COMBINED-CYCLE POWER SYSTEMS BURNING LOW-BTU GAS

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Abstract

Future power systems will be required to burn coal in an environmentally acceptable manner. One of the most attractive advanced technology power systems is the combined gas turbine and steam turbine system, the combined cycle, which offers higher efficiency and lower capital costs than the more conventional steam system. These advantages will enable the combined-cycle system to be used in conjunction with expensive fuel treatment processes such as gasification and subsequent pollutant cleanup resulting in reduced emissions while producing electrical power at costs projected to be significantly less than conventional coal-fired steam plants with stack gas cleanup.

Decriptions of the gasification process, fuel gas cleanup and power systems are given with pertinent characteristics. The estimated emissions of the various systems are tabulated and the costs of the integrated gasification/power plant are compared with those for a conventional steam plant with stack gas cleanup.

INTRODUCTION

One of the major energy goals set by the present Carter Administration is that of increased use of coal in industrial and utility applications. Historically, coal usage has been increasing slowly, < 3 percent/yr, and by 1985 would reach approximately 800 million ton/year (Figure 1). By emphasizing the use of coal, it is projected that 1.1 billion tons/yr could be used. While it is not clear that this goal can be achieved, the utility industry has indicated that it will meet its obligations by increasing the demand for coal from 430 million tons/yr to 790 million tons/yr in 1985.

This increased use of coal must be done in an environmentally acceptable manner and, thus, between now and 1985, emphasis will be placed upon low-sulfur western coals and upon flue gas desulfurization. In the years beyond 1985, it is hoped that more efficient and less costly coal-burning power systems having lower emissions of SO_2 and NO_x will become commercially feasible. One of the most attractive of these advanced power systems is the combined gas turbine and steam turbine system (combined cycle) used in conjunctin with coal gasification and fuel gas cleanup which produce clean low-Btu gases, i.e., gases having heating values on the order of 1150 kcal/m^3 (1,000 kcal/kg, 130 Btu/ft^3).

To achieve the potential savings in capital and in fuel use, the power system and the fuel processing system must be closely integrated such as shown in Figure 2. In this power plant, air from the gas turbine is used in the coal gasifier while steam generated by cooling the hot fuel gas is used in the power system. Other configurations are possible including the use of oxygen rather than air in the gasifier and the use of a variety of cleanup systems.

During the past several years, under EPA auspices, United Technologies Research Center, in conjunction with Foster Wheeler Energy Corp., Fluor Engineers and Constructors and Hittman Associates, Inc., have investigated the technical, economic, and emission characteristics of power plants based upon a number of gasifier types with both low- and high-temperature sulfur cleanup systems and advanced technology combined-cycle systems. The current paper will describe only a two-stage, entrained-flow gasifier with both low-temperature and high-temperature sulfur cleanup used with a combined-cycle system having a 1425° C (2600° F) gas turbine.

POWER SYSTEM

The power system is of nominal 1000-MW size and consists of 4 advanced gas turbines generating a total of 720 MW and a conventional heat recovery steam system generating

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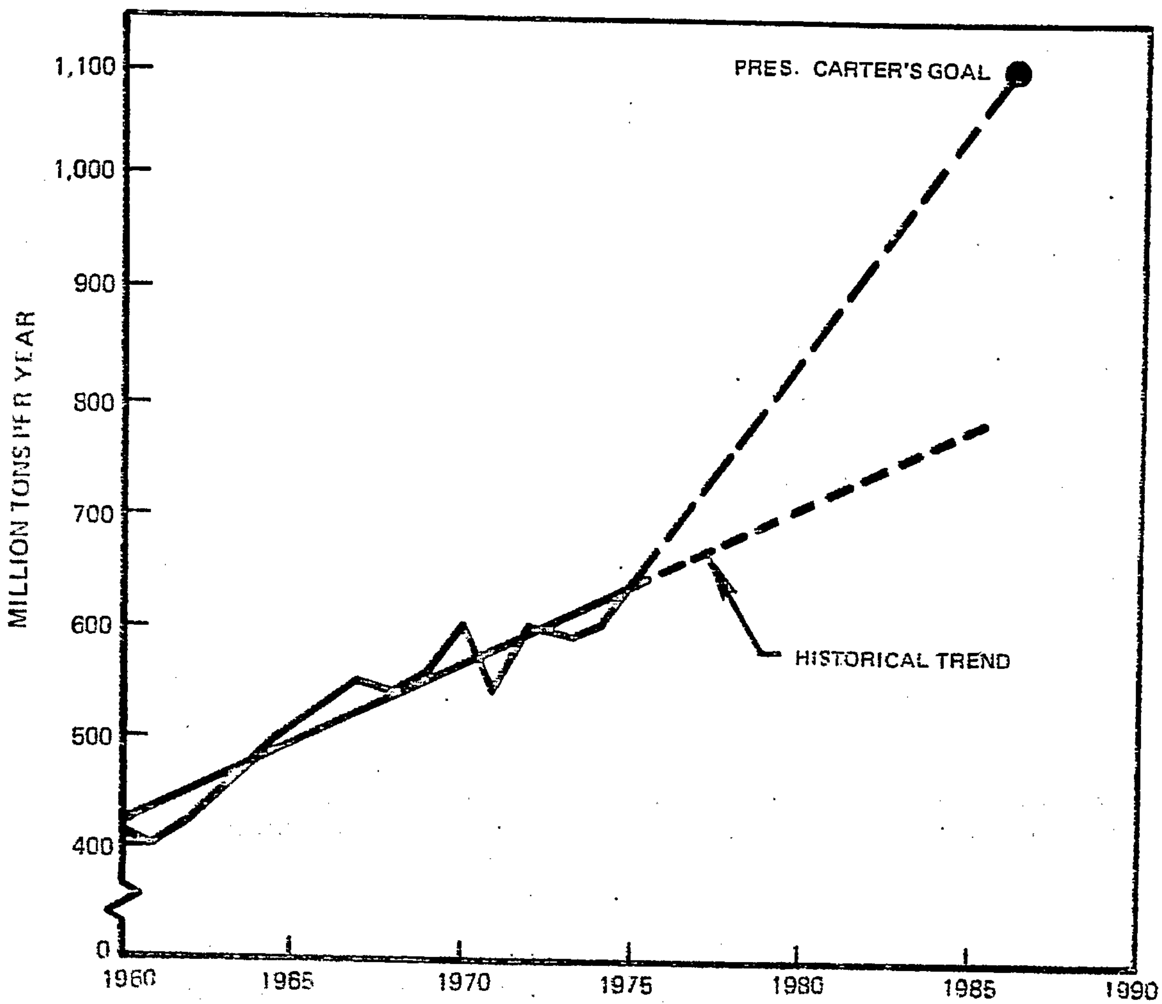

Figure 1. U.S. bituminous coal production.

