

Advanced, Low/Zero Emission Boiler Design and Operation

Quarterly Technical Progress Report

Reporting Period from April 1st, 2004 through June 30, 2004

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ABSTRACT

This document reviews the work performed during the quarter April – June 2004. Task 1 (Site Preparation) had been completed 2003, along with three weeks of oxycombustion tests in Task 2 (experimental test performance) of the project. In current reporting period, the experimental testing has been completed: one additional week of tests has been performed to finalize the optimization of the combustion characteristics in O_2/CO_2 environment ; two more days of testing were dedicated to mercury sampling in air-fired or O_2 -fired conditions, and to characterization of heat transfer in O_2 conditions vs to air-blown conditions. Task 3 (Techno-Economic Study) has also been completed in current quarter: 250MWe, 500MWe and 1000MWe oxygen-fired PC unit have been simulated and quoted, and their performance and cost have been compared to same-capacity air-fired pulverized coal (PC) unit and IGCC. New and retrofit cases have been evaluated. The comparison has been completed in terms of capital cost, operating cost, cost of electricity and cost of CO_2 avoided. The scope of task 4 (Conceptual Boiler Design) had been modified as per DOE request in previous quarter. Engineering calculations are currently in progress. Next steps include detail review of the experimental data collected during the entire testing campaign, finalization of detailed report on economic task, and reporting of the preliminary results in the boiler design task. Two papers summarizing the project main achievements have been presented at Clearwater coal conference in April 2004 (overall project results), and at the CO_2 sequestration conference in May 2004 (emphasis on economics). Out of the ~\$785k allocated DOE funds in this project, \$545k have been spent to date, mainly in site preparation, test performance and economics assessment. In addition to DOE allocated funds, to date approximately \$400k have been cost-shared by the participants, bringing the total project cost up to \$945k as on June 30, 2004.

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INTRODUCTION

The present report summarizes the work performed by the participants from April 1st, 2004 through June 30, 2004 (Q2 2004, Q7 of the project).

In the previous quarters (Q1, Q2, Q3 & Q4 2003: the first budget period and Q1 2004), the site preparation (Task 1) of the experimental test campaign had been completed and the final configuration of the pilot boiler had been described. The main part of the test performance task (Task 2: “Combustion and Emission Performance Optimization”) had also been completed, demonstrating the feasibility and characterizing the performance of the oxycombustion process in a 1.5MW_{th} boiler. Two-third of the Techno-Economic Study (Task 3) had also been performed. A detailed description of the methodology to be applied had been provided, along with basic references and overall selection of plant capacity and equipment to be evaluated. Process simulation and cost assessment of 500MWe air-fired and oxygen-fired pulverized coal (PC) units had been performed, and the comparison has been extended to two IGCC units. Task 4 (Conceptual Boiler Design) had also been initiated.

In the current quarter (Q2, 2004), the tests scheduled in task 2 have been completed. Preliminary results are provided in the “Results and Discussion section”. Detailed analysis is in progress. Task 3 has also been completed, and the final report of this task is under preparation. Engineering calculations are in progress in task 4.

This report also provides an update of the project financial status and schedule.

EXECUTIVE SUMMARY

The main effort of this quarter (April – June 2004) was primarily dedicated to **Task 2 (Test performance) & Task 3 (Techno-Economic Study)** of the project. The main achievements resulting from current reporting period are the following:

Task 1 (Site Preparation), had been completed in Q3 2003, and the final boiler configuration, as available for testing, had been described.

Task 2 (Tests performance) has been completed. In addition to data collected in 2003 on oxy-fired boiler and on air-fired boiler, the heat transfer characteristics and mercury samples have been collected. Although these results are yet to be fully analyzed and discussed, the highlights are as follows:

- **Burner stoichiometry, Flame stability and NO_x emission**: to avoid getting a cooler and less stable flame in O₂/CO₂ conditions vs air-conditions, a same burner has to be operated at higher burner stoichiometry in oxy-configuration. This is due to higher molecular weight and heat capacity of CO₂ vs N₂. Increasing the burner stoichiometry in oxy-combustion is feasible without affecting NO_x levels thanks to flue gas recirculation which keeps the NO_x emission very low (<0.1 lb/ 10⁶Btu) through the reburn mechanism.
- **Emmissivity Measurement**: The measured emissivity indicated that the flame emissivity under the oxy-combustion is similar to the flame emissivity under normal air firing conditions.
- **Temperature Measurement**: Gas Temperature (GT) measurements were performed at the flame (FGT), furnace exit (FEGT), and the convection pass (CPEGT) outlet for both air firing and oxy-firing, while the overall mass flow rate was kept constant. The data are being analyzed. Pilot results seem to indicate that under those optimized conditions, the temperature profiles are similar in oxy-firing and in air-firing conditions (previous tests showed an average FEGT 70⁰F lower in oxy-firing).
- **Mercury Measurement**: Mercury sampling was performed at the convection pass outlet of SBS under normal air firing and oxy-combustion conditions, and the samples are currently being analyzed at Western Kentucky University.

Task 3 (Techno-Economic Study) has been concluded in the current quarter. The simulation and cost estimate work performed on the 533MW_e Pulverized Coal (PC) air- and oxy-fired in Q1 2004 was extended to 250MW_e and 1,000MW_e plant size cases and are compared to IGCC system.

Techno-economic analyses showed that compared to the new air-blown PC plant without CO₂ capture, the cost of electricity (COE) of the oxycombustion process increased by about 25-30%, while that of the MEA-equipped air-blown PC plant increased by about 60% and that of the Selexol-equipped IGCC plant increased by 20%. The cost of the oxycombustion process is slightly higher than the IGCC plant, but is more competitive than the MEA-equipped air-blown PC plant.

The Oxycombustion process and MEA process are technically applicable for plant retrofit to capture CO₂ emissions. For a 533MW_e power plant, the Oxycombustion retrofit required less than \$300/kWe capital cost and increased 5 mills/kWh O&M cost. For the same

plant size, the MEA retrofit required \$460/kWe capital cost and 11 mills/kWh O&M cost. The Oxycombustion process is economically favorable for the CO₂ capture retrofit of the existing power plant.

Task 4 (Boiler Design) had been initiated in the last quarter (Q1 2004). The scope of work (SOW) to be performed had been modified as per DOE request and the updated SOW had been reported. Engineering calculations are in progress and the results will soon be reported.

The project main results have been presented in conferences in April and May 2004.

The current work schedule is to analyze the mercury samples and to review the experimental data collected during the entire 2003-2004 test campaign. The report summarizing the work performed in the Techno-Economic study (task 3) will be completed, and will report conclusions regarding oxycombustion competitiveness vs air-blown system with amine scrubbing and vs IGCC. Preliminary results on engineering effort currently in progress in the boiler design task (task 4) will be reported.

