poses. For example, coal ash—a toxic byproduct of burning coal—has been known to pollute the air near plants and taint nearby watersheds and land.⁷ Furthermore, fine particulate matter (PM_{2.5}) is particularly harmful to lung health and disproportionately burdens communities of color due to racist redlining practices during coal plant siting.⁸ Studies have shown that coal plants are more likely to be adjacent to low-income communities and communities of color.⁹ Early retirement of coal plants not only makes financial sense but also is an important start to correcting severe environmental injustice. Continuing running of coal plants risks a safe climate future but more immediately risks the health and well-being of our communities.

The location of a particular coal plant—especially its proximity to population centers—largely determines how its pollution affects public health. For purposes of this report, we provide aggregated fleet-level pollution estimates. We recommend reviewing the Clean Air Task Force’s Toll From Coal database to understand probable public health effects from individual coal plants across the U.S.¹⁰

Our analysis does not include externalized or social costs of coal, which typically include public health, climate, and other cost factors that frequently are not accounted for in primary cost analyses. These costs tend to be significant—often greater than plant operating and fuel costs. Estimates of socialized costs vary greatly among sources due to the difficulty of deriving and projecting indirect costs, as well as uncertainties about the exact impacts of air pollution.

We used three different analyses to determine a range of plausible external costs of coal per megawatt-hour (MWh). A 2020 Tokyo University study that estimated the external costs of electricity generation in G20 countries found that coal generation in the U.S. creates \$30/MWh in

external costs.^{11,vii} A report from Climate Advisors found the external cost of (pulverized) coal to be \$69/MWh in 2020 dollars.^{viii} Lastly, we used Energy Innovation’s Energy Policy Simulator to calculate the value of avoided premature deaths and of avoided climate damages by enacting policies that phase out coal by 2032, finding the external cost of coal generation in the U.S. to be \$146/MWh. The range of cumulative external costs from U.S. coal generation across three credible studies is \$30-146/MWh.^{ix} This range reflects plant averages, not the particular circumstances of coal plants, which may have significantly lower emissions from on-site emissions control technology. The studies also vary significantly in how they account for the health impacts and value of human life associated with air pollution and related deaths, leading to a wide range of estimates.

Applying the lowest external cost in the range (\$30/MWh) to the coal going-forward cost for each coal plant, we find that not one coal plant in the fleet remains economic. As such, even conservative estimates of the externalized cost of coal generation incorporated into the cost analysis show that continuing to operate the remaining “economic” coal plants in the U.S. is likely not economically justified.

DISCUSSION

Even the most economic coal plants face threats to their viability, including the cost of complying with more stringent emissions and pollutant standards. For example, one of the coal plants in our dataset that features some of the cheapest going-forward costs, the Gerald Gentleman plant in Nebraska, is attracting interest from a renewable energy developer eager to take advantage of its transmission capacity should it retire or materially reduce its output.¹² Additionally, with the right transmission access, wind and solar projects with even more favorable project economics than the local regional ones we used are available at a small premium and may further tip some plants into the red. Analysts, utilities, regulators, policymakers, and other stakeholders need to critically examine each and every coal plant in their jurisdiction given the overwhelming amount of existing coal and the rapidly changing economics of possible alternatives.

In this analysis, wind and solar replace all coal-fired generation solely on the annual generation basis. An important limitation of this analysis is that replacing annual generation does not capture coal generation dispatch timing. Despite its notorious inflexibility, coal is mostly dispatchable, while wind and solar are variable sources of energy whose output, even in aggregate, does not necessarily match demand. So-called “baseload” coal economics typically require high capacity

^{vii} The study reports external costs of \$28/MWh for hard coal and \$55/MWh for lignite coal. The figure we used in this report was calculated as a weighted average based on the historical ratio of hard coal (92 percent) to lignite coal (8 percent) use in the U.S. “Coal Explained,” U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/coal/>.

