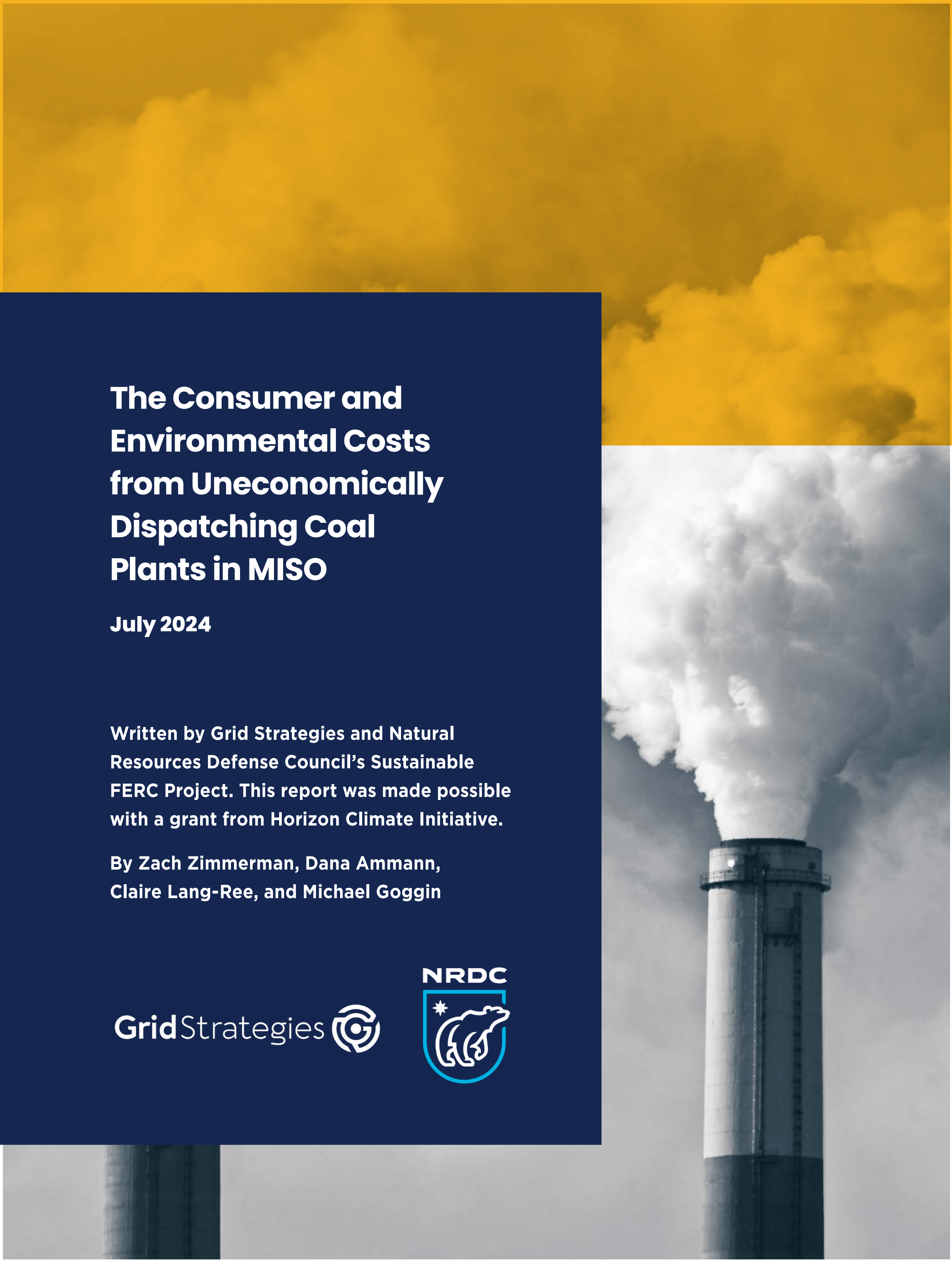

The Consumer and Environmental Costs from Uneconomically Dispatching Coal Plants in MISO

July 2024

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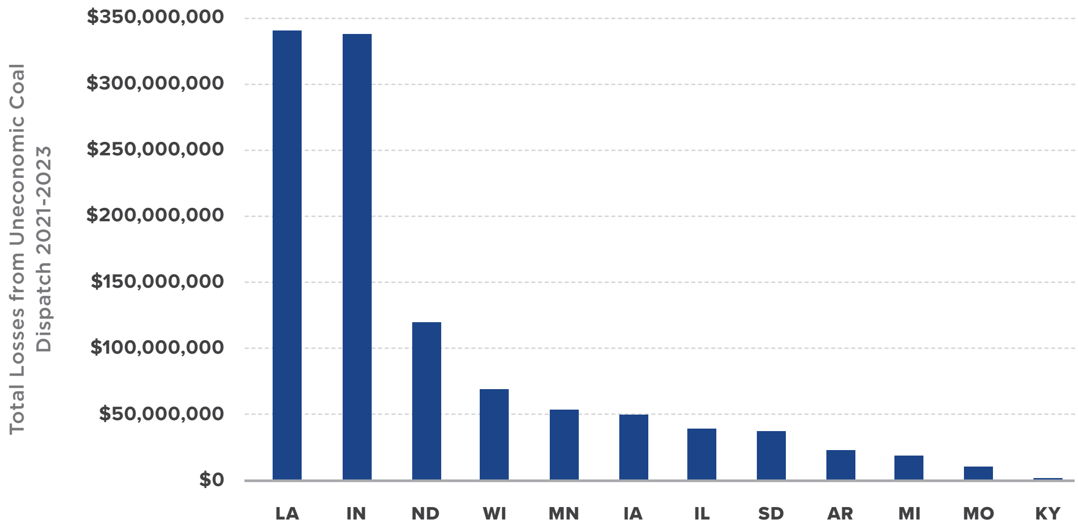
EXECUTIVE SUMMARY

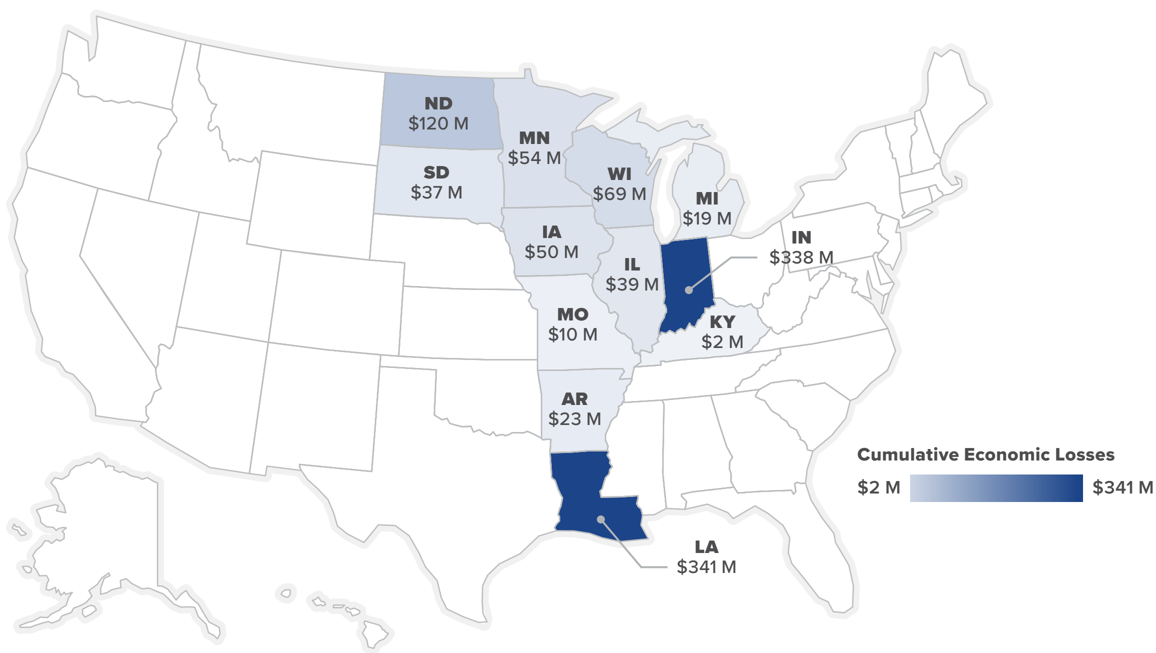
In regions covering the majority of the United States, wholesale electricity markets are operated by Regional Transmission Operators (RTOs) and Independent System Operators (ISOs), which are tasked with managing the supply and flow of electricity to keep the lights on. These wholesale electricity markets dispatch generating resources in order, starting with resources with the lowest marginal cost of producing an incremental amount of electricity and moving up the supply curve until supply meets demand. A power plant's marginal production cost includes its fuel cost and any variable operations and maintenance (O&M) costs. Capital and other fixed costs do not factor into the decision about which power plants are operated because those sunk costs are incurred regardless of whether the power plant operates. As a result, wind and solar resources that have no fuel cost and minimal variable O&M costs are typically dispatched first, and then the market operator progresses through resources in order of increasing marginal production cost. A typical generation supply curve is shown in Figure 17 in Appendix A.

To minimize costs for ratepayers, electricity markets are designed to ensure the lowest-cost sources of electricity like wind and solar generation are used first, before higher-cost resources like coal. The marginal production cost of the last and most expensive resource that is needed to meet demand sets the market clearing price for all electricity bought and sold in the market. That ensures that that resource breaks even, and all lower-cost resources earn a profit because the market price is greater than their cost of producing electricity.

However, our analysis indicates that many coal plants in the Midcontinent Independent System Operator (MISO) market are operating at a loss for extended periods of time, as their marginal cost of producing electricity is greater than market prices. This uneconomic dispatch of coal crowds out generation from lower-cost resources like wind, solar, and natural gas combined cycle generation, and the cost is passed on to the utility's ratepayers through fuel costs on their electric bills. Our analysis finds that consumers across the MISO region have borne more than $1 billion in excess costs from the uneconomic dispatch of coal plants over the last three years, as shown in the map, chart, and table below.

FIGURE 1 | Total consumer cost from uneconomic dispatch of coal plants over 2021-2023, by state





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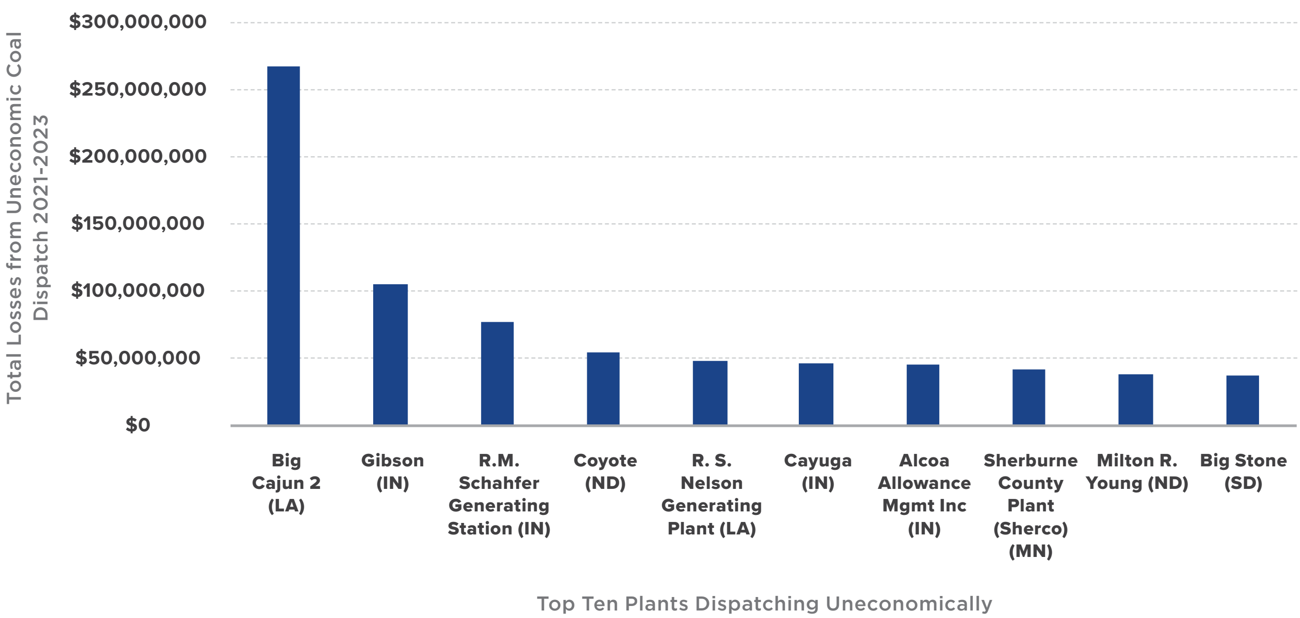
These excess costs accrue to consumers across MISO, though they are most pronounced in several states including Louisiana, Indiana, and North Dakota. This is primarily due to the frequency and magnitude of the uneconomic dispatch of coal plants in those states, as well as the availability of lower-cost alternatives like renewables and natural gas combined cycle generation. The uneconomic dispatch of coal instead of cleaner alternatives not only harms consumers, but also public health and the environment by causing excess emissions of smog-forming and health-harming sulfur dioxide and nitrogen oxides, as well as the greenhouse gas carbon dioxide.

