

The Shaky Economics of Gas-fired Power Generation

How Uneconomic Gas-fired Power is Costing Consumers

Fossil fuel-fired power plants have become harder to operate economically due historical declines in wholesale electricity prices and the presence of cheaper resources on the grid. However, some power providers still choose to operate thermal resources even when they lose money, creating losses that captive customers must pay. Coal plants are well known to generate such losses, and emerging evidence indicates that this problem extends to gas-fired power plants as well.

We analyzed how frequently gas plants are operated uneconomically, and at what cost, in the Midcontinent Independent System Operator and the Southwest Power Pool. We constructed a cash flow analysis comparing gas plants' revenues and costs in 2019. Our study found that utilities incurred an estimated \$117 million in losses in 2019 from operating gas plants during periods when operating expenses exceeded market revenues. Regulators and policymakers need to prevent these costs from falling on ratepayers and work toward replacing uneconomic gas plants with clean energy resources.

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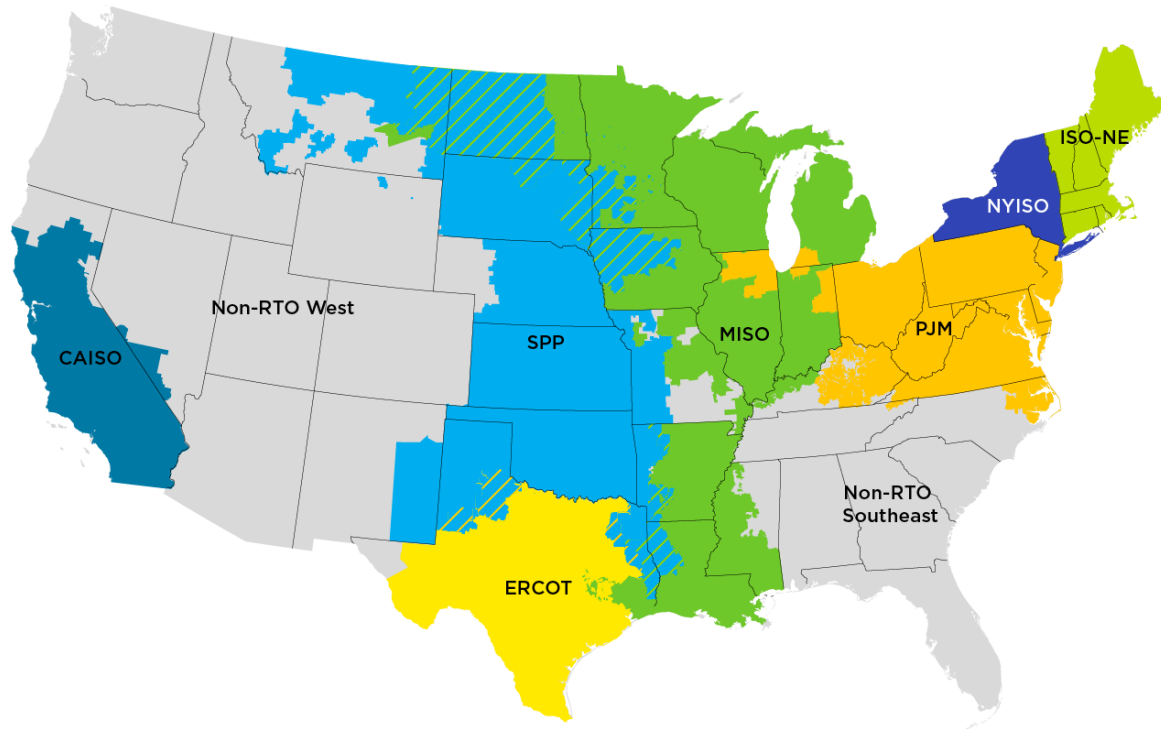
Introduction

Falling wholesale electricity prices over the past decade have put increased pressure on the operating economics of power plants. Between 2008 and 2017, annual average wholesale electricity prices in regions across the country fell by \$19 to \$64 per megawatt-hour (MWh), driven by a period of low prices of methane gas and increases in low-cost renewable energy resources on the grid (Mills et al. 2021). (In this report we refer to natural gas as methane gas, or simply gas.) Such historical declines in wholesale electricity prices have made it harder for higher-cost thermal resources to be cost-competitive, and have led overall to decreases in operating hours, especially for coal and some gas-fired power plants (EIA 2020b; Sims et al. 2021; Shwisberg et al. 2021). However, despite this, some power providers still choose to operate thermal resources when their operating costs exceed market revenues and/or when lower-cost resources are available on the grid to run instead. Multiple studies in the past few years have found that coal plants were operating in wholesale electricity markets across the country when lower-cost resources were available on the market (Daniel 2017; Nelson and Liu 2018; Fisher et al. 2019; Glick 2020). More recent reports from select wholesale markets indicate that this problem may extend beyond coal plants to include gas-fired power plants as well (SPP MMU 2019; MISO 2020).

Reasons Behind Uneconomic Generation in Wholesale Markets

Competitive wholesale electricity markets, operated by independent system operators and regional transmission operators (ISOs/RTOs), are designed to use the lowest variable cost resources available to meet demand at every hour of every day, subject to local constraints of the grid (Figure 1). The expectation of a properly functioning wholesale market is that any power provider running its generators and selling electricity to the grid should be recovering its fuel and variable operating expenses.¹

Figure 1. Map of Competitive Wholesale Electricity Markets in the United States

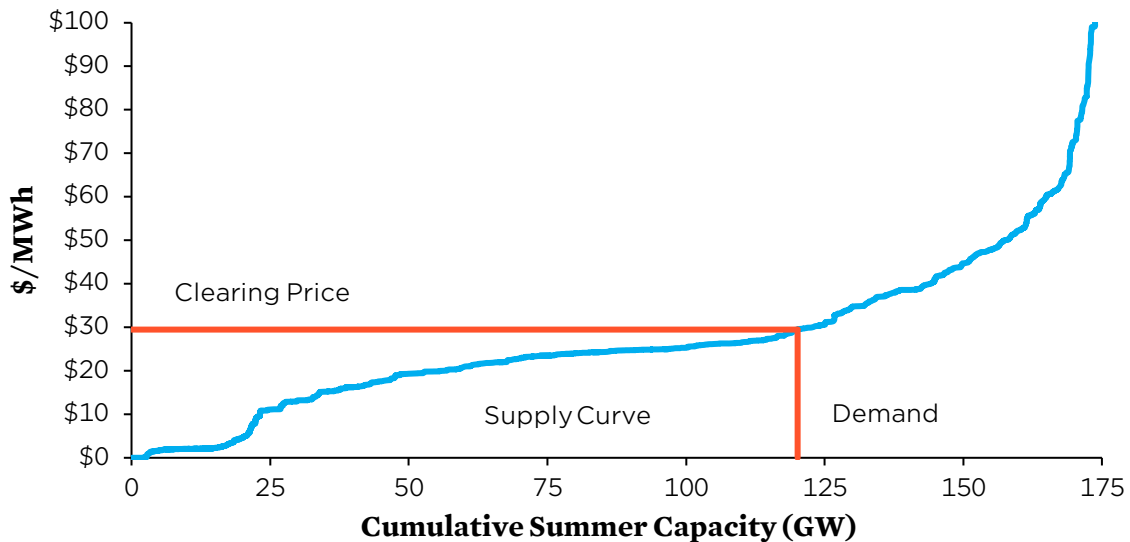


SOURCE : Daniel et al. 2020

HOW MARKET BIDS ARE FORMED AND MARKET PRICES ARE SET

Utilities and other power providers craft bids into the market for each generator. Those bids are intended to cover the costs of running that generator at that time, and are submitted to grid operators for either the day-ahead or real-time energy market. Grid operators then evaluate the bids in light of expected demand for that period and begin to call the lowest-cost resources to operate, adding higher-cost resources until demand is met. The last resource used to meet demand is (presumably) the highest-cost resource being dispatched at that time and sets the market clearing price (see Figure 2). Market clearing prices are determined for specific locations within an RTO and account for various physical constraints of the grid, such as transmission constraints, minimum generator run times, and generators' ramp rates (how quickly a plant, whether fossil fuel or renewable, can increase or decrease its power production).

Figure 2. Generation Resources' Operation in Wholesale Markets: Supply Curve, with Corresponding Demand and Clearing Price



This graph shows how generation resources are called to operate in wholesale markets. Power providers submit to grid operators a market bid for each generator, covering the cost of operating and the available capacity of the resource. The lowest-cost resources are called to operate (blue line) until demand is met. All operating generators receive the market clearing price (the point at which the blue line intersects with the vertical orange line), which is equal to the bid of the last-called generator.
SOURCE : Daniel et al. 2020

In this way, the last generator added, which sets the price, will break even—its revenue from the market will equal its bid, which is meant to cover its fuel costs and variable operating costs. All other dispatched units cost less to operate but receive the same payment per unit of energy provided; these units should both cover their operating costs and earn surplus revenue that can be used to either pay off fixed costs or earn a profit.²

This process, in theory, leads to market participants acting rationally and creates an economically efficient system. If a utility or other power provider submits a bid below its generator's operating cost and clears the market, it runs the risk of losing money. Conversely, if it overbids its operating costs, it runs the risk of not being called and missing the opportunity to make money.

