PACIFICORP ENERGY

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Fossil Fuel Heat Rate Improvement Plan

2014

Contents

Introduction

Energy Policy Act of 2005

The Energy Policy Act of 2005 amended the Public Utility Regulatory Policies Act (PURPA) of 1978. The amendments include a requirement that each electric utility develop and implement a 10-year plan to improve the efficiency of its fossil fuel generation. On August 10, 2007, The Utah Public Service Commission determined that it was in the public interest to adopt the PURPA Fossil Fuel Generation Efficiency Standard.

This standard reads as follows; **each electric utility shall develop and implement a 10 year plan to increase the efficiency of its fossil fuel generation.**

The implementation of this standard requires PacifiCorp Energy to annually file information related to the fleet heat rate efficiency and develop a plan to improve generation efficiency.

Per agreement with the Utah Public Services Commission, the fossil fuel fleet will include the owned and operated coal fired plants and the gas fired combined cycle plants

Integrated Resource Plan (IRP)

The integrated resource plan (IRP) is a comprehensive decision support tool and road map for meeting the company's objective of providing reliable and least-cost electric service to all of our customers while addressing the substantial risks and uncertainties inherent in the electric utility business. The IRP is developed with considerable public involvement from state utility commission staff, state agencies, customer and industry advocacy groups, project developers, and other stakeholders.

The key elements of the 2013 IRP include the following;

1. A finding of resource need, focusing on the 10-year period 2013-2022,
2. The preferred portfolio of incremental supply-side and demand-side resources to meet this need. (Ref Appendix A)
3. An action plan that identifies the steps the Company will take during the next two to four years to implement the plan.

The IRP uses system modeling tools as part of its analytical framework to determine the long-run economic and operational performance of alternative resource portfolios. These models simulate the integration of new resource alternatives with our existing assets, thereby informing the selection of a preferred portfolio judged to be the most cost-effective resource mix after considering risk, supply reliability, uncertainty, and government energy resource policies.

PacifiCorp continues to evaluate energy efficiency as a resource that competes with traditional supply-side resource alternatives when developing resource portfolios that are compared under a range of cost and risk metrics. The IRP includes core case resource portfolios developed assuming accelerated acquisition of energy efficiency resources. While the assumptions developed for these cases may require further validation and review, cost and risk analysis of these portfolios have led to action items to accelerate acquisition of cost-effective energy efficiency resources.

Summary

Improving the fleet efficiency of PacifiCorp's fossil fuel generation is embedded in the Company's bi-annual IRP, as currently implemented under the rules and standards within the States served. Fossil fuel generation efficiency is typically reported using average heat rate, measured in British Thermal Units (BTU) per kilowatt hour (kWh). The efficiency of a generating unit is improved when the heat rate is decreased. The efficiency of the Company's fleet of fossil fuel generation is improved when the weighted average heat rate of the fleet is decreased.

Fossil fuel generation fleet efficiency can be improved by the following three main activities;

1. Maintaining an emphasis on the continuous improvement of existing generating fleet efficiency
2. Adding new fossil fuel generation with improved efficiency
3. Retiring old and less efficient fossil units

For the purposes of this report, the Company's fleet is defined as coal fired units and gas fired combined cycle plants owned and operated by PacifiCorp Energy.

This report will describe the key items that specifically support the Company's on-going heat rate management and improvement process as it applies to the fossil fuel generation fleet. Charts and tables based on publically available data will be presented that indicate an on-going improvement in the fleet weighted average heat rate over the last 10 years. Charts and tables based on forecasted data will indicate on-going heat rate improvement over the next 10 years.

Factors Effecting Optimum Heat Rate

System Losses due to Equipment Degradation

In general terms, the efficiency of any system in a power plant is a ratio of the useful energy output by a system to the energy input to the system. This yields the following general equation for efficiency:

Efficiency = Useful Energy Output/ Energy Input

The useful energy output and the energy input can be defined in a number of different ways for different types of components or systems, however, for all systems, increasing efficiency results in reduced cost.

A power plant is a collection of individual components or systems that combine to convert chemical energy into electricity. The systems are designed to operate together, but each can be studied individually. A conventional power plant consists of the following systems: boiler, turbine, cooling, and condensate/feedwater.

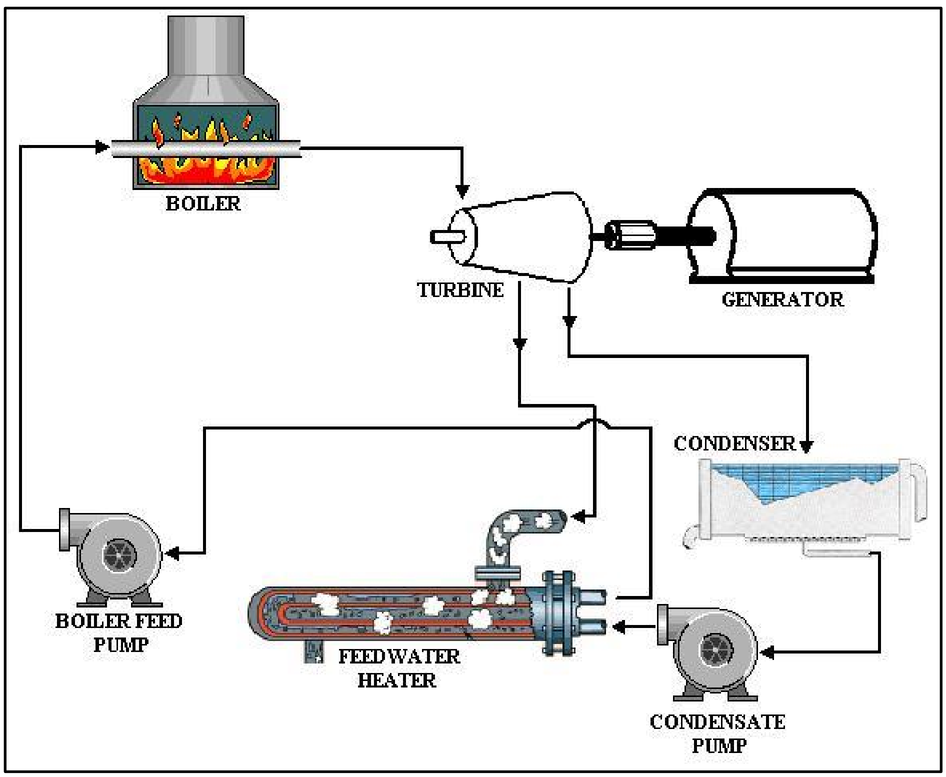
In a conventional fossil power plant, the process follows these steps:

- Combustion converts the chemical energy to heat
- Part of the heat is transferred to the working fluid (water or steam)
- Part of the heat is lost with the heated flue gas

- Part of the steam energy is transferred to the turbine
- The turbine converts the energy in the steam to mechanical energy
- Mechanical energy drives a generator, converting mechanical to electrical
- energy
- A large part of the steam energy is lost as exhaust steam is condensed and heat energy transferred to the condenser circulating water as waste heat.

The goal of combustion is to get as much heat transfer to the boiler while at the same time minimizing heat losses. These heat losses can occur through flue gas, incomplete combustion (unburned carbon) and radiation. On the turbine side the goal is to maximize the amount of energy being pulled from the steam while minimizing the use of auxiliary power and other losses, such as leaks, missing insulation, etc.

A steam power plant is based on the regenerative Rankine cycle. The figure below depicts a simple single-extraction regenerative Rankine cycle.



Single Extraction Regenerative Rankine Cycle

Within these described systems there are many areas where losses will occur due to equipment degradation. The following is a partial list of some of the more common losses along with a brief explanation

1. Turbine
    a. Deposition: Turbine deposits result from impurities in the boiler water being carried over into the steam turbine. Deposits have two primary effects on turbine performance. First, the deposits reduce the flow area in the turbine blades, which reduces flow through the turbine. This reduces the generating capacity of the unit and usually causes a decrease in efficiency. The second effect is an increase in surface roughness, which has a significant, negative impact on turbine stage efficiency.
    b. Solid Particle Erosion: Solid particle erosion occurs when the oxide scale formed in the boiler exfoliates (flakes off) and is carried by the steam to the turbine. This is usually a problem in the first stages of the high pressure and intermediate pressure turbines and is more pronounced on cycling units.
    c. Mechanical Damage: Mechanical damage to the steam path is considered any alteration of the turbine steam path from design other than that caused by deposits or erosion.
    d. Internal Seal Leakage: Internal leakage includes any shaft packing leakage, radial spill strip leakage, casing leakage, snout ring leakage, or any other leakage that allows steam to travel within the turbine shell to a destination other than the intended destination.
    e. Cycle Isolation: Steam power plants have a design flow path for all of the water or steam that enters the system. When flow is diverted from the normal steam path it can be lost from the cycle completely or returned to a section of the cycle where the energy is detrimental to unit performance.
    f. Non-Recoverable Losses: Due to the on-going wear within the turbine cycle, some degradation is non-recoverable. These losses have been documented in the 2-3% range across the industry.
2. Boiler
    a. Dry Gas Losses: The quantity and the temperature of the flue gas controls the total heat that exits the stack. The quantity of gas is dependent on the fuel being burned, but is also influenced by the amount of excess air supplied to the burners. While sufficient air must be provided to complete the combustion process, excessive quantities of air simply carry extra heat out of the stack.
    b. Excess O2 (oxygen): High excess air tends to increase the exit gas temperature and draft losses, and demands adjustments to the fuel/air ratio.
    c. Fuel Properties: Each fossil boiler is designed to burn fuel within a specific range of the design fuel. Fuel heat content variations can have a significant impact on unit performance.
    d. Air Heater Seal Leakage: Air heater leakage affects unit performance in two ways. First, it requires the operator to maintain boiler exit temperatures higher than normal to compensate for the cooling effect of the air leakage or it requires the use of energy using devices such as steam coils, glycol heaters, or hot air recirculation to raise the incoming combustion air temperature. Second, it places an additional duty upon the induced draft fans in a balanced draft plant which may result in capacity limitations.

e. Boiler Tube Surface Fouling: Fouling of the boiler tubes on either side of the tube decreases heat transfer and typically causes a decrease in boiler efficiency. Fouling on the inside of the tubes is usually called scaling or deposition.
f. Casing Leakage: On a balanced draft furnace, air in-leakage can occur at any location where the furnace pressure is less than atmospheric pressure. There are two primary effects of boiler casing in-leakage. In the first instance, air leaks in at ambient temperature, is heated in the boiler, and is carried out the stack. The second problem with air in-leakage is that most units measure boiler O2 at the economizer exit. If there is casing in-leakage after the furnace and before the economizer exit, the economizer O2 measurements will indicate a higher oxygen concentration in the flue gas than is appropriate for complete combustion.

