THERMAL INTEGRATION OF CO_2 COMPRESSION PROCESSES WITH COAL-FIRED POWER PLANTS EQUIPPED WITH CARBON CAPTURE

FINAL TECHNICAL REPORT

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by

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ABSTRACT

Coal-fired power plants, equipped either with oxycombustion or post-combustion CO_2 capture, will require a CO_2 compression system to increase the pressure of the CO_2 to the level needed for sequestration. Most analyses show that CO_2 compression will have a significant effect on parasitic load, will be a major capital cost, and will contribute significantly to reduced unit efficiency. This project used first principle engineering analyses and computer simulations to determine the effects of utilizing compressor waste heat to improve power plant efficiency and increase net power output of coal-fired power plants with carbon capture. This was done for units with post combustion solvent-based CO_2 capture systems and for oxyfired power plants, firing bituminous, PRB and lignite coals. The thermal integration opportunities analyzed for oxycombustion capture are use of compressor waste heat to reheat recirculated flue gas, preheat boiler feedwater and predry high-moisture coals prior to pulverizing the coal. Among the thermal integration opportunities analyzed for post combustion capture systems are use of compressor waste heat and heat recovered from the stripper condenser to regenerate post-combustion CO_2 capture solvent, preheat boiler feedwater and predry high-moisture coals.

The overall conclusion from the oxyfuel simulations is that thermal integration of compressor heat has the potential to improve net unit heat rate by up to 8.4 percent, but the actual magnitude of the improvement will depend on the type of heat sink used and to a lesser extent, compressor design and coal rank.

The simulations of a unit with a MEA post combustion capture system showed that thermal integration of either compressor heat or stripper condenser heat to preheat boiler feedwater would result in heat rate improvements from 1.20 percent to 4.19 percent. The MEA capture simulations further showed that partial drying of low rank coals, done in combination with feedwater heating, would result in heat rate reductions of 7.43 percent for PRB coal and 10.45 percent for lignite.

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EXECUTIVE SUMMARY

Analyses were performed to estimate the magnitudes of the performance improvements which could be achieved in an oxycombustion power plant by using heat released during CO_2 compression to predry coal, preheat boiler feedwater, and reheat recirculated flue gas. Analyses for a MEA type post-combustion CO_2 capture system investigated use of compressor heat and heat recovered from the stripper condenser to predry coal, preheat boiler feedwater and provide heat to the stripper reboiler.

Three compressor options were modeled: Inline and Integrally Geared centrifugal compressors and a shock-wave compression technology being developed by Ramgen Power Systems. For a given application and for the particular Inline and Integrally Geared compressor models which were analyzed (that is, Inline 4 and IG1), the Integrally Geared compressor has the lowest predicted power requirement followed by the Inline compressor and then the Ramgen compressor. Heat energy released during intercooling was found to increase with compressor power, with the Ramgen compressor releasing the most heat, and the Integrally Geared compressor the least.

Results for Oxycombustion Unit

For the recirculated flue gas and boiler feedwater heating cases, compression heat would reduce turbine steam extractions, resulting in increased net unit power. In the coal drying case, the compression heat would increase boiler efficiency, which, for fixed main steam flow rate, would reduce the energy input to the boiler provided by the coal and reduce pulverizer and ID fan power, rate of CO_2 formation and ASU and CO_2 compressor power.

The simulation results show the recirculated flue gas case would yield heat rate reductions from 0.73 to 0.85 percent, boiler feedwater heating would result in heat rate reductions from 1.0 to 4.78 percent, depending on the configuration of the feedwater heating system, and coal drying would result in heat rate reductions of 3.7 to 3.85 percent for PRB and 6.9 to 7.1 percent for lignite. (Note: It was assumed PRB was dried from 30 to 15 percent moisture and lignite was dried from 38.5 to 20 percent moisture.) Combinations of heat sinks were analyzed to take advantage of more of the compressor heat and this resulted in predicted heat rate reductions from 2.0 to 4.13 percent for Illinois #6, from 5.8 to 6.2 percent for PRB and from 7.7 to 8.4 percent for lignite.

Comparisons of predicted values of unit performance show that the net unit heat rate would be lowest for Illinois #6 compared to the other two coals. The results also show that for all three coals, the Integrally Geared compressor would result in a lower unit heat rate than either of the other two compressors.

The overall conclusion from the oxyfuel simulations is that thermal integration of compressor heat has the potential to improve net unit heat rate by up to 8.4 percent, but the actual magnitude of the improvement will depend on the type of heat sink used and to a lesser extent, compressor design and coal rank. For the specific Inline and Integrally Geared compressor models analyzed in this study (that is, Inline 4 and IG1), the Integrally Geared compressor results in the lowest predicted values of net unit heat rate and the Ramgen compressor, the highest, for each of the thermal integration cases considered.

Results for Unit with MEA Post-Combustion Capture System

Predicted heat rate improvements, resulting from use of either compressor heat or stripper condenser heat to preheat boiler feedwater in a unit with MEA post-combustion capture, range from 1.20 percent to 4.19 percent. Heat rate improvements in the 4.19 percent range would occur with heat captured from a Ramgen compressor being transferred to higher temperature feedwater heaters, while firing PRB coal. The simulations also showed that partial drying of low rank coals has the potential to cause the largest reductions in unit heat rate. Waste heat integration used for drying of low rank coals done in combination with feedwater heating is predicted to result in heat rate reductions of 7.43 percent for PRB coal and 10.45 percent for lignite.

Compressor heat can also be rejected to the reboiler, which would reduce the low pressure turbine (LP) steam extraction to the reboiler. Steam extraction for the reboiler would occur in the same location of the LP turbine as the extraction for FWH-4 and the results show that integrating heat to FWH-4 and integrating heat to the reboiler would result in the same steam cycle heat rate improvement.

Comparison of the three compressor options analyzed in this investigation (that is, Ramgen, Inline 4, and IG1) with PRB coal firing and no thermal integration shows the Ramgen compressor would result in the highest baseline heat rate due to its high compression ratio, however, this would be accompanied by larger potential gains in percent heat rate due to the high temperature of the cooling water leaving the compressor coolers. The thermal integration option yielding the lowest heat rates with PRB firing shows predicted heat rates of 12,143 Btu/kWh (Inline 4), 12,146 Btu/kWh (Ramgen) and 12,220 Btu/kWh (IG1).

CHAPTER 1: INTRODUCTION

All coal-fired power plants, equipped either with oxycombustion, post-combustion CO_2 capture or precombustion CO_2 capture, in the case of an IGCC plant, will require a CO_2 compression system to increase the pressure of the CO_2 to the level needed for sequestration. Most analyses show that CO_2 compression will have a significant effect on parasitic load, will be a major capital cost, and will contribute significantly to reduced unit efficiency.

Three of the technology options for CO_2 compression to pressures above 2,200 psia include:

- An inline centrifugal compressor
- An integrally geared centrifugal compressor
- A supersonic shock-wave compressor.

All three compressor types are multistage with interstage and post compression cooling.

Published estimates of the power requirements of these three compressor types show differences from one type to the next and there undoubtedly will also be significant differences in installed capital costs (Refs. 1-2). What is missing from published analyses is the potential for waste heat utilization for each technology option.

This project used first principle engineering analyses and computer simulations to determine the effects of utilizing waste heat to improve power plant efficiency and increase net power output of coal-fired power plants with carbon capture. This was done for units with post combustion solvent-based CO_2 capture systems and for oxyfired power plants. In both cases, analyses were carried out for bituminous, PRB and lignite coals. The thermal integration opportunities analyzed for oxycombustion capture are use of compressor waste heat to reheat recirculated flue gas, preheat boiler feedwater and predry high-moisture coals prior to pulverizing the coal. Among the thermal integration opportunities analyzed for post combustion capture systems are use of compressor waste heat and heat recovered from the stripper condenser to regenerate post-combustion CO_2 capture solvent, preheat boiler feedwater and predry high-moisture coals. The objective was to generate results which would provide new insights into the role that thermal integration strategies involving CO_2 compressors and the rest of the power plant can play in increasing the efficiencies of coal-fired steam power plants with CCS.

CHAPTER 2: CO_2 COMPRESSORS

Most carbon capture technologies for coal-fired power plants are designed to produce streams of relatively concentrated gaseous CO_2 at pressures ranging from close to one atmosphere to 20 atmospheres. Before it can be sequestered in a geologic formation, a stream of CO_2 must be compressed to pressures typically exceeding 2,200 psia.

Two generic types of centrifugal compressors, referred to as in-line and integrally-geared compressors, are commercially available for use with CO_2. In addition, a supersonic shock-wave type of compressor, being developed by RAMGEN Power Systems, is expected to be available for full scale use within a few years.

In-line compressors have rows of impellers mounted on a single shaft (Figures 2-1 and 2-2a). The flow enters the compressor at one end and after passing through four to five impellers, it flows into an external heat exchanger for cooling, after which it flows into the next compression stage[1] for additional compression. Depending on compressor inlet pressure, this type of compressor might need anywhere from two to four stages to achieve a final discharge pressure in excess of 2,200 psia.

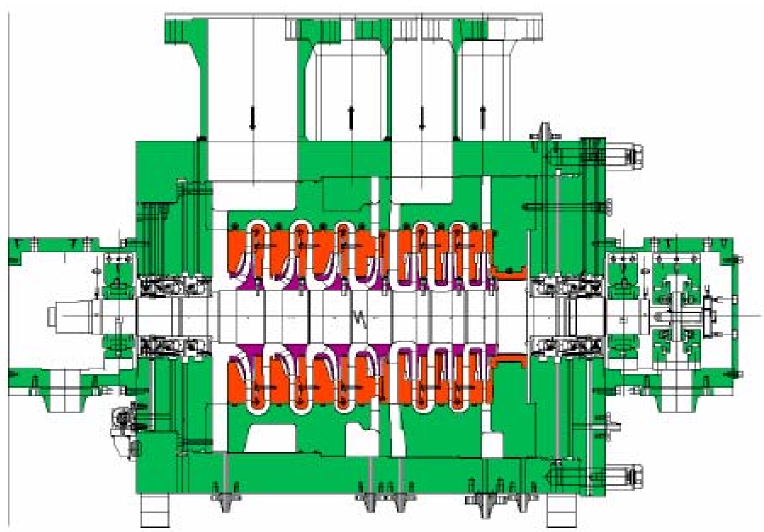

Figure 2-1: Cross-Sectional View of an In-Line Compressor

[1] *Note 1: A compressor "stage" is also referred to as a compressor "section" by some manufacturers.*

In-Line Centrifugal **Integral-Gear Centrifugal**

(2-2a) **(2-2b)**

Figure 2-2: Photographs of In-Line and Integrally-Geared Compressors

Integrally geared compressors have one impeller per stage. To maximize stage efficiencies, the individual impellers are on separate pinions, with each pinion geared to rotate at a distinct rotational speed (Figure 2-2b). The CO_2 is routed to an external heat exchanger after each stage, except after the seventh and eighth stages for some integrally geared designs. Depending on the type of carbon capture system, geared compressors might require anywhere from four to eight stages to achieve a final discharge pressure in excess of 2,200 psia.

The RAMGEN compressor concept uses a rotating impeller with a diffuser to create stage pressure ratios of up to 10/1 (Figures 2-3 and 2-4). This approach would make it possible achieve the desired CO_2 discharge pressures with one to three compression stages.

Some compressor vendors characterize compressor stage performance in terms of isentropic efficiency while others use polytropic efficiency. The analysis method used in this study is based on isentropic efficiencies of the individual compressor stages.

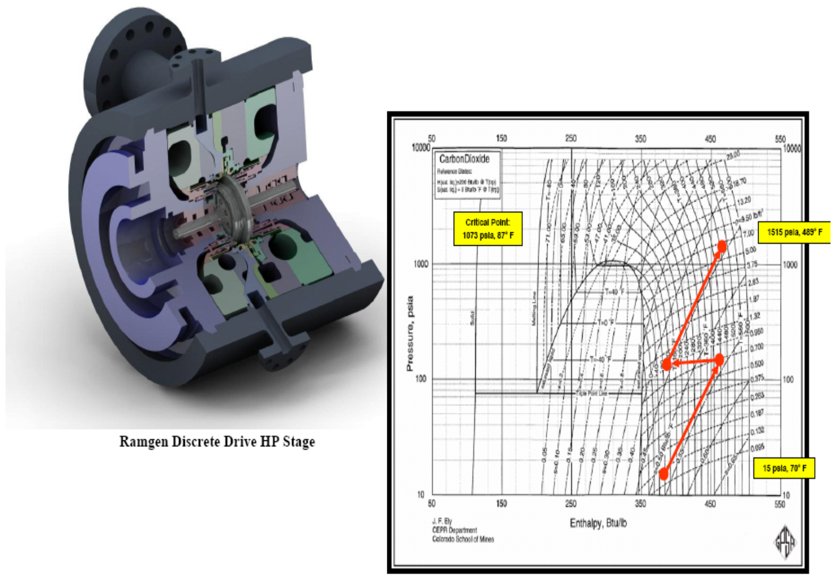

Figure 2-3: RAMGEN Compressor with Pressure-Enthalpy Diagram

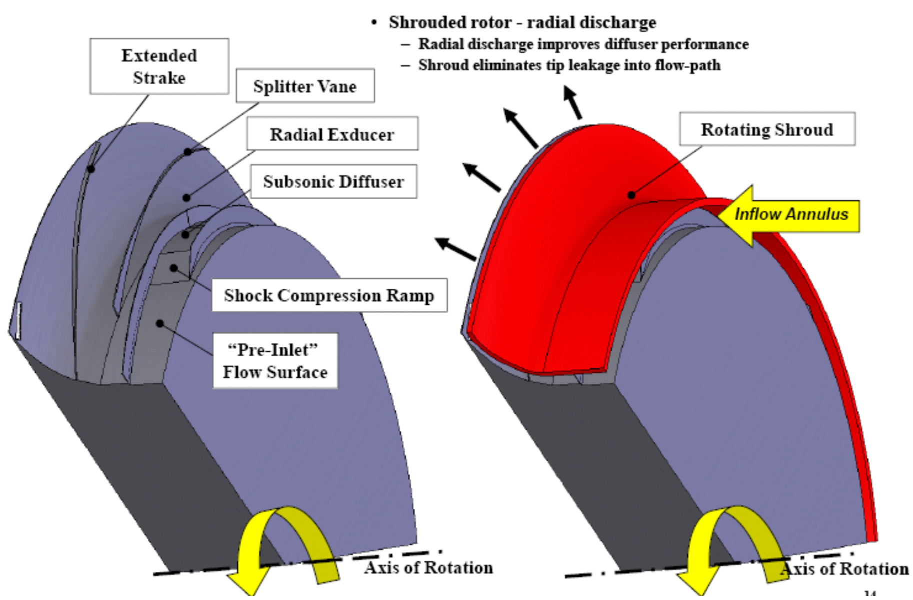

Figure 2-4: Rotor and Diffuser in RAMGEN Compressor

The equation for isentropic efficiency,

$$\eta = (h2s - h1) / (h2a - h1)$$

can be rearranged to solve for the actual discharge enthalpy, h2a

$$h2a = (h2s - h1) / \eta + h1$$

where h2s is the isentropic discharge enthalpy, h1 is the inlet enthalpy and η is the isentropic efficiency.

The shaft power requirement for each stage is obtained by multiplying the CO_2 mass flow rate by the resulting change in enthalpy and adding mechanical losses. Mechanical losses are typically given by the manufacturer as a percentage addition to the gas power (mass flow rate multiplied by enthalpy change). Representative values for mechanical losses are on the order of 2 to 5 percent.

Data obtained from compressor vendors show that compressor stage efficiency varies with compressor type, manufacturer, and specifics of compressor design. Figure 2-5 shows isentropic stage efficiencies for a RAMGEN compressor, four different in-line compressors and two different integrally-geared compressors. The stage efficiency values shown here are based on information obtained from compressor manufacturers and are plotted versus the natural log of average stage pressure expressed in atmospheres. These data show a spread of close to 10 percent in stage efficiency between the most efficient and least efficient of the four in-line compressors (Inline1 to Inline4) and even larger differences between stage efficiencies for the two integrally-geared compressors (IG1 and IG2). Of these, the compressors labeled IG1, Inline 4 and RAMGEN have the highest efficiencies.

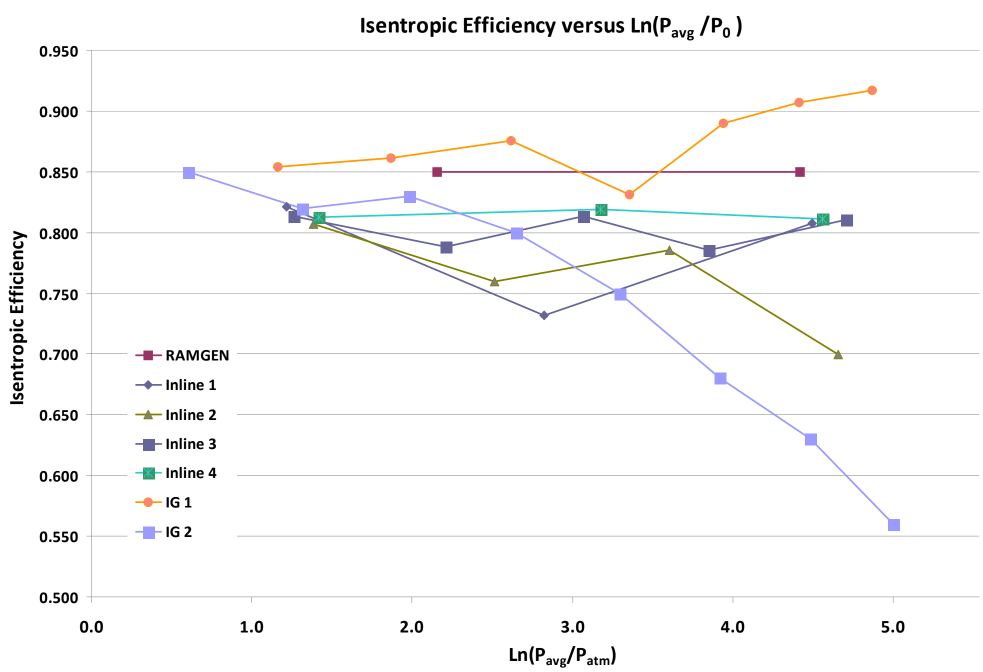

Figure 2-5: Isentropic Efficiencies for In-line, Integrally Geared and RAMGEN Compressors

There are also inherent differences in stage pressure ratios from one type of compressor to the next, with stage pressure ratios ranging from 2 to 6 for Inline compressors and from 1.5 to 2.5 for Integrally Geared compressors. The developers of the RAMGEN compressor have targeted a 10/1 stage pressure ratio for the shock wave-compression type of compressor. As a result, a MEA post combustion capture system might require a three stage in-line compressor, a two stage RAMGEN compressor and a seven stage integrally geared compressor. Figure 2-6 shows approximate numbers of stages of the different compressor types for oxycombustion, MEA and chilled ammonia applications.

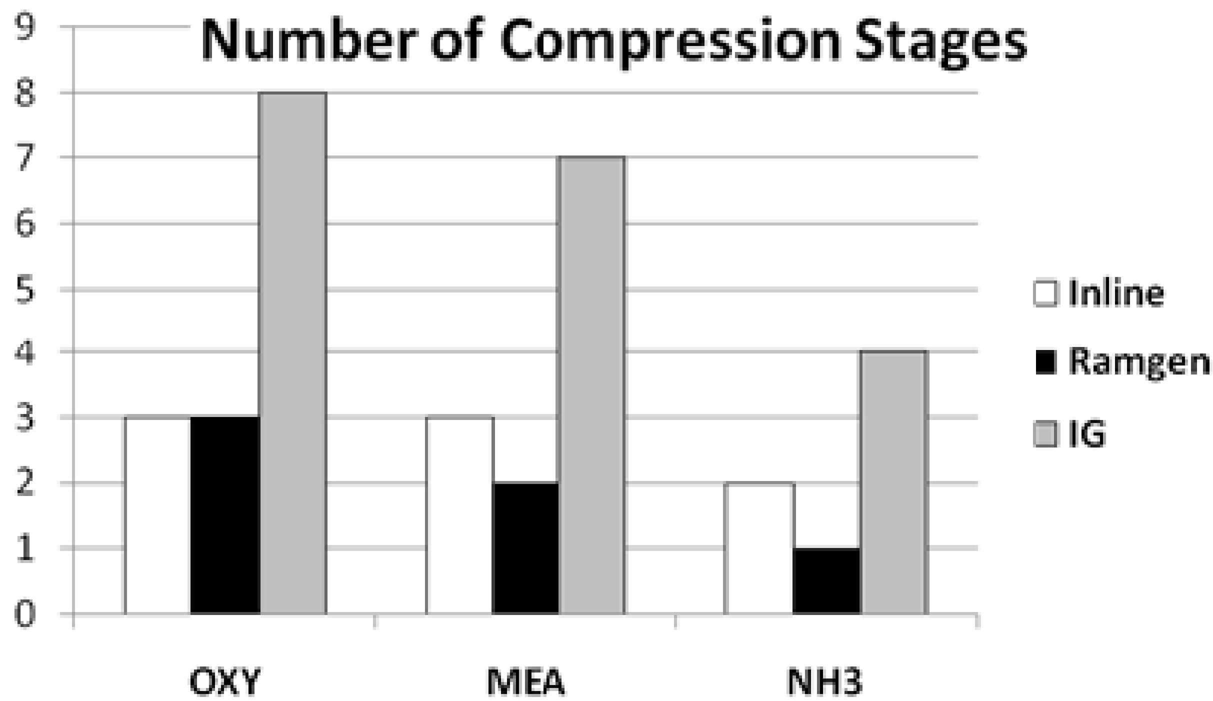

Figure 2-6: Approximate Number of Compressor Stages as Function of Type of Capture System and Compressor Type

A multistage compressor utilizes gas intercooling (Figure 2-7) between compressor stages to reduce the gas temperature entering each compressor stage to a suitably low value. This increases the gas density at the stage inlet, which results in lower compressor power requirements (Ref 3). Since overall compressor power depends on stage efficiency and numbers of intercooled stages, an analysis was performed to determine the relative effects of the two factors on overall power. The analysis was performed for an oxycombustion system, where for the purposes of this analysis, the gas was modeled as pure CO_2 with a flow rate of 1.3 million lbm/hr. The inlet temperature to each stage was assumed to be 110°F, and the compressor inlet and exit pressures were assumed to be 14.7 and 2,200 psia.

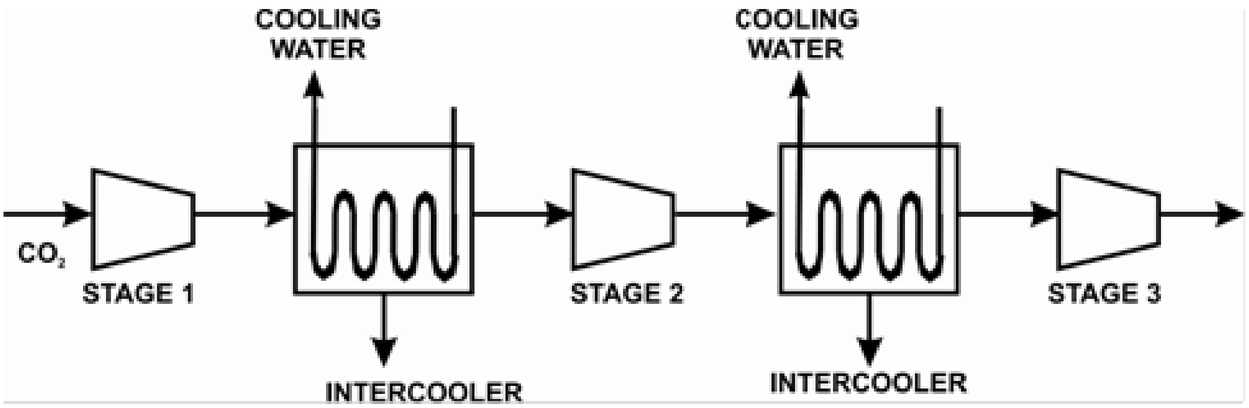

Figure 2-7: Sketch of Multistage Compressor with Water-Cooled Intercoolers

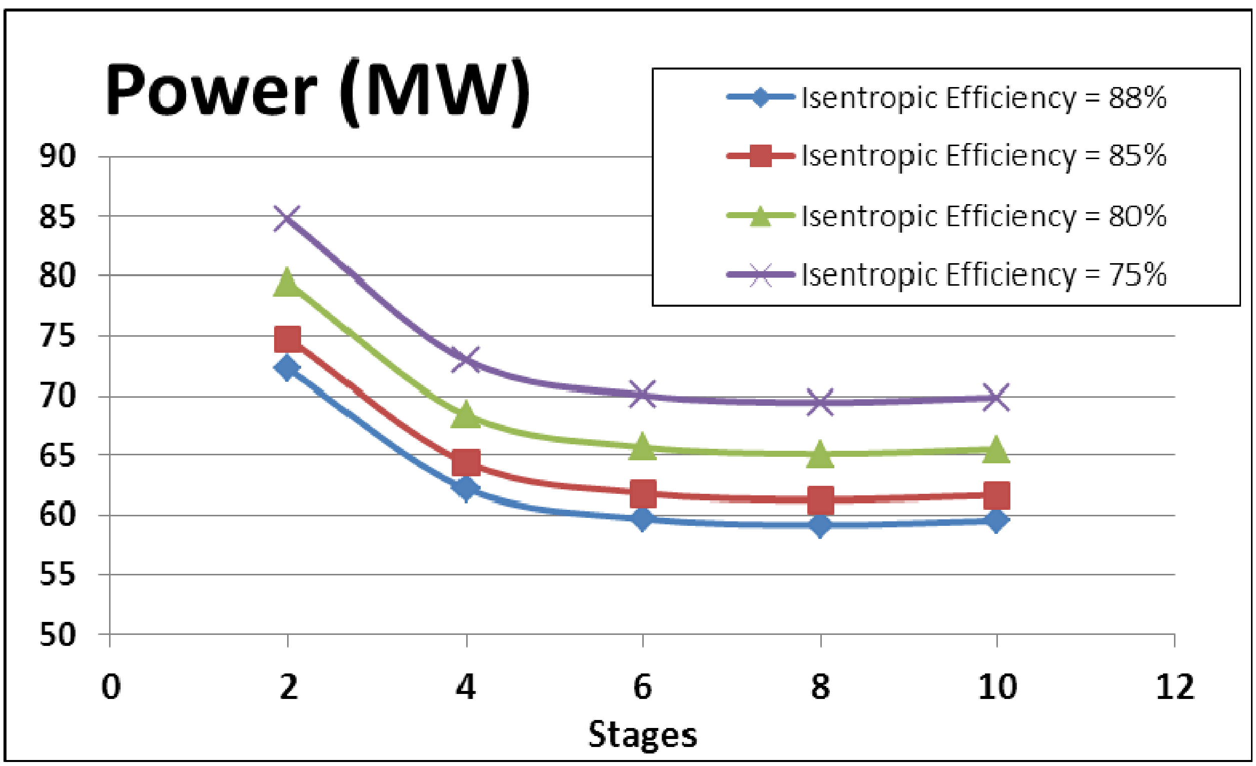

Figure 2-8: Compressor Power for an Oxy-Fired Unit as Functions of Compressor Stage Efficiency and Number of Intercooled Stages

The analyses compared hypothetical compressors with stage efficiencies ranging from 75 to 88 percent and with numbers of stages ranging from two to ten. The results (Figure 2-8) verify that predicted overall compressor power decreases with increasing stage efficiency and increasing numbers of stages, and they show that a compressor with relatively low stage efficiencies and a relatively large number of intercooled stages may require less compressor power than a compressor with high stage efficiencies and fewer compressor stages. For example, an eight stage compressor with individual stage efficiencies of 80 percent would require 65 MW and a three stage compressor with 88 percent stage efficiencies would require an overall power of 67 MW.

There are other compressor-related factors besides stage efficiency which are important for carbon capture applications, such as cooling water exit temperatures from the compressor intercoolers and the amount of compressor heat which would be available for use in other parts of the power plant. Table 2-1 compares predicted values of compressor power, recoverable heat, and average CO_2 exit temperature for a MEA capture system. Typical stage cooling water exit temperatures are shown in Figure 2-9 as a function of cooling water to CO_2 flow rate. The three curves, representing an inline, an integrally geared and a Ramgen compressor, show large differences in cooling water exit temperature with both cooling water flow rate and compressor type. For some applications, larger values of cooling water exit temperature will make it possible to achieve larger heat rate improvements through thermal integration.

Table 2-1: MEA System: Typical Values of Compressor Power, Recoverable Heat and CO_2 Exit Temperature

	Power (MW)	Q_{total} (MBtu/hr)	T_{CO_2} (°F)
Inline	43.1	245.8	431
RAMGEN	43.4	258.1	446
Integrally Geared	35.4	251.4	177

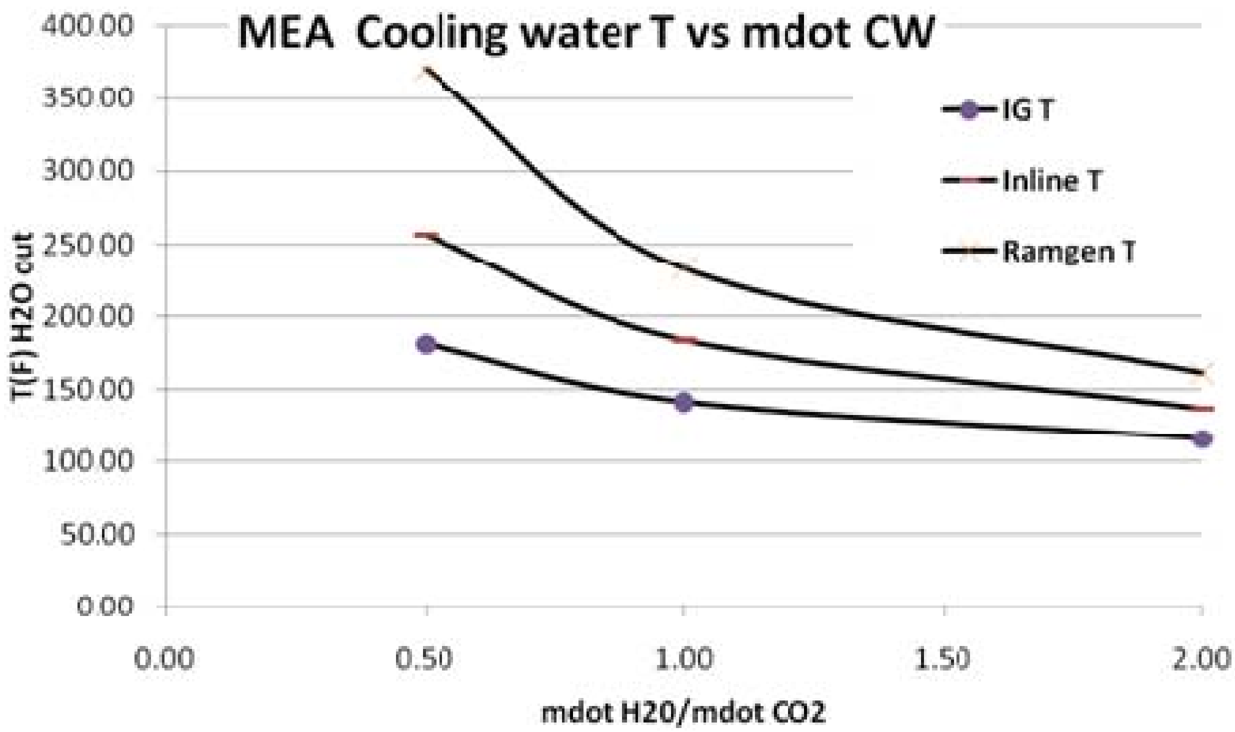

Figure 2-9: Cooling Water Exit Temperature as a Function of Cooling Water to CO_2 Flow Rate Ratio and Type of Compressor

Chapters 3 and 4 present results of analyses of oxycombustion and MEA post-combustion capture systems, where performance comparisons are made between the three basic types of compressors. Because Inline 4 has the highest stage efficiencies of the four inline compressors for which the project team was able to obtain data (Figure 2-5) and IG1 has the higher stage efficiencies of the two integrally geared compressors shown in Figure 2-5, the IG1 and Inline 4 compressor models, along with representative data for the Ramgen compressor, were selected for the analyses described in Chapters 3 and 4.

CHAPTER 3: OXY-FIRED POWER PLANT

Process Description

The configuration of the oxy-fired boiler analyzed in the project is shown in Figure 3-1. Oxygen is separated from air in a cryogenic ASU and it exits the ASU at ambient pressure and temperature with 95 percent purity on a mole fraction basis. ASU power requirements of 200 kWh/tonne of oxygen produced were assumed. Table 3-1 shows the assumed ASU oxygen composition.

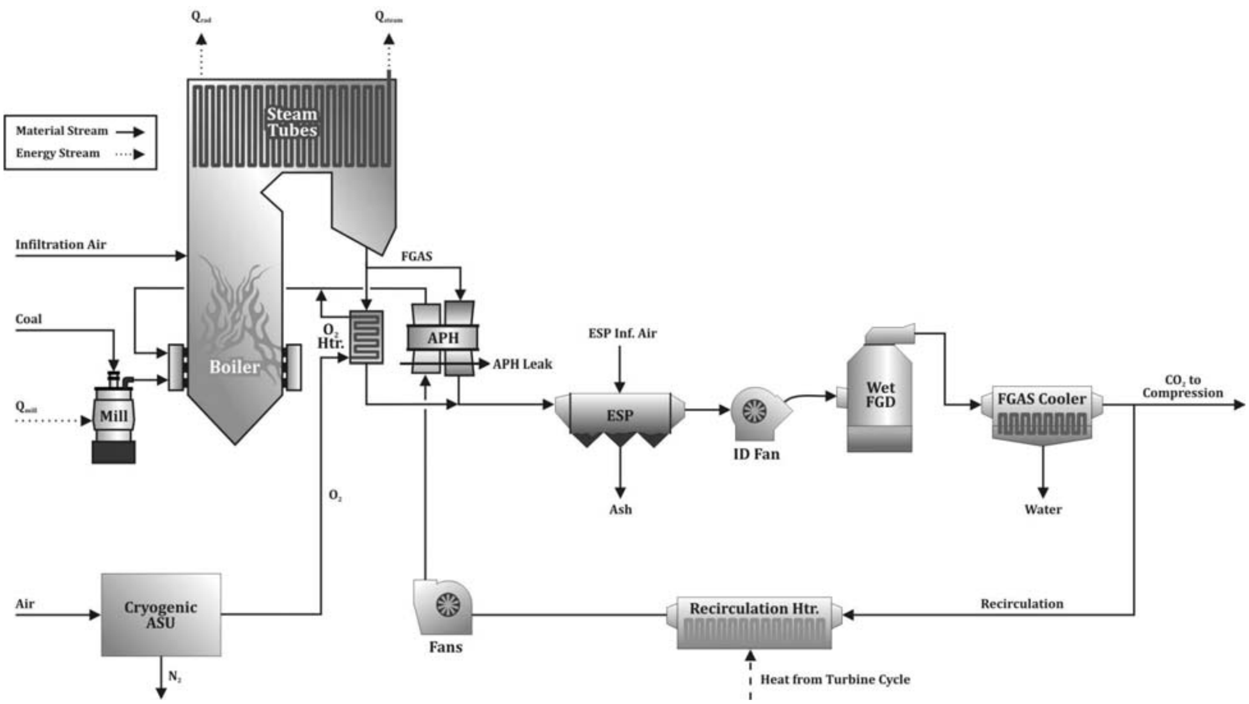

Figure 3-1: Diagram of Oxy-Fired Boiler

Table 3-1: Assumed Composition of O_2 Stream Leaving the ASU

Component	mol-frac
Ar	0.0340
N_2	0.0162
O_2	0.9498

Both the oxygen and recirculated flue gas are preheated before entering the furnace. A regenerative air preheater with six percent leakage heats the recirculated flue gas stream and a tubular heat exchanger heats the oxygen stream before it is mixed with recirculated flue gas downstream of the APH.

Forced draft fans, with fan pressure increases of 0.3 psia, are used to pressurize the oxygen and recirculated gas streams. An ID fan is located after the ESP and a 1.3 psia flue gas pressure increase was assumed. To achieve relatively pure CO_2 in the flue gas, infiltration air into the boiler was limited to one percent of the mass flow rate leaving the furnace (Figure 3-2). The flue gas is assumed to leave the wet FGD as a saturated mixture at 135°F and it then flows through a flue gas cooler which reduces the flue gas temperature to 100°F. The recirculated flue gas, representing 75 percent of the flue gas, is separated from the flue gas after the gas cooler. In the Base Case (The term "Base Case" refers to the oxy-fired unit without thermal integration.), the recirculated stream is then reheated to 150°F using steam extracted from the steam turbine cycle. Table 3-2 summarizes the process conditions used in the simulations and Table 3-3 shows ASPEN (Ref. 4) results for the boiler for the Base Case.

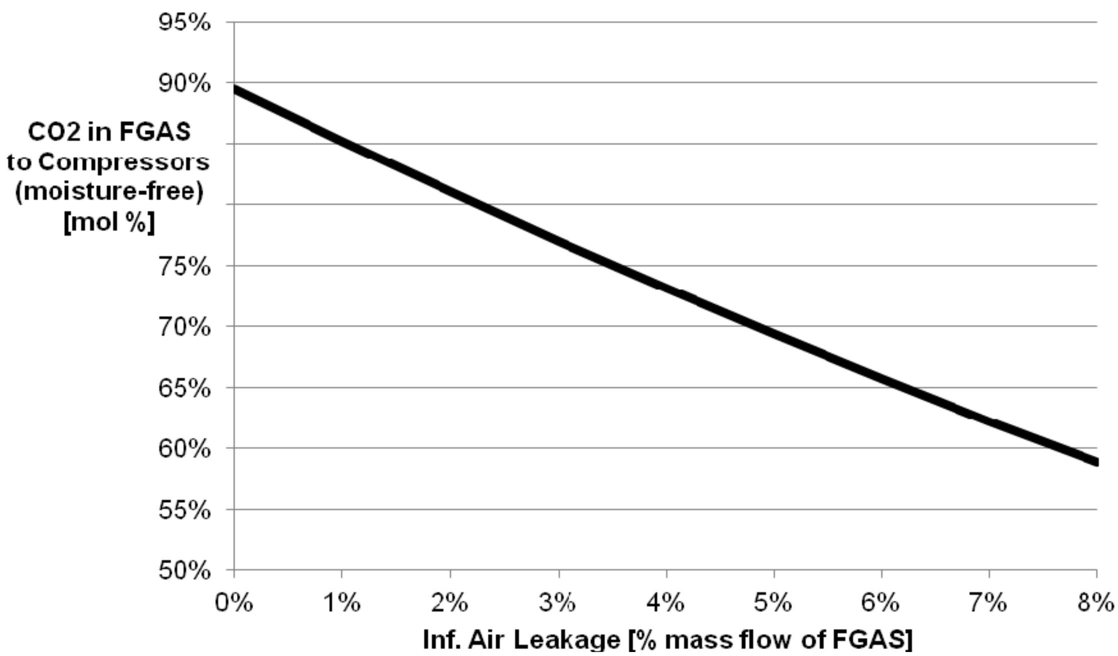

Figure 3-2: Effect of Boiler Air In-Leakage on Flue Gas CO_2 Concentration

A supercritical reheat, regenerative steam turbine cycle (Figure 3-3), was used in the analysis, with design values for turbine stage efficiencies; main steam and hot reheat steam flow rates, temperatures and pressures; steam extraction flow rates and pressures; and condenser pressure taken from the OEM's Turbine Kit. The turbine cycle was modeled using ASPEN and the resulting Base Case Model results are shown in Tables 3-4 and 3-5.

Table 3-2: Oxy-Fired Boiler Process Conditions

Coal	PRB
HHV [Btu/lb]	8426
Inf. Air Mass Flow [lb/lb_{FGAS}]	1.0%
APH Leakage Flow [lb/lb_{FGAS}]	6.0%
O_2 in FGAS [mol-frac]	3.5%
FGD SO_2 Removal Rate [%]	96.6%
Recirculation Rate [%]	75.0%
T_{FGAS} After Boiler [°F]	600
T_{FGAS} After APH [°F]	300
FGD T_{exit} [°F]	135
FGAS Cooler T_{exit} [°F]	100
Rec. Heater T_{exit} [°F]	150
Rec. Fan P_{out} [psia]	15.0
O_2 Fan P_{out} [psia]	15.0
ID Fan P_{out} [psia]	16.0
Isentropic Fan Efficiency [%]	80.0%
Q_{Steam} [Btu/hr]	-4.775E+09
Q_{Mill} [Btu/lb_{coal}]	18.05
Q_{Rad} [Btu/lb_{coal}]	-67.41

Three CO_2 compressors were analyzed: an Inline, an Integrally geared and a RAMGEN compressor. In each case, it was assumed the CO_2 temperature was 100°F at the inlet to the first compressor stage, with a 120°F CO_2 temperature entering each successive stage. The 120°F stage inlet temperatures allowed higher temperature cooling water to be used in the intercoolers and kept the compressed flue gas mixture well clear of the CO_2 saturation dome.

