The Shaky Economics of Gas-fired Power

How Uneconomic Gas-fired Power is Costing Consumers

Appendix: Methodology

Ashtin Massie

Joe Daniel

June 2022

www.ucsusa.org/resources/economics-gas-fired-power

CONTENTS

Methodology 3

Data Sources for Cashflow Calculation 3

- Generation and Heat Input 3
- Hourly Market Prices 5
- Gas Prices and Fuel Costs 6
- Non-fuel Variable Operations and Maintenance Costs 6
- Gas Facilities Analyzed 7

Methodology

We calculated the hourly cash flow of gas-fired power plants in the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) during 2019 by comparing day-ahead market revenues to fuel and variable operating expenses.

The formula used to calculate hourly cash flow was:

$$\begin{aligned} Hourly\ Cashflow \\ &= \left[Day\ Ahead\ LMP_{hourly}\left(\frac{\$}{MWh}\right) * Net\ Generation_{hourly}(MWh)\right] \\ &- \left[Spot\ Price\ of\ Fuel_{daily}\left(\frac{\$}{MMBtu}\right) * Heat\ Input_{hourly}\ (MMBtu)\right] \\ &- \left[Variable\ O\&M\ Costs_{annual}\left(\frac{\$}{MWh}\right) * Net\ Generation_{hourly}(MWh)\right] \end{aligned}$$

Data Sources for Cashflow Calculation

GENERATION AND HEAT INPUT

We used the Environmental Protection Agency's (EPA's) Clean Air Markets Division power sector emissions data for the hourly gross generation and heat input at the unit level (OAP 2022). These data were matched to the corresponding gas units in S&P Global's power plant database and retrieved for this analysis by analysts at S&P Global (S&P Global 2022). The raw EPA dataset includes the hourly gross generation, heat input, and emissions at the smokestack level at power plants across the United States and in 2018 the dataset included hourly emissions for almost all power plants in the United States (96 percent). We scaled the gross generation down to convert it to net generation (described below). We did not modify the heat input reported in this dataset.

CONVERTING GROSS GENERATION TO NET GENERATION

The EPA's hourly generation dataset provides the hourly gross generation of the gas-fired facilities analyzed; however, gas-fired facilities get paid based on how much electricity they put onto the grid, which is net generation. To determine market revenues when gas units are operating, we needed to calculate the net generation of these units at the hourly level. To estimate the hourly net generation, we used a ratio of net generation (reported in S&P Global's database) to gross generation as a scalar, which we used to reduce the hourly gross generation in the EPA's dataset.

Steam Turbines and Combined-Cycle Plants. For steam turbine and combined-cycle combustion turbine units, we did a month-by-month analysis of the gross and net generation of each. First, we looked to see whether the monthly reported gross generation at the unit level in the EPA dataset was less than the monthly net generation reported to Energy Information Administration. If it was, we scaled the monthly net generation down to equal the reported gross generation from the EPA, since having reported net generation exceed gross generation is non-physical. From there, we calculated the monthly ratio of net generation to gross generation in each month of 2019 and applied that ratio to reduce the hourly gross generation into an estimated hourly net generation at those facilities. We updated the ratio monthly, both because this is the highest resolution of net generation data publicly available (through EIA Form 923) and because by doing this conversion at the monthly level we can try to account for changes in plant efficiency on a finer temporal scale due to seasonal weather patterns, which can impact the efficiency and available generating capacity of power plants. In the months of the year in which hourly gross generation was missing from our dataset despite reported net generation for these units, we did not attempt to estimate the hourly generation profile.

According to the EPA dataset's user guide, combined-cycle power plants, which recover waste heat from a traditional gas turbine and use it to power a steam turbine, are "not required to report electrical generation from the steam turbine (although many combined-cycle electricity generating units do include the generation from the steam turbine in their electrical generation data)" (EPA n.d.). This indicates that hourly gross generation reported by electric generating unit at combined-cycle power plants (specifically at the combined-cycle combustion turbine units) may include (but is not required to include) gross generation from accompanying steam turbines at the combined-cycle plant on top of the gross generation required to be reported at the gas turbines themselves. Thus, when looking at unit-level gross generation at combined-cycle plants, the hourly gross generation reported for the gas turbine units may over-report that gas turbine's hourly generation if it includes steam generation as well. Over-reported gross generation at the gas turbines of combined-cycle plants reduces the scalar we used to convert the hourly gross generation at those units to net generation. However, because we are scaling the hourly gross generation profile to sum to the monthly-reported unit-level net generation at these units, we do not believe this affected our results.

For the steam units at combined-cycle plants, the hourly gross generation is not uniquely reported in the EPA's dataset at the unit level. To derive an hourly generation profile during 2019 for steam units at combined-cycle plants, we scaled the monthly net generation reported to EIA Form 923 of the combined-cycle steam unit to be proportional to the hourly heat input at the whole plant reported in the EPA's dataset, assuming that the steam unit's generation was proportional to its heat input. Because the generation of steam units was in terms of net generation, no additional scaling was required.