^{viii} The original report uses 2010 dollars to derive an estimate of \$58/MWh. Samuel Grausz, “The Social Cost of Coal: Implications for the World Bank,” Climate Advisers, October 2011, <https://www.climateadvisers.com/wp-content/uploads/2014/01/2011-10-The-Social-Cost-of-Coal.pdf>. We used the Bureau of Labor Statistics CPI Inflation Calculator to estimate the external cost figure for the 2020-dollar year: “CPI Inflation Calculator,” U.S. Bureau of Labor Statistics, https://www.bls.gov/data/inflation_calculator.htm.

^{ix} See “Public Health Findings” discussion above.

factors, limiting coal plants' use as flexibility resources (high capacity factors require avoiding frequent ramping up and down). Operating a coal plant to provide greater flexibility spreads capital costs across fewer megawatt-hours and increases wear and tear, both of which increase going-forward costs. Coal plants, already uneconomic at higher capacity factors, only increase consumer costs when run for flexibility.¹³

Modeling from RMI indicates that, more often than not, replacing coal energy with wind or solar is unlikely to negatively affect system reliability. More than 50 percent of coal plants in RMI's 2021 analysis could be economically replaced by renewables, allowing the balancing authority to still meet its reserve margin.¹⁴ Almost half the plants in our analysis, representing 39 percent of the megawatt-hours, had a going-forward cost more than 25 percent greater than wind or solar LCOEs, indicating room to complement these resources with storage, demand response, and energy efficiency to amplify their contributions to reliability.

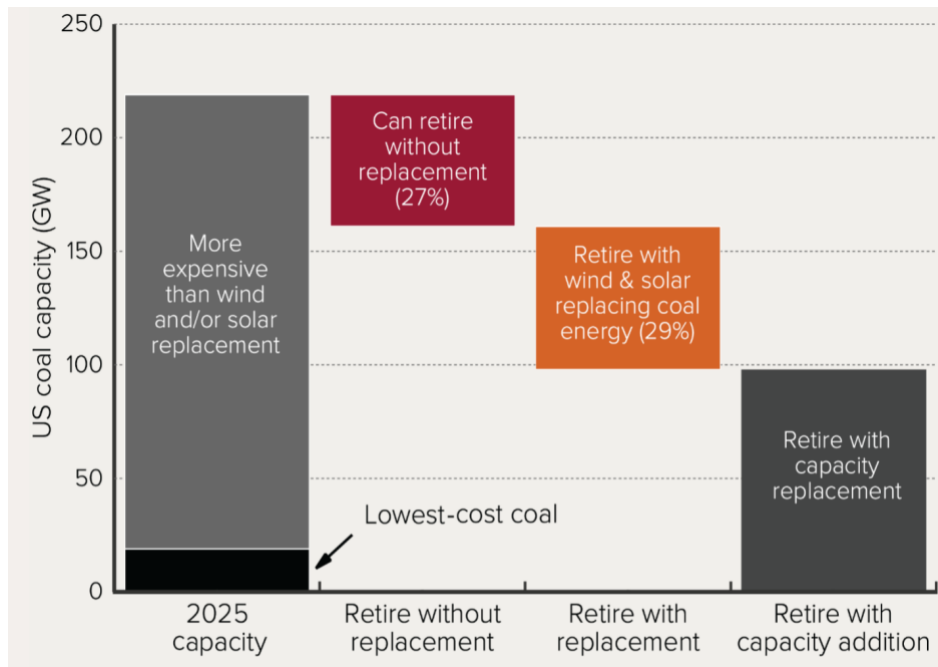


Figure 7. U.S.-Wide Opportunity to Replace 2025 Coal Capacity without Compromising Reserve Margins. Source: <https://rmi.org/insight/cutting-carbon-while-keeping-the-lights-on>

The wider the gap becomes between the marginal economics of coal versus wind and solar, the more coal plants will have to depend on their perceived capacity value to recover costs. Their capacity factors may drop even more, widening the gap and opening a window for dedicated resources like demand response, storage, and existing flexible resources to fill their niche. We are already seeing combined renewables-plus-storage plants win competitive solicitations and capture some of this value in high solar- and wind-potential regions (empirically, this appears to add roughly

\$4-8/MWh to renewable energy costs).¹⁵ We expect the trend to continue as battery prices slide down the learning curve.

