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JEA Large-Scale CFB Combustion Demonstration Project

A DOE Assessment

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Disclaimer

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EXECUTIVE SUMMARY

The U.S. Department of Energy's (DOE's) Clean Coal Technology (CCT) Program seeks to offer the energy marketplace more efficient and environmentally benign coal utilization technology options by demonstrating these technologies in industrial settings. This document is a DOE post-project assessment of one of the projects selected in Round I of the CCT Program, the JEA Large-Scale Circulating Fluidized Bed (CFB) Combustion Demonstration Project. CFB combustion, an alternative to pulverized coal (PC) fired combustion, has the advantage of being very flexible relative to the fuel burned and producing low emissions of pollutants. The project involved the installation of a 300 MWe CFB to re-power Unit 2 at JEA's Northside Station located in Jacksonville, FL. Construction of the unit was completed in December 2001, and test operations were completed in April 2005. The target project cost, as presented in the Cooperative Agreement, was $309.1 million. During the course of the project, the cost escalated to $321.4 million; DOE provided 23 percent of the total project funding.

Two types of fluidized bed boilers are in commercial operation: bubbling bed and circulating bed. In a bubbling bed boiler, a bed of solid particles (predominantly limestone, sand, ash, and calcium sulfate) is supported on a grid located near the bottom of the boiler. The bed is maintained in a turbulent state by air blown through the grid into the bed from a plenum beneath the grid. The velocity of the air is high enough to keep the bed fluidized but not so high as to entrain bed particles and carry them out the top of the boiler. Fuel particles of the proper size range are introduced into the bed, where combustion occurs. Typically, raw fuel in the bed does not exceed two percent of the total bed inventory.

The need to improve combustion efficiency and the desire to burn a wider range of fuels led to the development of the CFB boiler. A CFB differs from a bubbling bed in that the air velocity through the bed is higher so that particles are entrained and carried out of the bed. The gas passes through a cyclone, where particles are removed and returned to the fluidized bed. Boiler suppliers have slowly been increasing the size of CFBs. The 300

MWe unit constructed for this project is currently the largest CFB boiler in operation. Some of the advantages of CFBs are fuel flexibility, low SO_x and NO_x emissions, and high combustion efficiency.

The process design for the JEA unit was the same as for smaller Foster Wheeler CFB boilers, with fuel and sorbent feed size range, furnace velocity, temperature, and pressure drop being unchanged. Key design features include: single furnace with division walls, steam-cooled cyclones, INTREX™ heat exchanger, parallel-pass reheat control, startup duct burners, water-cooled air plenum and fluidizing nozzles, fluidized ash cooler, and fuel feed.

The overall project objective, as listed in the Statement of Work, was to demonstrate the technical and economic viability of a coal-fired facility utilizing a Foster Wheeler CFB combustion boiler capable of producing 1.8 million lb/hr of 2,400 psig steam superheated to 1,000 ^{o}F. Specific objectives were to demonstrate the feasibility of scaling up CFB boiler technology and mitigating concerns regarding risks; determine the effect on CFB boiler performance of variations in fuel and limestone properties; characterize the various by-product and process streams; characterize the environmental performance of the CFB boiler; provide sufficient operating and maintenance data to permit technical and economic evaluation of the CFB boiler technology; and provide JEA with a low-cost, efficient, and environmentally friendly electric generating facility.

Operation of the CFB unit was demonstrated through a series of operability, reliability, and performance tests. Operability tests determined the operability of the CFB boiler and its ancillary equipment under various conditions, including startup, shutdown, and full and changing load. Reliability tests entailed the collection of data to determine the overall reliability of the boiler and associated equipment. Performance tests verified achievement of guaranteed performance through testing in accordance with applicable codes and EPA/state emission test methods. Four performance tests were conducted burning four different fuels: (1) Pittsburgh No. 8 coal, (2) a 50/50 blend of petroleum coke and Pittsburgh No. 8 coal, (3) Illinois No. 6 coal, and (4) an 80/20 blend of petroleum coke and Pittsburgh No. 8 coal. (The fourth test was originally intended to be run feeding 100 percent petroleum coke; however, when it was found that the unit would not operate satisfactorily feeding 100 percent petroleum coke, the test was modified to use a blend of 80 percent petroleum coke and 20 percent coal.) These performance tests demonstrated the ability to meet design conditions while feeding a variety of fuels and limestones.

Initial operation of the boiler on coal and high ratios of coal and petroleum coke was successful. However, attempts to operate on 100 percent petroleum coke resulted in agglomeration of ash in the INTREX™ and cyclones within about a week, requiring a forced outage to remove the ash buildup. As a result of this problem, blending of at least 20 percent coal with petroleum coke was required for reliable operation of the boiler. Other significant problems encountered with the boiler operation included drying and feed problems with the limestone, stripper cooler plugging, expansion joint failures, and back sifting of dust into the primary air plenum. Problems were also encountered with density control and spray quality in the air quality control system. To a large extent these problems were mitigated by equipment modification or replacement and changes in operating procedures, but some issues remain to be resolved.

Although the average availability of 65.8 percent during 2003 and 2004 was not at the desired level and lower than typical for the fleet of comparably sized pulverized coal power plants (84.0 percent), this project proved that a large CFB boiler could be operated; and, once identified problems are corrected, availability should significantly improve. The project met or exceeded all the design environmental values. NO_x, SO_2, and particulate levels were very low, placing this unit among the cleanest coal fired units.

In conclusion, this project demonstrated the successful operation of a large CFB boiler for the production of electric power. Currently, this is the largest CFB ever constructed. When technology is scaled up, it is not unusual for problems to occur, and this project was no exception. A number of problems arose, most of which were successfully addressed through modifications to equipment or operating procedures.

In general, this project met the goals established in the Statement of Work. It demonstrated the feasibility of scaling up the CFB technology, tested different fuels and limestones, characterized the by-products, determined environmental performance, and provided data to permit economic evaluation of the CFB technology. However, during the timeframe of this project, the unit did not quite achieve the reliability or cost targets desired by JEA. The performance should improve as improvements to the unit are implemented over time.

Estimated economics indicate that the expected cost of electricity for a 300 MWe CFB plant at a greenfield site is 6 to 8¢/kWh, based on burning bituminous coal costing $48/ton. If low-cost petroleum coke is available as fuel, costs could be significantly reduced.

The lessons learned from this project will lead to design modifications so that new CFB units will avoid most of the problems encountered with the JEA unit. The very low level of emissions and the ability to burn fuel blends containing a high percentage of petroleum coke should make CFB technology an attractive option for new units or re-powering of existing units.

I. INTRODUCTION

The U.S. Department of Energy's (DOE's) Clean Coal Technology (CCT) Program seeks to offer the energy marketplace more efficient and environmentally benign coal utilization technology options by demonstrating these technologies in industrial settings. This document is a DOE post-project assessment of one of the projects selected in Round I of the CCT Program, the JEA Large-Scale CFB Combustion Demonstration Project.

Circulating fluidized bed (CFB) combustion is an alternative to pulverized coal (PC) fired combustion, which has the advantage of being very flexible relative to the fuel burned and producing low emissions of pollutants. Foster Wheeler Energy Corporation (FWEC) submitted a proposal to DOE to demonstrate CFB combustion. In November 1990, DOE awarded a Cooperative Agreement to conduct this project. The project was restructured in June 1992 and sited in York County, PA in June 1993. When this site fell through, the project was again restructured and re-sited to JEA's (formerly Jacksonville Electric Authority) Northside Station located in Jacksonville, FL. The Cooperative Agreement was modified in September 1997 to recognize this change.