The assumptions about hourly steam generation imply that a combined-cycle power plant's gas turbine and heat-recovery steam turbine are operating in tandem. This is not always true; the heat recovery steam turbines can be bypassed so that the plant runs exclusively with its gas turbine, or the steam turbine can be driven primarily through duct burners used to enhance steam recovery and output. Without knowing how a plant is dispatching and operating its units, we assumed the steam and gas turbines at a combined-cycle plant work in tandem. Therefore, we aggregated our cash flow results to the plant level for combined-cycle plants.

In doing this scaling for both steam turbines and combined-cycle plants, we were ensuring that the sum of the scaled hourly gross generation profile equaled the total monthly net generation reported in S&P Global's database for months of the year in which net generation was greater than zero.

Gas Turbines. Monthly net generation at the unit level is reported in EIA Form 923 for combined-cycle and steam-electric gas facilities, but not for other gas turbine facilities. For the gas turbine units that are not required to report their monthly net generation in EIA Form 923, we used the annual ratio of gross generation to net generation as the scalar to convert hourly gross to hourly net generation. For this type of unit, we limited that scalar such that the hourly generation of these gas turbines was not reduced by more than 10 percent of its hourly gross generation value, as we did not believe that losses from on-site consumption and parasitic load would typically exceed 10 percent of gross generation (Gellings 2013). This limit was only in place for gas turbines and was put in place because generation was reported less frequently (annually), making this scalar less resolute than it is for other technologies.

HANDLING OF DISCREPANCIES BETWEEN REPORTED NET AND GROSS GENERATION BETWEEN DATASETS

We used this protocol of scaling for all facilities and did not attempt to correct for when there were large discrepancies between reported net and gross generation between datasets. We flagged a total of 31 facilities in MISO and SPP as having large generation discrepancies between reported net and gross generation, accounting for 15 percent of the total losses we calculated. In the accompanying spreadsheet, we indicate which facilities showed discrepancies in generation between datasets. We assumed that these discrepancies are a result of above-average rates of on-site consumption or parasitic load (which creates negative generation values) that are incorporated in reported net generation values but are omitted from the gross generation dataset.

HOURLY MARKET PRICES

To determine the hourly day-ahead market price and subsequent energy-based revenue, we found the nearest independent system operator market pricing nodes within 10 miles of each gas plant we analyzed. We selected the nearest market node that also had reported market pricing data for every hour of 2019. We did not analyze power plants that did not match with a market node within a 10-mile radius.

We did an additional check to make sure that the assigned day-ahead market price did not misrepresent the area's market price by misrepresenting the locational marginal price of electricity in the area. The idea here is, while we cannot determine what the day-ahead market price was exactly for the power plants in question, we can estimate it by using distance mapping. However, if by chance the node that was matched to represent day-ahead market prices for the power plant via distance mapping was not accurate with the plant, and it coincidentally had a price spike not seen in other market nodes, we would be misrepresenting the market revenue received by the plant.

To address this, we looked at the day-ahead hourly market price of the market node matched to the plant based on the proximity analysis outlined above. We then compared the hourly day-ahead prices of that node to the hourly prices of all of the nodes within a 10-mile radius of the plant, looking to see whether any of the hourly prices of the matched node were indicated as outliers. If the distance from the node to the plant was less than three miles, we left the price as-is, since the closer the node is to the power plant, the more representative of a locational marginal price we believe the node has. If the distance from the node to the plant was more than three miles away, we adjusted the hourly day-ahead locational marginal price to be an inversely weighted average, based on distance, of the hourly price recorded among nodes within the 10-mile radius of the plant, only for the hours flagged as having price outliers. The inversely weighted average hourly price was based on the distance of the nodes to the plant, with nodes closer to the plant having a higher influence on the average locational marginal price than those farther away. If this process created a price change larger than 10 percent of the original day-ahead hourly price, we reverted the adjusted hourly price back to the originally matched value. Scaling as we did, compared to not scaling the day-ahead prices at all, decreased the annual cash flow for just 42 of the gas facilities analyzed (representing 20 power plants) across both regional transmission organizations; in all other instances in which this scaling was applied, it helped the bottom line (increased the annual cash flow) of the gas facilities.

Additional revenue sources from capacity and ancillary service markets were excluded from this analysis, as were uplift payments.

