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Low/Medium-Btu Coal-Gasification Assessment Program for Specific Sites of Two New York Utilities

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December 1980

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Prepared for:
U.S. Department of Energy
Assistant Secretary for Fossil Energy
Coal Resource Management Fossil Energy
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New York State Energy Research
and Development Authority
Albany, New York 12223
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Preface

This report is one of a series that was sponsored by the Office of Coal Resource Management, Resource Applications, Department of Energy, based on responses to a Program Interest Notice (PIN) (RA-21) issued March 15, 1979. The purpose of the Program Interest Notice was to obtain a realistic assessment of the feasibility (from the owner/user's point of view) of utilizing low or medium-Btu gas from coal in a variety of industrial or commercial applications.

Although processes for producing environmentally acceptable gas from coal are available commercially, the lack of commercial operating experience in the United States requires that the pioneer users of this technology to principally rely on engineering and economic analysis. The uncertainty of costs, operating reliability and retrofit impacts; effect of gas on product quality and plant processes; plant siting and environmental factors; gas distribution costs and safety; regulatory impacts; coal supply and transportation; capital/financing arrangements, etc., are all considerations which a potential owner/user must weigh when seriously considering the use of low/or medium-Btu coal gas as an alternative fuel option. This series of studies, by emphasizing site specific applications, was aimed at developing answers to some of these concerns.

Coal Resource Management
Fossil Energy

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EXECUTIVE SUMMARY

INTRODUCTION

This Study investigates the technical, economic, financial, and environmental aspects of using a low- or medium-Btu gas derived from coal to replace imported oil in utility power plant boilers. The power plants chosen for investigation are:

- Niagara Mohawk's Unit 6 at Oswego, New York is a new 850-MW oil-fired power plant
- Consolidated Edison's Unit 3 at Arthur Kill, Staten Island, New York is a 500 MW, low-sulfur, oil-firing plant, which was converted from a coal-firing plant.

The Oswego plant is bordered on three sides by the town of Oswego and fronts on Lake Ontario. There is no room for the receiving and gasification of coal at the power plant site; therefore, the gasification plant is located approximately 5 miles inland from the power plant and Lake Ontario on property owned by Niagara Mohawk. Niagara Mohawk owns most of the land in between, or has the right-of-way for the gas transfer pipeline.

The Consolidated Edison (CE) plant is located on the banks of the Arthur Kill. Consolidated Edison owns a sufficient amount of unused real estate to receive, store, and gasify the coal. The existing plant is equipped to receive 5000 TPD of coal by rail delivery.

SCOPE OF STUDY

The scope of this Study is to investigate the technical and economic aspects of coal gasification to supply low- or medium-Btu gas to the two power plant boilers selected for study. This includes the following:

- Investigate coals from different regions of the country, select a coal based on its availability, mode of transportation and delivered cost to each power plant site.
- Investigate the effects of burning low- and medium-Btu gas in the selected power plant boilers based on efficiency, rating and cost of modifications and make recommendations for each.
- Review the technical feasibility of converting the power plant boilers to coal-derived gas.

- Identify coal gasification systems that are compatible with the selected coals; have proven pilot, demonstration, or commercial plant operating experience; and produce a product gas which is compatible with the fuel requirements of the power plant.
- Review the technical feasibility of designing a coal gasification facility to meet the constantly changing fuel demands of a power plant.
- Select a low- or medium-Btu coal gasification system for study at Arthur Kill.
- Select a low- or medium-Btu coal gasification system for study at Oswego.
- Identify gas cleanup systems that are available and compatible with the coal gasification systems, and one capable of reducing the total sulfur emission levels to that required by environmental regulations.
- Select a gas cleanup system for use with the selected coal gasification systems.
- Review the regulatory and financial aspects of conversion to a coal-derived gas.
- Prepare capital cost estimates in 1980 dollars for each of the coal gasification system.
- Prepare capital cost estimates in 1980 dollars for the boiler modifications.

Perform the following economic evaluations for each of the synthetic gas-fired options, and compare them to the case of continued oil-firing:

- 1985 bus bar costs versus plant capacity factor.
- 25-year levelized bus bar costs versus plant capacity factor.
- Bus bar costs for 10 percent and 15 percent oil escalation.
- Bus bar costs for various coal costs.
- Bus bar costs as a function of product electric power credit.

DESIGN CRITERIA

The following general design criteria apply to both sites:

- The coal gasification plant is a separate, stand-alone installation which is self-contained with no tie-in or integration of systems between the gasification and power plants. Non-integration of the two systems avoids major modifications within the power plant. This allows the results to be used for other locations and results in a conservative cost estimate.
- The power plant is to receive gas only on an "over the fence" basis, as it does any other fuel.
- Byproduct electricity produced from waste heat in the gasification plant is wheeled over to the utility system at a cost determined by each utility.
- Alternate gasification systems are designed to provide 100 percent or 70 percent of the full load fuel requirements of the power plant without spare trains. The 70 percent gasifier case is intended to be supplemented with oil-firing as it operates in a load following mode for the power plant it serves. The power plant usually operate at considerably less than full load capacity.
- The power plant is to retain the ability to burn 100 percent fuel oil, a combination of fuel oil and gas, or 100 percent gas from the gasification plant.
- The gas cleanup system is designed so that the total sulfur emissions does not exceed those allowed by law.

RESULTS AND CONCLUSIONS

TECHNICAL RESULTS

The following two coal gasifications processes have been used as the basis for this Study:

- The Combustion Engineering coal gasification process produces a low-Btu gas at approximately 100 Btu/scf at near atmospheric pressure.
- The Texaco coal gasification process produces a medium-Btu gas at 292 Btu/scf at 800 psig.

The Combustion Engineering and Texaco processes are examined and compared for Arthur Kill, and only the Texaco process is examined and compared for Oswego. The Combustion Engineering process is not selected for Oswego due to the high costs associated with product gas compression and transmission, and the overall effect on the boiler efficiency and rating.

The following acid gas cleanup systems have been used as a basis for this Study:

- The Stretford process removes hydrogen sulfide (H_2S) from the product gas and converts it into elemental sulfur. This system is used with the Combustion Engineering gasification process.
- A Selexol unit removes sulfur components from the product gas, has a Claus unit to convert sulfur components into elemental sulfur and a Beavon/Stretford unit to cleanup the Claus unit tail gas. This system is used with the Texaco gasification process.

The Oswego boiler is convertible to medium-Btu gas-firing and the Arthur Kill boiler is convertible to medium- and low-Btu gas-firing without derating and with modest reductions in overall efficiency. The only modifications required to burn the gases are the addition of a gas supply system and modifications to air systems and burner controls. For low-Btu gas-firing at Arthur Kill, the existing induced-draft fans would have to be replaced by larger ones.

No gas storage is provided to meet variations in the power plant fuel demand. Gasifiers are capable of meeting normal variations; for other options, oil is used.

Both plants meet the Federal, state, and local environmental requirements for air quality, wastewater, liquid disposal, and ground level disposal of byproduct solids.

The ash and sulfur byproducts are temporarily stored on location. If no market can be developed for the ash, then it can be permanently stored in an environmentally acceptable manner on nearby property owned by Niagara Mohawk. Consolidated Edison does not have sufficient area for the permanent onsite storage of ash, therefore it will have to be disposed of at another site which may not be close to Arthur Kill. The sulfur by product probably will have a market value and will be sold, if not, it will be permanently disposed of in the same manner as the ash.

ECONOMIC CONCLUSIONS

- For Niagara Mohawk's Unit 6 at Oswego, the electricity costs at the bus bar when firing gas derived from coal are lower than with continued oil-firing on a levelized basis over 25 years (see Table 4). These results hold for either the 70-percent-capacity or 100-percent-capacity medium-Btu gasifier with supplemental oil-firing, with oil escalating at 10 percent. Although for initial year of commercial operation (1985), only the 70-percent-capacity gasifier option is cost effective and then only when compared to oil escalating at 15 percent. Within a few years both gasifier options are cost-effective on an annual basis when compared to oil-fired operation, regardless of whether oil is escalating at 10 or 15 percent.
- For Consolidated Edison's Unit 3 at Arthur Kill, the electricity costs at the bus bar when firing gas derived from coal are lower than with continued oil-firing on a levelized basis over 25 years (see Table 8). These results apply to both the 70-percent-capacity and 100-percent-capacity medium-Btu Texaco and low-Btu Combustion Engineering systems. The Combustion Engineering process yields lower bus bar costs with lower capital investments. Although for the initial year of gasifier operation (1985), only the 70-percent-capacity Combustion Engineering gasifier is cost effective, and then only when compared to oil escalating at 15 percent. Within a few years all gasifier options are cost-effective on an annual basis when compared to continued oil-fired operation, regardless of whether oil is escalating at 10 or 15 percent.
- All of the synthetic gas alternatives result in bus bar costs savings on yearly basis within a few years of start-up because the cost of gas escalates at a lower rate, approximately 4 to 5 percent (see Tables 3 and 7).
- If authorized by late 1980, this project could be in operation by 1985, including the time needed to modify and switch over to gas firing.

TECHNICAL DISCUSSION

BOILER FUEL REQUIREMENTS

Both Oswego and Arthur Kill power plant boilers are evaluated as to their ability to burn a low-Btu gas and a medium-Btu gas. This includes consideration to boiler derating, reduction in efficiency, extent of modifications required to burn this gas, estimated outage for modifications determined, and cost of modifications estimated.

Niagara Mohawk Unit 6 at Oswego is an 850-MW unit designed exclusively for burning fuel oil, however it can be modified for natural gas-firing. Medium-Btu gas can be fired without derating of the boiler at an overall boiler efficiency of 87.2 percent compared to 90.33 percent for fuel oil. Low-Btu gas is not recommended because of the reductions in boiler rating and efficiency and the extent of modifications required to the boiler and draft systems. Additionally, the cost associated with the compression and transportation of the low-Btu gas from the gasification site to the power plant would make it uneconomical. The modifications required to burn medium-Btu gas is the addition of a new gas supply system and modifications to the air supply system and burner controls. The unit retains its oil-burning capabilities.

The Consolidated Edison Unit 3 at Arthur Kill is a 500-MW unit originally designed for coal-firing and converted to oil-firing. Low- and medium-Btu gas can be fired without system derating. For medium-Btu gas, the boiler efficiency is 87.2 percent, and for low-Btu gas is 80.2 percent, as compared to 89.68 percent for oil-firing. A gas supply system and modifications to the air supply systems and burner controls are required for both low- and medium-Btu gases. For the low-Btu gas, the induced-draft fans and motors would have to be replaced by larger size units. After modifications to the boiler for gas-firing have been made, the boiler will still be capable of burning oil without any change in its original efficiency.

COAL AVAILABILITY, COST, AND SELECTION

The primary factors evaluated in the selection of coal are its availability and its delivered price in dollars per million Btu. Coals are classified by type, and coal fields and coal supply regions are identified, uncommitted reserves are reviewed, mine mouth costs determined, modes of transportation and cost determined, and a coal selected on the basis of its delivered costs to either Oswego or Arthur Kill are made.

Eastern bituminous, Pennsylvania anthracite, and a western subbituminous coal were evaluated. Bituminous coal from Harrison County in West Virginia was selected on the basis of its physical properties, availability and delivered cost.

The coal is delivered by railroad to either site. The railroads have been contacted for routing, size, and capacity of trainloads. For Arthur Kill, a 70-car, 5000-ton train is recommended and, for Oswego a 100-car, 10,000-ton unit train is recommended.

GASIFICATION SYSTEM SELECTION

The gasification systems for Oswego and Arthur Kill are selected for study on the basis of criteria specific to both sites and the following general criteria:

- The gasification system is compatible with the selected coal, has proven pilot or demonstration plant experience, and will be commercially available in 1981.
- The product gas is compatible with the fuel requirements of the power plant, can be desulfurized to comply with SOx emission regulations, and is produced at a cost which is competitive with alternative systems.

The Texaco gasification process, which produces a medium-Btu gas (292 Btu/scf) and byproduct waste heat, is evaluated at both Oswego and Arthur Kill.

- For the Oswego plant, the gasification system consists of seven parallel gasification trains from coal preparation through gas cleanup with supporting facilities. The byproduct waste heat not utilized internally as steam or electricity is converted into electricity for transmission on the Niagara Mohawk system.
- For the Arthur Kill plant, the gasification system consists of four parallel gasification trains. Byproduct waste heat not used internally is converted into electricity for transmission on the Consolidated Edison system. The byproduct electricity at Arthur Kill is proportionally higher than Oswego, based on either the coal-fired rate or the product gas energy output, because of the lower energy requirements for gas transport.

The Combustion Engineering gasification process, which produces a low-Btu gas (104.4 Btu/scf) and byproduct waste heat, is also evaluated at Arthur Kill. This system consists of three parallel

trains. The byproduct waste heat not used internally is converted into electricity for transmission on the Consolidated Edison system.

- The Combustion Engineering process was not evaluated for Oswego because of the high costs of gas compression and transmission, boiler derating, lower efficiency, and the high costs of boiler modifications.

The selection of the Combustion Engineering and Texaco gasification processes for evaluation does not necessarily imply their recommendation over competitive processes. A more thorough evaluation of competitive processes is required before such a recommendation can be made. The evaluated processes do, however, meet all of the Study criteria.

Byproduct energy in the form of steam, which is equivalent to about 25 percent of the energy in the coal, is produced by both gasification systems. For this Study, the byproduct energy not used directly or internally as steam is converted into electricity in a dedicated power plant located adjacent to the gasification facility. There are no large internal energy consumers in the Combustion Engineering process; therefore, a larger percent of the byproduct energy is exported as byproduct electricity. The high internal energy requirements of the Texaco process, mainly the oxygen plant, consumes a larger percent of the byproduct energy; therefore less energy is available for export as electricity than for the Combustion Engineering process.

GAS CLEANUP SYSTEMS SELECTION

Gas cleanup systems that are compatible with both the Texaco high pressure medium-Btu gasification and the low pressure low-Btu Combustion Engineering gasification system are evaluated in this study.

The following gas cleanup system is selected for use with the high pressure Texaco medium-Btu gasification system:

- Selexol unit to remove H₂S and other sulfur components from the gas.
- Claus unit to convert the sulfur components to elemental sulfur.
- Beavon/Stretford unit to remove unreacted sulfur components from the Claus unit tail gas.

The total SOx emission requirements are much more stringent for Arthur Kill than Oswego. This is reflected in the design and, consequently, the capital and operating costs.

For the Combustion Engineering low pressure, low-Btu, coal gasification system, the Stretford unit is the only system that can be utilized effectively. There is a possibility that this unit may not be able to meet the stringent New York City SOx emission requirements at Arthur Kill because the Stretford unit removes only hydrogen sulfide (H₂S) and not carbonyl sulfide (COS) and other organic sulfur components. This, however, should not eliminate the Combustion Engineering process from consideration because, for the present, the non-H₂S portion of sulfur in the product gas is not accurately known. Moreover, the Federal Environmental Protection Agency (EPA) has indicated a possible willingness to ease sulfur emission regulations for low-Btu gas derived from coal. In addition, Combustion Engineering is developing a catalyst for the Stretford system to remove carbonyl sulfide.

ENVIRONMENTAL

The gasification systems selected for the Oswego and Arthur Kill power plants meet the Federal, state, and local environmental requirements for air quality, wastewater, and liquid disposal and ground level disposal of byproduct solids.

The conversion of the Arthur Kill plant from oil to synthetic gas firing does not necessitate the preparation of an offset analysis even though the Arthur Kill unit is located in an air quality control region that is non-attainment for regulated pollutants (i.e., primary air standards for carbon monoxide and oxidants) and secondary air standards for total suspended particulates. It has been found that the power plant operation is only a small contributor to carbon monoxide and oxidant emissions (principal sources being vehicle emissions).

Conversion of Arthur Kill to synthetic gas operation with the proper safeguards, such as a flare system, will insure there will be no increase in the emission of these pollutants from the power plant. In addition, the particulate emissions from the combustion of synthetic gas is lower than the particulate emission from the burning of fuel oil.

The gas cleanup systems produce a clean gas that meets air quality standards when the gas is burned in a boiler. Byproduct gas streams produced in the coal gasification plant are treated to meet standards. As previously mentioned, there is a concern pertaining to the carbonyl sulfide and other organic sulfur component constituents from the Combustion Engineering low-Btu gasification system.

The solid byproducts produced by the two systems are ash from the coal and elemental sulfur. The latter is sold or permanently disposed of in an environmentally acceptable manner. The ash is stored onsite in a lined confined area until disposed of onsite or offsite in an environmentally acceptable manner in accordance with requirements of the Resource Recovery and Conservation Act.

Liquid wastes including rainwater runoff from the coal pile are stored in settling basins; from there they are sent to a wastewater treatment system to remove solids, oils, and other environmentally unacceptable constituents. The treated water is reused to the maximum extent with the balance, if any, discharged into the Arthur Kill or onsite at Oswego.

SYSTEM DESCRIPTION

This section presents a general description of the coal gasification and supporting systems which are evaluated for both power plants.

TEXACO MEDIUM-Btu GASIFICATION SYSTEM FOR OSWEGO

The Texaco coal gasification process gasifies 11,404 TPD of bituminous coal at its full design rating to produce 194.6×10^9 Btu/day of 292 Btu/scf fuel gas for Niagara Mohawk, Oswego, Unit 6 with a thermal efficiency of 66.14 percent for the product gas based on coal. In addition to the product gas, 68.3 MW of electricity is available for export. This results in a net overall efficiency of approximately 71.6 percent. Other byproducts include 389 TPD of elemental sulfur and 1379 TPD of ash.

The Texaco coal gasification process uses a high-pressure, single-stage, entrained-bed, oxygen-blown gasifier. The coal is ground, slurried with water, and pumped to the gasifier. Virtually all types and sizes of coal can be used. The oxygen and steam react with the coal at 800 psig and 2300 F to 2700 F to produce gas and molten slag.

The main plant is shown schematically on the Block Flow Diagram, Figure 10-8 (see Section 10), and consists of the following major units:

- One coal handling and storage system
- Seven coal grinding and water slurry preparation units (a proprietary Texaco design)
- Seven air separation plants to produce 10,289 TPD of 99.5 percent oxygen

- Seven Texaco gasification units which react the coal slurry with oxygen and steam at 800 psig
- Seven slag quenching and dewatering units
- Seven gas cooling process units which produce a total of 2,141,000 lb/hr of 1200 psig steam
- Seven Selexol units
- Two Claus units
- Two Beavon/Stretford units
- Seven reheating and expansion trains to reheat the product gas and reduce its pressure to recover available energy
- A pipeline to transmit the product gas to the power plant
- One boiler, turbine, feedwater, and condensate system. This system provides process steam and steam for mechanical steam-driven turbines within the Texaco gasification system, the required electricity for internal use, and 68.3 MW for export.
- A system to provide well water for cooling systems, boiler feedwater systems, hot gas quenching, potable water system, and fire water system.
- A cooling tower system
- A single startup boiler system
- A flare system
- A water treatment system
- A wastewater treatment system
- Additional supporting facilities--such as roads, sulfur and slag storage, offices, buildings, and facilities for the workers--that are required to operate this plant in a safe and environmentally acceptable manner

A more thorough description of each subsystem, with flow diagrams, is in Supplement C.

