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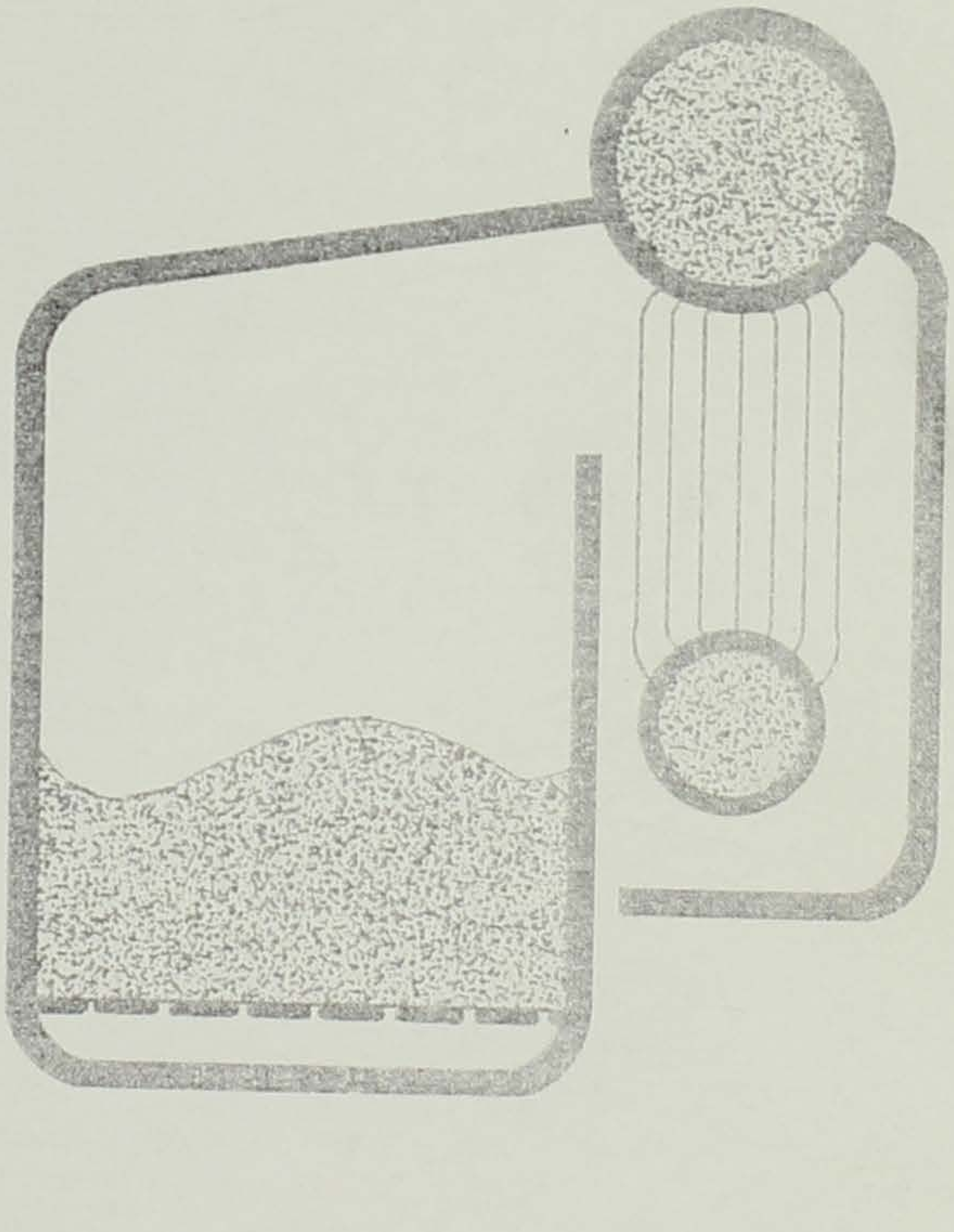
IOWA RESOURCES AND FLUIDIZED BED COMBUSTION



IOWA ENERGY POLICY COUNCIL

Volume 1 — Feasibility Study

NOVEMBER 1984

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SYNOPSIS

General

Iowa is dependent on outside resources of coal, natural gas, and oil for fuel supply. Even though there are coal reserves within the state, high ash and sulfur content have kept indigenous coal from wide use. With coal cleaning to enhance the quality, the Iowa coal industry still has not progressed appreciably.

New technology, in the form of the fluidized bed combustion (FBC), gives Iowa an opportunity to utilize native coal supplies in an economical and environmentally acceptable manner.

Test Burn

A FBC test burn was conducted at the University of North Dakota Energy Research Center with Iowa coal and limestone. Data from the combustion of washed/unwashed coal samples were used to assess the technical, environmental, and economic feasibility of using Iowa coal for a a 40,000 lb/hr industrial cogeneration system.

Conclusions

Findings of this study are:

- Iowa coal was successfully burned in a pilot fluidized bed combustor. Test results indicated that the coal should work well in a full-scale system.
- Iowa limestone used in the test burn worked well with the Iowa washed/unwashed coal.
- Unwashed Iowa coal is a lower cost fuel than washed coal when used in a fluidized bed combustor.
- Based on investigations to date, the use of Iowa coal and limestone in a fluidized bed system is environmentally acceptable without additional sulfur dioxide or nitrogen oxides removal equipment.

- The use of Iowa coal and limestone in an industrial cogeneration system offers an alternative method of using fluidized bed technology in a technically, environmentally, and economically feasible manner.
- A typical Iowa coal-fired cogeneration using fluidized bed combustion producing 40,000 lbs of steam per hour is estimated to cost $6,181,000. An industry financed project would pay for itself in less than 5 years depending on the turbine cycle selected. Project costs would be recovered by the savings resulting from using Iowa coal rather than natural gas as a fuel and reduced purchase of electricity.
- The use of the abundant Iowa resource of coal instead of imported fuels will specifically benefit the Iowa coal industry and in general all the citizens of Iowa.

Respectfully submitted,
STANLEY CONSULTANTS, INC.

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PART I - INTRODUCTION

General

The State of Iowa is nearly 100 percent dependent on outside resources for fuel supply. An abundant supply of inexpensive natural gas and oil soon after the turn of the century encouraged a shift from coal. Environmental concerns and economics favoring the "clean fuels" of natural gas and oil, furthered the demise of the Iowa coal industry.

However, as the cost of clean fuels "sky rocketed" in the 70s, coal once again was considered as a fuel for industry and utility power plants. At the same time, environmental concerns/awareness increased. Air emissions regulations concerning particulates, sulfur dioxide, and oxides of nitrogen from combustion sources became more strict.

Use of coal within the state gradually increased, but not to the advantage of the Iowa industry. Unit trains of low sulfur fuel from the west or shipments of medium sulfur coal from elsewhere outside Iowa filled the gap to provide "compliance" coal. One single utility, Muscatine Power & Water, Muscatine, Iowa, applied the recent flue gas cleaning technology to reduce sulfur emissions and burn high/medium sulfur coal cleanly. However, the coal the Muscatine power plant burns is from nearby Illinois - not Iowa.

Even though there still are coal reserves within Iowa, high ash and high sulfur content have deterred wide usage of these fuels. New technology, in the form of the fluidized bed combustion system (FBC), has given Iowa an opportunity to use native coal in an economical and environmentally acceptable manner. However, certain questions need to be answered if Iowa is to take advantage of its natural resources.

Background

In Spring 1984 the Iowa Energy Policy Council retained Stanley Consultants to assess the technical, environmental, and economic feasibility for Iowa industry to use local coal and limestone as a substitute for other fuels through the use of FBC technology. As a first step in the study, Stanley Consultants selected the University of North Dakota Energy Research Center (UNDERC) to perform a combustion test using Iowa coal and limestone in a pilot-scale atmospheric fluidized bed combustor at the Center. The objective of the test was to provide basic operational information and data on the use of washed and unwashed Iowa coal in the pilot plant.

By September 1984 the testing and reporting activities for use of Iowa coal and limestone were complete. Samples of Iowa unwashed and washed coal were successfully burned in the pilot plant at UNDERC.

In October 1984 Iowa State University, through its Mining and Mineral Resources Research Institute, completed additional preliminary studies concerning the use of Iowa limestones as sorbents in the burning of Iowa coal in FBC systems. Work is continuing on a more detailed survey of Iowa limestones. These investigations may identify additional locations of acceptable limestones. Volume 2 of this report contains the UNDERC test burn report, detailed information on the October limestone identification study, and economic backup data.

Scope of Work

This report (Volume I) evaluates the application of FBC technology burning Iowa coal as presented in the UNDERC test report. In addition, the report integrates the data supplied by UNDERC with an economic analysis of a 40,000 lb/hr FBC as applied to a cogeneration situation. The specific scope items of this complete study includes the following items:

- Test and documentation of the combustion characteristics of a sample of Iowa coal and limestone in a fluidized bed combustion system;
- Outline the economic benefits available to industry or utilities resulting from implementation of fluidized bed combustion of Iowa coal;
- Develop a general program for implementation of Iowa coal utilization in a FBC facility.

PART II - FLUIDIZED BED COMBUSTION

General

Fluidized bed combustion is in a stage of commercialization having successfully passed the proof-of-concept/development stage. FBC experts in the USA, and abroad, have demonstrated that the fluidized-bed concept, applied for decades in the process industries, can be successfully adapted to the combustion of solid fuels. As a result of this breakthrough, industrial and utility steam/power plant designers now have an alternative boiler to consider.

The basic reasons are straightforward. FBC boilers overcome the two fundamental limitations of the more established combustion techniques. That is, they can be designed to control sulfur dioxide and nitrogen oxide emissions within the combustion chamber, eliminating the need for scrubbers, low-sulfur coal purchases, or elaborate burner modifications (for nitrogen oxides control). Secondly, FBC boilers enhance the fuel flexibility by allowing the burning of a range of solid fuels with widely varying ash and moisture contents.

History

FBC technology began with a gasification process developed in Germany in the 1920s. Since then, it has been applied in the oil-refining industry as an aid to extracting more gasoline from crude oil; in the steel industry for ore-roasting; and in waste disposal as a method of incinerating solid, liquid, and gaseous wastes. From the late 1950s to the early 1960s, Great Britain's National Coal Board studied the technique as an improved way of burning coal.

Meanwhile, engineers in Peoples Republic of China began research work on FBC. It is interesting to note that overseas the primary motivation for FBC development was to obtain fuel flexibility by promoting the use of locally available, but in many cases, poor quality solid fuels. To illustrate: China has over 2,000 FBC boilers and many of them burn low-Btu coal containing up to 70 percent ash.

By contrast, the U.S. thrust for FBC development has been the need to burn coal within the regulations mandated by the Environmental Protection

Agency (EPA). In fact, EPA sponsored much of the effort in this country beginning in early 1970s. Department of Energy (DOE) efforts continued the EPA work by funding commercial demonstrations on industrial scale systems.

