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Abstract

Coal is the most abundant and lowest-cost domestic fuel for power generation and the only energy source that provides a path to energy independence. The relationship between the cost of electricity and the Gross Domestic Product per capita has been shown and current production versus demand margins are at their lowest levels. Despite these advantages, it remains difficult to gain approval for construction of new coal-fired plants. Though not well known by the general public, relatively inexpensive modern pollution control equipment is available that allows coal to be burned with very low emissions of regulated pollutants and mercury. However, combustion of coal does produce carbon dioxide (CO_2), and concern about the role of industrial CO_2 emissions on the greenhouse effect and global warming continues to inhibit new plant permitting. To address this concern, pre-combustion, post-combustion and oxy-combustion methods are being developed to concentrate the CO_2 for sequestration.

Babcock & Wilcox Power Generation Group, Inc. (B&W) in collaboration with Air Liquide (AL) have been working to develop and demonstrate oxy-coal combustion as a solution for carbon management for power generation.[1] During 2007 and early 2008, B&W's existing 30 MW$_t$ Clean Environment Development Facility (CEDF) was modified to operate in the oxy-coal combustion mode, and bituminous, subbituminous and lignite coals are being tested. This paper describes modifications to the CEDF and the oxy-coal process tested, summarizes the test results, and discusses operating experience.

Introduction

Energy availability and cost are direct indicators of economic stability and prosperity as demonstrated by the correlation between energy consumption and Gross Domestic Product shown in Figure 1. However, the future for power generation is clouded by fear of coal combustion's CO_2 byproduct impact on climate change, short supply cost escalation of natural gas, and the risks of nuclear plants and spent fuel disposal. The recent cancellation of several coal generating plants due to public opposition shows that these obstacles continue to prevent construction of new generating capacity as the demand continues to increase at 2% or more per year.

In fact, coal not only contributes over 50% of the electricity generated in the United States (U.S.), but the vast investment in infrastructure is impossible to rapidly replace.

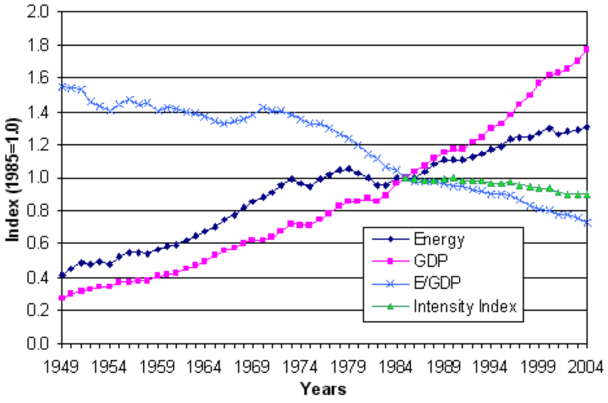


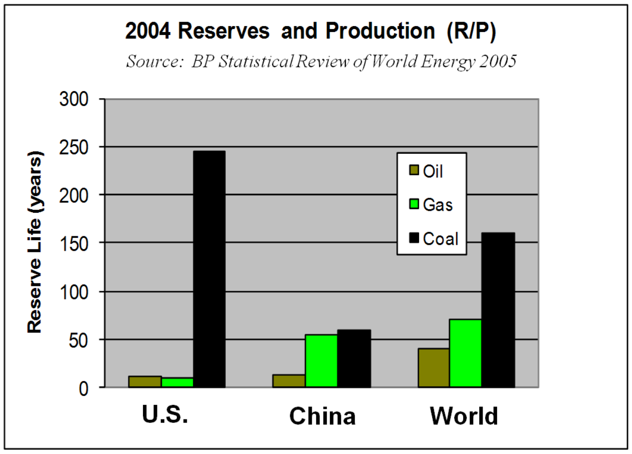
Fig. 1 Relationship between Energy and Gross Domestic Product (GDP) in the U.S.

In addition, the high efficiency of modern supercritical steam cycles and the very low emissions of regulated pollutants achievable with the latest control technologies have demonstrated conclusively that coal can be combusted with emissions rivaling those of natural gas. The only exception is CO_2, which is now coal's greatest challenge.

