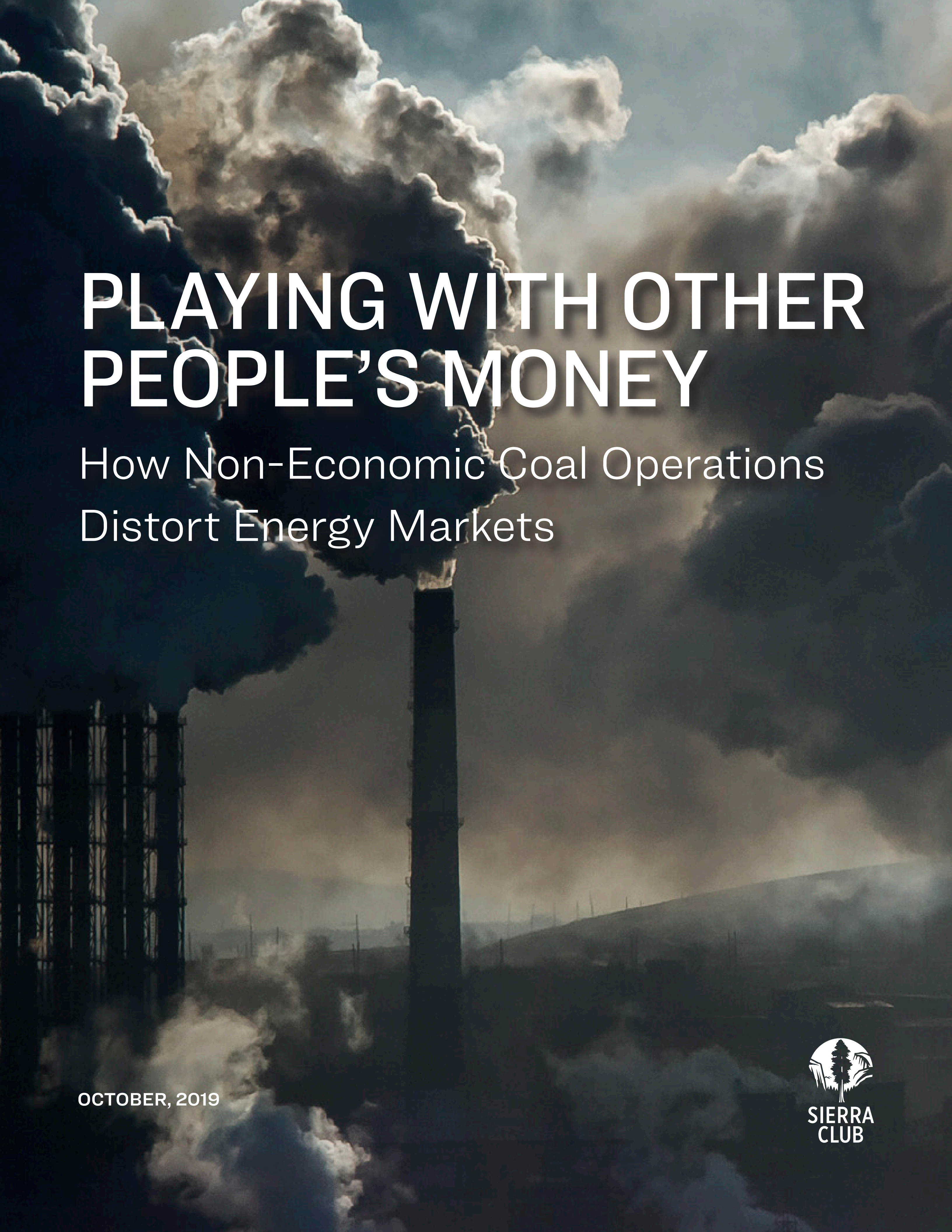

PLAYING WITH OTHER PEOPLE'S MONEY

How Non-Economic Coal Operations Distort Energy Markets

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SIERRA CLUB

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EXECUTIVE SUMMARY

Regional energy markets in the U.S. were designed to foster competition amongst power plants, in order to save electricity consumers money through efficient operation. There is growing evidence, however, that in several of these markets rate-regulated utilities are operating coal units out of merit for extended periods, rather than allowing the markets to determine when these units are competitive. The objective of this research was to examine the extent to which electric utilities operate coal units out of merit, and to quantify the impact of non-economic dispatch on consumers and merchant power generators.

We conducted several analyses examining the extent and consumer impacts of "self-scheduling" coal plants in the electric markets regions of MISO, SPP, ERCOT, and PJM from 2014 to 2017. Our analyses demonstrated that, in periods when energy market prices are low, coal plants owned by regulated, vertically integrated utilities are systematically operating coal plants out of merit, to an extent not seen in merchant-owned coal plants. The insensitivity of regulated coal plants to non-economic dispatch through extended periods of low market prices, and the clear actions by merchant coal plants to avoid non-economic dispatch was apparent in each of the market regions we examined. For example, within PJM, where most power units are merchants (i.e. unregulated), coal units generally operate in accordance with market prices. The few regulated coal units, owned by Dominion or American Electric Power (AEP), demonstrated a markedly different behavior, operating in far more hours than warranted by market prices.

Overall, we estimate that captive ratepayers of regulated utility coal plants paid $3.5 billion more for energy from 2015-2017 due to non-economic dispatch relative to the potential procurement of energy and capacity on the market. Accounting for the costs of fixed operations and maintenance (O&M) and revenues from capacity markets in MISO and PJM, **we estimate that coal plants with negative net revenue lost over $3.8 billion in 2015-2017, losses that are likely being made whole via state ratemaking.** The vast majority of the losses (79-87%, by year) were incurred at coal plants owned by regulated utilities.

The non-economic operation of a large number of units renders it difficult to determine what an alternative outcome could have looked like if all units had operated in merit order. Specifically, when units start to operate economically, it may change market prices and have interactive effects with other displaceable generators. To assess the practicality of units achieving economic dispatch, and the impact on both other dispatchable resources and market prices, Sierra Club retained Synapse Energy Economics to conduct intensive system modeling. Synapse ran unit-specific chronological dispatch modeling of MISO with transmission and operational constraints. The purpose was to compare actual MISO operations in 2017 to what would have happened had units dispatched economically.

The results of our modeling demonstrated that economic dispatch of MISO's coal units in 2017 was feasible, and would have resulted in less coal generation, lower system costs, and higher market revenues. If coal units had dispatched economically in 2017, rather than self-scheduling, generation from coal units would have fallen by about 10 percent, from about 324 TWh in our base case (representing actual 2017 conditions) to 293 TWh under economic dispatch, a reduction of 31 TWh. Consistent with our non-modeled findings, the reduction in coal **generation from economic dispatch is almost entirely (93%) attributable to coal units owned by regulated utilities.**

Operating out of merit, or dispatching more often than is dictated by market conditions, increases production costs; and economically dispatching coal drives down total production costs. When non-economic units are no longer forced online, they are replaced by more efficient and lower-marginal-cost resources. Our modeling indicates that the total production cost of coal-burning generators in MISO would have dropped from $10.07 billion to $8.78 billion in 2017, a savings of $1.29 billion in that year alone. The benefit of this production cost savings would likely be allocated almost entirely to the customers of regulated utilities who today pay for the operations of non-economically operated coal via state ratemaking processes.

Finally, **our modeling shows that operating out of merit likely suppresses market prices.** In contrast, economic dispatch lifts market prices, and increases revenues for efficient generators. We assess that across all nine modeled MISO regions, the median hourly market price would have increased by about $7.7/MWh, or around 30%, if coal units had economically dispatched in 2017. The increase in market prices is consistent across both low- and high-cost hours.

Utilities have sought to explain that they operate out of merit due to constraints faced by coal units, including slow ramp rates, large fixed-price fuel contracts, and thermal stresses incurred during startup. Nonetheless, the substantially different behavior of regulated merchant coal plants suggests that the decision to operate consistently out of merit order is not operational, but rather is related to the way that regulated coal plants make revenue. In particular, regulated coal units recoup fuel and operational costs directly from ratepayers, rather than through market revenues. This decoupling makes it harder for regulators to assess if a coal unit has operated competitively. In many states, fuel and operations costs are passed through *pro-forma* "adjustment" dockets, which further decouple the full costs of operation from dispatch decisions.

Captive customers of vertically integrated utilities that are part of multi-state energy markets may be paying more for electricity generated by coal units owned by their utility than could reasonably be obtained through market energy and capacity, particularly during periods of sustained low market energy prices. Those utility customers pay for expenses incurred when the coal plants were uneconomic and less-expensive power was available but not obtained by the utility.

There are concrete steps that could be taken by state commissions and others to better protect electric consumers from the uneconomic consequences of generation out of merit and excessive self-scheduling:

- **Commissions and consumer advocates** should examine the self-commitment and self-scheduling practices of regulated utility coal-burning power plants in market regions through investigations, expanded fuel or rate case dockets, or during resource planning reviews;
- **Commissions** should examine the current real and implied incentives driving non-economic dispatch, and consider alternative positive and negative incentive structures to ensure regulated coal plant operators dispatch competitively, including the potential disallowance of operational costs in excess of market necessity;
- **Utilities,** in the absence of a rigorous multi-day market, should develop a consistent and transparent set of practices for avoiding operations and commitment during periods of persistently low market prices;
- **Market monitors** should rigorously examine the behavior and bids of slow-ramping, coal-burning units to ensure that market costs are not being inappropriately depressed through the non-economic actions; and
- **ISOs and RTOs** should consider more advanced forward markets that send a clear commitment-relevant market signal to better inform utilities' decision making, and raise the barrier to self-commitment.

Improved dispatch practice would reduce customer costs, improve market revenues for efficient generators and renewable energy operators, and substantially reduce emissions. Centralized energy markets in the US have been designed — and touted for — their ability to ensure energy is used efficiently and competitively, but most market assessments seek to review if participants are inappropriately gaming the market for increased revenues. In this case, the markets should also work to ensure that regulated thermal plants aren't seeking to increase revenues from captive ratepayers at the expense of market prices and ratepayer costs.

1 INTRODUCTION

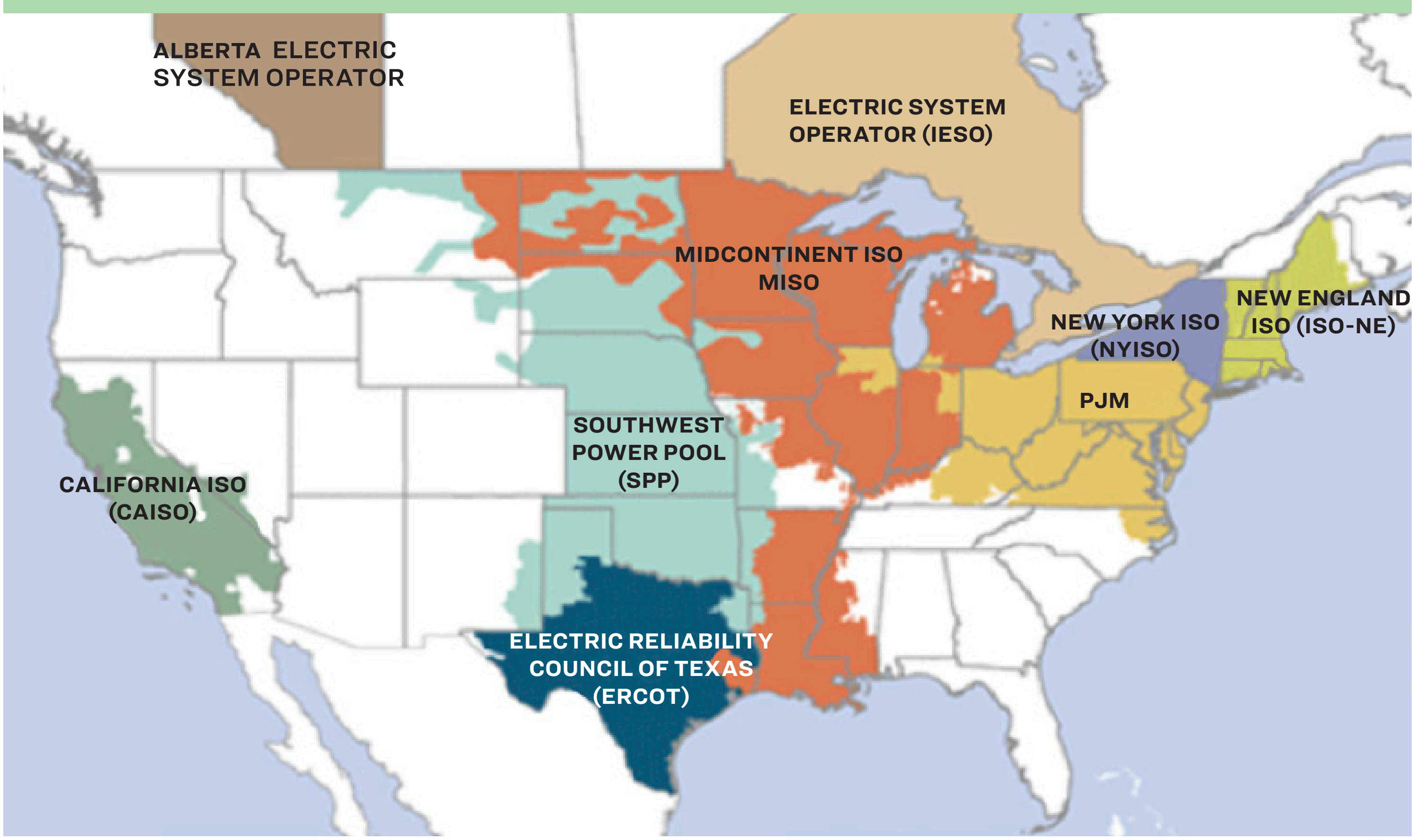
Almost two-thirds of all electricity generation, and just over two-thirds of coal-fired generation, in the United States is dispatched through one of seven centralized energy markets.[1] These markets are designed to provide customers with the lowest-cost reliable mix of generation, capacity, and other services. At its simplest level, the market structure is intended to minimize the short-run production costs needed to meet demand: the markets are designed to allow low-cost generators to compete, while coordinating the efficient operation of generators. There are seven energy market regions in the United States (Figure 1), called Independent System Operators ("ISO") or Regional Transmission Organizations ("RTO"). Each ISO/RTO (hereinafter simply "RTO") coordinates transmission, short-term reliability, and the operation of the grid.