Construction of the unit was completed in December 2001, and test operations were completed in April 2005. The project was installed to re-power Unit 2, which had been out of operation since 1983. At the same time, an identical CFB boiler was installed on Unit 1, but re-powering Unit 1 was not part of the CCT program, and none of those costs were covered by the DOE. The target project cost, as presented in the Cooperative Agreement, was $309.1 million. During the course of the project, the cost escalated to $321.4 million; DOE provided 23 percent of the total project funding.

II. PROJECT/PROCESS DESCRIPTION

A. Project Description

This project was proposed by FWEC in Round I of the CCT program, with the intended site being the Arvah Hopkins Power Station in Tallahassee, FL. A Cooperative Agreement was awarded on November 30, 1990. Subsequently, the City of Tallahassee decided not to continue its participation in the project. In June 1993, the project site was changed to York County, PA. However, in September 1996, York County Energy Partners and Metropolitan Edison Company terminated activities on the CFB project. On August 26, 1997, DOE approved transfer of the project to Jacksonville, FL. On September 29, 1997, DOE signed a modified Cooperative Agreement with JEA to cost share refurbishment of Unit 2 at JEA's Northside Generating Station.

At the time of project commencement, the Northside Generating Station consisted of three heavy oil/natural gas fired steam units and four diesel oil fired combustion turbine units. Units 1 and 2 each had a nominal rating of 297.5 MWe (gross), and Unit 3 had a rating of 518 MWe. Unit 1 came on line in 1966; Unit 2 was commissioned in 1972; and Unit 3 came online in 1977. Unit 2 had been inoperable since about 1983 due to major boiler problems. When JEA decided that additional base load capacity was needed to support Jacksonville's growing demand for electric power, the logical choice was to re-power Unit 2. The decision was then reached to re-power Unit 1 at the same time with an identical CFB boiler, but no DOE funding was used for the Unit 1 re-powering. In addition to increasing generating capacity, another objective of this project was to replace expensive gas and oil fuel, the cost of which limited plant utilization, with cheaper coal and petroleum coke, thus decreasing the cost of electricity.

Foster Wheeler handled the boiler island aspects of the project. Foster Wheeler Energy Corporation designed and supplied the CFB boilers. Foster Wheeler USA provided engineering, procurement, and construction management services for installation of the boilers and for furnishing and erecting the air pollution control system, chimney, limestone preparation system, and ash handling system. Foster Wheeler Environmental

Corporation provided environmental permitting services. Some parts of the project were implemented by the JEA staff, supplemented by Black & Veatch Corporation. Others providing services were Zachry Construction Corporation, Fluor Global Services, W.W. Gay Mechanical Contractor, Inc., and Williams Industrial Services Inc.

Work included construction of an ash management system and receiving and handling facilities for coal, petroleum coke, and limestone, as well as upgrades of the existing turbine island equipment and the electrical switchyard facilities.

B. Process Description

Two types of fluidized bed boilers are in commercial operation: bubbling bed and circulating bed. In a bubbling bed boiler, a bed of solid particles (predominantly limestone, sand, ash, and calcium sulfate) is supported on a grid located near the bottom of the boiler. The bed is maintained in a turbulent state by air blown through the grid into the bed from a plenum beneath the grid. The velocity of the air is high enough to keep the bed fluidized but not so high as to entrain bed particles and carry them out the top of the boiler. Fuel particles of the proper size range are introduced into the bed, where combustion occurs. Typically, raw fuel in the bed does not exceed two percent of the total bed inventory.

The turbulent mixing in a bubbling bed results in a residence time of up to five seconds. These boilers can operate at a temperature below 1,650 ^{o}F. At this temperature, limestone injected into the bed can achieve greater than 90 percent sulfur removal. The chemistry involved for sulfur removal by limestone injection is:

$$CaCO_3 \rightarrow CaO + CO_2$$
$$CaO + SO_2 \rightarrow CaSO_3$$
$$CaSO_3 + \frac{1}{2}O_2 \rightarrow CaSO_4$$
$$CaO + SO_3 \rightarrow CaSO_4$$

Combustion efficiency can be up to 92 percent with unburned carbon typically in the range of 2 to 5 percent. Problems with complete combustion may be encountered with low volatile fuels.

The need to improve combustion efficiency and the desire to burn a wider range of fuels led to the development of the circulating fluidized bed (CFB) boiler. A CFB differs from a bubbling bed in that the air velocity through the bed is higher so that particles are entrained and carried out of the bed. The gas passes through a cyclone, where particles are removed and returned to the fluidized bed. Boiler suppliers have slowly been increasing the size of CFBs. The 300 MWe unit constructed for this project is the largest CFB boiler currently in operation. Some of the advantages of CFBs are:

- Fuel Flexibility—The relatively low furnace temperature is below the ash softening temperature for nearly all fuels. As a result, the furnace design is independent of ash characteristics, which allows a given furnace to handle a wide range of fuels.

- Low SO_x Emissions—Limestone is an effective sulfur sorbent in the temperature range of 1,500 to 1,700 ^{o}F. A SO_x removal efficiency of 95 percent or higher has been demonstrated along with good sorbent utilization.

- Low NO_x Emissions—A low furnace temperature of 1,500 to 1,700 ^{o}F, together with air staging to the furnace, results in very low NO_x emissions.

- High Combustion Efficiency—The long residence time of solids in the furnace, as a result of the collection and recirculation of solids by the cyclone, plus the vigorous solids/gas contact in the furnace caused by the fluidization airflow, results in a high combustion efficiency (typically greater than 90 percent), even with difficult-to-burn fuels. The unburned carbon loss is typically in the range of 1 to 2 percent.

1. JEA CFB Unit 2

Figure 1 is a schematic of JEA CFB Unit 2. In addition to the CFB, Unit 2 includes fuel and limestone handling, limestone preparation, an air quality control system, ash handling, and a turbine island. The process design for the furnace on Unit 2 is the same as for smaller FW CFB boilers, with fuel and sorbent feed size range, furnace velocity, temperature, and pressure drop being unchanged.

Key design features include:

- Single furnace with division walls
- Steam-cooled cyclones
- INTREX™ heat exchanger
- Parallel-pass reheat control
- Startup duct burners
- Water-cooled air plenum and fluidizing nozzles
- Fluidized ash cooler
- Fuel feed

Each of these areas is discussed in the following sections.

a. Furnace

The main factors that influence CFB boiler configuration are the specified steam conditions and the fuel type. Fuel quality affects auxiliary equipment sizing more than furnace sizing for most fuels. The coal and ash flows increase by two to five times when waste coal is substituted for bituminous coal. However, the air and gas flows increase by only about seven and 12 percent, respectively, because the higher heating values (HHV) of waste coal and lignite are only about 30 percent that of bituminous coal. The range of