TABLE 1 | MISO-wide consumer cost, emissions, and renewable curtailment from uneconomic coal dispatch, 2021-2023

Ratepayer cost	CO_2 emissions	SO_2 emissions	NO_x emissions	Renewable curtailment
$1.102 billion	5.2 million short tons	16 million lbs	7.9 million lbs	3.8 million MWh

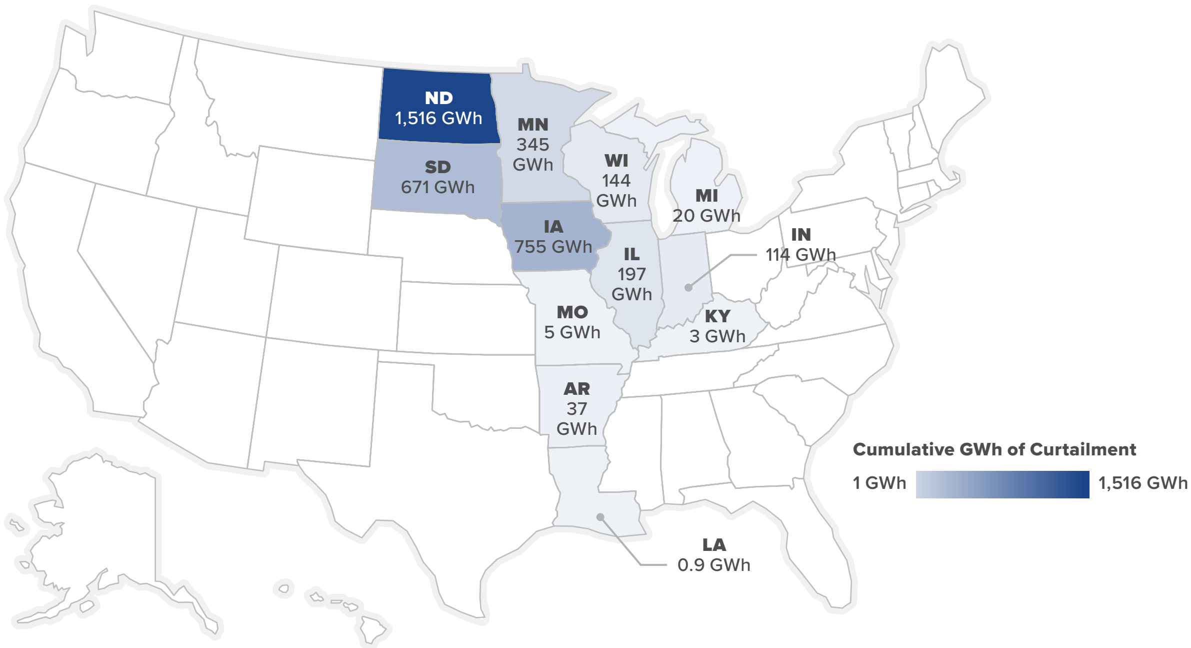
As noted above, the excess cost and emissions are heavily concentrated in several states due to the more frequent uneconomic dispatch of coal plants in those states. Our analysis identified the coal plants whose uneconomic dispatch imposed the largest cost on consumers, as shown in Figure 2 below. A comprehensive tally for each MISO coal plant of the excess cost, emissions, and renewable curtailment due to uneconomic dispatch can be found in Appendix B, while charts in *Section 3: Results* below show the top 10 plants for each pollutant and renewable curtailment.

FIGURE 2 | Economic losses for the top 10 coal plants, 2021-2023



As shown in the last column of Table 1 above, a significant share of the excess cost and emissions result from coal plants uneconomically displacing generation from renewable resources, like wind and solar. This occurs when the coal plant continues to operate even though lower-cost wind and solar generation was available, forcing the wind or solar plant to curtail its output. As indicated in the map below, this impact is largest in northwestern MISO, where coal plants overlap with a large concentration of wind plants. The 3.8 million MWh of renewable curtailment over the period 2021-2023 is the equivalent of curtailing the output of nearly 400 MW of wind capacity over those three years. This is a significant share of total wind curtailment in MISO over that period.[1] However, this does not capture the full harm uneconomic dispatch imposes on clean resources. By causing inefficiently low prices in electricity markets, uneconomic dispatch dissuades developers from building new low-cost resources like wind, solar, and battery storage. Uneconomic dispatch impairs states' abilities to cost-effectively meet their clean energy requirements, both through the direct curtailment of renewable resources and by suppressing market prices for new renewable development.

FIGURE 3 | Renewable curtailment due to uneconomic dispatch, by state, 2021-2023



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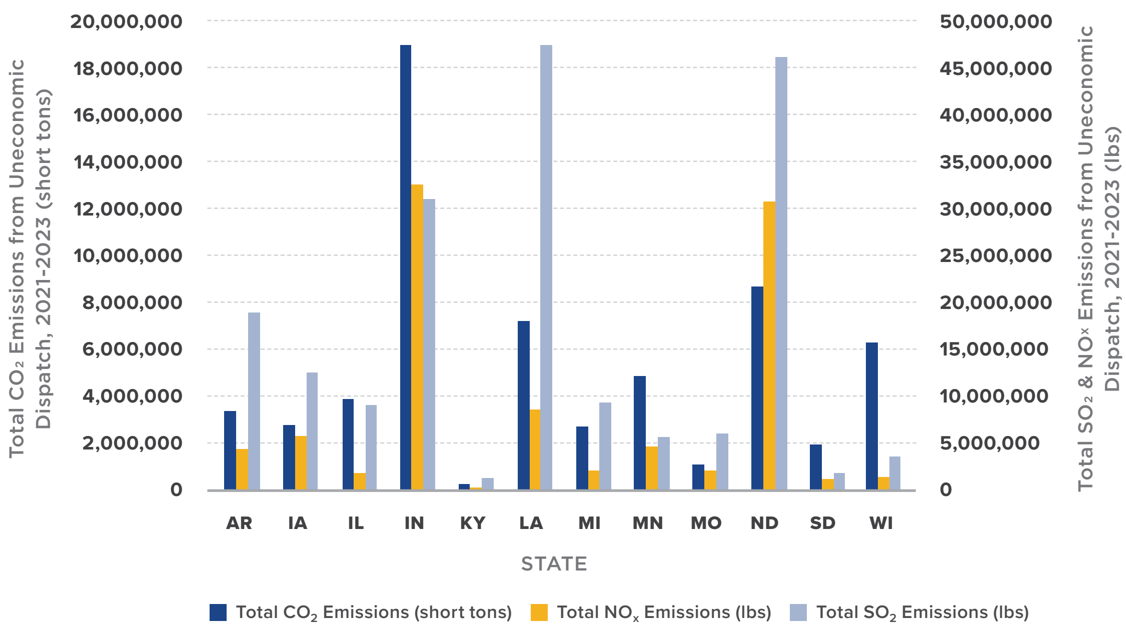
The excess pollution is also concentrated in states where coal plants are uneconomically dispatched. States where coal plants lack environmental controls for sulfur dioxide and nitrogen oxides also tend to see higher levels of those pollutants. Our analysis quantified these three pollutants because they are tracked by EPA's hourly emissions data, but coal plants emit a range of other pollutants that have harmful health impacts, including mercury and other heavy metals, particulate matter, and toxic runoff from coal combustion residuals that are stored onsite at many coal plants. The harmful public health impacts of coal generation, and its uneconomic dispatch, tend to be heavily concentrated in disadvantaged communities where a disproportionate share of coal plants are located.[2]

1 Our analysis indicates that renewable curtailment due to uneconomic coal dispatch averaged 145 MW per hour over 2021-2023. The MISO Independent Market Monitor's annual reports indicate that total wind curtailment averaged 507 MW per hour in 2023, 726 MW in 2022, and 660 MW in 2021. Assuming that essentially all renewable curtailment in MISO is wind and not solar curtailment, this suggests that uneconomic coal dispatch is responsible for around 23% of total curtailment over those three years. https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf, at ii; https://www.potomaceconomics.com/wp-content/uploads/2023/06/2022-MISO-SOM_Report_Body-Final.pdf, at ii; and https://www.potomaceconomics.com/wp-content/uploads/2022/06/2021-MISO-SOM_Report_Body_Final.pdf, at ii

2 https://www.epa.gov/power-sector/power-plants-and-neighboring-communities

FIGURE 4 | Excess emissions due to uneconomic dispatch, 2021-2023



Solutions to end uneconomic dispatch

The harm to consumers and public health from uneconomic dispatch can be countered by action at the state, regional, and federal level. As discussed at more length in Section 4, several MISO states have successfully taken steps towards phasing out uneconomic dispatch. Section 1 provides a more detailed explanation of the causes of uneconomic dispatch, and Section 2 offers a detailed list of actions states, MISO, and FERC can take to address the problem. These solutions are briefly summarized below.

State Utility Commissions

- Disallow utility costs associated with uneconomic dispatch, as some states have already done
- Review fuel supply contracts to ensure they do not perversely incentivize uneconomic dispatch

MISO and FERC

- Improve the accuracy of generator market bids and operating parameters
- Implement new market products to address uncertainty, if they do not further subsidize inflexible resources
- Decommit uneconomic generators
- Move to probabilistic unit commitment
- Create a voluntary multi-day market or look-ahead tool
- Provide more transparency and data regarding uneconomic dispatch

1 | THE PROBLEM

What is uneconomic dispatch?

As background, RTOs like MISO operate Day Ahead and Real-Time markets for electricity. The Day-Ahead market uses bids and prices to determine which generators will start up to meet expected demand the next day, a process known as unit commitment. The Real-Time market then fine tunes supply to match demand by setting the output level of each generator during each 5-minute period.

Uneconomic dispatch can be caused by several primary factors:

Self-commitment: A generator owner committing the resource instead of relying on selection in the Day-Ahead market. When a utility self-commits a unit, the unit is treated as “must-run” and will be operated regardless of whether the plant’s marginal production cost is below the market price.

Self-scheduling: Generators submitting their own generation schedule instead of relying on dispatch by the real-time market. Scheduling refers to real-time output levels for the resource.

Uneconomic bids in the market: Some generators submit bids below their true marginal production cost so they are more frequently committed by the Day-Ahead market or dispatched by the Real-Time market.

Understating the flexibility of the generator in market bids and dispatch parameters: Some generation owners understate the flexibility of their resources, including the speed at which the generator can ramp its output up or down, how far the plant can turn its output down, and how long the plant requires to start up and shut down. This typically results in the resources operating for more hours and at higher output levels than if they were bid in with more flexible operating parameters.

Our analysis does not try to distinguish among these mechanisms that can cause uneconomic dispatch. This is primarily because the information required to distinguish among them, particularly at a plant-specific and granular chronological level, is not made publicly available by MISO, the market monitor, generation owners, government data sources, or federal or state regulators. However, MISO market operators, the market monitor, and state and federal regulators could obtain access to the information needed to make that determination and therefore more precisely address the causes of the uneconomic dispatch. Our recommendations below include greater transparency around the causes of and impacts of uneconomic dispatch.

Why is uneconomic dispatch a concern?

A plant that is self-committed, self-scheduled, or otherwise uneconomically dispatched produces more energy in more hours than that plant would produce if it were to compete with other resources in the RTO's market-based security-constrained unit commitment and dispatch process. Plants that self-commit and self-schedule outside of the market effectively reduce the level of load to be served through the RTO's competitive market process, and thus the amount of energy that is priced through the RTO's centralized market competition. All forms of uneconomic dispatch tend to increase overall system costs because the unit is not necessarily the least-cost unit and may force more economic plants to curtail their output. This directly harms the efficiency of market-based commitment and dispatch in the day-ahead and real-time markets, which harms consumers by reducing generation from resources with a lower marginal cost of production. When coal plants do this, this also increases emissions by displacing lower-emitting and more efficient gas and renewable resources.

The inefficient pricing signals resulting from uneconomic dispatch also distort long-term generator investment and retirement decisions. Uneconomic dispatch suppresses energy market prices by introducing supply that is not responsive to demand or price signals. It is less attractive for developers to build new resources in areas where uneconomic dispatch is suppressing energy market prices. Perversely, this price suppression helps prevent the replacement of what tend to be the least economic and flexible coal resources on the power system with new lower-cost resources, including wind and solar resources as well as highly flexible battery storage resources. Price suppression from uneconomic dispatch can also dissuade investment in or incentivize the early retirement of more economic gas generating resources.

Why do some utilities operate their coal plants uneconomically?

Multiple factors can potentially cause coal plants to be uneconomically dispatched, though as noted above the precise reasons for utility decisions are generally not transparent. Fortunately, all of the potential causes of uneconomic dispatch identified below can be addressed by state and federal regulators and MISO.

As important background, most MISO coal plants are owned by vertically integrated monopoly utilities. These utilities earn profit based on the value of generating capacity they own multiplied by a rate of return that is approved by state regulators. These costs are passed on to ratepayers. In many other RTOs, like those in Texas, New York, New England, and the PJM region across the Mid-Atlantic and Great Lakes states, most generation is owned by merchant operators who depend on market revenue and not state-regulated rates of return to earn a profit. Regulated vertically-integrated utilities also directly pass through their fuel costs to their ratepayers, making the utility largely indifferent to fuel costs. In fact, MISO's Independent Market Monitor[3] and other analysts[4] have found that vertically integrated utilities are much more likely to uneconomically dispatch their coal plants than merchant plant owners. This is a

3 https://www.utilitydive.com/news/miso-integrated-utilities-lost-492m-from-2016-2019-via-uneconomic-coal-dis/586714/

4 https://www.ucsusa.org/sites/default/files/2020-05/Used%20but%20How%20Useful%20May%202020.pdf

primary reason our analysis focuses on MISO and not other RTOs. Vertically-integrated utilities' indifference to excessive fuel costs at their coal plants is a primary cause of most of the factors discussed below, and one that state utility commissioners can directly address through effective regulation.

Factors driving uneconomic coal dispatch include:

One potential reason a regulated utility has an incentive to operate a coal plant more than is economic is to make the plant appear "used and useful," which is the typical standard regulators use to determine that a plant should remain in the utility's rate-base and not be retired. Because a regulated utility earns its profit based on the value of rate-based generation it owns, and is indifferent to fuel costs from operating that generation, it has an incentive to continue operating generation it owns even when it is no longer economic. This is compounded by the fact that most renewable and battery storage resources are owned by independent power producers who sign contracts to sell their output to utilities, and the utility does not typically earn profit under that arrangement. As a result, retiring a utility-owned coal plant to replace it with lower-cost renewable and storage resources owned by an independent power producer directly reduces the utility's profit. While that utility profits, ratepayers pay the cost of continuing to maintain and operate the uneconomic coal plant instead of replacing it with more cost-effective resources.

For similar reasons, utilities can be averse to operating coal plants so they respond more flexibly to market prices because cycling the coal plant's output tends to increase maintenance costs and the risk of catastrophic equipment failures. Frequently ramping, starting up, and shutting down coal plants can cause equipment to fatigue and crack as metals and other materials expand and contract due to temperature changes. Utility coal plant owners may want to avoid major maintenance expenses and the risk of catastrophic equipment failures that can make regulators more interested in retiring those plants.

