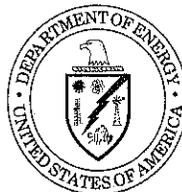


# 4<sup>th</sup> Annual Clean Coal Technology Conference



## The Global Opportunity TECHNICAL PAPERS

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National Mining Association  
Foundation For America's Future

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# **Session III**

## **Advanced Technologies for Power/Industrial Applications**



# **TRI-STATE'S NUCLA CFB DEMONSTRATES BENEFITS OF CLEAN COAL TECHNOLOGY PROGRAM**

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## **ABSTRACT**

In August of 1988, the U.S. Department of Energy (DOE) added the 110 MWe Nucla Station to its first round of Clean Coal Technology (CCT) Demonstration Projects. The intent of the program was to demonstrate the successful re-powering of an aging 36 MWe stoker-fired station with the first, utility-sized circulating fluidized bed boiler in the U.S. In cooperation with the Electric Power Research Institute (EPRI), a detailed Test Program was conducted on the unit in order to quantify and assess the unit's combustion and emissions performance, fuel flexibility and commercial viability. Completed in 1991, the results of this program were extensively documented and reported in a series of EPRI, DOE and international publications. To the industry, these results served as a springboard for unit scale up along with new design developments and technology innovations.

At the conclusion of the Demonstration Program, the unit began commercial operation with an operating availability below industry standards. Using the experience and knowledge gained through the Demonstration Program, Tri-State Generation and Transmission Association Inc., which had recently acquired the station during a bankruptcy reorganization, successfully completed upgrades to the unit in several areas that previously demonstrated poor reliability.

Since these modifications were completed in the fall of 1993, the unit has demonstrated a high level of reliability and availability; exceeding its pro forma operating goals to date. Combined with new fuel and power sales contracts, these changes have not only resulted in an economic turnaround at the station, but also have established the project as one of the first to begin repayment of DOE CCT funds as outlined in the Cooperative Agreement of 1987.

## INTRODUCTION

The original Nucla Station was commissioned in 1959 and consisted of three stoker-fired boilers and matching 12 MWe turbine-generator sets for a combined station capacity of 36 MWe. By 1980, the station had fallen to the lowest position on the utility's dispatch order as the result of low efficiencies and increasing maintenance costs. In 1985, construction was started on a repowering project that included a new 925 klb/h (420,000 kg/h) Ahlstrom Pyroflow® circulating fluidized bed (CFB) boiler and 74 MWe turbine-generator, bringing the gross output of the station to 110 MWe.

When the Nucla CFB was commissioned in 1987, it was the largest application of CFB technology in the world and the first of its kind in the U.S. utility industry. In order to assess the benefits of the technology, the Electric Power Research Institute (EPRI) and the U.S. Department of Energy (DOE) sponsored a three year Demonstration Test Program on the unit between 1988 and 1991. During this period, the operating history and performance of the station were reported extensively in the literature (References 1 through 8).

In April 1992, Tri-State assumed ownership of the Nucla Station from the Colorado-Ute Electric Association (CUEA) as part of a bankruptcy reorganization. At the time, life-to-date commercial performance statistics for the station were below industry standards. This resulted from several factors including CUEA's financial problems, high production costs, low system load requirements, impacts from the Demonstration Test Program, and reliability problems in certain areas of the original design (Reference 9). In 1992, Tri-State embarked on a program to improve the availability of the Nucla Station to a minimum annual level of 80 percent. This was motivated in part by incentives outlined in a new power sales agreement. As part of this program, several areas of the original design were identified where upgrades to improved design standards would increase the overall reliability and

operating performance of the station. A description of these upgrades and their current status after nearly two years of operation, along with a summary of various problems with the original as-installed equipment that was replaced in 1993, are the main focus of this paper. Performance statistics are used to demonstrate the improved reliability and commercial success of the station, and the repayment of Round 1 CCT funds to the DOE.

## DESCRIPTION OF FACILITY

The Nucla CFB generates 925 klb/h (420,000 kg/h) of steam at 1510 psig (10.4 MPa) and 1005°F (540°C) utilizing a twin combustor design with a height of approximately 110 feet (33.5 meters) and a total plan area of 1055 square feet (98 m<sup>2</sup>). Each top-supported combustion chamber is nearly square in cross section and consists of water wall membrane construction with a refractory-lined lower section (see Figure 1). Each chamber is equipped with a bottom-supported, refractory-lined hot cyclone having a

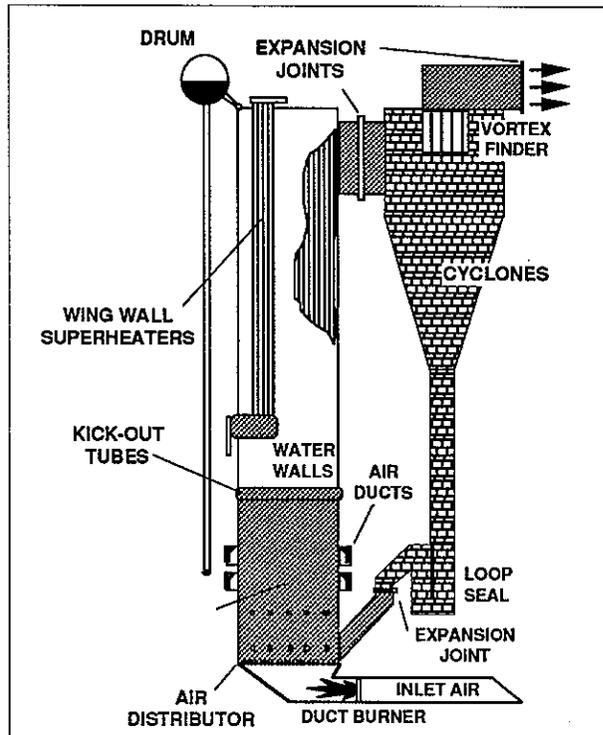


FIGURE 1. SIDE VIEW SCHEMATIC OF THE 110 MWe NUCLA CFB.

diameter of approximately 23 feet (7 m). The outlets of the cyclones join together and enter a common convection pass. Captured solids are recycled to the lower combustion chambers through loop seals located near the bottom of each chamber. The two combustion chambers have individual systems for fuel, air, and sorbent supply and ash removal. Fuel firing to both chambers must be matched since both share a common steam/water circuitry including the steam drum.

The water walls of the two combustion chambers rely on natural circulation only. Saturated steam exiting the steam drum travels to the steam-cooled convection cage and then to the primary superheater located in the convection pass. From here, it splits into parallel flow paths and through primary attemperators before entering the new wing wall secondary superheaters located in the upper region of each chamber. There are four parallel wing walls per combustor. After exiting these surfaces, steam travels through a second set of attemperator stations to the final superheater located in the upper convection pass.

## PROJECT SCOPE

The following areas of the boiler were identified by Tri-State in 1992 as candidates for upgrade and/or repair:

- Replacement of the secondary superheaters.
- Retrofit of air distributor nozzles.
- Retrofit of kick-out water wall tubes at the refractory interface in the lower combustor.
- Replacement and extension of lower combustion chamber refractory with new materials.
- Replacement of cyclone, cyclone downcomer and loop seal refractories with new materials.
- Replacement of damaged water wall tubes comprising approximately 30% of the overall water wall surface area.
- Replacement of loop seal and cyclone inlet expansion joints.
- Modifications to combustor wall boxes around penetrations into the boiler.
- Replacement of bent tubes around primary and secondary air port penetrations into the lower combustor region.

After careful review of several options, the original boiler manufacturer, Pyropower Corporation along with its subsidiary Pyropower Energy Services Company (PESCO), were selected for the engineering and construction/erection of these upgrades. In order to minimize unit downtime and the loss of generating revenue, Tri-State outlined a 10-week construction schedule with bonus and penalty clauses set around this interval. A project payment schedule was defined based on the delivery of materials and/or the completion of major work items. This payment schedule also included the satisfactory completion of a set of boiler performance guarantees at the conclusion of the project.

Following the completion of this effort in the third quarter of 1992, a period of detailed engineering design and review was initiated. This included the delivery of engineering drawings for all major equipment, details regarding home office and site management support, projected labor and material delivery schedules, demolition and erection plans, quality assurance plans, definition of site and contractor responsibilities, safety and dust control plans, site access provisions, and laydown and work areas.

## SUMMARY OF DESIGN UPGRADES/ REPAIRS

The upgrades and repairs to equipment areas on the Nucla CFB were designed to address reliability problems that impacted the station's availability. In the section below, the original designs are summarized along with some of the problems that developed over the subsequent five years of unit operation. This is followed by a description of the upgraded design in each area and its effectiveness over the past two years of service.

### Secondary Superheaters

Secondary superheaters are situated in the upper furnace section of both combustion chambers with attemperator spray stations located along the inlet and outlet headers. In the original

design, these superheaters consisted of four parallel panels per chamber that wrapped around the inside of three walls of the upper combustor area (see Figures 2 and 3). The panels were positioned in close proximity to the water wall surface and were supported at the base by water wall tubes that kicked out into the combustor cross-section. Each of the panels were comprised of a series of parallel tubes, with the lower half of each panel forming the inlet flow path and the upper half forming the return path.

Problems developed with this arrangement as a result of erosion and high temperature overheating. Tube erosion was attributed to the downward flow of solids along the walls of the boiler. Erosion occurred along the top tubes of the panels, in areas around the water wall support tubes, in the corners of the panels, at tube bends forming the return path, on water wall tubes situated behind the superheat panels, and at any location where the vertical alignment of tubes had been compromised. Vertical tube misalignment progressed during the first five years of unit operation and appeared to result from a combination of thermal expansion, overheat and inadequate support.

High temperature overheat of secondary superheater tubes became a serious problem following several years of unit operation and resulted in a series of tube failures during 1991. Data indicated excessive metal temperatures at full-load on the upper tubes forming the steam flow return path. As a temporary solution, inlet attemperator spray flows were increased to control these temperatures. This resulted in a 50°F (28°C) decrease in the turbine inlet steam temperature and an associated compromise in station efficiency.

A condition assessment of the existing panels indicated that a significant portion of the original surfacing would require replacement should this design concept be pursued. Ultimately, the decision was made to replace the wrap-around panels with wing wall surface similar to that used on newer Ahlstrom Pyropower installations.

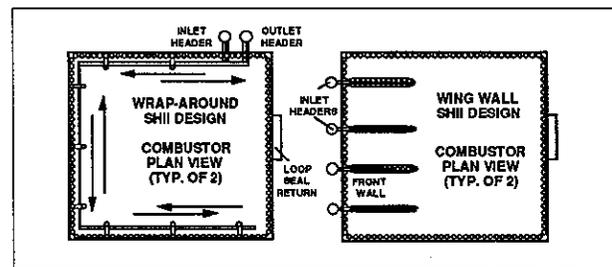


FIGURE 2. PLAN VIEW - ORIGINAL WRAP-AROUND & UPGRADED WING WALL SHII DESIGN.

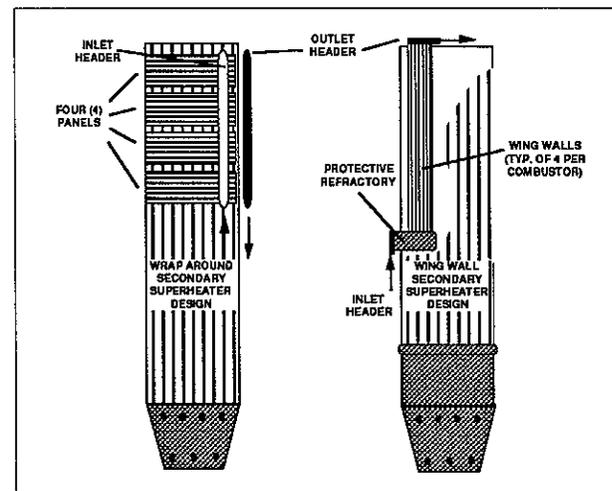


FIGURE 3. ORIGINAL SHII WRAP-AROUND & UPGRADED WING WALL DESIGN.

Each combustion chamber is now equipped with four parallel wing wall superheaters that extend approximately 5 feet (1.5 m) into the plan area over a distance covering half the overall height of the combustor. Superheated steam enters the panels through tubes that penetrate the front wall of the boiler and exit through the roof. A new series of inlet and outlet headers tie into existing headers near the attemperator spray stations. The lower portion of each wing wall panel contains a protective refractory covering and thermal spray coating to guard against erosion. A flexible wall box on the outlet (combustor roof) accommodates upward thermal expansion of the panels.

This modification has been completely successful since its installation during the 1993 outage. There have been no problems related to overheating or erosion on any surface, and the expansion system has performed without incident.

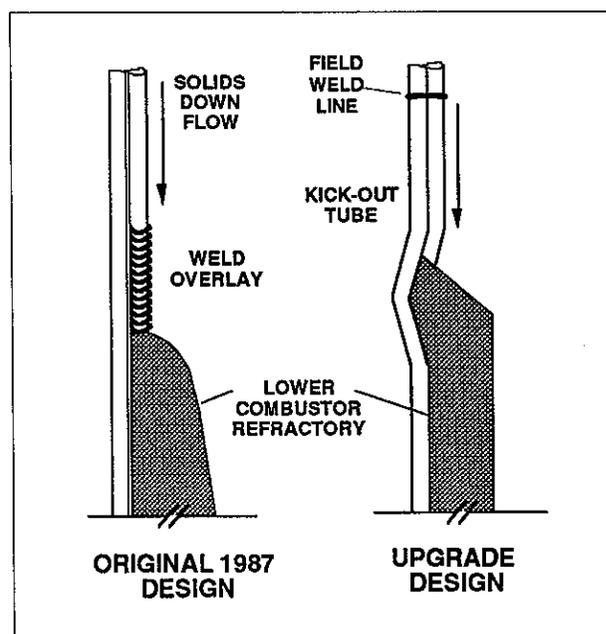
### Water Wall "Kick-Out" Tubes

Throughout the operating period between 1987 and 1992, water wall tube erosion was observed at the refractory interface in the lower combustion chambers (References 2 through 7). This erosion was more pronounced along the front wall, the front half of the side walls, and in the rear corners of both combustion chambers. A protective weld overlay was originally applied at these locations in anticipation of this erosion. In localized regions, erosion of this overlay had formed abrupt discontinuities which resulted in undercutting of the underlying tube, and/or the deflection of downward flowing solids onto adjacent tubes. This was particularly true of weld overlay applied to the membrane between tubes despite care taken to ensure a smooth transition on the upper portion of this protective weld.

Erosion in these areas initially was addressed by the operating group through periodic inspections, grinding and smoothing of any rough surfaces that had formed, and the reapplication of weld overlay in areas below acceptable minimum tube wall thicknesses. Despite these efforts, tube leaks continued to be an unpredictable and unpreventable problem. In addition, video inspections on the inside of the water wall tubes raised concerns over the tolerable frequency with which weld overlay could be reapplied to these areas.

To resolve this problem, a decision was made to retrofit the straight section of water wall tubes at the refractory interface with Ahlstrom Pyropower's proprietary bent ("kick-out") tube design as shown in Figure 4. With this design, downward flowing solids disengage from the water walls at the point where the tubes bend back from the vertical plane. Separated solids then impact the refractory away from the tube surface and are distributed outward into the combustion zone.

This design was implemented around the perimeter of both combustion chambers at the refractory interface. Four shop-fabricated water wall sections (with kick-out bends) were used



**FIGURE 4. COMPARISON OF THE ORIGINAL AND UPGRADED WATER WALL DESIGN AT THE REFRACTOR INTERFACE IN THE LOWER COMBUSTOR.**

along the width of each wall. Special attention was given to tube alignment between existing and new water wall surface, and to the quality and smoothness of all adjoining welds. As with the application of this design on new boiler installations, protective weld overlay or thermal spray coating was not applied to water wall tubes in this location.

This retrofit has been completely effective in eliminating erosion at the refractory interface in the lower combustor. However, at various points along certain water wall sections, erosion has been observed at the field weld line situated on the straight section of water wall approximately 0.5 m (1-2 ft.) above the kick-out elevation (see Figure 4). The cause of this erosion is believed to result from a slight misalignment between the original, upper tubes and the kick-out tubes at these locations. During the 1994 outage, approximately 50 tubes were repaired with an application of weld overlay to restore the tube wall thickness to a safe operating level. These areas continue to be monitored closely by the station during outages.

## Air Distributor

Approximately 50% of the combustion air flow is delivered to the process through a water-cooled air distributor situated at the base of each combustion chamber. This air flow is supplied by the primary air fan. After being preheated by a tubular air heater, it arrives at the air distributor inlet at 55-60 in.wg. (13.7-14.9 kPa) and 450°F (220°C). The air distributor is designed with a sufficient pressure drop to produce a uniform distribution of air flow across its entire cross section. Each floor tube is separated by a membrane containing penetrations for combustion air flow. These penetrations extend through a thin, refractory floor covering on the combustion chamber side.

A comparison of the original and upgraded nozzle designs used on these floor penetrations is shown in Figure 5. Several problems developed with the original multi-hole nozzle design including backsifting, retention and erosion. Backsifting of bed material from the combustion chamber into the windbox occurred primarily at low load and was more pronounced at locations around the perimeter of the air distributor. Nozzle retention and erosion were more severe around the perimeter of the air distributor and in front of the loop seal entrance to the boiler. Some of the problems associated with nozzle retention resulted from defects in the original installation and the partial success of subsequent repairs.

The upgraded air distributor design consists of pigtail nozzles that are standard on new Ahlstrom Pyroflow® boiler installations. The shape of the pigtail nozzle prevents backsifting into the windbox and precludes the need for a cap on the combustion chamber side. In order to maintain a similar air distributor pressure drop with the new design, approximately 80 percent more pigtail nozzles were required as compared to the number of multi-hole nozzles used on the original air distributor design. Rather than retrofit the existing floor tube arrangement with pigtail nozzles, time constraints dictated the complete replacement of the air distributor with a shop fabricated

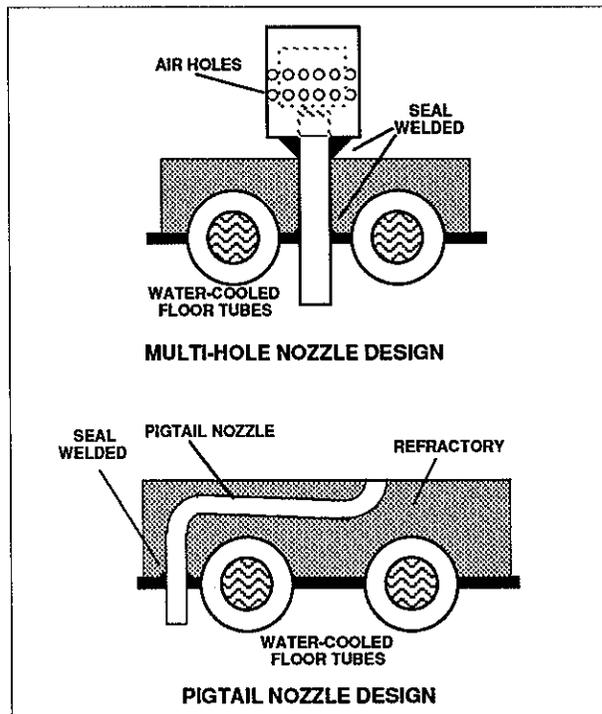


FIGURE 5. COMPARISON OF ORIGINAL MULTI-HOLE AND UPGRADED PIGTAIL NOZZLE DESIGNS.

assembly.

Since its installation in 1993, the new air distributor has been effective in reducing overall maintenance requirements compared to the original multi-hole nozzle assemblies. However, the pigtail nozzles have been susceptible to pluggage by bed particles that become lodged in the first bend directly below the nozzle opening, or at the crimped nozzle opening itself. Given a sufficient quantity of nozzles, this can eventually lead to an increase in the air distributor pressure drop. Unit cycling, particularly frequent start ups and shut downs, appeared to exacerbate the problem.

During restart of the unit following the 1993 outage, nozzle blockage forced a unit derate of approximately 10% because of primary air fan capacity limitations resulting from the increased pressure drop across the distributor. Compared to the rest of the air distributor, nozzle blockage was more pronounced along the first 8 to 10 rows adjacent to the sloped side walls forming the lower combustors. Since the Nucla CFB utilizes side-mounted ash coolers, blockage of these

nozzles also caused stagnant areas of bed material to form in front of the cooler inlets, thereby posing a problem with bed drain removal and combustor solids inventory control.

Ultimately, this problem was addressed by rounding out the ends of the crimped nozzles, and by compartmentalizing the wind box under the air distributor. Small plenum chambers were installed internal to the wind box around air nozzles situated directly in front of the ash coolers. A new dedicated, high pressure air source provides a fixed quantity of air to each of the new plenum chambers regardless of unit load.

This modification, completed during the 1994 annual outage, has performed well and no further unit derates or significant problems with ash removal have been experienced. Currently, the station cleans all pigtail nozzles during semi-annual outages as a matter of routine preventive maintenance.

#### Lower Combustor Refractory

The original refractory installation in the lower combustion chamber consisted of an abrasion resistant, hydro-bonded gunnite that extended approximately 12 feet (3.7 m) above the air distributor along the water wall surface. Along this distance, the refractory tapered from a 2 feet (0.6 m) thickness at its base to a 3 inch (75 mm) shelf at the water wall interface (see Figure 6). Studs and anchors were used to secure the refractory to the water wall surface.

During the first five years of operation, significant cracking, spalling and breakage were observed in many areas of the lower combustion chambers. Despite repairs, further deterioration caused periodic operating problems, including blockage of the bottom ash drain lines. Refractory separation from the water wall also occurred along the water wall interface as the result of "jacking" by bed material in combination with inadequate anchoring.

In order to correct these problems, a thinner application of high strength, low cement gunnite was used to replace the original installation. The

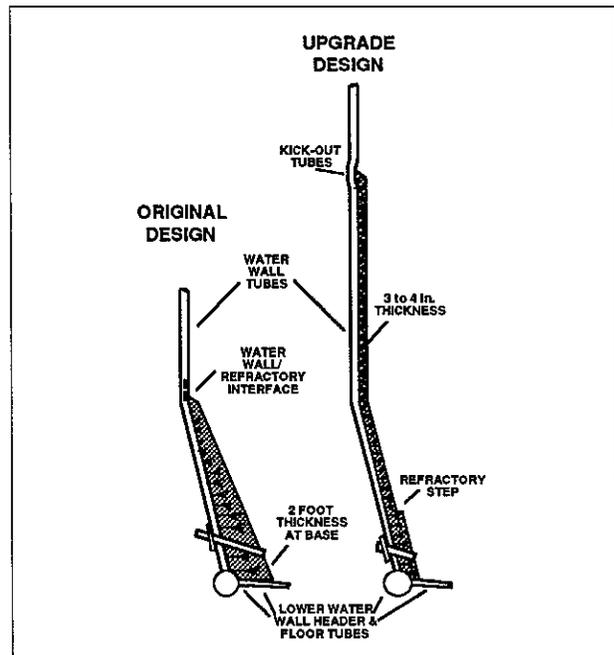


FIGURE 6. REFRACTORY CONFIGURATIONS IN THE LOWER COMBUSTOR.

new refractory extends to a distance approximately 29 feet (8.8 m) above the air distributor to the new "kick-out" tube location (see Figure 6). This extension was required to accommodate the exposure of existing water wall surface situated directly behind the original wrap-around superheat panels (see Figures 2 and 3). The higher heat flux to these newly exposed steam generating tubes following the removal of these panels was offset by a reduction in heat absorption in the lower combustion chamber from the extension of the refractory covering.

The refractory varies in thickness between 3 to 4 inches (75 to 100 mm) and is secured to the water walls using threaded studs. Stainless steel wire needles are imbedded in the refractory to provide additional strength. The sloped side walls of the lower chamber contain an anchored refractory shelf designed to interrupt the downward flow of solids along the walls.

This upgrade has performed extremely well, operating over the past two years since the original installation without any major incident or repair to report. Outside of periodic, planned maintenance, no further changes are anticipated.

### Cyclone and Loop Seal Refractory

All internal surfaces on the cyclones, downcomer legs, loop seals and recycle return legs were originally lined with a double layer of insulating and hydro-bonded, abrasion resistant refractory. Both layers were applied to a combined thickness of 12 inches (300 mm) and were anchored to the inside metal surface. Refractory brick was not used in the original installation.

Cracking, spalling and general breakage occurred in many of these areas including the scroll area, bullnose, cones and loop seal arches (see locations in Figures 7 and 8). In some areas, the loss of refractory created hot spots on the outside shell. The accumulation of refractory pieces in the loop seals also, on occasion, impeded the flow of recycle material back into the lower combustion zone. In 1990, several of these areas were repaired and the loop seals were rebuilt using a combination of brick, castable and gunned refractories. The overall condition of these areas continued to deteriorate in the ensuing years of service. Erosion had also progressed to an unsatisfactory level along the target area of the cyclones.

During the outage to upgrade the boiler, all of these refractories were removed with the exception of the cyclone outlet duct. Three layers of insulating and abrasion resistant refractory brick were applied over most of the inside surfaces (see Figure 9). The exception includes the cyclone roof, scroll piece, bullnose and portions of the return leg. Most of these areas were gunned and/or formed with an insulating layer and a high strength, low cement abrasion resistant layer that are anchored to the shell. In addition, the loop seal floors and arches were formed and cast with a high density, high strength material. Stainless steel wire needles were used with most of the gunned or cast refractory for additional strength.

Refractory brick in the cyclone barrels and conical sections are anchored to the outside shell using a proprietary, pivoting anchor design that accommodates some relative movement with the

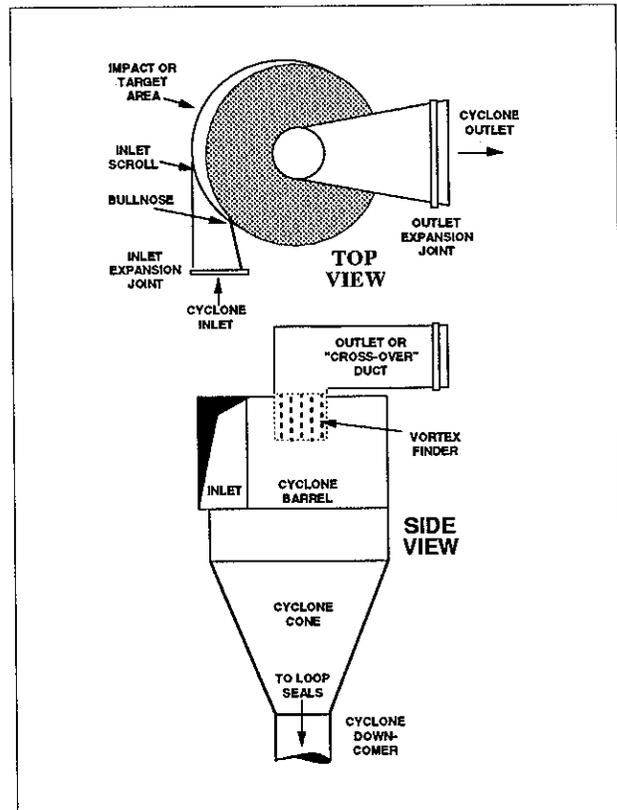


FIGURE 7. SCHEMATIC OF CYCLONES ON THE 110 MWe NUCLA CFB.

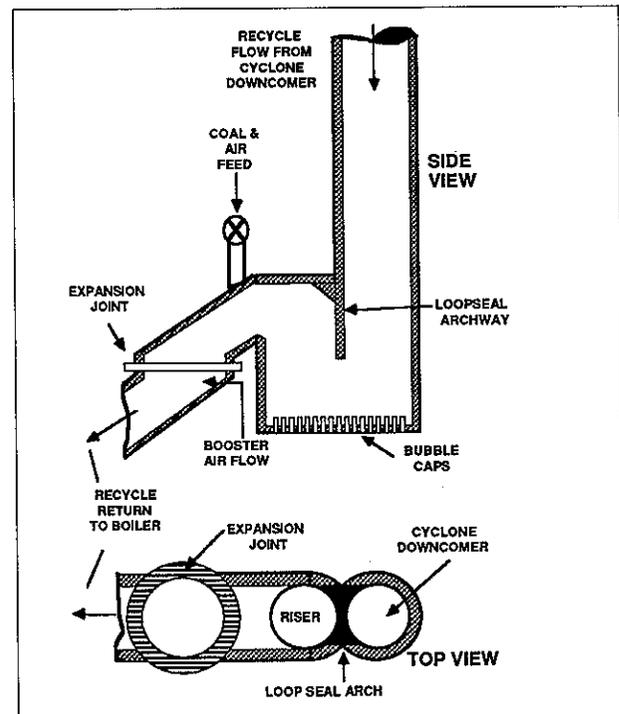


FIGURE 8. SCHEMATIC OF THE LOOP SEAL ARRANGEMENT ON THE 110 MWe NUCLA CFB.

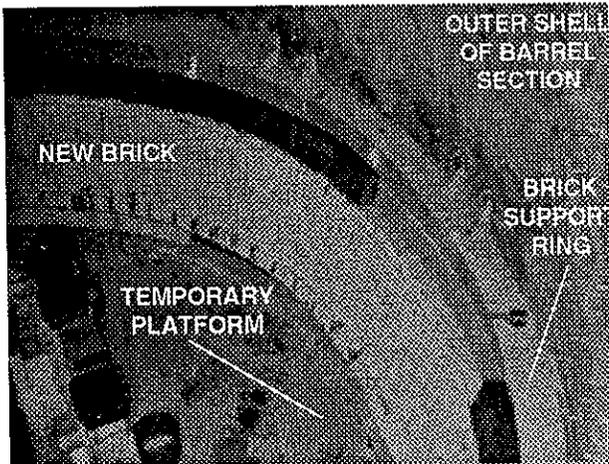


FIGURE 9. PHOTOGRAPH SHOWING NEW BRICK BEING INSTALLED IN THE BARREL SECTION.

outside shell. The bricks are shaped and installed using wedging techniques to interlock the brick via pressure. A thin layer of mortar is used along all brick joints. In order to support the brick along its height, steel shelves were welded at approximately 10 foot (3 m) intervals around the perimeter of the cyclone barrels and conical sections.

An inspection of the cyclones and loop seals in 1994 following the first year of service confirmed the overall improvement in refractory integrity with the new design. Except for the cyclone inlet scroll piece (see Figure 7 for location), only minor, routine refractory maintenance was required in various areas of the installation. The scroll piece appeared buckled and showed signs of significant breakage along with failure of the support anchors. To correct the problem, a more substantial anchoring system was added, allowances were made for expansion and movement, and a higher strength of castable material was installed. The effectiveness of these changes will be assessed during the 1995 annual fall outage.

#### Replacement of Damaged Water Walls

During the commissioning phase of the repowered Nucla Station in 1987, an overheat incident occurred that produced permanent displacements (bows) in five of the eight water walls that form the two combustors. These bows occurred at a frequency corresponding to the location of the



FIGURE 10. PHOTOGRAPH OF REMOVED SECTIONS OF WATER WALL SURFACE (NOTE WARPAGE OF ORIGINAL)

outside buckstays over a distance covering approximately two-thirds the height of the furnace shaft. The resulting displacement of the water walls in the vertical plane was on the order of plus or minus two inches (50 mm, see Figure 10).

Over a period of time, erosion was observed along areas of the warped water walls. Efforts to address this erosion included weld overlay and thermal spray coatings, neither of which were entirely successful due to the roughness of the damaged surface.

During the upgrade outage, these sections of damaged water wall were removed and replaced. Shop fabricated sections of water wall panel (four panels per wall) up to 60 feet (18 m) in length were used in the repair. Special attention was given to tube-to-tube alignment and to the quality and smoothness of all tube and membrane welds.

Based on inspections following the first year of service in 1994, this repair appears to have been effective in eliminating erosion on boiler water wall surfaces caused by deformation. As mentioned earlier in the discussion of the kick-out tube retrofit, some erosion has been observed along the upper field weld line at a distance approximately half way up the height of the combustor. These areas continue to be monitored closely.

### Miscellaneous Modifications

Wall boxes are used around all penetrations into the boiler that are formed by bending water wall tubes out of plane. These boxes are placed around the bent tubes and are then seal welded to the outside of the boiler and filled with refractory. In the original installation, all wall box attachments were welded to the crown of the water wall tubes along the vertical dimension as shown in Figure 11. This method of attachment caused stress cracks to develop and resulted in several tube leaks. During the outage, the vertical side plates on all wall boxes were removed and the original attachment area was ground smooth and dye checked for cracks. The wall boxes were then modified such that the vertical side plate is now welded to the membrane rather than to the crown of the tubes. This modification was completed on over 45 wall boxes per combustion chamber.

During the operating period leading up to the upgrade outage, a series of tube leaks occurred around bends forming the primary and secondary air ports in the lower combustion chamber. Metallurgical analysis of these sections indicated signs of stress corrosion cracking. These compound bent tubes (two tubes per port) were replaced with shop fabricated, annealed tubes with the bends formed in a single plane. Each port opening is now formed from a total of four of these tubes, two on each side of the port opening.

Inspections during the operating period leading up to the upgrade outage indicated the possi-

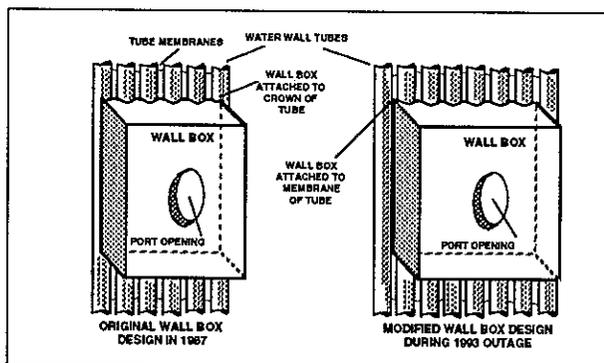


FIGURE 11. SCHEMATIC OF ORIGINAL AND UPGRADED WALL BOX INSTALLATION.

bility of binding in the expansion joints located at the cyclone inlets and recycle return legs. Since the performance of these joints is critical to maintaining refractory integrity, particularly with regards to anchoring and bonding of the refractory to the shell, the decision was made to replace these joints with upgraded designs. The cyclone inlet joint consists of the upgraded Ahlflex® design which provides improved flexing and sealing concepts. The expansion joint on the recycle return leg is designed to prevent binding during expansion and contraction. Some modifications were required to the air purge piping to this joint during the 1994 outage. The other modifications outlined above have performed well over the past two years of service.

A summary of the design upgrades, including changes to the original material specification, is outlined in Table 1.

DESIGN AREA	UPGRADED DESIGN	MATERIALS	ORIGINAL DESIGN	MATERIALS
• AIR DISTRIBUTOR	Pigtail Nozzles	Stainless	Multi-holed Nozzles	Stainless
• SECONDARY SUPERHEATERS	Wing Walls (4 panels per combustor)	SA213-T22 1.5 in. od	Wrap-around (4 panels per combustor)	SA213-T11 SA213-T22 1.5 in. od
• WATER WALL "KICK-OUT TUBES"	Kick-out Tubes at refractory interface	SA210-A1 2.5 in. od tubes 1/4" wall membrane	Straight tubes	SA210-A1 2.6" od tubes, 1/4 in. wall membrane
• WARPED SECTIONS OF WATER WALL	Replaced Approx. 30% of original water wall	SA210-A1 2.5 in. od tubes 1/4" wall membrane	Straight tubes & membranes	SA210-A1, 2.6" od tubes, 1/4 in. wall membrane
• LOWER COMBUSTOR REFRACTORY	High temp., abrasion resistant, pneumatic ~ 3" to 4" thick	Low Cement Gunitite (LC3)	Hydro-bonded Pneumatic, up to 24 in. thick at base	Abrasion resistant gunitite (ARG)
• CYCLONE REFRAC. - ROOF	Used original anchors and materials	abrasion resist. & light weight gunitite (LWG)	Insulating & abrasion resist. layer	ARG & light weight gunitite (LWG)
- BULLNOSE & SCROLL PIECE	New anchoring and handface refractory	Low cement & light weight gunitite	Insulating & abrasion resist. layer	Abrasion resist. & light weight gunitite
- BARREL, CONE & DOWNCOMER LEG	3 layers of brick with new anchoring	Insulating & abrasion resist. fire brick	2 layers, insulating & abras. resist. gunitite	Hydrobonded ARG & LWG layers
- LOOP SEAL	Multiple layers of custom cut brick with cast arches	Insulating & abrasion resist. fire brick & castable	2 layers of insulating & abrasion resist. gunitite	Hydrobonded ARG & LWG layers
- RETURN LEG	Combination of brick, gunitite & low cement castable	Insulating & abrasion resist., low cement cast. & ARG	2 layers of insulating & abrasion resist. gunitite	Hydrobonded ARG and LWG layers
• WALL BOXES	Attached to membranes between tubes	Plate steel and refractory	Attached to crowns of water wall tubes	Plate steel and refractory
• BENT TUBES AROUND AIR PORTS	2-Dimensional Tube Bends (4 tubes/port)	new SA210-A1 2.5 in. od tubes	Compound bends (2 tubes/port)	SA210-A1 2.5 in. od tubes
• CYCLONE INLET EXPANSION JOINT	Advanced design to prevent binding	Multiple stainless and fabric insulation matrl.	Slip joint type design w/ packing	Fabric Insulating materials
• RECYCLE RETURN LEG EXPANSION JOINT	Tapered design provides clearance during expansion	Plate steel and castable High strength refractory	Slip joint type design with fabric packing	Plate steel & abrasion resistant gunitite

TABLE 1. SUMMARY OF DESIGN UPGRADES AND CHANGES IN MATERIALS SPECS.

## MANPOWER AND CONSTRUCTION SUMMARY

Labor requirements varied over the course of the outage period to meet specific demands of the schedule. During the peak of outage construction, 173 people were brought on site, split about 60 to 40 percent between the day and night shifts. Work progressed six days per week and ten to twelve hours per shift. A breakdown of labor skills for the combined two shift operation during the peak level of construction is shown in Table 2. In total, over 100,000 hours were expended by these skills over the outage duration. No serious lost-time accidents were reported.

Over 2050 tube-to-tube and 57 heavy wall pipe welds were completed. Quality assurance and control procedures exceeded code requirements. Radiographs and heat treatment were completed on all thick wall pipe welds in accordance with the code. In addition, radiographs were completed randomly on approximately ten percent of the water wall tube-to-tube welds. Only a three percent rejection rate was experienced.

A total of 78 tons (70,800 kg) of water wall section with a surface area of over 6300 square feet (585 m<sup>2</sup>) were replaced. 52 tons (47,000 kg) of secondary superheater steel were replaced.

SKILL LEVEL	QTY.
• SITE SUPERINTENDENT	1
• MECHANICAL SUPERINTENDENTS	2
• REFRACTORY SUPERINTENDENTS	1
• FIELD ENGINEERS	2
• OFFICE MANAGER	1
• TIME KEEPER	1
• BOILERMAKER GENERAL FOREMEN	2
• BOILERMAKER FOREMAN	7
• REFRACTORY GENERAL FOREMAN	1
• REFRACTORY FOREMEN	6
• SAFETY COORDINATOR	1
• CARPENTER FOREMEN	2
• CARPENTERS	1
• BOILERMAKERS	58
• BOILERMAKER HELPERS	3
• PIPEFITTERS	1
• BRICKLAYERS	16
• CRAFT HELPERS	7
• LABORERS	60
<b>TOTALS</b>	<b>173</b>

**TABLE 2. SUMMARY OF LABOR SKILLS AND REQUIREMENTS DURING A ONE WEEK INTERVAL AT PEAK MANPOWER LEVELS.**

The removal and replacement of this tonnage was completed with an American Model 9310 crane equipped with a 150 foot (46 meter) high tower and 140 foot (43 meter) articulating boom. The lifting capacity of this crane varied with the cantilevered length and height of the boom from 14,800 pounds (6700 kg) at maximum radius to 48,900 pounds (22,000 kg) at a 51 foot (15.5 m) radius and an extended height of 292 feet (89 m).

A total of 361 tons (327,500 kg) of refractory, including approximately 105,000 refractory bricks, were installed during the outage. All materials were lifted into position on pallets through the boiler house lifting bay. Quality assurance/control procedures were followed prior to shipment and during installation of all refractories.

## IMPROVED UNIT RELIABILITY

During the first three years of commercial operation from 1988 through 1991, the Nucla station operated with an average equivalent availability of 56.5% and a capacity factor of 40.6%; numbers which were far below industry standards for coal-fired steam generating units. As discussed in Reference 9, there were many factors that contributed to these poor performance figures, among them forced or extended outage periods to address problems with boiler equipment in the areas outlined in this paper.

Since the upgrades and repairs during the 1993 outage, the unit has seen a considerable turnaround in overall reliability; operating with an average availability of 85% and a capacity factor of 77% over a 20-month period since the outage. Over the past 12-month operating period, unit availability has averaged 92%. These numbers include two planned maintenance outages per year, the longer of which covers a two to three week period. This level of performance exceeds that reported by NERC-GADS for equivalent sized coal-fired steam generating units. Between 1988-1992, these units averaged an equivalent availability of 82.4% and a capacity factor of 51.8% (Reference 12).

## CONCLUSIONS

During a 13-week outage in 1993, extensive repairs and upgrades were completed on Tri-State's 925 klb/h (420,000 kg/h) CFB boiler that powers the Nucla Station. The work was carried out by the original boiler manufacturer, Pyropower Corporation, and its subsidiary Pyropower Energy Services Company. By incorporating proven designs into various areas of the CFB boiler, Tri-State minimized project risks, uncertainties in the overall schedule, and ended up with a boiler design that incorporates the latest state-of-the-art equipment.

The scope of work included the retrofit of secondary superheaters and lower combustor air distributors with advanced designs, replacement of approximately 30 percent of the combustor water wall surface, change out of cyclone, loop seal and lower combustor refractories, retrofit of kick-out water wall tubes in the lower combustor at the refractory interface, the installation of new expansion joints at the cyclone inlet and recycle return leg, and modifications to air port openings and wall boxes in the lower combustors.

Tri-State's goal in completing the upgrades outlined in this paper was to improve the overall reliability and availability of its Nucla Station. The improvement in unit availability to 85 percent for the 20-month operating period since the upgrades is a testament to the fact that these goals are being attained.

The dramatic turnaround in unit reliability is one of the reasons that the station has been able to continue operating in a commercially successful manner in the post-Demonstration stage of its life. As a direct consequence, the project has become one of the first to begin repayment of DOE CCT funds as outlined in the 1987 Cooperative Agreement. Through the Demonstration Program and the subsequent period of upgrades and repairs, the Nucla Station has demonstrated a history of successful innovation in the CFB technology area. It continues to be an industry leader with the development of a first-of-a-kind, pc-based simulator to be completed in 1996.

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# Environmental Design Considerations for the York County Energy Partners Circulating Fluid Bed Boiler

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## I. Abstract

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The provisions of the Clean Air Act amendments of 1990 (CAAA) are a requirement for plant design and operation in the 1990's. These requirements add significantly to the challenge of siting large energy producing facilities, particularly in the United States. This paper will explore the impact of environmental requirements attributable to the CAAA and their impact on the design and construction of a cogeneration facility. This cogeneration facility will supply steam to an adjacent paper mill and power to a local utility. The impact of other environmental concerns, such as water usage, will be covered as will the background and status of the cogeneration project.

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## II. Introduction

The York County Energy Partners, L.P. (YCEP) cogeneration project is a 250 MW (gross) facility which will employ a single atmospheric circulating fluidized bed boiler (ACFB) and steam extraction turbine. The proposed facility (see figure 1) will be constructed in North Codorus Township, Pennsylvania and will supply up to 400,000 lb/hr of 600 psig steam to the adjacent P.H. Glatfelter Company paper mill. The facility will also supply 227 MWe of electricity under a long-term contract to Metropolitan Edison Company, the local investor-owned utility. Construction is scheduled to begin by mid 1995 with commercial operation beginning in early 1998.

YCEP is a wholly-owned project company of Air Products and Chemicals, Inc. of Allentown, Pennsylvania. Air Products is a leading developer, owner, and operator of environmental and energy systems. Air Products currently operates three large cogeneration facilities, two of which use circulating fluidized bed (CFB) technology.

Project highlights include:

- Scale-up and operation of the world's largest atmospheric circulating fluidized bed boiler (CFB).
- The facility will be the first coal-fired independent power plant in Pennsylvania to offer the purchasing utility economic dispatch up to 50% of its rated load.
- Ash by-product will have a beneficial use by reclaiming surface mining areas in eastern Pennsylvania.
- Curtailment of an existing P.H. Glatfelter Company boiler due to the steam supply from the YCEP facility will result in an net improvement in air quality (SO<sub>x</sub>, NO<sub>x</sub>, and PM<sub>10</sub>).
- Reuse of the paper mill's treated wastewater as the cooling water, thereby reusing a critical resource rather than consuming the areas' fresh water supplies.

The total capital cost of this facility is expected to be nearly \$400 million, with \$75 million of financial assistance to be provided through the Department of Energy's Clean Coal Technology program.

### **III. Project History**

#### Original Project Sponsor

In June 1989, the City of Tallahassee, Florida was selected to participate in Round I of the Department Energy's (DOE) Clean Coal Technology program. Tallahassee had proposed to repower one of its existing gas-fired boiler at its generating station with a single circulating fluidized bed boiler. The repowering would help Tallahassee decrease its complete reliance on natural gas for electricity production. A cooperative agreement was executed with the DOE in November 1990 which would provide \$75 million toward this repowering . In June 1991, Tallahassee executed a boiler supply agreement with Foster Wheeler Energy Corporation (Clinton, New Jersey) for the single CFB to be used for the project.

The repowering project at Tallahassee came under criticism for both economic and environmental reasons during 1991. This was principally the result of a drop in natural gas prices which occurred prior to 1991 and made the repowering project less economically attractive. In addition, local grassroots opposition brought up environmental concerns focused on the use of coal. As a result, Tallahassee decided in September 1991 to discontinue the repowering project and expressed its willingness to transfer the project to another party.

### Transfer to Air Products and Chemicals, Inc.

Since early 1991, Air Products had been developing a coal-fired project to provide for a documented electricity need in Pennsylvania. While Tallahassee was winding down its project, Air Products expressed an interest in the technology and the Clean Coal Technology program funding for its YCEP project. In June 1992, YCEP executed the necessary agreements with DOE and the project was officially moved to York County, Pennsylvania.

### P.H. Glatfelter Company As Steam Host

When originally proposed in 1991, the YCEP project was to be located adjacent to a dolomite refractory manufacturing facility in West Manchester Township, Pennsylvania. As part of the local discussions conducted to seek emissions offsets, discussions were conducted with local industrial facilities. P.H. Glatfelter Company was contacted during this period and it was determined that moving the project site adjacent to P.H. Glatfelter's Spring Grove paper mill would offer several environmental advantages for the project.

YCEP announced this relocation of the project in February 1993 to the P.H. Glatfelter Company location in North Codorus Township, approximately six miles southwest of the West Manchester site. At this site, YCEP will supply up to 400,000 pounds per hour of 600 psig steam to the Glatfelter paper mill which in turn will allow the mill to curtail operation of its 1950's-vintage No. 4 pulverized coal-fired boiler. This boiler curtailment will result in a net reduction of over three million pounds per year of sulfur dioxide emissions, as well as reduction of both nitrogen oxides and particulates.

P.H. Glatfelter will use the steam for power production as well as process uses in its paper mill. Low pressure start-up steam for the YCEP facility will be provided by P.H. Glatfelter Company.

## **IV. Project Overview and Status**

The YCEP facility is a coal-fired CFB boiler cogeneration facility producing 250 MWe (gross). The power island consists of a Foster Wheeler CFB boiler and a "utility style" reheat steam turbine generator (see figure 2). The facility also includes a baghouse collector, a 395-foot stack, a cooling tower, coal unloading and enclosed 30,000 ton storage facilities, limestone unloading and storage facilities, and a boiler water treatment and demineralization system.

The YCEP facility is partially funded by the DOE under the Clean Coal Technology program and as such was required to undergo an Environmental Impact Statement (EIS) assessment as part of the National Environmental Policy Act (NEPA) process. The EIS evaluates impacts to air and water emissions, public health and safety, traffic, noise, eco-systems, and historical and cultural resources. The DOE issued a draft EIS in November 1994 and is expected to complete the NEPA process and issue its Record of Decision completing the process in [            ].

The Pennsylvania Department of Environmental Resources (PA DER) issued a draft air permit in March 1995 to allow construction of the facility, and received final approval in June 1995. Land development and other state and local permits are [            ].

## **V. Environmental Permitting Challenges**

### **A. Introduction**

The facility includes a single coal-fired CFB boiler equipped with state-of-the-art air pollution control equipment. Expected permitted emissions levels for the facility are given in table 1. Since the facility would be subject to Prevention of Significant Deterioration (PSD) regulations, the regulated level for these pollution controls would be determined through a Best Available Control Technology (BACT) analysis. In addition, the YCEP site is located in the Northeast Ozone Transport Region established by the CAAA and would, therefore, be required to offset potential maximum NOx emissions at a ratio of 1.15 to 1. The facility would also be required to complete a Lowest Achievable Emission Rate (LAER) performance test to demonstrate whether the proposed facility can meet a lower NOx emission level than provided for in the air permit. Both the BACT analysis and the NOx offset plan approvals are being conducted as part of the facility's PSD air quality permit application process with the PA DER.

### **B. Sulfur Dioxide Emissions**

Sulfur dioxide emissions in the York County, Pennsylvania area will be significantly reduced based on steam supply from the YCEP facility. Steam supplied from the facility will allow the curtailment of operation of an existing 1950's vintage coal-fired boiler presently operated by the P.H. Glatfleter company. The curtailment of this boiler will result in a net reduction of permitted sulfur dioxide emissions by approximately 50%.

The site is located in a region that is in attainment for sulfur dioxide emissions and, therefore, sulfur dioxide offsets are not required. However, the CAAA of 1990 requires sulfur dioxide allowances to be purchased annually beginning in the year 2000. These allowances are required on a 1:1 basis with permitted emissions.

P.H. Glatfelter Company plans to participate in the Industrial "Opt-In" program for sulfur dioxide allowances provided by the Clean Air Act Allowance Program. YCEP would purchase the maximum allowable sulfur dioxide allowances from P.H. Glatfelter derived from the curtailment of the number four power boiler. The balance of the required allowances, if any are required, will come from the "open market".

Sulfur dioxide levels will be controlled in-situ in the boiler using limestone. The YCEP CFB boiler will have sulfur dioxide (SO<sub>2</sub>) emissions level of 0.25 pounds per million Btu which includes 92% reduction from the potential uncontrolled SO<sub>2</sub> emissions level.

### C. Nitrogen Oxides Emissions

Under Title I, Section 182, Pennsylvania has been included in an air quality area designated as the Northeast Ozone Transport Region (NOTR). Any major stationary source located in the NOTR with the potential to emit more than 100 tons per year of nitrogen oxides (NO<sub>x</sub>) or 50 tons per year of Volatile Organic Carbon (VOC) must offset these emissions by obtaining emission reduction credits (ERCs) from existing baseline facilities in the surrounding area. The new source emissions must be offset by a ratio of 1.15 to 1 of the potential to emit. The YCEP facility would be permitted to emit 1,437 tons of NO<sub>x</sub> per year.

These ERCs must be obtained by the facility as part of the air quality permitting process. The ERCs are required to be in-place and federally enforceable prior to commercial operation. It is expected that up to 900 tons of the NO<sub>x</sub> ERCs required by the CAAA would be obtained from the P.H. Glatfelter Company based on curtailment of the number 4 power boiler.

The remaining ERCs will be obtained from another source or sources located in Pennsylvania. A total of 1,652 tons per year of ERCs would be required by YCEP to provide a 1.15 to 1 offset of NO<sub>x</sub>.

The trading of NO<sub>x</sub> ERCs and the development of a trading market is in its infancy in Pennsylvania. This has made the acquisition of these NO<sub>x</sub> ERCs more difficult as many sources are wrestling with whether they have the potential to create transferable ERCs and what the value of these ERCs would be. In addition, due to the recent institution of Reasonably Achievable Control Technology (RACT) for existing stationary sources, many potential sources have yet to determine how many credits they will have to offer.

The RACT requirement has impacted P.H. Glatfelter as the number four power boiler has recently required the addition of low NO<sub>x</sub> burners. This has impacted the

ERCs available from P.H. Glatfelter for YCEP use. The NO<sub>x</sub> ERCs from P.H. Glatfelter will be based on post low NO<sub>x</sub> burner permitted emissions.

The P.H. Glatfelter Power boiler number 4 would be placed on back-up status. During periods when the YCEP CFB boiler is down for maintenance, power boiler number 4 would operate to provide the steam necessary for mill operation. Power boiler number 4 would be limited to operate no more than 720 hours per year in parallel operation with the YCEP facility. ERCs would not be gained during the parallel operation of power boiler number four with the YCEP facility.

The YCEP facility will have a permitted NO<sub>x</sub> emission of 0.125 lb./MMBtu which includes 40% reduction from the uncontrolled NO<sub>x</sub> emissions level. The facility will use a post-combustion technology known as Selective Non-Catalytic Reduction (SNCR) to achieve the 40% NO<sub>x</sub> reduction. The facility will be required to complete a Lowest Achievable Emission Rate (LAER) performance test program to demonstrate whether the plant can meet a lower NO<sub>x</sub> emission level through SNCR. The plant will have a one year demonstration period to complete the LAER test program.

#### D. Particulates Emissions

The uncontrolled particulate emissions from a CFB boiler is typically two to four times that of pulverized coal boilers. However, the particulate emission levels planned for the YCEP facility will be among the most stringent in Pennsylvania. A fabric filter collection system (baghouse) would be used to control particulate matter (PM<sub>10</sub>) to 0.011 lb. / MMBtu and achieve a 99.9 percent reduction from the potential uncontrolled particulate emissions. The baghouse would remove the fine particles in the boiler fluegas prior to release of the exhaust gas to the atmosphere.

#### E. Carbon Monoxide and Volatile Organic Carbon Emissions

The CFB boiler is an efficient combustion process which limits carbon monoxide (CO) and volatile organic compounds (VOCs) emissions. The YCEP CFB boiler would have a permitted CO emissions level of 0.15 lb./MMBtu and a permitted VOC emissions level of 0.004 lb./MMBtu. The permitted level of VOC emissions for the YCEP facility is 40 tons per year. Since this permitted emissions level is lower than the level established by the CAAA for emission reduction credits, VOC ERCs are not required.

#### F. Water Use

Fresh water is available in limited quantities at the North Codorus Township site. It was decided soon after relocation to this site that it would be necessary to consider the use of the P.H. Glatfelter Company wastewater (secondary effluent) as a cooling

water source for the facility. This would eliminate the use of an average of 3.0 million gallons per day of fresh water.

A pilot-plant cooling tower test program was conducted to further evaluate the use of the P.H. Glatfelter Company wastewater as a cooling water source. The pilot-plant test program proved the viability of this approach as well as determined chemical treatment requirements and operating costs. The data collected during this testing also aided in the engineering design of the cooling water system and in materials of construction selection.

The YCEP project will withdraw an average of 4.2 million gallons per day of P.H. Glatfelter Company wastewater prior to discharge to the Codorus Creek. This water would be used as a cooling water make-up source. P.H. Glatfelter Company will also supply an average of 200,000 gallons per day fresh water (process water) for use as boiler makeup and for miscellaneous plant uses.

Most of the YCEP plant wastewater, including cooling tower blowdown, will be returned to the P.H. Glatfelter Company secondary treatment plant. A portion of the plant high total dissolved solids wastewater will not be returned but will be used for fly and bottom ash conditioning. Some of the higher quality wastewater will be sent to the cooling tower.

Although concentrations of constituents in the P.H. Glatfelter company wastewater will be increased due to evaporative losses in the YCEP cooling tower, mass loadings (pounds per day) will not increase. Effluent biological oxygen demand (BOD) should decrease by maintaining a higher level of treatment in the cooling tower.

The YCEP cooling tower blowdown return to P.H. Glatfelter's secondary treatment plant will serve to reduce overall temperatures in the secondary effluent. This will result in a lowering of the temperature in the Codorus Creek. The lower creek temperature will have a beneficial impact to increase the dissolved oxygen level in the creek.

To assess the environmental impact of the reuse of the wastewater, studies were conducted as part of the NEPA process. A Creek Impact Study was performed to evaluate the environmental impact of the cooling tower operation on the Codorus Creek. In addition, the potential human health impact of the cooling tower operation was reviewed as part of the NEPA process and by the DER as part of the permitting process. Based on this review, it was determined that the cooling tower operation with the P.H. Glatfelter wastewater will meet all regulatory agency requirements.

Compliance with the appropriate water quality limitations is regulated through the Pennsylvania Department of Environmental Resources (PA-DES) approvals and state Water Quality Certification. The YCEP project will require a National Pollution

Discharge Elimination System (NPDES) General Permit for stormwater discharge. Wastewater return from the YCEP facility to P.H. Glatfelter is expected to be consistent with current wastewater discharge permit limits.

#### G. Solid Waste (Ash) Disposal

Ash generated by the combustion process will be collected and pneumatically conveyed to storage silos. Both bottom ash and fly ash streams will be handled in this manner. Both bottom ash and fly ash storage systems will be designed to allow for conditioned or dry unloading into trucks.

Fly ash conditioning will use high intensity mixing equipment to properly add water to this reactive material. Bottom ash conditioning will use pug mill technology. Conditioned ash, due to its alkaline properties, will be put to beneficial use to reclaim surface mining operations and in neutralizing acid mine drainage in Pennsylvania. Dry ash may be put to use in agricultural markets or other applications.

### **VI. Environmental Impacts to Plant Design**

#### A. Boiler Technology

In a fluidized bed combustor, the fuel is introduced to a bed of limestone sorbent which is fluidized by an upward flow of air. Most of the combustion occurs within the bed, but some smaller particles burn above the bed in the "freeboard" space. A circulating fluid bed (CFB) employs relatively high velocities to promote the carryover or circulation of solids. High temperature cyclones are used to capture the solid fuel and bed material for return to the primary combustion chamber. Figure 3 illustrates the proposed Foster Wheeler CFB design concept.

This boiler technology minimizes emissions by design. Limestone will be injected into the boiler to capture sulfur dioxide (SO<sub>2</sub>), reducing SO<sub>2</sub> emissions by 92%. Combustion air will be staged and combustion temperatures controlled to minimize the formation of nitrogen oxides (NO<sub>x</sub>) emissions. Carbon monoxide and hydrocarbon emissions will be minimized through the efficient combustion process which occurs in a CFB boiler. Fuel injection is also well-distributed to insure good emissions and temperature control as illustrated in figure 4.

Fuel for the facility is minus two-inch bituminous coal from Eastern Pennsylvania. The coal will be delivered by unit train and unloaded using a rotary railcar dumper. The limestone sorbent has a nominal size distribution of 16 mesh by 200 mesh with an average particle size of 400 - 600 microns. The sized limestone is received from the limestone supplier and stored in silos. The limestone is pneumatically conveyed from the silo to the boiler.

The boiler will use approximately 98.5 tons per hour of coal to produce 2.1 MM lbs./hr of 2,500 psig steam at 1,005 F. Approximately 18.2 lbs/hr of limestone will be injected pneumatically into the boiler for SO<sub>2</sub> reduction purposes. The steam produced by the circulating fluid bed boiler will be sent to the "utility style" turbine/generator to generate approximately 250 gross MW.

The major new technology for the project concerns the CFB boiler itself which represents the largest, single boiler of its kind in the United States. In designing a large-scale CFB furnace, the primary area of concern is to provide the conditions for optimum emission control, fuel burn-up, and heat transfer. These conditions can be achieved by providing good fuel, sorbent, and air mixing, as well as the proper configuration of heat transfer surface.

To provide for good fuel mixing and for proper heat transfer surface area, a full-length, water-cooled, division wall is provided for the YCEP CFB boiler (see figure 5). The division wall divides the length of the boiler combustion chamber in half and reduces the boiler dimensions to the value of existing, smaller combustion chambers. With a full length division wall the furnace volume ratios can be maintained in the ranges presently designed by the industry. By maintaining these standard ratios, maximum emission control and fuel burnup efficiency will be expected.

The division wall is considered a generating wall of the furnace - both mechanically and for a process point of view. Consideration in the design was made for proper solids mixing in the lower dense bed region. In the upper region of the wall, openings are provided to allow solids and gas communication through the wall.

The convective section of the boiler contains the primary superheater, reheater, and economizer heat transfer surfaces. This convective section, or "backpass", uses conventional technology to heat the boiler circuit. In addition, a tubular airheater is used to pre-heat the primary and secondary airstreams. Intermediate and final superheat is accomplished using a bubbling fluidized bed superheater, Intrex, developed by the boiler vendor.

The Intrex (INTEgral-REcycle-EXchanger) is composed of water wall tube construction. This heat exchanger is essentially an unfired bubbling bed that operates at low velocities utilizing the heat from the fine particulate from the cyclones. In-bed heat transfer surface in the Intrex transfers heat from the hot particulates to the superheated steam to provide for intermediate and finishing superheat sections.

Coarse ash material (bottom ash) accumulating in the CFB is removed from the using a specially designed directional grid and a fluidized bed stripper cooler. The bed ash is cooled by the fluidizing air flow to the stripper cooler. This heated air stream flows into the combustor along with the fines that are stripped out. The cooled bottom ash will be pneumatically conveyed to a bottom ash silo.

Fly ash collected in the economizer, air heaters, and baghouse hoppers will be pneumatically conveyed to the fly ash storage silo. Depending on the beneficial use for the by-product ash, the bottom and fly ash streams may require additional processing with water to condition the ash.

Limestone and coal selections were pre-screened using bench-scale testing to determine suitability for use in a CFB boiler. Large-scale pilot plant testing conducted by the boiler vendor with the expected coal and limestone was used to validate operations and emissions data. The data generated during the pilot plant testing, along with the boiler vendor's experience, was used to determine permitted emissions levels for use in facility permitting.

#### B. Selective Non-Catalytic Reduction System

Low levels of NO<sub>x</sub> generated by the oxidation of fuel nitrogen within the CFB combustor will be further reduced by decomposing NO<sub>x</sub> into N<sub>2</sub> and H<sub>2</sub>O using non-catalytic reduction with ammonia. Aqueous ammonia will be injected directly into the flue gas in the four ducts connecting the cyclones to the combustor (see figure 6). At this location, the temperature of the flue gas will range between 1550 to 1630 F.

At these temperatures, the NO<sub>x</sub> reduction of the flue gas reduction reactions proceed at a sufficient rate to achieve a NO<sub>x</sub> reduction level of at least 40%. Since staged combustion and low combustion temperatures in the CFB boiler already contribute to significantly lower NO<sub>x</sub> emissions than achieved with conventional pulverized coal boilers, extremely low NO<sub>x</sub> emissions will be achieved.

One of the challenges in implementing SNCR is achieving adequate mixing of the injected aqueous ammonia in the system. Good mixing assures nearly complete reaction of the SNCR reactions. Adequate mixing also helps to limit the "slip" of unreacted ammonia. Ammonia "slip" can cause the formation and subsequent deposition of ammonia bi-sulfate salts or the formation of an ammonium chloride plume.

A CFB boiler, with its high efficiency cyclones, presents an excellent mixing zone for the injection of ammonia. This coupled with the proper temperature range leads to a very good reduction potential for the CFB boiler. The cyclones are a definite advantage to applying SNCR for NO<sub>x</sub> reduction in the CFB boiler.

The use of SNCR was tested in the boiler vendor's pilot plant with the performance coal. The pilot plant testing demonstrated the effectiveness of ammonia injection for NO<sub>x</sub> reduction. The use of aqueous ammonia injection will be further optimized in the commercial plant during LAER testing.

On-site storage of aqueous ammonia will provide approximately three days of capacity. Aqueous ammonia (29 percent solution) will arrive at the facility by truck at

an estimated frequency of one delivery per week. The ammonia storage tank would be located within a fully contained and diked concrete area providing sufficient secondary containment of the storage tank to prevent a release.

### C. Baghouse

A multi-compartment filter system will be used to clean the flue gas exiting the primary and secondary air heaters. The baghouse will employ low energy pulse-jet technology for high efficiency cleaning. A design air-to-cloth ratio of two is specified with one compartment isolated for cleaning and one compartment out for maintenance. In addition, high efficiency felt fabric material is specified. The ash collected in the hopper will be discharged to the fly ash removal system.

### D. CEMS System

The YCEP facility will be equipped with a continuous emissions monitoring (CEM) system located in the stack, downstream of the pollution control equipment. The CEM will monitor exhaust gas flow, SO<sub>2</sub>, NO<sub>x</sub>, opacity, and carbon dioxide or oxygen. The CEM system would be used to assure that the facility is in constant compliance with the air quality permit approval.

### E. Cooling Water System

The reuse of the P.H. Glatfelter wastewater for cooling water had a significant impact on the design of the circulating cooling water system. This choice greatly impacted materials of construction selection, cooling tower chemical treatment, and cooling system operation.

Based on long-term cooling tower pilot plant testing, it is expected that up to three cycles of concentration can be achieved in the cooling tower. A cycle of concentration in a cooling tower refers to the increase in concentration of a given chemical species due to the evaporation of water. The "cycled-up" cooling water would have up to 3,000 ppm chlorides, 1,000 ppm sulfates, and the typical organic matter associated with a paper mill secondary effluent.

The materials of construction were impacted greatly by this choice of cooling water. Due to the presence of the elevated chlorides and sulfates in the "cycled-up" cooling water, non-metallic and non-ferrous metallic materials were closely considered for the cooling system. This had a significant impact to the plant capital equipment cost.

The plant surface condenser and equipment cooling heat exchanger will be constructed with titanium tubes and tube-sheet with a neoprene-lined steel waterbox. Circulating water pumps will be stainless steel. Circulating water pipelines will be

constructed of pre-stressed reinforced concrete piping below grade with Fiberglas piping above grade.

The cooling water treatment consists of biological control, pH adjustment, and dispersant addition. Biological control will be accomplished using a biocide, such as chlorine dioxide generated on-site. The use of chlorine dioxide is very effective for wastewater with a high biological content.

PH adjustment is accomplished using sulfuric acid. A polymer dispersant is added to keep dissolved and suspended solids from plating out in the system. Blowdown from the cooling tower is returned to the P. H. Glatfelter secondary wastewater treatment system.

#### F. Process Water System

The YCEP facility will supply up to 400,000 lb/hr of 600 psig superheated steam to the P.H. Glatfelter company. P.H. Glatfelter will supply 100% condensate or hot lime treated water return for the exported steam. Water losses from the steam system, water treatment, and boiler blowdown would be compensated for by using water supplied by the P.H. Glatfelter process water system. The average flow of process water will be 200,000 gpd to make up for these operating losses.

YCEP facility water treatment waste streams will be recycled as much as possible. A portion of the high TDS waste streams will be used for ash conditioning water. The higher quality YCEP wastewater streams will be sent to the cooling tower for reuse.

#### G. Material Handling Systems

The YCEP facility material handling systems have been designed to limit particulate emissions. Dust collection has been extensively employed in the coal unloading and handling system to limit particulate emissions. Dust collection at transfer points will be carefully designed to reduce dust generation. The coal handling dust collection equipment will be selected to achieve particulate emission levels in accordance with permit requirements.

The limestone and ash handling systems will use pneumatic conveying technologies to retain a totally enclosed system. The use of pneumatic conveying systems results in complete containment of dust and a significant reduction of particulate emissions. As in the fuel handling system, the dust collection equipment will be selected to maintain required particulate emissions requirements.

## VII. DOE Clean Coal Technology Program

The demonstration program is designed to provide the following important information:

- Demonstrate unit start-up and shut-down capabilities and provide data and experience on large ACFB boiler operation during these transients.
- Demonstrate ACFB boiler dispatching capabilities and constraints.
- Demonstrate ACFB boiler operation at full-load conditions for extended periods and continuous operation at part-load conditions.
- Provide quantitative results from a systematic study on the effects of important operating parameters and fuel characteristics on boiler performance and emissions which will aid in the optimum economic design and operation of future units.
- Identify constraints governing fuel selection based on test results from different fuels.
- Provide guidelines for inspection and maintenance along with information on maintenance costs.

Specific environmental boiler performance parameters to be quantified during the demonstration period include:

- Stack emissions: NO<sub>x</sub>, SO<sub>2</sub>, CO, VOC, and particulate.
- Percent SO<sub>2</sub> capture and limestone efficiency (Ca/S ratio).
- Percent NO<sub>x</sub> removal and SNCR system operation.
- Ash production and quality.
- Bed ash / fly ash split.
- Boiler thermal efficiency.

Tests are proposed for different coals: the combustor design basis coal and other test coals having different properties for the design coal. These tests will determine the range of coals that can be utilized and the impact of fuel characteristics on the performance and emissions of the ACFB.

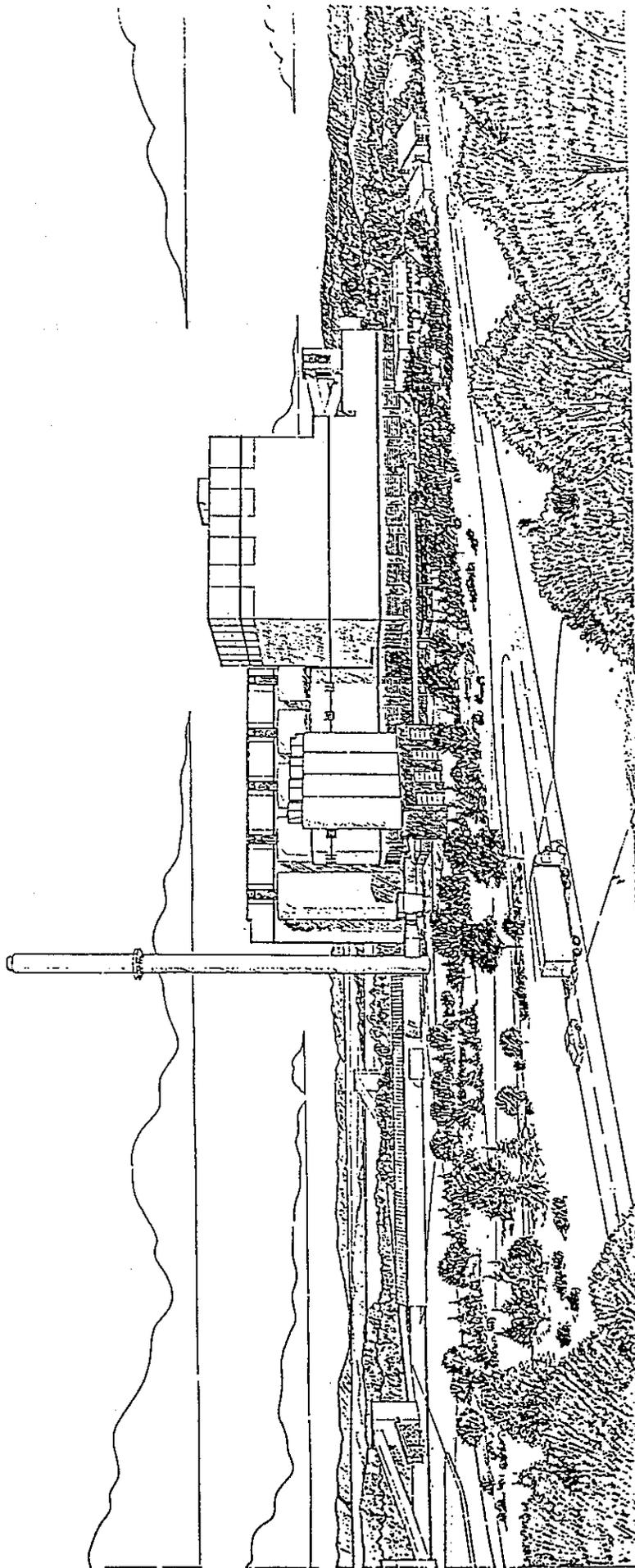
## VIII. Conclusions

As with any large energy project, the York County Energy Partners project has met and overcome many environmental and other permitting challenges during the development process. The Clean Air Act Amendment of 1990 has had significant impact in both the control of air emissions and in the permitting process. The use of boiler technology designed to minimize these emissions as well as state-of-the-art pollution control equipment has served to limit these impacts.

Partnering with a paper mill as a steam host has presented unique opportunities for emission reduction and water reuse. The curtailing of an existing mill power boiler with older boiler technology has presented a large quantity of necessary Emission Reduction Credits as well as overall emissions reductions of key pollutants. Unique water reuse and interface solutions have yielded a winning approach to difficult problems.

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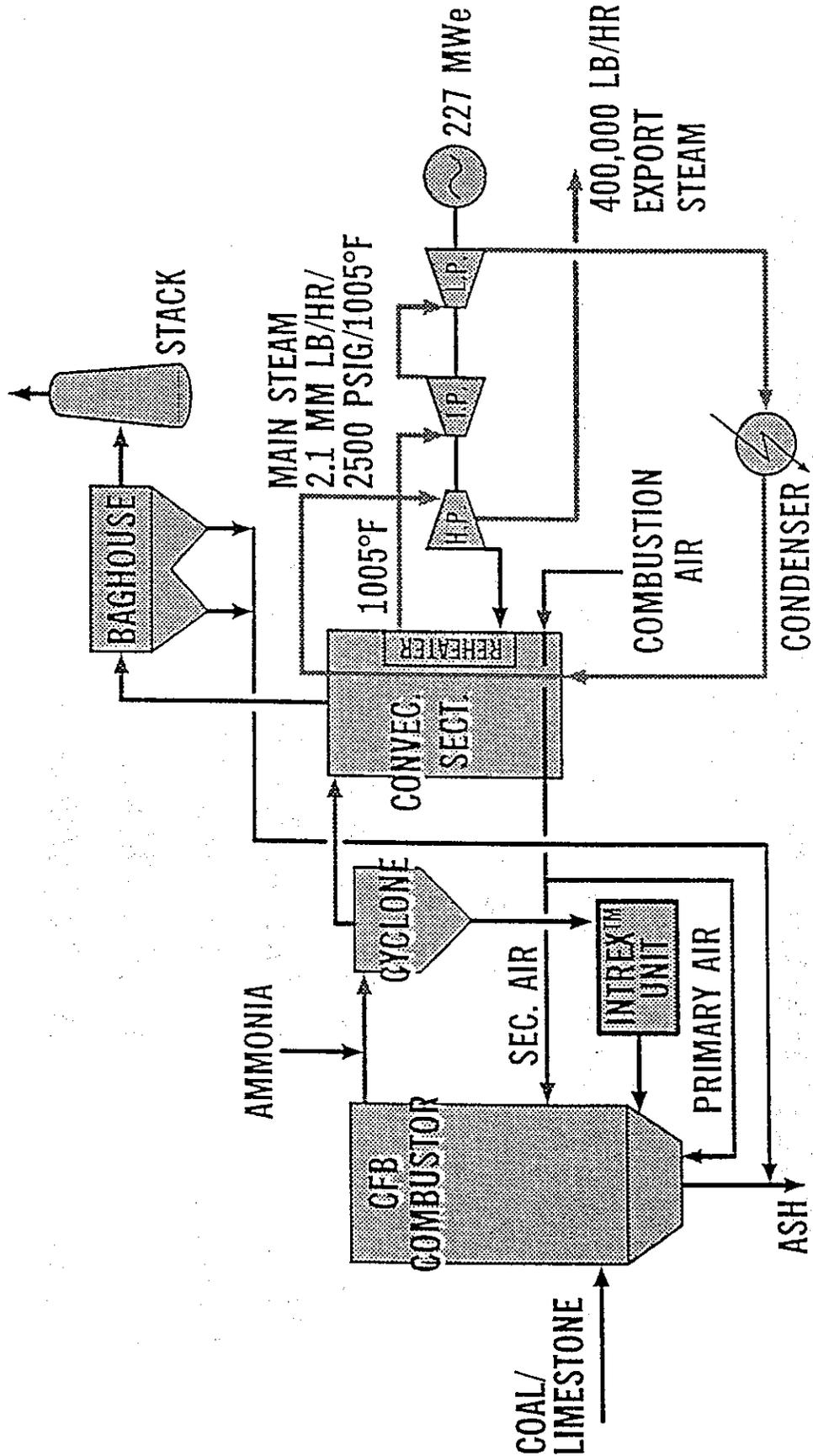
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York County Energy Partners  
Proposed Cogeneration Facility

Figure 1

# PROCESS FLOW DIAGRAM FOR YCEP COGEN PLANT



10632.025

Figure 2

# YCEP Expected Permitted Emissions Levels

Air Quality Permit Application Submitted to Pennsylvania DER  
January 1994.