Since natural gas contains less carbon than coal, it naturally produces about 60% of the CO_2 compared to coal per unit of heat released. However, natural gas is in much more limited supply. As Figure 2 shows, only about seven years remain in North America and its cost is much higher and more volatile. Its use for power generation would require import of liquified natural gas (LNG) from the Middle East or the former Soviet Union, increasing our reliance on foreign energy sources and jeopardizing our national energy security. Coal, on the other hand, is relatively low and stable in cost and abundant in supply domestically with over 200 years of reserves at the current rate of use. Clearly coal is the right fuel to use for electricity generation in the foreseeable future provided carbon emissions can be mitigated.

Three primary approaches to carbon capture and storage (CCS) for coal-based power generation are currently under development: Integrated Gasification Combined Cycle (IGCC), post-combustion scrubbing and oxy-coal combustion. In recent years IGCC garnered so much attention that some thought it meant Integrated Gasification Carbon Capture. But lower performance and higher costs and risks than initially predicted have redirected attention to coal combustion solutions. Recent cost analyses have shown that all three approaches are currently about equivalent in cost and performance and all share perhaps the greatest and least proven technical risk of carbon storage.

Considerable efforts are underway to develop IGCC components for hydrogen combustion, identify and test new solvents for post-combustion systems and demonstrate oxy-coal combustion. Unlike IGCC, oxy-combustion technology can be applied either to new plants or retrofit to existing plants for capturing CO_2. Recent studies[2] performed by the U.S. Department of Energy (DOE) showed that it is economically competitive compared to other technologies for pulverized coal (PC) plants.


2004 Reserves and Production (R/P)

Source: BP Statistical Review of World Energy 2005

Fig. 2 Global supply of oil, natural gas and coal.

The main technological challenge for oxy-combustion technology today is to demonstrate at significantly larger scale. B&W and AL are currently addressing this challenge and this paper reports on the current status and recent results of the 30 MW_t oxy-coal demonstration at B&W's Clean Environment Development Facility located in Alliance, Ohio.

Background

Oxy-combustion for enhanced oil recovery (EOR) was evaluated by B&W initially in 1979 at the request of a major oil company and by the DOE's Argonne National Lab in 1987. In the late 1990s it was recognized that oxy-combustion may be a solution to carbon management that could have significant retrofit as well as new unit potential. In that time frame, development of commercial design processes began to provide oxy-combustion performance predictions for use as the basis for the paper studies and benchmarked against the pilot-scale Small Boiler Simulator (SBS1) results.

Since 2000, B&W has been a member of the CANMET CO_2 (oxy-combustion) Consortium and participated in 1 MBtu/h tests in Canada. Lab-scale pilot development of the technology for commercial applications began in 2001 at B&W in collaboration with American Air Liquide (AAL) and the State of Illinois, which led to testing in B&W's 5 MBtu/h SBS1 in 2001-2002 with Illinois No.6 coal and in 2003-2004 with Powder River Basin (PRB) coal (co-sponsored by DOE). In addition to technology development, B&W and AL also participated in studies to assess the technical and economic viability and the potential competitiveness of oxygen combustion with flue gas recycle, including a 2002 study for the Canadian Clean Power Coalition, design and proposal of a retrofit demonstration converting the 25 MW_e unit at the City of Hamilton, Ohio, in 2005 and DOE's "Advanced, Low/Zero Emission Boiler Design and Operation" project (DE-FC26-02NT41586).

In late October 2006, SaskPower announced agreement with B&W and AL to jointly develop a 520 gross MW_e plant for service in 2012 using oxy-combustion and selling the concentrated CO_2 for enhanced oil recovery. Compelled by Canadian government regulations related to the Kyoto Protocol to address carbon emissions, SaskPower had been studying amine scrubbing and oxy-coal combustion (OCC) to burn their pulverized lignite coal. IGCC had been eliminated due to site constraints, cost and risk concerns, and a desire for a combustion technology. Initial cost estimates indicated oxy-coal combustion as the least expensive and lowest risk, but concerns about combustion with lignite existed. To address these issues and provide a basis for performance predictions at a scale significantly larger than the 1.5 MW_t SBS1 unit provided, it was decided in the fall of 2006 to convert B&W's existing CEDF to oxy-coal combustion capability.

CEDF description and prior experience

In 1993 the Clean Environment Development Facility (CEDF), funded by B&W, DOE, and the Ohio Coal Development Office, was started up. A process flow diagram for the facility in its initial form is shown in Figure 3. 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.