Since the early work, much operating data and experience has been collected. DOE is no longer funding any work except new/advanced technology. Boiler manufacturers have picked up the work in marketing FBC systems. Today FBC boilers capable of producing from 10,000 to 600,000 lb/hr of steam are available at conditions comparable to those of conventional boilers in the same duty.

Technology

Fluidized bed combustion is accepted by industry, the DOE, and the EPA as a commercial technology capable of firing a variety of fuels in an environmentally acceptable manner void of special devices for control of sulfur dioxide and nitrogen oxides emissions. Generally accepted advantages of fluidized beds are:

1. Emissions of sulfur oxides can be reduced by over 90 percent through addition of limestone in the bed.
2. Nitrogen oxides emissions are low, typically 0.3 to 0.4 pounds per million Btu's. Emissions can be further reduced through staged combustion with no effect on combustion efficiency.
3. Wastes sent to disposal are dry, nonhazardous solids.
4. Efficient combustion of solid, liquid, and gaseous fuels simultaneously.

In addition to the emissions control and waste disposal advantages, fluidized beds have other operability advantages. For example, fluidized combustors usually can vary steam production by a ratio of 2 to 1 by simply varying the bed temperature. Additional turndown capability to nearly any ratio can be achieved through segmented/modular design of the windbox.

Load following is easily managed by the same two mechanisms, variation of bed temperature and slumping of bed segments. FBC load following ability similar to spreader stokers has been extensively demonstrated. In addition, bed slumping can result in nearly instantaneous load reduction. Overall load control is equal or superior to standard combustion methods.

Finally, the large mass of bed gives fluidized bed combustion a unique start-up advantage. The bed can be slumped for as long as 48 hours and still retain sufficient heat to support combustion without going through an extensive warm-up period.

An FBC usually has a high particulate emission requiring a baghouse particulate collector. However, a well designed baghouse will reduce particulate emissions below most environmental requirements.

The basic components of an FBC system are the windbox (plenum), the fluidized bed, freeboard, and a primary cyclone. The plenum distributes the fluidizing air to the distributor plate. The fluidized bed can be composed of sand, ash, and/or limestone which is fluidized by a stream of air. Air velocities of 4 to 12 feet per second are common. If sulfur removal is required, limestone is used in the bed. Coal or other fuel is injected into the bed and burned. The freeboard acts as a transport disengagement zone for reduction of entrained particulate matter. Boiler tubes can be submerged in the bed to remove heat at a sufficient rate to maintain bed temperatures in the range of 1,400°F to 1,600°F. Further heat transfer surface can be placed in the flue gas stream if superheat or economizers are required. The only add-on pollution control required for a fluidized-bed combustor is a baghouse or other particulate control device.

A fluidizing action results when a gas stream is passed vertically through the fixed bed at sufficient velocity to lift or suspend the solid particulate. As the gas velocity increases from zero to the minimum fluidization velocity, pressure drop across the bed gradually increases. Once the bed is fluidized, pressure drop falls off dramatically and then is maintained fairly constant as long as the bed remains in the bubbling or turbulent region. If gas velocity is further increased, pressure drop will once again be reduced.

This relationship between gas velocity and pressure drop has resulted in the development of two distinct classes of fluidized bed technology. The first class is the conventional or bubbling fluidized bed.

These beds exist where pressure drop first drops off until the point where the bed is fully entrained and pressure drop again starts to fall. The fully entrained or circulating beds exist at fluid velocities greater than the particulate matter entrainment velocity.

In actual practice, commercial designs fall into three classifications: those designed to operate at the low end of the bubbling range, those designed to operate with fluidization velocities at the high end of the bubbling range, and those designed to operate with fully entrained beds. For purposes of this discussion, these are termed "bubbling bed," "turbulent bed," and "entrained bed or circulating bed."

Bubbling Bed - The bubbling bed is characterized by fluidizing velocities at the lower half of the fluidizing range. Coal and limestone are continually fed into the bed. Air is injected through the plenum to provide both combustion and fluidizing air. Steam is generated in the in-bed tubes. Bubbling bed technology is the basis for this report.

The lower velocity results in a large bed cross section with minimal abrasion of internals as well as very good carbon burnup without the use of primary cyclones for particulate collection and reinjection. Solids feed systems are generally a simple design because the low superficial velocities allow sufficient time for good fuel distribution within the bed. Ash and spent limestone are continuously withdrawn from the bottom of the bed.

Bubbling beds are the classical design of fluidized bed combustion and are operating reliably throughout the world in thousands of fluidized bed combustion installations.

Turbulent Bed - Turbulent beds are characterized by gas velocities near the upper end of the fluidized bed region, resulting in an extremely turbulent bubbling action throughout the bed. Coal and limestone are fed into the bed. Air is injected through the plenum, and steam is produced in the in-bed heat transfer tubes. Ash and limestone are continuously withdrawn from the bottom of the bed.

The turbulent fluidized bed has higher flue gas dust loading than the bubbling bed. Entrained particulates, removed by the cyclone, are reinjected into the fluidized bed. This reinjection improves the carbon combustion efficiency.

Some of the first coal-fired fluidized bed combustors constructed in the United States were of the turbulent bed design. The turbulent bed design was selected because the small cross sectional area resulted in higher heat release rates. However, the capital cost savings achieved by the smaller cross section is offset by the added complexity of a primary cyclone and reinjection system as well as relatively high abrasion of internals resulting from the entrained particulate matter.

Entrained or Circulating Bed - Entrained beds operate at velocities in excess of the entrainment velocity. The design is also known as circulating bed FBC. In the entrained bed, coal and limestone are injected into a high velocity gas stream which fully entrains all of the solids injected into the bed. Because of the high velocities, heat exchange is typically not included within the bed perpendicular to the gas flow. Instead, heat exchange surface is installed parallel to the gas flow.

A hot primary cyclone collects the particulate matter, which is subsequently reinjected into the fluidized bed.

Industry trends are now in the direction of the entrained or circulating bed technology for large installations.

Air Pollutant Emission Control - All three of the fluidized bed designs have a high uncontrolled particulate emissions. As a result, a final particulate collection device is required to meet emission standards. Although electrostatic precipitators, moving bed filters, and secondary cyclones have all been used on commercial installations, only the baghouse has received wide commercial acceptance for FBC units.

Sulfur dioxide emissions from FBC units can be controlled by use of limestone or dolomite within the bed material. Emission reduction of 90 percent or more has been demonstrated for all three designs.

Control of oxides of nitrogen is accomplished by preventing their formation through control of the bed temperature. Lower bed temperatures in a FBC system results in considerably lower emission level of nitrogen oxides than conventional combustion processes/equipment.

Conclusion

Fluid bed combustion is a commercial technology capable of utilizing a variety of fuel sources. There are numerous advantages in selecting FBC over conventional combustion processes. However, the overriding advantage of FBC is the ability to burn low quality, high sulfur fuel in an environmentally acceptable manner.

PART III - FBC TEST RESULTS

General

The University of North Dakota Energy Research Center, under subcontract to Stanley Consultants, Inc., performed a combustion test with Iowa coal and Iowa limestone in a 2.25 ft^2 pilot scale fluidized bed combustor at the Center. The objective of the test program was to provide basic operational information on the use of washed and unwashed Iowa coal in an FBC.

FBC Facility Description

An overall schematic view of the 2.25 ft^2 pilot scale FBC unit at the UNDERC is shown in Figure 1. The major components of the FBC system are the combustor, the combustion air system, the feed system, the flue gas system, and the gas sampling system.

The 18-inch square combustor is a refractory-lined steel shell with a removable door which provides easy access to the combustor. The tube surface area for bed cooling is varied from 0 to 28.8 ft^2 to match the desired operating conditions. The combustion system has been designed to operate over a wide range of conditions:

Average bed temperature. . . . . .1300°-1800°F
Superficial gas velocity . . . . 3-12 ft/sec
Excess air 0-50%
Ash reinjection (percent of cyclone catch) 0-100%

The nominal fuel rate for the combustor is 180 lb/hr of coal at 6 ft/sec superficial gas velocity and 20 percent excess air.

The combustion air system consists of a forced draft fan, a flue gas/combustion air heat exchanger (primary), and a natural gas fired preheater. The bed is fluidized by means of a positive displacement forced draft blower which forces combustion air through the primary heat exchanger for combustion air preheat, and through the direct fired natural gas burner section which warms up combustion air during the preheat phase (prior to injection of solid fuel). The combustion air then passes through a flat drilled-plate distributor.

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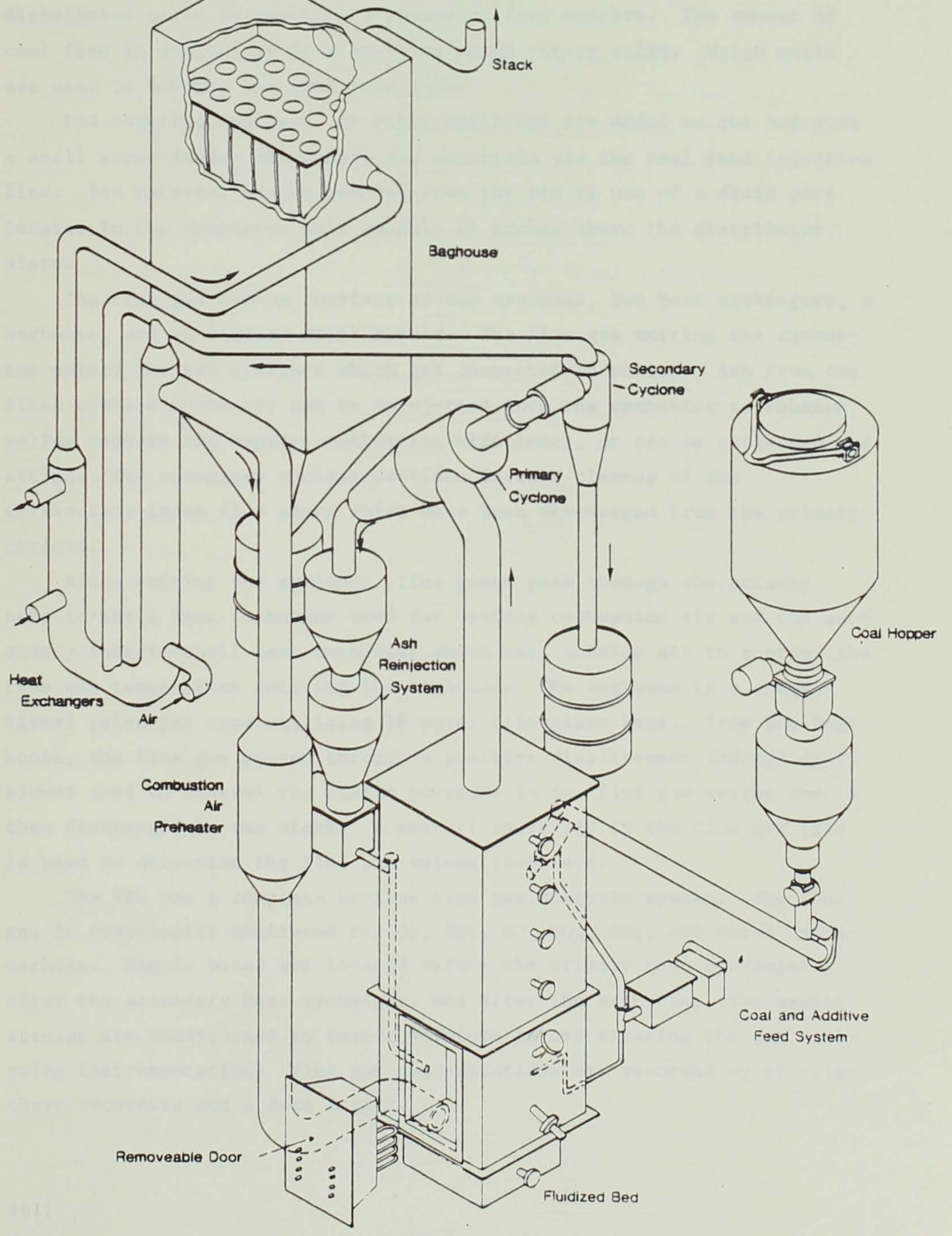