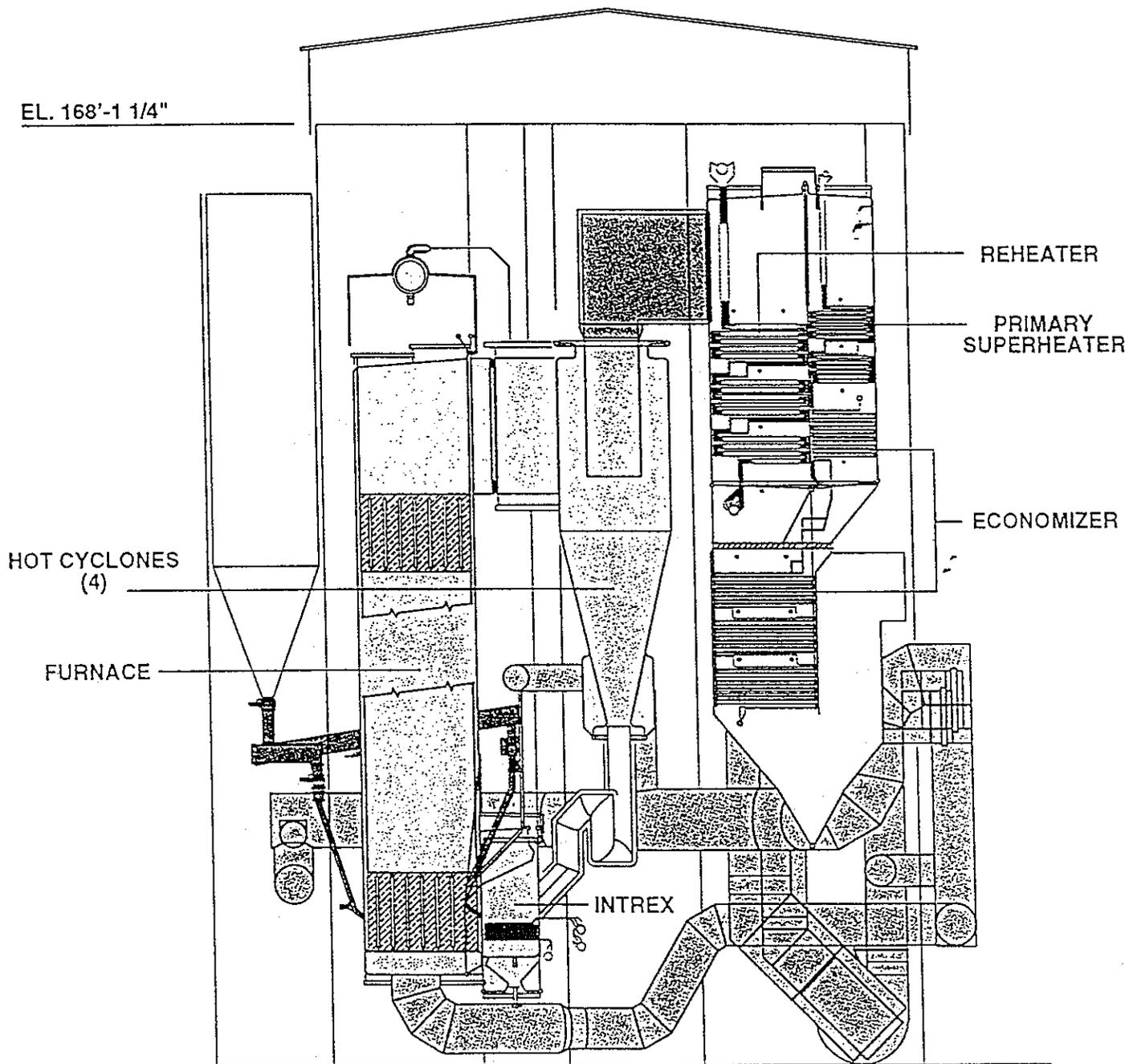
Draft Permit Issued March 1995

<b>SO2</b>	<b>0.25 lb/MMBtu @ 92% Capture</b>
<b>NOx</b>	<b>0.125 lb/MMBtu with SNCR</b>
<b>PM-10</b>	<b>0.011 lb/MMBtu</b>
<b>CO</b>	<b>0.15 lb/MMBtu</b>
<b>VOC</b>	<b>0.004 lb/MMBtu</b>

Table 1



**FOSTER WHEELER ENERGY CORPORATION**  
**YORK COUNTY ENERGY PARTNERS PROJECT**



YORK:5

Figure 3

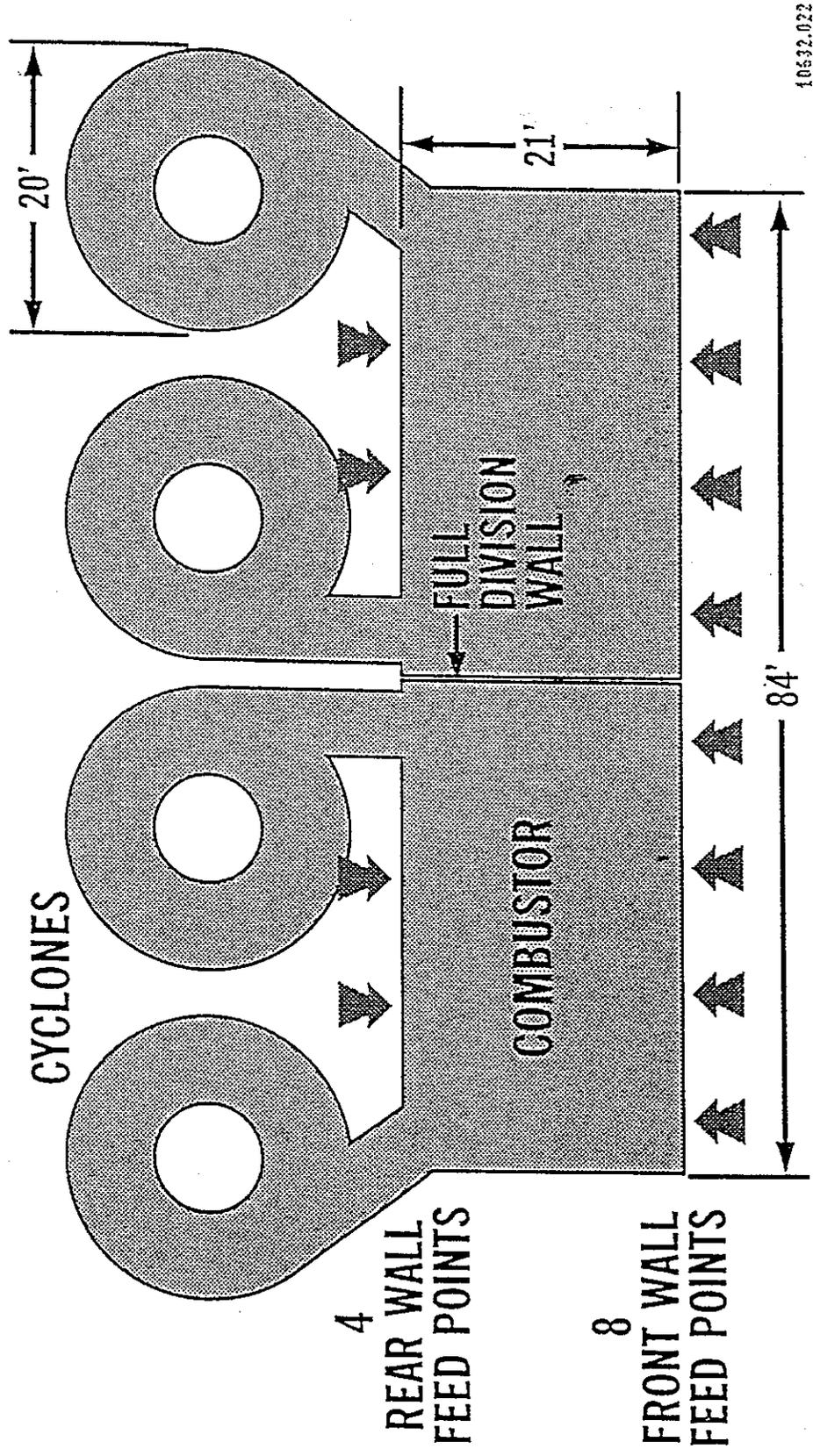
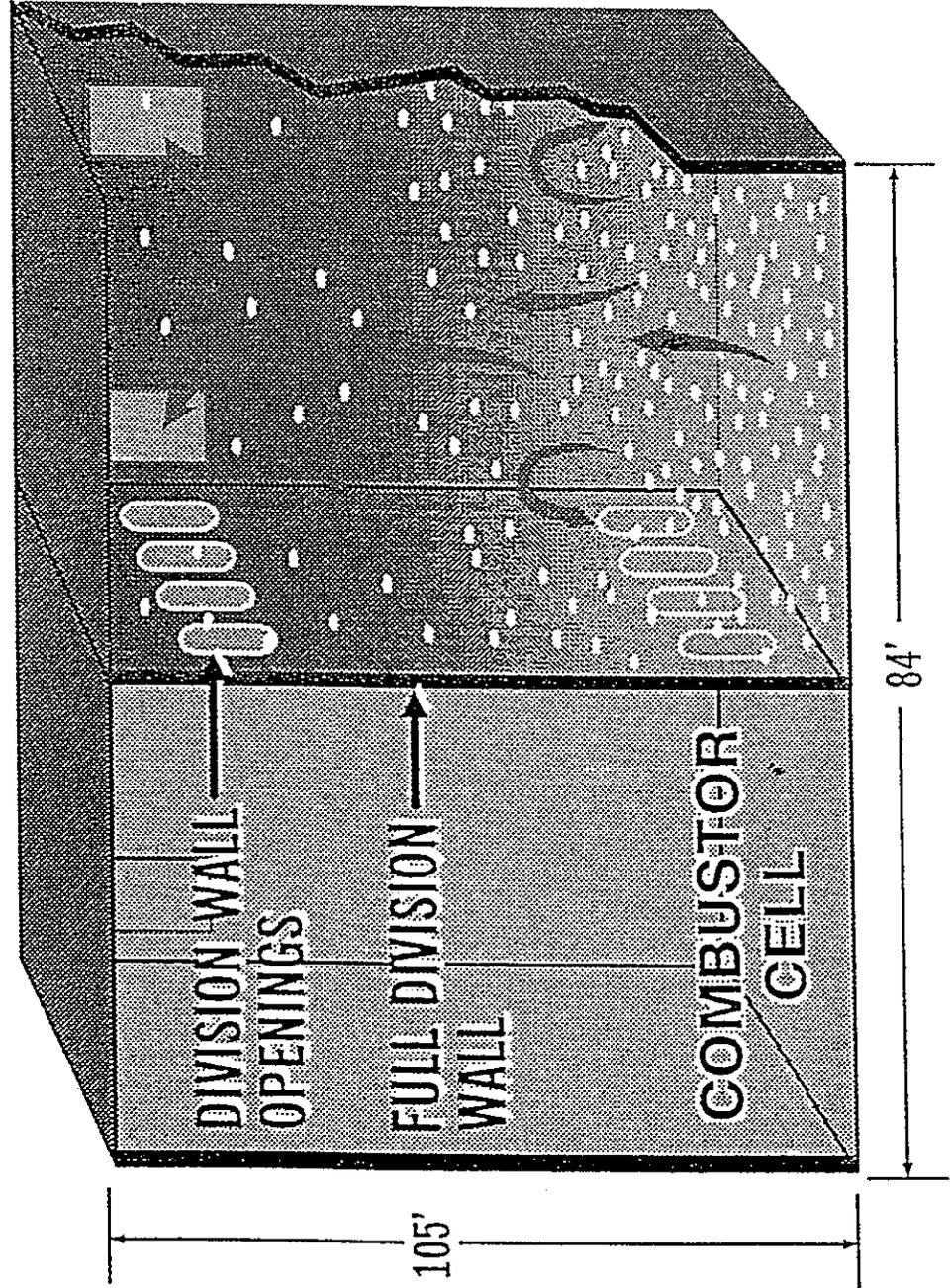


Figure 4

# ILLUSTRATION OF DIVISION WALL



10632.026

Figure 5

# SNCR System Schematic

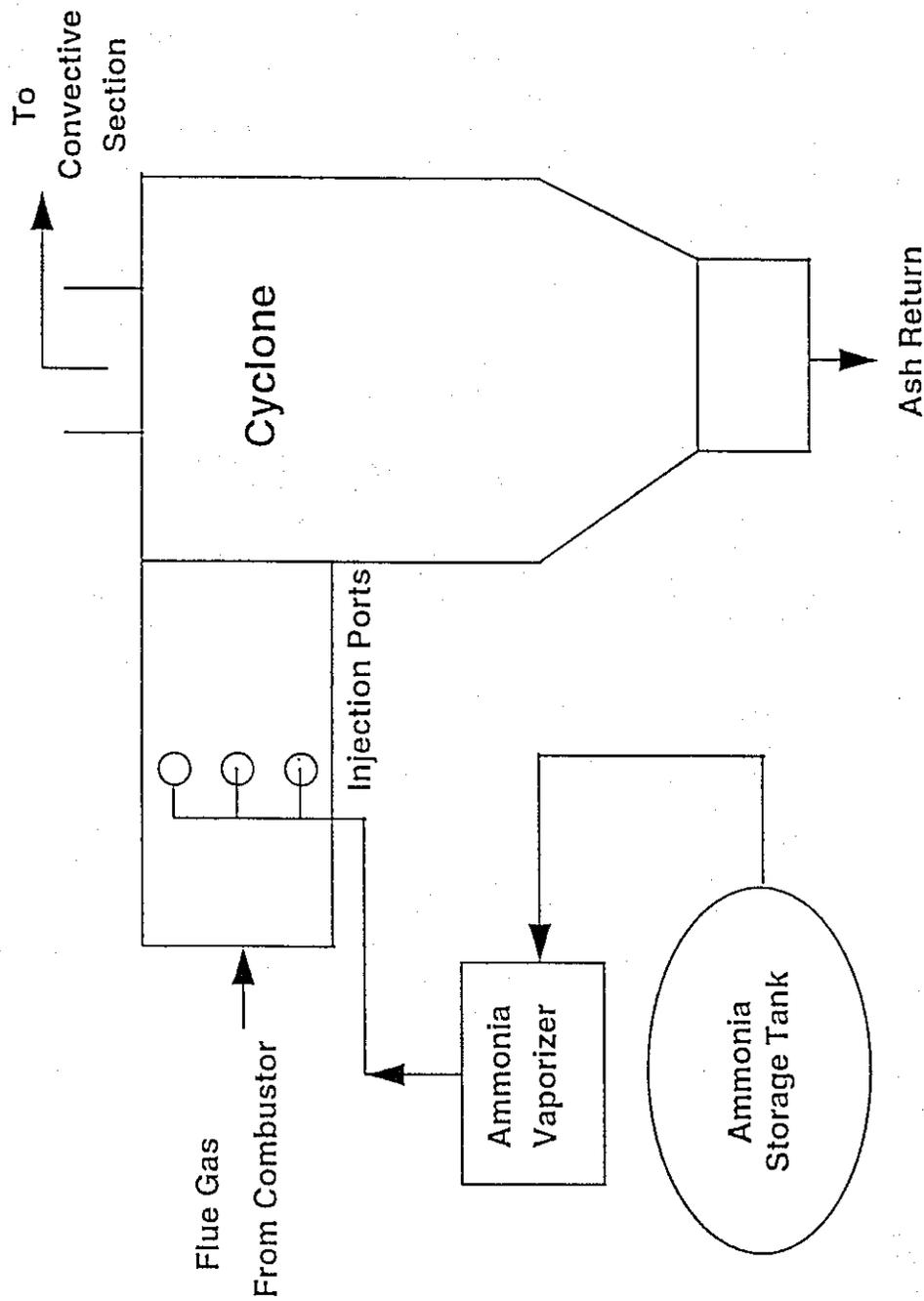


Figure 6

# **TIDD PRESSURIZED FLUIDIZED BED COMBUSTION DEMONSTRATION PLANT ASSESSMENT**

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## **ABSTRACT**

The Ohio Power Company's Tidd Pressurized Fluidized Bed Combustion (PFBC) program has now completed its 49 month demonstration period. The plant, which initially coal fired in November, 1990, began its demonstration period on February 1, 1991. The plant generated its final megawatt on March 30, 1995 and is presently being decommissioned. The Tidd Plant accumulated approximately 11,500 hours of coal fired operation during its demonstration run. During its four years of operation, the plant provided valuable information about PFBC process performance and furnished a data base which identified the unique challenges associated with operating and maintaining a PFBC power plant. All of the goals defined for the demonstration project were met or surpassed. The process, which was demonstrated during early Tidd operation, has been refined and optimized to the point that first generation PFBC technology is ready for commercial deployment.

This paper reviews the Tidd Demonstration Program and presents a synopsis of both the operating history and the final process performance results for the fourth year of operation.

## **INTRODUCTION**

The Tidd Pressurized Fluidized Bed Combustion (PFBC) Demonstration Plant was the first utility-scale pressurized fluidized bed combustor to operate in combined-cycle mode in the United States. The plant is owned by the Ohio Power Company (OPCo) and is located on the banks of the Ohio River, approximately 75 miles downstream of Pittsburgh, Pennsylvania.

The 45-year old pulverized coal plant was repowered with PFBC components in order to demonstrate that PFBC combined-cycle technology is an economic, reliable, and environmentally superior alternative to conventional technology in using high-sulfur coal to generate electricity. The PFBC related equipment was supplied by ASEA Babcock, a partnership between ASEA Brown Boveri Carbon (ABB Carbon) and the Babcock & Wilcox Company (B&W). American Electric Power Service Corporation (AEPSC) engineered and designed the plant. Construction of the PFBC Island and modification of the existing facility was performed by the Ohio Power Company.

The project received cost sharing from both the U.S. Department of Energy (DOE), administered by the Morgantown Energy Technology Center, and the Ohio Coal Development Office.

Detailed design work on the project began in May 1986 and site construction work started in April 1988. Unit start-up was initiated in November 1990 and the first combined-cycle operation was achieved on November 29, 1990. The three-year demonstration period started on February 28, 1991 and terminated on February 28, 1994. The fourth year of testing started on March 1, 1994 and terminated on March 30, 1995.

This paper reviews the experience of the 70-MWe Tidd PFBC Demonstration Plant during the fourth year of operation.

## PLANT DESCRIPTION

The project involved the repowering of a 1940's vintage pulverized coal plant by adding a PFBC island. The original Tidd plant consisted of two 110 MWe steam turbine generators supplied with steam by conventional coal fired boilers. The unit 1 steam turbine was repowered at approximately 50% capacity by adding a PFBC combustor and steam generator, a gas turbine and generator, a gas turbine exhaust economizer, coal and sorbent preparation and feed systems, a gas cleaning system, and cyclone and bed ash removal systems. The major balance of plant improvements included the addition of an electrostatic precipitator, bed ash and cyclone ash silos, and sorbent preparation facilities. The addition of an electrostatic precipitator, modification of the coal storage areas, and a revamped control room completed the needed improvements for the conversion.

The PFBC Power Island (Figure 1), which was incorporated into the existing plant, was designed to provide 440,000 pounds per hour of steam flow at 1300 psia and 925 F. Plant generation output was expected to be 72 MWe gross ( 57 MWe from the steam turbine generator and 15 MWe from the gas turbine generator).

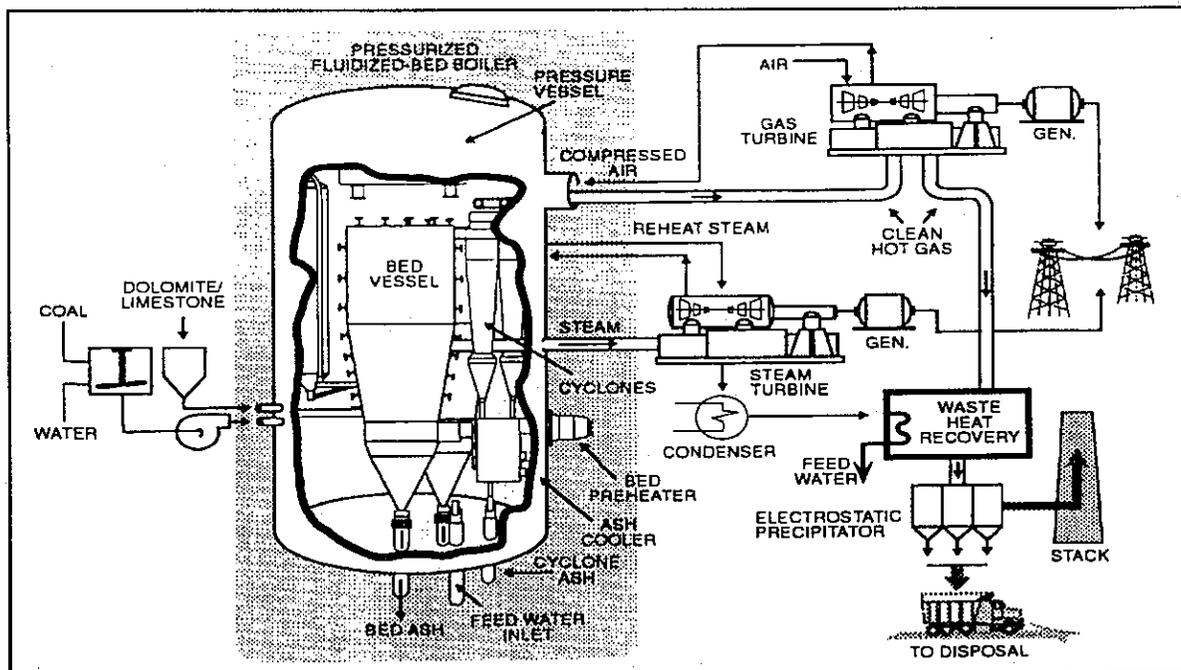


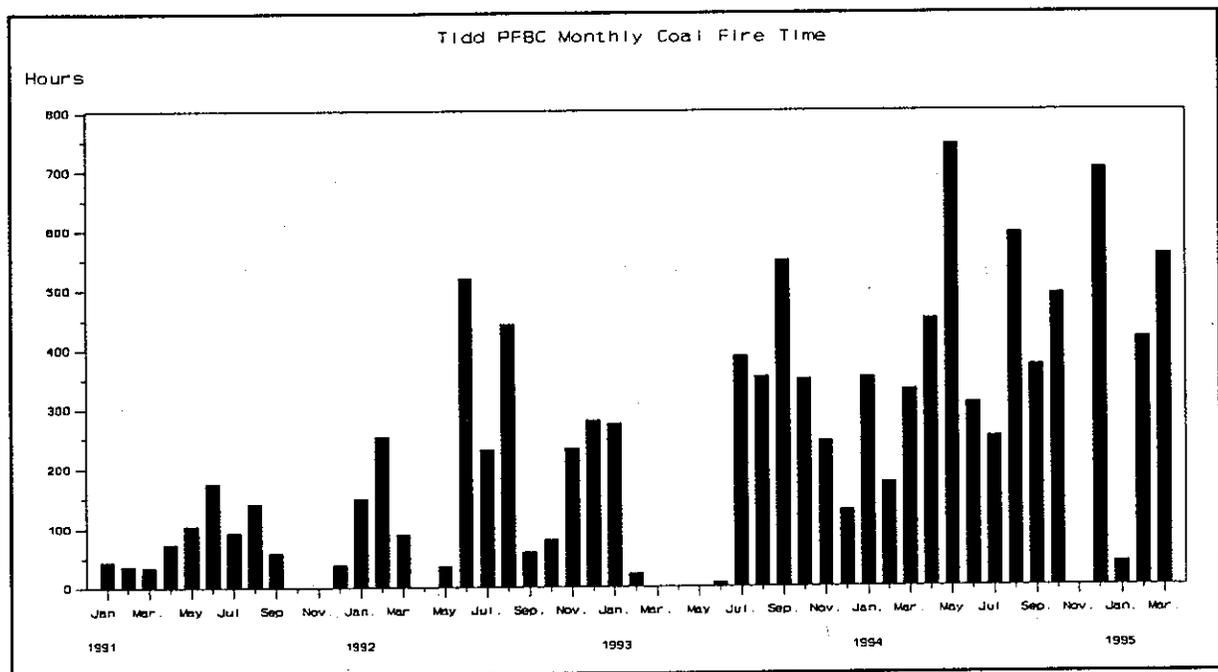
Figure 1 - Composite Cycle Diagram

## OPERATING OVERVIEW

The Tidd PFBC Demonstration Plant accumulated 11,445 hours of coal-fired operation during its four years of operation. The fourth year accounted for approximately 5400 hours of operation. An operational profile detailing coal fired operating hours for the entire test period is presented in figure 2. The achievements during this period were significant in establishing PFBC as a viable option for base-load, coal-fired generation. The highlights of the fourth year of operation are noted below:

First quarter 1994 - The unit continued to demonstrate improved operability. Unit availability and reliability were improving and achieving an acceptable level for a "first-of-a-kind" demonstration plant. However, attempts at achieving design bed operating temperature (1580 F) at high unit loads remained unsuccessful. Excessive "egg-sinter" formation continued to be an obstacle to achieving full bed temperature at higher loads. Sorbent utilization was still below-expectations. Plumes of high SO<sub>2</sub> concentration continued to be measured above the fuel nozzles. The ash removal systems were now working effectively. However significant maintenance effort was still required to maintain primary cyclone ash system integrity. The unit operated for a total of 850 hours on coal.

Second quarter 1994 - This period proved to be the most productive of the entire test program. From April to June the unit fired coal for 1521 hours. Unit reliability had reached a point where efforts could be focused on unit testing. Fifteen performance tests were conducted during this period. The plant established a new record for its longest continuous run on coal of 1079 hours surpassing its previous record of 740 hours. Unit availability for the first half of 1994 was 54.7%. The focus of the sintering investigation was shifted from inadequate fuel distribution/fuel splitting to inadequate bed fluidization. Since superficial fluidizing velocity could not be increased to improve agitation and mixing, the bed dynamics were modified by altering the size consist of the sorbent feed to produce a finer bed. The finer bed showed considerably improved properties including improved heat transfer and more uniform bed and evaporator tube outlet leg temperature profiles. No signs of excessive sintering were observed in any runs using finer dolomite as the sorbent.



**Figure 2 - Tidd Plant Operations Profile**

Third quarter 1994 - The unit continued to operate successfully. Fifteen performance tests were conducted. Unit availability for the first three quarters of the year remained at approximately 55%. Sintering had been basically resolved. Notable improvements in sorbent utilization were being achieved. Ca/S molar ratios below the "design" and "goals" were being demonstrated with "off-site" prepared sorbents. The unit operated for a total of 1213 hours during this period.

Fourth quarter 1994 - The unit continued to operate well during this period, a total of 1194 hours of coal fired operation were logged. Unit availability remained acceptable at approximately 55% for the year. Six performance tests were conducted. The unit continued to operate without excessive sintering when utilizing dolomite feedstock. Testing with limestone feedstock was attempted during this period. This resulted in a gradual deterioration of bed conditions. The test was aborted after about 36 hours.

First quarter 1995 -The unit continued to operate very effectively during this period. The unit operated on coal for a total of 1144 hours during the period. Twelve performance tests

were conducted during the quarter, bringing the total to 95 for the four year test period. Various coals tested during this period included M&M Coal Company Pittsburgh #8, Minnehaha, and Consol Mahoning Valley Pittsburgh #8. Sorbents tested included Plum Run Greenfield Dolomite, Mulzer Dolomite, and National Lime Delaware Limestone.

The final test of the Tiid program was completed on 3/28/95 while operating with Consol coal and National Lime Delaware limestone. The test was conducted at 115" bed level and 1580 F bed temperature. The unit operated for approximately 40 hours during which time the bed showed signs of deterioration (bed and evaporator temperature distribution were slowly deteriorating as bed density and steam production continued to drop). However, there were no signs of excessive egg sinters in the bed ash removal system. The fourth year test program was completed at the end of March 1995.

Over the final year of operation, the unit fired coal for a total of 5,386 hours. Unit availability for the fourth year of operation was 57.0%. The unit gross output factor was 68.8% and the gross unit capacity factor was 39.2%. Key operating statistics are presented in Table 1.

Key Operating Statistics October 1990 through March 30, 1995						
Yearly Data	1990 3 Months	1991	1992	1993	1994	1995 3 Months
G. T. Operating Hours	457	1482	2914	2544	5035	1301
Coal Fire Hours	61	795	2367	2310	4767	1145
Unit Availability	4.1%	9.6%	28.7%	26.6%	54.7%	54.5%
Gross Capacity Factor @ 70 MW <sub>gross</sub>	0.4%	3.6%	17%	15.5%	37%	38.9%
Number of Runs	9	43	29	16	18	10
Gross Unit Output Factor @ 70 MW <sub>gross</sub>	10.7%	37.3%	59.2%	58.2%	67.6%	71.4%
Maximum Gross Unit Load Achieved	N/A	53 MW	71 MW	64 MW	68 MW	72 MW

**Table 1 - Key Operating Statistics**

## **SIGNIFICANT FINDINGS**

### **Process Performance**

Bed dynamics, during the first three years of operation, were generally less than ideal. Relatively unstable conditions, attributed to poor paste quality and shortcomings in the feedstock distribution system, persisted. Continued efforts at improving paste quality and at enhancing the coal and sorbent feed stock distribution systems proved only moderately successful. Sintering and post bed combustion were controlled sufficiently to permit sustained unit operation, but sorbent utilization and heat transfer rates continued to be below expectations.

Bed temperatures above 1540 F were avoided even at reduced bed heights due to concerns that higher bed temperatures would exacerbate uneven bed temperature conditions, thus posing the risk of sintering even at lower heat input rates. It was determined that a major step was required to address this problem. The sorbent feedstock size consist had essentially been constant throughout the first three years of operation with a top size of 6 mesh and approximately 30% of the material below the directly elutriable size of 60 mesh. Despite the concern that finer sorbent feed stock would elutriate rapidly from the bed, a decision was taken to reduce sorbent feedstock size gradation from the original - 6 mesh material to a -12 mesh material.

In May of 1994, the first of a series of tests utilizing the finer sorbent feedstock was conducted. Excessive elutriation of the finer material did not materialize. Operation with the finer material proved to be a major breakthrough in process performance. The finer material resulted in a much more actively fluidized bed as evidenced by a 10% improvement in the heat transfer rate and an increase of approximately 30% in sorbent calcium utilization. In addition the process was much more stable as indicated by the reductions in temperature variations in both the bed and the evaporator tubes. Post bed combustion and sintering were effectively eliminated in normal operation. Unit testing could now focus on optimizing process performance.

## Boiler

The in-bed tube bundle experienced no widespread erosion that would require significant maintenance. Minor localized erosion was detected and addressed during the operating period. There was one tube leak in the in-bed tube bundle during the first three years of operation which was attributed to erosion induced by a missing access hatch seal. A routine air pressure leak test of the superheater circuit, conducted in the fourth year of operation (fall 1994), indicated leaking tubes in the secondary superheater. Two leaking tubes were found, one each on secondary superheater (SSH) circuit 15 and 16. Metallurgical examination determined the failure mechanism to be internal diameter initiated stress corrosion cracking of the #15 tube and water washing of the #16 tube. This is not considered a PFBC related occurrence.

Final inspection of the "in-bed" tube bundle included the removal of two evaporator and one secondary superheater platen. A minor amount of localized erosion, consistent with previous observations was noted. In addition there was some distortion of the superheater uncooled support trusses and loss of a number of retaining clips. Generally the tube bundle was in good condition. However, a significant amount of thinning was observed in certain areas of the water walls. The thinned areas were located on each of the four walls of the boiler. They were noticeable approximately 5 feet above the air sparge ducts and extended to about three feet below the top of the tube bundle. No operational failures occurred during the test program, but it is clear that these areas would have required attention in the near term.

Except for localized erosion in the in-bed tube bundle and the more general erosion of the water walls, the Tidd boiler performed extremely well and is considered a commercially viable design. The boiler water wall erosion presents a relatively minor problem which can be addressed by the use of refractory coatings. Such coatings were utilized on two commercial PFBC units and shown to be effective in precluding water wall erosion. The localized secondary superheater erosion can be eliminated by minor redesign of the area and/or by material changes. In addition, while the loss of support clips and the deformation

of support trusses posed no operating problem, these areas will require some attention to achieve commercial life.

### Gas Turbine

The gas turbine was the leading cause of unit unavailability during the first three years of operation. The Low-Pressure Turbine blades were replaced once due to cracks, and once due to a catastrophic failure of a Low-Pressure Turbine blade. In addition, the Low-Pressure Compressor stationary blades were replaced due to cracks at the guide vane ring attachments. However, it is important to note that the above failures were all related to the mechanical design of the gas turbine rather than to its operation in a PFBC plant. Gas turbine performance was improved in the fourth year. No significant mechanical failures occurred.

The gas turbine continued to experience noticeable erosion during the fourth year. Erosion on the turbine blades was relatively minor. However, significant erosion occurred at the Low-Pressure Turbine variable-pitch inlet guide vanes and inlet guide vanes inner and outer rings. This area was weld repaired twice during the last year of operation. It must be noted that a revised design, which was not installed at Tidd due to its limited remaining life, was installed at other operating PFBC unit and was effective in addressing this problem.

Inspection of the gas turbine, subsequent to unit shutdown, revealed no surprises. The areas of erosion observed were consistent with previous in-service observations. The LPT inlet guide vane rings showed significant erosion. While other areas of the machine showed signs of erosion, none were considered of great consequence.

The Tidd demonstration showed that a gas turbine could operate in a PFBC flue gas environment without excessive erosion. The operating time was sufficient to conclude that erosion is not an insurmountable problem and, in fact, is manageable with a scheduled maintenance program. The "first-of-a-kind" Tidd gas turbine performed acceptably, despite significant mechanical problems.

## Ancillary systems

The early operation of Tidd was plagued by difficulties associated with the materials handling systems. However, design changes during the first three years were successful in addressing and resolving most of these issues. All ancillary system issues had been adequately addressed when the program was terminated. Some system revisions, especially in the primary ash removal system, are anticipated to reduce routine maintenance to a commercially acceptable level.

## UNIT PERFORMANCE

Testing using various finer crushed grades of sorbents continued to demonstrate the effectiveness of finer sorbent feed stock in eliminating sintering, while concurrently demonstrating exceptional improvement in sorbent utilization. The improvements in performance were significant when using either finer site-prepared or finer off-site prepared

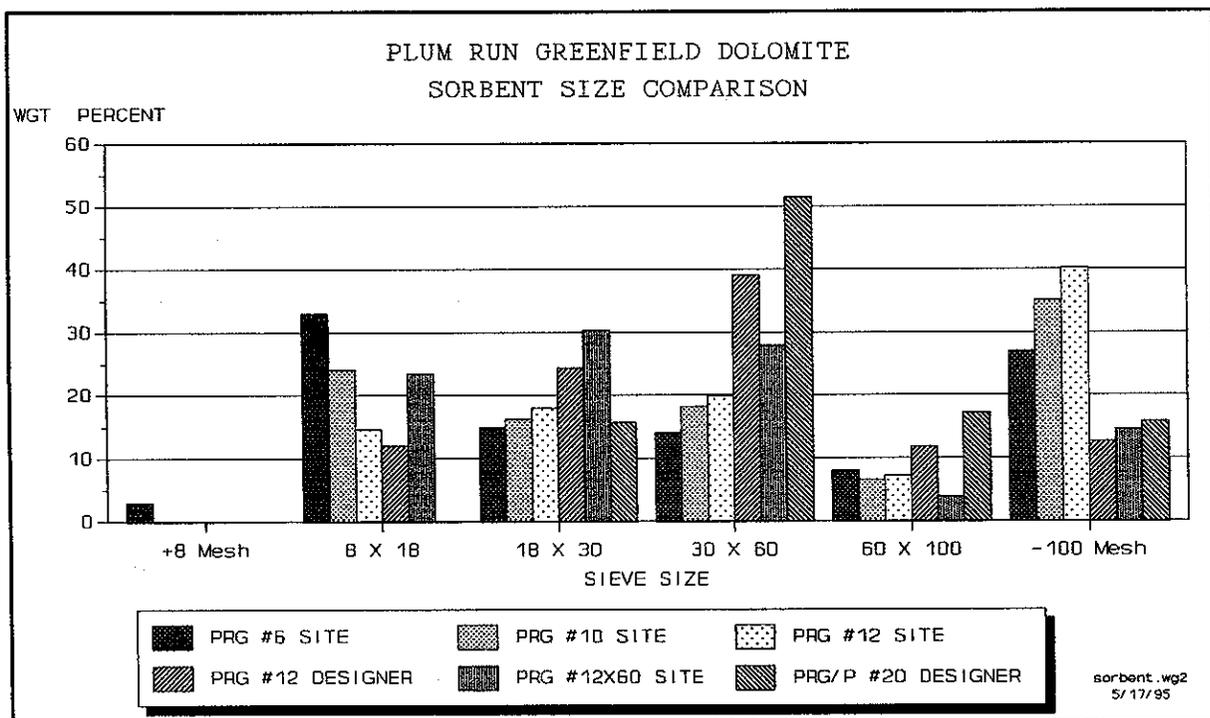


Figure 3 - Plum Run Greenfield Dolomite Size Comparison



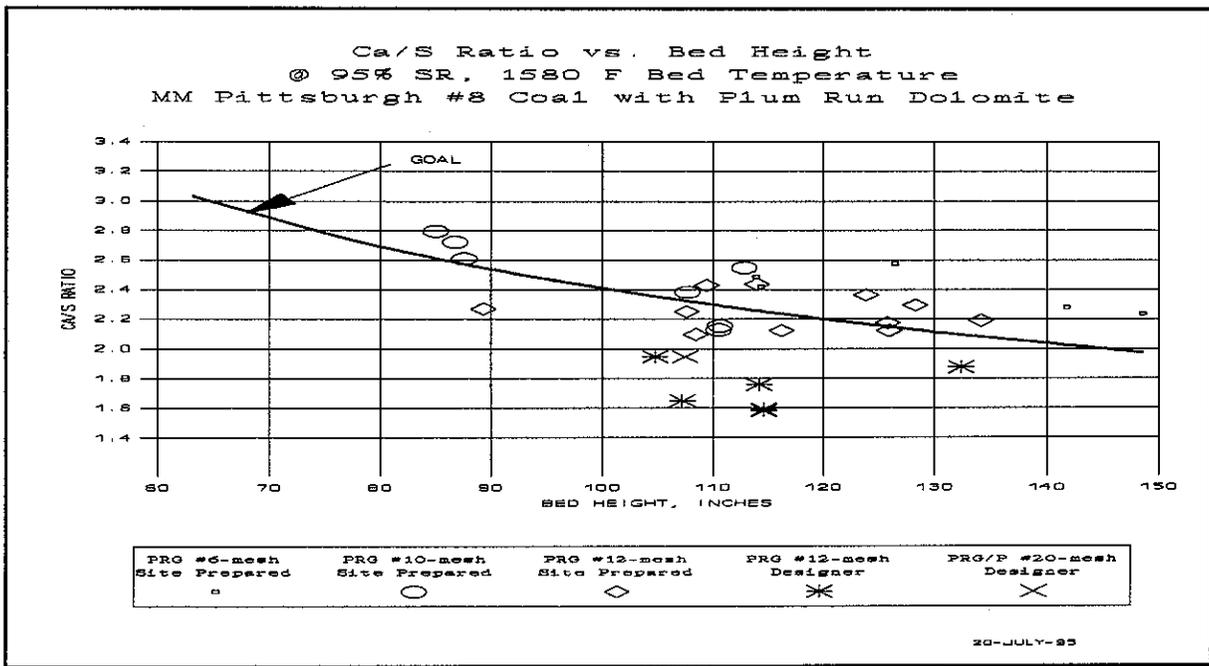


Figure 5 - Bed Height vs Ca/S Ratio, 95% Sulfur Capture

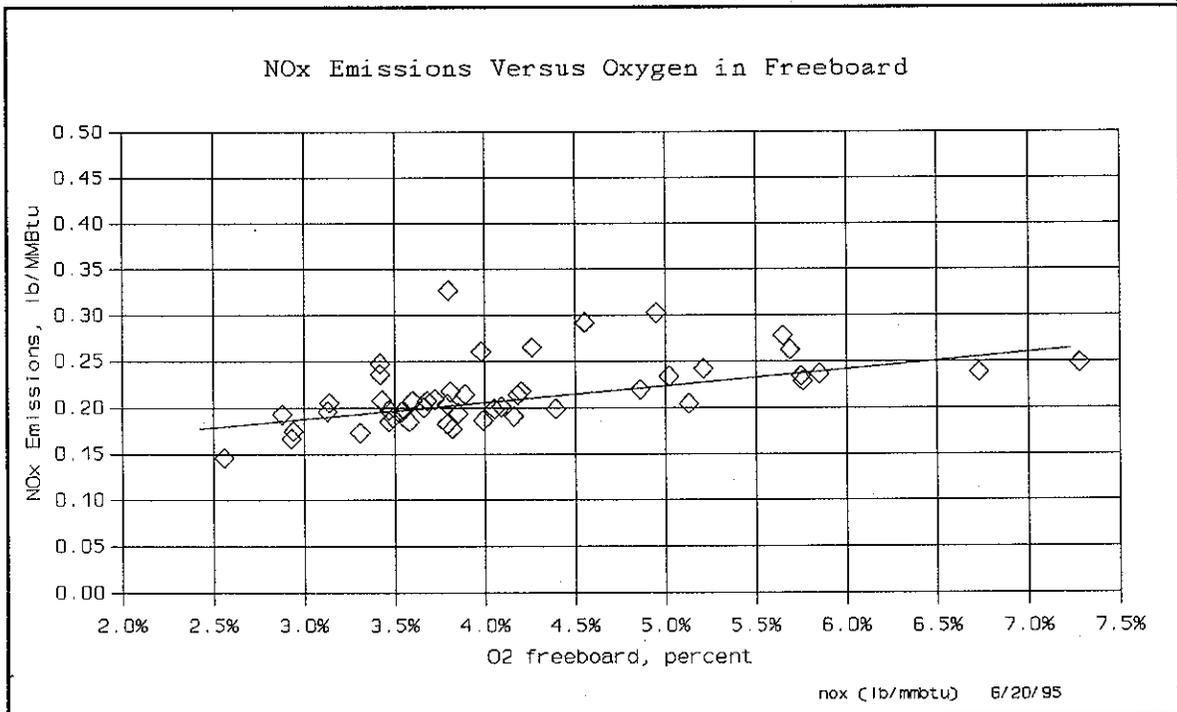


Figure 6 NO<sub>x</sub> Emissions Versus Oxygen in Freeboard

The NO<sub>x</sub> emissions levels at Tidd were in the range of 0.15 to 0.33 lb/mmBtu. NO<sub>x</sub> emissions were expected to be impacted by both the oxygen concentration in the exhaust gases and by nitrogen content of the coal. The Tidd test data confirmed an increase in NO<sub>x</sub> emissions as oxygen concentration increased. Figure 6 shows the correlation between these variables. The impact of nitrogen in the coal on NO<sub>x</sub> emissions was not investigated since no significant variation in nitrogen level existed in the coals which were of interest.

## UNIT TESTING

A total of 95 unit performance tests were conducted during the four-year test program. The fourth year of operation contributed 48 performance tests. The sorbent utilization recorded in the fourth year of testing are presented in Figures 4 and 5. Performance goals and guarantees were verified by acceptance tests conducted during the first three-years of operation. Testing in the fourth year of operation focused on resolving the problem of sintering and on sorbent utilization. An additional goal was established to operate the unit extensively to establish the survivability of both the gas turbine and the "in-bed" tube bundle.

During the fourth year, various coal and sorbent feedstocks were tested. The unit achieved its highest gross output of 72 MWe while achieving a firing rate of 218 MWt at a bed temperature of 1582 F. The sorbent utilization was found to be heavily dependent on the top size and size gradation of the sorbent feedstock. Testing indicated that Ca/S molar ratios of 1.1 were achievable at 90% sulfur capture, provided the size gradation of the sorbent being utilized was optimized. The data also indicated that Ca/S molar ratios of 1.5 were possible at 95% sulfur retention (These Ca/S ratios are normalized to 90 and 95% sulfur retention at 1580 F bed temperature and full bed height, utilizing the grimethorpe correlation).

The process demonstrated lower NO<sub>x</sub> emissions than predicted, typically in the range of 0.15 to 0.33 lb/mmBtu. These low emissions were inherent to the process and did not require any enhancements such as ammonia injection in the boiler freeboard. Such enhancements

could be expected to reduce NO<sub>x</sub> emissions even further.

## **CONCLUSION**

The Tidd PFBC Demonstration Plant successfully demonstrated the viability of PFBC technology, proving that the process could effectively control sulfur emissions from high-sulfur coal. The ability of a gas turbine to operate in a PFBC combined-cycle mode, utilizing exhaust gases from the PFBC process, has been demonstrated. While some erosion was observed, the amount was manageable. The ability of an in-bed tube bundle to perform acceptably in a bubbling bed environment was confirmed. The erosion of the in-bed tubes proved negligible. The systems required to apply PFBC technology to electric power generation were demonstrated and, in many cases, refined at Tidd. The significant problems of sintering, post bed combustion and poor sorbent utilization were effectively addressed during the fourth year of operation. The process, which was demonstrated in early Tidd operation, has been refined and optimized to the point that first generation PFBC is ready for full-scale commercial deployment.

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## **COMMERCIALIZATION OF THE LIQUIDS FROM COAL PROCESS**

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### **ABSTRACT**

ENCOAL Corporation, a wholly owned subsidiary of SMC Mining Company, which is a subsidiary of Zeigler Coal Holding Company, has operated a 1,000 Tons per day (TPD) Liquids From Coal (LFC) demonstration plant near Gillette, Wyoming for more than three years. A dozen unit trains containing up to 91% Process Derived Fuel (PDF), the low sulfur, high Btu solid product, have been delivered and burned by three utility customers. Nearly two million gallons of Coal Derived Liquid (CDL) have also been delivered to a number of industrial fuel users. The plant is now operational and domestic and international commercialization activity is in progress.

The Project, which is being cost shared by the U.S. Department of Energy under Round Three of the Clean Coal Technology program, achieved several of its long-term objectives in the past year. The Project has been extended for two years to achieve the remainder of its goals, namely the processing of alternate coals, test burning of unblended, high quality PDF and obtaining commitments for commercial plants. This paper covers the historical background of the Project, describes the process and reviews the commercialization efforts now underway.

## **BACKGROUND INFORMATION**

### **Objectives**

Beneficiation of low sulfur Powder River Basin (PRB) subbituminous coal is being demonstrated by the ENCOAL Mild Coal Gasification Project using the LFC process. The LFC Technology employs a mild gasification process, that is mild pyrolysis at relatively low temperatures, to produce both liquid and solid fuels with environmentally superior properties. The demonstration plant has been in the testing and operations mode for more than three years and has achieved several of its original goals.

ENCOAL's overall objective for the Project is to further the development of full sized commercial plants using the LFC Technology. In support of this overall objective, the following goals were established:

- Provide sufficient products for full-scale test burns
- Develop data for the design of future commercial plants
- Demonstrate plant and process performance
- Provide capital and operating cost data
- Support future LFC Technology licensing efforts

Significant progress has been made on the first four goals, and the commercialization and technology licensing efforts are in progress. This paper highlights several areas of immediate interest to potential customers and licensees. These include the status of the ENCOAL Project, plant operating experience, plant reliability, product properties, technology development and remaining challenges. Most importantly, the status of the commercialization of the LFC Technology is reviewed.

### **General Description**

ENCOAL Corporation is a wholly owned subsidiary of SMC Mining Company (SMC) which in turn is a subsidiary of the Zeigler Coal Holding Company. ENCOAL has entered into a Cooperative Agreement with the United States Department of Energy (DOE) as a participant in Round III of the Clean Coal Technology Program. Under this agreement, the DOE is sharing 50% of the cost of the ENCOAL Mild Coal Gasification Project. The Cooperative Agreement was extended in October 1994 for an additional \$18,100,000 bringing the Project total to

\$90,600,000 through September 17, 1996. A license for the use of LFC Technology has been issued to ENCOAL from the technology owner, TEK-KOL, a partnership between SGI International of La Jolla, California and SMC Mining Company.

The ENCOAL Project encompasses the design, construction and operation of a 1,000 TPD commercial demonstration plant and all required support facilities. The Project is located near Gillette, Wyoming at Triton Coal Company's Buckskin Mine. Existing roads, railroad, storage silos and coal handling facilities at the mine significantly reduced the need for new facilities for the Project.

A substantial amount of pilot plant testing of the LFC process and laboratory testing of PDF and CDL was done.<sup>[1]</sup> The pilot plant tests showed that the process was viable, predictable and controllable and could produce PDF and CDL to desired specifications. Key dates and activities in bringing the project from the pilot plant stage to its current status are:

- Through early 1987: Development of the LFC process by SGI.
- Mid 1987: SMC joined with SGI on further development.
- Mid 1988: Feasibility studies, preliminary design, economics and some detailed design work by SMC.
- June 1988: Submittal of an application to the State of Wyoming for a permit to construct the plant - Approved July 1989.
- August 1989: ENCOAL Project submitted to the DOE as part of Round III of the Clean Coal Technology Program - Selected in December 1989.
- September 1990: Cooperative Agreement signed. Contract awarded to The M. W. Kellogg Company for engineering, procurement and construction.
- October 1990: Ground breaking at the Buckskin Mine site.
- April 1992: Mechanical completion - commissioning begun.
- June 1992: First 24 hour run in which PDF and CDL were produced.
- November 1992: SMC Mining Company and its subsidiaries, including ENCOAL, acquired by Zeigler.
- April 1993: ENCOAL achieves two week continuous run.
- June 1993: Plant shut down for major modifications.
- December 1993: Plant recommissioned with added deactivation loop.
- July 1994: Completed 68 day continuous run - plant operational.
- September 1994: First unit train containing PDF shipped and burned successfully.
- October 1994: Two year extension and additional funding approved by DOE.
- April 1995: Completed 64 day run, shipped 12<sup>th</sup> unit train with PDF.

Although designed for 1000 TPD feed, the plant is currently processing 500 TPD of subbituminous PRB coal due to capacity limitations in the deactivation loop. The plant produces 250 TPD of PDF, which has the high heat content of Eastern coals but with low sulfur content, and 250 barrels/day of CDL, which is a low sulfur industrial fuel oil. While CDL is different from petroleum derived oils in its aromatic hydrocarbon, nitrogen and oxygen content, it has a low viscosity at operating temperatures and is comparable in flash point and heat content.

Not a pilot plant or a "throw-away", ENCOAL's processing plant is designed to commercial standards for a life of at least 10 years. It uses commercially available equipment as much as possible, state-of-the-art computer control systems, BACT for all environmental controls to minimize releases and a simplified flowsheet to make only two products matched to existing markets. The intent is to demonstrate the core process and not make the project overly complicated or expensive.

The ENCOAL Project has demonstrated for the first time the integrated operation of several unique process steps:

- Coal drying on a rotary grate using convective heating
- Coal devolatilization on a rotary grate using convective heating
- Hot particulate removal with cyclones
- Integral solids cooling and deactivation
- Combustors operating on low Btu gas from internal streams
- Solids stabilization for storage and shipment
- Computer control and optimization of a mild coal gasification process
- Dust suppressant on PDF solids

The product fuels are expected to be used economically in commercial boilers and furnaces to reduce sulfur emissions significantly at utility and industrial facilities currently burning high sulfur bituminous coal or fuel oils. Ultimately, installation of commercial scale LFC plants should help reduce U.S. dependence on imports of foreign oil.

### Process Description

Figure 1 is a simplified flow diagram of ENCOAL's application of the LFC Technology. The process involves heating coal under carefully controlled conditions. Nominal 3" x 0" run-of-

# Simplified Process Flow Diagram

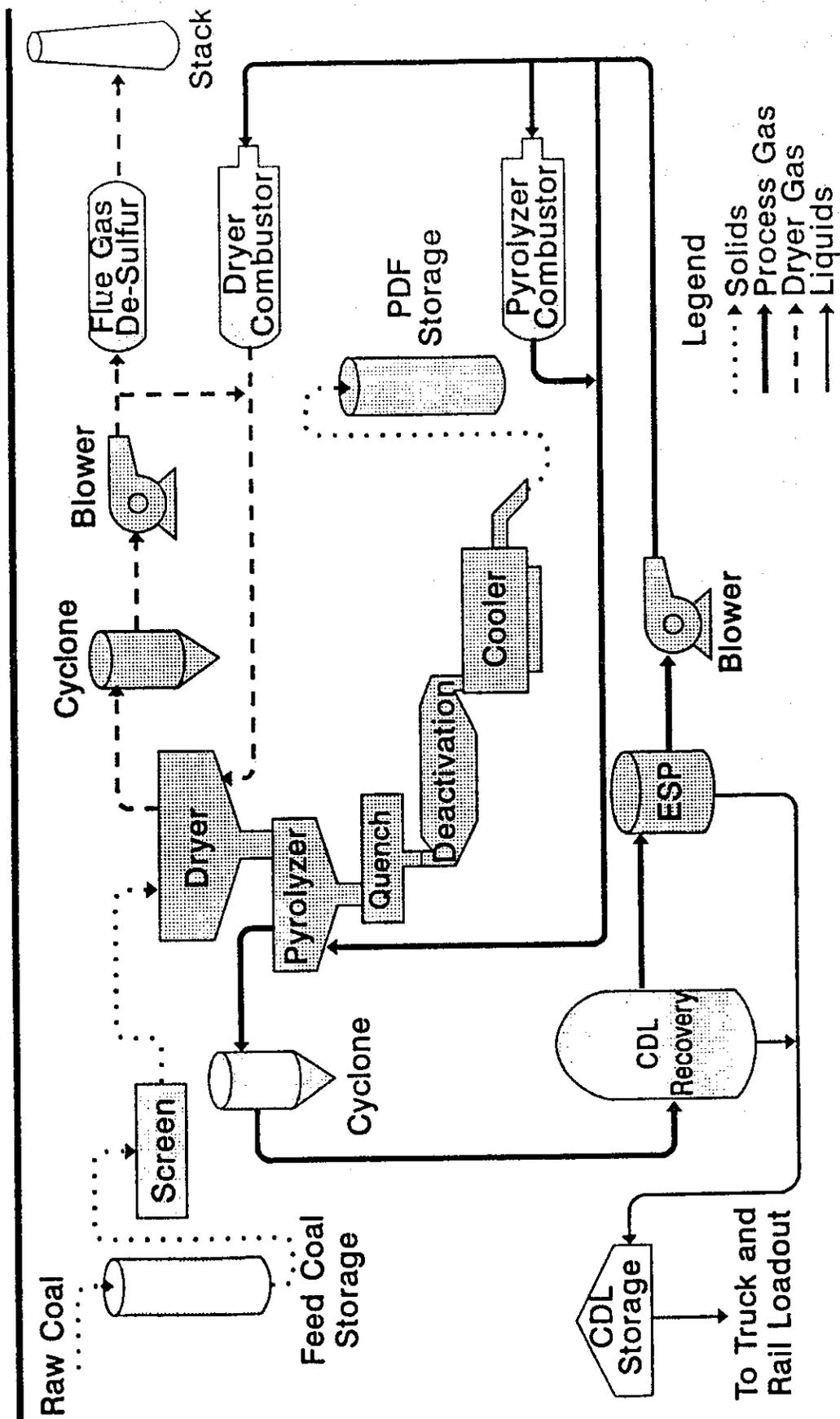


Figure 1. Simplified Process Flow Diagram

mine (ROM) coal is conveyed from the existing Buckskin Mine to a storage silo. The coal from this silo is screened to remove oversize and undersize materials. The 2" x 1/4" sized coal is fed into a rotary grate dryer where it is heated by a hot gas stream. The residence time and temperature of the inlet gas have been selected to reduce the moisture content of the coal without initiating chemical changes. The solid bulk temperature is controlled so that no significant amounts of methane, carbon monoxide or carbon dioxide are released from the coal.

The solids from the dryer are then fed to the pyrolyzer where the temperature is further raised to about 1,000°F on another rotary grate by a hot recycle gas stream. The rate of heating of the solids and their residence time are carefully controlled, because these parameters affect the properties of both solid and liquid products. During processing in the pyrolyzer, all remaining water is removed, and a chemical reaction occurs that results in the release of volatile gaseous material. Solids exiting the pyrolyzer are quickly quenched to stop the pyrolysis reaction, then transferred to a small surge bin that feeds the vibrating fluidized bed (VFB) deactivation unit.

In the VFB unit, the partially cooled, pyrolyzed solids contact a gas stream containing a controlled amount of oxygen. Termed "oxidative deactivation," a reaction occurs at active surface sites in the particles reducing the tendency for spontaneous ignition. The heat generated by this reaction is absorbed by a fluidizing gas stream which is circulated through a cyclone to remove entrained solids and a heat exchanger before being returned by a blower to the VFB. Oxygen content in the loop is maintained by introducing the proper amount of air through a control valve. Excess gas in the loop is purged to the dryer combustor for incineration.

Following the VFB, the solids are cooled to near atmospheric temperature in an indirect rotary cooler. A controlled amount of water is added in the rotary cooler to rehydrate the PDF to near its ASTM equilibrium moisture content. This is also an important step in the stabilization of the PDF. The cooled PDF is then transferred to a storage bin. Because the solids have little or no free surface moisture and, therefore, are likely to be dusty, a patented dust suppressant is added as PDF leaves the product surge bin. Patents are pending on both the oxidative deactivation and rehydration steps.

The hot gas produced in the pyrolyzer is sent through a cyclone for removal of the particulates and then cooled in a quench column to stop any additional pyrolysis reactions and to condense the desired liquids. Only the CDL is condensed in this step; the condensation of water is avoided. Electrostatic precipitators recover any remaining liquid droplets and mists from the gas leaving the condensation unit.

Almost half of the residual gas from the liquid recovery unit is recycled directly to the pyrolyzer, while some is first burned in the pyrolyzer combustor before being blended with the recycled gas to provide heat for the mild gasification reaction. The remaining gas is burned in the dryer combustor, which converts sulfur compounds to sulfur oxides. Nitrogen oxide emissions are controlled via appropriate design of the combustor. The hot flue gas from the dryer combustor is blended with the recycled gas from the dryer to provide the heat and gas flow necessary for drying.

The unrecycled portion of the off-gas from the dryer is treated in a wet gas scrubber and a horizontal scrubber, both using a water-based sodium carbonate solution. The wet gas scrubber recovers the fine particulates that escape the dryer cyclone, and the horizontal scrubber removes most of the sulfur oxides from the flue gas. The treated gas is vented to a stack. The spent solution is discharged into a pond for evaporation. The plant has several utility systems supporting its operation. These include nitrogen, steam, natural gas, compressed air, bulk sodium carbonate and a glycol/water heating and cooling system. Figure 2 is a plot plan for the ENCOAL Plant facilities including the Buckskin Mine rail loop that is used for shipping products.

## **PLANT OPERATING EXPERIENCE**

### Production History

ENCOAL's LFC plant and facilities have now operated in an integrated mode producing PDF and CDL for more than 6700 hours. The major pieces of equipment, including the large blowers, combustors, dryer, pyrolyzer and cooler have operated far more hours overall considering hot standby and ramping operations. This equipment has been demonstrated to operate reliably. Steady state operation at 90% availability has been achieved for extended periods for the entire plant, albeit at 50% of plant capacity, and the plant is now operational.

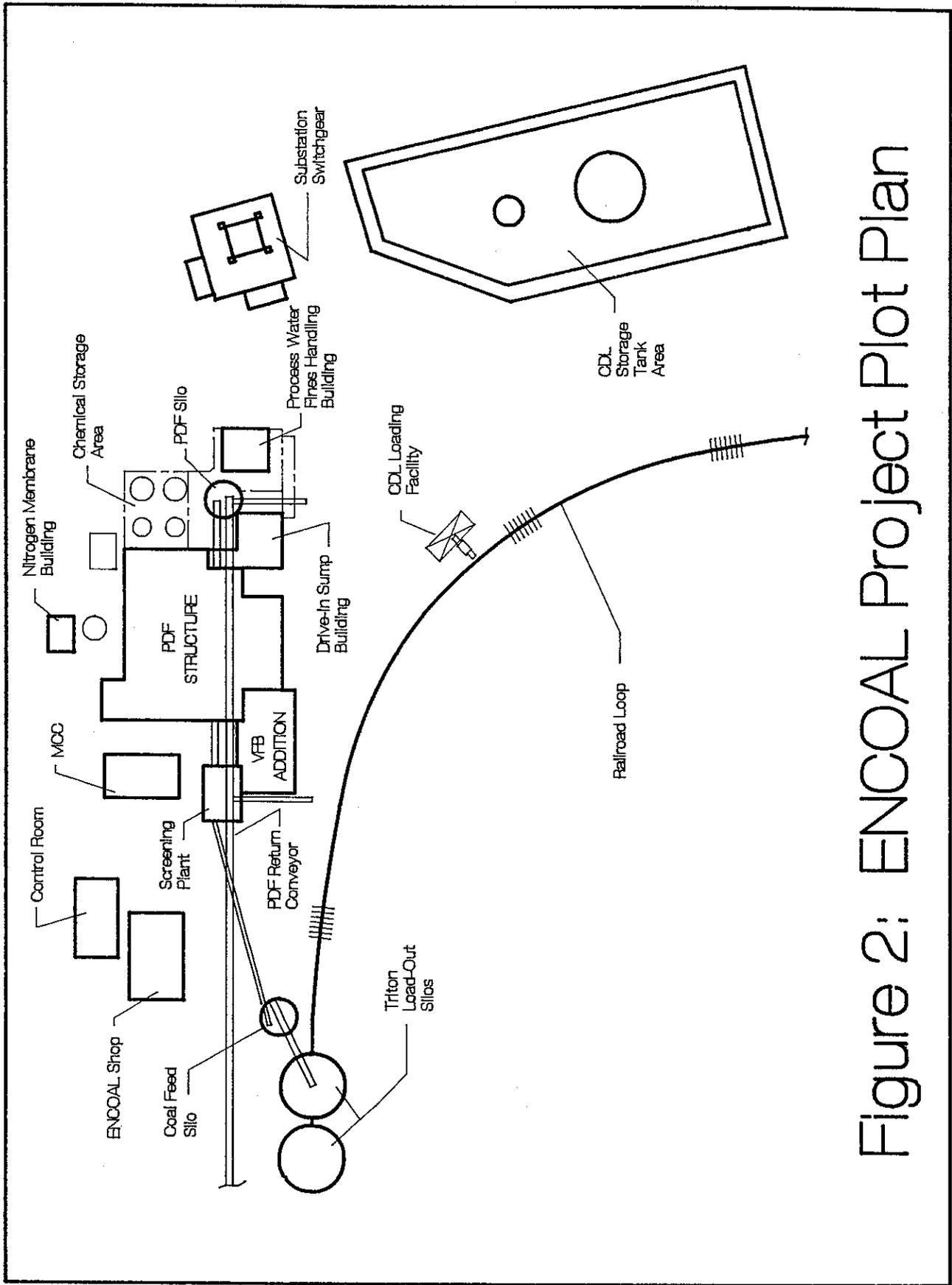


Figure 2: ENCOAL Project Plot Plan

Although some testing is still ongoing, most of the plant production of PDF and CDL is for test burns. Table 1 summarizes the plant operations over the last three years.

Product recoveries from the feed coal have varied somewhat from the original projections. In the case of PDF, recovery has been lower. This is because more fines are generated in the process than expected and they are not currently recovered. CDL recovery is higher than expected by 20-25%, apparently due to a more efficient liquid recovery system than the one used in the pilot plant.

### Product Deliveries

Commercialization of both the solid (PDF) and liquid (CDL) products from the ENCOAL Plant took a major step forward in 1994. PDF was shipped in trainload quantities for the first time to utility customers. The results of these shipments demonstrated that utility and industrial users can plan for test burns of PDF with confidence. Potential for extending the use of CDL into the industrial low sulfur residual fuel oil market was also demonstrated.

In September 1994, ENCOAL commenced shipment of PDF to utility customers via the Burlington Northern railroad. Shipments made to the first customer, the Western Farmers Electric Cooperative in Hugo, Oklahoma, started at a 15% blend level and ranged up to 30%. The upper level of these blends was determined by the heat content limit in the customer's boiler. Shipments to a second customer, Muscatine Power and Water in Muscatine, Iowa, started at 40% PDF and ranged up to 91%. The rail cars in this shipment were capped with a small amount of ROM Buckskin coal. Capping is one way to control loss of fine material during shipment. Because the ROM coal becomes blended with the PDF upon unloading, it ends up as a 91% blend.

<b>RUN START DATE</b>	<b>RUN TIME (DAYS)</b>	<b>TONS OF RAW COAL FEED</b>	<b>BARRELS OF CDL PRODUCED</b>	<b>TONS OF PDF PRODUCED</b>	<b>REASON FOR FINAL PLANT SHUTDOWN</b>
10/15/92	5	2,200	1,100	700	ESP Failure
01/05/93	9	2,800	1,100	700	Pyrolyzer sand seal failure
04/13/93	17	5,200	3,000	2,200	Normal plant shutdown
06/02/93	14	4,400	2,500	2,000	Normal plant shutdown
01/18/94	8	800	500	400	Pyrolyzer grate plugging
02/02/94	12	2,400	900	1,700	VFB solids plugging
03/08/94	5	1,100	600	500	Pyrolyzer grate & process water fines plugging
05/07/94	68	25,300	13,100	11,200	Plugged VFB and dryer grates
08/09/94	16	5,400	2,600	1,900	Plugged heat exchanger
09/09/94	39	14,600	7,300	6,200	VFB & Dryer grates plugged
10/24/94	38	15,800	6,400	6,400	Planned turnaround
02/25/95	49	22,700	11,700	10,600	Belt fire - Triton plant
<b>TOTALS</b>	280	102,700	50,800	44,500	

**Table 1. Significant Plant Runs (June 17, 1992 through June 10, 1995)**

With these first shipments, ENCOAL's goals were to demonstrate its ability to coordinate with the Buckskin Mine in loading and shipping consistent blends, to ship PDF with dust generation comparable to, or less than, ROM Buckskin coal and to ship PDF blends that are stable with respect to self heating. Furthermore, ENCOAL intended to demonstrate that PDF could be

transported and delivered to customers using regular commercial equipment. With respect to utilization, the goal for these shipments was for customers to burn trial amounts (1/2 train minimum) of PDF blends with minimal adjustment of equipment. These goals have all been met as reported in a more detailed test burn report<sup>[2]</sup>.

Since the initial shipments in 1994, ENCOAL has shipped an additional unit train to Muscatine and initiated shipments to a third customer, Omaha Public Power District (OPPD) in Omaha, Nebraska. Three unit trains have been shipped to OPPD containing approximately 25% PDF. This customer has been burning PRB coal in a boiler designed for bituminous coal for some time, and the increased heat content of the PDF blends help increase plant output. All PDF shipments to date are documented in Table 2.

DATE LOADED	CUSTOMER	BLEND (%PDF)	TONS SHIPPED			HEAT CONTENT
			PDF	COAL	BLEND	
09/17/94	W.FARMERS	14.4	922	5,448	6,370	8,760
09/24/94	W.FARMERS	21.2	1,080	4,020	5,100	8,910
10/01/94	W.FARMERS	25.1	1,508	4,493	6,001	8,940
10/10/94	W.FARMERS	31.9	1,603	3,241	5,024	9,310
10/24/94	W.FARMERS	24.0	2,665	8,426	11,091	9,060
11/23/94	MUSCATINE	39.0	1,957	3,122	5,079	9,630
11/29/94	MUSCATINE	66.6	3,423	1,713	5,136	9,670
12/13/94	MUSCATINE	90.7	10,576	1,082	11,658	10,000
04/23/95	MUSCATINE	33.0	3,979	8,094	12,073	10,607
05/05/95	OMAHA PPD	24.4	2,711	8,412	11,123	8,940
05/11/95	OMAHA PPD	24.0	2,669	8,464	11,133	8,939
05/13/95	OMAHA PPD	26.0	2,952	8,398	11,350	8,854

Table 2. Summary of Trains Shipped Containing PDF

Coincident with PDF shipments was a broadening of the customer base for the liquid CDL product. ENCOAL Corporation ships the majority of its CDL to Dakota Gasification in Beulah, North Dakota. However, Dakota Gasification's facility is unique and there is a need to demonstrate broader market applications for CDL as an industrial low sulfur boiler fuel. Two customers have recently received shipments of CDL, one a blender and the other a large industrial facility. ENCOAL Corporation laboratory data have shown that results will be dependent, chemically, on the source of any blend fuel. Initial results from these two customers confirm the data<sup>[2]</sup>.

Initial testing of CDL has shown that extraction of higher value products is both technically and economically feasible. Detailed characterization of the CDL and evaluation of upgrading opportunities are currently in progress. Additional work has also been done on blending opportunities and market applications for various upgraded products. Further work is planned in the balance of 1995. Table 3 summarizes the CDL tank car shipments thus far.

CUSTOMER	# OF CARS	DESTINATION	USE
Dakota Gas	58	Beulah, ND	Industrial Boiler
Texpar	3	Milwaukee, WI	Small Boilers
3 M Company	14	Hutchinson, MN	Industrial Boiler
Kiesel	2	St. Louis, MO	Blend W/ #6 Oil

**Table 3. Summary Of CDL Tank Car Shipments**

As indicated above, utilization of CDL will continue to evolve. Blends of CDL have been successful when customer handling equipment can be heated and the customer uses a compatible blending stock. ENCOAL will continue to develop a matrix of suitable blends from field experience tied to laboratory testing. ENCOAL is also investigating additives for improving compatibility. Furthermore, appropriate customers for testing and burning unblended CDL are also being evaluated.

## CHALLENGES

A detailed review of equipment and plant modifications through August 1994 has been presented<sup>[1,3]</sup>. The following table summarizes the major challenges that have been overcome and the solutions implemented;

AREA OF PLANT	DEFINITION OF PROBLEM	SOLUTION
Electrostatic Precipitators	Insulator Failures	Modified Insulators, Improved Temperature Control
Material Handling	Plugging and Spillage	Modified S-belts & Chutes
PDF Quenching and Steam Condenser	Oil and Coal Dust, Too Small	Added Scrubber, Added 2 Larger Exchangers
Dryer and Pyrolyzer	Sand Seal Failures	Replaced With Water Seals
Combustors	Unstable Operation	Revised Control System
Pumps and Blowers	Sizing Problems, Mostly Too Small	Replaced With Larger Equipment
Changing Process Variables	Initial Plant Design Parameters Were Off	Adjusted Operating Set Points
PDF Dust Collection	Dusty Conditions On Product Side of Plant - No Scrubbers	Added Two Wet Scrubbers
PDF Deactivation	Could Not Produce Stable PDF In Original Equipment	Added VFB Deactivation Loop Equipment
Process Water System	Accumulation of Oily Fines In Process Equipment	Installed Clarifier, Floc & Vacuum Filter
Plant Operability and Maintenance	Difficult Access, Labor Intensive Clean-up, Inflexible To Operate	Piping Revisions, Access Platforms and Doors, Relocate Valves

**Table 4. Summary Of Plant Modifications**

Still to be resolved are several challenges involving plant capacity, PDF stabilization and handling of coal fines produced in the cyclones. In addition, CDL upgrading even on the small scale of the ENCOAL plant, appears to be economically attractive as well as something that needs to be tested before application in a large commercial plant. Data collection and design work are in progress for these respective projects with implementation projected for next year.

### Plant Capacity

Two known bottlenecks remain that prevent attainment of full design capacity of 1000 TPD. The VFB loop is the primary limiting factor, since it was designed for 50% of plant capacity. A second unit was planned once the effectiveness of the PDF deactivation process was demonstrated. There appear to be better, more complete solutions to the PDF deactivation problem than the VFB, so addition of a second unit is on hold. The pyrolyzer blower is the second bottleneck. It is about 25% too small for the current processing conditions. Once the deactivation bottleneck is resolved, a decision on a blower upgrade can be made.

### PDF Deactivation

Product deactivation remains a key challenge. At the present time, the PDF is not completely stabilized in the plant but has to be "finished" by a short exposure to atmospheric conditions in a layered stockpile. In addition to atmosphere stabilized PDF, a stable product can be made by blending run-of-plant PDF with either ROM coal or the atmosphere stabilized PDF, but there is a Btu penalty. The VFB equipment added last year is doing most of the deactivation and plant testing is still underway to optimize its operation. However, it is believed that other approaches to oxidative deactivation that yield longer residence times may be more effective. A PDF stabilization task force has been established to develop an understanding of the requirements for stabilization and develop solutions. The equipment needed to effect complete, in-plant deactivation will be the focus of the next significant plant modification.

### Cyclone Fines

Each of the three major gas loops in the ENCOAL plant, namely the dryer, pyrolyzer and VFB, uses a cyclone to remove particulate material leaving the process unit. Their efficiencies vary with the required purity of the gas stream, but the quantity of solids collected are significant at 3%, 2% and 10% of the feed coal, respectively. At present, this total of 15% of the feed coal is not recovered as product PDF since the cyclone fines are slurried and discharged to a holding pond prior to disposal in the pit. This not only represents a large material handling and disposal cost, but a significant loss of revenue. Preliminary designs have been developed to recover a majority of these fines and reduce the operational costs. A plant modification project is planned for late 1995.

### CDL Upgrading

The ENCOAL plant was intentionally designed to capture a single wide-boiling-range liquid product, CDL, as opposed to making multiple liquid fractions. This was done to simplify the operation, lower the capital cost and reduce the risk associated with the added complication of liquid separations. It was determined that this would be evaluated after the basic LFC Technology had been demonstrated. Attention has now been turned to CDL upgrading since the plant has moved into a production mode.

Some preliminary feasibility and design work has indicated that upgrading of the CDL both in the ENCOAL plant and on a commercial scale makes economic sense; indeed it may be required to produce products that can be sold in quantity in existing markets. The M. W. Kellogg Company has recently been engaged to develop a design and cost estimate for modifying the existing plant for upgrading CDL, using information from these preliminary studies and all chemical characterization information available on CDL .

The basic concept is to produce three broad cut commercially viable streams; (1) a transportation grade fuel feedstock that would include most of the aliphatic compounds present in CDL, (2) a tar acid fraction that would include the cresylic acids, phenols and light aromatics and (3) a heavy residual bottom that would be mostly dense aromatic rings suitable as a source of carbon for products such as carbon black and activated carbon. The outcome of the Kellogg work, if it still proves economically viable, will be a project for the 1996-97 time frame.

### PDF Properties

After three years of operation and production of 44,500 tons of PDF, the properties of PDF that can be produced in the plant are fairly well defined. The variables that are controllable to some extent in the process are the heat content, volatiles and moisture. The components dictated by the composition of the feed coal are ash, sulfur, size consist and hardness. The LFC process has little impact on the ash composition or ash fusion temperature. Test data have been presented in previous reports<sup>[3]</sup> that show the variability of the PDF with process conditions. Table 5 represents the averages of the PDF that are currently being made at the ENCOAL plant.

PROXIMATE ANALYSIS	PLANT RUN	LAYDOWN BLEND	TARGET
Heat Content (Btu/lb)	11,112	9,649	11,400 - 11,600
Moisture (%)	9.81	17.15	7 - 8
Ash (%)	7.56	8.14	6 - 9
Volatile Matter	25.93	27.27	21 - 24
Fixed Carbon (%)	56.70	47.44	57 - 60
Sulfur (%)	0.41	0.36	0.51 Maximum
ULTIMATE ANALYSIS			
Moisture (%)	9.81	17.15	7 - 8
Carbon (%)	67.43	58.59	68 - 70
Hydrogen (%)	3.13	2.87	3.1 - 3.4
Nitrogen (%)	1.08	0.98	1.0 - 1.3
Sulfur (%)	0.41	0.36	0.51 Maximum
Ash (%)	7.56	8.14	6 - 9
Oxygen, by difference (%)	10.58	11.91	10 - 12
OTHER			
Hardgrove Grindability	57	48	45 - 50
#Sulfur/MMBtu	0.37	0.37	0.45 Maximum
#SO <sub>2</sub> /MMBtu	0.74	0.74	0.90 Maximum
Ash Mineral Analysis	Same as source coal	Same as source coal	Same as source coal
Ash Fusion Temperature	2220°F	2220°F	2220°F

Table 5. Average Representative Properties of PDF

#### CDL Properties

Like PDF, the properties of CDL are influenced by the pyrolyzer operation. However, the properties of CDL are also influenced by operation of equipment in the pyrolysis gas loop, including the pyrolyzer cyclone, the quench tower and the electrostatic precipitators. These

directly affect the amount of water and sediment in the CDL. Again, a significant amount of data has been presented in previous reports<sup>[3]</sup>, so only the following summary table is presented here. A significant amount of work has been done on the detailed chemical characterization of CDL for the upgrading project discussed above. This work is ongoing and will be the subject of future reports.

	CDL	Low Sulfur Fuel Oil
API Gravity (°)	1.3 - 3.2	5
Sulfur (%)	0.3 - 0.5	0.8
Nitrogen (%)	0.6	0.3
Oxygen (%)	6.2	0.6
Viscosity @ 122°F (cs)	280	420
Pour Point (°F)	66 - 90	50
Flash Point (°F)	165	150
MBtu/gal	140	150
Water (wt %)	0.5	<1
Solids (wt %)	2 - 4	<1
Ash (wt %)	0.5	<1

**Table 6. Average CDL Quality**

## **COMMERCIALIZATION**

ENCOAL Corporation has a sublicense for the LFC Technology from the TEK-KOL Partnership. The Partnership, owned by SGI International and SMC Mining Company, is responsible for the commercialization and licensing of the LFC Technology and thus is carrying out ENCOAL's obligation under the Cooperative Agreement. Under the TEK-KOL Partnership Agreement, SGI International is designated as the Licensing Contractor responsible for licensing and promoting the LFC Technology. SMC is the administrative partner responsible for preparation of lease agreements and contracts.