TEXACO MEDIUM-Btu GASIFICATION SYSTEM FOR ARTHUR KILL

The Texaco coal gasification process is one of two processes studied for use at Arthur Kill and is shown schematically on the Block Flow Diagram, Figure 10-9 (see Section 10). It is similar to that described for Oswego, but with the following modifications and adjustments:

- This plant gasifies 6434 TPD of bituminous coal to produce 109.8×10^9 Btu/day of fuel gas and 56.2 MW of byproduct electric power for export. By eliminating the long transport gas pipeline - that is required at the Oswego plant - additional electric power is available at Arthur Kill by depressurizing the product gas. On a percentage basis the byproduct electric power available for export is higher than for Oswego.
- The environmental requirements for SO₂ emissions for Arthur Kill are more stringent than for Oswego.
- A once-through saltwater cooling system is used for cooling the surface condenser of the steam turbines.
- The Arthur Kill gasification plant requires piling.

A description of each subsystem, with flow diagrams, is in Supplement D.

COMBUSTION ENGINEERING LOW-Btu GASIFICATION SYSTEM FOR ARTHUR KILL

The Combustion Engineering coal gasification plant gasifies 6895 TPD of bituminous coal to produce 119.38×10^9 Btu/day of 104.4 Btu/scf fuel gas with a thermal efficiency of 67.11 percent for the product gas based on coal. The byproduct electric power available for export is 132 MW.

The overall efficiency of the Combustion Engineering system is 84.5 percent versus 74.3 percent for Texaco for the delivered product gas when electricity available for export is included.

The Combustion Engineering gasifier is a two-stage, cyclone-type, slagging combustion boiler. The bottom section (first stage) is a cyclone-type slagging boiler similar to that used in some utility boilers. The top section is substantially an air deficient reduction section where the carbon monoxide and hydrogen is formed by the reaction between coal and carbon dioxide. The latter is produced in the slagging combustion section.

The Stretford process is used to remove the H_2S in the product gas. This is the only type unit that is suitable for low-pressure operations and economically competitive with processes available for higher pressure operations.

The system is shown schematically on the Block Flow Diagram, Figure 10-10 (see Section 10), and consists of the following major units:

- One coal handling and storage system. The trackage, railroad siding, and coal unloading and handling systems are existing.
- Three Combustion Engineering entrained-bed gasifiers, where the coal is combusted in a deficiency of air and converted to a low-Btu gas stream containing char and hydrogen sulfide
- Three slag quenching systems and one slag handling system including a dewatering system and a cooling tower
- Three gas cooling systems where the hot gases are cooled in a waste-heat boiler by generating 1,547,000 lb/hr of steam at 1450 psig and 950 F, heating boiler feedwater and condensate, and heating a high temperature solution which is used to preheat combustion air.
- Three char recovery systems
- Three Stretford units to remove the H_2S in product gas and convert it to 267 TPD elemental sulfur
- A boiler, turbine, feedwater and condensate system to convert surplus steam into electricity for internal use and for export
- A city water supply system
- A once-through saltwater system
- One wastewater treatment system
- One flare system

A more thorough description of each subsystem, with flow diagrams, is in Supplement E.

CAPITAL COST ESTIMATES

The capital cost estimates in first-quarter 1980 dollars for the following coal gasification options are as follows:

Table 1

CAPITAL COST ESTIMATES

<u>Gasification System</u>	<u>Costs in \$ x 1000 @</u>	
	<u>Power Plant Rated Capacity</u>	
	<u>100%</u>	<u>70%</u>
A. <u>Texaco Medium-Btu Gas at Oswego</u>		
Gasification plant	690,329	517,747
Power plant retrofit	6,569	6,569
Total Cost	696,898	524,316
B. <u>Texaco Medium-Btu Gas at Arthur Kill</u>		
Gasification plant	496,386	372,290
Power plant retrofit	6,054	6,054
Total Cost	502,440	378,344
C. <u>Combustion Engineering Low-Btu Gas at Arthur Kill</u>		
Gasification plant	358,624	268,968
Power plant retrofit	9,660	9,660
Total Cost	368,284	278,628

These estimates include the cost of material and labor to erect the facility, the engineering design and construction costs with paid-up royalties, and a contingency. Items not included are escalation, interest during construction, startup costs, working capital, coal, catalyst and chemical costs, etc. These items are included in the economic analysis.

ECONOMIC CONCLUSIONS

OSWEGO

For Niagara Mohawk's Unit 6 at Oswego, the projected total capital investments (gasifiers, power plant modification, and working capital) including interest during construction and

escalation for the initial project start by late 1980 and commercial operation in 1985 are shown on Table 2.

Table 2

CAPITAL INVESTMENT
FOR GASIFICATION ALTERNATIVES
AT OSWEGO NO. 6

<u>Process Alternative</u>	<u>Total Capital Investment (1985 \$ in millions)</u>
OS100%Tex	1,222
OS70%Tex	935

Table 3 shows the Oswego fuel costs in 1985 dollars. The cost of synthetic gas produced by both alternatives are shown to be higher than oil escalating at 10 percent while only the 100 percent gasifier alternative is higher than oil escalating at 15 percent in the initial year of gasifier operation. However, fuel savings from using synthetic gas instead of oil are realized over the life of the plant because after the gasification plant is built and operating, the gas cost escalates at a lower rate than oil. Synthetic gas escalation rates are much lower than those assumed for oil, because they are weighted averages of the escalation rates of their component costs: 0 percent for fixed capital costs, 8 percent for coal, and 8-10 percent for operating costs. The gas costs are adjusted (for the reduction in boiler efficiency due to the conversion from oil to gas) so that they may be directly compared to the oil cost figures.

The comparison is based on the 1980 delivered coal price of \$1.56 per million Btu with future escalation at 8 percent per year and a 1980 No. 6 fuel (0.7 percent sulfur) price of \$4.56 per million Btu. Two oil price escalation rates are analyzed: the expected rate of 15 percent per year, and a 10 percent rate - more in line with the general rate of inflation.

Table 3

OSWEGO NO. 6 FUEL COSTS
Gas Costs Adjusted For Boiler Efficiency
(At 70 Percent Power Plant Load)

<u>Fuel Alternative</u>	<u>1985 Fuel Costs (\$/MM Btu)</u>	<u>Life Cycle Escalation Rate (% per year)</u>
OS100%Tex	9.86	4.8
OS70%Tex	8.25	5.2
Cont'd oil use:		
15% escalation	9.17	15.0
10% escalation	7.34	10.0

As presented in Table 4, both synthetic gas alternatives result in 25-year levelized electricity costs of less than half the cost of oil-fired generation for the 15 percent oil escalation case. Gas is also less costly on a levelized basis than oil escalation at a 10 percent annual rate. First year synthetic gas costs, converted to cents/KWH, are lower only for the OS70%Tex alternative, and then only when compared to the 15 percent annual oil price escalation case.

Table 4

OSWEGO NO. 6 BUS BAR COSTS
(At 70 Percent Power Plant Load)

<u>Fuel Alternative</u>	<u>1985 Bus Bar Cost (¢/KWH)</u>	<u>Levelized Bus Bar Cost (¢/KWH)</u>
OS100%Tex	11.0	13.4
OS70%Tex	9.4	11.9
Cont'd oil use:		
15% escalation	10.3	32.9
10% escalation	8.5	16.7

However, in a few years both synthetic gas alternatives result in bus bar cost savings on a yearly basis, because the cost of producing gas escalates at approximately 5 percent per year, which is far below the escalation range expected for oil. The number of years until this breakeven point is reached for each alternative is shown in Table 5.

Table 5

BREAKEVEN YEAR
SYNTHETIC GAS versus OIL
(At 70 Percent Power Plant Load)

<u>Fuel Alternative</u>	<u>15% Oil Escalation (year)</u>	<u>10% Oil Escalation (year)</u>
OS100%Tex	2nd	5th
OS70%Tex	1st	3rd

Comparative 25-year levelized bus bar costs resulting from the full size gasifier alternative (OS100%Tex) and the two oil escalation cases are shown over a range of power plant load factors in Figure 1.

Figure 2 shows that the 70 percent gasifier alternative becomes attractive on a 25-year levelized basis, compared to the full size 100 percent gasifier, for steady base load operation at power plant load factors below 70 percent. The 70 percent case would not be attractive at high power plant load factors or for load following operation above 70 percent because of the high cost of the required supplemental fuel oil.

FIG. 1
OSWEGO NO.6 LEVELIZED BUS BAR COSTS:
SYNTHETIC GAS VERSUS OIL

FIG. 2
OSWEGO NO.6 LEVELIZED BUS BAR COSTS:
100% GASIFIER VS. 70% GASIFIER

- 100% TEXACO GASIFIER
- ▲ 70% TEXACO GASIFIER WITH SUPPLEMENTAL OIL (15% OIL ESC.)

ARTHUR KILL

For Consolidated Edison's Unit 3 at Arthur Kill, the projected total capital investments (gasifiers, power plant modifications, and working capital) including interest during construction and escalation for the gasification alternatives for initial project start by late 1980 and commercial operation in 1985 are shown in Table 6.

Table 6

CAPITAL INVESTMENT FOR GASIFICATION ALTERNATIVES AT ARTHUR KILL NO. 3

<u>Process Alternative</u>	<u>Total Capital Investment (1985 \$ in millions)</u>
AK100%Tex	891
AK70%Tex	681
AK100%CE	665
AK70%CE	512

Table 7 shows that the Combustion Engineering low-Btu process produces lower cost gas than that produced by the Texaco medium-Btu process. The cost of synthetic gas produced by the four alternatives are shown to be higher than oil for all cases except AK70%CE versus 15 percent oil escalation in the initial year of gasifier operation (1985). However, fuel savings from using synthetic gas instead of oil are realized over the life of the plant because once the gasification plant is built and operating, the gas cost escalates at a much lower rate than oil. The gas costs are adjusted (for the reduction in boiler efficiency due to the conversion from oil to gas) so that they may be directly compared to the oil cost figures.

The comparison is based on a 1980 delivered coal price of \$1.75 per million Btu with future escalation at 8 percent per year and a 1980 No. 6 fuel oil (0.3 percent sulfur) price of \$5.10 per million Btu. Oil price escalation rates of 10 and 15 percent are used.

Table 7

ARTHUR KILL NO. 3 FUEL COSTS
Gas Costs Adjusted For Boiler Efficiency
(At 70 Percent Power Plant Load)

<u>Fuel Alternative</u>	<u>1985 Fuel Costs (\$/MM Btu)</u>	<u>Life Cycle Escalation Rate (% per year)</u>
AK100%Tex	14.22	3.8
AK70%Tex	11.61	4.3
AK100%CE	10.58	3.9
AK70%CE	8.68	4.4
Cont'd oil use:		
15% escalation	10.26	15.0
10% escalation	8.21	10.0

Table 8 shows that for Arthur Kill the Combustion Engineering process results in lower cost electricity at the bus bar than does the Texaco process on both a first-year and levelized basis.

All of the synthetic gas alternatives result in 25-year levelized electricity costs of less than half the cost when using oil escalating at 15 percent. Gas is also less costly than oil escalating at a 10 percent annual rate, as shown in Table 8. First year synthetic gas costs, converted to cents/KWH, are lower only for the AK70%CE alternative, and then only when compared to the 15 percent annual oil price escalation case.

Table 8

ARTHUR KILL NO. 3 BUS BAR COSTS
(At 70 Percent Power Plant Load)

<u>Fuel Alternative</u>	<u>1985 Bus Bar Cost (¢/KWH)</u>	<u>Levelized Bus Bar Cost (¢/KWH)</u>
AK100%Tex	14.5	16.7
AK70%Tex	12.1	14.5
AK100%CE	11.1	12.9
AK70%CE	9.3	11.3
Cont'd oil use:		
15% escalation	10.6	35.7
10% escalation	8.7	17.9

Table 9 shows the number of years until this breakeven point is reached for each alternative. In a few years all of the synthetic gas alternatives result in bus bar cost savings on a yearly basis, because the cost of producing gas escalates at approximately 4 to 5 percent per year, which is far below the escalation range expected for oil.

Table 9

BREAKEVEN YEAR
SYNTHETIC GAS versus OIL
(At 70 Percent Power Plant Load)

<u>Fuel Alternative</u>	<u>15% Oil Escalation (year)</u>	<u>10% Oil Escalation (year)</u>
AK100%Tex	4th	9th
AK70%Tex	3rd	7th
AK100%CE	2nd	5th
AK70%CE	1st	3rd

Figure 3 shows the comparative 25-year levelized bus bar costs resulting from the full size gasifier alternatives (AK100%Tex and AK100%CE) and the two oil escalation cases over a range of power plant load factors.

Figure 4 shows that the 70 percent gasifier alternatives become attractive on a 25-year levelized basis, compared to the full size 100 percent gasifiers, for steady base load operation at power plant load factors below 70 percent. The 70 percent cases would not be attractive at high power plant load factors or for load following operation above 70 percent load because of the high cost of the required supplemental fuel oil.

FIG. 3
ARTHUR KILL NO.3 LEVELIZED BUS BAR COSTS:
SYNTHETIC GAS VERSUS OIL

- 100% TEXACO GASIFIER
- 100% COMBUSTION ENGINEERING GASIFIER
- CONTINUED OIL USE (15% OIL ESC.)
- CONTINUED OIL USE (10% OIL ESC.)

FIG. 4
ARTHUR KILL NO.3 LEVELIZED BUS BAR COSTS:
100% GASIFIER VS. 70%
GASIFIER

- 100% TEXACO GASIFIER
- ▲ 70% TEXACO GASIFIER WITH SUPPLEMENTAL OIL (15% OIL ESC.)
- 100% COMBUSTION ENGINEERING GASIFIER
- △ 70% COMBUSTION ENGINEERING GASIFIER WITH SUPPLEMENTAL OIL (15% OIL ESC.)

CONVERSION POTENTIAL

In this section, areas of uncertainty are identified that should be resolved before conversion can be assumed.

There are no large electric power generating stations that are being fueled with a gas derived from coal. There is, however, considerable experience related to industrial type boilers that are fueled with coke oven gas, and refinery and petrochemical off-gas. These are similar to the gas that is produced by the methods discussed in this Study.

There are no coal gasification plants in this country of recent vintage. There is, however, a limited amount of international experience. Texaco has two small pilot plants in operation and limited experience on a 160-TPD demonstration plant. Combustion Engineering has a 120-TPD pilot plant in operation under Department of Energy sponsorship. The commercial-size modular units proposed for this Study are greater than 10 times larger than any unit in operation today. Texaco and Combustion Engineering foresee no serious problems in a scaleup to a nominal 2000-TPD plant size module. Both are in the process of negotiating contracts for gasified modules of 1000 TPD or larger.

With the exception of the gasification units and certain ancillary equipment, such as high-pressure coal slurry pumps for Texaco, most of the supporting systems and components in the coal gasification facility have been used successfully in commercial applications. No insurmountable technical problems in placing coal gasification plants in operation are expected.

Many of the subsystems and components envisaged for a coal gasification plant are of conventional and proven design. Subsystems falling into this category include:

- Coal handling and receiving
- Oxygen plant
- Acid gas removal systems
- Byproduct steam generation
- Byproduct power recovery
- Wastewater treatment
- Electrical power generation
- Byproduct sulfur storage and handling

Section 1

INTRODUCTION

New York State is highly dependent upon imported oil for the firing of nearly 12,000 megawatts (MW) of electrical power. Replacing oil with coal-derived fuel could clearly reduce New York State's dependence on imported oil and reduce the drain of U.S. dollars to overseas suppliers of oil.

This Study has as a goal the investigation and assessment of the feasibility of firing appropriate low- or medium-Btu gas produced from coal in Consolidated Edison's Unit 3 at Arthur Kill located on Staten Island and in Niagara Mohawk's Unit 6 at Oswego, New York. One major problem in converting power plants from oil to other fuels in New York City and nearby areas is the extremely stringent sulfur emissions limitations.

The Study addresses locating available coals which could be transported with facility to the two sites. The sites were visited. Every effort is made to use existing mass handling facilities. Various gasification processes are evaluated and their products studied with regard to their effect on the performance of the power plants. The environmental constraints are studied, and cleanup and waste disposal systems are selected. Capital cost estimates are then prepared to reflect the equipment needed to convert the existing power plants to gas firing.

Finally, an economic analysis is prepared to determine the total costs for converting the plants to gas firing and to determine the operating costs over the assumed life of the plant. These figures are compared to the actual costs of producing power from oil-firing plants.

The supplements in Volume II present a more detailed discussion of pertinent data. The individual supplements in Volume II, as presented, stand alone or provide backup material for the main report. Additionally, there are supplements which cover topics that are not covered in the main report. The supplements cover the decisionmaking process, such as study on gas storage costs, gas transportation costs, the effects of low- and medium-Btu gas on power plant boilers designed for solid or liquid fuels, and supporting data for the economic evaluations. The complete list of supplements is shown in the Table of Contents.

The scope of this Study is to provide gasification systems to supply gas to one specific boiler at each power plant site. Each site, however, consists of more than one boiler. Considering the high cost of the gasification plant and the fact that an electric utility power plant seldom operates at rated capacity and with a varying load that fluctuates from hour to hour, day to day, and

so forth, consideration should be given to operating the power plant boiler on gas as a base load unit at maximum capacity.

Section 2

RESULTS AND CONCLUSIONS

TECHNICAL RESULTS

The following two coal gasification processes have been used as the basis for this Study:

- The Combustion Engineering coal gasification process produces a low-Btu gas at approximately 100 Btu/scf at near atmospheric pressure.
- The Texaco coal gasification process produces a medium-Btu gas at 292 Btu/scf at 800 psig.

The Combustion Engineering and Texaco processes are examined and compared for Arthur Kill, and only the Texaco process is examined and compared for Oswego.

The Combustion Engineering process is not selected for Oswego due to the high costs associated with product gas compression and transmission and the overall effect on the boiler efficiency and rating.

The following acid gas cleanup systems have been used as a basis for this Study:

- The Stretford process removes hydrogen sulfide (H_2S) from the product gas and converts it into elemental sulfur. This system is used with the Combustion Engineering gasification process.
- A Selexol unit removes sulfur from the product gas, has a Claus unit to convert sulfur components into elemental sulfur and a Beavon/Stretford unit to cleanup the Claus unit tail gas, this system is used with the Texaco gasification process.

The Oswego boiler is convertible to medium-Btu gas-firing and the Arthur Kill boiler is convertible to medium- and low-Btu gas-firing without derating and with modest reductions in overall efficiency. The only modifications required to burn the gases are the addition of a gas supply system and modifications to air systems and burner controls. For low-Btu gas-firing at Arthur Kill, the existing induced-draft fans would have to be replaced by larger ones.

No gas storage is provided to meet variations in the power plant fuel demand. Gasifiers are capable of meeting normal variations; for other options, oil is used.

Both plants meet the Federal, state, and local environmental requirements for air quality, wastewater, liquid disposal, and ground level disposal of byproduct solids.

The ash and sulfur byproducts are temporarily stored on location. If no market can be developed for the ash then it can be permanently stored in an environmentally acceptable manner on nearby property owned by Niagara Mohawk. Consolidated Edison does not have sufficient area for the permanent onsite storage of ash, therefore it will have to be disposed of at another site which may not be close to Arthur Kill. The sulfur probably will have a market value and will be sold, if not, it will be permanently disposed of in the same manner as the ash.