FBC SCHEMATIC

Figure 1

The coal feed system is capable of injecting minus 1/4 inch coal along with bed material and/or sorbent approximately 6 inches above the distributor plate by means of a pneumatic feed venturi. The amount of coal feed is controlled by a variable speed rotary valve. Weigh cells are used to monitor the coal feed rate.

Bed material, sorbent, or other additives are added to the bed with a small screw feeder which adds the materials via the coal feed injection line. Bed material can be removed from the bed by use of a drain port located in the combustor wall roughly 21 inches above the distributor plate.

The flue gas system consists of two cyclones, two heat exchangers, a baghouse, and an induced draft blower. The flue gas exiting the combustor enters the two cyclones which are connected in series. Ash from the first cyclone (primary) can be reinjected into the combustor to enhance sulfur capture and improve combustion efficiency, or can be collected and stored. The secondary cyclone provides further cleanup of the particulate-laden flue gases which have been discharged from the primary cyclone.

After exiting the cyclones, flue gases pass through the primary tube-in-shell heat exchanger used for heating combustion air and the secondary tube-in-shell heat exchanger which uses outside air to control the flue gas temperature entering the baghouse. The baghouse is a conventional pulse-jet type utilizing 18 woven fiberglass bags. From the baghouse, the flue gas passes through a positive displacement induced draft blower used to control the static pressure in the flue gas system and is then discharged to the stack. A venturi installed in the flue gas line is used to determine the flue gas volume flow rate.

The FBC has a complete on-line flue gas analysis system. The flue gas is continually monitored for O_2, CO_2, CO, NO_x, SO_2, and total hydrocarbons. Sample boxes are located before the primary heat exchanger, after the secondary heat exchanger, and after the baghouse. The sample streams are conditioned to remove moisture before entering the gas analyzing instrumentation. Flue gas concentrations are recorded by circular chart recorders and a data logger.

For further details of the system, the test procedures, and the analytical approach, see the appendices in Volume 2.

Results and Discussion

Iowa Coal Properties - Both unwashed and washed Iowa coal samples were provided to UNDERC by Stanley Consultants, Inc. The only coal preparation by UNDERC was to crush and classify the coal to minus 1/4 inch. Composite samples of both the unwashed and washed coals were collected and submitted for proximate, ultimate, sulfur forms, and sieve analyses of the coal. X-ray fluorescent analysis and ash fusion temperatures were determined using the coal ash. The results of these analyses are presented in Tables 1, 2, and 3.

Several differences were noted between the unwashed and washed Iowa coals. The percentage ash in the washed coal, 11.9 percent, was significantly lower than for the unwashed coal, 18.6 percent. This is approximately a 36 percent reduction in ash on a moisture-free basis. The percentage of sulfur in the washed coal, 3.63 percent on a moisture-free basis, was reduced as compared to the unwashed coal, 4.07 percent. An increased higher heating value was also noted for the washed coal. The primary reason for the higher value was probably due to the lower ash content of the washed coal.

Analysis of sulfur forms in the coal samples indicated that pyritic sulfur was significantly lowered by washing the coal and that sulfate sulfur and organic sulfur were relatively unchanged. The total sulfur in the unwashed and washed coals was independently verified by an outside lab.

As can be seen in Table 3, the size distributions of the unwashed and washed Iowa coal samples were very similar.

Iowa Limestone Properties - Table 4 shows the x-ray fluorescent analysis of the Iowa limestone that was used as starting bed material and sorbent during the test. The limestone was supplied to UNDERC by Stanley Consultants, Inc. From the analysis of the limestone, it is apparent that the limestone is primarily calcitic and is relatively pure.

TABLE 1

COAL AND COAL ASH ANALYSIS

	Iowa Unwashed Coal		Iowa Washed Coal	
	As Burned	Moisture Free	As Burned	Moisture Free
Proximate Analysis:				
Moisture	15.1	---	17.8	---
Ash	15.8	18.6	9.8	11.9
Volatile Matter	32.8	38.6	32.0	38.9
Fixed Carbon (diff.)	36.3	42.8	42.4	49.2
	100.0%	100.0%	100.0%	100.0%
Ultimate Analysis:				
Moisture	15.1	---	17.8	---
Ash	15.8	18.6	9.8	11.9
Carbon	55.22	65.01	58.71	71.41
Hydrogen	3.85	4.53	4.13	5.02
Nitrogen	1.29	1.52	2.18	2.65
Sulfur	3.46	4.07	2.98	3.63
Oxygen (diff.)	5.28	6.22	4.40	5.35
	100.00%	99.95%	100.00%	99.96%
Higher Heating Value:				
Btu/lb	9,792	11,527	10,330	12,565
Ash Fusion Temperatures (°F):				
Initial Deformation	2,050		1,980	
Softening Temperature	2,100		2,100	
Fluid Temperature	2,150		2,320	
Ash Analysis (% as Oxides):				
Silica, SiO_2	25.2		31.4	
Aluminum Oxide, Al_2O_3	11.7		14.9	
Ferric Oxide, Fe_2O_3	18.9		17.9	
Titanium Dioxide, TiO_2	0.6		0.8	
Phosphorous Pentoxide, P_2O_5	0.8		0.9	
Calcium Oxide, CaO	21.9		16.0	
Magnesium Oxide, MgO	0.6		1.0	
Sodium Oxide, Na_2O	0.0		0.0	
Potassium Oxide, K_2O	1.2		1.5	
Sulfur Trioxide, SO_3	19.1		15.6	
	100.0%		100.0%	

Source: UNDERC

TABLE 2

COAL SULFUR FORMS

	Iowa Unwashed Coal		Iowa Washed Coal	
	As Burned	Moisture Free	As Burned	Moisture Free
Pyritic Sulfur	2.06	2.43	1.25	1.51
Sulfate Sulfur	0.01	0.01	0.02	0.02
Organic Sulfur	1.01	1.19	0.96	1.17
Total Sulfur	3.08	3.63	2.21	2.69

Source: UNDERC

TABLE 3

COAL SIEVE ANALYSIS

Screen Mesh	Unwashed Iowa Coal (% Retained)	Washed Iowa Coal (% Retained)
8	34.0	32.8
10	14.2	14.0
16	12.9	12.8
20	9.4	9.4
30	7.2	7.5
35	5.7	5.8
<35	16.5	17.4
	99.9	99.7

Source: UNDERC

Specified and Actual Conditions of the Test - This test was performed according to standard experimental procedures as outlined previously. The test was divided into five separate periods:

1. Combustion of unwashed Iowa coal to sulfate the original bed material and collect sufficient ash for ash reinjection.
2. Combustion of unwashed Iowa coal with limestone addition and ash reinjection (sulfur retention to be 90%).

TABLE 4

IOWA LIMESTONE ANALYSIS

	Percent of Ash	Percent As Received
Loss on Ignition at 750°C	--	40.9
Silica, SiO_2	2.0	1.2
Aluminum Oxide, Al_2O_3	0.1	0.1
Ferric Oxide, Fe_2O_3	1.2	0.7
Titanium Dioxide, TiO_2	0.0	0.0
Phosphorous Pentoxide, P_2O_5	0.0	0.0
Calcium Oxide, CaO	95.8	56.3
Magnesium Oxide, MgO	0.0	0.0
Sodium Oxide, Na_2O	0.0	0.0
Potassium Oxide, K_2O	0.0	0.0
Sulfur Trioxide, SO_3	0.9	0.5
	100.0	99.7

Source: UNDERC

3. Combustion of unwashed Iowa coal with limestone addition and ash reinjection (sulfur retention to be 90%).
4. Combustion of washed Iowa coal with limestone addition and ash reinjection (sulfur retention to be 90%).
5. Combustion of washed Iowa coal with limestone addition and ash reinjection (sulfur retention to be 90%).

Period 1 involving sulfation of the bed took 20 hours. Ash reinjection and limestone addition was initiated at the beginning of Period 2 and continued through Period 5. Periods 2 through 5 lasted approximately 8 hours each.

The coal was fed under-bed with the pneumatic coal feed system. Recycle ash was pneumatically reinjected into the bed at the same level as the coal feed. The following parameters were specified for all test periods: 1550 ± 50°F average bed temperature, 6.0 ± 0.2 ft/sec superficial gas velocity, 20 ± 5 percent excess air, and a bed weight of 650 ± 50 lb.

A summary of average run conditions and results during periods 2 through 5 is presented in Table 5. Flue gas concentrations were obtained by time-averaging the data over each period. The percent excess air was calculated from flue gas concentrations.