As a result, power providers have an incentive to submit bids that accurately reflect their generators' operating costs and to behave in the market as it was intended, which should lead to economically optimal results for the system as a whole. However, in practice, power providers can operate power facilities at times when they do not recover fuel and variable operating costs through market revenues alone, leading to higher costs for ratepayers and at times displacing cleaner-energy resources.

OPERATING OUT-OF-MERIT BY SELF-SCHEDULING AND SELF-COMMITTING

In each of the ISO/RTOs, there are mechanisms that allow power plants to skip in line, being dispatched before lower-cost and less polluting resources, known as operating out-of-merit.³

Certain practices allow a power provider to operate regardless of whether it recovers its costs. For example, all power providers have the option to “self-schedule” and “self-commit” resources into day-ahead markets rather than wait for their units to be dispatched by the system operator according to different units’ relative costs. Power providers are allowed to self-schedule their units onto the market at a pre-determined level of energy production and time period, either because the providers need to test equipment or in order to fulfill a power-purchase agreement. Power providers may also self-commit their units by requiring that they operate continuously at a minimum, pre-determined level of energy production and be dispatched above that level only if the grid operator calls upon them based on their bid price.⁴ Reasons why some generators are allowed to self-schedule or self-commit include that they require an extended ramp-up time or long minimum operating times (more so for coal and nuclear plants). Regardless of the rationale, these practices allow a power provider to operate independently of whether it recovers its costs and independently of what market economics would suggest.

Both self-scheduling and self-commitment reduce grid flexibility and can create unnecessary costs for consumers. Their use can prevent grid operators from turning down or shutting down units that, based on market economics, should not be running. It also allows power providers to sell power at a loss and/or prevents lower-cost, cleaner resources from being used to meet demand.

SETTING BIDS ARTIFICIALLY LOW

In addition, power providers can choose to set their bids artificially low and bid into the market when operating costs are not being fully recovered. One way this can happen is when power plant operators improperly classify (either intentionally or accidentally) portions of their variable costs as fixed costs. For example, a utility might have a fuel contract that has a mix of variable costs (related to how much fuel it purchases) and fixed costs (numerous fees incorporated into the contract) and choose to account for the entirety of the contract as a long-run fixed cost. If plant operators improperly treat variable costs as fixed, they will not incorporate these costs into their market bids and will instead submit an artificially low market bid that does not encompass the full cost of operating. If then called to operate, they would run the risk of operating in place of cheaper resources and would be incurring unnecessary losses.

A utility might also operate a plant more than market economics would suggest (i.e., at a loss) to prove that the asset is “used and useful” to regulators. For ratepayers to pay for assets and for utilities to earn a return on them, power providers need to show that their assets are used and useful to ratepayers. If their assets do not pass this test, costs associated with them can be disallowed. Running a power plant more frequently than it should be allows utilities to continue receiving favorable returns on that asset from customers.

THE CONSEQUENCES OF INAPPROPRIATE DISPATCH OF GENERATORS

When power providers inappropriately dispatch their units at times when they do not recover their variable operating costs, they incur losses. If the power plant is serving captive ratepayers—customers of vertically integrated investor-owned utilities, electric cooperatives, and municipal utilities—those customers must cover the costs from inefficient and uneconomic operations. While state regulators can scrutinize imprudent operating decisions if the power provider is a regulated utility and disallow these costs in rate cases and fuel adjustment cases, operating decisions are not overseen by regulators for electric cooperatives, and disallowances for regulated utilities are rare. In both cases, ratepayers must absorb those costs, paying higher prices for more polluting energy sources.

The Emerging Problems with Gas

In 2020, gas-fired power accounted for 33 percent of generation in the U.S. power sector (EIA 2021). Utilities and fossil fuel interests have claimed that gas is cheap and clean when justifying the large-scale build-out of gas-fired facilities; however, mounting evidence shows those claims are specious, in part due to rising and volatile gas prices and more cost-competitive alternatives (Union of Concerned Scientists 2015; Tsao and Martin 2019; Gruenwald 2021).

ECONOMICS OF GAS-FIRED POWER PLANTS

Fossil fuel plants, including gas plants, carry substantial fuel and variable operating costs and typically have difficulty competing in short-term energy markets with clean energy resources, such as wind and solar, which do not carry such substantial variable operating costs. Extracting, transporting, and burning fossil fuels (including methane gas) is much more expensive than utilizing renewable energy resources for power that can meet the same grid demands. The environmental and public health costs associated with burning fossil fuels push their costs even higher (De Alwis and Limaye 2021).

ENVIRONMENTAL IMPACTS OF GAS-FIRED POWER PLANTS

Methane gas is frequently touted as a cleaner fuel than coal, but being cleaner does not make it clean. Burning gas creates localized air pollution harmful to human health by generating nitrogen oxide (NO_x) emissions, which can also react to form ozone and particulate matter through indirect processes (Donaghy and Jiang 2021). Since gas-fired plants tend to be in densely populated areas and in greater proximity to low-income communities and communities of color, an overreliance on gas for power exposes these communities to harmful pollution and has the potential to exacerbate existing disparities in pollution exposure from power plants (Thind et al. 2019; Diana, Ash, and Boyce 2021). From a climate perspective, methane gas is highly damaging—more than 80 times more potent of a heat-trapping gas than carbon dioxide over its first 20 years in the atmosphere. When accounting for upstream emissions resulting from leaks in gas distribution, burning gas instead of coal for power can have a similar or worse climate impact, negating any climate benefits from retiring coal power plants (Rives 2021).

The Importance of Evaluating Uneconomic Gas Generation

For power providers that operate in a monopoly environment, regardless of whether they participate in an RTO, there are numerous reasons and motivations used to justify operating fossil-fired plants uneconomically, creating unnecessary costs for ratepayers.

Uneconomic operations have been extensively studied and documented among coal plants, and it has been shown that coal resources have created estimated annual above-market costs of between \$211 and \$350 million in the Midcontinent Independent System Operator (MISO) alone and \$136-173 in the Southwest Power Pool (SPP) (Daniel 2017; Fisher et al. 2019; Daniel et al. 2020). While there is emerging evidence that out-of-merit generation from gas plants is occurring in these two RTOs, no comprehensive or detailed evaluations focused on the gas fleet have been completed.

This analysis sought answers to the following questions about the gas fleet in MISO and SPP:

- How frequently are gas plants in these RTOs operating uneconomically?
- What additional costs are ratepayers paying?
- How do these calculations of the uneconomic operation of gas plants impact the way regulators and policymakers think about the clean energy transition (and whether there is a role for gas in it)?

If existing gas-fired plants are operating for long and/or frequent periods at a loss and are struggling to find consistent periods of time when it is economic to operate, newly proposed gas plants would face a serious risk of confronting the same challenges, as the underlining trends—rising levels of renewables on the grid, increased energy efficiency, and rising fuel costs—are likely to continue.

Methodology

In order to examine the frequency and cost of uneconomic operation of gas-fired power plants in MISO and SPP, we calculated their cash flow in each hour of 2019. We focus on these two market regions for several reasons. Many previous analyses have found that utilities incurred losses from uneconomic coal generation in these two RTOs, ranging from \$211 to \$350 million per year in MISO and \$136 to \$173 million per year in SPP (Daniel 2017; Fisher et al. 2019; Daniel et al. 2020). However, analyses focused exclusively on uneconomic gas generation and its corresponding losses in these RTOs have not been completed.

SPP and MISO are the two markets with the highest percentage of gas plants in rate base (e.g., captive ratepayers), with rate-regulated gas plants making up nearly 74 percent and 67 percent of SPP's and MISO's gas-fired power plant capacity, respectively.⁵ Since operating out-of-merit is primarily an issue for customers of vertically integrated utilities, it has been most pronounced and most investigated in SPP and MISO, specifically among the coal fleets. Generation in the other RTOs—PJM, the New York Independent System Operator, the Independent System Operator of New England, and the California Independent System Operator—is mostly owned by non-utility parties, which do not have the same captive ratepayers that would pay for losses incurred from uneconomic generation.

Lastly, MISO and SPP have the highest levels of adoption of wind and some of the most frequent negative market prices (Seel et al. 2021). A high frequency of low or negative prices puts economic pressure on fossil-fired power plants, increasing the potential for these regions to experience more frequent out-of-merit activities.

A more detailed methodology can be found in the technical appendix.

Cash Flow Calculation

To calculate the operating economics of gas-fired power facilities and determine whether they were making economic dispatch decisions during 2019, we calculated the hourly cash flow of gas facilities in both MISO and SPP and aggregated the results to the weekly level for each week of 2019.