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 in. 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 equipped with a B&W dynamically staged, variable speed (DSVS®) classifier capable of online adjustment from 70% to 90% through 200 mesh. A dedicated constant speed pulverizer primary air fan and direct natural gas-fired air preheater provide the 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 CO_2 inerting. A second gravimetric feeder meters the PC into a coal pipe that conveys it to the burner. The conveying air for the coal pipe is provided by a second variable speed burner primary air fan and preheated by an indirect natural gas-fired heater. A humidifier in the burner pipe allows control of fuel moisture to the burner.

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

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 system through a 200 ft. stack and emissions are monitored for sulfur dioxide (SO_2), nitrogen oxides (NO_x) and opacity by a continuous emissions monitoring system (CEMS).

A 100 MBtu/hr test burner mounts on the 13 ft. wide by 15 ft. high by 31 ft. deep furnace extension, to provide for flame length and gas expansion, and the windbox extends from the burner front (not shown in Figure 4). OFA ports are provided in the lower and upper furnace for staging combustion. The 13 ft. wide by 10 ft. deep by 62 ft. high furnace is enclosed by a water jacket with refractory lining to maintain the proper combustion zone temperature. The atmospheric pressure steam generated in the water jacket is vented to the atmosphere. The furnace geometry and heat absorption simulate commercial boilers. B&W performed extensive numerical modeling to ensure that the flow geometry and thermal environment in the furnace properly simulate a middle row burner in a large utility boiler. The high resulting flame temperatures elevate NO_x emissions to levels representative of full-scale boilers.

The convection pass is carefully designed to simulate the gas time-temperature history and tube metal temperatures of a commercial boiler convection pass to accurately reproduce formation and destruction of compounds including volatile organic (VOC) and air toxic compounds. It consists of a 10 ft. by 12 ft. water-jacketed enclosure that has a horizontal section followed by a down flow vertical section containing

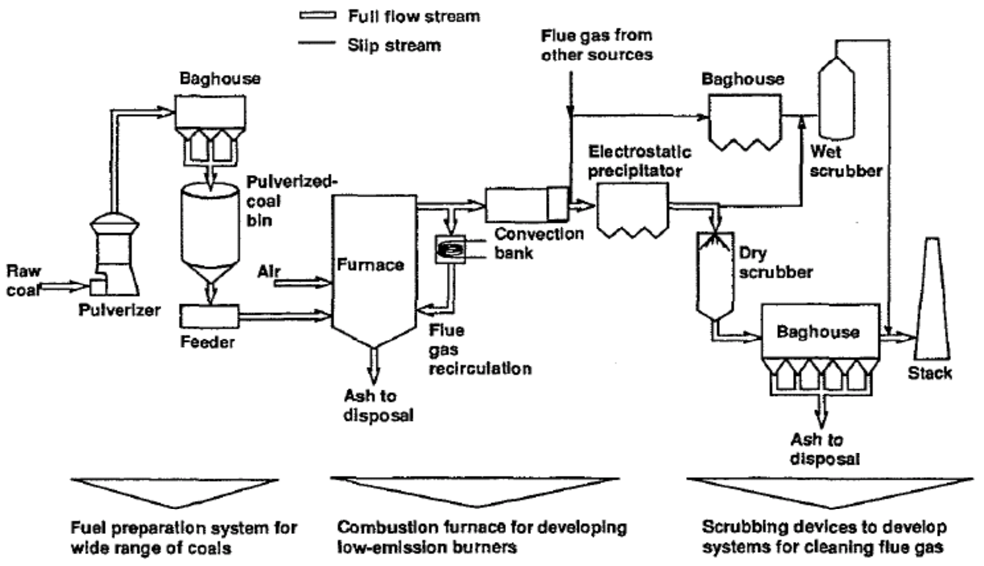


Fig. 3 Clean Environment Development Facility process flow diagram.