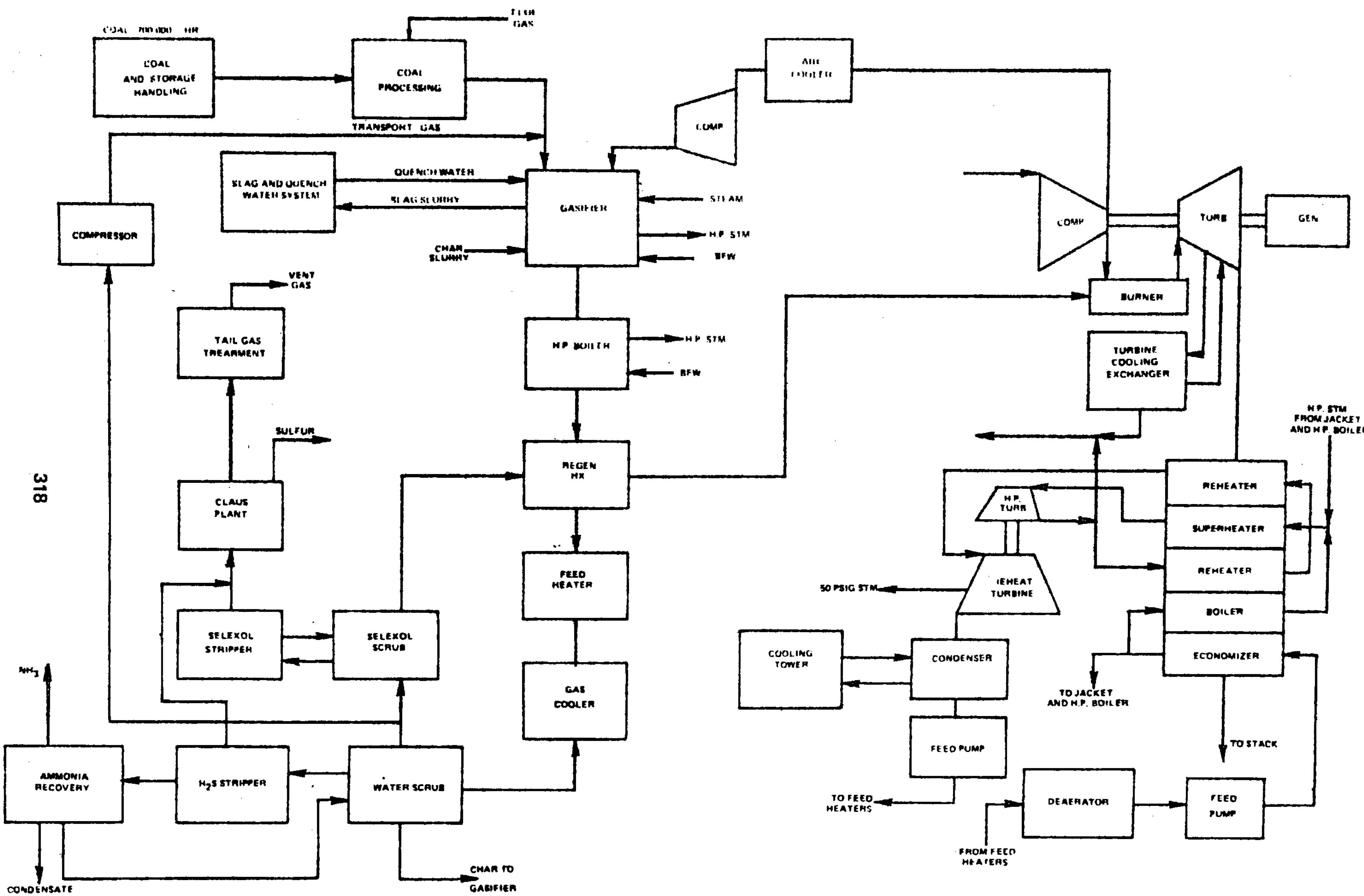

Figure 2. Air-blown BCR/Selexol

445 MW. The net output power (using low-temperature cleanup) is 1088 MW and the estimated overall efficiency, coal pile-to-busbar is 43.7 percent.

Gas Turbine

A number of studies [1,2,3] have indicated that the gas turbine portion of the combined-cycle system in the integrated coal gasification/power station must operate at temperatures of approximately 1325° C (2400° F) or above in order to achieve attractive overall efficiencies or heat rates. Prior UTRC work [3,4] has been based upon turbines of 1425° C turbine inlet with relatively high pressure ratios, e.g., 24:1. These turbines were assumed to have ceramic stators and other static structure requiring essentially no cooling combined with air-cooled rotating blades. While this projected use of ceramics results in attractive performance, a number of problems have been identified [5] and it is perhaps more realistic to identify a cooling scheme for the stators and other static structures which would require less development effort and which could be used in commercial service in the 1980's.

Current commercial engines operate in the 1000° C to 1100° C range with air-cooled stators and blades. However, when an air-blown gasifier is used, some 15-17 percent of the compressor discharge air is diverted to the gasifier and is unavailable for turbine cooling or combustion dilution. Thus, the use of another coolant medium such as water becomes advantageous. The gas turbine used in the present study is based upon advanced versions of large industrial turbines such as the prototype 100-MW UTC/Stal Laval FT50/GT200 (Figure 3), but using water-cooled static structures with air-cooled blades.

The major modification of the gas turbine resulting from the use of low-Btu fuel gas occurs in the combustor section. Because of the smaller amount of air available for cooling in systems using air-blown gasifiers, the combustor design must be one that minimizes the surface to volume ratio since this requires less coolant. The configuration which best fulfills the various requirements is the annular burner which resembles two concentric barrels surrounding the gas turbine between the compressor discharge and the turbine inlet (Figure 4).

A second combustor modification occurs in the fuel injector. Normal practice would have a single injector or perhaps several small injectors for each burner can. Because of the higher volume flow rate required for the low-Btu gas, much larger injector areas are necessary. Tests carried out by UTC and Texaco [6,7] have indicated that a premix injector, one in which the fuel gas and air are intimately mixed prior to combustion, would significantly lower the production of NO_x while lowering the peak temperatures within the burner can. Such a configuration is shown in Figure 4. The emissions characteristics of this combustor will be discussed in a later section.

Steam System

The steam system operates at conventional levels, i.e., 163 atm/510° C /510° C (2400 psi/950° F /950° F). While it would be possible to operate at throttle temperature of 535° C (1000° F), trade-off studies between heat exchanger size and materials versus small increases in performance indicate the lower temperature system would result in lower costs of electricity.

FUEL PROCESSING SYSTEM

The fuel processing system consisting of the coal gasifiers and the fuel gas cleanup system processes 317,460 kg/hr (700,000 lb/hr) of Illinois No. 6 coal into a clean fuel gas having a heating value of 1,584 kcal/m^3 (178 Btu/ft^3).

Although there is a wide variety of coal gasification processes currently under study, e.g., fixed-bed, entrained-flow, fluid-bed, and molten-bed, the present paper will emphasize only the entrained-flow gasifier. In particular, a two-stage gasifier based upon the Bituminous Coal Research, Inc., (BCR) BiGas design, but modified for air-blown fuel gas production by Foster Wheeler Energy Co., will be discussed.