As noted above, owners and operators of utility coal plants that pass through their fuel costs to ratepayers are more likely to be indifferent to the costs of uneconomic dispatch than merchant plants who must respond to market prices to earn profits. This indifference can manifest in decision-making at many levels in the utility and coal plant management. For example, the utility staff and managers responsible for operating a coal plant are likely to face greater professional downside from cycling the plant more and risking a significant equipment failure than they do from increasing fuel costs that are passed through to ratepayers.

A utility that is indifferent to fuel costs is more willing to accept economically inefficient fuel contract terms. As discussed in the next section, many coal supply and transportation contracts include requirements that the generator take delivery of a minimum amount of fuel, with financial penalties for falling short of that amount. These contracts can inefficiently incentivize coal generators to operate at a loss so they burn enough fuel to meet those contractual minimums.

2 | RECOMMENDED SOLUTIONS

State utility regulators, the Federal Energy Regulatory Commission (FERC), and MISO and its Independent Market Monitor (IMM) and other stakeholders, can all take concerted effort to protect consumers from uneconomic dispatch, while also reducing emissions and allowing lower-cost clean resources to grow by allowing electricity markets to operate as designed. In the United States, states have primary authority over utilities' generation decisions, which are typically overseen by state utility regulators, while the Federal Power Act grants FERC authority to maintain electric reliability and ensure rates in interstate electricity markets are "just and reasonable."

State regulators can directly address many of the primary factors driving uneconomic dispatch. State consumer advocates should also focus regulators' attention on these issues. In several states, regulators have already taken steps to counter uneconomic dispatch, and recent settlements have also resulted in refunds to ratepayers. For example, utility commissions in Michigan, Louisiana, and Ohio have opened proceedings to investigate cases of uneconomic coal dispatch in their states. In Louisiana, this resulted in $125 million in refunds to ratepayers for the uneconomic dispatch of a single coal power plant that has since retired, Dolet Hills.[5] In Michigan, an administrative law judge has proposed to disallow costs from the uneconomic dispatch of some Ohio Valley Electric Cooperative coal plants.[6] Ohio has also initiated an audit of the costs and dispatch of those same coal plants.[7]

MISO, its stakeholders, and FERC can also work together to implement market reforms that will reduce uneconomic dispatch. Significant reforms at RTOs can be initiated either by the RTO or FERC. In many cases RTOs take the lead in developing these reforms, as FERC tends to be deferential to RTOs and their stakeholder-driven processes. MISO stakeholders, including state regulators, consumer advocates, the market monitor, and owners of competing generation, have significant power to reform MISO market practices to curb uneconomic dispatch, as described below.

FERC can also help drive action. Because uneconomic dispatch affects prices in interstate wholesale electricity markets like MISO, the Federal Energy Regulatory Commission could

5 https://www.all4energy.org/watchdog/dolet-hills-settlement

6 https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000AszjrAAB

7 https:/dis.puc.state.oh.us/CaseRecord.aspx?CaseNo=21-0477-EL-RDR__;!!NO21cQ!FVnNDmCAIHAK4xXJNDS5CxUgdJVD0XihUKHCRHY97dZypKsArMvgZ0Ir6yBXqU6hE-NRbTMSeU4$

combat uneconomic dispatch under its Federal Power Act authority to ensure that wholesale electricity rates are just and reasonable. FERC could also act on the basis that conventional generator self-scheduling and self-commitment result in undue discrimination against renewable resources. Renewable resources are generally required to be dispatchable under MISO's Dispatchable Intermittent Resource (DIR) program, in contrast to coal plants that are uneconomically dispatching themselves outside of MISO's markets.

Public power utilities that own coal plants typically have little to no oversight from state regulators and FERC. Some large public power entities like Basin Electric are now subject to FERC regulation because some of their members are regulated by FERC,[8] which could be one avenue for combating the uneconomic dispatch of public power coal plants. Public power utilities are typically overseen by their Boards of Directors. To comply with their responsibility to minimize electricity costs for their customers, those Boards should push those public power utilities to eliminate the uneconomic dispatch of their generation.

Specific actions that can be taken either by state regulators, or by FERC, MISO and its stakeholders, are outlined below.

State regulators

Disallowing utility recovery of costs that result from uneconomic dispatch

State regulators' most powerful tool is their ability to disallow utility costs that were not prudently incurred. As noted above, several states have already taken this step in certain cases. These and additional cases can send a powerful signal to regulated utilities that uneconomic dispatch risks future disallowance of those costs. Regulators simply asking more questions about uneconomic dispatch or opening investigations into the practice should incentivize regulated utilities to end the practice to avoiding risking costly disallowances.

Rejecting inefficient fuel supply contract terms

State utility commissions generally have oversight of fuel contracts for regulated utilities, and should use that authority to require utilities to move to efficient fuel supply contracts. As noted above, some coal supply contracts include financial penalties if the utility or coal plant takes delivery of less than a certain amount of fuel. Fuel contracts that use minimum delivery requirements to recover fixed costs, such as those associated with building or operating the mine or coal transport, through the per-ton variable costs in the contract are inherently inefficient, as these fixed costs do not affect the marginal cost of the fuel. Capital and other fixed costs associated with investments in coal mining and delivery equipment should be recovered as fixed costs in the fuel supply contract, while the variable cost for each ton of coal delivered should only include the marginal cost of extracting and delivering that fuel. Economic theory states that the choice of which power plants to commit and dispatch should only be based on true variable costs (marginal production costs associated with producing and consuming a marginal increment of fuel), while fixed costs that have already been incurred

8 https://www.utilitydive.com/news/basin-electric-ferc-rates-coal-dakota-gasification/718824/

should be ignored because they are “sunk costs.” Subsidizing variable costs by factoring in the value of avoiding contract penalties that recover fixed costs can harm economic efficiency by incentivizing the excessive commitment and dispatch of these generators.

For a fuel buyer who is at risk of falling below a minimum requirement, these provisions create an incentive for the power plant to offer its electricity into wholesale markets at a price below its true marginal cost of producing electricity. This allows the plant to be dispatched to operate more, which allows it to consume more fuel and therefore avoid or minimize the contract penalties. While minimum delivery requirements may not have caused inefficiency decades ago because those clauses never took effect when coal plants operated at higher capacity factors, at this point coal has been increasingly uneconomic for 15 years due to competition from low-cost renewable and gas generation.

Most coal supply contracts have a relatively short duration, so regulators can review these contracts when they come up for renewal or new contracts are proposed. For all fuel supply contracts for which EIA reports an expiration date, more than 88% expire by the end of 2025, with nearly 66% expiring in 2024, both on a percentage basis weighted by delivery volumes.[9] Regulators should closely examine proposed fuel contracts to ensure they are economically efficient and do not incentivize the uneconomic dispatch of coal generators.

For contracts that do not expire for some time, it may be possible to renegotiate the contract to more efficiently separate fixed and variable costs. Fuel contract terms are generally confidential, but it appears that many contain penalties or other off-ramps that would allow the generator to get out of the minimum fuel delivery requirements at some cost. State commissions have visibility into fuel supply contract terms, and they should examine these contracts to determine the best solution for ratepayers. One potential solution is that regulators should require plant owners to offer into electricity markets based on their true variable costs, and the regulator can separately allocate the sunk or fixed costs associated with contract penalties or renegotiation. This would ensure that the penalties are not included in marginal cost offers into wholesale electricity markets, and therefore do not affect the commitment and dispatch of the plant. It would be up to the state commission to decide how to allocate any fixed or sunk contract costs to ratepayers versus utility shareholders, though regulatory principles typically allocate any cost that was prudently incurred or previously approved by the commission to ratepayers. Regardless, the allocation of sunk costs is irrelevant for economic efficiency going forward, as long as generator dispatch decisions are based on variable costs and not fixed costs.

FERC, MISO, and its stakeholders

MISO, its Independent Market Monitor (IMM) and other stakeholders, and FERC can also take steps to reduce uneconomic dispatch:

Improve the accuracy of generator bids and operating parameters

MISO’s IMM has consistently recommended that MISO take steps to ensure that bids reflect

9 EIA 923, May 2024

true marginal costs and the actual flexibility of those generators. MISO should adopt market rules that improve the accuracy of the minimum generation times, output levels, ramp rates, and other operating parameters submitted by generators for use in MISO's market-based commitment and dispatch decisions. In many cases, these submitted generator bid parameters understate the flexibility of the units, such as the use of ramp rate, startup time, minimum runtime, or minimum output limits for constraints that are not actually physical limits, but rather economic costs associated with more flexible dispatch. Expressing the flexibility capabilities of generators as costs instead of hard physical limits would facilitate more economically efficient dispatch. MISO needs to know each unit's actual capabilities to be able to efficiently commit and dispatch resources, but many conventional units' reported start-up, ramp rate, minimum runtime, and minimum output parameters are inaccurate.

As noted above, bid parameters that understate a unit's actual flexibility contribute to excess dispatch, and can perversely result in greater "make-whole" payments to inflexible units. Make-whole payments, also called uplift or Revenue Sufficiency Guarantee payments, are awarded to inflexible generators to cover their costs of operating for a certain period of time, which ensures they are willing to be committed but also perversely subsidizes their inflexibility. For example, an inflexible coal plant can receive make-whole payments if it is committed in the Day-Ahead market but then actual demand is lower than expected, causing Real-Time market prices to fall below its cost of generating. These payments can perversely incentivize a resource to remain inflexible or submit bid parameters understating its flexibility, as it can receive larger payments if it has a greater minimum operating time, minimum output level, or inability to ramp its output down.

MISO has examined how to improve bid parameter reporting to improve system operational flexibility and price transparency. As part of this effort, MISO is attempting to reduce make-whole payments and other out-of-market compensation and incorporate those costs into transparent market prices that are received by all resources. Incorporating these costs into prices allows flexible resources that do not incur these costs to earn a greater profit. This incentivizes all resources to operate more flexibly, and also promotes the efficient replacement of inflexible resources with more flexible new resources like battery storage. MISO can use more accurate and cost-based bid parameters to improve generator flexibility and performance, with or without the potential new categories of reliability services discussed below.

Implement new market products to address uncertainty, if they do not further subsidize inflexible resources

Directly incorporating intertemporal constraints and uncertainty into market commitment and dispatch should reduce the incentive for generation owners to self-commit or self-schedule their resources to hedge against those risks. MISO and its IMM have expressed interest in developing an additional market product to address uncertainty in the day-ahead and real-time markets. Specifically, MISO's IMM recommends that MISO

Develop a real-time capacity product for uncertainty: We recommend MISO evaluate the development of a real-time capacity product in the day-ahead and real-time markets to account for increasing uncertainty associated with intermittent generation output, [net *system interchange], load, and other factors. Such a product should be co-optimized with the current energy and ancillary services products. These capacity needs are currently procured out of market through manual commitment by MISO's operators. Clearing this product on a market basis would allow MISO's prices to reflect the need and reduce [Revenue Sufficiency Guarantee].*[10]

Using a market to procure flexible capacity to address uncertainty is more efficient than the status quo approach of over-committing resources and then compensating them with make-whole payments, which can perversely incentivize inflexible resources as explained above. However, MISO and other RTO/ISOs should carefully structure such uncertainty products so their pricing and selection of resources efficiently reflects the ability of a resource to cost-effectively provide flexibility. In particular, this compensation should not include make-whole payments that can perversely reward resources for their inflexibility. RTO/ISOs should also allow duration-limited resources, like battery storage and curtailed variable renewables, to provide this uncertainty product. These highly flexible resources do not typically have a cost associated with providing this product. Renewable resources are unlikely to be the most economic sources of flexibility during most market intervals today, but at higher renewable penetrations curtailed renewable resources will be a major source of flexibility.

Less controversially, the IMM also recommends that MISO

Develop a look-ahead dispatch and commitment model to optimally manage fluctuations in net load and the use of storage resources: As reliance on intermittent resources grows, the need to manage fluctuations in net load (load less intermittent output) will grow. Because these demand changes occur in multi-hour timeframes, managing them efficiently requires the market to optimize both the commitment and dispatch of resources over multiple hours. This multi-hour optimization will also allow the markets to optimize the scheduling of energy storage resources. This is important because these resources are likely to play a key role in operating an intermittent-intensive system. Therefore, we recommend that MISO begin developing a look-ahead dispatch and commitment model that would optimize the utilization of resources for multiple hours into the future. This is a long-term recommendation that will require substantial research and development. However, we believe this will be a key component of the MISO markets' ability to economically and reliably manage the transition of its generating portfolio.[11]

This tool should only increase the efficiency of commitment and dispatch without increasing make-whole payments that can perversely incentivize inflexibility.

Decommit uneconomic generators

MISO's IMM has recommended other reforms that could assist with reducing uneconomic dispatch, such as decommitting uneconomic generators:

10 https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf, at 100

11 *Id.*, at 111

Develop tools to recommend decommitment of resources committed in the day-ahead market: As congestion has increased in the MISO markets, we have observed with increasing frequency cases where substantial congestion relief could be achieved by decommitting resources that were scheduled in the day-ahead market. Because such cases produce very low and often negative prices, the owner of the resource would often benefit substantially by allowing the resource to be decommitted. Additionally, it would generally improve reliability by making severely binding constraints easier to manage. Unfortunately, such participants lack the information necessary to determine when their resources should be decommitted. MISO could optimize such decisions by allowing its [Look-Ahead Commitment] model to consider such decommitments. Hence, we recommend MISO implement changes in the LAC and settlement processes to allow day-ahead committed resources to be decommitted when appropriate and economic.[12]

The IMM's analysis suggests this reform could save millions of dollars on net by reducing uneconomic dispatch and resulting congestion, even if the decommitted resources receive make-whole payments.

Use probabilistic unit commitment

As noted above, unit commitment is the process by which generators are selected to start up and operate ahead of the real-time market, which is primarily achieved through the day-ahead market. Because the vast majority of energy is transacted in the day-ahead market and inefficient commitment imposes costs on consumers while distorting price signals, there is considerable benefit to improving the efficiency of the commitment process.

Probabilistic unit commitment refers to processes that directly incorporate information about uncertainty in electricity supply and demand forecasts into unit commitment decisions. Today, operators make conservative unit commitment and dispatch decisions in part because they recognize that their deterministic methods and forecasts are not fully accounting for uncertainty and risk.[13] Using more rigorous quantitative methods to account for that risk would produce more efficient, lower-risk operations.

