Economics of Retrofitting Power Plants for Coal-Derived Medium-Btu Gas

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Technical Planning Study TPS 78-773

Final Report, October 1979

Prepared by

BECHTEL NATIONAL, INC.
50 Beale Street
P.O. Box 3965
San Francisco, California 94119

Prepared for

Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, California 94304

EPRI Project Managers
Michael J. Gluckman
Edwin L. Force
Fossil Fuel and Advanced Systems Division

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NOTICE

Prepared by
Bechtel National, Inc.
San Francisco, California

ABSTRACT

Capital and operating cost estimates have been prepared for "over-the-fence" retrofitting of existing 500 MWe power plants to burn medium-Btu gas derived from developmental-stage, second-generation, oxygen-blown coal gasification processes. The economics of the retrofit installations, including the complete gasification system costs, have been compared to those of a reference power plant defined as a new, grass-roots, conventional coal-fired boiler facility equipped with flue gas desulfurization.

The two types of power plants selected for retrofit are representative of relatively new (1) natural-gas-fired boiler plants and (2) oil-fired combined-cycle units. The reference power plant contains two 500 MWe coal-fired units typical of current new installations.

The two oxygen-blown coal gasification systems evaluated for each retrofit were the Texaco process and the Combustion Engineering process. Neither of these gasification processes has been demonstrated at the commercial scale used in this study. Each coal gasification system was treated as a completely separate, self-contained facility supplying medium-Btu fuel gas to an adjacent existing power plant.

With coal priced at $1 per million Btu, busbar power costs ranged from 37.6 to 42.3 mills per kilowatt-hour for the retrofit plants and were 38.5 mills per kilowatt-hour for the reference coal-fired boiler plant. It is concluded that further study of these retrofit options is warranted. Actual implementation of any of the retrofit designs described in this study must await commercial demonstration of the particular coal gasification process.

EPRI PERSPECTIVE

PROJECT DESCRIPITON

This final report, Economics of Retrofitting Power Plants for Coal-Derived Medium-Btu Gas, presents the results of a technical planning study performed by Bechtel National Inc., as a preliminary investigation of the economic merits of "over-the-fence" retrofitting of existing 500-MWe power plants with developmental-stage, second generation coal gasification systems. In the "over-the-fence" retrofit mode, an existing oil-fired or natural-gas-fired power plant is converted to use a medium-Btu fuel gas supplied from a dedicated, self-supporting coal gasification unit located on an adjacent site. The "over-the-fence" mode represents a simple retrofit option in that no attempt is made to integrate the steam, condensate, and boiler feed water systems in the power plant with similar systems in the coal gasification unit.

With the recent passage of the Fuel Use Act (FUA), retrofitting of power plants with coal-derived fuel has become an important consideration for the utility industry. Construction of large new generating units based on petroleum or natural gas fuel is prohibited by the FUA unless a specific exemption is obtained. Since a future capability to use coal-derived synthetic fuel constitutes acceptable grounds for requesting an exemption from the FUA, individual utilities could be permitted to construct presently needed oil-fired or natural-gas-fired generating plants based on provisions for retrofitting these units with medium-Btu gas once the necessary coal gasification processes have been demonstrated on a commercial scale.

PROJECT OBJECTIVES

A major objective of this study was to develop preliminary analyses of both overall thermal efficiency and economics for retrofitting relatively new natural-gas-fired boiler plants and oil-fired combined-cycle units with medium-Btu gas produced by coal gasification. Two oxygen-blown gasification systems, the Texaco process and the Combustion Engineering (C-E) process, were chosen for retrofitting each of the foregoing types of power plants. Both of these developmental-stage processes have the potential for commercialization in the mid-to-late 1980s. Since EPRI is currently supporting pilot plant studies of both the oxygen-blown Texaco gasifier and the air-blown version of the C-E gasifier, an additional goal of this study was to use the resulting analyses as inputs in planning future experimental research programs. A final objective of the study was to compare the economics of the individual retrofit cases with the "benchmark" costs for construction of a new, 1000-MWe (two 500-MWe units), conventional coal-fired boiler plant equipped with flue gas desulfurization.

PROJECT RESULTS

Bechtel has developed overall thermal efficiencies and economics for a total of four retrofit cases. Two of these cases involve retrofitting of an existing 500-MWe natural-gas-fired boiler plant with Texaco and C-E gasification systems. The remaining two cases were based on retrofitting of an existing 600-MWe oil-fired combined-cycle unit with the same two gasification systems. Bechtel was involved in the original design and construction of the existing power plants used in this study. Each of these existing power plants is less than six years old and has both rail access and adequate site area to accomodate coal storage, coal handling, and the facilities required for retrofit. The absence of the required additional site area may preclude consideration of the retrofit option for certain existing power plants even after commercialization of the necessary coal gasification technologies.

Owing to the preliminary nature of this study, the bulk of the process data and cost information for the two developmental-stage gasification systems was drawn directly from previously published EPRI reports (AF-244, AF-642, and AF-782). Gasification process plant sizes and costs were scaled and updated as required to fit the individual cases. Additional process systems were added where necessary to provide totally self-supporting gasification plants. Information on the "benchmark" conventional 1000-MWe coal-fired boiler plant was derived from Bechtel experience as summarized in EPRI report AF-342. The estimated total plant investment for this "benchmark" unit is thought to be conservative by as much as 15%. Actual installed costs for 1000-MWe coal-fired boiler plants will vary depending upon factors such as siting considerations and specific requirements of individual utilities.

The tabulated economic comparisons in the report show that the power costs for the retrofit cases are generally competitive with the cost of electricity from the "benchmark" coal-fired plant. Bechtel has therefore concluded that further engineering and economic studies of gasification-based retrofit options are warranted. Development of this general conclusion regarding retrofitting satisfies a major objective of the study.

Examination of the results for the two natural-gas-fired boiler plant retrofit cases shows that the oxygen-blown C-E gasification process has an advantage over the Texaco process in terms of both cost and thermal efficiency. This result is not surprising since the atmospheric pressure C-E process provides a natural match with a boiler plant also operating at near-atmospheric pressure. In contrast, the Texaco process has the advantage in an oil-fired combined cycle retrofit application. The high (600 psig) operating pressure of the Texaco gasification process precludes the need for additional fuel gas compression upstream of the gas turbine combustor.

Heat rates for the four retrofit cases ranged from 1606 to 3099 Btu/kWh higher than the heat rate for the "benchmark" plant. Low thermal efficiency is therefore a specific characteristic of the "over-the-fence" retrofit mode. Power costs for the four retrofit cases are competitive with those for the "benchmark" plant as a result of lower total capital requirement (lower fixed charges). Future studies of additional retrofit options should therefore concentrate on improving thermal efficiency with minimum increase in capital cost.

On the basis of the results of this preliminary study, it is recommended that:

- Further engineering and economic studies be conducted on additional retrofit options.
- Retrofit study emphasis should be placed on thermal efficiency improvement through heat integration and repowering options.
- Consideration should be given to accelerating the development of the oxygen-blown version of the C-E coal gasification process for future retrofit applications.

E. L. Force, Project Manager
M. J. Gluckman, Program Manager
Fossil Fuel and Advanced Systems Division

CONTENTS

ILLUSTRATIONS

TABLES

SUMMARY

Capital and operating cost estimates have been prepared for "over-the-fence" retrofitting of two types of existing power plants to burn medium-Btu (300 Btu/scf) gas produced by coal gasification. These existing power plant types include relatively new natural-gas-fired boilers and oil-fired combined-cycle units having a nominal generation capacity of 500 MWe. Economics of the retrofit installations have been compared with costs for a reference plant defined as a new, grass-roots, conventional coal-fired power plant equipped with flue gas desulfurization.

A major goal of this preliminary study was to assess the economic potential of one option for future use of second-generation, oxygen-blown, coal gasification processes in a power plant retrofit application. Consequently, the two gasification systems used herein are both based on developmental-stage processes which have yet to be demonstrated on a commercial scale. Implementation of an actual "over-the-fence" retrofit project based on either of these processes must await a commercial-scale demonstration of the gasification system.

The "over-the-fence" retrofit concept requires that the new coal gasification system be self-supporting with respect to the power plant. No integration of steam, BFW, or other common systems is employed except that electric power may be imported or exported by the gasification system as required. Economic evaluations contained in this study include both the costs of the new, self-supporting gasification systems and the costs of retrofitting the existing power plants to burn the coal-derived medium-Btu gas as fuel.

GASIFICATION PROCESSES

EPRI specified two oxygen-blown coal gasification processes for inclusion in this study. These gasification systems, which had been studied previously by EPRI, are:

Technology	Pressure	Developer	Reference EPRI Report
Entrained Bed	Atmospheric	Combustion Engineering	AF-244(1) AF-782(2)
Entrained Bed	600 psig	Texaco	AF-642(3)

Although neither of these gasification processes has been proved in commercial operations, they both represent technologies which have a potential for commercialization sometime in the mid-to-late 1980's. The process currently under development by Combustion Engineering is a two-stage, air-blown system which was conceptually adapted to the oxygen-blown mode for the study contained in EPRI Report AF-244. The process offered by Texaco Development Corporation is an oxygen-blown, single-stage system. The Texaco process has been well proven in commercial operations on residual oil, but has not been demonstrated at commercial scale on coal. The gas produced by the Combustion Engineering process has an HHV (dry basis) of 312 Btu/scf, while the Texaco system yields gas with an HHV (dry basis) of 290 Btu/scf. The product fuel gas is delivered to the boiler plant at a pressure of 15 psig and to the combined-cycle plant at 245 psig.

It was necessary to extract technical and economic data from the previously referenced EPRI reports and modify this information to fit the present study. Neither the scope nor the budget for this study included provisions for checking or recalculating the capital costs contained in any of the cited EPRI reports. The only adjustments made were to scale the costs as necessary to meet plant size and other criteria for the retrofits including coal feed rate, gas delivery pressure, and product gas reheating. A standard, exponential, capacity-ratio-based method was used for capital cost scaling. Capital cost estimates were also developed for additional equipment which was added to each gasification system as necessary for the particular retrofit application.

Based on the process information contained in the referenced reports, new complete grass-roots plants were provided for both gasification systems to convert Illinois No. 6 coal to medium-Btu gas meeting the requirements of the retrofit boiler plant and retrofit combined-cycle unit. The self-contained gasification facilities are capable of meeting current environmental restrictions for an Illinois plant location, including SO_2 emissions from the gasification plants, power plants, and associated systems. The Combustion Engineering (C-E) plant described in the referenced EPRI Report AF-244 is a self-supporting, medium-Btu gas-producing system (Case EXL). Relatively minor rework was necessary to adapt Case EXL for the two C-E retrofit cases. However, the Texaco plant presented in EPRI Report AF-642 is a grass-roots, integrated gasification-combined-cycle system (Case EXTC). Extensive modifications of the Case EXTC steam balance were required to adapt this system to the two Texaco retrofit cases. Details of the gasification process are presented in Sections 3 and 4 of this report.

EXISTING POWER PLANTS

The existing power plants utilized in this study are each rated at approximately 500 MWe and are believed to be representative of relatively new natural-gas-fired power plant boilers and oil-fired combined-cycle units. The combined-cycle power plant is three years old, and the gas-fired boiler plant is five years old. The units selected have ample land area available to accommodate the installation of the equipment and gasification facilities required for the retrofit, including coal unloading, storage, and handling, and ash disposal. Details of the power plant retrofits are given in Sections 5 and 6 of this report.

REFERENCE PLANT

To permit meaningful economic comparison of the results from retrofitting the existing power plants described above, a reference power plant was established. This reference plant is defined as a new, grass-roots, conventional, coal-fired power plant facility. The reference plant contains two 500 MWe coal-fired units which were used as a basis for determining unit capital requirements and electrical generating costs.

The capital costs for the coal-fired reference plant were based on estimates contained in EPRI Report No. AF-342, titled "Coal-Fired Power Plant Capital Cost Estimates." Operating costs for the reference plant were estimated by Bechtel in accordance with standard industry practice and in compliance with guidelines supplied by EPRI. Details of the reference plant are given in Section 7 of this report.

DISCUSSION OF RESULTS

Several different options are available for achieving the conversion of existing natural-gas-fired or oil-fired power plants to coal or coal-derived gas. For example, medium-Btu gas might be obtained "over-the-fence" from a large central gasification facility supplying several users in close proximity to the facility. This option has the advantage of large-scale gas production enabling lower gas costs. Another option might be to close-couple a smaller gasification plant directly to the power plant, if space is available, rather than providing an "over-the-fence" supply. Possible advantages of close-coupling would be integration of steam and BFW systems to yield a higher overall thermal efficiency than that obtainable in an "over-the-fence" retrofit mode.

Although the above-described options could be considered, the following limiting assumptions were applied for purposes of this study:

- Coal-derived gas required for each of the two existing power plants would be supplied alternatively from either a Combustion Engineering or Texaco process coal gasification plant.
- The coal gasification plant would be constructed as a complete and separate unit located adjacent to the existing power plant. Coal-derived gas would be supplied through a connecting pipe on an "over-the-fence" basis, except that electric power could be imported or exported as required, thus reducing or increasing the output of the existing power plant.
- The total cost of generating electricity at the power plant would include the coal cost for the gasification plant; operating, maintenance, administrative, and support labor costs for both gasification plant and the power plant; and fixed charges on the capital costs of the gasification plant, power plant initial cost, and power plant retrofit costs incurred to convert to medium-Btu gas.
- Emissions from the power plant and associated facilities would meet current environmental restrictions for an Illinois plant location (except for OSHA Regulation 29 CFR 1910.95).

The four cases studied resulted from combinations of either the Texaco or Combustion Engineering (C-E) coal gasification plants with either the gas-fired boiler power plant or the combined-cycle unit. Table S-1 summarizes the heat rates and net power output from the four cases. Data for the reference plant are included for comparison.

Table S-1

HEAT RATES
BASIS: FULL LOAD

CASE	COAL†		Net Power, MW			Net Plant Heat Rate Btu/kWhr
	Tons/d	10^9 Btu/hr	Power Plt.	Gasif.	Overall	
C-E/Boiler	5771	5.884	486.3	-17.6	468.7	12,554
C-E/Combined Cycle	6097	6.216	603	-87.2	515.8	12,051
Texaco/Boiler	6333	6.457	486.3	+10.6	496.9	12,995
Texaco/Combined Cycle	6624	6.754	598	-10.8	587.2	11,502
Reference Plant	11,760	9.896	1000	0	1000	9,896

†For gasification plants, coal HHV = 12,235 Btu/lb. For reference plant, coal HHV = 10,100 Btu/lb.

As shown in the above table, the net power output of the boiler plant is 486 MW for either case, while the net output of the combined-cycle unit is approximately 600 MW for either case. However, the overall power output for the entire facility must be corrected to account for net power imported or exported by the gasification plant. The gasification plant power demand is greatest for the C-E/combined cycle case. Since the C-E process operates at essentially atmospheric pressure, compression of the product fuel gas is required prior to transport of this stream to the combustion turbine in the combined-cycle unit. The electric motor drivers for the product fuel gas compressors are major contributors to the high gasification plant power demand in the C-E/combined-cycle case. This high gasification plant power demand is not present in the Texaco/combined-cycle case since the gasification process operates at 600 psig and thus no product fuel gas compression is required.

Figure S-1, which follows, summarizes all cost estimates developed for the four cases and the reference plant including both capital requirements and operating costs. The resulting costs of electric power from the retrofit plants and the reference plant are also presented in Figure S-1 in mills per kilowatt-hour at the July 1, 1976 price level. Cost estimates for the total capital requirements of the four cases and the reference plant are detailed in Tables 3-3, 4-3, 5-3, 6-2, and 7-8 of this report. Similarly, operating costs are shown in Tables 3-4, 4-4, 5-4, 6-3, and 7-10. Plant investment costs and operating costs are estimated at the July 1, 1976 price level with the cost of delivered coal at two assumed price levels, \$1/MM Btu and \$2/MM Btu. All of the above economic results are tabulated in Section 8 of this report titled "Economic Summary." The 30-year levelized cost of electricity is presented in Appendix A. This appendix includes a narrative explaining the concept of levelized costs plus a side-by-side comparison of the levelized and standard cost elements used to derive the cost of electricity by each method.

In Figure S-1, all costs evolving from coal priced at \$2 per million Btu are shown for comparison in parentheses, ( ). The capital requirements include not only the plant investment but working capital and all other capital charges as well.

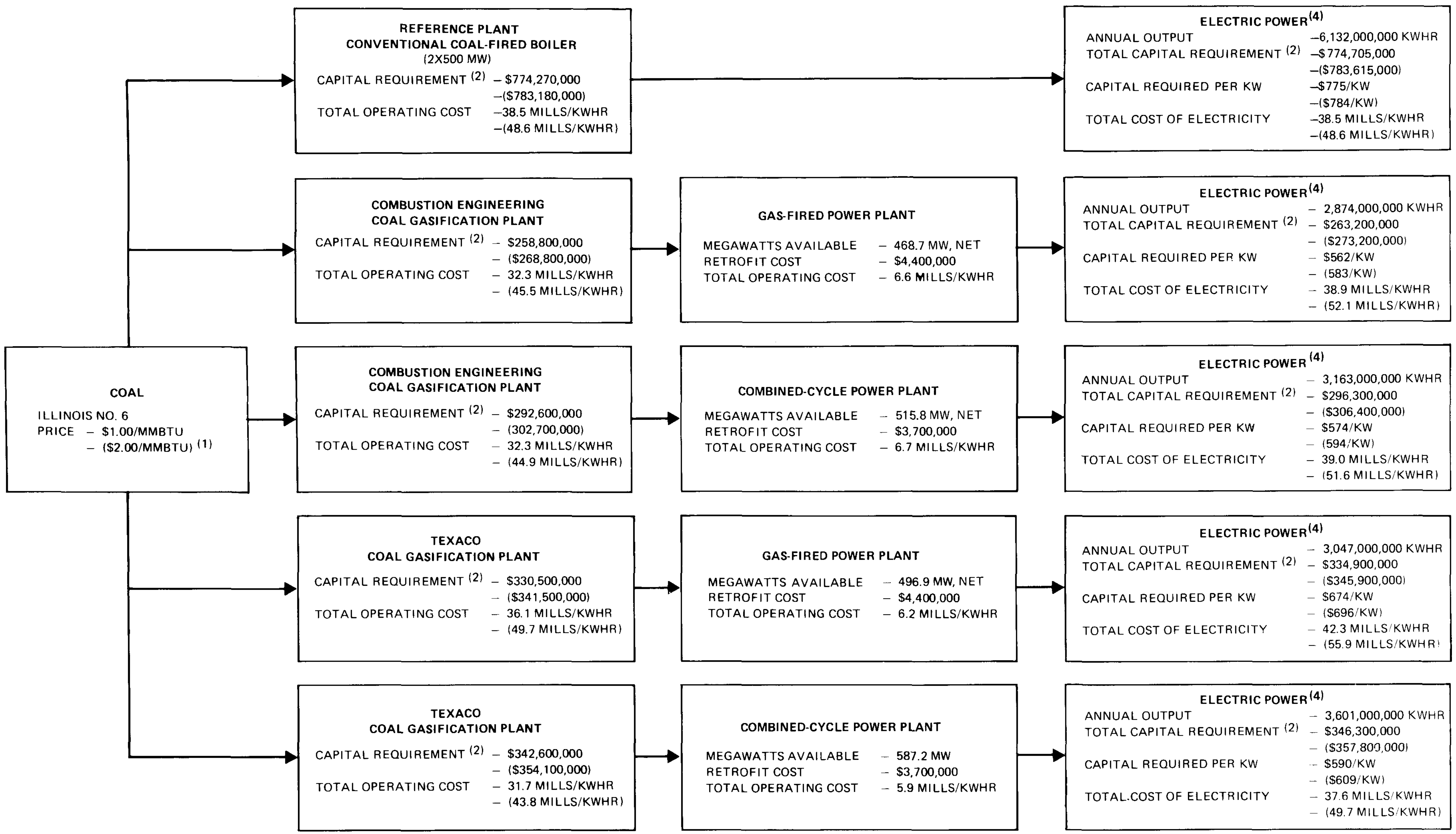
For the reference coal-fired power plant, with coal priced at \$1 per million Btu, electrical generating costs were 38.5 mills per kilowatt-hour. With coal priced at \$2 per million Btu, the resulting generating costs were 48.6 mills per kilowatt-hour. For the retrofitted power plants, with coal priced at \$1 per million Btu, electrical generating costs ranged from 37.6 to 42.3 mills per kilowatt-hour, and with coal at \$2 per million Btu, corresponding costs ranged from 49.7 to 55.9 mills per kilowatt-hour. From these results it can be concluded that further engineering and economic studies of gasification-based retrofit options is warranted.

REFERENCES

1. Economics of Current and Advanced Gasification Processes for Fuel Gas Production. Palo Alto, Calif. Electric Power Research Institute, Final Report, July 1976. EPRI AF-244.

2. Economics of Fuel Gas from Coal — An Update. Palo Alto, Calif. Electric Power Research Institute, Final Report, May 1978. EPRI AF-782.

3. Economic Studies of Coal Gasification Combined Cycle Systems for Electric Power Generation. Palo Alto, Calif. Electric Power Research Institute, Final Report, January 1978. EPRI AF-642.



NOTE (1) FIGURES SHOWN IN BRACKETS ( ) ARE RELATED TO COAL PRICED AT $2/MMBTU.

NOTE (2) CAPITAL REQUIREMENT INCLUDES PLANT INVESTMENT PLUS WORKING CAPITAL AND ALL OTHER CAPITAL CHARGES.

NOTE (3) ALL COSTS ARE ESTIMATED AT THE JULY 1, 1976 PRICE LEVEL.

NOTE (4) ELECTRICAL OUTPUT BASED ON 70% LOAD FACTOR

Figure S-1 ECONOMIC SUMMARY AND COMPARISON

Section 1

INTRODUCTION

GENERAL

The Electric Power Research Institute (EPRI) engaged Bechtel to perform a preliminary economic study concerned with retrofitting existing power plants, currently burning natural gas or oil, to the burning of coal-derived medium-Btu gas.

Many utilities that have substantial investments in relatively new natural-gas-fired boilers and oil-fired combined-cycle units are faced with conversion to coal or coal-derived fuel. Federal mandates to ultimately phase out the use of natural gas as a utility fuel, coupled with the uncertain future price and supply of oil, make it necessary for utilities to examine various alternatives for conversion to coal.

The goal of this preliminary study was to prepare capital and operating cost estimates for "over-the-fence" retrofitting of natural-gas-fired boilers and oil-fired combined-cycle units with coal-derived medium-Btu gas. A further goal of this study was to evaluate the economic potential for using developmental-stage, second-generation, oxygen-blown coal gasification processes in this type of retrofit application. The "over-the-fence" retrofit mode constitutes one option for future utility industry use of second-generation coal gasification processes once such systems have been demonstrated on a commercial scale.

Studies indicate that it is technically feasible to retrofit natural-gas or oil-fired utility boilers to burn medium-Btu (300 Btu/scf) gas produced by the gasification of coal. It appears possible that, with many such retrofitted boilers, design capacity can be retained by adding larger fuel burners and associated piping, valves, and controls to accommodate the increased fuel volume. Other studies indicate that combined-cycle gas turbines could be fitted with specially designed combustors to provide full design rating with medium-Btu gas. Therefore (aside from economic considerations) it appears technically feasible to retrofit existing power plants of either type with a medium-Btu gas derived from coal. Actual design and construction of a retrofit system must await a commercial-scale demonstration of the coal gasification process.

Specific objectives of this study included development of unit-related costs and data consisting of:

- The cost of adding the gasification system, in $/kW
- The cost of modifying the existing equipment to burn the medium-Btu gas, in $/kW
- The heat rate of the retrofitted units, in Btu/kWhr
- The cost of electricity produced by the retrofitted units, in mills/kWhr
- The cost of operating labor for the gasification system, in mills/kWhr
- The cost of maintenance of the gasification system, in mills/kWhr
- The cost of operating labor and maintenance on the retrofitted power plants, in mills/kWhr
- Generic problems associated with retrofitting natural-gas-fired boilers and oil-fired combined-cycle units to a medium-Btu gas fuel

As a benchmark for economic comparison, a reference power plant was established. This reference plant is defined as a new, grass-roots, conventional, coal-fired power plant facility. The cost of electricity produced by the reference plant is also expressed in mills/kWhr.

SCOPE

At EPRI's request, two types of coal gasification processes were evaluated for production of the medium-Btu (300 Btu/scf) gas required for the retrofit installations. Neither of these gasification processes has been proved in commercial operations, but they both represent technologies which have the desired potential. The first is the Combustion Engineering process, which is a two-stage atmospheric-pressure, entrained-bed system. The other process, offered by Texaco Development Corporation, also uses an entrained bed, but is a single-stage pressurized system.

Four cases were studied:

- A natural-gas-fired boiler retrofitted with an oxygen-blown Combustion Engineering gasification system
- An oil-fired combined-cycle unit retrofitted with an oxygen-blown Combustion Engineering gasification system

- A natural-gas-fired boiler retrofitted with an oxygen-blown, coal/water slurry-fed Texaco gasification system

- An oil-fired combined-cycle unit retrofitted with an oxygen-blown, coal/water slurry-fed Texaco gasification system

Representative generating units less than 10 years old, with a rated power output of approximately 500 MW, were selected for the retrofit. Plants selected for this study already had rail access and adequate site area to accommodate coal storage, coal handling, and the equipment and facilities required for the retrofit.

The following additional definitions of scope were provided by EPRI as guidelines for the study.

- Gasifier steam will not be integrated with steam generated by the boiler. The gasifier steam should be used to drive the air separation plant compressors and as process steam for the acid gas removal system.

- Raw water treating, cooling water, and wastewater treatment facilities required by the fuel gas system should be separate from those of either the natural-gas-fired boiler plant or the oil-fired combined-cycle unit.

- The fuel gas for the combined-cycle retrofits should be supplied to the combustion turbine fuel valve at 75 psi above the operating pressure of the combustion chamber for proper throttling control.

- Data and information should be obtained from the turbine manufacturers as required to estimate the cost of modifying the combustion turbine to burn medium-Btu gas.

- No change in the heat exchange surface of the boiler will be required.

- The boiler draft fans will not require change to accommodate the modified flow of gases.

- The cost of electricity produced by the retrofitted plant is to be calculated using criteria supplied by EPRI and titled "Cost of Services Basis."

- The cost of maintenance of the gasification system is to be based on information supplied by EPRI and titled "Data and Design Information."

- The cost of operating labor and maintenance on the existing units is to be based on upgrading existing maintenance to extend the life of the retrofitted units to 25 years from startup.

- A 30-year levelized cost of electricity produced by the retrofitted plants will be calculated using criteria supplied by EPRI and titled "Levelized Cost of Service Basis."

Details of the "Cost of Services Basis," the "Levelized Cost of Service Basis," and other "Data and Design Information," are described in the discussion of study bases, which follows.