Table 3-3: Oxy-Fired Boiler Model Results

Coal Flow [lb/hr]	643,343
Q_{coal} [Btu/hr]	5.421E+09
Q_{Steam} [Btu/hr]	4.776E+09
Boiler Efficiency [%]	88.10%
$P_{Rec\ Fan}$ [kW]	890
$P_{O2\ Fan}$ [kW]	255
$P_{ID\ Fan}$ [kW]	7,085
Total Fan Power [kW]	8,230
Pulverizer Power [kW]	3,405
Aux. Power [kW]	15,000
SS Power [kW]	26,635
Flue Gas Composition	[mol-frac]
AR	0.0287
CO_2	0.6894
H_2O	0.1896
N_2	0.0566
O_2	0.035
SO_2	0.0006

Figures 3-4 to 3-9 show process diagrams and TS diagrams for the three compressors. The inline compressor requires three stages with intercoolers and a post cooler. The flow rate ratio of cooling water to CO_2 in each intercooler was assumed to be 0.5 for the Inline compressor (Figure 3-4 and 3-5).

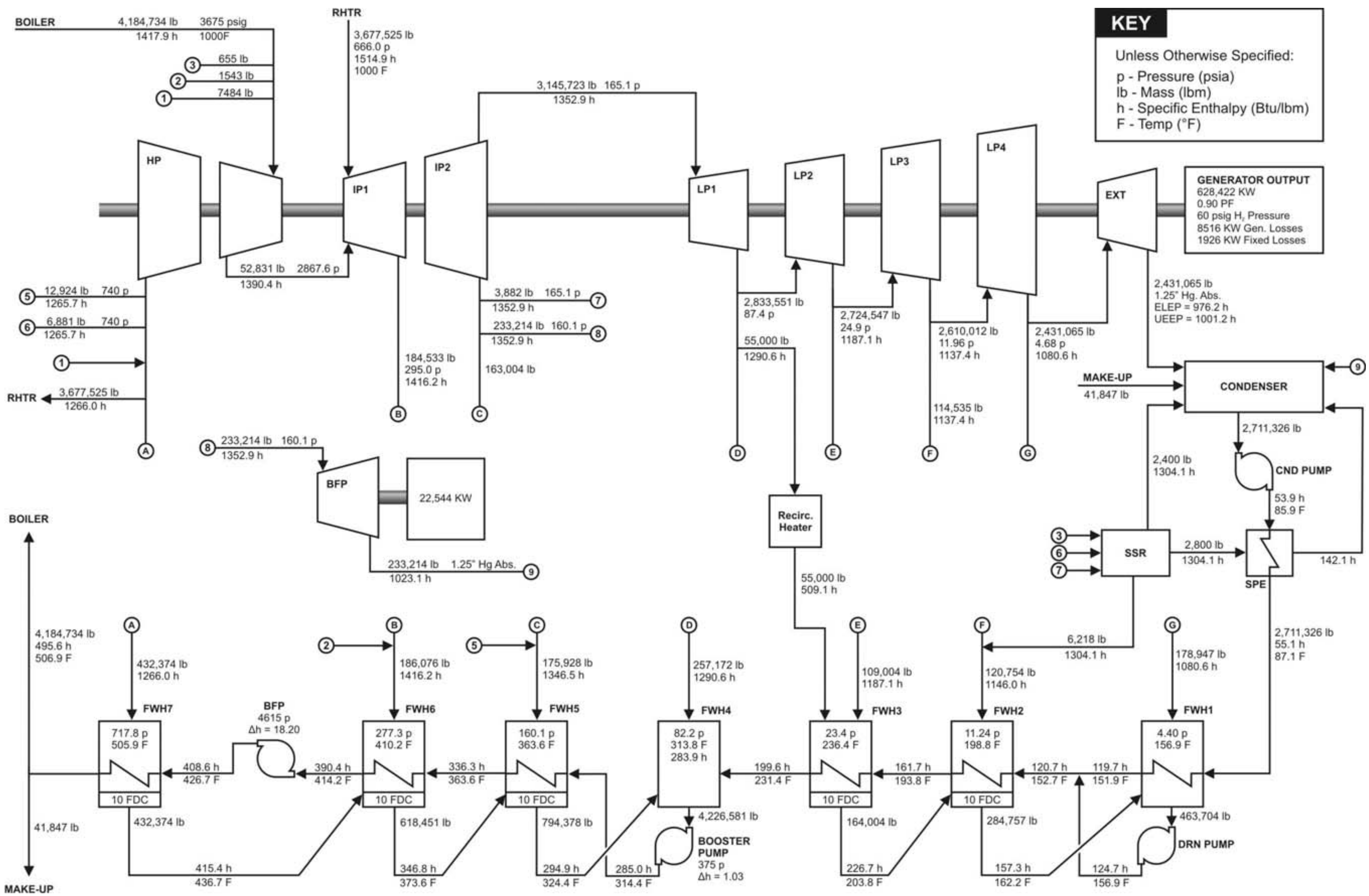

Figure 3-3: BASE Case Supercritical Steam Cycle

Table 3-4: Closed Feedwater Heater Design Conditions and Heat Duty Results

	Mass Flow Water [lb/hr]	$h_{f\,in}$ [Btu/lb]	$h_{f\,out}$ [Btu/lb]	Heat Duty [kBtu/hr]
FWH 1	2,675,463	55.1	119.7	172,835
FWH 2	3,175,031	120.5	161.7	130,811
FWH 3	3,175,031	161.7	199.6	120,334
FWH 5	4,226,581	285	336.3	216,824
FWH 6	4,226,581	336.3	390.4	228,658
FWH 7	4,226,581	408.6	495.6	367,713

Table 3-5: Supercritical Steam Turbine Cycle Model Results

	Turbine Kit	ASPEN	% Diff.
Main Steam Flow [lb/hr]	4,184,734	4,184,734	0.00%
Reheat Mass Flow [lb/hr]	3,677,525	3,677,526	0.00%
Δh Main Steam [Btu/lb]	922.3	919.5	0.30%
Δh Reheat [Btu/lb]	248.9	252.3	1.37%
Q_{steam} [Btu/hr]	4.775E+09	4.776E+09	0.02%
Turbine Power [kW]	635,900	635,817	0.01%
Generated Power [kW]	625,496	625,644	0.02%
Pump Power [kW]	1,712	1,712	0.01%
Net Power [kW]	623,784	623,932	0.02%
Turbine Cycle HR [Btu/kWh]	7,655	7,655	0.00%

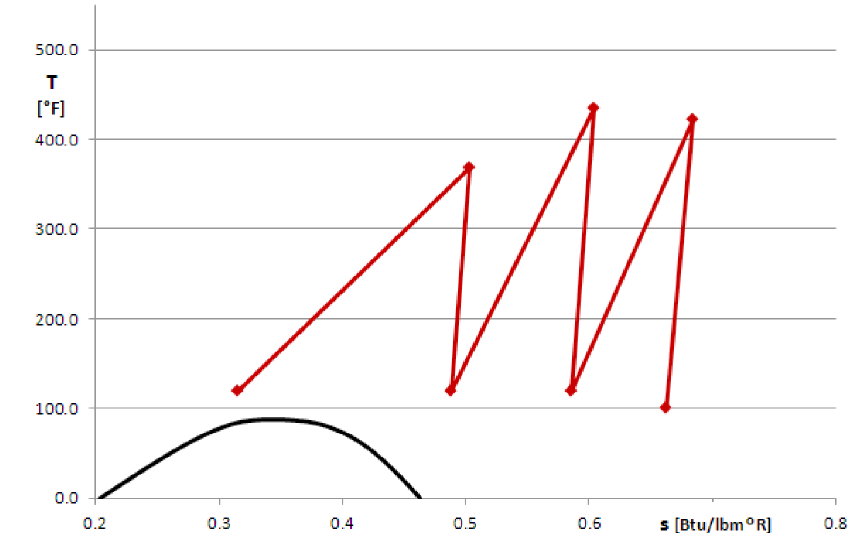

Figure 3-4: Inline 4 T-S Compression Plot for Pure CO_2

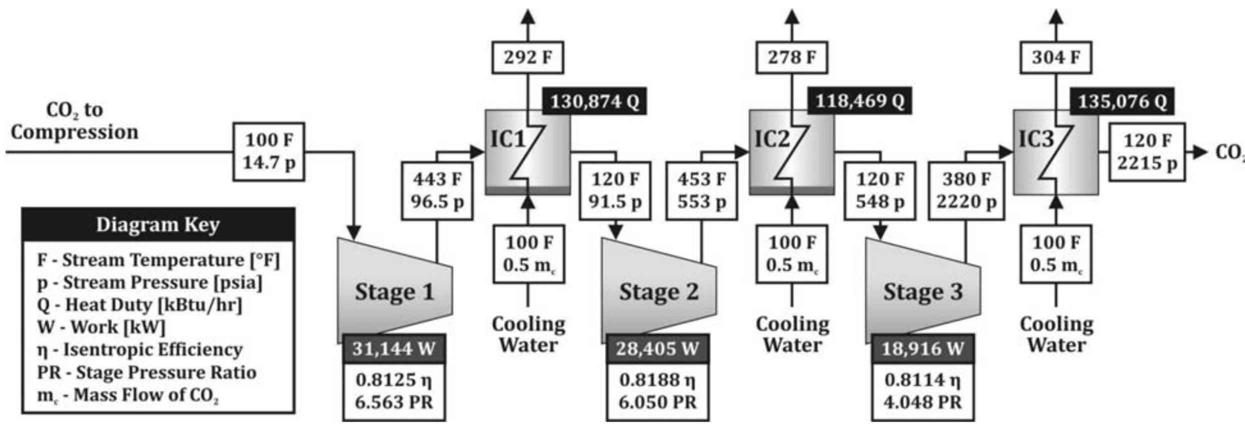

Figure 3-5: Graphical Representation of Inline 4 Compressor with Intercoolers

Since maximum stage pressure ratios of 10/1 were assumed for the RAMGEN compressor, a three-stage RAMGEN compressor would be needed to compress the CO_2 from 14.7 to 2215 psia. A first stage, with a 23.6 psia discharge pressure, was used along with second and third stages with 10/1 pressure ratios (Figures 3-6 and 3-7).

A seven-stage integrally geared compressor was assumed, and following the stage layout specified by the manufacturer, it was assumed there is no intercooling between the sixth and seventh stages (Figures 3-8 and 3-9).

Table 3-6 shows the resulting compressor power requirements and the intercooler heat duty for the three compressors. Of the three compressors, the RAMGEN compressor has the largest predicted compressor power and intercooler heat duty, while the Integrally Geared compressor has the smallest. As noted in Chapter 2, performance differences between the compressors are strong functions of stage efficiencies and numbers of stages. In some cases, compressor isentropic stage efficiencies used in this study are based on stage efficiencies provided by the manufacturers. In cases where isentropic stage efficiencies were not provided, stage efficiencies were calculated from design data provided by the manufacturers.

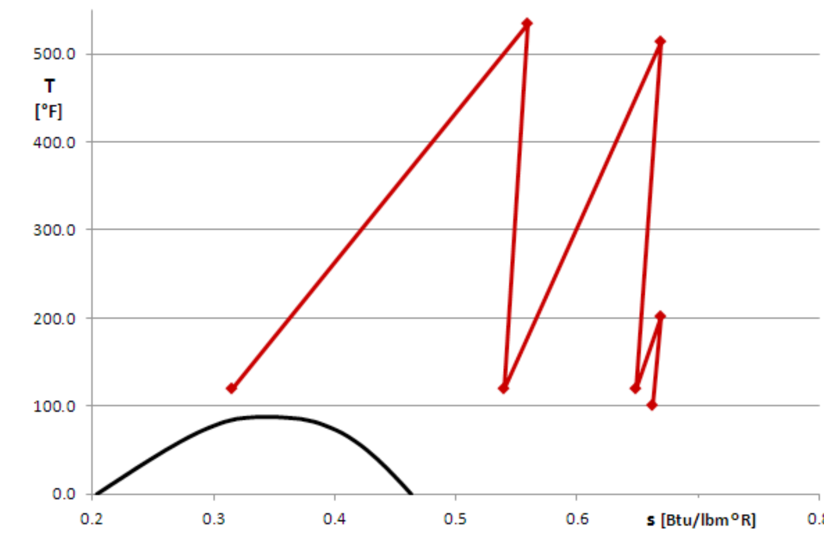

Figure 3-6: Ramgen T-S Compression & Intercooling Plot for Pure CO_2

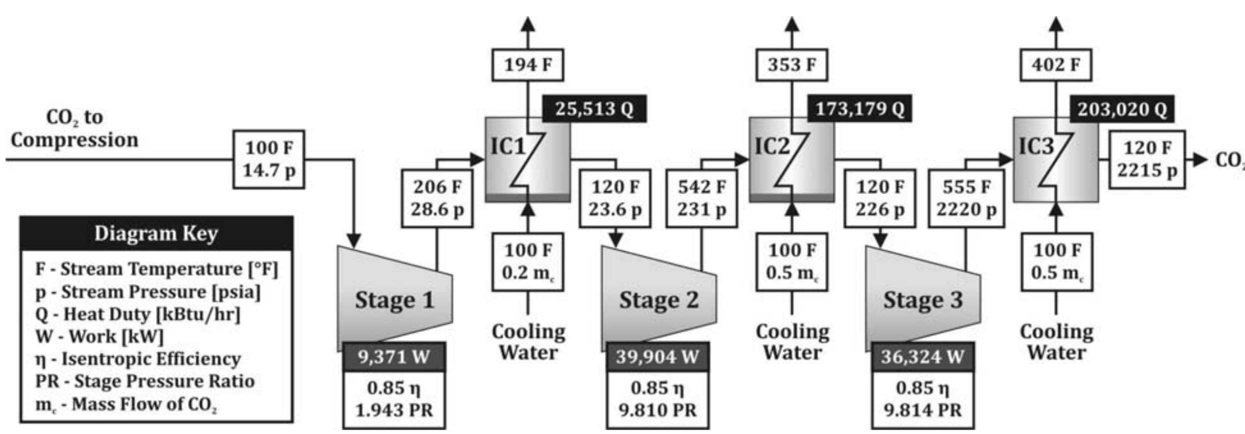

Figure 3-7: Graphical Representation of Ramgen Compressor with Intercoolers

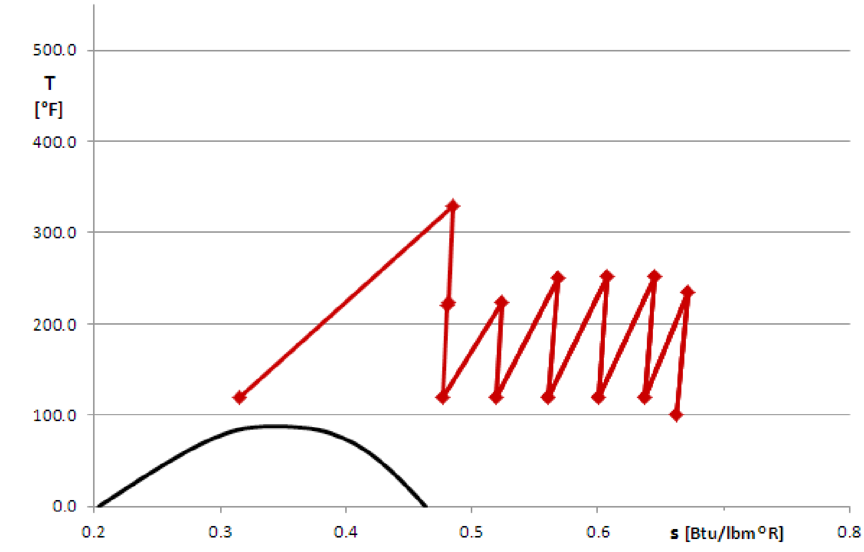

Figure 3-8: IG1 T-S Compression & Intercooling Plot for Pure CO_2

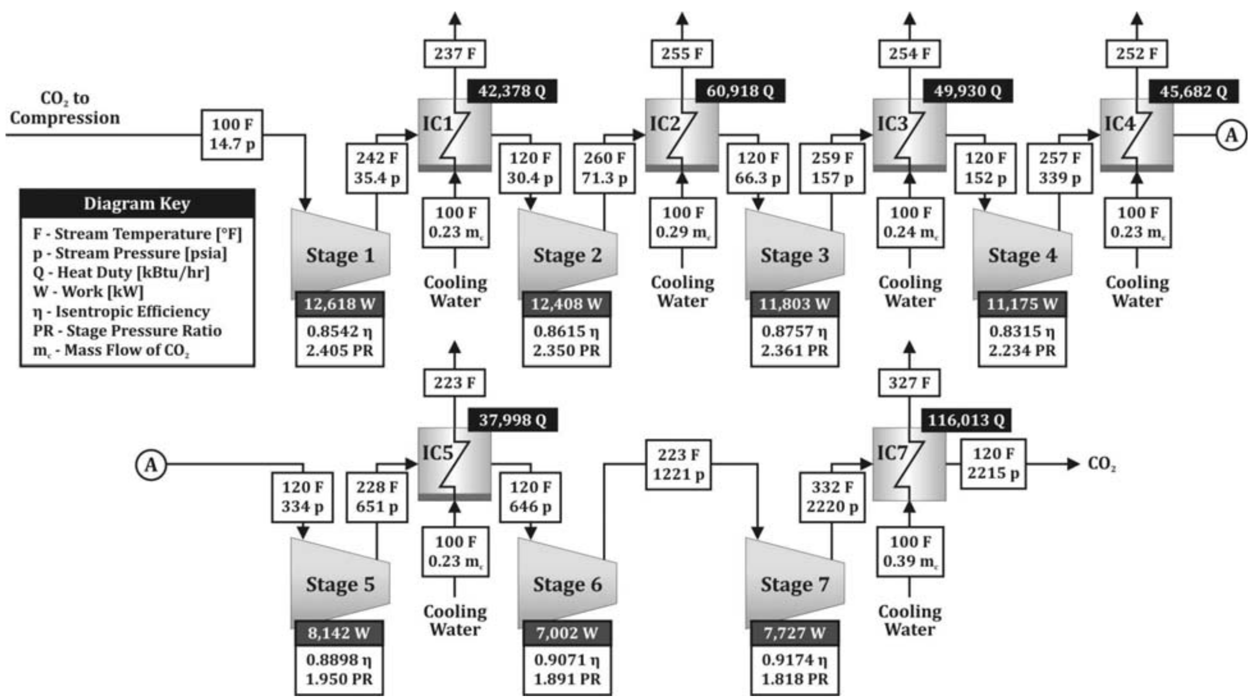

Figure 3-9: IG 1 Compressor with Intercoolers

Table 3-6: Compressor Power and Available Heat for Base Case Oxy-Fired Unit

Compressor Power (MW)			
	Lignite	**PRB**	**Illinois #6**
Inline 4	75.0	78.9	71.2
Integrally Geared	67.7	71.3	64.3
RAMGEN	81.8	86.1	77.7
Available Heat (kBtu/hr)			
	Lignite	**PRB**	**Illinois #6**
Inline 4	365,016	386,134	348,468
Integrally Geared	334,865	354,360	319,837
RAMGEN	380,971	402,970	363,660
Gas Flow Rate to Compressors (10^6 lbm/hr)			
	Lignite	**PRB**	**Illinois #6**
	1.274	1.346	1.213

This report includes results of the effects of predrying low rank coals on unit performance. In these cases, it was assumed coal drying is carried out in a fluidized bed dryer, with the fluidizing gas being heated air and additional energy for drying being provided by an in-bed tube bundle with hot water flowing through the bundle. An energy and mass conservation model for the fluidized bed dryer (Ref. 5) was used to analyze the effects of using compressor waste heat to predry coal. Figure 3-10 illustrates the general drying characteristics of the fluidized bed drying system.

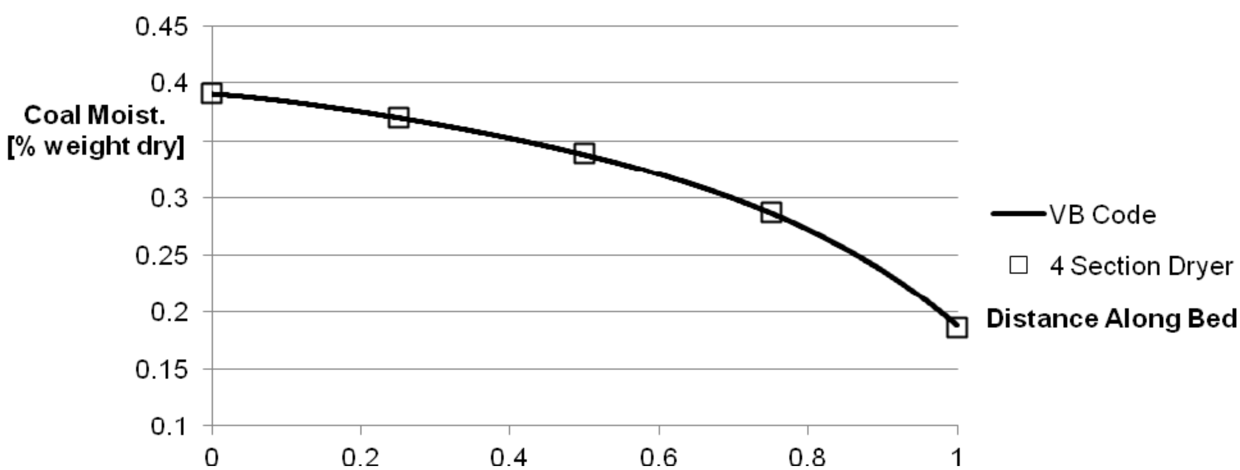

Figure 3-10: Coal Moisture Across Bed

Performance of Base Oxycombustion Plant

This section describes the results of ASPEN simulations performed for the BASE case oxy-fired unit with PRB coal. The Oxycombustion Boiler Stream Results are shown in Figure 3-11 and Table 3-7. Stream information (compositions, temperatures, pressures and flow rates), compressor stage power and intercooler heat transfer are given for the Inline compressor in Figure 3-12 and Table 3-8. The plant results for the Base Case with PRB coal and an Inline compressor are given in Table 3-9.

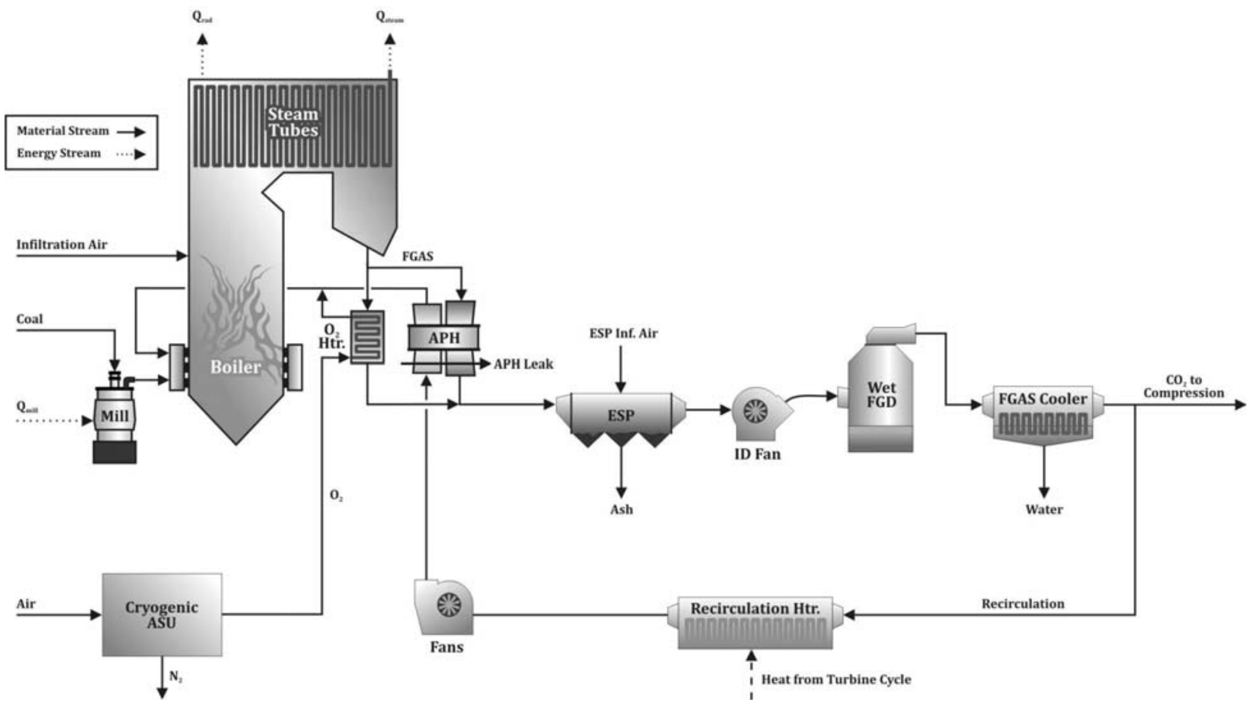

Figure 3-11: Oxycombustion Boiler Process Diagram

Table 3-7: Oxycombustion Boiler Stream Results

	1 Coal	**2** Oxy	**3** Hot Oxid.	**4** Inf. Air	**5** FGAS	**6** After APH	**7** After ID Fan	**8** After FGD	**9** After Cool.	**10** To Comp.	**11** Recirc.
Temp [°F]	77	77	521	77	600	292	309	135	100	100	100
Pressure [psia]	14.7	14.7	15.0	14.7	14.7	14.7	16.0	14.8	14.7	14.7	14.7
Mass Flow [lb/hr]	643,343	1,039,033	4,752,891	54,508	5,410,169	5,735,308	5,735,308	5,697,347	5,385,325	1,346,331	4,038,994
Composition	[mol-frac]										
AR	-	0.0340	0.0333	0.0000	0.0287	0.0289	0.0289	0.0293	0.0331	0.0331	0.0331
CO_2	-	0.0000	0.5880	0.0000	0.6894	0.6950	0.6950	0.7037	0.7956	0.7956	0.7956
H_2O	-	0.0000	0.0484	0.0203	0.1896	0.1831	0.1831	0.1735	0.0654	0.0654	0.0654
N_2	-	0.0162	0.0525	0.7740	0.0566	0.0571	0.0571	0.0578	0.0654	0.0654	0.0654
O_2	-	0.9498	0.2777	0.2057	0.0350	0.0353	0.0353	0.0357	0.0404	0.0404	0.0404
SO_2	-	0.0000	0.0000	0.0000	0.0006	0.0006	0.0006	0.0000	0.0000	0.0000	0.0000

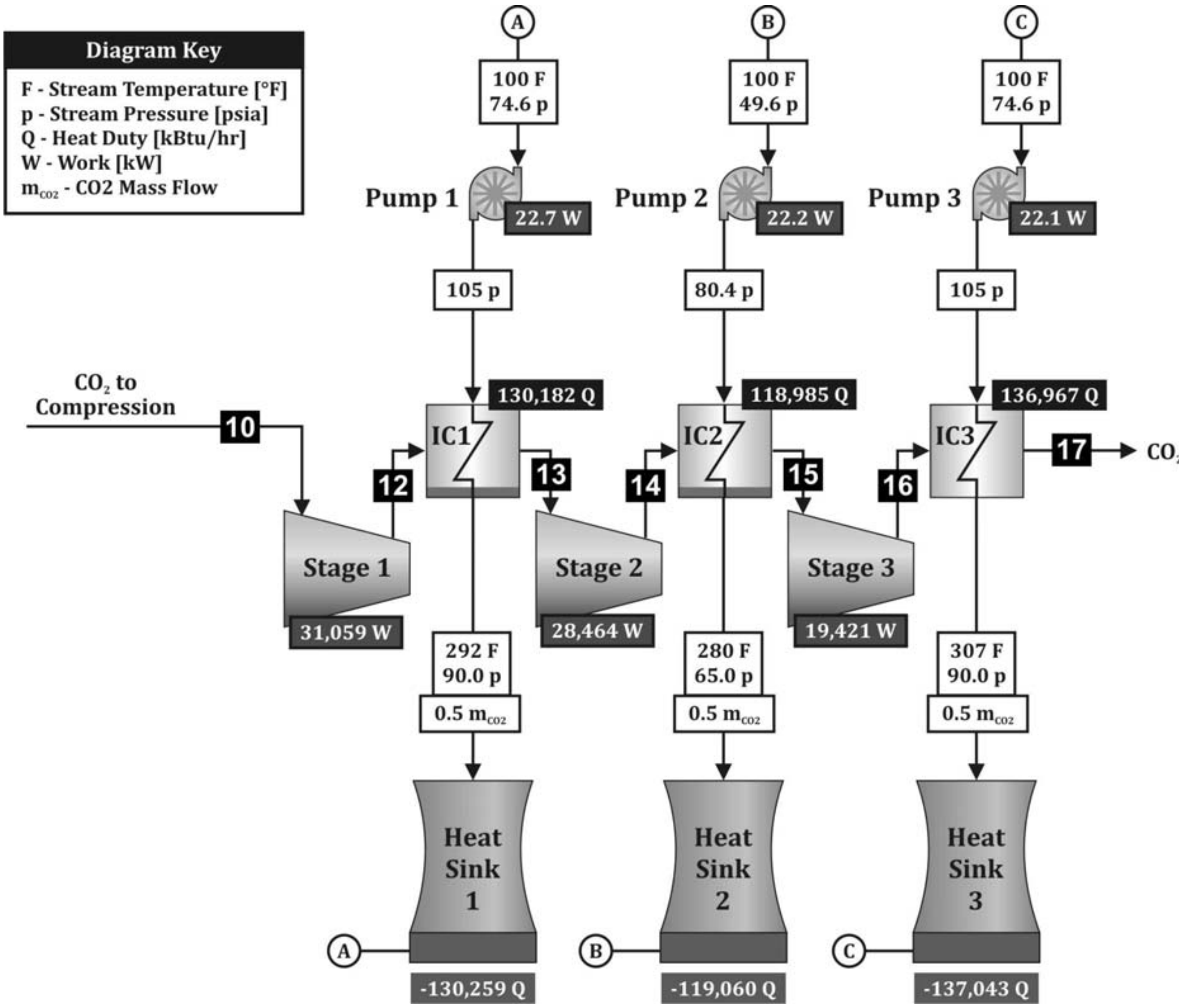

Figure 3-12: Inline 4 Compression and Intercooling – BASE

Table 3-8: Inline 4 Stream Information – BASE

	12 After Comp. 1	**13** Before Comp. 2	**14** After Comp. 2	**15** Before Comp. 3	**16** After Comp. 3	**17** After IC 3
Temp [°F]	442	120	453	120	384	120
Pressure [psia]	96.5	91.5	553.4	548.4	2,220	2,215
Mass Flow [lb/hr]	1,346,331	1,318,529	1,318,529	1,309,866	1,309,866	1,309,866
Composition	[mol-frac]					
AR	0.0331	0.0347	0.0347	0.0353	0.0353	0.0353
CO_2	0.7956	0.8345	0.8345	0.8473	0.8473	0.8473
H_2O	0.0654	0.0198	0.0198	0.0048	0.0048	0.0048
N_2	0.0654	0.0686	0.0686	0.0696	0.0696	0.0696
O_2	0.0404	0.0423	0.0423	0.0430	0.0430	0.0430
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

Table 3-9: Plant Results – BASE Case – PRB Coal and Inline 4 Compressor

Coal Flow [lb/hr]	643,343
HHV [Btu/lb]	8,426
Q_{coal} [Btu/hr]	5.421E+09
Main Steam Mass Flow [lb/hr]	4,184,734
Reheat Mass Flow [lb/hr]	3,677,526
Q_{Main} [Btu/hr]	3.848E+09
Q_{Reheat} [Btu/hr]	9.282E+08
Q_{Steam} [Btu/hr]	4.776E+09
Gross Power [kW]	628,422
Pump Power [kW]	1,711
Net TC Power [kW]	626,711
Rec. Fan Power [kW]	890
O_2 Fan Power [kW]	255
ID Fan Power [kW]	7,085
Pulv. Power [kW]	3,405
Auxiliary Power [kW]	15,000
ASU Power [kW]	94,458
Compressor Power [kW]	78,944
Intercooler Pump Power [kW]	67
Station Service Power [kW]	200,103
Net Unit Power [kW]	426,608
IC Heat Available [kBtu/hr]	386,134
Boiler Efficiency [%]	88.11
TC Heat Rate [Btu/kWh]	7,621
Net Unit Heat Rate [Btu/kWh]	12,707
Unit Efficiency [%]	26.85

Effects of Thermal Integration of Compressor Heat

Analyses were performed to determine the impacts of transferring heat recovered from the Inline 4 compressor intercoolers to the cold recirculated flue gas, to various feedwaters and to the coal drying system (Figure 3-13). This included analyses in which compressor heat was transferred separately to each of the three types of heat sinks and then to combinations of heat sinks.

Recirculated Flue Gas Heating

Table 3-10, which compares the heat required to increase the recirculated flue gas temperature from 100°F to 150°F to the amounts of heat available from the three Inline compressor stages and the cooling water temperatures leaving the various intercoolers, shows that there would be more than enough compressor heat available from just the first intercooler. As a result, the cooling water stream from the first compressor intercooler was connected to the flue gas heater. The cooling water flowed from there to a cooling tower to reduce its temperature to 100°F and dissipate 86,000 kBtu/hr and it then reentered the intercooler (Figure 3-14 and Table 3-11). To determine the heat rate impact, the analyses were performed with the steam turbine extraction flow to the recirculated flue gas heater decreased to zero, which increased the steam flow through successive LP turbine stages and increased net power. Table 3-12 shows the effects on unit performance for this case.

Coal Drying

The PRB coal used in this investigation has an inlet moisture level of 28.09 lbm moisture/lbm wet coal, and it was assumed the coal moisture level would be reduced to 15 lbm moisture/lbm wet coal in a fluidized bed dryer. Compressor heat is used to preheat the fluidization air and provide heat for the in-bed heat exchanger (Figure 3-15 shows the dryer and auxiliary components). The addition of a drying system would result in more efficient combustion, which would reduce the amount of coal burned from

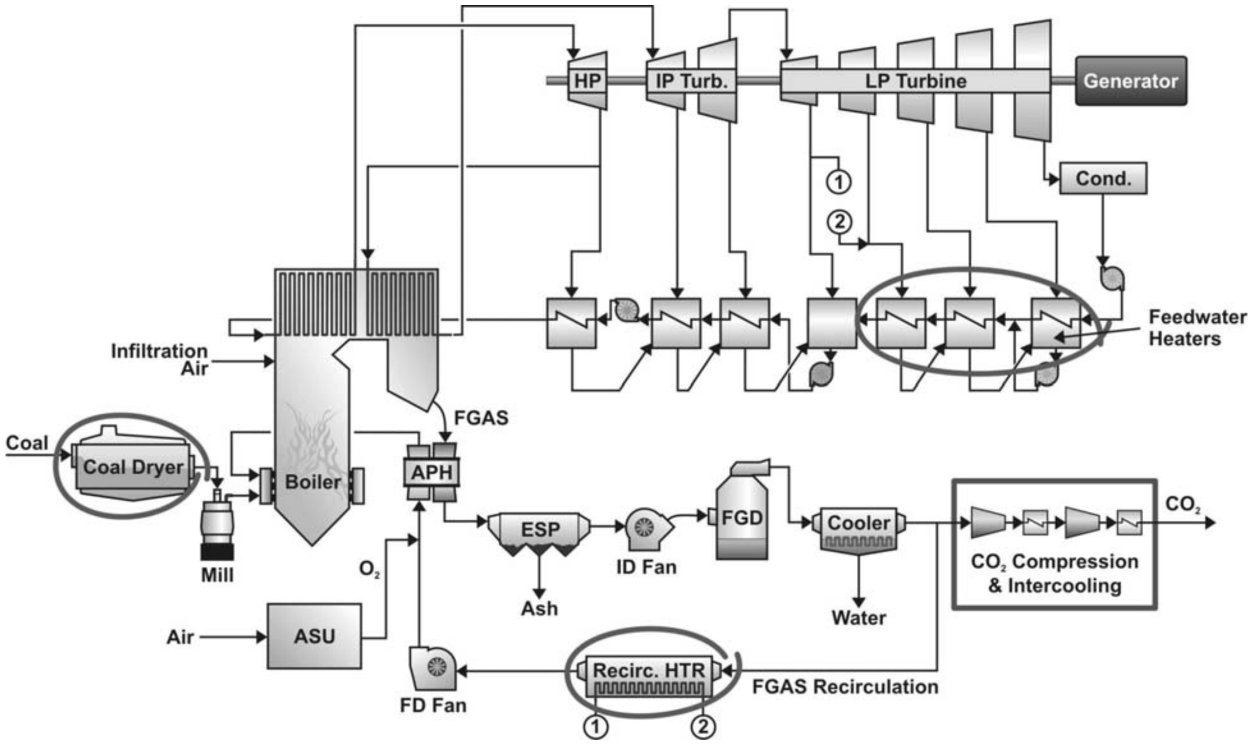

Figure 3-13: Complete Oxycombustion Plant with Heat Integration Options & Locations

Table 3-10: Heat and Water Temperatures Available for Recirculation Heating. Inline 4 Compressor.