Out of the ~\$785k DOE cost-share allocated in this project, \$545k have been spent to date, mainly in site preparation (~\$376k), test performance (~\$111k) and economics assessment (~\$41). In addition to DOE allocated funds, to date approximately \$400k has been cost-shared by the participants, bringing the total project cost up to \$945k as on June 30, 2004.

EXPERIMENTAL

During this reporting period, the participants have mainly worked on Task 2 (Test Performance), Task 3 (Techno-Economic Assessment) and Task 4 (Conceptual Boiler Design) of the project.

1 TASK 1: SITE PREPARATION

Task 1 has been completed in the previous reporting period. The resulting final configuration of the pilot boiler has been described.

2 TASK 2: COMBUSTION AND EMISSIONS PERFORMANCE OPTIMIZATION

The following subsections summarize the preliminary results obtained from the tests performed in 2003 and describe the tests performed in current reporting period. Preliminary results of those latest tests are reported and analyzed in the next section of this report “RESULTS AND DISCUSSION”.

2.1 Summary of conclusions from previous reporting periods

In previous reporting period, the following results had been obtained:

- The participants had demonstrated the feasibility of 100% air replacement by oxygen-enriched flue gas on the 1.5MW_{th} coal-fired boiler.
- The air infiltrations had been reduced to approximately 5% of the stoichiometry, enabling to reach around 80% of CO₂ in the flue gases.
- The flue gas volume exiting the boiler has been reduced by 70% thus making easier any additional flue gas treatment which may be necessary before stack exhaust or CO₂ reuse or sequestration.
- The NO_x emissions had been shown considerably lower in O₂-fired conditions than in air-baseline, the reduction rate averaging 70%. NO_x emissions is also impacted by oxygen flow rate into the primary air zone and by flue gas overall recirculation rate. The recirculated flue gas flow rate has been varied from 80% to 95% of total flue gas flow, and the total oxygen flow rate into the primary air zone of the boiler had been set to levels ranging from 15% to 25% of the total oxygen consumption in the overall combustion. The influence of those two parameters on NO_x emission can be explained by temperature increase resulting from increased O₂ content in primary air zone or from lower flue gas flow. Such higher temperature in the reducing zone of the boiler promotes the conversion of recirculated NO_x and devolatilized fuel nitrogen to molecular nitrogen.
- A stable flame had been obtained, with similar shape as in air-firing operation. From a visual judgment, the oxy-fired flame was colder than air-fired flame, presumably because of higher CO₂ specific heat.
- Furnace exit flame temperature (FEGT) and convection pass exit gas temperature (CPEGT) have been measured and compared in under oxy-firing than under air-firing

conditions. While lower FEGT was measured under oxy-firing conditions, the CPEGT was generally higher. Further studies are required to address boiler heat transfer and steam generation characteristics.

2.2 Tests performed during the reporting period

Additional full-oxy combustion optimization tests have been performed in this quarter totaling 5 days of experimental data gathering.

In addition to flue gas composition (NO_x , SO_x , CO , CO_2 , O_2) and Furnace Exit Gas Temperature (FEGT), the following measurement have been performed, both on air-blown flame and on oxy-flame:

- In-furnace gas temperature measurement to evaluate heat transfer in the boiler and convection pass
- Flame emissivity measurement
- Mercury emission measurement

3 TASK 3: TECHNO-ECONOMIC STUDY

In the scope of the techno-economics task of the project, process calculation and economics assessment are performed to compare various CO_2 capture technologies.

Three technologies are considered:

- Air-blown pulverized coal (PC) power plants with amine scrubbing
- Oxy-fired PC power plants with flue gas recirculation, also referred to as Oxycombustion process, or Oxygen Enhanced Combustion (OEC)
- IGCC units with Selexol for CO_2 capture

Air-blown and oxy-fired processes may be considered for both new and retrofit coal-fired applications. IGCC unit only apply to new units.

In Q₃ 2003, the various cases to be assessed (plant type, plant capacity, flue gas treatment technologies...) have been described, as well as the methodology to be applied for mass and energy balance calculation and cost assessment.

In Q₄ 2003, the power generation costs assessments have been performed for a specific plant gross capacity of 533MWe. Plants burning PRB coal under OEC process and conventional air-blown PC have been investigated.

In Q1 2004, More detailed process and cost calculations have been performed on the 533MWe air and oxy-fired PC units. Revised capital costs and power consumption data for ASU were included. Also, calculations were performed on two IGCC units (273 and 535MWe)

In the current reporting period, the following progress has been made for the process schematics that were described in Q1 2004 quarterly report:

- The process and cost calculations for air and oxy-fired PC units are extended to 250MWe and 1,000MWe plant sizes from the previously performed 533 MWe case. As the impact of oxygen purity was not significant on CO_2 avoided costs for 95% and

99% purity, only 99% purity oxygen case was considered for 250 and 1,000MWe cases to obtain richer CO₂ flue gas.

- Impact of plant capacity on electricity costs and CO₂ avoided costs were performed.
- Different technology options for CO₂ capture (O₂-CO₂, MEA and IGCC) were compared on both technical and economical perspectives.

The latest results are reported in the "results and discussion" section of this report.

In summary, the techno-economic analysis (Task 3) in the scope of the project is completed. Presently, results are being refined.

Table 1 shows the scenarios of the techno-economic analysis performed.

| | Approximate size, MWe |
|---|-----------------------|
| Air combustion, Baseline | |
| Without CO ₂ separation | 250,500,1000 |
| With the MEA process | 250,500,1000 |
| OEC combustion | |
| Wet O ₂ /CO ₂ recycle | 250,500,1000 |
| Dry O ₂ /CO ₂ recycle | 250,500,1000 |
| IGCC | 250,500 |

Table 1: Scenarios for techno-economic analysis

4 TASK 4: CONCEPTUAL BOILER DESIGN

The aim of this task is to provide a conceptual design for a boiler operating on oxygen. This study will investigate the achievable boiler size reduction using oxygen-combustion instead of air-combustion.

The specification of this task has been modified as per DOE request. The updated scope of work has been reported in the previous quarterly report. This task now includes two sub-tasks "Subtask 4.1 Recommendations for retrofit applications" and "Subtask 4.2 Preliminary Design of a New Generation Boiler".

The scope of the engineering study 4.2 is to determine the conceptual design of an oxygen-fired boiler with minimum flue gas recirculation. Cyclone firing is being considered a prime candidate since its slagging characteristics are suitable with hot oxygen combustion.

