2012

Thermal Integration of an MEA Post Combustion Carbon Capture System With a Supercritical Coal Fired Power Plant

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by

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A Thesis

Presented to the Graduate and Research Committee

of Lehigh University

in Candidacy for the Degree of

Master of Science

in

Mechanical Engineering

Lehigh University

December 2011

This Thesis is accepted and approved in partial fulfillment of the requirements for the Master of Science in Mechanical Engineering.

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Acknowledgements

I would like to thank my research advisor, Dr. Edward Levy, for providing me with the opportunity to work at the Energy Research Center. I would also like to thank him for the countless hours he spent with me to help complete this thesis as well as giving guidance and the extra time he put in to help me become a better engineer. I would also like to thanks Jodie Johnson and Ursla Levy for their administrative support during my time at the Energy Research Center. Joshua Charles, Erony Martin, Elaine Aiken, and Austin Szatkowski's previous theses work on the coal power plant and MEA system has been invaluable in helping me complete my thesis. More thanks is extended to Nipun Goel for help with other projects. Lastly I would like to thank my girlfriend Erica, my family, and friends for their support during the pursuit of my Master's degree.

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Abstract

The ASPEN Plus process modeling software was used to analyze a coal-fired power plant with a post combustion carbon capture system. Three different types of coals were modeled, a bituminous Illinois #6 coal, a subbituminous Powder River Basin coal, and a Lignite coal. The boiler firing these coals provides heat to a supercritical steam cycle, also modeled in ASPEN Plus. The flue gas leaving the boiler enters an MEA carbon capture system. This system requires a large amount of heat which will be provided by a steam extraction from the steam cycle. After leaving the MEA system, the carbon dioxide is then sent to a compression system where it is pressurized so that it can be sequestered. Three different compression systems were modeled, a higher compression ratio, RAMGEN compressor, an Inline compressor with moderate compression ratios, and a low compression ratio Integrally Geared compressor.

In the carbon capture and compression process, a large amount of heat is generated in the carbon dioxide compression system and in the MEA system's stripper condenser. This heat can be at a relatively high temperature, and integrating with other parts of the plant would improve the power plant efficiency. The heat sinks, which will use the rejected heat, analyzed in this thesis are the feedwater heaters, the stripper reboiler, and a coal drying system.

This analysis predicts maximum heat rate improvements in the range of 1.20 % to 7.43 % for a PRB coal with an Inline 4 compressor, depending on the integration technique. A range of 1.29 % to 3.59 % heat rate improvement was shown for Illinois #6 and 1.20 % to 10.45% for a Lignite coal, both with an Inline 4 compressor. These heat rate improvements will be explained throughout the thesis.

1.0 Introduction

Climate change has been a growing concern throughout the past few decades. It is widely believed that humans are impacting the recently changing global climate trends. One of the main traceable changes is carbon dioxide levels in the atmosphere, which is generally considered to be a major factor in global climate change. Carbon dioxide levels before the industrial revolution are estimated at 260-280 ppm. As of 2011 carbon dioxide levels are at 392 ppm and rising at approximately 2 ppm/year. The environmental impact of this rise in carbon dioxide levels is a much debated issue that will not be discussed in this thesis.

Reduction in carbon dioxide emissions is generally accepted as an important goal in reducing the impact on global climate. While not generating carbon dioxide at all would be the most beneficial to the environment, power plants, cars, and much of industry use fossil fuels for energy. The next best idea would be to capture the carbon dioxide that is being generated, and sequester it to a place where it would not be released to the atmosphere. Geological formations deep underground are one of the more favorable locations to sequester carbon dioxide. These locations, as with most others, would require carbon dioxide to be pumped underground at very high pressure.

This thesis analyzes a carbon capture system that is attached to a pulverized coal power plant operating with a supercritical steam cycle. The boiler combusts coal to form flue gas, of which carbon dioxide is a major component. Because carbon dioxide is only 10% to 12% (molar) of the flue gas stream, it will need to be separated from the rest of the flue gas stream before sequestration. There are many different ways to capture the carbon dioxide from the flue gas, however this thesis will look at an amine based scrubber. There are many different amines available, however, the most commercially viable amine at this time is monoethanolamine

(MEA). MEA, like all amines, absorbs the carbon dioxide in the absorber, and then releases it in the stripper. After leaving the stripper the carbon dioxide is compressed before it is sequestered.

Heat is required in the stripper to separate the carbon dioxide from the MEA. In the power plant model analyzed, the heat is provided by a steam extraction from the steam cycle. Because a large amount of steam is being used at the stripper instead of generating power, the net power of the plant is reduced. Combined with the power required to compress the carbon dioxide, these plant changes are expected to decrease the net power of a coal fired power plant roughly 33%.

During the compression process, intercoolers are used to cool the carbon dioxide between compression stages. This heat can be recycled elsewhere in the power plant to help improve plant performance. This thesis explores the possibilities of integrating waste heat from the stripper condenser and the compression system to various heat sinks such as the feedwater heaters in the steam cycle, the stripper reboiler, and a coal dryer. Integrating heat to the feedwater heaters and stripper reboiler would allow steam extractions to the feedwater heaters to be reduced, thereby allowing more steam to flow through the turbines and generate more power. Using a coal dryer would allow a smaller amount of coal to be burned with the same net power being produced.

This analysis considers three different coals and three different types of compressors to be used for heat integration. The results show the potential of utilizing thermal integration of waste heat to improve power plant performance. The different types of coal and types of compressors will also be compared to each other to show how these differences in coal and compressor influence the unit heat rate.

2.0 ASPEN Plus Modeling

The MEA system model used in this thesis was originally developed at the Energy Research Center by Dr. Edward Levy and Master's student Austin Szatkowski with guidance from Dr. Ian Laurenzi. The boiler, steam cycle, MEA system, and compression system were all linked together and modeled in ASPEN Plus. This model was also improved upon in Master's work by Erony Martin, whose model is altered slightly and used as a base case for the work done in this thesis. Many other graduate students at Lehigh University have helped develop the monoethanolamine (MEA) system model with major contributions also coming from Joshua Charles [7] and Elaine Aiken [1].

For a more detailed account on how the boiler, steam cycle, and MEA system models work, as well as error discussion, Szatkowski [15] and Martin's theses [10] should be referenced. These theses discuss the initial assumptions made, the reasons why certain design specifications (design specs) were chosen in ASPEN Plus, as well as the reason why certain parameters were used. These theses also discuss errors in the ASPEN model and compare the model's results using basic thermodynamic principles. For more detail into the development of the ASPEN model see Szatkowki's thesis [15] section 2 through section 4 and Martin's thesis [10] section 2.

While much of the work shown in this section is the work of previous students who have developed these models, it is important to highlight some of the main assumptions that are used to model the boiler, steam cycle, MEA system, and compression system that is being used throughout this thesis.

2.1 ASPEN Plus Boiler

The boiler model shown in Figure 1 has coal entering the pulverizer before being sent to the boiler to be burned. The pulverizer requires power to crush the coal so that it can be easily burned in the boiler. The pulverizer's energy consumption is assumed to be 10.58 kWhr/ton [15], and it will heat a Powder River Basin (PRB) coal with 28.09% moisture from its inlet temperature of 77 °F to 114.9 °F. After this, the pulverized coal is sent into the boiler to be burned.

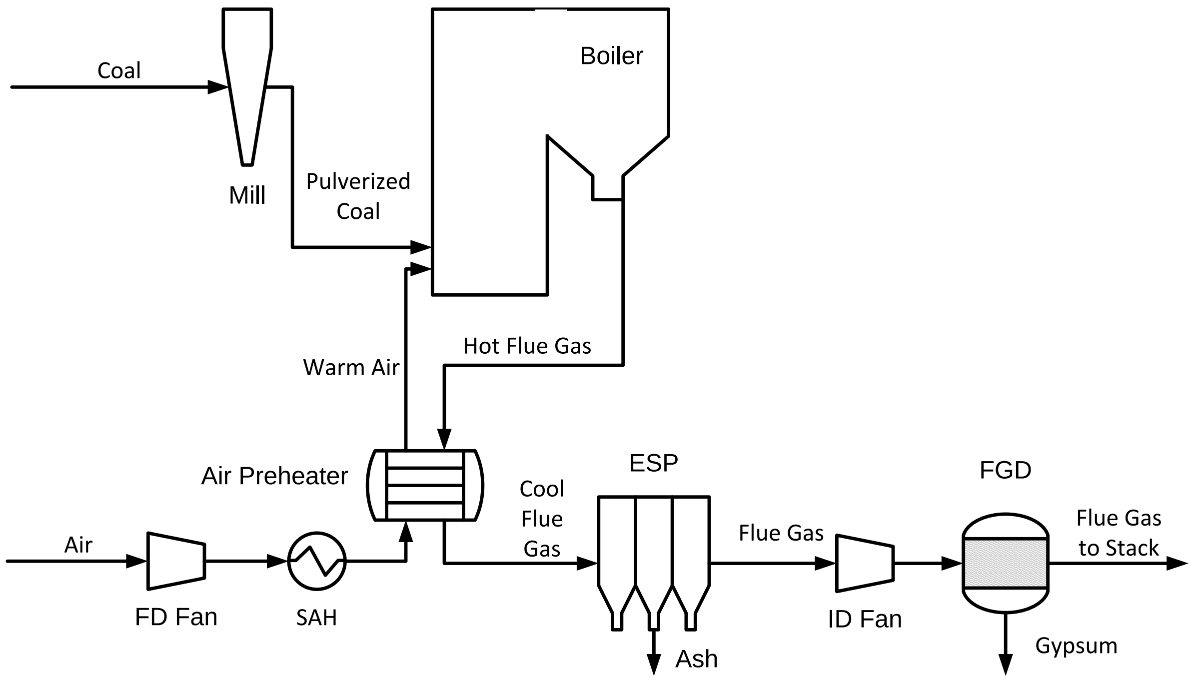

Figure 1. Diagram of Boiler

In this thesis three different types of coal are burned: a subbituminous PRB coal, a bituminous Illinois #6 coal, and a Lignite coal. Illinois #6 coal has a low moisture percentage of 7.97%, while the PRB coal has a higher moisture percentage of 28.09% and the Lignite coal has the highest moisture percentage of 38.50%. These different moisture percentages are the main differences between these coals, and will cause them to effect the boiler differently. A more detailed look at how coal moisture affects boiler efficiency can be observed in section 5. The properties of these coals are listed in Table 1.

Table 1. Coal Properties

	PRB	Illinois #6	Lignite
HHV_{dry} (btu/lbm)	11717	11951	10416
Proximate Analysis (wt%)			
Moisture (wet)	28.09	7.97	38.5
Fixed Carbon (dry)	45.87	39.64	35.56
Volatile Matter (dry)	44.73	40.05	44.44
Ash (dry)	8.77	15.48	20
Ultimate Analysis (wt%)			
Ash	8.77	15.48	20
Carbon	68.43	65.65	55.33
Hydrogen	4.88	4.23	4.83
Nitrogen	1.02	1.16	1.17
Chlorine	0.03	0.05	0
Sulfur	0.63	4.83	0.83
Oxygen	16.24	8.6	17.84
Sulfur Analysis (wt%)			
Pyritic	0.17	2.81	0.36
Sulfate	0.03	0.01	0.05
Organic	0.43	2.01	0.89

In this ASPEN model 100% complete combustion is assumed with nitrogen, carbon dioxide, oxygen, sulfur dioxide, water, chlorine, and ash being the only products of combustion. This assumes that no carbon monoxide, nitrogen oxides, sulfur oxides (other than sulfur dioxide), hydrogen, or methane is being produced. While it is well known that some of these products will be produced in an actual boiler, they are small enough in quantity that they will not affect the accuracy of the results shown.

The boiler's operation is controlled by two different design specs in ASPEN Plus. A design spec allows one variable, such as a flow rate, to be varied until another variable, such as a temperature, is reached. In the boiler the coal flow rate is varied until the temperature entering the air preheater is at 600 °F. This model assumes that there is a fixed amount of heat transferred to the steam cycle. It is assumed that for different types of coals, and coals with different moisture levels, the flow rate of water/steam through the boiler, and the inlet water temperature and outlet steam temperature will be constant. In the model used throughout this thesis, there will always be 4,185,000 lb/hr of water at 506.9 °F entering the boiler and leaving as steam at 1000 °F.

Air first enters the boiler through the forced draft (FD) fan. The FD fan increases the pressure from 14.7 psia to 15.0 psia giving it enough pressure to go through the steam air heater (SAH) and the air preheater before the entering the boiler. The FD fan is assumed to have an 80% isentropic efficiency. This air provides the oxygen necessary for coal combustion, and it is regulated by a design spec. This second design spec in the boiler varies the air flow rate until there is 3.5% oxygen on a molar basis in the flue gas leaving the boiler. This sets the air flow rate to levels that are typical for most power plants giving the fuel enough excess oxygen to prevent the formation of large quantities of carbon monoxide and unburnt carbon in the ash.

After the flue gas leaves the boiler, it enters the air preheater (APH), where the hot flue gas is used to preheat air entering the boiler. In the APH, it is assumed that the flue gas is cooled from 600 °F to 300 °F, which will heat the boiler air from 156 °F to 518 °F when firing PRB. Another design spec sets the air preheater leakage rate to equal 6% of the total flue gas flow rate. The APH leakage is the amount of air flowing through the APH that leaks into the flue gas duct instead of entering the boiler. After leaving the air preheater the flue gas is sent to the electrostatic precipitator (ESP), the induced draft (ID) fan, and the wet flue gas desulfurization system (FGD). There are small amounts of air leakage in these components along with the air leaving the wet FGD being saturated with water. The ESP removes large particulates in the air and also has a small amount of air leak into it. The wet FGD removes the sulfur oxides from the flue gas.

A flow rate of air equal to 5% of the total flow rate of the flue gas leaks into the flue gas between the gas exit of the APH and the FGD. In the FGD a flow rate of air equal to 1.07% of the flow rate of flue gas is added into the system to provide oxygen for the reactions taking place in the FGD. Along with the air, water is injected in the FGD so that the flue gas leaving the FGD is saturated with water at 135°F.

The ID Fan increases the pressure 2.17 psi providing suction to the flue gas in the boiler and pressure to the flue gas to go through the FGD. The flue gas leaving the FGD is then sent to the flue gas cooler in the post combustion carbon capture system. The ID fan is assumed to have an 80% isentropic efficiency.

A flow diagram with stream tables for the boiler is shown in Appendix A. These tables list the temperature, pressure, flow rate, and composition of the streams at different places throughout the boiler.

2.2 Steam Cycle

The steam turbine cycle that is used throughout this thesis was previously used by Martin [10], Szatkowski [15], Charles [7], and Aiken [1]. The model in ASPEN is based on the manufacturer's steam turbine kit shown in Figure 2. This model's accuracy was verified in previous theses and the accuracy of this model will not be discussed further in this thesis as it was previously determined to be accurate enough for the purposes of modeling the power plant.

The supercritical steam cycle modeled in this thesis runs at 1000 °F and 3690 psia leaving the boiler and entering into high pressure turbine 1 (HPT-1). After leaving HPT-1 at 740 °F, the steam is reheated in the boiler, which brings its temperature back up to 1000 °F with a pressure of 666 psia before entering intermediate pressure turbine 1 (IPT-1). After flowing through IPT-2, the steam flow enters low pressure turbine 1 (LPT-1) where it will flow through LPTs 1 to 5 and enter the condenser. There are seven steam extractions located in the steam cycle, with each of them corresponding to a turbine outlet.

When carbon capture is added, the steam cycle will need to be altered, adding an additional extraction downstream of LPT-1 which will send steam to the stripper reboiler to separate the CO2 from the amine mixture (see Figure 2). This will cause less steam to flow through LPTs 2 to 5 causing a decrease in generated power when compared to the same unit without carbon capture. The amount of steam to be sent to the reboiler will depend on the amount of carbon dioxide being captured by the model. The reboiler will return the condensed steam to the steam cycle. The location where the reboiler condensate returns will be discussed in section 3.1. The net power in a carbon capture case is expected to be approximately 33% less than the same unit without carbon capture.

The feedwater heaters (FWHs), shown in Figure 2, use steam that is extracted from the turbines to preheat feedwater going to the boiler. In Figure 2 it can be observed that extraction A is used to preheat feedwater in FWH-7, while extraction B is used to heat feedwater at FWH-6, and so on through all of the turbines with the last extraction G being used to preheat feedwater leaving the condenser at FWH-1. When heat integration is discussed in section 3, the extractions to the feedwater heaters will be reduced, but the boiler feedwater outlet temperatures will remain the same. The extraction steam will be replaced with another heat source.

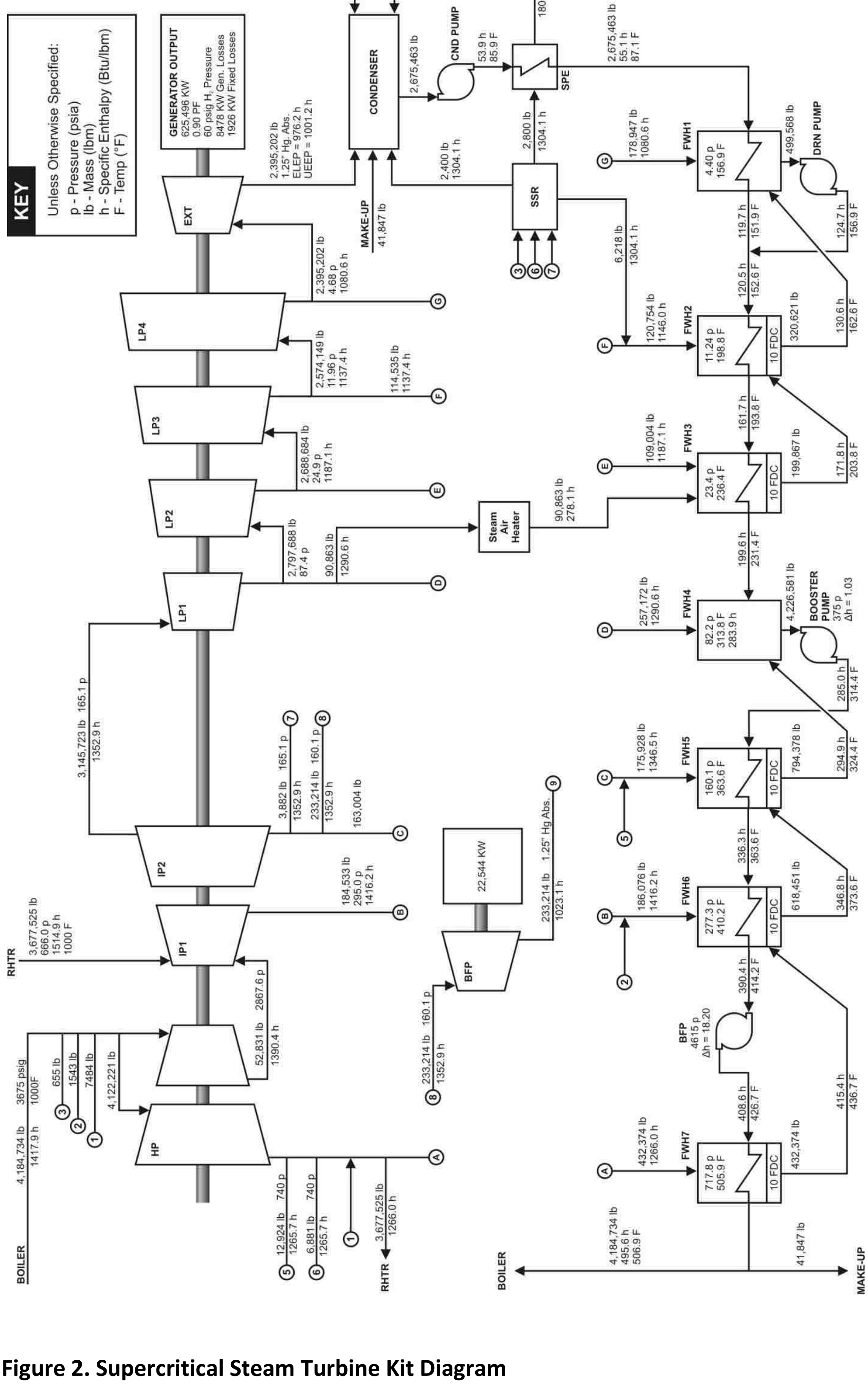

Figure 2. Supercritical Steam Turbine Kit Diagram

2.3 Post Combustion Carbon Capture System

The carbon capture system used in this thesis is an MEA system, and it is used to separate the carbon dioxide from the rest of the flue gas so that it can be sent to a storage location. The MEA is mixed with water in a 30% MEA by mass solution in this system as previously determined by Martin [10] and Szatkowski [15]. The model is also designed to capture 90% of the carbon dioxide that is entering the absorber. Being that MEA is a weak base in water, and carbon dioxide is a weak acid, the MEA solutions will selectively absorb the carbon dioxide from the flue gas, and allow the other components to exit the top of the absorber.

The main components of the MEA system are the flue gas cooler, absorber, amine pump, amine heat exchanger, and the stripper. These components can be seen in the MEA system diagram in Figure 3. The diagram shows flue gas entering the flue gas cooler (FG cooler) where the flue gas is cooled down from 135 °F to 100 °F before entering the absorber. During this process water is condensed out of the flue gas. In the absorber, carbon dioxide in the flue gas is absorbed by the MEA solution. The flue gas enters the absorber at the bottom, and leaves it from the top, while the lean MEA (MEA with small amounts of CO2 absorbed) enters from the top and the rich MEA (MEA with larger amounts of CO2 absorbed) leaves from the bottom. After the rich MEA leaves the absorber its pressure is increased from 14.7 psia to 44 psia in the amine pump. It is then sent to the amine heat exchanger where the colder rich amine is heated by the hotter lean amine leaving the reboiler. In this heat exchanger the rich amine is heated from 135 °F to 238 °F (in the base case PRB analysis)

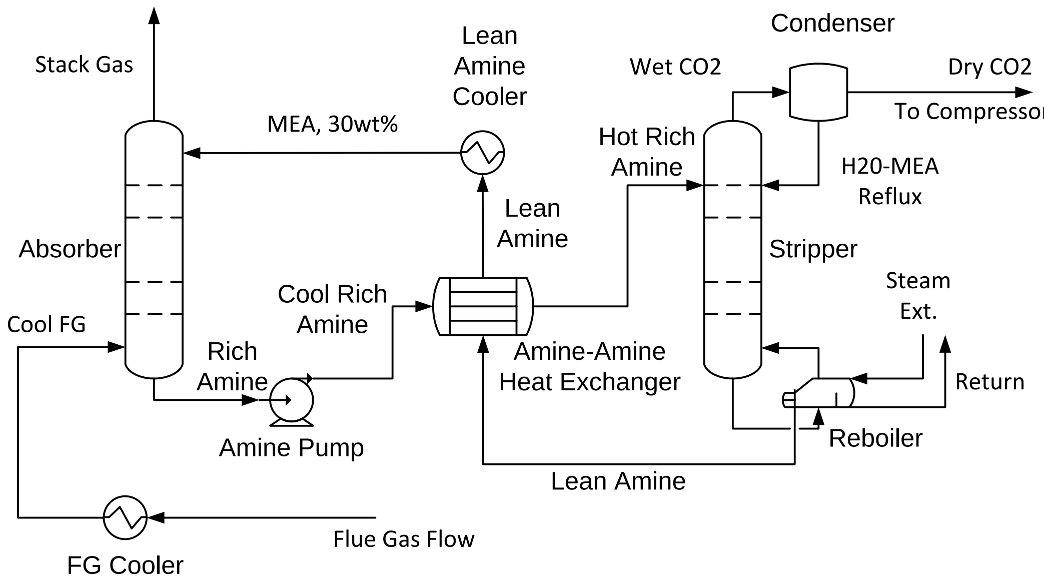

Figure 3. MEA System

After leaving the amine heat exchanger, the rich amine enters the stripper where the CO2 is separated from the MEA solution. Heat is added to the MEA solution in the reboiler to allow the CO2 to be separated from the MEA solution. The reboiler's heat duty is provided by condensing steam being sent from a steam cycle extraction. The reboiler heats the rich amine which releases water vapor and carbon dioxide. This gas mixture rises to the top of the stripper where it enters the stripper condenser. The stripper condenser cools the gas mixture to 100 °F, condensing most of the water in the mixture, and sending the carbon dioxide, with a reduced amount of moisture, to the compressors. The water condensed from the carbon dioxide in the condenser is then sent back into the stripper. The condenser uses cooling water for this process which will need to be cooled in a heat sink before reentering the condenser.

Lean amine leaves through the bottom of the stripper at 270 °F. The hot lean amine then goes to the amine heat exchanger, where it is used to preheat the rich amine entering the stripper. In this heat exchanger the lean amine is cooled from 270 °F to 149 °F (in the base case

PRB analysis). After leaving the amine heat exchanger the lean amine still requires cooling which is done in the lean amine cooler. It is assumed that cooling water from a cooling tower can be used in this process. In the lean amine cooler the lean amine is cooled to 100 °F before entering the absorber again.

A flow diagram with stream tables for the MEA system is shown in Appendix A. These tables list the temperature, pressure, flow rate, and composition of the streams at different places throughout the MEA system.

2.3.1 MEA System Design Specifications

There are five different design specs that allow the MEA system to work properly. These specifications control the amine flow rate, the percent of MEA in the amine solution, the amount of CO_2 in the lean amine, the stripper duty, and the extraction steam flow rate.
The first design spec controls the amine mass flow rate, which is calculated to be four times the mass flow rate of the flue gas entering the absorber. The second design spec controls the amount of MEA in the amine stream which is calculated to be 30% of the MEA-H_2O solution by mass (not including the mass of absorbed CO_2).

The third design spec calculates the amount of CO_2 in the lean amine stream (see Figure 3) called the CO_2 preloading. The amount of CO_2 in the lean amine mixture is varied until 90% of the CO_2 entering the absorber is captured. The CO_2 preloading can be varied to achieve higher or lower carbon capture rates. The rate of carbon capture performed in this study is 90%, which is standard among the analysis of most amine-based capture systems. Lower values of CO_2 preloading require more reboiler duty, whereas higher values of CO_2 preloading require a larger amine flow rate. The values used in this thesis are the values that Szatkowski [15] and Martin [10] have found to be the most realistic and were used throughout their analyses.

The fourth design spec varies the stripper reboiler duty until the CO_2 flow rate leaving the stripper is equal to the CO_2 preloading value that was calculated earlier. This allows the final reboiler duty to be calculated from the required capture rate. The fifth design spec calculates the required steam cycle extraction flow rate to give the reboiler enough heat.

2.4 Compressor Systems

After leaving the stripper condenser the CO_2 is sent to the compression system. Three different compressor systems were analyzed in this thesis. A Ramgen compressor, which has two stages of compression, is the compressor with the highest stage pressure ratios. An Inline compressor, which has three stages of compression with slightly lower pressure ratios, is also used. An Integrally Geared compressor, with seven stages of compression is also used, with each stage having a relatively low pressure ratio.

Manufacturer's data were obtained for each compressor system; however, the data was altered so that each compression system has inlet conditions of 44 psia and 100 °F and has an exit pressure of 2,210 psia. Also, in between each compression stage is an intercooler that cools the CO_2 from its outlet temperature to 110 °F. These intercoolers also "knock out" water in the CO_2 stream, which means that water has condensed, and the condensed water is removed. The data inputted into ASPEN for each compression system are shown in Table 2, Table 3, and Table 4. The diagrams for each compressor are shown in Figure 4, Figure 5, and Figure 6. The effect of different compressor systems on net power and unit heat rate will be discussed in section 6.

Each of the compressor systems has intercooling in between each compressor stage. In the intercooler, the carbon dioxide is cooled from its exit temperature to 110 °F. The CO_2 stream flows through a heat exchanger, and therefore will have a pressure drop due to the viscous flow of the CO_2. While the sizes of the heat exchangers were not considered during this analysis, it is assumed that the pressure drop for each intercooler is 5psia in all of the different compression options.