3. Condenser
    a. Condenser Pressure: Efficiency increases as condenser absolute pressure decreases. With condenser pressure as low as possible the amount of heat rejected is lower and the amount of work of the turbine increases, since the enthalpy drop across the turbine becomes greater. Increased condenser pressure will reduce efficiency.
    b. Cooling Water Inlet Temperature: High circulating water inlet temperature has a significant effect on unit performance. An increase in temperature will increase the condenser pressure.
    c. Heat Load: An increase in the heat load on the condenser will increase the condenser pressure. During normal operation, the increase in heat load would normally be a result of an increase in unit load. If the heat load increases for other reasons, then the condenser pressure increases and unit performance suffers.
    d. Circulating Water Flow: Low circulating water flow through the condenser tubes results in an increase in the average circulating water temperature. Since a decrease in flow results in a decrease in water velocity through the tubes, the water has more "residence time" in the tubes, absorbs more heat, and therefore increases the average water temperature.
    e. Tube Fouling: The cleanliness of the tubes in the condenser has a significant impact on the condenser's ability to transfer heat from the exhaust steam to the circulating water. If the circulating water flow through the condenser is normal and the terminal temperature difference is high, it is likely that the heat transfer is impaired due to fouling or scaling.
    f. Air-in Leakage: Air in-leakage can occur through gland seals or through leakage in the piping and components under vacuum. The effect of air in-leakage on the condenser vacuum is that the pressure increases and unit efficiency decreases.
4. Feedwater Heaters
    a. Feedwater Heater Out of Service: Operating a unit with one or more feedwater heaters out of service will have a significant impact on the performance of the turbine, the boiler and other plant auxiliaries. From the heat rate standpoint, removing a heater from service will almost always increase heat rate. Feedwater Heater Degradation: When tube leaks develop in feedwater heaters, the tubes are plugged. Plugging the

tubes reduces the heat transfer area of the feedwater heaters; however, most feedwater heaters are designed with approximately 10 percent excess heat transfer surface.

Controllable Losses

Controllable losses, often called operator controllable losses, are defined as those heat rate losses that can be directly impacted (either positively or negatively) by the actions of the unit control operator. In many cases, the actual "control" is handled by the control system, but often, operator intervention can impact the magnitude of the loss.

In a conventional fossil power plant, the following areas may have controllable losses:

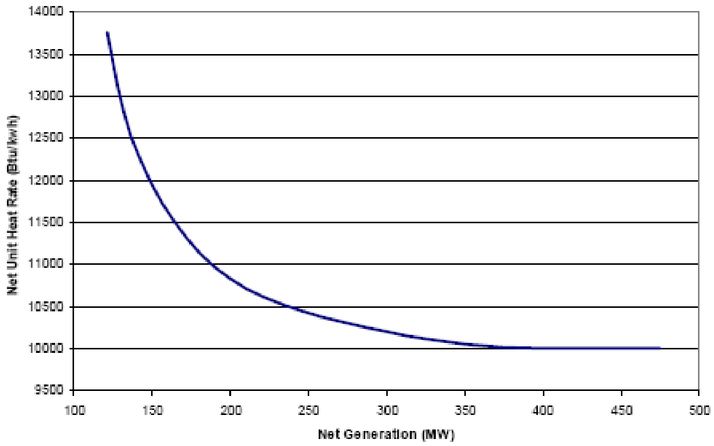
- Steam condition parameters including temperature and pressure
- Spray flows for the superheater and reheater sections
- Economizer O2 and exit gas temperature of the boiler
- Condenser pressure
- Final feedwater temperature
- Auxiliary steam and power

1. Main Steam Pressure: The primary effect of off design main steam pressure is not directly a heat rate effect, but more of a capacity effect. Higher main steam pressure increases the density of the steam entering the turbine, so that more steam flow can pass through the turbine at a fixed valve position.
2. Main Steam Temperature: Main steam temperature is one of the most important of the operator controllable parameters relating to heat rate. The design main steam temperature at the turbine for most modern generating units is 1000ºF (537.8ºC). Increasing the main steam temperature increases the energy available to the turbine.
3. Hot Reheat Temperature: Hot reheat temperature has a significant effect on both heat rate and generation. As with main steam temperature, a higher temperature yields higher steam enthalpy and more energy available to the turbine. Because the intermediate pressure and low-pressure sections produce about 70 percent of the power, this change in available energy has a strong impact.
4. Superheat and Reheat Spray Flows: Attemperation sprays are used for temperature control in a boiler. The sprays are usually controlled to yield either an intermediate temperature (intermediate superheater outlet temperature) or a final boiler temperature (main steam or hot reheat). Reheat and superheat spray flows have distinctly different effects on unit performance, but in general, both increase heat rate and unit output.
5. Excess O2: During the combustion process, the oxygen in the combustion air mixes with the combustibles in the fuel, primarily carbon, to release heat into the furnace. In theory, the combustion process requires an exact amount of oxygen to fully combust all of the carbon in the fuel. In the real world, an additional amount of oxygen is supplied so that as much of the carbon as possible is combusted. This additional amount of oxygen is called "excess air".

6. Exit Gas Temperature: The boiler exit gas temperature is considered the boundary of the boiler, or the last location where a benefit is derived from the hot flue gas. For most boilers, this point is at the air heater outlet. Maintaining the proper exit gas temperature is a delicate balancing act. On one hand, the lower the gas temperature can be maintained the better the boiler efficiency. On the other hand, problems result when the exit gas temperature is low enough to approach the acid dew point temperature.
7. Condenser Pressure: Condenser pressure has the single largest effect on unit performance of any single parameter. A change in condenser pressure causes a change in the enthalpy of the steam at the condenser, which affects the overall usable energy in the turbine cycle. In general, an increase in condenser pressure reduces turbine efficiency and output, and a decrease in condenser pressure improves turbine efficiency and output.
8. Final Feedwater Temperature: From the boiler standpoint, lower feedwater temperature to the economizer requires additional fuel to raise the water temperature in the boiler to the saturation point. If the temperature is low enough, the boiler has to be over fired to achieve the required temperature at the water wall exit.
9. Auxiliary Steam Flow: Most units are configured to supply auxiliary steam from the boiler, either from the drum or the primary superheat section, for startup and low load operation. As the unit load increases, the steam supply usually switches to the turbine crossover or a low-pressure turbine extraction. If steam is supplied from the boiler instead of the turbine, unit load will increase, but heat rate will also increase significantly. Auxiliary steam flow from a lower pressure location in the turbine train is typically more efficient than extraction from the boiler area because power is provided in the high pressure turbine section while reducing the pressure to the required steam supply conditions.
10. Auxiliary Power: Auxiliary power affects the amount of electricity that is available at the switchyard for sale. Increases in auxiliary power increase net unit heat rate and net turbine heat rate based on full load operation. As load decreases, one megawatt is a larger percentage of total power and results in a much more significant impact on heat rate.

Dispatch

Heat rate vs load curves are produced based on data from performance heat rate tests performed over the load range of the unit. These curves tend to be utilized by both the plant and dispatch personnel to know what the heat rate is for a particular unit at a particular load. The figure below is a typical heat rate vs load curve. As shown, heat rate normally increases with lower loads. Therefore if a unit is dispatched to a lower load due to any system condition, then unit efficiency will decrease.



Typical Heat Rate vs Load Curve

Unit dispatch based on incremental generation costs and incremental heat rate along with other factors is further discussed in the Dispatch Philosophy section.

Heat Rate Management Process Summary

Economics naturally drive the Company to improve the fuel efficiency of the existing fossil fuel fleet. Fossil fuel is the Company's single largest expense. PacifiCorp is committed to maximizing fleet generating efficiency.

Heat rate or thermal efficiency of the thermal generating units is affected by many factors including fuel quality, unit original design, load profile, unit operation, unit maintenance, weather, system conditions, and economics. All of these factors change over time. Some of these factors change minute by minute. Some of the factors are out of the control of PacifiCorp personnel. The overall objective of heat rate management is to continuously maintain the best possible unit heat rates given these changing factors.

Heat rate management and improvement is based on the following key principles and concepts:

- The Company maintains an emphasis on operating as near optimum efficiency as practical given fuel quality and maintenance schedules. Control software has been installed to help operators assess the efficiency impact of sub optimal operation on a real time basis. Monthly reports are prepared to track the fleet efficiency relative to budget.
- Units that are not dispatched at maximum output should always be operated in a manner that results in the lowest heat rate. Units that are dispatched at full load are operated in a manner that maximizes generator output and produces the best achievable heat rate at full load conditions.
- The load profile of each unit is dictated by the economic dispatch of the generating units to meet the system load
- Unit and equipment performance is monitored on a continuous basis where practical. Periodic testing is performed on key equipment that is not monitored continuously.
- The Company considers design upgrades to existing units when they become available through improved technology. Improvements are evaluated taking into consideration impact on

efficiency, availability and cost of operation. Economically justified improvements are incorporated into the capital budget and unit overhaul plans.

- Consistent and uniform heat rate reporting is essential for budgeting and regulatory requirements and is coordinated at the corporate level.
- Good feedback on unit heat rate and equipment performance is essential for plant personnel to control and manage heat rate. Personnel will take action if they recognize a problem. Appropriate feedback to personnel on equipment performance, in the form of testing, reports and real time displays, will increase personnel awareness of equipment problems.
- Employee training and awareness of how their actions and the equipment under their control affect heat rate is essential to managing and improving unit performance. Improvement results from knowledge. Unit heat rate will tend to become optimized as plant personnel increase their knowledge of equipment performance and testing.

Heat Rate Management and Improvement

1. **In the short term** (daily – weekly – monthly), continuous improvement is achieved by:

   - Operating the units with controllable parameters as close to target values as possible. Includes review of daily controllable losses report.
   - Maintaining calibrated instrumentation and monitoring systems that provide feedback to plant personnel.
   - Repairing equipment that impact unit heat rate taking into consideration heat rate and market economics.
   - Monitoring equipment performance and conducting equipment performance tests when necessary.
   - Preparing regular reports and ensuring that plant personnel are informed about the current condition of generating units and equipment. This includes regular (monthly) review of equipment performance trends and heat rate related parameters by plant staff.