Similarly, a number of low-temperature sulfur removal systems are commercially available which could be applied to the cleaning of fuel gas at low temperatures[3] i.e., < 120° C (250° F). However, only the Selexol physical

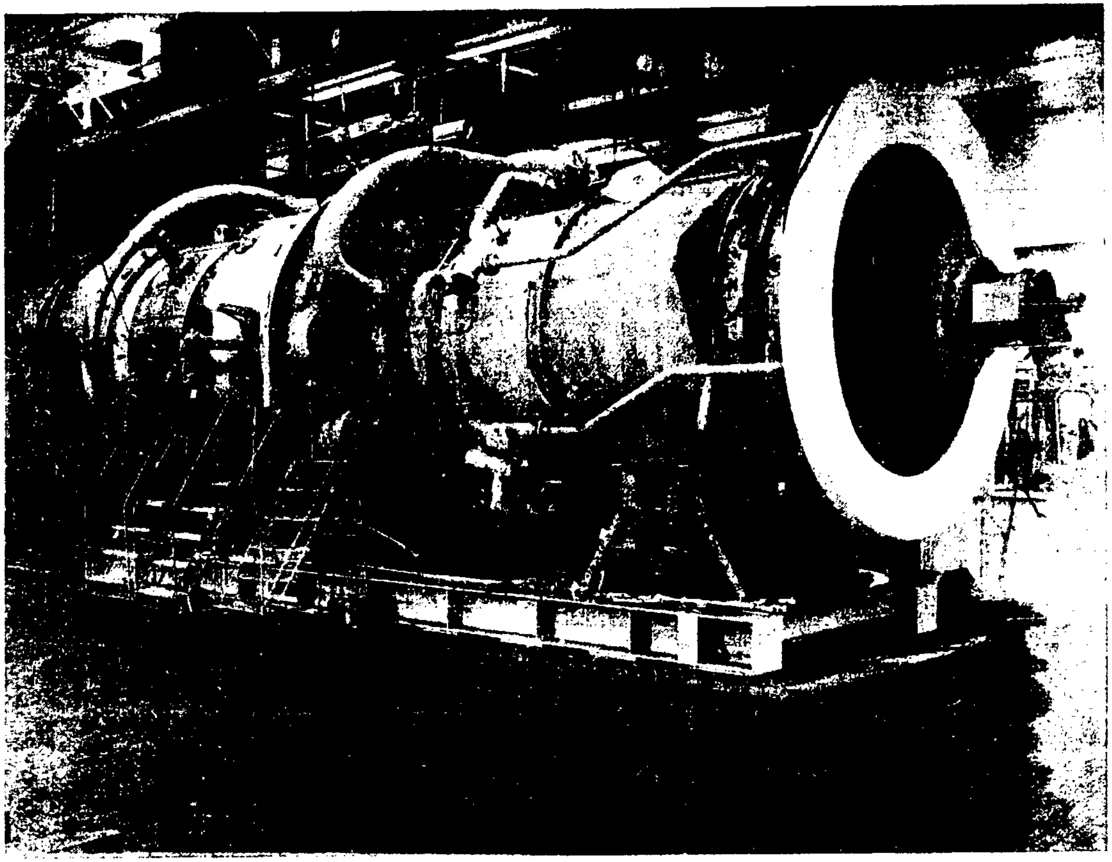

Figure 3. FT50 gas turbine.

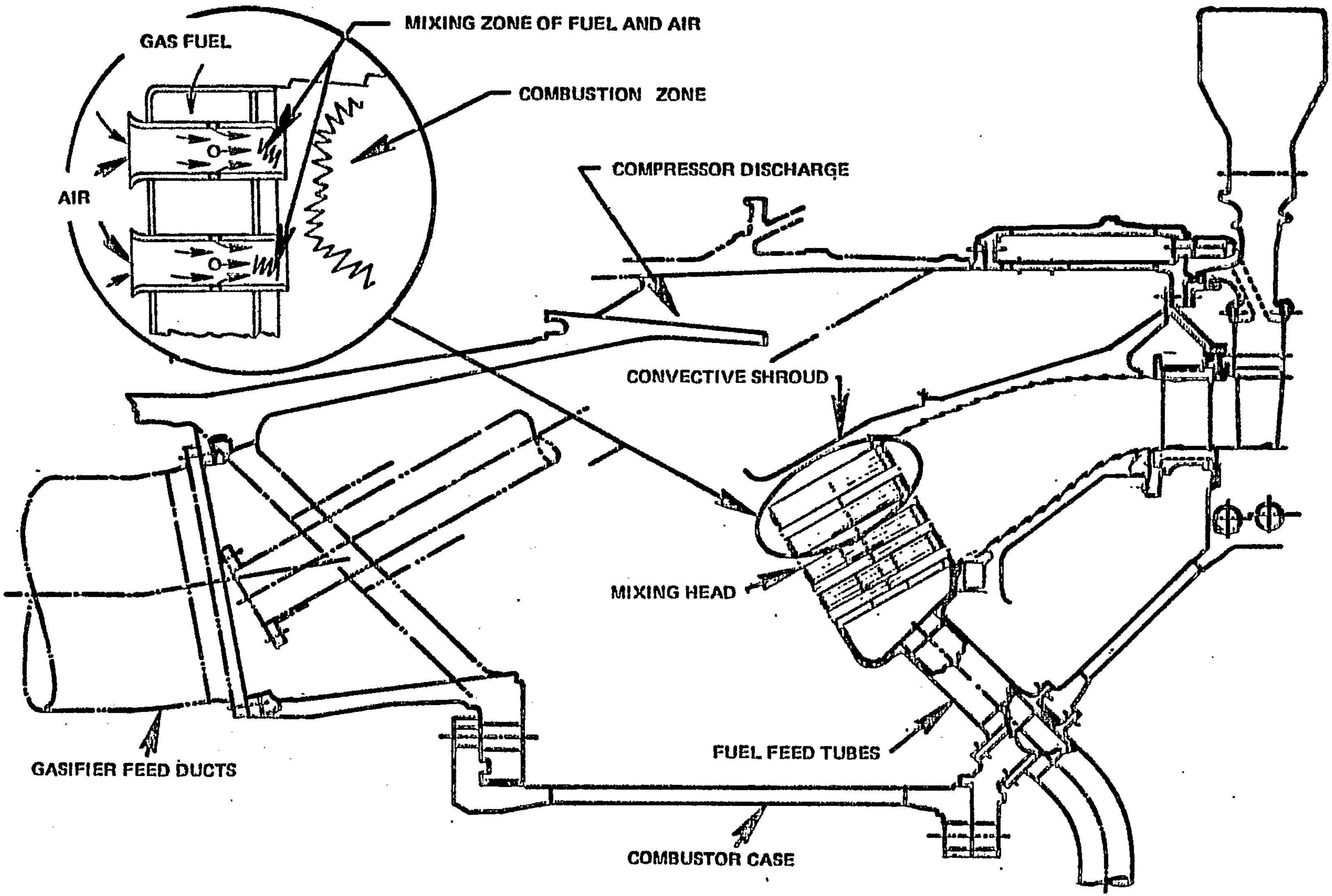

Figure 4. Potential pre-mix combustor layout.

absorbent process of the Allied Chemical Corporation will be discussed.