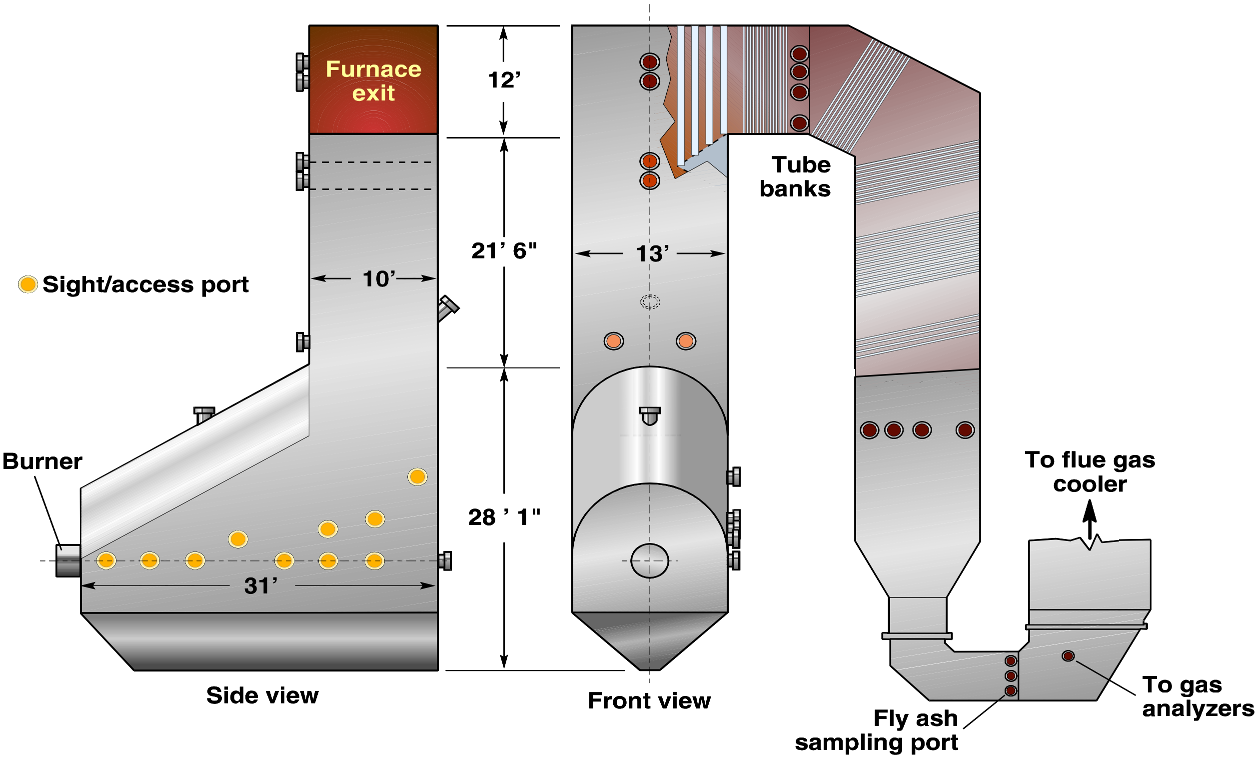


Fig. 4 Clean Environment Development Facility boiler simulator.

water-cooled tubes spaced uniformly across the width, but the number and row spacing are irregular to simulate the flue gas time-temperature pattern found in commercial boilers.

Because cooling is achieved with boiling water instead of superheated steam, a double-walled tube design with an air gap is used to achieve representative tube metal temperatures (600F to 1100F). Sufficient heat transfer surface is provided to cool the flue gas from the furnace exit temperature of 2250F to about 750F at the convection pass exit. Extensive modeling ensured that prototypical gas time-temperature profiles and tube metal temperatures compared to a commercial unit are obtained. Cavities were provided in the convection pass tube arrangement to allow the future addition of selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) systems for NO_x control studies, and lime/limestone injection for SO_2 control studies.

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

As Figure 3 shows, the flue gas can be directed to a 13.5 ft. diameter by 60 ft. tall full-flow dry scrubber. SO_2 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 6% gas flow slip-stream wet scrubber was also provided.

For particulate removal a full-flow electrostatic precipitator (ESP) removes dust prior to the dry scrubber, a six-module full-flow pulse-jet baghouse removes particulate from the humid and dust-laden gas exiting the dry scrubber, and a small slip-stream baghouse was provided upstream of the slip-stream wet scrubber.

The CEDF was initially designed as a combustion facility for burner development with provisions for performing emissions control and air toxics testing. 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, it was also used to test partial oxy-firing.