The boiler performance calculations are in progress, and corresponding results will be provided in further reports.

RESULTS AND DISCUSSION

Preliminary experimental results from June latest tests are reported. Detailed results analysis of the entire test campaign (2003-2004) will be provided in future reports.

Results from process and cost calculations on air and oxy-fired units performed on 533MWe plant capacity are extended for 250MWe and 1,000MWe cases. Impact of plant capacity has been assessed. Different oxy-fired plant configurations are compared with MEA and IGCC and are reported.

As reported in “Experimental Section”, the boiler design calculations are in progress and results will be reported in future reports.

Finally project management update is provided in the following “Project Schedule” and “Financial Status” subsections.

1 TASK 2: COMBUSTION AND EMISSIONS PERFORMANCE OPTIMIZATION

As stated in “Experimental” section of this report, additional measurement have been performed on the oxy-flame and compared air-flame results.

Several interesting results were obtained in regard to the flame shape, temperature and emissivity. Although these results are yet to be fully analyzed and discussed, the highlights are as follows.

1.1 Switching procedure from air-fired to oxygen-fired operation

During these tests the overall mass flow rate of the combustible gases and oxidizers in the combustion zone has been maintained when air was switched to flue gas and oxygen.

The switching of primary air to oxygen-enriched flue gas is initially performed with the addition of oxygen only through a lance at the burner. After all primary air was substituted with flue gas, and all oxygen was introduced through the lance, then some oxygen was removed from the lance to be introduced in the primary air line via an oxynator. The oxygen to the secondary air and overfire air port is introduced through an oxynator.

1.2 Overall Combustion characteristics in O₂/CO₂ environment – burner stoichiometry

As reported in the past progress report (and summarized in “Experiment” 2.1), during the previous tests we had noticed that the oxy-combustion flame was colder than the flame with air. The flame was judged to be cooler by visual observations and Flame View measurements. During these recent tests the coal feed system had been improved providing a very smooth combustion condition with very small convective pass exit O₂ fluctuations. As we switched from air firing to oxy-combustion while maintaining a flame stoichiometry of approximately 0.85, the combustion was affected negatively, judging from the high CO levels observed. We knew that the burner velocities were lower since nitrogen was substituted by CO₂. We could not reduce the burner throat since the unit needs to be able to start-up on air before switching to oxygen. Therefore, we increased the burner stoichiometry from 0.85 to 1.0-1.05 resulting in increased burner velocity. The combination effect of higher burner stoichiometry and velocity

resulted in a more stable and brighter flame. The staged oxy-combustion was originally considered as a means to control the NO_x emissions. Fortunately, we learned that oxy-combustion is much more insensitive to burner stoichiometry (in the range of 0.8 to 1.05) than normal air firing. NO_x emissions were always below 0.1 lb per million Btu during the oxy-combustion. The reason being that a large amount of NO_x is recirculated to the burner with the flue gas recirculation where they are destroyed by the reburn mechanism.

1.3 Emmissivity Measurement

The measured emissivity also indicated that the flame emissivity under the oxy-combustion is similar to the flame emissivity under normal air firing. These first-of-a-kind measurements enabled us to more accurately determine the boiler performance under oxy-combustion conditions.

1.4 Temperature Measurement

Temperature measurements were performed at the flame, furnace exit, and the convection pass outlet for both air firing and oxy-firing, while the overall mass flow rate was kept constant. The data is being analyzed, but our pilot results seem to indicate that the temperature profiles are similar under oxy-firing conditions. In the previous tests, the average FEGT with oxy-firing was lower by 70°F than with air firing.

1.5 Mercury Measurement

Mercury sampling was performed at the convection pass outlet of SBS under normal air firing and oxy-combustion conditions, and currently the samples are being analyzed at Western Kentucky University.

2 TASK 3: TECHNO-ECONOMIC STUDY

The following sub-sections report the simulation results and cost assessment obtained for:

- 250MW_e and 1,000MW_e plant cases for both air fired and oxy-fired scenarios and comparison to the previously performed 533MW_e case for 99% oxygen purity case
- Overall process performances of air-fired PC boiler cases with and without MEA
- Overall process performances of oxy-fired PC boiler cases

2.1 AIR BLOWN PC BOILER CASES WITH AND WITHOUT CO₂ REMOVAL

2.1.1 Process simulation

In process simulation, a power plant was divided into three main process areas that include the combustion system, steam turbine system and gas cleaning system. The combustion system is the same for both the conventional PC plant and the plant installed with an MEA unit. However, the steam turbine system is different between these two types of plants. In the plant with the MEA unit, a significant part of steam is drawn from the turbine for amine regeneration; the flow chart of the steam turbine simulation was modified correspondingly. The simulation for the MEA process was conducted in less detail, only for calculation of the basic mass and heat flows. Its performance equations defining the functional relationships among various key

operating parameters have been regressed from the data obtained from the process simulation in a DOE project ^[10]. The compression and further purification of the CO₂-rich stream are not simulated in this study. Some main process parameters are listed in Table 2.

| | Conventional PC W/O CO ₂ capt. | | | PC plant + MEA | | |
|---|---|----------------|------------------|----------------|----------------|----------------|
| Gross kWe (terminal) | 266,380 | 533,230 | 1,053,570 | 217,350 | 434,850 | 859,410 |
| | | | | | | |
| Combustion | | | | | | |
| Air/O ₂ equivalent ratio, / | 1.15 | 1.15 | 1.15 | 1.15 | 1.15 | 1.15 |
| Air flow rate, lb/h | 2,007,884 | 4,029,474 | 7,949,303 | 2,007,884 | 4,029,474 | 7,949,303 |
| O ₂ /Ar flow rate, lb/h | n/a | n/a | n/a | n/a | n/a | n/a |
| Coal feed rate, lb/h | 261,598 | 524,982 | 1,035,679 | 261,598 | 524,982 | 1,035,679 |
| Flue gas recycle ratio, lb/h | n/a | n/a | n/a | n/a | n/a | n/a |
| | | | | | | |
| Steam generation | | | | | | |
| Hot reheat steam, lb/h | 1,511,807 | 3,022,125 | 5,979,534 | 1,511,807 | 3,022,125 | 5,979,534 |
| Superheat steam, lb/h | 1,703,981 | 3,422,824 | 6,739,628 | 1,703,981 | 3,422,824 | 6,739,628 |
| IP steam to MEA process | n/a | n/a | n/a | 733,088 | 1,470,914 | 2,902,335 |
| Steam condensate, lb/h | 1,401,567 | 2,802,051 | 5,543,513 | 668,479 | 1,331,136 | 2,641,178 |
| Main feedwater, lb/h | 1,660,496 | 3,321,228 | 6,567,636 | 1,660,496 | 3,321,228 | 6,567,636 |
| Heat duty of cooling tower, 10 ⁶ Btu/h | 1,090 | 2,178 | 4,310 | 519 | 1,034 | 2,051 |
| | | | | | | |
| Flue gas for boiler system | | | | | | |
| Flue gas volume, lb/h | 2,255,746 | 4,526,825 | 8,930,601 | 2,255,746 | 4,526,825 | 8,930,601 |
| Flue gas temperature, °F | 295 | 295 | 295 | 295 | 295 | 295 |
| Composition: | | | | | | |
| N ₂ , vol% | 71.61% | 71.62% | 71.61% | 71.61% | 71.62% | 71.61% |
| O ₂ , vol% | 2.49% | 2.49% | 2.49% | 2.49% | 2.49% | 2.49% |
| CO ₂ , vol% | 14.55% | 14.55% | 14.55% | 14.55% | 14.55% | 14.55% |
| H ₂ O, vol% | 11.15% | 11.15% | 11.15% | 11.15% | 11.15% | 11.15% |
| Ar, vol% | 0 | 0 | 0 | 0 | 0 | 0 |
| SO ₂ , vol% | 0.03% | 0.03% | 0.03% | 0.03% | 0.03% | 0.03% |
| NO _x , lb/MMBtu | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Fly ash flow rate, lb/h | 10,987 | 22,049 | 43,499 | 10,987 | 22,049 | 43,499 |