Table 2. Ramgen Compressor Properties

	Stage 1	Stage 2
Inlet Pressure (psia)	44.1	310
Outlet Pressure (psia)	315	2215
Pressure Ratio	7.142	7.145
Isentropic Efficiency	0.85	0.85
Mechanical Efficiency	0.9704	0.9701
Inlet Temperature (F)	100	110
Outlet Temperature (F)	430.6	463

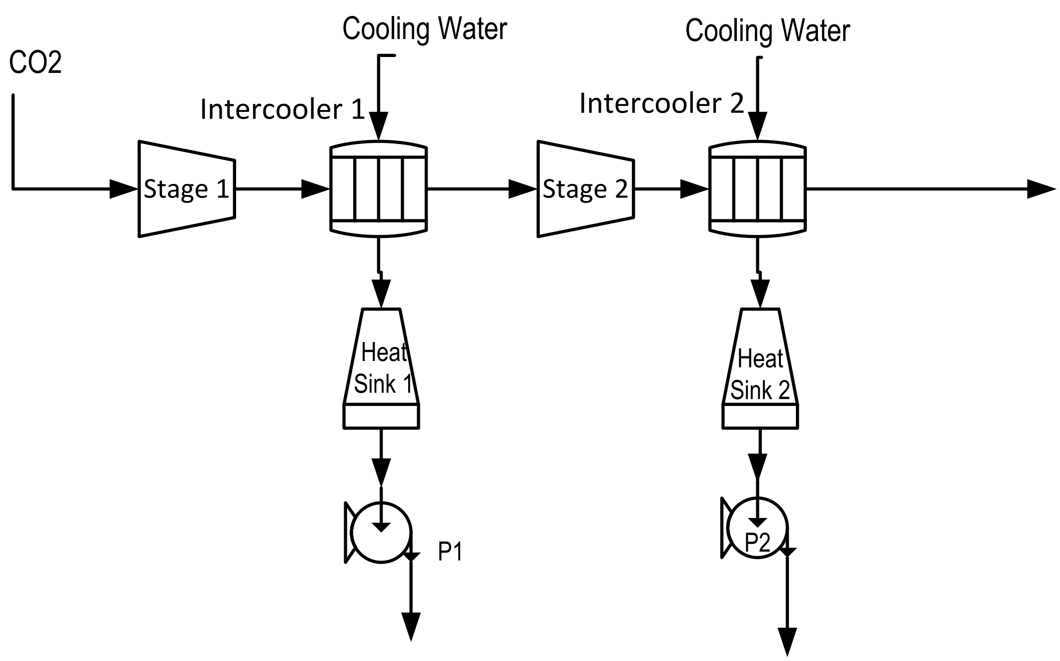

Figure 4. Ramgen Compressor Diagram

Table 3. Inline 4 Compressor Properties

	Stage 1	Stage 2	Stage 3
Inlet Pressure (psia)	44.1	284.3	1715.3
Outlet Pressure (psia)	289.3	1720.3	2219.6
Pressure Ratio	6.56	6.05	1.294
Isentropic Efficiency	0.8125	0.8188	0.8114
Mechanical Efficiency	0.993	0.992	0.998
Inlet Temperature (F)	100	110	110
Outlet Temperature (F)	427.1	436	125.9

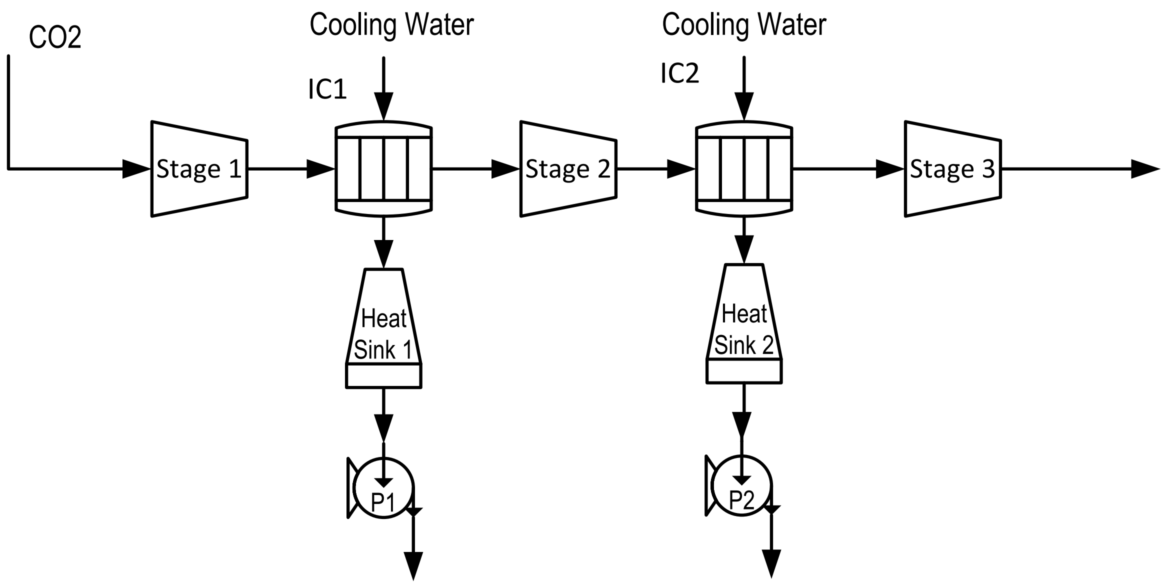

Figure 5. Inline 4 Compressor Diagram

Table 4. Integrally Geared 1 Compressor Properties

	Stage 1	Stage 2	Stage 3	Stage 4	Stage 5	Stage 6	Stage 7
Inlet Pressure (psia)	44.1	61.3	126.6	273.3	567.4	945	1435
Outlet Pressure (psia)	66.3	131.6	278.3	572.4	950	1440	2220
Pressure Ratio	1.503	2.1468	2.1982	2.0944	1.6743	1.523	1.547
Isentropic Efficiency	0.85423	0.86154	0.87572	0.83155	0.89152	0.90706	0.91745
Mechanical Efficiency	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Inlet Temperature (F)	100	110	110	110	110	110	110
Outlet Temperature (F)	161.9	228.1	232	232.1	192.9	175.7	145.2

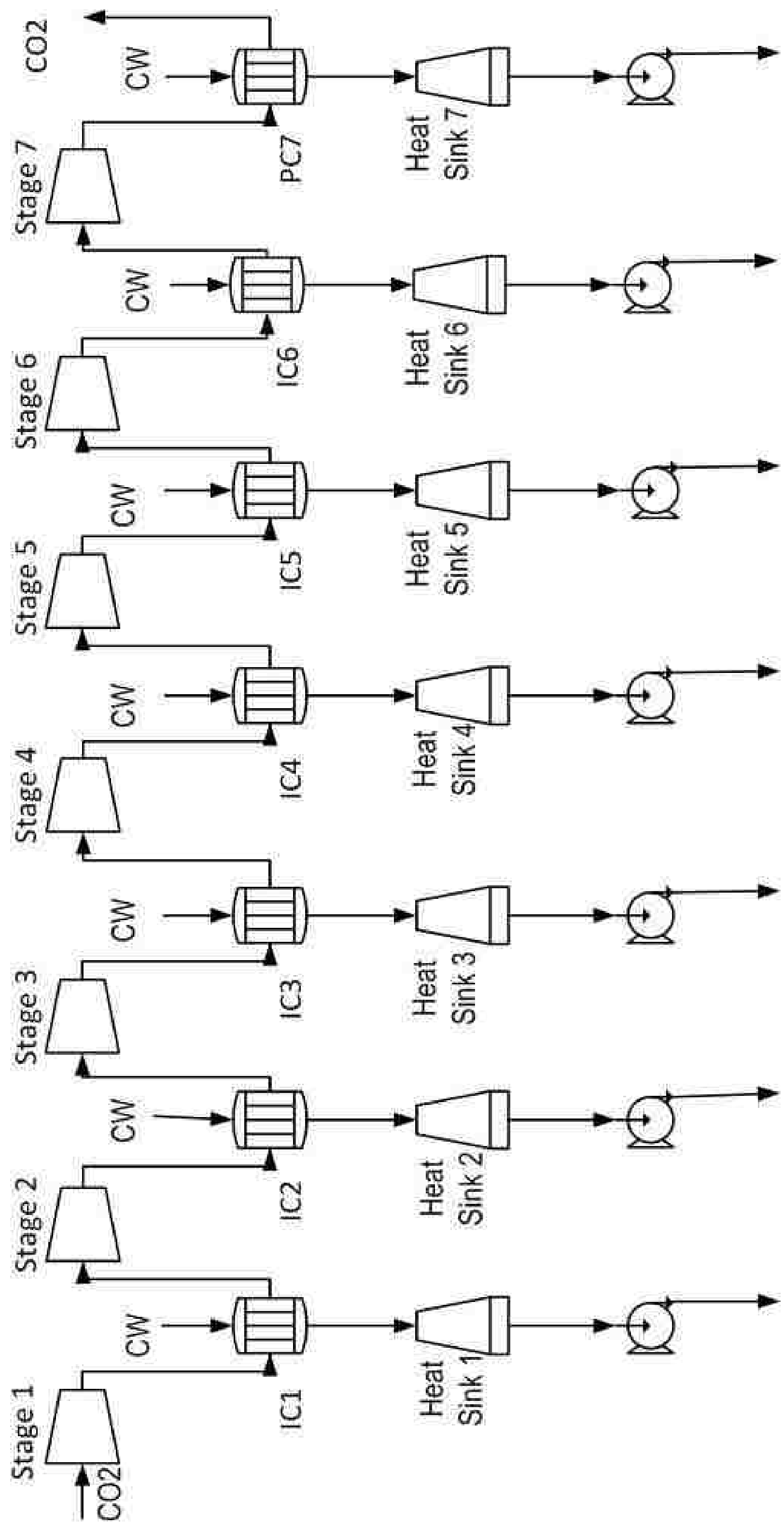

Figure 6. Integrally Geared Compressor Diagram

2.5 Analyzing Plant Performance

There are many different parameters that will be used to analyze the plant performance. It is necessary to discuss and define what each of these parameters are, as well as explain the calculations that are made when describing the ASPEN Plus model. A large table of variables is outputted from ASPEN Plus and then Excel is used to make the proper unit conversions and then used to describe plant performance.

When coal drying is analyzed, it is convenient to take the flow rate of “dried” coal and find out how much “as-mined” coal would need to be dried to make the dried coal. ASPEN Plus does not model the coal drying process, so it will blindly use the dried coal (which enters the pulverizer) without knowing the original as-mined flow rate. Using the flow rate of coal entering the boiler (which is the same as the dried coal flow) the amount of as-mined coal can be found. Assuming that the amount of moisture free coal is the same in both scenarios, the following equation is generated from Figure 7:

$$\begin{aligned} Moisture\ Free\ Coal\ Flow &= As\ Mined\ Coal\ Flow * (100 - \%Moisture\ of\ As\ Mined\ Coal) \\ &= Dried\ Coal\ Flow * (100 - \%Moisture\ of\ Dried\ Coal) \end{aligned}$$

The as-mined flow rate, or wet coal flow, is calculated by rearranging the equation above to get the equation below:

$$As\ Mined\ Coal\ Flow = Dried\ Coal\ Flow * \frac{100 - \%Moisture\ of\ Predried\ Coal}{100 - \%Moisture\ of\ As\ Mined\ Coal}$$

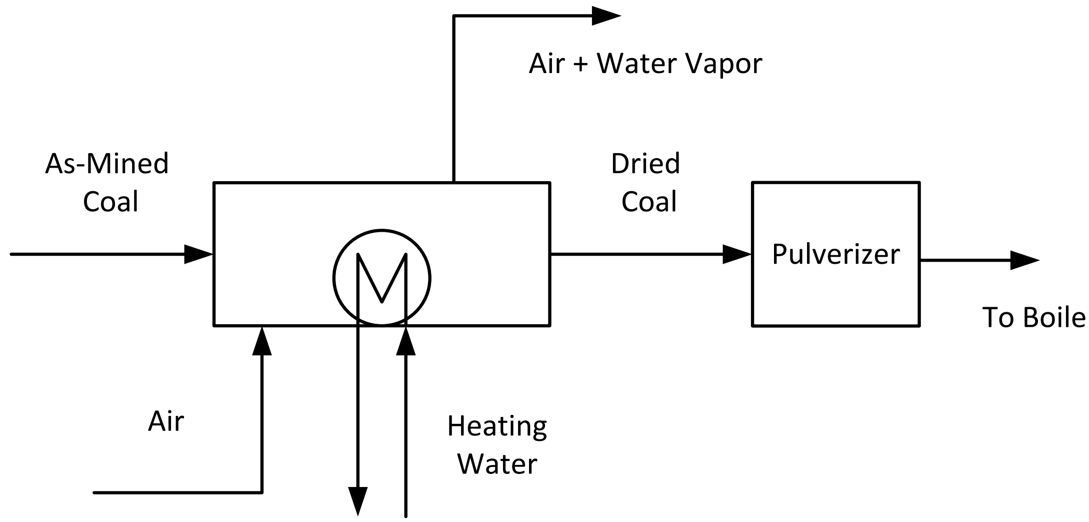

Figure 7. Coal Dryer

The boiler efficiency is an important parameter when describing boiler operation. It is calculated by taking the total amount of thermal energy sent to the steam cycle and dividing it by the total amount of fuel energy which enters the boiler. The equation below is used to define the boiler efficiency. Note that either of the coal flow rates can be used as long as the correct higher heating value (HHV) is used. Being that the wet HHV is defined already, it was chosen to use the wet coal flow rate and HHV for calculations in this thesis.

$$\eta_{Boiler} = \frac{Q_{steam}}{\dot{m}_{wet\ coal} * HHV_{wet}} = \frac{Q_{steam}}{\dot{m}_{dried\ coal} * HHV_{dried}}$$

The generated power is defined as the sum of the power of the HPT-1, IPTs 1 and 2, and LPTs 1 to 5, which can be observed in Figure 2. The power of these turbines is converted from horsepower in ASPEN to kW, and then multiplied by 0.985, which is assuming a 98.5% efficiency for the electric generator. It shall be noted the some of the generated power will be used to drive pumps in the steam cycle, as well as components throughout the rest of the plant. It is also noted that the power from HPT-2 and boiler feed pump (BFP) turbine are not added to the total.

This is due to HPT-2 being modeled as leakage from HPT-1, and the BFP turbine is used to drive the BFP. The equation for generated power is shown below:

$$P_{Generated} = (P_{HP1} + P_{IP1} + P_{IP2} + P_{LP1} + P_{LP2} + P_{LP3} + P_{LP4} + P_{LP5}) * \frac{0.745\ kW}{HP} * \eta$$

The fan power is the summation of the FD and ID fan powers converted from horsepower into kW. Most of the fan power requirements are from the ID fan due to its higher flow rate, higher temperature, and larger change in pressure. The pulverizer power is taken directly from ASPEN Plus and converted from btus/hr to kW.

The pump power is calculated by adding the power requirements of the drain pump, boost pump, condenser pump, and amine pump. The condenser, drain, and booster pumps are located in the steam cycle as shown in Figure 2. The amine pump is located in the MEA system and can be observed in Figure 3. The boiler feed pump is not included in this analysis because the BFP turbine provides the power for this pump.

The auxiliary power (aux power) is set at 15,000 kW and covers the rest of the power consumed throughout the power plant. The ASPEN Plus model does not specifically account for cooling water circulation pumps, heat integration water circulation pumps, and other power requirements not specifically mentioned above. It is assumed that the 15,000 kW of aux power will cover the other power requirements.

The compressor power takes the power requirements for each stage of whichever compressor is selected and converts it to kW. This will be one of the largest power requirements of the whole plant. This power requirement is not added to the station service power, however all of the other power requirements are added.

Station service power is defined as:

$$P_{ss} = P_{fan} + P_{pulverizer} + P_{pump} + P_{Aux}$$

Net power is defined as the total amount of power leaving the plant. It is calculated using the following equation:

$$P_{net} = P_{Generated} - P_{ss} - P_{compressor}$$

The net unit heat rate is a common measurement of power plant performance. It is found by the total amount of fuel energy entering the plant divided by the net power the plant is producing. It is calculated using the equation below.

$$HR = \frac{\dot{m}_{wet\ coal} * HHV_{wet}}{P_{net}}$$

It should be noted that the unit heat rate is measured in Btu/kWhr, and that a decrease in heat rate corresponds to a more efficient unit. The thermal efficiency of the plant is calculated using the following equation:

$$\eta_{thermal} = \frac{3412}{HR}$$

These parameters will be used to evaluate the performance of plants with different modifications. While none of these parameters looks at the costs associated with the power plant, they will give an idea of possible efficiency improvements that can be made in a power plant with carbon capture.

2.6 Power Plant Performance Without Carbon Capture

To properly analyze the effects that carbon capture will have on a power plant, it is first appropriate to show how the power plant behaves without carbon capture. This will give a basis of comparison for all heat integration options using the MEA system. The properties of the boiler and steam cycle are those described in section 2.1 and 2.2. The results of running PRB, Illinois #6, and a Lignite coal are shown in Table 5. The change in net power and unit heat rate were calculated using PRB coal as the base case.

Table 5. Power Plant Properties Without Carbon Capture

	PRB	Illinois #6	Lignite
Wet Coal Flow (lb/hr)	643,021	470,872	876,816
HHV wet (Btu/lb)	8,426	10,999	6,406
Coal In Boiler	643,021	470,872	876,816
Coal Moisture In Boiler	28.09	7.97	38.50
Boiler Efficiency	88.15%	92.22%	85.03%
Gen Power (kW)	625,466	625,466	625,466
FD Fan Power (kW)	1,499	1,381	1,458
ID Fan Power (kW)	16,504	14,527	16,899
Pulv Power (kW)	3,403	2,492	4,640
Pump Power (kW)	2,445	2,443	2,444
Aux Power (kW)	15,000	15,000	15,000
Pss (kW)	38,850	35,844	40,441
Boiler Steam Flow (lb/hr)	4,184,734	4,184,734	4,184,734
Air Flow to FD Fan (lb/hr)	5,425,475	5,001,133	5,277,132
Flue Gas leaving FGD (lb/hr)	6,716,556	5,978,287	6,741,819
CO2 Flow (lbm/hr)	1,178,953	1,059,576	1,113,252
Carbon Captured	0.0%	0.0%	0.0%
Reboiler Duty (Mbtu/hr)	1,795	1,795	1,795
Reboiler duty (Btu/lbmCO2)	2,716	3,029	2,878
Comp Power (kW)	0	0	0
Net Power (kW)	586,616	589,622	585,025
Δ in Net Power	0	3,006	-1,591
Unit Heat Rate (Btu/kWhr)	9,236	8,784	9,601
Δ in Heat Rate (%)	0.00%	-4.90%	3.95%
Efficiency (%)	36.9%	38.8%	35.5%
Details			
FWH1 Duty (kBtu/hr)	172,921	172,921	172,921
FWH2 Duty (kBtu/hr)	130,904	130,904	130,904
FWH3 Duty (kBtu/hr)	120,039	120,039	120,039
FWH5 Duty (kBtu/hr)	216,159	216,159	216,159
Extract G (lb/hr)	178,947	178,947	178,947
Extract F (lb/hr)	114,535	114,535	114,535
Extract E (lb/hr)	109,004	109,004	109,004
Extract D (lb/hr)	259,300	259,300	259,300
Extract C (lb/hr)	163,004	163,004	163,004
Heat Rejected			
Steam Condenser (Mbtu/hr)	2,516	2,516	2,516

3.0 MEA System Heat Integration

3.1 Martin's MEA System Model vs. Jonas' MEA System Model

In previous base case MEA system models, a large quantity (1.75 million lb/hr) of steam leaving LPT-1 is sent to the MEA reboiler in the stripper. This steam is condensed, and the heat is used to separate the CO2 from the MEA mixture. Afterwards, the lean amine is sent back to the absorber, and the CO2 can be compressed and sequestered. In Martin's base case model, shown in Figure 8, the condensed steam leaving the reboiler is sent back to the steam cycle condenser where it is cooled with the rest of flow leaving LPT5. Because this stream has a very high flow rate, is a liquid, and has a high temperature, it could possibly be used elsewhere in the plant instead of rejecting heat to the steam cycle condenser. The temperature of 300 °F makes it logical to integrate the reboiler condensate stream into FWH-4 which can be observed in Figure 9. FWH-4 is an open feedwater, and is also known as the deaerator. While this stream will lose pressure through the reboiler, it is assumed that a pump can be added with negligible power requirements. Using basic calculations, it can be shown that a pump for this purpose would require less than 100 kW, which is insignificant considering the heat rate improvements that are possible.

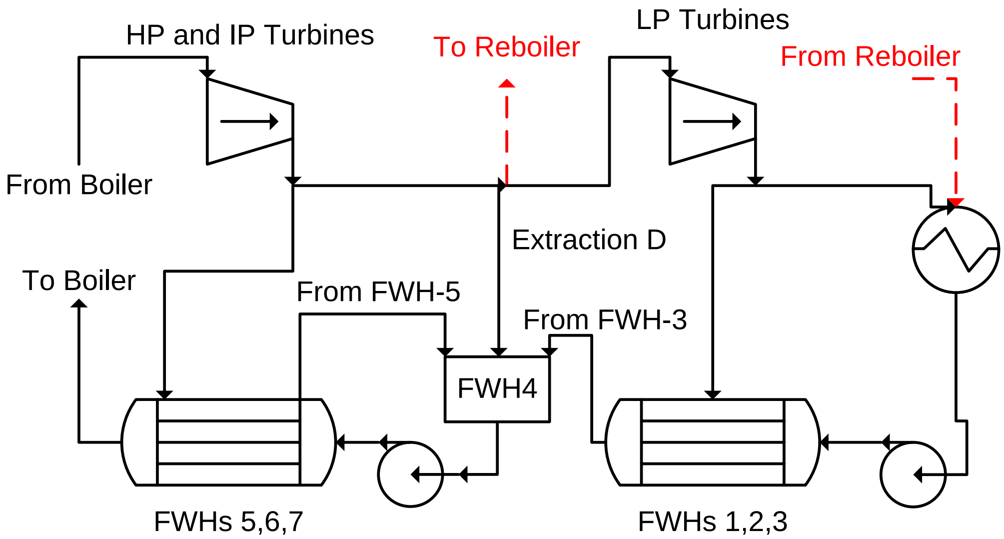

Figure 8. Martin's Base Case (Reboiler Condensate to Steam Cycle Condenser)

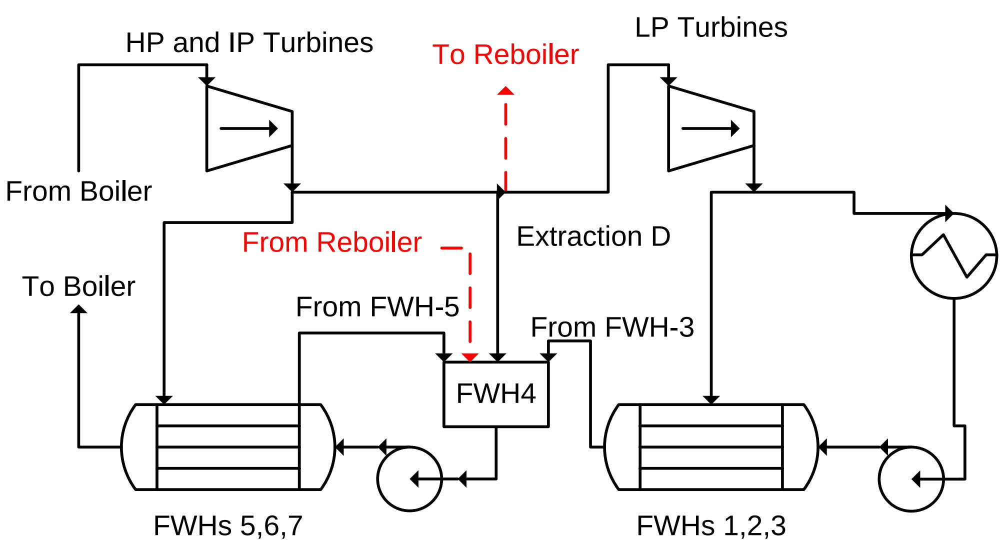

Figure 9. Jonas' Base Case (Reboiler condensate to FWH-4)

In the process of rerouting the reboiler stream, the mass flow rate of feedwater going through FWHs 1, 2, and 3 is greatly reduced. This reduction in flow is due to the 1.75 million lb/hr of steam condensate (in the base case PRB analysis) leaving the reboiler and bypassing the steam condenser and FWHs 1, 2, and 3. Because there is less feedwater flow going through FWHs 1, 2, and 3, extractions D, E, F, and G can be reduced. Extraction G is reduced from 178,947 lb/hr to 83,900 lb/hr, or 46.8% of its original value. Extraction F is reduced from 114,535 lb/hr to 49,500 lb/hr, or 43.2% of its original value. Extraction E is reduced from 109,004 lb/hr to 48,000 lb/hr, or 44.0% of its original value. Since the large flow rate of reboiler condensate is entering the deaerator at 300 °F instead of coming from FWH-3 at 231°F, Extraction D can be reduced as well because less steam is needed to increase the stream's temperature to 314°F before leaving FWH-4. Extraction D was reduced from 257,172 lb/hr to 146,000 lb/hr, or 56.8% of its original value, to maintain the required exit temperature. All of these alterations were made so that the outlet temperatures of all of the feedwater heaters were consistent with the original temperatures indicated in the steam turbine kit.

By incorporating these changes to the steam cycle, additional steam flow was able to go through low pressure turbine stages 2 to 5 and generate more power for the plant. An additional 16,871 kW of power can be generated from these changes with a heat rate improvement of 558 btu/kWhr. See Table 6 for more details on the results of these changes. The final base case heat rate with the reboiler condensate rerouted to FWH-4 is 13,118 btu/kWhr. This base case, with the reboiler condensate going into FWH-4 shall be known as "Jonas' base case," while the other, with the condensate going into the steam condenser shall be known as "Martin's base case."

It shall be noted that throughout this analysis that results labeled as "Martin's" may not agree with the actual values found in her thesis. Small edits were made to ensure that Martin's models are consistent with the models that are being used in this thesis. For example, all of the models had their burn blocks altered so that there will be 100% combustion, as it was found that the carbon monoxide levels leaving the boiler in Martin's models were higher than commonly accepted values. Other changes were made on a case by case basis so that the alterations to the base case are similar to the ones shown in this thesis.

An example of routing the reboiler condensate to the deaerator is shown in Figure 9. This method can be found in NETL Report "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity" [13] on page 418. This section of the thesis compares the two methods where the reboiler condensate is sent to the two different locations in the steam cycle. These differences will also have an effect on the ability to integrate heat from the stripper condenser and the compressor. The combined duty of feedwater heaters 1, 2, and 3 in Jonas' base case is 47.5% of the duty in Martin's base case. This is due to the smaller flow rate of feedwater entering FWH-1, which has been reduced from its original value of 2.68 million lb/hr to 1.25 million lb/hr (in PRB base case). Because there is a much smaller flow rate of feedwater, there is a much smaller amount of extraction steam that needs to be used to heat this water.

Table 6. Comparison of Base Cases (No Heat Integration) PRB Coal with Inline 4 Compressor

	Jonas' Base Case (Condensate to FWH-4)	Martin's Base Case (Condensate to Steam Condenser)
Wet Coal Flow (lb/hr)	643,021	643,021
Dried Coal Inlet Moisture	28.09	28.09
Gen Power (kW)	496,071	479,216
Fan Power (kW)	18,002	18,002
Pulv Power (kW)	3,403	3,403
Pump Power (kW)	2,291	2,458
Aux Power (kW)	15,000	15,000
Pss (kW)	38,697	38,863
Carbon Captured	89.99%	-
Reboiler duty (Btu/lbmCO2)	1,692	-
Comp Power (kW)	43,869	43,718
Boiler Steam Flow (lb/hr)	4,184,734	4,184,734
Air Flow to FD Fan (lb/hr)	5,425,475	5,425,475
Flue Gas leaving FGD (lb/hr)	6,716,556	6,716,556
Net Power (kW)	413,506	396,635
Unit Heat Rate (Btu/kWhr)	13,118	13,676
*Δ in Heat Rate (%)	-4.08%	0.00%
Efficiency (%)	26.0%	24.9%
Heat Integration Details		
FWH-1 Duty (kBtu/hr)	81,329	173,265
FWH-2 Duty (kBtu/hr)	62,882	130,650
FWH-3 Duty (kBtu/hr)	58,088	120,224
FWH-5 Duty (kBtu/hr)	216,159	215,945
Extract G (lb/hr)	83,900	178,947
Extract F (lb/hr)	49,500	120,754
Extract E (lb/hr)	48,000	109,004
Extract D (lb/hr)	146,000	257,172
Extract C (lb/hr)	163,004	163,004
Heat Rejected		
Steam Condenser (Mbtu/hr)	1,167	1,232
Stripper Condenser (Mbtu/hr)	491	491
Compressors (Mbtu/hr)	258	258
Amine Cooler (Mbtu/hr)	1,031	1,031
Flue Gas Cooler (Mbtu/hr)	503	503

*Measured using Martin's as a base case

3.2 Heat Integration Differences Between Martin's Base Case and Jonas' Base Case

For heat integration purposes, FWH 1, 2, and 3 cannot accept the large amounts of heat that is possible in Martin's base case. The Inline 4 compressor needs to reject 258 Mbtu/hr of heat and the stripper condenser needs to reject 491 Mbtu/hr, while FWHs 1-3 have a combined duty of 202 Mbtu/hr in Jonas' base case. Some of the compressor heat can be rejected to FWHs 4 and 5 because the cooling water leaving the Inline 4 compressor coolers has a high temperature at approximately 425 °F. This option was not explored in Martin's thesis, but will be analyzed in section 3.7 and 3.8. However, because FWHs 5 can only cool the heat integration water to 325 °F and FWH-4 can only cool it to 240 °F (with a minimum temperature difference of 10°F), additional cooling will be required from other heat sinks. The stripper condenser has cooling water leaving at 230 °F, and therefore it is only hot enough to heat boiler feedwater in place of FWHs 1, 2, and 3. The stripper condenser cooling water can fully replace the extractions for FWHs 1, 2, and 3; however, rejecting this heat will not cool it down to 90 °F, and it will need to reject heat to other heat sinks before returning to the stripper condenser.

Previous analysis of heat rate improvements by rejecting heat to FWHs 1, 2, and 3 was done with the reboiler condensate entering the steam condenser. With the model set up that way, there is a much larger flow rate of feedwater through FWHs 1, 2, and 3, and therefore much more heat that can be rejected to FWHs 1, 2, and 3. In Martin's base case FWHs 1, 2, and 3 have a total duty of 424 Mbtu/hr versus 202 Mbtu/hr in Jonas' base case. If the two scenarios have heat integration improvements implemented, Martin's base case will have a larger percent reduction in heat rate, which is due to the ability of the FWHs to accept large amounts of heat at low temperatures. Jonas' base case already has the low temperature extractions reduced, and even though there will be low temperature heat available from the compressors and condenser, the FWHs will not be able to accept all of it. In short, Jonas’ base case will not be able to decrease the extractions as much as in Martin’s case because the extractions have already been decrease from the base case steam turbine kit values.

The model used to generate Jonas’ heat integration improvements is set up differently than the model in Martin's thesis. This analysis does not reroute low pressure liquid leaving the steam air heater (SAH), and the steam leaving the steam seal regulator (SSR), which can be observed in Figure 11. These streams still go through FWHs 1, 2, and 3, even though the extractions to them may be shut off. This eliminates the possibility that these streams could not be integrated into the deaerator (FWH-4), and allows for more similarities in the flow sheet setup of each integration case. It is also more consistent with the original steam turbine kit on which the steam cycle model is based.

3.3 Heat Integration Results using Jonas’ Base Case

Using Martin's thesis as a guideline for heat integration, different simulations were performed using the waste heat from the stripper condenser and the compressors. For the remainder of this section a PRB coal with an Inline 4 compressor will be analyzed, with similar analyses done for different coals and compressors in later sections.

To implement heat integration, different heat sources were paired up with heat sinks. The heat sinks that were used in this analysis were FWHs 1, 2, 3, 4, and 5, as well as the reboiler, and a coal dryer. The stripper condenser, which rejects heat at a relatively low temperature of 230 °F, is used for lower temperature heat sinks such as FWHs 1, 2, and 3, as well as coal drying. The Inline 4 compressor has cooling water leaving at 425 °F, and its heat can be integrated to higher temperature heat sinks such as FWHs 4 and 5, the reboiler, and the low temperature FWHs. Assuming a minimum temperature difference of 10 °F, integrating to FWH-4 requires heat source temperatures greater than 240 °F, while integrating to FWH-5 requires heat source temperatures greater than 325 °F. FWHs 1 to 4 can be observed without heat integration, and are shown in Figure 10.