Although high-temperature sulfur cleanup processes are still in the laboratory-scale stage, they are potentially attractive from an overall power plant efficiency viewpoint. Thus, a calcium carbonate-based process developed by the Consolidation Coal Company, division of Continental Oil Corporation (CONOCO) will be described.

Coal Gasifier

A schematic of the two-stage, entrained-flow gasifier including the flow rates and operating parameters is given in Figure 5. In order to increase the efficiency of the system, the steam-to-coal ratio should be minimized since the energy in the steam consumed during gasification cannot be effectively recovered. A reduction in the steam consumption also enhances the performance of the high-temperature cleanup system as will be shown in a later section of this paper.

Fuel Gas Cleanup

The fuel gas coming from the gasifier must be cleaned not only to meet the EPA standards (Table 1), but also to meet restrictions set by the gas turbine. The latter are often more stringent as can be seen in Table 2.

Low-Temperature Cleanup - Many of the commercially available cleanup systems operate with comparable removal efficiencies

TABLE 1

EMISSION STANDARDS FOR COAL-FIRED POWER PLANTS

	Conventional Plant	Proposed gas turbines*
SO_2	0.57 kg/GJ (1.2 lb/10^6 Btu)	100 ppm
NO_x	0.33 kg/GJ (0.7 lb/10^6 Btu)	75 ppm
Particulates	0.047 kg/GJ (0.1 lb/10^6 Btu)	NA

* For all fuels and at ISO conditions with 15% O_2 in exhaust

and operating characteristics. The Selexol system selected for discussion uses a physical solvent having a high degree of selectivity for H_2S. A typical configuration for H_2S removal is shown in Figure 6. In those cases where the combination of coal and gasifier type results in significant quantities of COS, or when that component must be scrubbed to a low level, the solvent flow rate must be increased and a flash tank must be added along with a compressor to recycle the flashed gas to the absorber. While this increased flow minimizes the amount of CO_2 in the Selexol stripper off-gas, thereby benefiting the sulfur recover system, it adds to cost and utility requirements.

The absorber is generally run at temperatures slightly lower than ambient and, thus, requires some refrigeration. While this results in an in-

TABLE 2

GAS TURBINE REQUIREMENTS FOR FUEL GAS CLEANUP

	Low-Btu Gas	Typical Current Spec
Sulfur	0.05 Mol % or Less Than Amount to Form 0.6 ppm Alkali Metal Sulfate	< 1.0 Mol % or Less Than Amount to Form 5 ppm Alkali Metal Sulfate
Particulates	4 ppm Weight or 0.0012 gr/ft^3 > 2μ	30 ppm or 0.01 gr/ft^3
Metals		
Vanadium	< 0.003 ppm Weight See Sulfur Spec	< 0.02 ppm Weight < 0.6 ppm
Nitrogen	500 ppm as NH_3	

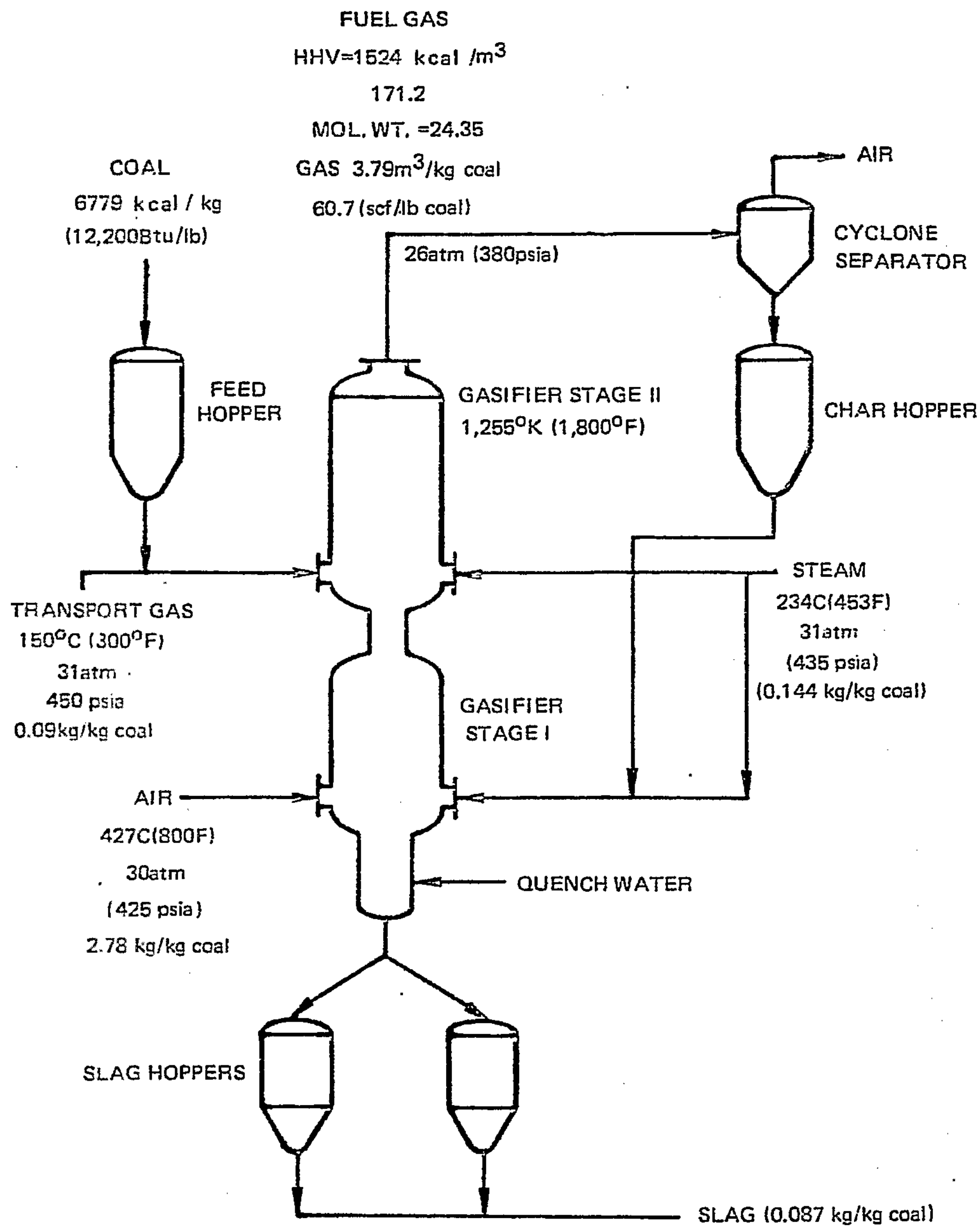

Figure 5. BCR entrained flow gasifier.