Today, each RTO in the United States operates a centralized energy market, serving essentially as a clearinghouse for generation bids to meet demand requirements. Load-serving utilities submit their demand requirements on a day-ahead basis, and the generators competing to serve that energy demand bid their generation into the market, typically at the individual generator's cost of production. The RTO aggregates the bids and determines, in conjunction with operational constraints, which generators should operate the next day, when, and at what levels. The RTOs also operate a real-time balancing market to respond to real-time demand changes and generating unit availability. In general, RTOs select bids on the basis of production cost—which is to say, at short-term variable cost, typically comprised of fuel costs as well as variable operations and maintenance ("O&M") costs. The RTO then creates a "merit order" supply curve of least-cost to highest-cost generators, and generally first calls upon the lesser-cost generators to satisfy energy needs. There are important exceptions, however, to that economically efficient order of dispatch.

In 2017, Sierra Club conducted preliminary research finding that coal-burning power plants in the central United States were likely operating more often than was warranted economically, and were acting outside of reasonable expectations for generators in a centralized energy market.

Here we build on that research to further examine the impact of non-economic coal-fired generation on cost and market prices. The objective of this research was to examine the extent of the over-dispatching problem by electric utilities and to quantify the impact of over-dispatching on consumers and merchant power generators.

Figure 1 Map of North American ISOs and RTOs.[2]



2 REGULATED UTILITIES AND THE SELF-SCHEDULING LOOPHOLE

Vertically integrated utilities are generally rate-regulated utilities that own, and charge their customers for, generation, transmission, and distribution services, rather than paying a wholesale cost for transmission or generation services. If a "regulated" utility[3] owns a power plant, the customers of that regulated utility pay for the fuel and O&M costs of that power plant.

In contrast, in regions of the country that have undergone "restructuring," utilities purchase energy from a centralized market. In these regions, the vast majority of generation is owned by independent power producers, or merchant generators. This is the case in The Electric Reliability Council of Texas ("ERCOT"), PJM Interconnection ("PJM"), New York ISO ("NYISO"), and ISO New England ("ISO-NE"). In those regions, utilities generally do not own generation stations.

However, some generators in these regions, and the majority of the generators in the market regions of Midcontinent ISO ("MISO") and the Southwest Power Pool ("SPP") are owned by regulated utilities. In these cases, the generators still bid into the market, but the costs of operation are paid for by ratepayers.

What is the connection between a regulated generator that bids into a competitive energy market, and yet has its production costs paid for by ratepayers?

In many circumstances, the generator still is expected to act as a market participant, but one backed by ratepayers rather than a private owner: the ratepayers pay for the costs of the generator, and in return are credited market revenues received by the generator. In such a set-up, the regulated generation owner is effectively participating in these regional RTO markets on behalf of its ratepayers.

If it costs a regulated generator less to produce electricity than to purchase energy at the market price, and the generator is economically dispatched, the retail customers that pay for the generator's operations could see a net benefit in the form of reduced rates relative to customers of utilities that purchase market energy to serve customers' energy demand.

On the other hand, **if it costs a regulated generator more to produce energy than the market, or if the generator is not economically** dispatched (*i.e.*, operates substantially out of merit order), **ratepayers can end up paying substantially more than the cost of market energy and capacity** — clearly an inefficient outcome**.**

How and why does a generator operate out of merit order in a competitive market?

RTOs almost always provide opportunities for generators to provide generation "out of merit," — or out of accordance with strictly competitive behavior— and there are reasons that a generator should be allowed to do so. In the simplest example, a generator may need to test equipment. In such a case, a unit might alert the RTO that it intends to operate, regardless of cost relative to alternatives.

As a general matter, there are three ways that a generator can operate out of merit order. It can indicate to the RTO that it will "self-schedule," it can indicate that it will "self-commit," or it can submit a bid below its cost of production.

- ***Self-scheduling:*** In self-scheduling, a generator identifies the hours in which it will operate, and the level at which it will provide generation. When a generator announces that it will self-schedule, it is included in the supply curve as a zero-cost bid, but (as occurs with every other generation that clears) it will receive prevailing market prices.
- ***Self-commitment:*** When a generator elects to self-commit, it guarantees that it will operate at its "minimum loading," *i.e.*, the lowest level of generation it can provide, often 25 to 50 percent of its nameplate capacity.[4] A unit might self-commit to ensure that it is online, and allow the RTO to dispatch its remaining capacity economically. As in self-scheduling, the minimum loading of the power plant is included in the supply curve as a zero-cost bid.
- ***Bid below production cost:*** A generator can theoretically provide a bid to provide energy well below its actual cost of production. Such a low bid may effectively guarantee that the unit will clear the market.

Theoretically, regulated generators should seek to dispatch economically, based on their cost of production, in order to reduce costs to ratepayers, subject to reliability considerations. This principle applies regardless of whether a generator resides in a wholesale energy market, or not. Our research shows, however, that regulated generators in market regions operate far more than warranted by during extended periods of lower market prices—*i.e.*, they operate regularly out of merit order. Moreover, this pattern cannot be explained entirely by operational constraints.

Why would a regulated coal generator seek to operate out of merit and more often than dictated by operational necessity?

In general, a perverse outcome is made possible because regulated generators are able to recover production costs through captive ratepayers, in contrast to merchant generators that must recover all costs through their revenues from a competitive marketplace. And since regulated utilities do not generally report the net market gains or losses of individual generators (or even their whole generation system relative to market prices) to regulators, it is difficult for regulators to discern whether this inefficient, ratepayer-harming phenomenon is in fact occurring.

One hypothesis is that it is difficult to justify continued investment in a plant which, originally built for "baseload" output, now operates only as a seasonal "peaker". In general, regulators assume that generators operating in market regions are dispatched economically, follow market signals, and consume only as much fuel as necessary. In fact, in many states, fuel costs are accepted into rates on a *pro forma* basis in fuel-adjustment proceedings.

This lack of scrutiny enables regulated generators to operate more than economically warranted, and at substantial cost to captive ratepayers. In effect, those retail customers are effectively subsidizing the generator's unnecessary uneconomic operations in the wholesale market. That is, the ratepayers are essentially paying, through mandated retail rates to their regulated utility, a cost above that which they would paid if the utility had instead chosen not to self-commit, and simply procured power for its customers from the wholesale market.

Here, we explore evidence that regulated coal plant operators in all market regions have operated coal plants out of merit, without apparent justification or detailed review, for years. This behavior becomes most apparent when market prices fall: merchant generators curtail operations while regulated generators continue operations. We show that these non-economic decisions have unnecessarily driven up costs to captive ratepayers of non-economic coal plants, increased emissions from non-economic coal plants, and driven down revenues to independent generators, renewable energy producers, and more economically efficient regulated generators. We also delve into the reasons given by utilities for operating coal units out of merit order, and propose a series of solutions to drive a more efficient market with better transparency.

3 COAL-BURNING UNITS IN MARKET REGIONS OPERATE NON-ECONOMICALLY

Prior research conducted independently by Sierra Club[5] and Union of Concerned Scientists (UCS)[6] demonstrated that units in SPP operate outside of merit order — meaning, again, that they dispatch more often than would be indicated by market prices, and would therefore likely lose substantial net revenue if they were merchant operators. In early 2018, the SPP Market Monitor, an independent entity charged with ensuring efficient and fair operation of the energy market, suggested that persistent negative pricing in the market could be attributed both to a large penetration of must-take wind and to excessive self-scheduling by existing coal units.[7] And in mid-2018, the Greater Springfield Chamber of Commerce released a report assessing that the City of Springfield's City Water, Light and Power ("CWLP") "operated generation resources in a non-economical manner." Specifically, this report found that "the full Marginal Cost of Generation for CWLP's generation resources was higher than the clearing market price for electricity in *all but 1.9% of the hours in 2016*."[8]

Here, we confirm that hypothesis and demonstrate that numerous coal-burning power plants in market regions operate non-economically, primarily by committing to operate during extended periods of low market prices—to a degree that is not justified or overcome by revenues earned during periods of high market prices.

Case Study: Gibson 5 (Indiana)

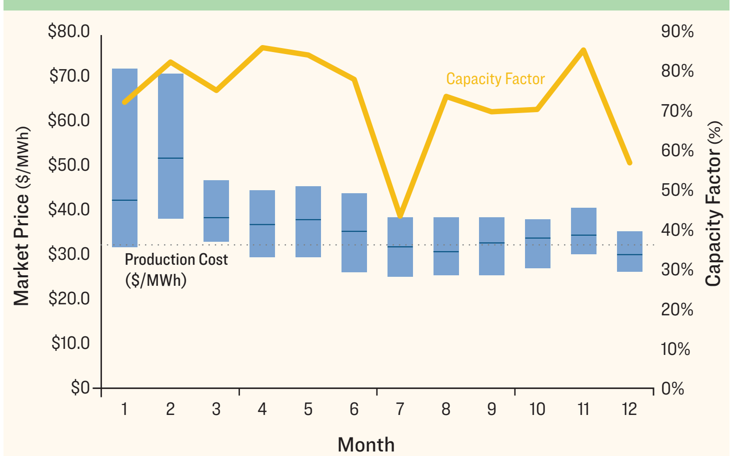
An example of dispatch behavior and market prices is shown in Figure 2 (2014) and Figure 3 (2016) for Gibson 5, a 665 MW coal unit owned by Duke Indiana.

The figure shows market energy prices by month (2nd and 3rd quartile, or the 25th to 75th percentile range of energy prices) compared against an estimated production cost from public data sources. Above the price comparison, we show the capacity factor of the plant during the same months.

In early 2014, market energy prices in Indiana were high — from $38 to $64/MWh between January and May,[9] comfortably above the coal plant's estimated production cost of $32/MWh.[10] However, after June 2014, median energy market prices fell to the plant's production cost of $32/MWh and stayed near that level.

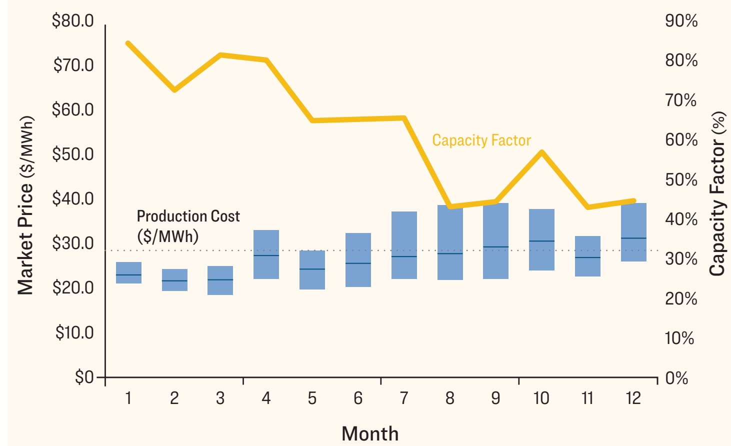
As a consequence, the unit began ramping on nearly a daily basis, seeking to avoid lower cost hours through cycling, but it didn't actually come offline — in other words, it operated nearly every day, even when market prices were substantially below the cost of operation. Despite brief market price increases late in the year, we estimate that Gibson 5 generated almost no net energy market revenue in the second half of 2014. And while Gibson 5 cleared $42 million in net market energy revenues in 2014, 70% of that was in the first three months of the year. Coal plant cycling (i.e. seeking to generate less energy during off-peak hours) is discussed in more depth in **Appendix A.**

Figure 2 Range of market prices and production cost (left axis) and capacity factor (right axis) for Gibson 5 (Indiana) in 2014.[11] Range of market prices represents monthly 25th to 75th percentiles, median shown in solid line.



In 2016, market prices in MISO's Indiana hub were much lower than the estimated production cost of Gibson 5 — even the highest quartile of market prices didn't exceed Gibson 5's $28.4/MWh production costs in January, February, March, or May (see Figure 3, below). And yet Gibson 5 dispatched at an average 75% capacity factor for the first half of the year, and thus operated at a net energy market loss in those months. We estimate that from January through March, Gibson 5 lost $5.3 million on an operational margin or net energy revenue. And while energy market prices climbed modestly in late spring (April through June), they still remained below Gibson's production cost. So while Gibson held a 70% capacity factor through the late spring, it made zero net energy market revenue. The profitability of Gibson 5 only improved in the second half of the year, due to two separate factors: (a) market prices increased to just above the unit's production cost, and (b) the unit began turning off for long stretches of time.

Figure 3 Range of market prices and production cost (left axis) and capacity factor (right axis) for Gibson 5 (Indiana) in 2016.[12] Range of market prices represents monthly 25th to 75th percentiles, median shown in solid line.



We estimate that Gibson 5 cleared about $8.6 million in net energy revenue in the second half of 2016, and just barely cleared $2.8 million in net energy revenues for the year, or $4.6/kW-yr.

Is $4.6/kW-yr in net energy revenues a reasonable revenue stream for a competitive coal plant? In addition to the variable costs of operation, plants also incur fixed costs, such as labor, maintenance, and taxes. And plants in MISO have the opportunity to sell capacity on a voluntary market as a "fixed" revenue stream. The Energy Information Administration ("EIA") estimates that conventional coal plants incur on the order of $42/kW-yr in fixed operations and maintenance ("O&M"). Accounting for MISO's capacity market and the prevailing price of capacity in 2016, we assess that if the utility were operating instead as a merchant, this coal unit would have *lost* about $8.5 million in 2016, after accounting for fixed O&M and market capacity value. Gibson 5 therefore likely cost ratepayers far more to operate in 2016 than if Duke Indiana had purchased energy and capacity from the wholesale market.

Why would a coal operator, legally obligated to provide least-cost service to ratepayers (in the case of a regulated utility), elect to dispatch a coal plant non-economically?

In a recent investigation into non-economic commitment and dispatch in Missouri,[13] utilities described four fundamental reasons that they commit units beyond a market-competitive level of dispatch:

- ***Fixed fuel contracts****:* Fuel contract with a "must take" provision may drive a unit to operate out of merit order to consume a contractual fuel obligation and avoid accumulating an unmanageable inventory on-site. A coal plant which has contracted for more fuel than warranted by energy market prices will incur net market losses.

- ***Preventing thermal cycles:*** Many coal plants, in particular older and less efficient models, require substantial ramp times from a cold start to a minimum operational level, and can incur substantial thermal wear during startup and shutdown periods.[14] Preventing a thermal cycle (*i.e.*, shutting down for a short period of time) is only warranted if the cost of the incremental cycle exceeds the revenues lost by operating through a low market price period. Continuously operating without such an explicit calculation may result in substantial net market losses.
- ***Compliance and equipment testing:*** Coal plant operators occasionally test systems during times of otherwise non-economic dispatch.
- ***Lack of a multi-day market signal:*** Today, no centralized market operates longer than a day-ahead market for energy, meaning that a plant is only provided a 24-hour signal that it is required or not. A plant with a slow ramp, long minimum downtime or uptime, or high cycling cost may require a multi-day signal to capture its runtime constraints.