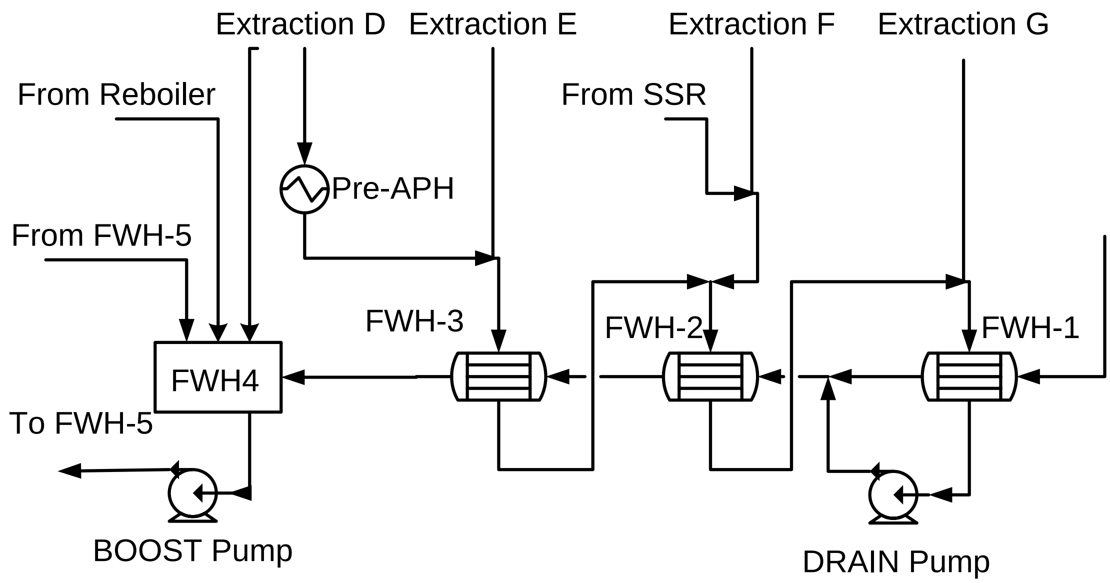

Figure 10. Feedwater Heaters 1, 2, 3, and 4 Base Case

When using a high temperature cooling water stream, it is best to place a heat exchanger before the highest temperature FWH that would allow the compressor cooling water stream to heat the boiler feedwater. If extractions to higher temperature feedwater heaters are reduced, it allows increased flow to the next turbine, as well as all of the other turbines. For example, in Figure 11 if extraction C is reduced, there is an increase in flow to LPTs 1 to 5, whereas if extraction D is reduced there is only an increase in flow to LPTs 2 to 5. Reducing the higher temperature extraction generates more power than reducing lower temperature extraction; therefore, more emphasis should be placed on reducing the higher extractions before proceeding to minimize lower temperature extractions. The steam cycle is optimized by reducing the flow rate of the high temperature extractions as much as possible, while also avoiding low temperature approaches. Low temperature difference approaches are avoided so that heat exchangers do not get larger then what is practical. The cooling water leaving a higher temperature feedwater heater, such as FWH-4, can also be used to integrate at a lower temperature feedwater heater, such as FWH-3. This cascading effect is shown in a later analysis.

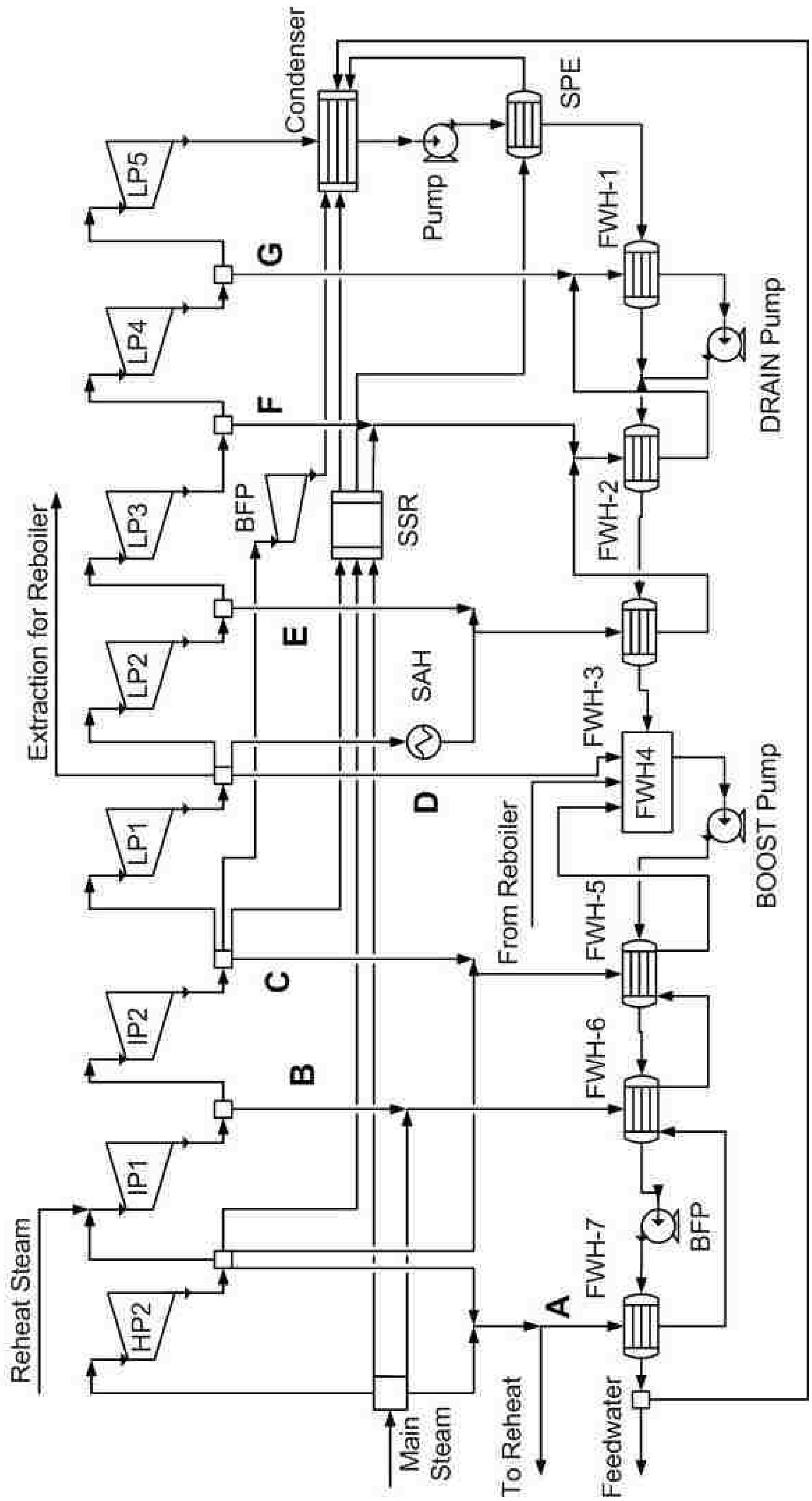

Figure 11. Steam Turbine Cycle with Reboiler Condensate Returned to FWH-4

3.4 Stripper Condenser Heat Integration

The stripper condenser (see Figure 3) cools the carbon dioxide and water mixture from 240 °F to 100 °F. It is assumed that cooling water entering at 90 °F will cool the mixture, and a cooling water flow rate will be calculated so that there is a 10 °F temperature difference at the outlet so that the water will be leaving at 230 °F. This gives the option of integrating heat from the stripper condenser to FWHs 1, 2, and 3. In the base case, with PRB coal, the stripper condenser rejects 491 Mbtu/hr to approximately 3.5 million lb/hr of water by heating it from 90°F to 230°F while FWHs 1, 2, and 3 require 202 Mbtu/hr to heat approximately 1.53 million lb/hr of boiler feedwater from 88.2 °F to 231.4 °F.

The stripper condenser cooling water is used to heat the feed water in place of FWHs 1, 2, and 3; the details of this heat integration are shown in Figure 12. Heat from the stripper condenser can completely replace extractions G, F, and E at FWHs 1, 2, and 3. This cools the cooling water from the stripper condenser from 230 °F to 181 °F, assuming that all of the heat integration water from the stripper condenser is being sent to the FWHs. To maintain a minimum temperature difference of 10 °F, the feedwater leaving FWH-3B will be at 220 °F instead of the usual 231.4 °F. This requires extraction D to increase slightly to make up for the lower enthalpy value of feedwater entering FWH-4. This extraction is increased from 146,000 lb/hr to 163,000 lb/hr to maintain the 314 °F temperature requirement leaving FWH-4. This heat integration increases the net power 5,026 kW and decreases the heat rate from 13,118 btu/kWhr to 12,961 btu/kWhr, an improvement of 1.20%. See Table 8 for more integration details.

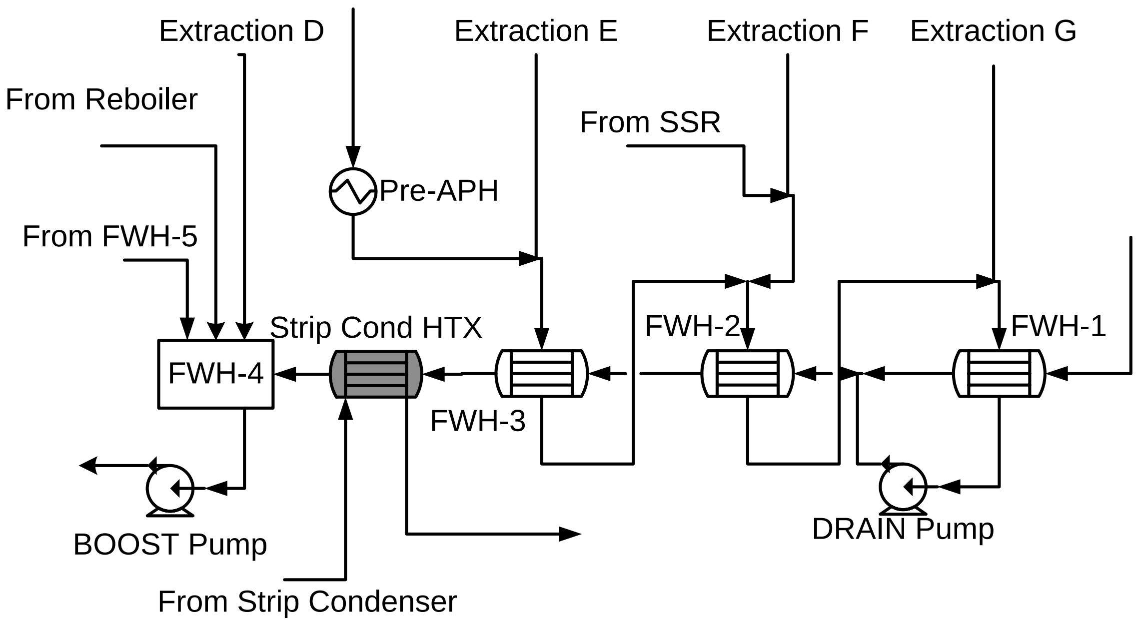

Figure 12. Feedwater Heaters 1, 2, 3, and 4 with Stripper Condenser Heat Integration

This heat rate improvement is less than the one shown in Martin's thesis, however it is necessary to point out that there is much less feedwater flow going through FWHs 1, 2, and 3, and therefore much less feedwater that can be heated. Due to the smaller feedwater flow rate, extractions E, F, and G are much smaller in Jonas' base case. Eliminating extractions with smaller flow rates will cause smaller power increases and a lower heat rate improvement percent. There was also an error made in Martin's results concerning the temperature leaving FWH-4. The error was corrected to show that instead of a 6.78% heat rate improvement; only a 3.74% heat rate improvement was possible.

Even though this 3.74% heat rate improvement is larger than the 1.20% heat rate improvement calculated from Jonas' base case, the heat rate of 12,961 btu/kWhr is 1.5% less than the heat rate of 13,165 btu/kWhr calculated using Martin's methodology. This lower heat rate is due to the reboiler condensate being rerouted. The condensate reroute entering FWH-4 at 300 °F saves large amounts of steam from extraction D that heats this feedwater in FWH-4 in Martin's analysis. This difference between the two analyses is shown by observing the required extraction D flow rate in Jonas' results is 163,000 lb/hr and in Martin's results the required flow is 244,000 lb/hr.

3.5 Compressor Heat Integration

In the Inline compressor train there are three different stages where the CO_2 stream is compressed. In between the three compressor stages, compressor intercoolers use cooling water entering at 90 °F to cool the CO_2 to 110 °F and in doing so, heat the water to 10 °F below the CO_2 temperature leaving the compressor. For the middle two stages this temperature is around 420-430 °F, and for the last stage of compression this temperature is around 170 °F. Due to the temperature of the cooling water being so low leaving the post compressor cooler (PCC) (see Figure 5), this cooling water was not used in the heat integration analysis. It can be assumed that the cooling water from the PCC is cooled in a cooling tower or the PCC can be removed and the CO_2 can be sent to a pipeline at that temperature.

The two cooling water streams leaving compressor intercoolers one and two are combined together giving a flow rate of approximately 720,000 lb/hr at 423 °F, which can be used to heat boiler feedwater in place of steam entering FWHs 4 and 5, reducing extractions C and D. The cooling water from the compressors can also be used to heat boiler feedwater in place of FWHs 1, 2, and 3, however, due to its higher temperatures it would provide a larger power improvement if the cooling water was integrated to boiler feedwater in place of FWHs 4 and 5 before being further cooled at FWHs 1, 2, and 3.

3.6 Compressor to FWH 1, 2, and 3

Using cooling water from the compressors to replace extractions G, F, and E at FWHs 1, 2, and 3 results in all three extractions being eliminated as well as the partial reduction in extraction D at FWH-4. Figure 13 shows where the compressor heat exchanger is located within the steam cycle. A total of 89.2% of the heat from the compressors is used to heat the boiler feedwater from 105 °F to 251 °F. This results in extraction D being reduced to 118,000 lb/hr giving a final heat rate of 12,846 btu/kWhr, a 2.08% improvement. After leaving the compressor heat exchanger (HTX) the compressor cooling water will have a temperature of 115 °F, which is greater than the required inlet temperature of the post compressor coolers. The compressor cooling water needs to be cooled additionally, possibly in a cooling tower, before reentering the post compressor cooler.

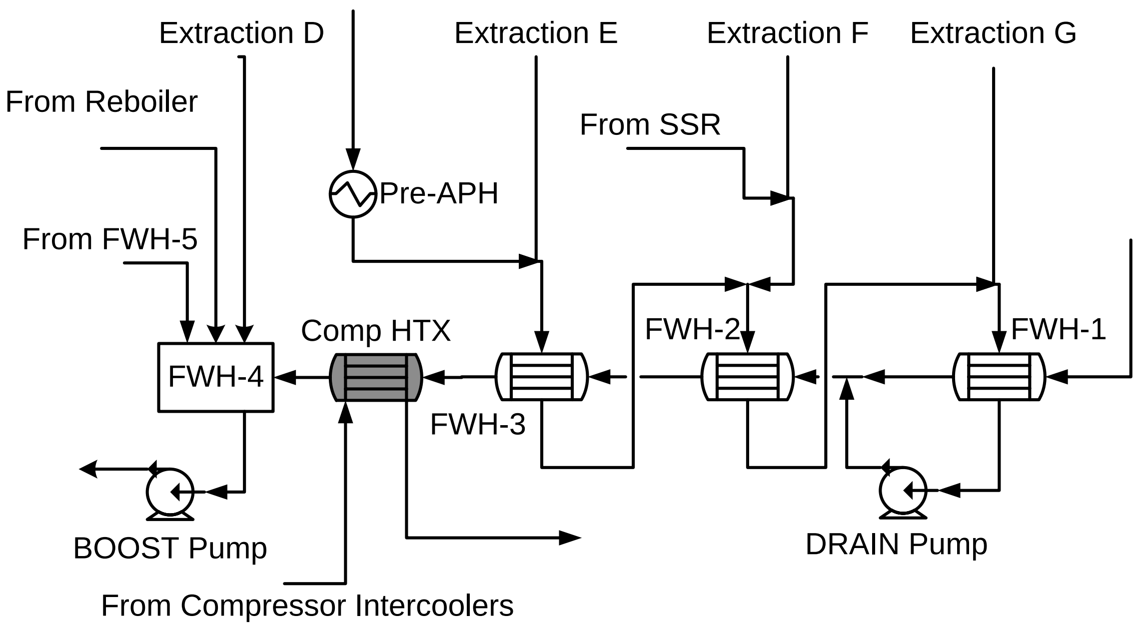

Figure 13. Feedwater Heaters 1 to 4 with Compressor Heat Integration to FWH1 to 3

Martin's heat rate improvement listed in her thesis of 1.76% reflects the improvement using one compressor cooler, and the results in this thesis use two compressor coolers to integrate heat to FWHs 1, 2, and 3. Redoing Martin's work using heat from compressor stages 1 and 2 yields an improvement of 2.33%, which is slightly more than the results presented here (see Table 8 and Table 9 for results). This is because in Martin's results, extraction E is reduced from 109,004 lb/hr to zero lb/hr, whereas, in Jonas' results extraction E is reduced from 48,000 lb/hr to zero lb/hr. Both of these reductions cause an increase in the flow through LPT-3, however, because Martin had more steam in her base case going to FWH-3, she is able to divert more steam to LPT-3. Therefore, Martin is going to have a higher heat rate improvement percentage, whereas Jonas' results will have a lower heat rate overall. Martin's final heat rate is 13,358 btu/kWhr, which is greater than the heat rate of 12,846 btu/kWhr found in this thesis by making improvements on Jonas' base case.

3.7 Compressor to FWH 1, 2, 3, 4, and 5

The compressors release heat at a relatively high temperature of 423 °F offering the possibility of integrating heat to higher temperature heat sinks, like FWH-4 and FWH-5. Using compressor heat exclusively to partially replace extraction C at FWH-5 would be a waste of heat because the heat integration water from the compressors can only be cooled to 324 °F at that location. Therefore, this heat is cascaded down to integrate into FHW-4 as well as FWHs 1-3; this process is shown in Figure 14. This allows cooling water to reject heat to the highest temperature heat sink causing the largest power benefit. To keep these heat exchangers at a realistic size, it is assumed that there is at least at 10 °F temperature difference between the feed water and the heat integration water.

Integrating the compressor heat to FWH-5 causes the compressor cooling water to be cooled from 423 °F to 324 °F and extraction C to be reduced from 163,004 lb/hr to 107,000 lb/hr. The heat integration water leaving compressor HTX-5 is also used to heat water entering FWH-4, which reduces extraction D from 146,000 lb/hr to 75,000 lb/hr. Using a similar cascading technique, shown in Figure 14, extraction E is reduced to 40,000 lb/hr, extraction F is reduced to 39,000 lb/hr, and extraction G is reduced to 24,000 lb/hr. The heat rate given by implementing these changes is 12,694 Btu/kWhr giving a 3.23% improvement over Jonas' base case with no heat integration.

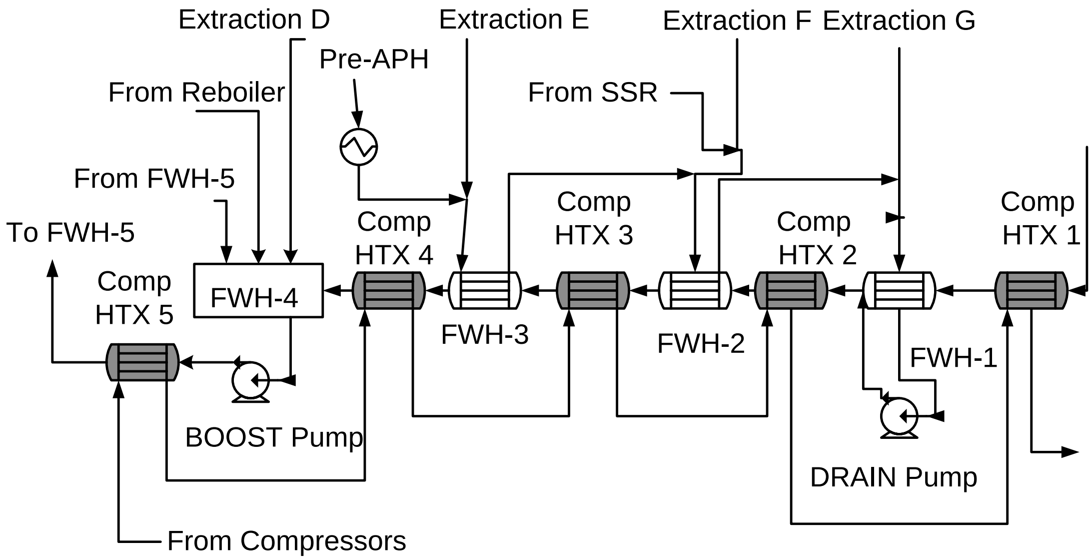

Figure 14. Feedwater Heaters 1, 2, 3, and 4 with Compressor Heat Integration to FWH1, 2, 3, 4, and 5

3.8 Compressor Heat to FWH 4 and 5

A similar scenario was evaluated where the heat from the compressor was only used to decrease extractions C and D at FWHs 4 and 5. For this scenario, extraction D was reduced to 83,500 lb/hr and extraction C was reduced to 107,000 lb/hr. The heat integration water was not cascaded down to preheat FWHs 1, 2, and 3 and it is assumed the compressor cooling water leaving compressor HTX-4 will need to be additionally cooled at another heat sink before returning to the compressors. Implementing these changes yields a heat rate of 12,789 Btu/kWhr, a 2.51% improvement over the base case. This process is shown in Figure 15.

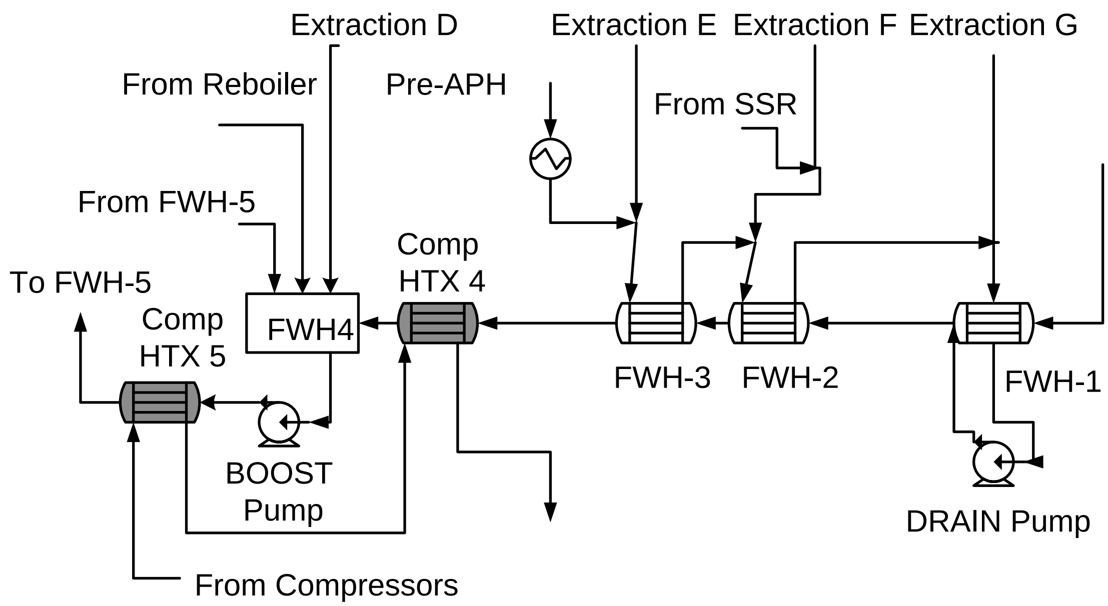

Figure 15. Feedwater Heaters 1, 2, 3, and 4 with Compressor Heat Integration to FWH 4 and 5

3.9 Compressor Heat to Reboiler

Compressor heat can also be rejected to the reboiler, reducing the reboiler extraction upstream of LPT-2. Observing Figure 11 the reboiler extraction is in the same location (between LPTs 1 and 2) as extraction D for FWH-4. Martin's thesis looks at heat integration to the reboiler extensively, however, it can be shown that integrating heat to FWH-4 and integrating heat to the reboiler achieves the same results. Using the compressor cooling water to heat the amine in the reboiler or the feedwater in compressor HTX-4 (see Figure 16 and Figure 17) both reduce the extraction upstream of LPT-2. Looking at both scenarios separately, the same amount of heat will be recovered from the compressor cooling water in the reboiler heat integration scenario and in compressor HTX-4 heat integration scenario. Both of these heat integration scenarios reduce the same amount of steam that would have been sent to FWH-4 or the reboiler. This steam will flow through LPTs 2 to 5 generating the same amount of additional power in both cases.

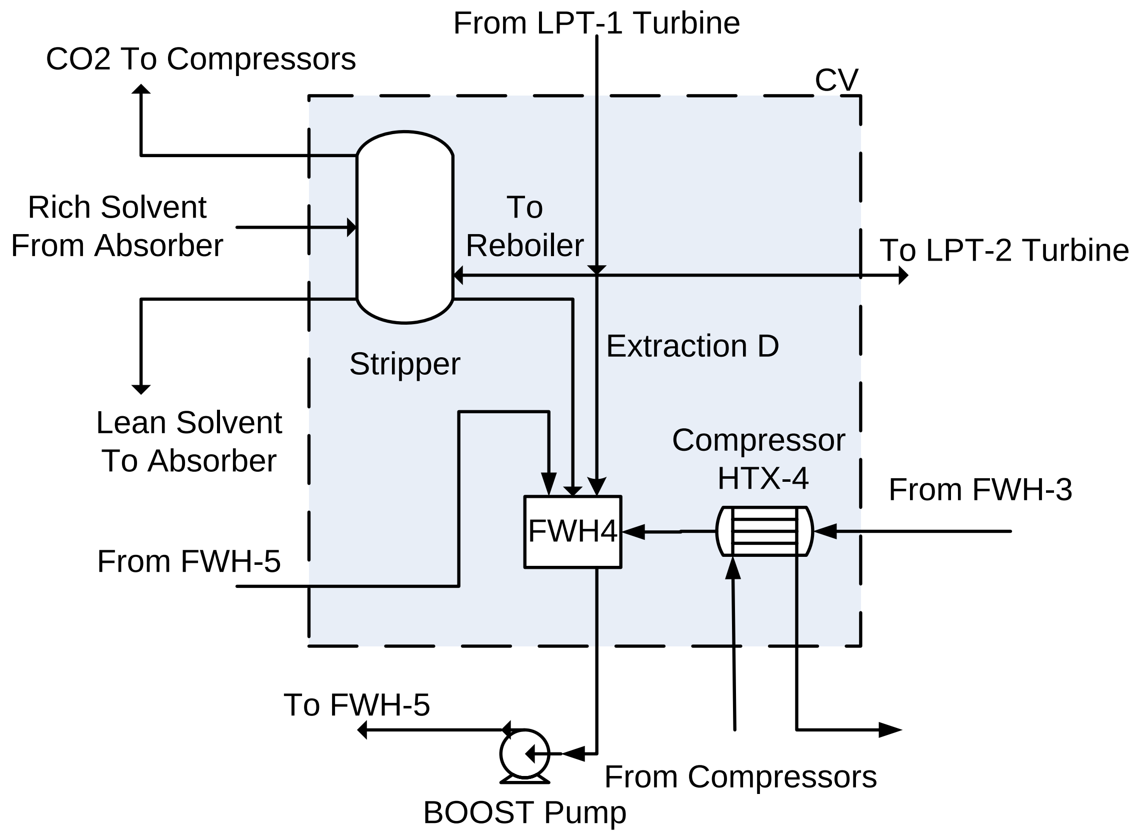

Figure 16. FWH-4 Heat Integration Control Volume

To help explain this, a control volume is shown in Figure 16 and Figure 17. As with all control volumes, the mass and energy in must equal the mass and energy out. The only stream value that would change with respect to different compressor cooling water conditions would be the "to LPT-2 Turbine" stream. Therefore, if the compressor cooling water streams are the same, the steam flow into LPT-2 will be the same. As long as the compressor HTX-4 is located within the control volume and has the same inlet and exit conditions, conservation of mass and energy will be observed, and the "to LPT-2 Turbine" stream will be constant. This means that the compressor HTX-4 can be located in the stripper and have the same effect on the inlet to LPT-2. To verify this logic, results were generated for both cases.

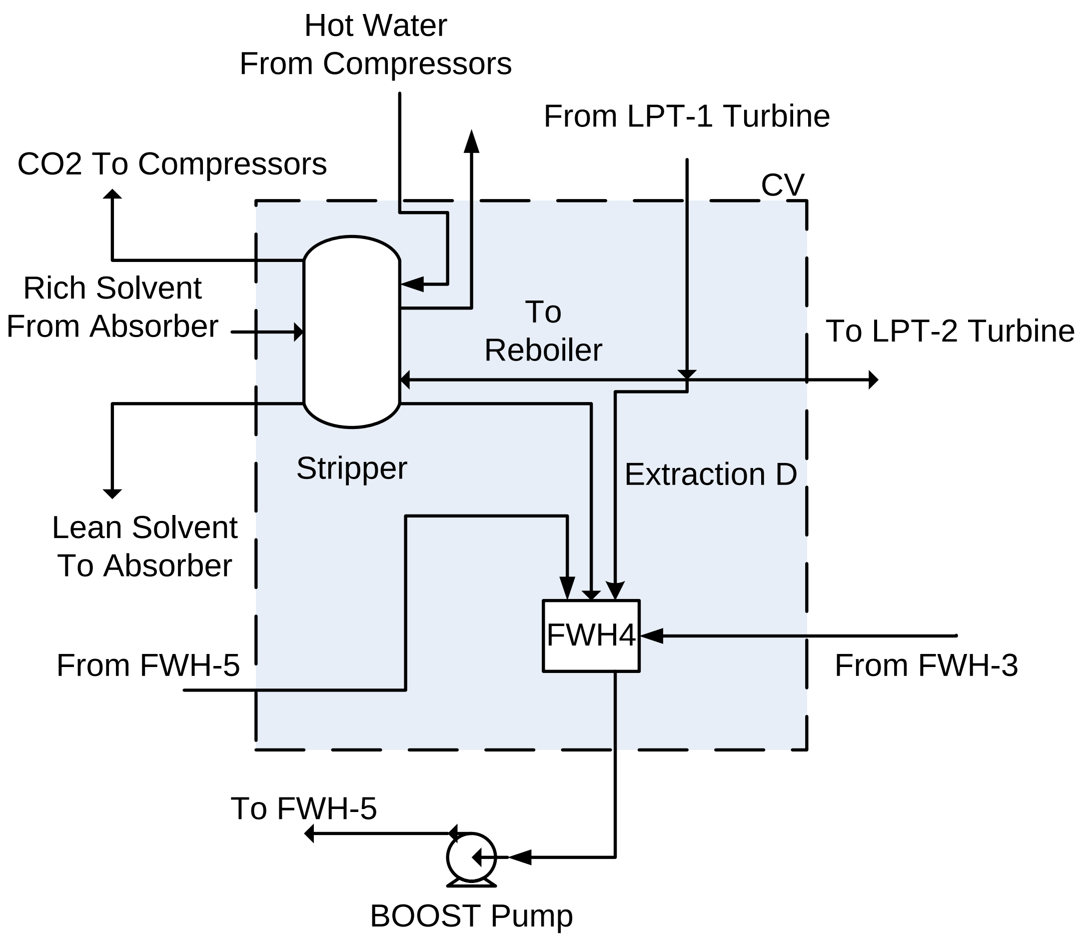

Figure 17. Reboiler Heat Integration Control Volume

It can be shown that if compressor cooling water enters the reboiler at 427 °F and leaves at 260 °F, it reduces the required steam extraction by 117,000 lb/hr and results in a 2.31% heat rate improvement over the base case. If the compressor cooling water is used to heat boiler feedwater and has an exit temperature of 260 °F (making the two scenarios have the same amount of heat integrated), extraction D is reduced by 117,000 lb/hr, giving the same heat rate improvement. Therefore, it can be assumed that any heat rejected to FWH-4 could also be rejected to the reboiler and give the same heat rate improvement results. During this analysis, it was also shown that there is not enough heat in the compressor cooling water streams to completely eliminate extraction D. Therefore, for simplicity, in this thesis heat will only be integrated to FWH-4 because treating the two scenarios separately will generate the same results. The 2.31% heat rate improvement obtained from both scenarios, compares well to the heat rate improvement of 2.43% listed in Martin's thesis for the case of heat transfer to the reboiler.

