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STAFF REPORT

Updating Thermal Power Plant Efficiency Measures and Operational Characteristics for Production Cost Modeling

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ABSTRACT

This report describes a method to estimate heat rates and operating ranges for thermal power plants, such as natural gas power plants. The heat rate of a power plant measures the amount of fuel used to generate one unit of electricity. Power plants with lower heat rates are more efficient than plants with higher heat rates. Heat rates are key inputs in production cost models. Production cost models simulate electric systems to estimate electricity production, cost, fuel consumption, reliability, and emissions.

This method uses hourly fuel consumption and electricity generation data, from public sources, for different power plants. The method finds the operating range of each power plant using hourly generation data and plant capacities. Then California Energy Commission staff analyzes the relationship between fuel use and electricity production to create trend lines of the heat rate. Finally, the method uses several points on the trend line to estimate the heat rate of the power plant in the associated operating range.

Based on the method results, staff changed the minimum operating level from 25 percent for all power plants to different levels depending on plant type. Staff found that the updated heat rates and operating ranges align well with recent power plant operations compared to the old values.

Staff recommends making periodic updates to power plant heat rates and operating ranges. These updates are important as increased renewable generation and other policy goals will affect the operation and efficiency of thermal power plants. To improve this method in future updates, staff also recommends using subhourly fuel use and generation, along with estimates of station service using public data.

Keywords: Btu, kWh, heat rate, capacity, natural gas, power plant, coal, steam turbine, steam boiler, combined cycle, regression, input output curve, load, generation, station service, Western Interconnection

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EXECUTIVE SUMMARY

California and other western states have a mix of renewable and fossil fuel power plants that generate electricity to meet customer demand. Plants that combust fossil fuels are considered “thermal” plants. The plant type, fuel, and operations affect how much fuel the plant consumes to generate electricity; the heat rate of a plant measures this. Plants with low heat rates are more efficient, consume less fuel, cost less to operate, and produce fewer emissions than higher heat rate plants.

Heat rates are a primary input for thermal power plants in production cost models. Production cost models use plant characteristics and expected costs to simulate an electricity system. These models estimate electricity production, fuel use, system cost, reliability, and emissions. Model simulations will operate plants with lower heat rates more often and for longer periods, due to the associated lower operating cost.

The California Energy Commission uses production cost model results to estimate system operations and natural gas demand in the power sector. These estimates feed into the Energy Commission’s demand forecast and into policy development, such as building codes and standards. The California Air Resources Board used the Energy Commission’s estimates of fuel consumption and carbon dioxide emissions for its Clean Power Plan analysis.

There is not a well-defined method to update heat rates. Prior to this method, heat rate estimates came from a variety of public and nonpublic sources, the most recent being from 2007. The Energy Commission, along with the Reliability Assessment Committee created this reproducible method using public data to update heat rates used in modeling. The Reliability Assessment Committee is part of the Western Electricity Coordinating Council and works with federal, state, and regional planning organizations to determine and analyze the potential reliability risks the Western Interconnection may face over the next 20 years.

Having a consistent, reproducible method for estimating heat rates will improve transparency of the production cost model and will result in more defensible and realistic results.

Method

This method uses public data from the United States Energy Information Administration, the United States Environmental Protection Agency Continuous Emissions Monitoring System, and the Energy Commission's Quarterly Fuel and Energy Report.

To find the operating range for each plant, staff graphs the historical hourly generation data to compare with the Energy Information Administration's estimates of minimum operating levels and maximum capacity. When the operating ranges for the two data sources are significantly different, staff uses the historical hourly generation to define the range. Staff then removes any data points outside the defined operating range.

Next, staff graphs the hourly fuel use against generation data to determine how they are related. The method adjusts the operating range to account for the onsite energy use of the plant by subtracting the onsite use from the generation output. The method uses trend lines for the data to estimate the average power plant heat rates.

Staff develops generic heat rates for each plant type. These generic heat rates compare well to historical plant-specific heat rates and are adequate for plants with no hourly fuel use and generation data.

Results

Staff implemented this method using data from 2010 through 2014. Staff found that the operating range depends on the plant type. Previously, the minimum operating level for all power plants was set at 25 percent of maximum output, so staff updated the operating range to different values based on plant type.

Table ES-1: Minimum and Maximum Operating Levels, by Plant Type

Plant Type	Average Minimum Operating Level (% of Nameplate Capacity)	Average Maximum Operating Level (% of Nameplate Capacity)
CC	50%	90%
GT	60%	93%
ST-Gas	18%	98%
ST-Coal	55%	98%

Source: Energy Information Administration—Form 860, Environmental Protection Agency Continuous Emissions Monitoring System data, and staff analysis.

Staff ran production cost model simulations to verify that the new heat rates and operating ranges are reasonable. Simulations using the new heat rates reflect recent plant operations better than the prior heat rates. Based on discussions with Reliability Assessment Committee members and model simulation results, staff believes the heat rates developed by this method are more accurate that the existing heat rates.

Next Steps

Staff will update heat rates and operating ranges periodically to incorporate new data and any additional public data on power plants in the western United States. Staff may revise the estimation method to accommodate changing plant operations due to increased renewable generation and other policy goals. Staff will continue to collaborate with industry stakeholders to update power plant heat rates and operating ranges to incorporate new data, including station service, changing plant operations, and additional hourly generation and fuel use for existing and new power plants.

CHAPTER 1: Heat Rate Use in Electrical System Modeling

Introduction

This paper explains California Energy Commission staff's method of using public data to estimate thermal power plant heat rates in the Western Interconnection.[1] This method and the resulting thermal power plant heat rates and operating ranges are more accurate for production cost modeling.

Energy Commission staff uses a production cost model to analyze natural gas and other fuel use, electricity generation, and the marginal electricity prices in the interconnected western North American electrical system. Heat rates of thermal electrical generation power plants are important within the model as they are a measure of the fuel efficiency of a plant. In addition, the heat rate of a thermal plant will affect the order in which it may be called to supply power, or dispatched,[2] compared to other plants. Using the best heat rate data available is key to the model providing information that is plausible, defensible, and useful.

Updated Heat Rate Estimates Improve Modeling Results and Transparency

Energy Commission staff performs several production cost modeling analyses, including scenarios for different levels of renewable resources, plant retirements, and various policy assumptions and options. Two major uses of staff's modeling results are the Energy Commission's biennial *Integrated Energy Policy Report (IEPR)* and energy policy formulation. The demand forecast is partially derived using staff's thermal power plant heat rates and production cost modeling analyses.

Other stakeholders benefit from staff's updated heat rate estimation method, such as the California Public Utilities Commission (CPUC), the Reliability Assessment Committee (RAC), and other stakeholders who work with modeling electric systems, thermal power plant operations, and greenhouse gas

1 In most of North America, heat rate units are expressed in British thermal units (Btu) of fuel used to generate 1 kilowatt-hour (kWh) of electricity.

2 Starting, stopping, and increasing or decreasing the electrical output of a plant are called "dispatch".

emissions. The CPUC uses the Energy Commission's energy demand forecast in resource procurement planning proceedings. The Western Electricity Coordinating Council's (WECC) RAC Anchor Dataset (ADS) models the "Western Interconnection," also known as the western electrical system interconnection or the western grid.[3] [4] Production cost modeling requires power plant characteristics including heat rates for thermal power plants, and Energy Commission staff's new method will help inform the RAC ADS in its biennial modeling.

Every two years, RAC creates what it refers to as the ADS that is used to describe the current physical grid and to postulate characteristics of that grid in 10 years.[5] The Energy Commission and the RAC working groups will benefit from consistent assumptions and publicly vetted data on thermal power plant heat rates, as well as plant operating characteristics.

The California Independent System Operator's (California ISO) Transmission Planning Process (TPP) evaluates the California electric grid and identifies potential system limitations, as well as opportunities to improve reliability and efficiency. The TPP analysis is performed over a 10-year planning horizon and uses the Energy Commission's *IEPR* long-term energy demand forecast. Energy Commission staff also uses the production cost model to estimate the quantity of natural gas fuel consumed by thermal power plants. The estimates serve as inputs to staff's North American Market Gas-Trade (NAMGas) model, which is used to estimate natural gas demand and prices that are, in turn, reported in natural gas assessments used to inform other *IEPR* work.

In 2015, staff assisted the California Air Resources Board (CARB) by using production cost modeling results to analyze California's state plan for the Environmental Protection Agency's Clean Power Plan (CPP).[6] The CPP sets emissions reduction goals for California through 2030. Energy Commission staff measures emissions and fuel use for many thermal power plants in California that are covered under the CPP rule. Heat rates used in the production cost

3 Western Electricity Coordinating Council Homepage

4 See US Department of Energy.

5 Reliability Assessment Committee Charter

6 See Complying with President Trump's Executive Order on Energy Independence

model are a major determinant of fuel use and emissions from thermal plants.

Another use of production cost modeling is to estimate the marginal cost of generation from thermal plants that staff use in time-dependent valuation analyses (TDV).[7] These analyses examine factors related to energy efficiency cost-effectiveness, such as electricity use during different hours of the year, fuel use, and electricity price impacts of energy efficiency measures. These TDV factors are used in preparing the Energy Commission's *Building Energy Efficiency Standards*.[8]

The heat rate of a thermal power plant is a measure of operational efficiency and is one important determinant in whether a particular plant will be dispatched. Although the heat rate of a plant can affect the cost to operate, other factors affect the operating cost of a plant. Other types of generators, such wind, solar, and hydroelectric, are dispatched as well, which affects the dispatch of thermal plants.

Before implementing this method, heat rates used in the production cost model were last updated before 2008. They came from different data sources, some publicly available, some not, and some from sources that are of unknown origin.