We utilized the following formula to calculate the cash flow at each gas facility analyzed:

$$\text{Hourly Cashflow} = \text{Market Revenue} - \text{Fuel Costs} - \text{Variable O\&M Costs}$$

The market revenue of each gas facility was determined by multiplying the hourly day-ahead locational marginal price of the market node associated with each gas facility by the estimated hourly net generation of the gas facility.⁶

S&P Global aggregates gas prices, reported at the daily level on business days at gas distribution hubs across the United States. To calculate the fuel costs incurred at each facility, we used the daily spot price of gas at the gas distribution hub that S&P Global matches with each gas facility for its own fuel cost calculations. The daily value was used for every hour of the day, given that this was the most granular way that fuel prices are reported. For days that

did not report daily prices, we used averages of spot prices of the preceding and succeeding days that daily spot prices were available. Hourly heat input was sourced from the Environmental Protection Agency’s power sector emissions data for each gas facility (OAP 2022).

Variable operation and maintenance costs per megawatt-hour (excluding fuel) are reported through the S&P Global Power Plant Database (S&P Global 2022). For this calculation a constant annual variable operation and maintenance cost value was applied from 2019 during hours when each gas facility was generating.

FACILITIES ANALYZED

The types of gas-fired facilities analyzed here were gas turbines (also known as combustion turbines, which are powered by the combustion of a mix of pressurized air and gas), steam turbines (which burn gas to create steam to power a generator), and combined-cycle power plants (which contain a mix of gas turbines and heat recovery steam generators). The facilities analyzed were those operating in 2019 in MISO and SPP whose primary fuel was gas (excluding cogeneration facilities, which generate both power and heat, and fuel cells). We chose 2019 as our analysis year to avoid impacts of the COVID-19 pandemic and because gas prices in 2019 were at record low levels (EIA 2020a). The low gas prices would have made it easier for gas plant owners to operate at a profit, making uneconomic generation in this period an even more egregious practice.

After excluding facilities that did not supply energy to the grid under normal circumstances (such as facilities that solely supply black-start capacity), we analyzed a total of 436 gas-fired facilities (277 in MISO and 159 in SPP). The capacity of the different types of gas facilities studied is shown in Table 1.

Table 1. Operating Capacity of the Gas Facilities Studied (2019)

	Combined Cycle (GW)	Gas Turbine (GW)	Steam Turbine (GW)
MISO	23.9	18.7	9.4
SPP	8.3	7.1	8.7

We aggregated combined-cycle units up to the plant level for the cash flow analysis, using the scaling factors described in the appendix, because the hourly generation data are not available for all units at combined-cycle plants. For all steam and gas turbines the cash flow analysis was conducted at the unit level.

We aggregated our hourly cash flow analysis up to the weekly level for a more conservative financial picture, and focused only on quantifying the amount of net operating losses that a gas facility incurred over the course of each week and over the course of 2019 in whole. We aggregated up to the weekly level in order to analyze longer-term commitment decisions and scrutinize repeated and sustained uneconomic operations, rather than get into the hour-to-hour dispatch choices of plant operators. While it would be unrealistic for any power plant to have perfect foresight and be able to operate every hour of the year without incurring

unexpected or unforeseen losses, at minimum, a gas-fired power plant should be able to recover its operating costs on a week-by-week basis. This is a conservative expectation: in reality, gas plants should do better than break even on a weekly basis. In this analysis this means that a gas plant could operate uneconomically for several hours or even days, but if at the end of the week it had been able to generate revenues that exceeded costs, it was not classified as uneconomic for that week.

LIMITATIONS OF THE ANALYSIS

More details on pricing metrics and operating costs would improve cash flow estimates. Using publicly available data, it is impossible to discern how units were committed or scheduled—be they self- or market-committed, in the day-ahead or real-time markets. Knowledge about how generators were committed or scheduled to the market would provide insight into the motives behind operation. This would provide insight to why a generator might be online, and whether it is online for a legitimate reason or whether it is ignoring market price signals. Knowledge about which market these units were dispatched into and how they were dispatched would improve cash flow estimates, because it would provide additional context and improve the accuracy of revenue estimates. However, it is unlikely this would materially alter the analysis, as more than 95 percent of typical market transactions occur on the day-ahead energy market (FERC 2020).

Similarly, the analysis did not consider any fuel price hedging, and the results are sensitive to fuel prices. Gas price hedging can be an important variable because it can offset some of the accumulated losses over the medium and long term. However, hedge contracts are rarely reported on, and the details of those settlements are almost universally considered confidential; therefore, these effects were not integrated into the analysis.

Finally, this analysis did not incorporate additional market revenues (from capacity or ancillary service markets). These revenues are meant to help recover fixed costs associated with power plants and are not relevant to the analysis of day-to-day operations of a gas plant.⁷ Therefore, these revenues (along with fixed costs) were omitted from calculations. Uplift payments (payments from grid operators used to cover the difference in operating costs and market revenues if a difference exists and the plant is needed to run) were also omitted due to data limitations. It is worth noting that power plants that self-commit or self-schedule are ineligible for uplift payments in the periods of time when they self-commit or self-schedule, and therefore could not count on uplift payments to make up for any incurred losses.

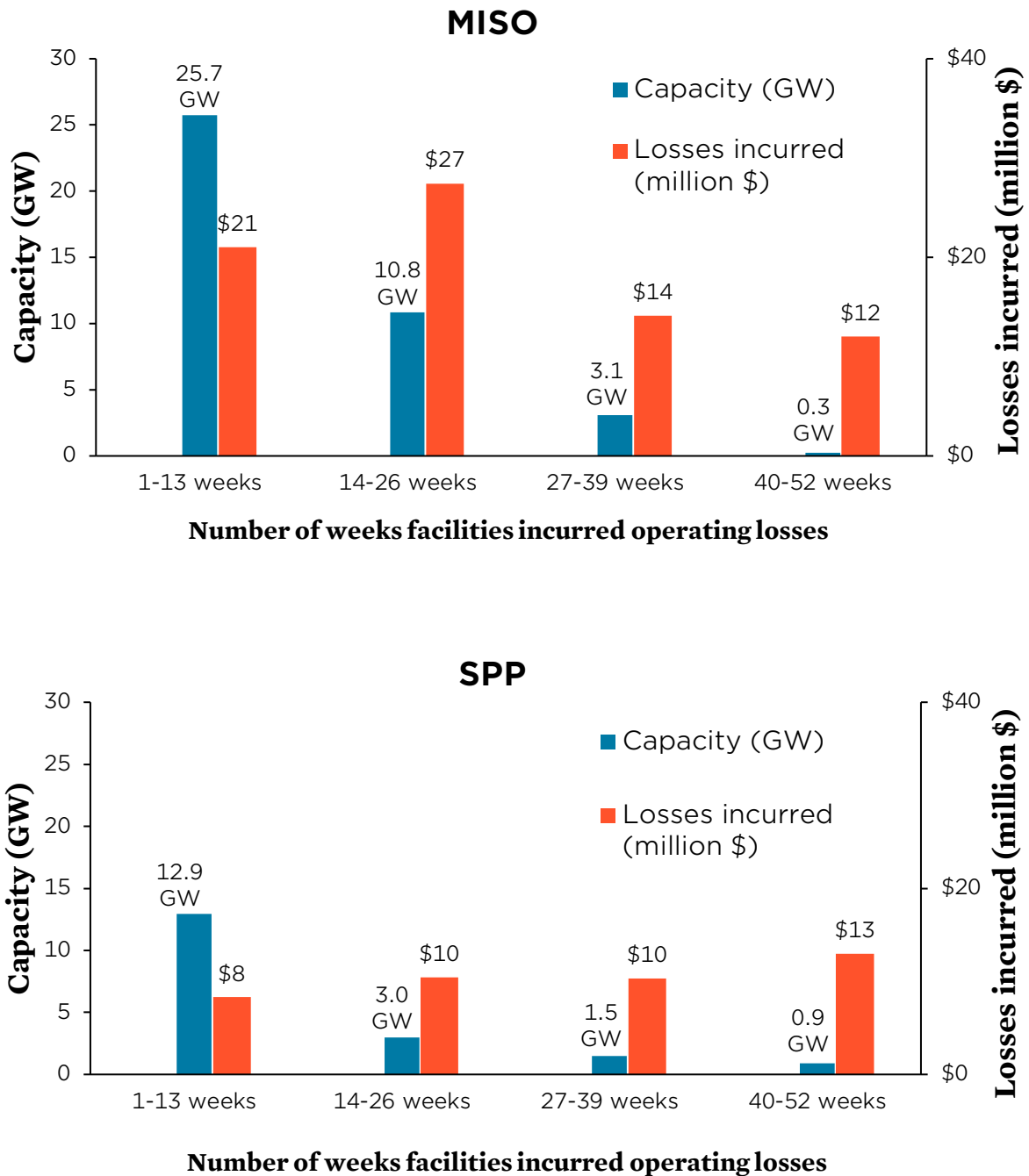
Results

The results of this analysis showed that almost all operators of the gas plants analyzed in SPP and MISO operated their gas plants uneconomically at some point during 2019. And the period of time this occurred was not insignificant: the average gas-fired power plant in MISO and SPP in 2019 incurred net operating losses for 11 to 13 weeks of the year. Summing the weekly operating losses incurred over the course of the year shows that utilities sustained an estimated \$117 million in operating losses (which are potentially avoidable losses) across both RTOs, a majority of which were caused by steam and gas turbines operated by regulated utilities.