A private or merchant coal plant owner cannot afford to incur ongoing market losses — except in rare circumstances, the vast majority of revenue for a merchant coal plant is derived from energy (and capacity) market sales,[15] and incurring ongoing losses is not a pathway to profitability.[16] Merchant coal plant owners are compelled to cover all costs (including fuel, variable and fixed O&M, emissions costs, and ongoing capital) with market-based revenues, regulated coal owners are not held to the same requirements. Instead, the fuel and O&M costs of regulated coal plants are passed through to ratepayers, and it is often up to a regulator (or other oversight entity) to assess if a coal plant has provided a net benefit to ratepayers.

There are, however, other reasons that a regulated coal plant might seek to operate non-economically or self-schedule that are not fundamental operational considerations:

- ***Perception of use and usefulness:*** A coal plant operating at a high capacity factor, irrespective of economics, can lend a perception that the plant is a meaningful contributor to customer demands, and is therefore providing useful service. By contrast, it is difficult to justify continued investment in coal plants that, although built as "baseload" facilities, now operate as peakers on a seasonal basis. This distinction is critical for investor-owned utilities, who in many cases hold substantial remaining debt in coal plants, and who rely on public utility commissions to continue to authorize generous rates of return, as well as any undepreciated initial capital investment on existing coal plant. A utility commission faced with a coal plant operating at very low capacity factors might legitimately challenge the value of a low-dispatch coal plant. By maintaining a high capacity factor for a non-economic unit, a utility can create an illusion of economic value, even if it is unwarranted. For example, a recent rate recovery case in Virginia touted the high capacity factors, rather than the fundamental economics, of a utility's coal units as justification for the value of the units.[17]
- ***Perception of need to self-supply:*** Centralized energy markets (RTOs) in the United States also take on the roles and responsibilities of reliability coordinators and balancing authorities. However, some regulated utilities still self-schedule with a claim that a plant might be needed for reliability, even if the RTO has not identified a near-term need for that plant.[18]
- ***Revenue tied to off-system sales:*** While these agreements are increasingly rare, some utilities are authorized to retain (for shareholders) a fraction of revenue from off-system sales. A utility may have a strong incentive to operate a plant out of merit order with the expectation of passing through excess fuel and O&M costs while collecting excess off-system sales revenue. A profit-seeking utility could seek, for example, to allocate as much cost to a fixed category (*i.e.* a long-term coal fuel contract) as feasible to ensure substantial off-system sales at a low variable cost, and collect for excess revenues for shareholders, while allocating the fixed costs to ratepayers.
- ***Contracts tied to certain plant operations:*** Some utilities and generation and transmission companies ("G&Ts") serve generation to smaller cooperative or municipal utilities through "full requirements" contracts. In some cases, these contracts may specify that the generation be provided by a certain plant (rather than by market energy procurement), or allow the serving utility to specify the plant which provides generation. In such cases, a utility might be incentivized to run their own plant to serve a full requirements contract rather than procuring market energy on behalf of their wholesale customer.

If it were the case that all coal operators — both regulated and merchant — were observing purely operational reasons for self-scheduling, we would expect both regulated and merchant plants to act equally optimally, or sub-optimally. If, in fact, regulated coal plants observe a different set of rules or reasons to operate out of merit order, we would expect to observe separable behavior.

4 MERCHANT OPERATORS OF COAL-BURNING UNITS DISPLAY BETTER MARKET BEHAVIOR THAN REGULATED UTILITIES

In 2018, Bloomberg New Energy Finance ("BNEF") published research finding that about half of US coal generators had negative long-run operating margins from 2012-2017 relative to market prices, with the vast majority (130 GW of 135 GW) of coal units with negative margins owned by regulated utilities.[19] They further point out that "half of these 'uneconomic' coal plants are located in vertically integrated, regulated balancing authorities; [but] the other half exist within liberalized markets"—*i.e.*, ISO/RTOs with centralized energy markets.[20] BNEF notes that "throughout the U.S., regulated plants are much more likely than IPPs [independent power producers] to enjoy . . . protection against power market signals."[21]

We compared the dispatch of coal plants against market prices for regulated and merchant plants in four market regions (PJM, MISO, SPP, and ERCOT[22]) and found that, as a general matter, merchant coal plant operators hew closer to market-based paradigms than regulated utilities. Later in our paper, we seek to observe how one market region, MISO, would have looked if units dispatched closer to optimal in a historic year. However, for the purposes of assessing historic behavior across a wider swath of units, we can compare actual operations against "perfect," or optimal, dispatch.[23]

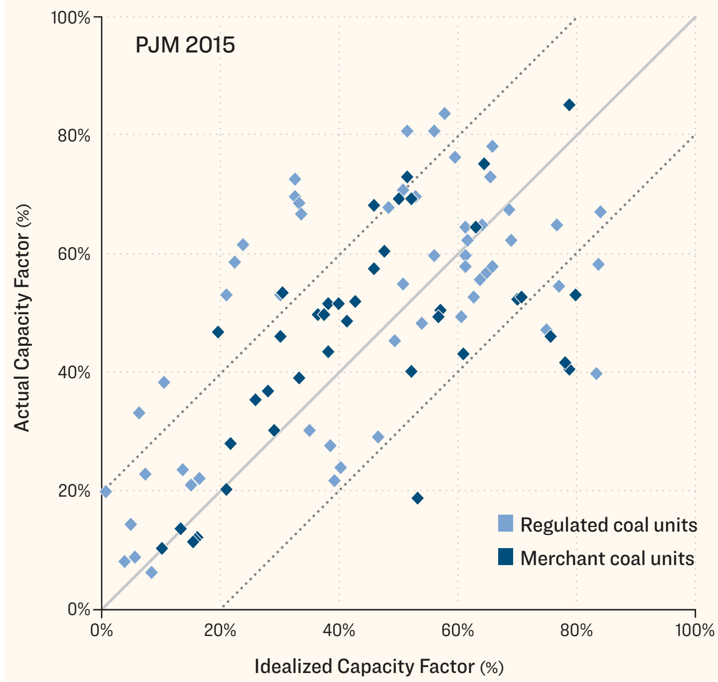
Using optimal, or "perfect," economic dispatch as a benchmark, we observed that merchant coal units in market regions are generally better aligned with market prices than regulated coal units in those same regions. In addition, under falling market prices, merchant generators dispatch downward (rationally), while regulated coal units do not, or dispatch downward far less.

Figure 4, below, compares the dispatch behavior of both merchant (shaded gray) and regulated coal units (shaded black) in PJM relative to optimal dispatch.[24] For illustrative purposes, a zone is defined around the 1:1 line representing dispatch within ±20% of the 1:1 line.[25]

A marker on or near the 1:1 line (*i.e.* within the ±20% zone) indicates that a unit should have had a certain capacity factor during the year, and hewed relatively closely to its expected outcome. Units that fall closer to the 1:1 line have generally preserved more market value in that year (or lost less relative to market prices).

A marker above the line indicates that a unit was operated more often than indicated by market prices (*i.e.* out of merit order more often than expected, relative to the ideal). A marker below the line indicates that a unit under-dispatched in 2015, relative to the optimal or idealized case.

Figure 4 Actual capacity factor for PJM coal units in 2015 plotted against market-based "ideal" capacity factor. Regulated coal units shaded light blue, merchant units shaded dark blue.



We see here that the majority of coal-burning units in PJM in 2015 fell within ±20% of their optimal dispatch on a capacity factor basis. There are a few notable exceptions, however, almost all of which are regulated utilities (*i.e.* shaded black). Almost every unit that operated more than expected based on market prices is a regulated plant, the majority of which are owned by either Dominion or American Electric Power ("AEP").

The pattern of regulated utilities acting outside of market conditions is even more apparent in MISO, as shown in Figure 5, below. As a whole, many coal-burning units in MISO do not demonstrate economic dispatch. In fact, a large fraction of MISO coal units fall in the upper quadrant, indicating substantially more generation than merited by market prices. For example, there is a large cohort of units that would be predicted to have an idealized capacity factor of 20% or below which ran at capacity factors of 40-80%. Like PJM, regulated utilities are shaded black in this representation. Almost all of the coal-burning plants which operated out of merit in MISO in 2016 belong to regulated utilities.

Figure 5 Actual capacity factor for MISO coal units in 2016 plotted against market-based "ideal" capacity factor. Regulated coal units shaded light blue, merchant units shaded dark blue. Star identifies Edgewater Unit 5 in Wisconsin.

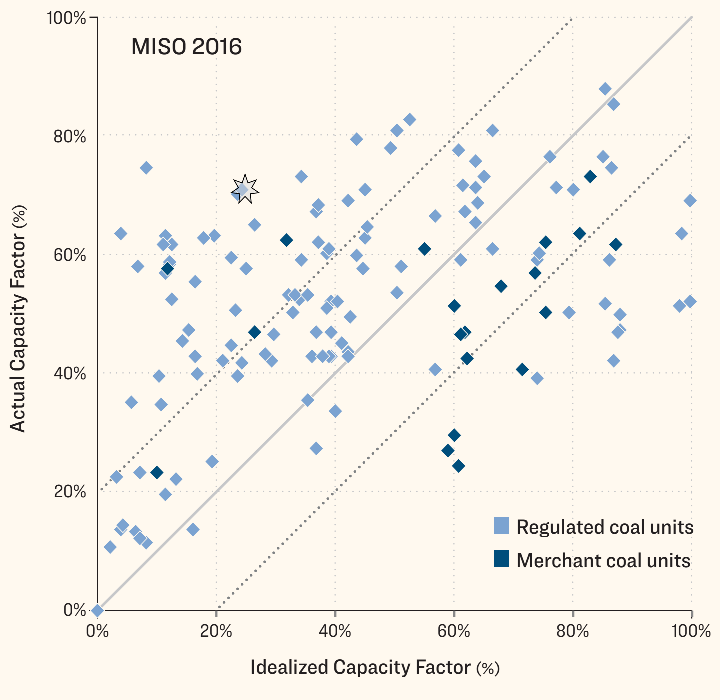
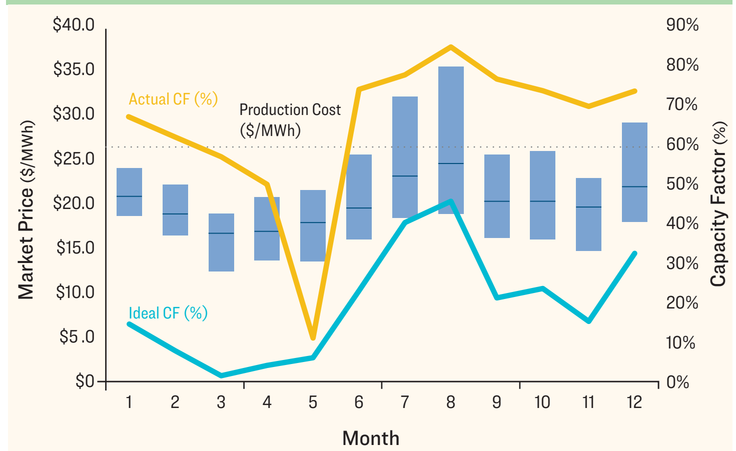


Figure 6 Production cost and market price at Edgewater Unit 5 (Wisconsin) in 2016, and actual and idealized capacity factors for the unit.



Case Example: Edgewater Unit 5 (Wisconsin)

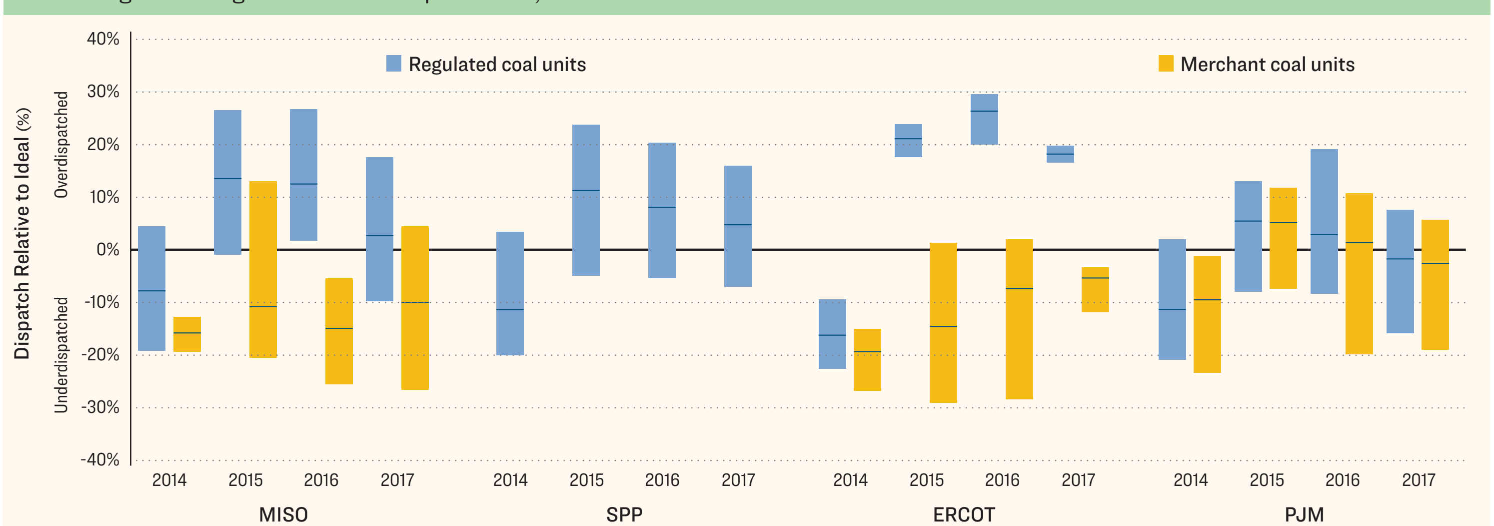
Let us consider what is actually happening with individual units that operated more than could be justified by market prices in MISO in 2016. The star in Figure 5 identifies an example plant, Edgewater Unit 5, owned by Wisconsin Energy and Light. According to this assessment, it should have had a capacity factor in 2016 around 18%. Instead, it operated at a 63% capacity factor.

