

Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment

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EXECUTIVE SUMMARY

The cost of operating existing coal power plants in the United States continues to increase while coal jobs, generation, and mining all decrease.ⁱ New coal retirement announcements seem to happen faster, even as natural gas prices skyrocket, and renewable energy prices keep dropping.

The Inflation Reduction Act (IRA), which extended and expanded clean energy tax credits, along with new funding to guarantee loans for refinancing fossil assets and reinvesting in clean energy infrastructure, has shifted the economic scale even further toward wind and solar. But it also creates thoughtful new investment opportunities in areas burdened by existing coal plants with a 10 percent tax credit boost for projects located in nearby communities.

These factors underpin the third iteration of our Coal Cost Crossover analysis, which shows wind and solar energy are unequivocally cheaper than coal-fired generation across the country. This study finds 99 percent of all coal-fired power plants in the U.S. are more expensive to operate on a forward-

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looking basis than the all-in cost of replacement renewable energy projects, and 97 percent are more expensive than renewable energy projects sited within 45 kilometers (approximately 30 miles), a significant acceleration from our two previous analyses. For more than three quarters of U.S. coal capacity, the all-in cost per MWh of the cheapest renewable option is at least a third cheaper than the going-forward costs for the coal it would replace.

In this report we compare the cost of operating each continental U.S. coal plant in 2021, totaling 220 gigawatts (GW) of coal capacity across the country, to the estimated costs of building new wind and solar generation. We consider the wind and solar costs within two geographic scopes: local to the coal plants (within 45 kilometers) and regionally (roughly within the utility balancing area), finding that nearly all existing coal plants have multiple lower-cost clean energy replacement options.

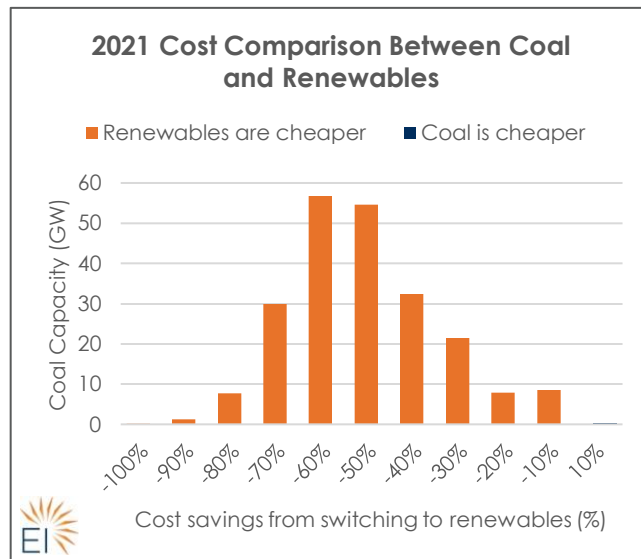
This research shows all but one of the country's 210 coal plants are more expensive to operate than either new wind or new solar. If the IRA's new energy community tax credit is included in the equation, 199 of the 210 plants are more expensive to operate compared to local solar resources sited within 45 kilometers of the plant. Local wind resources are also cost-effective and readily available, with 104 plants having cheaper wind resources within 45 kilometers.

Altogether, 205 plants have local renewable options that would be cheaper than coal-fired electricity. This potential to replace existing coal plants with cheap, local clean energy generation creates significant economic benefits for community transition. Our analysis finds replacing these plants with local solar or wind would drive \$589 billion in local capital investment that could support economic diversification, job creation, and tax revenue.

These local wind and solar resources could also help solve the problem of long interconnection queues—a significant barrier to renewables deployment. Renewable projects built near a retiring coal plant could use the existing plant's interconnection, helping to further lower costs. If more policymakers consider this dynamic, they can streamline economic replacement and anticipate coal retirements, which are accelerating due to the cost dynamics analyzed in this report.

While solar and wind replacement resources provide significant low-cost energy and reliability value to the grid, savings generated by switching from more expensive coal to cheaper clean energy can finance other resources to provide additional energy and reliability value.

We find that the savings generated by shifting to local solar could fund the addition of 137 GW of four-hour batteries across all plants, and 80 percent or more of the capacity at a third of existing coal plants—the economics of replacing coal with renewables are so favorable that they could fund a massive battery storage buildout to add reliability value along with emissions reductions. However, it is important to remember reliability is a system attribute—replacement renewable



portfolios need not bear sole responsibility for replacing the reliability services of individual coal plants.

While the economic case is clear and virtually universal, barriers remain to replacing coal with clean energy, and policymakers must act to unlock the cost savings and human health benefits for coal communities while reducing climate pollution.

Several policies can enable a faster coal-to-clean transition. Specifically:

- **To prepare the way for coal transition, regulators and system operators should:**
 - Improve methods to assess reliability and resource adequacy reflecting the reliability value of renewable portfolios and valuing the reliability attributes of a high-renewables grid.
 - Update interconnection study rules to leveraging existing coal plant interconnection rights to speed grid connection processes for local renewable replacement resources.
- **To proactively pursue the transition, regulators should:**
 - Encourage utilities to utilize IRA financing programs available through the Departments of Energy and Agriculture to remove financial barriers to coal community economic transition and investment.
 - Enable competitive resource procurement.
 - Require re-assessment of any utility investment plan, including integrated resource plans and market-based solicitations for renewable supply, completed prior to IRA as renewables costs are now out of date.
- **To create a just transition for affected communities, state legislatures and energy offices should:**
 - Plan for and fund a coal community-centered economic transition, where local clean energy resources are the anchor for a more expansive economic transition plan.

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INTRODUCTION

The U.S. power sector is in transition, with coal-fired power generation falling to 55 percent of its 2007 peak in 2021. This transition is also decreasing the number of coal mines, power plants, and workers. Over the same period, utility-scale solar and wind generation have increased more than

18,000 percent and 1,000 percent, respectively, as costs declined by 90 percent for solar and 72 percent for wind.^{1,ii}

In 2019, Energy Innovation Policy & Technology LLC® partnered with Vibrant Clean Energy to compile and analyze a 2018 dataset of capital, operations and maintenance, and fuel costs for coal, wind, and solar. Our first Coal Cost Crossover report found that 62 percent of existing coal capacity was uneconomic compared to producing the same amount of energy with new local wind or solar. To make this comparison, we evaluated the marginal cost of running each coal plant with the levelized cost of new wind and solar, where the levelized cost of energy (LCOE) is the cost of building and operating a new resource divided by its energy production over its lifetime. The analysis projected that by 2025, more than 80 percent of the coal fleet would be unable to compete against new renewables or would be retired, even without federal incentives.²

In 2021, we completed a similar analysis of 2019 data that considered the National Renewable Energy Laboratory's (NREL) 2018 Annual Technology Baseline (ATB) forecast showing steep cost declines for solar and wind energy, as well as an extension of the federal investment tax credit for solar coupled with a continued production tax credit for wind. The Coal Cost Crossover 2.0 report found that the coal crossover had significantly expanded, with 72 percent of coal capacity and 80 percent of plants already more expensive to run compared to either new solar or wind, including tax credits in effect.³

This Coal Cost Crossover 3.0 report uses new 2021 data to reevaluate the coal crossover economic dynamic. Since our 2.0 report, solar and wind costs continued fall, coal prices kept rising, and coal plant capacity factors continued decreasing, all continuing the trends observed between 2017-2019.ⁱⁱⁱ

Now, new federal tax credits in the IRA make the economic case for replacing coal with clean energy unequivocal. IRA incentive bonuses for clean energy projects located near retired coal infrastructure offer new, additional savings and reinvestment opportunities. This report combines elements of the previous two studies, analyzing both regional and local renewable resources, but now accounts for the new incentives.⁴ Given the IRA's expanded tax credits, we find all coal plants but one are more costly to run compared to new wind and solar energy, and all but five are more expensive than wind or solar sited within a 45 kilometer (km) radius.

Of course, examining relative economics using levelized cost faces limitations. The overall value of these power plants depends on much more than just cost. While the coal cost crossover describes a scenario in which renewable resources replace coal generation on a one-to-one basis, the reality is that coal retirement is a complex process that depends on the reliability needs of the local and

ⁱⁱ Coal generation decreased from 2,016,455 gigawatt-hours (GWh) in 2007 to 875,885 GWh in 2021. Solar generation increased from only 612 GWh in 2007 to 115,258 GWh in 2021. Wind generation increased from 34,449 GWh in 2007 to 378,196 GWh in 2021. In total, coal generation was still higher in 2021 than wind and solar in the U.S. by 382 GWh.

ⁱⁱⁱ Renewable costs continued to fall through 2021, the year we used for this analysis. Costs across the energy industry rose in 2022 due to supply chain constraints but are expected to fall again as supply issues ease.

regional electricity grid, which in turn, depends on the entire resource portfolio's dynamics. For example, in some regions one-to-one replacement with a combination of wind and solar resources may not adversely affect reliability. In others it may, depending on what other resources are serving the power grid.

Many communities also depend on coal plants for jobs and tax revenue. In addition to reliability value, policymakers must consider the potential of replacement energy resources to provide similar economic value. The new IRA incentives to locate replacement resources in the same communities where coal plants sit can contribute to a sustainable, economic transition. As we show in this report, these incentives fundamentally improve the prospect for coal communities to benefit from new clean energy resource development.

This report traces the shifting role of coal in the U.S. power sector and identifies key changes in the economics of coal-fired electricity generation due to the IRA's passage. We explain our coal cost crossover calculations, including how we compiled the coal dataset using publicly available data, and how we calculated the LCOE for both local and regional wind and solar using open-source modeling tools developed by NREL.

Four scenarios compare new renewable generation costs to marginal coal costs: regional wind, regional solar, local wind, and local solar, effectively assessing the replacement of every unit of energy produced by the coal plants. For the local solar scenario, we also analyze the economics of adding four hours of battery storage capacity to the solar resources. This analysis demonstrates a clean alternative to coal generation with added reliability value and an opportunity for local investment and economic diversification.

Finally, we provide policy recommendations to help policymakers successfully transition away from polluting, higher cost coal power to cheaper, clean energy. Because the IRA aligns the aims of least-cost electricity planning and procurement with an economic transition for coal communities, we highlight the opportunity for gradual economic transition centered around replacing coal generation with local renewables and storage. Local replacement also has the advantage of potentially being able to leverage existing grid interconnection rights. We describe how utilities can directly take advantage of key IRA provisions, as well as how policymakers can ensure utilities account for the changing economic landscape in their planning and procurement. We also explain how just transition planning, accurate reliability assessments, and transmission buildout can speed up and smooth out coal's phaseout in the U.S.

COAL'S ROLE IN THE U.S. POWER SECTOR

Coal-fired power was the bedrock of a reliable, affordable U.S. power sector for nearly a century. But since 2010, coal generation has declined 52 percent, and renewable power generation exceeded coal generation for the first time in 2020. In 2011, the U.S. had 317.6 GW of coal-fired

electricity generation capacity,⁵ but that number fell to 221 GW in 2021. Nearly a quarter of the remaining fleet is slated for retirement by 2029.⁶

Several factors explain this decline, including pollution control standards requiring costly retrofits, cheap natural gas and renewable power, state clean energy policies, and improved building and industrial efficiency.⁷ Coal's decline has been accompanied by a precipitous fall in coal industry employment.⁸ But even as employment fell, reduced pollution from coal plants dramatically improved public health. Annual deaths attributed to air pollution from coal plants fell from 30,000 deaths in 2000 to less than 3,000 in 2019.⁹

Coal's role in electricity system reliability has shrunk considerably. Coal-fired power plants operate as part of an integrated power system where supply and demand must remain in constant balance. The decline in coal-fired generation and capacity, and replacement by a more diverse portfolio of gas and renewable power plants with vastly different operational characteristics indicates that coal is not necessary for reliable power systems. For example, the United Kingdom reliably operated its grid without any coal generation for two straight months in 2020.¹⁰

The role of coal plants and their operation in the electricity system has also changed over time. Historically, coal plants operated as “baseload” power plants, relying on a relatively low-cost fuel supply to run at a constant, high output. But now markets are pushing coal plants to operate more variably, ramping up and down as the economics and availability of renewable energy fluctuate throughout the day and over a season.¹¹ Coal plants in our dataset had an average capacity factor of 46 percent, which means they ran, on average, only 46 percent of the time. This on-again, off-again operation increases wear and tear on coal plants designed for a different operating paradigm.