STUDY BASES

The process and economic data used as bases for this study were taken from three previously published EPRI reports. Capital and operating cost estimates and process designs for the Combustion Engineering gasification plant are described in EPRI Report No. AF-244, titled "Economics of Current and Advanced Gasification Processes for Fuel Gas Production," and in Appendix B of EPRI Report No. AF-782, which updates the economics. AF-244 describes an oxygen-blown Combustion Engineering gasification plant which supplies fuel gas at 40 inches water gauge pressure. The estimates and designs in AF-244 were based on converting 10,000 tons/day of Illinois No. 6 coal to clean fuel gas. Cost data and design information for the Texaco process are described in EPRI Report No. AF-642, titled "Economic Studies of Coal Gasification Combined-Cycle Systems for Electric Power Generation." The estimates and designs in AF-642 were based on an oxygen-blown system with a constant coal feed rate of 10,000 tons/day of Illinois No. 6 coal.

To perform the evaluations presented in this retrofit study, it was necessary to modify the data contained in the above-referenced reports and adjust them to fit the study conditions. For example, engineering scale-up factors were used to adjust the published cost estimates as appropriate for the retrofit cases. This was based on adjustments in the coal feed rate and fuel gas delivery pressure as required to meet study conditions. Generally, the gasification processes in this study follow the original concepts with no changes other than plant size and gas delivery pressure.

The capital costs for the coal-fired reference plant were based on the estimates contained in EPRI Report No. AF-342, titled "Coal-Fired Power Plant Capital Cost Estimates." Operating costs for the reference plant were estimated by Bechtel in accordance with standard industry practice and in compliance with the guidelines supplied by EPRI and titled "Cost of Service Basis."

Since neither the scope nor the budget for this study included provisions for checking or recalculating the cost information contained in any of the cited EPRI reports, the only adjustments made to the economic data were to modify them as necessary to meet plant size and other technical and economic criteria for the retrofits.

Gasifier material and heat balances and equipment requirements were supplied to EPRI by the organizations which developed or license the processes. This information is described in more detail in the referenced reports.

Tables 1-1 through 1-5 contain the technical and economic criteria supplied by EPRI for Bechtel's use in developing the plant designs and estimating the capital requirements and costs of services. These criteria are consistent with other recent EPRI reports. Tables 1-4 and 1-5 are composites of EPRI's current criteria for gasification plants and coal-fired boilers. It is recognized that there are differences between the bases for these criteria; however, the overall effect on economic results is minor.

The levelized cost of services is discussed more fully in the Appendix. A "levelized cost" is a convenient way of representing the varying annual revenue requirements of a system with a single "levelized" value using the "present worth" concept of money. The concept of levelized costs is widely used in the utility industry for generation/expansion studies.

The concept of levelization is discussed in Chapter V of the EPRI Technical Assessment Guide (August 1977 edition).

The economic criteria as defined by EPRI to be used for calculating the levelized cost of electricity are as follows:

- Inflation Rate: 6.0 percent per year
- Discount Rate: 10.0 percent per year
- Coal Escalation Rate: Gasification plant — 6.848%
Coal-fired power plant — 6.2%

Based on these criteria, the 30-year levelization factors to be used in this work are:

Item	30-Year Levelization Factor Gasification Plants	30-Year Levelization Factor Coal-Fired Boilers
Coal	2.093	1.932
O&M	1.886	1.886

A capital charge rate of 18.0 percent per year of the Total Capital Requirements is equivalent to the 30-year levelized fixed charge of 18 percent that is presented on page V-2 of the Technical Assessment Guide. The fixed-charge rate includes general and administrative expenses, property taxes, and insurance.

Table 1-1

COAL ANALYSIS
ILLINOIS NO. 6

	For Gasification Processes (Per EPRI AF-244 and AF-642)	For Reference Power Plant (Per EPRI AF-342)
Proximate Analysis, % Weight		
Moisture	4.2	12.0
Ash	9.6	16.0
Fixed Carbon	52.0	39.0
Volatile Matter	34.2	33.0
	100.0	100.0
Ultimate Analysis, % Weight		
Carbon	77.26	80.00
Hydrogen	5.92	5.14
Oxygen	11.14	8.06
Nitrogen	1.39	1.25
Sulfur	4.29	5.55
	100.00	100.00
Heating Value — As Received		
Higher Heating Value (HHV)	12,235 Btu/lb	10,100 Btu/lb
Lower Heating Value (LHV)	11,709 Btu/lb	Not Available
As Purchased		
Washed, sized 1-1/2" x 0", delivered by unit train to plant battery limits.		

Table 1-2

SITE CONDITIONS

Location	Chicago, Illinois
Elevation	600 ft
Design Ambient Pressure	14.4 psia
Design Ambient Temperatures	
Summer Dry Bulb	$88^{o}F$
Summer Wet Bulb	$75^{o}F$
Winter Dry Bulb	$0^{o}F$

Table 1-3

RAW WATER ANALYSIS

Silica (SiO_2)	1.8 ppm
Iron (Fe)	0.09
Manganese (Mn)	0
Calcium (Ca)	39
Magnesium (Mg)	10
Sodium (Na)	3.3
Potassium (K)	0.7
Carbonate (CO_3)	0
Bicarbonate (HCO_3)	132
Sulfate (SO_4)	23
Chloride (Cl)	7.2
Fluoride (F)	0.1
Nitrate (NO_3)	—
Dissolved Solids	168
Hardness as $CaCO_3$	
Total	138
Noncarbonate	30
Color	1 unit
pH	7.9
Turbidity	0
Specific Conductance at 25^{o}C	275 microohms

Table 1-4

CAPITAL INVESTMENT BASIS

Total Plant Investment (TPI)	Mid-1976 dollars with no escalation Chicago, Illinois location Clear and level site
TPI Definition	The total plant investment is defined as the sum of: • Process (or onsite) plant investment costs • General facilities (or offsite) investment costs • Contingencies — process and project
Process Plant Investment	Total constructed cost of all onsite processing units including all direct and indirect construction costs.
General Facilities	The capital cost of the offsite facilities is explicitly included. Offsite facilities include roads, buildings, railroad loading and unloading systems, electrical distribution and substations, cooling water systems, inerting systems, effluent water treatment facilities, etc. All sales taxes (5% of total materials) are included.
Process Contingency	This contingency is to be added to the process plant investment for unproven technology in an effort to quantify the uncertainty in the design, performance, and cost of the commercial-scale equipment. • For the gasification processes — 5% • For the flue gas desulfurization system of the power plant — 5% • Remainder of the power plant — 0%
Project Contingency	This contingency factor is intended to cover additional equipment that would result from a more detailed design of a definitive project at an actual site. An allowance of 15% of the combined process plant investment and general facilities cost is to be used.
Total Capital Requirement	The following capital requirement includes all capital necessary to complete the entire project. These capital charges include the following: (a) *Total plant investment* (b) *Paid-up royalties* (c) *Preproduction costs* (d) *Construction loan interest* (e) *Initial chemical and catalyst charge* (f) *Working capital* (g) *Inventory capital* (h) *Land*
(Item b) Paid-up Royalties	0.5% of gasification plant investment 0% of the reference power plant investment

Table 1-4 (Cont'd)

<table>
<tr><td>(Item c) Preproduction Costs</td><td>The preproduction costs are intended to cover operator training, equipment checkout, major changes in plant equipment, extra maintenance, and inefficient use of coal and other materials during plant startup.

The preproduction costs are to be estimated as follows:

<u>For the Gasification Plant</u>

• Two months' fixed costs excluding income taxes. Fixed costs are operating and maintenance labor, administrative and support labor, general and administrative expense, and property taxes and insurance.

• One month of variable operating costs excluding coal. Variable costs are catalysts and chemicals, utilities, and maintenance materials.

• 25% of full capacity coal cost for one month. This charge is to cover inefficient operation during the startup period.

• 5% of total plant investment. This charge allows for possible changes in process equipment, and charges associated with depreciation, bond interest, and return on equity during the preproduction period.

<u>For the Reference Power Plant</u>

• One month's fixed operating costs. These costs consist of operating and maintenance labor, administrative and support labor, and maintenance materials for the power plant.

• One month of variable operating costs at full capacity excluding coal. These costs consist of limestone, raw water, ash disposal, and sludge disposal charges.

• 25% of full capacity coal cost for one month. This charge is to cover inefficient operation during the startup period.

• 2% of total plant investment. This charge is to cover possible changes and modifications to equipment that will be needed to bring the plant up to full capacity.</td></tr>
<tr><td>(Item d) Construction Loan Interest</td><td>Based on compounded 8%/yr interest over the plant construction expenditure schedule for the gasification plants.

• For the gasification plants
0.1249 x total plant investment

• For the reference power plant
0.1660 x total plant investment

Assumed expenditures in a given year are uniform over that year.</td></tr>
</table>

Table 1-4 (Cont'd)

(Item e) Initial Catalyst and Chemicals Charge	The initial cost of the charge of catalyst or chemicals contained within the process equipment (but not in storage, since this cost is covered in the inventory capital) is to be included.
(Item f) Working Capital-Gasification Plant Only	1.5 months of total operating plus 3.5% of total plant investment. (This charge allows for accounts receivable.)
(Item g) Inventory Capital	The value of inventories of coal and other consumables is to be capitalized and included in the inventory capital account. Inventory capital is the sum of the following: • Cost of a one-month supply of coal at full capacity operation • Cost of a one-month supply of limestone, chemicals and other consumables (excluding water) based on full capacity operation
(Item h) Land	No allowance is to be made for the cost of land for the gasification plant. An allowance of $5000/acre is to be included for the reference power plant.

Table 1-5

COST OF SERVICES BASIS

Operating Load Factor	70%
Cost of Coal Delivered	\$1.00 /MM Btu and \$2.00/MM Btu
Chicago City Water Cost	40 cents/1000 gallons
Ash Disposal Cost	\$4.00/ton
Sludge Disposal Cost	\$8.50/ton
By-Product Ammonia Credit	\$100/ton
By-Product Sulfur Credit	Zero
Maintenance Costs	Annual maintenance costs are normally estimated as a percentage of the total installed plant cost of the facilities. The percentage varies widely depending on the nature of the processing conditions and the type of design. Maintenance costs shown below were used as a guide.

Process Unit	% of Total Plant Investment/Yr
Gasification Plant	
Coal Handling	3.0
Oxidant Feed	2.0
Gasification and Ash Handling	4.5
Gas Cooling	3.0
Acid Gas Removal and Sulfur Recovery	2.0
Fuel Gas Compression	3.0
Process Condensate Treating	3.0
Steam, Condensate and BFW	1.5
Power Equipment Support Facilities	1.5

Table 1-5 (Cont'd)

	Process Unit	**% of Total Plant Investment/Yr**
	Natural Gas-Fired Power Plant	2.0
	Combined-Cycle Plant	2.5
	Coal-Fired Power Plant	2 mills/kWh + 4.0% of the TPI including process and project contingencies for the FGD Sections
Maintenance Labor/ Materials Ratio	40/60	
Operating Labor $/MH	$11 per manhour (this labor rate corresponds to a direct labor charge of $8/hour plus a 35% payroll burden).	
Administrative and Support Labor	30% of operating and maintenance labor	
General and Administrative Expense, Property Taxes and Insurance	2.4%/yr of the total capital requirement. This includes an allowance to cover property taxes and insurance on the existing facilities.	
Fixed Capital Charges	The capital charges (income taxes, interest on debt, return on equity, and depreciation) are computed on a levelized basis with a 10% discount rate. The discount rate is based on the average cost of money. Using this basis, the capital charges will be 15.6% per year of the <u>Total Capital Requirement</u>. This capital charge rate is based on the following financial assumptions, which are shown for reference only. Coal-fired power assumptions are shown in ( ).	
	Depreciation	Straight Line
	Tax Life	25 years (20 years)
	Plant Book Life	25 Years (30 years)
	Debt/Equity Ratio	50/50
	Bond Interest	8% annually
	Bond Life	15 years (not given)
	Preferred Stock Ratio	Not given (15%)
	Preferred Stock Interest	Not given (8.5%/yr)
	Common Stock Ratio	Not given (35%)
	Common Stock Interest	Not given (13.5%)
	Return on Equity after Taxes	12% annually
	Fed & State Income Tax Rate	52% (50%)
	Escalation Rate	Not included (6%)
	Investment Tax Credit	Not included* (0)
	Iowa Type S. Retirement Dispersion	Applied

Table 1-5 (Cont'd)

	The fixed capital charge is based on the total capital requirement with working capital treated the same as depreciable capital. The cost of capital applies only to the new equipment. For the purposes of this study, the existing capital investment is to be considered on the same basis as the new plant.
Total Fixed Charges	18% per yr. This includes 15.6% per year for capital charges and 2.4% per year for general and administrative expenses, property taxes, and insurance. (2% for property taxes and insurance.)

NOTE: While no investment tax credit has been utilized for this report, the use of investment tax credit to finance the construction is a very likely possibility. However, since the tax rules are affected by the type of ownership, rate structure, and methods of financing, each plant would require special studies to establish the allowable credit for that plant.

Section 2

PRESENT AND FUTURE DEVELOPMENTS

STEAM BOILER RETROFIT

It is assumed that only relatively new plants would be considered for retrofit to burn coal-derived, medium-Btu gas. Such power plants are usually highly integrated and designed for compactness to minimize capital costs. The total plantsite area is usually so selected and the generating units so arranged as to permit a predetermined amount of plant expansion. Equipment ratings normally include fairly well standardized margins of capacity and safety to cover reasonable variations in operating conditions over the life of the component or plant. All of these factors can influence the degree of technical difficulty associated with the retrofit of an individual plant to burn medium-Btu gas derived from coal.

Some of the generic problems to be considered in a conversion decision are summarized below.

Required Site Area

Site area must be available or obtainable for addition of the required gasification plants, coal delivery area, handling and storage facilities, slag disposal facilities, and possibly product gas storage facilities.

Fuel System Modifications

Space must be available within the boiler or gas-turbine enclosures to accommodate larger fuel piping. Boiler and building structures must support the increased load from this larger piping. Building ventilation systems must be capable of removing the additional heat introduced by larger fuel piping carrying hot medium-Btu gas.

Burner Modifications

Space between boiler tubes must accommodate larger and/or more fuel nozzles.

Draft System Modifications

Fan systems must be evaluated to determine their capability to overcome any changes in pressure loss due to changes in the system pressure profile. Flue-gas ducts must be capable of withstanding these potential pressure changes. Economizers and air preheaters must be examined to determine the effect of either increased or decreased hot-side temperatures on the system's performance.

Furnace Modifications

Forced-draft boilers and heat recovery steam generators must be evaluated to determine their capability to withstand any changes in the system pressure profile. Furnace wall bracing and boiler support steel and foundations must withstand these potential changes in load. It is anticipated, however, that the conversion to medium-Btu gas will not require structural design changes to the boilers.

Steam Temperature Control System Modifications

Superheat and reheat controls must accommodate the expected higher combustion temperatures associated with firing coal-derived gas instead of natural gas. Superheater sections and/or desuperheat systems may require modification to limit steam temperatures.

Technical evaluation and resolution of each of the problem areas noted above is within the current state-of-the-art. Specific conditions at each retrofit candidate plant must be examined to determine the proper solution for these problems and their associated costs.

GAS TURBINE RETROFIT

Work is in progress within the gas turbine industry to develop replacement combustor systems for utility-scale industrial gas turbines to permit their conversion to dual-fuel service, firing either oil or a coal-derived fuel gas. Development of such dual-fuel capability has been given a high priority by industrial turbine manufacturers. Dual-fuel capability is desirable for operation during startup and because of the flexibility it provides for power production during interruption of fuel supplies. An industry consensus indicates that the manufacturers have operated, or are prepared to operate, their industrial gas turbines on coal-derived gases. Some manufacturers are certain that their gas turbines can be readily converted to burn medium-Btu gases such as those considered in this study. References (1) through (4) describe turbine industry work done on coal-derived-gas combustion turbines.

Modification of the fuel injectors and the fuel manifolding to the injectors would be required because of the density difference between oil and gas and the difference in the fuel heating values. The equivalent volumetric flow rate of medium-Btu gas is approximately 600 times that required when firing oil at a specific heat release rate. On the assumption that the nominal flow velocity for fuel gas is approximately 10 times that used in oil piping, the diameters of the individual fuel gas pipes would be about eight times the diameter of the corresponding oil pipes. The injectors would likewise have to be designed with larger flow passages to accommodate the lower-density and lower-heating-value fuel gas.

In addition to the specific combustion system modifications discussed above, there are several other basic considerations which would be important to the successful conversion of existing combined-cycle gas turbines. Four considerations are discussed briefly here, and will require careful evaluation by the engineer and the turbine manufacturer for any particular combined-cycle plant retrofit.

Flow Match

This consideration involves the effect of the medium-Btu gas on the flow match between the compressor and turbine sections of the gas turbine as originally designed. A gas turbine designed for oil fuel burns about 0.022 pound of oil for each pound of air passing through the compressor section. Therefore, this combustion produces 1.022 pounds of gas per pound of air compressed. The resulting gas expands through the turbine section to drive the compressor section and the power generator. When the gas turbine engine is converted to burn medium-Btu gas with a higher heating value of about 300 Btu/scf, the fuel flow required is then about 0.073 pound per pound of air. This converted operation produces 1.073 pounds of gas per pound of air compressed or a 5-percent increase in gas flow through the turbine over the original design.

Gas turbines can generally accommodate combustion-gas flow increases of up to about 10 percent. However, the turbine manufacturer may choose to open up the first-turbine-stage inlet nozzle vanes to achieve the increased flow without an increase in pressure; or, if the compressor has inlet guide vanes, he may choose to use guide-vane control to reduce the compressor air flow to keep the turbine gas flow at the original design value. In the event that turbine modifications are recommended by the manufacturer, the cost of these modifications will depend on the specific design of the turbine. The impact of these costs on the overall retrofit costs is not expected to be significant.

Plant Startup Methods

Combined-cycle power plants firing oil are usually considered relatively quick-starting. Typically, the gas turbine can be started and synchronized in about five minutes, and can be fully loaded within 20 minutes after the start signal. The steam system burner box and gas ducts follow the heat input from the gas turbine exhaust, and achieve full load about 55 minutes after the start signal. This startup timing would not be applicable when the turbine fuel gas source is an on-site coal gasification unit, unless expensive gas storage is designed into the system to provide fuel gas for startup and initial operation. It is assumed in this study that the combined-cycle gas turbines will be started up with No. 2 diesel oil. After startup, the gas turbine will be sustained at partial load (less than 50 percent) until the gasification unit is delivering sufficient fuel gas. The turbine will then be gradually switched from oil fuel to gas fuel, and brought up to full load. This dual-fuel start and operating mode is preferred because it provides greater operating flexibility in both the startup transient mode and in the steady-state operating mode, and eliminates the need for on-site fuel gas storage in addition to the existing fuel oil storage.

Operating Mode

Oil-fueled combined-cycle power plants are best suited to intermediate load operation because of their medium capital cost (approximately $400/kW) and use of high-cost fuel (approximately $2.50/million Btu). After conversion to fire coal-derived gas as the primary fuel, the total plant complex becomes best suited to base loading because of its increased capital cost (approximately $600/kW) and lower fuel cost (approximately $1.00/million Btu for coal).

Limitations in Load-Following

The normal capabilities of a combined-cycle plant for frequent startup and shutdown and its normally fast load-following characteristics become more limited when the plant becomes dependent on the gasification plant for its fuel supply. How well the retrofit combined-cycle power plant operating mode fits into the utility's generation plans, and how well the plant load-following characteristics meet the utility's requirements, will have to be evaluated for each such plant.

REFERENCES

1. D.J. Ahner. Gas Turbine Generation Concepts Utilizing Processed Fuels. Schenectady, NY: General Electric Co., 1976.

2. R.J. Palmer and M.R. Burgess. "Modern Gas Turbines for Low-Btu Gas Fuel Operation." New York, NY: ASME Conference Publication No. 76-GT-115, 1976.

3. P.W. Pillsbury. "A High Pressure Coal Gas Combustor Testing Program." New York, NY: ASME Conference Publication No. 74-PWR-11, 1974.

4. P.W. Pillsbury and S.S. Lin. "Recent Tests of Industrial Gas Turbine Combustors Fueled with Simulated Low Heating Value Coal Gas." New York, NY: ASME Conference Publication No. 76-WA/GT-3, 1976.

Section 3

COMBUSTION ENGINEERING COAL GASIFICATION PROCESS

GENERAL

Basic technical and economic information on the oxygen-blown Combustion Engineering (CE) gasification process was obtained from EPRI Report AF-244 and its update AF-782, Case EXL. The Case EXL system described in these reports is a complete, "stand-alone," grass-roots facility for production of medium-Btu fuel gas from 10,000 tons/day of Illinois No. 6 coal feed. This gasification system was adapted to each of the two retrofit cases employing this system, by simple proration plus redesign of the product fuel gas compression and reheat systems.

The Combustion Engineering gasification process is currently being developed by CE, EPRI, and the Department of Energy (DOE) in a Process Development Unit (PDU) located at Windsor, Connecticut. The PDU is designed to gasify five tons per hour of coal using air as the oxidant, and produce a low-Btu gas having a heating value of approximately 120 Btu/scf. The process configuration described below in this section of the report represents a conceptual design of the CE process which is an extension of the current PDU work. In this design oxygen, rather than air, is used as the oxidant, for the production of a medium-Btu fuel gas having a heating value of approximately 300 Btu/scf.

PROCESS DESCRIPTION

The Combustion Engineering coal gasification process employs a two-stage, entrained-bed gasifier operating at essentially atmospheric pressure. Approximately 41 percent of the pulverized coal feed plus all of the oxidant and recycle char feeds are injected tangentially into the bottom combustor stage of the gasifier. The remainder of the coal feed enters the upper reductor stage, where it contacts the 3200°F gases leaving the combustor. Splitting of the coal feed between the two stages is controlled to maintain 3200°F in the combustor.

The endothermic processes of coal devolatilization and cracking of volatile matter occur in the lower level of the reductor stage. As a result, the gases flowing up through this stage are cooled to an exit temperature of 1700°F. Entrained char is swept out with the exiting crude gas, and is subsequently recovered for recycle.

Molten slag drains from the combustor stage walls into a water-filled quench vessel. The resultant slag slurry is transferred to a dewatering step to produce a slag for disposal. A portion of the separated water is recycled to the slag quenching process.

The gasifier vessel is constructed with water-cooled, fin-welded, studded, refractory-covered walls. Cooling is accomplished by circulating boiler feedwater through the tube walls of the gasifier and generating 1450 psig saturated steam in a flash drum.

The complete Combustion Engineering coal gasification system also includes process units for coal handling and pulverization, oxidant feed preparation, gas cooling and char recovery, acid gas removal, and product gas compression and reheating. Support facilities include a cooling water system and raw water and wastewater treatment units. Detailed process and equipment descriptions can be found in EPRI Report AF-244.

DESIGN BASES

Table 3-1 is a summary of the major process design bases for the Combustion Engineering system used in this retrofit study. The bulk of this information was obtained from Case EXL as given in EPRI Report AF-244. Product gas flow rates were specified to meet the fuel gas demands of the retrofit power plants. Corresponding new coal feed rates were then obtained by proration based on the specified product gas flows. With the exception of the product gas compression and reheat systems, steam and electric power consumption and generation in all process units were prorated from Case EXL to match the calculated coal feed rates. The criteria established by EPRI for this report indicated that if the overall utility balance required the import of electric power it would be available from the power plant, thereby reducing the net power plant output by an equivalent amount. The converse was also true, an export from the gasification plant would add to the net power plant output. In this study, both power plant retrofit cases using the Combustion Engineering process were importers of electric power.

In Case EXL, the product fuel gas was delivered to the gasification process battery limits at a pressure of -0.5 psig. This pressure was increased to 15 psig for the boiler retrofit case. Although increasing the compression ratio of the product gas compressor resulted in a higher discharge temperature, the final battery-limit fuel-gas delivery temperature was maintained at the Case EXL value of 405°F. Temperature control was accomplished by diverting product gas heating steam to power generation within the gasification system battery limits.

For the combined-cycle retrofit case, product fuel gas was delivered to the gasification process battery limits at 245 psig, 436°F. The design of the product gas reheat system employed resaturation of the gas with the water condensed during compression. Steam usage for reheating was set at a flow obtained by proration of the steam required for this service in Case EXL based on the calculated coal feed rate for the retrofit section.

All environmental regulations pertaining to an Illinois location have been designed for, and are described in EPRI Reports AF-244 and AF-782.

BOILER RETROFIT CASE

A grass-roots Combustion Engineering gasification system to supply the fuel gas requirements "over-the-fence" to a 486 MW gas-fired steam boiler power plant is shown schematically in the Overall Block Flow Diagram, Figure 3-1. This flow diagram is similar to that developed and reported for Case EXL except that the product gas compressor and the transport gas compressor services have been separated. This gasification system consumes 5771 tons/day of Illinois No. 6 coal. The material balance and product gas composition are shown on this diagram.

Figure 3-1 also shows the number of parallel trains required for the main processing facilities and the necessary offsite, utility, and environmental facilities. The size of each unit shown in Figure 3-1 relative to the corresponding units employed for Case EXL is given in Table 3-2. A summary of the process unit sparing philosophy for the boiler retrofit case is also shown in Table 3-2.

The boiler retrofit case gasification plant contains steam, condensate, and boiler feedwater systems independent of those in the generating unit. These systems are shown in the flow diagram, Figure 3-3. There is no integration of the gasification plant steam, condensate, and boiler feedwater systems with those in the steam boiler power plant.

Due to the energy required to compress the product fuel gas, the gasification system is a net consumer of electric power. For the boiler retrofit case, the total power consumption of 26,762 kW consists of 8269 kW basic* and 18,493 kW for product gas compression. The total power production from the gasification facility is only 9124 kW, resulting in the importing of 17,638 kW from the power plant.

COMBINED-CYCLE RETROFIT CASE

Fuel gas requirements for a 603 MW combined-cycle unit are supplied by the grass-roots gasification plant shown schematically in the Overall Block Flow Diagram, Figure 3-2. This system consumes 6097 tons/day of Illinois No. 6 coal and produces 924,452 lb/hr of product gas. The overall material balance and the product gas composition are also shown in Figure 3-2. This figure is very similar to the Overall Block Flow Diagram, Figure 3-1 for the boiler retrofit case.

The size of each process unit relative to the size of the corresponding unit in Case EXL is given in Table 3-2. The process unit sparing philosophy is identical to that employed for the boiler retrofit case.

Steam, condensate, and boiler feedwater systems for the combined-cycle retrofit gasification plant are shown in the flow diagram, Figure 3-4. As in the boiler retrofit case, there is no integration of the gasification plant steam, condensate, and boiler feedwater system with the corresponding systems in the power generating unit.

Due to the requirement for a fuel-gas delivery pressure of 245 psig at the gas turbine combustor, the gasification plant for the combined-cycle retrofit case is a net consumer of power. For the combined-cycle retrofit case, the total power consumption of 95,461 kW consists of 15,778 kW basic* and 79,683 kW for product gas compression. The total power production from the gasification plant is only 8218 kW, resulting in the importing of 87,243 kW from the power plant.

Figures 3-5 and 3-6 contain process information on the redesigned product fuel gas reheating system for the combined-cycle retrofit. An expanded Block Flow Diagram of this process unit is shown in Figure 3-5. Accompanying heating/cooling curves for the reheat system exchangers are shown in Figure 3-6.

*By proration from the Case EXL power requirement without product fuel gas compression.