3.10 Combined Compressor and Condenser Heat Integration

Using both the condenser and compressor to replace extraction for feedwater heaters is a good way to reject the heat from both sources. By using the stripper condenser heat to replace the low temperature feedwater heaters such as FWHs 1 to 3, the compressor heat can be used to partially replace the extractions at FWHs 4 and 5. The full integration set up can be observed in Figure 18. Implementing these changes in a similar manner as described previously, extractions E, F, and G were eliminated, and extraction D was reduced to 90,500 lb/hr while extraction C was reduced to 107,000 lb/hr. This heat integration technique gives a heat rate of 12,607 btu/kWhr, which is a 3.90% reduction from the base case.

Martin's thesis quotes a 9% heat rate improvement using this approach; however after the FWH-4 outlet temperature was corrected only a 5.99% improvement was found. This improvement in Martin's thesis is larger than the one shown in this thesis due to the cooling water leaving the stripper condenser having the ability to eliminate all of the extractions to FWHs 1 through 3. The improvement from the stripper condenser in Jonas' heat integration results is less because there are smaller extraction flow rates in Jonas' base case, and therefore, less of a heat requirement in FWHs 1 to 3. The final heat rate found using Martin's model as a base case, with the reboiler condensate entering in the steam condenser, is 12,857 btu/kWhr, which is greater than the heat rate found using Jonas' model as a base case, with the reboiler condensate rerouted.

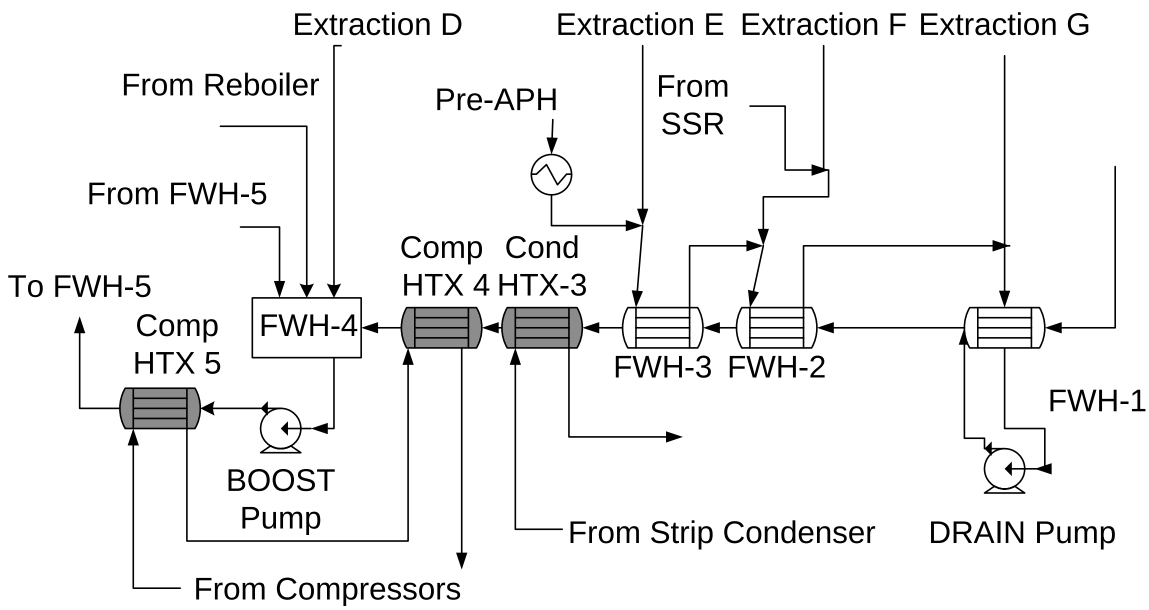

Figure 18. Feedwater Heaters 1, 2, 3, and 4 with Combined Compressor and Stripper Condenser Heat Integration

3.11 Coal Drying

Previous works by Charles, Martin, and Aiken have shown benefits of coal drying. Shown in these results is the assumption that PRB coal is dried from 28.09% moisture to 15% moisture. In section 5, coal drying to other moisture percents is analyzed for a PRB coal, as well as a Lignite coal. In their analyses the temperature leaving the dryer is calculated using a coal drying program developed by Charles, and inputted as the coal temperature entering in ASPEN. It was found that the temperature leaving the dryer is 182 °F, which is too high for most coals entering a pulverizer. Babcock and Wilcox's "Steam" book (13-9 Table 2) [5] recommends a temperature of 130-150 °F for sub-bituminous coals leaving the pulverizer to prevent accidental ignition of the coal; therefore, it can be inferred that 182 °F is too hot to be entering the pulverizer. For the analysis shown in this thesis, it is assumed that the temperature of the coal entering the pulverizer will not be dependent on how the coal is dried, and will always be entering at 77 °F, which is the same temperature that the coal enters without coal drying.

Drying the coal to 15% moisture and then burning it will have numerous effects on the boiler and carbon capture system. Reducing the amount of water that is going into the boiler will decrease the amount of coal that is required. The coal moisture, which requires energy to evaporate, is reduced in flow rate, therefore, allowing a larger percentage of heat released by burning to be sent to the steam cycle. The current model keeps the heat transferred to the steam cycle constant, so the dry coal flow rate will be decreased to keep this value the same. The reduction in coal flow rate will also cause a reduction in air flow rate. The reduction of these two variables will cause a reduction in pulverizer power, fan power, and decrease the amount of flue gas being sent to the MEA system. This reduction in flue gas flow rates causes a reduction in the flow rate of CO2, which will decrease the amount of extraction steam being sent to the reboiler, as well as decrease the power requirement of the CO2 compressors. The effects of coal drying to different moisture levels will be examined in greater detail in section 5 of this thesis.

Table 7. Coal Drying Comparison

	BASE CASE	Coal Drying
Wet Coal Flow (lb/hr)	643,021	627,317
Coal Inlet Moisture	28.09	15.00
Gen Power (kW)	496,071	498,975
Fan Power (kW)	18,002	17,022
Pulv Power (kW)	3,403	2,809
Pump Power (kW)	2,291	2,269
Aux Power (kW)	15,000	15,000
Pss (kW)	38,697	37,100
Comp Power (kW)	43,869	42,772
Net Power (kW)	413,506	419,102
Δ in Net Power (kW)	0	5,596
Unit Heat Rate (Btu/kWhr)	13,118	12,627
Δ in Heat Rate (%)	0.00%	-3.74%
Efficiency (%)	26.0%	27.0%

By drying the coal to 15% moisture the wet coal flow rate entering the dryer was reduced from 643,021 lb/hr to 627,317 lb/hr. In addition to the reduction in coal flow rate, other changes in power plant operation can be observed in Table 7. The coal flow rate leaving the dryer is calculated to be 530,710 lb/hr, and reduces the pulverizer power from 3,403 kW to 2,809 kW. The reduction in air and coal flow rate combine to reduce the fan power from 18,002 kW to 17,022 kW. The reboiler duty is reduced from 1,795 Mbtu/hr to 1,753 Mbtu/hr, and the compressor power is reduced from 43,869 kW to 42,772 kW. Due to the lower reboiler duty, there is more flow going to the steam condenser, and therefore, more flow coming from FWHs 1 through 3 into FWH-4. It is necessary to increase extraction D to 152,000 lb/hr to keep the temperature leaving FWH-4 constant. This gives a final heat rate of 12,627 btu/kWhr, which is a 3.74% heat rate improvement over the base case. This improvement compares very well to Martin's results of a 3.92% improvement using coal drying.

3.12 Combined Coal Drying and Integration to FWHs 1, 2, 3, 4, and 5

To provide a best possible heat integration approach, it was decided to create a combined case where coal drying is combined with integrating compressor cooling water to FWHs 4 and 5, as well as integrating stripper condenser cooling water to FWHs 1 to 3 (see Table 8). There are some minor differences in heat integration when compared to analysis done without coal drying. One of the differences being that due to a smaller CO2 flow rate, there will be less heat from the compressor and the stripper condenser to reject to the steam cycle. Combining the two methods presented previously, extractions G, F, and E were eliminated by using heat from the stripper condenser, while extraction D was reduced to 93,500 lb/hr and extraction C was reduced to 110,000 lb/hr by using heat from the post compressor coolers. These reductions in flow rates combined with the effects of coal drying give a final heat rate of 12,143 btu/kWhr, or a 7.43% heat rate improvement from the base case.

Table 8. Jonas' PRB Heat Integration Results Using Inline 4

	Jonas' BASE CASE	Stripper Cond to FWHs	Comp to FWH 1,2,3	Comp to FWH 1,2,3,4,5	Comp to FWH4 (Reboiler)	Comp to FWH 4,5
Wet Coal Flow (lb/hr)	643,021	643,021	643,021	643,021	643,021	643,021
Dried Coal Inlet Moisture	28.09	28.09	28.09	28.09	28.09	28.09
Gen Power (kW)	496,071	501,095	504,855	509,905	505,846	506,743
Fan Power (kW)	18,002	18,002	18,002	18,002	18,002	18,002
Pulv Power (kW)	3,403	3,403	3,403	3,403	3,403	3,403
Pump Power (kW)	2,291	2,289	2,293	2,302	2,301	2,302
Aux Power (kW)	15,000	15,000	15,000	15,000	15,000	15,000
Pss (kW)	38,697	38,694	38,698	38,707	38,707	38,707
Carbon Captured	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Reboiler duty(Btu/lbmCO2)	1,692	1,692	1,692	1,692	1,692	1,692
Comp Power (kW)	43,869	43,869	43,869	43,869	43,869	43,870
Net Power (kW)	413,506	418,532	422,288	427,329	423,271	424,166
Δ in Net Power	0	5,026	8,782	13,823	9,765	10,660
Unit Heat Rate (Btu/kWhr)	13,118	12,961	12,846	12,694	12,816	12,789
Δ in Heat Rate (%)	0.00%	-1.20%	-2.08%	-3.23%	-2.31%	-2.51%
Efficiency (%)	26.0%	26.3%	26.6%	26.9%	26.6%	26.7%
Heat Integration Details						
Stripper Condnsr heat used	0.0%	35.1%	0.0%	0.0%	0.0%	0.0%
Comp heat used (%)	0.0%	0.0%	88.1%	93.0%	55.4%	53.9%
FWH1 Duty (kBtu/hr)	81,329	558	558	23,957	81,329	87,175
FWH2 Duty (kBtu/hr)	62,882	11,044	11,044	56,286	62,882	65,400
FWH3 Duty (kBtu/hr)	58,088	9,343	9,343	45,655	58,088	58,088
FWH5 Duty (kBtu/hr)	216,159	216,159	216,159	141,041	216,159	141,033
Extract G (lb/hr)	83,900	0	0	24,000	83,900	90,000
Extract F (lb/hr)	49,500	0	0	39,000	49,500	52,000
Extract E (lb/hr)	48,000	0	0	40,000	48,000	48,000
Extract D (lb/hr)	146,000	163,000	118,000	75,000	29,000	83,500
Extract C (lb/hr)	163,004	163,004	163,004	107,000	163,004	107,000
Heat Rejected (Mbtu/hr)						
Steam Condenser	1,167	1,323	1,365	1,362	1,278	1,271
Stripper Condenser	491	318	491	491	491	491
Compressors	258	258	31		115	119
Amine Cooler	1,031	1,031	1,031	1,031	1,031	1,031
Flue Gas Cooler	503	503	503	503	503	503

Table 8. (Continued)

	Comp to FWH4,5 Str Cond to FWH1-3	Coal Drying	Coal Drying Comp and Cond to FWH1-5,
Wet Coal Flow (lb/hr)	643,021	627,317	627,317
Dried Coal Inlet Moisture	28.09	15.00	15.00
Gen Power (kW)	512,840	498,975	515,690
Fan Power (kW)	18,002	17,022	17,022
Pulv Power (kW)	3,403	2,809	2,809
Pump Power (kW)	2,300	2,269	2,278
Aux Power (kW)	15,000	15,000	15,000
Pss (kW)	38,705	37,100	37,109
Carbon Captured	90.0%	90.0%	90.0%
Reboiler duty (Btu/lbmCO2)	1,692	1,695	1,695
Comp Power (kW)	43,869	42,772	42,772
Net Power (kW)	430,266	419,102	435,809
Δ in Net Power	16,760	5,596	22,303
Unit Heat Rate (Btu/kWhr)	12,607	12,627	12,143
Δ in Heat Rate (%)	-3.90%	-3.74%	-7.43%
Efficiency (%)	27.1%	27.0%	28.1%
Heat Integration Details			
Stripper Condnsr heat used	38.6%	0.0%	40.4%
Comp heat used (%)	56.1%	0.0%	56.1%
FWH1 Duty (kBtu/hr)	558	81,329	558
FWH2 Duty (kBtu/hr)	11,044	62,882	11,044
FWH3 Duty (kBtu/hr)	9,343	58,088	9,343
FWH5 Duty (kBtu/hr)	141,041	216,159	142,879
Extract G (lb/hr)	0	83,900	0
Extract F (lb/hr)	0	49,500	0
Extract E (lb/hr)	0	48,000	0
Extract D (lb/hr)	90,500	152,000	93,500
Extract C (lb/hr)	107,000	163,004	110,000
Heat Rejected			
Steam Condenser (Mbtu/hr)	1,445	1,200	1,478
Stripper Condenser (Mbtu/hr)	301	480	286
Compressors (Mbtu/hr)	113	252	110
Amine Cooler (Mbtu/hr)	1,031	1,005	1,005
Flue Gas Cooler (Mbtu/hr)	503	482	482

Table 9. Martin's PRB Heat Integration Results Using Inline 4

	Martin's Base Case	Stripper Cond to FWHs	Comp to FWH 1,2,3	Comp to FWH 1,2,3,4,5	Comp to Reboiler	Comp to FWH 4,5
Wet Coal Flow (lb/hr)	643,021	643,021	643,021	Not	643,021	Not
Dried Coal Inlet Moisture				Analyzed		Analyzed
Gen Power (kW)	479,216	494,754	488,687		489,057	
Fan Power (kW)	18,002	18,002	18,002		18,002	
Pulv Power (kW)	3,403	3,403	3,403		3,403	
Pump Power (kW)	2,458	2,587	2,485		2,471	
Aux Power (kW)	15,000	15,000	15,000		15,000	
Pss (kW)	38,863	38,992	38,890		38,876	
Carbon Captured						
Reboiler duty (Btu/lbm)						
Comp Power (kW)	43,718	43,718	43,718		43,718	
Net Power (kW)	396,635	412,044	406,079		406,463	
Δ in Net Power						
Unit Heat Rate (Btu/kWhr)	13,676	13,165	13,358		13,346	
Δ in Heat Rate (%)	0.00%	-3.74%	-2.33%		-2.42%	
Efficiency (%)	24.9%	25.9%	25.5%		25.6%	
Heat Integration Details						
Stripper Condnsr heat						
Comp heat used (%)						
FWH1 Duty (kBtu/hr)	173,265					
FWH2 Duty (kBtu/hr)	130,650					
FWH3 Duty (kBtu/hr)	120,224					
FWH5 Duty (kBtu/hr)	215,945					
Extract G (lb/hr)	178,947					
Extract F (lb/hr)	120,754					
Extract E (lb/hr)	109,004					
Extract D (lb/hr)	257,172					
Extract C (lb/hr)	163,004					
Heat Rejected						
Steam Condenser	1,232					
Stripper Condenser						
Compressors (Mbtu/hr)						
Amine Cooler (Mbtu/hr)						
Flue Gas Cooler (Mbtu/hr)						

Table 9. (Continued)

	Comp to FWH4,5, Str Cond to FWH1-3	Coal Drying	Coal Drying, Comp & Str Cond to FWH1-5
Wet Coal Flow (lb/hr)	643,021	627,317	Not
Dried Coal Inlet Moisture			Analyzed
Gen Power (kW)	505,864	482,632	
Fan Power (kW)	18,002	17,022	
Pulv Power (kW)	3,403	2,809	
Pump Power (kW)	2,572	2,433	
Aux Power (kW)	15,000	15,000	
Pss (kW)	38,977	37,264	
Carbon Captured			
Reboiler duty (Btu/lbmCO2)			
Comp Power (kW)	43,718	42,626	
Net Power (kW)	423,169	402,742	
Δ in Net Power			
Unit Heat Rate (Btu/kWhr)	12,819	13,140	
Δ in Heat Rate (%)	-6.27%	-3.92%	
Efficiency (%)	26.6%	26.0%	
Heat Integration Details			
Stripper Condnsr heat used			
Comp heat used (%)			
FWH1 Duty (kBtu/hr)			
FWH2 Duty (kBtu/hr)			
FWH3 Duty (kBtu/hr)			
FWH5 Duty (kBtu/hr)			
Extract G (lb/hr)			
Extract F (lb/hr)			
Extract E (lb/hr)			
Extract D (lb/hr)			
Extract C (lb/hr)			
Heat Rejected			
Steam Condenser (Mbtu/hr)			
Stripper Condenser (Mbtu/hr)			
Compressors (Mbtu/hr)			
Amine Cooler (Mbtu/hr)			
Flue Gas Cooler (Mbtu/hr)			

4.0 Modeling Illinois #6 and Lignite Coal and Heat Integration

Previous work was done modeling a sub-bituminous, PRB, coal using the MEA system. This section looks at the effects of modeling a bituminous coal (Illinois #6) and a Lignite coal. The ASPEN model's coal properties, such as the Ultimate, Proximate, and Sulfur Analysis were changed along with the higher heating value to change the type of coal. Due to differences in the coals, the ASPEN model did not converge properly with the configuration used for a PRB coal. A few initial guesses were also changed such as the initial coal stream flow rate, the initial air stream flow rate, as well as the upper and lower bounds on some design specs. Once these changes were implemented, the models converged without error.

The base case models using different coals differed from each other in many ways. In order to give the same steam flow rate to the turbines, different amounts of coal needed to be burned for each type of coal. Lignite required the highest flow rate with 874,000 lb/hr, whereas PRB required 643,000 lb/hr, and Illinois #6 required 472,000 lb/hr. This is mostly due to the amount of moisture contained in each coal. The Lignite has the highest moisture percentage with 38.5% of the coal being water, PRB has 28.09%, and Illinois #5 has 7.97%. High moisture content in coals will lead to low boiler efficiency. For example the Lignite has a calculated boiler efficiency of 85.3%, PRB has 88.2%, and Illinois #6 has 92.0%. This lower boiler efficiency can be attributed to the heat of combustion of the coal being used to vaporize the water in the coal instead of heating steam to be sent to the turbines.

With the different coal flow rates, each coal's base case has a different CO_2 flow rate. The PRB coal has the highest CO_2 flow rate, with Lignite being next and then Illinois #6. It may seem peculiar that PRB has a higher CO_2 flow rate then Lignite, but this is due to lower carbon percentage in the Lignite coal with approximately the same moisture and ash free (MAF) HHV. The higher the CO_2 flow rate, the more CO_2 will be captured to reach 90%. With that increase, more extraction steam will be diverted away from LPTs 2 to 5, and sent to the reboiler. This will decrease the net power output of the plant. Therefore, it can be concluded that higher CO2 flow rate leads to lower power outputs. Table 10 shows the base case scenarios for each coal in more detail.

Table 10. Comparison of Different Coals Using the Inline 4 Compressor

	BASE CASE PRB	BASE CASE Illinois6	BASE CASE Lignite
Wet Coal Flow (lb/hr)	643,021	471,830	874,222
HHV Wet (Btu/lb)	8,426	10,999	6,406
Coal In Boiler	643,021	471,830	874,222
As Received Coal Moisture	28.09	7.97	38.50
Boiler Efficiency (%)	88.15%	92.03%	85.29%
Gen Power (kW)	496,071	509,360	504,686
Fan Power (kW)	18,002	15,941	18,302
Pulv Power (kW)	3,403	2,497	4,627
Pump Power (kW)	2,291	2,240	2,276
Aux Power (kW)	15,000	15,000	15,000
Pss (kW)	38,697	35,678	40,205
Carbon Captured	90.0%	90.0%	90.0%
CO2 Flow rate (lbm/hr)	1,178,953	1,061,731	1,109,959
Reboiler duty (Btu/lbmCO2 captured)	1,692	1,687	1,682
Reboiler duty (Mbtu/hr)	1,795	1,612	1,680
Comp Power (kW)	43,869	39,512	41,304
Net Power (kW)	413,506	434,170	423,176
Δ in Net Power	0	20,664	9,670
Unit Heat Rate (Btu/kWhr)	13,103	11,953	13,234
Δ in Heat Rate (%)	0.00%	-8.78%	1.00%
Efficiency (%)	26.0%	28.5%	25.8%
Heat Integration Details			
Stripper Condnsr heat used (%)	0.0%	0.0%	0.0%
Comp heat used (%)	0.0%	0.0%	0.0%
FWH1 Duty (kBtu/hr)	81,329	90,292	89,614
FWH2 Duty (kBtu/hr)	62,882	69,677	69,132
FWH3 Duty (kBtu/hr)	58,088	64,181	63,166
FWH5 Duty (kBtu/hr)	216,159	216,159	216,159
Extract G (lb/hr)	83,900	93,200	92,500
Extract F (lb/hr)	49,500	56,000	55,500
Extract E (lb/hr)	48,000	54,000	53,000
Extract D (lb/hr)	146,000	157,000	147,000
Extract C (lb/hr)	163,004	163,004	163,004

Further analysis was done to examine the effects of heat integration on the heat rate of the power plant running Illinois #6 and lignite coals. Using the same techniques as described in the PRB heat integration section, heat integration was added to the Illinois #6 and Lignite models. The results of these simulations can be observed in Table 11 and Table 12, as well as Figure 19 to Figure 22. Due to the already low moisture of Illinois #6, coal drying was not used as a potential heat integration option. Being that Lignite is high in moisture coal drying was implemented. It is assumed in the Lignite case that the coal is dried to 20% moisture which is 18.5% less than its original moisture level of 38.5%.

Table 11. Illinois #6 Heat Integration Results Using the Inline 4 Compressor

	BASE CASE Illinois6	Stripper Cond to FWH1-3	Comp to FWH1-3	Comp to FWH 4,5	Comp to FWH 1-5
Wet Coal Flow (lb/hr)	471,830	471,830	471,830	471,830	471,830
HHV Wet	10,999	10,999	10,999	10,999	10,999
Coal In Boiler	471,830	471,830	471,830	471,830	471,830
As Received Coal Moisture	7.97	7.97	7.97	7.97	7.97
Boiler Efficiency	92.03%	92.03%	92.03%	92.03%	92.03%
Gen Power (kW)	509,360	515,021	515,752	518,656	521,135
Fan Power (kW)	15,941	15,941	15,941	15,941	15,941
Pulv Power (kW)	2,497	2,497	2,497	2,497	2,497
Pump Power (kW)	2,240	2,238	2,238	2,249	2,249
Aux Power (kW)	15,000	15,000	15,000	15,000	15,000
Pss (kW)	35,678	35,676	35,676	35,687	35,687
Carbon Captured	90.0%	90.0%	90.0%	90.0%	90.0%
CO2 Flow (lbm/hr)	1,061,731	1,061,731	1,061,731	1,061,731	1,061,731
Reboiler duty (Btu/lbmCO2)	1,687	1,687	1,687	1,687	1,687
Reboiler duty (Mbtu/hr)	1,612	1,612	1,612	1,612	1,612
Comp Power (kW)	39,512	39,505	39,509	39,509	39,505
Net Power (kW)	434,170	439,840	440,567	443,460	445,942
Δ in Net Power	0	5,669	6,396	9,290	11,772
Unit Heat Rate (Btu/kWhr)	11,953	11,799	11,780	11,703	11,638
Δ in Heat Rate (%)	0.00%	-1.29%	-1.45%	-2.09%	-2.64%
Efficiency (%)	28.5%	28.9%	29.0%	29.2%	29.3%
Stripper Condnsr heat used	0.0%	44.3%	0.0%	0.0%	0.0%
Comp heat used (%)	0.0%	0.0%	88.5%	55.0%	83.4%
FWH1 Duty (kBtu/hr)	90,292	558	558	90,292	55,506
FWH2 Duty (kBtu/hr)	69,677	11,044	11,044	69,677	51,976
FWH3 Duty (kBtu/hr)	64,181	9,343	9,343	64,181	49,964
FWH5 Duty (kBtu/hr)	216,159	216,159	216,159	148,504	148,523
Extract G (lb/hr)	93,200	0	0	93,200	57,000
Extract F (lb/hr)	56,000	0	0	56,000	39,000
Extract E (lb/hr)	54,000	0	0	54,000	40,000
Extract D (lb/hr)	157,000	176,000	167,000	104,000	101,500
Extract C (lb/hr)	163,004	163,004	163,004	115,000	115,000
Steam Condenser (Mbtu/hr)	1,306	1,481	1,489	1,402	1,468
Stripper Condensr (Mbtu/hr)	439	244	439	439	439
Compressors (Mbtu/hr)	232	232	27	105	106
Amine Cooler (Mbtu/hr)	930	930	930	930	930
Flue Gas Cooler (Mbtu/hr)	455	455	455	455	455

Table 11. (Continued)

	Comp to FWH4+5, Str Cond to FWH1-3
Wet Coal Flow (lb/hr)	471,830
HHV Wet	10,999
Coal In Boiler	471,830
As Received Coal Moisture	7.97
Boiler Efficiency	92.03%
Gen Power (kW)	525,535
Fan Power (kW)	15,941
Pulv Power (kW)	2,497
Pump Power (kW)	2,247
Aux Power (kW)	15,000
Pss (kW)	35,685
Carbon Captured	90.0%
CO2 Flow (lbm/hr)	1,061,731
Reboiler duty (Btu/lbmCO2)	1,687
Reboiler duty (Mbtu/hr)	1,612
Comp Power (kW)	39,505
Net Power (kW)	450,345
Δ in Net Power	16,174
Unit Heat Rate (Btu/kWhr)	11,524
Δ in Heat Rate (%)	-3.59%
Efficiency (%)	29.6%
Stripper Condnsr heat used	47.8%
Comp heat used (%)	56.1%
FWH1 Duty (kBtu/hr)	558
FWH2 Duty (kBtu/hr)	11,044
FWH3 Duty (kBtu/hr)	9,343
FWH5 Duty (kBtu/hr)	148,523
Extract G (lb/hr)	0
Extract F (lb/hr)	0
Extract E (lb/hr)	0
Extract D (lb/hr)	108,500
Extract C (lb/hr)	115,000
Steam Condenser (Mbtu/hr)	1,590
Stripper Condensr (Mbtu/hr)	229
Compressors (Mbtu/hr)	102
Amine Cooler (Mbtu/hr)	930
Flue Gas Cooler (Mbtu/hr)	455

Table 12. Lignite Heat Integration Results Using the Inline 4 Compressor

	BASE CASE Lignite	Stripper Cond to FWH1-3	Comp to FWH1-3	Comp to FWH 4,5	Comp to FWH 1-5
Wet Coal Flow (lb/hr)	874,222	874,222	874,222	874,222	874,222
HHV Wet (Btu/lb)	6,406	6,406	6,406	6,406	6,406
Coal In Boiler	874,222	874,222	874,222	874,222	874,222
As Received Coal Moisture	38.50	38.50	38.50	38.50	38.50
Boiler Efficiency (%)	85.29%	85.29%	85.29%	85.29%	85.29%
Gen Power (kW)	504,686	509,828	511,748	514,288	516,797
Fan Power (kW)	18,302	18,302	18,302	18,302	18,302
Pulv Power (kW)	4,627	4,627	4,627	4,627	4,627
Pump Power (kW)	2,276	2,273	2,275	2,285	2,285
Aux Power (kW)	15,000	15,000	15,000	15,000	15,000
Pss (kW)	40,205	40,202	40,204	40,214	40,214
Carbon Captured	90.0%	90.0%	90.0%	90.0%	90.0%
CO2 Flow rate (lbm/hr)	1,109,959	1,109,959	1,109,959	1,109,959	1,109,959
Reboiler duty (Btu/lbmCO2)	1,682	1,682	1,682	1,682	1,682
Reboiler duty (Mbtu/hr)	1,680	1,681	1,680	1,680	1,680
Comp Power (kW)	41,304	41,303	41,304	41,304	41,303
Net Power (kW)	423,176	428,322	430,240	432,770	435,280
Δ in Net Power	0	5,146	7,063	9,593	12,104
Unit Heat Rate (Btu/kWhr)	13,234	13,075	13,017	12,941	12,866
Δ in Heat Rate (%)	0.00%	-1.20%	-1.64%	-2.22%	-2.78%
Efficiency (%)	25.8%	26.1%	26.2%	26.4%	26.5%
Stripper Condnsr heat used	0.0%	40.8%	0.0%	0.0%	0.0%
Comp heat used (%)	0.0%	0.0%	88.3%	54.2%	83.4%
FWH1 Duty (kBtu/hr)	89,614	558	558	89,614	43,987
FWH2 Duty (kBtu/hr)	69,132	11,044	11,044	69,132	48,748
FWH3 Duty (kBtu/hr)	63,166	9,343	9,343	63,166	44,886
FWH5 Duty (kBtu/hr)	216,159	216,159	216,159	145,459	145,451
Extract G (lb/hr)	92,500	0	0	92,500	45,000
Extract F (lb/hr)	55,500	0	0	55,500	36,000
Extract E (lb/hr)	53,000	0	0	53,000	35,000
Extract D (lb/hr)	147,000	170,700	148,000	96,500	94,500
Extract C (lb/hr)	163,004	163,004	163,004	110,000	115,000
Steam Condenser (Mbtu/hr)	1,254	1,422	1,444	1,352	1,430
Stripper Condensr (Mbtu/hr)	456	270	456	456	456
Compressors (Mbtu/hr)	243	243	28	111	109
Amine Cooler (Mbtu/hr)	973	972	973	973	972
Flue Gas Cooler (Mbtu/hr)	497	497	497	497	497