Figure 6 below shows the actual operations of Edgewater 5 against its idealized capacity factor on a month-by-month basis, superimposed on market prices (2nd and 3rd quartile, and median). It is notable that the $26.2/MWh production cost of Edgewater 5 remains above even the 75th percentile of market prices in every month but July, August and December. Consequently, the model predicts a dispatch of less than 30% in all but those three peak months. Idealized dispatch never rises above 50% in any given month.

In contrast, Edgewater 5 had above a 50% capacity factor in every month but April and May, when the unit was taken offline to tie in a new scrubber.[26] As a consequence, we assess that Edgewater 5 lost on the order of $8.3 million in net energy market revenues alone in 2016. That loss, together with fixed O&M charges, was covered by captured utility ratepayers, on top of what all ratepayers across the multistate region were normally charged for electricity.

If we look across regions and years, a few patterns emerge that suggest substantially different behavior between regulated and merchant coal. Figure 7, below, shows the range of the deviation of dispatch of coal units relative to the economic case from 2014 to 2017 in MISO, SPP, ERCOT and PJM. The size of each bar represents the range of dispatch

Figure 7 Range of dispatch of regulated (blue) and merchant coal units (yellow) relative to ideal, 2014-2017 in various US energy market regions. Range is 25th – 75th percentile, median marked with a line.



relative to the economic case: bars with medians near zero indicate that the median coal unit had dispatch near the economically optimal case. Conversely, bars that are entirely above or below the line suggest systematic over or under dispatch.

In 2014, most coal units in MISO, SPP, ERCOT and PJM dispatched *less* than expected, given market prices. A closer inspection of the data, however, shows that energy market prices in 2014 were relatively high, calling for a median optimal output of 75% capacity factor in MISO and up to a 96% capacity factor in ERCOT. Units with extended outages (possibly to tie in environmental controls), maintenance outages or faults, or simply an inability to ramp quickly enough to hit peak market prices, systemically dispatched less than might have been warranted by market prices.

In 2015, market prices fell substantially. In all of the regions analyzed here, the average all-hours price fell by about 30% (from $39.7 to $28.6/MWh in MISO, and from $51.0 to $35.8/MWh in PJM). In many cases, the average market price of energy fell below the production cost of coal generation, which should have driven down the economic dispatch of these units. Notably, in MISO in 2015, merchant coal generators were able to generally maintain a dispatch at or below optimal levels, while regulated coal units did not. In MISO, SPP, and ERCOT, regulated coal units operated out of merit in 2015, 2016, and 2017.

In PJM, both merchant and regulated coal units hewed to expected market behavior as a whole, with the exception of specific utilities discussed earlier.

5 MANY REGULATED UTILITY COAL PLANTS ARE UNECONOMIC IN MARKET REGIONS

We estimate that in the four market regions studied here (MISO, SPP, ERCOT, and PJM), regulated coal plants with negative net energy margins performed worse than the energy market by $1.5 billion from 2015 to 2017 (see Table 1). In total, between 28 and 33 GW of coal capacity incurred net energy market losses in those three years, the vast majority of which (77-84%) were regulated plants. MISO accounted for the single highest number of non-economically dispatched coal-burning power plants, with plants losing nearly $750 million in the energy market in MISO alone.

Table 1 Net energy market losses[27] across market regions, 2014-2017[28]

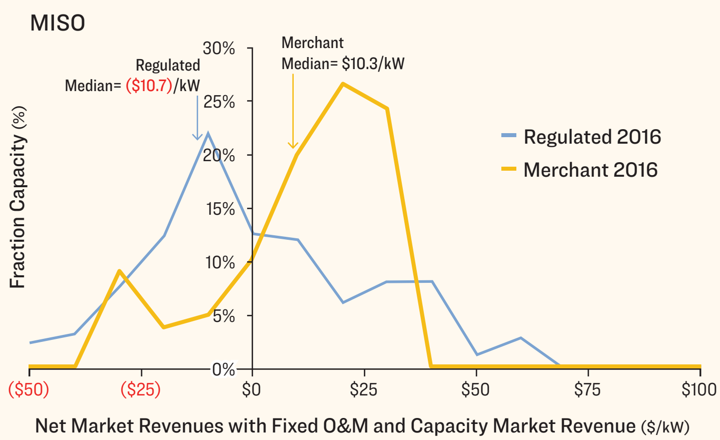
		2014	2015	2016	2017
MISO	Energy Market Losses (M$)	($10.9)	($216.3)	($316.4)	($211.6)
	Capacity w/ Energy Market Losses (MW)	884	18,498	15,445	13,754
	% Capacity Regulated	23%	82%	81%	81%
SPP	Energy Market Losses (M$)	$0.0	($172.5)	($139.0)	($136.0)
	Capacity w/ Energy Market Losses (MW)	–	5,279	4,435	5,141
	% Capacity Regulated	–	99%	99%	100%
ERCOT	Energy Market Losses (M$)	$0.0	($15.4)	($35.8)	($22.2)
	Capacity w/ Energy Market Losses (MW)	–	410	2,628	1,130
	% Capacity Regulated	–	0%	84%	64%
PJM	Energy Market Losses (M$)	$0.0	($42.2)	($134.8)	($87.1)
	Capacity w/ Energy Market Losses (MW)	–	3,332	10,401	7,752
	% Capacity Regulated	–	79%	60%	63%
All Regions	Energy Market Losses (M$)	($10.9)	($446.5)	($626.0)	($456.9)
	Capacity w/ Energy Market Losses (MW)	884	27,519	32,909	27,777
	% Capacity Regulated	23%	84%	77%	79%

However, losses in the energy market alone do not necessarily suggest net revenue loss, accounting for capacity market revenues and other incurred costs. Units in PJM depend on capacity market revenues to cover fixed, and potentially variable, costs. Accounting for the costs of fixed O&M and revenues from capacity markets in MISO[29] and PJM, coal plants with negative net revenue lost over $3.8 billion in 2015-2017 (see Table 2, below). Again, the vast majority of the losses (79-87%) was incurred at regulated power plants. **Overall, we estimate that captive ratepayers of regulated utility coal plants lost $3.5 billion from 2015-2017 relative to the procurement of energy and capacity on the market, due to non-economic dispatch.**

Table 2 Net market losses[30] across market regions, including fixed O&M and capacity market revenues, 2014-2017[31]

		2014	2015	2016	2017
MISO	Net Market Losses (M$)	($86.6)	($952.1)	($692.2)	($473.7)
	Capacity w/ Net Market Losses (MW)	4,500	38,311	32,014	22,265
	% Capacity Regulated	65%	84%	87%	80%
SPP	Net Market Losses (M$)	$0.0	($468.6)	($424.3)	($390.7)
	Capacity w/ Net Market Losses (MW)	–	16,129	16,061	15,256
	% Capacity Regulated	–	84%	88%	84%
ERCOT	Net Market Losses (M$)	$0.0	($75.5)	($154.5)	($110.4)
	Capacity w/ Net Market Losses (MW)	–	4,015	6,938	5,356
	% Capacity Regulated	–	90%	69%	58%
PJM	Net Market Losses (M$)	$0.0	$0.0	($63.3)	($31.2)
	Capacity w/ Net Market Losses (MW)	–	–	7,383	4,785
	% Capacity Regulated	–	–	88%	65%
All Regions	Net Market Losses (M$)	($86.6)	($1,496)	($1,334)	($1,006)
	Capacity w/ Net Market Losses (MW)	4,500	58,455	62,396	47,662
	% Capacity Regulated	77%	87%	87%	79%

Figure 8 Histogram of net market revenue in MISO (includes fixed O&M and capacity market revenue) in 2016, by capacity (% of MW) for regulated and non-regulated coal-burning units.



Some units that incurred marginal net energy market gains had high estimated fixed O&M costs, driving a net annual gain into an overall loss. In MISO, this pattern is particularly pronounced. In 2015, 18.5 GW of coal incurred negative net energy margins (see Table 1, above). Accounting for fixed O&M costs[32] and capacity revenues,[33] some 38 GW of coal capacity incurred costs greater than earned market revenues (Table 2). Again, the vast majority (87%) of the coal-burning units failing to cover costs through market revenues were regulated**.**

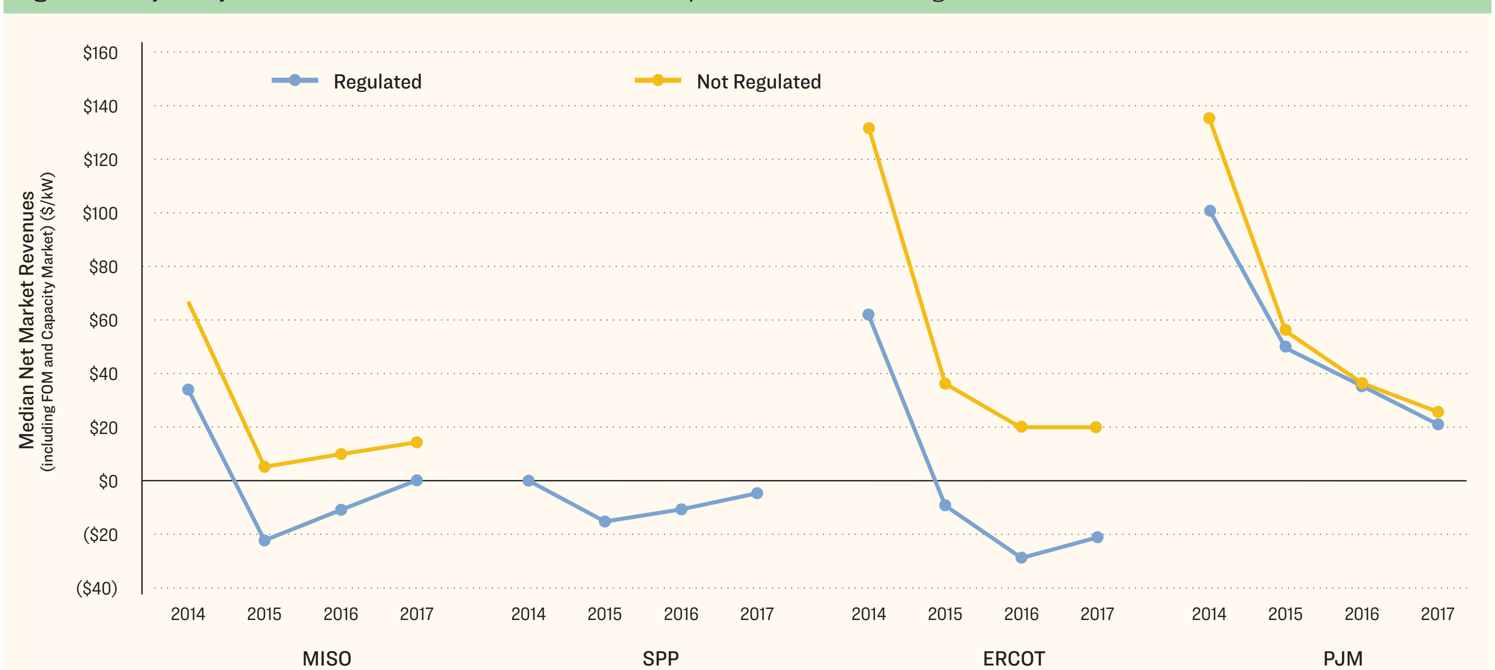
In PJM, prevailing capacity prices have generally been above the estimated fixed O&M cost of coal, and thus the pattern is reversed: some plants that are non-economic on a net energy market basis alone become economic (*i.e.*, receive revenues in excess of their costs) after they receive capacity revenues, despite fixed O&M costs. While we estimate that 10.4 GW of coal in PJM incurred net energy market losses in 2016, that number shrinks to 7.4 GW when we account for fixed O&M costs and capacity market revenues. Even in PJM, the units which incurred market losses were largely rate based (88%).

In every region, there is a separation between the net market revenues received by regulated and non-regulated coal plants. Figure 8, below, shows the separation between the net market revenues of coal-burning units in MISO in 2016 that are regulated and those that are not, weighted by capacity. The median merchant (*i.e.,* not regulated) had net market revenues of $10.3/kW, while the median regulated unit had losses of -$10.7/kW.

Over time, each of the market regions maintains a substantial separation between the median net market revenue for regulated and non-regulated coal units (Figure 7). It is particularly notable that in MISO, SPP, and ERCOT, from 2015-2017 the median coal-burning unit lost net market revenue.

Overall, it is clear that regulated coal units have a substantially different pattern of dispatch in market regions compared to merchant coal units. Namely, over-commitment and/or out-of-merit operation, and the subsequent loss of net market revenue, is almost exclusively constrained to coal units owned by regulated utilities. In contrast, merchant coal-burning plants reduce dispatch and commitment in response to low energy prices, thereby preserving net positive market revenue.

Figure 9 Trajectory of the net market revenue for the median plant in four market regions from 2014-2017



6 SELF-COMMITMENT DRIVES UP COSTS AND DRIVES DOWN MARKET ENERGY PRICES

Plants that dispatch in more hours than is economically optimal can incur substantial losses relative to the market, which are passed on to captive ratepayers if a unit is operated by a regulated utility. While we cannot readily determine if it is the practice of self-scheduling or self-commitment that has resulted in non-economic operation of coal plants, we can examine the impact the practices have had on market energy prices, and ultimately the revenues of other generators who sell on the market.

To determine the impact of self-commitment on generation and market prices, we employed an in-depth unit-specific electric sector model. First, we re-created MISO conditions in 2017; we then tested to see if different dispatch decisions were possible, and how prices, emissions, and costs would have changed if MISO had required economic dispatch from all coal-fired generators, regardless of regulatory status.

Sierra Club retained Synapse Energy Economics to use EnCompass, a unit-specific chronological dispatch model with transmission and operational constraints on coal units, to compare modeled baseline conditions in MISO in 2017 against modeled optimal dispatch in that same year. The methodology employed is described in more detail in **Appendix C.**

The analysis, run using the EnCompass model, was designed to observe the differences between a case calibrated to 2017 actual dispatch and prices (called the "Base Case" here), and a case in which units are operated optimally (the "Economic Dispatch Case"). The primary difference between these cases was that a "must-run" constraint imposed on most coal units in the Base Case was released in the Economic Dispatch Case. The "must-run" constraint is described in more detail below.

- ***Base Case**:* The Base Case was designed to replicate, as nearly as possible, actual operations and costs in 2017 in MISO. The baseline model[34] was calibrated with coal unit-specific production costs from 2017.[35] The variable O&M costs of individual coal units were adjusted such that monthly coal generation on a unit-by-unit basis and energy market prices on a zonal basis replicated, as nearly as possible, actual 2017 generation and prices. We retained operational constraints, including "must run" parameters as assessed by a markets intelligence group, Horizons Energy.
- ***Economic Dispatch Case:*** The Economic Dispatch Case was designed to test how MISO would be dispatched if all units were dispatched as if called upon by the market with a 72-hour look-ahead period. This run released the must-run constraint, but maintained all other parameters of the Base Case. The Economic Dispatch Case retained the composition of the fleet as it existed in 2017; we made no incremental retirements or additions.