ECONOMICS

Capital Investment Basis

In general, the capital investment cost estimates were obtained by adjusting the estimates for Case EXL in Tables E-7 and E-8, pp. B-21 and B-22, of EPRI Report AF-782 to correspond to the bases established for this report. As previously noted, the capital investment basis for this report is given in Table 1-4.

Cost adjustments for changes in process equipment were made on the basis of the size comparisons and sparing philosophy given in Table 3-2 for the process trains. Appropriate cost factors for such size adjustments were used.

Product gas compressor equipment was added to increase the gas delivery pressure from -0.5 psig for Case EXL to 15 psig and 245 psig as required for the boiler and combined-cycle retrofit plants, respectively.

Escalation was added to the Case EXL estimates to adjust the cost datum from a mid-1975 level to the mid-1976 price level established for this report.

Capital investment costs are summarized in Table 3-3. The 20-percent contingency can be considered as divided into two parts: a 15-percent project contingency to cover estimating uncertainties, and a 5-percent process contingency to cover uncertainties in developing the processes from the conceptual stage to commercial reality.

Operating Charges

A summary of operating costs is presented in Table 3-4. These costs are also based on adjusting the estimates for Case EXL in Table E-9, p. B-23, of EPRI Report AF-782 for the smaller size plant contained in this report.

The operating labor and maintenance labor estimates were based upon the requirements outlined in Case EXL and the size comparison and sparing philosophy outlined in Table 3-2.

Other operating costs were ratioed from the Case EXL numbers or developed on the bases set forth in Table 1-5.

Overall Economic Results

Overall economic results of this report are presented in Tables 8-1 and 8-2. Thirty-year levelized costs are presented in Tables A-3 and A-4 in the Appendix.

Table 3-1

SUMMARY OF DESIGN BASES
COMBUSTION ENGINEERING GASIFICATION RETROFIT CASES

	Combined Cycle	Steam Boiler
Coal Feed Rate, lb/hr (mf)†	486,744	460,718
Oxygen-Coal Ratio, lb (dry)/lb (mf)*†	0.839	0.839
Oxidant Temperature, ^{o}F	800	800
Gasifier Exit Pressure, inches water	-0.5	-0.5
Crude Gas Temperature, ^{o}F	1700	1700
Fuel Gas Temperature at BL, ^{o}F	436	405
Fuel Gas Pressure at BL, psig	245	15
Net Fuel Gas Production Rate, MM scfh†	15.70	14.88
Net Fuel Gas, Mscf/t mf coal†	64.51	64.59
HHV, Fuel Gas, Btu/scf†	312	312

†Dry basis (mf) = moisture free.
*100% O_2.

Table 3-2

TRAIN REQUIREMENTS AND SIZE BASIS
COMBUSTION ENGINEERING GASIFICATION RETROFIT CASES

Major Equipment Sections	EPRI Reports AF-244, AF-782 Case EXL - 10,000 T/D Coal		Boiler Case - 5771 T/D Coal			Combined Cycle Case - 6097 T/D Coal		
	Operating	Spare	Operating	Spare	Size Ratio*	Operating	Spare	Size Ratio*
Coal Handling	1	0	1	0	0.58	1	0	0.61
Coal Pulverizing and Drying	2	0	2	0	0.58	2	0	0.61
Air Compression	3	1	2	1	0.87	2	1	0.92
Air Separation	4	0	3	0	0.77	3	0	0.81
Oxygen Preheat	3	1	3	0	0.77	3	0	0.81
Gasification	3	1	3	0	0.77	3	0	0.81
Ash Handling	1	0	1	0	0.58	1	0	0.61
Gas Cooling and Char Recovery	3	1	3	0	0.77	3	0	0.81
Acid Gas Removal	3	0	2	0	0.87	2	0	0.92
Compression	3	1						
Product Gas			2	1		3	1	
Transport Gas			1	1		1	1	
Product Gas Heating	3	0	2	0	0.87	2	0	0.92
Waste Water Treating	1	0	1	0	0.58	1	0	0.61
Water Treating	1	0	1	0	0.58	1	0	0.61
Condensate Collection and Deaeration	1	0	1	0	0.58	1	0	0.61
Cooling Water System	1	0	1	0	0.58	1	0	0.61
Power Recovery	1	0	1	0	0.58	1	0	0.61

$$\text{*Size Ratio} = \frac{\text{Retrofit Case}}{\text{Case EXL}}$$

Table 3-3

COMBUSTION ENGINEERING COAL GASIFICATION PROCESS
CAPITAL INVESTMENT COST SUMMARY
70% OPERATING LOAD FACTOR

	Boiler Retrofit Case		Combined Cycle Retrofit Case	
Plant Investment	in Thousands of Dollars			
Coal Handling	$ 18,400		$ 19,300	
Oxidant Feed	75,600		78,200	
Gasification, Gas Cooling, Ash Handling, and Char Recovery	28,100		29,300	
Acid Gas Removal and Sulfur Recovery	13,100		13,500	
Product Gas Compression	8,700		25,100	
Power Recovery	3,400		3,500	
Support Facilities	20,200		20,800	
	167,500		189,700	
Contingency	33,500		38,000	
TOTAL PLANT INVESTMENT	$201,000		$227,700	
Price of Coal, $/MM Btu	$1	$2	$1	$2
Capital Charges	in Thousands of Dollars			
Preproduction Costs	$13,500	$14,600	$15,100	$16,300
Paid-up Royalties	1,000	1,000	1,100	1,100
Initial Chemical and Catalyst Charge	300	300	300	300
Construction Loan Interest	25,100	25,100	28,400	28,400
TOTAL CAPITAL CHARGES	39,900	41,000	44,900	46,100
Total Depreciable Capital*	240,900	242,000	272,600	273,800
Working Capital	17,900	26,800	19,600	28,900
TOTAL CAPITAL REQUIREMENT	$258,800	$268,800	$292,600	$302,700

*Sum of total plant investment and total capital charges.

Table 3-4

COMBUSTION ENGINEERING COAL GASIFICATION PROCESS
OPERATING COST SUMMARY†

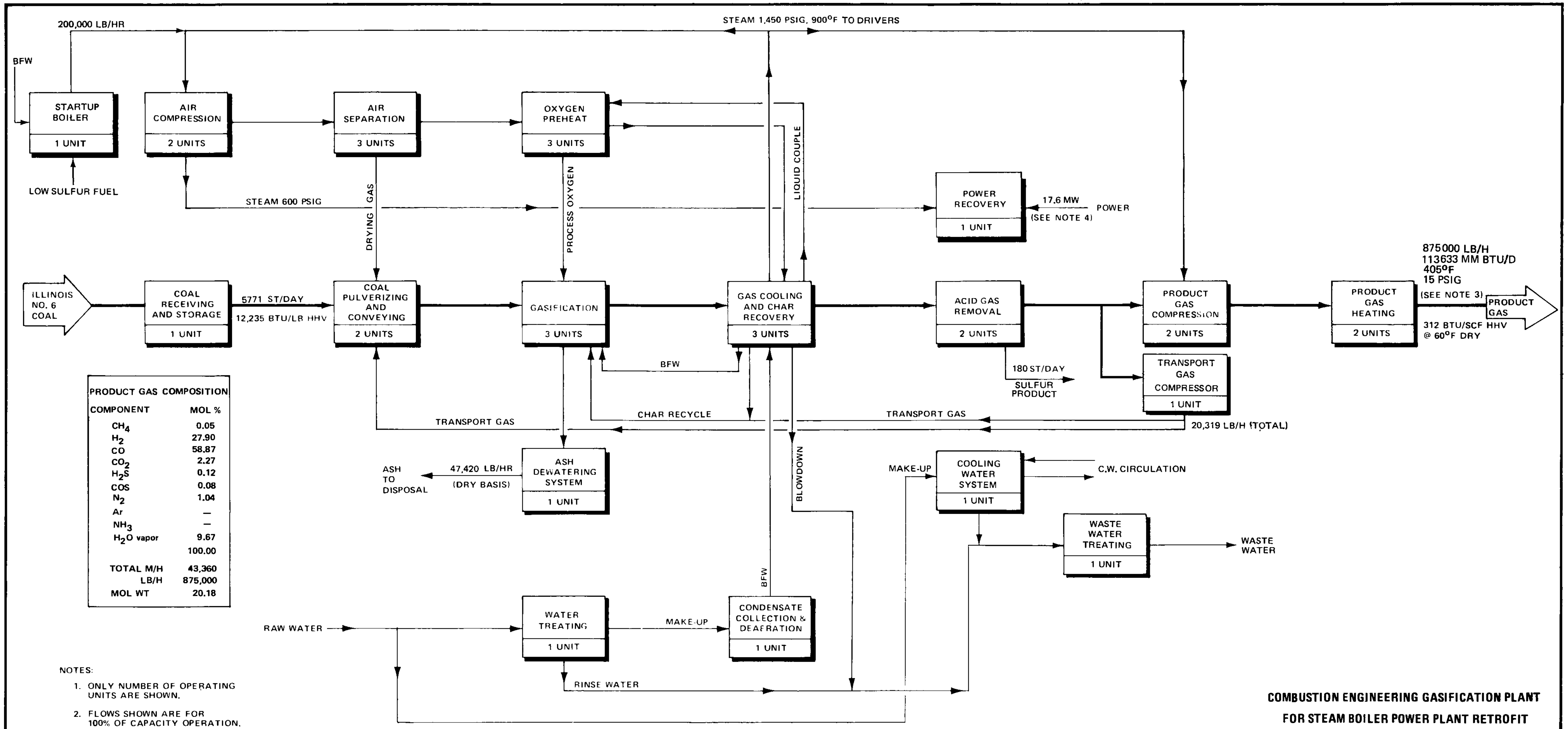
CONDITIONS	Boiler Retrofit Case	Combined Cycle Retrofit Case
Operating Load Factor	70%	70%
Net Production		
Fuel Gas, MM Btu/day x 10^6 (at 100% load)	141,216	149,184
Electric Power from Power Plant, MW	17.6 (import)	87.2 (import)
Coal Input (12,235 Btu/lb)		
Tons Per Day Full Load	5,771	6,097
Tons Per Year 70% LF.	1,474,491	1,557,784

OPERATING COSTS IN THOUSANDS OF DOLLARS

Coal Costs		
At $1/MM Btu	$36,080	$38,120
At $2/MM Btu	72,160	76,240
Operating Costs		
Operating Labor	$2,780	$2,780
Catalysts and Chemicals	120	130
Utilities - Water at 0.40/M gal	280	320
Ash Disposal, $4/ton	580	610
TOTAL OPERATING COSTS	3,760	3,840
Maintenance, Labor	2,010	2,370
Maintenance, Materials	3,020	3,550
TOTAL MAINTENANCE COSTS	5,030	5,920
Adm. and Support Labor	1,440	1,545
TOTAL*	$10,230	$11,305

†Annual operating costs at 7/1/76 price level excluding fixed charges and fuel.

*General and administrative expenses, property taxes, and insurance costs are not included above. These costs are treated as a fixed charge equal to 2.4% of the total capital requirement.



PRODUCT GAS COMPOSITION	
COMPONENT	MOL %
CH_4	0.05
H_2	27.90
CO	58.87
CO_2	2.27
H_2S	0.12
COS	0.08
N_2	1.04
Ar	–
NH_3	–
H_2O vapor	9.67
	100.00
TOTAL M/H	43,360
LB/H	875,000
MOL WT	20.18

NOTES:

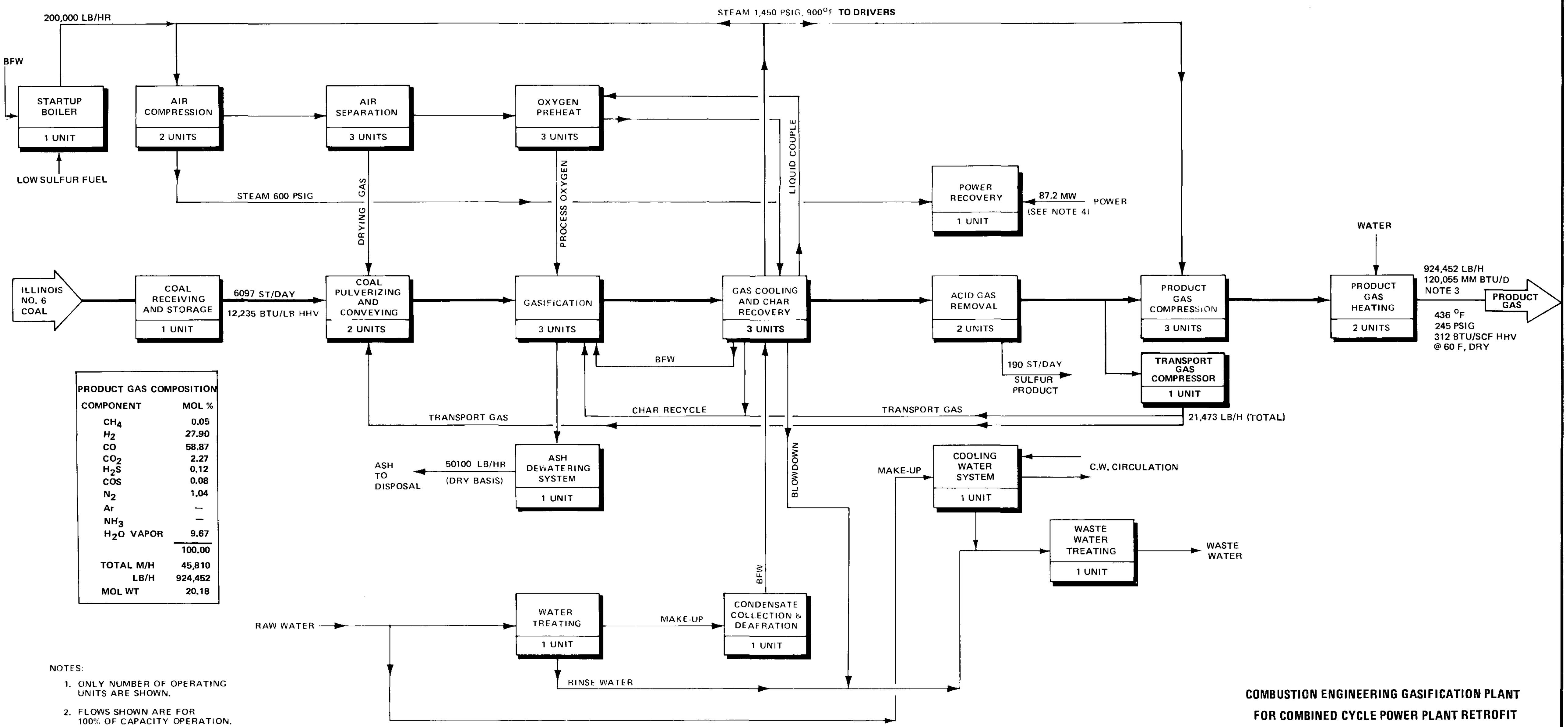
1. ONLY NUMBER OF OPERATING UNITS ARE SHOWN.
2. FLOWS SHOWN ARE FOR 100% OF CAPACITY OPERATION.
3. STREAM HEAT CONTENTS INCLUDE HIGHER HEATING VALUE AND SENSIBLE HEAT ABOVE 60°F.
4. POWER INPUT IS PLANT POWER CONSUMPTION LESS GROSS POWER RECOVERED.

SOURCE: ADAPTED FROM EPRI REPORT AF-244 PROJECT 239, DWG FOR CASE EXL, PG 185

COMBUSTION ENGINEERING GASIFICATION PLANT FOR STEAM BOILER POWER PLANT RETROFIT

FIGURE 3–1

OVERALL BLOCK FLOW DIAGRAM



PRODUCT GAS COMPOSITION	
COMPONENT	MOL %
CH_4	0.05
H_2	27.90
CO	58.87
CO_2	2.27
H_2S	0.12
COS	0.08
N_2	1.04
Ar	–
NH_3	–
H_2O VAPOR	9.67
	100.00
TOTAL M/H	45,810
LB/H	924,452
MOL WT	20.18

NOTES:

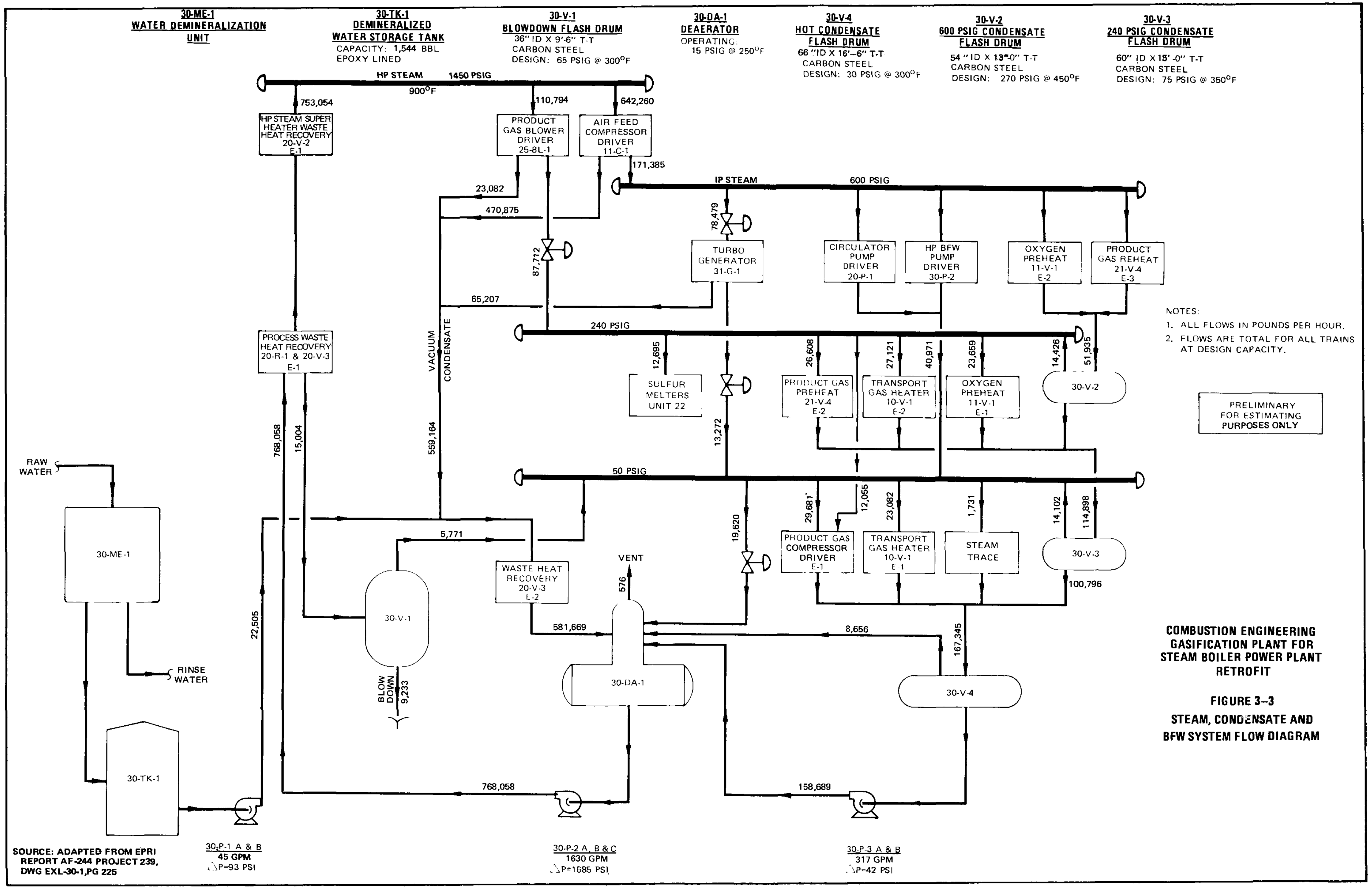
1. ONLY NUMBER OF OPERATING UNITS ARE SHOWN.
2. FLOWS SHOWN ARE FOR 100% OF CAPACITY OPERATION.
3. STREAM HEAT CONTENTS INCLUDE HIGHER HEATING VALUE AND SENSIBLE HEAT ABOVE 60°F
4. POWER INPUT IS PLANT POWER CONSUMPTION LESS GROSS POWER RECOVERED.

SOURCE: ADAPTED FROM EPRI REPORT AF-244 PROJECT 239, DWG FOR CASE EXL, PG 185

COMBUSTION ENGINEERING GASIFICATION PLANT FOR COMBINED CYCLE POWER PLANT RETROFIT

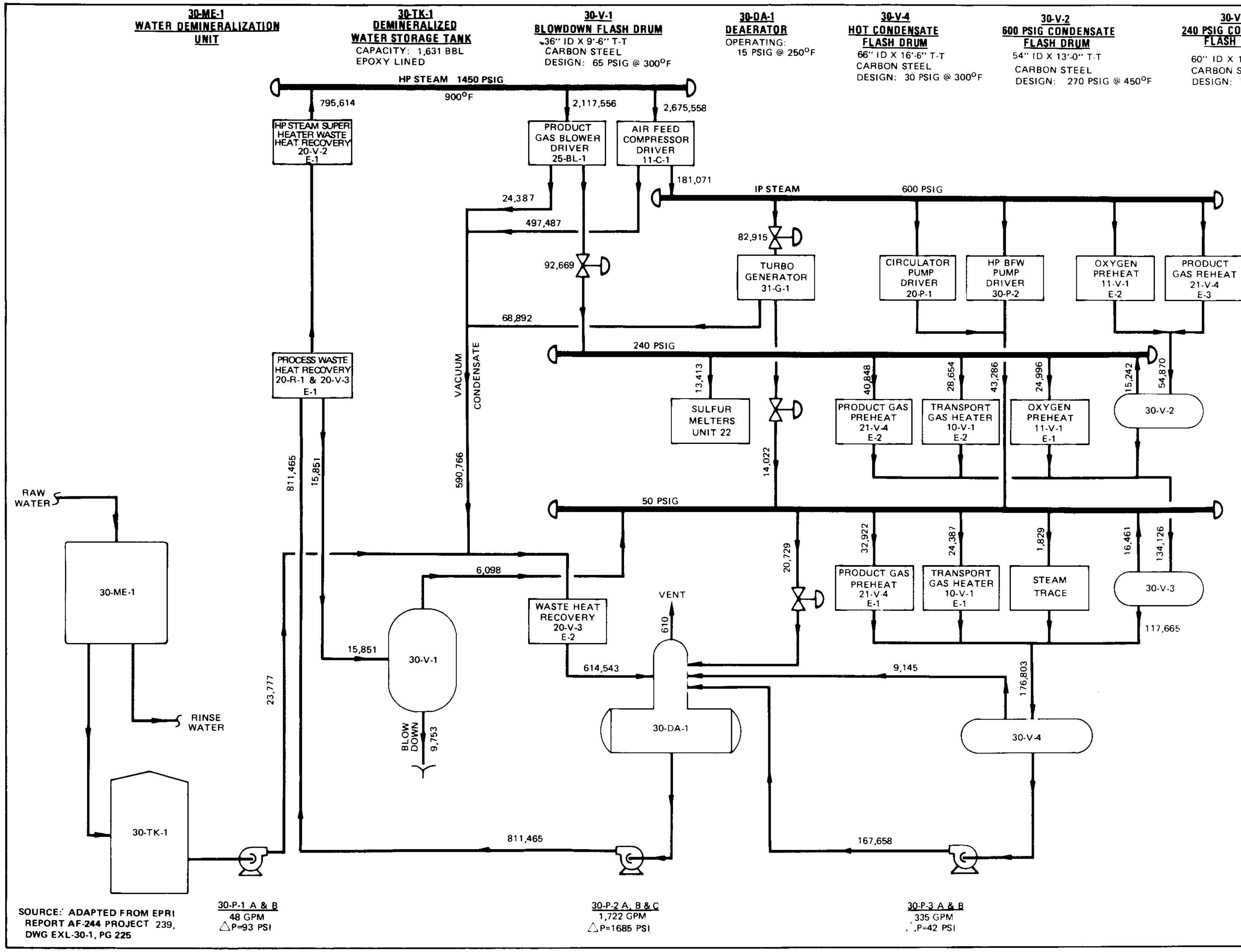
FIGURE 3–2

OVERALL BLOCK FLOW DIAGRAM



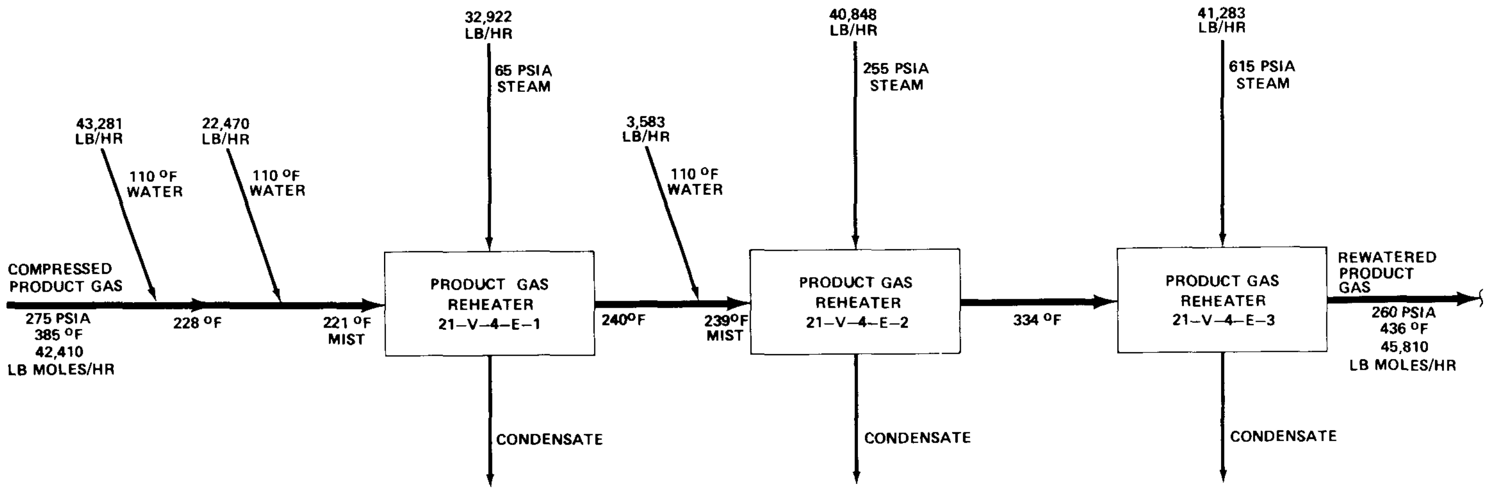
COMBUSTION ENGINEERING GASIFICATION PLANT FOR STEAM BOILER POWER PLANT RETROFIT

FIGURE 3–3
STEAM, CONDENSATE AND BFW SYSTEM FLOW DIAGRAM



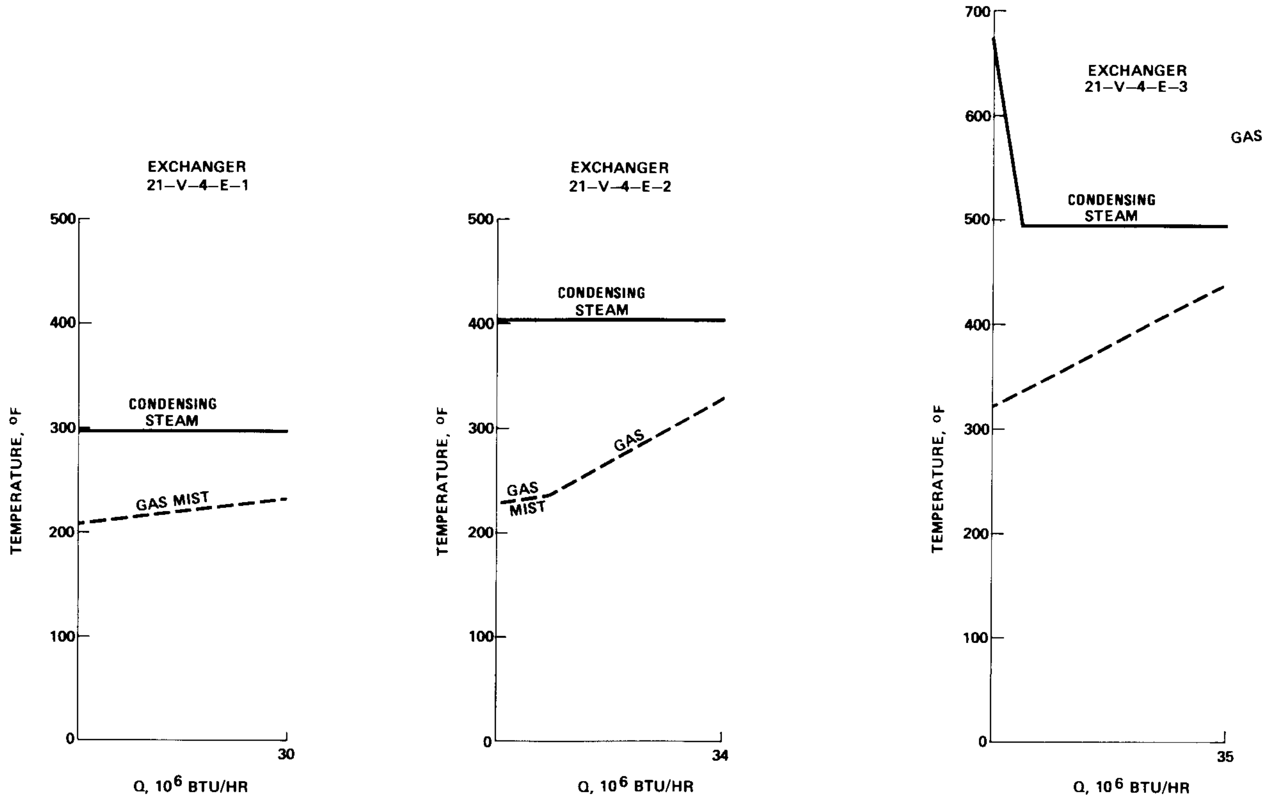
COMBUSTION ENGINEERING GASIFICATION PLANT FOR COMBINED CYCLE POWER PLANT RETROFIT

FIGURE 3-4
STEAM, CONDENSATE AND BFW SYSTEM FLOW DIAGRAM



COMBUSTION ENGINEERING GASIFICATION PLANT
FOR COMBINED CYCLE POWER PLANT RETROFIT

FIGURE 3–5
PRODUCT GAS REHEATING SYSTEM
FLOW DIAGRAM



COMBUSTION ENGINEERING GASIFICATION PLANT
FOR COMBINED CYCLE POWER PLANT RETROFIT

FIGURE 3–6
PRODUCT GAS REHEATING SYSTEM
HEAT EXCHANGER PROFILES

Section 4

TEXACO COAL GASIFICATION PROCESS

GENERAL

Basic technical and economic information on the oxygen-blown Texaco coal gasification process was obtained from EPRI Report AF-642, Case EXTC (Slurry Feed). In Case EXTC, described in Report AF-642, 10,000 tons/day of Illinois No. 6 coal was gasified to produce a medium-Btu fuel gas which was delivered at 522 psig to a combined-cycle power generation unit. The gasification and combined-cycle units were highly integrated in Case EXTC, in order to achieve a minimum heat rate.