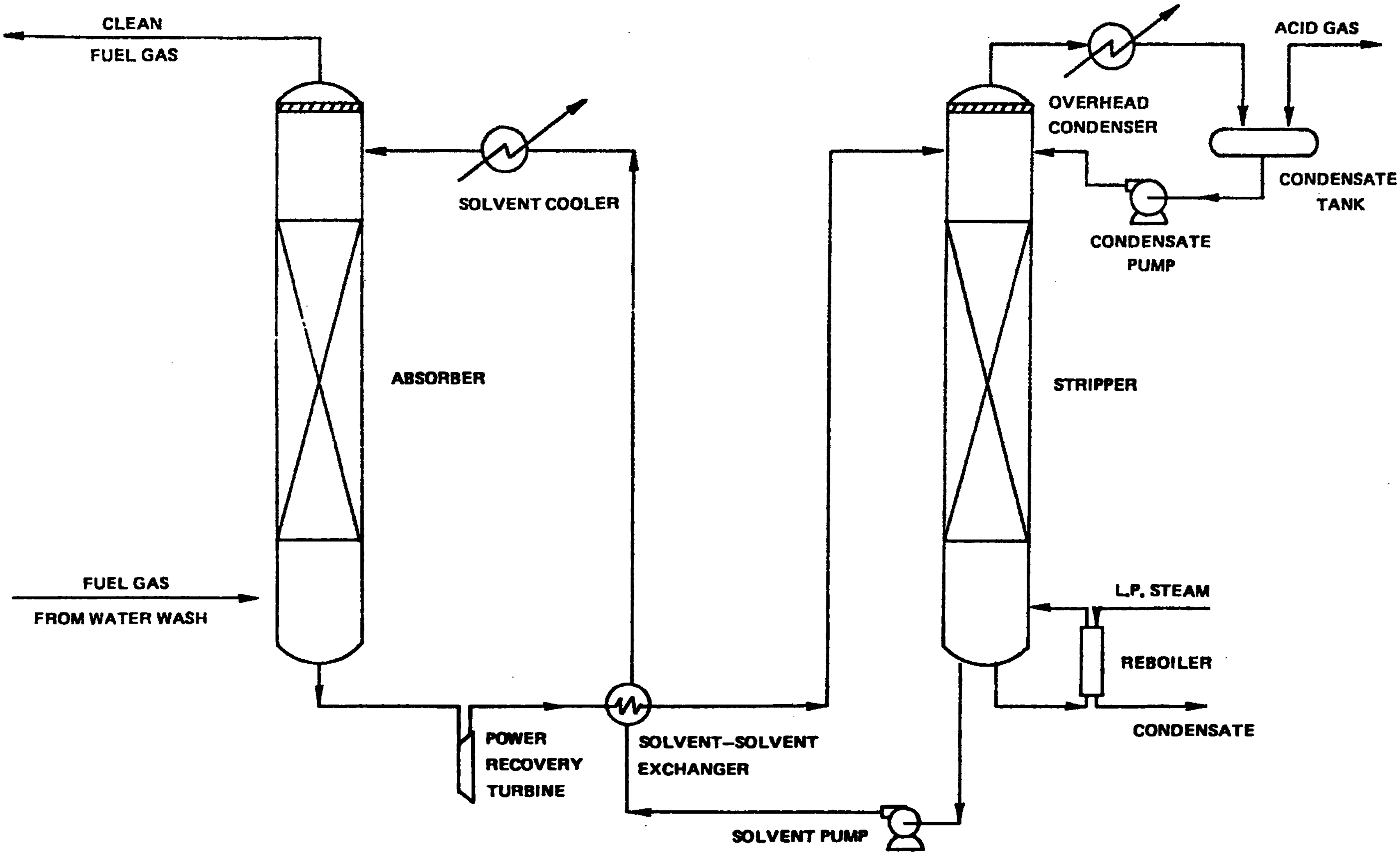

Figure 6. Selexol low-temperature desulfurization.

crease in power consumption over ambient absorber temperatures, solvent flow rate and therefore steam consumption and capital cost are less. The effect of operating temperature on utilities and cost is given in Table 3 for two different fuel gas compositions, one with a low COS concentration requiring only an H_2S-based design and the other with a significant amount of COS requiring a COS-based design. In each case, the differences clearly indicate that low-temperature operation is preferable.

For a Selexol desulfurization system operating with the BCR gasifier, a comparison of COS- and H_2S-based designs is given in Table 4. Both designs would result in emissions significantly less than current EPA regulations. The comparison in Table 4 gives an indication of the cost associated with the removal of sulfur to relatively low levels.

High-Temperature Cleanup - The high-temperature cleanup systems offer the advantage of providing a hot fuel gas directly to the gas turbine, thereby utilizing the fuel gas sensible heat in the topping cycle without the need for costly regenerative heat exchangers and without the losses associated with the heat exchange processes. As an example of one of the more attractive processes, the Conoco half-calcined dolomite process was selected for discussion. The desulfurizer operates at temperatures in the 850-900° C range. Both H_2S and COS react with the $CaCO_3$ component of the dolomite in a fluidized bed according to the following reactions:

$$(CaCO_3 \cdot MgO) + H_2S \rightarrow (CaS \cdot MgO) + H_2O + CO_2 \quad (1)$$

$$(CaCo_3 \cdot MgO) + COS \rightarrow (CaS \cdot MgO) + 2\,CO_2 \quad (2)$$

Regeneration of the sulfided acceptor is accomplished in a fluidized reactor at 700° C using a stream of carbon dioxide and water vapor. Makeup dolomite is supplied at 2 percent of the recirculation rate. A schematic of the process is shown in Figure 7. It includes a liquid-phase Claus plant as well as a converter for the spent dolomite.

The desulfurizer reactions are reported to be virtually at equilibrium and performance improves with increased temperature and decreased concentration of the reaction products, CO_2 and H_2O. Temperature is limited by CO_2 partial pressure which must be high enough to prevent calcination of the acceptor. For the BCR gasifier, desulfurization performance at two possible operating conditions is shown in Table 5. The primary difference between the two cases is the steam-to-coal ratio. At the lower ratio, oxidant feed is re-

TABLE 3

LOW VS. AMBIENT-TEMPERATURE SELEXOL OPERATION

	Equipment Designed for H_2S Removal		
	Ambient-Temperature	Low-Temperature	Δ
Steam - kg/hr	114,545	48,273	66,272
Net Power - kW	4,270	17,400	13,000
Cost - $\$10^6$	26	16	10

	Equipment Designed For COS Removal		
	Ambient-Temperature	Low-Temperature	Δ
Steam - kg/hr	345,454	138,636	206,818
Net Power - kW	25,530	38,940	13,400
Cost - $\$10^6$	72.6	47	25.6

NOTE: This data should not be used to compare H_2S vs COS removal.