TABLE 5

RUN CONDITIONS AND RESULTS

Period Number	2	3	4	5
Type of Coal	Unwashed	Unwashed	Washed	Washed
Average Bed Temperature, °F	1569	1557	1525	1530
Superficial Gas Velocity, ft/sec	5.3	5.2	5.1	5.0
Excess Air, %	22.3	21.7	15.8	16.0
Bed Weight, lb	541	574	599	591
Coal Feed Rate, lb/hr	112.2	105.9	103.2	106.0
Ash Reinjection Rate, lb/hr	60	83	89	80
Limestone Addition Rate, lb/hr	28.6	11.2	19.1	21.3
Inherent Ca/S Mole Ratio	0.57	0.57	0.30	0.30
Sorbent Ca/S Mole Ratio	2.37	0.99	2.00	2.17
Total Ca/S Mole Ratio	2.94	1.56	2.30	2.47
Bed Overall Heat Transfer Coefficient, Btu/hr-ft^2-°F	48.3	48.2	48.0	48.0
Flue Gas Concentrations:				
%O_2	3.6	3.7	3.0	2.9
% CO_2	15.8	15.3	15.9	15.9
% CO	0.03	0.03	0.04	0.03
ppm SO_2	331	319	371	337
ppm NO_x	421	464	349	284

Source: UNDERC

All parameters were maintained within specified limits except for the following changes. The specified superficial bed velocity was decreased from 6.0 to 5.0 ft/sec before the start of the second period. At that time, the specified bed weight was also decreased from 650 to 550 lb. These changes were necessary because of elutriation of the limestone bed material (see following section).

General Operability of the Unit - There were not any significant problems associated with the combustion characteristics of the coal. The coal ignited easily during start-up of the combustor after preheating the bed material to approximately 885°F. There was also very little burning of the coal in the freeboard as evidenced by similar temperatures in the bed and freeboard.

The Iowa limestone, which was used both as initial bed material and sorbent for sulfur retention, was a source of minor operational problems encountered during the testing. These problems were in part the result of a modified start-up procedure. Initially -8/+20 mesh Iowa limestone was charged into the bed. However, with this size distribution, it was not possible to maintain the specified bed weight (650 lb) because of bed elutriation. The problem was corrected by increasing the size of the limestone particles.

Percent carbon combustion efficiency was determined for Period 1 with no ash reinjection and was found to be 89.8 percent. Percent carbon combustion efficiency is defined as one hundred minus the percentage of combustible carbon lost with the fly ash. Due to the complexity of the test, combustion efficiencies could not be accurately determined for Periods 2 through 5. However, combustion efficiencies were higher with ash reinjection (Periods 2 through 5) based on loss on ignition (LOI) of the recycle ash. The average LOI for Period 1 (13.05%) was greater than the average LOI for Periods 2 through 5 (7.96%). This would indicate an approximate combustion efficiency of 93-94 percent with ash recycle. Combustion efficiency is primarily a function of unit design and hence was not considered a primary test variable.

Emissions - Sulfur dioxide emissions, sulfur retention, and calcium utilization results for Periods 2 through 5 are presented in Table 6.

The target sulfur control for all test periods was 90 percent reduction in sulfur emissions. This degree of reduction was essentially

TABLE 6

SULFUR EMISSIONS AND RETENTION

	Period 2	Period 3	Period 4	Period 5
SO_2 Emissions (lb $SO_2/10^6$ Btu):	0.63	0.63	0.71	0.64
Sulfur Retention (%):	91.1	91.1	87.8	88.9
Calcium Utilization (%):	31.0	58.4	38.2	36.0

Source: UNDERC

obtained during all of the test periods. A sulfur retention of 91.1 percent was obtained in both periods when burning unwashed Iowa coal. Sulfur retentions slightly less than 90 percent (87.8% and 88.9%) were obtained during the periods in which washed Iowa coal was burned. The total reduction in sulfur emissions during Periods 4 and 5 is actually 90.0 percent and 90.9 percent, respectively, if the reduction in sulfur resulting from the washing step is taken into account.

Some discrepancy was noted between the two periods in which the unwashed coal was burned. A total Ca/S ratio of 2.94 was required to reach 91.1 percent sulfur retention in Period 2. A much lower total Ca/S ratio, 1.56, resulted in identical sulfur retention during Period 3. The limestone addition rate for Period 2 was more than twice the rate for Period 3. Some of the difference is probably attributable to the lower ash reinjection rate for Period 2 as compared to Period 3. Calcium utilizations appeared to be quite high, ranging from 31.0 percent to 38.2 percent in Periods 2, 4, and 5 and 58.4 percent in Period 3.

NO_x Emissions - Nitrogen oxide emission results from Periods 2 through 5 are presented in Table 7. There is good agreement between the numbers calculated by the three methods.

The NO_x emissions were higher when burning the unwashed Iowa coal than when burning washed coal. This is in spite of the higher nitrogen content of the washed coal (see Table 1).

Particulate Emissions - Two 5-stage multicyclone flue gas particulate size distribution tests were performed, one test when burning

TABLE 7

NO_X EMISSIONS (lb $NO_x/10^6$ Btu)

Period 2	Period 3	Period 4	Period 5
0.57	0.65	0.48	0.39

Source: UNDERC

unwashed Iowa coal and the other when burning washed Iowa coal. The particulate sampling was done at a location between the secondary cyclone and baghouse to represent the size and type of particulate that could be expected in a commercial FBC. The results of these tests are tabulated in Table 8. As can be seen from the table, little difference was noted between the size distribution of flue gas particulate generated by the unwashed and washed coals.

TABLE 8

FLUE GAS PARTICULATE SIZE DISTRIBUTION

Iowa Unwashed Coal		Iowa Washed Coal	
Aerodynamic diameter, μm	Cumulative weight % less than stated size	Aerodynamic diameter, μm	Cumulative weight % less than stated size
1.25	11.62	1.29	11.95
2.23	45.16	2.30	40.65
4.62	59.79	4.73	54.37
6.14	74.33	6.29	69.69
11.22	86.73	11.41	86.22

Source: UNDERC

Conclusions

Samples of Iowa unwashed and washed coal were successfully burned in the 2.25 ft^2 atmospheric bed combustor at UNDERC. The washed coal had a significantly lower ash and sulfur content and a higher heating value than the unwashed coal. The combustion characteristics of both coals were good.

Sulfur retentions of approximately 90 percent were obtained during all four periods of the test. Total Ca/S mole ratios (including Ca from coal and limestone) ranged from 1.56 to 2.94 to achieve the required sulfur retentions. Calcium utilization was high, ranging from 31.0 percent to 58.4 percent for the test periods. Emissions of NO_x varied from 0.39 to 0.65 lb $NO_x/10^6$ Btu.

Very little difference was noted between the size distribution of the flue gas particulate collected when burning washed coal as compared to the unwashed coal.

PART IV - COGENERATION SYSTEMS USING IOWA COAL

General

As shown in previous sections of this report, fluidized bed combustion allows use of unwashed Iowa coal with pricing below premium fuels while meeting environmental control regulations. It is the intent of Part IV and V to illustrate the practical application of FBC technology in providing steam and electricity (cogeneration) simultaneously. Cogeneration provides an extension of the technology enhancing the economic feasibility of FBC for industry and electric utilities.

Although stoker firing of coal is a well established technology, fluidized beds were selected as the design approach for this study. The rationale for selection of fluidized bed combustion is twofold. The primary consideration involves emission control. Even though small boilers do not have to meet current emission standards, the trend is toward more stringent controls. Fluidized bed combustion provides sulfur and nitrogen oxides emission controls in lieu of installation of scrubbers or other treatments. In addition, fluidized bed combustion has a distinct advantage with regard to multifuel firing capability. The use of fluidized beds provides wide latitude in the switching and blending of fuels.

Coal-Fired Process

An FBC process with coal firing is examined. Coal is fired in a fluidized bed combustor to generate steam at a pressure of 650 psig, 750°F. The steam is reduced from the boiler pressure to the distribution pressure in a steam turbine with shaft output converted to electricity. The major items of equipment required include a fluidized bed combustor, a baghouse, a deaerator, a turbine generator, boiler feed pumps, water treatment and coal, waste, and limestone silos. In addition, for the condensing operation a condenser, cooling towers, and cooling water treatment are required. Typical operating conditions are shown in Table 9.

Generation/Condensing System Description

Two coal-fired cogeneration methods are investigated - a noncondensing turbine and a condensing turbine. Peak net electric generation is 1,044 kW for the noncondensing design. With a condensing turbine, peak generation is 3,600 kW.

The modular designed components selected for this system are shown on Figure 2. Approximately, an 80' x 80' building would be required for inclusion of all modules. Although a smaller structure is feasible where site restrictions prevail, we recommend a larger facility for ease of service.

TABLE 9

PROCESS SPECIFICATIONS

	Noncondensing	Condensing
Feedwater Temperature	220°F	220°F
Steam Conditions	650 psig, 750°F	650 psig, 750°F
Steam Flow	40,000 pounds per hour (pph)	40,000 pph
Flue Gas Temperature	300-350°F	300-350°F
Ca/S(molar) Ratio	1-2.5	1-2.5
Excess Air	15%	15%
Combustion Temperature	1,550°F	1,550°F
Extraction Pressure	120 psig	120 psig
Condensing Pressure	---	3 in. Hg abs.

Source: Stanley Consultants

Each of these modules can be factory assembled, prewired, and tested prior to delivery. This shop assembly will not only reduce construction time and cost but should also minimize startup problems.

The boiler system selected is a shop-assembled, atmospheric fluidized bed coal-firing unit. Steam conditions are 650 psig and 750°F. The unit as purchased includes all fans, controls, motor control centers, feed hoppers, and waste removal components.

The turbine-generator skid includes controls and breaker connections in addition to the turbine gearbox and generator. The condensing turbine operates on 3 in. Hg backpressure with a 120 psig extraction port. Peak shaft output is 3,600 kW. Gear losses, generator losses, and system power requirements reduce this output.