Frequency of Uneconomic Operations

Because the utilities in MISO and SPP are almost entirely rate regulated, they were able to pass these market losses onto customers. The frequency with which gas facilities operated uneconomically can be seen in Figure 3.

Figure 3. Frequency and Value of Weekly Operating Losses Across MISO and SPP



The four pairs of bars for MISO (top) and SPP (bottom) show the frequency with which gas facilities ended a week in 2019 with net negative operating revenues. The blue bars indicate the size of the gas fleet that lost money over that number of weeks, and the red bars indicate the financial losses incurred by the set of facilities as a result.

Each group of bars in Figure 3 represents the number of weeks that gas-fired facilities operated uneconomically (although those weeks are not necessarily consecutive) and the corresponding losses from that group’s uneconomic operations.

The first group of bars, 1 to 13 weeks, represents the majority of gas-fired facilities in both MISO and SPP. These gas-fired facilities were able to recover their variable costs in a majority of the weeks over the year (at least 75 percent of the weeks of the year) and were unable to recover their costs for 13 weeks of the year or fewer. Fifty-five percent of the facilities in MISO and 60 percent of facilities in SPP fall into this bucket. Even though those facilities were operating economically in the energy market during most weeks, it is surprising that any gas plant would run uneconomically for any prolonged period, given that uneconomic dispatch should not happen based on how markets are designed.

A smaller subset of gas facilities in each RTO was operating uneconomically more frequently. In SPP, 15 percent (3 GW) of gas facilities analyzed did not recover their operating costs on a weekly basis for 14 to 26 weeks of 2019—up to half the weeks of the year. In MISO, that fraction was even higher, at 29 percent (10.9 GW) of facilities. Furthermore, in each RTO there were facilities incurring net operating losses on a weekly basis for more than half of the weeks of the year (7 percent of the gas facilities (3.4 GW) in MISO and 17 percent of facilities (2.4 GW) in SPP).

Overall, in 2019, the average gas-fired facility in MISO and SPP ran for 11.3 and 12.6 weeks, respectively, without recovering its weekly operating costs from energy market revenues at the end of the week.⁸ Summing the net operating losses incurred over each week in 2019 shows that utilities in these RTOs could have avoided up to \$117 million in weekly net operating losses had they operated these gas facilities more economically.

Type of Gas Facility

The type of gas facility was strongly correlated with whether it was or was not operating economically and recovering its operating costs from day-ahead energy market revenues. Table 2 shows how power providers dispatched different types of gas facilities across the two RTOs.

Table 2. Average Number of Weeks that Each Facility Did Not Recover its Variable Operating Costs by Week’s End

	Combined Cycle	Gas Turbine	Steam Turbine
MISO	2 weeks (6%)	12 weeks (63%)	21 weeks (81%)
SPP	6 weeks (15%)	12 weeks (38%)	16 weeks (68%)

The average number of weeks that each facility did not recover its weekly operating costs in 2019 is shown, along with the average share (percentage) of weeks in 2019 that each type of plant was both operating and incurring net operating losses.

The types of plants that utilities are running most uneconomically tend to be steam turbines, which are sometimes former coal plants that have been converted to burn gas instead, and gas turbines, which typically run at peak hours of the day when demand is highest. These technologies tend to have lower thermal efficiencies than combined-cycle gas plants (EIA n.d.), which could be a contributing factor to their poorer economics in this analysis.

Financial Impacts of Uneconomic Operations on Generators

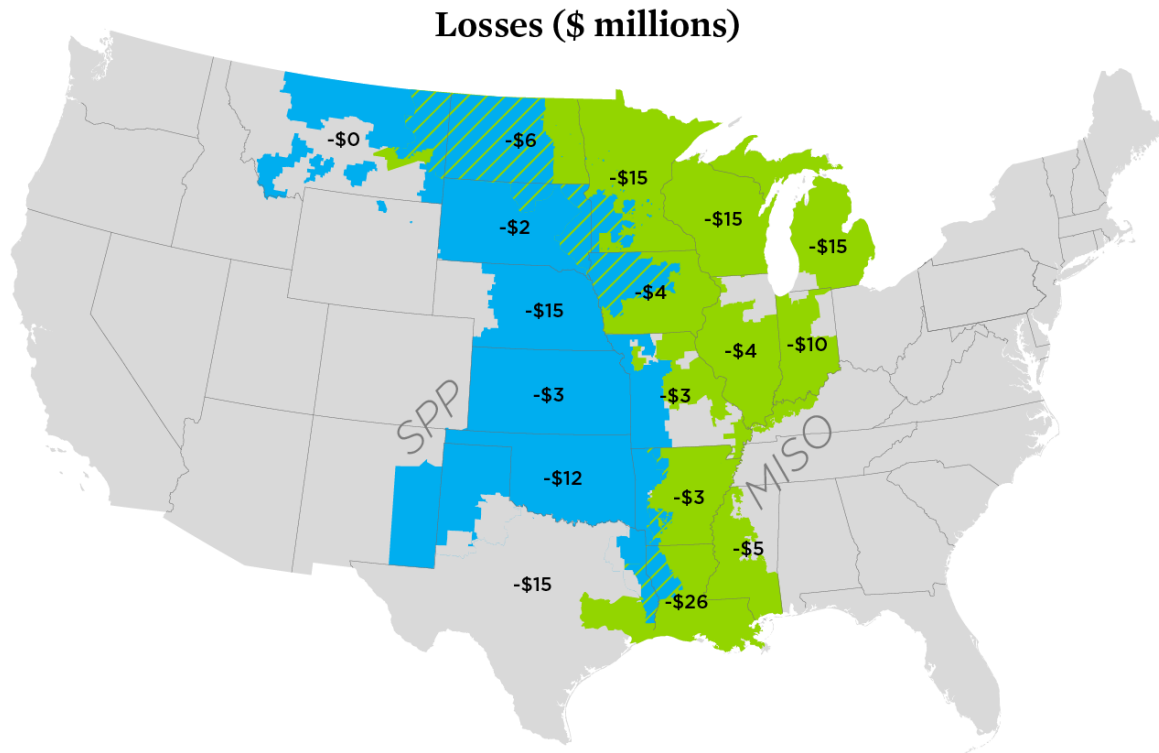
The frequency with which power providers operate gas plants uneconomically was rather consistent across both RTOs, and net operating losses followed a similar trend (see Table 2). The two types of gas plants, steam turbines and gas turbines, most frequently operated uneconomically on a weekly basis and represented a disproportionate amount of the total net operating losses incurred (Table 3).

Table 3. Losses Incurred from Uneconomic Gas Operations in 2019

RTO	Combined Cycle	Gas Turbine	Steam Turbine	Total
MISO	-\$7 million	-\$35 million	-33 million	-\$75 million
SPP	-\$3 million	-\$11 million	-\$28 million	-\$42 million
Total	-\$10 million	-\$46 million	-61 million	-\$117 million

The distribution of losses geographically and by owner of the gas facilities can be found in Figure 4 and Table 4. Net losses from uneconomic gas plant operations are higher among utilities in MISO than in SPP, and among utilities that own a significant amount of gas resource. MISO had roughly 2.2 times more gas capacity on its system than SPP in 2019 and nearly three times as much generation from gas resources, which may partially explain the higher losses incurred in MISO (Sustainable FERC Project 2020a; 2020b). States and regions where utilities incurred the greatest losses from uneconomic gas operations in 2019 were Louisiana, non-ERCOT regions of Texas, northern Midwest states (Minnesota, Wisconsin, and Michigan), Nebraska, Oklahoma, and Indiana.

Figure 4. Losses Incurred from Uneconomic Gas Operations in 2019 (\$ Millions)



The area shaded in green and blue shows the geographic distribution of losses from uneconomic gas operations. The cross-hatching indicates overlapping between RTOs. Note: Losses in Texas reflect losses for gas-fired power plants that operate in MISO and SPP, and not in the Electric Reliability Council of Texas system.