TABLE 4

COMPARISON OF H_2S AND COS BASED DESIGNS

BCR-TYPE GASIFIER-SELEXOL CLEANUP PROCESS

	H_2S-Based Design	COS-Based Design
H_2S in clean gas-ppm	38	13
COS in clean gas-ppm	447	52
Emissions $KgSO_2/GJ$	0.186	0.0252
Power - kW	20,400	39,500
Steam - kg/hr	59,773	153,500
Cost - $\$10^6$	26.3	53.8

Based on coal feed rate of 317,460 kg/hr and low-temperature absorbent.

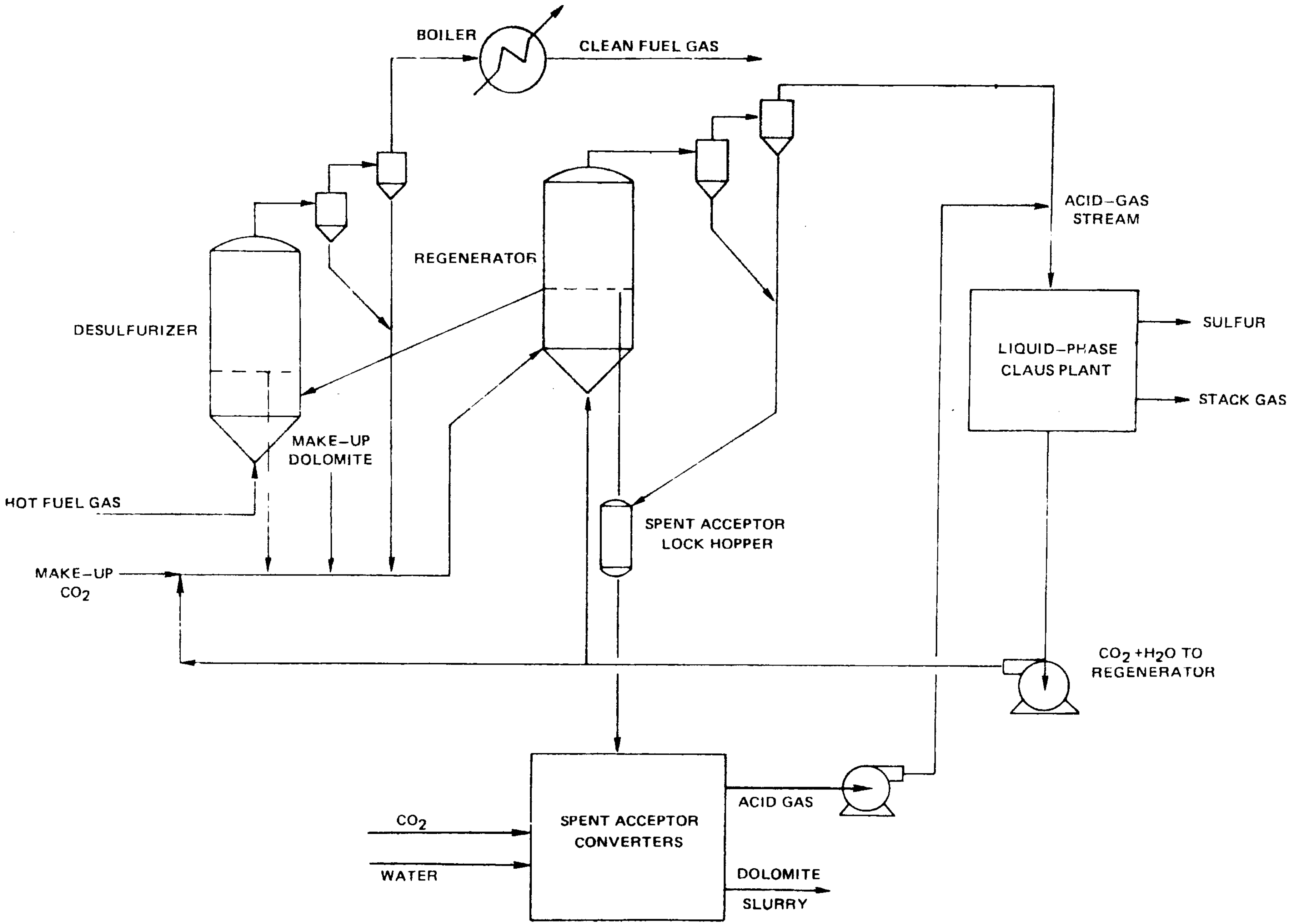

Figure 7. Conoco high-temperature desulfurization.

TABLE 5

EFFECT OF STEAM/COAL RATIO ON CONOCO DESULFURIZATION

	High Steam/Coal Ratio		Low Steam/Coal Ratio	
	Desulfurizer In	Desulfurizer Out	Desulfurizer In	Desulfurizer Out
CH_4-Mol/hr	5099.5	5099.5	3775.0	3775.0
H_2	18538.8	19270.9	15314.9	15894.5
CO	25582.2	24851.3	32189.6	31610.0
CO_2	11669.7	13289.7	3396.1	4863.4
H_2S	685.7	68.7	751.0	9.5
COS	143.5	8.6	75.6	2.5
NH_3	609.0	609.0	478.8	478.8
N_2	65634.5	65634.5	53753.3	57353.3
H_2O	14338.1	14222.4	2212.6	2374.5
	142301.0	143054.5	111946.9	112762.5
Steam/Coal Ratio	.567	.144		
Desulfurizer Temperature - C	.927	815		
Sulfur as SO_2 - kg/GJ	.27	.042		

duced to maintain a fixed gasifier temperature and both CO_2 and H_2O concentrations are quite low. The net result is a marked reduction in both. H_2S and COS concentrations in the clean gas. Fortunately, reduced steam feed rates have a favorable effect on both power conversion efficiency and sulfur removal.

Because the fuel gas would not be cooled, a water wash for the removal of ammonia and particulates is not feasible. Therefore, other provisions for handling these constituents must be made. In the case of particulate matter, the sensitivity of turbine materials and coatings dictates a very high degree of removal. Thus, the use of high-temperature desulfurization is contingent on the development of a high-temperature and high efficiency particulate removal device. Such a device will undoubtedly be used in conjunction with conventional cyclones as a "final filter." Several filtration type devices are under development using various concepts such as a porous metal or a sand bed.[5]

Ammonia presents a somewhat different problem in that it can either be removed prior to being burned in the gas turbine or it may be possible to modify the combustor to provide an environment where it will be decomposed to N_2 and H_2. Conventional burners will convert as much as 80 percent of the NH_3 to NO which makes some type of removal system or combustor modification necessary.[3]

EMISSIONS

The emisions from the integrated gasification combined-cycle offer the potential to be significantly lower than those from conventional steam systems with FGD.

Sulfur Oxides

Previous discussion has indicated that the amount of fuel sulfur compounds (H_2S and COS) removed during cleanup is a function of several variables such as type of cleanup, operating temperature, etc. However, no matter which cleanup system is used, the emissions of SO_2 are well below the current regulation for coal-fired steam system (See Figure 8) and below the levels usually removed during flue gas desulfurization.

