FGD Operation and Maintenance Costs:
A Function of First Cost - Or Is It?

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Abstract

The initial cost of an FGD system is affected by the quality of the materials and the standard of workmanship required to produce a functioning system.

It is generally accepted that this will improve the unit reliability and dependability. This paper investigates the relationship between the first cost and the system's operation and maintenance cost. These costs are reported on the Federal Energy Regulatory Commission (FERC) Form 67. This information was compiled and compared by Burns & McDonnell.

Flue gas desulfurization systems have been in operation since the mid-1970's. There are now a significant number of FGD systems in operation and a data base has been developed regarding both capital costs and operation and maintenance costs. It is generally accepted that additional capital costs can increase system reliability. This can be accomplished by improving materials of construction, providing excess capacity, or spare or redundant equipment items. Similarly, it is expected that additional capital costs would reduce maintenance costs and improve the overall system operation. However, improved reliability actually results in higher operation costs due to the increased reagent usage. A review of the available information indicates a correlation between higher first cost and higher maintenance cost. We were also able to conclude generally lower operation and maintenance costs and generally a lower levelized cost per ton of Sulfur Dioxide removal associated with limestone reagent systems.

The study was isolated on lime and limestone FGD systems. This was done because approximately 90 percent of the flue gas desulfurization systems in existence are lime or limestone.

Base-line data for this study was obtained through the Federal Energy Regulatory Commission office in Washington, D.C. The data was available on Federal Power Commission (FPC) Form 67. Unfortunately, not all of the information on these forms was complete and the number of units evaluated was reduced to obtain units reporting sufficient capital costs and operation and maintenance costs. In review of the operation and maintenance costs, it was recognized that operating costs can be misleading. Other than interest and depreciation, reagent cost is typically the greatest single component of operating costs. Poor utilization of reagent in the scrubber (or operating significantly above the theoretical stoichiometry) can result in unnecessarily high operating costs. On the other hand, very high reliability can also lead to the use of more reagent and, thus, greater operating costs. On the other side, very low operating costs can be experienced on units which are allowed to bypass the scrubber during malfunctions. As a result, units with excellent operating efficiency as well as units with very poor operating parameters can yield relatively high operating costs. This is not the case with maintenance costs. In general, maintenance costs are a reflection of the unit operating problems.

For our comparison, we used the capital cost information presented in the FERC forms. These values were adjusted for units which only scrub a portion of the flue gas. The end result is a dollars per total kilowatt of capacity being scrubbed. This represents a reasonable number for comparison purposes. We also developed a comparison based on dollars per acfm of flue gas.

The FERC data on total maintenance costs for limestone FGD systems was developed on a cost per unit power basis (mills per kWh). This is a standard unit for presentation of maintenance costs. However, there has been some suggestion that cost per unit capacity (dollars per kW) may be a better way to present this information because the boiler load factor does not enter into the cost calculations.[1]

It was noted during this study that the average dollars per kW and average mills per kWh costs were significantly less than similar values currently being reported in the literature. As a result of this, we did an additional investigation of capital costs. This investigation centered on units with which we were involved, and therefore, had accurate (actual contract) information readily available. These costs were escalated to 1986 dollars. Many capital cost estimates reported in the literature range from $140 to $180 per kW for existing units, and imply that retrofit units would cost approximately double this amount or more. This is not verified by our experience. This study presents actual numbers that are significantly less than those currently reported. The major differences appear to relate to the amount included for waste disposal systems, chimneys, and reheat systems. Our designs do not include a reheat system, which is significant, both in capital cost and operating cost.

References

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Biography

Mr. Norton is a Regional Manager with Burns & McDonnell, a 100% employee owned firm located in Kansas City, Missouri. He has worked on a variety of projects involving project management, design, environmental impact analysis and economic studies. Mr. Norton has served in both engineering and management capacities.

ABSTRACT

HOUSTON LIGHTING & POWER COMPANY

LIMESTONE ELECTRIC GENERATING STATION

UNIT 1 - 1985 INSTALLATION

UNIT 2 - 1986 EXTENSION

TRIAL OPERATION AND EXPERIENCE REPORT

FLUE GAS DESULFURIZATION SYSTEM

The Limestone Electric Generating Station is located 120 air miles north-northwest of Houston on a 3800 acre site near the junction of the Limestone, Freestone and Leon County lines.

Limestone Units 1 & 2 each consist of a Combustion Engineering corner fired CCRRD boiler, 5,520,000 lb/hr main steam and 5,000,000 lb/hr reheat steam, firing 657 tph of Texas lignite at an average heating value of 6,000 BTU/lb. The turbine generator is a General Electric tandem-compound unit with a guaranteed nameplate rating of 744 MW at design steam conditions. Four Lodge-Cottrell electrostatic precipitators per unit are provided for particulate collection, with a maximum expected collection efficiency of 99.95% at design conditions of 3,400,000 ACFM gas flow, 2.2 inches w.g. total pressure drop and 4.0 fps maximum gas velocity. The FGD system, provided by Combustion Engineering, consists of five spray tower absorbers (four operating/one spare) and sets of primary and secondary reaction tanks

per absorber. The system is designed for 90% sulfur dioxide removal below the EPA standards of 1.2 lbs. and So_2 per million BTU heat input when operating at a maximum design sulfur fuel of 8.24 lbs. SO_2 per million BTU. Limestone slurry is used for sulfur dioxide removal. The secondary dewatering and waste handling system, provided by General Electric Environmental Services, is designed to handle the sludge generated from the FGD systems using rotary vacuum filters and pug mills that mix dry fly sash with the sludge.

Construction started on the Limestone Project in October, 1981. The standby transformers for both units were energized in March, 1984. Unit 1 began trial operation on September 26, 1985 and was declared in commercial operation December 1, 1985. One year later, Units 2's trail operation began on September 17, 1986 and declared commercial on December 1, 1986.

Trial operation activities began on Unit 1 FGD system during May, 1985. The Furnish and Erect Contractor, Combustion Engineering and Houston Lighting & Power combined technical and craft forces in order to complete all checkout and trial operation activities in time for unit trial operation. Absorber wet runs began in September, 1985 followed by the first three sets of primary and secondary reaction tanks being charged with lime slurry on October 6, 1985. These three absorbers were placed in service on October 7 with the remaining towers being in service by late October. During initial trial operation, primary emphasis was to bring up and stabilize slurry pH as well as fine tuning controls.

Following commercial operation of Unit 1 through January, 1986, FGD system pH and makeup/recirculation water control loop problems were identified. The FGD system was operated with four absorber towers in service, three recycle pumps per tower in operation with slurry pH maintained at approximately 6.0 with no apparent SO_2 removal problems. In January, 1986, data obtained from certification tests of the stack continuous emissions monitoring system indicated that the FGD system SO_2 removal efficiency was out of compliance with NSPS and TACB regulations. Specific FGD emissions testing took place in late January that concluded that the FGD system SO_2 removal efficiency was out of compliance by a factor of 15 to 30 percent. During February, 1986, baseline SO_2 removal performance tests were performed on a "test" tower using various L/G ratios and slurry pH. Following baseline testing, it was decided to perform a series of tests using various concentrations of dibasic acid.

During March, 1986, diagnostic testing using concentrations of 500 and 1000 ppm diabasic acid (DBA) were performed separately on the "test tower" using various combinations of recycle pump operation and slurry pH. Results of these tests showed that for inlet SO_2 loadings ranging from 4.0 to 4.8 lb-SO_2/MBTU, SO_2 removal efficiencies ranged from 75 to 95 percent with 500 ppm (DBA) and from 89 to 90 percent using 1000 ppm (DBA). It was therefore concluded that (DBA) injection was required to maintain compliance with SO_2 emission regulations.

Combustion Engineering elected to proceed with modifications that altered flue gas and slurry liquid distribution within the "test" absorber. These modifications included redesigned spray nozzles (smaller droplet size), ball mill modifications (finer grind), flue gas inlet perforated plate modifications, inlet ladder vane orientation charges, and the installation of slurry "rain" gutters over the top of the absorber inlet penetration. Testing of these mechanical modifications was conducted in May, 1986. Data was collected during various operation configurations and levels of DBA. Tests results indicated no appreciable improvement in SO_2 collection efficiency.

Immediately, questions were raised by Combustion Engineering regarding the makeup water and limestone chemistry potentially influencing FGD performance. Burns and McDonnell consultants were commissioned and worked with C.E. to investigate the as received limestone and makeup water sources chemistry. They determined in July, 1986 that these factors were not detrimental to FGD SO_2 removal efficiency.

As a result of the modified spray nozzle tests, Unit 2 construction was released to install the original spray nozzle design. Only modifications involving gas path distributions were implemented on Unit 2 prior to its trial operation. Unit 2 absorber wet runs began in July, 1986, following spray nozzle installation. Wet runs continued on Unit 2 through August.

Following Unit 1 FGD mechanical modification testing, a comprehensive test program to assess the FGD system DBA requirements over the life of the plant was planned jointly with Combustion Engineering. The principle objectives of the program are: to determine the relationship between DBA concentration and FGD SO_2 removal efficiency; to quantify the relationship between DBA concentration, limestone utilization, and system power consumption as a function of SO_2 removal efficiency; to quantify the DBA addition rate to maintain a desired concentration of DBA in the recycle spray slurry; to identify a location and method in which DBA may best be added to the system; and to investigate system operating and waste disposal consideration resulting from DBA addition.

The test program was set up to be performed in four (4) phases. Completion of the program is expected in the Spring of this year. Prior to starting this test program, a system cleanup, equipment repair and calibration effort was required. This effort was completed in late October, 1986. A computer system for monitoring critical test data was also installed during this time.

Phase 1 of the test program was completed in November, 1986. This phase verified monitoring and data collection instrumentation calibration as well as verifying SO_2 removal efficiency of the individual absorber towers.

Phase 2 will be a series of ten (10) parametric tests to quantify the relationship between dibasic acid concentration, limestone utilization and system power consumptions as a function of SO_2 removal efficiency. By the end of January, 1987, five (5) of the ten (10) tests have been completed.

Phase 3 of the test program, currently scheduled to start March, 1987, will be conducted on Unit 2 by introducing DBA at various system locations while investigating the ability of the system to manage fluctuations in inlet sulfur loading and flue gas flow rate.

Phase 4, to begin after Unit 1's scheduled annual outage this spring, will confirm the DBA concentration which yields the best system operation using data collected from Phase 2. During this testing phase, the system will be operated in, as nearly possible, a steady state condition such that the DBA consumption rates may be quantified.

DESIGN OF MONTANA-DAKOTA UTILITIES 80 MW AFBC RETROFIT

By

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ABSTRACT

Montana-Dakota Utilities (MDU) Co.'s Unit 2 at the R.M. Heskett Station has recently been retrofitted to atmospheric fluidized bed combustion (AFBC). This bubbling-bed unit is designed to burn a high sodium North Dakota lignite. The unit is expected to show improved overall performance and increased boiler capacity as a result of the retrofit. The new AFBC combustor was designed and installed by Babcock & Wilcox (B&W). This project is currently the largest utility AFBC contract funded solely by the utility itself.

To evaluate and determine appropriate design parameters, a test burn of the fuel was conducted on the 6 ft by 6 ft AFBC test facility at the B&W research center. During this test, potential agglomeration problems such as those encountered by the University of North Dakota Energy Research Center (UNDERC) when burning this fuel were investigated. Other objectives of the test burn were to evaluate the overall operability performance, especially combustion efficiency, and to evaluate emissions characteristics, focusing primarily on expected ESP performance.

Results of this pilot testing and the successful retrofit of the MDU facility demonstrate that FBC can satisfy utility markets' increasing need for power plant upgrades, utilization of available low cost fuels, and emission reductions. The importance of pilot testing to determine the optimal design and operating requirements of a utility system was clearly demonstrated during this project. Results from the pilot testing and the design of the 80 MW retrofit are discussed. Available information on the construction and startup of the unit are also presented.

INTRODUCTION

In 1985, Montana-Dakota Utilities Co. (MDU) initiated a project to retrofit a 23 year old stoker-fired boiler to a bubbling fluid bed. The purpose of this retrofit was to increase the capacity and improve the overall unit performance of Unit 2 at the R. M. Heskett Station in Mandan, North Dakota. This stoker, originally rated at 650,000 lb/hr steam, is believed to have been the largest of its type in the country. After retrofit, the capacity will be increased to 700,000 lb/hr steam.

The fluid bed combustor (FBC) will fire Beulah North Dakota lignite. This lignite is characterized by a high alkali content, with sodium oxide levels as high as 12% in the ash. This high sodium level has caused clinkering and fouling problems when used in the stoker system at the Heskett station and was demonstrated to have an agglomerating tendency during FBC testing at the University of North Dakota Energy Research Center (UNDERC) (1,2,3). Therefore, a test burn of the fuel was conducted on the 6 ft by 6 ft AFBC facility at the Babcock & Wilcox (B&W) research center to investigate potential agglomeration problems associated with this fuel. Another major objective of this test burn was to evaluate and determine design parameters for the MDU retrofit.

The retrofit of the stoker-fired boiler to an FBC required minimal changes to the existing system. The existing spreader feeder system was reused. Few modifications to existing pressure parts were required. New equipment or modifications installed during the retrofit include a tubular type air heater, forced draft fan, control system modifications, and various auxiliary fluid bed systems. These changes have been discussed previously (4,5) and will be reviewed in this paper.

This project exemplifies how fluidized bed combustion can satisfy the market's increasing need for power plant upgrades, utilization of available low cost fuel, and emissions reductions.

BACKGROUND

Operational History

Unit 2 at Montana-Dakota's Heskett Station was placed in commercial operation on November 1, 1963. This Riley lignite-fired stoker was rated at 650,000 lb/hr steam at 1300 psig and has a General Electric turbine with a nominal rating of 81.2 MW at a steam flow of 682,700 lb/hr. Slagging and fouling were experienced when the unit was loaded near the original rating, reducing the effective load-carrying capacity of the boiler. Many different fuel additives were tried throughout the years; however, none were successful in reducing the slagging or fouling for long-term periods. The installation of water lances near the high temperature superheater tubes was successful in removing some of the slag on the superheater, but had limited overall success in improving continuous steam output.

Another problem experienced in burning the Beulah lignite was the build-up of a porcelain-type coating on the generating tubes between the two boiler drums. This deposit on the generating tubes was directly related to the amount of sodium found in the lignite ash. Due to the close tube spacing, the installation of sootblowers was impractical. Therefore, it was necessary to shut down the unit twice per year for water washing to remove the deposit.

The slagging and fouling also caused reduced combustion efficiency. This reduction was due to the unburned carbons that went to the bottom ash hoppers and from the carbon carryover past the reinjection hoppers and into the dust collectors. This reduction in efficiency, as well as the load reductions caused by the slagging and fouling, prompted MDU to seek alternatives that would allow Unit 2 to operate at full capacity. Fluid bed combustion was one of these alternatives.

Description of Unit

The overall arrangement of the unit is typical of most stoker-fired boilers. A sectional side view of the unit as it existed before the retrofit is shown in Figure 1a. The furnace is approximately 40 ft wide by 21 ft deep and contains three water-cooled wing walls. The furnace wall construction is a water-cooled tube and tile construction with a cold gas-tight casing. The wing walls, which are fed by downcomers from the lower drum, penetrate the lower rear furnace wall, rise through the furnace, and connect directly to the upper drum.

The convective pass contains superheater, steam generating, and economizer surfaces. The superheater is an all pendent-type. The generating surfaces have a 60-inch diameter upper drum and a 36-inch lower drum with all long-flow heating surface. The economizer surface is a bare-tube-counterflow type. The superheater and generating bank enclosure is of water-cooled tube and tile construction, while the economizer enclosure is refractory and insulation lined. Both enclosures have a cold gas-tight casing.

The coal feed system consists of three coal bunkers, three conical coal distributors, and ten stoker spreader feeders. The ten stoker spreader feeders are evenly spaced along the front wall of the furnace. Each unit has a separate cup-type rotary volumetric feeder with a drum-type rotary flipper.

Flue gas and air handling equipment consists of a multicyclone-type dust collector, one regenerative-type air heater, one FD and one ID fan, and an electrostatic precipitator. The multicyclone dust collector is used for the first stage of particulate control only. Ash from the collector is removed by the plant ash handling system, and is not reinjected to the furnace. Ash reinjection in the stoker originates in the boiling bank hopper only, and is accomplished pneumatically through the lower rear wall with injection air provided by a separate cinder return fan.

DESIGN GOALS

The design goals for the retrofit AFB boiler at the Heskett Station were based primarily on economic considerations. To minimize the overall project cost and maximize the benefits, the design goals were to:

- o Increase the boiler capacity to meet the existing turbine capacity;
- o Use a local river sand as bed material;
- o Reuse existing coal handling and feed systems;
- o Reuse existing side wall pressure parts, including the lower header walls;
- o Bottom-support the tubular air heater and fluid bed to limit structural steel modifications; and

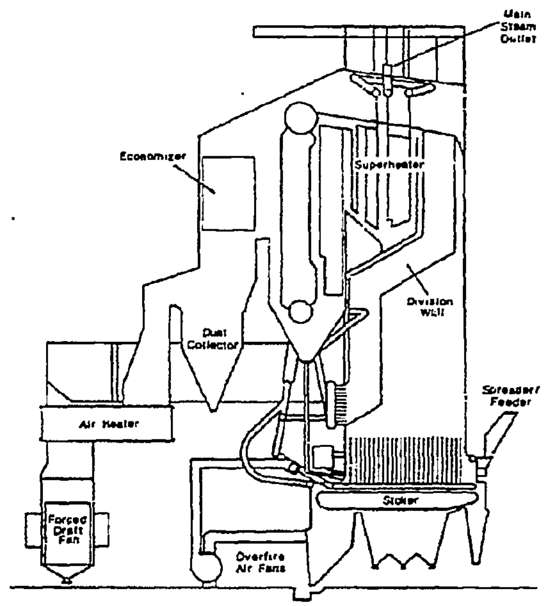

Figure 1a. Side View of Existing Boiler at Montana-Dakota's Heskett Station, Unit 2.

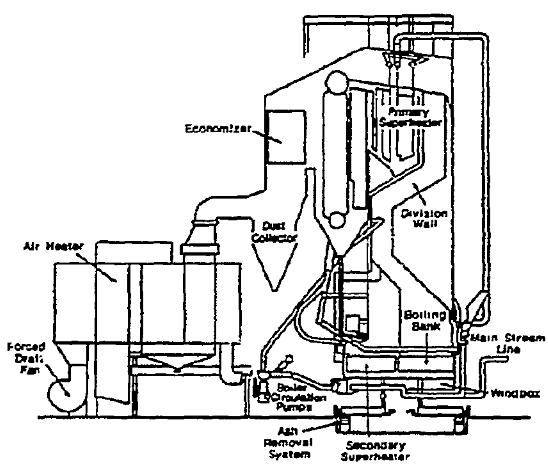

Figure 1b. View with Fluidized Bed and New Air Heater Added.

o Reuse the existing electrostatic precipitator and ID fan.

To help achieve these goals within the physical limitations of the existing boiler and the nature of the Beulah lignite, a test burn was performed. Results from the test burn were used to make the goals of the design a reality.

RESULTS OF TEST BURN

Test Objectives

Design parameters and concepts selected for this retrofit project were evaluated and verified in test burns of the fuel by B&W. While much fluidized bed combustion test data was available, little or no data existed for lignite fuel as overbed feed. In addition, previous research studies at UNDERC showed that bed agglomeration is a potential problem while firing this fuel (1,2,3). This agglomeration is believed to be caused by the formation of low-melting temperature eutectics from the sodium in the fuel ash.

Two test burns were performed at the B&W Alliance Research Center. The first test was for a duration of 250 hours and was performed on the 6' x 6' test unit. During this test, the necessary design data were collected, including operability performance, combustion efficiency, and emissions. In addition, operational procedures were investigated which would allow continued operation even in the event of agglomeration. A later 116-hour test was performed on B&W's 1' x 1' test unit to verify the necessary bed material turnover rates needed to prevent the catastrophic formation of agglomerates. Results from these test burns are discussed. A description of these test units can be found elsewhere (6,7).

A sample of lignite typical of that fired at the Heskett Station was used for the test burns. An analysis is presented in Table 1. In addition to using the same fuel, the fuel was prepared to have a particle size distribution similar to that fired at the Heskett Station. Using overbed feed, the particle size distribution can have a significant effect on performance. Of particular interest was the effect of the amount of fines on the bed-to-freeboard combustion split. Also of interest was the amount of rock material which might be present in the larger size fraction of the fuel.

Discussion

Overall performance during the test burns was satisfactory and close to that expected. No major operational problems were encountered while operating at design conditions. During testing on the 6' x 6' unit, three types of agglomeration were seen. The first type is characterized by a cluster of bed particles sticking together to form agglomerates about one-inch in diameter. These "egg" type agglomerates had hollow centers and a number of holes in the outer surface. One of these "egg" type agglomerates is shown in Figure 2. These agglomerates formed during a test period with low excess air and a high bed depth. It is likely that under these low conditions, reducing conditions were present in the bed.

TABLE 1

COAL AND ASH ANALYSIS

Proximate Analysis, % As Burned		Ash Analysis, %	
Moisture	32.6	SiO_2	16.2
Volatile Matter	26.7	Al_2O_3	11.6
Fixed Carbon	33.6	Fe_2O_3	11.7
Ash	7.1	TiO_2	0.2
		CaO	19.7
Ultimate Analysis, % As Burned		MgO	5.3
		Na_2O	8.5
Carbon	44.1	K_2O	0.8
Hydrogen	3.0	SO_3	25.5
Sulfur	1.3	P_2O_5	0.1
Nitrogen	0.7		
Oxygen	11.2		
Ash	7.1		
Moisture	32.6		
Heating Value, Btu/lb	7530		

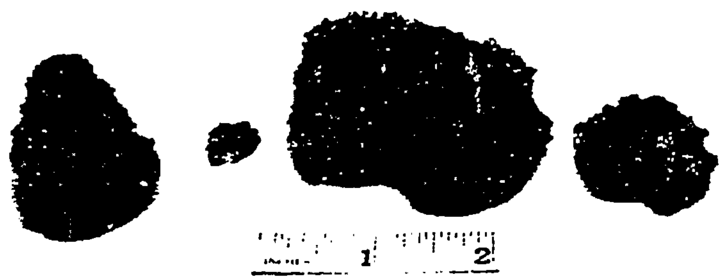

Figure 2. Agglomerates Found in Bed Material When Combusting Beulah Lignite in an AFBC Unit.

(Far Left From 6' x 6', Middle Two From 1' x 1', and Far Right From UNDERC)

In tests performed at UNDERC to examine the effect of excess air level on agglomeration, similar agglomerates were seen (8). Under these conditions, particles of coal will tend to gasify, rather than combust. The initial phase of devolatilization and evolution of the tars makes the surface of the coal particle sticky. Bed particles stick to the hot, tarry coal particle, trapping the coal particle. As the process continues, the coating of bed particles keeps the heat localized in the coal particle, causing the particle to become much hotter than the bulk of the bed, and the bed particles fuse together on the coal particle surface. As the coal continues to burn out, the escaping gases form a porous nature of the agglomerate, and leave the agglomerate hollow after the coal is burned.

During the testing, it was determined that a build up of these "egg" type agglomerates could be controlled by maintaining a constant bed drain while adding fresh sand to keep a constant bed depth. It was also seen that the formation of this type of agglomerate was virtually non-existent when the test conditions were changed to a lower bed depth (4 ft) and the excess air level increased (5% O_2). These changes had the effect of improving the fluidization quality and increasing the availability of oxygen for combustion.

The second type of agglomerate was noted after the start of ash reinjection. These "ash" agglomerates appeared to be composed of finely divided ash particles which were fused together. It appeared that during the testing that the removal rates used were inadequate to remove these agglomerates as fast as they formed resulting in a net accumulation. From the results of the testing, the effect of using overbed versus underbed ash recycle on the ash agglomeration process was not clear. Based on the test results, it is recommended that ash recycle of the proportion used during the tests at Alliance not be used in a commercial plant firing Beulah lignite. Tests at UNDERC indicate that a small level of recycle (50% of the coal feed rate) may be possible without severe "ash" agglomeration.

A third type of agglomeration was noted during testing on both the 6' x 6' and the 1' x 1' units. This agglomeration is characterized by individual bed particles sticking together, and is typical of the agglomeration noted at UNDERC (see figure 2). These sand agglomerates are loosely bonded when initially formed, and develop strength over time. The agglomerates formed during testing on the 6' x 6' test unit crumbled easily into smaller pieces during draining of the bed. No evidence of the loose sand agglomerates was found at the outlet of the bed drain screw on the 1/4" x 1/4" screen. Two small agglomerates (3/8-inch and 2-inch diameter) were formed during tests on the 1' x 1' test unit. Although these agglomerates did not cause any significant operating problems, they do indicate that conditions in the bed were approaching the condition for the onset of severe agglomeration such as the type noted by UNDERC (1,2,3,7). Bed particles taken from periodic bed drains and from the end of the tests were coated with ash. This ash coating was typical of that formed during the first two stages of the proposed four that can lead to severe agglomeration (1).

The results of the test burns at B&W's Alliance Research Center and UNDERC indicate that there is a potential for agglomeration to occur in a commercial FBC when firing Beulah lignite. However, it was also demonstrated that, by proper operating procedures, i.e., adequate bed replacement, the agglomeration process can be controlled to allow acceptable operation of the FBC. The tests at Alliance indicated that for the coal sample tested, a bed turnover every 50 hours would be required. Based on the observations during the ash recycle tests, a high level of ash recycle would not be recommended.

A combustion efficiency of approximately 96% was obtained using overbed feed without ash recycle in B&W's pilot AFBC's. A higher efficiency is expected in the MDU retrofit based on the longer freeboard residence times (5 seconds at the Heskett Station versus 1.8 seconds in the 6' x 6'). The sulfur capture during the test burns ranged from 39% to 56% based on flue gas measurements during the testing at Alliance. These high levels of sulfur capture in the sand bed can be attributed to the alkali in the lignite. No sorbent addition is planned for this FBC as the sulfur emissions are within MDU's current limits. NO_x emissions measured during the pilot testing ranged from 0.33 to 0.47 lb/MBtu and are within NSPS for the Heskett station.

Fly ash resistivity measurements were performed on samples from the B&W's 6' x 6' baghouse and MDU's Heskett Station electrostatic precipitator. Both samples indicated roughly the same resistivity, 3.2×10^9 and 3.0×10^9 ohm-cm, respectively. Therefore, assuming no major differences in particle size distribution, the fly ash generated from the AFBC retrofit should be as easy to collect in the ESP as that from the existing stoker fired unit at Heskett Station. This indicates that, if the fly ash loading is similar between the two units, the existing ESP can be used for fly ash collection after the retrofit.

FLUID BED DESCRIPTION

Performance Parameters

The fluid bed plan area is approximately 40 ft wide by 25 ft deep. The plan was limited by the existing unit arrangement. Operating conditions for the AFBC are given in Table 2. The primary factor setting the fluidization velocity was the available maximum bed plan area and the bed depth was set by the height of the in-bed tube surface. A view of the retrofit AFBC is shown in Figure 1b.

The fluid bed contains both boiling and superheater surface. The boiling surface is located in the front of the bed and the superheater is in the rear of the bed. Both are horizontally positioned, and span the entire 40-foot width of the unit. All in-bed surfaces are provided with additional wall thickness to protect against the abrasiveness of the selected bed material. Erosion-type shields are installed in those areas where higher erosion rates are expected. The entire in-bed tube bundle design and tube spacing is set with adequate clearance to prevent bridging of potential oversized bed material.

The distributor plate is a water-cooled membrane type with bubble caps for air distribution. The windbox, located below the water-cooled distributor plate, is divided into four main compartments for load control. Additional compartmentalization is provided to facilitate start-up operations and to allow for partial compartment fluidization.

TABLE 2

OPERATING CONDITIONS FOR THE MDU AFBC RETROFIT

SELECTED PERFORMANCE PARAMETERS	
Fluidization Velocity	12 ft/sec
Normal Bed Temperature	1500°F
Bed Depth	51 inches
Overall Excess Air	25%
Air Heater Gas Exit Temperature	275°F
Bed Material	Sand
STEAM CONDITIONS	
Superheater Flow	700,000 lb/hr
Superheater Outlet Pressure	1300 psig
Superheater Outlet Temperature	955°F
Feedwater Temperature	443°F

Changes Made During Retrofit

To accommodate the new equipment required for the retrofit, several existing systems were removed including the stoker grate, stoker ash hoppers, and grate cooling fan to allow installation of the fluid bed proper. The overfire air fans, cinder reinjection fan, and associated flue and duct work were removed to allow for installation of boiler circulation pumps. In addition, the existing regenerative air heater, along with associated flue and duct work was taken out to allow for installation of the new tubular air heater. The FD fan and motor were replaced.

Pressure part modifications were kept to a minimum. The only major water-side pressure part change was the removal of the existing lower drum-end downcomers, to and including the existing wing-wall inlet headers. These downcomers were rerouted to feed the inlet of the boiler circulation pump. The wing wall tubing was also removed to a point just inside the furnace. The main steam piping was modified to connect the superheater section to the new in-bed superheater.

New downcomers were connected to the existing lower drum and routed to new boiler circulation pumps located at the rear of the unit. From the pumps, supply tubes are routed to the fluidized bed floor, in-bed boiling surface, and to the bed enclosure walls. The entire bed enclosure and distributor plate is of water-cooled membrane type construction. All new water circuits, including the bed enclosure tubes, floor tubes, and in-bed boiling bank are routed and connected directly to the existing furnace wing walls.