Modifications for oxy-coal combustion

To permit full oxy-firing, several modifications were necessary. Additional flues, oxygen mixers and supply system, a full-flow wet scrubber (WFGD), additional coal preparation equipment, and controls and instrumentation were added in 2007. Due to the pulverizer, which is oversized to permit milling of a wide range of coals, the unit can not be operated with bituminous coal in the direct-fired mode. Therefore, following indirect-fired testing with bituminous coal in late 2007 the unit was converted to direct firing to permit full oxy-combustion operation with subbituminous and Saskatchewan lignite coals. As described previously, indirect-firing employs a bin for storage of pulverized coal which is then injected into the coal pipe and conveyed by the primary stream to the burner. Direct firing is an operation where the coal is fed from the raw coal bunker into the pulverizer. Instead of conveying the pulverized coal to a storage bin, it is conveyed directly to the burner as is the case for most conventional power plants.

The oxygen required for the tests is supplied by vaporizing liquid oxygen (LOX) stored in large tanks (Figure 5). 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. Floxynator is designed based on AL's patented Oxynator™ concept. Oxynator is a commercially proven technology for air oxygen mixing that is demonstrated mixing up to 800 tons/day of oxygen. The key feature of Floxynator technology is that the mixing is achieved in the center of the flue, safeguarding the walls from higher oxygen concentrations. It also has low pressure drop enabling the use of a low pressure Air Separation Unit (ASU).

To remove SO_2 and water from the flue gas, which would otherwise be concentrated to 3.5 to 4 times the levels found in flue gas from air-firing due to the removal of nitrogen from the process, a full-flow wet scrubber with integral heat exchanger was installed (Figure 6). The scrubber is capable of about 98% (or more) SO_2 removal and reduces the flue gas moisture by 1 to 5.25 percentage points on a mass basis depending on fuel moisture. SO_2 is reduced to avoid high concentrations in the furnace and resulting corrosion by sulfidation.[3] Moisture is reduced to enhance pulverizer and combustion performance.

Oxy-coal test program description

The testing addresses the impact of oxy-firing and the full range of coals on coal preparation, combustion, precipitator and wet scrubber performance and operation with the different flue gas composition. Testing includes control concepts for transitioning from air-to-oxy and oxy-to-air firing, load changing and major trips including Master Fuel Trip, and supports nearly full-scale testing of a new oxy-burner for PRB and lignite. Though the first campaign tests the configuration of ESP-WFGD, the CEDF is also capable of testing the dry scrubber-baghouse configuration in full oxy-firing mode in later campaigns.

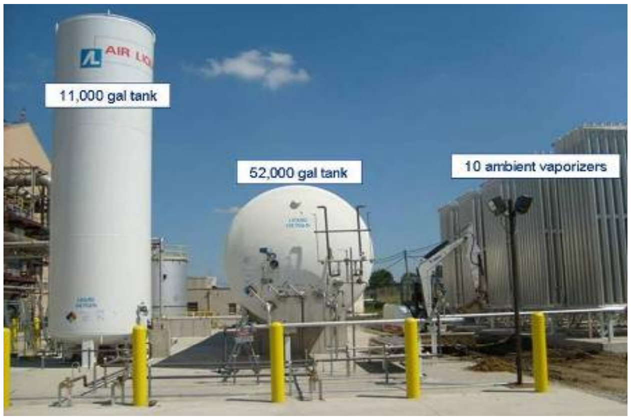


Fig. 5 Oxygen supply system.

Fig. 6 Wet FGD absorber tower.

The test program with bituminous coal fired indirectly focused on burner, ESP, Floxynators, and WFGD performance in the full oxy-mode compared to air-firing. In addition to gas composition, its impact on SO_2 removal and sulfur trioxide (SO_3) formation were also measured. Sub-bituminous and lignite testing are focused on performance of the new burner and pulverizer in the direct-fired mode and ESP performance.

The objectives of this project are to demonstrate the following main elements of oxy-coal combustion technology at 30 MW_t scale for the three coals:

- Optimum burner design for each coal
- NO_x emissions
- Floxynator performance
- Pulverizer performance
- Furnace exit gas temperature
- Boiler/convection pass heat transfer
- Wet scrubber performance
- SO_2 control
- SO_3
- Flue gas moisture control via novel B&W concept
- Potential enhancement of mercury speciation with oxy-combustion
- ESP performance
- Insights for materials development
- Air infiltration evaluations [impact on CO_2 Compression & Purification Unit (CPU) design].