On the basis of emissions per unit of output (kg/kWhr), the integrated gasification/

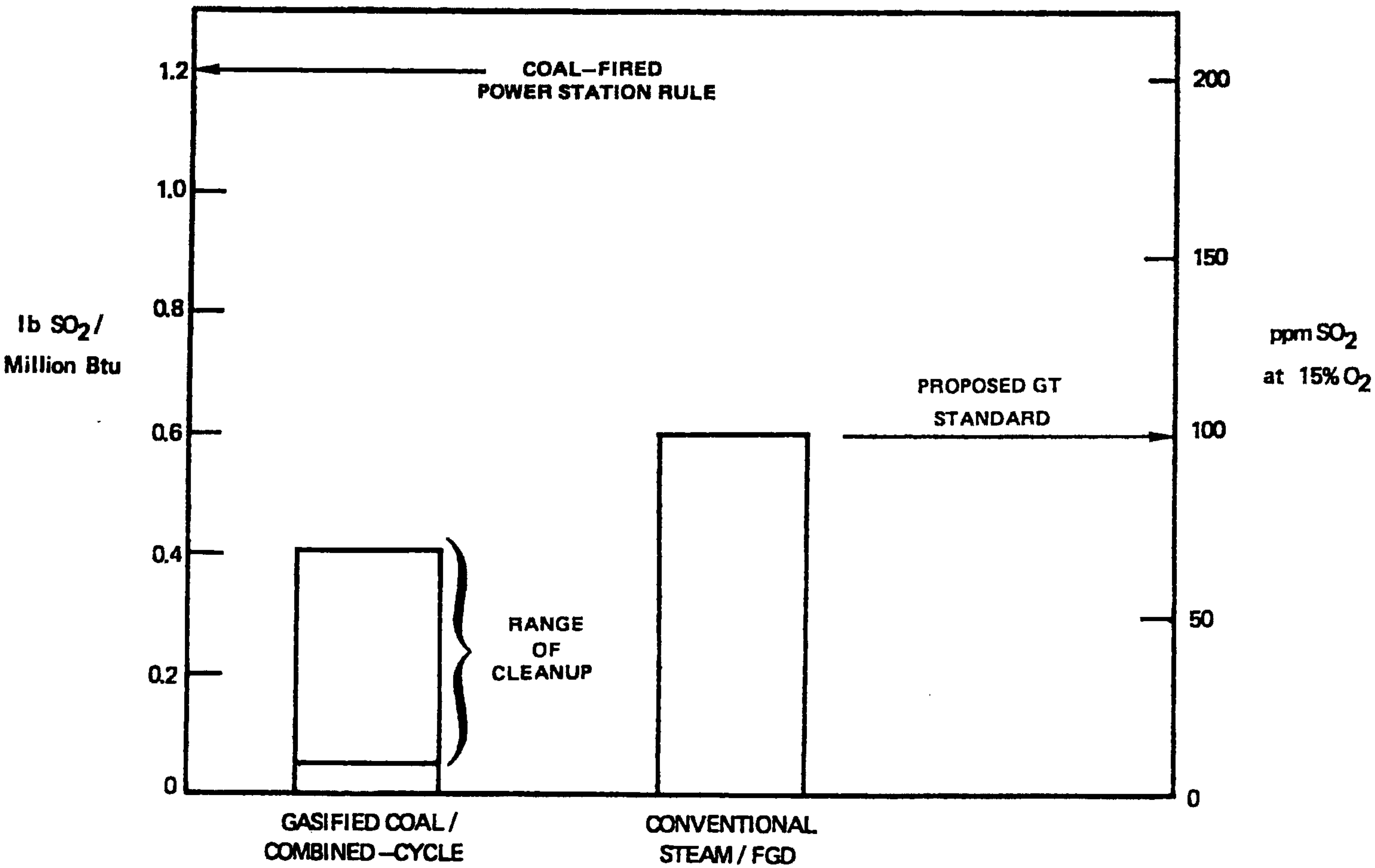

Figure 8. SO_2 emissions.

combined-cycle system would emit between 2.1 and 13.7 × 10^{-4} kg/kWhr versus 27.5 × 10^{-4} kg/kWhr for conventional steam with a 90 percent effective FGD system.

Nitrogen Oxides

The formation of nitrogen oxides results from two sources; thermal NO_x from the oxidation of atmospheric nitrogen at high temperature during combustion, and NO_x from the oxidation of nitrogen compounds in the fuel. Thermal NO_x can be controlled by combustors such as that previously described. Estimates of emissions of thermal NO_x are given in Figure 9.

Unfortunately, it is difficult to estimate the NO_x which could result from fuel-bound nitrogen in low-heating value fuel gases. The amount of nitrogen compounds, usually expressed in terms of ammonia, vary as a function of gasifier type and operating temperature. It is possible to remove a very large fraction of any ammonia in the fuel gas by water wash and in the H_2S removal system which may have some affinity for fuel-bound nitrogen compounds. Thus, with low-temperature systems it is possible to remove the major portion of the nitrogen prior to combustion.

Some consideration has been given to combustor modifications[9] which might be made to reduce the emissions due to fuel-bound nitrogen. At this time, this type of combustor modification would appear to result in combustor configurations which would not be practical for use in advanced combined-cycle systems.

COST OF ELECTRICITY

Overall generating costs are affected primarily by capital and fuel costs and by performance. In the case of low-Btu gasified coal power systems, performance affects the capital cost as well as the fuel cost contribution to overall cost. For a fixed coal feed rate, improved performance means that the capital cost of the fuel processing section can be spread over a greater number of installed kilowatts. As mentioned earlier, continued analyses and small-scale experimentation have led to reduced estimates for steam feed rates to the gasifier. The effect of a reduced steam-to-coal feed ratio and reevaluation of the transport gas requirements are shown in Table 6. The net improvement in gasifier performance is on the order of 6 percent. As an additional benefit, the heat previously required to raise gasifier steam would now be utilized in the power system.

The busbar generating efficiencies of the overall systems are estimated to be 43.7 percent for the low- and 45 percent for the high-temperature cleanup system. Table 7 gives the net power produced, capital cost, and generating costs for the two systems. The costs are based on previous studies[3,4] and are currently being updated. However, it presently appears that there should be little difference. This comparison of high- and low-temperature cleanup shows a lesser difference than did earlier studies. The improvement in gasifier performance, especially the reduced quantity of water vapor in the fuel gas, results in a marked increase in the low-temperature system performance. The high-temperature system, which

TABLE 6

EFFECT OF STEAM/COAL RATIO

Component	High Steam Feed Rate Mol%	Low Steam Feed Rate Mol%
CH_4	3.65	3.37
H_2	12.88	13.68
CO	18.38	28.75
CO_2	8.26	3.03
H_2S	0.48	0.67
COS	0.10	0.07
N_2	46.04	48.02
NH_3	0.4	0.43
H_2O	9.81	1.98
Other Characteristics		
HHV-kCal/m^3	1228	1524
Air/ Coal Ratio	3.09	2.78
Steam/ Coal Ratio	.567	.144
Transport gas/ Coal Ratio	.426	.088
Cold Gas Eff.	78.5%	83%