Displacement by cheaper gas and renewables means baseload operation is increasingly unprofitable for existing coal—operating at high output when plentiful clean energy resources operate at zero marginal cost is a waste of fuel. According to RMI, since 2012 utilities could have saved customers \$1–\$2 billion per year by turning down coal and relying on lower-cost, less polluting resources. This is partially due to self-scheduling, a practice through which monopoly utilities uneconomically run their coal plants in wholesale markets and charge captive customers the difference.¹²

Replacing coal with clean energy is not a one-to-one exercise. System operators and utilities only gain confidence that coal retirements won't adversely affect system reliability by evaluating the reliability of the entire energy portfolio. A recent North American Electric Reliability Corporation (NERC) assessment highlighted the need to build new generation before retiring old generation when reliability risks are present.¹³ But recent studies such as the 2030 Report, which found an 80 percent clean, coal-free electricity system to be both reliable and affordable, confirm we can maintain a dependable electricity system without coal.¹⁴

The U.S. will continue relying on coal plants for reliability until we add enough new clean resources (including demand-side resources and transmission) to replace their reliability and energy services.

The Coal Cost Crossover 3.0 analysis highlights opportunities to economically displace coal-fired generation and replace those services in part. With the IRA's passage, the economic case for shifting from coal to renewables is stronger than ever.

INFLATION REDUCTION ACT IMPACTS ON U.S. ENERGY ECONOMICS

The IRA will significantly affect the relative economics of coal and clean power in the U.S. In this analysis, the IRA's extended and improved tax credits, along with a pair of refinancing programs, have the greatest effect on the cost of coal compared to renewables.

Tax Credits

Clean energy tax credits have arguably been the most important federal climate policies to date, driving nationwide solar and wind growth. The IRA builds upon this successful policy to make the clean energy transition cost effective for the long term, with earlier Energy Innovation® analysis finding the credits to be the most impactful IRA provision for electricity sector decarbonization.¹⁵

The production tax credit (PTC) and investment tax credit (ITC) are the IRA's two key tax credits for new clean electricity resources. Historically, the PTC has primarily supported wind energy resources, and at its full value paid approximately \$26 per megawatt-hour (MWh) in 2022 dollars over the first 10 years of a wind project's commercial operations.¹⁶ The ITC has largely supported solar resources, and at its full value offered a tax credit for 30 percent of total system cost, paid out when it is first placed in service. Prior to the IRA's passage, the PTC had expired, and the ITC had begun phasing out with a value of 26 percent for projects starting construction in 2022.¹⁷ The IRA created long-term certainty for these tax credits, with the extension lasting through 2032 or until electricity sector greenhouse gas (GHG) emissions fall 75 percent below 2022 levels, whichever is later.

The IRA also immediately revived a long-expired option for solar projects placed in service in 2022 or later to elect the PTC instead of the ITC, which ensures that tax credits will stay impactful as solar capital costs continue to fall. In addition, the IRA provides an ITC for stand-alone energy storage technologies placed in service in 2022 or later, removing prior restrictions that required storage to be co-located with and charged primarily from solar energy resources.

Beyond the extension and increased flexibility, the IRA created several human impact bonuses that increase the value of the tax credit. To qualify for the full credit, a project must meet prevailing wage and apprenticeship requirements. Additionally, a project can earn a 10 percent boost for meeting domestic content requirements and an additional 10 percent for locating the project in an energy community (which includes census tracts in which coal-fired power plants have been retired since 2009 and adjacent census tracts, as defined by the IRA, see Figure 1).^{iv}

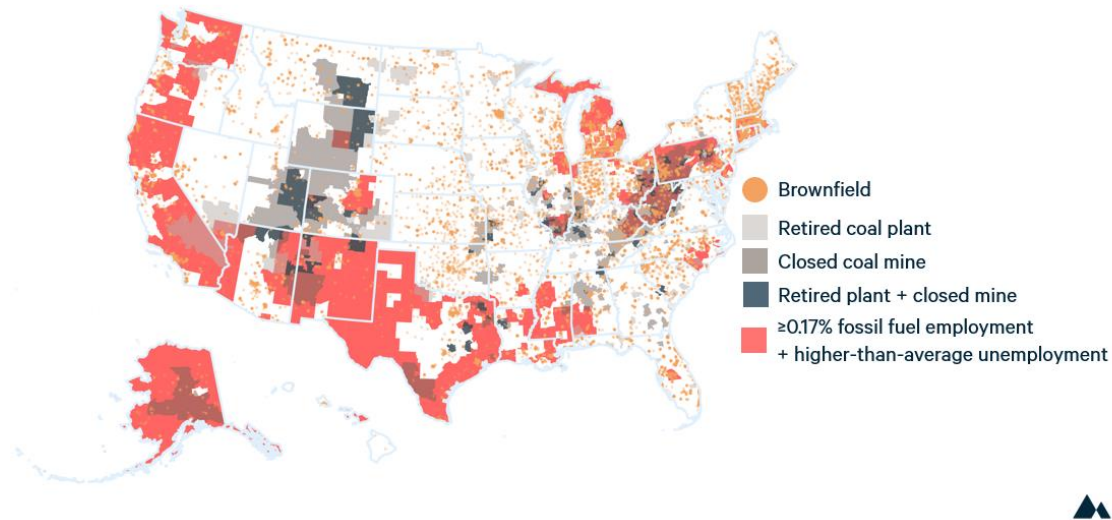


Figure 1. Map of probable energy communities, as defined by the IRA. Source: Resources for the Future.¹⁸

The combined impacts of energy community, labor, and domestic content bonuses reshape solar economics in coal communities. The median cost of new solar in these communities is about \$24/MWh with low variance, while the median marginal cost of coal is \$36/MWh with higher variance (see Figure 2). As discussed later in this report, this cost differential provides significant headroom for additional battery storage, which can also qualify for energy community bonuses.

^{iv} The 10 percent credit boost for siting projects in energy communities works slightly differently for the ITC and PTC, providing a 10-percentage point ITC bonus and a 10 percent bonus on the PTC credit value.

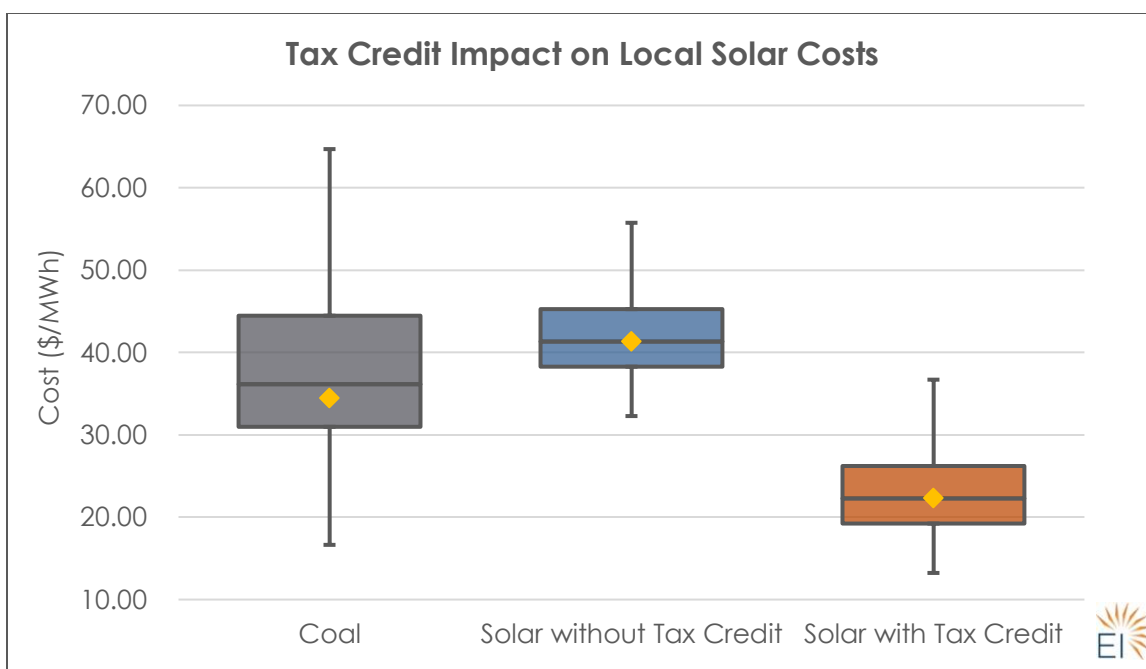


Figure 2. Impact of tax credits on local solar LCOEs in our analysis, including the energy community bonus. The yellow diamond indicates the average cost of each resource (weighted by generation). With the IRA, the economic case for local solar becomes unequivocal.

Reinvestment Financing

The PTC and ITC play the crucial role of decreasing the cost of developing clean electricity resources, but upfront cost is far from the only barrier to moving from coal generation to clean alternatives. One of the biggest hurdles to this transition is the rate impacts of adding large capital investments to utility rates when billions are still owed to debtors and investors on uneconomic coal assets. But a new IRA financing program to invest in clean energy infrastructure in current or former coal communities can overcome this hurdle. As the program only lasts until 2026, time is of the essence.

Most U.S. coal capacity is owned and operated by monopoly utilities, which collectively hold at least \$176 billion in unpaid fossil plant balances^v—accounting ledgers that represent the debt and equity capital structures utilities used to finance these plants over time. Utilities include this capital cost in electricity rates, typically recovered over the plant’s entire lifetime in a financial arrangement somewhat similar to a conventional 30-year mortgage (albeit one that is continuously extended as new capital is invested at coal plants). As long as the plant remains in operation or

until the investment is fully depreciated, customers are generally obligated to continue to cover these costs, which include substantial returns for utility shareholders. Without a change to this structure, monopoly utilities have little to gain from early coal plant retirement and they may perceive retirement or partial replacement as putting cost recovery at risk.

New IRA programs provide flexible, low-cost financing to clean up utility balance sheets by reducing the cost of investing in new local clean energy infrastructure, including wind, solar, batteries, transmission infrastructure, and reuse of the coal plant itself. Utilities and other power plant operators, such as independent power producers, can access low-cost government-backed loans to reduce the rate impacts associated with large capital expenditures required to transition from coal to clean and stimulate local economic development. The IRA created two novel programs to support utilities in transition:

First, the IRA appropriated \$5 billion to the U.S. Department of Energy's (DOE) Loan Programs Office (LPO) via the Energy Infrastructure Reinvestment (EIR) program to support \$250 billion in loan-making authority to facilitate refinancing and reinvestment in capital projects at fossil infrastructure sites, using below-market interest rates. Funds can be used flexibly to “re-tool, re-power, re-purpose, or replace” fossil infrastructure across the entire energy industry (including non-utilities), reducing the cost of replacement resources and creating numerous pathways for community diversification and redevelopment. The financing provisions are flexible enough to work for all parties—utilities, consumers, and communities. These stakeholders can use the financing to reduce the near-term rate impacts of capital transition, allowing new investment to arrive sooner in these communities that sorely need it as aging fossil plants ramp down.