Since the study basis for this report required that the gasification plant must "stand alone," all of the process and utility integration shown in Case EXTC was eliminated and replaced with appropriate independent facilities. The resulting independent gasification facility was adapted to each of the two retrofit cases of this report by simple proration plus redesign of the product fuel gas compression and reheat systems.

The Texaco coal gasification process is based on Texaco's broad commercial experience in the gasification of residual oil. The coal gasification process has been demonstrated on a pilot-plant scale by the Texaco Development Corporation in a 15-ton-per-day unit at Montebello, California. A 150-ton-per-day demonstration plant has been built, and is being operated by Ruhr Chemie, in West Germany. These facilities, as well as the conceptual design to be described in this section, use oxygen as the oxidant, and produce a medium-Btu gas having a heating value of approximately 300 Btu/scf.

PROCESS DESCRIPTION

The Texaco coal gasification process employs a downflow, entrained-bed type of gasifier operating at approximately 600 psig. The process coal is pulverized to a fine mesh in the coal preparation area and slurried with water. The resultant slurry, 66.5 percent by weight coal, is then pumped to reaction pressure and combined with 98 percent purity oxygen in a specially designed burner at the top of the gasifier. The gasifier is a refractory-lined pressure vessel. Reaction conditions are closely controlled to maximize the conversion of coal to hydrogen and carbon monoxide at a pressure of 600 psig and temperatures in excess of 2000°F. Under this range of operating conditions, the bulk of the ash in the coal turns to slag, is quenched in water at the bottom of the gasifier, and is removed from the gasifier by means of a lockhopper.

The hot raw product gas, containing some flyash and soot, flows to a waste heat boiler where the temperature of the gas is reduced and high-pressure steam is produced. The cooled raw product gas is then further cooled and flyash and soot are removed in a carbon scrubber. The particulate-free raw product gas is then further cooled to 100°F and sent to the acid gas removal unit.

The water containing flyash and soot from the carbon scrubber and water from the gasifier slag quench flow to a water clarifier. Recovered water is reused and a concentrated stream of water, soot, and flyash is recycled to the coal slurry preparation area.

The acid gas removal process employed in this facility is the Selexol® process. In this process step, the raw product gas is treated for removal of carbon dioxide and sulfur-containing compounds. The sour offgases from this unit are sent to the sulfur recovery section consisting of a conventional Claus plant coupled with a Bevon-Stretford tailgas treating unit. The clean medium-Btu product gas from the Selexol unit is preheated and expanded to the required delivery pressures.

In both the boiler retrofit and combined-cycle retrofit cases, a small portion of the medium-Btu gas produced is consumed within the gasification facility itself. This fuel gas is expanded to the system pressure of 16.1 psia and used for steam superheating. The power recovered in the expansion process is used to drive the air compressor in the air separation plant.

The remaining support and utility facilities incorporated in this design include the coal handling and conveying units, air separation plant, cooling water system, raw water and wastewater treatment units, steam superheating, and power generation equipment. Detailed process and equipment descriptions can be found in EPRI Report AF-642.

DESIGN BASES

Table 4-1 is a summary of the major process design bases for the Texaco gasification system used in this retrofit study. The bulk of this information was obtained from Case EXTC as given in EPRI Report AF-642. Product gas flow rates were specified to meet the fuel gas demands of the retrofit power plants. Corresponding new coal feed rates were then obtained by proration based upon the specified product gas flows. These prorate calculations were based upon the independent gasification facility which resulted from separating the integrated gasification and combined-cycle systems presented in EPRI Report AF-642.

The fuel gas delivery pressures used for the boiler and for the combined-cycle plants are the same as those used in the Combustion Engineering cases, i.e., 15 psig and 245 psig, respectively. The gas delivery temperatures of 329^{o}F for the boiler plant and 430^{o}F for the combined-cycle plant are those produced by expansion of gas from 525 psia and 580^{o}F to the required delivery pressures. The gas used as plant fuel within the gasification facilities is expanded to 16.1 psia in both cases.

Overall utility requirements were established by balancing each gasification system individually rather than by proration from Case EXTC. EPRI indicated that if import power were required by the utility balance it would be available from the power plant, thereby reducing the net power plant output by an equivalent amount. The converse was also true: an export from the gasification facility would add to the net power plant output. The boiler retrofit case was a power exporter, while the combined-cycle retrofit case was a power importer.

All environmental regulations pertaining to an Illinois location have been designed for, and are described in EPRI Report AF-642.

BOILER RETROFIT CASE

A grass-roots Texaco gasification system to supply the fuel gas requirements "over-the-fence" to a 486 MW gas-fired steam boiler is shown schematically in the Overall Block Flow Diagram, Figure 4-1. This plant consumes 6333 tons/day of Illinois No. 6 coal. The material balance and product gas composition are given in this diagram.

Figure 4-1 also shows the number of parallel trains required for the main processing facilities and the necessary offsite, utility, and environmental facilities. The size of each unit relative to the corresponding unit in Case EXTC is shown in Table 4-2.

The steam, condensate, and boiler feedwater system is shown in the flow diagram, Figure 4-3. There is no integration of the gasification plant steam, condensate, and boiler feedwater systems with the corresponding systems in the power generating unit.

The overall utility balance indicates a power production of 153,145 kW. This exceeds the total power consumption of 142,499 kW by 10,646 kW, resulting in the net export of power from the gasification facility.

The heat-transfer schemes assumed for product fuel gas heating and for superheater flue gas heat recovery are shown in Figures 4-5. These schemes include the revisions required by the elimination of the integration of the gasification system with the power plant as used in Case EXTC.

COMBINED-CYCLE RETROFIT CASE

Fuel gas requirements for a 598 MW combined-cycle unit are supplied by the grass-roots plant shown schematically in the Overall Block Flow Diagram, Figure 4-2. No integration of facilities with the power plant is assumed. The gasifier consumes 6624 tons/day of Illinois No. 6 coal to produce 881,834 lb/hr fuel gas. The material balance and product gas composition are shown in Figure 4-2. The product gas composition is the same as for the boiler retrofit case.

The block flow diagram differs from that for the boiler case in that separate expander systems are used for the main product gas and for the superheater fuel gas. The size of each unit relative to the corresponding unit in Case EXTC is given in Table 4-2.

The steam, condensate, and boiler feedwater system is shown in the flow diagram, Figure 4-4. As in the boiler retrofit case, there is no integration of the gasification plant steam, condensate, and boiler feedwater systems with those in the power plant.

The overall utility balance indicates a total power consumption of 149,044 kW. This exceeds the total power production of 138,268 kW, resulting in a net import requirement of 10,776 kW to be supplied by the power plant.

The heat-transfer schemes assumed for product fuel gas heating and for superheater flue gas heat recovery are shown in Figures 4-6. These schemes include the revisions required by the elimination of the integration of the gasification system with the power plant as used in Case EXTC.

ECONOMICS

Capital Investment Basis

In general, the capital investment cost estimates were obtained by adjusting the estimate for Case EXTC (Slurry Feed) in Table ET-8, p. 356, of EPRI Report AF-642 to agree with the bases established for this report. The capital investment bases for this report are given in Table 1-4.

The cost adjustments for changes in process equipment were made on the size comparisons and sparing philosophy stated in Table 4-2 for the process trains. Appropriate cost factors for such size adjustments were used.

Gas expansion equipment to reduce the 600 psig gas delivery pressure of Case EXTC to the 15 psig and 245 psig pressures established for the boiler and combined-cycle retrofit plants, respectively, was also included.

Escalation was not added, since the estimates for Case EXTC (Slurry Feed) are at the mid-1976 price level established for this report.

Capital investment costs are summarized in Table 4-3. The 20-percent contingency can be considered as divided into two parts: a 15-percent project contingency to cover estimating uncertainties, and a 5-percent process contingency to cover the uncertainties in developing a process from the conceptual stage to commercial reality.

Operating Charges

A summary of operating costs is presented in Table 4-4. These costs were derived by adjusting the estimates for Case EXTC (Slurry Feed) in Table ET-9, p. 357 of EPRI Report AF-642, to the smaller-size plant contained in this report.

The operating labor and maintenance labor estimates were based upon the requirements outlined for Case EXTC (Slurry Feed) and the size comparison and sparing philosophy outlined in Table 4-2.

Other operating costs were ratioed from the Case EXTC (Slurry Feed) numbers or developed on the bases set forth in Table 1-5.

Overall Economic Results

Overall economic results of this report are presented in Tables 8-1 and 8-2. Thirty-year levelized costs are presented in Tables A-3 and A-4 in the Appendix.

Table 4-1

SUMMARY OF DESIGN BASES
TEXACO GASIFICATION CASES

	Combined Cycle	Steam Boiler
Coal Feed Rate, lb/hr (mf)†	528,816	505,585
Oxygen-Coal Ratio, lb (dry)/lb (mf)*†	0.858	0.858
Oxidant Temperature, ^{o}F	300	300
Coal Slurry Conc., wt% coal	66.5	66.5
Gasifier Exit Pressure, psig	600	600
Crude Gas Temperature, ^{o}F	2300-2600	2300-2600
Fuel Gas Temperature at BL, ^{o}F	430	329
Fuel Gas Pressure at BL, psig	245	15
Net Fuel Gas Production Rate, MM scfh†	16.67	16.11
Net Fuel Gas, Mscf/t mf coal†	63.05	63.73
HHV, Fuel Gas, Btu/scf†	290	290

†Dry basis (mf) = moisture free.
*100% O_2.

Table 4-2

TRAIN REQUIREMENTS AND SIZE BASIS
TEXACO GASIFICATION CASE

Major Equipment Section	EPRI Report AF-642 Case EXTC - 10,000 T/D Coal		Boiler Case - 6333 T/D Coal			Combined Cycle Case - 6624 T/D Coal		
	Operating	Spare	Operating	Spare	Size Ratio*	Operating	Spare	Size Ratio*
Coal Handling	1	0	1	0	0.63	1	0	0.66
Oxidant Feed	5	0	4	0	0.79	4	0	0.83
Wet Coal Grinding	2	0	2	0	0.63	2	0	0.66
Slurry Preparation	1	0	1	0	0.63	1	0	0.66
Gasification	5	1	4	0	0.95	4	0	1.00
Ash Handling	1	0	1	0	0.63	1	0	0.66
Particulate Scrubbing	5	1	4	0	0.95	4	0	1.00
Gas Cooling	3	0	2	0	0.95	2	0	1.00
Acid Gas Removal	3	0	2	0	0.95	2	0	1.00
Sulfur Recovery and Tail Gas Treating	2	1	2	1	0.63	2	1	0.66
Steam, BFW and Condensate System								
Condensate Collection and Deaeration	1	0	1	0	0.31	1	0	0.30
Water Treating	1	0	1	0	0.63	1	0	0.66
Cooling Water System	1	0	1	0	0.20	1	0	0.24
Effluent Water Treating	1	0	1	0	0.63	1	0	0.66

$$\text{*Size Ratio} = \frac{\text{Retrofit Case}}{\text{Case EXTC}}$$

Table 4-3

TEXACO COAL GASIFICATION PROCESS
CAPITAL INVESTMENT COST SUMMARY
70% OPERATING LOAD FACTOR

	Boiler Retrofit Case	Combined Cycle Retrofit Case
Plant Investment	in Thousands of Dollars	
Coal Handling	$ 14,900	$ 15,500
Oxidant Feed	81,100	83,600
Gasification and Ash Handling	15,800	16,400
Gas Cooling	42,900	44,600
Acid Gas Removal and Sulfur Recovery	19,900	20,500
Steam, Condensate, and BFW	3,700	4,300
Support Facilities	37,300	38,600
	215,600	223,500
Contingency	43,100	44,700
TOTAL PLANT INVESTMENT	$258,700	$268,200

Price of Coal, $/MMBtu	$1	$2	$1	$2
Capital Charges	in Thousands of Dollars			
Preproduction Costs	$16,800	$18,100	$17,400	$18,700
Paid-up Royalties	1,300	1,300	1,300	1,300
Initial Chemical and Catalyst Charge	300	300	300	300
Construction Loan Interest	32,300	32,300	33,500	33,500
TOTAL CAPITAL CHARGES	50,700	52,000	52,500	53,800
Total Depreciable Capital*	309,400	310,700	320,700	322,000
Working Capital	21,100	30,800	21,900	32,100
TOTAL CAPITAL REQUIREMENT	$330,500	$341,500	$342,600	$354,100

*Sum of total plant investment and total capital charges.

Table 4-4

TEXACO COAL GASIFICATION PROCESS
OPERATING COST SUMMARY†

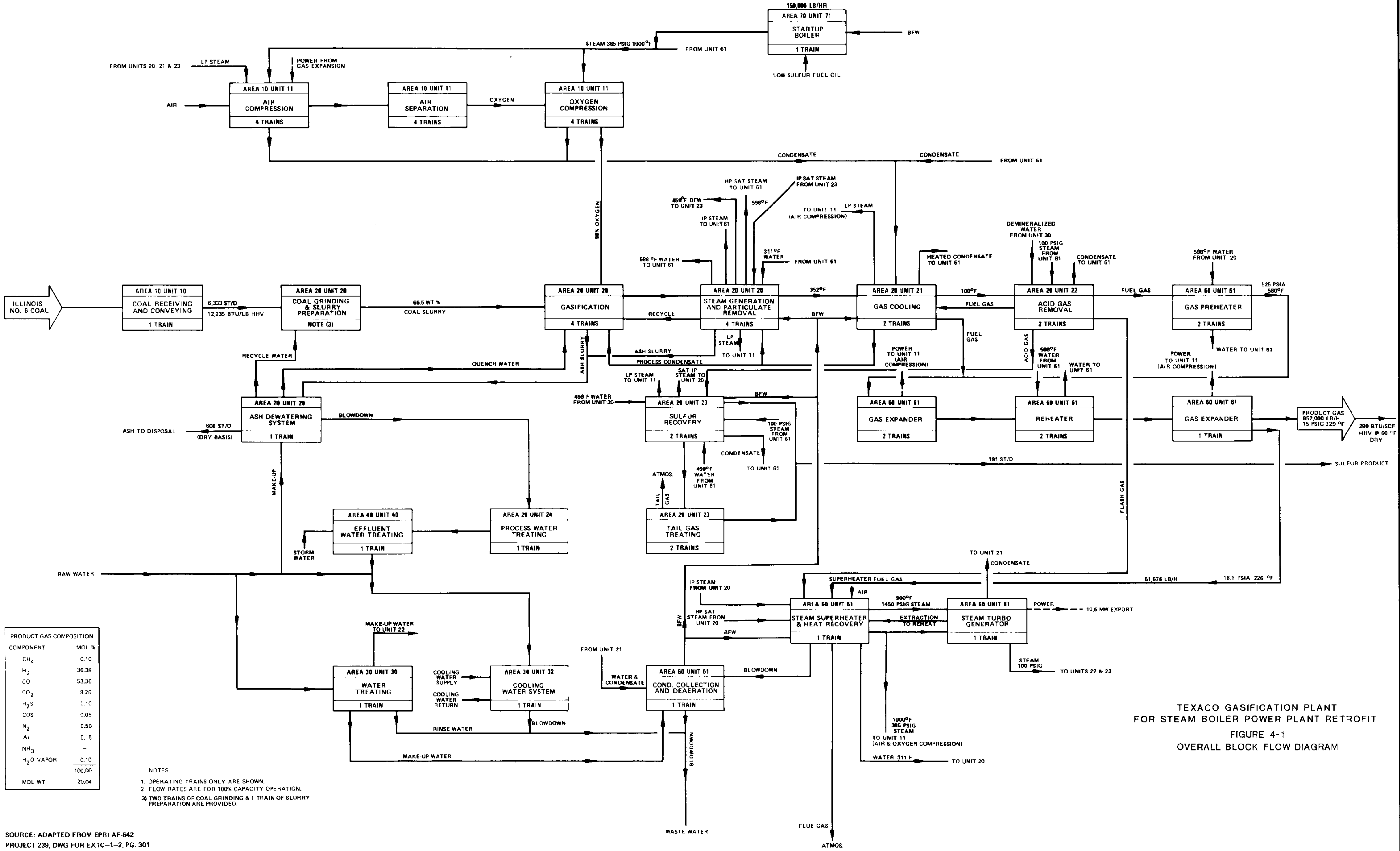
CONDITIONS	Boiler Retrofit Case	Combined Cycle Retrofit Case
Operating Load Factor	70%	70%
Net Production		
Fuel Gas, MM Btu/day x 10^6 (at 100% load)	154,968	162,096
Electric Power Import or Export, MW	10.6 (export)	10.8 (import)
Coal Input (12,235 Btu/lb)		
Tons Per Day Full Load	6,333	6,624
Tons Per Year - 70% LF	1,618,082	1,692,432

OPERATING COSTS IN THOUSANDS OF DOLLARS

Coal Costs		
At $1/MM Btu	$39,595	$41,414
At $2/MM Btu	79,190	82,828
Operating Costs		
Operating Labor	$ 2,290	$ 2,290
Catalysts and Chemicals	170	170
Utilities - Water at 0.40/M gal	300	350
Ash Disposal, $4/ton	620	650
TOTAL OPERATING COSTS	3,380	3,460
Maintenance, Labor	2,440	2,530
Maintenance, Materials	3,660	3,790
TOTAL MAINTENANCE COSTS	6,100	6,320
Adm. and Support Labor	1,420	1,445
TOTAL*	$10,900	$11,225

†Annual operating costs at 7/1/76 price level excluding fixed charges and fuel.

*General and administrative expenses, property taxes, and insurance costs are not included above. These costs are treated as a fixed charge equal to 2.4% of the total capital requirement.



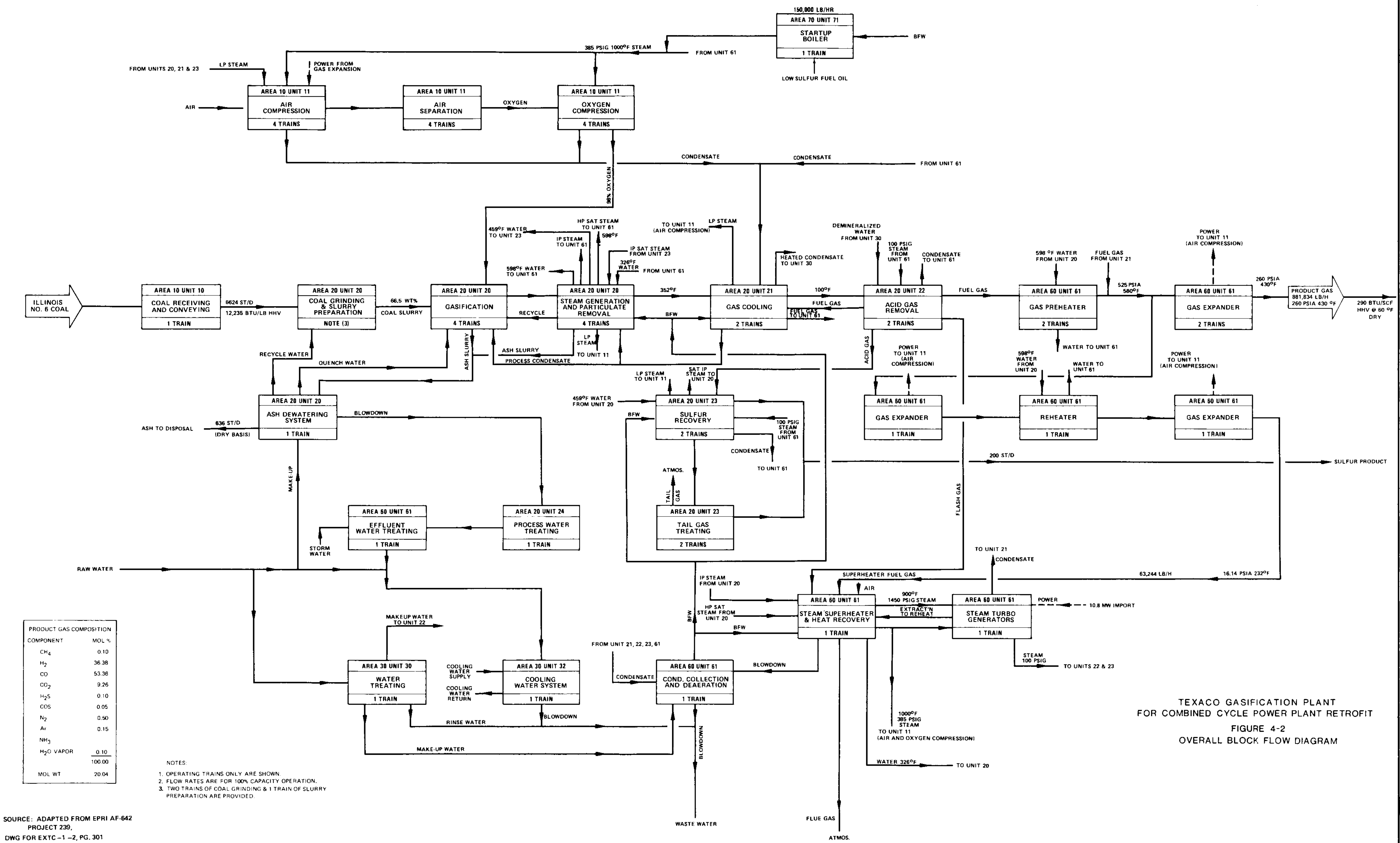
PRODUCT GAS COMPOSITION	
COMPONENT	MOL %
CH_4	0.10
H_2	36.38
CO	53.36
CO_2	9.26
H_2S	0.10
COS	0.05
N_2	0.50
Ar	0.15
NH_3	–
H_2O VAPOR	0.10
	100.00
MOL WT	20.04

NOTES:

1. OPERATING TRAINS ONLY ARE SHOWN.
2. FLOW RATES ARE FOR 100% CAPACITY OPERATION.
3) TWO TRAINS OF COAL GRINDING & 1 TRAIN OF SLURRY PREPARATION ARE PROVIDED.