Our model runs were designed to test if MISO's coal units, as they exist today, could be dispatched effectively and economically by a market signal and modest look-ahead period without self-committing,[36] and without imposing operational problems or incurring an undue number of startups and shutdowns. To ensure that we were capturing the operational constraints of coal plants, we employed a modeling construct that observed chronological dispatch (*i.e.*, sequential time matters), and which was bound by individual unit ramp rates, minimum runtime constraints (*i.e.*, the minimum number of hours online or offline), and startup costs. In other words, the Economic Dispatch Case would reflect the inflexibility of coal plants, rather than assuming perfectly dispatchable resources, consistent with the limitations system operators face when managing a generation fleet including coal.

- ***Production and fixed costs**:* Data on individual coal unit production and fixed costs were extracted from the S&P Global database, which in turn relies on reporting to EIA's Form 923 for fuel costs and average heat rates, and FERC Form 1 for variable and fixed O&M costs. S&P Global uses a model to gap fill non-reporting entities. Synapse adjusted variable O&M costs of individual coal units seeking to match approximate 2017 generation and regional market prices on a monthly basis. See **Appendix C** for details of the calibration.
- ***Must-run constraints:*** The "must-run" constraint requires that a plant at least operate at minimum load37 if not out on maintenance, effectively requiring the unit to be self-committed at all times. The Horizons Energy database (underlying the EnCompass model) assesses which units act, from a modeling perspective, as if they have a must-run constraint, and imposes such a constraint on those units for the purposes of modeling. This "must-run" constraint does not correspond to MISO-designated requirements to operate for reliability purposes, called a System Support Resource ("SSR"), but rather represents a modeling constraint designed to replicate historic behavior in the Base Case. No units were identified with a MISO-designated SSR designation, and thus every coal unit was released from this modeling constraint in the Economic Dispatch Case.

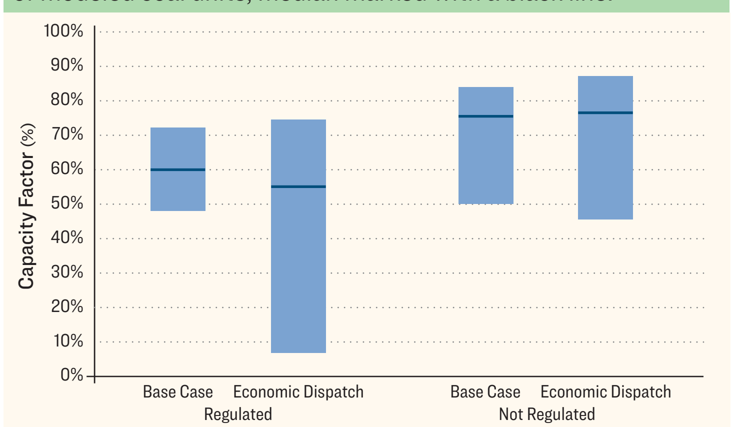
- ***Historic outages:*** Matching historic operations of a large fleet is complicated and is made more difficult by unpredictable forced outage schedules. In particular, without plant records, which are typically confidential, it is nearly impossible to distinguish forced outages, scheduled outages, and economic outages. We erred on the conservative side by assuming that any outage in 2017 lasting a day or longer was equivalent to a forced outage — in other words, it would occur in both the calibrated run (as it did in 2017) and in the economic model run. This effectively means that units which observed economic dispatch and thus, de-committed for a long period of time would see no adjustment from the baseline run to the Economic Dispatch Case; similarly, units which had extended maintenance outages in 2017 would also not see an adjustment between the two runs.

Our modeling demonstrates that the economic dispatch of MISO's coal units in 2017 was feasible, and would have resulted in less coal generation, lower system costs, and higher market prices. Under economic dispatch, coal generation in 2017 fell by about 10%, from about 324 TWh in the Base Case scenario to 293 TWh in the Economic Dispatch Case, a reduction of 30.8 TWh. **The reduction in coal generation when MISO is economically dispatched is almost entirely (93%) attributable to coal units owned by regulated utilities.**[38]

Because this is a historical analysis looking only at re-dispatch of existing units, the generation gap is largely taken up by existing gas-burning units that were already operational in 2017. While not tested here, we expect that on a going-forward, a larger share of the energy gap would be filled by new build renewable energy due to higher market prices.

As in the observed historic behavior, regulated coal units decline in their modeled capacity factor from the Base Case to the Economic Dispatch Case, while merchant units do not (see Figure 10, below).

Figure 10 Capacity factor of regulated and not regulated coal units in MISO in calibrated 2017 model (Base Case) and the Economic Dispatch Case. Bars represent 25th-75th percentile of modeled coal units; median marked with a black line.[39]



Rather than a gradational change, the model predicts that less non-economic units would effectively ramp down to a peaker capacity factor (*i.e.*, <10%) or off; in contrast, relatively economic units do not change dispatch substantially. In reality, we might expect that marginally economic units reduce their dispatch modestly, while uneconomic units are reduced to minimal, peaking capacity factors, or retired altogether if their fixed costs routinely exceed net market revenues.[40]

Economic dispatch increases market prices and revenues paid to all generators, including renewable energy.

When non-economic coal plants shift from self-commitment mode to economic dispatch, it results in an increase in the wholesale market price of energy.[41] Specifically, the supply curve is made somewhat steeper including the minimum operations segments of coal plants that were previously excluded from the bidding process. The dynamic underlying this increase in market prices due to market-based dispatch is discussed in more depth in **Appendix B.**

We assess that across all nine modeled MISO regions, the median hourly market price increases by $7.7/MWh, or around a 30% increase. According to the model results, market prices increase by 30% relatively consistently across both low and high cost hours if coal generators are modeled as operating under economic dispatch.

All units that participate in the energy market, including renewable energy generators, would be privy to higher market prices, and hence greater market revenues. These findings suggest that the practical effect of non-economic self-commitment by regulated coal units is that captive ratepayers pay more for their generation, and thereby subsidize ratepayers of utilities that buy energy from the market. The operation of non-economic coal plants also deprives independent power producers, including renewable energy producers, of critical market revenues — in this case, to the tune of a nearly a quarter of potential revenues. Our modeling suggests, for example, that a 100 MW wind farm could have been deprived of about $2 million[42] in 2017 due to the subsidization of market prices by non-economic coal.

Economic dispatch decreases total system costs.

Despite the increase in the marginal market price of energy, economic dispatch drives down total production costs. Total system costs decrease because non-economic units are no longer forced online, and they are replaced by more efficient and lower marginal cost resources. In reality, the benefit of this production cost decrease would be allocated to customers of regulated utilities who today are subsidizing the operations of out-of-merit coal via state ratemaking processes. **Our modeling indicates that the total production cost of coal-burning generators in MISO would have dropped, from an estimated $10.1 billion to $8.8 billion in 2017, or a savings of $1.3 billion in that year alone.[43] The increase in output of non-coal generators reduces the total savings to $682 million.**

Table 3. Core results from dispatch modeling for MISO, 2017

	Base Case	Economic Dispatch	Difference
Coal generation (GWh)	324,137	293,307	(30,830)
Median market price ($/MWh)	$21.80	$28.28	$7.68
Coal production cost[44] (million $)	$10,069	$8,782	($1,287)
System production cost[45] (million $)	$12,112	$11,430	($682)

These findings confirm that economic dispatch of coal units is both likely occurring, and can be remedied through improved dispatch practice. While our modeling effort does not purport to do a detailed examination of the reliability impacts of market-based dispatch, the model obeys basic reliability and operational constraints, and successfully dispatches MISO without self-scheduling coal-burning units.

One of the most substantial findings here is that the non-economic dispatch of coal units in market regions is likely depressing regional wholesale market prices.[45] This practice disadvantages independent power producers, qualified facilities under the federal Public Utility Regulatory Policies Act ("PURPA"), new renewable energy entrants, energy efficiency programs, net metering customers, and the customers of regulated units that are economically dispatching.

- ***Independent power producers:*** Independent power producers, both fossil-burning and renewable, rely on market revenues to support continued operation and new investments. Competitive providers may be losing substantial market revenue due to non-economic dispatch from regulated coal-burning facilities.
- ***Qualified facilities ("QF"):*** In some states, the contractual price provided to small renewable and combined heat and power producers is based on the prevailing market price, or predictions of market prices. In cases where those predictions are pegged to current prices, QF providers may be substantially undercompensated.
- ***New renewable energy entrants:*** Renewable energy projects are often financed on the basis of a power purchase agreement ("PPA"), which may be accepted (or rejected) in comparison to a market price index. To the extent that market prices are lower than reasonable, new PPAs may be rejected, even if they would otherwise be cost effective. Similarly, merchant renewable providers realize higher risks and lower revenues, discouraging new entrants.
- ***Energy efficiency providers:*** Energy efficiency programs are often assessed against, in part, the avoided cost of energy. When the prevailing market price of energy is higher, a wider array of energy efficiency programs can be employed cost-effectively. If market prices are suppressed, fewer efficiency programs may be deployed, and competitive efficiency providers may be undercompensated.
- ***Customers of economically dispatched regulated plants:*** Customers of regulated utilities that own economically-dispatched generation may be disadvantaged if their power plant is unable to collect due revenue, or have cost-effective generation driven offline by low market prices.

7 DISCUSSION

In recent years, central energy market observers and stakeholders have given substantial — and appropriate — focus to capacity market structures, debating if the market constructs overpay fossil generators or provide appropriate compensation to renewable energy, demand-side management, and storage. And while resolving these questions will be crucial to the development of an energy system that meets ratepayer needs — and that also can meet climate and public health goals — we should not make the assumption that energy markets in RTOs are perfectly competitive, let alone that they are reasonably aligned with climate or health goals.

Our research shows that as market energy prices decline, regulated coal-burning generators seek to preserve operations, at a substantial cost to customers and competitive generators. While regulated coal units in centralized market regions do not appear to be gaming the market, as might be signaled through withholding or seeking to drive up market compensation, they do appear to exploit the disconnect between market operations and fuel recovery before regulators. That gap in oversight — reviewed neither by market monitors nor by most state regulatory commissions—allows regulated coal plants to operate more than would be reasonable under market conditions. And because such behavior is not typically subject to oversight, it is a low risk to utilities but a high economic cost to customers (and on emissions).

Many plants owned by regulated, vertically integrated utilities operate far more often than is warranted by market prices.

This behavior is pronounced when market prices fall, driven either by low prices for pipeline gas or increasing penetrations of renewable energy. The non-economic dispatch of regulated coal plants stands in stark contrast to the generally economic, or at least risk averse dispatch of merchant coal-burning generators. We conclude that such non-economic dispatch (*i.e.*, operating out of merit order) is not fundamentally an operational constraint by coal plants, but rather a difference between operational decisions made by regulated utilities and merchant coal plants.

This systematic non-economic dispatch, whether through self-commitment or extended dispatch out of merit order (*i.e.* without response to market signals) has cost ratepayers of regulated coal units over $3.5 billion from 2015-2017. In other words, we estimate that regulated utility ratepayers, primarily in MISO, but also SPP, PJM, and ERCOT, could have saved more than $3.5 billion in those three years alone by purchasing market-based energy rather than dispatching existing coal-burning units out of merit.

The *pro forma* pass-through of fuel costs allows regulated owners to operate coal units out of merit, or with little respect to market revenue.

While merchant coal-burning power plants must recover all of their costs through energy and capacity markets, coal plants associated with captive ratepayers are able to pass through costs to ratepayers. In many states, the costs of coal are passed through via “fuel adjustment” proceedings, which are, in general, rapid, *pro forma* proceedings in which utilities report the incurred cost of fuel, and request adjustments to rates. These proceedings are often uncontested, and considered relatively low impact, despite the magnitude of costs that are considered during these proceedings. In some states, utilities have expressed an intent that fuel costs only be handled through adjustment proceedings, while other costs are handled through rate cases, or even other *pro forma* adjustment proceedings, such as purchased power adjustment proceedings. The decoupling of these proceedings, and their abbreviated nature, make it difficult for regulators or stakeholders to assess if units have dispatched economically with respect to market prices, and the magnitude of loss.

Regulated coal plant owners have traditionally had relatively little transparency to state utility commissions or customers on self-commitment and dispatch practices.

The operations of generation units in a market region, including commitment and dispatch practice, are complex issues that have traditionally had relatively little transparency before state utility commissions. Specifically, commissions often simply assume that if a market exists, then operators within that market will seek to dispatch economically within that market. Utilities are not generally required to disclose bidding behavior, self-scheduling, or self-commitment behavior, or to reconcile their costs with market revenues. In fact, as of the publication of this paper only two commissions, the Minnesota Public Utilities Commission and the Missouri Public Service Commission, had opened investigations to determine if units owned by regulated utilities were operating economically.[46]

Regulated coal plant owners may see an incentive in operating out of merit.

While utilities are charged with providing reliable, least-cost service to customers, utilities continue to have an incentive to support the operation of existing generation units. In particular, generation units that still have unrecovered plant balance pose a risk to regulated utilities,[47] and showing that those units still operate at high capacity factors — even if those high capacity factors are not merited — is often seen as an implicit demonstration that a generator continues to provide value. Conversely, a unit operated at a low capacity factor may attract unwelcome attention from regulators concerned about continued spending at a clearly non-economic plant. A company that is seeking, at the forefront, to protect shareholder value, and which perceives a lack of oversight in the matter, might see an incentive in operating existing coal units out of merit — even if the practice results in ratepayer losses.

Economic dispatch and economic commitment reduces total production costs, increases market prices, and reduces electric sector emissions.

When coal plants respond to market signals for dispatch and commitment, it reduces total production costs, because power is provided by less expensive generation during more hours. At the same time, market prices increase because those self-scheduled or self-committed high-cost coal units were compelled to operate—effectively pushing them to the bottom of the supply curve. By taking those units out of the bottom of the supply curve, we shift the supply curve to the left, and up, increasing the clearing price of energy. That increased price of energy benefits every generator that was acting competitively. And by decreasing the generation of non-cost effective coal-burning generation, we reduce emissions substantially.

Our research indicated that market prices may have been suppressed to 30% below expected priced due to excessive self-commitment in MISO in 2017.

By paying for excess energy out of merit, ratepayers of regulated coal generators are subsidizing the market price of energy for other consumers within market regions.