2. **In the long term** (annually), continuous improvement is achieved by:

   - Periodically analyzing the deviation between actual and target heat rate and initiating corrective action where possible. This includes evaluating the impact of the maintenance cycle on unit heat rate and evaluating the potential for changes in plant design that will improve unit heat rate. Appropriate maintenance work is planned for overhauls. Equipment improvements are budgeted and implemented.
   - Annually updating the ten year forecast of unit heat rates as part of the plant budgeting process.
   - Having readily available performance information for management decision making.
   - Ensuring that all levels in the plant organization have the appropriate heat rate related training.

Plant Level Roles and Responsibilities

Continuous improvement and management of unit heat rates is the responsibility of all plant personnel.

1. **Management** - Good management of heat rate requires that plant management make optimizing heat rate a priority each day.

2. **Operations** - Operations personnel monitor controllable parameters continuously with EtaPRO software and maintain parameters as close to target values as practicable. Benchmark

performance is established by conducting periodic VWO tests with no sootblowers and blowdown closed. Operations personnel conduct cycle isolation checks periodically and after every start-up to ensure that all drains and vents are in their correct position. Heat rate related work orders are appropriately prioritized on the forced outage list so that repairs are completed as soon as practicable. Unit performance and equipment performance combined with other predictive maintenance measures are used to determine if equipment should be overhauled during planned maintenance shut downs.

3. **Maintenance** - Maintenance personnel periodically calibrate key instrumentation required for heat rate and equipment performance monitoring. Equipment deficiencies that impact unit heat rate are corrected taking into consideration heat rate and market economics. High priority work orders directly impacting heat rate are completed on forced outages (as determined by economics). Equipment maintenance during planned overhauls takes into consideration equipment performance.

4. **Plant Performance Engineer:**
   - Monitors unit performance on a daily basis and works with operations personnel to ensure unit is controlled at the best heat rate when not at full load.
   - Works with operations personnel to ensure that unit achieves maximum output when market conditions require full load from each generating unit.
   - Periodically compares unit actual performance to target performance and reports to plant management the causes for the difference.
   - Continuously monitors equipment performance with performance software or conducts periodic tests to assess equipment condition.
   - Works with the plant team to ensure appropriate O&M and Capital monies are budgeted to maintain equipment performance.
   - Works with the plant team to justify and implement equipment upgrades that improve unit performance.
   - Conducts periodic full load capacity tests to validate unit rating.

Corporate Level Roles and Responsibilities

Heat rate related work at the corporate level can be divided into two general functions: 1) Provide technical support to plant personnel for day to day management of heat rate, and 2) Ensure consistent, accurate heat rate information for rate cases and regulatory reporting.

1. **Performance Engineer** - Thermal generation performance technical support is provided by a performance engineer in the Generation Engineering technical support group. The performance engineer:
   - Provides technical support to plant performance engineers for day to day management of heat rate.
   - Conducts and prepares studies requested by corporate management.
   - Provides performance related technical support to the project engineering group, regulation department, environmental department, and other corporate groups as requested.

- Coordinates performance work group meetings and heat rate related training classes for performance engineers.
- Works with plant performance engineers to standardize and maintain "tools" for managing heat rate. This would include PI data historian, performance software EtaPRO/Virtual Plant, and Emerson Enterprise Data Server (EDS).

2. **Combustion Engineer** – Support for coal combustion and related boiler operations is provided by a combustion engineer in the Generation Engineering technical support group. The combustion engineer:
   - Provides technical support to plant performance engineers for day to day management of boiler combustion related issues.
   - Coordinates performance work group meetings and coal combustion related training classes for performance engineers.
   - Establish best practices for combustion improvement and optimization that improve heat rate and reduce derates.
   - Support plant personnel with equipment inspections during scheduled and forced outages.

3. **Heat Rate Process Engineer** - Corporate heat rate related reporting is managed by an individual in the Generation Engineering technical support group. Heat rate data and reports are used for calculating net power costs for rate cases, preparing corporate budgets, financial reports, and for meeting the Company's reporting obligations for the Energy Policy Act of 2005. Managing these reporting requirements at the corporate level ensures consistency and accurate reporting, and provides a single point of contact for all thermal generation performance related data used by other corporate entities. The corporate heat rate related reporting includes:
   - Preparing and updating historical 4-year average input-output curves for each thermal unit every six months.
   - Preparing a monthly corporate level heat rate report.
   - Preparing an annual heat rate improvement plan report for the Utah Public Utilities Commission (Energy Policy Act of 2005)
   - Provides heat rate related data for outside data requests.

4. **System Analyst** - Administration of performance related software and hardware is performed by an individual in the Generation Engineering technical support group. Central administration of the performance software ensures consistency in the application of the software and seamless operation of the software across the corporate platform. The administrator is responsible for hardware and software related to the plant data historians (OSI PI) and plant performance software (EtaPRO/Virtual Plant). The administrator:
   - Ensures servers at each plant are maintained and backed up.
   - Works with corporate IT to ensure the software and hardware is integrated with corporate system and meets NERC/CIPS requirements.
   - Ensures these tools are available to plant personnel on a 24-7 basis.
   - Supports the Ovation Enterprise Data Server (EDS) tool.

5. **Database Management - AIS, EAS, FMS** - Three other key functions related to heat rate are also managed at the corporate level.
    - Unit availability data is recorded in the Availability Information System (AIS) system:
        - Provides technical support to plant personnel who enter data into the system.
        - Provides quality control of the data.
        - Provides PacifiCorp data to the NERC/GADS system.
        - Provides availability data for rate case calculations and regulatory reporting.
        - Provides availability data for outside data requests.
    - Generation data is recorded in the Energy Accounting System (EAS) and is managed by the Energy Operations Back Office. The EAS is the official record of generation from each of the thermal units. This generation is used to calculate monthly and annual heat rate reports.
    - Fuel consumed quantities and quality are recorded in the Fuel Management System (FMS) and managed by the Fuels Group. Fuel quantities and quality recorded in this data base are used to calculate monthly and annual heat reports.

Equipment – Maintenance Overhaul and Design Upgrades

Maintenance Overhaul

The efficiency of generating units, primarily measured by the heat rate (the ratio of heat input to energy output) degrades gradually as components wear over time. During operation, controllable process parameters are adjusted to optimize the unit's power output compared to its heat input. Typical overhaul work that contributes to improved efficiency and increased availability includes;

Turbine Improvements
- Steam path audit identifying key areas for blade and seal repairs or upgrades.
- Cycle isolation valves and controls
- Removal of turbine blade deposits

Boiler Improvements
- Heat Transfer surface cleaning and repair
- Fuel burner system inspection and repair
- Intelligent Sootblowers used to maintain clean heat transfer surfaces
- Repair and replacement of Airheater seals and baskets,
- Repair of air and flue gas ductwork (air-in leakage)

Balance of Plant Improvements
- Boiler Water Chemical Treatment
- Condenser monitoring & cleaning (air-in leakage)
- Cooling Water Treatment
- Feedwater Heaters (maintenance and material upgrades)
- Critical instrumentation
- Pollution control equipment to improve auxiliary power use
- VFD's for large motors to improve auxiliary power use
- Plant lighting to improve auxiliary power use

Operations (Post Outage)
- Combustion control tuning to optimize NOx and CO emissions
- Plant DCS tuning to optimize unit ramp rates and steady state operation

Design Upgrades

When economically justified, efficiency improvements are obtained through major component upgrades of the electricity generating equipment. The most notable examples of upgrades resulting in improved heat rate are steam turbine upgrades and generator upgrades. Turbine upgrades consist of adding additional rows of blades to the rearward section of the turbine shaft (generically known as a "dense pack" configuration), but can also include replacing existing blades, replacing end seals and enhancing seal packing media. Generator upgrades consist of cleaning and rewinding the coils in the stator, and servicing the electromagnetic core. Such upgrade opportunities are analyzed on a case-by-case basis, and are tied to a unit's major overhaul cycle, and, because they are often capital intensive, are only implemented if economically justified.

Dispatch Philosophy

Incremental Generating Cost and Incremental Heat Rate

The dispatch order of generating units is a function of incremental generating costs, transmission line constraints, spinning reserve requirements, and other transmission constraints. The incremental generating costs are calculated from incremental Operations and Maintenance (O&M) costs, incremental fuel costs, and incremental heat rate.

Incremental fuel costs: Some fuel contracts specify a fixed cost per BTU of fuel supplied. In these cases, the incremental cost of fuel is a constant $/mmBTU. Some contracts decrease the price of fuel as the quantity of fuel purchased increases. The incremental cost of fuel in these contracts decreases as the quantity of fuel purchased increases.

Incremental O&M costs: Some plant O&M costs are constant regardless of plant capacity factor. Regular labor, rents, leases, and many maintenance costs are typically “fixed” and independent of plant capacity factor. Other costs are directly proportional to plant capacity factor. Reagent for scrubbers, water treatment chemicals, and ash hauling contract costs are typically “variable” costs that change in direct proportion to net unit output. These variable costs make up the plant incremental O&M costs.