SOURCE: ADAPTED FROM EPRI AF-642
PROJECT 239, DWG FOR EXTC–1–2, PG. 301

TEXACO GASIFICATION PLANT
FOR STEAM BOILER POWER PLANT RETROFIT
FIGURE 4-1
OVERALL BLOCK FLOW DIAGRAM



PRODUCT GAS COMPOSITION	
COMPONENT	MOL %
CH_4	0.10
H_2	36.38
CO	53.36
CO_2	9.26
H_2S	0.10
COS	0.05
N_2	0.50
Ar	0.15
NH_3	
H_2O VAPOR	0.10
	100.00
MOL WT	20.04

NOTES:

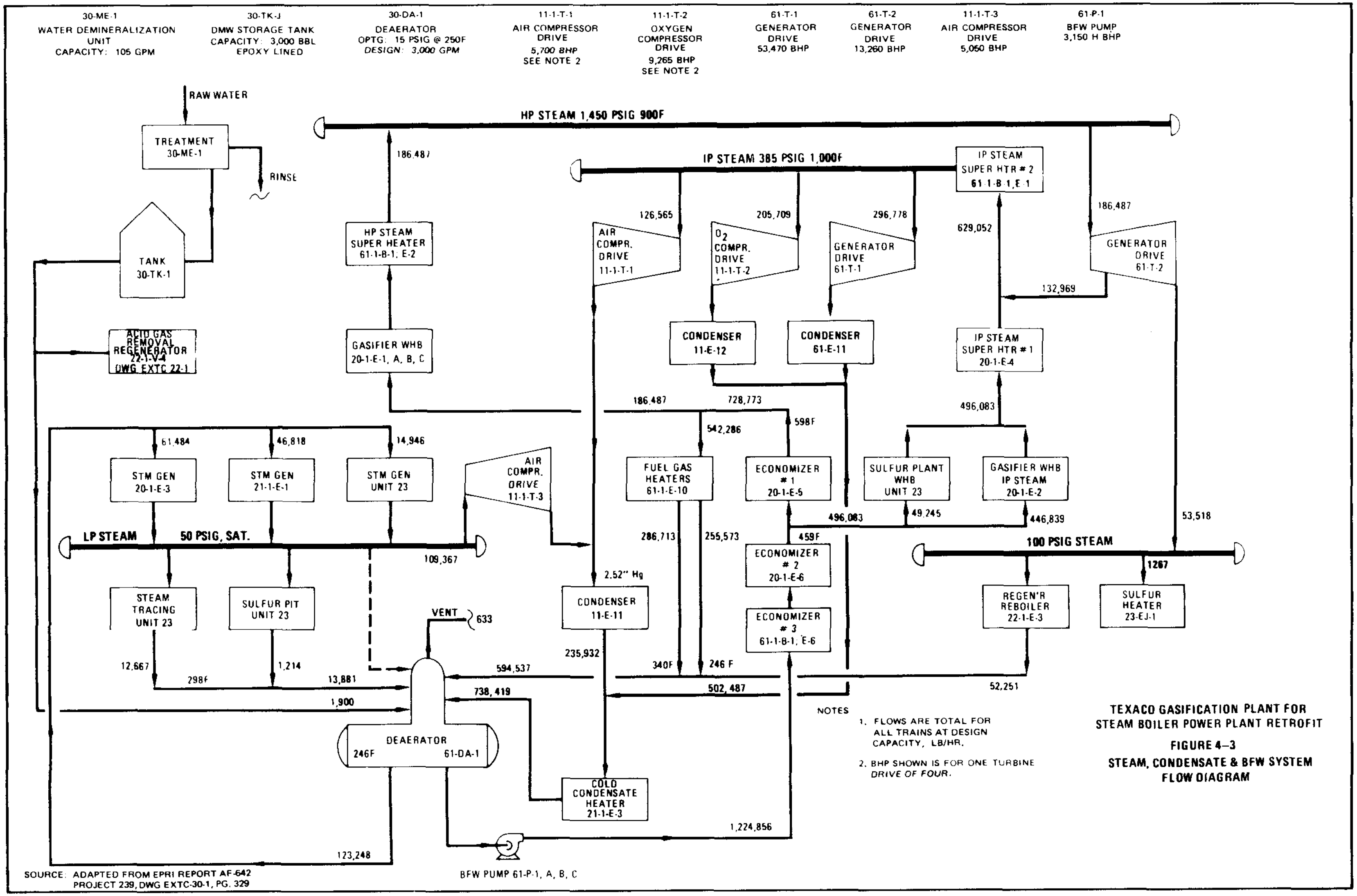
1. OPERATING TRAINS ONLY ARE SHOWN.
2. FLOW RATES ARE FOR 100% CAPACITY OPERATION.
3. TWO TRAINS OF COAL GRINDING & 1 TRAIN OF SLURRY PREPARATION ARE PROVIDED.

SOURCE: ADAPTED FROM EPRI AF-642 PROJECT 239, DWG FOR EXTC-1-2, PG. 301

TEXACO GASIFICATION PLANT FOR COMBINED CYCLE POWER PLANT RETROFIT

FIGURE 4-2

OVERALL BLOCK FLOW DIAGRAM



NOTES

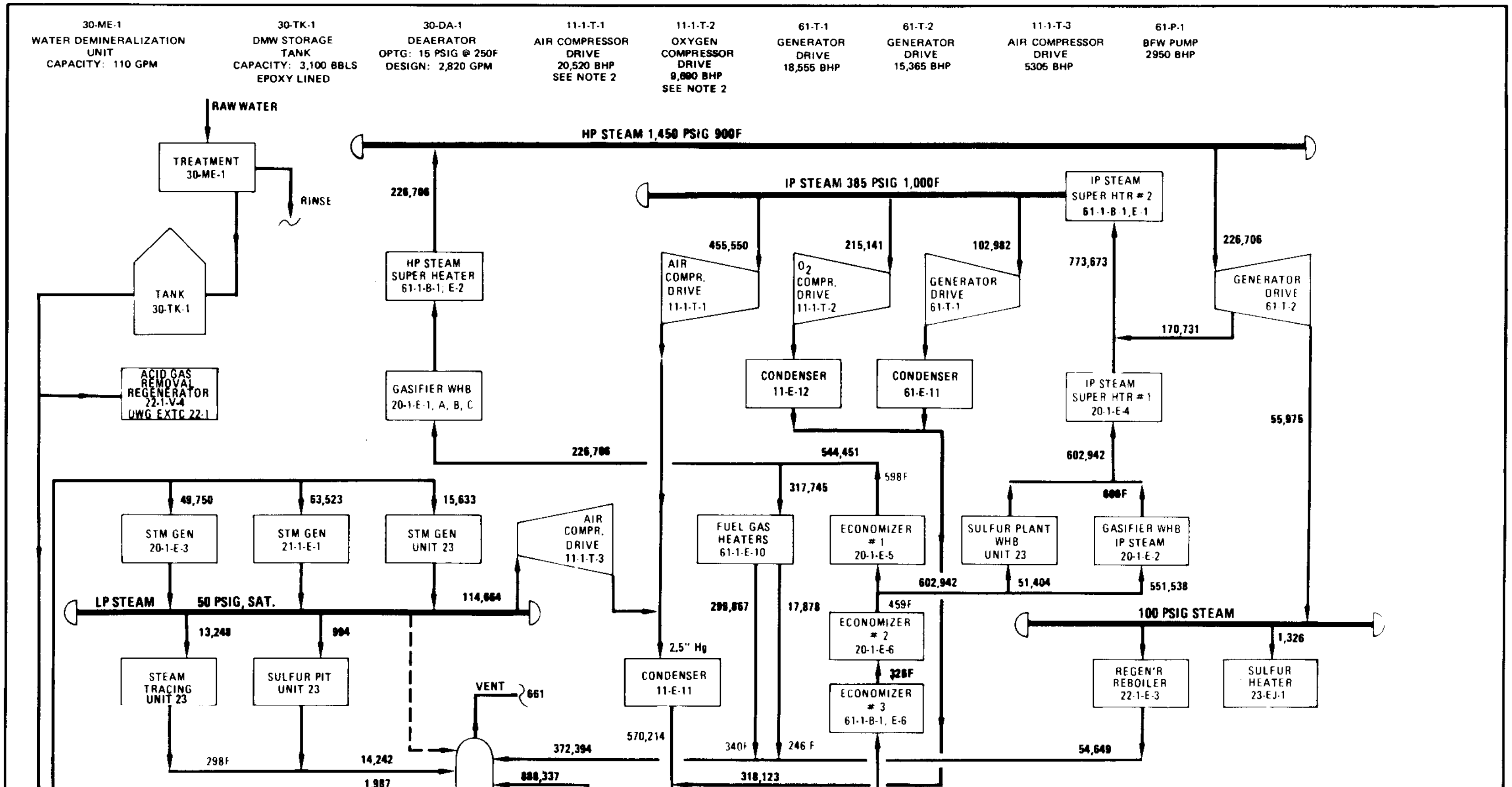
1. FLOWS ARE TOTAL FOR ALL TRAINS AT DESIGN CAPACITY, LB/HR.
2. BHP SHOWN IS FOR ONE TURBINE DRIVE OF FOUR.

SOURCE: ADAPTED FROM EPRI REPORT AF-642 PROJECT 239, DWG EXTC-30-1, PG. 329

TEXACO GASIFICATION PLANT FOR STEAM BOILER POWER PLANT RETROFIT

FIGURE 4–3

STEAM, CONDENSATE & BFW SYSTEM FLOW DIAGRAM



TEXACO GASIFICATION PLANT FOR
COMBINED CYCLE POWER PLANT RETROFIT

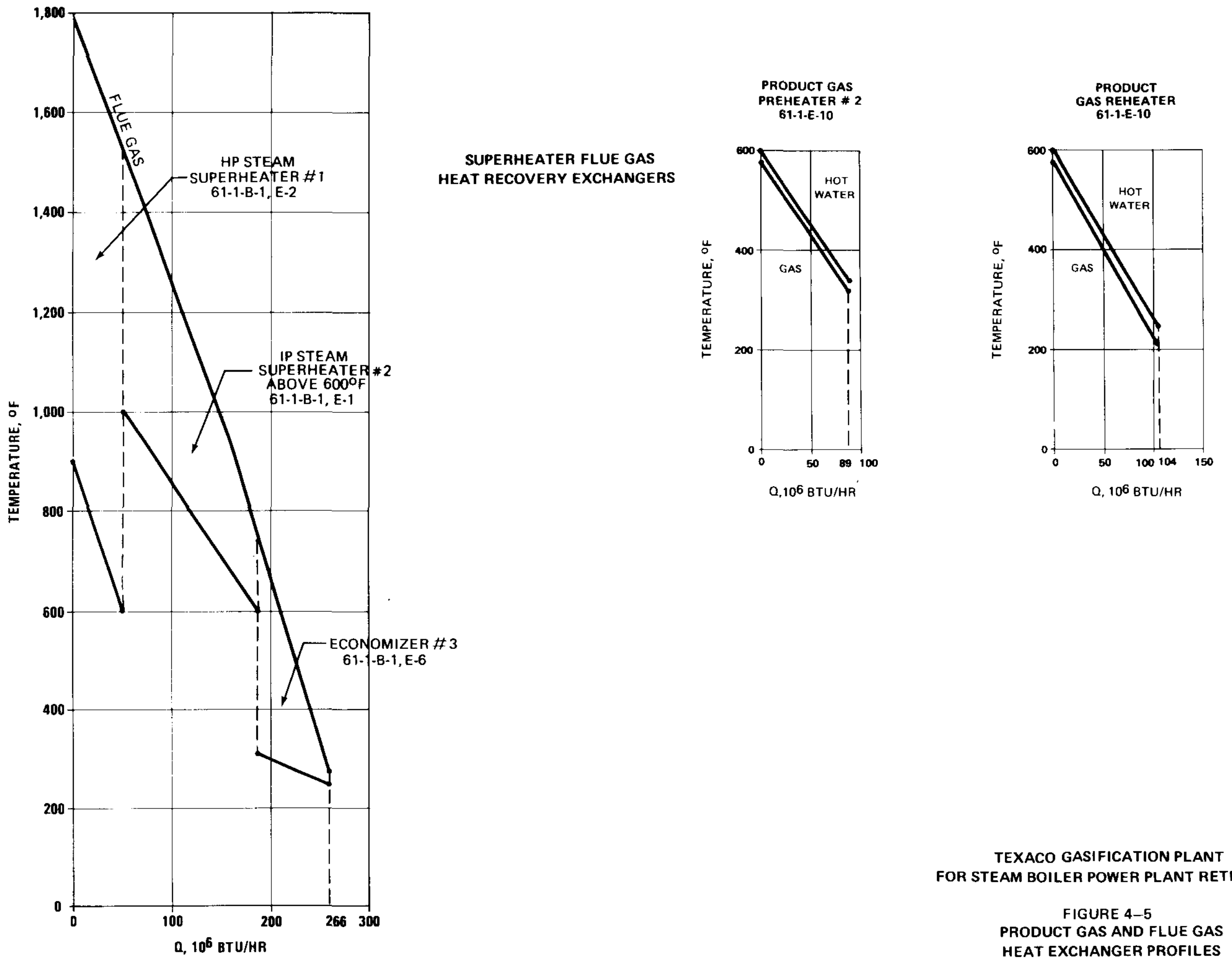
FIGURE 4–4

STEAM, CONDENSATE & BFW SYSTEM
FLOW DIAGRAM

NOTES

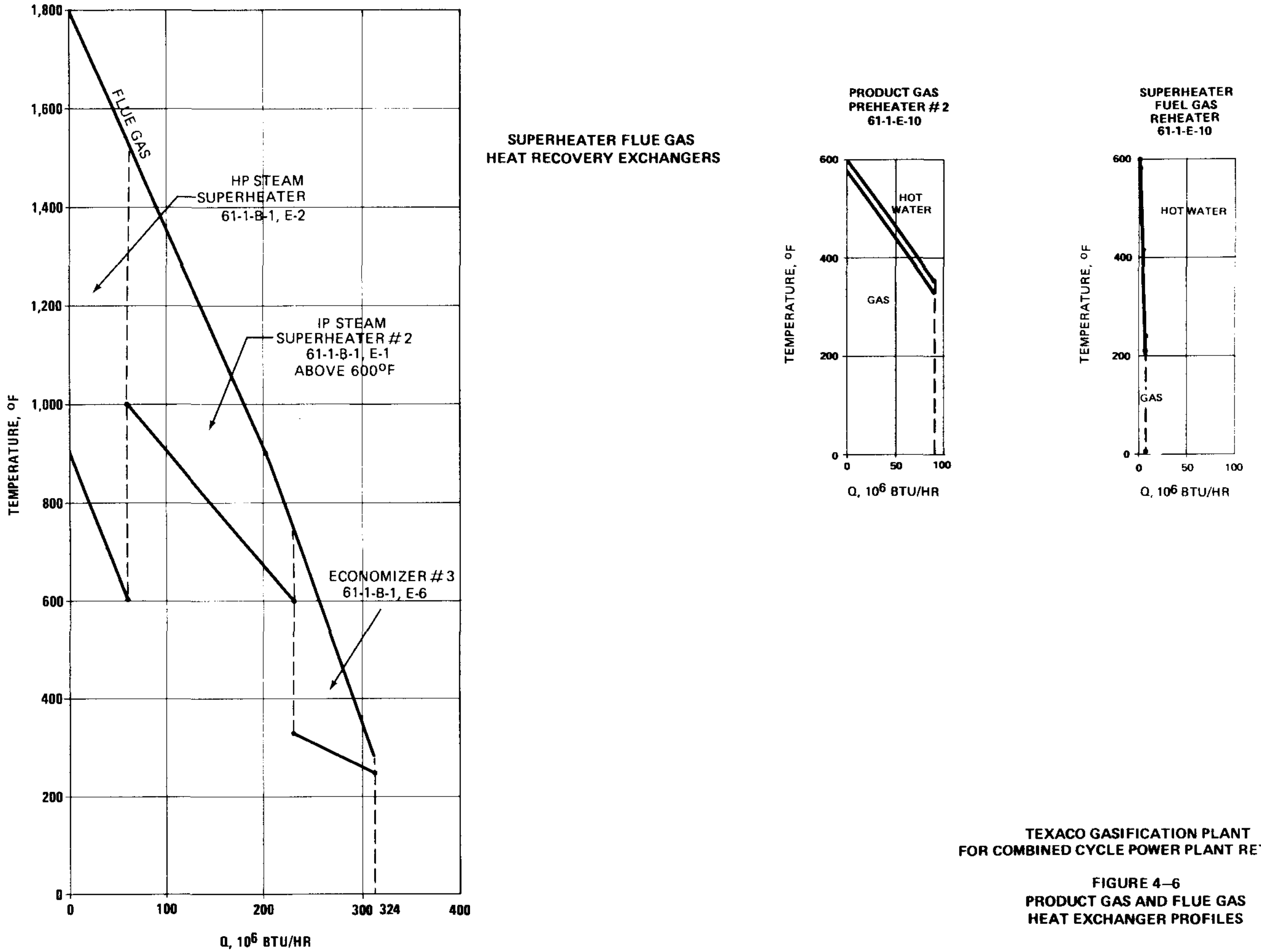
1. FLOWS ARE TOTAL FOR ALL TRAINS AT DESIGN CAPACITY, LB/HR.
2. BHP SHOWN IS FOR ONE TURBINE DRIVE OF FOUR.

SOURCE: ADAPTED FROM EPRI REPORT AF-642
PROJECT 239, DWG EXTC-30-1, PG. 329



TEXACO GASIFICATION PLANT
FOR STEAM BOILER POWER PLANT RETROFIT

FIGURE 4–5
PRODUCT GAS AND FLUE GAS
HEAT EXCHANGER PROFILES



TEXACO GASIFICATION PLANT
FOR COMBINED CYCLE POWER PLANT RETROFIT

FIGURE 4–6
PRODUCT GAS AND FLUE GAS
HEAT EXCHANGER PROFILES

Section 5

NATURAL-GAS-FIRED POWER PLANT RETROFIT

GENERAL

All steam boilers are designed and constructed to operate most effectively with a specified fuel, and any fuel change requires some boiler design and operational changes. The extent of the boiler design and operational changes depends on the difference between some important properties of the specified and the substitute fuels. In the case where the specified fuel is natural gas and the substitute fuel is a medium-Btu gas, the important properties are relatively similar, so the extent of the design and operational changes is relatively minor.

The fuel considerations which affect the design and operation of the boiler are: the quantities of fuel and air required, the fuel combustion temperature, and the emissivity of the resultant combustion product gases. These three parameters are important because they affect the heat transfer rates in the radiant and convection sections of the boiler. All three of these parameters are affected by the amount of excess air supplied to the boiler. As a result, varying the amount of excess air is an effective operational change which can be made when the boiler is operated with a medium-Btu fuel gas.

This section describes the representative boiler to be evaluated for retrofit in this study; discusses the retrofit of the representative boiler to burn medium-Btu coal-derived gas; and concludes with the estimated economics of the retrofit of the representative boiler.

NATURAL-GAS-FIRED POWER PLANT DESCRIPTION

The boiler selected for retrofit is approximately five years old. It burns natural gas as the primary fuel and Bunker "C" oil as a secondary fuel.

The plant site has rail access and an adequate area to accommodate coal storage, coal handling, and the gasification plant. For purposes of this study, the latter facility would be located approximately 1000 feet northwest of the steam generator.

Major Plant Equipment and Systems

The Babcock & Wilcox boiler is a drum-type, natural circulation unit. The unit is pressurized and designed for outdoor installation. With natural-gas firing, it is designed to generate steam at a maximum continuous rated (MCR) load of 3,464,850 lb/hr at 2300 psig and 950°F, and it has a net rating of 486.3 MWe. Original and predicted steam generator performance data are presented in Table 5-1. The equivalent quantities of fuel gas and air required for firing medium-Btu gas derived from the Combustion Engineering process and the Texaco process are also shown in Table 5-1. Boiler design data are given in Table 5-2 and a general arrangement section is shown in Figure 5-1. Figure 5-2 is the heat balance for the steam turbine cycle.

Combustion air is delivered by two 50-percent capacity forced-draft fans, each driven by a 6000 hp electric motor. Exit gas temperature is approximately 300°F, based on an ambient temperature of 80°F.

The fuel lines delivering the natural gas for the boiler include a 24-inch diameter main gas header, a 20-inch diameter burner gas header, and 12-inch vertical headers. Typical gas piping at a burner pair is a 6-inch pipe from the vertical header serving two 5-inch pipes, one to each burner. The burner exit pressure into the boiler cavity is approximately 7.5 psig.

Electrical Systems

The turbine driving the generator is a tandem, compound, reheat unit with four flow exhausts, and 26-inch exhaust buckets. The turbine is rated at 478,845 kW at 2285 psig throttle pressure and 950°F steam temperature, reheat temperature 950°F.

The generator has a water-cooled stator and a gas-cooled rotor and is rated at 585,000 kVA, 0.9 PF. The speed is 3600 rpm, and the output voltage is 22,000 volts.

The electric power is stepped up in a main transformer and distributed to the 138 kV high-voltage system in an adjacent switchyard.

RETROFIT REQUIREMENTS

Recently completed studies by boiler manufacturers (1, 2) have mutually arrived at certain consistent conclusions regarding the conversion of gas- or oil-fired boilers to burn coal-derived medium-Btu gas. These conclusions include the following for retrofit with only minor rework of the boiler for fuel burner and windbox changes:

- Boilers converted to burn medium-Btu gas (approximately 300 Btu/scf and higher) can maintain their previous rated steam capacities.
- Exhaust product flow rates will decrease slightly when firing medium-Btu gas derived from coal.

The following discussion confirms the above conclusions for retrofit of the gas-fired boiler to burn the C-E and Texaco medium-Btu gases that are produced in this study. Thus, it is estimated that the study boiler can be retrofitted to burn medium-Btu gas and provide rated steam capacity without requiring major rework of the boiler system.

Furnace Combustion Temperatures

Combustion temperatures reached inside the boiler furnace are affected by the change in fuel as shown in Figure 5-3. These temperatures were calculated based on $60^{o}F$ initial air temperature, assuming no heat loss and complete reaction of the fuel to CO_2, H_2O, O_2, and N_2 without dissociation. Boilers extract some heat of combustion and minor dissociation occurs at temperatures above $3000^{o}F$, resulting in lower combustion temperatures than those shown in Figure 5-3. However, the theoretical temperatures shown provide a basis for relative comparisons and show that medium-Btu gases have combustion temperatures approximately $400^{o}F$ higher than those of natural gas.

The adiabatic combustion temperature at the stoichiometric air-to-fuel ratio for natural gas is about $3730^{o}F$ while that for a coal-derived gas having a heating value of 290 Btu/scf is about $4100^{o}F$. Radiant heat transfer is a function of the combustion temperatures and the emissivity. Emissivity differences between natural and medium-Btu gas in the temperature range existing in the boiler furnace are small, since carbon dioxide and water vapor are the predominant radiating combustion products, and their relative compositions in the respective flue gases, at the same temperature, are approximately the same. This means that the boiler performance due to retrofitting is more dependent on the combustion temperature.

Since the combustion temperature of coal-derived medium-Btu gas is higher than that of natural gas, the effect of retrofitting on boiler performance is in the direction of a performance improvement. A study by Combustion Engineering for EPRI (2) predicted that a retrofit boiler with no changes to the heat exchange surfaces (similar to that selected for this study) would have an efficiency of 87.1 percent when fired with 292 Btu/scf gas. This compares with 84.8 percent when fired with natural gas. In this report, the boiler efficiency is assumed to remain at 84.8 percent. The effect of this assumption is a conservative increase in the estimated amount of fuel fired and a corresponding increase in the quantity of flue gas.

Volume of Gases

The volume of the gaseous fuel required to fire a boiler is inversely proportional to its heating value (1). The relationship between the high heating value of the gaseous fuel and the volume of gas per 10,000 Btu is illustrated in Figure 5-4.

The simple relationship in Figure 5-4 indicates that for a gas of about 290 Btu/scf, the volume of fuel required is about three and one-half times that required for natural gas having 1023 Btu/scf.

Two other fuel-related factors to be considered in retrofitting boilers with medium-Btu gas are the volume of air required for combustion and the volume of flue gas resulting from combustion. The quantities of air required for fuel combustion and the resulting flue gas flow rates for the natural-gas-fired boiler, and for the C-E and Texaco coal-derived-gas-fired boilers are shown in Table 5-3. These flow-rate comparisons are based on the assumptions that the same 10 percent excess air is required for each of the gas fuels and that the same quantity of heat must be provided by the coal-derived gases as for the original natural-gas fuel. In other words, the steam output of the boiler and the boiler efficiency are assumed to be the same in the medium-Btu-gas-fueled cases as in the original natural-gas-fueled case. The delivered heating values indicated on Table 5-3 represent the result of correcting the dry, $60^{o}F$, higher heating basis values for moisture and sensible heat content.

As shown by Table 5-3, the estimated fuel gas flow rates increase significantly for both the C-E and Texaco fuel gases relative to the original natural gas flow rate. The fuel gas flow rate (lb/hr) relative to that for natural gas is 4.1 times that for the C-E gas and 4.0 times that for the Texaco gas. Air required for combustion is reduced. The air flow rate (lb/hr) relative to that for natural gas is

22 percent less for the C-E gas and 20 percent less for the Texaco gas. The combustion of the fuel gases in the air results in flue gas flow rates slightly less than for the natural-gas fuel. The flue gas rate (lb/hr) relative to that for natural gas is three percent less for both the C-E gas and the Texaco gas.

The gas flow rate changes in the reference boiler, associated with retrofit to burn coal-derived fuel gas, determine the physical changes required to convert the boiler and its subsystems to use the coal-derived fuels. These physical changes are discussed in the following subsections.

Fuel Piping and Burners

Fuel piping and burners must be modified to accommodate the larger fuel gas flow rates associated with converting from natural gas to medium-Btu gas. As the heating value of the fuel gas decreases, the size of piping or ducting to transport the fuel increases. Table 5-3 shows that the volume of coal-derived gas to be delivered to the burners is four times that for natural gas firing. This means that the cross-sectional area of the fuel ducts has to be increased to four times its present size. The burners themselves have to be converted to handle the greater volume of fuel. This can be done in two ways. First, the burner size can be increased; or, second, the number of burners can be increased. It is assumed for this study that the natural-gas fuel nozzles are replaced with larger nozzles for the medium-Btu gas.

The existing physical plant layout will place restrictions on the routing of the new fuel piping. A detailed study of such restrictions was not within the scope of this study, and it has been assumed that piping of the required sizes can be accommodated.

In addition, the windbox has to be modified to accommodate the larger gas piping and reduced air flow. Since the net of both gas and air flow changes are relatively small, only minor modifications to the duct transporting the combustion air to the windbox will be required.

Flue Gas Ducting

Another factor to be considered in retrofitting the boiler to burn the medium-Btu gases is any net change in the volume of flue gases resulting from the increases in the volume of fuel gases and decrease in combustion air. The superficial gas velocities for a given combustion volume in a boiler must change in proportion to the change in combustion products gas-flow rates. This changes the residence time within the furnace section and affects the pressure losses throughout the boiler and its flue gas system. The retrofitted boiler and its draft system must be capable of handling these flue gas volumes.

In this study, the assumption that boiler efficiency will be the same for the retrofit as for the original design, and the effects of the actual chemical compositions of the C-E and Texaco gases result in no significant effect on flue gas flow rates relative to the natural-gas base case. The slight reduction in flue gas flow rate will have a negligible effect on fan discharge pressure.

Forced-Draft Fan Requirement

A basic assumption in this study is that the existing draft system will not require modification as part of the retrofit for medium-Btu gas. This assumption is consistent with the small effects on the flue gas flow noted above and with previous studies (1, 2). These studies predicted increased boiler efficiencies and reduced air flows when firing with 300 Btu/scf coal-derived gas, with the flue gas flow rates approximately equal to those produced when firing natural gas.

It is concluded that retrofit of the selected natural-gas-fired boiler to burn C-E or Texaco medium-Btu gas will probably not require modification of the draft fans to maintain the boiler's rated steam generating capacity.

Pressure on Furnace Walls

The estimated change in flue gas system pressure loss will produce a corresponding change in the pressure on the furnace walls when firing either C-E or Texaco medium-Btu gas. In the case of the selected boiler, this pressure change is approximately a six-percent reduction for both the C-E and the Texaco case. These small pressure differences can readily be accommodated in the existing boiler design.