Commercialization of the LFC Technology consists of marketing the products, PDF and CDL, to interested consumers at prices that will support the construction of commercial plants. Concurrently, the LFC Technology must be licensed to the prospective plant owners. These may or may not be the same as the consumers of the products. The technology and product marketing activities are closely interwoven and are carried out by both TEK-KOL partners. For the most part, ENCOAL carries out all SMC partnership activities.

### Domestic Markets

The most promising markets for the application of the LFC Technology in the U.S. are the subbituminous coal deposits in the Powder River Basin and the Texas lignite deposits near San Antonio. Close behind are the subbituminous reserves in Alaska's Beluga field and lignites in North Dakota. Testing on all of these coals has been conducted in the SGI Development Center (Center) pilot unit with favorable results.

Application of the LFC Technology to swelling or agglomerating coals is not feasible at this time, so most of the central and eastern U.S. coals are not candidates. Removal of sulfur by the LFC process has proven to be significant, especially when the sulfur form is highly organic, but these bituminous coals would still be too high in sulfur after processing to meet the amended clean air act requirements. Central and eastern U.S. coals are also more costly to mine than western subbituminous coal, leaving less margin for upgrading. For these reasons, central and eastern U.S. coals do not appear to be promising candidates for LFC processing.

**Powder River Basin.** A large portion of the extensive U.S. coal reserves lie in the Powder River Basin in Montana and Wyoming. Subbituminous and low in sulfur, this coal is ideal for processing via the LFC Technology. That is a major reason the ENCOAL plant was located near Gillette. The southern end of the PRB in Wyoming is of special interest because the sulfur and ash are especially low. Here the PDF product may have an increased value for metallurgical applications or as a super compliance blending material. Triton Coal Company's North Rochelle Mine, Arco's Black Thunder Mine and others are viable candidates. In fact, discussions have been held with both of these companies regarding commercial LFC plants and a test using Southern PRB coal in the ENCOAL plant is planned.

Overall, the PRB has the lowest mining costs in the U.S. and, being a long distance from the major utility markets, has the highest transportation costs. This combination yields a large differential value between the raw material cost and the delivered cost. The high incremental value, a well developed transportation infrastructure, qualified, available labor force and a large number of operating mines mean that the opportunities for installation of commercial LFC plants are very good for the PRB.

**Texas Lignite.** There are significant reserves of lignites in eastern and central Texas which are used for mine mouth power plants. One of these plants is owned and operated by Alcoa Corporation solely for the production of aluminum. Their operation near San Antonio could benefit from a commercial LFC plant that would replace their existing coal dryers. Furthermore, the stability of the PDF would not be an issue because it would be consumed on site. CDL recovery, predicted to be very high for the Sandow lignite, would help the economics.

Discussions have been held with Alcoa to explore the benefits of a commercial LFC plant. Other lignites in Texas, although extensively available, are not considered to be viable candidates because of their coal quality and proximity to existing power plants designed to burn the ROM material. Numerous tests on Texas lignites have been conducted at the Center.

**Alaska.** There are two promising areas in Alaska for the installation of commercial LFC plants, namely the Beluga fields and the Healy deposits. Both areas have extensive reserves, are largely subbituminous in nature and have low ash and sulfur. The Beluga coal is very near the Cook Inlet with the possibility of a deep water port for exports. However there is essentially no infrastructure to produce these reserves and this would be a costly venture. Current owners of the three main lease areas have not been able to attract buyers of the coal in the current market. Mine development would have to be included in any LFC plant venture.

At Healy, there is an existing producing mine and coal is shipped by rail to the coast for export. The Healy coal has been tested at the Center with good results. However the cost of mining is

fairly high, transportation costs are high and there is no local market. The PDF and CDL from a project in this area may have difficulty competing with other locations.

**North Dakota Lignite.** Significant reserves of lignites are present in the Williston Basin of North Dakota and tests on some of them indicate good potential for LFC processing. Others appear to have a tendency to be very friable when dried and yield a powder or dust that would need solids agglomeration. In particular, Knife River coal has been tested extensively at the Center. It produces good quality PDF and CDL yields are fairly high, but there is a question that the coal would hold together when handled in the LFC process.

Overall, the economics of commercial LFC plants for the North Dakota lignites appear attractive. The coal seams are relatively thick and the sulfur and ash content are low, although not as low as the PRB. However, North Dakota is closer to some important markets. This coal is being considered for an alternate coal test in the ENCOAL plant.

#### International Markets

**Pacific Rim.** The countries of the eastern Pacific Rim provide the most inviting conditions for the initial foreign development of the LFC Technology. There are huge reserves of subbituminous and lignite coal located in Asia. The impressive economic growth sustained over recent years and predicted to continue well past the year 2000 has stimulated the concomitant increase in the demand for electrical power. Furthermore, several different studies predict growth rates in Asian electrical power demand of 6 to 11% in general and as much as 13 to 15% in certain developing economies such as China and Indonesia. Over 80% of this demand is expected to be met with coal-fired electrical power plants. Japan remains the largest importer of steam coal in the world and, according to a recent study by Dr. Charles Johnson of the East West Center in Honolulu, Hawaii, is expected to expand its requirements by more than 34% by the year 2010. The predicted increases in steam coal imports are even greater in South Korea and Taiwan.

**China.** China is the largest producer as well as the largest consumer of coal in the world. Over a third of the coal production occurs in the three northern provinces of Shanxi, Shaanxi and

Inner Mongolia. However, due to significant transportation infrastructure problems, it is not always possible to move the coal within China to meet local needs. As a result of the extremely high economic growth in the southern and eastern coastal regions of China accompanied by a parallel demand for new electrical power, there are predictions that China may require imports of coal in the range of 10-50 million tons per year by 2010. Furthermore, the predictable result of burning such prodigious quantities of coal, much of it high in sulfur, is an environmental problem of such magnitude that it is a major concern not only of the Chinese government but also for the governments of neighboring countries and, indeed, the world.

For these reasons, China is viewed as one of the prime candidates for application of the LFC Technology. The LFC Technology offers China the opportunity:

- to more efficiently and effectively employ its vast resources of coal
- to conserve scarce and valuable railroad assets as a result of the moisture reduction aspect of the LFC Technology
- to vastly expand its exports into the world steam coal market and, thereby, generate much needed foreign revenue
- to augment valuable and increasingly scarce petroleum assets through the production of CDL
- to reduce the extremely severe pollution problems associated with burning high sulfur coal

The LFC Technology has been actively promoted in China for several years with the Ministry of Coal Industry (MOCI) and officials of regional coal mine administrations by explaining the value of employing the LFC Technology and developing potential commercial plant projects. Although China has huge quantities of bituminous and anthracite coal, it also has great reserves of subbituminous and lignite coals that are ideal candidates for upgrading using the LFC Technology. MOCI expressed keen interest in the advantage to China offered by the LFC Technology and has invited representatives of SGI to visit various mining areas in China that could be potential sites for LFC projects.

To date, four technical feasibility studies (called a Phase I Study as described previously<sup>[3]</sup>) of coal from Chinese mines have been completed. Three more sets of samples from other regions are undergoing analysis in the Center. MOCI is interested in examining opportunities in three additional areas of China.

Having identified the coal samples from the Longkou region of Shandong Province on the southern coast of the Bo Hai Gulf as one of the excellent opportunities, SGI is conducting, in conjunction with Mitsubishi Heavy Industries (MHI), an engineering and economic assessment (called a Phase II study) of a proposed project in Longkou. Determining and resolving the requirements of the Chinese system for project development has proven to be almost as challenging as initial process development. The Shandong project enjoys the advantages of being located immediately adjacent to an operating harbor capable of direct shipment to Japan and Korea. The short transportation routes make the potential market price for the solid product very attractive.

Another Phase I Technical Feasibility Study has been completed for lignite coals from the Zhalaier region of northern Inner Mongolia near the town of Manzhouli on the Russian border. While relatively remote, Zhalaier benefits from being located directly on the extension of the Trans-Siberian railroad that runs through China to the ports of Dalian and Qinhuangdao on the Bo Hai Gulf. Part of a Phase II study being proposed for the Zhalaier region will include a careful economic evaluation of the impact of the transportation costs on the overall economic assessment. The Phase I study was particularly encouraging and local officials are especially interested in the proposed project because of the pressing need for economic development in this remote area.

Visits to the mining areas of Shenyang in Liaoning Province, Taiyuan in Shanxi Province and Baoshan in Yunnan Province have resulted in several additional samples being drawn. The samples from Shanxi Province were all found to be bituminous, swelling coals not suited to LFC processing. The samples from Shenyang and Baoshan are definitely subbituminous and lignite but have not yet been processed in a Phase I program. Coal from the Fushun district of Province was similar to the Shanxi coal and is not a candidate for LFC processing. Other low-rank samples from the Zhaotong area of Yunnan Province are awaiting testing also.

In June of 1995, SGI visited the Shengli mine near Xilinhot in Inner Mongolia. A trip to the Tumen River area of Jilin Province and the Zhaotong mining area of Yunnan Province are scheduled for later in the year. Altogether, there is a good potential for successful project

development in China. The cooperation and enthusiasm of the Ministry of Coal Industry continues to be especially helpful.

**Indonesia.** Approximately 93% of Indonesia's reported 36+ billion metric tons of reserves are in the form of subituminous and lignite coal. Significantly, though, this accounts for over 97% of the identified recoverable reserves in all of the ASIAN countries. These reserves are split approximately 70% on the island of Sumatra and 30% on the island of Kalimantan. In fact, the Indonesian reserves have not been definitively studied yet and there exists some question as to the full extent of the identified and hypothetical reserves. On a positive note, the vast majority of the mines are open-cut operations enjoying thick seams and are mostly located near the coast or close to a navigable river, facilitating ready access to international as well as domestic markets.

Indonesia's rapid economic growth during the past decade has fueled an increase in the demand for electrical power that has grown at 11-15% per year. Furthermore, although Indonesia has been a major exporter of oil, as a result of the surging domestic growth and the limited oil reserves, it is predicted to become a net importer of petroleum by the year 2000. While a significant portion of the coal production will be destined to feed the growing domestic electrical power and industrial needs, Indonesia also requires the foreign exchange credits which will result from increasing the export market. Consequently, it is under strong pressure to better exploit its vast reserves of subituminous and lignite coal.

Toward this end, work has been ongoing in Indonesia for over four years to promote the advantages of the LFC Process in answering many of Indonesia's needs. The coal industry is dominated by P.T. Tambang Batubara Bukit Asam (PTBA), the state coal mining corporation which operates under the Ministry of Mines and Energy. The structure of the industry includes the state-owned mines operated by PTBA, national companies contracted by PTBA under coal concession contract agreements, private domestic companies operating under mining concessions issued by PTBA and a few local area coal cooperatives.

Employment of the LFC process to upgrade low-rank coal would permit Indonesia, which is closer to Japan, South Korea, Taiwan and Hong Kong, to become very competitive in the steam coal markets. A letter of intent has been signed with PTBA to evaluate the coal from the Tanjung Enim region of South Sumatra and proceed towards development of a commercial LFC plant. The plan is to upgrade the subituminous reserves for use in the Suralaya Power Plant and to export the PDF in the steam coal market. A Phase I study on some thirteen different samples indicated that several of the coals of the Tanjung Enim region were good-to-excellent candidates for upgrading using the LFC process. Indonesia, which is short on investment capital, has submitted a request to the U.S. Trade and Development Agency (TDA) for a grant for a Phase II study. The project is awaiting the outcome of TDA's determination to proceed with the project.

Additionally, three other Phase I studies on coals from South Sumatra and Kalimantan have been completed. Arrangements have also recently been completed to proceed with a Phase II study of coal from the P.T. Berau mine in East Kalimantan. This Phase II study is expected to start in mid 1995 and be completed in early 1996. All studies involved coal samples which were determined to be exceptional candidates for upgrading using the LFC Technology. However, local infrastructure issues must be resolved before the situation becomes favorable for a profitable development of a commercial LFC project.

Opportunities continue to be pursued in Indonesia from Aceh at the northern tip of Sumatra to lignite mines in Sulawesi. The value of the LFC Technology to Indonesia parallels very closely the advantages mentioned for China. The value of the CDL production in Indonesia is an even stronger impetus than in China, however. Where China enjoys huge production capabilities in all forms of coal, it is especially important to Indonesia to upgrade the vast reserves of subituminous and lignite coals in order to participate effectively in the world steam coal market. Much of Indonesian coal is already naturally low in sulfur, so the resulting PDF is particularly attractive to markets in Japan. Work is continuing with MHI and other Japanese firms interested in cooperating in the development of projects in Indonesia and the rest of Asia.

**Southeast Asia.** Coal samples from Thailand and the Philippines have also been examined. Thailand has a great need to upgrade the large reserves of very low rank lignite in the Mae Moh region of north eastern Thailand. Some 27% of the electrical power in Thailand has been generated in this area but severe environmental pollution problems have caused the government to focus on ways to clean up the emissions from the coal-fired power plants. Regrettably, the Phase I studies revealed that the ash and sulfur content were just too high for effective utilization by the LFC process. Similarly, acceptable candidate coals in the Philippines were not found. To date, no coals from Vietnam have been examined, but initial indications are that most of the reserves are anthracite and that overall reserves of low-rank coal are too limited to make an LFC project practical.

**India and Pakistan.** India has the second largest production and consumption of coal in Asia. However, limited in-house development assets and the anticipation of excessive bureaucratic involvement have slowed the pursuit of opportunities there. Pakistan has had recent discoveries of huge reserves of lignite in the Thar Desert region. Samples for analysis are being pursued. Initial studies of the infrastructure in that region of Pakistan indicate that extensive development of roads, communications, electricity, etc. must be accomplished to make consideration of an LFC project reasonable. However, the Pakistan government is most eager to develop these assets.

**Eastern Europe.** Following separation from the Soviet Union, Eastern Europe inherited a desperate pollution situation substantially caused by coal-fired electrical power plants burning high sulfur coal. Poland, Germany and the Czech Republic are noteworthy in their announced programs to resolve this important problem. Contacts have been made with representatives in the Czech Republic to obtain and analyze samples. Two samples are, in fact, in the Center awaiting analysis. The prospects in the Czech Republic are encouraging because they have a more stable government, appear to be committed to solving their environmental problems and have significant coal reserves.

Three Phase I studies on coal samples from Poland have been completed without identifying a good candidate for upgrading. The extremely high ash and sulfur in the coals analyzed to date

would require a washing step prior to processing by an LFC plant. However, governmental interest in reducing the pollution caused by the extremely high sulfur dioxide emissions of raw coal continues to stimulate a search for a solution. The LFC process remains one of the candidate technologies to solve this problem.

**Russia.** Russia accounts for about 60% of the coal production of the former Soviet Union with almost all the rest coming from Ukraine and Kazakhstan. The increasing importance of coal to the fuel and energy balance of Russia must be viewed with the understanding of the major drop in crude oil production and decreased growth rate of gas production. Representatives of the Russian coal group ROSUGOL and the Kemerovo Coal Certification Center in south central Siberia have been evaluating a project using the LFC Technology in the Kemerovo region. Following a visit to SGI's offices in La Jolla, California and the ENCOAL Plant in Gillette, Wyoming, the Russian representatives signed a letter of intent to proceed with Phase I and Phase II studies for an LFC project. The Russian delegation was particularly excited about the value added by the production of CDL which is so important in view of reduced oil production. The Phase I study should be complete by mid-1995 and the Phase II is expected to begin in August providing that the Phase I results are favorable. If successful, this Russian endeavor could be the first of many projects in this country with huge potential reserves.

**Australia.** Australia is currently the world's largest exporter of both steam and coking coal with total shipments of approximately 140 million metric tonnes (MT) in 1994. Most of the coal goes to Asia, and approximately 50% goes to Japan, roughly 60% of Japan's imported coal. With 50 billion MT of high quality bituminous coal reserves, Australia should continue to be a major player in Pacific Rim coal trade with or without coal upgrading.

However, environmental and other considerations have tightened specifications for ash and sulfur. Australia already uses relatively modern technology throughout the coal mining industry, including washing and blending, to meet increasingly stringent specifications from demanding customers like the Japanese. There are, of course, limits to the degree that traditional technology can economically upgrade the Australian bituminous coals.

Fortunately, Australia is also endowed with approximately 200 billion MT of very low rank brown coal (over 50% moisture content), predominantly located in the State of Victoria. These deposits are quite unique, with minimal overburden and seams up to 100 meters thick. This coal is easily and economically recovered with large bucket wheel excavating equipment, and is currently fed directly to large power stations at the mine sites. These Victorian brown coals are also very low in both ash and sulfur and would make a superior boiler fuel or metallurgical reductant if the moisture could be economically reduced. The deposits are also relatively close to a shipping port on the Southeast coast of Australia.

SGI International recognized the strategic potential for application of the LFC Technology to the brown coals in this area. A wholly owned subsidiary (SGI Australia Pty. Ltd.) was formed in 1985 and currently holds an exclusive license for the LFC Technology in Australia and New Zealand. Sample testing at the Center has indicated that the potential yields and quality of PDF and CDL warranted further technical and economic analysis. In particular, the PDF was a very superior low ash, low sulfur solid fuel that could easily meet the most stringent "clean coal" specifications. This PDF could also be used for the direct reduction of iron ore, also a major Australian product.

There are unique technical and economic issues related to the successful application of the LFC Technology to Victorian brown coals. For example, pre-drying and agglomerating the feed coal prior to the LFC drying step appears to be necessary because the brown coal is extremely friable. When dried, the material turns to powder. Small pellets made from the partially dried brown coal powder would then be processed in a typical LFC plant. Because of the low cost of the feed coal and excellent quality of the products, SGI Australia believes this application of the LFC Technology has a strong competitive advantage.

#### **FUTURE WORK**

The next step in the Project is to deliver high quality, pure PDF to Wisconsin Power and Light and other utility customers for test burns. A high sulfur feed coal is also being tested for a special application at Muscatine Power and Water. It is anticipated that at least one alternate coal will be processed in 1995 and another is scheduled for 1996. A commercial plant design

and economic feasibility study is underway and a report is due next year. Work on improving the current methods of PDF stabilization is in progress and recommendations for modifications to plant equipment or operating conditions are expected by the end of the year.

The goal is to achieve 90% availability of the plant this year and complete any remaining plant modifications by the end of 1996. Any plant capacity projects should also be done by that time. Third party testing of the stack gases is scheduled for August at 50% of plant capacity. Additional testing will be required to bring the plant up to full design capacity, but not an additional permit. Efforts to commercialize the LFC Technology will continue both at home and abroad. The evaluation of CDL upgrading will also be completed and a decision made about proceeding with a plant modification.

## **CONCLUSIONS**

The ENCOAL Project continues to progress toward its goals. The debugging phase is complete and steady state operation has been achieved. The LFC Technology is essentially demonstrated and marketable PDF and CDL are being produced. Significant quantities of both products have been shipped and successfully used by customers. Plant availability is improving and it can be operated safely. Efforts to commercialize the LFC Technology are in progress.

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## GLOSSARY

ASTM	American Society of Testing Methods
°API	American Petroleum Institute measure of oil density
BACT	Best Available Control Technology
Btu	British Thermal Unit
Center	SGI Development Center in Perrysburg, Ohio
CDL	Coal Derived Liquid
CO	Carbon Monoxide
CH <sub>4</sub>	Methane
DOE	U. S. Department of Energy
ENCOAL	ENCOAL Corporation, a wholly owned subsidiary of SMC Mining Co., which is a wholly owned subsidiary of Zeigler Coal Holding Co.
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic Precipitators
lb.	Pound
LFC	Liquid From Coal
MMBtu	Million British Thermal Units
MOCI	Ministry of Coal Industry
MT	Metric Tonnes
N/A	Not Available
NO <sub>x</sub>	Nitrogen Oxides
OSHA	Occupational Safety & Health Administration
PDF	Process Derived Fuel
PRB	Powder River Basin
ROM	Run-of-Mine
S-Belt	Vertical conveyor with flexible sidewalls and rubber buckets
SGI	SGI International, La Jolla, CA
SMC	SMC Mining Company, Evansville, IN
SO <sub>2</sub>	Sulfur Dioxide
Std. Dev.	Standard Deviation
TEK-KOL	Partnership between SGI International and SMC Mining Company
TGA	Thermogravimetric analysis, procedure for analyzing coal and PDF
TPD	Tons Per Day
vs.	Versus
WP&L	Wisconsin Power and Light
wt.	Weight
#	Pound

**BLAST FURNACE  
GRANULAR COAL INJECTION**

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**ABSTRACT**

A blast furnace coal injection system has been constructed and is being used on the large furnaces at the Burns Harbor Division of Bethlehem Steel. The injection system has been designed to deliver both granular (coarse) and pulverized (fine) coal. Construction was completed on schedule in early 1995. This project will demonstrate the use of granular coal injection on large blast furnaces at injection rates up to 400 lbs/ton of hot metal with a variety of domestic coal types. The test program with different coals will be initiated in late 1995.

## INTRODUCTION

A blast furnace coal injection system has been installed at the Burns Harbor Division of Bethlehem Steel Corporation. This is the first blast furnace coal injection system in the US that has been designed to deliver granular (coarse) coal - all previously installed blast furnace coal injection systems in the US have been designed to deliver pulverized (fine) coal. Financial assistance for the coal injection system was provided by the Clean Coal Technology Program.

The use of granular coal in blast furnaces was jointly developed by British Steel and Simon-Macawber and used at the Scunthorpe Works in England. The blast furnaces at Scunthorpe have about one-half the production capability of the Burns Harbor blast furnaces. Therefore, one of the main objectives of the Clean Coal Technology (CCT) test program at Burns Harbor is to determine the effect of granular coal injection on large high productivity blast furnaces. Another objective of the CCT test program at Burns Harbor is to determine the effect of different types of US coals on blast furnace performance.

The Burns Harbor Plant produces flat rolled steel products for the automotive, machinery and construction markets. The Plant is located on the southern shore of Lake Michigan about 30 miles east of Chicago. Burns Harbor is an integrated operation that includes two coke oven batteries, an iron ore sintering plant, two blast furnaces, a three vessel BOF shop and two twin-strand slab casting machines. These primary facilities can produce over five million tons of raw steel per year. The steel finishing facilities at Burns Harbor include a hot strip mill, two plate mills, a cold tandem mill complex, a hot dip coating line and an electrogalvanizing line.

When originally designed and laid-out, the Burns Harbor Plant could produce all the coke required for the two blast furnaces operating at 10,000 tons/day. However, improved practices and raw materials have resulted in a blast furnace operation that now can produce over 14,000 tons/day. Since the coke oven batteries are not able to produce the coke required for a 14,000 ton/day blast furnace output, other sources of coke and energy have been used to

fill the gap. Over the years, coke has been shipped to Burns Harbor from other Bethlehem plants and from outside coke suppliers. In addition, auxiliary fuels have been injected into the furnaces to reduce the coke requirements. The auxiliary fuels have included coal tar, fuel oil and natural gas. The most successful auxiliary fuel through the 1980s and early 1990s has been natural gas. It is easy to inject and, at moderate injection levels, has a highly beneficial effect on blast furnace operations and performance. However, there are two significant problems with the use of natural gas in blast furnaces. One problem is the cost and the other is the amount that can be injected and, therefore, the amount of coke that can be replaced. Our process and economic studies showed that more coke could be replaced and iron costs could be reduced by injecting coal instead of natural gas in the Burns Harbor blast furnaces.

This led Bethlehem to submit a proposal to the DOE to conduct a comprehensive assessment of coal injection in the Burns Harbor blast furnaces. Following an extensive review by the DOE, Bethlehem's Blast Furnace Granular Coal Injection System Demonstration Project was one of thirteen demonstration projects accepted for funding in the Clean Coal Technology Program third round of competition. The primary thrust of the project is to demonstrate commercial performance characteristics of granular coal as a supplemental fuel for steel industry blast furnaces. The technology will be demonstrated on large high productivity blast furnaces using a wide range of coal types available in the US. The planned tests will assess the impact of coal particle size distribution as well as chemistry on the amount of coal that can be injected effectively. Upon successful completion of the work, the results will provide the information and confidence needed by others to assess the technical and economic advantages of applying the technology to their own facilities.

A major consideration in evaluating coal injection in the US is the aging capacity of existing cokemaking facilities and the high capital cost to rebuild these facilities to meet emission guidelines under the Clean Air Act Amendments. The increasingly stringent environmental regulations and the continuing decline in domestic cokemaking capability will cause significant reductions in the availability of commercial coke over the coming years. Due to this decline in availability and increase in operating and maintenance costs for domestic cokemaking facilities, commercial coke prices are projected to increase by more than general

inflation. Higher levels of blast furnace injectants, such as coal, enable domestic integrated steel producers to minimize their dependence of coke.

### Blast Furnace Process

The ironmaking blast furnace is at the heart of integrated steelmaking operations. As shown in Figure 1, the raw materials are charged to the top of the furnace through a lock hopper arrangement to prevent the escape of pressurized hot reducing gases. Air needed for the combustion of coke to generate the heat and reducing gases for the process is passed through stoves and heated to 1500-2300°F. The heated air (hot blast) is conveyed to a refractory-lined bustle pipe located around the perimeter of the furnace. The hot blast then enters the furnace through a series of ports (tuyeres) around and near the base of the furnace. The molten iron and slag are discharged through openings (tapholes) located below the tuyeres. The molten iron flows to refractory-lined ladles for transport to the basic oxygen furnaces.

A schematic showing the various zones inside the blast furnace is given in Figure 2. As can be seen, the raw materials, which are charged to the furnace in batches, create discrete layers of ore and coke. As the hot blast reacts with and consumes coke at the tuyere zone, the burden descends in the furnace resulting in a molten pool of iron flowing around unburned coke just above the furnace bottom (bosh area). Reduction of the descending ore occurs by reaction with the rising hot reducing gas that is formed when coke is burned at the tuyeres.

The cohesive zone directly above the tuyeres is so called because it is in this area that the partially reduced ore is being melted and passes through layers of unburned coke. The coke layers provide the permeability needed for the hot gases to pass through this zone to the upper portion of the furnace. Unlike coal, coke has the high temperature properties needed to retain its integrity in this region and is the reason that blast furnaces cannot be operated without coke in the burden.

The hot gas leaving the top of the furnace is cooled and cleaned. Since it has a significant heating value (80-100 Btu/scf), it is used to fire the hot blast stoves. The excess is used to generate steam and power and for other uses within the plant.

## COAL INJECTION TECHNOLOGY

Bethlehem decided to utilize the Simon Macawber Blast Furnace Granular Coal Injection (BFGCI) System, because unlike more widely used systems that utilize only pulverized coal, it is capable of injecting both granular and pulverized coal. Bethlehem believes that the Simon Macawber system offers a variety of technical and economic advantages which make this system potentially very attractive for application in the US basic steel industry. A schematic showing the application of the technology to the blast furnace is shown in Figure 3. Some of the advantages of this technology include:

- The injection system has been used with granular coal as well as with pulverized coal. No other system has been utilized over this range of coal sizes.
- The potential costs for granular coal systems are less than for pulverized.
- Granular coal is easier to handle in pneumatic conveying systems. Granular coals are not as likely to stick to conveying pipes if moisture control is not adequately maintained.
- Research tests conducted by British Steel indicate that granular coal is more easily maintained in the blast furnace raceway (combustion zone) and is less likely to pass through the coke bed. Coke replacement ratios obtained by British Steel have not been bettered in any worldwide installation.
- Granular coal's coarseness delays gas evolution and temperature rise associated with coal combustion in the raceway. Consequently, it is less likely to generate high temperatures and gas flows at the furnace walls which result in high heat losses, more rapid refractory wear and poorer utilization of reducing gases.
- System availability has exceeded 99 percent during several years of operation at British Steel.

The unique variable speed, positive displacement Simon-Macawber injectors provide superior flow control and measurement compared to other coal injection systems.

The joint development by British Steel and Simon-Macawber of a process for the injection of granular coal into blast furnaces began in 1982 on the Queen Mary Blast Furnace at the Scunthorpe Works.(1,2) The objective of the development work was to inject granular coal into the furnace and test the performance of the Simon-Macawber equipment with a wide range of coal sizes and specifications. Based on Queen Mary's performance, coal injection systems were installed on Scunthorpe's Queen Victoria, Queen Anne and Queen Bess blast furnaces and on Blast Furnaces 1 and 2 of the Ravenscraig Works. Queen Victoria's system was brought on line in November, 1984 and Queen Anne's in January, 1985. The Ravenscraig systems were started up in 1988. The success of the GCI systems at Scunthorpe and Ravenscraig led Bethlehem to conclude that the system could be applied successfully to large blast furnaces using domestic coals.

### INSTALLATION DESCRIPTION

A simplified flow diagram of the coal handling system at Burns Harbor is shown in Figure 4. The Raw Coal Handling Equipment and the Coal Preparation Facility includes the equipment utilized for the transportation and preparation of the coal from an existing railroad car dumper until it is prepared and stored prior to passage into the Coal Injection Facility; the Coal Injection Facility delivers the prepared coal to the blast furnace tuyeres.

Raw Coal Handling. Coal for this project is transported by rail from coal mines to Burns Harbor similar to the way in which the plant now receives coal shipments for the coke ovens. The coal is unloaded using an existing railroad car dumper, which is currently part of the blast furnace material handling system. A modification to the current conveyor was made to enable the coal to reach either the coke ovens or the coal pile for use at the Coal Preparation Facility.

This modification required a new 60-inch wide transfer conveyor from the existing conveyor and to a junction house. There the coal is transferred to a new 60-inch wide stockpile conveyor for the raw coal storage pile. The coal pile is formed with a radial stacker capable of building a 10-day storage pile (approximately 28,000 tons). The material handling system from the car dumper to the coal storage pile is sized at 2,300 tons per hour to match the output of the car dumper.

Raw Coal Reclaim. The raw coal reclaim tunnel beneath the coal storage pile contains four reclaim hoppers in the top of the tunnel. The reclaim hoppers, which are directly beneath the coal pile, feed a 36-inch wide conveyor in the tunnel. The reclaim conveyor transports the coal at a rate of 400 tons per hour above ground to the south of the storage pile. A magnetic separator is located at the tail end of the conveyor to remove tramp ferrous metals. The conveyor discharges the coal onto a vibrating screen to separate coal over 2 inches from the main stream of minus 2-inch coal. The oversized coal passes through a precrusher which discharges minus 2-inch coal. The coal from the precrusher joins the coal that passes through the screen and is conveyed from ground level by a 36-inch wide plant feed conveyor to the top of the building that houses the Coal Preparation Facility.

Coal Preparation. The plant feed conveyor terminates at the top of the process building that houses the Coal Preparation Facility. Coal is transferred to a distribution conveyor, which enables the coal to be discharged into either of two steel raw coal storage silos. The raw coal silos are cylindrical with conical bottoms and are completely enclosed with a vent filter on top. Each silo holds 240 tons of coal, which is a four-hour capacity at maximum injection levels. Air cannons are located in the conical section to loosen the coal to assure that mass flow is maintained through the silo.

Coal from each raw coal silo flows into a feeder which controls the flow of coal to the preparation mill. In the preparation mill, the coal is ground to the desired particle size. Products of combustion from a natural gas fired burner are mixed with recycled air from the downstream side of the process and are swept through the mill grinding chamber. The air lifts the ground coal from the mill vertically through a classifier where oversized particles are

circulated back to the mill for further grinding. The proper sized particles are carried away from the mill in a 52-inch pipe. During this transport phase, the coal is dried to 1-1.5% moisture. The drying gas is controlled to maintain oxygen levels below combustible levels. There are two grinding mill systems; each system produces 30 tons per hour of pulverized coal or 60 tons per hour of granular coal.

The prepared coal is then screened to remove any remaining oversize material. Below the screens, screw feeders transport the product coal into one of four 180-ton product storage silos and then into a weigh hopper in two-ton batches. The two-ton batches are dumped from the weigh hopper into the distribution bins which are part of the Coal Injection Facility.

Coal Injection. The Coal Injection Facility includes four distribution bins located under the weigh hoppers described above. Each distribution bin contains 14 conical-shaped pant legs. Each pant leg feeds an injector which allows small amounts of coal to pass continually to an injection line. Inside the injection line, the coal is mixed with high-pressure air and is carried through approximately 600 feet of 1-1/2-inch pipe to an injection lance mounted on each of the 28 blowpipes at each furnace. At the injection lance tip, the coal is mixed with the hot blast and carried into the furnace raceway. The 14 injectors at the bottom of the distribution bin feed alternate furnace tuyeres. Each furnace requires two parallel series of equipment, each containing one product coal silo, one weigh hopper, one distribution bin and 14 injector systems.

### PROJECT MANAGEMENT

The demonstration project is divided into three phases:

Phase I	Design
Phase II	Construction and Start-up
Phase III	Operation and Testing

Phase I was completed in December 1993 and construction was completed in January 1995. Coal was first injected in four tuyeres of D furnace on December 18, 1994. The start-up period will continue to November 1995 at which time the testing will start. The operation and testing of coals (Phase III) is expected to continue to July 1998.

The estimated project cost summary is noted in Table I. The total cost is expected to be about \$191 million. The construction of the facility was completed on budget and it is anticipated that the test program will also be completed on budget. Additional information on project management was presented at the previous CCT Conferences. (3,4)

### Start-up

The start-up period began in January 1995 and will continue through most of 1995. The objective during start-up is to establish a consistent and reliable blast furnace operation with coal injection and to maintain the iron production at about 14,000 tons/day. After some start-up problems that are typical with a new facility, the coal handling, preparation and injection equipment has performed as designed. The injection rate through May on both blast furnaces is shown in Figures 5 and 6. The initial injection rate was low as each of the tuyeres was switched from natural gas to coal. The switch from gas to coal usually took place with four tuyeres at one time, first on D furnace and then on C furnace. All tuyeres on D furnace were converted to coal in April and C furnace was using only coal by mid-May.

The switch from natural gas to coal causes a significant change to the internal working of a blast furnace. The temperature and composition of gases formed in the raceway (see Figure 2) are different and these differences continue up through the furnace to the top. The raceway temperatures are higher and the hydrogen content of the gases are much lower with coal injection. The challenge for the furnace operators has been to bring the process into thermal and chemical balance with these changes in raceway conditions. As of early June, both furnaces had been stabilized with a coal injection rate of about 140 lbs/ton. Some iron production was lost during the February to May period, but a stable production rate was established by late May.

The coal injection rate will be increased on both furnaces as the start-up progresses. The objective is to reach about 200 lbs/ton on D furnace and 300 lbs/ton or more on C furnace. The aim injection level on C furnace is higher than on D furnace because of higher density cooling in the lower and mid-stack on C furnace. Coal injection will cause higher thermal loads in the lower and mid-stack areas and C furnace was modified to better handle those

increased loads during a rebuild in late 1994. Once a coal injection rate of 300 lbs/ton or more has been established on C furnace, the test program will start.

### Test Plan

The objective of the test program is to determine the effect of coal grind and coal type on blast furnace performance. The start-up operation has been conducted to date with high volatile coal from eastern Kentucky. The coal has 36% volatile matter, 8% ash and 0.63% sulfur. The coal preparation system has been operated to provide granular coal with nominal size of 30% minus 200 mesh (74 microns). A trial will be conducted to determine the effect of using pulverized coal with a nominal size of 80% minus 200 mesh. The results of this trial will be of great interest to blast furnace operators and could have a significant effect on the type of coal injection facilities that will be installed in the future.

Another series of trials will be conducted to determine the effect of coal types and coal chemistry on furnace performance. Candidate coals for these trials are high volatile coals with moderately higher sulfur and ash than the eastern Kentucky coal presently being used, low volatile coals and Illinois Basin coals.

The important furnace performance parameters that will be closely monitored during these trials are coke rate, raw material movement in the furnace, pressure drop in the furnace, gas composition profiles, iron analyses and slag analyses. All results of the blast furnace trials will be evaluated and documented in a comprehensive report.

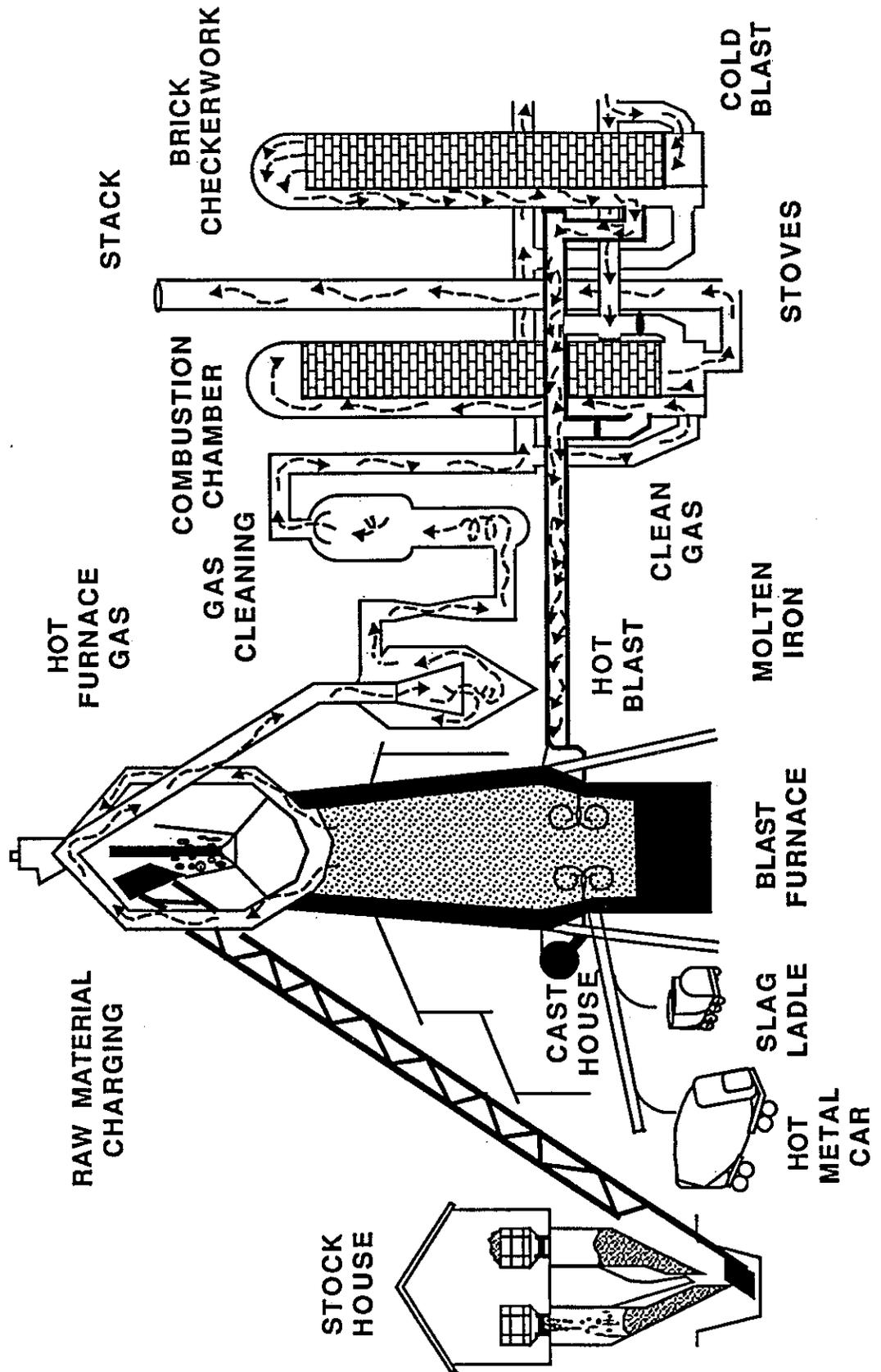
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2. D. S. Gathergood and G. Cooper, "Blast Furnace Injection - Why Granular Coal"? Steel Technology International, 1988.
3. D. Kwasnoski and L. L. Walter, "Blast Furnace Granular Coal Injection", Second Annual Clean Coal Technology Conference, Atlanta, GA, September 1993.
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**TABLE I. ESTIMATED GRANULAR COAL  
INJECTION PROJECT COST SUMMARY**

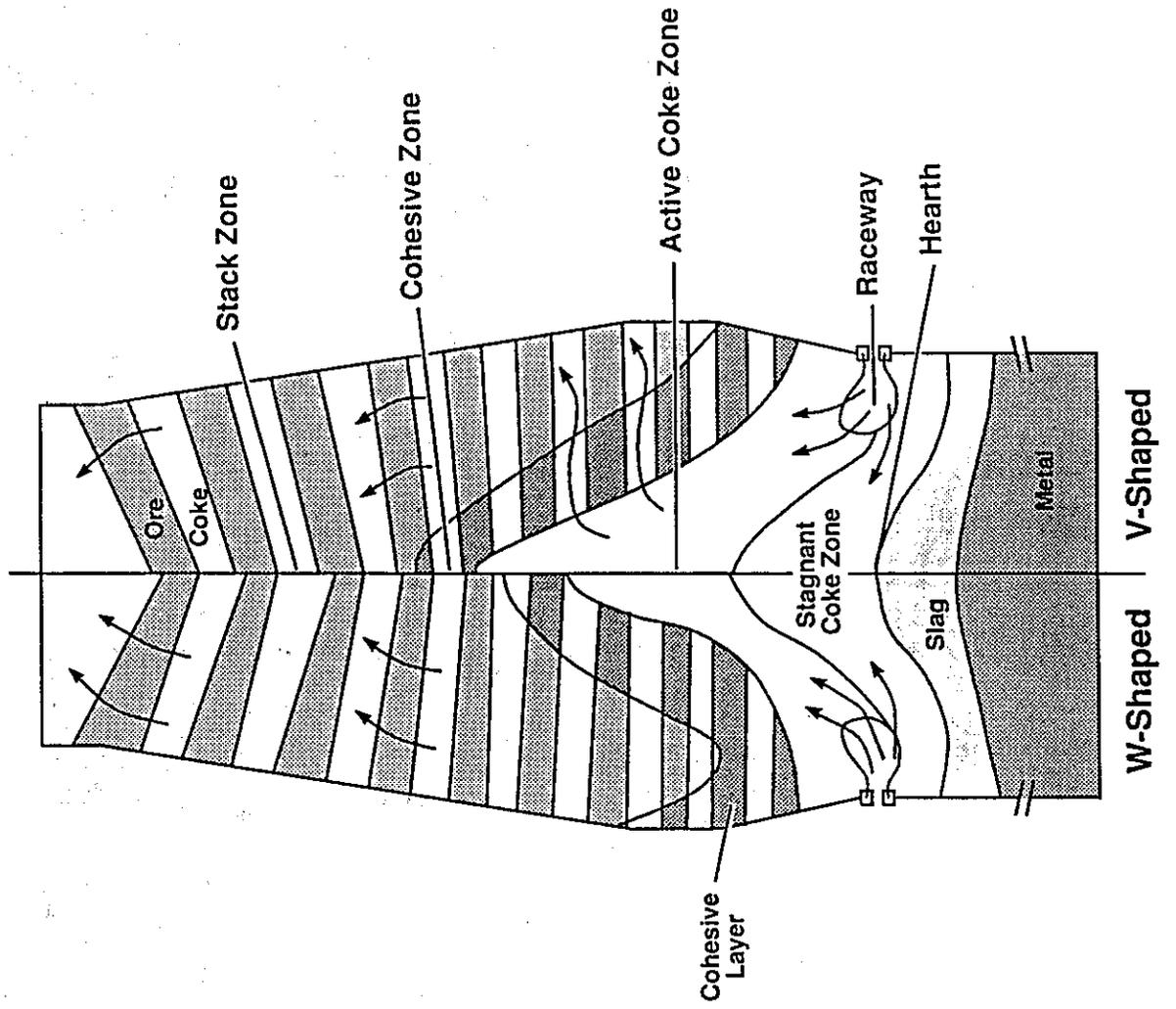
	<u>\$ Million</u>
Phase I Design	5.19
Phase II Construction and Start-Up	133.85
Phase III Operation	<u>51.61</u>
Total Cost	190.65
	<u>Cost Sharing</u>
DOE	31.26 (16.4%)
Bethlehem Steel	<u>159.39</u> (83.6%)
	190.65

**FIGURE 1**  
**THE BLAST FURNACE COMPLEX**

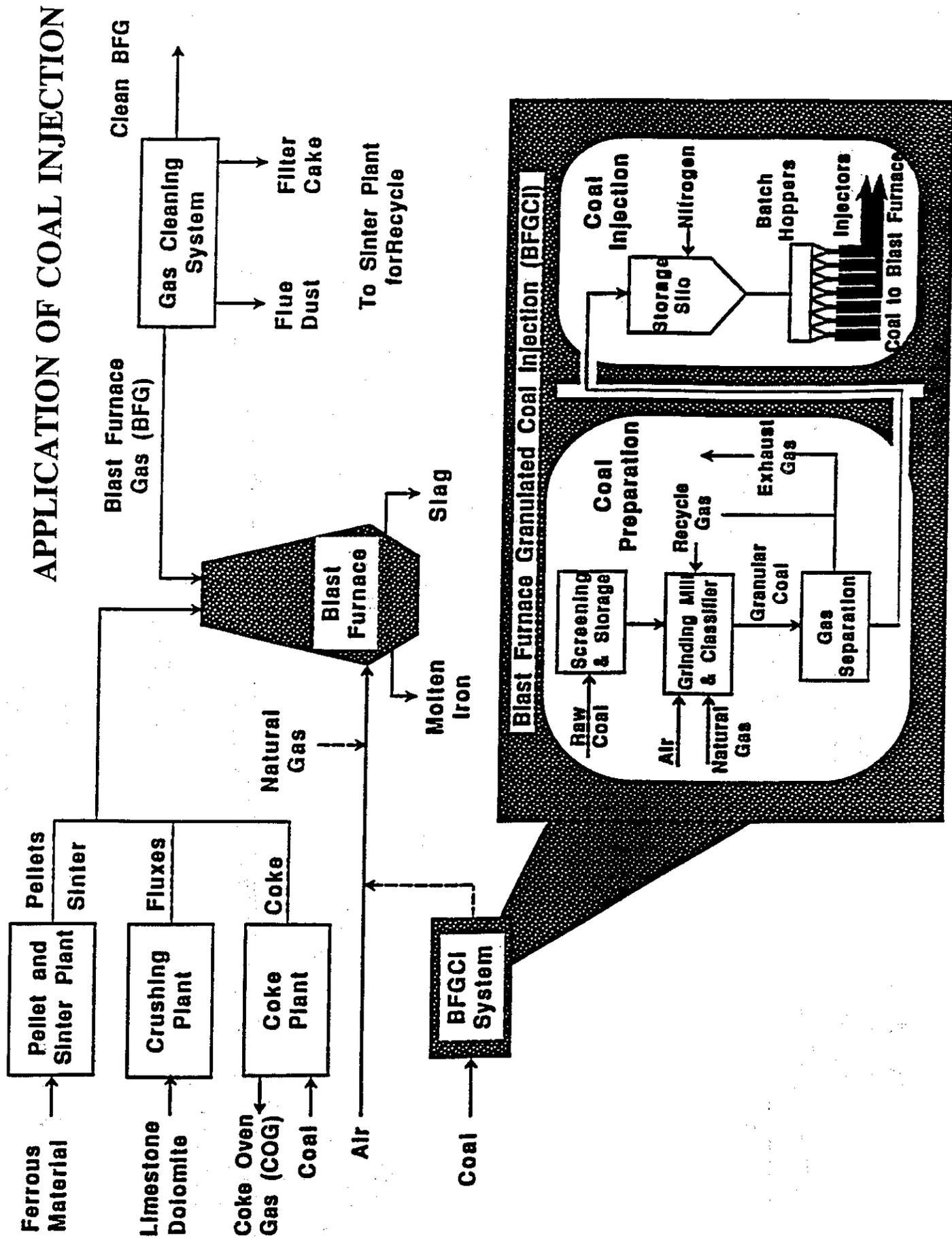


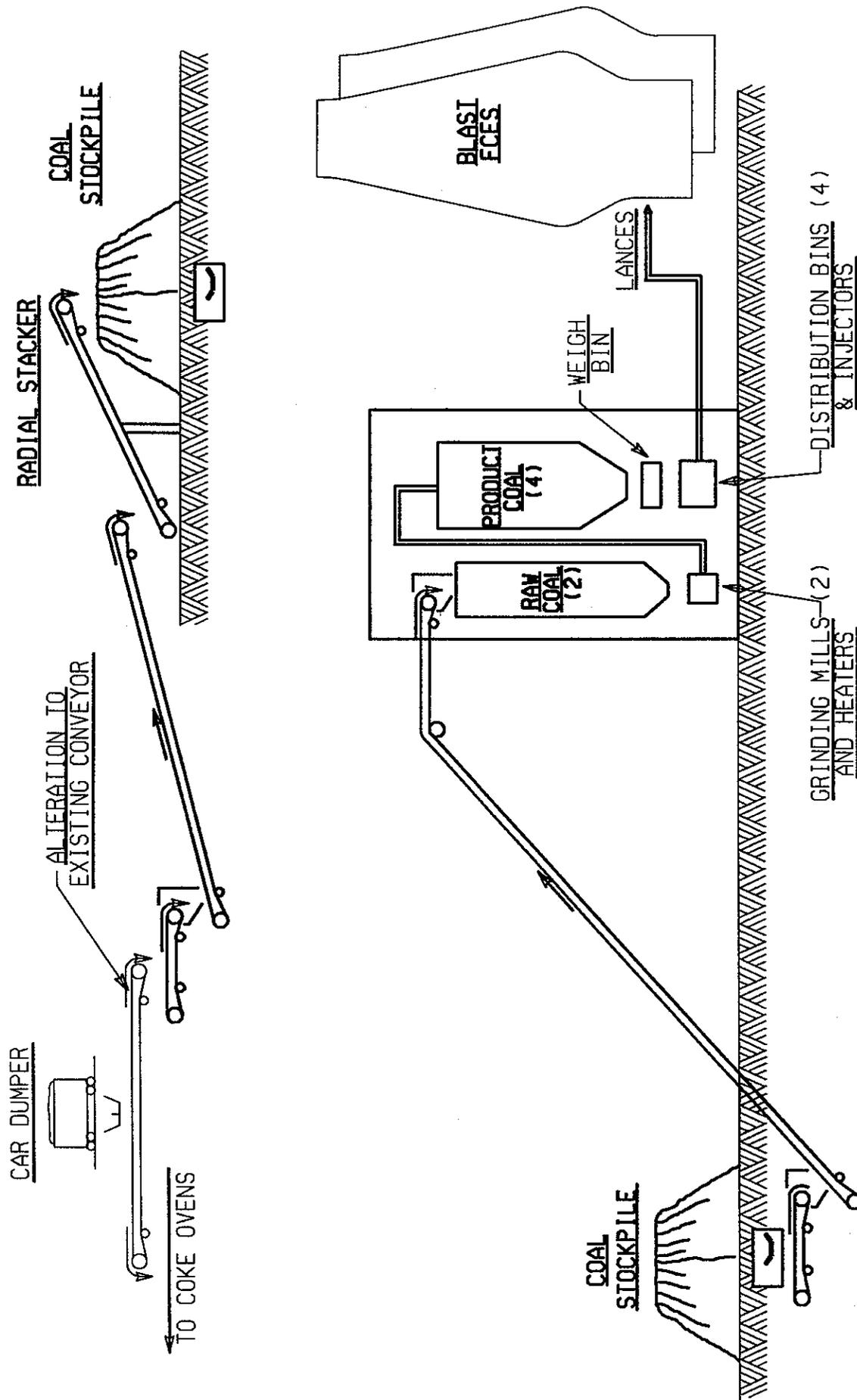
**FIGURE 2**

**ZONES IN THE BLAST FURNACE**



**FIGURE 3**





**FIGURE 4 - COAL PREPARATION AND INJECTION FACILITIES  
BURNS HARBOR PLANT**

FIGURE 5

BURNS HARBOR C FURNACE - COAL INJECTION

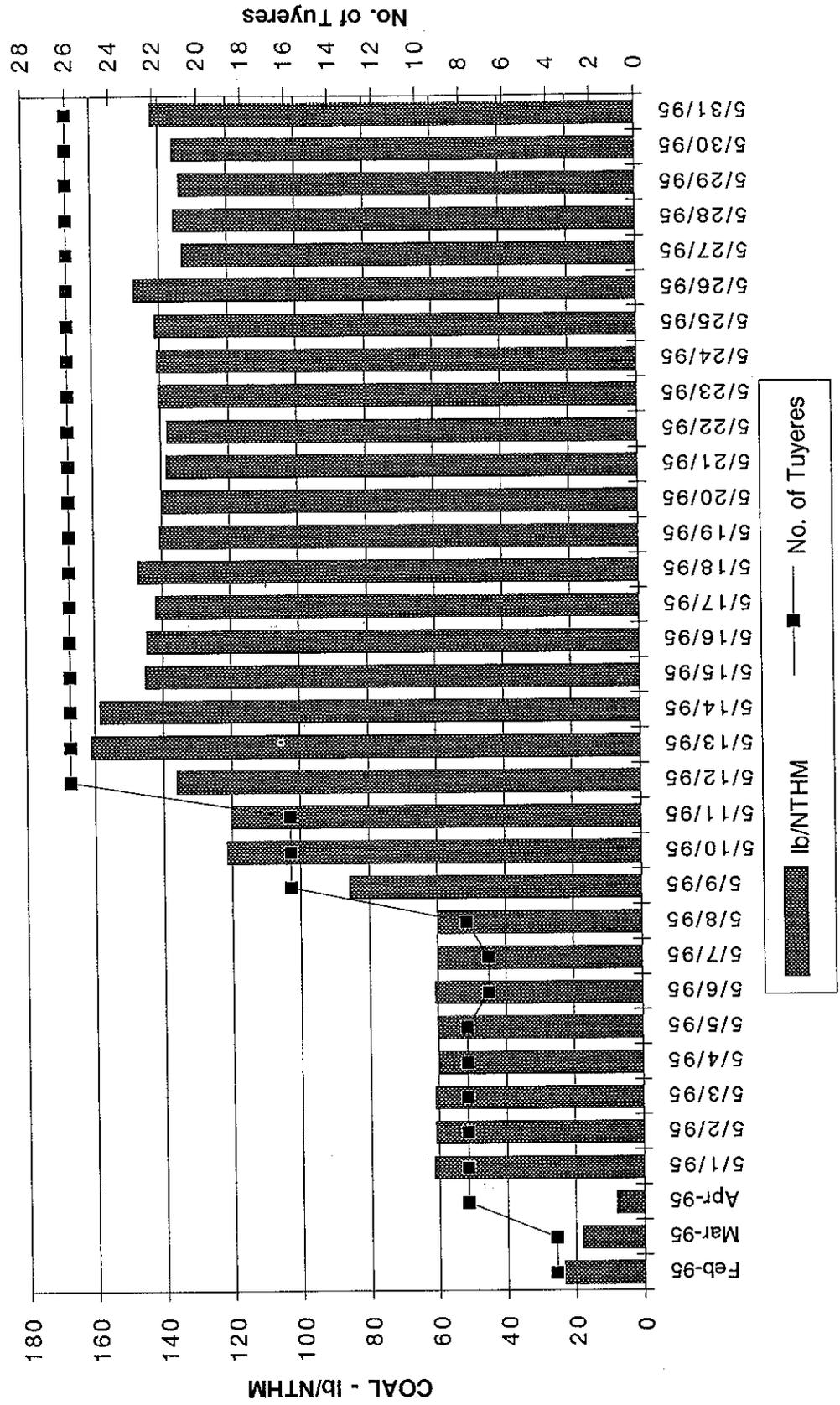
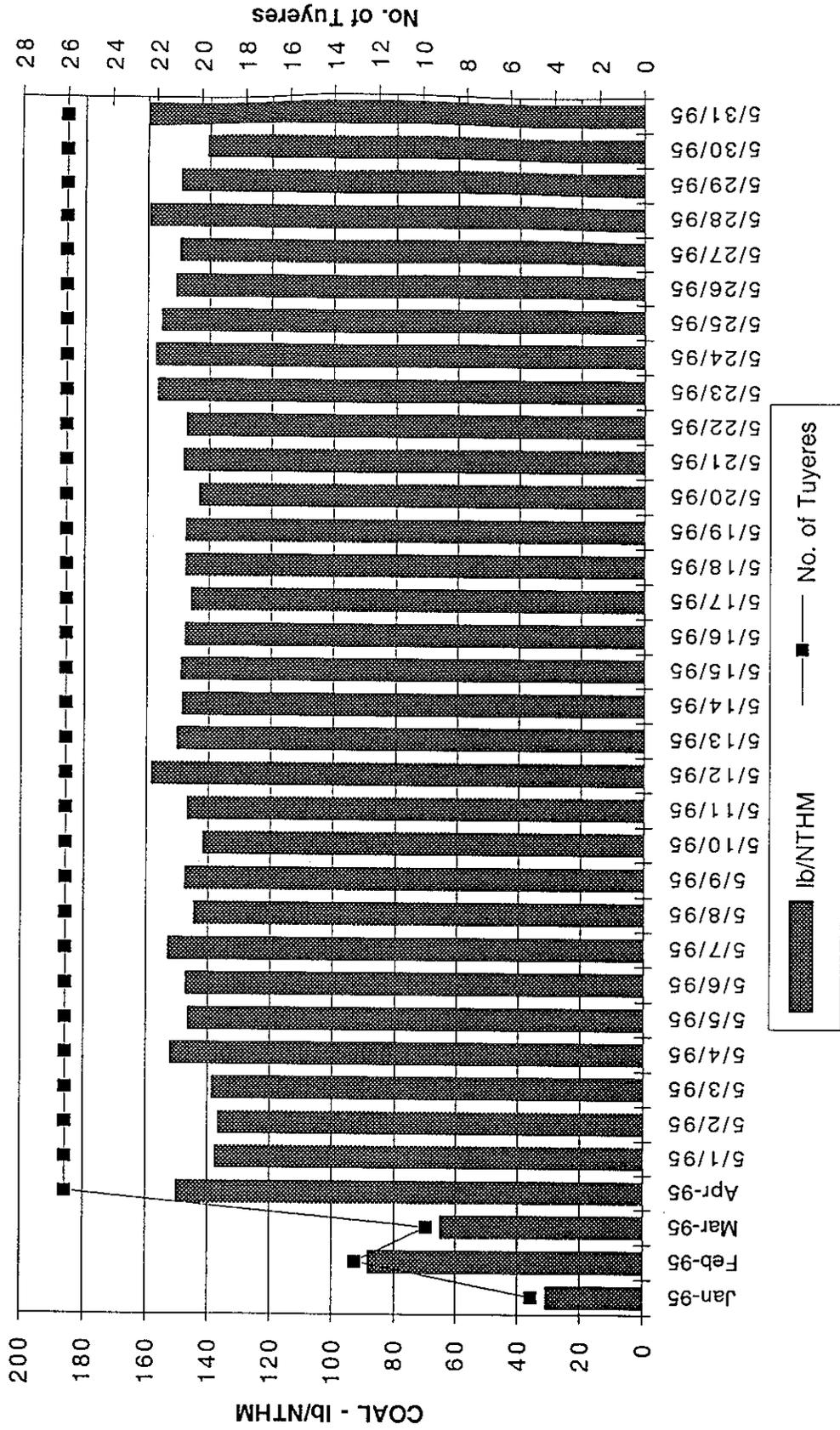
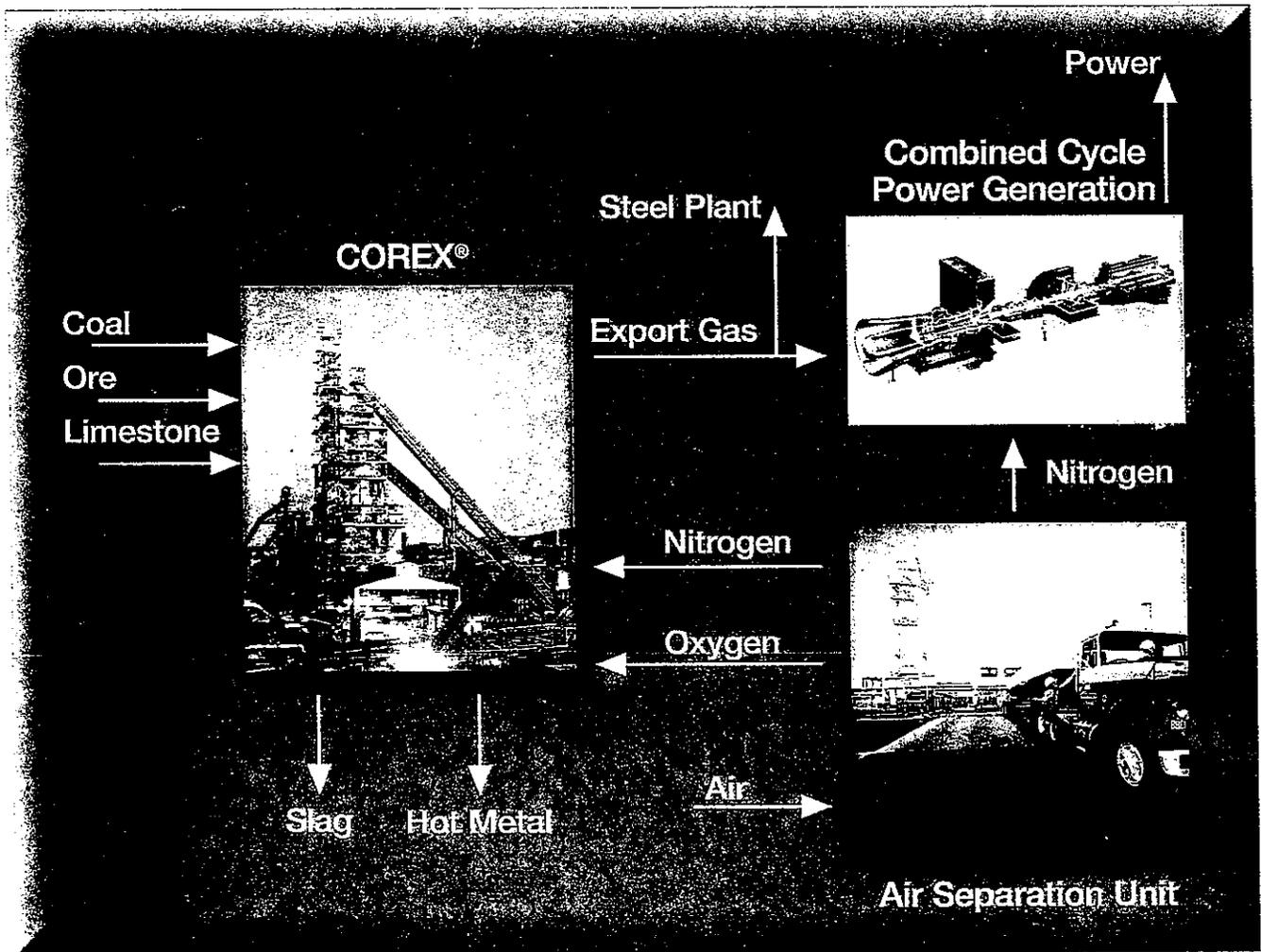


FIGURE 6

BURNS HARBOR D FURNACE - COAL INJECTION



# CPICOR™



BY  
REGINALD WINTRELL  
FOR  
GENEVA STEEL  
AIR PRODUCTS  
CENTERIOR ENERGY

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## BACKGROUND

The U.S. ability to produce iron and steel is under threat from a growing coke shortage. The shortage was initiated in the sixties as the government imposed increasingly stringent requirements upon the U.S. coking industry to substantially lower the level of airborne pollutants. The U.S. steel industry, subjected to the economics of the seventies and eighties and unable to justify the building of new coke ovens or the environmental modifications required to save its antiquated coking batteries (Figure 1), purchased foreign coke and commenced to close its coke batteries. The impact of

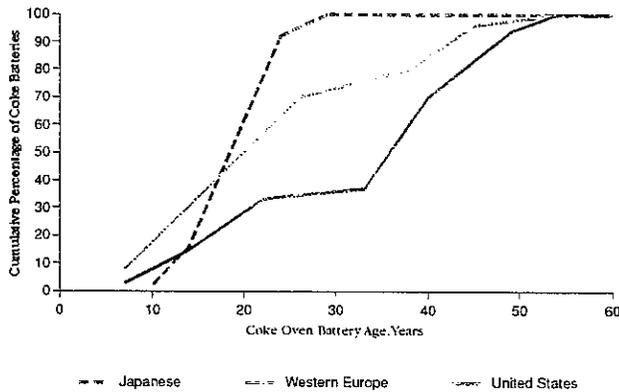
this policy in the mid nineties has been a rapid depletion of the world's surplus coke production. A depletion that is being accelerated by a growing European coke shortage, and a depletion that will continue to grow as the Clean Air Act Amendments of 1990 take effect to further pressure U.S. coke plant closures.

Reductions in blast furnace coke rates will be capital cost limited within the U.S. Figure 2 shows a histogram of U.S. coke rates for the third quarter of 1994. The chart clearly shows that coke rates can be reduced to approximately 650 - 700 lbs. per NTHM. The capital requirement, however, is substantial for increases in oxygen/fuel injection, higher hot blast temperatures, plasma, the production and charging of DRI (Direct Reduced Iron), etc. These are capital cost expenditures in which the ironmaking industry will not be prepared to invest while their base supply of coke is on the decline and their present blast furnaces near obsolescence. The need for the U.S. to produce iron directly from coal is, thus, imminent.

The COREX® (Coal/Ore Reduction) process is, however, the only commercial operation presently available. Driven by a need for the production of iron directly from coal, the COREX® process has moved rapidly from a pilot plant in 1980, to the first commercial unit in 1985. Presently, in the mid nineties,

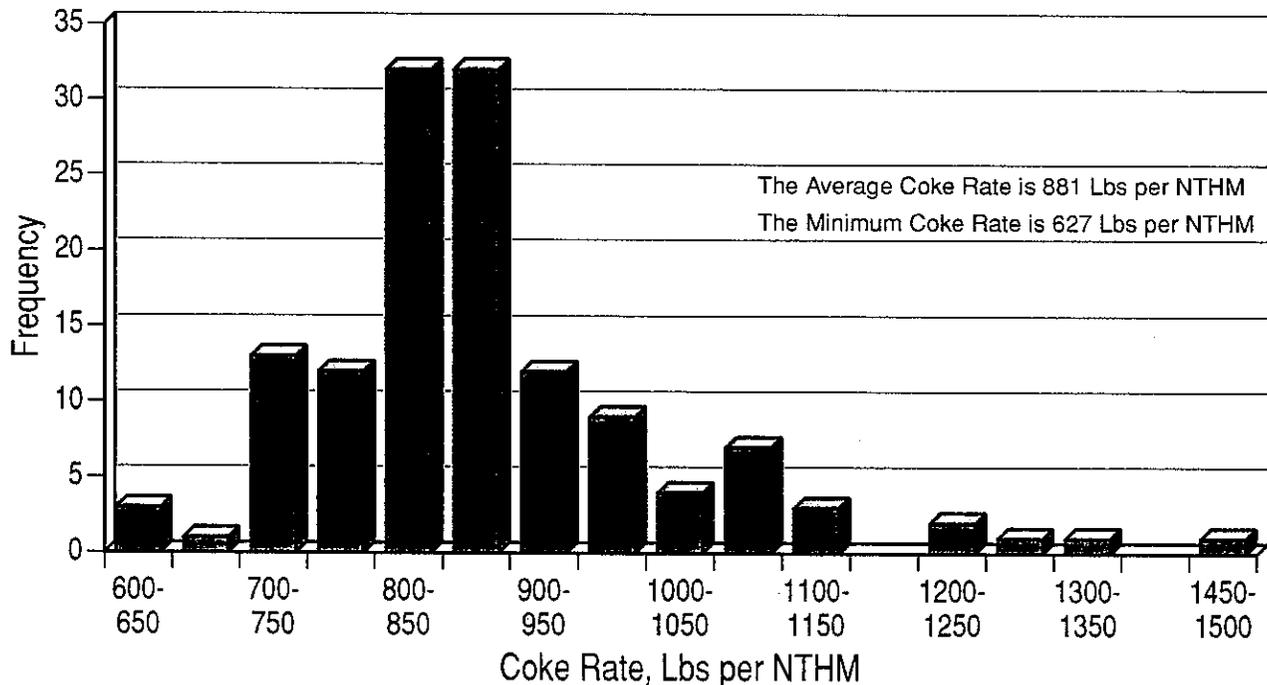
### Age of U.S. Coke Plants

FIG. 1



### Histogram of Coke Rates for 3<sup>RD</sup> Quarter 1994

FIG. 2



four additional new units are under construction in Korea and India. Encouraged by this Asiatic drive, Geneva is seeking, on behalf of the steel industry, to effectively demonstrate the process within the U.S.

The major issues to date, however, have been the effective utilization of the COREX® export gas. The COREX® process produces three times the gaseous BTU's of a similar capacity blast furnace. This level of BTU output, which exceeds the internal needs of most steel companies, must be effectively used to insure operational economics. Geneva has joined with Air Products and Centerior Energy to develop the CPICOR (Clean Power from Integrated Coal/Ore Reduction) process. This CPICOR process is to demonstrate the upgrading of the COREX® to a size compatible with U.S. requirements and to demonstrate the efficiency and economics of this ironmaking facility when integrated with a CCGP (Combined Cycle Power Generation) unit.

installed at Posco (Korea), one unit at Jindal (India) and for two units at Hanbo (Korea). The commercial impact of these units, and the Geneva unit, on world iron production is shown in **Figure 4**.

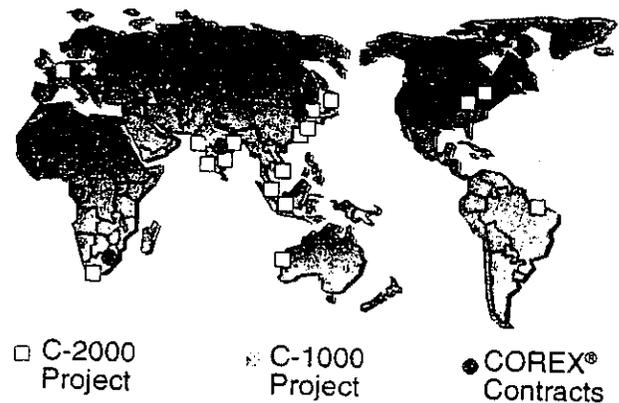
The COREX® Posco unit is of major international interest. This scale up to commercial production will now challenge the smaller blast furnace. The contract for the Posco unit was placed on December 8, 1992, and the plant is scheduled to start up in November 1995. The plant is located at the Pohang Works of the Pohang Iron and Steel Company, Korea (**Figure 5**). The unit will use Australian steam coal, lump ore, and pellets. It will produce between

## COREX® ON THE MOVE

The global interest in COREX® has expanded at a rapid rate. Since the effective commercial start up in 1989, the Iscor unit has demonstrated a capability to continuously produce high quality hot metal. Globally, this has led to project inquiries from nearly every major iron producing nation (**Figure 3**). Firm contracts have been made for one unit to be

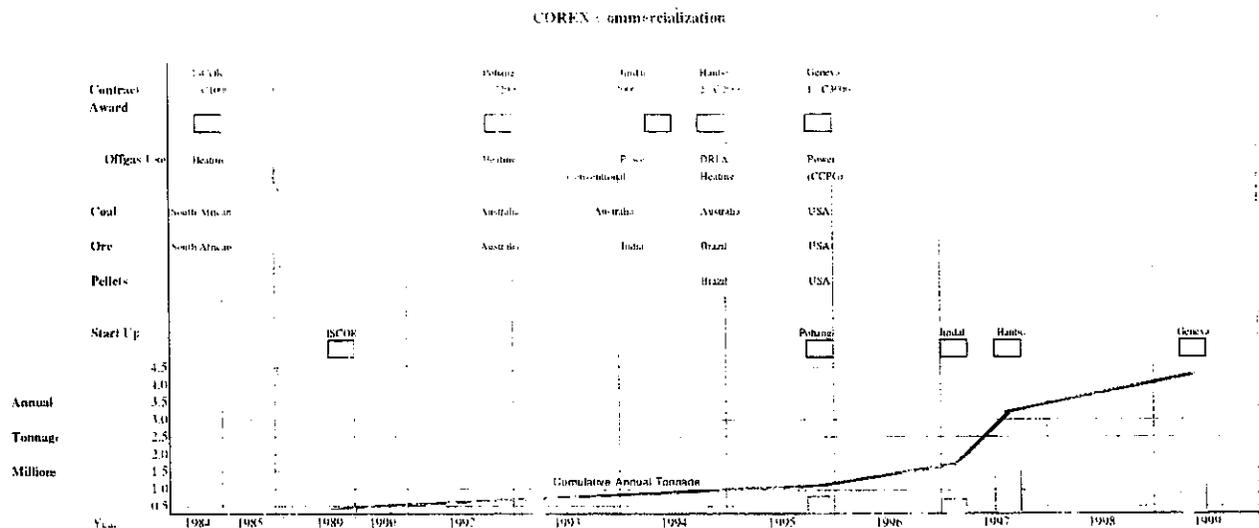
## COREX® Contracts and Potential Projects

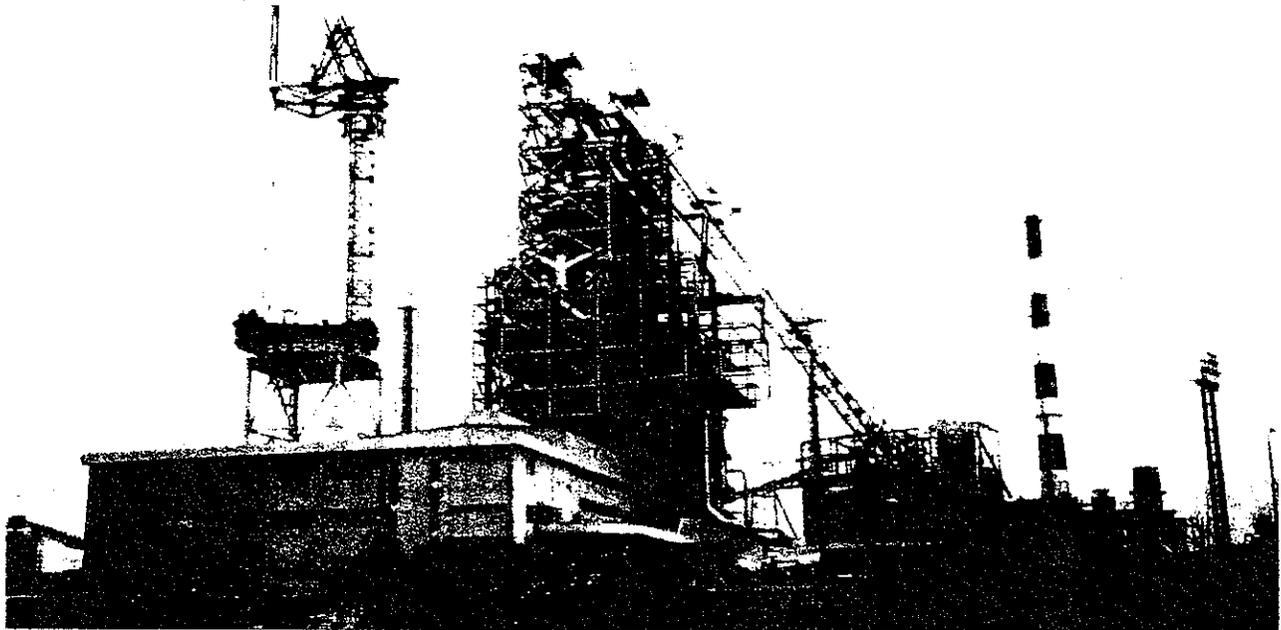
FIG.3



## COREX® Commercialization

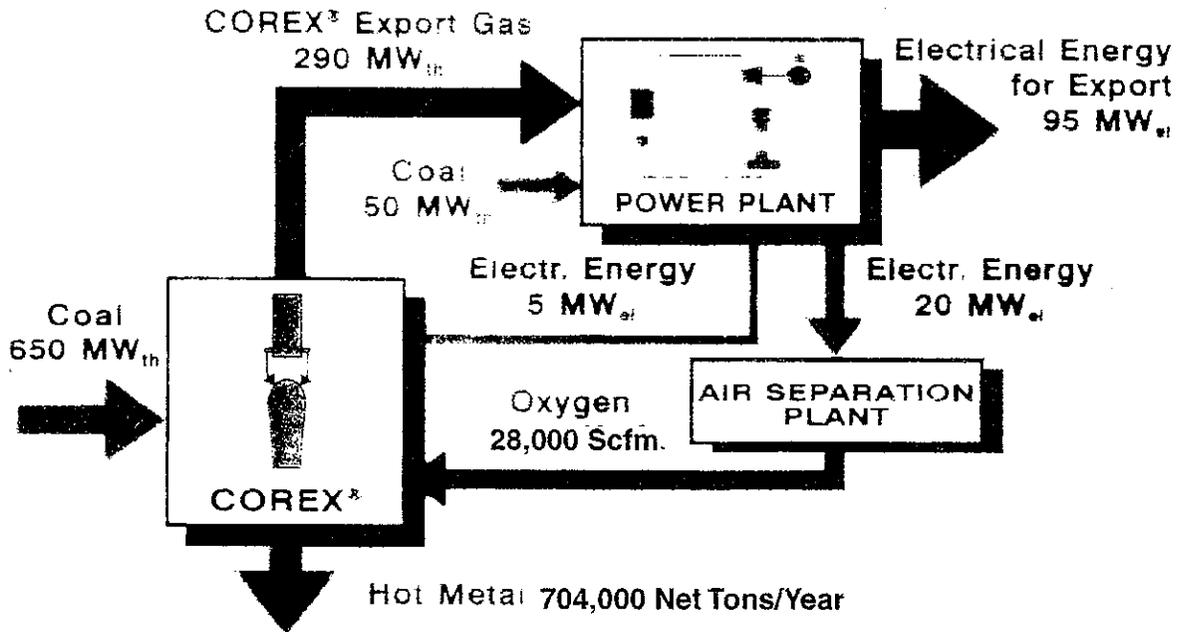
FIG.4





COREX® Jindal-Energy Grid

FIG.6



72,000 - 100,000 s.c.f.m. of export gas with an anticipated BTU level of 190 BTU's/scf. Present plans are to use this export gas for inplant heating purposes.