Table 2: Main operating parameters of the air-blown PC plants

Certain components of the power plant, such as pumps and conveyors, consume significant amounts of electricity. The auxiliary power use of the coal handling, pulverizer, ash handling and miscellaneous systems were scaled linearly from the reference plant based on the amount of solid flow or the plant size. For all other main components, energy usage was obtained from the process simulation. It is found that the auxiliary power usage of individual process components are almost linearly proportional to the plant scale. The results of the auxiliary power use are summarized in Table 3. For an air-blown PC plant without CO₂ capture, the total auxiliary use of electricity is about 6% of the total gross electricity output. The installation of the MEA process reduced a gross electricity output by 20%, compared to the conventional plant without CO₂ capture. This is due to the loss of a significant part of steam used to supply heat for amine regeneration, which otherwise is used for generating electricity. In addition, the gas

induced fan and amine recirculation pump in the MEA process consumed more than 1/3 of the total auxiliary power usage. As a result, the total auxiliary power usage increased to 10% of the total gross output in the PC plant equipped with the MEA process.

| | Air-blown PC W/O CO ₂ capture | | | Air-blown PC+MEA | | |
|-------------------------------------|--|----------------|------------------|------------------|----------------|----------------|
| Gross output (terminal), kWe | 266,380 | 533,230 | 1,053,570 | 217,350 | 434,850 | 859,410 |
| Auxiliary load, kWe | | | | | | |
| Coal handling | 169 | 339 | 670 | 169 | 339 | 670 |
| Pulverizers | 1,463 | 2,937 | 5,793 | 1,463 | 2,937 | 5,793 |
| Primary air fans | 603 | 1,212 | 2,388 | 603 | 1,212 | 2,388 |
| Forced Draft fans | 574 | 1,154 | 2,274 | 574 | 1,154 | 2,274 |
| Induced draft fans | 2,569 | 5,122 | 10,173 | 2,569 | 5,122 | 10,173 |
| Seal air blowers | 23 | 46 | 90 | 23 | 46 | 90 |
| Steam turbine auxiliaries | 441 | 884 | 1,748 | 441 | 884 | 1,748 |
| Condensate pumps | 475 | 949 | 1,878 | 445 | 891 | 1,763 |
| * Main feed pump | 5,468 | 10,938 | 21,629 | 5,468 | 10,938 | 21,629 |
| Circulating water pumps | 2,094 | 4,187 | 8,283 | 999 | 1,989 | 3,946 |
| Cooling tower fans | 1,184 | 2,367 | 4,684 | 565 | 1,125 | 2,232 |
| Ash handling | 710 | 1,424 | 2,809 | 710 | 1,424 | 2,809 |
| Miscellaneous | 1,383 | 2,411 | 4,160 | 1,383 | 2,411 | 4,160 |
| Transformer loss | 722 | 1,215 | 2,026 | 722 | 1,215 | 2,026 |
| ESP | 657 | 1,319 | 2,602 | 657 | 1,319 | 2,602 |
| LSD | 1,750 | 3,500 | 7,000 | 1,750 | 3,500 | 7,000 |
| SCR | 1,375 | 2,750 | 5,500 | 1,375 | 2,750 | 5,500 |
| MEA: gas induced fan | 0 | 0 | 0 | 7,892 | 15,837 | 31,244 |
| amine pump | 0 | 0 | 0 | 1,485 | 2,980 | 5,879 |
| ACI | 50 | 99 | 196 | 50 | 99 | 196 |
| Sub-total | 16,241 | 31,916 | 62,274 | 23,874 | 47,234 | 92,493 |

Table 3: Auxiliary power use in the air-blown PC plants with and without CO₂ capture

2.1.2 Performance summary

The overall process performances for the air-blown PC plants without and with CO₂ capture are shown in Table 4. The power generation efficiency for the sub-critical PC plant without CO₂ capture is about 37%, and remains the same for the different plant capacities investigated. When the MEA unit is installed for CO₂ capture, the generation efficiency drops to about 28.6%. In terms of the net electricity output, about 25% is lost due to the installation of the MEA unit. If the power use for CO₂ compression is included, these values will even become larger.

| | W/O CO ₂ Capture | | | With the MEA | | |
|-------------------------------------|-----------------------------|----------------|------------------|----------------|----------------|----------------|
| Gross output (terminal), kWe | 266,380 | 533,230 | 1,053,570 | 217,350 | 434,850 | 859,410 |
| Coal Flow Rate (lb/hr) | 261598 | 524982 | 1035679 | 261598 | 524982 | 1035679 |
| Steam Turbine Power (MWe) | 266.4 | 533.2 | 1053.6 | 217.4 | 434.9 | 859.4 |
| Aux. Power (MWe) | 16.2 | 31.9 | 62.3 | 23.9 | 47.2 | 92.5 |
| Net Power (MWe) | 250.1 | 501.3 | 991.3 | 193.5 | 387.6 | 766.9 |
| Net efficiency, HHV (%) | 37.00% | 37.00% | 37.10% | 28.60% | 28.60% | 28.70% |

