**DEVELOPMENT OF COST EFFECTIVE OXY-COMBUSTION RETROFITTING FOR
COAL-FIRED BOILERS**

Final Report

For

April 1, 2006 through December 31, 2010

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October 24, 2011

B&W Contract No.: RCD 1464

DOE Contract No.: DE-FC26-06NT42747

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ACKNOWLEDGMENT: “This material is based upon work supported by the Department of Energy under Award Number DE-FC26-06NT42747.”

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ACKNOWLEDGMENTS

The authors acknowledge numerous individuals from Air Liquide, B&W, Battelle, and U.S. DOE who have contributed tremendously to the successful execution of this project. Special thanks are due to the following individuals:

- Jose Figueroa, the DOE NETL project manager, who contributed by many technical discussions and reviews
- Paul Terrien from Air Liquide for his help in ASU/CPU analysis
- Shengteng Hu, Barteve Sakadjian, and Dong Zeng for participating in the pilot-scale tests
- Luis Vargas and Behrooz Ghorishi for mercury sampling and analysis
- Jason Fennell, Brian Clark, and Vijay Parekh for instrumentation and data acquisition
- Rajani Varagani, Taekyu Kang, Vivek Gautam, Kenneth Kaiser, Chendhil Periasamy, Kaleem Robinson, and Yuan Xue of Air Liquide for their participation in the pilot-scale tests and management of the oxygen supply system
- Terry Wilson, Larry Mohr, Jeff Dudley, Rob Porter, Vernon Burch, Terry Bert, Mike Shea, Wynn Feess, and Rick Schreckengost for operation of the pilot-scale facility
- Jim Warchol and Ralph Bailey for assistance with the wet scrubber
- Zumao Chen and Rick Wessel for performing numerical modeling

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EXECUTIVE SUMMARY

Introduction

To maintain economic competitiveness and meet growing energy demands, the U.S. must improve the utilization of its domestic resources. Our vast resources of coal will play a strategic role in future electric power production. Coal currently provides more than 50% of the United States' electricity. Hence, coal will continue to be a prime source for electricity generation. Over the past three decades, utilities have implemented emission control equipment to control NO_x, SO₂, and particulate emissions to a large portion of existing coal-fired boilers. Fossil fuel combustion is also a primary contributor of increased greenhouse gas (GHG) emissions. As fossil fuels continue to be a dominant fuel source for electricity generation, reducing carbon emissions by capturing and sequestering CO₂ from existing utility boilers is being considered to reduce these emissions and thereby control overall atmospheric GHG emissions.

The power industry has successfully met the challenge of reducing sulfur dioxide, oxides of nitrogen, particulate matter, and more recently mercury. Carbon dioxide challenges the industry in a new way because the quantities are vast and the technologies are still under development. Babcock & Wilcox Power Generation Group (B&W) and Air Liquide (AL) have been actively involved in the development of oxy-coal technologies for power generation for the past ten years. With the sponsorship of DOE and NETL through project NT42747, oxy-combustion was evaluated for existing wall-fired and CycloneTM boilers.

Objectives

The overall objective of this project is to further develop the oxy-combustion technology for commercial retrofit in existing wall-fired and Cyclone boilers by 2012. To meet this goal, a two-phase research project was conducted that included pilot-scale testing and a full-scale engineering and economic analysis.

Phase I objectives include:

- Evaluate at pilot-scale the effect of coal rank used in existing boilers (i.e., bituminous, subbituminous, and lignite) on oxy-combustion design.
- Determine the equipment requirements for the boiler island, including flue gas purification, CO₂ compression, transportation, and storage for different coals and combustion systems (Cyclone and wall-fired).
- Investigate the potential for multi-pollutant (NO_x, SO₂, and particulate) reduction.
- Validate an existing 3-dimensional computational flow, heat transfer, and combustion model for oxy-combustion scale-up to a commercial size boiler.

Phase II objectives are as follow:

- Evaluate the impact of oxy-combustion implementation on net power production and cost of electricity for Cyclone and wall-fired applications.
- Determine the boiler population with close proximity to candidate geologic CO₂ storage sites.

- Conduct an engineering and economic assessment of the technology for commercial-scale retrofit and greenfield application for Cyclone and wall-fired units.
- Assess potential CO₂ control cost reductions via the integration of the air separation unit, flue gas purification, CO₂ compression train, and CO₂ transportation and sequestration.

Pilot-scale Testing

The objective of these tests was to evaluate the effect of coal rank used in existing boilers (i.e., bituminous, subbituminous, and lignite) on oxy-combustion design. Specifically the following parameters were investigated:

- Flame stability
- NO_x, CO, and unburned combustibles
- Radiant boiler and convection pass heat absorption
- Furnace exit gas temperature
- SO₂/SO₃ emissions under air and oxy-firing conditions
- Recycle gas moisture concentration

Approach:

Since B&W had already demonstrated oxy-firing for wall-firing at 1.8 and 30 MW_{th} (See Section 3.1.6), this pilot-scale evaluation was conducted with a Cyclone configuration. In Cyclone boilers, high temperatures are used to capture and remove the majority of ash as molten slag. Crushed coal is introduced tangentially into the Cyclone barrel, where the large particles burn in a slag layer and small particles in suspension. Slag tapping problems may occur if oxy-firing reduces the Cyclone temperature and prevents slag flow.

The 6 MBtu/h Small Boiler Simulator-II (SBS-II) was used for the pilot-scale tests. It is a new test facility (commissioned in 2009) and is designed for evaluating various fuels, combustion processes, air pollution control devices, and associated hardware for potential commercial use. The pilot facility simulates the firing conditions of full-scale steam generating boilers. The furnace may be equipped with either a single wall-fired burner, or a Cyclone furnace. Various environmental controls such as baghouses and scrubbers are available according to the need of each project. A wet flue gas desulfurization (WFGD) scrubber was used for bituminous coal only. Figure S.1 shows a schematic diagram of the system configuration for this project and how various components are connected by ductwork. A condensing heat exchanger (CHX) is available to remove heat and moisture from the recycled gas. “Cold recycle” tests were performed for the majority of the tests, where the recycled gas was cooled down to a nominal 100°F. “Warm recycle” tests were performed with subbituminous coal without removing moisture or SO₂ from the recycled gas. The recycled flue gas was mixed with oxygen and recycled to primary and secondary oxidant streams. Oxygen measurements were performed via in-situ oxygen probes to control the oxidant streams’ oxygen concentrations. These oxygen concentration measurements were also used for safety interlocks.

Liquid oxygen was delivered to the test facility and stored on site in a 9000-gallon liquid oxygen tank. The liquid oxygen was vaporized using an ambient vaporizer and the oxygen was regulated to an appropriate pressure and delivered to the test area via stainless steel piping.

Three coals were tested: an Ohio #5 (Eastern bituminous), Black Thunder (Western subbituminous), and a lignite from North Dakota. Table S.1 shows the as-received fuel analyses.

Figure S.1 Schematic diagram of the SBS-II facility

	Eastern Bituminous	Western Sub-bituminous		Lignite
		Black Thunder		
	Ohio #5	Cold recycle	Warm recycle	North Dakota
Proximate Analysis (wt %, as received)				
Moisture	6.47	26.56	26.15	35.60
Ash	5.57	4.94	4.64	6.79
Volatile Matter	41.51	32.11	32.20	28.50
Fixed Carbon	46.45	36.39	37.01	29.11
Ultimate Analysis (wt %, as received)				
Carbon	71.10	50.98	51.80	41.91
Hydrogen	5.02	3.84	3.83	3.04
Nitrogen	1.41	0.76	0.81	0.64
Sulfur	2.56	0.38	0.24	0.74
Oxygen	7.87	12.53	12.53	11.29
Miscellaneous (as received, unless specified)				
As-fired fuel sulfur (wt %)	2.70	0.39	0.26	0.66
Calorific Value (Btu/lb)	12807	8841	8829	6938

Table S.1 Proximate, ultimate, and miscellaneous analyses for the coals

Pilot-scale Demonstration Summary

- Oxy-firing was successfully demonstrated in a slagging environment by optimizing Cyclone exit gas temperature to levels similar to air-firing.
- Smooth transition from air-firing to oxy-firing was achieved.
- Convection pass exit CO₂ concentrations up to 90% were achieved. Figure S.2 shows the effect of air leakage on CO₂ concentrations for different fuels and recycle gas configurations for SO₂ and moisture level control. The lowest CO₂ concentrations occurred with bituminous coal when the WFGD was in service and pressure drop across the environmental equipment was large. The highest CO₂ concentrations were achieved with subbituminous coal when the WFGD was out of service and the pressure drop was lower.
- NO_x and CO emissions, and unburned combustibles (LOI) were lower with oxy-firing than air-firing conditions (see Figure S.3).
- Heat absorption in oxy-firing was similar to air-firing under optimum conditions. Figure S.4 shows the heat absorptions for the Cyclone. Radiant furnace and convection pass heat absorptions were similar for air- and oxy-firing.
- SO₂ concentrations at the convection pass outlet increased by a factor of 4-5 with subbituminous and lignite coal when the WFGD was not in service (see Figure S.5); therefore, if oxy-firing is applied to a high sulfur coal, SO₂ must be scrubbed from recycle gas to maintain acceptable boiler corrosion rates.
- Warm recycle increases convection pass outlet moisture levels to 34% of the total flue gas volume (see Figure S.6).

- Higher SO_3 concentrations were observed with oxy-firing relative to air-firing at the convection pass exit but were reduced by operation of the WFGD/CHX. Higher SO_3 concentrations could increase corrosion if the flue gas temperature goes below the acid dew point.

Figure S.2 CO_2 at convection pass outlet as a function of infiltrated air

Figure S.3 Comparison of LOI, and emitted NO_x and CO for optimum operating conditions

Figure S.4 Comparison of the Cyclone, furnace, and convection pass heat absorption for optimum operating conditions

Figure S.5 Comparison of air and oxy-firing SO₂ and moisture concentrations (convection pass exit) showing the effect of SO₂ scrubbing of the recycle gas

Figure S.6 Comparison of air and oxy-firing SO₂ and moisture concentrations (convection pass exit) showing the effect of switching to warm recycle

CO₂ -CPU Process Modeling Study

The primary goal of this study was to develop a CO₂ compression and purification unit (CPU) that could accept flue gas from the boiler island and produce a purified CO₂ stream to meet pipeline specifications. A secondary goal was to understand the source of the costs, especially operating costs, in the purification process so as to guide future research in attempting to relax product specifications and/or improve capture efficiency.

B&W performed an evaluation of gas composition leaving the boiler for the compression and purification unit and/or recycled to the boiler. The purpose of this evaluation was to investigate the impact of coal type and air leakage on the flue gas composition. Three coals were used in this study: a North Dakota Lignite; Decker, a subbituminous coal from Montana; and Illinois No. 6, high volatile bituminous coal. The results were delivered to Air Liquide for CPU modeling.

Three purification schemes were studied to cover the spectrum of capture options and provide information about the costs of different processing steps within the CPU. The first case did not attempt any purification beyond dehydration of the flue gas to pipeline specifications. This case minimized processing operations in the CPU but resulted in large amounts of inerts present in the product stream to the pipeline. The second case provided a bulk separation of inert gases from the flue gas stream, in addition to dehydration, resulting in a smaller volume of higher purity CO₂ product to the pipeline. The final scheme further processed the latter product stream to remove minor contaminants like SO_x, NO_x, and O₂ down to ppm levels as required for some contaminants by current pipeline specifications (Kinder Morgan).

The main conclusion of the study is that removal of the inerts in a purification step leads to lower overall energy requirement of the CPU. This is because the compression of inerts to the high pipeline pressure (≥ 2200 psig) requires more energy than that spent in separating inerts from the flue gas. As a result, it is better to perform bulk separation of inerts even if there are no technical barriers to introducing inerts into the pipeline or the sequestration reservoir. The extent of energy savings depends on the pipeline pressure, but is significant for all practical pipeline pressures for CO₂ transport. Further treatment of the purified CO₂ to remove minor contaminants did not incur significantly higher energy costs. Thus, it is relatively inexpensive from an energy perspective to distill the product stream to achieve current pipeline specifications.

The major energy expense in the process is in the compression steps. The compression energy requirement depends on the amount of inerts present in the flue gas, or in other words, the CO₂ purity in the incoming flue gas. Higher CO₂ purity corresponds to lower compression energy (See Figure S.7). Reducing the inert volume by 10 percentage points (i.e. reducing N₂ from 20% to 10% by volume in the flue gas) led to a 15-18% decrease in the specific energy requirement of the CPU. Thus, reduction of air infiltration into the system can have a major impact on the overall expense of the CO₂ capture process.

Figure S.7 Comparison of CO₂ yield (recovery), CO₂ purity and specific energy of the 3 CO₂ capture processes for case of low air infiltration

In summary, purification of flue gas actually leads to lower specific energy expense due to the rejection of inerts at lower pressure than the final product pressure. It is possible to purify the flue gas to achieve current CO₂ pipeline specifications of major North American pipeline companies such as Kinder Morgan.

CO₂ Sequestration Modeling

Battelle performed the CO₂ sequestration study and their activities were conducted in two phases. In the first phase, an assessment was made to understand processing requirements for flue gas treatment that would be necessary for injecting CO₂ into deep geologic formations. In the second phase, Battelle conducted a broad screening level assessment of the potential for storing CO₂ in deep geologic formations in the vicinities of selected existing boilers. These data were used to qualitatively determine the suitability of each selected plant for a more detailed site-specific evaluation of CO₂ storage. Parameters that were considered critical to the process were identified and established as criteria for distinguishing between plants that may be acceptable candidates for storage evaluation, vs. plants that may be unacceptable. These parameters were:

- Boiler size
- Proximity to a storage location
- Seismic risk

Two paradigms were considered for disposing of the flue gas. One approach was to consider collecting and compressing the entire gaseous effluent for injection into a suitable geologic

formation (known as co-sequestration). The other approach looked at separating the gas components that may not be advantageous to long-term injection. For example, it may be advantageous to remove oxygen so that it does not react with metals and cause corrosion. Nitrogen and argon are non-condensable, inert gases that would take up pore space in the storage reservoir that otherwise could be used to store CO₂. Furthermore, SO_x and NO_x may need to be removed to meet regulatory compliance for down-hole injection.

The concept of carbon capture and storage (CCS) has dealt largely with relatively pure (98-99%) carbon dioxide (CO₂). The high purity of CO₂ used in most demonstration studies to date is the result of opting for industrial quality gas, as opposed to scrubbed CO₂ from a flue gas stream, or some other gas mixture containing dilute (<20%) CO₂. Indeed, flue gas from coal combustion contains a number of impurities (such as NO_x, SO₂, flyash, mercury etc.) that likely will have impact on compression, transportation, and storage. This investigation explores the potential need for conditioning oxy-coal flue gas to selectively remove compounds that would be problematic. A top down assessment was employed to understand the effects of flue gas impurities on the expected sequence of processes to assess economic viability (Figure S.8). The differences between the behaviors of pure CO₂ and simulated oxy-combustion flue gas were examined to understand how each of the process steps is affected by impurities in the flue gas.

Figure S.8 Process description for flue gas interactions

Numerical simulations of injecting pure CO₂ and oxy-combustion flue gas were conducted using the STOMP-WCS-R (water, CO₂, salt and reactions) simulator (1). The STOMP code is capable of modeling complex, coupled hydrologic, chemical, and thermal processes, including multi-fluid flow and transport, partitioning of CO₂ into the aqueous phase, and chemical interactions with aqueous fluids and rock minerals. Modeling showed that co-sequestration of oxy-

combustion flue gas is possible in some of the geological sites. It was concluded that water vapor has to be removed to reduce pipeline corrosion. However, as mentioned earlier, CPU modeling (performed by Air Liquide) determined that removal of the impurities in a purification step leads to lower overall energy requirement of the CPU. Therefore, the engineering feasibility and economic evaluation was performed with a CPU to reduce impurities of flue gas before transportation and storage in a geological site.

Engineering and Economic Evaluation

The purpose of the economic evaluation was to determine the cost of the oxy-combustion technology for a variety of boilers. A sensitivity study was performed to determine the following key parameters:

- Boiler firing conditions: wall-firing and Cyclone firing (tangential-firing was excluded)
- Boiler load: 650 MWe and 780 MWe
- Boiler steam cycle: subcritical, supercritical, and ultra-supercritical (greenfield application)
- ASU and CPU type: today's technology and upgraded technology that uses less power (ASU optimized for oxy-combustion).
- Overall, a 30% reduction in the capital cost of the CPU is forecasted for future greenfield cases
- Fuel: bituminous, subbituminous, and lignite
- Oxy-firing process: cool recycle (partially scrubbed), and warm recycle
- Boiler air infiltration : 2 to 10% of theoretical air
- Oxygen purity: 80%, 85%, 90%, and 95%

B&W and Air Liquide performed a joint study where B&W determined the boiler firing conditions such as mass flow rates of oxygen required, flue gas recycle, and flue gas to purification unit. This data was delivered to Air Liquide for determinations of energy required and the cost of the ASU and CPU equipment. B&W compiled all of the information and determined the overall cost of electricity. Most of the work was performed for existing boilers. In addition, greenfield applications were studied to evaluate the effect of higher boiler efficiency as well as future improvements to the ASU and CPU unit. Some of the pertinent findings are:

- The efficiency loss for retrofitting oxy-PC ranges between 7.9 and 8.9 percentage points and is fairly consistent whether for a subcritical or supercritical plant (see Figure S.9).
- The efficiency loss for oxy-PC in greenfield applications is considerably lower than for retrofit ranging between 5.3 and 6.4 percentage points. This is due to the ability to better integrate heat into the steam cycle and the higher efficiency of the steam cycle which reduces coal, oxidant, and CO₂ flows and all associated power requirements (see Figure S.10).

Figure S.9 Performance results for retrofit cases – net plant efficiency

Figure S.10 Performance results for greenfield cases – net plant efficiency

- The air infiltration sensitivity analysis shows that air infiltration should be kept as low as possible and that the impact is steep between 2% and 5% and then moderates out to 10%. Clearly no air infiltration is best but the amount of effort (cost) to minimize air infiltration must be weighed against the life-cycle cost. An investment on the order of \$90 million dollars could be justified to reduce air infiltration from 10% down to 2% (see Figure S.11). This represents about 12% of the total plant cost without CO₂ transportation, storage, and monitoring (TS&M).

Figure S.11 Breakeven capital investment to mitigate air infiltration

- The oxidant purity sensitivity analysis shows that oxidant purity has considerably less impact than air infiltration and the trends in both net efficiency and LCOE are nearly linear. However, decreasing oxidant purity below 95% has no benefit in that it not only reduces net efficiency but it also raises LCOE. This demonstrates that at least 95% purity is beneficial, and higher purity may further increase benefits. However, current thinking is that 96.5% may become the standard in that above 96.5% there is a technology change that has a drastic impact on ASU operating cost (see Figure S.12).

Figure S.12 Power consumption of ASU and CPU as a function of product oxygen purity

- This study demonstrated that oxy-combustion is an economically viable technology for existing boilers. Figure S.13 shows that the incremental cost¹ of oxy-combustion for existing boilers (subcritical and super-critical) varies between 5 to 7¢/kWh. Cost of electricity for greenfield boilers using oxy-combustion coupled with ultra-supercritical boilers was only 25% higher than LCOE for a supercritical boiler under air-firing, well below the DOE target of 35%.

Figure S.13 Comparison of Levelized Cost of Electricity

¹ The LCOE reported for all retrofit cases is based on incremental LCOE meaning it assumed the plant is fully depreciated and there is no capital expense remaining. No costs associated with the base plant operation are included in the O&M costs. Although this does not produce an LCOE comparable to a greenfield unit, this approach was taken to be consistent (and allow comparison with) previous DOE studies.

- The incremental LCOE shown in Figure S.13 for retrofit applications is not directly comparable to greenfield LCOE. However, if the base plant capital expense is zero (fully depreciated), then a direct comparison can be made by simply adding the base case O&M (fixed + variable), consumable, and fuel costs to the incremental retrofit LCOE. This total is comparable and could be used to compare the total cost of retrofit of an existing plant vs. building a new one. For example the LCOE for a greenfield USC plant for Decker coal would be 8.42 ¢/kWh (see Case 12) compared to 8.68 ¢/kWh for retrofitting an existing supercritical plant.

It is of prime importance to recognize the progress achieved to date. Earlier studies (2) showed oxy-combustion increased the LCOE by 44% for an ultra supercritical boiler. In a separate project sponsored by B&W and Air Liquide, heat integration between ASU, steam turbine, and boiler was performed that increased the gross turbine output and reduced auxiliary power requirement for oxy-firing. This current study further optimized the ASU, CPU, and boiler operation resulting in the lowest LCOE increase of only 25% over air-firing operation. Continued R&D funding is required to show its viability in commercial applications and to strive for reducing its cost.

Applicability of the Technology

Site Screening to Identify Potentially Suitable Sequestration Demonstration Sites

An important aspect of the overall geologic storage task was to consider high-level screening criteria to identify potentially suitable site locations. The criteria selected by the project team to evaluate plant sites for CO₂ storage potential were: boiler specifications; location in relation to deep sedimentary basins; and degree of seismic hazard. The boiler specification included nameplate rating (all exceeding 200 MWe generating capacity, in the interests of controlling project cost on a \$/kW basis), boiler type (wall-fired and Cyclone), and CO₂ emission rate. Location, and especially distance of less than 50 miles to a deep sedimentary basin, is an important consideration to avoid long run pipelines. Seismic hazard was selected as a screening parameter to avoid expenses of additional construction requirements. The current screening is a high-level evaluation of boilers in relation to regional geological setting. Overall, the screening, site assessment, and sequestration design are a multiphase, multi-year effort. Once a site is identified, a more detailed feasibility study may be completed to identify storage intervals. If the project proceeds further, the future phases may consist of site-specific seismic surveys, drilling and characterization, detailed reservoir modeling and system design. The results of this initial assessment should not be viewed or interpreted as a definitive assessment of suitability of candidate geologic CO₂ storage formations, the presence of suitable caprock, or sufficient injectivity to allow CO₂ sequestration to be carried out in an economic manner. Rather, this should be used as an initial screening assessment for potential storage opportunities for the boiler sites.

Data used in this study came from a few widely recognized sources. The USGS Earthquake Seismic Hazards program provided the seismic hazard contour lines used to assign a seismic hazard value to each boiler location. The deep saline basins shape file used to determine if a boiler location was in or near a deep saline formation was provided by NatCarb, a project funded by the U.S. Department of Energy's National Energy Technology Laboratory. This work was performed using ESRI Arc Map 9.3.1, a part of ArcGIS Desktop 9.3.1.

The criteria selected by the project team to evaluate plant sites for CO₂ storage potential reduced the number of applicable boilers from 1924 down to 146. These boilers were predominantly located in the Ohio River Valley and the Gulf Coast with a few scattered around the inter-mountain West and the Dakotas. The boilers located near the Ohio River Valley and the Gulf Coast are especially good potential sites for CCS projects as they are located in areas with heavy CO₂ emissions due to power plants and refineries.

Figure S.14 Boilers meeting size requirements (>200 MWe)

Conclusions and Recommendations

The following conclusions and recommendations were drawn from the results of this project:

Conclusions from the pilot scale evaluation:

- Oxy-firing is a technically viable technology for wall-fired and Cyclone boilers firing bituminous coal, western subbituminous coal, and North Dakota lignite.
- Flame stability and Cyclone slagging characteristics were not negatively impacted by oxy-firing.
- Boiler NO_x and CO emissions, and unburned combustibles are lower for oxy-firing than air-firing.

- Radiant boiler and convection pass heat absorptions under oxy-firing conditions can be similar to air-firing by controlling flue gas recycle and oxygen flow rates.
- Flue gas concentrations of CO₂ (up to 90%, dry volume basis) were achieved when air leakage was minimized by minimizing pressure drop in the boiler back-end equipment.
- For application of oxy-firing to high sulfur coals, SO₂ must be scrubbed from recycle gas to control boiler corrosion.
- Higher flue gas SO₃ emissions were generated at the convection pass exit with oxy-firing than air-firing. The SO₃ concentrations were reduced by operation of the wet scrubber and condensing heat exchanger. Higher SO₃ concentrations could increase corrosion if the flue gas temperature goes below the acid dew point.

Conclusions from compression, purification, transportation and sequestration evaluation:

- Co-sequestration of CO₂ and SO₂ might be feasible in deep geological reservoirs.
- Pipeline transportation corrosion caused by acid gases can be minimized by removing the moisture from the flue gas.
- CPU modeling demonstrated that the overall energy requirement is lower if flue gas inerts are removed in the CPU rather than compressing the entire flue gas for pipeline transport.

Conclusions from the feasibility and economics evaluation:

- Oxy-firing is an economically viable CCS technology for existing boilers. The predicted incremental cost of oxy-firing for existing boilers (subcritical and supercritical) varies between 5 to 7¢/kWh which is competitive with other CCS technologies.
- Levelized Cost of electricity for greenfield boilers using oxy-firing coupled with ultra-supercritical boilers was about 25% higher than LCOE for a supercritical boiler under air-firing, well below the DOE target of 35%.
- A supercritical retrofit with cool recycle, would have marginally higher LCOE than a new warm recycle USC plant (e.g. 8.68 versus 8.42 ¢/kWh for decker coal) but the capital investment for the new USC plant is over 67% higher than the retrofit which may be very attractive from a financing perspective for retrofitting an existing plant. This shows oxy-combustion retrofit of existing plants is a viable option. vs. building a new one.
- Oxy-firing can be applied to the majority of existing wall-fired and Cyclone boilers depending on space and existing equipment. The site requirements are very similar to those for post combustion capture but without process steam requirements (which impact the low pressure steam turbine).
- Units with 200 MWe or larger generating capacity were considered for oxy-firing retrofit. A study of these units indicated that the majority of these units are within 50 miles of a major geological storage site.

Recommendations for future study:

- Oxy-firing SO_3 emissions are important to corrosion but difficult to measure. Few data are available and the effectiveness of control processes is not well understood. Additional testing of SO_3 formation and removal is highly recommended.
- Testing of wet scrubbing systems in oxy-firing has been performed by B&W and others but little test data of dry scrubbing systems is available under oxy-firing conditions. Pilot testing with a dry scrubbing system is recommended since dry systems use less water, have lower capital cost, and better control acid gases (SO_2 , SO_3 , HCl , etc.). A better understanding of SO_2 and acid gas removal, operation, and operating costs is needed.
- Testing with a direct contact cooler polishing scrubber added to the oxy-firing process is also recommended. These studies are necessary to understand the SO_2 removal performance if very low levels of SO_2 are a required specification for the CPU.
- An evaluation to determine the SO_2 concentration requirements of the flue gas entering the compression and purification unit (CPU) is recommended. Currently, compressor manufacturers require very low levels of SO_2 (<1 ppm).
- A site-specific engineering and economic oxy-firing retrofit study for an existing coal-fired utility unit is recommended. This study would aid in developing a more reliable cost basis for evaluating retrofit of an existing unit with oxy-firing. A potential site for this engineering study is the AEP Conesville unit which would enable direct comparison with existing DOE studies using other technologies.

1. INTRODUCTION

1.1. Background

The key to a strong, stable, and secure economy is readily available, reasonably-priced energy. To maintain economic competitiveness and meet growing energy demands, the US must improve the utilization of its domestic resources. Our vast resources of coal play a strategic role in electric power production but fossil fuel combustion is also a primary contributor of increased GHG emissions. As fossil fuels continue to be the dominant fuel source for electricity generation, reducing carbon emissions by capturing and sequestering CO₂ from utility boilers is being considered to reduce these emissions and thereby control overall atmospheric GHG emissions. Development of the technologies that reduce GHG and minimize the cost of electricity is of a prime interest for existing coal-fired boilers. The Babcock & Wilcox Company (B&W) and Air Liquide (AL) teamed to further develop the oxy-combustion technology for retrofit applications in existing coal-fired wall-firing and CycloneTM boilers. The technology involves the replacement of the combustion air by pure oxygen diluted in recycled flue gases enabling CO₂ capture from coal-fired power plants. It will be applicable with minimal pressure-part modifications to existing boilers. B&W, AL and Battelle developed a preliminary design and prepared a budgetary cost estimate for the boiler retrofit. Air Liquide provided the expertise in the air separation unit (ASU), flue gas purification, and CO₂ compression. Battelle provided expertise in CO₂ transportation and sequestration.

1.2. Project Objectives

The overall objective of this project is to further develop the oxy-combustion technology for commercial retrofit in existing wall-fired and Cyclone boilers by 2012. To meet this goal, a two-phase research project was conducted that included pilot-scale testing and a full-scale engineering and economic analysis.

Phase I objectives include:

- Evaluate at pilot -scale the effect of coal rank used in existing boilers (i.e., bituminous, subbituminous, and lignite) on oxy-combustion design.
- Determine the equipment requirements for the boiler island, including flue gas purification, CO₂ compression, transportation, and storage for different coals and combustion systems (Cyclone and wall-fired).
- Investigate the potential for multi-pollutant (NO_x, SO₂, and particulate) reduction.
- Validate an existing 3-dimensional computational flow, heat transfer, and combustion model for oxy-combustion scale-up to a commercial size boiler.

Phase II objectives are as follow:

- Evaluate the impact of oxy-combustion implementation on net power production and cost of electricity for Cyclone and wall-fired applications.
- Determine the boiler population with close proximity to candidate geologic CO₂ storage sites.

- Conduct an engineering and economic assessment of the technology for commercial-scale retrofit and greenfield application for Cyclone and wall-fired units.
- Assess potential CO₂ control cost reductions via the integration of the air separation unit, flue gas purification, CO₂ compression train, and CO₂ transportation and sequestration.

Phase I activities entailed pilot-scale development of the technology at B&W's 6-million Btu/h oxy-combustion pilot facility using different coal ranks. Parametric tests were conducted to optimize the oxy-combustion process and evaluate the Cyclone slagging, heat transfer, and overall operability. B&W's computational fluid dynamics and combustion model was validated for oxy-combustion application with the pilot-scale data. Specifications for flue gas purification, compression, transportation, and sequestration were used to help design the environmental equipment required (e.g. scrubber, etc).

During Phase II, an engineering feasibility and economic evaluation was performed for Cyclone and wall-fired boilers. Various components of the oxy-combustion process such as ASU, flue gas purification, CO₂ compression train, CO₂ transportation, and sequestration were evaluated and the process was optimized. Net power production was calculated and the cost of electricity was estimated for retrofitting existing subcritical and supercritical boilers firing Eastern bituminous, Western subbituminous, and North Dakota lignite coals. For greenfield power applications ultra-supercritical boiler technology was considered and the cost of electricity was estimated.

2. METHODS AND APPROACH

2.1. Phase I – Pilot-scale Evaluation

2.1.1. Pilot-scale Test Facility: SBS-II

2.1.1.1. General SBS-II Facility Description

The 6 MBtu/h (1.8 MW_{th}) Small Boiler Simulator-II (SBS-II) was used for the pilot-scale tests. It is a new test facility and is designed for evaluating various fuels, combustion processes, air pollution control devices, and associated hardware for potential commercial use. The general layout is shown in Figure 2.1. There is a coal processing area, fan room, furnace with convection pass, heat exchangers, and various environmental controls such as baghouses and scrubbers. For oxy-firing there is an oxygen storage and delivery system, and ductwork for recirculation of flue gas. The furnace may be equipped with either a single wall-fired burner, or Cyclone furnace.

Figure 2.1 General layout of SBS-II pilot scale facility

The coal processing equipment consists of material handling equipment connecting a raw coal hopper to a coal dryer, coal crusher, crushed coal storage tank, MPS 32 K rolling mill (manufactured by Gebr. Pfeiffer AG, Germany), and pulverized fuel weigh feeder. If the as-received coal is adequately dry and sized for the mill, the dryer and crusher may be bypassed. The SBS-II has an indirect firing configuration; i.e. the air used to sweep the mill is not the same

gas used to convey the coal to the burner and initiate combustion. The mill is swept by air from a forced draft fan, and the pulverized coal (PC) and air mixture is delivered to a baghouse where the air is vented and the PC delivered to a storage tank. The coal fineness is controlled by a combination of mill settings and the variable speed of a single stage rotating classifier. During firing the coal is fed into the preheated primary air or oxidant stream by a gravimetric feeder. A full scale Cyclone burns crushed (as opposed to pulverized) coal. This physics of this pilot scale Cyclone (smaller diameter) requires pulverized coal, however with a lesser fineness requirement than a PC wall-fired burner.

The fan room contains the forced draft fans for the pulverizer, primary oxidant, and secondary oxidant. In addition, there is a booster fan that increases the pressure of the flue gas upstream of the environmental equipment. Downstream of the environmental systems, an induced draft (ID) fan (located outside of the building next to the stack) delivers flue gas to the stack. Ductwork from the outlet of the ID fan can also direct flue gas back to the fan room for recirculation. Each of the primary and secondary oxidant fans has two inlets – one for ambient air, and one for recirculated flue gas. Operator-controlled valves determine the ratio of air to recirculated flue gas for transition between air and oxy-firing. Figure 2.2 shows a schematic diagram of the system and how various components are connected by ductwork. Note that not all ductwork in the facility is represented, as some environmental equipment was not used for this work. In addition, it should be noted that bypass ducting exists for the wet flue gas desulfurization (WFGD) scrubber and the condensing heat exchanger (CHX).

Starting at the primary fan in the lower right of Figure 2.2, and following the directional arrows, the primary flow is metered prior to entering the FloxynatorTM where oxygen may be injected. An electric heater preheats the primary stream to typically 150-350°F before tertiary oxidant is bled off to the Cyclone, and coal is added by the weigh feeder. Moisture evaporation from the coal usually lowers the temperature of the primary stream at this point. The primary stream then goes to the scroll burner of the Cyclone furnace where it enters tangentially. Tertiary oxidant also enters the scroll burner, flowing along the axis of the Cyclone for control of the ignition location.

The secondary fan also delivers air and/or recirculated flue gas to a FloxynatorTM for oxygen addition during oxy-firing. The oxidant is then preheated in the air heater by hot flue gas leaving the convection pass. Independent control of the secondary oxidant temperature (desirable in a research facility) is possible by the gas-fired trim heater downstream of the air heater. Typical secondary oxidant temperatures are 600-700°F. A venturi meters the total flow of hot secondary oxidant prior to splitting into burner and overfire streams. The bulk of the flow goes to the Cyclone furnace tangential secondary duct, and the smaller overfire stream is separately metered, and directed to two ports at the rear of the furnace below the arch. Pressure drop indicators across in-duct orifice plates allow balancing of flow between these two ports. In most oxy-firing tests, a lance is used to add additional oxygen to the secondary stream just prior to entering the Cyclone.

Figure 2.2 Schematic diagram of the SBS-II facility with selected instrumentation. The WFGD and/or CHX may be bypassed. Locations of valves, flow measurement, and in situ H₂O and O₂ sensors are shown

In the Cyclone furnace the intense mixing and rapid combustion generates sufficiently high temperatures to melt the ash, which collects on the walls of the Cyclone and runs out the slag tap into the water seal at the bottom of the SBS-II furnace. Fuel-rich combustion products, including some fine char particles, leave the Cyclone through the reentrant throat and complete combustion in the SBS-II furnace upon mixing with oxidant from the overfire ports.

The SBS-II furnace absorbs heat from the hot gases primarily by radiant heat transfer. These gases then enter the convection pass where seven banks of water cooled tubes cool the gases by convection heat transfer, simulating the time-temperature profile of a full-scale boiler convection pass. Flue gas exits the convection pass at about 800°F.

Continuous emission monitors sample the gas at the convection pass exit for O₂, CO, CO₂, and NO_x. Fly ash may also be sampled at this point for determination of unburned carbon, fly ash loading, and ash particle size distributions.

The flue gas leaving the convection pass is cooled further in the air heater as it preheats the secondary oxidant. A fan in the fan room supplies cooling air to an additional heat exchanger called the flue gas cooler to extract further heat from the flue gas. This cooling air is vented to the atmosphere. The use of shell and tube heat exchangers for these two processes prevents infiltration of air into the flue gas.

The next device in the system is a booster fan that is used to control pressures in the ducts and devices between the convection pass and ID fan. This is followed by a venturi flow meter, baghouse, wet scrubber, and condensing heat exchanger. Depending on the coal, and type of experiment being performed, the latter two devices may be bypassed. If the wet scrubber is used, the flue gas is sampled for O₂ and SO₂ at the scrubber inlet.

Just upstream of the ID fan the flue gas is sampled continuously for O₂ and SO₂. The flue gas then enters the stack through the ID fan. Recirculated flue gas is returned to the boiler from the stack by controlling the valves on the primary and secondary fan inlets. All fan shafts have seals placed around them to minimize the possibility of air infiltration during oxy-firing.

2.1.1.2. Oxygen Delivery and Control System

Liquid oxygen is delivered by trucks to the test facility and stored on site in a 9000-gallon oxygen tank. The liquid oxygen is vaporized in an ambient vaporizer, sized for winter operating conditions (-7 °C/20 °F air temperature). The oxygen is regulated to an appropriate pressure and delivered to the test area via a stainless steel line. The oxygen delivery control system is integrated with the SBS control system, allowing oxygen flows to be controlled and monitored from a central location. It is also integrated into the boiler safety interlock system. Major components of the system are shown in Figure 2.3

Figure 2.3 The liquid oxygen storage tank and vaporizer (left) and the oxygen flow control skid (right)

2.1.1.3. Cyclone Burner and Oxygen Lances

As mentioned above, and shown in Figure 2.4 and Figure 2.5, the primary oxidant and coal mixture enters the Cyclone furnace through a tangential inlet to the scroll burner. Tertiary oxidant also enters the scroll burner, flowing along the axis of the Cyclone. The combination of the tertiary flow and the position or angle of the primary inlet relative to the secondary inlet controls the ignition location inside the furnace. The secondary inlet (the largest of the three) is located on the cylindrical barrel of the furnace. The barrel is connected to the scroll burner by a tapered neck and to the SBS-II furnace by a reentrant throat. The neck, barrel, and throat each have their own cooling water circuit. The inside surfaces of the steel Cyclone are pin-studded and coated with refractory. A notch at the bottom side of the reentrant throat exists to allow molten slag to drain out of the furnace barrel into the SBS-II furnace where it can flow further down to the water-filled slag tank. The extent to which the notch in the throat was blocked by frozen slag during operation was frequently observed and recorded to determine how well the operating conditions were achieving the goal of removing ash from the furnace in the form of molten slag.

Figure 2.4 Diagram of the Cyclone furnace internal volume

Additional oxygen beyond that delivered with the primary, secondary, and tertiary oxidizer flows may be injected into the furnace with a lance. Three lance designs were used during testing, as indicated in the tabulated experimental data in the appendix:

- Secondary duct lance – The majority of tests were performed with a tube that spanned the secondary inlet to the Cyclone and had several holes on the leading edge along the length of the tube. The direction of the holes was selected to maximize mixing of the oxygen into the secondary flow before the flow entered the Cyclone barrel. The location of the port for this lance is indicated in Figure 2.5.
- Open tube on tertiary line – In one test oxygen was injected axially in the center of the tertiary flow, using only an open tube.
- Scroll lance – A lance that injected the oxygen tangentially from the center of the scroll burner, (swirling in the same direction as the primary air flow) was used during the warm recycle test series. This same lance was also sometimes withdrawn when not in use to minimize flow disturbances in the burner. This lance was inserted through the tertiary oxidant duct along the Cyclone axis.

Figure 2.5 Rendering of the Cyclone furnace external features

2.1.1.4. Furnace and Convection Pass

The SBS-II is designed to accept both a wall-fired PC burner and a Cyclone furnace. When the conversion to Cyclone-firing from wall-firing is performed, the region of the SBS-II furnace required only for wall-firing is filled with removable firebrick as shown in Figure 2.6. The resulting internal volume of the furnace is then as illustrated in Figure 2.7. The same materials and equipment specifications used for air firing were used for oxy-firing.

Referring to Figure 2.7, the SBS-II furnace consists of a narrow primary furnace where gaseous products from the Cyclone turn upward to the lower furnace, and molten slag drains into a water tank/seal at the bottom of the structure. The primary, lower, and upper furnace are refractory-lined water-filled walls. Water that boils to steam during operation is vented from an atmospheric drum at the top of the furnace. Not shown in the figure are numerous sampling and observation ports for sampling, access, or visual observation. One example of this is an access port angled upward toward the slag drain that allows access to mechanically remove frozen slag during operation with a jackhammer. On the rear wall below the furnace arch two overfire air ports deliver additional oxidizer. Just below these and also on the rear wall is the port through which a FlameViewTM two color pyrometer camera can be inserted to view the flame exiting the Cyclone throat.

Figure 2.6 Drawing excerpt showing the location of firebrick installed in the SBS-II

The furnace exit gas temperature (FEGT) may be measured with an HVT (high velocity thermocouple) probe. The location of the port used for this probe is indicated in Figure 2.7 just above the furnace arch and before the first bank of convective cooling tubes. The convection pass consists of seven banks of tubes designed such that the SBS-II simulates the gas time-temperature profile of a full scale boiler. The first two tube banks are connected to the water drum above the furnace, and the remaining five to a water drum above the convection pass. This is important to interpretation of the heat transfer data presented in the results. Like the furnace water system, this system also vents steam at atmospheric pressure.

Gases exiting the convection pass enter an insulated duct to the air heater, and thence to other devices as previously described in connection with Figure 2.2.

Figure 2.7 Internal volume of the SBS-II in Cyclone configuration

2.1.1.5. Baghouse

Particulate matter is removed from the flue gas in an SPE-AMEREX pulse jet fabric filter baghouse. The bags are cleaned to maintain the pressure drop between permitted limits. Generally the bags were not cleaned during tests. Fly ash collected in the hoppers at the bottom of the baghouse was removed through rotary valves. The baghouse was well sealed to prevent air infiltration; however the pulse air is a potential source of air in the system during oxy-firing.

2.1.1.6. Wet Scrubber

The wet scrubber (or WFGD) downstream of the baghouse serves to remove a fraction of SO_2 from the flue gas. The reasons to do so in oxy-firing are twofold: first, to meet the requirements of the facility air permit (for the SBS-II this is $\leq 12 \text{ lb/h SO}_2$), and second, to maintain an acceptable SO_2 concentration in the furnace for corrosion considerations ($< 2000 \text{ ppm}$). The lignite and subbituminous coal had sufficiently low sulfur levels to meet these requirements without using the scrubber, and thus it was only employed for the Ohio #5 bituminous coal tests.

The WFGD subsystem includes the absorber tower with slurry recirculation tank, reagent feed system, mist eliminator system, and slurry dewatering and disposal system. It is designed to treat the entire flow of flue gas from the SBS-II facility while simulating a vertical section down through a commercial scrubber. Emphasis is placed on the duplication of gas/liquid interaction, minimization of wall impingement, and the proper simulation of operating parameters that affect SO₂, particulate, and air toxics removal mechanisms. The design is based on B&W's commercial scrubbers and incorporates a perforated-plate tray to increase gas-liquid contact. Figure 2.8 shows some of the details of the absorber tower, and primary design characteristics are summarized in Table 2.1.

Figure 2.8 Schematic diagram of the wet scrubber absorber tower

Capacity	5000-6000 lb/h gas at up to 4000 ppm SO ₂ or 6 MBtu/h (coal firing)
Design limestone stoichiometry	1.1 mole Ca/mole SO ₂ absorbed
Nominal SO ₂ removal	90%
Design liquid to gas (L/G) ratio	190 gpm/1000 acfm
Normal L/G ratio	120 gpm/1000 acfm
Tower velocity range	5.0-20 ft/s

Table 2.1 Primary design characteristics of the wet scrubber

Reaction products in the slurry leaving the absorber tower flow by gravity into the absorber recirculation tank (ART) below the tower. An air sparger system provides clean humidified air to the bottom of the tank for forced oxidation of the products. The ART is also equipped with an agitator to keep solids from settling. Slurry supplied to the spray headers of the absorber tower comes from the ART.

At the top of the absorber tower, mist eliminators minimize carryover of slurry and liquid droplets generated in the absorber tower. To prevent buildup and plugging, the mist eliminators are periodically washed by water spray nozzles.

Limestone slurry is prepared in batches in the limestone feed tank by mixing pulverized limestone with water. The limestone feed tank is equipped with an agitator and pump. The feed rate of limestone slurry from the limestone feed tank to the ART is controlled using the pH of the slurry stream from the ART to the spray nozzles (monitored continuously with an in-line pH sensor). The slurry density in the ART is monitored by a densitometer, which yields a solids concentration measurement. The solid gypsum product of the scrubber is periodically removed by pumping the slurry through a hydroclone and extracting the hydroclone underflow from the system. The same hydroclone can be operated to remove water from the system that accumulates during flue gas recirculation.

2.1.1.7. Condensing Heat Exchanger (CHX)

Downstream of the baghouse (and wet scrubber, if used) a condensing heat exchanger was used to lower the moisture content of the flue gas for all tests except the warm recycle test series. The term “warm recycle” implies that moisture is not removed from the recycled flue gas by cooling, which has the aim of improving plant efficiency relative to cold recycle operation. The heat exchanger is a Teflon[®]-coated shell and tube design and is supplied with city water to remove the heat from the flue gas. Condensed moisture collected in the bottom of the heat exchanger is pumped to the ART of the wet scrubber system. The water (which contains impurities from the combustion process) is thereby handled with the waste water stream from the wet scrubber. Downstream of the heat exchanger the flue gas is saturated with moisture which allows determination of the moisture content by temperature measurement alone.

2.1.1.8. Boiler Permissives and Interlocks

The boiler uses conventional flame/combustion safety interlocks and controls in addition to other requirements unique to oxy-firing. Some of these are procedural and depend on operator training as indicated below:

- SBS-II control system and Air Liquide oxygen control system are communicating (interlock)
- The use of oxygen is only permitted after stable operation of the boiler on air has been established (operator-controlled permissive in SBS-II Control system)
- Initiation of oxygen flow is preceded by:
 - Purging of the appropriate Floxynator[™] or Lance (procedural)
 - Opening of a manual valve (procedural)

In consultation with Air Liquide, alarm and trip conditions were established as follows:

- Oxygen concentration (wet basis) at the secondary Floxynator™ in-situ oxygen monitor:
 - 18% – Low alarm
 - 25% - High alarm
 - 28% - Master fuel trip (MFT)
- Oxygen concentration (wet basis) at the primary Floxynator™ in-situ oxygen monitor:
 - 16% – Low alarm
 - 21% - High alarm
 - 23.5% - MFT
- The following items can also trip the Air Liquide oxygen skid:
 - A master fuel trip (MFT) on the SBS-II
 - Local emergency stop push button
 - Loss of power
 - Loss of instrument air pressure
 - Low oxygen pressure
 - Low oxygen temperature

In the event of a MFT, the following sequence is initiated:

- Oxygen flow shut down
- Natural gas supply shut down
- Coal feeder shut down
- Primary fan stops
- Secondary flue gas recirculation valve closes and secondary air intake valve opens
- Secondary fan adjusts to a pre-determined speed
- ID fan adjusts to a pre-determined speed

2.1.1.9. Instrumentation and Laboratory Methods

Oxy-combustion requires monitoring and control of oxygen in the ducts, measurement of oxygen flows and measurement of recycled gas flow. In this section, the instrumentation used and other analysis methods are discussed.

For this project, five (5) in situ O₂ probes were used at the following locations:

- Cyclone secondary duct – oxidant concentration
- Secondary duct after secondary oxygen injection – oxidant concentration and interlock
- Primary duct after primary oxygen injection – oxidant concentration and interlock
- Recycle gas prior to oxygen injection – recycle gas oxygen concentration
- Convection pass exit – flue gas concentration

In addition to measuring the wet concentration of oxygen at their designated point in the process, these probes can be used to provide an output signal for safety interlocks. These analyzers were calibrated before and after testing. Note that the manufacturer's calibration procedure had to be modified: typically the sensors are calibrated at atmospheric pressure, but since the duct pressure at some locations can be different to atmospheric pressure the calibrations are performed at pressures representing the actual process pressure. An additional consideration is to maintain the calibration gas pressure at a value only slightly higher than the sensor pressure. Failure to follow

these modifications to the calibration procedure results in significant offsets in the oxygen readings.

During the first series of tests with bituminous coal, an in situ moisture analyzer was located at the Cyclone secondary duct. After obtaining favorable comparisons between the measured moisture content and the value calculated independently from other data, the analyzer was permanently relocated to the baghouse outlet. The calculation of gas composition in the ducts (on which flow rate calculations are based) usually depends on a temperature measurement at a point, such as the wet scrubber outlet, where the gas is saturated with moisture. For the warm recycle tests where no point in the duct system can be assumed saturated; this moisture analyzer becomes important to the calculation of flue and recycle gas composition.

The SBS-II has three gas analysis systems. The convection pass system consists of gas analyzers for O_2 , NO_x , CO , and CO_2 . The stack gas analysis system and the wet scrubber inlet system each consist of an O_2 and SO_2 analyzer. The corresponding sample locations are the convection pass exit, ID fan inlet, and wet scrubber inlet, as indicated in Figure 2.2. The gas samples are withdrawn with vacuum pumps, filtered, transported in a heated sample line to a refrigeration unit, and passed to the appropriate analyzers. All analyzers were calibrated once per shift during testing. The convection pass fly ash can be isokinetically sampled and analyzed for carbon content to determine carbon utilization in the system.

The SBS-II Cyclone, furnace, and convection pass are water cooled. Flow rates, levels, and temperatures of water in the system are important both for monitoring of operation, and determining heat absorption of the furnace. Figure 2.9 shows a process and instrumentation diagram (P&ID) for the blowdown system. Locations of thermocouples (TE), flow elements (FE), and flow control valves (FCV) are shown. In addition to the instrumentation shown, there is a water level sensor in each of the furnace and convection pass stream drums that is used for control of the respective makeup water flow.

Figure 2.9 P&ID for SBS-II water-side/blowdown system

The following measurement techniques and instrumentation were used during the SBS-II tests:

- Air and flue gas flow rates – Calibrated venturi flow meters, corrected for process temperature and pressure, and gas composition (molecular weight). Recycled flue gas flow was also calculated in some tests using the oxygen flow rate and oxygen concentrations before and after oxygen injection to the duct.
- Oxygen flow rates – Calibrated orifices
- Coal flow rate – Gravimetric coal feeder
- Ambient relative humidity and barometric pressure – Vaisala PTU 300 Combined Pressure, Humidity, and Temperature Transmitter
- Moisture
 - Temperature measurement at saturated conditions
 - MAC Instruments MAC 125 Analyzer (proprietary solid state sensor)
- O₂ (wet basis, in situ) – Zirconium oxide sensors
- O₂ (dry basis) – paramagnetic
- CO, CO₂ – NDIR
- NO_x – Chemiluminescent
- SO₂ – UV
- SO₃ – CleanAir Method 8B
- Hg – Cold vapor atomic absorption spectrometry (CVAAS) with Zeeman background correction
- Fly ash unburned combustibles – High volume sampler at convection pass exit, unburned combustibles determined by mass loss on ignition (LOI) of collected ash
- FEGT – High Velocity Thermocouple (HVT)
- Flame Temperature – Two color optical pyrometry (FlameView™ Camera)
- Cyclone and boiler water flows – calibrated orifices

Standard laboratory methods used for the analysis of the coals used and their constituents are listed in Table 2.2.

Test	Method (ASTM unless otherwise specified)
Proximate analysis:	D5142 or as listed below
Moisture	D2961, D3302, D3173
Ash	D3174
VM	D3175M
FC	D3172
Heating value (Btu/lb)	D5865
Ultimate analysis:	
C	D3178, D5373
H	D3178, D5373
N	D3179, D5373
S	D4239 Method B
O	D3176
Major/minor elements in ash (XRF) (SiO ₂ , Al ₂ O ₃ , Fe ₂ O ₃ , CaO, MgO, Na ₂ O, K ₂ O, P ₂ O ₅ , TiO ₂ , BaO, SrO, & SO ₃)	D4326
Mercury in coal (CVAAS)	D6414
Chlorine in coal	D4208
Flyash – LOI @ 800°C	B&W Test Method (based on ASME reference 4.07)
Coal sizing:	
Screening	B&W Test Method (based on D-197-30, D311)
Microtrac Particle Size Analyzer	Light scattering
Coal grindability test	D409 (Hardgrove Grindability Index)

Table 2.2 Standard laboratory methods used in coal analysis

2.1.1.10. Data Acquisition System (DAS) and Analysis

The SBS-II uses a Rockwell Automation data acquisition and control system that converts raw voltage and current signals from the instruments to engineering units in real time. Most data are displayed on the Human-Machine Interface (HMI) screens, and a selection of data is used as the input to an online data analysis program. The variables used by the data analysis are smoothed using the following equation:

$$A_{new} = \left(\frac{n-1}{n} \right) \cdot A_{old} + \left(\frac{1}{n} \right) \cdot A_{sensor\ value} \quad [2.1]$$

Where n is an operator adjustable parameter to achieve the desired balance between smooth data and quick response to system changes. This smoothing is particularly important for pressure data where fluctuations of significant magnitude occur. The value of n chosen for this test campaign, allows the system to respond 90% to a step change in 1.4 seconds, with acceptable smoothness in the data. The coal feeder has repeatable periodic features in the signal due to the conveyor belt

seam passing over the scale, and thus for the measured coal feed rate only, a higher value of n was applied.

This program (coded in Rockwell RS Logix structured text) runs continuously at a rate of about 30 Hz (times per second). Data such as flow rates, load, and pollutant emission rates are produced and also displayed on the HMI. A Rockwell Historian server logs data points at least every 60 seconds. The rate for storage of data is set by the operator, and during testing the time between samples was reduced from the maximum 60 seconds to 10 or 20 seconds. The logged data are a mixture of raw (sensor) values and calculated parameters. Every raw input used by the calculations is included in the logged data to allow off-line reprocessing of test data if required.

Data for a steady state test were exported from the historian server as summary data (i.e. average, standard deviation, minimum, maximum, and number of points). For data sets requiring off-line reprocessing, all logged data points over the time of interest were exported and reprocessed using a MATLAB routine that duplicated the calculations in the on-line system. The two primary purposes of reprocessing were 1) to allow replacement of data from failed sensors with values from backup sensors, and 2) to carefully select the time over which cyclic heat absorption data were averaged to produce more accurate averages for selected tests. More detail is given below.

Gas mass flow rates for pulverizer air, natural gas, primary and secondary air/oxidizer, overfire oxidizer, primary and secondary recycled flue gas (RFG), flue gas before environmental controls, and flow to the stack are calculated using flow venturi calculations with the manufacturers' calibration constants. These calculations are based on static pressure, temperature, and pressure drop measurements at the venturi. The adiabatic expansion factor is assumed constant. Molecular weight of the moist air or gas mixtures is calculated from humidity sensor and gas analyzer outputs. For safety, to provide meaningful flow rates to the operators in the event of a gas analyzer failure, the molecular weights are constrained between reasonable limits (for example between 28 and 42 lb/lbmol for gas exiting the convection pass). Oxygen mass flow rates are provided to the data acquisition system from the Air Liquide oxygen skid. They are calculated using the same principles as other gas mass flow rates.

Tertiary oxidizer is bled off the primary line just before coal is added (Figure 2.2). The flow is measured with a calibrated orifice, but static pressure is not measured locally and so is estimated to be equal to the static pressure for the primary flow. The tertiary flow measurement is for indication only and is not used in other calculations. Stoichiometry calculations are based on the primary flow which includes the tertiary stream. For the primary and secondary RFG streams the flow rates from the flow venturi calculations was not always consistent with calculation of these flow rates by other means. The RFG flow rates calculated from in-situ O₂ measurements or from the flow meters downstream of the forced draft fans were believed to be more reliable. For the warm recycle oxy-firing cases that were reprocessed, all calculations based on secondary RFG flow used the flow rate calculated from in-situ O₂ data. The ratio of infiltrated air to flue gas flow is calculated based on in-situ O₂ measurements. The windbox measurement took priority over the secondary FloxynatorTM reading in the calculations with the exception of the calculation of secondary RFG using the O₂ concentrations.

Water flows for the Cyclone, furnace, and convection pass cooling are measured with calibrated orifices and displayed on the HMI in gallons per minute. These values were converted to mass

flow for the furnace heat balance calculation using a correlation for water density variation with temperature. To simplify and increase the accuracy of the heat balance calculation, the drum levels are controlled within 0.2 inches, the overflow and blowdown lines (Figure 2.9) are not used, and the Cyclone drain flow measured for operator display is not used, but is replaced with the sum of inlet flows. The tight control on the furnace and convection pass drum levels results in a relatively rapid cyclic variation in calculated furnace and convection pass heat absorption as seen in Figure 2.10 below. High heat absorption for the furnace and convection pass is calculated when the makeup water valves are open, and zero heat absorption when they are closed. A complete cycle takes about 7 minutes. The true value of heat absorption is represented by the average of a whole number of these cycles. In the calculations (which are running at about 30 Hz) there is a numerical integration of the flow rate to track the average valve activity between logging of data, thus the “instantaneous” heat absorption in the figure is the average since the last data point was logged. The instantaneous values range from 0 to 6.5 MBtu/h, with the true average being on the order of 2 MBtu/h. When data are reprocessed to improve the accuracy of the heat balance calculations, the primary difference between the reprocessed data and the original data is that the furnace and convection pass heat transfer data are averaged over a whole number of valve cycles rather than the unrelated test time.

Figure 2.10 Furnace and convection pass heat transfer data illustrating the cyclic nature of the calculations based on instantaneous data.

There are three ways that the boiler load may be determined, each with different sources of uncertainty as follows:

- Heat transfer method, using water heat absorption as described above, combined with flue gas flow rate and convection pass exit temperature. This method is subject to uncertainties in the flow rates. The error associated with heat loss through the furnace insulation to the room was evaluated at less than 0.5% of heat input.

- Coal input method, using feed rate from the gravimetric coal feeder, combined with the coal heating value. Variations in coal heating value, moisture, and ash, coal feeder calibration, combustion efficiency, as well as noise in the signal contribute to uncertainty for this method.
- Element balance method, using gas analysis and flow rates to solve an ideal combustion equation for the coal flow rate. This is subject to the uncertainties of the input parameters (flow rates, gas concentrations, and unaccounted air infiltration).

For the first method, the need to average make up water flows over a whole number of valve cycles makes it impractical to determine load by this method during a test. In addition, the thermal mass of the boiler requires long operation at steady state for acceptable accuracy. Coal flow calculated by the third method was more stable than that from the coal feeder and was used to determine load during testing. Averaged over the entire test campaign the agreement between the calculated and measured flows was within 7.1% of the mean value, with a range of 0.2 to 19.6%. Over time and with decreased air infiltration the agreement generally improved, as leaks were found and eliminated, and operators gained experience. By the last day of testing agreement was within 4% on average, and in the worst case better than 10%. Figure 2.11 illustrates the agreement between the latter two methods. The calculations used for the element balance method are described next.

Figure 2.11 Comparison of measured and calculated coal flow rates

Calculation of the coal feed rate from other parameters is based on solving equations representing the basic combustion reaction below. This ideal reaction represents moist coal and/or natural gas burning in air and/or mixtures of O_2 and recycled flue gas to produce CO_2 , water, and minor species such as NO_x and SO_2 . Excess oxygen also appears on the product side.

In the above equation:

- A' (or "A prime") is the number of moles of water per mole of air (from the humidity sensor)
- m is 3.77 moles of N₂ per mole of air
- n is the mole fraction of impurities (assumed N₂) in the liquid oxygen (0.002)
- NG_C, NG_H, NG_N, and NG_O are the atoms of C, H, N, and O respectively per equivalent natural gas molecule (1.0396, 4.0397, 0.012, and 0.0138)

All other symbols are in units of moles per hundred pounds of as-fired coal as follows:

- x – carbon in coal (from ultimate analysis)
- y – hydrogen in coal (from ultimate analysis)
- z – nitrogen in coal (from ultimate analysis)
- q – oxygen in coal (from ultimate analysis)
- w – sulfur in coal (from ultimate analysis)
- v – chlorine in coal (from ultimate analysis)
- h – moisture in coal (from proximate analysis)
- A – air (including ambient moisture)
- B – oxygen from liquid oxygen supply
- C – CO₂ in recycled flue gas
- D – H₂O in recycled flue gas
- E – O₂ in recycled flue gas
- F – SO₂ in recycled flue gas
- G – N₂ in recycled flue gas
- H – Cl₂ in recycled flue gas
- K – equivalent natural gas

The coefficient of O₂ on the product side may be further simplified to:

$$\{ [q/2 + K NG_O/2 + A + B (1 - n) + E] - [x + K NG_C + y/4 + K NG_H/4 + w] \} \tag{2.3}$$

The coal proximate and ultimate analysis results are manually entered into the HMI. The nine letters A-K are unknown in the above equation but can be solved using a system of nine equations below. These equations express measured quantities in terms of the variables in the combustion reaction equation above.