Testing of PRB followed by lignite was planned to be completed in May 2008. The test data is currently being evaluated and both data and experience will be used for design of a larger scale demonstration.

Oxy-coal operating experience

Current results demonstrated a process for smooth transition from air-firing to oxy-firing and back again. Different quantities of oxygen were injected directly to the burner as well as varying the amount of oxygen in the primary and secondary recycle streams. These parametric tests helped establish the process for good flame stability and oxygen mixing in the various streams. Scrubber and ESP performance were tested and verified.

The procedure for transition from air to oxygen and back as defined by McDonald and Zadiraka[4] was followed and experience has shown that it can be performed in a smooth, safe, and timely manner. In addition, the HAZOP (hazardous operation) analysis, performed prior to operation, was shown to have adequately identified safety issues prior to performing the transition. Due to the single burner configuration, the transition was performed at 70% heat input with the lighter in service. The burner was characterized with air-firing first to establish stable firing configurations and then retuned in the oxy-mode.

At the CEDF, the transition is made by replacing air in the system with oxygen and recycled flue gasses. Figure 7 shows the relationship between air and recycle flue gas flows during a transition from air to oxy-mode. Air, recycle, oxygen, and fuel flows are varied to maintain the excess oxygen concentration at the boiler exit within the control range.

As recycled flue gas is increased and air decreased, the oxygen flow is increased at appropriate locations, including mixing it with the recycled flue gas using Air Liquide's Floxynator. Oxygen flow into the recycled gas stream is controlled to maintain the oxygen level in the gas stream within the desired range as the flow of recycle gas is increased.

Experience has shown that the transition can be achieved in a smooth and safe manner. As the recycle dampers were opened, as oxygen was introduced, and as the air intakes were isolated, neither the pressures nor the pressure balance throughout the process changed drastically and furnace draft could be safely maintained during the transition. Oxygen could readily be added in controlled quantities as the amount of recycled gas is increased to offset the reduction in available oxygen from air. The required oxygen quantity and rate of increase or decrease was predictable and response to changes was rapid. During the transition it is important to maintain velocity through the pulverizer to minimize the amount of coal drop out. This was not difficult and posed no significant complexity. In addition, combustion remained stable and flame scanner signals remained high during the transition and subsequent oxidant composition change.

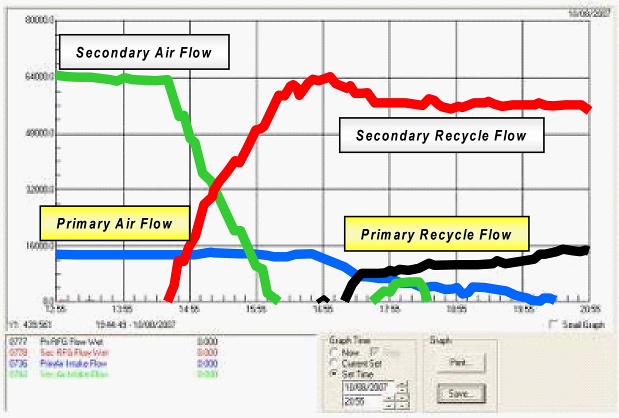


Fig. 7 CEDF boiler simulator.

Transitions have been successfully achieved with as-received bituminous coal in the indirect-fired mode and with subbituminous coal (≈ 30% moisture) in the direct-fired mode. For the CEDF, all controls were in manual mode, but the process has proven it can be readily automated for commercial operation.

Since the CEDF must comply with EPA emissions limits and the exhaust gases are released to the atmosphere rather than compressed and stored (no CPU or sequestration), the continuous emissions monitoring system (CEMS) program had to be modified to allow F-Factors to be used that are consistent with pure oxygen instead of air as the oxidant.

Since the CEDF was being operated in the direct-firing configuration for the first time, some minor changes to the control logic had to be made to accommodate conditions not previously experienced with indirect air firing. For example, the CEDF's single pulverizer system was designed with intention of pulverizing a wide variety of coals sometimes running under test conditions that could be extreme and not typical of commercial. As a safety precaution, an explosion protection system was installed. Because the unit would now be operated in the direct-fired mode, the pressure set point for the pulverizer explosion protection system had to be raised to accommodate the pressure rise associated with deadheading the pulverizer primary air fan as the pulverizer outlet valve was closed during a pulverizer trip.