The COREX® Jindal unit will be the first unit to use the export gas for conventional power generation. A contract for this unit was awarded in July of 1994 by Vijayanager Steel Ltd. The plant, a 2,100

ton per day unit, is scheduled for startup in March 1997. The export gas, approximately 77,500 s.c.f.m. with an anticipated BTU value of around 200 BTU's/scf, will be used with coal to generate approximately 120 MW of power. Approximately 20 MW will be used to operate a 1,700 ton oxygen plant and approximately 5 MW for the COREX® unit (Figure 6). Iron from the unit will be used in a conventional BOF melt shop (Figure 7).

### COREX® Jindal-Iron and Steel Operation

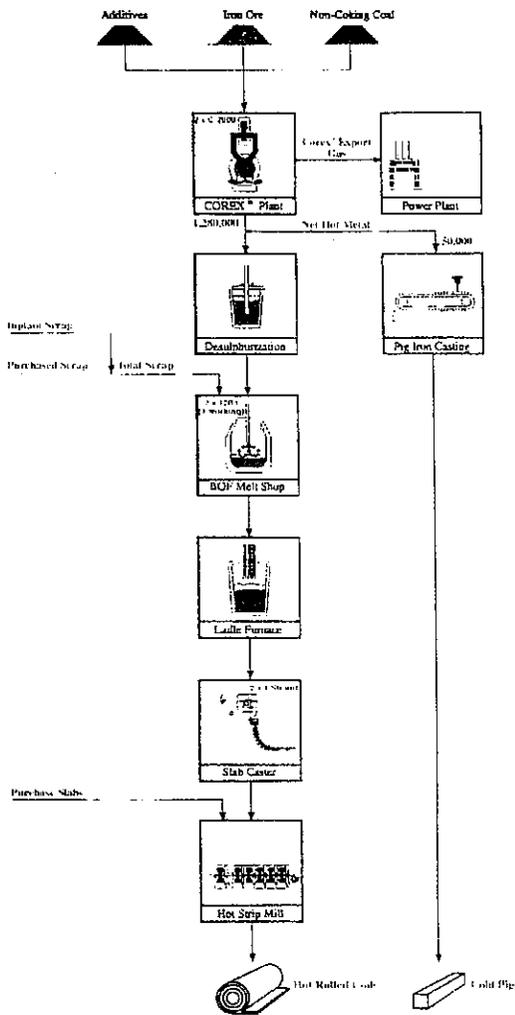


FIG. 7

The two Hanbo COREX® units will be the first to utilize the export gas for DRI production. Contracts for these two 2,400 tons of hot metal per day units and the Midrex™ DRI plant were awarded on September 5, 1994, and October 30, 1994, respectively. The plant, which is to be installed for Hanbo Steel and General Construction Co., will be located at Asan Bay, Korea. The plant will use Australian steam coal and Brazilian lump ore and pellets. The export gas will be passed through a Vacuum Pressure Swing Absorption (VPSA) system for CO<sub>2</sub> removal prior to passing through the Midrex shaft for DRI production (Figure 8). The DRI plant is anticipated to produce approximately 900,000 net tons of DRI per year. The hot metal, DRI, and additional scrap will be fed to an electric arc furnace from which the steel will be processed through a ladle furnace, thin slab caster, and a cold rolling mill (Figure 9).

### COREX® Hanbo-EAF/DRI Operation

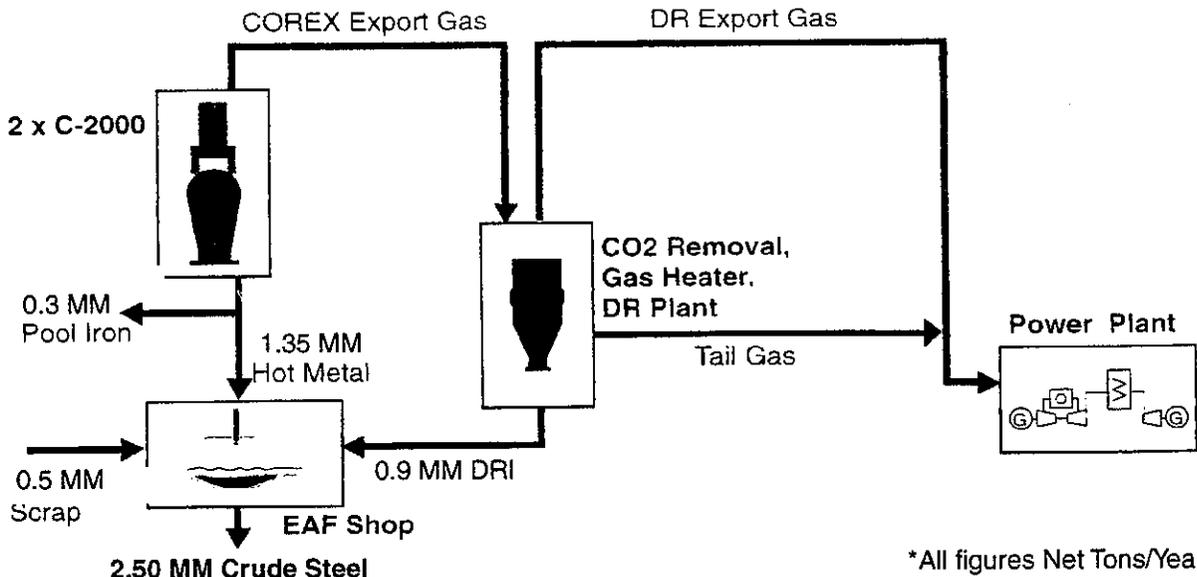
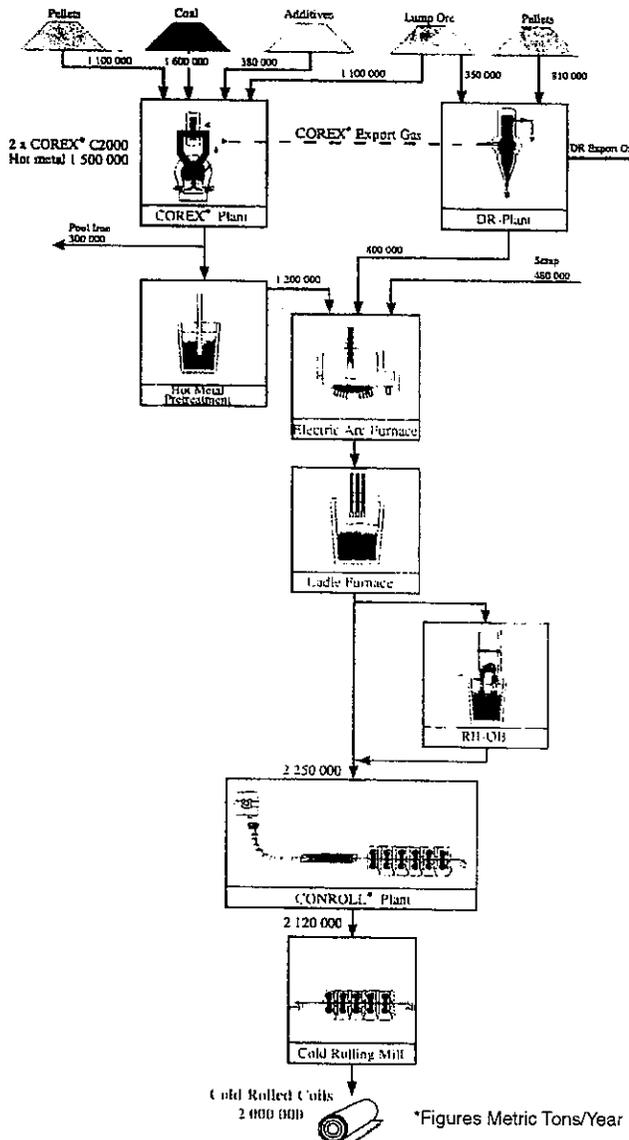


FIG. 8

\*All figures Net Tons/Year

## COREX® Hanbo-Plant Operation

FIG. 9



## THE CPICOR™ GENEVA COREX®

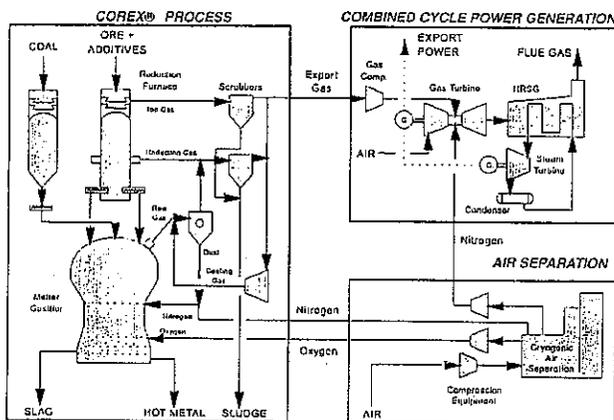
The CPICOR process (Figure 10) was proposed to and accepted by the Department of Energy under the Clean Coal V Program. The CPICOR process goes one step further than the Jindal unit in its goal to integrate an advanced combined cycle power generation facility with the COREX®. In this manner, the process will demonstrate optimum efficiencies both in the economic production of hot metal and in the environmentally acceptable generation of power.

The selection of the COREX® process was based upon several favorable factors. The U.S. urgently requires a demonstration of direct iron production on a scale commercially acceptable to the iron and steel industry. The COREX® is the only process presently ready for upgrading to a production capacity suitable for the U.S. The Environmental Protection Agency requires a clean ironmaking process independent of coke making. The COREX® process uses no coke and has fully demonstrated its compliance with environmental requirements. The domestic steel industry is seeking economic high quality iron units. The COREX® produces a low cost, high quality hot metal. The utilities require a clean coal gas for commercial power generation. The COREX® provides a high volume medium calorific coal gas with extremely low sulfur and NO<sub>x</sub> levels that make it ideally suited for combined cycle power generation.

### Intrinsic Desulfurization Capability

CPICOR technology has a distinct environmental advantage over conventional coal fired power generation units. Conventional coal fired units require an expensive flue gas desulfurization to clean the offgas to acceptable environmental levels. This flue gas cleanup is totally eliminated in the CPICOR process. The limestone and/or dolomite charged to the COREX® is extremely effective in scavenging the sulfur. The sulfur is removed almost totally as Ca(Mg)S with a small portion entering the iron as FeS and a fraction less than 50 ppm as H<sub>2</sub>S or COS in the offgas.

## CPICOR Conceptual Flow Diagram FIG. 10

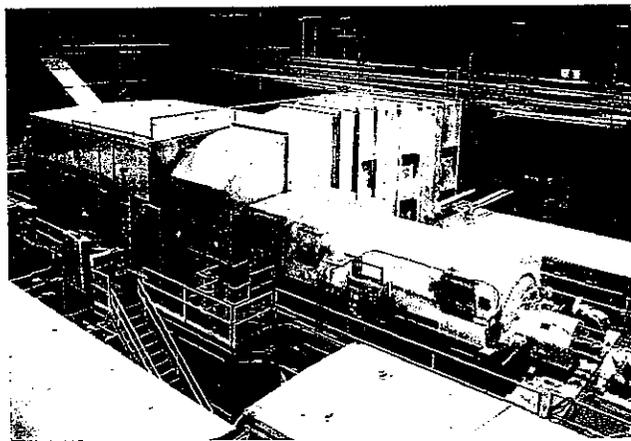


## GLOBAL INTEGRATION

CPICOR is the integration of international innovations in power generation, direct ironmaking, and air separation that have reached a maturity for full scale commercialization. The U.S. Department of Energy and the major power generation equipment

companies have spearheaded the development of the industrial gas turbine in the United States. From the first jet engines of the forties and through five decades of development, combined cycle power generation, using various energy sources, has developed to be the global answer for the nineties and beyond. Single combined cycle units can generate power levels to 220 megawatts (MW) with units under design for 350 MW (**Figure 11**). Coal gasification, as an energy source, has been successfully demonstrated at the Plaquemines facility in Louisiana and the Cool Water facility in California. These generation and gasification technologies will be the basis for CPICOR's high efficiency electrical power generation.

**Typical Gas Turbine Installation** FIG. 11



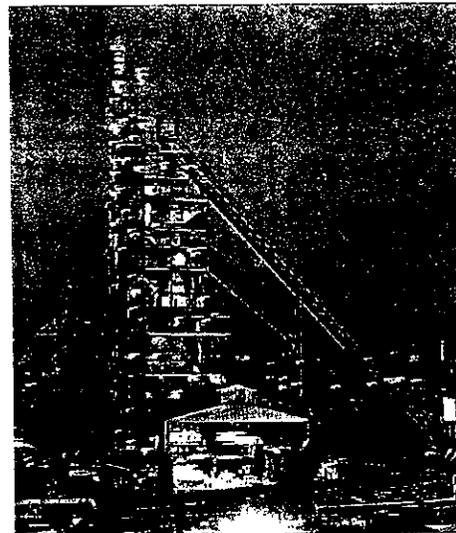
Development of direct ironmaking has been a recent challenge. Dominated by the simplicity and efficiency of the stolid blast furnace, direct ironmaking received secondary interest until the impact of environmental restrictions in the 70's and 80's. Focused specifically on coke oven emissions, environmental requirements have driven the cost of coke plants to a plateau unacceptable to U.S. and European industries. In response, the Germans and Austrians developed a direct ironmaking pilot plant in the 80's based on a concept of Korf Industries, which was eventually termed the COREX® process.<sup>1</sup> In the late 1980's, political pressure on South Africa resulted in the start up of the first small scale 330,000 tons per year COREX® unit (**Figure 12**). Since restarting in 1989, this plant at ISCOR has operated successfully on lump ores and non-coking coals. Encouraged by the success of the COREX® process and pressured by tightening environmental restrictions, the world's leading iron producers

entered a belated race for direct ironmaking. The U.S. has under development the AISI direct ironmaking process (**Figure 13**), Japan the DIOS (**Figure 14**), Australia the Hismelt (**Figure 15**), and Russia the ROMELT. Today, as evidenced by Korea's and India's selection of 770,000 tons per year COREX® processes, no other unit is yet ready for commercialization or offers any substantial benefit over COREX®/CPICOR for the United States.

The commercial production of oxygen in air separation units (ASU) is a well established technology (**Figure 16**). The process used for the first small 1.3 tons per day oxygen plant in the U.S. in the early 1900's was basically the same as that used in present 2,500 tons per day (TPD) installations. Over the history of the air separation industry, hundreds of commercial oxygen plants have been built, and presently more than 70,000 tons per day of oxygen capacity exists in the U.S. The ASU is proven, reliable, and highly efficient and will be integrated with the CCPG and COREX® within the CPICOR process. CPICOR will expand the U.S. coal base by including a wider range of coals for the simultaneous production of iron and power and will provide an integrated environmental solution for the economical revival of our steel, coal and power industries.

## PROJECT OBJECTIVES

The project objectives are to demonstrate a scale up of the COREX® and its commercial integration with the advanced combined cycle power gen-

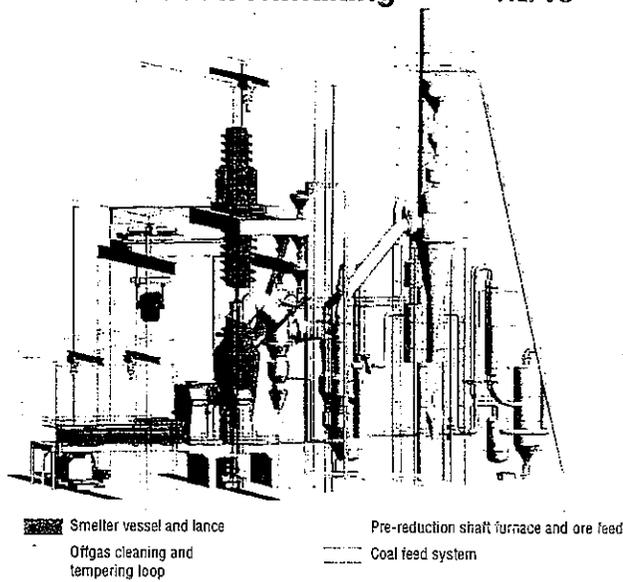


**ISCOR  
COREX®**

FIG. 12

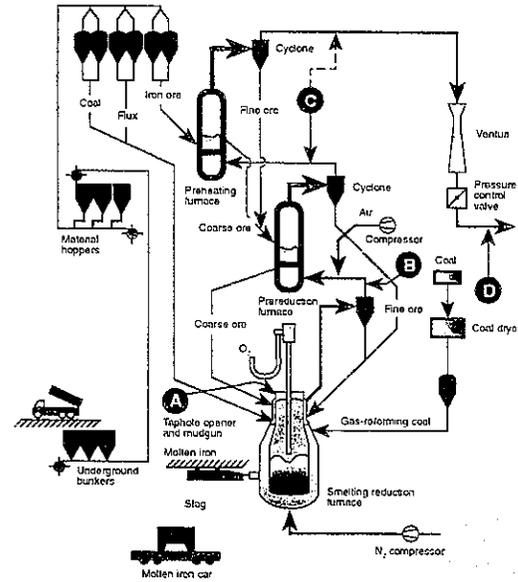
## AISI Direct Ironmaking

FIG. 13



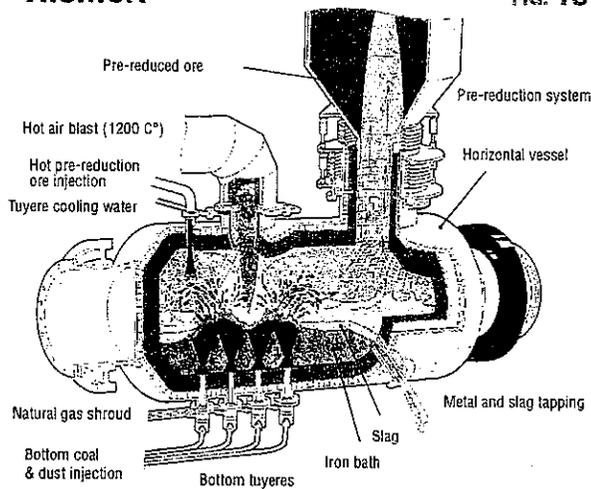
## DIOS

FIG. 14



## Hismelt

FIG. 15



## ASU Facility

FIG. 16



eration system. To date, the COREX® process has demonstrated the ability to produce 330,000 tons of hot metal per year on lump ore, with the generated gas used for inplant heating purposes. To be commercially viable in the U.S., the value of the generated gas must be optimized, such as by partial integration with power generation, and the COREX® must be scaled up to a size compatible with modern blast furnace operation. The purpose of the CPICOR project is to demonstrate that COREX® technology can be integrated with combined cycle power generation. This is an efficient and environmentally attractive way to utilize the COREX® export gas. The

3,300 net tons per day COREX® unit selected for the CPICOR project will produce 1,160,000 tons of hot metal per year to further demonstrate a 3:1 scale-up over the existing ISCOR facility, a 3:2 scale-up over POSCO's planned Pohang facility in Korea, and a viable size for U.S. operations.

## PROJECT TEAM

The project team is comprised of: Centior Energy Corp.; Air Products and Chemicals, Inc.; and Geneva Steel. Together with their principal subcontractors, Deutsche Voest Alpine Industrialanlagen-

bau (DVAI) and Voest Alpine Industrialanlagenbau (VAI), this team is well qualified to effectively execute all phases of the CPICOR demonstration. The CPICOR project will be managed through a joint-venture entity of the partners, CPICOR Management Company, who have executed the cooperative agreement with the DOE.

DVAI, the developer of the COREX® process, will work with Geneva Steel to design and construct CPICOR's 3,300 TPD COREX® facility. Geneva Steel will provide the infrastructure of their fully integrated steel plant in Vineyard, Utah, and consume the hot metal product (**Figure 17**). Centerior Energy will bring power generation expertise. Air Products will supply its extensive project experience and technology leadership in innovative air separation plants and power generation systems.

## TECHNOLOGY DESCRIPTION

The backbone of the CPICOR project is the innovative process known as COREX® in which molten iron is produced by continuous reduction and smelting of iron ore (**Figure 18**). The most innovative feature of this process is the segregation of the iron reduction and smelting into two separate reactors. This allows direct injection of coal into the high temperature melter/gasifier which thermally cracks the coal volatiles as they are released. The process is thus independent of coke. The two reactors are:

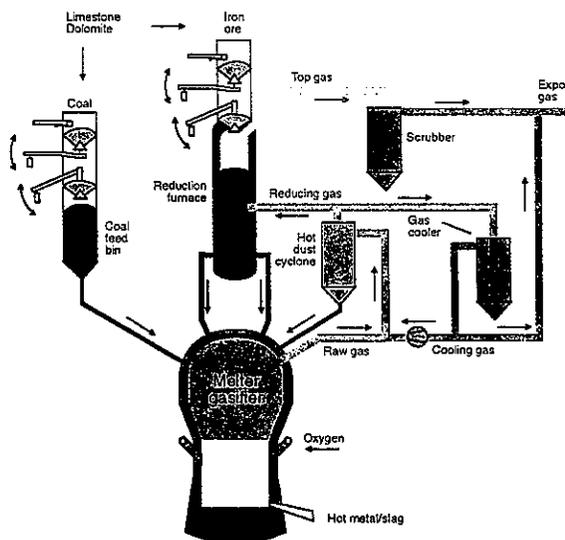
- 1) A **reduction shaft furnace** for reduction of lump ores, pellets, or sinter.
- 2) A **melter/gasifier** into which a wide variety of coals can be fed directly to produce the heat needed for smelting and to generate the reducing gases required for reducing the iron ore.

The coke oven plant with its related emissions is eliminated, and the coal gases normally required for coking can be more efficiently utilized for generating power. Hence, in addition to hot metal production, significant volumes of a clean, low-calorific value gas (175-230 BTU/SCF) are continuously generated from the COREX® process. This gas then serves as the fuel for a combined cycle power generation system.

The COREX® flow diagram shows coal fed directly into the COREX® melter/gasifier. The coal, a blend of Western and Eastern coals, is devolatilized and gasified with oxygen to generate a reducing gas and sufficient heat to smelt hot metal. The process will normally use some 3,570 tons of coal and 2,700 tons of oxygen to produce 3,300 tons of hot metal per day. The high temperatures (1,800°F-2,000°F) in the melter/gasifier result in the thermal dissociation of the coal volatiles, leaving only small amounts of CH<sub>4</sub> in the reducing gas. The gas exits the melter/gasifier and passes through the dust separation cyclone before it is cooled to 1,550°F and transferred into the reduction shaft furnace. The reduction furnace is fed 5,180 TPD of iron ore and pellets and 953 TPD of raw fluxes. The charge is reduced or calcined by the ascending reducing gas. During the ascent, the sulfur contained in the gas reacts with the reduced iron and the calcined lime and dolomite. The reduced iron and the calcined fluxes are fed by water-cooled screws into the melter/gasifier. In the melter/gasifier, the reduced iron is melted by heat generated from the partial oxidation of the coal. The sulfur released during the smelting process is chemically captured in a calcium-rich, basic slag. The hot metal and slag are tapped periodically from the furnace hearth. The molten metal is sent directly to the steel mill for processing and the tapped slag (1,354 TPD) is recovered and used in the same manner as blast furnace slag.

**COREX® Process Flow**

**FIG. 18**





The spent reducing gas (or top gas) leaves the reduction shaft essentially desulfurized and is quenched and cleaned through a series of wet scrubbers equipped with cyclonic separators. The cleaned export gas (1,790 MMBTU/hr) is delivered to the CCPG facility where it is compressed, mixed with air and nitrogen, and burned in a gas turbine/generator system. Process steam is generated in a heat recovery steam generator (HRSG) by extraction of heat from hot turbine exhaust gases and the combustion of surplus export gas. The steam produced in the HRSG drives an electric generator. This combination results in a total of 250 MW to 330 MW of generated power depending on the type of gas turbine used.

## **INHERENT ADVANTAGES OF CPICOR**

CPICOR technology, by virtue of its integral co-production of hot metal and power, offers a number of distinct technical and economic advantages over the competing commercial technology. The conventional method of producing hot metal from ore and coal involves two separate processes:

- 1) **Cokemaking** — Coal is heated to drive off volatile matter and produce “coke” to be used as both fuel and reducing agent in a smelting operation.
- 2) **Blast furnace smelting** — Ore, coke, limestone, and hot air are charged to reduce and smelt the ore to produce molten iron.

Approximately 30% of the coke oven gas produced during cokemaking is used to provide heat for the cokemaking operation. The excess gas is typically sent to a utility steam boiler where it is mixed with the surplus off-gas from the blast furnace to generate power. At comparable hot metal production rates, this technology generates only about one-fifth the power produced by CPICOR technology.

### ***Highly Efficient Use of Coal***

The energy efficiency of the CPICOR technology is over 30% greater than the competing commercial technology when considering only the effective production of hot metal and electric power. The higher efficiency of the CPICOR technology is due to the more effective use of the sen-

sible heat and volatile matter than the coke-making/blast furnace process. In addition, the CCPG achieves energy efficiencies in the 50% range compared to a maximum of 34% with conventional coal-based power systems equipped with flue gas desulfurization.

### ***Dramatic Reduction in Emissions***

CPICOR technology is less complex and environmentally superior to conventional processes. All criteria air pollutants, particularly the acid rain and PM<sub>10</sub> precursors, SO<sub>x</sub> and NO<sub>x</sub>, are reduced by more than 85%. This reduction is due largely to the desulfurizing capability of the COREX® process, efficient control systems within the CCPG facility, and the use of oxygen in place of air in the COREX® process. The gaseous emissions from the CPICOR plant, resulting from the combustion of air and export gas in the gas turbine, are effectively controlled.

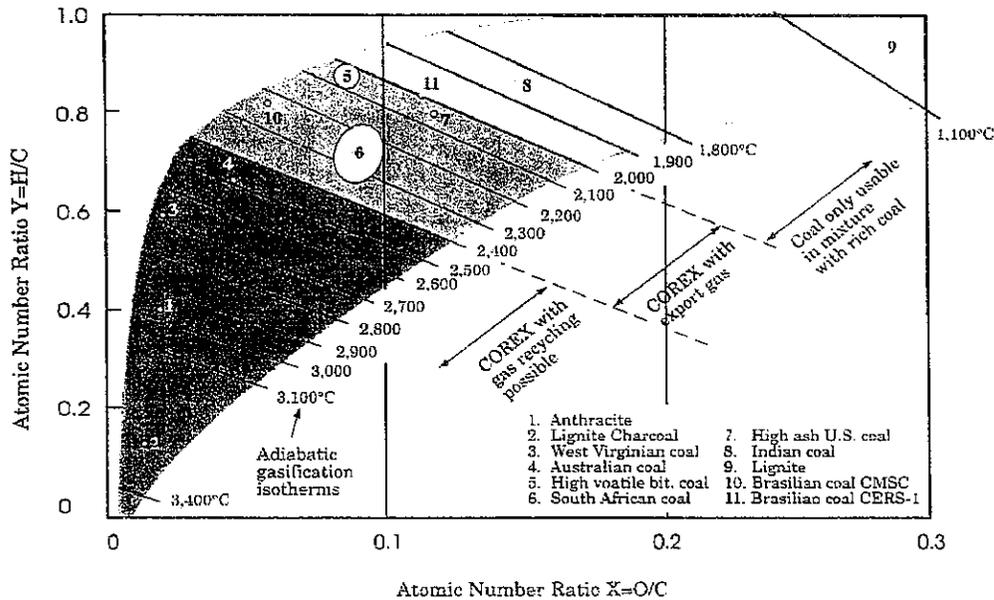
As the air toxics provisions of the Clean Air Act Amendments of 1990 take effect, the steel industry faces a serious challenge of reducing coke plant emissions. CPICOR meets this challenge because it eliminates the need for cokemaking and the associated problems of controlling fugitive emissions. The COREX® process releases no air toxics from the high temperature gasifier to the environment, and most trace elements are captured in the slag. There is no negative impact from the discharge of solids or waste waters from the CPICOR plant since all discharges are non-hazardous. The predominant solid by-product of the COREX® process is a usable slag which is very similar to blast furnace slag and can be sold as construction ballast.

### ***Intrinsic Desulfurization Capability***

CPICOR technology has a distinct environmental advantage over conventional coal fired power generation units. Conventional coal fired units require an expensive flue gas desulfurization to clean the offgas to acceptable environmental levels. This flue gas cleanup is totally eliminated in the CPICOR process. The limestone and/or dolomite charged to the COREX® is extremely effective in scavenging the sulfur. The sulfur is removed almost totally as Ca(Mg)S with a small portion entering the iron as FeS and a fraction less than 50 ppm as H<sub>2</sub>S or COS in the offgas.

Reference Chart for COREX® Coals

FIG. 19



**Operational Flexibility with a Range of Coals**

Unlike blast furnace technology, which requires the use of coke produced from coking coals, the COREX® process operates effectively with a wide variety of coals fed directly into the process (Figure 19). Since coke is produced from a narrow range of coal types with specific properties, the vast majority of the United States coal reserves cannot be utilized in conventional ironmaking. The spectrum of available coal reserves for domestic ironmaking is considerably enhanced by CPICOR. The COREX® process effectively operates over a broad range of coal qualities: volatile matter up to 35%, ash up to 25%, and sulfur up to 1.5%. Even very high sulfur coals (>1.5%) can be used effectively in the COREX® process provided they are blended appropriately with low sulfur coals. The major limitation is coal size which requires essentially that 50% of the coal is over 10 mm in particle size.

**Competitive Co-Product Economics**

Current commercial technology uses stand-alone process units to produce hot metal, supply industrial gases and co-produce electric power. As a result, capital costs are high, and the opportunity to integrate various process flows and heat sources among the processes is lost. In contrast, the CPICOR design is based on achieving capital,

operating, and energy benefits by integrating the processes without sacrificing the flexibility for commercial operation and the reliability of power or hot metal production.

**FEASIBILITY OF CCPG INTEGRATION**

Although this is the first CCPG application to be fueled with COREX® export gas, the proposed design is based on proven technology. Similarly sized and larger CCPG facilities have been designed and are currently in reliable operation today with 94% to 97% availability. The steam pressure levels selected for the CPICOR design are typical of those which have been used in power generation facilities for years. The proposed gas turbine system is a proven, reliable design with a considerable number of the candidate models currently in operation. There are many heat recovery steam generator (HRSG) units of similar design and size in operating CCPG installations. Many steam turbine/electric generator sets of the type and capacity proposed for CPICOR currently exist in electric power generation facilities and have been in operation for years. All other major equipment items for the CCPG facility are likewise based on existing technology and similarly sized units (Figure 20).

## Combined Cycle Statistics

FIG. 20

### Installed Combined Cycle Units

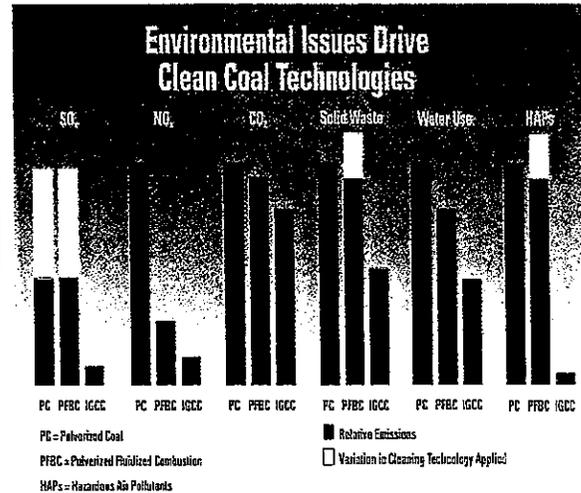
Installed Capacity (U.S.)	Over 66,000 megawatts
Operation Hours (U.S.)	Over 77 million hours
Power Range	Up to 350 MW per unit
Thermal Efficiencies	Up to 54+%
Availability	90 to 97%
Heat Rates	9000 to 6200 BTU/KWH

### Coal Gasification Units

Plaquemine	two 104 MW units installed 1974
Cool Water	one 120 MW unit installed 1984
Environmental	1/10 of coal fired units

The fueling of a CCGT system gas turbine with low-BTU gas produced by the COREX® process is unique. However, fueling gas turbines with medium and low-BTU fuel is a technology which exists commercially and is being studied, developed, and optimized by the gas turbine manufacturers. Consuming COREX® export gas in a turbine presents some technical challenges not encountered with fired boiler combustion cycles. Particulates greater than 5 microns and alkali metals can lead to turbine blade erosion. In combination with H<sub>2</sub>S and SO<sub>2</sub>, these materials can lead to hot metal corrosion of the combustor and inlet transition duct as well as blading of the turbine section. These potential problems are addressed by adequate scrubbing and filtration of the export gas in the CPICOR design. The use of proven and reliable wet scrubber technology will provide over 99.5% dust removal. Performance data from the ISCOR operation shows the COREX® export gas has contaminant levels generally within the gas turbine manufacturers' maximum specifications.

Considerable advancements have also been made in gas turbine hot section metal coatings. Cooling technologies have been developed to reduce the erosion and corrosion effects of firing offgases from processes such as COREX®. Westinghouse, Mitsubishi Heavy Industries (MHI), Siemens, ABB, General Electric, and European Gas



Turbines (Ruston) all report capabilities to accept the COREX® export gas with only minor modifications to the gas turbine designs.

Operation of the gas turbine with COREX® export gas and integration with the ASU pose some unique control requirements. Nevertheless, Air Products has studied the requirements of gas turbine and ASU integration in depth and is currently demonstrating ASU-gas turbine integration, analogous to CPICOR's design, at DEMKOLEC's Integrated Gasification Combined Cycle (IGCC) facility in Buggenum, Netherlands.

## DEMONSTRATION SITE

The CPICOR demonstration plant will be constructed at Geneva Steel's plant located in Vineyard, Utah. At that site, Geneva owns and operates a fully integrated steelmaking facility.

The site will take advantage of existing infrastructure to use the generated electricity at the site and transmit the surplus to the local power grid (Figure 16). All of the hot metal will be consumed in the steel plant. Raw materials for the demonstration plant, coal, iron ore and limestone, will be supplied by existing transportation, storage, and processing infrastructure on the site.

## PROJECT SCHEDULE AND MILESTONES

The project is scheduled to commence upon the signing of the cooperative agreement with the DOE and to be completed following a multiple-phase program (Figure 21).

### *Demonstration Operating Plan*

CPICOR's main objective is to demonstrate the economic, environmental, and operational aspects of a commercial-scale integrated facility and to qualify the plant using a variety of U.S. coals. CPICOR will be operated in most modes expected to be encountered in commercial applications, with the following goals:

- Establishing steady and reliable operation which compliments and enhances steel mill operations.
- Collecting performance data at various loads and conditions to assess process sensitivities, optimum conditions, and limits of sustainable operation.
- Verifying suitability of equipment and materials.

- Assessing the effect of applying new information to design and cost estimates for future commercial plants of this type.
- Testing different U.S. bituminous coals and blends to observe the effects of volatile matter, sulfur, and ash variation on performance and equipment.

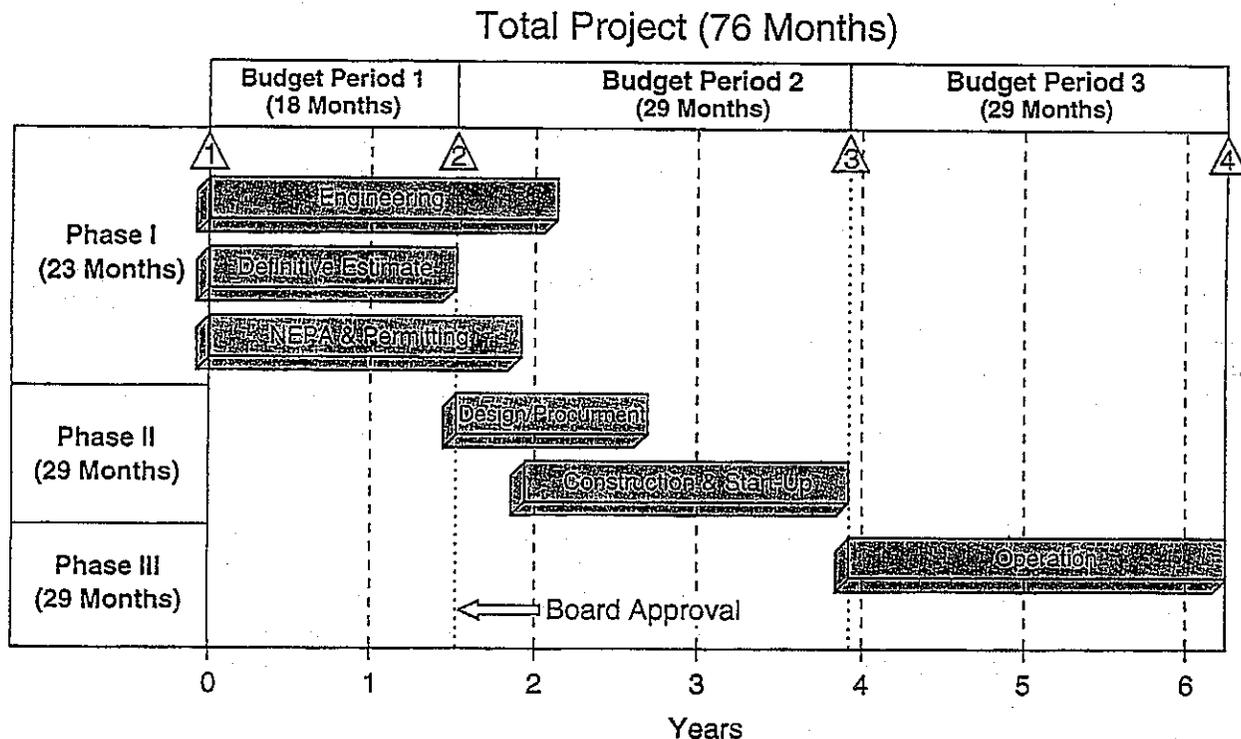
To achieve these goals, a 29 month program consisting of four commercial operating periods is planned:

1. Base Coal Line-Out (4 months)
2. Steady-State Integration and Optimization (9 months)
3. Coal Quality Testing (14 months)
4. Maximum Capacity Testing (2 months)

Once the CPICOR demonstration plant is operational, it will be run as a commercial facility, producing and selling products. It will become a major source of hot metal and a net producer of electric power.

### Project Time Line

FIG. 21



The plant will be run by the operating staffs of Geneva and Air Products. Geneva will operate the COREX® facility and will monitor all CPICOR-related systems as part of its normal steel mill functions. Air Products will operate the CCPG and ASU facilities. Each partner will supply engineering, plant staff, labor, materials, routine and major maintenance, home office support, subcontracts, and all other services needed. In addition, DVAI will provide continuous on-site support, advice, and evaluation on the technical aspects of the COREX® operation.

### Post Demonstration Phase

Upon completion of the DOE program, it is anticipated that the CPICOR plant will continue to operate as a commercial facility for at least 20 years, supplying Geneva's hot metal and power.

## COMMERCIAL OUTLOOK

CPICOR is intended to replace commercial coke oven/blast furnace technology in the production of hot metal for use in steelmaking. The best candidates for utilizing CPICOR technology are existing integrated steel plants with blast furnaces and coke ovens nearing the end of their useful lives and located where the local electric utility requires additional capacity. While commercialization of the COREX® process is driven primarily by the need for an environmentally sound source of hot metal for the steel industry, the production of electric power from the COREX® export gas is key to the economic competitiveness of the technology. Thus, commercialization will be facilitated by the ability of this project to obtain an attractive price for the power created by the plant.

Conventional coke oven/blast furnace technology is too expensive to be utilized as replacement units or to expand domestic ironmaking capacity. Recent studies<sup>2, 3, 4</sup> conclude that no new coke batteries will be built in the United States. Of the existing 79 coke oven batteries, 40 are thirty years of age or older and are due for either replacement or major rebuilds.

As a consequence of the Clean Air Act Amendments of 1990, the emissions from existing coke ovens must be reduced substantially over the next several years. It has been estimated that the

total capital investment for rebuilding or replacing current capacity could be in the range of \$4 to \$6 billion. The capital cost of coke ovens is about \$166 per ton of equivalent hot metal capacity. Coupled to the cost of a blast furnace rebuild at \$155 per ton equivalent hot metal capacity, the investment in a new COREX® facility at approximately \$255 per ton compares favorably on a capital basis.

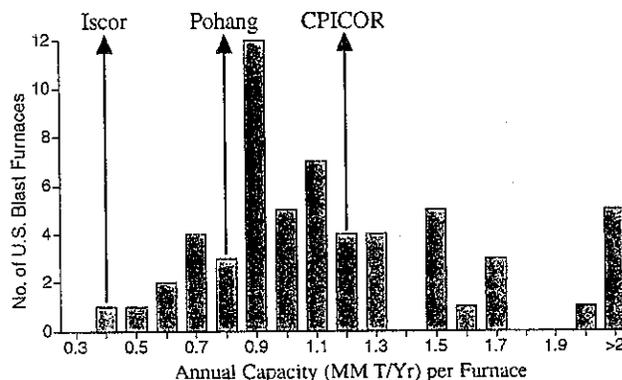
If the iron and steel industry is to continue to produce liquid iron in the form of hot metal, a new technology must be developed and installed. Future competition to COREX® is likely to come from the new direct ironmaking processes being developed in both Japan (the DIOS process, **Figure 14**) and in the U.S. (the AISI process, **Figure 13**). Both of these processes produce iron and a lower calorific value export gas directly from iron ore and coal. However, the development of the COREX® technology is 8 to 12 years ahead of these other processes. Consequently, COREX®/CPICOR should become the technology of choice as domestic ironmaking capacity declines due to severe limitations in global coke supply.

## RATIONALE FOR CPICOR PROJECT SIZE

In the U.S., there are currently about 60 blast furnaces, all of which have been operating for more than ten years, with some originally installed up to 90 years ago. **Figure 22** shows the size distribution of these furnaces. As can be seen, the largest operating COREX® facility (~330,000 TPY) is only large enough to replace the smallest of these 60 blast furnaces. The construction of a new facility by POSCO

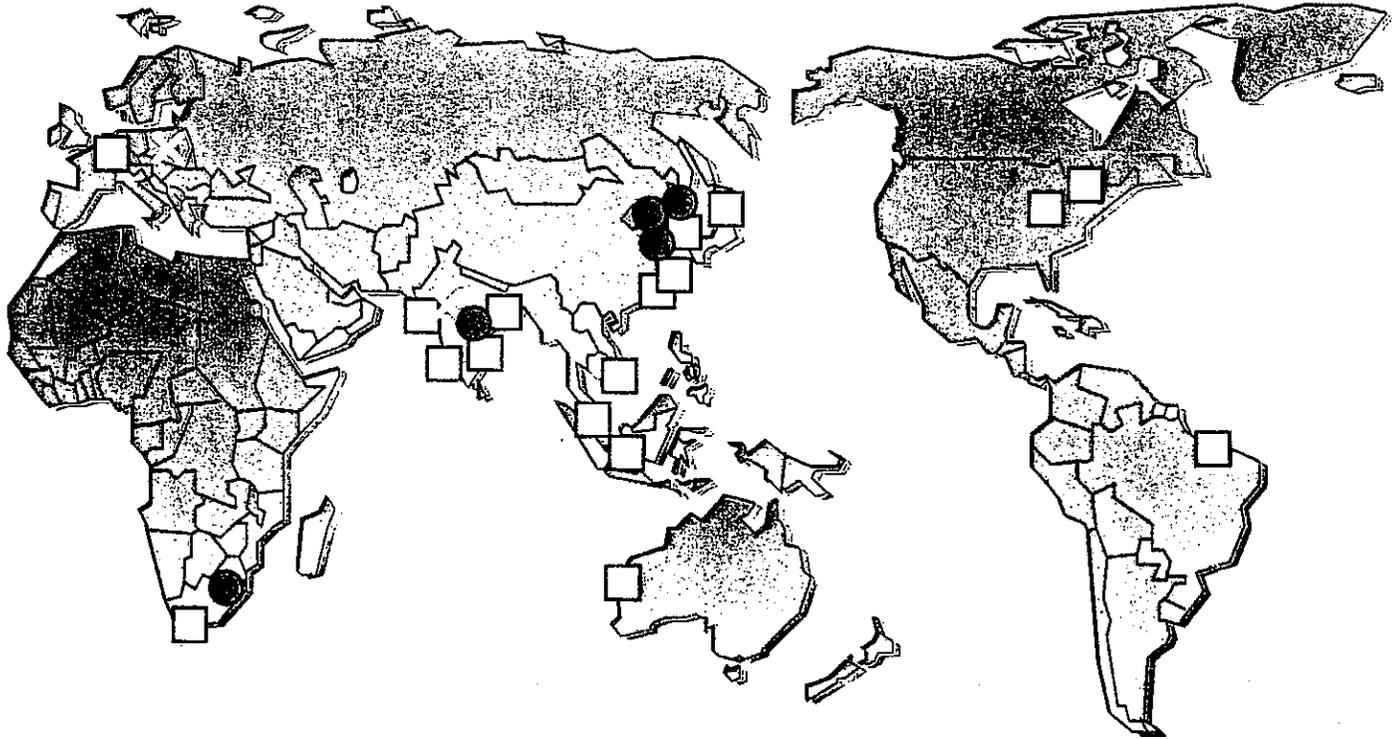
### Size Distribution of Domestic Blast Furnaces

FIG. 22



# COREX®

## -ON THE MOVE-



□ C-2000  
Project

▣ C-1000  
Project

● COREX®  
Contracts

## **DEMONSTRATION OF THE AIR COOLED SLAGGING COMBUSTOR ON A 500 KW COAL FIRED POWER PLANT**

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### **ABSTRACT**

This paper summarizes recent progress on commercializing Coal Tech Corp's air cooled, slagging coal combustor. Coal Tech is currently installing a second generation air cooled combustor in a new 500 kW demonstration plant in Philadelphia, PA. This plant incorporates the results of 2000 hours of testing between 1987 and 1993 on an air cooled 20 MMBtu/hr combustor that was retrofitted to a 17,500 lb/hr saturated steam boiler. Key changes in this new 20 MMBtu/hr combustor are its increased length which yields efficient combustion with coarse pulverized coal, and improved air cooling which sharply reduces the auxiliary power requirements. Other innovations are real time removal of bottom ash from the flat bottom oil design boiler, and the modularization of all the plants components for future factory assembly of plant sub-systems. This new plant design results in an estimated capital costs of less that \$1000/kW in the 1 MW to 20 MW output range. Based on prior test results, the new plant will meet the Philadelphia air quality standards of less than 0.5 lb/MMBtu of SO<sub>2</sub>, less than 0.3 lb/MMBtu of NO<sub>x</sub>, and less than 0.06 lb/MMBtu of particulates. 500 hours of testing will begin in the Fall of 1995. This will be followed by installation of a steam turbine generator to produce on-site power for melting metal using a new proprietary process.

### **INTRODUCTION**

This paper summarizes the results of work performed on Coal Tech's commercial scale 20 MMBtu/hour air cooled, slagging coal combustor since the last report at the 1994 Clean Coal Conference [1]. Air cooling recycles the combustor wall heat transfer loss to the combustion air,

(making this heat available to the thermodynamic cycle). A portion of the SO<sub>2</sub> and NO<sub>x</sub> emissions are controlled inside the combustor. The combustor is designed for new and retrofit boiler applications. Development of the air cooled combustor began in the late 1970's using a 1 MMBtu/hr air cooled cyclone combustor [2], and it continued in the mid 1980's with SO<sub>2</sub> and NO<sub>x</sub> control tests in a 7 MMBtu/hr water cooled cyclone combustor [3]. This work was followed by the design, construction, and installation of the present 20 MMBtu/hr, air cooled, combustor between 1984 and 1987 [4]. Between 1987 and 1993 about 2000 hours of test operation were performed using coal, coal water slurry, refuse derived fuel, oil, and gas. The first three years of this demonstration effort, consisting of 800 hours of test operation, were conducted under DOE Clean Coal Program sponsorship. Subsequently, tests were conducted on ash vitrification [5] and refuse derived fuel combustion [6].

Testing under the current DOE sponsored project began in 1992 [7]. The first phase of testing in 1992 and 1993 was conducted on the 20 MMBtu/hr air cooled combustor facility in Williamsport, PA, that was used in prior testing since 1987. The focus of the phase 1 tests was on combustor durability and combustor operation under automatic computer control. Modifications were made to the combustor and boiler to increase its durability. Also, data generated in prior manual combustor operation were utilized to automate combustor operation. These efforts yielded major improvements in durability. Several hundred hours of operation over a 7 months period in 1993 were implemented without any internal refurbishment of the combustor walls. Some the results of these tests were reported at the Third Annual Clean Coal Technology Conference [7].

In the second phase of this project which is currently in progress, a second generation combustor rated at 20 MMBtu/hr was designed and fabricated for installation in a 500 kW power plant. The design of this plant was optimized to utilize the unique features of the air cooled combustor. This included a modified oil design flat bottom boiler that was redesigned for real time removal of any ash or slag carried over from the air cooled cyclone combustor. It also included a coal processing system that produces coarsely pulverized coal ( 50% passing 100 mesh) compared to previous operation at 70% passing 200 mesh). This greatly reduces the capital and operating cost of the coal handling system. This coal processing was made possible by recent improvements in combustion efficiency of coarsely pulverized coal. All the auxiliary sub-systems, such as cooling and combustion air, fuel supply, and cooling circuits were simplified and modularized to reduce capital cost and operating and maintenance costs. As part of this latter effort, the in-plant power requirements for the 20 MMBtu/hr combustor were reduced by two-thirds.

The modified components and sub-systems were fabricated during the past year. The 20 MMBtu/hr air cooled combustor steam power plant is being installed at a new facility located in an industrial park on the Delaware River in the City of Philadelphia. The installation is proceeding in stages, with the coal storage and processing system, combustor, boiler and its auxiliary components being installed and tested for 500 hours within the next year. This will be followed by the installation of a 500 kW steam turbine whose power output will be used for operating a revenue producing electric metal melting furnace. This latter effort will be on a fully commercial basis.

Philadelphia has very stringent air emission standards for SO<sub>2</sub>, NO<sub>x</sub>, and particulates. Therefore, the plant operation will provide verification of both the operational and environmental performance of the air cooled combustor.

The installation of the fuel processing, combustor, and boiler section is nearing completion and initial test are planned for early Fall, 1995. The effort to date has yielded major simplifications in plant design and reductions in cost. Application of these designs features to fully commercial plants will result in capital costs well under \$1000/kW. This paper will highlight the novel features of this second generation air cooled combustor-boiler plant.

#### Coal Tech's Advanced Air Cooled, Cyclone Coal Combustor

The cyclone combustor is a high temperature (> 3000°F) device in which a high velocity swirling gas is used to burn crushed or pulverized coal. Figure 1 shows a schematic of Coal Tech's patented, air cooled combustor. A gas and oil burner is used to pre-heat the combustor and boiler during startup. Dry pulverized coal and sorbent powder for SO<sub>2</sub> control are injected into the combustor in an annular region enclosing the gas/oil burners. Air cooling is accomplished by using a ceramic liner, which is cooled by the swirling secondary air. The liner is maintained at a temperature high enough to keep the slag in a liquid, free flowing state. The slag is drained through a tap at the downstream end of the combustor.

Nitrogen oxide emissions are reduced by operating the combustor fuel rich. In the 20 MMBtu/hr combustor, under optimum conditions about two-thirds stack NO<sub>x</sub> reductions to 0.26 lb/MMBtu, or 200 ppm (at 3 % O<sub>2</sub>) have been measured at about 70% of stoichiometric air/fuel ratio and high combustion efficiencies. Sulfur emissions are controlled primarily by sorbent injection into the combustor. Measurement of SO<sub>2</sub> levels at the stack gas outlet from the boiler yielded average SO<sub>2</sub> reductions of 50% to 70%, and as high as 85%, with calcium hydrate injected into combustor

at a Ca/S mol ratios of 3 to 4. Furthermore, measurements of SO<sub>2</sub> at the outlet of the wet stack particulate scrubber yielded reductions of 98% to 0.048 lb/MMBtu in 1.5% sulfur coal.

Particulate emissions are controlled in part by slag retention in the combustor which can remove at best 70% to 80% of the coal ash. It is augmented with a wet particle scrubber which has reduced the particle emissions to 0.26 lb/MMBtu. In the future, a baghouse will be used, which can achieve 0.03 lb/MMBtu/hr emissions.

### The Williamsport 20 MMBtu/hr Combustor-Boiler Test Facility

The initial commercial scale tests were performed between 1987 and 1993 in a 20 MMBtu/hr combustor that was installed on a 17,500 lb/hr steam, 250 psig saturated steam boiler in an industrial plant in Williamsport, PA in early 1987. Figure 2 shows a side view drawing of the combustor attached to the boiler. The coal was pulverized off-site, and stored in a 4 ton capacity coal storage bin at the site. The coal was metered and fed in a pneumatic line to the combustor. The bin was refilled without combustor shutdown. A wet particulate scrubber was used to meet local emission requirements. Slag drained from the combustor into a water filled tank from which it was removed with a conveyor belt and deposited in a drum. The fuel and air streams to the combustor were computer controlled using the combustor's thermal performance as input variables. Diagnostics consist of measurement of fuel, air and cooling water flows, combustor wall temperatures, and stack gases taken in the stack above the boiler, upstream of the wet particle scrubber. Since the combustor's best slag retention is in the 70% to 80% range, it did not meet local particulate emission standards of 0.4 lb/MMBtu. Therefore, a wet particulate scrubber was used for this purpose.

## **THE PHILADELPHIA 500 KW POWER PLANT WITH THE ADVANCED 20 MMBTU/HR AIR COOLED COMBUSTOR**

### Site Selection Considerations

The design of this plant was based on the results of tests in the 20 MMBtu/hr air cooled combustor in Williamsport, PA, and on various site specific combustor applications studies that were performed in the past several years [1,7,8]. The economic studies revealed that a major factor in commercial acceptability of the combustor was demonstration of its operation in a commercial environment over extended periods. The Williamsport test site did not meet this requirements because the only use for the steam output of the boiler was for winter space heating.

Therefore, it was planned to reinstall the 20 MMBtu/hr combustor-boiler at a new host site that would utilize the energy produced. By using an atmospheric back pressure turbine, it is possible to generate almost 500 kW of power from the 17,500 lb/hr, 250 psig boiler. Early in 1994, a number industrial plants, including paper plants, food plants, and industrial parks in Southeast Pennsylvania, were contacted for this purpose. This region has substantially higher energy and power costs than the Williamsport region. Negotiations were initiated with the owners of a paper plant and an industrial park to provide process steam to the former and steam heat to the latter. Both sites also had a requirement for all the electric power that could be generated by the 20 MMBtu/hr combustor. However, the negotiations were terminated due to conflicting requirements by both parties. The primary interest of the site owners was an assured and continuous supply of energy, while the test objectives required periodic shutdowns and modifications to assess various aspects of the system performance and to introduce additional system improvements. Therefore, an alternate approach was selected. Instead of selling the energy production, the test site's energy production would be used to produce a salable energy intensive product whose rate of production would be determined by the test requirements.

Various energy intensive production processes were investigated, including paper/plastic waste combustion, CO<sub>2</sub> or H<sub>2</sub> production, and metals refining. The first option while the simplest to implement in the slagging combustor involves too long a regulatory approval process. Gas production was not economical at a small scale. Metal remelting was selected after a novel electric furnace design was invented at Coal Tech. A prototype is under development and following its testing, a production model will be fabricated to utilize the power output of the combustor plant. The 500 kW steam turbine generator will be installed to power the production melting furnace. The revenue from metal production will be used to extend the test operation beyond the 500 hours planned for the current project.

A site was selected in mid-1994 in a stand alone building in an industrial park in Philadelphia. It is a 3000 square feet, one story building, with an adjacent walled in alley suitable for placement of the coal storage and stack cleanup equipment. Figure 3 shows a plot plan of the building with a layout of the test equipment. The latter will be discussed below. One factor in selecting this site was its location adjacent to the Delaware River which could be used for once through cooling of the steam condenser. Prior to installation of the equipment, site improvements were made. They included an enlarged door to allow installation of the 17,500 lb/hr boiler, pavement of the enclosed alley for placement of the coal bins, coal mill, baghouse, and cooling tower, and an enlarged municipal water supply for combustor cooling, boiler feedwater, and cooling tower

operation. This work was completed in January 1995 and it was followed by the installation of the test equipment.

### Permitting

Relocating a boiler requires a new permit, as the environmental permits are not transferable to another site. The Pennsylvania Department of Environmental Resources (DER) is responsible for air emission regulation in the State with the exception of Philadelphia, which is under the jurisdiction of the City.

In preparing the application for the Philadelphia Air Permit, which was granted in early 1995, the test data accumulated in Williamsport in prior tests were re-examined for data on the emissions at the stack downstream of the wet particle scrubber. Since the combustor development emphasized its internal environmental performance, little emphasis was placed on data collected from the stack exhaust except to insure that it met Williamsport emission standards. During the re-examination, a series of test results were found where the SO<sub>2</sub> emissions at the outlet of the wet particle scrubber averaged 0.048 lb/MMBtu. This equaled a 98% reduction for the 1.5% sulfur content coal. The SO<sub>2</sub> emission standard for Williamsport PA was above the SO<sub>2</sub> level that would be achieved with 100% emission from 2% sulfur coal, namely 4 lb/MMBtu. On the other hand, the Philadelphia SO<sub>2</sub> emission standard for 2% sulfur coal requires 85% reduction of SO<sub>2</sub> to 0.5 lb/MMBtu. As noted above, this has been achieved on a several occasions with sorbent injection in the combustor as measured at the boiler outlet. However, the average reduction has been 70%. Therefore, reliance will be made on additional reduction in the stack upstream of the baghouse by stack sorbent injection.

To meet the particle emission standard for Philadelphia a baghouse is required in place of the wet particle scrubber that was used in Williamsport. The latter's best performance resulted in a particle emission of 0.26 lb/MMBtu, which was below the local standard of 0.4 lb/MMBtu. The Philadelphia standard is 0.06 lb/MMBtu. With a baghouse, emissions of less than 0.03 lb/MMBtu can be readily achieved.

The NO<sub>x</sub> standard for Philadelphia is very stringent, namely, 0.3 lb/MMBtu, while Williamsport has no standard. The lowest NO<sub>x</sub> level measured in Williamsport with staged combustion was 0.26 lb/MMBtu, while the average level was 0.45 lb/MMBtu. To achieve the Philadelphia standard may require additional control such as ammonia injection in the stack, if the optimum performance cannot be achieved on a consistent basis.

Operation of a steam turbine requires a steam condenser cooling source. One factor in the site selection was its location next to the Delaware River. It was initially planned to use a once through steam condenser with water from a well at the site with a year round temperature of 60°F as a source and discharging it into the River. The discharge temperature into the River had to be below 110°F. This required about 38,000 gph of cooling water, equal to about 300,000 gallons per 8 hour test. A detailed series of tests over a period of time revealed that the well's capacity was less than 10,000 gph. This shortfall could have been made up from the municipal water supply at considerable cost. Of greater significance was that the discharge of such a major quantity of cooling water would involve a lengthy permitting process from the State and the Delaware River Water Authority. Accordingly, the feasibility of a low cost cooling tower for steam condensation was evaluated. This approach required a cooling water discharge of less than 1800 gph, or 14,000 gallons per 8 hour day of testing. An equal amount of water is vaporized in the cooling tower. Furthermore, for the initial 500 hours of operation during which the steam turbine would not be used, it is more economical to blow off the steam. In either case, the waste water discharge is the same. As a result, a permit was obtained from the City to discharge less than 24,000 gpd of waste water to the City Municipal Sanitary system instead of the River. The peak discharge temperature must be below 140°F. This permit from the City Water Department was issued effective July 1, 1995.

Finally, an environmental consulting firm was retained to measure the hydrocarbon and heavy metal concentrations in the soil surrounding the test building to determine the baseline for future comparison. No evidence of high concentrations was found.

#### Design Factors in the Philadelphia Facility:

The results of the prior work, specifically the most recent tests in the Williamsport combustor facility and the power plant economic studies, were used to configure the test facility for the demonstration. Key issues considered in the design were:

Ease of maintenance and refurbishment. The goal was to allow combustor disassembly for maintenance in less than one day, compared to more than one week in Williamsport.

Modularity: Since the primary market application of this combustor is in the 1 to 20 MW range, a modular design of the major components was used. This will allow shipment to a customer's site of factory assembled sub-systems, such as the combustor and its associated ducting, piping, controls, and valves; the control system; the boiler; blower assemblies; and fuel processing.

Optimization to minimize installed and operating costs: A review of the Williamsport combustor test facility showed that a substantial number of inefficiencies had been incorporated in the installation. For example, high pressure air was used for air lines that operated at low pressure. The piping for the combustor and boiler air supply was much heavier than required for the conditions applicable to the combustor. This not only resulted in a higher cost for the piping but they also required much heavier supports.

This optimization is a continuing process from the design, fabrication, and through the current installation phase. In many cases simpler designs were not apparent until the equipment was installed. For example, an important maintenance goal is the ability to rapidly (within one day) disassemble the combustor from the boiler for maintenance. It was not until the combustor was installed that a simple method was developed and tested which allows disassembly of the combustor in several hours.

A very important part of this optimization has been reducing the electric power necessary to operate the facility. In Williamsport the local utility's power charge for single daily shift operation was **one-fourth** of that in Philadelphia. The total power consumption was about 200 kW, excluding coal pulverization which was performed off site. This is about 40% of the 500 kW power that could be produced with this boiler in a single stage, high backpressure, steam turbine. This power consumption was reduced to 73 kW, without coal pulverization. This represents a factor of three reduction in power consumption. Due to the use of coarse coal grinding the pulverization power consumption including all auxiliaries, such as fans, feeders, etc., is only 30 kW per ton, or 20 kW per hour of operation. These results are directly applicable to a fully commercial power plant.

#### Test Facility Design and Equipment Configuration

Figure 3 shows a schematic plan view of the Philadelphia test facility. Both the combustor and boiler that were used in Williamsport have been modified and relocated to Philadelphia. The major modifications will be discussed below. The 4 ton pulverized coal bin has been relocated without modification. As the scrubber cannot meet the Philadelphia emission standard, it has been replaced with a baghouse. The design included the installation of a refurbished single stage steam turbine operating at 200 psi saturated steam. A steam condenser is cooled by a wet cooling tower. In addition, provision was made to store between 16 and 25 tons of raw coal and pulverize it on site, as opposed to the off-site pulverization used in Williamsport. The coal

handling, baghouse, and cooling tower are placed in the alley adjacent to the test building, while all the other equipment is placed inside the building.

All this equipment was specified and priced using competitive vendor quotations. This included the purchase and refurbishment of the boiler, a refurbished 600 kW steam turbine, a refurbished coal mill, a modified combustor, a wet cooling tower, and a steam condenser. The total cost was substantially below the range anticipated from prior economic studies. This is consistent with the prior conclusion that this technology can be installed in power plants at under \$1000/kW in the 1 to 20 MW range.

Since the primary current objective remains full demonstration of the combustor, a conservative plan for the initial 500 hour test effort has been adopted. The combustor was substantially modified, and the facility must meet strict environmental standards. To assure that these modifications function properly, the first 100 hours will be performed with off site coal pulverization and with the steam being blown off to the atmosphere, as was done in Williamsport. This will be followed with the installation of the on-site raw coal storage system for the final 400 hours of operation. This schedule will meet all current project objectives. Depending on the status of the metal remelting project, which would provide operating revenue, the steam turbine, condenser and cooling tower will be added to provide on site power for the melting furnace. This will in effect be a commercial operation of the facility. The facility will be also be used to showcase this power plant technology.

Additional details of the major modifications that were made are as follows:

Combustor Modification: The analysis of the previous tests indicated that lengthening the combustor would improve the combustion efficiency and the slag retention. Also, economic analysis showed that the use of coarser coal sizes would allow the use of much lower cost coal pulverizers. Coarse coal tests were performed in Williamsport which yielded acceptable combustion. Also, in the most recent prior tests, a substantial improvement in exit nozzle thermal performance was obtained when the adiabatic exit nozzle was converted to partial air cooling.

These items were incorporated in the modification of the combustor which consisted in lengthening it and adding air cooling to the exit nozzle. The fabrication of the modified combustor section was completed at the end of the first quarter of 1995.

Installation of Test Equipment: Figure 3 shows a plot plan of the installation of the test facility in Philadelphia. The installation of the test equipment began in late January 1995 with the delivery

of all the equipment from Williamsport. This included the modified 17,500 lb/hr boiler which was placed on an elevated platform to allow placement beneath the boiler floor of an ash removal system. The fabricated sections of the combustor were delivered to the site at the end of March, 1995, and the refractory was installed on-site. The combustor is installed in a manner that allows its removal and reconnection for internal refurbishment in less than one day.

The original 4 ton pulverized coal bin was placed in the alley adjacent to the test building. A new baghouse was installed as was the stack ducting and the induced draft fan. The steam piping for operation in the blowoff mode was installed. The combustion air fans, propane pilot gas feed system, combustor and slag tank water cooling systems, and oil fuel systems were installed in a modular configuration which allows simple connection and removal from the combustor. Major simplifications in the design of these systems were implemented which greatly reduce the cost of the installation and of its operation. The combustor control system is being converted from relay control to programmable logic control. This is addition to the computer operating control that was already in operation in Williamsport.

A key feature of the installation has been the simplification and cost reduction of the entire system to achieve a low cost commercial plant. As of the date of this paper, the only remaining work needed to begin test operations are the installation of an oil storage tank, connection of the air, water, propane and oil lines to the combustor from the modular subassemblies of these sub-systems, installation of the power lines, installation of the controls and diagnostic wiring, and connection of the boiler controls.

It is planned to complete the installation in late Summer 1995. This will be followed by the 100 hour equipment shakedown test beginning in the third quarter of 1995. This will be followed by the remaining 400 hours of tests. For the latter, on site coal storage and pulverization will be used.

## CONCLUSIONS

The results of the effort to date on the 500 kW power plant have confirmed that the present design of the slagging combustor-boiler system is very low in capital and operating costs. Major component and sub-system simplifications have been implemented on all aspects of the power plant. Therefore, its commercial viability as a low capital and operating cost coal fired power system in the 1 to 20 MW power range is assured.

## ACKNOWLEDGMENTS

Current test efforts are supported in part by the DOE-Advanced Combustion Technology Program at the Pittsburgh Energy Technology Center (PETC). Mr. Andrew Karash is the DOE/PETC Technical Project Manager. The authors also wish to acknowledge the continuing interest and advice in the development of this technology by Mr. Arthur L. Baldwin. Mr. Baldwin was the DOE Technical Project Manager during the Clean Coal Project on this combustor.

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Figure 1: Schematic Diagram of the Coal Tech Air Cooled Combustor

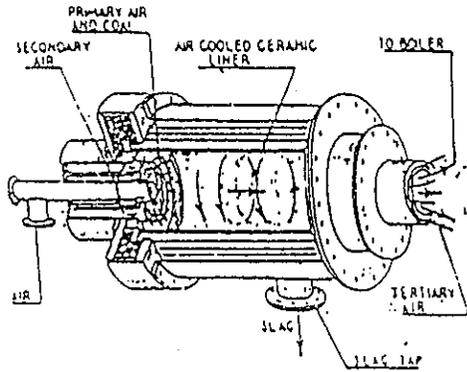


Figure 2: Drawing of Coal Tech's Air Cooled Combustor Installed on a 20 MMBtu/hr Oil Designed Boiler

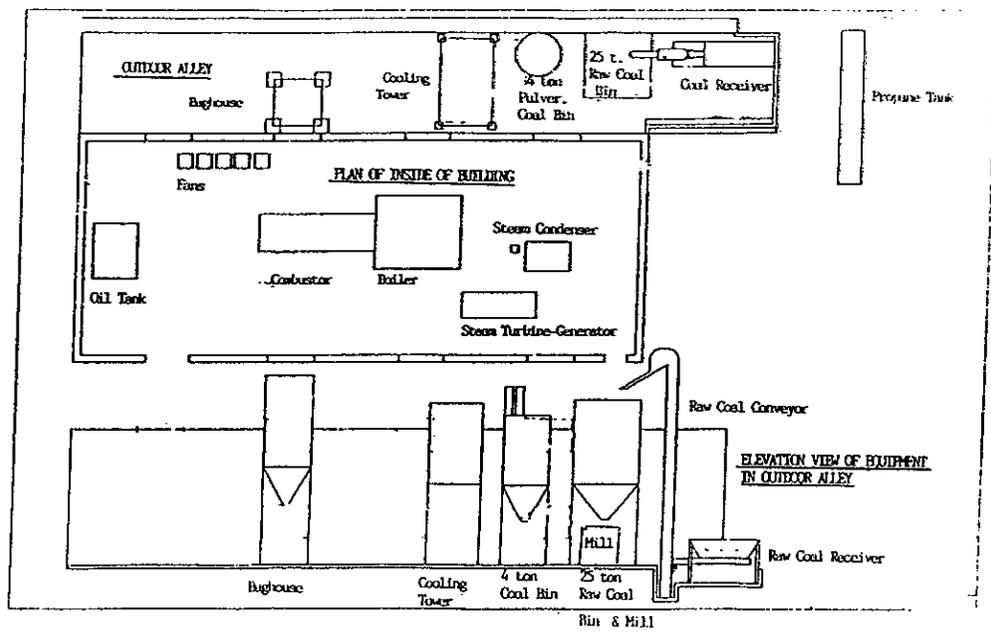
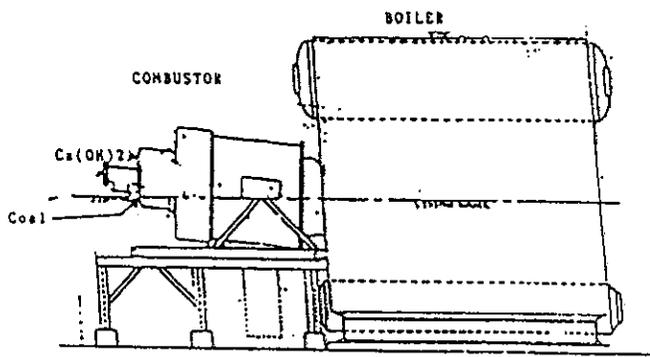


Figure 3: Plot Plan of the 20 MMBtu/hr Combustor-Boiler Test Site in Philadelphia.

# **Session IV**

## **Advanced Emissions Reduction Technologies**



BAILLY STATION AFGD  
DEMONSTRATION PROGRAM

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The 4th Annual Clean Coal Technology Conference  
September 5-8, 1995  
Denver, Colorado

ABSTRACT

Pure Air's Advanced Flue Gas Desulfurization (AFGD) Clean Coal Project has completed three highly successful years of operation at NIPSCO's Bailly Station. As part of their program, Pure Air has concluded a six-part study of system performance. This paper will summarize the results of the demonstration program, including AFGD performance on coals ranging from 2.0 - 4.5% sulfur. The paper will highlight novel aspects of the Bailly facility, including pulverized limestone injection, air rotary sparger for oxidation, wastewater evaporation system and the

production of the PowerChip® gypsum. Operations and maintenance which have lead to the facility's notable 99.99% availability record will also be discussed. A project company, Pure Air on the Lake Limited Partnership, owns the AFGD facility. Pure Air was the turn key contractor and Air Products and Chemicals, Inc., is the operator of the AFGD system.

**THE CLEAN COAL TECHNOLOGY PROGRAM  
10 MWe DEMONSTRATION OF GAS SUSPENSION ABSORPTION  
FOR FLUE GAS DESULFURIZATION**

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CLEAN COAL TECHNOLOGY CONFERENCE  
September 5-8, 1995  
Denver, Colorado

**ABSTRACT**

AirPol Inc., with the cooperation of the Tennessee Valley Authority (TVA) under a Cooperative Agreement with the United States Department of Energy, installed and tested a 10 MWe Gas Suspension Absorption (GSA) Demonstration system at TVA's Shawnee Fossil Plant near Paducah, Kentucky. This low-cost retrofit project demonstrated that the GSA system can remove more than 90% of the sulfur dioxide from high-sulfur coal-fired flue gas, while achieving a relatively high utilization of reagent lime.

This paper presents a detailed technical description of the Clean Coal Technology demonstration project. Test results and data analysis from the preliminary testing, factorial tests, air toxics tests, 28-day continuous demonstration run of GSA/electrostatic precipitator (ESP), and 14-day continuous demonstration run of GSA/pulse jet baghouse (PJBH) are also discussed within this paper.

## INTRODUCTION

AirPol, with the assistance of the Tennessee Valley Authority (TVA), demonstrated the Gas Suspension Absorption (GSA) technology in the Clean Coal Technology project entitled "10 MW Demonstration of Gas Suspension Absorption." AirPol performed this demonstration under a Cooperative Agreement awarded by the United States (U.S.) Department of Energy (DOE) in October 1990. This project was selected in Round III of the Clean Coal Technology Program.

This project was the first North American demonstration of the GSA system for flue gas desulfurization (FGD) for a coal-fired utility boiler. This low-cost retrofit project achieved the expected target, which was to remove more than 90% of the sulfur dioxide (SO<sub>2</sub>) from the flue gas while achieving a high utilization of reagent lime. TVA furnished its Center for Emissions Research (CER) as the host site and provided operation, maintenance, and technical support during the project. The CER is located at the TVA's Shawnee Fossil Plant near Paducah, Kentucky.

The experience gained by AirPol in designing, fabricating, and constructing the GSA equipment through the execution of this project will be used for future commercialization of the GSA technology. The results of the operation and testing phase will be used to further improve the GSA system design and operation.

The specific technical objectives of the GSA demonstration project were the following:

- Demonstrate SO<sub>2</sub> removal in excess of 90% using high-sulfur U.S. coal.
- Optimize design and operating parameters to maximize the SO<sub>2</sub> removal efficiency and lime utilization.
- Compare the SO<sub>2</sub> removal efficiency of the GSA technology with existing spray dryer/electrostatic precipitator (SD/ESP) technology.

DOE issued an amendment to the Cooperative Agreement to include the additional scope of work for air toxics testing and also the operation and testing of a 1 MWe fabric filter pilot plant in cooperation with TVA and the Electric Power Research Institute (EPRI). The two-fold purpose of this additional work was the following:

- Determine the air toxics removal performance of the GSA technology.
- Compare the SO<sub>2</sub>, particulate, and air toxics removal performance between GSA/ESP and GSA/fabric filter systems.

The fabric filter used in this project is a pulse-jet baghouse (PJBH) which can treat flue gas removed either upstream or downstream of the ESP. The testing of the PJBH was conducted for both configurations.

The total budget for the project with the added scope of work was \$7,720,000; however, the project cost was under the budget. The favorable variance resulted mainly from actual material and construction costs being much lower than the original estimate. The performance period of the project, including the air toxics measurements, PJBH testing, and report preparation was from November 1990 to June 1995.

AirPol began the design work on this project in November 1990, shortly after award of the Cooperative Agreement by DOE in October 1990. At the outset of the project, access to the site at the CER was delayed for one year by TVA to allow the completion of another project. That caused a one-year delay in this Clean Coal Technology project. The design phase of the GSA project was completed in December 1991. The fabrication and construction of the GSA unit was completed ahead of schedule in early September 1992. The planned operation and testing of the demonstration unit were conducted from late October 1992 to the end of February 1994.

## **HISTORY OF THE GSA TECHNOLOGY**

The GSA process is a novel concept for FGD that was developed by AirPol's parent company, F.L. Smidth miljo a/s in Copenhagen, Denmark. The process was initially developed as a

cyclone preheater system for cement kiln raw meal (limestone and clay). This innovative system provided both capital and energy savings by reducing the required length of the rotary kiln and lowering fuel consumption. The GSA system also showed superior heat and mass transfer characteristics and was subsequently used for the calcination of limestone, alumina, and dolomite. The GSA system for FGD applications was developed later by injecting lime slurry and the recycled solids into the bottom of the reactor to function as an acid gas absorber.