To update heat rates used in the production cost model, staff devised this method for updating heat rates using current data from public sources. Updating the heat rates in the production cost model makes staff's modeling results more plausible, transparent, and useful. In addition, providing documentation and using public data sources allow staff to share heat rate data with other stakeholders, such as plant operators, to gain insight and feedback.

A well-documented method for updating heat rates in the production cost model will make updating heat rates easier, less time-consuming, and adaptable to changing conditions. Because actual plant heat rates can degrade over time, updating them periodically is important for achieving good modeling results.

7 The marginal cost of generation is the operating cost to produce each unit of electricity.
8 [2019 Building Efficiency Standards]

CHAPTER 2: Data Used to Improve Estimated Heat Rates

Updating Heat Rates in the Production Cost Model

The United States Environmental Protection Agency's (U.S. EPA) Continuous Emissions Monitoring System (CEMS) and the United States Energy Information Agency's (U.S. EIA) Form EIA-860 are the two main data sources used for the new method. Data used for this analysis cover 2010 through 2014

Survey Form EIA-860 collects generator-level specific information concerning existing and planned power plants, including annual power plant capacity values and technology types. Summary level data can be found in U.S EIA's *Electric Power Annual*.[9]

CEMS data include hourly fuel use and electric generation data, as well as emissions data.[10] Although CEMS collects data on many thermal power plants, it does not collect data on biomass power plants. CEMS requires only thermal power plants larger than 25 megawatts (MW) to report the associated generation, fuel use, and emissions data.

CEMS and Form EIA-860 were key to creating the new method, but CEMS data had to be "scrubbed" before use. This "scrubbing" consisted of two main steps. First, only data for an entire hour were used. When a power plant did not operate for an entire hour, CEMS data values generally appeared to be outliers from the rest of the data. Therefore, staff deleted any data that were for less than a full hour of operation. The partial-hour data that staff deleted were determined to be less than 1 percent of the total data.

Second, staff removed any extreme outliers from the data by removing any data points that diverged significantly from the general trend of the data. Outlying data may occur for several reasons:

- Power plant maintenance may have occurred, and the plant was not operating normally.

9 *Electric Power Annual*. Data for 2015, release date November 21, 2016,.

10 Air market programs data and CEMS data.

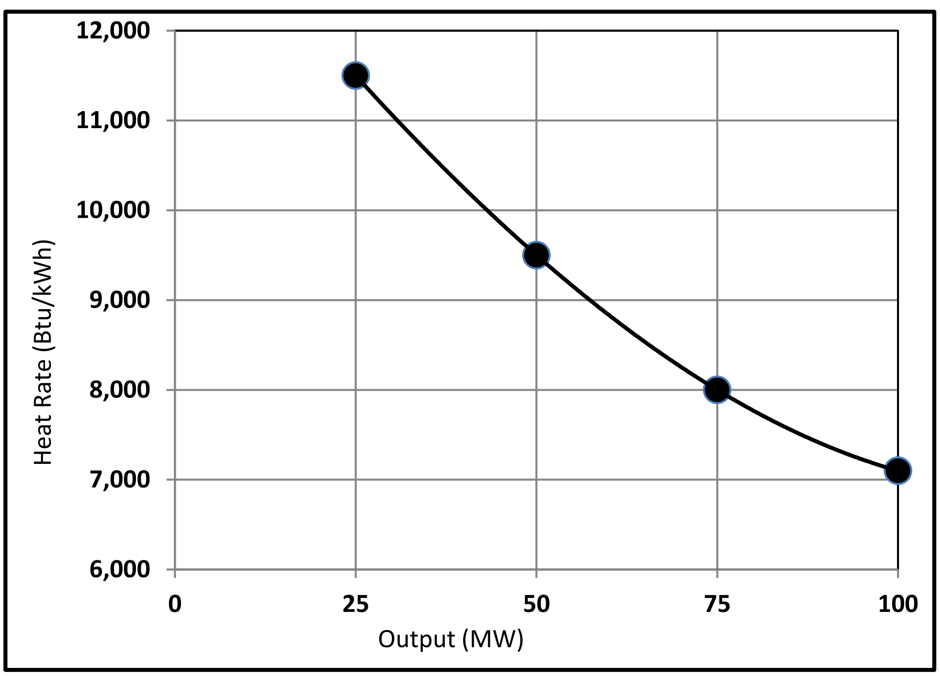
- Testing of new equipment may have taken place, and the plant was not operating normally.
- Monitoring equipment may have been malfunctioning and providing false data.
- Data may have been entered into the CEMS data set incorrectly or missed.

Scrubbed CEMS data provided a data set that represents normal operating characteristics. Appendix A provides an example of the scrubbing process.

Modeling Heat Rates

In the Energy Commission's production cost model, staff models heat rates in four 25 percent increments, or "blocks." The blocks are 25 percent, 50 percent, 75 percent, and 100 percent of the electrical output of a thermal power plant. Each block percentage represents a portion of the maximum output of a thermal power plant. For example, the first block of a 100 MW capacity thermal power plant is 25 percent of maximum capacity, or 25 MW. Therefore, the heat rate will be modeled for 25 MW. Because the first block includes fuel used to start the plant, the heat rate may be a little higher than otherwise expected. **Figure 1** is an example of how block heat rates appear in the production cost model.

Figure 1: Average Block Heat Rates



Source: California Energy Commission staff.

Once staff enters the block heat rates, the production cost model uses the blocks, shown as four points in **Figure 1**, to estimate a second order polynomial curve. The heat rate is defined for any output level within the four blocks.

Figure 1 shows that the production cost model creates a smooth transition between blocks using a polynomial curve to represent the heat rate. Although average block heat rates produce reasonable results, staff explored ways to represent more realistically heat rates in the production cost model.

One consideration was using additional heat rate blocks. While this method produced more realistic results, the time needed for model runs was increased to unacceptable levels. After some test runs, staff decided the more realistic results did not provide enough benefit over using four heat rate blocks.

Staff also considered using continuous heat rate functions that are provided as an option within the production cost model. Both full-load and no-load heat rates were entered, and the production cost model used a continuous curve to model the heat rate based on plant output. As with adding additional blocks, this method increased model simulation run times to unacceptable levels. Therefore, staff decided to continue using the block heat rate method.

CHAPTER 3: Heat Rate Estimation

Procedure to Determine Heat Rates

This section summarizes the steps of estimating heat rates from publicly available data. First, this paper outlines the heat rate estimation method and describes key inputs. Each step of the method is discussed in detail later in this chapter.

Staff uses these steps to estimate heat rates for each plant by using publicly available data to:

1. Determine the category of each plant (for example, combined cycle).
2. Determine a reasonable operating range for each plant in gross kWh.
3. Construct "input/output" curves showing the relationship between the fuel input (Btu) of each plant and the electric generation output.
4. Account for electricity generated by the plant that is used at the plant complex ("station use").
5. Convert the operating range for each plant from gross to net values.
6. Compute average heat rates for each plant and check for reasonableness.

To estimate thermal power plant heat rates, staff first determined a reasonable operating range for each plant analyzed. Staff did this by using publicly available data on hourly generation to construct histograms. Staff used the histograms to choose high and low cutoff points for defining the operating range for each plant. Staff determined the cutoff points for each plant by finding the output levels that went from operating many hours to a few hours.

Once staff determined a reasonable operating range for each thermal power plant, input/output curves were constructed to show the relationship between the fuel input of a plant and the electric generation output. Staff created an equation for the input/output curve of each plant where fuel input is a function of electricity generation output. Staff used the input/output equations to estimate the fuel input of the plant for different level of electricity generation output. The operating range for the input/output curves is in gross terms.

Staff measures average heat rates in net values, not gross. Before estimating average heat rates for each thermal power plant, staff converted the operating range from gross to net values. This was done by subtracting the estimated amount of electricity used at the power plant itself, known as "station service."

Using the net operating range, staff computed average heat rates for each plant by dividing fuel input by electricity generation output. Staff estimated average heat rates for different levels of net electricity generation output (25 percent, 50 percent, 75 percent, and 100 percent of maximum net generation).

Once average heat rates were computed, staff examined the average heat rates to ensure reasonableness. This was done by looking at past thermal power plant operations.

Power Plant Categories

Due to differences in heat rates and operational characteristics, staff categorized each thermal power plant into one of four main types and one subtype based on general characteristics:

- Steam boilers fueled by natural gas (ST-Gas).
- Steam boilers fueled by coal (ST-Coal).
- Combustion turbines fueled by natural gas, sometimes called a simple-cycle, peaking power plant, or gas turbine (GT).[11]
- Combined-cycle (CC) units that use one or more natural gas-fired combustion turbines and one or more steam turbines. Steam used in the steam turbines is generated using hot gases exhausted from the combustion turbine(s).

11 From here onward, a GT will refer to a simple-cycle combustion turbine power plant or a gas peaking power plant.

Operating Range

Staff used a reasonable operating range for each thermal power plant, one that represented normal operating conditions. Staff used Form EIA-860 and CEMS hourly data to estimate a minimum generation level for each power plant.[12] Among other things, Form EIA-860 provides estimates of the minimum generating levels for each power plant. Staff constructed histograms of the gross generation for each power plant using hourly CEMS data. The U.S. EIA minimum generation level and the hourly CEMS histograms were used to determine a minimum operating level for each power plant.