The reduced market prices resulting from systemic non-economic dispatch mean that the ratepayers of regulated coal units which operate out-of-merit are effectively paying to reduce market prices for other consumers in the market region. This cross-subsidization means that utilities in market regions that do not own generation and that exclusively purchase market-based energy were provided lower prices at the expense of vertically integrated coal-owning utilities.

Regulated coal operators, through non-competitive operation, may have suppressed clean energy uptake.

New renewable energy projects in market-based regions rely either directly on market prices or on PPAs, which in turn are accepted or rejected on the basis of avoided market energy prices. When market energy prices are suppressed, renewable energy projects realize lower revenues (or lower PPA prices), which restricts the number of projects that may come online. In addition, self-scheduled coal units may generate too much energy during off-peak hours, driving up the curtailment of renewable energy projects. On a going forward basis, we may see lower market energy prices with increasing penetrations of near-zero marginal cost renewable energy, but those market prices will be a result of competitive behavior, rather than market price suppression.

8 RECOMMENDATIONS

How we can remedy the non-economic dispatch of existing coal-burning facilities?

Regulated utilities have argued that the dispatch of existing coal units is premised entirely on operational constraints, and that the lack of a multi-day market inhibits any form of reasonable market-based commitment. Yet co-located merchant generators have successfully avoided taking excessive losses in the market, or have cut their losses through retirement. Even in the absence of a multi-day market, it is clear that there are actions that could be taken by regulated utilities today to more closely hew to market signals when market prices are low.

Commissions and consumer advocates should examine the self-commitment and self-scheduling practices of regulated utility coal-burning power plants in market regions. Such examinations should examine the assessed production cost of existing coal, the bids offered by the utility into the market, how often units are self-committed or self-scheduled, the net losses incurred from these practices, and the process — if any — used by the utility to assess market prices and minimize commitment during low market priced periods.

Commissions should consider alternative incentives to ensure regulated coal plant operators align operations with market prices. Such incentives could include allowing utilities to recover the market price of energy from customers (plus or minus a deadband if required), rather than the production cost of coal generators. Under this kind of structure, a regulated coal plant owner would be incentivized to only run below market costs in order to increase recovery and avoid a penalty. On a near-term basis, Commissions may consider disallowing the recovery of excessive fuel costs if a utility cannot demonstrate that it has dispatched competitively.

Utilities, in the absence of a rigorous multi-day market, should develop a consistent and transparent set of practices for avoiding operations and commitment during periods of persistent low market prices. Such practices include rigorously assessing near-term market price forecasts to inform commitment decisions, and setting internal operating standards that define when a unit should be committed out of market or follow market signals. Rather than simply seeking to avoid startup/shutdown, these standards should rigorously assess the costs associated with full unit cycling, and clearly seek to minimize both short and long-term costs.

Market monitors should rigorously examine the behavior and bids of slow-ramping, coal-burning units to ensure that market costs are not being inappropriately depressed through the non-economic actions. In addition, market monitors should ensure that excessive commitment from coal-burning generators does not displace opportunities for renewable energy, and does force excessive curtailment of renewable generators during low-demand hours.

ISOs and RTOs should consider more advanced forward markets that send a clear commitment-relevant market signal to better inform utilities' decision making, and raise the barrier to self-commitment.

Today, utility regulators rely on market oversight to ensure competitive dispatch by their regulated utilities, while ISOs and RTOs have generally relied on utility regulators to ensure that regulated generators are providing competitive bid information, and have generally assumed that utilities are not incentivized to act non-competitively. The decoupled responsibility of utility regulators and RTOs has had the consequence of allowing non-economic dispatch by regulated utilities to go relatively unchecked, at the expense of captive ratepayers and competitive independent generators. The behavior of merchant coal-fired generators suggests that economic dispatch is achievable. Improved market behavior by regulated coal generators will not only have benefits to the market; it will also have significant climate benefits, and reveal if certain generators effectively serve customer interests in a paradigm of falling market costs and increasing penetrations of clean energy.

APPENDIX A: CYCLING IN COAL-BURNING POWER PLANTS

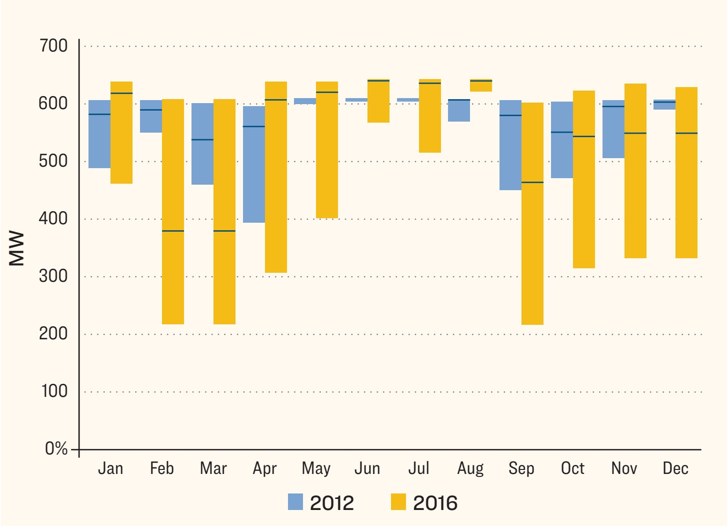
Most coal-burning power plants in operation today were built to provide what has been characterized as "baseload" power — *i.e.* continuous power at all hours of the day. Up until the mid-2000s, that was a fair characterization. Indeed, the variable cost of operation at coal plants was often low enough to warrant very high capacity factors. As a consequence, coal plant operators, and then market designers and stakeholders, generally assumed that coal units would operate cost effectively under most conditions.

However, as gas prices and, as a corollary, energy market prices dropped over the last decade, coal-burning plant operators increasingly saw a need for cycling in order to avoid operations during low-cost market prices, and to capture higher cost hours.

By way of illustration, Figure 11 (below) shows the output of Nebraska Public Power District ("NPPD's") Gerald Gentleman Station in 2012 — just prior to the onset of low market prices — as well as in 2016 — one of the lowest market price years experienced to date. The height of the bars indicates the range from the 25th to the 75th percentile, with the median marked between. Taller bars indicate that a unit cycled more during that month, in this case between a minimum operational level of 220 MW and a maximum gross output of about 630 MW. [48]

Cycling is a function of prevailing market prices. Gerald Gentleman ramped substantially during the shoulder seasons (spring and fall) of 2012, but it had a nearly continuous output of 600 MW during the summer. In 2016,

Figure 11 Output of Gerald Gentleman Station (Nebraska) by month, 2nd and 3rd quartile, 2012 & 2016



this changed: Gerald Gentleman had to contend with low market prices not just in the shoulder seasons, but also through the winter and early summer. In 2016, the unit ramped on nearly a daily basis, seeking to avoid operation during lower-cost hours.

Many utilities seek to avoid operating coal-burning units during relatively low-cost hours by ramping, and falling market prices have required that ramping occur with greater frequency. However, despite the fact that Gerald Gentleman unit ramped on a daily basis in 2016, it only turned off five times, the longest span of which was less than 3.5 days (81 hours). In total, the unit did not operate for only 8.4 days in 2016.

APPENDIX B: WHY OUT-OF-MERIT OPERATION DRIVES DOWN MARKET PRICES

In an open energy market, the price in any given hour is set as the marginal cost of energy.[49] This pricing structure is meant to minimize incentives for gaming; it helps ensure that generators bid no more than they require, while also ensuring that they receive the clearing price of energy. When a generator provides an "economic" bid to a central marketplace, it is bidding its cost of operation. If that generator has lower variable costs of operation than other resources, and — along with resources that are lower-cost than it is — will meet demands, it will be dispatched by the central operator. The clearing price of generation is set at the highest marginal cost unit (*i.e.*, unit that provided the highest-cost bid) that was still required to meet demand. The bids from generation units, ordered from least cost to highest cost is referred to as the bid stack, and forms a supply curve (*i.e.*, the cost to provide supply ordered by lowest to highest cost generator).

A unit that bids too high risks not being selected by the market operator, but a unit that bids too low risks taking a loss if market prices aren't sufficient to cover its costs. A unit that bids its cost of operation and is selected by the market operator can be assured — under most circumstances — that it will at least recover its costs of operation and potentially more if it is a very low cost unit at high cost hours.

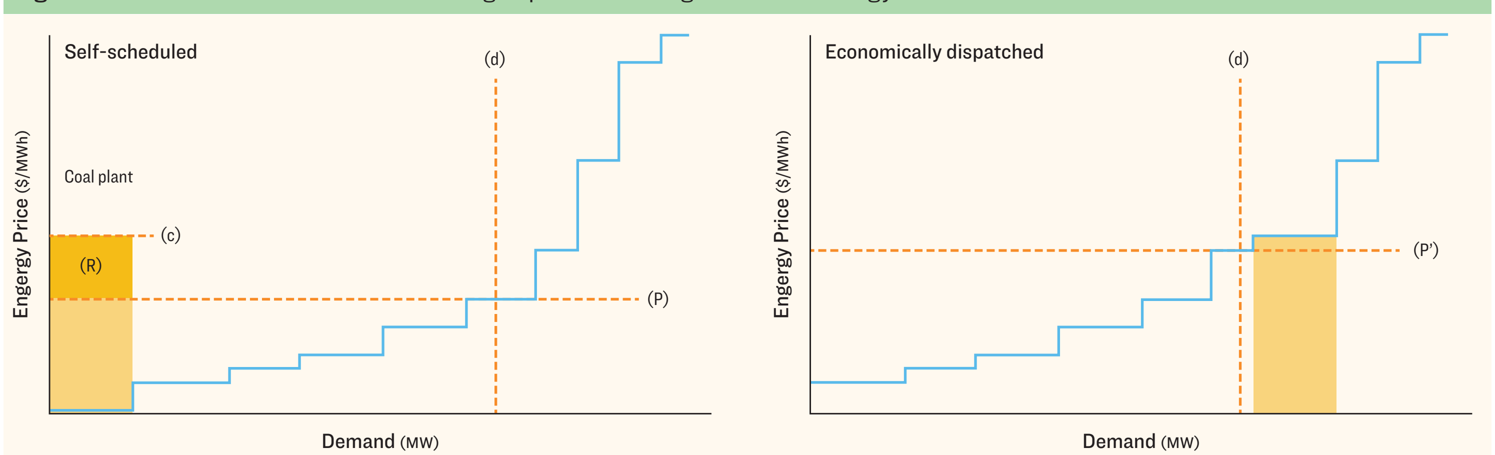
When a generator "self-commits," it guarantees that it will run at its minimum operational level irrespective of its cost or market prices; a "self-scheduling" signal means that the unit will select its own output above its minimum operational level irrespective of cost or market price. When a market operator receives these signals, it pushes the generator into the bottom of the bid stack — *i.e.* at a cost of zero. While a self-committing generator receives market revenues, it has no guarantee that those revenues will be sufficient to cover its costs. And by inserting itself at a cost of zero at the bottom of the bid stack, a self-committing generator pushes the supply curve to the right, lowering the clearing price of energy.

Figure 12 below is a schematic supply curve, demonstrating how self-scheduling impacts the market price of energy. In the left-side schematic, the coal plant (cost *c*) is self-scheduled, and is put into the supply curve at a zero cost. The level of demand (*d*) in this hour determines the marginal resource and the price of energy (*P*). In this case, the price of energy is less than the cost of the coal plant, and thus the coal plant takes a net operating loss, indicated by (*R*). The coal plant is called upon and operates, but can't recoup its costs of that hour through market revenues.

In the right-hand graph, the system is economically dispatched. The coal plant still has the same cost (*c*) but because it bids its cost, it is shifted up in the same supply curve. In this case, the same level of demand does not require the coal plant to be dispatched. However, because the coal plant is no longer at the bottom of the supply curve, the whole curve shifts, and the marginal cost of energy is higher, at P'. All of the generators with costs less than or equal to P' see an increase in revenue.

In the self-scheduled schematic, the losses (*R*) are realized by the plant. But if that plant is owned by a regulated utility, those losses are passed onto ratepayers. As a result, the ratepayers of a regulated, but non-economically dispatched coal plant are charged above-market prices and, by suppressing market energy prices, subsidize the costs of market energy for other consumers. In addition, because

Figure 12 Schematic of how self-scheduling impacts the marginal cost of energy



market prices are suppressed, independent power producers realize a loss of revenue — or don't operate at all if relatively higher cost.

Ratepayers of utilities with self-scheduled generators may not realize that they've incurred the losses shown here. [50] In fact, without an examination of a coal plant's operations relative to market prices, it can be very difficult to assess these losses. Regulated utilities typically pass their costs of generation through to ratepayers as a bulk cost and the revenues from market operations as an offset to those costs. But since most regulated utilities own more than one generator, it may not be obvious to a casual observer that market revenues haven't covered the operational costs of a plant.

APPENDIX C: MODELING ECONOMIC DISPATCH IN MISO, 2017

Sierra Club retained Synapse Energy Economics ("Synapse") to conduct unit-specific economic dispatch modeling in MISO, assessing the impact of economic dispatch against conditions and operations in 2017. The following study was conducted by Synapse, and provided to Sierra Club in June, 2019.

Background

Coal retirements across the MISO region, and downward pressure on energy market prices from increasing energy efficiency (lower demand), increased wind quantities, and natural gas ("gas") prices have spurred questions around the economic dispatch of the existing fleet. In its most recent market roadmap the Midcontinent System Operator (MISO) renewed its commitment to enhancing unit commitment and economic dispatch processes.[51] Accordingly, the Sierra Club tasked Synapse with an exploration of whether regulated coal units in the MISO market region are systematically, uneconomically committed and dispatched. Such a widespread commitment/dispatch inefficiency would represent an effective subsidy of coal units through state-level cost recovery of fuel and operational costs which have not, economically speaking, been reasonably incurred.

The Synapse team utilized the EnCompass model to run two scenarios for the MISO region:

- **The Base Case** simulates unit-specific operational conditions at a monthly time-step granularity, to reflect actual 2017 energy production as reported to the U.S. Environmental Protection Agency (EPA, Air Markets Program data). It includes "must run" designations for coal units.[52]
- **The Optimized Dispatch Case** simulates a purer economic commitment and dispatch. It holds all operational parameters from the Base Case constant and eliminates the must run designations, thereby allowing for a different (i.e., more economically optimal) commitment and dispatch result.