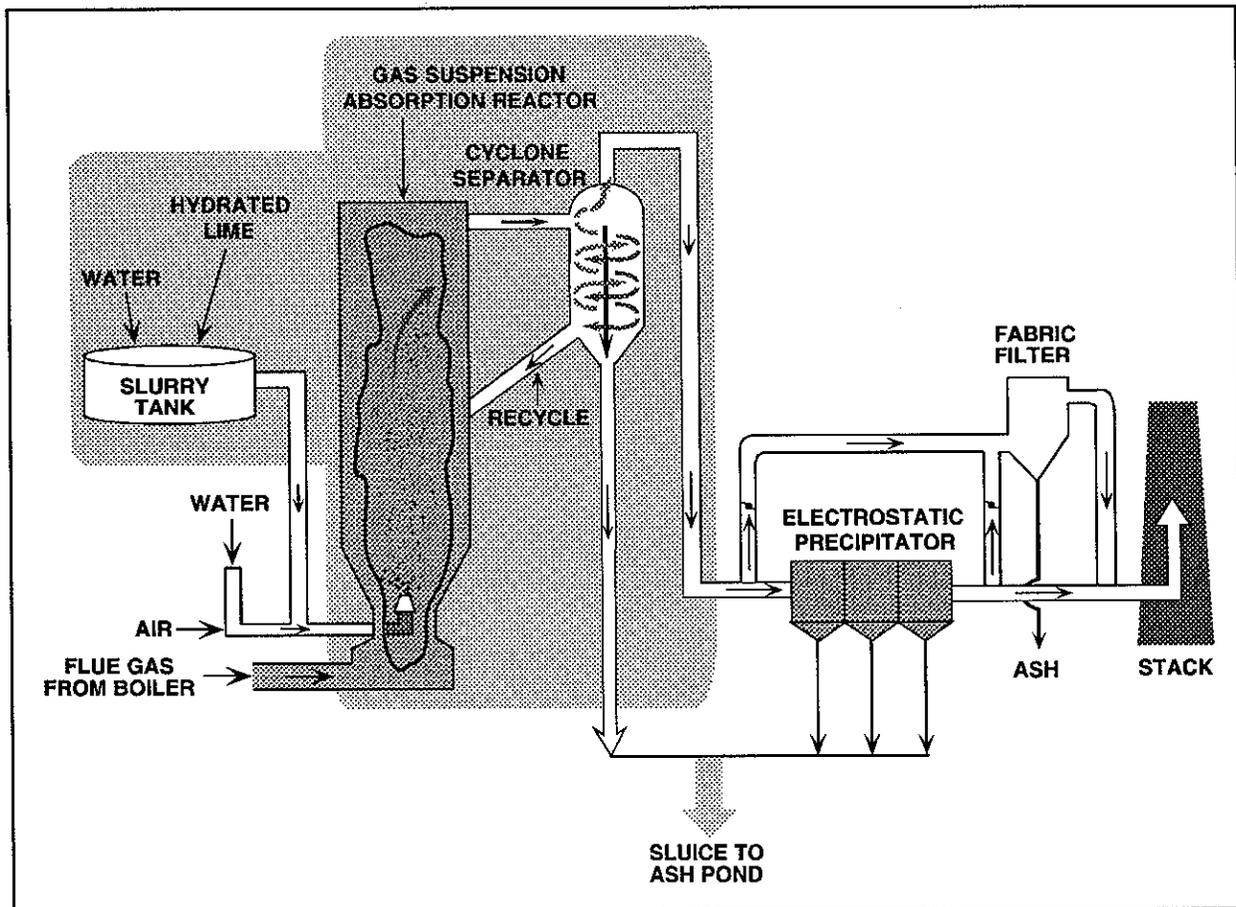
In 1985, a GSA pilot plant was built in Denmark to establish design parameters for SO<sub>2</sub> and hydrogen chloride (HCl) absorption for waste incineration applications. The first commercial GSA unit was installed at the KARA Waste-to-Energy Plant at Roskilde, Denmark, in 1988. Currently, there are seventeen GSA installations in Europe; 15 are municipal solid waste incinerator applications, and two are industrial applications (cement and iron ore reduction).

With the increased emphasis on SO<sub>2</sub> emissions reduction by electric utility and industrial plants as required by the Clean Air Act Amendments of 1990, there is a need for a simple and economic FGD process, such as GSA, by the small to mid-size plants where a wet FGD system may not be feasible. The GSA FGD process, with commercial and technical advantages confirmed in this demonstration project, will be a viable alternative to meet the needs of utility and industrial boilers in the U.S.

## **GSA FGD PROCESS DESCRIPTION**

The GSA FGD system, as shown in the Figure 1 Process Flow Diagram, includes:

- A circulating fluidized bed reactor.
- A separating cyclone incorporating a system for recycling the separated material to the reactor.
- A lime slurry preparation system which proportions the slurry to the reactor via a dual-fluid nozzle.
- A dust collector which removes fly ash and reaction products from the flue gas stream.



**Figure 1.** Gas Suspension Absorption Process Flow Diagram

The flue gas from the boiler air preheater is fed into the bottom of the circulating fluidized bed reactor, where it is mixed with the suspended solids that have been wetted by the fresh lime slurry. The suspended solids consist of reaction products, residual lime, and fly ash. During the drying process in the reactor, the moisture in the fresh lime slurry, which coats the outer surface of the suspended solids, evaporates. Simultaneously, the lime particles in the slurry undergo a chemical reaction with the acid components of the flue gas,  $\text{SO}_2$  and  $\text{HCl}$ , capturing and neutralizing them.

The partially cleaned flue gas flows from the top of the reactor to the separating cyclone and then to an ESP (or a fabric filter), which removes the dust and ash particles. The flue gas, which has now been cleaned, is released into the atmosphere through the stack.

The cyclone separates most of the solids from the flue gas stream. Approximately 95% to 99% of these collected solids are fed back to the reactor via a screw conveyor, while the remaining solids leave the system as a byproduct material. Some of these solids recirculated to the reactor are still reactive. This means that the recirculated lime is still available to react and neutralize the acid components in the flue gas.

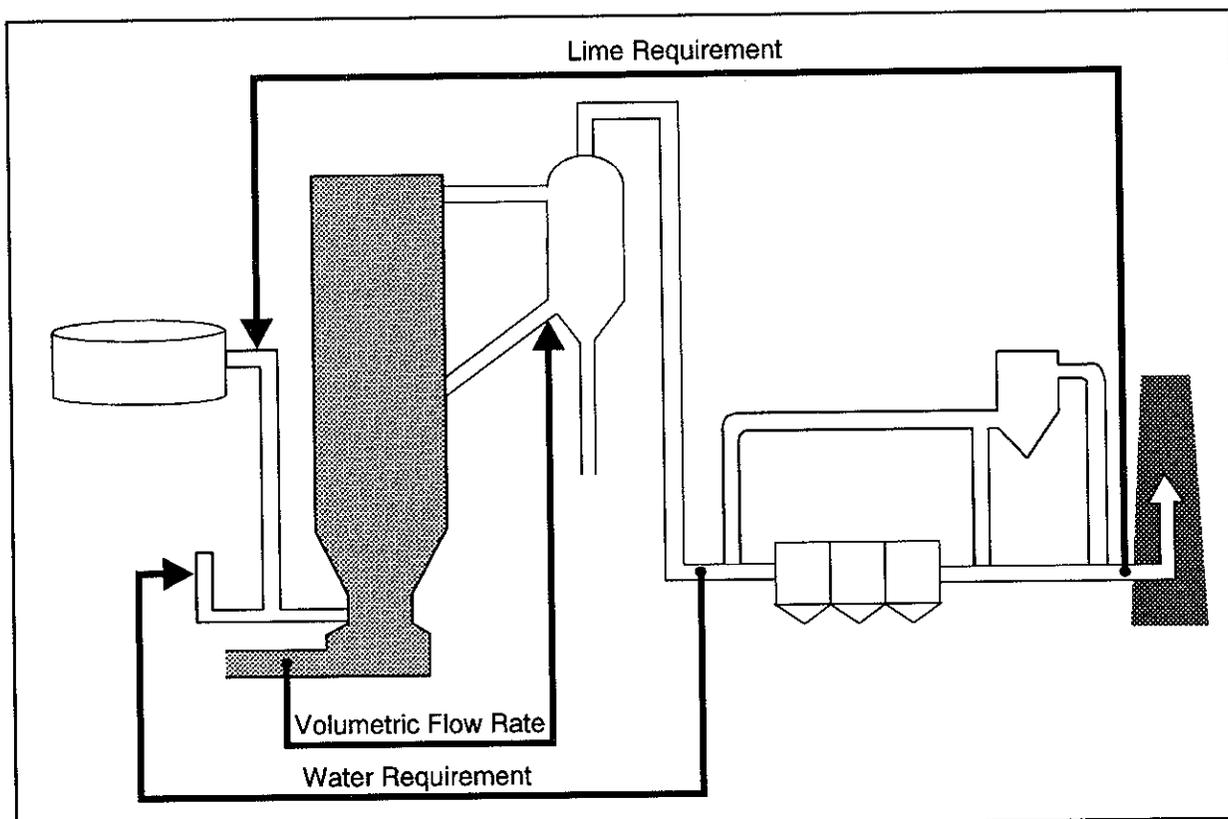
The pebble lime is slaked in a conventional, off-the-shelf system. The resulting fresh slaked lime slurry is pumped to an interim storage tank and then to the dual-fluid nozzle. The slurry is diluted with trim water prior to being injected into the reactor.

#### Automatic Process Adjustment

An effective monitoring and control system automatically ensures that the required level of SO<sub>2</sub> removal is attained while keeping lime consumption to a minimum. This GSA control system, which is shown in Figure 2, incorporates three separate control loops:

1. Based on the flue gas flow rate entering the GSA system, the first loop continuously controls the flow rate of the recycled solids back to the reactor. The large surface area for reaction provided by these fluidized solids and the even distribution of the lime slurry in the reactor, provide for the efficient mixing of the lime with the flue gas. At the same time, the large volume of dry material prevents the slurry from adhering to the sides of the reactor.
2. The second control loop ensures that the flue gas is sufficiently cooled to optimize the absorption and reaction of the acid gases. This control of flue gas temperature is achieved by the injection of additional water along with the lime slurry. The amount of water added into the system is governed by the temperature of the flue gas exiting the reactor. This temperature is normally set a few degrees above flue gas saturation temperature to insure that the reactor solids will be dry so as to reduce any risk of acid condensation.

- The third control loop determines the lime slurry addition rate. This is accomplished by continuously monitoring the  $\text{SO}_2$  content in the outlet flue gas and comparing it with the required emission level. This control loop enables direct proportioning of lime slurry feed according to the monitored results and maintains a low level of lime consumption.



**Figure 2.** Gas Suspension Absorption Control System

## COMPARISON OF GSA PROCESS WITH COMPETING TECHNOLOGY

Simplicity is the key feature of the GSA system. The advantages of the GSA system over competing technologies are summarized as follows:

### Slurry Atomization

The major difference between GSA and competing technologies lies in the way the reagent is introduced and used for  $\text{SO}_2$  absorption. A conventional semi-dry scrubber:

- Requires a costly and sensitive high-speed rotary atomizer or a high-pressure atomizing nozzle for fine atomization,
- Absorbs SO<sub>2</sub> in an "umbrella" of finely atomized slurry with a droplet size of about 50 microns,
- May require multiple nozzle heads or rotary atomizers to ensure fine atomization and full coverage of the reactor cross section, and
- Uses recycle material in the feed slurry necessitating expensive abrasion-resistant materials in the atomizer(s).

The GSA process, on the other hand,

- Uses a low-pressure, dual-fluid nozzle,
- Absorbs SO<sub>2</sub> on the wetted surface of suspended solids with superior mass and heat transfer characteristics,
- Uses only one spray nozzle for the purpose of introducing slurry and water to the reactor, and
- Uses dry injection of recycle material directly into the reactor, thereby avoiding erosion problems in the nozzle or technical limitations on the amount of solids that can be recycled.

#### Simple and Direct Method of Lime/Solid Recirculation

The recirculation of used lime is the trend for semi-dry scrubbing systems. The recirculation of solids in the GSA system is accomplished using a feeder box under the cyclone, which introduces the material directly into the reactor. The recirculation feature commonly used in most other semi-dry processes has an elaborate ash handling system to convey and store the ash. The method of introducing the recirculated material is usually by mixing it with the fresh lime slurry. The presence of ash in the lime slurry may cause sediment problems in the slurry lines and excessive nozzle wear.

### High Acid Gas Absorption

The GSA reactor is capable of supporting an extremely high concentration of solids (recirculated material) inside the reactor, which acts like a fluidized bed. This concentration will normally be as high as 200-800 grains/scf. These suspended solids provide a large surface area for contact between the lime slurry (on the surface of the solids) and the acidic components in the flue gas. This high contact area allows the GSA process to achieve levels of performance that are closer to those of a wet scrubber, rather than a dry scrubber. Since drying of the solids is also greatly enhanced by the characteristic large surface area of the fluidized bed, the temperature inside the reactor can be reduced below that of the typical semi-dry scrubber. This lower operating temperature facilitates acid gas removal in the GSA system.

### Low Lime Consumption / Minimum Waste Byproduct Residue

The design of the GSA reactor allows for more efficient utilization of the lime slurry because of the high internal recirculation rate and precise process control. The higher lime utilization (up to 80%) lowers the lime consumption, thereby minimizing one of the major operating costs. In addition, the lower lime consumption reduces the amount of byproduct generated by the system.

### Low Maintenance Operation

Unlike typical semi-dry scrubbers, the GSA system has no moving parts inside the reactor, thus ensuring relatively continuous, maintenance-free operation. The orifice diameter of the GSA injection nozzle is much larger than that used in a conventional semi-dry process, and there is little chance for it to plug. Nozzle wear is also minimized. Should the need for replacing the nozzle arise, it can be replaced in a few minutes. The cyclone also has no moving parts. Both the reactor and the cyclone are fabricated from unlined carbon steel.

The GSA process also has few pieces of equipment. Most of the equipment is in the lime slurry preparation area, which typically is an off-the-shelf item, and the technology is well known.

### No Internal Buildup

By virtue of the fluidized bed inside the reactor, the inside surface of the reactor is continuously "brushed" by the suspended solids and is kept free of any buildup. Internal wall buildup can be a problem with the conventional semi-dry scrubber. There is also no wet/dry interface on any part of the equipment and this avoids any serious corrosion problem.

### Modest Space Requirements

Due to the high concentration of suspended solids in the reactor, the reaction occurs in a relatively short period of time. A high flue gas velocity of 20 to 22 feet per second as compared to 4 to 6 feet per second for a semi-dry scrubber, as well as the shorter residence time of 2.5 seconds as compared to 10 to 12 seconds for a semi-dry scrubber, allow for a smaller diameter reactor which leads to a considerable reduction in space requirements.

### Short Construction Period

The compact design of the GSA unit requires less manpower and time to be erected as compared to the typical semi-dry scrubbers. Despite the relatively complicated tie-ins and extremely constrained work space, the retrofit GSA demonstration unit at the TVA's CER was erected in three and a half months.

### Heavy Metals Removal

Recent test results from waste incineration plants in Denmark indicate that the GSA process is not only effective in removing acidic components from the flue gas but is also capable of removing heavy metals, such as mercury, cadmium, and lead. This heavy metal removal capability of the GSA process at the CER was confirmed by the air toxics tests.

## PROJECT STATUS AND KEY MILESTONES

The project schedule and tasks involved in the design, construction, and operation and testing phases are as follows:

Phase I - Engineering and Design		Start - End
1.1	Project and Contract Management	11/01/90-12/31/91
1.2	Process Design	11/01/90-12/31/91
1.3	Environmental Analysis	11/01/90-12/31/91
1.4	Engineering Design	11/01/90-12/31/91
Phase II - Procurement and Construction		
2.1	Project and Contract Management	01/01/92-09/30/92
2.2	Procurement and Furnish Material	01/01/92-04/30/92
2.3	Construction and Commissioning	05/01/92-09/30/92
Phase III - Operating and Testing		
3.1	Project Management	10/01/92-12/31/94
3.2	Start-up and Training	10/01/92-10/14/92
3.3	Testing and Reporting	10/15/92-06/30/95

The parametric optimization tests were completed on schedule in August 1993. Following the air toxics testing, which was finished in October 1993, there was a 28 day, around-the-clock demonstration run from the later October to late November 1993 and a 14-day, around-the-clock PJBH demonstration run from late February to mid-March 1994. All testing has been completed and the project reports have been prepared.

## TEST PLAN

A test plan was prepared to depict in detail the procedures, locations, and analytical methods to be used in the tests. All of the following objectives were achieved by testing the GSA system:

- Optimization of the operating variables.
- Determination of stoichiometric ratios for various SO<sub>2</sub> removal efficiencies.
- Evaluation of erosion and corrosion at various locations in the system.
- Demonstration of 90% or greater SO<sub>2</sub> removal efficiency when the boiler is fired with high-sulfur coal.

- Determination of the air toxics removal performance.
- Evaluation of the PJBH performance in conjunction with the GSA process.

### Optimization Tests

The optimization of the SO<sub>2</sub> removal efficiency in the GSA system was accomplished through the completion of a statistically-designed factorial test plan. For each test series, the GSA system was set to operate at a certain combination of operating parameters. The results of these test series were analyzed statistically to determine the impact of the parameters, thus arriving at the optimum operating point for the GSA process at the various operating conditions expected in future applications. Operating parameters studied in this phase of the project were the following:

- Inlet flue gas flow rate
- Inlet flue gas temperature
- Inlet dust loading
- Solids recirculation rate
- Stoichiometric ratio
- Approach-to-saturation temperature
- Coal chloride level

### Data Collection

The following data were sampled and recorded during the tests by either the computerized data sampling and recording system (via field mounted instruments) or by manual field determinations:

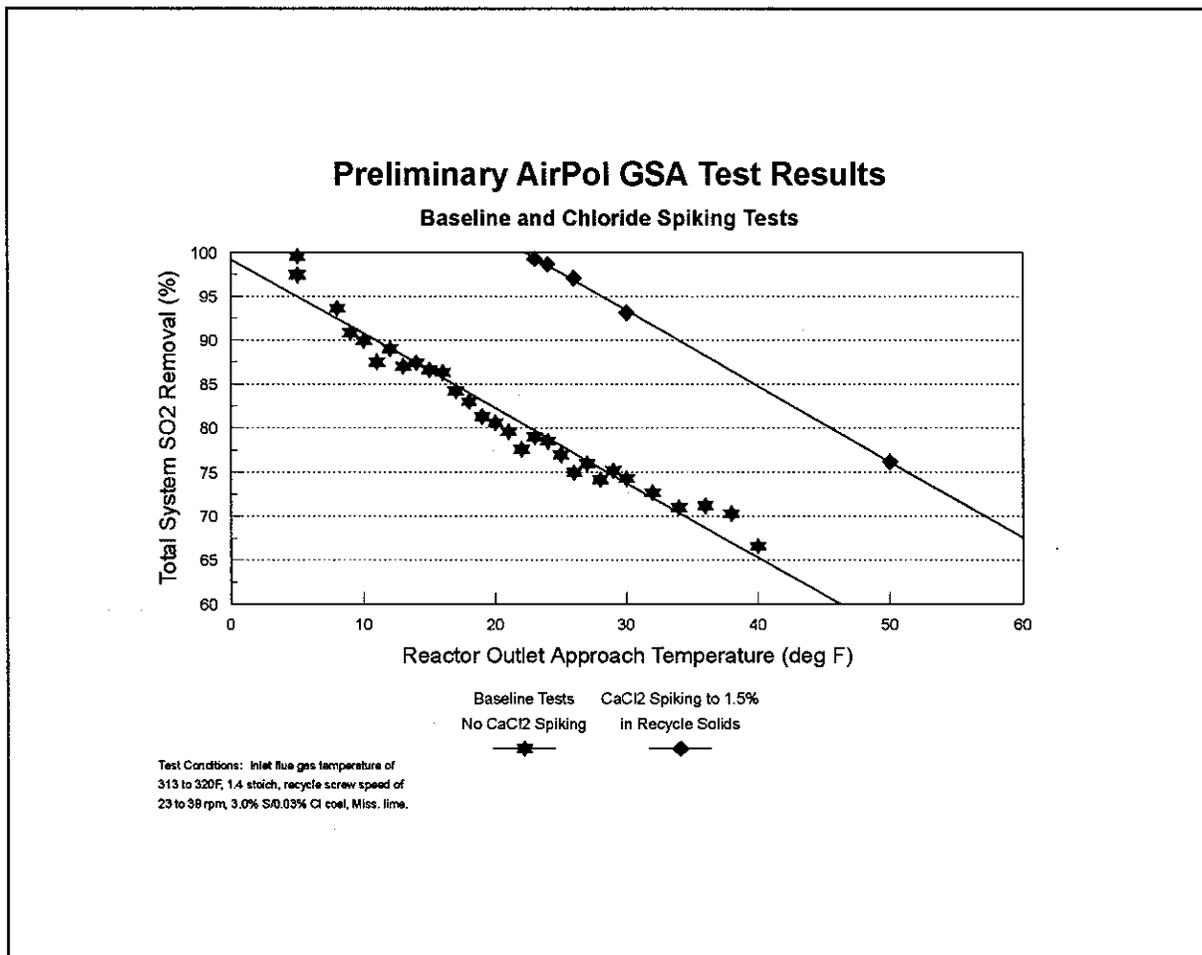
- Inlet flue gas flow into the system
- SO<sub>2</sub> loading at the system inlet, SO<sub>2</sub> loading at the ESP inlet and outlet
- Flue gas temperature at the system inlet, the reactor outlet, and the ESP outlet
- Particulate loading at the ESP inlet and outlet
- Fresh lime slurry flow rate and composition (for lime stoichiometry calculation)
- Water flow rate
- Wet-bulb temperature at the reactor inlet (for approach-to-saturation temperature calculation)
- Coal analysis (proximate and ultimate)
- Lime analysis
- Byproduct rate and composition

- Water analysis
- Power consumption

## PRELIMINARY TESTING

Immediately after the dedication of the AirPol GSA demonstration plant in late October 1992, a series of preliminary tests was begun. The purpose of these tests was to investigate the operating limits of the GSA system as installed at the CER. The results from several of the preliminary tests completed at the CER in November and December were very interesting, and these results were used as the basis for the design of the factorial test program. During one of the preliminary tests, the approach-to-saturation temperature in the reactor was gradually decreased and the overall system (reactor/cyclone and ESP) SO<sub>2</sub> removal efficiency was monitored over this four-day test. The overall system SO<sub>2</sub> removal efficiency increased from about 65% to more than 99% at the closest approach-to-saturation temperature (5°F). The other conditions, which remained constant, were 320°F inlet flue gas temperature, 1.40 moles Ca(OH)<sub>2</sub>/mole inlet SO<sub>2</sub> for the lime stoichiometry, and essentially no chloride in the system. The SO<sub>2</sub> removal results from this test are shown in Figure 3.

The data from this test show that the SO<sub>2</sub> removal efficiency increased dramatically as the flue gas temperature in the reactor more closely approached the saturation temperature of the flue gas, with the incremental increases in SO<sub>2</sub> removal becoming more and more significant as the approach-to-saturation temperature declined. The ability of the GSA system to operate at this close approach-to-saturation temperature without any indication of plugging problems was surprising. Later analysis showed that the moisture level in the solids remained below 1%.



**Figure 3.** Preliminary AirPol GSA Test Results

A second extended test was run during December 1992. This test was run at the same conditions as the previous test, except that in this test, calcium chloride was added to the system to simulate the combustion of a high-chloride (about 0.3%) coal. Previous work by TVA at the CER had demonstrated that spiking these semi-dry, lime-based FGD processes with a calcium chloride solution adequately simulated a high chloride coal application. Again, the approach-to-saturation temperature was gradually decreased over a four-day period with all other conditions held constant and the overall system SO<sub>2</sub> removal efficiency was monitored. The results from this second test, which are included in Figure 3 above, show that the presence of chlorides enhances SO<sub>2</sub> removal.

The overall system SO<sub>2</sub> removal efficiency for the chloride-spiked tests increased from about 70% at the high approach-to-saturation condition to essentially 100% at the closer approach-to-saturation temperature (23°F). No attempt was made to operate the system at the close approach-

to-saturation temperatures used in the first test because the SO<sub>2</sub> removal efficiency was approaching 100%. In addition, there were initially some concerns about the secondary effect of calcium chloride addition. Calcium chloride is an ionic salt that tends to depress the vapor pressure of water in the system and thus, slows the evaporation of water from the slurry. Calcium chloride is also a hygroscopic material, which means it has the ability to absorb moisture from the humid flue gas. The increased moisture in the "dry" solids allows more reaction with SO<sub>2</sub>, but also increases the potential for plugging in the system. The easiest method for mitigating this potential for plugging is to increase the approach-to-saturation temperature in the reactor. However, the moisture levels in the solids during this test remained below 1%, even at the closest approach-to-saturation temperature.

Another interesting finding from the preliminary testing is that the GSA process is capable of supporting a very high level of recirculation material in the reactor. This high solid concentration inside the reactor is the reason for the superior drying characteristics of the GSA system. Based on the results from these initial tests, the recycle rate back to the reactor was doubled prior to starting the factorial testing.

## **FACTORIAL TESTING**

The purpose of the statistically-designed factorial test program was to determine the effect of process variables on the SO<sub>2</sub> removal efficiency in the reactor/cyclone and the ESP.

Based on the successful preliminary testing, the major process design variables were determined, levels for each of these variables were defined, and an overall test plan was prepared. The major variables were approach-to-saturation temperature, lime stoichiometry, fly ash loading, coal chloride level, flue gas flow rate, and recycle screw speed. Two levels were determined for nearly all of the variables, as shown in Table 1 below. The one exception was the approach-to-saturation temperature where three levels were defined, but the third level was run only for those tests at the lower coal chloride level.

Major Variables and Levels for Factorial Testing Table		
Variable		Level
Approach-to-saturation temperature	°F	8 <sup>a</sup> , 18, and 28
Ca/S	moles Ca(OH) <sub>2</sub> /mole inlet SO <sub>2</sub>	1.00 and 1.30
Fly ash loading	gr/acf	0.5 and 2.0
Coal chloride level	%	0.02 and 0.12
Flue gas flow rate	kscfm	14 and 20
Recycle screw speed	rpm	30 and 45
<sup>a</sup> 8°F level run only at the low-chloride level		

**Table 1.** Major Variables and Levels for Factorial Testing

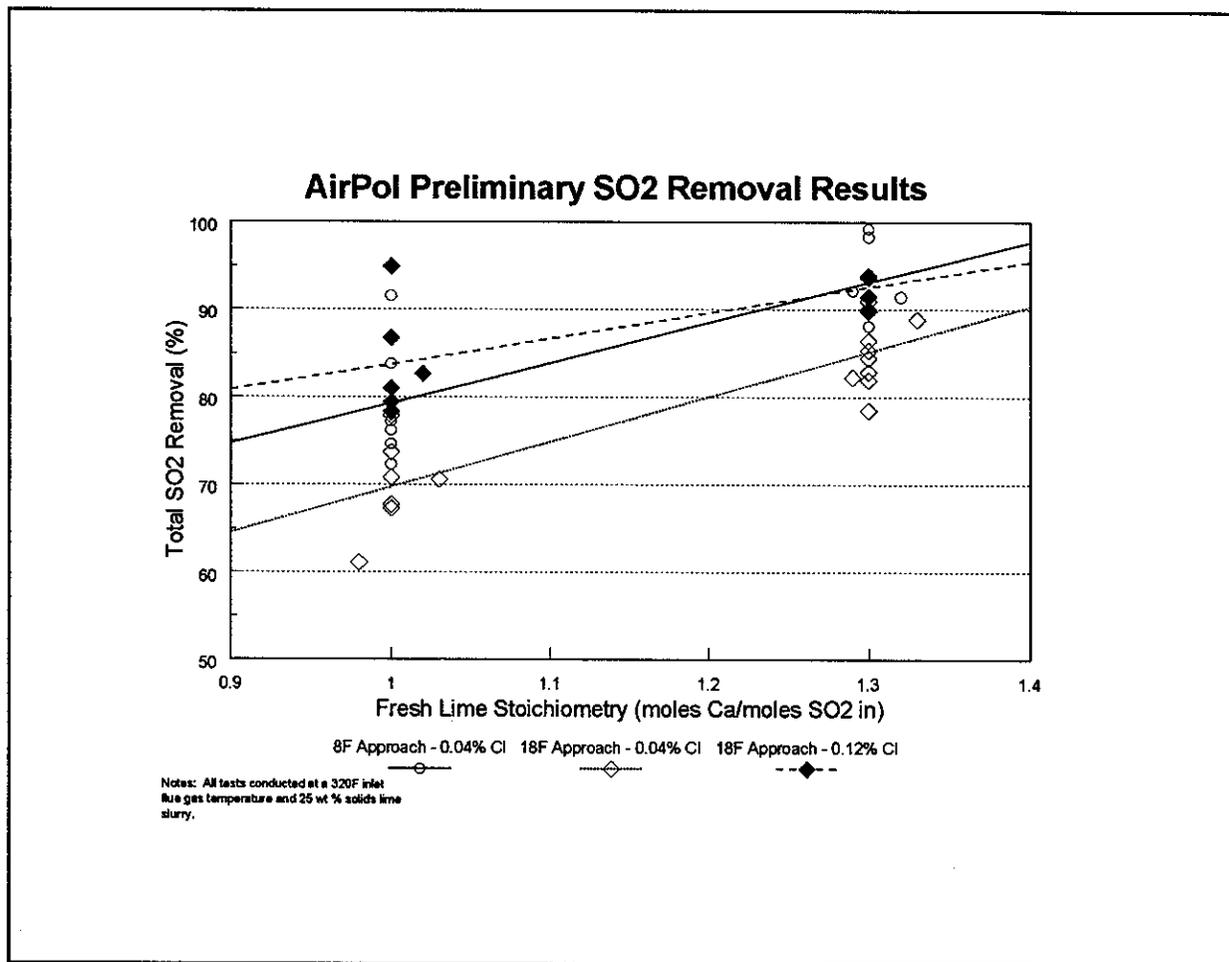
Although the preliminary chloride spiking tests had not been run at an approach-to-saturation temperature below 23°F, the decision was made to complete these chloride-spiking factorial tests at an 18°F approach-to-saturation temperature. There was some risk in this decision because the water evaporation rate decreases at the higher chloride levels. However, based on previous test work at the CER, the expectation was that at the lower chloride levels in this test plan, equivalent to a coal chloride level at 0.12%, the GSA system could operate at the 18°F approach-to-saturation temperature condition.

## RESULTS OF FACTORIAL TESTING

### SO<sub>2</sub> Removal Efficiency

The overall system SO<sub>2</sub> removal efficiency results from these factorial tests have been analyzed, and several general relationships have become apparent. First, as was expected based on previous testing at the CER, significant positive effects on the SO<sub>2</sub> removal efficiency in the system came from increasing the lime stoichiometry and other factors such as increasing the coal chloride level or decreasing the approach-to-saturation temperature. Increasing the recycle rate resulted in higher SO<sub>2</sub> removal, but the benefit appeared to reach an optimum level, above which further increases in the recycle rate did not seem to have a significant effect on SO<sub>2</sub> removal. Increasing the flue gas flow rate had a negative effect on the SO<sub>2</sub> removal in the system.

The overall system SO<sub>2</sub> removal efficiency during these tests ranged from slightly more than 60% to nearly 95%, depending on the specific test conditions. The higher SO<sub>2</sub> removal efficiency levels were achieved at the closer approach-to-saturation temperatures (8 and 18°F), the higher lime stoichiometry level (1.30 moles Ca(OH)<sub>2</sub>/mole inlet SO<sub>2</sub>), and the higher coal chloride level (0.12%). The lower SO<sub>2</sub> removal efficiency levels were achieved at the higher approach-to-saturation temperature (28°F), the lower lime stoichiometry level (1.00 mole Ca(OH)<sub>2</sub>/mole inlet SO<sub>2</sub>), and the lower coal chloride level (0.02-0.04%). The data from these factorial tests completed at these conditions are shown in Figure 4. The slight scatter in the data in this figure is due to the variations in the other major process variables in these tests (i.e. flue gas flow rate, recycle screw speed, etc.). Most of the SO<sub>2</sub> removal in the GSA system occurs in the reactor/cyclone, with only about 2 to 5 percentage points of the overall system removal occurring in the ESP. There was substantially less SO<sub>2</sub> removal in the ESP than in previous testing at the CER, but the overall system SO<sub>2</sub> removal efficiencies appear to be comparable with the GSA process for most test conditions.



**Figure 4.** Overall System SO<sub>2</sub> Removal Results from the GSA Factorial Testing

As one would expect, the lime stoichiometry level, which was tested at 1.00 and 1.30 moles Ca(OH)<sub>2</sub>/mole inlet SO<sub>2</sub>, seems to have the most significant effect on the SO<sub>2</sub> removal efficiency in the GSA system.

The approach-to-saturation temperature, which was evaluated at three levels of 8, 18, and 28°F for the low coal chloride conditions and the two levels of 18 and 28°F for the higher coal chloride condition, appears to be the second most important variable in the GSA system in terms of the overall system SO<sub>2</sub> removal efficiency.

The third most important variable seems to be the chloride level in the system. Two coal chloride levels were tested, the baseline coal chloride level of 0.02 to 0.04% and the equivalent of a 0.12% coal chloride level. The higher chloride level was achieved by spiking the feed slurry with a calcium chloride solution.

One of the most surprising results of this factorial testing was the ability of the GSA system to operate at an 8°F approach-to saturation temperature at the low-chloride condition without any indication of plugging. This is even more impressive given the very low flue gas residence time in the reactor/cyclone. The second interesting result of this testing was the ability of the GSA system to operate at the 18°F approach-to-saturation temperature at the higher chloride level. In the preliminary testing at a much higher coal chloride level (0.3%), the lowest approach-to-saturation temperature tested was 23°F. No operating problems were encountered in the tests completed at the 0.12% coal chloride level and 18°F approach-to-saturation temperature conditions. In fact, the average moisture level in the solids remained below 1.0% in all of these factorial tests, even at the higher coal chloride level.

### ESP Performance

The ESP installed at the CER is a relatively modern, 4-field unit with 10-inch plate spacing, similar in design to several full-scale ESPs installed on the TVA Power System. This unit has 23-feet-high plates with 8 parallel gas passages. The specific collection area (SCA) of the unit is about 440 ft<sup>2</sup>/kacfm under the cooled, humidified flue gas conditions downstream of the reactor/cyclone. (For the untreated flue gas at 300°F, i.e., in a fly-ash-only application, the SCA of this ESP is about 360 ft<sup>2</sup>/kacfm.)



However, during the testing there were disturbing indications of low power levels in the first field of the ESP, particularly in those tests involving chloride spiking. In some of these chloride-spiking tests completed at the high flue gas flow rate (20,000 scfm), the power level in the first field was only about 5% of the normal level, effectively meaning that the first field had "collapsed." Even with these low power levels in the first field of the ESP, the particulate removal efficiencies were still 99.9+ percent and the emission rate was in the range of 0.010 lb/MBtu. The cause of these low power levels in the first field of the ESP is being investigated. These low power levels could be the result of a number of factors, including plate-wire alignment problems as observed in a recent internal inspection.

One surprising result of this ESP testing was that there was no significant improvement in the ESP performance with increasing SCA. For some of these tests, the SCA in the ESP approached 800 ft<sup>2</sup>/kacfm and the flue gas velocity in the ESP dropped below 2.0 ft/sec and yet the emission rate remained in the same range as in the other tests, i.e., 0.010 lb/MBtu.

#### Pulse Jet Baghouse Performance

Although not part of the original GSA project, TVA and EPRI had co-funded the installation of a 1-MWe PJBH pilot plant at the CER to be operated in conjunction with the existing GSA demonstration. Later, AirPol and DOE joined in the operation and testing of this PJBH pilot plant program. The PJBH pilot plant, which was started up in late January, can pull a slipstream of flue gas from either the ESP inlet or outlet, as shown in Figure 1. In the first series of factorial tests, the PJBH pilot plant pulled flue gas from the ESP inlet and, thus, treated flue gas with the full particulate loading (3 to 5 gr/acf) from the GSA reactor/cyclone. The inlet flue gas flow rate was about 5,000 acfm, which corresponds to an air-to-cloth ratio (A/C) of 4.0 acfm/ft<sup>2</sup> in the PJBH. During the second series of factorial tests, the PJBH pilot plant pulled flue gas from the ESP outlet. The same inlet flue gas flow rate was treated (5,000 acfm), but two-thirds of the bags were removed prior to this testing and thus, the A/C for these tests was 12 acfm/ft<sup>2</sup>.

The cleaning of the bags in the PJBH was pressure-drop-initiated during this testing with the cleaning cycle beginning whenever the tubesheet pressure drop reached 6 inches of water. The cleaning continued until the tubesheet pressure drop had declined to about 4-1/2 inches of water. The bags were cleaned by a low-pressure, high-volume, ambient air stream delivered by a rotating manifold.

#### SO<sub>2</sub> Removal Efficiency for Reactor/Cyclone/PJBH System

The SO<sub>2</sub> removal efficiency in the reactor/cyclone/PJBH system was typically about 3-5 percentage points higher than that achieved in the reactor/cyclone/ESP system at the same test conditions. This higher SO<sub>2</sub> removal efficiency in the PJBH system was not unexpected given the intimate contact between the SO<sub>2</sub>-laden flue gas and the solids collected on the outside of the bags as the flue gas passed through the filter cake and the bags before being discharged to the stack. However, it should be noted that most of the SO<sub>2</sub> removal occurred in the reactor/cyclone; the PJBH SO<sub>2</sub> removal efficiency, based on the inlet SO<sub>2</sub> to the reactor, contributed less than 8 percentage points to the overall system SO<sub>2</sub> removal efficiency during this testing.

#### Particulate Removal

The particulate removal efficiency in the PJBH was 99.9+ percent for all of the tests completed with the full dust loading from the GSA reactor/cyclone. The emission rate for all of these tests was well below the New Source Performance Standards for particulates and was typically in the range of 0.010 lb/MBtu.

#### **AIR TOXICS TESTING**

The air toxics tests, which followed the factorial tests, were conducted during September and October, 1993. The objectives of these tests were to:

- Determine emissions and net removal efficiency of hydrogen chloride (HCl), hydrogen fluoride (HF), total particulate matter and trace metals. The trace metals included antimony (Sb), arsenic (As), barium (Ba), beryllium (Be), cadmium (Cd),

chromium (Cr), cobalt (Co), lead (Pb), manganese (Mn), mercury (Hg), nickel (Ni), selenium (Se) and vanadium (V).

- Evaluate the impact of the particulate control device configuration (ESP alone, PJBH alone, or ESP plus PJBH in series) on final emissions of hazardous air pollutants.
- Compare the emissions of HCl, HF and trace metals with and without the injection of lime slurry.

The tests were conducted in two configurations, i.e. with the PJBH in series and parallel with the ESP. Two test conditions were evaluated for each configuration: baseline, with no lime introduction into the system; and demonstration, with lime slurry injection. Three simultaneous sampling runs were performed at each of the four permutations. The streams sampled are shown in Table 2.

Type of Sample	Location
Gaseous	GSA inlet, ESP inlet, ESP outlet, PJBH inlet and PJBH outlet
Aqueous	Lime slurry and trim water
Solid	Coal, GSA cyclone, ESP field 1, ESP field 2,3,4, PJBH hopper and re-injected fly-ash

**Table 2.** Sampling Locations For The Air Toxics Tests.

All of these tests were completed while the boiler was burning the high-sulfur (2.7%), low-chloride Andalex coal and were run at the high flue gas flow rate (20,000 scfm) and the high fly ash loading (2.0 gr/acf) test conditions. The baseline tests were performed at 270°F GSA reactor inlet temperature to protect the acrylic bags in the PJBH. The demonstration tests operated at 320°F GSA reactor inlet temperature, with a 12°F approach to saturation temperature at the GSA outlet.

## RESULTS OF AIR TOXICS TESTING

Tables 3 and 4 present the removal efficiencies and uncertainties of the baseline and demonstration case with varying ESP and baghouse configurations. Removal efficiencies for beryllium and nickel were not determined due to analytical laboratory error. The removal efficiency for most trace metals is generally over 90 percent. Caution is required when reviewing the removal efficiency of antimony, since most of the antimony measurements were below detection limits. Mercury concentration was also low. Only trace levels of mercury, i.e. close to the method detection limits, could be detected in the baseline and parallel tests. The removal efficiency for mercury appears to fall in the 50%-95% range.

The GSA/ESP arrangement indicated average removal efficiencies of greater than 99 percent for arsenic, barium, chromium, lead and vanadium. Removal efficiencies are significantly less than 99 percent for antimony, manganese, mercury and selenium. Lower removals for mercury and selenium are expected because of the volatility of these metals.

The GSA/PJBH configuration showed 99+ percent removal efficiencies for arsenic, barium, chromium, lead, manganese, selenium and vanadium. Cadmium removal was much lower with this arrangement than any of the other arrangements in both baseline and demonstration tests. Mercury removal efficiency for this arrangement was lower than with the GSA/ESP arrangement.

The removal of HCl and HF was dependent on the utilization of lime slurry and was relatively independent of particulate control device configuration. The removal efficiencies were greater than 98% and 96% for HCl and HF, respectively.

Parameter	GSA + ESP Series		GSA + ESP Parallel		GSA + FF Parallel		GSA + ESP + FF Series	
	Reported RE (%)	Total Uncertainty (%)	Reported RE (%)	Total Uncertainty (%)	Reported RE (%)	Total Uncertainty (%)	Reported RE (%)	Total Uncertainty (%)
Antimony	89.71	18.38	96.91	13.49	97.68	14.17	89.67	17.10
Arsenic	98.74	8.17	98.48	8.14	99.83	8.10	99.98	8.11
Barium	98.37	7.81	99.58	7.92	99.54	7.92	99.69	7.77
Cadmium	97.42	10.99	86.98	11.31	71.40	13.11	94.03	10.85
Chromium	99.09	8.63	98.14	9.24	99.46	9.23	99.65	8.47
Cobalt	98.38	9.55	98.24	9.52	98.68	9.51	98.66	9.51
Lead	98.79	9.47	97.36	9.16	99.51	9.16	99.69	9.35
Manganese	99.20	9.13	98.28	9.36	99.57	9.24	99.77	9.13
Mercury	79.15	38.24	66.38	11.71	31.97	527.49	94.45	14.26
Selenium	73.05	28.46	81.56	35.36	99.93	9.49	99.11	10.41
Vanadium	98.73	13.98	98.71	13.00	99.07	12.90	99.17	13.74
Particulate	99.59	9.70	99.52	4.16	99.86	4.16	99.90	9.70
HCl	---	---	---	---	7.71	478.82	-12.38	370.75
HF	---	---	---	---	22.08	488.02	-73.24	248.95

Table 3. Baseline Tests Removal Efficiencies and Uncertainties

Parameter	GSA + ESP Series		GSA + ESP Parallel		GSA + FF Parallel		GSA + ESP + FF Series	
	Reported RE (%)	Total Uncertainty (%)	Reported RE (%)	Total Uncertainty (%)	Reported RE (%)	Total Uncertainty (%)	Reported RE (%)	Total Uncertainty (%)
Antimony	84.72	37.99	98.78	14.24	98.65	14.20	95.01	18.59
Arsenic	99.96	8.37	96.36	47.79	99.98	8.24	99.99	8.37
Barium	99.63	8.80	92.72	90.19	99.49	9.44	99.74	8.81
Cadmium	98.68	10.77	93.27	64.71	78.63	20.31	97.37	11.73
Chromium	99.48	9.58	95.11	58.92	99.50	8.85	99.66	9.60
Cobalt	98.66	9.48	94.27	64.39	98.91	9.47	99.13	9.62
Lead	99.88	9.08	92.08	107.09	99.61	9.51	99.88	9.07
Manganese	92.44	33.45	95.58	53.68	99.13	10.18	99.87	9.67
Mercury	88.27	24.72	-38.89	1918.94	49.23	136.17	90.16	27.34
Selenium	76.87	88.86	99.81	10.34	99.80	10.32	99.96	10.18
Vanadium	99.18	13.87	93.37	75.62	99.00	12.50	99.46	13.90
Particulate	99.86	3.63	96.63	43.05	99.94	4.00	99.96	3.62
HCl	---	---	---	---	99.96	11.85	98.71	13.03
HF	---	---	---	---	96.82	14.67	98.99	12.81

**Table 4.** Demonstration Tests Removal Efficiencies and Uncertainties

## DEMONSTRATION RUN

### 28-day GSA/ESP Demonstration Run

The 28 day demonstration run, with GSA operating in conjunction with ESP only, started on October 25, 1993 and ended on November 24, 1993. This demonstration run began with the boiler burning the high-sulfur (2.7%), low-chloride Andalex coal and test conditions of: 320°F inlet flue gas temperature; 18°F approach-to-saturation temperature; 1.5 gr/acf fly ash injection; 0.12 percent coal chloride level; 20,000 scfm flue gas flow rate; and 30 rpm recycle screw speed. The SO<sub>2</sub> control mode was engaged for this run with an overall system SO<sub>2</sub> removal efficiency set-point of 91 percent. Due to some problems encountered in obtaining the test coal, a switch was made to burning a higher-sulfur (3.5%) coal for a period of time. The Ca/S ratio averaged 1.40 - 1.45 moles of Ca(OH)<sub>2</sub>/mole inlet SO<sub>2</sub> during this demonstration run.

The demonstration run showed that all three of the major objectives were successfully achieved.

- The overall system SO<sub>2</sub> removal efficiency averaged 90-91 percent, i.e., very close to the set-point. The switch to the higher-sulfur coal demonstrated the flexibility of the GSA system
- The particulate removal efficiency was good at an average of 99.9+ percent, with an emission rate below 0.015 lbs/MBtu.
- The GSA system demonstrated the reliability of this technology by remaining on-line for the entire 28-day period that the boiler was operating.

### 14-day PJBH Demonstration Run

The purpose of the 14-day demonstration run was to demonstrate that the GSA system (reactor/cyclone/PJBH), as installed at the CER, could operate reliably and continuously, while simultaneously achieving 90+ percent SO<sub>2</sub> removal and maintaining the PJBH outlet emissions below the NSPS for particulates.

The specific design test conditions for this run were the same as those used for the previous 28-day GSA demonstration, except that the fly ash addition rate was reduced slightly from 1.5 to 1.0 gr/acf. This demonstration run was successfully completed in March 1994, and the following observations were made.

- The overall system (reactor/cyclone/PJBH) SO<sub>2</sub> removal efficiency averaged more than 96 percent during the entire 14-day demonstration run.
- The average Ca/S level during this run ranged from about 1.34 to 1.43 moles Ca(OH)<sub>2</sub>/mole inlet SO<sub>2</sub>.
- The PJBH particulate removal efficiency averaged 99.99+ percent. The emission rate was 0.001 to 0.003 lbs/MBtu.

### **ECONOMIC EVALUATION**

Under the scope of this project, Raytheon Engineers & Constructors prepared an economic evaluation of the GSA FGD process using the same design and economic premises that were used to evaluate about 30-35 other FGD processes for the Electric Power Research Institute. The relative process economics for the GSA system were evaluated for a moderately difficult retrofit to a 300-MW boiler burning a 2.6 percent sulfur coal. The design SO<sub>2</sub> removal efficiency was 90 percent.

The resulting capital cost estimate (in 1990 dollars) is shown in Table 5 together with the estimate for the conventional wet limestone, forced-oxidation (WLFO) scrubbing system. The total capital requirement of \$149/kW for the GSA process is substantially lower than the \$216/kW for the WLFO system. The significant reduction in capital is primarily due to lower costs in the SO<sub>2</sub> absorption area.

<b>Total Capital Investment Comparison</b>		
<b>(1990 \$, 300-MW, 2.6% S coal)</b>		
<u>Area</u>	<u>\$/kW</u>	
	<u>GSA</u>	<u>WLFO</u>
Reagent Feed	25	37
SO <sub>2</sub> Removal	38	71
Flue Gas Handling	18	24
Solids Handling	5	7
General Support	1	2
Additional Equipment	4	4
Total Process Capital	91	145
Total Capital Requirement	149	216

**Table 5.** Total Capital Investment Comparison

The levelized annual revenue requirements for the two processes (in 1990 dollars) are shown in Table 6. The levelized annual requirement for the GSA process is somewhat lower than that for the WLFO system. The principal operating cost for the GSA process is the cost of the pebble lime.

<b>LEVELIZED COSTS</b>		
<b>(300-MW, 2.6% S coal, 15-year levelizing)</b>		
	<b>Mills/kWh</b>	
<u>Fixed Costs</u>	<u>GSA</u>	<u>WLFO</u>
Operating Labor	0.52	0.66
Maintenance	1.49	1.74
Administrative and Support Labor	<u>0.34</u>	<u>0.41</u>
	2.35	2.81
<u>Variable Costs</u>		
Raw Material	1.82	0.65
Solids Disposal	0.86	0.57
Water	0.01	-
Steam	-	0.55
Electricity	<u>0.47</u>	<u>1.16</u>
	3.16	2.93
<u>Fixed Charge (Capital)</u>	<u>5.40</u>	<u>7.30</u>
<b>Total</b>	<b>10.91</b>	<b>13.04</b>

**Table 6. Levelized Costs**

## **COMMERCIALIZATION**

One of the objectives of this demonstration project was for AirPol to establish its capability in designing, fabricating, and constructing the GSA system so that the demonstrated technology can be effectively commercialized for the benefit of the U.S. electric utility and industrial markets. The progress of this demonstration project matches very well with the development of the utility

FGD market. The GSA technology is now being commercialized in order to meet the Phase II Clean Air Act Amendments compliance requirements.

During the course of designing the demonstration unit, an effort was made by AirPol to standardize the process design, equipment sizing, and detailed design so that the installation of a commercial unit can be accomplished within a relatively short time frame. Furthermore, equipment design was simplified, resulting in reduced material and construction costs. With the confidence that the GSA system is capable of achieving the required levels of performance, AirPol has developed a standard design of scale-up units.

The successful effort from the project has resulted in a commercial application in Ohio. AirPol will supply a GSA system for a 50 MWe municipal boiler burning Ohio coal as its first commercial utility installation in the United States. The state of Ohio, in conjunction with the Ohio Coal Development Office, awarded the city of Hamilton a grant to install a GSA system in the city's municipal power plant. In order to meet the requirements of the CAAA, it has been necessary to burn relatively expensive, low-sulfur coal in this plant. The installation of the GSA will allow the city to meet environmental regulations while using high-sulfur Ohio coal for power generation.

#### **DISCLAIMER**

Reference in this report to any specific commercial product, process, or service is to facilitate understanding and does not necessarily imply its endorsement or favoring by either DOE or TVA.



## ABSTRACT

### Chiyoda Thoroughbred 121 Phase II Demonstration Results

Ira G. Pearl,  
Radian Corporation

The Chiyoda Thoroughbred CT-121 flue gas desulfurization (FGD) process at Georgia Power's Plant Yates has recently completed a two-year demonstration of its capabilities under both high- and low-particulate loading conditions. This \$43 million demonstration was co-funded by the Southern Company, EPRI and the U.S. Department of Energy under the auspices of the Innovative Clean Coal Technology (ICCT) program's second round.

The focus of the project was to demonstrate several cost-saving modifications to the already efficient CT-121 process. These modifications included: the extensive use of fiberglass reinforced plastics (FRP) in the construction of the scrubber vessel and other associated vessels, the elimination of flue gas reheat through the use of a FRP wet chimney, and reliable operation without a spare absorber module.

This presentation focuses on the results from the last trimester of the Phase II testing. Specifically, operation under elevated ash loading conditions, the effects of low-sulfur coal, and of air toxics verification testing results, among other highlights will be discussed.

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## **Performance of the Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> Emissions Control System**

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### **ABSTRACT**

The Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> Emissions Control System was installed at Public Service Company of Colorado's Arapahoe 4 generating station in 1992 in cooperation with the U.S. Department of Energy (DOE) and the Electric Power Research Institute (EPRI). This full-scale 100 MWe demonstration combines low-NO<sub>x</sub> burners, overfire air, and selective non-catalytic reduction (SNCR) for NO<sub>x</sub> control and dry sorbent injection (DSI) with or without humidification for SO<sub>2</sub> control. Operation and testing of the Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> Emissions Control System began in August 1992 and will continue through mid 1995. Results of the NO<sub>x</sub> control technologies show that the original system goal of 70% NO<sub>x</sub> removal has been easily met and the combustion and SNCR systems can achieve NO<sub>x</sub> removals of up to 80% at full load. Duct injection of commercial calcium hydroxide has achieved a maximum SO<sub>2</sub> removal of nearly 40% while

humidifying the flue gas to a 20°F approach to saturation. Sodium-based dry sorbent injection has provided short-term SO<sub>2</sub> removal of over 70% without the occurrence of a visible NO<sub>2</sub> plume. Combined dry sodium injection and SNCR has yielded both lower NO<sub>2</sub> levels and NH<sub>3</sub> slip than either technology alone.

## INTRODUCTION

Beginning in the late 1980s Public Service Company of Colorado (PSCC) began retrofitting its wall and tangential coal-fired boilers located in the Denver Metropolitan area with low-NO<sub>x</sub> burners. However, the company also operates seven top-fired boilers for which no previous NO<sub>x</sub> reduction research had been completed. There are only a small number of top-fired boilers in operation in the United States, but these compact boilers generally have much higher NO<sub>x</sub> emissions than the more common wall- and tangential-fired boilers. PSCC had also been investigating sodium-based dry sorbent injection for SO<sub>2</sub> control. Although PSCC installed the first permanent utility dry sorbent system in the United States, the technology needed further research to develop its commercial potential. After further research, PSCC submitted a proposal to the DOE to complete the Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> Emissions Control system as part of Round III of the Clean Coal Technology Program. Table 1 shows the participants involved in the project and their major responsibilities.

**Table 1. Project Participants**

Participant	Function
Public Service Company of Colorado	Project Manager, Design, Construction, Funding
U.S. Department of Energy	Funding, Technical Assistance
Electric Power Research Institute	Funding, Technical Assistance
Babcock & Wilcox	Combustion Modifications and Humidification System Design, Supply, and Erection
NOELL, Inc.	Urea Injection System Design, Supply
Fossil Energy Research Corporation	Testing
Stone & Webster Engineering Corporation	General Engineering and Design
Western Research Institute	Waste Analysis and Research
Colorado School of Mines	Sodium Injection Process Research

## **UNIT DESCRIPTION**

PSCC selected Arapahoe Unit 4 as the demonstration site for this project. The station has four top-fired boilers supplied by Babcock & Wilcox in the early 1950s. Arapahoe Unit 4 is a nominal 100 MWe unit that began operation in 1955. The boiler fires low-sulfur (0.4%) Colorado bituminous coal as its main fuel source but also has 100% natural gas capability. While Arapahoe Unit 4 is an older unit, having operated nearly 40 years, PSCC plans to operate it into the next century.

This small, turbulent boiler was an efficient coal combustor but it also generated high NO<sub>x</sub> emissions. The baseline NO<sub>x</sub> level for this boiler was approximately 1.10 lb/MMBtu. The pulverized coal was injected through 12 intertube burners located in the roof of the boiler as shown in Figure 1. The intertube burner consists of a splitter box that separates into 20 smaller nozzles that inject the coal and primary air mixture evenly across the furnace roof. Secondary air was injected beside the coal nozzles, and the system contained no adjustments to control the rate of secondary air and fuel mixing.

## **PROJECT DESCRIPTION**

The Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> Emissions Control System combines five major control technologies to form an integrated system to control both NO<sub>x</sub> and SO<sub>2</sub> emissions. The system uses low-NO<sub>x</sub> burners, overfire air, and urea injection to reduce NO<sub>x</sub> emissions, and dry sorbent injection using either sodium- or calcium-based reagents with (or without) humidification to control SO<sub>2</sub> emissions. The goal of the project is to reduce NO<sub>x</sub> and SO<sub>2</sub> emissions by up to 70%. The combustion modifications were expected to reduce NO<sub>x</sub> by 50%, and the SNCR system was expected to increase the total NO<sub>x</sub> reduction to 70%. Dry Sorbent Injection was expected to provide 50% removal of the SO<sub>2</sub> emissions while using calcium-based reagents. Because sodium is much more reactive than calcium, it was expected to provide SO<sub>2</sub> removals of up to 70%. Figure 2 shows a simplified schematic of the Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> Emissions Control System at Arapahoe Unit 4.

The total cost of this innovative demonstration project is estimated to be \$27,411,000. The project cost breakdown is shown in Table 2. Funding is being provided by the DOE (50%), PSCC (43.7%), and EPRI (6.3%). The DOE funding is being provided as a zero interest loan and is expected to be paid back from the proceeds obtained during commercialization of the technology over a 20-year period from the conclusion of the demonstration project.

**Table 2. Project Cost**

Task	Estimated Cost
Pre-Award	\$358,000
Design	\$3,744,000
Equipment Procurement	\$8,887,000
Construction	\$8,421,000
Operations & Maintenance	\$6,001,000
Total	\$27,411,000

#### Low-NO<sub>x</sub> Burners

Babcock & Wilcox (B&W) was selected to provide the low-NO<sub>x</sub> burners for the Arapahoe 4 project. B&W's DRB-XCL® (Dual Register Burner-axially Controlled Low-NO<sub>x</sub>) burner had been successfully used to reduce NO<sub>x</sub> emissions on wall-fired boilers but had never been used in a vertically-fired furnace. The burner has two main features that limit NO<sub>x</sub> formation. The first feature is a sliding air damper. In many older burners, a single register is used to control both total secondary air flow to the burner and the rate of air/fuel mixing. The use of the sliding damper in the DRB-XCL® separates the functions and allows the secondary air flow to be controlled independently of the spin. The burner includes a 30-point pitot tube grid so that a relative indication of the secondary air flow at each burner is possible. The second feature of the burner is dual registers. The most important variable in the control of the formation of NO<sub>x</sub> is the rate at which oxygen is mixed with the fuel in the near burner region. The ability to adjust both inner and outer registers provides more control over the rate of combustion and thus the amount of NO<sub>x</sub> formed.

A low-NO<sub>x</sub> retrofit on a top-fired unit is much more complex and expensive than modifications to most wall- or tangential-fired units. At Arapahoe Unit 4, the modifications required the replacement of all boiler roof tubes to provide the circular openings required for a conventional burner. The burners were placed in 4 rows of 3 burners. One major design problem of the retrofit was locating the secondary air ductwork, which originally entered the windbox at the rear of the furnace roof. The new burners required significantly more space than the original intertube burners, so there are now four burners where the secondary air duct was originally placed. Smaller ductwork was added to the furnace roof and the remaining combustion air was added through an abandoned gas recirculation duct that entered the front of the windbox.

Arapahoe Unit 4 was originally designed with the ability to fire 100% natural gas. Natural gas firing capabilities were maintained with the DRB-XCL® burners by installing a gas ring header at the tip of the burner. However, the burner is not specifically designed to be a low-NO<sub>x</sub> burner with natural gas firing.

#### Overfire Air

While low-NO<sub>x</sub> burners alone have proven to be effective for reducing NO<sub>x</sub> emissions, combustion staging can provide further reductions. Overfire air delays combustion by redirecting a part of the secondary air downstream of the main combustion zone. Three B&W dual zone NO<sub>x</sub> Ports were added to each side of the furnace approximately 20 feet below the boiler roof. These ports can inject up to 28% of the total combustion air through the furnace sidewalls. The NO<sub>x</sub> ports separate the overfire air into two streams. The outer area of the port contains adjustable registers that can be used to spread the overfire air next to the wall. The center area of the port uses a sliding disk damper to control air flow. This core zone injects a high velocity jet across the furnace toward the division wall. This two-stage air injection allows for faster mixing and more equal distribution of the air and combustion gases in the furnace.

The NO<sub>x</sub> ports are located on the two sides of the furnace in a small windbox. New ductwork was added that directs secondary air from the boiler roof to the overfire air windbox. Each duct that supplies the overfire air windboxes contains an opposed blade louver damper to control

air flow. The ducts also contain a pitot tube grid with a flow straightener to measure total overfire air flow.

### Selective Non-Catalytic Reduction

The purpose of the SNCR system at Arapahoe was to further reduce the final  $\text{NO}_x$  emissions obtained with the combustion modification so that the goal of 70%  $\text{NO}_x$  removal could be achieved. Urea was selected as the base chemical for the SNCR system, because urea, unlike either aqueous or anhydrous ammonia, is not a toxic chemical. Urea injection is a simple process. A liquid solution of urea is injected into the boiler. Urea decomposes at approximately 1700 to 1900°F, and then reacts with  $\text{NO}_x$  to form primarily nitrogen and water. The disadvantage of urea injection, as with any SNCR chemical, is that the process is very temperature-sensitive. If the temperature is too high, some urea can be converted to  $\text{NO}_x$ . If the temperature is too low, the products of decomposition do not remove  $\text{NO}_x$ , and  $\text{NH}_3$  becomes an unacceptable new pollutant. PSCC selected NOELL, Inc. to design and supply the urea-based SNCR system. Figure 3 shows a simplified flow diagram of the system at Arapahoe Unit 4.

During original testing of the urea-based SNCR system, it was found that  $\text{NO}_x$  reductions at low load were less than expected. A short-term test using aqueous ammonia achieved greater  $\text{NO}_x$  reduction than urea. Although ammonia was more effective than urea, it remained desirable to store urea due to safety concerns. A system was installed that allows on-line conversion of urea into ammonia compounds. As will be discussed, the online conversion system improved low load performance, but the improvement was not as large as desired at the lowest load (60 MW).

Recently an additional SNCR injection location was installed to further increase low load performance. The new injection location will make use of a pair of unused sootblower openings in order to avoid the cost of installing new penetrations and the associated outage. Figure 4 shows the new location relative to the two existing locations. The new injectors consist of a pair of in-furnace lances which provide a high degree of load following flexibility through on-line adjustments of the injection angle. This paper will present results of proof of concept tests

conducted with a short lance that treated a portion of the flue gas. Testing of the complete lance system is in progress.

The SNCR system at Arapahoe Unit 4 uses NOELL's proprietary dual fluid injection nozzles to distribute the chemical uniformly into the boiler. A centrifugal compressor is used to supply a large volume of medium pressure air to the injection nozzles to help atomize the solution and rapidly mix the chemical with the flue gas.

### Dry Sorbent Injection

A combination of dry technologies is being demonstrated at Arapahoe Unit 4 to reduce SO<sub>2</sub> emissions. PSCC designed and installed a dry sorbent injection system that can inject either calcium- or sodium-based reagents into the flue gas upstream of the fabric filter. Figure 5 shows a simplified flow diagram of the equipment. The reagent is fed through a volumetric feeder into a pneumatic conveying system. The air and material then pass through a pulverizer where the material can be pulverized to approximately 90% passing 400 U.S. Standard mesh. The material is then conveyed to the duct and evenly injected into the flue gas. After the original testing results suggested that the duct flue gas temperature was too low for effective SO<sub>2</sub> removal with sodium bicarbonate, the dry injection system was modified to allow injection of sodium-based compounds at the entrance to the air heater where the flue gas temperature is approximately 600°F.

The pulverizer can be bypassed allowing calcium hydroxide to be fed from the silos and injected either ahead of the fabric filter or into the boiler economizer region where the flue gas temperature is approximately 1000°F. While significant SO<sub>2</sub> reductions can be achieved with sodium-based reagent, calcium hydroxide is less reactive. To improve SO<sub>2</sub> removal with calcium hydroxide, a humidification system has been installed. The system was designed by B&W and includes 84 I-Jet humidification nozzles which can inject up to 80 gpm of water into the flue gas ductwork. The humidifier is located approximately 100 feet ahead of the fabric filter and there is no bypass duct. Although the system is designed to achieve a 20°F approach to

saturation, it was not expected to operate below a 40°F approach to saturation temperature to protect the fabric filter.

### Balance of Plant

Besides the major environmental equipment, the project also included required upgrades to the existing plant. Arapahoe 4 originally used a Bailey pneumatic control system with limited controls for burner management. Due to the complexity of the retrofit, a new distributed control system was required to control the boiler and other pollution control equipment added as part of the project. The fly ash collection system was also converted from a wet to a dry collection system to allow dry collection of the ash and injection waste products. A Continuous Emissions Monitor (CEM) system was installed at Arapahoe Unit 4 to collect data for the extensive test program. This monitor allows measurements of N<sub>2</sub>O, NH<sub>3</sub>, NO<sub>2</sub>, and H<sub>2</sub>O in addition to the more common pollutants.

### **PROJECT SCHEDULE**

The Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> Emissions Control System began with its selection by the DOE in December 1989. Negotiations for the project were completed with approval of the Cooperative Agreement on March 11, 1991. Construction began in July 1991 and was completed in August 1992. The test program began in August 1992 and all low sulfur coal testing was scheduled for completion in June 1994. Addition of the new SNCR injection location will extend the test program through July 1995. A ten day test of the integrated system using a high sulfur coal (2.5%) was planned for late 1994. This high sulfur coal test was canceled since the SO<sub>2</sub> removal with the duct humidification/calcium system was not high enough to technically justify the expense of this subtask. Project completion is currently scheduled in November 1995. Table 3 shows the project schedule.

**Table 3. Arapahoe Unit 4 Project Schedule**

	1989	1990	1991	1992	1993	1994	1995
Project Selection	▲						
Cooperative Agreement Signed			▲	→			
Construction			▲	→			
Baseline Testing			▲	→			
SNCR Testing/Original Burners			▲	→			
Low-NO <sub>x</sub> Burner Startup				▲			
Combustion Mods Testing				▲	→		
SNCR Testing					▲	→	
Calcium-Based DSI Testing					▲	→	
Sodium-Based DSI Testing					▲	→	▲
Air Toxics Testing				▲	▲	▲	▲
Integrated Testing						▲	→
SNCR Testing (Lances)							▲
Final Report							▲
Project Completion							▲

## RESULTS

Fossil Energy Research Corporation (FERCo) of Laguna Hills, California, was selected to perform all testing of the Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> Emissions Control System. The test program is nearing completion and the individual testing of the low-NO<sub>x</sub> burners, overfire air, urea injection, calcium duct injection, calcium economizer injection, and sodium injection has been completed. Testing of the complete integrated system while firing low-sulfur coal is in progress, as well as modifications to the urea injection system. In addition to efficiency and emissions measurements, four tests were conducted to determine baseline and removal capabilities of the system for many common air toxic emissions. This paper briefly reviews the NO<sub>x</sub> data and SO<sub>2</sub> data obtained to date along with an overview of work in progress. Prior papers also discussed some of the preliminary results <sup>[1-10]</sup>.

## **NO<sub>x</sub> Reduction Performance**

### *Low-NO<sub>x</sub> Combustion System Performance*

The following section describes the performance of the low-NO<sub>x</sub> combustion system (low-NO<sub>x</sub> burners and OFA ports).

Low-NO<sub>x</sub> Burners: Figure 6 compares the Arapahoe Unit 4's NO<sub>x</sub> emissions before and after the retrofitting of the low-NO<sub>x</sub> combustion system. Note, NO<sub>x</sub> (NO + NO<sub>2</sub>) and NO are used interchangeably since NO<sub>2</sub> levels are very low for this unit. The original combustion system produced nearly uniform NO<sub>x</sub> emissions of 800 ppmc (corrected to 3% O<sub>2</sub>, dry) or 1.1 lb/MMBtu across the boiler's load range. The low-NO<sub>x</sub> combustion system greatly reduced NO<sub>x</sub> emissions to less than 300 ppmc across the boiler's load range. Note that all testing was conducted under steady-state conditions and with the careful supervision of test technicians to achieve the maximum possible reduction in NO<sub>x</sub> emissions for each system at Arapahoe Unit 4.

Overfire Air: At full load, opening the OFA control dampers to full open (maximum OFA) diverts about 24% of the total combustion air to the OFA ports and at low load (60 MWe) it diverts about 28% of the combustion air. At maximum OFA, the low-NO<sub>x</sub> combustion system reduces NO<sub>x</sub> emissions by 62 to 69% across the load range. Since the OFA ports are located in a very hot part of the boiler, a significant amount of cooling air is required and the minimum amount of OFA is limited to about 15% of the total combustion air at full load and about 8% at low load. At minimum OFA, the retrofitted combustion system reduces NO<sub>x</sub> emissions by 60 to 63%. Arapahoe Unit 4 cannot be tested at 0% OFA, but the small difference in NO<sub>x</sub> reduction between maximum and minimum OFA indicates that the low-NO<sub>x</sub> burners are responsible for most of the NO<sub>x</sub> reduction.

Unlike wall- or tangential-fired boilers, it appears that the low-NO<sub>x</sub> burners in a top-fired boiler can control stoichiometry along most of the length of the boiler. This delayed mixing of the burner overlaps that of the OFA ports and minimizes their effectiveness at further reducing NO<sub>x</sub> emissions.

However, while OFA did not substantially improve NO<sub>x</sub> reduction, it appears to reduce unburned carbon emissions and help maintain steam temperatures at low loads. Apparently, increasing OFA helps eliminate fuel-rich areas by improving the mixing of the flue gas, thus decreasing both fly ash unburned carbon and CO emissions. At low loads, increasing OFA appears to slightly raise the flue-gas temperature at the furnace exit, which also provides better steam temperature control.

*Load Following:* Since Arapahoe Unit 4 is normally operated under automatic control as a load-following unit, Figure 7 compares the unit's NO<sub>x</sub> emissions at constant loads under optimized test conditions to its NO<sub>x</sub> emissions at varying loads under normal, load-following conditions. NO<sub>x</sub> emissions under load-following conditions were about 10 to 25% higher. Additional modifications to the control system and additional operator training may decrease this difference.

*Natural Gas Firing:* A short test of the low-NO<sub>x</sub> combustion system firing natural gas at full load was also conducted. The low-NO<sub>x</sub> burners were not designed to reduce NO<sub>x</sub> while firing natural gas and the baseline NO<sub>x</sub> emissions of the original combustion system firing natural gas are not available, so Figure 8 shows the NO<sub>x</sub> emissions at minimum and maximum OFA as a function of excess O<sub>2</sub> level. At minimum OFA, NO<sub>x</sub> emissions are slightly lower than those of the original combustion system firing coal. At maximum OFA, NO<sub>x</sub> emissions are from 54 to 60% less than at minimum OFA (depending on excess O<sub>2</sub> levels) and comparable to those produced by firing coal at maximum OFA at similar excess O<sub>2</sub> levels. The more rapid mixing of natural gas and air in the near burner region accounts for the improved effectiveness of the OFA ports when firing natural gas.

### *SNCR System Performance*

In addition to reducing NO<sub>x</sub> emissions significantly, the low-NO<sub>x</sub> combustion system also reduced the temperature of flue gas at the furnace exit by about 200°F (Figure 9). Since SNCR systems are very sensitive to changes in flue-gas temperatures, this reduction made the flue-gas

temperature too cold for one row of injection nozzles, so all testing was performed using the row of injection nozzles originally designed for loads below 80 MWe.

NO<sub>x</sub> Reduction: Figure 10 compares the full load NO<sub>x</sub> reduction of the SNCR system at various stoichiometric ratios before and after the combustion system retrofit. At an ammonia slip (NH<sub>3</sub>) limit of 10 ppm, the SNCR system reduced NO<sub>x</sub> emissions by about 37% with the original combustion system and by about 45% with the retrofitted system. After the retrofit, the SNCR system required less urea to achieve the higher NO<sub>x</sub> removal rate due to both the lower initial NO<sub>x</sub> level and lower required N/NO ratio (NSR). The lower NSR requirement is not directly related to the lower baseline NO<sub>x</sub> levels of the retrofitted combustion system, but rather the decrease in flue-gas temperature at the injection location, as was shown in Figure 10. This is further supported by the NH<sub>3</sub> slip data (see Figure 10), showing higher NH<sub>3</sub> slip for a given NSR after the retrofit (even though the initial NO<sub>x</sub> level was substantially reduced).

Arapahoe Unit 4 is believed to be the first full-scale coal-fired installation that can use either urea or ammonia for SNCR. Figure 11 compares the NO<sub>x</sub> reduction of urea and urea-converted-to-ammonia-compounds (converted urea) at an ammonia slip limit of 10 ppm. At 100 MWe, both chemicals achieve similar NO<sub>x</sub> reductions, but urea is more efficient in terms of chemical utilization. At 80 MWe, converted urea achieves higher NO<sub>x</sub> reduction, but still less efficiently. As Arapahoe Unit 4's load is reduced to 60 MWe, converted urea attains a higher NO<sub>x</sub> reduction and is more efficient than urea. The improved performance of the converted urea at low loads is due to the fact that the temperature window for ammonia is nominally 100°F lower than for urea.

The lower flue-gas temperatures following the burner retrofit caused the low load SNCR operation with urea to be less effective than at high loads. Although the ammonia conversion system increased the low load effectiveness, the NO<sub>x</sub> removals are still below those for mid- and full-load operation. Currently, an additional SNCR injection location is being installed in order to further increase the low load effectiveness (see Figure 4). The new injection location makes use of a pair of unused sootblower openings in order to avoid the cost of installing new penetrations and the associated outage. The new injectors consist of a pair of in-furnace lances

which will provide a high degree of load following flexibility through on-line adjustments of the injection angle.

To support the design of the in-furnace lances, proof-of-concept tests were conducted to provide an indication of the level of  $\text{NO}_x$  removal attainable at the new location, as well as assess the magnitude of the injection angle effect. These tests were run using a single, short lance which covered nominally one-sixth the boiler width, and were conducted with urea injection at 60 MWe. Figure 12 shows the local  $\text{NO}_x$  removal (measured in the area of treatment only) as a function of injection angle for a fixed chemical injection rate. The results indicate that injection angle has a large effect on process performance.

The results of the proof-of-concept tests are compared to those for the existing injection location in Figure 13. On the basis of ammonia slip as a function of  $\text{NO}_x$  removal, the performance with the short lance was sufficient to warrant installation of a pair of lances which will cover the entire width of the furnace. Testing of the complete lance system is currently ongoing.

***N<sub>2</sub>O Emissions:*** In addition to ammonia slip, the use of SNCR can increase nitrous oxide ( $\text{N}_2\text{O}$ ) emissions. Before the combustion system was modified, about 7 to 17% of the SNCR system's  $\text{NO}_x$  reduction appeared as  $\text{N}_2\text{O}$ . After the combustion system retrofit, about 20 to 35% of the SNCR system's  $\text{NO}_x$  reduction appeared as  $\text{N}_2\text{O}$ , apparently because of the lower flue gas temperatures. With converted urea the  $\text{N}_2\text{O}$  generation was much less, under 10%.

## **SO<sub>2</sub> Reduction Performance**

### *Calcium-Based Economizer Injection*

$\text{SO}_2$  removal has been less than expected with calcium hydroxide injection at the economizer. Pilot-scale testing near 1000°F has shown the potential for  $\text{SO}_2$  removals near 50%.<sup>[11]</sup> At Arapahoe, initial testing at a stoichiometry of 2.0 without humidification resulted in  $\text{SO}_2$  removals in the range of 5 to 8%. It was found that distribution of the sorbent was very poor, and only approximately 1/3 of the flue gas was being treated. Although  $\text{SO}_2$  removals of slightly above 30% were obtained in the area of treatment, the local stoichiometry in this area was estimated

to be 6.0. New nozzles that increased reagent distribution were installed on one-half of the boiler. With the improved distribution, SO<sub>2</sub> removal was nearly doubled to 15% at a stoichiometry of 2. Although distribution of the calcium reagent is far from perfect, it appears that high levels of SO<sub>2</sub> removal are not possible at Arapahoe Unit 4 using the current Ca(OH)<sub>2</sub> material, even in areas with high stoichiometries. Samples of the reagent have been analyzed for surface area and particle size, both parameters being important for economizer injection.<sup>[11]</sup> The BET surface area of the Ca(OH)<sub>2</sub> is 14.8 m<sup>2</sup>/gm and the mass mean particle size diameter is 2.7 microns (determined by sedimentation). The relatively low surface area of the Ca(OH)<sub>2</sub> may be contributing to the low SO<sub>2</sub> removals obtained with economizer injection.

Operation of the humidification system during economizer injection increased SO<sub>2</sub> removal by only 3 to 4%. An analysis of a sorbent/fly ash mixture sample collected at the boiler exit found that approximately 63% of the calcium in the sample was CaCO<sub>3</sub> and only 32% of the calcium was Ca(OH)<sub>2</sub>. It appears that the Ca(OH)<sub>2</sub> preferentially reacted with CO<sub>2</sub>, and it is likely that the CaCO<sub>3</sub> is coating the surface of the sorbent particles, retarding access to the Ca(OH)<sub>2</sub>.