The condenser system is sized for condensation of the full 40,000 pounds per hour steam generation. Pumping capacity is installed with

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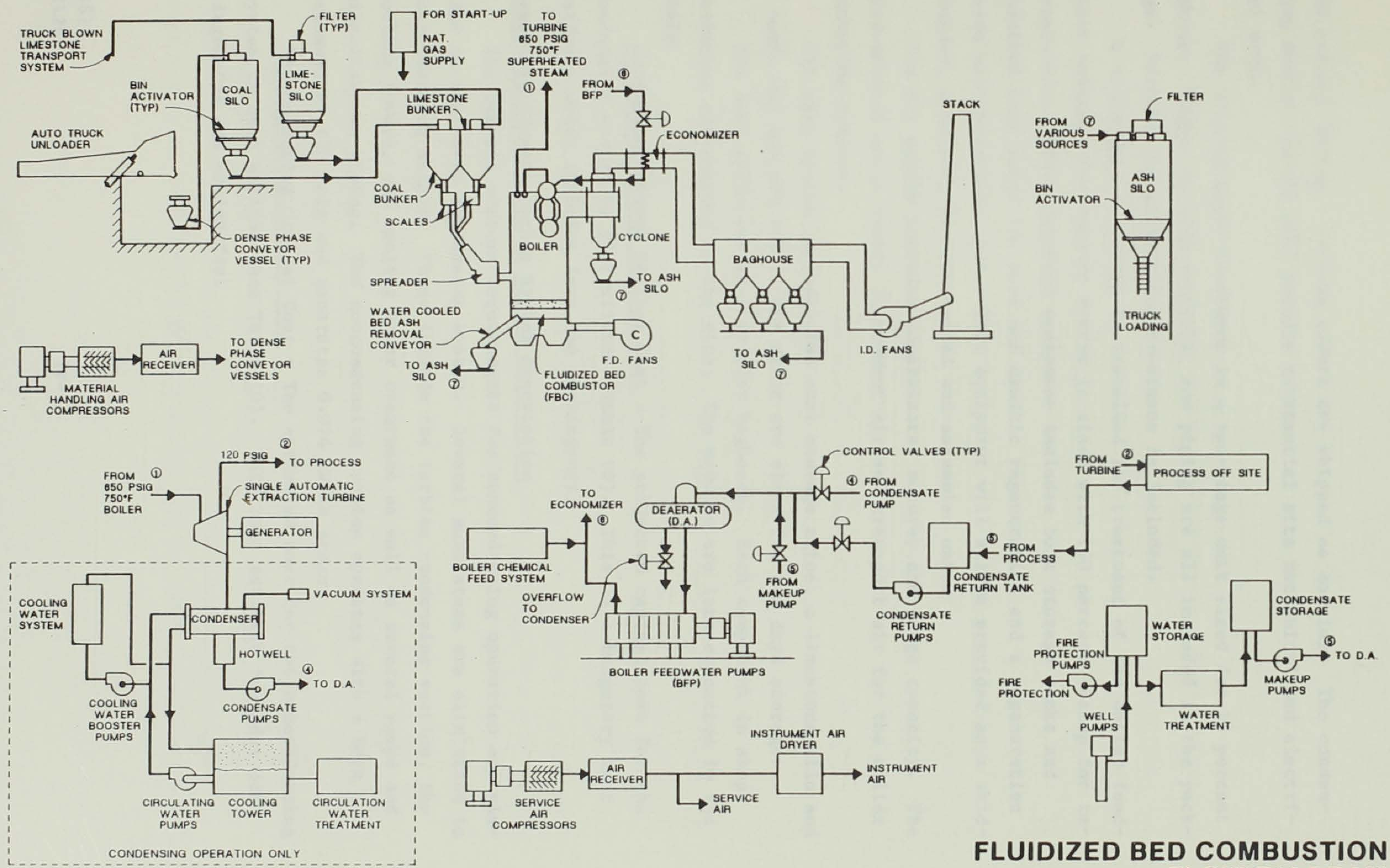


FLUIDIZED BED COMBUSTION FLOW DIAGRAM

Figure 2

100 percent backup. Cooling towers are shipped as modules. The condensing system overall will require substantial site mechanical and electrical work.

The cooling water treatment is a two-stage unit sized for 15 percent makeup. Pumps, cooling controls, and piping are all included in the package. Biocide and antiscaling treatment is included.

A demineralizer system is installed for treatment of the boiler feedwater makeup. The make-up system is sized with 100 percent backup for regeneration. Other required equipment includes bulk storage tanks and chemical feed pumps for acid and caustic regeneration and a regeneration waste neutralization tank. This equipment will all be provided as a skid-mounted, prewired, factory tested and assembled unit.

The air supply includes compressors, motors, and surge capacity. The skid-mounted units supply instrument air and transport air for the solids conveying systems.

The silo system includes two coal storage silos, a limestone silo and a spent bed and ash silo. The silos are sized for ten days storage.

The dust collector is a modular baghouse. Each component is shop assembled and shipped to the site. The modules are interconnected in the field.

Condensing System Capital Cost - The projected capital cost for the condensing system is \$7.1 million (Table 10). This is a budgetary cost estimate which includes fees and contingency.

Generation/Noncondensing System Description

The overall systems requirements for noncondensing operation are similar to the above condensing system. Several subsystems are eliminated in noncondensing design. These include the turbine condensing section, the cooling towers, and cooling water treatment as well as several pumps and miscellaneous piping. The noncondensing turbine operates with a back pressure of 120 psig and generates 0.026 kW/lb steam.

Noncondensing Capital Cost - The estimated cost for the noncondensing system is \$6.1 million (see Table 10). This cost estimate includes contingencies and design fee.

TABLE 10

SUMMARY CONCEPTUAL COST ESTIMATE

	Noncondensing Cogeneration	Condensing Cogeneration	No Cogeneration
Building	$ 510,000	$ 510,000	$ 450,000
Major Equipment	2,303,000	2,985,000	1,520,000
Ash Handling	190,000	190,000	190,000
Coal Conveying	625,000	625,000	625,000
Limestone Handling	100,000	100,000	100,000
Miscellaneous Equipment	629,000	720,000	629,000
Piping	312,000	315,000	312,000
Electrical Power	480,000	480,000	480,000
Subtotal	5,149,000	5,925,000	4,306,000
Contingencies & Fee	1,032,000	1,187,000	863,000
Total	$6,181,000	$7,112,000	$5,169,000

Source: Stanley Consultants

These costs for both the condensing and the noncondensing systems are budgetary estimates. Project contingencies as well as design developmental contingencies are included. In addition, during the bidding process equipment may well be purchased at less than the budgetary price. Finally, the full range of equipment included for this analysis may not be required for a given installation. The cumulative effect from each of these categories could result in an installed cost well below the estimate developed for this report.

Ancillary Power Requirements

Power requirements for the coal-fired facility with a condensing turbine are approximately 900 hp. This includes all fan, pump, and material-handling motors. For the noncondensing system about 320 hp associated with the cooling tower and condensers is eliminated. For modeling purposes parasitic losses are 335 kW at full load for the noncondensing system and 430 kW for the condensing system. The apparent discrepancy between reduced installed horsepower and parasitic losses results from redundant capacity. For instance, cooling tower pumps are sized at 100 hp. Two pumps are installed; one operating and one spare. Since only one operates, connected horsepower is reduced by 200 hp but operating kilowatts by less than 75.

Utility Interconnects

Provision for connection of the generator to the substation is necessary. All transformers for connection to the plant power bus and the substation should be included. The generator operates at 4,160 volts or the substation voltage.

The generator should be equipped with metering, instrumentation, and controls for synchronization and parallel operation with the electric utility. The generator should be capable of supplying power to the plant system as well as back into the local utility's system. Relay and safety requirements vary dramatically among utilities and will affect site specific design cost.

The generator will require a complement of relays for protection of the unit in the event of electrical and mechanical malfunction. Provision will also be made for supply connections from the distribution system to supply the auxiliaries required for boiler operation.

Site Compatibility

The fluidized bed combustor, steam-turbine generator, and ancillary equipment are housed in a new building. The baghouse and stack, along with the coal, limestone, and ash storage silos, are exterior to the new building. Steam lines and condensate return will be required for connection of the new system to the existing facility.

Environmental Regulations

Several guidelines and regulations have been promulgated on the federal and state levels to mitigate environmental concerns resulting from solid fuel combustion. The primary environmental concerns include air emissions, water intake and discharge, and solid waste disposal. These may require environmental impact assessment.

Air Emissions - The major permitting requirements for air emissions are contained in the federal regulation for Prevention of Significant Deterioration (PSD). When determining the necessity for a PSD permit, two criteria apply.

1. Potential emissions of the new source.
2. Actual increased emissions from the modified source.

The first criterion for PSD applicability governs the increase in emissions from the proposed new source or modification. After consideration of control, if emissions exceed the significant levels listed in Table 11, a PSD permit is required. Preliminary estimates of air emissions have been made for sulfur dioxide (174 tons per year), particulate (7 tons per year), and nitrogen oxides (146 tons per year) for a 40,000 lb/hr boiler. These preliminary estimates indicate that sulfur dioxide and nitrogen oxides exceed significant levels. PSD regulations require the following actions:

- A modeling demonstration to show that the increase in emissions of criteria pollutants will not exceed national ambient air quality standards.
- A monitoring program on air quality analysis to determine baseline air quality.
- The application of best available control technology for control of the pollutants subject to this regulation.

All or part of these actions may be required depending on available data or previous air quality monitoring. An applicability determination must be performed and submitted to the United States Environmental Protection Agency to determine if PSD regulations could apply to this project.

In addition to PSD permitting, the proposed new source may be subject to regulations governing nonattainment areas. If an area is classified as not attaining the air quality standards rules governing nonattainment areas, such as offsets and lowest achievable emission rates, may apply. The expected emission rates for the example boiler will satisfy best available control technology, but may not be the lowest achievable emission rate applied in nonattainment areas.

New sources must also obtain a state air quality permit. Often information provided in the PSD permit is sufficient for a state permit. If PSD permitting is not required, the state may request air quality dispersion modeling in addition to the information needed to obtain a permit. The state agency should be consulted before any applications for air permits are made.

TABLE 11

SIGNIFICANT EMISSION RATES
FOR PSD APPLICABILITY

Pollutant	Emission Rates (tons/yr)
Carbon monoxide	100
Nitrogen oxides	40
Sulfur dioxide	40
Particulate matter	25
Ozone (VOC)	40 (of VOCs)
Lead	0.6
Asbestos	0.007
Beryllium	0.0004
Mercury	0.1
Vinyl chloride	1
Fluorides	3
Sulfuric acid mist	7
Hydrogen sulfide (H_2S)	10
Total reduced sulfur (including H_2S)	10
Reduced sulfur compounds (including H_2S)	10

Source: 40 Code of Federal Regulations 52.21 (b) (23) of the United States.

Solid Waste Disposal - The solid discharge from a fluidized bed combustor is presently classified as a nonhazardous waste similar to fly ash. These solids may be disposed in a landfill after obtaining the appropriate permits. This report assumes the waste will be disposed of at the coal mine.

Water Intakes and Discharge - It is not anticipated that a modified facility will have a significant impact on either the water requirements or the water discharges; however, an analysis must be conducted to determine water quality impacts. The actual water inputs and outputs will have to be estimated as part of the permitting process. A new facility must comply with all state and federal water quality requirements for water intake and discharge. In both cases a NPDES permit will probably be required.

Environmental Assessment - As part of the procedure for obtaining permits, an environmental assessment of the project is often required. This assessment summarizes all environmental impacts of the proposed new source and the surrounding environment. This assessment is used to determine if an environmental impact statement should be performed.

PART V - ECONOMIC ANALYSIS

General

An essential ingredient to the success of FBC technology is its economic feasibility in a variety of applications. Therefore, this study includes economic analysis of a cogeneration example.

Projection of the economic feasibility of a "typical" FBC cogeneration unit, requires development of a comprehensive simulation model. This enables the manipulation of engineering criteria, fuel costs, and facility operation patterns to determine the conditions under which the use of Iowa coal is advantageous. The model developed for these reports uses rates in the Des Moines area.