This analysis is consonant with other analyses of the economics of coal and clean alternatives. In 2021, RMI reported that more than half of the coal fleet could be retired economically with wind and solar replacement.¹⁶ RMI also made a strong case that the rest of the fleet probably could be economically replaced by clean energy portfolios of wind, solar, storage, and demand-side management if utilities adopt best practices for competitive procurement. The CEO of NextEra Energy, who manages the country's largest electricity utility by market value, announced on a recent conference call with analysts that "[t]here is not a regulated coal plant in this country that is economic today...when it's dispatched on any basis, not a single one."¹⁷ Morgan Stanley predicted that U.S. coal would retire by 2033, largely replaced by least-cost wind, solar, and batteries.¹⁸

But our analysis and others indicate that at least some continued coal plant operation represents a market failure; were the electricity system truly competitive, we would see more renewable deployment and much faster coal retirements. For example, Vibrant Clean Energy's 2020 analysis of the impact of competition in the Southeast indicates that while utility plans in the region assume most coal will continue to operate past 2040, a cost-optimal system would retire nearly all coal by 2035.¹⁹

Various forces keep uneconomic coal around, including:

- Captured regulators trust utility claims that coal is needed for reliable system operation, enabling utilities to keep operating coal plants that aren't needed.
- Regulated monopoly utilities receive protection from competition and face disincentives to retire coal or explore less expensive clean energy alternatives.
- There is a continued failure to recognize the negative public health and environmental externalities associated with coal-fired generation, and the associated benefits of clean alternatives.
- Tens of billions in unpaid capital account balances owed to utilities remain to be recovered from customers through rates. This number has increased even as coal plants have retired.²⁰
- Wholesale market mechanisms to ensure reliability value and reward coal's operating characteristics at the expense of clean resources that do not provide precisely the same reliability attributes.
- Communities built around coal mining and power generation require economic development and reinvestment that may be difficult to address alongside coal retirement.
- Transmission build-out is insufficient and interconnection costs too onerous to bring viable profitable projects online. Over 600 GW of clean energy resources were in interconnection queues in 2019.²¹

These factors are not set in stone, and regulators and state policymakers can take concrete steps to remedy these market failures. Step one is examining the economics of continued coal plant operation as compared to replacement renewable resources. We hope this dataset provides an initial lens through which policymakers can justify taking an even closer look at coal plant economics and investigating the cost of alternatives.

POLICY RECOMMENDATIONS

Coal generation has been on a secular downward trend, declining 50 percent since its peak in 2011. Simultaneously, renewable energy costs are plummeting. Our analysis indicates that the coal decline will continue and policymakers should seize this opportunity for consumers, public health, and climate. Policies informed by cost analysis of coal and renewables and focused on competitive procurement and coal asset securitization can enable a transition that more effectively balances utility, consumer, environmental, equity, and community interests.

Policymakers play a key role in assessing the comparative economics of various generation resources and creating a policy pathway toward clean, reliable, and cost-effective portfolios. Comparing going-forward cost of existing coal plants to the levelized cost of new renewable generation is necessary but not sufficient to justify replacing these assets—reliability depends on sufficient generation and ability to deliver power to customers at the right time. Electric system modeling that determines whether reliability can be maintained as some generation resources are retired and replaced with others can help assure the transition keeps the lights on. Portfolios constructed of diverse resources (energy efficiency, demand management, wind, solar, storage, customer-sited and distributed resources, energy and system flexibility gained from implementing broader and more efficient wholesale markets, regional transmission, plus conventional generation maintained to support the transition) can provide modeling alternatives that reduce overall system operational, transition, and integration costs.^x

To examine these economics holistically, regulators can require utilities to undertake all-source procurement. Best practices for all-source procurement are outlined in a 2020 resource from Energy Innovation and Southern Alliance for Clean Energy,²² a RMI report from 2021,²³ and a 2021 Berkeley Lab report.²⁴ In particular, regulators and utilities should observe the following principles in procurement:

- Regulators should use an open resource planning process to determine a technology-neutral total procurement need before opening procurement.
- Regulators should require utilities to conduct competitive, all-source bidding processes, including demand-side resources, with robust bid evaluation.