Table 4. Losses Incurred by Gas Facility Owners

Owner	Weekly Operating Losses in 2019	Total Number of Facilities in MISO and SPP	Largest Single Unit Loss
Entergy Corporation	\$24.6 million	30	\$3.5 million
American Electric Power Company	\$12.4 million	26	\$1.8 million
Great River Energy	\$11.3 million	11	\$10.0 million
Xcel Energy	\$9.0 million	34	\$2.6 million
Cleco Partners LP	\$8.8 million	13	\$3.8 million
Basin Electric Power Cooperative	\$7.4 million	12	\$1.2 million
OGE Energy Corp.	\$6.1 million	19	\$1.7 million
Ameren Corporation	\$3.3 million	22	\$1.6 million
Wabash Valley Power Alliance	\$2.9 million	12	\$2.0 million
The AES Corporation	\$2.8 million	9	\$2.0 million
Sunflower Electric Power Corporation	\$2.2 million	7	\$1.4 million
Duke Energy Corporation	\$2.2 million	17	\$0.9 million
MGE Energy	\$2.1 million	5	\$1.1 million
Ames City of	\$2.1 million	2	\$2.0 million
Lincoln Electric System	\$1.8 million	4	\$1.3 million

Table 4 shows the losses incurred by different facility owners across MISO and SPP. A full breakdown of losses by facility can be found in the technical appendix. Note that losses are the total losses in any entire week where a facility did not recover its operating costs. Gains from weeks with a net profit are not included in this value; it is possible that facilities were profitable at the end of the year but operated at a loss for many weeks over the course of that year.

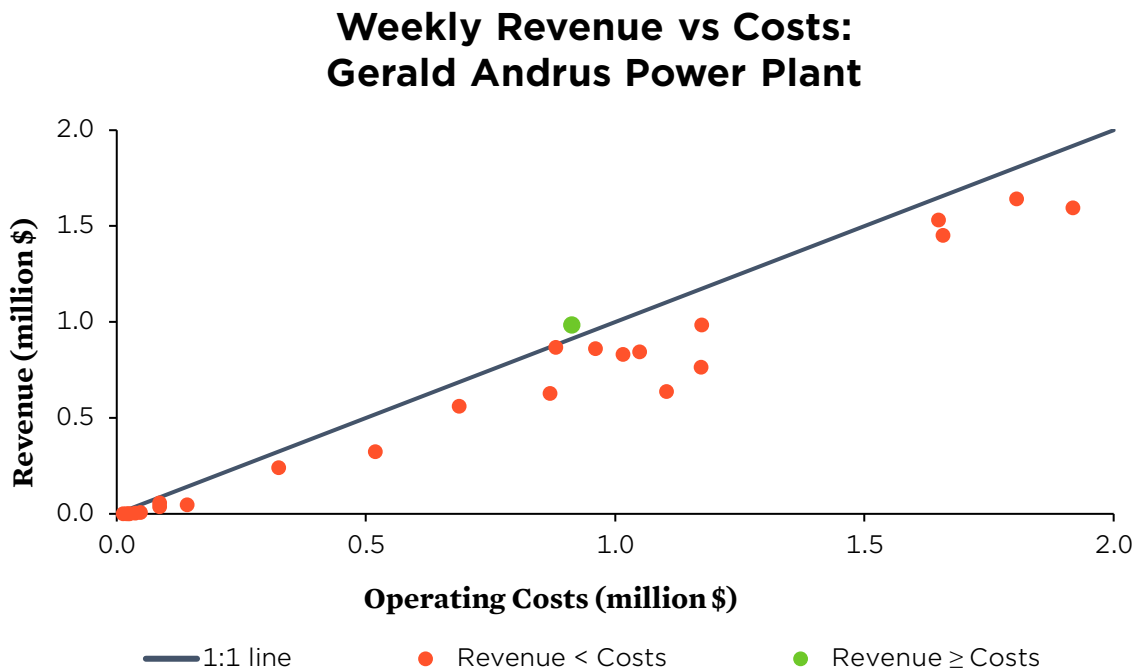
Case Studies

Gerald Andrus Power Plant

Entergy, the utility identified as losing the most ratepayer dollars on uneconomic gas operations, operates Gerald Andrus Power Plant in Greenville, Mississippi, in the southern footprint of MISO. Its operation as part of MISO is a result of a Department of Justice directive to join an RTO after being caught engaging in anti-competitive market behavior (DOJ 2012). The plant has one gas-fired steam turbine unit with a nameplate capacity of 781.4 MW that started operating in January 1975. This plant had an 8 percent capacity factor during 2019, meaning that it ran at 8 percent of its full capacity in 2019 (likely during peak periods of demand), and did not report that it consumed any other fuels than gas in 2019.⁹

Figure 5 compares this plant's revenue and costs at the weekly level. The plant operated uneconomically during 22 of the 23 weeks that it ran in 2019.

Figure 5. Weekly Revenue Versus Costs at Gerald Andrus Power Plant



A comparison of the weekly revenue earned by the Gerald Andrus Power Plant to the costs to operate it shows that in almost every week in 2019 that this plant operated, it ended the week with a net operating loss.

This plant had a low capacity factor and did not generate electricity for 29 weeks of the year. Yet when Entergy did operate this plant, it operated it at times when day-ahead market revenues were insufficient to cover the plant's operating costs. There are several possible reasons for this. For example, the plant takes more than 12 hours to ramp up from cold start to full load.¹⁰ Such a long ramp time means this plant undoubtedly has difficulty responding to fluctuations in market price, given how long it takes for it to adjust its output, and the plant could, as a result, be incurring losses over the 12 hours it takes to fully ramp up. Similarly, once the plant is ramped up, if market prices are no longer favorable, the plant would incur losses at that point.

Given the plant's inflexibility, the plant operators could have chosen to self-commit this plant to the market as well, running it at its minimum operating level for extended periods of time. While this choice reduces ramping, it also causes the plant to run at a minimum operating level for an extended period of time instead of fully turning off if market prices dictated that it do so. If during periods of self-commitment, market revenues dipped below the point that the plant would earn a profit (which is not unlikely over an extended period of time), this plant would incur losses. All of these operational concerns could be at play, and grid concerns—like a lack of available transmission for this utility (and its customers) to access cheaper alternative resources in other parts of MISO's footprint—could be compounding the issue.

In the 23 weeks when the Gerald Andrus Plant was running, Entergy incurred \$3.3 million in unrecovered operating costs that were passed on to ratepayers, all while contributing to disproportionate pollution and energy burdens in Greenville, a predominantly Black community. This plant is not scheduled to retire until June 2035.¹¹

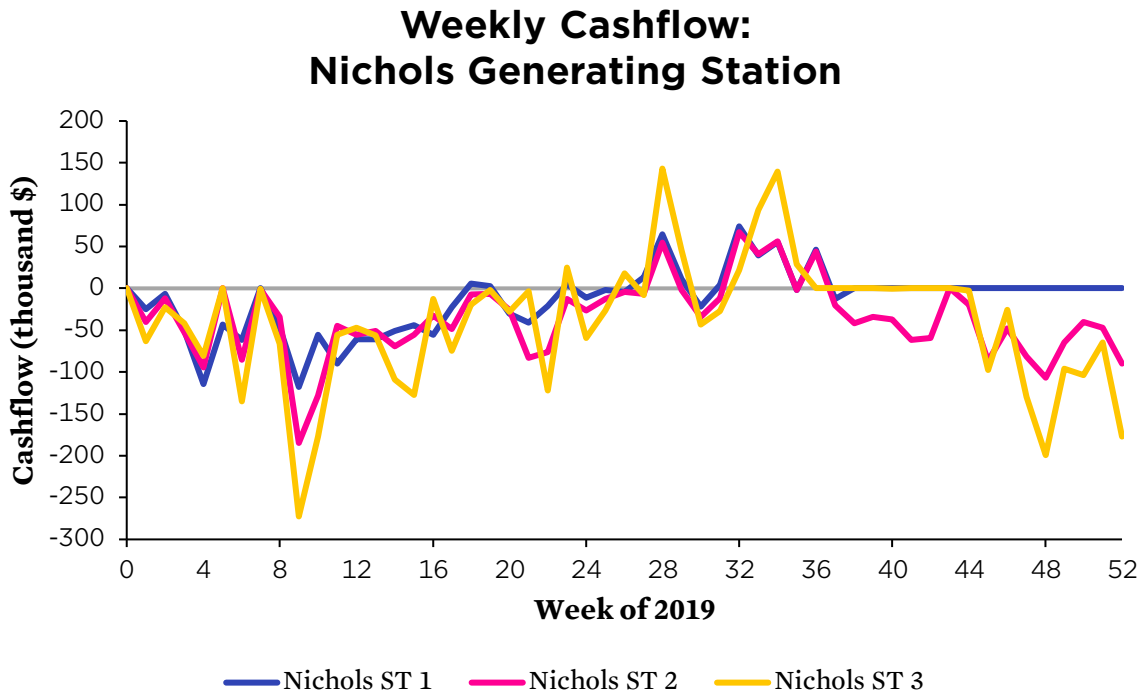
Nichols Generating Station

Nichols Generating Station is a 474 MW gas-fired power plant located in Amarillo, Texas, owned by Southwestern Public Service Company, a subsidiary of Xcel Energy. This power plant has three steam-turbine units, all of which began operating in the 1960s, and is used in part to treat sewage effluent, which is then used at the plant for cooling (Xcel Energy 2022). In 2019 it had a plant-level capacity factor of 29 percent, which makes it a more intermittently running resource, and it runs exclusively on gas.