Steam side pressure part modifications were also minimal. The convective superheater was reused. The main steam line leading from the convective superheater has been rerouted to connect to the new in-bed superheater. From the new in-bed superheater outlet, a new steam line has been added and routed back to the existing main stream line to the turbine. A new superheat attemperator has been added in the new interconnecting piping between the convective pass and in-bed surface.

The entire coal handling and feed system was reused. The only change made was grouping the feeder drive controls for control on a bed compartment basis. To remove bed material, seven letdown systems consisting of individual drain points, downspouts, valves, and ash coolers was installed. Since sulfur capture is not a requirement, a relatively small amount of sand will be used to maintain a bed instead of the larger quantities of limestone required for most fluidized bed boilers. Because of this the bed drain rates will be relatively low. However, of major concern with this retrofit is the removal of oversized bed material, i.e., agglomerates. The number, sizing, and locations of the bed drain systems were set by oversized material removal requirements.

The old regeneration air heater was replaced with a new tubular-type air heater. This replacement was required due to the higher air side pressure requirements and the desire to reduce the flue gas exit temperature from the air heater to improve performance. Additional requirements were space limitations and a gas side pressure drop not exceeding the existing ID fan static capacity. The new air heater which has been installed is a three-gas pass, one-air pass arrangement.

Because of the higher air-side pressure requirements, the existing FD fan and drive were replaced with a new single, centrifugal-type fan. The original two overfire-air fans and cinder return air fan were eliminated. The overfire air ports and boiler-hopper-cinder return system were reused. The air for these systems will be taken directly from the new secondary air system, with all air being provided by the new FD fan.

Since the new fluidized bed combustor enclosure walls, floor, and in-bed boiling surfaces are mostly horizontal, water circulation through these circuits must be pump-assisted. Three, 50% capacity, wet motor-type pumps were installed to pump these circuits. Only the new fluidized bed combustor water circuits, all of which connect directly to the existing furnace wing walls, will be pumped. All the remaining furnace enclosure walls and the boiling bank remained in natural circulation.

Other changes and modifications required to complete the retrofit included control systems modifications, addition of a sand handling and feed system, rerouting and new flue and air ductwork, and addition and modification of structural steel and foundations.

CONSTRUCTION AND STARTUP

MDU determined the most beneficial construction schedule to be from November 1986 through March 1987. Factors affecting this decision were the availability of power at reasonable costs during this period of time and a light load period during the couple months following initial coal fire to facilitate start-up problems. With such a short construction schedule, it was recognized that close coordination between MDU; Black and Veatch, the consultant for the balance of plant equipment; and Babcock & Wilcox, the AFBC supplier and constructor; had to be established to achieve the project schedule.

Demolition of the unit was started October 14, 1986. Demolition was completed and construction had begun by October 31, 1986. The unit was hydrostatically tested February 18, 1987, and the first coal fire was during the week of March 25, 1987.

The bed enclosure and in-bed service components were shop modularized to help meet the tight erection schedule. The 40 to 50 ton modules were positioned beneath the existing furnace by using a track for rolling the modules on and into position. Once the three modules were in beneath the furnace, they were then raised into their final position by a hydraulic jacking system. Other components which were modularized were the air heater, the connections to the furnace division walls, flues, and ductwork.

BENEFITS

The fluidized bed retrofit is expected to greatly improve boiler efficiency and operation. The unit originally was load-limited due to furnace slagging and fouling of the convective pass when lignite was fired on the grate. The lower combustion temperature of the FBC will greatly reduce the fouling and slagging, and capacity is expected to increase from 50 MW to 80 MW in continuous operation.

The elimination of fouling and slagging will increase the boiler availability. Decreased availability resulted from a unit shutdown twice a year to remove slag from the convective pass.

The exit gas temperature from the air heater was approximately 70°F greater than design when the unit was fired as a stoker due to the effects of fouling and slagging. The gas temperature will be reduced to the original design values after the retrofit as a result of elimination of slagging and fouling, increasing the efficiency of the unit by almost two percentage points.

The fluid bed retrofit will allow continuous use of the local Beulah, North Dakota lignite.

In summary, Montana-Dakota Utilities expects the unit's thermal efficiency, availability, and capacity to be increased by retrofitting the stoker-fired steam generator with a bubbling fluidized bed while continuing to burn a locally available fuel.

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Capital Costs for Fluidized Bed Installations Utilizing Lower Grade Fuels

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Because large-scale, commercial fluidized bed boiler technology has only recently been introduced in the U.S., there is limited published information available on the capital costs of such facilities. This paper will provide insight into the typical range of capital costs for large (50-200 MW) fluidized bed projects for industrial generation or utility power plants. In addition, the paper will address, based upon our experience, the fundamental factors which cause the costs to vary on a project-to-project basis.

Burns & McDonnell is involved in a number of large fluidized bed cogeneration projects for which capital costs have been determined. These costs have been established, for the most part, by obtaining firm, lump sum bids for the entire project or, in some cases, by developing definitive costs estimates. This cost data has been tabulated in a form which permits relationships to be derived between capital cost and two sizing criteria: the rated boiler steaming capacity and the electrical output of the plant.

The tabulated cost data will cover four or five fluidized bed projects, utilizing lower grade fuels, including the steam flows and electrical capacities. The owners and locations of the individual projects will not be revealed in the tabulation.

NORTHERN STATES POWER COMPANY
BLACK DOG GENERATING PLANT - UNIT 2

Update of the Black Dog Atmospheric Fluidized Bed Combustion Project

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ABSTRACT

The Black Dog Project is a 130 MW Atmospheric Fluidized Bed Combustion (AFBC) boiler retrofit firing western coal in a fluidized limestone bed. Initial operation was in July of 1986. The Unit 2 boiler at Northern States Power Company's (NSP) Black Dog Plant was originally commissioned in 1954 as a pulverizer coal boiler rated at 100 MW. When firing western coal the unit was down rated to 85 MW. In late 1984 work began to extend the life of the unit and convert it to an AFBC. The conversion not only returned the unit to its original capacity but increased capacity to 130 MW.

This paper is an update of the project's progress through January 1987 and discusses the design, start-up activities and experiences of note encountered by the project to date. The specific areas that will be addressed are the AFBC boiler operation from steam blow through commercial operation.

INTRODUCTION

Northern States Power Company (NSP), headquartered in Minneapolis, Minnesota, serves more than 1.5 million gas and electric customers in an area over 49,000 square miles (Fig. 1). NSP's system consists of 46 electric generating units with a combined capacity of over 6,200 MW. In 1985 approximately 43 percent of the electrical output was generated from coal fired plants, 41 percent from nuclear fueled plants, and 16 percent from hydroelectric and other sources.

NSP has demonstrated a strong history of involvement with new environmental control technologies for electric power generation. One of the most recently completed and operating endeavors is the Black Dog Generating Plant Unit 2 AFBC Retrofit (Fig. 2). Unit 2 was upgraded and refurbished to burn 100 percent Sarpy Creek Coal, with Linwood Limestone as the sorbent, thereby extending the unit's life another 25 years and increasing its capacity by 30 percent. By converting to fluidized bed, new environmental emission standards could easily be met.

PROJECT SCOPE

Technical scope of work for the Black Dog AFBC Project consisted of the following:

- Adding a new sorbent receiving, handling, storage and feeding system.

- Modifying the existing coal handling, feeding and storage system from the in-plant coal storage silos to the spreader feeder inlets at the boiler.

- Retrofitting the boiler and boiler auxiliary systems to the Foster Wheeler AFBC design.

- Upgrading of the particulate removal system and adding a new hot multiclone dust collection system to enhance particulate removal and provide overbed hot fly ash recycle to the furnace.

- Refurbishing and upgrading the Westinghouse Turbine-Generator.

- Refurbishing and upgrading the Unit 2 Condensate and Feedwater Systems.

- Retrofitting the existing control systems to a microporcessor based distributed control system.

- Modifying the existing structural steel and the existing platforms and walkways to accommodate the new AFBC system.

- Upgrading the existing electrical auxiliary system to service the new AFBC load requirements.

- Modifying the existing plant facilities and services as necessary.

- Perform initial inspection of the AFBC boiler and related systems for erosion, refractory damage, expansion problems, cleanliness of the convection pass and airheater, etc.

- Completion of the initial operation punch list items (1986).

BACKGROUND

Original Steam Generator Description

The original Black Dog Unit 2 Boiler (Fig. 3) was a Foster Wheeler non-reheat steam generator with a maximum working pressure of 1,770 psig, a maximum steaming rate of 860,000 lb/hr and a final steam temperature of 1,000 F.

The unit had a fixed external pressure casing with top supported pressure parts and was front wall fired with pulverized coal, oil, or natural gas.

A few pertinent characteristics of the unit, as originally designed, are listed below.

- The furnace front wall consisted of both up and down flow radiant superheater circuits.
- The unit contained a full furnace division wall.
- The unit had no furnace arch.
- At the top of the convection pass gas velocities reached 70 fps.
- The horizontal convection pass and economizer surfaces consisted largely of gilled ring extended surface tubes.
- The two (2) regenerative type air preheaters were located directly below the economizer and were subject to plugging from sintered ash and broken refractory.
- When firing western coals, the unit load was curtailed to approximately 85 MW gross generation due to both pulverizer and fan capacity limitations and furnace slagging problems.

AFBC RETROFIT DESIGN

New AFBC Steam Generator And Auxiliaries

Table 1 shows the predicted performance for the Foster Wheeler AFBC Boiler. Figure 4 is a sectional side view of the unit as of the completion date in 1986.

Due to existing design limits of the existing boiler and it's related auxiliaries, and due to NSP's desire to increase the unit's rating from 100 MW to 130 MW, certain project design features were necessary. These features are as listed below.

- Bed superficial velocity was specified at 10 fps maximum to minimize the carryover of unburned coal and unreacted sorbent and thus reduce the recycle rate to levels approaching those used on stoker coal-fired units.

- The design of the convection pass gas velocities was set at less than 50 feet per second at the maximum continuous rating (MCR) of the unit. This criteria was established to prevent the tube erosion in the convection pass during 100% recycle operation. The particulate loading to the existing particulate removal system was also maintained at suitable levels through proper recycle system design so that the outlet loading from the unit can be controlled to NSP's Emission Levels without replacement of the precipitators.

- The unit would burn Sarpy Creek Coal as well as other sub-bituminous coals and lignites with a maximun SO_2 removal requirement of 80 percent. Sulfur capture would be from the limestone sorbent and the available alkali in the coal ash (Table 2).

- Alternate fuels such as refuse derived fuels, petroleum coke and higher sulfur content eastern coals will be test fired in the unit to determine their potential use.

- The unit was designed with an overbed coal and sorbent feed system because of the project teams strong preference for the relative simplicity and reliability of this design as compared to the existing under bed designs.

- Overfired air ports located above the coal feeder inlets disburse the incoming coal fines and increase carbon burn-up.

- The two existing air preheaters were replaced by a single regenerative air preheater, complete with an automatic low leakage seal adjustment system.

- A new hot multicyclone dust collector was added between the boiler outlet and the air preheater to help reduce the particulate loading to the precipitators and to collect higher carbon content fly ash to be recycled when necessary through the over bed reinjection system.

- New forced draft fans and modified induced draft fans were installed for the higher static head and flow requirements of the AFBC System.

The lower furnace plan area was expanded to the north and south sides by the addition of wing cells. This was to increase the unit capacity while maintaining a maximum superficial velocity of 10 fps. More flexible turndown rates were available with this single main cell and double wing cell configuration. This approach also required minimum modification to the existing boiler support steel and reduced the complexity and cost for the coal and sorbent feed systems. The new AFBC lower furnace is bottom supported, while the upper furnace remained top supported from the existing steel. No new pilings or substructures were required for the retrofit.

The unit is designed to provide a turndown capability of approximately 5:1 with superheater temperature of 1,000 F from 50 to 100 percent load.

The retrofit boiler is designed for variable pressure operation by use of a pressure reduction station upstream of the primary superheater. Combined with the in-bed finishing superheater loops this arrangement is designed to offer maximum turbine temperature and pressure matching during hot restarting.

The Black Dog AFBC boiler design approach did require a circumferencial seal around the furnace to accommodate the differential expansion between the top-supported existing furnace and the bottom supported fluidized bed section. This seal is a combination water/mechanical and slipjoint seal located approximately midway up the main furnace height where the furnace pressure is balanced.

The steam generating circuits of the AFBC, including the main furnace and convection pass waterwalls, are force circulated.

The design residence time in the furnace of approximately 4 seconds should result in a relatively low recycle rate requirement for achieving the guaranteed unit sorbent utilization rate and coal combustion efficiency. The design results in an arrangement of the coal feeders, sorbent feeders, overfired air ports and ash reinjection ports similar to a conventional stoker fired unit.

Reliable and economic opration of the unit is the goal of all these specific AFBC design considerations.

DEMOLITION

Demolition and relocation work for the boiler retrofit commenced on September 13, 1984 and included complete asbestos removal from all Unit 2 equipment. The only remaining demolition is that associated with the 1987 spring turbine outage to upgrade the turbine/generator (T/G). This work includes modifications to the steam chest and main steam inlets, turbine rotors and internal casings, generator rotor, T/G electro-mechanical controls, excitor, and miscellaneous interconnecting piping and controls.

CONSTRUCTION

The initial AFBC construction effort started in mid-September 1984 with NSP's asbestos removal, relocation efforts and demolition. NSP also dismantled the T/G to facilitate Westinghouse's life extention study inspection. With completion of the asbestos removal, NSP purchased the necessary structural steel for Foster Wheeler Energy Corporation (FWEC) and the mechanical contractor to mobilize in February of 1985. Mechanical and electrical/I & C mobilization took place in July and August of 1985, respectively. The boiler was hydro tested in January 1986. First coal fires occurred in June of 1986 followed by the unit being declared commercial in July of 1986.

The only remaining construction effort is to install the fly ash reinjection system piping and the ash weighing systems presently scheduled for the spring of 1987 and the upgrading of the T/G set to its final 130 MW capacity in spring of 1987.

START UP-INITIAL OPERATION

Summary

Start-up of the AFBC Boiler and balance of plant was performed by a co-ordinated effort by start-up teams from NSP, SWEC, and FWEC.

The inital effort was in May of 1985 with development of the start-up schedule and proceeded with the establishment of the administrative and safety tagging procedures. Mechanical testing procedures were also written for major start-up procedures such as: boiler air test, preboiler chemical cleaning, boiler chemical cleaning, and main steam line blowing. The boiler hydro procedures were developed by FWEC.

The Black Dog site start-up operations officially started in March of 1986 with the arrival of the NSP start-up group. The group consisted of a Start-up Superintendant, (part-time) Lead Start-up Engineer, three System Start-up Engineers, one I & C Engineer and one Electrical Engineer. Responsibility for all hard-wired electrical checkout, prior to turn over to the start-up teams, was by NSP's Electrical Construction Test Group (ECT). The Black Dog Plant I & C Group was responsible for all instrument calibration and instrument loop checkout. The NSP Special Forces Group, assigned to the Black Dog Station, provided pipefitter support to the start-up program for temporary hookups and restoring systems to operation.

The start-up activities (Table 3) commenced with the boiler hydro on January 6, 1986. The condensate pumps were run on March 6, 1986 in preparation for boilout. Preboiler chemical cleaning was started on March 14, 1986. FD Fan # 21 was run on March 22 in preparation for the boiler air test, which was run on March 24, 1986. Gas burner test firing began on April 28 and boiler chemcial cleaning began on May 5, 1986.

Main Steam blowing started on May 21, 1986 and was completed on May 29, 1986. The fluided bed was charged with sand on June 16, 1986. The unit reached 40 MW for the first time on July 9 and the unit was accredited for 42 MW on July 21. Accreditation to 89 MW was received on July 28, 1986, when the unit was declared commercial. Late July 28 the unit tripped and a 23 day outage commenced to correct system start-up problems associated with the steam generator as well as the precipitator and the ash handling system.

Boiler Cleaning Operations

Table 4 outlines a chronology of the various chemical cleaning phases of the unit. Test firing of the gas burners delayed commencement of chemical cleaning from the scheduled date of April 29, 1986 to May 2, 1986.

Two additional hot boiler rinses were performed on May 16 and 17 to remedy excessive foaming in the boiler when the unit was restarted for steamblows.

Steam Blows

The steam blows were conducted in four separate phases:

- Phase I steam blows consisted of the auxiliary steam line through the pegging steam line to the DA Tank. This was done on May 21, 1986 and took a total of 10 steam blows to clean the line.

- Phase II steam blows were through the auxiliary steam line to the steam coil airheaters. Three very long continuous blows of 30 minutes each, conducted on May 22, were sufficient.

- Phase III steam blows were through the superheaters and main steam line. The blows were started on May 22 and continued for eight days. A total of 46 steam blows were made.

  A 24 inch hydraulicly actuated blow control valve was used with an outlet pipe silencer that reduced the noise level to 65 DB at 1000 ft.

- Phase IV steam blows were through the turbine bypass valve into the condenser. 5 blows on May 30, 1986 were required.

Acceptance targets were only used on Phase III steam blows. These targets were accepted by NSP on May 29, 1986.

Boiler Safety Valve Setting

The boiler safety valves were hydroset on May 29, 1986. All testing and setting was completed by the valve manufacturer's field representative with the assistance of NSP's mechanics. All set pressures were verified by NSP, FWEC and SWEC representatives.

Steam To Turbine

The turbine was rolled off of turning gear for the first time after the retrofit on June 27, 1986 at 11:20 P.M. Only gas fires were used to maintain steam flow. The unit load was held between 4 and 6 MW for load protection relay testing.

On July 21, 1986 the unit was back on line and was accredited for 42 MW on July 21 after a 12 hour run. The unit tripped at 1:30 P.M. on the same day. Fast bus transfer tests were done on July 23 and the fans were run to tune up furnace pressure control loops.

The unit was back on line July 26, 1986 and attained a load accreditation of 89 MW on July 28, 1986. While lowering load the unit tripped. The flyash storage silo was found full, so the unit remained down for this and other outage work. During this outage the precipitators were inspected and sand blasted clean. Some inbed superheater tube misalignment was corrected by FWEC by adding additional support brackets. The flyash storage silo was emptied and flyash handling problems resolved. The outage lasted 23 days and was completed on August 29, 1986, when the unit was again back on line. Precipitator performance with respect to high stack opacity continued to be evaluated by NSP. The schedule for operation of the unit after the 89 MW accreditation was 16 hours per day (2-shifts) to correct any issues as they occurred.

Boiler Fluidization

The first activity after steam blows dealing with the fluidized bed was to blow sand into the bed area. NSP made the decision to use sand as bed material in place of limestone or dolomite in case a boiler tube leak should occur or other problems develop that would require work in the bed area. The sand was an inert bed and would not harden if a leak occurred. However, the density of the sand was greater than either the limestone or the dolomite, requiring a higher than design air flow to obtain correct fluidizing conditions. The ash handling equipment also found the sand difficult to handle unless it was slowly metered into the lock hoppers.

During the unit operation on July 12, 1986 the boiler start-up zones #22 and #23 (Fig. 5) were found to have clinkers from operating in a low air flow condition (the bed was not completely fluidized) and feeding sorbent too quickly. The sand was removed along with the clinkers, and spent bed material from TVA's Test Fluid Bed Facility was blown into the bed. Visual inspection of the new bed material showed it was fluidized in all areas of the main cell. This was a great improvement over the sand.

The recommended start-up procedure consisted of firing the plenum start-up burner to heat the bed material in the #23 front section of the main cell to 850-1000 F in the conjunction with the two over bed burners to raise the drum pressure to 1000 psig. When these two conditions are met coal is fed into the 23 front section only, along with an increase of fluidizing air to bring the bed temperature to approximately 1200F. When the temperatures are stable, coal and air is admitted to the 22 front cell which ignites from the hot material of section 23 front. With both front cells stabilized the original start-up procedure was to wait until the steam flow reached 20%. However, after a long waiting period it became apparent that 20% steam flow would not be attained. FWEC concluded that the next step could be taken even though the steam flow had only stabilized at approximately 18%. Air was admitted to the rear section of 23 cell while adjusting the throw of the coal spreader-flipper to cover the entire cell, thereby bringing the entire 23 section to operating temperature. The last step would be to perform the same function to the rear section of the 22 cell. At this point the entire main cell is in service and load can be raised to approximately 50% by adjusting air and coal flow. Prior to load raising the three start-up burners are taken out of service. With no unexpected problems the main cell can be brought up in 1.5 hours after initial introduction of coal.

Further increase in load can be performed by the same basic method of flame propagation. Fuel and air is admitted to either of the two wing cells while opening the inter-bed slide gate.

During early operation of the unit, with fresh limestone, the elutriation rate was high. Due to fines in the coal along with its low sulfur content the calcined bed material (CaO) broke up before it could be converted to a more stable and stronger sulfated bed material ($CaSO_4$). Once higher bed levels are established and the entire bed is sulfated, material carryover is expected to decrease.

The Black Dog Unit #2 was restarted on November 18 following an unscheduled seven week outage due to an upper furnace tube leak. The following tasks were performed during the seven week outage.

1. Removal of water-hardened bed material that covered 25% of the main cell plan area.
2. Repair of the front wall steam header drain line.
3. Modification of the finishing superheater tube supports.
4. Modification and replacement of the finishing superheater seal box.
5. Hydrotest of the boiler.
6. Replacement of 18 tube welds on the front wall and furnace roof radiant superheaters. These welds were retained from the original boiler during the conversion to AFBC.
7. Cleaning and inspection of the precipitators.
8. Drain all the bed material from the cells and blow in inert clay in its place.

Operation was initiated on the main cell with only inert fired clay used for bed material. This was done to isolate reasons for high stack opacity while operating with a limestone bed. During this period 67 hours of operation on coal were accumulated without sorbent addition. Unit operation was very stable with stack opacity between 4 and 7%. Load was held between 35 and 55MW with the unit operating automatically on the unit (load) master for the first time. Operating difficulties of the spent bed removal system (i.e. elutriating drains, screw coolers, and clinker separator) were encountered during this operating period and were promptly resolved.

Tube Bundle And Cell Areas

Due to high differential temperatures developed between the upper and lower tubes of an in-bed superheater loop during start-up, some loops were deforming. This occurred only during the start-up phase, when the superheater section of the bed was defluidized.

During the seven week outage, Foster Wheeler modified the finishing superheater design by physically constraining the loop end of each of the 72 main cell in-bed superheat tubes to the corresponding vertical steam generating tube and replacing the seal box with flexible tube seals (FiberFrax) and flexible seal plates at the rear wall penetations.

Foster Wheeler expects any outside header movement and/or differential thermal expansion between the upper and lower finishing superheat tubes to be absorbed by the flexible seal box. Following these repairs, Foster Wheeler instrumented a single finishing superheat tube with thermocouples to confirm the calculated difference in upper and lower tube surface temperature during start-up.

Air And Gas Systems

On restart of the unit a high speed eight channel strip chart recorder was set up to monitor air and gas pressures, along with differential pressure at various locations throughout the boiler. This was done in order to resolve the problems the unit had experienced in the past with draft excursions and draft main fuel trips (MFT).

During the November 18th start-up, several draft excursions were recorded, one resulting in an MFT. The draft MFT occurred while propagating to the rear of 23 cell with the unit operating on two ID fans and one FD fan. The high speed chart recorders indicate that a fluctuation in furnace draft caused changes in ID fan speeds and damper positions which over-corrected the draft with progressively larger positive and negative instability. The fluctuation was thought to originate when secondary air, introduced into the previously slumped 23 rear cell, cause rapid ignition of the coal which had built up on the top of the slumped surface. The cracking open of the 23 rear cell air damper also caused a furnace pressure excursion irrespective of combustion.

After further control tuning and modifications to the start-up procedures, the unit was restarted with all four fans in service. The start-up procedures were changed to allow some air to flow through the entire main cell at all times. As a result, when the flame propagation was made to the rear cells, the draft fluctuations were greatly reduced. The unit has operated without draft trips since.

Precipitators

Prior to the November 18 restart both the primary and secondary precipitators were sandblasted clean and the main cell was filled with inert fired clay bed material in an attempt to improve precipitator performance. The fired clay was successfully used to reduce calcium oxide carryover from the bed to prevent precipitator fouling experienced during start-up with a limestone bed.

Load Accreditation

On July 21, 1986 the unit was operated at or above 42 MW for 12 hours or more. This allowed the unit to be accredited to generate 42 MW.

On July 27 and 28, 1986 the unit operated at or above 89 MW for 12 hours, accrediting the unit for 89 MW. This was the highest load obtained by the unit since the AFBC start-up. It was obtained with the main cell and one wing cell in service.

AUXILIARY SYSTEMS STARTUP ACTIVITIES

Instrument Air System

Except for the headers the instrument air system on Unit 2 retained the existing system. Prior to connection to instruments the headers were blown out. The air compressor and air dryers were plant maintenance items and not in the start-up scope.

Cooling Water System

The cooling water system was not ready during the initial operation of the ID-FD Fans. Temporary cooling water supply had to be piped to the fans and boiler circulating water pumps during boiler chemical cleaning. The permanent cooling water system was put into service prior to steam blows. Existing cooling water pumps are used and were not part of the start-up scope.

Condensate System

The condensate system piping was existing except for some piping at the discharge of the condensate pumps and several feet at the DA Tank. Both condensate pumps were replaced and a new DA Tank level control valve was installed. Both condensate pumps were used to flush the condensate and feedwater system prior to chemical cleaning. The condensate pumps were not used to circulate chemical during chemcial cleaning. The condensate system was chemically cleaned using one percent phosphate solution circulated at 180 F by Dowell Pumps for 24 hours.

Feedwater System

Approximately 50 percent of the feedwater piping was replaced with new pipe. New feedwater control valves (3 inches and 8 inches) were installed. Feedwater heaters No. 24 and 25 were replaced, and the internals of all three boiler feed pumps were removed and refurbished. The feedwater system was chemically cleaned at the same time as the condensate system. A new flow nozzle was also installed in the feedwater line. Boiler Feedwater Pump No. 21 was run for the first time on April 23, 1986.

Fans And Hydraulic Couplings

The ID Fans and the FD Fans were both equipped with new hydraulic variable speed couplings. The lube oil flush on No. 21 FD Fan was started on March 10, 1986 and the fan ran for the first time on March 22, 1986. The fan was used for the boiler air test which was started on March 24, 1986. FD Fan No. 21 and ID Fan No. 21 was used to control furnace draft for the first time on April 17, 1985; no major problems were noted. The draft control system caused boiler trips during the coal firing periods. The controls were eventually tuned to allow satisfactory control of draft.

Precipitators

Black Dog Unit No. 2 utilizes two precipitators for particulate collection. The electrical controls were completely changed out in both precipitators by FSA (Field Service Associates, Inc). During the initial coal fires, it appeared that the modifications were not very effective. On subsequent inspection cracked bushings and bad wires were found. Since all ash collected in the mechanical dust collector was not recycled but evacuated to waste, the poor precipitator performance was puzzling. Under these conditions, the dust loading to the ESP's should be a fraction of that expected during 100% recycle. Analysis of the dust samples taken from the ESP plates and wires indicate that the electrical resistivity of the particulate to be very, very high (1x 10^{14}ohms/cm). This value is well above the typical range where acceptable ESP performance can be expected. NSP/SWEC are continuing to study the reasons and causes of the high resistivity.

Ash Handling System

The plant installed two ash handling systems, a pressure system to remove spent bed material from the bed material screw coolers and a vacuum system for flyash removal from the mechanical dust collectors and the two precipitators. The pressure system worked without problems, but the ash from the mechanical dust collectors was so hot (burning particles) that it was difficult to be transported. The evacuation time was reduced to allow some ash to remain in the hoppers and a high temperature alarm was put on the ash piping. Flyash removal problems were also encountered when the ash flooded into the conveying line from the MDC Hoppers. Metering orifices were installed at the ash E-Valves to control the flooding problem.

Sorbent Handling Systems

The sorbent system consisted of a limestone silo, created by modifying Unit 3's old stack, and a dense phase transport system to move sorbent to the two 10 ton day storage tanks. Two rotary feeders under each day tank controlled the sorbent feed to the boiler. The sorbent silo was first filled with sand and then local dolomite. Both of these products were very hard to transport with the dense phase transport system. The conveying lines plugged up and had to be cleaned out or hammered to break loose the plug. Air nozzles were added to the pipeline to help prevent plugging. The changes helped move the material, but the system still needs further modifications to make it work properly. The local dolomite material had too many fine particles in it to transport properly.

The rotary feeders below the day tanks were a problem. The material would wedge between the rotor clearances and caused the feeder to trip out and sometimes fail to re-start. It also caused the rotor side plates to wear out quickly. SWEC is actively working to resolve the feeder and dense phase transport system problems.

AFBC TEST PROGRAM

Once the boiler and T/G Acceptance Testing work confirms the maximum capability and performance, the unit will be operated commerically in combination cycling/peaking mode before the AFBC Testing Program is conducted.

The planned three year test program will result in ample time for the testing of various operating modes and allow for any required unit outages for inspection prior to and immediately following tests. The AFBC Test Program, now being developed, will coordinate maximum and minimum unit load tests with NSP's system load requirements on a seasonal and daily basis.