^x See, e.g., discussion of clean energy portfolios to replace the San Juan Coal Generating Station in New Mexico. John D. Wilson, Mike O’Boyle, Ron Lehr, and Mark Detsky, *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement*, April 2020, https://energyinnovation.org/wp-content/uploads/2020/04/All-Source-Utility-Electricity-Generation-Procurement-Best-Practices_EI_SACE.pdf.

- Regulators should review and approve procurement assumptions and terms in advance.
- Regulators should renew procedures to ensure that utility ownership is not at odds with competitive bidding.

These procedures require utilities to solicit competitive bids from diverse technologies when procuring resources to replace retiring coal plants. They are flexible to accommodate public policy needs like employment and location—for example, plans in Colorado include requirements for the monopoly utility to solicit renewable bids in Pueblo County, which will be most affected by lost coal mining and power plant jobs. Utility ownership can also coexist with competitive procurement with careful oversight,²⁵ providing some investment upside for coal-owning utilities.

A parallel step to procurement is addressing and reducing the cost of unpaid coal capital and decommissioning costs. When a plant is retired before it has been fully depreciated, the utility and its regulator face the question of how to account for the remaining, undepreciated investment in the plant. Often this becomes a “regulatory asset” that the utility continues to earn a rate of return on, but recovers on an accelerated timeline. But this can lead to near-term increases in rates. An alternative approach is to use “securitization,” whereby the regulator authorizes the issuance of bonds with low interest rates, and those bonds are used to replace the remaining capital invested in the plant. The bonds are then repaid over time by ratepayers, reducing any potential rate impact driven by accelerated recovery of remaining capital invested in the plant.²⁶ Securitization legislation was recently adopted in Colorado, Kansas, Montana, and New Mexico, and these approaches compared in an Energy Innovation brief.²⁷

Putting together these steps—cost analysis, competitive procurement, and coal asset securitization—policymakers can craft a deal that balances utility, consumer, environmental, equity, and community interests. Immense savings are available across the country, with ample opportunities to reinvest locally in replacement clean energy portfolios.

POLICYMAKER	POLICY RECOMMENDATION
State Legislators	Authorize public utilities commissions to use ratepayer-backed securitization to reduce the consumer cost of uneconomic coal plant retirement; include provisions to replace these plants with competitive clean electricity portfolios; and set aside funding for community transition.
PUCs	Require public processes to assess the economics of early coal retirement as a part of system planning.

PUCs	Require utilities to undertake all-source procurements when they identify the need for more generation resources, allowing all resources to compete to meet a technology-neutral need, using the principles above.
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Conclusion

Coal is a highly polluting and expensive way to generate electricity. This analysis shows that we have economic alternatives to continuing to burn coal for power in the U.S. Furthermore, analyses such as “The 2035 Report” show that we can fully retire coal, stop building other fossil fuel plants (namely gas), and still reliably meet electricity demand, while providing a host of environmental and societal benefits.²⁸ There are existing policies that can help policymakers closely examine the cost burden of generation resources used today, procure cheaper and cleaner generation resources going forward, and address current assets on the books. The continuation and intensification of the coal cost crossover demands attention from policymakers and consumers alike.