Current results and future plans

Results have shown that stable combustion can be maintained with enhancement by oxygen injection into the burner. As high as 60% NO_x reductions relative to air-firing were achieved as previously demonstrated in B&W's 5 MBtu/h Small Boiler Simulator in 2001 and 2003. Carbon monoxide and unburned carbon were also low. No measurable difference in SO_2 removal was detected between air and oxy-combustion. Due to the age of the equipment at the CEDF, air infiltration was significant. Several attempts were made to eliminate infiltration, but due to the initial design for air-firing, it was difficult and often impractical to modify the existing equipment to achieve gas-tight conditions. This was particularly the case for primary and secondary fan intakes for which air infiltration is irrelevant in the air-fired mode so they were not initially designed to be gas-tight. In addition, due to the design intent to provide equipment testing flexibility, the dry scrubber module and baghouse upstream of the ID fan, though not in service, are in the gas path imposing additional pressure drop and potential for air infiltration. Based on test data, as much as 10% air infiltration is estimated to produce the CO_2 concentrations measured at about 67% (dry volume) compared to about 85% (dry volume) expected for a new unit designed for oxy-combustion with about half that amount.

Oxygen mixing is critical to safe operation. Test data has shown that the mixing of oxygen with flue gas was occurring in the central area of the flue keeping the flue walls at lower concentrations as intended by the design. Since the flue walls can be maintained at normal or lower concentrations compared to air, no special considerations are required because of oxygen introduction. Figure 8 shows the cross-sectional concentrations that were measured for one of the test conditions at the end of the mixing zone in the flue. For this test condition, the theoretical or perfectly mixed oxygen concentration is around 16.5%. As illustrated, the oxygen concentrations at the walls are maintained 14% or less from the point of oxygen injection through the end of mixing section.

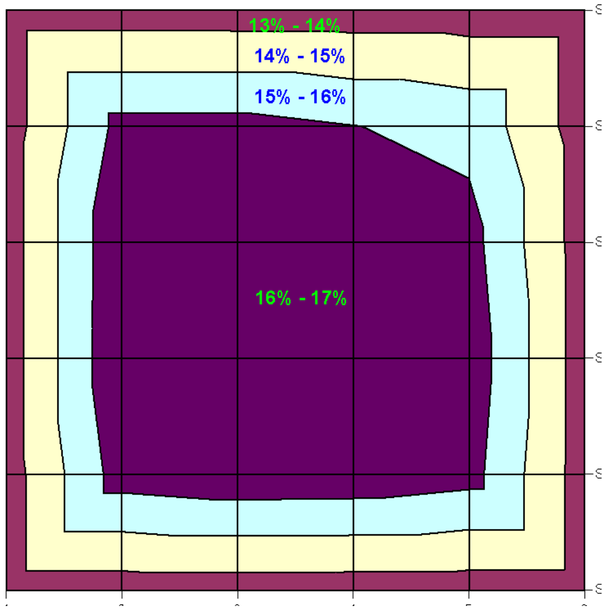


Fig. 8 Measured O_2 concentrations exiting mixing section (wet basis).

Conclusions

CEDF testing has provided detailed combustion, ESP and WFGD data in full oxy conditions with three widely varying coals as well as very valuable operating experience and insights. Since the CEDF was designed to produce data representative of a commercial plant, which has been demonstrated in numerous previous air-fired testing, and it contains all of the equipment present in a commercial unit, both the data and especially the operating experience provide a solid basis for B&W and AL to design the first commercial demonstration plant. A summary of the key findings are:

- Ability to combust coal with oxygen flue gas mixture at near commercial scale burner demonstrated
- Safe and smooth transitions between air-fired mode to oxy-combustion mode in both indirect- and direct-fired operation
- Control and communication schemes between oxygen system and burner management system identified and developed
- Safe and efficient mixing of oxygen with flue gas demonstrated
- WFGD performance verified
- ESP performance verified
- Predictive tools for process and boiler design validated.

Oxy-combustion is one key solution for sustainable power generation. Large-scale tests and commercial projects under development will confirm its performance and economic competitiveness. Together, B&W and Air Liquide are combining their expertise in oxy-combustion, boiler-island, emission controls, oxygen production, and CO_2 processing to develop a unique and effective commercial offering.

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