ECONOMIC CONCLUSIONS

- For Niagara Mohawk's Unit 6 at Oswego, the electricity costs at the bus bar when firing gas derived from coal are lower than with continued oil firing on a levelized basis over 25 years for the base case (see Section 12, Table 12-1). These results hold for either the 100-percent-capacity or 70-percent-capacity medium-Btu gasifier with supplemental oil firing. Although for initial year of commercial operation (1985), only the 70-percent capacity gasifier option is cost effective and then only when compared to oil escalating at 15-percent, within a few years both gasifier options are cost-effective on an annual basis when compared to oil-fired operation, regardless of whether oil is escalating at 10 or 15 percent. If authorized by late 1980, this project could be in operation by 1985, including the time needed to modify and switch over to gas firing.
- For Consolidated Edison's Unit 3 at Arthur Kill, the electricity costs at the bus bar when firing gas derived from coal are lower than with continued oil-firing on a levelized basis over 25 years (see Section 12, Table 12-6). These results apply to both the 70-percent and 100-percent-capacity-size medium-Btu Texaco and low-Btu Combustion Engineering system. The Combustion Engineering process yields lower bus bar costs with lower capital investments. Although for initial year of gasifier operation (1985), only the 70-percent capacity Combustion Engineering gasifier is cost effective, and then only when compared to oil escalating at 15 percent, within a few years all gasifier options are

cost-effective on an annual basis when compared to continued oil-fired operation, regardless of whether oil is escalating at 10 or 15 percent.

The reason that all of the synthetic gas alternatives result in bus bar costs savings on yearly basis within a few years of start-up is because the cost of gas escalates at a lower rate, approximately 4 to 5 percent than oil (see Section 12, Tables 12-4 and 12-9).

Section 3

OBJECTIVE AND METHODOLOGY

The objective of this Study is to determine the technical and economic feasibility of replacing oil with a gas derived from coal at Niagara Mohawk's Unit 6 at Oswego and at Consolidated Edison's Unit 3 at Arthur Kill. This is accomplished by investigating the following:

Fuel Requirements

The efficiency of the boiler and the amount of fuel gas required to meet the rated maximum demand of each boiler is determined.

Coal Availability and Delivered Costs

Coals from many regions are investigated. Several coals that are available in the quantity required are then identified, and their delivered costs to either site are determined.

Gasification Systems Available

Systems are identified that are commercially available, can use the selected coals efficiently, can produce a fuel compatible with the boiler systems, and can accommodate the site constraints. One system is selected for each site.

Environmental Constraints

The total sulfur emissions, air pollutants, and wastewater are studied.

Gas Cleanup Systems

Cleanup systems that are available and that are compatible with the coal gasification system must be capable of reducing the sulfur emission levels to that required by environmental regulations in the most cost-effective manner. These are identified, and one or more are selected for detailed analysis.

System Conceptual Design

Conceptual designs are prepared to provide for coal gasification and gas cleanup. These designs include the supporting systems which, when integrated into the plant as a whole, are capable of producing a gas that is suitable for either plant in the most cost-effective manner.

Capital Cost Estimates

Capital cost estimates are prepared for Oswego and Arthur Kill on the basis of the selected systems which are capable of supplying 100 percent of each power plant's fuel demand at rated conditions. Estimates are also prepared for gasification systems which supply 70 percent of each power plant's fuel demand.

Economic Evaluations of Alternatives

Economic analyses are prepared for each facility which include: the cost of gas in 1980 and 1985 dollars; levelized bus bar costs for the life of each plant as a function of power plant capacity factor; sensitivity analysis for coal costs; and electric costs for both the 100-percent and 70-percent coal gasification options.

Economic Comparison with Continued Use of Oil

The cost of oil in 1980 and 1985 dollars and the levelized bus bar costs for the life of each plant are compared with the coal gasification options over the life of each plant as a function of power plant capacity factor.

Financial Options and Constraints

The principal financial options including tax incentives, federal support, methods of financing, and the legal and social constraints of financing are investigated.

Section 4

DESIGN CRITERIA

The basic design criteria for the coal gasification plant design described herein are: minimizing bus bar electric costs while avoiding major modifications to existing facilities, and meeting environmental requirements.

DESCRIPTIONS OF EXISTING FACILITIES

Oswego

Niagara Mohawk's Unit 6, a new 850-MW unit designed to burn No. 6 fuel oil, is readily convertible to gas-firing but not to coal-firing and is selected for conversion to gas-firing. The unit is scheduled for commercial operation in the first half of 1980.

The Niagara Mohawk station is in the town of Oswego, which is located on Lake Ontario in Oswego County, New York. The station consists of two identical 850-MW units (Units 5 and 6) and three smaller units with a combined capacity of 376 MW. The 850-MW units were designed to burn fuel oil and the three smaller units were originally designed for and fired on coal but have been converted to oil firing. Unit 6 is located on the former site of the coal handling and storage area. There is no space near the power plant for the gasification plant. A site for the gasification plant has been selected on property owned by Niagara Mohawk which is located 5 miles inland from Lake Ontario and the town of Oswego. The right-of-way from the site to the power plant is owned by Niagara Mohawk. Coal is delivered to the gasification site via railroad.

Staten Island

Consolidated Edison's Unit 3 at Arthur Kill, a 10-year-old 500-MW unit that was originally designed as a coal-fired unit but was converted to No. 6 fuel oil to comply with local environmental regulations, is studied for conversion to gas-firing.

The station, which consists of the 500-MW unit and a 350-MW unit, is located at Fresh Kills on Staten Island, New York. There is space adjacent to the power plant for the gasification plant. The area is serviced by a railroad line and operational coal unloading facilities. Alternatively, coal may be delivered to the site by barges; however, unloading facilities would have to be built.

SPECIFIC DESIGN CRITERIA

To simplify the Study and to enable the results to be applicable to other power plants, the following general guidelines are provided:

- One boiler at each site is selected for study.
- The power plant receives gas only from the coal gasification facility.
- There is no integration of the steam generated in the gasification facility with the power plant.
- Steam generated in the gasification facility is used to meet process heat requirements and is used in steam turbines to supply the energy requirements of major power consumers. The balance of the steam is used to produce electric power for internal consumption with the balance of the electric power available to the electric utility.
- Makeup water, raw water treatment, cooling water, and waste treatment facilities required in the gasification facility are separate from those of the power plant.
- The gasification facility is designed without spare trains. Each power plant retains 100-percent oil-firing capabilities.
- Each of the gasification options consists of separate multitrain systems; it is highly improbable that there will be a total failure of the system. It is envisaged that a complete gasification train could be taken off-line for normal maintenance or emergency purposes without adversely affecting the operations of the power plant or the balance of the gasification plant.
- The total sulfur emissions for each site do not exceed those allowed by applicable Federal, New York State, and local sulfur emission regulations.
- For Oswego, all water for process cooling water systems and fire protection systems as well as potable water supply is from wells located on the property.
- For Arthur Kill, saltwater is used to meet the major cooling requirements and the fire protection system. Water from New York City is used for process and

miscellaneous services as well as the potable water supply system.

- The only major changes in the power plant are those necessary to fire the gas.

Section 5

BOILER FUEL REQUIREMENTS

OSWEGO

Boiler No. 6 at Oswego is an 850-MW, Foster Wheeler natural circulation, front-fired, balanced-draft steam generator, designed for burning fuel oil. Figure 5-1 shows a sectional side view and Table 5-1 gives the predicted performance of this unit, as prepared by the boiler manufacturer.

The recently completed unit is presently in trial operation and scheduled for commercial operation in early 1980. To fire low-Btu gas, produced in air-blown gasifiers, in steam generators designed for oil firing requires major modifications of pressure parts. It also requires increases in capacity and structural strength of the draft system to accommodate the increase in fuel gas rate in addition to the required burner and control modifications. Furthermore, extensive reductions in the rating and efficiency must be expected in spite of these modifications.

Investigation for Oswego was, therefore, limited to the proposed use of medium-Btu gas produced in oxygen-fed gasifiers. The implication of this decision is the judgment that the cost of derating the boiler capacity and derating its efficiency for low-Btu gas, when added to the cost of modifications, may exceed the differential costs associated with the medium-Btu gas (especially when the higher differential costs associated with the transportation of low-Btu gas from the gasification plant to the power plant are considered).

The boiler manufacturer has concurred that burning medium-Btu gas in boiler No. 6 at Oswego should present no major problem.

ARTHUR KILL

The boiler at Arthur Kill is a 500-MW, Combustion Engineering (CE), tangentially fired, radiant reheat, controlled circulation, balanced-draft steam generator. Figure 5-2 shows a sectional side view, and Table 5-2 shows performance data obtained from the boiler manufacturer. The boiler was originally designed to burn an eastern bituminous coal. It began commercial operation in 1969.

In 1972, a conversion of the boiler from burning coal to burning No. 6 fuel oil was completed. This involved removal of superheater platens and bypassing steam to the finishing superheater; adding gas recirculation; reorificing waterwalls; and increasing desuperheater spray valve capacity. Five windbox compartments were converted for oil firing at each corner.

Low-Btu Gas

In June 1973, Combustion Engineering performed a study to determine the technical and economic feasibility of burning a low-Btu or medium-Btu coal-derived gas in Unit 3. In case 1, burning low-Btu coal-derived gas, having a heating value of 127 Btu/scf, in Unit 3 was studied. The conclusions were:

- 100-percent maximum continuous rating of the boiler capacity could be retained.
- Full-load boiler efficiency would drop by about 3 percent.
- Modifications required to accomplish the conversion are as follows:
 - Modify burner windboxes.
 - Design and install new low-Btu gas ducts and piping.
 - Replace induced-draft fans and motors with new larger fans and motors and adapt to ductwork and electric power supply.
 - Modify instruments and controls.
- Fuel oil is retained as a secondary fuel.

On the basis of the information in the referenced study, the performance predictions and the modifications required for converting the same boiler to low-Btu gas should present no major problems.

Medium-Btu Gas

The conclusion of the Combustion Engineering study case 2, medium-Btu coal-derived gas, indicated that medium-Btu gas could be fired in Unit 3 without any derating of the boiler capacity and with a modest reduction in boiler efficiency.

The investigation of both low- and medium-Btu gas firing at Arthur Kill is made to compare the overall costs of the two gasified options. The overall effects on the power plant are investigated, including extent of modifications, efficiency and rated capacity of the boiler, the cost of gas to the boiler, and the bus bar costs of electricity. It had been shown in previous studies that low-Btu gas could be produced at a lower cost per million Btu than medium-Btu gas. However, when the greater reduction in the boiler efficiency is included, the power plant

bus bar cost advantages with low-Btu gas are not so evident. The Combustion Engineering low-Btu system and the Texaco medium-Btu gas process are examined.

Table 5-1
Foster Wheeler Corp.

SUMMARY OF PERFORMANCE SHEET

Purchaser... Niagara Mohawk Power Company... Contract No.
Location... Oswego Steam Plant, Unit No. Date ..
Design pressure .2875/851 psig..... Dwg. No... 79-1148-6-20.....

Fuel		011	011	011	Each unit will include the following	
Steam	M lb/hr	4,200	6,300	6,300	Convection surface	3,830 sq ft
Pressure superheater outlet	psi	2,135	2,180	2,180	Walls in furnace	33,266 sq ft
Temperature steam superheater outlet	F	1,005	1,005	1,005	Radiant superheater	15,374 sq ft
Pressure Boiler Drum	psi	2,509	2,616	2,616	Convection superheater	127,130 sq ft
Reheat steam	M lb/hr	3,864	5,722	5,722	Reheater I.	165,720 sq ft
Temperature steam entering reheater	F	632	696	696	Reheater II.	sq ft
Temperature steam leaving reheater	F	1,005	1,025	1,025	Economizer	203,030 sq ft
Pressure steam entering reheater	psi	1,88	731	731	Air heater (2)	820,000 sq ft
Pressure steam leaving reheater	psi	1,71	706	706	Total furnace volume	405,000 cu ft
Air Dilution Fan	Cu	On	On	On	Total furnace surface	43,670 sq ft
Temp feed entering unit	F	166	509	509	Firing equipment	Barney Eng. Burners
Temp feed leaving econ.	F	581	614	589	Superheat control by	
Temp air entering unit	F	139	117	123	Performance based on fuel specified below:	
Temp air leaving air heater	F	558	629	538	Kind	
Temp gas leaving furnace	F	2,025	2,225	2,250	Grindability	(ASTM; D-409-37-T)
Temp gas leaving boiler	F				Size	Max moisture
Temp gas leaving economizer	F	635	735	700	Prox. Analysis Per Cent	Moisture
Temp gas leaving air heater	F	277	293	287		Volatile matter
Ditto corrected for leakage	F	265	284	280		Fixed carbon
						Ash
						Fusion temp. of ash
Excess air leaving	%	5	5	5		
Wet gas entering air heater	M lb/hr	4,610	6,510	6,520		
Wet gas leaving air heater	M lb/hr	4,960	6,952	6,892		
Air entering air heater	M lb/hr	4,660	6,532	6,472		
Air leaving air heater	M lb/hr	4,340	6,110	6,100		
Draft in furnace	in. H ₂ O	0.10	0.10	0.10		
Gas side loss thru boiler	in. "					
Gas side loss thru suptr. & rehr.	in. "					
Gas loss thru economizer	in. "	6.70	10.65	9.67		
Gas side loss thru airheater	in. "	3.18	6.55	6.30		
Gas side loss thru flues	in. "	0.70	1.70	1.13		
Gas side loss thru dust collector	in. "	10.88	19.00	17.20		
Air side loss thru air heater	in. H ₂ O	2.50	1.70	1.60		
Air side loss thru ducts	in. "	3.20	5.20	5.90		
Air side loss thru burners	in. "	4.00	6.60	5.00		
Air side loss,	in. "	0.80	1.50	1.50		
Air side loss,	in. "	12.50	19.00	17.00		
Icon. Friction Press. Drop	psi	30	63	63		
Air & gas loss total	in. H ₂ O					
Pressure loss Drum to Sho Hdr.	psi	71	166	166		
Fuel burned	M lb/hr	301	431	430		
Liberation, total vol.	Btu/hr x cu ft.	14,000	19,600	19,500		
Furn. cooling Factor net,	Btu/hr x sq. ft.	118,000	172,000	168,000		
Heat Losses						
Dry gas	%	2.18	3.33	3.11		
Hydrogen and moisture in fuel	%	5.21	5.36	5.32		
Moisture in air	%	0.06	0.08	0.08		
Unburned combustible	%					
Radiation	%	0.25	0.16	0.16		
Unaccounted for and mfrs. margin	%	1.00	1.00	1.00		
Losses	%	9.00	9.93	9.67		
Efficiency	%	91.00	90.07	90.33		

Steam Temp. Control Range From 4,200,000 lb/hr. To 6,300,000 lb/hr. Guarantee Point .. 6,300,000 lb/hr.

*Includes loss thru windbox compartments, dust and mix. pipe
--Includes balancing valve loss

Issued

TABLE 5-2
ACTUAL AND PREDICTED PERFORMANCE, OIL AND LOW-BTU GAS
ARTHUR KILL BOILER NO. 3

ITEM	ORIG.DESIGN COAL FIRING**	TEST DATA OIL FIRING 10/31/72	PREDICTED PERFORMANCE LOW-BTU GAS FIRING (127 BTU/SCF)
LOAD		506 MW	506 MW
EXCESS AIR	25%	11%	15%
AIR FLOW FROM FD FAN	NOT AVAILABLE	3.857X10 ⁶ LB/HR	3.389X10 ⁶ LB/HR
GAS RECIRCULATION	NOT INSTALLED	47%	0%
FLUE GAS FLOW LEAVING ECONOMIZER	NOT AVAILABLE	5.680X10 ⁶ LB/HR	5.680X10 ⁶ LB/HR
SUPERHEATER OUTLET TEMPERATURE	1000 F	1013 F	1013 F
SH FINISHING INLET TEMPERATURE		871 F	853 F
SH PANEL OUTLET TEMPERATURE		820 F	795 F
SH DESH* OUTLET TEMPERATURE		734 F	734 F
SH DESH* INLET TEMPERATURE		795 F	821 F
ECONOMIZER OUTLET TEMPERATURE		573 F	582 F
ECONOMIZER INLET TEMPERATURE		475 F	475 F
REHEATER OUTLET TEMPERATURE	1000 F	1000 F	1006 F
RH RADIANT WALL OUT- LET TEMPERATURE		702 F	670 F
RH INLET TEMPERATURE		618 F	618 F
MAIN STEAM FLOW	3.580X10 ⁶ LB./HR	3.325X10 ⁶ LB./HR	3.325X10 ⁶ LB./HR
SH DESUPERHEATER SPRAY FLOW		247,000 LB./HR	397,000 LB./HR
REHEATER STEAM FLOW		2.956X10 ⁶ LB/HR	2.956X10 ⁶ LB/HR
GAS TEMPERATURE LEAVING ECONOMIZER	NOT AVAILABLE	618 F	643 F
GAS TEMPERATURE LEAVING AIR HEATER	265 F	238 F	276 F
BOILER EFFICIENCY %	90.42	89.7	36.6

SH - SUPERHEATER, DESP - DESUPERHEATER, RH REHEATER.
 *OBTAINED FROM CONSOLIDATED EDISON "DESCRIPTION OF
 EQUIPMENT & SYSTEMS", DATED JULY 1969.

2892-TAB.5-2

FOSTER WHEELER

FIG-5-1
SECTIONAL SIDE VIEW OF
OSWEGO UNIT NO. 6

NAME.....NIAGARA MOHAWK COMPANY
LOCATION.....OSWEGO STEAM PLANT, UNIT NO. 6
NO. OF UNITS..1.....CONTRACT NO. 6

DESIGN PRESSURE.....2875/850 PSIG
FINAL STEAM TEMPERATURE.....605/1005 F
CAPACITY 6,300 ALB/HR TYPE..REHEAT

FIGURE 5-2

SIDE ELEVATION
ARTHUR KILL BOILER NO. 30
AS A COAL-FIRED UNIT

Section 6

COAL AVAILABILITY, COST, AND SELECTION

The primary factors evaluated in the selection of coal for the production of low- or medium-Btu gas are its availability and the delivered cost of the coal in dollars per million Btu. Additional factors include the differential costs of ash and sulfur on both the capital and operating costs of the coal gasification system, the sulfur removal systems, and the supporting facilities, as well as the costs associated with the storage and disposal of the ash and sulfur.

Coals were classified, coal fields and coal supply regions were studied, uncommitted coal reserves were reviewed, and the equivalent costs of coal were investigated to determine the coal selected for this Study.

COAL SUPPLY

Coals of different types and ranks are available in the United States, and their reserves are subdivided into coal-producing regions based on geographic location. Six coals from Appalachian and Western regions were evaluated.

Lignites are not considered because of the problems associated with transportation and handling, as well as the higher transportation costs associated with their low-Btu content.

Imported coals are not considered because the primary objective of this Study is to lessen our dependency upon imported fuels.

The parameters considered for coal supply and transportation at Oswego are shown in Table 6-1, NYSERDA Coal Selection Information Matrix - Oswego Plant; for Arthur Kill, they are shown in Table 6-2, NYSERDA Coal Selection Information Matrix - Arthur Kill Station, Staten Island.

Specifications and quotes were obtained for three eastern bituminous coals, two Pennsylvania anthracites, and one western subbituminous coal. The coal location, coal seam and ownership, as well as the estimated coal reserve and types of transportation are identified. The coal supply evaluation methodology is discussed in detail in Supplement A, Coal Supply.

COAL SELECTION

Table 6-3, Coal Selection, shows that bituminous coal from Harrison County in West Virginia is the recommended coal for both Oswego and Arthur Kill.

The Oswego and Arthur Kill coal gasification facilities are also designed with the same coal assumed in order to permit the transfer of the basic coal gasification design from one site to the other.

The Hazelton anthracite is not recommended because of the uncertainties of long-term supply.

COAL TRANSPORTATION

The selected coal for Oswego is transported to the Oswego plant by rail; the rail route is shown on Figure 6-1. The railroad and routing are listed in the Oswego Plant Selection Information Matrix, Table 6-1.