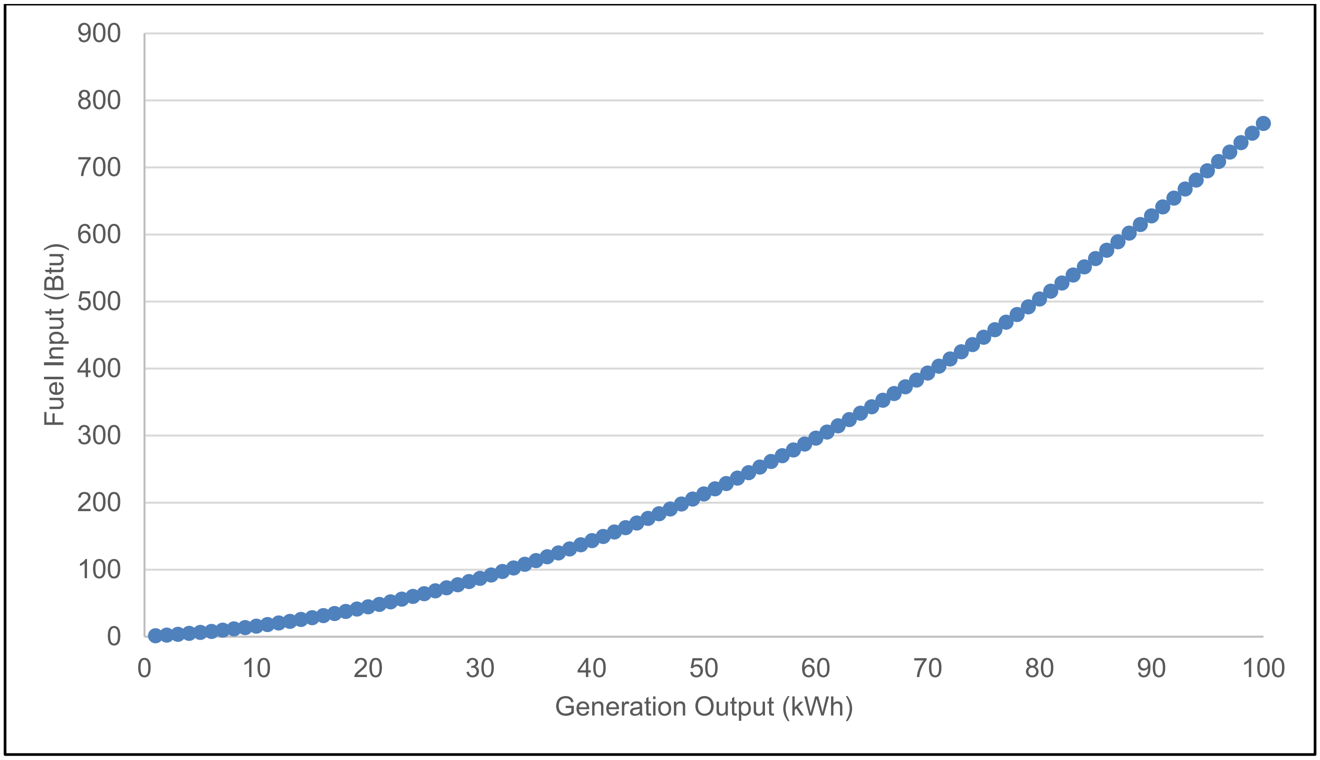
Staff determined the maximum output level for each thermal power plant using hourly CEMS data to construct histograms of gross output, and capacity values from Form EIA- 860. A reasonable maximum output level was determined by comparing histograms to the nameplate capacity values, and staff used the smaller of the two for the maximum generation output level. Data points below the minimum generation level and above the maximum generation level were deleted.

Input/Output Curves

Before estimating heat rates, staff created input/output curves with data available for 289 thermal power plants in the Western Interconnection. These curves show the relationship between the amount of fuel a power plant burns and the amount of electricity it generates. As expected, input/output curves generally slope upward from left to right; that is, higher plant output levels require more fuel. An example of an input/output curve is shown in **Figure 2.**

12 The *minimum generation level* is the lowest level a plant can operate at consistently and stably.

Figure 2: Example Input/Output Curve



Source: California Energy Commission staff analysis.

Once minimum and maximum generation output levels for each power plant type were estimated, hourly CEMS data were used to construct an input/output curve.[13] Staff used linear regression methods to "fit" a second order (quadratic) polynomial equation to the hourly CEMS data. The regression equation for each power plant type is:

$$\textbf{Fuel input} = a_0 + a_1 * (\textbf{generation output}) + a * (\textbf{generation output})^2$$

Where a_0, a_1, a_2, are constants determined by the regression analysis, fuel input is hourly fuel consumption, and generation output is the hourly gross electricity generation of the plant. After regression equations were constructed, average heat rates and average incremental heat rates were computed.[14] Average heat rates are fuel input (Btu) divided by generation output (kWh) for a given output level or output range. For example, a natural gas-fired turbine that requires 200,000 Btu of gas to generate 20 kWh of output

13 An input/output curve looks at the relationship between fuel input (Btu) and electric generation output (kWh).

14 An *incremental heart rate* is the change in fuel input divided by the change in generation output.

for one hour would have an average heat rate of 10,000 Btu/kWh for that hour.[15] The input/output curves were constructed using gross values, not net values. Gross values are converted to net for estimating heat rate curves; this conversion is discussed in the next section.

After constructing input/output curves, heat rates were calculated for each thermal power plant for different generation output levels. Some thermal power plants used the four output levels:

- 25 percent of maximum output
- 50 percent of maximum output
- 75 percent of maximum output
- 100 percent of maximum output

Constructing input/output curves was an iterative process. After the first iteration, hourly data for an input/output curve were examined with the estimated input/output curve from the regression equation. Extreme outliers were removed, and the input/output curve was again estimated. Most plants required only two iterations.

Accounting for Thermal Power Plant Station Service

While input/output curves were created using gross electricity generation data, staff modeled net generation, which is electrical energy that goes to the larger electrical system (the grid), as opposed to electrical energy used at the power plant (station service). Common station service uses are lighting, office, control and operations equipment, and shop heating and cooling. Staff accounted for station service when computing average heat rates and estimated it using different sources such as the Energy Commission's Quarterly Fuels Energy Reports (QFER) database, the WECC 2015 power flow case, and information provided by RAC members.

The operating range determined in the calculation of the input/output curves was adjusted to account for station service. The minimum and maximum generation levels were decreased slightly to go from gross to net values.

15 A heat rate of 3,413 Btu/kWh represents a power plant that is 100 percent efficient. Heat rates above this are less than 100 percent efficient

The plant type characteristics affect assumptions about station service. An ST power plant uses pressurized steam from a water boiler to drive an electrical generator.

For GTs, zero station service was assumed. Staff based this on guidance by RAC expert staff who stated that although GTs have some onsite electricity usage, it is insignificant when compared to gross generation.

For CCs, a station service rate of 2.2 percent was used. These machines are more complicated than GTs and have station service loads that are significant enough to warrant inclusion. For example, if the gross generation of a CC power plant is 100 MW, net generation would be
100 MW minus (2.2%*100 MW) = 100 MW – 2.2 MW = 97.8 MW.

For ST-Coal plants, station service estimates from the WECC 2015 mid power flow case were used. ST-Coal units use electricity onsite to handle the coal and crush it into a fine powder before it is burned. Therefore, these units generally have a higher station service rate than CCs.

For ST-Gas plants, zero station service is assumed. The WECC 2015 power flow case shows low station service, generally less than 1 MW.

As a check, staff developed station service estimates using data obtained from the QFER system. Station service was estimated for each thermal power plant technology type using the median difference between annual gross and net generation data for 2010 through 2014. Because QFER shows annual station service estimates, startup fuel is included; therefore, QFER station service estimates may be inflated.

This table shows station service estimates using QFER data. The QFER station service estimates may be used in future work if other data are not available. **Table 1** shows these estimates.

Table 1: 2010-2014 Median Station Service Estimates

Plant Type	2010–2014 Median Station Service
ST-Gas	9.66%
ST-Coal	12.68%
GT	3.11%
CC	3.20%

Source: Quarterly Fuels Energy Reports data and California Energy Commission staff analysis.

Average Heat Rates

Average heat rates for each plant were estimated using the input/output curves for each of the following thermal power plant types: ST-Coal, ST-Gas, CCs, and GTs. While heat rates are net values, input/output curves are gross values.

To estimate average heat rates for a given thermal power plant, staff first looked at four operating levels of the plant. The operating levels are 25, 50, 75, and 100 percent of net maximum electricity generation. For each operating level, the estimated fuel input (from the input/output curve equation) is divided by the net electricity generation. This equation gives an average heat rate in each of the four operating levels, for each thermal power plant.

Once staff determined the four average heat rates for each plant, the heat rates were examined for plausibility. For example, average incremental heat rates from the average heat rates and output levels were calculated and checked to ensure they were not decreasing as the output of the power plant increased.

Decreasing incremental heat rates causes production cost modeling problems. If an incremental heat rate decreases, generation costs decrease as output increases. This scenario is contrary to how power plants operate. For power plants exhibiting a decreasing incremental heat rate, staff reexamined the data, and some data were found implausible and removed from further use. If staff could not rectify the problem, it removed the plant from analysis. Fortunately, only a few plants exhibited decreasing incremental heat rates.

Combined Heat and Power and Biomass Power Plants

The method described in this report is not used to estimate heat rates of combined heat and power (CHP) and biomass-fired thermal power plants. Because these two plant types operate differently and have different types of fuel compared to other thermal power plants, staff estimated the heat rates of these plant types on a plant-by-plant basis.

CHP power plants burn fuel, usually natural gas, to boil water into steam that is used onsite by the "thermal host," such as a canning plant. In addition, the power plant generates electricity that is either used on site, sold into the larger electricity system, or both. Because staff is concerned only with electricity going to the grid, the capacity and heat rate of each CHP plant were adjusted to reflect only fuel used for electric generation to the grid.

The California ISO 2015 net qualifying capacity (NQC) list was used to adjust the capacity of a CHP plant.[16] The NQC lists, by month, the capacity of a plant that is expected to provide in response to California ISO dispatching instructions. For CHP plants, the NQC values are generally much lower than the nameplate capacity because much of the nameplate capacity is used onsite.