ESTIMATE OF RETROFIT PLANT PERFORMANCE

Conversion of the selected boiler to fire a medium-Btu coal-derived fuel gas while maintaining the rated load of 3,464,850 lb/hr of steam at 2300 psig and 950°F can be accomplished by modification of two specific boiler subsystems:

- Fuel piping
- Burner windbox system

Predicted performance of the retrofitted boiler is summarized in Table 5-1 and indicates no change in output or efficiency.

Changes to the existing forced-draft fans or modifications to the boiler tubes or furnace walls should not be necessary.

ECONOMICS OF THE RETROFIT

Capital Investment Basis

The capital investment bases for this report are given in Table 1-4 with the following exceptions. The overall contingency used in the steam boiler economic evaluation is 15 percent rather than the 20 percent used in the gasification economic evaluations, since the 5-percent process contingency is not applicable to this case. In addition, the retrofit work does not require paid-up royalties, preproduction costs, or working capital requirements. Construction loan interest is only four percent rather than 12.4 percent, because the construction expenditure schedule is less than one year rather than three years.

The price level of the estimates is mid-1976, and Chicago, Illinois, has been assumed for pricing and productivity. Scope of the retrofit work has been defined earlier in this section.

A small difference in insulation requirements for the fuel gas lines has not been evaluated. The capital investment costs are summarized in Table 5-4.

Operating Charges

The summary of operating charges, excluding fuel and fixed charges, is presented in Table 5-5. These costs were developed on the basis stated in Table 1-5. Column one summarizes the normal cost without the retrofit. Column two summarizes the additional costs after the retrofit. Column three is the total of columns one and two.

The normal annual maintenance cost has been established at two percent (from Table 1-5) of the $70,000,000 (7-1-72 price level) plant cost, excluding construction loan interest. The additional maintenance for the retrofit has been assumed to be 100 percent of the normal maintenance allowance. This additional yearly expenditure is for gradual improvement of the older power plant so that it has the same investment life as the newer gasification plant. The operating labor requirements, exclusive of maintenance and administrative and support labor, have been based on internal information, Federal Power Commission reports, and other published reports.

Overall Economic Results

Economics associated with both the Combustion Engineering and Texaco process gasification plants are detailed in Sections 3 and 4, respectively. Overall economic results are presented in Tables 8-1 and 8-2. Thirty-year levelized costs are presented in Tables A-3 and A-4 in the Appendix.

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1. A.M. Frendberg, "Performance Characteristics of Existing Utility Boilers when Firing Low-Btu Gas." Proceedings of the Electric Power Research Institute Conference on Power Generation — Clean Fuels Today. Monterey, California, April 1974.

2. U.S. Department of Commerce. National Technical Information Service. Assessment of the Capability of Firing Clean Low-Btu Gases in Existing Coal-, Oil- and Gas-Fired Steam Generators. Washington, D.C.: Government Printing Office, December 1975. PB-248-328. (Prepared by Combustion Engineering, Inc. for Electric Power Research Institute).

Table 5-1

ORIGINAL AND PREDICTED STEAM GENERATOR PERFORMANCE

	Original Performance Natural Gas	Predicted Performance with Modifications	
		C-E	Texaco
Rating, kW Net, Excl. Gasifier Req'mt	486,309	486,309	486,309
Evaporation, lb/hr	3,464,850	3,464,850	3,464,850
SH Outlet Pressure, psig	2,300	2,300	2,300
SH Outlet Temperature, ^{o}F	950	950	950
Feedwater Temperature, ^{o}F	477	477	477
Reheat Steam Flow, lb/hr	3,111,105	3,111,105	3,111,105
RH Outlet Temperature, ^{o}F	950	950	950
RH Inlet Temperature, ^{o}F	584	584	584
RH Inlet Pressure, psig	493	493	493
Total Heat Rate, Btu/hr	4.76×10^{9}	4.76×10^{9}	4.76×10^{9}
Heating Value of Fuel, Btu/scf	1,023†	289*	295*
Fuel Fired, scf/hr	4,655,941	16,480,000	16,150,000
Combustion Rate, Btu/hr-scf	29,500	29,500	29,500
Net Heat Release Rate, Btu/hr-scf	200,347	200,347	200,347
Plant Net Heat Rate, Btu/kWhr	9,788	9,788	9,788
Boiler Efficiency, %	84.82	84.82	84.82

*As delivered, wet basis, corrected for sensible heat content.

†Higher heating value.

Table 5-2

BOILER DESIGN DATA

Design Pressure	2825 psig (superheater, waterwall and drum)
Furnace Size (W x D)	W = 45, D = 48 ft
Furance Volume	161,350 ft^3
Effective Project Radiant Heat Surface	23,060 ft^2
Total Heating Surfaces	622,460 ft^2
Boiler & Waterwalls	23,060 ft^2
Superheater	149,850 ft^2
Reheater	45,700 ft^2
Economizer	96,150 ft^2
Air Preheater	307,700 ft^2
Air Preheater	Regenerative Air Heater
Firing System	Front and rear wall burners Total of 32 burners: 2 x 4 x 4
Draft Equipment	Two 50% capacity FD Fans — 6000 hp each
Fuel Fired	Natural Gas 1023 Btu/scf HHV
Fuel Gas System	
Pressure at Burners	7.5 psig
Pipe Size at Burners	5-inch diameter
Boiler Feed Pump	One 20,000 hp, turbine-driven rated at 9600 gpm at total dynamic head of 6800 ft
Furnace Design Pressure	1.5 psig

Table 5-3

GAS FLOW RATES IN THE REFERENCE BOILER FOR NATURAL GAS AND RETROFIT COAL-DERIVED GAS FUELS

Fuel	Delivered Heating Value	Fuel Req'd.		Total Air Req'd. 10% Excess		Flue Gas Product	
	Btu/scf	Million scfh	Million lb/hr	Million scfh	Million lb/hr	Million scfh	Million lb/hr
Natural Gas	1023†	4.66	.214	48.17	3.662	52.94	3.875
CE Gas	289*	16.48	.876	37.80	2.874	47.11	3.750
Texaco Gas	295*	16.15	.853	38.32	2.913	47.21	3.766

*Wet basis, corrected for sensible heat content.

†Higher heating value.

Table 5-4

CAPITAL INVESTMENT COST SUMMARY
STEAM BOILER RETROFIT†

	C-E	Texaco
Retrofit Power Plant, MWe Net	486.3	486.3
Fuel Gas as Delivered		
Flow Rate, MM scf/hr	16.48	16.15
Temperature, °F	405	329
Pressure, psig	15	15
Heating Value, Btu/scf	289*	295*
Main Gas Header		
Nominal Length, ft	1000	
Inside Diameter, in.	81 or equivalent area	

PLANT INVESTMENT COST, $1000†

Fuel Gas Lines and Supports	
Material	$ 700
Installation	1300
Insulation	700
Burners and Windbox Changes	600
Engineering, H.O. and Const. Management	350
Contingency, 15%	550
Subtotal	$4200
Construction Loan Interest	200
TOTAL INVESTMENT COST	$4400

†In thousands of dollars, 7/1/76 price levels.

*Wet basis, corrected for sensible heat content.

Table 5-5

STEAM BOILER POWER PLANT RETROFIT,
OPERATING COST SUMMARY†

Operating Load Factor, % 70% Plant Output, MW Net 486.3			
	Normal Without Retrofit	Additional After Retrofit	Total Costs
Operating Labor	$1300	$130	$1430
Materials and Utilities	300	30	330
TOTAL OPERATING COSTS	1600	160	1760
Maintenance, Labor	560	560	1120
Maintenance, Material	840	840	1680
TOTAL MAINTENANCE COSTS	1400*	1400	2800
Administration and Support Labor	560	210	770
TOTAL ANNUAL OPERATING COSTS†	$3560	$1770	$5330

†In thousands of dollars at 7/1/76 price level excluding fuel and fixed charges.
*2% of $70,000,000 new plant cost at 7/1/72 price level.

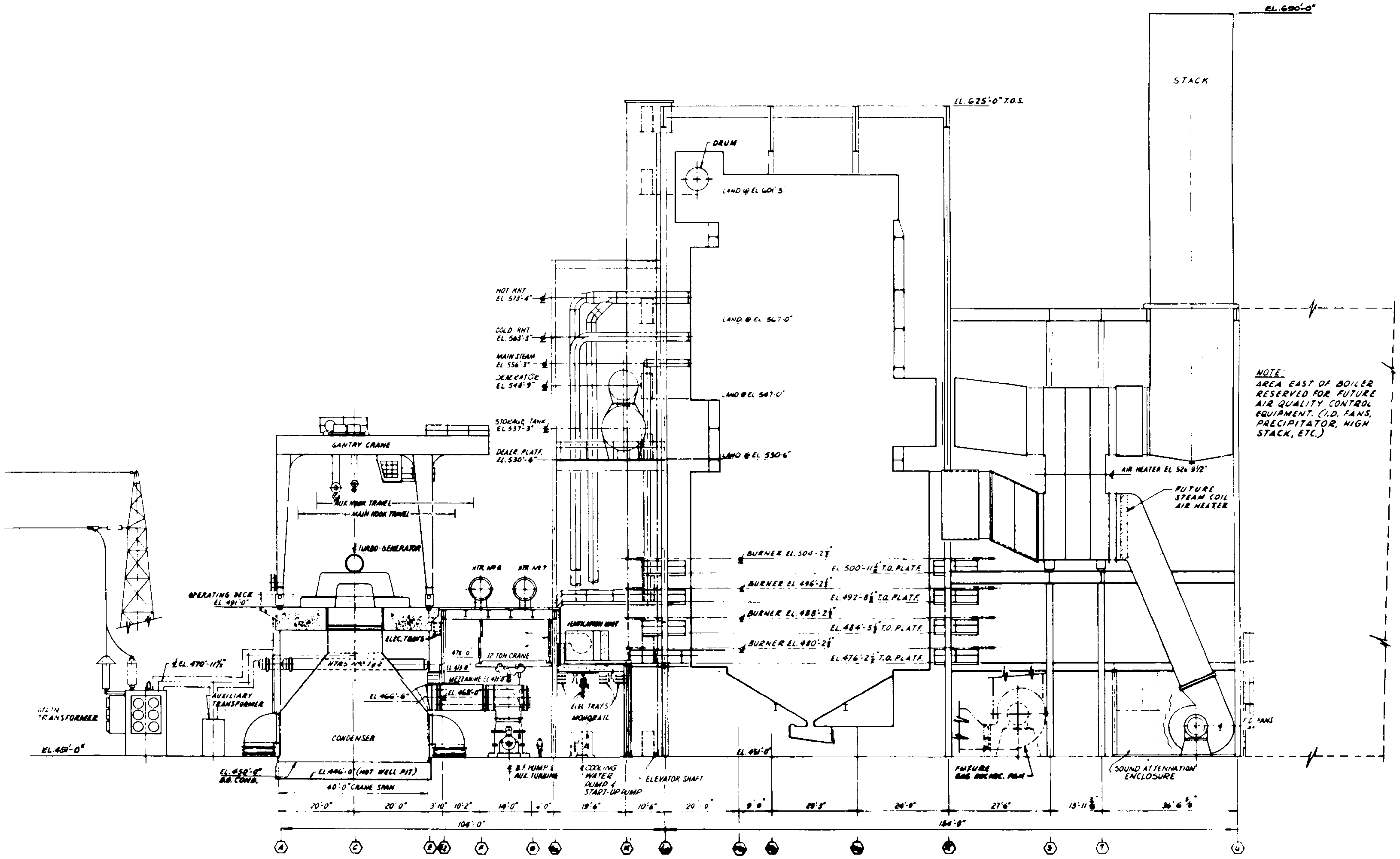
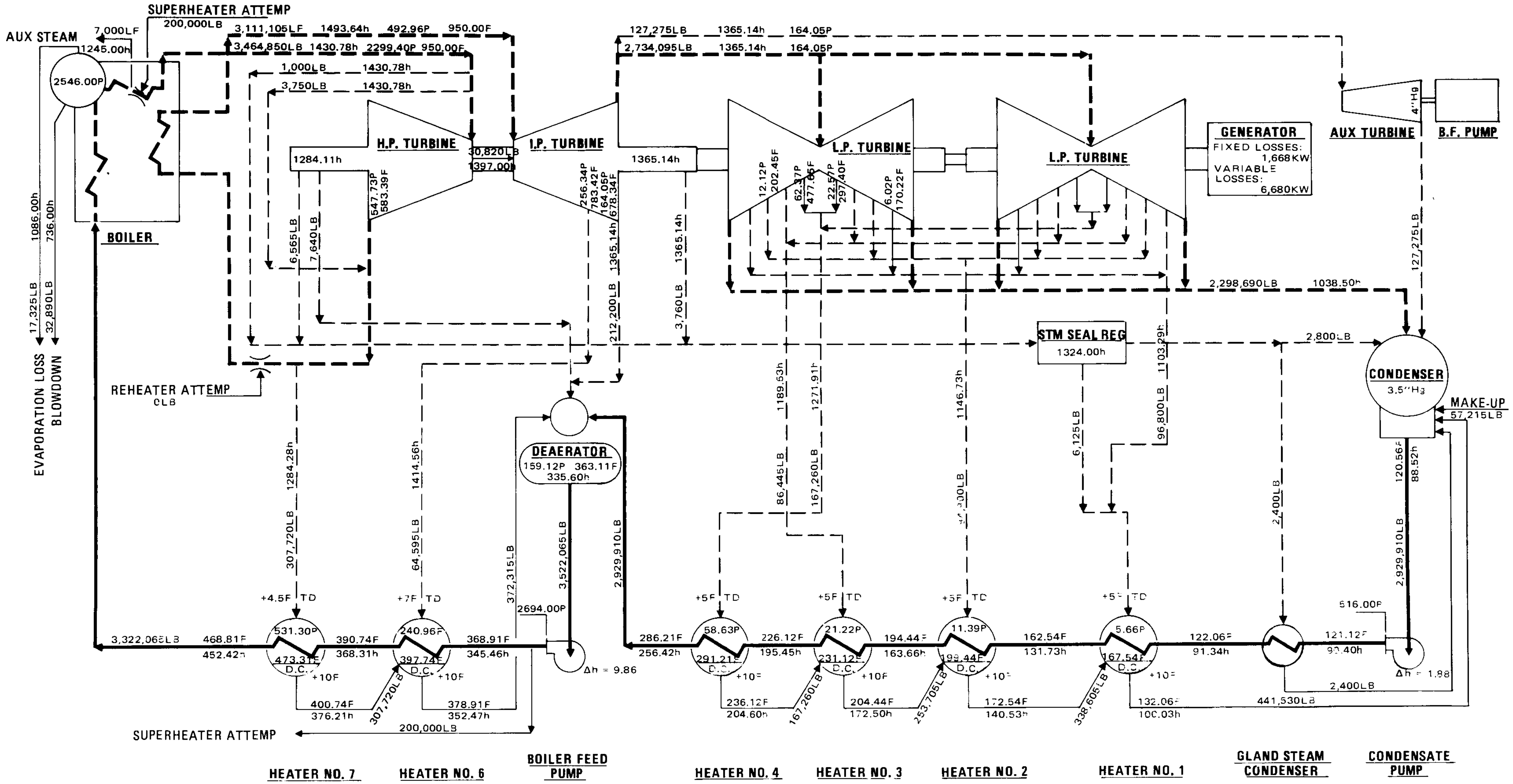


Figure 5-1 EXISTING POWER PLANT WITH NATURAL GAS FIRED BOILER GENERAL ARRANGEMENT SECTION



BASIS FOR HEAT BALANCE CALCULATIONS

1. PRESSURE DROPS
   - (A) REHEAT SYSTEM = 10.0%
   - (B) EXTRACTION LINES (INCL EXTRACTION FLANGES)
     - HEATER NO. 1 = 6.0%
     - HEATER NO. 2 = 6.0%
     - HEATER NO. 3 = 6.0%
     - HEATER NO. 4 = 6.0%
     - DEAERATOR = 3.0%
     - HEATER NO. 6 = 6.0%
     - HEATER NO. 7 = 3.0%
2. MAKE-UP = 57,215LB

SUMMARY

1	TURBINE GEN OUTPUT AT TERMINAL	KW	497,722
2	NET TURBINE HEAT RATE	BTU/KWH	8214.38
3	STATION AUXILIARY POWER	KW	11,413
4	STATION NET OUTPUT (1-3)	KW	486,309
5	STEAM GENERATOR EFICIENCY	%	84.82
6	STATION NET HEAT RATE	BTU/KWH	9911.77
7	AUX. TURBINE POWER FOR P.F. PUMP	KW	10,210

* DOES NOT INCLUDE B.F. PUMP TURBINE POWER

— — — —	MAIN, REHEAT AND EXHAUST STEAM LINES
– – – – –	EXTRACTION AND SECONDARY STEAM LINES
———	CONDENSATE AND BOILER FEED LINES
———	OTHER WATER LINES
LB	FLOW, POUNDS PER HOUR
h	ENTHALPY, BTU PER POUND
F	TEMPERATURE, DEGREES FAHRENHEIT
P	PRESSURE, POUNDS PER SQUARE INCH ABSOLUTE
"Hg	PRESSURE, INCHES OF MERCURY ABSOLUTE

GAS FIRING 2285 PSIG/950F/950F

Figure 5-2 HEAT BALANCE FOR RATED LOAD – 486.3 MW NET

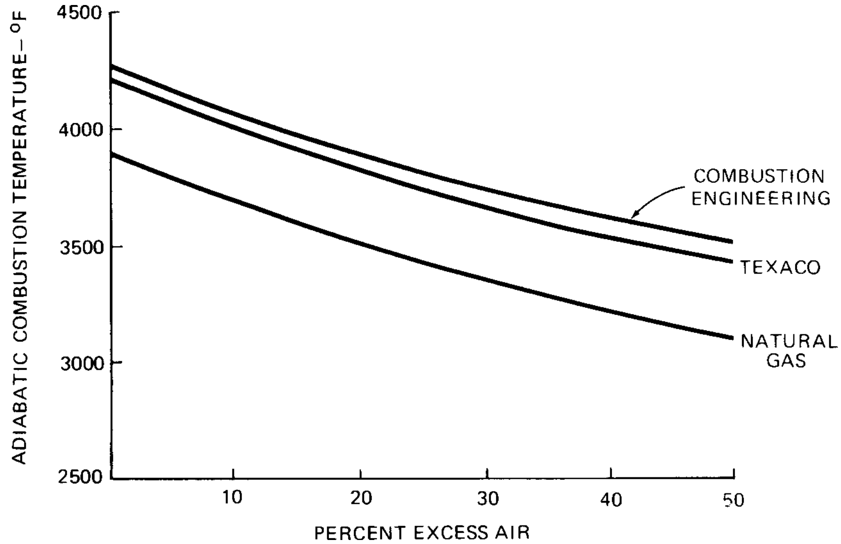


Figure 5–3 THEORETICAL ADIABATIC COMBUSTION TEMPERATURE VARIATION WITH PERCENT EXCESS AIR FOR VARIOUS FUEL GASES

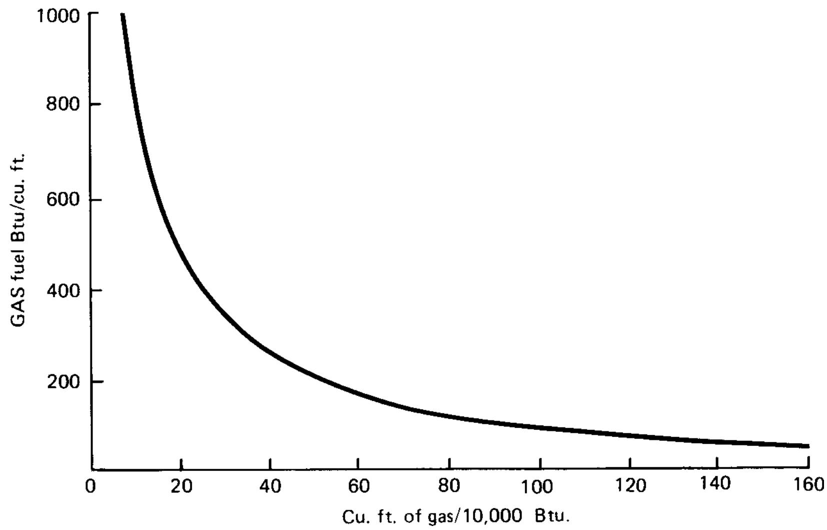


Figure 5–4 THE RELATIONSHIP BETWEEN THE HIGH HEATING VALUE OF THE GASEOUS FUEL AND THE VOLUME OF GAS PER 10,000 Btu.

Section 6

OIL-FIRED COMBINED-CYCLE POWER PLANT RETROFIT

GENERAL

The combined-cycle gas-turbine/steam-turbine power plants considered in this study for retrofitting to burn a medium-Btu gas derived from coal are oil-burning industrial units of the STAG (General Electric) or PACE (Westinghouse) type. These combined-cycle units are assumed in this study to include combustion gas turbines which burn either No. 2 diesel oil or No. 6 residual oil. Thus, the retrofit of the gas turbines to burn medium-Btu coal-derived gas will require the modification of the combustors, fuel injectors, and fuel lines.

The combustion system for typical U.S. industrial gas turbines consists of from 10 to 16 cylindrical combustors arranged around the circumference of the gas turbine with the combustor centerlines parallel to the turbine shaft centerline. This arrangement is referred to as a "can-annular" configuration, which provides for combustion products from each combustor to flow through a corresponding segment of the axial-flow gas turbine first-stage. The combustor configuration is shown in Figure 6-1.

To modify the gas turbine for medium-Btu fuel gas, each of the multiple combustors shown in Figure 6-1 will be replaced by one designed for the particular medium-Btu fuel gas to be fired. The replacement combustor assembly will consist of the pressure-containing outer cylinder, combustor liner, transition piece, and fuel nozzle. The retrofit assembly will be longer and of large diameter to provide the additional volume required for combustion of the lower-density, and lower-heating-value coal-derived fuel gas as compared to firing No. 2 or No. 6 oils.

COMBINED-CYCLE POWER PLANT DESCRIPTION

For purposes of this study, a representative combined-cycle power plant consisting of two units was selected for retrofit. This typical plant is designed to burn either No. 2 diesel oil or No. 6 residual oil. The MWe output for each unit, adjusted for altitude and July mean high air temperature, is 281 MW gross, 272 MW net

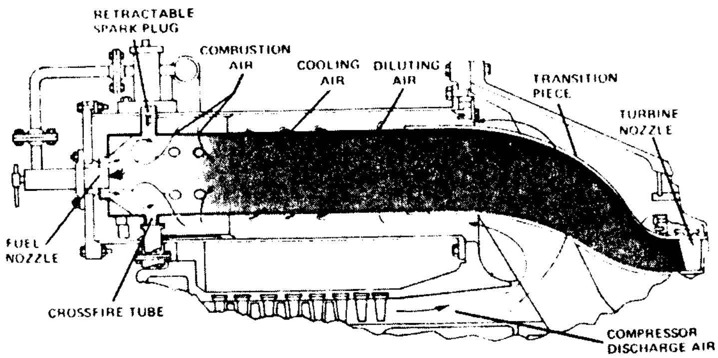


Figure 6-1. Typical Combustor for an Industrial Gas Turbine

on the No. 2 oil. When the plant is fired with No. 6 residual oil, the ratings are 268 MW gross and 258 MW net. The plant selected for this study was placed in commercial operation in 1976.

Major Plant Equipment and Systems

Major components of this combined-cycle plant consist of gas turbine generators, unfired heat recovery steam generators (HRSGs), associated flue gas ducts and bypass ducts and stacks, and a condensing steam turbine-generator. These units are designed for intermediate-load duty, broadly defined as cyclic operation with annual load factors between 20 percent and 80 percent, but are capable of sustained full-power operation. It is expected that the units will be operated at approximately 80 to 90 percent capacity for 50 to 60 percent of the year, for an overall capacity factor of 50 percent.

For a balanced design with a minimum plant heat rate using unfired HRSGs, the gas turbine generators produce approximately 73 percent of the total plant output, with the steam turbine producing the remaining 27 percent. A diagram of the power plant process for this type of plant is shown in Figure 6-2. Typical temperature and pressure conditions are shown.

The gas turbines exhaust into a ducting system with dampers to control exhaust gas flow to either the bypass stack or the HRSG, depending on the station operation condition. Bypass stacks are included to improve overall operating flexibility and unit availability. A closed-loop circulating-water system with a cooling tower provides cooling water to the condenser, and a condensate return system completes the steam cycle.

Plant Arrangement

Plot plans indicating plant arrangements are shown in Figures 6-3 and 6-4 for the diesel-fuel and residual-fuel operations, respectively. Though not pictured in the figures, a security fence encloses the entire area. Not shown, but included in the estimates, are the plant access road and railroad, the wellfield of eight wells providing the raw water makeup, and the connection to the municipal water supply. The entire plant is of outdoor design.

Electrical Systems

Unitized system designs are used for all electrical equipment. Each generator is connected to a main power transformer through isolated-phase bus and disconnect links. A tap with disconnect links from the isolated phase bus is provided for connection to the unit auxiliary transformer.

Synchronizing, metering, relaying, and control of the generator, and control of the 4160-volt and selected 480-volt station electrical systems are provided in the control room.

RETROFIT REQUIREMENTS

The work required to retrofit the representative combined-cycle power plant gas turbines to burn the coal-derived medium-Btu fuel gas consists of replacing the multiple cylindrical combustor assemblies with units designed for dual-fuel combustion. These new assemblies will be supplied by the turbine manufacturer for field installation at the plant site.

In addition to replacing the combustors, it is assumed that the first-stage-turbine inlet nozzles will be field-modified to increase the flow area to accommodate the increase in turbine gas flow resulting from firing medium-Btu gas.

A new fuel gas manifold will be installed to distribute the fuel gas to the several combustors. This manifold is assumed to consist of a 20-inch header with 6-inch branches to each fuel nozzle. There will be from 10 to 16 nozzles per gas turbine, depending on the particular gas turbine being modified.

ESTIMATE OF RETROFIT PLANT PERFORMANCE

Estimated performance data for the reference combined-cycle power plant are presented in Table 6-1. This table provides comparative performance data for the original power plant burning No. 2 diesel oil and for the retrofit power plant burning medium-Btu gas derived from both the Combustion Engineering process and the Texaco process. The performance of the medium-Btu gas-fueled turbine power plants is based on the same compressor-pressure ratio (approximately 10:1), the same turbine inlet temperature (approximately 2000^{o}F), and the same compressor airflow as for the original oil-fueled gas turbine. The combustion gas products flow rate for the gas-fueled turbine has increased to reflect the larger flow requirement of the medium-Btu gas relative to the original oil fuel.

ECONOMICS OF THE RETROFIT

Capital Investment Basis

The capital investment bases for this report are given in Table 1-4 with the following exceptions. The overall contingency used in the combined-cycle economic evaluation is 15 percent rather than the 20 percent used in the gasification economic evaluations, since the 5-percent process contingency is not applicable to this case. In addition, the retrofit work does not require paid-up royalties, pre-production costs, or working capital requirements. Construction loan interest is 4 percent rather than 12.49 percent, because the construction expenditure schedule is less than one year rather than three years.