Second, the IRA authorized a \$9.7 billion program specifically for rural electric cooperatives through the U.S. Department of Agriculture (USDA). Rural electric cooperatives provide electricity to more than 40 million people. Their power supply is particularly coal-heavy, with coal accounting for 28 percent of generation in 2020 compared to 19 percent nationwide.¹⁹ This means surrounding rural communities bear a disproportionate burden of coal-related pollution, while member-owned cooperative customers remain tethered to coal debt. While members may want to transition to clean energy to capture pollution and cost savings, this debt holds them back. Furthermore, simply shutting down cooperative coal plants could impact communities that rely on relatively high-paying jobs where economic opportunities are sparse. To address these challenges, the IRA funds USDA to provide direct grants or loans for rural electric cooperatives to procure clean energy, with an express purpose of reducing GHG emissions.

METHODOLOGY

As in the previous two coal cost crossover studies, this report compares the marginal cost of energy (MCOE) for existing coal plants across the U.S. with the LCOE for solar and wind. We compare the same coal costs to four different cost scenarios for renewables. Scenarios vary by resource type

(wind or solar) and by geographic scope (regional or local). For the first two scenarios, regional solar and regional wind, we separately examine the costs of solar and wind located within the same region as a given coal plant, calculating the LCOE to replace each plant's annual generation within a nearby region that corresponds roughly to the utility's service territory.^{vi}

For the last two scenarios, local solar and local wind, we look at local costs for solar and wind separately, calculating the cost if all replacement renewables are sited within a 45 km radius of the existing coal plant. Local solar and wind projects get the additional energy community tax credit bonuses in the IRA, which helps to offset losses in power resource quality due to the local siting constraint. A more detailed explanation of our methodology is available in this report's Appendix.

Coal Economics

To calculate the MCOE at each coal plant, we sum three cost components: the cost of fuel, the fixed and variable costs of operations and maintenance, and the going-forward routine capital expenditure costs, each calculated on a per-MWh basis. Using 2021 U.S. Energy Information Administration (EIA) data, we calculate the total going-forward marginal cost for all coal plants operated by utilities or independent power producers in the continental U.S., excluding plants that are used for co-generation of heat. These costs appropriately comprise marginal cost because they would not be paid if the coal plant retired. By contrast, we do not include unpaid capital balances as part of the MCOE because their payment does not depend on whether the plant retires.^{vii}

Renewable Economics

We used NREL's Regional Energy Deployment System (ReEDS) model to calculate solar and wind LCOE values, which are all-in estimates of the cost of energy output in MWh, taking into account all capital expenditure, operations, and maintenance costs. We used the 2021 actual cost values from the 2022 NREL ATB.

The ReEDS model uses solar and wind resource potential values at around 50,000 sites across the country, accounting for comprehensive exclusion criteria, including land cover, elevation, slope, environmentally sensitive areas, and local siting regulations. The model also provides annual capacity factors at each of these sites. The site-specific LCOE is then calculated based on capacity factor, as well as a comprehensive list of parameters including capital costs, fixed operation and maintenance costs, equity costs, interest rates, construction costs by location, construction period,

^{vi} We use regions defined by NREL's Regional Energy Deployment System model, explained in detail in the appendix.

^{vii} These remaining balances are the primary target of the reinvestment programs created by the IRA. Though we don't include the balances in our cost calculations, the potential to refinance and replace with clean energy is another path toward reducing coal generation beyond operating costs.

IRA tax credits, and depreciation. We calculate the LCOE after accounting for both the ITC and PTC 2022 tax credit values, using the cheaper of the two.

Renewables key assumptions

Across the four renewable scenarios, we make several key assumptions:

- Regional solar and wind costs include new grid interconnection costs, while local resources do not.
- All renewable resources qualify for the prevailing wage and apprenticeship hour tax credit bonus.
- All wind resources qualify for the full domestic content bonus, while 42 percent of solar resources qualify for the domestic content tax credit bonus based on current domestic content levels.²⁰
- Storage does not qualify for the domestic content credit bonus.
- All tax credits are reduced by 10 percent to account for transfer losses.

Regional renewables scenarios

For the two regional renewable cost scenarios, regional wind and regional solar, we start by finding the LCOE for regional wind and solar that could replace each plant's 2021 annual generation. The region we study for each plant is based on the ReEDS balancing area (of which there are 134, see Appendix) in which the plant is located, corresponding roughly to the utility territory. For each coal plant, we sort the wind and solar sites available in that region by LCOE and choose the best sites based on capacity factor to replace the coal generation. For selected sites within each region, we capacity-weight the site-level LCOEs to estimate the weighted average regional LCOE. Interconnection costs associated with transmission lines that connect the project to the grid are also added into these LCOEs, while we make no assumption about broader grid impacts.

Local renewables scenarios

For the local wind and local solar scenarios, we first determine the viability of the local wind or solar replacements for each coal plant. Using the plant's latitude and longitude as the center, we create concentric circles around each coal plant, starting with a radius of 5 km and moving up to 45 km in 5 km increments. We identify the solar and wind sites that fall within each of these concentric circles and separately estimate the site-level capacity and annual generation potential for solar and wind resources. We then estimate the minimum radius needed to replace the annual generation from each coal power plant with solar or wind resources.

If there is enough generation found within the 45 km radius, we then determine the local LCOE by capacity-weighting the site-level LCOEs for the maximum radius needed to match the existing

plant's generation. For solar, nearly all plants meet the generation requirement within a 20 km radius while for wind, the average radius is much larger and there are many plants without enough wind generation within 45 km because of the more site-specific nature of wind energy potential and the larger land footprint (see Figure 3).

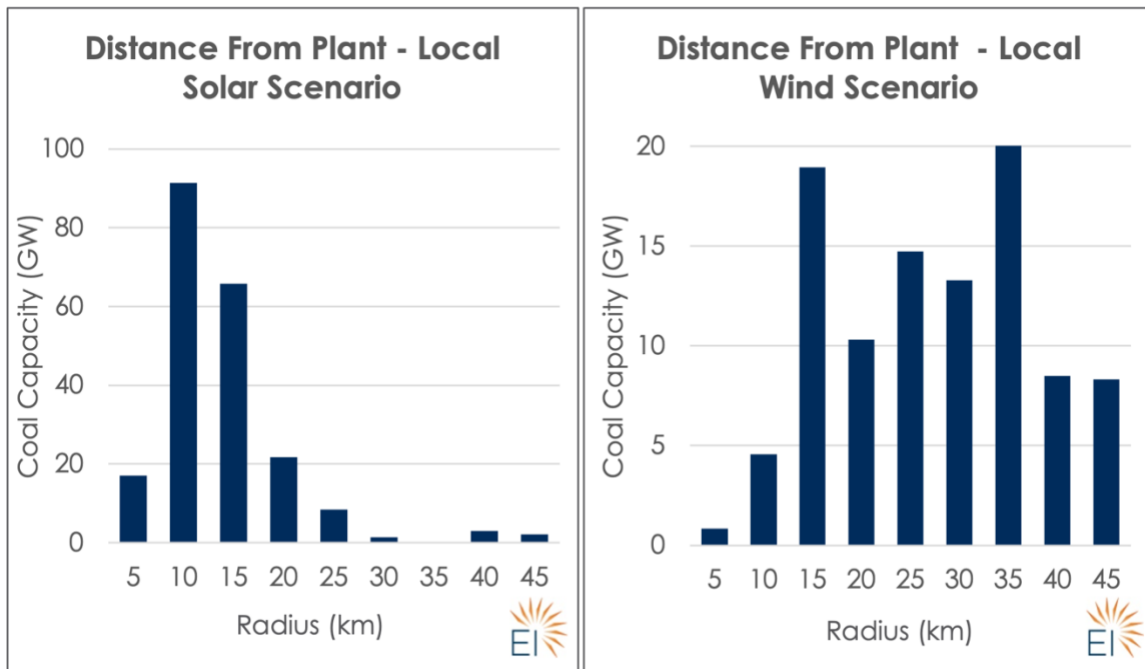


Figure 3. This figure plots the radius needed to match each plant's generation, while still being cheaper than coal, for both local solar and local wind. The majority of coal capacity has enough solar potential within a 20 km radius to meet the plant's entire annual generation in our local analysis and still provide cheaper energy than coal. While many plants have sufficient and cost-effective local wind nearby, less potential is available in close proximity for local wind.

For the local scenarios, we assume that all projects sited within 45 km of the plant will receive the IRA's 10 percent energy community bonus tax credit, given that both the census tract and neighboring census tract to any retiring coal plant fit the IRA's definition of an energy community. For these scenarios, interconnection costs are not included in the LCOEs as we assume that the new resources can utilize the existing plant's interconnection infrastructure.

Storage analysis

For the local solar scenario, we also analyze the economic feasibility of installing four-hour battery storage capacity along with the solar to provide additional reliability services to the grid. For this analysis, we start with a \$330 per kilowatt-hour (kWh) price for the storage,^{viii} and we include a 36

^{viii} This price is based on the 2021 actual storage costs in the NREL 2022 ATB.

percent ITC (the full credit plus the energy community bonus, minus transferability losses). After calculating the savings from replacing the coal generation with local solar generation, we then determine how much battery capacity those cost savings would fund. Due to uncertainty in the battery price going forward, we calculate the battery capacity funded for storage prices ranging from \$100 to \$400/kWh.

RESULTS & DISCUSSION

Main findings:

1. >99 percent of plants studied are more expensive to run than to replace with new renewable wind or solar energy.
2. >97 percent of plants studied are more expensive to run than to replace with either local solar or local wind energy within 45 km (approximately 30 miles) of the coal plant.
3. Replacing coal generation with local solar resources could drive up to \$589 billion in clean energy investment in energy communities across the U.S.
4. Replacing coal generation with local renewable resources could save enough to finance installation of 137 GW of four-hour battery storage—62 percent of the coal fleet's nameplate capacity.

Overall comparison between coal and renewable costs

For this report we combined elements of the two previous Coal Cost Crossover reports: We looked at replacing coal power with regional wind or solar resources *and* at replacing coal power with local wind or solar resources close enough to a plant to take advantage of its transmission connection and the energy community bonus tax credit. Across these four scenarios, we found that:

- 199 plants are more expensive to run than to replace with regional wind.
- 190 plants are more expensive to run than to replace than regional solar.
- 104 plants are more expensive to run than to replace than local wind.
- 199 plants are more expensive to run than to replace than local solar.

Analyzing these scenarios together, we found all but a single coal plant^{ix} in the dataset of U.S. coal plants to be more expensive (lower renewable LCOE than coal MCOE) compared to replacement by at least one of these renewable options. Between local solar and local wind, 205 out of 210 plants had at least one cost-effective local renewable option. Of these, 98 had *both* local solar and local wind options that were cheaper than coal (see Figure 4). This represents a sharp acceleration

^{ix} The single coal plant is the Dry Forks Station in Wyoming. It is the newest and among the cleanest coal plants in the U.S. coal fleet and is still only \$0.32/MWh cheaper to operate than available regional wind. It is also a testbed for carbon capture use and storage (see <https://www.powermag.com/dry-fork-a-model-of-modern-u-s-coal-power/>). A similar plant built today would include capital costs and would not be competitive with new renewables.

in the previously observed trend in our coal cost crossover reports (see Figure 5). The full results of all four scenarios can be viewed in the accompanying [spreadsheet](#).