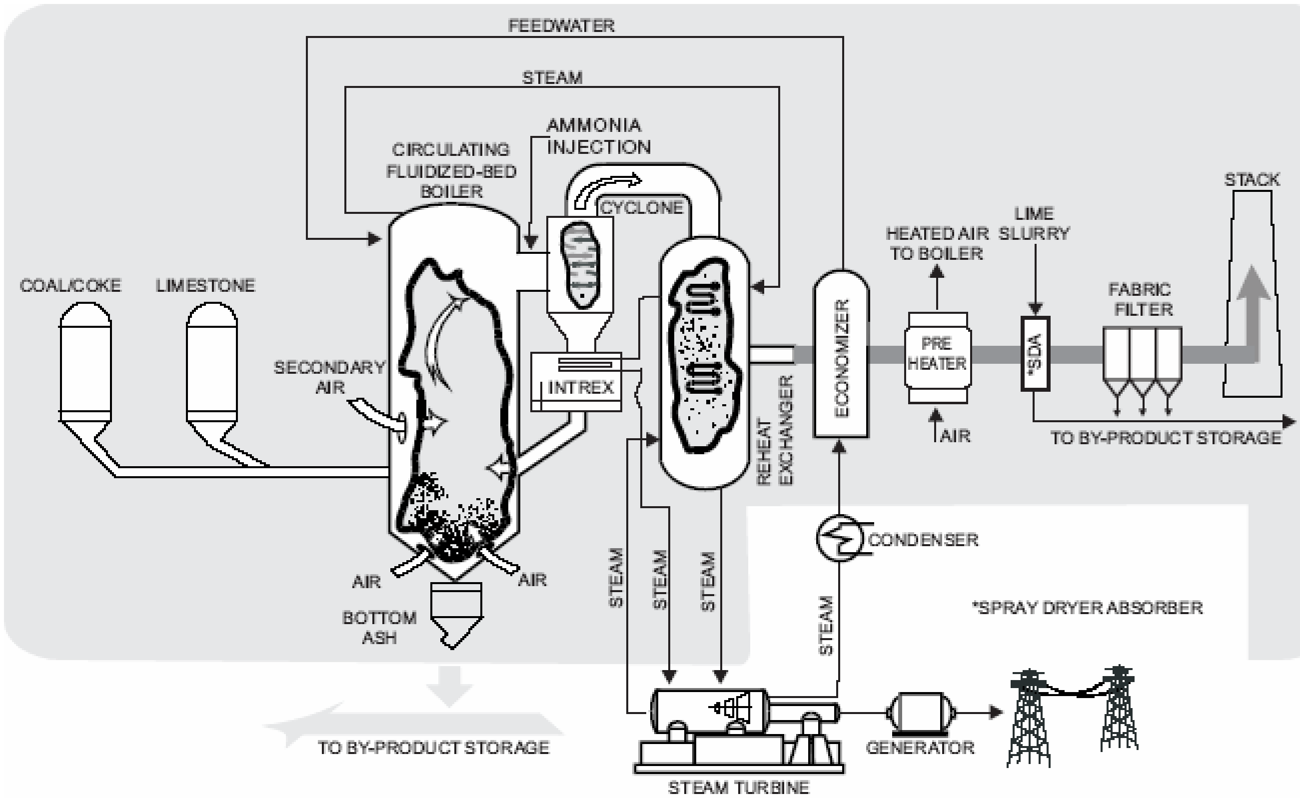

Figure 1 Schematic of JEA Unit 2

fuels to be burned normally determines auxiliary equipment selection, while furnace design and performance are optimized for the design fuel.

Furnace temperature can be controlled by changing the solids loading in the upper furnace by varying the primary/secondary air ratio. The design intent was also to control temperature by changing the solids flow over the INTREX™ superheater surface; however, this did not perform satisfactorily, as the solids flow bypassing the INTREX™ could not be controlled. The evaporative duty of the CFB unit is provided by the furnace enclosure and division water walls. This arrangement of furnace surfaces gives uniform heat removal, thereby minimizing temperature variations. The furnace division walls, which have been used in several FW CFB boilers, provide more uniform solids loading to the three cyclones.

b. Steam-Cooled Cyclone

The function of the cyclone in the CFB furnace is to capture enough solids to ensure good bed quality, which is manifested by proper furnace temperature, low furnace pressure drop, low carbon loss, and low emissions. The efficiency of this key piece of equipment is of paramount importance to the success of the CFB. The 300 MWe unit uses three steam-cooled cyclones, each of which is lined with FW's standard one-inch thick low-cement refractory on studs as protection against erosion. Higher stud densities are used in areas of high solids impact. Operating experience has shown that this refractory system works reliably in this service.

Classical cyclone theory, which does not account for particle interactions, predicts that separation efficiency decreases as the diameter of the cyclone increases. In the case of CFB cyclones, it appears that with the heavy solids loading, interaction between particles occurs to a significant extent with the larger particles carrying smaller particles with them to the wall of the cyclone and, thus, out the bottom.

c. INTREX™ Heat Exchanger

Hot re-circulating solids enter the inlet channels of the INTREX™. The solids are passed into the superheater cells by fluidizing both the inlet channels and the superheater cells. The INTREX™ enclosure is constructed of refractory lined plates and comprises several inlet channels, superheat bundle cells, and a common return channel to distribute solids evenly back into the furnace. The INTREX™ design for the 300 MWe unit differed from that used in the NISCO plant in several ways. The intended advantages of the INTREX™ were:

- Reduced corrosion and erosion—The high-temperature superheat surface in the INTREX™ is not exposed to corrosive materials in the flue gas stream. This means that corrosive fuels are not a threat to the INTREX™. Also, the very low fluidization velocity (<1.0 ft/sec) and the very fine particle sizes (~200 μm) eliminate the potential for internal erosion.

- Independent superheat/reheat control—With all of the reheat duty in the backpass and most of the superheating done in the INTREX™, superheat and reheat temperatures can be controlled somewhat independently over a wide range of conditions.

Unfortunately, problems were encountered with operation of the INTREX™, as discussed later, and it is unlikely that this design will be used in future large CFB units.

d. Parallel Pass Reheat Control

The backpass contains two parallel gas passes; the front pass houses the reheat surface, and the rear pass the primary superheater. Gas flow is biased between the two passes by dampers located underneath each pass. Although, during normal operation, reheat temperature control is accomplished without water spray attemperation by controlling the gas flowing past the reheater, sprays are necessary during startup.

e. Start-Up Duct Burners

For start-up, duct burners firing natural gas to preheat the primary air stream were installed. It was intended that the primary air would then preheat the bed material to the temperature needed for solid fuel combustion. However, the startup burners proved to be inadequate, and above-bed burners were added to supplement the duct burners.

f. Water-Cooled Air Plenum

A plenum under the grid at the base of the furnace distributes primary air to the fluidizing nozzles in the furnace floor. FW uses a water-cooled plenum, formed from tubing which then forms the furnace walls. The plenum is designed to handle high temperature gas so that boiler start-up time is minimized.

g. Bottom Ash Cooler

A bottom ash cooler is required to cool the ash to a temperature that is acceptable to the ash handling system. The 300 MWe CFB boiler uses the FW patented stripper/cooler design. The stripping (classifying)/cooling process consists of draining material from the bed and fluidizing this material in the stripper zone at a velocity sufficient to strip the required amount of fines from the stream, then returning these fines to the furnace. The remaining material, which is primarily coarse, passes through the cooling zones to the ash drain in the floor of the last zone. These zones are fluidized and cooled by cold primary air.