Appendix

DETAILS ON FACTORING A PTC EXTENSION INTO WIND

In December 2020, the U.S. Congress extended the lifetime of the wind production tax credit (PTC) for one year, nominally at \$25/MWh, discounted to 60%, or \$15/MWh. The initial values for local regional wind levelized costs by regions that we obtained from the ReEDS did not factor in any PTC. To factor in the impacts of the new 2020 PTC level, we followed an algorithmic approach modeled on NREL's ATB spreadsheet. This breaks roughly into two parts, one that is largely a fixed offset regardless of the initial value of a wind LCOE (the gross PTC) and one that depends on the value of the LCOE without a PTC. The transformation looks like this:

$$PTC_{Gross} = \$25/MWh \times (\text{Scheduled Discount Modifier}) \times (\text{Tax Modifier}) \times (10\text{-year life of PTC Modifier})$$

$$LCOE_{with_PTC} = [(\text{Capital Cost Modifier}) \times (LCOE_{without_PTC} - \text{Weighted_Fixed_O\&M}) + \text{Weighted_Fixed_O\&M}] - PTC_{Gross}$$

One important factor in how we account for the PTC is that we assume that the real weighted average cost of capital ($WACC_{real}$) is higher because these resources need to use more equity financing to access tax equity. We assume that the $WACC_{real}$ goes from 2.75 percent without the PTC to 4.48 percent with the PTC. This is relevant for both terms above.

For the first equation, the three modifiers are:

- Scheduled Discount Modifier: The sunset factor for the PTC. We assume a 2021 schedule value of 60 percent.
- Tax Modifier = 1.1346: To make an apples-to-apples comparison of the economics of projects after tax, we gross-up the PTC dividing by $(1 - \text{Tax Rate})$ using NREL ATB's estimated combined 25.7 percent federal and state tax.
- 10-year life of PTC Modifier = 0.619: The PTC is only available for the first ten years of a project, but in our LCOE calculation its benefits are spread out over the 20-year lifetime of a project. This modifier is the ratio of the capital recovery factor over 20 years to the capital recovery factory factor over 10 years using the real WACC.

The net effect of all these modifiers is $PTC_{Gross} = \$12/MWh$.

The capital recovery factor (CRF) is a standard mathematical factor based on a discount rate and span of years to spread a fixed amount of capital or net present value over a fixed number of years. The CRF also features in our second equation, because the WACC used as a discount factor in the LCOE without a PTC is lower than the WACC with the PTC. So we use:

- Capital Cost Modifier = $CRF_{High\ WACC} / CRF_{Low\ WACC} = 1.169$

Fixed operations and maintenance (O&M) costs are already an annual expense, so their discount rate doesn't need to be renormalized. Hence they must be pulled out and then put back in, as in the equation above. In the LCOE formula, fixed O&M costs are spread out over annual production, which is why a capacity-factor weighted version appears in the formula:

- $\text{Weighted_Fixed_O\&M (\$/MWh)} = [\text{Annual Fixed O\&M (\$/kW-year)} \times 1000 / (8760 \text{ h} \times \text{Capacity Factor})]$ using the NREL ATB wind fixed O&M value of \$43/kW-year and capacity factors from ReEDS data set.

The impact of the PTC formula is that it lowers the most competitive wind LCOEs by about \$8/MWh, with the benefits steadily declining to zero, turning into a liability for initial LCOEs over \$93/MWh. Presumably for such high values initial capital costs are high enough that tax equity represents a smaller fraction of financing and the impact on the WACC is lessened—so the formula should not be trusted in that regime. As far as our analysis is concerned, such wind projects are unlikely to get built, or to compare well to solar LCOEs or coal going-forward costs, so this is a non-issue. The NREL-derived PTC formula seems to work well for cheaper LCOEs, as these are more often representative of what is offered in commercial markets today, according to LevelTen's 2020 Q4 report.²⁹

DETAILS ON THE COAL GOING-FORWARD COSTS COMPILATION

Our goal was to develop as accurate an estimate of the going-forward cost of running U.S. coal plants as possible using publicly available data from EIA, FERC, and EPA. In assembling a master list of U.S. coal plants, we restricted ourselves to plants running mostly coal (with some wood waste and petroleum coke burning units, as well) operated by utilities and independent power-producers (sectors 1 and 2, in EIA parlance), excluding plants used for combined heat and power. This last category represents roughly another 4.3 GW of coal capacity (an incremental 2 percent to the fleet we cover) but the economics are more complicated because these plants receive other revenues from providing heat.