Synapse performed a detailed calibration of the Base Case by aligning monthly coal unit generation, external energy transfers, and market prices to actual 2017 data. The EnCompass model optimizes unit commitment and dispatch to simulate economic operation at the hourly level. Both scenarios are run for all hours of 2017, and are required to meet energy balance, regulation, and operating reserve constraints, along with zonal transmission constraints broadly across and into/out of MISO.

The following memorandum outlines our analysis, presents the results from both scenarios, and summarizes the impact on MISO's generation mix, total system costs (inclusive of fixed O&M), and production costs (exclusive of fixed O&M).

Base Case

Base Case Calibration Process

Synapse calibrated the Base Case to historical U.S. Energy Information Administration (EIA) generation data prior to running the Optimized Dispatch scenario. Our preliminary calibration included checking coal unit capacity levels, simplifying the external regional topology, and calibrating annual generation and net import flows. More specifically:

- **Capacity Check:** Synapse cross-checked the capacity (MW) and retirement dates of coal units included in the EnCompass National Database against data provided by EIA. Where the capacity discrepancy between databases was greater than 25 MW, we performed an additional unit-specific check using publicly available data.[53] We updated retirement dates for six coal units based on EIA data.
- **Topology:** Synapse developed a simplified topology for all regions abutting MISO to streamline the model setup and expedite model run-times. We represented each area within each abutting region (MRO-Manitoba Hydro, NPCC-Ontario, PJM, SERC-North, SERC-Southeast, and SPP) as a single resource with a single capacity and energy value, and priced imports into MISO to approximate the cost of a marginal gas-fired unit.
- ***Annual Operation:*** Synapse calibrated total annual MISO generation by fuel type and net import flows to historical MISO market data.

Our calibration included a careful iteration of coal plant parameters. The Synapse team effectively aligned monthly modeled coal plant output to actual coal plant output levels in 2017 by incrementally adjusting heat rate, operating cost, and outage parameters at the unit level. Based on guidance from the Sierra Club, this calibration focused on four major areas of alignment:

1. **Individual Unit Output:** Synapse calibrated individual coal unit output to actual 2017 monthly generation, as reported by EPA. We also fixed outages to daily reported outages in 2017 at the unit-level.
2. **Must Run Designations:** Synapse found no evidence of any existing MISO system support resource (SSR) agreements for modeled coal units. We maintained effective must run designations determined by Horizons Energy to replicate actual 2017 operation, as described below.
3. **External Transfers:** Synapse aligned our modeling with actual monthly 2017 transfers between MISO and external regions, based on MISO market reports.

4. **Market Prices:** Synapse calibrated to average monthly on- and off-peak 2017 LMPs, for one pricing node in each MISO zone, as reported by MISO.

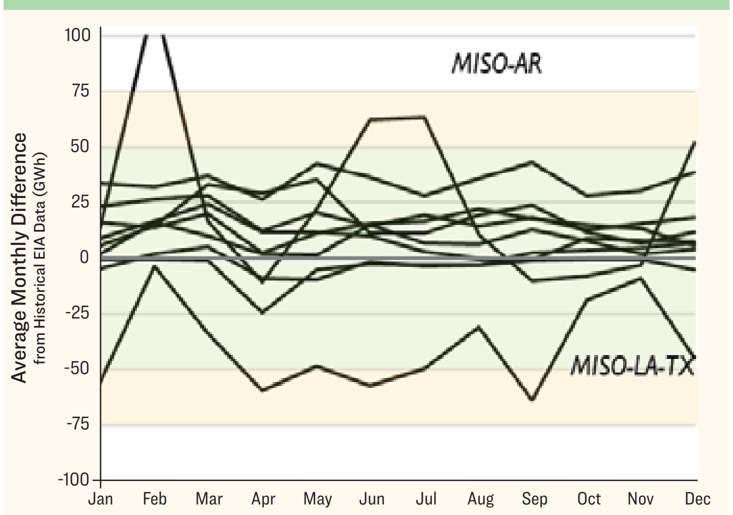
Synapse utilized unit-level data provided by Sierra Club from S&P Global to align actual variable and fixed operating costs, delivered fuel costs, and heat rates. We also utilized hourly data from the EPA Clean Air Markets division to mirror exact daily unit outage patterns in the MISO region.

Detailed Calibration Results

Individual Unit Output

The Synapse team began by aligning model unit dispatch to historical monthly generation, as reported by EPA. We prioritized alignment for units larger than 150 MW. Figure 13 shows the average monthly delta at the individual unit level by month and MISO region for all units. Figure 14 shows the same calibration data by percent delta. They demonstrate that we met our goal of calibration within an average monthly delta by region of 50 GWh (75 GWh stretch) and 50 percent (100 percent stretch), with few exceptions.[54] The 2017 EPA monthly historical coal generation, modeled monthly coal generation, and the resulting delta are displayed by region in Table 4 below. While we calibrated within our target, the final iteration of modeling saw Base Case generation higher than reported EIA data by an average of 2.1 TWh each month.

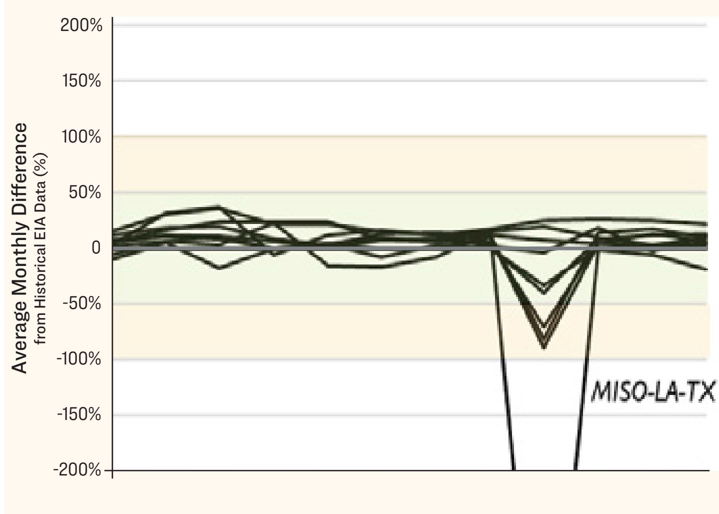
Figure 13. Average Monthly Delta, EIA Historical Generation to Modeled Base Case by MISO region



Must Run Designations

Synapse determined that there are no active SSR agreements for the slate of modeled coal units in MISO. We rely on the must run designations as defined in the Horizons Energy National Database. These are mostly determined based on Horizons' historical operation calibration to Continuous Emission Monitoring System (CEMS) and EIA data. They are also designed to replicate historical regional

Figure 14. Average Monthly % Delta, EIA Historical Generation to Modeled Base Case by MISO region



stress situations for any period of time. In Encompass, the must run designation requires units to generate at their set minimum capacity level (MW).

External Transfers

Synapse aligned transfers between MISO and external balancing authorities first to historical annual levels and then to monthly levels. On an annual basis, we were able to calibrate net imports to within 15% of historical data without unduly influencing market prices. Monthly net imports reflected in MISO market data and as Base Case modeled outputs are included in Table 5.

Table 5. Monthly Net Imports to the MISO region as reported by MISO and modeled in the EnCompass Base Case

	NET IMPORTS (TWh)		
MONTH	Actual	Modeled	% Diff. Modeled vs. Actual
JAN	3.5	2.9	-16%
FEB	3.4	2.8	-19%
MAR	4.5	3.3	-27%
APR	5.0	4.5	-11%
MAY	5.4	4.3	-21%
JUN	5.1	4.0	-22%
JUL	5.1	4.0	-21%
AUG	5.1	4.6	-9%
SEP	5.1	4.4	-15%
OCT	3.6	4.5	26%
NOV	2.9	2.3	-22%
DEC	2.8	2.5	-13%
TOTAL	51.6	44.0	-15%

Table 4. Coal Generation by Month and MISO region, Historical EIA data, Modeled Base Case, Delta

AREA	GWh	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
MISO-AR	EIA	2,309	1,243	520	964	1,300	1,749	2,065	2,230	1,777	1,127	1,387	1,880
	BASE	2,379	1,822	604	910	1,410	2,059	2,381	2,284	1,727	1,087	1,370	2,140
	DELTA	69	579	84	-53	110	310	316	54	-50	-40	-16	260
MISO-IA	EIA	2,653	1,058	1,159	1,541	2,049	2,568	2,825	2,709	1,971	1,208	1,631	1,899
	BASE	3,183	1,560	1,732	1,952	2,731	3,152	3,285	3,284	2,660	1,655	2,103	2,506
	DELTA	529	501	573	411	683	584	460	575	689	447	471	608
MISO-IL	EIA	3,779	2,886	3,045	2,829	3,123	3,768	3,927	3,580	3,512	3,221	3,751	3,959
	BASE	4,023	3,331	3,728	3,183	3,482	4,053	4,020	3,591	3,498	3,486	3,960	4,160
	DELTA	244	445	682	354	359	285	93	10	-14	264	208	201
MISO-IN-KY	EIA	5,678	4,045	4,147	4,151	4,083	4,803	5,681	5,204	4,153	4,511	4,452	5,048
	BASE	5,462	4,084	4,379	3,770	3,703	4,736	5,482	5,029	4,253	4,610	4,593	5,259
	DELTA	-217	39	232	-381	-379	-67	-198	-176	100	100	141	211
MISO-LA-TX	EIA	1,180	860	525	464	970	1,140	1,121	945	1,096	797	685	954
	BASE	902	842	356	166	728	853	873	790	776	703	640	730
	DELTA	-278	-18	-169	-298	-241	-287	-248	-155	-320	-94	-45	-223
MISO-MI	EIA	3,424	2,906	3,377	3,607	3,659	3,845	4,171	3,354	3,150	3,165	3,324	3,161
	BASE	4,174	3,752	4,259	4,016	4,327	4,328	4,800	3,848	3,731	3,619	3,831	3,788
	DELTA	750	846	881	409	668	483	629	494	581	453	507	628
MISO-MO	EIA	2,704	2,334	2,296	2,335	2,524	2,427	2,840	2,609	2,194	2,562	2,507	2,736
	BASE	2,910	2,515	2,552	2,367	2,672	2,627	3,063	2,899	2,425	2,757	2,682	2,811
	DELTA	207	181	256	32	148	200	223	291	232	195	175	75
MISO-MS	EIA	0	0	1	49	10	4	6	6	8	0	0	10
	BASE	0	0	0	0	0	0	0	0	6	0	0	0
	DELTA	0	0	-1	-49	-10	-4	-6	-6	-2	0	0	-10
MISO-ND-MN	EIA	3,466	2,964	2,629	1,903	2,521	2,755	3,650	3,465	3,084	3,009	3,485	3,482
	BASE	3,541	3,314	2,874	1,971	2,565	3,095	3,828	3,609	3,360	3,204	3,567	3,608
	DELTA	75	350	245	68	44	340	178	144	276	195	82	126
MISO-WI-UM	EIA	3,090	2,680	2,081	1,834	1,963	2,918	3,439	2,936	2,608	2,649	2,877	3,151
	BASE	3,202	3,022	2,848	2,509	2,788	3,171	3,677	3,360	3,147	2,895	3,039	3,398
	DELTA	112	341	767	674	825	253	238	424	539	246	163	247
MISO-ALL	EIA	28,283	20,976	19,780	19,678	22,202	25,978	29,726	27,040	23,552	22,250	24,099	26,280
	BASE	29,775	24,241	23,331	20,844	24,408	28,073	31,410	28,695	25,584	24,017	25,786	28,401
	DELTA	1,492	3,265	3,550	1,166	2,206	2,095	1,684	1,655	2,031	1,767	1,687	2,121

Market Prices

Synapse aligned regional market prices to monthly historical levels. The resulting annual on- and off-peak 2017 prices are shown in Table 6. We calibrated both on- and off-peak prices within 25 percent of actual monthly 2017 LMPs in nearly every area.

Table 6. Historical EIA and Modeled Base Case On- and Off-peak prices by MISO region

	ON-PEAK PRICE (NOM$/MWh)			OFF-PEAK PRICE (NOM$/MWh)		
AREA	EIA	Base	%	EIA	Base	%
MISO-AR	30.53	32.23	6%	23.90	22.61	-5%
MISO-IA	26.10	32.23	23%	19.09	22.61	18%
MISO-IL	31.05	32.23	4%	23.17	22.61	-2%
MISO-IN-KY	34.03	32.23	-5%	25.15	22.61	-10%
MISO-LA-TX	37.27	33.28	-11%	27.31	23.24	-15%
MISO-MI	33.94	32.15	-5%	25.60	22.58	-12%
MISO-MO	28.58	32.23	13%	21.48	22.61	5%
MISO-MS	33.98	33.28	-2%	25.30	23.24	-8%
MISO-ND-MN	27.14	32.23	19%	19.72	22.61	15%
MISO-WI-UM	32.08	32.17	0%	24.28	22.59	-7%
AVERAGE	31.47	32.43	3%	23.50	22.73	-3%

Optimized Dispatch

Optimized Dispatch Set-up

For the Optimized Dispatch Scenario, Synapse used the Base Case as a starting point and removed must run designations from all coal units. The model maintained constraints on energy balance, regulation, operating reserves, and transmission across all time periods. Around 80% of the units representing 95% of the capacity had must run designations (see Table 7). This includes all coal units larger than 200 MW and over half of the units smaller than 200 MW.

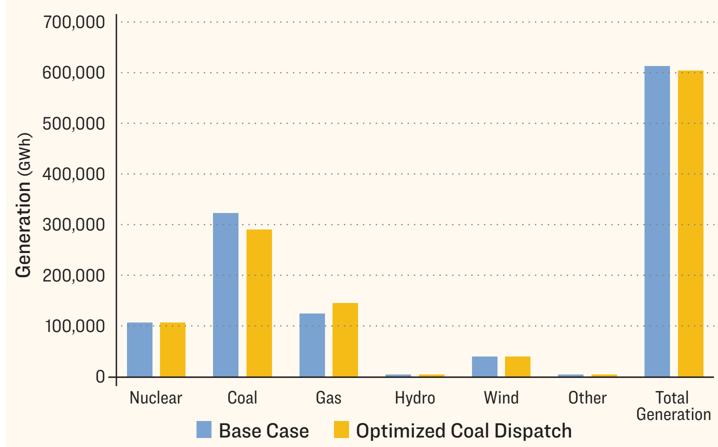
Table 7. MISO Coal Units with Must Run Status

STATUS	# UNITS	CAPACITY (MW)
Must run	154	57,820
% of total	82%	95%
Total	188	60,627

Optimized Dispatch Results

When Synapse removed the coal must run designations, coal generation dropped 10%, largely replaced by existing gas-fired generation.[55] In addition, total production costs within MISO dropped by 5.6% compared to the baseline scenario, driven by decreased generation from relatively high marginal cost coal plants. While total system costs decreased, on-peak wholesale power prices increased by 42%.