Table 4: Overall process performances of air-blown PC plants

2.2 OXY-FIRED PC BOILER CASES

2.2.1 Process simulation

The process simulation was conducted separately for three process areas, i.e., the combustion system, steam turbine system and gas cleaning system. The air separation unit (ASU) was not simulated because the related data has been available. The other process components specific to the OEC process, such as the O₂/CO₂ flue gas recycle and flue gas condensation, are included in the simulation. The compression and further purification of the CO₂-rich stream is not simulated. A 99% O₂ purity from the ASU was mainly assumed in the simulation, while a 95% O₂ purity was used only in a case for comparison. The main process parameters are listed in Table 5.

| | Wet OEC | | | Dry OEC | | |
|---|-----------|-----------|-----------|-----------|-----------|-----------|
| Gross output, MWe | 266,380 | 533,230 | 1,053,570 | 266,380 | 533,230 | 1,053,570 |
| Combustion | | | | | | |
| O ₂ /fuel equivalent ratio, lb/h | 1.03 | 1.03 | 1.03 | 1.03 | 1.03 | 1.03 |
| O ₂ flow rate (99% purity), lb/h | 407,741 | 817,540 | 1,600,007 | 420,296 | 843,885 | 1,663,566 |
| Coal feed rate, lb/h | 252,670 | 506,615 | 991,497 | 260,450 | 522,941 | 1,030,883 |
| Flue gas recycle ratio, lb/h | 71.60% | 71.60% | 71.60% | 75.10% | 75.10% | 75.10% |
| Steam generation | | | | | | |
| Hot reheat steam, lb/h | 1,511,807 | 3,022,125 | 5,979,534 | 1,511,807 | 3,022,125 | 5,979,534 |
| Superheat steam, lb/h | 1,703,981 | 3,422,824 | 6,739,628 | 1,703,981 | 3,422,824 | 6,739,628 |
| IP steam to MEA process | n/a | n/a | n/a | n/a | n/a | n/a |
| Steam condensate, lb/h | 1,401,567 | 2,802,051 | 5,543,513 | 1,401,567 | 2,802,051 | 5,543,513 |
| Main feedwater, lb/h | 1,660,496 | 3,321,228 | 6,567,636 | 1,660,496 | 3,321,228 | 6,567,636 |
| Heat duty of cooling tower, mBtu/h | 1,090 | 2,178 | 4,310 | 1,090 | 2,178 | 4,310 |
| Flue gas for cleaning | | | | | | |
| Flue gas volume, b/h | 647,151 | 1,297,622 | 2,543,667 | 553,563 | 1,111,510 | 2,191,106 |
| Flue gas temperature, oF | 395 | 395 | 395 | 295 | 295 | 295 |
| Composition: | | | | | | |
| N ₂ , vol% | 0.34% | 0.34% | 0.34% | 0.49% | 0.49% | 0.49% |
| O ₂ , vol% | 2.27% | 2.27% | 1.86% | 3.28% | 3.28% | 3.28% |
| CO ₂ , vol% | 54.72% | 54.72% | 55.02% | 79.26% | 79.26% | 79.26% |
| H ₂ O, vol% | 41.93% | 41.93% | 42.04% | 15.90% | 15.90% | 15.90% |
| Ar, vol% | 0.64% | 0.64% | 0.64% | 0.93% | 0.93% | 0.93% |
| SO ₂ , vol% | 0.10% | 0.10% | 0.10% | 0.14% | 0.14% | 0.14% |
| NO _x , lb/MMBtu | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 |
| Fly ash flow rate, lb/h | 10612 | 21,278 | 41643 | 10939 | 21964 | 43297 |
| Flue gas after cleaning | | | | | | |
| Flue gas volume, b/h | 500,246 | 997,016 | 1,965,081 | 515,625 | 1,031,076 | 2,041,339 |
| Flue gas temperature, oF | 68 | 68 | 68 | 68 | 68 | 68 |
| Composition: | | | | | | |
| N ₂ , vol% | 0.57% | 0.57% | 0.58% | 0.57% | 0.58% | 0.57% |
| O ₂ , vol% | 3.83% | 3.83% | 3.14% | 3.82% | 3.83% | 3.82% |
| CO ₂ , vol% | 92.84% | 92.83% | 93.53% | 92.85% | 92.83% | 92.86% |
| H ₂ O, vol% | 1.64% | 1.65% | 1.64% | 1.64% | 1.64% | 1.64% |
| Ar, vol% | 1.09% | 1.09% | 1.09% | 1.09% | 1.10% | 1.09% |
| SO ₂ , vol% | 0.02% | 0.02% | 0.02% | 0.02% | 0.02% | 0.02% |

Table 5: Main operating parameters of the OEC processes (99% purity O₂ used)

From the process simulation, the auxiliary power usage of the main equipment in the OEC plant was also obtained as listed in *Table 6*. The ASU for O₂ production consumed a considerable amount of electricity, contributing to 80% of the total auxiliary power. This is based on the specific energy consumption of 0.394 kWh/Nm³ pure O₂, independent of the O₂ purity (99% or 95%), according to the Air Liquide. The O₂/CO₂ flue gas recycle and the condenser consumed another 2.5% of the total auxiliary power. The auxiliary power required for the gas cleaning units and induced draft fan decreased due to the reduced flue gas volume in the OEC process. Overall, the auxiliary power in the OEC process accounted for about 24% of the gross output, compared to 6% in the conventional air-blown PC plant.