All test instrumentation equipment connections required have been identified and installed, and will be ready for field connection by the test contractor at the start of the three year test program.

NSP anticipates that the AFBC Test Program will result in a Unit No. 2 capacity factor of between 20 and 40 percent, depending on NSP's system load demand and the requirements of the test program.

CONCLUSION

The Black Dog Station Unit No. 2 Retrofit Project was a fast track project, resulting in initial steam to turbine in only 25 months after award. The start-up and check out of equipment was begun on March 1, 1986 and the unit was accredited for 89 MW on July 28, 1986. Generally, the start-up progressed well, with normal start-up problems that were resolved as they occurred.

Due to the limited operation to date, a complete performance test has not been done. This testing will be done following the turbine modifications scheduled for March - June 1987.

When the Black Dog Unit No. 2 AFBC Retrofit Project is complete in June 1987 as a 130 MW coal-fired power plant, NSP expects to fully evaluate the practicability and cost effectiveness of the AFBC emerging technology as a viable electric utility industry approach to acid rainfall as well as other air pollution problems. NSP also expects to determine the technology's capability for utilizing alternate lower cost fossil fuels as a means of reducing the cost of electric generation.

NSP sees the success of the Black Dog AFBC Project as making a significant contribution to the entire electric utility industry. Similar plant retrofits will also help other utilities meet their near term electric demands and simultaneously addressing environmental concerns while utilizing a wider range of potentially lower costing fuels.

SERVICE AREA
NORTHERN STATES POWER COMPANY

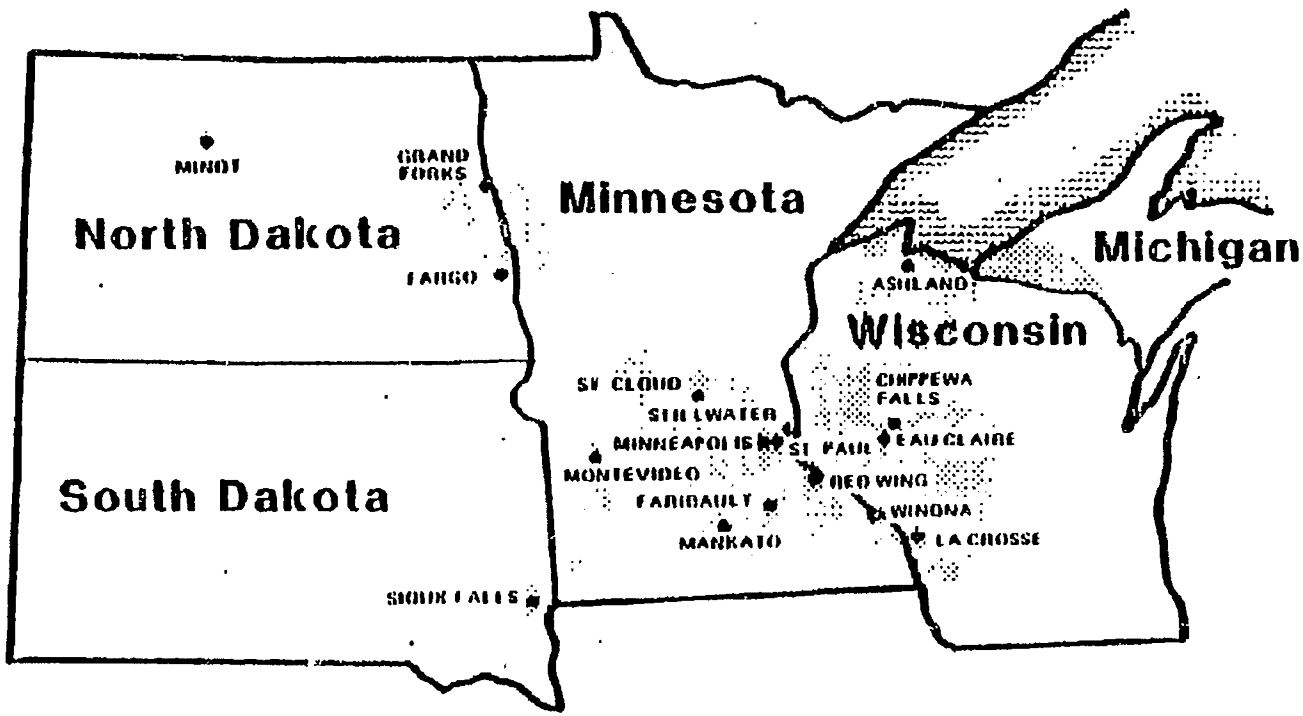

FIGURE 1

6 B3-15

BLACK DOG POWER PLANT

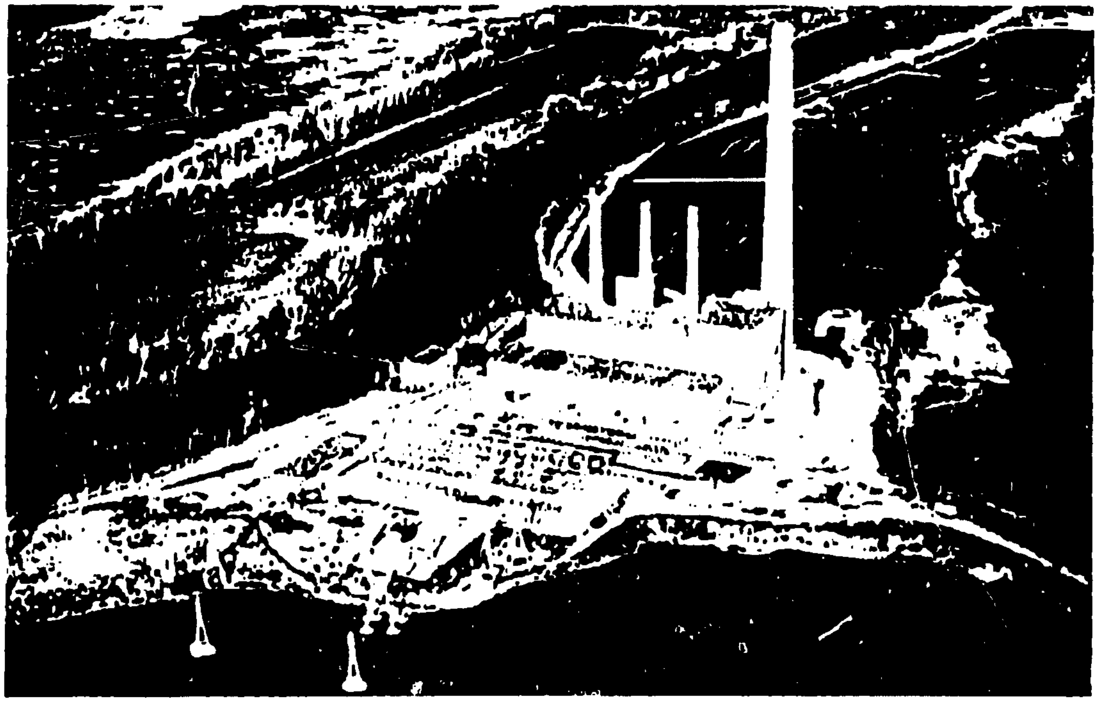

FIGURE 2

ORIGINAL BLACK DOG UNIT 2
PULVERIZED COAL FIRED STEAM GENERATOR

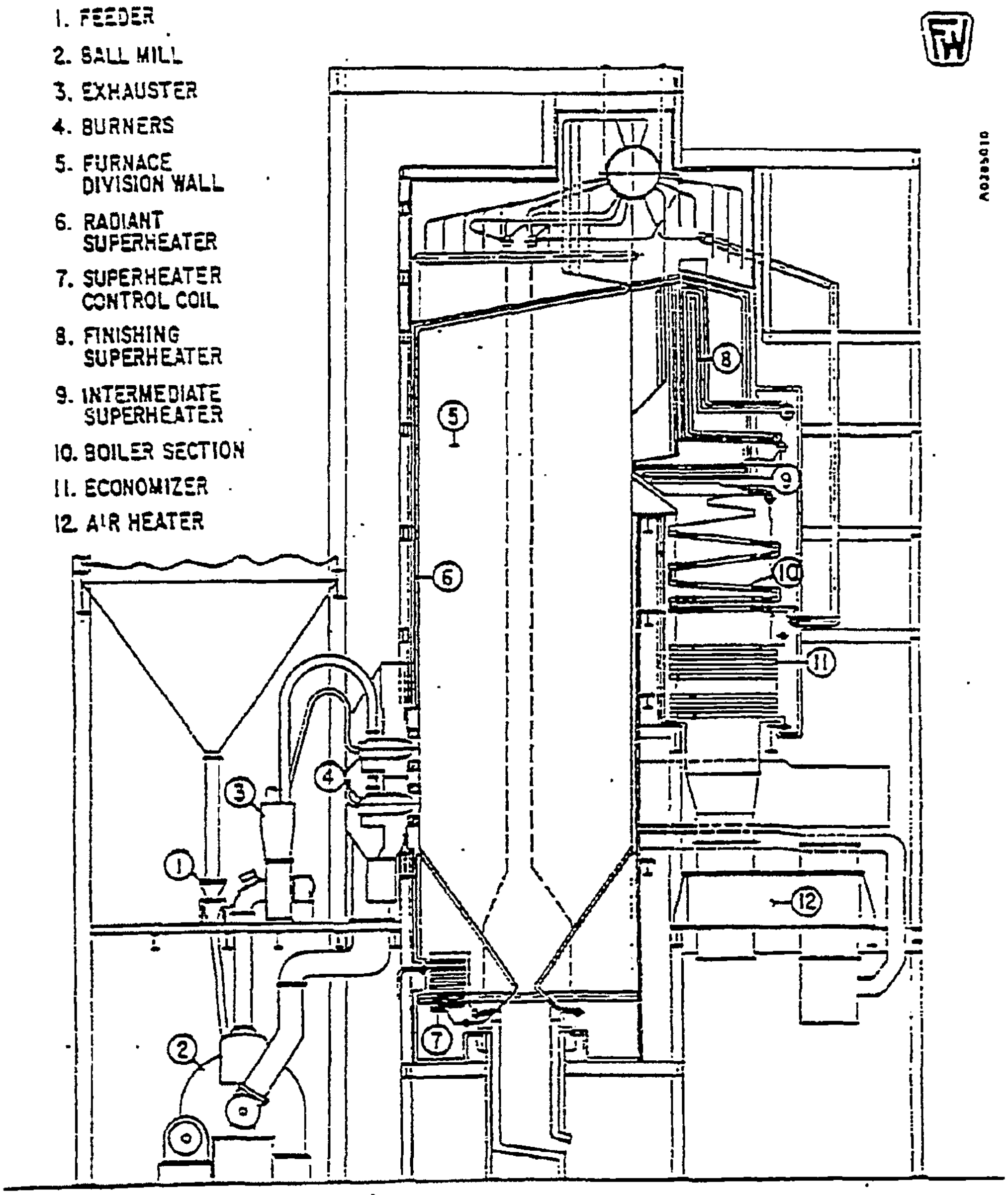

FIGURE 3

STEAM GENERATOR RETROFIT ARRANGEMENT

SIDE ELEVATION

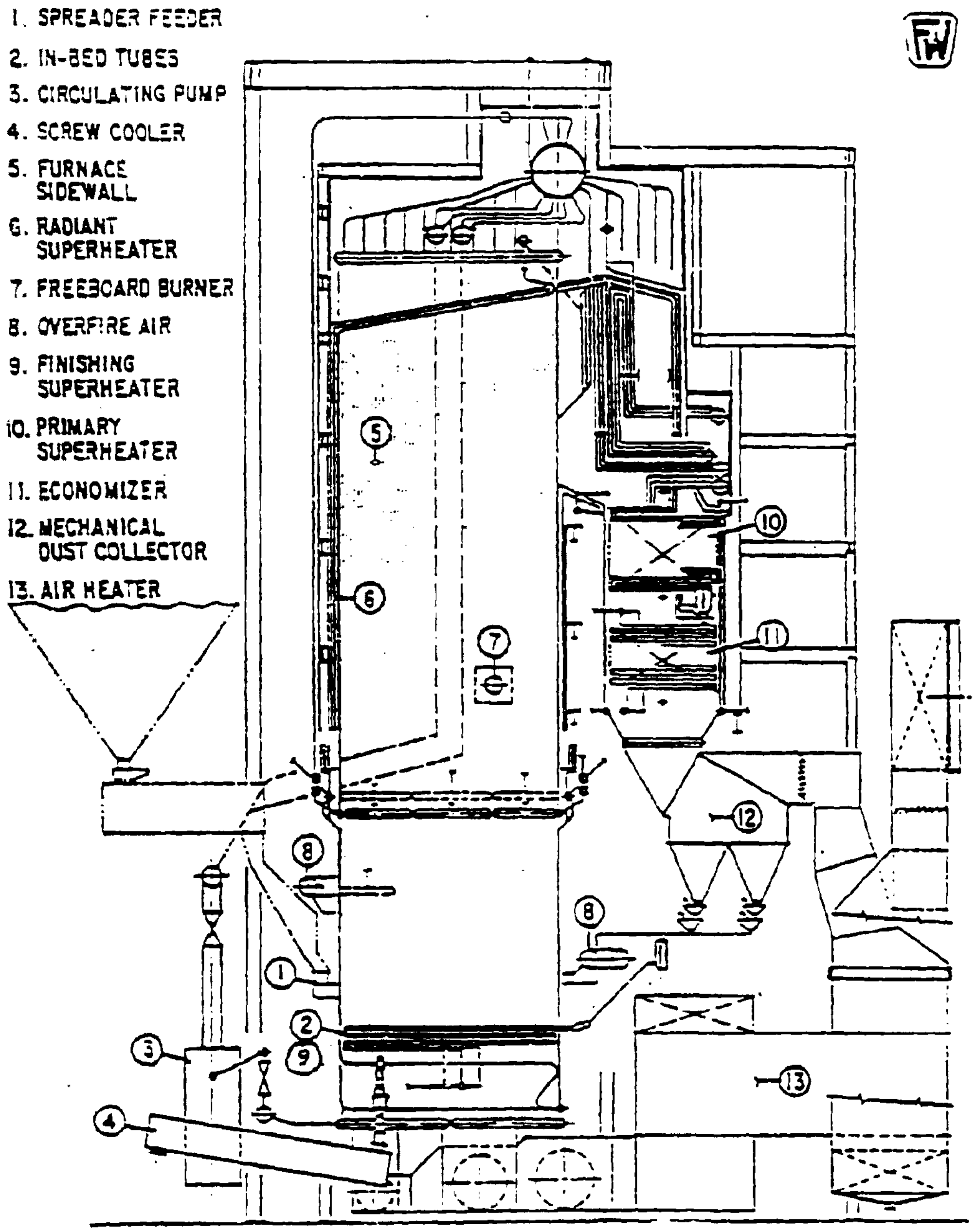

FIGURE 4

FLUID BED CELL ARRANGEMENT

PLAN VIEW

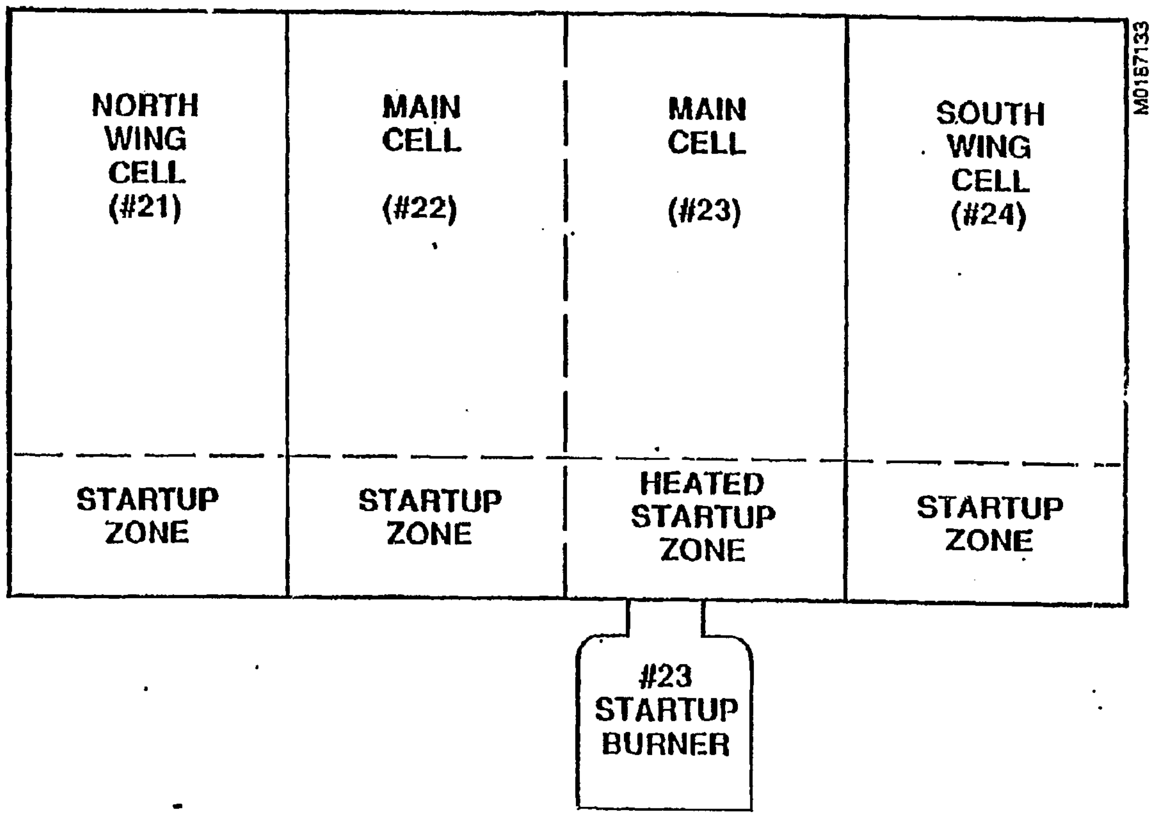

FIGURE 5

6 B3-19

AFBC STEAM GENERATOR SYSTEM HEAT AND MATERIAL BALANCE

NOMENCLATURE	UNITS	SARPY CREEK PERF COA
TURBINE THROTTLE PRESSURE	PSIG	1,450
MAIN STEAM TEMPERATURE	°F	1,000
NET GENERATION	MW	115
GROSS GENERATION	MW	125
TURBINE THROTTLE STEAM FLOW	M#/HR	1,039
ECONOMIZER INLET TEMPERATURE	°F	469
NET PLANT HEAT RATE	BTU/KWH	10,930
EXCESS AIR AT ECONOMIZER OUTLET	%	18.5
AIR PREHEATER AIR TEMPERTURE ENTERING (FD FAN/AIR PREHEATER)	°F	80/110
AIR PREHEATER LEAKAGE	%	10
AIR PREHEATER FLUE GAS TEMPERATURE IN	°F	690
AIR PREHEATER FLUE GAS TEMPERATURE OUT	°F	250
BOILER EFFICIENCY	%	87
CARBON UTILIZATION	%	99
CO IN FLUE GAS	PPM	210
NOx IN FLUE GAS	PPM	245
SO_2 LIMIT (NSPS)	#/BTU X 10^6	0.6
SO_2 REMOVAL REQUIRED	%	72
Ca/S MOLE RATIO (LIMESTONE)	-	1.7
GROSS HEAT INPUT FROM FUEL	BTU/HR X 10^6	1,257
FLUE GAS WEIGHT AT AIR PREHEATER INLET	M#/HR	1,260
COMBUSTION AIR WEIGHT TO AFBC	M#/HR	1,129
FUEL BURNED	M#/HR	147.9
LIMESTONE REQUIRED	#/HR	7,375
TOTAL WASTE SOLIDS	#/HR	23,339
TOTAL SOLIDS TO BED DRAIN	#/HR	4,606
TOTAL SOLIDS ENTERING CYCLE	#/HR	18,783
FG WEIGHT TO ESP INCLUDING 10% AIR LEAKAGE	M#/HR	1,405
FLUE GAS (AT 800 FT.)	ACFM	442,953

TABLE 1

PERFORMANCE AND DESIGN FUELS
COAL FIRED AFBC BOILER RETROFIT PROJECT
BLACK DOG UNIT 2

NOMENCLATURE	UNITS	SARPY CREEK PERF COAL	SARPY CREEK DSGN COAL	TEST COAL	ALTERNATE FUELS
COAL ULTIMATE ANALYSIS (% BY WEIGHT)					
SULFUR	%	0.90	1.20	3.00	RDF AND COKE
MOISTURE	%	23.90	25.00	15.00	
CARBON	%	49.70	48.55	-	
OXYGEN	%	10.77	10.45	-	
HYDROGEN	%	3.20	3.07	-	
ASH	%	10.80	11.00	-	
NITROGEN	%	0.70	0.70	-	
CHLORINE	%	0.03	0.03	-	
TOTAL	%	100.00	100.00	100.00	
HIGHER HEATING VALUE (GIVEN)	Btu/#	8,500	8,300	10,000	
ASH ANALYSIS (% BY WEIGHT)					
SiO_2	%	35.2		ILLINOIS BITUMINOUS HIGH FOULING AND SLAGGING	RDF AND COKE
Al_2O_3	%	17.2			
TiO_2	%	0.7			
Fe_2O_3	%	6.9			
CaO	%	17.4			
MgO	%	4.3			
Na_2O	%	1.5 MEDIUM FOULING	4.0 HIGH FOULING		
K_2O	%	0.4			
P_2O_5	%	0.5			
SO_3	%	15.3			
Trace	%	0.6			
TOTAL	%	100.0			
ASH FUSION TEMP. (REDUCING/OXIDIZING)					
I.D.	°F	2165/2250 HIGH SLAGGING	2100/2150 HIGH/SEVERE SLAGGING		
H=W	°F	2170/2260	2120/2180		
H=W/2	°F	2180/2270			
FL	°F	2190/2285			

TABLE 2

MAJOR EVENTS - BY DATES

1.	Boiler Hydro	- January 6, 1986
2.	First Condensate Pump Run	- March 6, 1986
3.	Preboiler Chemical Cleaning Started	- March 14, 1986
4.	Furnace Air Test	- March 24, 1986
5.	Boiler Test Fired	- April 28, 1986
6.	Boiler Chemical Cleaning Started	- May 2, 1986
7.	Steam Blows Started	- May 21, 1986
8.	First Coal Fires	- June 26, 1986
9.	First Time Synchronized	- June 28, 1986
R3 10.	42 MW Accreditation	- July 22, 1986
R3 11.	80 MW Accreditation	- July 28, 1986

TABLE 3

BOILER FOULING : EXPERIMENTAL VERSUS FULL-SCALE BEHAVIOUR OF LOY YANG COAL

by

B Anderson (1), K P Bailey (2), J B Bell (2) and A L Ottrey (1)

ABSTRACT

Long-term experimental combustion tests have proven necessary to provide a realistic assessment of ash fouling behaviour (under sootblown conditions) of Latrobe Valley brown coals. Convection pass deposits formed during combustion of Yallourn and Morwell coals in the experimental furnace are directly comparable with those from full-scale power stations.

In anticipation of the development of a new open cut/ power station complex at Loy Yang, a range of coals from this area were tested in the experimental furnace. The main features of Loy Yang area coals are a generally low ash content with, dependent on location and depth, significant levels of sodium-in-ash. Subsequent to the major bore-hole analysis program, significant concentrations of acid-extractable aluminium have also been identified in some of the coal; this constituent can have a marked influence on ash behaviour.

Several parameters based on the analysis of the coal have been formulated to describe the ash behaviour of these Loy Yang coals. In particular, the rate of ash fouling is strongly correlated with the level of sodium-in-ash, although the rate of fouling was lessened at a moderate ratio of acid-extractable aluminium to sodium in the coal.

Initial operation of the first two 500 MW units of the Loy Yang A power station have generally confirmed (at least qualitatively) the findings of these experimental furnace tests. Extensive monitoring of convection pass (water and steam-side) temperatures and flow rates, combined with back-end flue gas temperature provide the basis for detailed boiler performance calculations and fouling assessments.

Rapid deterioration of the furnace heat transfer is the most serious effect of this high fouling, low ash coal. The subsequent combustion of high ash, low sodium content coal can also cause further deterioration of furnace heat transfer. To date, convection pass fouling has not been a serious problem in these boilers.

Some action has already been taken to reduce the rate and impact of furnace fouling. Work is also currently in progress to define the extent of this high fouling coal and to determine the nature of the ash deposition.

ADDRESSES

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Benefits of Partial Moisture Reduction of High Moisture Fuels on Power Plant Performance, Operations and Maintenance.

by Samuel W. Seabury

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Abstract

Moisture reduction of high moisture fuels prior to delivery into steam generator silo storage can extensively effect unit performance. It can be shown that benefits result throughout all phases of the fuel cycle.

The major consideration is to control the magnitude of moisture reduction to an optimum point. Drying fuel past the optimum point can lead to a reduction in unit performance and unacceptable dust generation.

Drying equipment can be retrofitted into plant operations without interfering with unit generation. Combined fuel cycle operation can result in favorable financial analysis even where fuel transportation savings are not taken into account.

Introduction

Past studies of moisture reduction of high moisture fuels have, in general, concentrated on the cost/benefits associated with transporting and handling less material. Such considerations had little benefit for mine-mouth plants. One exception, AlCOA's Sandow (TX) Plant, has burned predried lignite in three 115 MW CE wet bottom reheat units since the early '50s. The fuel is dried on site, but not pulverized. Subsequent lignite installations abandoned drying in favor of conventional pulverized coal, dry bottom furnaces or cyclone furnaces burning run of mine fuel. The same is true for stations burning Western sub-bituminous fuels.

The economic reasoning was simple: (1) the combination cost of dryers and steam generators equaled or exceeded the cost of conventional designs, (2) the cycle efficiencies were not significantly different so as to save fuel, (3) drying required additional and special handling.

Recently, GFERC and others have suggested drying Western fuels at mining sites to reduce transportation and handling costs, but to date there is little activity to commercially promote the idea.

Most significantly lacking in all the past investigative work is a technical and financial evaluation of the power plant operating and maintenance gains/limitations possible when firing partially dried fuel. This paper evaluates the effects of controlled moisture reduction through a conceptual case study of a typical mine-mouth lignite station.

Effects on unit performance are discussed in two sections. The first section investigates moisture reduction effects on boiler performance and environmental handling systems. The second section examines the initial stages of the fuel cycle from mining through pulverizer operation.

A conceptual drying system design is briefly described.

System design allows equipment to be retrofitted into existing stations or designed into new stations. Equipment arrangements are in parallel to existing fuel handling systems allowing for the delivery of run-of-mine fuel or partially dried fuel.

In light of current fuel costs, the gains resulting from firing partially dried fuel are significant.

Summary

The unit used for this conceptual case study is a 575 MW lignite fired boiler located at a Texas mine mouth facility. Table 1 summarizes unit operating conditions. Table 2 lists fuel cycle components discussed in this study.

Table 1

Turbine:			
Gross Rating, MW	575		
Heat Rate, Btu/KW	8150		
Steam Generator:			
Primary Pressure, psig	3500		
SHO, °F	1000		
RHO, °F	1000		
Pulverizers	8		
Ljungstrom APH	2		
ESP	4		
Fuel:		Case 1	Case 2
Moisture, %		32	24
Ash,%		15	16.9
HHV Btu/#		6800	7600

Table 2

Steam Generator and Auxiliaries:
- Boiler Performance and Efficiency
- Furnace & Convection Surfaces
- Ljungstrom APH
- ESP (Baghouse/Wet Scrubber)
- FD & ID Fans
- Ash Handling

Fuel Supply:
- Pulverizers
- Primary Air System
- Feeders and Bunkers
- Crushers and Conveyors
- Mining and Transportation

Dryer System:
- Combined Fuel Cycle

Table 3 describes the two fuel conditions compared throughout this case study. Case 1 is typical run-of-mine lignite. Case 2 is the same lignite dried eight percentage points less as measured by ultimate analysis with all constituents normalized to 100%.

Table 3

Ultimate Analyses -(%)	Case 1	Case 2
Ash	15.0	16.8
Moisture	32.0	24.0
Carbon	39.6	44.3
Hydrogen	2.8	3.2
Sulfur	0.5	0.6
Nitrogen	0.6	0.6
Oxygen	9.5	10.6
Total	100.0	100.0
HHV (Dulong)	6800 Btu/#	7600 Btu/#

All subsequent evaluations refer back to these analyses.

Steam Generator and Auxiliaries

Performance and Efficiency

Boiler performance and efficiency calculations in this case study follow ASME PTC 4.1 procedures.

The ASME abbreviated efficiency test PTC 4.1 employs the Heat Loss Method to calculate efficiency. Heat input is set to 100%. Heat losses due to radiation, carbon in the ash, stack gases and an allowance for manufacturer's margin are evaluated. These losses are then determined as a percentage of the heat input.

Beginning the calculations, fuel, air and gas weights in pounds per million Btu's (#/MMBtu) are then determined for both cases as shown in Table 4.

Table 4

Lignite, Air and Gas Products - (#/MMBtu)

	Case 1	Case 2
Lignite	147	132
Stoichiometric Air	758	758
Combustion Air	910	910
Flue Gas Products	1035	1020
Moisture from H2	38	38
Moisture in Fuel	47	32
Moisture in Air	12	12
Dry Gas Products	938	938
Ash	22	22

The pounds of lignite and the stoichiometric dry air per million Btu are determined first. The combustion air is calculated by correcting the stoichiometric air for humidity (standard conditions) and adding excess air, which in this case is 18%. Flue gas products are calculated by adding fuel to combustion air and then subtracting ash.