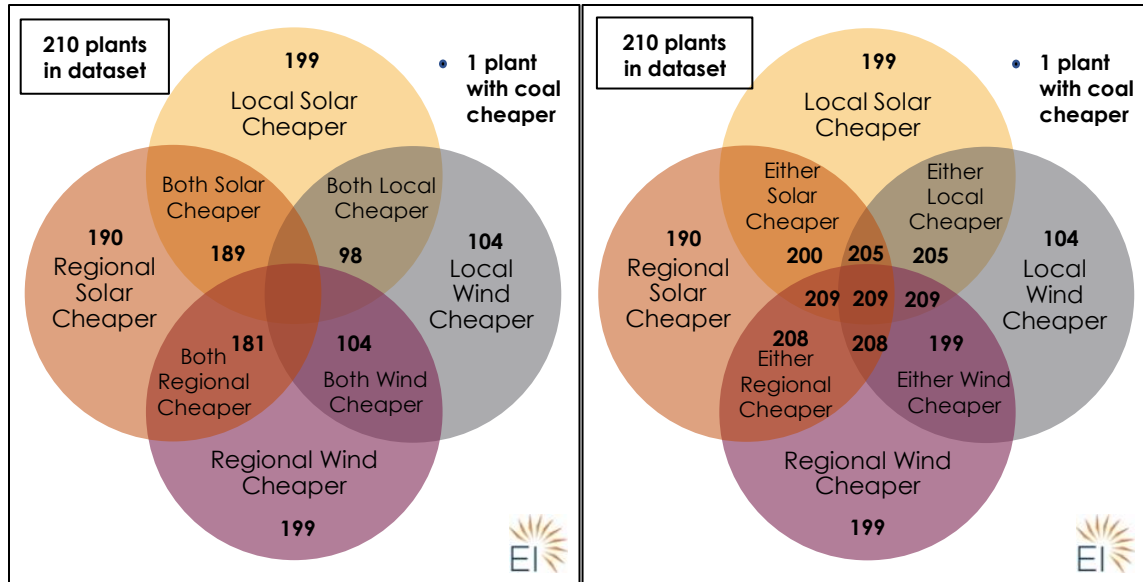


Figure 4. A closer look at the 210 coal plants in our data set based on the specific comparison with renewables that was made. The Venn diagram on the right looks at inclusive intersections (either resource is cheaper than coal) while the one on the left looks at exclusive intersections (both resources are cheaper than coal). We did not analyze any hybrid combinations of wind and solar, although this is clearly a possibility in the local context (98 plants) and the regional context (181 plants).

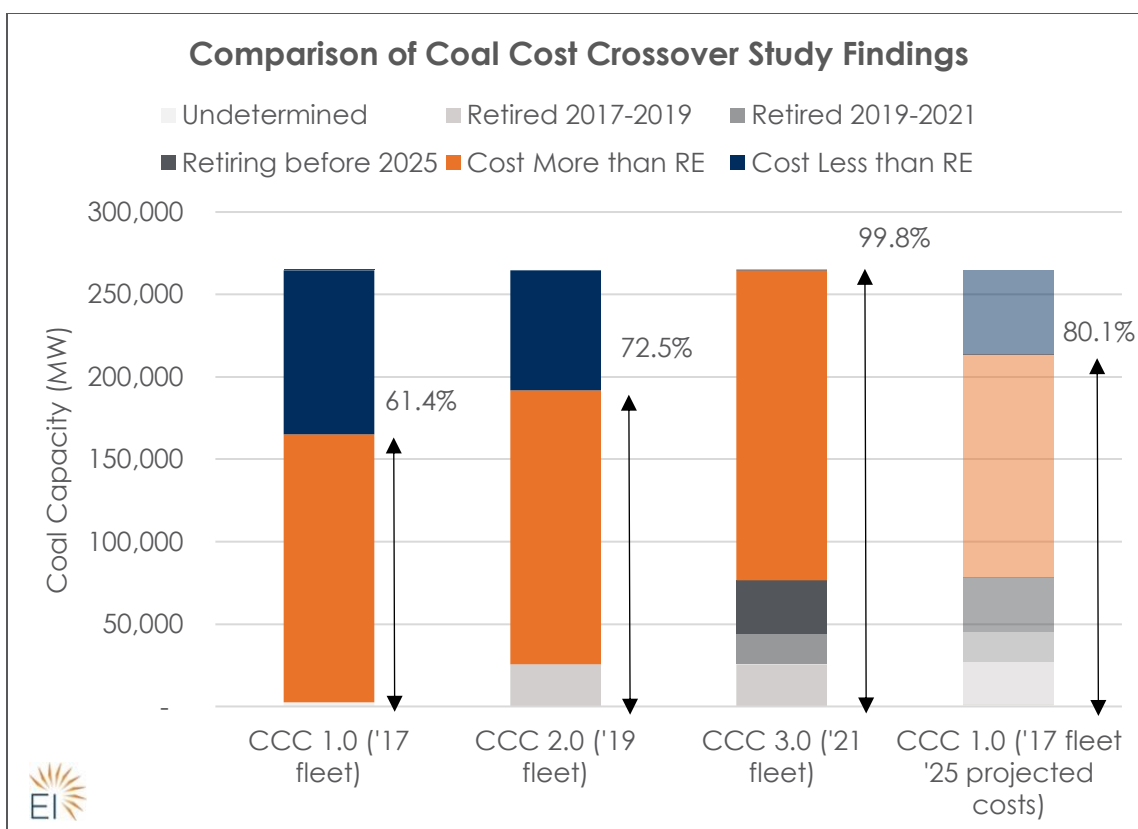


Figure 5. Comparison of our two original analyses of renewables and coal cost-competitiveness. The first included a 2025 projection for renewable costs to compare with 2017 coal going-forward costs. This comparison highlights how much the trend for coal being uneconomic compared to replacement by renewables has accelerated since the first report published in 2019.

Comparison between coal and cheapest available wind or solar resource

For the plants that were uneconomic, multiple renewable options were less expensive than coal generation, but regional wind and local solar were most frequently the cheapest overall resources (see Figure 6 and Figure 7). Regional wind was the cheapest option for 117 plants, while the most economic resource was local solar for 75 plants, local wind for 13, and regional solar for only four.

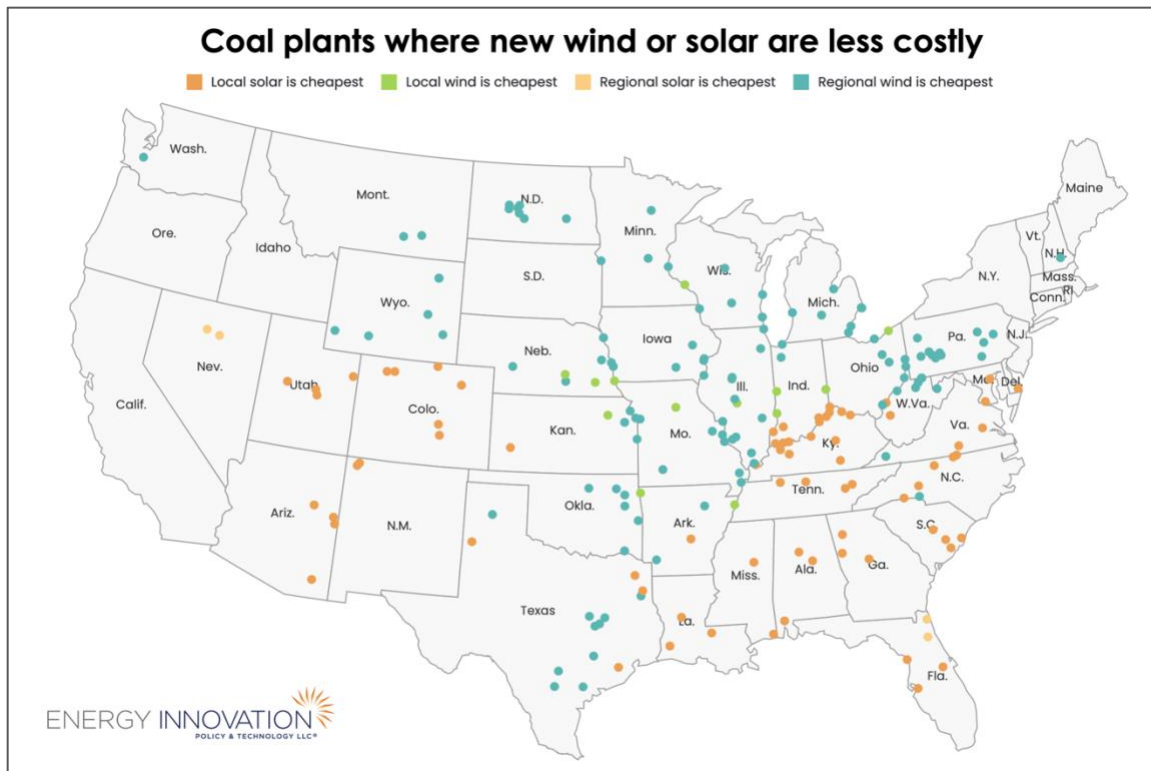


Figure 6. While most plants have multiple cheaper renewable options, the overall cheapest renewable resource varies by geography.

Notably, for solar, local replacement is cheaper than regional replacement in many cases due to low regional cost variability, lower transmission spur line costs,^x and IRA energy community bonuses. For regional versus local wind, however, regional resources tend to be cheaper even with the added costs due to higher variation in resource quality for wind—going further from the plant often yields significantly better wind energy sites.

^x A “spur line” is the transmission line that connects a renewable project to the bulk system at a point of interconnection. In this analysis, we do not make assumptions about interconnection costs beyond the cost of building the spur line. In this limited respect, we anticipate that local wind and solar costs would be lower than regional renewables, because local renewables are adjacent to the coal plant’s point of interconnection. We recognize that interconnection costs for renewables have been increasing for a variety of reasons as they sit in ever-growing interconnection queues around the country, but also hypothesize that some renewables could reuse existing coal plant interconnection rights with very low interconnection costs. See <https://emp.lbl.gov/news/pjm-data-show-substantial-increases>.

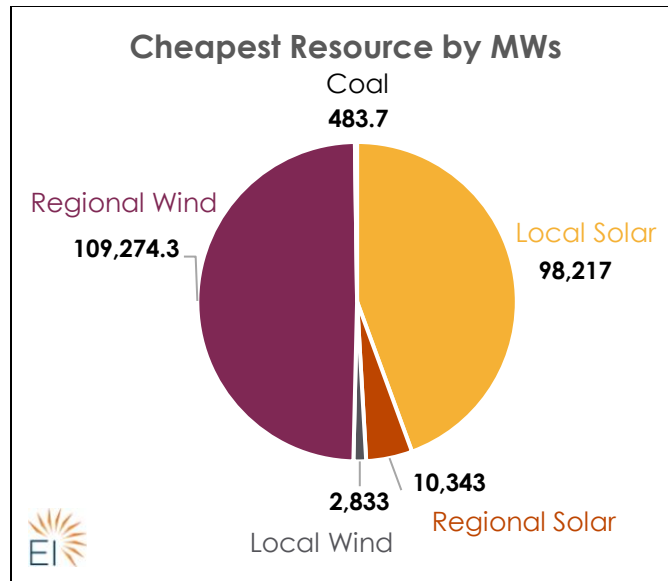


Figure 7. This chart shows the cheapest renewable resource option for each MW of coal capacity studied in this report. Local solar and regional wind are the cheapest renewable resources for nearly all plants.

We still see a wide range in the relative economics between existing coal and new wind or solar, with the all-in costs for the cheapest renewable option anywhere from zero (for one plant) up to 80 percent cheaper than the going-forward costs for coal, absent a few edge cases. Typically, the least economic plants have low capacity factors that result in very high fixed marginal costs per MWh or very high fuel costs.

For more than three-quarters of U.S. coal capacity, the all-in cost per MWh of the cheapest renewable option is at least a third cheaper than the going-forward costs for the coal it would replace (see Figure 8).

The substantial cost savings from replacing coal with renewables indicates the potential to invest in additional resources that provide complementary services like flexibility and transmission, without raising costs. Policymakers should consider a portfolio of clean resources that together provides adequate value and any needed reliability services. These resources could include storage,

regional or interregional transmission upgrades, demand-side resources, and complementary portfolios of wind and solar.