Expressing the directly measured oxygen concentration (dry basis) at the convection pass in terms of the unknown variables yields:

$$X_{\text{Conv.PassO}_2(\text{dry})} = \frac{\{[q/2 + K * NG_{\text{O}}/2 + A + B(1 - n) + E] - (x + K * NG_{\text{C}} + y/4 + K * NG_{\text{H}}/4 + w)\}}{[K * (NG_{\text{O}} + NG_{\text{N}} - NG_{\text{H}}/2)/2 + A * (1 + m) + B + C + E + F + G + H - y/4 + z/2 + q/2 + v/2]} \quad [2.4]$$

Similarly, expressing the dry basis concentrations of CO₂ and SO₂ at the convection pass (also directly measured) in terms of the unknowns:

$$X_{\text{Conv.PassCO}_2(\text{dry})} = \frac{(x + C + K * NG_{\text{C}})}{[K * (NG_{\text{O}} + NG_{\text{N}} - NG_{\text{H}}/2)/2 + A * (1 + m) + B + C + E + F + G + H - y/4 + z/2 + q/2 + v/2]} \quad [2.5]$$

$$X_{\text{Conv.PassSO}_2(\text{dry})} = \frac{(w + F)}{[K * (NG_{\text{O}} + NG_{\text{N}} - NG_{\text{H}}/2)/2 + A * (1 + m) + B + C + E + F + G + H - y/4 + z/2 + q/2 + v/2]} \quad [2.6]$$

Windbox O₂ is directly measured by an in-situ sensor. Relating the windbox oxygen concentration (wet basis) to the flow rates of air, oxygen, and recycled flue gas into the windbox:

$$X_{\text{WindboxO}_2} = \frac{[A * \dot{m}_{\text{SA}}/\dot{m}_{\text{Air}} + B * (1 - n) * \dot{m}_{\text{SecO}_2}/\dot{m}_{\text{O}_2} + E * \dot{m}_{\text{SecRFG}}/\dot{m}_{\text{RFG}}]}{[A * (1 + m + A') * \dot{m}_{\text{SA}}/\dot{m}_{\text{Air}} + B * \dot{m}_{\text{SecO}_2}/\dot{m}_{\text{O}_2} + (C + D + E + F + G + H) * \dot{m}_{\text{SecRFG}}/\dot{m}_{\text{RFG}}]} \quad [2.7]$$

Where $\dot{m}$ indicates mass flow in lb/h of the stream indicated by the subscript:

- SA – secondary air (includes overfire air)
- Air – Total air (primary and secondary air including overfire air)
- Sec O₂ – Oxygen to secondary FloxynatorTM
- O₂ – Total oxygen (primary, secondary, and Cyclone lance)
- Sec RFG – Secondary recycled flue gas
- RFG – Total recycled flue gas

If either the wet scrubber (WFGD) or condensing heat exchanger (CHX) was in use the partial pressure of water vapor was calculated from saturated conditions. For warm recycle tests the mole fraction of water vapor was directly measured by the moisture analyzer. Expressing partial pressure (or mole fraction) of water in the recycled flue gas in terms of C, D, E, F, G, and H yields:

$$X_{\text{H}_2\text{ORFG}} = \frac{D}{(C + D + E + F + G + H)} \quad [2.8]$$

The measured ratios of oxygen or recycled flue gas to air mass flows, expressed in terms of the variables in the combustion reaction equation are:

$$\frac{\dot{m}_{\text{O}_2}}{\dot{m}_{\text{Air}}} = \frac{\{B * [32 * (1 - n) + 28 * n]\}}{[A * (32 * 1 + 28 * m + 18 * A')]} \quad [2.9]$$

and:

$$\frac{\dot{m}_{\text{RFG}}}{\dot{m}_{\text{Air}}} = \frac{(44 * C + 18 * D + 32 * E + 64 * F + 28 * G + 71 * H)}{[A * (32 * 1 + 28 * m + 18 * A')]} \quad [2.10]$$

The next equation equates the mass ratio of chlorine to carbon in the coal with that in the recycled flue gas. It assumes that chlorine exists as gas-phase Cl_2 , and does not drop out in the environmental equipment and recycle ducts. The equation does not apply when natural gas is flowing (during startup) as including this situation would make the equation system non-linear. The equation is included here for completeness of the documentation, but as the chloride content of coal was not used in the data analysis the equation was effectively deactivated. There was no instrumentation to measure Cl compounds beyond the off-site fuel analysis. The equation has minimal effect on the equation system as a whole due to the low levels of Cl, and only has practical use for warm recycle (no WFGD) to estimate the upper limit of Cl (as Cl_2) in the recycle gas.

$$\frac{35.5 * v}{12 * x} = \frac{71 * H}{12 * C} \quad \text{or} \quad \frac{v}{x} = \frac{2 * H}{C} \quad [2.11]$$

The last of the nine equations expresses the ratio of mass flow of natural gas to air and oxygen mass flows (all measured) in terms of the variables in the combustion reaction equation:

$$\frac{\dot{m}_{\text{NG}}}{\dot{m}_{\text{Air}} + \dot{m}_{\text{O}_2}} = \frac{[K * (12 * \text{NG}_C + 1 * \text{NG}_H + 16 * \text{NG}_O + 14 * \text{NG}_N)]}{\{A * [32 * 1 + 28 * m + 18 * A'] + B * [32 * (1 - n) + 28 * n]\}} \quad [2.12]$$

The nine equations form a linear system that may be expressed as a matrix equation and solved using elementary row operations. The specific algorithm used is known as LU decomposition because the procedure decomposes the matrix of coefficients to express it as the product of a lower (L) triangular matrix and an upper (U) triangular matrix. The results are used to calculate overall and burner stoichiometry, coal flow rate, load, total convection pass mass flow, and emissions rates.

2.1.1.11. Data Reporting

The data were prepared for publication using Microsoft Excel, and are shown graphically in the Results and Discussion chapter, and tabulated in the Appendix. Key points to note regarding the data are as follows:

- The SO_2 emission rate is calculated using the concentration measurement at the stack. Some SO_2 readings at the convection pass were acquired by an IR analyzer but were biased high (by up to 300 ppm) due to moisture interference and are not presented. Instead, the data from UV SO_2 analyzers at either the wet scrubber inlet or stack (as appropriate) were corrected to the oxygen concentration measured at the convection pass and reported as convection pass SO_2 .
- It is suspected that the thermocouple at the CHX outlet was wetted by condensate resulting in a low reading. This affects the calculation of moisture in the recycled flue

gas, which because it is used in the system of equations above, has effects on several variables. The resulting error in calculated coal flow, load, and stoichiometry is however less than 1% (for a 14°F error in the CHX outlet temperature in test “prb oxy Cyclone test13”). From September 3rd, 2009 the problem was solved by calculating saturation conditions using the thermocouple at the ID fan inlet instead of that at the CHX outlet. Reprocessed test data (marked in the tables) also had this correction applied. The warm recycle tests did not use the CHX.

- The reported moisture content of the primary oxidant stream does not include moisture from the coal that evaporates between the coal pickup point and the burner, as indicated by significant cooling of primary oxidizer when the coal is picked up. The energy balance calculations do account for this effect by using the primary oxidant temperature before coal addition.
- Bottled CO₂ rather than compressed air was used in an eductor for fly ash sampling in the oxy-firing tests. This avoided introduction of unwanted compressed air to the system. The fly ash sampled was not captured under the targeted isokinetic conditions because the required pressure of CO₂ could not be reached with the bottled gases.
- Coal was only sampled intermittently for coal fineness and as-fired moisture determination. Values were assumed to apply until the next time a sample was taken and analyzed.
- The maximum temperatures from the FlameView camera have a resolution of 100°F and may not be representative of the temperature map. See the temperature maps in Results and Discussion for more information.
- Data missing from the tables are due to them either not being applicable (e.g. O₂ flows in an air-fired test), or being obviously bad values that are discarded. Some heat transfer data are discarded because the test time was insufficient for the averages to be accurate.

2.1.2. Coal Analyses

The coals tested were Ohio #5 (an Eastern bituminous coal), Black Thunder (a Western subbituminous coal from the Powder River Basin (PRB)), and North Dakota Lignite. Proximate, ultimate, and other analysis data are shown in Table 2.3. Elemental ash analysis results are shown in Table 2.4. The subbituminous coal for the warm recycle testing was delivered in a separate shipment and notably differed in sulfur content from the subbituminous coal used previously. For this reason, both analyses are shown. Both as-received and as-fired sulfur contents are listed, as some sulfur is removed as pyrite during pulverizing. The high sulfur content of the bituminous coal is an important distinction between it and the other two coals for this work.

	Eastern Bituminous	Western Sub-bituminous		Lignite
		Black Thunder		
	Ohio #5	Cold recycle	Warm recycle	North Dakota
Proximate Analysis (wt %, as received)				
Moisture	6.47	26.56	26.15	35.60
Ash	5.57	4.94	4.64	6.79
Volatile Matter	41.51	32.11	32.20	28.50
Fixed Carbon	46.45	36.39	37.01	29.11
Ultimate Analysis (wt %, as received)				
Carbon	71.10	50.98	51.80	41.91
Hydrogen	5.02	3.84	3.83	3.04
Nitrogen	1.41	0.76	0.81	0.64
Sulfur	2.56	0.38	0.24	0.74
Oxygen	7.87	12.53	12.53	11.29
Miscellaneous (as received, unless specified)				
As-fired fuel sulfur (wt %)	2.70	0.39	0.26	0.66
Calorific Value (Btu/lb)	12807	8841	8829	6938
Chlorine (ppm)			12	20
Hg (ppb)			35	72
Hardgrove Grindability Index	56			50

Table 2.3 Proximate, ultimate, and miscellaneous analyses for the coals tested

	Bituminous	Sub-bituminous		Lignite
		Black Thunder		
	Ohio #5	Cold recycle	Warm recycle	North Dakota
SiO ₂		25.92	31.60	21.98
Al ₂ O ₃		13.29	15.68	10.30
Fe ₂ O ₃		7.04	5.23	7.66
CaO		19.78	21.95	20.01
MgO		4.27	5.16	7.25
Na ₂ O		0.81	1.22	4.05
K ₂ O		0.50	0.41	0.26
P ₂ O ₅		1.34	1.83	0.28
TiO ₂		0.82	0.95	0.33
BaO		0.49	0.67	0.78
SrO		0.28	0.40	0.71
SO ₃		14.11	11.76	21.10

Table 2.4 Elemental ash analysis of the coals tested

3. RESULTS AND DISCUSSION

3.1. Phase I - Equipment Specification and Pilot-scale Evaluation

3.1.1. Environmental Equipment Requirement

3.1.1.1. Task 1 – Specification of Flue Gas Purification, Compression, Transportation, and Sequestration

Optimization of the flue gas purification train and boiler enable cost saving. The key is to view the whole process of oxygen separation, coal combustion, steam generation, flue gas purification (if required), transportation, and sequestration together. Cost savings can be realized by optimizing the flue gas handling through two fundamental options: one is to compress the flue gas and inject it directly into a suitable geologic formation; another is to separate gas components that may not be advantageous to long-term injection. The former case will require less environmental control equipment (e.g., SO_x and NO_x removal). However, the feasibility of this option will require rigorous reservoir and geochemical modeling. In particular, non-condensable gases, such as nitrogen and oxygen, may affect the subsurface processes by creating a multi-phase flow situation that may reduce injectivity or reduce the capacity of the aquifer for CO₂ over the lifetime of the power plant. If it is determined that additional purification is needed to remove certain impurities such as excess oxygen, nitrogen, or other post-capture impurities that may affect compression, handling, or regulatory requirements, then the equipment for scrubbing these impurities will need to be evaluated.

Our approach was to: 1) determine the flue gas composition from an oxy-fired boiler, 2) review the pipeline gas requirement, and 3) determine the steps that are required for the flue gas purification.

B&W performed an evaluation of gas composition leaving the boiler for the purification system and/or recycled to the boiler. The purpose of this evaluation is to investigate the impact of coal type and air leakage on the flue gas composition. The next step then is then to consider what purification steps are required before sequestration of the gas. Three coals were used in this study: a North Dakota Lignite; Decker, a subbituminous coal from Montana; and Illinois No. 6, high volatile bituminous coal.

	ND Lignite				Decker				Illinois # 6			
	Wet		Dry		Wet		Dry		Wet		Dry	
Item	wt%	mol%	wt%	mol%	wt%	mol%	wt%	mol%	wt%	mol%	wt%	mol%
H ₂ O	8.61%	17.41%	0.00%	0.00%	8.64%	17.42%	0.00%	0.00%	8.70%	17.43%	0.00%	0.00%
CO ₂	72.08%	59.63%	78.87%	72.20%	72.20%	59.57%	79.03%	72.14%	70.96%	58.18%	77.73%	70.46%
N ₂	12.32%	16.01%	13.48%	19.38%	12.59%	16.32%	13.78%	19.76%	13.68%	17.63%	14.99%	21.35%
O ₂	3.60%	4.10%	3.94%	4.96%	3.53%	4.00%	3.86%	4.85%	3.64%	4.11%	3.99%	4.97%
SO ₂	0.67%	0.3797%	0.73%	0.46%	0.24%	0.1350%	0.26%	0.16%	0.18%	0.1004%	0.20%	0.12%
Ar	2.63%	2.40%	2.88%	2.90%	2.75%	2.50%	3.01%	3.03%	2.77%	2.50%	3.04%	3.03%
NO ₂	0.078%	0.0619%	0.086%	0.075%	0.031%	0.0248%	0.034%	0.030%	0.048%	0.0380%	0.053%	0.046%
CO	0.013%	0.0165%	0.014%	0.020%	0.013%	0.0165%	0.014%	0.020%	0.013%	0.0165%	0.014%	0.020%

**Table 3.1 Flue gas inlet compositions for three coal types
(worst case scenario for air infiltration)**

It must be stressed that the compositions in Table 3.1 represent a worst-case-scenario of air infiltration into the boiler unit (i.e. boiler, ducts and air heaters). With investment in the plant to minimize leaks it is possible that nitrogen levels in the flue gas will be up to 50% lower than those shown above (based in pilot scale test results).

3.1.2. Flue Gas Purification and Compression Train

Among the goals of this work is the objective to develop a flue gas compression and purification train that processes flue gas from an oxy-combustion pulverized coal-fired boiler unit to recover at least 90% CO₂ (DOE target) at a composition suitable for sequestration with the lowest possible power consumption. This task is complicated by the fact that no clear definition exists for a ‘sequestration-ready’ gas stream. In fact, one of the goals of this project is to define acceptable ranges/limits for various flue gas components in a sequestration-ready gas stream. For the purposes of this section, a ‘sequestration-ready’ gas stream has been defined as follows:

A ‘sequestration-ready’ gas stream is the product of a compression and purification train that contains at least 90% of the CO₂ present in the feed stream at a total pressure of 175 bar (~2540 psia) and a temperature of 95°F. This stream also contains no more than 30 lb H₂O per MMSCF of CO₂ (equivalent to 600ppmv).

The above specification on water concentration is identical to the specification for pipeline transport of CO₂ from Kinder Morgan (a major North American pipeline company). No restrictions are placed on other components in the gas stream because no specifications exist for NO_x & SO_x in commonly accepted pipeline specifications such as Kinder Morgan.

Several compression and purification schemes (Cases A-C in Figure 3.1 to Figure 3.3) were developed for converting flue gas obtained by combustion of 3 different coals to ‘sequestration-ready’ gas (Quarterly Technical Progress Reports No. 3 & 5). It was observed that the flue gases could be purified to a very large extent using partial condensation or distillation processes with similar or less expenditure of compression energy as a compression only process, for a product pressure of 175 bar. For Decker coal for example, Figure 3.5 for specific energy in the range of 155 to 160 kWh/ton captured CO₂, one can obtain 100% CO₂ recovery with essentially feed CO₂ concentration in a compression only process (Case A2a), or 94-95% CO₂ concentration in the product stream using partial condensation or distillation processes at 90% CO₂ recovery (Cases B and C). Since the energy expenditure in purification and non-purification processes is close or lower for purification schemes, it is useful to consider purification and try to minimize the amount of ‘contaminants’ (i.e. gases other than CO₂) sent to underground reservoirs for storage.

The above results formed the basis for selecting processes for detailed study. These processes are described below.

3.1.2.1. Description of the Cases

The basic process developed for processing flue gas to ‘sequestration-ready’ specifications is as follows:

- Compression of wet flue gas.
- Drying of the flue gas at the outlet of the “wet compression” step.

- Flue gas purification (if considered).
- Compression of the dry product gas to a pressure at which it condenses at 20°C.
- Pumping of the condensed product to pipeline pressure.

The combination of compression, condensation and pumping minimizes power consumption of the process. However, the condensation and pumping processes can be used only in cases where the condensation pressure is lower than the final product pressure. The calculation of power consumption in various stages of the above process is detailed in the Appendix (Section 8.1).

Three processes were designed, optimized and compared to arrive upon the process with the least specific energy requirement:

- A. Compression and drying only: In this process, flue gas is compressed and dried to obtain a gas stream with 30lb H₂O/MMSCF CO₂ at the desired pressure. No further purification is attempted. The 'dry' gas is then compressed, condensed and pumped to the product pressure. This process corresponds to a case of 100% CO₂ recovery.
- B. Partial condensation: In this process, flue gas is compressed, dried, and then purified using a partial condensation scheme with 2 vessels in series to recover 90% of the CO₂ in the feed stream. The purified stream is then compressed, condensed and pumped to the final product pressure.
- C. Partial condensation and distillation: This process is an extension of process 2. In this process, in addition to partial condensation, distillation is used to reduce O₂ in the purified stream to 1ppm. The purified stream, containing 90% of the CO₂ from the feed stream, is then compressed, condensed and pumped to the final product pressure.

The above processes are shown schematically in Figure 3.1 through Figure 3.3.

The purpose of this study is primarily to compare the three schemes. Therefore some assumptions and approximations are made consistently between the three cases but those won't be made for the detailed study (e.g. neglecting dryers' regeneration energy).

The processes above were simulated for flue gases obtained by oxy-combustion of 3 different types of coals – North Dakota Lignite, Decker, and Illinois #6 – in retrofitted coal-fired boilers. Flue gas compositions were provided by B&W (see Table 3.1 above). As noted in Section 3.1.1, the flue gas compositions represent a worst-case scenario of air infiltration into the boiler unit and it is possible to obtain N₂ levels in the flue gas that are 50% lower than those currently shown. To understand the influence of excessive air infiltration expected in retrofitted units, a 4th flue gas composition was generated by reducing N₂ and O₂ mole fractions in the flue gas to 10% and 3% respectively and increasing the other gas components accordingly, as shown in Table 3.2. Each of the 3 processes above was simulated with this flue gas composition also, and the results provide an estimate of the potential specific energy savings by achieving low air infiltration in retrofit boilers.

The product pressure was fixed at 175 bar (~2540 psia). However, to ensure that the conclusions of this study are not overly biased by the product pressure, a study of the influence of product

pressure on the specific energy was also undertaken and the results are discussed in Section 3.1.2.4, below.

In all the processes, an adsorption process was used to dry the gas. This drying is common to all three processes and won't affect the comparison. Power consumption for reactivation of the adsorbent was not taken into account in this study. Therefore, for the sake of simplicity, all calculations were performed on a dry basis. CO₂ losses in dryers, water scrubbing or during compression were also not taken into account. These losses can account for up to 1% of total inlet CO₂. Pressure losses in heat exchangers were 150 mbar (~2.2 psia) for each stream. However, more realistic assumptions are taken into account in the detailed study.

In Case A, the entire gas stream is compressed to the final product specifications and thus provides no opportunity for optimization. Case B was optimized by varying the pressure to the purification unit and the temperature of the first separation vessel in the purification unit. In Case C, the pressure in the distillation column was used as an additional parameter for optimizing the process. Heat exchange within the purification units in Cases B and C was also optimized to achieve the lowest pressure loss during purification. Since comparisons are made on a specific energy basis (i.e. per unit captured CO₂), the fact that Case A recovers 10% more CO₂ than Cases B and C does not affect the conclusions.

Figure 3.1 Schematic diagram for Case A: compression and drying only

Figure 3.2 Schematic diagram for Case B: partial condensation

Figure 3.3 Schematic diagram for Case C: partial condensation and distillation

Item	mol%
H ₂ O	0.00%
CO ₂	84.38 %
N ₂	10 %
O ₂	3 %
SO ₂	0.5%
Ar	2 %
NO ₂	0.1%
CO	0.020%

Table 3.2 Flue gas composition (dry) for “low air infiltration” case

3.1.2.2. Comparison of CO₂ Capture Processes

Table 3.3 lists the product composition achieved by each of the processes for the 3 coals. Figure 3.4 to Figure 3.6 compare the performance of the CO₂ capture processes for North Dakota Lignite, Decker coal and Illinois #6 coal, respectively. Each figure shows the CO₂ recoveries

achieved by the processes, CO₂ concentrations in the product streams (purities) and the specific energies of the processes to achieve a product pressure of 175 bar (2540 psia). For each coal, the compression only case (Case A) provides 100% CO₂ recovery while the purification cases (B and C) are targeted to achieve 90% purity.

From Table 3.3 and Figure 3.4 to Figure 3.6, Cases B and C achieve significant purification of the flue gas stream for all coals. Partial condensation of the flue gas (Case B) provides ~95% CO₂ in the product, while addition of a distillation column to the partial condensation scheme (Case C) gives CO₂ product purities in excess of 99% for all 3 coals. Thus, there is not a significant effect of coal rank on the product stream purities achieved by a particular process. From Table 3.3, the distillation column in Case C mainly rejects the air gases – N₂, O₂ and Ar. The concentrations of SO₂ and NO₂ are virtually unchanged from Case B, indicating that these components are condensed along with CO₂ in the distillation column. Thus, the distillation column does not help in reducing the amount of SO₂ and NO₂ in the product stream.

From Figure 3.4 to Figure 3.6, the absolute magnitudes of the specific energies for each case are similar for ND Lignite and Decker coals, while the Illinois #6 coal requires slightly higher specific energy. For example, for the compression only case, ND Lignite and Decker require 160 kWh/ton CO₂ while Illinois #6 requires 164 kWh/ton CO₂. The slightly higher specific energy requirement for Illinois #6 coal is due to the greater amount of ‘contaminant’ gases relative to CO₂ in the flue gas. From Table 3.1 above, flue gases from ND Lignite and Decker coals contain ~72mol% CO₂ on a dry basis while the flue gas from Illinois #6 coal contains only 70.5mol% CO₂.

Interestingly, for a product pressure of 175 bar, the purification schemes require lower specific energy than the compression only scheme for all 3 coals. For example, for Decker coal (Figure 3.5), Cases B and C require 3% and 6% lower specific energy, respectively, than Case A. Thus, the purification schemes provide significant enhancement in CO₂ purity with lower energy requirement. From a compression energy minimization perspective, Case C is the best option as it provides the highest CO₂ purity in the product with the lowest specific energy.

Item	ND Lignite			Decker			Illinois #6		
	Case A	Case B	Case C	Case A	Case B	Case C	Case A	Case B	Case C
	mol%	mol%	mol%	mol%	mol%	mol%	mol%	mol%	mol%
CO ₂	72.21%	94.36%	99.18%	72.15%	94.47%	99.71%	70.46%	93.77%	99.73%
N ₂	19.38%	3.01%	0.00%	19.76%	3.28%	0.00%	21.35%	3.84%	0.00%
O ₂	4.96%	1.04%	0.00%	4.85%	1.08%	0.00%	4.97%	1.19%	0.00%
SO ₂	0.46%	0.67%	0.70%	0.16%	0.23%	0.25%	0.12%	0.18%	0.19%
Ar	2.90%	0.81%	0.00%	3.03%	0.90%	0.00%	3.03%	0.96%	0.00%
NO ₂	0.08%	0.11%	0.11%	0.03%	0.04%	0.05%	0.05%	0.07%	0.07%
CO	0.02%	0.00%	0.00%	0.02%	0.00%	0.00%	0.02%	0.00%	0.00%

Table 3.3 Product compositions (dry basis) obtained by subjecting flue gases from the 3 coals to the 3 processes of this study

Figure 3.4 Comparison of CO₂ yield (recovery), CO₂ purity and specific energy of the 3 CO₂ capture processes for North Dakota Lignite

Figure 3.5 Comparison of CO₂ yield (recovery), CO₂ purity and specific energy of the 3 CO₂ capture processes for Decker coal

Figure 3.6 Comparison of CO₂ yield (recovery), CO₂ purity and specific energy of the 3 CO₂ capture processes for Illinois #6 coal

Figure 3.7 Comparison of CO₂ yield (recovery), CO₂ purity and specific energy of the 3 CO₂ capture processes for case of low air infiltration

3.1.2.3. Effect of Excess Air Infiltration

As described in 3.1.2.1, to understand the parasitic effect of excess air infiltration in retrofit pulverized coal-fired boilers, a 4th flue gas composition was generated by reducing N₂ mole fraction in the gas to 10% (cf. Table 2). The performance of the 3 processes in capturing CO₂ from this flue gas is shown in Figure 3.7 above and the corresponding product compositions are reported in Table 3.4.

Item	Low air infiltration case		
	Case A	Case B	Case C
	mol%	mol%	mol%
CO ₂	84.38%	97.47%	99.21%
N ₂	10.00%	0.97%	0.00%
O ₂	3.00%	0.41%	0.00%
SO ₂	0.50%	0.64%	0.65%
Ar	2.00%	0.38%	0.01%
NO ₂	0.10%	0.13%	0.13%
CO	0.02%	0.00%	0.00%

Table 3.4 Product compositions (dry basis) obtained by subjecting flue gases from the low air infiltration case to the 3 processes of this study

From Figure 3.7 and Table 3.4, several observations can be made. Similar to the higher air infiltration cases, the purification processes provide significant CO₂ purity enhancement in the product with lower specific energy than the compression only case. Case C is the best option here too with the highest CO₂ product purity at the lowest specific energy. However, the absolute magnitudes of the specific energies for the low air infiltration case are much lower than for the higher air infiltration cases above. For example, from Figure 3.4 through Figure 3.7, compression and drying (Case A) of flue gas from the high air infiltration flue gases requires ~160 kWh/ton CO₂ while the low air infiltration situation requires 135 kWh/ton CO₂, a decrease of ~ 15%. Similarly, treating the low air infiltration flue gas requires 15% and 18% lower specific energies in Cases B and C, respectively, than treating flue gases from the higher air infiltration cases. Thus, reductions in air infiltration can result in energy savings of about 15-18% to achieve a product pressure of 175 bar.

3.1.2.4. Effect of Product (Pipeline) Pressure

From Figure 3.5, compression and purification processes require much higher specific energy to achieve a product pressure of 2540 psia (155-160 kWh/ton CO₂) than to achieve a product pressure of 2200 psia (136-138 kWh/ton CO₂). At the lower product pressure, the specific energy of the partial condensation case (Case 5) is nearly equal to the compression only case (Case 2a) (<1.5% difference) while for the higher product pressure, the partial condensation requires 3% lower energy. Thus, conclusions about the lowest energy consuming process can be affected by the required product pressure. To understand the effect of product pressure on the specific energy requirement of the 3 processes, each of them were simulated at a range of product pressures from 80 to 180 bar (1160-2610 psia). Figure 3.8 to Figure 3.11 display the specific energies of the 3 processes as a function of product pressure for flue gases derived from North Dakota Lignite, Decker coal, Illinois #6 coal and the low air infiltration case, respectively.

From Figure 3.8 to Figure 3.11, similar trends are seen for the specific energy requirements of the 3 processes for all 4 flue gas compositions. The partial condensation and distillation process (Case C) requires lower specific energy than partial condensation alone (Case B) over the entire range of product pressures considered. At the lower end of the product pressure range, the compression only process demands the lowest specific energy while at the top end of the range it requires the highest specific energy. Figure 3.12 shows the “cross-over” pressures at which the specific energy of the compression only case is identical to that of the purification cases. Above these pressures, the specific energy of Case A exceeds that of Case B or C, as the case may be. For the 3 coals, the specific energy of the compression only case exceeds that of Case C around 120-125 bar and that of Case B around 140 bar. Interestingly, for the low air infiltration case, the crossover pressures for Cases B and C are lower than the corresponding cross-over pressures of the higher air infiltration cases. The specific energy of Case A is lower for the low air infiltration case as compared to the other coals, due to the lower amount of non-CO₂ gas components to be compressed relative to the amount of CO₂. However, the lower cross-over pressures indicate that the purification processes experience an even bigger decline in specific energies than the compression only process due to the ease of recovering CO₂ from a more concentrated stream.

Figure 3.8 Specific energy requirement of the 3 processes as a function of the product (pipeline) pressure for North Dakota Lignite

Figure 3.9 Specific energy requirement of the 3 processes as a function of the product (pipeline) pressure for Decker coal

Figure 3.10 Specific energy requirement of the 3 processes as a function of the product (pipeline) pressure for Illinois #6 coal

Figure 3.11 Specific energy requirement of the 3 processes as a function of the product (pipeline) pressure for the low air infiltration case

Figure 3.12 Cross-over pressures for the 4 flue gas compositions of this study. Below the cross-over pressure, the compression only process requires lower specific energy than the particular purification process, while above the cross-over pressure, the purification scheme has a lower specific energy requirement

It was concluded that:

- Coal rank does not have a significant effect on the extent of CO₂ purity achievable in the product stream at 90% CO₂ recovery by either of the purification processes considered in this study.
- The specific energy required by each process is similar for North Dakota Lignite and Decker coals and slightly higher for Illinois #6 coal due to the higher amount of non-CO₂ gas components in the flue gas relative to CO₂ for this coal.
- The two purification processes provide a significant performance improvement over the compression only process at 175 bar product pressure because they significantly increase the CO₂ purity in the product with lower specific energy requirement. Among the purification cases, the partial condensation and distillation scheme provides the highest CO₂ purity in the product stream at the lowest specific energy for all 3 coals, for a product pressure of 175 bar. It must be noted that these conclusions are based on the current level of optimization of the purification designs. The net specific energies of the two purification processes are not very different (2-5%), and it is not inconceivable that future improvements in design might change the relative order of energy requirements of these processes.
- The distillation column in Case C achieves high CO₂ purity in the product mainly by rejecting air gases; SO₂ and NO₂ are not separated from CO₂ in the column.
- Excess air infiltration results in an increase in specific energy. If N₂ in the flue gas can be reduced by 50%, it can result in 15-18% savings in specific energy, depending upon the compression and purification scheme.
- The final product pressure has a bearing on the determination of the least energy intensive process. The partial condensation and distillation process always has lower specific energy than the partial condensation process, over the product pressure range 80-180 bars. However, for all the 3 coals, the compression only process has the lowest specific energy below about 120 bars. Above a product pressure of 120 bars, the partial condensation and distillation process has the lowest specific energy. At lower air infiltration, the partial condensation and distillation process becomes less energy intensive than the compression only process at lower product pressure.

3.1.3. CO₂ Transportation and Sequestration

3.1.3.1. Introduction

For Phase 1 of the project, Battelle assessed the flue gas preparation and equipment necessary for CO₂ injection into deep geologic formations. At the outset of this project, two fundamental options were considered for disposing of the flue gas. One option was collecting and compressing the entire gaseous effluent for injection into a suitable geologic formation. Option 2 was separating the gas components (e.g., SO_x and NO_x removal) that may not be advantageous to long-term injection.

Regardless of whether post-combustion purification is needed, modeling is essential for developing a geologic and conceptual framework based on site characterization data and forms the basis for regulatory permits. It is also useful in developing the designs for CO₂ injection (e.g., maximum injection pressure, radius of influence, and CO₂ phase behavior) and monitoring

program. It was envisaged that, at some later time, the modeling results could be used with the future injection data to upscale field tests for evaluation of full-scale, long-term injection of CO₂. The principal tool used for reservoir simulation was the state-of-the-art STOMP-CO₂(1) multiphase, multi-component model, which previously has been used for modeling the geologic injection for a pilot demonstration project (American Electric Power's Mountaineer Plant site). It was anticipated that the US Department of Energy and the project team, would be able to use the knowledge gained from field tests to upscale the models for simulation of full-scale injection at these sites and evaluate the design, number of wells needed, and total storage potential for long-term, large-scale projects.

3.1.3.2. Investigation of Potential for Multi-pollutant Reduction

Concerns about global warming have prompted research into the mitigation of greenhouse gases through carbon capture and sequestration (CCS). Injection of CO₂ into deep rock formations is an attractive option because suitable rock formations exist throughout the world with large storage capacities. Sequestration in geologic environments is considered a very promising and realistic long-term option for reduction of greenhouse gases from large point sources. Deep saline reservoirs, depleted oil and gas reservoirs, fractured basalts, and unmineable coal seams are potential reservoirs for long-term storage. Many of these formations are located in close proximity to major point sources of greenhouse gas emissions.

The concept of carbon capture and storage (CCS) has dealt largely with relatively pure (98-99%) carbon dioxide (CO₂). However, flue gas from coal combustion contains impurities (such as NO_x, SO₂, flyash, mercury etc.) which likely will have impact on compression, transportation, and storage. This investigation explores the potential need for conditioning oxy-coal flue gas to selectively remove compounds that would be problematic. From an economic point of view, it would be highly desirable if the flue gas could be injected into deep geologic formations with minimal treatment, such as dehydration. On the other hand, a worst-case situation in terms of economics would arise if the flue gas required extensive purification, as that would negate some of the expected benefits of oxy-combustion. A top down assessment was employed to understand the effects of flue gas impurities on the expected sequence of processes to assess economic viability. The differences between the behaviors of pure CO₂ and simulated oxy-combustion flue gas were examined to understand how each of the process steps is affected by impurities in the flue gas.

It is important to view the entire system, which includes oxygen separation, coal combustion, steam generation, flue gas purification (if required), transportation, and geologic storage, together as an integrated collection of subsystems. The ultimate cost to dispose of the produced CO₂ falls between two extremes: The lowest total cost would apply to an outcome where the flue gas is handled with minimal conditioning, then injected into a suitable geologic formation directly beneath the source. A more costly outcome, involves separating certain components that may be disadvantageous to injection and long-term storage in a formation that is a significant distance from the plant. The lower cost case could require less environmental control equipment than is commonly used in air-fired pulverized coal (PC) combustion units, which typically are required to remove sulfur oxides (SO_x) and nitrogen oxides (NO_x). The feasibility of this option will require a thorough understanding of reservoir mechanics and geochemistry. The reason is that non-condensable gases, such as nitrogen, oxygen, and argon, may adversely affect fluid

transport properties in the subsurface. For example, the accumulation of non-condensable gases near the injection well could reduce injectivity and lower the capacity of the reservoir for CO₂ storage over the lifetime of the power plant. Conversely, if some level of purification is needed to remove non-condensable gases or other impurities, then equipment for scrubbing the CO₂ would need to be brought on line, thus adding to the cost of storing CO₂. Considerations for flue gas purity as it leaves the boiler and is processed in downstream unit operations are illustrated in Figure 3.13. Whether some treatment of the flue gas (physical or chemical) is needed prior to storage may be determined based on the following tasks:

- 1) Quantify all flue gas components from an oxy-fired boiler
- 2) Determine whether the gas mixture meets safety and regulatory requirements for high pressure transport in a given pipeline material
- 3) Perform reservoir and geochemical modeling to determine whether prolonged injection into a deep geologic reservoir (with competent caprock) is feasible.

Figure 3.13 Process description for flue gas interactions

3.1.3.2.1. Comparison of Flue Gas Properties to Pure CO₂

The physical properties of pure CO₂ are well known for a wide range of temperatures and pressures. It is an important behavior of all gases that, near the critical point, a slight change in pressure or temperature has a large effect on density. For safety to equipment and human

operators, abrupt changes in fluid properties near the critical point phase should be avoided throughout the transportation and injection processes. Therefore, the nominal pressure in the pipeline should be maintained well above the critical pressure of CO₂ (7.39 MPa, or 1070 psi) when it is transported as a pure fluid. As a typical safety precaution, a CO₂ pipeline would be operated at pressures no lower than 1400 or 1500 psi, which corresponds to a 30 to 40% increase above the critical pressure. When a pipeline runs a long distance or over elevated terrain, it may be necessary to install a booster pump wherever the pressure dips below the safety threshold. CO₂ becomes a supercritical fluid when both the pressure and temperature conditions are above the critical points (the critical temperature is 31.0°C).

Aspen-Plus simulations were performed by B&W on models of retrofitted oxy-combustion boilers for three coal types: North Dakota Lignite, Decker (Montana), and Illinois #6.

Compositions resulting from simulated flue gas streams cooled to 160°F are shown in Table 3.5, where it can be seen that the CO₂ content is between 58 and 60% by volume. When dehydration and oxygen scrubbing are performed on these same flue gas streams the CO₂ content increases to between 74 and 76% by volume (Table 3.6).

Coal Type	O ₂	H ₂ O	CO ₂	N ₂	Ar	SO ₂
	(%)	(%)	(%)	(%)	(%)	(ppmv)
North Dakota Lignite	4.1	17.4	59.6	16	2.4	3825
Decker	4.0	17.4	59.5	16.3	2.5	1348
Illinois #6	4.1	17.4	58.1	17.6	2.5	1003

Table 3.5 Estimated flue gas composition (molar %) after cooling to 160°F

Coal Type	O ₂	H ₂ O	CO ₂	N ₂	Ar	SO ₂
	(ppmv)	(ppmv)	(%)	(%)	(%)	(ppmv)
North Dakota Lignite	100	650	76.0	20.4	3.1	4877
Decker	100	650	75.8	20.8	3.2	1718
Illinois #6	100	650	74.2	22.5	3.2	1280

Table 3.6 Estimated molar flue gas composition following dehydration and oxygen scrubbing

The critical properties of the *pure* flue gas components are shown in Table 3.7. Critical properties of gas mixtures are important in understanding their behavior in transportation and injection. However, these properties are not well known for multi-component systems near the critical point of CO₂, and they are not easily estimated because such systems do not obey simple mixing rules. The thermophysical properties of fluid mixtures can be estimated using a combination of theoretical and empirical techniques which are based on evaluated data. These techniques have been tested and incorporated into interactive computer programs that generate a large variety of properties based upon the specified composition and the appropriate state

variables. In this investigation, we have used the program REFPROP (ver. 8) (3), which was developed by the National Institute of Science and Technology (NIST).

Component	Critical Pressure (MPa)	Critical Temperature (°C)	Critical Density (kg/m ³)
CO ₂	7.39	31.0	467.6
N ₂	3.39	-147.0	313.3
O ₂	5.04	-118.6	436.1
Ar	4.87	-122.4	535.6
SO ₂	7.87	157.8	525.0
CO	3.49	-140.3	303.9

Table 3.7 Critical point conditions for the constituents of the flue gas

To illustrate the critical properties of a mixture, consider a gas containing 80 mole% CO₂ and 20 mole % N₂. Using REFPROP the critical point properties were estimated to be of $P_c = 10.22$ MPa, $T_c = 12.0$ °C, and $\rho_c = 480.3$ kg/m³. This example calculation gives a result that is counterintuitive, which is that the critical pressure of the mixture is much higher than either of the pure endpoints. This increase in critical pressure is a common behavior for mixtures of fluids and is well established for binary mixtures. A somewhat more typical flue gas that has been dehydrated is given by the following composition: 72.56% CO₂, 19.50% N₂, 2.92% Ar, 0.02% CO, and 5.00% O₂ (mole basis). The estimated (REFPROP) critical properties of this mixture are $P_c = 9.91$ MPa, $T_c = -0.52$ °C, and $\rho_c = 478$ kg/m³. Compared with pure CO₂ the dehydrated flue gas has a higher critical pressure and a lower critical temperature.

Most experience in the CO₂ pipeline industry is product purity of 95.5% or greater. This is because most pipelines handle naturally occurring CO₂ that usually does not require purification beyond dehydration. Commercial pipelines have a long operating history with a good safety record, which is on par with natural gas piping systems. For pipelines with significant amounts of constituents other than CO₂, the composition has a significant impact on pipeline design, compressor power, pressure drop over a given distance, and capacity. These factors influence both the technical and economic feasibility of developing a carbon dioxide transport infrastructure. In principle, while pipelines can be designed using materials that can meet safety and handling requirements for almost any situation, the cost of such pipelines can increase significantly, such that resulting capital cost can be several times that for pure CO₂.

Computational tools for predicting the fluid behavior of pipelines containing CO₂ with significant levels of non-condensable gases, such as nitrogen, oxygen, and argon, are only recently being developed. An equation of state (EOS) method is often the simplest approach, but unfortunately, there are few experimental data for the plethora of possible compositions, to validate the results of such calculations. In addition, there is no consensus regarding the applicability of other types of modeling to estimate fluid properties within a pipeline. Additional work, particularly in model development and experimental verification, is required to understand the implications of impurities and to ensure that pipelines transporting CO₂ are designed and operated safely and economically. If these issues are not considered in the pipeline design, transportation issues for CO₂ with impurities could present significant problems.

The composition of the product flow in the pipe has a significant impact on integrity and selection of materials. Water is the most important factor. Currently, CO₂ pipelines operate with very low levels of water content, such that the water component is under saturated with respect to the liquid state at the lowest anticipated service temperature. The presence of liquid water in the presence of CO₂, SO₂, and O₂ can lead to severe internal corrosion in steel pipelines, which is detrimental to the safety and operability of such pipelines. However, attaining dry product can add significant cost to the capture process. In situations where a chemical absorber is used upstream, it is possible that this may introduce small amounts of solvent vapor due to breakthrough, which could accelerate corrosion or initiate stress corrosion cracking in the pipeline steel. Detailed corrosion analysis is needed to assess the viability of carbon steel materials, as well as the array of corrosion resistant materials. Corrosion that occurs in pipelines where there is a liquid phase (condensate) is influenced by temperature, the partial pressure of CO₂ (which may be close to the total pressure, depending on purity), other impurities such as soluble salts, flow velocity, water wetting, as well as the composition and surface condition of the steel.

In the presence of oxygen, SO₂ reacts with water to form sulfuric acid, H₂SO₄. The formation of sulfuric acid modifies the iron carbonate layer by changing the electrolyte (solution) conditions in terms of the pH and the formation of corrosion products, such as FeSO₄; further, the presence of oxygen can increase the kinetics of the anodic dissolution. The corrosion rate or metallic dissolution will be a function of chemical species and environmental parameters when steel pipelines are used as transmission line application.

By assuming a carbon steel material exposed to free liquid water under static conditions, corrosion rates can be calculated. Sample calculations for SO₂ and O₂ are given to illustrate the corrosion potential. Figure 3.14 shows the corrosion rate behavior in terms of pH, the higher the concentration of H₂SO₄ (from SO₂ oxidation and hydrolysis) the lower the pH. The quantification of the pH is a function of the amount of SO₂ dissolved in the mixture. Flow characteristics inside pipelines are often highly turbulent, which has the effect of increasing corrosion rates above that which would occur under static level.

Figure 3.14 Corrosion rate of carbon steel exposed to different H_2SO_4 concentrations in terms of pH at different CO_2 pressures (static conditions)

Figure 3.15 shows the corrosion rate in terms of oxygen content dissolved in the aqueous system at different CO_2 partial pressure (concentration). The SO_2 content will increase the corrosion rate by lowering the pH magnitude and the O_2 content increases the corrosion rate. Figure 3.15 shows a potential corrosion rate of about 0.2 mm per year for static conditions. For 20 years of operation, the average loss of wall thickness would be 4 mm. Since the nominal pipe wall thickness would be 12 mm, a substantial amount of the pipe wall thickness could be lost to corrosion. Because a pipeline operating under such conditions would be subject to failure in a few decades, it would require, frequent regular safety verification, or else substituted with a more corrosion resistant material. Note that these calculations are for static conditions. They do not consider the additional effect of flow, which can add significantly to wear and abrasion.

Figure 3.15 Corrosion rate of carbon steel exposed to different O₂ concentrations at different CO₂ pressures (static conditions)

Figure 3.16. Water content vs. number of potential corrosion sites (per square meter for a corrosion rate of 0.2 mm/yr)

While the concentrations of oxygen and sulfur compounds affect the overall corrosion rates, the water content defines the potential number of corrosion sites. Figure 3.16 shows the number of potential sites for pitting over a one square meter (1 m^2) area associated with the 0.2 mm/yr corrosion rate according to the water content. The low free water content minimizes the general corrosion conditions, but does not eliminate the number of localized spots in the pipeline wall. The 2500 ppm of water in an area of 1 m^2 might have 10 potential sites for localized corrosion at corrosion rates described in the previous two plots. The Kinder Morgan specification for water is 30 lb per MMSCF in the vapor phase, which is equivalent to 650 ppm. Even under these relatively dry conditions, one or two corrosion sites could be expected to form per square meter of steel surface. Nevertheless, pipelines have operated safely for extended periods at this maximum level of moisture.

3.1.3.2.2. *System Optimization*

The plant design and operation define the amount of CO_2 that needs to be stored and the rate at which it is delivered to the storage reservoir. Reservoir geology and depth determine the temperature and constrain the injection pressure to a lower limit needed to induce flow of CO_2 into the formation and to an upper limit of approximately two-thirds the fracture pressure of the formation. However, an exact value must be determined by modeling rock mechanics. Design variables also need to be considered. For example:

- Smaller diameter pipelines are less expensive but can experience higher-pressure drops. The increased cost of a larger diameter pipeline must be traded against the cost of compression.
- The diameter of the well is significant variable since this is a principal source of pressure drop. The increased cost of a larger diameter well, or multiple wells, also needs to be factored against the cost of compression. The main driver for well diameter and number is the hydraulic conductivity of the host reservoir, which can vary greatly from one type of formation to another, and in fact, may vary significantly within a given formation.

That oxy-combustion flue gas contains nitrogen, oxygen, argon and several minor constituents in addition to CO_2 , has significant bearing on many of the fundamental parameters that affect fluid flow. For example, N_2 mixed with CO_2 reduces the density of the gas mixture compared with pure CO_2 , which decreases the hydrostatic pressure inside the well column. Wellhead pressure must be increased to compensate for the reduced bottom hole pressure (which determines the rate of fluid ingress), thus demanding higher compression pressures. Frictional factors also increase with mixing of CO_2 with nitrogen and other incondensable gases. This causes a greater pressure drop, increases with pipeline distance, and again must be compensated with higher compression or more frequent recompression (booster) stations.

3.1.3.2.3. *Considerations for Pipeline Transport*

The flow characteristics for CO_2 pipelines used in the US for enhanced oil recovery (EOR) are sufficiently well understood to enable safe and economic operation. However, transporting products comprised of multiple constituents can lead to significant problems. In the natural gas industry, additional engineering is needed for natural gas pipelines when even small amounts of heavier hydrocarbons are present.

The composition of the product to be transported has a great impact on pipeline design, compressor power, recompression distance, pipeline capacity, and could also have implications on decompression behavior at potential points of pipeline failure. These effects have direct implications for both the technical and economic feasibility of developing a CO₂ transport infrastructure.

Design equations for predicting CO₂ transport in pipelines are well established. However, flow characteristics of a gas mixture are much more complicated than for a pure gas. Compared to pure CO₂, mixtures create two major challenges:

- It is important to determine the mixture transport parameters for a given fluid state. The major component of the fluid is CO₂, which is relatively compressible and undergoes significant changes in properties, hence constant properties cannot be assumed for the mixture even if the lesser constituents' transport properties were constant in behavior (which they are not). The phase behavior of the components must be compatible also since phase change during pipeline transport is typically avoided.
- The equilibrium composition needs to be studied to ascertain if any significant reactions are present as the fluid undergoes transport. For example, reactions between the species may be negligible for the surface pipe pressures and timescales. Deleterious chemical reactions may be substantially higher near the bottom of the well where the pressures are higher. Use of instruments to monitor chemical conditions at depth would be prudent.

The transport properties of fluid mixtures can be difficult to predict over a wide range of conditions. Many pure fluids have been tested experimentally and validated predictive equations of state exist, but arbitrary mixtures do not always have data. Binary mixtures can be predicted and ternary and multi-component mixture models continue to be developed (4). The behavior depends on the type of fluid, the composition, and the conditions. Predictions for mixtures depend heavily on the accuracy of the EOS and dependent empirical parameters.

If heat transfer in pipeline flow is ignored, then the main properties necessary for modeling transport behavior are the fluid viscosity and the fluid density. (The ratio of these properties, fluid viscosity / fluid density, is called the *kinematic viscosity*). An analysis performed using REFPROP shows that the kinematic viscosity of the dry flue gas mixture can range between 0.7 to 1.4 times that of pure CO₂, as shown in Figure 3.17. This is an important transport quantity, because it will affect the pipeline flow, and most certainly affects the injectability into the geologic formation. Furthermore, fluid density is an important property because it contributes to the downhole pressure in a vertical well due to body forces. To perform a detailed analysis of an injection system, temperature and heat transfer would need to be considered, due to bottom hole pressure effects.

Figure 3.17. Kinematic viscosity of approximate flue gas mixture divided by the kinematic viscosity of pure CO₂. Shown for various temperatures (50°F steps) and pressures (500 psi steps). Calculations were performed with NIST REFPROP v8.0. Mole fractions used: 0.7259 CO₂, 0.1948 N₂, 0.0292 Ar, 0.0002 CO, 0.0499 O₂.

For large Reynolds number flows where the behavior is fully turbulent, the pressure difference required to move a given mass flow rate of fluid in a pipe depends more on the density of the fluid rather than the viscosity. For this flow regime, the friction factor remains fairly insensitive to the Reynolds number, and the predominant effect is the increase in pressure drop because of the lower density of the flue gas mixture. Figure 3.18 shows that the flue gas mixture is generally much less dense than pure CO₂, hence the pressure requirement for a given total mass flow will be higher. The penalty will be even higher if the requirements are normalized by the CO₂ fraction of the flow.

This effect applies to both the surface pipe and the well pipe. In addition, the well pipe will have comparatively less hydrostatic pressure gain because of the lower fluid density. Therefore, because of the lower density, the pressure required at the wellhead will be higher, for the same bottom hole pressure. In summary, both the surface and well pipeline capacities decrease when CO₂ is mixed with non-condensable gases.

Simple porous-media transport models indicate that in the geologic formation the flow is proportional to the inverse of kinematic viscosity (5). As Figure 3.17 shows, the kinematic viscosity of the mixture is generally higher than that of pure CO₂. Hence, reduced mass flow into the formation is expected.

Figure 3.18. Density of approximate flue gas mixture divided by the density of pure CO₂. Shown for various temperatures and pressures. See Figure 3.17 for additional notes. A large decrease in the density ratio occurs near the CO₂ critical point

3.1.3.2.4. *Injection Well Permitting*

CO₂ storage projects will require drilling permits, Underground Injection Control (UIC) permits, seismic road permits, and other construction permits associated with pipeline installation. Drilling permits require standard information on well location, construction specifications, and site restoration that any oil and gas well would necessitate. These permits are usually regulated by state agencies. Similarly, pipeline construction typically requires permits from the county road commission. A pipeline permit would require survey of the pipeline route, construction method, and restoration plan. Long pipelines (whether intra-state or inter-state) require negotiations of right of way routes and environmental assessments.

Injection wells will require a UIC permit application submitted to appropriate state or regional UIC programs. The permit application must include details on the injection target, injection operations, system monitoring, wells in the area of review, financial assurance, and other items necessary to fulfill UIC regulations. The UIC permit review process includes EPA technical review, a 30-day public comment period, and possibly a public hearing may be required. Consequently, the permit review process may require 3-9 months. Once the injection permit is issued, the EPA must approve the mechanical integrity test before they provide final permission to inject. During injection, monthly operating reports must be completed summarizing daily injection flow, injection pressure, and operations.

In response to CCS developments, EPA has recently proposed several new rules to regulate CO₂ storage:

- In July 2008, EPA proposed new requirements for geologic sequestration (GS) of carbon dioxide. The proposed rule would establish a new “Class VI” CO₂ sequestration well. The proposed rule included regulations beyond those required for typical injection wells for enhanced oil recovery or hazardous waste disposal. In August 2009, EPA announced released “Notice of Data Availability” supplementing the UIC Class VI proposal, noting that the agency was evaluating the need for a more comprehensive regulatory framework for GS.
- In April 2010, the EPA proposed additional mandatory reporting of greenhouse gases for injection and geologic sequestration of carbon dioxide. These reporting requirements included an assessment of risk of leakage, strategy for detecting and quantifying CO₂ leakage to the surface, strategy for establishing pre-injection environmental baselines, and tailor mass balance equation for CO₂ sequestered. While separate from the proposed Class VI rule, in practice the mandatory reporting would be integrated into the Class VI permitting process.
- Several other guidance documents on site characterization, monitoring, and post-closure procedures have been announce by the EPA; although, no public versions of these documents have been released.

None of these proposed regulations has been added to the Federal Register at this time, and consequently, they do not represent official requirements for CO₂ storage. However, these regulations may become mandatory during most CCS project timelines, and bear consideration during permitting. Many of the proposed regulations would require more site characterization, monitoring, reporting, and long term monitoring than have been applied at other deep well injection sites.

Class	Permit Required	Life of Permit	Area of Review	Mechanical Integrity Test required		Other Tests	Monitoring	Reporting
				Part I (Internal)	Part II (External)			
I H	Yes + Land Ban Petition (see 40 CFR 148)	Up to 10 years	2 mile minimum for hazardous waste wells.	Pressure test annually and after each work over	A temperature, noise or other approved log at least every five years	Yearly radioactive tracer survey, yearly Fall-off test, casing inspection log after each work over, continuous corrosion testing	Continuous injection pressure, flow rate, volume, temperature, and annulus pressure + fluid chemistry + ground-water Monitoring as needed	Quarterly
I NH	Yes	Up to 10 years	1/4 mile minimum	Pressure test or alternative at least once every five years	Each 5 yrs	Fall-off - Annually	Continuous injection pressure, flow rate, volume, and annulus pressure + fluid chemistry and yearly pressure falloff test	Quarterly
II	Yes except for existing EOR wells authorized by rule	Specific Period-may be for life of well	New wells- 1/4 mile fixed radius or radius of endangerment	Pressure test/at least once every five years	Adequate Cement records may be used in lieu of logs	annual fluid chemistry and other tests as needed/required by permit	Injection Pressure, flow rate and cumulative volume, observed weekly for disposal and monthly for enhanced recovery	Annual

Table 3.8 Federal Regulation requirements of injection well classifications (6)

Table 3.8 continued on next page.

Class	Permit Required	Life of Permit	Area of Review	Mechanical Integrity Test required		Other Tests	Monitoring	Reporting
				Part I (Internal)	Part II (External)			
III	Yes	Specific period-may be for life of project	Yes- either 1/4 mile fixed radius or radius of endangerment	initially and every five years for salt wells	Adequate cement records and RTS, noise, or Temperature unless limited by construction	As needed/required by permit	Continuous injection pressure, flow rate, volume, and fluid chemistry +Ground-water monitoring as required	Quarterly
IV	Banned except for those authorized under 40 CFR 144.13(c)	Closed upon identification unless authorized cleanup projects	No new wells are allowed except those that are part of an EPA or State approved RCRA or CERCLA cleanup and meets the criteria of Section 7010(b) of HWSA (1984). EPA must review and approve technical plans. Monitor ring for system performance may be necessary. The cleanup plan must be designed to be protective of human health.					Closure or compliance report on schedule
V	Authorized by rule unless Permit required by 40 CFR 144.12(c) and (d) or 144.84, 144.88 and 144.89.	Following an assessment of Class V wells in 1987 (See Report to Congress Class V Injection Wells- Current Inventory, Effects on Ground Water and Technical Recommendations by Office of Water: September 1987, 435 pages (main text); EPA 570/9-87-006), EPA commenced an effort to develop regulations covering certain types of wells, such as large-capacity cess pools and motor vehicle waste disposal wells. This effort included a more detailed assessment of certain well types which was published in 1999 (See Class V Underground Injection Control Study, Office of Water: EPA/816-R-99-014, September 1999; 23 volumes and 5 Appendices [see http://www.epa.gov/safewater/uic/cl5study.html]) The new Class V regulations were published in the Federal Register on December 7, 1999, and were effective on April 5, 2000. The new rules include new definitions for wells; clarifies the Class V inventory requirements (40 CFR 144.83); moves a Class V subclass into another class; bans new large capacity cesspools and new motor vehicle waste disposal wells; and establishes a phase-out process for existing large capacity cesspools and motor vehicle waste disposal wells.						Required for permitted wells. All wells must be inventoried per 40 CFR 144.83

Continuation of
Table 3.8 Federal Regulation requirements of injection well classifications (6)

Class	Definitions
I	Inject hazardous, non-hazardous industrial or municipal waste, and radioactive waste, below the lowermost formation containing a USDW within one quarter mile of the wellbore
II	Inject, for the purpose of disposal, fluids produced from downhole that are associated with oil and gas production as well as fluids associated with the operation of natural gas storage operation, methane gas dehydration and sweetening plant. Also includes wells used for the enhanced recovery of oil and gas and the storage of hydrocarbons that are liquids at standard temperature and pressure.
III	Used for in-situ extraction of minerals.
IV	Inject hazardous or radioactive waste fluids into or above USDW
V	This category includes all other wells not covered in Classes I-IV

Table 3.9 Definitions of UIC defined classification of injection wells (6)

Citation in Title 40, Code of Federal Regulations (7)	Hazardous Waste Characteristic	Would flue gas stream be expected to possess this characteristic?	Comments
§261.21	Ignitibility	No	-
§261.22	Corrosivity	Possibly	A corrosive liquid as per the regulations has a pH of less than 2 or greater than 12.5. The determination of pH of the flue gas stream is important to determine whether the stream is corrosive. A stream can also be corrosive if it can corrode steel at a rate of 6.35 mm per year
§261.23	Reactivity	Possibly	Assessment of the proposed waste stream with respect to the §261.23(5) criterion for sulfide bearing waste must be performed by the generator.
§261.24	Toxicity	Possibly	The presence of trace amount of mercury in the flue gas stream might render it toxic.

Table 3.10 Hazardous waste characteristics and comparison of each with the flue gas stream characteristics

Table 3.8 and Table 3.9 define and explain UIC classifications and regulations on injection wells. The UIC guidelines are regulated by the EPA and have been set into place to comply with the Safe Water Drinking Act of 1980. The regulations are designed to protect drinking water supplies by establishing citing, operating, monitoring, closure, and review protocols. The UIC program entails various requirements for underground injection to protect human health and the environment. Unless a new class is established for CO₂ sequestration wells they may fall into Class V. According to the UIC regulations, hazardous waste is not permitted to be injected into Class V wells, therefore everything that is injected with the CO₂ must not be considered hazardous waste or have harmful components above allowed levels for non-hazardous waste.

According to 40 CFR Part 261 Subpart D (1986), the four characteristics of a hazardous waste are: corrosivity, reactivity, ignitability, and toxicity(7). Under UIC regulations, underground injection of hazardous wastes requires a Class I UIC permit and a no-migration demonstration (40 CFR Sections 144.6 and 148.20). Table 3.10 is a list of all the characteristics of a hazardous waste and whether or not the flue gas from an oxy-fuel boiler possesses a particular characteristic.

In circumstances where regulated hazardous substances, such as mercury (Hg) and SO₂, are present in the effluent flue gas there is a possibility that the injection well cannot be permitted as Class V. Labeling the well as Class I, is a risk if impurities which are known as hazardous wastes are not carefully monitored and maintained at an acceptable level. Changing from Class V to a Class I injection well would increase the level of permitting needed and the amount of regulatory and public scrutiny placed on the injection well.

Testing should be done to monitor any aspect that could be considered hazardous or change the classification of the injection well. The EPA has published a document to encourage testing for corrosivity titled “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, and SW-846.” Testing for pH should be done using EPA recommended test number 9040C. All other characteristics should be tested for using Toxicity Characteristic Leaching Procedure (test Method 1311) in EPA Publication SW-846 as a primary method. Maximum acceptable levels of contaminants which are metals can be found in Table 3.11.

Prior to injection, plans must be drawn up to adequately test for all aspects of the injectate which could be hazardous and therefore result in a hazardous waste classification. The system for injection should have a built in monitoring system to maintain the Class V title instead of being classified as a Class I hazardous waste injection site. Levels of contaminants deemed hazardous must be removed before injection and EPA regulators should approve the system which should follow UIC guidelines. The majority of impurities in all likelihood will not affect injection, however the levels set forth by regulators must be adhered to in order to protect the classification of the well as well as the USDW² systems nearby the injection site.

A number of field validation and development scale projects for geologic storage assessments are being conducted under the DOE’s seven Regional Carbon Sequestration Partnerships (RCSP). The results of the Phase II (Validation Phase) of this program are likely to be available during late 2010 and will be useful in providing an assessment of field practices, storage potential, and monitoring technologies. For example, the Midwestern Regional Carbon Sequestration Partnership (MRCSP) has conducted deep saline injection projects in Michigan, Ohio, and Kentucky. These projects have also provided experience in obtaining the Class V injection well permits from EPA or relevant state authorities. Furthermore, these smaller-scale tests provide the necessary information for larger-scale deployment, as well as, the information needed for environmental impact assessments for larger projects.

² Underground source of drinking water

EPA HW Number	Contaminant	CAS Number	Regulatory Level (mg/L)
D004	Arsenic	7440-38-2	5.0
D005	Barium	7440-39-3	100.0
D006	Cadmium	7440-43-9	1.0
D007	Chromium	7440-47-3	5.0
D008	Lead	7439-92-1	5.0
D009	Mercury	7439-97-6	0.2
D010	Selenium	7782-49-2	1.0
D011	Silver	7440-22-4	5.0

Table 3.11 Maximum concentrations of metal contaminants for toxicity characteristics

3.1.3.2.5. *Overview of Deep Sedimentary Basins in the US*

Deep sedimentary basins in the United States are of three primary types: oil and gas reservoirs, unmineable coal seams, and saline reservoirs. Other potential geologic sequestration options include basalt formations and organic rich shales.