Coal from the same mines is selected for the Arthur Kill plant. Transportation is by rail; the rail route is shown on Figure 6-2. The railroads and routing are also listed in the Arthur Kill Selection Information Matrix, Table 6-2. Alternatively, the coal could be transported by rail to Port Reading on the New Jersey side of the Arthur Kill from where it could be shipped by barges to the plant site. Facilities exist for the delivery of coal to Arthur Kill by railroad, whereas barge unloading facilities do not exist at present.

The coal transportation evaluation methodology is discussed in detail in Supplement B, Coal Transportation.

TABLE 6-1

COAL GASIFICATION PROJECT—OSWEGO PLANT SELECTION INFORMATION MATRIX

COAL TYPE	LOCATION SEAM	PROXIMATE COAL ANALYSIS (BY WEIGHT)	TRANSPORTATION	DISTANCE BETWEEN MINE AND PLANT SITE (RAIL MILES)	COAL COST FOB MINE \$/TON	TRANSPORTATION COST \$/TON	TOTAL DELIVERED COST 1979 DOLLARS/TON	DOLLARS/MMBTU	REMARKS
BITUMINOUS	BOONE COUNTY, WEST VIRGINIA (SOURCE—EASTERN ASSOCIATED COAL CORP.)	MOISTURE - 6.5% ASH - 8% SULFUR - 1% VOLATILE MATTER - 34% CARBON - 51.5% BTU/LB - 13100 FUSION TEMP - 2730 °F GRINDABILITY - 53	CHESSIE SYSTEM AND CONRAIL VIA CHARLESTON, COLUMBUS, TOLEDO, BUFFALO & SYRACUSE	850 (APPROX) UNIT TRAINS	38.00 (QUOTE)	16.5 (ESTIMATED @ \$0.019/TON MILE BASED ON CHESSIE QUOTE)	54.15	2.07	7000-10000 TON UNIT TRAINS ESTIMATED COAL RESERVE = 55 MILLION TONS CONTRACT FOR 10 MILLION TONS COAL AFTER APRIL 1980
BITUMINOUS	COMPASS & MARS HARRISON COUNTY W. VIRGINIA (SOURCE: PITTSBURGH COAL SALES CORP.)	MOISTURE - 4.5% ASH - 11.5% SULFUR - 3.9% VOLATILE MATTER - 38% CARBON - 46% BTU/LB - 12,900 FUSION TEMP - 2150 °F GRINDABILITY - 58	CHESSIE SYSTEM AND CONRAIL VIA CLEARFIELD, BUFFALO AND SYRACUSE	640 (APPROX)	25.00 (QUOTE)	12.16 (SOURCE CHESSIE SYSTEM)	37.16	1.44	7000-10000 TON UNIT TRAINS ESTIMATED COAL RESERVE = 56 MILLION TONS NO LONG TERM CONTRACT AT PRESENT.
BITUMINOUS	DENT'S RUN MINE PITTSBURGH SEAM MARION COUNTY, W. VA. (SOURCE: CONSOLIDATION COAL CO.)	MOISTURE - 4% ASH - 6.9% SULFUR - 3.2% VOLATILE MATTER - 37% CARBON - 52.1% BTU/LB - 13,400 FUSION TEMP - 2260 °F GRINDABILITY - 62	CHESSIE SYSTEM AND CONRAIL VIA CLEARFIELD, BUFFALO AND SYRACUSE	640 (APPROX)	31.00 (QUOTE)	12.16 (SOURCE CHESSIE SYST.)	43.16	1.61	7000-10000 TON UNIT TRAINS ESTIMATED COAL RESERVE = 100 MILLION TONS NOT YET COMMITTED ADDITIONAL COAL RESERVE OVER 1 BILLION TONS
SUB-BITUMINOUS	BUCKSKIN MINE, WYOMING (SOURCE: BURLINGTON NORTHERN INC.)	MOISTURE - 29% ASH - 6% SULFUR - 0.5% VOLATILE MATTER - 32% CARBON - 33% BTU/LB - 8214 FUSION TEMP - 2240 °F GRINDABILITY - 62.7	BURLINGTON—NORTHERN TO SUPERIOR, MN. FROM SUPERIOR TO OSWEGO BY LAKE VESSELS ALTERNATE, E-N TO CHICAGO, THENCE CONRAIL TO OSWEGO VIA SYRACUSE	BY RAIL-1100 BY LAKE-1150 TOTAL -2250	9.00 (QUOTE) 9.00 (QUOTE)	RAIL \$12.50 LAKE \$9.26 TOTAL \$21.76 (ESTIMATED RAIL TRANS. COST @ \$0.019/TON—MILE BASED ON CHESSIE QUOTE) 36.10 (ESTIMATED @ \$0.019 PER TON-MILE BASED ON CHESSIE SYSTEM QUOTE)	30.76 45.10	1.87 2.75	7000-10000 TON UNIT TRAINS PROPOSED ROUTE OPEN 280 DAYS/YEAR ALTERNATE ALL—RAIL ROUTE OPEN YEAR-ROUND ESTIMATED COAL RESERVE = 60 BILLION TONS
ANTHRACITE	WILKES-BARRE, PA (SOURCE—LEHIGH VALLEY COAL SALES CO.)	MOISTURE - 1% ASH - 10% SULFUR - 0.7% VOLATILE MATTER - 5% FIXED CARBON - 84% BTU/LB - 13500 FUSION TEMP - 2900 °F GRINDABILITY - 34	CONRAIL TO OSWEGO	175 (APPROX)	45.00 (QUOTE)	3.33 (ESTIMATED @ \$0.019/TON-MILE BASED ON CHESSIE QUOTE)	48.33	1.79	7000-10000 TON UNIT TRAINS 71.8 BILLION TON TOTAL RECOVERABLE COAL CURRENT COAL PRODUCTION 5 MILLION TONS PER YEAR
ANTHRACITE	HAZELTON, PA (SOURCE—LEHIGH VALLEY COAL SALES CO.)	MOISTURE - 1% ASH - 20% SULFUR - 0.7% VOLATILE MATTER - 5% FIXED CARBON - 74% BTU/LB - 11500 FUSION TEMP - 2900 °F GRINDABILITY - 32-34	CONRAIL TO OSWEGO	225 (APPROX)	30.00 (QUOTE)	4.28 (ESTIMATED @ \$0.019/TON-MILE BASED ON CHESSIE QUOTE)	34.28	1.49	7000-10000 TON UNIT TRAINS 71.8 BILLION TON TOTAL RECOVERABLE COAL CURRENT COAL PRODUCTION 5 MILLION TONS PER YEAR

TABLE 6-2

COAL GASIFICATION PROJECT—ARTHUR KILL STATION, STATEN ISLAND **SELECTION INFORMATION MATRIX**

COAL TYPE	LOCATION SEAM	PROXIMATE COAL ANALYSIS (BY WEIGHT)	TRANSPORTATION	DISTANCE BETWEEN MINE AND PLANT SITE (RAIL MILES)	COAL COST FOB MINE \$/TON	TRANSPORTATION COST \$/TON	TOTAL DELIVERED COST 1979 DOLLARS TON	DOLLARS/MMBTU	REMARKS
BITUMINOUS	BOONE COUNTY W VIRGINIA (SOURCE EASTERN ASSOCIATED COAL CORP)	MOISTURE - 6.5% ASH - 8% SULFUR - 1% VOLATILE - 34% MATTER CARBON - 51.5% BTU/LB - 13100 FUSION TEMP - 2730°F GRINDABILITY - 53	CHESSIE SYSTEM TO PHILADELPHIA VIA WASHINGTON BALTIMORE, THENCE CONRAIL TO PORT READING TO PLANT BY BARGE	700 (APPROX)	38 0 (QUOTE)	RAIL = 15 60 (QUOTE) BARGE = 1 25 TOTAL = 16 85 (BARGE RATES ESTIMATED—REF: ICF REPORT)	54 85	2 09	7000-10000 TON UNIT TRAINS ESTIMATED COAL RESERVE - 55 MILLION TONS CONTRACT FOR 10 MILLION TONS COAL AFTER APRIL 1980
BITUMINOUS	COMPASS & MARS, HARRISON COUNTY W VIRGINIA (SOURCE PITTSBURGH COAL SALES CORP)	MOISTURE - 4.5% ASH - 11.5% SULFUR - 3.9% VOLATILE - 38% MATTER CARBON - 46% BTU/LB - 12,900 FUSION TEMP - 2150°F GRINDABILITY - 58	CHESSIE SYSTEM TO SHIPPENSBURG, PA, THENCE BY CONRAIL TO PORT READING TO PLANT BY BARGE	700 (APPROX)	25 00 (QUOTE)	RAIL = 15 60 (QUOTE) BARGE = 1 25 TOTAL = 16 85 (BARGE RATES ESTIMATED—REF: ICF REPORT)	41 85	1 62	7000-10000 TON UNIT TRAINS ESTIMATED COAL RESERVE - 56 MILLION TONS NO LONG TERM CONTRACT AT PRESENT
BITUMINOUS	DENT S RUN MINE PITTSBURGH SEAM MARION COUNTY, W VA (SOURCE CONSOLIDATION COAL CO)	MOISTURE - 4% ASH - 6.9% SULFUR - 3.2% VOLATILE - 37% MATTER CARBON - 52.1% BTU/LB - 13,400 FUSION TEMP - 2260°F GRINDABILITY - 62	CHESSIE SYSTEM TO SHIPPENSBURG, PA, THENCE BY CONRAIL TO PORT READING TO PLANT BY BARGE	700 (APPROX)	31 (QUOTE)	RAIL = 15 60 (QUOTE) BARGE = 1 25 TOTAL = 16 85 (BARGE RATES ESTIMATED—REF: ICF REPORT)	47 85	1.79	7000-10000 TON UNIT TRAINS ESTIMATED COAL RESERVE - 100 MILLION TONS NOT YET COMMITTED. ADDITIONAL COAL RESERVE OVER 1 BILLION TONS
SUB-BITUMINOUS	BUCKSKIN MINE, WYOMING (SOURCE BURLINGTON—NORTHERN INC)	MOISTURE - 29% ASH - 6% SULFUR - 0.54% VOLATILE - 32% MATTER CARBON - 33% BTU/LB - 8214 FUSION TEMP - 2240°F GRINDABILITY - 62.7	BURLINGTON—NORTHERN TO CHICAGO, THENCE CONRAIL TO PORT READING VIA PITTSBURGH & HARRISBURG TO PLANT BY BARGE	1900 (APPROX)	9 00 (QUOTE)	RAIL = \$36 10 (ESTIMATED @ \$0 019/TON-MILE) BARGE — \$1 25 (REF: ICF REPORT) TOTAL = \$37 35	46 35	2 82	7000-10000 TON UNIT TRAINS ESTIMATED COAL RESERVE - 60 BILLION TONS
ANTHRACITE	WILKES-BARRE, PA (SOURCE — LEHIGH VALLEY COAL SALES CO)	MOISTURE - 1% ASH - 10% SULFUR - 0.7% VOLATILE - 5% MATTER FIXED CARBON - 84% BTU/LB - 13500 FUSION TEMP - 2900°F GRINDABILITY - 34	CONRAIL TO PORT READING THENCE BY BARGE TO PLANT	150 (APPROX)	45 00 (QUOTE)	RAIL = 2 85 BARGE = 1 25 TOTAL = 4 10 (ESTIMATED RAIL TRANS COST @ \$0 019/ MILE-TON BASED ON CHESSIE QUOTE) (BARGE RATE ESTIMATED—REF: ICF REPORT)	49 10	1 82	7000-10000 TON UNIT TRAINS 7.8 BILLION TON TOTAL RECOVERABLE COAL CURRENT COAL PRODUCTION 5 MILLION TONS PER YEAR
ANTHRACITE	HAZELTON, PA (SOURCE — LEHIGH VALLEY COAL SALES CO)	MOISTURE - 1% ASH - 20% SULFUR - 0.7% VOLATILE - 5% MATTER FIXED CARBON - 74% BTU/LB - 11500 FUSION TEMP - 2900°F GRINDABILITY - 32-34	CONRAIL TO PORT READING THENCE BY BARGE TO PLANT	125 (APPROX)	30 00 (QUOTE)	RAIL = 2 38 BARGE = 1.25 TOTAL = 3 63 (ESTIMATED RAIL TRANS COST @ \$0 019/ MILE-TON BASED ON CHESSIE QUOTE) (BARGE RATE ESTIMATED—REF: ICF REPORT)	33 63	1 46	7000-10000 TON UNIT TRAINS 7.8 BILLION TON TOTAL RECOVERABLE COAL CURRENT COAL PRODUCTION 5 MILLION TONS PER YEAR

TABLE 6-3
COAL SELECTION

	<u>OSWEGO</u>		<u>ARTHUR KILL</u>	
<u>SOURCE OF COAL</u>	<u>DELIVERED COST (\$/MM BTU)</u>	<u>SELECTION RATING</u>	<u>DELIVERED COST (\$/MM BTU)</u>	<u>SELECTION RATING</u>
BOONE COUNTY, W.VA.	2.07	4	2.09	5
COMPASS AND MARS MINES, HARRISON COUNTY, W.VA.	1.49	1A	1.67	2
DENT'S RUN MINE, PITTSBURGH SEAM, MARION COUNTY, W.VA.	1.61	2	1.79	3
BUCKSKIN MINE, WYO.	2.38 2.75*	5 6*	2.82	6
WILKES-BARRE, PA.	1.79	3	1.82	4
HAZELTON, PA.	1.49	1B	1.46	1
RECOMMENDED COAL FOR OSWEGO - SELECTION 1A			RECOMMENDED COAL FOR ARTHUR KILL - SELECTION 2	
*ALTERNATE ROUTE

Figure 6-1
 Coal Transportation Route From
 Compass and Mars Mines, W. Virginia to Oswego
 Plant

Figure 6-2
Coal Transportation Route From Compass and
Mars Mines, W. Virginia to Staten Island
Plant

Section 7

GASIFICATION SYSTEM SELECTION

SELECTION CRITERIA

The gasification systems for both Oswego and Arthur Kill are selected on the basis of criteria specific to both locations and the following general criteria:

- The gasification system is compatible with the selected coal.
- The gasification system is commercially available in 1981.
- The gasification system has proven pilot plant, demonstration plant, or commercial plant operating experience.
- The product gas is compatible with the fuel requirements of the power plant.
- The product gas has the least impact on the boiler with respect to boiler rating and boiler efficiency. Also, the extent and cost of boiler modifications to accommodate the gas and the downtime modifications should be minimal.
- The product gas can be economically treated to reduce the sulfur level to comply with local environmental regulations.
- The product gas is cost competitive with gas from other available gasification systems.
- The relative capital and operating costs are cost competitive with other available gasification systems.

Criteria based on specific power plants, locations, and site-related items are discussed under the individual site selections.

In the selection of an air- or oxygen-blown gasification process, consideration is given to the fact that either process could be designed to operate with air, oxygen, or a combination thereof. The gasification units for each site are, however, specified for a specific type of oxidant feed. In this manner, the gasification system is specified to produce a gas that is compatible with the boiler and at the lowest probable cost.

From the data presented in Section 5, Boiler Fuel Requirements, it appears that oil-designed boilers can operate on gas with 300 Btu/scf or higher without any major modifications or impairments of efficiency; whereas extensive modifications, with a corresponding reduction in efficiency, would result from operation with low-Btu gas. For coal-designed boilers, it appears that 200 Btu/scf and higher gas could be used without major modifications and with only a small decrease in efficiency. For a gas with less than 200 Btu/scf heat content, there would be an increase in the extent of modifications and a decrease in boiler efficiency with decreasing Btu content of the gas. This, however, is not detrimental if the cost of gas and the resultant cost of electricity produced therefrom is equal to or less than the cost with a gas of higher heat content.

The selection of a specific gasification process for medium- or low-Btu gas does not necessarily imply that the particular process is recommended over competitive processes. The selection of the process is based on (among other criteria given above) the availability of data and the willingness of specific gasification vendors to support this project and provide the necessary technical and financial information.

There are many companies with proven experience in coal gasification that are willing to commit themselves to providing a "commercial" plant and that will offer guarantees on gasification performance. Table 7-1, Matrix of Gasification Process Selection, shows those coal gasification processes that were considered.

Texaco has recently negotiated contracts to license and build one or more units.

Lurgi has proven experience in the operation of their gasifiers on noncaking coals, but their unit is not suitable for high-caking eastern bituminous coals. They have commercial operations in South Africa and other places.

Allis-Chalmers has a pilot unit in operation and is currently in the design stage for a commercial-size demonstration plant. They expect to be commercial in the late 1980s.

Combustion Engineering has a 120-ton-per-day (TPD) pilot plant in operation under Department of Energy (DOE) sponsorship. Their unit is essentially a conventional slagging-type coal-fired boiler that operates in a starved-air mode. Combustion Engineering is currently in contract negotiations for a commercial size unit of 1000 TPD or larger, and claim that they will be commercially available by the required date.

Babcock & Wilcox has previously made a proposal to the DOE in conjunction with Dravo Corp. and Consolidated Natural Gas Company (CNG) to produce medium-Btu gas for use in an industrial complex. They have operating experience going back to the 1950s and claim to be commercially available today.

The British Gas Council Slagger, which is currently one of the two processes that the DOE is supporting for demonstration and commercialization, is not expected to be available by the required date.

The Westinghouse unit, which shows high promise of being both a technical and commercial success, will not be available by the required date.

First-generation plants, such as Koppers-Totzek, Winkler, and others, are commercially available today. Plants of varying capacities are currently in operation in India, Turkey, Spain, and other countries. The economics for these units appear to be less favorable than some of the aforementioned units.

A gasification system capable of providing 100 percent of the power plant's fuel demand is specified. The power plant seldom operates at its rated capacity. A gasification system that is capable of meeting about 70 percent of the power plant's requirements with oil, used as a supplementary fuel, when the power plant is operating at capacities higher than 70 percent is also investigated. The oil consumption for a 70 percent gasification plant is not 30 percent of the total fuel requirements because on a yearly average the production of electric power is often approximately 70 percent of the total power-generating capacity of a system. A power plant operating in the annual range of 60 to 70 percent of total capacity would require supplementary oil firing during periods of high electric power demand. For a 70-percent gasification option, supplementary fuel is required for those periods when the capacity of the boiler exceeds 70 percent.

OSWEGO GASIFICATION PROCESS SELECTION

The Texaco medium-Btu coal gasification process is selected because it meets the general criteria and the following site-specific criteria:

- Power plant studies show that medium-Btu gas can be fired in an oil-burning plant with the least overall impact upon the boiler. The firing of low-Btu gas, on the other hand, results in a derating of the oil-fired boiler, a larger reduction in its efficiency and the need for extensive modifications to the boiler itself.

- A high-pressure gas can be transportated via pipeline to the power plant site more economically because low-pressure gas would have to be compressed for transport.

ARTHUR KILL GASIFICATION PROCESS SELECTION

The Texaco high-pressure, medium-Btu coal gasification process and the Combustion Engineering near-atmospheric-pressure, low-Btu coal gasification process are both selected for study at Arthur Kill. This provides a comparative technical and economic analysis of burning either low- or medium-Btu gas in the boiler. Power plant studies show medium-Btu gas could be fired with the least overall impact on this boiler. With low-Btu gas, however, there is a greater reduction in boiler efficiency (about 10 percent versus 3 percent for medium-Btu gas), and the modifications to the boiler are somewhat more extensive, new induced-draft fans and motors being required.

However, the higher overall conversion efficiency of the Combustion Engineering gasification process and the resultant lower cost of the product gas tend to offset the reduction in boiler efficiency and the cost of the conversion.