Table 12. (Continued)

	Comp to FWH4+5, Str Cond to FWH1-3	Coal Drying	Coal Drying, Comp & Str Cond to FWH1-5
Wet Coal Flow (lb/hr)	874,222	832,257	832,257
HHV Wet (Btu/lb)	6,406	6,406	6,406
Coal In Boiler	874,222	639,797	639,797
As Received Coal Moisture	38.50	20.00	20.00
Boiler Efficiency (%)	85.29%	89.59%	89.59%
Gen Power (kW)	521,309	509,921	526,126
Fan Power (kW)	18,302	16,348	16,348
Pulv Power (kW)	4,627	3,386	3,386
Pump Power (kW)	2,284	2,234	2,241
Aux Power (kW)	15,000	15,000	15,000
Pss (kW)	40,213	36,967	36,974
Carbon Captured	90.0%	90.0%	90.0%
CO2 Flow rate (lbm/hr)	1,109,959	1,055,433	1,055,433
Reboiler duty (Btu/lbmCO2 capt)	1,682	1,688	1,688
Reboiler duty (MBtu/hr)	1,680	1,603	1,603
Comp Power (kW)	41,304	39,273	39,273
Net Power (kW)	439,791	433,681	449,878
Δ in Net Power	16,615	10,505	26,702
Unit Heat Rate (Btu/kWhr)	12,734	12,293	11,851
Δ in Heat Rate (%)	-3.78%	-7.11%	-10.45%
Efficiency (%)	26.8%	27.8%	28.8%
Stripper Condnsr heat used (%)	46.6%	0.0%	48.0%
Comp heat used (%)	54.6%	0.0%	56.3%
FWH1 Duty (kBtu/hr)	558	89,614	558
FWH2 Duty (kBtu/hr)	11,044	69,132	11,044
FWH3 Duty (kBtu/hr)	9,343	63,166	9,343
FWH5 Duty (kBtu/hr)	145,459	216,159	148,965
Extract G (lb/hr)	0	92,500	0
Extract F (lb/hr)	0	55,500	0
Extract E (lb/hr)	0	53,000	0
Extract D (lb/hr)	98,000	160,000	116,000
Extract C (lb/hr)	110,000	163,004	110,000
Steam Condenser (Mbtu/hr)	1,541	1,314	1,596
Stripper Condenser (Mbtu/hr)	243	437	227
Compressors (Mbtu/hr)	110	231	101
Amine Cooler (Mbtu/hr)	973	924	924
Flue Gas Cooler (Mbtu/hr)	497	456	456

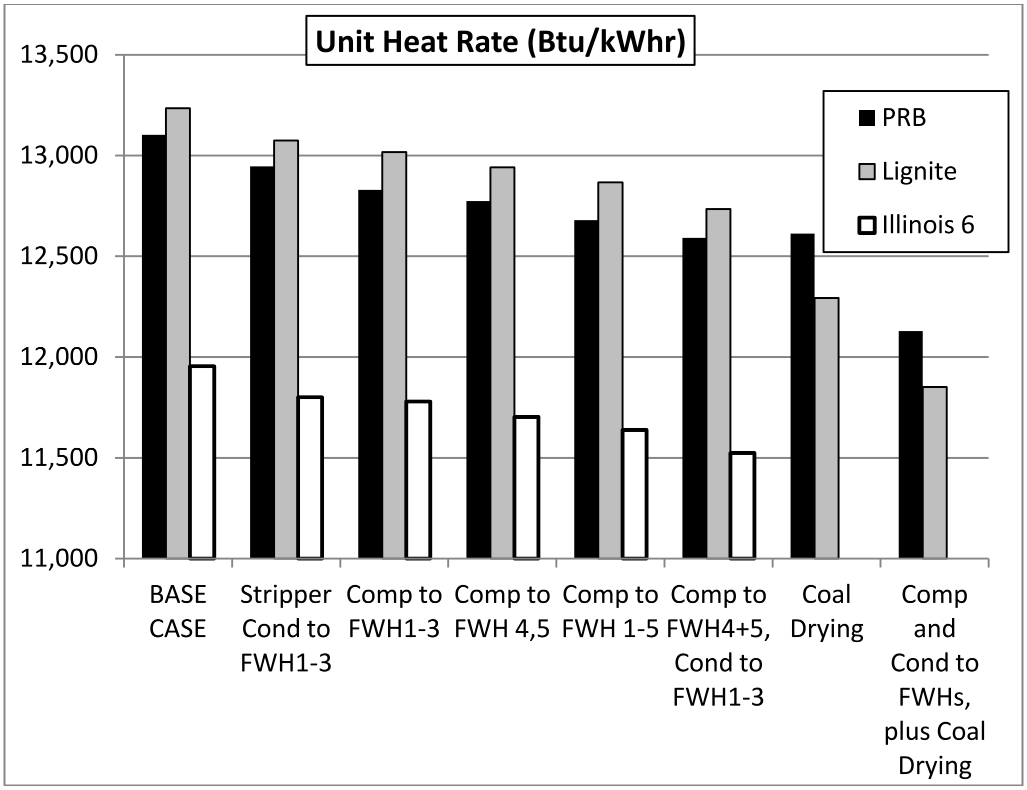

Figure 19. Unit Heat Rate Comparison of Different Coals (Inline 4)

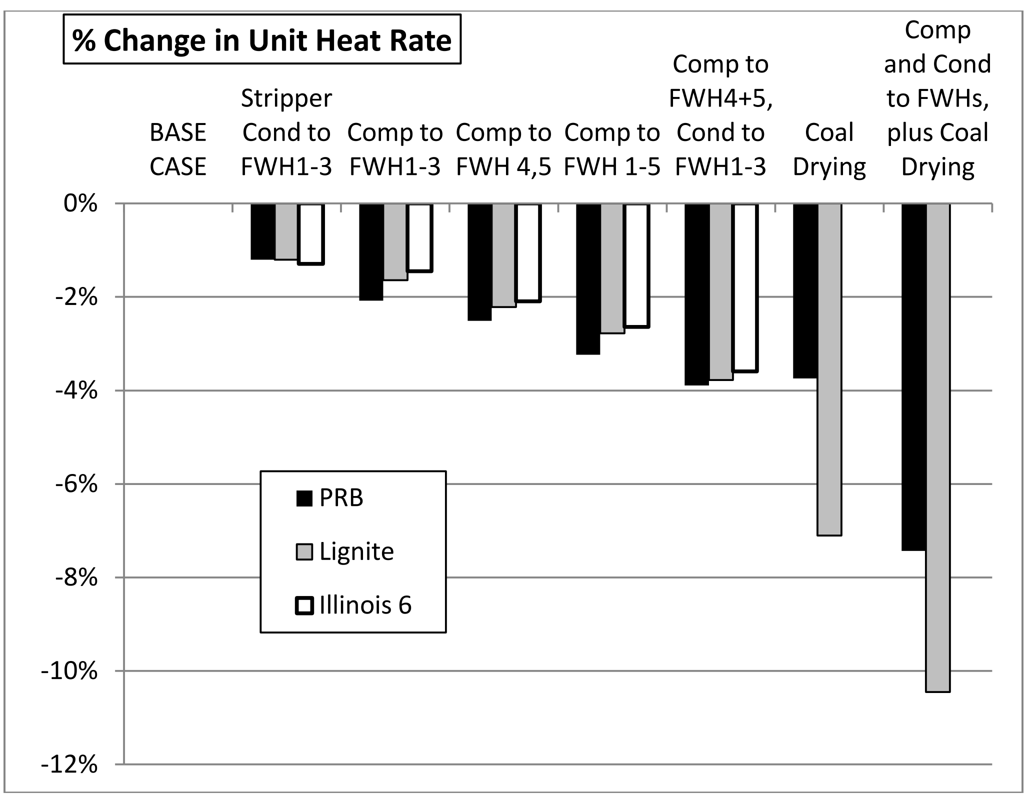

Figure 20. Change in Unit Heat Rate Comparison of Different Coals (Inline 4)

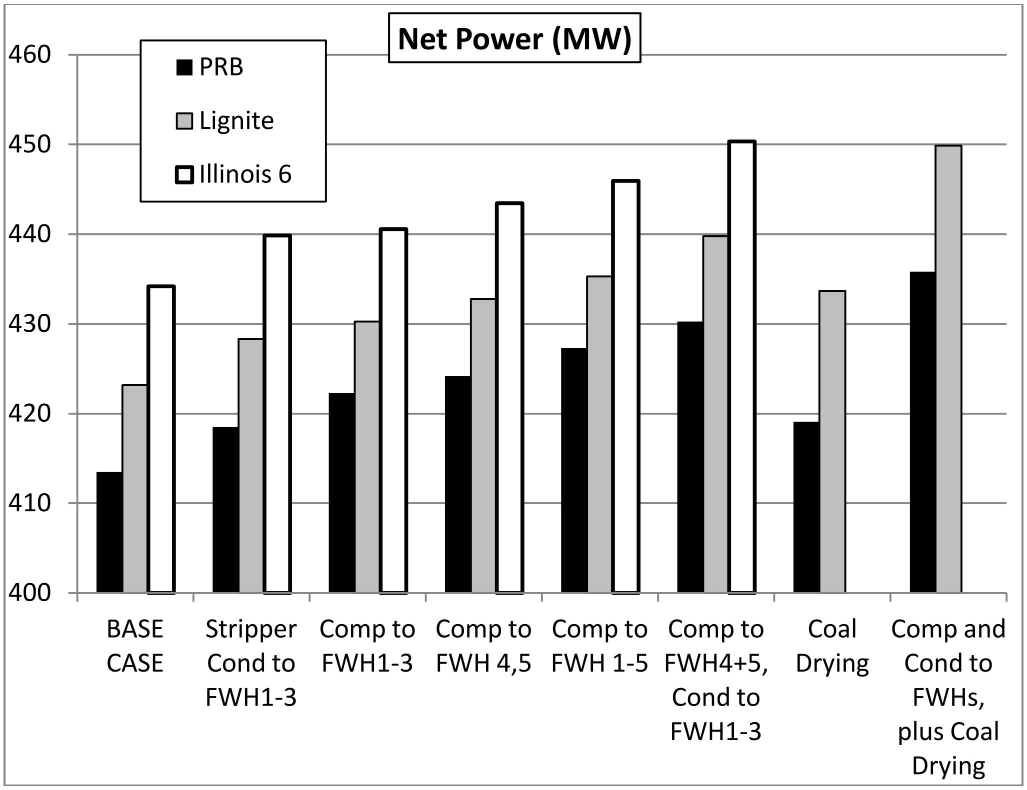

Figure 21. Net Power Comparison of Different Coals (Inline 4)

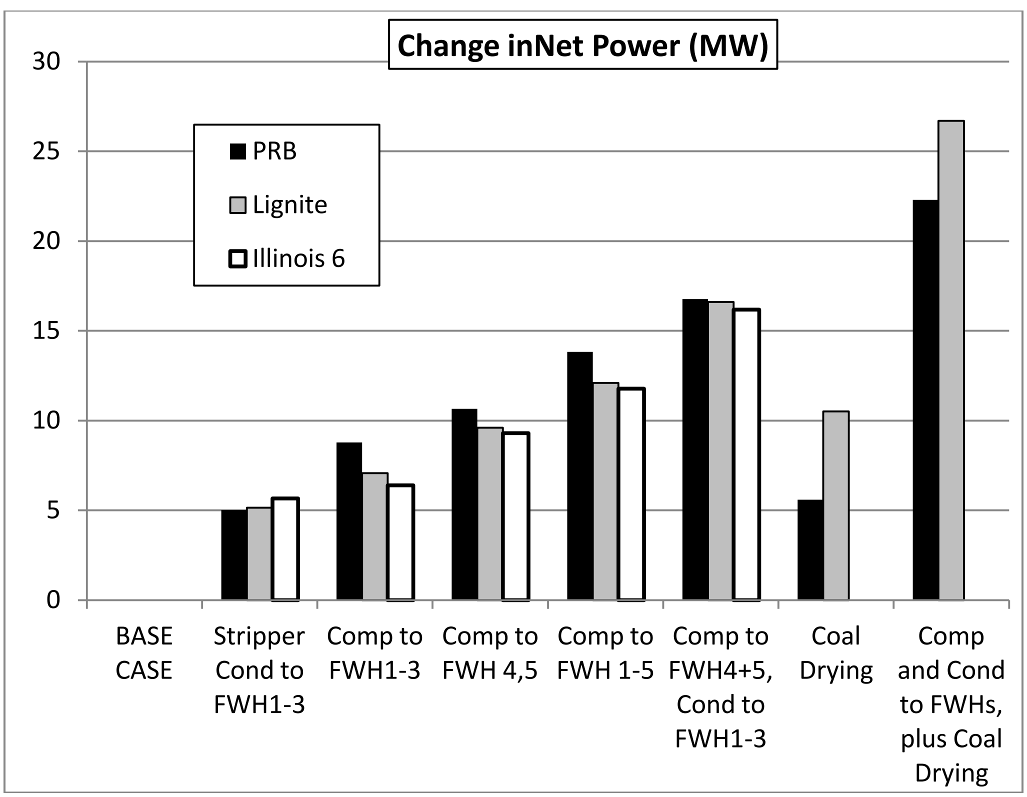

Figure 22. Change in Net Power of Different Coals (Inline 4)

5.0 Effects of Firing a Predried Coal

The effects of firing a pre-dried coal were analyzed in ASPEN Plus by varying the initial moisture content of the coal. This analysis ignores any heat requirement to dry the coal and ignores the possibility of having a higher temperature coal entering the pulverizer. By analyzing the coal this way, the effects of using a pre-dried coal on different components can be isolated and compared. Analyses were performed on a PRB coal from 28.09% moisture to 0% moisture, as well as a Lignite coal from 38.5% moisture to 0% moisture. While it is known that achieving zero percent moisture is difficult and may not be economically feasible, the analysis is shown for comparison.

The process of coal drying and modeling a coal dryer, as well as a more detailed look at the heat requirements of a coal dryer, is looked at more extensively in Charles' thesis. This thesis does not go into details of coal drying. In this section it is assumed that the coal is already dried, and it does not look into the coal drying process.

The PRB coal and the Lignite coal modeled in this analysis have the properties that are given in Table 13, and these are the same properties that ASPEN Plus uses in its calculations (Note: The data from the sulfur analysis for lignite was not given, however, it was approximated by using the values from similar coals).

Table 13. PRB and Lignite Properties

	PRB	**Lignite**
HHV (dry)	11717 (btu/lbm)	10416 (btu/lbm)
Proximate Analysis		
Moisture (wet)	28.09	38.5
Fixed Carbon (dry)	45.87	35.56
Volatile Matter (dry)	44.73	44.44
Ash (dry)	8.77	20
Ultimate Analysis		
Ash	8.77	20
Carbon	68.43	55.33
Hydrogen	4.88	4.83
Nitrogen	1.02	1.17
Chlorine	0.03	0
Sulfur	0.63	0.83
Oxygen	16.24	17.84
Sulfur Analysis		
Pyritic	0.17	0.36
Sulfate	0.03	0.05
Organic	0.43	0.89

5.1 PRB Coal Drying Results and Discussion

The inlet coal temperature remains at the standard 77°F which used for all other models. The inlet moisture percentage of the coal was varied from the initial moisture content down to zero percent moisture. Again, it is well known that achieving zero percent moisture is very difficult, a may not be cost effective; however, the results are shown for comparison purposes. The drying of the coal has many different effects on a coal fired power plant. The boiler efficiency increases which is due to less moisture in the coal that needs to be vaporized. This allows a larger percentage of the HHV of the coal to go to the steam cycle. This change in efficiency can be observed in Figure 23.

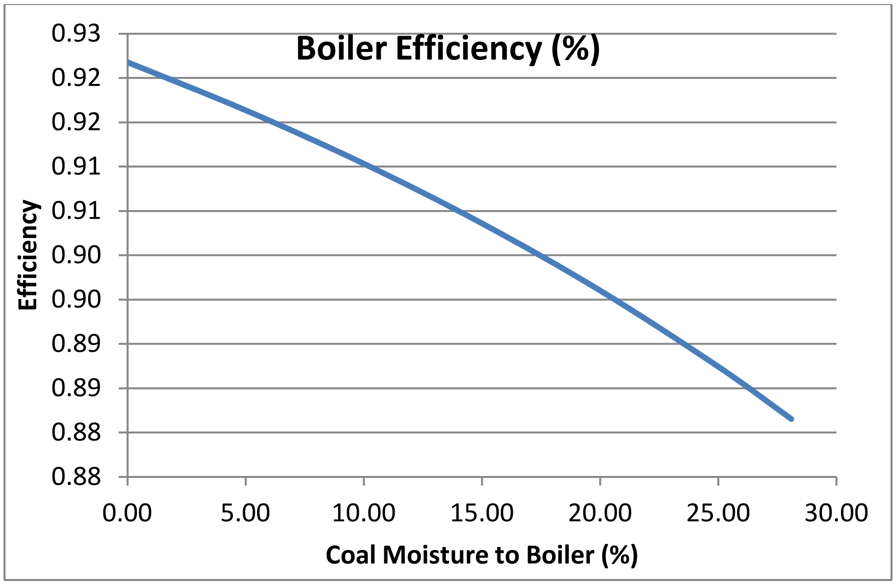

Figure 23. PRB Boiler Efficiency

In this model, the total amount of heat rejected to the steam cycle is constant. Therefore, if the total heat to the steam cycle is constant, and the boiler efficiency increases, the coal flow rate must decrease. The reduction in coal flow rate into the boiler is very significant because not only is there less dry coal, but there is also less moisture in the coal. The coal flow going into the boiler was normalized to give the flow rate of "Coal Flow In Dryer" by using the following equation which has been explained in section 2.5:

$$Coal\ Flow\ In\ Dryer = Flow\ in\ Boiler * \frac{100 - \%Moisture\ of\ Predried\ Coal}{100 - \%Moisture\ of\ As\ Mined\ Coal}$$

The reduction in coal flow rate can be observed in Figure 24. The coal flow rate into the boiler is the amount of coal that ASPEN calculates would be needed to run the power plant. The coal flow rate into the dryer is the amount of as-mined coal that needs to be dried to give the proper amount of coal going into the boiler at the given moisture level. The amount of BTUs that the power plant is burning is directly proportional to the amount of coal flow put into the dryer. The reduction in coal flow into the boiler is mostly due to the decrease in the mass of water in the coal, however, there is also a smaller amount of coal entering the dryer.

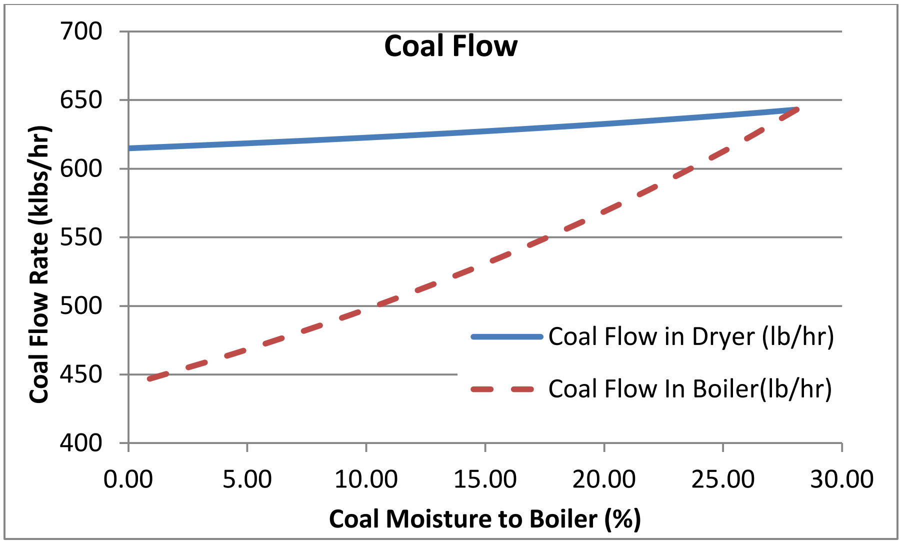

Figure 24. PRB Coal Flow

Because there is less coal, there is a smaller power requirement by the pulverizers. Although work has been done to correlate the power requirements with moisture percentage, for this analysis it is assumed that the power input is constant for a given amount of coal. The value used in previous analyses by Szatkowski [15], Martin [10], Charles [7], and Aiken [1] is 10.58 kWhr/ton. The power requirements of the pulverized coal are calculated using the coal flow rate going into the pulverizer, which is equal to the coal flow rate entering the boiler in Figure 24. Therefore, the pulverizer power is going to be equal to the mass flow rate of coal multiplied by 10.58 kWhr/ton. The pulverizer power is plotted in Figure 25.

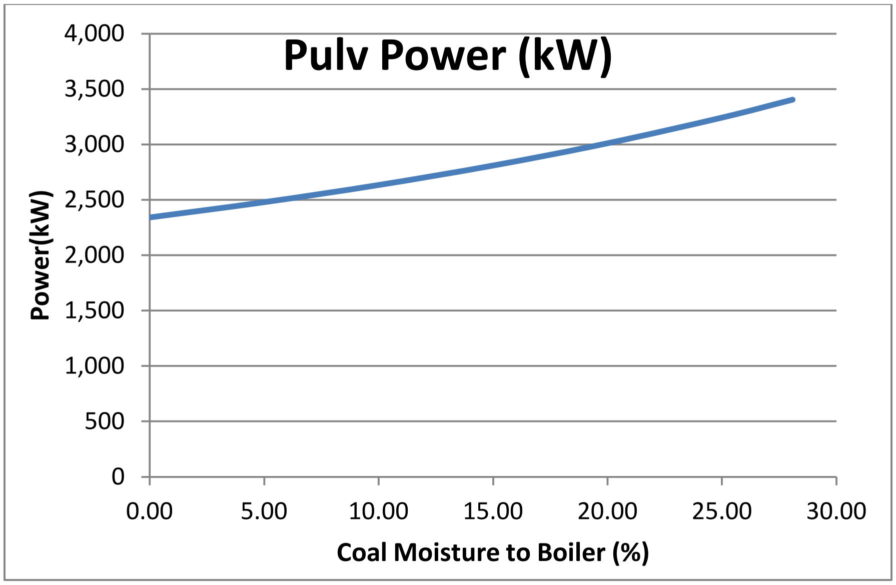

Figure 25. PRB Pulverizer Power

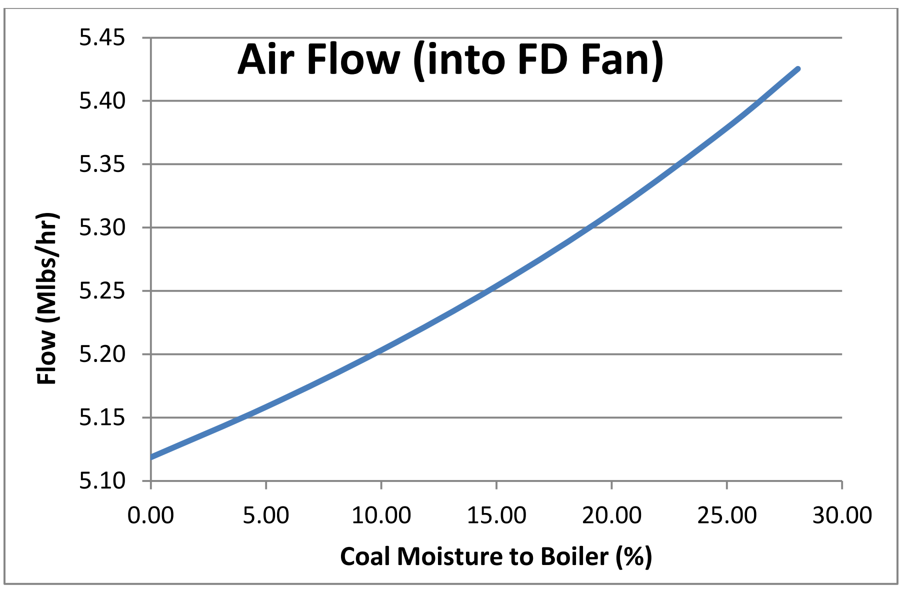

Figure 26. PRB Air Flow Rate

Due to the smaller coal flow rate, there is also less air needed to burn the coal. The decrease in air flow rate is shown in Figure 26. This will cause the power requirements from the FD fan to decrease. The smaller coal flow rate combined with the smaller air flow rate gives a lower flue gas flow rate, which is shown in Figure 27. This lower flue gas flow rate leads to a reduction in the ID fan power requirements. The ID and FD fan powers are added together and plotted in Figure 28.

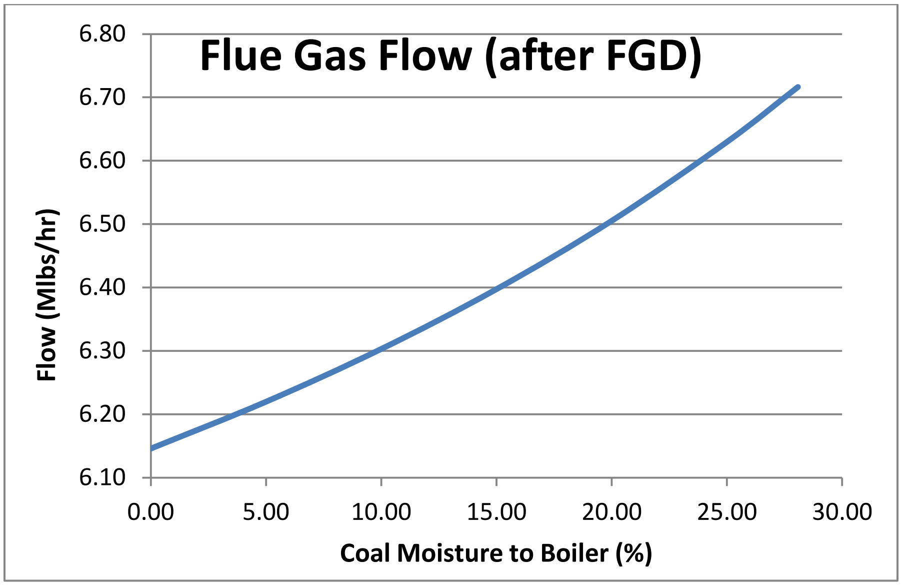

Figure 27. PRB Flue Gas Flow Rate

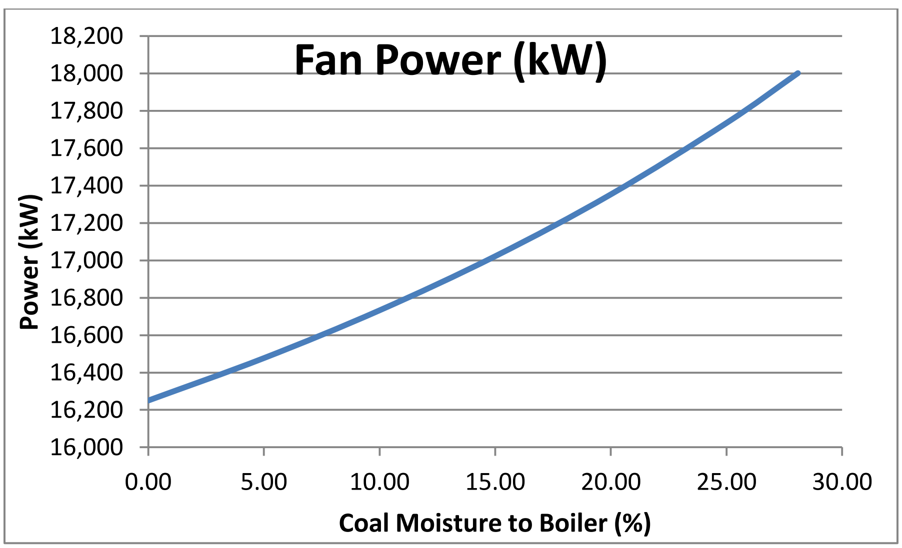

Figure 28. PRB Fan Power

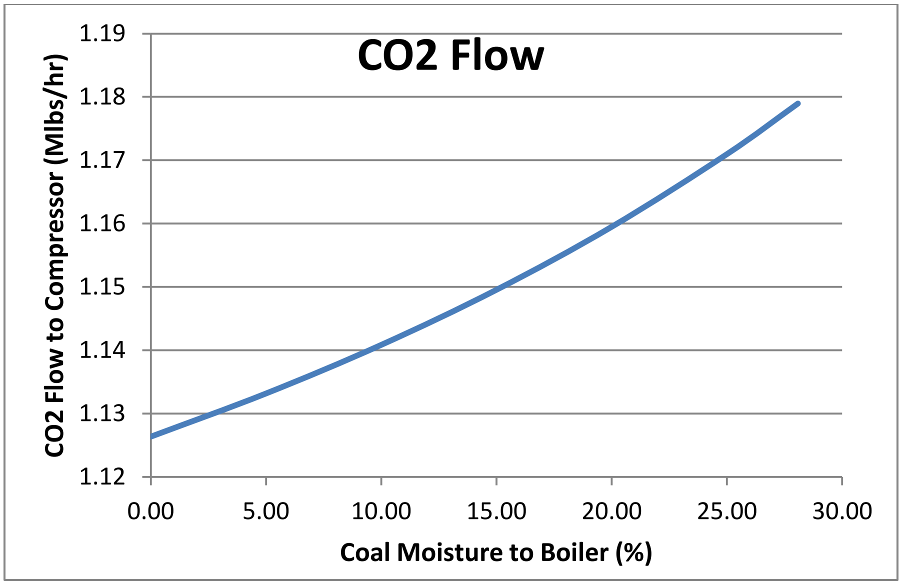

Figure 29. PRB Carbon Dioxide Flow

Due to the decrease in coal flow rate to the dryer (which is due to the increase in boiler efficiency), there is a decrease in the amount of carbon dioxide that needs to be separated from the flue gas. This decrease in CO2 flow can be observed in Figure 29. The reboiler duty in the stripper is directly proportional to the amount of carbon dioxide that is being sequestered. The reboiler gets its heat from a steam extraction located downstream of LPT-1 (see Figure 11). Because the net CO2 flow is being reduced, the amount of captured CO2 can be reduced and still meet the 90% capture requirement. The reboiler extraction located downstream of LPT-1 will then be decreased, which will increase the steam flow to LPTs 2 to 5. This will increase the power produced by the generator, and is shown in Figure 30. The increase in the flow to these turbines also increases the flow leaving the steam condenser. This puts additional feedwater flow into FWHs 1 to 3 which will require extractions D, E, F, and G to be slightly increased. These differences can be observed in Table 16.