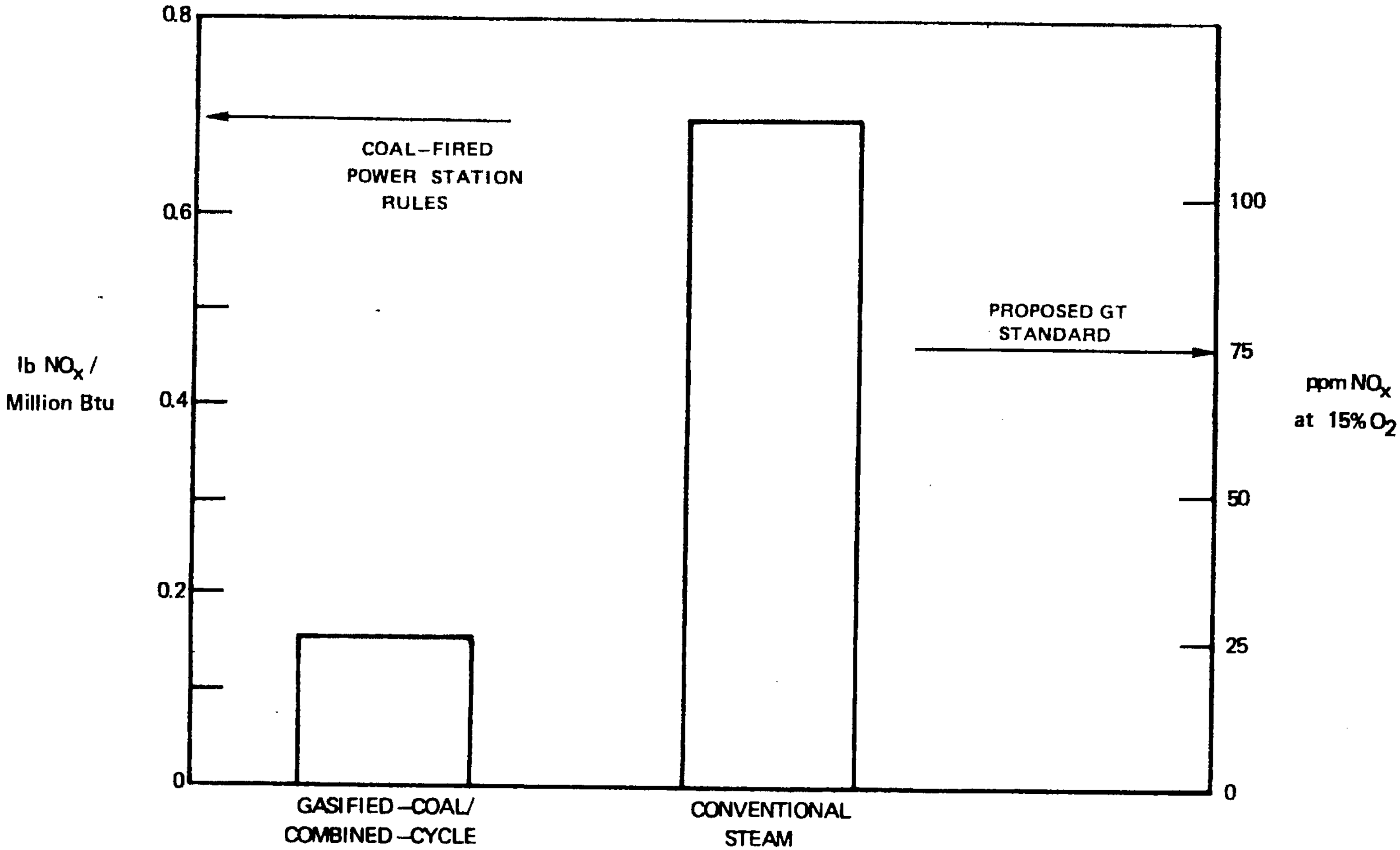

Figure 9. NO_x emissions.

does not require cooling and reheating of the fuel gas, does not benefit from the reduced steam feed rate to the same extent.

The costs for the steam station are those associated with a twin 500-MW station (957-MW net output) with limestone FGD. The cost of power shown in Table 7 is approximately 15 percent higher than for the integrated gasification/combined-cycle systems.

The potential attractiveness of the relatively simple fuel processing section and the somewhat lower generating costs associated with the high-temperature process are predicated on the availability of a high-temperature particulate removal device and also on a gasification system that will produce low levels of ammonia in the fuel gas. It is hoped that efforts will continue in those areas.

SUMMARY

The integration of the combined-cycle power generating system with a pressurized air-blown gasifier makes it possible to economically remove sulfur compounds prior to combustion. The majority of the sulfur in the fuel gas appears as H_2S at a relatively high partial pressure, thus making possible the use of physical as well as chemical sorbents.

In addition to being at pressure, the total gas flow rate through the desulfurization process is reduced by more than a factor of two when compared to the flue gases from a coal-fired boiler. Thus, for a gas turbine cycle having a pressure ratio of 16:1, the cleanup system volumetric flow rate is reduced by over 32:1 when compared to a flue gas desulfurization system.

As a result of the high-pressure operation, high removal efficiency is possible. Also, most processes produce an acid gas stream that is rich in H_2S thereby providing an excellent feed to a Claus sulfur recovery plant.

The capital costs associated with sulfur cleanup also appear to favor the integrated system. For example, estimates of the fuel gas cleanup and sulfur recovery system costs show that for a removal effectiveness of approximately 94 percent, the associated cost per lb/hr of S removed is $1075; for over 99-percent removal, the cost is $2070. In comparison, the costs for 90 percent effective flue gas desulfurization systems are $2600 lb/hr of S for limestone slurry[10] and $10,000 lb/hr of S for citrate[11] systems. None of the foregoing include credit for sulfur recovery or costs for offsite waste disposal.

While sulfur removal costs do not tell the whole story, they are indicative of overall power costs; e.g., estimates of busbar costs for the advanced combined-cycle systems[4,12]

TABLE 7

PERFORMANCE AND COST SUMMARY

	BCR-Selexol Low-Temp	BCR-Conoco High-Temp	Conventional Steam FGD
Gasifier & Cleanup System Cost - $	231,300,000	210,800,000	94,000,000
Power System Cost - $	285,300,000	296,500,000	415,400,000
Total Cost - $	516,600,000	507,300,000	509,400,000
Net Plant Output - MW	1088	1126	957
Overall Plant Efficiency - %	43.5	45.0	36.5
Generating Costs - mills/kwh			
Owning Costs	13.2	12.5	14.7
Operation and Maintenance	4.4	4.1	4.0
Fuel ($1.00/MMBtu)	7.8	7.6	9.6
Total Generating Cost - mills/kwh	25.4	24.2	28.3

are as much as 15 percent lower than that of a conventional steam plant with limestone FGD.

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