	Heat Required [kBtu/hr]	Required Exit Temp. [°F]
Recirc. Heater	42,412	150
	Heat Available [kBtu/hr]	**Available Water Temp. [°F]**
IC 1	130,190	292
IC 2	118,991	279
IC 3	136,965	307
Total	386,146	-

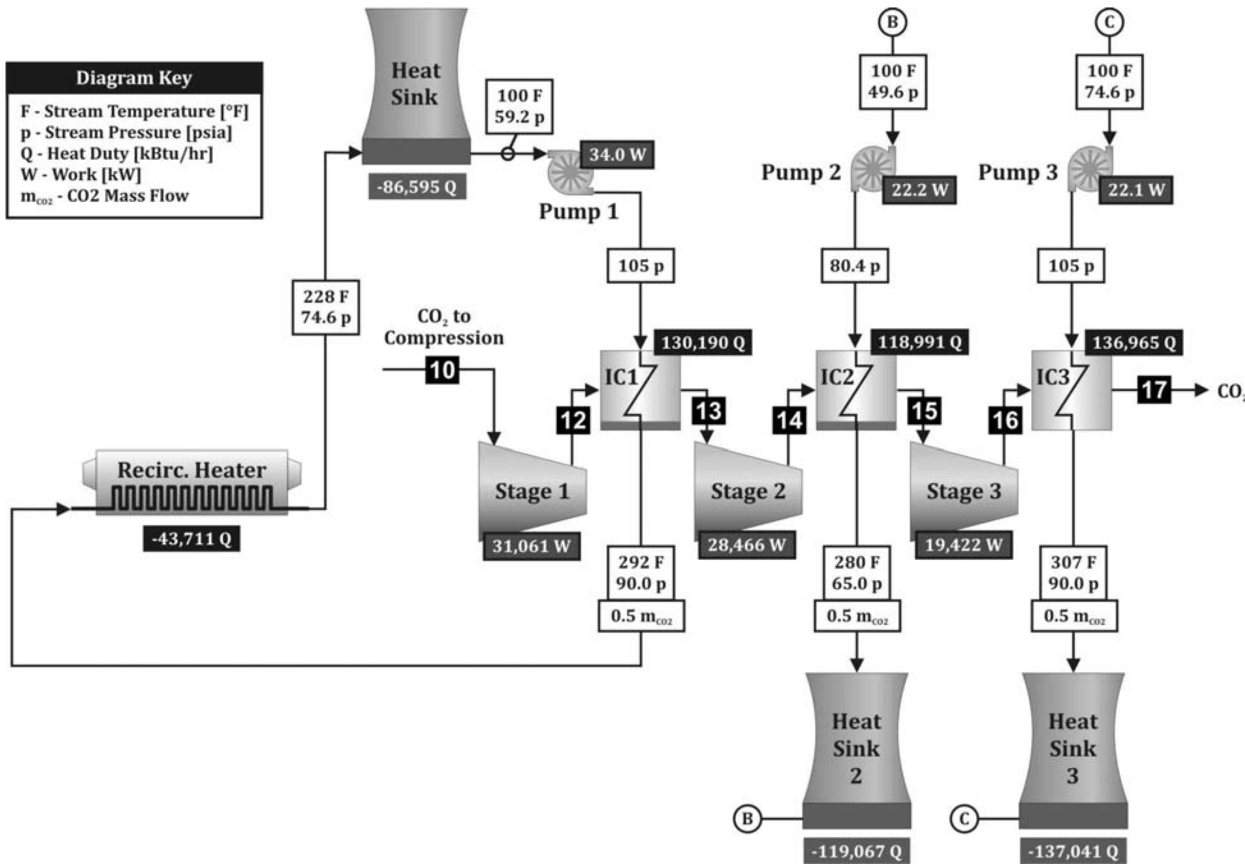

Figure 3-14: Inline 4 Compression and Intercooling – Rec. Heating

Table 3-11: Inline 4 Stream Information – Rec. Heating

	12 After Comp. 1	**13** Before Comp. 2	**14** After Comp. 2	**15** Before Comp. 3	**16** After Comp. 3	**17** After IC 3
Temp [°F]	442	120	453	120	384	120
Pressure [psia]	96.5	91.5	553.4	548.4	2,220	2,215
Mass Flow [lb/hr]	1,346,391	1,318,587	1,318,587	1,309,923	1,309,923	1,309,923
Composition	[mol-frac]					
AR	0.0331	0.0347	0.0347	0.0353	0.0353	0.0353
CO_2	0.7956	0.8344	0.8344	0.8472	0.8472	0.8472
H_2O	0.0654	0.0198	0.0198	0.0048	0.0048	0.0048
N_2	0.0654	0.0685	0.0685	0.0696	0.0696	0.0696
O_2	0.0404	0.0424	0.0424	0.0431	0.0431	0.0431
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

Table 3-12: Plant Results – Rec. Heating Case with PRB Coal and Inline 4 Compressor

	Boiler & Steam Turbine Cycle		
	Rec. HT	**BASE**	**% Diff**
Coal Flow [lb/hr]	643,331	643,343	0.00%
HHV [Btu/lb]	8,426	8,426	0.00%
Q_{coal} [Btu/hr]	5.421E+09	5.421E+09	0.00%
Main Steam Mass Flow [lb/hr]	4,184,734	4,184,734	0.00%
Reheat Mass Flow [lb/hr]	3,677,526	3,677,526	0.00%
Q_{Main} [Btu/hr]	3.848E+09	3.848E+09	0.00%
Q_{Reheat} [Btu/hr]	9.282E+08	9.282E+08	0.00%
Q_{Steam} [Btu/hr]	4.776E+09	4.776E+09	0.00%
Gross Power [kW]	632,011	628,422	0.57%
Pump Power [kW]	1,710	1,711	-0.06%
Net TC Power [kW]	630,301	626,711	0.57%
Rec. Fan Power [kW]	890	890	0.00%
O_2 Fan Power [kW]	255	255	0.00%
ID Fan Power [kW]	7,085	7,085	0.00%
Pulv. Power [kW]	3,405	3,405	0.00%
Auxiliary Power [kW]	15,000	15,000	0.00%
ASU Power [kW]	94,462	94,458	0.00%
Compressor Power [kW]	78,949	78,944	0.01%
Intercooler Pump Power [kW]	78	67	16.42%
Station Service Power [kW]	200,124	200,103	0.01%
Net Unit Power [kW]	430,176	426,608	0.84%
IC Heat Available [kBtu/hr]	386,146	386,134	0.00%
Boiler Efficiency [%]	88.11	88.11	0.00%
TC Heat Rate [Btu/kWh]	7,577	7,621	-0.58%
Net Unit Heat Rate [Btu/kWh]	12,601	12,707	-0.83%
Unit Efficiency [%]	27.08	26.85	0.23%

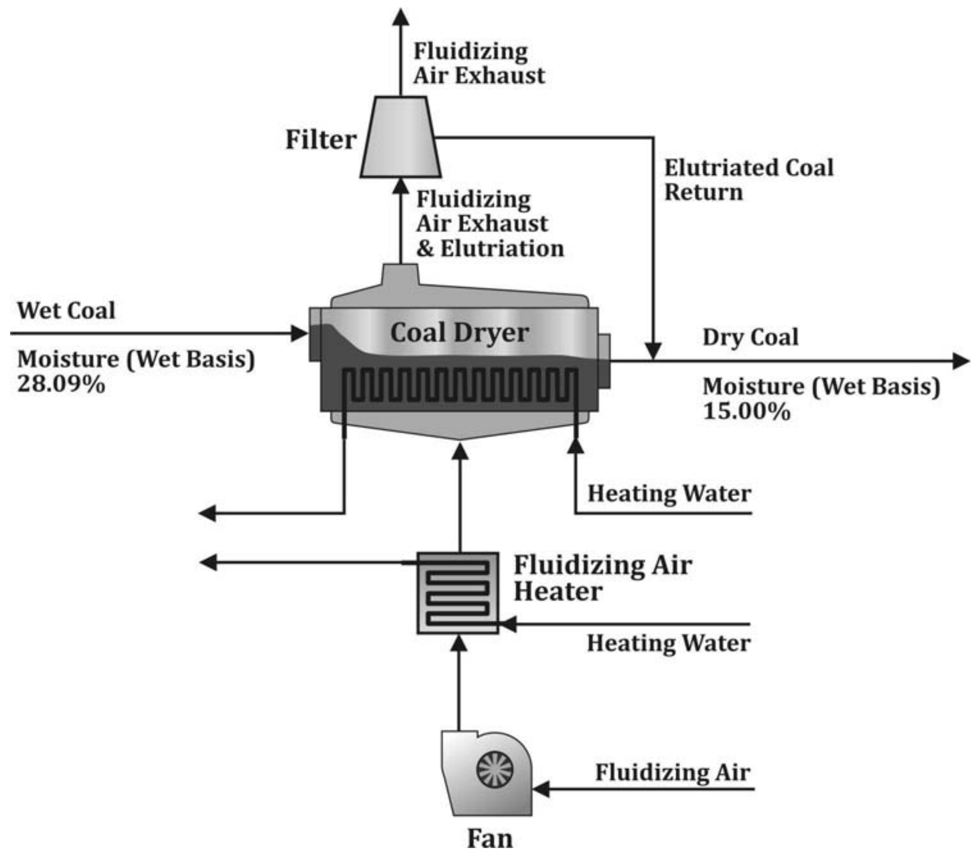

Figure 3-15: Coal Dryer & Auxiliaries

that shown in the BASE case, and this would reduce the rate of CO_2 formation and the compressor power and waste heat. Figure 3-16 and Table 3-13 show a diagram of the coal drying system for an Inline compressor and the CO_2 stream information. Table 3-14 shows the effects of coal drying on unit performance for the Inline compressor case. The major performance impact of coal drying is to reduce the coal feed rate and the coal Btu input to the boiler. This also results in small percentage changes in pulverizer power, ASU power and CO_2 compressor power (Table 3-15).

Boiler Feedwater Heating

The Base Case supercritical steam turbine cycle is presented in Figure 3. Seven feedwater heaters are fed by steam extractions after the HP, IP, and first four LP turbines. The last six feedwater heaters all operate with a 10°F temperature difference between the cold inlet and hot outlet temperatures. Steam extractions to FWH3 through FHW1 are cascaded from one feedwater heater to the next until they are mixed with the feedwater downstream of the drain pump. Likewise, extractions to FWH7 through FWH5 are cascaded through the heaters until they empty into FWH4.

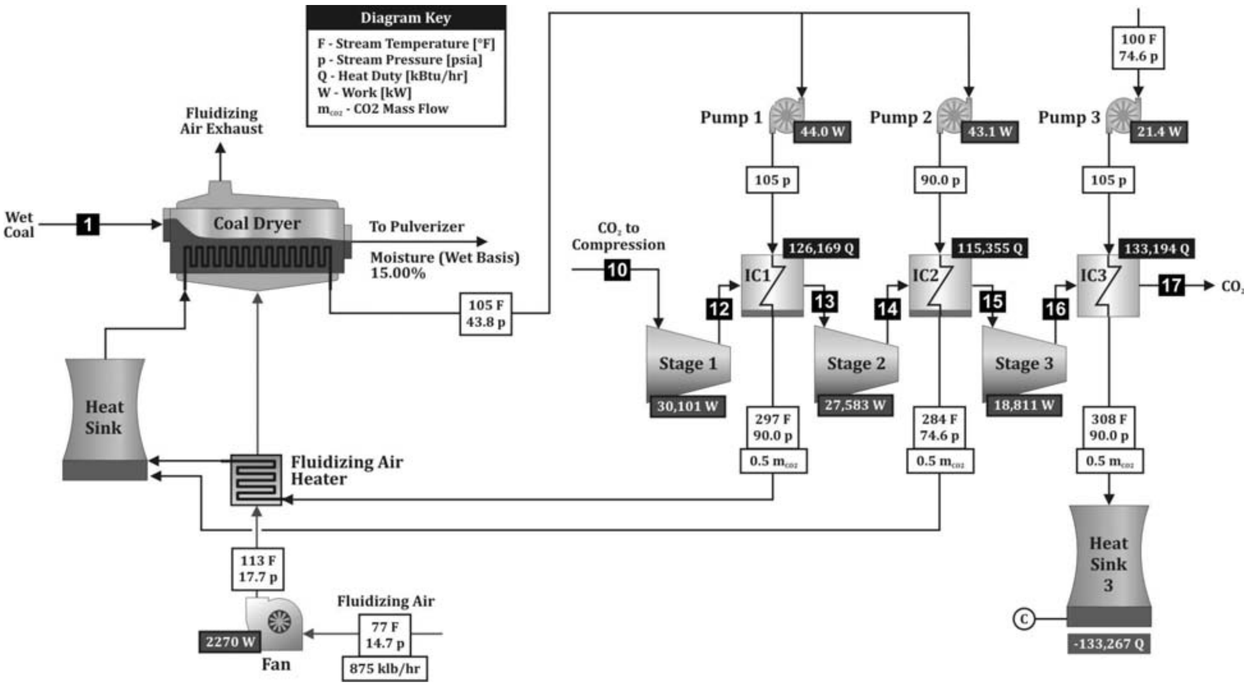

Figure 3-16: Inline 4 Compression and Intercooling – Coal Drying

Table 3-13: Inline 4 Stream Information – Coal Drying

	12 After Comp. 1	**13** Before Comp. 2	**14** After Comp. 2	**15** Before Comp. 3	**16** After Comp. 3	**17** After IC 3
Temp [°F]	441	120	453	120	384	120
Pressure [psia]	96.5	91.5	553.4	548.4	2,220	2,215
Mass Flow [lb/hr]	1,305,919	1,278,971	1,278,971	1,270,575	1,270,575	1,270,575
Composition	[mol-frac]					
AR	0.0332	0.0348	0.0348	0.0353	0.0353	0.0353
CO_2	0.7979	0.8368	0.8368	0.8497	0.8497	0.8497
H_2O	0.0654	0.0198	0.0198	0.0048	0.0048	0.0048
N_2	0.0647	0.0678	0.0678	0.0689	0.0689	0.0689
O_2	0.0388	0.0407	0.0407	0.0413	0.0413	0.0413
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

Table 3-14: Plant Results – Coal Drying Case with PRB Coal and Inline 4 Compressor

	Boiler & Steam Turbine Cycle		
	Coal Drying	**BASE**	**% Diff**
Coal Flow [lb/hr]	625,286	643,343	-2.81%
HHV [Btu/lb]	8,426	8,426	0.00%
Q_{coal} [Btu/hr]	5.269E+09	5.421E+09	-2.80%
Main Steam Mass Flow [lb/hr]	4,184,734	4,184,734	0.00%
Reheat Mass Flow [lb/hr]	3,677,526	3,677,526	0.00%
Q_{Main} [Btu/hr]	3.848E+09	3.848E+09	0.00%
Q_{Reheat} [Btu/hr]	9.282E+08	9.282E+08	0.00%
Q_{Steam} [Btu/hr]	4.776E+09	4.776E+09	0.00%
Gross Power [kW]	628,422	628,422	0.00%
Pump Power [kW]	1,711	1,711	0.00%
Net TC Power [kW]	626,711	626,711	0.00%
Rec. Fan Power [kW]	862	890	-3.15%
O_2 Fan Power [kW]	248	255	-2.75%
ID Fan Power [kW]	6,619	7,085	-6.58%
Coal Dryer Fan Power [kW]	2,270	-	-
Pulv. Power [kW]	2,800	3,405	-17.77%
Auxiliary Power [kW]	15,000	15,000	0.00%
ASU Power [kW]	91,670	94,458	-2.95%
Compressor Power [kW]	76,495	78,944	-3.10%
Intercooler Pump Power [kW]	98	67	46.27%
Station Service Power [kW]	196,061	200,103	-2.02%
Net Unit Power [kW]	430,650	426,608	0.95%
IC Heat Available [kBtu/hr]	374,718	386,134	-2.96%
Heat Used to Dry Coal [kBtu/hr]	124,441	-	-
Boiler Efficiency [%]	90.65	88.11	2.88%
TC Heat Rate [Btu/kWh]	7,621	7,621	0.00%
Net Unit Heat Rate [Btu/kWh]	12,234	12,707	-3.72%
Unit Efficiency [%]	27.89	26.85	1.04%

Table 3-15: Change in Unit HR & Sources of Improvements – Coal Drying Case

Source of HR Improvement	Δ Unit HR
Δ Fan Power	0.43%
Δ Q_{coal}	-2.70%
Δ Pulverizer Power	-0.14%
Δ ASU Power	-0.62%
Δ Compressor Power	-0.54%
Combined Effect	-3.57%

Complete Feedwater Heater Replacement. One option would be to replace the steam extraction either to FWH1, FWH2, or FWH3 with hot water from the compressor. Figure 3-17 gives an example of the turbine-side connection change necessary for replacing the steam extraction to FWH1. When the extraction to FWH1 is shut off, 178,947 lb/hr more steam passes through LP5, resulting in a 0.7% increase in net turbine cycle power.

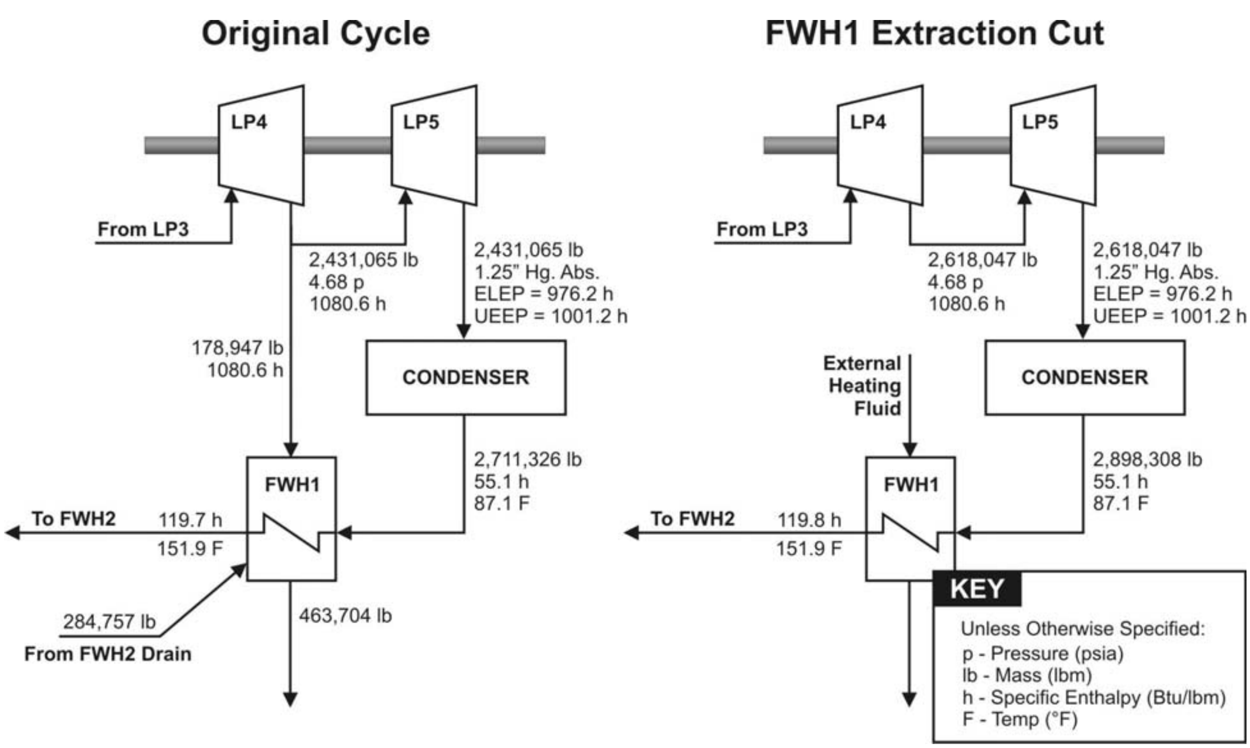

Figure 3-17: Change in Steam Turbine Cycle for Replacement of Extraction to FWH1

Compressor heat can also be used to replace the extractions to FWH2 or FWH3. Replacing the extraction to FWH2 would result in a net turbine cycle power increase of 0.87% over the BASE case, while the increase in net turbine cycle power would be 0.93% for the replacement of FWH3. It is interesting to note that the Base Case extraction to FWH2 is smaller than that to FWH1, and the one to FWH3 is smaller than the extraction to FWH2. This shows that the higher net turbine cycle power corresponding to the replacement of higher temperature feedwater heaters is not due to the mass flow rate of the extraction being replaced. Rather, the governing parameter is the number of turbine stages downstream of the extraction in question. For instance, the extraction to FWH3 is upstream of three turbine stages, which means that flow formerly diverted to the feedwater heater can produce power in three turbine stages. Conversely, the larger extraction to FWH1 is only upstream of one turbine stage, which is the reason for the smaller increase in net turbine cycle power when this extraction is eliminated.

Combinations of feedwater heating cases are also possible, in addition to the three individual feedwater heating cases described above. For example, both FWH2 and FWH3 extractions could be simultaneously replaced with compression heat. However, simultaneously replacing the steam extractions to all three heaters would not be possible for the Inline compressor, given the quantity of heat available. Figure 3-18 shows the unit heat rate improvement results associated with the feedwater heating cases shown. Figure 3-19, which presents the percent utilization of compression heat for each of the cases, shows that 30 percent to 80 percent of the heat would be used for these six cases.

All Combined Cases with Complete Feedwater Heater Replacement. By combining the recirculated flue gas heating and coal drying cases with the three individual feedwater heater replacement cases, a total of 31 cases are possible. Ten of these cases can be eliminated due to the required heat exceeding that supplied by the Inline 4 compressor. The remaining cases were either modeled or their results were predicted based on the results from other modeled cases. Figure 3-20 presents the change in net unit heat rate across all options, with the designators above a particular case as follows: R-Recirculation Heating, D-Coal Drying, FWH1-Replacement of extraction to FWH1, FWH2-Replacement of extraction to FWH2, FWH3-Replacement of extraction to FWH3. As seen, the addition of the recirculation heating and coal drying cases results in combined cases with the potential for much greater improvements in net unit heat rate. The best case involving only feedwater heating is the FWH2&3 case at approximately a 2.5% improvement in unit HR. However, when coal drying and recirculation heating are combined with feedwater heating, unit heat rates fall by up to 5.81%.

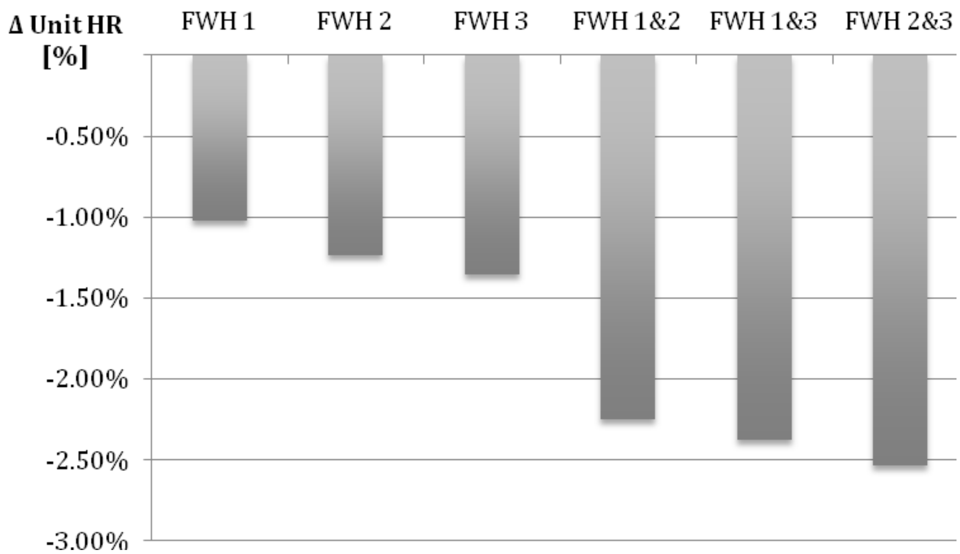

Figure 3-18: Change in Unit HR for Complete Feedwater Heater Replacement Cases

Cascading Feedwater Heating. The preceding section describes thermal integration options possible when entire feedwater heater extractions are replaced with hot water streams from compressor intercoolers. However, this is not the only option for utilizing CO_2 compression waste heat for heating feedwater. If insufficient heat or water temperatures exist to fully replace a feedwater heater's steam extraction, a supplemental feedwater heater utilizing hot intercooler water can be placed either before or after the heater in question. Figure 3-21 illustrates this concept of partial feedwater heating. FWH3 is designed to boost the feedwater temperature from 194°F to 231°F. However, if insufficient intercooler heat is available to accomplish this amount of heating, a supplemental heat exchanger (FWH3A) can be placed downstream of existing FWH3. The hot water heater, FWH3A, increases the feedwater temperature from199°F to 231°F and the original FWH3 feedwater heater increases the feedwater temperature from 194°F to 199°F. Steam Extraction flow E to FWH3 is thus reduced from 109,004 lb/hr to only 13,800 lb/hr.

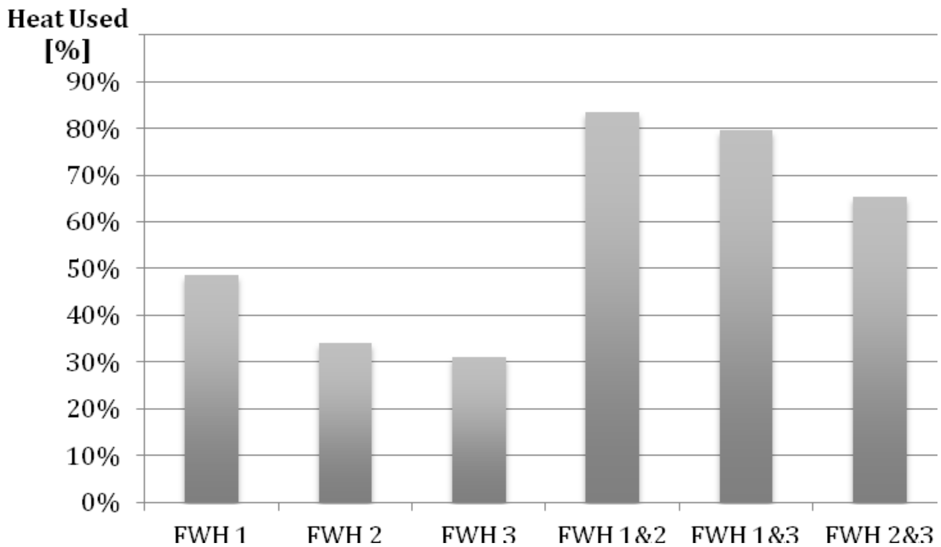

Figure 3-19: Heat Used for Complete Extraction Feedwater Heating Cases

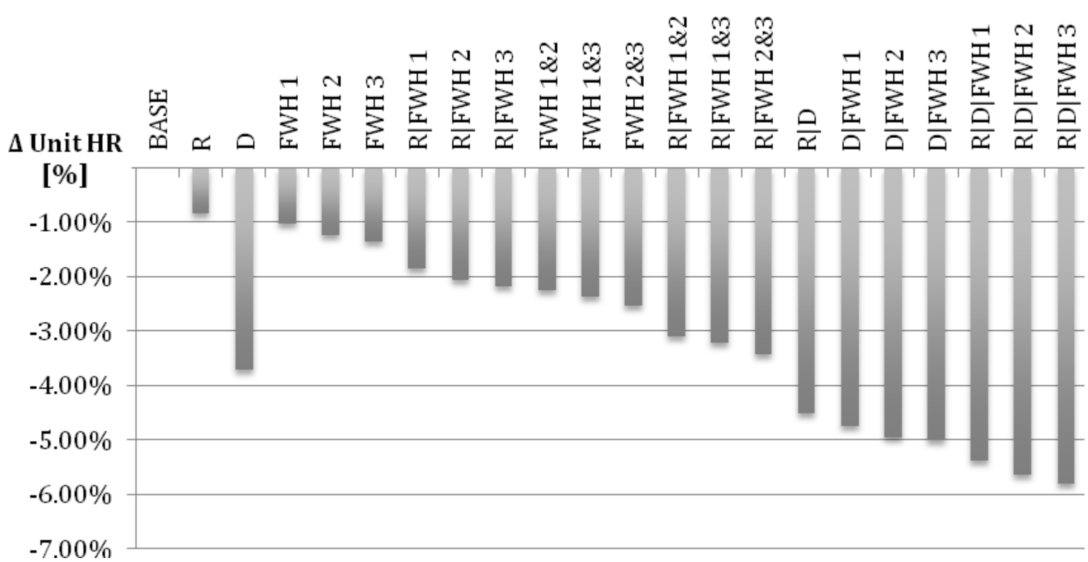

Figure 3-20: Change in Net Unit HR for all Possible Combined Cases

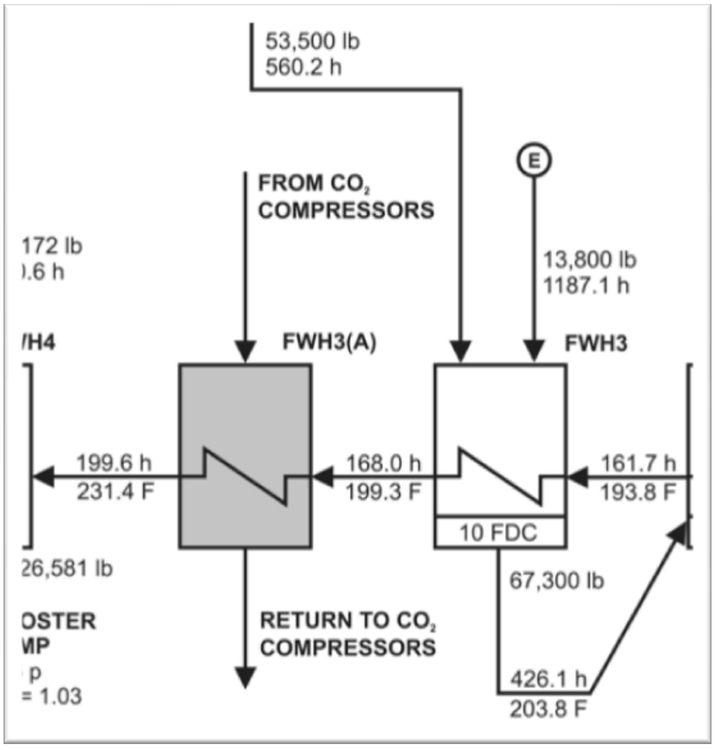

Figure 3-21: Supplemental Feedwater Heater After FWH3

This method of partial feedwater heating allows nearly all of the available compressor heat to be used to perform useful heating. It also opens up the potential to supply heat to feedwater heaters working at higher cold-side temperatures. As shown earlier, a smaller extraction reduction in a higher-temperature feedwater heater will result in a larger power increase than a larger extraction reduction in a low-temperature feedwater heater.

For all integration cases examined thus far, the flow of cooling water through the Inline compressor intercoolers had been fixed at 50 percent of the CO_2 flow rate. This worked well because it provided a relatively high flow rate of water at a relatively high temperature (280°F to 307°F). These water temperatures are high enough to provide feedwater heating up to FWH3 as well as for recirculated flue gas heating and coal drying. The only drawback to such a high flow rate is that integration with feedwater heaters beyond FWH3 is not possible, due to insufficiently high water temperatures.

In order to have the elevated water temperatures required to heat feedwater downstream of FWH3, a different method of specifying the water flow rate was used. Instead of fixing the cooling water flow rate as a function of CO_2 flow rate, the cooling water flow was adjusted until the intercooler exit cooling water temperature was 10°F below that of the hot CO_2 temperature entering the intercooler. In this way, maximum possible water temperatures were achieved. At between 374°F and 443°F, these temperatures are high enough to provide feedwater heating in place of FWH4 and FWH5. As seen in Figure 3-22, the three hot water streams from the intercoolers were combined before supplying heat to the feedwater heaters.

Figure 3-22 presents the intercooler process diagram for feedwater heating of higher temperature feedwater. In one case which was examined, hot water from the intercoolers was supplied to a series of supplemental feedwater heaters to partially offset the extractions to FWH1 through FWH5. Figure 3-23 is the turbine cycle diagram for such an arrangement, with the supplemental feedwater heaters shaded in gray.

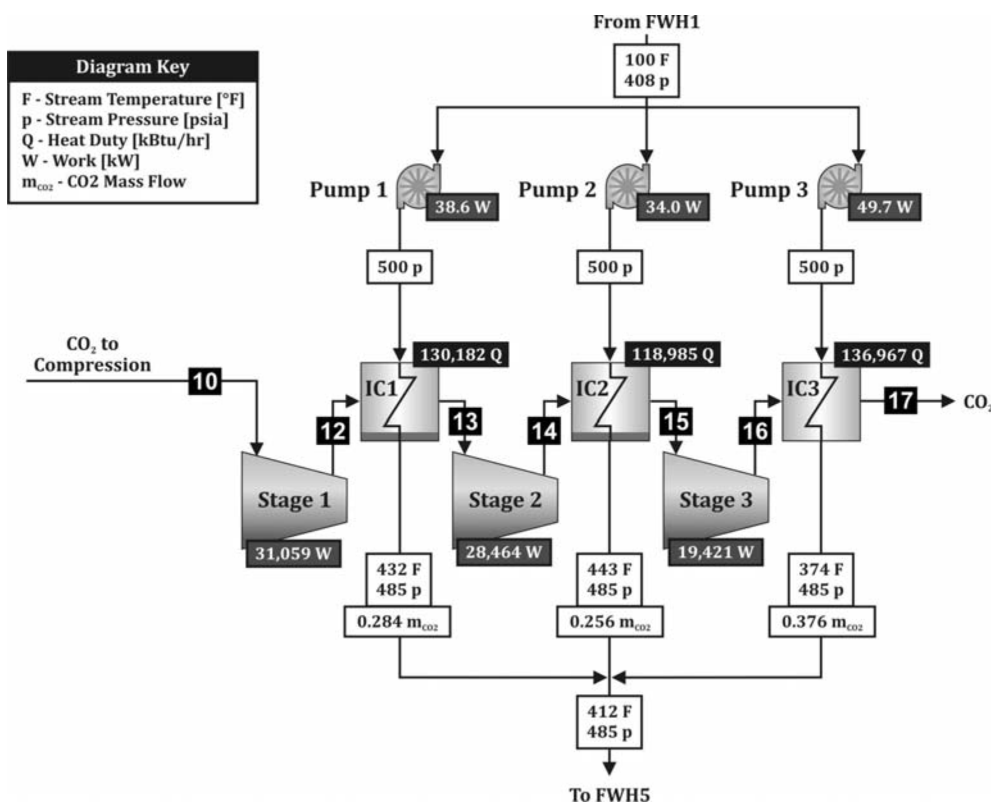

Figure 3-22: Inline 4 – Cascading FWH5 Case

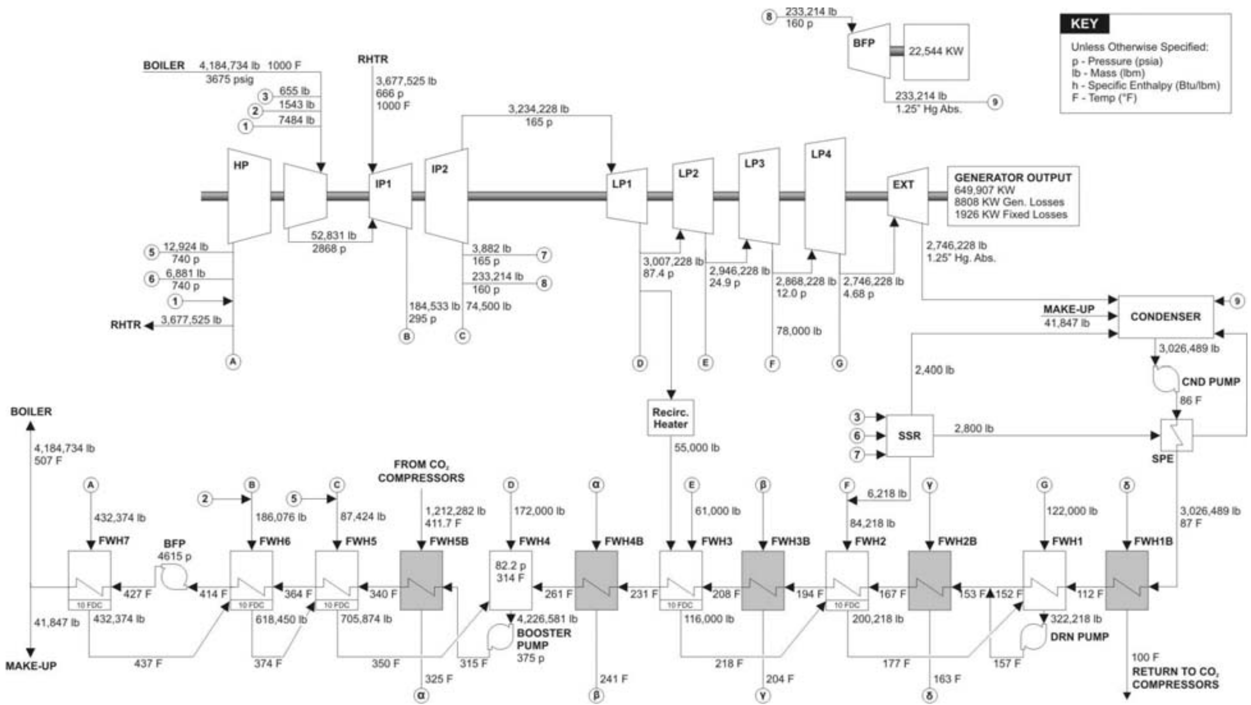

Figure 3-23: Supercritical Turbine Cycle Diagram – Cascading Feedwater Heating Case

Hot water from the intercoolers is supplied to the supplemental feedwater heater placed upstream of FWH5; named FWH5B because it is before FWH5. The hot compressor cooling water enters this FWH5B at 412°F and exits at 325°F, which is approximately 10°F higher than the cold feedwater inlet temperature to FWH5B. By adding heat exchanger FWH5B, the FWH5 extraction can be reduced from 163,004 lb/hr to 74,500 lb/hr.

After exiting FWH5B, the heating water is fed to a similar heat exchanger (this is labeled FWH4B) located before FWH4. As with FWH5, a large portion of the extraction to FWH4 is replaced by compressor heat by way of FWH4B. Continuing upstream, three additional feedwater heaters were added, with hot water for each heater supplied from the new feedwater heater immediately downstream. In this fashion, the heating water is cascaded through the supplemental feedwater heaters until it exits FWH1B at 100°F, at which point it is returned to the intercoolers.

A disadvantage of the cascading feedwater heating approach is that it would be more capital intensive, with the addition of five new feedwater heaters. Another aspect that could pose a problem is that of finding the space needed to install the new heaters.

The process concept shown in Figure 3-23 attempts to follow the original turbine cycle design as closely as possible. Feedwater exit temperatures are maintained for each existing heater, with hot-side exit temperatures being adjusted based on a 10°F temperature approach. Therefore, if any feedwater heater is looked at together with its corresponding “B” heater, the feedwater temperatures entering and exiting the pair will be consistent with those of the single original feedwater heater.

Steam extractions to the feedwater heaters were simultaneously reduced for FWH1 through FWH5. The reason for this is that a change in any extraction influences the quantity of water flowing through the cold-side of FWH1 through FWH3. A change in the feedwater flow thus changes the quantity of steam needing to be supplied to FWH1 through FWH3. Figure 3-23 shows the extraction flow rates that resulted in all of the stream temperatures converging to their desired values.

Comparison of Cascading FWH Results to Complete FWH Replacement Results. Cascading hot intercooling water through FWH5B to FWH1B as described results in an increase in gross generated power. Table 3-16 presents overall plant results for this case and compares them to the BASE case. As seen, net turbine cycle power has increased 3.31%, or by 21,471kW, with the implementation of cascading feedwater heating from FWH5. This change in turbine cycle power contributes to a 4.8 percent decrease in the net unit heat rate.

Figure 3-24 compares the change in unit heat rate for all possible complete feedwater heater replacement cases and compares it to the results for the FWH5 cascading option. As shown, FWH5(CAS) results in a ΔHR twice as large as the next best case. The reasons for this are twofold: (i) the increased positive impact of transferring heat to higher temperature feedwater heaters, (ii) FWH5(CAS) utilizes

100% of the heat released during compression, while the next best case, FWH2&3, utilizes only about 80% of the available heat. The FWH5(CAS) case produces 10,000 kW more power than the next best case (Figure 3-25).

Table 3-16: Plant Results for Cascading Feedwater Heating Case from FWH5

	FWH5(CAS)	**BASE Case**	**% Diff.**	
Moisture [% weight wet]	28.09	28.09	0.00%	*
Coal Flow [lbm/hr]	643,343	643,343	0.00%	†
Qcoal [Btu/hr]	5.421E+09	5.421E+09	0.00%	†
Steam Duty [Btu/hr]	4.776E+09	4.776E+09	0.00%	†
Boiler Efficiency	88.10%	88.10%	0.00%	*
Gross Power [kW]	649,909	628,422	3.42%	†
Pump Power [kW]	1,726	1,711	0.86%	†
Net Power [kW]	648,182	626,711	3.43%	†
TCHR [Btu/kWh]	7,368	7,621	3.31%	†
$P_{rec\ fan}$ [kW]	890	890	0.00%	†
$P_{O2\ fan}$ [kW]	255	255	0.00%	†
$P_{ID\ fan}$ [kW]	7,085	7,085	0.00%	†
$P_{coal\ dryer\ fan}$ [kW]	0	0	-	†
Total Fan Power [kW]	8,229	8,229	0.00%	†
IC Pump Power [kW]	122	67	82.81%	†
Pulverizer Power [kW]	3,405	3,405	0.00%	†
Aux. Power [kW]	15,000	15,000	0.00%	†
SS Power [kW]	26,756	26,701	0.21%	†
ASU Power [kW]	94,458	94,458	0.00%	†
Compressor Power [kW]	78,944	78,944	0.00%	†
Unit Efficiency	28.20%	26.85%	1.35%	*
Unit Heat Rate [Btu/kWh]	12,099	12,707	4.78%	†

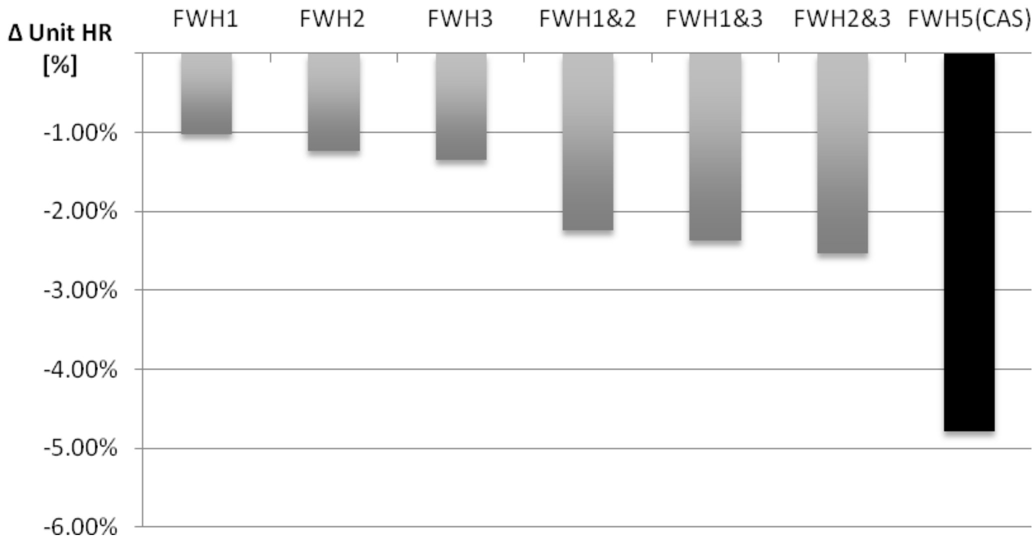

Figure 3-24: Change in HR for Complete FWH Replacement and FWH5 Cascaded Cases

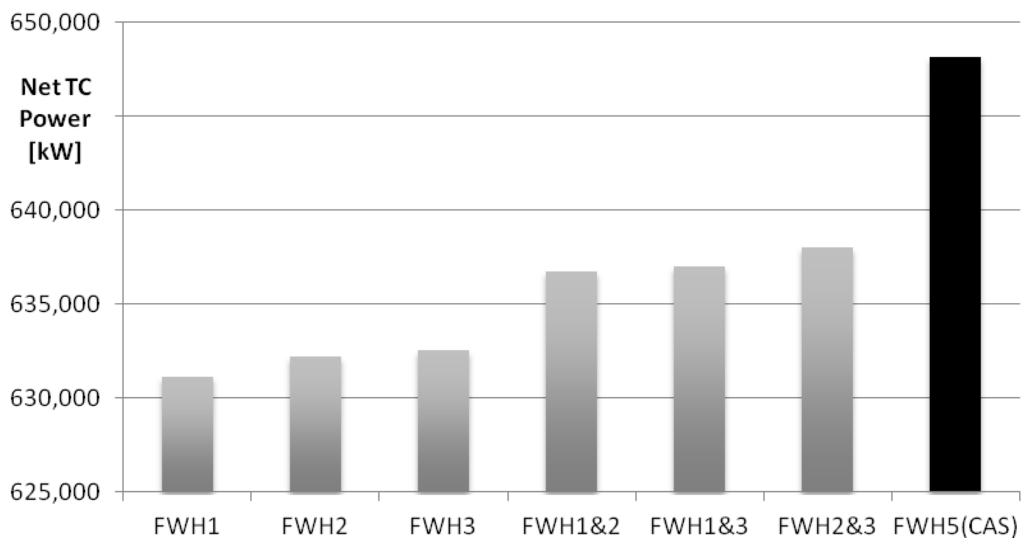

Figure 3-25: Net TC Power for Complete FWH Replacement and FWH5 Cascaded Cases

<u>Comparison of Cascaded FWH Results to All Combined Cases.</u> Figure 3-26 compares the change in unit heat rate between the cascaded FWH5 case to cases incorporating recirculated flue gas heating and coal drying. The comparison shows FWH5(CAS) has the same or a greater magnitude of change in unit heat rate than all but three of the cases. Although FWH5(CAS) does not have the largest change in unit heat rate, its results approach those of cases incorporating coal drying.