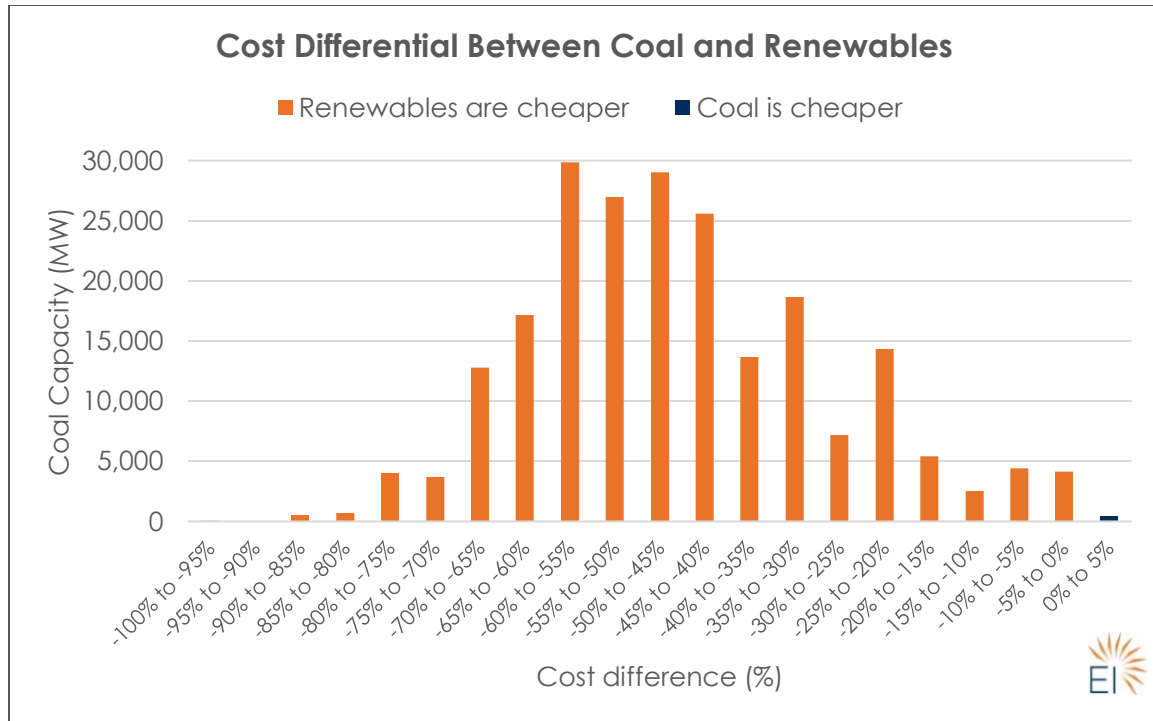


Figure 8. Aggregated plant capacity shown as percent difference between renewables LCOE and coal going-forward cost. The orange bars indicate capacity where renewables are cheaper than coal and coal is deemed "uneconomic." The one blue bar indicates the sole plant that is still cheaper to operate than replace with renewables.

Local replacement of coal

Local solar and wind

For 199 of the 210 plants studied we find that local solar replacement is more economic than coal, based on energy generation alone, and for 75 plants it is the cheapest option entirely. Local wind is also a viable option for many plants, with 104 plants having cost-effective local wind resources and 13 having local wind as the cheapest option. For 98 plants, both local wind and local solar were

cheaper than coal. While we did not study any combinations of the two, this result indicates that a portfolio that includes both local wind and local solar would likely be a viable option with additional reliability value near many plants.

In these local replacement scenarios, we looked at replacing all the annual electricity generated by a given coal plant with either local wind or local solar within 45 km of the plant. This allowed us to assume lower interconnection costs^{xi} (a significant barrier for new projects)²¹ while taking advantage of the IRA's energy community tax credit bonus. In nearly all cases we studied, the reduced interconnection costs and added tax credit compensates for potentially lower resource quality when restricting site selection in areas close to the plant. We find particularly good resource quality in the local solar scenario, where 191 plants have sufficient sites nearby such that their generation can be replaced within 20 km.

Local replacement offers three other benefits. First, local replacement can help preserve livelihoods and tax revenue for surrounding communities through the energy transition.^{xii} Second, local resource replacement falls into the category of projects that can qualify for loans via the DOE's

Solar plus storage stepping in at North Valmy

In Nevada, NV Energy has already realized the cost and community benefits of using solar plus storage in place of the 567 MW North Valmy Generating Station, near Winnemucca. Two new solar plus storage facilities located within the same county will replace this plant when they are completed by 2025. The two replacement projects will provide 250 MW solar capacity plus 200 MW of storage, and 350 MW of solar plus 280 MW of storage. These projects will also create several hundred construction jobs, and the storage will help shift the solar generation to the times of day it is most needed, serving the reliability needs of the area. This is consistent with our analysis, which finds that it would be cheaper to use solar plus storage up to the full plant's capacity than to continue to run the coal plant. Plants across the country can now follow Valmy's example and effectively decarbonize with solar plus storage.

^{xi} In our modeling, we use ReEDS spur line costs as a proxy for interconnection costs of regional renewables. For local renewables, we assume no interconnection costs because the point of interconnection already exists at the coal plant. This is a simplification—each site will be different and will require an interconnection study or transmission plan to ascertain the interconnection costs.

^{xii} New renewable energy installations are only one piece of the puzzle when it comes to community transition as they typically do not provide as many jobs or as much tax revenue as a coal plant. While local energy replacement can contribute, further community re-development and economic diversification is needed, as discussed further in the policy recommendations section.

EIR program, as the projects would be a direct reinvestment in energy infrastructure. Our analysis shows investment in local solar resources could drive \$589 billion in capital investment to energy communities across the country (see Figure 9).

Third, siting renewables in proximity to plants creates the possibility that these new resources could use the existing plant's grid interconnection. Recent analysis of PJM's interconnection process shows that the median interconnection cost from 2020 to 2022 grew ten-fold over the costs from 2017 to 2019, largely due to transmission network upgrade costs.²² While we considered reduced interconnection costs for local resources, the advantage of local replacement could be even more considerable as the cost of the line is only a part of the problem. For clean energy projects across the country, long interconnection wait times are also a major hurdle to overcome.

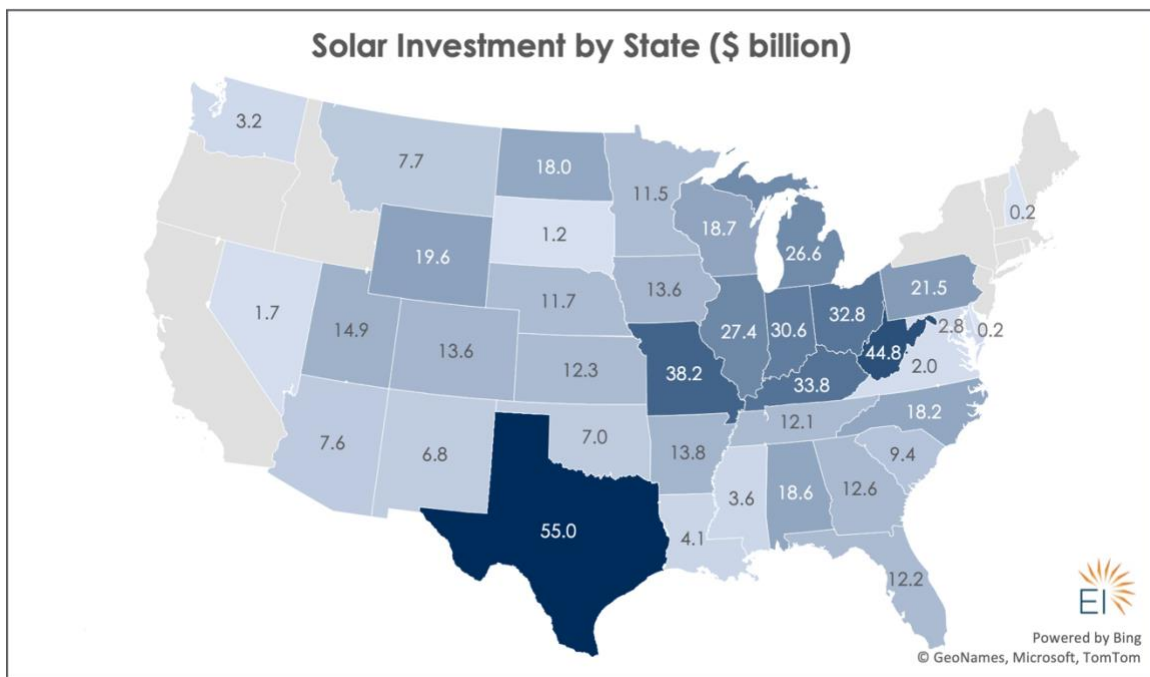


Figure 9. The solar capacity needed to provide enough energy to make up for coal generation across the country would drive hundreds of billions in investment. States with no investment number had no plants in our data set.

Local solar plus storage

We followed up on our local solar scenario by looking at a solar plus storage replacement option for each plant that includes local solar energy plus four-hour batteries to provide additional capacity value and higher market profitability in some cases. We find that the savings available from switching from coal generation to local solar generation can finance 137 GW of four-hour battery capacity at a price of \$330/kWh across the coal fleet.

For more than a third of the coal capacity studied, we find that in addition to energy generation replacement with local solar, 80 percent or more of the plant's capacity can be replaced with four-hour batteries at a combined levelized cost that is still less than the going forward cost of the plant. For the remaining plants, the percentage of capacity that can be economically replaced is still quite significant: We find that savings from renewable generation could fund storage at more than 50 percent plant capacity at 136 plants.

Renewable options cheaper than expensive upgrades at Mitchell plant

In 2021, American Electric Power determined it would likely be more cost-effective to retire West Virginia's Mitchell Power Plant than pay for expensive pollution control upgrades required by the U.S. Environmental Protection Agency (EPA). However, the West Virginia Public Service Commission (PSC) ruled that the utility had to keep the plant open, and that WV ratepayers must pay for the upgrades. At the same time, in Kentucky and Virginia, who were also receiving power from the plant declined to make their state's customers pay, leaving West Virginians to shoulder a \$448 million price tag. Our analysis shows taking advantage of regional wind resources would be 48 percent cheaper than continuing to run this polluting plant. Replacement with local solar and battery storage would be 50 percent cheaper and would provide the reliability the PSC seeks while saving ratepayers hundreds of dollars every year.

This local solar plus storage arrangement has at least three advantages:

First, solar plus storage provides resources with a significant capacity and ancillary service value at the same place on the power grid, addressing in part possible reliability concerns that may be associated with coal plant retirement.

Second, the new storage ITC means batteries do not need to be co-located with renewables to take advantage of the tax credit. This means that while local renewables may need to be sited a short distance from the plant, storage can be placed directly at the coal plant site and use existing electrical infrastructure to act as a central collection site for renewables. This arrangement also bolsters economic development opportunities in coal communities.

Third, combining solar and storage empowers a gradual coal phase-out, benefiting communities and grid reliability. Electricity generated from coal can be reduced, while keeping the coal boiler and generator available for emergencies. If needed, the generator can eventually be transformed into a piece of grid regulation hardware requiring no boiler, and batteries can store and release renewable energy to make the whole system available at times of highest grid demand. Renewable energy can

be a part of an economic diversification package that may include other re-purposing of the site, such as a plant in Michigan that was re-developed into an insurance company's headquarters.²³

The reliability implications of coal plant retirement should be evaluated for each specific plant. A one-to-one replacement is often not necessary given the capabilities of the remaining power plant fleet. For example, the battery capacity necessary to take over the reliability burden of any given coal plant is varied, depending on the role of the plant and broader resource mix, and it is not needed at all in many cases. Wind and solar (especially in a complementary combination) already tend to provide a measure of capacity value to the regional grid. Other assets like faster, more flexible gas units or behind-the-meter resources may already be carrying more of the regional reliability burden, and transmission expansion can help reduce the need for dispatchable generation for resource adequacy as well. Therefore, coal capacity is not always necessary for reliability depending on the resource adequacy in each region as determined by the balancing authority.²⁴

Figure 10 shows the percentage of battery capacity at each plant that can be funded by coal replacement with local solar, providing a range of options for combining renewables with storage.