Figure 15 Comparison of 2017 Generation by Scenario by Fuel Type



The switch from coal to gas-fired generation was driven primarily by relatively low gas costs, and headroom in existing gas infrastructure. When the must run requirements were relaxed, approximately MISO coal generation dropped by 30.8 TWh and natural gas generation increased by 19.8 TWh.

Under the optimized dispatch scenario, gross production costs in 2017 fell by about 5.6% relative to base costs, a decrease of $683 million, as shown in Table 8. Production costs are comprised of fuel costs, non-fuel variable costs, commitment, and environmental program costs, and do not include fixed operating and maintenance costs. System-wide production costs fall in the optimized dispatch scenario because coal units are no longer forced to generate when the cost of operating a gas unit is more competitive.

Table 8. Production Cost by Scenario and Region

	PRODUCTION COST (MILLION NOM$)	
AREA	Base	Economic
MISO-AR	1,014	1,105
MISO-IA	399	388
MISO-IL	1,176	1,221
MISO-IN-KY	1,824	1,564
MISO-LA-TX	1,904	1,918
MISO-MI	1,909	1,686
MISO-MO	1,023	784
MISO-MS	318	347
MISO-ND-MN	1,119	1,165
MISO-WI-UM	1,428	1,252
TOTAL	12,112	11,430

Gross production cost savings do not include possible increases in O&M costs that could arise through increased cycling of the coal plants. Of the total of roughly 60 GW of coal plant in MISO, 12.1 GW of this amount experienced increased starts per year exceeding one per month. It is possible that these plants, generally smaller-sized units, would incur increased maintenance costs associated with increased cycling. The magnitude of those costs is uncertain; we have no specific data to estimate what the increase might be.[56]

Table 9 provides a high-level summary of scenario energy price deltas. In the Economic Dispatch Scenario, on-peak energy market prices (marginal energy costs) are 42% higher than the Base Case on average. Although energy prices, which represent marginal market prices, are higher in the Economic Dispatch Scenario, total system production costs (Table 8) are lower than Base Case costs. Must run designations commit coal units that would otherwise not run. EnCompass uses a supply stack to determine the price at which there is enough energy to meet demand (the marginal price point). The committed coal units provide energy to meet demand that would otherwise be met further along the supply stack, at a higher price. Thus, when must run designations are removed, the market clears at a higher marginal price.

Table 9. On- and Off-Peak Prices by Scenario and Region

	ON-PEAK PRICE (NOM$/MWh)		OFF-PEAK PRICE (NOM$/MWh)	
AREA	Base	Economic	Base	Economic
MISO-AR	32.23	46.03	22.61	28.05
MISO-IA	32.23	46.02	22.61	28.05
MISO-IL	32.23	46.02	22.61	28.05
MISO-IN-KY	32.23	46.03	22.61	28.05
MISO-LA-TX	33.28	46.63	23.24	28.37
MISO-MI	32.15	46.32	22.58	28.13
MISO-MO	32.23	46.03	22.61	28.05
MISO-MS	33.28	46.63	23.24	28.37
MISO-ND-MN	32.23	46.03	22.61	28.05
MISO-WI-UM	32.17	46.03	22.59	28.13
AVERAGE	32.43	46.18	22.73	28.13

ENDNOTES

1 Data from S&P Global, 2018.

2 Federal Energy Regulatory Commission, 2019. https://www.ferc.gov/industries/electric/indus-act/rto.asp.

3 In this paper, "regulated" will be used as a shorthand for utilities that are vertically integrated — *i.e.*, own both generation and distribution infrastructure—and have captive ratepayers. The term "regulated generators" will be used as shorthand for generation units that are majority-owned by regulated utilities. In this context, the term "regulated" does not specifically mean oversight by a state utility regulatory commission, but includes investor-owned utilities, municipal utilities, and member-owned cooperatives. It is used to draw a contrast with independent power producers, or "merchant" generators. We define if a coal plant is regulated by the status of its majority owner, or first listed operator if evenly divided, according to EIA Form 860 (2017). We identify "regulated" owners as investor-owned, municipally-owned, owned by a cooperative, a state, or other political subdivision. Merchant generators are restricted, in this analysis, to generation units majority-owned by independent power producers.

4 Coal and other steam turbines often have a minimum loading level. A slow-ramping generator, like a coal unit, may elect to self-commit to ensure that it is available to capture anticipated higher priced hours at a future time, rather than being required to go offline during low priced hours.

5 Daniel, J., 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.

6 Daniel, J., 2018. *The Coal Bailout Nobody is Talking About*. NASUCA Annual Conference, 2018. Orlando, Florida. Union of Concerned Scientists. https://www.nasuca.org/nwp/wp-content/uploads/2018/01/NASUCA-Coal-bailout-nobody-is-talking-about.pdf.

7 Southwest Power Pool Market Monitor Report, 2017. May 2018. *E.g.*, Page 6 ("Self-commitment of generation continues to be a concern because it does not allow the market software to determine the most economic market solution. Furthermore, it can contribute to market uplifts and low prices. Some of the reasons for self-committing may include contract terms for coal plants, low gas prices that reduce the opportunity for coal units to be economically cleared in the day-ahead market, long startup times, and a risk averse business practice approach."). https://www.spp.org/documents/57928/spp_mmu_asom_2017.pdf.

8 The Power Bureau. 2018/ Analysis of Market Impact for Proposed EmberClear Generation Facility in Pawnee Illinois. http://files.sj-r.com/media/news/Chamber_Report_on_EmberClear.CWLP.pdf

9 MISO Indiana Hub, flat average of hourly day-ahead energy prices. Data from S&P Global.

10 Estimates compiled from data in S&P Global supply curve.

11 Source: EPA Clean Air Markets Data (CAMD) Air Markets Program Data (AMPD), hourly data for 2012 and 2016. Author's calculations.

12 Source: EPA Clean Air Markets Data (CAMD) Air Markets Program Data (AMPD), hourly data for 2012 and 2016. Author's calculations.

13 Refer to In the Matter of an Investigation of Missouri Jurisdictional Generator Self-Commitments into SPP and MISO Day-Ahead Energy Markets, File No. EW-2019-0370 (Aug. 23, 2019).

14 National Renewable Energy Laboratory. April 2012. Power Plant Cycling Costs. https://www.nrel.gov/docs/fy12osti/55433.pdf.

15 There may be circumstances in which a coal unit seeks to primarily capture capacity market revenues (rather than energy and capacity market revenues). However, even in these cases, a coal unit will attempt to avoid market prices below its production cost.

16 We note that in most market regions, generators are provided "uplift" payments when they are committed or dispatched as part of the optimal solution but energy market revenues are not sufficient (on a daily basis) to cover production and commitment costs. For any coal units that are somehow relatively low-cost overall but entail high start costs and long start times, uplift payments may be substantial. We do not expect large differences between uplift payments at merchant and regulated utilities.

17 Virginia Docket PUR-2018-00195, Dominion Rate Adjustment Clause (RAC) for coal ash retrofits at various coal units. Rebuttal testimony of Glenn Kelly, page 18 at 3-5 ("The forecasted capacity factors [for Chesterfield Units 5 & 6], in conjunction with the historical capacity factors, are indicative of units that are providing significant fuel savings and effectively serving customer load"). In contrast, we estimate that Chesterfield 5-6 operated more than expected by increasing capacity factors more than 37% above ideal (more than double the ideal output in 2016), and subsequently lost more than -$22 million in net energy market revenues, or -$19 million when accounting for capacity market revenue and fixed O&M costs.

18 We distinguish here the need for short-term reliability as scheduled by the RTO against a utility's legitimate longer-term need for capacity in market regions where capacity is primarily self-supplied (i.e MISO and SPP). For long-term purposes, a utility might identify a capacity need, but that capacity need almost certainly does not justify ongoing non-economic dispatch, and may be more readily served by lower cost resources.

19 Nelson, W., Liu, S. March 26, 2018. "Half of U.S. Coal Fleet on Shaky Economic Footing: Coal Plant Operating Margins Nationwide." Bloomberg New Energy Finance.

20 *Id*. Page 46

21 *Id*. Page 46

22 "Regulated" generation units, for the purposes of this paper, are units owned by municipal utilities (like Austin and San Antonio's municipal utility districts) and rural electric cooperatives (such as San Miguel). It does not include any state commission-regulated investor-owned utilities.

23 For a slow-ramping coal unit, or any unit with operational constraints, optimal dispatch is effectively impossible. It entails capturing 100% of every hour in which market prices are above production costs, and rejecting every hour in which market prices are below production costs. And while that theoretical optimal level of dispatch is not fully achievable in practice, it is a useful benchmark for the operations of units on a statistical basis — and substantial improvement in the real world towards theoretical optimality can in fact be made. Over a year-long period, we would expect units to fall slightly above or below the optimal dispatch behavior — slightly above if risk tolerant, or slightly below if risk averse or incurring extended maintenance outages.

24 This analysis excludes co-generation facilities, which produce both process steam and power as revenue sources, and may be de-linked from energy market pricing.

25 Because units have operational constraints and may have scheduled or forced outages, we would not expect even the most efficiently dispatched units to necessarily fall along the 1:1 line.

26 "Construction kicks off for Edgewater Unit 5 scrubber." Transmission Hub. April 25, 2014. Accessed August 2019. https://www.transmissionhub.com/articles/2014/04/construction-kicks-off-for-edgewater-unit-5-scrubber.html. The scrubber cost $230 million. Power Magazine, October 2017. Accessed August 2019. https://www.powermag.com/a-breath-of-cleaner-air-on-the-lake-michigan-shore/.

27 "Net Energy Market" loss refers to the differential between total revenues received on the energy market (only) and production costs (*i.e.* fuel and variable O&M).

28 Regions and years with zero values indicate that no plants incurred losses relative to market prices.

29 MISO's capacity market is a voluntary residual market. We assume that the resulting capacity price reflects the opportunity cost of acquiring or selling excess capacity in that year.

30 "Net market" loss refers to the differential between total revenues from both the energy and capacity markets, less production costs and fixed O&M costs. We do not estimate incremental losses due to ongoing capital expenditures.

31 Regions and years with zero values indicate that no plants incurred losses relative to market prices.

32 Estimated by S&P Global from FERC Form 1 filings and modeled.

33 Weighted average capacity price of $11.2/MW-day in most zones.

34 Based on a topology and default unit costs and operational constraints from Horizons Energy database, acquired as part of the model licensure.

35 Derived from S&P Global, 2017

36 While we can capture self-commitment practice (i.e. staying on at minimum loading), neither the calibration run nor the optimal run can capture self-scheduling practices without internal information about decisions made by plant operators.

37 Coal units and other steam-based power plants have a minimum output (in MW), below which the unit is unable to operate effectively. A decision to operate is a "commitment" to generate at least at the minimum load.

38 The remainder of the reduction is attributable to units identified as owned by industrials, a type excluded from this analysis otherwise because industrial users often have other criteria for the use of on-site energy, such as steam generation.

39 Assessment restricted to units which operated in 2017 according to data reported to EIA Form 923.

40 The model characterizes the number of unit starts (i.e., the number of times a unit is started from zero generation) during the year. Operators try to prevent numerous unit starts at coal units to reduce wear and maintenance costs. In both modeled cases, the median number of unit starts remained the same between at approximately five (5) unit starts per year. However, the model predicts that, even with substantial startup costs, less economic units might be subject to more unit starts. In the economic dispatch case, twenty-six units are subjected to more than 15 unit starts per year in the economic dispatch case. In reality, a unit might simply elect not to run rather than be subject to this many starts per year.

41 Note that an increase in wholesale rates does not necessarily translate to an increase in retail rates.

42 Assuming a 30% capacity factor and all-hours increase of $7.7/MWh.

43 This value accounts for the fixed O&M cost of coal generators in the analysis.

44 The cost of production in this table reflects total fuel, variable O&M, and fixed O&M, although only fuel and variable O&M are used to determine the short-term variable cost of production for dispatch purposes. The change in production cost from the base case to the economic dispatch case reflects only change in fuel and variable O&M. Fixed costs remain fixed.

45 It is important to note that depressed wholesale prices do not necessarily imply that retail costs have been suppressed or reduced. In fact, captive ratepayers of utilities with non-economically dispatched coal units likely have paid higher retail rates.

46 Minnesota Public Utilities Commission, Docket Nos. E-999/AA-17-492, E-999/AA-18-373, In the Matter of the Review of Automatic Adjustment Reports for All Electric Utilities; Missouri Public Service Commission, Docket No. EW-2019-0370, In the Matter of an Investigation of Missouri Jurisdictional Generator Self-Commitments into SPP and MISO Day-Ahead Energy Markets.

47 Sierra Club, 2018. Harnessing Financial Tools to Transform the Electric Sector. Available online at www.sc.org/financial

48 Source: EPA Clean Air Markets Data (CAMD) Air Markets Program Data (AMPD), hourly data for 2012 and 2016. Author's calculations.

49 Marginal cost of energy: the cost of the last megawatt to come online, or the first megawatt that would get turned off if that energy was not required.

50 Ratepayers who pay for an out-of-market coal unit (*i.e.*, above market price) also have a slight offset from lower energy market prices for the portion of their energy usage purchased off the market and not attributable to plants owned by their utility.

51 Also, notably, ongoing annual technical conferences at FERC address the inefficiencies associated with RTO-based unit commitment and dispatch operations, and software utilization to aid those processes. The issues are numerous, and highly complex. See, e.g., https://www.ferc.gov/industries/electric/indus-act/market-planning.asp.

52 Must run designations represent minimum run time or operational levels for coal units coded into the database of unit parameters.

53 Units with joint ownership shares outside of MISO were excluded from this process.

54 The two large coal plant in the MISO-AR region, Independence Steam and White Bluff, see consistently higher modeled output than historical generation, on average 40 MWh more per month. The Synapse team was unable to replicate the high output of these units using cost parameters without unduly impacting regional market prices. Similarly, in the MISO-LA-TX region, the Synapse team was unable to incent operation for Big Cajun unit 2:1 without affecting regional price and generation patterns, which caused the divergent percent deltas shown.

55 Imports also increased by nearly 23%. Imports were priced as marginal natural gas units, and thus imply an even greater shift toward natural gas.

56 An increase on the order of $10/kW-year of fixed O&M for 12.1 GW of coal plant would translate to $121 million/year, or roughly 17.7% of the gross production cost savings seen.

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