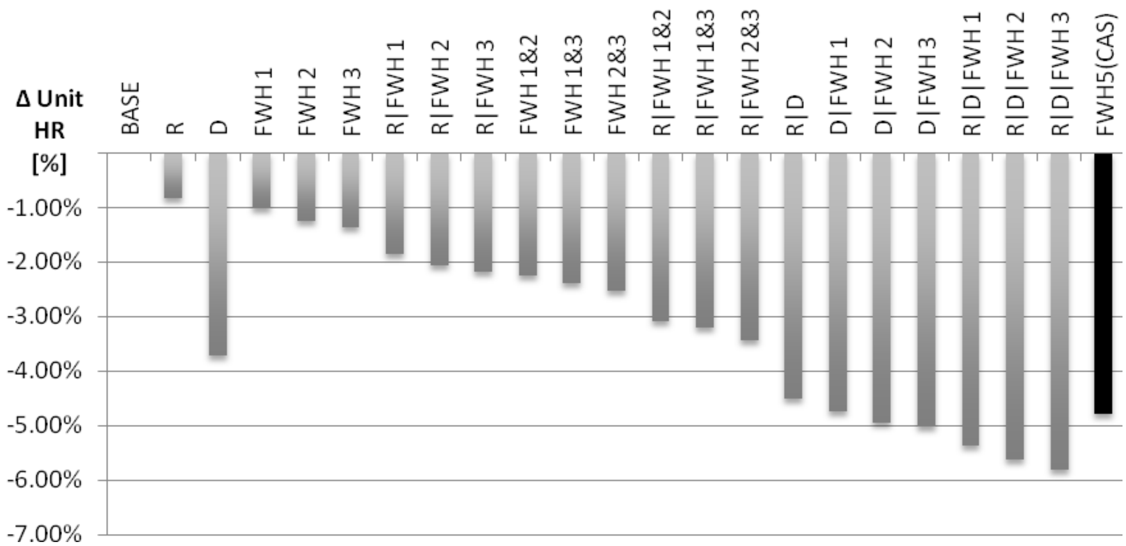

Figure 3-26: Change in HR for All Combined Cases vs. FWH5 Cascaded Case

Figure 3-27 shows the percentage of available compression heat used for each case. As seen, the cascaded FWH5(CAS) case is the only case to utilize 100% of the available heat.

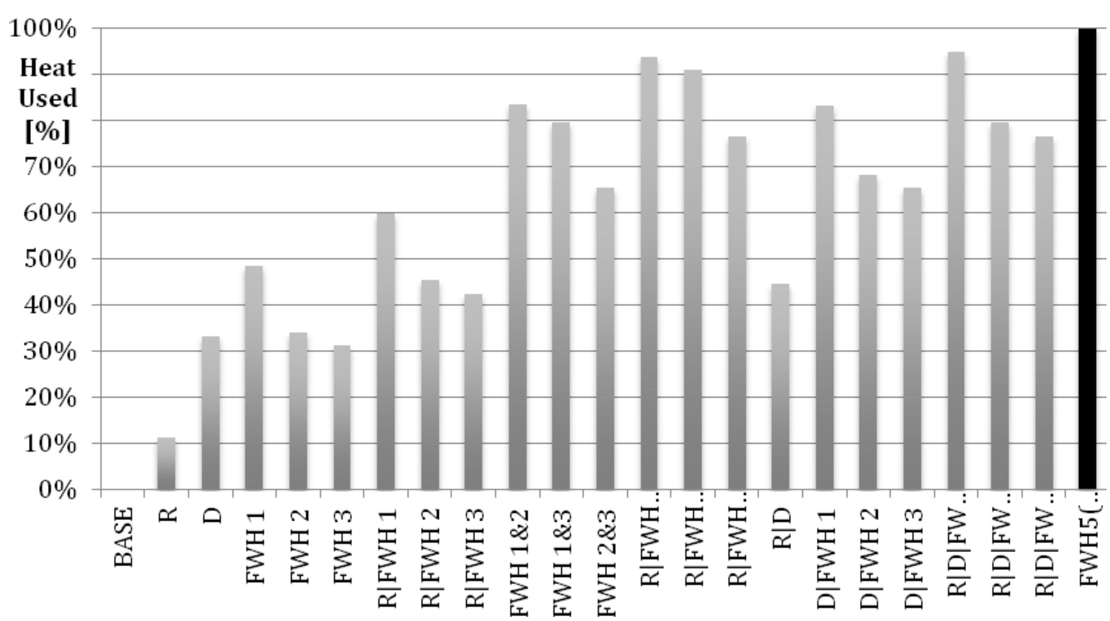

Figure 3-27: % Heat Used for All Combined Cases vs. FWH5 Cascaded Case

Effects of Coal Type

The simulation results described earlier in this Chapter were performed for a PRB coal. Simulations were also carried out for a North Dakota Lignite and Illinois #6 to determine how coal rank affects thermal integration options. Table 3-17 shows the proximate and ultimate analyses and the higher heating values (HHV) for the three coals.

Table 3-17: Analysis of Coals Used in this Report

	PRB		**ND Lignite**		**Illinois #6**	
Proximate Analysis (weight %)						
	AR	Dry	AR	Dry	AR	Dry
Moisture	28.09	0	38.50	0	7.97	0
Fixed Carbon	32.98	45.87	-	-	36.47	39.64
Volatile Matter	32.17	44.73	-	-	36.86	40.05
Ash	6.31	8.77	12.30	20	14.25	15.48
HHV	8,426	11,717	6,406	10,416	10,999	11,951
Ultimate Analysis (weight %)						
Ash	6.31	8.77	12.30	20.00	14.25	15.48
Carbon	49.21	68.43	34.03	55.33	60.42	65.65
Hydrogen	3.51	4.88	2.97	4.83	3.89	4.23
Nitrogen	0.73	1.02	0.72	1.17	1.07	1.16
Chlorine	0.02	0.03	0.00	0.00	0.05	0.05
Sulfur	0.45	0.63	0.51	0.83	4.45	4.83
Oxygen	11.67	16.24	10.97	17.84	7.91	8.6
Sulfur Analysis (weight %)						
Pyritic	-	0.17	-	0.15	-	2.81
Sulfate	-	0.03	-	0.03	-	0.01
Organic	-	0.43	-	0.65	-	2.01

North Dakota Lignite Intercooler Heat Integration Results

The previous results outlined the benefits of using heat rejected during the compression of CO_2 from an oxycombustion power plant firing a PRB coal. Just as with PRB, complete ASPEN Plus power plant models were created for the ND Lignite and Illinois #6. The heat integration options examined included the recirculated flue gas heater, the first three feedwater heaters, and in the case of high moisture lignite, the coal dryer. Also, since each compression option provides more heat than any one integration option can utilize, combinations of these heat integration options were also considered.

BASE Oxycombustion Plants – ND Lignite and Illinois #6

Complete BASE case plant models were run for the two coals using the supercritical steam turbine cycle shown in Figure 3-3. Since the thermal duty required by the recirculated flue gas heater depends on coal composition, the turbine extraction steam flow rate to the recirculated gas heater differs with coal. Figure 3-28 shows the oxycombustion boiler arrangement. Individual stream values for lignite and Illinois #6 are shown in Tables 3-18 and 3-19.

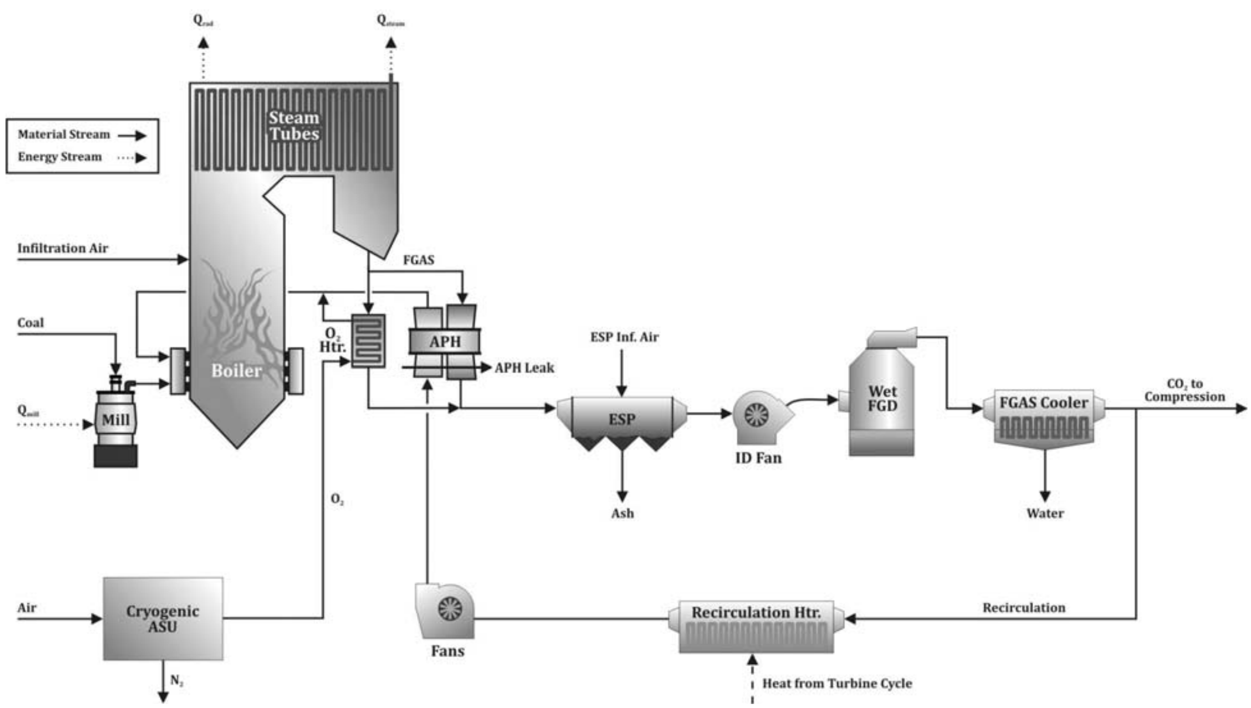

Figure 3-28: Oxycombustion Boiler Process Diagram

Table 3-18: Oxycombustion Boiler Stream Results for ND Lignite

	1 Coal	**2** Oxy	**3** Hot Oxid.	**4** Infil. Air	**5** FGAS	**6** After APH	**7** After ID Fan	**8** After FGD	**9** After Cool.	**10** To Comp.	**11** Recirc.
Temp [°F]	77	77	551	77	600	293	310	135	100	100	100
Pressure [psia]	14.7	14.7	15.0	14.7	14.7	14.7	16.0	14.8	14.7	14.7	14.7
Mass Flow [lb/hr]	875,249	998,266	4,498,543	53,149	5,319,329	5,638,231	5,633,800	5,388,518	5,096,763	1,274,191	3,822,572
Composition	**[mol-frac]**										
AR	-	0.0340	0.0337	0.0000	0.0268	0.0271	0.0270	0.0296	0.0335	0.0335	0.0335
CO_2	-	0.0000	0.5810	0.0000	0.6300	0.6381	0.6377	0.6973	0.7887	0.7887	0.7887
H_2O	-	0.0000	0.0482	0.0203	0.2526	0.2431	0.2431	0.1735	0.0654	0.0654	0.0654
N_2	-	0.0162	0.0532	0.7740	0.0531	0.0538	0.0557	0.0609	0.0665	0.0665	0.0665
O_2	-	0.9498	0.2832	0.2057	0.0350	0.0354	0.0355	0.0388	0.0438	0.0438	0.0438
SO_2	-	0.0000	0.0000	0.0000	0.0010	0.0009	0.0009	0.0000	0.0000	0.0000	0.0000

Table 3-19: Oxycombustion Boiler Stream Results for Illinois #6

	1 Coal	**2** Oxy	**3** Hot Oxid.	**4** Infil. Air	**5** FGAS	**6** After APH	**7** After ID Fan	**8** After FGD	**9** After Cool.	**10** To Comp.	**11** Recirc.
Temp [°F]	77	77	502	77	600	292	309	135	100	100	100
Pressure [psia]	14.7	14.7	15.0	14.7	14.7	14.7	16.0	14.8	14.7	14.7	14.7
Mass Flow [lb/hr]	473,011	974,103	4,324,663	47,781	4,778,069	5,064,284	5,064,284	5,137,454	4,855,947	1,213,987	3,641,960
Composition	**[mol-frac]**										
AR	-	0.0340	0.0344	0.0000	0.0316	0.0318	0.0318	0.0304	0.0344	0.0344	0.0344
CO_2	-	0.0000	0.5836	0.0000	0.7317	0.7353	0.7353	0.7041	0.7962	0.7962	0.7962
H_2O	-	0.0000	0.0480	0.0203	0.1357	0.1319	0.1319	0.1735	0.0654	0.0654	0.0654
N_2	-	0.0162	0.0496	0.7740	0.0568	0.0571	0.0571	0.0547	0.0618	0.0618	0.0618
O_2	-	0.9498	0.2829	0.2057	0.0350	0.0352	0.0352	0.0337	0.0381	0.0381	0.0381
SO_2	-	0.0000	0.0001	0.0000	0.0055	0.0052	0.0052	0.0002	0.0002	0.0002	0.0002

Figures 3-29 and 3-30 and Tables 3-20 and 3-21 show process diagrams for the inline compressor and information on the compositions of the CO_2 stream through the compressor stages and intercoolers for the two coals.

Tables 3-22 and 3-23 show the corresponding performance results for the Base Case Oxycombustion power plant with an Inline compressor.

<u>Thermal Integration with Recirculated Flue Gas Heating.</u> Figures 3-31 and 3-32 and Tables 3-24 and 3-25 show the thermal integration process diagrams and unit performance summaries for the two coals.

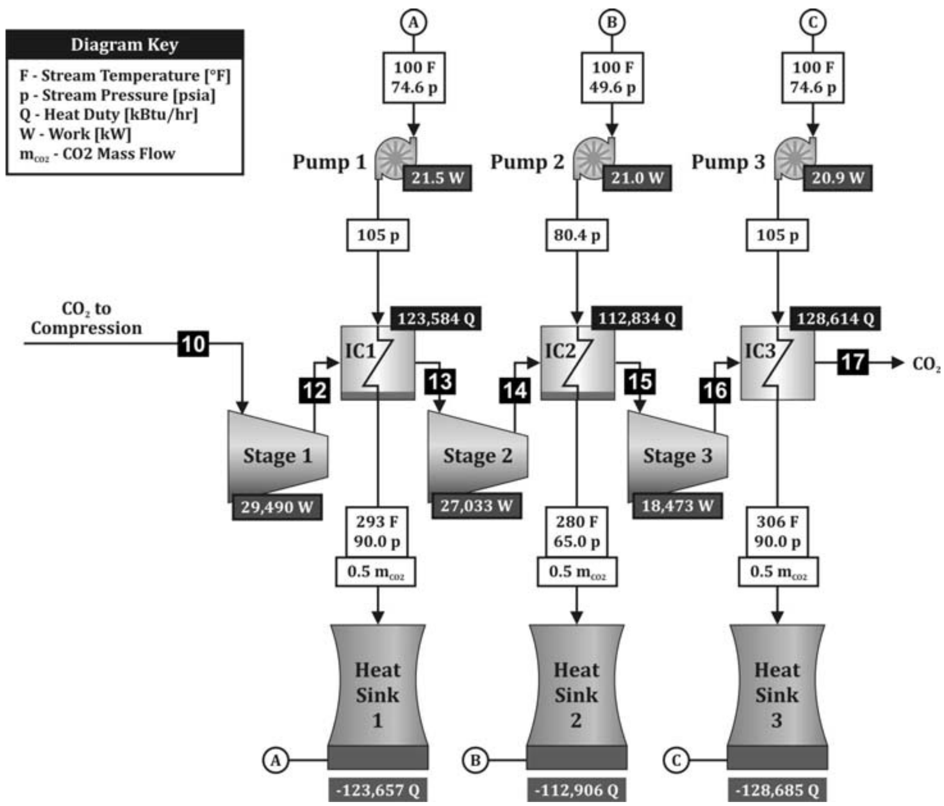

Figure 3-29: Inline 4 Compression and Intercooling – BASE ND Lignite Case

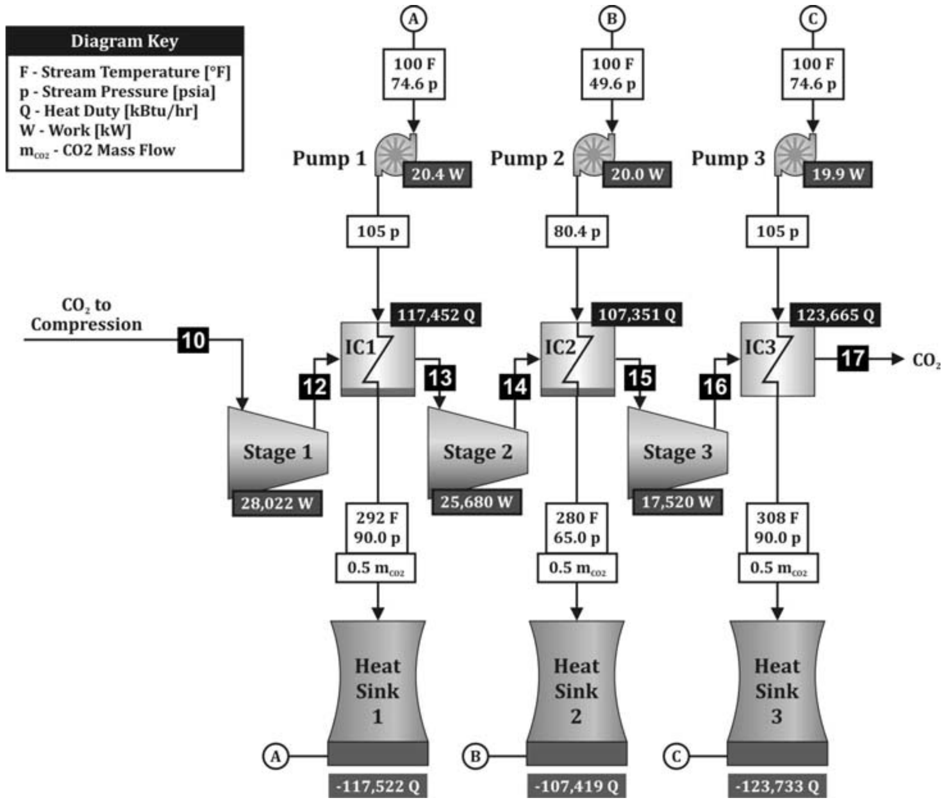

Figure 3-30: Inline 4 Compression and Intercooling – BASE Illinois #6 Case

Table 3-20: Inline 4 Stream Information – BASE ND Lignite Case

	12 After Comp. 1	**13** Before Comp. 2	**14** After Comp. 2	**15** Before Comp. 3	**16** After Comp. 3	**17** After IC 3
Temp [°F]	442	120	454	120	384	120
Pressure [psia]	96.5	91.5	553.4	548.4	2,220	2,215
Mass Flow [lb/hr]	1,274,191	1,247,805	1,247,805	1,239,581	1,239,581	1,239,581
Composition	**[mol-frac]**					
AR	0.0335	0.0352	0.0352	0.0357	0.0357	0.0357
CO_2	0.7887	0.8272	0.8272	0.8399	0.8399	0.8399
H_2O	0.0654	0.0198	0.0198	0.0047	0.0047	0.0047
N_2	0.0665	0.0697	0.0697	0.0708	0.0708	0.0708
O_2	0.0438	0.0460	0.0460	0.0467	0.0467	0.0467
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

Table 3-21: Inline 4 Stream Information – BASE Illinois #6 Case

	12 After Comp. 1	**13** Before Comp. 2	**14** After Comp. 2	**15** Before Comp. 3	**16** After Comp. 3	**17** After IC 3
Temp [°F]	442	120	453	120	384	120
Pressure [psia]	96.5	91.5	553.4	548.4	2,220	2,215
Mass Flow [lb/hr]	1,213,987	1,188,903	1,188,903	1,181,085	1,181,085	1,181,085
Composition	**[mol-frac]**					
AR	0.0344	0.0361	0.0361	0.0367	0.0367	0.0367
CO_2	0.7962	0.8350	0.8350	0.8478	0.8478	0.8478
H_2O	0.0654	0.0198	0.0198	0.0048	0.0048	0.0048
N_2	0.0618	0.0648	0.0648	0.0658	0.0658	0.0658
O_2	0.0381	0.0400	0.0400	0.0406	0.0406	0.0406
SO_2	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002

Table 3-22: Plant Results – BASE ND Lignite Case with Inline 4 Compressor

Coal Flow [lb/hr]	875,249
HHV [Btu/lb]	6,406
Q_{coal} [Btu/hr]	5.607E+09
Main Steam Mass Flow [lb/hr]	4,184,734
Reheat Mass Flow [lb/hr]	3,677,526
Q_{Main} [Btu/hr]	3.848E+09
Q_{Reheat} [Btu/hr]	9.282E+08
Q_{Steam} [Btu/hr]	4.776E+09
Gross Power [kW]	628,548
Pump Power [kW]	1,711
Net TC Power [kW]	626,837
Rec. Fan Power [kW]	843
O_2 Fan Power [kW]	245
ID Fan Power [kW]	7,262
Pulv. Power [kW]	4,632
Auxiliary Power [kW]	15,000
ASU Power [kW]	90,751
Compressor Power [kW]	74,996
Intercooler Pump Power [kW]	63
Station Service Power [kW]	193,793
Net Unit Power [kW]	433,044
IC Heat Available [kBtu/hr]	365,032
Boiler Efficiency [%]	85.18
TC Heat Rate [Btu/kWh]	7,619
Net Unit Heat Rate [Btu/kWh]	12,948
Unit Efficiency [%]	26.35

Table 3-23: Plant Results – BASE Illinois #6 Case with Inline 4 Compressor

Coal Flow [lb/hr]	473,011
HHV [Btu/lb]	10,999
Q_{coal} [Btu/hr]	5.203E+09
Main Steam Mass Flow [lb/hr]	4,184,734
Reheat Mass Flow [lb/hr]	3,677,526
Q_{Main} [Btu/hr]	3.848E+09
Q_{Reheat} [Btu/hr]	9.282E+08
Q_{Steam} [Btu/hr]	4.776E+09
Gross Power [kW]	628,715
Pump Power [kW]	1,711
Net TC Power [kW]	627,004
Rec. Fan Power [kW]	801
O_2 Fan Power [kW]	239
ID Fan Power [kW]	6,045
Pulv. Power [kW]	2,503
Auxiliary Power [kW]	15,000
ASU Power [kW]	88,555
Compressor Power [kW]	71,223
Intercooler Pump Power [kW]	60
Station Service Power [kW]	184,426
Net Unit Power [kW]	442,578
IC Heat Available [kBtu/hr]	348,468
Boiler Efficiency [%]	91.80
TC Heat Rate [Btu/kWh]	7,617
Net Unit Heat Rate [Btu/kWh]	11,755
Unit Efficiency [%]	29.03

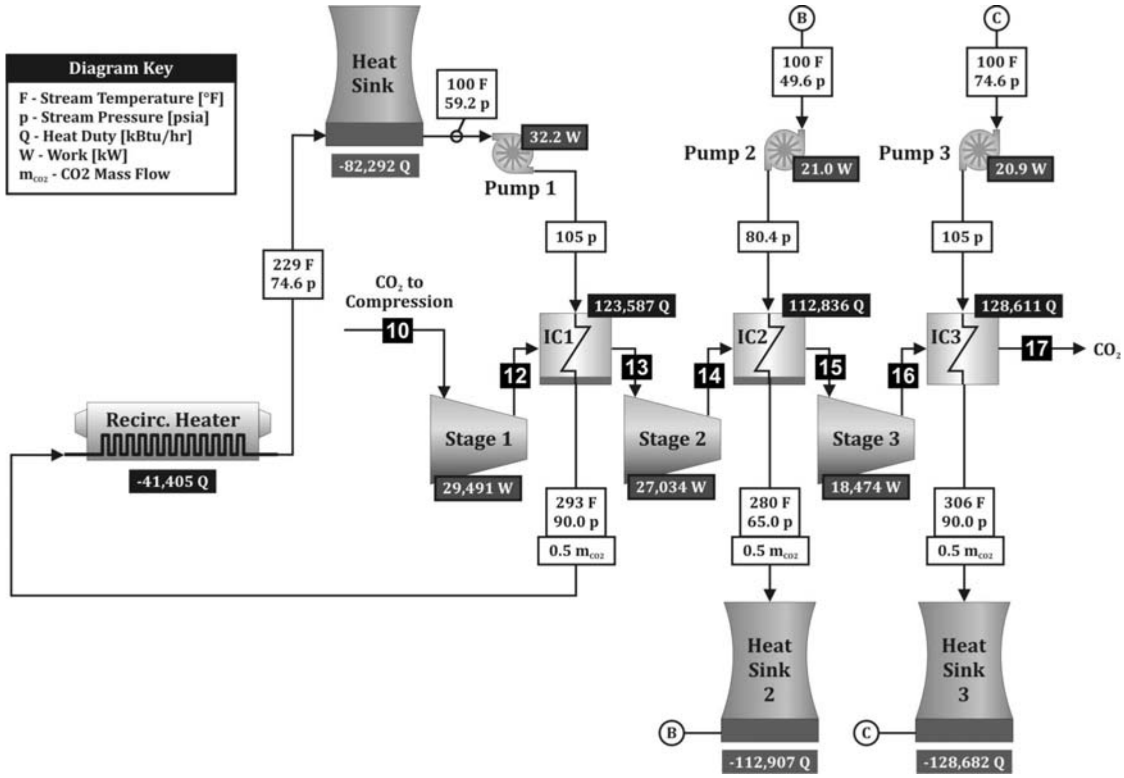

Figure 3-31: Inline 4 Compression and Intercooling – Rec. Heating ND Lignite Case

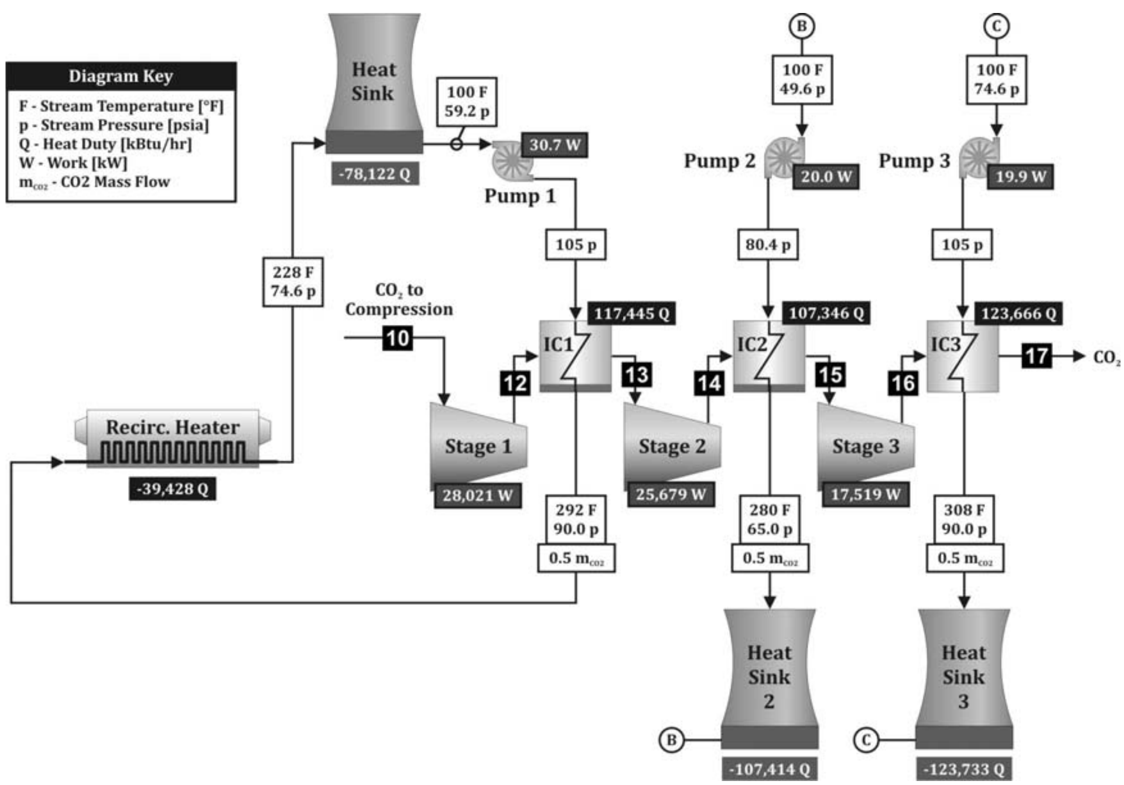

Figure 3-32: Inline 4 Compression and Intercooling – Rec. Heating Illinois #6 Case

Table 3-24: Plant Results – Rec. Heating ND Lignite Case with Inline 4 Compressor

	Boiler & Steam Turbine Cycle		
	Rec. HT	**BASE**	**% Diff**
Coal Flow [lb/hr]	875,249	875,249	0.00%
HHV [Btu/lb]	6,406	6,406	0.00%
Q_{coal} [Btu/hr]	5.607E+09	5.607E+09	0.00%
Main Steam Mass Flow [lb/hr]	4,184,734	4,184,734	0.00%
Reheat Mass Flow [lb/hr]	3,677,526	3,677,526	0.00%
Q_{Main} [Btu/hr]	3.848E+09	3.848E+09	0.00%
Q_{Reheat} [Btu/hr]	9.282E+08	9.282E+08	0.00%
Q_{Steam} [Btu/hr]	4.776E+09	4.776E+09	0.00%
Gross Power [kW]	632,011	628,548	0.55%
Pump Power [kW]	1,710	1,711	-0.06%
Net TC Power [kW]	630,301	626,837	0.55%
Rec. Fan Power [kW]	843	843	0.00%
O_2 Fan Power [kW]	245	245	0.00%
ID Fan Power [kW]	7,262	7,262	0.00%
Pulv. Power [kW]	4,632	4,632	0.00%
Auxiliary Power [kW]	15,000	15,000	0.00%
ASU Power [kW]	90,753	90,751	0.00%
Compressor Power [kW]	74,998	74,996	0.00%
Intercooler Pump Power [kW]	74	63	17.46%
Station Service Power [kW]	193,807	193,793	0.01%
Net Unit Power [kW]	436,494	433,044	0.80%
IC Heat Available [kBtu/hr]	365,033	365,032	0.00%
Boiler Efficiency [%]	85.18	85.18	0.00%
TC Heat Rate [Btu/kWh]	7,577	7,619	-0.55%
Net Unit Heat Rate [Btu/kWh]	12,845	12,948	-0.80%
Unit Efficiency [%]	26.56	26.35	0.21%

Table 3-25: Plant Results – Rec. Heating Illinois #6 Case with Inline 4 Compressor

	Boiler & Steam Turbine Cycle		
	Rec. HT	**BASE**	**% Diff**
Coal Flow [lb/hr]	473,013	473,011	0.00%
HHV [Btu/lb]	10,999	10,999	0.00%
Q_{coal} [Btu/hr]	5.203E+09	5.203E+09	0.00%
Main Steam Mass Flow [lb/hr]	4,184,734	4,184,734	0.00%
Reheat Mass Flow [lb/hr]	3,677,526	3,677,526	0.00%
Q_{Main} [Btu/hr]	3.85E+09	3.85E+09	0.00%
Q_{Reheat} [Btu/hr]	9.28E+08	9.28E+08	0.00%
Q_{Steam} [Btu/hr]	4.78E+09	4.78E+09	0.00%
Gross Power [kW]	632,011	628,715	0.52%
Pump Power [kW]	1,710	1,711	-0.06%
Net TC Power [kW]	630,301	627,004	0.53%
Rec. Fan Power [kW]	801	801	0.00%
O_2 Fan Power [kW]	239	239	0.00%
ID Fan Power [kW]	6,045	6,045	0.00%
Pulv. Power [kW]	2,503	2,503	0.00%
Auxiliary Power [kW]	15,000	15,000	0.00%
ASU Power [kW]	88,550	88,555	-0.01%
Compressor Power [kW]	71,218	71,223	-0.01%
Intercooler Pump Power [kW]	71	60	18.33%
Station Service Power [kW]	184,427	184,426	0.00%
Net Unit Power [kW]	445,874	442,578	0.74%
IC Heat Available [kBtu/hr]	348,456	348,468	0.00%
Boiler Efficiency [%]	91.80	91.80	0.00%
TC Heat Rate [Btu/kWh]	7,577	7,617	-0.53%
Net Unit Heat Rate [Btu/kWh]	11,668	11,755	-0.74%
Unit Efficiency [%]	29.24	29.03	0.21%

Thermal Integration with Coal Drying. The ND Lignite coal analyzed here has an as-received moisture of 38.5 lbs of water per 100 lbs of wet coal. As previously discussed, a high moisture coal can be dried in a fluidized bed dryer to significantly reduce its moisture level. A reduction in coal moisture not only increases boiler efficiency but it also reduces pulverizer and fan power. The drying simulations for PRB coal assumed the coal would be dried from 30 to 15 percent. It was assumed the lignite would be dried from 38.5 percent to 20 percent.

Complete plant models utilizing ND Lignite drying were created in ASPEN Plus for each compressor option. Figure 3-33 presents the Inline 4 coal drying configuration. In contrast to the PRB drying case, it was assumed hot water from all three intercoolers would be needed to supply heat to the drying system for lignite. Just as with PRB, the heat sink was placed upstream of the bed so that the water would exit the dryer bed relatively close to 100°F.

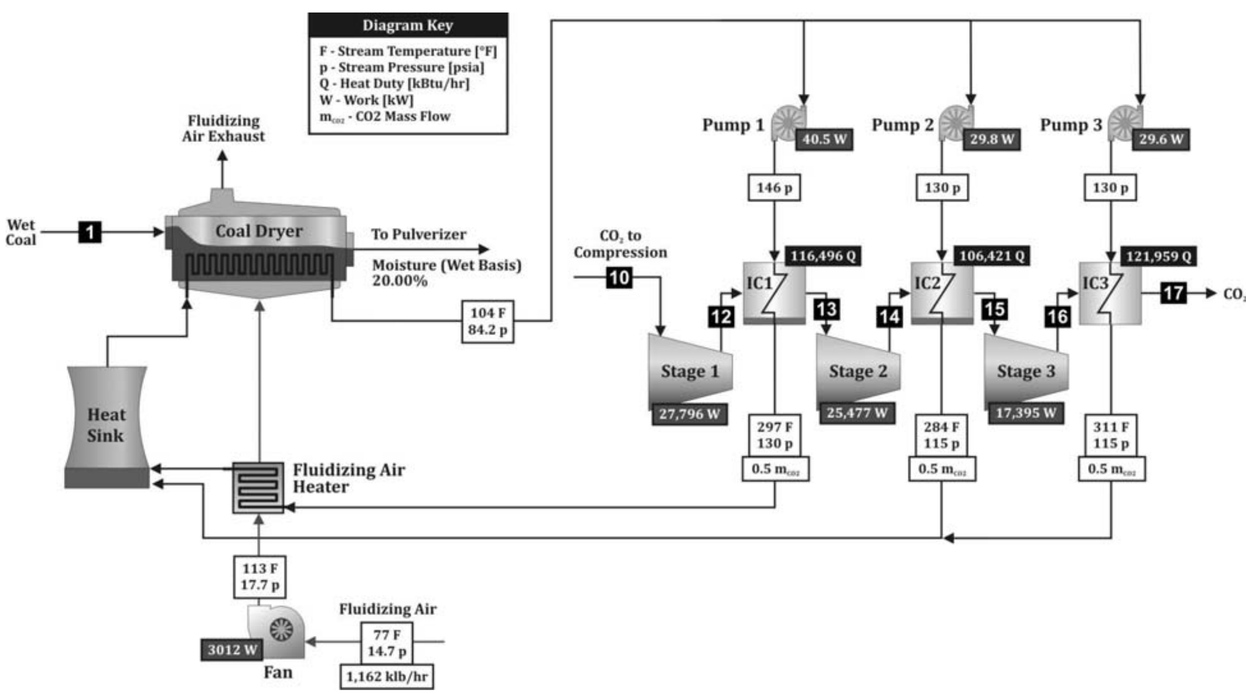

Figure 3-33: Inline 4 Compression and Intercooling – Coal Drying ND Lignite Case

Table 3-26 shows the plant performance results for coal drying. The predicted heat rate improvement due to coal drying of the Lignite is approximately 7 percent.

Figure 3-34 shows previous Energy Research Center ΔHR results for the drying of both a PRB and ND Lignite (Ref. 6). Since with a carbon capture system, waste heat from compression is being utilized to dry the lignite, the “Off-Site Drying” curve of Figure 3-34 should compare to the ND Lignite drying results shown in Table 3-27. Indeed, both the present results and those in Figure 3-34 suggest that drying a lignite to about 50 percent of its original moisture will result in about a 7 percent improvement in heat rate, if this drying is accomplished without the addition of heat taken from elsewhere in the plant. Just as with PRB coal drying, the improvement in heat rate is due to reductions in coal feed rate and to reductions in station service power.

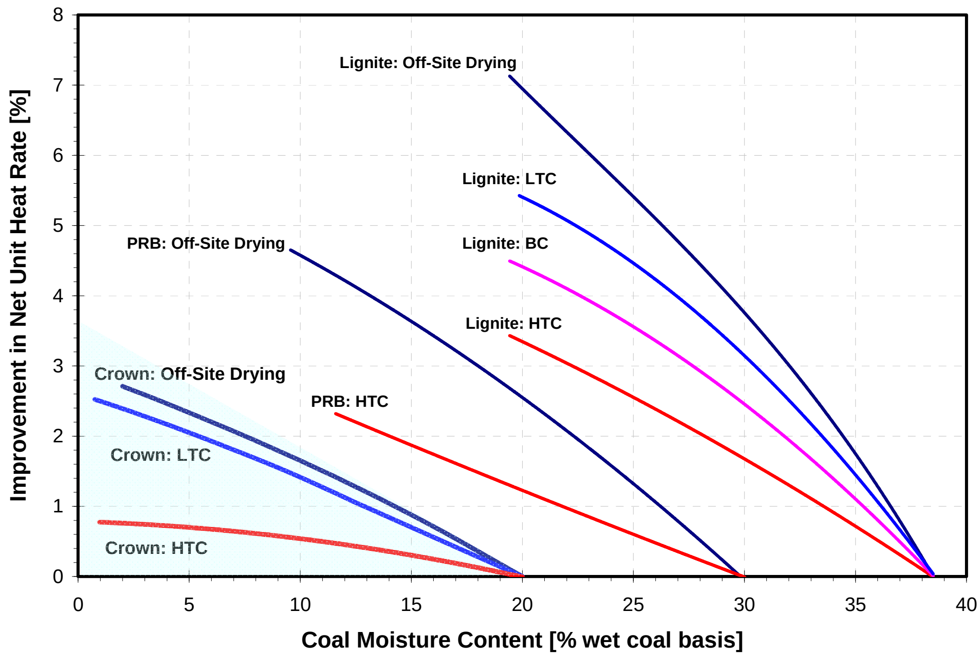

Figure 3-34: Improvement in Net Unit HR for Various Coals & Dryer Heating Options

No calculations were performed on coal drying with Illinois #6. This coal has only about 8 percent moisture; and, as a result, use of coal drying technology is not likely to be cost effective in this case.