Oil and Gas Reservoirs

Oil and Gas Reservoirs consist of layers of permeable rock, saturated with hydrocarbons, which are capped by impermeable rocks in sedimentary or structural traps. Such reservoirs have successfully contained the associated hydrocarbons in the subsurface for millions of years until their discovery in subsequent exploration. The conditions that trap the oil and gas are also the conditions for the successful sequestration of carbon dioxide in the subsurface. Additionally, CO₂ injection into previously explored oil and gas reservoirs may be used as a method of EOR (Enhanced Oil Recovery) that provides additional incremental hydrocarbon reserves while reducing the net economic cost of injection.

Oil and Gas Reservoirs are found in certain regions throughout the continental United States and Alaska, as well as offshore. Much characterization of these reservoirs has previously been done in private industry with only limited amounts of the relevant data released into the public domain. 2007 estimates from the DOE Carbon Sequestration Atlas (8) are on the order of 91 billion tons of CO₂ for carbon storage in oil and gas reservoirs in the United States.

Unmineable Coal Seams

Unmineable coal seams are uneconomic resources of coal that cannot be mined due to depth or insufficient thickness. Coal beds all contain some amount of methane that can be recovered either via primary recovery methods, such as dewatering and depressurization, or via secondary recovery by CO₂ sweep. Similar to EOR in oil and gas reservoirs, coal beds can be another method of storing CO₂ while increasing the availability of gas reserves. At this time, early state analyses are being performed to determine feasibility and economics. 2007 estimates from the DOE Carbon Sequestration Atlas (8) are on the order of 173 to 203 billion tons of CO₂ for carbon storage in unmineable coal seams in the United States.

Deep Saline Reservoirs

Deep saline reservoirs are layers of sedimentary rock in which the pore space has become saturated with brine. These are much more extensive than either hydrocarbon-bearing rock or coal seam formations and therefore represent the best potential for CO₂ sequestration by available volume. A suitable saline reservoir must have adequate porosity and permeability, such as is found in many sandstone and carbonate formations. Additionally, the formation must be located at a depth suitable to keep CO₂ in its supercritical state. Finally, the saline reservoir must be capped by impermeable rock, such as shale, in order to keep the injected CO₂ from migrating up and out of the storage zone.

Characterization of deep saline reservoirs has previously been much sparser than the characterization of economic hydrocarbon and coal reservoirs. There is a great amount of uncertainty regarding the suitability of specific reservoirs with regards to CCS. As more work is done, a greater volume of data will be available for estimating CO₂ capacity at any given site. 2010 estimates from the DOE Carbon Sequestration Atlas (9 p. 27) range from 1,822 to 22,281 billion tons of CO₂ for deep saline reservoir storage in the United States. At present, reservoir data are most abundant in the northeast, northwest, and Midwestern regions.

3.1.3.2.6. *Injection Process*

The injection process relies on moving the injection stream from the wellhead, through the injection tubing, and into the storage formation. Assuming a supply of CO₂ at the wellhead at supercritical conditions, no additional compression may be necessary at shallower depths. Deeper injection targets may require additional booster compression to reach injection pressures.

Despite the added complexity, impurities in the injection stream are unlikely to be detrimental to the concept of CO₂ storage by deep well injection. As long as the gas stream has low level of impurities, CO₂ production wells (10) and sour gas (H₂S) injection wells (11) generally encounter few problems with operations. The gas components would be in either supercritical or liquid phase at the wellhead. In pure phase, the compounds CO₂, SO₂, and NO₂ are not reactive until they react with water to form acids. Ar and N₂ are inert gases while O₂ can promote corrosion of well materials.

The main cost and operational issues with regard to injection are summarized below:

- Volumetric increase – The overall injection volume with impurities will be greater than a pure CO₂ stream. Additional injection wells, larger casing, larger diameter tubing, and associated equipment may be necessary to inject CO₂ on a mass basis. The added costs associated with this additional volume are likely to be a fraction (10-25%) of the capital and operation costs associated with an injection system. However, this increase may be substantial for larger sources (e.g. 10 million tonnes per year for CO₂ with impurities versus 12 million tonnes per year for CO₂ only stream).
- Injection pressures – The impurities will lower the density of the injection stream to some extent, mainly due to N₂ and Ar. The injection process relies on the weight of the fluid column in the injection well to complement injection pressures. Thus, a lighter injection stream will require additional injection pressure and associated compression commensurate with the lower density of the fluid.

- Enhanced oil recovery limitations – Impurities may limit potential to utilize the gas stream for enhanced oil recovery projects. NO_x can decrease oil recovery, and SO_x may improve oil recovery, but at the specified concentrations, the compounds are not likely to affect recovery rates. Oxygen can react exothermally with oil in the reservoir and limit recovery. It can also promote bacterial growth and corrosion of metallic tools or instruments. For these reasons, oxygen is always removed from water for water flooding EOR operations. Nitrogen is often used for EOR floods, but it may reduce the effectiveness of CO₂ oriented EOR because the two gases facilitate oil displacement by slightly different processes.

3.1.3.2.7. *Injection Materials*

Corrosion of injection materials is a significant concern for impurities. CO₂ related corrosion and well-bore leakage has been identified as a significant issue for CO₂ storage projects, in both injection wells and abandoned wells that penetrate the storage target (12); (13); (14).

Consequently, the effect of impurities on the various injection materials was examined in more detail. Materials for deep injection wells typically include wellhead fittings, casing, well cement, injection tubing, packers, annulus fluid, and other monitoring/metering equipment. However, corrosion is most likely to affect the casing, tubing, and well cements at depth as the CO₂ stream mixes with formation waters and moves into the areas around and overlying the injection well.

Table 3.12 summarizes compatibility of the injection stream components with well materials. N₂ and Ar are generally inert gases unlikely to affect well materials. CO₂, SO₂, and NO₂ are similar to some extent in that they form weak to moderately strong acids with water, which then can cause corrosion in steel. O₂ is well known to cause corrosion and bacterial growth in deep wells with water floods. While CO is present in natural gas production, not as much is known as to injecting this compound.

Compound	Compatibility	Comments
CO ₂	Corrosive with water	Forms carbonic acid with water
O ₂	Strong oxidizer	Causes oxidation of iron and other metals
SO ₂	Potentially corrosive	Forms sulfuric acid with water and O ₂
N ₂	Inert	Commonly used in oil and gas industry for fracking and EOR
Ar	Inert	May behave similar to N ₂
NO ₂	Potentially corrosive	Forms nitric acid with water and O ₂
CO	Unknown	CO not common in natural gas production

Table 3.12 Summary of impurity compatibility with well materials

Well Casing and Tubing

A variety of materials, alloys, and coatings are available to address corrosion of well casings and tubing. Table 3.13 summarizes well materials, applications, and limitations. Injection casing and

tubing are classified by American Petroleum Institute (API) type of steel (H-Q) and minimum yield pressure (40-125+ thousand pounds per square inch). In general, higher grades of steel are specified for deeper wells, higher temperatures, higher pressures, and corrosion resistance. Many grades of steel are designed to be more ductile to prevent brittle failure from H₂S gas, also known as “sour gas.”

Material	Type	Applications	Limitations
Carbon and Low-Alloy Steel	Hardness <HRC 22	“Dry” CO ₂ transmission, shallow casing (i.e., conductor casing).	Brittle at temperatures < -20°F. Corrodes in presence of wet CO ₂ or H ₂ S. Corrodes more rapidly when CO ₂ partial pressure exceeds 15 psia or temperature > 300°F.
Stainless Steel (Martensitic)	Hardness <HRC 22 (AISI 410; 9Cr/1Mo)	“Dry” or “wet” CO ₂ transmission.	Oxygen, H ₂ S, H ₂ O, increasing partial pressures of CO ₂ , or Cl rapidly increase corrosion rates, especially at temperatures > 200°F.
Stainless Steel (Austenitic)	Hardness < HRC 22; 35 (AISI 304, 316; Nitronic-50)	“Dry” or “wet” CO ₂ transmission.	Oxygen, H ₂ S, H ₂ O, and Cl increase corrosion rate, especially at temperatures > 150°F.
Bimetallic	Carbon steel outer, corrosion-resistant inner (Alloy 625)	Inexpensive carbon steel handles stresses, is protected from corrosion by liner. Cheaper than high-alloy steel pipe.	Segments must be joined by special welding technique. Very susceptible to problems (including galvanic corrosion) if holes form in liner.
Other Internally-coated Carbon Steel	Phenolics, epoxy-phenolics, glass epoxies, nickel	Provides extra protection to inexpensive steels (alternative to more expensive material).	Only effective when not damaged (i.e., scratched). Damaged areas will corrode quickly.
Fiberglass	—	Can be used alone or as an outer covering to protect carbon steel from corrosion.	Pure fiberglass may not withstand high pressures, can be brittle when cold, and its length can vary dramatically with temperature.
Fiberglass-Reinforced Plastic (FRP)	Polyester/glass, epoxy/glass	Currently used in natural CO ₂ production and oil-field injection.	CO ₂ swells and alters resin, worse at increasing pressures. Results in brittleness, delamination. H ₂ S limits service temperatures. Length varies dramatically with temperature.

Table 3.13 Casing/tubing materials, applications, and limitations

CO₂ is referred to as “sweet gas” when encountered in the oil and gas industry and can cause pitting and pinhole leaks in casing, joints, tubing, and packers. API grade of L-80 or greater is recommended for these applications. If the NO₂ and SO₂ result in a similar acidic corrosion process, then the same grade of steel may be sufficient for these compounds as well. Other options for corrosion resistance include alloy plating (nickel, chrome, etc), polymer coatings, stainless steel, and fiberglass casing. These options are typically more expensive and more

difficult to handle in the field and are susceptible to damage. Many operators use common steel grades (J-55) with few problems so long as they produce or inject relatively pure CO₂. Some EOR fields encounter significant corrosion when injecting alternating cycles of water and CO₂ (the water alternating gas or WAG process).

Well Cement

Cement also must be able to withstand the pressures, temperatures, and chemical impurities expected in the borehole. Table 3.14 summarizes basic well field cements and their properties. Basic ASTM (American Society for Testing and Materials) Portland cement mixes are typically used to cement wells. American Petroleum Institute class cement may be available in certain areas with established oil and gas operations. Various additives may be used to fortify the cement and extend temperature and pressure ranges. Acid resistant additives may be added to the cement to prevent corrosion. Well cements are specifically designed by an engineer for the well based on various parameters such as well depth, lithology, pressures, temperatures, and fluids in the borehole.

API Class	Description	ASTM Equivalent	Normal Density (ppg)
A	Surface to 6,000 feet. Basic cement when special properties are not required.	Type I	15.6
B	Surface to 6,000 feet. Moderate to high sulfate-resistance.	Type II	15.6
C	Surface to 6,000 feet. High early strength. Fine grind.	Type III	14.8
G	Surface to 8,000 feet. Basic cement. Popular in Western US.	Type IV	15.8
H	Surface to 8,000 feet. Basic cement with high sulfate resistance. Popular in Gulf Coast and Central US	Type IV	16.5
Note: several other specialized classes of cements are available for extreme conditions. ppg = pounds per gallon			

Table 3.14 Typical well field cements

Portland-based cements undergo chemical reactions in the presence of CO₂, mainly the formation of limestone, which can alter the physical and mechanical properties of Portland-filled annular spaces over the life of a CO₂ injection well. Limestone production in the cement is typically not a problem. However, water and CO₂ mix in the pore spaces and create carbonic acid, which is corrosive to the casing inside the cement sheath.

One possible way to minimize reactions is to use a high-solids Portland cement mix. By filling additional cement porosity with solids, rather than gas or liquid, seepage of CO₂ and water into the cement is slowed. Remaining pore spaces can be filled, and CO₂ infiltration can be further slowed, with the addition of a latex-based polymer to the high-solids Portland cement. Research also is currently being conducted on CO₂-resistant epoxy-based cements. These cements are expected to offer good containment of CO₂, but have several drawbacks including being relatively untested, expensive, and difficult to emplace in the well.

3.1.3.2.8. Injection Operations

A deep well injection system typically consists of a several deep wells connected to a supply pipeline. The wells are open to a porous rock formation that receives the injection stream, which is sequestered in the deep rock formation. Deep injection wells are installed by drilling progressively smaller borings and cementing steel casing in the hole after each drilling run to stabilize the well and protect near surface groundwater supplies (Figure 3.19). Injection tubing is then secured in the well with an expanding packer system to isolate the injection interval. The annular space between the tubing and the casing is then filled with a dense annulus fluid designed to shut in the well in case of some mechanical failure in the well.

To a large extent, well casing and injection tubing are subject to the same physical and chemical corrosion issues as identified in the surface pipeline analysis. Many of the same metal alloy and coating options are applicable to the well casing and tubing.

Figure 3.19. Injection well components

However, once the injection stream reaches the targeted rock formation, there are more chances for the compounds to react with the formation water and affect the injection system and well materials (Scherer, 2004; Huerta, 2007). Until relatively recently, most of the experience with injection well performance and well materials came from the oil and gas industry and waste injection. Future guidance on storage issues will come from studies and actual CO₂ injection tests by the MRCSP (<http://www.mrcsp.org/>) and other partnerships.

3.1.3.2.9. Numerical simulations

Numerical simulations of injecting pure CO₂ and oxy-combustion flue gas were conducted using STOMP-WCS-R (water, CO₂, salt and reactions) simulator (1). The STOMP code is capable of modeling complex, coupled hydrologic, chemical, and thermal processes, including multi-fluid flow and transport, partitioning of CO₂ into the aqueous phase, and chemical interactions with aqueous fluids and rock minerals. Because an EOS for a flue gas mixture was not available at the time these simulations were conducted, a mixture of 72% CO₂ and 28% air was used instead. Other parameters used in the model are summarized in Table 3.15. The STOMP computer code has been verified against other codes used for simulation of geologic disposal of CO₂ as part of the GeoSeq code intercomparison study (15), and has been used in previous investigations of CO₂ injection potential at the Mountaineer Power Plant site (16).

Property	Value
Aqueous-Phase Salt Mass Fraction	0.1
Temperature	90°F
Saturated Intrinsic Permeability	100 mD
Porosity	15%
Rock Type	Homogeneous, isotropic sandstone
Saturation Function	Berea Sandstone, Brooks and Corey Extended: Air Entry Pressure = 42 cm, $\lambda = 3.033$, Residual Saturation = 0.299
Aqueous/Gas Relative Permeability	Burdine pore distribution function
Formation Thickness	100 ft
Depth to bottom of formation	3600 ft
Hydrostatic Gradient	0.433 psi/ft
Injection Rate	0.5 MMT/year
Injection Time	61 days
Simulation Time	1 year
Coordinate System	2 dimensional cylindrical
Radial Grid spacing	67 nodes, variable spacing from 0.26 ft to 206 ft
Vertical Grid Spacing	100 to 400 nodes, uniform 1 ft spacing
Upper and Lower Boundary Conditions	no flow
Boundary Condition at R	0: Axis of Symmetry
Boundary Condition at R	3342 ft: Hydrostatic Gradient = 0.433 psi/ft

Table 3.15 Model input parameters

At the modeled temperature of 90°F, the flue gas plume (Figure 3.20) is more buoyant than the CO₂ plume (Figure 3.21) due to the lower density of air. CO₂ (Figure 3.22) is over an order of magnitude more soluble in brine than air (Figure 3.23) at this temperature. For this reason, CO₂ solubility in brine is not appreciably different when injected with flue gas, rather than pure CO₂ (Figure 3.24). The pressure distribution around the well during injection is relatively similar for Flue Gas (Figure 3.25) and CO₂ (Figure 3.26). The pressures are slightly higher for flue gas injection. Because air is less dense than supercritical CO₂, higher pressures are needed to achieve the same mass injection rate for the flue gas plume, relative to the pure CO₂ plume.

Figure 3.20. Gas-phase saturation after 60 days of flue gas injection

Figure 3.21. Gas-phase saturation after 60 days of CO₂ injection

Figure 3.22. Aqueous-phase CO₂ mass fraction after 60 days of flue gas injection

Figure 3.23. Aqueous-phase air mass fraction after 60 days of flue gas injection

Figure 3.24. Aqueous-phase CO₂ mass fraction after 60 days of pure CO₂ injection

Figure 3.25. Gas-phase pressure after 60 days of flue gas injection

Figure 3.26. Gas-phase pressure after 60 days of CO₂ injection

3.1.3.2.10. Considerations for Injection Well Placement

Depth Requirements

The estimated phase behavior of the flue gas indicates that for the stream to trend towards a phase with supercritical properties, the pressures would need to be marginally greater (10-20%) than that of pure CO₂. The only way to increase the storage pressure is to inject into a deeper formation. Initial calculations show the minimum formation depth for flue gas may have to be several hundred meters deeper than the minimum depth needed for pure CO₂.

For example, in the Midwestern United States, pure CO₂ will be supercritical at an approximate depth of 800 meters. To create supercritical type conditions for the oxy-combustion flue gas in the Midwest, that depth would need to be extended to between 1200 and 1500 meters.

Density and Volume Changes

Density is an important factor in effective storage. A less dense fluid will take up more volume per given mass and will reduce the storage capacity of a formation. This, in turn, will lead to more wells as each well will have to be abandoned with less mass stored.

Due to lower compressibility of some flue gas components, the density of the flue gas is much lower than the density of pure CO₂. In addition, the flue gas cannot be compressed to a point where the density will approach that of CO₂, even if deeper (hence warmer) storage formations are used. Preliminary calculations show that the density of the flue gas will be between ¼ and ½ that of compressed CO₂ (Figure 3.18). Consequently, the injected flue gas will take 2 to 4 times more pore space to sequester than the pure CO₂.

A volume increase of 2 to 4 times will have significant effects on aspects of storage such as monitoring and permitting. The predicted plume size will be much larger, causing the area of review for permitting to be extended. If the goal of the monitoring plan is to track the areal extent of the plume, more monitoring points will be needed to image the larger area.

An injection well will have a finite lifetime over which injection can occur. Eventually, the near borehole formation will be saturated with injectate and the injection pressures required to continue to push injectate into the formation will exceed the fracture pressure. In this scenario, the well would need to be abandoned. For the lower density flue gas, the need for new wells would occur much sooner than with pure CO₂. If specialized well materials are needed, building new wells would be a very large cost driver.

Injectivity

Injectivity is a function of both rock and fluid properties. Holding the rock properties constant, the effects of fluid properties can be determined. For a given pressure and temperature, the viscosity and density of the fluid are the main factors. Permeability is a measure of a fluid's ability to travel through a rock over a given time period. Furthermore, assuming two different fluids are traveling through the same rock, at a given temperature and pressure, the differences in the kinematic viscosities of the fluids will control the differences in permeability.

The ratio of kinematic viscosities for pure CO₂ and flue gas, over the range of pressures and temperatures likely to be seen in a storage formation, is close to one. There is likely to be little change in injectivity of the flue gas from that of pure CO₂.

Other Geologic Constraints

Many of the geologic constraints on sequestration of either flue gas or CO₂ are site specific. Each potential site will need to be evaluated for sequestration potential; however, some of the potential geologic pitfalls are presented here.

As mentioned above, for the flue gas to remain in supercritical state, it must be injected into formations with higher pressure than would be needed if the gas were pure CO₂. However, the injectivity for the two gasses is comparable. In a typical sedimentary column, the porosity and permeability are preserved over a certain depth interval, and then there is a significant decline in these properties due to compaction and cementation. The depth at which this occurs is site specific. In essence, the addition of the flue gas in a given geologic regime lowers the upper

bound but does not lower the bottom. In essence, there is effectively less rock to choose from for potential storage of flue gas CO₂.

Another possible constraint is the structural geology in the area of interest. In an unbounded system where displaced brine can continue to travel out of the formation allows the pressure increase to dissipate over time. Nevertheless, at many sites, an unbounded system is probably unrealistic. A sealing fault system cutting the injection formation may allow for the pressures to build up as the displaced brine and the injectate velocities are reduced in the fault zone. Other features, such as regional dip or anticlines may also allow the formation pressures to increase.

Effects such as these will be studied as site-specific scenarios are examined.

Geochemical Interactions

Brines cannot contain as much dissolved gas as pure water at the same temperature and pressure because high concentrations of dissolved salts (up to 400,000 parts-per-million) in brines inhibit solubilization of gases and other non-electrolytes. This phenomenon is often referred to as the “salting out” effect. On the other hand, pressures typical of deep saline reservoirs favor dissolution of CO₂ up to 5-10%. For example, the hydrostatic head at 800 m is 1140 psia. Once gas phase CO₂ is converted to the dissolved (aqueous) form, hydrolysis reactions convert the CO₂ to carbonic acid. In the absence of natural buffers, such as carbonate minerals, the brine will become mildly acidic (pH ~4.5).

Geochemical modeling with PHREEQC³ was used to understand the interaction between the injectate (consisting of CO₂), the brine, and rock minerals, including carbonates (dolomite and calcite). Dissolution of carbonate minerals enhances the solubility of CO₂ due to the following chemical reaction:

As indicated in Equation 3.1, two moles of CO₂ are converted to aqueous bicarbonate for each mole of dolomite dissolved from the formation matrix. This geochemical reaction creates “solubility storage” within the formation and represents an additional mechanism for enhancing long-term sequestration of CO₂. Residual formation water saturation also provides an additional storage mechanism for CO₂ within the reservoir horizon.

However, if the brine contains high concentrations of sulfate, then precipitation of gypsum may take place by the following chemical reaction:

Equation 3.2 describes an equilibrium condition involving two solid phases, dolomite and gypsum (or anhydrite at temperatures above 55 °C). Modeling results (Figure 3.27) indicate that dolomite dissolution is larger on a molar (and volumetric) basis than gypsum precipitation. If

³ http://wwwbrr.cr.usgs.gov/projects/GWC_coupled/phreeqc/

that were the case, CO₂ injection might increase the effective porosity of the formation and enhance injectivity and storage capacity within the host reservoir. On the other hand, transient effects such as partial dissolution of dolomite followed by displacement and mobilization of mineral fragments could fill pore spaces, thereby reducing formation permeability. The likelihood and consequences of these short-term gypsum precipitation effects should be assessed experimentally with core flood tests to ascertain the risks of clogging prior to an actual demonstration in the field.

Figure 3.27. Geochemical modeling results for Equation 3.2

In addition, co-sequestration of CO₂ and SO₂ appears to be technically feasible in many, if not most deep saline reservoirs. Injection of up to, say, 1% SO₂ in a CO₂ stream, does not appear to favor side reactions that would reduce the usable lifetime of the reservoir. However, models would need to be run for specific formations and injectate compositions to ensure that no undesirable precipitation reactions can take place.

3.1.4. Pilot-scale Evaluation

Pilot-scale evaluation focused on Cyclone boilers because B&W had already demonstrated the oxy-firing technology for wall-fired application at 30 MW_{th} for a wide range of coals (See Section 3.1.6). Pilot scale testing of oxy-combustion in a Cyclone furnace was performed in the SBS-II facility described above. Baseline tests with air were also performed, and the data gathered was used to determine differences between air and oxy-firing in terms of emissions, and boiler heat absorption. These results are described below.

3.1.4.1. NO_x Emissions and Carbon Conversion

Typically, combustion modifications to control NO_x suffer from a tradeoff between conditions conducive to complete combustion of carbon, and conditions favorable for NO_x reduction. Thus it is advantageous to discuss these topics together. Carbon conversion is quantified by measured

CO emissions and carbon remaining in flyash, estimated by the weight loss of flyash samples on ignition (LOI). In this section NO_x and CO emissions between tests are compared using units of lb of the pollutant per MBtu to eliminate the influence of varied recycled flue gas flow on the comparison. Concentration measurements such as ppm do not allow an objective comparison of emissions, although they are important to understanding chemical reaction rates in various processes.

In the pilot scale data the term “emissions” refers to pollutants directed to the stack after the extraction of gas used in flue gas recycle. In a CCS plant this stream would be directed to the CPU island. Pollutants in the recycled flue gas are not included in emissions data.

Figure 3.28 presents the NO_x emissions data with separate trend lines for air and oxy-firing as a function of the stoichiometry in the Cyclone. As the Cyclone stoichiometric ratio is lowered (staged combustion) the amount of NO_x decreases, consistent with expectations. However, at all stoichiometries, oxy-firing emits less NO_x than air firing. In addition, as the Cyclone stoichiometric ratio is increased, the air fired cases increase in NO_x at a faster rate than oxy-firing. This reduced sensitivity to stoichiometric ratio under oxy-firing conditions may be due to a number of reasons including the lack of N_2 available for thermal and prompt NO_x formation, and the increased rates of recycled NO_x reduction as the NO_x concentration in the recycled flue gas increases. Note that the stoichiometry values used in the plots are derived from the analysis described in Section 2.1.1.10 that includes the effects of infiltrated air.

The bituminous coal produced the most NO_x at a given stoichiometry under both air and oxy-firing conditions, whereas the lower rank coals were comparable to each other. This is consistent with the coals’ nitrogen content with the higher rank coal having roughly twice the nitrogen content of the other two.

In some tests with subbituminous coal, difficulties were experienced in keeping the flame inside the Cyclone. This was detected by observing the data for Cyclone heat absorption, which was low when the flame was not retained. When the flame was successfully retained in the Cyclone the NO_x analyzer experienced an operational problem, hence the error bar on the data point in Figure 3.28. The error bar was sized using the available data for air combustion with the flame in and out of the Cyclone, and led to the conclusion that with the flame inside the Cyclone, NO_x emissions for warm and cold recycle conditions with this coal are probably similar.

Figure 3.28 Comparison of NO_x emissions between air and oxy-firing for three coals fired

Figure 3.29 shows the expected reduction in NO_x emissions when changing from air to oxy-firing for the three coals. This figure is based on the trend lines in Figure 3.28 at a Cyclone stoichiometric ratio of 0.9. The reduction in NO_x ranges from 53-67%, and there is no clear trend with coal rank. Over 60% NO_x reductions were achieved with bituminous and lignite coals. The NO_x reduction with the subbituminous coal was lower (53%) which is caused by lower air-firing

NO_x emissions with this coal. As expected, air-firing NO_x emissions with subbituminous coal was lower than other two coals since the subbituminous coal fuel-nitrogen content was very low. There may be competing effects or multiple factors that determine the NO_x reduction, including volatile yield and nitrogen content.

Figure 3.29 Expected reductions in NO_x emissions when changing from air to oxy-firing for the three coals based on trend lines at a Cyclone stoichiometric ratio of 0.9

The data presented above are in terms of emitted NO_x, which is lower in oxy-firing. Counter to intuition developed from air firing experience, these lower emissions are associated with a higher concentration, as most of the flue gas flow is recycled to the boiler. NO_x has the opportunity in the boiler to be reduced in the combustion zone to N₂, and thus the enrichment of NO_x in the flue gas during oxy-firing is not as great as experienced for other species (such as SO₂) that are not amenable to control by combustion. As shown by the lignite test results in Figure 3.30, SO₂ concentrations may increase by a factor of 3-5 in oxy-firing (relative to air firing) whereas NO_x in the same tests only increased in concentration by a factor of 2 or less.

An example of CO emissions in terms of concentration at the convection pass exit is shown in Figure 3.31. Overall the concentration was slightly higher for oxy-firing relative to air at the same Cyclone stoichiometry, but like NO_x, CO is easily converted to other species (e.g. CO₂) on recycling and does not show the high levels of enrichment seen with SO₂ during oxy-firing.

Figure 3.31 also shows an increase in CO with deeper staging (lower Cyclone stoichiometry), as would be expected. Also seen are very high values of CO at the lower stoichiometries. These are attributable to fluctuations in coal flow that occurred in a few tests. The CO data over time for these tests show generally low values with occasional sharp peaks that raise the average CO reported. For example, test “Warm Rec-PRB Air Test 2a” has an average CO concentration of 428 ppm, with standard deviation of 707, minimum level 10, and maximum corresponding to the analyzer range limit (2073).

Figure 3.30 Data showing the enrichment of pollutants NO_x and SO_2 by flue gas recycling for the lignite tests

**Figure 3.31 Example CO concentration data at the convection pass exit:
Subbituminous coal for air-firing and warm recycle oxy-firing**

As only a fraction (29-41% in these tests) of the flue gas is directed to the stack, the emitted CO (lb/MBtu) is on average lower (by 62% averaged over all tests) in oxy-firing than air-firing, as demonstrated by the data in Figure 3.32. For the subbituminous coal no significant difference is observed between cold and warm recycle conditions.

Figure 3.33 presents the measured loss on ignition (LOI) of fly ash samples for all tests. Two trends can be easily observed: first, LOI increases with the coal rank, consistent with known trends in char reactivity with rank; and second, deeper staging tends to increase LOI. Overall it appears that the LOI measured in oxy-firing is slightly lower than an equivalent air-firing condition, with the difference increasing with the coal rank. While scatter in the data is present, LOI measurements for cold and warm recycle oxy-firing are comparable.

In summary, despite higher concentrations of CO and NO_x in oxy-firing flue gas, the recycling of the majority of flue gas results in lower emitted quantities and the increased opportunity to convert these pollutants to desired products in the furnace. A comparison of emitted levels of these pollutants for optimum test cases is presented in Figure 3.34, along with LOI data which is also slightly lower under oxy-firing conditions. For this comparison, the optimum test cases were selected based on good slag flow in the Cyclone combined with acceptable emissions and heat transfer performance. These data indicate that for NO_x emissions and carbon utilization, oxy-firing is superior to air-firing.

Figure 3.32 CO emissions data for all tests as a function of Cyclone stoichiometry

Figure 3.33 LOI data for all tests as a function of Cyclone stoichiometry

Figure 3.34 Comparison of LOI, and emitted NO_x and CO for optimum operating conditions

3.1.4.2. SO₂ Emissions and Flue Gas Moisture

As mentioned in the discussion of NO_x emissions, SO₂ in an oxy-firing system is enriched as flue gas is recycled. For the same optimum combustion cases presented in Figure 3.34, flue gas SO₂ and moisture concentrations are presented in Figure 3.35 and Figure 3.36. For the lignite measurements in the right column of Figure 3.35, the SO₂ concentration in oxy-firing is 3.6 times higher than in air, and for the bituminous coal (left column) the increase is by a factor of 1.5. This difference illustrates the role of flue gas desulfurization in the recycle loop to limit the enrichment of SO₂. Enrichment of water in oxy-firing for the lignite and bituminous cases is 1.6 and 1.7 times respectively, comparable because both tests made use of the condensing heat exchanger.

Figure 3.35 Comparison of flue gas SO₂ and moisture concentrations (convection pass exit) between air and oxy-firing for bituminous coal and lignite

Figure 3.36 indicates the effect of removing the condensing heat exchanger from the system. In the cold recycle test results (left column) the moisture is enriched in oxy-firing by 1.8 times, but in warm recycle tests (right column) the moisture is increased by a factor of 3. Note that SO₂ in both cases is significantly enriched (4.5 times in cold recycle and 3.8 times in warm recycle). The SO₂ data are presented on a dry basis, removing the influence of the water on the SO₂ comparison. Note that as previously mentioned, the subbituminous coal used in the warm recycle tests had lower sulfur content than used in the cold recycle subbituminous tests.

The increased moisture levels in warm recycle may have several effects including altered oxidant properties (heat capacity, density etc.) and increased importance of char gasification by H₂O in the furnace. In this work the similarities noted above in LOI, and CO emissions, and that the oxygen concentration required in the Cyclone secondary oxidizer was not higher under warm recycle conditions for satisfactory operation, it appears that these differences may not be important from a furnace operating standpoint. There may however be a need to consider the

increased potential for condensation of moisture with dissolved acid gases in the ductwork to prevent corrosion.

Figure 3.36 Comparison of flue gas SO₂ and moisture concentrations (convection pass exit) between air and oxy-firing for subbituminous coal (warm and cold recycle)

As noted for NO_x and CO, the quantity of SO₂ emitted is actually lower in oxy-firing despite the higher concentrations in the flue gas. Average test data are presented in Figure 3.37. The greatest reduction in SO₂ occurs for the bituminous coal, which is to be expected because the recycled SO₂ will have multiple passes through the wet scrubber and therefore increased capture potential. The reduction observed for the other coals was investigated further by performing a sulfur balance calculation where predicted levels of SO₂ in the flue gas were compared with those actually measured. SO₂ at the furnace exit was predicted by assuming SO₂ measured in the recycled flue gas simply passed through the boiler and 100% of fuel sulfur (as-fired, after pyrite removal in the pulverizer) was oxidized to SO₂. Results of this analysis are shown in Table 3.16. Measurements of SO₃ were not taken into account and are discussed in Section 3.1.4.3.

Figure 3.37 Average SO₂ emitted between air and oxy-firing for each coal

Referring to Table 3.16, for all cases the measured SO₂ after the baghouse was lower than the predicted level of SO₂ after the furnace. The difference is greater in the oxy-fired cases than in air-firing for all coals. No significant trends in the data with variables such as temperature were found. The differences between air and oxy-firing on the same day with the same coal require further testing to explain.

Coal:	Bituminous		PRB 1st Shipment		Lignite		PRB 2nd Shipment	
Firing Mode:	Air, with WFGD	Oxy, with WFGD	Air	Oxy	Air	Oxy	Air	Oxy (warm recycle)
Date:	7/30/2009	7/30/2009	8/5/2009	8/25/2009	9/3/2009	9/3/2009	9/17/2009	9/17/2009
Time:	11:23	17:16	10:08	14:53	10:21	16:37	10:02	18:02
As-fired Fuel Sulfur (wt %)*	2.70	2.70	0.39	0.39	0.66	0.66	0.26	0.26
As-fired Fuel HHV (Btu/lb)*	13201	13201	9627	9627	8649	8649	9709	9709
Stack SO ₂ (Air Firing) (ppmdv, @ 3% O ₂)	140		403		643		194	
Recycled Flue Gas SO ₂ (Oxy Firing) (ppmdv, @ 3% O ₂)		492		1689		2416		773
Expected SO ₂ After Conv. Pass [(Fuel S → SO ₂) + RFG SO ₂] (ppmdv, @ 3% O ₂)	2182	3460	410	1785	829	2774	280	1007
Measured SO ₂ After Baghouse (ppmdv, @ 3% O ₂)	1963	3126	403	1689	642	2416	194	773
Expected SO ₂ - Measured SO ₂ (ppmdv, @3%O ₂)	219	335	7	96	186	357	86	234

*From short analysis performed for this sulfur balance.

Table 3.16 Comparison of predicted and measured SO₂ levels in the flue gas

Others (17) have reported increased sulfur capture with ash under oxy-firing conditions. This has yet to be fully investigated, but it is safe to say that the recycling of SO₂ gives increased opportunity to a given SO₂ molecule to be scrubbed in the recycle loop by either flue gas

desulfurization or a suitable flyash. Increased SO_2 and moisture concentrations may also play a role.

3.1.4.3. SO_3 Emissions

Higher SO_3 emissions could be a negative side effect of the oxy-firing technology with high sulfur coals. If SO_3 is not scrubbed and condenses in equipment, it could cause corrosion. One of the objectives of the SBS-II program was to assess the SO_3 concentrations in the recycled flue gas. SO_3 sampling tests (using the controlled condensation method) were performed while firing the Ohio #5 bituminous coal. Additional tests with the Black Thunder subbituminous coal and North Dakota lignite were ruled out due to the low sulfur content of these fuels.

Repeated SO_3 testing was performed by CleanAir Engineering for both air- and oxy-firing at two locations:

- Air heater outlet (flue gas side)
- ID fan inlet

The first point is located before all environmental equipment and demonstrates the conversion of fuel sulfur to SO_3 inside the radiant furnace and convection pass. Measurements at the ID fan inlet show the SO_3 concentration after all environmental equipment (baghouse, WFGD, CHX) in the flue gas recycled to the boiler.

Figure 3.38 shows the SO_3 concentration in the recycled flue gas for air- and oxy-firing. The SO_3 concentration after the environmental equipment was 0.2 ppm for air-firing and 1.7 ppm (average) for oxy-firing. At this location, the temperature ranged from 94 to 109°F and as expected, no SO_3 in the form of vapor was detected. Non-vapor SO_3 could be calcium sulfate carryover from WFGD but little carryover was seen with air-firing. Therefore the SO_3 must be in the form of aerosol which was absorbed in the probe liner. The SO_3 concentration ranged from 0.2 to 4 ppmdv during oxy-firing. Further investigation is required to determine if the cause was combustion conditions and/or the operation of environmental equipment.

Table 3.17 provides a list of SO_3 test names to allow cross-referencing with other pilot-scale test data tabulated in the Appendix (Section 8.2).

Figure 3.38 Total SO₃ concentration after environmental equipment (bituminous coal, vapor and non-vapor SO₃ forms combined)

Figure 3.39 shows that oxy-firing generated higher SO₃ in the radiant furnace and convection pass than air-firing. The average SO₃ concentrations for air- and oxy-firing were 8.1 and 48.2 ppm respectively. At these high temperatures (375 to 400°F), the majority of SO₃ was in vapor form and the remainder was absorbed by fly ash. From these data, it is concluded that oxy-firing produces higher concentrations of SO₃ but the combination of baghouse, wet scrubber, and condensing heat exchanger employed in these tests was capable of reducing SO₃ to very low levels as illustrated by Figure 3.38.

SO ₃ Test	Test Name in Appendix	SO ₃ Test Start Time (Duration 60 minutes)
Air-firing Test 1	OH #5 Air Long Term #1	7/21/2009 8:59
Air-firing Test 2	OH #5 Air Long Term 3	7/21/2009 11:18
Air-firing Test 3	OH #5 Air Long Term 4	7/21/2009 14:18
Oxy-firing Test 1	Ohio #5 Oxy Long Term Test 1	7/22/2009 11:46
Oxy-firing Test 2	Ohio #5 Oxy 7 Long Term 2	7/28/2009 12:52
Oxy-firing Test 3	Ohio #5 Oxy 7 Long Term 3	7/28/2009 16:45
Oxy-firing Test 4	Ohio #5 Oxy 7 Long Term 4	7/28/2009 19:05

Table 3.17 SO₃ test names and corresponding names in the Tabulated Pilot-scale Test Data (Appendix Section 8.2)

Figure 3.39 Total SO₃ concentration before environmental equipment (bituminous coal, vapor and non-vapor SO₃ forms combined)

In an attempt to determine the fate of SO₃, Figure 3.40 and Figure 3.41 show the vapor and non-vapor forms of SO₃ concentrations at the air heater outlet before the environmental equipment. For oxy-firing conditions (Figure 3.40) an average of 24% of SO₃ was non-vapor (absorbed by flyash or an aerosol). This particle-bound or aerosol SO₃ could be easily captured in the baghouse. As a result, an average 37 ppm vapor phase SO₃ would enter the WFGD. After the WFGD and CHX only 1.7 ppm was detected in the recycle gas. A WFGD can capture some SO₃ but is not very effective for capturing aerosols. Our previous investigation (18) in the 30 MW_{th} Clean Environment Development Facility (CEDF) showed that 23% of SO₃ was captured in the WFGD. Although there are many differences between the SBS-II and CEDF, if we assume the WFGD removes 23%, the WFGD outlet concentration would be 28 ppm, suggesting that the majority of SO₃ was removed in the CHX.

A commercial oxy-firing plant could employ other strategies to eliminate or reduce SO₃ and the associated corrosion potential such as: (1) increasing recycle gas temperature above the acid vapor dew point, (2) reducing SO₃ by a dry sorbent injection system, (3) using a dry scrubber.

Figure 3.40 Vapor and non-vapor SO₃ concentrations at the air heater outlet during oxy-firing

Figure 3.41 Vapor and non-vapor SO₃ concentrations at the air heater outlet during air-firing

3.1.4.4. Mercury Emissions Measurements

The mercury concentration in the flue gas was measured using a Field Transportable Mercury Analyzer (FTMA). The FTMA consists of a sampling probe, mercury scrubber, oxidized-to-elemental thermal mercury converter, and a total mercury analyzer (Ohio Lumex Mini CEM 915). The probe samples a small portion of the flue gas, which is filtered to remove particulate and diluted with air at a given ratio. The total mercury concentration is measured by sending a portion of the clean and diluted sample to the total mercury analyzer. In order to measure elemental mercury, another portion of the diluted sample is sent first to a scrubber to remove oxidized mercury only, and then to the total mercury analyzer while the unscrubbed portion bypasses the analyzer. This latter reading corresponds to the amount of elemental mercury in the gas. The concentration of oxidized mercury can be calculated by subtracting the amount of elemental mercury from the total mercury measurement.

The FTMA was calibrated before and after each test using standard gases with a known mercury concentration. The gases were generated using a HOVOCAL® system. The standard gases were introduced in random order for statistical validity. The measured and the expected mercury concentrations were fitted to a straight line with a zero intercept. Using the slope of the line generated, the mercury readings were corrected. As shown in Figure 3.42 the probe calibration did not change significantly through the duration of the tests.

Figure 3.42 Mercury analyzer calibration data

Figure 3.43 shows mercury measurements taken on July 21, 2009 during combustion of Ohio #5 bituminous coal in air. No flue gas was recycled. Initially, measurements were taken at the outlet of the wet flue gas desulfurization scrubber. Due to problems on this day with the probe

calibration⁴, these values are not accurate and can only be discussed qualitatively. The ratio of oxidized to elemental mercury, however, is valid and is representative of the test because both the oxidized and the elemental mercury measurements are affected by the same calibration factor.

As can be seen in Figure 3.43, prior to time 13:27, the oxidized and the total mercury have similar values. The difference between the total and the elemental mercury corresponds to the oxidized mercury, which appears negligible. Hence, downstream of the WFGD the mercury in the flue gas is in its elemental form (Hg^0).

Between 13:27 and 14:30 (indicated by two vertical lines in the figure) the probe was moved to the inlet of the scrubber. As can be seen the mercury concentration at the inlet of the scrubber is higher, and about 90% of the mercury is in an oxidized form (Hg^{2+}). The oxidized mercury concentration, however, slowly decrease with time. It is suspected that this decrease in mercury concentration was due to the accumulation of unburned carbon particles on the filters in the baghouse.

Wet scrubbers are known to capture oxidized mercury as was observed here. Comparing the outlet and the inlet readings we can see that the oxidized mercury was captured in the scrubber, while elemental mercury passes through it. Negligible amounts of oxidized mercury were detected at the outlet.

⁴ For the data taken July 21, the mercury sampling probe was exposed to fly ash which partially blocked a flow orifice in the sample dilution system, and thereby affected the calibration. Once this problem was discovered and remedied the calibrations were valid (see Figure 3.42).

Figure 3.43 Mercury concentration at the outlet and inlet of the wet scrubber for tests performed on July 21, 2009 (Qualitative data only)
Ohio #5 bituminous coal, air-firing

Figure 3.44 shows mercury measurements taken on September 3 firing lignite. The probe was located between the baghouse and condensing heat exchanger, downstream of the bypassed wet scrubber.

The unit was started in air firing mode and transition to oxy-firing began at 11:30. Complete transition to oxy-firing was achieved at 16:25. Between 10:00 AM and 12:00 PM, the mercury readings were unstable. The reason for this noise is probably related to unstable combustion in the boiler as indicated by the large fluctuations in convection pass exit CO.

During the transition period, the total and elemental mercury concentrations increased as the flue gas recycle flow rate increased. The CO₂ concentration is also shown in Figure 3.44 for reference. As can be seen, the CO₂ and total mercury concentration followed similar trends.

The ratio of oxidized mercury to elemental mercury, on the other hand, was not constant. For example, at about 13:00, the ratio of oxidized to elemental mercury is close to 0.25. At full recycle (16:25), the ratio of oxidized to elemental mercury is about 1.64. The increase in the oxidized-to-elemental mercury ratio indicates that oxy-firing with flue gas recycle generates larger proportions of oxidized mercury. At 18:25 the unit tripped and coal combustion stopped. The mercury concentration dropped accordingly.

Figure 3.44 Mercury concentration for tests performed on September 3, 2009 firing lignite

Figure 3.45 shows mercury measurements taken during warm recycle tests on September 17th. In this test the probe was located downstream of the baghouse and the bypassed wet scrubber. Downstream of the sample location the CHX was also bypassed.

The unit was started on air, firing subbituminous coal. Transition to oxy-firing started at 10:20 and was complete at 12:45. Flue gas CO₂ content increased from 16% to 79 % during this period. For the remainder of the day, the CO₂ concentrations remained constant around 80%. As can be seen in Figure 3.45, mercury concentrations slowly increased until reaching a maximum concentration around 16:00. Between 16:00 and 17:25, the mercury concentration was stable, and decreased thereafter. Some of these trends are easily explained by considering the operating conditions. For each test condition starting at 12:45 the flue gas recycle flow rate was incrementally increased. At about 17:25 a combustion condition corresponding to the highest mercury concentration and highest flue gas recycle flow with stable combustion was achieved. Thereafter, further increases in flue gas recycle flow led to unstable combustion, and higher unburned carbon in the flue gas, which could explain the decrease in mercury after 17:25. The gradual rise in mercury during the baseline test period may be related to capture of mercury in cold ductwork and on unburned carbon in the ducts, which gradually decreases as the unit warms up, and the available capture sites become saturated.

Figure 3.45 Mercury and CO₂ concentration data obtained during warm recycle tests (September 17 2009) firing PRB coal

Since the scrubber and CHX were not in operation during this test, the amount of CO₂, elemental mercury, and oxidized mercury could be expected to increase proportionally with the recycling of flue gas. However, as shown in Figure 3.45, and consistent with the results already discussed in connection with Figure 3.44, CO₂ and total mercury increased as expected, but the ratio of oxidized to elemental mercury increased under oxy-firing conditions.

Figure 3.46 shows the average values for elemental and oxidized mercury during air and oxy-firing from the periods marked as “Baseline” and “Oxyfuel” in Figure 3.45. Also shown is the ratio of oxidized-to-elemental mercury. During air combustion, the ratio of oxidized-to-elemental mercury is near zero, which is expected based on experience with Powder River Basin coals such as this with low chloride content. During full recycle oxy-firing mode, the oxidized-to-elemental mercury ratio is about 2, which is only possible if part of the elemental mercury in the recycled flue gas is converted to its oxidized form in the boiler. Since oxidized mercury is water soluble, the use of a wet scrubber in the recycle loop combined with a higher oxidized-to-elemental mercury ratio in oxy-firing may lead to higher levels of mercury removal in oxy-firing relative to air firing. Quantification of this however requires further investigation as the mercury removal efficiency of a scrubber depends not only on the oxidized-to-elemental mercury ratio, but also the rate of re-emission of oxidized mercury that is reduced to elemental mercury in the scrubber. Longer-term combustion studies are recommended to establish the effect of oxy-combustion on mercury speciation. Longer tests will also demonstrate the effect of a scrubber (either in the recycle loop, or on the flue gas flow to the stack), on mercury speciation as the presence of a wet scrubber may affect the ratio of oxidized-to-elemental mercury by removing chlorine compounds from the gas that could be important to the oxidation of mercury in the boiler. A wet scrubber

would not be economical for mercury capture alone, however if a wet scrubber in the recycle loop is employed for SO₂ and SO₃ control, the question of mercury speciation would be of great importance in determining whether a separate method of mercury capture is required.

Figure 3.46 Average elemental and oxidized mercury results from the warm recycle test series (PRB subbituminous coal)

3.1.4.5. Boiler Thermal Conditions and Heat Transfer

As will be discussed below in Section 3.1.5 - Computational Model Validation, gas emissivity, specific heat, and other heat transfer variables are changed considerably by the difference in gas composition between air and oxy-firing. During the pilot-scale tests, the radiant furnace and convection pass heat absorptions were directly measured and compared with air-firing to assess the impact on boiler steam generation. In general, oxy-firing does not seem to overly impact the boiler heat transfer conditions in the radiant furnace and the convection pass as long as the mass flow through the furnace is the same as air-firing.

Figure 3.47 shows the overall heat input to SBS-II for different conditions. The majority of the heat is introduced by coal and hot secondary air. These tests were conducted at approximately 6 MBtu/h for bituminous and subbituminous coals. Lignite tests were conducted at approximately 5 MBtu/h.

Figure 3.47 Available heat with various conditions

Figure 3.48 Overall heat absorption

Generally, very good heat balance was obtained for these tests. Figure 3.48 shows the energy balance in the SBS-II. Cyclone furnace, primary furnace, and convection pass heat absorptions were determined from the water side of the boiler. Heat loss for the flue gas was computed from flue gas composition and temperature. Overall 95% heat balance was obtained for subbituminous coal tests and over 90% closure was obtained for the remainder of the tests. The air-firing tests with the bituminous coal on average had the highest uncertainty.

Figure 3.49, Figure 3.50, and Figure 3.51 show the Cyclone furnace, primary furnace, and convection pass heat absorptions, respectively. Generally, these data demonstrate that the heat absorptions are not drastically different between air- and oxy-firing. To further investigate the impact on heat absorption, the optimum conditions for each coal were selected and compared. Figure 3.52 shows that under the optimum conditions, Cyclone, primary furnace, and convection pass heat absorptions are not negatively impacted by oxy-firing. The heat absorptions are almost identical for subbituminous coal and lignite tests when over 95% heat balance was obtained. The difference in the primary furnace heat absorption with the bituminous coal may be due to lack of closure in the heat balance rather than actual differences in heat absorption as heat balance closure was approximately 80%). Boiler heat absorption is further discussed in connection with numerical modeling in Section 3.1.5.

Figure 3.49 Cyclone furnace heat absorption

Figure 3.50 Primary furnace heat absorption

Figure 3.51 Convection pass heat absorption

Figure 3.52 Comparison of heat absorption in Cyclone, primary furnace and convection pass

In addition to furnace heat absorption, the impact of oxy-firing on the flame temperature and furnace exit gas temperature (FEGT) was evaluated. As mentioned earlier, flame temperature was measured with an in-furnace pyrometer and FEGT with a High Velocity Thermocouple (HVT). Figure 3.53, Figure 3.54, and Figure 3.55, show examples of two-dimensional

measurements of the flame temperature exiting the Cyclone furnace. Although oxy-firing flame temperatures can be substantially different from air-firing, by optimization of oxy-firing conditions, a similar flame temperature could be obtained.

Figure 3.53 FlameView images and temperature maps for subbituminous coal

Figure 3.54 FlameView images and temperature maps for bituminous coal

Figure 3.56 shows the calculated adiabatic flame temperature for air-firing and oxy-firing with “Cold-Recycle” and “Warm-Recycle”. In these calculations, the total mass flow rate to the boiler was the same for air-firing and oxy-firing conditions. Due to higher specific heat of CO₂ than nitrogen, as expected, adiabatic flame temperature under air-firing conditions is higher than the flame temperature under the oxy-firing conditions. In addition, the adiabatic flame temperature under the oxy-firing with “Cold-Recycle” is higher than the adiabatic flame temperature under the oxy-firing with “Warm-Recycle” because less water vapor exists in the flue gas under the “Cold-Recycle” than “Warm-Recycle”. This could be troublesome and prevent adequate slagging for some of the Cyclones, but as Figure 3.56 shows by strategic addition of oxygen into the Cyclone, the temperature can be increased and alleviate the potential slagging problem. Experimental measurements of flame temperature obtained from the FlameView camera (Figure 3.57) show trends consistent with the calculations.

Numerous FEGT measurements were performed during these pilot-scale tests to assess the impact of oxy-firing on FEGT. Figure 3.58 indicates that for optimum operating conditions, when coal fineness was within the specified range and flame was in the Cyclone, the FEGT under oxy-firing conditions is comparable to the FEGT under air-firing. There could be some exception to this general statement such as the results with the bituminous coal which showed the FEGT was approximately 100° F lower during oxy-firing conditions (see Figure 3.59). This general trend was also observed in the numerical modeling (see Section 3.1.5).

Figure 3.56 Calculated adiabatic flame temperatures for various conditions

Figure 3.57 Experimental flame temperature data for various conditions (compare Figure 3.56)

Figure 3.58 Comparison of FEGT for various conditions

Figure 3.59 Comparison of FEGT for bituminous coal

The impact of oxy-firing on FEGT can be substantial in non-optimum conditions. Figure 3.60 shows the impact of the mass flow rate through the boiler on FEGT. In air firing the mass flow at a given load is controlled by excess air. In oxy-firing the recycle flue gas flow is the dominant factor and a wider range of mass flow per unit heat input is possible. FEGT for air- and warm recycle oxy-firing is comparable when the mass flow rate through the boiler is the same but the FEGT, as expected, has a strong dependence on recycle flow rate. It should be noted that Cyclone tapping is improved at lower RFG flow, presumably due to higher Cyclone temperature.

Figure 3.60 Effect of reduced flue gas recycle on FEGT

Further discussion of heat transfer, temperature profiles, and gas radiation properties appears in Section 3.1.5.

3.1.4.6. Factors that Affect and Control CO₂ Concentrations (Air Infiltration)

As the primary purpose of oxy-firing is generating a CO₂-rich flue gas that can be easily stored, the concentration of CO₂ is of prime interest. CO₂ concentrations are affected by air infiltration and impurities introduced to the process with the oxygen. There is also some nitrogen in coal that is partially converted to N₂, but the amount is typically small in comparison with the other aforementioned sources. During these pilot-scale tests, liquid oxygen was used (purity above 99.8%); therefore, the only major source of impurities was air infiltration which will be discussed.

Air infiltration is an influx of outside air into the process gas. The sources of air infiltration are areas in the process that operate under negative pressure primarily located between the convection pass outlet and the ID fan inlet. Air can also infiltrate at the inlets of the primary and secondary forced draft fans. When a unit is run under air-firing conditions, the impact on flue gas composition is unimportant because it mixes with the flue gas and goes up the stack, but in oxy-firing when flue gas is recycled, it is a significant factor since nitrogen is introduced into the process, diluting the CO₂ concentration.

During fabrication and erection of SBS-II, with insight gained from the previous oxy-firing R&D projects (see Section 3.1.6 - Wall-firing Pilot Scale Testing and Analysis), an attempt was made to seal as many sources of air infiltration, such as fan shafts, fan inlets, flue work, as was practical. During start-up and shakedown of the SBS-II, the unit was checked and several air leaks were located and repaired. A major leak was found in the connection at the duct work at the outlet of CHX. Figure 3.61 shows a large difference between the oxygen measurements at the inlet and outlet of CHX indicating an air leak.

Boiler operation can minimize the air in the boiler. For a balanced draft boiler, a balance point is typically set at the radiant boiler, before the convection pass and minimal air infiltration is expected in the radiant boiler and convection pass. A significant factor on the amount of air infiltration is pressure drop across the major back-end equipment. The boiler back-end equipment is operating under negative pressure and is a large source of the air infiltration. The pilot-scale investigation showed that air infiltration increased when the pressure drop between the convection pass outlet and the ID fan inlet went up. Figure 3.62 shows the effect of air infiltration on CO₂ concentration during oxy-firing. It should be noted that during oxy-firing with bituminous coal, a wet FGD was used to scrub SO₂ and the overall back-end pressure drop was higher than the tests with lignite and subbituminous coal.

Figure 3.63 shows the CO₂ concentration at the optimum conditions. For the subbituminous coal, up to 90% CO₂ was achieved while the CO₂ for bituminous coal was 73% due to the additional pressure drop caused by the scrubber. The high level of CO₂ concentration achieved in the SBS-II is remarkable and helps reduce the energy requirement and cost of the CPU system as discussed in Section 3.2.2.3.2 of this report.

Figure 3.61 Oxygen measurements in the flue gas path compared to simultaneous measurements of convection pass exit O₂ (7/29/2009)

Figure 3.62 Effect of air infiltration on CO₂ concentration

Figure 3.63 CO₂ concentrations achieved with various coals and oxy-firing process

3.1.5. Computational Model Validation

As part of this research project, numerical modeling was conducted with the objective of seeing: 1) if state of the art computational fluid dynamics could reasonably predict heat absorption under different conditions; and 2) to better understand the heat transfer characteristics in the furnace under oxy-firing conditions.

B&W has leading edge capabilities for computational fluid dynamics (CFD) and combustion modeling. These capabilities were developed over the past 25 years and have culminated in the proprietary combustion model COMOSM. This model has been used routinely at B&W for more than a decade for improving the design and operation of boilers, boiler components, and combustion equipment. The CFD model uses an unstructured mesh with a mixture of element shapes for greater geometric flexibility, and adaptive mesh refinement to control resolution in regions of high gradients (e.g. turbulent jets, diffusion flames, etc.). COMO includes advanced capabilities for simulating turbulent flow, energy and radiation, heterogeneous reactions, particle transport, deposition, surface reactions, gas phase reactions, and tube banks. Physical models for coal combustion and emissions (CO and NO_x) are maintained and improved on a continuous basis.

Specialized capabilities for Cyclone combustors were developed for predicting coal particle deposition and combustion on Cyclone walls and furnace walls. Combustion reactions of coal deposits on these surfaces include coal drying, devolatilization, and char combustion/gasification which are an extension of coal particle combustion mechanisms to planar surfaces of porous char deposits. Combustion reactions are controlled by heterogeneous chemical kinetics and heat/mass

transfer with local gas species near the surface. The model assumes quasi-steady state conditions, in which fuel reacts wherever particles are deposited. Equations for mass and energy balances are solved at every surface element of the mesh where coal-ash deposition and reactions occur, and are included in the calculation of deposit surface temperature and wall heat absorption. Conduction heat transfer through the water-cooled metal wall, refractory, and slag layer is calculated using a thermal heat conductance which is specified as input for each wall boundary.

The primary limitation of the model for Cyclone combustion applications is that it does not predict molten slag flow, char transport, slag melting/solidification, or slag build-up on the walls. Therefore, the model does not consider these effects on local slag thickness and wall thermal conductance. Future development of coal combustion sub-models is planned (or proposed) to include these mechanisms with more extensive validation from bench- and pilot-scale combustion data.

The model was based on as-built furnace dimensions and insulation specifications. Figure 2.4 and Figure 2.7 presented in the Methods and Approach section show the furnace geometry used in this model. The oxygen lance in the cases modeled was in the secondary duct position intended to mix the oxygen before the Cyclone entrance, thus, in the model, the oxygen from the oxygen lance was premixed with the Cyclone secondary oxidant. The numerical model contained approximately 1,220,000 control volumes.

Pilot scale test data as given in this report for the subbituminous coal warm recycle testing was used to model three cases as shown in Table 3.18: air firing, oxy-firing with low levels of recycled flue gas, and oxy-firing with high levels of recycled flue gas. Case 3 has a secondary oxidant flow rate about 21% higher than that for Case 2, which leads to a shorter gas residence time in the furnace, potentially altering the heat transfer characteristics.

Model Case:	Case 1	Case 2	Case 3
Conditions:	Air Firing	Oxy-firing (Low RFG)	Oxy-firing (High RFG)
Test Name (see Tabulated Pilot-scale Test Data in the Appendix)	Warm Rec-PRB Air Test 2e	Warm Rec PRB Oxy 1	warm rec oxy prb 5

Table 3.18 List of pilot scale tests modeled with CFD

The thermal input and the Cyclone stoichiometry for the three cases were similar. The furnace stoichiometric ratio for the air-firing case was slightly higher than that for the oxy-firing conditions. The oxygen concentration in the primary and tertiary streams was approximately the same for all three cases, but that in the secondary stream was significantly higher for the oxy-firing conditions. Air infiltration is simulated using the nitrogen content of the oxidant streams calculated by the pilot scale data analysis system. For the oxy-firing conditions, the oxidant streams contained roughly 10% (by volume) nitrogen.

Thermal boundary conditions such as wall conductance and emissivity of the furnace walls, which represent a combination of insulation and ash deposits, were assumed to be the same for all the cases presented here. An adiabatic boundary condition was used for the wall insulated with firebricks shown in Figure 2.7. A uniform surface emissivity of 0.9 was used for the

Cyclone furnace and an emissivity of 0.6 was used for the SBS-II to account for ash deposition on the surfaces.

The model predictions of mass-averaged gas temperature, mass-averaged gas species concentrations, and heat absorption are shown in Table 3.19. Pilot scale test data are also shown for comparison.

In Table 3.19 the predicted gas temperatures at the Cyclone exit are shown first. During the testing, a FlameViewTM camera was used to measure the gas temperature at the Cyclone exit. For Case 2, a maximum gas temperature of 3200°F was observed, while the model predicts a maximum temperature of 3586°F and an average gas temperature of 3197°F. For Case 3, the measured maximum gas temperature is 3100°F, while the predicted maximum and average gas temperatures are 3318°F and 3047°F, respectively. For the air-firing case, no test data was reported. Case 2 is expected to have a higher maximum gas temperature due to a lower recycled flue gas flow rate and a higher oxygen concentration in the secondary oxidant stream.

The furnace exit gas temperature (FEGT) was sampled using a high velocity thermocouple (HVT). A probe was inserted into the furnace from the right-hand side wall, and gas temperature at five different locations was measured. An average of the measured gas temperatures, corrected for radiation heat loss from the thermocouple to surrounding surfaces (19) is reported in Table 3.19 and in Figure 3.64, in comparison with the model predictions. The predicted FEGT is in good agreement with the measured gas temperature for Cases 1 and 3. However, for Case 2, the disparity between the predicted and the measured FEGT is 106°F. Possible reasons for this disparity will be discussed shortly.