The price level of the estimates is mid-1976 using the Chicago, Illinois, area as a basis for pricing and productivity. Capital investment costs are summarized in Table 6-2.

Operating Charges

The summary of operating charges, excluding fuel and fixed capital charges, is presented in Table 6-3. These costs were developed on the basis stated in Table 1-5, and represent the costs when utilizing medium-Btu gas derived from either the Combustion Engineering or Texaco processes. Column one summarizes the normal cost without the retrofit. Column two summarizes the additional costs after the retrofit. Column three is the summation of the two columns.

The normal annual maintenance cost was established at 2.5 percent (from Table 1-5) of the $80,000,000 (7-1-72 price level) plant cost, excluding construction loan interest. The additional maintenance for the retrofit is assumed to be 100 percent of this normal maintenance allowance. This additional yearly expenditure is intended to provide for the gradual improvement of the older power plant so that it will have the same investment life as the new gasification plant.

The operating labor requirements, exclusive of maintenance and administrative and support labor, were based on internal information, Federal Power Commission reports, and other public sources. Property taxes and insurance are based upon using 2.4 percent of new plant capital costs as established in Table 1-5 of this report.

Overall Economic Results

Economics associated with the process gasification plants, both Combustion Engineering and Texaco, are detailed in their respective Sections 3 and 4. Overall economic results are presented in Tables 8-1 and 8-2. Thirty-year levelized costs are presented in Tables A-3 and A-4 in the Appendix.

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Table 6-1

COMBINED-CYCLE PLANT PERFORMANCE DATA

Fuel	No. 2 Diesel Oil		CE — Medium Btu Gas		Texaco — Medium Btu Gas	
Plant Location	ISO	Chicago	ISO	Chicago	ISO	Chicago
Altitude, feet*	SSL	588	SSL	588	SSL	588
Atmospheric Pressure, psia	14.7	14.39	14.7	14.39	14.7	14.39
Air Temperature, ^{O}F (July Mean High)	90	83	90	83	90	83
Gross Power, MW	608	562	677	621	670	616
Auxiliary Power, MW	18	18	18	18	18	18
Net Power, MW	590	544	659	603	652	598
Fuel HHV, Btu/lb	19,430	19,430	5,701†	5,701†	5,959†	5,959†
Fuel Flow, lb/hr	252,776	233,666	940,630	869,221	884,564	817,402
Gross Combined Cycle Heat Rate, Btu/kWhr	8,078	8,079	7,921	7,980	7,867	7,907
Net Combined Cycle Heat Rate, Btu/kWhr	8,538	8,346	8,137	8,218	8,084	8,145
Overall Gasification/ Combined Cycle Net Heat Rate, Btu/kWhr based upon total coal input and net power production	—	—	—	12,051	—	11,502

*SSL = Standard Sea Level

†Wet basis, as delivered, corrected for sensible heat content.

Table 6-2

COMBINED-CYCLE POWER PLANT RETROFIT
CAPITAL INVESTMENT COST SUMMARY†

CONDITIONS	CE	Texaco
Fuel Gas as Delivered		
Flow Rate, MMscf/hr	15.70	16.67
Temperature, ^{o}F	436	430
Pressure, psig	245	245
Heating Value, Btu/scf	289*	297*
Main Gas Header		
Nominal Length, ft	1000	1000
Inside Diameter, in	20	20
Wall Thickness, in	3/8	3/8

PLANT INVESTMENT IN THOUSANDS OF DOLLARS†

Fuel Supply Lines	
Material	$ 70
Installation	150
Insulation	80
Replace Six Combustors	2600
Engineering, H.O., and Construction Management	200
Subtotal	3100
Contingency at 15%	460
Subtotal	$3560
Construction Loan Interest at 4%	140
TOTAL INVESTMENT COST	$3700

† In thousands of dollars, 7/1/76 price level

* Wet basis, corrected for sensible heat content

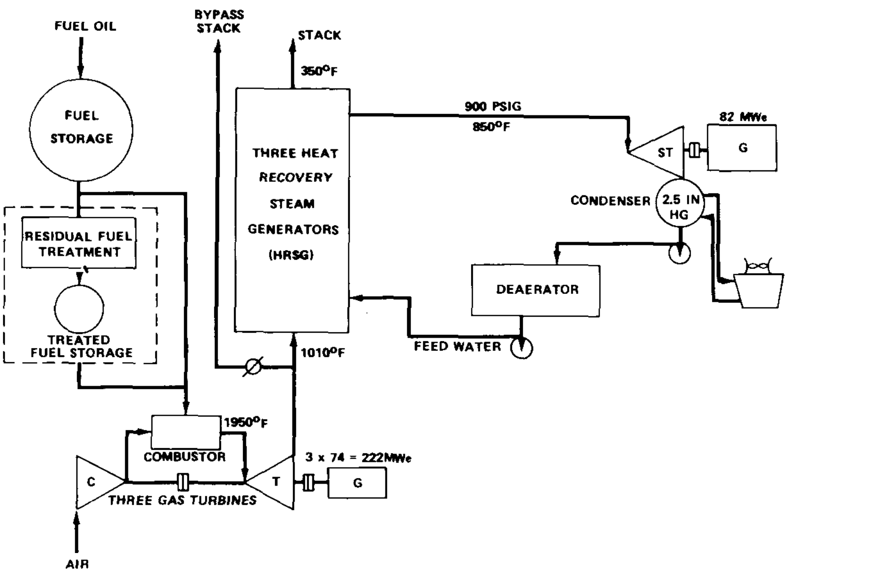
Table 6-3

COMBINED-CYCLE POWER PLANT RETROFIT
OPERATING COST SUMMARY†

CONDITIONS			
Operating Load Factor, %		70%	
Plant Output, MW net		603 (CE) or 598 Texaco	
	Normal Without Retrofit	Additional After Retrofit	Total Costs
OPERATING COSTS IN THOUSANDS OF DOLLARS			
Operating Labor	$1,000	$ 100	$1,100
Materials and Utilities	200	20	220
TOTAL OPERATING COSTS	1,200	120	1,320
Maintenance, Labor	800	800	1,600
Maintenance, Material	1,200	1,200	2,400
TOTAL MAINTENANCE COSTS	2,000*	2,000	4,000
Administrative & Support Labor	540	270	810
TOTAL ANNUAL OPERATING COSTS	$3,740	$2,390	$6,130

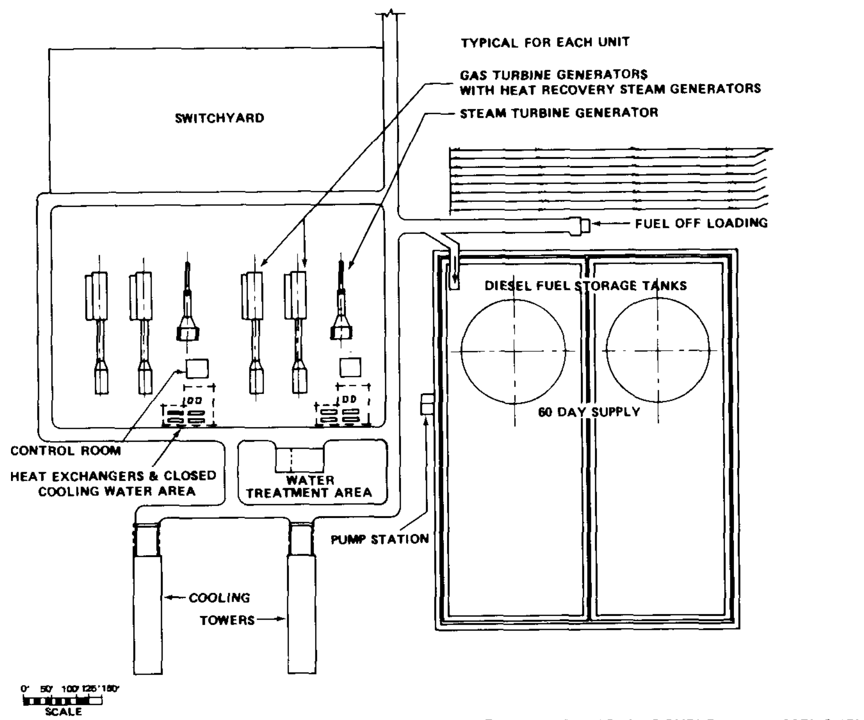
†Annual operating costs at 7/1/76 price level excluding fuel and fixed capital charges.

*2.5% of $80,000,000 new plant cost at 7/1/72 price level.



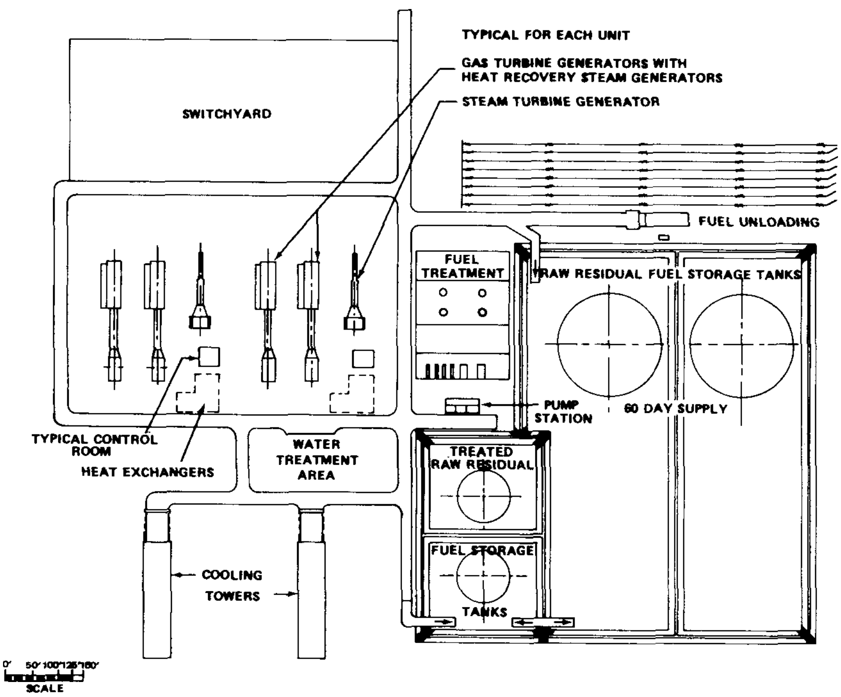
SOURCE: EPRI AF 610, SOA 77-402, PG. A-8

Figure 6-2 DIAGRAM OF POWER PLANT PROCESS



SOURCE:
EPRI AF 610, SOA 77-402, PG. A-5

Figure 6-3 PLOT PLAN DOUBLE UNIT DIESEL FUEL



SOURCE: EPRI AF 610, SOA 77-402, PG A-7

Figure 6-4 PLOT PLAN DOUBLE UNIT RESIDUAL FUEL

Section 7

REFERENCE COAL-FIRED POWER PLANT

GENERAL

This facility is a complete stand-alone, grass-roots, coal-fired plant consisting of two 500 MW net units. It is included in this report as a reference to help place in perspective the economic results of the retrofit cases described in the previous sections. For design compatibility with the retrofit cases, the equipment and plant features are those required to meet the standards of mid-1976. Technical features, capital cost information, and operating characteristics are those of Plant No. 1 in the EPRI Report AF-342, "Coal-Fired Power Plant Capital Cost Estimates." The total electric power output of Plant No. 1 is approximately twice the output of the retrofit power plant cases. The general plant arrangement is shown in Figure 7-1.

MAJOR EQUIPMENT AND PLANT FEATURES

Each unit of this plant is self-contained, with only minimum interconnections. The boiler of each unit is the modern balanced-draft, pulverized coal-fired design which delivers 4,000,000 lb of superheated steam per hour at 2650 psig and $1000^{\circ}F$.

Each turbine is a tandem, compound, four-flow unit with 26-inch last-stage blades, and has a total gross rating of 530 MW. The generator is a 3600-rpm hydrogen-cooled unit design for 624 MVA at 0.85 power factor. The main condenser has two shells and 200,000 square feet of surface area. The condensate would be cooled by a circulating water system which includes mechanical-draft cooling towers.

For this study, high-efficiency (99.5 percent) electrostatic precipitators are provided to remove the flyash from the flue gas. For the high-sulfur Illinois No. 6 coal, each precipitator has a specific collection area of 400 and a total surface area of 670,000 square feet. A limestone slurry flue gas desulfurization (FGD) facility for sulfur dioxide removal completes the cleaning of the flue gas. Table 7-1 is a summary of the FGD system design parameters.

Flyash removed by the precipitator is mixed with the dewatered sludge from the FGD unit along with a small amount of lime which is added for stabilization. Disposal of the stabilized sludge would be carried out through a 10-hour-per-day, 5-day-per-week trucking operation to an offsite waste disposal burial area. Table 7-2 summarizes the raw materials and solids production from the FGD system.

Other major plant features include seven regenerative feedwater heater stages (including a deaerator), and two boiler feed pumps driven by steam turbines. Make-up water for the boiler feed-water cycle, cooling towers, and other plant needs is assumed to be obtained from Lake Michigan through a six-mile pipeline. An eight-day supply of water is stored in a 500 acre-ft surge pond located near the plant. Table 7-3 is a summary of site data for this plant; and Table 7-4 lists the principal plant systems, excluding FGD systems.

This reference plant scope also includes a 345 KV switchyard for the two generating units with bays for two startup transformers, three transmission lines, and an emergency supply line at 115 KV voltage.

A two-unit control room is located centrally between the units with an electrical relay room and cable-spreading space provided immediately below. A testing laboratory incorporating water and steam sample stations, and an analyzing equipment and coal sample room are located in the area between the units. The turbine bay is served by two 85-ton turbine room cranes which may be coupled together for simultaneous lifting of heavy loads.

The coal handling system for this power plant is essentially the same as that for the gasification plants. The coal is delivered by a unit train in 100-ton cars, and the system is capable of receiving, unloading, and stacking out coal from the unit trains at a rate of about 30 cars or 3000 tons an hour.

The coal storage pile provides a long-term reserve storage of 60 days for the two units. It includes a live-storage area at one end, with the capacity to operate both units at full load during a two-day weekend or 64 hours between successive deliveries.

The system to reclaim coal from the live storage area and deliver it to the common surge bin at the power house consists of duplicate parallel systems each rated at 250 percent, or about 600 tons per hour. The surge bin has two outlets for each unit, and the coal is fed through these outlets to vibratory feeders and on conveyors to the five silos in front of each boiler unit.

PLANT OPERATION DATA

Plant operation data for each unit are given in Table 7-5, including the steam cycle heat rate, boiler efficiency, gross and net heat rates, and rated heat input to the boilers for the annual average performance at 70 percent load factor and performance at full load. The coal burn rates for the average load and full load are also given.

ECONOMICS

The capital investment cost estimates were obtained directly from AF-342 for plant No. 1. The estimates are given in Table 7-6 for the coal-fired power plant and general facilities without FGD, and in Table 7-7 for the flue gas desulfurization facility. The estimates were based on cost information available from Bechtel's mid-1976 projects and other knowledge of coal-fired power plant costs.

General scope definition for the estimates is a complete plant, including switchyard, on the assumed site which is without special site requirements other than the scope and design features described in other sections of this report.

The plant is assumed to be engineered and constructed to comply with all federal, state, and local requirements, known and defined, as of July 1, 1976. Requirements of OSHA Regulation 29 CFR 1910.95 (noise exposure of 90 dBA for eight-hour duration during plant operation) are yet to be fully defined. Therefore, engineering and design requirements and costs for complying are not included.

The estimates and schedules assume availability of materials and permanent plant equipment on present-day lead times, and availability of manual and nonmanual personnel in numbers and skills as required for the engineering and construction.

The estimates reflect the costs of labor and labor-related factors and wage rates expected at the plant location. It is assumed that no incentives are needed to attract and hold labor with the skills and in the numbers needed at the site because of its proximity to population centers.

Table 7-8 is the capital requirement cost summary developed from the summary estimates given in Tables 7-6 and 7-7. The capital charges were computed on the bases stated in Table 1-4.

The operating cost summary is given in Table 7-9. This summary was developed from the bases stated in Table 1-5. An allowance of $8.50 per ton is included for sludge and flyash disposal.

Table 7-10 summarizes the busbar power cost at 70-percent capacity factor for both the first-year cost and the 30-year levelized cost when the price of coal is assumed to be $1.00 per million Btu and $2.00 per million Btu.

REFERENCES

1. Coal-Fired Power Plant Capital Cost Estimates. Electric Power Research Institute Final Report, January 1977. EPRI AF-342. Palo Alto, Calif.

Table 7-1

FGD SYSTEM PARAMETERS

Conditions	
Plant No.	1
Site Location	Great Lakes
Source of Coal	Illinois
Coal Sulfur, Avg., %†	4.0
Max., %	4.6
As SO_2 in Flue Gas, %	100
HHV, Btu/lb	10,100
Rated Heat Input to Boiler, 10^6 Btu/hr	4948
Environmental Regulations	EPA
Load Factor (Yearly Basis), %	70
Flue Gas from Boiler (285°F, -16 in w.g.), 10^3 acfm	2250

Data for Each Unit

Flue Gas per Absorber (Saturated), 10^3 acfm	601
Flue Gas Bypass Around Absorbers, %	Nil
SO_2 Possible Emission (Max. S. Full Load), lb/hr	44,230
Allowable Emission (Full Load), lb/hr	5830
Removal (Overall Max S. Full Load), %	87
Removal (Absorber, Max S. Full Load), %	87
Number of Absorber Trains	3
Absorber Type	Spray Tower
Superficial Gas Vel. (Sat'd, Full Load), ft/sec	8.5
System Pressure Drop, in. H_2O	10
Liquid/Gas Ratio, gal/mcf	100
Presaturation Sprays, gal/mcf	2
Alkali/SO_2 Stoic. Ratio (Basis SO_2 Abs'd)	1.3
Absorber Delay Tank Residence Time, min.	5
Absorbent Solids, %	15
Dewatered Sludge Solids, %	45
Stack Gas Reheat, °F	50

†SO_2 removal not required when burning less than 0.482 sulfur coal.

Table 7-2

FGD SYSTEM
RAW MATERIALS AND SOLID PRODUCTION

RAW MATERIALS PER UNIT

Alkali Type	Limestone
Storage Capacity, Days	60
Quantity (Avg. Load, Avg. S.), tons	36,000
Consumption (Full Load, Max. S.), tons/d	1,000
(Avg. Load, Avg. S.), tons/yr	220,000

WASTES PER UNIT

Stabilized Sludge (Full Load, Max. S.), cu yd/d	3,800
tons/d	4,100
(Avg. Load, Avg. S.), cu yd/yr	853,000
tons/yr	921,000

Table 7-3

SITE DATA

Road, miles	1
Railway, miles	2
Distance from Major Water, miles	6 (Lake Michigan)
Elevation above Sea Level, feet	600
Seismic Zone	1
Environmental Regulations	EPA
Foundation Type	Piles
River Intake Structure and Pumping Plant	Yes, at Lake Michigan
Raw Water Supply Pipeline, Surge Pond, and Surge Pond Pumping Plant	6 Miles Pipeline Pond 500 Acre-Ft. Pumping Plant
Raw Water Treatment Plant, 11,000 gpm	None
Cooling Tower Type	Mechanical Draft

Table 7-4

PRINCIPAL PLANT SYSTEMS
(Excluding FGD Systems)

Rail Car Type — Gondola	Rotary Dump
Coal Dead Storage Pile, tons/unit (60 d)	250,000
Coal Live Storage Pile, tons/unit (3 d)	15,000
Precipitators, Specific Collection Area, sq ft/1000 cfm	400
Gas Flow, cfm	2,250,000
Total Surface, sq ft	900,000
Bottom Ash System, tons/hr	
Bottom Ash Pond, area	15 acres
Cooling Tower Blowdown Disposal after Treatment (assume detaining pond of 3 acres)	To the Lake
Coal Yard Drainage, 0.5 acre	To the Pond

Table 7-5

PLANT OPERATION DATA
(Data for each 500 MW Unit)

Annual Average Performance at 70% Load Factor

Avg. Steam Cycle Heat Rate, Btu/kWhr	7945
Avg. Boiler Efficiency, %	88.1
Avg. Gross Heat Rate, Btu/kWhr	9018
Avg. Penalty for Scrub. Gas Reheat, Btu/kWhr	180
Avg. Adjusted Gross Heat Rate, Btu/kWhr	9198
Avg. Allowance for Auxiliaries, Btu/kWhr	736
Avg. Net Heat Rate, Btu/kWhr	9934
Avg. Heat Input to Boiler, 10^6 Btu/hr	3477
Avg. Coal Burn Rate, tons/hr	172
Annual Coal Consumption, 10^3 Tons/yr	1507

Performance at Full Load (For Comparison Only)

Steam Cycle Heat Rate, Btu/kWhr	7914
Boiler Efficiency, %	88.1
Gross Heat Rate, Btu/kWhr	8983
Net Heat Rate, Btu/kWhr	9896
Rated Heat Input to Boiler, 10^6 Btu/hr	4948
Rated Coal Burn Rate, tons/hr	245
Turbine-Generator Gross Output, kW	540

Table 7-6

COAL FIRED POWER PLANT AND GENERAL FACILITIES WITHOUT FGD
ORDER OF MAGNITUDE ESTIMATE SUMMARY†

Account Code	Item	Cost ($1000)
10	Concrete	$ 16,100
20	Civil/Structural/Architectural	
21,22,24	Structural & Misc. Iron & Steel	14,700
25	Architectural & Finish	7,300
26	Earthwork	14,700
27	Piles and Caissons	7,400
28	Site Improvements	9,100
30	Steam Generators	102,200
41	Turbine Generators	46,600
42	Main Condenser & Auxiliaries	3,800
43	Rotating Equipment, Ex. T/G	12,000
44	Heaters & Exchangers	3,400
45	Tanks, Drums, & Vessels	1,400
46	Water Treatment/Chemical Feed	2,400
47.0	Coal/Ash/FGD Equipment	
47.1	Coal Unloading Equipment	2,900
47.2	Coal Reclaiming Equipment	2,800
47.3	Ash Handling Equipment	2,400
47.4	Electrostatic Precipitators	26,400
47.6	FGD Removal Equipment	—
47.8	Stack (Incl. Lining, Lights, etc.)	4,300
48.0	Other Mechanical Equipment Incl. Insulation & Lagging	7,700
49.0	Heating, Ventilating, Air Conditioning	1,400
50	Piping	38,500
60	Control & Instrumentation	9,600
70	Electrical Equipment (Switchgear/Transformers/MCCs/Fixtures)	9,600
80	Electrical Bulk Materials	
81,82,83	Cable Tray & Conduit	10,100
84,85,86	Wire & Cable	11,500
—	Switchyard	9,600
	SUBTOTAL	$377,900
90	Field Distributables	34,100
	SUBTOTAL	$412,000
	Engineering & Home Office Service Including Fees	38,500
	TOTAL† WITHOUT CONTINGENCY AND OWNERS COSTS	$450,500

†In thousands of dollars at 7/1/76 Price Level

Table 7-7

COAL FIRED POWER PLANT FLUE GAS DESULFURIZATION FACILITY
ORDER OF MAGNITUDE ESTIMATE SUMMARY†

Account Code	Item	Cost ($1000)
10	Concrete	$ 4,800
20	Civil/Structural/Architectural	
21,22,24	Structural & Misc. Iron & Steel	4,400
25	Architectural & Finish	2,000
26	Earthwork	4,400
27	Piles & Caissons	2,200
28	Site Improvements	2,700
47.6	FGD Removal Equipment	
	SO_2 Absorption System	6,100
	Flue Gas Ducts & Insulation	11,500
	Reheaters & Fans	5,300
	Pumps	7,200
	Thickener, Clarifier & Vacuum Filters	5,600
	Other FGD Equipment	6,600
50	Piping	7,000
60	Control & Instrumentation	3,100
70	Electrical Equipment (Switchgear/Transformers/MCCs/Fixtures)	2,900
80	Electrical Bulk Materials	
81,82,83	Cable Tray & Conduit	1,800
84,85,86	Wire & Cable	2,300
	SUBTOTAL	$ 79,900
90	Field Distributables	11,300
	SUBTOTAL	$ 91,200
	Engineering & Home Office Service Including Fees	10,300
	TOTAL†	$101,500

†In thousands of dollars at 7/1/76 price level, without contingency.

Table 7-8

COAL-FIRED POWER PLANT
CAPITAL REQUIREMENT COST SUMMARY†

Plant Investment†		
Power Plant and General Facilities without FGD	$450,500	
FGD System	101,500	
Process Contingency for FGD System	5,075	
Project Contingency	82,800	
TOTAL PLANT INVESTMENT†	$639,875	
	$1/MM Btu Coal	$2/MM Btu Coal
Capital Charges†		
Prepaid Royalties	—	—
Preproduction Costs	$ 17,890	$ 19,670
Inventory Capital	7,520	14,650
Initial Catalyst and Chemicals Charge	200	200
Allowance for Funds During Construction	106,220	106,220
Land	3,000	3,000
TOTAL CAPITAL CHARGES	$134,830	$143,740
TOTAL CAPITAL REQUIREMENT†*	$774,705	$783,615

†In thousands of dollars at 7/1/76 price level.

*Sum of Total Plant Investment and total capital charges.

Table 7-9

COAL-FIRED POWER PLANT
ANNUAL OPERATING COST SUMMARY†

Operating Load Factor	70%
Net Production	
Electric Power Capacity, MW	1,000
Electric Power, kW hr/yr x 10^6	6,132
Coal Input (10,100 Btu/lb)	
Tons per Day Full Load	11,760
Tons per Year at 70% LF	3,013,440
Coal Costs, \$1000/yr	
At \$1/MM Btu	\$60,880
At \$2/MM Btu	\$121,760
Operating Costs, \$1000/yr	
Operating Labor	\$ 2,960
Catalysts and Chemicals	800
Utilities — Water at 0.40/M gal	1,620
Limestone at \$10/ton	2,200
Sludge and Flyash Disposal \$8.50/T	7,830
TOTAL OPERATING COSTS	\$15,410
Maintenance, Labor	\$ 6,860
Maintenance, Materials	10,280
TOTAL MAINTENANCE COSTS	\$17,140
Administration & Support Labor	\$ 2,950
TOTAL OPERATING COSTS/YR†	\$35,500

†Annual cost in thousands of dollars at 7/1/76 price level, excluding fixed charges and fuel.