As a matter of convenience, we limited ourselves to coal plants in the lower 48 states and excluded a few plants for various practical reasons like corrupted or unavailable data. The companion spreadsheet to this report lists these in detail. In any case, these cuts did not materially reduce the number of GWs of capacity we covered. In addition, we noted which plants had announced retirement dates by 2025 and removed these from consideration in the economic analysis topline findings. Finally, we grouped boilers and generating units together at one location as single plants, while excluding boilers and generating units fueled mostly with natural gas. The final master list of 235 coal plants is available in the companion spreadsheet to this report. Each plant had different levels of available public information, so we attached a confidence tier label to each. We thank the Catalyst Cooperative³⁰ for scraping and making publicly available much of the raw data we used and helping us assemble our dataset and confidence tiers.

The going-forward cost for each coal plant in our master list comprises three principal components:

1. The cost of fuel on a per MWh of coal generation basis.
2. The O&M cost of each plant levelized over the total generation from each included boiler and generating unit.
3. The average annual going-forward costs for capital investments needed to replace and upgrade part of the power plant levelized over the total generation from each included boiler and generating unit.

This appendix reviews our methodology for each of these three elements in more detail.

COST OF FUEL

Our principal method for calculating fuel cost for any given coal plant comes from first computing its cost of energy inputs in dollars per million British Thermal Units (\$/mmBTU). We need a heat rate in mmBTU/MWh to convert this input into a cost of delivered energy in \$/MWh. The heat rate is a number particular to any given plant that varies according to any number of contextual factors (e.g., fuel-type, technology, age, outside temperature, capacity factor). As a matter of simple expediency, we use a heat rate for each power plant defined by the sum of BTUs from all non-natural gas fuels burned at that plant in 2019 divided by all the net-generation from these fuels as defined in the first page of EIA Form 923. We used this to convert input fuel costs into output electricity fuel costs.

One key difference between coal plants in our dataset is the degree to which they are regulated, i.e., receive monopoly protection under state regulation. Regulated plants tend to report input fuel costs to the EIA and FERC (Form 1) while plants in a more competitive setting do not. This fact triggers the first part of our tiering system with one group (Tiers 1-3) directly reporting fuel costs to EIA and/or FERC, and others (Tiers 4-6) that do not.

For the first group, we started by looking for a direct report of fuel costs per mmBTU reported on the FERC Form 1 “steam table” for individual plants. For plants with multiple owners, the FERC form report may be available from each owner, sometimes with slightly different values for fuel input costs. We then averaged these by MWh share for each reporting owner. Sometimes, however, no plant data is reported to FERC—usually when a plant is under public ownership or is otherwise difficult to trace accurately. In these cases, we used EIA data on fuel contracts paid by the plant; for plants not subject to direct market competition these fuel purchase contracts are listed on page 5, “Fuel Receipts and Costs,” of EIA Form 923. EIA contracts provide a slightly different estimate of fuel costs from those reported to FERC because they represent a forward-looking benchmark of coal costs per mmBTU—not all newly purchased stocks are burned right away, and the coal that was burned in 2019 might have been purchased in an earlier year.