Cooling coils in the cooling zone carry low-pressure condensate. It was intended that these coils be the primary heat pickup, but the operating cooler bed level has usually been inadequate to get substantial heat transfer to the condensate, and maintaining controllable flow through the coolers has been difficult. The stripper section is important for returning the fines, mainly unburned carbon and unused limestone, to the furnace, thereby increasing carbon burnout efficiency and reducing limestone consumption.

h. Fluidizing Nozzles

Directional and non-directional fluidizing nozzles were provided. These nozzles were designed for low pressure drop, but this resulted in poor fluidization and back-sifting. The directional grid nozzles were replaced with arrowhead nozzles with a higher pressure drop.

i. Fuel Feed System

The fuel feed system consists of a number of individual trains, each of which is made up of a bunker outlet gate valve, a belt feeder, an isolation gate valve, and an air-swept fuel distributor. The system is designed to accommodate a positive pressure condition with the furnace pressure balance point set at the cyclone inlets. Seal air is provided from the primary air fan to the belt feeder. This fan also provides air to the air swept fuel distributors. The air swept fuel distributors add horizontal momentum to the fuel to assist in injecting it into the boiler. Seal legs of solid particles are provided in the downspouts above the belt feeders. These legs are of sufficient height to seal against the furnace pressure. Although the fuel distributors were designed to propel the fuel into the furnace in such a manner as to avoid hang-ups and back-flow from the furnace and to distribute the fuel throughout the bed, indications are that the fuel may not be evenly distributed due to bed flow patterns. Air is admitted into each distributor at two locations.

j. Emissions Control

SO_2 emissions are controlled by feeding limestone to the boiler; 90 percent SO_2 removal is typical and 95 to 98 percent removal is achieved in some units. The Ca/S ratio for 90 percent SO_2 capture is normally around 2.0 for fuels with moderate to high sulfur content. SO_2 reduction is enhanced by good mixing in the bed and by increased excess O_2 level. Limestone ash in the bed helps to improve the bed quality, especially for low ash fuels, because most limestone ash is less friable than the fuel ash and, thus, stays in the bed longer.

NO_x emissions are inherently low due to a low furnace temperature and staged combustion. Most of the NO_x is formed in the lower portion of the furnace, with NO_x emissions increasing with fuel volatile content, furnace temperature, O_2 level, and free lime in the furnace and decreasing with an increase in the amount of char. Therefore, minimizing excess O_2 in the furnace is important for NO_x control, but this is in conflict with SO_2 reduction. The FW CFB process is optimized in such a way that the dense bed in the lower furnace provides a long residence time for char and limestone particles, thereby minimizing both SO_2 and NO_x emissions.

2. Limestone Preparation System

The limestone preparation system grinds and dries raw limestone and pneumatically transports it to the limestone storage silos. The system consists of three rod mills with accessories. The mills are sized to grind limestone at a maximum feed size of one inch to a product size of less than 2 mm with a residual moisture content of one percent maximum. Raw limestone is fed to the mills by conveyors. A natural-gas fired burner provides hot air to dry the limestone during grinding, if necessary. Product from the mills is sent to two vibrating screens for sizing. Oversized material is returned to the mills, with the rest being sent to the storage silos.

3. Air Quality Control System (AQCS)

The polishing scrubber for the unit was provided by Wheelabrator Air Pollution Control and consists of a spray dryer absorber (SDA)/fabric filter (FF) dry scrubbing system to control SO_2, other acid gases (HCl and HF), particulates, and heavy metals. The system consists of:

- A two fluid nozzle SDA.
- Medium pressure pulse jet FF.
- Feed slurry preparation system.
- Absorbent preparation system, consisting of a lime storage silo, vertical ball mill slaking system, and transfer/storage tanks and pumps.
- Air compressor to provide atomizing air for the SDA, dried pulse air for the FF, and instrument air.

a. Dry Scrubbing System

Flue gas from the CFB boiler air heater outlet enters the top of the SDA. Lime slurry is atomized into the flue gas in the spray drying zone. The fine spray droplets absorb acid gases from the flue gas. The hot flue gas evaporates the water in the slurry, leaving solid particles. The flue gas is ducted to a fabric filter, where the fly ash from the boiler and the dried reaction products from the SDA are collected. Additional acid gas removal occurs as the flue gas passes through the dust cake on the fabric filter bags. Filtered flue gas flows from the fabric filters to the induced draft (ID) fans. The bags are periodically cleaned by a reverse jet of air. Dislodged solids fall to a hopper and are pneumatically conveyed to either the recycle surge bin or to the fly ash silo for disposal.

The slurry to the SDA consists of lime slurry and recycle slurry. The lime slurry is supplied by the absorbent preparation system, and the recycle slurry is prepared by mixing a portion of the fly ash and reaction products collected in the SDA and FF with water. Recycle slurry is used to improve lime utilization and minimize operating costs.

b. Absorbent Preparation System

Pebble lime is delivered by truck and stored in a silo. Lime is fed from the silo to a vertical ball mill slaking system. The slaking system mixes water with lime and produces a slaked lime, $Ca(OH)_2$, slurry. A lime feeder meters lime into the feed chute where sufficient water is added to produce a 25 wt percent slurry. The slurry drops into the Vertimill, consisting of a vertical mixing chamber with a center screw agitator and grinding balls. The agitator mixes the lime, water, and balls, which grind the pebble lime to promote the slaking reaction. Slurry overflows to the separating chamber, where oversized particles are pumped back to the bottom of the Vertimill. Lime slurry overflows the separating chamber and flows to the lime slurry transfer tank, from which it is pumped to the lime slurry storage tank.

c. NO_x Control

Ammonia is injected into the backpass (cyclone inlet) area of the boiler for control of NOx. Un-reacted ammonia in the flue gas is referred to as ammonia slip. This un-reacted ammonia combines with SO_3 to form ammonium bisulfate, which melts at about 300 ^oF, so that it is semi-liquid at typical flue gas temperatures. Ammonium bisulfate acts as a binding agent when it mixes with the fly ash and significantly increases the adhesive properties of the ash as it cools. Ammonium bisulfate can also react with metals in the ash and adversely affect bag life. Ammonia, up to a concentration of 40 ppm, enhances the performance of the fabric filter. The rate of increase of the pressure drop across the bag is lower, and particulate emissions are reduced. Experience at other locations indicates that at between 40 to 60 ppm of ammonia, the ash cake weight on the bags begins to increase because the filtercake becomes sticky and difficult to remove by normal pulsing. Pressure drop across the bags increases significantly, although emissions continue to drop. Typically, for this project, ammonia slip has been less than 1 ppm, and no problems with cake removal from the bags due to ammonium bisulfate formation have been experienced.

4. Fuel Handling System

The function of the fuel handling system is to receive coal, petroleum coke, and limestone from vessels and convey these materials to stockout and storage areas, from which coal and petroleum coke are reclaimed and conveyed to the fuel silos, and the limestone is reclaimed and conveyed to the limestone preparation system. Coal and petroleum coke are delivered in 60,000 ton capacity vessels and unloaded by a continuous bucket-type ship un-loader. Limestone arrives in 40,000 ton capacity self-unloading vessels. There are two storage domes.

5. Ash Handling System

The ash handling system transports bed ash from the outlet of the stripper cooler to the bed ash silo. It also transports fly ash from the economizer and air heater hoppers, as well as the baghouse hoppers, to the fly ash silos. The bed ash handling system consists of a mechanical conveying system from three stripper coolers to an intermediate surge hopper and a dilute phase pressure pneumatic conveying system from the surge hopper to the ash silo. The fly ash vacuum conveying system automatically and sequentially removes fly ash from the air-heater hoppers (ten), economizer hoppers (four), and AQCS baghouse hoppers (eight) and pneumatically transports the ash to the fly ash silo. JEA has developed a market for its ash and plans to dispose of it through sales.