Table 3.19 also shows the predicted mass-averaged gas temperature at the convection pass exit in comparison with measurements. For Cases 1 and 3, the difference between the predicted gas temperature and the measurements is within 40°F. For Case 2, the difference is 79°F. Note that the predicted temperatures are mass-averaged values, while the measurements were made at a single point. Examination of the predicted gas temperature distribution at the convection pass exit for Case 2 indicates that the difference between the maximum and minimum gas temperatures is about 60°F. The non-uniform temperature distribution at the convection pass exit may partially contribute to the difference in gas temperature between the model predictions and test data.

Concentrations of gas species at the convection pass exit (the model exit) are compared in Table 3.19. For major gas species, the model predictions are generally in agreement with the measurements, indicating that the fuel to oxidant ratios used in the model are similar to the actual test conditions. For all the cases, the model predicts negligible CO emissions at the convection pass exit, while the measured CO concentrations were less than 30 ppm. Predicted gas species concentrations at the Cyclone exit are also reported in Table 3.19 for reference. CO concentrations at this location are 2% or higher for all three cases.

Predicted Furnace Effluents		Case 1		Case 2		Case 3	
		Test	COMO	Test	COMO	Test	COMO
Firing Mode		Air-Firing		Oxy-Firing: Low RFG		Oxy-Firing: High RFG	
Test Date		9/15/2009		9/17/2009		9/17/2009	
Test Start Time		8:44		12:45		18:02	
Gas Temperature							
Cyclone Exit	(°F)	-	3185	3200 (max)	3197	3100 (max)	3047
FEGT (corrected)	(°F)	2259	2253	2381	2275	2249	2251
Convection Pass Exit	(°F)	821	820	809	730	831	795
Gas Composition (Cyclone Exit)							
wet, vol.%	H ₂ O	-	14.12	-	34.79	-	35.54
	CO ₂	-	13.74	-	51.34	-	52.64
	O ₂	-	1.48	-	2.14	-	1.93
	N ₂	-	68.41	-	8.67	-	7.33
	CO	-	1.94	-	2.59	-	2.17
	H ₂	-	0.17	-	0.24	-	0.18
	minors	-	0.14	-	0.23	-	0.22
Gas Composition (Convection Pass Exit)							
dry, vol.%	CO ₂	15.52	15.37	79.03	82.21	81.22	83.60
	O ₂	3.98	4.00	4.25	3.99	4.66	4.66
dry, ppm	CO	23	0.00	28	0.00	27	0.00
Flue Gas Flow Rate	(lb/hr)	5922	5932	4869	4791	5477	5389
Heat Absorption							
Cyclone	(MBtu/hr)	0.45	0.44	0.64	0.45	0.49	0.43
Furnace	(MBtu/hr)	2.26	2.15	2.67	2.41	2.54	2.20
Convection Pass	(MBtu/hr)	1.76	2.22	1.69	2.13	1.84	2.28
Total Absorption	(MBtu/hr)	4.47	4.80	5.00	4.99	4.87	4.91
Total Available Energy*	(MBtu/hr)	4.83	4.83	4.84	4.99	4.83	4.91
Net Balance	(%)	7.49	0.54	-3.28	-0.05	-0.92	0.06
Carbon Exiting with Slag (% of Initial C)		-	0.17	-	0.02	-	0.03
Entrained Carbon Exiting Cyclone (% of Initial C)		-	3.31	-	2.70	-	2.48
Entrained Ash Exiting Cyclone (% of Initial Ash)		-	18.58	-	17.19	-	15.68
* Total available energy is based on inlet fuel and oxidant, outlet flue gas flow and slag flow leaving the system at their respective temperatures. Slag flow rate and temperature for test conditions were estimated assuming 80% of the fuel ash leaving the system as molten slag at ash fluid temperature under reducing conditions.							

Table 3.19 Summary of modeling predictions compared to available pilot-scale test data.

Figure 3.64 Comparison of FEGT between model predictions and measurements: air-fired baseline and two warm recycle cases

Also compared in Table 3.19 are predicted and measured heat absorption totals in the Cyclone, furnace, and convection pass. For the Cyclone, the model predictions are in good agreement with the measurements for both Case 1 and Case 3. For Case 2, the difference is about 30%. This disparity may be attributed to changes in the surface conditions, such as changes in ash deposition and slag flow. During the testing, build-up was observed in the slag tap of the Cyclone for Cases 1 and 3, with Case 3 having more slag accumulation on the Cyclone surfaces. For Case 2, the slag tap was clear with little slag accumulation on the Cyclone surfaces. As mentioned earlier, the same thermal conductance was used for the Cyclone walls in the model for all three cases. Since the model does not predict molten slag flow and slag build-up on the walls, it appears that different thermal conductance would be required for different cases to improve agreement, especially for Case 2 in which Cyclone wall surfaces were cleaner than the other two cases.

Figure 3.65 illustrates the predicted heat flux through the Cyclone walls for the three cases. The model predicts very similar heat flux distributions for the air-firing and oxy-firing cases. The maximum heat flux occurs on the Cyclone barrel wall adjacent to the neck of the Cyclone, and is similar in magnitude for all three cases. The heat flux to the neck is lower than that to the barrel of the Cyclone. Particle deposition rate predictions (Figure 3.66) for the three cases are also similar and indicate particle deposition occurs mostly on the neck of the Cyclone, while the particle deposition on the barrel surface is very small.

Figure 3.65 Predicted heat flux distribution on the Cyclone wall surfaces

Figure 3.66 Predicted particle deposition rates on the Cyclone wall surfaces

Figure 3.67 Predicted oxidation rate of deposited carbon on the Cyclone wall surfaces

Figure 3.68 Predicted gasification rate of deposited carbon on the Cyclone wall surfaces

The oxidation and gasification rates for the deposited carbon were also calculated (Figure 3.67 and Figure 3.68). Carbon oxidation rates are predicted higher on the barrel surface near the secondary inlet and on the neck around the scroll burner where oxygen concentration (Figure 3.69) is higher. At some regions of the neck where oxygen concentration is low and temperatures (Figure 3.70) are high carbon gasification rates are higher than carbon oxidation rates.

Figure 3.69 Predicted oxygen concentration profiles in the Cyclone

Figure 3.70 Predicted gas temperature profiles in the Cyclone

A comparison of predicted and measured heat absorption totals are shown in Figure 3.71 through Figure 3.73 for the Cyclone, furnace, and convection pass. The predictions for the furnace are in

reasonable agreement with the measurements for all the three cases. The model also correctly predicts the trend in the measured convection pass heat absorption for the three cases; however, the predictions are higher by 26% for Cases 1 and 2, and 24% for Case 3. The reason for this disparity is attributed to lack of closure in the energy balance in the measurements, with most of the measurement error in the convection pass, indicated in Table 3.19. Note that the predicted heat absorption is in excellent agreement with the available energy calculated from a simple balance for all the three cases, with a maximum error of 0.54%, while the test data has errors in the energy balance ranging from -3.28% to 7.49%.

Figure 3.71 Comparison of measured and predicted heat absorption in the Cyclone: air-fired baseline and two warm recycle cases

Comparing modeling results and measurements, the largest disparities are noted for Case 2. Predicted gas temperatures at the furnace exit and the convection pass exit are lower than measured, while predicted heat absorption in the Cyclone and the furnace is also consistently lower. In addition to the changes in the surface conditions as discussed above, another possible cause for this disparity is experimental error in the fuel flow rate and other operating conditions used as inputs to the model. It is expected that model predictions for Case 2 would be in better agreement with measurements if fuel and oxidant flow rates were all increased proportionally to match the FEGT.

Figure 3.72 Comparison of measured and predicted heat absorption in the furnace (including the first two tube banks of the convection pass): air-fired baseline and two warm recycle cases

Figure 3.73 Comparison of measured and predicted heat absorption in the convection pass: air-fired baseline and two warm recycle cases (excluding tube banks 1 and 2)

The final predictions presented in Table 3.19 are unburned carbon trapped in molten slag, and carbon and ash carryover from the Cyclone to the furnace. For all the cases, the unburned carbon in slag is very small: 0.17% for the air-firing case and less than 0.03% for the oxy-firing cases. The carbon carryover from the Cyclone is in the range of 2.5% to 3.3%, and the ash carryover is less than 20%; the remainder of the fuel ash deposits on the Cyclone wall as molten slag.

The computational model also allows an exploration of heat transfer characteristics to compare air and oxy-firing. Local gas properties are extracted from the modeling results for comparison, along a centerline path shown in Figure 3.74.

Figure 3.74 Path for extracting local gas properties in the Cyclone and SBS-II

Figure 3.75 presents the predicted local gas temperature as a function of the distance from the Cyclone tertiary inlet along the path shown in Figure 3.74. In this and similar figures the furnace is defined as the region from the Cyclone exit to the plane in the upper furnace/convection pass entrance that is the vertical extension of the furnace rear wall. The largest difference between air and oxy-firing appears in the region slightly below the OFA ports. The temperature profiles in Figure 3.76 suggest greater penetration of the OFA jets in the air-firing case, which is consistent with the higher mass flow in Case 1 (1170 lb/h) versus oxy-firing Cases 2 and 3 (612 and 725 lb/h respectively). With this difference excepted, the predicted gas temperature profiles are qualitatively similar for the three cases. As suggested by the measurements for Case 1 and Case 3 (Table 3.19), with the appropriate operating conditions the furnace exit gas temperature could be matched for air and oxy-firing. However, the predictions indicate that when FEGT is matched, convection pass exit temperature is not. To understand these differences the various parameters affecting heat transfer are examined.

Figure 3.75 Predicted local gas temperature along the path shown in Figure 3.74: air-fired baseline and two warm recycle cases

Figure 3.76 Predicted gas temperature profiles under air and two warm recycle oxy-firing conditions

The significant differences between the three modeled cases include flue gas flow rate, higher moisture and CO₂ concentrations in the oxy-firing cases, and the resulting changes to gas density, emissivity, and heat capacity.

The predicted local gas emissivity is reported in Figure 3.77. The sharp changes in the gas emissivity in the convection pass are due to the presence of the tube banks. The local gas emissivity increases roughly 65% when switching from air-firing to oxy-firing, which is consistent with data reported in the literature for small boilers or short beam lengths (20); (21); (22); (23). Gupta et al., 2006(21) calculated gas emissivity using a wide band model for air-firing and oxy-firing conditions for a range of radiation path lengths and found that the difference in gas emissivity for the air-firing and oxy-firing conditions could be 25% for larger boilers and 40% for smaller furnaces. When the beam length was in the order of 1 m, as in the current work, they found that gas emissivity could increase as much as 100% when changing from air-firing to oxy-firing. Andersson and Johnsson (23) also found that total gas emissivity increased about 20-30% in a range of gas temperature from 1300 to 2372°F when changing from air-firing to oxy-firing with an oxygen concentration of 27% (by volume). For comparison, gas emissivity increased 34% for earlier oxy-firing studies in the 30 MW_{th} Clean Environment Development Facility (CEDF) (24) and 22% for a commercial scale boiler (25) when switching from air-firing to oxy-firing conditions.

Figure 3.77 Predicted local gas emissivity along the path shown in Figure 3.74: air-fired baseline and two warm recycle cases

Predictions of local gas heat capacity are shown in Figure 3.78. The gas heat capacity under the oxy-firing conditions is approximately 10-20% higher than that under the air-firing conditions in the furnace, since water vapor and carbon dioxide concentrations are $2\frac{1}{2}$ and $3\frac{3}{4}$ times higher respectively for the oxy-firing conditions; and both gas species have a higher heat capacity than nitrogen which dominates under air-firing conditions. A higher heat capacity of the flue gas leads to a lower adiabatic flame temperature under the oxy-firing conditions when the oxygen concentration in the oxidant stream is similar. However, the total mass flow rate of the flue gas is about 10% lower for Case 3 under the oxy-firing conditions than that in Case 1, which increases the adiabatic flame temperature. Since the oxygen concentration in the secondary oxidant stream is higher in Case 3 than that in Case 1, the net effect is a higher adiabatic flame temperature for Case 3.

Figure 3.78 Predicted local gas heat capacity along the path shown in Figure 3.74: air-fired baseline and two warm recycle cases

The predictions of local gas density along the data extraction path are shown in Figure 3.79. The gas density for the oxy-firing cases is approximately 10-20% higher than in the air-firing case in the furnace, because of higher CO₂ concentrations. Since the total mass flow rate of the flue gas is lower under the oxy-firing conditions, the volumetric flow rate is roughly 20-25% lower, leading to an increase in gas residence time and a possible increase in heat transferred to the furnace walls.

The above modeling results are consistent with those found in two previous projects for comparison of heat transfer characteristics between air-firing and oxy-firing in a modeling study of a commercial scale utility boiler (25) and in a modeling and experimental study of a large pilot-scale test facility (24).

As mentioned earlier, Case 2 and Case 3 were modeled to examine the influence of changes in the flow rate of the recycled flue gas on the performance of the SBS-II. The flow rate of the Cyclone secondary stream for Case 3 was about 21% higher than that for Case 2. The other flow rates were similar.

As shown in Figure 3.77 through Figure 3.79, local emissivity, heat capacity, and density are similar for both oxy-firing cases. Since the oxygen concentration in the secondary oxidant stream is higher and the oxidant flow rate is lower in Case 2 than Case 3, the adiabatic flame temperature is expected to be higher for Case 2. As a result, the gas emissive power ($\epsilon\sigma T^4$) is higher in Case 2, leading to higher radiative heat transfer to the Cyclone and the furnace, as shown in Table 3.20. Note that in this table the convective heat transfer in the Cyclone and the furnace is very similar for both oxy-firing cases.

**Figure 3.79 Predicted local gas density along the path shown in Figure 3.74:
air-fired baseline and two warm recycle cases**

Despite a higher heat loss to the Cyclone and the furnace, both the test data and the model predictions Table 3.19 indicate that the FEGT is higher in Case 2 than that in Case 3. This is attributed to a higher adiabatic flame temperature in Case 2.

Heat Absorption		Case 1	Case 2	Case 3
Firing Mode		Air-Firing	Oxy-Firing: Low RFG	Oxy-Firing: High RFG
Test Date		9/15/2009	9/17/2009	9/17/2009
Test Start Time		8:44	12:45	18:02
Radiative Heat Transfer				
Cyclone	(MBtu/hr)	0.351	0.399	0.387
Furnace	(MBtu/hr)	1.459	1.835	1.623
Convection Pass	(MBtu/hr)	1.144	1.312	1.388
Convective Heat Transfer				
Cyclone	(MBtu/hr)	0.108	0.114	0.113
Furnace	(MBtu/hr)	0.705	0.585	0.584
Convection Pass	(MBtu/hr)	1.079	0.818	0.895
Deposit Absorption				
Cyclone	(MBtu/hr)	0.022	0.062	0.074
Furnace	(MBtu/hr)	0.019	0.008	0.008
Convection Pass	(MBtu/hr)	0.000	0.000	0.000

Table 3.20 Predictions of heat transfer divided into radiative, convective, and deposition process components: air-fired baseline and two warm recycle cases

In the convection pass, both the radiative heat transfer and the convective heat transfer are lower in Case 2, in comparison with Case 3. The total heat absorption in the convection pass in Case 2 is about 7% lower than that in Case 3. However, the flue gas flow rate in Case 2 is approximately 12% lower. Therefore, a higher temperature drop is expected in the flue gas for Case 2. Consistent with this conclusion, the predictions and test data exhibit a lower convection pass exit temperature in Case 2 than Case 3.

Finally, it is worthy of note that the sum of the radiative and convective heat transfer in Table 3.20 is different from the net heat absorption given in Table 3.19. The difference is due to heat absorption by the deposits on the walls, which is also summarized in Table 3.20. Deposit heat absorption includes the exchange of enthalpy by particle deposition, chemical reaction, slag removal, and mass transfer with the gas.

In summary,

- The model predicts that less than 0.2% of unburned carbon is trapped in molten slag in the Cyclone for both air-firing and oxy-firing conditions, and that the ash carryover from the Cyclone to the furnace is less than 20%.
- The predicted total heat absorption is in good agreement with the net thermal input. The predicted heat absorption for both the Cyclone and the furnace is in reasonable agreement with the test data. The model correctly predicts the trend in the measured heat absorption in the convection pass for different cases; however, the difference between the test data

and the model predictions is relatively large. The predicted furnace exit gas temperature compares favorably with the corresponding test data.

- Model predictions are generally in good agreement with pilot-scale measurements. The largest disparities occur in Case 2, which are probably due to the effect of Cyclone ash build-up on thermal boundary conditions, and possibly experimental uncertainty in the inputs to the model.
- Higher concentrations of H_2O and CO_2 in the flue gas under oxy-firing conditions lead to increases in the gas specific heat, gas density, and gas emissivity compared to air-firing conditions.
 - The increase in the specific heat tends towards lower adiabatic flame temperatures, but this may be offset by lower flow rates of recycled flue gas.
 - The increase in the gas density tends to increase gas residence time, and hence higher heat transfer to the furnace walls.
 - The increase in gas emissivity (ϵ) may be offset by a decrease in the adiabatic flame temperature (T). The net result is that similar gas emissive power ($\epsilon\sigma T^4$) and similar radiation heat transfer to the furnace walls may be maintained when changing from air to oxy-firing conditions.
 - The higher specific heat of the flue gas also reduces the impact of cooling on gas temperature under oxy-firing conditions.
- The furnace exit gas temperature and the furnace heat transfer can be similar when switching from air-firing to oxy-firing conditions. The flow rate of recycled flue gas can be used to adjust the adiabatic flame temperature if needed.

It is recommended that future testing should include measurements of gas temperature and composition at the Cyclone exit to provide further validation of the model. Slag carbon content should also be analyzed in future tests. Possible avenues for model improvement include development of detailed models to improve predictions of carbon conversion in char deposits, and to describe molten slag flow and slag build-up on Cyclone walls.

3.1.6. Wall-firing Pilot Scale Testing and Analysis

Previously, with DOE sponsorship B&W had performed oxy-combustion evaluation at 1.5 MW_{th} using PRB coal in a wall-fired configuration. This early development was performed between 2001 and 2004 in B&W's Small Boiler Simulator-I (SBS-I) and provided encouraging operational and performance data that led to further testing with various coal ranks and with a cyclone configuration. When approached by a commercial customer in 2005-2006, B&W decided to modify the existing 30 MW_{th} Clean Environment Development Facility (shown in Figure 3.80) to operate in full oxy-fired mode. In early October of 2007, the unit was operated in full oxy-fired mode; a world first at this scale. This section describes that work, which was funded by B&W, Air Liquide, and a consortium of electric utilities and is included here to support the engineering and economic evaluation discussion below.

Figure 3.80 B&W's 30 MW_{th} Clean Environment Development Facility

3.1.6.1. Facility Description

In 1993 the Clean Environment Development Facility (CEDF), funded by B&W, DOE, and the Ohio Coal Development Office, was started up. It was initially designed as a combustion facility for burner development with provisions for performing emissions control and air toxics testing. As such, the furnace and convection pass were specially designed to provide the same flue gas time-temperature profile as found in full scale utility boilers and a full complement of AQCS equipment was installed including ESP or baghouse and wet or dry scrubbers. In addition to development of several generations of low NO_x burners and SNCR, it was used in support of the U.S. DOE Combustion 2000 program, the "Advanced Emissions Control Development Program" (AECDP) as well as early mercury testing, and has produced excellent data. In 2005, in cooperation with AL, work began to modify the facility to test oxy-firing with flue gas recycle. In 2007-2008, three coals and two process configurations were tested and data gathered on all process equipment except air separation (vaporized liquid oxygen was used) and CO₂ compression and purification (the concentrated CO₂ flue gas was vented to atmosphere). The pulverizer was also operated using recycle flue gas and the burner direct fired with both sub-bituminous and lignite coals.

A process flow diagram for the facility in its current form showing both equipment and key measurement locations is provided in Figure 3.81. The blue components represent modifications to the original facility to permit full oxy-combustion operation and testing.

Figure 3.81 Clean Environment Development Facility process flow diagram

The facility was designed for a heat input of 100 MBtu/hr burning pulverized coals ranging from bituminous to North Dakota lignite to test essentially full-scale industrial or utility size burners. It was also designed to produce flue gas conditions and composition typical of a commercial plant in order to test pollutant removal equipment and evaluate air toxics and control methods.

Pulverized coal (PC) is supplied to the burner by an indirect or “bin feed” system so that a wide range of coal types, air-to-fuel ratios, fuel moistures, and PC size distributions can be independently controlled and studied. Raw coal with 2 inch top size can be dried, if necessary, and conveyed to a 50 ton raw coal storage silo. A gravimetric feeder meters the raw coal into a B&W EL-56 pulverizer (mill) equipped with a B&W dynamically staged, variable speed (DSVS[®]) classifier capable of online adjustment from 70% to 90% through 200 mesh.

Coal can be fed to the burner either directly or indirectly. For indirect feed, a dedicated constant speed pulverizer primary fan and direct natural gas-fired preheater provide the drying and conveying medium to the pulverizer that discharges into a baghouse. The pulverized coal is separated from the humid air and discharged into a 16 ton PC bin equipped with CO₂ inerting. A second gravimetric feeder meters the PC into a coal pipe that conveys it to the burner. The primary flow for conveying the coal to the burner is provided by a second variable speed burner primary fan and preheated by an indirect natural gas-fired heater. The fuel feed system can be converted to dry and convey the coal directly to the burner (direct feed). This is accomplished using the burner primary fan with its indirect fired preheater to provide flow to the pulverizer.

Instead of sending the dried pulverized coal to the PC bin, it is sent directly to the burner. Which fuel delivery approach is used is dictated by the test requirements and the fuel relative to the pulverizer capacity.

A variable speed secondary fan supplies secondary air to the windbox and overfire (OFA) ports and enables control of the primary-to-secondary air ratio. The secondary flow is preheated to about 500°F by a plate-type recuperative heater using flue gas after the convection pass. An indirect natural gas-fired heater downstream provides trim control of the temperature of the secondary flow to the windbox. Flow monitors are used to measure secondary flow.

The boiler and convection pass are specially designed to produce the same time-temperature profile as found in conventional utility scale units. The furnace is a refractory lined water jacketed enclosure, and the convection banks are double walled water cooled surfaces where the outer wall emulates tube metal typical temperatures. The steam generated is vented to atmosphere.

After the boiler, the flue gas enters a plate type secondary air heater followed by a cooler to reduce gas temperature leaving the convection pass from 700°F to approximately 350°F. The hot flue gas from the unit is used to preheat the secondary air to 500°F, and the cooler uses ambient air to control the final temperature to the inlet of the gas cleanup systems.

As Figure 3.81 shows, the flue gas can be directed through an idle electrostatic precipitator (CESP) to a 13.5 ft. diameter by 60 ft. tall full-flow spray dry absorber (SDA). SO₂ is removed using atomized hydrated lime slurry sprayed into the tower with a single B&W DuraJet™ atomizer. The dry scrubber is designed to comfortably meet the U.S. Environmental Protection Agency's (EPA) emission limit of 1.2 lb/MBtu continuously with a 3.5% sulfur coal. A six-module full-flow pulse-jet fabric filter follows the SDA to collect particulate before entering the ID fan.

An induced-draft (ID) fan with variable inlet vane controls furnace draft and balances pressure losses in the system, depending on the combination of full-flow and slip-stream equipment that is in operation. The flue gas exits the ID fan and flows through a full-flow wet scrubber. From the wet scrubber the flue gas flows to the stack in air firing mode or is split between recycle and the stack when in oxy mode. The stack is 200 feet tall and houses a continuous emissions monitoring system (CEMS) to monitor sulfur dioxide (SO₂), nitrogen oxides (NO_x) and opacity.

The system can be configured for wet scrubbing using the ESP with the SDA idle, and the very small amount of particulate leaving the ESP would be caught in the fabric filter. The fabric filter could also be used alone by leaving the ESP idle.

In addition to installing a new full-flow wet scrubber with patented integrated dehumidification, the key equipment added to provide oxy-combustion capability are an oxygen supply system, oxygen mixers, and the interconnecting flues. The oxygen supply and mixing system, provided by Air Liquide, vaporizes liquid oxygen (LOX) stored in large tanks. The oxygen distribution system (ODS) supplies the controlled flow of oxygen to the burner and oxygen flue gas mixers. The ODS also interfaces with the burner management system to ensure safe use of oxygen. Mixing of oxygen and flue gas is achieved by AL's Floxynator™ technology which mixes in the

center of the flue, safeguarding the walls from higher oxygen concentrations. Figure 3.82 shows the oxygen supply system.

Figure 3.82 Oxygen supply system

3.1.6.2. Test Description and Methods

The testing addressed the impact of oxy-firing and the full range of coals on coal preparation, combustion, precipitator and wet scrubber performance, and operation with different flue gas compositions. Testing included control concepts for transitioning from air-to-oxy and oxy-to-air firing, load changing, and major trips including Master Fuel Trip, and supported nearly full-scale testing of a new oxy-burner for PRB and lignite. These tests were in the configuration of ESP-WFGD. Testing with bituminous coal (indirect fired) focused on burner, ESP, Floxynators, and WFGD performance in the full oxy-mode compared to air-firing. In addition to gas composition, impact on SO₂ removal and sulfur trioxide (SO₃) formation were also measured. Subbituminous and lignite testing focused on performance of the new burner and the pulverizer in the direct-fired mode, and the ESP.

The objectives were to demonstrate for all three coals: optimum burner design for each coal, NO_x emissions, efficient oxygen mixing, pulverizer performance, furnace exit gas temperature (FEGT), boiler/convection pass heat transfer, ESP and WFGD performance, SO₂ removal, SO₃ formation, flue gas moisture control via B&W's novel concept, mercury speciation with oxy-

combustion, corrosion insights for materials development, and evaluate the impact of air infiltration.

3.1.6.3. Results

Test campaigns were successfully conducted for each of the three coals shown in Table 3.21. In addition to cold recycle, testing was conducted with the sub-bituminous coal to emulate the much higher moisture levels in the secondary recycle associated with the warm recycle design. The higher moisture did not adversely impact operation or significantly change the results from testing with cold recycle.

As-Received Coal Analyses			
	Bituminous Mahoning #7	Sub-Bituminous Black Thunder	Lignite SaskPower
Air Dry Loss Moisture (%)	0	2.56	3.85
Proximate Analysis (%)			
Moisture	3.34	28.03	32.92
Ash	7.48	4.17	8.09
Volatile Matter	37.02	31.83	28.31
Fixed Carbon	52.16	35.96	30.69
Ultimate Analysis (%)			
Carbon	76.28	49.97	41.85
Hydrogen	5.16	3.69	2.86
Nitrogen	1.58	0.55	0.3
Sulfur	1.52	0.25	0.34
Oxygen	4.64	13.33	13.65
Calorific Value, Btu/lb	13261	8815	7142

Table 3.21 Coals tested in the 30 MW_{th} CEDF

For both sub-bituminous and lignite coals, the unit was direct-fired and the higher density of the primary recycle gas permitted a reduction in the primary flow to coal flow ratio without impact on mill performance (Figure 3.83). In addition, the primary recycle dried and conveyed the coal over the load range without difficulty.

Figure 3.83 Comparison of air-fired and oxy-combustion primary flow to coal flow for the direct-fired fuels

Previous small pilot test results showing 50%-70% reduction in NO_x were also verified at larger scale as shown in Figure 3.84.

Figure 3.84 Reductions in NO_x in the CEDF switching from air-firing to oxy-combustion

For these tests the mass flow through the boiler was about the same for air and oxy firing. To evaluate heat transfer in the furnace, a water cooled tube panel with chordal thermocouples was installed. Although this data provided qualitative information, the CEDF's refractory furnace affected these results, so it is not quantitative or conclusive. Figure 3.85 shows that with normal air firing, heat fluxes in the test panel were as much as double those experienced with oxy firing and cold recycle. This difference is due to changes in gas density and emissivity resulting from higher CO₂ concentration, and the impact of moisture content on flame temperature.

Figure 3.85 Impact of oxy-firing on heat transfer in the CEDF

For the air firing curve, the flue gas moisture content began at about 13% by volume at the boiler outlet which is typical of an air fired unit burning sub bituminous coal. As indicated, steam injection into the secondary air stream was initiated, and as it was increased, heat fluxes decreased significantly. However, they remained much higher than with oxy firing due to the lower CO₂ concentration and gas density in air-firing relative to oxy-firing.

In the oxy firing mode flue gas moisture was around 25% by volume at the boiler outlet for the cold recycle tests. To simulate warm recycle, steam injection was initiated in the secondary recycle stream which increased the moisture content at the boiler outlet to about 33%. Interestingly, steam injection had little impact on heat fluxes, which is probably due to the already high moisture content.

During testing SO₂ was removed by a full flow limestone forced-oxidation wet scrubber. Test data showed that it performed as well in the oxy mode as when air firing. In fact there is some indication that removals were 5%-10% higher during oxy firing under the same conditions as shown in Figure 3.86.

Removal of moisture was accomplished by B&W's patented method of controlling the saturation temperature at the outlet of the wet scrubber. As Figure 3.87 shows, this method worked extremely well. Control of moisture from the scrubber does not affect SO₂ removal performance.

Figure 3.86 Effect of oxy-firing on SO₂ removal performance of the wet scrubber

Figure 3.87 Moisture removal

Limited SO_3 measurements were also taken during the bituminous campaign, but data indicated a doubling of SO_3 formation in the oxy mode when expressed on a heat input basis. The heat input basis removes the effect of nitrogen dilution with air firing, and allows an objective comparison. As stated earlier further investigations in SBS-II facility confirmed the CEDF results (see section 3.1.4.3). Higher SO_3 concentration raise the acid dew point temperature so care must be taken to either remove SO_3 or prevent condensation and resulting corrosion in any commercial system.

During these test campaigns the electrostatic precipitator was used to remove particulate. In general it performed similarly in either air or oxy-firing. However, during oxy-firing the field ESP voltage had to be slightly increased to achieve the same removal as Figure 3.88 illustrates. This is due to the higher concentrations of moisture and ash in the flue gas during oxy-combustion.

ESP Field 1 Voltage-Current Operating Characteristic with the PRB Coal

Figure 3.88 Effect of oxy-combustion on ESP operating characteristics

Air Liquide supplied the liquid oxygen system. Control and coordination of the oxygen splits and flows with the burner management system worked very well. For the addition of oxygen to recycled flue gas specially designed (by AL) oxygen mixers kept the higher oxygen concentrations in the center of the flues (away from the walls) and minimized the difference between the highest and lowest oxygen concentrations, as shown in Figure 3.89.

Figure 3.89 Oxygen mixing in the flue gas ducts

On-line mercury measurements were recorded during the lignite testing. As expected, the level of mercury oxidation with air firing was low, about 25%. As the unit transitioned from air to oxy-firing and the nitrogen was purged from the system, the mercury concentration increased accordingly. Data also indicated that the oxidation increased to about 30%. This indicates that mercury removal in the scrubbers with oxy-combustion will be no worse and perhaps better than air firing. In a commercial plant mercury is also removed in the CPU.

Air infiltration between the boiler and ID fan inlet can be an issue with oxy-combustion because it introduces unwanted nitrogen into the process. This additional nitrogen adds mass and volume flow, which results in increased ID fan and CPU power to fire the same amount of fuel and process the same amount of CO_2 . If it becomes excessive it can limit plant load. In addition, it reduces fuel efficiency because more fuel must be fired to heat the additional gas. The CEDF was originally designed for air firing, so air infiltration was high, in the worst case 11.5% (% of theoretical air) in spite of reasonable efforts to minimize it. The major sources were the ESP and fan inlets where the negative static pressure is high, and the inlet vane connection to the fan was not designed to be gas tight. Idle equipment in the flow path (dry scrubber and baghouse) also contributed. With proper design considerations, a commercial plant should be able to maintain no more than 5% air infiltration. As Figure 3.90 shows this will produce CO_2 concentrations

between 80% and 85%, high enough to minimize impact on fans and for efficient operation of the CPU.

Figure 3.90 ASPEN simulation results of the effect of air infiltration on flue gas CO₂ concentration

Figure 3.91 Operational data for transition between air and oxy-firing

Control of the transition from air to oxy and back was experienced many times. In Figure 3.91 the left chart shows how the secondary air flow is decreased and the secondary recycle is increased until the secondary air is completely replaced by oxygenated recycle. The same process is used for the primary flow until there is no air entering the process and the unit is in full oxy mode. The center portion of the figure shows how the CO₂ concentration increases, and the right chart shows the transition from oxy back to air firing. Though most transitions took about 40 minutes due to test conditions, and maintaining manual control of the process. The process could be easily automated and would take less than a half hour for a commercial plant. During

our four test campaigns, all of the major trips and upsets that would be experienced in a commercial plant, including master fuel trips and pulverizer trips, were experienced and safely managed.

3.2. Phase II, Part A – Engineering and Economic Evaluation

3.2.1. Background

With climate change legislation and carbon dioxide regulation under serious consideration, the need to address CO₂ emission from existing power plants while maintaining the ability to use the most abundant and lowest cost domestic energy resource, coal, for electricity production is economically essential. Carbon Capture and Storage (CCS) is being developed to meet that need. Three technologies are at the demonstration stage, Integrated Gasification Combined Cycle (IGCC), post-combustion capture (PCC), and oxy-combustion capture (OCC).

Recent studies by the US Department of Energy (DOE) and others have shown that oxy-combustion has the potential to be the greenfield option with the highest efficiency at the lowest cost of electricity (2). IGCC cannot be retrofit to existing plants, nor is it suitable for repowering high pressure steam cycles. Thus retrofit and repowering of existing pulverized coal fired plants will be with either OCC or PCC.

Early confidential studies to retrofit small existing units in the 100-300 MWe range showed OCC to be an expensive retrofit⁵ so a general impression prevailed that OCC was not a suitable retrofit technology. Simultaneously those developing post combustion capture (PCC) were touting lower costs, partial capture, and ease of retrofit so PCC seemed more suitable for retrofit application. However, a recent reevaluation indicates that small units typically have no primary SO₂ removal and very tight site conditions requiring the Air Separation Unit (ASU) and Compression and Purification Unit (CPU) to be located a significant distance from the boiler. These and other factors such as high air infiltration due to non-membrane enclosed designs and/or age drove up cost.

More detailed evaluations of PCC retrofit requirements and cost by DOE and others has shown it not to be as simple and inexpensive as initially projected. In fact, the current requirement for a primary SO₂ removal device, SO₂ polishing, moisture reduction, and space for the CPU are essentially identical between OCC and PCC. Therefore, the economic advantages of PCC for retrofit compared to OCC perceived earlier are not valid. Also, OCC needs about the same amount of space for the ASU as PCC needs for the absorption and regeneration equipment. So basic site requirements for both are about the same but PCC has the disadvantage of needing a significant amount of low pressure steam. This steam would be provided by either major changes to the low pressure steam turbine or the addition of an auxiliary boiler.

⁵ Due to confidentiality these studies cannot be referenced, but the results that led to the conclusion were that due to site constraints, lack of an existing scrubber, and the economy of scale small unit retrofits are much more costly on a \$/kW basis than large scale retrofits, especially if at the large scale there is an existing scrubber and space at the site to efficiently arrange the ASU and CPU.

PCC may still have a partial capture advantage due to lower capital cost but that is not clear. Depending upon legislation and the owner's system, partial capture on an individual unit itself may not be beneficial. Oxy-combustion can be operated in a manner that provides partial capture but at a higher capital cost. This is accomplished by operating in oxy-combustion mode to achieve the desired amount of CO₂ capture and air firing the remainder of the time. If this scenario is coordinated with peak and off-peak periods so operation in the oxy-combustion mode is during off-peak periods when the price of electricity is low and air fired during peak periods when the selling price is high, revenue is maximized (these techniques are being patented by Air Liquide). Some capital can also be saved by under sizing the ASU and CPU for the lower loads desired during off-peak hours when generation is not as valuable. If advantageous, a smaller ASU with liquid oxygen (LOX) storage could be run during air firing to store oxygen for the off-peak oxy firing periods if economically attractive compared to the lost generation to run the ASU during peak operation. If full capture is desired at a later date, additional ASU and CPU modules could be installed.

Many think that partial capture may not be desirable for a single unit. In addition, power prices are low in off-peak periods, sometimes even negative so minimizing net output during those periods may be desirable. To accommodate the load profile while operating in oxy mode, a swing plant design could be adopted. This approach with oxy-combustion may not be available with the other CCS options. In the swing mode the ASU sizing is matched to the load profile for the plant so that the net power to the grid is maximized during peak periods and minimized during off-peak periods. When in the oxy-combustion mode during peak periods, the ASU output is supplemented from a LOX storage tank to achieve full output and the CPU is in operation. When operating during off-peak periods the ASU operates at a level necessary to make and store oxygen for the next peak period and the boiler generates sufficient power to supply the house load with little or no power to the grid. The CPU operates with the boiler output. If the load profile changes, additional ASU capacity can be added to ensure maximum net output during peak periods.

No direct comparison of this method against PCC has been made. If partial capture is a permanent solution at a site, PCC may have a lower capital cost advantage. But studies by DOE and others have shown that as capture decreases, the cost of CO₂ removed and avoided increase compared to 90% capture. If full capture is in the longer term plan, oxy-combustion is expected to have an advantage overall. A comprehensive analysis (outside the scope of this project) is required to determine the magnitude of the advantage of oxy-combustion.

As a result, interest in the potential for oxy-combustion for retrofit application is renewed and this study was undertaken to evaluate that potential.

3.2.2. Performance Basis

The basis for the performance analysis of the various Base and Sensitivity Cases is explained in the following sections at three levels; the plant, the power block, and the ASU and CPU. The plant basis addresses site conditions and assumptions concerning the existing balance of plant equipment (not including the steam cycle). The power block defines the existing boiler, air quality control system, and steam cycle equipment. The design basis for the ASU and CPU is also described.

3.2.2.1. Plant Basis

A gross plant output of 650 MWe was selected as the basis for this study for all cases except Case 10, which is identical to Case 5 except that the gross output is 780 MWe to assess the impact of scale. Cases were evaluated for three coals; an Illinois #6 bituminous, Decker subbituminous, and North Dakota lignite, whose properties are given in Table 3.22. The bituminous coal and its properties were selected to allow direct comparison of the results of this study with the results from DOE's "Carbon Dioxide Capture from Existing Coal-Fired Power Plant" study DOE/NETL-401-110907, "Cost and Performance Baseline for Fossil Energy Plants" DOE/NETL-2007/1281, and "Pulverized Coal Oxy-combustion Power Plants" DOE/NETL-2007/1291 revised August 2008. These are references (26),(27), and (2) respectively in this report. As will be discussed in more detail later, financial assumptions and cost estimating timeframe were also selected to match these studies to allow direct comparison of results.

The retrofit site conditions are assumed to be reasonably favorable for retrofit, similar to those existing at the American Electric Power (AEP) Conesville site which was the basis for DOE/NETL-401/110907 Post Combustion Capture (PCC) study. It was assumed that the plant was at or near sea level for ambient conditions including barometric pressure, and wet and dry bulb temperatures. It is also assumed that sufficient space for the ASU and CPU is available at a reasonable distance from the power block.

	Lignite ND Lignite		Sub-bituminous (PRB) Decker		Bituminous Illinois #6	
item	Wt% dry	Wt% wet	Wt% dry	Wt% wet	Wt% dry	Wt% wet
H ₂ O		33.30		23.40		11.12
C	63.3	42.22	72.00	55.15	71.73	63.75
H ₂	4.5	3.00	5.00	3.83	5.06	4.50
O ₂	19	12.67	16.41	12.57	7.74	6.88
S	1.1	0.73	0.44	0.34	3.04	2.70
N ₂	1	0.68	0.95	0.73	1.41	1.25
Ash	11.1	7.40	5.20	3.98	11.02	9.80
TOTAL	100	100	100	100	100	100
HHV	10630	7090	12450	9540	13126	11666

Table 3.22 Coal properties

3.2.2.2. Power Block Basis

As shown in Table 3.23, twelve (12) base retrofit (Retro) cases, and five (5) greenfield (GF) cases were evaluated. Base Cases 1-3 assume the existing plant has a subcritical 2535 psig, 1000°F main, 1000°F reheat steam cycle yielding a pre-retrofit net plant efficiency of 35% to match the AEP Conesville Unit 5 basis in DOE/NETL-401/110907. Retrofit Cases 4-10 employ a 3500 psig supercritical steam cycle based on the DOE/NETL-1291 Case 5 study with 1110°F main and 1150°F reheat steam temperatures. Greenfield Cases 11-14 employ advanced USC conditions of 4000 psi, 1350°F, 1400°F, also to match the DOE/NETL-1291 Case 6 study and compare to the DOE/NETL-1291 air fired base Case 2 for cost of CO₂ removed and avoided.

Case	Steam Cycle	Recycle Process	Size MWe Gross	Site	Fuel	Firing	Primary SO ₂ / Part	Polishing SO ₂ + H ₂ O	ASU	CPU or Comp
1	SubC	Cool	650	Retro	Illinois #6	PC	FF/WFGD	Pri + CPU	ASU-C	CPU -C
1A	SubC	Cool	650	Retro	Illinois #6	PC	FF/WFGD	Pri + CPU	ASU-F	CPU -F
2	SubC	Cool	650	Retro	Decker	PC	SDA/FF	Pri + CPU	ASU-C	CPU -C
3	SubC	Cool	650	Retro	ND Lignite	PC	SDA/FF	Pri + CPU	ASU-C	CPU -C
4	SC	Cool	650	Retro	Illinois #6	PC	FF/WFGD	Pri + CPU	ASU-C	CPU -C
5	SC	Cool	650	Retro	Decker	PC	SDA/FF	Pri + CPU	ASU-C	CPU -C
5A	SC	Cool	650	Retro	Decker	PC	SDA/FF	Pri + CPU	ASU-F	CPU -F
6	SC	Cool	650	Retro	ND Lignite	PC	SDA/FF	Pri + CPU	ASU-C	CPU -C
7	SC	Cool	650	Retro	Decker	CYC	FF/no FGD	CPU	ASU-C	CPU -C
8	SC	Cool	650	Retro	Decker	CYC	FF/no FGD	CPU	ASU-C	Comp-C
9	SC	Cool	650	Retro	Decker	PC	FF/no SDA	Pri + CPU	ASU-C	CPU -C
10	SC	Cool	780	Retro	Decker	PC	SDA/FF	Pri + CPU	ASU-C	CPU -C
11	USC	Warm	650	GF	Illinois #6	PC	SI, FF/WFGD	Pri + CPU	ASU-F	CPU -F
12	USC	Warm	650	GF	Decker	PC	SDA/FF	Pri + CPU	ASU-C	CPU -C
13	USC	Warm	650	GF	Decker	CYC	SDA/FF	Pri + CPU	ASU-F	CPU -F
13A	USC	Warm	650	GF	Decker	CYC	FF/no SDA	CPU (H ₂ O)	ASU-F	CPU -F
14	USC	Warm	650	GF	Decker	PC	SDA/FF	Pri + CPU	ASU-F	CPU -F

Existing for retrofit
New for Greenfield

-C = Current Improvements
-F = Future Improvements
Comp = Compression only

Table 3.23 Definition of base cases

A summary of the base cases and associated Gas Quality Control System (GQCS) equipment and CPU assumptions are shown in Table 3.23. For all retrofit cases it is assumed that the base plant already has an existing Air Quality Control System (AQCS) including particulate and primary SO₂ removal equipment. In all retrofit cases, full, cool recycle was assumed (see Figure 3.92 and Figure 3.93). In other words, the recycle mass flow approximately matches the mass flow for air firing so that no heat transfer surfaces need be changed in the existing boiler and all of the recycle is treated by the primary GQCS before being returned to the boiler as primary or secondary recycle. For most cases (as indicated in Table 3.23) both the primary recycle and the flow to the CPU are also polished in a sodium-bicarbonate based direct contact cooler with integrated direct sulfur polishing (DCCPS, aka sodium scrubber/quench cooler or polishing scrubber) to about 1 ppmv SO₂ (in the table this is referred to as “Pri + CPU”). The temperature is also reduced to 100°F to limit moisture.

ASPEN was employed to model the process and provide the gas composition from the power block to the CPU. The base cases were modeled assuming an air infiltration, defined as a percentage of wet theoretical air, of 2% in the boiler and an additional 3% between the boiler outlet and the Induced Draft (ID) fan inlet. The result of the ASPEN modeling for these conditions is given in Table 3.24. For Case 11, 12, 13, and 14 reduced air infiltration was assumed for the ultra-supercritical with warm flue gas recycle producing the gas compositions shown in Table 3.25 and for Case 13A the composition in Table 3.25 was modified to assume no SO₂ removal resulting in the composition shown in Table 3.26.

Figure 3.92 Cool recycle process configuration for bituminous retrofit cases

All base cases assume 95% oxidant purity with a composition as shown in Table 3.27. For all cases it was also assumed that the boiler would be operated to maintain 3% excess oxygen at the boiler outlet (dry basis).

For the processes shown in Figure 3.92 and Figure 3.93, the existing primary GQCS equipment was assumed to be fabric filter (FF) with a limestone wet scrubber (WFGD) for bituminous coal cases and a hydrated lime spray dryer absorber (SDA) followed by a fabric filter for subbituminous and lignite cases. For cases with a WFGD, limestone with 80.4% CaCO_3 and 98% SO_2 removal were assumed. For cases with a SDA, pebble lime with 90% available CaO and 95% SO_2 removal were assumed. An SO_2 removal of 99.8% was assumed in bicarbonate based DCCPS taking the SO_2 concentration in the gas to the CPU down to 1 ppmv⁶ and quench-cooled to 100°F saturated.

⁶ The reasons for 1 ppmv at the outlet of the DCCPS are a) to precondition the gas for Air Liquide's CPU design to avoid corrosion in CPU components, and b) to minimize sulfur in the primary stream which acts to dilute the SO_2 in the boiler to levels manageable in regard to corrosion especially with high sulfur coals. Depending on the CPU design and sulfur level in the coal, lower removals may be tolerable.

Figure 3.93 Cool recycle processes for PRB and North Dakota Lignite retrofit cases

Figure 3.94 Warm recycle for process configuration for bituminous greenfield case

Figure 3.95 Warm recycle for PRB and North Dakota Lignite for greenfield PC Cases 12 and 14

Figure 3.96 Warm recycle for PRB and North Dakota Lignite for greenfield Cyclone Cases 13 and 13A

	ND Lignite					Decker					Illinois #6					
Component	Wet		Dry			Wet		Dry			Wet		Dry			
	Mol %	Wt. %	Mol %	Wt. %		Mol %	Wt. %	Mol %	Wt. %		Mol %	Wt. %	Mol %	Wt. %		
H2O	6.55	3.01	0.00	0.00		6.55	3.02	0.00	0.00		6.55	3.02	0.00	0.00		
N2	16.42	11.75	17.57	12.12		16.56	11.86	17.72	12.23		17.19	12.35	18.40	12.73		
O2	3.27	2.67	3.49	2.75		3.40	2.78	3.64	2.87		3.52	2.89	3.76	2.98		
NO (ppm)	600.80	461.02	642.88	475.34		476.37	385.51	509.74	397.50		316.07	243.19	338.20	250.78		
SO2 (ppm)	1.23	2.01	1.31	2.07		1.22	2.00	1.31	2.07		1.26	2.07	1.35	2.13		
CO (ppm)	70.23	50.16	75.15	51.72		50.05	37.81	53.56	38.99		123.84	88.95	132.52	91.73		
CO2	70.44	79.19	75.38	81.65		70.23	79.02	75.14	81.47		69.46	78.39	74.32	80.83		
AR	3.26	3.32	3.49	3.43		3.21	3.28	3.44	3.38		3.24	3.32	3.47	3.43		
Oxidant Flow (lb/klb coal)					1318.68						1748.64					
CPU Flow (lb/klb coal)					1964.59						2562.02					
	2% Boiler Infiltration 3% Boiler Outlet O2 (dry) 3% Back End Infiltration 95% Oxidant Purity from ASU Based on H2O @ Tsat=100F and ≈1 ppmv SO2															

Table 3.24 Gas composition to the CPU for each coal for retrofit cases

Component	Illinois #6				Decker			
	Wet		Dry		Wet		Dry	
	Mol %	Wt. %	Mol %	Wt. %	Mol %	Wt. %	Mol %	Wt. %
H ₂ O	6.55	2.93	0.00	0.00	6.55	2.92	0.00	0.00
N ₂	9.12	6.34	9.76	6.54	8.68	6.02	9.29	6.20
O ₂	3.56	2.83	3.81	2.91	3.30	2.62	3.53	2.70
NO (ppm)	256.82	191.35	274.81	197.12	413.27	307.15	442.22	316.39
SO ₂ (ppm)	1.35	2.14	1.44	2.21	1.35	2.15	1.45	2.21
CO (ppm)	104.64	72.78	111.98	74.98	47.95	33.27	51.31	34.27
CO ₂	77.18	84.34	82.58	86.89	77.90	84.92	83.36	87.48
AR	3.56	3.53	3.81	3.64	3.52	3.48	3.77	3.59
Oxidant Flow (lb/klb coal)				2181.19	1791.61			
CPU Flow (lb/klb coal)				2806.47	2383.60			
0% Boiler Infiltration 3% Boiler Outlet O ₂ (dry)					0% Boiler Infiltration 3% Boiler Outlet O ₂ (dry)			
2% Back End Infiltration					2% Back End Infiltration			
95% ASU Oxidant Purity					95% ASU Oxidant Purity			

Table 3.25 Gas composition to the CPU for Cases 11, 12, 13 and 14

Component	Decker			
	Wet		Dry	
	Mol %	Wt. %	Mol %	Wt. %
H ₂ O	6.55	2.92	0.00	0.00
N ₂	8.68	6.02	9.29	6.20
O ₂	3.30	2.62	3.53	2.69
NO (ppm)	414.00	307.00	443.01	316.23
SO ₂ (ppm)	1712.00	2715.00	1831.96	2796.65
CO (ppm)	48.00	33.00	51.36	33.99
CO ₂	77.73	84.66	83.17	87.21
AR	3.52	3.48	3.77	3.58
Oxidant Flow (lb/klb coal)				1791.61
CPU Flow (lb/klb coal)				2386.32
0% Boiler Infiltration 3% Boiler Outlet O ₂ (dry)				
2% Back End Infiltration				
95% ASU Oxidant Purity				

Table 3.26 Gas composition to the CPU for Case 13A

Fuel (boiler) efficiency was adjusted based on fuel characteristics. For the pulverized coal (PC) cases firing Illinois #6 bituminous coal, 88.12% was used for fuel (boiler) efficiency which is based on DOE/NETL's study of AEP Conesville Unit #5 in DOE/NETL-401/110907 and in the "Pulverized Coal Oxy-combustion Power Plants" DOE/NETL-2007/1291 revised August 2008 report. For the subbituminous Decker coal, a 2% reduction in fuel efficiency from bituminous was assumed yielding 86.12%. For North Dakota Lignite, a 4% reduction in fuel efficiency from bituminous was assumed yielding 84.12%.

The Cyclone boiler cases all fired subbituminous Decker coal and due to the lower excess oxygen and other minor differences, the fuel efficiency was reduced by 1.82% from bituminous instead of the 2% for PC firing yielding 86.3%. This slight improvement is based on internal studies by B&W showing slightly less reduction in fuel efficiency between bituminous and Decker coal for Cyclone firing compared to PC firing.

ASU Oxygen Concentration				
	95%	90%	85%	80%
Composition (molar)				
N ₂	1.70%	6.80%	12.00%	17.10%
Ar	3.30%	3.20%	3.00%	2.90%
O ₂	95.00%	90.00%	85.00%	80.00%
Composition (mass)				
N ₂	1.50%	6.00%	10.50%	15.20%
Ar	4.00%	3.90%	3.80%	3.70%
O ₂	94.40%	90.10%	85.60%	81.10%

Table 3.27 Oxidant composition

Base plant auxiliary power was based on an assumption of 6.4% of gross power for the base plant PC cases which was derived from the AEP Conesville Unit #5 PCC study in DOE/NETL-401/110907 study using a fuel efficiency of 88.12% and net plant efficiency before retrofit of 35%. This resulted in a turbine cycle (gross) heat rate of 8040 Btu/kWh which was used for all retrofit cases with subcritical steam conditions.

The base plant auxiliary power was adjusted based on B&W data to compensate for WFGD, SDA, or no FGD. Auxiliary power for the ASU and CPU were provided by Air Liquide and added. Additional power was also added for the DCCPS and its associated wet cooling tower and for additional cooling capacity for the ASU and CPU compressors. No benefit from heat integration was assumed for retrofit cases, though a benefit is possible in reality depending upon the existing equipment. This would increase electricity generation without additional fuel input resulting in an increase in plant performance without significant added cost.

Using this turbine cycle heat rate, fuel efficiency, and the total auxiliary power, the heat rate and net plant efficiency under oxy-combustion conditions was calculated. The fuel flow was unchanged from the base air-fired plant and the oxidant requirement was calculated based on oxidant purity and theoretical oxygen required (fuel dependent) assuming 99.9% combustion efficiency and 3% excess oxygen at the boiler outlet. The total flue gas flow to the CPU was determined by calculating the CO₂ produced from the fuel flow and composition divided by the mass percentage of CO₂ wet from the ASPEN base calculation of the gas composition (see Table 3.24). These flows and compositions were provided to Air Liquide for each case to determine the ASU and CPU auxiliary power and CAPEX. Since the boiler heat input does not change with auxiliary power this information could be determined directly.

Cases 1A and 5A are identical to Cases 1 and 5 respectively except the A cases use ASU and CPU power and CAPEX based on future technological improvements. The five (5) greenfield base Cases 11-14 (see Figure 3.94 thru Figure 3.96) were also evaluated for comparison of performance and cost with each other and with studies done by DOE. The bituminous Case 11 was also compared with the results of the aforementioned DOE studies which were done on the same performance and financial basis.

For the USC greenfield cases an additional gross generation of 5% of the base gross power (650 MWe) was added to account for steam turbine advancements, deep integration of heat from

the ASU, gas coolers, and gas reheaters reducing extraction steam for feedwater heating, and by other power recovery methods within the processes. This value is based on an internal integration study by B&W and Air Liquide completed in 2008. Case 13A is identical to Case 13 except it has no primary scrubber and only moisture is removed in the stream to the CPU so the CPU accepts the full sulfur loading.

3.2.2.3. ASU and CPU Basis

3.2.2.3.1. *ASU Basis*

Air Liquide has a long history in developing Air Separation Units (ASUs) based on cryogenic distillation of air gases. A traditional ASU typically produces 99%+ purity oxygen. The most efficient ASUs today consume about 200kWh/tm of oxygen produced. In recent years, Air Liquide has optimized this ASU specifically for oxy-combustion to further reduce the energy requirement of this unit (see Figure 3.97). This section provides details of the Air Liquide approach.

ASU for oxy-combustion and specific energy

The oxy-combustion process does not require nitrogen. Also, internal Air Liquide-B&W studies have shown that there is no real benefit to supplying very high purity oxygen to an oxy-combustion boiler (the next section provides details). Air Liquide has modified the ASU design, taking into consideration the factors mentioned above to decrease the cost of oxygen production. An optimized ASU for oxy-combustion producing 95% purity oxygen can be offered today at less than 160 kWh/tm including heat integration. Heat integration means that heat from compression is utilized by transferring the heat energy to streams within the power block and steam cycle.

Figure 3.97 3D model of ASU for oxy-combustion

Oxygen Purity

The specific energy of oxygen separation from air by cryogenic distillation increases with increase in the purity requirement of the oxygen product. In particular, beyond 95% oxygen purity the separation energy requirement increases exponentially (Figure 3.98). As a result, the energy requirement of the ASU increases.

Figure 3.98 Specific energy consumption of ASU as a function of product oxygen purity

Higher purity oxygen though decreases the size of the flue gas stream to the CPU hence decreasing the capital cost of the CPU. From Figure 3.99, the reduction in flue gas volume leads to a marginal decrease in overall capital cost of the ASU and CPU. However, from Figure 3.100, the additional power requirement to produce high purity oxygen beyond 96.5% purity more than compensates for the reduction in power requirement of the CPU due to processing of smaller flow rates of flue gas.

The increase in power consumption beyond 96.5% in Figure 3.100 is more abrupt than in Figure 3.98 because Figure 3.98 shows the theoretical energy change for additional purification while Figure 3.100 shows the power consumption of an actual unit wherein an additional distillation column is required to separate argon (the main contaminant remaining in the oxygen stream) from oxygen.

Figure 3.99 Capital cost of ASU and CPU as a function of product oxygen purity

Figure 3.100 Power consumption of ASU and CPU as a function of product oxygen purity

Between 95% and 96.5%, there is negligible change in overall costs and power requirements. Therefore, for this study, 95% oxygen purity was assumed for all standard cases. 95% purity oxygen has a balance of 3.3% argon and 1.7% nitrogen.

3.2.2.3.2. CPU Basis

The goal of the CO₂ Compression and Purification unit is to process flue gas from the power block and recover 90% of the CO₂ at a composition suitable for sequestration. A typical CO₂ CPU scheme, as shown in Figure 3.101, consists of the following steps:

- Treatment for SO_x reduction to 1 ppmv (if required) and dust removal to levels acceptable by compressors
- Compression of wet flue gas
- Drying of the flue gas at the outlet of the “wet compression” step
- Flue gas purification
- Compression of the dry product gas to a pressure at which it condenses at 20°C
- Pumping of the condensed product to pipeline pressure

Figure 3.101 Schematic diagram of a typical CO₂ CPU scheme

The specifications for a “sequestration-ready” stream are not clearly defined today, except for the particular case of CO₂ for enhanced oil recovery applications. In that case too, there is no specification on SO_x and NO_x in the gas stream. To understand the influence of the level of purification on overall cost, two extreme cases were considered:

1) Compression only (Case 8) –The flue gas, after treatment to reduce SO_x to 1 ppm and reduce dust loading, is compressed and dried to the required water specifications. The gas is further compressed and then cooled down to the desired product temperature. This process can lead to 100% CO₂ recovery.

2) Partial condensation and distillation (all other cases) - This case involves the following purification operations after the wet compression step:

- Water scrubbing of compressed flue gas to simultaneously cool it down and remove some impurities (typically NO₂)
- Drying using a classical TSA (Temperature Swing Adsorption) process as commonly used in ASUs
- Mercury removal in a single adsorption bed
- Cryogenic purification using a multi-step partial condensation and distillation process to recover 90% of the CO₂ in the flue gas. A different extent of CO₂ recovery might be a more economical option but was not considered in this study

The main advantage of adding a distillation column is the increase in product purity. Without a distillation column, the oxygen content in the CO₂ product remains close to 1% (molar) or higher. As nitrogen, argon, carbon monoxide, and NO are removed with O₂ in the distillation column, CO₂ product purity is increased to nearly 100%. In terms of energy requirements adding

the distillation column is a small increment that is second order of magnitude (i. e. the energy consumption of the CPU is increased by 3% to 4%).

CPU Performance

For the CPU, the additional assumptions shown in Table 3.28 have been taken into account. As previously mentioned, all cases assume 90% of the CO₂ is captured. In order to achieve this, the compressor outlet pressure is chosen appropriately. The lower the CO₂ concentration in the flue gas, the higher the pressure required and the higher the specific energy consumption.

Cooling water temperature in (°C)	15
Cooling water temperature out (°C)	25
Inlet pressure after SO _x removal (bar)	1.01325

Table 3.28 CPU design assumptions

All retrofit cases have similar CO₂ concentrations. For all retrofit cases the energy requirement of the CPU is the same: 138 kWh/tm of CO₂ captured. When the CO₂ concentration is reduced or increased (infiltration or oxygen purity changed), specific energy consumption of the CPU changes accordingly. Table 3.29 shows all CO₂ concentrations assumed and associated specific energy:

CO ₂ concentration (% mol, dry basis)	Specific energy of CPU (kWh/tm)	Specific energy of 2020 CPU (kWh/tm)
83.36	120	108
75.00	138	124
71.06	141	127
70.40	143	129
67.10	148	133
63.16	155	140

Table 3.29 Assumed CO₂ concentrations and associated specific energy

Utility Consumption

The primary utility consumption of the CPU is electricity. The main secondary utilities are cooling water and steam. These can be considered proportional to the amount of CO₂ produced. Table 3.30 summarizes secondary utility consumption:

Cooling water (tm/tm of CO ₂ captured)	23.2
HP Steam (sat @ 148 psig) (lbs/tm of CO ₂ captured)	9.26
MP Steam (sat @ 60 psig) (lbs/tm of CO ₂ captured)	3.7
LP Steam (sat @ 19 psig) (lbs/tm of CO ₂ captured)	34.5

Table 3.30 Secondary utility consumptions

Future CPU

The CPU described in the previous paragraph corresponds to current CPU technology which can be offered at commercial scale today. Air Liquide is actively working to improve this scheme in terms of capital and operating costs. Improvements are expected in process optimization, rotating

equipment performance improvement and cost reduction. The so-called future cases (Cases 1A, 11, 13, 13A, 14) include such expected improvements.

The Future cases assume a plant built after 2020. By then the following modification are expected in the CPU which will decrease energy consumption:

- Compressor efficiencies (Ramgen compressors for example)
- Expansion turbines efficiencies
- Pressure drop optimization
- Refrigeration cycle improvement

As a result of these efficiency improvements, specific energy is expected to decrease by 10%. Greenfield cases are also considered to have low air infiltration (83.36% CO₂ (dry molar basis) for Decker coal in Table 3.25), specific energy in these cases will be 108 kWh/tm of CO₂.