Staff assumed that 40 percent of the total fuel used in CHP plants is for onsite applications, while 60 percent of the fuel goes toward electricity generation. Therefore, staff adjusted the heat rate of each CHP plant by 40 percent. For example, if a CHP unit has a full-load heat rate of 16,000 Btu/kWh, staff adjusted this heat rate to 0.60*(16,000) Btu/kWh = 9,600 Btu/kWh.

Biomass-fired power plants were assumed to be either generating electricity at full load or not generating at all. Staff used the following process to estimate biomass-fired power plant full-load heat rates:

1. Biomass-fired power plants were assumed to be either generating electricity at full load or not generating; that is, for each biomass-fired power plant, only one full-load generation output level and the associated heat rate were used.

16 Reliability requirements from California Independent System Operator

2. Full-load heat rates for biomass-fired power plants were updated using QFER data to determine monthly heat rates for natural gas-fired and biomass-fired power plants, by plant type.
3. The difference in monthly heat rates between gas-fired and biomass-fired power plants, for the same plant type (for example, ST-Gas), was determined.
4. The difference was used to estimate full-load heat rates for biomass-fired power plants.

In the case of a natural gas-fired turbine, if the average monthly heat rates for natural gas- and biomass-type plants are 8,000 Btu/kWh and 12,000 Btu/kWh respectively, the biomass-fired power plants have a heat rate that is 12,000/8,000 = 1.5 or 50 percent greater than the natural gas plant. To update the heat rate of a biomass plant in the Energy Commission's production cost model, a similar vintage and capacity natural gas- fired plant of the same plant type would be found, and the full-load heat rate was increased by 50 percent.

CHAPTER 4: Results

The new method estimates the input/output curve, operating range, and average heat rates for each thermal power plant in the Western Interconnection. These estimates are based on publicly available data and appear to be reasonable. Energy Commission staff will use the estimated heat rates to update the Energy Commission's production cost model, and RAC staff will use them to update its 2026 common case.[17]

This chapter compares full-load heat rates of each power plant by plant type. The full- load heat rate of a power plant is the heat rate at maximum generation level. A full-load heat rate allows a comparison of efficiency between plants. For example, a power plant with a full-load heat rate of 8,000 Btu/kWh is twice as efficient as a power plant with a 16,000 Btu/kWh heat rate.

This chapter also describes estimating input/output curves and average heat rates for power plants with little or no public data available. For these plants, staff estimated a generic input/output curve and average heat rate curve for each thermal power plant type. Thermal power plants of the same type will have the same generic average heat rate curve. This chapter provides an example of estimating a generic input/output curve and average heat rates.

Full-load heat rates can vary by plant as well as by technology. Much of this variation may be explained by the size of the plant (in nameplate capacity) as well as age in years, or vintage. Generally, larger plants have lower full-load heat rates than smaller plants, and newer plants have lower full-load heat rates than older plants. Finally, CC plants had the lowest full-load heat rates, followed by gas turbines, then steam boilers.

Steam Boilers

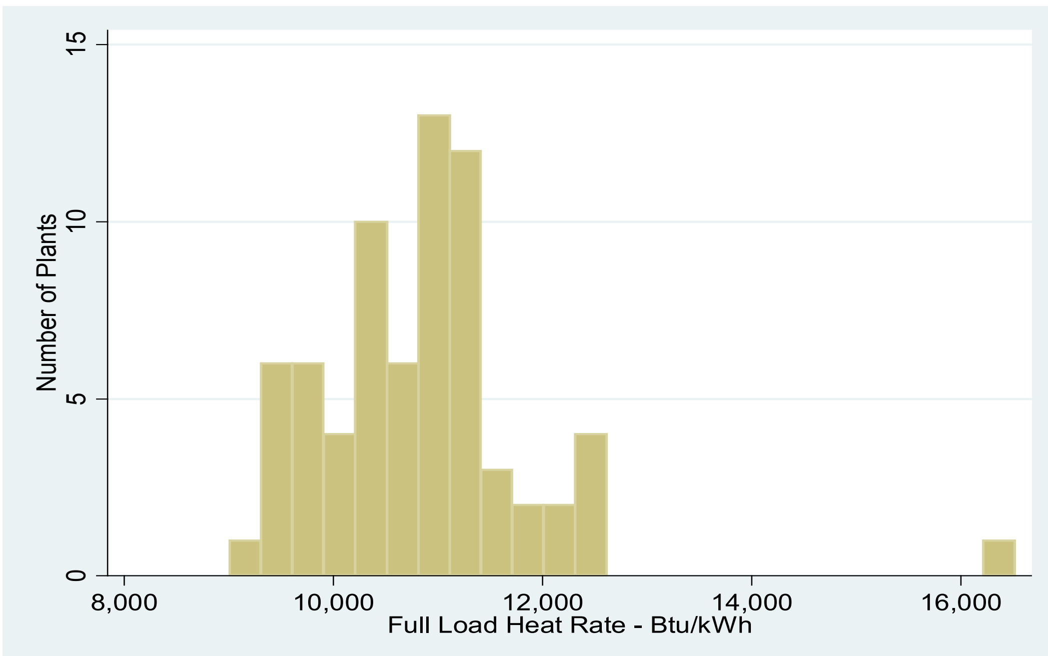
ST-Coal power plants have full-load heat rates ranging from 9,000 Btu/kWh to 12,000 Btu/kWh. The analysis of these plants for 2010 through 2014 showed an average full-load heat rate of 10,800 Btu/kWh. Natural gas-fired steam plants showed full-load heat rates ranging from 9,000 to 12,000 Btu/kWh

17 Transmission Expansion Planning

however, the average full- load heat rate was 10,200 Btu/kWh, slightly lower than the coal-fired steam plants. Both plant types fit the estimated regression equation for input/output curves well. For both plant types, there were a few outliers, with full-load heat rates around 16,000 Btu/kWh for coal-fired and 14,000 Btu/kWh for natural gas-fired plants.

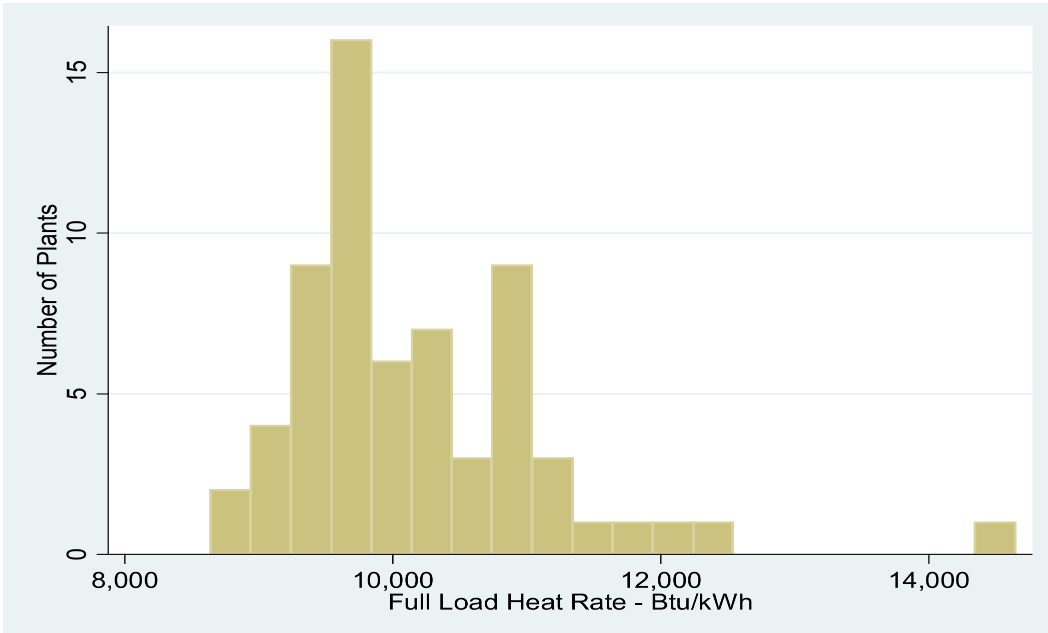
Figure 3 and **Figure 4** illustrate these full-load heat rates.

Figure 3: Coal-Fired Steam Boiler Full-Load Heat Rates



Source: California Energy Commission and Western Electricity Coordination Council staff analysis.

Figure 4: Natural Gas-Fired Steam Boiler Full-Load Heat Rates



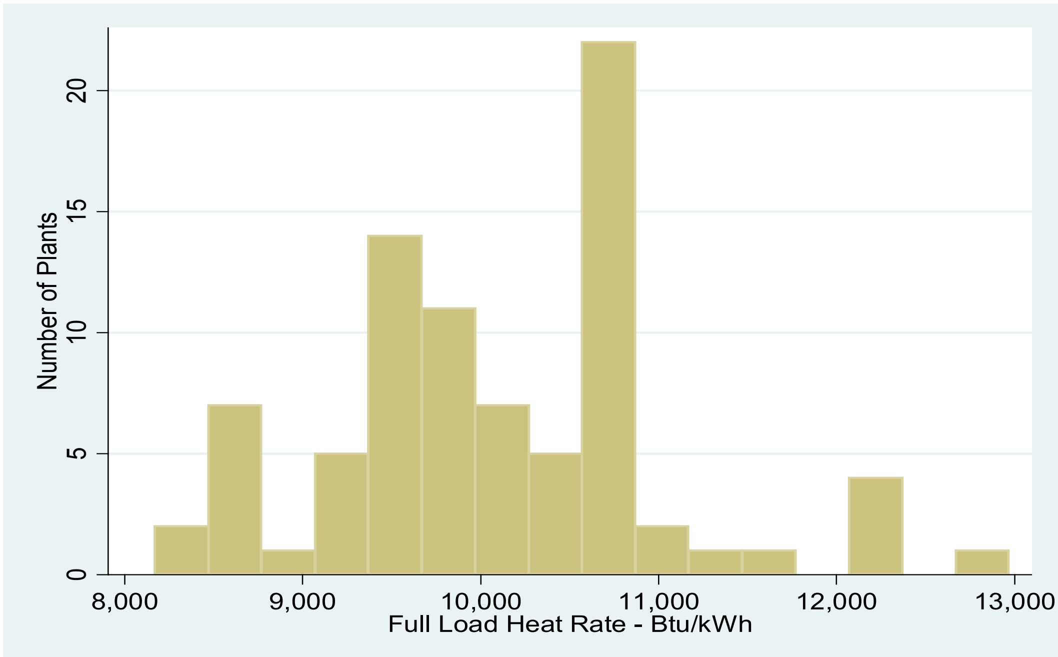
Source: California Energy Commission and Western Electricity Coordination Council staff analysis.