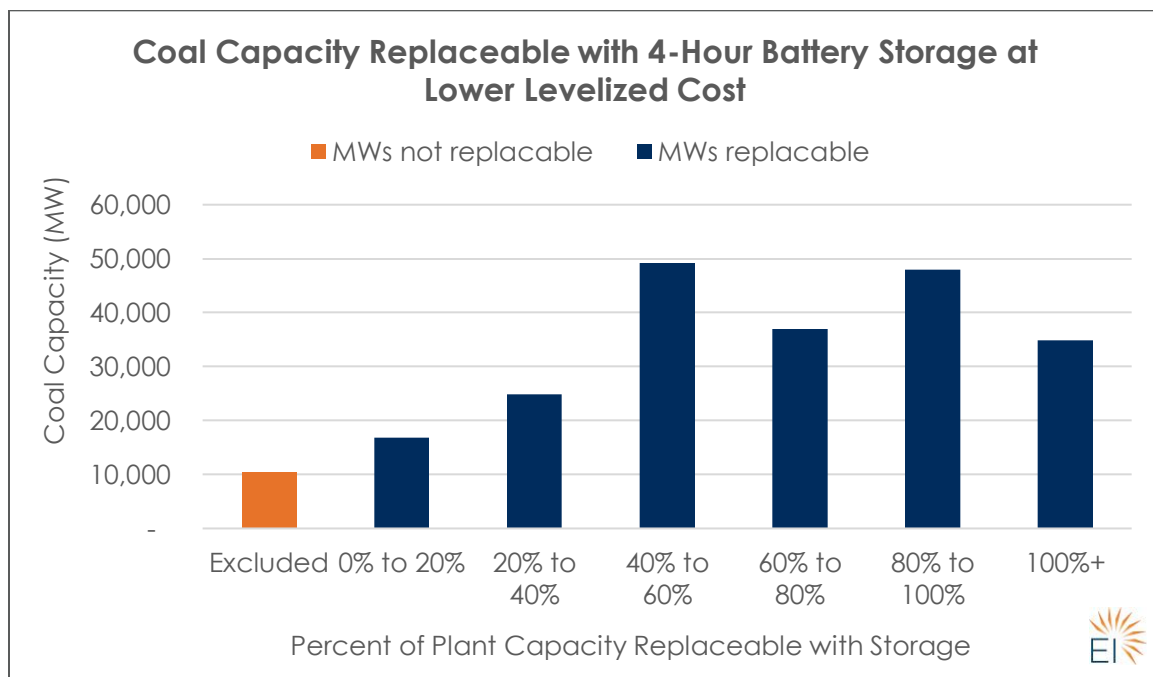


Figure 10. Coal plant capacity (in MW) by the percentage that can be replaced using only coal crossover savings. "Excluded" indicates plants for which local solar generation was available but was not cheaper than coal.

The economics of battery replacement for capacity are highly dependent on battery costs. For the analysis above, we used \$330/kWh as the cost of storage, which is the 2021 cost for storage in the NREL 2022 ATB.²⁵ Our cost accounted for the new standalone storage ITC and energy community tax credit. To study the sensitivity of these findings to battery prices, we evaluated the potential for capacity replacement across prices ranging from \$100/kWh to \$400/kWh (see Figure 10).

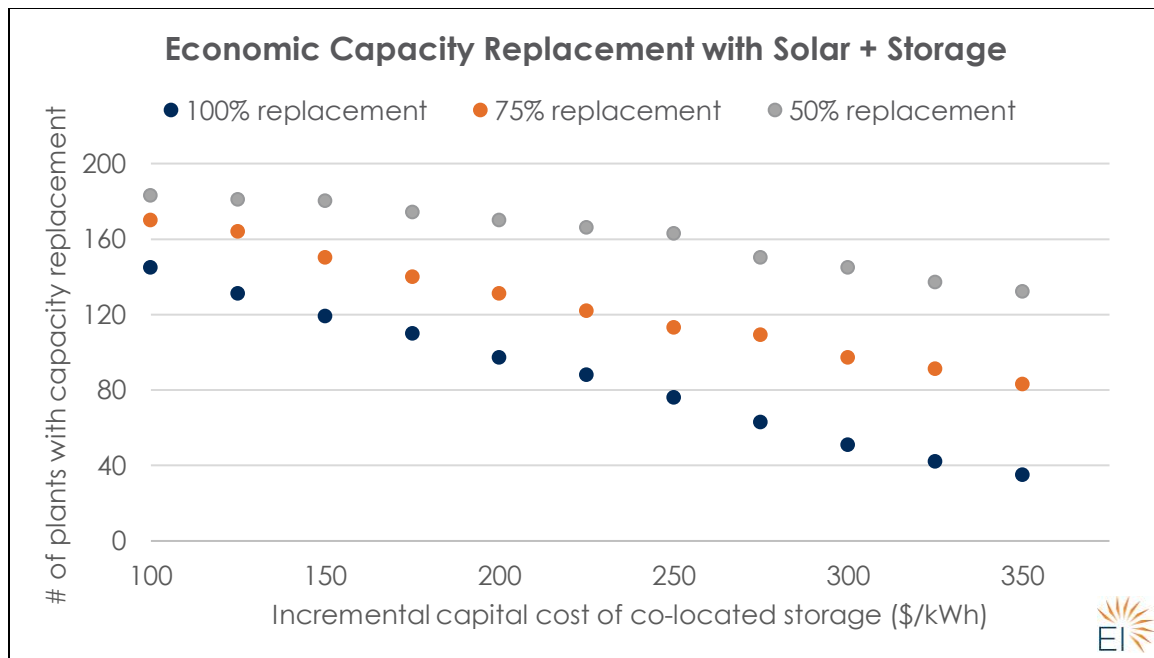


Figure 11. Economic battery capacity relative to battery price by percent capacity that can be replaced at each plant.

Utilizing additional financing to fund local resources: Ameren’s Rush Island Plant

It is important to note, however, that fuel savings are not the only source of savings that could help finance replacement batteries in a coal-to-local renewables swap.

For example, Ameren’s Rush Island power plant in Missouri is not a strong candidate for financing batteries solely with savings from switching to local renewables. Yet by also accounting for needed upgrades, the plant’s remaining balance, and reliability concerns, the case for financing batteries for reliability value becomes stronger.

Ameren was planning to retire the 1,195 MW coal plant in September 2022 partially due to the expense of adding court-ordered selective catalytic reduction (SCR) to address air pollution

noncompliance, with a price tag of \$310 million^{xiii} to \$1 billion.²⁶ Unfortunately, because early retirement could cause severe voltage stability problems leading to cascading power outages, the Midcontinent Independent System Operator (MISO) sought to keep the plant online and received Federal Energy Regulatory Commission (FERC) approval for a 12-month system support resource agreement to be renewed annually.^{xiv} According to the grid operator, potential renewable energy additions or possible demand-response programs wouldn't adequately address the location-specific voltage problem. However, due to the geographic nature of the potential voltage instability, local renewables coupled with batteries could go a long way toward mitigating this concern without waiting for the transmission upgrades MISO deemed necessary.

Our initial analysis finds that switching to renewables could generate savings to pay for replacing replacement of only 4 percent of the plant's capacity with batteries. However, the IRA now creates new possibilities. Because Ameren faces capital expenditures in the \$300 million to \$1 billion range, and already holds an estimated \$600 million for the plant in its rate-base (interest on which is paid by its customers at standard utility rate of return), existing state public utility commission securitization authority could be used to refinance this obligation in combination with the EIR program, generating much greater customer savings.^{xv} Investing these savings in four-hour battery storage could match 85 to 165 percent of the plant's capacity. Furthermore, batteries would only be necessary if the local renewables on their own were not sufficient to provide voltage support or if the proposed transmission solutions proved too slow or expensive.^{xvi}

New IRA financing and tax credits make replacing coal plants with a combination of local wind and solar power supported by batteries an attractive option for most coal plants in the U.S. Such replacement can be done with a minimum of disruption to the grid while keeping jobs in affected communities—not to mention the great improvements to public health from reduced pollution.

POLICY RECOMMENDATIONS

Our analysis makes it clear the comprehensive the IRA tax incentives have created a favorable policy environment for the coal-to-clean transition. However, the transition can be made even more cost-effective if utilities harness the IRA's loan and grant programs and use best practices to assess cost-saving replacement options.

^{xiii} Assuming \$250/kW all-in costs. See <https://www.powermag.com/estimating-scr-installation-costs/>.

^{xiv} MISO identified four transmission upgrades that are needed to maintain voltage on the grid, with the last one expected online by June 2025, according to the grid operator. See <https://www.utilitydive.com/news/ameren-missouri-coal-rush-island-miso-ferc/630226/>.

^{xv} The interest rate on the securitized loans or government-backed loans through EIR are assumed to be 2.95 percent, or the average of the 20-treasury yield across the last 10 years plus 0.375 percent. Missouri law already allows for coal plant securitization.

^{xvi} While MISO investigated replacement of the plant with renewable energy, it does not appear that MISO considered renewables in geographic proximity to the plant.

Planners and policymakers should make sure they are not caught unprepared by a wave of retirements, and that replacement renewables and complementary flexible resources can be deployed in a timely manner. Advocates and policymakers interested in capturing the economic and public policy benefits of shifting away from coal can take several actions to ensure that power plant operators take advantage of the moment by requiring utilities to account for IRA incentives and funding programs in planning and procurement. Finally, our analysis suggests that IRA provisions designed to encourage a just transition for coal communities are well positioned to spur

new investment in generation and grid balancing resources in the immediate vicinity of existing plants, but experience has shown that a just transition will only happen with the careful attention of legislators and regulators alongside local communities.

Reliability assessment keeping expensive Indian River plant online

Delaware's only remaining coal plant, Indian River Generating Station, was planned for retirement by June 2022—until the grid operator, PJM, requested it remain open until 2026. PJM had determined that transmission upgrades would be needed to stabilize the grid before the plant could be taken offline. The plant, which only has one remaining unit, is historically the worst polluter in Delaware and also the eighth most expensive plant we analyzed due to low capacity factor and high estimated fuel costs. Local replacement of this plant could assuage reliability concerns by providing generation and capacity needs at the same location on the grid. Our local analysis finds that 246 MW of storage could be funded via savings. At over 50 percent of the plant's capacity, this is a good candidate for re-assessment of reliability needs.

Preparing the way for coal transition

Improving interconnection and transmission processes

The Rush Island Power Station example discussed above is not unique and blocking retirement of uneconomic plants due to broader system stability concerns and transmission requirements harms customers. To move forward while maintaining reliability, independent system operators (ISOs) and regional transmission organizations (RTOs) should proactively study solutions that can enable plant retirements. The alternative—overriding utility retirement plans and requiring FERC approval for expensive stopgap payments to keep high-cost plants running—is not good for utilities or their customers.

Our analysis shows that post-IRA, almost every coal plant has reached its economic tipping point. As pollution standards and clean energy policies continue to worsen coal

plant economics, ISO/RTOs will increasingly encounter situations where innovative resource

portfolios will be needed to economically and reliably replace coal plants, including transmission. As neutral arbiters of just and reasonable rates, system operators must be ready to enable cheaper electricity and public policy goals by allowing utilities to retire uneconomic plants. Proactive transmission planning and deployment, alongside improvements to interconnection processes are both crucial to prepare for uneconomic plant replacement.