3.2.2.4. Sensitivity Studies

Two sensitivity studies were undertaken with four (4) cases each; 1) an evaluation of the impact of air infiltration and 2) an assessment of the impact of oxidant purity on performance and cost. For both studies, Case 5 was chosen as the basis. Case 5 is retrofit of a 650 MW gross supercritical boiler burning subbituminous Decker coal with a spray dryer absorber (SDA) followed by a fabric filter as the existing primary GQCS and having a direct contact cooler with integral polishing scrubber (DCCPS) treating the primary recycle and CPU streams along with current ASU and CPU technology. It should be noted that the greatest impact is on the ASU and CPU CAPEX and power with negligible impact on the power block.

3.2.2.4.1. *Air Infiltration Study*

It is believed that air infiltration will be higher for retrofit applications and, whether retrofit or greenfield, it is likely to increase as the unit ages. Air infiltration introduces additional nitrogen and additional mass into the process which has a minor impact on NO_x but much more importantly must be handled by the ID fan and CPU. This increases power consumption and capital cost since both have to be sized to accommodate an upper limit on air infiltration. Since air infiltration also introduces some oxygen, the ASU demand will slightly decrease if the boiler is operated at the same outlet oxygen level. This means that the ASU can be sized for the lower air infiltration of a tight unit knowing that as air infiltration increases over time, the ASU output will reduce by the amount of additional oxygen gained from air infiltration and ASU power consumption will decrease slightly. Evaluation of the net impact of these factors is the intent of the air infiltration cases.

The impact of air infiltration on performance and cost was evaluated in Cases AI-1 to AI-4 based on retrofit Case 5. Air infiltration flow is based on a percentage of wet theoretical air flow. Air infiltration is either intentionally introduced as a cooling or sealing medium or unintentionally introduced through equipment leakage in areas in the process that operate below atmospheric pressure. Examples of intentional air infiltration are scanner or instrument cooling air, pulverizer seal air, and fabric filter back pulsing air. These sources can be greatly reduced by using clean dry CO₂ instead of air. Unintentional sources can be incomplete welds in equipment and flues, and poor sealing of openings and access doors where the internal operating pressure is sub-

atmospheric. By using CO₂ for cooling, sealing, and back pulsing, air infiltration can be maintained at relatively low levels.

Component	Case AI-1				Case AI-2				Case AI-3				Case AI-4			
	Wet		Dry		Wet		Dry		Wet		Dry		Wet		Dry	
	Mol %	Wt. %	Mol %	Wt. %	Mol %	Wt. %	Mol %	Wt. %	Mol %	Wt. %	Mol %	Wt. %	Mol %	Wt. %	Mol %	Wt. %
H ₂ O	6.54	3.15	0.00	0.00	6.55	3.02	0.00	0.00	6.55	2.96	0.00	0.00	6.55	2.92	0.00	0.00
N ₂	26.52	19.84	28.38	20.49	16.56	11.86	17.72	12.23	11.47	8.05	12.28	8.30	8.68	6.02	9.29	6.20
O ₂	4.17	3.56	4.46	3.68	3.40	2.78	3.64	2.87	3.47	2.78	3.71	2.87	3.30	2.62	3.53	2.70
NO (ppm)	610.90	489.58	653.68	505.49	476.37	385.51	509.74	397.50	463.25	348.29	495.71	358.90	413.27	307.15	442.22	316.39
SO ₂ (ppm)	1.09	1.86	1.16	1.92	1.22	2.00	1.31	2.07	1.31	2.11	1.40	2.17	1.35	2.15	1.45	2.21
CO (ppm)	46.16	34.53	49.39	35.66	50.05	37.81	53.56	38.99	46.16	32.40	49.39	33.38	47.95	33.27	51.31	34.27
CO ₂	59.89	70.39	64.08	72.68	70.23	79.02	75.14	81.47	75.05	82.76	80.31	85.28	77.90	84.92	83.36	87.48
AR	2.82	3.01	3.01	3.10	3.21	3.28	3.44	3.38	3.41	3.41	3.65	3.52	3.52	3.48	3.77	3.59
Oxidant Flow (lb/klb coal)	1695.11				1748.64				1780.25				1791.61			
CPU Flow (lb/klb coal)	2877.00				2562.02				2446.60				2383.60			
Assumptions	Coal: Decker 3% Boiler Outlet O ₂ (dry) 2% Boiler Infiltration 8% Back End Infiltration 95% ASU Oxidant Purity				Coal: Decker 3% Boiler Outlet O ₂ (dry) 2% Boiler Infiltration 3% Back End Infiltration 95% ASU Oxidant Purity				Coal: Decker 3% Boiler Outlet O ₂ (dry) 0% Boiler Infiltration 3% Back End Infiltration 95% ASU Oxidant Purity				Coal: Decker 3% Boiler Outlet O ₂ (dry) 0% Boiler Infiltration 2% Back End Infiltration 95% ASU Oxidant Purity			

Table 3.31 Gas composition to the CPU for air infiltration cases

Case AI-1 assumes 2% air infiltration in the boiler and 8% between the boiler outlet and ID fan inlet. Case AI-2 assumes 2% and 3% respectively (the base case assumption), Case AI-3 assumes 0% and 3% respectively and Case AI-4 assumed 0% and 2%. In all of these cases, boiler outlet excess oxygen was held to 3% dry. Again, ASPEN was used to determine the gas composition to the CPU and the results are shown in Table 3.31.

3.2.2.4.2. Oxidant Purity Study

Although several studies have been made to identify the optimum oxidant purity, some questions remain. To confirm the widely accepted conclusion that 95% oxidant purity is optimum, Case 5 was again evaluated using the four purities and compositions shown in Table 3.27, the 95% being the same as the base Case 5 analysis. The resulting gas compositions are shown in Table 3.32. The impact of oxidant purity on the capital cost and power consumption for the ASU and CPU is discussed above in Section 3.2.2.3.1 (under the heading "Oxygen Purity"). Based on those parameters alone, which are believed to govern the outcome, a maximum purity of about 96.5% O₂ is economical. At that point, due largely to the great difference in flows handled by the ASU compared to the CPU, the cost and power consumption for the ASU outweighs any savings in the CPU.

It is also clear that the ASU and CPU contribute the largest portion of the incremental cost and power consumption by far. The analysis in this sensitivity study attempts to account for all impacts at the plant level rather than just the two components to assess potential benefits of reducing oxidant purity from the current 95% to as low as 80% oxygen.

Component	ASU O ₂ Purity: 95%				ASU O ₂ Purity: 90%				ASU O ₂ Purity: 85%				ASU O ₂ Purity: 80%			
	Wet		Dry		Wet		Dry		Wet		Dry		Wet		Dry	
	Mol %	Wt. %	Mol %	Wt. %	Mol %	Wt. %	Mol %	Wt. %	Mol %	Wt. %	Mol %	Wt. %	Mol %	Wt. %	Mol %	Wt. %
H ₂ O	6.55	3.02	0.00	0.00	6.55	3.06	0.00	0.00	6.59	3.13	0.00	0.00	6.54	3.16	0.00	0.00
N ₂	16.56	11.86	17.72	12.23	20.41	14.85	21.84	15.32	24.35	18.01	26.06	18.60	28.20	21.19	30.17	21.89
O ₂	3.40	2.78	3.64	2.87	3.47	2.88	3.71	2.97	3.41	2.89	3.66	2.98	3.37	2.89	3.60	2.99
NO (ppm)	476.37	385.51	509.74	397.50	602.32	469.54	644.51	484.38	665.03	527.01	711.94	544.06	720.02	579.70	770.45	598.63
SO ₂ (ppm)	1.22	2.00	1.31	2.07	1.19	1.97	1.27	2.03	1.13	1.92	1.21	1.98	1.07	1.84	1.15	1.90
CO (ppm)	50.05	37.81	53.56	38.99	49.56	36.06	53.03	37.20	46.59	34.47	49.88	35.58	43.86	32.96	46.93	34.04
CO ₂	70.23	79.02	75.14	81.47	66.41	75.93	71.06	78.33	62.68	72.85	67.10	75.21	59.03	69.70	63.16	71.98
AR	3.21	3.28	3.44	3.38	3.10	3.22	3.32	3.32	2.90	3.06	3.10	3.16	2.79	2.99	2.99	3.09
Oxidant Flow (lb/klb coal)	1748.64				1848.87				1956.09				2077.01			
CPU Flow (lb/klb coal)	2562.02				2666.74				2779.45				2905.28			
	2% Boiler Infiltration 3% Boiler Outlet O ₂ (dry) 3% Back End Infiltration 95% ASU Oxidant Purity				2% Boiler Infiltration 3% Boiler Outlet O ₂ (dry) 3% Back End Infiltration 90% ASU Oxidant Purity				2% Boiler Infiltration 3% Boiler Outlet O ₂ (dry) 3% Back End Infiltration 85% ASU Oxidant Purity				2% Boiler Infiltration 3% Boiler Outlet O ₂ (dry) 3% Back End Infiltration 80% ASU Oxidant Purity			

Table 3.32 Gas composition to the CPU for oxidant purity cases

3.2.3. Financial Basis

In order to permit direct comparison of the results of this study with DOE's "Carbon Dioxide Capture from Existing Coal-Fired Power Plant" study DOE/NETL-401-110907, "Cost and Performance Baseline for Fossil Energy Plants" DOE/NETL-2007/1281, and "Pulverized Coal Oxy-combustion Power Plants" DOE/NETL-2007/1291 revised August 2008, the same financial conditions were assumed. The basis for calculating levelized cost of electricity (LCOE) is identical to that used in the DOE/NETL-2007/1291 study and the financial assumptions and methodology for determining the Capital Charge and Levelization factors are explained in detail in Section 2.9 of the Final Report for that study. All estimates are in January 2007 dollars and the assumptions for determining the levelization factors are shown in Table 3.33. The financial structure for the High Risk scenario was selected and is shown in Table 3.34. The resulting Capital Charge factor used for calculating LCOE is 0.175 and the levelization factor for fixed and variable O&M is 1.16 and 1.20 was used for fuel as shown in Table 3.35.

The cost of transport and storage of CO₂ is also estimated using the same basis as the DOE/NETL-2007/1291 study assuming 50 miles of pipeline, wells, and 100 years of monitoring costs. This resulted in 0.26 ¢/kW for transport, 0.04 ¢/kW for wells and 0.10 ¢/kW for storage costs. The cost of these contributions for a given Case was determined by converting these levelized costs backward to a CAPEX using the net kW for each Case. It was assumed that these do not change due to fuel.

LCOE for all retrofit cases includes makeup power to achieve the same net output as the base air fired plant in the form of variable O&M cost. The rate used for the incremental power is the levelized rate from the DOE/NETL 401/11/0907 "Carbon Dioxide Capture from Existing Coal-Fired Power Plants (rev. Nov.2007) report of 6.4 ¢/kW. The LCOE reported for all retrofit cases is based on incremental LCOE meaning it assumed the plant is fully depreciated and there is no

capital remaining and no costs associated with the base plant operation are included in the O&M costs. Although this does not produce an LCOE comparable to a greenfield unit, it is consistent with previous DOE studies. When retrofit cases are compared to greenfield cases, such as shown in Figure 3.109, the base plant O&M costs are included.

Parameter	Value
Income Tax Rate	38% effective (34% Federal, 6% State less 1% Property and 1% insurance)
Repayment Term of Debt	15 years
Grace Period on Debt Repayment	0 years
Debt Reserve Fund	None
Depreciation	20 years, 150% declining balance
Working Capital	zero for all parameters
Plant Economic Life	30 years
Investment Tax Credit	0%
Tax Holiday	0 years
Start-up Costs (% of EPC)	2%
All other additional capital costs (\$)	0
EPC escalation	0%
Duration of Construction	3 years

Table 3.33 Parameter assumptions for capital charge factors

Type of Security	% of Total	Current (nominal) Dollar Cost	Weighted Current (nominal) Cost	After Tax Weighted Cost of Capital
Debt	45	11%	4.95%	3.07%
Equity	55	12%	6.6%	6.6%
Total			11.55%	9.67%

Table 3.34 Financial structure for investor owned utility high risk projects

	Factor
Capital Charge Factor	0.175
Coal Levelization Factor	1.2022
General O&M Levelization Factor	1.1618

Table 3.35 Economic parameters for LCOE calculation high risk projects

The costs of CO₂ removed (captured) and avoided (mitigated) are calculated in the same manner as given in DOE/NETL-401/110907 meaning that the LCOE is incremental and does not include the cost of operation and maintenance or fuel costs for the base plant being retrofit.

3.2.4. Cost Basis

3.2.4.1. Power Block and BOP Basis

All equipment contributing costs to the retrofit or the greenfield cases were either factored from the DOE Case 5 (SC) or Case 6 (USC) base costs from the DOE/NETL-2007/1291 Revised study, generated for the B&W-AL Integration Study, or developed in support of this effort. The

basis for the detailed costs including explanation of the factoring applied to correct for plant size, fuel type and GQCS configuration are provided in Table 3.36 for the retrofit cases and Table 3.37 and Table 3.38 for the greenfield cases. The resulting costs are shown in Table 3.40 and Table 3.41.

Account	D&E Cost Basis	Case Correction Factor	Project Contingency
1.0 COAL & SORBENT HANDLING	Existing		
2.0 COAL & SORBENT PREP & FEED	Existing		
3.0 FEEDWATER & MISC BOP SYSTEMS	Existing		
4.0 PC BOILER & ACCESSORIES			
4.1 Boiler	B&W estimated modifications; burners, fans, airheater	(DOE Case 5 fuel η /Case fuel η) ^{0.6}	10.0%
4.2 ASU/Oxidant Compression	Air Liquide Estimate for each case	none	10.0%
5.0 FLUE GAS CLEANUP			
5.1 Absorber Vessels & Accessories	Existing		10.0%
5.2 Other FGD	Existing		10.0%
5.3 Baghouse & Accessories	Existing		10.0%
5.4 Other Particulate Removal Materials	Existing		10.0%
5.5 Gypsum Dewatering System	Existing		10.0%
5.6 Mercury Removal System	Existing		10.0%
5.7 Sodium Scrubber/Quench Cooler (DCCPS)	B&W estimate	(Case flue gas flow/DOE Case 5 flow) ^{0.5}	10.0%
5.8 Trona Injection System	B&W estimate	(Case sulfur flow/DOE Case 5 sulfur flow) ^{0.6}	10.0%
5.0B CO₂ REMOVAL & COMPRESSION			
5B.1 CO ₂ Removal System	combined with 5B.2		15.0%
5B.2 Compression & Drying	Air Liquide Estimate for each case	none	20.0%
6.0 COMBUSTION TURBINE/ACCESSORIES	Not Applicable		
7.0 HR, DUCTING & STACK			
7.1 Flue Gas Recycle Heat Exchanger	B&W estimate	(Case MWeg/DOE Case 5 MWeg) ^{0.6}	15.0%
7.2 SCR System	Existing		20.0%
7.3 Ductwork	B&W estimate		15.0%
7.4 Stack	Existing		10.0%
7.9 Duct & Stack Foundations	B&W estimate		20.0%
8.0 STEAM TURBINE GENERATOR	Existing		
9.0 COOLING WATER SYSTEM			
9.1 Cooling Towers	DOE Case 5 *(New heat duty/DOE Case 5 Heat Duty)		10.0%
9.2 Circulating Water Pumps	same as 9.1		10.0%
9.3 Circ. Water System Auxiliaries	same as 9.1		10.0%
9.4 Circ. Water Piping	same as 9.1		15.0%
9.5 Make-up Water System	Existing		15.0%
9.6 Component Cooling Water Sys	Existing		15.0%
9.9 Circ. Water System Foundations	same as 9.1		20.0%
10.0 ASH/SPENT SORBENT HANDLING SYS	Existing		
11.0 ACCESSORY ELECTRIC PLANT			
11.1 Generator Equipment	Existing		7.5%
11.2 Station Service Equipment	Existing		7.5%
11.3 Switchgear & Motor Control	Existing		10.0%
11.4 Conduit & Cable Tray	Existing		15.0%
11.5 Wire & Cable	50% of DOE Case 5	Case oxidant flow/DOE Case 5 oxidant flow) ^{0.5}	15.0%
11.6 Protective Equipment	Existing		10.0%
11.7 Standby Equipment	Existing		10.0%
11.8 Main Power Transformers	80% of DOE Case 5	(Case MWeg/DOE Case 5 MWeg) ^{0.6}	10.0%
11.9 Electrical Foundations	80% of DOE Case 5	(Case MWeg/DOE Case 5 MWeg) ^{0.6}	20.0%
12.0 INSTRUMENTATION & CONTROLS			
12.1 PC Control Equipment	Existing		10.0%
12.2 Combustion Turbine Control	Existing		10.0%
12.3 Steam Turbine Control	Existing		10.0%
12.4 Other Major Component Control	Existing		10.0%
12.5 Signal Processing Equipment	Existing		10.0%
12.6 Control Boards, Panels & Racks	50% of DOE Case 5	none	15.0%
12.7 Computer & Accessories	50% of DOE Case 5	none	10.0%
12.8 Instrument Wiring & Tubing	50% of DOE Case 5	none	15.0%
12.9 Other I & C Equipment	50% of DOE Case 5	none	10.0%
13.0 IMPROVEMENTS TO SITE			
13.1 Site Preparation	50% of DOE Case 5	(MWeg/DOE Case 5 MWeg) ^{0.6}	20.0%
13.2 Site Improvements	50% of DOE Case 5	(MWeg/DOE Case 5 MWeg) ^{0.6}	20.0%
13.3 Site Facilities	Existing		20.0%
14.0 BUILDINGS & STRUCTURES	Existing		
15.0 TRANSPORTATION, STORAGE & MONITORING			
15.1 Transport	DOE Case 5 LCOE converted to dollars	none	
15.2 Storage Wells	same as 15.1	Case Carbon flow/DOE Case 5 Carbon flow)	
15.3 Monitoring	same as 15.1	none	

NOTE: DOE Case 5 refers to Case 5 in the DOE study "Pulverized Coal Oxycombustion Power Plants" DOE/NETL-2007/1291 revised August 2008

Table 3.36 Detailed cost basis for retrofit cases

	Account	D&E Cost Basis	Case Correction Factor	Project Contingency	Comments
1.0 COAL & SORBENT HANDLING					
	1.1 Coal Receive & Unload	DOE Case 6	(Case coal flow/DOE Case	15.0%	DOE Case 6 coal flow = 488097 lb/h
	1.2 Coal Stackout & Reclaim	DOE Case 6	Same as 1.1	15.0%	Same as 1.1
	1.3 Coal Conveyors & Yard Breaker	DOE Case 6	Same as 1.1	15.0%	Same as 1.1
	1.4 Other Coal Handling	DOE Case 6	Same as 1.1	15.0%	Same as 1.1
	1.5 Sorbent Receive & Unload	DOE Case 6	(Case sulfur flow/DOE	15.0%	DOE Case 6 sulfur flow =
	1.6 Sorbent stackout & Reclaim	DOE Case 6	Same as 1.5	15.0%	Same as 1.5
	1.7 Sorbent Conveyors	DOE Case 6	Same as 1.5	15.0%	Same as 1.5
	1.8 Other Sorbent Handling	DOE Case 6	Same as 1.5	15.0%	Same as 1.5
	1.9 Coal & Sorbent Hnd. Foundations	DOE Case 6	Same as 1.1	15.0%	Same as 1.1
2.0 COAL & SORBENT PREP & FEED					
	2.1 Coal Crushing & Drying	DOE Case 6	(Case coal flow/DOE Case	15.0%	DOE Case 6 coal flow = 488097 lb/h
	2.2 Coal Conveyor to Storage	DOE Case 6	Same as 2.1	15.0%	Same as 2.1
	2.3 Coal Injection System	Not Applicable		15.0%	
	2.4 Misc. Coal Prep Equipment	Not Applicable		15.0%	
	2.5 Sorbent Prep Equipment	DOE Case 6	(Case sulfur flow/DOE Case 6 sulfur flow)*0.6	15.0%	DOE Case 6 sulfur flow = 488097*0.0251 lb/h
	2.6 Sorbent Storage & Feed	DOE Case 6	Same as 2.5	15.0%	Same as 2.5
	2.7 Sorbent Injection System	Not Applicable		15.0%	
	2.8 Booster Air Supply System	Not Applicable		15.0%	
	2.9 Coal & sorbent Feed Foundation	DOE Case 6	Same as 2.1	15.0%	Same as 2.1
3.0 FEEDWATER & MISC BOP SYSTEMS					
	3.1 Feedwater System	DOE Case 6	(Case MWeg/DOE Case 6	15.0%	DOE Case 6 MWeg = 759200 lb/h
	3.2 Water Makeup & Pretreating	DOE Case 6	Same as 3.1	20.0%	Same as 3.1
	3.3 Other Feedwater Subsystems	DOE Case 6	Same as 3.1	15.0%	Same as 3.1
	3.4 Service Water Systems	DOE Case 6	Same as 3.1	20.0%	Same as 3.1
	3.5 Other Boiler Plant Systems	DOE Case 6	Same as 3.1	15.0%	Same as 3.1
	3.6 FO Supply Sys & Net Gas	DOE Case 6	Same as 3.1	15.0%	Same as 3.1
	3.7 Waste Treatment Equipment	DOE Case 6	Same as 3.1	20.0%	Same as 3.1
	3.9 Misc. Power Plant Equipment	DOE Case 6	Same as 3.1	20.0%	Same as 3.1
4.0 PC BOILER & ACCESSORIES					
	4.1 Boiler	DOE Case 6	((Case HR/DOE Case 6 HR)*(MWeg/DOE Case 6	10.0%	DOE Case 6 HR = 10353 Btu/kWh, MWeg = 759200
	4.2 ASU/Oxidant Compression	Air Liquide Estimate	none	10.0%	
5.0 FLUE GAS CLEANUP					
	5.1 Absorber Vessels & Accessories	B&W Integration Study	(Case coal flow/B&W Integration Study coal	10.0%	B&W Integration Study Coal Flow = 744646 lb/h
	5.2 Other FGD	B&W Integration	Same as 5.1	10.0%	Same as 5.1
	5.3 Baghouse & Accessories	B&W Integration	Same as 5.1	10.0%	Same as 5.1
	5.4 Other Particulate Removal Materials	DOE Case 6	none	10.0%	
	5.5 Gypsum Dewatering System	incl in 5.1		10.0%	
	5.6 Mercury Removal System	incl in 5.1		10.0%	
	5.7 Sodium Scrubber/Quench Cooler (DCCPS)	B&W estimate	(Case flue gas flow/DOE Case 5 sulfur flow)*0.6	10.0%	DOE Case 5 flue gas flow = 2992988
	5.8 Trona Injection System	B&W estimate	Case 5 sulfur flow)*0.6	10.0%	549470*0.0251
5.0B CO2 REMOVAL & COMPRESSION					
	5B.1 CO2 Removal System	combined with 5B.2		15.0%	
	5B.2 Compression & Drying	Air Liquide Estimate	none	20.0%	
6.0 COMBUSTION TURBINE/ACCESSORIES		Not Applicable			
7.0 HR, DUCTING & STACK					
	7.1 Flue Gas Recycle Heat Exchanger	DOE Case 6	((Case HR/DOE Case 6 HR)*(MWeg/DOE Case 6	15.0%	DOE Case 6 HR = 10353 Btu/kWh, MWeg = 759200
	7.2 SCR System	Not Applicable		20.0%	
	7.3 Ductwork	DOE Case 6	Same as 7.1	15.0%	Same as 7.1
	7.4 Stack	DOE Case 6	Same as 7.1	10.0%	Same as 7.1
	7.9 Duct & Stack Foundations	DOE Case 6	Same as 7.1	20.0%	Same as 7.1
8.0 STEAM TURBINE GENERATOR					
	8.1 Steam TG & Accessories	DOE Case 6	((Case HR/DOE Case 6 HR)*(MWeg/DOE Case 6	10.0%	DOE Case 6 HR = 10353 Btu/kWh, MWeg = 759200
	8.2 Turbine Plant Auxiliaries	DOE Case 6	Same as 8.1	10.0%	Same as 8.1
	8.3 Condenser & Auxiliaries	DOE Case 6	Same as 8.1	10.0%	Same as 8.1
	8.4 Steam Piping	DOE Case 6	Same as 8.1	15.0%	Same as 8.1
	8.9 TG Foundations	DOE Case 6	Same as 8.1	20.0%	Same as 8.1
9.0 COOLING WATER SYSTEM					
	9.1 Cooling Towers	DCCPS/Case 6 condenser duty)	HR)*(MWeg/DOE Case 6 Mweg))*0.6	10.0%	MWeg = 759200, Case 6 Condenser duty = 2408 MBtu/h
	9.2 Circulating Water Pumps	Same as 9.1	Same as 9.1	10.0%	Same as 9.1
	9.3 Circ. Water System Auxiliaries	Same as 9.1	Same as 9.1	10.0%	Same as 9.1
	9.4 Circ. Water Piping	DOE Case 6	Same as 9.1	15.0%	Same as 9.1
	9.5 Make-up Water System	Same as 9.1	Same as 9.1	15.0%	Same as 9.1
	9.6 Component Cooling Water Sys	DOE Case 6	Same as 9.1	15.0%	Same as 9.1
	9.9 Circ. Water System Foundations	DOE Case 6	Same as 9.1	20.0%	Same as 9.1

Table 3.37 Detailed cost basis for greenfield cases

	Account	D&E Cost Basis	Case Correction Factor	Project Contingency	Comments
	10.0 ASH/SPENT SORBENT HANDLING SYS				
	10.1 Ash Coolers	Not Applicable			
	10.2 Cyclone Ash Letdown	Not Applicable			
	10.3 HGPU Ash Letdown	Not Applicable			
	10.4 High Temperature Ash Piping	Not Applicable			
	10.5 Other Ash Recovery Equipment	Not Applicable			
	10.6 Ash Storage Silos	DOE Case 6	(Case ash flow/DOE Case		DOE Case 6 ash flow = 488097*0.097
	10.7 Ash Transport & Feed Equipment	DOE Case 6	Same as 10.6		Same as 10.6
	10.8 Misc. Ash Handling Equipment	DOE Case 6			
	10.9 Ash/Spent Sorbent Foundations	DOE Case 6	Same as 10.6		Same as 10.6
	11.0 ACCESSORY ELECTRIC PLANT				
	11.1 Generator Equipment	DOE Case 6	((Case HR/DOE Case 6 HR)*(MWeg/DOE Case 6	7.5%	DOE Case 6 HR = 10353 Btu/kWh, MWeg = 759200
	11.2 Station Service Equipment	DOE Case 6	Same as 11.1	7.5%	Same as 11.1
	11.3 Switchgear & Motor Control	DOE Case 6	Same as 11.1	10.0%	Same as 11.1
	11.4 Conduit & Cable Tray	DOE Case 6	Same as 11.1	15.0%	Same as 11.1
	11.5 Wire & Cable	DOE Case 6	Same as 11.1	15.0%	Same as 11.1
	11.6 Protective Equipment	DOE Case 6	Same as 11.1	10.0%	Same as 11.1
	11.7 Standby Equipment	DOE Case 6	Same as 11.1	10.0%	Same as 11.1
	11.8 Main Power Transformers	DOE Case 6	Same as 11.1	10.0%	Same as 11.1
	11.9 Electrical Foundations	DOE Case 6	Same as 11.1	20.0%	Same as 11.1
	12.0 INSTRUMENTATION & CONTROLS				
	12.1 PC Control Equipment	w/12.7		10.0%	
	12.2 Combustion Turbine Control	Not Applicable		10.0%	
	12.3 Steam Turbine Control	w/8.1		10.0%	
	12.4 Other Major Component Control	0		10.0%	
	12.5 Signal Processing Equipment	w/12.7		10.0%	
	12.6 Control Boards, Panels & Racks	DOE Case 6	none	15.0%	
	12.7 Computer & Accessories	DOE Case 6	none	10.0%	
	12.8 Instrument Wiring & Tubing	DOE Case 6	none	15.0%	
	12.9 Other I & C Equipment	DOE Case 6	none	10.0%	
	13.0 IMPROVEMENTS TO SITE				
	13.1 Site Preparation	DOE Case 6	none	20.0%	DOE Case 5 Mweg = 785900
	13.2 Site Improvements	DOE Case 6	none	20.0%	DOE Case 5 Mweg = 785900
	13.3 Site Facilities	DOE Case 6	none	20.0%	
	14.0 BUILDINGS & STRUCTURES				
	14.1 Boiler Building	DOE Case 6	(Case coal flow/DOE Case	15.0%	DOE Case 6 coal flow = 488097 lb/h
	14.2 Turbine Building	DOE Case 6	(Case MWeg/DOE Case 6	15.0%	DOE Case 6 MWeg = 759200 lb/h
	14.3 Administration Building	DOE Case 6	none	15.0%	
	14.4 Circulation Water Pumphouse	DOE Case 6	Same as 14.2	15.0%	Same as 14.2
	14.5 Water Treatment Buildings	DOE Case 6	Same as 14.2	15.0%	Same as 14.2
	14.6 Machine Shop	DOE Case 6	none	15.0%	
	14.7 Warehouse	DOE Case 6	none	15.0%	
	14.8 Other Building s & Structures	DOE Case 6	none	15.0%	
	14.9 Waste Treating Building & Str.	DOE Case 6	Same as 14.2	15.0%	Same as 14.2
	15.0 TRANSPORTATION, STORAGE & MONITORING				
	15.1 Transport	DOE Case 5 LCOE converted to dollars	none		
	15.2 Storage Wells	same as 15.1	Case Carbon flow/DOE Case 5 Carbon flow)		DOE Case 5 CO2 = 549470*0.6375 lb/h
	15.3 Monitoring	same as 15.1	none		

NOTE: DOE Case 6 refers to Case 6 in the DOE study "Pulverized Coal Oxycombustion Power Plants" DOE/NETL-2007/1291 revised August 2008
DOE Case 5 refers to Case 5 in the DOE study "Pulverized Coal Oxycombustion Power Plants" DOE/NETL-2007/1291 revised August 2008

Table 3.38 Detailed cost basis for greenfield cases

3.2.4.2. ASU and CPU Basis

3.2.4.2.1. ASU Cost Basis

Present Cases

The ASU was based on Air Liquide's ASU design for oxy-combustion applications as described in Section 3.2.2.3.1. The equipment and installation costs were estimated assuming installation in the US Gulf Coast region. Detailed cost calculations were performed for a single ASU train with a nominal supply capacity of 3,700 tm/day of oxygen. If the oxidant requirement was slightly different, the ASU cost was scaled based on the required oxidant flow rate to the 0.65 power, based on Air Liquide's prior experience with costs of such systems. For significantly higher

oxidant requirements, multiple ASUs in parallel were used. For current ASU cases, three ASU trains in parallel were required for a 650 MWe power plant.

Future Cases

The greenfield future ASU was assumed to be available in the year 2020. In these ultra-supercritical steam cycle plants, the oxygen requirement is lower. The lower oxygen requirement coupled with higher forecasted efficiency of future ASUs results in a design of only 2 ASU trains in parallel for a 650 MWe power plant. On the basis of economy of scale (Nth of a kind plant) and reduction in manufacturing cost, a 15% reduction was estimated in the capital cost of the ASU.

3.2.4.2.2. CPU Cost Basis

Present Cases

The CO₂ CPU is a single train unit that can process all the flue gas from the power plant. The engineering basis for this system was the same as for the ASU (US Gulf Coast). Detailed cost calculations were performed for several cases. Costs for certain cases, which closely resembled cases for which detailed cost calculations had been performed, were scaled proportional to the flue gas flow rate to the 0.6 power. The lower scaling power for CPU relative to ASU is due to higher economies of scale for the larger size of equipment (single train) for the CPU.

Future Cases

Future cases were presumed to be constructed in the year 2020. As they are greenfield plants, much lower air infiltration was assumed, resulting in a higher CO₂ concentration in the flue gas (see Table 3.25 for composition). This results in some reduction in capital cost. More importantly, significant improvements in materials of construction and their cost are forecasted. Currently, compressors for flue gas compression cost approximately three times the cost of equivalent air compressors due to the use of stainless steel to avoid corrosion. Considerable research and development is current in progress to avoid corrosion and permit the use of less costly carbon steels. Also, the current CPU is a very conservative design today. An “Nth of a kind” unit in 2020 will have lower safety margins based on the operational experience gained through the operation of these units at demonstration projects, such as the Callide project in Australia. Overall, a 30% reduction in the capital cost of the CPU is forecasted for future greenfield cases.

3.2.5. Base Case Performance and Economic Results and Discussion

Performance and economic analyses were run in accordance with the fuel, firing system, existing equipment, SO₂ polishing and moisture requirement, and type of ASU and CPU (current technology, future technology, or compression only) for each of the cases shown in Table 3.23. For discussion purposes the base cases are broken into retrofit and greenfield categories.

Table 3.39 shows the impact of the case variations on plant performance and Table 3.42 shows the same for LCOE calculation. The detailed costs for these cases, developed as described in Section 3.2.4.1, are given in Table 3.40 and Table 3.41.

These results are displayed graphically and observations and conclusions identified in the sections that follow. Figure 3.102 shows the performance as net plant efficiency for the retrofit

Cases 1 to 10 and Figure 3.103 shows LCOE. Figure 3.104 shows the cost of CO₂ avoided and removed for the retrofit cases.

Figure 3.105 shows the performance for the greenfield Cases 11 to 14 and Figure 3.106 shows LCOE. The blue bars in the performance charts represent the base air fired unit with no CO₂ capture and the red bars show the impact of retrofitting oxy-combustion. The legend for the components of LCOE is shown on the charts. The conditions for each case are summarized at the bottom of the chart to simplify comparison. It is interesting to note that except for Case 8, the efficiency loss for retrofitting oxy-PC ranges between 7.9 and 8.9 percentage points and is fairly consistent whether for a subcritical or supercritical plant.

3.2.5.1. Retrofit Cases 1-10

Refer to Figure 3.102 for performance, Figure 3.103 for LCOE and Figure 3.104 for Cost of CO₂ Removed and Avoided. LCOE for all retrofit cases includes makeup power to achieve the same net output as the base air fired plant in the form of variable O&M cost. The rate used for the incremental power is the levelized rate from the DOE/NETL 401/11/0907 “Carbon Dioxide Capture from Existing Coal-Fired Power Plants (rev. Nov.2007) report of 6.4 ¢/kW.

Cases 1-3 employ subcritical steam conditions. Cases 1 and 1A show the difference between current and expected future ASU and CPU technology plus addition of heat integration which is assumed to increase gross generation by 2% of the base gross power (650 MWe). In the retrofit scenario the improvements would provide about a 0.90 percentage point improvement in net efficiency. The greatest impact, however, is in the reduction in LCOE which drops by about 1.44¢/kW mostly due to lower capital cost (CAPEX) for the future ASU and CPU but also reduced operating and maintenance cost (O&M) from higher efficiency.

Cases 2 and 3 show the impact of fuel and Gas Quality Control System (GQCS) changes which are somewhat fuel related. The bituminous cases (1 and 1A) use FF with WFGD while the subbituminous and North Dakota lignite, Cases 2 and 3, have SDA-FF as the existing equipment. It can be observed by comparing Cases 1, 2 and 3, that the loss in percentage points of efficiency due to the impact of fuel is about the same for air firing and oxy firing (0.7% for subbituminous and 1.7% for North Dakota Lignite). As would be expected, lower grade fuels also increase LCOE. For this study the impact from Case 1 bituminous to subbituminous Case 2 is about 0.08¢/kW and going from bituminous Case 1 to North Dakota Lignite Case 3 increases LCOE by 0.5¢/kW.

Cases 4-10 employ supercritical steam conditions. Cases 4, 5, and 6 again compare the impact of fuel. As with the subcritical cases, the reductions in efficiency are essentially the same for air or oxy firing. Cases 5 and 5A show the promise of improving net efficiency by about 0.80 percentage points as a result of using expected future ASU and CPU technology plus addition of heat integration assumed to increase gross generation by 3% of the base gross power (650 MWe) to the retrofit scenario. Interestingly, the improvement for supercritical is slightly less than for subcritical due to the better turbine cycle heat rate for supercritical ($NPHR = TCHR / [\eta_{fuel} * (1 - AP/GP)]$ where AP = aux power and GP = gross power). Since the effect is an increase in GP, the term $(1 - AP/GP)$ becomes larger decreasing the heat rate and increasing the net efficiency but since the TCHR is significantly lower for supercritical (10% lower) the impact is diminished. Though the efficiency improvement is modest, the impact on LCOE is significant at about

1.42¢/kW, essentially the same as for the subcritical Cases 1 and 1A. As with the subcritical cases, comparing Cases 4, 5 and 6 shows an increase in LCOE with lower fuel rank. From bituminous to subbituminous LCOE increased by 0.11¢/kW and from bituminous to North Dakota Lignite it increased 0.44¢/kW, similar in magnitude to the subcritical cases.

In the tables and figures that follow the following abbreviations and acronyms are used:

ASU-C	Air separation unit (Conventional design)
ASU-F	Air separation unit (Future design)
Cool	Cool recycle
CPU-C	Compression and purification unit (Conventional design)
CPU -F	Compression and purification unit (Future design)
PC	Pulverized Coal
Pri + CPU	The combined primary recycle and CPU streams
SC	Supercritical (steam conditions)
SDA	Spray dryer absorber (dry scrubber)
SubC	Subcritical (steam conditions)
Warm	Warm recycle
WFGD	Wet flue gas desulfurization (wet scrubber)
x% GP-HI	specified percentage of Gross Power being used for Heat Integration

Note that all retrofit cases are incremental, i.e. the incremental cost is added to the existing plant costs if oxy-firing is retrofitted.

PERFORMANCE

PARAMETER	CASE 1	CASE 1A	CASE 2	CASE 3	CASE 4	CASE 5	CASE 5A	CASE 6	CASE 7	CASE 8	CASE 9	CASE 10	CASE 11	CASE 12	CASE 13	CASE 13A	CASE 14
Turbine Cycle Net Power (plant gross power), kW/e	650000	650000	650000	650000	650000	650000	650000	650000	650000	650000	650000	780000	650000	650000	650000	650000	650000
Additional Power from Heat Integration & Improvements	0	13,000	0	0	0	0	19500	0	0	0	0	0	32500	32500	32500	32500	32500
Application	Retrofit	Retrofit	Retrofit	Retrofit	Retrofit	Retrofit	Retrofit	Retrofit	Retrofit	Retrofit	Retrofit	Retrofit	Greenfield	Greenfield	Greenfield	Greenfield	Greenfield
Recycle	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Warm	Warm	Warm	Warm	Warm
Steam pressure	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC
Firing System	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC
Existing Scrubber Type	WFGD	WFGD	SDA	WFGD	SDA	SDA	SDA	SDA	NONE	NONE	NONE	SDA	LWFGD	SDA	SDA	NONE	SDA
Polishing Scrubber Stream	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU
Type of ASU (C=Current, F= Future technology)	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C
Type of Compression (C=Current, F= Future technology)	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC
Coal Type	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	ND Lignite	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6
Heating Value (HHV)	11666	11666	9540	7090	9540	9540	9540	7090	9540	9540	9540	9540	9540	9540	9540	9540	9540
Coal Ash Content	9.79%	9.79%	3.98%	7.40%	3.98%	3.98%	3.98%	7.40%	3.98%	3.98%	3.98%	3.98%	9.79%	3.98%	3.98%	3.98%	3.98%
Sulfur	2.70%	2.70%	0.34%	0.73%	0.34%	0.34%	0.34%	0.73%	0.34%	0.34%	0.34%	0.34%	2.70%	0.34%	0.34%	0.34%	0.34%
Carbon	63.75%	63.75%	55.15%	42.22%	55.15%	55.15%	55.15%	42.22%	55.15%	55.15%	55.15%	55.15%	63.75%	55.15%	55.15%	55.15%	55.15%
Oxygen	6.88%	6.88%	12.57%	12.67%	12.57%	12.57%	12.57%	12.67%	12.57%	12.57%	12.57%	12.57%	6.88%	12.57%	12.57%	12.57%	12.57%
Hydrogen	4.50%	4.50%	3.83%	3.00%	3.83%	3.83%	3.83%	3.00%	3.83%	3.83%	3.83%	3.83%	4.50%	3.83%	3.83%	3.83%	3.83%
Nitrogen	1.25%	1.25%	0.73%	0.67%	0.73%	0.73%	0.73%	0.67%	0.73%	0.73%	0.73%	0.73%	1.25%	0.73%	0.73%	0.73%	0.73%
Moisture	11.12%	11.12%	23.40%	33.30%	23.40%	23.40%	23.40%	33.30%	23.40%	23.40%	23.40%	23.40%	11.12%	23.40%	23.40%	23.40%	23.40%
Base Plant Auxiliary Power	41600	41600	37310	37310	33900	29510	29510	29510	26719	26719	24180	35412	26357	25707	24561	22481	25707
Air Separation Unit Main Compressor	92000	82000	94000	97000	82000	76000	76000	89000	84000	84000	85000	101000	64000	73000	66000	66000	66000
Trona	104	104	0	0	93	0	0	0	0	0	0	0	0	79	0	0	0
Polishing Scrubber	2111	2211	2620	3148	1983	2358	2358	2832	1279	1279	1282	2829	1628	1938	1934	1934	1938
Compression & Purification Unit	56000	50000	60000	64000	50000	49000	49000	57000	54000	56000	54000	65000	36000	44000	38000	38000	39000
Additional Cooling Tower Fans (ASU/CPU Cooling)	2808	2808	2880	2983	2528	2582	2582	2880	2587	2587	2587	3732	2185	2243	2238	2238	2243
TOTAL AUXILIARY POWER (kW/e)	194722	178722	198810	204446	170408	173460	159460	180032	168584	160584	167053	207973	130249	146889	132734	130654	134889
Net Power (kW/e)	455278	484278	453190	445554	479591	476540	510040	469968	481416	489416	482947	572027	552251	535611	549766	551846	547611
Pre-retrofit net plant efficiency (%)	35.00%	34.21%	33.41%	33.41%	38.51%	38.51%	38.51%	37.61%	38.71%	38.71%	38.71%	38.51%	44.60%	43.59%	43.59%	43.91%	43.59%
Pre-retrofit Heat Rate (Btu/kWh HHV)	9749	9749	9975	10213	8862	8863	8863	9074	8798	8798	8817	8863	7654	7832	7774	7774	7832
Pre-retrofit (Aux Power)/(Gross Power) Ratio	6.4%	6.4%	6.4%	6.4%	5.2%	5.2%	5.2%	5.2%	4.7%	4.7%	4.7%	5.2%	4.6%	4.6%	4.1%	4.1%	4.6%
Turbine Cycle Heat Rate (Btu/kWh HHV)	8041	8041	8041	8041	7236.0	7236.0	7236.0	7236.0	7236.0	7236.0	7236.0	7236.0	6433	6433	6433	6433.4	6433.4
Fuel (Btu/lb) Efficiency	88.1%	88.1%	88.1%	88.1%	88.1%	88.1%	88.1%	88.1%	86.3%	86.3%	86.3%	86.1%	86.1%	86.1%	86.3%	86.3%	86.1%
Net Plant Heat Rate (Btu/kWh HHV)	13028	12586	13392	13945	11129	11461	11134	11897	11321	11610	11309	11457	8674	9163	8899	8864	8955
Net Plant Efficiency	26.2%	27.1%	25.5%	24.5%	30.7%	30.7%	30.6%	28.7%	30.1%	29.4%	30.2%	29.8%	39.3%	37.2%	38.3%	38.5%	38.1%
CONSUMABLES																	
As-Received Coal Feed, lb/h	508425	508425	636167	876351	457529	572483	572483	788623	571289	571289	572483	686979	386441	483535	482526	482526	483535
Thermal Input, kWh	1738462	1738462	1779835	1821127	1564430	1600761	1600761	1638920	1597422	1597422	1600761	1920913	1321361	1352047	1349227	1352047	1352047
WFGD Limestone Sorbent Feed, lb/h (Ca/S)=1.05	54880	54880	0	0	49386	0	0	0	0	0	0	0	41713	0	0	0	0
SDA Pebble Lime Feed, lb/h	0	0	7500	22490	0	6749	6749	20238	0	0	0	80999	0	5700	5688	0	5700
Trona (sodium bicarbonate) for Polishing FGD, lb/h	1290	1290	503	1509	1161	453	453	1358	9040	9040	9059	544	980	383	392	0	393
Trona (sodium bicarbonate), for SO ₂ control, lb/h	965	965	0	0	869	0	0	0	0	0	0	0	734	0	0	0	0
OXYGEN																	
Oxygen Purity	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
Oxidant Required (short tons/day) - includes impurities	13015	13015	13353	13856	11712	12016	12016	12469	11991	11991	12016	14419	10128	10398	10377	10377	10398
CO2 REMOVAL																	
Recovery Efficiency	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Total Gas Flow to CPU (lb/h)	1538230	1538230	1626948	1712047	1384242	1464079	1464079	1540659	1461026	1461026	1464079	1756895	1086687	1150687	1148287	1148287	1150687
Carbon Dioxide Produced (lb/h)	1206918	1206918	1285614	1355770	1085107	1156916	1156916	1220048	1154503	1154503	1156916	1388298	915152	977163	975126	975126	977163
Carbon Dioxide Produced (short tons/d)	14470	14470	15427	16269	13021	13883	13883	14641	13854	13854	13883	16660	10998	11728	11701	11701	11728
Carbon Dioxide Produced (short tons/yr)	4489261	4489261	4786343	5047531	4039855	4307197	4307197	4542238	4298213	4298213	4307197	5168638	3412174	3637978	3630390	3630390	3637978
Carbon Dioxide Removed (lb/h)	1085236	1085236	1157053	1220193	976597	1041224	1041224	1099043	1039052	1039052	1041224	1249469	824861	879447	879447	879447	879447
Carbon Dioxide Removed (short tons/d)	13023	13023	13885	14642	11719	12495	12495	13177	12469	12469	12495	14994	9898	10553	10531	10531	10553
Carbon Dioxide Removed (short tons/yr)	4040335	4040335	4307708	4542778	3635669	3876477	3876477	4088014	3868392	3868392	3876477	4651772	3070956	3274180	3267351	3267351	3274180

Table 3.39 Performance results for all cases

DETAILED COSTS

PARAMETER	CASE 1	CASE 1A	CASE 2	CASE 3	CASE 4	CASE 5	CASE 5A	CASE 6	CASE 7	CASE 8	CASE 9	CASE 10	CASE 11	CASE 12	CASE 13	CASE 13A	CASE 14
Turbine Cycle Net Power (plant gross power) kW																	
Application	650000	650000	650000	650000	650000	650000	650000	650000	650000	650000	650000	780000	650000	650000	650000	650000	650000
Recycle	Retrolf	Retrolf	Retrolf	Retrolf	Retrolf	Retrolf	Retrolf	Retrolf	Retrolf	Retrolf	Retrolf	Retrolf	Retrolf	Retrolf	Retrolf	Retrolf	Retrolf
Steam pressure	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool
Firing system	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC
Existing Scrubber Type	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC
Polishing Scrubber Stream	WFGD	WFGD	SDA	SDA	WFGD	SDA	SDA	SDA	SDA	SDA	SDA	SDA	SDA	SDA	SDA	SDA	SDA
Type of ASU (C=Current, F= Future technology)	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU
Type of Compression (C=Current, F= Future technology)	ASUC	ASUC	ASUC	ASUC	ASUC	ASUC	ASUC	ASUC	ASUC	ASUC	ASUC	ASUC	ASUC	ASUC	ASUC	ASUC	ASUC
Coal Type	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC	CPUC
Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6
1.0 COAL & SORBENT HANDLING																	
1.1 Coal Receive & Unload																	
1.2 Coal Reclaim & Reclaim																	
1.3 Coal Conveyors & Yard Breaker																	
1.4 Other Coal Handling																	
1.5 Sorbent Receive & Unload																	
1.6 Sorbent Reclaim & Reclaim																	
1.7 Sorbent Conveyors																	
1.8 Other Sorbent Handling																	
1.9 Coal & Sorbent Hnd. Foundations																	
SUBTOTAL																	
2.0 COAL & SORBENT PREP & FEED																	
2.1 Coal Crushing & Drying																	
2.2 Coal Conveyor to Storage																	
2.3 Coal Injection System																	
2.4 Misc. Coal Prep Equipment																	
2.5 Sorbent Prep Equipment																	
2.6 Sorbent Storage & Feed																	
2.7 Sorbent Injection System																	
2.8 Boiler Air Supply System																	
2.9 Coal & sorbent Feed Foundation																	
SUBTOTAL																	
3.0 FEEDWATER & MISC BOP SYSTEMS																	
3.1 Freshwater System																	
3.2 Water Makeup & Pretreating																	
3.3 Other Feedwater Subsystems																	
3.4 Service Water Systems																	
3.5 Other Boiler Plant Systems																	
3.6 FO Supply Sys & Net Gas																	
3.7 Waste Treatment Equipment																	
3.9 Misc. Power Plant Equipment																	
SUBTOTAL																	
4.0 PC BOILER & ACCESSORIES																	
4.1 Boiler																	
4.2 ASU/Oxidant Compression																	
SUBTOTAL																	
5.0 FLUE GAS CLEANUP																	
5.1 Absorber Vessels & Accessories																	
5.2 Other FGD & Accessories																	
5.3 Other FGD & Accessories																	
5.4 Other FGD & Accessories																	
5.5 Other FGD & Accessories																	
5.6 Mercury Removal System																	
5.7 Sodium Scrubber/Quench Cooler																	
5.8 Tona Injection System																	
SUBTOTAL																	
5.0B CO2 REMOVAL & COMPRESSION																	
5B.1 CO2 Cooler in separate vessel																	
5B.2 Compression & Drying																	
SUBTOTAL																	
7.0 HR. DUCTING & STACK																	
7.1 Flue Gas Recycle Heat Exchanger																	
7.2 SCR System																	
7.3 Ductwork																	
7.4 Stack																	
7.5 Duct & Stack Foundations																	
SUBTOTAL																	
8.0 STEAM TURBINE GENERATOR																	
8.1 Steam TG & Accessories																	
8.2 Turbine Plant Auxiliaries																	
8.3 Condenser & Auxiliaries																	
8.4 Steam Piping																	
8.5 TG Foundations																	
SUBTOTAL																	

Table 3.40 Detailed cost results for all cases

DETAILED COSTS																	
PARAMETER	CASE 1	CASE 1A	CASE 2	CASE 3	CASE 4	CASE 5	CASE 5A	CASE 6	CASE 7	CASE 8	CASE 9	CASE 10	CASE 11	CASE 12	CASE 13	CASE 13A	CASE 14
9.0 COOLING WATER SYSTEM																	
9.1 Cooling Towers																	
9.2 Circulating Water Pumps	\$5	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1117	13750	14215	13863	13890	14016
9.3 Circ. Water System Auxiliaries	\$5	168	168	168	168	168	168	168	168	168	168	187	2305	2383	2341	2335	2350
9.4 Circ. Water Piping	\$5	49	49	49	49	49	49	49	49	49	49	54	666	689	676	675	679
9.5 Make-up Water System	\$5	706	706	706	706	706	706	706	706	706	706	787	7933	8202	8056	8037	8087
9.6 Component Cooling Water Sys	\$5	0	0	0	0	0	0	0	0	0	0	0	1244	1266	1264	1261	1268
9.9 Circ. Water System Foundations	\$5	542	542	542	542	542	542	542	542	542	542	604	6146	6354	6241	6226	6255
SUBTOTAL	\$5	2465	2465	2465	2465	2465	2465	2465	2465	2465	2465	2750	32764	33674	33273	33193	33398
10.0 ASH/SPENT SORBENT HANDLING SYS																	
10.1 Ash Coolers	\$5																
10.2 Cyclone Ash Letdown	\$5																
10.3 HSCU Ash Letdown	\$5																
10.4 High Temperature Ash Piping	\$5																
10.5 Other Ash Recovery Equipment	\$5																
10.6 Ash Storage Silos	\$5																
10.7 Ash Transport & Feed Equipment	\$5																
10.8 Misc. Ash Handling Equipment	\$5																
10.9 Ash/Spent Sorbent Foundations	\$5																
SUBTOTAL	\$5																
11.0 ACCESSORY ELECTRIC PLANT																	
11.1 Generator Equipment	\$5	0	0	0	0	0	0	0	0	0	0	0	1949	2015	1980	1975	1987
11.2 Station Service Equipment	\$5	0	0	0	0	0	0	0	0	0	0	0	7676	7936	7795	7776	7824
11.3 Switchgear & Motor Control	\$5	0	0	0	0	0	0	0	0	0	0	0	8122	8397	8249	8280	8280
11.4 Conduit & Cable Tray	\$5	0	0	0	0	0	0	0	0	0	0	0	20554	21250	20873	20823	20952
11.5 Wire & Cable	\$5	15425	15425	15664	16015	14479	14703	15033	14685	14855	14703	16403	20940	21765	21327	21267	21423
11.6 Protective Equipment	\$5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11.7 Standby Equipment	\$5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11.8 Main Power Transformers	\$5	7124	7124	7124	7124	7124	7124	7124	7124	7124	7124	7947	8049	8322	8174	8155	8205
11.9 Electrical Foundations	\$5	1161	1161	1161	1161	1161	1161	1161	1161	1161	1161	1296	1306	1350	1326	1323	1331
SUBTOTAL	\$5	23710	23948	24300	22764	22988	22988	23318	22969	22989	22988	25645	72598	75056	73724	73547	74002
12.0 INSTRUMENTATION & CONTROLS																	
12.1 PC Control Equipment	\$5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12.2 Combustion Turbine Control	\$5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12.3 Steam Turbine Control	\$5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12.4 Other Major Component Control	\$5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12.5 Signal Processing Equipment	\$5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12.6 Control Boards, Panels & Racks	\$5	527	527	527	527	527	527	527	527	527	527	527	1037	1037	1037	1037	1037
12.7 Computer & Accessories	\$5	3702	3702	3702	3702	3702	3702	3702	3702	3702	3702	3702	7290	7290	7290	7290	7290
12.8 Instrument Wiring & Tubing	\$5	5427	5427	5427	5427	5427	5427	5427	5427	5427	5427	5427	10688	10688	10688	10688	10688
12.9 Other I & C Equipment	\$5	2982	2982	2982	2982	2982	2982	2982	2982	2982	2982	2982	5874	5874	5874	5874	5874
SUBTOTAL	\$5	12637	12637	12637	12637	12637	12637	12637	12637	12637	12637	12637	24889	24889	24889	24889	24889
13.0 IMPROVEMENTS TO SITE																	
13.1 Site Preparation	\$5	668	668	705	744	589	621	656	619	619	621	773	1461	1461	1461	1461	1461
13.2 Site Improvements	\$5	2361	2361	2462	2630	2080	2195	2195	2317	2190	2195	2732	5163	5163	5163	5163	5163
13.3 Site Facilities	\$5	0	0	0	0	0	0	0	0	0	0	0	8192	8192	8192	8192	8192
SUBTOTAL	\$5	3029	3029	3196	3374	2669	2816	2816	2973	2809	2816	3505	14816	14816	14816	14816	14816
14.0 BUILDINGS & STRUCTURES																	
14.1 Boiler Building	\$5																
14.2 Turbine Building	\$5																
14.3 Administration Building	\$5																
14.4 Circulation Water Pumphouse	\$5																
14.5 Water Treatment Buildings	\$5																
14.6 Machine Shop	\$5																
14.7 Warehouse	\$5																
14.8 Other Building's & Structures	\$5																
14.9 Waste Treating Building & Str.	\$5																
SUBTOTAL	\$5																
15.0 TRANSPORTATION, STORAGE & MONITORING																	
15.1 Transport	\$5	60946	60946	60946	60946	60946	60946	60946	60946	60946	60946	60946	60946	60946	60946	60946	60946
15.2 Storage Walls	\$5	8654	9367	9878	9878	7787	8429	8889	8412	8412	8429	10115	6577	7120	7105	7105	7120
15.3 Monitoring	\$5	23402	23402	23402	23402	23402	23402	23402	23402	23402	23402	23402	23402	23402	23402	23402	23402
SUBTOTAL	\$5	92901	92901	93615	94126	92035	92677	93137	92659	92659	92677	94363	90825	91367	91352	91352	91367
Total Plant Cost (TPC) w/o T&M	\$5	743048	620341	753468	782513	698209	709159	590184	735115	679669	572979	796521	1207629	1336021	1200205	1148315	1234694
Total Plant Cost (TPC) w/ T&M	\$5	835950	713242	847082	876639	790244	801835	682861	828252	772648	665639	799356	1286454	1427388	1293378	1240668	1326662
Capital Cost w/o T&M	\$5	1632.06	1280.96	1662.59	1756.27	1455.84	1488.14	1564.18	1412.48	1220.62	1463.26	1381.97	2186.74	2494.39	2186.43	2082.67	2254.69
Capital Cost w/ T&M	\$5	1836.13	1472.79	1869.15	1967.53	1647.75	1652.62	1762.36	1604.95	1418.01	1655.16	1546.93	2351.20	2684.97	2352.60	2248.21	2421.54

Table 3.41 Detailed cost results for all cases

LEVELIZED COST OF ELECTRICITY

PARAMETER	CASE 1	CASE 1A	CASE 2	CASE 3	CASE 4	CASE 5	CASE 5A	CASE 6	CASE 7	CASE 8	CASE 9	CASE 10	CASE 11	CASE 12	CASE 13	CASE 13A	CASE 14
Turbine Cycle Net Power (plant gross power) kW _e	650000	650000	650000	650000	650000	650000	650000	650000	650000	650000	650000	780000	650000	650000	650000	650000	650000
Application	Retrofit	Retrofit	Retrofit	Retrofit	Retrofit	Retrofit	Retrofit	Retrofit	Retrofit	Retrofit	Retrofit	Retrofit	Greenfield	Greenfield	Greenfield	Greenfield	Greenfield
Recycle	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Cool	Warm	Warm	Warm	Warm	Warm
Steam pressure	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	SubC	USC	USC	USC	USC	USC
Firing System	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	CYC	CYC	CYC	CYC	PC
Existing Scrubber Type	WFGD	WFGD	WFGD	WFGD	WFGD	WFGD	WFGD	WFGD	WFGD	WFGD	WFGD	WFGD	WFGD	WFGD	WFGD	WFGD	WFGD
Polishing Scrubber Stream	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU	PRH-CPU
Type of ASU (C-current, F- Future technology)	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C	ASU-C
Type of Compression (C-current, F- Future technology)	CPU-C	CPU-C	CPU-C	CPU-C	CPU-C	CPU-C	CPU-C	CPU-C	CPU-C	CPU-C	CPU-C	CPU-C	CPU-C	CPU-C	CPU-C	CPU-C	CPU-C
Coal Type	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6
Net Power (kW _e)	454278	484278	453190	445554	479591	476540	510040	469988	481416	489416	482947	572027	552251	535611	549768	551946	547611
Fuel Cost (\$/MBtu)	1.18	1.18	1.15	0.9	1.15	1.15	1.15	0.9	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Net Plant Heat Rate (Btu/kWh)	13028	12598	13392	13945	11129	11481	11134	11897	11321	11610	11309	11457	8674	9169	8899	8864	8855
Book Life (years)	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Capacity Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Total Plant Cost (TPC) w/o TS&M (k\$)	743048	620341	753468	782513	688209	709159	590184	735115	679889	572979	706679	790521	1207629	1336021	1202025	1149315	1234694
Total Plant Cost (TPC) w/T S&M (k\$)	835950	713242	847082	876639	790244	801835	682861	828252	772648	666939	799356	884884	1298454	1427388	1293378	1240668	1326062
Aux Power before Retrofit (as % of GP, w/o BFP)	6%	6%	6%	6%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
Net Power Before Retrofit (kW _e)	608400	608400	608400	608400	616200	616200	616200	616200	619450	619450	619450	739440	619450	619450	619450	619450	619450
Levelized Cost of Replacement Power (\$/kW)	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064
Annual Net MWh before Retrofit	4530146	4530146	4530146	4530146	4588225	4588225	4588225	4588225	4612425	4612425	4612425	5505870	4612425	4612425	4612425	4612425	5505870
Annual Net MWh after Retrofit	3390000	3605934	3374553	3317595	3571035	3548317	3797758	3490382	3584624	3496722	3596023	4250313	3496722	3596023	3596023	3596023	4250313
Power Reduction MWh/yr	1140146	924212	1155694	1212551	1071791	1039908	790467	1088843	1027801	1177153	1016401	1246557	1177153	1016401	1016401	1016401	1246557
ANNUAL INCREMENTAL COSTS (\$1000)																	
Fixed O&M (LF=1.16)	7132	6109	7218	7460	6758	6849	5858	7065	6606	5714	6828	7527	16640	17710	16593	16154	16866
Variable O&M (LF=1.16) including replacement power	7430	6203	7535	7825	6982	7092	5902	7351	6800	5730	7067	7905	12076	13360	12020	11493	12347
Consumables (LF=1.16)	72989	59150	73964	77803	65100	66554	50590	66779	65779	71498	65050	79780	60931	3325	3319	1552	3325
Fuel Cost (k\$)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LEVELIZATION (20 year)																	
Fixed O&M (LF=1.16)	0.244	0.197	0.248	0.261	0.220	0.224	0.179	0.234	0.214	0.190	0.220	0.205	0.468	0.514	0.469	0.455	0.478
Variable O&M (LF=1.16) including replacement power	2.407	1.840	2.451	2.613	2.050	2.107	1.512	2.235	2.055	2.236	2.037	2.088	0.340	0.388	0.340	0.324	0.350
Consumables (LF=1.16)	0.053	0.050	0.014	0.037	0.046	0.012	0.011	0.032	0.197	0.202	0.197	0.012	0.198	0.096	0.094	0.044	0.094
Fuel (LF=1.2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.771	1.557	1.514	1.508	1.523
Total Production Cost	2.704	2.087	2.713	2.911	2.315	2.343	1.702	2.501	2.466	2.627	2.454	2.305	2.776	2.555	2.416	2.330	2.446
Capital Cost Factor w/o TS&M (17.5)	3.833	3.009	3.905	4.125	3.419	3.495	2.718	3.674	3.317	2.867	3.437	3.246	5.139	5.862	5.139	4.895	5.299
Capital Cost Factor w/T S&M (17.5)	4.312	3.459	4.390	4.621	3.870	3.952	3.144	4.139	3.769	3.330	3.887	3.633	5.526	6.263	5.529	5.284	5.691
LCOE w/o TS&M (¢/kWh)	6.54	5.10	6.62	7.04	5.73	5.84	4.42	6.17	5.78	5.49	5.89	5.55	7.92	8.42	7.55	7.22	7.74
LCOE w TS&M (¢/kWh)	7.02	5.55	7.10	7.53	6.19	6.30	4.85	6.64	6.24	5.96	6.34	5.94	8.30	8.82	7.95	7.61	8.14
CO ₂ COSTS																	
LCOE w/o CO ₂ Removal (DOE 1291 Case 1)																	
CO ₂ Produced w/o CO ₂ Removal (lb/hr)																	
\$/ton CO ₂ Removed w/o TS&M	54.85	45.47	51.84	51.38	56.32	53.44	43.30	52.86	53.59	49.64	54.64	50.83	19.89	24.20	14.09	9.99	16.38
\$/ton CO ₂ Avoided w/o TS&M	76.14	58.80	72.34	73.13	74.73	71.43	53.55	71.79	71.22	67.92	72.36	67.91	27.58	36.35	21.10	14.96	24.59
\$/ton CO ₂ Removed w TS&M	58.87	49.49	55.64	55.00	60.75	57.62	47.48	56.84	57.78	53.83	58.82	54.37	25.07	29.09	18.98	14.89	21.26
\$/ton CO ₂ Avoided w TS&M	81.73	64.00	77.65	78.29	80.60	77.02	58.72	77.20	76.79	73.65	77.90	72.65	34.76	43.68	28.42	22.29	31.93

Note: The LCOE for the retrofit cases is incremental (additional to the cost of power for the base plant before retrofit).