Our analysis found that Southwestern Public Service Company frequently runs this plant uneconomically, seemingly through the practice of self-commitment. Part of its uneconomic operation may be attributed to the inflexibility of this gas plant, as the time from cold start-up to full load for each steam turbine unit is more than 12 hours.¹²

Figure 6 plots weekly revenue compared to costs, and Figure 7 plots the three units' cash flow over the course of the year.

Figure 7. Weekly Cash Flow at Each Unit at Nichols Generating Station



For most of the weeks of 2019 in which this gas plant was operating, it was incurring losses from operating uneconomically, as seen from the lines representing the three units falling below zero.

A few trends stand out in these charts. First, the weekly cash flow of the plant is not negative throughout the entire year; it does turn positive during the summer months, when market prices are typically higher and there are more opportunities to profit.

In addition, the hourly operations of the units provide preliminary evidence that this plant engages in uneconomic self-commitment. The way the plant operator ran one of the units in mid-March, for example (March 14 through March 31, 2019), reveals a few key insights (Figure 8 and Figure 9). First, the Nichols ST 3 unit operated for extended periods of time when its fuel and operation and maintenance costs per megawatt-hour generated exceeded market prices (day ahead or real time). This almost exclusively occurs when the plant operator designates the unit as a self-committed resource.

When looking at the generation profile during this two-week period, we see that when operating, the unit is frequently operating near its minimum operating level, which is typically a signature of self-commitment (although MISO could be dispatching the unit to the market based on an improperly set bid or so that the unit has enough time to ramp up for high-demand periods). If its owner is self-committing the unit into the market, the unit may potentially be dispatched above its minimum operating level by grid operators, since we do see the output of this unit fluctuate as market prices fluctuate. However, if that is the case, the bid submitted—on which grid operators based their decision to market-commit this resource—does not seem to cover the fuel and variable costs incurred from operating.

These periods in which fuel and variable operating costs are higher than market revenues create costs that fall to ratepayers. It is likely that, had this power plant been market-committed with a bid that fully covered both fuel and operating expenses, rather than been self-committed at its chosen minimum operating level with a market bid that was potentially too low, this power plant would have sat idle rather than operate at a loss during this two-week period—and for many other periods in 2019. Unit ST 3 is scheduled to retire in December 2030, and ST 1 and ST 2 in December 2022 and December 2023, respectively.

Figure 8. Generation Profile at Nichols ST 3, March 14 Through March 31, 2019

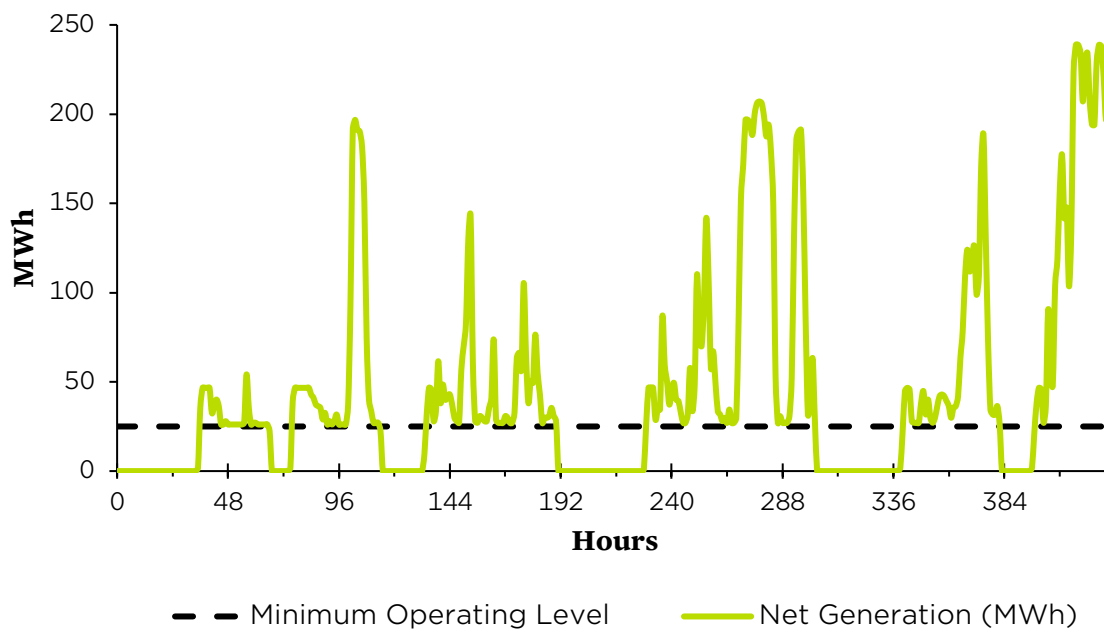
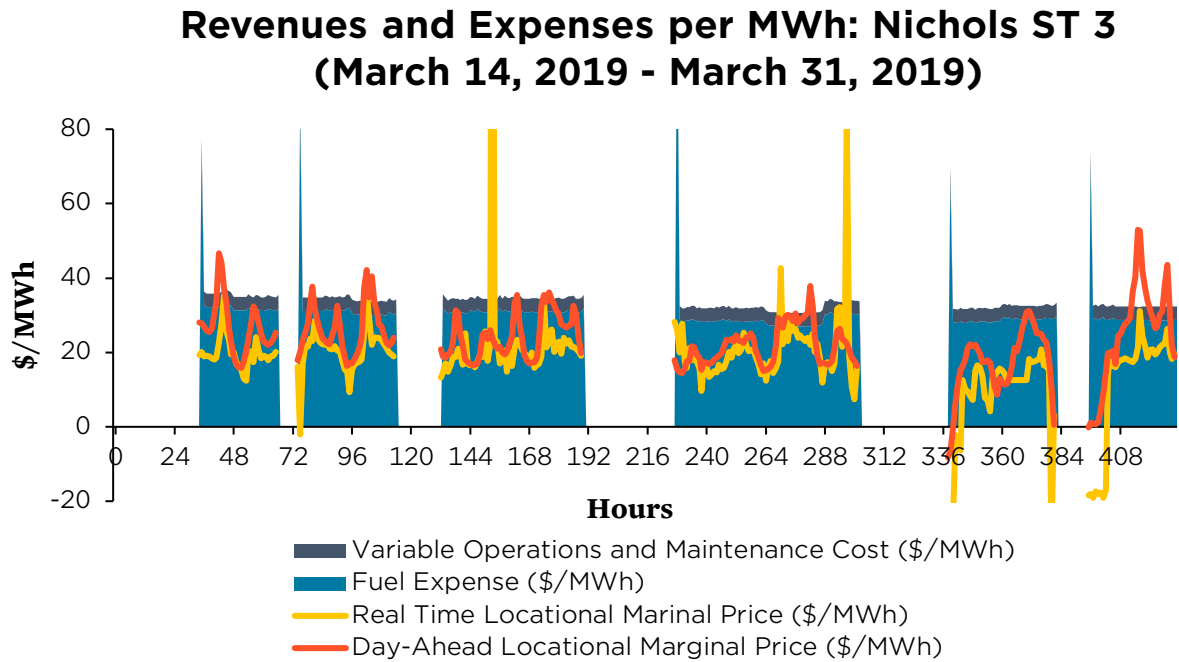


Figure 8 illustrates the generation from March 14 through March 31, 2019, showing what looks like some evidence of self-commitment. During this two-week period, while this unit’s output does continue to ramp (presumably to meet demand), it operates for long hours of the day at its minimum operating level. Given that this unit was flagged to be operating at a loss for this period, if self-commitment was keeping this unit online, it could have played a role in the incurred losses that were passed through to ratepayers.

Figure 9. Revenue and Expenses at Nichols ST 3, March 14 Through March 31, 2019



The fuel and variable expenses this plant incurred while operating during this test period are shown as blue and black shaded areas, and the day-ahead and real-time locational marginal prices incurred as market revenue are shown as yellow and orange lines. When the day-ahead or real-time locational marginal prices exceed the incurred expenses, the unit is making a profit; otherwise, this unit is operating at a loss. Although the unit's output ramps up at various points throughout this period (see Figure 8), potentially indicating moments when the unit could be responding to high price signals and potentially profitable as a result, when the revenue and costs are broken down on a per-megawatt-hour basis, it can be seen that the ramping does not seem to change how frequently costs exceed earned market revenues. The use of more granular fuel cost rates and variable operating cost rates could change the hourly cash flow pictured and could change which periods appear uneconomic.

Note: Spikes in fuel expenses in the beginning of operating hours are an artifact of ramping of the plant. High fuel usage and low generation creates these artificially high spikes in fuel costs per megawatt-hour.