For example, commercially available renewable output and electricity demand forecasts typically include detailed information about the uncertainty of those forecasts, but it is common for only the median (p50) value to be used as the deterministic input for committing and dispatching other resources. Most forecast vendors can quantify the uncertainties around a production forecast, such as uncertainty about the magnitude of a weather event (e.g., the distribution of temperature, irradiance or wind speed outcomes) and the timing of an event (e.g., when a cold front resulting in abrupt temperature, wind speed, or cloud cover changes will arrive). Probabilistic unit commitment tools that incorporate such uncertainties would yield more efficient commitment of resources based on risk-managed intertemporal solutions, especially considering that many of the uncertainties have correlated impacts on

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12 *Id.*, at 102-103

13 Even with these conservative assumptions, RTOs/ISOs may not always accurately predict tail-end events, such as MISO's inaccurate forecast for both load and available supply during Winter Storm Elliott. See: https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf.

both electricity supply and demand. For example, if forecasts indicate a significant chance of both very high load and very low renewable output, operators will likely want to commit more resources. However, because those risks are not reflected in the median value for either forecast, current deterministic methods do not automatically incorporate them into commitment decisions, forcing operators to attempt to subjectively incorporate them.

While human operators have many advantages relative to computers due to their deep knowledge of the system developed over years of experience, operators can benefit from greater use of decision support tools that identify statistical patterns and use probabilistic methods to make better, lower-risk commitment and dispatch decisions. In particular, humans can struggle to appreciate the risk and impact of weather and other factors that have correlated impacts on electricity supply and demand. Moreover, the use of subjective judgement can be time-consuming during critical events. The use of such tools would minimize inefficient dispatch and uplift costs and reduce generation overcommitment. Many resource owners and power traders use probabilistic methods to make decisions about the dispatch of energy-limited resources like energy storage, and therefore MISO operators would also benefit from the use of those tools. MISO's report to FERC in a recent proceeding on market design correctly notes the benefits of using probabilistic tools:

MISO's operators must continue to make real-time decisions and commitments based on recommendations based on data analysis inside of their tools. Real-time decisions are often made to mitigate reliability risks and may sacrifice efficiency. But we are working to better quantify the uncertainty around various risk factors so that we can continue to improve these tools, the operator decisions they inform, and over the long term, identify and implement market products to maintain reliability and efficiency (see the two other key workstreams of MISO's Reliability Imperative, MSE and Operations of the Future). Another way to better quantify the risks is to create probabilistic forecasts that account for the uncertainty…[14]

However, MISO does not currently use probabilistic tools. MISO's comments to FERC first propose creating a daily risk assessment to inform operator decisions, and eventually progressing to directly incorporating probabilistic analysis into unit commitment through a Dynamic Reserve Requirement:

As MISO is able to better quantify the uncertainty, it will be able to use advanced data analytics, to visualize risks from weather, load, wind, solar and so forth to aggregate net load, do advanced scenario analysis, and extend foresight. This work is needed to create a daily risk assessment, in essence, showing us the risk we need to manage on a given day and what is needed to mitigate it. Then, based on the use of the daily risk assessment, we'll be able to use dynamic reserve requirements to reduce operator commitments and inform additional market design changes that incentivize the resource attributes at the right time and location. This would allow MISO to create Dynamic Reserve Requirements, operationalizing and automating analytical and meteorological expertise… At a more structural level and over time, such information will help inform and improve market product demand curves and align them with systemwide, regional,

14 https://cdn.misoenergy.org/MISO%20Report%20AD21-10-000626724.pdf, at 24.

or local reliability requirements.[15]

We encourage MISO to quickly move towards directly incorporating probabilistic tools into unit commitment. While the interim step of using probabilistic tools to inform grid operators provides value, directly incorporating probabilistic analysis into unit commitment greatly exceeds the capabilities of human operators to automatically synthesize different types of risk (e.g., magnitude vs timing) as well as correlations among load and the output of different types of generators across a lengthy historical record, and optimally mitigate that risk.

Create a voluntary multi-day market or look-ahead tool

A voluntary multi-day ahead market could also provide coal plant owners and other MISO market participants with transparent price signals and hedging mechanisms that reduce the incentive to self-schedule and self-commit their resources. When owners of inflexible coal plants are unsure of supply and demand a few days ahead of time, they tend to over-commit their resources to ensure they will have sufficient generation. A centralized multi-day-ahead market in which resources and loads could voluntarily procure energy would create price signals that reflect expected electricity supply and demand, allow participants to create financial hedges against uncertainty, and yield more efficient resource commitment. With better resource commitment, there would be fewer instances when generators would have to operate at a loss over a multiday or multi-hour period for reliability purposes, so there would be less need to pay generators make-whole payments that can perversely insulate a generator from the costs of its inflexibility. The financial opportunity in such a market would also encourage better forecasting of renewable output and electricity demand. As an easy interim step, the IMM has advocated that MISO publish the full 36 hours of price results it obtains from its Day-Ahead market, instead of just the 24 hours of prices that it currently publishes.[16]

If implemented well, a multi-day market could tend to reduce over-commitment and over-generation that suppresses energy market prices. Importantly, participation in this market would be voluntary, and would not entitle a committed resource to any type of make-whole payment if it ended up not being needed. This ensures inflexible resources are not insulated from the costs of their inflexibility. Grid operators could also offer a shorter commitment window for resources that need less than a day to start up, purchase fuel, etc. In MISO some are considering rolling unit commitment based on the actual start-up time for each resource, or a potential 2-hour ahead commitment. This would improve market efficiency and reduce over-commitment by reducing supply and demand forecast error.

Provide more transparency regarding uneconomic dispatch

As noted above, there is generally a dearth of public information regarding the commitment and dispatch decisions of generators, which makes it challenging to identify and correct the causes of economic dispatch. Important information regarding fuel prices and contract terms and generator operating parameters and bids are not generally made public. To the extent MISO,

15 *Id.*, at 26.

16 https://www.potomaceconomics.com/wp-content/uploads/2020/09/Coal-Dispatch-Study_9-30-20.pdf, at 2

the IMM, and state regulators can make more information publicly available without risking the potential for market manipulation or the disclosure of commercially sensitive information, that would be beneficial. For example, PJM reports generator bid pricing information with a delay and without disclosing the identity of the bidder to protect sensitive market information,[17] while some state regulators disclose fuel supply contract terms and pricing.[18]

MISO's IMM has consistently recommended closer documentation and tracking of MISO operator dispatch and commitment decisions that can result in the over-commitment of resources. Specifically, the IMM recommends that

Evaluate and reform MISO's unit commitment processes: In 2021, we observed increased out-of-market commitments by MISO and associated RSG costs. During 2022, we worked with MISO to identify commitments that were not ultimately needed to satisfy MISO's energy, operating reserves, or other reliability needs. We also identified the assumptions, procedures, and forecasting issues that have led to these unneeded commitments.

In addition to raising RSG costs borne by its customers, excess commitments depress real-time prices and result in inefficiently lower imports from neighboring areas, inefficiently lower day ahead procurements and resource commitments, and distort long-term price signals. Therefore, it is important to minimize excess out-of-market commitments and the accompanying RSG costs. We recommend that MISO:

1. *Implement the identified improvements in its tools, procedures, and the criteria used to make out-of-market commitments.*
2. *Ensure that operators can observe the relevant offer costs that MISO will guarantee associated with each out-of-market commitment.*
3. *Update VLR operating guides in a timely manner when resources enter or exit the VLR area or transmission upgrades are made that affect the VLR area.*[19]

As discussed above, moving to probabilistic unit commitment should also reduce the need for operators to use out-of-market actions to address uncertainty.

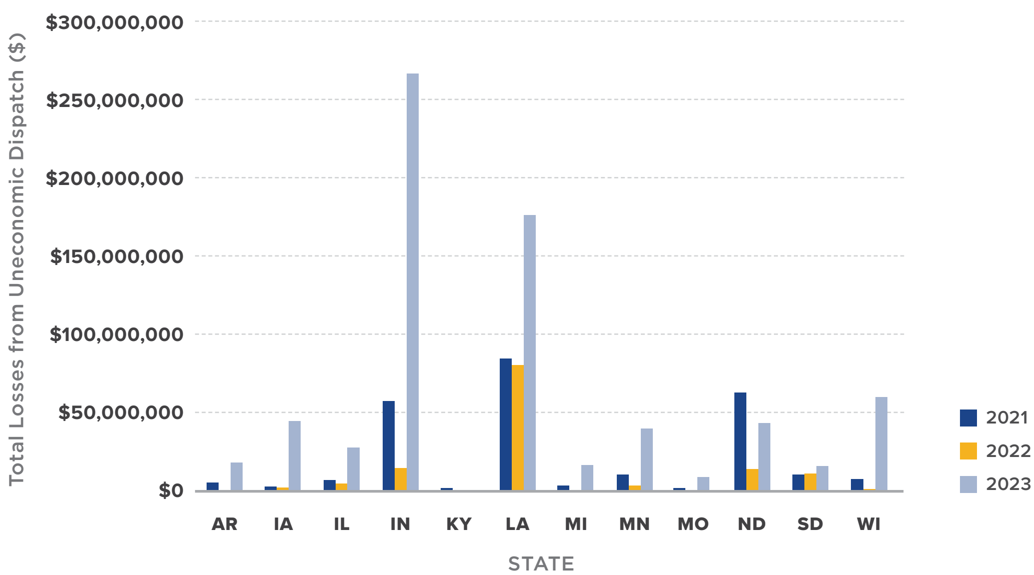
Finally, some generators that dispatch into MISO also dispatch into other RTOs, like PJM or the Southwest Power Pool. Coordinating MISO's dispatch of these resources with that of the other operator can be challenging, and can result in a plant operating uneconomically. The IMM could work with MISO and state regulators to obtain greater transparency around this concern and develop solutions.

17 https://dataminer2.pjm.com/feed/energy_market_offers/definition
18 https://psc.ky.gov/webnet/fuelcontracts
19 https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf, at 110-111

3 | ANALYSIS RESULTS

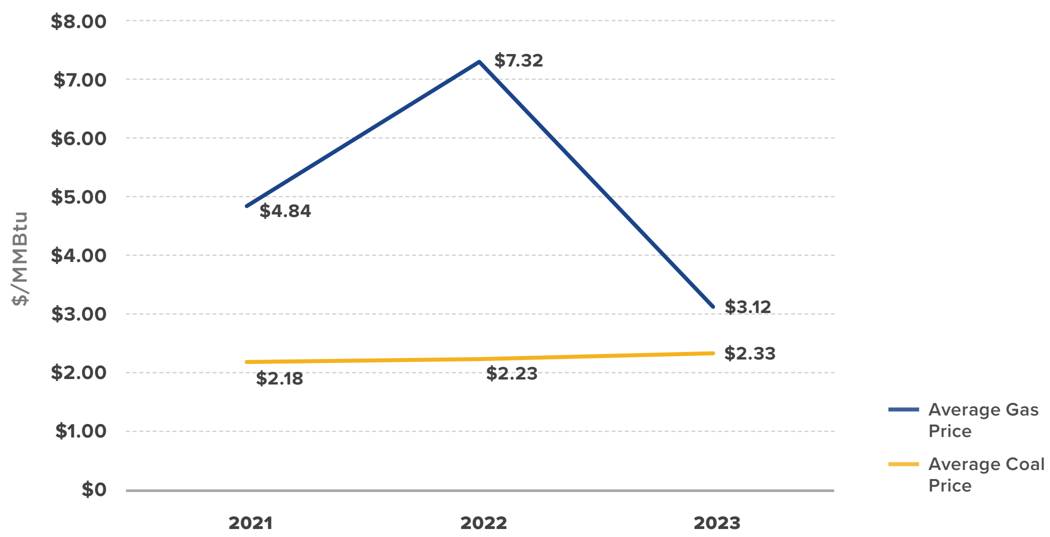
Our analysis reveals that many coal plants in the MISO market are operating at a loss for extended periods of time, as their marginal cost of producing electricity is greater than market prices. This uneconomic dispatch of coal crowds out generation from lower-cost resources like wind, solar, and natural gas combined cycle generation, driving up costs for ratepayers and increasing emissions of health-harming pollutants. Our analysis finds that consumers across MISO have been saddled with more than $1.1 billion in excess costs from the uneconomic dispatch of coal plants over the last three years. These costs totaled $255 million in 2021, $131 million in 2022, and increased to $716 million in 2023.

FIGURE 5 | Economic losses by state by year



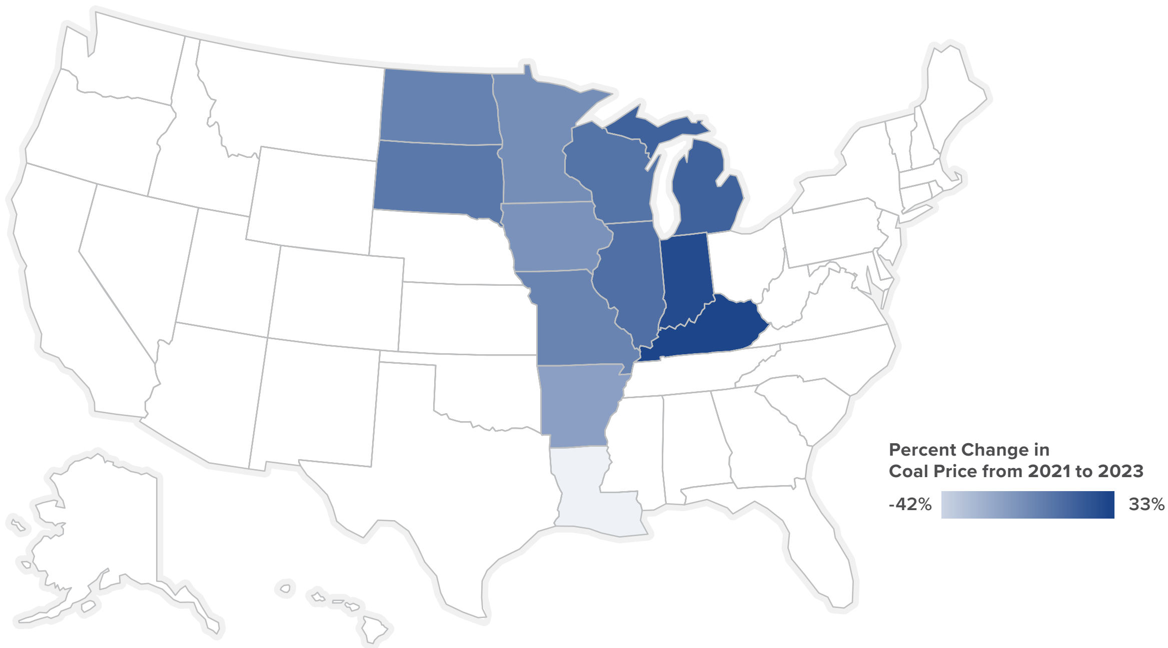
The inter-annual variability in these costs is primarily driven by fluctuations in the relative prices of coal and natural gas fuel. Natural gas prices increased dramatically leading up to and following Russia's invasion of Ukraine in February 2022, with liquefied natural gas exports increasingly tethering the domestic price of natural gas to global markets. Because natural gas generators set the marginal price of electricity in most hours, this resulted in higher electricity market prices for all generators. As a result, coal generators operate uneconomically much less frequently when electricity prices are higher due to natural gas prices.