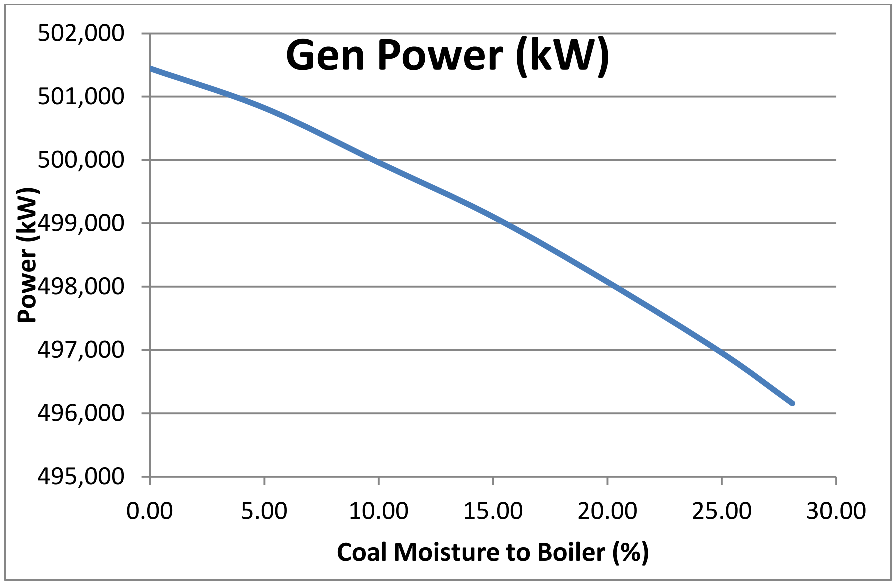

Figure 30. PRB Generated Power

The carbon capture system is designed to capture 90% of the total CO2 formed by the coal. Therefore, with less total CO2, shown in Figure 29, less CO2 needs to be captured. The CO2 leaving the stripper needs to be compressed to 2,215 psia before leaving the plant, which requires a significant amount of power. The compressor system used in this analysis is the Inline 4 compressor described in section 2.4. With the reduction in CO2 flow rate with coal drying, the compressors will need less power to compress the smaller amounts of CO2. The compressor's decrease in power with respect to coal moisture can be seen in Figure 31.

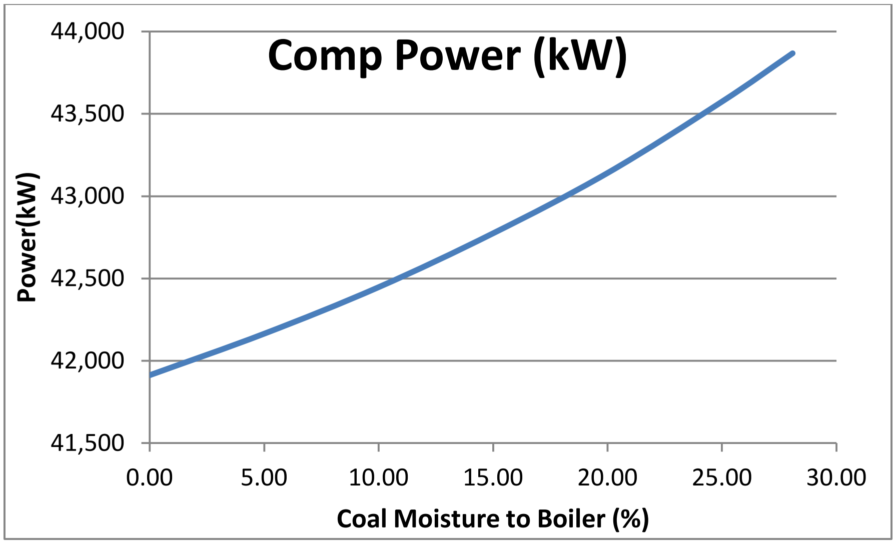

Figure 31. PRB Compressor Power

The calculated net power is the result of many variables. The net power is calculated by taking the generated power, and subtracting the power requirements of the power plant components. The net power is shown for different moisture levels in Figure 32. The value is increasing with lower moisture levels due to the increase in generated power and a decrease in compressor, fan, and pulverizer power.

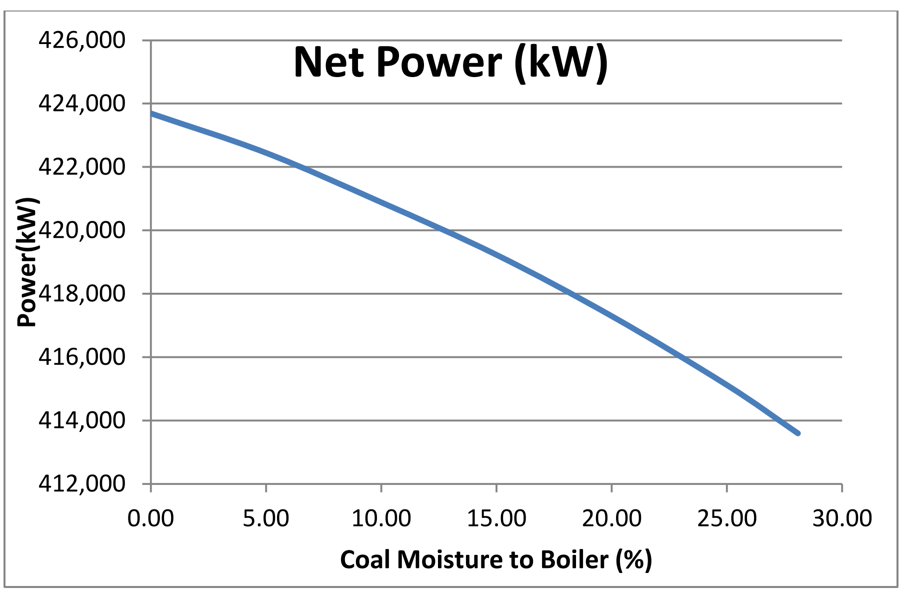

Figure 32. PRB Net Power

The unit heat rate is calculated using the following equation:

$$Unit\ Heat\ Rate = \frac{Coal\ Flow\ Rate\ In\ Dryer * HHV_{wet}}{Net\ Power}$$

The unit heat rate uses the results of other variables to give the graph shown in Figure 33. The percent decrease in unit heat rate can be found in Figure 34. These plots show the potential heat rate improvements of coal drying and its effect on the unit heat rate.

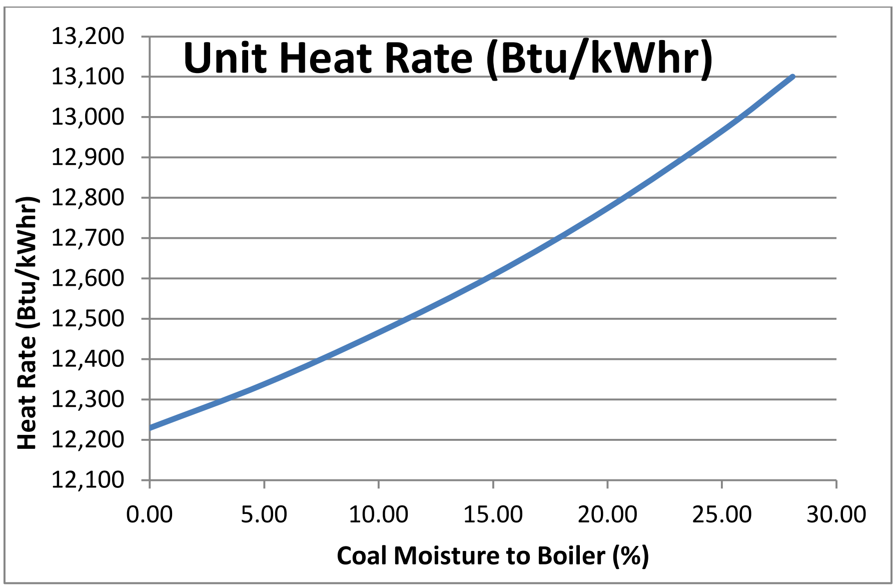

Figure 33. PRB Unit Heat Rate

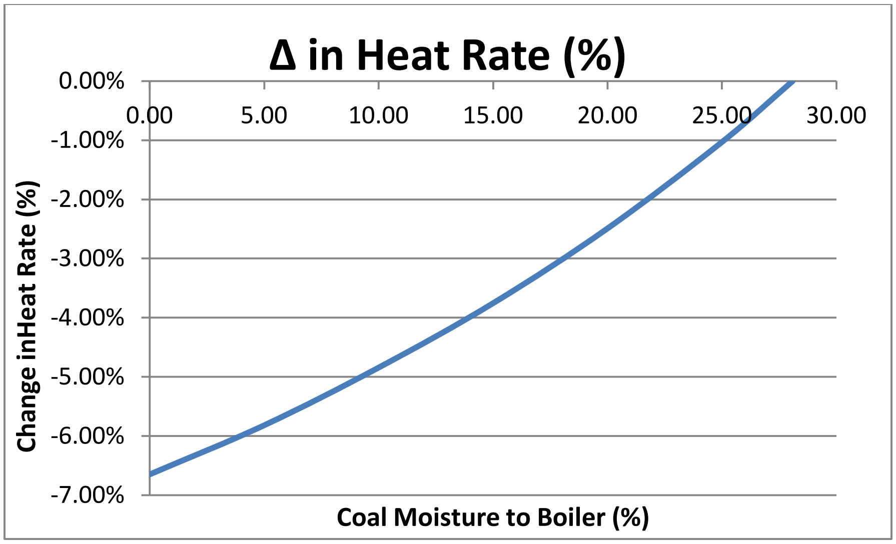

Figure 34. PRB Percent Change in Unit Heat Rate

The overall heat rate improvement is affected by many different parts of the power plant. To determine how much each component contributes to the overall heat rate improvement, each component's improvement is compared to the base case performance of all the other components. For coal drying, the percentage of heat rate improvement by each component is relatively constant throughout the different levels of coal moisture. Table 14 and Table 15 show the individual contributions to the total heat rate improvement as a percentage of the total heat rate improvement at a given moisture level.

Table 14. PRB Component Heat Rate Contribution

Component	Contribution
Coal Flow %	64.3%
Reboiler Duty (Gen Pow)	18.7%
Comp Power	6.9%
Fan Power	6.2%
Pulv Power	3.8%
Pump	0.1%
Sum	100.0%

Table 15. Lignite Component Heat Rate Contribution

Component	Contribution
Coal Flow %	65.7%
Reboiler Duty (Gen Pow)	17.4%
Comp Power	6.5%
Fan Power	6.3%
Pulv Power	4.0%
Pump	0.1%
Sum	100.0%

Table 16. PRB Coal Drying Details

Inlet Coal Moisture =>	BASE CASE	25	20	15	10
Coal Flow in Dryer (lb/hr)	643,021	638,743	632,622	627,317	622,676
HHV Wet (btu/lb)	8,426	8,426	8,426	8,426	8,426
Coal Flow In Boiler(lb/hr)	643,021	612,427	568,648	530,711	497,518
Dried Coal Inlet Moisture	28.09	25.00	20.00	15.00	10.00
Boiler Efficiency (%)	88.2%	88.7%	89.6%	90.4%	91.0%
Gen Power (kW)	496,155	496,954	498,074	499,103	499,961
Fan Power (kW)	18,002	17,735	17,353	17,022	16,732
Pulv Power (kW)	3,403	3,241	3,009	2,809	2,633
Pump Power (kW)	2,291	2,285	2,277	2,270	2,263
Aux Power (kW)	15,000	15,000	15,000	15,000	15,000
Pss (kW)	38,697	38,262	37,639	37,100	36,629
CO2 Flow(lbm/hr)	1,178,953	1,170,939	1,159,472	1,149,536	1,140,842
Carbon Captured	90.0%	90.0%	90.0%	90.0%	90.0%
Reboiler duty (MBtu/hr)	1,795	1,784	1,768	1,754	1,741
Reboil duty (Btu/lbmCO2)	1,692	1,693	1,694	1,695	1,696
Comp Power (kW)	43,869	43,575	43,141	42,775	42,448
Net Power (kW)	413,589	415,118	417,293	419,228	420,884
Δ in Net Power	0	1,528	3,704	5,638	7,295
Unit Heat Rate (Btu/kWhr)	13,100	12,965	12,774	12,608	12,466
Δ in Heat Rate (%)	0.00%	-1.03%	-2.49%	-3.75%	-4.84%
Efficiency (%)	26.0%	26.3%	26.7%	27.1%	27.4%
Stripper Condnsr heat used	0.0%	0.0%	0.0%	0.0%	0.0%
Comp heat used (%)	0.0%	0.0%	0.0%	0.0%	0.0%
FWH1 Duty (kBtu/hr)	81,329	81,329	81,329	81,349	82,401
FWH2 Duty (kBtu/hr)	62,882	62,882	62,882	64,476	64,476
FWH3 Duty (kBtu/hr)	58,088	58,088	58,088	60,119	60,119
FWH5 Duty (kBtu/hr)	216,159	216,159	216,159	216,159	216,160
Extract G (lb/hr)	83,900	83,900	83,900	83,900	85,000
Extract F (lb/hr)	49,500	49,500	49,500	51,000	51,000
Extract E (lb/hr)	48,000	48,000	48,000	50,000	50,000
Extract D (lb/hr)	145,000	146,500	149,000	148,500	150,000
Extract C (lb/hr)	163,004	163,004	163,004	163,004	163,004
Heat Rejected					
Steam Cond. (Mbtu/hr)	1,168	1,177	1,190	1,200	1,209
Stripper Cond. (Mbtu/hr)	491	488	484	480	477
Compressors (Mbtu/hr)	258	256	254	252	250
Amine Cooler (Mbtu/hr)	1,031	1,024	1,014	1,005	997
Flue Gas Cooler (Mbtu/hr)	503	497	489	482	476

Table 16. (Continued)

	5	0
Coal Flow in Dryer (lb/hr)	618,581	614,941
HHV Wet (btu/lb)	8,426	8,426
Coal Flow In Boiler(lb/hr)	468,234	442,204
Dried Coal Inlet Moisture	5.00	0.00
Boiler Efficiency (%)	91.6%	92.2%
Gen Power (kW)	500,823	501,447
Fan Power (kW)	16,477	16,250
Pulv Power (kW)	2,478	2,340
Pump Power (kW)	2,258	2,252
Aux Power (kW)	15,000	15,000
Pss (kW)	36,212	35,842
CO2 Flow(lbm/hr)	1,133,171	1,126,352
Carbon Captured	90.0%	90.0%
Reboiler duty (MBtu/hr)	1,730	1,721
Reboil duty (Btu/lbmCO2)	1,697	1,698
Comp Power (kW)	42,165	41,914
Net Power (kW)	422,445	423,691
Δ in Net Power	8,855	10,102
Unit Heat Rate (Btu/kWhr)	12,338	12,229
Δ in Heat Rate (%)	-5.82%	-6.65%
Efficiency (%)	27.7%	27.9%
Stripper Condnsr heat used	0.0%	0.0%
Comp heat used (%)	0.0%	0.0%
FWH1 Duty (kBtu/hr)	84,313	84,313
FWH2 Duty (kBtu/hr)	64,476	64,476
FWH3 Duty (kBtu/hr)	60,119	60,119
FWH5 Duty (kBtu/hr)	216,159	216,159
Extract G (lb/hr)	87,000	87,000
Extract F (lb/hr)	51,000	51,000
Extract E (lb/hr)	50,000	50,000
Extract D (lb/hr)	150,000	151,500
Extract C (lb/hr)	163,004	163,004
Heat Rejected		
Steam Cond. (Mbtu/hr)	1,217	1,224
Stripper Cond. (Mbtu/hr)	474	472
Compressors (Mbtu/hr)	248	246
Amine Cooler (Mbtu/hr)	990	984
Flue Gas Cooler (Mbtu/hr)	471	462

5.2 Lignite Coal Drying Results

This coal drying analysis was also done for a Lignite coal. Both the PRB and Lignite coals show comparable results, with the Lignite coal having the ability to have larger improvements due to its higher initial moisture content. The properties of the Lignite coal are described in Table 13. The same types of figures that were generated for the PRB coal are also generated for Lignite coal, and can be observed in Figure 35 through Figure 46.