#### *Calcium-Based Duct Injection*

Higher SO<sub>2</sub> removal was achieved with duct injection of calcium hydroxide and humidification as shown in Figure 14. The data was collected at loads from 60 to 110 MWe, but there was no correlation of SO<sub>2</sub> removal and load. As expected, the strongest correlation occurred with the flue gas approach to adiabatic saturation temperature. A marked improvement in SO<sub>2</sub> removal was noted at an approach to saturation temperature of approximately 45°F. As Arapahoe Unit 4 uses a fabric filter dust collector for particulate control, it was not originally planned to reach approach temperatures below 40°F, but SO<sub>2</sub> removal was significantly below the goal of 50% removal. Monitoring of the ash/reagent dropout in the ductwork showed only minimal buildup and no fabric filter operational problems occurred, so it was decided to further decrease the approach to saturation temperature. At a 20°F approach temperature, nearly 40% SO<sub>2</sub> removal was obtained. These levels of SO<sub>2</sub> removal are consistent with the prior DOE study at Ohio Edison's Edgewater Station.<sup>[12]</sup> Immediately after this test, problems developed with the dry fly ash transport system, and it is suspected that the low approach temperature contributed to this

problem. It was decided to limit testing to a 30°F approach temperature. At the end of the calcium test program after a short period of 24 hour/day testing during load following operation, fabric filter pressure drop significantly increased. Upon further investigation, a hard ash cake was found on the fabric filter bags which could not be cleaned during normal reverse air cleaning. Fabric filter bag weights had increased by approximately 50% from pre-humidification testing. The heavy ash cakes were caused by the humidification system, but it was not possible to determine if the problem was caused by operation at a 30°F approach temperature or a short-excursion to a lower approach temperature caused by a rapid decrease in boiler load. All bags were manually cleaned and reinstalled, with apparently no permanent bag damage.

### *Sodium-Based Injection*

SO<sub>2</sub> Removal: Sodium-based reagents are much more reactive than calcium-based sorbents and can achieve significantly higher SO<sub>2</sub> removals during dry injection.<sup>[13,14]</sup> Figure 15 shows the SO<sub>2</sub> removal for dry sorbent injection for sodium bicarbonate and sodium sesquicarbonate. Sodium bicarbonate provided the highest SO<sub>2</sub> removal and was also the most efficient reagent in terms of sodium utilization.

Flue gas temperature at the fabric filter inlet duct at Arapahoe Unit 4 varies from 250 to 280°F. The dry sorbent injection system was originally designed for duct injection before the fabric filter only. However, initial testing with sodium bicarbonate showed that SO<sub>2</sub> removal was erratic. Over ten hours were required for the SO<sub>2</sub> removal to stabilize and the removal dropped significantly during fabric filter cleaning cycles. The DSI system was modified to inject sodium sorbents at the air heater inlet where the flue gas temperature is approximately 600°F. Figure 16 shows SO<sub>2</sub> versus time traces for duct and air heater injection of sodium bicarbonate at an NSR of 1.0. With air heater injection, SO<sub>2</sub> removals leveled in slightly over an hour; with direct injection, removals were not stable after eight hours. With injection ahead of the air heater, 20% SO<sub>2</sub> removal occurred in suspension ahead of the fabric filter. It is believed that at the low flue gas temperatures, the sodium bicarbonate requires many hours to decompose and thus react with the SO<sub>2</sub>. It should be noted that sodium sesquicarbonate does not exhibit this slow reaction rate when injected ahead of the fabric filter.

A limited number of sodium sesquicarbonate tests were run with humidification. These tests were run with approach to saturation temperatures of approximately 50°F, 60°F, and 90°F. The results of these tests are compared to the SO<sub>2</sub> removals without humidification in Figure 17. The data show that humidification results in increased SO<sub>2</sub> removals at higher sorbent feedrates (2Na/S ratios in excess of 1.0). At a nominal 2Na/S ratio of 2.0, the removals are increased from approximately 70 to 90 percent with an approach to saturation temperature of nominally 60°F.

Insight into the effect of humidification on SO<sub>2</sub> removal with sodium injection is provided by looking at the compartment-by-compartment SO<sub>2</sub> removal. These are shown in Figures 18a and 18b for tests with and without humidification, respectively. The fabric filter has 12 compartments, six on the west side and six on the east side with flue gas entering from the south side. Without humidification, the majority of the SO<sub>2</sub> removal occurs in the compartments located in the center of the fabric filter. Little SO<sub>2</sub> removal occurs in the two end compartments, on the north side. This compartment-by-compartment distribution of SO<sub>2</sub> removal indicates that each compartment collects varying amounts of sodium. The distribution of SO<sub>2</sub> removal within the fabric filter is quite different with humidification (Figure 18b). With humidification, the removals in each compartment are relatively equal. This suggests that with humidification, a greater amount of the SO<sub>2</sub> removal may have occurred in the duct upstream of the fabric filter. Moisture becoming associated with the sodium particles during the humidification process would be expected to increase the overall reactivity with SO<sub>2</sub>, thus allowing more of the SO<sub>2</sub> removal process to occur before the sorbent reaches the bags.

Long Term Tests: A long term test of nominally four months was conducted with sodium sesquicarbonate injection ahead of the fabric filter. During this test, the control system was set to achieve a 40% SO<sub>2</sub> removal and the result of this test is shown in Figure 19. Daily average SO<sub>2</sub> removals of 40% were easily achievable during this four month period. Figure 19 shows that there were brief periods when the sodium injection system was off line due to minor problems of line pluggage on system maintenance requirements. Normally, when these occur, a second pulverizer and injection system would be brought on line. However, during much of this test period the second pulverizer was undergoing maintenance. After completion of

the SNCR testing, a comparable long term test is planned with the control system set to achieve 70% SO<sub>2</sub> removal.

NO<sub>2</sub> Production and NO<sub>x</sub> Removal: A major disadvantage of sodium-based injection is that it converts some existing NO in the flue gas to NO<sub>2</sub>. During the conversion process a small amount, 5 to 15%, of the total NO<sub>x</sub> is removed. However, the net NO<sub>2</sub> exiting the stack is increased. While NO is a colorless gas, small quantities of the brown/orange NO<sub>2</sub> can cause a visible plume to develop. The chemistry of the conversion is not well understood but it is generally accepted that NO<sub>2</sub> increases as SO<sub>2</sub> removal increases. Figure 15 shows that NO<sub>2</sub> emissions are generally higher with sodium bicarbonate, although a significant amount of data scatter exists. The threshold NO<sub>2</sub> level that forms a visible plume is site specific. At Arapahoe Unit 4, a visible plume appears when NO<sub>2</sub> concentrations reach 30 to 35 ppm.

While the NO<sub>2</sub> emissions generally increase as the amount of sodium injection increases, other variables are also important. During the current test program, the NO<sub>2</sub> emissions and NO<sub>x</sub> removal were recorded as a function of time from the start of sodium injection. These traces revealed phenomena not previously reported in either pilot or full scale studies.<sup>[13, 14]</sup> Figure 20 shows the NO<sub>2</sub> emissions and NO<sub>x</sub> removals for tests with both sodium sesquicarbonate (Figure 20a), and sodium bicarbonate (Figure 20b). Note, for the data in Figure 20b, the sodium bicarbonate was injected ahead of the air preheater. With both sorbents, the NO<sub>2</sub> emissions increase dramatically after each cleaning cycle. Following the cleaning cycle there is a slow decrease in NO<sub>2</sub> emissions until the second cleaning cycle begins. This would indicate that the NO<sub>2</sub> emissions are not only dependent on the sodium/SO<sub>2</sub>/NO<sub>x</sub> chemistry, but also involve interaction with the fly ash in the fabric filter. To date, at full scale, it has not been possible to determine how the fly ash impacts this chemical mechanism.

The NO<sub>x</sub> removal characteristics as a function of time are shown in Figure 20 for the two sodium sorbents. For these tests, the behavior is somewhat different for the two sorbents. For the test with sodium sesquicarbonate, the NO<sub>x</sub> removal follows the same general trend, as the NO<sub>2</sub>, increasing as the NO<sub>2</sub> levels increase. Just the opposite is seen with the sodium bicarbonate. Again, these results indicate that the NO<sub>2</sub> and NO<sub>x</sub> removal chemistry also must consider

interaction with ash as well as the basic sodium/ $\text{NO}_x$ / $\text{SO}_2$  chemistry. This behavior may also explain some of the apparent data scatter in previous sodium injection demonstrations, in terms of both  $\text{NO}_2$  production and  $\text{NO}_x$  removal.<sup>[13,14]</sup>

### *Integrated System Testing*

It was originally projected that concurrent operation of the sodium-based dry sorbent injection system and the urea system would interact synergistically and reduce the negative effects of both systems. Testing of the integrated system continues, but preliminary indications are that both  $\text{NH}_3$  emissions generated by urea injection and  $\text{NO}_2$  emissions created from sodium injection are reduced when both systems are in operation. Figure 21 shows a plot of  $\text{NO}_2$  emissions versus  $\text{SO}_2$  removal for sodium bicarbonate both with and without concurrent urea injection. The data shows hourly averages of  $\text{NO}_2$  and  $\text{SO}_2$  removal obtained during 24 hours-per-day testing. Only data obtained two hours after a fabric filter cleaning cycle is plotted. While there is significant data scatter, concurrent sodium/urea injection appears to result in lower  $\text{NO}_2$  emissions. Figure 22 shows the stack  $\text{NH}_3$  emissions compared to  $\text{NH}_3$  emissions at the air heater exit, ahead of the point of sodium injection. The plot shows two important points. First, in all cases the stack  $\text{NH}_3$  emissions were lower when the dry sodium injection system was in operation. Second, stack  $\text{NH}_3$  emissions were always significantly lower than the  $\text{NH}_3$  emissions at the air heater exit. The majority of the initial testing with the SNCR system collected data only at the air heater exit as the stack took many hours at constant  $\text{NH}_3$  slip to stabilize. All the plotted data in Figure 22 were taken during testing performed 24 hours-per-day, during which both load and the urea injection rate were constantly changing. Under these operating conditions, it would not be expected to arrive at stabilized conditions.

## **CONCLUSIONS**

Public Service Company of Colorado, in cooperation with the U.S. Department of Energy and the Electric Power Research Institute, has installed the Integrated Dry  $\text{NO}_x$ / $\text{SO}_2$  Emissions Control System. The system has been in operation for over two years and preliminary conclusions are as follows:

- NO<sub>x</sub> reduction during baseload operation of the unit with the low-NO<sub>x</sub> burners and overfire air ranges from 63 to 69% with no increase in unburned flyash carbon or CO emissions.
- It is believed that the low-NO<sub>x</sub> burners provided most of the NO<sub>x</sub> reduction, however, due to cooling air requirements, it was not possible to test the system without overfire air.
- Urea injection allows an additional 11 to 45% NO<sub>x</sub> removal with an ammonia slip of 10 ppm at the fabric filter inlet. This increases total system NO<sub>x</sub> reduction to greater than 80% at full load, significantly exceeding the project goal of 70%.
- Higher NO<sub>x</sub> reduction is possible using ammonia as the SNCR chemical, but significantly higher stoichiometric ratios are required at loads above 70 MWe.
- N<sub>2</sub>O generation is a potential concern with urea injection but was greatly reduced when ammonia compounds were injected.
- SO<sub>2</sub> removal with the calcium-based dry sorbent injection into the boiler at approximately 1000°F flue gas temperature was disappointing with less than 10% removal possible.
- SO<sub>2</sub> removal with the calcium-based dry sorbent injection into the fabric filter duct has been less than expected with a maximum short term removal rate approaching 40%.
- Sodium bicarbonate injection before the air heater has been very effective with short term SO<sub>2</sub> removals of over 80% possible. Longer term testing has demonstrated removal near 70% at an approximate stoichiometric ratio of 1.0.
- Sodium sesquicarbonate injection ahead of the fabric filter can easily achieve 40% removal on a long term basis. Short term tests have demonstrated 70% SO<sub>2</sub> removal at an approximate stoichiometric ratio of 2.0.
- NO<sub>2</sub> emissions are generally higher when using sodium bicarbonate than when using sodium sesquicarbonate. The NO<sub>2</sub> generated during sodium-based injection is related to SO<sub>2</sub> removal and the cleaning cycle of the fabric filter, but all factors important to NO<sub>2</sub> generation are not fully understood.
- The integration of urea-based SNCR and sodium-based dry sorbent injection appears to reduce the net stack NH<sub>3</sub> and NO<sub>2</sub> emissions. Further testing is ongoing to confirm the amount of reduction that occurs due to the integration of the two technologies.
- Tests are ongoing at another SNCR injection level in order to increase low-load performance.

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### **ACKNOWLEDGEMENTS**

The authors would like to thank Mr. Jim Love, Arapahoe Plant Manager, and his maintenance and operating staff for the exceptional cooperation they have provided during this project. Special thanks are also deserved to Mr. Jerry Hebb, Mr. Tom Arrigoni, and Mr. Tim McIlvried of PETC DOE, whose contributions are greatly appreciated. We are all saddened by Tom Arrigoni's and Tim McIlvried's deaths in the USAir accident. The advice and technical assistance provided by Ms. Barbara Tool-O'Neil at EPRI have also been of great assistance throughout the project. Last, but definitely not least, is our appreciation to the many PSCo Engineering and Construction personnel and other contractors who have made the Integrated Dry NO<sub>x</sub>/SO<sub>2</sub> Emissions Control System a success.

### **DISCLAIMER**

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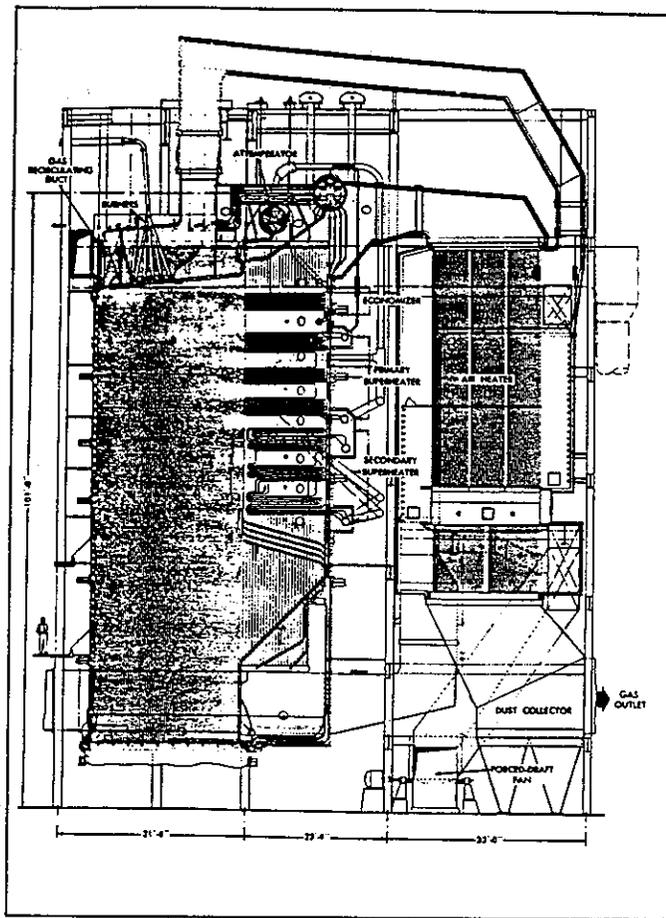


Figure 1. Boiler Elevation

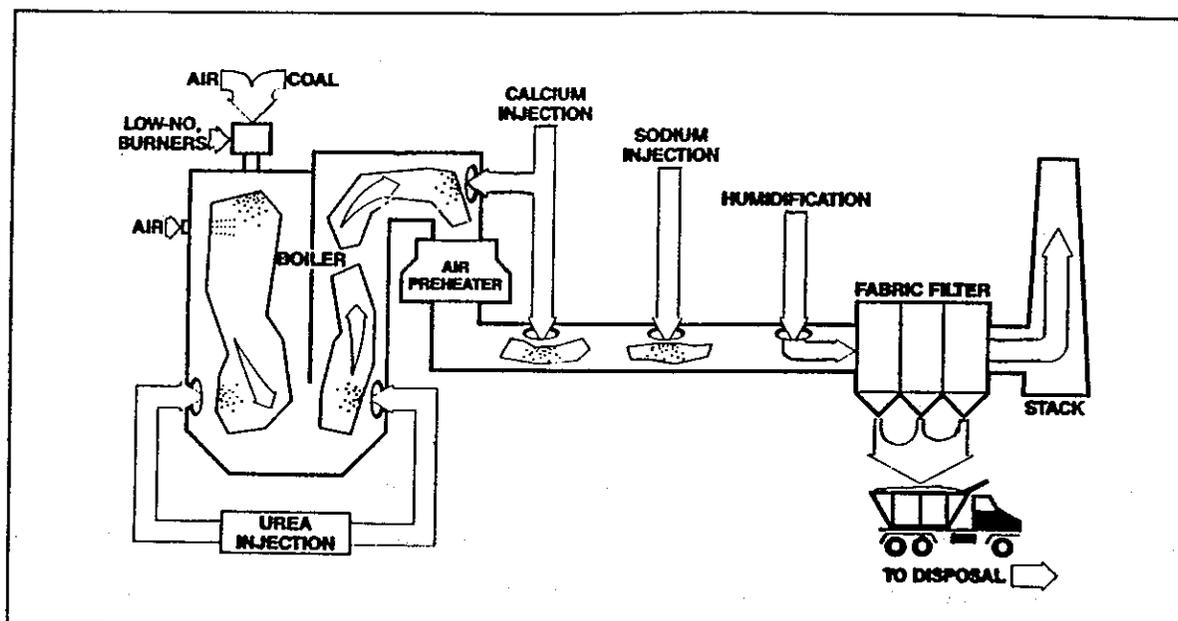


Figure 2. Process Flow Diagram

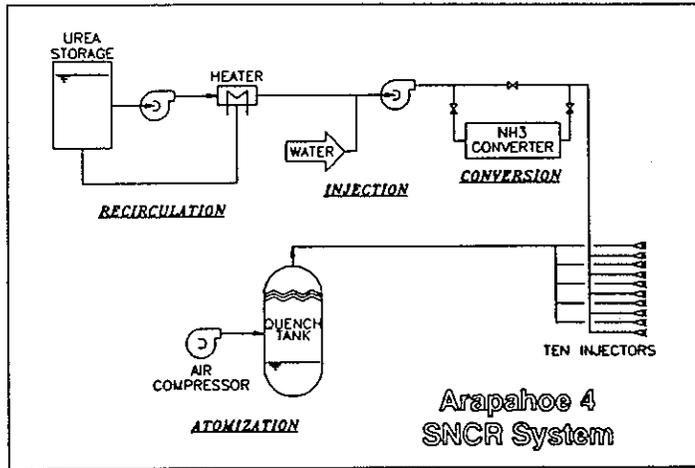


Figure 3. SNCR System Flow Diagram

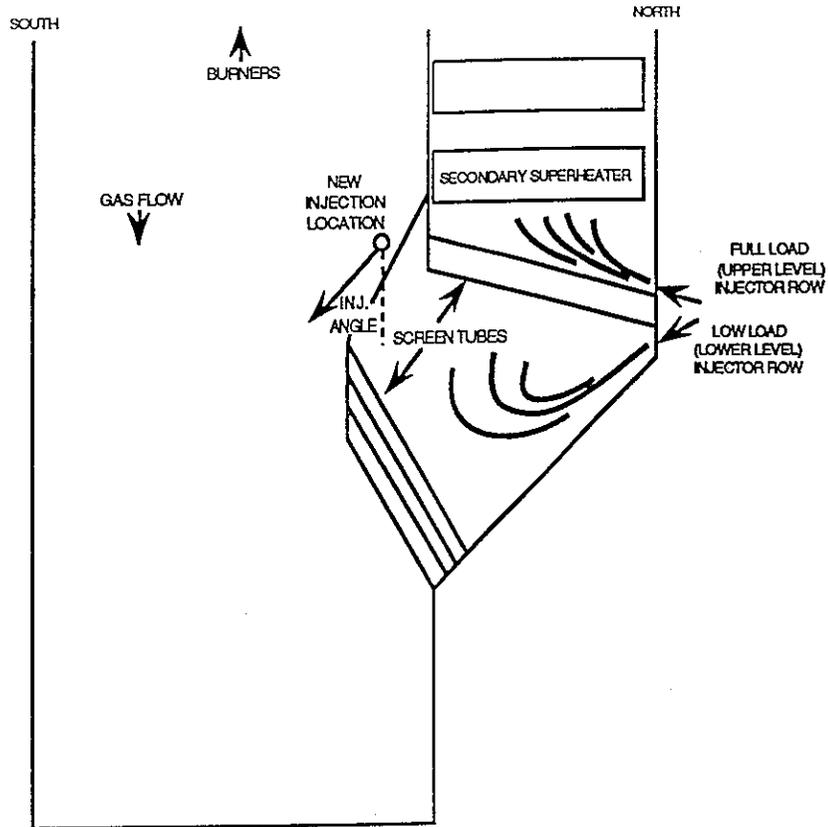


Figure 4. SNCR Injection Locations

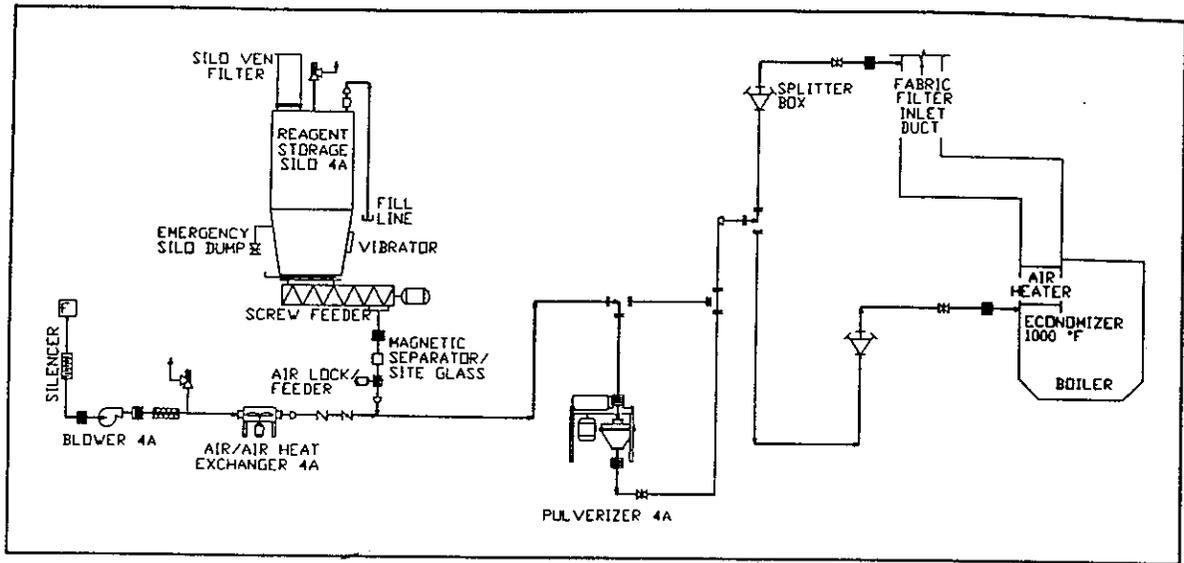


Figure 5. Dry Sorbent Injection Flow Diagram

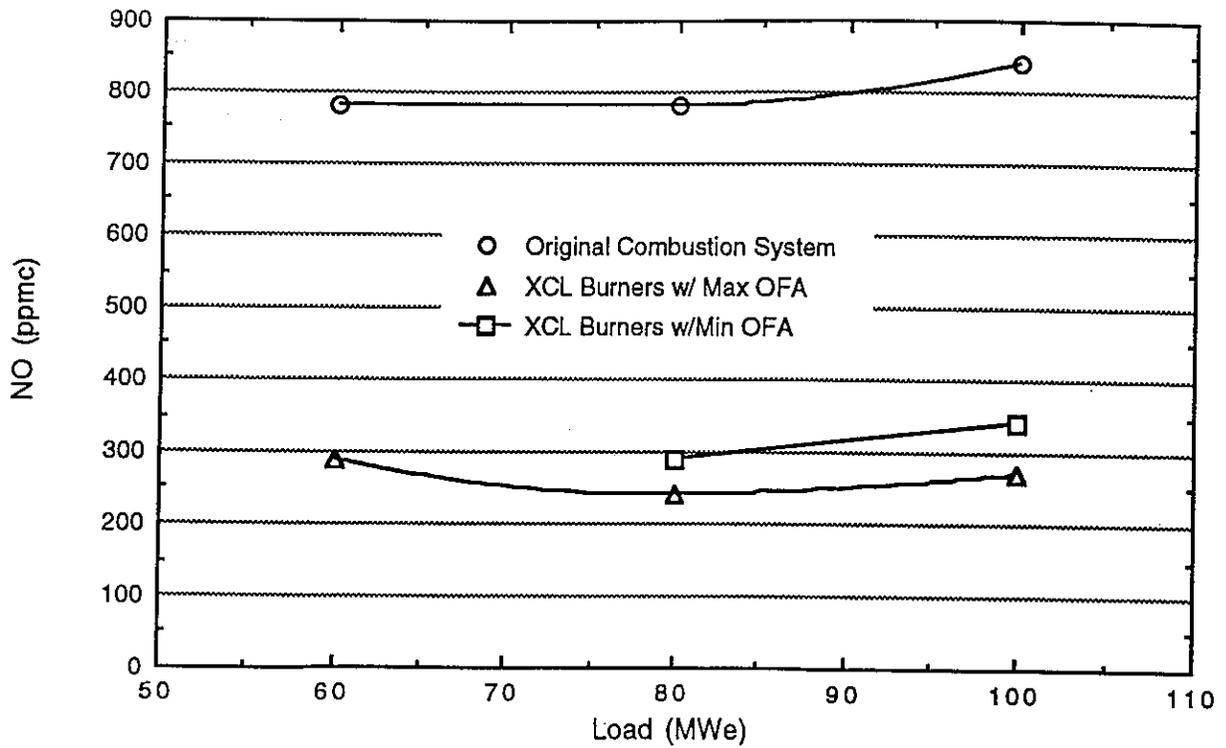


Figure 6. NO Emissions Before and After Low-NO<sub>x</sub> Combustion System Retrofit

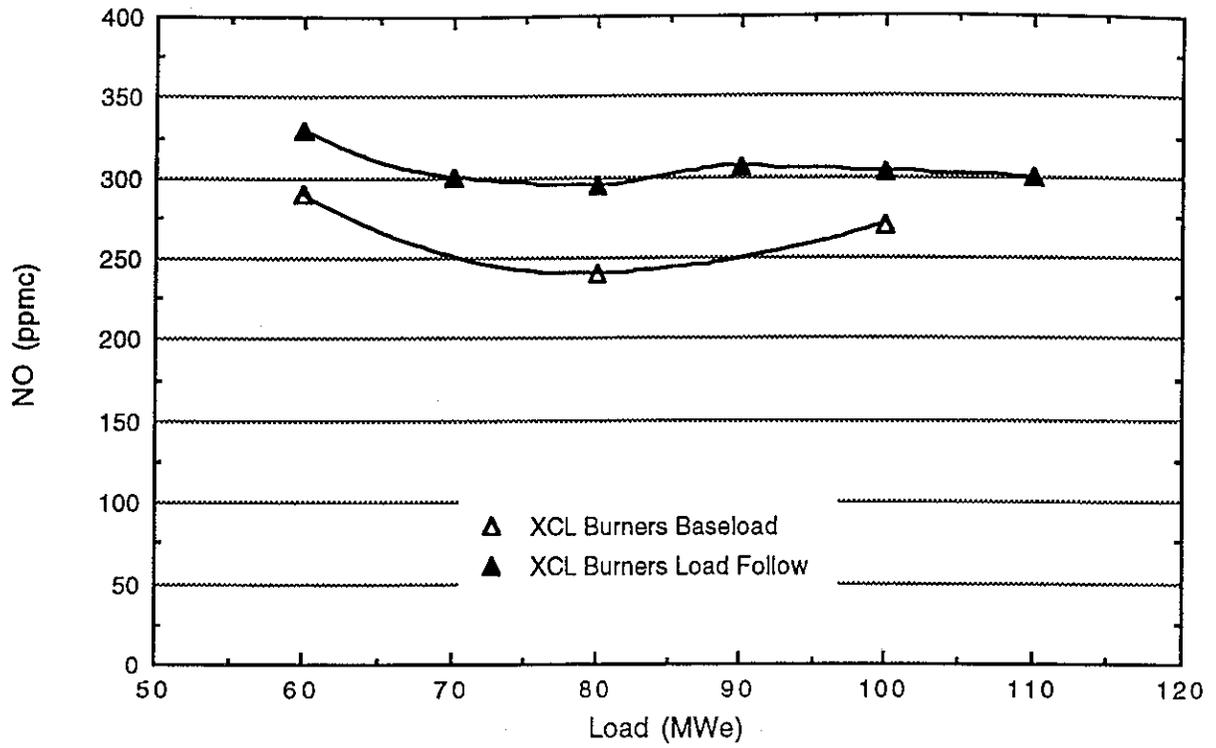


Figure 7. Load Following NO Emissions

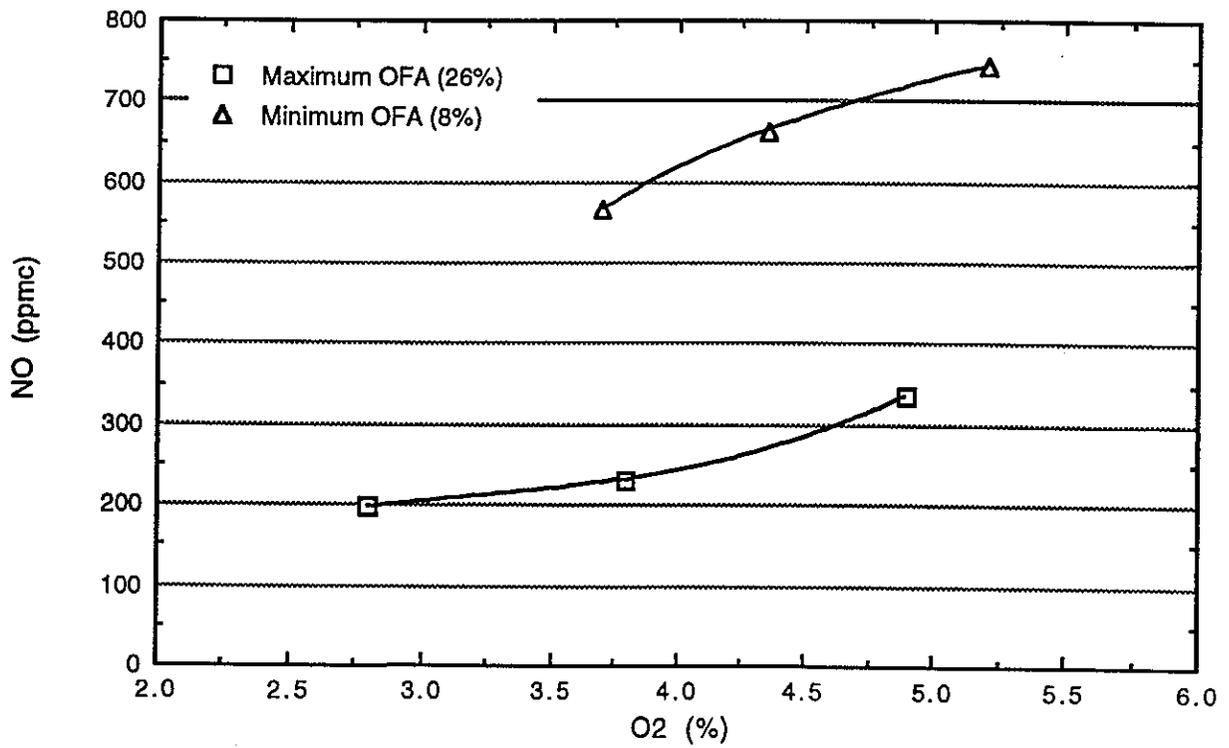


Figure 8. Full Load NO Emissions with Natural Gas Firing

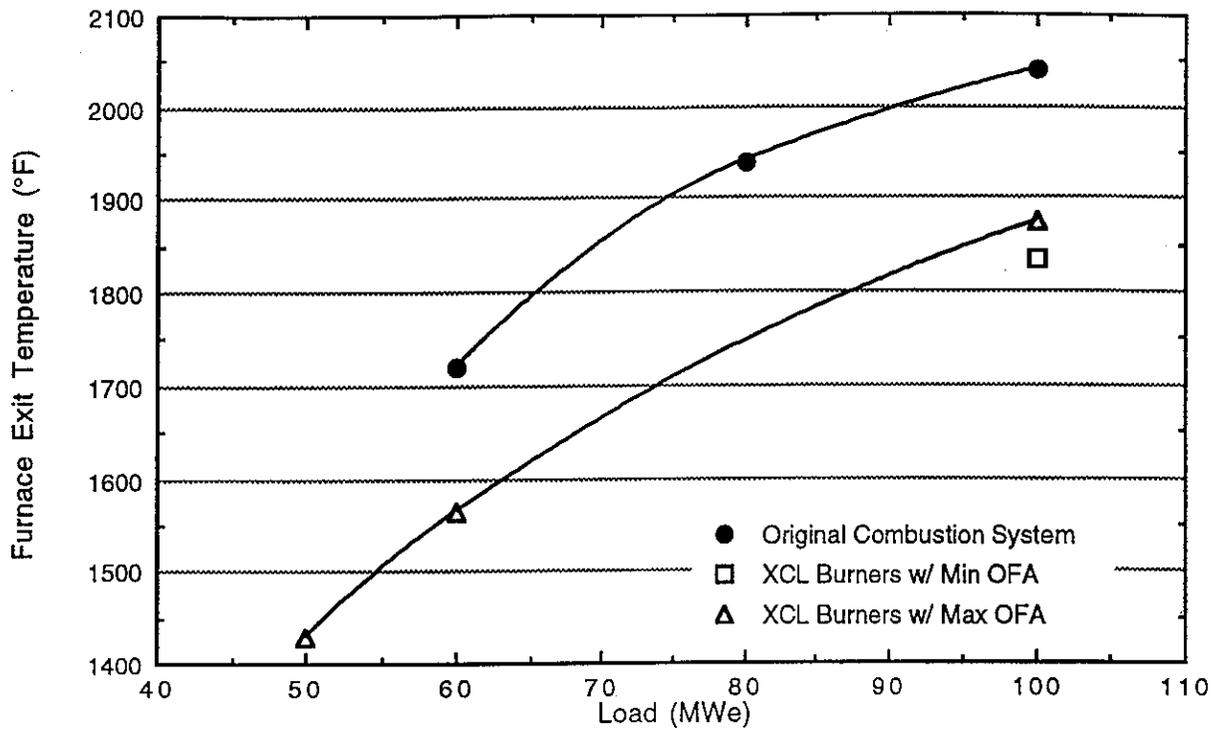


Figure 9. Furnace Exit Flue-Gas Temperatures

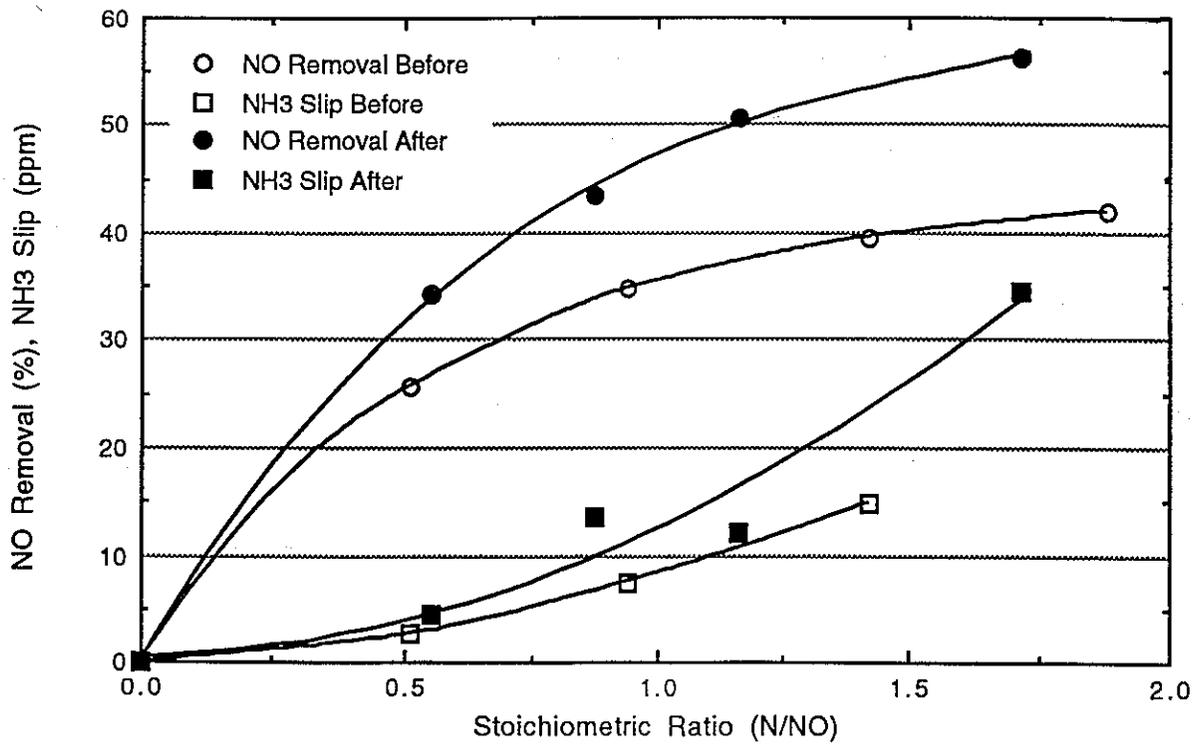


Figure 10. Full Load SNCR NO Removal and NH<sub>3</sub> Slip Before and After Combustion Modifications

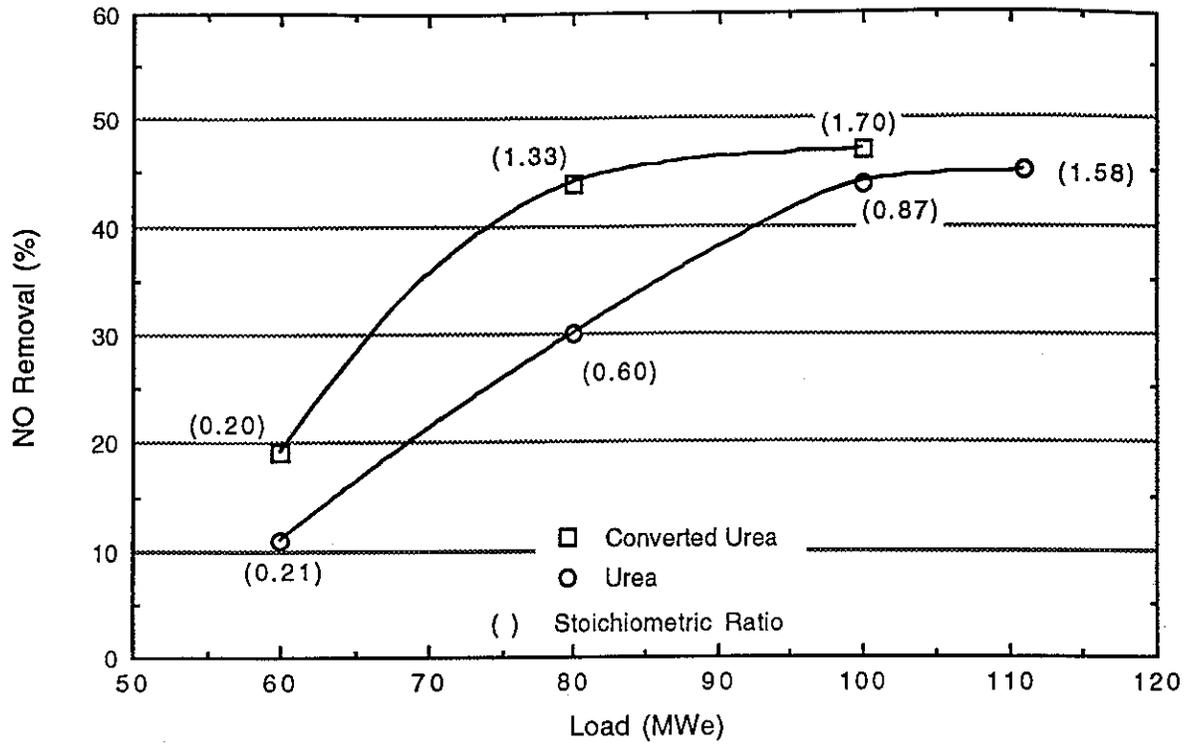


Figure 11. Comparison of NO Reductions with Urea and Converted Urea at an  $\text{NH}_3$  Slip Limit of 10 ppm

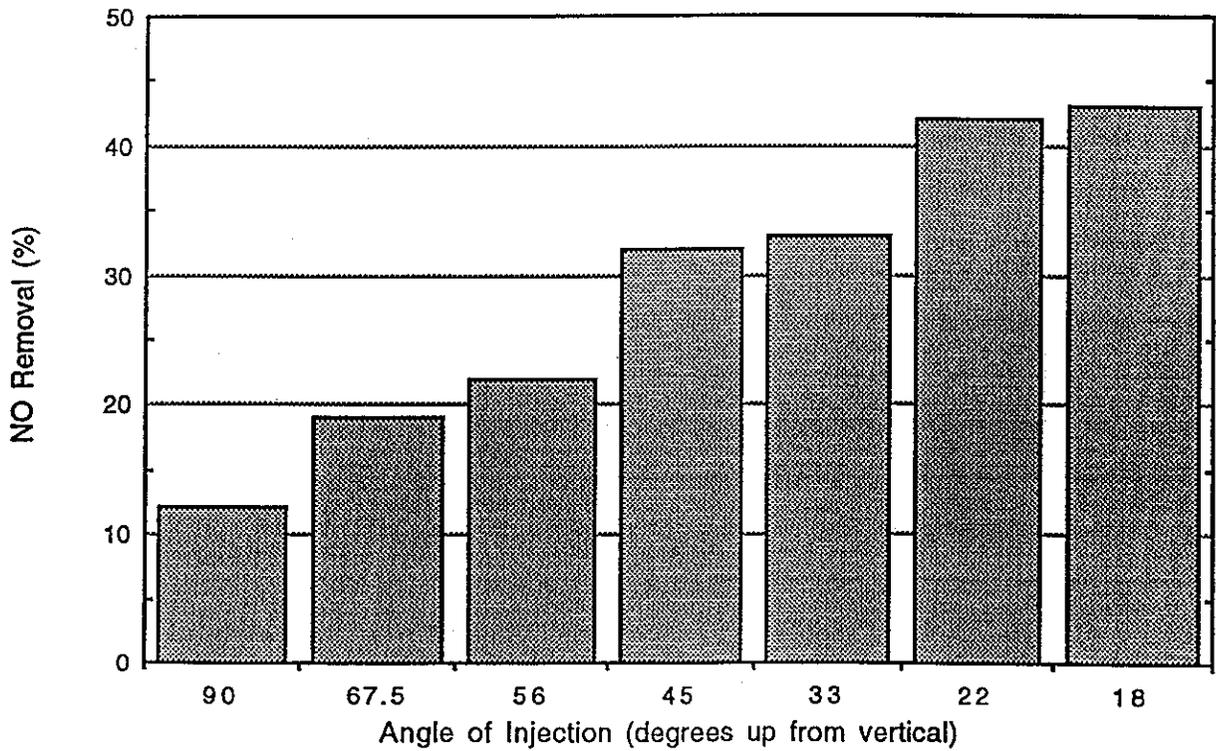


Figure 12. Effect of Injection Angle for Proof-of-Concept SNCR Lance Tests

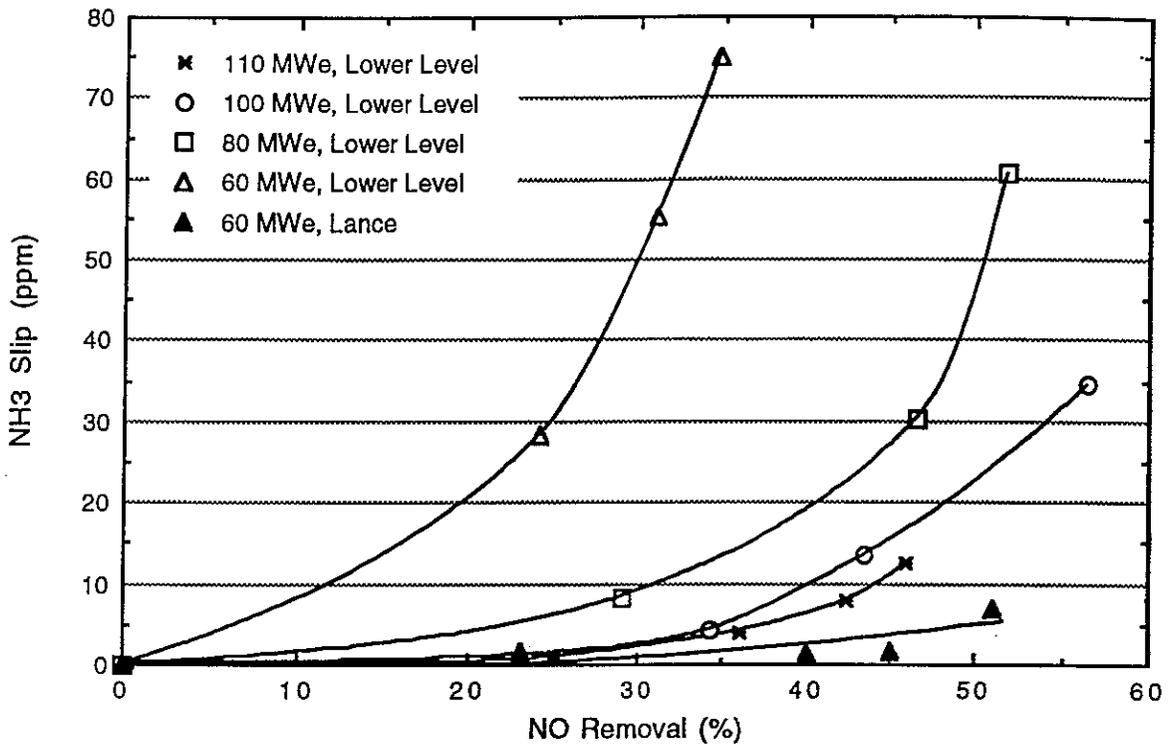


Figure 13. Proof-of-Concept SNCR Lance Results

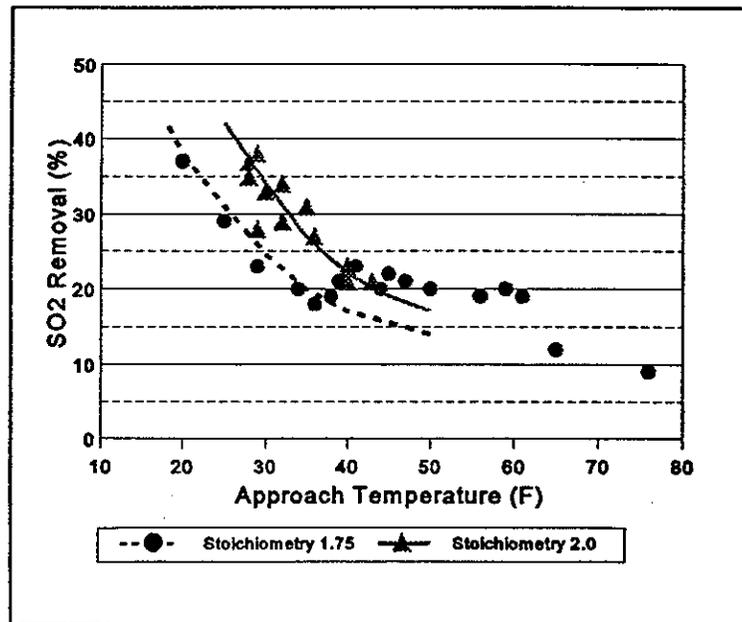


Figure 14. Calcium Duct Injection

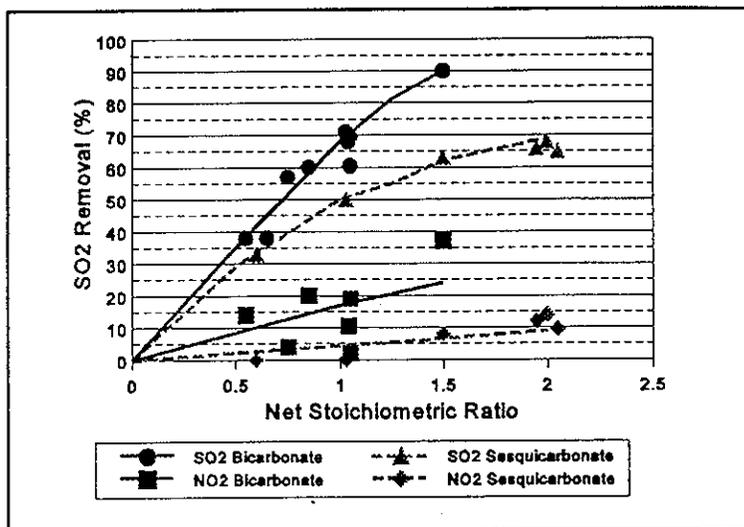


Figure 15. Sodium Duct Injection

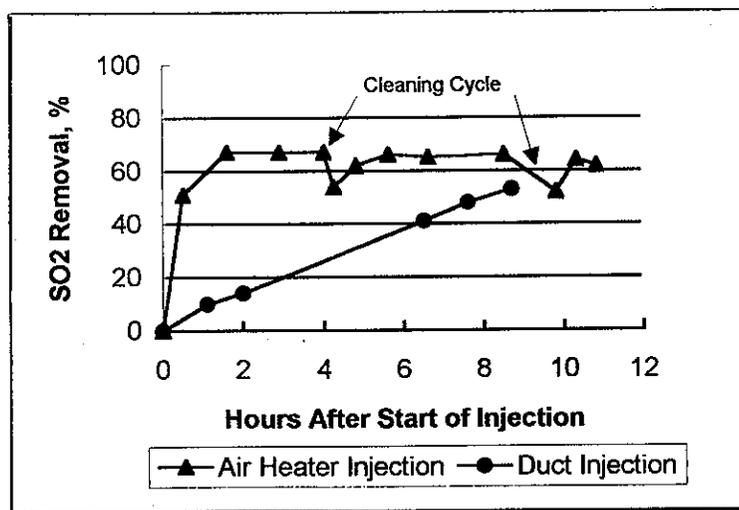


Figure 16. Sodium Bicarbonate SO<sub>2</sub> Removals as a Function of Time

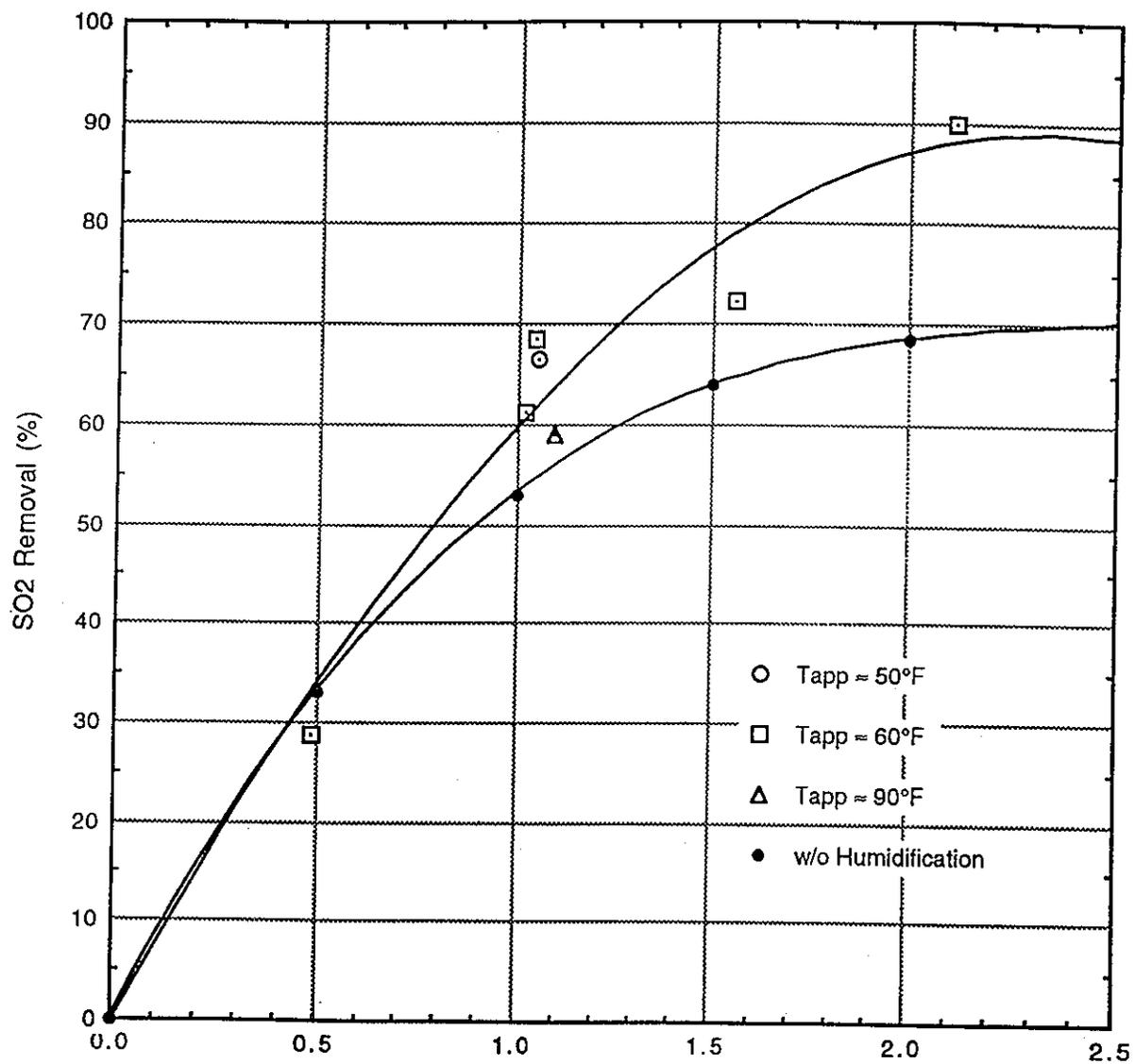
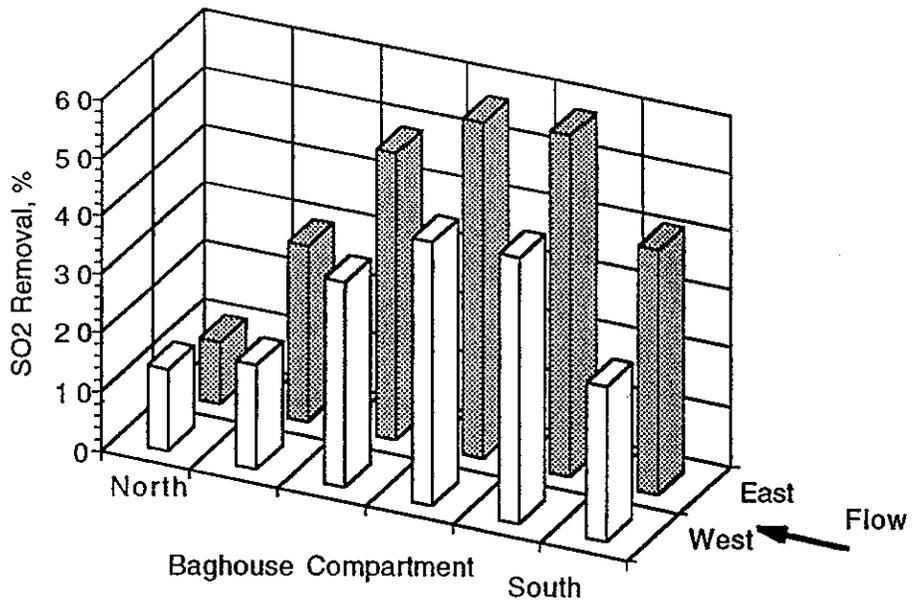
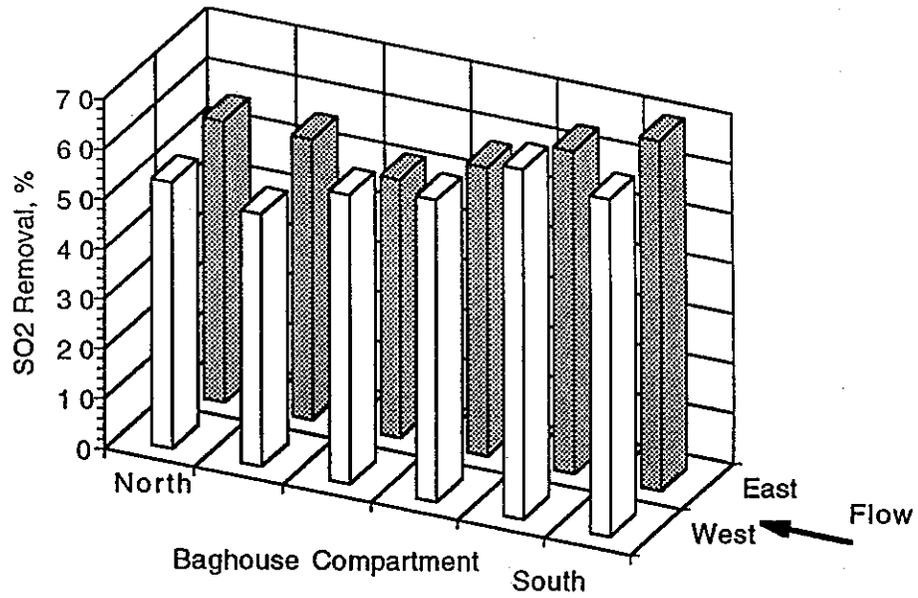


Figure 17. Effect of Approach Temperature on SO<sub>2</sub> Removal for Sodium Sesquicarbonate Injection Ahead of the Fabric Filter



(a)  
Without Humidification, NSR = 0.88



(b)  
With Humidification, NSR = 1.0, 60°F Approach

**Figure 18. Compartment-by-Compartment SO<sub>2</sub> Removals for Sodium Sesquicarbonate Injection; The Effect of Humidification**

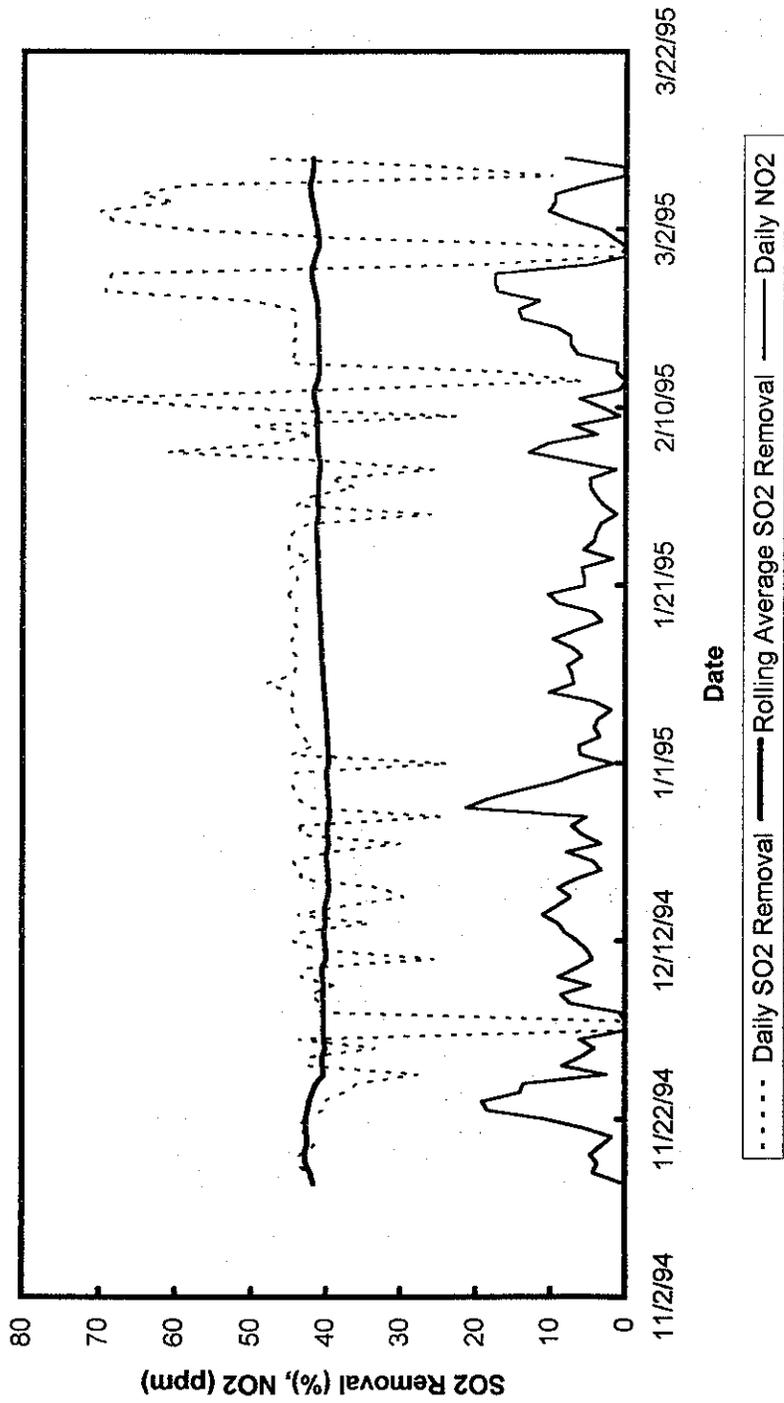
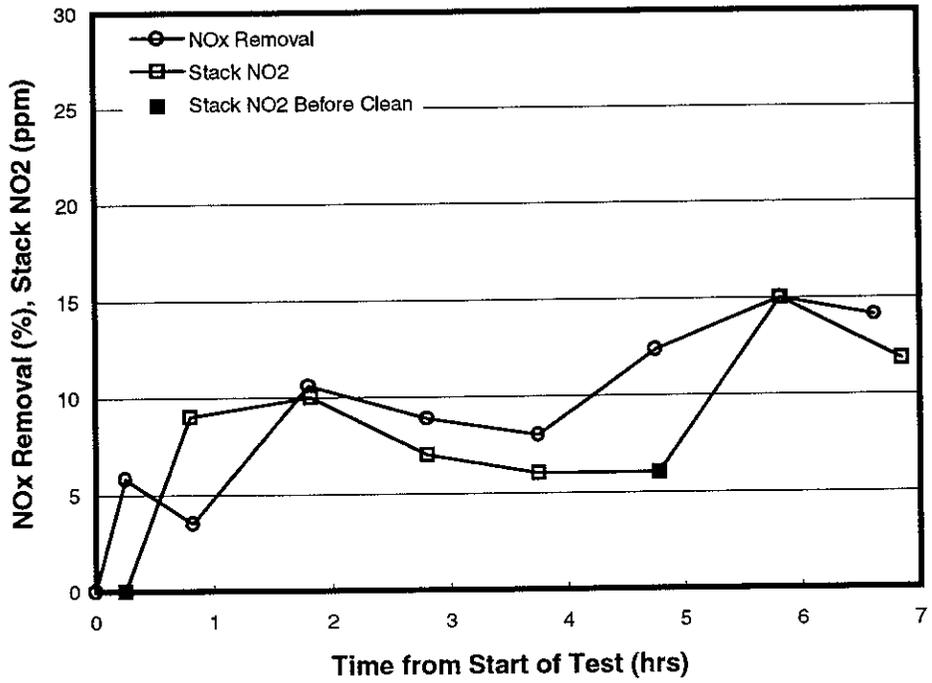
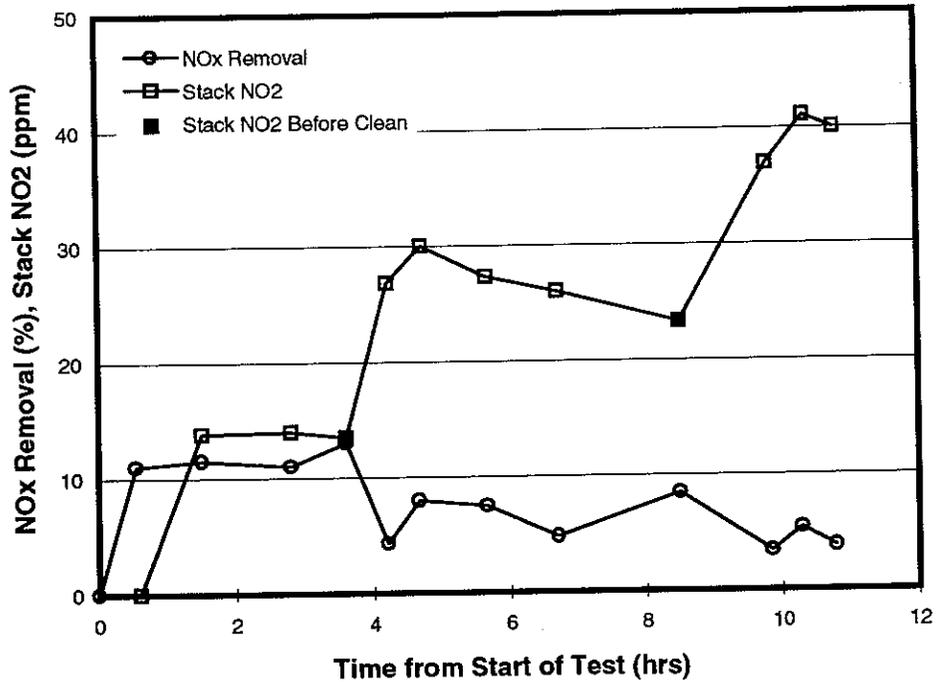


Figure 19. Long Term Test with Sodium Sesquicarbonate; 40% SO<sub>2</sub> Removal Set Point



(a)  
Sodium Sesquicarbonate (Ahead of the Fabric Filter)



(b)  
Sodium Bicarbonate (Ahead of the Air Preheater)

Figure 20. NO<sub>x</sub> Removal and NO<sub>2</sub> Emissions Versus Time for Sodium Injection

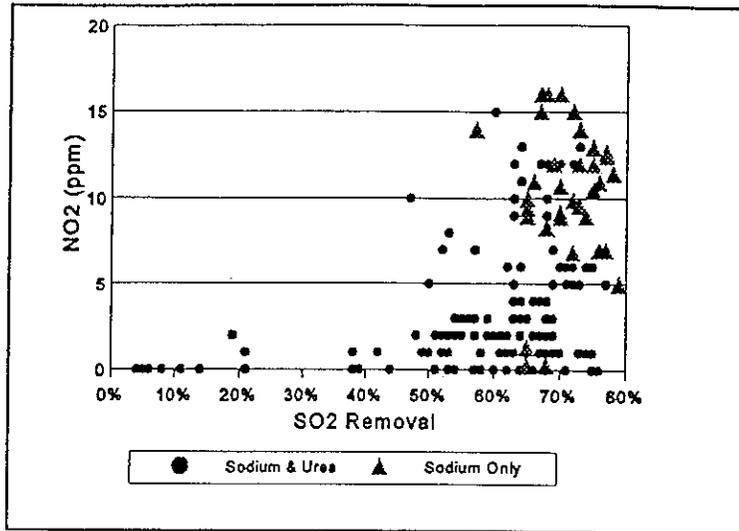


Figure 21. Integrated NO<sub>2</sub> Emissions

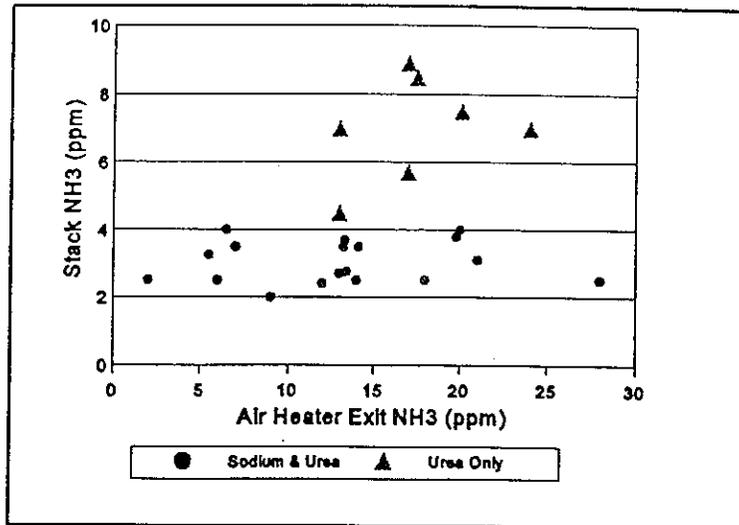


Figure 22. Stack/Air Heater Exit NH<sub>3</sub>

# MILLIKEN STATION DEMONSTRATION PROJECT FGD RETROFIT UPDATE-1995

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## **Abstract**

The Milliken Clean Coal Demonstration Project is one of the nine Clean Coal Projects selected for funding in Round 4 of the U.S. DOE's Clean Coal Demonstration Program. The project will provide full-scale demonstration of a combination of innovative emission-reducing technologies and plant upgrades for the control of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>) emissions from a coal-fired steam generator without a significant loss of station efficiency. The project incorporates several unique aspects including low pH operation, a ceramic tile-lined, cocurrent/countercurrent, split module absorber, a wet stack supported on the roof of the FGD building, and closed loop, zero liquid discharge operation producing commercial grade gypsum and calcium chloride brine. This paper provides an update of the current status of the project with emphasis on startup experiences and the demonstration testing plan.

## Introduction

The project's sponsor is New York State Electric and Gas Corporation (NYSEG). Project team members include CONSOL Inc., Saarberg-Holter-Umwelttechnik (SHU), NALCO FuelTech, Stebbins Engineering and Manufacturing Co., DHR Technologies, Inc and ABB Air Preheater. Project cofunders include NYSEG, CONSOL, Electric Power Research Institute, New York State Energy Research and Development Authority and Empire State Electric Energy Research Corporation. Gilbert/Commonwealth is the Architect/Engineer and Construction Manager for the flue gas desulfurization (FGD) retrofit portion of the project.

The project will provide full-scale demonstration of a combination of innovative emission-reducing technologies and plant upgrades for the control of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>) emissions from a coal-fired steam generator without a significant loss of station efficiency. The overall project goals are:

98% SO<sub>2</sub> removal efficiency using limestone while burning high sulfur coal;

Up to 70% NO<sub>x</sub> reduction using the NOXOUT selective non-catalytic reduction (SNCR) technology in conjunction with combustion modifications;

Minimization of solid wastes by producing marketable by-products including commercial grade gypsum, calcium chloride, and fly ash;

Zero wastewater discharge;

Maintenance of station efficiency by using a high-efficiency heat-pipe air heater system and a low-power-consuming scrubber system.

The demonstration project is being conducted at NYSEG's Milliken Station, located in Lansing, New York. Milliken Station has two 150-MWe pulverized coal-fired units built in the 1950's by Combustion Engineering. The SHU FGD process and the combustion modifications are being installed on both units, but the NOXOUT process, Plant Economic Optimization Advisor(PEOA), and the high-efficiency air heater system will be installed on only one unit.

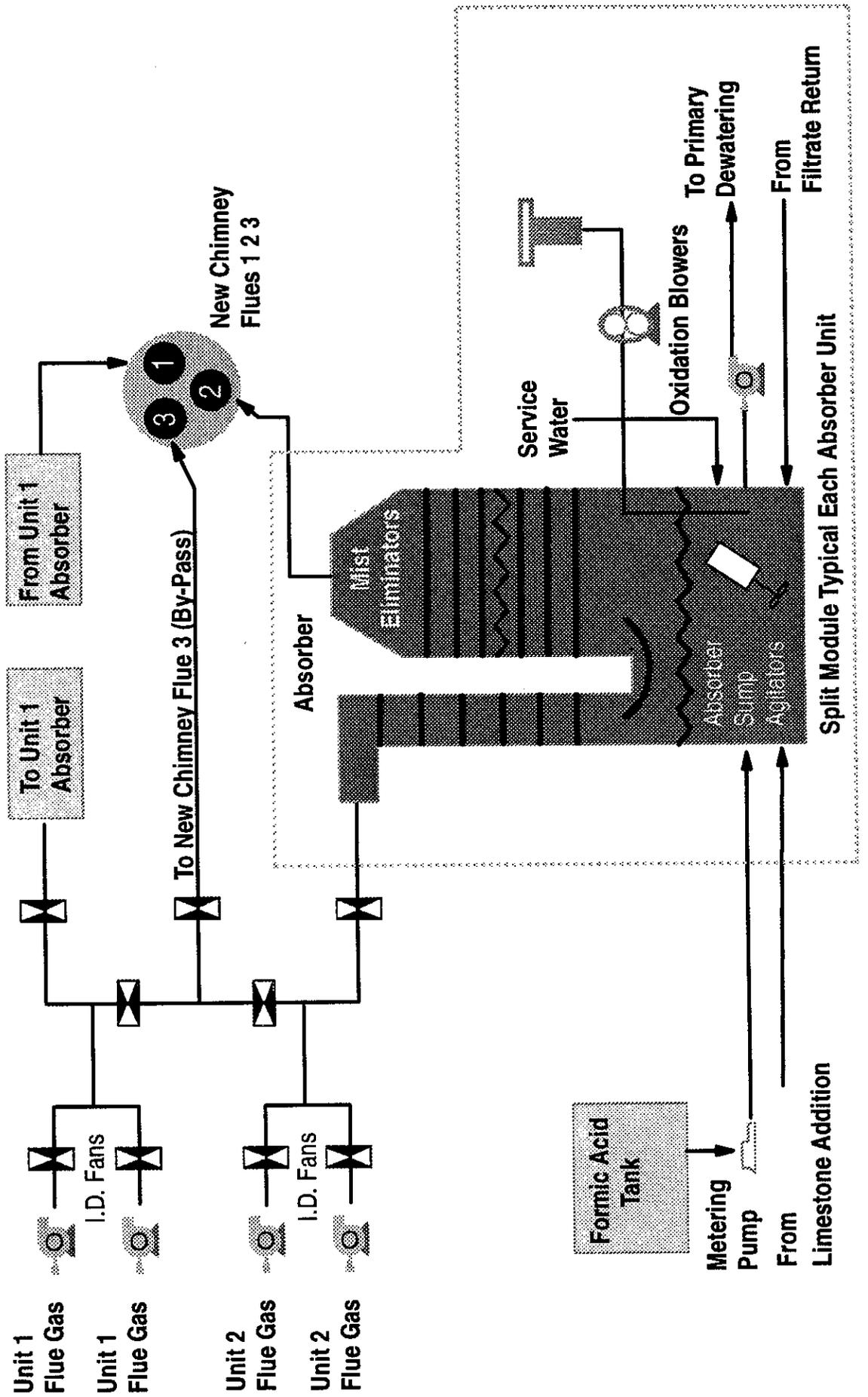
The total cost of the project, including the three year demonstration program, will be \$181,953,000 with DOE contributing \$ 45,000,000.

## SO<sub>2</sub> Removal

The SHU process (Figure 1) is the only developed wet-limestone FGD process designed specifically to employ the combined benefits of low-pH operation, formic acid enhancement, single-loop cocurrent/countercurrent absorption, and in situ forced oxidation. In the SHU process, the flue gas is scrubbed with a limestone solution in a cocurrent/countercurrent absorber vessel.

The SHU solution is maintained at a low pH by adding formic acid, which acts as a buffer, to the absorber. Formic acid addition enhances the process in several ways, including better SO<sub>2</sub> removal efficiency with limestone, lower limestone reagent consumption, lower blowdown rate, freedom from scaling and

**Figure 1**  
**Simplified SHU Flow Diagram**



plugging, higher availability, lower maintenance, production of wallboard grade by-product, and improved energy efficiency compared to conventional FGD technologies.

With operation at lower pH, the limestone reagent dissolves more quickly. This means that less limestone is needed, the limestone doesn't have to be ground as fine, and there is less limestone contamination of the gypsum by-product. Operation at lower pH results in more efficient oxidation of the bisulfite reaction product to sulfate. Less excess air is needed for the oxidation reaction and the gypsum crystals created are larger and more easily dewatered. Formic acid buffering improves SO<sub>2</sub> removal efficiency. Slurry recirculation rates are reduced, saving both capital cost and energy. Buffering provides excellent stability and easy operation during load changes and transients. The process can tolerate higher chloride concentrations, reducing the amount of wastewater that must be processed. Finally, the potential for scaling of absorber internals is eliminated, resulting in reduced maintenance costs and improved availability.

The FGD process has been installed on both Units 1 and 2 with common auxiliary equipment. A single split absorber is used. This innovation features an absorber vessel divided into two sections to provide a separate absorber module for each unit. The design allows for more flexibility in power plant operations than does a single absorber while saving space on site and capital cost compared to two separate absorber vessels. The absorber shell construction is concrete, with an integral, cast in place ceramic tile liner. The tile has superior abrasion and corrosion resistance compared to rubber and alloy linings and is expected to last the life of the plant. In addition, the concrete/tile system is easily installed at existing sites where space for construction is at a premium, making it ideal for use in retrofit applications.