TABLE 7-1 MATRIX OF GASIFICATION PROCESS SELECTION

SYSTEM	EXPERIENCE -PILOT PLANT 5 TO 199 TONS PER DAY	DEMONSTRATION PLANT 200 TO 2000 TONS PER DAY	COMMERCIAL AVAILABILITY (NO LATER THAN 1/81)	SUITABILITY ALL COALS
TEXACO	YES	YES	YES	YES
LURGI		YES	YES MULTI-UNITS	NONCAKING COALS ONLY
ALLIS CHALMERS	YES	NO	NO	YES
COMBUSTION ENGINEERING	YES	NO	YES	YES
BABCOCK & WILCOX	YES	NO	YES	YES
BGC SLAGGER	YES	NO	NO	YES
WESTINGHOUSE	YES	NO	NO	YES
KOPPERS- TOTZEK	YES	NO	YES MULTI-UNITS	YES
HINKLER	YES	NO	YES MULTI-UNITS	NONCAKING COALS ONLY
SELECTED OTHERS	YES	NO	YES MULTI-UNITS	-

Section 8

GAS CLEANUP SYSTEM SELECTION

SYSTEM SELECTION CRITERIA

The selection of gas cleanup systems for both Oswego and Arthur Kill is based on criteria specific to both locations and to the following:

- The gas cleanup system is compatible with the coal gasification systems selected.
- The gas cleanup system is capable of reducing the sulfur content of the product gas to the level meeting environmental regulations.

There are several gas cleanup processes available to remove sulfur components in the gas. These include the amines, hot carbonates, caustic, coal methanol (Rectisol), and Stretford and Selexol processes.

With the exception of Stretford and Selexol, most of the others are eliminated because of their higher capital and operating costs. For example, the amines and hot carbonate type processes require large amounts of low-pressure steam to regenerate the absorbent solution. The Stretford and Selexol processes remained for consideration and are studied further.

The Stretford process removes H_2S from the gas and converts it to elemental sulfur. The Selexol unit, however, is used in combination with a Claus unit and a Beavon/Stretford type unit. The Selexol unit removes the sulfur components from the gas; the Claus unit converts the sulfur components to elemental sulfur; the Beavon/Stretford unit removes unreacted sulfur components from the Claus unit tail gas.

The Stretford unit has the ability to remove hydrogen sulfide (H_2S) from the gas at any pressure and then to convert H_2S to elemental sulfur by air blowing of the H_2S -bearing solution. This makes it an acceptable system for use with the low-pressure Combustion Engineering coal gasification system. The primary disadvantage of the Stretford unit is that it does not remove carbonyl sulfide (COS), or other organic sulfur compounds (RSH) from the gas. Because of this, the Stretford unit may not be capable of meeting the very stringent SO_x emissions requirements, such as those that exist at Arthur Kill. This will be a function, among others, of the sulfur content of the coal and the quantity of COS produced in the gasifier. It could, however, be used where SO_x emission requirements are less stringent, such as those that exist at Oswego.

The Selexol unit removes COS, RSH, carbon dioxide (CO₂), and so on, in addition to H₂S. It has the ability to reduce the sulfur in the gas to below 100 parts per million (ppm), which is well below any current EPA requirements for sulfur removal from coal or coal products. It operates at high pressure, thereby making it a compatible system for use with processes such as the Texaco coal gasification process. The Selexol unit, however, has certain disadvantages. It has load following limitations, inasmuch as at low gas throughputs it absorbs large amounts of CO₂ and heavy hydrocarbons, if present in the gas. The removal of CO₂ improves the heat content of the gas, but it impairs the operations of the Claus unit. Also, hydrocarbons in the gas degrade the quality of the sulfur product from the Claus unit. The Claus unit requires supplementary fuel when the H₂S content of the feed gas thereto falls below approximately 15 percent. The low-sulfur tail gas from the Claus unit may require an additional processing step to remove the unreacted sulfur compounds.

The tail gas unit is a modified Stretford unit. The COS and SO₂ in the tail gas is converted to H₂S by catalytic hydrogenation in a Beavon unit, upstream from the Stretford unit. This step requires that the gas be heated to about 800 F, passed over a catalyst, and then cooled down to below 200 F before the H₂S is removed. This operation requires clean fuel for direct gas heating.

The Beavon/Stretford combination is not practical for use on a low-pressure gasification system for the following reasons:

- The unit is much more costly than other options.
- Larger quantities of clean fuel gas are required, thereby reducing the overall efficiency of gasification.
- The conversion of RSH, etc., to H₂S requires the consumption of H₂, thereby reducing the hydrogen content of the product gas.
- The Btu content of the product gas is reduced because of the second and third reasons.

OSWEGO GAS CLEANUP SYSTEM SELECTION

The Selexol unit, in combination with a Claus unit and a Beavon/Stretford unit, is chosen for the cleanup of the Texaco coal gasification process for Oswego.

The system is designed to reduce the sulfur emissions level to that required by applicable environmental regulations.

The sulfur product is stored in liquid form pending its sale or ultimate disposal.

ARTHUR KILL GAS CLEANUP SYSTEM SELECTION

For the Texaco coal gasification option, a Selexol unit in combination with a Claus and Beavon/Stretford unit is used for Arthur Kill. The Selexol unit is designed to achieve an even greater level of sulfur removal at Arthur Kill than at Oswego because of the more stringent SOx emission requirements. The sulfur product is stored in liquid form pending its sale or ultimate disposal.

For the Combustion Engineering coal gasification option, the Stretford unit is the only system that can effectively and economically remove the sulfur from the gas. There is a possibility that this unit may not be able to meet the very stringent SOx emissions specifications at Arthur Kill. This, however, does not eliminate the Combustion Engineering process from consideration because at present the SOx emissions are not known. Laboratory testing and the proper design of the gasifier is required to ensure a viable system. The sulfur content and sulfur components in the coal also determine the non-H₂S portions of the sulfur in the product gas.

Section 9

ENVIRONMENTAL CONSIDERATIONS

SULFUR EMISSIONS

The fuel gas generated by the gasifier is treated to remove sulfur.

In the Texaco medium-Btu process, the raw gas from the gasifier is passed through a Selexol unit to clean the gas. The acid gas from this unit is passed to a Claus unit where sulfur compounds are converted to hydrogen sulfide (H_2S) and removed as liquid elemental sulfur. A Beavon/Stretford unit is used for Claus unit tail gas cleanup.

The sulfur balance for the Texaco medium-Btu coal gasification process at Oswego is shown on Figure 9-1.

To meet the SO_x emission requirements for Oswego, 85 percent of the sulfur in the high sulfur coal must be removed, thereby producing 389 TPD of elemental sulfur at system design conditions. Normally the power plant does not operate at its design rating; therefore, the amount of elemental sulfur produced is less. The total SO_x emission rate to the atmosphere is 0.94 lb sulfur dioxide (SO_2) per million Btu of input from the coal, which is below the Oswego emission limit of 1.2 lb SO_2 per million Btu.

The sulfur balance for the Texaco process at Arthur Kill is shown on Figure 9-2.

The SO_x emission requirements for Arthur Kill are much more stringent than for Oswego; therefore, 96.8 percent of the sulfur in the coal must be removed, thereby producing 250 TPD of elemental sulfur at system design conditions. The total SO_x emission rate to the atmosphere is 0.2 lb SO_2 per million Btu of input from the coal, which is less than the current emission of approximately 0.3 lb SO_2 per million Btu from the firing of 0.3 percent sulfur fuel oil. The SO_2 emission standard for Arthur Kill (New York City Local Law 45) is 200 ppm by volume at 10 percent excess air. This translates into an equivalent emission rate of approximately 0.3 lb per million Btu for the synthetic gas.

The sulfur balance for the Combustion Engineering low-Btu coal gasification process at Arthur Kill is shown on Figure 9-3.

The percent sulfur removal and the SO_x emissions rate are the same as for the Texaco process at Arthur Kill. The total coal requirements are greater for the Combustion Engineering process

in order to produce the same heat absorption rate in the boiler; therefore, 268 TPD of sulfur are produced at system design conditions.

Some of the sulfur compounds produced in the gasification process are removed with the slag as particulate matter.

PARTICULATE EMISSIONS

Particulates in the product gas are removed within the coal gasification processes by solid separation and water washing prior to entering the acid gas removal systems. Any trace of particulate matter finding its way into the countercurrent liquid acid washing systems will be removed therein. The wet solids are recirculated to the gasification process and removed with the slag.

SOLID AND LIQUID WASTES

Solids

The solid wastes consist of slagged coal ash from the gasifier, particulates from the coal handling facilities, and fines washed by rainfall from outdoor coal or slag storage areas.

The principal solid waste is slag from the gasifier. All of the ash from the coal feed, plus mineral matter from solution purges internal to the gasification system, is contained in the slag. The slag, which is molten in the gasifier, is water quenched in equipment beneath the gasifier's slag-discharge opening. The slag is granular, essentially unreactive, easily handled, and a relatively nondusting material. It is suitable as landfill or as aggregate for concrete. Precautions are taken to ensure that the material poses no danger of environmental contamination if used for landfill.

Storm water runoff from the site may contain coal and slag fines from coal handling storage areas, minerals leached from slag, or chemicals or lubricant spills from operating areas. All potentially contaminated storm water runoff discharges are collected and routed through a detention basin to remove suspended solids treated further with flocculating agents, if needed, to meet effluent limitations. The runoff, after settling, is used as makeup to the raw-gas scrubber for the Texaco gasification system.

Liquids

The liquids include purges from process systems, blowdown from boilers, solutions of spent chemicals from regeneration of boiler-feedwater treatment units, cooling water discharge from the slag-quench system, cooling tower blowdown, and storm water runoff from the plant site.

Boiler water blowdown from the plant is typical of utility plant practice. The estimated blowdown which contains sodium phosphate, silica, calcium, magnesium, and sodium salts is approximately 240 gallons per minute (gpm).

Discharges from the plant water treatment systems are typical of utility plant practice. Makeup water for the high-pressure boiler system is treated by carbon filtration followed by mixed-bed demineralization. Makeup water for the process steam system makeup is treated by a cation-ion exchange softener. Regeneration of the demineralization system results in an average daily discharge of approximately 1100 gallons per hour (gph) at Oswego. At Arthur Kill, with the Combustion Engineering process, approximately 800 gph are discharged from the demineralizer; the Texaco process at Arthur Kill results in a discharge of approximately 600 gph. These discharges consist of neutral pH water containing 5000 to 10,000 ppm total dissolved solids, predominantly sodium sulfate. Regeneration of the softener system results in an average daily discharge of neutral pH water containing about 20,000 ppm total dissolved solids, predominantly sodium chloride. Although fairly high in dissolved solids, the combined stream is relatively innocuous in composition and sufficiently small to permit the total flow to be mixed with the cooling tower blowdown for effective dilution.

Cooling tower blowdown contains minerals from makeup water plus water treatment chemicals added in the circulation system to control algae, pH, and slime. The blowdown discharge is on the order of 100 gpm at or near ambient temperature. The total dissolved solids in the blowdown is approximately 5000 ppm, predominantly calcium sulfate, sodium bicarbonate, and sodium chloride. This is a relatively clean effluent and presents no discharge problems.

PERMITS AND REGULATIONS

Air

New Source Review. Pursuant to Section III of the Clean Air Act, the USEPA has established national New Source Performance Standards (NSPS) (i.e., maximum allowable pollutant emission standards) for gas turbines, steam-electric generating plants, steam boilers, and coal dryers. New source performance standards for coal gasification plants have not been established. It appears that NSPS for low-Btu coal gasifiers are not expected to be issued before 1983 or 1984.

Federal law requires that all new major stationary sources use the Best Available Control Technology (BACT) to substantially reduce emissions. However, a Memorandum of Understanding between the USEPA and the USERDA (predecessor to the U.S. Department of Energy) specifically exempts coal reconversions from the definition of major modification as defined in the New Source Performance Standards. For the Arthur Kill unit, which was originally a coal-burning unit, conversion to synthetic gas firing would have a lesser environmental impact than reconversion to coal. It is, therefore, highly likely that the conversion to synthetic gas will not be considered a major modification. Reinforcing this conclusion is the fact that the USEPA has defined major modification as "a change in a major stationary source which would result in a significant net emissions increase in the emissions of any regulated pollutant." Since the conversion to synthetic gas from oil at Arthur Kill and Oswego will not result in a significant net emissions increase, the New Source Performance Standards should not apply.

Prevention of Significant Deterioration (PSD) Permit. Prevention of Significant Deterioration regulations (40 CFR 52) of June 19, 1980, require a preconstruction review and permit process for all new sources with the potential to emit 250 tons per year (TPY) of a regulated pollutant, and from some new sources with potential to emit 100 TPY of pollutant. The PSD permit system applies to attainment areas.

The USEPA is considering including coal gasification plants within the 100-TPY limit. Should a coal gasification system emit in excess of 100 TPY of SO_x as a byproduct (not including the sulfur in the product gas), it would, therefore, be subject to PSD review under present regulations. However, the gasification systems employed for this Study include BACT for the control of such pollutants.

The conversion of Arthur Kill No. 3 or Oswego No. 6 to synthetic gas will not increase the emission of regulated pollutants,

notably SO₂, particulate, carbon monoxide, oxidants, etc., from the power plants. In most cases, a reduction in emissions will occur. However, the existence of the gasification plant, with some attendant emissions, may require a PSD review, since the gasification plant would definitely be a new source.

Under PSD review, the applicant may be required to: perform extensive ambient air quality monitoring; provide models predicting dispersion of emissions; demonstrate that the proposed emissions use only a portion of the available PSD increment; assess the direct and the indirect effects on visibility, soils, and vegetation; and demonstrate that BACT is applied.

Water

National Pollution Discharge Elimination System (NPDES). USEPA has delegated the NPDES permits responsibility (including the 316(a) and 316(b) permit programs) to the NYS Department of Environmental Conservation. Under NPDES, the discharge of any pollutant from a point source to surface or subsurface waters requires a new source permit or a revised permit for a modified source.

Any discharge to surface or subsurface waters requires a National Pollutant Discharge Elimination System Permit, which is discussed in "Permits and Regulations."

The only process-system purge of consequence is spent absorbent solution from the acid gas removal system. The stream is not discharged directly into streams or sewers without further processing. A purge of approximately 20 to 25 gpm of absorbent solution from the acid gas removal system is used as makeup to the raw-gas scrubber of the gasification system. In this way, the entire dissolved solids content on the purge steam is either burned in the gasifier (combustible portion) or becomes a constituent of the slagged ash eliminating any potential pollution problem, and no NPDES permit should be necessary.

Section 316(a) - Clean Water Act - Thermal Discharge. Existing discharges from once-through cooling systems must have permits in accordance with Section 316(a) of Public Law 92-500 (Clean Water Act).

Section 316(b) - Clean Water Act - Cooling Water Intake Structure. A permit under Section 316(b) of the Clean Water Act may be required for a cooling water intake structure if a once-through cooling system is used.

For the Texaco gasification process for either Arthur Kill Unit No. 3 or Oswego Unit No. 6, there is no net increase in thermal discharges. However, for the Combustion Engineering process at

Arthur Kill Unit No. 3, a once-through cooling water system is envisaged to handle the generation of the 132 MW of byproduct electricity available. This will result in a substantial increase in thermal discharge and a new intake structure, thus 316(a) and (b) permits would be required.

COAL
950333 LB/HR
HHV=12900 BTU/LB
Q=12259x10⁶ BTU/HR

COAL
GRINDING
AND
SLURRYING

CCAL
38108 LB/HR
SULFUR

TEXACO
GASIFICATION

RAW GAS
38108 LB/HR
SULFUR

SELEXOL-
SULFUR
REMOVAL

CLEAN GAS
5707 LB/HR
SULFUR

BOILER

FLUE GAS TO ATMOSPHERE
11418 LB/HR SO₂

CLAUS
SULFUR
RECOVERY

STRET-FORD
TAIL GAS
CLEANUP

VENT GAS TO ATMOSPHERE
64 LB/HR SO₂

SULFUR PRODUCT
32369 LB/HR

OSWEGO
TEXACO PROCESS

SULFUR BALANCE-TEXACO MEDIUM-
BTU GAS - OSWEGO
(4.01% SULFUR IN COAL)

Chas. E. Hill, Inc.
ENGINEERS, DESIGNERS, CONSTRUCTORS
NEW YORK

SCALE: NONE

FIGURE 9-1

JOB NO. 11-2892-001

11/24/60

CRONE/PRP/HISC

COAL
536167 LB/HR
HHV=12900 BTU/LB
6197 x 10⁶ BTU/HR

COAL
GRINDING
AND
SLURRYING

COAL
21500 LB/HR
SULFUR

TEXACO
GASIFICATION

RAW GAS
21500 LB/HR
SULFUR

SELEXOL-
SULFUR
REMOVAL

CLEAN GAS
673 LB/HR
SULFUR

BOILER

FLUE GAS TO ATMOSPHERE
1346 LB/HR SO₂

CLAUS
SULFUR
RECOVERY

BFAVON/
STRETFORD
TAIL GAS
CLEANUP

VENT GAS TO ATMOSPHERE
98 LB/HR SO₂

SULFUR PRODUCT
20808 LB/HR

ARTHUR KILL TEXACO PROCESS

SULFUR BALANCE - TEXACO
MEDIUM-BTU GAS - ARTHUR KILL
(4.01% IN SULFUR)

Chas. E. Hill, Inc.
ENGINEERS DESIGNERS, CONSTRUCTORS
NEW YORK

SCALE: NONE

FIGURE 9-2

JOB NO. 11-2892-001

11/21/80

CADRE/PRP/HISC

OSHEGO TEXACO PROCESS	
SULFUR BALANCE-COMBUSTION ENGINEERING LOW-BTU GAS FOR ARTHUR KILL (4.01% SULFUR IN COAL)	
Chubb & Hill, Inc. ENGINEERS DESIGNERS CONSTRUCTORS NEW YORK	SCALE: NONE
JOB NO. 11-2892-001	FIGURE 9-3

Section 10

SYSTEM DESCRIPTION

GENERAL

This section presents a general description of the coal gasification systems selected for study for both power plants. This includes a general location drawing, an overall plot plan, a description of power plant modifications, and a general description of the coal gasification systems. Detailed descriptions of the latter are included in the Supplements.

Niagara Mohawk - Oswego

The coal gasification plant for Niagara Mohawk, which is shown on Figure No. 10-1, is located about 5 miles from the Oswego electric power generating plant. The right-of-way for the pipeline is along the same route as the high voltage transmission lines. Most of the property along this right-of-way is owned by Niagara Mohawk.

The overall plot plan for the coal gasification site is shown on Figure No. 10-2. The overall site requirements for coal receiving, handling, and storage, the gasifications plant, ash and sulfur storage, and supporting facilities are about ninety acres. The plant is located in a very sparsely populated area, away from major highways and roads, on property owned by Niagara Mohawk.

Consolidated Edison - Arthur Kill

Two coal gasification options are considered for Consolidated Edison to provide gas derived from coal to be burned in their Arthur Kill Unit 3. The plant is located adjacent to their electric power generation plant at Arthur Kill on Staten Island. The location of the plant is shown on Figure No. 10-3.

The overall plot plan for the coal gasification site is shown on Figure No. 10-4 for the rail delivery option for coal and on Figure No. 10-5 for the barge supply option. For this Study, railroad delivery of coal is recommended primarily because the facilities are existing and can handle the required amount of coal. The barge unloading option is included for economic comparison and future consideration when Port Reading is fully operational.

The overall site requirement for the coal gasification plant is about seventy acres. The plant is located adjacent to a highway and bordered on two sides by water. There is no room for future

expansion or permanent storage of slag. The slag is temporarily stored onsite for later transport to a permanent disposal site.