Feedwater Heater Integration/Complete Feedwater Heater Replacement. As described in an earlier section of this report, one option would be to replace the steam extraction to either FWH1, FWH2, or FWH3 with hot water from the compressor, or to use compressor heat to replace the extractions to both FWH2 and FWH3. Combinations of feedwater heating cases, in addition to the three individual feedwater heating cases described above, are also possible. Tables 3-27 and 3-28, show the effects of transferring compressor heat to FWH3 when firing lignite and bituminous coals. The results show that the impacts on turbine cycle and net unit heat rates of thermal integration to FWH3 are relatively insensitive to coal type.

Combined Heat Integration Options

Since only up to 77 percent of the available heat is used for the five individual ND Lignite integration cases, methods of utilizing the remaining heat were sought. These methods involved combining recirculation heating (R), coal drying, (D) and feedwater heating (FWH1, FWH2, FWH3) into all possible configurations. ΔHR values were predicted for all possible combined heat integration cases, in some cases by simply adding together the ΔHR values of the individual cases being combined and in others by fully modeling the cases in ASPEN Plus. Figure 3-35 presents the estimated and modeled ΔHR values for all possible Inline 4 integration options burning ND Lignite. The results show predicted heat rate reductions range up to 8 percent for this coal and compressor type.

Figure 3-36 shows the corresponding values for a unit burning an Illinois #6 coal.

Figure 3-37 compares percentage heat rate improvements for the three coals with an Inline 4 compressor. This shows comparable heat rate reductions for all three coals when compressor heat is integrated with the feedwater heaters and/or used to reheat the recirculated flue gas stream. Maximum predicted heat rate reductions exceed 3 percent in these cases. However, when coal drying is accounted for, the predicted heat rate reductions reach 8 percent for the lignite and approach 6 percent with PRB coal.

Table 3-26: Plant Results – Coal Drying ND Lignite Case with Inline 4 Compressor

	Boiler & Steam Turbine Cycle		
	Coal Drying	**BASE**	**% Diff**
Coal Flow [lb/hr]	829,674	875,249	-5.21%
HHV [Btu/lb]	6,406	6,406	0.00%
Q_{coal} [Btu/hr]	5.315E+09	5.607E+09	-5.21%
Main Steam Mass Flow [lb/hr]	4,184,734	4,184,734	0.00%
Reheat Mass Flow [lb/hr]	3,677,526	3,677,526	0.00%
Q_{Main} [Btu/hr]	3.848E+09	3.848E+09	0.00%
Q_{Reheat} [Btu/hr]	9.282E+08	9.282E+08	0.00%
Q_{Steam} [Btu/hr]	4.776E+09	4.776E+09	0.00%
Gross Power [kW]	628,548	628,548	0.00%
Pump Power [kW]	1,711	1,711	0.00%
Net TC Power [kW]	626,837	626,837	0.00%
Rec. Fan Power [kW]	795	843	-5.69%
O_2 Fan Power [kW]	232	245	-5.31%
ID Fan Power [kW]	6,355	7,262	-12.49%
Coal Dryer Fan Power [kW]	3,012	-	-
Pulv. Power [kW]	3,376	4,632	-27.12%
Auxiliary Power [kW]	15,000	15,000	0.00%
ASU Power [kW]	85,798	90,751	-5.46%
Compressor Power [kW]	70,668	74,996	-5.77%
Intercooler Pump Power [kW]	100	63	58.73%
Station Service Power [kW]	185,334	193,793	-4.36%
Net Unit Power [kW]	441,502	433,044	1.95%
IC Heat Available [kBtu/hr]	344,876	365,032	-5.52%
Heat Used to Dry Coal [kBtu/hr]	242,665	-	-
Boiler Efficiency [%]	89.86	85.18	5.49%
TC Heat Rate [Btu/kWh]	7,619	7,619	0.00%
Net Unit Heat Rate [Btu/kWh]	12,038	12,948	-7.03%
Unit Efficiency [%]	28.34	26.35	1.99%

Table 3-27: Plant Results – ND Lignite FHW3 Case with Inline 4 Compressor

	Boiler & Steam Turbine Cycle		
	FWH3	**BASE**	**% Diff**
Coal Flow [lb/hr]	875,234	875,249	0.00%
HHV [Btu/lb]	6,406	6,406	0.00%
Q_{coal} [Btu/hr]	5.607E+09	5.607E+09	0.00%
Main Steam Mass Flow [lb/hr]	4,184,734	4,184,734	0.00%
Reheat Mass Flow [lb/hr]	3,677,526	3,677,526	0.00%
Q_{Main} [Btu/hr]	3.848E+09	3.848E+09	0.00%
Q_{Reheat} [Btu/hr]	9.282E+08	9.282E+08	0.00%
Q_{Steam} [Btu/hr]	4.776E+09	4.776E+09	0.00%
Gross Power [kW]	634,413	628,548	0.93%
Pump Power [kW]	1,709	1,711	-0.12%
Net TC Power [kW]	632,704	626,837	0.94%
Rec. Fan Power [kW]	843	843	0.00%
O_2 Fan Power [kW]	245	245	0.00%
ID Fan Power [kW]	7,261	7,262	-0.01%
Pulv. Power [kW]	4,632	4,632	0.00%
Auxiliary Power [kW]	15,000	15,000	0.00%
ASU Power [kW]	90,747	90,751	0.00%
Compressor Power [kW]	74,991	74,996	-0.01%
Intercooler Pump Power [kW]	84	63	33.33%
Station Service Power [kW]	193,804	193,793	0.01%
Net Unit Power [kW]	438,900	433,044	1.35%
IC Heat Available [kBtu/hr]	365,016	365,032	0.00%
Boiler Efficiency [%]	85.18	85.18	0.00%
TC Heat Rate [Btu/kWh]	7,548	7,619	-0.93%
Net Unit Heat Rate [Btu/kWh]	12,775	12,948	-1.34%
Unit Efficiency [%]	26.71	26.35	0.36%

Table 3-28: Plant Results – Illinois #6 FHW3 Case with Inline 4 Compressor

	Boiler & Steam Turbine Cycle		
	FWH3	**BASE**	**% Diff**
Coal Flow [lb/hr]	473,011	473,011	0.00%
HHV [Btu/lb]	10,999	10,999	0.00%
Q_{coal} [Btu/hr]	5.203E+09	5.203E+09	0.00%
Main Steam Mass Flow [lb/hr]	4,184,734	4,184,734	0.00%
Reheat Mass Flow [lb/hr]	3,677,526	3,677,526	0.00%
Q_{Main} [Btu/hr]	3.848E+09	3.848E+09	0.00%
Q_{Reheat} [Btu/hr]	9.282E+08	9.282E+08	0.00%
Q_{Steam} [Btu/hr]	4.776E+09	4.776E+09	0.00%
Gross Power [kW]	634,580	628,715	0.93%
Pump Power [kW]	1,708	1,711	-0.18%
Net TC Power [kW]	632,872	627,004	0.94%
Rec. Fan Power [kW]	801	801	0.00%
O_2 Fan Power [kW]	239	239	0.00%
ID Fan Power [kW]	6,045	6,045	0.00%
Pulv. Power [kW]	2,503	2,503	0.00%
Auxiliary Power [kW]	15,000	15,000	0.00%
ASU Power [kW]	88,556	88,555	0.00%
Compressor Power [kW]	71,224	71,223	0.00%
Intercooler Pump Power [kW]	91	60	51.67%
Station Service Power [kW]	184,459	184,426	0.02%
Net Unit Power [kW]	448,413	442,578	1.32%
IC Heat Available [kBtu/hr]	348,472	348,468	0.00%
Boiler Efficiency [%]	91.8	91.8	0.00%
TC Heat Rate [Btu/kWh]	7,546	7,617	-0.93%
Net Unit Heat Rate [Btu/kWh]	11,602	11,755	-1.30%
Unit Efficiency [%]	29.41	29.03	0.38%

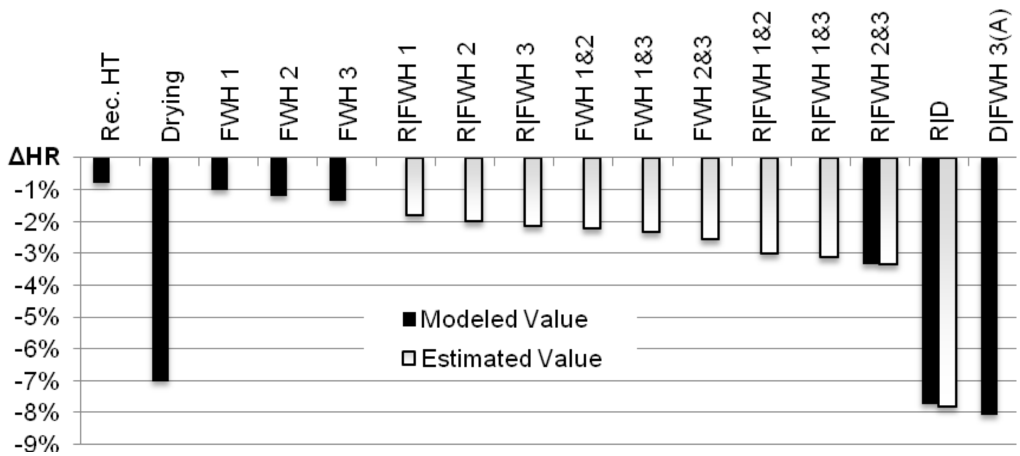

Figure 3-35: Modeled and Estimated ΔHR Values for Inline 4 – ND Lignite

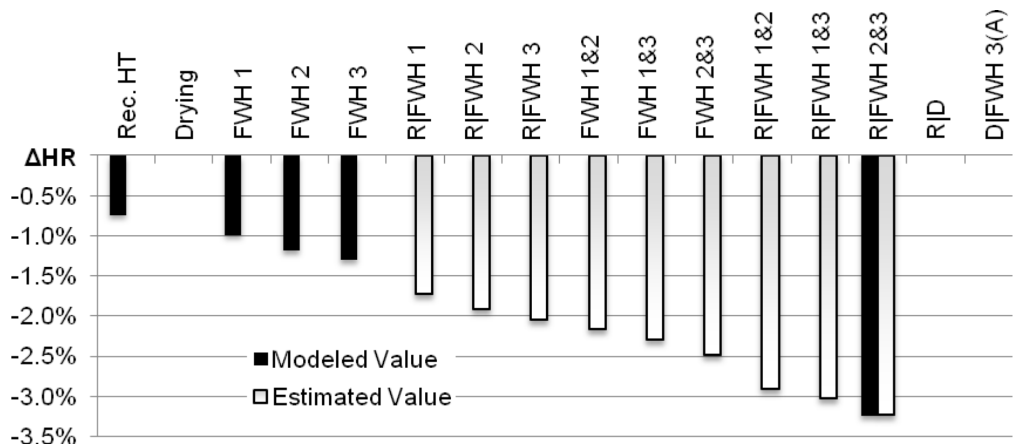

Figure 3-36: Modeled and Estimated ΔHR Values for Inline 4 – Illinois #6

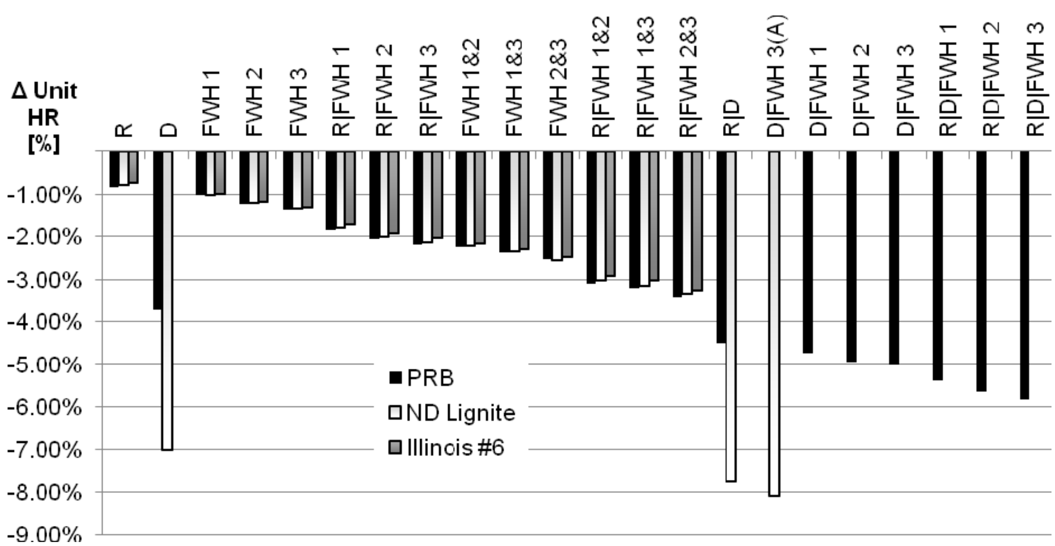

Figure 3-37: Δ Net Unit HR vs. Integration Option & Coal – Inline 4 Compressor

Figures 3-38 and 3-39 show the absolute values of heat rate and the percentage of available heat which is used for the various heat integration cases. Finally, Figure 3-40 shows the net unit power as a function of coal type and heat integration case. The consistently larger values of net power and smaller values of net unit heat rate for Illinois #6 reflect the relatively low moisture content and high fixed carbon content of Illinois #6 compared to lignite and PRB coals.

Effects of Compressor Type

Table 3-29 shows compressor power and available compressor heat as a function of compressor type and coal for the Base Case unit (no thermal integration). The values of compressor gas flow rate with coal type in Table 3-30 assume the same boiler thermal duty for each coal. The table shows the Integrally Geared compressor would consume the least power and the RAMGEN compressor the most power. As discussed in Chapter 2, the differences in compressor power requirements are due to differences in numbers of compressor stages with intercooling and differences in compressor stage efficiencies.

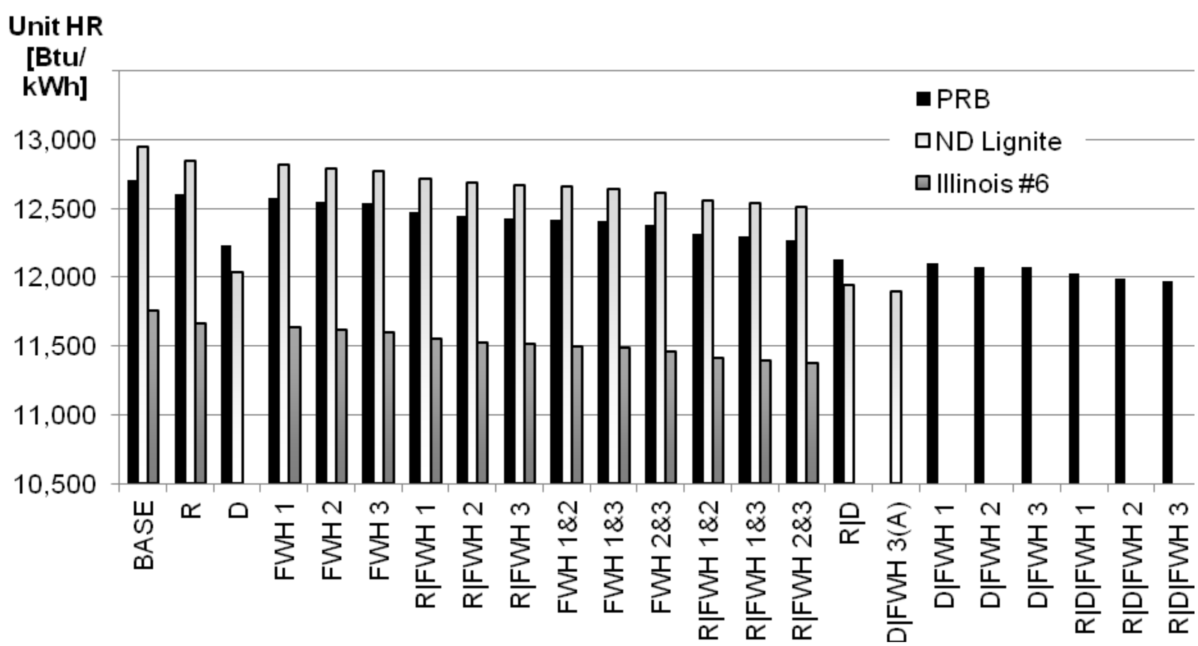

Figure 3-38: Net Unit HR vs. Integration Option & Coal – Inline 4 Compressor

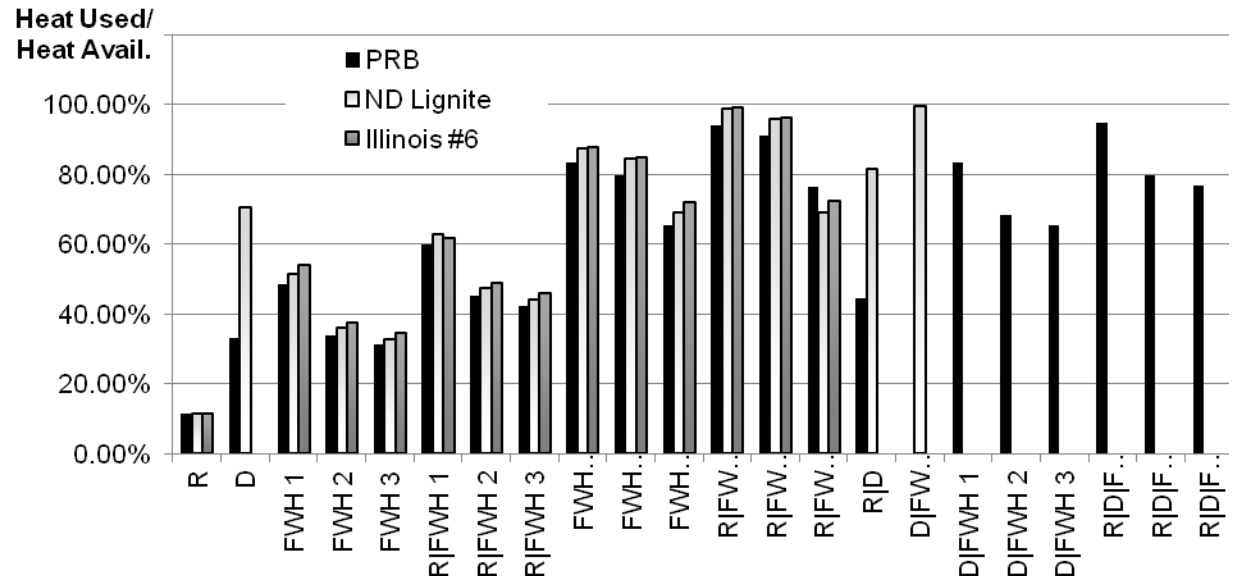

Figure 3-39: % Heat Used vs. Integration Option & Coal – Inline 4 Compressor

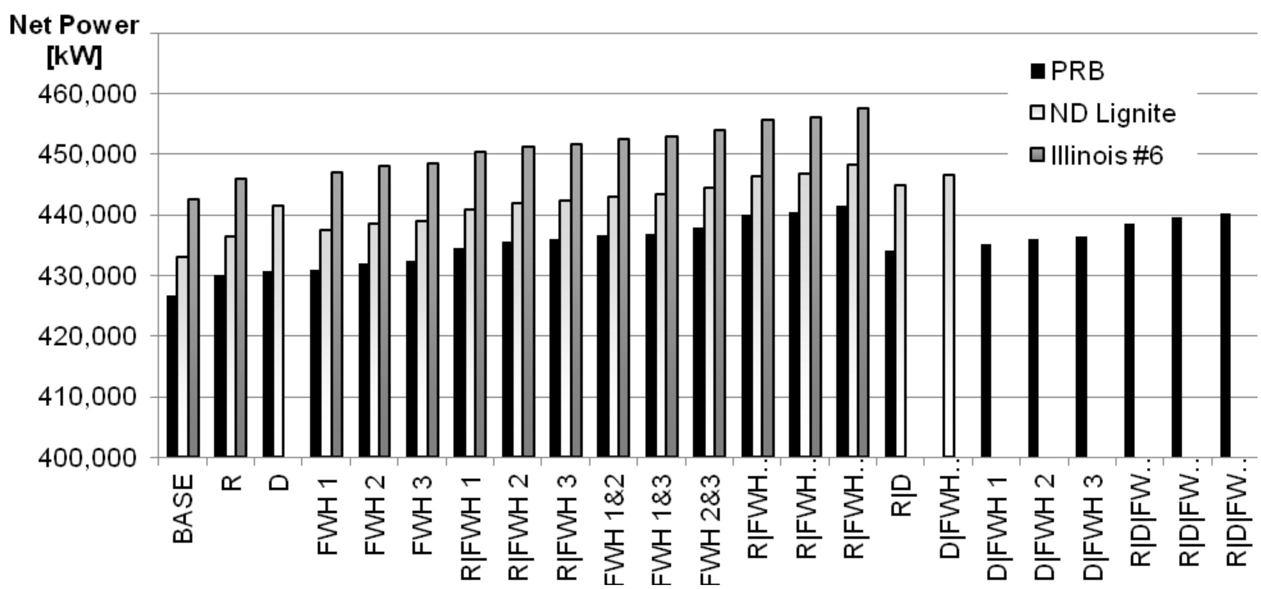

Figure 3-40: Net Unit Power vs. HI Option and Coal – Inline 4 Compressor

Table 3-29: Compressor Power and Available Heat for Base Case Oxy-Fired Unit

Compressor Power (MW)			
	Lignite	**PRB**	**Illinois #6**
Inline 4	75.0	78.9	71.2
Integrally Geared	67.7	71.3	64.3
RAMGEN	81.8	86.1	77.7
Available Heat (kBtu/hr)			
	Lignite	**PRB**	**Illinois #6**
Inline 4	365,016	386,134	348,468
Integrally Geared	334,865	354,360	319,837
RAMGEN	380,971	402,970	363,660
Gas Flow Rate to Compressors (10^6 lbm/hr)			
	Lignite	**PRB**	**Illinois #6**
	1.274	1.346	1.213

The thermal integration results presented in the preceding pages were developed assuming the Inline 4 compressor was being used. Separate analyses were performed using the RAMGEN and Integrally Geared compressors and comparisons were then made on unit performance vs. compressor type. The results are summarized in the following pages.

PRB Coal: Figures 3-41 to 3-45 show the effects of type of compressor and thermal integration option on net unit power, net unit heat rate, and percentages of available compressor heat which would be utilized for PRB coal. Not all thermal integration options would be possible for all three compressor types with PRB coal. In particular, because of limitations on amounts of available heat and on the temperature of the cooling water leaving the compressor intercoolers, three of the combinations of thermal integration options (D/FWH 2&3, R/D/FWH1, and R/FWH 2&3) would not be possible with the Integrally Geared compressor. Similarly, the D/FWH 2&3 option would not be possible with the Inline 4 compressor.

Because for a given coal, the available heat from the RAMGEN compressor is the largest of the three compressors, the percentage increases in net power and percentage reductions in net unit heat rate are largest for RAMGEN (Figures 3-41 and 3-43). However, because it would require the smallest amount of compressor power, the Integrally Geared compressor would result in the largest net unit power and would have the smallest net unit heat rate (Figures 3-42 and 3-44).

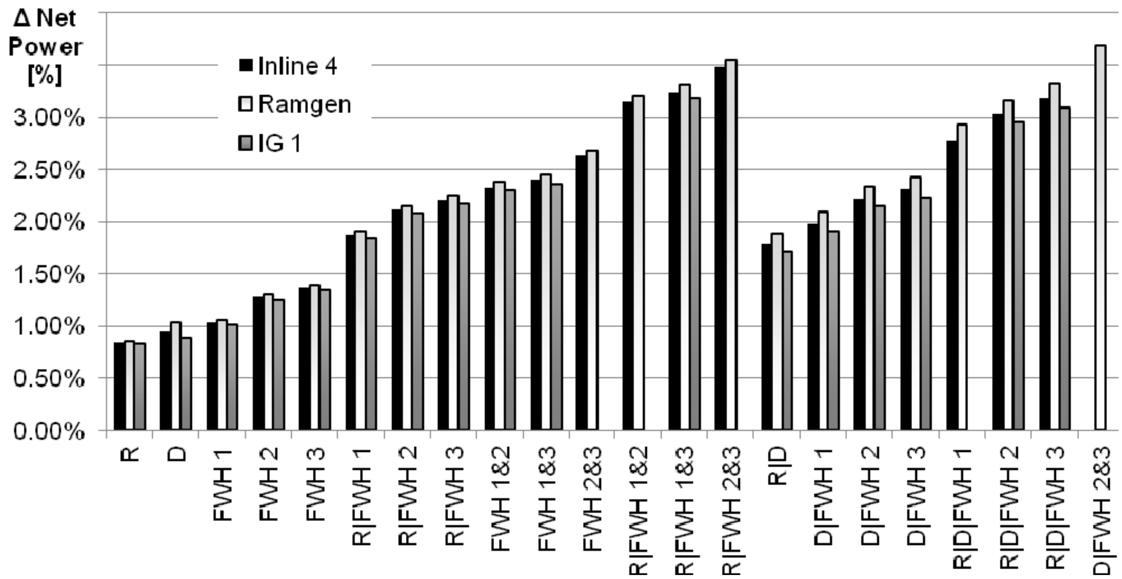

Figure 3-41: Δ Net Unit Power vs. Heat Integration Options and Compressors – PRB Coal

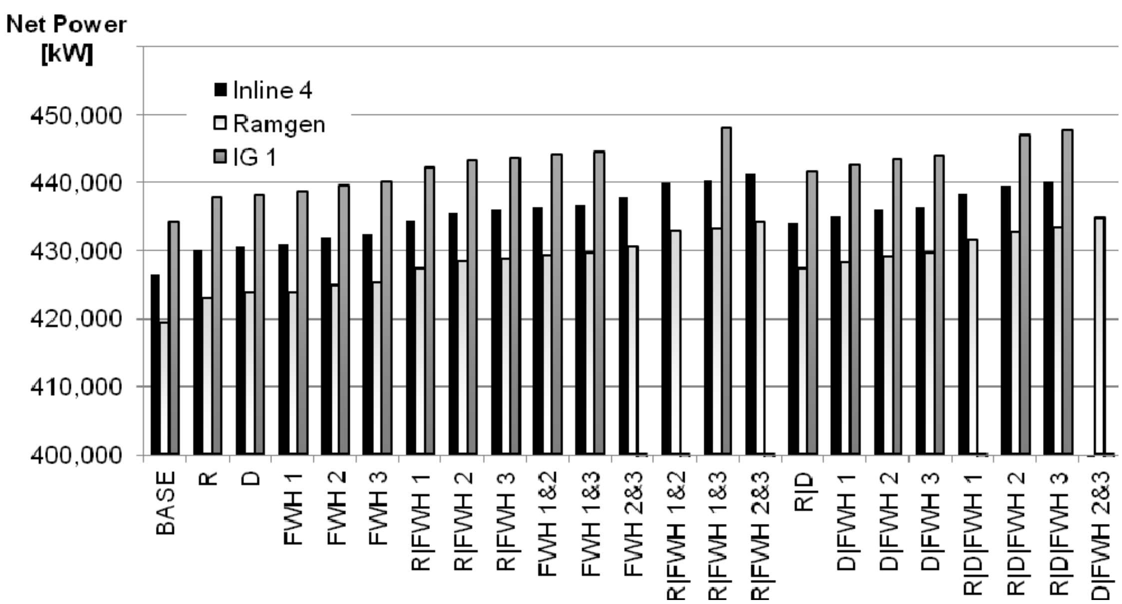

Figure 3-42: Net Unit Power vs. Heat Integration Options and Compressors – PRB Coal

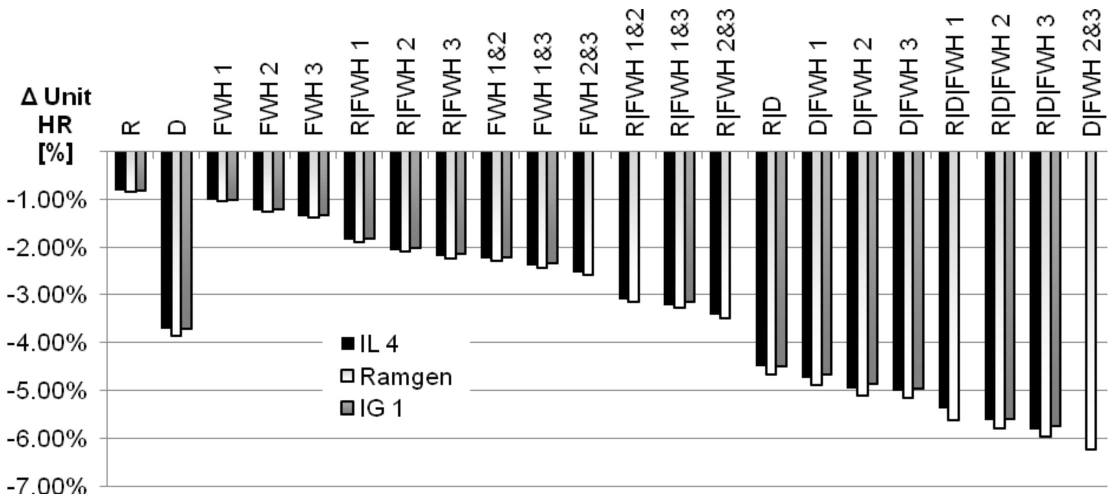

Figure 3-43: Δ Net Unit HR vs. Heat Integration Options and Compressors – PRB Coal

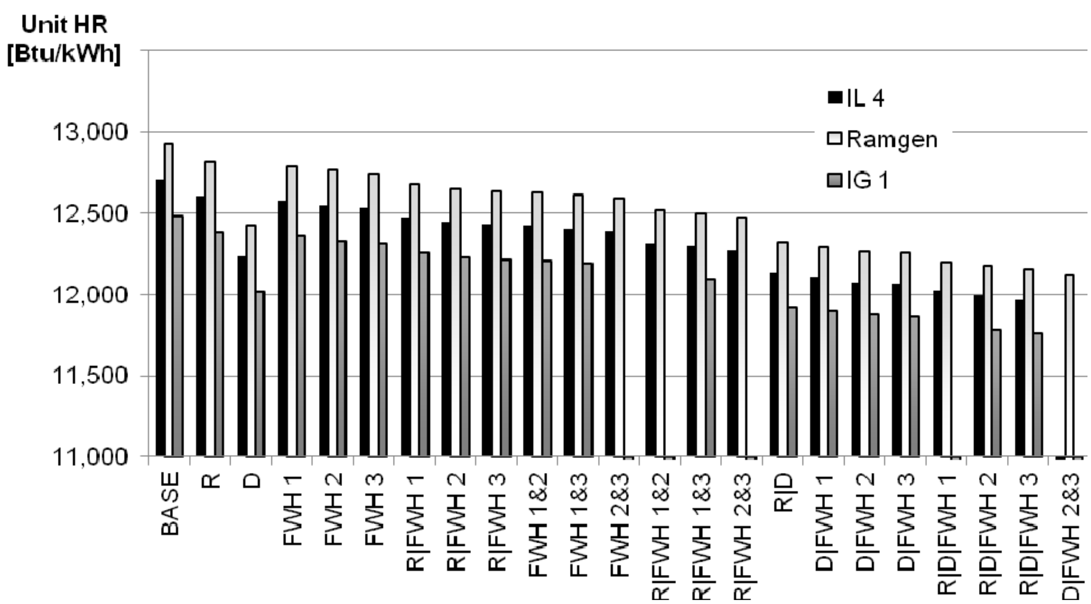

Figure 3-44: Net Unit HR vs. Heat Integration Options and Compressors – PRB Coal

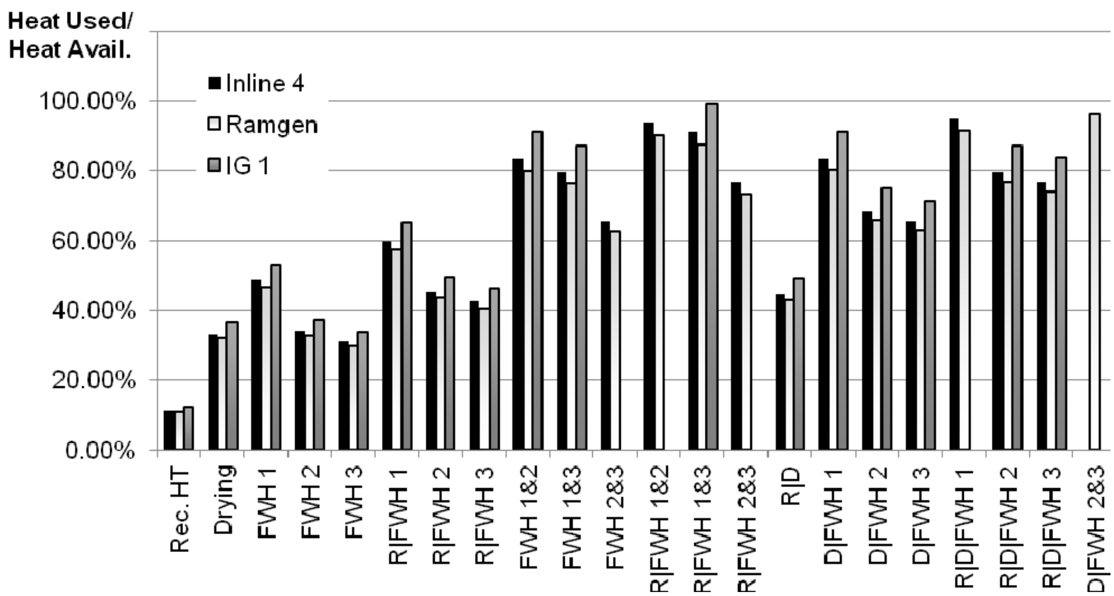

Figure 3-45: % Heat Used vs. Heat Integration Options and Compressors – PRB Coal

North Dakota Lignite: Figures 3-46 to 3-50 show trends with compressor type for lignite which are similar to those for PRB.