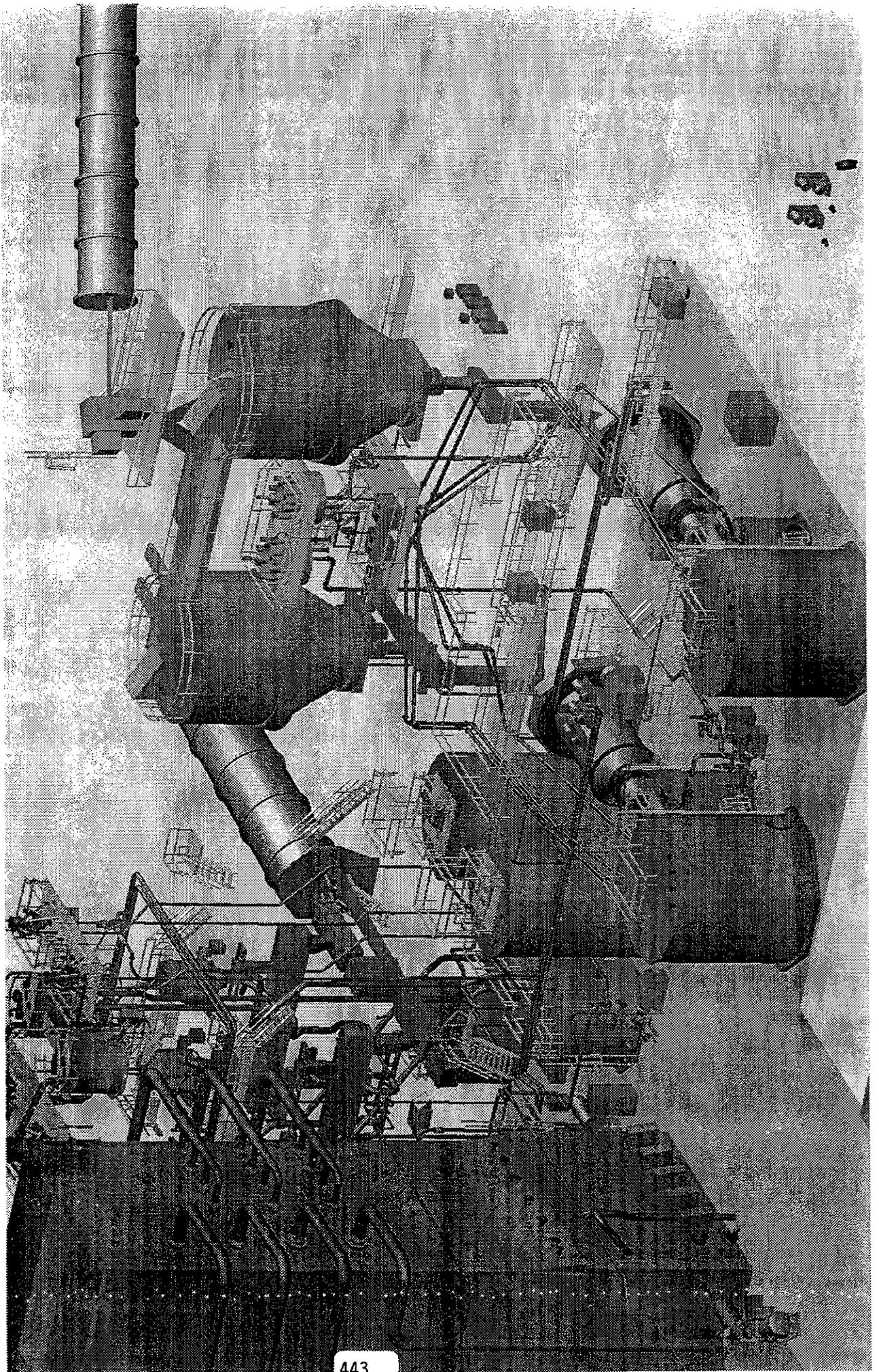
The absorbers use two-stage mist eliminators furnished by Munters. Whereas model DV 210 is used for the first stage in both absorber modules, the modules use two different second-stage designs. One absorber uses model DV-2130 and the other uses model T271. Model T271 is the vertical flow type tested by EPRI and commonly found in US installations. DV-2130 is the Munters-Euroform v-shaped module design commonly used in European installations. The project will provide a side-by-side performance comparison of the two designs.

The design incorporates a new chimney erected on the roof of the FGD building, directly over the absorber vessel. Each absorber module discharges directly into a dedicated fiberglass (FRP) flue. The two FRP flues, along with a common steel start-up bypass flue are enclosed within a 40-ft (12.2m) diameter steel chimney. This design saves space on site and eliminates the need for absorber outlet isolation dampers, which are typically high maintenance items.

#### Limestone Preparation and Addition

Limestone is delivered to the station by truck. Space is provided on site for a 180-day inventory. The stone is reclaimed by front-end loader and transferred by belt conveyor to two 24-hr surge bins in the FGD building. The limestone is ground and slurried with clarified water (recycled process liquor) in conventional closed-circuit, horizontal, ball mill, wet-grinding systems (Figure 2) provided by Fuller. The 25% solids product is transferred

**Figure 2**  
**Limestone Preparation System**



by gravity to either of two 12-hour fresh slurry feed tanks. Redundant, continuous-loop piping systems are used to transfer the product slurry to the absorbers from the fresh slurry feed tanks. Two grinding systems are provided, each with a capacity of 24 tph. One mill, operating 12 hours per day, can support the process. Each system is provided with two sets of classifiers. This allows the production of slurry with two different particle size distributions, 90% passing through 170 mesh and 90% passing through 325 mesh. The coarser grind is used during normal operation with formic acid. The finer grind allows the system to be operated without formic acid. The limestone preparation/addition system can be aligned as two independent trains, effectively segregating Unit 1 and Unit 2 process streams. This feature enhances the flexibility of the installation for process evaluation purposes.

### Gypsum Dewatering

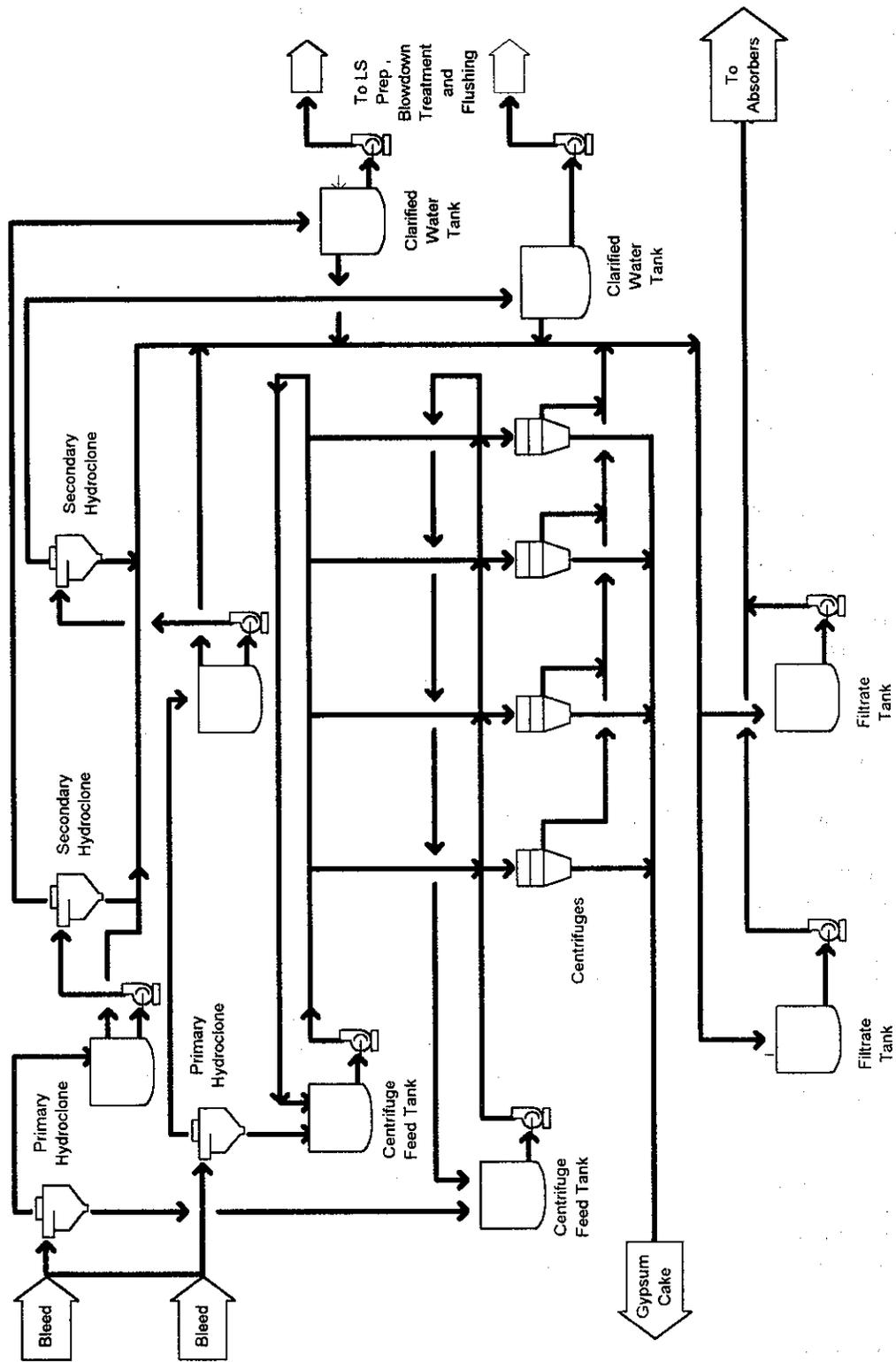
A bleed stream of recycle slurry is processed for recovery of high quality by-product gypsum and calcium chloride brine. Water is recovered and recycled back to the process. There is zero wastewater discharge from the process. The gypsum is dewatered to 6% surface moisture for delivery to customers in powder form. The absorber building has been designed for future addition of agglomeration equipment should market conditions require agglomerated product.

In the dewatering system (Figure 3) a bleed stream containing by-product gypsum solids is withdrawn from each absorber module by bleed pumps. The bleed streams are fed to primary hydrocyclones where the gypsum solids are concentrated to 25 wt%. The underflow from the primary hydrocyclones discharges to the centrifuge feed tanks. The overflow discharges to the secondary hydroclone feed tanks. Two primary hydrocyclone assemblies are provided. Each assembly can process the bleed from either or both absorber modules. The feed manifold of each hydrocyclone assembly has an internal partition which segregates the unit 1 and unit 2 bleed streams. This feature ensures that the feed rate to each individual hydrocyclone is constant whether or not the assembly is handling the bleed from one or both absorbers. In normal operation, the bleed from both absorbers is processed through one hydrocyclone assembly and the second assembly is a spare. If desired, both assemblies can operate in parallel.

The gypsum solids from the primary hydrocyclone underflow are concentrated to 94 wt% by Krauss-Maffei vertical basket centrifuges. Four centrifuges are provided, three operating and one standby. The centrifuges are fed from either of two centrifuge feed tanks through continuously circulating feed loops. The rubber-lined centrifuges are batch operated and incorporate a washing step designed to achieve a residual chloride concentration of less than 100 ppm. The system is configured to allow segregation of the unit 1 and unit 2 liquid streams. The centrate is returned to the absorbers through the filtrate tanks. The gypsum solids are transferred by belt conveyor to an on-site storage building. Gypsum in the 5000-ton capacity storage building is reclaimed by front-end loader and trucked from the site.

A portion of the overflow from the primary hydrocyclones is processed by the secondary hydroclones for use as clarified water for limestone preparation, system flushing, and blowdown to the FGD wastewater treatment system. Gypsum solids in the underflow from the secondary hydrocyclones and the balance of

**Figure 3**  
**Gypsum Dewatering Flow Diagram**



the primary hydrocyclone overflow are returned to the absorbers via the filtrate tanks. Two secondary hydrocyclone assemblies are provided, one dedicated to each primary hydrocyclone assembly, maintaining the capability of segregating the unit 1 and unit 2 process streams.

### FGD Blowdown Treatment

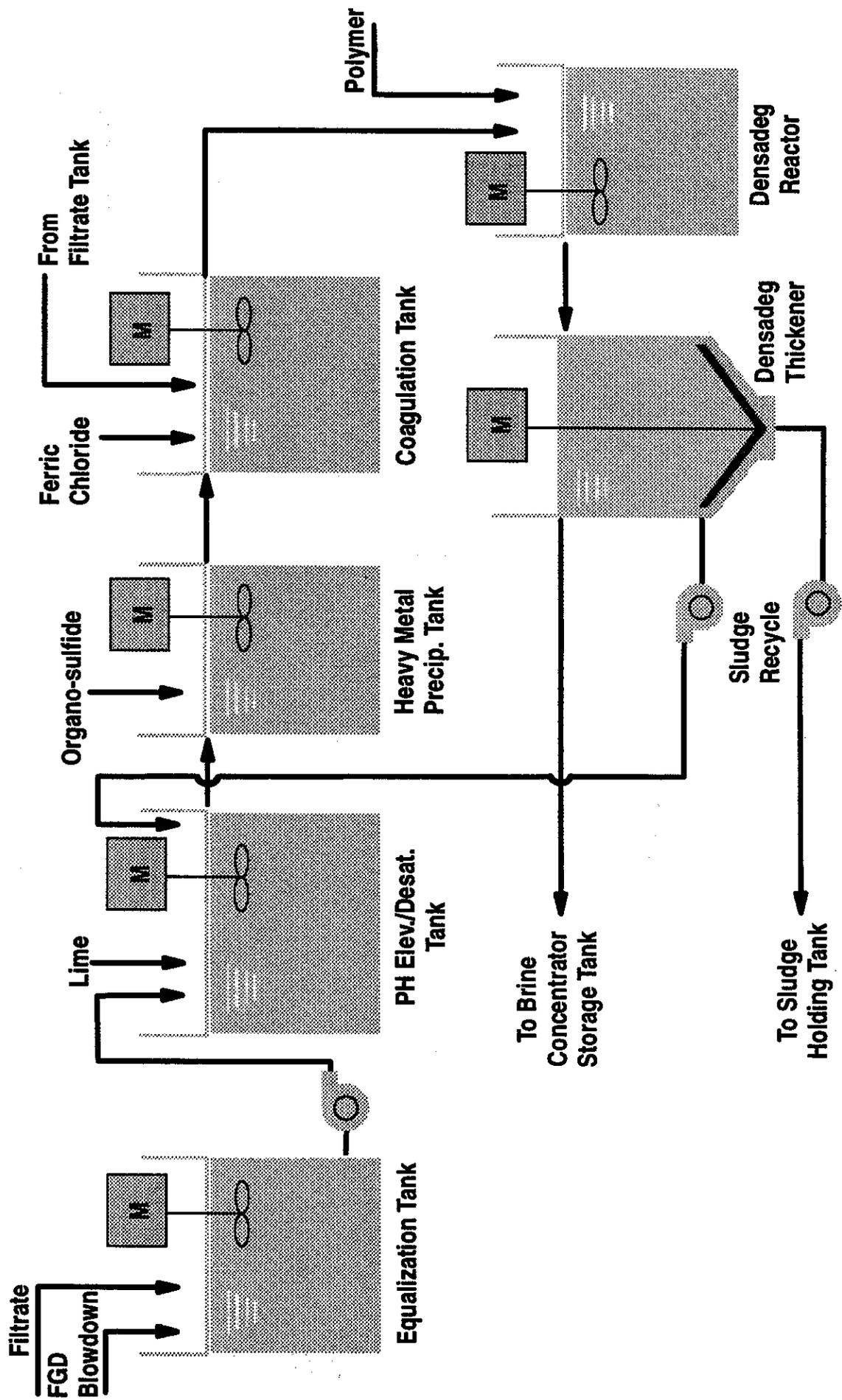
The FGD Blowdown Treatment System consists of two subsystems, the pretreatment system furnished by Infilco Degremont Inc. (IDI) and the brine concentration system, furnished by Resources Conservation Co. (RCC). The project will be the first demonstration of the production and marketing of FGD by-product calcium chloride.

The pretreatment system (Figure 4) removes suspended and dissolved solids from the blowdown stream prior to the brine concentration process. The pretreatment process consists of the following steps:

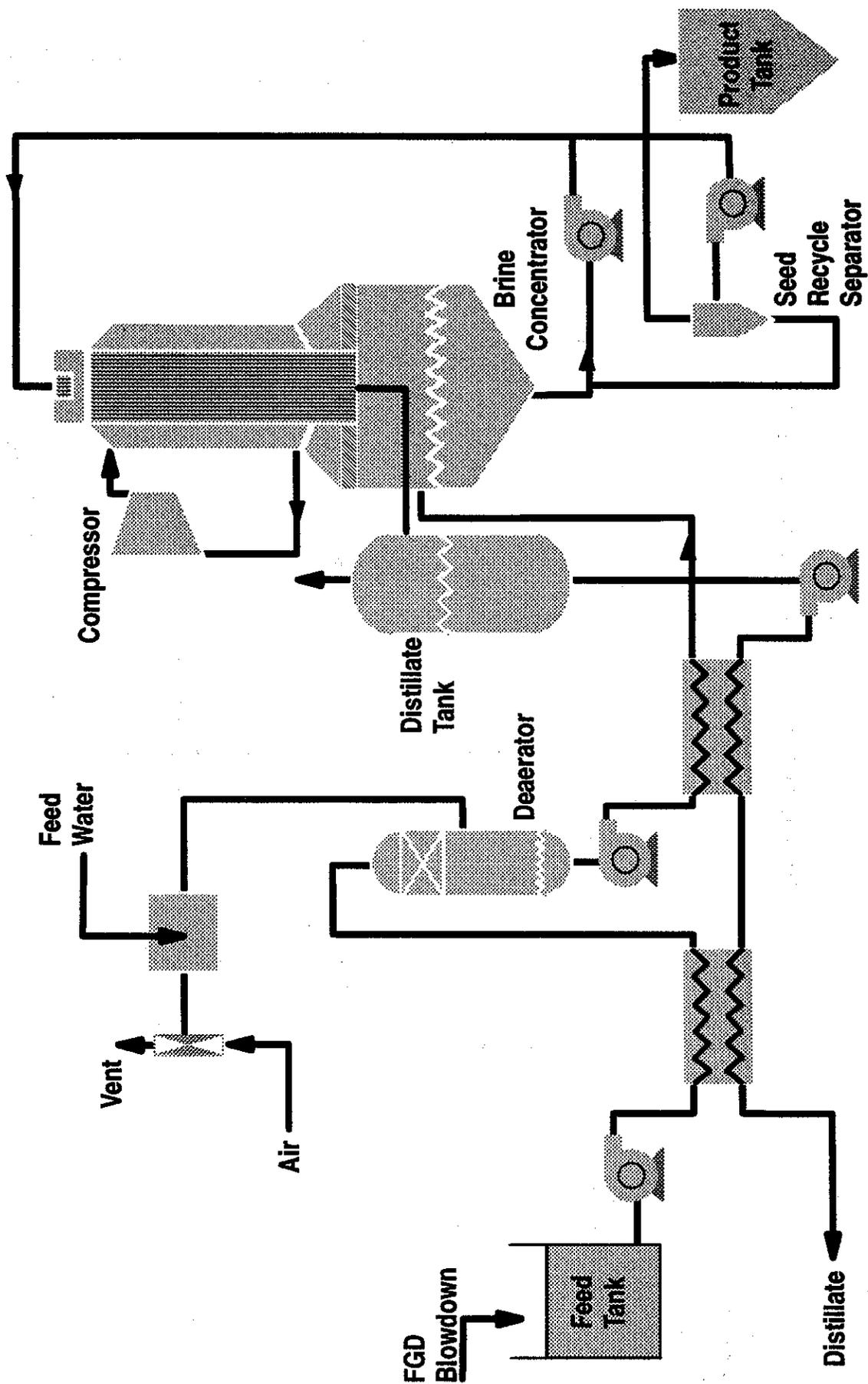
1. An agitated equalization tank to balance the FGD wastewater composition and flow.
2. pH elevation, calcium sulfate desaturation and magnesium hydroxide precipitation using lime. By elevating the pH to 11.0-11.2, most heavy metals will be removed. In particular, the high pH leads to precipitation of magnesium hydroxide, leading to a purer calcium chloride salt product. The use of lime also enhances the removal of fluoride ion as calcium fluoride. Sludge is recirculated from the downstream clarifier to aid the desaturation process.
3. Secondary precipitation of heavy metals as more insoluble organosulfides using the organosulfide TMT.
4. Coagulation with ferric chloride.
5. Dosing of flocculant to the reactor of the DensaDeg unit to improve sedimentation.
6. Flocculation/sludge densification, thickening, and final clarification in the DensaDeg unit. The DensaDeg is a three-stage unit comprising a solids-contact reaction zone, a presettler-thickener, and lamellar settling tubes in the upper part of the thickener. The water entering the clarification zone has a very low solids content and the lamellar tubes serve only to catch fugitive particles carried over. Water leaving this zone has less than 20 ppm solids.
7. Excess sludge withdrawal conditioning with lime, and dewatering with a plate and frame filter press. The addition of lime in the sludge holding tank aids the dewaterability of the sludge, allowing a drier cake to be formed, and also helps stabilize the metal hydroxides.

The brine concentration system (Figure 5) processes the effluent from the pretreatment system through a vapor-compression type falling-film evaporator, producing a very pure distillate that is recycled to the FGD system as process makeup water. The system's by-product salt will be calcium chloride meeting NYSDOT requirements for use in dust control, soil stabilization, ice control,

**Figure 4**  
**FGD Blowdown Pretreatment Flow Diagram**



**Figure 5**  
**Brine Concentrator Flow Diagram**



and other highway construction related purposes. This material will be Type B (liquid calcium chloride solution) with at least 33% CaCl<sub>2</sub>, meeting ASTM D98.

The pretreated FGD blowdown is conditioned with sulfuric acid and an inhibitor for scale prevention. It is then preheated, deaerated, heated to near boiling, and fed to the evaporator sump where it mixes with recirculating, concentrated brine slurry. The slurry is pumped to the brine concentrator (BC) condenser floodbox where it is distributed as a thin film on the inside walls of titanium tubes. As the slurry film flows down the tubes, the water is evaporated. The resulting steam is drawn through mist eliminator pads to the vapor compressor, which raises its saturation temperature to above the boiling temperature of the recirculating brine. The compressed steam is then introduced to the condenser where it gives up its heat of vaporization (to heat the thin film in the inside of the tubes) and condenses on the outside of the tube walls. This condensate is collected in the distillate tank, cooled by heat exchange with the feed stream, and returned to the FGD system. As the falling film evaporates, calcium sulfate begins to crystallize. The calcium sulfate seed crystals provide nucleation sites to prevent scaling of the tubes. Control of the concentration of both suspended and dissolved solids in the evaporator sump is critical to prevent the precipitation of secondary salts and the resultant scaling of the evaporator tubes. A side stream of recirculating brine is processed by a hydrocyclone. The underflow is returned to the BC sump. The overflow is either recirculated to the brine concentrator or diverted to the product tank, based upon its dissolved solids concentration. A second side stream of recirculating brine is diverted to the product tank to control the concentration of suspended solids. The 33% brine product is then cooled and transported to market by truck.

#### FGD System Startup Experiences

Engineering and design work for the FGD portion of the project began in January 1992. Construction started in April 1993, and was essentially complete by December 1994. System checkout and startup activities began in May, 1994. As construction of each subsystem was completed it was turned over to the Startup Team. Electrical systems were started up first, followed by utility systems. Limestone supply and preparation systems were then started up in parallel with gypsum dewatering systems. These were followed by startup of the absorber itself. The FGD system was pronounced ready for on-line operation on December 22, 1994.

The Unit 2 absorber was placed on line on January 17, 1995. Within the first hours of operation the boiler, operating on 2% sulfur coal, was brought up to full load and SO<sub>2</sub> removal efficiencies in excess of 94% were achieved. The first gypsum was produced on January 21. This was followed by a period of calibration, operational tuning and debugging of the integrated systems. Much of the activity during this period centered around the gypsum dewatering system.

The primary hydrocyclone vortex finder and apex sizes had been selected during system checkout using gypsum imported from Bailey Station. It was necessary to fine tune the system with gypsum produced in the Milliken absorber in order to obtain underflow which matched the feed requirements of the centrifuges.

There were initial concerns that the solids capture efficiency of the primary hydroclones was too low. With too high a percentage of the solids in the bleed slurry reporting to the hydroclone overflow it was feared that the dewatering system would not be able to satisfy system capacity requirements. Varying vortex finder and apex sizes and increasing the supply pressure improved the operation somewhat, but did not entirely resolve the problem. After a series of diagnostic tests it was determined that the system was operating at too low a solids concentration in the absorber. The calibration of the bleed density gauge had not corrected for the specific gravity of the scrubbing liquor. Once the calibration had been corrected the hydrocyclone capture efficiency improved dramatically. Vortex finder and apex sizes were optimized and the primary dewatering system operation was able to meet specification.

With the primary system operating per design the Startup Team turned its attention to optimizing the operation of the centrifuges. As described above the centrifuges are batch-operated machines. They are charged with slurry, one centrifuge at a time, from a continuously circulating feed loop. Each branch line from the feed loop is equipped with an automatically actuated knife gate valve which opens to admit gypsum slurry to each machine in turn. The system was having difficulty producing dry enough centrifuge cake. Inspection of cake samples indicated that the innermost layer of cake had a higher fraction of fines than the rest of the cake. It was hypothesized that this high fines layer was preventing optimal dewatering of the cake as well as optimal washing for chlorides removal. It was suspected that, at the end of the feed step as the feed valve slowly closed and feed line velocities fell, larger sized gypsum particles settled out in the feed line, resulting in a high concentration of fines being deposited on top of the cake. Quick acting drain valves were added to each feed line to divert the flow to the filtrate tank at the end of the feed step. This modification enabled the system to improve cake dryness to acceptable levels.

While the problems with the gypsum dewatering system were being resolved the FGD blowdown pretreatment system was being commissioned. System operation began on March 21, 1995.

The Unit 1 tie in outage began on April 18, and was completed on June 18, 1995. Flue gas was initially directed up the FGD bypass flue while boiler combustion was optimized. The Unit 1 FGD module began scrubbing on June 20. The module came on line smoothly with little or no incident.

With both units on line startup activity was focused on the brine concentration system. The brine concentrator began operation on July 20, 1995. Once operation of this system has been stabilized startup activities will be complete and formal demonstration testing can begin.

#### Demonstration Testing Program

The demonstration testing program for the FGD System, summarized in Table 1, is designed to characterize the performance of the S-H-U FGD process. The testing program will be conducted over a period of 36 months. The goals of the program are to demonstrate the effectiveness of the process at several operating conditions and to demonstrate the system's long term reliability and performance. Typical evaluations will include SO<sub>2</sub> reduction efficiency, power

**Table 1**  
**Milliken Project Test Plans**  
**FGD Process Testing**

Process	Variable	Variable Range	Goals
SHU	Coal Sulfur Content	1.6% to 4.0%	-95% to 98% SO <sub>2</sub> removal -95% reliability -Minimum energy consumption for base coal -Determine impact of variables on SO <sub>2</sub> removal, gypsum quality and chloride brine quality when operating with design coal -Determine impact of FGD on net plant heat rate -Confirm calcium use and formic acid makeup rate.
	Formic Acid Concentration	0, 400, 800, 1600 ppm	
	Combination of Spray Headers	various spray header combinations	
	Gas Velocity in Cocurrent Section of Absorber	18 to 22 fps	
	Limestone Grind Size	90% -170 mesh and 90% -325 mesh	

consumption, process economics, load following capability, reagent utilization, byproduct quality and additive effects.

Unit 1 will be operated continuously at the design conditions while parametric tests are performed on Unit 2 to define the performance limits of the S-H-U FGD system. Because they are nearly identical modules, Unit 1 will provide a baseline while the parametric tests are being performed as well as serving as a long-term test. The parametric tests are set up to study the effects of formic acid concentration, L/G ratio, mass transfer, coal sulfur content and flue gas velocity on scrubber performance. Although load following capability will be monitored, load will not be a controlled variable. As much as possible, load changes during the parametric testing period will be handled by Unit 1 in order to keep Unit 2 at full load. The same coal will be fed to both units simultaneously. The chloride content will not be a controlled variable. At the design bleed rate chloride level is expected to stabilize at about 40,000 ppm Cl<sup>-</sup> by weight when burning a 0.1 wt % chlorine coal. Limestone utilization will be held constant at the design level except for a few FGDPRISM Model calibration runs. Oxidation will be monitored and optimized using an experimental on-line liquid phase sulfite analyzer developed by EPRI. A list of process variables to be measured is shown as Table 2.

### Test Parameters

#### a. Coal Sulfur Content

The plant design is based on a nominal coal sulfur content of 3.2 wt %. The project will use Pittsburgh seam coal. The coal sulfur content will be varied over a range of 1.6 to 4.0 wt % using at least three different coals. Tests will be performed using the lower sulfur coal first, followed by the design coal, and conclude with a short (ca. two months) period using high sulfur coal. The high sulfur coal testing will be done on Unit 2 during a scheduled outage on Unit 1 because the equipment for dewatering and reagent preparation is not designed to handle the output of both units simultaneously using high-sulfur coal. Parametric tests will not be performed using high-sulfur coal but the process will be operated at optimum conditions based on the results of parametric tests using the design coal and FGDPRISM modeling results. The purpose of using high sulfur coal is to demonstrate the operability of the process using 4% sulfur coal, not to determine the effect of operating parameters on performance.

#### b. Formic Acid Concentration

The process design is based on 800 ppm formic acid in the scrubber slurry. Testing will be conducted at concentrations of 0, 400, 800, and 1600 ppm. Ideally, in this type of testing program, all parameters should be randomized; however, the large capacity (270,000 gal) in the scrubber sump makes it impractical to frequently increase and decrease the formic acid concentration. Therefore, the program is set up in blocks of tests in which the formic acid concentration is kept constant for long periods of time (4 to 25 days). Each block of tests will be conducted in order of increasing formic acid concentration, because it takes substantially more time to lower the concentration than to raise it.

#### c. Limestone Grind Size

The design limestone grind size is 90%-170 mesh when using formic acid and 90%-325 mesh using no formic acid. The design grind size limestone will be

**Table 2  
Process Variables to be Measured**

Sample Location †	Stream Type	Flow	Temp	SO <sub>2</sub> Content	ΔP	Formic Acid Conc.	Pressure	pH	Density	Belt Speed	CF Concentration	Level Indicator	On/Off Indicator	Moisture
Flue Gas From ID Fan to Absorber (500)	Gas	C	C	C										
Flue Gas in Chimney (511)	Gas	C		C										
Pressure Across Absorber (500) & (511)	Gas				C									
Compressed Oxidation Air to Absorber (505)	Gas		C				C							
Formic Acid to Absorber (504)	Liquid	C				P								
Recycle Scrubber Slurry (503) & (502)	Slurry					D	C	C						
Limestone Slurry From Slurry Tank (506)	Slurry						C		C					
Total Process Water to System (514)	Liquid	C					C							
Gypsum Slurry to Dewatering (600)	Slurry								C					
Limestone Feed Belt (400)	Solid									C				
Clarified Water to Mills (402)	Liquid	C					C							
Gypsum From Vacuum Filter to Storage (604)	Solid									C			C	C
Clarified Water to Blowdown Treatment (700)	Liquid	C									D			
Filter Cake Wash Water (601)	Liquid	C	C				C							
All Process Tanks	Liquid											C		
Mist Eliminator	Gas				C									

C = Continuous Monitoring    D = Daily Analyses    P = Periodic

used for all but a few test runs which will be done to observe the effects of grind size on performance.

d. Spray Header Combination-L/G Ratio

There are four cocurrent spray headers and three countercurrent spray headers in each SHU module. The spray headers operate in an on/off mode, i.e., there is no flow control on the headers. The scrubber L/G ratio is varied by changing the number of spray headers in operation. The process design calls for operation of five spray headers to achieve 95% SO<sub>2</sub> removal and all seven headers to achieve >98% SO<sub>2</sub> removal. At least two of the seven headers should be operating at all times. In addition, at least one of the top two headers on the cocurrent side must be operating at all times in order to protect vessel internals from over temperature. Thus, the possible combinations of operating spray headers are as shown in table 3. Parametric testing will include operating various combinations of spray headers in the cocurrent and countercurrent sections to determine the combination that provides the best SO<sub>2</sub> removal performance and lowest scrubber energy consumption. For each combination, the uppermost headers will be used. For each test coal, the pressure drop and SO<sub>2</sub> removal will be measured for each spray header combination used. The gypsum crystal morphology and formic acid consumption rate will be determined for selected spray header combinations using the design coal only.

The results of these tests will also be used to determine the mass transfer coefficients individually for the cocurrent and countercurrent sections. The results from tests with all countercurrent sprays turned off will be used to determine the mass transfer in the cocurrent section. The mass transfer in the countercurrent section will be determined by comparing these results with results from tests in which countercurrent sprays are operating.

e. Gas Velocity in the Cocurrent Scrubber Section

The design gas velocity in the cocurrent scrubber section is 18 ft/sec. Tests at higher velocity will be performed on the Unit 2 scrubber by shunting some of the gas flow from Unit 1 to the Unit 2 scrubber. The purpose is to provide data on high gas velocity scrubbers. These tests will be performed using two formic acid concentrations (0 and 800 ppm) and two coals (lower sulfur coal and the design coal). The pressure drop and SO<sub>2</sub> removal will be measured for several spray header combinations. The gypsum crystal morphology and formic acid consumption rate will be determined for selected spray header combinations while using the design coal.

Test Description

a. Tests Using Design Gas Velocity-Lower Sulfur Coal

All of the possible spray header combinations will be used for the tests using design gas velocity, design limestone grind size, and lower sulfur coal. Each test will be repeated, giving 28 tests total at each formic acid concentration. These tests will be run in random order at constant formic acid concentration. In addition, two tests will be run at each formic acid concentration using an alternative grind size. The effect of grind size will be determined by comparing the results of these tests with the results of tests using the design grind size at the same header configuration and formic acid concentration.

**Table 3**  
**Possible Spray Header Combinations**

No. of Cocurrent Headers in Operation	No. of Countercurrent Headers in Operation
4	3
4	2
4	1
4	0
3	3
3	2
3	1
3	0
2	3
2	2
2	1
2	0
1	3
1	2

Each test is scheduled for eight hours. Pressure drop and SO<sub>2</sub> removals will be measured after SO<sub>2</sub> levels have lined out. If eight hours are not sufficient for line-out, the schedule will be adjusted by eliminating some repeat runs or some of the lower L/G runs. Gypsum crystal morphology will not be characterized in this series of tests.

b. Tests using High Gas Velocity-Lower Sulfur Coal.

These tests will be performed using no formic acid and the design formic acid concentration (800 ppm). A minimum of five total spray headers will be in operation at all times. Five of the tests will be repeated, giving thirteen tests total. The tests will be run in random order using the design limestone grind size. SO<sub>2</sub> removal will be measured. Alternative grind sizes will not be tested. Gypsum crystal morphology will not be characterized.

c. Tests Using Design Gas Velocity-Design Sulfur Coal

Fewer spray header combinations will be tested using the design coal because it is not a compliance coal. Since low L/G ratios might not remove enough SO<sub>2</sub> to keep the station in compliance, at least four spray headers will be operating at all times. If SO<sub>2</sub> removal drops to unacceptably low levels during a test, that test will be terminated and compliance performance will be re-established before proceeding to the next test.

Measurements and sampling during each test will include SO<sub>2</sub> removal, pressure drop, gypsum crystal morphology (particle size distribution, sulfate/sulfite ratio, and SEM micrographs), gypsum samples for wallboard evaluation, calcium and sulfur balances, formate consumption rate, and O<sub>2</sub> consumption for oxidation. Sampling will begin after 10 turnovers (4 days) have passed to insure solid phase lineout.

The larger (-170 mesh) grind-size limestone will not be tested without formic acid because of the danger of not reaching sufficient SO<sub>2</sub> removal for compliance. The limestone grind size is not something that can be changed quickly if higher SO<sub>2</sub> removal is needed. The -170 mesh grind size is the design size when formic acid is used. The alternate (-325 mesh) grind size will be used for one test at each formic acid concentration.

Data for FGD system performance guarantee verification will also be collected during this period.

d. Tests Using High Gas Velocity-Design Sulfur Coal

The same tests that were run using the low-sulfur coal at high gas velocity will be run using the design coal. If SO<sub>2</sub> removal drops to an unacceptable level during a test, that test will be terminated and compliance performance will be re-established before proceeding to the next test. Alternative grind sizes will not be tested. SO<sub>2</sub> removal will be measured. Gypsum crystal morphology will not be characterized.

In addition to the above program, a short series of tests will be conducted in which the process pH will be varied from 4.5 to 5.5; these tests will be performed to calibrate the FGDPRISM model. The process operating conditions for these calibration tests will be set by EPRI after the model is programmed. These tests will be performed with no formic acid after completion of the test block using design gas velocity, lower sulfur coal and no formic acid.

The testing program is scheduled to begin this summer. By this time next year results of the lower and design sulfur coal testing should be available for review.

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3. H.K.Petzel, Development and Operating Experiences of the S-H-U FGD Process at the Volklingen Power Station, 1991 SO2 Control Symposium, Washington, D.C., December, 1991.
4. New York State Electric & Gas Corporation, Environmental Monitoring/Test Plan, Milliken Clean Coal Technology Demonstration Project, December, 1994.



**SELF SCRUBBING COAL - A PROGRESS UPDATE**

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## INTRODUCTION

On October 29, 1992, a Cooperative Agreement was executed by the United States Department of Energy (DOE) and Custom Coals International (CCI). This agreement provides for the design, construction and operation of a coal preparation facility to produce Carefree Coal and Self-Scrubbing Coal, two fuels that will provide many United States utilities the opportunity to achieve compliance with the 1990 Clean Air Act Amendments (CAAA) without incurring major expenditures for power plant modifications.

Carefree Coal is coal cleaned in a proprietary dense-media cyclone circuit, using ultrafine magnetite slurries, to remove noncombustible material, including up to 90% of the pyritic sulfur. Deep cleaning alone, however, cannot produce a compliance fuel from coals with high organic sulfur contents. In these cases, Self-Scrubbing Coal will be produced. Self-Scrubbing Coal is produced in the same manner as Carefree Coal except that the finest fraction of product from the cleaning circuit is mixed with limestone-based additives and pelletized. The reduced ash content of the deeply-cleaned coal will permit the addition of relatively large amounts of sorbent without exceeding boiler ash specifications or overloading electrostatic precipitators. This additive reacts with sulfur dioxide (SO<sub>2</sub>) during combustion of the coal to remove most of the remaining sulfur. Overall sulfur reductions in the range of 80-90% are achieved.

After nearly 5 years of research and development of a proprietary coal cleaning technology coupled with pilot-scale validation studies of this technology and pilot-scale combustion testing of Self-Scrubbing Coal, CCI organized a team of experts to prepare a proposal in response to DOE's Round IV Program Opportunity Notice for its Clean Coal Technology Program under Public Law 101-121 and Public Law 101-512. The main objective of the demonstration project is the production of a coal fuel that will result in up to 90% reduction in sulfur emissions from coal-fired boilers at a cost competitive advantage over other technologies designed to accomplish the same sulfur emissions and over naturally occurring low sulfur coals.

## PROJECT DESCRIPTION

The Demonstration Project, called the Laurel Facility, consists of a 500 TPH, state-of-the-art, coal preparation plant and various product and raw coal handling and storage facilities. After design and construction of the facilities are completed, the Operations Budget Period calls for demonstration of the advanced coal cleaning cyclone and various ancillary magnetite recovery schemes as well as the demonstration of combustion of the Carefree Coal™ and Self-Scrubbing Coal™ at full size power plant boilers.

### Goals

CCI's goal for the project is to successfully commercialize its first plant and use that success to build a merchant coal preparation business. DOE's goal is to ensure the long term availability of a low cost, environmentally friendly fuel for our nation's long term energy supply.

### Participants

The Project Team assembled to carry out the demonstration project includes:

- DOE's Project Management Team from PETC
- Custom Coals International (CCI), overall project manager and lessee of patents for the technology to be demonstrated.
- Affiliated Engineering Technologies, Inc., design contractor
- Riggs Industries Construction Managers
- Richmond Power & Light, utility host site for Self-Scrubbing Coal test burn using Illinois #5 coal

- Centerior Energy, utility host site for Self-Scrubbing Coal test burn using Lower Freeport coal
- Pennsylvania Power and Light, utility host site for Carefree Coal test burn using Lower Kittanning coal

Cost

As approved, the final Continuation Application calls for a total project cost of \$87,386,102. DOE is providing \$37,994,437, 43.5% of the funds. Costs expended to date, May 31, 1995, are as follows:

<u>Item</u>	<u>Provided by DOE</u>	<u>Provided by CCI</u>
Design Engineering Activities	\$1,770,453	\$1,958,308
Site Acquisition	2,833,020	2,833,020
Equipment and Material	7,621,238	7,621,238
Construction	6,952,336	6,952,336
Operations	1,392,570	1,407,630
Project Management	1,957,988	2,564,205

Schedule

This demonstration project has been planned for a forty-six (46) month schedule. It is being accomplished in four phases and in three budget periods. Budget Period I encompassed the Project Definition Phase and was planned for a six month duration. Approval was received to extend this period for six months. Budget Period II included a Design Phase and a Construction Phase. The Design Phase is scheduled for a six month duration and the Construction Phase will be 18 months long. Budget Period III includes the 16 month long Operations Phase. Figure 1 shows the overall schedule and the individual Work Breakdown Structure (WBS) subtask durations planned for this project.

As of June 30, 1995, the project was in its thirty-second month. Design activities began in month eleven and construction activities began in month 15. The first ten months of the project were used to perform the flowsheet finalization and equipment signing activities as well as to assemble all of the information required under the National Environmental Policy Act (NEPA).

Construction activities and plant start up should be complete in October of 1995. The first power plant test is planned for late 1995 and both other power plant demonstrations are planned for the first six months of 1996.

## **TECHNOLOGY DESCRIPTION**

The advanced technology specifically being demonstrated by CCI has, at its heart, a newly designed heavy media cyclone (HMC). This HMC has been specifically designed to clean much finer sizes of coal than any currently commercially available device that uses particle separation techniques based on specific gravity differences of the particles. The cyclone is only part, however, of an integrated flowsheet that is required to provide many other ancillary operations in support of the separation.

Figure 2 presents a block flow diagram of the entire process. The raw coal is first sized into an intermediate size fraction (1.5 in x 0.5 mm), a fine size fraction (0.5 mm x 0.105 mm) and an ultrafine size fraction (0.105 mm x 15 microns) with each of the fractions being processed in separate heavy-media cyclone coal cleaning circuits. The coarse and intermediate cleaning circuits will be two-stage, with the capability of producing a low-gravity clean coal, a high-gravity refuse, and an intermediate-gravity middlings fraction. This middlings fraction contains coal particles with pyrite and other mineral matter locked in the coal matrix. In the coarse coal circuit, the middlings fraction will be crushed to a finer size to liberate the sulfur-bearing mineral matter from the coal matrix. The crushed coal along with the natural fines will then be processed in either the fine or ultrafine advanced coal cleaning circuits to separate clean coal from refuse.

The effect of the cleaning process is to maximize clean coal recovery while simultaneously maximizing pyritic sulfur and ash rejection. If the composite clean coal can meet overall SO<sub>2</sub> compliance levels, then the product is ready for shipment as Carefree Coal. If the sulfur content of the composite clean coal is too high (primarily due to the organic sulfur content), then, before being blended with the other fractions, the ultrafine clean coal fraction is agglomerated with enough sorbent to enable the clean coal to meet compliance levels. If this option is taken, then the coal product is called Self-Scrubbing Coal. The reduced ash content of the clean coal allows the addition of relatively large amounts of sorbent without exceeding the ash specifications of the boiler or overloading the electrostatic precipitator (ESP).

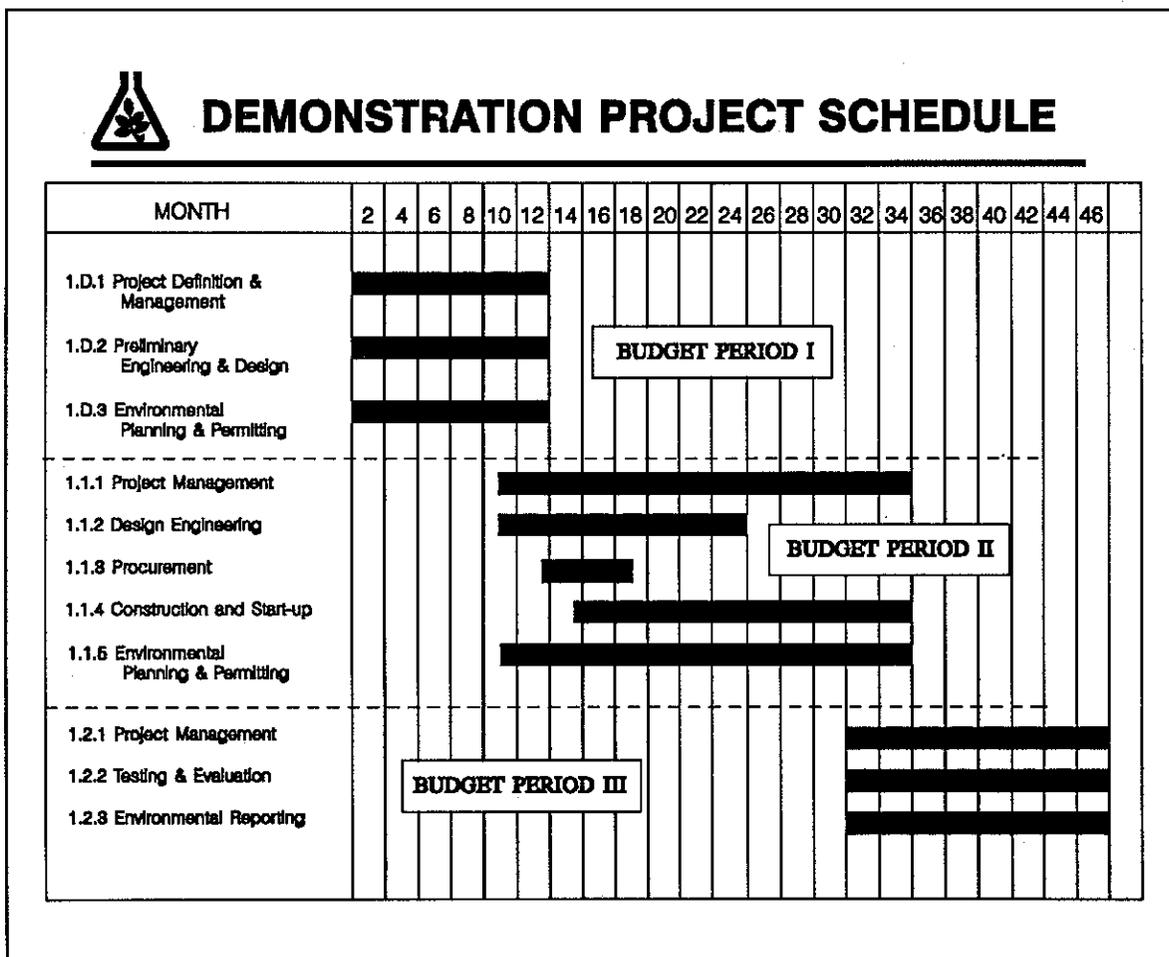


Figure 1 Project WBS and Schedule

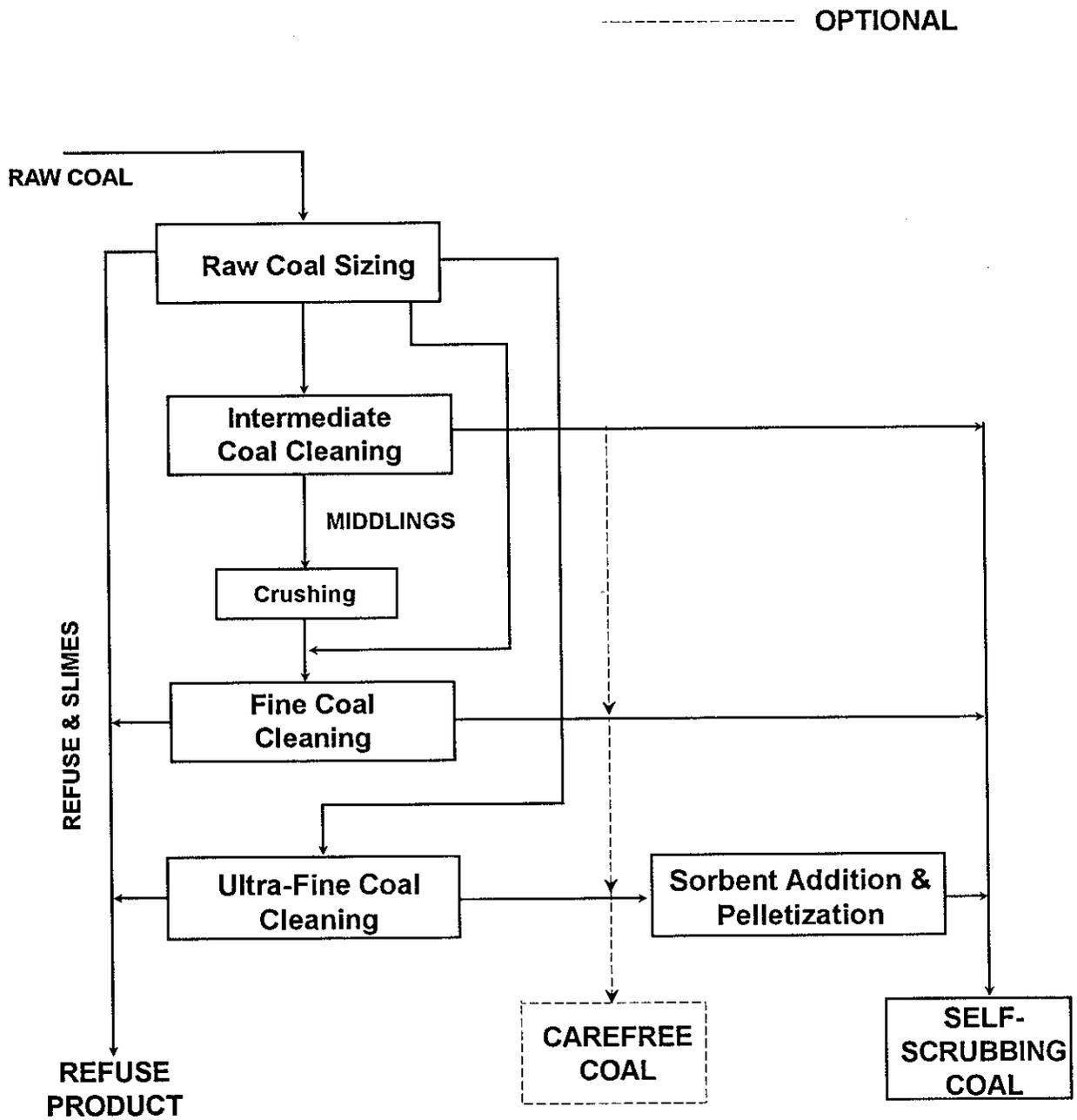


Figure 2. Schematic Diagram for the Technology

The processes utilized in the plant represent a combination of conventional and advanced circuits. The coal handling systems, the coarse coal cleaning circuits and the fine coal cleaning circuit are all conventional. The ultrafine cleaning circuit and the associated drying and briquetting system are advanced processes. The technology risk inherent in these advanced circuits has been addressed in two ways: (1) avoiding any scale-up from pilot plant operations and (2) isolating the advanced circuitry so that its failure would have no impact on the remainder of the plant.

The site can receive up to 40 trucks of raw coal per hour, or approximately one truck every ninety seconds. Raw coal will be weighed and sampled before being dumped into one of four 60-ton capacity raw coal bins from which it will be conveyed to stacking tubes. Each bin will have its own vibrating feeder, and each pair of bins feeds a separate stacking tube, permitting two distinct raw coal feedstocks to be received and stockpiled at the same time. Coal will be reclaimed to the preparation plant at the rate of 500 tons per hour. A reinforced concrete reclaim tunnel with a total of ten draw-down hoppers and ten vibrating feeders will permit the plant to be fed by a minimum of two feeders or by any desired combination of feeders. The feeders will be equipped with variable frequency controllers to permit the rate of discharge to be controlled by the plant operator. This provides substantial flexibility in blending raw coals as they enter the preparation plant.

The Laurel plant employs a three product separation as the starting point for producing Carefree Coal. The first separation at a low gravity floats the nearly pure coal and sinks all other particles. The second separation at a high gravity floats the middling particles and sinks the pyrite and refuse. The clean coal and refuse separated during this two step process are removed from the circuit and only the middling particles are passed along for further processing. The middling particles are crushed, in closed circuit, to pass ½mm and then cleaned in two size fractions. The 16M x 150M size fraction is cleaned first in spiral separators, with a middling product from the spirals recleaned by advanced heavy media cyclones. The 150M x 500M material is cleaned in advanced heavy media cyclones.

Dewatering is accomplished by centrifuges for the coarse and intermediate size fractions. The finest coal is thermally dried and can be discharged to the clean coal conveyor or go instead to a briquetting process. The briquetting machine (compactor) uses very high pressures to form the fine clean coal into stable briquettes measuring 2" x 1" x ¾".

The Laurel facility also includes state-of-the-art clean coal handling and sampling capabilities. A two-stage sampling system and an on-line elemental analyzer monitor have been furnished to provide both a reference sample for laboratory analysis and an on-line record of the quality of clean coal being generated by the cleaning plant. The immediate availability of product quality information afforded by the analyzer allows the plant operator to make real-time adjustments in the processing circuits to maintain product quality within established limits.

Clean coal can be directed into either of two 5,000-ton clean coal silos leading to the railcar loadout facility or to the 5,000-ton silo that is part of the truck loadout facility. The railcar loading facilities have a rated capacity of 2500 tons per hour and a flood loading unit train loading bin. The automated truck loadout facility is capable of loading trucks at a rate of 750 tons per hour.

The clean coal product shipped from the plant will meet the 1990 Clean Air Act Amendments year 2000 SO<sub>2</sub> emission standard of 1.2 lbs SO<sub>2</sub>/MMBtu. It will have a heating value of 13,200 Btus/lb with 9 percent ash, 6 percent moisture and 17 to 18 percent volatiles. The size distribution of the clean coal product would be as follows:

1½ inches x ¼ inch	30.2%
¼ inch x 100 M	62.2%
100M x 150 M	7.6%
-150M	0.0%

## TEST PLAN

The demonstration phase of the program will include the generation of Carefree and Self-Scrubbing coals at the coal preparation facility and test burns of those coals at three utility host

sites. Figure 3 shows the various locations and raw coal sources for the planned test burns. Carefree Coal will be tested at Pennsylvania Power and Light Company's Martins Creek plant in eastern Pennsylvania, and will use Lower Kittanning seam coal from Somerset County, Pennsylvania.

Two test burns of Self-Scrubbing Coal will take place. Centerior Service Company's Astabula C unit will burn the Self-Scrubbing coal produced from raw Lower Freeport seam coal in Belmont County, Ohio. The Whitewater Valley Unit 2, owned by Richmond Power & Light, will burn a Self-Scrubbing product produced from an Illinois #5 seam coal mined in Wabash County, Illinois.

### **Goals and Objectives of the Cleaning Plant Test Program**

The cleaning plant demonstration test program has several specific goals and objectives:

- Conduct performance testing to assure optimization of the various circuits throughout the demonstration plant.
- Demonstrate the Carefree and Self-Scrubbing coal technology for producing compliance coal. This will be the first demonstration of the integrated circuitry required to produce Carefree and Self-Scrubbing coal.
- Produce quantities of Carefree and Self-Scrubbing coals for combustion test burns at selected utility power stations.

### **Strategies**

To achieve the goals of the cleaning plant demonstration test program, engineers and technicians will follow all ASTM quality control and quality assurance procedures including those for sample collection, sample tracking, laboratory analysis, data collection, and data reduction. Each phase of testing will be carefully coordinated with plant operation and maintenance personnel.

## **Testing Equipment and Procedures**

In order to determine quantity and quality of coal produced in individual circuits and by the entire plant, samples of feed and product streams must be collected. In addition, flow rates and densities for various streams must be obtained either mechanically or manually. Also, where appropriate the weight of various streams will be determined by belt scale or weighfeeder. Cyclone feed pressures must also be measured and reagents controlled in thickening and dewatering devices.

**Sample Collection and Analysis.** Samples must be reduced and analyzed for appropriate parameters using ASTM procedures. Appropriate sample collection devices will be obtained for each sample point so that the samples will all be collected in a safe manner and will be representative of the entire stream being sampled. Samples will be composited in 55-gal drums (plastic drums or steel drums with liners) and will be sealed to avoid contamination and moisture loss prior to analysis.

Sampling points are found throughout the cleaning plant. Actual locations of access doors for bulk sample collection and valves for slurry sample collection will be determined during plant start-up. Many samples represent parallel flow streams in the plant. For example, there are four drain and rinse screens for the overflow from the first stage coarse coal dense-media cyclones. The sample from this stream will be collected by rotating sample cuts between screen discharges.

### **Performance Testing of the Cleaning Plant**

Performance tests will be conducted using the plant design settings established for the startup coal. The performance test will be conducted in a six-hour period during normal operating shifts. The plant feed rate during this test will be maintained at the rated 500 TPH tonnage for the plant, and operating parameters will be held constant at the plant design values.

Custom Coals International will provide supervisors and sampling personnel for the testing program.

**Sample Procedures.** The following procedures will be followed for performance test sampling:

- The feed rate will be maintained at near 500 tph and recorded every 30 minutes.
- Any scheduled or unscheduled shutdown will be followed by at least 15 minutes of normal resumed operation prior to the resumption of sampling.
- The specific gravities in the dense-media circuits will be maintained constant, checked using an approved scale, and the results recorded every 15 minutes.
- Any samples that are to be analyzed for magnetite will be collected and stored using non-ferrous (generally plastic) devices and containers.
- Samples that are to be tested for moisture will be stored in airtight containers.
- When testing for screen analysis, the samples will be screened on square hole screens for 3/8-in. and larger size fractions; Tyler-mesh square openings will be used for all minus 3/8-in. size fractions, which will be wet screened.
- Sample increment weights will be dependent on the top size of the material being sampled. All material over 32 mesh will have a minimum increment weight of ten pounds, and all material under 32 mesh will have a minimum increment weight of one pound.
- A minimum of 40 increments will be taken for each sample, at approximately 9 minute intervals unless noted otherwise.
- A split of each sample will be maintained by the coal testing laboratory in case a recheck of an analysis is required.

## **Goals and Objectives of the Combustion Test Program**

The primary objective of the Combustion Test Program is to demonstrate that the Carefree and Self-Scrubbing coals generated by Custom Coals International's advanced coal cleaning technology can meet the SO<sub>2</sub> reduction requirements set forth in the 1990 Clean Air Act Amendment. This will be accomplished by performing full-scale combustion test burns at three coal-fired utility power plants.

Once the selection of the appropriate sorbent is made, full-scale testing in utility boiler will be performed. In general, the combustion testing of coals in a full-scale, commercial boiler is necessary, even if combustion testing at the pilot scale is performed, because some aspects of combustion--such as gas turbulence and heat release rate--are extremely difficult to scale.

Utilities considering the purchase of Self-Scrubbing coal will likely perform their own test burns as well, but utility test burns are rarely performed to the level of detail that is suggested here. If adverse performance under less well monitored conditions occurs, well documented, successful test burns will be crucial to addressing utility concerns. Therefore, during the full-scale test combustion program, the project team has the following objectives:

- Demonstrate the use of Carefree and Self-Scrubbing coals in three units of different design and capacity without incurring significant derates.
- Demonstrate the ability of each unit to achieve Clean Air Act 1990 amendment compliance using Self-Scrubbing or Carefree coal.
- Generate technical data that will support the commercialization of Self-Scrubbing and Carefree coals.

## Strategies

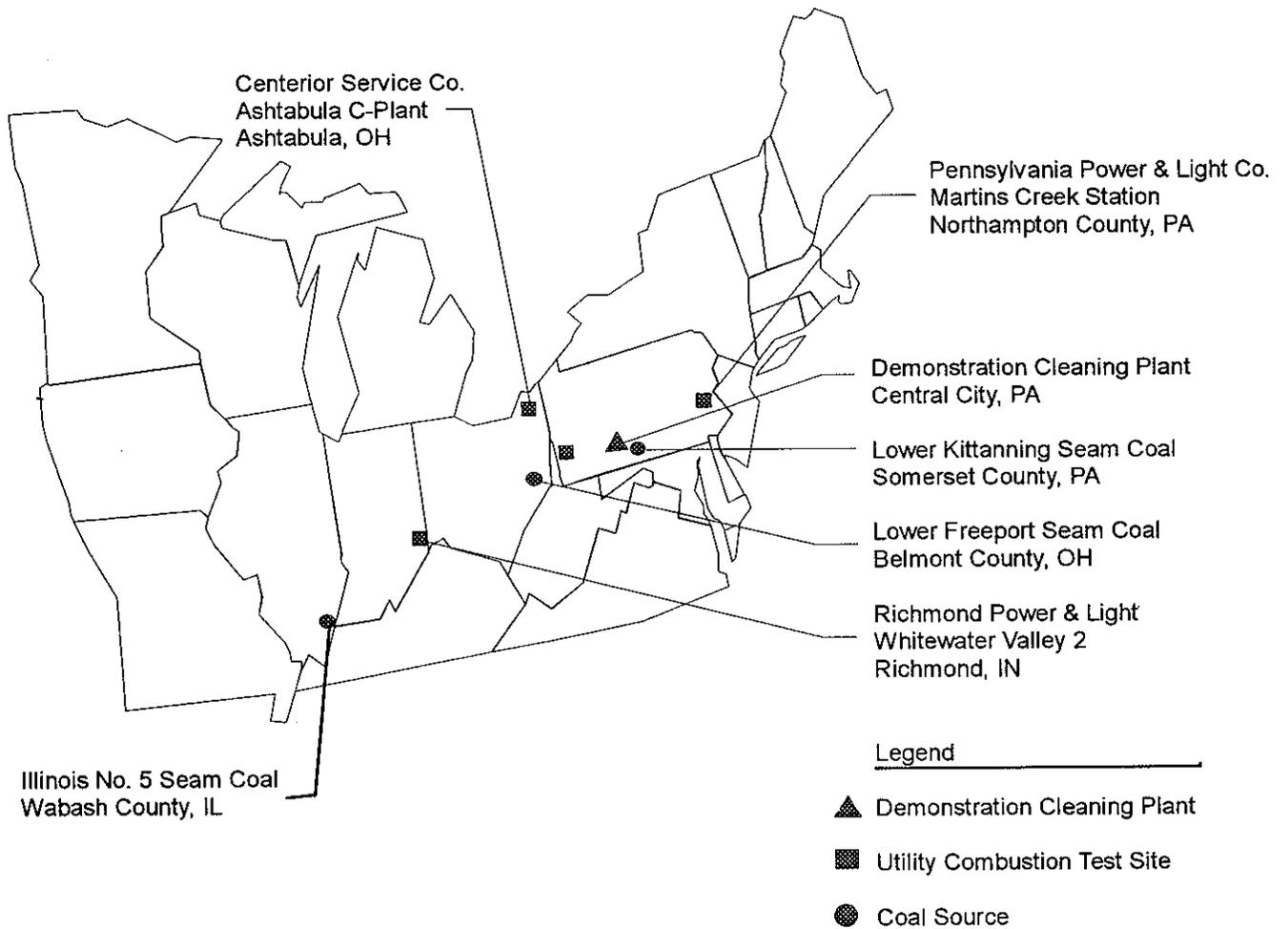
To achieve the goals and objectives of the combustion test program, the project team will follow the procedures outlined in detailed test plans for the full-scale combustion test sites, including those for sample collection, test measurements, data collection, and data reduction.

Testing at full scale will characterize how potential users of Carefree or Self-Scrubbing coal can expect those coals to behave in their boilers. Because of the differences between pilot-scale boilers and full-scale boilers, there is a limit to how well a pilot-scale test, no matter how well conducted, can predict the performance of a full-scale boiler. Therefore, to completely answer the questions that a potential user of Carefree or Self-Scrubbing coal may have, the demonstration test program contains three full-scale test burns in utility boilers. The three sites are also shown in Figure 3.

**Test Protocol.** The full-scale combustion tests will consist of an initial baseline test, under which the performance of the unit will be monitored to establish current operating conditions and to correct any conditions that may adversely affect the performance of the unit while burning Carefree or Self-Scrubbing coals. The Carefree or Self-Scrubbing coal will then be burned, and the performance of the unit monitored, according to the approved Test Plan.

Global concerns about sulfur emissions, coupled with the advanced age of many coal-fired boilers and the growing need for enhanced electrical power, suggest that CCI's proprietary coal processing technologies represent a superior approach to long-term emission compliance in domestic and international markets. CCI sees itself as a coal refiner . . . not involved in the mining or burning of coal . . . but exclusively engaged in projects that create environmentally superior coal based products.

Projects will take the form of merchant coal preparation plants producing compliance coals for steam coal power plants and other value-added products. The projects will be build-own-operate transactions. Usually a consortium will be assembled for each project which includes the required disciplines from within CCI as well as whatever outside skills required.



**Figure 3. Demonstration Test Sites and Coals**

## COMMERCIALIZATION

While acid rain, sulfur emissions, clean air, nuclear power, hydroelectric power, and a host of energy related issues are frequently mentioned in the news, a simple fact remains: there are 1,400 coal-fired boilers in the United States which provide 57 percent of domestic electric power. Roughly 200 of these boilers are equipped with scrubbers and are not candidates for either of our proprietary coal products, Carefree Coal™ or Self-Scrubbing Coal™. Of the remaining 1,200 boilers, half are fully depreciated and their owners are not prepared to spend tens of millions of dollars for the installation of scrubbers. These are our customers. They need to be brought into compliance with the Clean Air Act by burning the Company's low sulfur coal. By applying the Company's proprietary technologies to raw coal available near the power plants, low sulfur coal can be "created" at a cost which is substantially less than scrubbers and very competitive with the delivered cost of low sulfur coal from distant coal fields. By applying state-of-the-art technology to a local resource, the local economy benefits, creating goodwill and a positive political atmosphere.

The flagship of the Company's U.S. operations will be the Laurel coal preparation plant. Laurel will serve two primary objectives. First, it will launch the commercial application of the Company's coal cleaning technology by producing over 2 million tons of clean coal annually. Second, it will provide a marketing showcase with its capacity for producing railcar test shipments of cleaned coals for potential customers.

While the Laurel facility will be used to support numerous marketing objectives, the project has been designed to be a profitable commercial operation. The cost for producing compliance coal is expected to be under \$30.00 per ton FOB Laurel including both the cost of raw coal and plant operating costs. The expected selling price is \$32 to \$35 per ton FOB Laurel. Projected gross revenues from the Laurel plant approximate \$64 million annually. As the more stringent standards of the Clean Air Act Amendments of 1990 become effective in 2000, price differentials paid for low sulfur coal are expected to improve.

In November 1993, the Company purchased the Dilltown Coal Preparation Plant, in Indiana County, Pennsylvania, from Pennsylvania Power & Light (PP&L). This 750 ton per hour plant was purchased at a favorable price in return for giving PP&L the right to first refusal on a portion of the clean coal produced there. Plans are underway for the upgrade of the Dilltown facility to enable it to produce the same clean coal products made at Laurel. Design, engineering and construction are expected to begin as soon as the start up of the Laurel facility is complete. Upon retrofit completion, Dilltown will produce 3 million tons per year of compliance coal with production costs and selling price similar to Laurel. Revenues from the Dilltown plant will approximate \$100 million annually.

While the Laurel plant is CCI's flagship facility, the Dilltown plant is the prototype facility for the roll out of its U.S. marketing strategy. There are 450 conventional coal cleaning plants operating in the United States, many of which can be converted to utilize our advanced coal cleaning technology. Where coal cleaning operations are owned and operated in connection with mines producing noncompliance coal there exists a niche for the technology. As the noncompliance coal becomes "unsalable" because it cannot be made clean enough using conventional techniques, CCI would propose to acquire ownership of the plants in exchange for long term contracts to purchase raw coal. Thereafter, the Company would convert the plants to production of Carefree Coal and Self-Scrubbing Coal.

A substantial opportunity exists for the purchase or construction of additional plants in the Pennsylvania market. The coal fired power plants in Pennsylvania that have not been outfitted with scrubbers burn in excess of 30 million tons of coal per year. Without exception, they are all interested in the potential for purchasing low sulfur, high Btu coal from within the state. Competitively priced, clean coal produced within Pennsylvania could also find acceptance in power plants in New York and New England. Two to three facilities are anticipated to be constructed in Pennsylvania prior to the year 2000. These projects will follow the model of Laurel and Dilltown where existing cleaning plant sites are acquired and upgraded. The total production capacity from projects in Pennsylvania is expected to be from 10 to 12 million tons per year by the year 2000.

The closing of high sulfur coal fields in Ohio, Indiana, and Illinois is the key to expanding into the high sulfur coal cleaning markets. The Company's second stage technology is referred to as Self-Scrubbing Coal. This proprietary process enables cleaning and burning of coal characteristically high in organic sulfur. Self-Scrubbing Coal is produced by adding limestone "capture agents" to already deep cleaned Carefree Coal. During combustion, gaseous sulfur is liberated and absorbed. The additional sulfur captured in the boiler permits coals containing up to two percent organic sulfur to be brought within the year 2000 emissions limits. During 1996 Laurel will ship test runs of Self-Scrubbing Coal made from two distinct coal regions. These test shipments will be burned at power plants in Ohio and Indiana. Once quantifiable test burn data is available, CCI will begin actively pursuing projects in the Ohio and Illinois coal basins.

An additional opportunity is expected to arise as the deregulation of the electric utility industry continues. As competition among power stations becomes a reality, a market will exist for low cost generating capacity that can be marketed directly to power customers over existing transmission and distribution networks. By teaming with power plant construction companies, operating entities, and power marketers, the Company will be positioned to participate in the power generation market as an advanced fuel supplier.

The Company's coal products provide an excellent match to market needs in Poland. The majority of Poland's 125 million metric tons of coal mined yearly is shipped unwashed to power plants. However, Polish law establishes sulfur emission limits beginning in 1998. Clearly, Poland's unwashed coal will not be in compliance. While there is much discussion of flue gas scrubbers, there is simply no capital available to fund them.

It is now well established that removing most of the ash from coal will save enough in transportation and operating costs to substantially pay for the coal cleaning. This realization has been well received by Polish power stations. In consequence, letters of intent have now been signed with three plants for purchase of 7.5 million tons of clean coal annually.

The project structure anticipated in Poland is for the Company to build, own and operate cleaning plants on independent sites near raw coal fields. Power plant customers will purchase processing services from Company-owned facilities. Raw coal purchased by the power plants will be

delivered to the Company's processing plant for cleaning and then shipped to the power plant. This model has been chosen to minimize risk given inconsistent performance by state operated coal mines.

Plans are proceeding to formalize contracts with these power plants to purchase cleaned coal. These obligations, together with a parallel commitment from the Polish power grid, will be the foundation for financing the facilities. In 1996, the Company expects to move forward with site selection, plant design, cost estimating, and financing in Poland for a first facility. The Company projects an eventual market of 10 to 14 million tons per year. While revenues from processing contracts are substantially less than for clean coal sales, the profits are expected to approximate \$20 million annually when the market is fully developed.

China represents a huge and fast growing clean coal market. China is the single largest producer and consumer of coal (1.2 billion tons per year). Coupled with an economy which averaged eight percent annual growth in recent years and an increased environmental consciousness, China's appetite for electric power and hence clean coal is immense. For that reason, Custom Coals China Limited, a British Virgin Islands Limited Company, was incorporated in January 1994 and is currently a wholly owned subsidiary of CCI's parent. Custom Coals China Limited is in the business of developing joint venture projects in the People's Republic of China in which an equity interest, technology royalties and management authority will be retained by Custom Coals China Limited, while its partners and outside contractors will be responsible for the detailed design, construction and operation of those projects. Custom Coals China Limited's principal asset at this time is a 47 percent (600,000 shares) ownership interest in Pipeline Holdings Ltd., the managing partner of China Coal Pipeline Company, Ltd. (the "Pipeline Venture"). The ownership structure is illustrated in Figure 4.

**The Company**  
*(Custom Coals China Ltd.)*

47% Ownership  
Interest



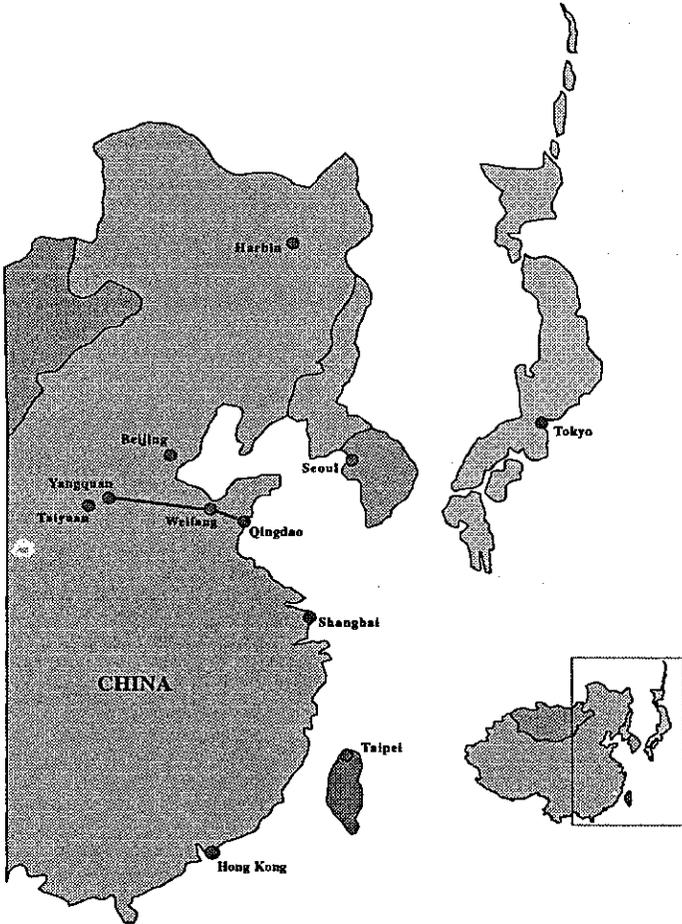
**Pipeline Holdings**  
*(China Pipeline Holdings Ltd.)*

51% Ownership  
Interest

70% Profit Share in the  
1<sup>st</sup> 20 Years of the Project



**The Pipeline Venture**  
*(China Coal Pipeline Company, Ltd.)*



**Figure 5. China Pipeline Site Location**

The Pipeline Venture's first project is called the Yu-Wei Pipeline Project, an integrated clean coal slurry pipeline that will link the coal mines of Eastern ShanXi Province, near Shouyang, to Chinese and world markets through the port of Qingdao in Shandong Province. (See Figure 5) Based on design decisions still to be made, the pipeline will transport between 5 and 15 million tons per year of cleaned coal 600 to 800 kilometers. China Pipeline Holdings Ltd. (CPHL) and its partners will utilize coal cleaning technology developed by Genesis to wash the coal before transporting as a slurry to Weifang and Qingdao, in Shandong Province. Assuming the 15 million ton per year design, CPHL is projecting its share of the annual income over the first five years of operation at \$127.3 million, of which Custom Coals China Limited's share would be \$42 million.



## THE NOXSO CLEAN COAL PROJECT

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### ABSTRACT

The NOXSO Clean Coal Project will consist of designing, constructing, and operating a commercial-scale flue gas cleanup system utilizing the NOXSO process. The process is a waste-free, dry, post-combustion flue gas treatment technology which uses a regenerable sorbent to simultaneously adsorb sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>) from flue gas from coal-fired boilers. The NOXSO plant will be constructed at Alcoa Generating Corporation's (AGC) Warrick Power Plant near Evansville, Indiana and treat all the flue gas from the 150-MW Unit 2 boiler. The NOXSO plant is being designed to remove 98% of the SO<sub>2</sub> and 75% of the NO<sub>x</sub> when the boiler is fired with 3.4 weight percent sulfur, southern-Indiana coal. The project by-product will be liquid SO<sub>2</sub>.

The \$82.8 million project is co-funded by the U.S. Department of Energy (DOE) under Round III of the Clean Coal Technology program. The DOE manages the project through the Pittsburgh Energy Technology Center (PETC).

## INTRODUCTION

The NOXSO process is a waste-free, dry, post-combustion flue gas cleanup technology which uses a regenerable sorbent to simultaneously adsorb  $\text{SO}_2$  and  $\text{NO}_x$  from flue gas from coal-fired utility and industrial boilers. In the process, the  $\text{SO}_2$  is converted to a saleable sulfur by-product (liquid  $\text{SO}_2$ , elemental sulfur, or sulfuric acid) and the  $\text{NO}_x$  is converted to nitrogen and oxygen. Since  $\text{SO}_2$  and  $\text{NO}_x$  removal occur at normal flue gas temperatures (downstream of the combustion air preheater), the NOXSO process is equally suited for retrofit as well as new installations.