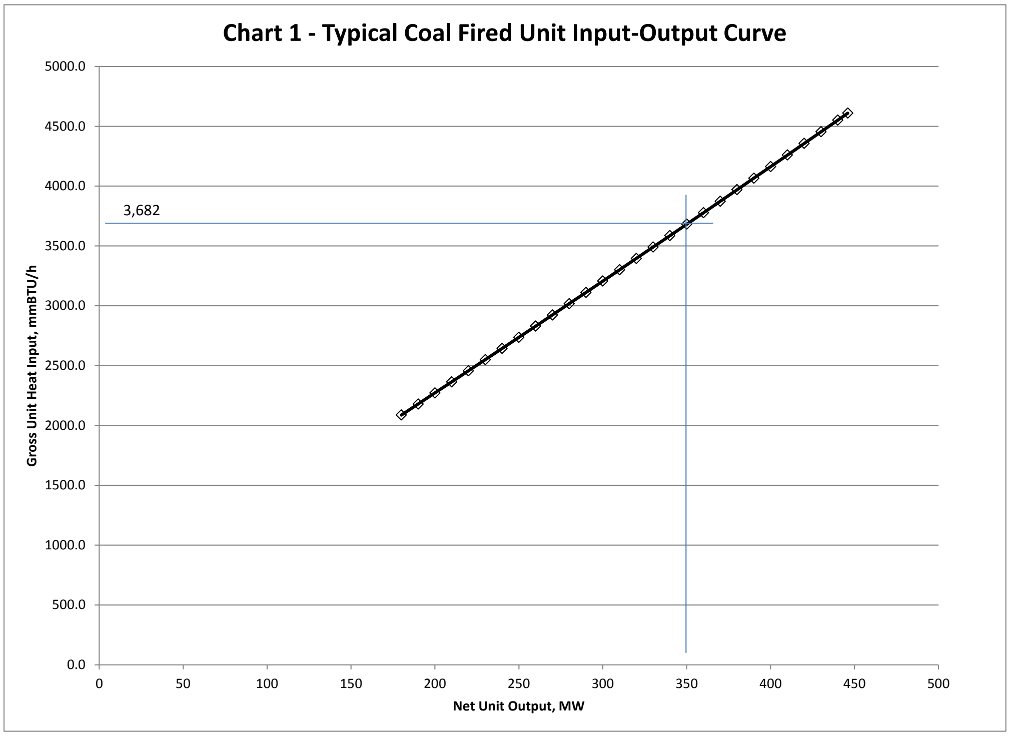
Incremental Heat Rate: Generating unit efficiency varies from minimum load to maximum load. Three curves are used to describe thermal generating unit performance from minimum load to maximum load. The fundamental curve is the “Input Output” curve that shows the relationship between heat input to the unit and net electrical output out. Chart 1 represents a typical input-output curve for a coal fired unit.

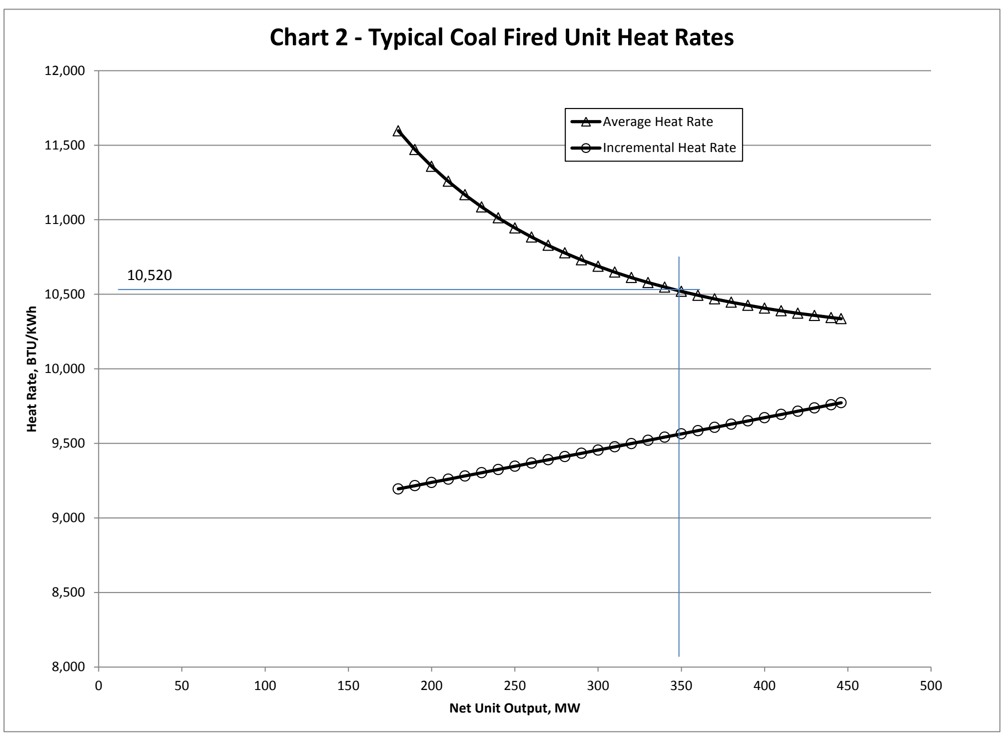
The second curve is the “Heat Rate” curve or more specifically the average heat rate curve. The “average” heat rate is the total BTU heat input at any given output divided by the net unit output. This value is commonly referred to as the unit “heat rate” and is the efficiency of the unit for a net unit output. The average heat rate curve is derived from the Input-Output curve. For example on Chart 1, a load of 350 MW requires a heat input of 3682 mmBTU. The average heat rate is:

$$Average\ Heat\ Rate = \frac{\left(\frac{3{,}682\ mmBTU}{h} * \frac{1{,}000{,}000\ BTU}{mmBTU}\right)}{\left(350\ MWh * \frac{1{,}000\ KWh}{1\ MWh}\right)} = 10{,}520\ \frac{BTU}{KWh}$$

Chart 2 shows that the average heat rate for 350 MW is 10,520 BTU/KWh. The average heat rate of a unit improves (decreases) as the net unit output is increased.

The third curve is the “Incremental Heat Rate” curve or “Incremental” curve. The incremental heat rate is the number of BTUs required to increase the net unit output one more KW. The incremental curve is obtained by taking the derivative of the Input-Output curve or plotting the slope of the Input-Output curve at different outputs. Chart 2 shows the incremental heat rate curve for a typical coal fired unit. The incremental heat rate increases with net unit output.





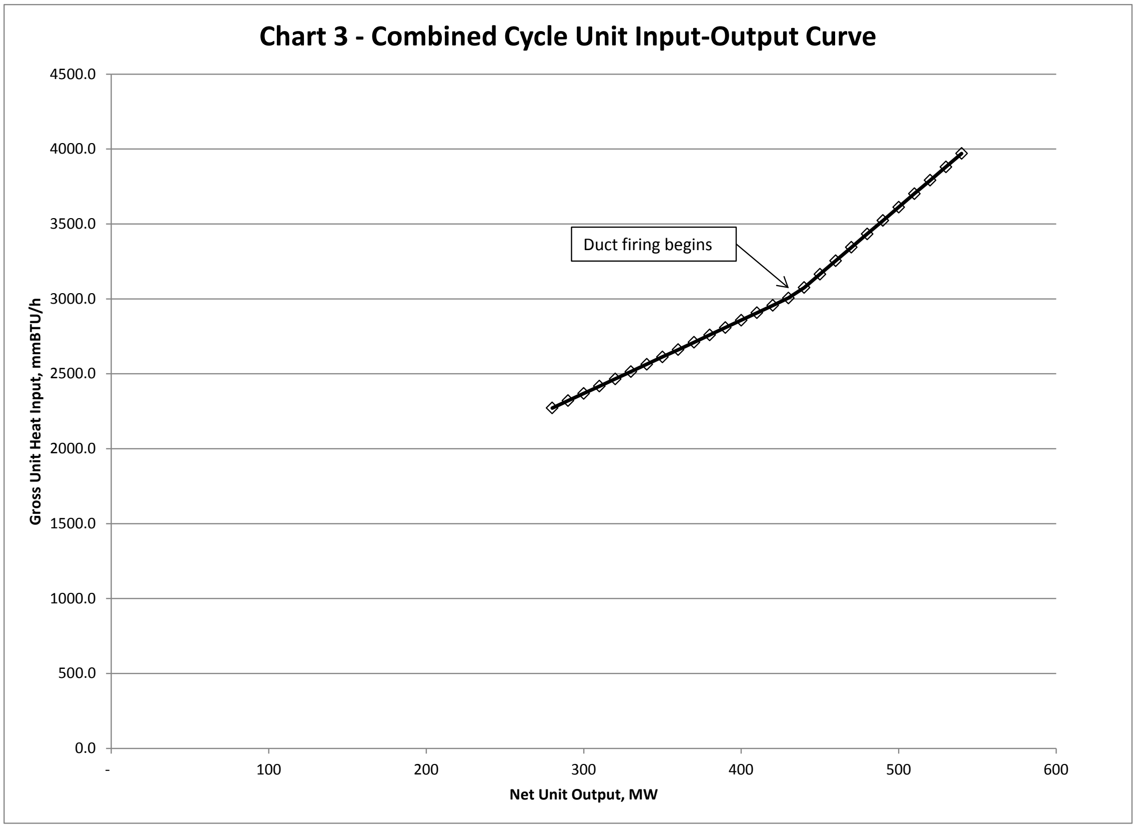


Chart 3 - Combined Cycle Unit Input-Output Curve
Duct firing begins
Gross Unit Heat Input, mmBTU/h
Net Unit Output, MW
4500.0
4000.0
3500.0
3000.0
2500.0
2000.0
1500.0
1000.0
500.0
0.0
-
100
200
300
400
500
600

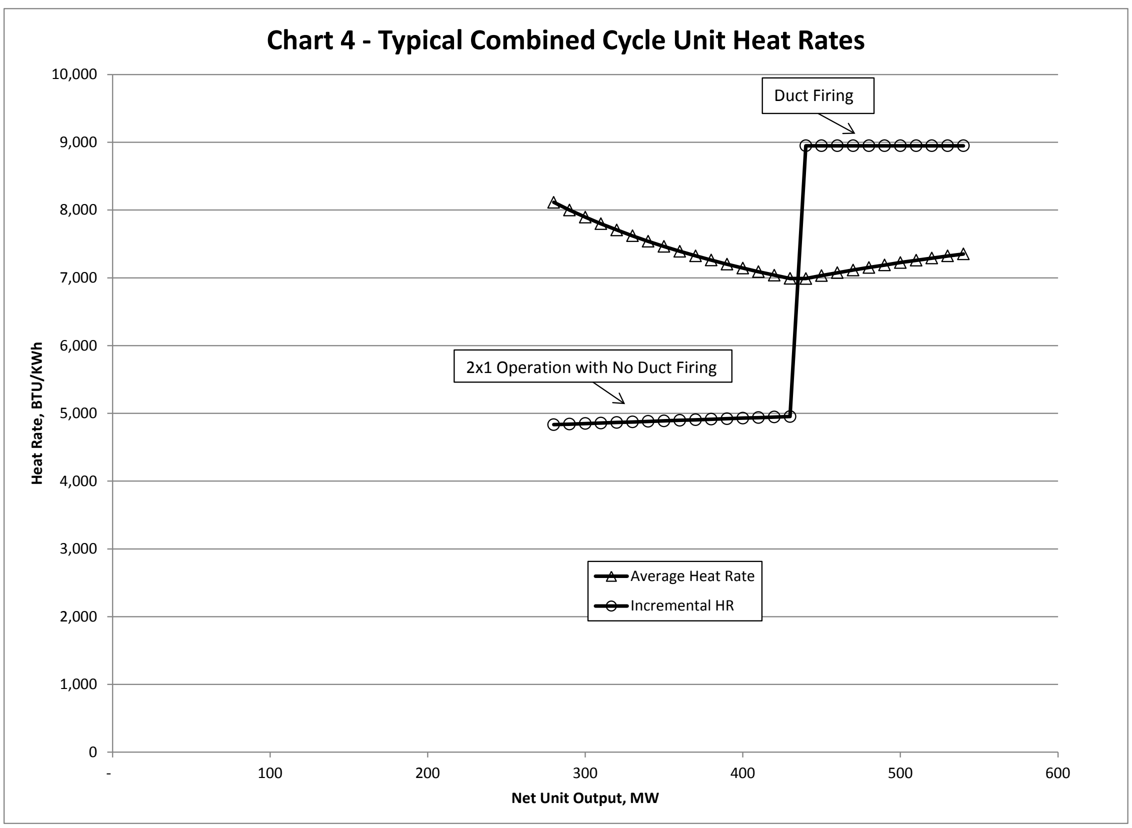


Chart 4 - Typical Combined Cycle Unit Heat Rates
Duct Firing
2x1 Operation with No Duct Firing
Average Heat Rate
Incremental HR
Heat Rate, BTU/KWh
Net Unit Output, MW
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
-
100
200
300
400
500
600