Table 3.42 Economic results for all cases

Case 7 shows the impact of having Cyclone firing with no existing scrubber leaving the recycle untreated and treating only the CPU stream to remove SO₂ and moisture and using current CPU technology. Moisture does not need to be removed for Cyclone firing as it does for PC where it is used to dry and convey coal to the burners. In addition, for all Cyclone cases there is only one recycle stream rather than two. It must also be recognized that the SO₂ level in the furnace may become excessive with no sulfur removal in the recycle. This would result in potentially aggressive corrosion and use of higher grade materials in the furnace and high temperature sections of the superheaters and potentially aggressive corrosion not fully accounted for in this study.

Assuming the SO₂ concentration in the furnace could be tolerated without noticeable economic impact on the boiler, comparison of Case 7 (Cyclone) with Case 5 (PC) indicates about a 0.3 percentage point net efficiency improvement. As indicated previously, Cyclone firing also produces a slightly better fuel efficiency, slightly higher aux power and slightly lower boiler cost compared to a PC firing system. However, as Figure 3.103 shows, the LCOE for Case 7 without consumables is 0.25¢/kW lower than Case 5 without consumables. This indicates that removing all of the sulfur in the DCCPS, which uses more costly bicarbonate reagent, increases the consumable component of the LCOE making Case 7 only 0.06¢/kW lower overall.

Case 8 considers the same scenario as Case 7 but does no purification in the compression step (compression only). This results in a significant increase in compression power as shown in Table 3.36 and Figure 3.102 which produces a 0.4 percentage point reduction in net efficiency compared to Case 5. However, in spite of the higher auxiliary power consumption and higher consumable cost, the much lower capital cost for compression versus a CPU results in a 0.29¢/kW lower LCOE than Case 7 and 0.35¢/kW lower LCOE than PC Case 5.

Case 9 is based on Case 5 but assumes future ASU and CPU technology is applied to a plant without an existing scrubbing system but since it is PC fired the DCCPS must remove SO₂ and moisture from both the primary and CPU streams. This would result in acceptable conditions for PC firing and furnace corrosion and results in a 0.4 percentage point improvement in net efficiency compared to Case 5. However, since the consumable cost is increased, the total LCOE is 0.05¢/kW higher than Case 5 with only current ASU and CPU technology and an existing scrubber.

Case 10 is identical to Case 5 but scaled up to 780 MWe instead of 650 MWe gross. From a performance perspective this makes no difference. However, as expected there is some economy of scale economic advantage of about 0.29¢/kW.

The costs of CO₂ removed (captured) and avoided (mitigated) are given in Figure 3.104. It should be noted that in they are calculated in the same manner as given in DOE/NETL-401/110907 meaning that the LCOE is incremental and they do not include the cost of operation and maintenance or fuel costs for the base plant being retrofit.

Figure 3.102 Performance results for retrofit cases – net plant efficiency

Figure 3.103 Economic results for retrofit cases (incremental LCOE)

Figure 3.104 Cost of CO₂ removed and avoided for retrofit cases

3.2.5.2. Greenfield Cases 11-14

All of the greenfield cases were analyzed assuming warm instead of cool recycle because warm recycle offers higher cycle efficiency and is therefore what would be used commercially provided SO₂ levels in the furnace can be maintained at acceptable levels for corrosion. This configuration returns the secondary recycle to the 'air heater' and boiler at a higher temperature removing only particulate in that stream. For Case 11 firing high sulfur bituminous coal, it is assumed that the sorbent injection ahead of the secondary recycle baghouse achieves sufficient SO₂ removal along with the primary recycle (in which SO₂ is reduced to 1 ppmv) to result in an acceptable SO₂ concentration in the furnace. Sorbent injection is not employed for subbituminous or North Dakota Lignite. Figure 3.94, Figure 3.95, and Figure 3.96 show the warm recycle process configurations for these cases.

Refer to Figure 3.105 for performance, Figure 3.106 for LCOE and Figure 3.107 for cost of CO₂ removed or avoided for greenfield Cases 11 to 14. All of these cases employ ultra-supercritical steam conditions of 4000 psi, 1350°F, 1400°F. Again, the performance is given as net plant efficiency, the blue bars on Figure 3.104 represent the base air fired unit with no CO₂ capture and the red bars show the impact of oxy-combustion. The case conditions are summarized at the bottom of the chart to facilitate comparison.

The penalty for oxy-PC in greenfield applications is considerably lower than for retrofit ranging between 5.3 and 6.4 percentage points. This is due to the ability to better integrate heat into the steam cycle and the higher efficiency of the steam cycle which reduces coal, oxidant, and CO₂ flows and all associated power requirements.

Case 11 shows the results for a unit burning bituminous coal using sorbent injection in the secondary recycle stream to control SO₂ concentration in the boiler and employing warm recycle and a dry scrubber-fabric filter combination for SO₂ removal in the combined primary and CPU streams. Due to the high sulfur and chlorine content in Illinois #6 coal, achieving acceptable furnace and superheater corrosion conditions at USC steam conditions will be challenging but it is assumed to be achievable.

Future technology for the ASU and CPU is also incorporated. Compared to the other cases it provides the highest net efficiency due both to the fuel and the future ASU and CPU which have lower power and costs than the current technology in Case 12. Case 14 is identical to Case 12 except it applies the advanced ASU and CPU designs. The difference between these cases is about 0.9 percentage points of net efficiency. Case 14 is identical to Case 11 except for a fuel difference of Decker for Case 14 versus Illinois #6 for Case 11. This fuel difference results in a 1.2 percentage points reduction in net efficiency but the lower consumable cost as a result of much lower sulfur content and lower fuel cost (\$1.8 per MBtu for bituminous vs. \$1.5 per MBtu for subbituminous) results in 0.18¢/kW lower LCOE for the subbituminous coal in Case 14.

Cases 13 and 13A both employ Cyclone firing systems which provide slight increases in both fuel efficiency and auxiliary power and reduces significantly boiler cost relative to PC (about 10%). The distinction between these two cases is that for Case 13A there is no primary scrubber in Case 13A and only moisture is removed from the CPU stream so no sulfur is removed in any of the recycle streams. Figure 3.105 shows that this produces only a 0.2% improvement in net efficiency and Figure 3.106 shows a 0.33¢/kW reduction in LCOE. However, the high SO₂

concentration in the furnace coupled with the USC steam conditions in Case 13A will be very challenging in regard to furnace and superheater corrosion even with subbituminous coal and may be impractical. In addition, the pipeline and storage reservoir must be able to accommodate the sulfur.

The cost of CO₂ removed and avoided is shown in Figure 3.107. The impact of Cyclone firing coupled with future ASU and CPU benefits are quite evident when comparing Cases 12 and 13.

Figure 3.105 Performance results for greenfield cases – net plant efficiency

Figure 3.106 Economic results for greenfield cases (LCOE)
 (See Section 3.2.6 for comparisons with other studies and base cases)

Figure 3.107 Cost of CO₂ removed and avoided for greenfield cases
 (See Section 3.2.6 for comparisons with other studies and base cases)

3.2.6. Comparison of Performance and Economic Results with Other Studies

3.2.6.1. DOE Oxy-firing Study (DOE/NETL-2007/1291)

Refer to Figure 3.108 for performance, Figure 3.109 for LCOE and Figure 3.110 for cost of CO₂ removed or avoided. These graphs compare the results from Oxy-PC retrofit Case 4, employing supercritical steam conditions and firing Illinois #6 bituminous coal, with Cases 1 (air fired), and Case 5 (oxy PC fired) from the DOE study “Pulverized Coal Oxy-combustion Power Plants” DOE/NETL-2007/1291 revised August 2008. Comparing the Case 4 retrofit with the DOE Case 5 net efficiencies shows about a 1.4 percentage point gain since the DOE study primarily as a result of improvements to ASU and CPU designs since 2007. It should also be noted that Cases 5 and 6 from the DOE/NETL-2007/1291 indicate cold recycle while the process for this study is called cool recycle. The cold recycle process takes the secondary recycle stream after moisture

removal and at a somewhat lower temperature than cool recycle. As described earlier, cool recycle takes the secondary recycle stream after the primary scrubber which is at moisture saturation temperature for wet scrubbers and about 30°F higher for dry scrubbers.

In the LCOE graph only, to make the retrofit Case 4 comparable to the greenfield cases, the O&M and fuel costs for the base plant (base plant capital assumed fully depreciated) have been added to the incremental retrofit costs to calculate LCOE. Note that the retrofit Case 4 also shows a variable cost component which is the makeup power to achieve the net output of the air-fired unit without CCS. It is believed that with these corrections the retrofit Case 4 LCOE can be directly compared to the other greenfield cases.

Greenfield Cases 11 to 14 are also comparable with DOE Case 6 (oxy PC) from the DOE study DOE/NETL-2007/1291 employing the same USC steam conditions. Case 2 from the DOE study DOE/NETL-2007/1291 (not shown on the chart) yielded 44.6% net efficiency with air firing. Incorporation of warm recycle, expected future improvements to the ASU and CPU, along with deep integration of heat into the steam cycle (not considered in the DOE study) show potential for reduction of the penalty for oxy-PC with USC steam conditions from 11.6 percentage points to about 5.4 percentage points.

Reference: DOE/NETL-1291 Rev. 8/08

Figure 3.108 Performance comparisons with other studies

Even with the penalty of carbon capture, Case 11 shows that with USC steam conditions, warm recycle, heat integration, and future ASU and CPU benefits there is potential to achieve the same

net plant efficiencies achieved by current day state-of-the-art SC plants without carbon capture. The net efficiency for the DOE Case 1 is 39.4% and the predicted efficiency for Case 11 in this study is 39.3% so the performance is essentially the same. The LCOE for DOE Case 1 is 6.32¢/kW and the LCOE for Case 11 of this study is 7.92¢/kW. This shows the potential to reduce the cost of oxy-combustion to about 25.3% more than an equivalent air fired plant – well below the current DOE target of 35%. If this can be achieved it will mean that future USC oxy-PC plants with carbon capture can operate at the same net efficiency as modern air fired supercritical plants today for a 25% increase in LCOE.

Case 12 indicates the possibilities with subbituminous coal and USC conditions using current ASU and CPU technology. The 7.9 percentage point improvement in net efficiency and 1.65¢/kW lower LCOE for Case 12 of this study compared to the 2007 DOE Case 5 can be attributed to the beneficial impact of lower sulfur fuel in Case 12 on cost (but is detrimental to efficiency) and three major advancements that primarily improve efficiency, 1) warm recycle which provides some fuel efficiency and power gain, 2) integration of ASU and process heat which provides a significant increase in power generated, and 3) 2010 ASU and CPU technology which has greatly reduced the power requirements and costs for the ASU and CPU since 2007.

The impact of these improvements on cost of CO₂ removed and avoided is apparent in Figure 3.110. As might be expected, the costs removed and avoided for Case 4 are much higher than for a greenfield application.

Figure 3.109 Economic comparisons with other studies (LCOE)

Reference: DOE/NETL- 1291 Rev. 8/08

Figure 3.110 Cost of CO₂ removed and avoided for comparison cases**3.2.6.2. DOE Post Combustion Capture Study (DOE/NETL-401/110907)**

Refer to Figure 3.111 for performance, Figure 3.112 for LCOE, and Figure 3.113 for cost of CO₂ removed or avoided comparing the results from this study with results from DOE/NETL 401/11/0907 “Carbon Dioxide Capture from Existing Coal-Fired Power Plants rev. Nov.2007.

The first three bars in Figure 3.111, Figure 3.112, and Figure 3.113 labeled Case 1, Case 1-R1 and Case 1-R2 are Case 1 from this study and two modifications to improve oxy-PC retrofit performance in the mid-term and the longer-term. The mid-term improvement consists of integration of ASU and process heat to achieve a 2% increase in gross power and is labeled Case 1-R1. The longer-term improvement is the same heat integration plus future ASU and CPU designs and is labeled Case 1-R2.

The last three bars in Figure 3.111 labeled DOE 401 Case 1, DOE 401 Case 1-R1 and DOE 401 Case 1-R2 are Case 1 from the DOE/NETL 401/11/0907 study and two modifications to improve PCC retrofit performance and cost in the mid-term and longer-term. The mid-term improvement consists of a reduction in the solvent cost by 50% and is labeled Case DOE 401 Case 1-R1. The longer-term improvement consists of a reduction in the solvent cost by 50% plus a 10% reduction in auxiliary power consumption and is labeled Case DOE 401 Case 1-R2.

The performance results indicate that oxy-PC currently provides a potential 1.8 percentage point advantage over post combustion capture as defined in the DOE/NETL 401/11/0907 study (Case 1 vs. DOE 401 Case1). To assess the impact of potential advancements in the near to midterm, the oxy-PC retrofit Case 1 was modified as described previously. As Figure 3.111 shows, even with a 10% reduction in auxiliary power, the current oxy retrofit provides a 0.7 percentage point efficiency advantage (Case 1 vs. DOE 401 Case 1-R2).

Figure 3.111 Performance comparisons with post combustion capture study

Figure 3.112 Economic comparisons with other post combustion capture study (LCOE)

In regard to LCOE, current oxy retrofit also has a 0.38¢/kW advantage over current PCC retrofit (Case 1 vs. DOE 401 Case1). Case 1-R2 shows that with future advancements, the oxy retrofit could have about a 1.02 ¢/kW advantage over PCC retrofit (Case 1-R2 vs. Case 401 1-R2).

According to these comparisons of performance and cost, oxy-PC has a potential advantage over PCC for retrofit. The trends in costs of CO₂ removed and avoided are similar to the efficiency and LCOE graphs showing oxy retrofit as having an advantage. Considering the uncertainty band for these studies it is at least fair to say that oxy-PC does not indicate any disadvantage in performance relative to PCC and as indicated above, it also shows potential cost advantages.

3.2.7. Performance and Economic Results for Sensitivity Studies

3.2.7.1. Sensitivity to Air Infiltration

Four cases were evaluated to assess the impact of air infiltration on performance and cost as described in Section 3.2.2.4.1. The gas compositions for the four air infiltration cases are shown in Table 3.31. Retrofit Case 5 employing the cool recycle configuration with supercritical steam conditions firing Decker subbituminous coal with a dry primary scrubber and current ASU and

CPU technology was used as the basis for all four comparative cases. Case AI-1 assumes 2% of theoretical air (wet) in the furnace and 8% in the backend of the process between the boiler and ID fan inlet where the process pressure is below atmospheric. This total of 10% air infiltration is believed to be quite high and much lower levels are readily achievable. Case AI-2 assumes the same infiltration in the boiler but only 3% in the backend for a total of 5% air infiltration. Cases AI-3 and AI-4 reduce the boiler infiltration to 0% assuming a tight enclosure construction operating very slightly positive in the boiler (pressure balance point at the boiler outlet) and using dry, clean CO₂ for all sealing and cooling gas needs. Case AI-3 considers 3% infiltration in the backend and Case AI-4 assumes 2%.

Figure 3.113 Cost of CO₂ removed and avoided for comparison cases

Table 3.43 shows the performance for these four cases and Figure 3.114 shows the net efficiencies. Table 3.44 shows the cost breakdown, Table 3.45 provides the LCOE details and Figure 3.115 compares LCOE graphically. As Figure 3.114 shows, the impact of 10% air infiltration versus 2% air infiltration is about 0.82 percentage points of efficiency. However, the impact on cost is significant resulting in a 0.46¢/kW lower LCOE, or a 7.7% reduction.

PERFORMANCE

PARAMETER	CASE 5 AI-1	CASE 5 AI-2	CASE 5 AI-3	CASE 5 AI-4
Turbine Cycle Net Power (plant gross power), kWe	650000	650000	650000	650000
Application	Retrofit	Retrofit	Retrofit	Retrofit
Recycle	Cool	Cool	Cool	Cool
Steam pressure	SC	SC	SC	SC
Firing System	PC	PC	PC	PC
Existing Scrubber Type	SDA	SDA	SDA	SDA
Polishing Scrubber Stream	PRI+CPU	PRI+CPU	PRI+CPU	PRI+CPU
Type of ASU (C=current, F= Future technology)	ASU-C	ASU-C	ASU-C	ASU-C
Type of Compression (C=current, F= Future technology)	CPU-C	CPU-C	CPU-C	CPU-C
Coal Type	Decker	Decker	Decker	Decker
Heating Value (HHV)	9540	9540	9540	9540
Coal Ash Content	3.98%	3.98%	3.98%	3.98%
Sulfur	0.34%	0.34%	0.34%	0.34%
Carbon	55.15%	55.15%	55.15%	55.15%
Oxygen	12.57%	12.57%	12.57%	12.57%
Hydrogen	3.83%	3.83%	3.83%	3.83%
Nitrogen	0.73%	0.73%	0.73%	0.73%
Moisture	23.40%	23.40%	23.40%	23.40%
Base Plant Auxiliary Power	29510	29510	29510	29510
Air Separation Unit Main Compressor	85000	85000	85000	85000
Trona	0	0	0	0
Polishing Scrubber	2482	2358	2319	2295
Compression & Purification Unit	56000	54000	49000	43000
Additional Cooling Tower Fans (ASU/ CPU Cooling)	2513	2592	2639	2656
TOTAL AUXILIARY POWER (kWe)	175505	173460	168468	162460
Net Power (kWe)	474495	476540	481540	487540
Pre-retrofit net plant efficiency (%)	38.51%	38.51%	38.51%	38.51%
Pre-retrofit Heat Rate (Btu/kWh HHV)	8863	8863	8863	8863
Pre-retrofit (Aux Power)/(Gross Power) Ratio	5.2%	5.2%	5.2%	5.2%
Turbine Cycle Heat Rate (Btu/kWh HHV)	7236.0	7236.0	7236.0	7236.0
Fuel (Boiler) Efficiency	86.1%	86.1%	86.1%	86.1%
Net Plant Heat Rate (Btu/kWh HHV)	11510	11461	11342	11202
Net Plant Efficiency	29.64%	29.77%	30.08%	30.46%
CONSUMABLES				
As-Received Coal Feed, lb/h	572483	572483	572483	572483
Thermal Input, kWth	1600761	1600761	1600761	1600761
WFGD Limestone Sorbent Feed, lb/h (Ca/S)=1.05	0	0	0	0
SDA Pebble Lime Feed, lb/h	6749	6749	6749	6749
Trona (sodium bicarbonate) for Polishing FGD, lb/h	1926	1829	1829	1829
Trona (sodium bicarbonate), for SO ₃ control, lb/h	0	0	0	0
OXYGEN				
Oxygen Purity	95.0%	95.0%	95.0%	95.0%
Oxidant Required (short tons/day) - includes impurities	11648	12016	12233	12311
CO2 REMOVAL				
Recovery Efficiency	90.0%	90.0%	90.0%	90.0%
Total Gas Flow to CPU (lb/h)	1644076	1464079	1398133	1362120
Carbon Dioxide Produced (lb/h)	1156916	1156916	1156916	1156916
Carbon Dioxide Produced (short tons/d)	13883	13883	13883	13883
Carbon Dioxide Produced (short tons/yr)	4307197	4307197	4307197	4307197
Carbon Dioxide Removed (lb/h)	1041224	1041224	1041224	1041224
Carbon Dioxide Removed (short tons/d)	12495	12495	12495	12495
Carbon Dioxide Removed (short tons/yr)	3876477	3876477	3876477	3876477

Table 3.43 Performance results for variations of air infiltration

COSTS					COSTS				
PARAMETER	CASE 5 AI-1	CASE 5 AI-2	CASE 5 AI-3	CASE 5 AI-4	PARAMETER	CASE 5 AI-1	CASE 5 AI-2	CASE 5 AI-3	CASE 5 AI-4
	650000	650000	650000	650000	8.1 Steam TG & Accessories	k\$			
Application	Retrofit	Retrofit	Retrofit	Retrofit	8.2 Turbine Plant Auxiliaries	k\$			
Recycle	Cool	Cool	Cool	Cool	8.3 Condenser & Auxiliaries	k\$			
Steam pressure	SC	SC	SC	SC	8.4 Steam Piping	k\$			
Firing System	PC	PC	PC	PC	8.9 TG Foundations	k\$			
Existing Scrubber Type	SDA	SDA	SDA	SDA	SUBTOTAL	k\$			
Polishing Scrubber Stream	PRI+CPU	PRI+CPU	PRI+CPU	PRI+CPU					
Type of ASU (C=current, F= Future technology)	ASU-C	ASU-C	ASU-C	ASU-C	9.1 Cooling Towers	k\$	1001	1001	1001
Type of Compression (C=current, F= Future technology)	CPU-C	CPU-C	CPU-C	CPU-C	9.2 Circulating Water Pumps	k\$	168	168	168
Coal Type	Decker	Decker	Decker	Decker	9.3 Circ. Water System Auxiliaries	k\$	49	49	49
					9.4 Circ. Water Piping	k\$	706	706	706
1.1 Coal Receive & Unload	k\$				9.5 Make-up Water System	k\$	0	0	0
1.2 Coal Stackout & Reclaim	k\$				9.6 Component Cooling Water Sys	k\$	0	0	0
1.3 Coal Conveyors & Yard Breaker	k\$				9.9 Circ. Water System Foundations	k\$	542	542	542
1.4 Other Coal Handling	k\$				SUBTOTAL	k\$	2465	2465	2465
1.5 Sorbent Receive & Unload	k\$								
1.6 Sorbent stackout & Reclaim	k\$				10.1 Ash Coolers	k\$			
1.7 Sorbent Conveyors	k\$				10.2 Cyclone Ash Letdown	k\$			
1.8 Other Sorbent Handling	k\$				10.3 HGU Ash Letdown	k\$			
1.9 Coal & Sorbent Hnd. Foundations	k\$				10.4 High Temperature Ash Piping	k\$			
SUBTOTAL	k\$				10.5 Other Ash Recovery Equipment	k\$			
					10.6 Ash Storage Silos	k\$			
2.1 Coal Crushing & Drying	k\$				10.7 Ash Transport & Feed Equipment	k\$			
2.2 Coal Conveyor to Storage	k\$				10.8 Misc. Ash Handling Equipment	k\$			
2.3 Coal Injection System	k\$				10.9 Ash/Spent Sorbent Foundations	k\$			
2.4 Misc. Coal Prep Equipment	k\$				SUBTOTAL	k\$			
2.5 Sorbent Prep Equipment	k\$								
2.6 Sorbent Storage & Feed	k\$				11.1 Generator Equipment	k\$	0	0	0
2.7 Sorbent Injection System	k\$				11.2 Station Service Equipment	k\$	0	0	0
2.8 Booster Air Supply System	k\$				11.3 Switchgear & Motor Control	k\$	0	0	0
2.9 Coal & sorbent Feed Foundation	k\$				11.4 Conduit & Cable Tray	k\$	0	0	0
SUBTOTAL	k\$				11.5 Wire & Cable	k\$	14431	14703	14862
					11.6 Protective Equipment	k\$	0	0	0
3.1 Feedwater System	k\$				11.7 Standby Equipment	k\$	0	0	0
3.2 Water Makeup & Pretreating	k\$				11.8 Main Power Transformers	k\$	7124	7124	7124
3.3 Other Feedwater Subsystems	k\$				11.9 Electrical Foundations	k\$	1161	1161	1161
3.4 Service Water Systems	k\$				SUBTOTAL	k\$	22716	22988	23147
3.5 Other Boiler Plant Systems	k\$								
3.6 FO Supply Sys & Net Gas	k\$				12.1 PC Control Equipment	k\$	0	0	0
3.7 Waste Treatment Equipment	k\$				12.2 Combustion Turbine Control	k\$	0	0	0
3.9 Misc. Power Plant Equipment	k\$				12.3 Steam Turbine Control	k\$	0	0	0
SUBTOTAL	k\$				12.4 Other Major Component Control	k\$	0	0	0
					12.5 Signal Processing Equipment	k\$	0	0	0
4.1 Boiler	k\$	35765	35914	36112	12.6 Control Boards, Panels & Racks	k\$	527	527	527
4.2 ASU/Oxidant Compression	k\$	359551	359551	359551	12.7 Computer & Accessories	k\$	3702	3702	3702
SUBTOTAL	k\$	395315	395464	395663	12.8 Instrument Wiring & Tubing	k\$	5427	5427	5427
					12.9 Other I & C Equipment	k\$	2982	2982	2982
5.1 Absorber Vessels & Accessories	k\$	0	0	0	SUBTOTAL	k\$	12637	12637	12637
5.2 Other FGD	k\$	0	0	0					
5.3 Baghouse & Accessories	k\$	0	0	0	13.1 Site Preparation	k\$	610	621	628
5.4 Other Particulate Removal Materials	k\$	0	0	0	13.2 Site Improvements	k\$	2155	2195	2219
5.5 Gypsum Dewatering System	k\$	0	0	0	13.3 Site Facilities	k\$	0	0	0
5.6 Mercury Removal System	k\$	0	0	0	SUBTOTAL	k\$	2764	2816	2847
5.7 Sodium Scrubber/Quench Cooler	k\$	43655	42545	42198					
5.8 Trona Injection System	k\$	0	0	0	14.1 Boiler Building	k\$			
SUBTOTAL	k\$	43655	42545	42198	14.2 Turbine Building	k\$			
					14.3 Administration Building	k\$			
5B.1 CO2 Cooler in separate vessel	k\$	0	0	0	14.4 Circulation Water Pumphouse	k\$			
5B.2 Compression & Drying	k\$	231001	216481	209881	14.5 Water Treatment Buildings	k\$			
SUBTOTAL	k\$	231001	216481	209881	14.6 Machine Shop	k\$			
					14.7 Warehouse	k\$			
7.1 Flue Gas Recycle Heat Exchanger	k\$	2411	2480	2521	14.8 Other Building s & Structures	k\$			
7.2 SCR System	k\$	0	0	0	14.9 Waste Treating Building & Str.	k\$			
7.3 Ductwork	k\$	7635	7693	7734	SUBTOTAL	k\$			
7.4 Stack	k\$	0	0	0					
7.9 Duct & Stack Foundations	k\$	3589	3589	3589					
SUBTOTAL	k\$	13635	13762	13844					
					15.1 Transport		60846	60846	60846
					15.2 Storage Wells		8429	8429	8429
					15.3 Monitoring		23402	23402	23402
					SUBTOTAL		92677	92677	92677
						k\$	724189	709159	702682
						k\$	816866	801835	795359
						\$/kW	1526.23	1488.14	1459.24
						\$/kW	1721.55	1682.62	1651.70

Table 3.44 Cost summary results for variations of air infiltration

LCOE

PARAMETER	CASE 5 AI-1	CASE 5 AI-2	CASE 5 AI-3	CASE 5 AI-4
Turbine Cycle Net Power (plant gross power) kWe	650000	650000	650000	650000
Application	Retrofit	Retrofit	Retrofit	Retrofit
Recycle	Cool	Cool	Cool	Cool
Steam pressure	SC	SC	SC	SC
Firing System	PC	PC	PC	PC
Existing Scrubber Type	SDA	SDA	SDA	SDA
Polishing Scrubber Stream	PRI+CPU	PRI+CPU	PRI+CPU	PRI+CPU
Type of ASU (C=current, F= Future technology)	ASU-C	ASU-C	ASU-C	ASU-C
Type of Compression (C=current, F= Future technology)	CPU-C	CPU-C	CPU-C	CPU-C
Coal Type	Decker	Decker	Decker	Decker
Net Power (kWe)	474495	476540	481540	487540
Fuel Cost (\$/MBtu)	1.5	1.5	1.5	1.5
Net Plant Heat Rate (Btu/kWh)	11510	11461	11342	11202
Book Life (years)	30	30	30	30
Capacity Factor	85%	85%	85%	85%
Total Plant Cost (TPC) wo/T,S&M (k\$)	724189	709159	702682	699957
Total Plant Cost (TPC) w/T,S&M (k\$)	816866	801835	795359	792634
Aux Power before Retrofit (as % of GP, w/o BFP)	5%	5%	5%	5%
Net Power Before Retrofit (kWe)	616200	616200	616200	616200
Levelized Cost of Replacement Power (\$/kW)	0.064	0.064	0.064	0.064
Annual Net MWh before Retrofit	4588225	4588225	4588225	4588225
Annual Net MWh after Retrofit	3533090	3548317	3585547	3630223
Power Reduction MWh/yr	1055135	1039908	1002678	958002
Makeup Power CO ₂ (36% fleet avg. efficiency) lb/h	241825	238335	229803	219563
ANNUAL INCREMENTAL COSTS (\$1000)				
Fixed Operating & Maintenance Costs	6974	6849	6795	6772
Variable Operating & Maintenance Costs	7242	7092	7027	7000
Levelized Replacement Power Cost	67529	66554	64171	61312
Consumable Operating Costs (less Fuel)	359	359	359	359
Fuel Cost (k\$)	0	0	0	0
LEVELIZATION (20 year)				
Fixed O&M (LF=1.16)	0.229	0.224	0.220	0.216
Variable O&M (LF=1.16) including replacement power	2.149	2.107	2.017	1.913
Consumables (LF=1.16)	0.012	0.012	0.012	0.011
Fuel (LF=1.2)	0.000	0.000	0.000	0.000
Total Production Cost	2.390	2.343	2.249	2.140
Capital Cost Factor wo/T,S&M (17.5)	3.585	3.495	3.427	3.372
Capital Cost Factor w/T,S&M (17.5)	4.043	3.952	3.879	3.818
LCOE w/o TS&M (¢/kW)	5.97	5.84	5.68	5.51
LCOE w TS&M (¢/kW)	6.43	6.30	6.13	5.96
CO₂ COSTS				
LCOE w/o CO ₂ Removal (DOE 1291 Case 1)				
CO ₂ Produced w/o CO ₂ Removal (lb/h)				
\$/ton CO ₂ Removed w/o TS&M	54.45	53.44	52.50	51.62
\$/ton CO ₂ Avoided w/o TS&M	73.14	71.43	69.33	67.22
\$/ton CO ₂ Removed w TS&M	58.63	57.62	56.68	55.80
\$/ton CO ₂ Avoided w TS&M	78.76	77.02	74.85	72.66

Table 3.45 Economic results for variations of air infiltration

Figure 3.114 Performance results for variations of air infiltration

Figure 3.115 Economic results for variations of air infiltration

Figure 3.116 Cost of CO₂ removed and avoided for variations of air infiltration

Figure 3.117 Impact of air infiltration on net plant efficiency

Figure 3.118 Impact of air infiltration on LCOE

Figure 3.117 shows the impact of air infiltration on net plant efficiency and Figure 3.118 shows the impact on LCOE graphically. The impact on efficiency from 2% to 5% air infiltration is 0.7 percentage points of efficiency loss, a 2.7% reduction in net plant efficiency, along with an increase in LCOE of 0.46 ¢/kW, a or 7.7% increase in LCOE. Beyond 5% air infiltration the impact on performance is much more moderate at 0.1 percentage point loss between 5% and 10%. The impact on LCOE is again of greater significance than the impact on efficiency but the curve is not as steep as between 2% and 5% air infiltration.

3.2.7.2. Sensitivity to Oxidant Purity

Four cases were evaluated to assess the impact of reducing oxidant purity on performance and cost as described in Section 3.2.2.4.2. The gas compositions for the four oxidant purity cases are shown in Table 3.32. Retrofit Case 5 employing the cool recycle configuration with supercritical steam conditions firing Decker subbituminous coal with a dry primary scrubber and current ASU and CPU technology was used as the basis for all four comparative cases. Air infiltration of 2% in the boiler and 3% in the backend equipment for a total of 5% was assumed and excess oxygen was held at 3% at the boiler outlet for all cases.

Case OP-1 assumes 95% oxidant purity (% oxygen in the oxidant from the ASU; the remainder is nitrogen and argon), which was the basis for the study, Case OP-2 assumes 90%, Case OP-3 assumes 85% and Case OP-4 assumes 80%. Table 3.46 shows the performance for these four cases and Figure 3.119 compares the net efficiencies. Table 3.47 shows the cost breakdown, Table 3.48 provides the LCOE details, and Figure 3.120 shows LCOE graphically.

Section 3.2.2.3.1 above (under the heading “Oxygen Purity”) discusses the impact of oxidant purity on the capital cost and power consumption for the ASU and CPU. Based on those parameters alone, which are believed to govern the outcome, a maximum purity of about 96.5% O₂ is believed economical. This is based on the premise that the great difference in flows handled by the ASU compared to the CPU results in the cost and power consumption for the ASU outweighing any savings in the CPU.

PERFORMANCE

PARAMETER	CASE 5 OP-1	CASE 5 OP-2	CASE 5 OP-3	CASE 5 OP-4
Turbine Cycle Net Power (plant gross power), kWe	650000	650000	650000	650000
Application	Retrofit	Retrofit	Retrofit	Retrofit
Recycle	Cool	Cool	Cool	Cool
Steam pressure	SC	SC	SC	SC
Firing System	PC	PC	PC	PC
Existing Scrubber Type	SDA	SDA	SDA	SDA
Polishing Scrubber Stream	PRI+CPU	PRI+CPU	PRI+CPU	PRI+CPU
Type of ASU (C=current, F= Future technology)	ASU-C	ASU-C	ASU-C	ASU-C
Type of Compression (C=current, F= Future technology)	CPU-C	CPU-C	CPU-C	CPU-C
Coal Type	Decker	Decker	Decker	Decker
Heating Value (HHV)	9540	9540	9540	9540
Coal Ash Content	3.98%	3.98%	3.98%	3.98%
Sulfur	0.34%	0.34%	0.34%	0.34%
Carbon	55.15%	55.15%	55.15%	55.15%
Oxygen	12.57%	12.57%	12.57%	12.57%
Hydrogen	3.83%	3.83%	3.83%	3.83%
Nitrogen	0.73%	0.73%	0.73%	0.73%
Moisture	23.40%	23.40%	23.40%	23.40%
Base Plant Auxiliary Power	29510	29510	29510	29510
Air Separation Unit Main Compressor	85000	82000	80000	78000
Trona	0	0	0	0
Polishing Scrubber	2358	2543	2753	3000
Compression & Purification Unit	54000	57000	60000	63000
Additional Cooling Tower Fans (ASU/ CPU Cooling)	2592	2911	3282	3726
TOTAL AUXILIARY POWER (kWe)	173460	173964	175545	177236
Net Power (kWe)	476540	476036	474455	472764
Pre-retrofit net plant efficiency (%)	38.51%	38.51%	38.51%	38.51%
Pre-retrofit Heat Rate (Btu/kWh HHV)	8863	8863	8863	8863
Pre-retrofit (Aux Power)/(Gross Power) Ratio	5.2%	5.2%	5.2%	5.2%
Turbine Cycle Heat Rate (Btu/kWh HHV)	7236.0	7236.0	7236.0	7236.0
Fuel (Boiler) Efficiency	86.1%	86.1%	86.1%	86.1%
Net Plant Heat Rate (Btu/kWh HHV)	11461	11473	11511	11552
Net Plant Efficiency	29.77%	29.74%	29.64%	29.54%
CONSUMABLES				
As-Received Coal Feed, lb/h	572483	572483	572483	572483
Thermal Input, kWth	1600761	1600761	1600761	1600761
WFGD Limestone Sorbent Feed, lb/h (Ca/S)=1.05	0	0	0	0
SDA Pebble Lime Feed, lb/h	6749	6749	6749	6749
Trona (sodium bicarbonate) for Polishing FGD, lb/h	1829	1973	2136	2328
Trona (sodium bicarbonate), for SO ₃ control, lb/h	0	0	0	0
OXYGEN				
Oxygen Purity	95.0%	90.0%	85.0%	80.0%
Oxidant Required (short tons/day) - includes impurities	12016	13497	15215	17275
CO2 REMOVAL				
Recovery Efficiency	90.0%	90.0%	90.0%	90.0%
Total Gas Flow to CPU (lb/h)	1464079	1523922	1588331	1660237
Carbon Dioxide Produced (lb/h)	1156916	1156916	1156916	1156916
Carbon Dioxide Produced (short tons/d)	13883	13883	13883	13883
Carbon Dioxide Produced (short tons/yr)	4307197	4307197	4307197	4307197
Carbon Dioxide Removed (lb/h)	1041224	1041224	1041224	1041224
Carbon Dioxide Removed (short tons/d)	12495	12495	12495	12495
Carbon Dioxide Removed (short tons/yr)	3876477	3876477	3876477	3876477

Table 3.46 Performance results for variations of oxidant purity

Table 3.47 Cost summary results for variations of oxidant purity

LCOE

PARAMETER	CASE 5 OP-1	CASE 5 OP-2	CASE 5 OP-3	CASE 5 OP-4
Turbine Cycle Net Power (plant gross power) kWe	650000	650000	650000	650000
Application	Retrofit	Retrofit	Retrofit	Retrofit
Recycle	Cool	Cool	Cool	Cool
Steam pressure	SC	SC	SC	SC
Firing System	PC	PC	PC	PC
Existing Scrubber Type	SDA	SDA	SDA	SDA
Polishing Scrubber Stream	PRI+CPU	PRI+CPU	PRI+CPU	PRI+CPU
Type of ASU (C=current, F= Future technology)	ASU-C	ASU-C	ASU-C	ASU-C
Type of Compression (C=current, F= Future technology)	CPU-C	CPU-C	CPU-C	CPU-C
Coal Type	Decker	Decker	Decker	Decker
Net Power (kWe)	476540	476036	474455	472764
Fuel Cost (\$/MBtu)	1.5	1.5	1.5	1.5
Net Plant Heat Rate (Btu/kWh)	11461	11473	11511	11552
Book Life (years)	30	30	30	30
Capacity Factor	85%	85%	85%	85%
Total Plant Cost (TPC) w/o T,S&M (k\$)	709159	720587	732855	746325
Total Plant Cost (TPC) w/T,S&M (k\$)	801835	813264	825532	839002
Aux Power before Retrofit (as % of GP, w/o BFP)	5%	5%	5%	5%
Net Power Before Retrofit (kWe)	616200	616200	616200	616200
Levelized Cost of Replacement Power (\$/kW)	0.064	0.064	0.064	0.064
Annual Net MWh before Retrofit	4588225	4588225	4588225	4588225
Annual Net MWh after Retrofit	3548317	3544564	3532792	3520201
Power Reduction MWh/yr	1039908	1043661	1055433	1068024
Makeup Power CO ₂ (36% fleet avg. efficiency) lb/h	238335	239195	241894	244779
ANNUAL INCREMENTAL COSTS (\$1000)				
Fixed Operating & Maintenance Costs	6849	6944	7047	7159
Variable Operating & Maintenance Costs	7092	7206	7329	7463
Levelized Replacement Power Cost	66554	66794	67548	68354
Consumable Operating Costs (less Fuel)	359	359	359	359
Fuel Cost (k\$)	0	0	0	0
LEVELIZATION (20 year)				
Fixed O&M (LF=1.16)	0.224	0.227	0.231	0.236
Variable O&M (LF=1.16) including replacement power	2.107	2.120	2.153	2.188
Consumables (LF=1.16)	0.012	0.012	0.012	0.012
Fuel (LF=1.2)	0.000	0.000	0.000	0.000
Total Production Cost	2.343	2.359	2.396	2.435
Capital Cost Factor w/o T,S&M (17.5)	3.495	3.555	3.628	3.708
Capital Cost Factor w/T,S&M (17.5)	3.952	4.012	4.087	4.168
LCOE w/o TS&M (¢/kW)	5.84	5.91	6.02	6.14
LCOE w TS&M (¢/kW)	6.30	6.37	6.48	6.60
CO₂ COSTS				
LCOE w/o CO ₂ Removal (DOE 1291 Case 1)				
CO ₂ Produced w/o CO ₂ Removal (lb/h)				
\$/ton CO ₂ Removed w/o TS&M	53.44	54.08	54.90	55.79
\$/ton CO ₂ Avoided w/o TS&M	71.43	72.37	73.74	75.25
\$/ton CO ₂ Removed w TS&M	57.62	58.26	59.08	59.97
\$/ton CO ₂ Avoided w TS&M	77.02	77.97	79.36	80.89

Table 3.48 Economic results for variations of oxidant purity

Figure 3.119 Performance results for variations of oxidant purity

Figure 3.120 Economic results for variations of oxidant purity

Figure 3.121 Cost of CO₂ removed and avoided for variations of oxidant purity

Figure 3.122 Impact of oxidant purity on net plant efficiency

Figure 3.123 Impact of oxidant purity on LCOE

Figure 3.122 shows the impact of oxidant purity on net plant efficiency and Figure 3.123 shows the impact on LCOE graphically. The impact on efficiency between 95% and 80% oxidant purity is a loss of 0.23 percentage points of efficiency loss, a 0.7% reduction in net plant efficiency, along with an increase in LCOE of 0.30 ¢/kW, a 4.9% increase in LCOE. The loss in net efficiency appears nearly linear down to about 90% purity and then flattens out while the LCOE penalty is nearly linear over the entire range.

3.2.8. Summary and Conclusions

This study provides the ability to compare a variety of retrofit conditions in terms of performance and LCOE. The impact of fuel, type of primary scrubber, combustion system type (PC or Cyclone), and ASU and CPU technology can be readily understood. Though the costs are estimated by modifying the detailed cost components from the previous study “Pulverized Coal Oxy-combustion Power Plants” DOE/NETL-2007/1291 revised August 2008, it is believed they are sufficiently accurate to draw general observations and perhaps conclusions at this level. Certainly they are sufficiently accurate to show that oxy-combustion has the potential to be a lower cost retrofit or greenfield option compared to current PCC technology as reported in the study “Carbon Dioxide Capture from Existing Coal-Fired Power Plant” study DOE/NETL-401-110907.

The results of this study should provide strong motivation to pursue further and more in-depth investigation into the cost of oxy-combustion as a retrofit technology for the existing fleet. Although oxy-combustion may not provide as simple an avenue to partial capture on an individual unit as PCC, it is questionable whether an owner would install partial capture for anything except a demonstration since regulations are likely to require full capture at some future point and that would increase cost significantly. Partial capture aside, this study at 90% CO₂ capture shows oxy-combustion has the potential to be as low or lower in cost than PCC even with reasonable future improvements (see Figure 3.112).

The air infiltration sensitivity analysis shows that air infiltration should be kept as low as possible and that the impact is steep between 2% and 5% and then moderates out to 10%. Clearly no air infiltration is best but the amount of effort (cost) to minimize air infiltration must be weighed against the life-cycle cost. Figure 3.124 shows the breakeven capital investment to

mitigate air infiltration. This figure is based on back-calculation of the capital investment represented by the incremental increase in LCOE as air infiltration increases relative to the 2% air infiltration base. It shows that an investment on the order of \$90 million dollars could be justified to reduce air infiltration from 10% down to 2%. This represents about 12% of the total plant cost without CO₂ transportation, storage, and monitoring (TS&M).

Figure 3.124 Breakeven capital investment to mitigate air infiltration

The oxidant purity sensitivity analysis shows that oxidant purity has considerably less impact than air infiltration and the trends in both net efficiency and LCOE are nearly linear. However, decreasing oxidant purity below 95% has no benefit in that it not only reduces net efficiency but it also raises LCOE. This demonstrates that at least 95% purity is beneficial, and higher purity may further increase benefits. However, current thinking is that 96.5% may become the standard in that above 96.5% there is a technology change that has a drastic impact on ASU cost.

3.3. Phase II, Part B – Assessment of Potential for Geologic CO₂ Storage for Existing US Power Plants

For Phase II of the project, Battelle assessed the potential for storing CO₂ from existing US power plants in deep geologic formations. The assessment was based on a review of geologic data in the vicinities of selected existing boilers. These data were used to qualitatively determine the suitability of each selected plant for CO₂ storage. Parameters that were considered critical to the process were identified and established as criteria for distinguishing between plants that may be acceptable for storage, vs. plants that may be unacceptable. The National Energy Technology Laboratory's (NETL) Coal Power Plant Database (CPPDB) was the main source for plant data. This database contains information on 1924 boilers and associated units; 191 fields provide information on plant parameters. In the interest of controlling project cost, the number of plants to be considered was reduced by selecting boilers above 200 MWe⁷. The key data to be used in

⁷ As explained above (Section 3.2.1) the reasons for not considering 200 MWe and smaller boilers are that retrofit is too costly as was explained on top of page 139 - retrofit was found to be too costly because most of these smaller units have no scrubber, are site constrained and economy of scale works against them.

this investigation are: plant identification, plant location, and boiler capacity (MWe). Several candidate sites for CO₂ storage were identified based on a qualitative assessment of each plant's suitability for storage. The locations of each candidate plant site that met screening criteria were plotted on geologic maps.

3.3.1. Site Screening to Identify Potentially Suitable Sequestration Demonstration Sites

Another important aspect of the overall geologic storage task was to consider high-level screening criteria to identify potentially suitable site locations. The criteria selected by the project team to evaluate plant sites for CO₂ storage potential were: boiler specifications; location in relation to deep sedimentary basins; and degree of seismic hazard (Figure 3.125). The boiler specification included nameplate rating (all exceeding 200 MWe generating capacity), boiler manufacturer, and CO₂ emission rate. Location, and especially distance of less than 50 miles to a deep sedimentary basin, is an important consideration to avoid long run pipelines. Seismic hazard was selected as a screening parameter to avoid expenses of additional construction requirements.

Figure 3.125. Screening Flow Diagram.

The current screening is a high-level evaluation of boilers in relation to regional geological setting. Overall, the screening, site assessment, and sequestration design are a multiphase, multi-year effort. Once a site is identified, a more detailed feasibility study may be completed to identify storage intervals. If the project proceeds further, the future phases may consist of site-specific seismic surveys, drilling and characterization, detailed reservoir modeling and system design. The results of this initial assessment should not be viewed or interpreted as a definitive assessment of suitability of candidate geologic CO₂ storage formations, the presence of suitable caprock, or sufficient injectivity to allow CO₂ sequestration to be carried out in an economic manner. Rather, this should be used as an initial screening assessment for potential storage opportunities for the boiler sites.

3.3.1.1. Boiler Size

Boiler information for the screening was obtained from the National Energy Technology Laboratory (NETL) Coal Power Plant Database (CPPDB). This database details emissions, generation, location, and firing information for all coal power plants in the United States. The database lists 1,924 boilers and provides 191 fields of information. The information is based on the most recent release of the Annual Steam-Electric Plant Operation and Design data form, Energy Information Agency (EIA) form 767. The most current data available from DOE is from 2005. Data used in this investigation were obtained from a spreadsheet (*netl_cppdb_2007_-_public_-_boiler_list_-_rev1*) amended by B&W. Data is listed for individual boilers, and many plants have multiple boilers. Note that the screening is based on individual boilers, not plant sites.

3.3.1.2. Proximity to Deep Sedimentary Basins

The deep saline basins shape file used to determine if a boiler location was in or near a deep saline formation was provided by NatCarb, a project funded by the US Department of Energy's National Energy Technology Laboratory. This work was performed using ESRI Arc Map 9.3.1, a part of ArcGIS Desktop 9.3.1.

3.3.1.3. Seismic Hazards

Seismic hazard represents items related to earthquake ground shaking, faults, seismicity, and geodesy. Areas with high seismic hazard may be unsuitable for CO₂ storage due to fault leakage pathways, seismic instability, and or ground instability which would preclude deep well injection. It should be noted that CO₂ storage may be applied in areas of low to moderate seismic hazard with proper system design, operation, and monitoring (28). However, areas with higher seismic hazard may have higher cost and risk associated with construction, operation, and public outreach. Therefore, seismic hazard is a useful screening criterion for evaluating CO₂ storage sites.

The USGS Earthquake Seismic Hazards program provided the seismic hazard contour lines used to assign a seismic hazard value to each boiler location. The US Geological Survey (USGS) National Seismic Hazard Maps (29) display earthquake ground motions for various probability levels across the United States and are applied in seismic provisions of building codes, insurance rate structures, risk assessments, and other public policy (Figure 3.126). The resulting maps are derived from seismic hazard curves calculated on a grid of sites across the United States that describe the frequency of exceeding a set of ground motions. Hazard ratings expressed as levels

of horizontal shaking in % g have a 2-in-100 chance of being exceeded in a 50-year period. In general, areas with more earthquake activity such as the west coast of California have higher seismic hazard. Areas near the New Madrid Fault zone in the Midwest also have a high seismic hazard.

Figure 3.126. USGS Seismic Hazard Map (Petersen et al., 2008)

3.3.2. Results of Applying High-Level Screening Criteria

The first screening step involved selecting coal burning wall-fired or Cyclone boilers with generator nameplate rating over 200 MWe. In addition, twelve boilers with natural gas or distillate fuel oil listed as a primary alternate fuel that can be burned were screened out, because these plants have readily available options for reducing CO₂ emissions. The initial screening reduced the population of boilers from 1924 to 251. Many facilities have multiple boilers. The 251 boilers are located at 143 plants and are listed in the Appendix (Section 8.3).

The next screening step involved identifying boilers located within 50 miles of sedimentary basins deeper than 800 m. These sedimentary basins may have suitable deep saline reservoirs or depleted oil and gas formations capable of CO₂ storage in supercritical phase. Deep saline formation maps were based on the US DOE 2008 Carbon Sequestration Atlas database (8) developed as part of the Carbon Sequestration Partnership program. Maps generally outline the major sedimentary basins throughout the US with suitable depth for CO₂ storage (>800 m). This screening step reduced the boiler population to 183.

The final screening step involved identifying locations with low seismic hazard. Boiler sites were plotted against the seismic hazard maps from the USGS National Seismic Hazards map (29).

Boiler sites with seismic hazard of greater than 6% g were removed from the database. This screening step reduced the list of boiler sites to 143.

Figure 3.127 summarizes the screening population according to generator nameplate rating. As shown, the general list of boilers follows a bi-modal distribution with most boilers less than 700 MW capacity. Figure 3.128 summarizes the screening process according to boiler CO₂ output. The initial population is weighted toward plants with emissions less than 3,000,000 tons CO₂ per year. However, the screened list trends toward boilers with emissions more than 3,000,000 tons CO₂ per year. Overall, the screening suggests that there may be a large amount of less efficient boilers in suitable locations for CO₂ storage. These boilers may have higher CO₂ emissions, but lower generating capacity. A detailed assessment of boiler design and CO₂ storage feasibility would be required to qualify sites for CCS.

Figure 3.127. Screening Population by Generator Nameplate Rating.

Figure 3.128. Screening population by boiler annual CO₂ emissions

3.3.2.1. Geographic Information System (GIS) Results

The initial database started with 1924 boilers located throughout the continental United States as shown in Figure 3.129. The first selection criterion was to choose only those boilers that were wall fired and Cyclone boilers above 200 MWe nameplate rating. Twenty two boilers with ability to burn natural gas or distillate fuel oil were not counted. This brought the total number of eligible boilers down to 251 as shown in Figure 3.130.

Figure 3.129. Locations of boilers in the original database before screening

Figure 3.130. Boilers meeting size requirements (>200 MWe)

The next selection criterion was to choose those boilers located within 50 miles of a deep sedimentary basin. Deep sedimentary basin maps were based on the *US DOE 2008 Carbon Sequestration Atlas* (8) database developed as part of the Carbon Sequestration Partnership program. These maps outline the presence of porous rock saturated with brine which may be candidates for CO₂ storage. Maps generally outline the major sedimentary basins throughout the US with suitable depth for CO₂ storage (>800 m). By applying these criteria, the number of boilers was brought down to 183 as shown in Figure 3.131.

Figure 3.131. Plant locations in close proximity to deep sedimentary basins

The final selection criterion was based on seismic risk. The US Geological Survey (USGS) National Seismic Hazard Maps display earthquake ground motions for various probability levels across the United States. The maps are derived from seismic hazard curves calculated on a grid of sites across the United States that describe the frequency of exceeding a set of ground motions. Hazard ratings expressed as levels of horizontal shaking in % g that have a 2-in-100 chance of being exceeded in a 50-year period. Figure 3.132 shows a seismic hazard of 1-2 and has 66 boilers that qualify. Figure 3.133 shows a seismic hazard of 1-4 and has 136 boilers that qualify. Figure 3.134 shows a seismic hazard of 1-6 and has 146 boilers that qualify.

Figure 3.132. Plant locations in areas with low seismic risk, SH 1-2

Figure 3.133. Plant locations in areas with seismic risk, SH 1-4

Figure 3.134. Plant locations in areas with seismic risk, SH 1-6

3.3.3. Implications for Oxy-combustion Retrofitting of Coal-fired Power Plants in the Continental US

The criteria selected by the project team to evaluate plant sites for CO₂ storage potential were: boiler specifications; location in relation to deep sedimentary basins; and degree of seismic hazard. These criteria reduced the number of applicable boilers from 1924 down to 146. These boilers were predominantly located in the Ohio River Valley and the Gulf Coast with a few scattered around the inter-mountain West and the Dakotas. The boilers located near the Ohio River Valley and the Gulf Coast are especially good sites for potential CCS projects as they are located in areas with heavy CO₂ emissions due to power plants and refineries. For each of the 146 identified boilers, a more detailed feasibility study may be completed to identify storage intervals. If the project proceeds further, the future phases may consist of site-specific seismic surveys, drilling and characterization, detailed reservoir modeling and system design. It should be mentioned that this does not mean that oxy-combustion in other boilers is not feasible. The locations of the existing plants have been examined when the units were constructed and have been running for decades. These 146 boilers are especially good and should be considered for demonstration of the technology.

4. CONCLUSIONS AND RECOMMENDATIONS

From the work performed in this project, the following conclusions and recommendations are derived.

4.1. Conclusions

From the pilot-scale evaluation:

- Oxy-firing is a technically viable technology for wall-fired and Cyclone boilers.
- Flame stability and Cyclone slagging characteristics were not negatively impacted by oxy-firing.
- Boiler NO_x and CO emissions, and unburned combustibles are lower for oxy-firing than air-firing.
- Radiant boiler and convection pass heat absorptions under oxy-firing conditions can be similar to air-firing by controlling flue gas recycle and oxygen flow rates.
- Flue gas concentrations of CO₂ (up to 90%, dry volume basis) were achieved when air leakage was minimized by minimizing pressure drop in the boiler back-end equipment.
- For application of oxy-firing to high sulfur coals, SO₂ must be scrubbed from recycle gas to minimize boiler corrosion.
- Higher flue gas SO₃ emissions were generated at the convection pass exit with oxy-firing than air-firing. The SO₃ concentrations were reduced by operation of the wet scrubber and condensing heat exchanger. Higher SO₃ concentrations could increase corrosion if the flue gas temperature goes below the acid dew point.

From compression, purification, transportation and sequestration evaluation:

- Co-sequestration of CO₂ and SO₂ might be feasible in deep geological reservoirs.
- Pipeline transportation corrosion caused by acid gases can be minimized by removing the moisture from the flue gas.
- CPU modeling demonstrated that the overall energy requirement is lower if flue gas inerts are removed in the CPU rather than compressing the entire flue gas for pipeline transport.

From the feasibility and economics evaluation:

- Oxy-firing is an economically viable CCS technology for existing boilers. The predicted incremental cost of oxy-firing for existing boilers (subcritical and super-critical) varies between 5 to 7¢/kWh which is competitive with other CCS technologies.
- Cost of electricity for greenfield boilers using oxy-firing coupled with ultra-supercritical boilers was 25% higher than COE for a supercritical boiler under air-firing, well below the DOE target of 35%.
- Oxy-firing can be applied to the majority of the existing wall-fired and Cyclone boilers depending on space and existing equipment. The site requirements are very similar to those for post combustion capture but without process steam requirements.

- Units with 200 MWe or larger generating capacity were considered for oxy-firing retrofit. A study of these units indicated that majority of these units are within 50 miles of a major geological storage site.

4.2. Recommendations

The following recommendations are derived:

- Oxy-firing SO_3 emissions are important to corrosion but difficult to measure. Little data are available on SO_3 emissions under oxy-combustion conditions and processes for effective control are not well understood. Additional testing of SO_3 formation and removal is highly recommended.
- Testing of wet scrubbing systems in oxy-firing has been performed by B&W and others but little test data of dry scrubbing systems is available under oxy-firing conditions. Pilot testing with a dry scrubbing system is recommended since dry systems use less water and have lower capital cost. A better understanding of SO_2 removal, operation, and operating costs is needed.
- Testing of a direct contact cooler polishing scrubber added to the oxy-firing process is also recommended. These studies are necessary to determine the performance of the polishing SO_2 scrubber especially if very low levels of SO_2 are a required specification for the CPU.
- An evaluation of the need for extremely low SO_2 concentrations in the flue gas entering the compression and purification unit (CPU) is recommended. Currently, compressor manufactures require very low levels of SO_2 (<1 ppm).
- A site-specific engineering and economic oxy-firing retrofit study of an existing coal-fired utility unit is recommended. This study would aid in developing a more reliable cost analysis for retrofitting a unit with oxy-firing. A potential site for this engineering study is the AEP Conesville unit which would enable comparison with existing DOE studies.