Table 7-10

BUSBAR POWER COST, COAL-FIRED POWER PLANT AT 70% CAPACITY FACTOR
(Net Power, 1000 MW)

	$1.00/MM Btu Coal		$2.00/MM Btu Coal	
	First-Year Cost	30-Year Levelized Cost	First-Year Cost	30-Year Levelized Cost
Fixed Operating Cost, $1000/Yr				
Operating Labor	2,960	5,583	2,960	5,583
Maintenance Labor	6,860	12,938	6,860	12,938
Maintenance Materials	10,280	19,388	10,280	19,388
Administrative and Support Labor	2,950	5,563	2,950	5,563
TOTAL FIXED O&M COSTS	23,050	43,472	23,050	43,472
Variable Operating Costs (Excluding Coal), $1000/Yr				
Raw Water	1,620	3,055	1,620	3,055
Limestone	2,200	4,149	2,200	4,149
Chemicals and Consumables	800	1,509	800	1,509
Sludge Disposal	7,830	14,767	7,830	14,767
Ash Disposal with Sludge Disposal	-	-	-	-
TOTAL VARIABLE O&M COSTS	12,450	23,480	12,450	23,480
Coal Cost, $1000/Yr	60,880	117,620	121,760	235,240
Total Operating Costs, $1000/Yr	96,380	184,572	157,260	302,192
Levelized Fixed Charges, $1000/Yr	139,447	139,447	141,051	141,501
Total Cost of Electricity				
$1000/Yr	235,827	324,019	298,311	443,243
mills/kWhr	38.46	52.84	48.65	72.28

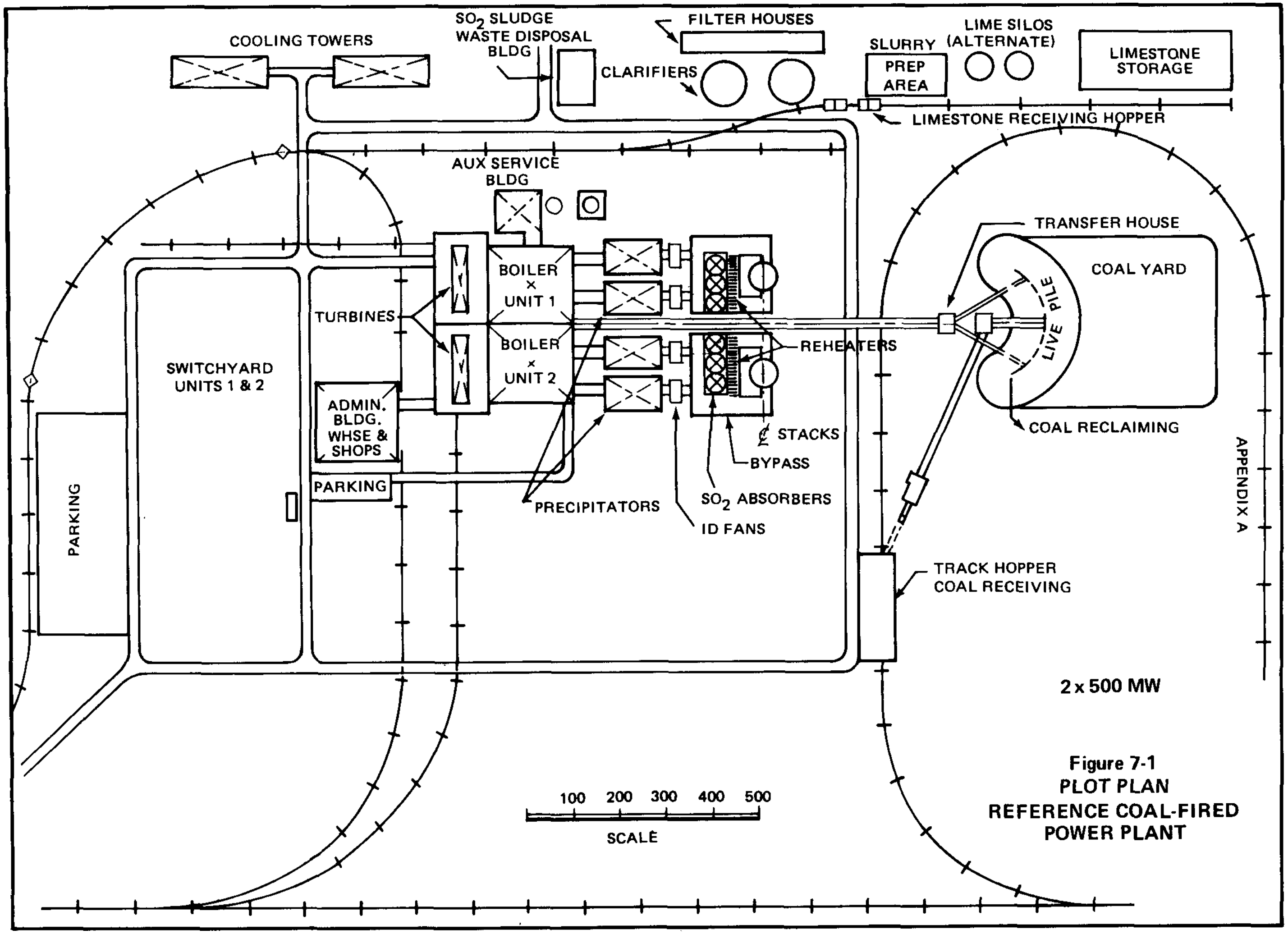


Figure 7-1
PLOT PLAN
REFERENCE COAL-FIRED
POWER PLANT

Section 8

ECONOMIC SUMMARY

Individual estimates of capital requirements and operating costs were presented in Sections 3, 4, 5, 6, and 7 of this report. These estimates have been combined in this section to provide an overall economic summary and comparison of the cases studied.

Table 8-1 shows the total capital requirements and operating costs for both the Texaco process and Combustion Engineering process when coupled with either the boiler power plant or the combined-cycle unit. Costs are given in millions of dollars for two levels of coal pricing — \$1.00 per million Btu and \$2.00 per million Btu. As noted previously in Table 1-5, the total capital requirements for the existing power plants have been treated on the same basis as the total capital requirements for the modifications and new facilities involved in retrofitting. This approach to calculation of total fixed charges has been adopted for simplicity in this study. The remaining undepreciated fraction of the original total capital requirement constitutes a more correct basis for calculation of the fixed charge contribution of the existing power plant.

The cost of electricity is summarized in Table 8-2. This table follows the format of Table 8-1, but expresses the operating cost components and totals in mills per kilowatt-hour.

Table 8-3 contains a summary of cost estimates for the reference coal-fired power plant. This table follows the same general format as Tables 8-1 and 8-2; however, the annual operating costs (in millions of dollars) and total cost of electricity (in mills per kilowatt-hour) are both shown.

Information extracted from these tables was used to prepare the overall economic summary and comparison shown in Figure S-1 of the summary section.

Table 8-1

SUMMARY COST ESTIMATES†

Conditions	Combustion Engineering				Texaco			
	Boiler Case		Combined-Cycle Case		Boiler Case		Combined-Cycle Case	
Assumed Price of Coal, $/MM Btu	$1	$2	$1	$2	$1	$2	$1	$2
Retrofitted Power Plant, MWe Net Overall	468.7	468.7	515.8	515.8	496.9	496.9	587.2	587.2
Annual Output at 70% LF, kWhr/yr x 10^6 Net	2,874	2,874	3,163	3,163	3,047	3,047	3,601	3,601
CAPITAL REQUIREMENTS†								
Gasification Plant	258.8	268.8	292.6	302.7	330.5	341.5	342.6	354.1
Power Plant Retrofit Cost	4.4	4.4	3.7	3.7	4.4	4.4	3.7	3.7
Total Capital Requirements, $\$10^6$	263.2	273.2	296.3	306.4	334.9	345.9	346.3	357.8
$/kW	562	583	574	594	674	696	590	609
Power Plant Initial Cost (7/1/72 Price Level)	70	70	80	80	70	70	80	80
OPERATING COSTS†								
Fixed Charges at 18.0%								
On Power Plant Initial Cost	$ 12.6	$ 12.6	$ 14.4	$ 14.4	$ 12.6	$ 12.6	$ 14.4	$ 14.4
Gasification and Retrofit Costs	47.4	49.2	53.3	55.2	60.3	62.3	62.3	64.4
Subtotal	60.0	61.8	67.7	69.6	72.9	74.9	76.7	78.8
Gasification Plant								
Fuel, 12,235 Btu/lb Coal	36.1	72.2	38.1	76.2	39.6	79.2	41.4	82.8
Operating Costs	3.8	3.8	3.8	3.8	3.4	3.4	3.5	3.5
Maintenance Costs	5.0	5.0	5.9	5.9	6.1	6.1	6.3	6.3
Administration and Support Labor Costs	1.4	1.4	1.6	1.6	1.4	1.4	1.4	1.4
Subtotal, Excluding Fuel	10.2	10.2	11.3	11.3	10.9	10.9	11.2	11.2
Power Plant								
Fuel, 312 or 290 Btu/scf gas	Above	Above	Above	Above	Above	Above	Above	Above
Operating Costs	1.8	1.8	1.3	1.3	1.8	1.8	1.3	1.3
Maintenance Costs	2.8	2.8	4.0	4.0	2.8	2.8	4.0	4.0
Administration and Support Labor Costs	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Subtotal, Excluding Fuel	5.4	5.4	6.1	6.1	5.4	5.4	6.1	6.1
Total, Including Fixed Charges†	$111.7	$149.6	$123.2	$163.2	$128.8	$170.4	$135.4	$179.0

†Total cost in millions of dollars at the retrofitted plant; 70 percent load factor; 7/1/76 price level.

Table 8-2

SUMMARY COST OF ELECTRICITY†

Conditions	Combustion Engineering				Texaco			
	Boiler Case		Combined-Cycle Case		Boiler Case		Combined-Cycle Case	
Assumed Price of Coal, \$/MM Btu	\$1	\$2	\$1	\$2	\$1	\$2	\$1	\$2
Retrofitted Power Plant, MWe Net Overall	468.7	468.7	515.8	515.8	496.9	496.9	587.2	587.2
Annual Output at 70% LF, kWhr/yr x 10^6 Net	2,874	2,874	3,163	3,163	3,047	3,047	3,601	3,601
COST OF ELECTRICITY AT THE RETROFITTED POWER PLANT, Mills per kWh								
Fixed Charges at 18.0%								
On Power Plant Initial Cost	4.4	4.4	4.5	4.5	4.1	4.1	4.0	4.0
Gasification and Retrofit Costs	16.5	17.1	16.9	17.4	19.8	20.4	17.3	17.9
Subtotal	20.9	21.5	21.4	21.9	23.9	24.5	21.3	21.9
Gasification Plant								
Fuel, 12,235 Btu/lb Coal	12.6	25.2	12.1	24.2	13.0	26.0	11.5	23.0
Operating Costs	1.3	1.3	1.2	1.2	1.1	1.1	1.0	1.0
Maintenance Costs	1.7	1.7	1.9	1.9	2.0	2.0	1.7	1.7
Administration and Support Labor Costs	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4
Subtotal, Excluding Fuel	3.5	3.5	3.6	3.6	3.6	3.6	3.1	3.1
Power Plant								
Fuel, 312 or 290 Btu/scf gas	Above	Above	Above	Above	Above	Above	Above	Above
Operating Costs	0.6	0.6	0.4	0.4	0.6	0.6	0.4	0.4
Maintenance Costs	1.0	1.0	1.3	1.3	0.9	0.9	1.1	1.1
Administration and Support Labor Costs	0.3	0.3	0.2	0.2	0.3	0.3	0.2	0.2
Subtotal, Excluding Fuel	1.9	1.9	1.9	1.9	1.8	1.8	1.7	1.7
Total†	38.9	52.1	39.0	51.6	42.3	55.9	37.6	49.7

†Total cost in mills per kWhr at the retrofitted plant; 70 percent load factor; 7/1/76 price level.

Table 8-3

SUMMARY COST ESTIMATES
COAL-FIRED POWER PLANT

Assumed Price of Coal, \$/MM Btu	\$1	\$2
MWe Net Overall	1,000	
Annual Output at 70% LF, kWh/yr x 10^6 net	6,132	
Capital Requirements		
TOTAL CAPITAL REQUIREMENT, \$$10^6$	774.7	783.6
\$/kW	775	784
Operating Costs, \$$10^6$/Year		
Fixed Charges at 18%	139.4	141.0
Fuel, 10,100 Btu/lb coal	60.9	121.8
Operating Costs	15.4	15.4
Maintenance Costs	17.1	17.1
Administration and Support Labor Costs	3.0	3.0
TOTAL, 7/1/76 PRICE LEVEL	235.8	298.3
Total Cost of Electricity, mills/kWhr		
Fixed Charges at 18%	22.8	23.0
Fuel, 10,100 Btu/lb coal	9.9	19.8
Operating Costs	2.5	2.5
Maintenance Costs	2.8	2.8
Administration and Support Labor Costs	0.5	0.5
TOTAL, 7/1/76 PRICE LEVEL	38.5	48.6

Appendix A

CONCEPT OF LEVELIZED COSTS

INTRODUCTION

Power plant economic studies contain two basic elements. One is the capital investment cost, a once-only expenditure, which has an investment life. The other is the yearly cost associated with the investment over the period of the investment life.

The interest concept is used to place the once-incurred capital investment cost and the yearly costs on an equivalent basis so that all costs are compared at a single point in time. Three basic methods, each with many variations, are used. Costs may be compared at the start of an accounting period — the present-worth analysis. Costs may be compared at the end of the period — a future-worth analysis. Or costs may be compared over the accounting period — an equivalent-annual-payment analysis.

Past studies were often made without considering the effect of inflation on the operating costs, including fuel. The levelizing procedure permits the effect of inflation to be included. Levelizing compares the costs at the initial service date of the generating unit, a variation of the present-worth analysis. When a levelizing factor is applied to the operating cost over a period of (n) years, the most probable value of the electric power cost over the (n) year period is obtained.

SUMMARY

To be realistic, power plant economic studies must consider the effect of present and future inflation on yearly costs over the plant investment life. The levelizing procedure described herein represents an accepted and easily understood method for incorporating such effects into economic studies.

The single multiplier designated as the levelization factor, L, is defined as a Capital Recovery Factor, CRF, multiplied by a Present Worth Factor, PWF, which includes the effect of inflation. The levelized cost is calculated by multiplying the estimates of present-day costs by the appropriate L.

The accuracy of levelized costs, particularly over long periods of time, is strongly dependent on the validity of the assumptions made regarding the uniformity of the rates assumed for inflation and interest over the levelizing period. However, the absolute values of the assumed rates and the resulting levelized costs are relatively unimportant because decisions are normally based on the differential or percentage difference between studies. When levelized numbers have been developed on the same basis, the differentials can be compared and prudent conclusions can be drawn without concern about the validity of the rates assumed for inflation and interest. Evaluation of absolute levelized costs must, however, consider the effects of possible changes in the uniform rates assumed for inflation and interest over the levelizing period.

LEVELIZING PROCEDURE

The procedure for levelizing is one that converts a series of nonuniform annual amounts into a uniform series involving a single equivalent annual amount. This greatly simplifies the computations. In the power generation industry, this procedure is particularly applicable to fuel costs or operations and maintenance costs, which change yearly because of inflation.

To calculate this levelized equivalent annual amount, each individual amount is discounted to the reference date by using single-payment present-worth factors. The present worth of all the amounts is then summed up.

A formula has been developed to calculate this single equivalent annual amount taking into account the effect of uniform inflation over the period of time on the yearly amounts. A single multiplier, designated as the levelization factor (L), is calculated by this formula.

LEVELIZATION FACTOR FORMULA

The standard formula for the levelization factor (L), used by EPRI and others, is the Capital Recovery Factor multiplied by the Present Worth Factor. The present worth factor is computed to include the effect of inflation.

$$L = CRF \times PWF \text{ (including the effect of inflation)}, \qquad \text{(A-1)}$$

where

$$CRF = \frac{r(1 + r)^n}{(1 + r)^n - 1} \qquad \text{(A-2)}$$

$$PWF = \frac{k(1 - k^n)}{1 - k} \text{ (including the effect of inflation)} \qquad \text{(A-3)}$$

where

$$k = \frac{1 + e}{1 + r}, \quad PWF = \left[\frac{\left(\frac{1 + e}{1 + r}\right) \left[1 - \left(\frac{1 + e}{1 + r}\right)^n\right]}{\left[1 - \left(\frac{1 + e}{1 + r}\right)\right]} \right] \qquad \text{(A-4)}$$

therefore

$$L = \left[\frac{r\ (1 + r)^n}{(1 + r)^n - 1} \right] \times \left[\left(\frac{1 + e}{r - e}\right) \left[1 - \left(\frac{1 + e}{1 + r}\right)^n\right] \right] \qquad \text{(A-5)}$$

r = Interest Rate = Weighted Cost of Capital = Discount Rate

e = Inflation Rate, includes escalation

n = Number of Years in Period = Investment life used to determine fixed charge rates

CRF = Capital Recovery Factor

PWF = Present Worth Factor including the effect of inflation.

Generally speaking, $CRF = \frac{1}{PWF}$, and therefore L = 1.0 in an economy with a stable r and e = 0. However, the PWF used above in Eq. (A-3) has been developed to include the expectation of inflation and reflects both the inflation and "deflation" during the process of present-worthing from the (n) year back to the present year.

The CRF, a textbook equation, does not include the effect of inflation. The uniform levelized payments represent money with purchasing power at day zero or at the initial service date of power generation.

TABULAR DEMONSTRATION

Demonstration that the Present Worth Factor given in Eq. (A-1) includes the effect of inflation over a uniform series of payments is shown in Table A-1 through the calculation of the PWF portion of Eq. (A-5) in two ways for each year for an initial ten-year period.

Column 1 is developed from the formula. Column 4 is developed by summation of unit-years. It will be noted that Columns 1 and 4 are identical. This demonstrates that the formula for the PWR portion of Eq. (A-5) is equal to the summation of unit-years.

DEVELOPMENT OF TABLE A-2

Economic criteria specified by EPRI and used in this report for calculating the levelized cost of electricity have been stated in the last paragraphs of Section 1 and are repeated as follows:

- Inflation Rate: 6.0 percent per year
- Discount Rate: 10.0 percent per year
- Coal Escalation Rate: Gasification Plants — 6.848 percent per year
Coal-fired Power Plants — 6.2 percent per year

Based on these criteria, the levelizing factors for Year 30 are given by EPRI as follows:

	Gasification Plants	Coal-Fired Power Plants
Coal	2.093	1.932
O&M	1.886	1.886

As a further aid to understanding the levelizing concept, and with the thought that the reader may be interested in levelization factors for years other than the thirtieth year (of plant life), Table A-2 has been developed.

Levelization factors have been computed for each year (n), from 1 through 30, for both coal and O&M. Please note that the L's for the 30th year are the same, although carried out to two more decimal places, as reported from EPRI in Section 1.

Again, to further the reader's understanding of levelizing, the CRF and PWF are also given for each year. The CRF column was taken directly from the interest Table E-16 in the economic textbook, Grant & Ireson's Principles of Engineering Economy, page 553, fourth edition, 1964. The PWF columns have been developed using a small calculator having y^x computational ability. The L factor for any (n) and for any (e) and any (r) can be calculated in the same manner.

APPLICATION OF LEVELIZING

The estimated costs of electricity produced by the retrofitted units have been summarized in Table 8-2 in the Economic Summary section. These costs are not levelized, but rather are expressed in mills/kWh at the July 1, 1976 price level. Effects of inflation on these costs, as the plant continues to produce electricity over the thirty years following this date, are not included.

Application of levelizing to these costs simply requires multiplying them by the appropriate levelizing factor. Table A-3 presents the resulting cost data. The levelization factors used are those established for this report. In Table A-3, the costs at the July 1, 1976 price level are restated and compared with 30-year levelized costs.

Differences between the levelized costs and the July 1, 1976 costs represent the effects of inflation on plant fuel and plant operation and maintenance costs during each year of the 30-year period. The fixed costs remain the same since they represent costs which, in effect, are already levelized.

COMPARISON OF GASIFICATION RETROFIT CASES

The two gasification process-retrofit cases are compared in Table A-4. Levelized costs are restated from Table A-3. For the retrofit cases employing the Texaco process and those employing the Combustion Engineering process, the 30-year levelized costs are higher than the costs at the July 1, 1976 price level. Therefore, when the 30-year levelized costs are compared, the same economic decision would be reached, but possibly with a greater degree of confidence.

ACCURACY OF LEVELIZED COSTS

The relative accuracy of the levelized costs shown in Tables A-3 and A-4 is strongly dependent on the validity of the uniform yearly rates assumed for the 30-year period. Such numbers must therefore be used with caution in estimating absolute costs. Levelizing over much shorter periods could increase the decision maker's confidence in the resulting estimates.

However, in using levelized costs in the evaluation of alternate plans for generation, the absolute accuracy of such rates over such a long period is relatively unimportant. It is the percentage difference between the costs of the alternate plans which is important. This percentage difference is valid if the levelized costs have been developed on the same basis. If they have not been developed from the same rates, and/or rates that are considered equivalent for inflation and interest over the identical period, the comparison will not be valid.

SENSITIVITY OF LEVELIZATION FACTORS

The influence of changes in the rate of inflation on levelization factors is shown in Table A-5. In developing this table, a 4-percent differential between the inflation rate, e, and the interest rate, r, was maintained. This differential represents the real return to the investor.

From Table A-5 it can be seen that the increase in the levelization factor over 20 years is approximately 55 to 60 percent of the corresponding increase in the inflation rate assumed for the period.

Table A-1

TABULAR DEMONSTRATION
OF THE PRESENT WORTH FACTOR
(PWF)

(1) PWF Portion of Eq. (A-3) $\frac{k(1-k^n)}{1-k}$	(2) For n	(3) $\left(\frac{1+e}{1+r}\right)^n$	(4) PWF Portion of Eq. (A-3) Summation of Units $\frac{1+e}{1+r} + \left(\frac{1+e}{1+r}\right)^2 \cdots + \left(\frac{1+e}{1+r}\right)^n$
0.96364	1	0.963636 →	0.96363
1.89223	2	0.928595	1.89223
2.78706	3	0.894828	2.78706
3.64935	4	0.862289	3.64935
4.48028	5	0.830933	4.48028
5.28100	6	0.800717	5.28100
6.05260	7	0.771600	6.05260
6.79614	8	0.743542	6.79614
7.51265	9	0.716504	7.51265
8.20309	10	0.690449	8.20309

where:

$$e = .06 \; ; \; r = .10 \; ; \; k = \frac{1+e}{1+r} = \frac{1.06}{1.10} = 0.963636$$

Table A-2

LEVELIZATION FACTORS FOR 1 THROUGH 30 YEARS

r = 0.100		L for O&M e = 0.060 r = 0.100 k = 0.963636*		L for Coal e = 0.06848 r = 0.100 k = 0.971345*	
n	CRF $\frac{r(1+r)^n}{(1+r)^n-1}$	PWF for O&M $\frac{k(1-k^n)}{1-k}$	L for O&M CRF x PWF	PWF for Coal $\frac{k(1-k^n)}{1-k}$	L for Coal CRF x PWF
1	1.10000	0.96364	1.06000	0.97135	1.06848
2	0.57619	1.89223	1.09028	1.91486	1.10332
3	0.40211	2.78706	1.12070	2.83133	1.13851
4	0.31547	3.64935	1.15126	3.72155	1.17404
5	0.26380	4.48028	1.18190	4.58625	1.20985
6	0.22961	5.28100	1.21257	5.42618	1.24591
7	0.20541	6.05260	1.24326	6.24204	1.28218
8	0.18744	6.79614	1.27386	7.03453	1.31855
9	0.17364	7.51265	1.30450	7,80430	1.35514
10	0.16275	8.20309	1.33505	8.55202	1.39184
11	0.15396	8.86844	1.36539	9,27831	1.42849
12	0.14676	9.50966	1.39564	9.98378	1.46522
13	0.14078	10.12742	1.42574	10.66905	1.50199
14	0.13575	10.72278	1.45562	11.33468	1.53868
15	0.13147	11.29650	1.48515	11.98124	1.57517
16	0.12782	11.84936	1.51458	12.60927	1.61172
17	0.12466	12.38211	1.54355	13.21930	1.64792
18	0.21293	12.89550	1.57235	13.81185	1.68408
19	0.11955	13.39021	1.60080	14.38742	1.72002
20	0.11746	13.86701	1.62882	14.94650	1.75562
21	0.11562	14.32630	1.65641	15.48956	1.79090
22	0.14401	14.76898	1.68381	16.01706	1.82610
23	0.11257	15.19556	1.71056	16.52945	1.86072
24	0.11130	15.60663	1.73702	17.02715	1.89512
25	0.11017	16.00276	1.76302	17.51059	1.92914
26	0.10916	16.38447	1.78853	17.98018	1.96272
27	0.10826	16.75231	1.81361	18.43631	1.99591
28	0.10745	17.10679	1.83812	18.87937	2.02859
29	0.10673	17.44836	1.86226	19,30973	2.06093
30	0.10608	17.77751	1.88584	19.72777	2.09272

*Calculated from formula (A-4) $k = \frac{1+e}{1+r}$

Table A-3

LEVELIZED COST OF ELECTRICITY AT THE RETROFIT PLANTS

Price of Coal, $MM Btu†	$1	$2	30-Year Levelization Factors	$1	$2
	From Table 8-2 Mills/kWhr†			Levelized Cost for 30-Year Period	
Combustion Eng.-Boiler					
Fixed Charges	20.9	21.5	—	20.9	21.5
Fuel Costs	12.6	25.2	2.093	26.4	52.7
All Other O&M Costs	5.4	5.4	1.886	10.2	10.2
TOTAL	38.9	52.1		57.5	84.4
Combustion Eng.-Comb. Cycle					
Fixed Charges	21.4	21.9	—	21.4	21.9
Fuel Costs	12.1	24.2	2.093	25.3	50.7
All Other O&M Costs	5.5	5.5	1.886	10.4	10.4
TOTAL	39.0	51.6		56.8	82.8
Texaco-Boiler					
Fixed Charges	23.9	24.5	—	23.9	24.5
Fuel Costs	13.0	26.0	2.093	27.2	54.4
All Other O&M Costs	5.4	5.4	1.886	10.2	10.2
TOTAL	42.3	55.9		61.3	89.1
Texaco-Combined Cycle					
Fixed Charges	21.3	21.9	—	21.3	21.9
Fuel Costs	11.5	23.0	2.093	24.1	48.2
All Other O&M Costs	4.8	4.8	1.886	9.1	9.1
TOTAL	37.6	49.7		54.5	79.2
Reference Plant (from Table 8-3)					
Fixed Charges	22.8	23.0	—	22.8	23.0
Fuel Costs	9.9	19.8	1.932	19.1	38.3
All Other O&M Costs	5.8	5.8	1.886	10.9	10.9
TOTAL	38.5	48.6		52.8	72.2

†Costs at 7/1/76 price level.

Table A-4

COMPARISON OF LEVELIZED COSTS[†]

	$1/MM Btu Coal		$2/MM Btu Coal	
	7-1-76 Price Level	30-Year Levelized	7-1-76 Price Level	30-Year Levelized
RETROFIT OF GAS-FIRED STEAM BOILER PLANT				
Gasification Process				
Texaco	42.3	61.3	55.9	89.1
Combustion Engineering	38.9	57.5	52.1	84.4
Differential	+3.4	+3.8	+3.8	+4.7
RETROFIT OF OIL-FIRED COMBINED-CYCLE PLANT				
Gasification Process				
Texaco	37.6	54.5	49.7	79.2
Combustion Engineering	39.0	56.8	51.6	82.8
Differential	(1.4)	(2.3)	(1.9)	(3.6)

[†]Costs in mills per kWhr.

Table A-5

COMPARISON OF DIFFERENT r's AND e's

Assumed		% Change In e	Calculated L_{30}	% Change In L_{30}
r	e			
.10	.06	Base	1.886	Base
.12	.08	+33	2.226	+18
.15	.11	+83	2.765	+47
.20	.16	+167	3.718	+97