6. Balance of Plant

Much of the balance of plant was upgraded as part of the re-powering project. Upgraded auxiliaries included the condensing, circulating water, boiler feed, condensate, condensate polishing, main steam, reheat steam, high- and low-pressure extraction systems, and the 480 volt, 4160 volt, and DC power supplies (see Table 11). The existing steam turbine was reused.

C. Feed Properties

1. Fuel

Properties of the fuels used during the test period are given in Table 1.

Table 1 Properties of Fuels Used in Performance Tests

Fuel	Pittsburgh No. 8 Coal	50/50 Blend of Pittsburgh No. 8 Coal and Petroleum Coke	Illinois No. 6 Coal	80/20 Blend of Petroleum Coke and Pittsburgh No. 8 Coal
Analysis, wt% (as received)				
Carbon	72.40	73.97	64.68	81.72
Hydrogen	4.77	4.50	4.44	3.65
Sulfur	4.70	5.60	3.24	3.72
Nitrogen	1.36	1.55	1.26	1.94
Chlorine	0.16	0.10	0.15	0.03
Oxygen	2.32	1.25	7.25	1.30
Ash	6.97	5.83	6.84	2.37
Moisture	7.32	7.20	12.14	5.27
Higher Heating Value, Btu/lb	12,924	13,340	11,656	14,083

2. Limestone and Lime

Table 2 presents the properties of the limestone fed to the boiler and the lime slurry fed to the spray dryer absorber during the test periods.

Table 2 Analyses of Limestone and Lime Used in Performance Tests

Test No.	Test 1	Test 2	Test 3	Test 4
Limestone Analysis, wt%				
$CaCO_3$	91.34	88.90	96.49	97.09
$MgCO_3$	3.13	2.88	1.35	1.17
Inerts	5.12	7.79	1.97	1.44
Moisture	0.41	0.43	0.19	0.30
Lime Analysis, wt%				
CaO	45.59	46.90	46.24	46.24
MgO	54.41	53.10	53.76	53.76
Lime in Slurry, wt%	5.57	5.23	5.23	1.33

D. Project Objectives and Statement of Work

The overall objective, as listed in the Statement of Work (SOW), was to demonstrate the technical and economic viability of a coal-fired facility utilizing a Foster Wheeler CFB combustion boiler, capable of producing 1,802,519 lb/hr of 2,400 psig steam superheated to 1,000 ^{o}F. Specific objectives were to:

- Demonstrate the feasibility of scaling up CFB boiler technology and mitigating concerns regarding risks.
- Determine the effect on CFB boiler performance of variations in fuel and limestone properties.
- Characterize the various by-product and process streams.
- Characterize the environmental performance of the CFB boiler.
- Provide sufficient operating and maintenance data to permit technical and economic evaluation of the CFB boiler technology.
- Provide JEA with a low-cost, efficient, and environmentally friendly electric generating facility.

The project was divided into three phases, as follows:

- Phase 1A—All activities prior to re-siting the project at JEA's facility
- Phase 1B—JEA design activities
- Phase 2—Construction and startup
- Phase 3—Operations

This post-project assessment is concerned mainly with Phase 3. As stated in the SOW, "During Phase 3, the Participant will, through a series of operability, capability and performance tests, demonstrate successful function of the unit; establish initial operation, inspection and maintenance criteria; establish constraints with respect to dispatching the unit; and demonstrate continuous full load and part load capability and performance."

In addition to operability testing, the Participant was to "conduct tests per the test plan on individual coals and coal/fuel blends to evaluate boiler operability, capacity and performance. Such tests will be used to establish fuel, process parameters and boiler performance factors for use in determining the extent to which coal and coal/fuel blend characteristics can be varied." Also, "the Participant shall conduct long term durability tests of the CFB system."

III. REVIEW OF TECHNICAL AND ENVIRONMENTAL PERFORMANCE

A. Technical Performance

Operation of the CFB unit was demonstrated through a series of operability, reliability, and performance tests, as follows:

- Operability Tests—These tests determined the operability of the CFB boiler and its ancillaries under various conditions, including startup, shutdown, changing load, and full load.
- Reliability Tests—These tests entailed the collection of reliability data to determine the overall reliability of the boiler and associated equipment. The data were analyzed to determine the monthly and overall availability and capacity factor and to identify the duration and causes of forced outages and forced load reductions.
- Performance Tests—These tests verified achievement of guaranteed performance through testing in accordance with applicable codes and EPA/state emission test methods. Testing addressed boiler efficiency, power consumption, and environmental performance. Four performance tests were conducted, as follows:

  - Test 1—Pittsburgh No. 8 coal (January 13-16, 2004)
  - Test 2—50/50 blend of petroleum coke and Pittsburgh No. 8 coal (January 27-31, 2004)
  - Test 3—Illinois No. 6 coal (June 7-9, 2004)
  - Test 4—80/20 blend of petroleum coke and Pittsburgh No. 8 coal (August 10-13, 2004)

1. Startup

First fire of Unit 2 on gas occurred on December 1, 2001, and steam blows were completed on January 15, 2002. Initial synchronization occurred on February 19, 2002, and full load operation on coal was achieved and sustained on May 5, 2002. As with any developing technology, some problems were encountered during startup. The modifications made during startup are listed in a report by JEA [JEA, May 2004]. The cost of these modifications was about $9 million.

2. Performance Testing

The purpose of the test program was to confirm the ability of the CFB to burn a variety of fuels and fuel blends in a cost effective and environmentally responsible manner. The following parameters were measured during these tests: boiler efficiency, CFB sulfur capture, AQCS sulfur and particulate capture, flue gas emissions (particulates, NO_x, SO_2, CO, NH_3, Pb, Hg, HF, and dioxins and furans), and stack opacity. The tests were conducted in accordance with Attachment A to the Fuel Demonstration Test Protocol [JEA, March 2004]. During these tests, data were collected at 100 percent load, 80 percent load, 60 percent load, and 40 percent load. The design performance conditions for the boiler were:

- Boiler efficiency (Pittsburgh No. 8 coal) 88.1 percent HHV
- Boiler efficiency (petroleum coke) 90.0 percent HHV
- Main steam flow at turbine inlet 1,993,591 lb/hr
- Main steam temperature at turbine inlet 1,000 ^{o}F
- Main steam pressure at turbine inlet 2,500 psig
- Reheat steam temperature at turbine inlet 1,000 ^{o}F

a. Test 1—Feeding 100 percent Pittsburgh No. 8 Coal

Test 1, for which the fuel was 100 percent Pittsburgh No. 8 coal, was conducted during the period of January 13-16, 2004. Table 3 presents the results from Test 1.