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7. LIST OF ACRONYMS AND ABBREVIATIONS

AEP	American Electric Power
AL	Air Liquide
AP	Auxiliary power
API	American Petroleum Institute
AQCS	Air quality control system
AR	Argon
ART	Absorber recirculation tank
ASPEN	Process analysis software
ASTM	American Society for Testing and Materials
ASU	Air Separation Unit
ASU-C	Air separation unit (Conventional design)
ASU-F	Air separation unit (Future design)
B&W	The Babcock & Wilcox Company
Ca	Calcium
CAPEX	Capital expense
CCS	Carbon Capture and Storage
CEDF	Clean Environment Development Facility
CEM(S)	Continuous emissions monitoring (system)
CFD	Computational fluid dynamics
CHX	Condensing heat exchanger
¢	Cents
Comp	Compression
CO	Carbon monoxide
Cool	Cool recycle

COMO	B&W's proprietary COmbustion MOdel CFD code
CO ₂	Carbon dioxide
CPPDB	NETL's Coal Power Plant Database
CPU	Compression and Purification Unit
CPU-C	Compression and purification unit (Conventional design)
CPU-F	Compression and purification unit (Future design)
CVAAS	Cold vapor atomic absorption spectrometry
CYC	Cyclone
°C	Degrees Celsius
DAS	Data acquisition system
DCCPS	Direct contact cooler and polishing scrubber (aka sodium scrubber/quench cooler or polishing scrubber)
D&E	Delivered and Erected
DOE	US Department of Energy
EOR	Enhanced oil recovery
EOS	Equation of State
EPA	US Environmental Protection Agency
EPC	Engineer, procure, construct
ESP	Electrostatic precipitator
°F	Degrees Fahrenheit
FCV	Flow control valve
FD	Forced Draft
FE	Flow (measuring) element
FEGT	Furnace exit gas temperature
FF	Fabric Filter

FGD	Flue gas desulfurization
FTMA	Field transportable mercury analyzer
GF	Greenfield
GP	Gross power
GQCS	Gas quality control system
GS	Geologic sequestration
H ₂ O	Water
HI	Heat Integration
HMI	Human-machine interface
HP	High pressure
HVT	High velocity thermocouple
ID	Induced Draft
IR	Infrared (light)
IGCC	Integrated Gasification Combined Cycle
k	Kilo, one thousand
kW	Kilowatts
kWh	Kilowatt hours
lb	Pounds
lb/h	Pounds per hour
LCOE	Levelized cost of electricity
LI	Limestone Injection
LF	Levelization Factor
LOI	Loss on ignition
LOX	Liquid oxygen
MFT	Master fuel trip

MMSCF	Million standard cubic feet
MWe	Mega-watts electric
MRCSP	Midwestern Regional Carbon Sequestration Partnership
N ₂	Nitrogen
ND	North Dakota
NDIR	Nondispersive infrared
NETL	National Energy Technology Laboratory
NIST	National Institute of Standards and Technology
NO	Nitrogen oxide
NO ₂	Nitrogen dioxide
NPHR	Net plant heat rate
NTU	Number of (gas phase) Transfer Units (equal to $-\ln(1-E)$, where E is the overall SO ₂ removal efficiency)
O ₂	Oxygen
OCC	Oxy-combustion capture
ODS	Oxygen distribution system
OFA	Overfire air
OPEX	Operating expense
O&M	Operating and maintenance
Oxy	Oxy-combustion
PA	Primary air
PC	(Wall-fired) Pulverized Coal
PCC	Post-combustion capture
PHREEQC	A computer program for geochemical calculations
P&ID	Process and Instrumentation Diagram
ppm	Parts per million

ppmv	Parts per million by volume
PRB	Powder River Basin
Pri	Primary
Pri + CPU	The combined primary recycle and CPU streams
Retro	Retrofit
RCSP	Regional Carbon Sequestration Partnerships
RFG	Recycled flue gas
S	Sulfur
SBS-II	Small Boiler Simulator II
SC	Supercritical (steam conditions)
SDA	Spray dryer absorber (dry scrubber)
SI	Sorbent Injection
SO ₂	Sulfur dioxide
SO ₃	Sulfur trioxide
SR	Stoichiometric ratio
STOMP	Subsurface Transport Over Multiple Phases (computer model)
STOMP-WCS-R	STOMP-Water, CO ₂ , salt-reactions
SubC	Subcritical (steam conditions)
TCHR	Turbine cycle heat rate
TE	Temperature (measuring) element or thermocouple
tm	Metric ton
Ton	Short ton
TSA	Temperature Swing Absorption
TS&M	Transportation, storage and monitoring
UIC	Underground Injection Control

USC	Ultra-supercritical (steam conditions)
USDW	Underground source of drinking water
UV	Ultraviolet (light)
WAG	Water alternating gas (process)
Warm	Warm recycle
WFGD	Wet flue gas desulfurization (wet scrubber)

8. APPENDIX

8.1. Methods for Flue Gas Purification & Compression Train Study

The compositions of the flue gases for the 3 coals were obtained from B&W and are listed in Table A.1. For these simulations, the dry basis compositions were used.

General assumptions (for all coals):

Mass flow rates: 1,200 klb/h

Temperature: 137°F

Pressure: 15.24psia

Barometric pressure: 14.69psia

Assumptions on pollutants emissions downstream the flue gas treatment units:

200ppmv of CO dry basis for all coals

750, 300 and 460ppmv NO_x dry basis (accounted for as 100% NO₂ in simulations and not (80%NO, 20%NO₂)) for ND Lignite, Decker and Ill#6 coals respectively

Hg and particulates are not taken into account.

It must be stressed that the compositions in Table A.1 represent a worst-case-scenario of air infiltration into the boiler unit (*i.e.* boiler, ducts and air heaters) and it is possible that nitrogen levels in the flue gas will be up to 50% lower than those shown above.

Power calculations

Power consumption in various stages of each process is calculated as follows:

Dry and wet compression: The compression power in these stages is calculated by the “log formula”:

$$P = 0.1 \times Q \times \log(\tau)$$

where P = Power (kW);

Q = molar flow (Nm³/h) on a dry basis;

τ = compression ratio ($P_{\text{outlet}}/P_{\text{inlet}}$ in absolute pressure units).

This formula depicts a compressor with a total adiabatic efficiency close to 70%, including mechanical and electrical losses.

Recovered energy from vent gas expansion: In the purification schemes, non-condensable gases are vented from the process. These gases are at high pressure and therefore contain energy which can be recovered in a turbo-expander. The power recovered from these gases is calculated as follows:

$$P = 0.05 \times Q \times \log(\tau)$$

This formula assumes that only half the power is recoverable, and is a good approximation when accounting for the energy of the boiling feed water used to heat the gases before the turbo expander.

Liquid pump: The power required by the liquid pump was calculated in HySys with an adiabatic efficiency of 85%.

The overall specific energy required by the process is the net power consumed per ton of CO₂ captured in the product stream.

$$E(kWh/ton) = \frac{P(kW)}{\dot{m}(ton/h)}$$

where E is the specific energy, P is the net power and $\dot{m}$ is the CO₂ flow rate in the product.

8.2. Tabulated Pilot-scale Test Data

The rows of the tables in this appendix are ordered first by air/oxy-firing, then nominal load (5 or 6 MBtu/h), then Cyclone stoichiometric ratio.

Test Name	Start of Test	Test Parameters						Ambient Conditions		Primary and Tertiary Oxidant													
		Test Duration (min)	Air, Transition, or Oxy-firing	Coal Load (MBtu/h)	Cyclone Stoichiometric Ratio	Overall Stoichiometric Ratio	Relative Humidity	Barometric Pressure (in.Hg)	Primary Oxidant Flow Before Oxynator (lb/h)	Primary RFG Flow From O ₂ Measurements (wet lb/h)	Primary O ₂ Flow (lb/h)	Cyclone Tertiary Flow (lb/h)	Cyclone Tertiary Flow Temp (°F)	Primary Oxidant Temp After Heater (°F)	Primary Oxidant Temp After PC Addition (°F)	% O ₂ Primary Oxidant (vol%, wet)	% N ₂ Primary Oxidant (calculated vol%, wet)	% H ₂ O Primary Oxidant (vol%, wet)	% CO ₂ Primary Oxidant (vol%, wet)	SO ₂ Primary Oxidant (ppm, wet)	MW Primary Oxidizer (lb/lbmole)		
Lignite Air 5 MM/BTU ▲	9/1/2009 8:35	45	Air	4.87	0.91	1.20	51%	29.34	744			11	55	323	163	20.75	78.17	1.08			28.72		
Lignite Air test #4	8/27/2009 13:27	22	Air	4.80	0.92	1.22	71%	29.12	807			9	71	314	157	20.54	77.41	2.05			28.62		
Lignite Air test #4B	8/31/2009 13:33	38	Air	4.60	0.92	1.22	37%	28.58	842			14	66	320	171	20.75	78.18	1.07			28.72		
Lignite Air Test 2 6MBtu/hr ▲	9/3/2009 10:21	60	Air	5.47	0.99	1.28	51%	29.18	795			32	83	315	155	20.68	77.92	1.41			28.69		
Lignite Air Test #3	9/2/2009 13:17	30	Air	5.01	1.11	1.48	31%	29.26	776			5	71	309	159	20.75	78.18	1.07			28.72		
Lignite Air Test #2	9/2/2009 12:30	34	Air	5.06	1.12	1.42	34%	29.28	769			5	69	309	158	20.74	78.14	1.12			28.72		
lignite air test 1	9/2/2009 14:01	31	Air	5.08	1.15	1.37	33%	29.25	723			4	73	307	150	20.73	78.12	1.14			28.72		
lignite air test1B	9/2/2009 14:58	40	Air	5.88	1.00	1.20	30%	29.23	732			5	74	311	149	20.75	78.18	1.07			28.72		
lignight oxy test 09/01/09	9/1/2009 19:32	16	Oxy	4.15	1.03	1.29	42%	29.25	813	785	104	6	71	321	183	17.29	14.30	4.42	63.69	1530	38.45		
lignite oxy test 4.3Mbtu	8/31/2009 18:49	6	Oxy	4.08	1.23	1.39	51%	29.21	846	810	82	13	76	321	177	15.55	13.51	4.87	65.75	1498	38.66		
lignite oxy test 16b	8/27/2009 18:09	21	Oxy	4.68	0.93	1.15	67%	29.08	818	823	116	13	81	313	156	16.17	24.03	4.99	54.57	1839	36.93		
lignite oxy test 6	9/3/2009 17:20	13	Oxy	5.47	0.94	1.14	35%	29.09	825	842	166	18	87	312	147	20.49	14.98	6.74	57.59	1935	37.43		
lignite oxy test 5 ▲	9/3/2009 16:37	33	Oxy	5.40	1.04	1.17	34%	29.09	822	837	166	20	89	313	146	21.04	15.09	6.66	57.05	1639	37.36		
Lignite Oxy Test 16	8/27/2009 17:37	24	Oxy	4.57	1.06	1.32	65%	29.08	812	808	116	10	80	313	158	18.39	21.81	4.85	54.61	1610	37.00		
lignite oxy test 9	9/2/2009 19:01	20	Oxy	5.55	1.04	1.26	38%	29.20	847	844	122	5	76	308	185	17.38	13.87	5.77	62.21	1615	37.96		
▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.																							

▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.

Table 8.1 Pilot scale test data for lignite – table 1 of 5: test parameters, ambient conditions, and primary and tertiary oxidant data

Test Name	Secondary and Overfire Oxidant														Cyclone Lance Oxygen				Fuel					
	Total Secondary Oxidant Flow From Flowmeter (lb/h)	Secondary RFG Flow From O ₂ Measurements (wet lb/h)	Secondary O ₂ Flow (lb/h)	Secondary Oxidant Flow to Cyclone (lb/h)	Windbox Temperature (°F)	Overfire Oxidant Flow (lb/h)	Overfire Oxidant Temp (°F)	% O ₂ at Windbox (vol%, wet)	% O ₂ Secondary Oxidant (vol%, wet)	% N ₂ Secondary Oxidant (calculated vol%, wet)	% H ₂ O Secondary Oxidant (vol%, wet)	% CO ₂ Secondary Oxidant (vol%, wet)	SO ₂ Secondary Oxidant (ppm, wet)	MW Secondary Oxidizer (lb/lbmole)	Cyclone O ₂ Lance Position	Cyclone Lance O ₂ Flow (lb/h)	Cyclone Lance O ₂ Temperature (°F)	As Fired Fuel Ash (wt%)	As Fired Fuel Moisture (wt%)	Measured Coal Feed Rate (lb/h)	Calculated Coal Feed Rate (lb/h)	Coal Load (MBtu/h)	Coal Fineness (% passing 200 mesh)	
Lignite Air 5 MM/BTU ▲	3898			2792	684	1118	684	20.51	20.74	78.18	1.08			28.72	Sec. Duct		59	8.05	23.66	595	592	4.87	44.19	
Lignite Air test #4	3897			2756	684	1151	684	20.30	20.54	77.41	2.05			28.62	Sec. Duct		75	8.05	23.66	620	584	4.80	45.86	
Lignite Air test #4B	3668			2599	682	1080	682	20.39	20.74	78.19	1.07			28.72	Sec. Duct		69	8.33	23.66	613	562	4.60	44.19	
Lignite Air Test 2 6MBtu/hr ▲	4706			3485	689	1234	689	20.56	20.67	77.92	1.40			28.69	Sec. Duct		69	8.05	23.66	670	665	5.47	44.19	
Lignite Air Test #3	5030			3594	691	1450	691	20.69	20.74	78.19	1.07			28.72	Sec. Duct		76	8.33	23.66	608	612	5.01	44.19	
Lignite Air Test #2	4853			3663	689	1204	689	20.72	20.73	78.15	1.12			28.72	Sec. Duct		75	8.33	23.66	611	618	5.06	44.19	
lignite air test 1	4657			3789	690	882	690	20.84	20.73	78.13	1.14			28.72	Sec. Duct		77	8.33	23.66	605	620	5.08	44.19	
lignite air test1B	4740			3848	690	905	690	20.83	20.74	78.19	1.07			28.72	Sec. Duct		78	8.33	23.66	694	718	5.88	44.19	
lignight oxy test 09/01/09	3530	3121	450	2554	681	1173	681	19.81	19.22	13.97	4.32	62.20	1495	38.30	Sec. Duct	200	71	8.33	23.66	567	507	4.15	44.19	
lignite oxy test 4.3Mbtu	3881	3416	456	3423	684	726	684	19.51	18.81	12.99	4.68	63.20	1440	38.40	Sec. Duct	209	68	8.33	23.66	590	498	4.08	44.19	
lignite oxy test 16b	3575	3116	587	2739	682	1030	682	21.16	20.86	22.68	4.71	51.51	1736	36.65	Sec. Duct	120	74	8.05	23.66	644	569	4.68	45.86	
lignite oxy test 6	4225	3457	778	3501	686	969	686	23.91	23.07	14.49	6.52	55.73	1873	37.25	Sec. Duct	0	80	8.05	23.66	620	666	5.47	57.83	
lignite oxy test 5 ▲	3999	3241	777	3655	685	586	685	25.42	24.58	14.42	6.36	54.49	1566	37.12	Sec. Duct	0	81	8.05	23.66	595	657	5.40	57.83	
Lignite Oxy Test 16	3540	3039	582	2700	681	1032	681	23.30	22.92	20.60	4.58	51.58	1520	36.72	Sec. Duct	146	75	8.05	23.66	625	555	4.57	45.86	
lignite oxy test 9	4827	4063	690	3905	690	1232	690	20.73	19.81	13.46	5.60	60.38	1567	37.78	Sec. Duct	193	74	8.33	23.66	703	677	5.55	44.19	
▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.																								

▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.

Table 8.2 Pilot scale test data for lignite – table 2 of 5: Secondary and overfire oxidant, Cyclone lance oxygen, and fuel test data

Test Name	Convection Pass Gases									Stack/Emissions						
	CO Conv Pass (ppm, dry)	O ₂ Convection Pass (vol%, dry)	O ₂ Convection Pass (vol%, wet)	CO ₂ Convection Pass (vol%, dry)	SO ₂ Convection Pass (ppm, dry)	NO _x Convection Pass (ppm, dry)	Vol % H ₂ O at Convection Pass	Convection Pass Flue Gas Flow (wet lb/h)	MW Flue Gas at Convection Pass (lb/lbmole)	CO Emissions (lb/h)	SO ₂ at Stack (ppm, dry)	SO ₂ Emissions (lb/MBtu)	NO _x Emissions (lb/MBtu)	Vol % H ₂ O at Stack	O ₂ at Stack (vol%, dry)	MW Flue Gas at Stack and RFG (lb/lbmole)
Lignite Air 5 MM/BTU ♣	27	3.40	3.18	16.39	642	452	11.38	5198	29.33	0.119	578	1.185	0.668	5.89	5.144	30.27
Lignite Air test #4	6	3.74	3.34	16.09	663	473	11.99	5252	29.22	0.028	592	1.242	0.714	4.39	5.227	30.31
Lignite Air test #4B	86	3.67	3.33	16.20	677	392	11.13	5036	29.35	0.364	600	1.265	0.596	4.18	5.352	30.45
Lignite Air Test 2 6MBtu/hr ♣	652	4.61	3.79	15.05	614	483	11.10	6156	29.22	3.376	532	1.162	0.766	6.61	6.080	29.97
Lignite Air Test #3	90	6.80	5.98	13.21	473	536	9.69	6382	29.20	0.499	411	1.044	0.982	4.34	7.959	29.88
Lignite Air Test #2	155	6.26	5.64	13.66	493	599	10.07	6201	29.20	0.818	429	1.039	1.047	4.33	7.625	29.95
lignite air test 1	5	5.78	5.34	14.13	548	710	10.48	5962	29.20	0.027	484	1.109	1.174	4.32	7.154	30.04
lignite air test1B	6	3.55	3.26	16.27	652	712	11.62	6144	29.29	0.033	582	1.168	1.028	4.67	5.156	30.33
lignight oxy test 09/01/09	27	5.57	4.97	79.04	2023	915	14.71	5404	37.57	0.019	1840	0.736	0.263	5.05	6.420	39.42
lignite oxy test 4.3Mbtu	27	6.73	5.76	78.76	1937	1196	14.12	5838	37.71	0.019	1754	0.689	0.338	5.39	7.202	39.43
lignite oxy test 16b	60	3.14	2.78	69.81	2432	659	15.90	5444	35.99	0.054	2241	0.956	0.202	5.73	4.205	37.69
lignite oxy test 6	25	3.13	2.91	79.41	2725	716	18.21	6185	36.76	0.023	2558	1.004	0.202	8.18	4.015	38.59
lignite oxy test 5 ♣	27	3.98	3.64	78.33	2329	1254	18.34	5948	36.61	0.024	2163	0.850	0.354	8.07	4.873	38.51
Lignite Oxy Test 16	24	6.35	5.63	68.21	2156	985	15.54	5417	35.95	0.019	1962	0.803	0.289	5.58	7.014	37.81
lignite oxy test 9	896	5.07	4.17	80.03	2206	995	16.10	7039	37.37	0.879	1997	0.816	0.290	6.66	5.766	39.08

♣ Indicates test data was reprocessed for higher quality - particularly for the heat balance.

**Table 8.3 Pilot scale test data for lignite – table 3 of 5:
Convection pass and stack gases, and emissions data**

Test Name	Heat Transfer and HVT Data																																				
	Heat in with Primary Oxidant (MBtu/h)		Heat in with Secondary Oxidant (MBtu/h)		Heat Absorbed in Cyclone (MBtu/h)		Heat Absorbed in Furnace (MBtu/h)		Heat Absorbed in Convection Pass (MBtu/h)		Heat Out With Flue Gas (MBtu/h)		Total Heat Release in SBS-II (MBtu/h)		Convection Pass Exit Temperature (°F)		Max Temperature from FLAMEVIEW Camera (°F)		FEGT by HVT, Probe Insertion, 12" into Furnace (°F)		FEGT by HVT, Probe Insertion, 18" into Furnace (°F)		FEGT by HVT, Probe Insertion, 24" into Furnace (°F)		FEGT by HVT, Probe Insertion, 30" into Furnace (°F)		FEGT by HVT, Probe Insertion, 36" into Furnace (°F)		FEGT by HVT, Probe Extraction, 36" into Furnace (°F)		FEGT by HVT, Probe Extraction, 30" into Furnace (°F)		FEGT by HVT, Probe Extraction, 24" into Furnace (°F)		FEGT by HVT, Probe Extraction, 18" into Furnace (°F)		FEGT by HVT, Probe Extraction, 12" into Furnace (°F)
Lignite Air 5 MM/BTU ▲	0.14	1.11	0.60	1.84	1.36	1.66	4.21	789		1995-2020	2014-2050	2023-2041	2040-2140	2039-2095	2039-2095	2040-2070	2038-2080	2029-2071	2028-2040																		
Lignite Air test #4	0.15	1.11	0.57	1.61	1.78	1.69	4.39	794	3100	2090	2100-2118	2113	2101	2119	2113	2097-2114		2127-2144	2083-2116																		
Lignite Air test #4B	0.16	1.04	0.51	1.94	1.20	1.61	4.06	788																													
Lignite Air Test 2 6MBtu/hr ▲	0.15	1.35	0.53	2.07	1.87	2.09	5.06	862	3100	1992-2011	2110	2169-2175	2193	2158	2179	2146	2144	2149	2172																		
Lignite Air Test #3	0.15	1.44	0.56	2.28	1.71	2.12	5.08	841																													
Lignite Air Test #2	0.15	1.38	0.57	2.03	1.80	2.04	4.91	826		2045	2032-2053	2073-2091	2045-2062	2070-2160	2070-2160	2061	2067	2033	2003																		
lignite air test 1	0.14	1.33	0.59	1.94	1.59	1.97	4.62	828																													
lignite air test1B	0.14	1.35	0.71	1.85	1.67	2.11	4.85	870																													
lignight oxy test 09/01/09	0.16	0.91	0.16	1.54	1.43	1.63	3.67	850																													
lignite oxy test 4.3Mbtu	0.16	1.02	0.34			1.70		816																													
lignite oxy test 16b	0.16	0.94	0.13	2.20	1.93	1.71	4.85	864		2290	2270	2300	2305	2320	2320	2310	2290	2302	2340																		
lignite oxy test 6	0.17	1.12	0.37			1.91		853																													
lignite oxy test 5 ▲	0.17	1.06	0.49	2.20	1.49	1.81	4.76	836	3100	2034	2100	2120	2133	2138	2138	2141	2143	2136	2100																		
Lignite Oxy Test 16	0.16	0.93	0.13	2.13	2.16	1.68	5.00	852																													
lignite oxy test 9	0.16	1.28	0.55	2.01	1.77	2.22	5.08	890																													
▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.																																					

▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.

**Table 8.4 Pilot scale test data for lignite – table 4 of 5:
Heat transfer and temperature data**

Test Name	System Static and Differential Pressures									Miscellaneous				
	Cyclone Differential Pressure (in.H ₂ O)	Furnace Pressure (in.H ₂ O)	Baghouse Inlet (flow venturi) Static Pressure (in.H ₂ O)	Baghouse Differential Pressure (in.H ₂ O)	CHX Inlet Static Pressure (in.H ₂ O)	CHX Outlet Static Pressure (in.H ₂ O)	ID Fan Inlet Static Pressure (in.H ₂ O)	Primary RFG Static Pressure at Venturi (in.H ₂ O)	Secondary RFG Static Pressure at Venturi (in.H ₂ O)	Fly Ash % LOI @ 800°C	CHX Outlet Temperature (°F)	ID Fan Inlet Temperature (°F)	Flow Rate of Infiltrated Air in RFG (lb/h)	Total RFG Flow (lb/h)
Lignite Air 5 MM/BTU ♣	8.1	0.6	>0	6.2	-6.2	8.4	-22.5	0.2	0.2	0.91	86	97		
Lignite Air test #4	8.1	0.2	>0	3.6	-3.8	8.8	-18.4	0.3	0.4	1.12	88	105		
Lignite Air test #4B	7.2	0.5	>0	6.9	-5.3	7.3	-19.6	0.2	0.2	0.81	85	97		
Lignite Air Test 2 6MBtu/hr ♣	10.4	-0.5	>0	7.1	-6.5	14.7	-30.5	0.3	0.3	1.04	102	102		
Lignite Air Test #3	11.3	-0.2	>0	6.7	-7.9	15.5	-34.8	0.3	0.3		88	103		
Lignite Air Test #2	12.0	-0.2	>0	6.4	-7.3	14.7	-32.1	0.3	0.3	0.80	88	103		
lignite air test 1	12.8	1.3	>0	6.0	-6.7	14.9	-31.6	0.2	0.3	0.96	88	103		
lignite air test1B	13.5	0.1	>0	6.8	-7.5	15.1	-33.8	0.2	0.3	0.80	90	106		
lignight oxy test 09/01/09	4.3	-0.5	>0	3.5	0.5	9.8	-9.9	-0.2	-0.4		92	106	92	3906
lignite oxy test 4.3Mbtu	7.6	-0.6	>0	3.2	1.6	11.9	-9.8	-0.3	-0.7		95	108	74	4226
lignite oxy test 16b	4.7	0.0	>0	3.3	-0.7	8.4	-11.3	-0.2	-0.5		96	116	142	3940
lignite oxy test 6	6.7	0.7	>0	3.6	1.5	13.0	-11.5	-0.3	-0.7		109	109	134	4299
lignite oxy test 5 ♣	8.2	-0.3	>0	3.6	1.0	12.0	-11.5	-0.3	-0.6	1.00	108	108	121	4077
Lignite Oxy Test 16	4.7	0.5	>0	3.7	-0.6	8.6	-11.3	-0.2	-0.5	1.32	95	116	73	3846
lignite oxy test 9	9.8	0.8	>0	5.0	0.4	20.1	-21.7	-0.5	-1.2	1.13	102	117	145	4907

♣ Indicates test data was reprocessed for higher quality - particularly for the heat balance.

Table 8.5 Pilot scale test data for lignite – table 5 of 5: Static and differential pressures and miscellaneous data

Test Name	Start of Test	Test Parameters					Ambient Conditions		Primary and Tertiary Oxidant												
		Test Duration (min)	Air, Transition, or Oxy-firing	Coal Load (MBtu/h)	Cyclone Stoichiometric Ratio	Overall Stoichiometric Ratio	Relative Humidity	Barometric Pressure (in.Hg)	Primary Oxidant Flow Before Oxymator (lb/h)	Primary RFG Flow From O ₂ Measurements (wet lb/h)	Primary O ₂ Flow (lb/h)	Cyclone Tertiary Flow (lb/h)	Cyclone Tertiary Flow Temp (°F)	Primary Oxidant Temp After Heater (°F)	Primary Oxidant Temp After PC Addition (°F)	% O ₂ Primary Oxidant (vol%, wet)	% N ₂ Primary Oxidant (calculated vol%, wet)	% H ₂ O Primary Oxidant (vol%, wet)	% CO ₂ Primary Oxidant (vol%, wet)	SO ₂ Primary Oxidant (ppm, wet)	MW Primary Oxidizer (lb/lbmole)
PRB AIR 01	8/4/2009 15:18	66	Air	5.25	0.91	1.18	59%	28.88	798			41	85	187	150	20.51	77.28	2.21			28.60
PRB Air Cyclone Test 2 ▲	8/25/2009 9:28	57	Air	5.60	0.98	1.25	64%	27.85	904			42	84	269	156	20.60	77.64	1.75			28.65
PRB Air Test #3C	8/13/2009 8:29	27	Air	5.78	0.87	1.20	66%	29.12	867			6	63	269	150	20.60	77.61	1.79			28.64
PRB Air Test #3C(Redo)	8/13/2009 8:56	3	Air	5.91	0.88	1.20	66%	29.12	883			6	63	269	150	20.59	77.58	1.84			28.64
PRB air test 2 ▲	8/5/2009 10:08	60	Air	6.01	0.90	1.17	52%	29.02	849			43	75	164	150	20.70	78.00	1.30			28.70
PRB Air test 3	8/11/2009 8:08	32	Air	5.71	0.91	1.21	71%	28.95	907			40	83	247	135	20.47	77.13	2.40			28.58
PRB Air Test #3B	8/12/2009 9:12	80	Air	5.80	0.92	1.21	59%	29.02	881			26	78	280	153	20.55	77.43	2.03			28.62
PRB-OXY 15b	8/11/2009 12:03	26	Oxy	5.47	0.84	1.10	64%	28.94	840	713	122	45	95	261	156	15.00	10.91	6.00	67.95	1357	38.92
PRB Oxy Open Tube on Tertiary Line	8/12/2009 17:50	30	Oxy	5.92	0.84	1.11	50%	29.01	815	839	145	4	75	266	157	18.66	20.41	5.53	55.28	1229	37.08
PRB-OXY 15	8/11/2009 11:48	13	Oxy	5.73	0.86	1.10	69%	28.95	886	788	123	44	96	262	156	15.96	12.54	6.38	65.00	1276	38.45
prboxy16 08/11/09	8/11/2009 16:34	37	Oxy	6.02	0.88	1.13	59%	28.87	850	887	157	44	95	263	155	19.99	10.37	5.47	64.05	1175	38.54
prb oxy cyclone test13 ▲	8/25/2009 14:53	51	Oxy	5.56	0.90	1.06	50%	27.82	756	787	147	37	91	266	151	19.64	9.08	7.19	63.96	1285	38.35
PRB OXY Cyclone test #6	8/25/2009 13:00	39	Oxy	5.76	0.90	1.11	50%	27.83	775	799	120	39	96	269	152	17.36	16.00	5.72	60.81	1096	37.89
PRB Oxy Test 6 ▲	8/6/2009 16:08	55	Oxy	5.65	0.90	1.11	51%	29.02	852	832	112	43	99	248	150	15.03	22.57	10.96	51.35	973	35.76
PRB Oxy Heat Balance #5	8/13/2009 18:55	30	Oxy	5.56	0.92	1.09	44%	29.09	863	892	152	52	97	267	168	18.80	9.07	5.45	66.53	1186	38.89
PRB OXY 01	8/5/2009 17:45	54	Oxy	6.18	0.92	1.12	39%	29.00	847	830	118	46	101	231		15.97	17.74	8.98	57.19	1158	36.93
prb oxy heat balance 3	8/13/2009 15:28	33	Oxy	6.02	0.92	1.13	41%	29.10	851	881	173	3	78	269	172	21.25	11.02	5.98	61.65	1004	38.15
prb oxy 15c 08/11/09	8/11/2009 14:40	113	Oxy	5.68	0.93	1.19	55%	28.89	867	900	142	44	95	263	156	19.18	12.30	5.46	62.92	1259	38.33
PRB Oxy Heat Transfer 1	8/13/2009 12:32	13	Oxy	5.98	0.94	1.15	48%	29.12	885	898	137	5	73	268	169	18.06	12.63	6.05	63.12	1302	38.26
PRB Oxy Heat Transfer 2	8/13/2009 12:44	36	Oxy	5.95	0.95	1.16	48%	29.11	891	903	133	4	74	268	170	17.75	12.00	6.19	63.93	1242	38.37
PRB Oxy Heat Transfer 1 & 2	8/13/2009 12:32	48	Oxy	5.96	0.95	1.16	48%	29.12	889	901	134	4	74	268	170	17.83	12.17	6.15	63.72	1258	38.34
prb oxy heat transfer 4	8/13/2009 17:44	30	Oxy	5.56	0.95	1.14	38%	29.09	845	873	151	51	97	267	165	19.63	10.89	5.67	63.69	1144	38.45
PRB Oxy Test 7	8/6/2009 18:25	45	Oxy	5.70	0.95	1.16	43%	29.03	900	886	112	46	99	248	152	15.39	22.14	8.46	53.91	991	36.43
▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.																					

▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.

Table 8.6 Pilot scale test data for subbituminous coal – table 1 of 5: test parameters, ambient conditions, and primary and tertiary oxidant data

Test Name	Secondary and Overfire Oxidant															Cyclone Lance Oxygen			Fuel							
	Total Secondary Oxidant Flow From Flowmeter (lb/h)	Secondary RFG Flow From O ₂ Measurements (wet lb/h)	Secondary RFG Flow from Flowmeters (wet lb/h) (Secondary Oxidizer minus Secondary O ₂ Flow)	Secondary O ₂ Flow (lb/h)	Secondary Oxidant Flow to Cyclone (lb/h)	Windbox Temperature (°F)	Overfire Oxidant Flow (lb/h)	Overfire Oxidant Temp (°F)	% O ₂ at Windbox (vol%, wet)	% O ₂ Secondary Oxidant (vol%, wet)	% N ₂ Secondary Oxidant (calculated vol%, wet)	% H ₂ O Secondary Oxidant (vol%, wet)	% CO ₂ Secondary Oxidant (vol%, wet)	SO ₂ Secondary Oxidant (ppm, wet)	MW Secondary Oxidizer (lb/lbmole)	Cyclone O ₂ Lance Position	Cyclone Lance O ₂ Flow (lb/h)	Cyclone Lance O ₂ Temperature (°F)	As Fired Fuel Ash (wt%)	As Fired Fuel Moisture (wt%)	Measured Coal Feed Rate (lb/h)	Calculated Coal Feed Rate (lb/h)	Coal Load (MBu/h)	Coal Fineness (% passing 200 mesh)		
PRB AIR 01	4066				2964	685	1113	685	20.13	20.50	77.28	2.21			28.60	Sec. Duct		83	5.68	15.60	454	517	5.25	58.12		
PRB Air Cyclone Test 2 ▲	4454				3303	688	1164	688	20.49	20.60	77.65	1.75			28.65	Sec. Duct		70	5.55	17.50	589	564	5.60	34.20		
PRB Air Test #3C	4473				3039	697	1446	697	20.42	20.59	77.62	1.79			28.64	Sec. Duct		68	5.68	15.60	589	569	5.78	46.46		
PRB Air Test #3C(Redo)	4592				3162	698	1444	698	20.39	20.58	77.58	1.84			28.64	Sec. Duct		69	5.68	15.60	596	582	5.91	46.46		
PRB air test 2 ▲	4482				3274	688	1221	688	20.65	20.69	78.01	1.30			28.70	Sec. Duct		72	5.68	15.60	586	592	6.01	58.12		
PRB Air test 3	4450				3154	698	1309	698	20.27	20.46	77.14	2.40			28.58	Sec. Duct		74	5.68	15.60	580	562	5.71	58.12		
PRB Air Test #3B	4519				3225	698	1306	698	20.39	20.54	77.43	2.03			28.62	Sec. Duct		74	5.68	15.60	557	570	5.80	58.12		
PRB-OXY 15b	4228		3487	741	2947	697	1292	697	22.53	21.28	10.11	5.56	62.92	1257	38.41	Sec. Duct	118	84	5.68	15.60	594	538	5.47	58.12		
PRB Oxy Open Tube on Tertiary Line	4291		3499	792	3149	696	1364	696	23.41	23.06	19.33	5.23	52.26	1162	36.80	Tertiary	50	79	5.68	15.60	568	582	5.92	50.11		
PRB-OXY 15	4253		3497	756	3193	697	1294	697	22.80	22.49	11.57	5.88	59.95	1177	37.94	Sec. Duct	94	80	5.68	15.60	591	564	5.73	58.12		
prboxy16 08/11/09	4382		3552	830	3385	697	1243	697	24.56	24.24	9.83	5.18	60.64	1112	38.19	Sec. Duct	50	85	5.68	15.60	567	593	6.02	58.12		
prb oxy cyclone test13 ▲	3169	2762	2570	600	2566	680	836	680	23.18	22.90	8.71	6.90	61.36	1233	38.09	Sec. Duct	209	84	5.55	17.50	620	560	5.56	34.20		
PRB OXY Cyclone test #6	4047		3314	733	3202	686	1099	686	22.84	22.78	14.95	5.34	56.82	1024	37.50	Sec. Duct	137	85	5.55	17.50	621	580	5.76	34.20		
PRB Oxy Test 6 ▲	4082	3480	3355	727	3307	685	1084	685	22.01	21.72	20.80	10.09	47.30	896	35.46	Sec. Duct	82	76	5.68	15.60	551	557	5.65	58.12		
PRB Oxy Heat Balance #5	3649		3056	593	2902	692	973	692	21.33	20.76	8.85	5.32	64.93	1158	38.72	Sec. Duct	202	80	5.68	15.60	592	547	5.56	50.11		
PRB OXY 01	3748		3009	739	3406	682	1008	682	24.34	22.47	16.38	8.28	52.76	1068	36.55	Sec. Duct	96	78	5.68	15.60	566	608	6.18	58.12		
prb oxy heat balance 3	4260		3470	790	3440	697	1079	697	24.11	23.58	10.69	5.80	59.83	975	37.97	Sec. Duct	63	86	5.68	15.60	573	593	6.02	50.11		
prb oxy 15c 08/11/09	4338		3571	766	3295	697	1282	697	23.86	23.52	11.63	5.16	59.54	1192	37.99	Sec. Duct	74	86	5.68	15.60	551	559	5.68	58.12		
PRB Oxy Heat Transfer 1	4209		3421	788	3383	696	1059	696	24.74	24.26	11.69	5.59	58.34	1204	37.79	Sec. Duct	101	81	5.68	15.60	590	589	5.98	50.11		
PRB Oxy Heat Transfer 2	4248		3461	787	3417	696	1069	696	24.61	24.11	11.08	5.71	58.99	1146	37.87	Sec. Duct	101	83	5.68	15.60	587	586	5.95	50.11		
PRB Oxy Heat Transfer 1 & 2	4238		3450	787	3408	696	1066	696	24.65	24.15	11.24	5.68	58.82	1161	37.85	Sec. Duct	101	83	5.68	15.60	588	587	5.96	50.11		
prb oxy heat transfer 4	4051		3459	592	3189	696	1119	696	20.18	19.54	10.90	5.67	63.77	1145	38.46	Sec. Duct	201	82	5.68	15.60	588	547	5.56	50.11		
PRB Oxy Test 7	3900		3323	577	3394	683	1233	683	19.72	18.30	21.38	8.17	52.06	957	36.28	Sec. Duct	186	75	5.68	15.60	555	561	5.70	58.12		
▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance																										

▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.

Table 8.7 Pilot scale test data for subbituminous coal – table 2 of 5: Secondary and overfire oxidant, Cyclone lance oxygen, and fuel test data

Test Name	Convection Pass Gases									Stack/Emissions						
	CO Conv Pass (ppm, dry)	O ₂ Convection Pass (vol%, dry)	O ₂ Convection Pass (vol%, wet)	CO ₂ Convection Pass (vol%, dry)	SO ₂ Convection Pass (ppm, dry)	NO _x Convection Pass (ppm, dry)	Vol % H ₂ O at Convection Pass	Convection Pass Flue Gas Flow (wet lb/h)	MW Flue Gas at Convection Pass (lb/lbmole)	CO Emissions (lb/h)	SO ₂ at Stack (ppm, dry)	SO ₂ Emissions (lb/MBtu)	NO _x Emissions (lb/MBtu)	Vol % H ₂ O at Stack	O ₂ at Stack (vol%, dry)	MW Flue Gas at Stack and RFG (lb/lbmole)
PRB AIR 01	32	3.13	2.89	16.34	372	438	10.75	5363	29.39	0.144	331	0.770	0.732	6.17	5.118	29.71
PRB Air Cyclone Test 2 ▲	38	4	3.81	15.32	276	546	10.37	5904	29.32	0.190	245	0.505	0.810	8.67	6.086	29.60
PRB Air Test #3C	13	3.48	3.21	16.07	471	412	10.39	5889	29.41	0.067	419	0.832	0.589	4.89	5.394	30.17
PRB Air Test #3C(Redo)	12	3.48	3.14	16.06	462	387	10.41	6036	29.41	0.062	404	0.803	0.553	4.93	5.660	30.17
PRB air test 2 ▲	112	3.07	2.82	16.33	401	468	10.27	5902	29.45	0.567	358	0.684	0.644	5.82	5.000	29.74
PRB Air test 3	45	3.66	3.27	15.83	374	353	10.80	5899	29.33	0.227	343	0.689	0.511	5.88	5.108	29.99
PRB Air Test #3B	57	3.64	3.27	15.87	372	376	10.54	5951	29.37	0.279	352	0.704	0.544	5.00	4.572	30.10
PRB-OXY 15b	39	2.25	1.99	87.55	1729	525	15.61	5932	38.39	0.035	1665	0.755	0.171	6.86	2.951	35.48
PRB Oxy Open Tube on Tertiary Line	431	2.50	2.29	75.88	1704	506	15.45	6188	36.86	0.412	1559	0.662	0.161	6.55	4.074	38.03
PRB-OXY 15	194	2.34	1.98	85.84	1672	520	15.95	6234	38.08	0.181	1588	0.621	0.146	7.35	3.286	39.43
prboxy16 08/11/09	67	2.97	2.68	87.15	1577	518	15.73	6348	38.33	0.066	1515	0.587	0.144	6.59	3.683	39.89
prb oxy cyclone test13 ▲	168	1.78	1.72	89.44	1804	1036	18.81	5136	37.85	0.146	1709	0.628	>0.27	8.73	2.782	39.71
PRB OXY Cyclone test #6	295	2.66	2.44	81.11	1486	425	16.13	5978	37.41	0.282	1371	0.555		6.68	4.077	38.88
PRB Oxy Test 6 ▲	391	2.51	2.03	75.24	1394	484	19.34	6101	35.91	0.427	1252	0.618	0.172	12.36	4.394	36.24
PRB Oxy Heat Balance #5	166	2.26	2.01	88.70	1586	976	15.97	5708	38.46	0.142	1521	0.559	0.258	6.53	3.021	40.26
PRB OXY 01	58	2.86	2.39	80.66	1607	640	18.64	6186	36.78	0.059	1472	0.622	0.194	10.24	4.378	37.63
prb oxy heat balance 3	52	3.03	2.79	85.60	1386	699	16.30	6268	37.98	0.050	1327	0.500	0.189	7.32	3.797	39.53
prb oxy 15c 08/11/09	220	4.02	3.56	83.94	1660	645	15.10	6293	38.08	0.199	1590	0.627	0.185	6.44	4.737	39.48
PRB Oxy Heat Transfer 1	63	3.64	3.34	83.85	1724	767	16.07	6231	37.83	0.064	1639	0.634	0.213	7.08	4.502	39.32
PRB Oxy Heat Transfer 2	34	3.72	3.42	84.45	1634	755	16.08	6273	37.91	0.033	1559	0.597	0.208	7.20	4.512	39.42
PRB Oxy Heat Transfer 1 & 2	42	3.70	3.40	84.29	1657	758	16.07	6262	37.89	0.041	1580	0.607	0.209	7.17	4.506	39.39
prb oxy heat transfer 4	36	3.18	2.95	85.55	1527	668	15.47	6119	38.19	0.032	1472	0.546	0.178	6.80	3.818	39.74
PRB Oxy Test 7	93	3.38	2.95	75.45	1366	714	17.01	6491	36.48	0.101	1232	0.581	0.242	9.52	5.112	36.99

▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.
 NOx analyzer was saturated during test prb oxy cyclone test13

**Table 8.8 Pilot scale test data for subbituminous coal – table 3 of 5:
 Convection pass and stack gases, and emissions data**

Test Name	Heat Transfer and HVT Data																		
	Heat in with Primary Oxidant (MBtu/h)	Heat in with Secondary Oxidant (MBtu/h)	Heat Absorbed in Cyclone (MBtu/h)	Heat Absorbed in Furnace (MBtu/h)	Heat Absorbed in Convection Pass (MBtu/h)	Heat Out With Flue Gas (MBtu/h)	Total Heat Release in SBS-II (MBtu/h)	Convection Pass Exit Temperature (°F)	Max Temperature from FLAMEVIEW Camera (°F)	FEGT by HVT, Probe Insertion, 12" into Furnace (°F)	FEGT by HVT, Probe Insertion, 18" into Furnace (°F)	FEGT by HVT, Probe Insertion, 24" into Furnace (°F)	FEGT by HVT, Probe Insertion, 30" into Furnace (°F)	FEGT by HVT, Probe Insertion, 36" into Furnace (°F)	FEGT by HVT, Probe Extraction, 36" into Furnace (°F)	FEGT by HVT, Probe Extraction, 30" into Furnace (°F)	FEGT by HVT, Probe Extraction, 24" into Furnace (°F)	FEGT by HVT, Probe Extraction, 18" into Furnace (°F)	FEGT by HVT, Probe Extraction, 12" into Furnace (°F)
PRB AIR 01	0.13	1.16	0.61	2.13	1.58	1.67	4.70	763	3100										
PRB Air Cyclone Test 2 ▲	0.16	1.27	0.67	2.10	1.67	2.00	5.01	861	3100	2163	2174	2179	2173	2173	2168	2173	2177	2187	2160
PRB Air Test #3C	0.16	1.29	0.36	2.22	1.36	1.84	4.33	766		2220	2240	2241	2254	2250	2250	2250	2245	2235	2236
PRB Air Test #3C(Redo)	0.16	1.32	0.24			1.91		780											
PRB air test 2 ▲	0.13	1.28	0.55	2.51	1.71	1.90	5.27	805		2163	2159	2180	2165	2170	2169	2168	2164	2166	2170
PRB Air test 3	0.16	1.29	0.21	2.58	2.19	1.90	5.43	800											
PRB Air Test #3B	0.16	1.30	0.19	2.81	1.55	1.92	5.01	804		2295	2306	2316	2313	2306	2306	2286	2309	2304	2301
PRB-OXY 15b	0.15	1.05	0.18	2.69	2.31	1.77	5.75	844	3000										
PRB Oxy Open Tube on Tertiary Line	0.16	1.14	0.18	2.46	2.48	1.86	5.68	834											
PRB-OXY 15	0.16	1.12	0.18			1.86		835											
prboxy16 08/11/09	0.16	1.15	0.15	2.63	2.16	1.95	5.58	871											
prb oxy cyclone test13 ▲	0.14	0.84	0.60	2.48	1.71	1.51	5.30	810	3200	2260	2329	2367	2381	2385	2385	2375	2366	2350	2298
PRB OXY Cyclone test #6	0.14	1.07	0.42	2.44	2.20	1.85	5.68	868	3000	2282	2296	2277	2271	2326	2326	2345	2353	2309	2267
PRB Oxy Test 6 ▲	0.16	1.14	0.19	2.60	2.03	1.90	5.41	845	3100	2136	2197	2203	2210	2206	2206	2209	2209	2205	2209
PRB Oxy Heat Balance #5	0.16	0.95	0.30	2.55	2.71	1.69	6.11	833	3200	2260	2394	2409	2414	2404	2404	2382	2390	2412	2402
PRB OXY 01	0.15	1.12	0.18	3.04	1.87	1.89	5.69	837	3100										
prb oxy heat balance 3	0.16	1.13	0.18	3.27	1.90	1.88	5.93	839											
prb oxy 15c 08/11/09	0.16	1.14	0.18	2.62	2.09	1.90	5.47	851	3100										
PRB Oxy Heat Transfer 1	0.16	1.11	0.19			1.84		824											
PRB Oxy Heat Transfer 2	0.16	1.12	0.20	2.46	2.33	1.86	5.55	828		2360	2364	2363	2370	2372	2372	2378	2386	2376	2367
PRB Oxy Heat Transfer 1 & 2	0.16	1.12	0.19	2.24	2.65	1.85	5.65	827											
prb oxy heat transfer 4	0.15	1.07	0.25	2.78	2.21	1.84	5.83	847											
PRB Oxy Test 7	0.17	1.18	0.19	2.57	2.13	2.01	5.54	853		2204	2221	2221	2232	2240	2240	2247	2238	2238	2202
▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.																			

▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.

**Table 8.9 Pilot scale test data for subbituminous coal – table 4 of 5:
Heat transfer and temperature data**

Test Name	System Static and Differential Pressures									Miscellaneous				
	Cyclone Differential Pressure (in.H ₂ O)	Furnace Pressure (in.H ₂ O)	Baghouse Inlet (flow venturi) Static Pressure (in.H ₂ O)	Baghouse Differential Pressure (in.H ₂ O)	CHX Inlet Static Pressure (in.H ₂ O)	CHX Outlet Static Pressure (in.H ₂ O)	ID Fan Inlet Static Pressure (in.H ₂ O)	Primary RFG Static Pressure at Venturi (in.H ₂ O)	Secondary RFG Static Pressure at Venturi (in.H ₂ O)	Fly Ash % LOI @ 800°C	CHX Outlet Temperature (°F)	ID Fan Inlet Temperature (°F)	Flow Rate of Infiltrated Air in RFG (lb/h)	Total RFG Flow (lb/h)
PRB AIR 01	8.9	0.6	>0	11.8	-16.1	-22.7	-29.6	0.2	0.3	3.04	96	108		
PRB Air Cyclone Test 2 ♣	10.7	0.3	>0	11.9	0.0	8.0	-31.1	0.3	0.3	2.18	109	109		
PRB Air Test #3C	8.1	0.6	>0	9.0	-16.1	-22.7	-29.7	0.3	0.3		88	101		
PRB Air Test #3C(Redo)	8.0	0.2	>0	10.1	-17.3	-23.9	-31.7	0.3	0.3		89	101		
PRB air test 2 ♣	11.2	0.4	>0	5.6	-16.8	-23.4	-31.0	0.4	0.5	2.05	94	107		
PRB Air test 3	8.5	1.2	>0	8.1	-12.6	-19.1	-24.2	0.2	0.3	2.22	95	108		
PRB Air Test #3B	8.5	0.8	>0	4.8	-4.4	-11.0	-10.4	0.3	0.3	1.73	90	102		
PRB-OXY 15b	6.0	1.1	>0	10.0	-0.1	-6.7	-1.5	-0.3	-0.6	1.24	101	114	148	4200
PRB Oxy Open Tube on Tertiary Line	5.4	0.0	>0	3.6	-3.7	-10.3	-8.4	-0.4	-0.7		99	112	258	4338
PRB-OXY 15	6.2	0.7	>0	9.3	-0.1	-6.7	-1.5	-0.3	-0.6		103	116	190	4284
prboxy16 08/11/09	5.4	1.4	>0	3.5	0.1	-6.5	-0.9	-0.2	-0.6	1.42	99	113	171	4439
prb oxy cyclone test13 ♣	6.6	-0.8	>0	3.3	0.0	6.0	-1.1	-0.1	-0.3	1.81	109	109	120	3549
PRB OXY Cyclone test #6	7.2	-0.2	>0	9.4	0.0	-1.2	-12.2	-0.3	-0.6	1.63	99	113	195	4113
PRB Oxy Test 6 ♣	6.7	1.2	>0	3.1	-11.2	-17.8	-21.2	-0.4	-0.7	2.56	120	120	401	4312
PRB Oxy Heat Balance #5	4.9	0.8	>0	3.3	-0.3	-6.9	-1.9	-0.2	-0.4	1.21	99	112	112	3948
PRB OXY 01	5.4	0.4	>0	7.7	-7.0	-13.6	-14.3	-0.3	-0.5	1.28	114	125	321	3839
prb oxy heat balance 3	6.4	0.6	>0	3.6	-0.2	-6.8	-1.8	-0.3	-0.6	1.32	103	116	156	4352
prb oxy 15c 08/11/09	5.9	0.8	>0	3.5	0.1	-6.5	-0.9	-0.3	-0.7		99	112	179	4472
PRB Oxy Heat Transfer 1	6.3	0.8	>0	4.0	-0.2	-6.8	-1.7	-0.3	-0.6	1.04	102	115	171	4319
PRB Oxy Heat Transfer 2	6.4	0.6	>0	3.6	-0.2	-6.8	-1.7	-0.3	-0.6		103	116	162	4363
PRB Oxy Heat Transfer 1 & 2	6.4	0.7	>0	3.7	-0.2	-6.8	-1.7	-0.3	-0.6		102	116	165	4352
prb oxy heat transfer 4	6.7	0.8	>0	3.7	-0.2	-6.8	-1.8	-0.3	-0.6	1.35	101	114	135	4332
PRB Oxy Test 7	5.4	1.5	>0	3.5	-11.6	-18.2	-21.9	-0.3	-0.7	1.38	111	121	407	4209

♣ Indicates test data was reprocessed for higher quality - particularly for the heat balance.

Table 8.10 Pilot scale test data for subbituminous coal – table 5 of 5: Static and differential pressures and miscellaneous data

Test Name	Start of Test	Test Parameters					Ambient Conditions		Primary and Tertiary Oxidant												
		Test Duration (min)	Air, Transition, or Oxy-firing	Coal Load (MBtu/h)	Cyclone Stoichiometric Ratio	Overall Stoichiometric Ratio	Relative Humidity	Barometric Pressure (in.Hg)	Primary Oxidant Flow Before Oxynator (lb/h)	Primary RFG Flow From O ₂ Measurements (wet lb/h)	Primary O ₂ Flow (lb/h)	Cyclone Tertiary Flow (lb/h)	Cyclone Tertiary Flow Temp (°F)	Primary Oxidant Temp After Heater (°F)	Primary Oxidant Temp After PC Addition (°F)	% O ₂ Primary Oxidant (vol%, wet)	% N ₂ Primary Oxidant (calculated vol%, wet)	% H ₂ O Primary Oxidant (vol%, wet)	% CO ₂ Primary Oxidant (vol%, wet)	SO ₂ Primary Oxidant (ppm, wet)	MW Primary Oxidizer (lb/lbmole)
Warm Rec-PRB Air Test 2a	9/14/2009 11:32	25	Air	5.93	0.87	1.14	54%	28.23	791			14	83	334	153	20.59	77.57	1.84			28.64
warm recycle prb air test 2d	9/14/2009 15:10	40	Air	5.83	0.93	1.19	42%	29.03	802			31	133	301	171	20.61	77.65	1.74			28.65
Warm Rec-PRB Air Test 2e ▲	9/15/2009 8:44	56	Air	5.56	0.96	1.23	59%	29.03	842			35	121	324	149	20.57	77.52	1.91			28.63
warm recycle prb air test 2c	9/14/2009 14:01	69	Air	5.98	0.99	1.20	44%	29.05	824			32	135	303	179	20.60	77.63	1.76			28.65
Warm Rec-PRB Air Test 2b	9/14/2009 12:56	62	Air	6.14	0.99	1.18	47%	29.08	838			34	121	332	170	20.60	77.63	1.76			28.65
Warm Rec-PRB Quick Baseline 9-17-09	9/17/2009 10:02	13	Air	5.77	1.00	1.16	59%	29.19	791			23	76	321	142	20.70	78.00	1.30			28.70
Warm Rec-PRB Air Test 2f	9/16/2009 8:22	54	Air	6.14	1.12	1.21	65%	29.16	817			21	86	323	148	20.69	77.96	1.35			28.69
warm rec-prb oxy test 5b	9/14/2009 18:00	12	Trans.	5.42	1.04	1.16	51%	29.00	936			36	137	286	184	20.59	77.61	1.80			28.64
Warm Rec-PRB secondary trans	9/15/2009 12:40	35	Trans.	5.41	1.05	1.21	44%	29.04	809	75	16	15	102	338	149	98.68	0.95	0.16	0.21	2	31.96
warm rec-prb oxy test 5a	9/14/2009 17:17	43	Trans.	5.35	1.06	1.18	42%	29.01	917			35	138	288	185	20.61	77.65	1.74			28.65
Warm Rec-PRB Secondary Trans 3	9/17/2009 11:41	19	Trans.	5.65	0.99	1.15	50%	29.18	824			22	103	323	145	20.68	77.92	1.40			28.69
Warm Rec-PRB Secondary Trans2	9/16/2009 12:16	50	Trans.	6.00	1.02	1.14	45%	29.19	840			20	102	315	146	20.73	78.13	1.14			28.72
warm rec-prb oxy test5c	9/14/2009 19:30	25	Oxy	5.37	1.13	1.26	60%	29.00	779	668	139	31	142	230	164	30.00	12.40	23.69	33.86	244	32.25
warm rec oxy prb 6	9/17/2009 19:31	12	Oxy	6.12	0.92	1.07	58%	29.08	735	752	171	14	137	307	183	19.50	8.79	26.95	44.71	464	33.25
Warm Rec PRB Oxy 1 ▲	9/17/2009 12:45	61	Oxy	5.76	0.97	1.13	45%	29.15	736	748	166	17	137	341	186	20.52	11.25	24.43	43.75	359	33.39
warm rec prb oxy 2	9/17/2009 14:11	57	Oxy	5.94	0.98	1.14	45%	29.13	746	761	166	13	136	347	187	20.31	10.26	24.95	44.43	379	33.44
warm rec oxy prb 5 ▲	9/17/2009 18:02	43	Oxy	5.84	0.98	1.16	43%	29.09	712	743	168	14	136	306	179	20.71	9.00	25.71	44.54	374	33.40
warm rec oxy prb 4 ▲	9/17/2009 16:34	58	Oxy	5.70	0.98	1.15	42%	29.10	719	752	167	14	136	307	179	20.39	9.27	25.61	44.68	397	33.42
warm rec prb oxy 3	9/17/2009 15:08	24	Oxy	5.64	1.00	1.14	42%	29.11	735	755	167	13	135	348	186	20.51	9.86	24.78	44.79	407	33.52
▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance and secondary RFG flow.																					

▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance and secondary RFG flow.

**Table 8.11 Pilot scale test data for subbituminous coal (warm recycle) – table 1 of 5:
test parameters, ambient conditions, and primary and tertiary oxidant data**

Test Name	Secondary and Overfire Oxidant														Cyclone Lance Oxygen				Fuel - Coal					
	Total Secondary Oxidant Flow From Flowmeter (lb/h)	Secondary RFG Flow From O ₂ Measurements (wet lb/h)	Secondary O ₂ Flow (lb/h)	Secondary Oxidant Flow to Cyclone (lb/h)	Windbox Temperature (°F)	Overfire Oxidant Flow (lb/h)	Overfire Oxidant Temp (°F)	% O ₂ at Windbox (vol%, wet)	% O ₂ Secondary Oxidant (vol%, wet)	% N ₂ Secondary Oxidant (calculated vol%, wet)	% H ₂ O Secondary Oxidant (vol%, wet)	% CO ₂ Secondary Oxidant (vol%, wet)	SO ₂ Secondary Oxidant (ppm, wet)	MW Secondary Oxidizer (lb/lbmole)	Cyclone O ₂ Lance Position	Cyclone Lance O ₂ Flow (lb/h)	Cyclone Lance O ₂ Temperature (°F)	As Fired Fuel Ash (wt%)	As Fired Fuel Moisture (wt%)	Measured Coal Feed Rate (lb/h)	Calculated Coal Feed Rate (lb/h)	Coal Load (MBtu/h)	Coal Fineness (% passing 200 mesh)	
Warm Rec-PRB Air Test 2a	4421			3218	688	1215	688	20.34	20.58	77.58	1.84			28.64	Scroll		74	5.51	18.16	592	602	5.93	31.15	
warm recycle prb air test 2d	4548			3391	689	1170	689	20.42	20.60	77.66	1.74			28.65	Withdrawn		80	5.51	18.16	577	592	5.83	31.15	
Warm Rec-PRB Air Test 2e ▲	4527			3369	688	1170	688	20.38	20.57	77.53	1.91			28.63	Scroll		72	5.13	18.34	574	570	5.56	54.49	
warm recycle prb air test 2c	4676			3728	690	960	690	20.51	20.60	77.64	1.76			28.65	Withdrawn		79	5.51	18.16	583	607	5.98	31.15	
Warm Rec-PRB Air Test 2b	4650			3800	689	862	689	20.55	20.60	77.64	1.76			28.65	Withdrawn		77	5.51	18.16	597	623	6.14	31.15	
Warm Rec-PRB Quick Baseline 9-17-09	4249			3556	739	705	739	20.73	20.69	78.01	1.30			28.70	Sec. Duct		65	5.49	18.34	573	587	5.77	39.51	
Warm Rec-PRB Air Test 2f	4701			4299	690	414	690	20.90	20.68	77.97	1.35			28.69	None		66	5.49	18.34	577	624	6.14	46.00	
warm rec-prb oxy test 5b	4012	3238	899	3703	686	552	686	23.63	23.16	29.45	20.89	26.45	218	31.07	Scroll	28	81	5.51	18.16	475	550	5.42	31.15	
Warm Rec-PRB secondary trans	4252	3318	975	3916	687	597	687	25.96	25.13	29.63	18.69	26.53	221	31.39	Withdrawn		82	5.49	18.34	521	550	5.41	46.00	
warm rec-prb oxy test 5a	4170	3387	888	3856	687	562	687	22.42	21.97	29.83	21.55	26.47	219	30.99	Scroll	32	82	5.51	18.16	473	543	5.35	31.15	
Warm Rec-PRB Secondary Trans 3	3046	2426	750	2607	728	580	728	26.28	26.14	28.84	16.43	28.52	239	31.96	Sec. Duct	98	75	5.49	18.34	571	575	5.65	39.51	
Warm Rec-PRB Secondary Trans2	3371	2577	887	3097	733	441	733	27.54	27.23	28.82	17.57	26.34	235	31.55	Sec. Duct		74	5.49	18.34	574	610	6.00	46.00	
warm rec-prb oxy test5c	4047	3288	882	3768	687	502	687	25.36	24.86	12.35	25.92	36.83	268	32.30	Scroll	27	76	5.51	18.16	485	545	5.37	31.15	
warm rec oxy prb 6	3561	2927	800	3162	737	680	737	23.98	23.04	8.40	25.77	42.74	444	33.20	Sec. Duct	47	70	5.49	18.34	566	622	6.12	39.51	
Warm Rec PRB Oxy 1 ▲	3120	2463	773	2624	729	612	729	27.50	27.44	10.28	22.30	39.94	328	33.27	Sec. Duct	94	76	5.13	18.34	597	590	5.76	39.51	
warm rec prb oxy 2	3321	2699	740	2897	733	650	733	25.17	24.38	9.74	23.68	42.16	359	33.36	Sec. Duct	111	77	5.49	18.34	601	605	5.94	39.51	
warm rec oxy prb 5 ▲	3861	3043	855	3172	740	725	740	25.65	25.50	8.46	24.15	41.85	351	33.31	Sec. Duct	30	73	5.13	18.34	572	598	5.84	39.51	
warm rec oxy prb 4 ▲	3586	2851	778	2954	737	676	737	25.15	24.94	8.89	24.54	42.13	375	33.34	Sec. Duct	77	76	5.13	18.34	599	584	5.70	39.51	
warm rec prb oxy 3	3240	2727	643	2819	732	651	732	22.91	22.09	9.67	24.29	43.91	399	33.49	Sec. Duct	155	77	5.49	18.34	607	573	5.64	39.51	
▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance and secondary RFG flow.																								

▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance and secondary RFG flow.