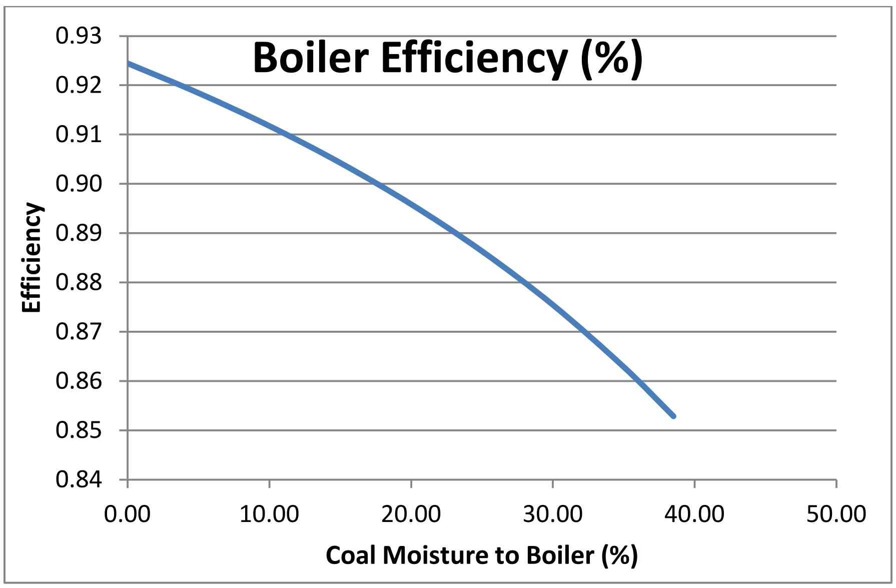

Figure 35. Lignite Boiler Efficiency

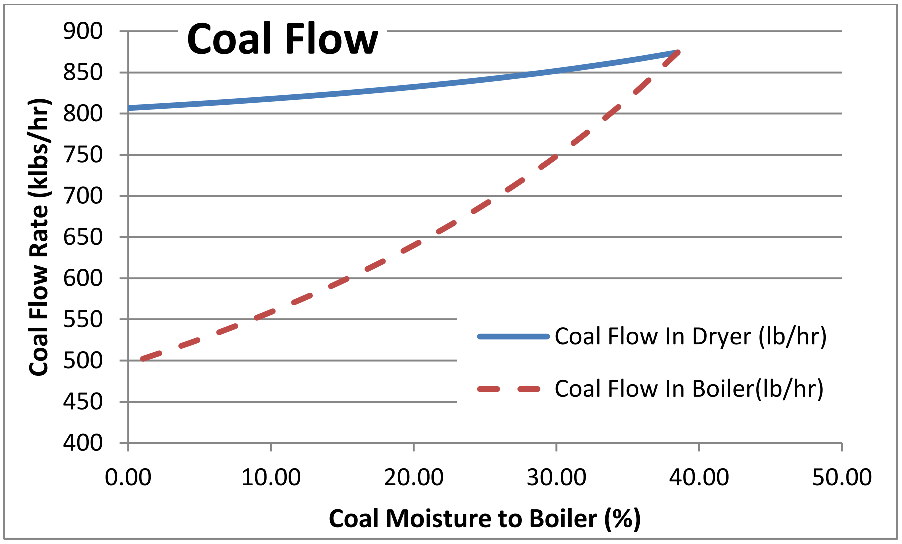

Figure 36. Lignite Coal Flow Rate

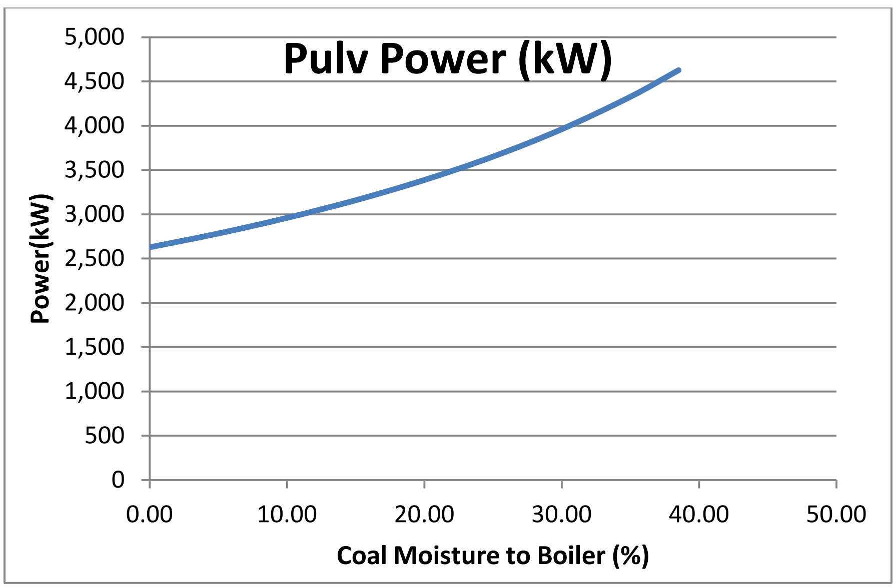

Figure 37. Lignite Pulverizer Power

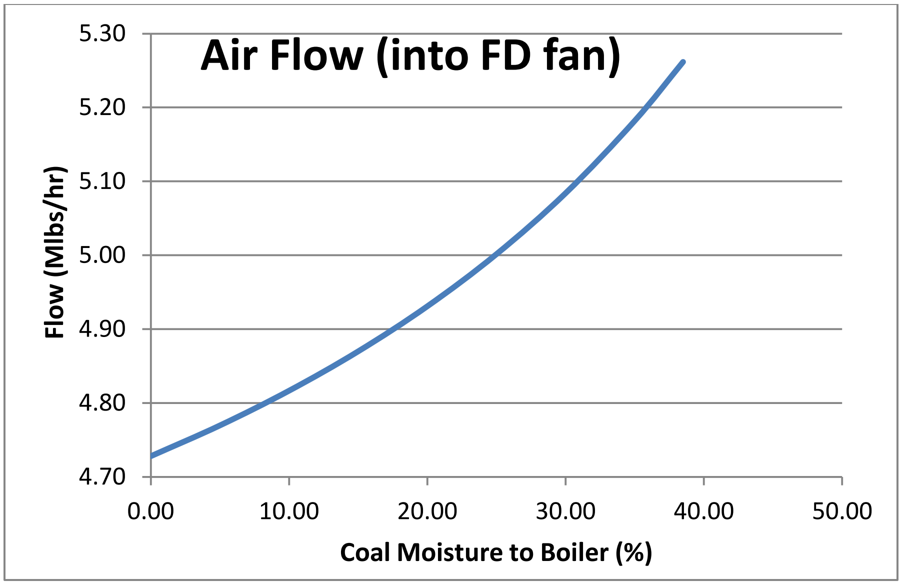

Figure 38. Lignite Air Flow Rate

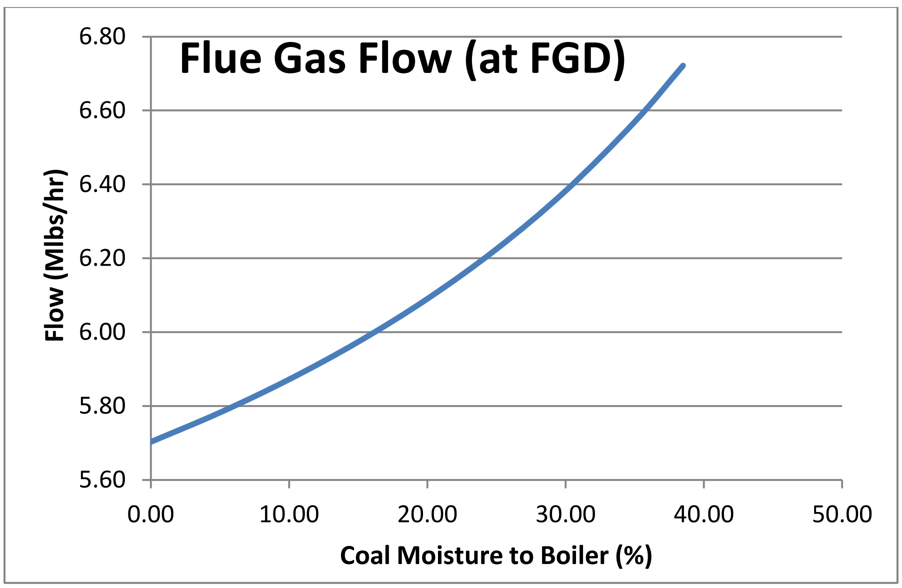

Figure 39. Lignite Flue Gas Flow rate

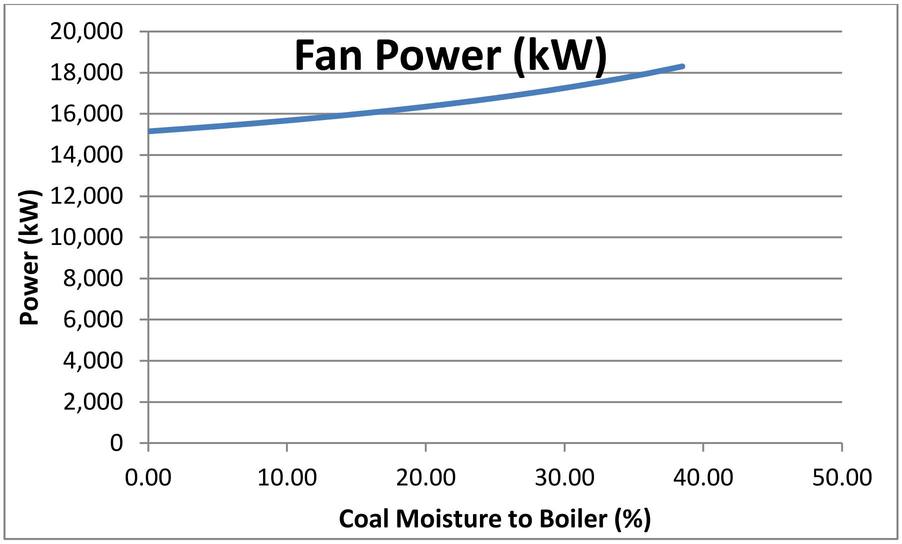

Figure 40. Lignite Fan Power

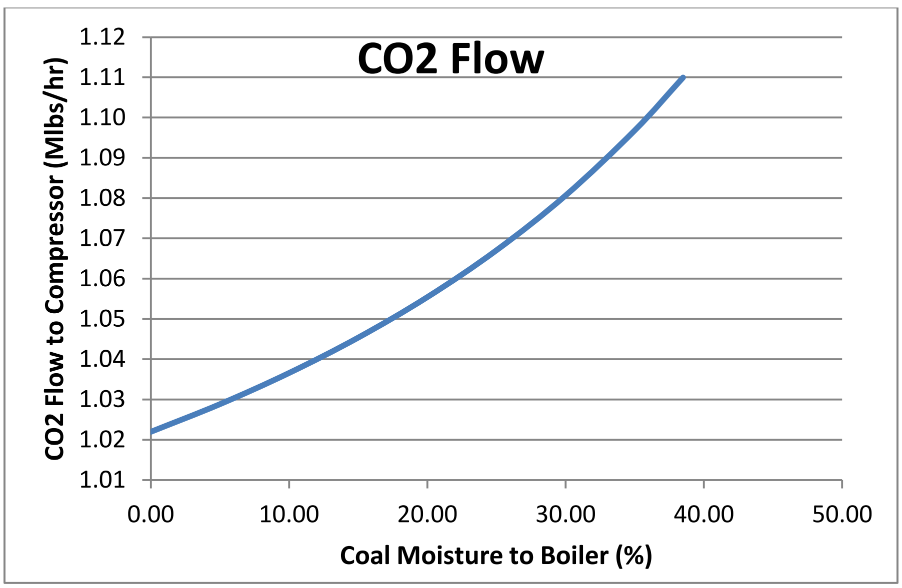

Figure 41. Lignite CO2 Flow

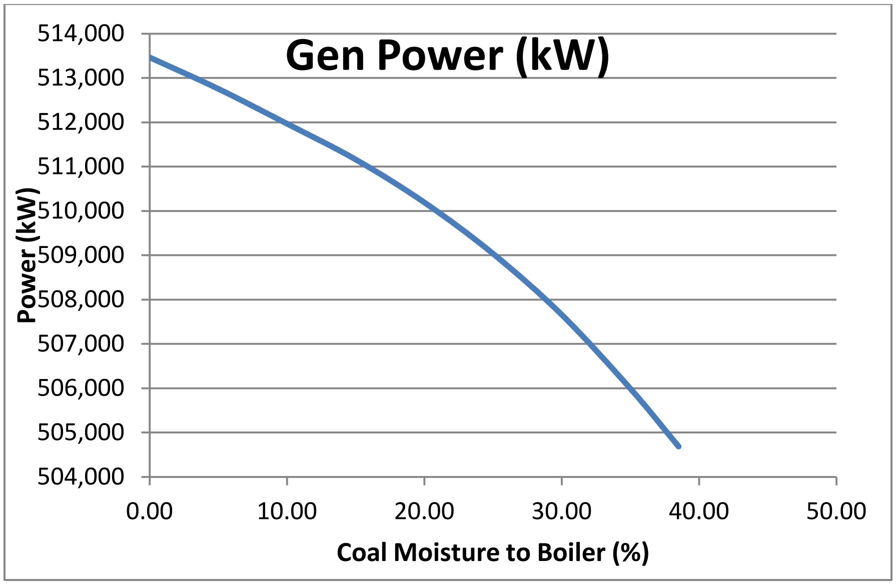

Figure 42. Lignite Generated Power

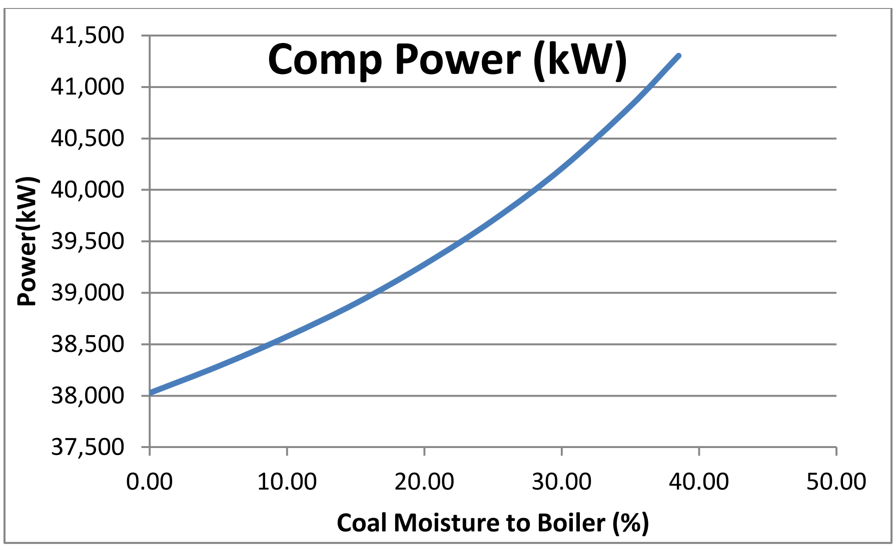

Figure 43. Lignite Compressor Power

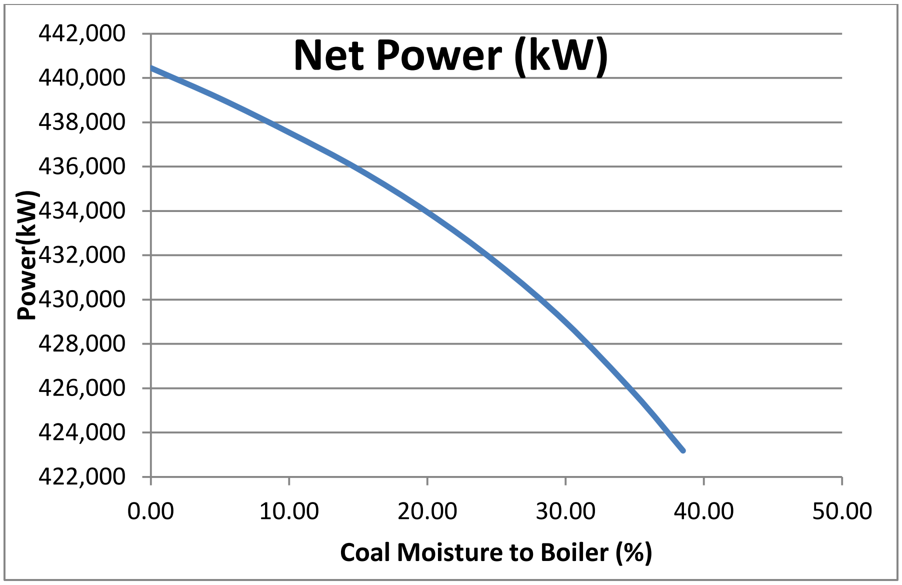

Figure 44. Lignite Net Power

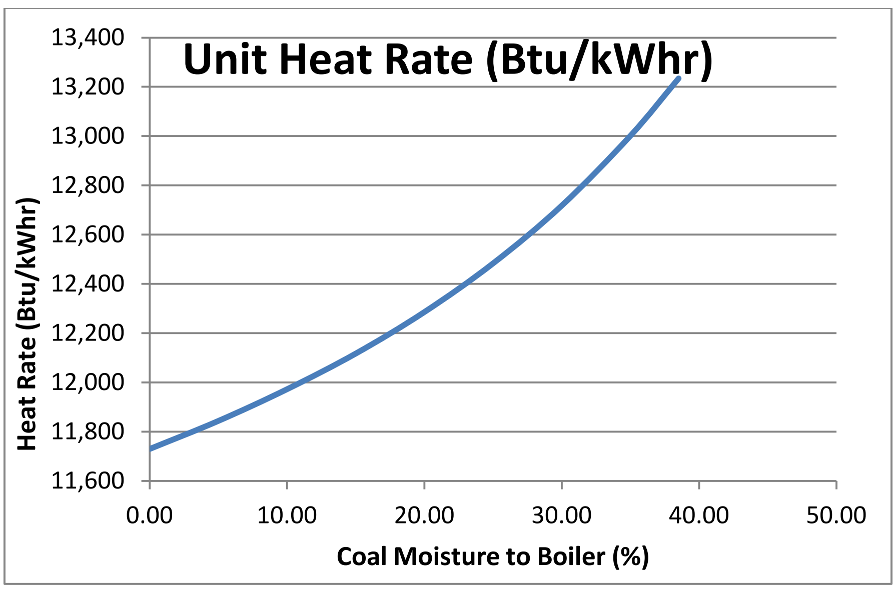

Figure 45. Lignite Unit Heat Rate

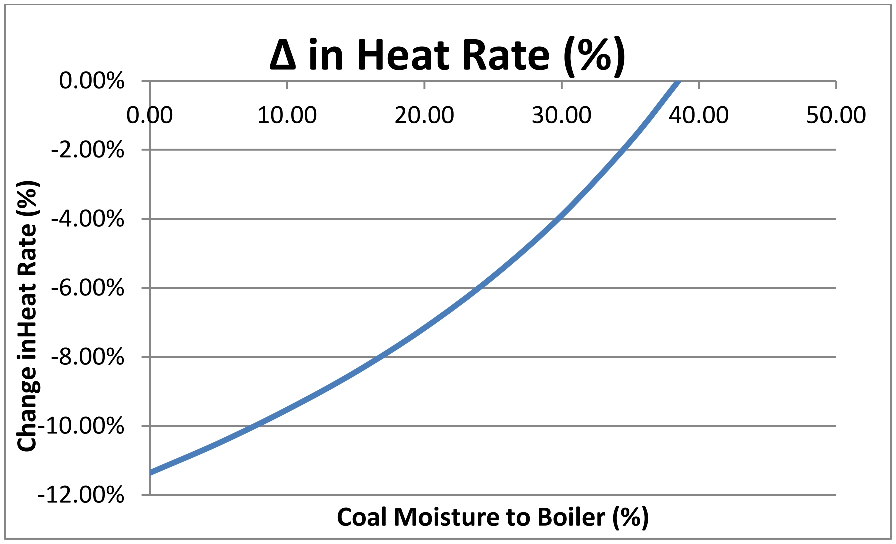

Figure 46. Lignite Change in Unit Heat Rate

Table 17. Lignite Coal Drying Details

Inlet Coal Moisture =>	BASE CASE Lignite	35	30	25	20
Coal Flow In Dryer (lb/hr)	874,222	864,109	851,672	841,206	832,257
HHV Wet (btu/lb)	6,406	6,406	6,406	6,406	6,406
Coal Flow In Boiler(lb/hr)	874,222	817,580	748,254	689,789	639,798
Dried Coal Inlet Moisture	38.50	35.00	30.00	25.00	20.00
Boiler Efficiency (%)	85.3%	86.3%	87.5%	88.6%	89.6%
Gen Power (kW)	504,686	505,989	507,657	509,033	510,190
Fan Power (kW)	18,302	17,831	17,252	16,764	16,348
Pulv Power (kW)	4,627	4,327	3,960	3,651	3,386
Pump Power (kW)	2,276	2,266	2,254	2,243	2,234
Aux Power (kW)	15,000	15,000	15,000	15,000	15,000
Pss (kW)	40,205	39,423	38,466	37,658	36,968
CO2 Flow (lbm/hr)	1,109,959	1,096,817	1,080,659	1,067,060	1,055,433
Carbon Captured	90.0%	90.0%	90.0%	90.0%	90.0%
Reboiler duty (MBtu/hr)	1,680	1,662	1,639	1,620	1,603
Reboiler duty (Btu/lbmCO2)	1,682	1,684	1,685	1,687	1,688
Comp Power (kW)	41,304	40,815	40,209	39,706	39,276
Net Power (kW)	423,176	425,751	428,982	431,669	433,946
Δ in Net Power	0	2,574	5,805	8,493	10,770
Unit Heat Rate (Btu/kWhr)	13,234	13,002	12,718	12,484	12,286
Δ in Heat Rate (%)	0.00%	-1.75%	-3.90%	-5.67%	-7.16%
Efficiency (%)	25.8%	26.2%	26.8%	27.3%	27.8%
Stripper Condnsr heat used (%)	0.0%	0.0%	0.0%	0.0%	0.0%
Comp heat used (%)	0.0%	0.0%	0.0%	0.0%	0.0%
FWH1 Duty (kBtu/hr)	89,614	89,628	91,074	92,042	92,041
FWH2 Duty (kBtu/hr)	69,132	70,684	71,732	72,781	72,781
FWH3 Duty (kBtu/hr)	63,166	64,181	65,197	66,212	66,212
FWH5 Duty (kBtu/hr)	216,159	216,159	216,160	216,160	216,159
Extract G (lb/hr)	92,500	92,500	94,000	95,000	95,000
Extract F (lb/hr)	55,500	57,000	58,000	59,000	59,000
Extract E (lb/hr)	53,000	54,000	55,000	56,000	56,000
Extract D (lb/hr)	147,000	148,000	149,000	150,000	152,500
Extract C (lb/hr)	163,004	163,004	163,004	163,004	163,004
Heat Rejected					
Steam Condenser (Mbtu/hr)	1,254	1,268	1,285	1,299	1,312
Stripper Condenser (Mbtu/hr)	456	451	446	441	437
Compressors (Mbtu/hr)	243	240	236	233	231
Amine Cooler (Mbtu/hr)	973	961	946	934	924
Flue Gas Cooler (Mbtu/hr)	497	487	475	465	456

Table 17. (Continued)

	15	10	5	0
Coal Flow In Dryer (lb/hr)	824,518	817,758	811,803	806,516
HHV Wet (btu/lb)	6,406	6,406	6,406	6,406
Coal Flow In Boiler(lb/hr)	596,563	558,801	525,535	496,007
Dried Coal Inlet Moisture	15.00	10.00	5.00	0.00
Boiler Efficiency (%)	90.4%	91.2%	91.8%	92.4%
Gen Power (kW)	511,158	511,966	512,753	513,462
Fan Power (kW)	15,987	15,672	15,395	15,148
Pulv Power (kW)	3,157	2,957	2,781	2,625
Pump Power (kW)	2,226	2,219	2,213	2,208
Aux Power (kW)	15,000	15,000	15,000	15,000
Pss (kW)	36,370	35,849	35,389	34,981
CO2 Flow (lbm/hr)	1,045,377	1,036,594	1,028,856	1,021,987
Carbon Captured	90.0%	90.0%	90.0%	90.0%
Reboiler duty (MBtu/hr)	1,589	1,577	1,566	1,556
Reboiler duty (Btu/lbmCO2)	1,689	1,690	1,691	1,692
Comp Power (kW)	38,897	38,574	38,286	38,026
Net Power (kW)	435,891	437,543	439,077	440,454
Δ in Net Power	12,714	14,366	15,901	17,278
Unit Heat Rate (Btu/kWhr)	12,117	11,973	11,844	11,730
Δ in Heat Rate (%)	-8.44%	-9.53%	-10.50%	-11.36%
Efficiency (%)	28.2%	28.5%	28.8%	29.1%
Stripper Condnsr heat used	0.0%	0.0%	0.0%	0.0%
Comp heat used (%)	0.0%	0.0%	0.0%	0.0%
FWH1 Duty (kBtu/hr)	92,041	92,041	92,053	93,009
FWH2 Duty (kBtu/hr)	72,781	72,781	73,829	73,829
FWH3 Duty (kBtu/hr)	66,212	66,212	67,228	67,228
FWH5 Duty (kBtu/hr)	216,159	216,159	216,160	216,160
Extract G (lb/hr)	95,000	95,000	95,000	96,000
Extract F (lb/hr)	59,000	59,000	60,000	60,000
Extract E (lb/hr)	56,000	56,000	57,000	57,000
Extract D (lb/hr)	155,000	157,000	157,000	158,000
Extract C (lb/hr)	163,004	163,004	163,004	163,004
Heat Rejected				
Steam Condenser (Mbtu/hr)	1,323	1,332	1,340	1,348
Stripper Cond (Mbtu/hr)	433	430	428	425
Compressors (Mbtu/hr)	229	227	225	224
Amine Cooler (Mbtu/hr)	915	907	900	894
Flue Gas Cooler (Mbtu/hr)	449	442	437	432

6.0 Heat Integration Using Different Compressor Options

The Inline 4 compressor was used in previous heat integration analyses in this thesis. In this section, the Inline 4 compressor is compared with the Ramgen and IG 1 compressors. The physical differences between the compressors were discussed in section 2.4. Due to the different configuration of each compressor, each will have a different power requirement, cooling water flow rate requirements, and cooling water outlet temperatures. Each compressor model also has different efficiencies that are listed in section 2.4. A comparison of each compressor's base case is shown in Table 18 with the variables that change based on compressor type in bold. In all of the comparisons shown in this section, a PRB coal will be used to compare the three compressor systems.

It can be noticed that the Ramgen compressor has the highest power requirements, and therefore the worst base case heat rate. This is because Ramgen compresses the CO2 in two stages with intercooling, while the Inline compressor uses three stages with intercooling. The Integrally Geared compressor uses seven stages with intercooling, which results in even lower power requirements.

Table 18. Comparison of Different Compressor Option's: Base Case (Without Heat Integration) with PRB Coal

	RAMGEN	INLINE 4	IG 1
Wet Coal Flow (lb/hr)	643,021	643,021	643,021
HHV Wet (btu/lb)	8,426	8,426	8,426
Coal Flow In Boiler(lb/hr)	643,021	643,021	643,021
Dried Coal Inlet Moisture	28.09	28.09	28.09
Boiler Efficiency (%)	88.2%	88.15%	88.15%
Gen Power (kW)	496,071	496,071	496,071
Fan Power (kW)	18,002	18,002	18,002
Pulv Power (kW)	3,403	3,403	3,403
Pump Power (kW)	2,291	2,291	2,291
Aux Power (kW)	15,000	15,000	15,000
Pss (kW)	38,697	38,697	38,697
CO2 Flow (lbm/hr)	1,178,953	1,178,953	1,178,953
Carbon Captured	90.0%	90.0%	90.0%
Reboiler duty (MBtu/hr)	1,795	1,795	1,795
Reboiler duty (Btu/lbmCO2)	1,692	1,692	1,692
Comp Power (kW)	**45,511**	**43,869**	**35,854**
Net Power (kW)	**411,864**	**413,506**	**421,521**
*Δ in Net Power	**-1,642**	**0**	**8,015**
Unit Heat Rate (Btu/kWhr)	**13,155**	**13,103**	**12,854**
*Δ in Heat Rate (%)	**0.40%**	**0.00%**	**-1.90%**
Efficiency (%)	**25.9%**	**26.0%**	**26.5%**
FWH1 Duty (kBtu/hr)	81,329	81,329	81,329
FWH2 Duty (kBtu/hr)	62,882	62,882	62,882
FWH3 Duty (kBtu/hr)	58,088	58,088	58,088
FWH5 Duty (kBtu/hr)	216,159	216,159	216,159
Extract G (lb/hr)	83,900	83,900	83,900
Extract F (lb/hr)	49,500	49,500	49,500
Extract E (lb/hr)	48,000	48,000	48,000
Extract D (lb/hr)	146,000	146,000	146,000
Extract C (lb/hr)	163,004	163,004	163,004
Heat Rejected			
Steam Condenser (Mbtu/hr)	1,167	1,167	1,167
Stripper Condenser (Mbtu/hr)	491	491	491
Compressors (Mbtu/hr)	260	258	228
Amine Cooler (Mbtu/hr)	1,031	1,031	1,031
Flue Gas Cooler (Mbtu/hr)	503	503	503

*Compared to the Inline 4 Base Case

6.1 Heat Integration of a Ramgen Compressor

When integrating heat from the Ramgen and IG 1 compressors, the methodology will be very similar to heat integration with the Inline 4 compressor. The basic strategy will be to use high temperature cooling water to reject heat to the boiler feedwater at the highest temperature possible in between FWHs.

As shown in Table 2 and Table 3 the exit temperature of the Ramgen compressor is slightly higher than the exit temperature of the Inline 4 compressor. These two systems can be integrated to the same heat sinks in a similar fashion. The results show that the Ramgen will result in a larger increase in net power due to the higher temperature of the cooling water as well as a higher cooling water flow rate. Five different heat integration cases are illustrated in Table 19 for the Ramgen compressor.

Table 19. Ramgen Compressor with Heat Integration and PRB Coal

	BASE CASE PRB	Stripper Cond to FWH1,2,3	Comp to FWH1,2,3	Comp to FWH4,5	Comp to FWH4,5 Str Cond to FWH1-3
Wet Coal Flow (lb/hr)	643,021	643,021	643,021	643,021	643,021
HHV Wet (btu/lb)	8,426	8,426	8,426	8,426	8,426
Coal Flow In Boiler(lb/hr)	643,021	643,021	643,021	643,021	643,021
Dried Coal Inlet Moisture	28.09	28.09	28.09	28.09	28.09
Boiler Efficiency (%)	88.2%	88.2%	88.2%	88.2%	88.2%
Gen Power (kW)	496,071	501,179	505,857	507,919	514,100
Fan Power (kW)	18,002	18,002	18,002	18,002	18,002
Pulv Power (kW)	3,403	3,403	3,403	3,403	3,403
Pump Power (kW)	2,291	2,289	2,294	2,303	2,301
Aux Power (kW)	15,000	15,000	15,000	15,000	15,000
Pss (kW)	38,697	38,694	38,699	38,708	38,706
Carbon Captured	90.0%	90.0%	90.0%	90.0%	90.0%
Reboiler duty (MBtu/hr)	1,795	1,795	1,795	1,795	1,795
Reboiler duty (Btu/lbmCO2)	1,692	1,692	1,692	1,692	1,692
Comp Power (kW)	45,511	45,512	45,511	45,510	45,511
Net Power (kW)	411,864	416,973	421,648	423,701	429,883
Δ in Net Power	0	5,109	9,784	11,837	18,019
Unit Heat Rate (Btu/kWhr)	13,155	12,994	12,850	12,788	12,604
Δ in Heat Rate (%)	0.00%	-1.23%	-2.32%	-2.79%	-4.19%
Efficiency (%)	25.9%	26.3%	26.6%	26.7%	27.1%
Stripper Condnsr heat used	0.0%	35.1%	0.0%	0.0%	38.9%
Comp heat used (%)	0.0%	0.0%	93.0%	59.3%	61.2%
FWH1 Duty (kBtu/hr)	81,329	558	558	87,175	558
FWH2 Duty (kBtu/hr)	62,882	11,044	11,044	65,400	11,044
FWH3 Duty (kBtu/hr)	58,088	9,343	9,343	58,088	9,343
FWH5 Duty (kBtu/hr)	216,159	216,159	216,159	126,661	126,660
Extract G (lb/hr)	83,900	0	0	90,000	0
Extract F (lb/hr)	49,500	0	0	52,000	0
Extract E (lb/hr)	48,000	0	0	48,000	0
Extract D (lb/hr)	146,000	162,000	106,000	84,000	90,000
Extract C (lb/hr)	163,004	163,004	163,004	95,000	95,000
Steam Condenser (Mbtu/hr)	1,167	1,324	1,377	1,282	1,456
Stripper Cond.(Mbtu/hr)	491	318	491	491	300
Compressors (Mbtu/hr)	260	260	18	106	101
Amine Cooler (Mbtu/hr)	1,031	1,031	1,031	1,031	1,031
Flue Gas Cooler (Mbtu/hr)	503	503	503	503	503

Table 19. (Continued)

	Coal Drying, Comp & Str Cond to FWH1-5
Wet Coal Flow (lb/hr)	627,317
HHV Wet (btu/lb)	8,426
Coal Flow In Boiler(lb/hr)	530,711
Dried Coal Inlet Moisture	15.00
Boiler Efficiency (%)	90.4%
Gen Power (kW)	516,686
Fan Power (kW)	17,022
Pulv Power (kW)	2,809
Pump Power (kW)	2,279
Aux Power (kW)	15,000
Pss (kW)	37,110
Carbon Captured	90.0%
Reboiler duty (MBtu/hr)	1,754
Reboiler duty (Btu/lbmCO2)	1,695
Comp Power (kW)	44,375
Net Power (kW)	435,201
Δ in Net Power	23,337
Unit Heat Rate (Btu/kWhr)	12,146
Δ in Heat Rate (%)	-7.67%
Efficiency (%)	28.1%
Stripper Condnsr heat used	39.6%
Comp heat used (%)	62.0%
FWH1 Duty (kBtu/hr)	558
FWH2 Duty (kBtu/hr)	11,044
FWH3 Duty (kBtu/hr)	9,343
FWH5 Duty (kBtu/hr)	128,870
Extract G (lb/hr)	0
Extract F (lb/hr)	0
Extract E (lb/hr)	0
Extract D (lb/hr)	96,000
Extract C (lb/hr)	98,000
Steam Condenser (Mbtu/hr)	1,486
Stripper Cond.(Mbtu/hr)	290
Compressors (Mbtu/hr)	96
Amine Cooler (Mbtu/hr)	1,005
Flue Gas Cooler (Mbtu/hr)	482

6.2 Heat Integration of an Integrally Geared 1 Compressor

The IG 1 compressor is treated very differently from the Ramgen and Inline 4 compressors. Due to the low temperatures of the cooling water leaving the compressors, it is impractical to use this heat for replacing extractions to FWHs. The temperature of the cooling water is less than 230 °F, which means that the cooling water from the stripper condenser would be better suited due to its higher temperature and relatively high flow rates. For this reason, the compressor to FWH 1-3 scenario was not modeled. Temperatures leaving the compressor coolers were also too low to integrate heat at FWHs 4 and 5 and this case was not modeled either.

Data for heat integration are shown in Table 20. Figure 47 through Figure 50 compare the unit heat rate performance between the three compressor options. It should be noted that there are no plots for the Integrally Geared compressor for some integration cases due to the lower water temperature. The last heat integration case (coal drying) shown in the figures does not utilize compressor heat at FWHs 4 and 5 for the IG 1 case, due to the low temperature compressor heat.

Table 20. Integrally Geared Compressor Heat Integration with PRB Coal

	BASE CASE	Str. Cond to FWH1-3	Coal Drying Cond to FWH1-3
Wet Coal Flow (lb/hr)	643,021	643,021	627,317
HHV wet (Btu/lb)	8,426	8,426	8,426
Coal In Boiler	643,021	643,021	530,711
Coal Moisture In Boiler	28.09	28.09	15.00
Boiler Efficiency	88.15%	88.15%	90.36%
Gen Power (kW)	496,071	501,179	504,603
Fan Power (kW)	18,002	18,002	17,022
Pulv Power (kW)	3,403	3,403	2,809
Pump Power (kW)	2,291	2,289	2,268
Aux Power (kW)	15,000	15,000	15,000
Pss (kW)	38,697	38,694	37,098
CO2 Flow (lbm/hr)	1,178,953	1,178,953	1,149,536
Carbon Captured	90.0%	90.0%	90.0%
Reboiler Duty (Mbtu/hr)	1,795	1,795	1,753
Reboiler duty (Btu/lbmCO2)	1,692	1,692	1,695
Comp Power (kW)	35,854	35,854	34,958
Net Power (kW)	421,521	426,631	432,547
Δ in Net Power	0	5,110	11,026
Unit Heat Rate (Btu/kWhr)	12,854	12,700	12,220
Δ in Heat Rate (%)	0.00%	-1.20%	-4.93%
Efficiency (%)	26.5%	26.9%	27.9%
Stripper Condnsr heat used (%)	0.0%	35.1%	36.1%
Comp heat used (%)	0.0%	0.0%	0.0%
FWH1 Duty (kBtu/hr)	81,329	558	558
FWH2 Duty (kBtu/hr)	62,882	11,044	11,044
FWH3 Duty (kBtu/hr)	58,088	9,343	9,343
FWH5 Duty (kBtu/hr)	216,159	216,159	216,159
Extract G (lb/hr)	83,900	0	0
Extract F (lb/hr)	49,500	0	0
Extract E (lb/hr)	48,000	0	0
Extract D (lb/hr)	146,000	162,000	162,000
Extract C (lb/hr)	163,004	163,004	163,004
Steam Condenser (Mbtu/hr)	1,167	1,324	1,363
Stripper Condenser (Mbtu/hr)	491	318	307
Compressors (Mbtu/hr)	228	228	223
Amine Cooler (Mbtu/hr)	1,031	1,031	1,005
Flue Gas Cooler (Mbtu/hr)	503	503	482

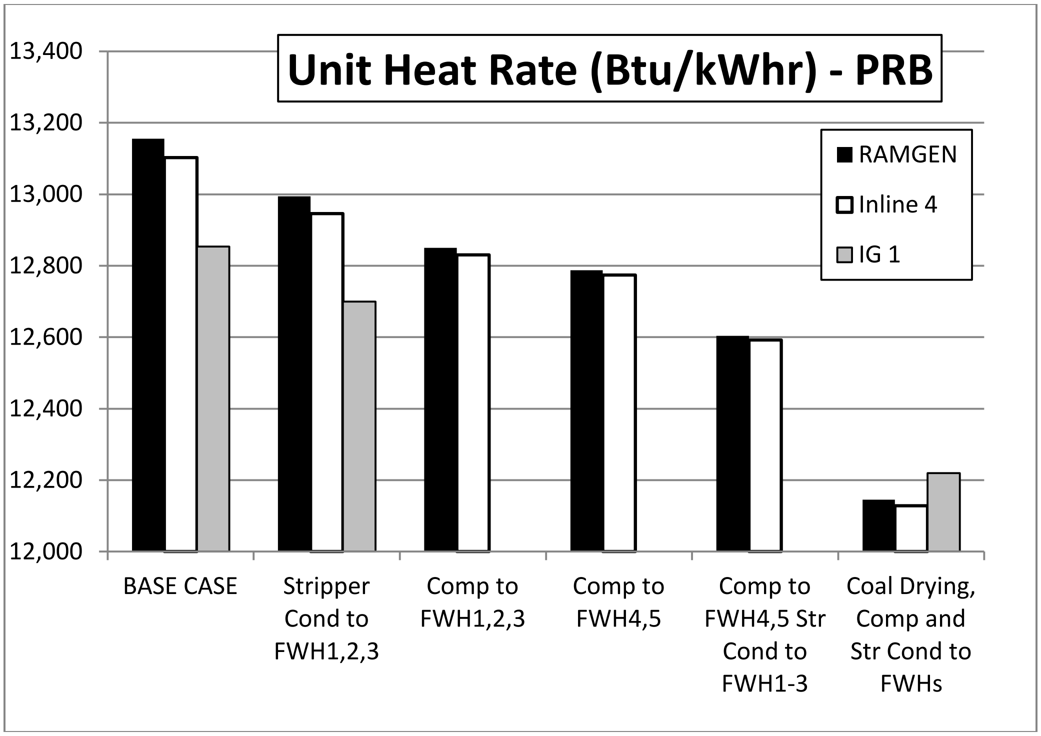

Figure 47. Unit Heat Rate Comparison of Different Compressor Heat Integration Options (PRB)

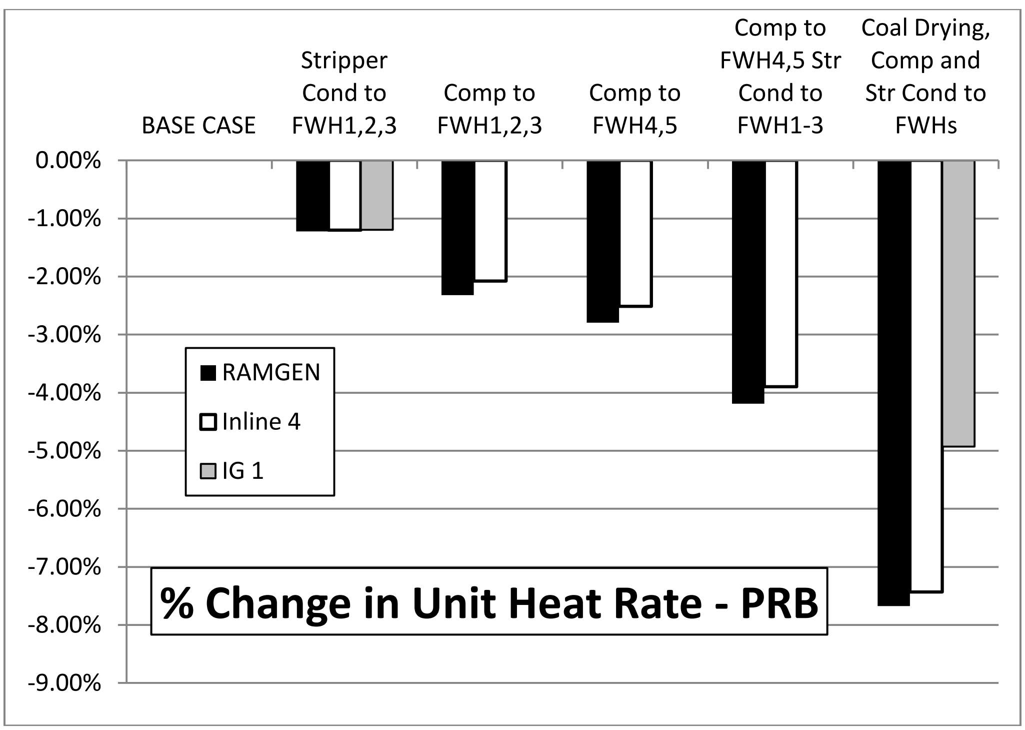

Figure 48. Change in Unit Heat Rate Comparison of Different Compressor Heat Integration Options (PRB)

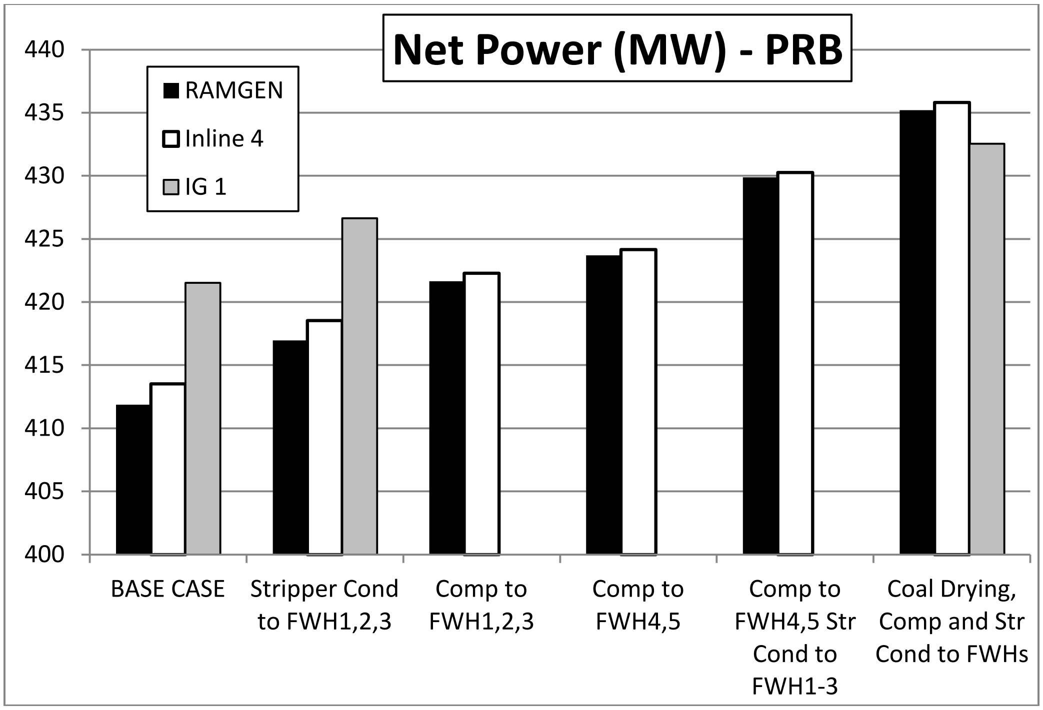

Figure 49. Net Power Comparison of Different Compressor Heat Integration Options (PRB)

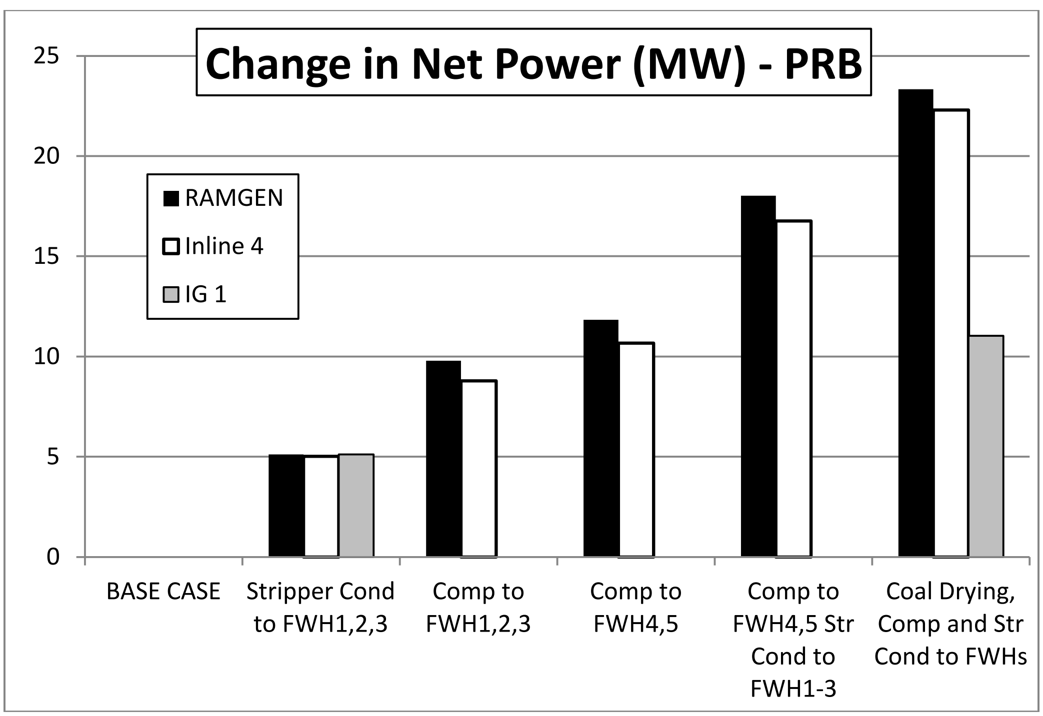

Figure 50. Change in Net Power Comparison of Different Compressor Heat Integration Options (PRB)

7.0 Conclusions

Using the boiler and steam cycle described in section 1, numerous heat integration options have been shown throughout this thesis. The results from these heat integration options have been calculated for different coal types, and different compressor options. The main heat integration options analyzed in this thesis are shown in Table 21.