Gas Turbines

GTs exhibited heat rates ranging from 9,000 Btu/kWh to 12,000 Btu/kWh and an average full-load heat rate of 10,100 Btu/kWh. Hourly CEMS data for GTs did not fit the input/output curve regression equation as well as the other plant types. Poor fit to the regression equation may be due to full-load heat rates being more spread out than those of steam boilers.

The general assumption for GTs was a plant either was not operating or was operating at 100 percent output. However, some GT heat rates exhibited two points: the minimum generating level and full load. **Figure 5** provides estimated GT full-load heat rates.

Figure 5: Natural Gas-Fired Turbine Full-Load Heat Rate

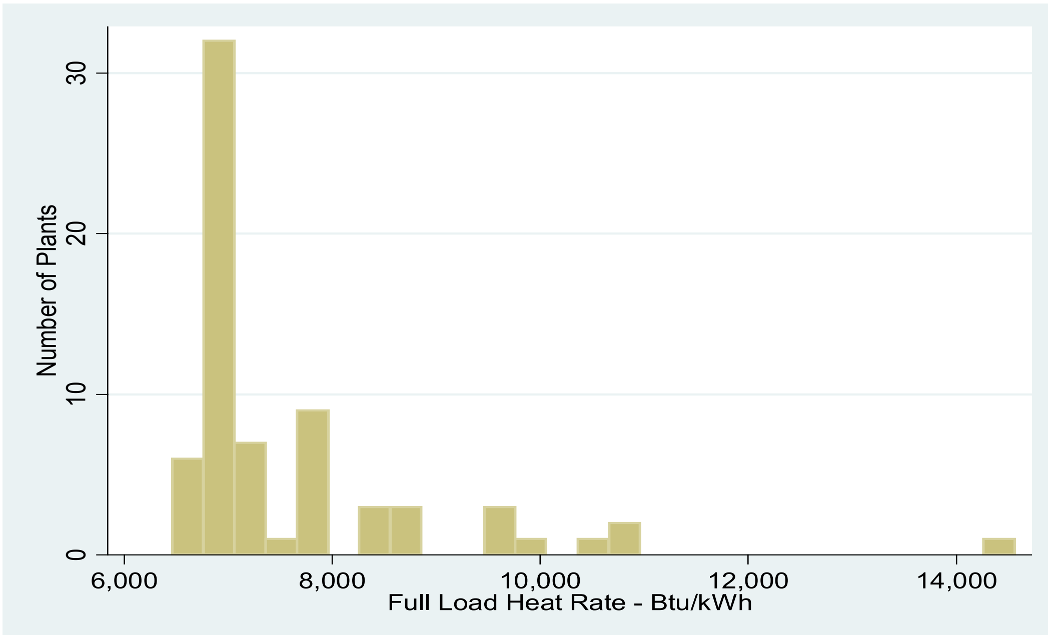


Source: California Energy Commission and Western Electricity Coordination Council staff analysis.

Combined Cycles

CC plants had full-load heat rates ranging from 6,750 Btu/kWh to 11,000 Btu/kWh and an average full-load heat rate of 7,640 Btu/kWh. Full-load heat rate variability may be explained by plant vintages and capacities. CC plant regression equations for the input/output curve fit well, and staff encountered few difficulties. **Figure 6** shows estimated full-load heat rates for CC plants.

Figure 6: Combined-Cycle Full-Load Heat Rates



Source: California Energy Commission and Western Electricity Coordination Council staff analysis

Generic Heat Rate Curves

Not every thermal power plant has CEMS equipment and is monitored by CEMS. For plants missing CEMS data, generic input/output curves were created using plants with CEMS data. Table 2 shows, by plant type, that hourly CEMS data do not exist for about half of the plants in the western grid. The CS plant type is not included in **Table 2** as it is lumped together with the CC plant type. The CC and CS plant types have similar input/output curves, operating characteristics, and estimated heat rates; thus, staff decided to combine the CS plants into the CC plant type category. The plant types used to calculate generic input/output curves were GT, CC, ST-Gas, and ST-Coal.

Table 2: CEMS Data by Power Plant Type

	Data Exist	Data Do Not Exist	Total
CC	69	109	178
GT	83	97	180
ST-Gas	66	11	77
ST-Coal	71	23	94
Total	289	240	529

Sources: Energy Information Administration—Form 860, Environmental Protection Agency Continuous Emissions Monitoring System data, and staff analysis.

Computation of generic input/output curves for a given plant type uses the following process:

1. Minimum and maximum operating levels are estimated for each plant type. Operating levels determine generation output levels at which to model heat rates. **Table 3** shows estimates of minimum and maximum operating levels, by plant type. Operating levels are in terms of gross generation.

Table 3: Minimum and Maximum Operating Levels, by Plant Type

Plant Type	Average Minimum Operating Level (% of Nameplate Capacity)	Average Maximum Operating Level (% of Nameplate Capacity)
CC	50%	90%
GT	60%	93%
ST-Gas	18%	98%
ST-Coal	55%	98%

Source: Energy Information Administration—Form 860, Environmental Protection Agency Continuous Emissions Monitoring System data, and staff analysis.

2. Unitize the input/output curve by unitizing the generation output. Unitizing the output of a plant makes the maximum output equal to one (1). To unitize the generation output, the generation output of a plant is divided by the maximum generation output. For example, a plant with generation output levels of 25 MW, 50 MW, and 100 MW, the maximum output would have unitized output levels of 25/100 = 0.25, 50/100 = 0.5, and 100/100 = 1 (the maximum unitized generation output).

   Unitizing the output of a plant takes away the units of electricity generated and converts the plant output to a percentage of the capacity. For example, a unitized output of 0.5 means a power plant is operating at 50 percent of capacity, whereas, a unitized output of 1 means the plant is operating at full capacity. Unitizing generation output makes comparing thermal power plants of different sizes easier. For example, a 100 MW power plant and a 750 MW power plant both have a unitized output of 1 when they are operating at full capacity. This scenario makes certain calculations and comparisons easier.

3. The average heat rate of each plant is unitized by dividing the average

heat rate by the full-load heat rate, making the full-load heat rate of each plant equal to 1. For example, if a plant has average heat rates of 10,000, 8,500, and 7,000 (full- load heat rate) Btu/kWh for generation output levels 25, 50, and 100 MW, it will have unitized average heat rates of 10,000/7,000 = 1.42, 8,500/7,000 = 1.21, and 7,000/7,000 = 1

4. Unitized fuel input is calculated by multiplying the unitized average heat rate by the unitized generation output level. At full load the unitized fuel input will equal 1. For example, from steps 1 and 2, the plant would have unitized fuel inputs of (0.25)*(1.42) = 0.35, (0.5)*(1.21) = 0.61, and (1)*(1) = 1, for the full-load fuel input.

5. With unitized fuel inputs and generation outputs estimated for all plants with usable data, a generic input/output curve is estimated for each plant type. For example, a quadratic regression equation is estimated for the input/output curve for a given plant type. the equation is:

   Unitized fuel input = a_0 + a_1*(unitized generation output) + a_2*(unitized generation output)^2

To use the generic unitized input/output curve to estimate average heat rates for a plant missing CEMS data, the following process is used:

1. Determine the maximum capacity of the plant and how many generation output levels you want. For example, a 200 MW coal steam plant may have assumed gross output levels at 100, 150, and 200 MW.
2. Determine the full-load heat rate of the plant. If this is not available, the average full-load heat rate of that plant type may be used. For coal steam plants, the average full-load heat rate estimated is 10,800 Btu/kWh. Thus, 10,800 Btu/kWh will be used in this example. The full-load heat rate of a similar plant may be used, if necessary.
3. Unitize the generation output levels of the plant by dividing each gross output level by the maximum capacity. In this example, the unitized output levels are 100/200 = 0.5, 150/200 = 0.75, and 200/200 = 1.

4. Use the generic unitized input/output curve to calculate the unitized fuel input. The generic unitized input/output curve equation (for coal plants) is:

   Unitized fuel input = 0.078 + 0.85*(unitized generation output) + 0.068*(unitized generation output)2

Using the unitized gross generation output values of 0.5, 0.75, and 1 gives unitized fuel input values of 0.52, 0.754, and 1. The values in this equation represent the relationships between fuel input and generation output. The constant, 0.078, represents the amount of fuel input when the plant is not generating, but spinning to maintain temperature and inertia. This value is sometimes referred to a "no-load heat rate." The 0.85 and 0.068 coefficients measure the positive relationship between generation output and fuel input.

To calculate average heat rates, generation output levels must be in net values, not gross.

1. Reduce gross generation values to net by subtracting an estimated station service value. Because coal-fired power plant station service data are not readily available for all plants, staff assumed a generic station service of 5 percent.[18.] Thus, the net output levels are 100*(0.95) = 95, 150*(0.95) = 142.5, and 200*(0.95) = 190 MW. Unitized net output levels are the same as the unitized gross output levels in this example.

2. Determine unitized average heat rates using the unitized net output levels and unitized fuel input values from step 1. For the unitized net generation output level of 0.5, the unitized average heat rate is 0.52/0.5 = 1.04. Similarly, the unitized average heat rates for unitized net output of 0.75 and 1 are 1.0053 and 1.00, respectively.