The EIA 923 spreadsheet lists fuel contracts with heat contents (mmBTU per fuel unit) and price paid in cents per mmBTU. From these contracts we can establish an mmBTU-weighted cost per mmBTU for coal, which we use as an input cost for that plant. Note that this does not include fuel

processing costs that might be covered in values reported to FERC. Probably the most important example of fuel processing comes from plants that report burning so-called “refined coal” on one part of Form 923 while at the same time reporting direct purchases of other coal, e.g., bituminous coal, on another part of the form. This discrepancy is due to the fact that “refined coal” involves processing purchased coal (usually by spraying it with certain chemical agents) to reduce emissions from the smokestack. It is hard to know how much this extra processing costs on a per mMBTU basis, but we understand that the economic rationale for doing so is driven mostly by a tax credit. Historical trend analysis of some plants that burn “refined coal” shows that they sometimes choose to apply this processing and sometimes not—reflecting, in our opinion, the likelihood that there is only a small impact on fuel costs to “refining” after netting out processing costs and tax credit income.

Comparing the FERC Form 1 fuel costs and the fuel contracts reported to EIA, we find that on a fleet-wide basis the difference between the fuel input cost sourced from EIA and FERC data is usually within plus or minus 10 percent for individual plants with both values available. FERC fuel costs trend slightly higher on average (perhaps representing some extra fuel handling or processing costs). Because of this consistency in the overlap in FERC and EIA data sources, we did not create a separate confidence tier.

For plants that do not report input fuel costs to a regulator, however, other less plant-specific sources of information were required. We assigned these plants lower confidence tiers: tiers 4-6. Instead of specifically reported plant data, we used state-based data on the average cost of coal from EIA. To accurately reflect the diversity of coal types and relative mix of types that various plants consume, we used a combination of total plant coal consumption and state average coal costs from EIA as well as historical fuel consumption trends at the plant to estimate source coal type and marginal fuel costs. We used the following procedure:

Step 1: Extract the various mMBTU quantities of coal by type used by the boilers in each coal plant of interest from the 2019 EIA Form 923.

Step 2: Link each coal type with a state benchmark input fuel price in \$/mMBTU. We establish that benchmark price by combining information on electric power sector coal prices by coal type and plant state from [EIA’s Coal Data Browser](#) with coal heat content (mMBTU/ton) by state and coal type, also from [EIA’s Coal Data Browser](#) (if heat content for a given coal type was unavailable for the 2019 reporting year, we used the most recent year).

Step 3: Tag “refined coal.” One type of coal that appears in boiler consumption figures but not price tables is “refined coal.” To price this type of consumption, we assigned each instance of “refined coal” to a coal sub-type, just as with plants in tiers 1-3. Depending on the plant, the source coal for “refined coal” might be bituminous, sub-bituminous, or lignite. With some painstaking work, we were able to infer from other nearby plants and historical fuel consumption trends at the plant which coal type was being refined with high confidence.

Step 4: Combine coal types to get a plant fuel cost. We combined price and consumption levels at each plant to get a weighted fuel input cost in \$/mmBTU. We then converted this to \$/MWh using the heat rate—just like the plants that report their input fuel costs.

O&M COSTS

For O&M data, we used three different sources of information, which conferred varying levels of confidence. We had the highest confidence level when a plant reported its O&M costs on FERC Form 1. On that form, in the steam tables for various power plants, owners report total annual costs to run a plant, annual fuel expenses, and MWhs generated. We subtracted fuel expense from total annual expenses and divided by MWhs generated to get a volumetric \$/MWh estimate of O&M costs. If multiple owners of a plant reported to FERC, we used a generation weighted average of their reported costs. Plants with reported FERC O&M costs correspond to confidence tiers 1 and 4.

If no FERC O&M data was available, with the help of the Catalyst Cooperative we were able to use plant-by-plant O&M estimates obtained from the Electricity Market Module (EMM) in EIA’s North American Energy Modeling Systems (NEMS).^{xi} These plants are in our confidence tiers 2 and 5. For some plants, no NEMS value for O&M was available and we used a national average value (tiers 3 and 6). Figure A1 below gives a useful visual to explain confidence tiers:

^{xi} EIA maintains an archive (<https://www.eia.gov/outlooks/aeo/archive.php>) of assumptions used in the NEMS model.