FIGURE 6 | Average Coal vs. Natural Gas Cost ($/MMBtu) for generators in MISO states, by year



Uneconomic dispatch of coal may also be increasing over time as coal prices increase and aging coal plants become increasingly uneconomic relative to new low-cost wind and solar resources. As shown below, MISO states have seen a large divergence in coal prices over the last several years, with coal prices increasing much more rapidly in eastern MISO than in western MISO. This has caused a spike in the uneconomic dispatch of coal plants in eastern MISO states. The divergence in coal prices likely reflects that eastern MISO is heavily supplied from the Illinois Basin and Appalachian coal producing regions, while western MISO is supplied by Wyoming Powder River Basin coal or local lignite mines. Wyoming and lignite coal mining is generally heavily mechanized surface mining, while Illinois Basin and Appalachian coal production is typically labor-intensive underground mining. It is therefore intuitive that increasing labor prices have had a larger impact on the cost of coal in eastern MISO than in western MISO.

FIGURE 7 | Percent Change in Coal Price from 2021 to 2023

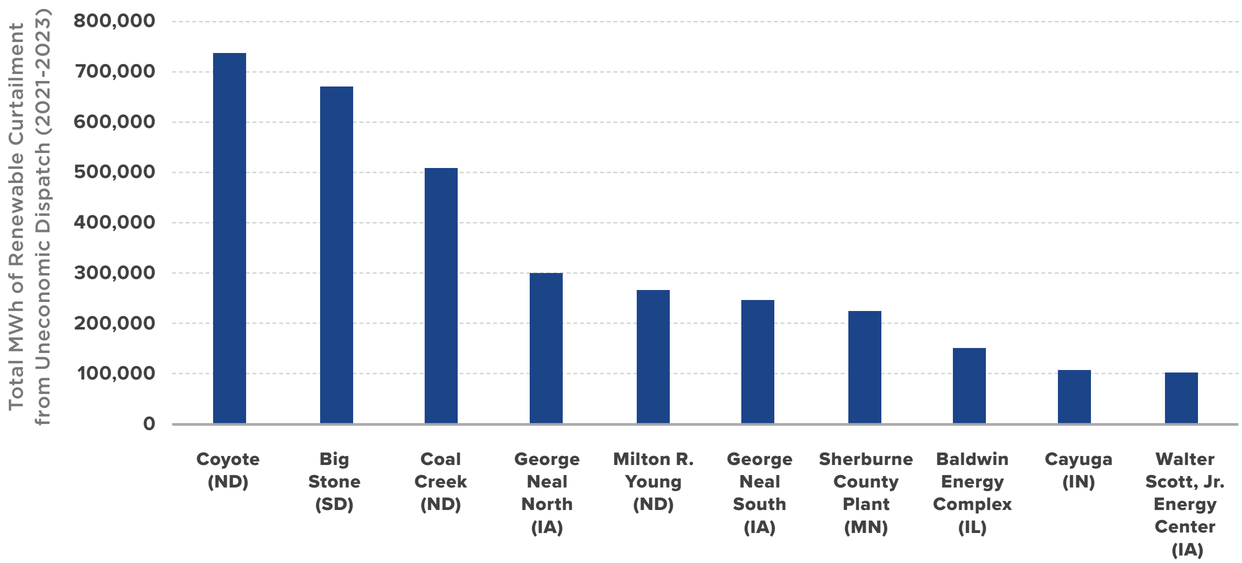


Powered by Bing ©GeoNames, Microsoft, TomTom

The expansion of renewable resources is also making coal plants increasingly uneconomic. As explained above, wind and solar resources offer into electricity markets at prices of around $0/MWh or below, reflecting these resources' lack of fuel cost and variable O&M costs. Coal plants in wind producing areas in northwestern MISO are particularly being challenged as wind generation increases, as shown in Figure 8 below. Continued expansion of wind resources in that area will tend to further increase uneconomic dispatch of those coal plants, and MISO's plans for major transmission expansion over the next decade will bring additional wind resources online and allow them to compete with coal plants throughout MISO's footprint. The expansion of solar resources will also increasingly challenge the economics of coal plants, particularly in southern MISO states with the strongest solar resources.

The uneconomic dispatch of coal can also slow the development of low-cost renewable resources by suppressing market prices. This occurs because, when coal plants operate uneconomically, they add supply to the market that is typically indifferent to price, reducing prices and undercutting lower-cost resources. Lower cost resources which are curtailed because they no longer clear the market are deprived of revenue, and market prices are suppressed for all resources. As noted above, uneconomic dispatch threatens the ability of states to cost-effectively meet their renewable energy requirements by increasing renewable curtailment and impeding the development of new renewable resources.

FIGURE 8 | Renewable Curtailment Top 10 Plants, 2021-2023



By displacing lower-cost and lower-emitting generation, uneconomic coal dispatch also increases emissions of pollutants that harm public health and the environment. The following three charts show how uneconomic coal dispatch has increased emissions of various pollutants in each state.

FIGURE 9 | Cumulative CO_2 Emissions by State, 2021-2023

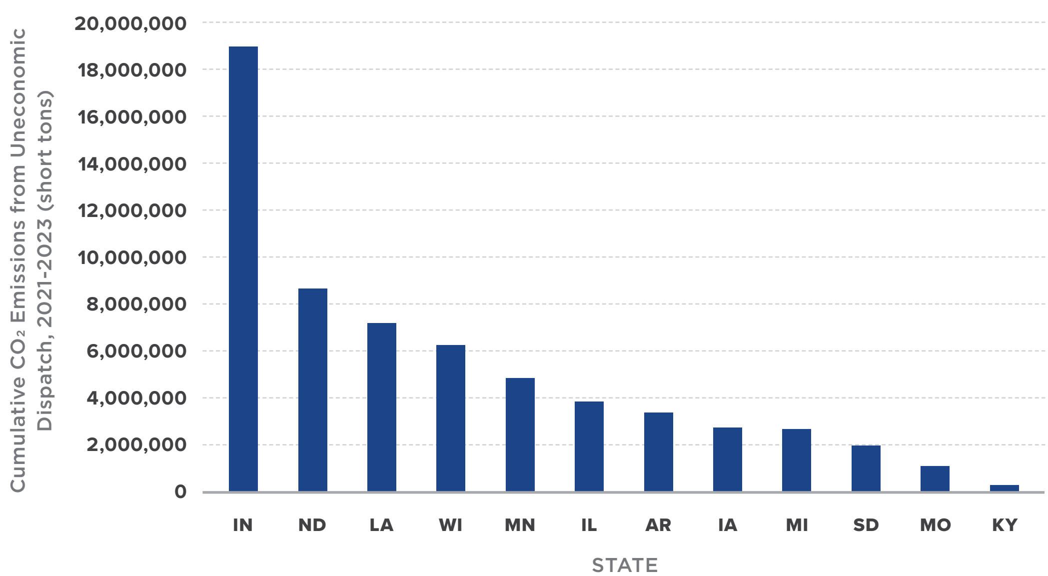


FIGURE 10 | Cumulative SO_2 Emissions by State, 2021-2023

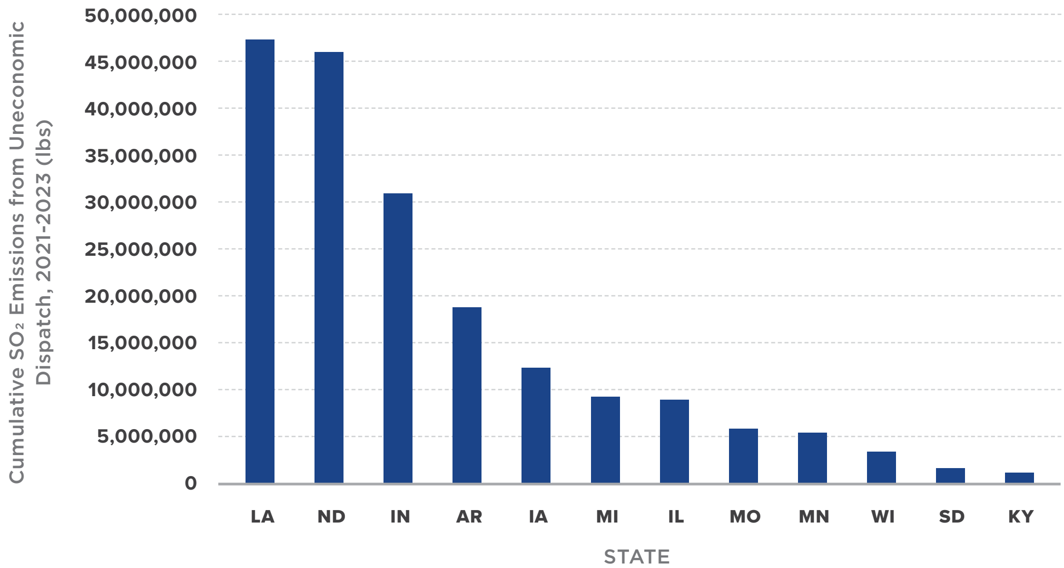
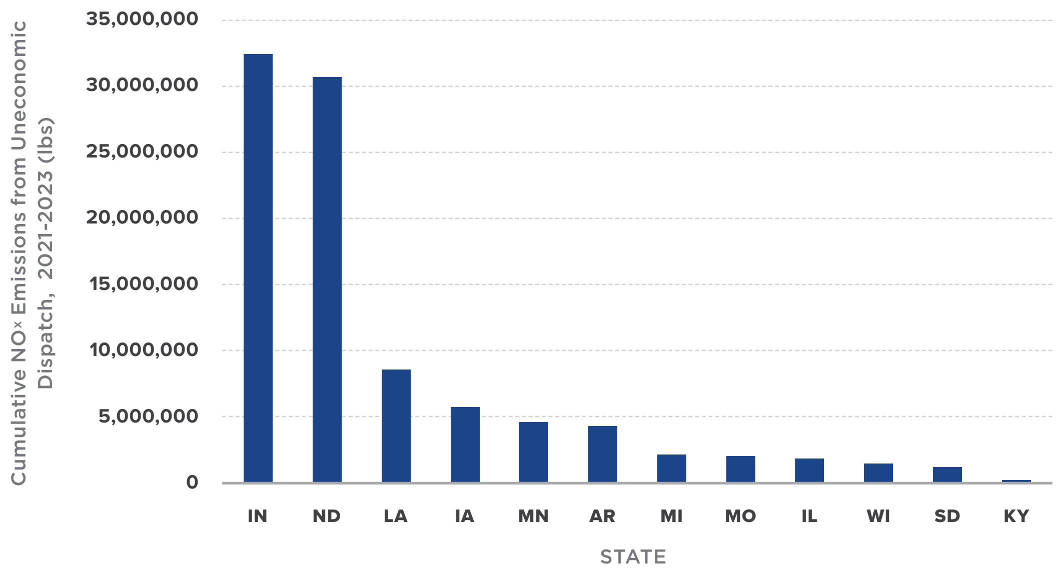


FIGURE 11 | Cumulative NO_X Emissions by State, 2021-2023



The next three charts identify the top 10 plants for emissions of each pollutant caused by uneconomic dispatch. Some plants make all three lists because they are large and frequently operate uneconomically. Other plants show up on the top 10 lists for sulfur dioxide or nitrogen oxides because they lack modern environmental controls or use high sulfur coal. As noted above, many of these coal plants are located in or near disadvantaged communities, and local pollutants like sulfur dioxide, nitrogen oxides, and other pollutants like mercury, particulate matter, and coal ash runoff have a concentrated impact on those communities. If uneconomic dispatch is not addressed, the harm to consumers and public health will only increase as uneconomically dispatched coal plants displace generation from new low-cost and non-emitting wind and solar resources.