The flue gas products are comprised of dry gases (N_2, O_2, CO_2, SO_2, etc.) and water vapor from three sources, H_2, fuel, air. The specific heat (Btu/#/oF) of the flue gas products can be calculated using the breakdown of the water vapor and the dry gases.

Two results are apparent (Table 5). The total gas weight in Case 2 will be less than Case 1 due to moisture reduction. Similarly, the specific heat of the flue gas in Case 2 will be less than Case 1. The implications of these results show up in the following ASME efficiency calculation.

Table 5

ASME Efficiency		
Losses (%):	Case 1	Case 2
Dry Gas	6.84	6.31
H2	4.51	4.37
H20 in fuel	5.67	3.59
H20 in air	0.17	0.16
Radiation	0.17	0.18
Unburned Carbon	0.15	0.15
Margin	1.00	1.00
Total Losses	18.51	15.89
Efficiency (%)	81.49	84.13
Specific Heat Btu/#/F	0.286	0.282
Turbine Heat Rate Btu/KWhr	8150	8150
Unit Gross Heat Rate BTU/Kwhr	10,000	9685

The change in efficiency is, as expected, due primarily to the reduction in fuel moisture. Changes in flue gas product specific heat results in additional improvements in other losses. The boiler efficiency improvement has a substantial effect on gross unit heat rate.

Furnace & Convection Surfaces

Having developed the gross heat rate in Table 5, we are now in a position to evaluate Unit operating conditions for Case 1 and 2. (Table 6)

Fuel moisture reduction and the resulting boiler efficiency gain result in a reduction of fuel weight to the furnace. The efficiency gain reduces the air and fuel weights to the furnace also. This combination reduces gas weights from the furnace by 4.5%.

The mean specific heat of the flue gas is reduced by the fuel moisture reduction. As a result of gas weight and specific heat changes, convection surfaces see approximately 6% less heat available for absorption at the same furnace exit gas temperature.

Table 6

Unit Operations	Case 1	Case 2
Gross Rating, MW	575	575
Gross Heat Rate, Btu/KWhr	10,000	9685
Lignite, Air and Gas Weights - (1000 #/hr.)		
Fuel - Mined	845	819
Fired	845	733
Air	5230	5065
Flue Gas (uncorr)	5950	5675
Air Preheater Conditions - (^{o}F)		
Gas In	850	825 (est.)
Gas Out (Corr)	375	355
Air In	105	105
Air Out	710	695

In our example, fuel moisture reduction therefore positively effects the boiler performance by reducing flue gas volumes, temperatures and velocities. But the need for controlled moisture reduction also becomes obvious. Excessive moisture reduction could reduce the superheater and reheater control range as well as lower exit gas temperatures below flue gas acid dewpoints.

Air Preheater, FD and ID Fans

Heat balance calculations on the air preheater system show a decrease in the uncorrected exit gas temperature for Case 2. This is due to the reductions in flue gas weight and flue gas specific heat.

Capacity margin is gained in the ID fans due to reductions in the flue gas weight and flue gas temperature, whereas gains in FD fans margin are due directly to boiler efficiency gains only.

Environmental Systems

This particular unit is fitted with an electrostatic precipitator (ESP) only. Reductions in gas temperature and weight combine to reduce gas velocity (volume) through the ESP by 10%. This should improve collection efficiency.

An additional improvement in ESP performance occurs in this case due to reduced exit gas temperatures directly decreasing flyash resistivity values.

Baghouse operation, where applicable, should also improve due to reduced baghouse pressure drop. If a scrubber existed, operational improvements would also be expected. Even though pounds of SO2 per million Btu's remain constant for compliance regulation purposes, the total pounds of SO2 generated is reduced. Reduced gas volume, lime or limestone throughput and water vapor in the flue gas should all improve scrubber performance.

Ash handling reductions would be directly proportional to the reduced fuel consumption. In Case 2, some maintenance benefits may occur due to decreased volumes of ash handled. Ash reduction has no affect on boiler efficiency and performance per ASME.

Boiler Performance Conclusions

1. It is easy to be misled when evaluating the effects of fuel moisture reduction if one only looks at percent moisture and fuel Btu. An example is shown in Table 7.

Table 7

	Case 2	Comparable Moisture Fuel
Moisture, %	24	26.5
Ash, %	16.75	5
Btu/#	7600	8400
# $H_2O/10^6$ Btu	31.6	31.6

Even though the percent moistures are different and the Btu/# are different, the pounds of water per million Btu's are the same. Near identical boiler performance can be expected only from two high moisture fuels having the same pounds of water per million Btu. This analysis must be made to evaluate the effect of fuel moisture reductions.

2. If a unit currently burning low moisture fuel is converted to high moisture western fuel or lignite, consider the following. Excessive gas flow and specific heat from the high moisture fuel may require superheater and reheater surface reduction. High moisture fuel will negatively effect the air preheater, precipitator, (baghouse, scrubber), and ID fans. Controlled drying of fuel should be evaluated as an alternative to other capital expenditures.

3. If a unit currently burning high moisture fuel is converted to low moisture fuel, the following considerations should be taken into account. Decreased gas flows and specific heat may result in an inability to reach design superheat and reheat temperatures. Boiler efficiencies gained may therefore be lost due to increased turbine heat rate. The amount of moisture reduction per million Btu's must be carefully controlled or RH surface addition costs must be added into the fuel switch evaluation.

Fuel Handling

Pulverizers and Feeders

Reduction in fuel moisture has an obvious positive effect on feeder and pulverizer throughput. The lignite firing rate in Case 2 (Table 6) requires one less pulverizer to maintain 575 MW.

The tonnage capacity per pulverizer is not diminished by drying. Figure 2 shows GFERC test results from laboratory pulverizers. Similar test information was obtained from a pulverizer manufacturer. This information suggests benefits in maintenance costs, maintenance scheduling and auxiliary power requirements.

Two additional pulverizer system criteria should be closely examined before deciding on the extent of moisture reduction desired: the pulverizer exit moisture of the fuel, and tempering air requirements. The following pulverizer operational review is instructive.

Pulverizers for coal fired steam generators perform a dual service. Fuel is pulverized to 60% or greater passing a 200 mesh screen and is partially dried by acting as a heat sink for utilizing boiler exhaust heat.

Drying in a pulverizer follows the principle of suspension drying.

Principle:

1. A body of heated gas will retain the same wet-bulb temperature while being partially or fully saturated with moisture, provided the total heat remains unchanged.

2. A particle suspended in a body of hot gas assumes the wet-bulb temperature of the gas, provided some moisture remains in the particle.

Typically, the ratio of heated air to the fuel entering the pulverizer is in the range of 1.5 pounds of heated air to 1 pound of fuel.* The pulverizer outlet temperature is a mixture temperature of the fuel and air; it is neither the fuel temperature, nor the air temperature. So long as free moisture remains in the fuel it will remain at wet bulb temperature (or lower). The inlet air temperature will be reduced by humidification to a temperature in the range of 60% to 80% relative humidity on the wet bulb line before exiting the pulverizer.

Any pre-pulverizer moisture reduction evaluation must include analysis of fuel temperatures expected out of the pulverizer. If drying is excessive, pulverizer exit temperatures will become unacceptable, necessitating excessive use of tempering air.

Tempering air (Fig. 1) is a form of cold air bypassing of the air preheater. Cold air bypassing decreases the air flow through the air heater and reduces pulverizer inlet gas temperatures, which in turn elevates the A/H exit gas temperature. The result is lower boiler efficiency.

In retrofitting an existing facility with a dryer system, the extent of moisture reduction should take into account the minimizing of tempering air.

Table 8 shows typical pulverizer operation in Case 1 and expected operation in Case 2. Following the principles of suspension drying, tempering air for Case 2 would not be necessary since fuel moisture exiting the pulverizer is 10.5%.

Table 8

	Case 1	Case 2
Fuel In, oF	80	100
Pulverizer Air In, oF	650	625
Pulverizer Out, oF	150	150
Fuel Moist In, %	32	24
Fuel Moist Out, %	20	10.5
# Moist/#Lignite Diff	.15	.15
Air: Fuel Ratios	1.5:1	1.5:1

* For high moisture fuel such as lignite, this air to fuel ratio is fairly easily determined by measuring the moisture gain in the pulverizer air and the moisture loss in the fuel.

Silos and Bunkers

Several test results indicate that the bulk density of high moisture fuel remains essentially the same throughout the drying process. It shrinks when dried.

The capacity, in Btu's, of the bunkers is therefore expanded as the moisture is reduced. This would directly benefit operating time available in the event of fuel source interruption. In considering the possibility of bunker fires, conditions are not significantly different with dried fuel than with run-of-mine fuel. A source of air is required to sustain a fire. Attention to eliminating sources of air in either case is required.

Crushers and Conveyors

It is desirable that the fuel to be dried be < 3/4" x 0. In this case operation of the current handling system from the mine through to the secondary crushers remains unchanged. Fuel is sent from the secondary crusher outlet to the dryer system and returned to the same location. The fuel can be expected to be dusty. Particular attention should be given to the dust control system between secondary crusher outlet and the silos or bunkers.

Mining and Transportation

Mining and transportation costs can generally be expected to follow the decrease in the steam generation firing rate. The life expectancy of the mine-mouth fuel deposit will be extended by summing the percent savings per year if unit generation is maintained at 575 MW.

Fuel System Conclusions

Boiler efficiency improvements due to decreased moisture fuel result in decreased fuel demand from mining operations by approximately 3.5%. Some increase in fuel deposit lifetime is expected if unit generation is not increased.

Dried fuel material flow from the drying system through the pulverizers is approximately 13% less due to moisture reduction and boiler efficiency improvements. This should result in increased silo capacity on a MMBtu/hr basis, and decreased maintenance on the fuel handling system in general. One less pulverizer in service is needed in this case in order to maintain 575 MW.

Controlled moisture reduction of high moisture fuels can be accomplished without the need for tempering air increases or unacceptable pulverizer fuel or air outlet temperatures.

Dryer System

Combined Fuel Cycle *

Combined Fuel Cycle* is the proprietary concept of using combustion turbine exhaust as the drying medium to reduce moisture in high moisture fuels to a practical level.

As an example, 800,000 #/hr of gas turbine exhaust at 800 °F is more than adequate to reduce 420 tons of a 32% moisture fuel to 24%. The 8% change in ultimate analysis moisture is a reduction of 31% of the dryer inlet fuel moisture. A single 30 MW gas turbine will provide controlled drying of the fuel for the case study 575 MW lignite unit.

The dryer system can be retrofitted into the existing station in parallel with existing fuel handling systems. The dryers are of commercially available design and would operate balanced draft complete with dust collection and pelletizers for dust processing.

In dryer tests, the dust collector fines analyses were much higher in ash than the dryer inlet or outlet fuel analyses, in some instances approaching 50% ash. This suggests a possibility of "dry cleaning" in addition to moisture reduction. Further studies are required in this area. In dryer tests at GFERC, no off-gassing of volatiles was detected.

* Patent applied for.

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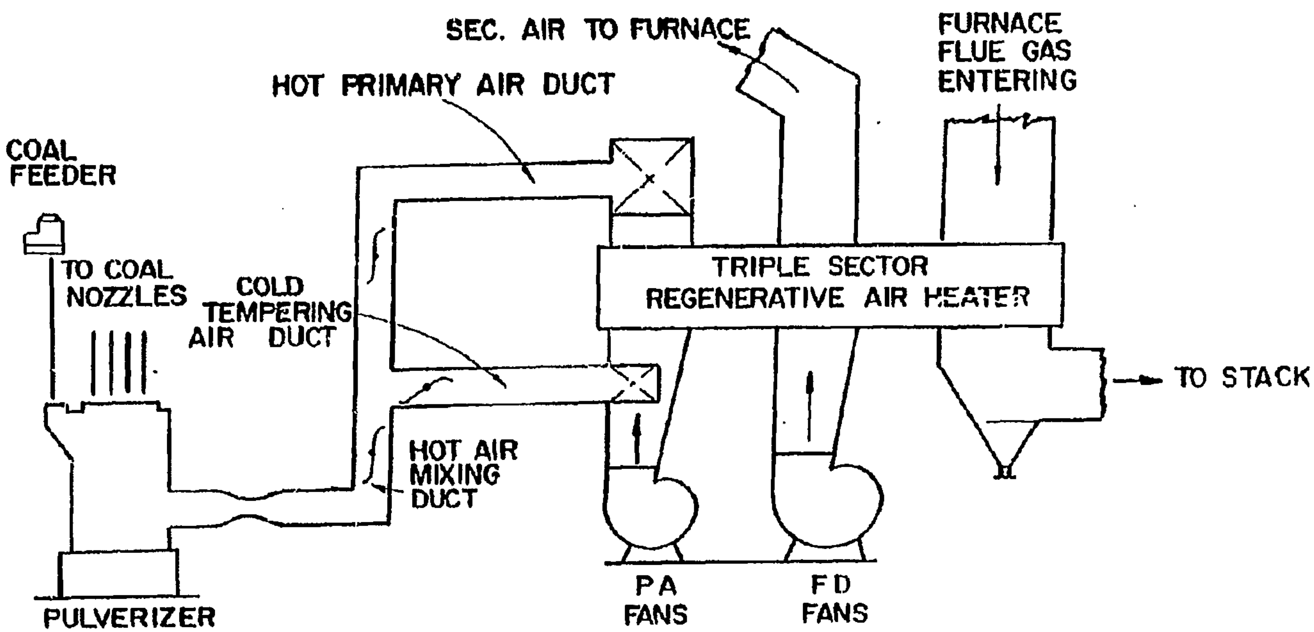
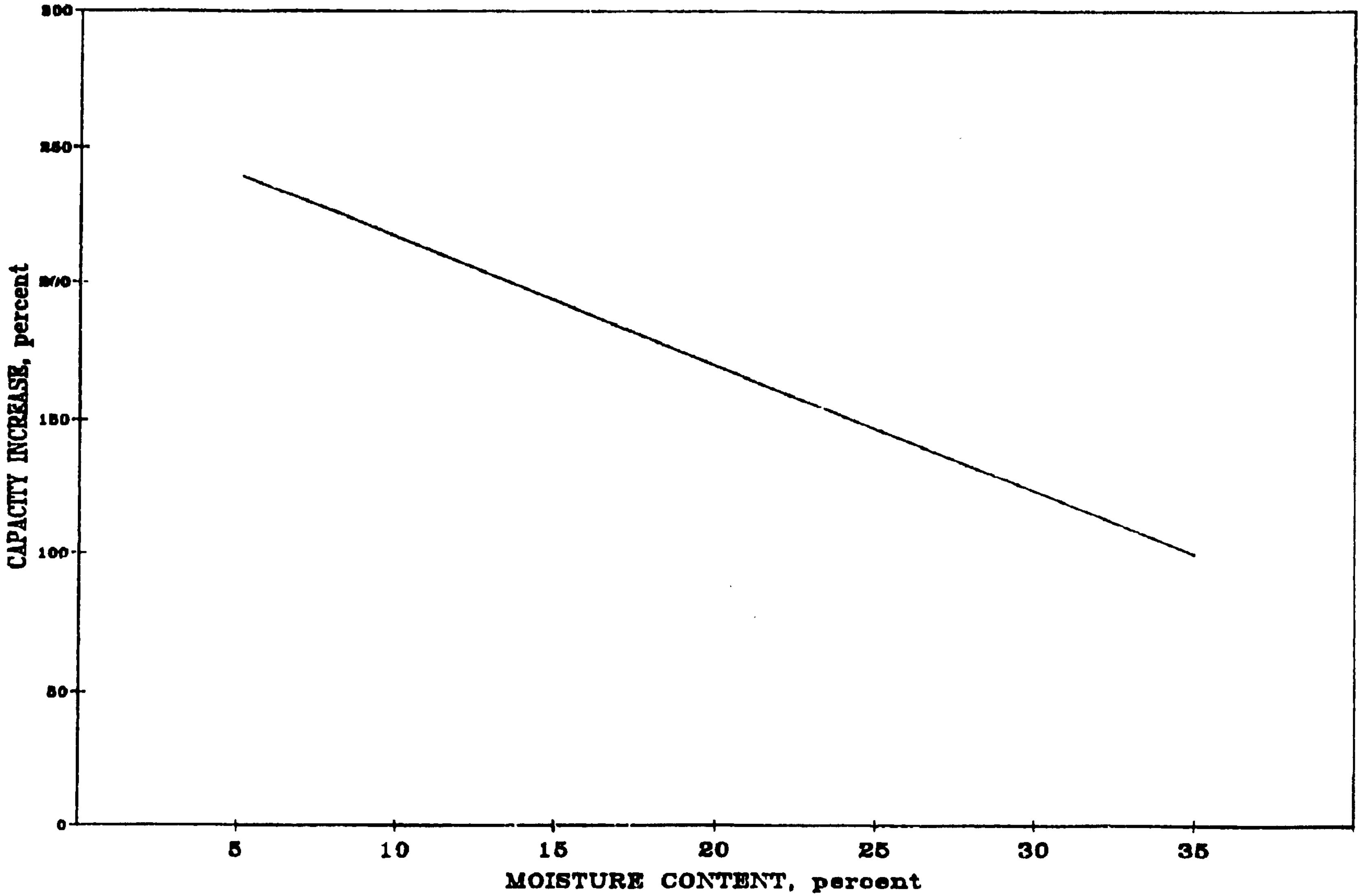
FIGURE 1



PRIMARY-AIR SYSTEM OF BALANCED-DRAFT FURNACE

EFFECT OF DRYING ON CAPACITY OF PILOT PLANT PULVERIZERS



SOURCE: B.MINES IC 8376

FIGURE 2

7 B2-15

PRODUCING ELECTRIC POWER FROM LOW GRADE LIGNITE: EXPERIENCE GAINED IN THE DESIGN, CONSTRUCTION AND OPERATION OF CENTRAL STATION POWER PLANTS UTILIZING LIGNITE FROM THE JACKSON FORMATION IN TEXAS

T. G. Edwards, P.E.
Tippett & Gee, Inc.
Abilene, Texas

ABSTRACT

Near-surface lignite deposits in Texas represent a very large potential for energy development. There are two major near-surface lignite groups in Texas - the Wilcox and the Jackson. All of the development prior to 1974 by utilities in Texas was in the Wilcox group. Generally, lignites from the Jackson group are of lower rank than those from the Wilcox group. The Jackson group lignites have been identified as the lowest rank solid fuels considered for power production in the United States. In 1974, Brazos Electric Power, South Texas Electric, and Medina Electric Cooperatives embarked upon the San Miguel Project, the first major development of Jackson group lignite for electric energy production. The following year, Texas Municipal Power Agency, a consortium of four Texas municipalities, embarked upon a similar project in Grimes County, Texas - the Gibbons Creek Steam Electric Station. Both plants have now been in operation for a sufficient period of time to evaluate the use of Jackson group lignites for power plant production on the basis of operating experience.

This paper outlines the comparison of Jackson group lignites with other Texas lignites, and gives a review of the power plant design approaches of other utilities in projects utilizing Texas lignites. The paper traces the history of the San Miguel and Gibbons Creek projects from the conceptual design through the development of the specific design and construction, and through the operating experiences. Wherever possible, conventional design was used including pulverized coal radiant furnace designs and 2400 psig/1000°/1000° steam cycle. Description is given of the fuel delivery procedures; the fuel handling systems, the steam generators, including pulverizers, fans, air heaters, and other auxiliaries; and the environmental protection control strategies. The performance of the boiler is discussed with comparison of original design and realized operation. This paper further outlines the specific major problem areas of furnace fouling, bottom ash removal, component erosion, and fly ash removal resulting from ash quantities as high as 70 pounds per million Btu; flowability of fuel with moisture as high as 40%; flue gas desulfurization; and pulverizer and fuel pipe erosion.

The experiences gained during design, construction and operation of the San Miguel and Gibbons Creek Plants have been used in upgrading these plants and in conceptual designs of other plants. This paper summarizes features of these programs.

PRODUCING ELECTRIC POWER FROM LOW GRADE LIGNITE: EXPERIENCE GAINED IN THE DESIGN, CONSTRUCTION AND OPERATION OF CENTRAL STATION POWER PLANTS UTILIZING LIGNITE FROM THE JACKSON FORMATION IN TEXAS

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Near-surface lignite deposits in Texas represent a very large potential for energy development. There are two major near-surface lignite groups in Texas - the Wilcox and the Jackson. All of the development prior to 1974 by utilities in Texas was in the Wilcox group. Generally, lignites from the Jackson group are of lower rank than those from the Wilcox group. The Jackson group lignites have been identified as the lowest rank solid fuels considered for power production in the United States. In 1974, Brazos Electric Power, South Texas Electric, and Medina Electric Cooperatives embarked upon the San Miguel Project, the first major development of Jackson group lignite for electric energy production. The following year, Texas Municipal Power Agency, a consortium of four Texas municipalities, embarked upon a similar project in Grimes County, Texas - the Gibbons Creek Steam Electric Station. Both plants have now been in operation for a sufficient period of time to evaluate the use of Jackson group lignites for power plant production on the basis of operating experience.

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The experiences gained during design, construction and operation of the San Miguel and Gibbons Creek Plants have been used in upgrading these plants and in conceptual designs of other plants. This paper summarizes features of these programs.

HISTORICAL BACKGROUND

Texas has two major near-surface lignite formations, the Wilcox and the Jackson. A third formation of interest is the Yegua which is generally associated with the Jackson in the deposits of commercial significance. Utilization of lignite from the Wilcox group began in the 1920's on a rather small scale. Major utilization for electric utility power generation began with the building of the Sandow Plant in Milam County in the middle 1950's. Following that plant, Texas Utilities built the Big Brown Steam Electric Station (two units), Monticello Steam Electric Station (three units), Martin Lake Steam Electric Station (three units), and Sandow Unit 4, all of which became commercial in the period from 1971 through 1979. Throughout this development, all potential sources of lignite for power production were investigated by the major utilities such as Texas Utilities, Central and South West and Houston Lighting & Power, and energy companies such as Shell, Phillips Coal Company and Exxon. Included in those investigations were studies of the extensive deposits in the Jackson and associated Yegua formations. Investigation was made in the Jackson group deposits in Atascosa and McMullen Counties as early as the 1950's. When comparisons were made of the quality of the fuel, the over-burden strip ratios and other economic factors regarding mining of the lignite, none of the potential Jackson deposits were seriously considered at that time.

Beginning in 1969, a consortium of Brazos Electric Power Cooperative (BEPC), South Texas Electric Cooperative (STEC), and Medina Electric Cooperative (MEC) made serious investigations into the possibility of developing a source of lignite for power production in Atascosa and McMullen County deposits. This consortium is now known and referred to hereinafter as San Miguel Electric Cooperative (SMEC). In spite of the confirmation of earlier findings of rather poor quality of the fuel and the rather high strip ratio, an economic analysis indicated that the extent of the deposits in the area was great enough to warrant serious consideration for power production; therefore, SMEC proceeded with the development of the San Miguel Project.

In 1974, in parallel with the efforts by SMEC, the Texas Municipal Power Agency (TMPA), which is a consortium of the four Texas municipalities of Bryan, Denton, Garland and Greenville, began similar investigations of Jackson formation lignite deposits in Grimes County, Texas. Their findings of economic feasibility were also favorable, and the Gibbons Creek project developed from those investigations.

The two projects proceeded from initial fuel investigations, mining studies, identification of properties and the obtaining of leases. These decisions were encouraged by the effects of the OPEC actions of the early 1970's.

Very early in the development of these projects, Tippett & Gee, Inc., a consulting engineering firm located in Abilene, Texas, was retained by SMEC to work with them in the conceptual design of a plant to generate power from the burning of the Atascosa-McMullen County lignite. In 1975, TMPA retained Tippett & Gee for the design of their Gibbons Creek Plant. Tippett & Gee's efforts in the San Miguel Project began very early in the investigation of the utilization of the fuel. We worked closely with the Department of Energy Laboratories in Grand Forks, North Dakota, for early burn tests both of San Miguel and Gibbons Creek fuels. Burn tests were also conducted at Babcock & Wilcox and Combustion Engineering facilities. These tests and the results have been reported previously in this symposium and other similar symposia. (References 1, 2, 3 and 4.) The locations of fuel deposits, plants and mines are shown on the map, Figure 1.

JACKSON GROUP FUEL DESCRIPTION

By means of comparison of the Jackson group lignite deposits with other better known lignites, Table 1 lists the important properties. The tabulations for Gibbons Creek and San Miguel are based upon actual experienced fuel use. Other data is obtained from published literature. (References 7, 8, 9 and 10.)

It should be noted that, although the percentages of sulfur and alkaline ash constituents appear to be moderate in the gross analysis, they become very large when listed on a pounds per million Btu basis and indicate the seriousness of potential operating problems. For example, the soluble sodium oxide equivalent content in pounds per million Btu of the San Miguel fuel deposits is the highest of any commercial coal, including North Dakota lignite or Australian brown coal.

ECONOMICS

By using modern strip mining methods and having the power plant immediately adjacent to the mine, the cost in dollars per million Btu of lignite from the larger deposits of Jackson group lignite can be lower than that for gas or oil or transported coal and comparable to mine mouth Wilcox lignite. Since most sites of power plant scope and suitability utilizing Wilcox lignite had been taken prior to the SMEC project time frame, the Jackson group deposits became attractive. The key to success of these projects was to design the plants for reasonable capital and maintenance costs and good availability and efficiency.

CONCEPTUAL PLANT DESIGN

All of the power plants designed for use of Wilcox formation lignite which preceded the San Miguel and Gibbons Creek projects, with the exception of the Units at Sandow, were large supercritical units. Big Brown Units 1 and 2 and Monticello Units 1 and 2 were nominally 575 MW; Martin Lakes Units 1, 2 and 3 and Monticello Unit 3 were 750 MW each. The heat release rate for those furnaces was very low in comparison with coal-fired units of the same era at $1.5X10^6$ Btu/hr/ft^2 plan area. The earlier units did not have flue gas desulfurization systems although they had electrostatic precipitators for particulate removal (Martin Lake Units 1, 2 and 3, and Monticello Unit 3 have scrubbers). All of the electrostatic precipitators used with those units were of the American weighted-wire design.