Absent regulators stepping in, retiring a plant is much easier than building a new renewable project. Price signals may induce coal retirements before new renewable projects can be approved and built to take their place. The growing interconnection queue backlog is of particular concern here. As of 2022, the two largest power markets in the U.S., MISO and PJM, had about three times more renewables capacity waiting in the queue than they had existing coal capacity.

For PJM, this backlog was deemed insurmountable. While PJM works through its existing interconnection requests, it will not review new requests until early 2026. It is clear that additional measures to improve the interconnection process, including better regional transmission planning, are needed to avoid similarly extreme measures in the future.²⁷ FERC is currently considering interconnection policy changes, but state public utility commissions can also help by examining their state's queue and assessing whether proactive transmission buildout could connect cost-effective clean energy. In states outside an ISO/RTO, states hold sole responsibility for proactive transmission and planning process reform to reduce wait times and hasten the pace of in-state clean energy investment.

Building local: accelerating deployment while maintaining reliability

Action from FERC and other policymakers on interconnection reform and transmission buildout cannot come too soon. A recent brief from Lawrence Berkeley National Lab (LBNL) analyzing interconnection costs in the PJM region finds that, alongside the tremendous lengthening of the interconnection queue, interconnection costs have increased substantially in recent years.²⁸ The main driver behind these increases has been broader network upgrade costs, reflecting system changes due to the influx of renewables and the fact that optimal renewable sites are often far from the coal they might replace.

There is no doubt that variable renewable resources are fundamentally different from dispatchable fossil generators, but variability does not imply unreliability. Studies are clear: A coal-free U.S. electricity system can be dependable.²⁹ Yet renewables do require a different resource adequacy framework, which makes resource diversity, energy sufficiency, regional and interregional transmission, and demand response more important. As system operators design new resource adequacy metrics, regulators should support them by defining minimum resource adequacy requirements and soliciting cost information.³⁰

In a high-renewables environment, interregional electricity transfer can help manage local weather variation, providing higher reliability at lower cost. RTOs and regulators can enable interregional

coordination by expanding planning areas or subsidizing transmission lines that provide for specific reliability needs. Finally, regulators and state legislatures can require resources that bolster reliability like energy storage has become a cost-effective way to integrate renewables, as this report shows. However, storage still lags in investment. A legislative storage mandate, like the one passed in California in 2013 can help accelerate storage deployment.³¹

Ultimately, building out the network to include and adapt to some of the best available renewable resources, evolving the bulk power system’s resource adequacy framework, and improving inter-regional coordination supports a least-cost, reliable electricity system given the new IRA incentives. But, as is evidenced by the delays described above, all this takes time. Building local resources closer to or at the same site as coal plants could dramatically accelerate clean energy deployment while providing significant incremental reliability value.

Prior to the IRA, local replacement was not always economic on an annual generation cost basis relative to the cost of maintaining a coal plant. However, to support a just transition, the IRA includes additional incentives for building new clean resources near coal plants or “energy communities.” Our analysis shows that local wind or local solar plus storage could create a cheaper electricity portfolio than nearly every plant, while delivering the same amount of electricity and providing significant reliability value. Even if a coal plant weren’t completely shut down, it could work in tandem with cleaner, cheaper resources fed through the same point of interconnection to deliver cheaper, cleaner electricity without materially affecting the transmission system and system operations (it might even improve these). Utilities, ISO/RTOs, and state and federal regulators should move swiftly to develop standard templates that allow for coal plant hybridization or replacement with clean portfolios. These templates would have to be generically robust enough to satisfy system reliability and stability concerns under a variety of conditions to replace coal without a lengthy interconnection process.^{xvii}

Proactively pursuing transition

Re-evaluation of integrated resource plans and improving competitive procurement

While measures to proactively plan for and better accommodate new renewable projects are necessary to capture the huge economic benefits of transitioning expensive coal plants to cheaper renewables, they are not sufficient. Utility integrated resource plans routinely overestimate new renewable costs, and the IRA programs will likely make these overestimations even higher. Any

^{xvii} There may be concerns about undermining competition if some resources are allowed to skip ahead of the line, but presumably standard templates will involve costlier investments than what might be proscribed in a more specific interconnection study. In any case, it makes sense to recognize that providing replacement resources at or near an existing resource is easier and simpler for the network, and the benefits of just transition and accelerated deployment should be balanced against competition concerns.

investment plan or market-based solicitation for renewable contracts completed before August 2022 is now out of date. Regulators can expect independent power producers to offer lower bids for just about any clean energy technology. Under their authority to set just and reasonable rates, PUCs should insist that utilities redo integrated resource plans and resource solicitations, despite the procedural complexity. For example, advocates have already submitted evidence to the North Carolina Utility Commission that such a re-examination would be prudent for Duke Energy's Integrated Resource Plan and Carbon Plan.³²

In addition to cost updates, integrated resource plans should account for the benefits of location-based procurement to replace coal generation. In New Mexico, the Energy Transition Act required the Public Service Company of New Mexico to site some of the replacement resources for the San Juan Generating Station in the nearby school district to replace lost tax revenue.³³ Because of location-specific tax credit bonuses, traditional regulatory requirements to minimize consumer costs now require an examination of local investment in replacement wind, solar, and battery resources.

FERC and NERC should work with the ISO/RTOs to create standardized approaches to gradual replacement with local resources and eventual development of reliable resource portfolios that include renewables, transmission, and emerging technologies like power electronics and synchronous condensers.

In addition to accurately assessing renewables during planning processes, enabling competitive procurement is crucial to getting steel in the ground. Even before the IRA, unsubsidized renewables were the cheapest new resource in most of the country. However, regulators can have difficulty discerning the true cost of clean energy or comparing variable clean resources with dispatchable fossil power providing different services. Such assessments generally depend on limited utility information.

All-source procurement is a way around this—it is a well-established but underutilized process that requires the utility to provide assessments of resource need, then bid these services to the market. For example, Xcel Energy Colorado achieved record-low wind, solar, and storage prices that shocked the electricity world with an all-source procurement in 2018, avoiding costly investments in gas and accelerating coal retirement.³⁴ PUCs should establish all-source procurement rules that link these solicitations as inputs to integrated resource planning processes that ultimately result in resource procurement—a key part of the Colorado planning process.³⁵ These solicitations also provide the opportunity to assess and define needed system reliability attributes after coal plants retire and allow supply-side, demand-side, transmission expansion, and regional market resources all compete to fill that need.³⁶

Utilizing IRA funding and financing programs

Our comparison of the going-forward costs of existing coal plants with regional or local renewables doesn't capture all the economic advantages of such a transition. The IRA also includes measures that facilitate savings from lower cost financing.

First, the IRA created a \$9.7 billion fund for rural electric cooperatives to reduce GHG emissions via a myriad of methods. With cooperative assets highly tied up in coal and without the same access to capital as investor-owned utilities, the transition to cheaper clean resources can be particularly challenging. To take advantage of these funds as soon as possible, co-ops should develop clear plans that use new clean energy and coal generation replacement to achieve deep GHG emissions reductions, in accordance with the IRA's statutory language.³⁷ For their part, states should provide resources to support the planning and application processes. With nearly 18 GW of plants in this analysis majority-owned by cooperatives, this program, if used to its greatest potential, could spur billions in rural economic development.

In addition to rural cooperative funding, the IRA provides substantial debt refinancing potential, when paired with reinvestment in new clean energy infrastructure. While we find all but one plant are uneconomic when compared to replacement with new wind and solar, many plants have large debt burdens that hamper the customer savings available from clean energy replacement. Some states have explicitly allowed utilities to refinance these remaining balances via securitization, but now all power plant owners have access to flexible low-cost capital to finance new clean energy projects reusing coal-

Cleaning up coal ash at the G G Allen Steam Plant

In 2014, the now-retired Dan River Power Station leaked 39,000 tons of coal ash into the Dan River—leaving residents without drinking water for years and requiring a \$3 million clean-up. It also kicked off an investigation of Duke Energy in North Carolina that found all 14 coal plants in the state were leaking coal ash. G G Allen has the largest amount of coal ash on site out of all the plants with 19 million tons of that need to be removed. In addition to this high pollution impact, it is also the second most expensive coal plant to run in the U.S. according to our analysis. But it needn't be this way. North Carolinians can have clean air and water with cheaper clean energy. All four renewable scenarios in our analysis were cheaper than running the G G Allen plant. In addition to clean energy replacement, the use of a DOE loan guarantee could save ratepayers even more by using low-cost financing for replacement infrastructure including the coal ash remediation.

plant infrastructure via the DOE's new loan program.³⁸ PUCs should require utilities to update prior investment and coal retirement plans to reflect the low-cost capital now available for reinvestment in communities.

Particularly for independent power producers, which own 23 percent of the coal capacity we studied, these DOE loans will be significantly cheaper than those without government backing. The

loan guarantee must be used to reduce GHG emissions and reinvest in that same community.³⁹ Funds can be used for a wide range of applications including partial or full coal replacement with renewable resources, transmission and storage, and even remediation of former fossil fuel sites, improving environmental conditions and serving as another source of job creation for the local community. Given the flexibility of the program, this is far from an exhaustive list. To smooth community transition, loans need not require immediate plant retirement, but instead could support projects that gradually reduce coal while increasing renewable generation and diversifying the community's economy.⁴⁰ The local renewable replacement plus storage scenario we study fits this approach.

Just transition in Colorado

In 2019, the Colorado legislature passed a bill creating the first Office of Just Transition (OJT), and just in time. With six coal mines and seven coal-fired power plants still operating, small communities, particularly in Western Colorado, risked near-total economic collapse. Since the legislation passed, the OJT created a Just Transition Action Plan to support economic diversification and job retraining. The town of Nucla illustrates how this plan can work. When their coal plant shut down three years ahead of schedule, it was the largest employer. The plant also provided nearly half the tax revenue that supported the whole region—including the fire department and school district. Residents were rightfully concerned, but Nucla has worked with OJT to transition their economy to focus on tourism and small businesses. Nucla still has a way to go and more funding is needed, but Nucla shows how pre-emptive planning can help ease the sting of coal closures. Now, newly appropriated OJT funds will continue to help Nucla restructure while preparing other Colorado coal communities.

Just transition for affected communities

State PUCs, legislatures, and state energy offices all have a role to play ensuring a just transition for coal communities. New IRA funding mechanisms mean traditional, least-cost utility planning practices now require reinvestment in communities whose economic prosperity depends on coal plants and coal mining. Assessing and including reinvestment in

these places is now essential to “least cost, best fit” resource planning.

Of course, the nuances of community needs are more complex than simple economics, and fully considering viable transition strategies in integrated resource plans is not possible unless state regulators and utilities seek input from affected communities at the beginning of the planning process. Seeking community input is not typically part of existing integrated resource planning processes, and it can be challenging for resource-constrained PUCs or utilities to incorporate new, innovative approaches to stakeholder engagement and ultimately community transition.⁴¹

State legislation should require PUCs and utilities to plan for community transition and assess the value of federal loan guarantees and tax credits for community transition, starting with outreach in an investigatory proceeding that provides access by holding commission forums in those communities. With this input, utility investment plans can better meet community economic needs, which can include tax revenue, workforce development, infrastructure investment, pollution clean-up, and community ownership models like community solar.

While the IRA has several reinvestment programs, energy communities cannot rely on clean energy alone to fully replace coal jobs and tax revenue. However, local clean energy can provide the opportunity for additional industrial development if new data centers or industrial facilities like synthetic fuel producers seek direct on-site access to low-cost clean energy. Proactive diversification of local economies is another path for success, which would benefit from state resources. The transition can even begin before the plant retires—gradual replacement and interconnection could ramp up in anticipation of the plant’s eventual retirement, growing jobs and reducing pollution along the way.