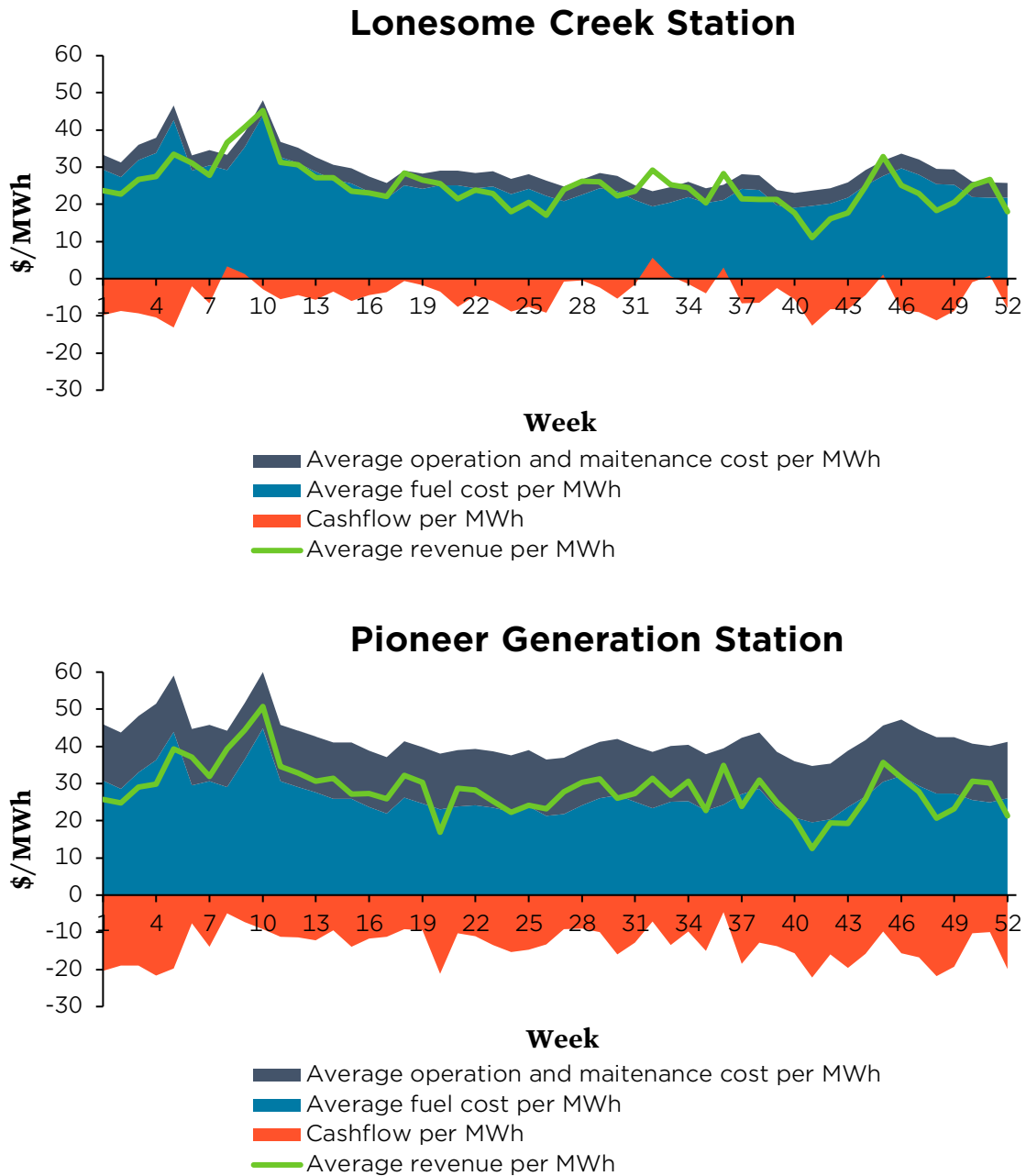
Basin Electric Power Cooperative's Lonesome Creek and Pioneer Generation Stations

Basin Electric Power Cooperative is a wholesale electricity generation and transmission cooperative in the SPP footprint that distributes electricity to its 131-member cooperative systems, serving nearly three million customers in nine states across the Great Plains. The cooperative owns two gas turbine power plants that were flagged in our analysis as operating while incurring losses.

The first plant, Lonesome Creek Station, is a peaking station (used during times when demand is highest) located in Watford City, North Dakota, and in 2019 had five 45 MW combustion turbine units operating on site (BEPC n.d.a). Based on its hourly generation profile and capacity of the units, the plant ran at a 44 percent capacity factor in 2019. The second plant, Pioneer Generation Station in Williston, North Dakota, also has three 45 MW combustion turbine units on site, running at a 23 percent capacity factor in 2019 (BEPC n.d.b). Both of these plants receive fuel from Dakota Gasification Company, a subsidiary of the power plant owner Basin Electric Power Cooperative, via the Northern Border pipeline.

Figure 10 shows the fuel and operating costs associated with each power plant in 2019, the average day-ahead revenues during times that these plants were operating, and their weekly cash flow. At the Lonesome Creek Station, the revenues earned from the market seemed to just barely, if that, cover the fuel costs incurred by operating. The bids submitted to the market seemed to be correlated to fuel costs alone, rather than both fuel and operations and maintenance costs together. The same was true at Pioneer Generation Station. Over the course of 2019, the Lonesome Creek and Pioneer Generation Stations incurred \$3.2 and \$2.9 million in losses, respectively.

Figure 10. Weekly Average Revenue, Costs, and Cash Flow of Lonesome Creek Station and Pioneer Generation Station During 2019



These charts show the weekly average costs incurred (blue and grey) and revenues earned (green) at each of these combustion turbine power plants owned by Basin Electric Power Cooperative, along with the weekly cash flow of these plants (orange). For almost all weeks of 2019, these power plants appeared to be operating at a loss. The losses incurred were paid for by the co-op's ratepayers.

Conclusions and Recommendations

Conclusions

This analysis provides a snapshot of the economics of gas-fired plants, comparing their operating expenses with their revenue for all hours of the year in 2019 and finding that many of these gas plants in large swaths of the United States operate at a loss for weeks on end. As a result, ratepayers in MISO and SPP are incurring millions of dollars of unnecessary costs.

Because of the lack of publicly available data on the rationale behind why gas plants were running when they were, we were unable to conclusively determine whether a utility improperly set bids for dispatching its units by exploiting market rules around self-scheduling/committing to achieve this outcome, or whether there is a plausible reason why they were operating out-of-merit.¹³ However, when other less costly resources could have met demand instead, the effect on consumers is the same: higher electricity bills.

If utilities get reimbursed for their fuel and operating costs from ratepayers (as most owners of generation capacity in MISO and SPP do), then they are insulated from market prices and can run power plants in a way that is economically inefficient: rather than negatively impacting the utility's bottom line, they create excessive costs that customers pay. Running gas plants economically would benefit consumers while having a neutral impact on the utility.

Furthermore, if gas plant operators continue to be inflexible and at times unresponsive to cost and market price signals, the consumer impacts from this uneconomic operation of gas plants will only increase when gas prices are high. Inflexible fossil resources are one of the many barriers to further renewable adoption on the grid (Camp, Tagasucki, and Knight 2021). Efforts to increase investments in renewables, storage, energy efficiency, demand response, and transmission while also addressing the practices that allow inflexible resources to operate uneconomically can benefit ratepayers, by preventing them from paying for uneconomic operations by their power providers. This suite of investments would increase the grid's flexibility, allow for cheaper sourced energy to be utilized instead of more expensive resources, and reduce demand during peak hours of the day, reducing or even abolishing the need for more expensive and uneconomic resources (including gas resources).

We did not seek to determine what resources could have replaced the output from gas plants at times they were operating uneconomically (or if any other resources were available to meet demand, especially during high-demand periods). Based on the resources that were on the grid in 2019, it is possible that cheaper resources that would have replaced gas plants operating uneconomically might have included other gas plants. While it benefits customers financially to use lowest-cost resources to meet demand in wholesale markets, replacing gas output with other gas output does nothing to achieve the carbon reduction goals needed to address the climate crisis, nor does it do anything to reduce pollution resulting from gas plants that disproportionately impact low-income communities and communities of color.

However, if wind and solar were being curtailed during the hours and weeks when gas plants were operating uneconomically, these resources could have been utilized (accounting for transmission constraints) instead, saving customers money as well as helping to reduce the

emission of heat-trapping gases and other pollutants. Such a correlation between coal generation and wind curtailment was studied in SPP during 2020, during which time coal resources were operating while wind was being curtailed on the system (Daniel and Gomberg 2021). Policies that encourage and mandate clean energy adoption can help resolve both issues, by adding clean resources that can reduce all fossil generation and benefit ratepayer bills, and by reducing pollution that impacts air quality and public health.

Recommendations

Regulators need to track and monitor uneconomic generation, and not allow imprudently incurred costs to be passed through to ratepayers.