FIGURE 12 | Top 10 Plants Cumulative CO_2, 2021-2023

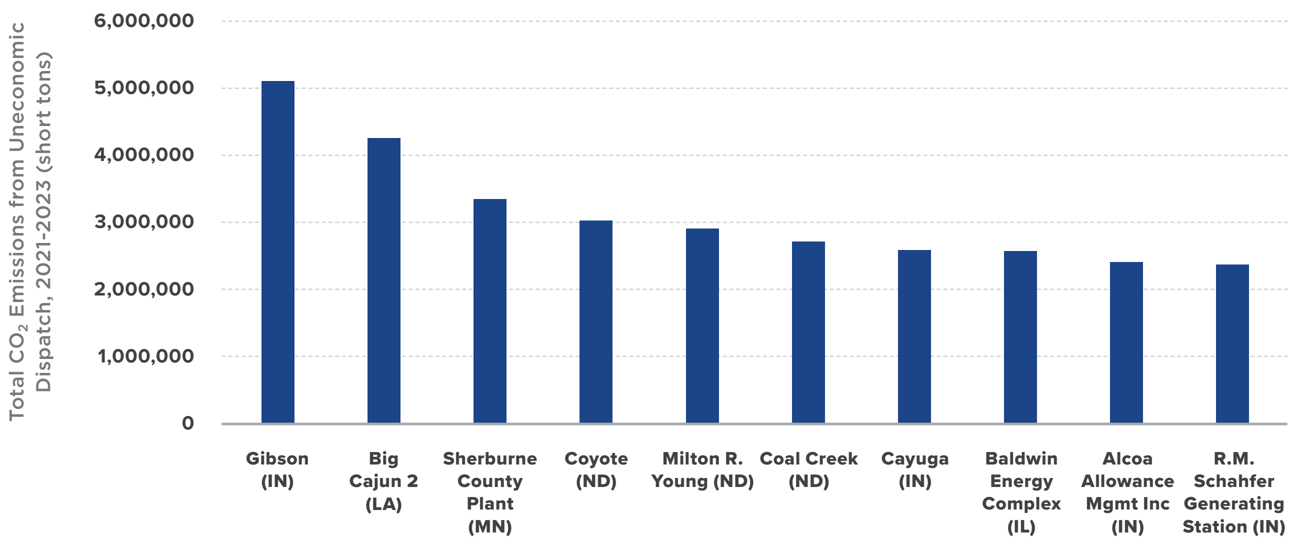


FIGURE 13 | Top 10 Plants Cumulative SO_2, 2021-2023

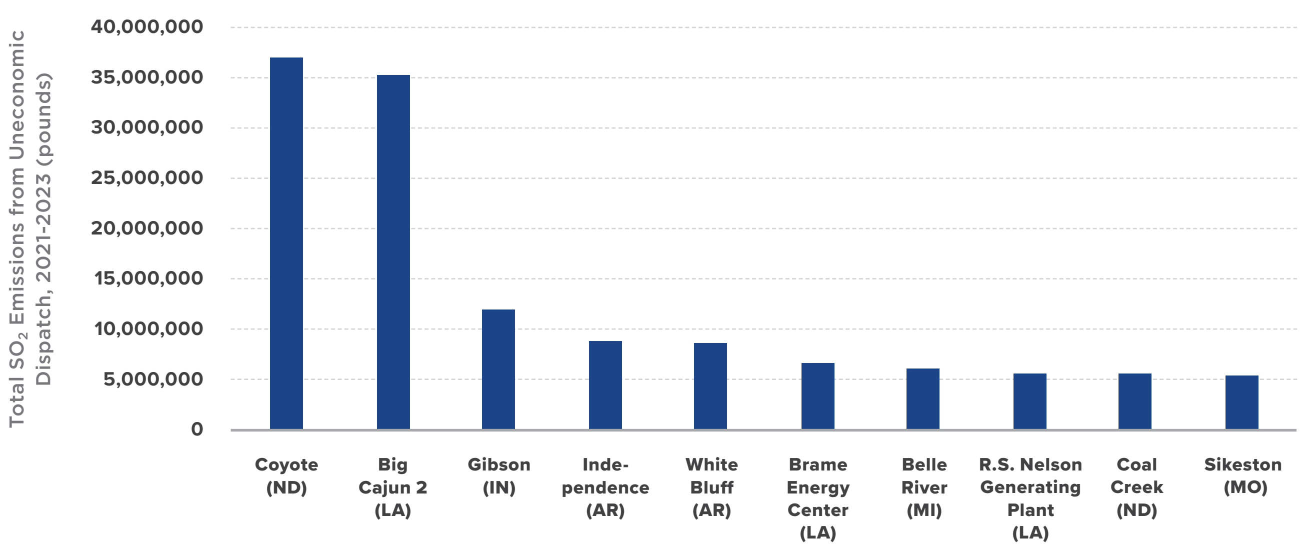
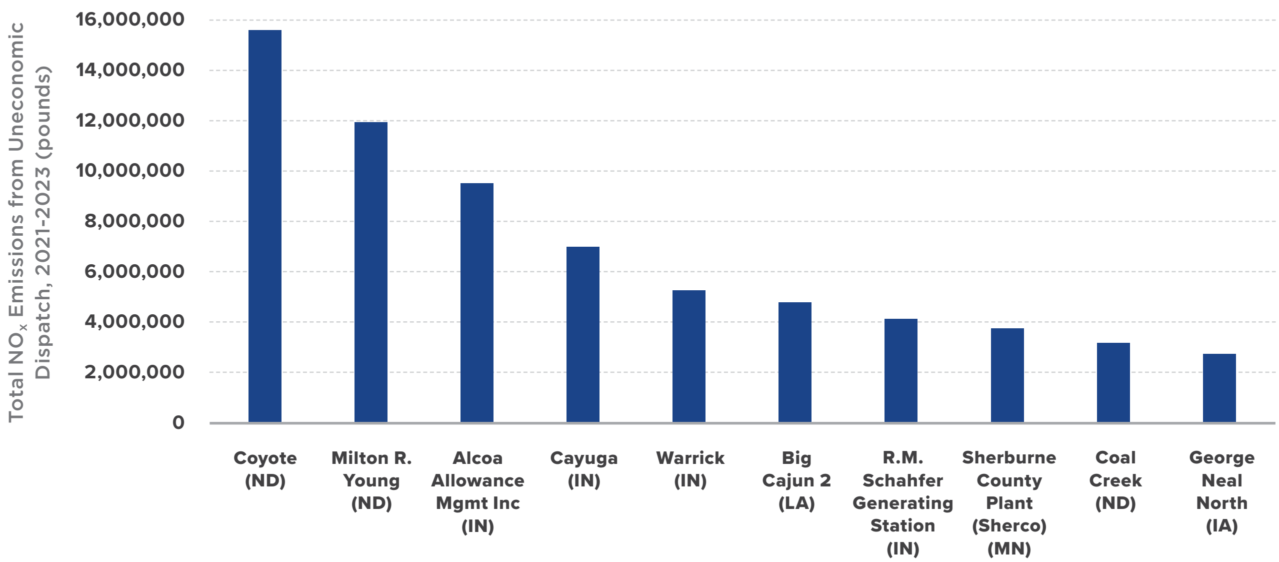


FIGURE 14 | Top 10 Plants Cumulative NO_x, 2021-2023



4 | FOR FURTHER READING

This analysis builds on prior research by the Union of Concerned Scientists,[20] the Sierra Club,[21] and the Rocky Mountain Institute (RMI).[22] The consumer cost of uneconomic dispatch quantified in our analysis is consistent with the results of these previous studies. RMI's Economic Dispatch Dashboard calculates that the uneconomic dispatch of MISO coal plants imposed excess costs on consumers ranging from a high of $764 million in 2015 to a low of $138 million in 2022.[23] The $131 million in excess costs our analysis quantified for 2022 is nearly identical to RMI's result for that year, as is our calculation of $255 million in costs for 2021 relative to RMI's result of $264 million for that year. RMI's analysis also shows that uneconomic dispatch also imposes a large cost in other regions, indicating that many states and regions could benefit from the policy solutions discussed above.

20 Daniel, Joe, Sandra Sattler, Ashtin Massie, Mike Jacobs. 2020. *Used, But How Useful? How Electric Utilities Exploit Loopholes, Forcing Customers to Bail Out Uneconomic Coal-Fired Power Plants*. Union of Concerned Scientists. https://www.ucsusa.org/resources/used-how-useful

21 Daniel, Joe. 2017. *Backdoor Subsidies for Coal in the Southwest Power Pool*. Sierra Club. https://www.sierraclub.org/sites/www.sierraclub.org/files/Backdoor-Coal-Subsidies.pdf; Fisher, Jeremy, Al Armendariz, Matthew Miller, Brendan Pierpont, Casey Roberts, Josh Smith, and Greg Wannier. 2019. Playing with Other People's Money: How Non-Economic Coal Operations Distort Energy Markets. Sierra Club. https://www.sierraclub.org/sites/default/files/Other%20Peoples%20Money%20Non-Economic%20Dispatch%20Paper%20Oct%202019.pdf

22 "Economic Dispatch Dashboard," Utility Transition Hub, RMI, 2024. https://utilitytransitionhub.rmi.org/economic-dispatch/

23 *Ibid.*

In a 2020 report, MISO's IMM also quantified how frequently coal plants in MISO are uneconomically dispatched.[24] As noted above, that analysis found some vertically-integrated utilities uneconomically dispatch their coal plants far more frequently than merchant coal plants and coal plants operated by other vertically-integrated utilities, confirming that uneconomic dispatch can be greatly reduced if market and regulatory structures provide the right economic incentives.

The IMM has updated that analysis, as shown in the table below that is reproduced from the IMM's market report for 2023. The IMM's updated analysis confirms that many MISO coal plants owned by regulated utilities continue to be uneconomically dispatched, while merchant plants generally follow market dispatch signals. The IMM's updated analysis also confirms our finding that uneconomic coal dispatch experienced a resurgence in 2023, following a temporary dip in 2022 when higher gas prices drove power prices higher, making coal plants less uneconomic.

FIGURE 15 | MISO IMM table showing continued uneconomic dispatch of regulated utility coal plants[25]

	2018-2021			2022			2023		
	Annual Starts	% of Starts	Net Rev. ($/MWh)	Starts	% of Starts	Net Rev. ($/MWh)	Starts	% of Starts	Net Rev. ($/MWh)
Regulated Utilities	**1,765**		**$9.43**	**1,765**		**$22.41**	**1,555**		**$5.75**
Profitable Starts	1,533	86%		1,635	93%		1,337	86%	
Offered Economically	735	38%		754	43%		686	44%	
Must-Run and profitable	798	47%		881	50%		651	42%	
Unprofitable (Must Run)	232	14%		130	7%		218	14%	
Merchants	**168**		**$11.06**	**84**		**$30.42**	**42**		**$6.75**
Profitable Starts	167	100%		84	100%		41	98%	
Offered Economically	153	90%		84	100%		39	93%	
Must-Run and profitable	14	10%		0	0%		2	5%	
Unprofitable (Must Run)	1	0%		0	0%		1	2%	

Previous analysis co-authored by Grid Strategies used statistical analysis to identify coal plants in MISO and PJM that operate at a much higher capacity factor than would be expected given their high fuel costs.[26] That analysis estimated that those outlier plants that were suspected of uneconomic dispatch imposed $127 million in excess costs on MISO ratepayers in 2017.

This report builds on prior work by using market price data to quantify how the uneconomic dispatch of coal causes the curtailment of renewable resources. Once it is determined that a

24 https://www.potomaceconomics.com/wp-content/uploads/2020/09/Coal-Dispatch-Study_9-30-20.pdf

25 https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf, at 43

26 https://gridstrategiesllc.com/wp-content/uploads/2024/05/wsa-consumer-benefits-quantification-final-9.27.19.pdf, at 8-10

coal plant was operating uneconomically for a set of hours, the second step of our analysis uses MISO market prices to determine the consumer cost, emissions, and renewable curtailment caused by the uneconomic dispatch. Specifically, our analysis uses the nodal LMP in MISO's Day-Ahead market to reconstruct what type of generation was likely displaced due to the coal plant running uneconomically. This allows our analysis to estimate the renewable curtailment impact of uneconomic dispatch, something that prior analyses have not attempted to quantify.

APPENDIX A
METHODOLOGY

The general approach of our analysis was to identify hours during 2021-2023 when a MISO coal plant was generating even though its marginal cost of producing electricity was higher than the MISO day-ahead market price at that node. Marginal production cost data for each coal plant was obtained from S&P's Global Market Intelligence dataset.[27] This dataset is largely populated with public data compiled by the Energy Information Administration (EIA) on Form 923[28] and Form 861[29] regarding the heat rate, fuel cost, and other variable O&M costs for each plant. In cases where data for a plant is missing or otherwise not disclosed by EIA, S&P uses its own estimates based on state average fuel costs, utility cost data disclosed on FERC Form 1,[30] and other inputs to fill in missing data.

Locational Marginal Price (LMP) data for the market nodes where those coal plants bid into MISO were obtained from S&P's dataset, which is also available in MISO's public dataset.[31] Prices from the Day-Ahead market and not the Real-Time market were used to assess the relative economics of coal generators for several reasons. In MISO, most electricity transactions occur in the Day-Ahead market, with the Real-Time market typically only used by generators and load-serving entities to respond to unexpected deviations in supply and demand. Moreover, inflexible resources like coal plants that participate in the market typically sell the vast majority of their output in the Day-Ahead market, as they cannot start up or change their output quickly enough to respond to prices in the Real-Time market. As a result, Day-Ahead market prices are the best indicator of the prices received by coal generators and the price signal the plant owner should have been responding to when making its commitment decision.

Finally, data tracking hourly generation by each coal plant was obtained from EPA's Continuous Emission Monitoring Systems (CEMS) data.[32] This was used to determine when the coal plant was operating, and thus whether it was uneconomically generating during periods when its marginal production cost exceeded market prices.