3. Convert the unitized values back to actual values (in terms of Btu/kWh) by multiplying each unitized average heat rate by the full-load heat rate of the plant. In this example, the full-load heat rate is 10,800 Btu/kWh, and the unitized average heat rates are 1.04, 1.0053, and 1.00. Therefore, the average heat rates are 1.04*(10,800) = 11,232,

[18] This station service value comes from the NERC/GADS gross to net conversion factor for fossil plants. See www.nerc.com/files/section_4_performance_reporting.pdf.

1.0053*(10,800) = 10,858, and 1.00*(10,800) = 10,800 Btu/kWh. (Recall that net output levels associated with these three average heat rates are 95 MW, 142.5 MW, and 190 MW, respectively).

To summarize this example:

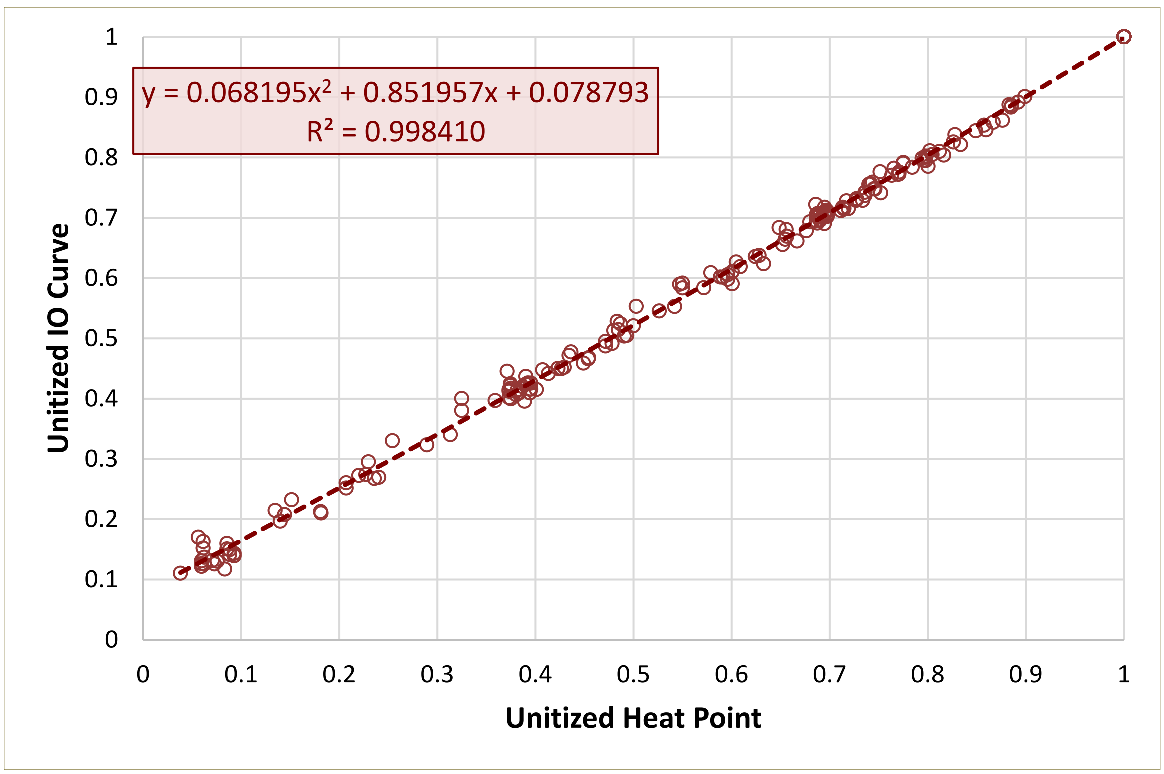
- At a 95 MW net output, the average heat rate is 11,232 Btu/kWh.
- At a 142.5 MW net output, the average heat rate is 10,858 Btu/kWh at 190 MW net output (maximum); the full-load heat rate is 10,800 Btu/kWh.

Appendix A provides an example of using the generic unitized input/output curve to estimate average heat rates for a plant.

Generic ST-Coal and ST-Gas Input/Output Curve

The generic, unitized input/output curve for ST-Coal and ST-Gas plants fits the regression equation well, as demonstrated by the R-squared value being greater than 0.99. Furthermore, the data do not vary much around the fitted input/output line. **Figure 7** illustrates this.

Figure 7: Generic Unitized Input/Output Curve for ST-Coal and ST-Gas Plants



Source: California Energy Commission and Western Electricity Coordinating Council staff analysis

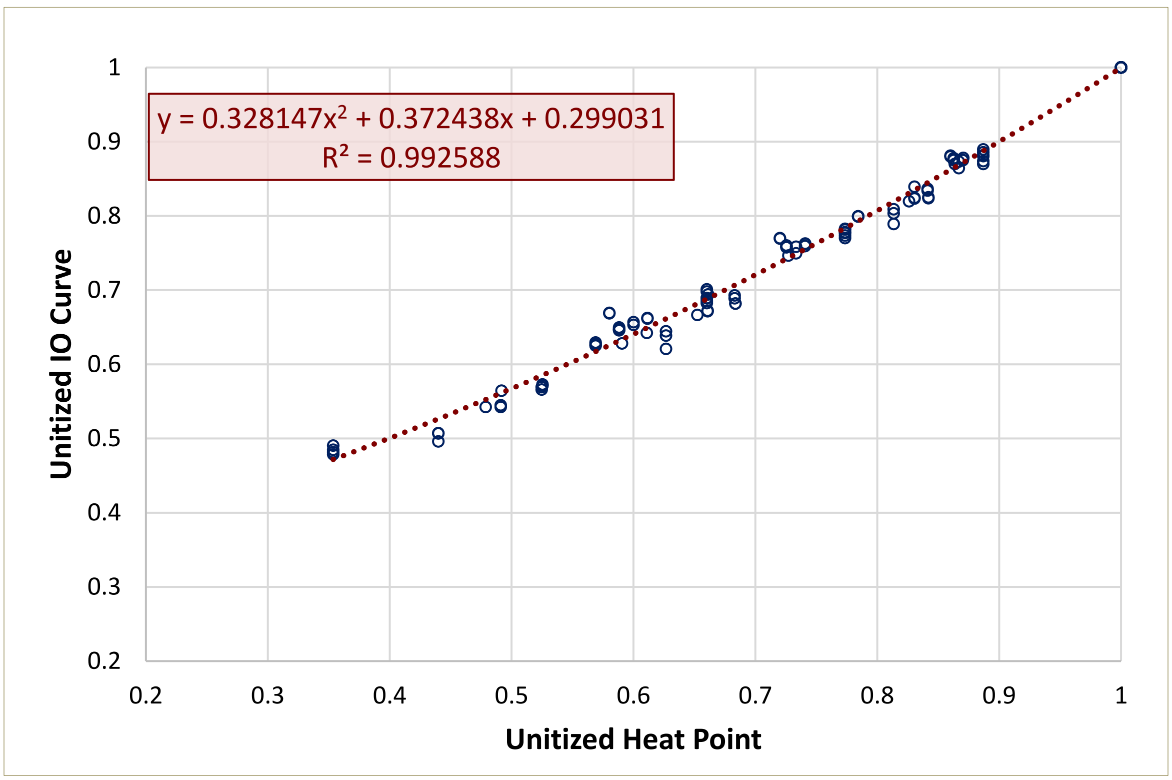
Generic Combined-Cycle Input/Output Curve

The generic unitized input/output curve for CC plants also fits the data very well, with an R-squared value greater than 0.99. In addition, the data points do not vary much from the fitted line. **Figure 8** illustrates the generic input/output curve for CC plants.

Generic Gas Turbine Input/Output Curves

Staff did not create generic unitized input/output curves because the operational profiles of most GTs are either at full load or off. Staff attempted estimating a generic unitized input/output curve, but the data did not fit well. Staff will continue to use the data available for GTs and calculate average heat rates at full load. If better data become available, staff will explore creating generic input/output curves for GTs.

Figure 8: Generic Unitized Input/Output Curve for Combined-Cycle



Source: California Energy Commission and Western Electricity Coordinating Council staff analysis.

Summary of Creating Generic Heat Rate Curves

The following summarizes the steps in creating the generic unitized heat rate curves for a given plant type:

- Unitize the generation output data for all plants.
- Unitize the fuel input data for all plants.
- Estimate generic unitized input/output curve (by plant type) by regressing unitized fuel input on unitized generation output (using a quadratic equation from original input/output curve estimations, from all plants of that type).

To use the generic unitized input/output curve to estimate average heat rates for a given plant type:

- Select output levels of the plant (minimum generation level, maximum generation level, and so forth).
- Unitize the output levels by dividing each output level by the maximum output of the plant. This ensures the maximum output level is 1.
- Insert the unitized output level into the generic unitized input/output equation, unitizing fuel inputs and generation outputs.
- Calculate unitized average heat rates for each unitized output level by dividing each unitized fuel input level by each unitized generation output level.
- Determine the actual heat rate of the plant by multiplying each unitized average heat rate by the full-load heat rate of the plant.
- Reverse unitized output levels to actual values by multiplying each unitized generation output level by the maximum generation output level of the plant

CHAPTER 5: Next Steps and Future Work

Current Use

The RAC working group used the revised heat rates to update its 2026–2028 ADS. In 2016, Energy Commission and RAC staff presented the proposed heat rate determination method and results to the RAC working group to elicit stakeholder comments and suggestions. Staff took useful stakeholder comments and suggestions into account in finalizing the method.

Staff completed the analysis and stakeholder vetting and created a spreadsheet to contain all pertinent power plant characteristics, including:

- Input/output curves (both specific and generic).
- Average and average incremental heat rates.
- Nameplate, summer, and winter capacities.
- Minimum and maximum operating (generation) levels.
- Any other plant characteristics that pertain.