Chart 3 and Chart 4 illustrate the curves for a combined cycle unit. Combined cycle units are much more efficient than coal fired units. The average heat rates on Chart 4 are much lower than the average heat rates on Chart 2. Many combined cycle units are equipped with duct firing to provide additional capacity. Producing MW with duct firing is not as efficient as combined cycle with no duct firing. Chart 3 and Chart 4 illustrate that the heat input for each KW increases when duct firing. Chart 4 shows that the average heat rate improves (becomes less) as unit output increases up to the point of duct firing. After duct firing begins, the heat rate becomes poorer as load increases.

Incremental Generating Costs

Incremental Generating Costs are calculated in the following manner:

$$Incremental\ Generating\ Costs, \$/KWh = IOM + IFC * IHR$$

IOM = Incremental O&M Costs, $/KWh
IFC = Incremental Fuel Costs, $/mmBTU
IHR = Incremental Heat Rate, BTU/KWh

The lowest generation cost occurs when all operating units are at the same incremental generating cost.

At PacifiCorp, the sale, production, transmission, distribution, and delivery of the electrical product all occur at the same instant of time. The dispatch of the generating units is handled by a dispatch group. This group, in real time, determines which unit will generate the next unit of electrical power. This is always the least cost MW determined by not only the least cost of generation at the plant, but considering the loss due to transmission, and many other factors. The dispatch group always has the most up-to-date values of unit heat rate, and all costs associated with each generating unit and source. This ensures that at any given instant of time that the next MW sold is the one that costs PacifiCorp, and therefore our customers, the least amount of money. Figure 1 shows the resulting heat rate history and future forecast heat rate for our system.

The following Charts 5 and 6 illustrate the differences between incremental generating cost and incremental heat rate. These are only examples and are based on data collected during 2013. It should be noted that units that have the best incremental heat rates do not always have the lowest incremental cost.