27 https://www.spglobal.com/marketintelligence/en/campaigns/energy

28 https://www.ferc.gov/general-information-0/electric-industry-forms/form-1-electric-utility-annual-report

29 https://www.eia.gov/electricity/data/eia861/

30 https://www.eia.gov/electricity/data/eia923/

31 https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AHistorical%20LMP%2FMarketReportName%3AHistorical%20Annual%20Day-Ahead%20LMPs%20(zip)&t=10&p=0&s=MarketReportPublished&sd=desc

32 https://campd.epa.gov/data/custom-data-download

FIGURE 16 | Hourly MISO prices in April 2021 compared to the marginal production cost for the Coyote coal plant in North Dakota

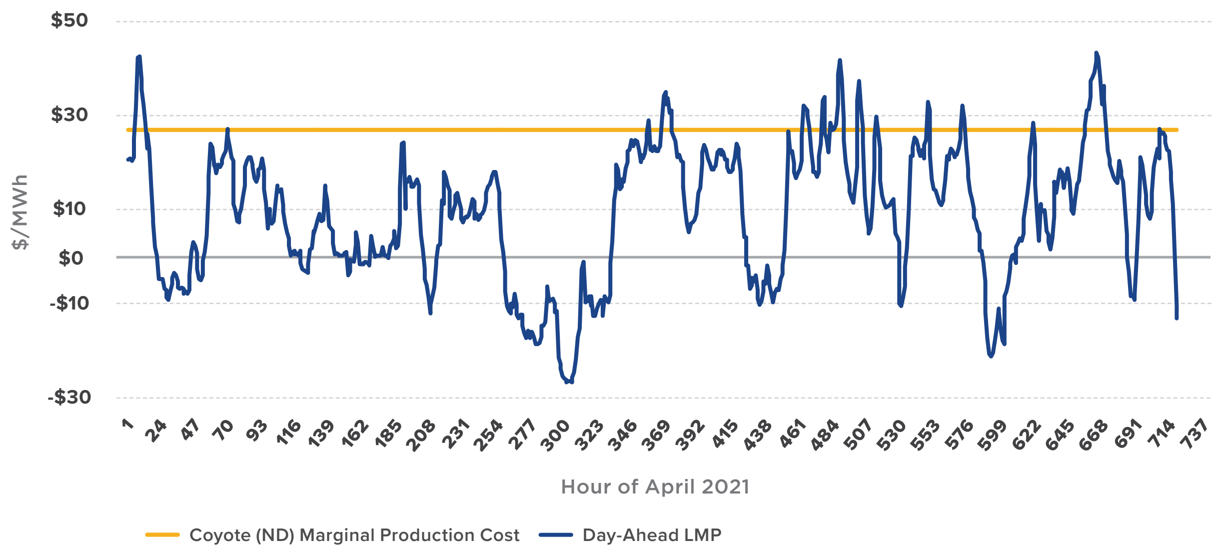
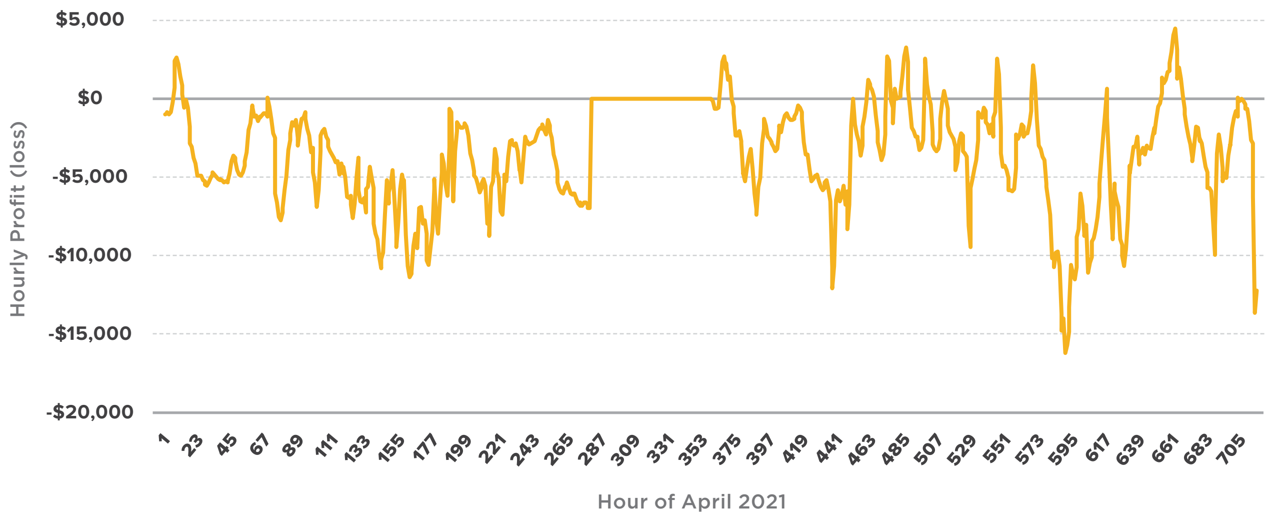


FIGURE 17 | Hourly profit and losses for the Coyote coal plant in North Dakota



As an example to illustrate these methods, Figure 16 above compares the variable Day-Ahead prices at the Coyote coal plant in North Dakota for the month of April 2021 against the plant's cost of producing electricity, which is fixed at around $27/MWh as indicated by the horizontal line. Figure 17 shows the resulting hourly profits and losses for the plant for that month, based on the plant's generation in that hour multiplied by the amount market prices at that node were above or below its marginal cost of producing electricity. Profit/loss is shown as $0 when the plant was not operating, including the sustained low-price period just prior to the middle of the month in Figure 16. The analysis summed those hourly loss figures for all periods in which the coal plant was uneconomically dispatched.

To be conservative, our analysis only counted hours as uneconomic dispatch when the coal plant a.) has cumulatively lost money for at least 48 hours, and b.) its losses from operating exceed revenue by at least 5% for that period. The 48-hour exemption accounts for the inflexibility of coal plants, as in some cases it can make sense for a coal plant to continue operating at a loss for a short period of time, such as overnight when demand is low and wind output is typically high, rather than incurring the cost of shutting down and starting back up to meet high demand the next day. The 5% threshold for expenses exceeding revenue is to conservatively account for uncertainties regarding the plant's precise economics that can apply in some cases:

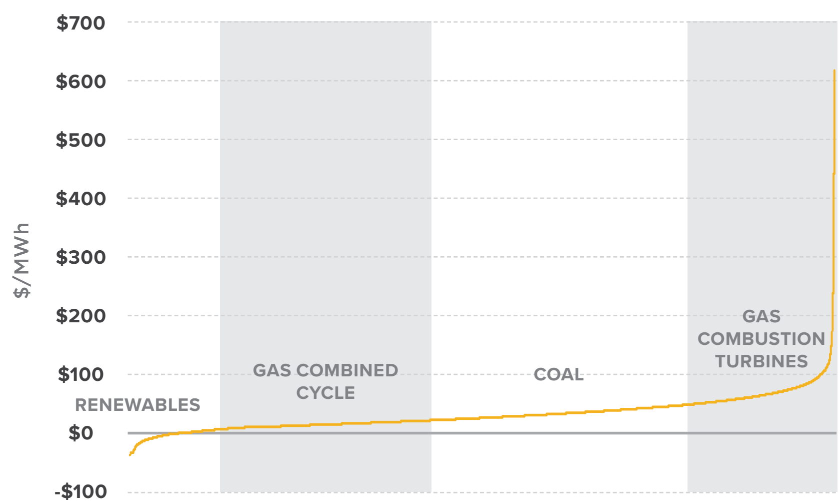
- The coal plant's generator commitment and dispatch decisions were made without perfect foresight, and some instances in which the plant operated at a narrow loss may have been rational hedging behavior. The coal plant owner could have expected demand to be higher or renewable output to be lower than was reflected in Day-Ahead market prices. Said another way, the plant owner may have committed the coal plant to hedge against the risk of supply being short and market prices being significantly higher than expected. *Section 2* above suggested market reforms MISO could implement to provide less costly mechanisms for utilities to hedge that risk.
- Lack of public information about the generator's fuel efficiency and thus its marginal production cost under different operating and ambient conditions and at various points on its heat rate curve. Most coal generators have a heat rate curve, with efficiency generally declining at lower levels of output. Our analysis is based on the heat rate a coal plant reports to EIA, which is measured at maximum output,[33] so the $/MWh fuel cost would typically be higher at lower output levels. In most cases this likely makes our analysis conservative, though if the efficiency of the plant is higher under certain ambient or operating conditions that could cause our analysis to overstate instances of uneconomic dispatch.
- Lack of public information about fuel prices. For some coal plants the pricing and terms of coal supply contracts are not public, so in those cases the S&P data used in our analysis relies on state average prices. Those average prices may not accurately reflect the coal price for that plant, though instances in which a plant's actual coal cost is lower than the state average should roughly offset instances in which the actual cost is higher than the state average. Fuel price data also does not include coal minimum delivery requirements or other contract terms that can incentivize the coal plant owner to generate uneconomically to consume fuel. While contracts with those provisions are economically inefficient, as explained in Section 2 above, in some cases a coal plant owner over-generating to consume fuel is arguably operating rationally under the terms of that contract.

33 https://www.seia.org/sites/default/files/EIA-860.pdf, at 8

Once it is determined that a coal plant was operating uneconomically for a set of hours, the second step of our analysis is to determine the cost, emissions, and renewable curtailment caused by the uneconomic dispatch. As noted above, our analysis builds on previous work by using the nodal LMP to reconstruct what type of generation was likely displaced due to the coal plant running uneconomically, and what type of generation likely would have replaced its output if the coal plant had not operated. This allows our analysis to estimate the renewable curtailment impact of uneconomic dispatch, something that prior analyses have not quantified.

In electricity markets the LMP reflects the marginal production cost of the resource that is meeting marginal demand at that node at that time. The marginal resource, or a resource with a similar marginal production cost and emissions profile, would typically increase or decrease output in response to an incremental change in supply or demand. However, in some instances in which a large amount of coal generation is operating uneconomically and must be replaced, some of the replacement generation could come from a resource with a production cost that is higher than that of the marginal resource. This should be relatively rare and have a small impact, as in most electricity markets the generation supply curve has long flat stretches, as shown in Figure 18 below.

FIGURE 18 | **Electricity supply curve reconstructed from observed market prices in MISO**



Moreover, most uneconomic coal dispatch occurs during periods of low market prices on the left side of the supply curve, where the supply curve is very flat. For example, replacing a large amount of uneconomic coal generation may exceed the ability of the marginal gas combined cycle generator to ramp up its output, but another gas combined cycle generator with an inconsequentially higher fuel cost and emissions rate would typically be the next in line along the supply curve.

Our analysis had to account for changes in the relative fuel prices of coal and gas generators over time to accurately reconstruct the generation supply curve to determine the impact of uneconomic dispatch on emissions. Our analysis used monthly average gas price data from EIA to reconstruct the supply curve in each state for each month, yet natural gas prices can fluctuate from that average over time within the month and by location within the state. However, these fluctuations should not result in a systemic bias in our analysis, as instances in which gas prices were higher than the average should be almost exactly offset by instances in which gas prices were lower than the average.

A more detailed explanation of the steps involved in our analysis is provided below:

1. A list of coal plants and individual units operating in MISO in 2021 and 2022 was created from the S&P Global Market Intelligence[34] dataset, which is based on FERC Form 1,[35] EIA 923,[36] and EIA 861[37] data. Plants that provide combined heat and power, have recently retired, or routinely operate on fuels other than coal were removed from the dataset.
    a. Using the monthly data on fuel cost, non-fuel variable O&M cost, net generation, and heat rate a monthly fuel cost and non-fuel variable operations and maintenance (O&M) cost on a per MWh basis were calculated for each coal unit.
    b. For 2023, the same methodology was used. However, S&P did not have complete data on net generation, fuel prices, or variable O&M costs for 2023 for every coal plant evaluated. When net generation data was unavailable, we used that plant's gross to net generation ratio from the same month in 2022 (see item #5 below for an explanation of how hourly EPA CEMS gross generation was converted to net generation). The same was done for fuel price and variable O&M costs.
2. Each coal plant was mapped to a MISO LMP node in the S&P dataset, and the hourly Day Ahead locational marginal prices (DA LMP) for that node were pulled for 2021-2023.
3. EPA Continuous Emissions Monitoring Systems (CEMS) hourly emissions data (CO_2, SO_2, NO_x)[38] were pulled for all coal plant units operating in MISO for 2021-2023.
4. The monthly variable O&M, monthly fuel costs, and hourly nodal DA LMPs from S&P Global's dataset were merged with the hourly emissions data from EPA CEMS.
5. Using the monthly net generation from S&P and the gross generation from EPA CEMS (net generation measures electricity actually delivered to the grid, after parasitic losses required to operate the coal plant are subtracted from gross generation), a monthly gross to net generation ratio was created for each coal plant unit and used to convert the hourly gross generation data in the CEMS dataset to an estimated net generation output for that hour.
6. The monthly variable O&M cost per MWh and the annual fuel cost per MWh were combined to create the hourly marginal cost of operating each coal plant unit. This hourly marginal cost was then compared to the nodal hourly DA LMP to determine whether the plant was

34 https://www.spglobal.com/marketintelligence/en/campaigns/energy
35 https://www.eia.gov/electricity/data/eia923/
36 https://www.ferc.gov/general-information-0/electric-industry-forms/form-1-electric-utility-annual-report
37 https://www.eia.gov/electricity/data/eia861/
38 https://campd.epa.gov/data/custom-data-download

running "economically" and to get an hourly profit (LMP minus marginal cost) for the unit. As explained above, a 48-hour and 5% loss threshold were conservatively applied to exclude periods when it may have been economically rational for a coal plant to operate at a loss.

7. To understand what generation was being displaced by a coal plant running uneconomically, we assembled a generation bid stack using the marginal cost of four different generation types, including renewables, combined cycle natural gas generation plants, coal plants, and combustion turbine natural gas generation plants.

    a. For market price values less than or equal to $0 per MWh, we assumed renewable resources were on the margin.

    b. To identify market prices that were likely set by combined cycle natural gas generation plants, we created a monthly marginal production cost by pulling each state's average cost of natural gas from EIA Electricity Data Browser[39] and the national average heat rate (7.146 MMBtu/MWh) for combined cycle plants from the EIA.[40] In gas-producing states like North Dakota and Louisiana, during some periods electricity market prices in the ~$7-15/MWh range were observed, lower than the typical bid range for a combined cycle plant. We inferred these were likely gas combined cycle generators running on gas that was priced lower than normal due to pipeline constraints. This assumption is likely conservative because in some instances those prices could have been set by non-emitting renewable resources, potentially wind resources bidding in at positive prices to reflect the cost of transmission charges to wheel in power from SPP.

    c. To identify market prices that were likely set by combustion turbine natural gas generation plants, we used the same methodology as for combined cycle plants, but with the national average heat rate for combustion turbines (10 MMBtu/MWh).[41]

    d. To identify market prices that were likely set by coal plants, we used an annual average $/MWh fuel price for 2021 and 2022 by taking the monthly-weighted average of annual generation and fuel costs. The 2022 fuel price results were used for 2023 because EIA has not yet published annual coal price data..

    e. Winter Storm Uri drove the average natural gas price significantly higher for February 2021, but the impact was concentrated into approximately one week. To account for this spike in average monthly prices we used the February 2021 average monthly natural gas price for February 14-20, and we used January's average monthly natural gas price for February days prior to Winter Storm Uri and March's average monthly natural gas prices for days after Winter Storm Uri.

8. The marginal prices developed for each fuel type were then sorted lowest to highest creating price "bins" and compared to the hourly nodal DA LMP. When the hourly LMP fell

39 https://www.eia.gov/electricity/data/browser/#topic/15?agg=1,0,2&fuel=1&geo=000002&sec=808&freq=M&start=202101&end=202312&ctype=map&ltype=pin&rtype=s&pin=&rse=0&maptype=0

40 https://www.eia.gov/todayinenergy/detail.php?id=52158

41 *Ibid.*

between two marginal prices, the lower of the two marginal prices was considered to be the price setting generation fuel type. For example, if the marginal price of a combined cycle plant was $30/MWh and a combustion turbine plant was $40/MWh, if the hourly LMP was $35/MWh then the combined cycle was considered to be the price setting generation type. But if the LMP rose above $40/MWh, then the combustion turbine becomes the generation type on the margin.