POWER PLANT MODIFICATIONS FOR MEDIUM-Btu GAS FIRING AT OSWEGO

The analysis of boiler fuel requirements shows that a medium-Btu gas as produced in the Texaco gasification system is the recommended gas for Oswego. This yields the following:

- The boiler retains its original maximum continuous rating.
- The boiler efficiency drops from its original oil-fired design efficiency of 90.33 percent at rated conditions to 87.2 percent efficiency at rated conditions with medium-Btu gas.
- The original fuel oil-firing capabilities of the boiler are retained to have the option of burning either fuel.

Required Modification

The following modifications are required to accomplish the proposed conversion.

Windbox and Burners. Revise construction of existing burner windbox and install 32 new medium-Btu gas burners. The revised construction includes all necessary changes required for fuel oil guns, ignitors, and flame failure safeguards.

Medium-Btu Gas Ductwork and Piping. Furnish and install all medium-Btu gas ductwork, piping, valves, fittings, slide gates, instrument and purge connections, supports, and auxiliary support steel as conceptually shown on Figure No. 10-6.

Integration of Retrofit Into Existing Operations. An overall engineering and design effort is required to assure proper physical and functional integration of the new fuel supply system into the present plant and its operating practices. This requires a detailed study of existing instruments and controls and physical obstructions to prepare design solutions to accomplish a satisfactory installation. However, preliminary design studies have been made which indicate that the retrofit can be accomplished with the modifications discussed.

Outage Required

It is anticipated that most of the work can be done while the unit remains in operation and that an outage of 6 to 8 weeks is sufficient to make all final connections.

POWER PLANT MODIFICATION FOR LOW- OR MEDIUM-Btu GAS FIRING AT ARTHUR KILL

An analysis of boiler fuel requirements shows that a low-Btu gas similar to that produced by the Combustion Engineering gasification system or a medium-Btu gas similar to that produced by the Texaco gasification system could be burned in Arthur Kill Unit 3.

Low-Btu Gas Firing

The factors involved with burning low-Btu gas are as follows:

- The boiler retains its original guaranteed maximum continuous rating, provided new induced-draft (ID) fans and motors are included in the modifications listed below.
- The boiler efficiency drops from its present oil-firing efficiency of 89.7 percent at full rating to 80.2 percent at full rating for low-Btu gas.
- Note that the original fuel oil-firing capabilities of the boiler are retained in order to have the option of burning either fuel.
- The replacing of the ID fans and motors represents a net increase of about 3000 kW in the unit's auxiliary power requirements over the present oil-firing system.

Required Modifications

The following modifications are required to accomplish the conversion:

Windbox and Burners. The present burner windboxes are modified to replace 48 coal burner nozzles with new gas nozzles, oil guns are rearranged, air nozzles, ignitors, flame sensors, and so forth, are added as required.

Low-Btu Gas Ductwork and Piping. Low-Btu gas is piped from the gas plant to the boiler through two or more rectangular ducts or pipes and distributed to each of the 48 burners. A conceptual arrangement is shown on Figure No. 10-7.

The system contains gates, valves or dampers, and controls as required for safety and to integrate the new fuel into the present control system.

ID Fan Replacement. The two existing ID fans and motors are removed and replaced with larger fans and motors. New fan

foundations are required as well as changes and additions to the existing auxiliary power switchgear to accommodate the motors, which are approximately twice as large as the existing motors. The ductwork is modified to match the larger ID fans.

Outage Required

An overall detailed engineering and design effort is required to assure proper physical and functional integration of the new fuel supply system and the ID fan replacements. This requires a detailed study of existing structures, accessways for gas piping, extent of modifications to accommodate the new fans, instruments and controls, and extent of modifications to the electric wiring and switchgear.

The outage of the unit depends primarily on the time required to remove and replace the ID fans. Without establishing a precise schedule and specifications for the new fans and associated modifications required to the existing site conditions, it is difficult to estimate the required outage time. It appears that an outage of from 3 to 5 months is required.

Medium-Btu Gas Firing

The factors involved with burning medium-Btu gas are as follows:

- The boiler retains its original guaranteed maximum continuous rating.
- The boiler efficiency drops from its present oil-firing efficiency of 89.7 percent at full rating to 87.2 percent at full rating for medium-Btu gas.
- The original oil-firing capabilities of the boiler are retained.

Required Modifications

The following modifications are required to accomplish the proposed conversion:

Windbox and Burners. Same as for low-Btu gas, but with fewer coal burner nozzles modified for gas fuel.

Medium-Btu Gas Ductwork and Piping. In general, the same fuel supply piping system is required as for low-Btu gas, except that smaller cross-sectional areas are required. This reduces the scope of required modifications to existing facilities and structures, thereby reducing the cost of this installation compared to low-Btu gas.

ID Fan Replacement. No fan replacement or modifications are required for medium-Btu gas burning.

Integration of Retrofit Into Existing Operations. The work required would be similar to that described for the low-Btu gas, except that the omission of fan changes and use of smaller conduits reduces the scope of engineering and design work involved.

Outage Required

It is anticipated that most of the work can be done while the unit remains in operation and that an outage of 3 months or less suffices to make all final connections.

TEXACO MEDIUM-Btu GASIFICATION SYSTEM FOR OSWEGO

The Texaco coal gasification process produces a medium-Btu gas with a heating value of 292 Btu/scf.

This plant gasifies 11,404 TPD of bituminous coal from Harrison County, West Virginia, to produce 194.6×10^9 Btu/day (8108.2×10^6 Btu/hr) of fuel gas for Niagara Mohawk, Oswego Unit 6.

This represents a thermal efficiency of 66.14 percent for the product gas based on coal. The actual gas production efficiency, however, is 74.53 percent. The difference is due to the gas used in the process for steam superheating and process usage. In addition to the product gas, 68.3 MW of byproduct electricity is available for export. This yields a net overall efficiency of 71.6 percent. Other byproducts include 389 TPD of elemental sulfur and 1379 TPD(dry) of slag. The latter two may or may not have a marketable value.

The Texaco coal gasification process uses a high-pressure, single-stage, entrained-bed, oxygen-blown gasifier to produce the medium-Btu gas.

The coal is ground and slurried with water; therefore, virtually all types and sizes of coal can be used. The oxygen and steam react with the coal at 800 psig to produce 2300 F to 2700 F gas and molten slag. The resulting gases and molten slag are cooled by quenching in water.

The main plant consists of seven parallel trains consisting of oxidant feed, gasification gas cooling, and acid-gas removal. In addition to the main processing trains, the plant includes the necessary utility and environmental facilities.

The system is shown schematically on Block Flow Diagrams, Figure No. 10-8, and consists of the following major units:

- One coal handling and storage system to receive coal delivered to the site by rail.
- Seven parallel coal grinding and water slurry preparation processing units (a proprietary Texaco design) to prepare the water-coal slurry for the gasifiers.
- Seven parallel air separation plants to produce 10,289 TPD 99.5 percent oxygen at 1000 psig.
- Seven parallel Texaco entrained-bed gasification units which react the coal slurry with oxygen and steam at 800 psig to produce medium-Btu gas and molten slag.
- Seven parallel slag quenching and dewatering process units to cool the molten slag and remove it from the high-pressure gasification system (1379 TPD dry slag or 1838 TPD wet).
- Seven parallel gas cooling process units consisting of the following major equipment:
 - Waste-heat boilers to generate 1200-psig saturated steam.
 - Scrubbers to remove the entrained carbon and fly ash.
 - Heat exchangers to cool the gas after the waste-heat boilers from 360 F to 100 F by exchange with boiler feedwater, sweet product gas, and finally with cooling water.
- Seven parallel Selexol units to remove H₂S, COS, and other organic sulfur components from sour product gas.
- Two parallel Claus units to convert the H₂S and other sulfur components to 385 TPD of molten sulfur.
- Two parallel Beavon/Stretford units to remove and recover residual sulfur compounds present in the Claus unit tail gas.
- Seven parallel reheating and expansion trains to reheat the product gas to 360 F prior to reducing the pressure from 700 to 100 psig in order to recover the available energy.

- A 5-mile 48-in. pipeline to transmit the product gas from the coal gasification plant to the power plant.
- One steam boiler feedwater and condensate system which consists of the following basic equipment:
 - One superheater to superheat 470-psig steam to 900 F
 - One deaerator with a chemical treatment injection package
 - 2 steam condensing turbine generators

This system provides process steam and steam for mechanical steam-driven turbines, the required electricity for internal use, and 68.3 MW for export.

- A well water supply system to provide 8000 gpm water for use in cooling systems, boiler feedwater systems, hot gas quenching, a potable water system, and fire water system.
- A cooling tower system to provide 346,800 gpm of circulating cooling water.
- A single startup boiler system to provide 300,000 lb/hr of 440 psig 900 F steam to meet the total steam requirements of one processing train during startup and shutdown.
- A flare system to dispose of the gases during periods of abrupt demand changes, system upsets, and startup and shutdown.
- A water treatment system, with a 100 percent spare unit, to prepare 115 gpm each of makeup water for the gasification system waste-heat boilers.
- A wastewater treatment system to treat all liquid effluents from the plant, as well as rainwater runoff from the coal piles and the plant process areas.
- Additionally, all supporting facilities, such as roads, sulfur and slag storage, offices, buildings, and facilities for the workers that are required to operate this plant in a safe and environmentally acceptable manner.

A more detailed description of each system with flow diagrams, material and energy balances, and the interconnecting system, as

well as a description of the supporting system, is discussed in Supplement C.

TEXACO MEDIUM-Btu GASIFICATION SYSTEM FOR ARTHUR KILL

The Texaco coal gasification process is one of two processes proposed for Arthur Kill. The basic process, shown schematically on Block Flow Diagram, Figure No. 10-9, is similar to that described for Oswego, but with the following modifications and adjustments:

- This plant gasifies 6434 TPD of bituminous coal from Harrison County, West Virginia, to produce 109.8×10^9 Btu/day (4574×10^6 Btu/hr) of fuel gas and 56.2 MW of byproduct electric power for export. On a percentage basis, this is higher than at Oswego.

The elimination of the long transport gas pipeline permits the recovery of additional power by the depressuring of the product gas. This results in a net overall efficiency for the Texaco process at Arthur Kill of 74.3 percent versus 71.6 percent at Oswego.

- The byproduct power is sent to the existing onsite transformers.
- The environmental requirements for SO₂ emissions for Arthur Kill are more stringent than for Oswego. In order to comply with these requirements, more complex and larger size Selexol and Claus units are specified for Arthur Kill than for Oswego.
- The gasification plant is located near the Arthur Kill; therefore, a once-through saltwater cooling system is used for cooling the surface condenser of the steam turbines. This reduces the amount of freshwater cooling and the resultant size of the cooling water system which provides cooling water to the basic process consumers, mechanical steam-driven turbines, and miscellaneous users.
- The geologic formation of the onshore location of the Arthur Kill gasification plant requires piling.

A more detailed description of each system with flow diagrams, material and energy balances, the interconnecting system, and a description of the supporting system, is in Supplement D.

COMBUSTION ENGINEERING LOW-Btu GASIFICATION SYSTEM FOR ARTHUR KILL

The Combustion Engineering coal gasification process produces a low-Btu gas with a heating value of 104.4 Btu/scf.

This plant gasifies 6895 TPD of bituminous coal from Harrison County, West Virginia, to produce 119.38×10^9 Btu/day (4974×10^6 Btu/hr) of fuel gas for Consolidated Edison's Unit 3 at Arthur Kill.

This represents a thermal efficiency of 67.11 percent for the product gas based on coal. There is no internal consumption of gas to meet process requirements as there is in the Texaco process.

The byproduct electric power available for export is higher than for the Texaco process (132 MW for Combustion Engineering versus 56 MW for Texaco).

The overall efficiency of the Combustion Engineering system is 84.5 percent versus 74.3 percent for the Texaco system when both the product gas and byproduct electricity available for export are included. The difference in overall efficiency is related to the oxidant feeds. More net energy is required to operate the air plant for Texaco than is required to supply air to the Combustion Engineering system.

The Combustion Engineering process uses a low-pressure, two-stage, entrained-bed, air-blown gasifier to produce the low-Btu gas. The gasifier is basically a two-stage, cyclone-type, slagging combustion boiler (i.e., the bottom section, first stage, is of a cyclone-type slagging boiler used by many utilities). Because of this, it is similar in design to a conventional waterwall-type boiler on which there is extensive operating experience.

The coal is ground in conventional coal pulverizers and conveyed into the boiler with air, as in conventional pulverized coal-fired boilers. About one-third of the coal is combusted with a near stoichiometric amount of air in the first-stage cyclone combustor. The remaining coal is fed to a reduction section, which is located directly above, where it reacts with the hot combustion gases to form a low-Btu gas consisting mainly of hydrogen, carbon monoxide, carbon dioxide, and nitrogen. The exit gas temperature is about 1700 F.

The gas is cooled to near ambient temperatures by the generation of steam in a downflow connection section and then scrubbed with water to remove entrained ash and unburned carbon.

The main plant consists of four parallel trains consisting of air-fed gasifiers, gas cooling, and acid gas removal. In addition to the main processing trains, the plant includes the necessary utility and environmental facilities.

The Stretford process is used to remove the H₂S in the product gas. This is the only type unit that is suitable for low-pressure operations and economically competitive with processes available for higher pressure operations.

The system is shown schematically on Block Flow Diagram, Figure No. 10-10, and consists of the following major units:

- One system for coal handling and storage facilities to receive coal delivered to the site by rail. The trackage, railroad siding, and coal unloading and handling systems are existing.
- One system to convey the coal to the storage silos and to the coal pulverizers.
- Three parallel systems to grind the coal to 70 percent, passing 200-mesh, dry and pneumatically convey the coal to silos.
- Three parallel Combustion Engineering entrained-bed gasifiers, where the coal is partially combusted in a deficiency of air and converted to a low-Btu gas stream contaminated by char and hydrogen sulfide.
- Three slag quenching systems (one for each gasifier) and one slag handling system which includes a dewatering system and a cooling tower.
- Three gas cooling systems where the hot gases from the gasifiers are cooled in a waste-heat boiler, by generating high pressure steam (1450 psig, 950 F), heating boiling feedwater and condensate, and heating high temperature solution for indirect preheating of combustion air.
- Three char recovery systems where the cooled gas-char effluent flows through the spray dryer whose function is to dry and agglomerate the solids, which are collected in the wet removal system.
- Three Stretford units to remove the H₂S in product gas and to convert it to 267 TPD elemental sulfur.
- One power recovery system which uses the steam generated in the waste-heat boilers to generate a total of 141 MW

which includes 9 MW for internal consumption and 132 MW for export.

- A city water supply system to provide 1000 gpm for the cooling tower, water treatment system, potable water, and so forth.
- A once-through saltwater system to provide the required 78,000 gpm for the surface condensers of the steam turbines.
- One wastewater treatment system to treat all liquid effluents from the plant, as well as rainwater, runoff from the coal, and the process plant area.
- One flare system to dispose the gases during periods of abrupt demand changes, system upsets, and startup and shutdown.

A more detailed description of each system with flow diagrams, material and energy balances, and the interconnecting system, as well as a detailed description of the supporting systems, is discussed in Supplement E.

Figure 10-1
Oswego Plant Site Location

NEW YORK STATE ENERGY RESEARCH & DEVELOPMENT AUTH. COAL GASIFICATION STUDY			
NIAGARA MOHAWK POWER CO. OSMO PLANT PLANT LAYOUT			
Globe & H. Inc.			SCALE: 1"=200'
JOB NO. 2612			FIGURE 10-2
11/27/82

Figure 10-3
Arthur Kill Plant Site Location
10-14

10-16

SECTION LOOKING NORTH

SECTION LOOKING SOUTH

PLAN VIEW

NYSERDA	
PROPOSED CONVERSION TO LOW-BTU GAS FIRING	
ARTHUR KILL STATION UNIT NO.3	
SCALE: NONE	FIG-10-7
ISSUED FOR	DATE
APPROVALS	DATE

OSWEGO TEXACO PROCESS	
OVERALL BLOCK FLOW DIAGRAM	
CH2M HILL <small>ENGINEERING DESIGN-CONSTRUCTION NEW YORK</small>	SCALE: NONE
JOB NO. 11-2892-001	FIGURE 10-8

Section 11

CAPITAL COST ESTIMATES

Capital cost estimates are prepared for the following coal gasification options which are capable of meeting the fuel demands of the power plants at 100 percent of their rated capacity:

- Oswego - Unit 6
Texaco - Medium-Btu Gasification
- Arthur Kill Unit 3
Texaco - Medium-Btu Gasification
- Arthur Kill Unit 3
Combustion Engineering - Low-Btu Gasification

Capital cost estimates summaries are also prepared for the above gasification options, which are capable of providing 70 percent of the power plant fuel requirements. These estimates are derived from the 100-percent case estimates using a 0.75 scale factor.

These estimates include the cost of equipment and labor to erect the facilities, the engineering design and construction management, a contingency, and paid-up royalties, where applicable. This represents an estimate of the total plant investment in first quarter 1980 dollars. Items not normally included in the capital cost estimates are escalation and interest during construction, startup costs, working capital, owner's costs, coal stockpile, catalyst and chemical costs, operator training, and so forth. These items are included in the economic analysis.

Capital cost estimates were obtained from vendors on major pieces of equipment, published data, and in-house experience on similar units and supporting systems.

Quotes were obtained for a 2000-TPD oxygen plant and a typical three train gasifier Texaco gasification system. These were adjusted in-house for the specific design options. Previously published design and cost data were provided by Combustion Engineering for their gasification process. These data were compared with previously published studies prepared for Electric Power Research Institute (EPRI), and the EPRI studies were used because they are similar to the systems used for this Study. It was escalated to first quarter 1980 dollars and adjusted for size, number of units, and differences in the coal properties.

The costs for sulfur removal systems were taken from EPRI studies and likewise adjusted. Of prime importance in the selection and costing of these systems was the degree of sulfur removal required at Oswego and Arthur Kill to meet state environmental requirements.

The balance of plant costs, consisting of water makeup and treatment, cooling water system, the steam and condensate system, byproduct power generation and support facilities such as roads, building, fire protection, and flare systems, are estimated from in-house experience on similar type units. Material, equipment, and subcontract prices where not provided by vendors were taken from published costs and in-house data.

The gasification facility consists of a complete self-contained gasification facility including coal handling, sulfur removal, byproduct power generation, and all necessary support facilities required to operate the plant.

Labor rates based on a crew composition for civil, structural, mechanical, and electrical trades are used.

For Oswego, the manhours were based on Syracuse productivity with a 40-hour work week with no premium time included. For Arthur Kill, the manhours were based on New York City productivity with a 40-hour work week with no premium time included.

The following general assumptions pertaining to the sites have been assumed for the purpose of the estimate:

- The sites are clear.
- There are no unusual subsurface ground conditions.
- Piling is not required at Oswego.
- Piling is required at Arthur Kill.
- There are no unusual ongrade or overhead obstructions.
- Byproduct transmission lines are 500 feet or less from the transformer.
- All water and sewer mains at Arthur Kill are 100 feet from the gasification plant battery limits.
- Well water is obtained from onsite well at Oswego with waste products including sanitary sewage treated and discharged at the plant site.
- There are no unusual access conditions at either site.

- A railroad spur is included for Oswego.
- Existing trackage at Arthur Kill is acceptable.