This analysis includes a fluidized bed combustion system both with and without cogeneration. Cogeneration is included in the analysis even though utilization of Iowa resources in an FBC is the main concern of this study. The incremental payback for on-site power generation is attractive for most sites. Because preliminary screening indicated a back pressure cogenerator provided the best payback, the economic discussion will focus on this option.

Description of Model

A model was developed for this study which not only analyzes the economic and financial considerations of a potential Iowa project but also simulates hour-by-hour fuel usage, steam generation, air conditioning requirements, and electrical loads. The model illustrates the interplay between a facility's various energy consumption factors. Modeling of mechanical process and energy use patterns resulted in estimation of annual fuel and electrical requirements with and without a proposed project. The financial performance of this unit is presented in a balance sheet format projected to the year 2000.

Further details on input parameters for the model are provided as follows:

Energy Loads - The model assumes that a facility has existing "base case" electric power and steam requirements which are provided as inputs to the model. Without the project, the electric requirements are met through purchase from a utility company and the steam requirements are met through existing natural gas boilers. Average monthly loads for steam and electric power are necessary inputs for this simulation. Inputs for electric power usage include both energy and demand components. Electric loads include a base load which is constant for each month, to which is added an air conditioning demand for seven months of the year. This assumes that "base case" air conditioning is being provided by electrical chilling units.

Steam demands are input to the model in units of lbs/hr. Because in this hypothetical facility the predominant use of steam is for building heating, significantly higher steam demands occur during winter months. In the example presented for this report, average hourly steam demands range from in excess of 53,000 lbs/hr in December to under 16,000 lbs/hr in July and August. Where the coal-fired system cannot meet peak steam demands, existing gas-fired boilers provide peak and backup capacity.

While the monthly electric and steam use parameters just described provide information on the relative size and scale of energy requirements, the model allows further refinement of demands into terms of specific hourly use over a 24-hour period. This is necessary due to "time-of-day" electric rate provisions. The average monthly or daily demands are broken down into hourly segments through percent-of-day load patterns for base electric energy consumption, chiller electric energy consumption, and steam. These hourly load patterns, when combined with monthly electric and steam requirements, allows the simulation of hourly electric and steam demands and electric demands. With these inputs, comparisons can be made for alternative projects.

Fuel Costs - To determine the financial impacts of gas versus coal use, unit costs are developed for the two alternative fuels. Natural gas costs of $4.50/mBtu are assumed. A coal cost of $1.33/mBtu have been developed based on price quotes from a coal supplier. The determination of the $1.33 cost per mBtu of coal is presented in Table 12. These unit costs are multiplied by the total Btu requirements with and without the project. In the base case, the inclusion of an FBC unit resulted in an estimated 1986 natural gas purchase cost savings of $1.368 million. Coal and limestone purchase and solids disposal for the cogeneration system are $516,000.

TABLE 12

DOLLARS PER TON COAL

	Raw	Washed
Coal	20.00	27.90
Delivery	4.11	4.11
Limestone	0.89	1.49
Waste Disposal	1.03	1.07
Total	26.03	34.57
Btu/lb	9,792	10,330
Dollars/mBtu	1.33	1.67

Source: Stanley Consultants

Since environmental considerations are always an integral part of any coal conversion, the cost of limestone has been included with the coal. Compliance with the most stringent emissions limits in effect is assumed. Therefore costs associated with a 90 percent reduction in sulfur emissions are included for the FBC coal model.

Limestone purchase for 90 percent sulfur reduction with the unwashed coal is \$.89/ton coal and limestone disposal is \$.41/ton coal. The composite is 6.6¢/mBtu. For a 40,000 lb/hr unit, yearly cost for limestone purchase and disposal is \$21,500 for an 86 percent efficient boiler operating at 80 percent load factor.

It is interesting to note that the limestone cost for washed coal is \$1.49/ton coal or approximately \$0.60/ton coal more than the raw/unwashed coal. Test results by UNDERC indicate that the unwashed coal contains significant calcium. Burning the raw coal in the FBC boiler takes advantage of the inherent calcium for sulfur capture in the boiler.

<u>Escalation Rate Assumptions</u> - Projection of future benefits and costs require escalation assumptions for fuel, electric power, and project maintenance items. A large component of the escalation rates assumed in the model can be attributed to inflation. In projecting future electric

rates, the assumption has been made that demand charges will escalate significantly over the next three years. Projected energy rates are at an annual escalation level of zero percent until they resume increases which are pinned to the inflation level in the late 1980s.

Both gas and coal are assumed to escalate at the same rate. Both fuels should escalate below the general inflation rate for the next several years. For long-term projections coal may not escalate as fast as gas.

Electricity Sell Back - With cogeneration, electric power could be sold back to a utility company under provision of the Public Utilities Regulatory Policy Act of 1978 (PURPA). The power available for selling back depends on the size of generating unit and the operational characteristics of the facility (load factor). A facility which has strong seasonal or daily peaks of power usage usually has a low load factor and is inclined to sell back more power than a facility with a stable demand.

While the model used for this study is capable of simulating a variety of load factors and sell back situations, this report has a sufficiently high load factor that surpluses do not result. During sensitivity analysis, load factors were varied with mixed results. Low sell back prices reduce returns, and high sell back prices improve returns for systems with reduced load factors. With high load factor, the sell back price had no effect on feasibility since no power was available for sale.

Sell back rates remain one of the most controversial aspects of cogeneration. Under the conditions of PURPA, utility companies are obliged to establish sell back rates which reflect their marginal costs of purchasing power. The factors which influence marginal costs are difficult to establish and even more difficult to project into the future.

Treatment of Capital Costs - The project cost estimate provided in Table 10 reflects the total construction costs of the FBC system with and without cogeneration including plant, engineering, and contingencies. The model used for this study is based on the total costs of FBC cogeneration over a conventional gas-fired unit. The use of the total project cost of $6.181 million in the model assumes that a facility's existing boiler has been prematurely taken out of service and replaced by the FBC unit with no recovery of salvage value and no consideration of depreciation. This most conservative assumption nevertheless results in a feasible project.

To the opposite extreme would be the consideration of a facility which is not yet constructed or an existing facility where boiler replacement is imminent. In this type of situation, only the capital cost differential would be modeled, resulting in substantially higher returns for coal firing.

As previously discussed, the project capital cost estimate is a budgetary estimate with significant contingency. Reduction in equipment pricing and elimination of contingencies would significantly increase the project net present value.

Use of standard general estimating techniques results in an estimated project cost of $4.86 million rather than $6.18 million. The discrepancy reflects a difference in design philosophy as well as project objectives. The $6.2 million installation is for a clean, low maintenance system with high quality components throughout. The lower cost substantially enhances project returns since no penalties are assessed by the model for premature component replacement.

Financial Parameters - The model developed for the Iowa Energy Policy Council reflects a private sector investment. Because of this, depreciation, investment tax credit, and income tax have been incorporated into the cash flow analysis.

For this analysis, a cost of capital (interest rate) was assumed to be 14 percent. Use of this interest level reflects the likelihood of continued tight money in the foreseeable future and is consistent with the conservative approach taken for other inputs. This 14 percent interest rate is also used to calculate the present value and net present value of the project.

With 100 percent equity (no financing) the unleveraged years-payback is 4.7 years.

Results of Analysis

This analysis determined that the use of Iowa coal for a FBC cogeneration system is feasible and can result in considerable savings through

through the lifetime of the facility. Actual savings, of course, will depend on specific project requirements and site location.

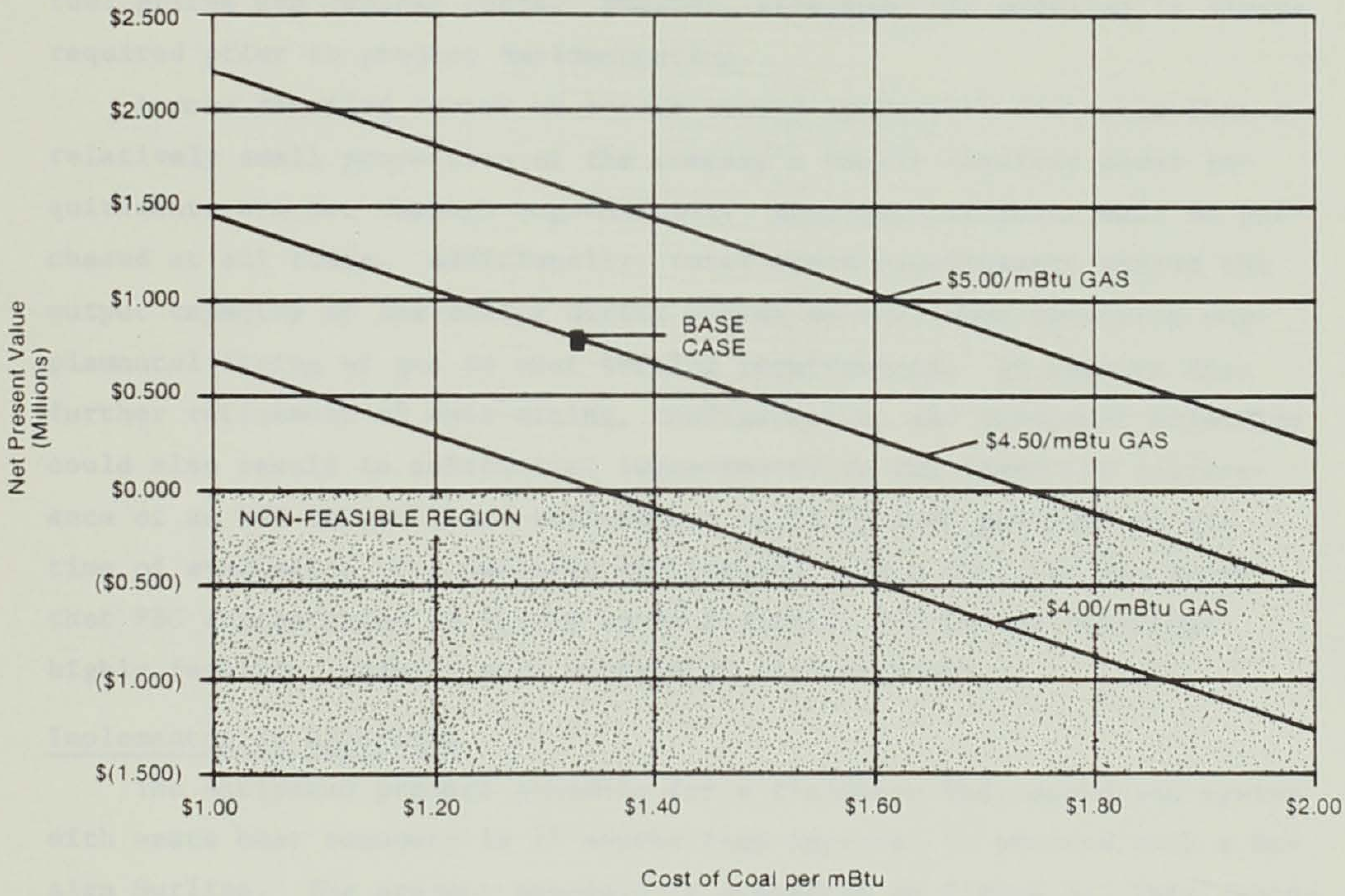
Cogeneration using FBC technology has been the focus of the model. Whether or not to include cogeneration must be an integral part of any site specific analysis. In most cases, FBC for steam generation would be all that is required. With no cogeneration, the first year savings from fuel conversion is $851,000. This is a six-year payback excluding operations and maintenance expense.