Table 3 Results from Performance Test 1

Item	Load			
	100%*	80%	60%	40%
Boiler Efficiency, %	90.6			
Fuel Feed Rate, lb/hr	207,232			
Boiler Limestone Rate, lb/hr	56,113			
Main Steam (Turbine Inlet)				
Flow, lb/hr	1,999,971	1,435,543	1,070,747	738,397
Pressure, psig	2,400	2,400	1,800	1,300
Temperature, ^oF	997	1,003	998	999
Reheat Steam (HP Turbine Exhaust)				
Flow, lb/hr	1,794,439			
Pressure, psig	569			
Temperature, ^oF		577	573	566
Reheat Steam (Turbine Inlet)				
Flow, lb/hr	1,794,912			
Pressure, psig	569			
Temperature, ^oF	1,008	1,005	1,006	1,004

*Average of two test periods.

b. Test 2—Feeding a 50/50 Blend of Petroleum Coke and Pittsburgh No. 8 Coal

Test 2, for which the fuel was a 50/50 blend of petroleum coke and Pittsburgh No. 8 coal, was conducted during the period of January 27-31, 2004. Table 4 presents the results from Test 2.

Table 4 Results from Performance Test 2

Item	Load			
	100%*	80%	60%	40%
Boiler Efficiency, %	91.65			
Fuel Feed Rate, lb/hr	194,675			
Boiler Limestone Rate, lb/hr	69,718			
Main Steam (Turbine Inlet)				
Flow, lb/hr	1,847,186	1,442,226	1,049,633	715,464
Pressure, psig	2,401	2,340	1,701	1,062
Temperature, ^{o}F	1,002	1,004	993	997
Reheat Steam (HP Turbine Exhaust)				
Flow, lb/hr	1,774,719			
Pressure, psig	567			
Temperature, ^{o}F		578	558	574
Reheat Steam (Turbine Inlet)				
Flow, lb/hr	1,776,514			
Pressure, psig	567			
Temperature, ^{o}F	1,008	1,006	1,011	999

*Average of two test periods.

c. Test 3—Feeding 100 percent Illinois No. 6 Coal

Test 3, for which the fuel was 100 percent Illinois No. 6 coal, was conducted during the period of June 7-9, 2004. Table 5 presents the results from Test 3.

Table 5 Results from Performance Test 3

Item	Load			
	100%*	80%	60%	40%
Boiler Efficiency, %	88.2			
Fuel Feed Rate, lb/hr	232,632			
Boiler Limestone Rate, lb/hr	68,503			
Main Steam (Turbine Inlet)				
Flow, lb/hr	1,950,345	1,541,871	1,087,192	715,411
Pressure, psig	2,400	2,400	1,700	1,200
Temperature, ^{o}F	999	1,001	1,002	1,001
Reheat Steam (HP Turbine Exhaust)				
Flow, lb/hr	1,874,415			
Pressure, psig	572			
Temperature, ^{o}F		561	575	561
Reheat Steam (Turbine Inlet)				
Flow, lb/hr	1,878,585			
Pressure, psig	572			
Temperature, ^{o}F	1,008	1,007	966	1,004

*Average of two test periods.

d. Test 4—Feeding an 80/20 Blend of Petroleum Coke and Pittsburgh No. 8 Coal

Test 4, for which the fuel was an 80/20 blend of petroleum coke and Pittsburgh No. 8 coal, was conducted during the period of August 10-13, 2004. The fourth test was originally intended to be run feeding 100 percent petroleum coke; however, when it was found that the unit would not operate satisfactorily feeding 100 percent petroleum coke, the test was modified to use a blend of 80 percent petroleum coke and 20 percent coal. Table 6 presents the results from Test 4.

Table 6 Results from Performance Test 4

Item	Load			
	100%*	80%	60%	40%**
Boiler Efficiency, %	91.55			
Fuel Feed Rate, lb/hr	186,934			
Boiler Limestone Rate, lb/hr	50,649			
Main Steam (Turbine Inlet)				
Flow, lb/hr	1,905,935	1,393,557	1,021,784	
Pressure, psig	2,401	2,200	1,450	
Temperature, ^oF	913	981	981	
Reheat Steam (HP Turbine Exhaust)				
Flow, lb/hr	1,719,405			
Pressure, psig	593			
Temperature, ^oF		579	595	
Reheat Steam (Turbine Inlet)				
Flow, lb/hr	1,719,446			
Pressure, psig	592			
Temperature, ^oF	1,001	984	992	

*Average of two test periods.
**Test cancelled due to hurricane.

3. Summary of Operations

Initial operation of the boiler on coal and high ratios of coal and petroleum coke was successful. However, attempts to operate on 100 percent petroleum coke resulted in agglomeration of ash in the INTREX™ and cyclones within about a week, requiring a forced outage to remove the ash buildup. As a result of this problem, blending of coal with petroleum coke was required for reliable operation of the boiler. Initially, this ratio was limited to a maximum of 70 percent petroleum coke, but this was later increased to 80 percent.

Other significant problems encountered with the boiler operation included drying and feed problems with the limestone, stripper cooler plugging, expansion joint failures, and back sifting of dust into the primary air plenum. Problems were also encountered with density control and spray quality in the AQCS. Table 7 presents a summary of performance data for Unit 2 for 2003 and 2004. By-product sales commenced in 2004, and anticipation of selling all by-products led to cancellation of plans to increase the size of the by-product storage area.

The average equivalent availability factor (EAF) for Unit 2 during 2003 and 2004 was 65.8 percent, compared to 84.0 percent for comparably sized coal fired units [NERC, 2004]. Although availability during 2003 and 2004 was not at the desired level and lower than typical for the fleet of comparably sized pulverized coal power plants, this project proved that a large CFB boiler could be operated; and, once identified problems are corrected, availability should significantly improve.

Table 7 Summary of Operating Data

Parameter	Year	
	2003	2004
Power Generated, MWh (gross)	1,791,221	1,459,351
Power Generated, MWh (net)	1,673,981	1,357,427
Heat Rate, Btu/kWh	9,514	9,518
Starts*	15	9
Time on Line, hr	6,843	5,450
Load Factor (gross), %	88.0	90.0
Net Output Factor, %	87.2	89.3
Capacity Factor (gross), %	68.7	55.8
Net Capacity Factor, %	68.2	55.6
Equivalent Availability Factor, %	72.8	58.7
Bed Ash, tons	153,236	96,515
Fly Ash, tons	88,145	75,865
By-product Sales, tons	0	38,312

*Excluding attempted starts.

4. Discussion of Major Problems

Several major problems were encountered during operations that need to be corrected in order for the CFB to meet the desired availability. The most important of these problems are discussed in the following sections.

a. INTREX™

The INTREX™ contains both the loop seal and the intermediate and finishing superheater surfaces. There are three INTREX™ boxes, two with intermediate superheat surfaces and one with finishing superheat surface. Both failure of superheater tube supports and tube cracking occurred. There was also agglomeration of hot loop material within the INTREX™ which resulted in backup of material into the cyclones. As an interim measure, the support system was redesigned, and the finishing superheater bends were replaced with solution annealed bends. At the same time, a new design was developed for the finishing superheater tube bundles. These replacement bundles were installed during the fall 2004 planned outage and have provided satisfactory performance, but the tube support and bundle restraint system continues to experience failures.