Behavioral, market, and policy changes can reduce the amount of time that gas plants operate uneconomically. During rate cases, fuel cost adjustment cases, and integrated resource planning proceedings, for example, regulators need to ensure that utilities are spending ratepayers' dollars as efficiently as possible. Regulators can do this by reviewing assumptions that go into how utilities craft their bids to the market operator (such as how variable and fixed operations and maintenance costs are classified), how fuel contract terms are determined, how power purchase agreements are made, and how fuel and power price forecasting is completed, among others. In addition, regulators can validate whether a utility's operating decisions were prudent by conducting their own hourly cash flow calculations, using utility data that are not available to the public. And when gas plant operation is flagged as unjustified based on hourly market prices, utilities need to transparently demonstrate, with data analysis, why that plant was running and why ratepayers should pay.

Grid operators and federal regulators can start tracking self-commitment and make those data available to the public.

For grid operators, a simple way to reduce uneconomic generation of gas plants is to track when gas facilities are self-committing to the market along with their average realized market revenue and make those data available to the public. SPP does track how frequently units are self-committing and makes those data available to the public; however, the data are aggregated across the SPP footprint and are not region- or generator-specific. More can be done by MISO, SPP, and the Federal Energy Regulatory Commission to report on self-commitment practices at the unit-level to regulators. The frequency with which fossil plants are self-committing to the market needs to be recorded and policies need to be developed to reduce uneconomic generation, in order to improve the flexibility and efficiency of wholesale markets. In addition, that data collection should be bolstered with additional operational data, such as the type and amount of revenue that plants are receiving from different market sources when they operate (energy markets, ancillary service market, and uplift payments), to help keep power providers accountable and ensure the market is working as efficiently as possible.

Grid operators can reduce barriers that clean energy resources face when interconnecting to the grid.

Another way for grid operators to reduce uneconomic gas generation is to eliminate barriers for cheaper resources to connect to the grid. Addressing restrictive interconnection rules, reducing backlogs of interconnection requests, and bolstering transmission in areas of

congestion would allow markets to operate more efficiently, reduce system costs, and add more capacity to the grid that can be used especially during peak periods.

State regulators need to consider how to retire uneconomic gas plants and replace them with clean energy portfolios.

During long-term utility resource planning processes, regulators need to scrutinize which gas plants need to retire, especially steam and gas turbines, based on the scale and frequency with which they operate uneconomically. Compelling, comprehensive research shows how these types of plants, specifically ones with lower capacity factors that typically operate only during peak periods, can be replaced with clean energy alternatives that can also come at a cost savings to ratepayers (PSE Healthy Energy 2020; Strategen Consulting 2021).

Similarly, regulators should consider whether new spending on gas infrastructure and gas operations is a prudent investment of ratepayer money. Our analysis suggests that utilities were operating certain gas plants uneconomically and spending ratepayer money imprudently in a year with low gas prices. While gas price projections are difficult to make, the Energy Information Administration's Annual Energy Outlook does not show Henry Hub gas prices declining to 2019 levels under any of its modeled scenarios (EIA 2020a, EIA 2022). In light of uneconomic generation by gas plants identified in this analysis, together with the reality that fuel costs will likely rise much higher than 2019's low prices, clean energy portfolios stand as an excellent cost-competitive alternative to new spending on gas infrastructure and gas operations in the power sector. Clean energy portfolios—portfolios of solar, wind, storage, energy efficiency, and demand response—have been found to be more economic than more than 80 percent of proposed gas facilities that would enter service by 2030 (Shwisberg et al. 2021). Regulators should be evaluating these resources to replace the need for proposed gas plants, either by challenging assumptions proposed by utilities or by requiring competitive solicitations to identify new resources to meet the needs of the power provider.

Policymakers need to reject the notion that extensive reliance on gas-fired electricity generation is needed for a clean energy future.

Policymakers need to consider the impact of including gas-fired power in clean energy plans and the impact that this inclusion could have on ratepayers, from both air quality and financial perspectives. While at the burner tip, gas plants emit less pollution than coal, their upstream methane emissions and localized air pollution do a great deal of damage. It has been shown that new gas plants are not needed to reach high levels of clean energy adoption on the grid, and that we can reliably achieve high renewable adoption across the country while at the same time reducing our dependence on and consumption of gas in the power sector (Phadke et al. 2020; Baek et al. 2021; García et al. 2022). Additional investments in storage, energy efficiency, demand response, and transmission can increase grid flexibility, reduce peak demand, and allow cheaper and cleaner energy resources to meet the needs of the grid, which would reduce the need for uneconomic gas resources.

This analysis shows that gas plants across MISO and SPP have already started to show signs of being uncompetitive with lower-cost resources, and continuing our reliance on gas in the power sector could worsen this reality. It is very likely that operating gas plants in the future will be more expensive than operating them now, given the presence of stronger environmental regulations reflecting an increased understanding of the public health impacts

of air pollution, together with operating and maintenance costs that increase with the age of the plant. Furthermore, projected increases in gas prices will increase the variable operating expenses incurred at gas plants; this, coupled with current trends in renewable additions, will put increased market pressure on the economics of gas plants. Clean energy policies should focus on encouraging investment in technologies that will be beneficial, economic, and useful for years to come, instead of propping up gas plants or delaying the transition away from them.

The Writing Is on the Wall

Gas-fired power plants appear to be following the same path as the previously dominant fossil fuel, coal. Over the past decade, coal-fired power plants went from being a year-round, high-capacity-factor resource to being uneconomic to run for most of the year (Daniel 2020). Even the owners of coal-fired power plants now agree that it is no longer an economic resource year-round (FTC 2020). Coal rapidly became uneconomic as a result of the combined pressures of long overdue enforcement of pollution and public health regulations, an aging and inefficient fleet of power plants, and low market prices from historically low gas prices and increasingly cheaper alternatives for power production. Now, 98 percent of coal-fired power plants are propped up by mechanisms such as the continued availability of the option to self-commit into the market (Porter et al. 2020; Gimon, Myers, and O'Boyle 2021). History now appears to be repeating itself with a significant subset of gas-fired power plants that also operate uneconomically for many weeks out of the year.

Zero-marginal-cost renewable energy will continue to put downward pressure on wholesale power prices. Simultaneously, a multitude of environmental and climate concerns and age-related operating expenses will put upward pressure on the cost to operate gas-fired plants, repeating the same cycle the industry saw for coal. Will regulators, investors, and utility companies read the writing on the wall, or will they let history repeat itself?

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- ¹ *Another term for fuel and variable operating expenses is short-run marginal cost of dispatch. This excludes long-term fixed costs, which are not meant to be recouped from hourly energy market revenues.*
 - ² *Profits earned by independent power providers go to shareholders. Profits from vertically integrated monopolies go either back to ratepayers or to shareholders depending on local regulations.*
 - ³ *There are also market protocols that allow the market operator to call on resources out-of-merit. This is usually reserved for resources with long lead times for start-up whose market cost offers would otherwise not clear in the market but which are needed down the road for reliability reasons. In this paper we are excluding resources with long lead times and reserve the term “out-of-merit” for resources whose owners self-select to operate out-of-merit.*
 - ⁴ *This terminology is derived from the Midcontinent Independent System Operator’s market manual. Other ISO/RTOs have similar protocols, though sometimes use different terms to describe the practice.*
 - ⁵ *This includes all vertically integrated utilities and municipal utilities. In S&P Global Marketplace’s power sector database, cooperative utilities are not classified as “regulated” because they are not regulated by a public utility commission or municipal utility; however, their customers are still considered captive customers.*
 - ⁶ *Hourly gross generation for each gas facility was obtained from the Environmental Protection Agency’s Clean Air Markets Division (OAP 2022), and a scaling factor was applied to convert hourly gross generation to hourly net generation.*
 - ⁷ *Capacity market revenues are determined from seasonal or annual auctions used to ensure there are sufficient resources on the grid to meet peak demand. Ancillary service revenues are earned for stabilizing the grid on short time scales. SPP does not operate a capacity market, and MISO’s capacity market is voluntary and in 2019 represented a minimal portion of the market’s all-in electricity price (Potomac Economics 2021). Ancillary service market revenues could come into play when making decisions about how to operate an individual gas plant day to day; however, overall, this type of revenue is typically very small compared to energy market revenues in all power markets except the Electric Reliability Council of Texas’ market, and the units that such revenues or contracts impact are unknown (Potomac Economics 2021). In 2022, the capacity market price in MISO’s northern footprint spiked to \$236/MW-day, compared to \$2.88/MW-day in MISO’s southern footprint (MISO 2022).*
 - ⁸ *The average number of weeks gas facilities were operating uneconomically is unweighted and is determined by adding the number of weeks gas facilities in each RTO incurred negative weekly cash flow, divided by the number of gas facilities in each RTO.*
 - ⁹ *See EIA Form 860, which collects generator-level information about existing and planned generators in the United States.*
 - ¹⁰ *See EIA Form 860.*

¹¹ See EIA Form 860.

¹² See EIA Form 860.

¹³ Self-commitment by hour is only tracked publicly in SPP and is not attributed to specific generators.