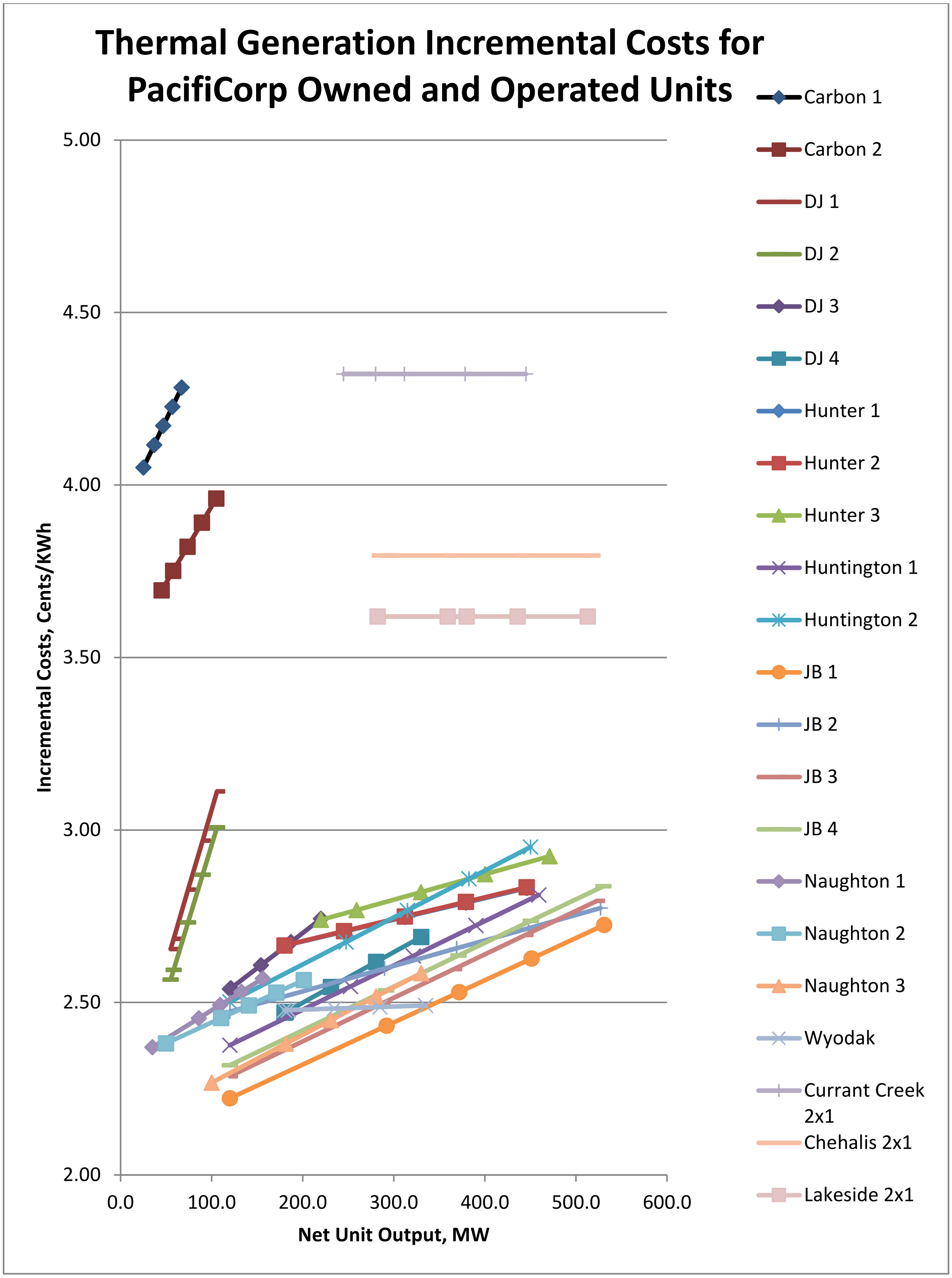


Chart #5 - Incremental Generating Cost Curves

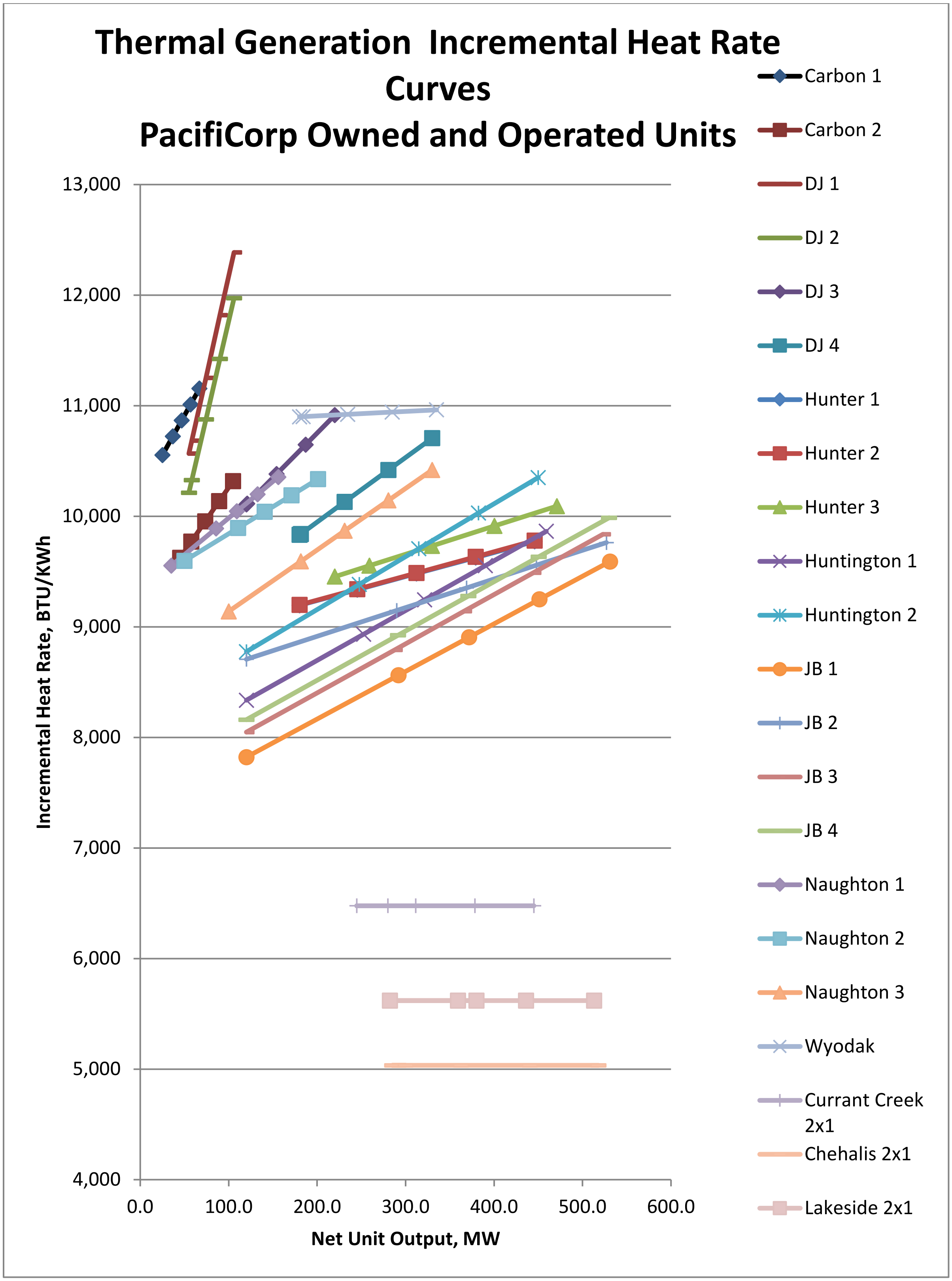


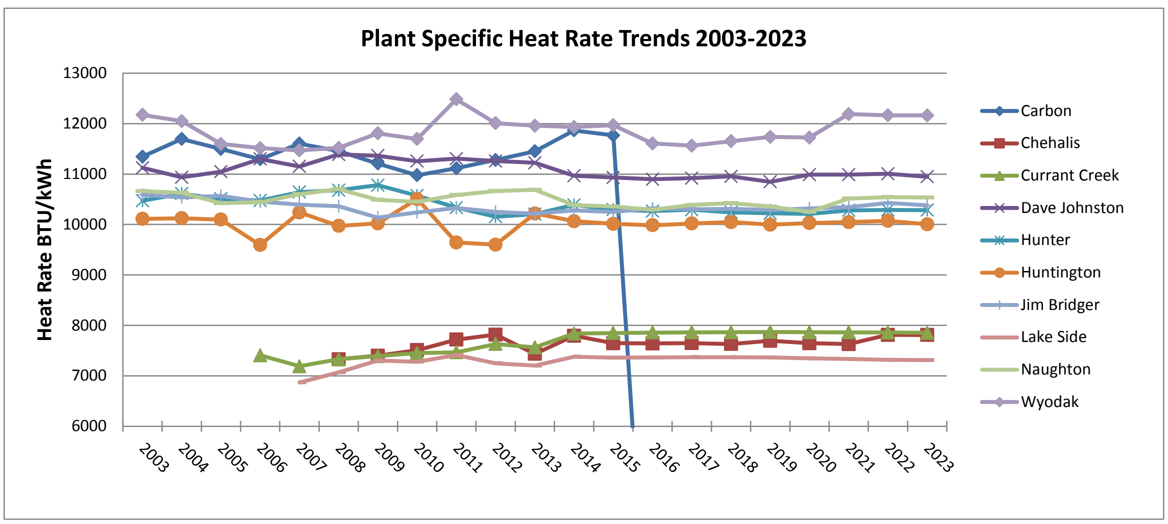
Chart #6 - Incremental Heat Rate Curves

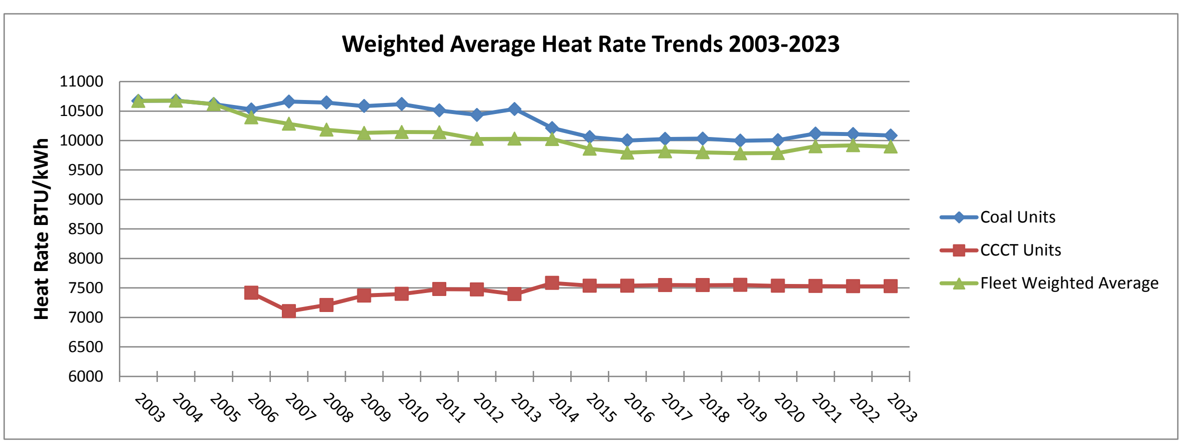
Fleet Heat Rate Trends

10 Year Historical and 10 Year Forecast

The table and two charts below represent both historical and forecast heat rates for each of the PacifiCorp owned and operated plants. The historical data is based on FERC form 1 reports and the forecast data is based on PacifiCorp's 10 year budget forecast. This data shows there is an on-going improvement with the fleet weighted average heat rate.

Plant/Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Carbon	11346	11694	11498	11295	11603	11454	11209	10978	11115	11279	11451	11865	11767	0	0	0	0	0	0	0	0
Chehalis						7331	7401	7511	7720	7817	7437	7797	7648	7644	7650	7632	7696	7648	7631	7813	7810
Currant Creek				7409	7192	7331	7391	7452	7468	7632	7566	7839	7850	7858	7862	7865	7873	7866	7863	7860	7852
Dave Johnston	11122	10937	11047	11300	11151	11388	11365	11256	11305	11259	11222	10965	10932	10896	10919	10953	10847	10989	10989	11006	10947
Hunter	10471	10613	10509	10474	10642	10678	10779	10572	10336	10155	10,206	10388	10295	10266	10293	10243	10222	10209	10281	10289	10285
Huntington	10112	10124	10099	9595	10240	9972	10023	10504	9644	9601	10219	10066	10014	9986	10021	10048	9996	10030	10048	10071	10004
Jim Bridger	10591	10538	10569	10453	10392	10363	10138	10240	10328	10251	10217	10282	10250	10319	10301	10313	10289	10320	10345	10430	10379
Lake Side					6872	7071	7305	7280	7413	7251	7205	7380	7363	7365	7371	7369	7364	7348	7335	7318	7313
Naughton	10663	10629	10425	10442	10603	10704	10490	10451	10585	10664	10687	10386	10357	10294	10388	10424	10357	10252	10513	10541	10536
Wyodak	12172	12050	11597	11514	11469	11520	11808	11695	12482	12009	11957	11933	11968	11605	11562	11652	11736	11723	12189	12164	12163
	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Coal Units	10673	10676	10618	10527	10662	10645	10584	10619	10510	10434	10534	10211	10058	10001	10027	10033	9997	10006	10118	10108	10085
CCCT Units				7416	7104	7211	7371	7397	7480	7474	7395	7584	7538	7538	7548	7546	7551	7535	7532	7529	7528
Fleet Weighted Average	10673	10676	10618	10391	10284	10183	10129	10145	10140	10027	10031	10025	9860	9795	9816	9800	9783	9787	9902	9919	9898





Heat Rate Index

The term "Heat Rate" is a performance indicator that was developed in the early days of the electric power generation industry to assist power plant owner/operators to price their product - electricity. Simply multiply a quantity of electricity by the Heat Rate number to determine the thermal cost of the product. Heat Rate quickly became the industry standard to use by plant owners/operators for the purpose of measuring electricity production efficiency.

Efficiency can always be defined as "what you got" divided by "what you had to pay for to get it". Heat Rate is inversely proportional to the power production process efficiency:

$$\text{Heat Rate} = 3413 \text{ BTU/KWH} / \text{Efficiency}$$

Power plant Heat Rate is a number that is initially determined by the designer designing the power plant:

$$\text{Heat Rate} = \frac{\text{Energy into the process in British Thermal Units, or BTU's}}{\text{Energy out of the process in Kilowatt-Hours}}$$

It is a value that can be measured and tested after the plant is built to determine how close the final product came to meeting the intent of the designer and builder. Following construction, it is calculated routinely for various purposes, including monitoring steam turbine performance, unit gross performance, unit net performance, gas turbine performance, and combined cycle performance, each with several possible variations and definitions for their distinct purposes. The units attached to Heat Rate are Btu/kWh.

The value of calculated Heat Rate does not necessarily remain constant, and changes regularly due to external "boundary conditions" in flux. Boundary conditions are the conditions that surround the system in question. For example, some key boundary conditions of a power plant would be the ambient air temperature, pressure, ambient relative humidity, fuel temperature, fuel constituents, and many more.

The Heat Rate of a power plant is very dependent upon many conditions outside of the control of the plant owners and operators. This list of conditions would include the boundary conditions, fuel constituents, equipment and process changes, and more. Those used to adjust our Unit Design Heat Rates are listed below.

- Operation less than 100% load
- Off design fuel quality
- Auxiliary power consumption
- Main transformer losses
- Compressor inlet air temperature

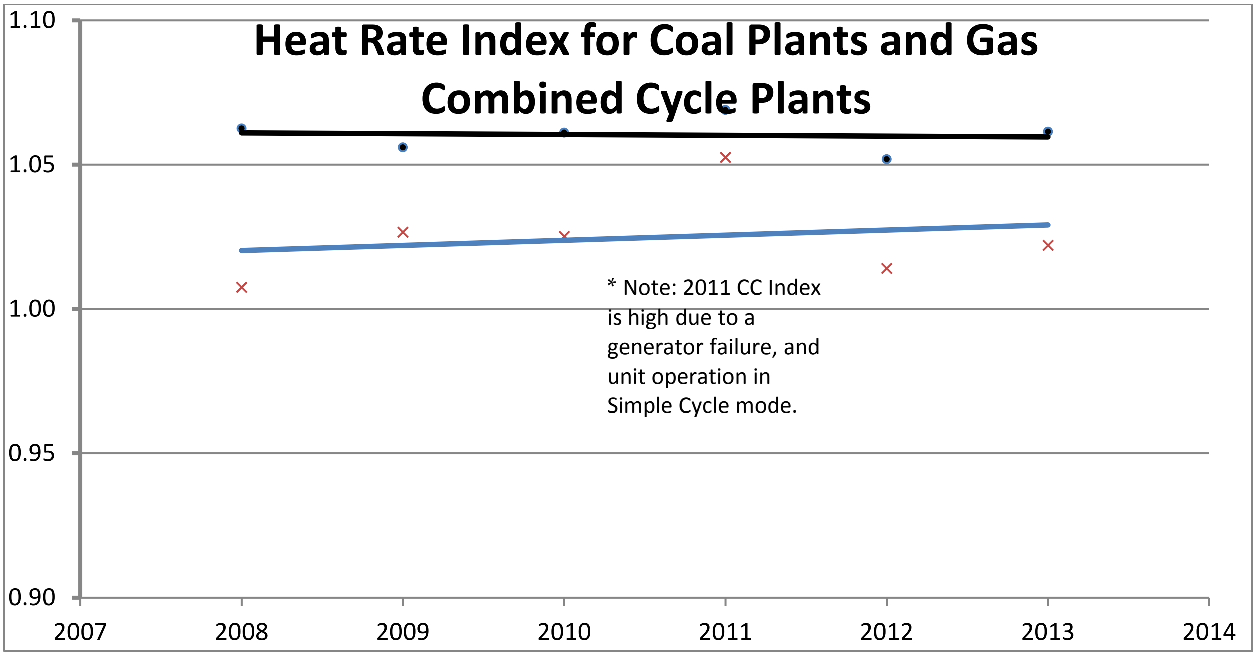
At the request of the Public Service Commission of Utah, PacifiCorp has agreed to calculate a "Heat Rate Index". This Index will be used to measure how well our plants performance is relative to how well our plants performance was originally designed to be, and purchased by PacifiCorp. The Heat Rate Index is therefore a ratio of the above two values.