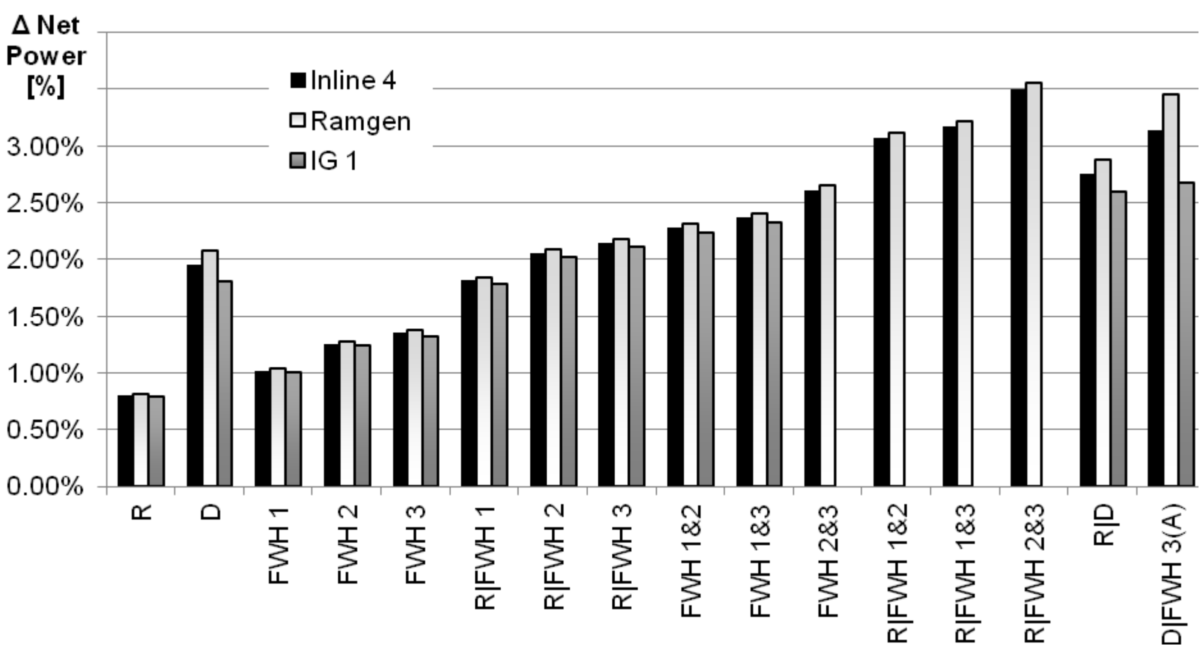

Figure 3-46: Δ Net Unit Power vs. Heat Integration Option & Comp. – ND Lignite

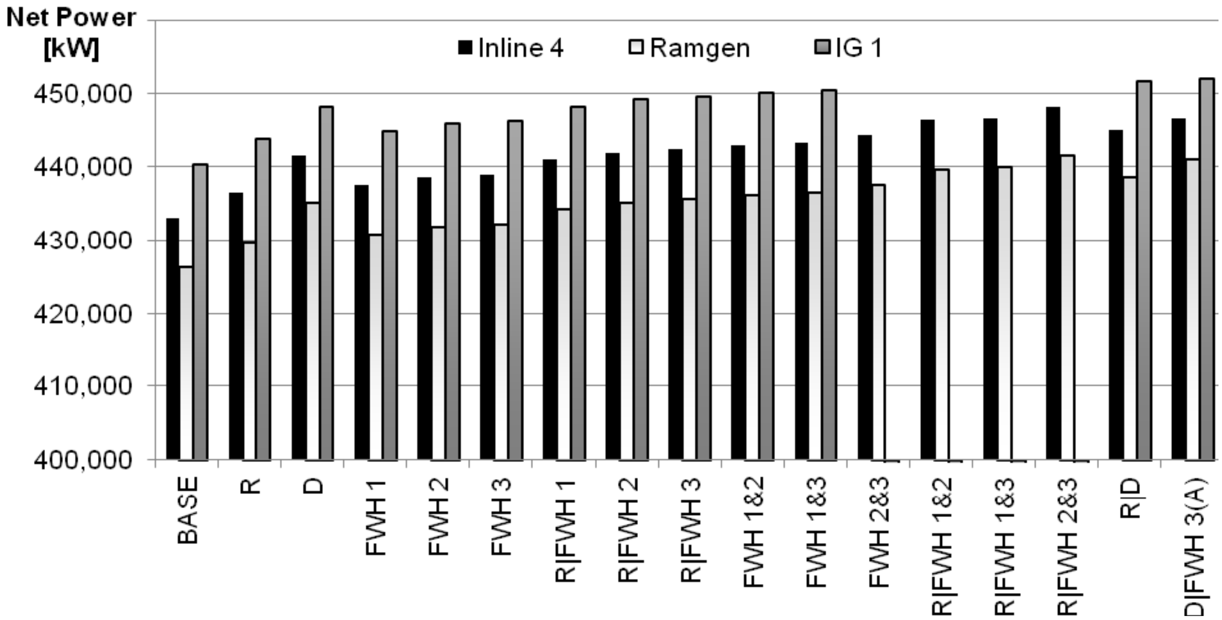

Figure 3-47: Net Unit Power vs. Heat Integration Option & Comp. – ND Lignite

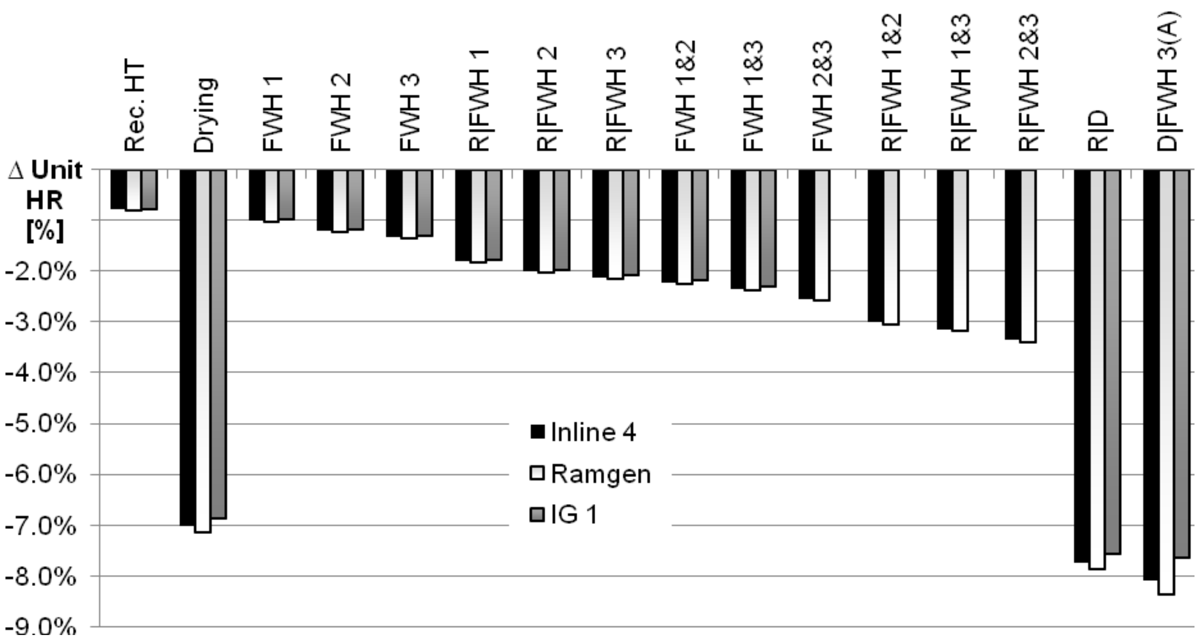

Figure 3-48: Δ Net Unit HR vs. Integration Option & Comp. – ND Lignite

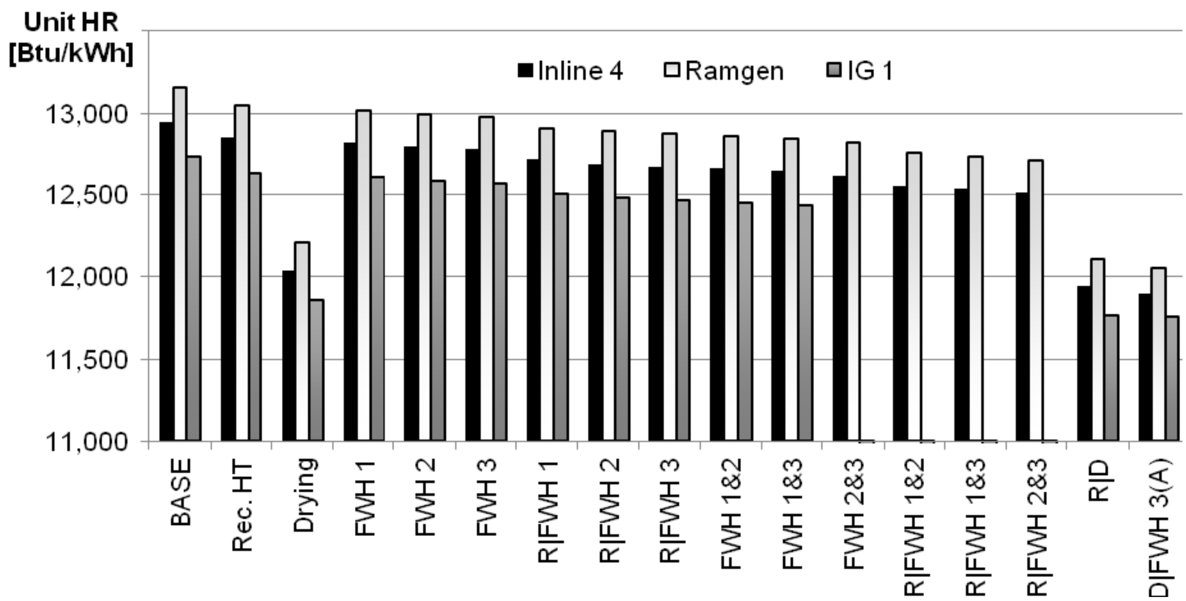

Figure 3-49: Net Unit HR vs. Integration Option & Comp. – ND Lignite

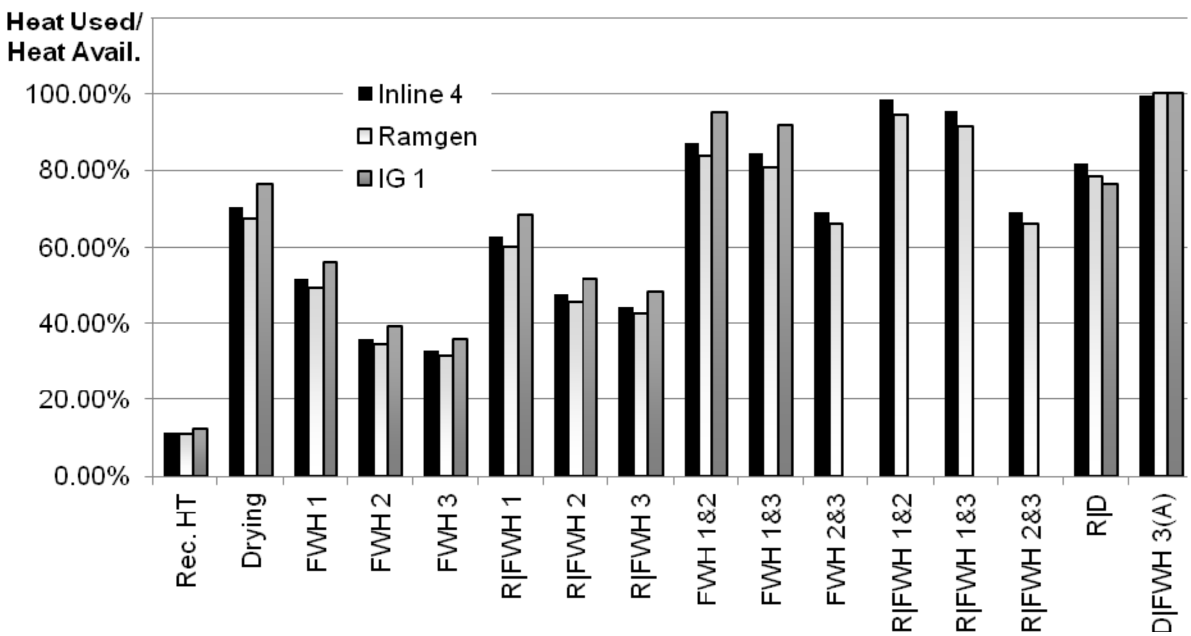

Figure 3-50: % Heat Used vs. Integration Option & Comp. – ND Lignite

Illinois #6: Figures 3-51 to 3-55 cover the results for Illinois #6. Comparisons between Figure 3-53 for Illinois #6, Figure 3-48 for lignite and Figure 3-43 for PRB show that there would be less flexibility in improving net unit heat rate with the Integrally

Geared compressor while firing Illinois #6 than with the other two coals. This is due to less compressor heat being available with the Integrally Geared compressor compared to the other two compressors and less compressor heat being available for Illinois #6 coal compared to the other two coals for each type of compressor (see Table 3-29).

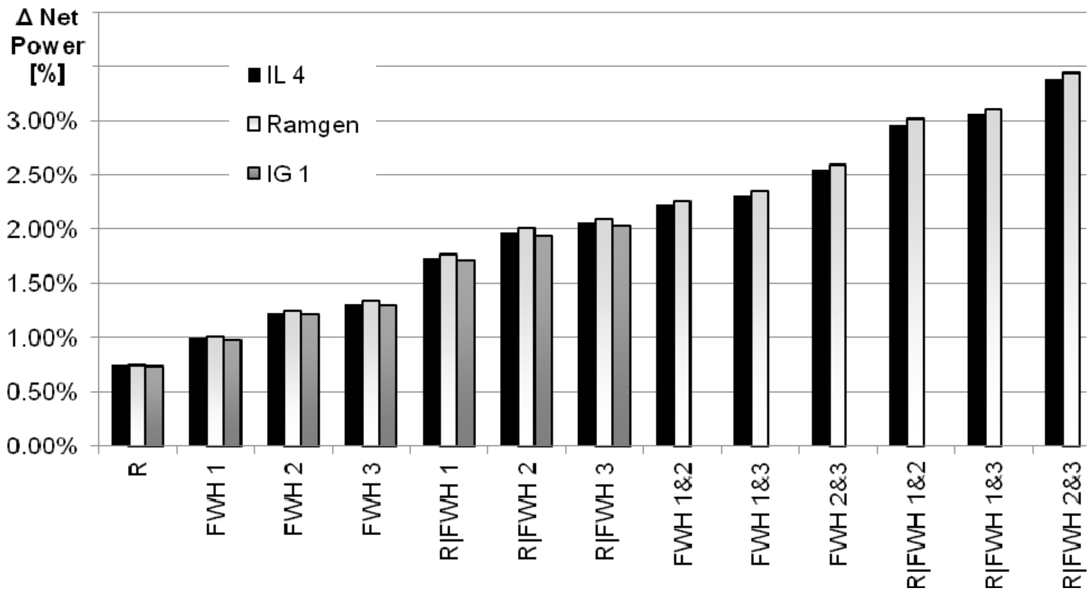

Figure 3-51: Δ Net Unit Power vs. Heat Integration Option & Comp. – Illinois #6

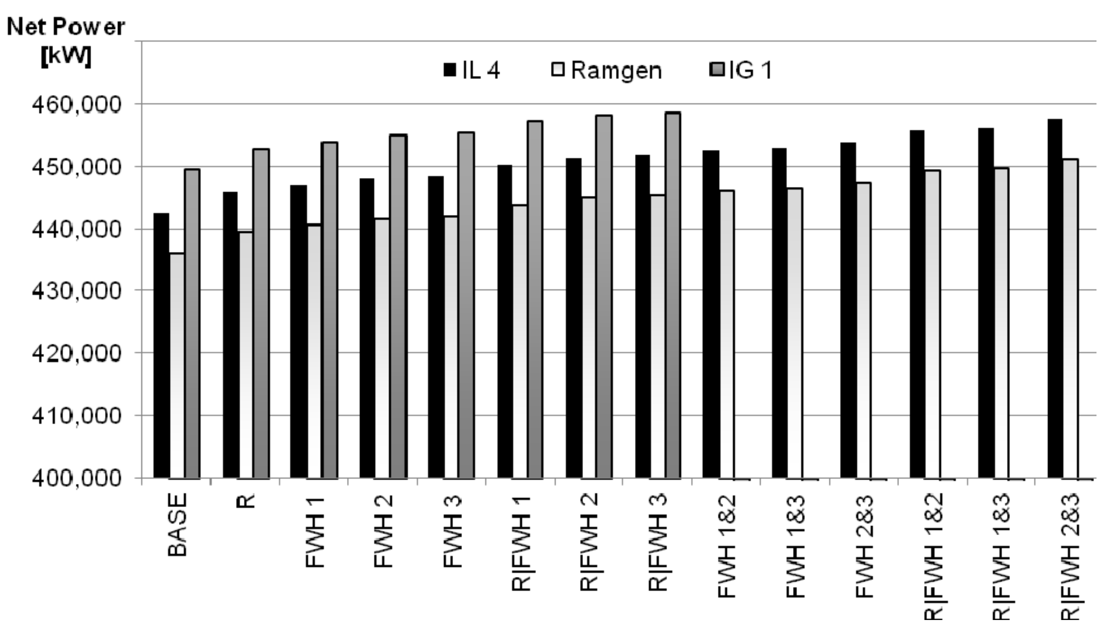

Figure 3-52: Net Unit Power vs. Heat Integration Option & Comp. – Illinois #6

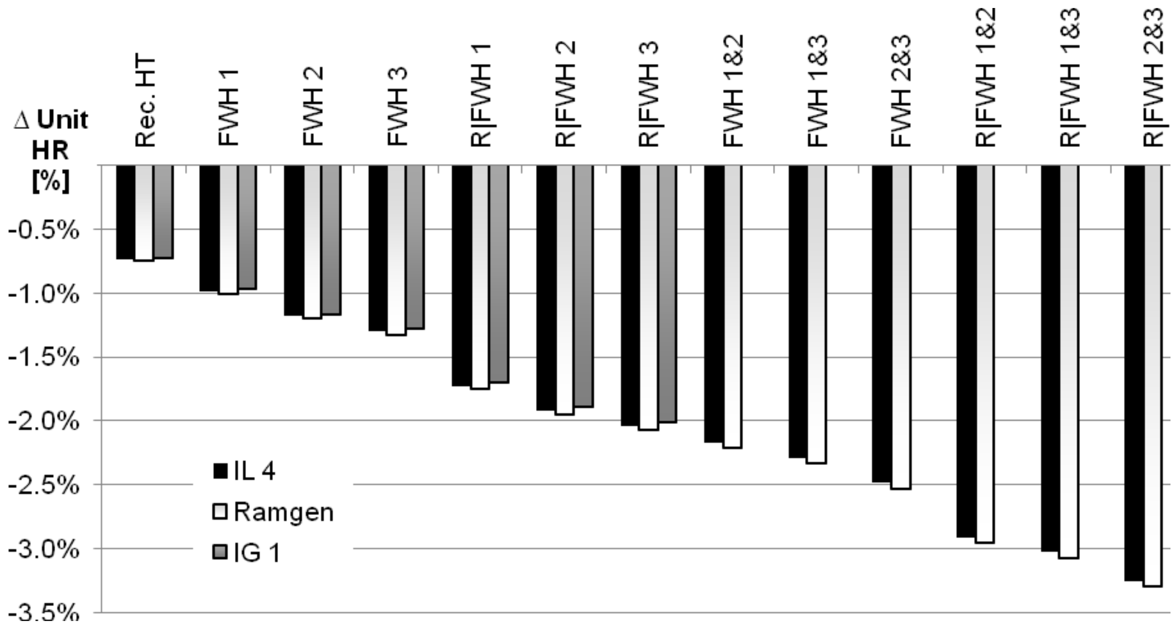

Figure 3-53: Δ Net Unit HR vs. Integration Option & Comp. – Illinois #6

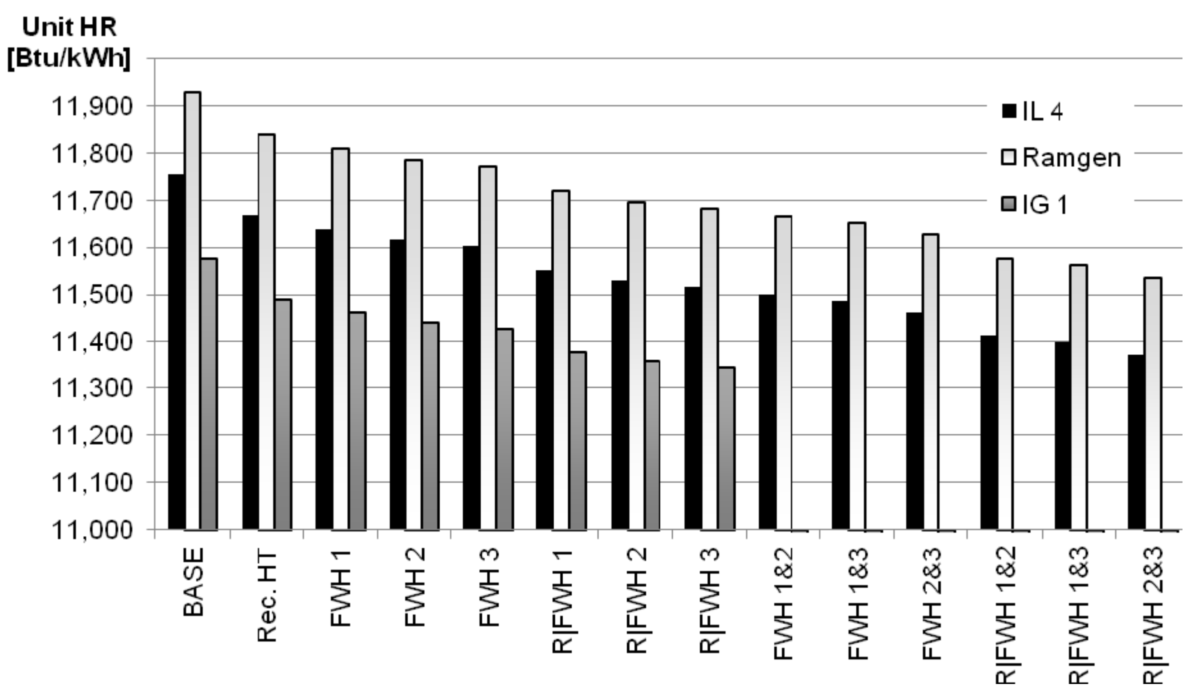

Figure 3-54: Net Unit HR vs. Integration Option & Comp. – Illinois #6

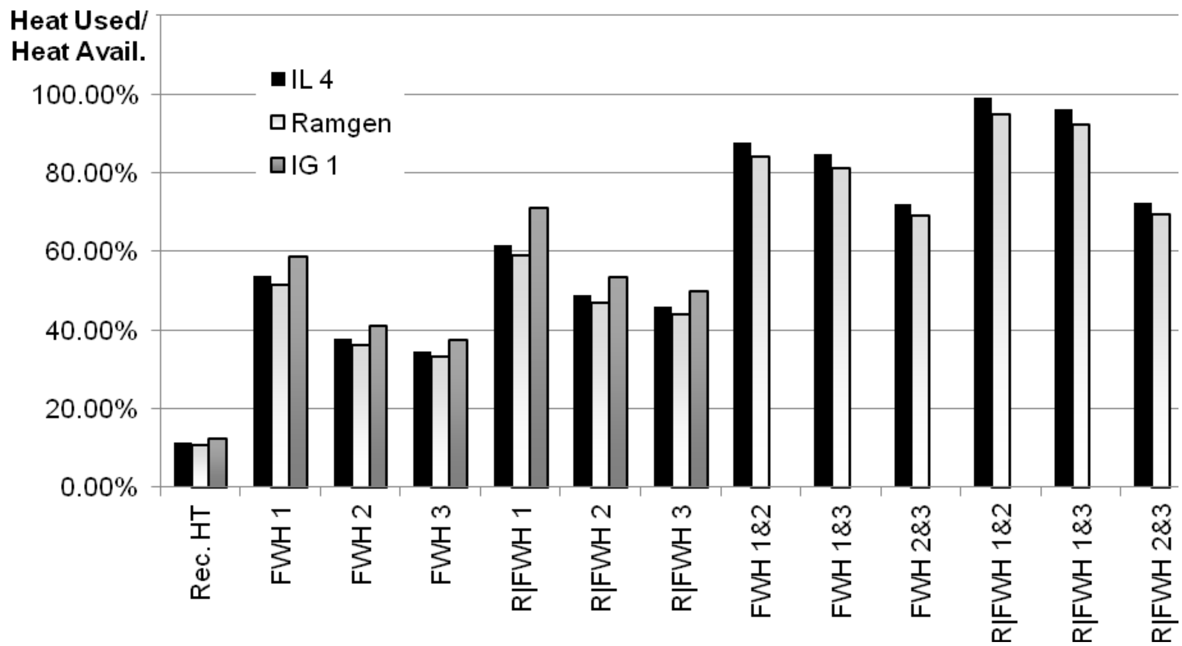

Figure 3-55: % Heat Used vs. Integration Option & Comp. – Illinois #6

SUMMARY AND CONCLUSIONS

Analyses were performed to estimate the magnitudes of the performance improvements which could be achieved in a coal-fired oxycombustion power plant by using heat released during CO_2 compression to provide thermal energy to existing heat loads within the plant. ASPEN Plus was used to model the boiler, supercritical steam turbine cycle and CO_2 compression systems.

Three compressor options were modeled: Inline and Integrally Geared centrifugal compressors and a new shock-wave compression technology being developed by Ramgen Power Systems. For a given application and for the particular centrifugal compressor models which were analyzed (that is, Inline 4 and IG 1), the Integrally Geared compressor has the lowest power requirement, followed by the Inline compressor and then the Ramgen compressor. Heat energy released during intercooling was found to increase with compressor power, with the Ramgen compressor releasing the most heat, and the Integrally geared compressor the least.

A BASE case was specified for each compressor, where the heat from intercooling was dissipated in cooling towers. Changes in net unit heat rate and net power were then determined with compressor heat being used for heating recirculated flue gas, heating boiler feedwater and predrying coal. For the recirculated flue gas and boiler feedwater heating cases, compression heat was used to reduce turbine steam extractions, resulting in increased net unit power. In the coal drying case, the compressor heat resulted primarily in increased boiler efficiency, which, for fixed main steam flow rate, reduced the energy input to the boiler provided by the coal. Pulverizer and ID fan power, rate of CO_2 formation and ASU and CO_2 compressor power were also reduced.

Simulations were performed for each compressor option and each type of coal for each of the following two types of heat sinks: recirculated flue gas and boiler feedwater. Results for coal drying were generated only for PRB and North Dakota Lignite, which are both high moisture coals. Since none of the individual heat integration cases used all of the available heat for any compression option, cases utilizing combinations of individual cases were also analyzed.

Tables 3-30 to 3-32 compare predicted changes in net unit heat rate for the three coals, three types of compressors and three types of heat sinks. The results show the recirculated flue gas case yields heat rate reductions from 0.73 to 0.85 percent, boiler feedwater heating resulted in heat rate reductions from 1.0 to 2.6 percent, depending on the number of feedwater heaters being replaced, and coal drying resulted in heat rate reductions of 3.7 to 3.85 percent for PRB and 6.9 to 7.1 percent for lignite. (Note: It was assumed PRB was dried from 30 to 15 percent moisture and lignite was dried from 38.5 to 20 percent moisture.)

Table 3-30: Heat Rate Improvement (%): Inline 4 Compressor

Coal	Recirculated Flue Gas	FWH1 to FWH2 and FWH3	Coal Drying	Best Combined Case
PRB	0.83	1 to 2.5	3.72	5.8
Lignite	0.79	1 to 2.6	7.02	8.1
Illinois #6	0.74	1 to 2.5	--	3.3

Table 3-31: Heat Rate Improvement (%): Ramgen Compressor

Coal	Recirculated Flue Gas	FWH1 to FWH2 and FWH3	Coal Drying	Best Combined Case
PRB	0.85	1.1 to 2.6	3.85	6.2
Lignite	0.80	1 to 2.6	7.1	8.4
Illinois #6	0.75	1 to 2.5	--	3.3

Table 3-32: Heat Rate Improvement (%): Integrally Geared 1 Compressor

Coal	Recirculated Flue Gas	FWH1 to FWH2 and FWH3	Coal Drying	Best Combined Case
PRB	0.82	1 to 2.3	3.7	5.8
Lignite	0.78	1 to 2.3	6.9	7.7
Illinois #6	0.73	1 to 2.0	--	2.0

The results show that, in general, the percentage heat rate improvement was lowest for Illinois #6 and highest for lignite. Compressor type also affected heat rate improvement, with Ramgen producing the largest heat rate reduction and the Integrally Geared compressor the smallest.

Combinations of heat sinks were analyzed to take advantage of more of the compressor heat and this resulted in predicted heat rate reductions from 2.0 to 3.3 for Illinois #6, from 5.8 to 6.2 for PRB and from 7.7 to 8.4 for lignite.

The results described above show that heating of boiler feedwater by replacing the entire steam extraction to a particular feedwater heater has a positive impact on net unit heat rate. However, large percentages of available heat cannot be utilized by this method. By adding additional heat exchangers heated by hot water from the compressors, either before or after existing high pressure feedwater heaters, the steam extractions to these feedwater heaters can be reduced, allowing for full utilization of available compressor heat. Furthermore, partially cooled water can be cascaded from one feedwater heater to the next, resulting in reduced steam extractions to multiple feedwater heaters. The partial feedwater heating approach with hot water cascading to lower pressure feedwater heaters was compared to the complete FWH steam extraction replacement strategy for PRB coal and the Inline compressor. The results show a heat rate reduction of 4.78 percent for the cascaded strategy versus 2.5 percent for the complete FWH steam extraction replacement strategy.

A cascading partial feedwater heating system will require additional heat exchangers to be purchased and integrated with existing ones. A cost study is needed to compare the increase in turbine cycle power to the additional capital costs of a cascaded partial feedwater heating system.

Table 3-33 and Figure 3-56 show results of predicted net unit heat rate for the Best Combined Case and the Base Case (no thermal integration). These show that the net unit heat rate would be lowest for Illinois #6 compared to the other two coals. The results also show that for all three coals, the Integrally Geared compressor would result in a lower unit heat rate than either of the other two compressors for both the Base Case and the Best Combined Case.

Table 3-33: Effects of Coal Type and Compressor Model on Net Unit Heat Rate

Unit Heat Rate [Btu/kWh]						
	BASE Case			Best Combined Case		
	Inline 4	Ramgen	IG 1	Inline 4	Ramgen	IG 1
PRB	12,707	12,923	12,482	12,099	12,117	11,764
Lignite	12,948	13,153	12,733	11,900	12,051	11,759
Illinois #6	11,755	11,929	11,575	11,373	11,536	11,342

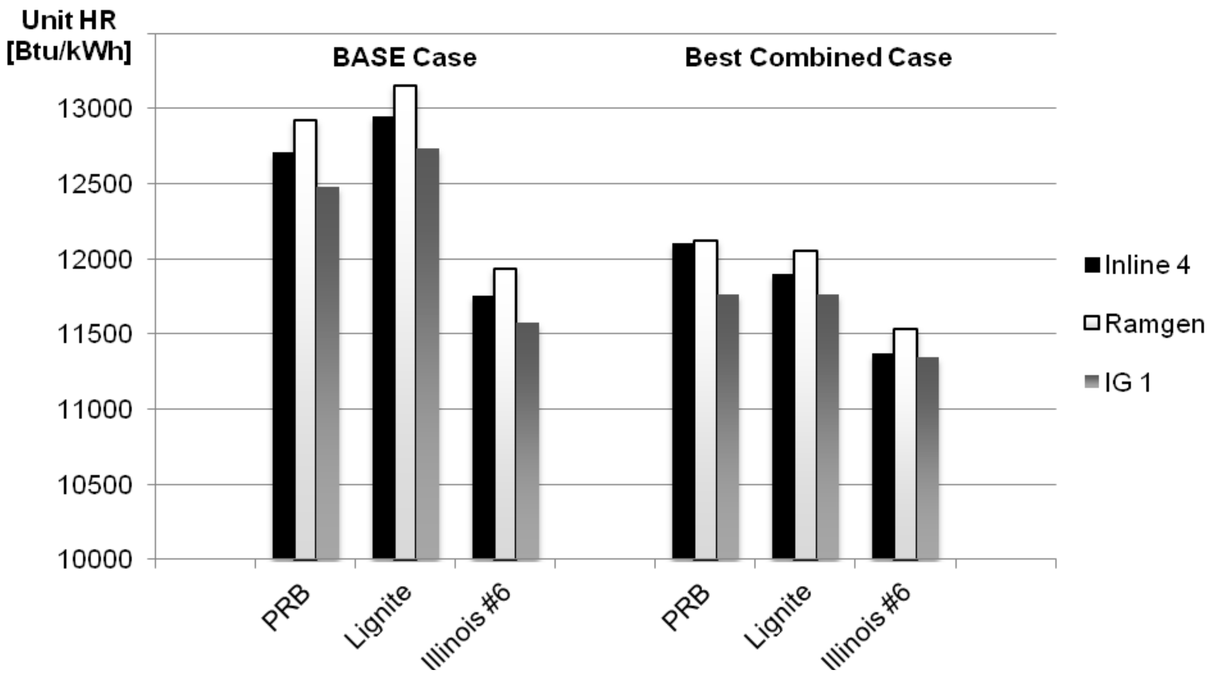

Figure 3-56: Effects of Coal Type and Compressor Model on Net Unit Heat Rate

The overall conclusion from these oxyfuel simulations is that thermal integration of compressor heat has the potential to improve net unit heat rate by up to 8.4 percent, but the actual magnitude of the improvement will depend on the type of heat sink used and to a lesser extent, compressor design and coal rank. For the specific Inline and Integrally Geared compressor models analyzed in this study (that is, Inline 4 and IG 1), the Integrally Geared compressor results in the lowest predicted values of net unit heat rate and the Ramgen compressor, the highest, for each of the thermal integration cases considered.

CHAPTER 4: MEA POST-COMBUSTION CAPTURE SYSTEM

Description of Boiler

Figure 4-1 shows the boiler and back end pollution control equipment. The coal compositions and heating values are given in Table 4-1, and Tables 4-2 to 4-4 give predicted process conditions, gas flow rates and compositions at locations throughout the boiler for PRB, North Dakota Lignite and Illinois #6 coals, for the case without carbon capture or thermal integration.

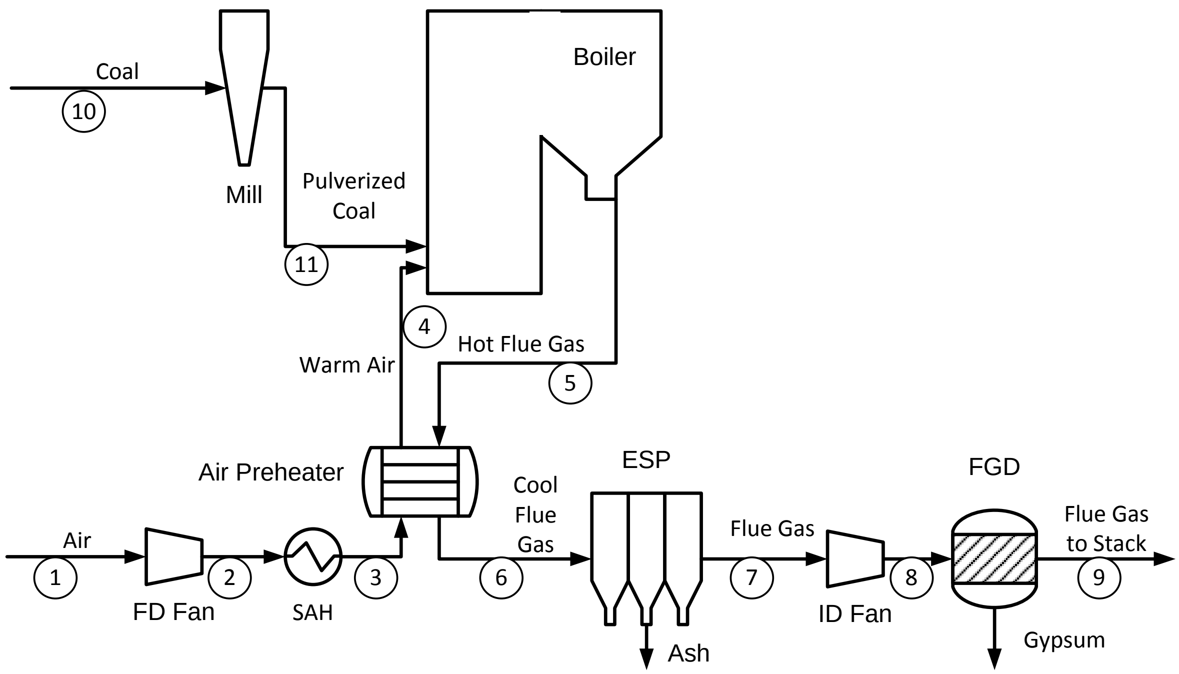

Figure 4-1: Diagram of Boiler

Table 4-1: 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

Table 4-2: 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						
CO_2	0.0%	0.0%	0.0%	0.0%	13.5%	12.7%
H_2O	2.0%	2.0%	2.0%	2.0%	12.7%	12.1%
N_2	77.4%	77.4%	77.4%	77.4%	70.3%	70.7%
O_2	20.6%	20.6%	20.6%	20.6%	3.5%	4.5%
SO_2	0.000%	0.000%	0.000%	0.000%	0.046%	0.044%
Mass Flow (lb/hr)						
CO_2	0	0	0	0	1,159,400	1,159,400
H_2O	69,317	69,317	69,317	64,958	447,238	451,598
N_2	4,108,620	4,108,620	4,108,620	3,850,230	3,854,950	4,113,330
O_2	1,247,540	1,247,540	1,247,540	1,169,080	219,202	297,659
SO_2	0	0	0	0	5,820	5,820

Table 4-2 *(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 4-1 for coal properties	
CO_2	12.1%	12.1%	11.3%		
H_2O	11.6%	11.6%	17.8%		
N_2	71.0%	71.0%	65.9%		
O_2	5.3%	5.3%	5.0%		
SO_2	0.042%	0.042%	0.000%		
Mass Flow (lb/hr)					
CO_2	1,159,400	1,159,400	1,178,950		
H_2O	455,448	455,448	763,179		
N_2	4,341,580	4,341,580	4,392,120		
O_2	366,962	366,962	382,308		
SO_2	5,820	5,820	0		

Table 4-3: 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						
CO_2	0.0%	0.0%	0.0%	0.0%	13.8%	13.0%
H_2O	2.0%	2.0%	2.0%	2.0%	8.4%	8.1%
N_2	77.4%	77.4%	77.4%	77.4%	73.9%	74.1%
O_2	20.6%	20.6%	20.6%	20.6%	3.5%	4.5%
SO_2	0.000%	0.000%	0.000%	0.000%	0.380%	0.357%
Mass Flow (lb/hr)						
CO_2	0	0	0	0	1,044,530	1,044,530
H_2O	64,025	64,025	64,025	60,109	261,860	265,777
N_2	3,794,970	3,794,970	3,794,970	3,562,820	3,567,860	3,800,010
O_2	1,152,310	1,152,310	1,152,310	1,081,810	192,991	263,482
SO_2	0	0	0	0	41,902	41,902

Table 4-3 *(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 4-1 for coal properties	
CO_2	12.3%	12.3%	11.5%		
H_2O	7.8%	7.8%	14.3%		
N_2	74.3%	74.3%	69.1%		
O_2	5.3%	5.3%	5.1%		
SO_2	0.340%	0.340%	0.000%		
Mass Flow (lb/hr)					
CO_2	1,044,530	1,044,530	1,061,730		
H_2O	269,237	269,237	539,930		
N_2	4,005,080	4,005,080	4,049,540		
O_2	325,749	325,749	339,248		
SO_2	41,902	41,902	0		

Table 4-4: 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						
CO_2	0.0%	0.0%	0.0%	0.0%	12.4%	11.7%
H_2O	2.0%	2.0%	2.0%	2.0%	17.5%	16.6%
N_2	77.4%	77.4%	77.4%	77.4%	66.5%	67.2%
O_2	20.6%	20.6%	20.6%	20.6%	3.5%	4.5%
SO_2	0.000%	0.000%	0.000%	0.000%	0.070%	0.066%
Mass Flow (lb/hr)						
CO_2	0	0	0	0	1,090,000	1,090,000
H_2O	67,222	67,222	67,222	62,863	631,509	635,869
N_2	3,984,460	3,984,460	3,984,460	3,726,060	3,732,350	3,990,750
O_2	1,209,840	1,209,840	1,209,840	1,131,380	224,218	302,678
SO_2	0	0	0	0	8,916	8,916

Table 4-4 *(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 4-1 for coal properties	
CO_2	11.1%	11.1%	10.4%		
H_2O	15.9%	15.9%	21.8%		
N_2	67.6%	67.6%	62.8%		
O_2	5.2%	5.2%	5.0%		
SO_2	0.063%	0.063%	0.000%		
Mass Flow (lb/hr)					
CO_2	1,090,000	1,090,000	1,109,960		
H_2O	639,720	639,720	953,706		
N_2	4,219,000	4,219,000	4,270,570		
O_2	371,985	371,985	387,643		
SO_2	8,916	8,916	0		

Steam Cycle

The steam turbine cycle used in this Chapter is the same supercritical reheat steam cycle used in Chapter 3. Steam at 1000°F and 3690 psia enters the high pressure turbine (HPT-1), and the hot reheat steam is at 1000°F and 666 psia. There are seven steam extractions located in the steam cycle.

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 CO_2 from the amine mixture (see Figure 4-2). This will cause less steam to flow through LPTs 2 to 5, which will cause 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. The reboiler will return the condensed steam to FWH4 in the steam cycle. The net power in a carbon capture case is expected to be approximately 33 percent less than the same unit without carbon capture.

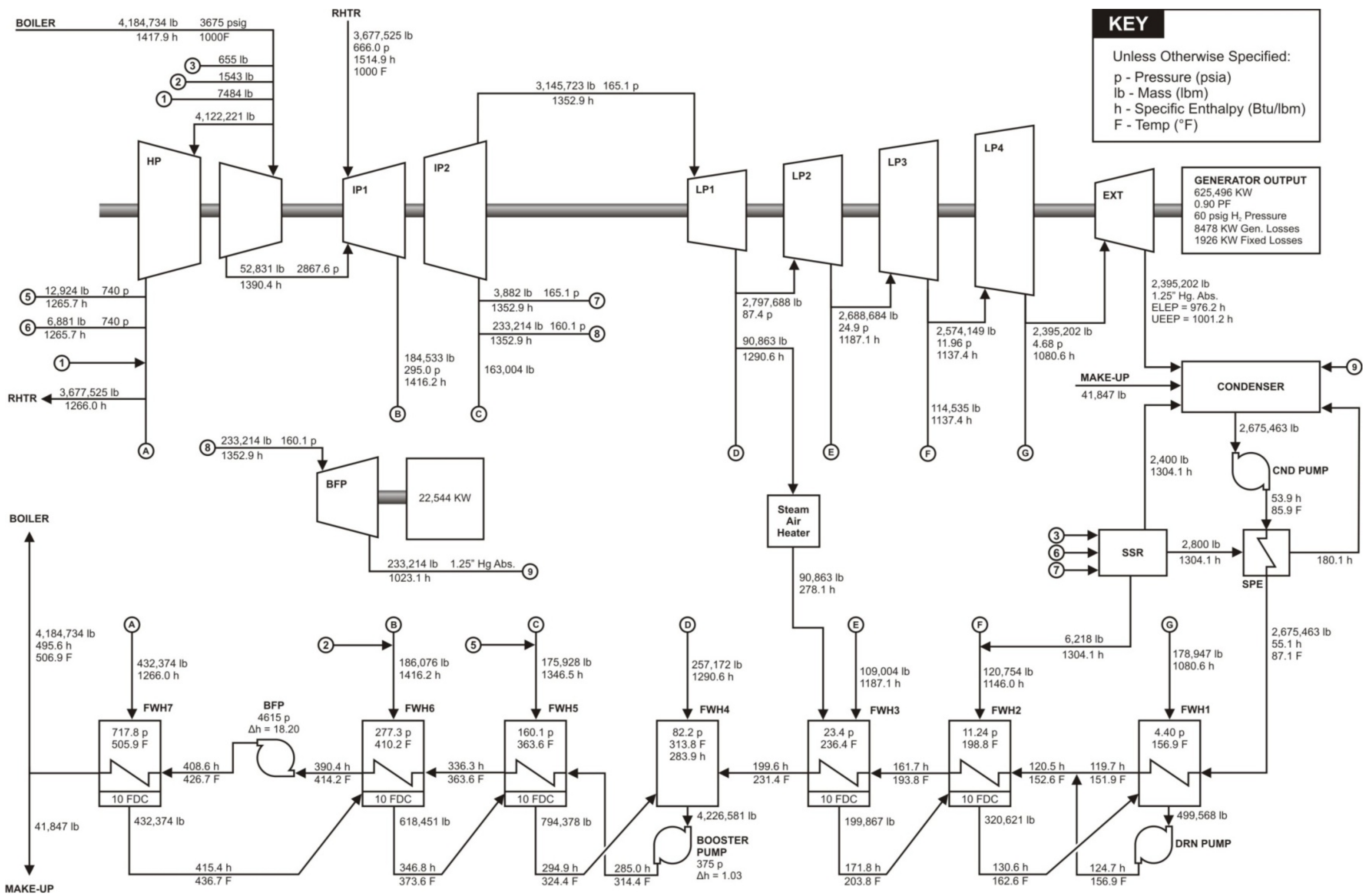

Figure 4-2: Supercritical Steam Turbine Kit Diagram

The feedwater heaters (FWHs) shown in Figure 4-2, use steam extracted from the turbines to preheat feedwater going to the boiler. Extraction A is used to preheat feedwater in FWH-7, extraction B is used to heat feedwater at FWH-6, and so on through all of the turbine stages with the last extraction G being used to preheat feedwater leaving the condenser at FWH-1. When heat integration is discussed later in this Chapter, the extractions to some of the feedwater heaters will be reduced or eliminated, while keeping the boiler feedwater outlet temperatures the same for each FWH. In this case, the extraction steam is replaced with heat from other sources.