Table 21. Heat Integration Options

1	Using the waste heat from the stripper condenser to replace steam extractions at FWHs 1 to 3.
2	Using the waste heat from the compressors to replace steam extractions at FWHs 1 to 3.
3	Using the waste heat from the compressors to partially replace steam extractions at FWHs 1 to 5 using a cascading technique
4	Using the waste heat from the compressors to partially replace steam extractions at FWHs 4 and 5.
5	Using the waste heat from the compressors to partially replace steam extractions at FWHs 4 and 5 as well as using the waste heat from the stripper condenser to replace steam extractions at FWHs 1 to 3.
6	Using waste heat to dry PRB and Lignite coal to a lower moisture percentage (15% for PRB and 20% for Lignite).
7	Using waste heat to dry PRB and Lignite coal to a lower moisture percentage (15% for PRB and 20% for Lignite). In addition to coal dying the waste heat from the compressors is used to partially replace steam extractions at FWHs 4 and 5 (except when IG 1 Compressor is used) as well as using the waste heat from the stripper condenser to replace steam extractions at FWHs 1 to 3.

Throughout the thesis different analyses were done using different coals and different compressors. The heat rate analysis for the different coals can be found in Table 22 and Table 23. These tables shown the different heat rates for all of the heat integration cases modeled with the Inline 4 compressor for each of the different coals. As explained previously, the Lignite coal has the most improvement potential utilizing coal drying due to its relatively high moisture percentage. The Illinois #6 will not have this improvement option due to it already low moisture percentage, while the PRB is in between these options. The heat rate improvements for other heat integration cases are similar throughout the three coals.

Table 22. Heat Rate Comparison of Different Coals with Inline 4 (Btu/kWhr)

Heat Integration Option	PRB Inline 4	Illinois #6 Inline 4	Lignite Inline 4
No Carbon Capture	9,236	8,784	9,601
BASE	13,118	11,953	13,234
1	12,961	11,799	13,075
2	12,846	11,780	13,017
3	12,694	11,638	12,866
4	12,789	11,703	12,941
5	12,607	11,524	12,734
6	12,627	-	12,293
7	12,143	-	11,851

Table 23. Heat Rate Comparison of Different Coals with Inline 4 (% Change)

Heat Integration Option	PRB Inline 4	Illinois #6 Inline 4	Lignite Inline 4
No Carbon Capture	-	-	-
BASE	0%	0%	0%
1	-1.20%	-1.29%	-1.20%
2	-2.08%	-1.45%	-1.64%
3	-3.23%	-2.64%	-2.78%
4	-2.51%	-2.09%	-2.22%
5	-3.90%	-3.59%	-3.78%
6	-3.74%	-	-7.11%
7	-7.43%	-	-10.45%

In Table 24 and Table 25 the different compressor options are compared with each other, showing the results of different compressor heat integration options. The Ramgen compressor has the highest initial heat rate due to its high compression ratio, however, this is accompanied by larger gains in percent heat rate due to the high temperature of cooling water leaving the compressor coolers. The IG 1 compressor has the lowest initial heat rate and the lowest percent improvement due to the low temperature heat that is leaving the compressor. The Inline 4 compressor is in between the other two compression options.

Table 24. Heat Rate Comparison of Different Compressor Options with PRB (Btu/kWhr)

Heat Integration Option	PRB Inline 4	PRB Ramgen	PRB IG 1
No Carbon Capture	9,236	9,236	9,236
BASE	13,118	13,155	12,854
1	12,961	12,994	12,700
2	12,846	12,850	-
3	12,694	-	-
4	12,789	12,788	-
5	12,607	12,604	-
6	12,627	-	-
7	12,143	12,146	12,220

Table 25. Heat Rate Comparison of Different Compressor Options with PRB (% Change)

Heat Integration Option	PRB Inline 4	PRB Ramgen	PRB IG 1
No Carbon Capture	-	-	-
BASE	0%	0%	0%
1	-1.20%	-1.23%	-1.20%
2	-2.08%	-2.32%	-
3	-3.23%	-	-
4	-2.51%	-2.79%	-
5	-3.90%	-4.19%	-
6	-3.74%	-	-
7	-7.43%	-7.67%	-4.93%

These heat integration options have different heat rate improvement potential for power plants firing different coals and using different types of compressors. These heat rate improvements have shown what is thermodynamically possible using each configuration. Additional work will need to be done to find the most cost effective way of implementing heat integration, however this thesis provides a guideline of what can be expected using different heat integration methods.

Even with these heat integration methods, there is still a huge increase in heat rate when compared to a power plant without carbon capture. These heat integration options will help the overall plant performance, and allow more power to be produced from a pulverized coal supercritical power plant that chooses to use an MEA carbon capture system.

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Appendix A.

Stream Data for the Boiler and MEA System using a PRB coal with no Heat Integration

Appendix A shows the stream data for the boiler and MEA system for a PRB, Illinois #6, and Lignite coal. Table 26 through Table 27 give the temperature, pressure, mass flow, and molar percentage of the products of the streams shown in Figure 51 and Figure 52 for a PRB coal.

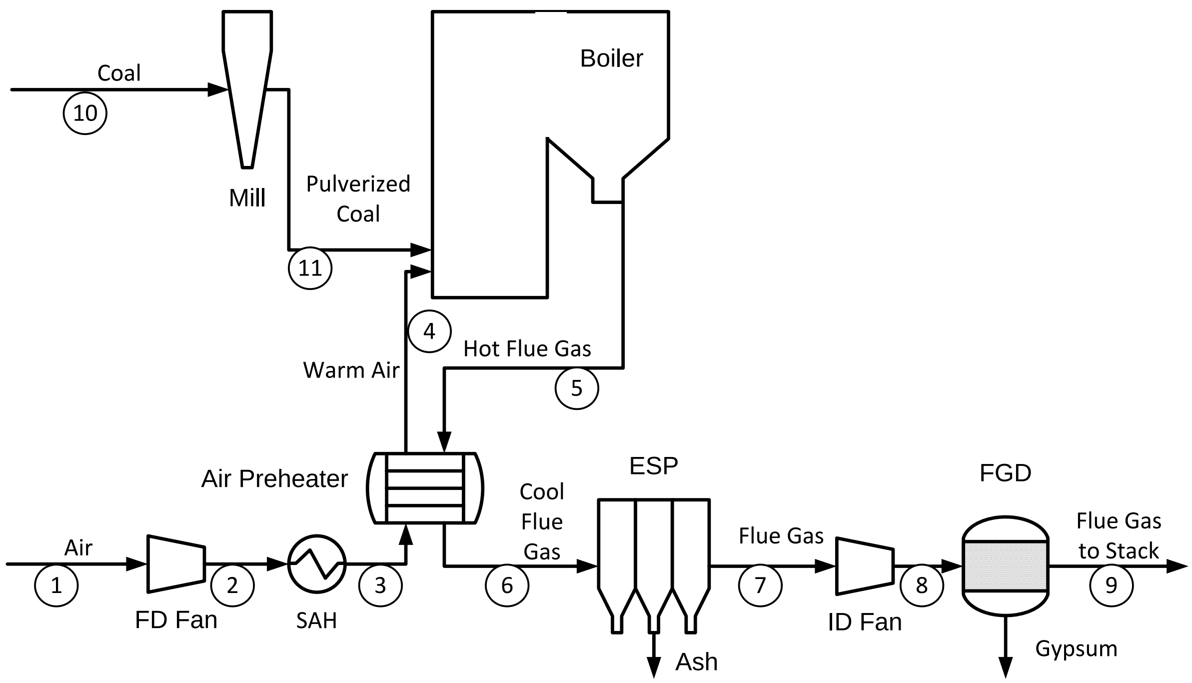

Figure 51. Boiler

The boiler's operation was explained in section 2.1, and the results of the design specs, described in section 2.1, for a PRB coal can be observed in Table 26. The air, entering the boiler in stream 1 is at 77 °F, and after going through the FD Fan will leave at a slightly elevated temperature and pressure. Stream 2 then enters the SAH where the air is heated to 156 °F. The heated air in stream 3 enters the air preheater, where some of it is leaked into stream 6, however most gets heated to 518.6 °F and enters the boiler. In the boiler the coal from stream

11 is combusted with the air forming the products shown in stream 5 and leaving at a temperature of 600 °F after transferring heat to the steam cycle. The hot flue gas is then cooled in the air preheater to 300 °F before it enters the ESP. In the ESP ash and other solids are removed and air is leaked into the system. Stream 7 then goes through the ID Fan, which increases the temperature and pressure of the flue gas before heading into the FGD. The FGD removes the SO2 from the flue gas and adds more air and water into the flue gas stream. In streams 10 and 11 the coal is heated from 77 °F to 114.9 °F in the pulverizer before heading into the boiler. The coal's composition is shown in Table 1 shown previously in this thesis.

Table 26. Boiler Stream Data with PRB and No Heat Integration

Stream #	1	2	3	4	5	6
Mass Flow (lb/hr)	5,425,480	5,425,480	5,425,480	5,084,270	5,686,740	6,027,940
Temp (F)	77.0	80.9	156.0	518.6	600.0	292.3
Pressure (psia)	14.7	15.0	15.0	15.0	14.7	14.7
Mole Fraction						
CO2	0.0%	0.0%	0.0%	0.0%	13.5%	12.7%
H2O	2.0%	2.0%	2.0%	2.0%	12.7%	12.1%
N2	77.4%	77.4%	77.4%	77.4%	70.3%	70.7%
O2	20.6%	20.6%	20.6%	20.6%	3.5%	4.5%
SO2	0.000%	0.000%	0.000%	0.000%	0.046%	0.044%
Mass Flow (lb/hr)						
CO2	0	0	0	0	1,159,400	1,159,400
H2O	69,317	69,317	69,317	64,958	447,238	451,598
N2	4,108,620	4,108,620	4,108,620	3,850,230	3,854,950	4,113,330
O2	1,247,540	1,247,540	1,247,540	1,169,080	219,202	297,659
SO2	0	0	0	0	5,820	5,820

Table 26. (Continued)

Stream #	7	8	9	10	11
Mass Flow (lb/hr)	6,329,340	6,329,340	6,716,560	643,021	643,021
Temp (F)	282.6	316.9	135.0	77	114.9
Pressure (psia)	14.7	16.9	14.7	14.7	14.7
Mole Fraction				See Table 1 for coal properties	
CO2	12.1%	12.1%	11.3%		
H2O	11.6%	11.6%	17.8%		
N2	71.0%	71.0%	65.9%		
O2	5.3%	5.3%	5.0%		
SO2	0.042%	0.042%	0.000%		
Mass Flow (lb/hr)					
CO2	1,159,400	1,159,400	1,178,950		
H2O	455,448	455,448	763,179		
N2	4,341,580	4,341,580	4,392,120		
O2	366,962	366,962	382,308		
SO2	5,820	5,820	0		

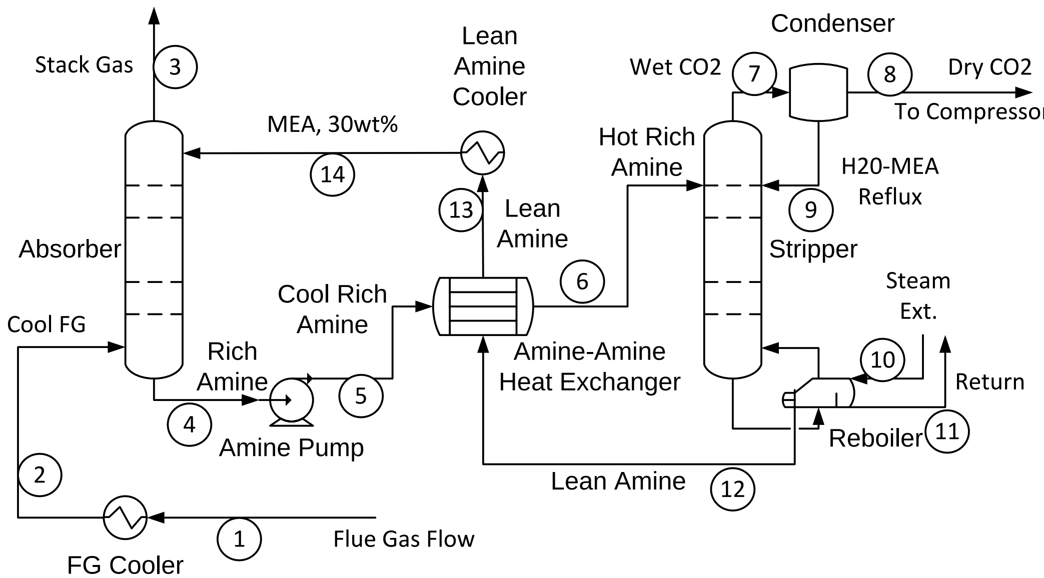

Figure 52. MEA System

The MEA system's operation was explained in section 2.3, and the design specs were explained in section 2.3.1. The stream data shown in Table 27 shows the ASPEN simulation results. Stream 1 is the same as Stream 9 in the boiler; it is the flue gas leaving the FGD before it enters the FG cooler, where it is cooled to 100 °F. Stream 2 then enters the absorber where 90% of the CO2 is absorbed before leaving at stream 3. The CO2 absorbed leaves in stream 4 where it enters the amine pump, increasing the pressure in stream 5 before entering the amine-amine heat exchanger. This increases the amine solution's temperature to 238 °F in stream 6 before entering the stripper.

In the stripper the CO2 leaves through the top in stream 7 where the moisture is condensed out, along with some MEA before being sent to the compressors in stream 8. The moisture and MEA condensed out is added back into the stripper in stream 9. Streams 10 and 11 provide the heat to the reboiler which enters as steam, condenses, and leaves as liquid water. The lean amine leaves the stripper in stream 12 with a much smaller mass flow rate of CO2 then when it entered as most of it had been separated and sent to the compressors. The lean amine, with its high temperature of 270 °F, is then used to heat the rich amine in the amine-amine heat exchanger, with stream 13 leaving at 148.6 °F. The lean amine is then cooled further, with stream 14 leaving at 100 °F. Stream 14 then enters the absorber to absorb more CO_2.

Table 27. MEA System Stream Data with PRB and No Heat Integration

Stream #	1	2	3	4	5	6
Mass Flow (lb/hr)	6,716,560	6,199,590	5,356,780	25,641,200	25,641,200	25,641,200
Temp (F)	135.0	100.0	129.3	135.1	135.1	238.0
Pressure (psia)	14.7	14.7	14.7	14.7	44.1	44.1
Mole Fraction						
CO2	11.3%	12.8%	1.4%	3.5%	3.5%	3.5%
H2O	17.8%	6.5%	13.0%	85.6%	85.6%	85.6%
N2	65.9%	74.9%	79.5%	0.0%	0.0%	0.0%
O2	5.0%	5.7%	6.1%	0.0%	0.0%	0.0%
MEA	0.000%	0.000%	0.011%	10.956%	10.956%	10.956%
Mass Flow (lb/hr)						
CO2	1,178,950	1,178,880	117,891	1,649,950	1,649,950	1,649,950
H2O	763,179	246,294	463,280	16,729,600	16,729,600	16,729,600
N2	4,392,120	4,392,110	4,392,010	96	96	96
O2	382,308	382,307	382,292	15	15	15
MEA	0	0	1,299	7,261,530	7,261,530	7,261,530

Table 27. (Continued)

Stream #	7	8	9	10	11	12
Mass Flow (lb/hr)	1,492,600	1,070,950	421,656	1,757,870	1,757,870	24,570,300
Temp (F)	240.0	100.0	100.0	522.0	300.0	270.0
Pressure (psia)	44.1	44.1	44.1	87.4	87.4	44.3
Mole Fraction						
CO2	50.7%	97.8%	0.4%	0.0%	0.0%	1.3%
H2O	49.2%	2.2%	99.3%	100.0%	100.0%	87.5%
N2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
O2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
MEA	0.142%	0.000%	0.294%	0.000%	0.000%	11.211%
Mass Flow (lb/hr)						
CO2	1,065,240	1,060,980	4,265	0	0	588,968
H2O	423,088	9,860	413,237	1,757,870	1,757,870	16,719,800
N2	96	96	0	0	0	0
O2	15	15	0	0	0	0
MEA	4,154	0	4,154	0	0	7,261,530

Table 27. (Continued)

Stream #	13	14
Mass Flow (lb/hr)	24,570,300	24,570,300
Temp (F)	148.6	100.0
Pressure (psia)	44.3	14.7
Mole Fraction		
CO2	1.3%	1.3%
H2O	87.5%	87.5%
N2	0.0%	0.0%
O2	0.0%	0.0%
MEA	11.211%	11.211%
Mass Flow (lb/hr)		
CO2	588,968	588,968
H2O	16,719,800	16,719,800
N2	0	0
O2	0	0
MEA	7,261,530	7,261,530

Table 28 and Table 29show the boiler and MEA system stream results for an Illinois #6 coal. The main differences between this flow and the PRB flow are the decreased CO2 and flue gas flow rate. The Illinois #6 coal has a lower flue gas flow rate due to the lower moisture in the coal, giving a higher boiler efficiency, and requiring less coal.

Table 28. Boiler Stream Data with Illinois #6 and No Heat Integration

Stream #	1	2	3	4	5	6
Mass Flow (lb/hr)	5,011,300	5,011,300	5,011,300	4,704,740	5,109,350	5,415,920
Temp (F)	77.0	80.9	156.0	501.5	600.0	292.2
Pressure (psia)	14.7	15.0	15.0	15.0	14.7	14.7
Mole Fraction						
CO2	0.0%	0.0%	0.0%	0.0%	13.8%	13.0%
H2O	2.0%	2.0%	2.0%	2.0%	8.4%	8.1%
N2	77.4%	77.4%	77.4%	77.4%	73.9%	74.1%
O2	20.6%	20.6%	20.6%	20.6%	3.5%	4.5%
SO2	0.000%	0.000%	0.000%	0.000%	0.380%	0.357%
Mass Flow (lb/hr)						
CO2	0	0	0	0	1,044,530	1,044,530
H2O	64,025	64,025	64,025	60,109	261,860	265,777
N2	3,794,970	3,794,970	3,794,970	3,562,820	3,567,860	3,800,010
O2	1,152,310	1,152,310	1,152,310	1,081,810	192,991	263,482
SO2	0	0	0	0	41,902	41,902

Table 28. (Continued)

Stream #	7	8	9	10	11
Mass Flow (lb/hr)	5,686,710	5,686,710	5,990,450	471,830	471,830
Temp (F)	282.3	316.7	135.0	77	127
Pressure (psia)	14.7	16.9	14.7	15	15
Mole Fraction				See Table 1 for coal properties	
CO2	12.3%	12.3%	11.5%		
H2O	7.8%	7.8%	14.3%		
N2	74.3%	74.3%	69.1%		
O2	5.3%	5.3%	5.1%		
SO2	0.340%	0.340%	0.000%		
Mass Flow (lb/hr)					
CO2	1,044,530	1,044,530	1,061,730		
H2O	269,237	269,237	539,930		
N2	4,005,080	4,005,080	4,049,540		
O2	325,749	325,749	339,248		
SO2	41,902	41,902	0		

Table 29. MEA System Stream Data with Illinois #6 and No Heat Integration

Stream #	1	2	3	4	5	6
Mass Flow (lb/hr)	5,990,450	5,676,300	4,914,460	23,467,000	23,467,000	23,467,000
Temp (F)	135.0	100.0	128.8	134.6	134.7	238.0
Pressure (psia)	14.7	14.7	14.7	14.7	44.1	44.1
Mole Fraction						
CO2	11.5%	12.6%	1.3%	3.4%	3.4%	3.4%
H2O	14.3%	6.5%	12.8%	85.6%	85.6%	85.6%
N2	69.1%	75.4%	79.9%	0.0%	0.0%	0.0%
O2	5.1%	5.5%	5.9%	0.0%	0.0%	0.0%
MEA	0.000%	0.000%	0.011%	10.953%	10.953%	10.953%
Mass Flow (lb/hr)						
CO2	1,061,730	1,061,690	106,178	1,507,740	1,507,740	1,507,740
H2O	539,930	225,837	418,444	15,314,500	15,314,500	15,314,500
N2	4,049,540	4,049,530	4,049,440	89	89	89
O2	339,248	339,247	339,234	13	13	13
MEA	0	0	1,161	6,644,730	6,644,730	6,644,730

Table 29. (Continued)

Stream #	7	8	9	10	11	12
Mass Flow (lb/hr)	1,341,210	964,429	376,783	1,578,200	1,578,200	22,502,600
Temp (F)	239.8	100.0	100.0	522.0	300.0	269.5
Pressure (psia)	44.1	44.1	44.1	87.4	87.4	44.3
Mole Fraction						
CO2	50.9%	97.8%	0.4%	0.0%	0.0%	1.3%
H2O	49.0%	2.2%	99.3%	100.0%	100.0%	87.5%
N2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
O2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
MEA	0.141%	0.000%	0.294%	0.000%	0.000%	11.204%
Mass Flow (lb/hr)						
CO2	959,252	955,447	3,805	0	0	552,292
H2O	378,150	8,880	369,275	1,578,200	1,578,200	15,305,600
N2	89	89	0	0	0	0
O2	13	13	0	0	0	0
MEA	3,703	0	3,703	0	0	6,644,730

Table 29. (Continued)

Stream #	13	14
Mass Flow (lb/hr)	22,502,600	22,502,600
Temp (F)	147.9	100.0
Pressure (psia)	44.3	14.7
Mole Fraction		
CO2	1.3%	1.3%
H2O	87.5%	87.5%
N2	0.0%	0.0%
O2	0.0%	0.0%
MEA	11.204%	11.204%
Mass Flow (lb/hr)		
CO2	552,292	552,292
H2O	15,305,600	15,305,600
N2	0	0
O2	0	0
MEA	6,644,730	6,644,730

Table 30 and Table 31 show the boiler and MEA system stream results for a Lignite coal. The flue gas flow rate leaving the boiler (boiler stream 9) in the Lignite case has an approximately equal flow rate when compared to the PRB case. As shown for the Illinois #6 coal, a lower moisture percent coal should lead to a lower flue gas flow rate. If the trend continued, the Lignite flue gas flow rate would be much higher than the PRB flow rate, but this is not what is observed. To help explain this, the Lignite and PRB coals are compared, and it can be observed that the Lignite coal has a smaller weight percentage of carbon then the PRB coal (see Table 1). A lower carbon percentage coal will require less oxygen to combust with the carbon, and therefore smaller air flow rates. This will decrease the flue gas flow rate leaving the boiler. It is assumed that this factor is causing the Lignite flue gas flow rate to be smaller then expected.

Table 30. Boiler Stream Data with Lignite and No Heat Integration

Stream #	1	2	3	4	5	6
Mass Flow (lb/hr)	5,261,520	5,261,520	5,261,520	4,920,300	5,687,000	6,028,220
Temp (F)	77.0	80.9	156.0	543.6	600.0	292.6
Pressure (psia)	14.7	15.0	15.0	15.0	14.7	14.7
Mole Fraction						
CO2	0.0%	0.0%	0.0%	0.0%	12.4%	11.7%
H2O	2.0%	2.0%	2.0%	2.0%	17.5%	16.6%
N2	77.4%	77.4%	77.4%	77.4%	66.5%	67.2%
O2	20.6%	20.6%	20.6%	20.6%	3.5%	4.5%
SO2	0.000%	0.000%	0.000%	0.000%	0.070%	0.066%
Mass Flow (lb/hr)						
CO2	0	0	0	0	1,090,000	1,090,000
H2O	67,222	67,222	67,222	62,863	631,509	635,869
N2	3,984,460	3,984,460	3,984,460	3,726,060	3,732,350	3,990,750
O2	1,209,840	1,209,840	1,209,840	1,131,380	224,218	302,678
SO2	0	0	0	0	8,916	8,916

Table 30. (Continued)

Stream #	7	8	9	10	11
Mass Flow (lb/hr)	6,329,630	6,329,630	6,721,880	874,222	874,222
Temp (F)	283.1	317.3	135.0	77	112
Pressure (psia)	14.7	16.9	14.7	15	15
Mole Fraction				See Table 1 for coal properties	
CO2	11.1%	11.1%	10.4%		
H2O	15.9%	15.9%	21.8%		
N2	67.6%	67.6%	62.8%		
O2	5.2%	5.2%	5.0%		
SO2	0.063%	0.063%	0.000%		
Mass Flow (lb/hr)					
CO2	1,090,000	1,090,000	1,109,960		
H2O	639,720	639,720	953,706		
N2	4,219,000	4,219,000	4,270,570		
O2	371,985	371,985	387,643		
SO2	8,916	8,916	0		

Table 31. MEA System Stream Data with Lignite and No Heat Integration

Stream #	1	2	3	4	5	6
Mass Flow (lb/hr)	6,721,880	6,007,120	5,208,350	24,827,300	24,827,300	24,827,300
Temp (F)	135.0	100.0	128.3	134.3	134.4	238.0
Pressure (psia)	14.7	14.7	14.7	14.7	44.1	44.1
Mole Fraction						
CO2	10.4%	12.4%	1.3%	3.4%	3.4%	3.4%
H2O	21.8%	6.5%	12.7%	85.6%	85.6%	85.6%
N2	62.8%	75.1%	79.6%	0.0%	0.0%	0.0%
O2	5.0%	6.0%	6.3%	0.0%	0.0%	0.0%
MEA	0.000%	0.000%	0.010%	10.951%	10.951%	10.951%
Mass Flow (lb/hr)						
CO2	1,109,960	1,109,860	110,977	1,593,420	1,593,420	1,593,420
H2O	953,706	239,059	438,069	16,204,800	16,204,800	16,204,800
N2	4,270,570	4,270,560	4,270,470	94	94	94
O2	387,643	387,641	387,626	15	15	15
MEA	0	0	1,207	7,028,990	7,028,990	7,028,990

Table 31. (Continued)

Stream #	7	8	9	10	11	12
Mass Flow (lb/hr)	1,400,020	1,008,340	391,667	1,645,370	1,645,370	23,818,900
Temp (F)	239.7	100.0	100.0	522.0	300.0	269.2
Pressure (psia)	44.1	44.1	44.1	87.4	87.4	44.3
Mole Fraction						
CO2	51.0%	97.8%	0.4%	0.0%	0.0%	1.3%
H2O	48.8%	2.2%	99.3%	100.0%	100.0%	87.5%
N2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
O2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
MEA	0.141%	0.000%	0.293%	0.000%	0.000%	11.198%
Mass Flow (lb/hr)						
CO2	1,002,900	998,951	3,951	0	0	594,470
H2O	393,168	9,284	383,873	1,645,370	1,645,370	16,195,500
N2	94	94	0	0	0	0
O2	15	15	0	0	0	0
MEA	3,843	0	3,843	0	0	7,028,990

Table 31. (Continued)

Stream #	13	14
Mass Flow (lb/hr)	23,818,900	23,818,900
Temp (F)	147.4	100.0
Pressure (psia)	44.3	14.7
Mole Fraction		
CO2	1.3%	1.3%
H2O	87.5%	87.5%
N2	0.0%	0.0%
O2	0.0%	0.0%
MEA	11.198%	11.198%
Mass Flow (lb/hr)		
CO2	594,470	594,470
H2O	16,195,500	16,195,500
N2	0	0
O2	0	0
MEA	7,028,990	7,028,990

Vita

Gordon Jonas graduated from high school in Allentown, NJ in 2006. He attended Lehigh University for undergraduate, where he received his B.S. in mechanical engineering in 2010. After graduating, he decided that four years of Lehigh wasn't enough fun. Gordon accepted an excellent opportunity as a research assistant at the Energy Research Center while working on his Master's degree. Gordon is graduating in December of 2011, and after completing his degree he will begin working for Air Products and Chemicals, Inc.