Using the spreadsheet of updated heat rates staff created, the Energy Commission’s modeling unit updated the out-of-date heat rates in the production cost model. The production cost model, with the new heat rates, provide input values for use in the NAMGas model, as well as the California energy demand forecast.

After replacing the existing heat rates in the production cost model with the new heat rates, staff ran simulations to determine how well the new heat rates and plant characteristics (minimum/maximum operating level) performed. Staff found no major issues with the production cost model, using the updated heat rates.

Next Steps

Staff will determine a reasonable timeline to keep the spreadsheet of plant characteristics and heat rates current. Staff will update the heat rates and plant characteristics using data that are more recent.

Potential Future Work

Because staff was unable to obtain operational data for all thermal power plants in the Western Interconnection, the search for additional plant data will continue. In addition, because of a lack of data and information regarding station service of power plants, staff will continue searching for those data. Finding more complete station service data will augment staff's heat rate analyses and reduce the number of assumptions that must be used.

Many combined-cycle plants have the ability to use duct-firing to augment the steam turbine to gain additional power, but data on duct-firing at such power plants are scarce and discontinuous. Staff was unable to estimate heat rates for duct burners with the data available but will continue its search for data because modeling duct-firing will improve overall modeling results.

Duct burners generally make up a small portion of the total capacity of a thermal power plant and may turn on for only a few hours out of the year. Staff believes that accounting for duct burners when estimating average heat rates can make a small improvement to the method. Staff does not believe adding duct burners to the method will change the results significantly.

If information on duct burners becomes publicly available, staff will analyze the effect on average heat rates. If staff finds duct burners do not materially affect average heat rates of combined-cycle plants, the duct burner information will not be included in the method.

Staff may revisit the heat rate estimation method and modify/simplify it if that makes the method easier to understand and duplicate for stakeholders. Staff plans to present any changes to the estimation method to industry stakeholders for feedback.

ACRONYMS

Acronym	Name
ADS	Anchor Data Set
Btu	British thermal unit
California ISO	California Independent System Operator
CC	Combined-cycle plant
CEMS	Continuous Emissions Monitoring System
CHP	Combined heat and power
CPUC	California Public Utilities Commission
CS	Combined-cycle, single-shaft plant
Energy Commission	California Energy Commission
GADS	Generating Availability Data System
GT	Gas turbine
IC	Internal combustion reciprocating engine
IEPR	Integrated Energy Policy Report
kWh	Kilowatt-hour
LTPP	Long-Term Procurement Planning
MWh	Megawatt-hour
NAMGas (model)	North American Market Gas Trade (model)
NERC	North American Electric Reliability Cooperation
NQC	Net qualifying capacity
QFER	Quarterly Fuels and Energy Reports
ST	Steam boiler/steam turbine
RAC	Reliability Assessment Committee
TPP	Transmission Planning Process
U.S. EIA	United States Energy Information Administration
U.S. EPA	United States Environmental Protection Agency
WECC	Western Electricity Coordinating Council

GLOSSARY

Term	Definition
Combined heat and power plant	A power plant that burns fuel, usually natural gas, to boil water into steam that is used onsite for an industrial process, such as a space heating. In addition, the power plant generates electricity that is either used on site, sold into the larger electricity system, or both.
Combined-cycle power plant	A power plant has a generation block consisting of at least one combustion turbine, a heat recovery steam generator, and a steam turbine.
Combustion turbine/gas turbine power plant	Fast-starting power plants intended to operate for short durations to meet peak-load system requirements.
Generating unit	A combination of physically connected generators, reactors, boilers, combustion turbines, and other prime movers operated together to produce electric power. In the context of this staff paper, a generating unit can only be assigned to a single natural gas-fired generation category.
Heat rate	Expresses how much fuel is necessary (measured in British thermal units [Btu]) to produce one unit of electric energy (measured in kilowatt-hours [kWh]).
Incremental heat rate	For a thermal power plant, the change in fuel input divided by the change in generation output between two generation output levels.
Input/output curve	Describes the relationship between the fuel consumed by the power plant and the related electric generation output
Maximum operating level	The highest level that a power plant can produce electricity continuously and reliably
Minimum operating level	The lowest level that a power plant can continuously and reliably operate and generate electricity
Operating range	The operating range defines the minimum and maximum output levels that a power plant can reliably operate between
Production cost model	A computer-based program that simulates an electric system that estimates electricity production, electricity cost, fuel consumption, reliability, and air pollution
Station service	The energy a power plant uses onsite for internal operations such as lighting, heating, and cooling.
Steam boiler power plant	A power plant that heats water in a boiler to create pressurized steam to drive an electrical generator to produce electricity
Thermal power plant	A thermal power plant is defined as a station composed of one or more electric generating units that combusts fossil fuel (such as coal, natural gas, or biomass) to generate electricity.

APPENDIX A: Example of Method for a Coal-Fired Power Plant

The following provides a step-by-step example of "scrubbing" CEMS data, as well as creating an input/output curve and average heat rates for a specific plant.

The histograms and scatterplots use whole-hour data; that is, only data where the plant operated for the whole hour are shown. CEMS data specify which data are whole hour.

The plant in this example, the Craig 1 plant, is a coal-fired steam boiler thermal power plant in Colorado. It has a nameplate capacity of 446 MW and winter and summer operational capacity of 428 MW each. The U.S. EIA minimum generation level is 130 MW. The histogram in **Figure A-1** shows that gross generation starts to be consistent and significant at an output of about 300 MW.

The scatterplot in **Figure A-2** is similar, showing that around 300 MW gross generation increases from sparse to dense. (There are many more hours of operation at levels above 300 MW than below). For this plant, staff estimated the minimum generation level as 300 MW. When scrubbing the data, all data points below 300 MW are deleted. Note that 300 MW is greater than U.S. EIA's minimum generation level of 130 MW.

To estimate the maximum generation level, staff examined the histogram that shows the last significant level of gross generation between 450 MW and 460 MW, which is 451 MW. Gross generation higher than 451 MW is infrequent. Therefore, 451 MW is deemed a good cutoff capacity.

Examining the scatterplot, gross generation hours start to become less numerous after roughly 450 MW, showing that the scatterplot agrees with the histogram on the maximum gross generation level. This agreement sets the minimum and maximum gross generation levels for the input/output curve at 300 MW and 451 MW, respectively. Note that 451 MW is greater than the U.S. EIA nameplate capacity of 446 MW.

Figure A-3 and **Figure A-4** show the histogram and scatterplot with only data in the range of the estimated minimum and maximum generation levels (300 MW to 451 MW). With this operating range, the input/output curve may be calculated.

Variability in Fuel Use

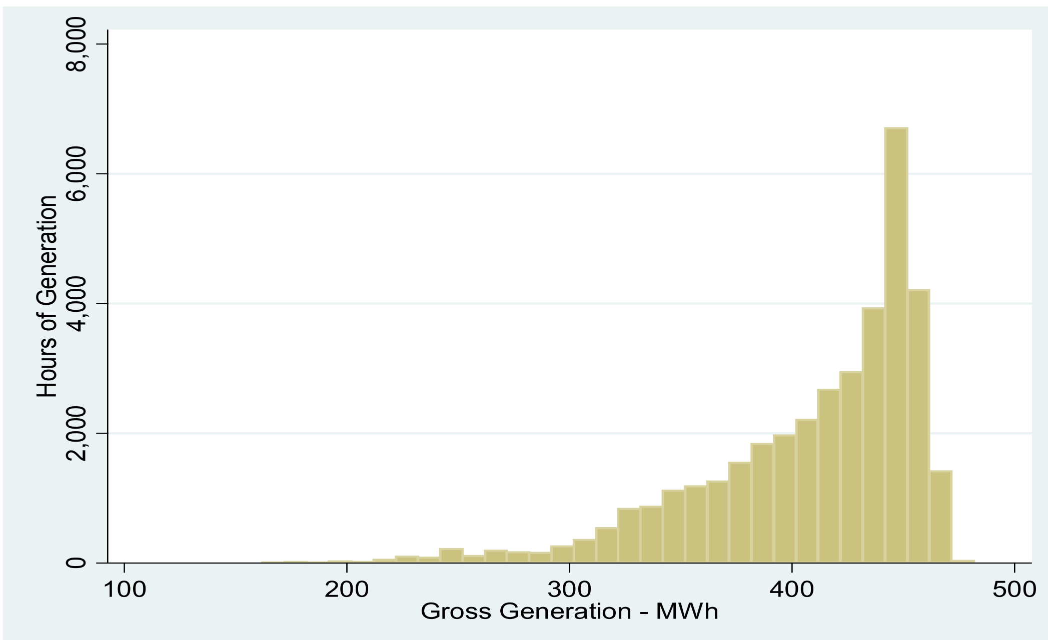
Fuel input for a given plant will vary for each level of generation output. Variation may be due to poor-quality data reporting, malfunctioning CEMS equipment, plant maintenance or testing, ambient air temperature, and random operational variation.
Some fuel input variation occurs only a few hours a year and does not follow the general pattern of the rest of the fuel input data and are data outliers.

Staff removed outlier data points because they do not represent normal operating conditions and worsen the fit of the estimated input output curves.[19]
In **Figure A-2**,
between 300 MW and 400 MW gross load, there are roughly 15 data points where the fuel input does not follow the pattern of the rest of the data.

To remove these outlying data points, the fitted input/output curve (the red line in **Figure A-2**) was examined and values well above or below the curve were deleted. In the Craig 1 plant example, values 485 (1,000s of MMBtu) above and below the fitted input/output curve were deleted. **Figure A-4** shows these outlying data points removed.