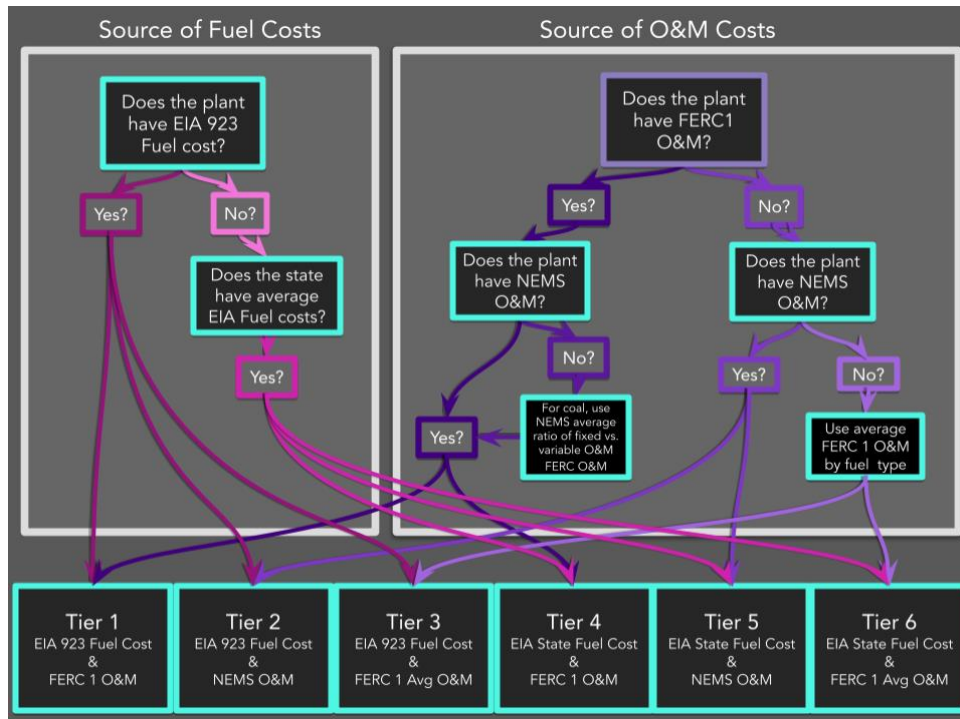


Figure A1. The coal plant confidence tier matrix shows how we determined a confidence tier label for each coal plant in the dataset based on the type and fidelity of publicly available data in each instance.

GOING FORWARD CAPITAL COSTS—NATIONAL ENERGY MODELING SYSTEM

The third element in our overall coal going-forward cost estimate is the going-forward capital cost. For this element we used a fairly simple but crude method. We started by taking the average age (weighted by generator capacity) of a given coal power plant and compared it to the EIA NEMS table³¹ found in Figure A2. From this NEMS table and the average age of the plant, we obtained a per kW-year going-forward cost, which we multiplied by the overall capacity of the plant. We then divided by the total net MWh output from the plant (defined by the included set of generators) as reported on EIA Form 923. This includes any natural gas-fueled generation and results in a \$/MWh, which then factors into the complete coal going-forward cost.

Age	Annual Capital Investment Requirement (\$/kW-yr)
0 - 10 years	\$ 17.16
10 - 20 years	\$ 18.42
20 - 30 years	\$ 19.68
30 - 40 years	\$ 20.94
40 - 50 years	\$ 22.20
50 - 60 years	\$ 23.46
60 - 70 years	\$ 24.72
70 - 80 years	\$ 25.98

Figure A2. National Energy Modeling System annual capital investment requirement estimate table based on the age of a coal-fired plant.

Notes

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- ⁴ National Renewable Energy Laboratory, *Annual Technology Baseline*, <https://atb.nrel.gov/>.
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- ¹⁵ Next Era Energy and Next Era Energy Partners, *Investor Conference 2019*, <http://www.investor.nexteraenergy.com/~media/Files/N/NEE-IR/news-and-events/events-and-presentations/2019/06-20-2019/june-2019-investor-presentation.pdf>.
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