| | Wet OEC | | | Dry OEC | | |
|------------------------------------|---------------|----------------|----------------|---------------|----------------|----------------|
| Gross output (terminal), kWe | 266,380 | 533,230 | 1,053,570 | 266,380 | 533,230 | 1,053,570 |
| Auxiliary load summary, kWe | | | | | | |
| Coal handling | 163 | 328 | 641 | 168 | 338 | 667 |
| Pulverizers | 1,413 | 2,834 | 5,546 | 1,457 | 2,925 | 5,767 |
| Primary air fans | 613 | 1,221 | 2,407 | 594 | 1,192 | 2,350 |
| Forced Draft fans | 583 | 1,163 | 2,292 | 565 | 1,135 | 2,238 |
| Induced draft fans | 737 | 1,470 | 2,897 | 631 | 1,266 | 2,496 |
| Seal air blowers | 23 | 46 | 90 | 22 | 45 | 88 |
| Steam turbine auxiliaries | 441 | 884 | 1,748 | 441 | 884 | 1,748 |
| Condensate pumps | 475 | 949 | 1,878 | 475 | 949 | 1,878 |
| * Main feed pump | 5,468 | 10,938 | 21,629 | 5,468 | 10,938 | 21,629 |
| Circulating water pumps | 2,094 | 4,187 | 8,283 | 2,094 | 4,187 | 8,283 |
| Cooling tower fans | 1,184 | 2,367 | 4,684 | 1,184 | 2,367 | 4,684 |
| Ash handling | 685 | 1,374 | 2,690 | 706 | 1,419 | 2,796 |
| Miscellaneous | 1,383 | 2,411 | 4,160 | 1,383 | 2,411 | 4,160 |
| Transformer loss | 722 | 1,215 | 2,026 | 722 | 1,215 | 2,026 |
| ESP | 189 | 376 | 741 | 161 | 324 | 638 |
| LSD | 502 | 998 | 1,994 | 429 | 859 | 1,717 |
| ACI | 14 | 28 | 56 | 12 | 24 | 48 |
| OEC auxiliary | | | | | | |
| Flue gas recycle fan | 911 | 1,817 | 3,581 | 766 | 1,540 | 3,258 |
| Recycle gas condenser pump | 0 | 0 | 0 | 308 | 768 | 1,228 |
| Flue gas condenser pump | 257 | 507 | 1,015 | 98 | 157 | 391 |
| Flue gas water spray cooling | 263 | 526 | 1,031 | 0 | 0 | 0 |
| ASU | 50,413 | 101,081 | 197,826 | 51,966 | 104,339 | 205,685 |
| Sub-total | 63,066 | 125,782 | 245,586 | 64,183 | 128,344 | 252,146 |

Table 6: Auxiliary power usage in the oxy-combustion processes

2.2.2 Performance summary

Table 7 lists the overall performances of the OEC power plants. Due to as high as 20% of the gross power output consumed for oxygen production, the generation efficiency of the OEC process drops to a range of 30-32%, compared to about 37% in the conventional air-blown plant without CO₂ capture. However, the OEC process is much more efficient than the air-blown plant installed with the MEA unit. The dry OEC process has a generation efficiency slightly lower than the wet OEC process since a small amount of heat is lost during condensation in the flue gas recycle loop.

| | Wet OEC | | | Dry OEC | | |
|------------------------------------|--------------|--------------|------------|--------------|--------------|--------------|
| Gross output (terminal), MW | 266,380 | 533,230 | 1,053,570 | 266,380 | 533,230 | 1,053,570 |
| | | | | | | |
| Coal Flow Rate (lb/hr) | 252670 | 503044 | 991497 | 260450 | 522941 | 1030883 |
| Steam Turbine Power (MWe) | 266.4 | 533.2 | 1053.6 | 266.4 | 533.2 | 1053.6 |
| ASU Power (MWe) | 50.41 | 100.08 | 197.83 | 51.97 | 104.34 | 205.68 |
| Other Aux. Power (MWe) | 12.7 | 24.7 | 47.8 | 12.2 | 24 | 46.5 |
| Net Power (MWe) | 203.3 | 407.4 | 808 | 202.2 | 404.9 | 801.4 |
| Net efficiency, HHV (%) | 31.20% | 31.20% | 31.60% | 30.00% | 30.00% | 30.10% |

Table 7: Overall process performances of the OEC plants

3 TASK 4: CONCEPTUAL BOILER DESIGN

As stated in “Experimental” section of last quarterly report (Q1 2004), the specification of this task as been modified and described in DOE/AL amendment. The task has been initiated with B&W and some results will be provided in future quarterly reports.

4 PROJECT SCHEDULE

The current status of the project tasks and sub-tasks is displayed below, followed by a short description of the work to be performed in the next quarter (July-Sep 2004).

4.1 Status of the project tasks and sub-tasks

The sub-tasks completed in previous reporting periods (**bold & black**), completed in the current reporting period (**bold & blue**), currently in progress or soon to be ongoing, are reported in Table 8 below.

| | | <u>Expected Completion</u> | <u>Status</u> |
|--|--|--------------------------------|----------------------------|
| Task 1: Site Preparation | | | |
| Task 1.1: | List of required modifications | March 30, 2003 | - Completed |
| Task 1.2: | Conceptual design of SBS adaptations | April 15, 2003 | - Completed |
| Task 1.2: | Technical design of SBS adaptations | April 30, 2003 | - Completed |
| Task 1.3: | Implementation of SBS adaptations | July 30, 2003 | - Completed |
| Task 1.4: | System shake-down | August 1, 2003 | - Completed |
| Task 2: Test Performance | | | |
| Task 2.1: | Test matrix definition | Sept. 15, 2003 | - Completed |
| Task 2.2: | Tests performance | Dec. 15, 2003 | - 13 days completed |
| | Heat Transfer and Mercury measurements | June 30, 2004 | - Completed |
| Task 2.3&2.4: Test analysis & Report | | Sep 30, 2004 | - In progress |
| Task 3: Techno-Economic Study | | | |
| Task 3.1: | Cases Specification | Sept. 15, 2003 | - Completed |
| Task 3.2: | Methodology Definition | Aug. 30, 2003 | - Completed |
| Task 3.3: | Process Simulation & Cost Estimation | | |
| | 500MWe PC and oxy-boiler | Dec.31, 2003 | - Completed. |
| | 500MWe PC calculation refinements | Mar. 31, 2004 | - Completed. |
| | 250 & 500MWe IGCC | Mar. 31, 2004 | - Completed. |
| | 250MWe PC and oxy-boiler | June 30, 2004 | - Completed |
| | 1,000MWe PC and oxy-boiler | June 30, 2004 | - Completed |
| Task 3.4: | Results analysis & Report | June 30, 2004 | - In progress |
| Task 4: Preliminary Boiler Design | | | |
| Task 4.1: | Task specification | Mar. 30, 2004 | - Completed |
| Task 4.2: | Design performance | Sep. 30, 2004 | - In progress |
| Task 4.3: | Results analysis & Report | Dec. 31, 2004 | - Future |

Table 8: Project Schedule

4.2 Next quarters sub-tasks

During the next quarter (July 1st to September 30th 2004), the following activities will be performed:

- The analytical chemistry of the mercury samples will be performed, and related data reduction and analysis completed.
- The experimental results gathered during the entire test campaign of this project will be analyzed and summarized.
- The report summarizing the work performed in the techno-economical study (task 3) will be completed. Conclusion regarding oxycombustion competitiveness vs air-blown system with amine scrubbing and vs IGCC will be reported.
- Preliminary results on engineering effort currently in progress in the boiler design task (task 4) will be reported.