9. Once the supply curve was created and compared to the hourly LMP, we could determine the marginal generation type that was most likely setting the LMP. This allowed us to estimate what type of generation was being displaced due to the coal plant running uneconomically, and what would have replaced the coal plant's generation if it did not operate.

10. Cost: The total economic losses were summed for all hours in which a coal plant was uneconomically dispatched (i.e. the plant was operating at a loss and met the 48-hour and 5% loss conditions discussed above). As explained above, this method assumes that if the uneconomic plant were not running then its output would be fully replaced by the resource that is on the margin.

11. Emissions and curtailment: When a plant was determined to be running uneconomically, we compared the coal plant's actual emissions of CO_2, SO_2, and NO_x in that hour from the EPA CEMS data against the emissions profile of the marginal generation type in that hour to determine the incremental emissions caused by the uneconomic dispatch of the coal plant.

12. If the marginal fuel in that hour was renewables, then the full reported CO_2, SO_2, and NO_x emissions from the coal plant running uneconomically were considered to be the incremental impact of the coal plant's uneconomic dispatch because it was displacing non-emitting renewable generation. This displaced renewable generation was then summed across all uneconomic dispatch hours to calculate the amount of renewable curtailment that is attributable to the uneconomic dispatch of coal plants.

    a. If natural gas combined cycle or combustion turbine generation was on the margin, then the additional emissions was determined by taking the difference between the reported coal emissions in that hour and the average emissions of a combined cycle or combustion turbine generation facility.[42]

    b. If a coal plant was the marginal resource being displaced by the uneconomic dispatch of another coal plant, it was assumed that the plant's uneconomic dispatch in that hour had no net impact on emissions.

    c. The additional CO_2, SO_2, and NO_x emissions caused by coal plants running uneconomically and displacing more economic generation were summed across all uneconomic dispatch hours and reported at the plant and state level.

42 For natural gas fired plants, the SO_2 emissions rates assumed was 0.00487 lbs/MWh and the NO_x emissions rates assumed was 0.582 lbs/MWh. The emissions rates were based on rates reported by the EIA at https://www.eia.gov/electricity/data/emissions/xls/emissions2022.xlsx

APPENDIX B
DETAILED RESULT TABLES

TABLE 2 | Cumulative state-level results for excess costs, renewable curtailment, and pollution caused by uneconomic coal dispatch from 2021 to 2023

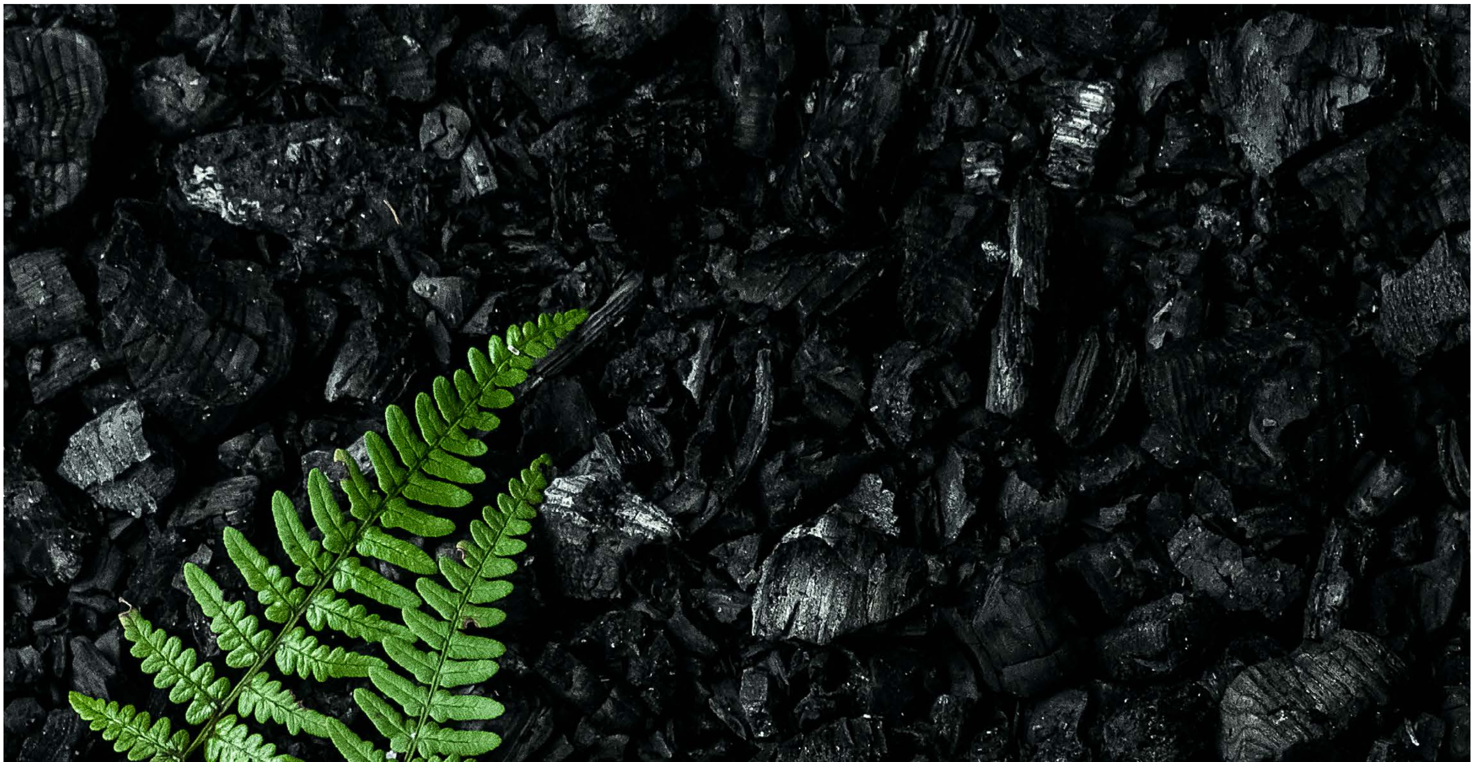
	Losses	Sum of Total Curtailment (MWh)	Sum of Total CO_2 Emissions (Short tons)	Sum of Total SO_2 Emissions (lbs)	Sum of Total NO_x Emissions (lbs)
AR	($23,172,783)	36,797	3,366,313	18,869,053	4,303,106
IA	($49,733,940)	755,051	2,748,790	12,438,576	5,720,890
IL	($39,382,922)	196,724	3,855,376	9,057,309	1,818,555
IN	($337,973,676)	113,564	18,953,779	31,023,017	32,469,397
KY	($1,510,171)	2,878	243,367	1,256,020	201,441
LA	($340,623,731)	868	7,172,003	47,444,385	8,538,788
MI	($19,484,885)	19,657	2,689,218	9,340,152	2,046,867
MN	($53,741,823)	344,711	4,847,232	5,547,692	4,540,784
MO	($10,030,686)	5,074	1,080,960	5,935,118	1,996,724
ND	($120,110,373)	1,515,926	8,651,028	46,090,812	30,751,584
SD	($37,083,140)	671,366	1,957,562	1,727,771	1,157,038
WI	($68,883,452)	144,106	6,251,949	3,521,120	1,428,617
Grand Total	**($1,101,731,581)**	**3,806,721**	**61,817,577**	**192,251,025**	**94,973,791**

TABLE 3 Cumulative plant-level results for excess costs, renewable curtailment, and pollution caused by uneconomic coal dispatch from 2021 to 2023

	Losses	Sum of Total Curtailment (MWh)	Sum of Total CO_2 Emissions (Short tons)	Sum of Total SO_2 Emissions (lbs)	Sum of Total NO_x Emissions (lbs)
AR	($23,172,783)	36,797	3,366,313	18,869,053	4,303,106
Independence	($7,550,110)	27,945	1,284,976	8,781,524	2,392,463
John W. Turk, Jr. Power Plant	($2,495,309)	8,630	236,284	164,126	(100,967)
Plum Point Energy Station	($4,983,063)	-	642,366	1,404,157	150,680
White Bluff	($8,144,300)	222	1,202,686	8,519,246	1,860,929
IA	($49,733,940)	755,051	2,748,790	12,438,576	5,720,890
Cedar Rapids	-	-	-	-	-
Clinton	-	-	-	-	-
Des Moines	-	-	-	-	-
George Neal North	($22,241,329)	301,111	873,633	4,621,228	2,747,529
George Neal South	($21,618,741)	246,951	698,445	3,774,910	1,311,251
Louisa	($2,795,400)	43,845	478,278	2,452,067	941,509
Muscatine	($4,519)	304	24,491	214,568	263,622
Ottumwa	($2,063,577)	61,003	368,491	320,576	76,900
Walter Scott, Jr. Energy Center	($1,010,375)	101,838	305,452	1,055,228	380,080
IL	($39,382,922)	196,724	3,855,376	9,057,309	1,818,555
Baldwin Energy Complex	($26,457,212)	151,521	2,569,629	3,025,199	938,764
Dallman	($394,161)	2,253	57,882	58,869	19,192
Marion	($10,759,844)	-	855,481	4,644,942	555,292
Newton	($1,255,160)	-	246,716	1,094,560	277,828
Prairie State Generating Station	($516,544)	42,950	125,668	233,739	27,479

	Losses	Sum of Total Curtailment (MWh)	Sum of Total CO_2 Emissions (Short tons)	Sum of Total SO_2 Emissions (lbs)	Sum of Total NO_x Emissions (lbs)
IN	($337,973,676)	113,564	18,953,779	31,023,017	32,469,397
Alcoa Allowance Management Inc	($45,225,211)	-	2,405,163	1,052,625	9,510,251
Cayuga	($46,627,064)	106,065	2,584,281	4,673,016	6,985,918
F. B. Culley Generating Station	($19,852,643)	301	1,549,727	3,258,750	1,715,536
Gibson	($105,502,981)	-	5,101,073	11,906,696	2,706,743
IPL - Petersburg Generating Station	($10,020,245)	1,932	1,261,282	3,698,773	1,782,282
Merom Generating Station	($15,712,153)	-	1,745,892	3,132,413	32,877
Michigan City Generating Station	($6,795,832)	3,869	676,604	975,216	372,704
R.M. Schahfer Generating Station	($77,462,197)	806	2,379,224	1,974,911	4,115,321
Warrick	($10,775,351)	591	1,250,533	350,617	5,247,765
KY	($1,510,171)	2,878	243,367	1,256,020	201,441
D.B. Wilson	($1,510,171)	2,878	243,367	1,256,020	201,441
LA	($340,623,731)	868	7,172,003	47,444,385	8,538,788
Big Cajun 2	($267,680,299)	427	4,264,764	35,297,527	4,809,014
Brame Energy Center	($24,346,318)	441	2,187,274	6,558,139	2,480,243
R. S. Nelson Generating Plant	($48,597,114)	-	719,964	5,588,719	1,249,531
MI	($19,484,885)	19,657	2,689,218	9,340,152	2,046,867
Belle River	($3,571,929)	1,334	614,437	5,996,710	1,647,390
J.H. Campbell	($9,304,628)	475	1,201,506	2,738,126	303,418
Monroe	($6,608,327)	17,848	873,275	605,316	96,058

	Losses	Sum of Total Curtailment (MWh)	Sum of Total CO_2 Emissions (Short tons)	Sum of Total SO_2 Emissions (lbs)	Sum of Total NO_x Emissions (lbs)
MN	($53,741,823)	344,711	4,847,232	5,547,692	4,540,784
Allen S. King	($3,146,217)	23,152	286,776	514,670	197,300
Clay Boswell Energy Center	($8,900,433)	96,020	1,208,061	370,236	585,234
Sherburne County Plant (Sherco)	($41,695,172)	225,539	3,352,395	4,662,786	3,758,249
MO	($10,030,686)	5,074	1,080,960	5,935,118	1,996,724
Labadie	($872)	-	288	1,308	488
Rush Island	($116,864)	-	28,755	236,316	11,551
Sikeston	($5,767,513)	1,727	589,356	5,339,781	547,227
Sioux	($4,145,437)	3,348	462,561	357,713	1,437,458
ND	($120,110,373)	1,515,926	8,651,028	46,090,812	30,751,584
Coal Creek	($27,314,676)	509,791	2,708,903	5,561,254	3,194,471
Coyote	($54,727,250)	738,509	3,030,373	36,991,701	15,590,750
Milton R. Young	($38,068,446)	267,626	2,911,752	3,537,857	11,966,363
SD	($37,083,140)	671,366	1,957,562	1,727,771	1,157,038
Big Stone	($37,083,140)	671,366	1,957,562	1,727,771	1,157,038
WI	($68,883,452)	144,106	6,251,949	3,521,120	1,428,617
Biron Division	-	-	-	-	-
Columbia Energy Center	($19,486,871)	25,762	1,628,482	1,505,614	812,948
Edgewater	($1,979,309)	4,297	289,624	208,861	(63,098)
Elm Road Generating Station (Oak Creek)	($14,974,003)	40,083	1,314,268	220,448	(42,064)
John P. Madgett	($12,559,841)	61,507	1,150,735	1,369,081	450,374
South Oak Creek	($18,375,936)	5,294	1,734,603	144,611	289,321
Weston	($1,507,492)	7,163	134,237	72,504	(18,865)
Grand Total	($1,101,731,581)	3,806,721	61,817,577	192,251,025	94,973,791



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Grid Strategies LLC is a power sector consulting firm helping clients understand the opportunities and barriers to integrating clean energy into the electric grid. Drawing on extensive experience in transmission and wholesale markets, Grid Strategies analyzes and helps advance grid integration solutions.

Based in the Washington DC area, the firm is actively engaged with the Federal Energy Regulatory Commission, Department of Energy, state Public Utility Commissions, Regional Transmission Organizations, the North American Electric Reliability Corporation, Congressional committees, the administration, and various stakeholders.

NRDC

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NRDC works to safeguard the earth—its people, its plants and animals, and the natural systems on which all life depends.

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