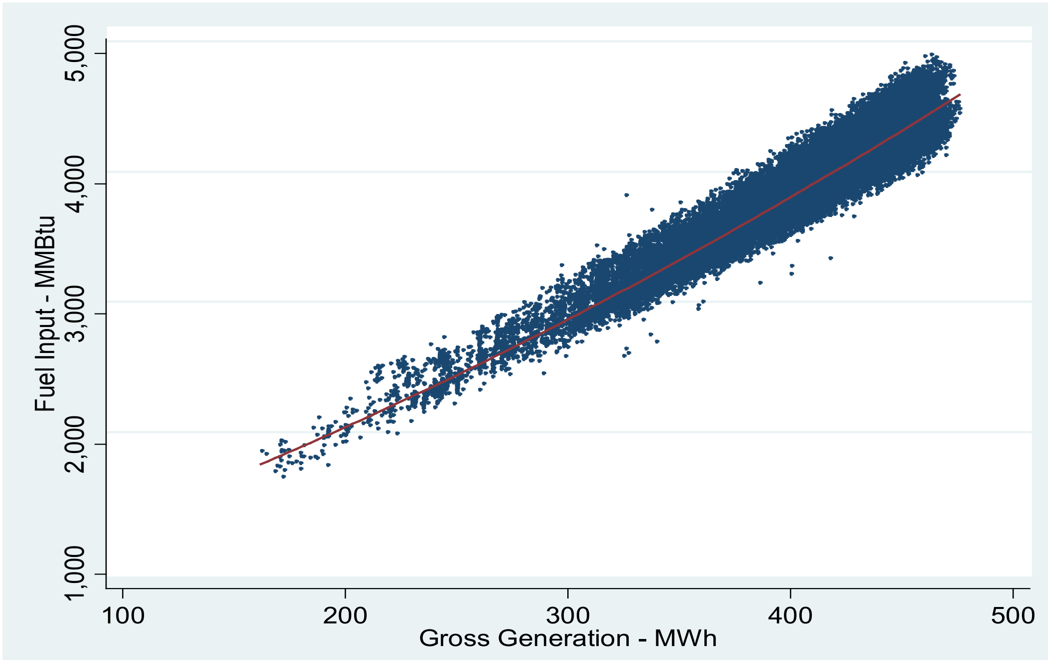
To review, fitted values for the estimated input/output curve for each power plant were examined, and outlier data values above and below the curve were determined. Then outlier values above and belo w the estimated curve were deleted. For example, if the value above the input/output curve is 200 MMBtu of gas, staff deleted data 200 MMBtu of gas above and below the fitted values for the estimated input/output curve. Although removing outliers above and below the curve is time consuming, it provides reasonable and defensible results.

Figure A-1: Histogram of Gross Generation, Craig Coal Plant



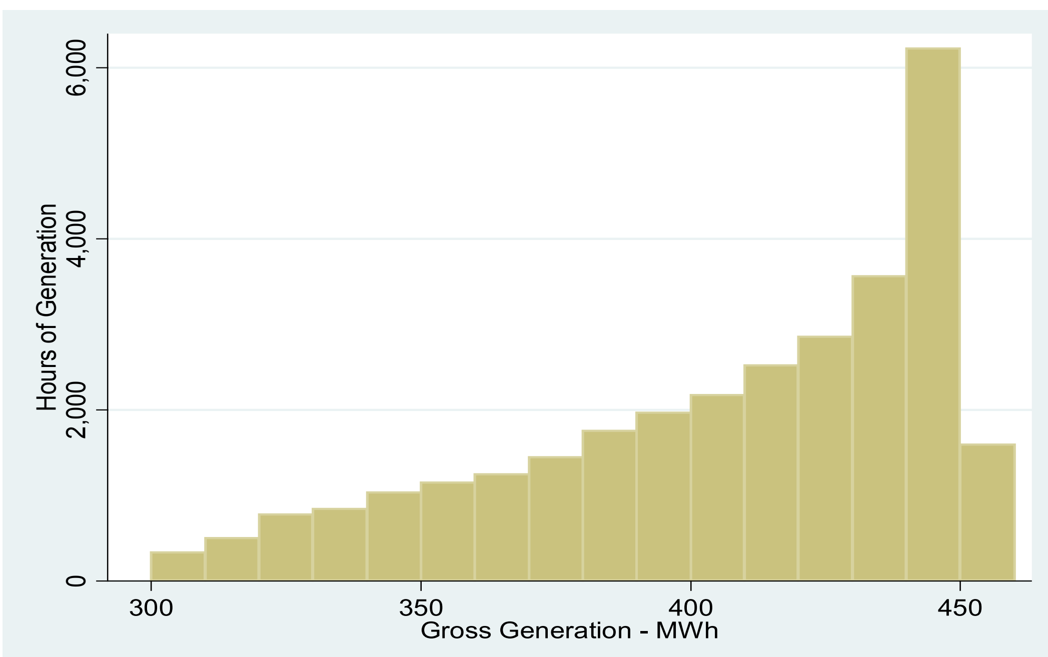
Source: California Energy Commission and Western Electricity Coordinating Council staff analysis.

Figure A-2: Scatterplot of Gross Load vs. Fuel Input



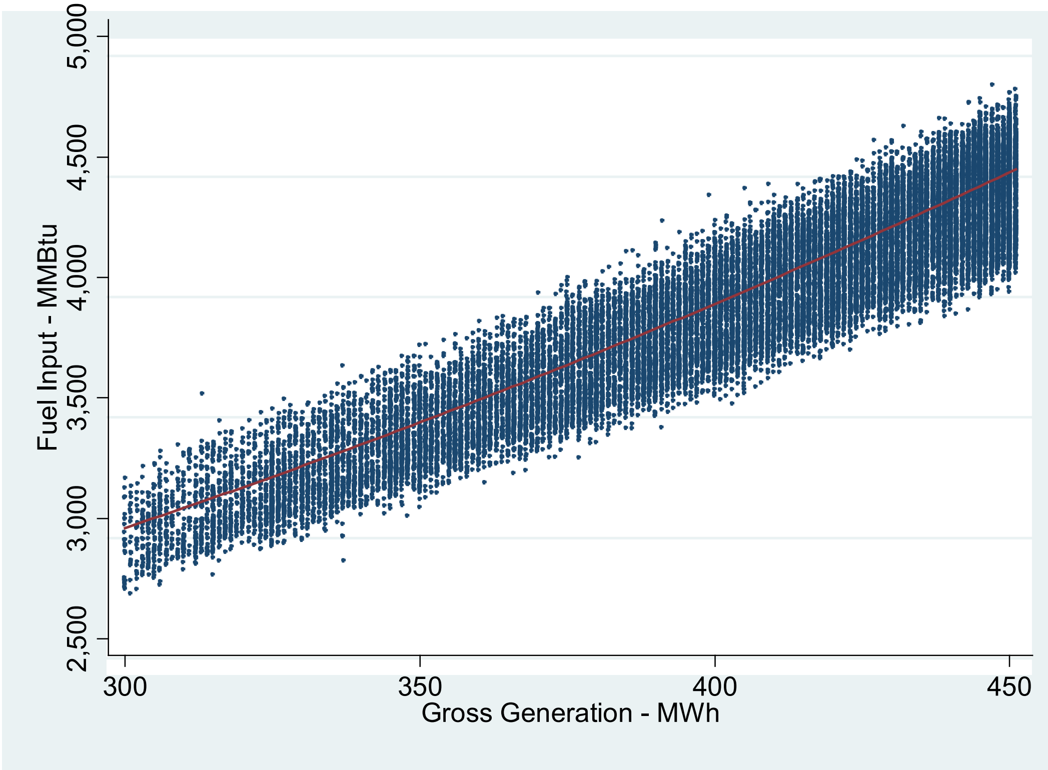
Source: California Energy Commission and Western Electricity Coordinating Council staff analysis.

Figure A-3: Histogram of Gross Generation With Minimum and Maximum Generation Level



Source: California Energy Commission and Western Electricity Coordinating Council staff analysis.

Figure A-4: Scatterplot of Gross Generation With Minimum and Maximum Generation Level



Source: California Energy Commission and Western Electricity Coordinating Council staff analysis

The regression equation for the input/output curve is:

$$\textbf{Fuel input} = a_0 + a_1*(\text{gross generation}) + a_2*(\text{gross generation})^2$$

Where a_0, a_1, and a_2 are estimated constants. Fuel consumed by the plant is in thousands of MMBtu per hour. Gross generation is the gross electricity generated in MWh/hour.

Using regression analysis to derive the equation, fuel input becomes:

$$\textbf{Fuel input} = 540 + 6.76*(\text{gross generation}) + 0.004*(\text{gross generation})^2$$

Average heat rates and average incremental heat rates are calculated using the input/output curve. Recall that the curve is in gross terms, while the heat rates are in net because a net MWh is supplied to the electricity grid.

The station service for the Craig 1 coal plant is 23 MW. Therefore, the net minimum generation level is 300-23 = 277 MW, and the net maximum generation level is 451-23 = 428 MW. Using net generation levels and the input/output equation, the average and average incremental heat rates may be calculated to get values for different net output levels.

The Craig 1 coal plant has a full-load heat rate of 9,771 Btu/kWh; this heat rate seems reasonable for a coal plant. In addition, the average incremental heat rates increase as plant output increases, matching how incremental heat rates should look. Heat rates in **Table A-1** seem reasonable and may be used with confidence.

Table A 1: Estimated Average Heat Rates.

Net Output Level (MW)	% Of Net Maximum Output Level	Fuel Input (1000s of MMBtu)	Average Heat Rate (Btu/kWh)	Average Incremental Heat Rate (Btu/kWh)
277	64%	3,020	9,742	
315	73%	3,367	9,704	9,388
352	82%	3,726	9,702	9,684
390	91%	4,095	9,727	9,980
428	100%	4,475	9,771	10,276

Source: California Energy Commission staff analysis