In the conceptual design of both San Miguel and Gibbons Creek, it was decided that, because of the overall problems evident in the use of such low rank fuel, it would be best to stay with conventional design wherever possible rather than to try to develop new technology to produce the power. It was decided that boiler design would be a pulverized coal radiant furnace with steam drum. Turbine steam conditions of 2400 psig/1000°/1000° were chosen over supercritical conditions. The size in each case was chosen to be 400 MW because this size fitted the Owner's needs. The furnace design heat release rates would be lower than was used for the Texas Utilities units ($1.5X10^6$ Btu/ft plan; 10,000 Btu/ft^3 volume). Specified furnace exit gas temperatures (FEGT) would be low enough to reduce slagging and fouling thereby requiring taller furnaces. This would reduce volume heat release rate to below 8000 Btu/ft^3. In like manner, the design of the fuel handling system from

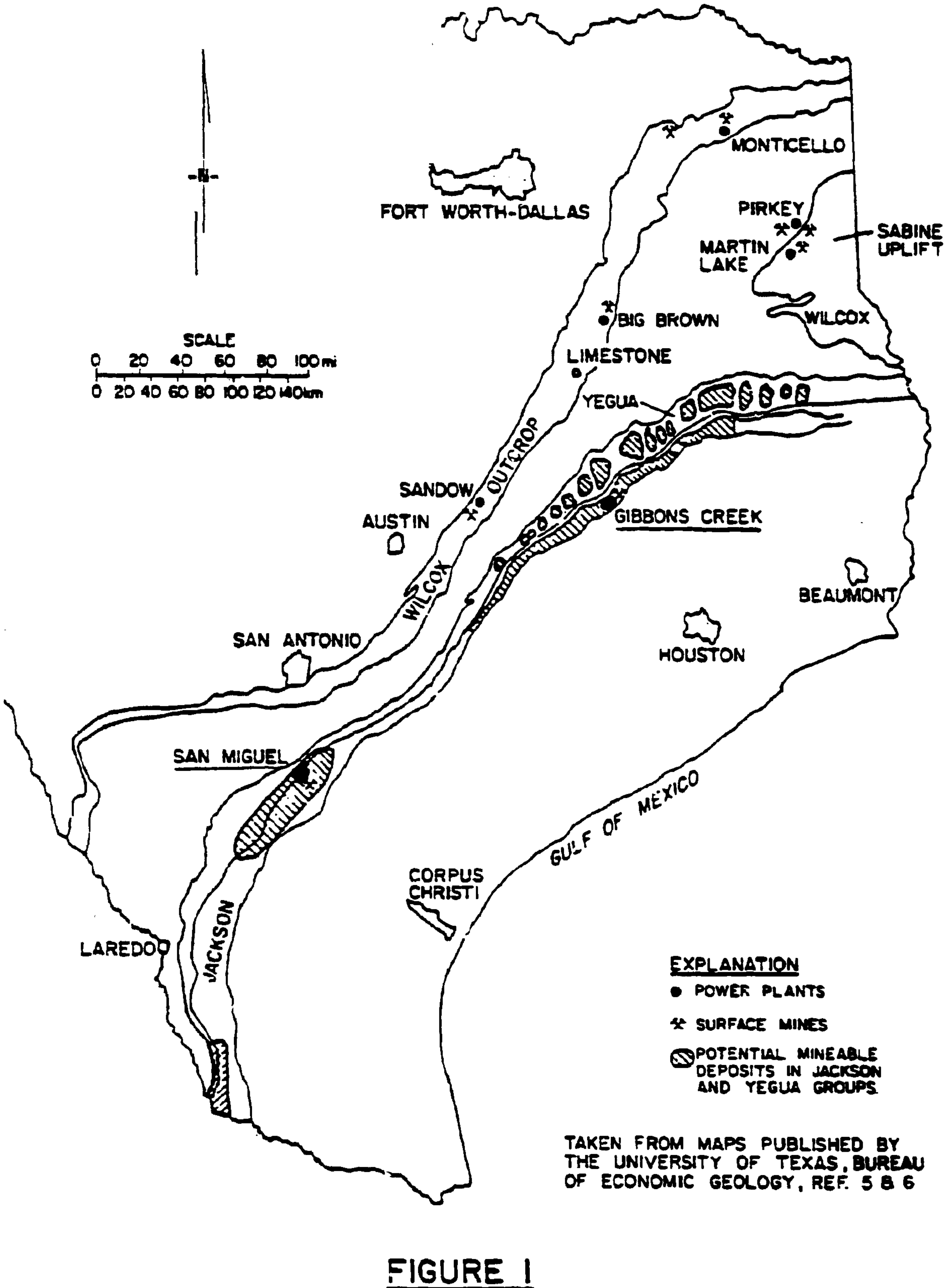

FIGURE 1
TEXAS LIGNITE LOCATIONS

TABLE I. FUEL PROPERTIES

PROPERTY (All values percent unless identified otherwise. All values on equilibrium moisture basis unless stated otherwise.)	TYPICAL WILCOX (1)	TYPICAL NO. DAKOTA (BEULAH) (2)	TYPICAL SAN MIGUEL (3) / (4)	TYPICAL GIBBONS CREEK (4)
Fuel Analysis				
Proximate				
Water	32.3	38.00	30.00 / 35	36.5 / 40
($lb/10^6$ Btu)	(48.3)	(57.6)	(55.89)	(84.3)
Ash	15.1	8.00	26.00 / 29	27.6 / 30
($lb/10^6$ Btu)	(22.6)	(12.1)	(48.44) / (70)	(63.7) / (70)
Volatile Matter (VM)	28.3	25.87	24.54	22.3
Fixed Carbon (FC)	24.3	28.13	19.46	13.6
Sulfur (% of gross, included in VM & FC)	0.9	0.62	1.90	0.8
($lb/10^6$ Btu)	(1.36)	(0.94)	(3.54) / (4.0)	(1.85) / (5.5)
Ultimate				
Water	32.0	38.0	30.00	36.5
Ash	15.0	8.0	26.00	27.6
C	40.0	38.70	30.56	24.8
H	3.0	2.70	2.82	2.3
S	0.9	0.62	1.90	.8
N	0.8	0.70	0.25	.6
O	8.3	11.26	8.47	7.4
Gross Calorific Value - Btu/lb				
Equilibrium Moisture Basis	6,625	6,600	5,368 / 4,200	4,330 / 3,900
Mineral Matter Free (ASTM D 388) Basis	7,943	7,241	7,538	6,225
Moisture and Mineral Matter Free Basis	12,500	12,222	12,200	12,040
Grindability		25	80	58-80 / 30-90
Ash Analysis				
SiO_2	48.3	23.07	53.64	63.4
Al_2O_3	16.0	11.25	17.79	19.6
Fe_2O_3	5.7	7.71	1.95	2.6
TiO_2	1.0	0.53	0.79	1.0
CaO	13.7	24.22	5.41	4.4
MgO	2.1	5.15	.56	.9
Na_2O	1.5	8.50	2.63	.4
K_2O	0.5	0.48	1.65	.9
SO_3	11.2	18.35	15.45	6.8
P_2O_5	<0.1	0.75	0.13	Not Avail.
Fusion Temperature °F (Reducing)				
Initial Deformation	2,214	2,170	2,100	2,220
Softening	2,241	2,180	2,400	2,350
Hemispherical	2,279	2,210	2,450	2,530
Fluid	2,343	2,230	2,700+	2,610
Soluable Alkali (Weak Acid Na Equivalent)				
$lb/10^6$ Btu	0.11	0.37	0.97	.44
Base/Acid Ratio	0.36	1.51	0.169	.11
SiO_2/Al_2O_3 Ratio	3.02	2.05	3.02	3.23

NOTES: (1) From Ref. 7 and 8
(2) From Ref. 9.
(3) From Ref. 10.
(4) Possible worst case values are given beside typical values.

receipt of fuel through pulverizing and feed into the furnace was based upon proven equipment and conventional design. The ash handling systems specified were based upon proven equipment and design.

Because of the then-current and pending air quality control regulations, the equipment for flue gas cleaning had to go beyond what was, at the time, "conventional". There had been enough experience with flue gas desulfurization (FGD or scrubber) system design to have confidence of technological feasibility. There had been enough poor experience with American design electrostatic precipitators (ESP) and enough good experience with European ESP design to specify the latter. Specified performance would meet current and anticipated regulations for emissions. Other performance parameters would be evaluated. The limits for NO_x emission had not yet been set for lignite boilers. The current limits for coal fired boilers were specified.

PLANT DESIGN

FURNACE:

As a result of the findings of the various test programs, it was determined that the furnace design had to minimize the effects of slagging and fouling. At San Miguel, the fuel was considered to be both severely slagging and fouling with the ash having low fusion temperature and very high sintering strength. This is related to the high sodium oxide content in the ash. In the case of the Gibbons Creek furnace, the sodium ash content is lower, and it was found that the ash would be severely fouling, but the slagging potential was not as great. The San Miguel furnace design called for a furnace exit temperature on a HVT basis of 1850°F. That for Gibbons Creek was 1875 °F. The design for San Miguel initially used hot gas recirculation with tempering gas injected at the upper part of the furnace with no radiant superheater surface section in the furnace. The Gibbons Creek design used platen superheaters and a radiant reheat section surface in the upper part of the furnace. Figure 2 shows the furnace configuration, dimensions and heat release rates for the two boilers. References 11, 12, 13, 14 and 15 describe the furnace designs in more detail.

CONVECTION PASS (HEAT RECOVERY AREA OR HRA):

In the convection passes of the boiler, attention was paid to the anticipated fouling characteristics of the fuel. Tube spacings and velocities were limited based on temperature as follows:

TABLE II

San Miguel:				
Temperature - Maximum °F	1760	1650	1500	1110
Spacing - inches	24	12	9	4 1/2
Velocity - ft/sec	28	33	38	45
Gibbons Creek:				
Temperature - Maximum °F or Location	1950	1650	Lower SH	Economizer
Spacing - inches	20	7 1/2	6 min	2 1/2
Velocity - ft/sec max	45	45	45	45

Boiler manufacturers quoted on boiler efficiencies based upon exit temperatures of 315°F (295°F when corrected for nominal expected air leakage). In both cases, the boiler manufacturers' conventional calculation procedures were used in predicting efficiencies. Both manufacturers, B&W in the case of San Miguel and Combustion Engineering in the case of Gibbons Creek, used 1.5% for unknown and manufacturers margin factors. The quoted efficiencies were 81.22% for B&W at San Miguel and 80.58% for C.E. at Gibbons Creek.

SOOTBLOWERS:

Because the actual ash slagging and fouling within an utility furnace was unknown, it was decided to use steam as the soot blowing medium with that steam taken from the primary superheater outlet header in each case. Such selection would allow increased steam use at a future date should it be necessary without extensive capital outlay such as would be the case with compressed air. The B&W furnace design for San Miguel included 76 furnace wall blowers originally and 80 retractable blowers with space for future additional blowers. At Gibbons Creek, C.E. installed 162 wall blowers and 56 retractable blowers. Header pressure was selected in both cases at 600 psig.

PULVERIZERS (MILLS):

The pulverizers specified in both cases were standard roller mills sized on the basis of an expected worst grindability to produce 70% through 200 mesh with less than 1% retained on 50 mesh. Grindability was expected to be medium to high (50-90). Sizing and selection was based upon having one pulverizer of the full complement out of service with the boiler at its maximum continuous rating (MCR) with design fuel. Further, the complement of pulverizers was specified such that, with worst expected fuel, MCR could be obtained with all pulverizers in operation. Primary air fan and primary air heaters were sized to provide the necessary air flow and heating for drying of the fuel within the pulverizers and transport of the fuel through the fuel pipes to the burners. At San Miguel, dedicated secondary and primary air preheaters of regenerative-type manufactured by Rothemuhle were provided. At Gibbons Creek, two Air Preheater Corporation (Ljungstrom) air heaters with trisector arrangement were provided. Because of the very high ratio of primary to secondary air, the trisector segments for these air heaters were the largest, with respect to the overall size, ever produced.

FUEL PIPES AND BURNERS:

Initial tests of the expected mineral species in the lignite at San Miguel indicated a rather low quartz count; therefore, the fuel was not considered to be significantly abrasive. Carbon steel pipes with wall thickness greater than used with past boilers and standard burner design were initially installed. At Gibbons Creek, the amount of sand within the lignite was high enough to warrant special consideration for abrasion resistance, therefore basalt-lined fuel pipes and erosion resistance burner nozzle design were used.

FANS:

Because of the variability of the fuel and in anticipation of fouling, specified fan design margins were high compared with general industry practice - 1.25 on flow and 1.56 on pressure. These were based on specified excess air with worst fuel and expected air heater leakage. The boiler contracts were very comprehensive and included the fans. Axial flow fans with variable pitch blades were being marketed vigorously because of problems with large centrifugal fans, better part load efficiency, lower noise levels, and smaller size. The large margins specified for San Miguel and Gibbons Creek made the axial flow fans look good because of better part load efficiency. All of the large fans at both projects are axial flow except for the gas recirculation fans at San Miguel which, because of high dust loading and high temperature, are radial blade centrifugal.

FUEL HANDLING:

Both power plants are situated at the mines serving them. Run-of-mine fuel would be delivered to the plant and all subsequent size reduction and handling would begin at the plant property lines. Primary breakers were installed at both plants. It was determined that the best means of ready storage for the fuel would be in vertical concrete silos because of the volatile nature of the fuel and the potential for fire, to provide dry storage, and to have first-in/first-out inventory. The concrete silos constructed for this purpose in both plants are among the largest ever built. In fact, the pair of silos at Gibbons Creek were the largest at the time.

Stackout using telescopic chutes is used as a means of bypassing the silos and to build the dead storage pile. Secondary crushers are supplied downstream from the storage silos. As-fired fuel sampling is done at the transfer tower downstream of secondary crushers. Vibrating feeders were used at the transfer points. Since the number of pulverizers in each case required arrangement on either side of the boiler, a transfer tower was installed for dividing flow to the two sides of the boiler in each case. A tripper conveyor was installed above the boiler bins for distribution of fuel into the bins. The boiler bins were each sized for 1.3 hours of lignite storage. The initial design used 60° (San Miguel) and 68° (Gibbons Creek) cone bottoms. Based on experience at Texas Utilities, vibrating feeders were used. These fed into downspouts sized using criteria established by the gravimetric feeder supplier, Stock Equipment Company, for sealing and for proper flow. At San Miguel, 24-inch downspouts, which were the largest at the time, were used. At Gibbons Creek, 36-inch downspouts were available and were used.

ASH HANDLING:

The bottom ash handling system in both plants includes wet hoppers mounted at the furnace bottom. Each of these has three separate hopper bottoms. Each hopper bottom has two clinker grinders at the paired outlets. At San Miguel, a water jet pump system is used for bottom ash removal. At Gibbons Creek, a centrifugal pump system was used. In both cases, two completely separate bottom ash conveying lines are used with means for switchover using permanently installed valves. Bottom ash is conveyed to dewatering bins with the decanted water going to ash ponds for cooling and storage for recycle. The large quantities of fly ash collected at each plant requires an extensive fly ash removal system. At San Miguel, the system consists of a pressurized air conveying system for the first row of precipitator hoppers and the gas recirculation hoppers with the remaining hoppers using a vacuum system. At Gibbons Creek, all fly ash is conveyed by pressurized air.

AIR QUALITY CONTROL, FLUE GAS DESULFURIZATION:

The Clean Air Act regulation at the time of the San Miguel and Gibbons Creek projects required removal of SO_2 to a level of 1.2 lb/10^6 Btu The best available control technology (BACT) was wet scrubbing with limestone as the reagent. The scrubber system was specified accordingly. It was further specified to remove SO_2 down to the required level when burning the worst fuel (lb sulfur per Btu basis) with one scrubber module out of service. At the time the San Miguel scrubber was specified, the perceived BACT was to use a two-stage scrubber. At that time because of then-recent history of severe pluggage of in-line reheaters, a heated ambient air system of reheat was used. The San Miguel scrubber has a Venturi first stage with upflow absorber tower second stage. The predicted and realized pressure drop through this scrubber was relatively high at approximately 12.0 inches of water column at maximum through-put. When the Gibbons Creek scrubber was specified, it was determined that advancement and development of open absorber tower scrubber design was such that that design could be used. In addition, there was more confidence in the use an in-line reheater. Therefore, that arrangement was specified and supplied. The predicted pressure drop through the system was 3.4 inches of water column.

AIR QUALITY CONTROL, ELECTROSTATIC PRECIPITATOR:

It was determined at an early date that a European style rigid frame electrostatic precipitator would be used placed downstream of the air heater (cold side). This was based upon experience in Europe with such designs behind boilers burning brown coal (West Germany) and certain lignites (Yugoslavia, Czechoslovakia and Turkey). This is also a result of the rather poor experience being had at the time with hot side precipitators and with cold side precipitators having weighted-wire construction.

It was determined that the fuel at San Miguel, because of its high sulfur and sodium content, would produce ash having very good resistivity for collection by electrostatic means. The Texas Air Control Board, however, requested that further proof be obtained by having in-situ resistivity determined. The only lab available for this at the time was in Chatswood, Australia. Samples of the fuel were sent there and tests made. These indicated that the ash should be readily collected. The precipitator for San Miguel supplied by Rothemuhle and has two casings, each having four fields with two bus sections per field with a specific collection area (sca) of 390 ft^2 per 1000 acfm. The amount of ash collected in the first stage is so great that a very deep hopper was required for collection. This required that the precipitator be raised with the bottom of the casing 40 feet above the grade level.

The Gibbons Creek fuel is lower in sulfur and sodium than the San Miguel fuel. Fuel and ash analyses indicated that the ash would have high resistivity and would be difficult to collect. The particulate removal equipment supplied by Lodge-Cottrell includes two precipitator casings, each with six fields and four bus sections per field. The total specific collection area (sca) is 596 sq. ft. per 1000 acfm. The Gibbons Creek precipitator also has oversized first stage hoppers.

EXPERIENCE

As anticipated, the Jackson group lignites cause many operational problems. Almost all the problems relate to the shear bulk of noncombustible material in the fuel. Typically, the fuel delivered to the pulverizers is only 35-45% combustible. Pulverizing is the first step in altering the raw fuel's composition. It is dried there to about 15% moisture; however, all the removed water stays with the fuel as vapor in the transporting primary air. As the fuel flows through the burners and is ignited, the great amount of mineral matter forms a cloud which makes the flame very difficult to detect by scanners. There is inherent ash which is typical of fossil vegetable matter at about 5%; however, most of the mineral matter is associated clay and sand. The dry ash-free material burns very readily and to completion. Unburned carbon is very low (less than 0.002 lb per lb of ash or 0.1 lb per 10^6 Btu). The large quantity of ash particles seem to inhibit combustion at least to the extent that the flame is extended. All this ash causes fouling and erosion as it passes on through. The ESP's, which remove down to less than 0.1 lb per 10^6 Btu, must be very efficient (better than 99.8%). There is at least one benefit from the ash - it captures some of the SO_2 and SO_3 produced. The experiences with the various systems and components follow.

FURNACE:

- San Miguel. B&W's original scheme for control of furnace exit temperature to the specified 1850°F maximum was to use gas tempering by means of recirculated flue gas into ports at the upper part of the furnace (Ref. 12). A cyclone type dust collector was used between the economizer hopper and the gas recirculation fan to reduce the dust loading on the fan and to reduce the amount of dust recirculated by the system. From the very beginning, the great amount of dust created so many problems in terms of fan erosion and dust build-up in corners, duct work, and in the tempering gas plenum that flue gas recirculation for tempering was abandoned. This system had also been designed for recirculation of flue gas into the lower part of the furnace for reheat steam temperature control at lower loads. The abandonment of the flue gas recirculation system solved the problems created by the large amounts of dust; however, it exacerbated problems with regard to slagging in the furnace. The original complement of 76 wall soot blowers was not sufficient to handle the furnace slagging when operating at high loads continuously. Nineteen soot blowers were added and the sequence was changed to blow four at a time. Blowing pressure was reduced to reduce tube erosion. These changes have had partial success.

It appears that the addition of more wall soot blowers would further help the situation. Most of the ash has low bulk density and strength and is easily removed by blowing. However, there is a portion which forms a very hard strong deposit. In the extreme, the furnace slagging has produced very large clinkers which will let go and fall into the bottom ash hopper in very large pieces. This causes a radical change in the heat transfer characteristics of the furnace which exacerbates the overall problem of maintaining a low furnace exit temperature. With the diligent use of wall soot blowers and continuous monitoring of the slagging situation, the operating personnel at San Miguel have maintained good, efficient operation of the furnace. One of the problems which has aggravated the situation is the extension of the flame. It is normal to observe fuel still burning past the nose of the furnace. It is known that improving of the grind in the pulverizers helps this situation. It is extremely important to assure that no more than 3% of the pulverized fuel is retained on a 50-mesh screen because larger particles lengthen burn time. It is believed that the extension of flame is probably an inherent problem with high ash lignite because of the great amount of noncombustible material which is carried along with the burning particles of lignite.

- Gibbons Creek. The furnace exit temperatures are apparently within the limits specified of 1875°; however, because of the platen superheater surface in the furnace, there is fouling which affects overall performance. There have not been any instances of bridging between platens. As is the case at San Miguel, the vast majority of the ash deposited within the furnace is very light and fluffy and easily removed. However, there is a portion which is sticky and difficult to remove. With the original complement of wall soot blowers, essentially all possible soot blower positions were filled. Operating procedure calls for blowing of four at a time. In general, the operating personnel have been successful at avoiding severe problems from the furnace slagging; however, there have been instances of very large clinkers formed just like those at San Miguel. As in the case of San Miguel, the formation and then falling off of these large clinkers radically affects the heat transfer within the furnace and, hence, the overall performance.

CONVECTION PASS (HEAT RECOVERY AREA OR HRA):

- San Miguel. At San Miguel, all of the superheater and reheat surfaces are past the nose of the furnace in the HRA. The originally anticipated severe fouling of these surfaces has not developed. The long, retractable blowers appear to be capable of good removal of the ash as long as proper sequence is maintained and close monitoring is done. The major problem in the HRA passes has been tube erosion. The specifications required limitation of flue gas velocity (see Table II). The flow is not distributed evenly throughout those passes, therefore there are some areas where the velocities are high enough to cause erosion. The greatest problem with erosion, however, is associated with the soot blowing. The steam jet produced by the long retractable soot blower entrains fly ash which then becomes extremely abrasive because of the very high velocity. Reduction in blowing pressure is limited because of the need for long jets; therefore, the only fix for the erosion which seems to be practical is to install shields on those tubes in the areas where the high velocities occur.

- Gibbons Creek. The HRA problems at Gibbons Creek have been similar to those at San Miguel; however, because of the higher ash loading during early years of operation at Gibbons Creek, the problems were correspondingly worse. The flow distribution in the convection pass at Gibbons Creek appears to be worse than that at San Miguel and this has caused part of the problem. During initial operation of the Gibbons Creek plant, it was noted that an excessive amount of superheater surface was resulting in high superheater desuperheater spray flows, and a portion of the superheater surface was removed. This resulted in higher flue gas temperature from the economizer, which resulted in higher primary air temperature to the mills, which allowed better fuel drying; however, it also resulted in a higher exit gas temperature from the air heater and a loss in boiler efficiency. This higher exit temperature has also been identified as one of the factors adversely affecting precipitator performance.

AIR HEATERS:

Although the detailed design of Rothemuhle (B&W) and Ljungstrom (CE-APC) regenerative air heaters is quite different, they both rely on sheet metal baskets and rotating seals. By the time the ash gets to the air heaters, the temperature is low enough to preclude any sintering type fouling; however, the amount of SO_3 is high enough to present a potentially serious problem of acid fouling. The average cold end temperature was specified to be high enough (195-200°F) to prevent acid condensation, but only a small amount of such condensation is sufficient to produce advanced fouling because of the large amount of ash and available SO_3 (about 0.08 lb per 10^6 Btu). In spite of the best efforts of the suppliers, Rothemuhle and APC, in designing cleaning systems, the fouling caused by the acid accumulates. The paradox is that the ash erodes the baskets so the baskets are being plugged as they are being worn down. Air heater effectiveness is being reduced. The ash also erodes the seals. Leakage rates have exceeded 25%. These effects are most pronounced in the primary air heater at San Miguel and the primary air sector of the trisector air heaters at Gibbons Creek. Fouling and leakage have been greater at San Miguel. In spite of these problems, the practical effectiveness of the air heaters has been sufficient to keep final exit temperature within 10° - 15° of design and to provide sufficient hot air to the pulverizers. Actual primary air has not been up to design temperature because of leakage of tempering air dampers.

In an attempt to lower the exit gas temperature and improve boiler efficiency, TMPA replaced the air heater baskets at Gibbons Creek with a dense-pack design with more heat transfer surface and smaller openings. This resulted in approximately one inch additional draft loss. The dense-pack baskets have worked well, and pluggage, which was an early concern, has not been a problem.

PULVERIZERS AND FUEL PIPES:

Original tests on the San Miguel lignite indicated that fuel transport erosion would not be a problem. That was not the case. Even though the bulk of the mineral matter is clay, enough is dense hard matter, such as sand, garnet, and pyrites to be abrasive. In the recirculation process within the pulverizer, these abrasives are concentrated causing very severe erosion. This has affected all internal parts of the pulverizer above the lower plenum. Extensive lining with ceramics has been done at San Miguel. Roller tire materials have been sought which are hard enough to withstand the abrasion. Even so, this has been a significant maintenance problem. Fuel pipe erosion advanced rapidly from the first at San Miguel. All pipes have been lined with ceramic blocks. The burners have been redone with ceramic wear-resistant areas.

Although abrasion was anticipated at Gibbons Creek and erosion resistant materials were used, the experience was similar to that at San Miguel and it was found necessary to add abrasion resistant materials to pulverizers.

Under normal circumstances with little surface moisture and inherent moisture at average value (29-35%), grindability is between 50 and 70 (Hardgrove units). If unusually dry fuel (moisture less than 23%) is delivered to the pulverizers, grindability may be as high as 90. If, however, total moisture is above 35%, drying is not as effective and grindability drops radically (less than 30). There have been events of the mill not being able to deliver fuel caused by unusually wet fuel.

FUEL BURNING:

- San Miguel. This plant has been operated at the highest practical load. So far, there have been few periods at part load. The pulverizer/feeder/burner system is capable of a safe load variation of about 100% to 50% for a given number of operating pulverizers. However, the flame scanning system has not been capable of discriminating flame below 80%. This is because of the clouding from dust. Many attempts have been made to correct this. The most successful have been to add scanners with corresponding reduction in coverage and lowering flicker frequency. Further development work should be done if such units are to be used in cyclic operation.

- Gibbons Creek. The tangential firing used by C.E. does well with low grade lignite. Flow turndown has been 100% to 50% or better. However, the cyclonic action separates the ash and contributes to slagging and tube erosion. In an effort to improve overall boiler performance, modifications were made to produce "concentric firing". Air is injected toward the outside of the cyclonic fireball to produce variation in stoichiometric ratio from the center out with the outside being fuel lean. This has changed the pattern of ash deposition and tube erosion with general improvement. It apparently has stretched out the flame which may be contributing to increased fouling. The cyclonic flow is straightened to uniform flow in the direction of and along the path of the complete boiler setting - at least, that was the hope. The fact is that there is a residual component to the right with counter-clockwise flow. This resultant uneven distribution has contributed to problems in the ESP and to HRA erosion. In boilers burning better fuels, this effect is minor and is usually ignored.

FANS:

It has been found that the large flow and pressure margins specified for the large boiler fans were justified. Inability to maintain good sealing of air heaters, higher flue gas temperatures, fouling of air heaters and high drop through scrubbers have been the major causes of use of margins. In the case of primary air fans, excessive flow has not been a significant problem, but high pressure has required operation approaching the stall line. The blades of the ID fans at both plants were designed for erosion resistance. In spite of good overall performance of the electrostatic precipitators, there have been enough events of high dust loading of the fans to cause advanced erosion. Blades have been reworked to resore hard facing many times. In some cases, it was necessary to replace blades.

FUEL HANDLING:

All fuel handling system components were designed for the very high flow rates (typically 450 tons/hr) required. Deficiencies such as excessive vibration, insufficient idlers under belts at drop points and cracked structural members were identified and corrected early. The more serious problems directly resulted from the high moisture content. The inherent moisture (within two percentage points of the equilibrium moisture determined by ASTM D 1412) is the same in the mineral matter as in the lignite. Most of the mineral matter is clay. Hence, the bulk material tends to be sticky. If surface moisture is present, the condition becomes very bad.

There were many cases of complete stoppage in bins and hoppers. The original boiler bins (metal silos above the gravimetric feeders) had straight cones with vibrating feeders. This design did not work. All bins at both plants were redone with variable angle cones to achieve mass flow. The vibrating feeders were removed. These modifications improved flow greatly. Some vibrating feeders used elsewhere at transfer points failed in various modes, either structurally or functionally. In a number of such places, replacement with belt feeders has been successful. In others, modification of the original design has been satisfactory. (Ref. 13, 15 and 16.)

ASH HANDLING:

Both San Miguel and Gibbons Creek use wet ash hoppers with water seal troughs. Water is circulated through the hopper and seal trough for cooling. Early in their operation, both plants had severe problems of ash removal. The large falling clinkers were bad enough, but clinkers would also form in the hopper. At times, clinkers would grow to a size to bridge the furnace bottom slot. This would invariably cause an outage. One problem was in setting up of control logic for the systems. This was done after much trial. The clinker problems were largely solved by more diligent soot blowing and assuring that cold water was supplied (less than 100°F) which is well distributed throughout the hopper and recirculated at high enough rate to keep the water temperature below a 140°F limit under all circumstances of bottom ash fall. The cold water causes the clinkers and smaller bottom ash pieces to shatter. Most of the bottom ash has the consistency of fine sand. Part acts just like pyroclastic ash from volcanoes and swells greatly. Such pieces can pose serious problems because their effective specific gravity is about 0.2. They plug the seal trough and have, in the extreme, built up on the water surface sufficient to plug the furnace opening. The only way to remove such pieces during operation is to draw down the hoppers and use cooling sprays. The use of cold water in the hopper helps by shattering the pieces. Even so, the small (less than 1/8") shards float and will build up. These floaters will, when removed and sluiced out, be carried with the decanted water from the dewatering bins and end up in the ash pond. This has caused maintenance problems in the ponds. These "floaters" have been much worse at San Miguel than at Gibbons Creek.

During the engineering of San Miguel, it was thought that the high alkaline content of the ash would elevate the pH of the recirculated ash water beyond acceptable value. An acid feed system was installed for pH control. A portion of the recycled scrubber water was piped to the ash pond. The combination of use of the scrubber water and the apparent capture in the furnace of SO_2 by the ash has kept the ash water pH below 9.

At both plants, clay-lined ash ponds were used. The finished lining was tested for permeability and was acceptable in each case. It was anticipated that, if any leaks developed, the ash would help seal them. Although the integrity of the liner and the sealing effect has largely been good, good is not enough. Any leakage is not acceptable. It was necessary at San Miguel to drain and seal one pond. Indications are that sealing will be a recurring maintenance effort. Pond capacities are 400 acre feet at San Miguel and 600 acre feet at Gibbons Creek. The dewatering bins are effective but only about 75% efficient. The 25% solids which pass represent a large volume after a few years of operation. It is necessary to excavate the accumulated solids after three to eight years depending on actual fuel used and load factor. This is done with dragline and front end loaders. Even though ash pond maintenance has been costly, the capital cost for alternate systems would have been very high. Life cycle analyses indicate possible advantage in certain of the alternate systems.

AIR QUALITY CONTROL, FLUE GAS DESULFURIZATION:

- San Miguel. As anticipated, the two stage scrubber had high pressure drop (12" wc). Initial scrubber performance was poor. Control of pH was difficult; limestone utilization was high, scaling was a problem. Corrosion was severe in places. However, emission limits were met. At first it was thought that buying limestone at 3/4" X 0 would save money. It didn't because of the effects of fines on utilization and reactivity. Apparently the fines contain higher percentage of impurities; therefore, physical separation improves purity. By using screened limestone at 3/4" X 10-mesh, most of the problems were solved and limestone consumption dropped. San Miguel was among the first plants to experiment with buffering by means of dibasic acid (Ref. 17). This was so successful that permanent facilities were installed to use that additive. Operation was much improved. It has become possible to bypass some flue gas, thereby reducing system pressure drop and reducing reheating by heated outside air. This has reduced auxiliary load and has improved the heat rate. Corrosion has been a continuing problem. The use of high alloy metal sheets "wallpapered" on critical areas and chlorobutyl rubber in lower temperature areas (Ref. 18) holds great promise. The FGD sludge is dewatered and mixed with fly ash to produce a truckable mixture. Even with improved limestone use, good removal efficiency and apparently significant capture of SO_2 by ash in the furnace, the solid product amounts to 237 tons per hour at maximum load. Fortunately, the mined area floors are impervious clay, therefore this product is returned to the mine for disposal.