The failure mechanism for material buildup appears to be agglomeration under conditions of poor fluidization. This problem has been ameliorated by burning at least 20 percent coal with the petroleum coke. It is hoped that a long-term solution will be achieved within five years, perhaps through elimination of the INTREX™. It is unlikely that FW will use the same INTREX™ design in future CFB units.

b. Expansion Joints

Failures of the hot loop expansion joints, including the cyclone inlet, cyclone outlet, and INTREX™ return leg, were experienced. Minor design modification were instituted which reduced forced outages due to these failures. Further modifications are planned in conjunction with the INTREX™ modifications discussed above and also to the primary air, secondary air, and stripper cooler inlet joints.

c. Stripper Cooler

Bed ash is removed from the boiler through stripper coolers which are designed to remove carbon and cool the ash. The stripper coolers are close-coupled to the boiler through a sliding expansion joint. Numerous failures have occurred associated with these expansion joints. Modifications to these joints have improved operation, but further improvement is needed. Another problem is that the coolers are not able to operate reliably at design rate, resulting in forced de-rating of the unit due to plugging or inadequate flow. Further modification or replacement of the coolers is needed.

d. Limestone Silo and Feed Systems

The original limestone feed system was prone to "rat-holing" and bridging, interrupting the flow of limestone to the boilers. To eliminate the limestone feed interruptions, the lower conical portion of each limestone silo was replaced with a mass flow hopper bottom, and the rotary feed type valves were replaced with hopper outlet slide gate valves, mass flow screw feeders, diverter valves, and stainless steel pipe chutes to the inlets of existing rotary air lock valves. Although this did not completely eliminate problems, it greatly improved operations. Remaining problems may be related to moisture in the finished limestone.

e. Limestone Preparation System

The limestone preparation system was not able to meet the design drying capacity or the design sizing curve. Improvements have been made to the system to improve drying capacity and reduce fines production, but complete resolution of problems has yet to be achieved.

B. Environmental Performance

Table 8 presents a summary of the stack emissions for the JEA CFB boiler. As this table shows, the project met or exceeded all the design values. In general, NO_x, SO_2, and particulate levels were very low, placing this unit among the cleanest coal fired units.

Table 8 Summary of Stack Emissions

Emissions*	Maximum Design Value	100% Pittsburgh Coal	50/50 Pet Coke/Pitt	100% Illinois Coal	80/20 Pet Coke/Pitt
SO_2, lb/10^6 Btu	0.15	0.104	0.101	0.094	0.064
NO_x, lb/10^6 Btu	0.09	0.078	0.070	0.095	0.01
CO, lb/10^6 Btu	0.22	0.027	0.016	0.022	0.01
Particulates, lb/10^6 Btu	0.011	0.004	0.0041	0.0019	0.0024
HF, lb/10^6 Btu	1.57×10^{-4}	$<3.1 \times 10^{-5}$	1.7×10^{-5}	$<4.6 \times 10^{-5}$	$<5.3 \times 10^{-6}$
Lead, lb/10^6 Btu	2.6×10^{-5}	3.5×10^{-7}	8.2×10^{-7}	$<4.4 \times 10^{-7}$	4.4×10^{-7}
Mercury, lb/10^6 Btu (at stack)	10.5×10^{-6}	7.2×10^{-6}	$<8.5 \times 10^{-6}$	0.35×10^{-6}	$<0.07 \times 10^{-6}$
Dioxins/Furans, lb/10^6 Btu	---	6.5×10^{-14}	---	---	---
Opacity, %	10	1.1	1.4	1.3	0.08
Ammonia slip, ppmvd	2	1.17	0.325	<0.5	0.27

*Based on higher heating value at 100% load.

1. Sulfur Removal

Table 9 presents results of sulfur capture in the CFB and AQCS. A problem with the limestone feed led to the practice of overfeeding limestone to the boiler in order to preclude SO_2 excursions at the stack. This resulted in most of the SO_2 removal occurring in the CFB rather than in the spray dryer, as Table 9 clearly shows.

Table 9 Sulfur Capture Results

Parameter	Test Period			
	Test 1	Test 2	Test 3	Test 4
Uncontrolled SO_2, lb/10^6 Btu	7.28	8.40	5.57	5.28
Boiler outlet SO_2, lb/10^6 Btu	0.264	0.240	0.283	0.139
Stack SO_2, lb/10^6 Btu	0.104	0.102	0.094	0.064
Sulfur capture in CFB, %	96.4	97.2	94.9	97.4
Sulfur capture in AQCS, %	2.2	1.6	3.4	1.4
Total sulfur capture, %	98.6	98.8	98.3	98.8

Although the AQCS was run at very low SO_2 capture levels during the test period, it has since undergone optimization which has resulted in excellent performance. SO_2 levels are typically at 100 to 140 ppm with a 20 percent solids recycle slurry with no added lime and a scrubber outlet temperature of 185 ^{o}F. Further optimization is planned to improve performance by increasing slurry solids loading and reducing outlet temperature.

IV. MARKET ANALYSIS

A. Market Potential

The market potential for the CFB technology appears to be excellent. The Nucla project, which was completed in 1992 and demonstrated the CFB technology at a 110 MWe (gross) scale, continues to operate in base load mode. Older CFBs tended to be smaller units, but the Nucla and JEA projects have demonstrated that CFBs are suitable for mid- to large-scale utility applications. The JEA Northside units are the largest CFBs operating in the world. Two boilers in the 250 to 275 MWe range came on line in 2002 at the Red Hills Generation Facility; and two boilers in this size range, burning waste coal, were built at the Seward Station. A project has been announced in Poland that will use a single CFB to supply a 460 MWe supercritical turbine. If built, it will be the largest CFB in the world. The value of the JEA demonstration project in gaining acceptance for larger CFB units is evident.

There are now sixteen CFBs operating in the U.S., including the two at JEA's Northside Station that can be classified as major utility boilers. This represents less than two percent of utility boilers. EIA data indicate that there are an additional 88, generally small, FBC units in operation for industrial, commercial, institutional, and small municipal utility applications. Holt [Holt, 2005] indicates that there are currently a total of eight active projects to provide new utility capacity in the U.S. that will use CFBs. This compares to nineteen pulverized coal projects and two IGCC projects. The eight projects using CFBs represent 33 percent of the total new utility projects, which further supports the view that CFB technology is now a major factor when new capacity is considered.

The reason CFBs are being considered is that a CFB plant costs essentially the same as a pulverized coal plant, while offering several advantages, including high efficiency, superior environmental performance, and a very high degree of fuel flexibility. This latter reason is especially important for situations where cheap alternate fuels, such as petroleum coke, are available. Like all coal based technologies, CFBs are receiving increased interest due to high gas and oil prices. CFBs are also becoming more acceptable to the general public with growing awareness that coal based technologies can operate cleanly. Thus, the performance, cost, and environmental characteristics of CFBs, along with high gas and oil prices, point to a very large potential domestic and foreign market.

While there are a number of differing estimates on the need for new capacity, the EIA [EIA, 2004] estimates that an additional 281,000 MW of new capacity, including coal-fired heat and power, will be needed in the next 20 years. The EIA projects that nearly one-third of this new capacity will be coal fired, with most of this coal-fired capacity coming on line after 2015 as coal becomes increasingly competitive with oil and gas. There are also approximately 300,000 MWe of existing coal-fired U.S. capacity that is 15 to 50 years old and can be considered as a candidate for retrofit with CFB boilers.

B. Economics

The Participant did not provide any information on the capital or operating costs for a greenfield CFB installation. Therefore, the following economic estimates are for rough guidance purposes only.