GAS PRICES AND FUEL COSTS

The gas price location for each gas facility was derived from S&P Global's database; this is the gas price hub that S&P uses for its internal fuel cost calculations for each power plant. Historical daily gas spot prices for each price location were derived from S&P Global. The hourly fuel costs are a product of the gas facility's gross hourly heat input (from the EPA's dataset) and the corresponding daily gas spot price of its corresponding fuel location. We were unable to incorporate any additional related fuel expenses or savings, such as price discrepancies between spot and contract prices, fuel hedges, costs arising from take-or-pay provisions or costs of firm gas supply in fuel contracts, or any specific fuel-related costs explicitly excluded from the spot fuel price itself.

We realize that our calculations are sensitive to fuel price and having access to the terms of fuel contracts would only improve fuel cost calculations. Similarly, we did not account for power plants that are able to switch fuels; however, based on CO2 emissions rates, more than 99 percent of our dataset had a CO2 emissions rate of within 5 percent of the expected value for burning gas. Therefore, we calculated the cash flow assuming that this is what the financial picture of the plant looked like in 2019 if the plant operated every hour of the year on gas.

NON-FUEL VARIABLE OPERATIONS AND MAINTENANCE COSTS

An annual value (in dollars per net megawatt-hour generated) was derived from S&P Global's power plant database to represent the non-fuel-related variable operations and maintenance expense (in dollars per megawatt-hour generated) for each unit. The non-fuel variable operations and maintenance costs (in dollars) are either reported through the Federal Energy Regulatory Commission's Form 1 or modeled by S&P Global using regression analysis. When the costs were reported costs, they were then divided by the plant-level net generation reported in S&P Global's database in 2019 to get the rate of non-fuel variable O&M costs per megawatt-hour. We assumed that the costs that S&P Global incorporates into its variable operating cost value are the same costs a power provider would consider when crafting its bid into the day-ahead energy market, although this might not be consistent across power providers.

GAS FACILITIES ANALYZED

The gas facilities analyzed were those operating in MISO and SPP in 2019. The term gas facility was used here because of different ways we aggregated our results based on technology. For gas facilities whose prime mover is either steam or gas turbine, the cash flow analysis was conducted at the unit level. For gas facilities whose prime mover is a combined-cycle unit, the cash flow analysis was also conducted at the unit level, but aggregated to the plant level. This difference in aggregation was due to how combined-cycle power plants use steam recovery for excess generation, which provides additional unit-level revenue for its combined-cycle steam units while attributing a majority of the fuel costs to the combined-cycle combustion turbine units.[1]

The attributes of the gas facilities we analyzed were derived from S&P Global's power plant database. The facilities we analyzed are gas-fired units that were operating in 2019 in MISO and SPP. We filtered those facilities further to avoid fuel cells and gas facilities used for cogeneration and including only gas-fired facilities whose primary fuel type was listed as gas.[2] We also filtered to make sure that the gross generation in 2019 in the EPA's generation dataset was greater than zero, unless the unit's technology type was a combined-cycle steam unit, as those do not explicitly report unit-level generation in the EPA's dataset. We excluded facilities that did not have a market node match for market prices that was within 10 miles of the facility, as well as facilities known to us to not supply the grid under normal circumstances (such as facilities that solely supply black-start capacity).

A total of 522 gas facilities were identified, and 86 facilities (12 percent of the operating capacity) were eliminated because of data limitations or known limitations that led us to exclude these facilities from analysis, leaving 436 facilities across MISO and SPP in this analysis.

AUTHORS

Ashtin Massie is an energy analyst in the UCS Climate and Energy Program. **Joe Daniel** is a Manager in RMI's Carbon-Free Electricity Practice.

---

[1] *Combined-cycle steam units can incur fuel costs if they utilize duct burners for additional steam recovery; however, fuel costs associated with that were not uniquely considered in this analysis, as they are unable to be estimated accurately at less than a monthly temporal resolution. It is possible that those fuel costs are captured in our calculations if the reported heat input in the EPA's dataset includes that from duct burners. However, we were unable to determine whether that was the case.*

[2] *The primary fuel type of a gas facility is defined by S&P Global as the "dominant fuel type listed as primary at the power plant unit from the EIA 860 or through research" (S&P Global 2022).*

REFERENCES

EPA (Environmental Protection Agency). n.d. "CAMD's Power Sector Emissions Data Guide." Washington, DC. https://www.epa.gov/sites/default/files/2020-02/documents/camds_power_sector_emissions_data_user_guide.pdf

Gellings, Clark W. 2013. "Back to Basics: Enhancing Efficiency in the Generation and Delivery of Electricity." In Energy Efficiency, edited by Fereidoon P. Sioshansi, 375–417. Academic Press. https://doi.org/10.1016/B978-0-12-397879-0.00015-3

OAP (Office of Atmospheric Programs). 2022. "Power Sector Emissions Data." Washington, DC: Environmental Protection Agency.

S&P Global (S&P Global Market Intelligence). 2022. "S&P Interactive." New York. Online at www.spglobal.com (paywall restricted)