- Gibbons Creek. Although most fuel properties realized during the first years of operation were to the bad extreme, sulfur was not. Hence, the FGD system inlet SO_2 loading has been below design. So far, the scrubber has met emission regulation limits and removal efficiency has been high. However, limestone usage has been high and scaling has been a problem. Somewhat surprisingly, corrosion has not been a serious problem - yet. The control of pH has not been the problem it was at San Miguel, so the promise of performance improvement by buffer addition is not as great. Adjusting the wet ball mill classifier to produce finer grind has improved performance. The solids production is very great at 277 tons per hour at maximum load. An on-site landfill is used.

AIR QUALITY CONTROL, ELECTROSTATIC PRECIPITATORS:

- San Miguel. The design of the ESP at San Miguel has been very successful. The system, including adjacent ducts was flow modeled. Flow distribution has been good. The operating efficiency has been better than specified and final opacity has been below the regulated amount. It has been extremely important to maintain good operation of all components of the fly ash removal system. Moisture, even at very low levels, causes serious problems.

- Gibbons Creek. Recent emissions tests at Gibbons Creek plant indicated that the precipitator outlet emissions were less than 0.1 lb per million Btu. The particulate removal efficiency was 99.96% with inlet grain loading of approximately 14 grains per dry standard cubic foot.

  This exceptional precipitator performance verifies the validity of the conservative design philosophy established by Tippett & Gee and the soundness of the European style, rigid frame design by Lodge-Cottrell.

  The particulate removal system performance has not always been this good. Particulate removal efficiencies as low as 99% have been recorded, and the unit experienced extended operating periods with efficiency between 99.3 and 99.5%. This poor performance was the result of numerous factors. The Gibbons Creek fuel is low in sodium and sulfur, and the resulting ash has a high resistivity which results in back corona in the precipitator. This was recognized during early fuel investigations and precipitator sizing criteria was set accordingly. The ash resistivity appears to be very temperature dependent in the 320 to 340°F range, and experimental work with numerous additives, including SO_3 and ammonia indicate that the ash resistivity does not respond well to such additives.

  Flue gas flow and ash distribution into the precipitator was identified as being a portion of the problem. Model studies were conducted and modifications to improve distribution were made.

  Problems with removing ash from the precipitator hoppers resulted in high ash levels requiring that certain fields be removed from service. This compounded the problems of particulate removal due to a portion of the precipitator not being available for service. Improvements to the hopper heating and fluidizing air systems as well as an intensive fly ash handling system maintenance program have corrected this problem. It should be noted that with its high silica and alumina content, the fly ash at the Gibbons Creek plant is extremely abrasive, and even with highly abrasive-resistant materials, the maintenance requirements of the fly ash handling system are very great.

COMPARISON WITH LABORATORY

Throughout the early development of these projects, extensive laboratory tests were done. Standard ASTM tests were performed. Proximate and ultimate analyses, higher heating valve with bomb calorimeter, equilibrium moisture, ash fusion, and grindability were done. Special tests such as sintering strength, fouling tendency, slagging tendency, and ash resistivity were done using proven or carefully designed controlled procedures. All this is as it should be. In reviewing all the tests, one must be impressed by the courage of the utilities which embarked on these projects. Fortunately, in most respects, the real world for Jackson lignites is better than that in the laboratory. The mineral matter, which is mostly clay, moving with the burning fuel serves to weaken the ash deposits. The sodium oxide captures SO_2 and SO_3 and apparently does not lower fusion temperature to the extent found in the laboratory. The ash is not as severely slagging and fouling as was thought. Reference 3 reported on the possible benefit of kaolin as an additive with North Dakota lignite. There is a lot of kaolin in Jackson lignite. Reference 1 reported on the possible benefits of calcium as an additive. There is a lot of lime in Gibbons Creek fuel. There is an apparent significant negative effect of the mineral matter.

The bomb calorimeter test for gross calorific value is done at low temperature (Ref. 19). The furnace temperature is high enough to convert the kaolin and other complex clays to simple oxides. That requires heat. It is not accounted for in the heating value test or boiler heat loss test. Operating data shows that there is as much as a two percentage point discrepancy between heat loss boiler efficiency and input/output efficiency using fuel flow and tested HHV. Assuming the 25% mineral matter is half clay and using known energy requirements for firing clay results in about 100 Btu per lb of as-fired fuel, or about 2%. The effects of clays were studied by Nettleton & Wall, et al., (Ref. 20 and 21), but primarily to determine effects on burning and ash properties. The direct effects of the clays on realized heating value has not received much study. It is hoped that a means for accurate determination of these effects will be forthcoming.

FUTURE DESIGN.

A number of design improvements should be considered for future plants using Jackson group lignites. Tippett & Gee has made a number of conceptual designs done for such plants. The following are some of these improvements:

- Increase furnace plan area (decrease plan area heat release rate) by about 20% to provide greater residence time for burning.
- Derate pulverizer capacity so that consistent operation with very fine grind can be obtained. Provision must be made for effective drying when fuels are received with 40% or greater moisture.
- Design all fuel related components for at least 5% greater fuel flow than that predicted using ASTM D 2015 higher heating values.
- Improve air heater design.
- Use centrifugal fans with variable speed drives.

While not a part of this paper, the development of Lower Colorado River Authority's Fayette Unit 3 project has been followed with interest. This plant is to come on line in 1988. Reference 22 gave an interim report on the project in 1984. It has been interesting to note that, although a different utility and Engineer/Architect were involved, the conceptual design is very similar to those for San Miguel and Gibbons Creek.

RESULTS

During the first year of operation of each of the two plants, the various problems cited hereinbefore were dealt with at least to the identifying and planning for remedies. The next years saw further maturing. In looking only at problems, the realized feasibility of these projects might be questioned. In fact, these plants have been very successful. Both plants have realized excellent availability. For fiscal year 1986 (October 1, 1985 to September 30, 1986), the availability factor, the forced outage factor and gross capacity factor (GADS definition, Ref. 23) for the two plants were as follows:

TABLE III

	San Miguel	Gibbons Creek	1985 All Coal-Fired Average
Availability Factor (%)	87.72	82.24	82.12
Forced Outage Factor (%)	0.39	4.15	5.68
Gross Capacity Factor (%)	70.84	73.46	57.10

These rank high compared with mature plants burning good Midwest bituminous coal with no scrubbers. They are better than other lignite plants. The fuel costs are the lowest of plants started in the same period. The plant costs per kW are comparable to those of other coal plants of the same period.

CONCLUSIONS

The use of conventional pulverized coal technology can be very successful when utilizing Jackson group lignite. Careful attention must be paid to plant design and operation. Problems must be identified early and dealt with expeditiously. Since the proven reserves of readily mineable Jackson group lignite are large, this can be a very important and economic source of bulk electric energy.

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Market and Policy

Stream Chairman: G. A. Wiltsee

UND Energy Research Center

A COMPARISON OF COAL AND LIGNITE FUEL COSTS FOR EXISTING AND NEW GENERATING STATIONS IN TEXAS

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Abstract

Publicly available information is used to compare historical, current and projected costs of coal to lignite for generating stations in Texas. The cost of these fuels are compared on both a delivered price basis and at the busbar. Data is presented, as filed by utilities with various public agencies or as compiled by the agencies themselves. In all cases, lignite is found to be the least cost generating fuel.

Introduction

Within the industry and in the general news media, there has been discussion regarding the ability of Texas lignite to economically compete with other fuels, primarily western coal, as fuel for new electric generating stations. This is partially because declining coal, rail and gas prices have been well publicized while lignite prices, from historically captive lignite projects, are more difficult to quantify.

This study uses data from 19 generating stations (ten coal fired and nine lignite fired) located primarily in Texas (see Table 1). Eight (8) comparisons are made of the costs related to generating power from these two fuels. These comparisons use historical (1983, 1984, 1985) and current (1986) data for the generating stations, projections by the Texas PUC staff pursuant to Docket 6992 (Application of Texas-New Mexico Power for certification of a lignite-fired generating station) and projections by utilities pursuant to avoided cost filings. The results are shown graphically on Figures one (1) through eight (8). Publicly available information is used, as filed, with the following agencies:

(1) Federal Energy Regulatory Commission: FERC Form 1.
(2) Department of Energy: Compiled data from FERC Form 423.
(3) Energy Information Administration: EIA Form 412.
(4) Rural Electrification Administration: REA Form 12.
(5) Texas Public Utility Commission: Monthly Fuel Reports, Avoided Cost Filings, Docket 6992.

The author recognizes that some comparisons made in this study are not on an "apples to apples" basis. The fuel charges reported by utilities are subject to both project specific and company specific considerations. The fuel related charges most subject to these considerations are railcar ownership, handling charges and mining related capital charges. The difficulty in making "apples to apples" comparisons is the primary reason for making a variety of comparisons, as this study has done.

Historical Costs

Delivered fuel prices and busbar fuel and O&M costs were obtained from FERC, REA and EIA filings for the years 1983, 1984 and 1985. A total of nine (9) coal plants and five (5) to seven (7) lignite plants were used to determine annual averages for the two fuels (some of the plants shown on Table 1 were not in commercial operation during these years). Busbar costs include the cost of oil or gas burned in conjunction with the solid fuels. Results depicted on Figures 1 and 2 show that the costs to purchase and burn lignite is 46 percent to 68 percent of the cost to purchase and burn coal.

Current Costs

Monthly delivered fuel prices and busbar fuel costs for 1986 were obtained from the monthly fuel reports filed by utilities with the Texas Public Utility Commission. These filings report both the cost of purchasing and the cost of burning electric generating fuels, for all plants, on a monthly basis. A total of ten (10) coal plants and nine (9) lignite plants were used to develop monthly averages for the two fuels. Only the solid fuel component was used in the event gas or oil was also burned in the plant. If multiple purchases of solid fuel were made (coal contract and spot), then the total cost was determined by weighting on a BTU basis. The total was used in cases where the fuel cost was itemized by transportation, handling, fuel or other. Results are depicted graphically on Figures 3 and 4. These plots show that while lignite is consistently the least cost fuel, the margin has narrowed during 1986. This is the result of declining delivered coal prices and the subsequent response by utilities to renegotiate contracts, decrease contract purchases while increasing spot purchases and obtaining contracted rail rates below tariff. This effect is most evident on Figure 4.

Projected Costs

Three different sources are used to compare the future cost of purchasing and burning coal and lignite. Those sources are:

(1) Utility Avoided Cost Filings.

(2) Coal and lignite busbar cost comparison by the Texas PUC staff pursuant to Docket 6992.

(3) Coal and lignite costs projected by the Texas PUC staff pursuant to Docket 6992.

While some interpretation of data by the author was necessary, an effort was made to present the data as filed by the utilities or as compiled by the PUC staff. These interpretations are referenced where appropriate.

Avoided Cost Filings

The original avoided cost filings were obtained for six (6) utilities and their associated avoidable unit (see Bibliography). The costs given in these filings were converted to and compared on a cents per kilowatt-hour basis for both total busbar cost and busbar fuel cost. Some interpretation and calculation was required in making these conversions. For example, some filings specified hours of operation or capacity factors on an annual basis while others assumed a life-cycle average and still others specified busbar cost directly. In some cases, specific cost components, such as fixed fuel costs, variable O&M costs and rail charges, had to be added to or subtracted from energy costs to obtain consistent comparisons. In one case, fuel costs were calculated from given first year costs and specified annual inflation rates.

Results are shown graphically on Figures 5 and 6. These plots show that lignite is anticipated to be the least cost alternative on a life cycle basis. It should be noted that the highest cost lignite unit, shown in these figures, has since been cancelled and is no longer in that utility's capacity expansion plan.

PUC Staff Busbar Cost Comparison

Pursuant to PUC Docket 6992, the Texas PUC staff made a busbar cost comparison of burning lignite and coal in 156 MW fluidized bed boilers. These costs were given directly in staff testimony and are shown here graphically on Figure 7. While the costs are very close in the early years, lignite is the least cost alternative on a life-cycle basis.

Projected Coal and Lignite Market Prices

Pursuant to Docket 6992, the Texas PUC staff made a 40 year projection of the total cost of purchasing, delivering and burning both lignite and coal in a fluidized bed boiler located in Texas. The lignite was assumed to be from the Wilcox formation.

Five year averages of this projection are shown on Table 2. All costs, except the rail transportation component of the coal FOB plant costs, are escalated using the DRI trend forecast (series OPTIM25YR0986) of the GNP Implicit Price Deflator as published in the U.S. Long Term Review, September 1986. The DRI forecast is through the year 2011. Beyond 2011, the IPD is extrapolated based on the average rate of change for the first 25 years. This results in an average inflation rate of 4.1 percent annually.

The rail transportation component of the coal FOB plant costs is escalated, according to a model developed by the PUC to forecast the ICC rail cost index. It uses DRI projections of various producer price indices to forecast the ICC index. Table 3 below shows the components of the ICC index, their weighting factor and the DRI index used. The DRI forecasts are through the year 2000. Beyond 2000, the rates are an extrapolation based on the average rate of change prior to the year 2000. This method results in an average inflation rate of 5.58 percent annually.

Table 3. TRANSPORTATION ESCALATION

ITEM	ICC WEIGHT	DRI INDEX
Labor	0.505	Wages, Transportation
Fuel	0.108	Diesel to Commercial Customers
Materials	0.078	Non-food, fuel Industrial Commodities
Rents	0.094	Non-food, fuel Industrial Commodities
Depreciation	0.074	Rail Equipment
Other Operating	0.141	Non-food, fuel Industrial Commodities

The five year averages shown on Table 2 were calculated directly from the annual costs estimated by the PUC staff. The timing and amount of capital expenditure for rail car and coal handling was taken directly from staff testimony. Unit costs were calculated by depreciating on an annual straight-line basis (20 years for rail cars, life-of-plant for handling) and computing a return on invested capital of 12 percent. This was necessary to enable a valid comparison to the lignite handling costs which include depreciation, return, taxes and insurance. Coal handling and railcar capital costs shown do not include taxes and insurance.

The results shown on Table 2 are also shown graphically on Figure 8. These demonstrate that lignite is projected to be the least cost generating fuel for electric utilities in Texas.

Conclusions

All comparisons made show that lignite is the least cost generating fuel. This cost advantage has diminished significantly during 1986. All projections show that coal and lignite will be very close in price for the foreseeable future. On a life-cycle basis however, lignite still enjoys a competitive edge.

STATE POLICY CONSIDERATIONS

This study has assumed that both lignite and delivered coal prices will escalate over time. It should be noted however that lignite prices are driven more by production costs while coal has been influenced more by market factors, i.e., excess capacity. This is evidenced by the declining price of coal during the past several years (note Figures 1 and 3) while price levels increased. This situation will continue as long as unutilized capacity exists and there is still a margin between price and incremental cost for coal.

During this past year, members of the Texas State Legislature have discussed adding a tax on lignite production while Wyoming and Montana are discussing reducing coal taxes. A tax would further diminish, and possibly eliminate, the price advantage that lignite still enjoys.

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Table 1. GENERATING STATIONS

UTILITY	PLANT	UNIT(S)#	UNIT SIZE(MW)	FUEL	LOCATION
Central Power and Light	Coleto Creek	1	609	Coal	Texas
City Public Service of San Antonio	Deeley	1,2	405	Coal	Texas
Gulf States Utilities	Nelson	6	540	Coal	Louisiana
Houston Lighting and Power	Limestone	1	720	Lignite	Texas
	Parish	5,6,7,8	630,540	Coal	Texas
Lower Colorado River Authority	Fayette	1,2	570	Coal	Texas
San Miguel Electric Cooperative	San Miguel	1	391	Lignite	Texas
Southwestern Electric Power Co.	Dolet Hills	1	640	Lignite	Louisiana
	Flint Creek	1	480	Coal	Arkansas
	Pirkey	1	640	Lignite	Texas
	Welsh	1,2,3	528	Coal	Texas
Southwestern Public Service	Harrington	1,2,3	330,350,360	Coal	Texas
	Tolk	1,2	524,508	Coal	Texas
Texas Municipal Power Agency	Gibbons Creek	1	390	Lignite	Texas
Texas Utilites	Big Brown	1,2	575	Lignite	Texas
	Martin Lake	1,2,3	750	Lignite	Texas
	Monticello	1,2,3	575,750	Lignite	Texas
	Sandow	4	545	Lignite	Texas
West Texas Utilities	Oklaunion		665	Coal	Texas

Table 2.

PROJECTED MARKET PRICES

Lignite vs. Coal

$ per MBTU

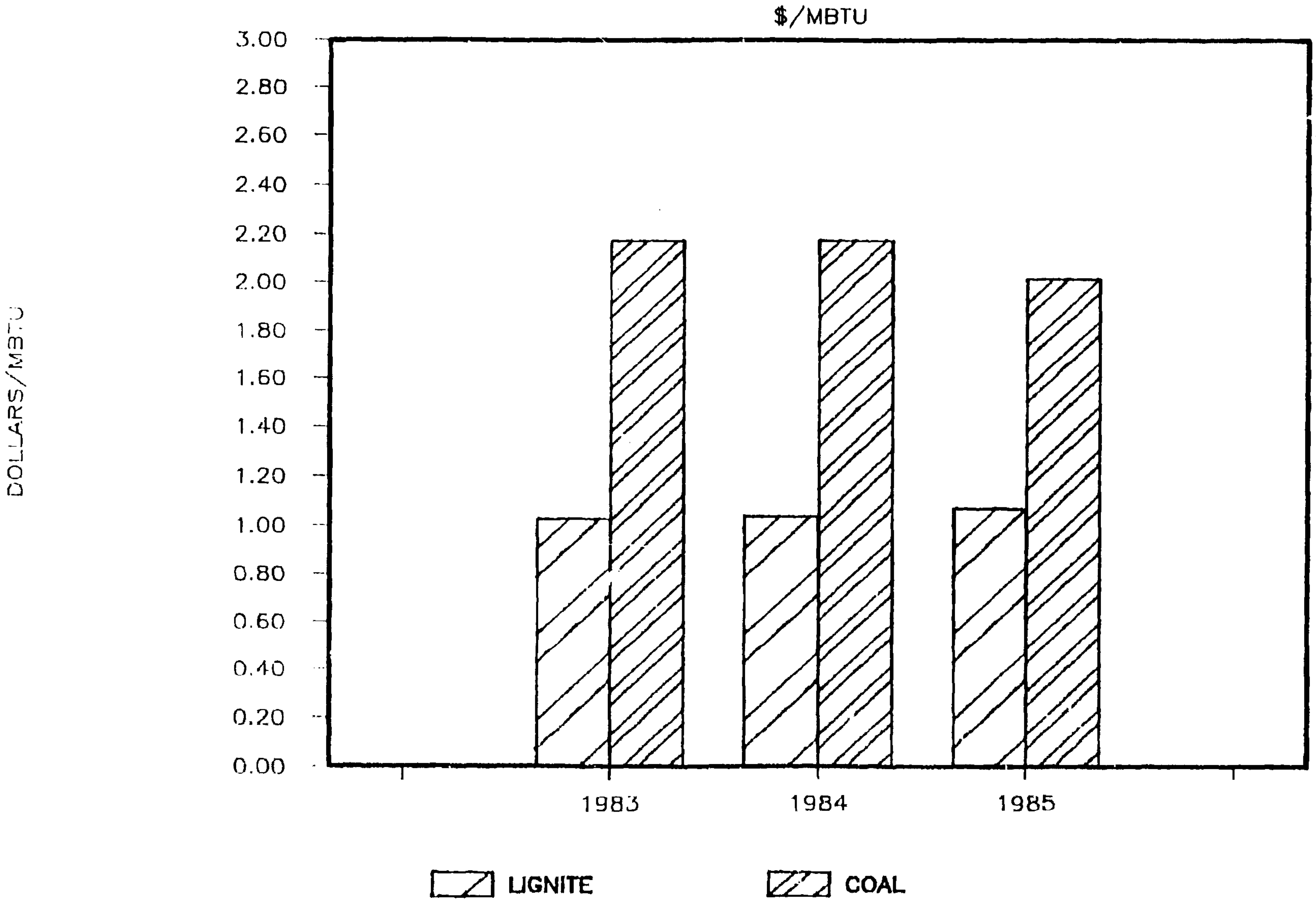
	COAL							LIGNITE			LIGNITE VS. COAL		
YEAR	FOB+ PLANT	RAIL+ CAR O&M	RAIL* CAR CAPITAL	SUBT. FOB PLANT	COAL+ HAND. O&M	COAL* HAND. CAP.	TOTAL IN PLANT	FOB+ MINE	LIG.+ HAND.	TOTAL IN PLANT	DIFFER. IN PLANT	TUSBAR+ DIFFER.	DIFFER. OUT-PLANT
1987	1.15							1.13					
1990-94	1.47	0.05	0.08	1.60	0.09	0.10	1.78	1.35	0.34	1.69	(0.09)	0.09	0.00
1995-99	1.92	0.06	0.06	2.05	0.11	0.06	2.20	1.65	0.42	2.07	(0.13)	0.11	(0.02)
2000-04	2.54	0.08	0.05	2.66	0.13	0.05	2.84	2.04	0.52	2.56	(0.28)	0.13	(0.15)
2005-09	3.17	0.09	0.03	3.30	0.16	0.05	3.49	2.51	0.63	3.14	(0.35)	0.16	(0.19)
2010-14	3.97	0.11	0.14	4.22	0.20	0.04	4.43	3.08	0.78	3.86	(0.58)	0.20	(0.38)
2015-19	4.97	0.14	0.14	5.25	0.24	0.03	5.49	3.78	0.96	4.74	(0.75)	0.25	(0.50)
2020-26	6.52	0.18	0.11	6.80	0.31	0.02	7.10	4.85	1.23	6.08	(1.03)	0.32	(0.71)

+Data taken directly from PUC Staff testimony Docket 6992
Staff Witness, Stan Kaplan

*Timing and amount of capital expenditure taken directly from PUC Staff testimony, calculated by depreciating on straight line basis and adding return at 12%.

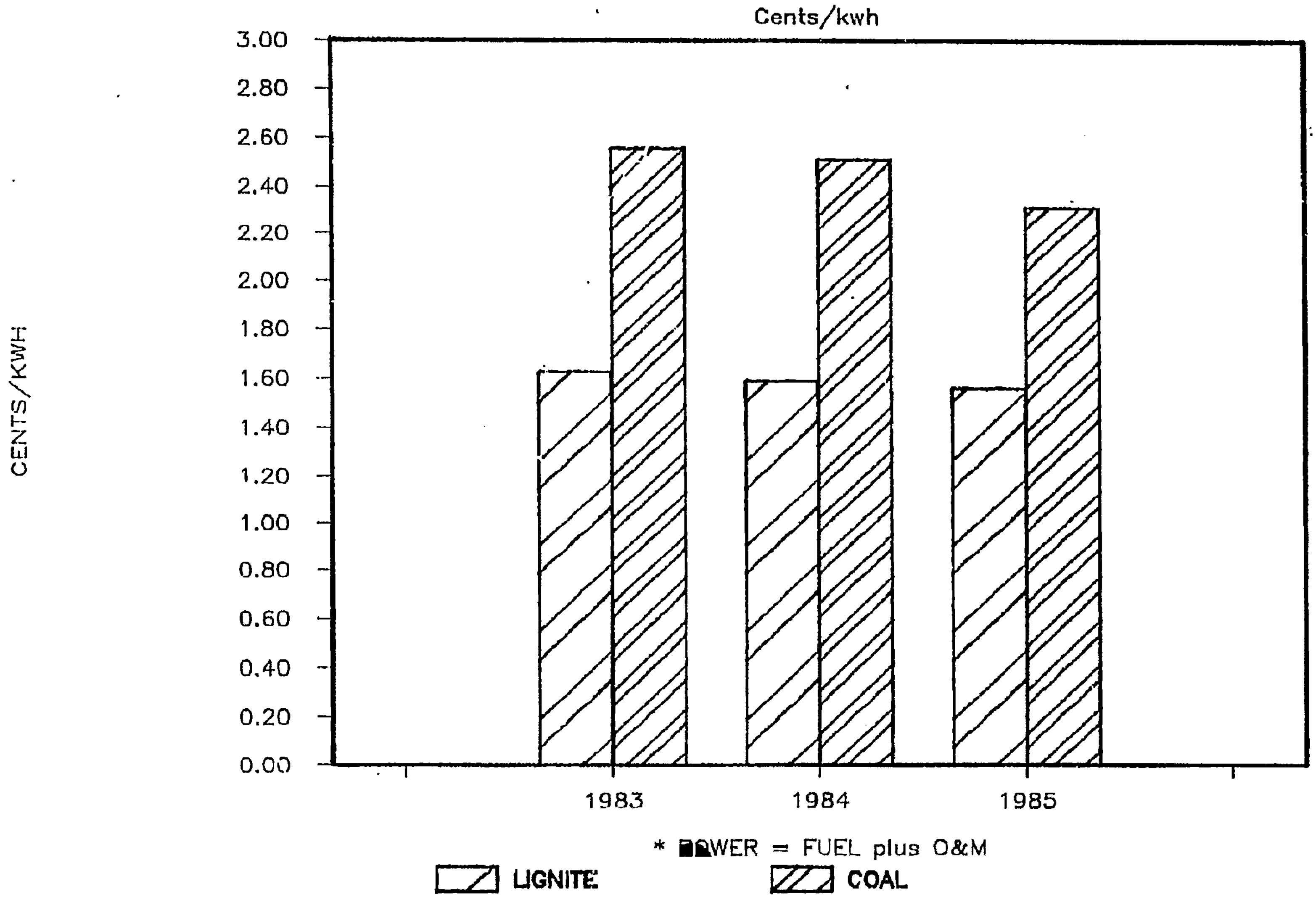
Note: Five year averages calculated from annual costs. Rounding error may occur.