It is felt that this index will make the indication of our performance more stable over time as it will normalize changing boundary conditions, and provide more meaning to the user. The Heat Rate Index is defined here as a ratio of the actual measured Heat Rate divided by the designers calculated Heat Rate (adjusted for deviations from design boundary conditions). The numerator and denominator of this ratio must be adjusted so that an “apples to apples” comparison can be made. Our units operate in a changing environment.

For the purposes of this report, an index is calculated for each power generation unit by measuring the actual total fuel burned energy during the period (in BTU) and dividing this by the total net product output for the period (in KWH). The resulting value is then divided by the design heat rate adjusted for the period average boundary conditions for the year of interest, ambient air temperature, fuel differences, and more.

$$\text{Heat Rate Index or } HR_i = \frac{\text{Period Measured Heat Rate}}{\text{Unit Designers Heat Rate}}$$

A load weighted average of these unit indices is then determined as the PacifiCorp fleet Heat Rate Index for each year of study. A plot of these PacifiCorp Heat Rate Indices is shown below.



The Commission has also requested that this process be duplicated for the gas turbine combined cycle units as well. This is also shown in the figure above. The upper (black) curve represents the Coal Fleet and the lower (blue) curve represents the Combined Cycle Fleet.

There is one anomaly that stands out on the curve for these Heat Rate Indices above, and must be addressed here. For the Combined-Cycle Heat Rate Index, the data point for the year 2011 is markedly higher and out of the normal trend. This is due to a physical problem that occurred and required a combined cycle unit to be operated in simple cycle mode for an extended period of time. Simple-Cycle operation is operation at a very much higher heat rate due to the loss of the steam cycle to scavenge lost energy. This resulted in a remarkably higher heat rate for this unit, as well as the PacifiCorp combined cycle heat rate index for this year.

Data used for the construction of these Heat Rate Index curves shown above are presented below.

Source\Year	2008	2009	2010	2011	2012	2013
Coal	1.062512	1.055966	1.061122	1.069029	1.051894	1.061398
Gas/CC Units	1.007596	1.026657	1.025194	1.052603	1.014124	1.022043

One of the intents of the calculation of this Index is to normalize much of the effects of changing boundary conditions from year to year. The resulting performance measurement, or Heat Rate Index, will be less dependent on operational boundary conditions than the basic, unadjusted, Heat Rate measurement reported.

All efforts have been made to make comprehensive adjustments to our design Heat Rates used in the calculations of the Heat Rate Indices. However, adjustments have not been made for regulatory requirements imposed upon each unit in varying degrees causing unit efficiency and heat rate changes. This would include scrubber additions, and other back-end clean-up additions that may modify the process and add station, and unit, parasitic loads. These have a marked effect on our Heat Rates, and therefore, the indices calculated.

PacifiCorp routinely performs best maintenance practices to maintain our Units heat rate and efficiency. Therefore, Most of our routine annual maintenance outages shown in the below Table are used for normal routine maintenance, such as air heater cleaning, gas turbine internal washes, and routine boiler maintenance and cleaning work. The table shown in Appendix 3, lists PacifiCorp's schedule of planned outages longer than 7 days for the period of 2014-2023. This information in this table routinely changes in order to optimize the scheduled work, and facilitate any unplanned unit repairs and maintenance work.

For a coal unit, unit loading has the largest effect on heat rate. Unit loading is defined here as the actual average period net load for the unit while it is operating and generating electricity, and is calculated on a unit net basis. By using the entire period's data, it covers the entire load range experienced while generating electricity for the year.

Operational boundary conditions should be as close to the designers plan as possible. These include levels of soot blowing (dependent on fuel ash variations), boiler blow-down (to maintain cycle water quality), and other designer considered boundary conditions. PacifiCorp units operate per the designers' plans and specifications wherever possible.

The PacifiCorp Net Heat Rate Index is calculated by taking the generation weighted average for the year in question of the unit net heat rate indices. This is calculated for both the coal fired units and the gas fired combined cycle units, independently, and is displayed in the previous heat rate index graph. From this, it can be seen how close our performance is, compared to the designers' original intended performance. This will continue to be tracked in the future to monitor how well our units are performing compared to how they were intended to operate.

10 Year Capital Project List Effecting Heat Rate

The following capital projects have been identified that reduce our units' performance, including:

Plant	Unit	Project Description	Year	Unit HR Effect Btu/KWh	Measure	Project Number	Estimated Cost
Dave Johnston	1	Mercury Capture	2015	2	HR Increase	10002178	$2,035,000
Dave Johnston	2	Mercury Capture	2015	2	HR Increase	10002179	$2,035,000
Dave Johnston	3	Mercury Capture	2015	2	HR Increase	10002180	$2,961,094
Dave Johnston	4	Mercury Capture	2015	2	HR Increase	10002181	$2,961,094
Dave Johnston	1	Low NOx Burners	2016	10	HR Increase	10002176	$13,444,925
Dave Johnston	2	Low NOX Burners	2018	10	HR Increase	10005972	$13,444,925
Dave Johnston	3	Low NOX Burners	2015	10	HR Increase	SDVJ/2008/C/CA3	$533,904
Hunter	1	Baghouse	2014	20	HR Increase	SHTR/2012/C/100	$55,575,828
Hunter	2	SCR Addition	2023	36	HR Increase	10009397	$128,352,593
Hunter	3	SCR Addition	2022	36	HR Increase	10002885	$66,567,392
Jim Bridger	1	Mercury Capture	2015	2	HR Increase	10003392	$1,164,545
Jim Bridger	2	Mercury Capture	2015	2	HR Increase	10003393	$1,164,545
Jim Bridger	3	Mercury Capture	2015	2	HR Increase	10003394	$1,164,545
Jim Bridger	4	Mercury Capture	2015	2	HR Increase	10003395	$1,164,545
Jim Bridger	1	SCR Addition	2022	57	HR Increase	1003391	$128,259,644
Jim Bridger	2	SCR Addition	2021	57	HR Increase	1003395	$158,481,630
Jim Bridger	3	SCR Addition	2015	57	HR Increase	10003396	$157,660,078
Jim Bridger	4	SCR Addition	2016	57	HR Increase	1009398	$193,399,446
Naughton	1	Mercury Capture	2014	2	HR Increase	10003749	$1,187,500
Naughton	2	Mercury Capture	2014	2	HR Increase	10003750	$1,187,500
Wyodak	1	Mercury Capture	2014	2	HR Increase	10004048	$2,961,094
Total				372	HR Increase		$935,706,827

Each of these projects increases our units' parasitic consumption of electric power, thereby reducing our efficiency and increasing our unit heat rate.

Vendor improvements to our gas turbine gas paths may be possible, and are being considered that may prove economical for our future consideration. Time and engineering analysis will prove their destiny.

Appendix A: IRP Preferred Portfolio 2013-2032:

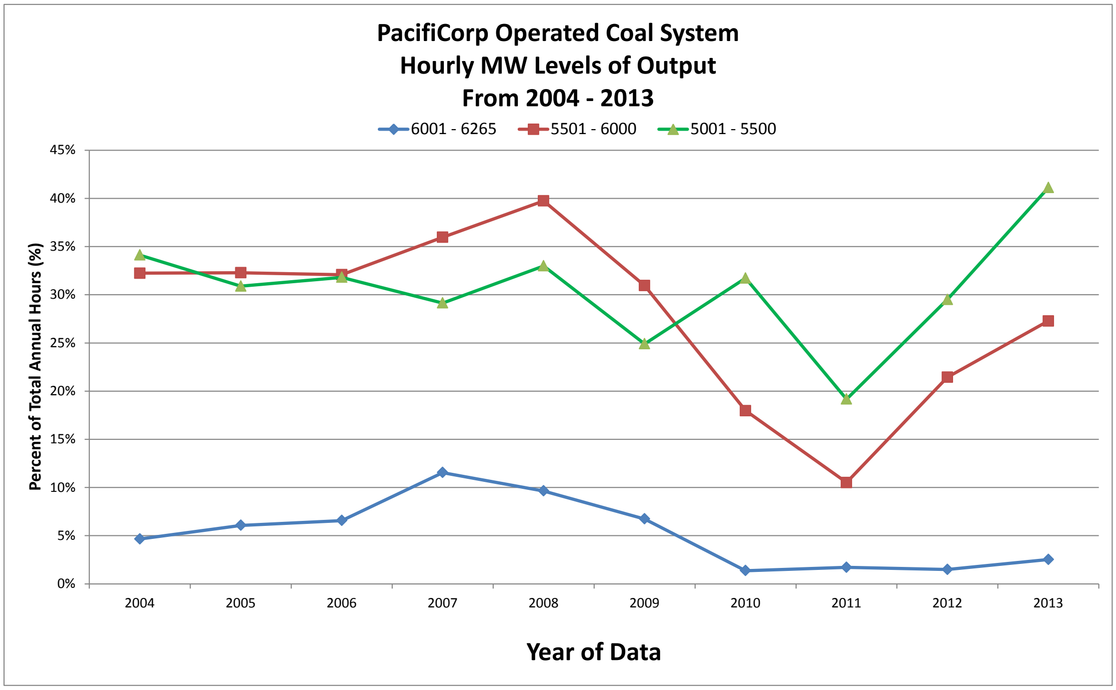
This table is from PacifiCorp's 2013 Integrated Resource Plan (IRP). It describes new resources that would become available and old resources and the anticipated retirement years.