Legislators should consider creating and funding a just transition office, following Colorado’s example, to help coal communities develop transition plans. In addition to these legislative actions, PUCs can consider putting community transition funding into rates or creating ratepayer and shareholder cost sharing arrangements, similar to the arrangement made following closure of the coal plant in Colstrip, Montana.⁴²

CONCLUSION

The economic case for replacing highly polluting and expensive coal-fired generation with clean energy is stronger than ever. Our new analysis, based on 2021 data, already surpasses our previous projection for 2025, finding that 99 percent of all U.S. coal plants are more expensive to run compared to new clean energy generation. Local replacement is more attractive than ever due to the IRA’s new incentive and funding programs. Including battery storage along with local renewable generation can be an economic way to bolster the reliability value that these renewable projects provide to the grid. Building new wind or solar before completely retiring existing coal can be a recipe for success, a paradigm supported by the DOE’s new loan authority. The near-complete crossover of coal economics versus renewables makes the imperative to transition clearer than

ever before, but policymakers, utilities, consumers, and coal-dependent communities must recognize the benefits and seize this moment.

APPENDIX: DETAILED METHODOLOGY

Coal Costs

Our goal was to develop an accurate estimate of the going-forward cost of running U.S. coal plants 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 (excluding wood waste and petroleum coke burning units) operated by utilities and independent power-producers (sectors 1 and 2, in EIA parlance), excluding plants used for combined heat and power, for which 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. 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 210 coal plants is available in the companion spreadsheet to this report.

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

- The cost of fuel on a per MWh of coal generation basis.
- The operation and maintenance cost of each plant levelized over the total generation from each included boiler and generating unit.
- 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 2021 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.

We then used EIA data on fuel contracts paid by the plant; listed on page 5, “Fuel Receipts and Costs,” of EIA Form 923. 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.

For plants that do not report input fuel costs to a regulator, however, other less plant-specific sources of information were required. In these cases, 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 2021 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 2021 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. 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.

Operation and Maintenance Costs

We used plant-by-plant operation and maintenance estimates obtained from the Electricity Market Module (EMM) in EIA’s North American Energy Modeling Systems (NEMS). For some plants, no NEMS value for operation and maintenance was available and we used a national average value.

Going forward capital costs — National Energy Modeling System (NEMS)

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 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 table found in Figure 12. 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 12. NEMS estimates of going forward capital costs by age of plant.

Renewables Costs

Identifying Renewable Energy Sites

We use NREL’s ReEDS model that provides high spatial resolution solar and wind potential datasets in the U.S. The solar and wind potential numbers in ReEDS are, in turn, taken from the Renewable Energy Potential (ReV) model, which assesses the wind and solar energy potential at 11.2 km x 11.2 km spatial resolution after applying comprehensive exclusion criteria, including land cover, elevation, slope, environmentally sensitive areas, local siting regulations, etc. Across the continental U.S., ReV and ReEDS identify nearly 50,000 individual solar sites totaling a potential of 96,000 GW, and around 50,000 individual wind sites totaling a potential of 6,600 GW. The ReEDS model also provides annual capacity factors at each of these sites, which are estimated using the wind speed, solar irradiance, temperature, and other weather parameters from the Wind

Integration National Dataset (WIND) and National Solar Radiation Database (NSRDB). More information on this can be found in ReEDS documentation.

Technology Costs

We run the ReEDS model using technology costs from ATB 2022 and IRA incentives and estimate the wind and solar LCOE at each of the 50,000 sites. ReEDS uses a comprehensive list of parameters to estimate a site-specific LCOE including capital costs, fixed operation and maintenance costs, equity costs, interest rates, construction costs differentiated by location across the U.S., construction period, ITC and PTC incentives per IRA, tax equity haircuts, depreciation, and taxes (see Figure 13). Additional details on LCOE estimation could be found in ReEDS documentation.

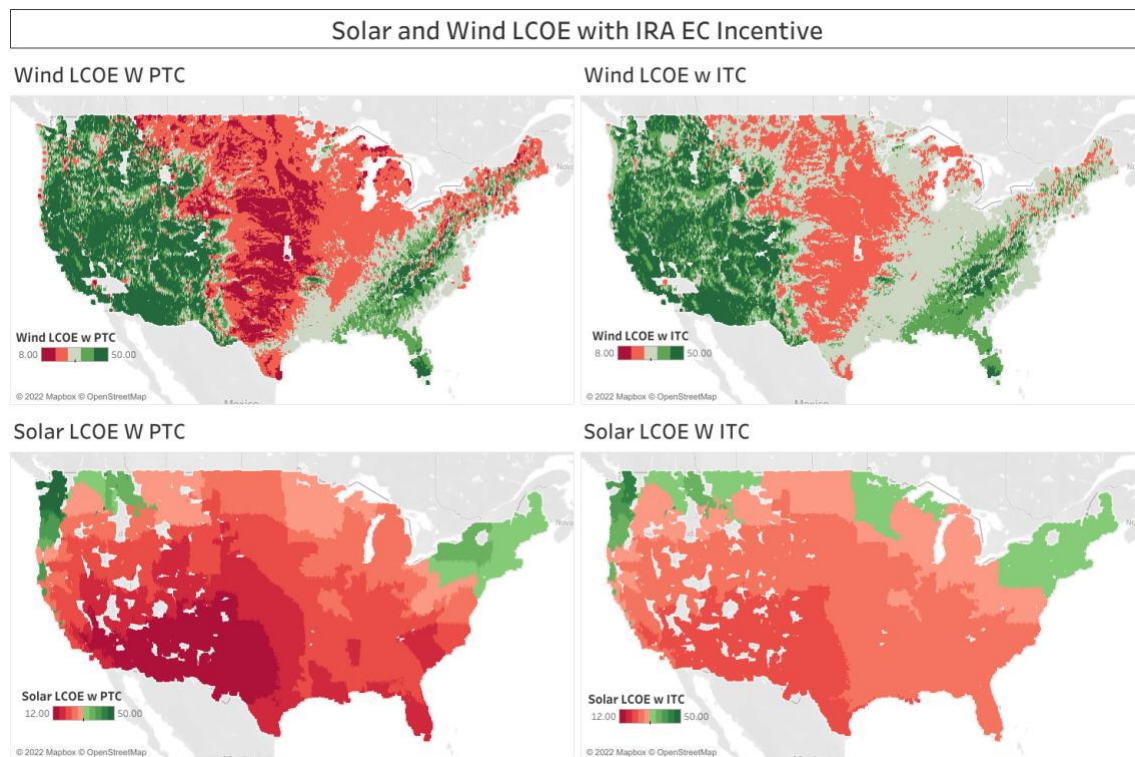


Figure 13. Wind and Solar LCOE including IRA incentives (including energy community) at each of the individual 50,000 sites across the U.S.

Assessing Hyperlocal Potential and LCOEs

The objective of this exercise is to assess the physically closest (hyperlocal) solar or wind resources that could replace the generation from each coal power plant in the country. We start with the location (latitude and longitude) of each of the 210 coal plants in the US. We then create concentric circles around each coal plant with radiuses starting from 5 km up to 45 km in increments of 5 km. Within each of these concentric circles, we identify the solar and wind sites that fall within that circle and estimate the site-level capacity and annual generation potential for solar and wind resources separately, using the high-resolution solar and wind datasets available from ReEDS, as described earlier. We then estimate the minimum circle radius (“hyperlocal circle”) needed to replace the annual generation from each coal power plant with solar or wind resources. Within each hyperlocal circle, we assume that the solar and wind projects get the Energy Community Tax Credit per IRA and will not incur any interconnection costs since they could continue using the coal plant interconnection. We weight the site-level LCOEs within each hyperlocal circle by the site-level capacity potential to arrive at a weighted average hyperlocal LCOE to replace the generation from each coal power plant.

We find that annual generation at almost all coal power plants can be cost-effectively replaced by solar resources within a 20 km radius. The minimum radius for wind is much higher.

Regional LCOEs

In addition to the hyperlocal LCOEs, we also estimate the regional LCOEs in the regions where coal plants are located. The ReEDS model divides the contiguous U.S. into 134 regions which are generally aligned with the utility territories (see Figure 14). These regions never cross state boundaries

The rationale for estimating the regional LCOEs in addition to the hyperlocal LCOEs is that the higher-quality resources might not be available in the near vicinity of the coal plants but slightly farther away, and so from the perspective of the developer, it might make sense to move further from the coal plants to access the higher quality resource. This is more important for wind as wind speeds can vary significantly over short distances. As compared to wind, solar is more energy dense, as we can get almost 10 times the capacity of solar in the same amount of land as wind.

The methodology used for estimating regional LCOEs is very similar to that of hyperlocal LCOEs. For each coal plant, we sort the wind and solar sites available in that region (i.e., ReEDS balancing area) by LCOE and choose the best sites to replace the coal generation. For selected sites within each region, we capacity-weight the site-level LCOEs to estimate the weighted average regional LCOE. For the regional LCOE, we do not account for the Energy Community tax credit available in IRA. We also add the interconnection costs to the LCOEs as we assume that these sites may not be able to access the existing coal power plant interconnection.

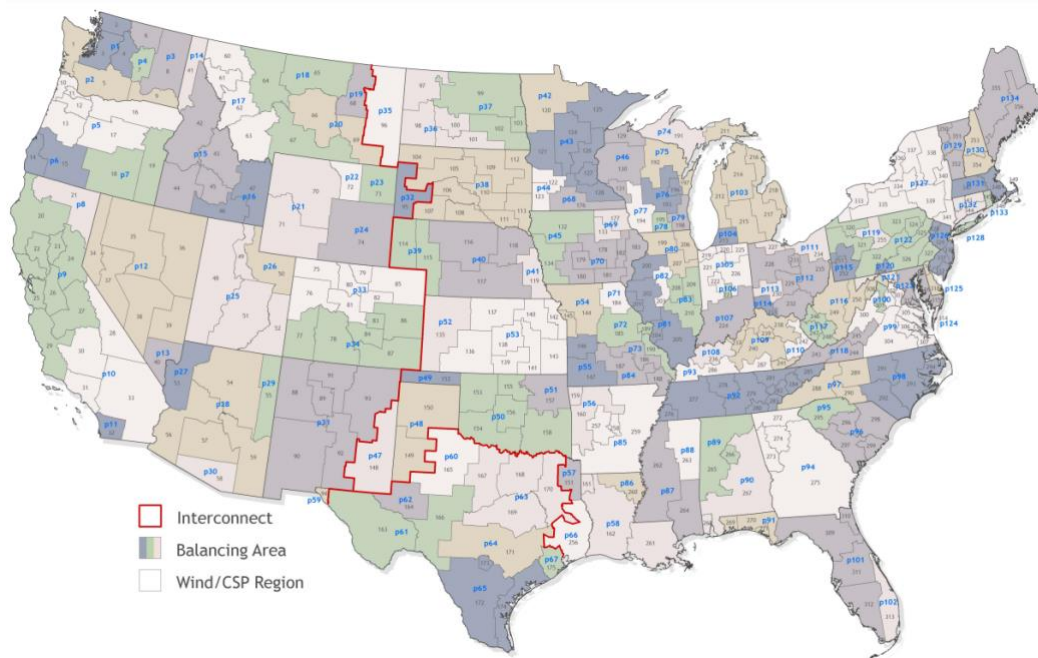


Figure 14. ReEDS balancing areas, used for our regional analysis and roughly corresponding to utility service territories, are highlighted by the different colors in this map. Source: National Renewable Energy Laboratory.

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