The overall results of this analysis indicate a feasible project when cogeneration is included (see Appendix A for detailed results). The unleveraged internal rate of return was 16.8 percent. While these indicators demonstrate that the investment in the project would yield positive results, it assumes the premature replacement of an operating gas-fired unit with years of operating lifetime remaining. The more likely situation of new construction or replacement of an aging boiler would result in substantially higher returns.

Sensitivity Analysis - The degree of feasibility of FBC cogeneration is dependent on numerous variables, including:

- Project Cost
- Coal Cost
- Gas Cost
- Electricity Purchase and Sell Back Rates
- Project Construction Costs
- Interest Rates
- Facility Operation Requirements

Three of the most critical of the above variables were the targets of sensitivity analysis to determine the impact of variation. Gas and coal costs were manipulated, resulting in Figure 3. Alternative year 1984 gas costs of $4.00, $4.50, and $5.00 were investigated simultaneously, with coal costs ranging between $1.00 and $2.00 per mBtu. Since the desirability of FBC technology increases as the differential between gas and coal cost, it can be seen that the greatest benefit occurs with $1.00/mBtu coal and $5.00/mBtu gas. Conversely, the project would not be feasible with $2.00/mBtu coal and $4.00/mBtu gas.



PROJECTED NET PRESENT VALUES
TYPICAL COGENERATION PROJECT
Figure 3

Variations in capital costs were also tested, where the cost parameter input is the cost differential between an FBC cogeneration facility, and a conventional gas-fired boiler with "average" efficiency. Net present value is plotted versus marginal cost on Figure 4.

This sensitivity analysis of three variables has concluded that an FBC cogeneration project will remain feasible despite wide variations in fuel prices and capital costs. However, site specific modeling is always required prior to project implementation.

A more detailed review of hourly energy production indicates that a relatively small proportion of the company's hourly electric power requirements are met through cogeneration. Supplemental power must be purchased at all times. Additionally, total steam requirements exceed the output capacity of the boiler during winter months, thus requiring supplemental firing of gas to meet heating requirements. It appears that further refinement of unit sizing, configuration, and equipment selection could also result in substantial improvements to the financial performance of an FBC unit. These refinements would be best provided at the time of evaluation of a specific application. This analysis concludes that FBC cogeneration is likely to be feasible, and in new buildings highly feasible, under a wide variety of circumstances.

Implementation Algorithm

The estimated project schedule for a fluidized bed combustion system with waste heat recovery is 37 months from approval to proceed with a Design Outline. The project schedule is presented on Figure 5. This schedule could be reduced to approximately 24 months by careful scheduling and an accelerated design process.

Both the Design Outline and the permit application activities start at time zero. The Design Outline is a report which preceeds the actual design of the faciltity. The Design Outline document includes information on the design criteria for the project. This is composed of plant site, building, and equipment layouts. Environmental, civil, electrical, and mechanical requirements are delineated for the owner's review and approval before starting final design.

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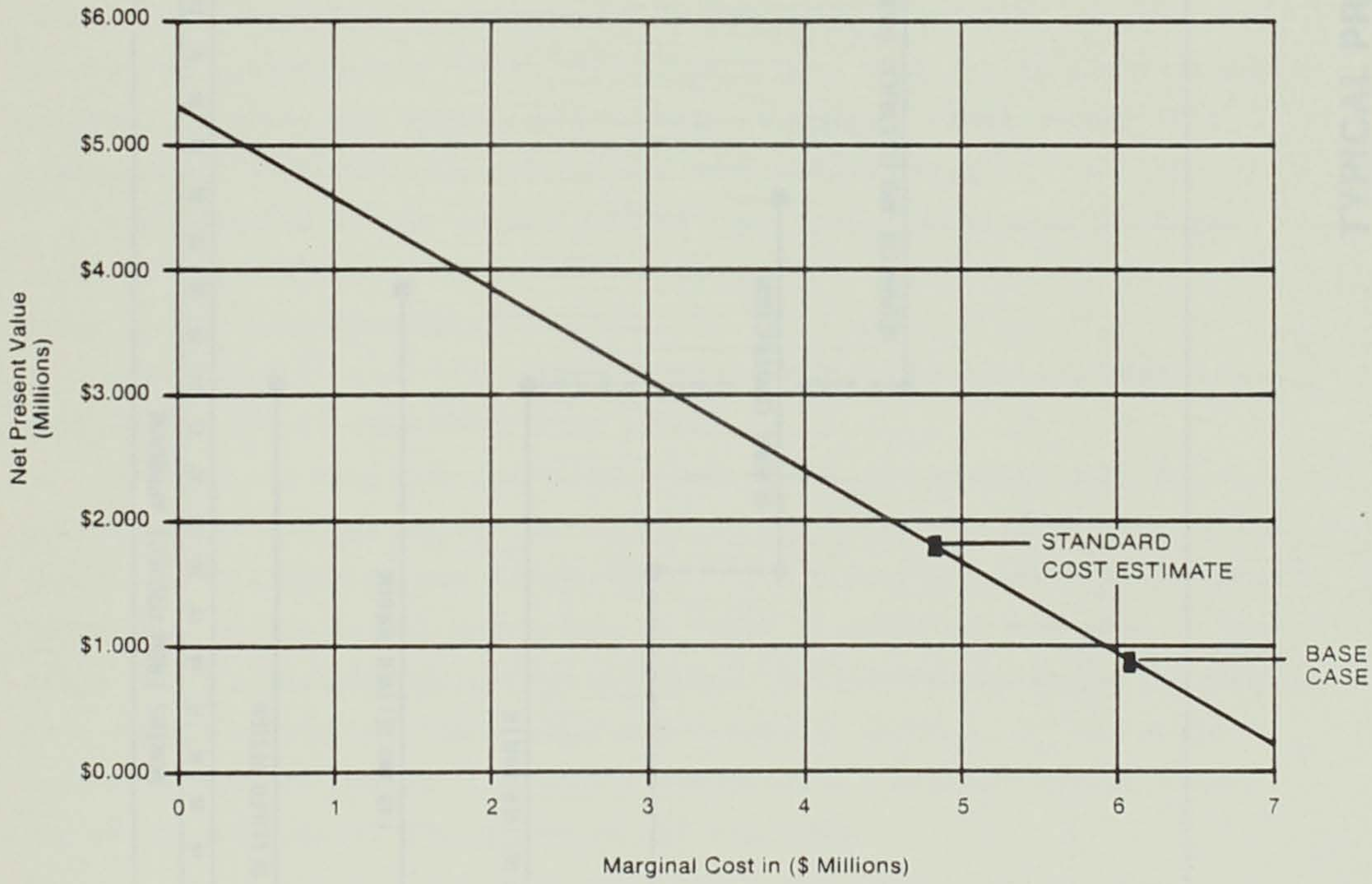

NET PRESENT VALUES
TYPICAL COGENERATION PROJECT

Figure 4

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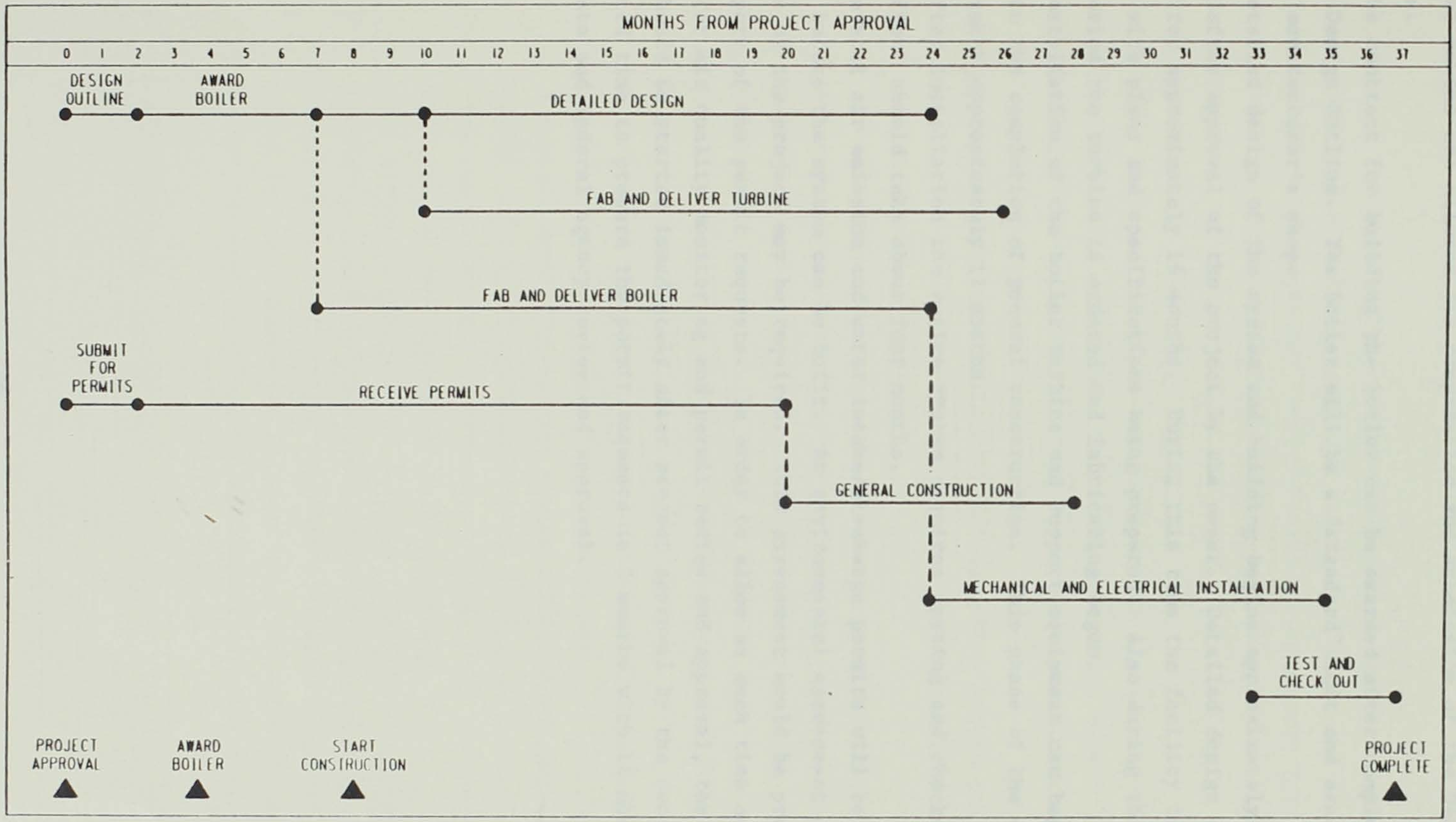

TYPICAL PROJECT SCHEDULE

Figure 5

Two months are allowed for preparation and submission of the Design Outline.