**Table 8.12 Pilot scale test data for subbituminous coal (warm recycle) – table 2 of 5:
Secondary and overfire oxidant, Cyclone lance oxygen, and coal test data**

Test Name	Fuel - Natural Gas		Convection Pass Gases									Stack/Emissions						
	Nat Gas Flow (lb/h)	Nat Gas Load (MBtu/h)	CO Conv Pass (ppm, dry)	O ₂ Convection Pass (vol%, dry)	O ₂ Convection Pass (vol%, wet)	CO ₂ Convection Pass (vol%, dry)	SO ₂ Convection Pass (ppm, dry)	NO _x Convection Pass (ppm, dry)	Vol % H ₂ O at Convection Pass	Convection Pass Flue Gas Flow (wet lb/h)	MW Flue Gas at Convection Pass (lb/lbmole)	CO Emissions (lb/h)	SO ₂ at Stack (ppm, dry)	SO ₂ Emissions (lb/MBtu)	NO _x Emissions (lb/MBtu)	Vol % H ₂ O at Stack	O ₂ at Stack (vol%, dry)	MW Flue Gas at Stack and RFG (lb/lbmole)
Warm Rec-PRB Air Test 2a			428	2.48	2.09	16.88	254	430	11.29	5793	29.37	2.091	227	0.427	0.581	9.56	4.408	29.80
warm recycle prb air test 2d			74	3.35	2.94	16.12	200	493	10.82	5922	29.35	0.376	189	0.373	0.699	9.58	4.311	29.57
Warm Rec-PRB Air Test 2e ▲			23	3.98	3.55	15.52	185	631	10.60	5922	29.31	0.116	172	0.358	0.943	9.52	5.114	29.50
warm recycle prb air test 2c			12	3.57	3.27	15.92	188	603	10.84	6086	29.32	0.062	177	0.349	0.856	9.38	4.661	29.57
Warm Rec-PRB Air Test 2b			280	3.16	2.80	16.24	212	657	11.07	6090	29.33	1.455	195	0.376	0.911	9.44	4.519	29.62
Warm Rec-PRB Quick Baseline 9-17-09			8	2.92	2.66	16.59	195	686	10.89	5607	29.39	0.036	178	0.333	0.925	9.07	4.508	29.76
Warm Rec-PRB Air Test 2f			36	3.78	3.49	15.73	185	844	10.68	6121	29.33	0.189	170	0.331	1.178	8.88	5.100	29.59
warm rec-prb oxy test 5b	40.9	0.95	54	4.12	3.06	46.44	398	1344	27.49	5780	30.77	0.094	373	0.225	0.583	26.29	5.197	30.84
Warm Rec-PRB secondary trans	25.4	0.59	17	5.89	4.50	46.29	407	1431	29.33	5075	30.48	0.018	368	0.148	0.415	23.72	7.330	31.23
warm rec-prb oxy test 5a	40.8	0.95	40	3.99	2.83	46.25	391	1252	27.76	5920	30.73	0.066	371	0.225	0.538	26.78	4.840	30.78
Warm Rec-PRB Secondary Trans 3			86	4.05	3.16	48.78	425	1497	23.87	4654	31.69	0.127	399	0.249	0.671	21.49	5.111	31.97
Warm Rec-PRB Secondary Trans2			50	3.83	2.95	47.34	439	1534	25.01	4955	31.31	0.084	408	0.255	0.690	23.35	5.056	31.41
warm rec-prb oxy test5c	25.3	0.59	23	7.27	5.04	71.16	545	1170	35.08	5696	32.08	0.022	505	0.185	0.308	32.74	8.292	32.39
warm rec oxy prb 6			114	2.07	1.58	84.49	888	1335	35.28	5465	33.30	0.103	843	0.296	0.336	32.87	3.024	33.53
Warm Rec PRB Oxy 1 ▲			28	4.25	3.06	79.03	672	1649	32.75	4869	33.36	0.026	621	0.238	0.454	29.68	5.517	33.69
warm rec prb oxy 2			27	4.23	3.10	80.41	707	1686	33.32	5218	33.38	0.025	659	0.240	0.441	30.26	5.368	33.75
warm rec oxy prb 5 ▲			27	4.66	3.40	81.22	702	1650	33.56	5477	33.42	0.025	663	0.245	0.438	31.30	5.562	33.70
warm rec oxy prb 4 ▲			27	4.46	3.21	81.06	743	1662	33.48	5249	33.42	0.024	700	0.258	0.440	31.09	5.402	33.72
warm rec prb oxy 3			36	4.27	3.11	80.76	756	1767	33.11	5152	33.47	0.031	708	0.255	0.457	30.14	5.316	33.86

▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance and secondary RFG flow.

**Table 8.13 Pilot scale test data for subbituminous coal (warm recycle) – table 3 of 5:
Natural gas flow, convection pass and stack gases, and emissions data**

Test Name	Heat Transfer and HVT Data																		
	Heat in with Primary Oxidant (MBtu/h)	Heat in with Secondary Oxidant (MBtu/h)	Heat Absorbed in Cyclone (MBtu/h)	Heat Absorbed in Furnace (MBtu/h)	Heat Absorbed in Convection Pass (MBtu/h)	Heat Out With Flue Gas (MBtu/h)	Total Heat Release in SBS-II (MBtu/h)	Convection Pass Exit Temperature (°F)	Max Temperature from FLAMEVIEW Camera (°F)	FEGT by HVT, Probe Insertion, 12" into Furnace (°F)	FEGT by HVT, Probe Insertion, 18" into Furnace (°F)	FEGT by HVT, Probe Insertion, 24" into Furnace (°F)	FEGT by HVT, Probe Insertion, 30" into Furnace (°F)	FEGT by HVT, Probe Insertion, 36" into Furnace (°F)	FEGT by HVT, Probe Extraction, 36" into Furnace (°F)	FEGT by HVT, Probe Extraction, 30" into Furnace (°F)	FEGT by HVT, Probe Extraction, 24" into Furnace (°F)	FEGT by HVT, Probe Extraction, 18" into Furnace (°F)	FEGT by HVT, Probe Extraction, 12" into Furnace (°F)
Warm Rec-PRB Air Test 2a	0.15	1.26	0.55	1.98	1.42	1.98	4.51	870											
warm recycle prb air test 2d	0.15	1.30	0.48	2.47	1.94	2.02	5.46	866		2345	2349	2335	2319	2350	2344	2315	2320	2318	2300
Warm Rec-PRB Air Test 2e ▲	0.16	1.29	0.45	2.26	1.76	1.94	4.96	821		2132	2196	2199	2205	2206	2206	2211	2208	2195	plugged
warm recycle prb air test 2c	0.15	1.34	0.50	2.52	2.02	2.07	5.61	867											
Warm Rec-PRB Air Test 2b	0.16	1.33	0.55	2.41	2.07	2.11	5.65	886		2329	2333	2353	2331	2343	2335	2314	2324	2332	2281
Warm Rec-PRB Quick Baseline 9-17-09	0.15	1.27	0.71			1.81		801											
Warm Rec-PRB Air Test 2f	0.16	1.34	0.65	1.93	1.53	2.02	4.64	831	3100	2141	2155	2162	2164	2166	2166	2166	2165	2167	2156
warm rec-prb oxy test 5b	0.17	1.22	0.52			1.98		842											
Warm Rec-PRB secondary trans	0.00	1.28	0.51	2.81	1.89	1.72	5.64	814											
warm rec-prb oxy test 5a	0.17	1.27	0.51	2.68	1.78	2.04	5.58	848											
Warm Rec-PRB Secondary Trans 3	0.16	0.92	0.66	2.23	1.80	1.47	5.06	777											
Warm Rec-PRB Secondary Trans2	0.16	1.04	0.66	2.46	1.64	1.57	5.12	771	3200	2276	2273	2271	2276	2279	2281	2290	2282	2274	2240
warm rec-prb oxy test5c	0.14	1.22	0.23	2.24	2.11	1.96	5.19	847											
warm rec oxy prb 6	0.17	1.13	0.45	2.49	1.70	1.81	5.14	824											
Warm Rec PRB Oxy 1 ▲	0.18	0.94	0.64	2.67	1.69	1.58	5.46	809	3200	2300	2325	2312	2310	2311	2311	2311	2309	2306	2279
warm rec prb oxy 2	0.18	1.03	0.60	2.74	1.77	1.73	5.62	833		2310	2301	2303	2306	2304	2304	2297	2295	2296	2279
warm rec oxy prb 5 ▲	0.17	1.14	0.49	2.54	1.84	1.82	5.37	831	3100	2180	2183	2190	2191	2190	2190	2191	2186	2183	2175
warm rec oxy prb 4 ▲	0.17	1.06	0.53	2.51	1.75	1.77	5.31	847		2227	2246	2254	2260	2260	2260	2260	2267	2261	2255
warm rec prb oxy 3	0.18	1.01	0.56	2.41	1.80	1.70	5.27	829											
▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance and secondary RFG flow.																			

**Table 8.14 Pilot scale test data for subbituminous coal (warm recycle) – table 4 of 5:
Heat transfer and temperature data**

Test Name	System Static and Differential Pressures							Miscellaneous			
	Cyclone Differential Pressure (in.H ₂ O)	Furnace Pressure (in.H ₂ O)	Baghouse Inlet (flow venturi) Static Pressure (in.H ₂ O)	Baghouse Differential Pressure (in.H ₂ O)	ID Fan Inlet Static Pressure (in.H ₂ O)	Primary RFG Static Pressure at Venturi (in.H ₂ O)	Secondary RFG Static Pressure at Venturi (in.H ₂ O)	Fly Ash % LOI @ 800°C	ID Fan Inlet Temperature (°F)	Flow Rate of Infiltrated Air in RFG (lb/h)	Total RFG Flow (lb/h)
Warm Rec-PRB Air Test 2a	9.8	-0.5	> 0	5.7	-10.1	0.2	0.2	1.20	261		
warm recycle prb air test 2d	10.7	-0.5	6.0	5.0	-3.6	0.3	0.4	1.02	297		
Warm Rec-PRB Air Test 2e ♠	10.7	-0.6	6.7	8.0	-6.2	0.3	0.4	1.26	277		
warm recycle prb air test 2c	12.5	-0.4	6.0	5.4	-4.3	0.3	0.4	1.29	298		
Warm Rec-PRB Air Test 2b	13.0	-0.1	3.8	5.9	-7.2	0.3	0.4	1.3	294		
Warm Rec-PRB Quick Baseline 9-17-09	13.4	0.3	3.1	6.8	-7.8	0.2	0.2		215		
Warm Rec-PRB Air Test 2f	17.2	-0.2	5.1	6.3	-6.0	0.3	0.4	1.36	264		
warm rec-prb oxy test 5b	10.6	-1.4	4.8	4.1	-3.2	-0.6	-1.2		303	65	3239
Warm Rec-PRB secondary trans	13.9	-1.1	4.5	5.7	-5.1	-0.4	-1.0	2.66*	283	117	3393
warm rec-prb oxy test 5a	11.2	-0.5	5.3	4.5	-3.2	-0.6	-1.4		299	68	3387
Warm Rec-PRB Secondary Trans 3	7.9	-2.0	5.2	4.1	-1.3	-0.1	-0.4		262	46	2427
Warm Rec-PRB Secondary Trans2	8.1	-1.6	5.4	4.0	-1.3	-0.2	-0.5	1.78	269	68	2578
warm rec-prb oxy test5c	6.5	-0.1	4.5	4.1	-3.4	-0.8	-1.2		310	64	3957
warm rec oxy prb 6	12.5	-0.1	6.0	3.9	-0.9	-0.6	-0.9		304	88	3679
Warm Rec PRB Oxy 1 ♠	6.4	-0.4	4.7	3.6	-1.3	-0.4	-0.6	1.44	280	87	3211
warm rec prb oxy 2	8.6		5.3	3.7	-1.2	-0.5	-0.7	1.37	289	86	3460
warm rec oxy prb 5 ♠	13.1		6.4	4.0	-0.8	-0.6	-1.0	2.74*	311	65	3786
warm rec oxy prb 4 ♠	11.4		5.8	3.8	-1.0	-0.6	-0.9	1.65	305	68	3603
warm rec prb oxy 3	8.7		5.3	3.7	-1.1	-0.5	-0.7	1.64	295	76	3482
♠ Indicates test data was reprocessed for higher quality - particularly for the heat balance and secondary RFG flow.											
* Indicates ash sample size was small.											

**Table 8.15 Pilot scale test data for subbituminous coal (warm recycle) – table 5 of 5:
Static and differential pressures and miscellaneous data**

Test Name	Start of Test	Test Parameters						Ambient Conditions		Primary and Tertiary Oxidant													
		Test Duration (min)	Air, Transition, or Oxy-firing	Coal Load (MBtu/h)	Cyclone Stoichiometric Ratio	Overall Stoichiometric Ratio	Relative Humidity	Barometric Pressure (in.Hg)	Primary Oxidant Flow Before Oxynator (lb/h)	Primary RFG Flow From O ₂ Measurements (wet lb/h)	Primary O ₂ Flow (lb/h)	Cyclone Tertiary Flow (lb/h)	Cyclone Tertiary Flow Temp (°F)	Primary Oxidant Temp After Heater (°F)	% O ₂ Primary Oxidant (vol%, wet)	% N ₂ Primary Oxidant (calculated vol%, wet)	% H ₂ O Primary Oxidant (vol%, wet)	% CO ₂ Primary Oxidant (vol%, wet)	SO ₂ Primary Oxidant (ppm, wet)	MW Primary Oxidizer (lb/lbmole)			
OHIO5 AIR FIRING TEST3	7/21/2009 17:52	38	Air	4.70	0.81	1.18	71%	29.02	786			47	72	161	20.56	77.48	1.96			28.63			
OH #5 Air Long Term 4	7/21/2009 14:18	213	Air	4.73	0.86	1.13	55%	29.02	790			47	78	160	20.62	77.70	1.68			28.66			
OH #5 Air Long Term #1	7/21/2009 8:58	65	Air	5.03	0.88	1.13	67%	29.10	802			48	72	160	20.60	77.62	1.78			28.65			
ohio 5 Air-2 7-16-09	7/16/2009 10:54	20	Air	4.96	0.88	1.14	49%	28.87	802			47	77	151	20.60	77.61	1.79			28.64			
OH #5 Air Long Term 3	7/21/2009 11:03	131	Air	4.84	0.88	1.14	54%	29.08	788			47	77	160	20.60	77.62	1.78			28.65			
Ohio #5 Air #2	7/14/2009 10:59	15	Air	4.94	0.89	1.14	31%	29.15	800			48	70	91	20.76	78.24	1.00			28.73			
OH #5 Air Long Term 2	7/21/2009 10:19	43	Air	4.85	0.89	1.15	63%	29.10	794			47	74	160	20.60	77.62	1.78			28.65			
Ohio #5 Test B1	7/7/2009 10:26	18	Air	5.10	0.91	1.10	42%	28.81	803			46	74	150	20.70	78.02	1.27			28.70			
OHIO5 AIR FIRING TEST1	7/21/2009 18:53	31	Air	4.87	1.00	1.17	71%	29.01	783			47	72	160	20.58	77.54	1.88			28.64			
ohio #5 Air test 3-1	7/30/2009 8:45	32	Air	5.97	0.87	1.14	93%	28.91	788			40	71	158	20.53	77.36	2.11			28.61			
Ohio #5 air 3-1 B ▲	7/30/2009 11:23	10	Air	5.96	0.90	1.17	77%	28.91	804			41	76	159	20.52	77.33	2.15			28.61			
ohio5 oxy 6	7/13/2009 15:18	16	Oxy	5.16	0.84	1.12	24%	28.99	709	687	104	46	85	151	16.69	33.18	5.11	44.96	599	35.37			
ohio5 oxy 5.2 07/16/09	7/16/2009 16:24	16	Oxy	4.96	0.85	1.09	35%	28.84	693	606	119	45	88	152	15.14	20.55	4.88	59.38	518	28.80			
ohio 5 oxy 5 07/14/2009	7/14/2009 13:49	19	Oxy	5.17	0.86	1.06	30%	29.12	716	694	112	49	79	98	16.12	34.52	4.68	44.61	643	35.34			
Ohio #5 Oxy 7 Long Term 2	7/28/2009 12:38	72	Oxy	5.26	0.88	1.10	47%	28.88	732	738	104	43	91	178	16.35	31.33	4.97	47.33	252	35.74			
Ohio #5 Oxy 5 7-16-2009	7/16/2009 14:46	38	Oxy	5.25	0.88	1.09	35%	28.84	704	690	109	46	85	104	16.67	25.37	4.87	53.05	309	35.51			
Ohio #5 Oxy 5.1 7-16-2009	7/16/2009 15:25	34	Oxy	5.01	0.90	1.13	35%	28.84	631	577	119	42	84	106	17.65	20.34	4.68	57.28	389	31.09			
Ohio #5 Oxy 7 Long Term 3	7/28/2009 16:44	139	Oxy	5.21	0.90	1.13	45%	28.83	728	732	104	42	90	166	16.92	31.53	4.84	46.69	192	35.65			
Ohio #5 test Oxy 5	7/9/2009 14:03	10	Oxy	5.17	0.90	1.07	39%	29.11	722	714	102	46	87	151	15.71	29.92	5.17	49.14	595	36.00			
ohio 5 oxy 5 B P 07/14/09	7/14/2009 15:00	37	Oxy	5.20	0.90	1.11	30%	29.12	717	697	122	50	80	97	17.89	31.27	4.44	46.38	241	35.70			
Ohio #5 long term oxy 4	7/29/2009 11:06	59	Oxy	5.15	0.93	1.07	90%	28.75	733	727	99	41	86	190	15.28	27.22	4.85	52.64	136	36.27			
Ohio5 oxy6.1 07/16/09	7/16/2009 18:31	18	Oxy	5.48	0.95	1.20	36%	28.83	675	632	109	43	90	152	17.52	19.24	5.97	57.22	544	30.89			
Ohio #5 Oxy 7 Long Term 4	7/28/2009 19:04	138	Oxy	5.06	0.95	1.19	52%	28.82	734	737	104	42	90	187	17.40	27.57	5.14	49.86	381	36.13			
Ohio #5 Oxy Long Term Test 1	7/22/2009 11:45	76	Oxy	5.22	0.96	1.19	59%	29.04	693	681	109	43	94	171	18.79	26.01	7.09	48.04	637	35.75			
Ohio #5 Oxy Test #8	7/29/2009 18:28	28	Oxy	6.26	0.84	1.11	81%	28.77	604	602	99	39	89	202	17.41	22.50	6.13	53.92	324	36.72			
Ohio #5 Oxy Test #7	7/29/2009 17:39	26	Oxy	5.93	0.86	1.12	86%	28.77	604	602	100	38	88	200	17.37	23.13	6.13	53.34	238	36.62			
Ohio #5 Oxy Test #6	7/29/2009 16:53	25	Oxy	5.95	0.90	1.17	82%	28.76	610	607	100	39	88	198	18.14	22.38	6.13	53.33	204	36.65			
ohio 5 oxy 6 07/16/09	7/16/2009 17:41	17	Oxy	5.47	0.93	1.18	36%	28.83	664	618	109	43	89	152	17.26	20.04	5.53	57.12	512	30.62			
ohio #5 Oxy 9	7/29/2009 13:32	46	Oxy	6.00	0.93	1.16	91%	28.75	671	663	99	41	88	208	17.01	23.36	6.20	53.39	463	36.62			
Ohio #5 Oxy Test 9 with HVT ▲	7/30/2009 17:16	20	Oxy	5.86	0.92	1.17	68%	28.85	752	742	115	43	91	191	17.63	23.32	7.85	51.16	363	36.12			
Ohio #5 Oxy4	7/7/2009 13:54	28	Oxy	3.90	0.96	1.12	27%	28.81	714	664	112	45	90	152	16.05	26.46	7.28	45.16	1136	33.04			
Full Oxy-firing First Time	7/2/2009 12:19	17	Oxy	2.89	1.24	1.41	56%	28.83	719	676	104	45	82	150	18.62	35.03	6.86	31.96	183	31.07			

▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.

Table 8.16 Pilot scale test data for bituminous coal – table 1 of 5: test parameters, ambient conditions, and primary and tertiary oxidant data

Test Name	Secondary and Overfire Oxidant													Cyclone Lance Oxygen			Fuel - Coal								
	Total Secondary Oxidant Flow From Flowmeter (lb/h)	Secondary RFG Flow From O ₂ Measurements (wet lb/h)	Secondary RFG Flow from Flowmeters (wet lb/h) (Secondary Oxidizer minus Secondary O ₂ Flow)	Secondary O ₂ Flow (lb/h)	Secondary Oxidant Flow to Cyclone (lb/h)	Windbox Temperature (°F)	Overfire Oxidant Flow (lb/h)	Overfire Oxidant Temp (°F)	% O ₂ at Windbox (vol%, wet)	% O ₂ Secondary Oxidant (vol%, wet)	% N ₂ Secondary Oxidant (calculated vol%, wet)	% H ₂ O Secondary Oxidant (vol%, wet)	% CO ₂ Secondary Oxidant (vol%, wet)	SO ₂ Secondary Oxidant (ppm, wet)	MW Secondary Oxidizer (lb/lbmole)	Cyclone O ₂ Lance Position	Cyclone Lance O ₂ Flow (lb/h)	Cyclone Lance O ₂ Temperature (°F)	As Fired Fuel Ash (wt%)	As Fired Fuel Moisture (wt%)	Measured Coal Feed Rate (lb/h)	Calculated Coal Feed Rate (lb/h)	Coal Load (MBtu/h)	Coal Fineness (% passing 200 mesh)	
OHIO5 AIR FIRING TEST3	3673				2325	701	1358	701	19.92	20.56	77.49	1.96			28.63	Sec. Duct		74	4.81	4.20	319	354	4.70	49.22	
OH #5 Air Long Term 4	3682				2648	700	1045	700	20.05	20.61	77.71	1.68			28.66	Sec. Duct		80	4.81	4.20	335	357	4.73	49.22	
OH #5 Air Long Term #1	3735				2748	698	998	698	20.05	20.59	77.63	1.78			28.65	Sec. Duct		71	4.81	4.20	358	379	5.03	49.22	
ohio 5 Air-2 7-16-09	3700				2720	696	990	696	20.04	20.59	77.62	1.79			28.64	Sec. Duct		79	4.81	4.20	355	374	4.96	52.68	
OH #5 Air Long Term 3	3632				2651	698	991	698	20.04	20.59	77.63	1.78			28.65	Sec. Duct		76	4.81	4.20	316	365	4.84	49.22	
Ohio #5 Air #2	3691				2720	644	982	725	20.16	20.76	78.25	1.00			28.73	Sec. Duct		73	4.81	4.20	344	373	4.94	52.68	
OH #5 Air Long Term 2	3663				2681	698	993	698	20.05	20.59	77.63	1.78			28.65	Sec. Duct		73	4.81	4.20	319	366	4.85	49.22	
Ohio #5 Test B1	3620				2877	695	754	724	20.22	20.70	78.03	1.27			28.70	Sec. Duct		74	4.81	4.20	421	385	5.10	52.68	
OHIO5 AIR FIRING TEST1	3730				3080	701	661	701	20.12	20.57	77.55	1.88			28.64	Sec. Duct		74	4.81	4.20	324	367	4.87	49.22	
ohio #5 Air test 3-1	4530				3310	689	1233	689	20.20	20.52	77.37	2.11			28.61	Sec. Duct		72	4.81	4.20	415	450	5.97	49.22	
Ohio #5 air 3-1 B ▲	4676				3437	690	1252	690	20.18	20.51	77.34	2.15			28.61	Sec. Duct		77	4.81	4.20	419	450	5.96	49.22	
ohio5 oxy 6	3067		2506	561	2290	654	1221	727	22.99	21.65	31.21	4.80	42.28	564	35.17	Sec. Duct	121	80	4.81	4.20	341	389	5.16	52.68	
ohio5 oxy 5.2 07/16/09	3449		2868	581	2513	696	1058	696	22.17	18.57	19.72	4.69	56.98	498	37.41	Sec. Duct	123	88	4.81	4.20	350	375	4.96	52.68	
ohio 5 oxy 5 07/14/2009	3269		2707	561	2779	637	949	726	20.61	19.47	33.14	4.50	42.83	618	35.20	Sec. Duct	103	80	4.81	4.20	340	390	5.17	52.68	
Ohio #5 Oxy 7 Long Term 2	3234		2638	596	2721	677	1033	677	22.67	21.78	29.30	4.65	44.25	236	35.50	Sec. Duct	104	87	4.81	4.20	338	397	5.26	49.22	
Ohio #5 Oxy 5 7-16-2009	3561		2987	575	2987	697	1046	697	21.31	19.51	24.51	4.71	51.24	299	36.45	Sec. Duct	105	89	4.81	4.20	348	397	5.25	52.68	
Ohio #5 Oxy 5.1 7-16-2009	3313		2736	577	2555	695	1013	695	23.21	20.15	19.72	4.54	55.55	377	36.53	Sec. Duct	123	89	4.81	4.20	343	378	5.01	52.68	
Ohio #5 Oxy 7 Long Term 3	3219		2621	598	2711	676	1015	676	23.25	22.36	29.46	4.52	43.63	179	35.43	Sec. Duct	100	86	4.81	4.20	330	393	5.21	49.22	
Ohio #5 test Oxy 5	3379		2830	548	3030	694	878	726	20.28	19.18	28.69	4.96	47.11	571	35.83	Sec. Duct	125	85	4.81	4.20	368	390	5.17	52.68	
ohio 5 oxy 5 B P 07/14/09	3090		2535	554	2592	635	926	726	22.31	21.02	30.07	4.27	44.61	232	35.56	Sec. Duct	128	82	4.81	4.20	347	393	5.20	52.68	
Ohio #5 long term oxy 4	3223		2626	597	3083	677	629	677	22.44	21.37	25.27	4.50	48.85	126	36.23	Sec. Duct	96	73	4.81	4.20	338	389	5.15	49.22	
Ohio5 oxy6.1 0716/09	3766		3115	651	2984	701	1153	701	24.32	21.39	18.33	5.69	54.54	518	37.03	Sec. Duct	127	84	4.81	4.20	409	414	5.48	52.68	
Ohio #5 Oxy 7 Long Term 4	3394		2794	600	2882	678	1057	678	22.98	22.10	26.00	4.84	47.02	360	35.94	Sec. Duct	100	81	4.81	4.20	325	382	5.06	49.22	
Ohio #5 Oxy Long Term Test 1	3229		2634	595	2734	694	1002	694	24.09	22.98	24.81	6.71	45.44	603	35.54	Sec. Duct	124	76	4.81	4.20	354	394	5.22	49.22	
Ohio #5 Oxy Test #8	4218		3382	836	3524	687	1380	687	24.09	22.78	21.04	5.73	50.41	303	36.41	Sec. Duct	44	74	4.81	4.20	388	472	6.26	49.22	
Ohio #5 Oxy Test #7	4163		3421	741	3466	687	1387	687	22.04	20.86	22.15	5.87	51.09	228	36.43	Sec. Duct	85	73	4.81	4.20	386	447	5.93	49.22	
Ohio #5 Oxy Test #6	4134		3402	732	3413	687	1398	687	22.79	21.62	21.43	5.87	51.06	195	36.46	Sec. Duct	114	73	4.81	4.20	389	449	5.95	49.22	
ohio 5 oxy 6 07/16/09	3688		3039	649	2890	699	1131	699	24.38	21.35	19.05	5.26	54.30	487	37.03	Sec. Duct	127	86	4.81	4.20	408	413	5.47	52.68	
ohio #5 Oxy 9	4217		3484	733	3687	687	1202	687	22.30	21.15	22.19	5.89	50.72	440	36.39	Sec. Duct	116	71	4.81	4.20	393	453	6.00	49.22	
Ohio #5 Oxy Test 9 with HVT ▲	4118	3472	3345	773	3198	687	1193	687	23.65	23.99	21.53	7.24	47.21	335	35.80	Sec. Duct	125	77	4.81	4.20	415	442	5.86	49.22	
Ohio #5 Oxy4	3055		2504	551	2777	691	691	725	21.63	19.72	25.30	6.96	43.19	1086	33.16	Sec. Duct	120	83	4.81	4.20	264	295	3.90	52.68	
Full Oxy-firing First Time	3262		2747	515	3160	675	636	705	21.97	20.72	34.12	6.68	31.13	178	31.10	Sec. Duct	132	71	5.57	4.96	239	222	2.89	52.68	
▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.																									

▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.

Table 8.17 Pilot scale test data for bituminous coal – table 2 of 5: Secondary and overfire oxidant, Cyclone lance oxygen, and coal test data

Test Name	Fuel - Natural Gas		Convection Pass Gases									Stack/Emissions						
	Nat Gas Flow (lb/h)	Nat Gas Load (MBtu/h)	CO Conv Pass (ppm, dry)	O ₂ Convection Pass (vol%, dry)	O ₂ Convection Pass (vol%, wet)	CO ₂ Convection Pass (vol%, dry)	SO ₂ Convection Pass (ppm, dry)	NO _x Convection Pass (ppm, dry)	Vol % H ₂ O at Convection Pass	Convection Pass Flue Gas Flow (wet lb/h)	MW Flue Gas at Convection Pass (lb/lbmole)	CO Emissions (lb/h)	SO ₂ at Stack (ppm, dry)	SO ₂ Emissions (lb/MBtu)	NO _x Emissions (lb/MBtu)	Vol % H ₂ O at Stack	O ₂ at Stack (vol%, dry)	MW Flue Gas at Stack and RFG (lb/lbmole)
OHIO5 AIR FIRING TEST3			44	3.10	2.74	15.57	1914	289	8.04	4807	29.67	0.182	352	0.827	0.489	7.93	4.878	29.43
OH #5 Air Long Term 4			26	3.19	2.81	15.49	1901	550	7.81	4823	29.69	0.108	380	0.954	0.932	7.20	5.013	29.51
OH #5 Air Long Term #1			38	2.38	2.16	16.26	1982	518	8.19	4909	29.73	0.160	368	0.851	0.863	4.43	4.196	29.88
ohio 5 Air-2 7-16-09			67	2.48	2.17	16.29	1943	444	8.18	4869	29.74	0.284	551	1.303	0.753	3.84	4.289	29.94
OH #5 Air Long Term 3			35	2.58	2.32	16.07	1982	531	8.12	4778	29.72	0.142	509	1.167	0.876	6.33	4.518	29.66
Ohio #5 Air #2			41	2.53	2.16	16.13	2007	578	7.42	4857	29.81	0.174	397	0.917	0.960	4.72	4.302	29.85
OH #5 Air Long Term 2			32	2.70	2.42	15.94	1959	554	8.09	4816	29.71	0.133	429	0.988	0.917	5.55	4.710	29.74
Ohio #5 Test B1			78	1.91	1.80	16.20	2146	507	7.96	4801	29.74	0.321	564	1.282	0.827	6.31	3.598	29.60
OHIO5 AIR FIRING TEST1			22	3.02	2.70	15.68	1907	664	8.11	4874	29.68	0.095	347	0.778	1.069	8.22	4.750	29.44
ohio #5 Air test 3-1			36	2.50	2.37	16.14	2071	438	8.58	5760	29.67	0.181	178	0.393	0.695	5.33	4.242	29.80
Ohio #5 air 3-1 B ▲			16	3.04	2.82	15.60	1959	482	8.42	5922	29.62	0.083	136	0.266	0.681	7.95	4.611	29.73
ohio5 oxy 6			53	2.86	2.42	62.66	3340	1036	12.47	4931	35.74	0.053	726	0.367	0.376	5.83	5.280	35.85
ohio5 oxy 5.2 07/16/09			52	2.00	1.94	79.45	3192	755	12.25	4997	30.67	0.066	622	0.398	0.345	5.54	3.562	29.95
ohio 5 oxy 5 07/14/2009			149	1.28	1.27	61.65	3188	369	11.87	5145	35.66	0.151	782	0.386	0.131	5.39	3.496	35.84
Ohio #5 Oxy 7 Long Term 2			50	2.36	2.09	67.69	2901	798	12.23	5211	36.47	0.053	304	0.168	0.316	5.64	4.458	36.25
Ohio #5 Oxy 5 7-16-2009			186	2.08	1.90	73.83	2893	651	12.05	5461	37.35	0.257	377	0.197	0.241	5.60	4.201	36.59
Ohio #5 Oxy 5.1 7-16-2009			110	2.99	2.78	78.34	3147	887	12.30	4926	34.24	0.157	476	0.282	0.376	5.42	4.532	32.28
Ohio #5 Oxy 7 Long Term 3			57	2.93	2.82	67.09	2811	840	12.10	5165	36.43	0.063	231	0.130	0.344	5.50	5.049	36.17
Ohio #5 test Oxy 5			136	1.60	1.35	69.25	3161	789	12.18	5355	36.67	0.138	719	0.373	0.294	5.88	3.166	36.55
ohio 5 oxy 5 B P 07/14/09			81	2.51	2.34	63.68	2964	693	12.00	4974	35.95	0.079	297	0.138	0.231	5.18	4.346	36.32
Ohio #5 long term oxy 4			190	1.67	1.64	72.17	2800	924	12.17	5138	37.08	0.188	163	0.079	0.319	5.50	3.659	37.17
Ohio5 oxy6.1 0716/09			57	4.68	4.19	78.24	3384	1036	13.10	5583	37.68	0.079	665	0.378	0.423	6.80	6.150	33.68
Ohio #5 Oxy 7 Long Term 4			39	4.14	3.79	69.46	2826	995	11.97	5373	36.83	0.039	461	0.240	0.374	5.84	5.768	36.73
Ohio #5 Oxy Long Term Test 1			58	4.55	3.70	70.43	3238	973	14.13	5159	36.53	0.059	802	0.429	0.373	8.19	6.545	36.34
Ohio #5 Oxy Test #8			80	2.58	2.52	75.18	2876	548	13.44	6227	37.25	0.086	404	0.180	0.175	7.11	4.183	37.48
Ohio #5 Oxy Test #7			77	2.56	2.46	74.41	2729	586	13.13	6192	37.21	0.085	297	0.135	0.191	7.11	4.078	37.36
Ohio #5 Oxy Test #6			60	3.72	3.54	74.40	2725	880	13.13	6187	37.25	0.067	254	0.117	0.290	7.10	5.132	37.39
ohio 5 oxy 6 07/16/09			89	4.17	3.74	78.21	3390	1036	12.87	5455	36.86	0.131	623	0.365	0.436	6.31	5.700	33.22
ohio #5 Oxy 9			98	3.43	3.32	73.65	2989	921	13.04	6334	37.16	0.107	571	0.263	0.306	7.10	4.855	37.29
Ohio #5 Oxy Test 9 with HVT ▲			39	3.90	3.36	73.00	2968	913	14.55	5940	36.76	0.044	458	0.226	0.324	9.02	5.367	36.74
Ohio #5 Oxy4	44.5	1.03	49	2.74	2.23	64.55	2630	987	16.22	4847	35.21	0.059	1407	0.934	0.460	8.26	4.717	31.58
Full Oxy-firing First Time	75.9	1.77	66	7.71	6.39	44.59	2091	1036	15.89	5140	32.72		223	0.128	0.428	7.70	8.877	30.96
▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.																		

▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.

Table 8.18 Pilot scale test data for bituminous coal – table 3 of 5: Natural gas flow, convection pass and stack gases, and emissions data

Test Name	Heat Transfer and HVT Data																			
	Heat in with Primary Oxidant (MBtu/h)	Heat in with Secondary Oxidant (MBtu/h)	Heat Absorbed in Cyclone (MBtu/h)	Heat Absorbed in Furnace (MBtu/h)	Heat Absorbed in Convection Pass (MBtu/h)	Heat Out With Flue Gas (MBtu/h)	Total Heat Release in SBS-II (MBtu/h)	Convection Pass Exit Temperature (°F)	Max Temperature from FLAMEVIEW Camera (°F)	FEGT by HVT, Probe Insertion, 12" into Furnace (°F)	FEGT by HVT, Probe Insertion, 18" into Furnace (°F)	FEGT by HVT, Probe Insertion, 24" into Furnace (°F)	FEGT by HVT, Probe Insertion, 30" into Furnace (°F)	FEGT by HVT, Probe Insertion, 36" into Furnace (°F)	FEGT by HVT, Probe Extraction, 30" into Furnace (°F)	FEGT by HVT, Probe Extraction, 30" into Furnace (°F)	FEGT by HVT, Probe Extraction, 24" into Furnace (°F)	FEGT by HVT, Probe Extraction, 18" into Furnace (°F)	FEGT by HVT, Probe Extraction, 12" into Furnace (°F)	
OHIO5 AIR FIRING TEST3	0.12	1.06	0.71	1.89		1.52		795	3000											
OH #5 Air Long Term 4	0.12	1.06	0.73	2.06		1.52		795	2900											
OH #5 Air Long Term #1	0.12	1.08	0.74			1.49		754												
ohio 5 Air-2 7-16-09	0.12	1.07	0.86			1.43		715												
OH #5 Air Long Term 3	0.12	1.05	0.73			1.49		781												
Ohio #5 Air #2	0.11	1.01	0.69			1.47		749												
OH #5 Air Long Term 2	0.12	1.06	0.73			1.49		772												
Ohio #5 Test B1	0.12	1.04	0.93			1.38		688												
OHIO5 AIR FIRING TEST1	0.12	1.08	0.70			1.55		803	3300											
ohio #5 Air test 3-1	0.12	1.30	0.82	2.10	1.45	1.99	4.94	897	3100											
Ohio #5 air 3-1 B ▲	0.12	1.34	0.83	1.86	1.42	2.01	4.66	878		2225	2235	2235	2231	2254	2254	2258	2245	2244	2240	
ohio5 oxy 6	0.12	0.87	0.58			1.35		731												
ohio5 oxy 5.2 07/16/09	0.14	0.90	0.70			1.78		798												
ohio 5 oxy 5 07/14/2009	0.11	0.91	0.50			1.45		763												
Ohio #5 Oxy 7 Long Term 2	0.13	0.95	0.73	2.00	1.17	1.51	4.31	796												
Ohio #5 Oxy 5 7-16-2009	0.11	1.03	0.73			1.54		784												
Ohio #5 Oxy 5.1 7-16-2009	0.11	0.92	0.73			1.55		777												
Ohio #5 Oxy 7 Long Term 3	0.12	0.94	0.70			1.50		800	3300											
Ohio #5 test Oxy 5	0.12	1.00	0.86			1.43		718												
ohio 5 oxy 5 B P 07/14/09	0.11	0.85	0.63			1.40		761												
Ohio #5 long term oxy 4	0.13	0.93	0.63			1.49		807												
Ohio5 oxy6.1 0716/09	0.13	1.05	0.77			1.68		846												
Ohio #5 Oxy 7 Long Term 4	0.13	0.99	0.69			1.56		810												
Ohio #5 Oxy Long Term Test 1	0.12	0.97	0.60			1.46		772												
Ohio #5 Oxy Test #8	0.11	1.24	0.55	2.55	1.41	1.96	5.12	894												
Ohio #5 Oxy Test #7	0.11	1.23	0.59	2.60	1.44	1.94	5.23	887												
Ohio #5 Oxy Test #6	0.11	1.22	0.65	2.10	1.42	1.93	4.76	884												
ohio 5 oxy 6 07/16/09	0.13	1.02	0.78			1.68		841												
ohio #5 Oxy 9	0.12	1.24	0.65	2.20	1.42	1.98	4.89	888	3300											
Ohio #5 Oxy Test 9 with HVT ▲	0.13	1.12	0.64	2.41	1.55	1.82	5.16	857	3000	2113	2121	2133	2124	2120	2122	2129	2135	2123	2106	
Ohio #5 Oxy4	0.12	0.91	0.90			1.28		681												
Full Oxy-firing First Time	0.12	0.99	0.93			1.42		684												
▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.																				

▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.

**Table 8.19 Pilot scale test data for bituminous coal – table 4 of 5:
Heat transfer and temperature data**

Test Name	System Static and Differential Pressures												Miscellaneous							
	Cyclone Differential Pressure (in. H 2O)	Furnace Pressure (in. H 2O)	Baghouse Inlet (flow venturi) Static Pressure (in. H 2O)	Baghouse Differential Pressure (in. H 2O)	Absorber Inlet Static Pressure (in. H 2O)	Absorber Differential Pressure (in. H 2O)	Absorber Outlet Static Pressure (in. H 2O)	CHX Inlet Static Pressure (in. H 2O)	CHX Outlet Static Pressure (in. H 2O)	ID Fan Inlet Static Pressure (in. H 2O)	Primary RFG Static Pressure at Venturi (in. H 2O)	Secondary RFG Static Pressure at Venturi (in. H 2O)	Fly Ash % LOI @ 800°C	Baghouse Fly Ash % LOI (end of day)	Absorber Outlet Temperature (°F)	CHX Outlet Temperature (°F)	ID Fan Inlet Temperature (°F)	Flow Rate of Infiltrated Air in RFG (lb/h)	Total RFG Flow (lb/h)	
OHIO5 AIR FIRING TEST3	5.4	1.0	> 0	4.9	-2.2	4.7	-6.9	-10.9	-14.2	-21.7	0.1	0.2	30.62	23.09	119	105	113			
OH #5 Air Long Term 4	6.9	0.6	> 0	4.0	-1.8	4.6	-6.3	-10.4	-13.9	-20.9	0.1	0.2	13.74	23.09	116	102	109			
OH #5 Air Long Term #1	7.1	0.6	> 0	3.4	-3.4	3.9	-7.3	-9.5	-11.0	-19.4	0.2	0.2	45.34	23.09	100	86	94			
ohio 5 Air-2 7-16-09	6.9	0.6	> 0	2.7	-3.0	6.7	-9.7	-10.9	-11.5	-21.7	0.3	0.3			102	81	90			
OH #5 Air Long Term 3	7.0	0.8	> 0	5.6	-2.5	3.9	-6.4	-9.6	-12.1	-19.5	0.1	0.2	21.97	23.09	112	98	105			
Ohio #5 Air #2	7.0	0.1	> 0	2.8	-2.8	4.1	-7.0	-9.9	-12.2	-19.9	0.1	0.2			112	88	97			
OH #5 Air Long Term 2	7.1	0.8	> 0	4.2	-1.1	4.0	-5.1	-8.6	-11.4	-17.8	0.1	0.2	18.08	23.09	108	94	101			
Ohio #5 Test B1	8.6		-1.1	3.1	-3.3	3.5	-6.8	-8.9	-10.2	-18.6	0.2	0.2			101	98	104			
OHIO5 AIR FIRING TEST1	8.9	0.5	> 0	3.6	-1.4	4.8	-6.3	-10.9	-15.0	-21.6	0.1	0.2	11.42	23.09	120	106	114			
ohio #5 Air test 3-1	10.9	1.1	> 0	5.0	-4.6	6.8	-11.4	-17.5	-23.9	-32.6	0.2	0.3	12.33		112	91	99			
Ohio #5 air 3-1 B ▲	11.9	-0.2	> 0	3.9	-4.8	7.4	-12.3	-19.7	-26.3	-37.7	0.4	0.4			116	104	104			
ohio5 oxy 6	3.5	0.0	> 0	3.7	-4.1	3.5	-7.6	-7.7	-7.4	-15.8	-0.1	-0.3			127	95	104	387	3193	
ohio5 oxy 5.2 07/16/09	5.7	3.7	> 0	4.8	0.3	3.6	-3.2	-5.1	-6.9	-11.3	-0.2	-0.5			124	94	103	375	3474	
ohio 5 oxy 5 07/14/2009	5.3	0.3	> 0	2.9	-2.7	4.6	-7.3	-7.8	-7.9	-16.0	-0.1	-0.4			123	93	102	378	3402	
Ohio #5 Oxy 7 Long Term 2	5.7	0.5	> 0	1.7	0.2	5.5	-5.3	-6.8	-7.9	-14.1	-0.2	-0.4	11.18	18.24	124	94	104	498	3376	
Ohio #5 Oxy 5 7-16-2009	5.9	0.6	> 0	4.4	-2.9	4.1	-6.9	-8.0	-8.6	-16.2	-0.2	-0.5			122	94	103	460	3677	
Ohio #5 Oxy 5.1 7-16-2009	5.3	2.2	> 0	4.2	-0.1	3.5	-3.6	-5.2	-6.4	-11.2	-0.1	-0.4			124	93	102	386	3313	
Ohio #5 Oxy 7 Long Term 3	5.4	1.0	> 0	2.1	0.6	5.3	-4.8	-6.4	-7.8	-13.4	-0.2	-0.4	7.66	18.24	123	93	103	509	3353	
Ohio #5 test Oxy 5	5.8	0.3	> 0	3.7	-2.8	4.5	-7.3	-8.0	-8.3	-16.5	-0.1	-0.4			126	96	105	459	3545	
ohio 5 oxy 5 B P 07/14/09	4.9	0.4	> 0	3.2	0.1	4.6	-4.4	-5.6	-6.5	-12.0	-0.1	-0.3			124	92	101	311	3232	
Ohio #5 long term oxy 4	7.0	-0.3	> 0	5.3	-2.2	5.1	-7.3	-7.8	-7.9	-15.9	-0.1	-0.3			124	93	102	379	3353	
Ohio5 oxy6.1 0716/09	6.8	4.0	> 0	7.5	-0.8	4.7	-5.6	-7.9	-9.8	-16.1	-0.2	-0.6			127	100	109	441	3746	
Ohio #5 Oxy 7 Long Term 4	5.9	0.8	> 0	3.6	0.0	5.4	-5.4	-7.0	-8.4	-14.5	-0.2	-0.4	10.89	18.24	125	95	105	429	3531	
Ohio #5 Oxy Long Term Test 1	5.3	1.3	> 0	2.2	-2.1	4.8	-6.9	-8.5	-9.6	-17.4	-0.2	-0.4	6.47		141	107	116	422	3316	
Ohio #5 Oxy Test #8	6.6	3.9	> 0	6.2	-0.7	6.3	-7.0	-9.8	-12.0	-19.5	-0.3	-0.7	8.52		129	101	110	375	3984	
Ohio #5 Oxy Test #7	6.5	4.0	> 0	5.9	-0.5	6.2	-6.7	-9.8	-12.2	-19.4	-0.2	-0.6	10.70		128	101	110	382	4024	
Ohio #5 Oxy Test #6	6.6	4.0	> 0	5.4	-0.2	6.5	-6.6	-9.7	-12.3	-19.4	-0.2	-0.6	10.48		128	101	110	384	4009	
ohio 5 oxy 6 07/16/09	6.4	4.8	> 0	6.4	-1.2	5.0	-6.2	-8.0	-9.3	-16.2	-0.1	-0.5			126	98	106	453	3656	
ohio #5 Oxy 9	8.4	1.8	> 0	2.9	0.2	6.7	-6.5	-10.0	-13.0	-20.1	-0.3	-0.7	8.84		128	101	110	395	4147	
Ohio #5 Oxy Test 9 with HVT ▲	8.2	0.5	> 0	2.9	-0.7	7.1	-7.8	-12.2	-15.9	-23.4	-0.3	-0.7	11.75		135	109	109	385	4214	
Ohio #5 Oxy4	5.8		-1.8	3.6	-2.9	3.1	-6.0	-7.0	-7.6	-14.7	-0.2	-0.5	15.46		129	107	115	465	3168	
Full Oxy-firing First Time	7.8		-2.2	5.9	-5.0	2.9	-7.9	-10.2	-11.7	-20.6	-0.3	-0.6			126	104	112	434	3423	

▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.

▲ Indicates test data was reprocessed for higher quality - particularly for the heat balance.

Table 8.20 Pilot scale test data for bituminous coal – table 5 of 5: Static and differential pressures and miscellaneous data

8.3. List of Boilers Evaluated for Geologic CO₂ Storage Potential

Table 8.21 below lists all 251 boilers evaluated by Battelle for geologic CO₂ storage potential. Boiler ID refers to a specific boiler at a plant. In some cases more than one boiler per plant are present.

Plant Name	Utility EIA Code	State	County	Boiler ID	Generator Nameplate Rating (MW)
Muskingum River	14006	OH	Washington	2	220
Canadys Steam	17539	SC	Colleton	CAN3	218
Muskingum River	14006	OH	Washington	3	238
Muskingum River	14006	OH	Washington	4	238
Lovett	12792	NY	Rockland	5	201
Muskingum River	14006	OH	Washington	1	220
Cane Run	11249	KY	Jefferson	5	209
Kammer	14006	WV	Marshall	1	238
Asheville	3046	NC	Buncombe	1	207
River Rouge	5109	MI	Wayne	3	358
Kammer	14006	WV	Marshall	3	238
C P Crane	4161	MD	Baltimore	2	209
Kammer	14006	WV	Marshall	2	238
Asheville	3046	NC	Buncombe	2	207
Cooper	5580	KY	Pulaski	2	230
Glen Lyn	733	VA	Giles	6	238
Kyger Creek	14015	OH	Gallia	3	217
Kyger Creek	14015	OH	Gallia	1	217
Big Sandy	22053	KY	Lawrence	BSU1	281
Lee	3046	NC	Wayne	3	252
Kyger Creek	14015	OH	Gallia	5	217
Kyger Creek	14015	OH	Gallia	4	217
Jack Watson	12686	MS	Harrison	4	250
Kyger Creek	14015	OH	Gallia	2	217
Lansing	9417	IA	Allamakee	4	275
PSEG Mercer Generating Station	15147	NJ	Mercer	2	326
Deerhaven Generating Station	6909	FL	Alachua	B2	251
A B Brown	17633	IN	Posey	2	265
Allen Steam Plant	18642	TN	Shelby	3	330
Duck Creek	49756	IL	Fulton	1	441
Allen Steam Plant	18642	TN	Shelby	2	330
PSEG Mercer Generating Station	15147	NJ	Mercer	1	326
Allen Steam Plant	18642	TN	Shelby	1	330
E D Edwards	49756	IL	Peoria	2	281
A B Brown	17633	IN	Posey	1	265
Charles R Lowman	189	AL	Washington	2	236
R D Green	20546	KY	Webster	G2	264
North Valmy	17166	NV	Humboldt	1	254
Crist	7801	FL	Escambia	6	370
George Neal North	12341	IA	Woodbury	2	349

Plant Name	Utility EIA Code	State	County	Boiler ID	Generator Nameplate Rating (MW)
W H Sammis	13998	OH	Jefferson	5	334
Greene County	195	AL	Greene	1	299
Indian River Generating Station	9332	DE	Sussex	4	442
Winyah	17543	SC	Georgetown	1	315
Philip Sporn	3277	WV	Mason	51	496
Charles R Lowman	189	AL	Washington	3	236
Big Bend	18454	FL	Hillsborough	BB03	446
Leland Olds	1307	ND	Mercer	1	216
Joliet 9	12384	IL	Will	5	360
R D Green	20546	KY	Webster	G1	264
Roxboro	3046	NC	Person	3B	745
H L Spurlock	5580	KY	Mason	1	358
Hatfields Ferry Power Station	23279	PA	Greene	1	576
Greene County	195	AL	Greene	2	269
F B Culley	17633	IN	Warrick	3	265
Roxboro	3046	NC	Person	4A	745
Tanners Creek	9324	IN	Dearborn	U4	580
Winyah	17543	SC	Georgetown	2	315
Roxboro	3046	NC	Person	3A	745
Milton R Young	12658	ND	Oliver	B1	257
J H Campbell	4254	MI	Ottawa	2	404
Winyah	17543	SC	Georgetown	4	315
Edgewater	20856	WI	Sheboygan	4	330
Wateree	17539	SC	Richland	WAT2	386
Meramec	19436	MO	St Louis	4	359
Bailly	13756	IN	Porter	8	413
Edgewater	20856	WI	Sheboygan	5	380
Herbert A Wagner	4161	MD	Anne Arundel	3	359
Reid Gardner	13407	NV	Clark	4	270
E D Edwards	49756	IL	Peoria	3	364
Sibley	770	MO	Jackson	3	419
Big Bend	18454	FL	Hillsborough	BB01	446
Winyah	17543	SC	Georgetown	3	315
North Valmy	17166	NV	Humboldt	2	267
Merrimack	15472	NH	Merrimack	2	346
Big Bend	18454	FL	Hillsborough	BB02	446
Powerton	12384	IL	Tazewell	61	893
Crist	7801	FL	Escambia	7	578
San Juan	15473	NM	San Juan	2	369
Wateree	17539	SC	Richland	WAT1	386

Plant Name	Utility EIA Code	State	County	Boiler ID	Generator Nameplate Rating (MW)
Roxboro	3046	NC	Person	1	411
Comanche	15466	CO	Pueblo	2	396
Powerton	12384	IL	Tazewell	51	893
Jack Watson	12686	MS	Harrison	5	500
San Juan	15473	NM	San Juan	1	369
Mayo	3046	NC	Person	1A	736
Mitchell	14006	WV	Marshall	2	816
Miami Fort	3542	OH	Hamilton	7	557
Warrick	306	IN	Warrick	4	323
Holcomb	18315	KS	Finney	SGU1	349
John P Madgett	4716	WI	Buffalo	B1	387
C D McIntosh Jr	10623	FL	Polk	3	364
Sioux	19436	MO	St Charles	1	550
Fort Martin Power Station	12796	WV	Monongalia	2	576
Hammond	7140	GA	Floyd	4	578
Welsh	17698	TX	Titus	2	558
J M Stuart	4922	OH	Adams	3	610
Michigan City	13756	IN	La Porte	12	540
Allen S King	13781	MN	Washington	1	598
Mill Creek	11249	KY	Jefferson	3	463
Kincaid Generation LLC	5269	IL	Christian	1	660
Ghent	10171	KY	Carroll	3	557
Coronado	16572	AZ	Apache	U2B	411
R M Schahfer	13756	IN	Jasper	14	540
Avon Lake	14181	OH	Lorain	12	680
J M Stuart	4922	OH	Adams	1	610
Hatfields Ferry Power Station	23279	PA	Greene	3	576
Ghent	10171	KY	Carroll	4	556
Craig	30151	CO	Moffat	C3	446
Mill Creek	11249	KY	Jefferson	4	544
Cardinal	3006	OH	Jefferson	1	615
R M Schahfer	13756	IN	Jasper	15	556
Hatfields Ferry Power Station	23279	PA	Greene	2	576
Wyodak	14354	WY	Campbell	BW91	362
Stanton Energy Center	14610	FL	Orange	2	465
Big Stone	14232	SD	Grant	1	456
Miami Fort	3542	OH	Hamilton	8	558
Baldwin Energy Complex	5517	IL	Randolph	1	623
Hunter	14354	UT	Emery	3	496
Cardinal	3006	OH	Jefferson	2	615

Plant Name	Utility EIA Code	State	County	Boiler ID	Generator Nameplate Rating (MW)
Hugo	20447	OK	Choctaw	1	446
Coronado	16572	AZ	Apache	U1B	411
Merom	9267	IN	Sullivan	1SG1	540
Havana	5517	IL	Mason	9	488
J M Stuart	4922	OH	Adams	2	610
Pawnee	15466	CO	Morgan	1	552
New Madrid	924	MO	New Madrid	1	600
Muskingum River	14006	OH	Washington	5	615
Sioux	19436	MO	St Charles	2	550
Gibson	15470	IN	Gibson	1	668
Killen Station	4922	OH	Adams	2	666
Brandon Shores	4161	MD	Anne Arundel	1	685
Flint Creek	17698	AR	Benton	1	558
East Bend	3542	KY	Boone	2	669
W H Sammis	13998	OH	Jefferson	6	680
New Madrid	924	MO	New Madrid	2	600
Stanton Energy Center	14610	FL	Orange	1	465
Harrison Power Station	12796	WV	Harrison	1	684
Brayton Point	23106	MA	Bristol	3	643
Monroe	5109	MI	Monroe	2	823
San Miguel	16624	TX	Atascosa	SM-1	410
Coyote	14232	ND	Mercer	B1	450
PSEG Hudson Generating Station	15147	NJ	Hudson	2	660
Mitchell	14006	WV	Marshall	1	816
San Juan	15473	NM	San Juan	4	555
Leland Olds	1307	ND	Mercer	2	440
Welsh	17698	TX	Titus	1	558
Merom	9267	IN	Sullivan	2SG1	540
Milton R Young	12658	ND	Oliver	B2	477
Kincaid Generation LLC	5269	IL	Christian	2	660
Boardman	15248	OR	Morrow	1SG	601
Welsh	17698	TX	Titus	3	558
San Juan	15473	NM	San Juan	3	555
Craig	30151	CO	Moffat	C2	446
GRDA	7490	OK	Mayes	1	490
Gibson	15470	IN	Gibson	2	668
J M Stuart	4922	OH	Adams	4	610
Cardinal	3006	OH	Jefferson	3	650
Pleasants Power Station	12796	WV	Pleasants	2	684

Plant Name	Utility EIA Code	State	County	Boiler ID	Generator Nameplate Rating (MW)
Rodemacher	3265	LA	Rapides	2	558
Belle River	5109	MI	St Clair	2	698
D B Wilson	20546	KY	Ohio	W1	440
Louisa	12341	IA	Louisa	101	738
John E Amos	733	WV	Putnam	1	816
George Neal North	12341	IA	Woodbury	3	550
Homer City Station	12520	PA	Indiana	1	660
Hawthorn	10000	MO	Jackson	5A	594
Craig	30151	CO	Moffat	C1	446
GRDA	7490	OK	Mayes	2	520
St Johns River Power Park	9617	FL	Duval	1	679
George Neal South	12341	IA	Woodbury	4	640
La Cygne	10000	KS	Linn	1	893
Paradise	18642	KY	Muhlenberg Pointe	1	704
Big Cajun 2	11252	LA	Coupee	2B3	619
Belle River	5109	MI	St Clair	1	698
Brandon Shores	4161	MD	Anne Arundel	2	685
Gibson	15470	IN	Gibson	5	668
Harrison Power Station	12796	WV	Harrison	3	684
Monroe	5109	MI	Monroe	1	817
Homer City Station	12520	PA	Indiana Pointe	3	692
Big Cajun 2	11252	LA	Coupee	2B1	626
Homer City Station	12520	PA	Indiana	2	660
Pleasant Prairie	20847	WI	Kenosha Pointe	1	617
Big Cajun 2	11252	LA	Coupee	2B2	626
Bruce Mansfield	14716	PA	Beaver	1	914
Harrison Power Station	12796	WV	Harrison	2	684
Laramie River Station	1307	WY	Platte	3	570
Pleasants Power Station	12796	WV	Pleasants	1	684
Baldwin Energy Complex	5517	IL	Randolph	2	635
Monroe	5109	MI	Monroe	3	823
Gibson	15470	IN	Gibson	3	668
Paradise	18642	KY	Muhlenberg	3	1150
Cross	17543	SC	Berkeley	1	591
Gibson	15470	IN	Gibson	4	668
Oklaunion	20404	TX	Wilbarger	1	720
Seminole	21554	FL	Putnam	1	715
AES Somerset LLC	22129	NY	Niagara	1	655

Plant Name	Utility EIA Code	State	County	Boiler ID	Generator Nameplate Rating (MW)
Nebraska City	14127	NE	Otoe	1	652
John E Amos	733	WV	Putnam	2	816
Monroe	5109	MI	Monroe	4	817
W H Sammis	13998	OH	Jefferson	7	680
Thomas Hill	924	MO	Randolph	MB3	670
W A Parish	18717	TX	Fort Bend	WAP5	734
St Johns River Power Park	9617	FL	Duval	2	679
Seminole	21554	FL	Putnam	2	715
Four Corners	803	NM	San Juan	5	818
Laramie River Station	1307	WY	Platte	1	570
James H Miller Jr	195	AL	Jefferson	4	706
Laramie River Station	1307	WY	Platte	2	570
Iatan	10000	MO	Platte	1	726
Pleasant Prairie	20847	WI	Kenosha	2	617
W A Parish	18717	TX	Fort Bend	WAP6	734
Paradise	18642	KY	Muhlenberg	2	704
Gerald Gentleman	13337	NE	Lincoln	2	681
Big Sandy	22053	KY	Lawrence	BSU2	816
James H Miller Jr	195	AL	Jefferson	3	706
Sherburne County	13781	MN	Sherburne	3	809
Four Corners	803	NM	San Juan	4	818
James H Miller Jr	195	AL	Jefferson	1	706
Council Bluffs	12341	IA	Pottawattamie	3	726
Gerald Gentleman	13337	NE	Lincoln	1	681
La Cygne	10000	KS	Linn	2	685
Crystal River	6455	FL	Citrus	4	739
Pirkey	17698	TX	Harrison	1	721
J H Campbell	4254	MI	Ottawa	3	871
James H Miller Jr	195	AL	Jefferson	2	706
Dolet Hills	3265	LA	De Soto	1	721
Crystal River	6455	FL	Citrus	5	739
Bruce Mansfield	14716	PA	Beaver	3	914
Bruce Mansfield	14716	PA	Beaver	2	914
Monticello	44372	TX	Titus	3	793
Belews Creek	5416	NC	Stokes	1	1080
Belews Creek	5416	NC	Stokes	2	1080
Intermountain Power Project	11208	UT	Millard	1SGA	820
Intermountain Power Project	11208	UT	Millard	2SGA	820
Cumberland	18642	TN	Stewart	1	1300
Rockport	9324	IN	Spencer	MB1	1300

Plant Name	Utility EIA Code	State	County	Boiler ID	Generator Nameplate Rating (MW)
John E Amos	733	WV	Putnam	3	1300
General James M Gavin	14006	OH	Gallia	1	1300
Cumberland	18642	TN	Stewart	2	1300
W H Zimmer	3542	OH	Clermont	1	1426
Rockport	9324	IN	Spencer	MB2	1300
Mountaineer	733	WV	Mason	1	1300
General James M Gavin	14006	OH	Gallia	2	1300
Bonanza	40230	UT	Uintah	1-1	500
Indiantown Cogeneration LP	9253	FL	Martin	AAB01	395
Chambers Cogeneration LP	3325	NJ	Salem	BOIL1	285
Logan Generating Plant	11132	NJ	Gloucester	B01	242
Council Bluffs	12341	IA	Pottawattamie	4	923
Coffeen	520	IL	Montgomery	02	617
Coffeen	520	IL	Montgomery	01	389

Table 8.21 A list of the 251 boilers evaluated for geologic CO₂ storage potential