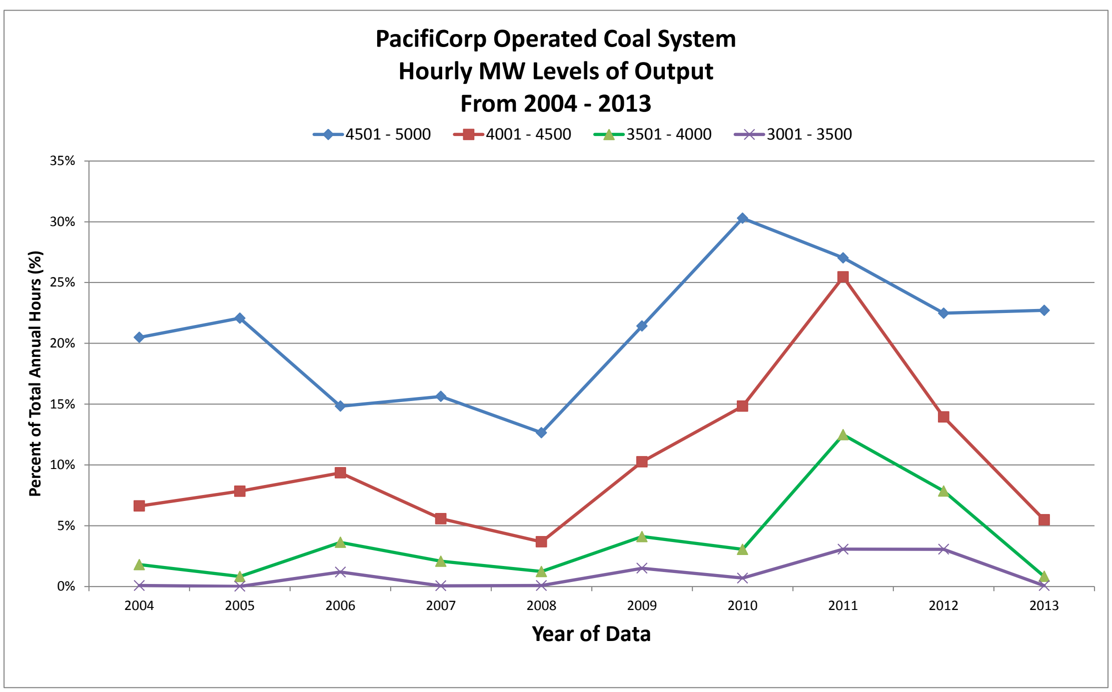
	Preferred Portfolio	Capacity (MW)																				Resource Totals 1/	
	(EG-2 Case-07a)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	423	-	-	-	846
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	181
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	88	-	-	-	-	88
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	19	-	-	-	-	-	22
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14	19	88	-	-	-	-	121
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	3	3	31	59
	DSM, Class 2, UT	63	61	54	52	50	48	48	43	42	40	30	33	30	28	27	26	24	22	21	20	500	760
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	7	7	8	7	7	7	7	7	56	127
	DSM, Class 2 Total	69	67	61	60	59	57	58	52	52	51	39	42	39	38	37	36	34	32	31	30	587	946
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	37	151	248	19	161	255	-	132	253	297	292	300	59	109	74	62	119
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	-	-	-	-	-	-	72
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	37	41	33	32	29	28	24	21	20	23	23	22	22	23	26	26	24	19	22	22	288	517
	DSM, Class 2, WA	8	7	8	8	8	7	7	6	6	7	5	5	5	5	5	4	4	3	3	3	71	112
	DSM, Class 2 Total	45	49	42	41	38	35	32	28	27	30	28	28	28	29	32	30	29	23	26	26	368	647
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	131	130	247	262	297	297	297	297	297	297	297	237	297	297	297	297	297	297	297	297	255	273
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	221	305	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	260	317
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	141	777	121	119	116	106	104	95	96	98	84	942	302	84	171	944	167	1,155	73	254		
	Annual Additions, Short Term Resources	650	709	845	983	1,102	1,209	1,323	1,420	1,191	1,333	1,427	1,112	1,304	1,425	1,469	1,464	1,472	1,231	1,281	1,246		
	Total Annual Additions	791	1,486	966	1,102	1,218	1,315	1,427	1,515	1,287	1,431	1,511	2,054	1,606	1,509	1,640	2,408	1,639	2,386	1,354	1,500		

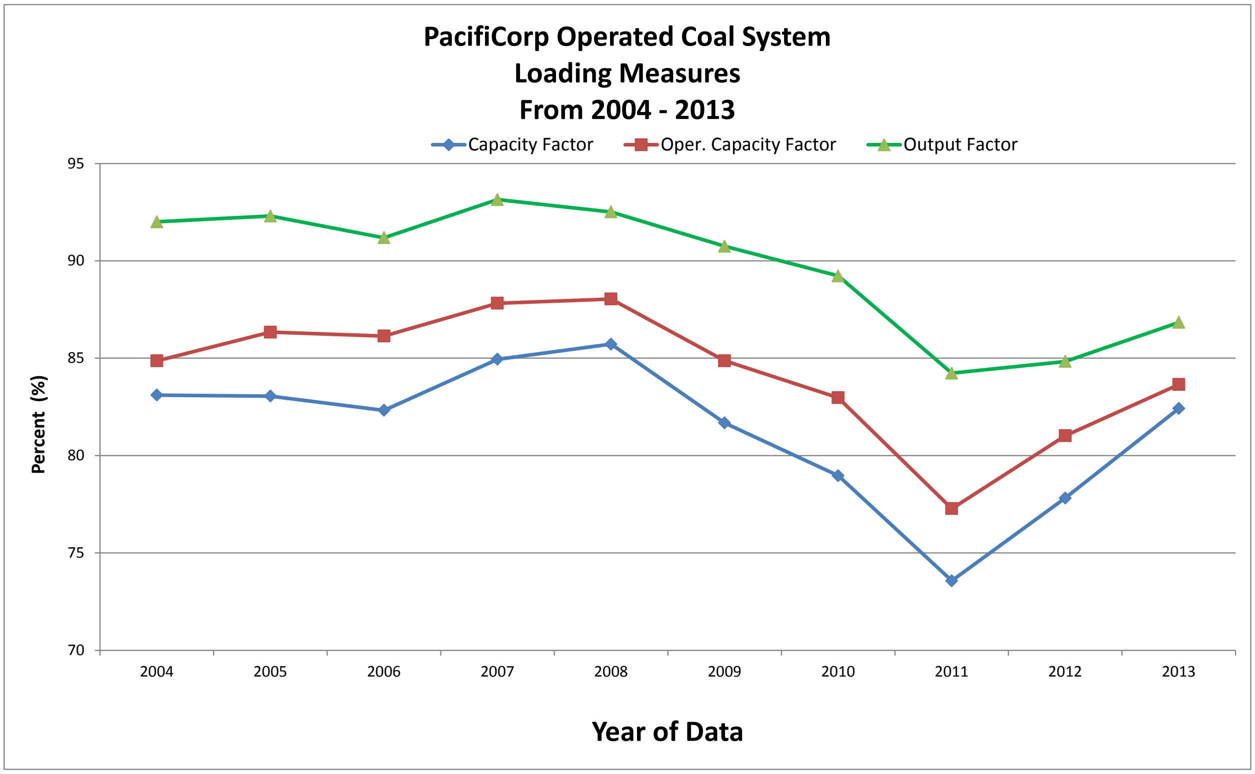
1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Appendix B: PacifiCorp Owned and Operated Coal Fleet MW Output Levels

Per request of the commission, the following charts are provided to illustrate the capacities and output of the coal fleet. Each line on the first two charts represents a MW output range and the percent total annual hours at that range. The third chart represents the capacity factor, operating capacity factor and the output factor of the coal fleet. In general, these charts indicate that the coal fleet has been operating at reduced capacity up to 2011 and then has begun to increase over 2012 and 2013.






PacifiCorp Operated Coal System
Loading Measures
From 2004 - 2013
Capacity Factor
Oper. Capacity Factor
Output Factor
95
90
85
80
75
70
Percent (%)
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
Year of Data

Appendix C: PacifiCorp Owned and Operated Major Outage Schedule

Major Outage Schedule for PacifiCorp Coal and Gas-Fired Combined-Cycle Units

Plant-Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Chehalis 1		5/2/2015				5/4/2019				
Chehalis 2		5/2/2015				5/4/2019				
Currant Creek 1A			4/22/2016			4/18/2019			3/26/2022	
Currant Creek 1B			4/22/2016			4/18/2019			3/26/2022	
Dave Johnston 1			3/26/2016				3/21/2020			
Dave Johnston 2	4/12/2014				4/7/2018				3/17/2022	
Dave Johnston 3		3/9/2015				3/17/2019				3/17/2023
Dave Johnston 4				3/17/2017				3/17/2021		
Hunter 1	3/22/2014				3/3/2018				2/26/2022	
Hunter 2		3/7/2015				3/2/2019				2/25/2023
Hunter 3			2/27/2016				2/29/2020			
Huntington 1	9/27/2014				9/23/2018				9/3/2022	
Huntington 2		9/19/2015				10/15/2019				9/16/2023
Jim Bridger 1	4/12/2014				4/7/2018				3/26/2022	
Jim Bridger 2				4/8/2017				3/27/2021		
Jim Bridger 3		9/5/2015				4/27/2019				4/1/2023
Jim Bridger 4			9/3/2016				4/25/2020			
Lake Side 11		5/9/2015			9/29/2018			10/4/2021		
Lake Side 12		5/9/2015			9/29/2018			10/4/2021		
Lake Side 21			4/1/2016	10/1/2017		10/1/2019		10/4/2021		4/1/2023
Lake Side 22			4/1/2016	10/1/2017		10/1/2019		10/4/2021		4/1/2023
Naughton 1			4/16/2016				3/28/2020			
Naughton 2		4/4/2015				10/12/2019				3/11/2023
Naughton 3		1/1/2015					3/21/2020			
Wyodak			4/16/2016				3/14/2020			

Signature Page

Corporate Heat Rate Engineer		Al Hall	
Signature:		Date:	28 April 2014

Manager Engineering/Environmental		Greg Hunter	
Signature:		Date:	28 April 2014

Managing Director, Generation Support		Rod Roberts	
Signature:		Date:	28 April 2014