5 FINANCIAL STATUS

Table 9 and Table 10 show the financial status of the report to-date. An amount of ~\$75k has been spent by the main contractor in the reporting period (Q1, 2004), including ~ \$17k of direct labor, ~\$1k of travel, ~ \$7k of material & equipment related to oxygen, \$28k of contractual and ~ \$22k of indirect charges. To date, \$945k have been spent and reported in the project. \$470k has been reimbursed by DOE-NETL.

| 10. Transactions: | | I Previously Reported | II This Period | III Cumulative |
|---|--|--------------------------------------|----------------------------------|---------------------------|
| a. Total outlays | | \$ 869,503.95 | \$ 75,383.54 | \$ 944,887.49 |
| b. Recipient share of outlays | | \$ 399,503.95 | \$ 75,383.54 | \$ 474,887.49 |
| c. Federal share of outlays | | \$ 470,000.00 | - | \$ 470,000.00 |
| d. Total unliquidated obligations | | | | - |
| e. Recipient share of unliquidated obligations | | | | - |
| f. Federal share of unliquidated obligations | | | | - |
| g. Total Federal share (Sum of lines c and f) | | | | - |
| h. Total Federal funds authorized for this funding period | | | | \$ 785,268.00 |
| i. Unobligated balance of Federal funds (Line h minus line g) | | | | \$ 315,268.00 |
| 11. Indirect Expense | a. Type of Rate (Place "X" in appropriate box) <input type="checkbox"/> Provisional <input checked="" type="checkbox"/> Predetermined <input type="checkbox"/> Final <input type="checkbox"/> Fixed | | | |
| | b. Rate see attachment | c. Base see attachment | d. Total Amount \$ 225,211.95 | e. Federal Share \$ 0 |

Table 9: Financial situation to-date.

| Indirect Expenses | Rate | Base | Indirect expense charged to the project | Federal share for indirect expense |
|--------------------------------|--------|---|---|------------------------------------|
| Labor Overhead | 87.94% | Total Direct Labor Costs \$ 155,232.00 | \$ 136,511.02 | \$ 0 |
| General & Administrative | 10.36% | Total Direct Project Costs and Overhead Costs \$ 856,186.56 | \$ 88,700.93 | \$ 0 |
| Total Indirect Expenses | | | \$ 225,211.95 | \$ 0 |

Table 10: Indirect Expenses (details)

6 OTHER ACHIEVEMENTS

The project main results have been summarized in two papers and have been presented in Clearwater coal conference (April 2004) and CO₂ sequestration conference (May 2004):

Sangras R., Châtel-Pélage F., Pranda P., Farzan, H., Vecchi, S.J., Lu Y., Chen S., Rostam-Abadi M., Bose A.C., *Oxycombustion process in pulverized coal-fired boilers: a promising technology for CO₂ capture*, The 29th International Technical Conference on Coal Utilization & Fuel Systems, Clearwater, FL, USA, **2004**.

Varagani R., Châtel-Pélage F., Pranda P., Farzan H., Vecchi S.J., Lu Y., Chen S., Rostam-Abadi M., Bose A.C., *Oxycombustion in pulverized coal-fired boiler: a promising technology for CO₂ capture*, Third Annual Conference on Carbon Sequestration, Alexandria, VA, May 2-6, **2004**.

CONCLUSION

Significant progress have been made in the current reporting period on Task 2 (Experimental) Task 3 (economics) and Task 4 (boiler design).

Task 2 (Tests performance) has been completed. In addition to data collected in 2003 on oxy-fired boiler and on air-fired boiler, the heat transfer characteristics and mercury samples have been collected. Although these results are yet to be fully analyzed and discussed, the highlights are as follows:

- **Burner stoichiometry, Flame stability and NO_x emission:** to avoid getting a cooler and less stable flame in O₂/CO₂ conditions vs air-conditions, a same burner has to be operated at higher burner stoichiometry in oxy-configuration. This is due to higher molecular weight and heat capacity of CO₂ vs N₂. Increasing the burner stoichiometry in oxy-combustion is feasible without affecting NO_x levels thanks to flue gas recirculation which keeps the NO_x emission very low (<0.1 lb/ 10⁶Btu) through the reburn mechanism.
- **Emmissivity Measurement:** The measured emissivity indicated that the flame emissivity under the oxy-combustion is similar to the flame emissivity under normal air firing conditions.
- **Temperature Measurement:** Temperature measurements were performed at the flame, furnace exit, and the convection pass outlet for both air firing and oxy-firing, while the overall mass flow rate was kept constant. The data are being analyzed. Pilot results seem to indicate that under those optimized conditions, the temperature profiles are similar in oxy-firing and in air-firing conditions (previous tests showed an average FEGT 70⁰F lower in oxy-firing).
- **Mercury Measurement:** Mercury sampling was performed at the convection pass outlet of SBS under normal air firing and oxy-combustion conditions, and the samples are currently being analyzed at Western Kentucky University.

The **Techno-Economic Study** (Task 3) has been completed in the current quarter. The oxycombustion process (OEC) using 99% purity of oxygen can achieve a CO₂ level concentrated to about 93% in the gas stream. If a higher CO₂ concentration is necessary, further gas separation and dehydration are required.

The auxiliary power use in the OEC process accounted for about 24% of the gross power output, resulting in a decrease of power generation efficiency to 30-32%. The ASU contributed to 80% of the total auxiliary power usage.

Techno-economic analyses showed that compared to the new air-blown PC plant without CO₂ capture, the cost of electricity (COE) of the OEC process increased by about 25-30%, while that of the MEA-equipped air-blown PC plant increased by about 60% and that of the Selexol-equipped IGCC plant increased by 20%. The cost of the OEC process is slightly higher than the IGCC plant, but is more competitive than the MEA-equipped air-blown PC plant.

The OEC process and MEA process are technically applicable for plant retrofit to capture CO₂ emissions. For a 533MW_e power plant, the OEC retrofit required less than \$300/kW_e capital cost and increased 5 mills/kWh O&M cost. At the same plant size, the MEA retrofit required \$460/kW_e capital cost and 11 mills/kWh O&M cost. The OEC process is economically favorable for the CO₂ capture retrofit of the existing power plant.

The **Boiler Design Task** (Task 4) had been initiated in the last quarter (Q1 2004). The scope of work (SOW) to be performed had been modified as per DOE request and the updated SOW had been reported. Engineering calculations are in progress and the corresponding results will be reported in further reports.

The project main results have been reported in two papers to be presented in conferences in April and May 2004.

The current work schedule is to perform analytical chemistry of the mercury samples, and to reduce and analyze the corresponding results. The experimental data collected during the entire 2003-2004 test campaign will be reviewed in details, analyzed and the main conclusions highlighted. The report summarizing the work performed in the Techno-Economic study (task 3) will be completed. Conclusion regarding oxycombustion competitiveness vs air-blown system with amine scrubbing and vs IGCC will be reported. Preliminary results on engineering effort currently in progress in the boiler design task (task 4) will be reported.