Figure 1 HISTORICAL DELIVERED FUEL PRICES



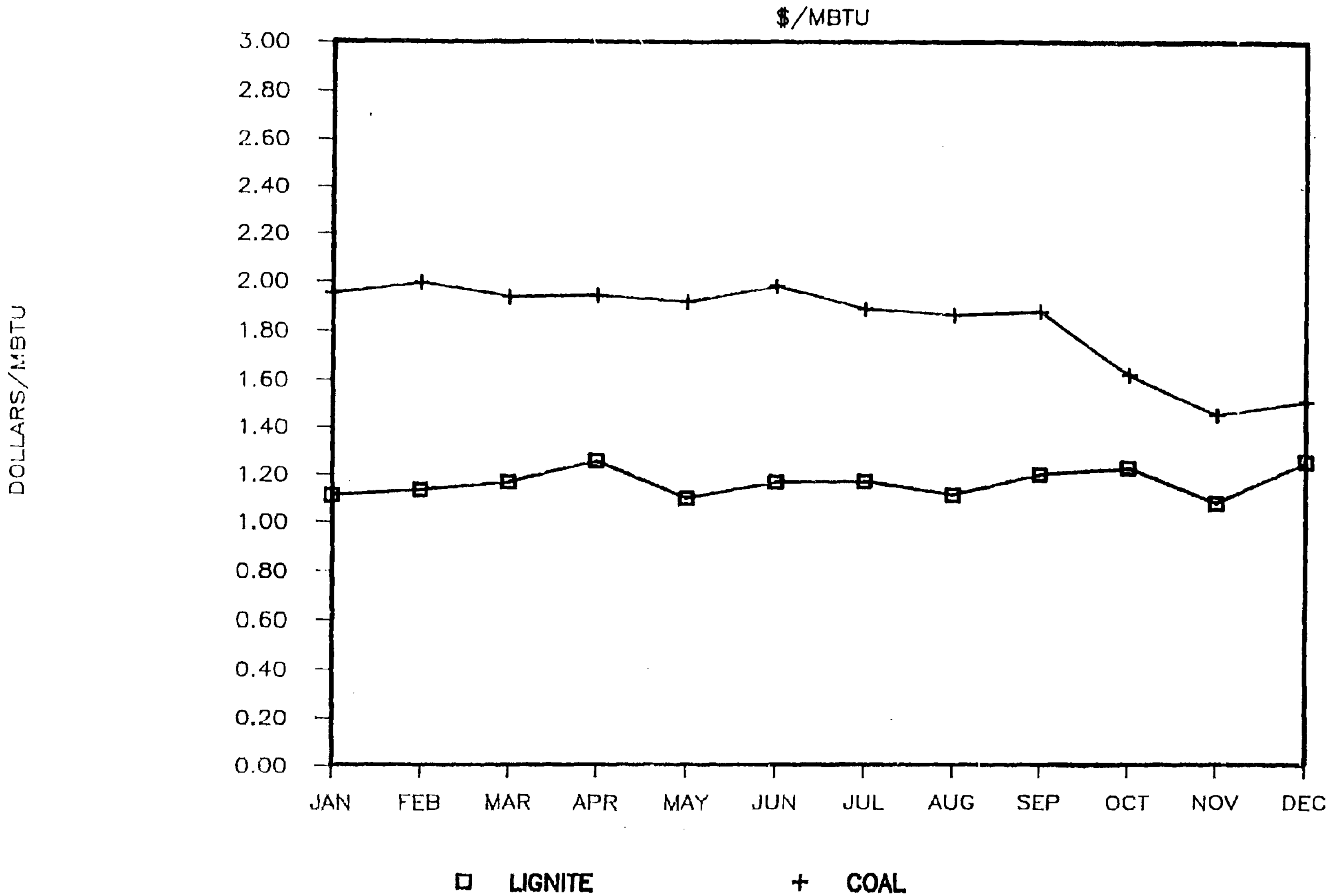
1 C1-8

Figure 2 HISTORICAL BUSBAR POWER COSTS



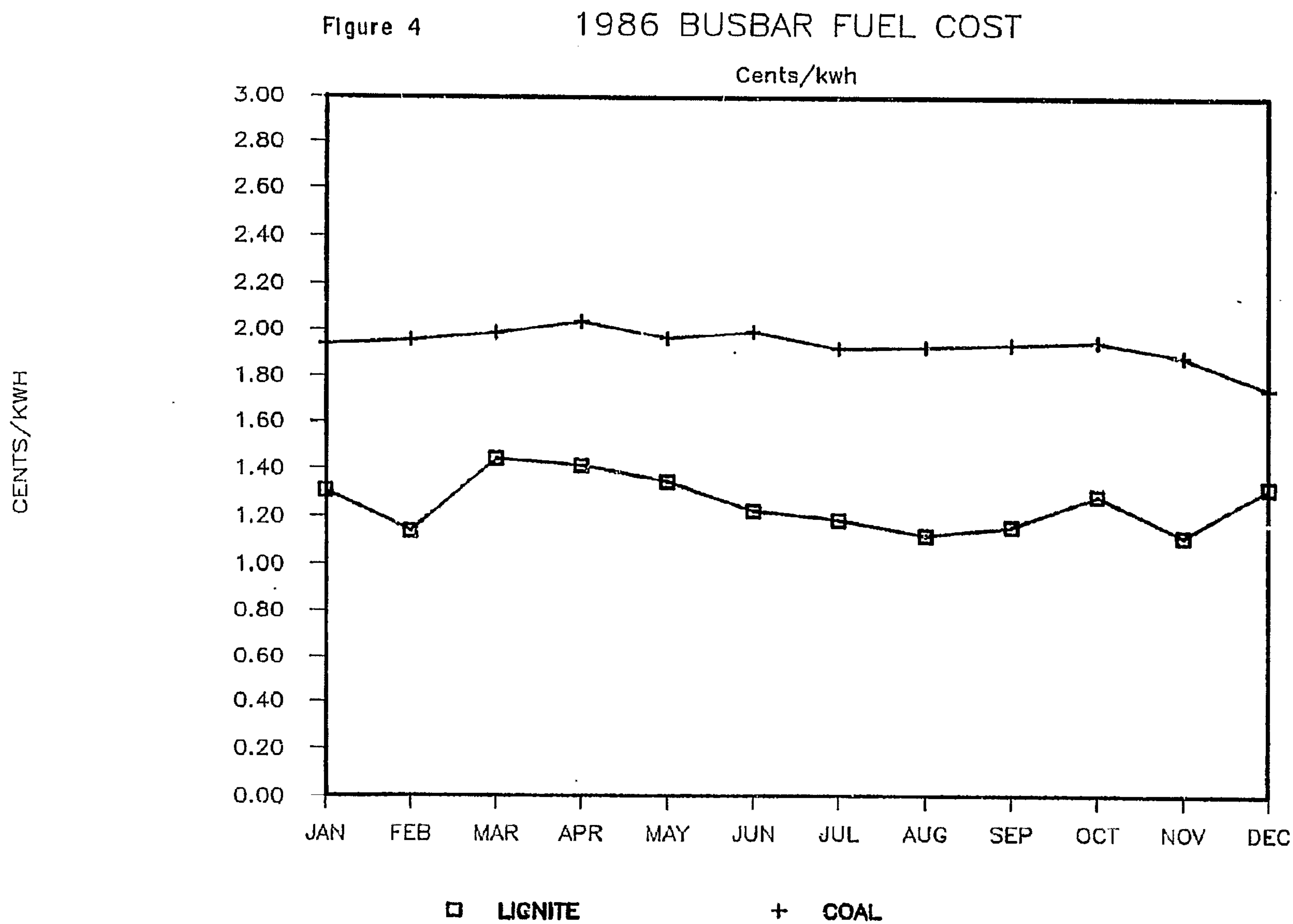
1 C1-9

Figure 3 1986 DELIVERED FUEL PRICES



1 C1-10

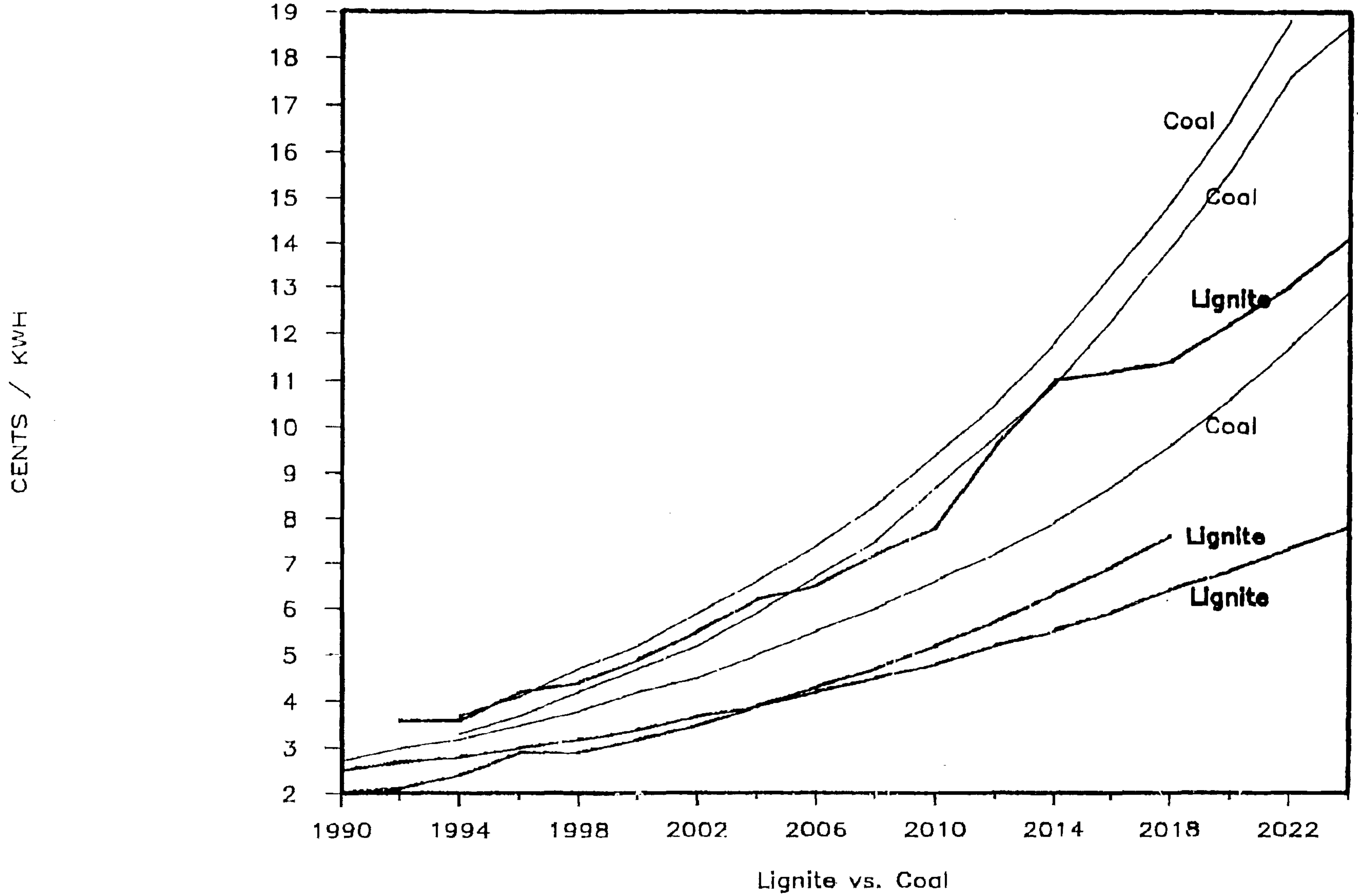
Figure 4



1 C1-11

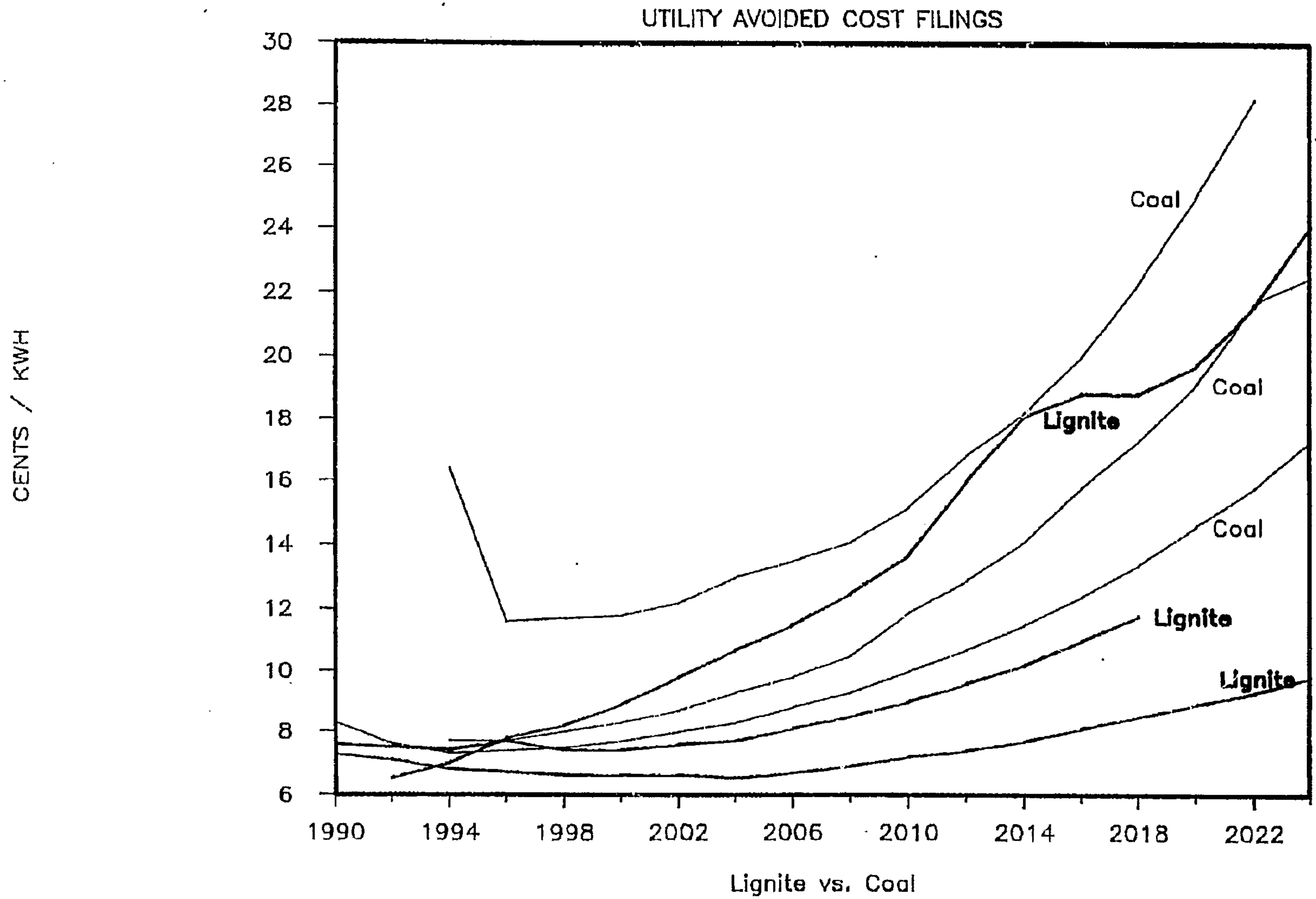
Figure 5 PROJECTED BUSBAR FUEL COST

UTILITY AVOIDED COST FILINGS



1 CI-12

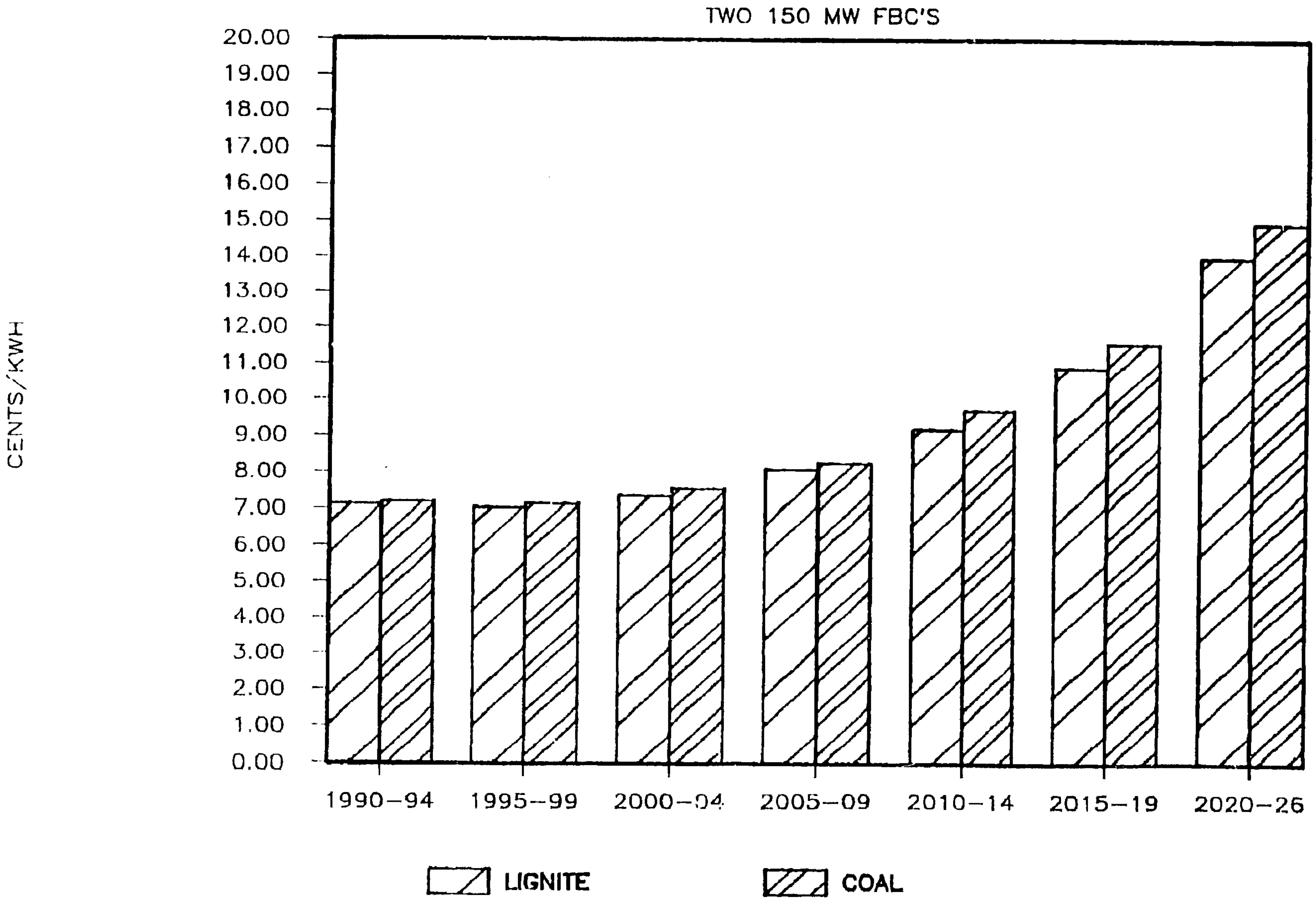
Figure 6 PROJECTED BUSBAR POWER COST



1 C1-13

Figure 7

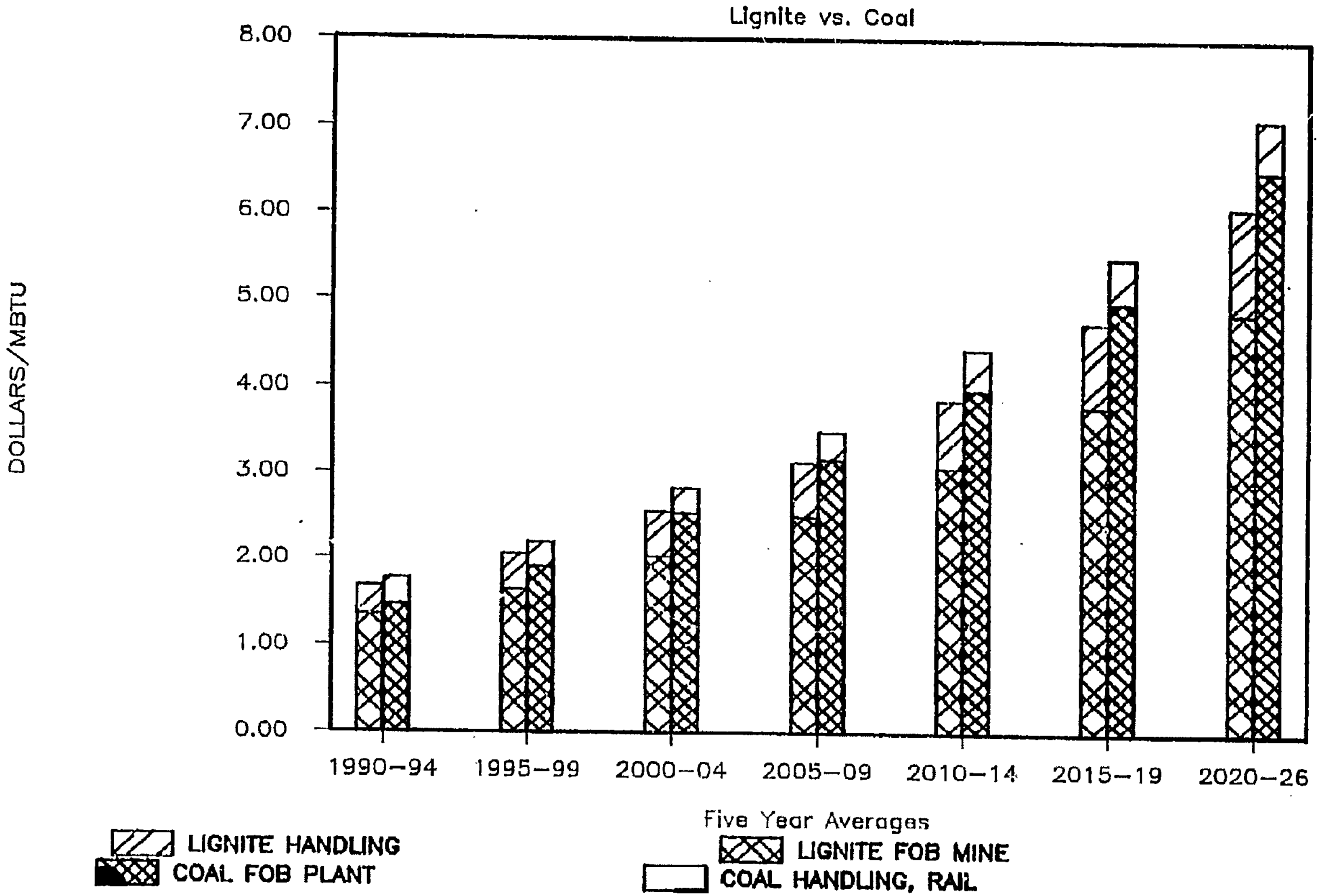
BUSBAR COST COMPARISON



1 C1-14

Figure 8

PROJECTED FUEL COSTS



1 C1-15

ABSTRACT

LIGNITE DEVELOPMENT IN PAKISTAN

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Water and Power Development Authority (WAPDA), Lahore, Pakistan,
and Douglas W. Huber
USAID Mission to Pakistan, Islamabad, Pakistan

Pakistan possesses extensive deposits of sub-bituminous and lignitic coal, which up to recently has received little developmental attention. Current coal production have plateaued at about 2 million tonnes annually, used largely in brick manufacture. Production occurs from many small, labor-intensive underground mines serving localized markets. The coals are almost always of extraordinarily-high sulfur content. Interest has specifically focused on the potential for use of the coal resource as a basic fossil fuel input to power generation to minimize dependence on imported oiland on natural gas to meet Pakistan's rapidly growing electricity demand. Coal use for power generation so far exists only at Quetta on a scale of 15 MW in two stoker-fired steam generators.

A major prospect for fully employing the coal resource and establishing a modern coal producing industry lies in the coalfields of Lakhra, near Hyperabad. WAPDA and USAID have collaborated and recently completed a comprehensive feasibility assessment to produce 500 MW of electricity from the Lakhra coalfield. This Lakhra Project would require the establishment of two large surface mines and one underground mine, having a combined output of about 3 million tonnes annually. Washing and combustion characteristics of the coal have been tested in the United States as part of the assessment. The Government of Pakistan has agreed that the implementation of the mining activity will be in the hands of the private sector. Meanwhile, the Geological Survey of Pakistan has a large exploration program underway to develop better and more definitive knowledge of the coal resource in terms of identifying immediate exploitation opportunities.

Another prospective market for Pakistani coal lies in the manufacture of smokeless fuel briquets to replace scarce fuelwood and the use of petroleum fuels. For many years, uncarbonized briquets have been manufactured at Quetta for space heating purposes. Both the private and public sectors in Pakistan are interested in expanding the use of coal briquettes and the United States AID Mission is financing a comprehensive market study of their potential use. Private sector development of the industry has already started.

The paper will concentrate on the power generation aspects of coal development in Pakistan, discuss the progress made so far, the technical problems encountered, and the role foreseen for Pakistani coal in helping to alleviate the serious power supply shortfalls that exist in the country.

ABSTRACT

UTILIZATION OF LOW-GRADE COALS IN ASIAN DEVELOPING COUNTRIES

by Henri-Claude Bailly
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Manager, Fossil Fuels Technologies
Burns and Roe Company.
Oradell, N.J.

Most developing countries in Asia must spend a large portion of their foreign exchange to pay for imported fuels. Limitation on availability of capital and foreign exchange becomes a major constraint in successful implementation of their national development plans. Some countries have sizeable deposits of coal, generally of low-grade quality. To utilize these indigeneous resources, technical, institutional, logistical and financial obstacles have to be resolved.

The paper discusses briefly quality impact on the required technologies for coal mining, transportation and utilization. Government policies and legislation are discussed with respect to their impact on the economic and financial attractiveness of using local coals. Examples are given to illustrate the problems and potential solutions to promote low-grade coal utilization in Thailand, Philippines, Pakistan, South Korea and Indonesia.

COMMERCIAL LOW GRADE COAL DEVELOPMENT IN COSTA RICA

by

Oldemar Ramirez - Refinadora Costarricense de Petroleo
San Jose, Costa Rica

Ernest Y. Lam - Bechtel National, Inc.
Arlington, Virginia

Alberto J. Sabadell - Office of Energy, Bureau for Science and Technology, U.S. Agency for International Development, Washington, D.C.

ABSTRACT

Costa Rica's heavy dependence on oil imports is causing an increasing drain on its foreign exchange earnings and compromising the country's national security interests. In addition, the country is excessively dependent on hydro resources for electric power. The government has set a goal to increase thermal power generation to reduce the impact of hydropower seasonal variations on the economy. To deal with this situation, the Government of Costa Rica has initiated a number of programs to develop indigenous low grade coal. Costa Rica's situation is typical of many developing nations where unexploited low grade coal is a potential solution to easing foreign debt and stimulation of economic development. The United States Government, acting through the Agency for International Development (U.S.A.I.D.), is assisting the Government of Costa Rica in the exploration, assessment and development of Costa Rica's coal resources in order to further its national objectives.

The existence of coal in several locations of the country has been known for a long time. In 1981, the Instituto Costarricense de Electricidad (ICE) initiated a program of geological investigations in collaboration with Japan International Cooperation Agency (JICA). Later, the responsibility for coal exploration in Costa Rica was transferred to Refinadora Costarricence de Petroleo (RECOPE), the national petroleum refining company. In 1983, a program for

exploration was formulated by U.S.A.I.D. in cooperation with the U.S. Geological Survey (U.S.G.S.). Most of the work for this program was completed in the summer of 1985. The work included exploratory drilling, geophysical logging, collecting core and cuttings samples, coal analysis and surface mapping.

The exploration program was followed up by a mining feasibility study for coal deposits in the Uatsi project area in the Baja Talamanca coal field near Limon. The report concluded that extraction of coal from the deposits of the Uatsi project area was technically feasible. A further U.S.A.I.D. sponsored study to develop a preliminary conceptual design has been completed for a 50 MWe coal fired power plant, and has provided order of magnitude capital and operating cost estimates for evaluating power generation alternatives. Additional aspects of this study also included the substitution of coal at cement facilities. A significant aspect for the development of Costa Rican coal will be the policy changes and fiscal incentives needed for potential private sector participation.

This paper summarizes the findings of the coal fired power plant and cement plant conversion studies and makes recommendations on Costa Rica's plan to develop the Uatsi coal deposit for these potential projects.

I. Introduction

In the last ten years, Costa Rica's economy has deteriorated due primarily to weakened coffee world market, increased oil imports and national debt service. Its export of manufactured goods has also declined. Figure 1 shows that total energy consumption in Costa Rica has increased during most of that period (increased at an average annual rate of 5% during 1977-1980, decreased at 2% during 1980-82, and increased again at 4% since 1982). This increase is putting pressure on escalated oil imports in the future, and will further exacerbate the balance of payment problem. During 1981-86, Costa Rica suffered a trade deficit of $63.6 million per year. The 1986 imports exceeded the exports by $255 million.

In addition, the country is excessively dependent on hydropower for generation of electricity. It is highly desirable to increase thermal power generation to reduce the impact of hydropower seasonable variations on the economy. Continued reliance on hydropower to meet future increase in energy demand will tax the limit of this resource and cause load management to become even more difficult. Hydropower plants are also capital intensive.

The development of indigenous coal presents an attractive option to meet the growing energy need, to balance the hydro/thermal energy mix and to ease foreign debt.

II. Development of Coal in Costa Rica

Costa Rica imports its petroleum primarily from Mexico and Venezuela. Figure 2 shows the petroleum consumption for the period 1982-85, averaging about five million barrels per year. The trend of increase in imports, about 9% per year, is obvious, and is projected to continue unless indigenous energy resources can be developed to reverse that trend.

Figure 3 shows the energy mix in the generation of electricity in Costa Rica. It can be seen that hydropower dominates over thermal sources such as diesel, fuel oil and bagasse. Because of their small contribution, these thermal resources are grouped together on the bottom curve. The trend of decreasing contribution of the thermal component to the total electricity generation is due to the diversion of these thermal energy sources to non-electric services in the industrial and residential sectors. For reasons discussed previously, the Government of Costa Rica has set a goal to increase the generation of electricity from thermal resources to at least 25%.

Figure 4 provides an additional comment that electricity is generated primarily by the state owned utility the Instituto Costarricense de Electricidad (ICE). It contributes about 97% (1985) of the total electricity generated. To alleviate the financial burden on the government to install more power plants, work is underway to encourage private sector to participate in power plant investment, construction, ownership, operation and sales of power to the national grid.

The Costa Rica Electrical Institute (El Instituto Costarricense de Electricidad) advertised on February 17, 1987 in the newspaper La Nacion informing the public of its intention to purchase electricity from small private industries with excess power generation capacity. This marks an important step for Costa Rica, opening the way for private sector involvement in power generation.

The Government of Costa Rica has adopted a national energy policy to encourage and support coal development. Project opportunities to convert from oil to coal use will be identified, and considerations will be given to provide incentives for private domestic and foreign financing requirements of coal projects. In addition, potential opportunities will be publicized to attract foreign funding, grants, and investment for fossil resource exploration and exploitation. In this regard, the Refinadora Costarricence de Petroleo (RECOPE) is the cognizant and lead agency.

ICE has analyzed the national energy requirement for 1986-2005 and made a number of recommendations to the Government. Specifically, ICE recommends additional installation of 1054 MWe new capacity, and that coal be developed initially at a pilot exploitation rate of 30,000 tonnes per year for use in cement and other industries. This will be followed by a higher level of mining to support electric power generation. It further recommends the completion of a site-specific mine mouth coal fired power plant feasibility study to assess the role coal could play in thermal power generation.

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III. U.S.A.I.D. Assistance in Costa Rica Coal Development

As the United States moves into the second decade since the beginning of the worldwide energy crisis, the nation's creative efforts have alleviated many of the serious problems facing our economy that resulted from energy shortages and higher prices. However, while the energy crisis has abated in the United States -- helped along by the temporary drop in oil prices -- energy problems in the developing countries continue as a serious and fundamental barrier, threatening their sustained economic development and national security.