1. Capital Cost

Actual capital costs for this project are shown in Table 10. Costs in this table include the cost for Unit 2 plus half the cost for facilities common to Units 1 and 2. These costs are those that were actually incurred for the Northside 2 retrofit. While there is always some difficulty in applying the cost of a retrofit to another installation, several factors unique to this project make the above costs particularly difficult to apply to other potential retrofits. One is that JEA simultaneously carried out the same retrofit on Unit 1 (not part of the DOE project). A substantial part of the costs for the combined retrofits involved work that was done for systems that are used by both units (e.g., the cooling water system). The total cost was simply divided by two to get the Unit 2 share of the costs. However, the scale of these shared systems was 600 MWe, which would result in a lower cost due to economies of scale, than if two separate 300 MWe projects were carried out. Thus, the cost for common systems may not be representative of cost for a single 300 MWe retrofit.

Table 10 Summary of Capital Costs

Item	Cost, 1999 $
Unit 2 Design	
Project Management and Support	3,164,454
Permitting	2,390,444
Preliminary Design	2,175,695
Engineering/Detailed Design	23,371,293
Unit 2 Design Subtotal	31,101,886
Unit 2 Construction and Startup	
Project Management and Support	5,826,510
Environmental Monitoring	29,871
Boiler Equipment/AQCS	119,043,822
Balance of Plant Equipment	35,070,257
Turbine/Generator Refurbishment and Upgrade	15,588,735
Unit 2 Construction and Startup Subtotal	175,559,195
Common Design	
Engineering/Detailed Design	2,932,126
Common Design Subtotal	2,932,126
Common Construction and Startup	
Project Management and Support	20,294,905
Environmental Monitoring	115,751
Boiler Equipment/AQCS	9,141,358
Balance of Plant Equipment	29,254,423
Fuel Handling Equipment	52,992,980
Common Construction and Startup Subtotal	111,799,417
Total Capital Cost	321,392,624
Capital Cost, $/kW (gross)	1,070

The second factor that may cause the JEA retrofit costs to be atypical is that Unit 2 was shut down for fourteen years prior to the beginning of the project. Even if a facility is properly mothballed, the longer it is shut down, the more work is required to bring it back to operational status. It is unclear whether the plant was mothballed or simply shut down in 1983. Therefore, the cost of restoring the various systems that were not replaced may not be representative of other retrofit projects.

A major cost benefit for a retrofit is the ability to use the same turbine/generator set. Refurbishing the turbine/generator cost approximately $15.6 million, while a comparably sized new system would be expected to cost around $35 million. Table 11 illustrates the varying levels of effort needed to refurbish/replace individual components and highlights the need to consider each retrofit individually.

Published data indicate that most new coal-fired power plants will cost between $1,375/kW and $1,700/kW. This indicates that retrofitting Unit 2 saved between $80 million to $170 million compared to current new plant costs. It is estimated that a greenfield 300 MWe CFB plant would cost about $1,500/kW or $450 million.

2. Operating Cost

Estimated operating and maintenance costs (2002 dollars) for a new 300 MWe CFB-based power plant, using the technology installed at JEA, including lessons learned are given below:

Operating labor (1 percent of capital cost)	$ 4,500,000/yr	
Maintenance (2 percent of capital cost)	$ 9,000,000/yr	
Fixed O&M cost		$13,500,000/yr
Fuel cost ($48/ton)	$32,500,000/yr	
Limestone ($10/ton)	$ 1,700,000/yr	
Other (lime, water, ash disposal, etc.)	$ 650,000/yr	
Variable O&M cost		$34,850,000/yr

Fuel cost is based on coal with a 12,000 Btu/lb higher heating value, a unit heat rate of 9,500 Btu/kWh, a 65 percent capacity factor, and a coal cost of $2/million Btu. Limestone cost was based on a usage rate of 0.25 tons/ton of coal. Other variable costs were based on two percent of coal cost.

Table 11 Upgrades to Common Facilities

Equipment/System	Action (Comment)
Steam Condensing System	
Heat exchanger	Re-tubed (titanium replaced Al/brass)
Condensate pumps	Restored to reliable service
Drains, piping	Inspected and cleaned
Circulating Water System	
Circulating water pumps	Replaced pumps and motors (structure refurbished)
Piping/valves	Cleaned and repaired
Traveling screens	New screens installed
Intake canal	Inspected for integrity
Boiler Feed System	
HP feedwater heaters	Replaced
Boiler feed pumps	Rotating elements replaced
Feedwater piping	Inspected, hydrotested, cleaned
Attemperation piping	Replaced, hydrotested
Condensate Handling System	
Deaerator heater	Replaced
Storage tanks	Replaced
Bitter water piping	Replaced (bitter H_2O–demineralizer output)
Feedwater heaters	Replaced one tube bundle and two entire heaters
Condensate piping	Inspected, cleaned, hydrotested (some piping replaced)
Flash chamber, hot well, flashpot	Inspected, refurbished, cleaned
Condensate Polishing	
Condensate polishing system	Entire system replaced
Main Steam System	
Piping	Replaced (40% bypass installed)
Reheat Steam System	
Piping	Replaced (40% bypass installed)
High Pressure Extraction	
Piping	Inspected, hydrotested
Low Pressure Extraction	
Piping	Inspected, hydrotested
480 Volt Power Supply	
Substation & MCC	Replaced
Supply system	Inspected (some circuits decommissioned/removed)
4160 Volt Power Supply	
Substation and MCC	Replaced
Supply system	Inspected (some circuits decommissioned/removed)
DC Power Supply	
System	Replaced (installed tie-in with Unit 3 system)

3. Economics

Table 12 presents economics based on the capital and operating costs presented above. These are estimated economics based on a 300 MWe CFB plant at a greenfield site.

Table 12 Economics of Electricity Production Using a 300 MWe CFB Boiler

Cost Factor	Base, $\$10^3$	Current Dollars		Constant Dollars	
		Factor	mils/kWh	Factor	mils/kWh
Capital Charge	450,000	0.160	42.15	0.124	32.67
Fixed O&M Cost	13,500	1.314	10.38	1.000	7.90
Variable Operating Cost	34,850	1.314	26.81	1.000	20.40
Levelized Cost of Electricity			79.34		60.97

These economics are based on the production of 1,708 million kWh/yr and indicate an expected cost of 6 to 8¢/kWh. The availability of a low-cost fuel (for example, petroleum coke) that was much cheaper than the bituminous coal used in this estimate would substantially reduce the cost of electricity.

V. CONCLUSIONS

This project demonstrated the successful operation of a large CFB boiler for the production of electric power. The JEA units are currently the largest CFBs ever constructed. When technology is scaled up, it is not unusual for problems to occur, and this project was no exception. A number of problems arose, most of which were successfully addressed through modifications to equipment or operating procedures, although some issues remain unresolved. A goal of the project was to conduct performance tests burning four different fuels, one of which was 100 percent petroleum coke. When it was found that the unit would not operate satisfactorily feeding 100 percent petroleum coke, this test was modified to use 80 percent petroleum coke and 20 percent coal. Since, during the period of the project, petroleum coke was the cheapest fuel, inability to operate on 100 percent coke resulted in an increased cost of electricity for JEA.

In general, this project met the goals established in the SOW. It demonstrated the feasibility of scaling up the CFB technology, tested different fuels and limestones, characterized the by-products, determined environmental performance, and provided data to permit economic evaluation of the CFB technology. However, during the timeframe of this project, the unit did not quite achieve the reliability or cost targets desired by JEA. This should improve as modifications to the unit are implemented over time.

The lessons learned from operation of this project will lead to design modifications that will avoid most of the problems encountered with the JEA unit. The very low level of emissions and the ability to burn fuel blends containing a high percentage of petroleum coke make CFB technology an attractive option for new units or re-powering of existing units.

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