The contract for building the boiler can be awarded after completion of the Design Outline. The boiler will be a "standard" unit and assembled in the manufacturer's shop.

Detailed design of the system and building begins approximately seven months after approval of the project by the owner. Detailed design continues for approximately 16 months. During this time the facility is designed with plans and specifications being prepared. Also during this time period the turbine is ordered and fabricating begun.

Installation of the boiler turbine and support equipment can begin prior to the completion of general construction. This phase of the operation takes approximately 11 months.

After installation the entire system requires testing and checkout. This effort should take about four months.

Several air emission and water intake/discharge permits will be required before the system can be built. An environmental assessment of the impacts of the project may be required. This assessment would be prepared in support of the permit requests. In order to allow as much time as possible for air quality monitoring and permit review and approval, the process should be started immediately after project approval by the owner. Estimated time to prepare the permit requests is 2 months with 18 months for state and federal agency review and approval.

PART VI - CONCLUSIONS

An FBC test burn was conducted at the University of North Dakota Energy Research Center with Iowa coal and limestone. Data from the test were used to access the technical, environmental, and economic feasibility of burning Iowa coal for a steam plant and an industrial cogeneration system example.

Conclusions of the study are:

- Iowa coal and limestone was successfully burned in a pilot fluidized bed combustor. Data from washed and unwashed coal indicate that no particular problems would be expected in a commercial sized unit.
- Unwashed Iowa coal is a lower cost fuel than washed coal when burned in a fluidized bed combustor and assuming a 90 percent sulfur dioxide removal.
- Based on this investigation, the use of Iowa coal and limestone in a fluidized bed system is environmentally acceptable without additional sulfur dioxide or nitrogen oxides removal equipment.
- FBC offers a choice of utilizing a variety of nonconventional fuels in lieu of coal.
- Cogeneration is an alternative application for FBC technology which usually enhances project returns.
- A typical small cogeneration system utilizing FBC producing 40,000 lb/hr steam was demonstrated to payback in less than five years. Typical construction periods will run 2-3 years duration and cost approximately $6 million.
- Iowa stands to gain a major industry (coal) by using FBC technology fueled by Iowa's abundant coal/limestone supply. Direct benefits of burning unwashed Iowa coal in an FBC will go to the coal industry. Indirect benefits effecting all Iowans can also be gained by using the indigenous fuel supply.

APPENDIX A

DETAILED FINANCIAL MODEL

FOR COGENERATION

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IOWA ENERGY POLICY COUNCIL - JOB 8511-01 72,381
FEC Cogeneration Models 46.912
Back Pressure Turbine

BASIC DATA SHEET

Unit Size:
Steam: 40,000 Lbs./Hour

Equity Required:	$6,181
PV (Acc.):	$2,596
PV (Cash):	$6,983
NPV (Cash):	$802
IRR (Cash):	16.9%
S/I Ratio:	1.13
Yr. Payback:	4.7

Investment:	$6,181 Thousand
O&M Expense:	$311 Thousand
Insurance Expense:	$62 Thousand
Years Financed:	0
Interest Rate:	14.0%
Percent Equity:	100.0%

Fuel Cost:

Gas	$4.50 per MM BTU
Coal	$1.33 per MM BTU

Income Tax Rate: 46%

Steam Chiller:

Minimum Output	0 TONS
Maximum Output	1,000 TONS

Steam Turbine Factor 0.0261 KW/Lb. Steam

Minimum Steam Available for Electric Generation 0

1984 Purchase Rate Structure

Energy Charges (per kwh)

ON-PEAK	$0.02420
OFF-PEAK	$0.02000

Demand Charges (per kw) - No Cogen.

		Peak	Off Peak
Non-Summer			
First	600	$10.70	$5.21
Over	600	$8.77	$5.21
Summer			
First	600	$12.35	$5.21
Over	600	$10.42	$5.21

Escalation Rate Assumptions

	1984-86	1987	1988	1989	1990	After 1990
Gas/Coal:	1.5%	7.0%	7.0%	7.0%	7.0%	6.0%
O&M Expense:	6.2%	6.0%	6.0%	6.0%	6.0%	6.0%
Insurance Expense:	12.4%	6.0%	6.0%	6.0%	6.0%	6.0%
Electric Rates						
Demand:	15.0%	12.8%	3.4%	3.5%	3.6%	3.3%
Energy:	0.0%	0.0%	7.1%	6.9%	7.0%	7.0%
Other:	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%

Monthly Energy-Demand-Steam Requirements

	1	1.2	1	1	1.3
	Energy		Demand		Avg. Daily
Month	Base (MWH)	Chiller (MWH)	Base (MW)	Chiller (MW)	Steam (Lbs/Hr.)
January	2010	0	3.26	0	50,310
February	2010	0	3.70	0	38,454
March	2010	0	3.62	0	43,017
April	2010	205	3.62	0.97	31,863
May	2010	548	3.62	1.48	25,038
June	2010	1,190	3.62	2.6	18,681
July	2010	2,497	3.62	3.67	15,678
August	2010	1,970	3.62	3.57	15,678
September	2010	1,588	3.62	2.96	24,063
October	2010	707	3.62	1.41	28,509
November	2010	0	3.62	0.9	41,730
December	2010	0	3.62	0	53,469

CASH FLOW ANALYSIS ($1,000)

	EQUITY	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Benefits:																
Sale of Excess Energy		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Elec. Cost Savings																
Purchases w/o Cogen.		1,510.9	1,602.2	1,685.3	1,772.5	1,866.4	1,963.1	2,065.5	2,174.0	2,288.9	2,410.6	2,539.5	2,676.2	2,821.2	2,974.9	3,138.0
Purchases w/ Cogen.		1,033.7	1,093.9	1,151.7	1,212.4	1,277.7	1,345.2	1,416.7	1,492.5	1,572.8	1,658.0	1,748.2	1,844.0	1,945.6	2,053.3	2,167.7
Elec. Savings		$477.2	$508.4	$533.6	$560.1	$588.6	$617.9	$648.8	$681.5	$716.0	$752.6	$791.3	$832.3	$875.6	$921.6	$970.2
Gas Cost Savings																
Purchases w/o Cogen.		1,681	1,799	1,925	2,060	2,204	2,336	2,476	2,625	2,782	2,949	3,126	3,314	3,513	3,724	3,947
Purchases w/ Cogen.		271	290	310	332	355	377	399	423	449	476	504	534	566	600	636
Gas Savings		$1,410	$1,509	$1,615	$1,728	$1,849	$1,959	$2,077	$2,202	$2,334	$2,474	$2,622	$2,760	$2,946	$3,123	$3,310
Total Benefits		$1,887.4	$2,017.4	$2,148.2	$2,287.7	$2,437.2	$2,577.3	$2,725.8	$2,883.1	$3,049.8	$3,226.4	$3,413.5	$3,611.8	$3,822.0	$4,044.7	$4,280.7
Expenses																
Added Coal Purch.		$532.5	$524.5	$532.5	$569.8	$609.6	$652.3	$698.0	$739.9	$784.3	$831.3	$881.2	$934.1	$990.1	$1,049.5	$1,112.5
Op & Maint.		351.1	375.6	401.9	430.1	460.2	487.8	517.0	548.1	580.9	615.8	652.7	691.9	733.4	777.4	824.1
Insurance		69.7	73.9	78.3	83.0	88.0	93.3	98.9	104.8	111.1	117.8	124.8	132.3	140.3	148.7	157.6
Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Depreciation		973.5	1,427.8	1,362.9	1,362.9	1,362.9										
Income Taxes		(18.1)	(176.9)	(104.6)	(72.7)	(38.4)	618.2	649.5	685.6	723.8	764.3	807.2	852.6	900.8	951.8	1,005.8
Less Inv. Tax Credit		(618.1)														
Total (Accrual Method):		$1,290.6	$2,225.0	$2,271.0	$2,373.1	$2,482.3	$1,851.6	$1,963.4	$2,078.3	$2,200.1	$2,329.2	$2,466.0	$2,610.9	$2,764.5	$2,927.4	$3,100.0
Subtract Deprec.		(973.5)	(1,427.8)	(1,362.9)	(1,362.9)	(1,362.9)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Add Prin. Pmt.	6,181	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total (Cash Method	6,181	$317.1	$797.2	$908.1	$1,010.2	$1,119.4	$1,851.6	$1,963.4	$2,078.3	$2,200.1	$2,329.2	$2,466.0	$2,610.9	$2,764.5	$2,927.4	$3,100.0
Net Benefits																
Accrual Method		$596.9	($207.6)	($122.8)	($85.3)	($45.1)	$725.7	$762.4	$804.8	$849.7	$897.2	$947.6	$1,000.9	$1,057.4	$1,117.3	$1,180.7
Cash Method	($6,181)	$1,570.4	$1,220.2	$1,240.1	$1,277.6	$1,317.8	$725.7	$762.4	$804.8	$849.7	$897.2	$947.6	$1,000.9	$1,057.4	$1,117.3	$1,180.7
Present Value of Net Benefits																
Accrual Method		523.6	(159.8)	(82.9)	(50.5)	(23.4)	330.6	304.7	282.1	261.3	242.0	224.2	207.7	192.5	178.4	165.4
Cash Method	(6,181.0)	1,377.5	938.9	837.0	756.4	684.4	330.6	304.7	282.1	261.3	242.0	224.2	207.7	192.5	178.4	165.4
Total Accrual:	2,596.1															
Total Cash:	6,983.4															
Cum. Cash Flow		1,570.4	2,790.6	4,030.7	5,308.2	6,626.1	7,351.8	8,114.2	8,919.0	9,768.7	10,665.9	11,613.5	12,614.4	13,671.8	14,789.1	15,969.8
ccf/Equity		25.4%	45.1%	65.2%	85.9%	107.2%	118.9%	131.3%	144.3%	158.0%	172.6%	187.9%	204.1%	221.2%	239.3%	258.4%
Years Payback Comp		5000.0	5000.0	5000.0	5000.0	4.7	4.4	4.5	4.6	4.8	5.0	5.3	5.6	5.9	6.3	6.7
		0.0	0.0	0.0	0.0	4.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0