Unit Performance without Carbon Capture

To properly analyze the effects that carbon capture would have on the unit, it is helpful to first show how the power plant would behave without carbon capture. Table 4-5 compares predicted values of turbine cycle and boiler parameters for the three coals, all for the case without carbon capture. In order to provide the same throttle steam flow rate to the HP turbine, different amounts of coal would need to be burned for each coal. Lignite would require the highest flow rate with 874,000 lb/hr, PRB would require 643,000 lb/hr, and Illinois #6 would require 472,000 lb/hr. The large differences are due primarily to differences in coal moisture content. The lignite used here has 38.5 percent moisture, PRB has 28.09 percent, and Illinois #6 has 7.97 percent. Boiler efficiency depends strongly on moisture content, which results in calculated efficiencies of 85.3 percent for lignite, 88.2 percent for PRB, and 92.0 percent for Illinois #6. The reduced boiler efficiencies for the low rank coals can be attributed to a portion of the heat of combustion of the coal being used to evaporate water in the coal instead of generating steam to be sent to the turbines.

Post Combustion Carbon Capture System

The carbon capture system described in this Chapter is an MEA post combustion scrubber. The ASPEN model was configured to capture 90 percent of the carbon dioxide that enters the absorber.

Table 4-5: Power Plant Parameters 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
CO_2 Flow (lbm/hr)	1,178,953	1,059,576	1,113,252
Carbon Captured	0.0%	0.0%	0.0%
Reboiler Duty (MBtu/hr)	0	0	0
Reboiler Duty (Btu/lbmCO_2)	0	0	0
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

The principal components of the MEA system are the flue gas cooler, absorber, amine pump, amine heat exchanger, and the stripper (see Figure 4-3). The diagram shows flue gas entering the flue gas cooler (FG cooler) where the flue gas is cooled 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 at the top, while the lean MEA (MEA with small amounts of CO_2 absorbed) enters from the top and the rich MEA (MEA with larger amounts of CO_2 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 cold rich amine is heated by the hot lean amine leaving the reboiler. In the base case PRB analysis, the rich amine is heated in this heat exchanger from 135°F to 238°F.

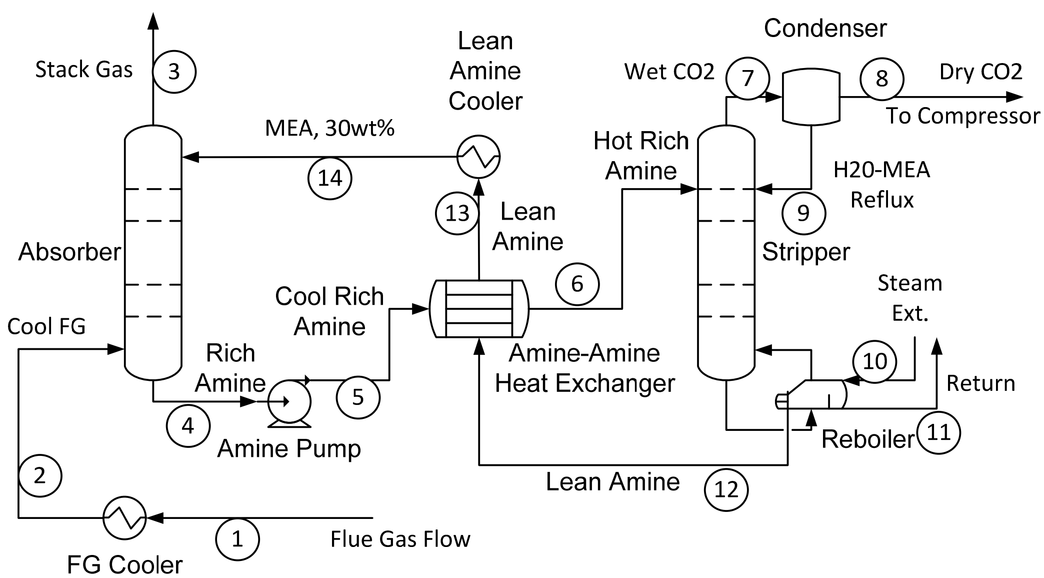

Figure 4-3: MEA Capture System

After leaving the amine heat exchanger, the rich amine enters the stripper where the CO_2 is separated from the MEA solution. Heat is added to the MEA solution in the reboiler to allow the CO_2 to be separated from the MEA solution. The reboiler's heat duty is provided by a flow of steam extracted from the turbine cycle. The reboiler heats the rich amine solution, releasing 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 reduced moisture concentration, 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. The lean amine is cooled to 100°F in the lean amine cooler before reentering the absorber.

Tables 4-6 to 4-8 list the temperature, pressure, flow rate, and composition of the streams at different locations throughout the MEA system.

Table 4-6: 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						
CO_2	11.3%	12.8%	1.4%	3.5%	3.5%	3.5%
H_2O	17.8%	6.5%	13.0%	85.6%	85.6%	85.6%
N_2	65.9%	74.9%	79.5%	0.0%	0.0%	0.0%
O_2	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)						
CO_2	1,178,950	1,178,880	117,891	1,649,950	1,649,950	1,649,950
H_2O	763,179	246,294	463,280	16,729,600	16,729,600	16,729,600
N_2	4,392,120	4,392,110	4,392,010	96	96	96
O_2	382,308	382,307	382,292	15	15	15
MEA	0	0	1,299	7,261,530	7,261,530	7,261,530

Table 4-6 *(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						
CO_2	50.7%	97.8%	0.4%	0.0%	0.0%	1.3%
H_2O	49.2%	2.2%	99.3%	100.0%	100.0%	87.5%
N_2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
O_2	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)						
CO_2	1,065,240	1,060,980	4,265	0	0	588,968
H_2O	423,088	9,860	413,237	1,757,870	1,757,870	16,719,800
N_2	96	96	0	0	0	0
O_2	15	15	0	0	0	0
MEA	4,154	0	4,154	0	0	7,261,530

Table 4-6 *(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		
CO_2	1.3%	1.3%
H_2O	87.5%	87.5%
N_2	0.0%	0.0%
O_2	0.0%	0.0%
MEA	11.211%	11.211%
Mass Flow (lb/hr)		
CO_2	588,968	588,968
H_2O	16,719,800	16,719,800
N_2	0	0
O_2	0	0
MEA	7,261,530	7,261,530

Table 4-7: 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						
CO_2	11.5%	12.6%	1.3%	3.4%	3.4%	3.4%
H_2O	14.3%	6.5%	12.8%	85.6%	85.6%	85.6%
N_2	69.1%	75.4%	79.9%	0.0%	0.0%	0.0%
O_2	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)						
CO_2	1,061,730	1,061,690	106,178	1,507,740	1,507,740	1,507,740
H_2O	539,930	225,837	418,444	15,314,500	15,314,500	15,314,500
N_2	4,049,540	4,049,530	4,049,440	89	89	89
O_2	339,248	339,247	339,234	13	13	13
MEA	0	0	1,161	6,644,730	6,644,730	6,644,730

Table 4-7 *(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						
CO_2	50.9%	97.8%	0.4%	0.0%	0.0%	1.3%
H_2O	49.0%	2.2%	99.3%	100.0%	100.0%	87.5%
N_2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
O_2	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)						
CO_2	959,252	955,447	3,805	0	0	552,292
H_2O	378,150	8,880	369,275	1,578,200	1,578,200	15,305,600
N_2	89	89	0	0	0	0
O_2	13	13	0	0	0	0
MEA	3,703	0	3,703	0	0	6,644,730

Table 4-7 *(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		
CO_2	1.3%	1.3%
H_2O	87.5%	87.5%
N_2	0.0%	0.0%
O_2	0.0%	0.0%
MEA	11.204%	11.204%
Mass Flow (lb/hr)		
CO_2	552,292	552,292
H_2O	15,305,600	15,305,600
N_2	0	0
O_2	0	0
MEA	6,644,730	6,644,730

Table 4-8: 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						
CO_2	10.4%	12.4%	1.3%	3.4%	3.4%	3.4%
H_2O	21.8%	6.5%	12.7%	85.6%	85.6%	85.6%
N_2	62.8%	75.1%	79.6%	0.0%	0.0%	0.0%
O_2	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)						
CO_2	1,109,960	1,109,860	110,977	1,593,420	1,593,420	1,593,420
H_2O	953,706	239,059	438,069	16,204,800	16,204,800	16,204,800
N_2	4,270,570	4,270,560	4,270,470	94	94	94
O_2	387,643	387,641	387,626	15	15	15
MEA	0	0	1,207	7,028,990	7,028,990	7,028,990

Table 4-8 *(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						
CO_2	51.0%	97.8%	0.4%	0.0%	0.0%	1.3%
H_2O	48.8%	2.2%	99.3%	100.0%	100.0%	87.5%
N_2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
O_2	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)						
CO_2	1,002,900	998,951	3,951	0	0	594,470
H_2O	393,168	9,284	383,873	1,645,370	1,645,370	16,195,500
N_2	94	94	0	0	0	0
O_2	15	15	0	0	0	0
MEA	3,843	0	3,843	0	0	7,028,990

Table 4-8 *(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		
CO_2	1.3%	1.3%
H_2O	87.5%	87.5%
N_2	0.0%	0.0%
O_2	0.0%	0.0%
MEA	11.198%	11.198%
Mass Flow (lb/hr)		
CO_2	594,470	594,470
H_2O	16,195,500	16,195,500
N_2	0	0
O_2	0	0
MEA	7,028,990	7,028,990

Compressors

Three different compressor systems (Ramgen, Inline 4 and IG1) were analyzed in this project. Of the three, the Ramgen compressor, which has two stages of compression, is the compressor with the highest stage pressure ratios. Inline 4, has three stages of compression with slightly lower pressure ratios, and IG1, has seven stages of compression, with each stage having a relatively low pressure ratio.

Manufacturer's data were obtained for each compressor system, however, the data had to be modified so that each compression system would work with inlet conditions of 44 psia and 100°F and an exit pressure of 2,210 psia. An intercooler is located between each compression stage to cool the CO_2 from its outlet temperature to 110°F. It is further assumed that the pressure drop for each intercooler is 5 psia for all of the compressor options. The compressor operating data used in the simulations are shown in Tables 4-9 to 4-11.

Table 4-9: 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

Table 4-10: 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

Table 4-11: IG1 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

Base Case Performance of the Unit with Carbon Capture

The results presented in this Chapter are based on having the condensate from the reboiler flow into FWH4 (See Figure 4-4). (Note: FWH4, an open feedwater heater, is also referred to as the deaerator). This stream will lose pressure through the reboiler, so a pump must be added to overcome the reboiler pressure drop, but the additional pump power will be less than 100 kW.

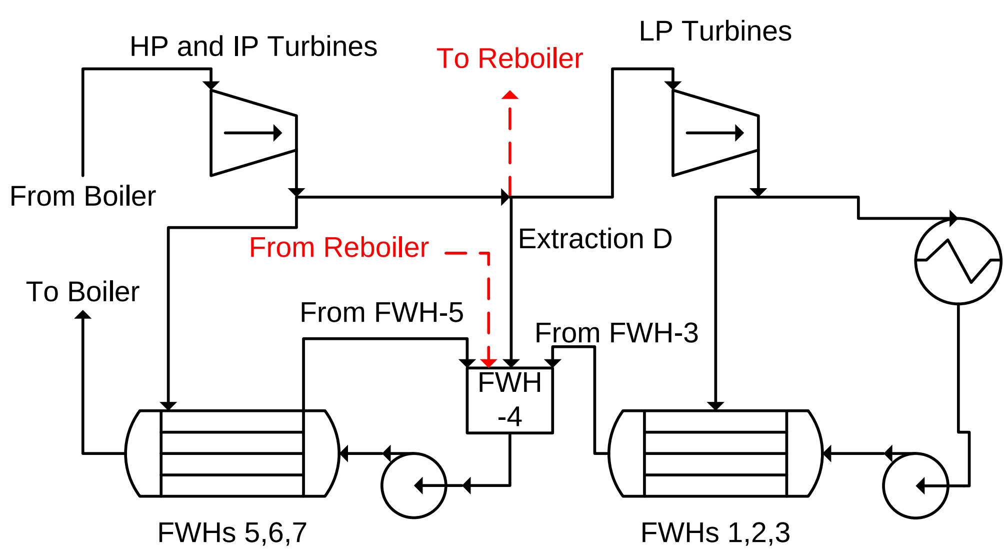

Figure 4-4: Base Case (Reboiler Condensate to FWH-4)

Table 4-12 shows the unit performance with PRB coal and an inline compressor (Inline 4), but without thermal integration. For a main steam flow rate of 4,184,734 lbm/hr, the predicted net unit power is 413.5 MW and the net unit heat rate is 13,118 Btu/kWh.

Table 4-12: Unit Performance with PRB Coal and an Inline 4 Compressor, but without Heat Integration

Wet Coal Flow (lb/hr)	643,021
Dried Coal Inlet Moisture	28.09
Gen Power (kW)	496,071
Fan Power (kW)	18,002
Pulv Power (kW)	3,403
Pump Power (kW)	2,291
Aux Power (kw)	15,000
Pss (kW)	38,697
Carbon Captured	89.99%
Reboiler duty (Btu/lbmCO_2)	1,692
Comp Power (kW)	43,869
Boiler Steam Flow (lb/hr)	4,184,734
Air Flow to FD Fan (lb/hr)	5,425,475
Flue Gas leaving FGD (lb/hr)	6,716,556
Net Power (kW)	413,506
Unit Heat Rate (Btu/kWhr)	13,118
Efficiency (%)	26.0%
Heat Integration Details	
FWH-1 Duty (kBtu/hr)	81,329
FWH-2 Duty (kBtu/hr)	62,882
FWH-3 Duty (kBtu/hr)	58,088
FWH-5 Duty (kBtu/hr)	216,159
Extract G (lb/hr)	83,900
Extract F (lb/hr)	49,500
Extract E (lb/hr)	48,000
Extract D (lb/hr)	146,000
Extract C (lb/hr)	163,004
Heat Rejected	
Steam Condenser (MBtu/hr)	1,167
Stripper Condenser (MBtu/hr)	491
Compressors (MBtu/hr)	258
Amine Cooler (MBtu/hr)	1,031
Flue Gas Cooler (MBtu/hr)	503

Heat Integration Simulations

Simulations were performed using waste heat from the stripper condenser and compressors. Results for a PRB coal with an Inline 4 compressor are described in this section of the Chapter, with results for other coals and compressors in a subsequent section.

The heat sinks used in the analysis were FWHs 1, 2, 3, 4, and 5, the stripper reboiler, and a coal dryer. The stripper condenser, which rejects heat at a relatively low temperature of 230°F, can be used for lower temperature heat sinks such as FWHs 1, 2, and 3, and 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 FWH's. 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. FWH's 1 to 4 are shown in Figure 4-5 without heat integration, which is also referred to as the Base Case.

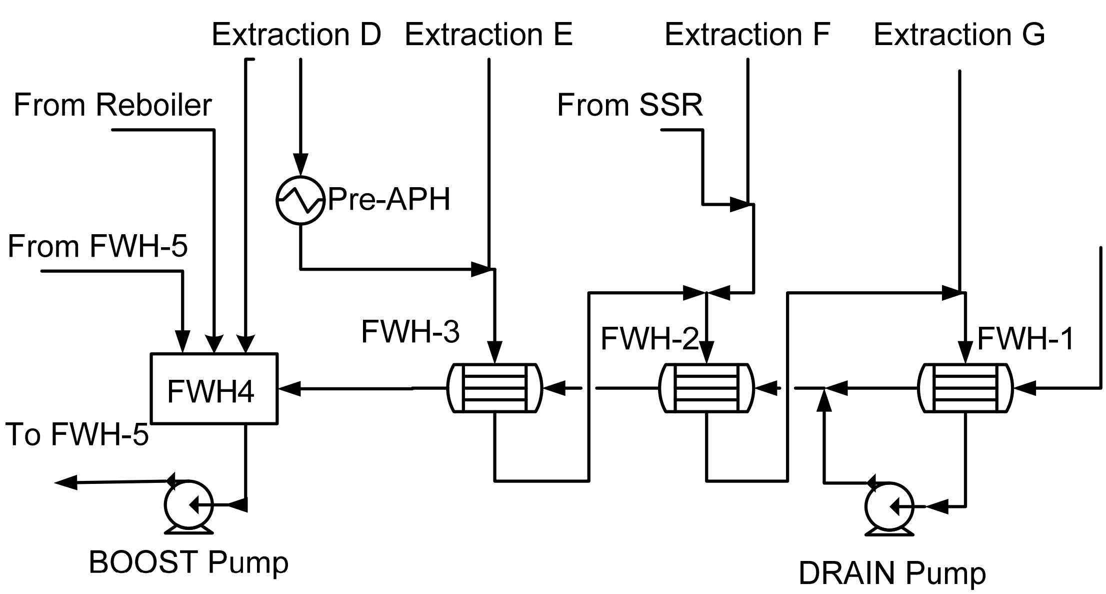

Figure 4-5: Feedwater Heaters 1, 2, 3, and 4: Base Case

When using a high temperature cooling water stream, it is best to place the 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 stage and all of the turbine stages further downstream. This is illustrated in Figure 4-6, where 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 a higher temperature extraction generates more power than reducing a lower temperature extraction; therefore, the emphasis should be placed on reducing the higher extractions before proceeding to minimize lower temperature extractions.

The cooling water leaving a higher temperature feedwater heater, such as FWH-4, can also be used to transfer heat to a lower temperature feedwater heater, such as FWH-3. This cascading effect is described later in this Chapter.

<u>Stripper Condenser Heat Integration</u>

The stripper condenser (see Figure 4-7) cools the carbon dioxide and water mixture from 240°F to 100°F. It is assumed that cooling water enters at 90°F, and the cooling water flow rate is specified so that there is a 10°F temperature difference at the outlet, with the water leaving at 230°F. This gives the option of integrating heat from the stripper condenser to FWH's 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 FWH's 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 can be used to heat feed water in place of FWH's 1, 2, and 3; the details of this heat integration are shown in Figure 4-7. If used in this way, heat from the stripper condenser would completely replace extractions G, F, and E at FWHs 1, 2, and 3, and the cooling water from the stripper condenser would be cooled from 230°F to 181°F. The feedwater leaving FWH-3B would be at 220°F instead

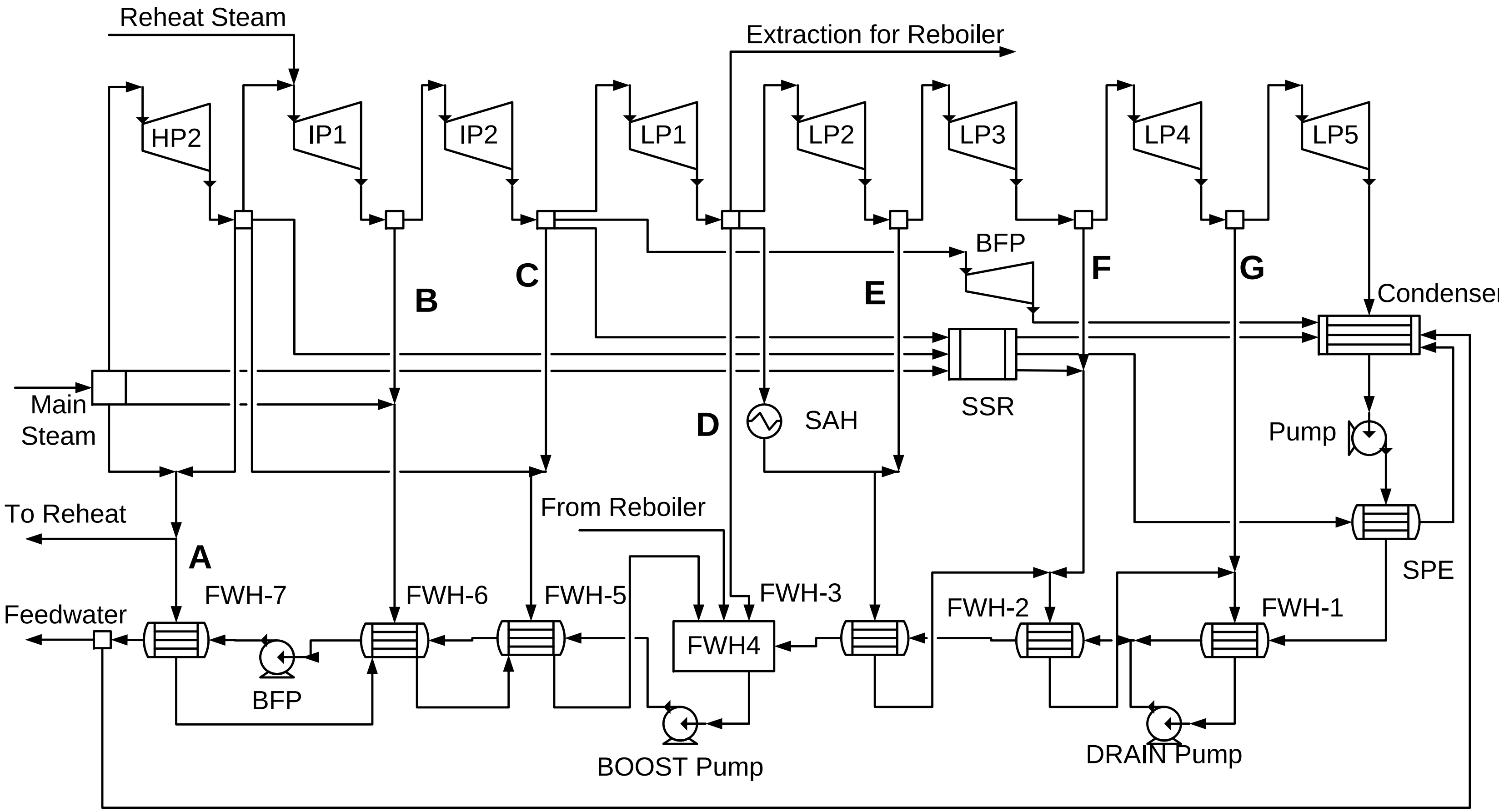

Figure 4-6: Steam Turbine Cycle with Reboiler Condensate Returned to FWH-4

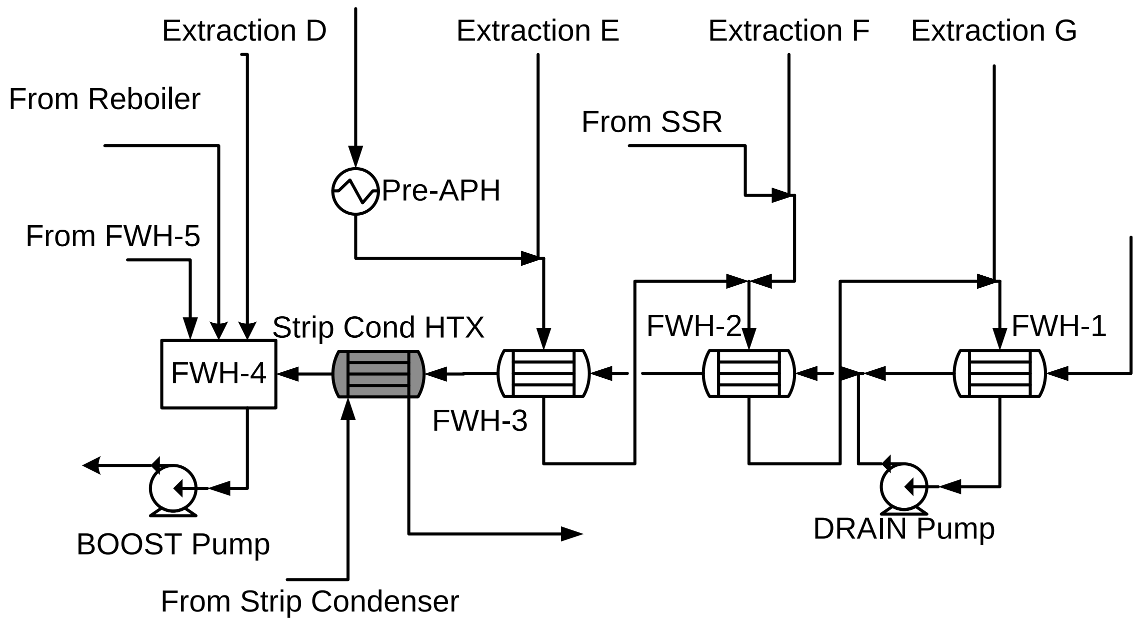

Figure 4-7: Feedwater Heaters 1, 2, 3, and 4 with Stripper Condenser Heat Integration

of the usual 231.4°F. To compensate, extraction D would be increased from 146,000 lb/hr to 163,000 lb/hr to maintain the 314°F temperature requirement leaving FWH-4. This heat integration strategy would increase the net power by 5,026 kW and decrease the heat rate from 13,118 Btu/kWhr to 12,961 Btu/kWhr, an improvement of 1.20%. See Table 4-13 for more integration details.

Compressor Heat Integration

Three stages of compression would be needed for the MEA capture system while using the Inline 4 compressor. Exit CO_2 temperatures would be in the range of 420 to 430°F for the first two stages and approximately 170°F for the last stage. Due to a relatively low cooling water temperature after the last stage, this cooling water was not used in the heat integration analysis. It was assumed instead that the cooling water from the PCC would be cooled in a cooling tower or the CO_2 would be sent to a pipeline from the last stage without post compressor cooling.

Table 4-13: PRB Heat Integration Results Using Inline 4

	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/lbmCO_2)	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 Condenser 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 4-13 *(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/lbmCO_2)	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 Condenser 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

If the two cooling water streams leaving the first two compressor intercoolers were combined, they would create a water flow rate of approximately 720,000 lb/hr at 423°F, which could be used to heat boiler feedwater in place of turbine extraction steam entering FWHs 4 and 5, thus reducing extractions C and D. As an alternative, cooling water from the compressors could also be used to heat boiler feedwater in place of FWHs 1, 2, and 3, however, it would provide a larger power improvement if the cooling water were integrated to boiler feedwater in place of FWHs 4 and 5 before being further cooled at FWHs 1, 2, and 3.

Compressor to FWH 1, 2, and 3

Using cooling water from the compressors to replace extractions G, F, and E to FWHs 1, 2, and 3 results in all three extractions being eliminated as well as partial reduction in extraction D at FWH-4. Figure 4-8 shows where the compressor heat exchanger would be located within the steam cycle. A total of 89.2% of the heat from the compressors would be needed to heat the boiler feedwater from 105°F to 251°F. This would result in extraction D being reduced to 118,000 lb/hr and give a final heat rate of 12,846 Btu/kWhr, a 2.08% improvement (Table 4-13). After leaving the compressor heat exchanger (Comp HTX) the compressor cooling water would have a 115°F temperature, which is greater than the required inlet temperature of the post compressor cooler. The compressor cooling water needs to be cooled further, possibly in a cooling tower, before reentering the post compressor cooler.

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

The Inline 4 compressor stages release heat at a relatively high temperature of 423°F, which offers the possibility of integrating heat to 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, in the analyses, this heat was cascaded down to integrate into FHW-4 and then to FWHs 1-3 (Figure 4-9). To keep these heat exchangers at a realistic size, it was assumed that there is at least at 10°F temperature difference between the feed water and the heat integration water.

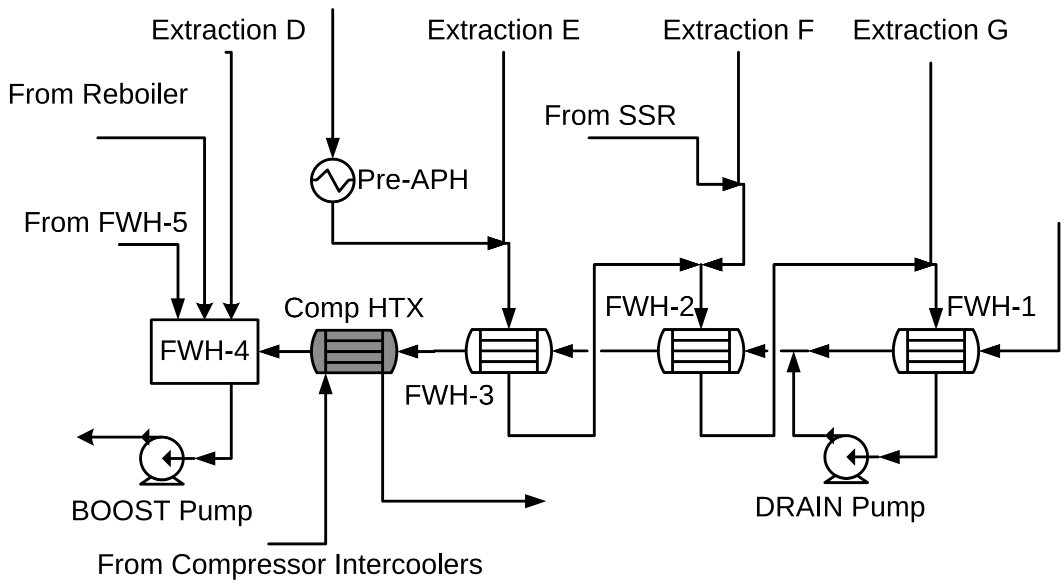

Figure 4-8: Feedwater Heaters 1 to 4 with Compressor Heat Integration to FWH1 to 3

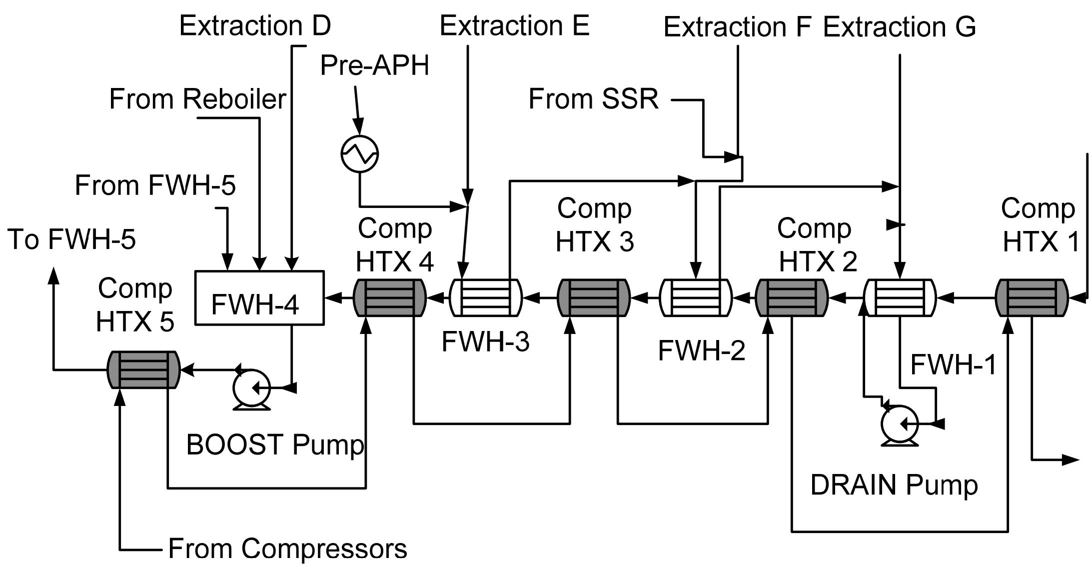

Figure 4-9: Feedwater Heaters 1, 2, 3, and 4 with Compressor Heat Integration to FWH1, 2, 3, 4, and 5

Integrating the compressor heat to FWH-5 would cause 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 hot water leaving compressor heat exchanger HTX-5 could also used to heat water entering FWH-4, which would reduce extraction D from 146,000 lb/hr to 75,000 lb/hr. Using a similar cascading technique, shown in Figure 4-9, extraction E would be reduced to 40,000 lb/hr, extraction F to 39,000 lb/hr, and extraction G to 24,000 lb/hr. The heat rate obtained by implementing these changes is 12,694 Btu/kWhr giving a 3.23% improvement over the case without heat integration (Table 4-13).

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 hot cooling water was not cascaded down to preheat FWHs 1, 2, and 3 and it was assumed the compressor cooling water leaving compressor heat exchanger HTX-4 would need to be cooled further before returning to the compressors. Implementing these changes yielded a predicted heat rate of 12,789 Btu/kWhr, which is a 2.51% improvement over the base case (Table 4-13). This process is shown in Figure 4-10.

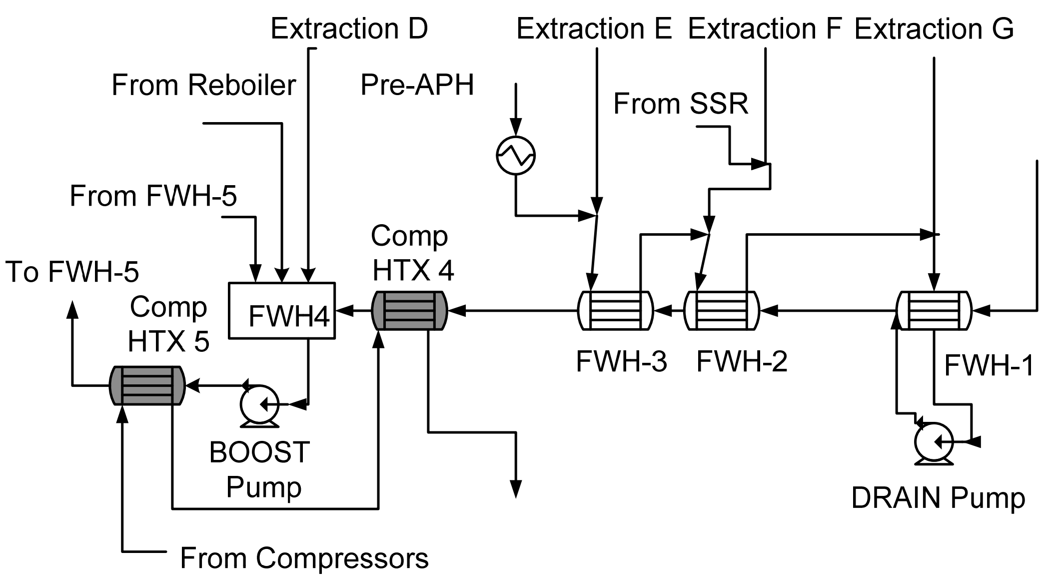

Figure 4-10: Feedwater Heaters 1, 2, 3, and 4 with Compressor Heat Integration to FWH 4 and 5

Compressor Heat to Reboiler

Compressor heat can also be rejected to the reboiler, reducing the reboiler extraction upstream of LPT-2. The reboiler extraction is in the same location (between LPTs 1 and 2) as extraction D for FWH-4 and it can be shown that integrating heat to FWH-4 and integrating heat to the reboiler would achieve the same results (Figures 4-11 and 4-12). Both of these heat integration scenarios would reduce the same amount of extraction steam that otherwise would have been sent to FWH-4 or the reboiler. Instead, this steam will flow through LPTs 2 to 5, generating the same amount of additional power in both cases.

As an example, 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

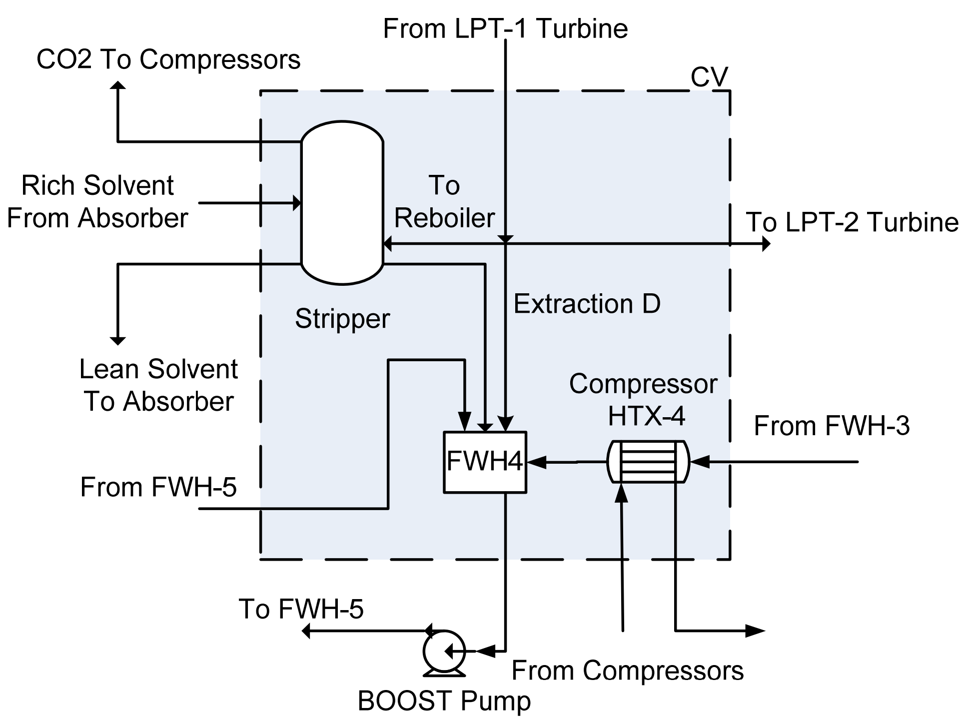

Figure 4-11: FWH-4 Heat Integration Control Volume

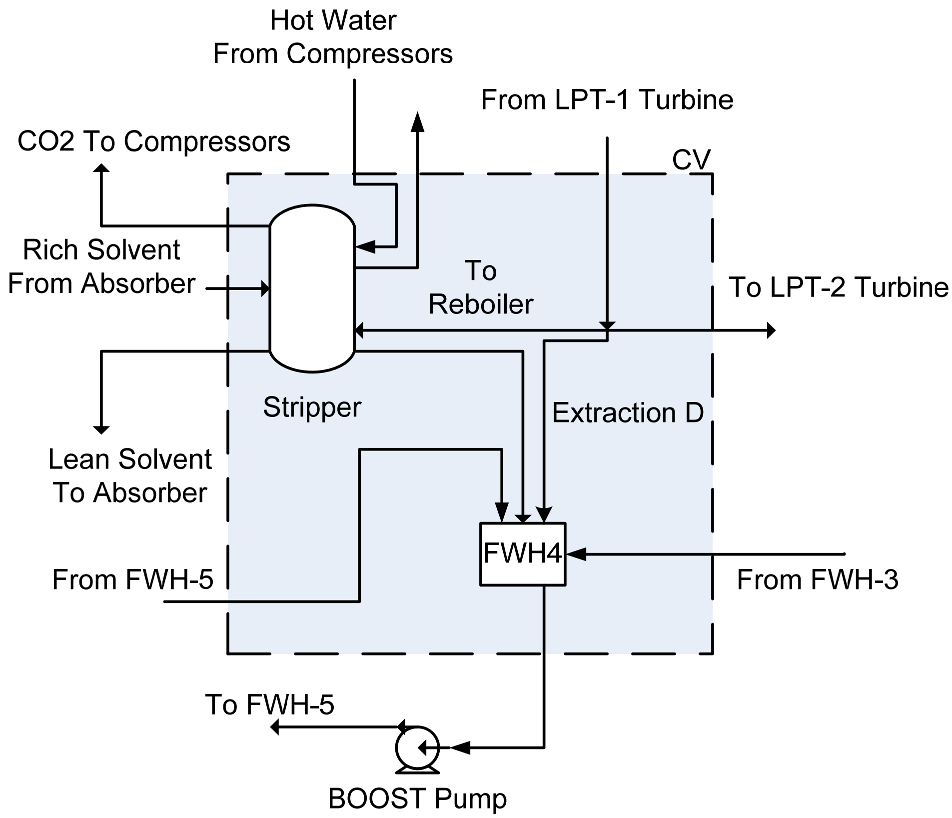

Figure 4-12: Reboiler Heat Integration Control Volume

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 2.31 percent heat rate improvement. Therefore, it can be assumed that any heat rejected to FWH-4 could instead be rejected to the reboiler and give the same heat rate improvement results.

Combined Compressor and Stripper Condenser Heat Integration

Combining heat from the stripper condenser and compressor to replace steam extractions to feedwater heaters provides a mechanism to achieve even larger heat rate reductions. For example, by using stripper condenser heat to replace 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. This combined integration approach is shown in Figure 4-13. Implementing these changes in a similar manner as described previously, extractions E, F, and G were eliminated, extraction D was reduced to 90,500 lb/hr and extraction C was reduced to 107,000 lb/hr. This heat integration technique would give a heat rate of 12,607 Btu/kWhr, which is a 3.90% reduction from the base case (Table 4-13).