The following items are not included:

- Land costs including right-of-way for the gas transmission line at Oswego
- Owner's costs
- Premium time
- Spare parts
- Air freight
- Permits

Engineering design and construction management costs are estimated at 12 percent of the total direct and indirect costs for the following:

- Coal receiving and handling
- Coal preparation (Combustion Engineering process at Arthur Kill only)
- Steam boiler feedwater and condensate system
- Plant makeup water system
- Wastewater treatment
- Cooling water system
- Electric power generation
- Startup boiler for Texaco units
- Other plant supporting systems and facilities
- Piling for Arthur Kill
- Gas transmission line for Oswego
- Power plant retrofit

Engineering design and construction management is included in direct and indirect costs for the oxygen plant, gasification plants, and sulfur removal facilities.

The scope, budget, and schedule did not allow for a detailed design of all of the units and interconnecting systems. In preparations of capital cost estimates for relatively new, unproven technology, there is a tendency for cost estimates to be somewhat low. Redundancy and spare equipment may not be included. Interconnecting piping and support systems may not be included or assumed to have been included elsewhere. Thus, the possibility exists that there may not be a full and complete estimate presented due primarily to the lack of a full and complete mechanical definition of the plant. To offset this, a project contingency of 15 percent has been included in the Total Plant Investment Cost. This includes systems such as the oxygen plants and gasification systems which were quoted as "Turnkey or Lump Sum" by the appropriate vendors.

Paid-up royalties were estimated at 2-1/2 percent for the following:

- Sulfur Removal - Selexol Unit
- Sulfur Recovery - Claus Unit
- Tail Gas Cleanup - Beavon/Stretford Unit
- Sulfur Removal - Stretford Unit

Royalties for the oxygen plant and the Texaco and Combustion Engineering gasification systems are already included in the respective plant costs. The other items including coal receiving and handling, steam, boiler feedwater, and condensate systems and all systems listed thereafter do not require royalties.

The breakdown of costs by section, the total direct and indirect costs, engineering design and construction management, contingency and paid-up royalties, and the total plant investment costs are shown in the following tables:

- Table 11-1, Medium-Btu Coal Gasification - Oswego
- Table 11-2, Medium-Btu Coal Gasification - Arthur Kill
- Table 11-3, Low-Btu Coal Gasification - Arthur Kill
- Table 11-4, Power Plant Retrofit Costs

TABLE 11-1
TOTAL PLANT INVESTMENT COSTS MEDIUM - BTU COAL GASIFICATION - OSWEGO
(1980 \$ X 1000)

	TOTAL
COAL RECEIVING AND HANDLING	\$ 14,500
COAL PREPARATION (INCL. IN GASIFICATION)	-
OXYGEN PLANT	161,000
GASIFICATION SYSTEM	200,000
GASIFICATION PROCESS EFFLUENT WATER SYSTEM (INCL. IN GASIFICATION)	-
SULFUR REMOVAL - SELEXOL	52,000
SULFUR RECOVERY - CLAUS UNITS AND	9,000
TAIL GAS CLEAN UP - BEAVON/STRETTFORD (INCL. IN SULFUR RECOVERY)	-
STEAM, BFW, AND CONDENSATE SYSTEMS	35,700
PLANT MAKEUP WATER SYSTEM	6,600
WASTEWATER TREATMENT SYSTEM	3,700
COOLING WATER SYSTEM	34,000
ELECTRIC POWER GENERATION SYSTEMS	16,100
STARTUP BOILER	3,600
OTHER PLANT SUPPORTING SYSTEMS AND FACILITIES	30,000
GAS TRANSFER LINE	<u>12,800</u>
TOTAL DIRECT AND INDIRECT COST	580,000
ENGINEERING DESIGN AND CONSTRUCTION MANAGEMENT (ED&CM) NOTE 1	<u>18,960</u>
SUBTOTAL	598,960
CONTINGENCY	89,844
PAID-UP ROYALTIES	<u>1,525</u>
TOTAL PLANT INVESTMENT, 100 PERCENT GASIFIER OPTION	\$690,329
TOTAL PLANT INVESTMENT, 70 PERCENT GASIFIER OPTION	\$517,747

NOTE 1: ED&CM FOR COAL PREPARATION THROUGH TAIL GAS CLEANUP INCLUDED
IN DIRECT AND INDIRECT COSTS

TABLE 11-2

TOTAL PLANT INVESTMENT COSTS MEDIUM - BTU COAL GASIFICATION - ARTHUR KILL
(1980 \$ X 1000)

	TOTAL
COAL RECEIVING AND HANDLING	\$ 12,900
COAL PREPARATION (INCL. IN GASIFICATION)	-
OXYGEN PLANT	108,000
GASIFICATION SYSTEM	134,000
GASIFICATION PROCESS EFFLUENT WATER SYSTEM (INCL. IN GASIFICATION)	-
SULFUR REMOVAL - SELEXOL	58,000
SULFUR RECOVERY - CLAUZ UNITS AND TAIL GAS CLEAN UP - BEAVON/STRETFORD (INCL. IN SULFUR RECOVERY)	11,700
STEAM, BFW, AND CONDENSATE SYSTEMS	27,600
PLANT MAKEUP WATER SYSTEM	5,300
WASTEWATER TREATMENT SYSTEM	3,100
COOLING WATER SYSTEM	176,500
ELECTRIC POWER GENERATION SYSTEMS	13,500
STARTUP BOILER	4,000
OTHER PLANT SUPPORTING SYSTEMS AND FACILITIES	18,900
GAS TRANSFER LINE	900
PILING	1,500
TOTAL DIRECT AND INDIRECT COST	417,500
ENGINEERING DESIGN AND CONSTRUCTION MANAGEMENT (ED&CM) NOTE 1	12,624
SUBTOTAL	430,124
CONTINGENCY	64,519
PAID-UP ROYALTIES	1,743
TOTAL PLANT INVESTMENT, 100 PERCENT GASIFIER OPTION	\$496,386
TOTAL PLANT INVESTMENT, 70 PERCENT GASIFIER OPTION	\$372,290

NOTE 1: ED&CM FOR COAL PREPARATION THROUGH TAIL GAS CLEANUP INCLUDED
IN DIRECT AND INDIRECT COSTS

TABLE 11-3

TOTAL PLANT INVESTMENT COSTS
 LOW-BTU COAL GASIFICATION
 ARTHUR KILL
 1980 \$ X 1000

	<u>TOTAL</u>
COAL RECEIVING AND HANDLING	12,900
COAL PREPARATION	\$14,100
COAL GASIFICATION	100,000
GASIFICATION PROCESS EFFLUENT WATER SYSTEMS (INCL. IN GASIFICATION)	-
SULFUR REMOVAL - STRETFORD	63,600
STEAM, BFW, AND CONDENSATE SYSTEMS	26,700
PLANT MAKEUP WATER	3,400
WASTEWATER TREATMENT SYSTEM	1,900
COOLING WATER SYSTEM	5,500
ELECTRIC POWER GENERATION SYSTEMS	20,000
PILING	1,500
OTHER PLANT SUPPORTING SYSTEMS & FACILITIES	19,900
GAS TRANSFER AND COMPRESSION	<u>27,400</u>
TOTAL DIRECT AND INDIRECT COST	296,300
ENGINEERING DESIGN AND CONSTRUCTION MANAGEMENT (ED&CM) NOTE 1	14,164
SUBTOTAL	<u>310,464</u>
CONTINGENCY	46,530
PAID-UP ROYALTIES	<u>1,590</u>
TOTAL PLANT INVESTMENT 100 PERCENT GASIFIER OPTION	<u>\$358,624</u>
TOTAL PLANT INVESTMENT 70 PERCENT GASIFIER OPTION	\$268,968

NOTE 1: ED & CM COAL PREPARATION THROUGH SULFUR REMOVAL
 INCLUDED IN DIRECT AND INDIRECT COSTS

TABLE 11-4
TOTAL POWER PLANT RETROFIT COSTS
(1980 \$ X 1000)

	<u>TEXACO MEDIUM-BTU GAS OSWEGO</u>	<u>ARTHUR KILL</u>	<u>CE LOW-BTU GAS ARTHUR KILL</u>
GAS SUPPLY SYSTEMS	\$3,100	\$2,900	\$3,600
10 FANS AND MOTORS	-	-	2,100
BUILDING AND STRUCTURAL MODIFICATIONS AND SUPPORTS	<u>2,000</u>	<u>1,800</u>	<u>1,800</u>
TOTAL DIRECT AND INDIRECT COST	5,100	4,700	7,500
ENGINEERING DESIGN AND CONSTRUCTION MANAGEMENT	<u>612</u>	<u>564</u>	<u>900</u>
SUBTOTAL	5,712	5,264	8,400
CONTINGENCY	<u>857</u>	<u>790</u>	<u>1,260</u>
TOTAL PLANT INVESTMENT	\$6,569	\$6,054	\$9,660

Section 12

ECONOMIC EVALUATION

GENERAL

This evaluation determines the economic feasibility of using low- or medium-Btu coal gas in the Arthur Kill No. 3 and Oswego No. 6 boilers, which are both presently oil-fired. The coal gasification cases are compared to the continued use of oil in both boilers.

This analysis is broken down by major facility in order to allow comparison with and possible application to coal gasification retrofit projects proposed for other power plant locations. The breakdown is between coal supply and the gasification plant (including coal receiving through gas output) and between the gasification plant and the retrofitted power plant.

SCOPE

The analysis covers six coal gasification retrofit cases as follows:

Case 1

Oswego No. 6 with a 100-percent Texaco medium-Btu gasifier, i.e., a gasifier of sufficient capacity to fuel the power plant when it is operating at 100 percent of rated load. (Case abbreviation: OS100%Tex.)

Case 2

Oswego No. 6 with a 70-percent Texaco gasifier, i.e., a gasifier sized to supply 70 percent of the fuel requirements for the power plant at its rated capacity. It is assumed that supplemental firing with No. 6 fuel oil would be used during periods of operation above 70 percent of the power plant's rated capacity. (Case abbreviation: OS70%Tex.)

Case 3

Arthur Kill No. 3 with a 100-percent-capacity Texaco gasifier. (Case abbreviation: AK100%Tex.)

Case 4

Arthur Kill No. 3 with a 70-percent-capacity Texaco gasifier. (Case abbreviation: AK70%Tex.)

Case 5

Arthur Kill No. 3 with a 100-percent-capacity Combustion Engineering low-Btu gasifier. (Case abbreviation: AK100%CE.)

Case 6

Arthur Kill No. 3 with a 70-percent Combustion Engineering gasifier. (Case abbreviation: AK70%CE.)

The analysis includes performance and discussion of the following items:

- Gasification plant required revenues are computed for each case in order to calculate the gas cost, over the life of the plant and in today's cost, in dollars per million Btu.
- Bus bar electricity costs are calculated based on computed required revenues for operation of the gasification plant alternatives plus retrofitted power plants.
- Bus bar cost sensitivities to variations in the delivered cost of coal, power plant capacity factor, and byproduct power price are analyzed.
- Bus bar costs are levelized over 25 years to facilitate life cycle cost comparison between the gas retrofit and continued oil use cases.
- Bus bar cost sensitivity to variations in future oil price escalation rates is analyzed.

Recommendations and conclusions are based on a comparison of the Texaco process at Oswego, the Texaco process at Arthur Kill, and the Combustion Engineering process at Arthur Kill over a range of average annual power plant capacity factors. Comparison of the 70-percent-gasifier versus 100-percent-gasifier alternatives for each of the above process/site combinations is also based on average power plant capacity factors because developing daily, weekly, and seasonal capacity factor projections is beyond the scope of this Study.

Institutional, legal, and financial factors are discussed in Section 13, as they pertain to Niagara Mohawk and Consolidated Edison.

The analysis does not consider the alternative of conversion to direct coal firing. This option would be technically feasible

for Arthur Kill No. 3, which was originally constructed as a coal-fired plant and later converted to oil. However, conversion to direct coal firing at Oswego No. 6 is not readily feasible because it was designed for oil firing and therefore could not easily be converted to coal. In addition, Oswego No. 6 has space constraints that do not allow sufficient room for integral coal receiving, storage, and handling facilities.

OSWEGO FINDINGS

- Both Texaco gasification plant alternatives are shown to result in lower electricity costs at the bus bar when compared to continued oil firing over the life of the plant. Projected, alternative bus bar costs are shown in Table 12-1 for the case of project commencement by late 1980 with commercial operation in 1985.

The comparison is based on a 1980 delivered coal price of \$1.56 per million Btu with future escalation at 8 percent per year and 1980 No. 6 fuel oil (0.7 percent sulfur) price of \$4.56 per million Btu. Two oil price escalation rates are analyzed since this parameter has a large effect on gasifier economic attractiveness. Oil price escalation is expected to be in the area of 15 percent per year, although significant diversity of opinion exists on this point. Therefore, a 10 percent annual rate, approximating the general inflation rate, is also analyzed.

Both synthetic gas alternatives are shown in Table 12-1 to produce electricity at less than half the cost of oil, on a 25-year levelized basis when compared to oil escalating at 15 percent per year. The 25-year levelized cost of gas is also less than oil escalating at a 10 percent annual rate, although the difference is not as great as for the 15 percent escalation case.

Table 12-1

OSWEGO NO. 6 BUS BAR COST (At 70 Percent Power Plant Load)

<u>Fuel Alternative</u>	<u>1985 Bus Bar Cost (¢/kWh)</u>	<u>Levelized Bus Bar Cost (¢/kWh)</u>
OS100%Tex	11.0	13.4
OS70%Tex	9.4	11.9
Cont'd oil use:		
15% escalation	10.3	32.9
10% escalation	8.5	16.7

First year (1985) bus bar cost savings from consuming synthetic gas instead of oil occur only for the OS70%Tex

alternative when compared to the 15 percent annual oil price escalation case. Neither gasification alternative offers first year savings when compared to the 10 percent escalation case. However, it is only a matter of years before all of the synthetic gas alternatives become cost effective on a yearly basis compared to oil. This is because the cost of producing gas escalates at approximately 5 percent per year--far below the range expected for oil (see Table 12-5). The number of years until this breakeven point is reached for each alternative is shown in Table 12-2.

Table 12-2

BREAKEVEN YEAR
SYNTHETIC GAS versus OIL
(At 70 Percent Power Plant Load)

<u>Fuel Alternative</u>	<u>15% Oil Escalation (year)</u>	<u>10% Oil Escalation (year)</u>
OS100%Tex	2nd	5th
OS70%Tex	1st	3rd

• Comparative bus bar costs resulting from the full size gasifier alternative (OS100%Tex) and the two oil cases are shown for the 100 to 25 percent power plant load range on Figures 12-1 and 12-2. Figure 12-1 compares costs on a first-year (1985) basis, and Figure 12-2 compares 25-year levelized costs over the life of the project.

FIG. 12-1
OSWEGO NO.6 1985 BUS BAR COSTS:
SYNTHETIC GAS VERSUS OIL

- 100% TEXACO GASIFIER
- CONTINUED OIL USE (10% OIL ESC.)
- CONTINUED OIL USE (15% OIL ESC.)

FIG. 12-2
OSWEGO NO.6 LEVELIZED BUS BAR COSTS:
SYNTHETIC GAS VERSUS OIL

● 100% TEXACO GASIFIER
□ CONTINUED OIL USE (10% OIL ESC.)
■ CONTINUED OIL USE (15% OIL ESC.)

- The 70 percent gasifier alternative would be attractive, compared to the full sized 100 percent gasifier, for steady base load operation at power plant loads below 70 percent. It would not be attractive for load following operation because of the necessity to cofire a significant amount of oil during peak demand periods. Bus bar costs resulting from the 70 and 100 percent gasifiers are compared, on Figure 12-3, over a range of power plant loads. The 70 percent curve is based on a constant year round power plant load, and would be unrealizable with hourly, daily, or seasonal load fluctuations. For load following, the bus bar cost advantage of the 70 percent gasifier relative to the 100 percent gasifier would be less, in practice, than shown on Figure 12-3; and the crossover point between the two would actually occur at a lower power plant load than indicated.

FIG. 12-3
OSWEGO NO.6 LEVELIZED BUS BAR COSTS:
100% GASIFIER VS. 70% GASIFIER

- Total capital investment and payback period for the gasifier alternatives are shown in Table 12-3. Total capital investment includes plant and initial working capital investments for the gasification plant including interest and escalation during construction as well as for the power plant retrofit. Payback period is the number of years until the cumulative yearly return on equity, for both gasifier and retrofit investments, equals the equity portion of the total capital investment.

Table 12-3

OSWEGO NO. 6 GASIFICATION ALTERNATIVES

<u>Alternative</u>	<u>Total Capital Investment (1985 \$ x 10⁶)</u>	<u>Payback Period (years)</u>
OS100%Tex	1222	10.9
OS70%Tex	935	10.7

- First year (1985) fuel costs are shown in Table 12-4. The synthetic gas alternatives are shown to be more expensive than oil at 1980 prices but the percentage price difference decreases by 1985. Fuel savings, from using synthetic gas instead of oil, are realized over the life of the plant because once a gasification plant is built and operating, the gas cost is expected to escalate at a much lower rate than that of oil. The gas costs are adjusted (to reflect the reduction in boiler efficiencies due to converting from oil to synthetic gas) in order to allow direct comparison between the gas and oil cost figures. The comparison is also shown on a 1980 dollar basis by de-escalating the 1985 gas costs at an 8 percent annual rate.

Table 12-4

OSWEGO NO. 6 FUEL COSTS
Gas Costs Adjusted For Boiler Efficiency
(At 70 Percent Power Plant Load)

<u>Fuel Alternative</u>	<u>1985 Fuel Cost (\$/MM Btu)</u>	<u>1980 Fuel Cost (\$/MM Btu)</u>
OS100%Tex	9.86	6.71
OS70%Tex	8.25	5.61
Cont'd oil use:		
15% escalation	9.17	4.56
10% escalation	7.34	4.56

- Gas escalation rates, as shown in Table 12-5, are low relative to oil because they are weighted averages of the escalation rates of their component costs: 0 percent for fixed capital costs; 8 percent for coal and by-product power credit; and 10 percent for operating and maintenance costs and chemical catalysts.

Table 12-5

OSWEGO NO. 6 FUEL ESCALATION RATES
(At 70 Percent Power Plant Load)

<u>Fuel Alternative</u>	<u>Escalation Rate (%/yr)</u>
OS100%Tex	4.8
OS70%Tex	5.2
Cont'd oil use	15.0 10.0

- The economic analysis is prepared on a conservative basis. A 10 percent investment tax credit is used for the analysis (amortized over the life of the project) while a 20 percent credit may actually be available through 1986 if the project meets certain schedule requirements. Also, straight line depreciation is used for the analysis while accelerated depreciation methods are actually used by the utility. Taking advantage of these more generous financing parameters would further enhance the economic attractiveness of the project.

ARTHUR KILL FINDINGS

- The Combustion Engineering low-Btu gasifier produces lower cost electricity at the bus bar than that produced by the Texaco medium-Btu gasifier for the Arthur Kill unit; and all four gasification plant alternatives are shown to result in lower bus bar costs when compared to continued oil firing over the life of the plant. Projected, alternative bus bar costs are shown in Table 12-6 for the case of project commencement by late 1980 with commercial operation in 1985.

The comparison is based on the 1980 delivered coal price of \$1.75 per million Btu with future escalation at 8 percent per year and 1980 No. 6 fuel oil (0.3 percent sulfur) price of \$5.10 per million Btu. Two oil price escalation rates are analyzed since this parameter has a large effect on gasifier economic attractiveness. Oil price escalation is expected to be in the area of 15 percent per year, although significant diversity of opinion exists on this point. Therefore, a 10 percent annual rate, approximating the general inflation rate, is also analyzed.