Process development began in 1979 with laboratory-scale tests and progressed to pre-pilot-scale tests (3/4-MW) and a life-cycle test. Each of these test programs [1,2,3] has provided data necessary for the process design. Tests of the  $\text{NO}_x$  recycle concept, which is inherent to the NOXSO process, have been conducted on small boilers at PETC and at the Babcock & Wilcox (B&W) Research Center in Alliance, Ohio [4].

A 5-MW Proof-of-Concept (POC) pilot-plant test at Ohio Edison's Toronto Plant in Toronto, Ohio, was completed in 1993 [5]. Based on more than 7,000 hours of operation with flue gas, it was demonstrated the process can economically remove more than 95% of the acid rain precursor gases from the flue gas stream.

The NOXSO Clean Coal Project is the final step in commercialization of the technology. The project was selected during Round III of the DOE Clean Coal Technology Program and is managed through PETC. NOXSO Corporation is the project participant, project manager and technology supplier. The project will be hosted by AGC at their Warrick Power Plant (WPP) near Evansville, Indiana. Final processing of the sulfur by-product to make liquid  $\text{SO}_2$  will be completed at Olin Corporation's Charleston, Tennessee facility. The project will utilize a unique burn-in-oxygen process for converting sulfur to liquid  $\text{SO}_2$ . The burn-in-oxygen process is simpler and more environmentally friendly than conventional technologies. Morrison Knudsen Corporation will provide engineering, procurement, and construction management services.

The objective of the NOXSO Clean Coal Technology Project is to design, construct, and operate a NOXSO plant at commercial scale. At the completion of this project, performance, operability, reliability, construction cost, and operating cost data will be available to assist utilities in making decisions regarding the choice of flue gas cleanup technology.

Design and procurement activities are currently being conducted. Construction is scheduled to begin in late summer with mechanical completion occurring in January 1997. After commissioning and startup, the plant will be operated for two years as part of the Clean Coal Project.

Funding for the \$82.8 million project will be provided by the DOE, NOXSO, AGC, the Gas Research Institute (GRI), W.R. Grace, and the Electric Power Research Institute (EPRI). NOXSO will raise most of its project funds through the sale of revenue bonds issued and guaranteed by the state of Indiana. The guarantee is made possible by state legislation signed into law on March 28, 1995. NOXSO will repay the bonds from revenue generated by the sale of SO<sub>2</sub> allowances and the sulfur by-product during a ten-year time period which includes the two-year demonstration operation period.

#### **HOST SITE INFORMATION**

The WPP is owned by AGC and operated by the Southern Indiana Gas and Electric Company (SIGECO). The plant supplies electricity to Alcoa's adjacent Warrick Operations aluminum facility and to the utility grid. The WPP consists of three coal-fired steam electric generating units (Units 1, 2, and 3), each rated at 150 MW, and Unit 4, rated at 300 MW. Unit 4 is jointly owned by AGC and SIGECO. Approximately 80% of the electric power generated at WPP is used by Warrick Operations, with the remainder being sent to the utility grid.

As shown in Figure 1, the WPP is located in Warrick County, about 15 miles east of Evansville, Indiana, on Indiana Route 66. The WPP and Warrick Operations are located on approximately 600 acres of land between Indiana Route 66 and the Ohio River.

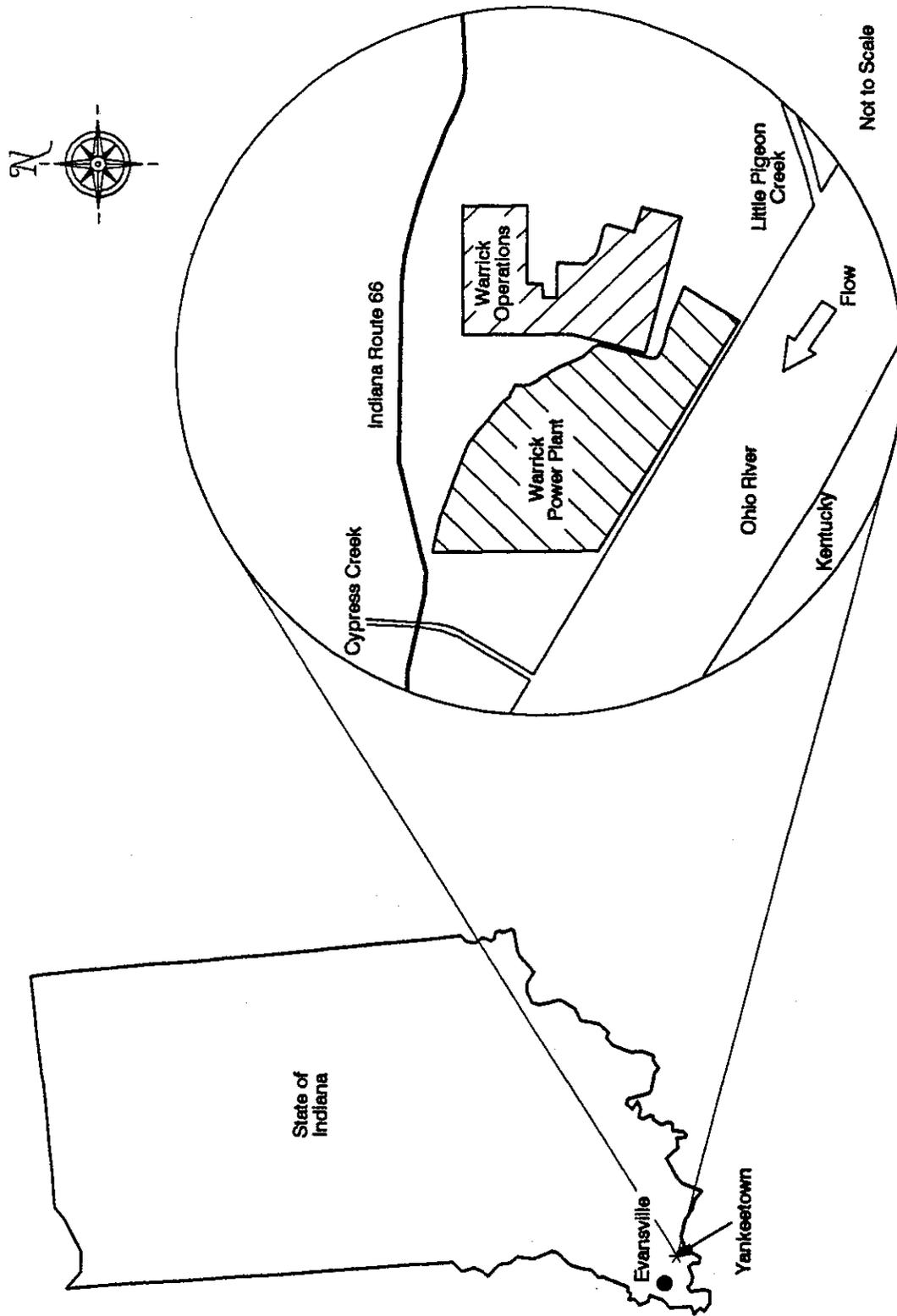


Figure 1. Warrick Power Plant and Warrick Operations Site Location.

High sulfur Squaw Creek coal with composition as shown in Table 1 will be burned in Unit 2 after the NOXSO plant is installed. Squaw Creek coal is currently blended with a low sulfur coal for use in Units 1, 2, and 3 to satisfy the Warrick County State Implementation Plan (SIP) limit of 5.11 pounds SO<sub>2</sub> per million Btu of heat input.

Parameter	Weight Percent (%)
Moisture	12.92
Carbon	62.02
Hydrogen	4.58
Nitrogen	1.22
Chlorine	0.05
Sulfur	3.39
Ash	8.23
Oxygen	7.60
Higher Heating Value (HHV) (Btu/lb)	11,307

**Table 1. Squaw Creek Coal - Ultimate Analysis**

AGC intends to opt-in WPP Units 1, 2, and 3 to the Acid Rain Program of the Clean Air Act (CAA) Amendments of 1990. The Opt-In Program (40 CFR Part 72) allows nonaffected sources, like AGC's WPP Units 1, 2, and 3, to enter the SO<sub>2</sub> portion of the acid rain program and receive SO<sub>2</sub> emission allowances.

Table 2 shows the design parameters for Unit 2. The wall-fired unit built by Babcock & Wilcox Company (B&W) was placed into service in 1964. The boiler is a natural circulation, Carolina-type radiant unit with 16 circular coal burners arranged in a 4-by-4 grid on a single furnace wall. Coal is reduced from 3/4 inches (in) to 60% less than 200 mesh by B&W EL-76 ball and race pulverizers.

Boiler Manufacturer	Babcock & Wilcox
Operation Date	1964
Primary Fuel	Coal
Start-up Fuel	oil (gas with co-fire)
Boiler Type	wall-fired, natural circulation, Carolina-type radiant unit
Nameplate Rate	144 MW
Steam Flow	1,000,000 lb/hr
Steam Temperature	1,005°F
Design Pressure	1,975 psig
Turbine/Generator Set	160 MW
Existing Burners	16 wall-fired burners
Particulate Control	Western Precipitator electrostatic precipitator designed for 1.83 grains/acfm outlet dust for 688,600 acfm flue gas at 710°F

**Table 2. Unit 2 Design Parameters**

## **NOXSO PROCESS DESCRIPTION**

The NOXSO process is a dry, post-combustion flue gas treatment technology which will use a regenerable sorbent to simultaneously adsorb SO<sub>2</sub> and NO<sub>x</sub> from the flue gas from Unit 2 of AGC's WPP. In the process, the SO<sub>2</sub> will be converted to liquid SO<sub>2</sub> and the NO<sub>x</sub> will be reduced to nitrogen and oxygen. The NOXSO plant is designed to remove 98% of the SO<sub>2</sub> and 75% of the NO<sub>x</sub>. Details of the NOXSO process are described with the aid of Figure 2. Flue gas from the power plant is drawn through two flue gas booster fans which force the air through two fluid-bed adsorbers and a baghouse before passing to the power plant stack. For simplicity, only one adsorber train is shown in Figure 2. Water is sprayed directly into the adsorber fluid beds as required to lower the temperature to 250-275°F by evaporative cooling. The fluid-bed adsorber contains active NOXSO sorbent. The NOXSO sorbent is a 1.2 mm diameter stabilized  $\gamma$ -alumina bead impregnated with sodium. A baghouse removes sorbent which may be entrained in the flue gas and directs it to the fly ash sluicing system.

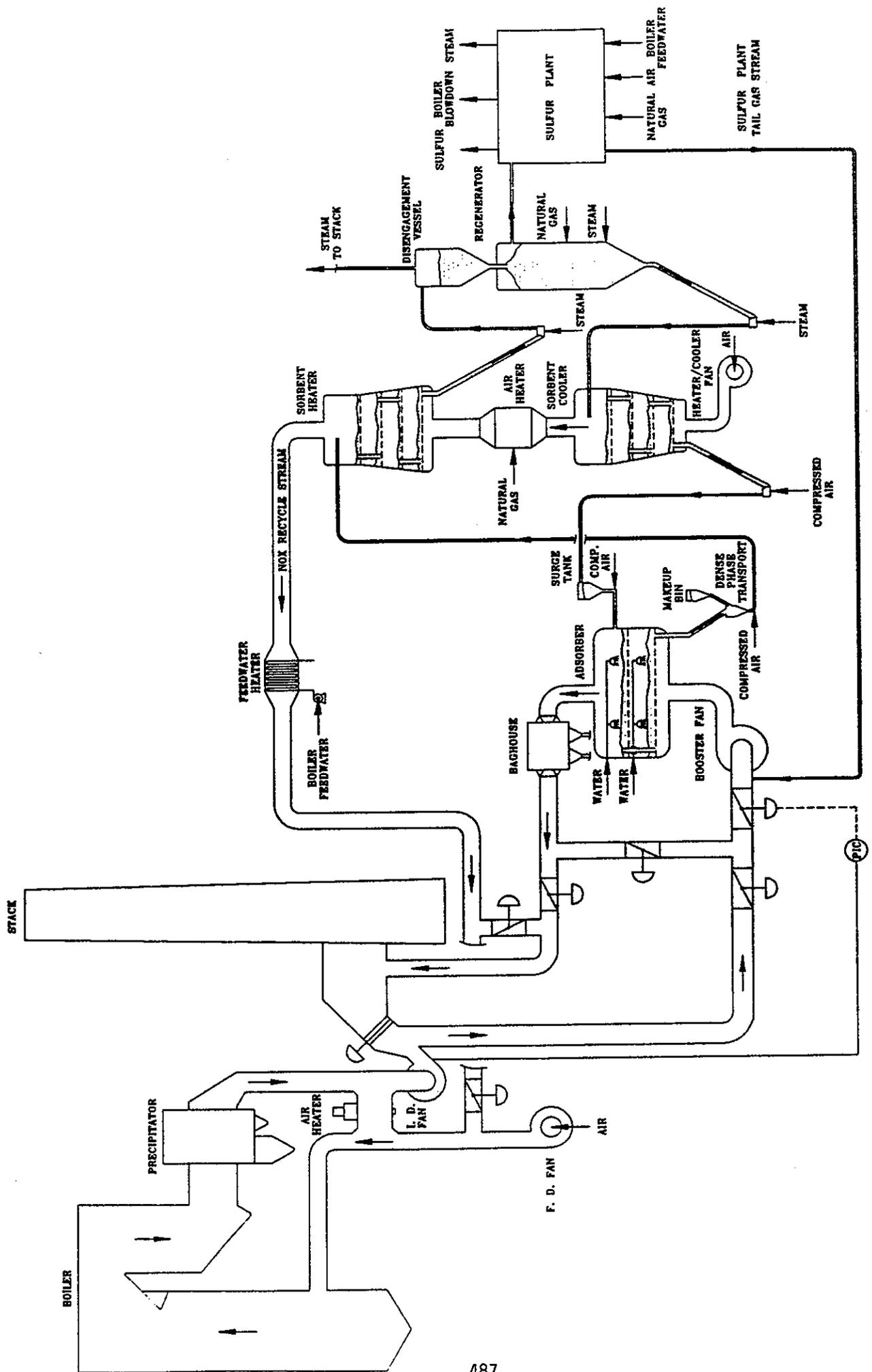


Figure 2. NOXSO Process Diagram - Alcoa Generating Corporation  
Warrick Plant Unit 2

Spent sorbent from the adsorbers flows into a dense-phase conveying system which lifts the sorbent to the top bed of the sorbent heater vessel. The sorbent flows through the four-stage fluidized-bed sorbent heater in counterflow to the heating gas which heats the sorbent to the regeneration temperature of approximately 1150°F.

In heating the sorbent, the NO<sub>x</sub> is driven off and carried to the power plant boiler in the NO<sub>x</sub> recycle stream. The NO<sub>x</sub> recycle stream is cooled from approximately 360°F to 140°F in the feedwater heater. This heat-exchanger heats a slip stream of the power plant's feedwater, thereby reducing the amount of extraction steam taken from the low pressure turbine, enabling the generation of additional electricity. The cooled NO<sub>x</sub> recycle stream replaces a portion of the combustion air. The presence of NO<sub>x</sub> in the combustion air suppresses the formation of NO<sub>x</sub> in the boiler resulting in a net destruction of NO<sub>x</sub>.

The heated sorbent is transported through an L-valve to the steam disengaging vessel. Transport steam is separated from the sorbent to reduce the volume of the off-gas stream. Sorbent gravity flows into the regenerator where it is contacted with natural gas. Through a series of chemical reactions, the sulfur on the sorbent combines with the methane and forms SO<sub>2</sub> and H<sub>2</sub>S. Additional regeneration occurs in the steam treater section of the regenerator when the sorbent is contacted with steam, converting the remaining sulfur on the sorbent to H<sub>2</sub>S. The regenerator off-gas stream is directed to a sulfur recovery plant where the H<sub>2</sub>S and SO<sub>2</sub> are converted to elemental sulfur. Tail gas from the sulfur recovery plant will be oxidized and recycled back through the adsorbers to remove any residual sulfur compounds.

The elemental sulfur will be shipped to Olin Corporation's Charleston, Tennessee facility for additional processing. The elemental sulfur will be oxidized to SO<sub>2</sub> in a stream of compressed oxygen. The compressed SO<sub>2</sub> vapor will be cooled and condensed.

High temperature sorbent exiting the regenerator is conveyed with an L-valve to the four-stage fluidized-bed sorbent cooler. The sorbent flows counter to the ambient air which cools the sorbent. Regenerated sorbent exits the cooler at 320°F. The sorbent is then conveyed through

an L-valve to the sorbent surge tank before being returned to the adsorber, completing the sorbent cycle.

Ambient air which is forced through the sorbent cooler by the heater-cooler fans exits the sorbent cooler at approximately 950°F. This preheated air then enters the air heater where it is heated to approximately 1340°F. The high temperature air is used in the sorbent heater to heat the sorbent to the regeneration temperature of 1150°F.

## **PLANT ARRANGEMENT**

The Demonstration Plant will be located in a generally unoccupied area of the plant yard south of Unit No. 2. This area requires minimal site preparation and provides adequate space for the NOXSO plant while offering a convenient tie-in point for the flue gas ductwork, see Figure 3, since the existing flue gas plenum and plant stacks are located on the south side of the power plant. This location also provides plant access from the south for sorbent and nitrogen delivery while the sulfur recovery unit is accessible by rail and road. The general arrangement is shown in Figure 4.

The NOXSO plant will take up an area approximately 250' × 200' in size, just south of Precipitator Road, which is an east-west running plant access road south of the power plant. The analyzer and control building is located to the east of the NOXSO plant while the sulfur recovery unit is situated to the west, at the southern end of the battery limits.

The locations of the major process vessels within this area are chosen to minimize the amount of ductwork required to deliver and return the flue gas, and to minimize the horizontal distances that the sorbent must travel between vessels. Thus, the adsorption trains, including booster fans, adsorbers, and baghouses, are situated furthest north within the battery limits. The adsorption trains are shown in the foreground of Figure 4. The adsorbers, like the regenerator and sorbent cooler, are self-supporting vessels through the use of vessel skirts which reduce the overall amount of structural steel required.

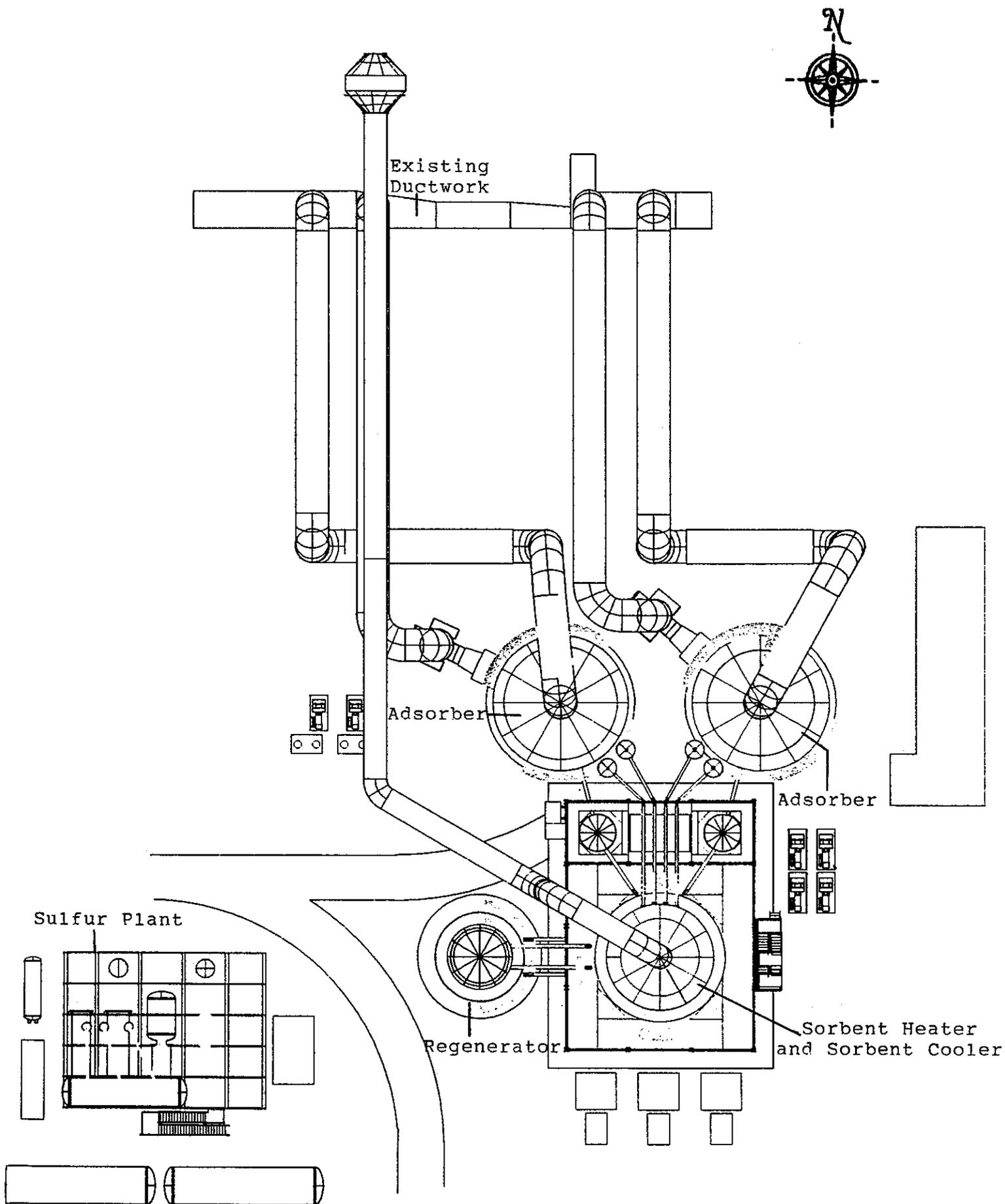


Figure 3. Plant Layout

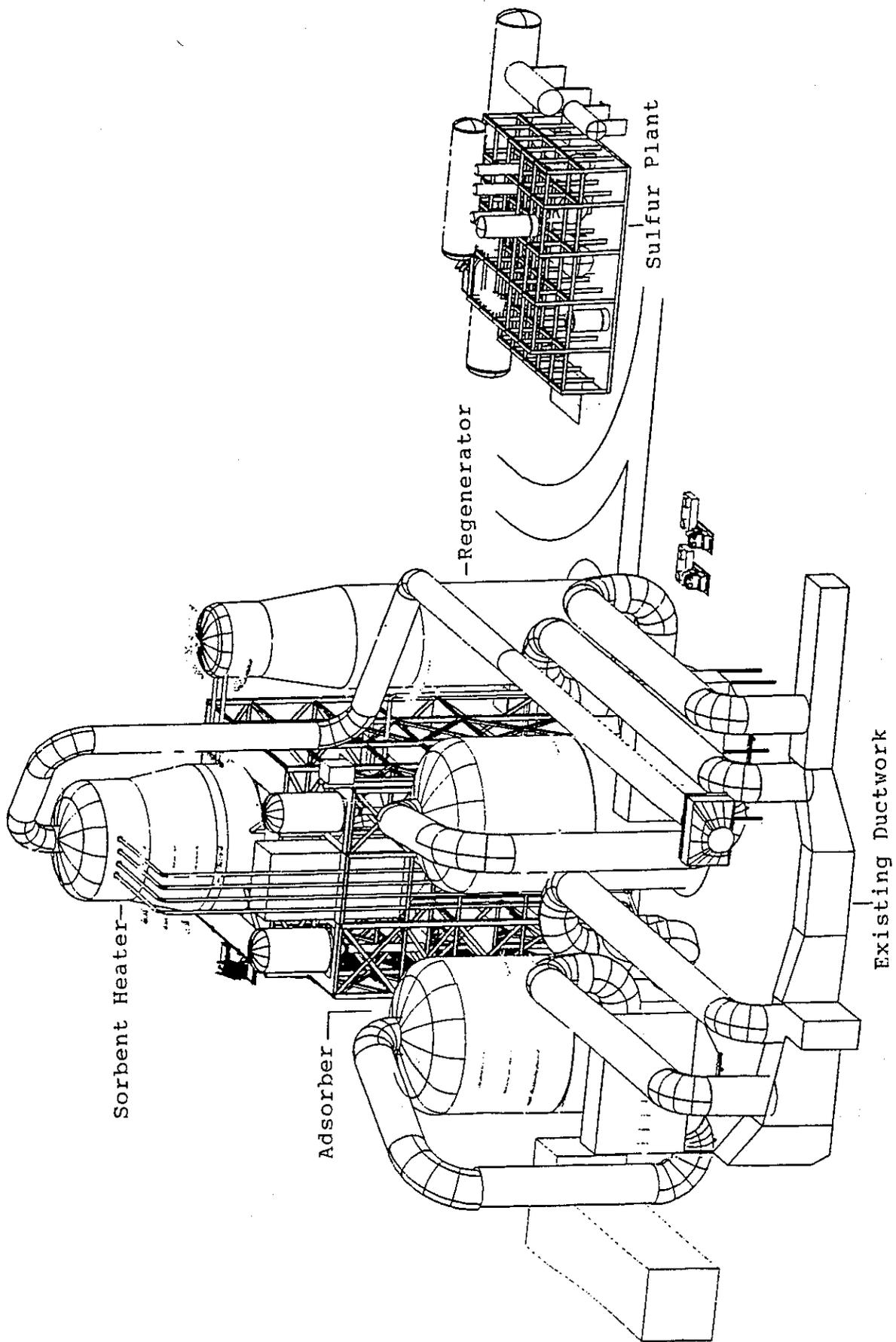


Figure 4. General Arrangement

The regeneration train, consisting of the sorbent heater, steam disengaging vessel, regenerator and sorbent cooler, is just south of the adsorption trains. The sorbent cooler and sorbent heater are in a stacked arrangement, so that the heat energy recovered by the fluidizing air in the sorbent cooler may be used in the sorbent heater. The sorbent cooler, hidden by the structural tower in Figure 4, is skirt supported on the ground, while the sorbent heater is supported 95' in the air at its base by the sorbent heater tower. This tower is centered behind and situated as close as possible to the two adsorbers to minimize the horizontal distance that the sorbent must travel between the two trains.

The regenerator and steam disengaging vessel are in a stacked arrangement to allow gravity flow of the sorbent between the two vessels. Again, to minimize the horizontal sorbent conveying distance, the regenerator is situated as close as possible to the sorbent heater tower. The regenerator is located on the west side of the tower because of space availability for the sulfur recovery unit, which is to the west of the regenerator. It is essential to position the sulfur recovery unit as close as possible to the regenerator to limit the distance of the steam-traced, regenerator off-gas line.

## ECONOMICS

The utility and consumable requirements are listed in Table 3. The NOXSO process requires natural gas, NOXSO sorbent, electricity, and water. Energy credits are derived from a reduction in the power requirements of the power plants forced draft fans, heat recovered from the NO<sub>x</sub> recycle stream, sulfur plant export steam, and elimination of combustion air preheat requirements. Table 4 lists plant, process, emissions, and economic data which are used in the design of the NOXSO plant and the economic analysis.

Results of the economic analysis for the project, including 8 years of operation after the Clean Coal Project is completed, are summarized in Table 5. The total capital cost for the project is \$65.8 million. If the SO<sub>2</sub> plant is excluded, the capital cost is \$56.9 million or \$379/kW. The gross O & M cost for operation of the NOXSO portion of the plant is \$4.7 million annually. Including the revenue from the sale of project by-products, the net O & M cost shows an annual

<b>NATURAL GAS</b>	
Air Heater	841 scfm
Regenerator	534 scfm
Sulfur Plant	646 scfm
TOTAL	<hr/> 2021 scfm
SORBENT MAKEUP	145 lb/hr
<b>GROSS ELECTRICAL CONSUMPTION</b>	
Flue Gas Booster Fans	3,430 kW
Sorbent Cooler Fans	1,163 kW
Sulfur Plant	350 kW
Air Compressors	925 kW
Miscellaneous	450 kW
TOTAL	<hr/> 6,318 kW
<b>ELECTRICAL ENERGY CREDIT</b>	
FD Fan	100 kW
NOx Recycle	1,453 kW
Sulfur Plant Steam	1,895 kW
Combustion Air Preheat	50 kW
TOTAL	<hr/> 3,498 kW
NET ELECTRICAL CONSUMPTION	2,820 kW
	1.9 % Gross Power
WATER	147 gpm

**Table 3. Utility and Consumable Requirements**

PLANT INFORMATION	
Power Plant Gross Capacity	150 MW
Power Plant Capacity Factor	0.94
NOXSO Plant Capacity Factor	0.98
Combined Capacity Factor	0.92
Heat Rate	9,800 Btu/kWh
Coal Heating Value	11,300 Btu/lb
Coal Sulfur	3.4 %
Flue Gas SO <sub>2</sub> Concentration	2860 ppm @ 4% O <sub>2</sub>
Flue Gas NO <sub>x</sub> Loading	0.79 Lb/MMBtu
Flue Gas NO <sub>x</sub> Concentration	540 ppm @ 4% O <sub>2</sub>
NOXSO PROCESS REMOVAL EFFICIENCIES	
SO <sub>2</sub>	98 %
NO <sub>x</sub>	75 %
Combined	95 %
EMISSIONS DATA	
Uncontrolled SO <sub>2</sub>	35,350 tpy
Controlled SO <sub>2</sub>	1,400 tpy
SO <sub>2</sub> Allowances	25,000 tpy
Uncontrolled NO <sub>x</sub>	4,781 tpy
Controlled NO <sub>x</sub>	1,267 tpy
ECONOMIC PARAMETERS	
Electricity	\$0.021 /kWh
Natural Gas	\$2.29 /Mscf
Sorbent	\$1.00 /lb
Net Liquid SO <sub>2</sub> Value	\$100 /ton
SO <sub>2</sub> Allowance Value	\$300 /allowance
Capital Charge Rate (1)	14.4 %
NO <sub>x</sub> Value (2)	\$800 /ton
(1) Based on 7.28% interest for 10 year term	
(2) Conservative cost of NO <sub>x</sub> removal based on SCR technology	

Table 4. Plant, Process, Emissions, and Economic Data

(1995 Dollars)  
(Based on 10-Year Payoff of Capital Investment)

**CAPITAL COST**

Including SO2 Plant	\$65.8 million
	\$439 /kW
Excluding SO2 Plant	\$56.9 million
	\$379 /kW

**OPERATING AND MAINTENANCE COSTS**

Fixed Operating Cost

Operating Labor (1)	\$306,000 /yr
Maintenance	\$530,164 /yr
TOTAL	\$836,164 /yr

Variable Operating Cost

Natural Gas	\$2,240,841 /yr
Sorbent	\$1,170,108 /yr
Net Electricity	\$477,888 /yr
TOTAL	\$3,888,838 /yr

**NET OPERATING AND MAINTENANCE COSTS**

Gross O & M Costs	\$4,725,002 /yr
SO2 Allowance Revenue	\$7,080,046 /yr
Liquid SO2 Revenue	\$3,394,978 /yr
Total	(\$5,750,023)/yr

**LEVELIZED CAPITAL COST PLUS O & M**

\$3,725,177 /yr (2)
3.02 mills/kWh
\$110 /ton SO2

**LEVELIZED CAPITAL COST PLUS O & M WITH NOx CREDIT**

\$913,771 /yr (3)
0.74 mills/kWh
\$27 /ton SO2

- (1) 1/2 skilled and 1/2 unskilled operator per shift
- (2) Capital Cost X Capital Charge Rate + Gross O & M  
- SO2 Allowance Revenue
- (3) Capital Cost X Capital Charge Rate + Gross O & M  
- SO2 Allowance Revenue - NOx Credit

**Table 5. NOXSO Process Economic Analysis**

profit of \$5.8 million. Factoring in the capital charge rate of 14.4% based on an interest rate of 7.28% and a ten-year term, the annual levelized capital and O & M cost is \$3.7 million. If an \$800/ton credit is allocated for the removal of NO<sub>x</sub>, the same cost is reduced to \$0.9 million. This represents a cost of 0.7 mills/kWh or \$27/ton SO<sub>2</sub> removed.

## ACKNOWLEDGEMENT

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**CHIYODA THOROUGHbred 121 CLEAN COAL PROJECT  
AT GEORGIA POWER'S PLANT YATES  
PHASE II DEMONSTRATION RESULTS**

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**ABSTRACT**

The Chiyoda Thoroughbred CT-121 flue gas desulfurization (FGD) process at Georgia Power's Plant Yates has recently completed a two year demonstration of its capabilities under both high- and low-particulate loading conditions. This \$43 million demonstration was co-funded by The Southern Company, the Electric Power Research Institute, and the U.S. Department of Energy under the auspices of the Innovative Clean Coal Technology (ICCT) program's second round.

The focus of the project was to demonstrate several cost-saving modifications to the already efficient CT-121 process. These modifications included: the extensive use of fiberglass reinforced plastics (FRP) in the construction of the scrubber vessel and other associated vessels, the elimination of flue gas reheat through the use of an FRP wet chimney, and reliable operation without a spare absorber module.

This paper will focus on the results from the last trimester of the second phase (high-ash loading) of testing. Specifically, operation under elevated ash loading conditions, the effects of low- and high-sulfur coal, and air toxics verification testing results are discussed.

## **INTRODUCTION**

The demonstration at Georgia Power's Plant Yates involved the retrofit construction of a CT-121 wet-limestone scrubber to an existing 100 MWe pulverized coal-fired boiler. The principle difference between the CT-121 process and more common spray tower-type FGD systems is the use of a single process vessel, Chiyoda's patented jet bubbling reactor (JBR), in place of the usual spray tower/reaction tank/thickener arrangement. Initial startup of the process occurred in October 1992, and the demonstration project was completed in December 1994. Process operation continues with the CT-121 scrubber as an integral part of the site's Phase I Clean Air Act compliance plan.

Several of the latest evaluations that comprised the CT-121 demonstration project are discussed in this paper. In the last trimester of testing the CT-121 process was operated under moderate-ash inlet loading conditions while process reliability and availability were continuously evaluated. Additionally, exceptional concurrent particulate removal efficiencies were measured under moderate-particulate loading conditions, which was consistent with particulate removal efficiencies observed in earlier measurements under both high- and low-particulate loading conditions.

Parametric testing was also conducted under moderate-ash loading conditions while burning both high- and low-sulfur coals. The data gathered were regressed and multi-variable regression models were developed to provide an accurate prediction of the scrubber's SO<sub>2</sub> removal efficiency under the most likely future operating conditions. As part of the moderate-particulate removal evaluation, limited air toxics measurements were also performed for the second time. The purpose of this additional testing was to evaluate air toxics removal across the CT-121 under elevated ash loading conditions as well as to validate or controvert the findings of an earlier air toxics testing effort that was sponsored by DOE in June of 1993<sup>1</sup>.

A brief discussion of findings on the properties of the gypsum stack (not contaminated with flyash) following one year of dormancy is also included in this paper. An analysis of the chloride content showed that chloride levels in the gypsum decreased over time without any specific action by the project team. This finding increases the possible uses of the unwashed gypsum produced by this process.

In general, the Yates CT-121 process performed well, exhibiting excellent SO<sub>2</sub> removal efficiency, particulate removal and reliability. In addition to these successes, several possible process improvements were identified during the demonstration that could improve future designs of an already superior process.

## **FACILITY AND OPERATING DESCRIPTION**

Plant Yates, comprises seven coal-fired boilers, all Phase I affected units, with a total rated capacity of 1250 MWe. Plant Yates' 100 MWe Unit 1 is the source of flue gas for the CT-121 process. All of the flue gas from Unit 1 is treated by the CT-121 wet FGD process with no provision for flue gas bypass. During the low flyash phase of parametric testing in 1992 and 1993, the existing ESP for Unit 1 was used for particulate control. The design efficiency for this ESP is 98%. In March, 1994, the ESP was fully deenergized at the start of high-particulate parametric testing, and partially energized to a target efficiency of 90% between June 1994 and November 1994.

A simplified process flow diagram for the CT-121 process is presented in Figure 1. The equipment comprising the scrubber demonstration facility can be divided into five major subsystems:

- Boiler/ESP;
- CT-121 scrubber/wet chimney;
- Limestone preparation circuit;
- Byproduct gypsum stacking area; and
- Process control system.

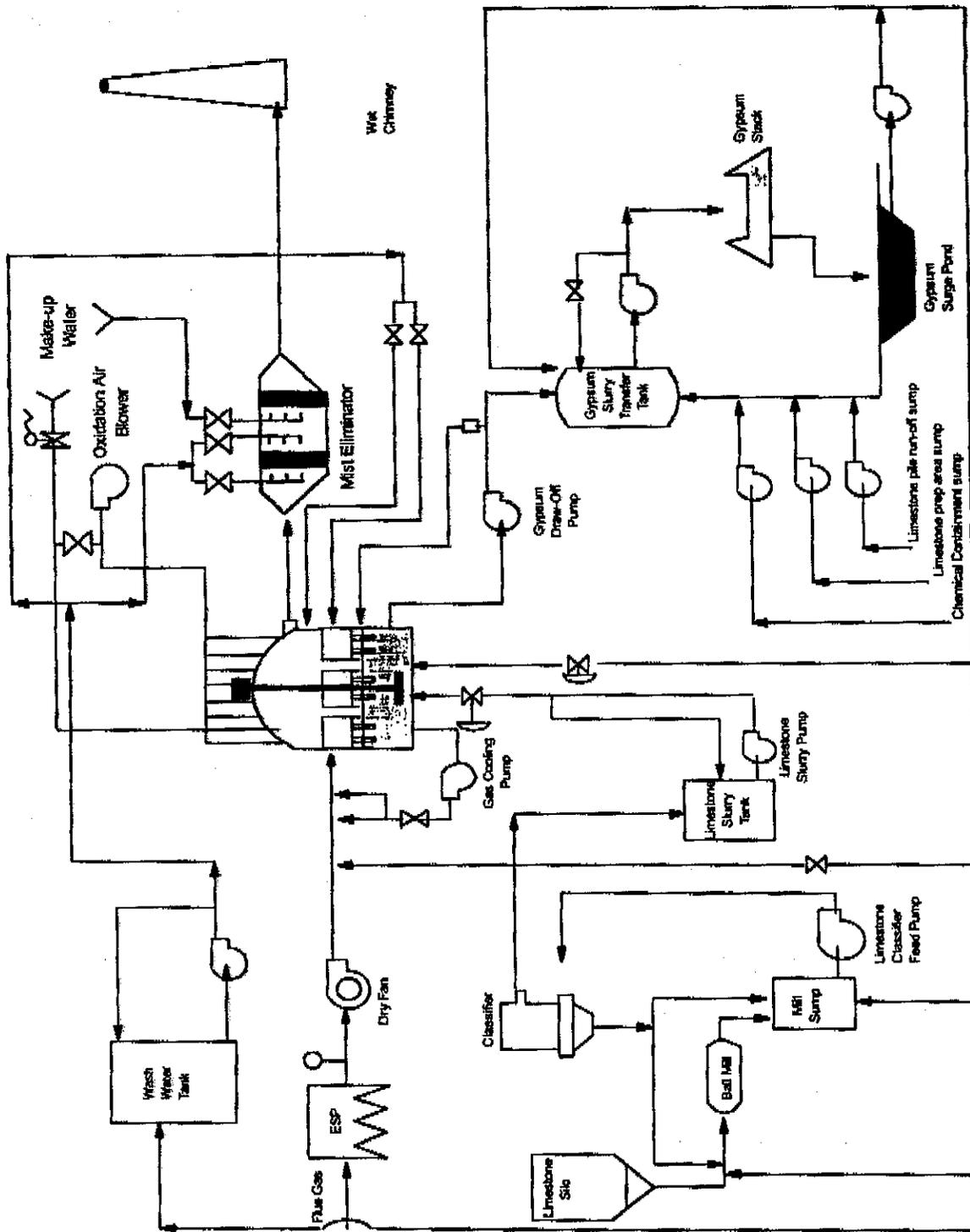
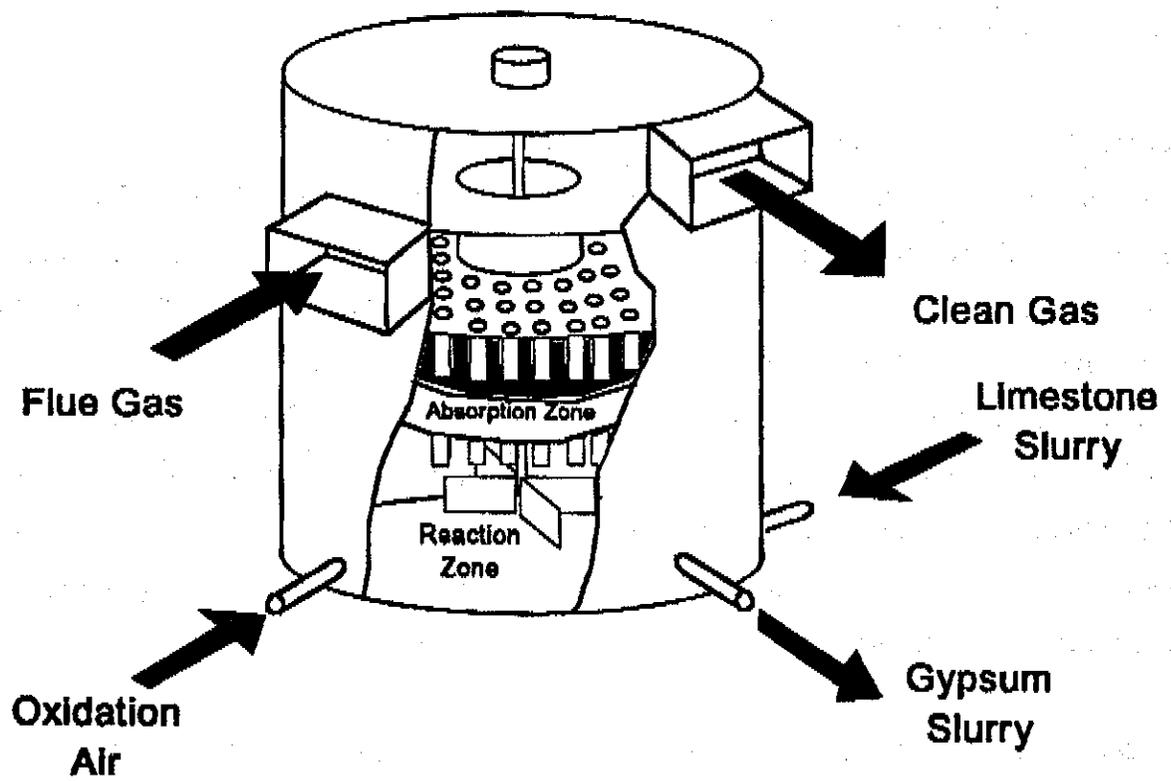


Figure 1. CT-121 Simplified Process Flow Diagram

The central feature of the process is Chiyoda's unique absorber design, called a Jet Bubbling Reactor (JBR), which combines concurrent chemical reactions of SO<sub>2</sub> absorption/neutralization, limestone dissolution, sulfite oxidation, gypsum precipitation and gypsum crystal growth together in one vessel. A cut-away view of the JBR is illustrated in Figure 2. Since much of the undesirable crystal attrition and secondary nucleation associated with the large centrifugal pumps in conventional FGD systems is eliminated in the CT-121 design, large, easily dewatered gypsum crystals are consistently produced. This design also significantly reduces the potential for gypsum scaling, a problem that frequently occurs in natural-oxidation FGD systems.

In the Yates installation (see Figure 1), the flue gas enters the scrubber's inlet gas cooling section down-stream of the boiler's induced draft (I.D.) fan. Here the flue gas is cooled and saturated with a mixture of pond water and JBR slurry. From the gas cooling section, the flue gas enters an enclosed plenum chamber in the JBR formed by the upper deck plate and lower deck plate. Sparger tube openings in the floor of the inlet plenum force the inlet flue gas below the level of the slurry reservoir in the jet bubbling zone (froth zone) of the JBR. After bubbling through the slurry, where all the concurrent reactions occur, the gas flows upward through large gas riser tubes that bypass the inlet plenum. Entrained liquor in the cleaned gas disengages in a second plenum above the upper deck plate due to a drastic velocity reduction and the cleaned gas passes to the 2-stage, chevron-style, horizontal-flow mist eliminator, then on to a wet FRP chimney.

A closed-circuit, wet ball mill limestone preparation system is used to grind raw (3/4x0) limestone. The particle size of the ground limestone is small enough (90% passing a #200 mesh screen) to ensure that it is dissolved easily and that the amount of unreacted limestone in the JBR can be minimized or eliminated.



**Figure 2. JBR Cross-Section**

The JBR slurry reservoir provides approximately 36 hours of solid-phase residence time, depending on the SO<sub>2</sub> pick-up rate. The slurry from the JBR is pumped intermittently to a gypsum slurry transfer tank (GSTT) for JBR slurry level control and slurry density control. In the GSTT, the slurry is diluted for pumping to a Hypalon®-lined gypsum (or gypsum/ash) stacking area for gravity dewatering and storage. Gypsum stacking is a disposal technique that involves filling a diked area with slurry for gravity sedimentation. Over time, this area fills with settled solids. The filled area is then partially excavated to increase the height of the containment dikes. The process of sedimentation, excavation, and raising of perimeter dikes continues on a regular basis during the active life of the stack. Process water is naturally decanted, stored in a surge pond and then returned to the process. There is no blowdown or discharge from the Yates CT-121 process.

During normal operation of the FGD system, the amount of SO<sub>2</sub> removed from the flue gas is controlled by varying the JBR pressure drop ( $\Delta P$ ) or slurry pH. However, changing  $\Delta P$  is easier and quicker to respond to changing conditions since it is done by adjusting the JBR liquid level. Higher liquid levels result in increased SO<sub>2</sub> removal because of increased contact time between the incoming flue gas and the scrubbing slurry. The pH can also be varied to affect SO<sub>2</sub> removal with higher pH resulting in increased removal efficiency. Boiler load and flue gas SO<sub>2</sub> concentration also affect removal efficiency, but are less controllable.

One of the most unique aspects of the CT-121 installation at Plant Yates is the wide use of fiberglass reinforced plastics (FRP) in several of the vessels to avoid the traditional corrosion damage associated with closed-loop FGD systems. Two of the vessels (the JBR and the limestone slurry storage tank) were constructed on site since their large size precluded shipment. The JBR inlet transition duct, where the flue gas is cooled prior to contacting the sparger tubes, is also made completely of FRP. (This was discovered to be an area prone to erosion during the testing, particularly under conditions of high-ash loading.) A distinct advantage of the FRP construction was that it eliminated the need for a flue gas prescrubber to remove chlorides because the corrosion resistance properties of the fiberglass are superior to those of alloys. This represented a large capital cost savings to the project.

## **PROJECT OBJECTIVES**

To evaluate the effectiveness of the Yates CT-121 design advances, the following objectives of the two year demonstration program were established:

- Demonstrate long-term reliable operation of the CT-121 FGD system;
- Evaluate particulate removal efficiency of the JBR and system operation at normal and elevated particulate loadings;
- Correlate the effects of pH and JBR gas-side pressure drop ( $\Delta P$ ) on system performance;
- Correlate the effect of limestone grind on system performance;
- Evaluate the impact of boiler load on system performance;
- Evaluate the effects of alternate fuels and reagents on system performance;
- Evaluate equipment performance and construction material reliability; and
- Monitor solids properties, gypsum stack operation and possible impacts of the gypsum stack on ground water.

Many of these objectives were investigated during this last trimester of the second phase of the demonstration project, also known as the High-Particulate Auxiliary Test block. Two of the test periods in this test block provided data relevant to the focus of this paper:

- High-Particulate Alternate Coal Tests which evaluated scrubber performance under elevated particulate loading conditions while burning high-sulfur (3.4% sulfur) coal; and
- High-Particulate Alternate Limestone Tests which evaluated an alternate limestone reagent source, while under elevated particulate loading and burning low-sulfur (1.2% sulfur) coal.

Particulate and air toxics removal testing were also conducted during the Alternate Limestone testing. The data from the parametric portion of this test period was regressed to develop a predictive

performance model for the conditions at which the testing was conducted, since these conditions are the most likely scenario for post-demonstration operation

## **RESULTS**

The CT-121 scrubber at Plant Yates continued to prove itself a very viable and cost effective technology for use in Clean Air Act, Title IV compliance. It exhibited excellent availability, maintained greater than 97% limestone utilization, and demonstrated the ability to exceed 98% SO<sub>2</sub> removal efficiency with high sulfur coal, while at maximum boiler load. The flexibility of the CT-121 process was also demonstrated through the use of a wide range of coals, varying from 1.2% to 4.3% sulfur content.

### Operating Statistics

The duration of the demonstration, including the startup and shake-down phase, was 27 months, or approximately 19,000 hours. The low-particulate test phase (including shake-down) consisted of 11,750 hours, during which time the scrubber was operated for 8,600 hours. The remaining 7,250 hours of the demonstration included 5,510 hours of operation at elevated particulate loading. The period of testing discussed in this paper was conducted under these elevated ash loading conditions. The most important of the operating statistics, availability, is defined as the ratio of the time the scrubber was available to operate divided by the amount of time in the operating period. Complete operating statistics for the entire demonstration project are detailed in Table 1.

For the low-ash test phase, the availability was 97%, and for the high-ash test period, it was 95%. The availability index was lower during the high-ash test phase because of sparger tube plugging problems. The sticky flyash demonstrated a tendency to agglomerate on the inside surface of the sparger tubes. The "high-ash" test period actually consisted of a high-ash loading period (during the Parametric Test block) in which the ESP was completely deenergized, and a moderate-ash loading period (during the Long-Term and Auxiliary Test blocks) during which the ESP was partially denenergized to simulate a more realistic scenario: a CT-121 retrofit to a boiler with a marginally

performing particulate collection device. The moderate-ash loading condition resulted in better availability than did the high-ash loading condition.

	Low-Ash Test Phase	High-Ash Test Phase	Demonstration Project (Cumulative)
Total Hours in Test Period	11750	7250	19000
Scrubber Available Hours	11430	6310	18340
Scrubber Operating Hours	8600	5210	13810
Scrubber Called Upon Hours	8800	5490	14290
Reliability <sup>1</sup>	0.98	0.95	0.96
Availability <sup>2</sup>	0.97	0.95	0.97
Utilization <sup>3</sup>	0.73	0.72	0.75

1. Reliability = Hours scrubber operated divided by the hours called upon to operate.
2. Availability = Hours scrubber available divided by the total hours in the period.
3. Utilization = Hours scrubber operated divided by the total hours in the period.

**Table 1. Operating Statistics Summary**

### Effect of Inlet SO<sub>2</sub> Concentration

The SO<sub>2</sub> removal efficiency of the scrubber was measured under five different inlet SO<sub>2</sub> concentration ranges; three during this most recent testing. The coal burned by Unit 1 for a majority of the testing was a blend of Illinois No.5 and No.6 bituminous coal that averaged 2.4% sulfur (as burned), except for a brief, unplanned period when 3.0% sulfur coal was burned. A 4.3% sulfur bituminous coal was burned during the Low-Particulate Alternate Coal Test block, and a 3.8% sulfur coal was burned for the High-Particulate Alternate Coal Test block. The High-Particulate Alternate Limestone Test (the last test of the demonstration project) coincided with Plant Yates' compliance-driven transition to a low sulfur (approximately 1.2%) coal. This provided the scrubber project an opportunity to evaluate a fifth coal source.

## Particulate Removal Efficiency by Particle Size

The particle size distribution of the scrubber inlet and outlet particulate matter was measured at all four test conditions as shown in Table 3. The results of these analyses indicate that excellent particulate removal efficiency occurred in most of the measured size ranges (cut-points). Figures 4 and 5 illustrate the particulate removal efficiency of the scrubber by comparing inlet and outlet mass loading at different particle size cut-points (shown using a logarithmic scale). The inlet data were combined for both 50 MWe tests and for both 100 MWe tests to simplify the plots since inlet conditions were identical in each case. In the plots, each decade separating the points on the y-axis represents an order of magnitude difference between the inlet and outlet mass loading. For example, a one decade difference represents 90% removal efficiency, two decades - 99%, three decades - 99.9%, etcetera.

As observed in the plots, the 100 MWe case showed better particulate removal efficiency than the 50 MWe case at most cut-points. One possible explanation is based on the mechanism of particulate removal in the scrubber. Because the velocity of flue gas is higher at higher loads, the particulate has more momentum and is more likely to come into contact with the slurry as each flue gas "bubble" travels beneath the slurry.

As was reported during earlier particulate removal tests, and again observed in Figures 4 and 5, the best removal efficiencies were observed for particle sizes greater than  $10\mu\text{m}$ . At all test conditions, there was greater than 99% particulate removal efficiency of particles in this size bin. In some cases, efficiency exceeded 99.99%. As the particle size decreased, there was a drop in observed particulate removal efficiency, but over 90% efficiency was observed at all particle sizes between  $1\mu\text{m}$  and  $10\mu\text{m}$ . Between  $0.5\mu\text{m}$  and  $1\mu\text{m}$ , the particulate removal dropped to sometimes negligible values. In this range, it is believed that acid mist carryover offset the ash particulate removal, resulting in poor particulate removal values. Analyses of the outlet catch indicated that an average of 30% of the outlet particulate can be attributed to gypsum and acid mist carryover. Below about  $0.5\mu\text{m}$ , the particulate removal efficiency increased to above 90%.

Condition	ESP Energization	ESP Collection	JBR Inlet Loading
1	Full	High	Low
2	<i>Partial</i>	<i>Moderate</i>	<i>Moderate</i>
3	Off	Low	High

**Table 2. Particulate Testing ESP Configuration**

Measurements of particulate removal across the JBR (at Condition 2 from Table 2, above) were made near the minimum and maximum nominal boiler loads (50 and 100 MWe), and at low and high JBR  $\Delta P$  settings (10 and 18 in.WC). The test conditions and results are shown in Table 3. As shown in Table 3, the JBR exhibited excellent particulate removal efficiency, ranging from 97.7% to 99.3%, at all tested inlet particulate loadings, boiler loads, and JBR pressure drops.

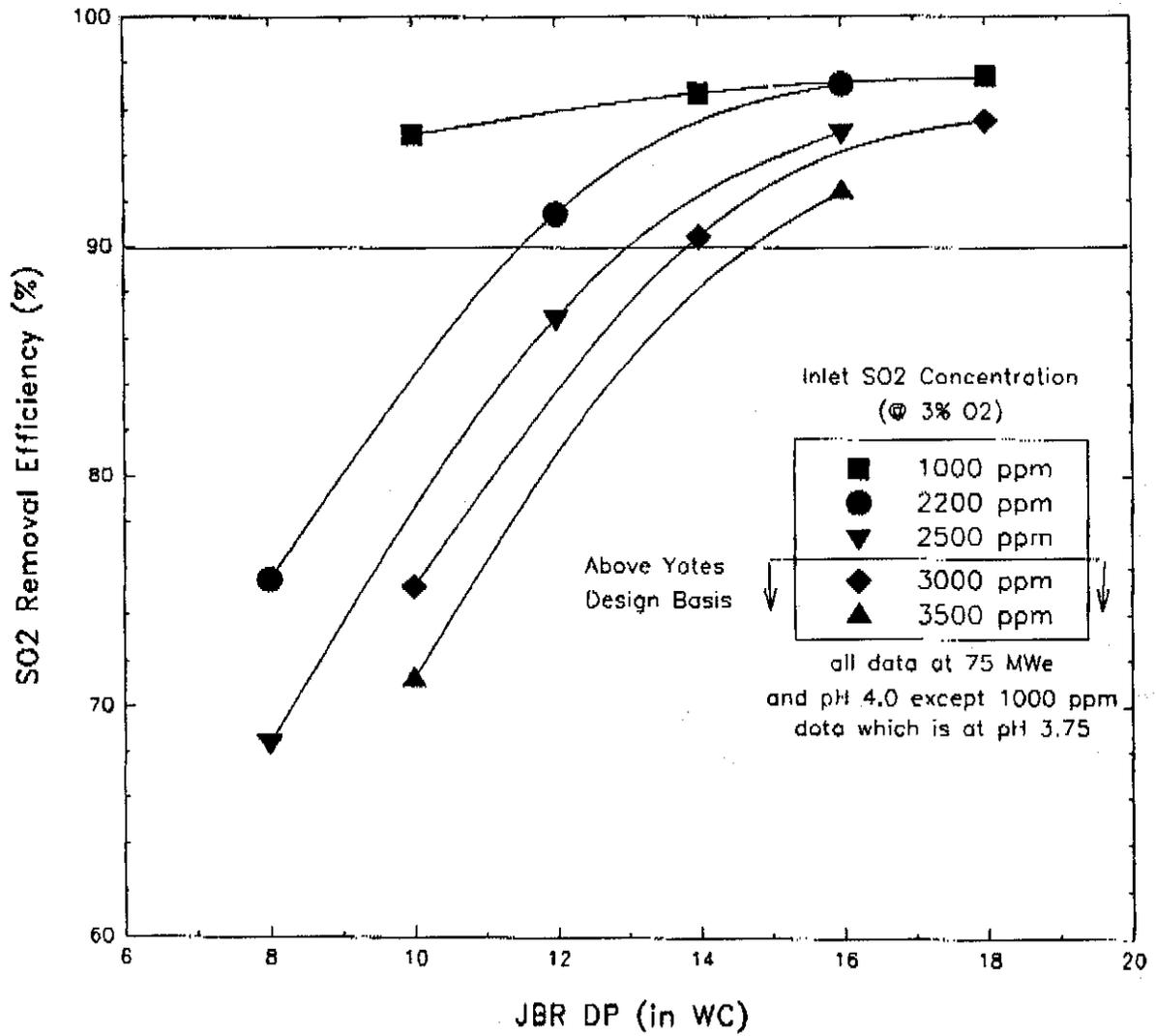
Although the outlet particulate loading varied from 0.005 to 0.029 lb/MMBtu, analytical results indicate that from 20 to 80 percent of outlet particulate is sulfate ( $SO_4$ ), likely a result of a combination of acid mist and gypsum carryover. Based on the calcium analyses performed on the same material, it is believed that the measured sulfate originated from gypsum carryover and acid mist carryover. This finding reduces the estimate of ash mass loading at the outlet of the scrubber to an average of approximately 70% of the measured outlet particulate.

Test I.D.	Approximate ESP Efficiency	JBR $\Delta P$ (in. WC)	Boiler Load (MWe)	Inlet Mass Loading (lb/MMBtu)	Outlet Mass Loading <sup>1,2</sup> (lb/MMBtu)	Removal Efficiency (%)
AL2-1	90	18	100	1.288	0.029	97.7
AL2-2	90	10	100	1.392	0.010	99.3
AL2-3	90	18	50	0.325	0.005	98.5
AL2-4	90	10	50	0.303	0.006	98.0

<sup>1</sup> Federal NSPS is 0.03 lb/MMBtu for units for which construction began after 9/18/78

<sup>2</sup> Plant Yates permit limit is 0.24 lb/MMBtu as an existing unit

**Table 3. Particulate Removal Testing - Summary of Results**



**Figure 3. Effect of Inlet SO<sub>2</sub> Concentration on SO<sub>2</sub> Removal Efficiency**

The effect of inlet SO<sub>2</sub> concentration on SO<sub>2</sub> removal efficiency is quite significant. Figure 3 illustrates the decrease in SO<sub>2</sub> removal as inlet SO<sub>2</sub> concentration increased for the coal sources evaluated. Performance of the scrubber was outstanding during the low-sulfur coal burn. It should be noted that the low-sulfur coal tested limited the JBR pH to a maximum of 3.8 because of Aluminum-Fluoride-inhibited limestone dissolution (Al-F blinding). The Al-F blinding stems from the low-ionic strength of the scrubbing liquor, the elevated ash loading to the JBR and the coal trace metals concentrations. A maximum operating pH of 3.75 was chosen to ensure that near-complete limestone utilization was maintained in the scrubber. As shown in Figure 3, the test data from 1000 ppm (inlet SO<sub>2</sub> concentration) operations indicates that SO<sub>2</sub> removal efficiency did not decline at a slightly lower pH.

The evaluation of five different inlet SO<sub>2</sub> concentrations demonstrates the flexibility of the CT-121 process as well as its exceptional SO<sub>2</sub> removal capability, even when burning fuels with a very high sulfur content. This is even more impressive considering that the designed sulfur content for the demonstration unit was only 3.0%, and that this limit was exceeded by 43% in one test period. Note that Figure 3 was prepared using mostly data collected at a pH of 4.0. Other test data shows that even higher SO<sub>2</sub> removal efficiencies are achievable at higher pH values.

### Particulate Removal Efficiency

Because of the torturous path taken by the flue gas during treatment in the JBR, an effort was made to quantify particulate removal. Consequently, the ability of the CT-121 process to remove flyash particulate was evaluated several times throughout the demonstration. Particulate loading measurements were made at the inlet and outlet of the scrubber under three different conditions of inlet mass loading, summarized in Table 2. This paper will focus on the particulate removal capabilities of the scrubber under only the moderate-ash loading conditions.

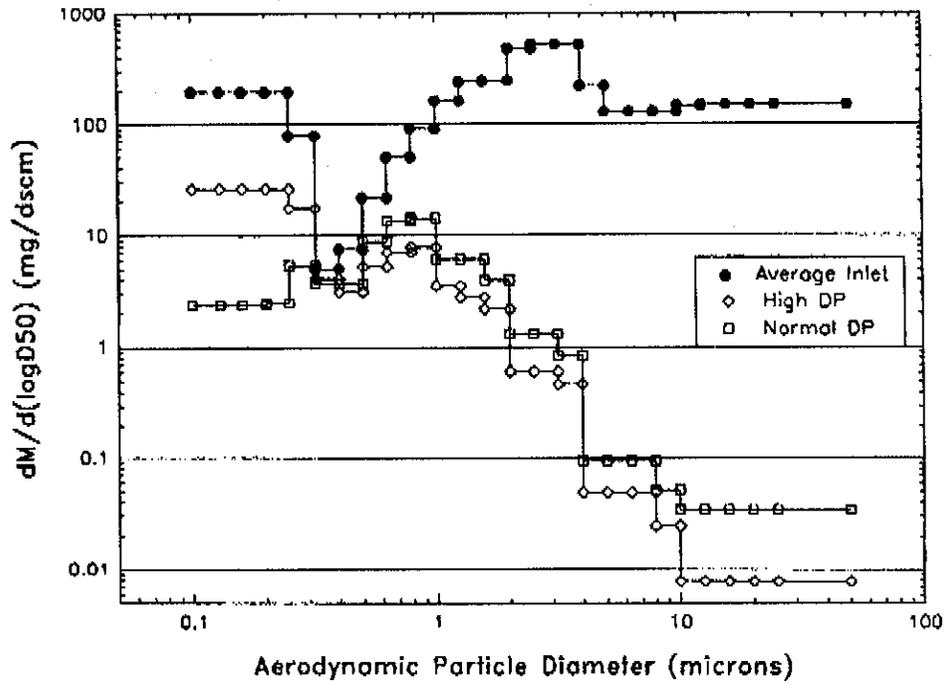


Figure 4. Particulate Removal by Size (100 MWe)

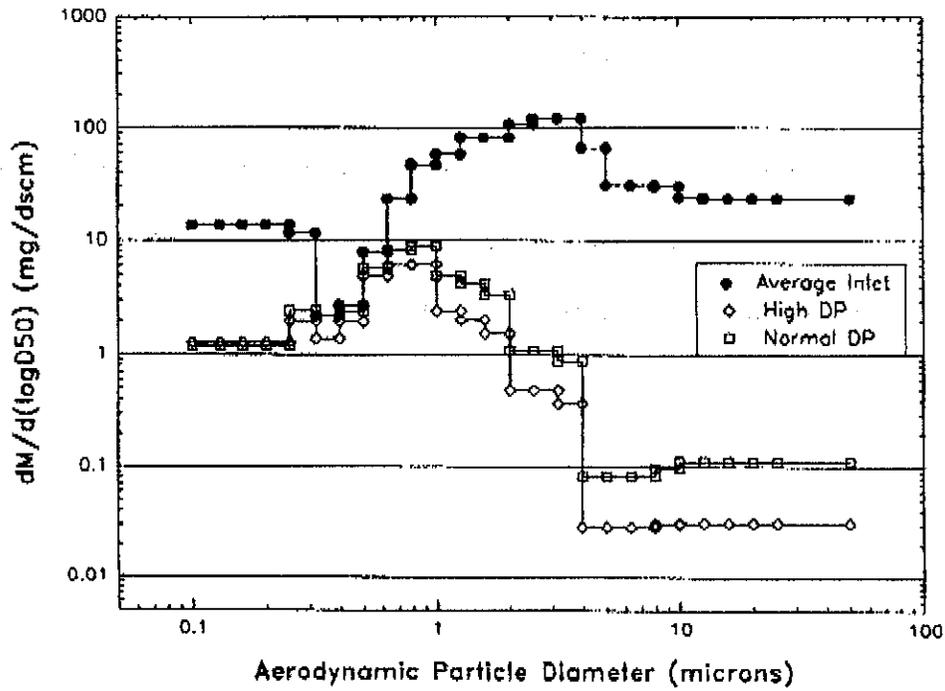


Figure 5. Particulate Removal by Size (50 MWe)

Also observed in Figures 4 and 5 was a higher particulate removal efficiency at the higher JBR  $\Delta P$  values. This increase in removal efficiency ranged from 1 decade (90%), at the largest particle sized, to less than 1/10th of a decade (10%) at the 0.5 $\mu$ m cut-point. The increased particulate removal at the higher JBR  $\Delta P$  in this size range results from a deeper sparger tube submergence depth and therefore, a longer gas-phase residence time allowing more opportunity for the particulate to be captured in the slurry.

## **AIR TOXICS TESTING**

The Yates CT-121 ICCT Project had two opportunities to measure its air toxics removal potential (also referred to as HAP or hazardous air pollutants). In 1993, Yates was chosen by the DOE as one of its eight coal-fired sites for an air toxics study<sup>1</sup> conducted on EPA's behalf in support of Clean Air Act Title II requirements for subsequent health risk determinations. In late 1994, the Yates ICCT Project expanded its scope of work to duplicate portions of that 1993 effort, in an attempt to validate the DOE's 1993 results. The results are both interesting and mutually supportive. However, the fossil fuel sources between the two tests were radically different and an exact comparison of results can not be easily made.

In 1993, the DOE was hoping to investigate three issues;

- Air toxics characterizations/penetrations in fossil fuel systems (fuel/boiler/ESP);
- Air toxics removal potential for postcombustion equipment (ESP/wet scrubber); and
- Air toxics emissions factors in lb/10<sup>12</sup> BTU.

From the 1993 results, the DOE concluded that:

- As much as 99% of the HAPs of interest are in the particulate phase;
- Specie removal across the ESP was proportional to total particulate removal;
- Uncertainty was high because most measurements were near the minimum analytical detection limits; and
- Special difficulties were encountered with selenium, mercury, and Hexavalent chromium.

The 1994 air toxics sampling conducted as part of the ICCT Project by Radian at Plant Yates was performed to address the technical difficulties encountered during the 1993 tests, specifically:

- Selenium sampling and analysis;
- Mercury partitioning and speciation;
- Flyash penetration of the FGD process; and
- Source apportionment (origin of exiting and particulate matter),

as well as to be able to compare emissions and removals from a radically different coal source within the same boiler/ESP/scrubber flue gas pathway.

In comparing the results of the two efforts from a macro-perspective, several observations emerge that may effect the use of air toxics data in further rulemaking and health risk determinations:

- The 1993 effort saw significantly more measurement error than the 1994 effort;
- The Chiyoda CT-121 JBR is highly efficient at HAP removal;
- Sampling is very sensitive to ANY error (e.g.: Contamination) at these near-minimum detection level measurements; and
- Source apportionment identifies a significant emission contribution from particulate generated within the wet scrubbing process.

Note, in Figure 6, that the uncertainty in the 1994 testing is generally lower than that of the 1993 testing (i.e., sampling procedures improved). Secondly, due to the larger uncertainty of certain species in 1993, the accuracy of any calculated emission factors would likewise be suspect. It is apparent from the data that some species can be measured with much lower uncertainty than others. These include arsenic, vanadium, and lead. Conversely, antimony, chromium, manganese, and nickel all had high measurement confidence intervals, sometimes as high as 10 times the value of the measurement itself. Calculated removal efficiencies from the 1994 tests for the above mentioned species are shown in Figure 7. It is prudent to remind ourselves that extrapolation of admittedly uncertain data does not lend itself to producing certain results for emission factor estimation or subsequent health effects determinations. Caution should be emphasized in the use of these and any similar air toxics measurement data.

## **GYPSUM QUALITY**

The gypsum stacking area at Plant Yates comprises three cells, a "clean" gypsum stack, a gypsum/flyash stack, and a recycle water pond. During Phase I (the low-ash test phase) of this demonstration project, the "clean" gypsum stack was used to dewater and store the gypsum byproduct. During the high-ash test phase (Phase II), the segregated gypsum/ash stack was used for the same purpose. Since these stacks are physically separated "cells", the original "clean" gypsum stack was left idle for the last year of testing.

The gypsum slurry deposited in the stack had a high chloride content due to the closed loop nature of the scrubber's operation, with liquid phase chloride concentrations often exceeding 35,000 ppm at equilibrium. Because of these high chloride concentrations, the gypsum in the stack would normally require washing to be useful in the gypsum wallboard or cement manufacturing industries. Core samples of the "clean" stack that were taken after the stack had been idle for over a year indicated a surprising result: the chloride concentration in the gypsum had decreased from about 6000 ppm, measured 3 months after Phase I completion, to less than 50 ppm less than one year later. Table 4 presents chloride concentration data for the gypsum stack.

There are two likely reasons for this decrease in chloride concentration in the gypsum in the "clean" gypsum stack. The first is that the rainfall that occurred over the idle year washed the gypsum and decreased the chloride concentration. The rate of chloride decrease over time, or as a function of rainfall, was not measured because this was an unplanned and at the time, unknown, benefit of the gypsum stacking technique. The other reason lies in the fact that a majority of the chloride content in the gypsum solids is due to the chlorides in the water entrained in the gypsum solids. Core samples from the gypsum stack typically indicated that the solids content was approximately 83 wt.% on average shortly after the stack was idled. After around one year, the solids content had increased to an average of 90 wt.% at a depth of 3 feet. Although this decrease in entrained water played some role in decreasing the chloride concentration in the gypsum, it is likely that rainwater washing of the stack was the predominant cause of the decrease in chloride concentration. This is further evidenced by the data presented in Table 4 that shows free moisture did not decrease at the 6 foot level, but chloride concentration decreased significantly.

Dike	Inactive Period	Sample Depth (ft)	Chloride (ppm)	Moisture (%)
West	3 months	4	930	16.0
West	3 months	8	7610	17.5
West	3 months	9.5	5720	17.7
West	3 months	14.5	5540	15.1
West	13 months	1	60	8.1
West	13 months	3	40	9.2
West	13 months	6	20	12.0
South	3 months	10	5740	14.5
South	3 months	13.5	5610	17.4
South	3 months	16.5	6710	17.4
South	13 months	1	20	8.0
South	13 months	3	20	11.0
South	13 months	6	20	18.3

**Table 4. Chloride and Moisture Levels in "Clean" Gypsum Stack**

## **REFERENCES**

1. "A Study of Toxic Emissions from a Coal-Fired Power Plant Utilizing an ESP While Demonstrating the ICCT CT-121 FGD Project," Radian Corporation Final Report for U.S. DOE, Contract No., DE-AC22-93PC93253. June 16, 1994.

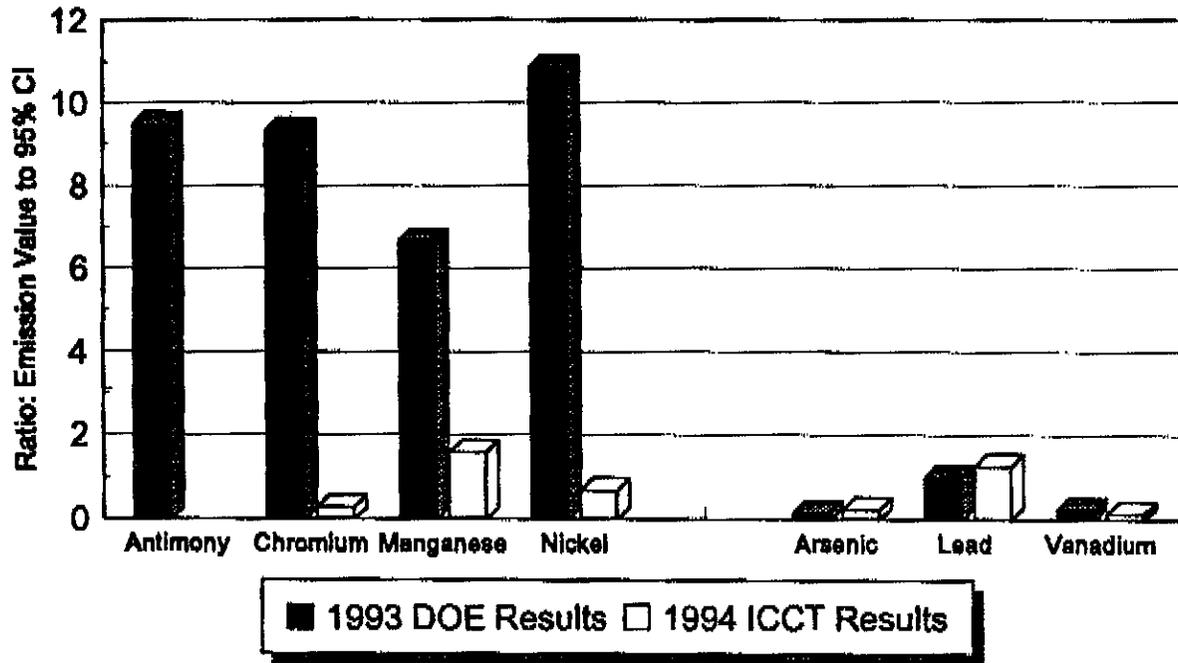


Figure 6. Ratio of Measured Emission Value to 95% Confidence Interval

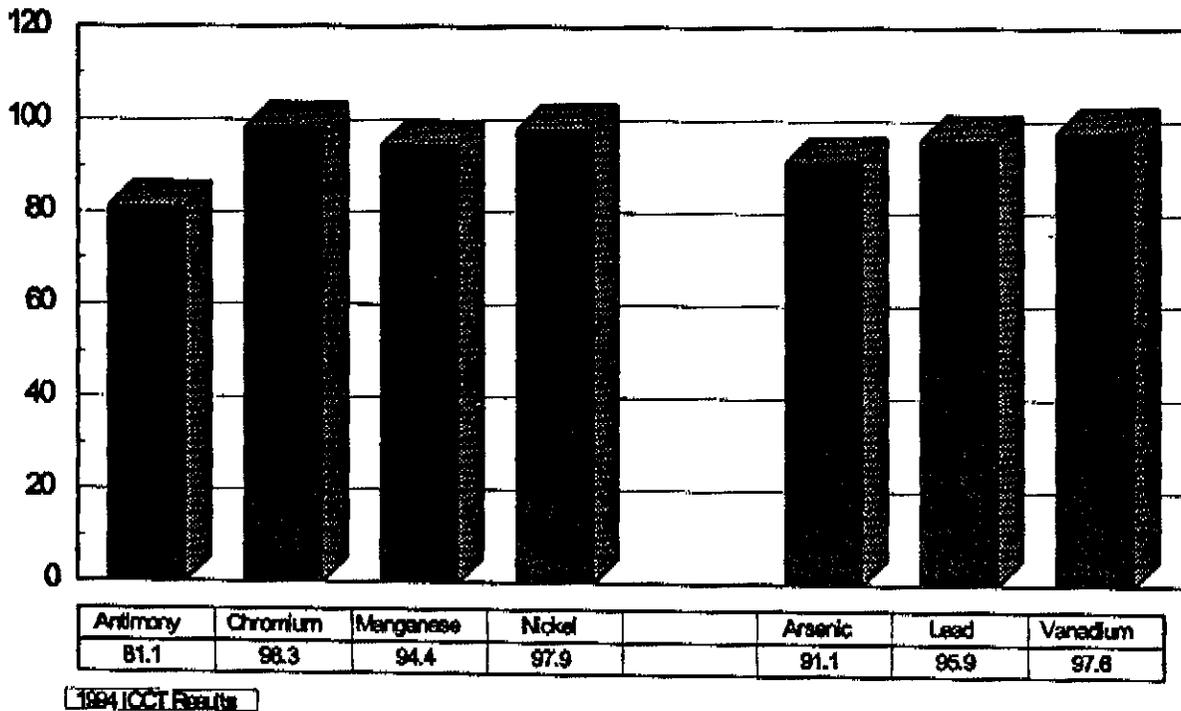


Figure 7. Calculated HAP Removals Across the CT-121 JBR