The plight of Costa Rica typifies many U.S.A.I.D. assisted countries. Swelling energy demand has to be met by imported oil. To pay for this, scarce capital and foreign currency are being diverted from investment, leaving little to support essential development needs in agriculture, industry or critical infrastructure. Costa Rica is also typical of many developing nations where unexploited low grade coal is a potential solution to these problems. The United States Government, acting through the U.S.A.I.D., is assisting the Government of Costa Rica in the exploration, assessment and development of the country's coal resources in order to further its national objectives. Experience gained in this effort in Costa Rica will be helpful in assisting other developing nations. This is significant in not only helping them to achieve better economic growth and national security, but to allow U.S. private sector better opportunities to provide goods and services to these overseas low grade coal projects.

The existence of coal in several locations of Costa Rica has been known for a long time. There are a total of eight deposits. The total proven reserve of the three main deposits has been estimated to be 48.5 million tonnes (Uatsi - 32.5 million tonnes, Zent - 14 million tonnes, and Venado - 2 million tonnes). In 1981, the Instituto Costarricense de Electicidad (ICE) initiated a program of geological investigations in collaboration with Japan International Cooperation Agency (JICA). Later, the responsibility for coal exploration in Costa Rica was transferred to RECOPE. In 1983, a program for exploration was formulated by U.S.A.I.D. in cooperation with the U.S. Geological Survey (U.S.G.S.). Most of the work for this program was completed in the summer of 1985. The work included exploratory drilling, geophysical logging, collecting core and cutting samples, coal analysis, and surface mapping.

The exploration program was followed up by a mining feasibility study by Dravo International, Inc. for coal deposits in the Uatsi project area in the Baja Talamanca coal field near Limon. Based on data available at that time, the 1986 report concludes, with some qualifications, that extraction of coal from this deposit is technically feasible, and that approximately five million tonnes could be recovered by open pit and underground mining.

The preliminary drilling and outcrop exploration of the Uatsi field indicate that this deposit has at least 10 coal seams. Drilling activities has continued and a recent update of recoverable reserves indicates more than 7 million tonnes, mineable by a labor intensive underground mining method.

The characterization of the coal quality is preliminary and more data are needed. Proximate analysis indicate typical values of 26.85% moisture,

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The characterization of the coal quality is preliminary and more data are needed. Proximate analysis indicate typical values of 26.85% moisture, 12.53% ash, 27.83% volatile matter, 32.79% fixed carbon, and a high heating value of 4254 kcal/kg (7657 BTU/lb). The ultimate analysis shows averages by weight of 31.90% carbon, 3.23% hydrogen, 0.64% sulfur, 27.66% oxygen, 0.51% nitrogen, 9.21% ash and 26.8% moisture.

In November 1986, Bechtel was funded by U.S.A.I.D. to conduct a prefeasibility study on the potential use of this coal in a 50 MWe mine mouth power plant. This paper summarizes the characterization of such a power plant to provide a technical and economic overview on such a potential project.

IV. Power Plant Description

The plant design is based on conventional Rankine cycle, which is considered to be proven and technically adequate to utilize the low grade coal. The turbine cycle is based on using a non-reheat condensing steam turbine rated at 52.6 MWe (gross) with throttle conditions of 103 kg/sq cm Abs (1465 psia) and 510 C (950 F). The design turbine back pressure is 89 mm HgA (3.5 inches HgA). The turbine throttle flow is 207,700 kg/hr (458,000 lb/hr) at the design point. The turbine has five uncontrolled extractions for feedwater heating. The turbine cycle was chosen in consideration of capital cost, cycle efficiency, and fuel cost.

The boiler is a pulverized coal fired, balanced draft, drum type unit with no reheat.

Other major equipment and systems of the power plant are summarized as follows:

- A circulating water system with mechanical draft cooling tower
- A coal receiving, storage, and reclaming system
- A baghouse for the gas treatment
- A 91 meter (300 ft.) high stack
- A bottom ash and fly ash handling and storage system
- A makeup water treatment system
- All electrical, control, maintenance and administrative facilities

The study concludes that the Uatsi reserve appears to be adequate to support the operation of such a 50 MWe plant for 30 years. The plant will consume coal at the rate of about 200,000 tonnes per year. The performance of this plant is summarized in Table 1.

For planning purposes, this 50 MWe design was also factored to provide similar information in the 10-60 MWe capacity range. The corresponding range of annual coal consumption is 48,000 to 240,000 tonnes.

V. Power Plant Costs and Construction Schedule

Order of magnitude (± 25%) estimates were developed for the projected capital requirements, first year operation and maintenance costs as well as cost of electricity for the 50 MWe baseline power plant. These estimates were developed using historical Bechtel data and other available reports supplemented by labor rates and productivity data obtained in Costa Rica in early 1986.

Capital cost estimates were developed to be at January 1987 price levels in accordance with technical specifications set forth in the preconceptual engineering design. Also, the impact on major equipment purchased in the world-wide market and maximum use of locally available materials and labor have been assumed. This recognizes the indigenous skills available from past experience with hydro and thermal power plants. In general, cost adjustments to reflect the conditions in Costa Rica were made as appropriate.

In this first level of study effort, the capital cost estimates do not include interest on money during construction of plant (also known as allowance for funds during construction). Also, they do not include escalation during construction and other owner's costs such as transmission line, coal storage inventory, land and water rights, and spare parts.

Cost of electricity was calculated as the sum of the capital cost component and the operating and fuel cost component. The capital component is derived from the annual capital cost or fixed charge. For this study, 13.5% of the total capital cost is used as the fixed charge rate to calculate the cost of electricity. Coal cost was estimated to be $25.3 per tonne.

Cost information on the 50 MWe baseline plant is summarized in Table 2. Again, for planning purposes, these data were factored to cover a plant capacity size range of 10-60 MWe.

A schedule for engineering, procurement and construction was conceptualized for the 50 MWe coal fired unit (Figure 5). The schedule critical path runs entirely through the boiler activities from contract award through fabrication, erection and startup to the commercial operation stage. It will take three years to bring the project from notice to proceed to commercial operation. This information was quantified using recent data on supplying similar 50 MWe boilers for overseas locations. The schedule provides a generous allowance of three months for U.S. suppliers to ship the equipment whereas shipping from Europe would take about six months.

VI. Environmental Considerations

The study reviewed the environmental guidelines for applicability to coal mining and mine-mouth power plants. At the present, Costa Rica has not adopted emission standards or guidelines of its own. Therefore, the World Bank guidelines were used for the purpose of the coal fired power plant study. It concludes that such a power plant, in the order of 50 MWe, burning indigenous low sulfur coal, can probably be constructed and operated in a presently unpolluted area and meet the World Bank guidelines. Specifically there should be no need for flue gas sulfur removal systems. The major pollution control equipment recommended is a bag house for controlling particulate (dust) emissions from the power plant stack. Nitrogen oxides emissions are controlled by low NOx burners available from boiler manufacturers as standard equipment. Liquid and other solid wastes can be disposed of without undesirable environmental effects. It is, however, prudent to assess the longer term and potentially more extensive use of the local coal to ensure that this resource development and utilization will not be limited by environmental concerns.

VII. Coal Use in Existing Cement Plants

The Bechtel study also commented on the feasibility of coal substitution for Bunker C oil in major cement plants in Costa Rica. This was explored as an option for using indigenous coal.

The National Cement Industry (NCI), located near the capital city of San Jose, has a total clinker production capacity of 1,800 tonnes per day. Currently, Bunker C oil is the primary fuel.

At the current level of cement production, about 50,000 tonnes per year of Uatsi coal would be required to displace all the oil consumption. An order-of-magnitude cost estimate shows that about 2.5 to 3.0 million dollars will have to be invested to retrofit the plant for this coal conversion. There is sufficient room at the plant site to accommodate the coal receiving, storage, preparation and coal firing equipment. Because of the high moisture content in the coal, it appears that the plant may have to use an indirect-fired system with pneumatic transport of pulverized coal to a cyclone separation and then to the kiln.

The technical feasibility of this conversion appears to be straightforward. Such retrofits are common in many places in the world, and this plant imposes no technical obstacles. One factor that deserves a closer study is the transportation of coal from the mine to the plant over a distance of about 130 miles. Trucking may tax the limit of the existing road. It must also be pointed out that conversion will lead to higher operating and maintenance costs.

The Pacific Cement Plant has one kiln with a production capacity of 1,250 tonnes of clinker per day. It also uses Bunker C oil. The review of this plant yielded conclusions similar to that mentioned above for the NCI plant. Again, there are no insurmountable technical barriers but the transportation aspects are more acute since the plant is located at about 250 miles from the coal resource.

VIII. Uatsi Coal Resource Development

From the information available to date, it appears that the Uatsi coal mine lends itself to small scale underground mining. The area is deformed by faults, anticlines and synclines which make it unsuitable for large scale underground mining. The major portion of the reserve is under thick overburden. It is, therefore, not amenable to open pit mining. Considering the low cost of labor available locally, it appears that the mining operations can rely on labor intensive rather than equipment intensive methods.

An order-of-magnitude estimate shows that the capital cost necessary to mine 240,000 tonnes/year would be about $9.2 million (excluding interest during construction). The annual cost of such an operation will be about $6.4 million. The cost of coal will be about $25.3 per tonne ($1.50 per million Btu).

IX. Conclusions

The information summarized in this paper on the Uatsi resource development, and the potential use of this coal for electric power generation or fuel substitution in cement plants, will constitute the basis for RECOPE to further assess whether these projects should be implemented.

The prefeasibility study on the baseline 50 MWe power plant indicates a capital requirement of $60.2 million and cost of electricity of about 51.4 mills/kwh. This information should be reviewed by the Government of Costa Rica in the light of the national policy to curtail oil imports, and in the light of ICE's need to balance the hydro/thermal energy mix of generation in addition to comparative economics. The coal fired power plant appears to be a reasonable option that deserves further consideration.

Coal substitution at the cement plants also appears to be a reasonable option. With a capital investment of $2.5 million to use 50,000 tonnes of coal per year, a pay back in about 5 years can be achieved if the oil price is maintained at, or escalates from, the present level.

Considerations should be given by the Government of Costa Rica to private sector financing of these coal projects. Long term committments are needed by the Government to minimize the risk to private capital involved in these projects. Existing government policies need to be reviewed to identify and remove any barriers that tend to inhibit private sector participation. Financial incentives may have to be provided to allow a reasonable return on investment to attract private capital.

Preliminary results as outlined in this paper are meant to provide general guidance only. Further studies are required to better define project requirements and to chart plans of action.

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Table 1

PLANT PERFORMANCE SUMMARY

1.	Nominal Plant Rating, MW	50
2.	Gross Plant Output, MW	52.6
3.	Net Expected Output, MW	47.3
4.	Expected Annual Salable KWhr (10^6) production at Plant at 0.7 Capacity Factor	290.0
5.	Net Full Load Heat Rate Kcal/KWhr	2931
6.	Net Plant Efficiency	29.3
7.	Boiler Heat Input 10^6 Kcal/hr	139
8.	Full Load Coal Consumption, tonnes/day	784
9.	Annual Coal Consumption, tonnes	200000

Table 2

CAPITAL AND OPERATING COST SUMMARY

1.	Nominal Plant Rating, MW	50
2.	Estimated Capital Cost in 1987 Dollars (Million)	60.2
3.	Capital Cost, $/Installed KW	1145
4.	Annual Operating and Maintenance Costs, Dollars (Million)	6.8
5.	First Year Cost of Electricity at Plant, Mills/KWhr	51.4

FIGURE 1

ENERGY CONSUMPTION (1977 - 1986)

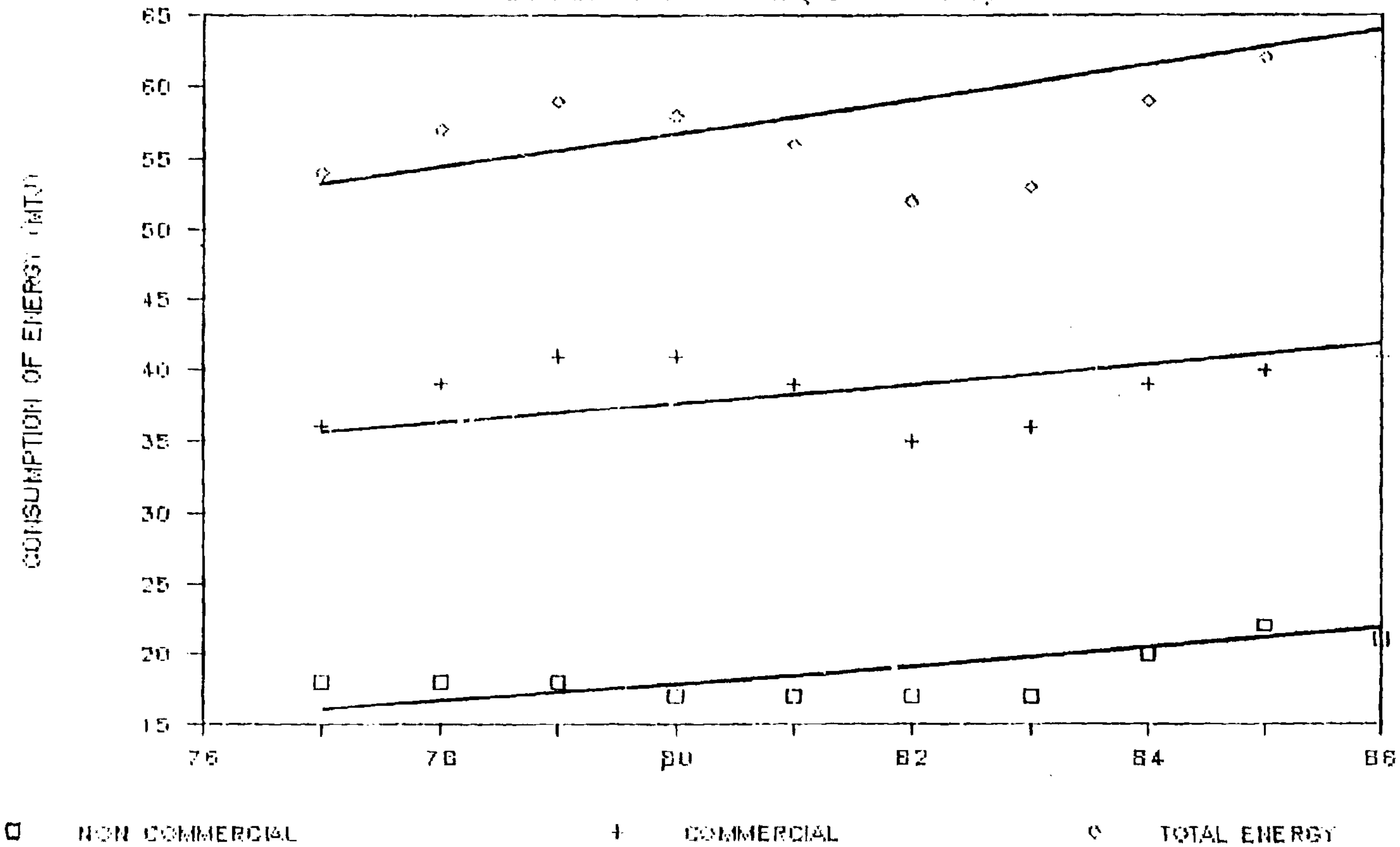

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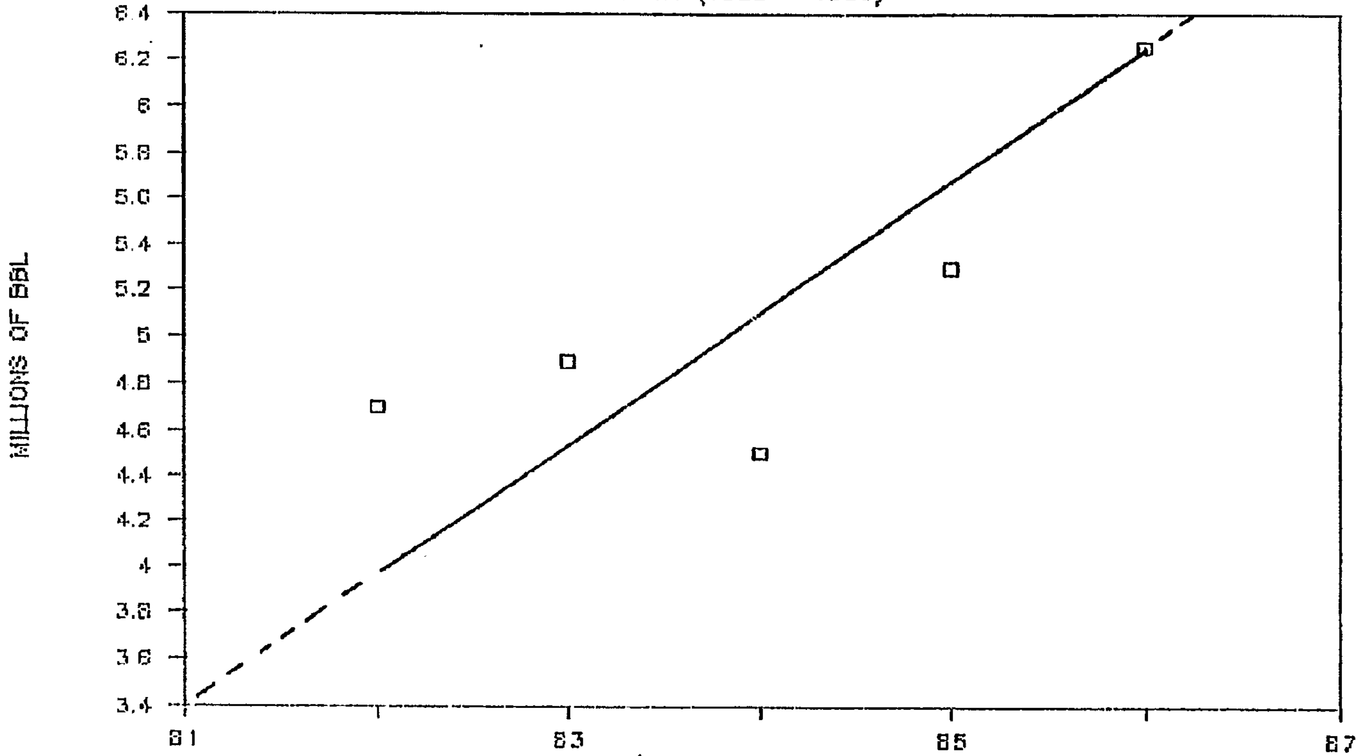
FIGURE 2

OIL IMPORT (1982 - 1986)



2 C3-12

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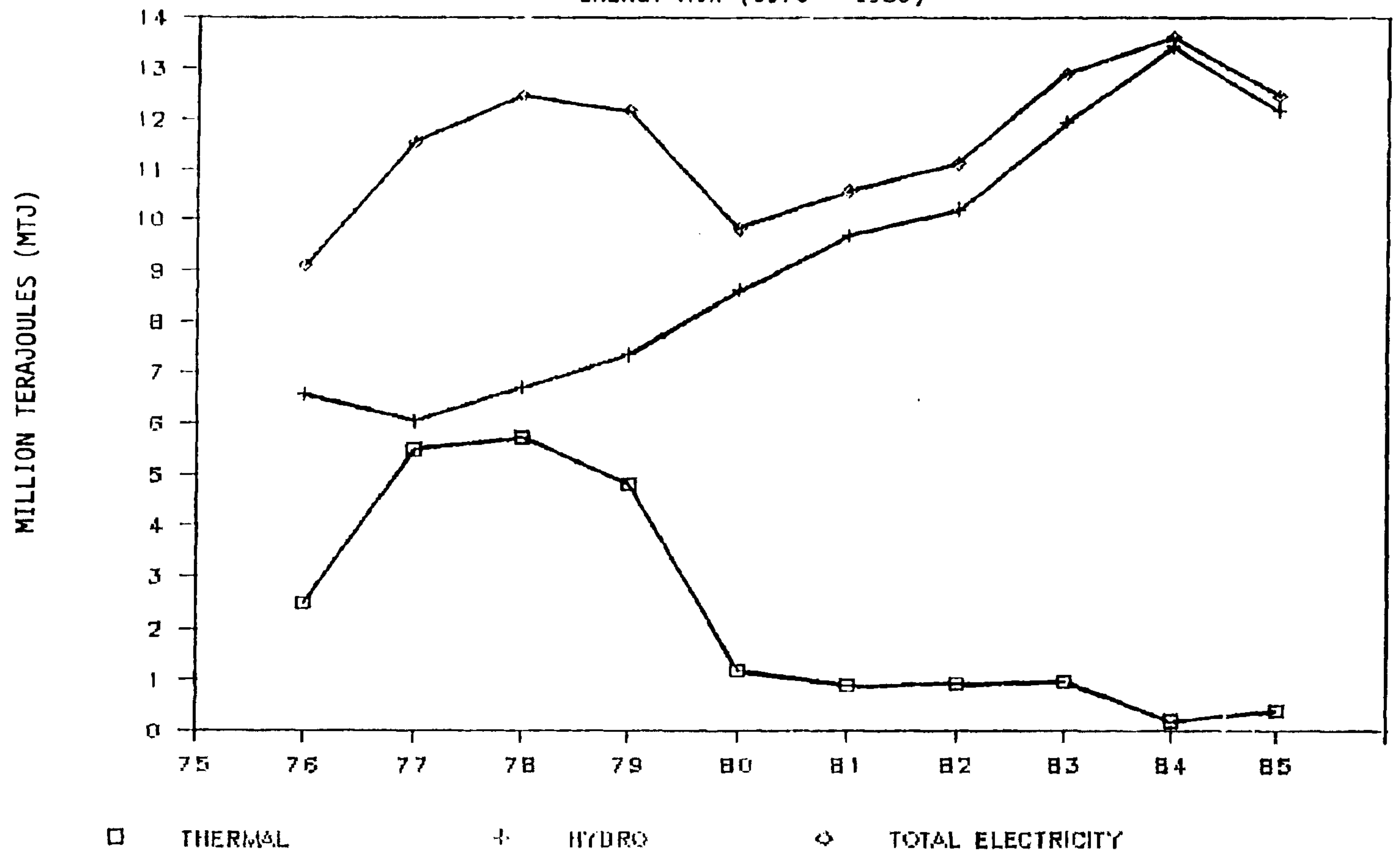
FIGURE 3

ENERGY MIX (1976 - 1985)



2 C3-13

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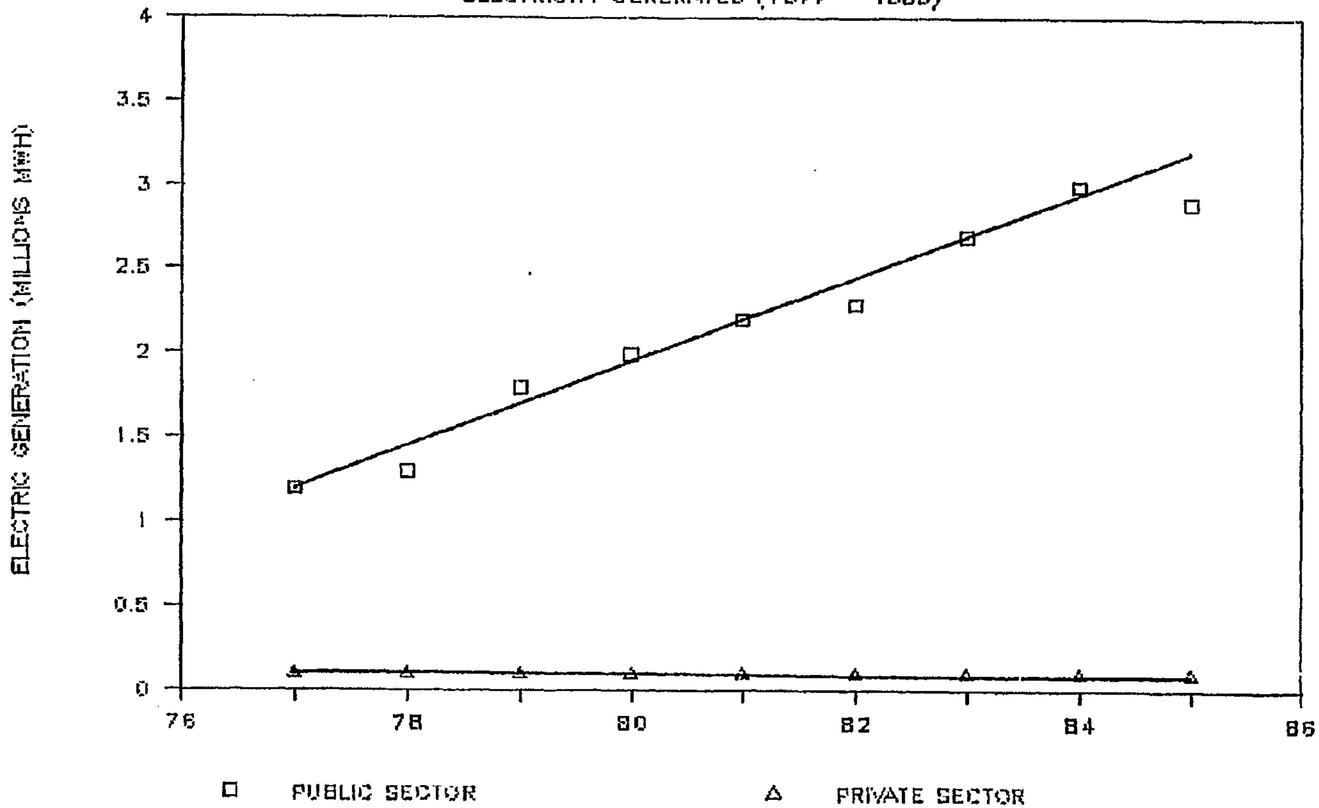
FIGURE 4

ELECTRICITY GENERATED (1977 – 1985)



2 C3-14

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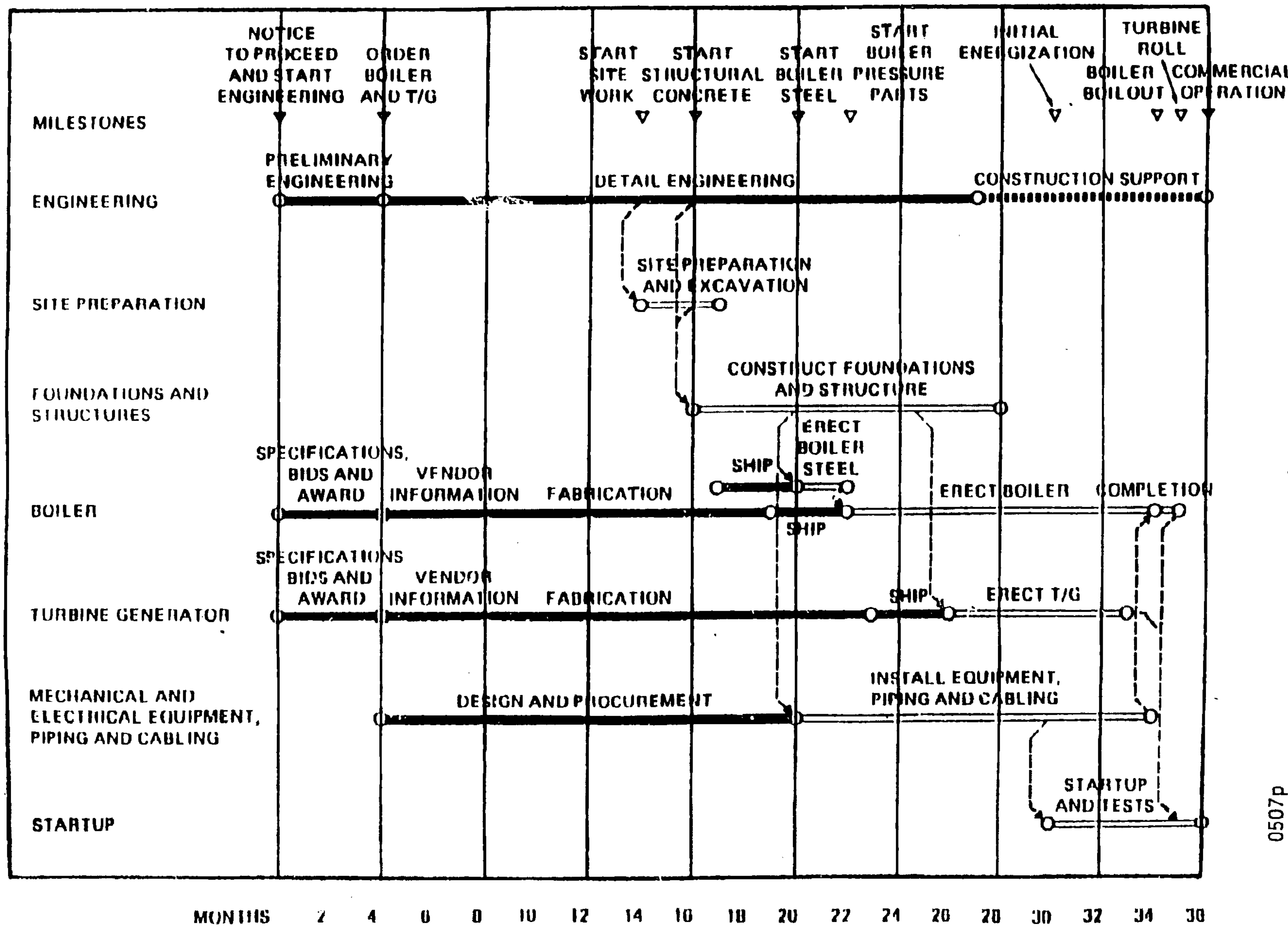
FIGURE 5

PROJECT SCHEDULE



2 C3-15

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