REFERENCES

List of published reports that will be used for performing the **techno-economic analyses** (estimation of auxiliary powers and costs associated with various process areas):

1 CONVENTIONAL PC POWER PLANT

- (1) Gilbert/Commonwealth Inc., Clean Coal Reference Plants: Pulverized Coal Boiler with Flue Gas Desulfurization, DE-AM21-94MC311 66, September 1995
- (2) Office of Fossil Energy, US DOE, Market Based Advanced Coal Power Systems, DOE/FE-0400, May 1999
- (3) United Engineers & Constructors Inc, Total Generation Cost: Coal and nuclear Plants, DOE EY-76-C-02-2477, February 1979
- (4) EIA, Electric plant cost and power production expenses 1988, DOE/EIA-0455, August 1990
- (5) DOE/EIA , Steam-electric plant construction cost and annual production expenses, 1977

2 CO₂ REMOVAL PROCESS

- (6) EPRI, Evaluation of Innovative Fossil Fuel Power Plants with CO₂ Removal, Interim Report 1000316, December 2000
- (7) EPRI, Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO₂ Removal, Interim Report 10004483, December 2002
- (8) Henrik Birkestad, Separation and Compression of CO₂ in O₂/CO₂-Fired Power Plant, master thesis, Chalmers University of Technology, Sweden, 2002
- (9) D. Singh, E. Croiset, P. L. Douglas and M. A. Douglas, Techno-economic study of CO₂ Capture from an Existing Coal-Fired Power Plant: MEA Scrubbing vs. O₂/CO₂ Recycle Combustion, Energy Conversion and Management, 44(19), 2003: 3073-3091
- (10) Edward S Rubin and Anand B Rao, A Technical, Economic and Environmental Assessment of Amine-based CO₂ Capture Technology for Power Plant Greenhouse Gas Control, Annual Technical Process Report, DE-FC26-00NT40935, Oct. 2002

3 FGD PROCESS

- (11) United Engineers and Constructors, Inc., Economic Evaluation of Flue Gas Desulfurization Systems, EPRI GS-7193, February 1991
- (12) Srivastava R K, Controlling SO₂ Emissions: A review of the Technologies, EPA/600/R-00/093, November 2000

4 SCR PROCESS

- (13) Foerter D and Jozewicz W, Cost of Selective Catalytic Reduction (SCR) Application for NO_x Control on Coal-fired Boilers, EPA/600/R-01/087, October 2001

5 MERCURY REMOVAL PROCESS

- (14) US EPA, Mercury Study Report to Congress, Vol. VIII: An Evaluation of Mercury Control Technologies and Costs, EPA-452/R-97-010, December 1997
- (15) U.S. EPA clean Air Markets Division, Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model, EPA-68-D7-0081, March 2002

6 IGCC PLANT

- (16) Scott Chen, Subhash Bhagwat, Massoud Rostam-Abadi, Techno-Economic Studies of Illinois Coal in Future Power production processes. ICCI Project No: 01-1/2.3C-1, October, 2002
- (17) Destec Gasifier IGCC Based Cases, PED-IGCC-98-003, Prepared by EG&G, Sept. 1998, revised June 2000.
- (18) Economic Assessment of the Impact of Plant Size on Coal Gasification-Combined Cycle Plants, Prepared by Fluor Engineers, Inc. EPRI Report, AP-3084, May 1983.
- (19) NETL of DOE, Destec gasifier IGCC Base cases, PED-IGCC-98-003, June 2000
- (20) N. V. Akunuri, Modeling the Performance, Emissions, and Costs of Texaco Gasifier-Based Integrated Gasification Combined Cycle Systems, Master Thesis, North Carolina State University, 2000.
- (21) IEA Greenhouse Gas R&D Programmer, Potential for Improvement in Gasification Combined Cycle Power Generation with CO₂ Capture, Report No.PH4/19, May 2003.
- (22) Parsons Energy and Chemicals Group Inc, and Wolk Integrated Technical Services, Evaluation of Innovative Fossil Fuel Power Plants with CO₂ removal, 1000316, DOE interim Report, Dec.2000
- (23) Parsons Infrastructure & Technology Group, Inc., Integrated Technical Services, Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO₂ removal, 1004483, DOE interim Report, Dec.2002

7 OTHERS

- (24) EG&G Technical Services, Inc., ASPEN Plus Simulation of CO₂ Recovery Process, DOE/NETL-2002/1182, Sep.2002

LIST OF ACRONYMS AND ABBREVIATIONS

| | |
|-----------|--|
| AAL | American Air Liquide |
| ACI | Activated Carbon Injection |
| BSR | Burner Stoichiometric Ratio |
| B&W | Babcock and Wilcox |
| CHx | Condensing Heat Exchanger |
| CPEGT | Convective Pass Exit Gas Temperature |
| COE | Cost of Electricity |
| DOE | Department of Energy |
| EPA | Environmental Energy Agency |
| EPRI | Electric Power Research Institute |
| ESP | Electrostatic Precipitator |
| FD Fan | Forced Draft Fan |
| FEGT | Furnace Exit Gas Temperature |
| FG | Flue Gas |
| FGD | Flue Gas Desulfurization |
| FGR / RFG | Flue Gas Recirculation / Recycled flue gas |
| FGT | Flame Gas Temperature |
| Hg | Mercury |
| HMI | Human Machine Interface |
| HRSG | Heat Recovery Steam Generator |
| ID Fan | Induced Draft Fan |
| IGCC | Integrated Gasification Combined Cycle |
| ISGS | Illinois State Geological Survey |
| LOI | Lost On Ignition (same as UBC) |
| LSD | Lime Spray Dryer |
| MEA | Mono Ethanol-Amine |
| NETL | National Energy Technology Laboratory |
| OEC | Oxygen Enriched Combustion (Oxycombustion) |
| O&M | Operating And Maintenance |
| PA | Primary Air |
| PACI | Pulverized Activated Carbon Injection |
| PC | Pulverized Coal (Boiler) |
| PO | Primary Oxidant |
| PRB | Powder River Basin |
| SA | Secondary Air |
| SBS | Small Boiler Simulator |
| SCR | Selective Catalytic Reduction |
| SNCR | Selective Non Catalytic Reduction |
| SO | Secondary Oxidant |
| TA | Tertiary Air |

| | |
|-----|--------------------------------------|
| TBD | To be defined |
| TCR | Total Capital Requirement |
| TO | Tertiary Oxidant |
| TPC | Total Plant Cost |
| TPI | Total Plant Investment |
| UBC | Unburned Carbon in Ash (same as LOI) |