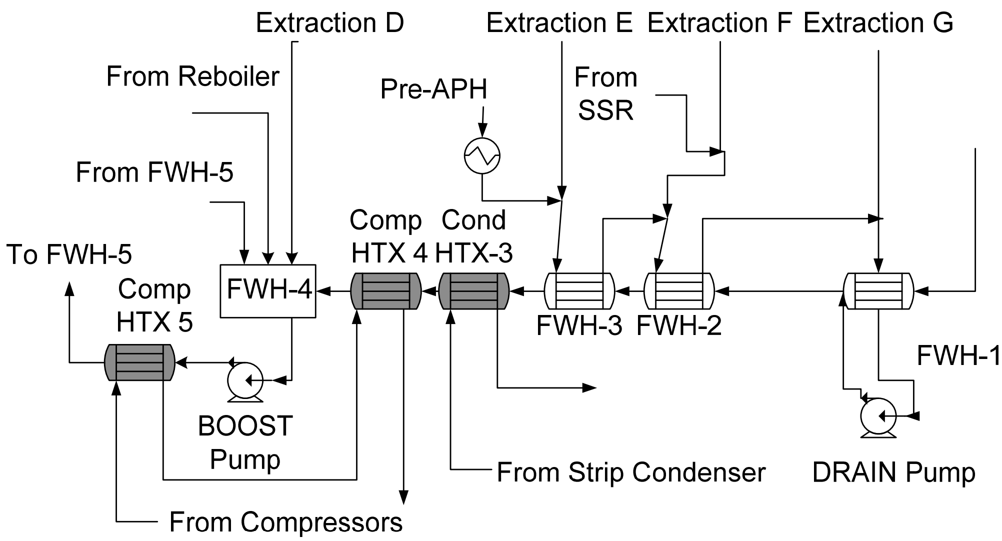

Figure 4-13: Feedwater Heaters 1, 2, 3, and 4 with Combined Compressor and Stripper Condenser Heat Integration

Coal Drying

Simulations were performed to determine the heat rate impacts of using waste heat to predry PRB and lignite coals in a power plant with a MEA capture system. It was assumed the PRB is dried in a fluidized bed dryer from 28.09 to 15 percent moisture and the North Dakota lignite from 38.5 to 20 percent moisture.

Predrying a coal using waste heat would decrease the amount of coal required to generate a given amount of electrical power. The coal moisture, which requires energy for evaporation, would be reduced in flow rate, resulting in a larger percentage of heat released by combustion being transferred to the steam cycle. Since the simulations were performed for a fixed rate of heat transfer to the steam cycle, coal drying would result in a reduced feed rate of dry coal. The reduction in coal and air flow rates would result in flow rate result in reduction in pulverizer and FD fan power and would decrease the flow rates of flue gas and CO_2 being sent to the MEA system. A reduced CO_2 flow rate would decrease the amount of extraction steam being sent to the reboiler and decrease the power requirement of the CO_2 compressors.

The simulations show that by drying PRB coal to 15 percent moisture, the wet coal flow rate entering the dryer would be reduced from 643,021 lb/hr to 627,317 lb/hr (Table 4-14). The coal flow rate leaving the dryer is calculated to be 530,710 lb/hr, which reduces the pulverizer power from 3,403 kW to 2,809 kW. The reduction in air and coal flow rate would combine to reduce the fan power from 18,002 kW to 17,022 kW. The reboiler duty would be reduced from 1,795 MBtu/hr to 1,753 MBtu/hr, and the compressor power would be reduced from 43,869 kW to 42,772 kW. Due to the lower reboiler duty, there would be a higher steam flow rate going to the steam condenser, and therefore, more flow coming from FWHs 1 through 3 into FWH-4. It would be necessary to increase extraction D to 152,000 lb/hr to keep the temperature leaving FWH-4 constant. This would give a final heat rate of 12,627 Btu/kWhr, which is a 3.74% heat rate improvement over the base case.

Table 4-14: Coal Drying Comparison: PRB Coal

	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%

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

Simulations were performed in which coal drying was combined with integrating compressor cooling water to FWHs 4 and 5 and integrating stripper condenser cooling water to FWHs 1 to 3 (see Table 4-13). There are minor differences in heat integration when compared to the analyses done without coal drying, one of which is that due to a smaller CO_2 flow rate, there would be less heat from the compressor and the stripper condenser to transfer 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 compressor coolers. These reductions in flow rates combined with the effects of coal drying give a final predicted heat rate of 12,143 MBtu/kWhr, which is a 7.43% heat rate improvement from the base case.

Heat Integration While Firing Illinois #6 and Lignite Coals

Using the same modeling and simulation methods described in the preceding pages for PRB coal, analyses were carried out with Illinois #6 and North Dakota lignite.

The predicted CO_2 flow rate is highest when firing PRB coal and lowest with Illinois #6. It may seem inconsistent that PRB results in a higher CO_2 flow rate than Lignite, but this is due to the lower MAF carbon percentage in Lignite. The higher the CO_2 flow rate leaving the boiler, the more CO_2 will be needed to be captured to reach 90 percent capture and the more the extraction steam will be diverted away from LPTs 2 to 5 and sent to the reboiler. These factors result in decreased power output of the plant. Table 4-15 shows the base case scenarios in more detail for each coal.

Analyses were performed to examine the effects of heat integration on the heat rate of the power plant operating with Illinois #6 and lignite coals. The results of these simulations are shown in Table 4-16 and 4-17 and Figure 4-14 to 4-17. Due to the low as-received moisture of Illinois #6, coal drying was not used with that coal as a potential heat integration option. It was assumed that the Lignite was dried from 38.5 percent to 20 percent moisture.

Table 4-15: 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%
CO_2 Flow rate (lbm/hr)	1,178,953	1,061,731	1,109,959
Reboiler duty (Btu/lbmCO_2 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)	13,118	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 Condenser 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

Table 4-16: 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 1-5**	**Comp to FWH 4,5**
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	521,135	518,656
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%
CO_2 Flow (lbm/hr)	1,061,731	1,061,731	1,061,731	1,061,731	1,061,731
Reboiler duty (Btu/lbmCO_2)	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	39,505	39,509
Net Power (kW)	434,170	439,840	440,567	445,942	443,460
Δ in Net Power	0	5,669	6,396	11,772	9,290
Unit Heat Rate (Btu/kWhr)	11,953	11,799	11,780	11,638	11,703
Δ in Heat Rate (%)	0.00%	-1.29%	-1.45%	-2.64%	-2.09%
Efficiency (%)	28.5%	28.9%	29.0%	29.3%	29.2%
Stripper Condenser Heat Used	0.0%	44.3%	0.0%	0.0%	0.0%
Comp heat used (%)	0.0%	0.0%	88.5%	83.4%	55.0%
FWH1 Duty (kBtu/hr)	90,292	558	558	55,506	90,292
FWH2 Duty (kBtu/hr)	69,677	11,044	11,044	51,976	69,677
FWH3 Duty (kBtu/hr)	64,181	9,343	9,343	49,964	64,181
FWH5 Duty (kBtu/hr)	216,159	216,159	216,159	148,523	148,504
Extract G (lb/hr)	93,200	0	0	57,000	93,200
Extract F (lb/hr)	56,000	0	0	39,000	56,000
Extract E (lb/hr)	54,000	0	0	40,000	54,000
Extract D (lb/hr)	157,000	176,000	167,000	101,500	104,000
Extract C (lb/hr)	163,004	163,004	163,004	115,000	115,000
Steam Condenser (MBtu/hr)	1,306	1,481	1,489	1,468	1,402
Stripper Condenser (MBtu/hr)	439	244	439	439	439
Compressors (MBtu/hr)	232	232	27	106	105
Amine Cooler (Mbtu/hr)	930	930	930	930	930
Flue Gas Cooler (Mbtu/hr)	455	455	455	455	455

Table 4-16 *(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%
CO_2 Flow (lbm/hr)	1,061,731
Reboiler duty (Btu/lbmCO_2)	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 Condenser 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 Condenser (MBtu/hr)	229
Compressors (MBtu/hr)	102
Amine Cooler (MBtu/hr)	930
Flue Gas Cooler (MBtu/hr)	455

Table 4-17: Lignite Heat Integration Results Using the Inline 4 Compressor

	BASE CASE Lignite	Stripper Cond to FWH1-3	Comp to FWH1-3	Comp to FWH 1-5	Comp to FWH 4,5
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	516,797	514,288
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%
CO_2 Flow rate (lbm/hr)	1,109,959	1,109,959	1,109,959	1,109,959	1,109,959
Reboiler duty (Btu/lbmCO_2)	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	41,303	41,304
Net Power (kW)	423,176	428,322	430,240	435,280	432,770
Δ in Net Power	0	5,146	7,063	12,104	9,593
Unit Heat Rate (Btu/kWhr)	13,234	13,075	13,017	12,866	12,941
Δ in Heat Rate (%)	0.00%	-1.20%	-1.64%	-2.78%	-2.22%
Efficiency (%)	25.8%	26.1%	26.2%	26.5%	26.4%
Stripper Condenser Heat Used	0.0%	40.8%	0.0%	0.0%	0.0%
Comp heat used (%)	0.0%	0.0%	88.3%	83.4%	54.2%
FWH1 Duty (kBtu/hr)	89,614	558	558	43,987	89,614
FWH2 Duty (kBtu/hr)	69,132	11,044	11,044	48,748	69,132
FWH3 Duty (kBtu/hr)	63,166	9,343	9,343	44,886	63,166
FWH5 Duty (kBtu/hr)	216,159	216,159	216,159	145,451	145,459
Extract G (lb/hr)	92,500	0	0	45,000	92,500
Extract F (lb/hr)	55,500	0	0	36,000	55,500
Extract E (lb/hr)	53,000	0	0	35,000	53,000
Extract D (lb/hr)	147,000	170,700	148,000	94,500	96,500
Extract C (lb/hr)	163,004	163,004	163,004	115,000	110,000
Steam Condenser (MBtu/hr)	1,254	1,422	1,444	1,430	1,352
Stripper Condenser (MBtu/hr)	456	270	456	456	456
Compressors (MBtu/hr)	243	243	28	109	111
Amine Cooler (MBtu/hr)	973	972	973	972	973
Flue Gas Cooler (MBtu/hr)	497	497	497	497	497

Table 4-17 *(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%
CO_2 Flow rate (lbm/hr)	1,109,959	1,055,433	1,055,433
Reboiler duty (Btu/lbmCO_2 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 Condenser 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

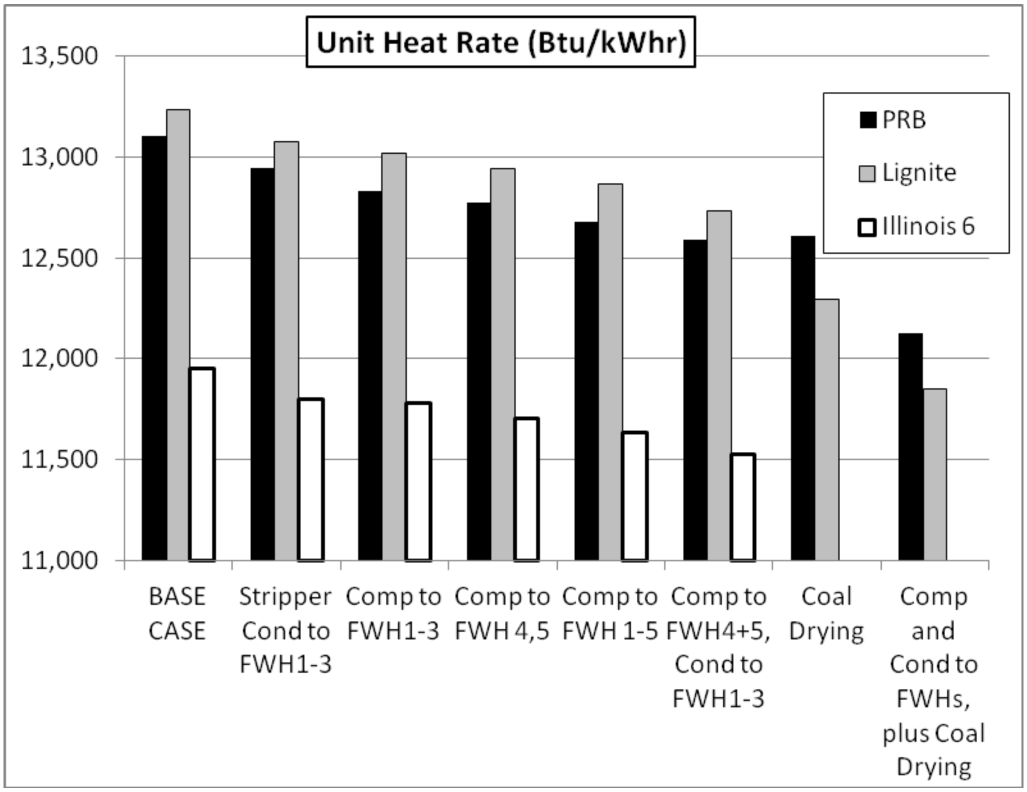

Figure 4-14: Unit Heat Rate Comparison of Different Coals (Inline 4)

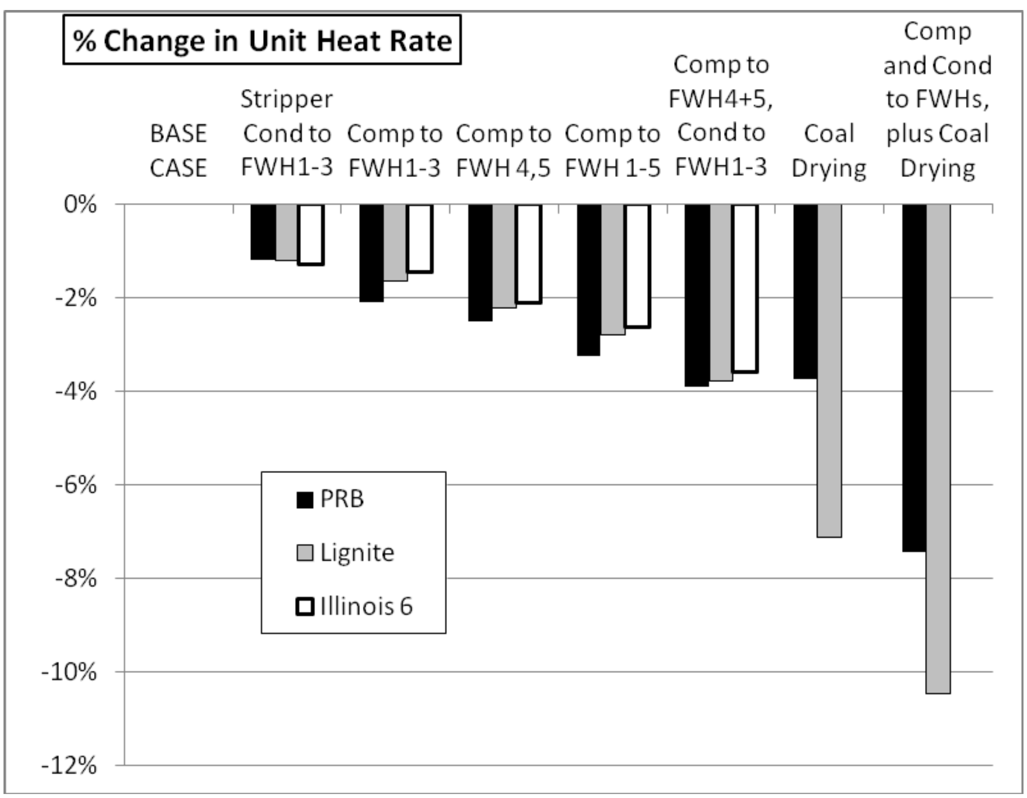

Figure 4-15: Change in Unit Heat Rate Comparison of Different Coals (Inline 4)

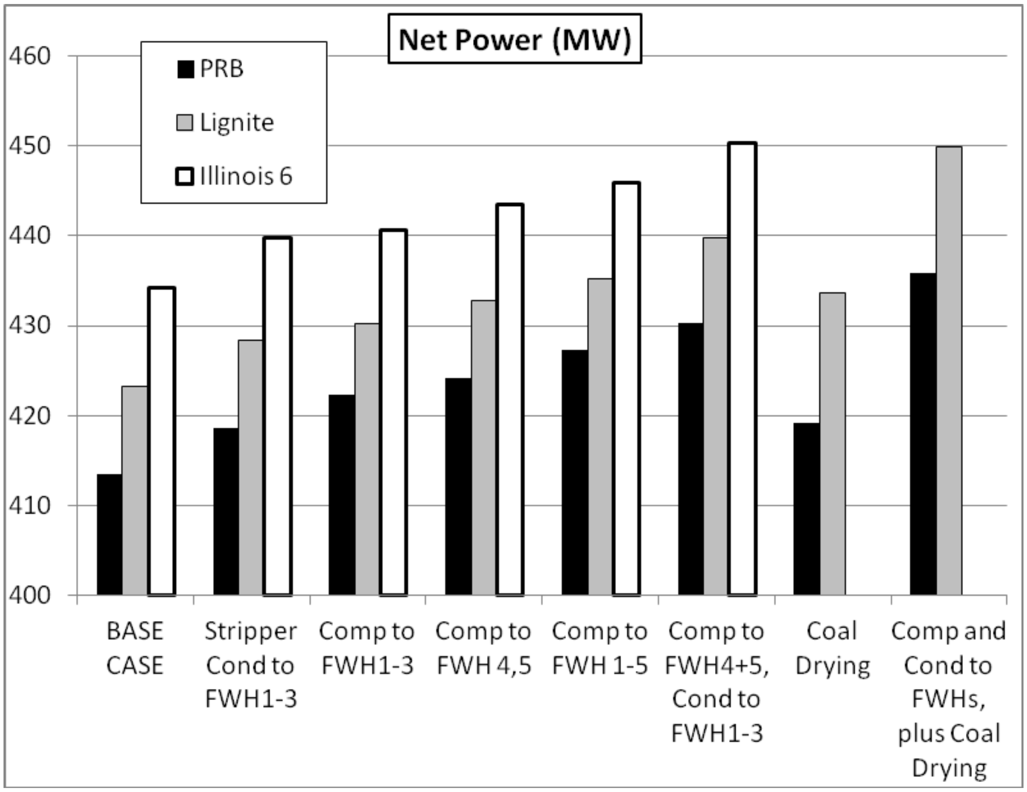

Figure 4-16: Net Power Comparison of Different Coals (Inline 4)

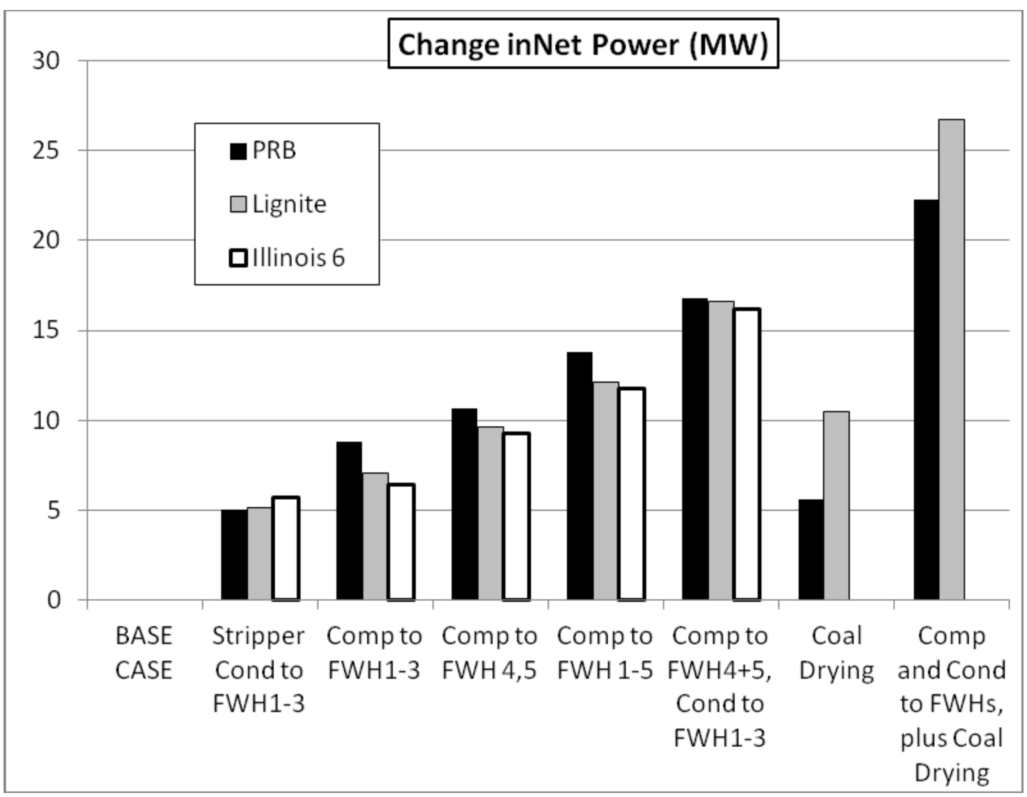

Figure 4-17: Change in Net Power of Different Coals (Inline 4)

Heat Integration Using Different Compressor Options

The results in previous sections of this Chapter are based on using an Inline 4 CO_2 compressor. This section shows results of compressor type on unit performance, both with and without utilization of compressor waste heat. The performance characteristics of the Inline 4, IG1 and Ramgen compressors are discussed in an earlier section of this Chapter. Due to different configurations and designs, each compressor will have its own stage efficiencies, power and cooling water flow rate requirements, and cooling water outlet temperatures. Comparisons are given in Table 4-18 for the effects of the three compressors on unit performance for a unit firing PRB coal, but without thermal integration of compressor heat. Table 4-18 shows that of the three compressors, the Ramgen compressor has the highest predicted power requirements and the highest base case heat rate, and the Integrally Geared compressor has the lowest predicted power and the lowest base case heat rate. These differences in performance are primarily due to stage compression ratios and the required number of stages with intercooling. For this application, Ramgen would need to have two compression stages with intercooling, the Inline 4 compressor would need three stages with intercooling, and the IG1 compressor would require seven stages with intercooling.

Simulations, comparable to those performed with the Inline 4 compressor, were performed with the Ramgen shock wave compressor and the Integrally Geared compressor (IG1) to determine the effects of compressor type on unit performance, both with and without heat integration.

As was shown in Tables 4-9 and 4-10, the exit temperatures of the RAMGEN compressor stages would be slightly higher than those of the Inline 4 compressor stages. As a result, these two types of compressors can be integrated to the same heat sinks in a similar fashion. The predicted results show that of the two compressor types, the RAMGEN compressor would result in a larger increase in net power due to higher cooling water temperature and flow rate. Five different integration cases are illustrated in Table 4-19 for the RAMGEN compressor.

Table 4-18: 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
CO_2 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/lbmCO_2)	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*

Table 4-19: 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/lbmCO_2)	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 Condenser 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 4-19 *(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/lbmCO_2)	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 Condenser 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

The IG1 compressor will need to be treated very differently from the Ramgen and Inline 4 compressors, due to the low temperatures of the cooling water leaving the IG1 compressor. The temperature of the hot cooling water would be less than 230°F, which means that use of cooling water from the stripper condenser would be better suited for heat integration due to its higher temperature and relatively high flow rates. For this reason, the integration of IG1 compressor heat 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. Results for three heat integration cases with IG1 are shown in Table 4-20.

Figures 4-18 through 4-21 compare the unit heat rate and net power performance with the three compressor options with PRB coal. It should be noted that due to the relatively low cooling water temperature, there are no results for the Integrally Geared compressor for some thermal integration cases. Unlike the other two compressors, the coal drying case with the IG1 compressor does not utilize compressor heat.

The base case results with PRB coal show that of the three compressors, the IG1 compressor would result in the lowest heat rate and the highest net power. Because of relatively low cooling water temperature, thermal integration opportunities would be limited in the IG1 case, and the lowest heat rate would occur with the Inline 4 compressor with a combination of stripper condenser heat and compressor heat transferred to feedwater heaters 1 to 5 and to a coal dryer. The results further show the largest improvements in heat rate and increases in net power due to thermal integration would occur with the Ramgen compressor.

Table 4-20: 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
CO_2 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/lbmCO_2)	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 Condenser 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

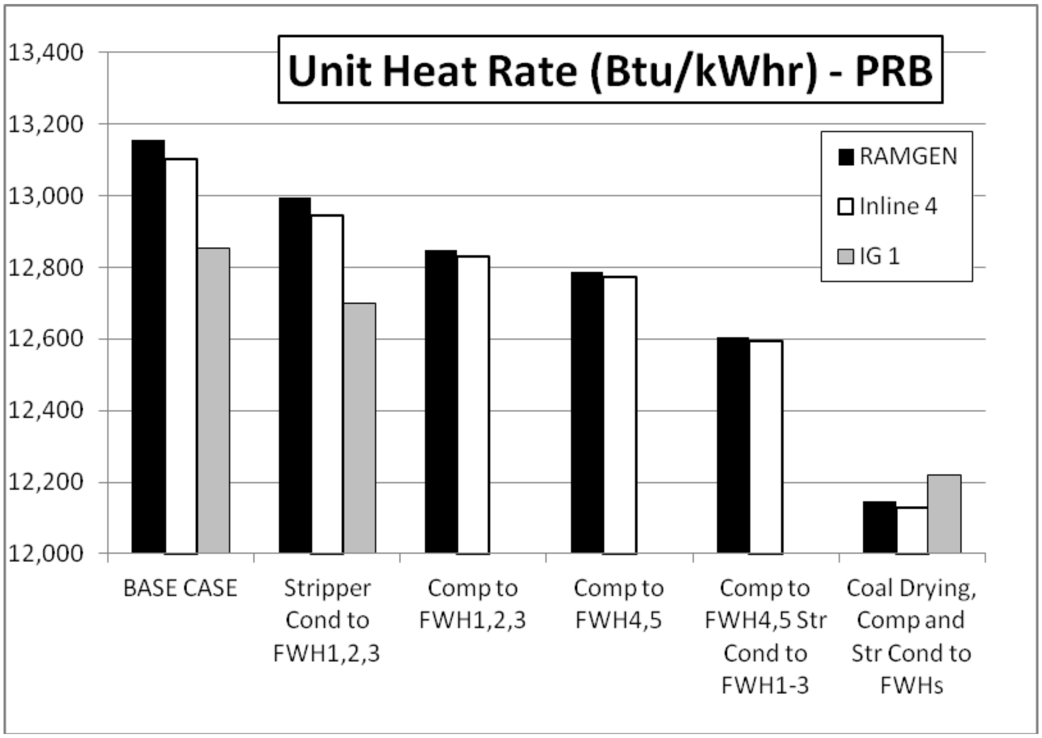

Figure 4-18: Unit Heat Rate Comparison of Different Compressor Heat Integration Options (PRB)

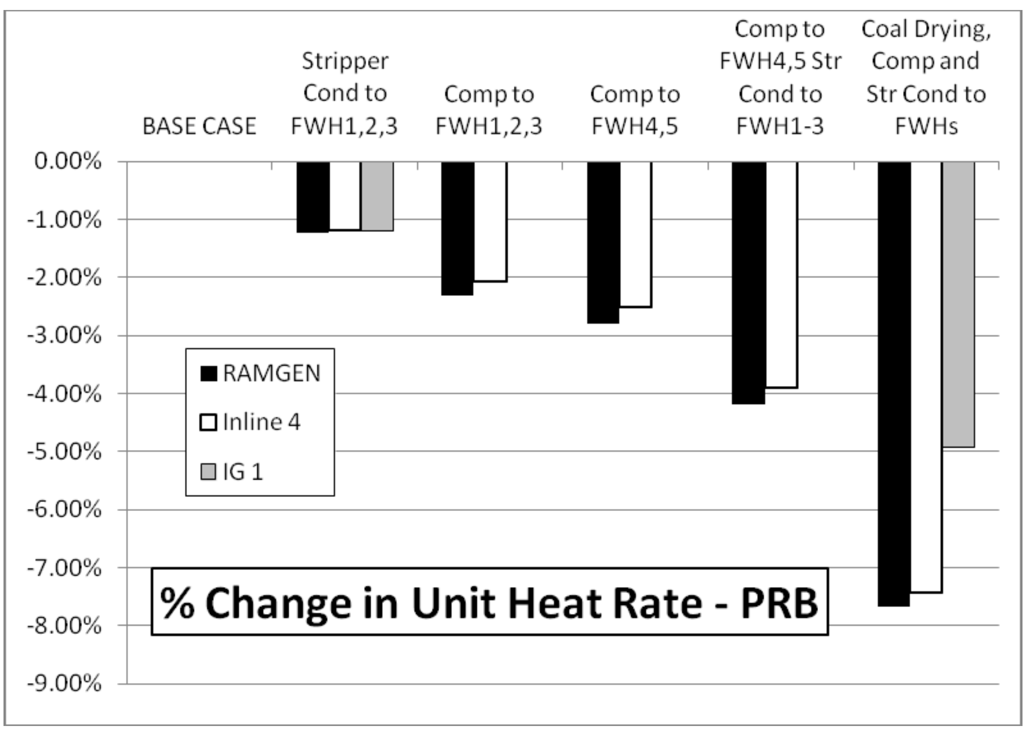

Figure 4-19: Change in Unit Heat Rate Comparison of Different Compressor Heat Integration Options (PRB)

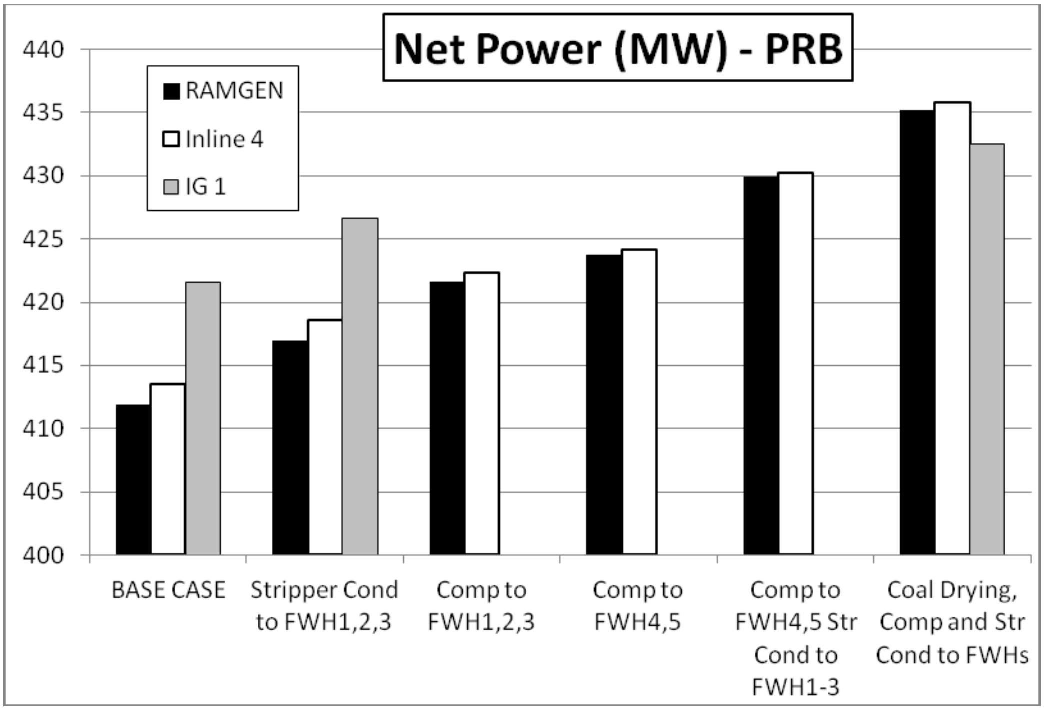

Figure 4-20: Net Power Comparison of Different Compressor Heat Integration Options (PRB)

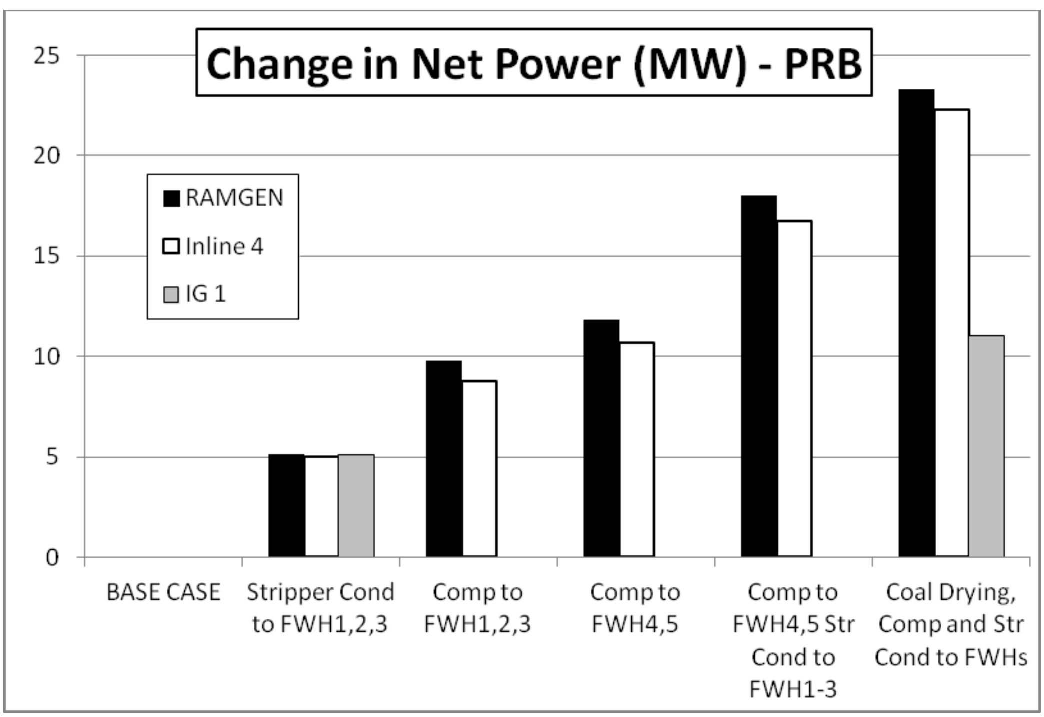

Figure 4-21: Change in Net Power Comparison of Different Compressor Heat Integration Options (PRB)

CONCLUSIONS

Eight different heat integration options were analyzed for the MEA post combustion capture system (see Table 4-21), with results obtained for different coals and compressor options.

Table 4-21: Heat Integration Options

1	Using waste heat from the stripper condenser to replace steam extractions at FWHs 1 to 3.
2	Using waste heat from the compressors to replace steam extractions at FWHs 1 to 3.
3	Using waste heat from the compressors to partially replace steam extractions at FWHs 1 to 5 using a cascading technique.
4	Using waste heat from the compressors to partially replace steam extractions at FWHs 4 and 5.
5	Using waste heat from the compressors to partially replace steam extractions at FWHs 4 and 5 and using 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 percentages (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 drying 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.
8	Using waste heat from compressors to partially replace steam extraction at FWH 4 or to provide heat to the Stripper Reboiler.

Simulations performed for a supercritical unit with an Inline 4 compressor and with three different coals (Table 4-22) show that the net unit heat rate would depend strongly on coal rank. For the case without thermal integration (Base Case), Illinois #6 would yield the lowest unit heat rate and lignite, the highest heat rate value. While unit performance dependence on coal properties is well known, these results helped to confirm that the simulations generated reasonable trends.

Table 4-22: Heat Rate Comparison of Different Coals with Inline 4 Compressor (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
8	12,801	11,719	12,963

The predicted heat rate improvements resulting from use of either compressor heat or stripper condenser heat to preheat boiler feedwater range from 1.20 percent to 3.90 percent, with the larger heat rate improvements occurring with thermal integration involving higher temperature feedwater heaters (Table 4-23). The simulations also showed that partial drying of low rank coals has the potential to cause the largest reductions in unit heat rate. Waste heat integration used for drying of low rank coals done in combination with feedwater heating is predicted to result in heat rate reductions of 7.43 percent for PRB coal and 10.45 percent for lignite.

Compressor heat can also be rejected to the reboiler, reducing the reboiler extraction upstream of LPT-2. The reboiler extraction is in the same location (between LPTs 1 and 2) as extraction D for FWH-4 and it was shown that integrating heat to FWH-4 and integrating heat to the reboiler would achieve the same results. Both of these heat integration scenarios would reduce steam extraction to FWH-4 or the reboiler steam by the same amount. As a consequence, additional steam will flow through LPT’s 2 to 5, generating the same amount of additional power in both cases.

Table 4-23: Heat Rate Comparison of Different Coals with Inline 4 Compressor (% 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%
8	-2.31%	-1.96	-2.06

The various compressor options are compared in Tables 4-24 and 4-25 for use with PRB coal. For a given application and for the particular compressor models which were analyzed (that is, Ramgen, Inline 4 and IG1), the Ramgen compressor would result in the highest baseline heat rate due to its high compression ratio, however, this would be accompanied by larger potential gains in percent heat rate due to the high temperature of the cooling water leaving the compressor coolers. The IG 1 compressor would result in the lowest Baseline heat rate and the lowest percent improvement due to the low temperature cooling water leaving the compressor. The heat rate for the Inline 4 compressor would be between those of the other two compression options.

Table 4-24: 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
8	12,801	12,815	-

Table 4-25: 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%
8	-2.31%	-2.59%	-

CHAPTER 5: SUMMARY AND CONCLUSIONS

Analyses were performed to estimate the magnitudes of the performance improvements which could be achieved in an oxycombustion power plant by using heat released during CO_2 compression to predry coal, preheat boiler feedwater, and reheat recirculated flue gas. Analyses for a MEA type post-combustion CO_2 capture system investigated use of compressor heat and heat recovered from the stripper condenser to predry coal, preheat boiler feedwater and provide heat to the stripper reboiler.

Three compressor options were modeled: Inline and Integrally Geared centrifugal compressors and a shock-wave compression technology being developed by Ramgen Power Systems. For a given application and for the particular Inline and Integrally Geared compressor models which were analyzed (that is, Inline 4 and IG1), the Integrally Geared compressor has the lowest predicted power requirement followed by the Inline compressor and then the Ramgen compressor. Heat energy released during intercooling was found to increase with compressor power, with the Ramgen compressor releasing the most heat, and the Integrally Geared compressor the least.

Results for Oxycombustion Unit

For the recirculated flue gas and boiler feedwater heating cases, compression heat would reduce turbine steam extractions, resulting in increased net unit power. In the coal drying case, the compression heat would increase boiler efficiency, which, for fixed main steam flow rate, would reduce the energy input to the boiler provided by the coal and reduce pulverizer and ID fan power, rate of CO_2 formation and ASU and CO_2 compressor power.

The simulation results show the recirculated flue gas case would yield heat rate reductions from 0.73 to 0.85 percent, boiler feedwater heating would result in heat rate reductions from 1.0 to 4.78 percent, depending on the configuration of the feedwater heating system, and coal drying would result in heat rate reductions of 3.7 to 3.85 percent for PRB and 6.9 to 7.1 percent for lignite. (Note: It was assumed PRB was dried from 30 to 15 percent moisture and lignite was dried from 38.5 to 20 percent moisture.) Combinations of heat sinks were analyzed to take advantage of more of the compressor heat and this resulted in predicted heat rate reductions from 2.0 to 4.13 percent for Illinois #6, from 5.8 to 6.2 percent for PRB and from 7.7 to 8.4 percent for lignite.

Comparisons of predicted values of unit performance show that the net unit heat rate would be lowest for Illinois #6 compared to the other two coals. The results also show that for all three coals, the Integrally Geared compressor would result in a lower unit heat rate than either of the other two compressors.

The overall conclusion from the oxyfuel simulations is that thermal integration of compressor heat has the potential to improve net unit heat rate by up to 8.4 percent, but the actual magnitude of the improvement will depend on the type of heat sink used and to a lesser extent, compressor design and coal rank. For the specific Inline and Integrally Geared compressor models analyzed in this study (that is, Inline 4 and IG1), the Integrally Geared compressor results in the lowest predicted values of net unit heat rate and the Ramgen compressor, the highest, for each of the thermal integration cases considered.

Results for Unit with MEA Post-Combustion Capture System

Predicted heat rate improvements, resulting from use of either compressor heat or stripper condenser heat to preheat boiler feedwater in a unit with MEA post-combustion capture, range from 1.20 percent to 4.19 percent. Heat rate improvements in the 4.19 percent range would occur with heat captured from a Ramgen compressor being transferred to higher temperature feedwater heaters, while firing PRB coal. The simulations also showed that partial drying of low rank coals has the potential to cause the largest reductions in unit heat rate. Waste heat integration used for drying of low rank coals done in combination with feedwater heating is predicted to result in heat rate reductions of 7.43 percent for PRB coal and 10.45 percent for lignite.

Compressor heat can also be rejected to the reboiler, which would reduce the low pressure turbine (LP) steam extraction to the reboiler. Steam extraction for the reboiler would occur in the same location of the LP turbine as the extraction for FWH-4 and the results show that integrating heat to FWH-4 and integrating heat to the reboiler would result in the same steam cycle heat rate improvement.

Comparison of the three compressor options analyzed in this investigation (that is, Ramgen, Inline 4, and IG1) with PRB coal firing and no thermal integration shows the Ramgen compressor would result in the highest baseline heat rate due to its high compression ratio, however, this would be accompanied by larger potential gains in percent heat rate due to the high temperature of the cooling water leaving the compressor coolers. The thermal integration option yielding the lowest heat rates with PRB firing shows predicted heat rates of 12,143 Btu/kWh (Inline 4), 12,146 Btu/kWh (Ramgen) and 12,220 Btu/kWh (IG1).

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