All the synthetic gas alternatives shown in Table 12-6 produce electricity at less than half the cost of oil, on a 25-year levelized basis accounting for escalation over the gasifier life, when compared to oil escalating at 15 percent per year. Gas is also less costly than oil escalating at a 10 percent annual rate, although the difference is not as great as for the 15 percent escalation case.

Table 12-6

ARTHUR KILL NO. 3 BUS BAR COST
(At 70 Percent Power Plant Load)

<u>Fuel Alternative</u>	<u>1985 Bus Bar Cost (¢/kWh)</u>	<u>Levelized Bus Bar Cost (¢/kWh)</u>
AK100%Tex	14.5	16.7
AK70%Tex	12.1	14.5
AK100%CE	11.1	12.9
AK70%CE	9.3	11.3
Cont'd oil use		
15% escalation	10.6	35.7
10% escalation	8.7	17.9

- First year (1985) bus bar cost savings from consuming synthetic gas instead of oil occur only for the AK70%CE alternative compared to the 15 percent annual oil price escalation case. However, it is only a matter of years before all of the synthetic gas alternatives become cost effective on a yearly basis compared to oil. This is because the cost of producing gas escalates at approximately 4 percent per year--far below the range expected for oil (see Table 12-10). The number of years until this breakeven point is reached is shown in Table 12-7 for each alternative.

Table 12-7

BREAKEVEN YEAR
SYNTHETIC GAS versus OIL
(At 70 Percent Power Plant Load)

<u>Fuel Alternative</u>	<u>15% Oil Escalation (year)</u>	<u>10% Oil Escalation (year)</u>
AK100%Tex	4th	9th
AK70%Tex	3rd	7th
AK100%CE	2nd	5th
AK70%CE	1st	3rd

- Comparative bus bar costs resulting from the full sized gasifier alternatives (AK100%Tex and AK100%CE) and the two oil cases are shown for the 100 to 25 percent power plant load range on Figures 12-4 and 12-5. Figure 12-4 compares costs on a first-year (1985) basis, and Figure 12-5 compares 25-year levelized costs over the life of the project.

FIG. 12-4
ARTHUR KILL NO.3 1985 BUS BAR COSTS:
SYNTHETIC GAS VERSUS OIL

FIG. 12-5
ARTHUR KILL NO.3 LEVELIZED BUS BAR COSTS:
SYNTHETIC GAS VERSUS OIL

- 100% TEXACO GASIFIER
- 100% COMBUSTION ENGINEERING GASIFIER
- CONTINUED OIL USE (15% OIL ESC.)
- CONTINUED OIL USE (10% OIL ESC.)

- The 70 percent gasifier alternatives would be attractive, compared to the full size 100 percent gasifiers, only for steady base load operation at power plant loads below 70 percent. They would not be attractive for load following operation because of the necessity to cofire oil during peak demand periods. Bus bar costs resulting from the 70 and 100 percent gasifiers are compared, on Figure 12-6, over a range of power plant loads. The 70 percent curves are based on constant year round power plant loads and would be unrealizable with hourly, daily, or seasonal load fluctuations. For load following, the bus bar cost advantage of the 70 percent gasifiers relative to the 100 percent gasifiers would be less, in practice, than shown on Figure 12-6; and the crossover points between the two would actually occur at lower power plant loads than indicated.

FIG. 12-6
ARTHUR KILL NO.3 LEVELIZED BUS BAR COSTS:
100% GASIFIER VS. 70%
GASIFIER

- 100% TEXACO GASIFIER
- ▲ 70% TEXACO GASIFIER WITH SUPPLEMENTAL OIL (15% OIL ESC.)
- 100% COMBUSTION ENGINEERING GASIFIER
- △ 70% COMBUSTION ENGINEERING GASIFIER WITH SUPPLEMENTAL OIL (15% OIL ESC.)

- Total capital investments for the Combustion Engineering gasifier alternatives are shown, in Table 12-8, to be less than those of the Texaco alternatives, although the payback periods are essentially the same for all gasification alternatives. Total capital investment includes plant and initial working capital investments for the gasification plant including interest and escalation during construction as well as for the power plant retrofit. Payback period is the number of years until the cumulative yearly return on equity, for both gasifier and retrofit investments, equals the equity portion of the total capital investment.

Table 12-8

ARTHUR KILL NO. 3 GASIFICATION ALTERNATIVES

<u>Alternative</u>	<u>Total Capital Investment (1985 \$ x 10⁶)</u>	<u>Payback Period (years)</u>
AK100%Tex	891	7.6
AK70%Tex	681	7.5
AK100%CE	665	7.6
AK70%CE	512	7.5

- The Combustion Engineering gasification alternatives produce lower cost gas than the Texaco alternatives, as shown in Table 12-9. The synthetic gas alternatives are shown to be more expensive than oil at 1980 prices but the percentage price difference decreases by 1985. Fuel savings, from using synthetic gas instead of oil, are realized over the life of the plant because, once a gasification plant is built and operating, the gas cost is expected to escalate at a much lower rate than that of oil. Fuel costs are shown in Table 12-9. The gas costs are adjusted (to reflect the reduction in boiler efficiencies due to converting from oil to synthetic gas) in order to allow direct comparison between the gas and oil cost figures. The comparison is also shown on a 1980 dollar basis by de-escalating the 1985 gas costs at an 8 percent annual rate.

Table 12-9

ARTHUR KILL NO. 3 FUEL COSTS
Adjusted for Boiler Efficiency
(At 70 Percent Power Plant Load)

<u>Fuel Alternative</u>	<u>1985 Fuel Cost (\$/MM Btu)</u>	<u>1980 Fuel Cost (\$/MM Btu)</u>
AK100%Tex	14.22	9.68
AK70%Tex	11.61	7.90
AK100%CE	10.58	7.20
AK70%CE	8.68	5.91
Cont'd oil use:		
15% escalation	10.26	5.10
10% escalation	8.21	5.10

Gas escalation rates, as shown in Table 12-10, are low relative to oil because they are weighted averages of the escalation rates of their component costs: 0 percent for fixed capital costs, 8 percent for coal and by-product power credit; and 10 percent for operating and maintenance costs and chemical catalysts.

Table 12-10

ARTHUR KILL NO. 3 FUEL ESCALATION RATES
(At 70 Percent Power Plant Load)

<u>Fuel Alternative</u>	<u>Escalation Rate (%/yr)</u>
AK100%Tex	3.8
AK70%Tex	4.3
AK100%CE	3.9
AK70%CE	4.4
Cont'd oil use	15.0
	10.0

- The economic analysis is prepared on a conservative basis. A 10 percent investment tax credit is used for the analysis (amortized over the life of the project) while a 20 percent credit may actually be available through 1986 if the project meets certain schedule requirements. Also, straight line depreciation is used for the analysis while accelerated depreciation methods are actually used by the utility. If the utility were to take advantage of these more generous financing parameters it would further enhance the economic attractiveness of the project.

BASIS FOR ANALYSIS

General Assumptions

- Gasification plant owned by utility
- Fuel Costs
 - Coal:¹ Niagara Mohawk \$1.44/MM Btu (1979)
 - Consolidated Edison 3 \$1.62/MM Btu (1979)
 - No. 6 oil: Niagara Mohawk² \$4.56/MM Btu (1980)
 - Consolidated Edison 3 \$5.10/MM Btu (1980)
- Annual Escalation Rates⁷
 - No. 6 fuel oil 15 percent, 10 percent
 - Operation and maintenance costs 10 percent
 - Catalysts and chemicals 10 percent
 - Coal (delivered) 8 percent
 - Capital equipment 8 percent
 - By-product power credit 8 percent

Discussion of Fuel Escalation Rate Assumptions

- The economic and financial analysis herein requires that long range estimates be made of annual percent price escalation rates for coal and oil over the life of the project.

This task is made difficult by the fact that domestic U.S. oil prices as well as international oil prices are highly influenced by political actions taken by the major oil exporting countries. Oil prices, in turn, have an effect on the price of other major fuels, although not as direct in the case of coal as in the case for natural gas.

- Oil Escalation Rate

The oil market can correctly be characterized as non-competitive, as the world price of oil is set by a cartel which takes collective action to achieve its price targets. Under those conditions, given the ambitious political and economic development plans of most of the oil exporting countries, prices would have to be assumed to be increasing at a rate in excess of the long range U.S. general inflation rate, since oil prices are set in U.S. dollars. Experience over many years and a consensus of informed U.S. opinion indicates that the domestic inflation rate will continue to hover in a range of 8-10 percent (average). Therefore, this figure provides the lower bound of annual oil price escalation, which would be expected if there were large and long-lasting potential oil reserves.

On the upside, consider the effects of, for example, a 20 percent annual oil price increase sustained over a long period. If such an increase took place, this would result in an oil price of 200 dollars per barrel by 1990, which can reasonably be expected to result in prolonged economic recessions in the major industrial countries with resulting cutback in oil consumption, neither of which benefit the cause of the oil-exporting countries. Hence, oil prices are expected, long range, to fluctuate between these limits of no price increase in real terms for some years and high escalation rates in other years, i.e., 8-10 to 20 percent, or 15 percent on average. A figure of 15 percent is used to indicate that the forecast accuracy is low. Some oil companies in their forecasts have used 5 percent in real terms, i.e., 5 percent above the 8-10 percent inflation rate, i.e., in the same range as our 15 percent.

This situation is unlikely to change in the foreseeable future since the potentials of synthetic oils, energy conservation, coal conversion, expanded nuclear power and new energy technologies are now widely predicted not to have a major impact on energy requirements before the year 2000.

- Coal Escalation Rate

Unlike oil, coal is in abundant supply in the U.S., both where long range reserves are concerned as well as current productive capacity. Furthermore, total coal production is shared by over 3000 coal producing companies, although there is a degree of concentration of market power inasmuch as the largest 15 U.S. coal companies produced 40 percent of the approximately 750 million tons produced in 1979. The effect of competition in domestic coal can be seen in terms of

unused coal mining capacity, unemployment of coal miners, a large gap between coal production and consumption, and excessive number of bids for coal supply, when these are asked for, e.g., recently TVA received 70 bids for long term coal supply.

In addition, electric utilities, by far the largest single consumer of U.S. coal, have taken energetic steps to secure long range supplies for their coal generating units. These steps have included acquisition of outright ownership of coal rights, i.e., captive coal production, as well as take-or-pay contracts and other measures intended to secure coal on advantageous terms. In particular, the long-term take-or-pay contracts, since they must, out of necessity, include a variety of cost escalation clauses to protect the seller against inflation, also act to limit profit. This arises from the fact that the contracts are bid in a highly competitive environment, are relatively risk-free to the bidder, and terms are hard to keep secret. Under those conditions low annual escalation rates are likely. However, counteracting this trend, coal producers cannot avoid inflationary cost increases any better than the rest of the society. They are a labor intensive industry and transportation costs and investment costs in new mines to replace worked out mines are high.

However, coal mining is not a heavily unionized labor field, only 50 percent of coal miners are members of the United Mine Workers of America Union with another 50 percent who work for smaller companies and who are not unionized. This helps to maintain competition.

Additionally, there is transportation cost - a substantial component of delivered coal price (approximately 25 percent in 1979) - and cost escalation: The recent deregulation of railroad freight rates, which applies to coal traffic tariffs and allows buyers and suppliers of coal to negotiate and set freight rates without intervention. This is expected to increase transportation charges, both in the short and long term, but is not likely to escalate at a rate significantly beyond the general inflation rate.

Investment in new mines is not yet a major factor in coal escalation rates (projected at approximately 6 percent per year), because production and consumption of coal are growing very slowly (4.5 percent) and there is current overcapacity because the facilities to burn the additional coal are slow in being built.

Finally, the synthetic fuels program and coal exports are considered as factors influencing future price escalation.

Concerning synthetic fuels, it is now estimated that it will be at least 20 years before a significant annual coal tonnage will be required for this purpose. Coal exports, are expected to increase at an annual growth rate of 15.0 percent from the 1979 level of 14.0 million tons. Therefore, coal demands for synthetic fuels and exports represent only a small percentage of total U.S. coal capacity over the life of the plant.

Considering all the above facts, an average cost escalation rate for steam coal in the same range as the general inflation rate (8-10 percent) is justifiable.

Gasification Plant Capital Investment Basis

Total capital investment for each of the six gasification plant alternatives, including coal receiving up to the product gas delivery point at the power plant boundary, but not including the power plant retrofit, is shown in Table 12-11 and is estimated based on the following:

- Total direct and indirect costs are taken from Tables 11-1, 11-2, and 11-3 and include engineering design, construction management, contingencies, and paid-up royalties.
- Escalation and interest during construction are based on the following:
 - Engineering, construction, and startup period: 1981-1984
 - Standard S-curve capital expenditure pattern
 - Capital equipment escalation rate: 8 percent⁷
 - Niagara Mohawk average cost of incremental capital: 14 percent²
 - Consolidated Edison average cost of incremental capital: 14.7 percent¹
- Startup cost is the sum of the following:
 - 6 months of O&M
 - one week of full-load coal costs
 - one week of full-load process water costs

- Inventories of the following materials are capitalized:
 - Reserve coal stockpile (approximately 3 months' supply at 70 percent power plant rating)
 - Initial catalyst and chemical charge
- Working capital is 1.5 months of initial year (1985) required revenues, escalating at 5 percent per year.
- Niagara Mohawk and Consolidated Edison are exempt from sales and use tax on the purchase of producing assets.^{2,3}

TABLE 12-11
TOTAL GASIFICATION PLANT CAPITAL INVESTMENT
(\$ X 1000)

	DS100ZTEX	0970ZTEX	AK100ZTEX	AK70ZTEX	AK100ZCE	AK70ZCE
TOTAL DIRECT AND INDIRECT COSTS (1980 \$)	\$ 690,329	\$ 517,747	\$ 498,386	\$ 372,290	\$ 358,624	\$ 268,968
ESCALATION	130,058	97,544	93,518	70,139	67,564	
INTEREST DURING CONSTRUCTION	200,569	150,427	151,428	113,571	109,402	50,673
STARTUP COST (1985 \$)	23,004	17,400	16,018	12,198	13,715	82,052
RESERVE COAL STOCKPILE (1985 \$)	93,994	96,024	92,788	34,144	36,835	10,467
INITIAL CATALYST AND CHEMICAL CHANGE (1985 \$)	<u>1,533</u>	<u>1,073</u>	<u>1,214</u>	<u>850</u>	<u>1,245</u>	<u>37,868</u> <u>872</u>
PLANT INVESTMENT (1985 \$)	1,079,487	<u>820,215</u>	791,330	603,192	587,385	450,900
WORKING CAPITAL (1985 \$)	<u>48,000</u>	<u>41,000</u>	<u>35,400</u>	<u>29,700</u>	<u>32,900</u>	<u>28,700</u>
TOTAL CAPITAL INVESTMENT (1985 \$)	\$ 1,127,487	\$ 861,215	\$ 826,730	\$ 632,892	\$ 620,285	\$ 479,600

Gasifier Operating Cost Basis

- Straight-line depreciation over 25 years is assumed for both book and tax purposes in order to simplify the analysis. Both Niagara Mohawk and Consolidated Edison use the straight-line method for financial statement preparation; however, accelerated depreciation methods are actually used by both companies for tax purposes.
- Project life is 25 years with commercial operation commencing 1985.
- Capital Structure^{2, 3}

Niagara Mohawk:	48 percent debt at 14 percent interest
	52 percent equity at 14 percent ROE
Consolidated Edison:	55 percent debt at 12 percent interest
	45 percent equity at 18 percent ROE
- Long-term debt is assumed to be mortgage type with life equal to 25-year plant life.⁷
- Investment tax credit is 10 percent, amortized over the life of the plant.
- Insurance: annual cost is one-tenth of 1 percent of total capital cost,^{2, 3} constant over the life of the plant.⁷
- Operation & Maintenance Expense. Average prevailing labor rates are used, with an allowance for supervision, overhead burden, and general and administrative costs. Initial year (1985) maintenance expense is equal to 2.5 percent of total plant investment.⁴ Total O&M expense is escalated at 10 percent per year.
- Gasification Plant Operating Staff.⁵ Operating staff levels, including a factor for vacations, holidays, and sick time, are listed below:

<u>Gasifier Alternative</u>	<u>Operating Staff Level</u>
OS100%Tex	112
OS70%Tex	92
AK100%Tex	92
AK70%Tex	78
AK100%CE	92
AK70%CE	78

- Property Tax

Niagara Mohawk:

One percent per year of initial depreciable capital, escalating at 8 percent per year.²

Consolidated Edison:

Seven percent per year of initial depreciable capital, constant over the life of the plant.³

- Coal Cost¹

Niagara Mohawk:

Base case coal cost is \$1.44 per million Btu in 1979 dollars and is estimated to escalate at 8 percent per year. A sensitivity analysis is performed using 1979 costs of \$1.00 per million Btu and \$2.00 per million Btu.

Consolidated Edison:

Base case coal cost is \$1.62 per million Btu in 1979 dollars and is estimated to escalate at 8 percent per year. A sensitivity analysis is performed using 1979 costs of \$1.25 per million Btu and \$2.25 per million Btu.

- Base case power plant load factor is assumed to be 70 percent. A sensitivity analysis is performed using factors of 25 percent, 50 percent, 90 percent, and 100 percent.⁷

- Process Water Cost

Niagara Mohawk:

The gasification plant site for Oswego No. 6 has its own well and pump station. Water costs are therefore included in the capital and O&M costs for the plant.

Consolidated Edison:³

City water at \$5.25/MCF in 1980 (assumed to escalate at 8 percent per year).⁷

- Annual catalyst and chemicals costs at 70 percent power plant load factor are as follows in 1980 dollars:

Oswego, Texaco	\$498,000 per year
Arthur Kill, Texaco	\$380,600 per year
Arthur Kill, CE	\$489,300 per year
(assumed to escalate at 10 percent per year) ⁷	

The initial charges of catalyst and chemicals are as follows, in 1980 dollars:

Oswego, Texaco	\$666,200
Arthur Kill, Texaco	\$527,800
Arthur Kill, CE	\$541,400

- The base case analysis uses a byproduct power credit of 6.5¢/kWh² in 1985 based on the projected costs of alternative power. A sensitivity analysis is performed using zero credit, 3.1¢/kWh,³ and 11.0¢/kWh (a rate in excess of the production cost at any of the gasifier fueled alternatives). The credit is assumed to escalate at 8 percent for all cases.
- Byproduct sulfur and ash credits are assumed, conservatively, to have a net zero value.⁷
- The effective income tax rate for both Niagara Mohawk and Consolidated Edison is 46 percent.^{2,3}
- Gross Receipts Tax

Niagara Mohawk 4.368 percent ⁽²⁾

Consolidated Edison 6.1 percent ⁽³⁾

Power Plant Retrofit Capital Investment Basis

The capital investment required for retrofitting the existing boilers is calculated on the same basis as the gasifier capital cost. Total direct and indirect costs are taken from Table 11-4. The only difference is that the retrofit is estimated to require six months. Therefore, work would commence in mid-1984 and would be completed by the end of that year. Startup costs are assumed negligible. Capital costs for the three cases are estimated in Table 12-12.

TABLE 12-12
TOTAL POWER PLANT RETROFIT CAPITAL INVESTMENT

	(\$ THOUSANDS)					
	OS100%TEX	OS70%TEX	AK100%TEX	AK70%TEX	AK100%CE	AK70%CE
TOTAL DIRECT AND INDIRECT COSTS (1980 \$)	6,569	6,569	6,054	6,054	9,660	9,660
EXCALATION	2,716	2,716	2,512	2,512	4,008	4,008
INTEREST DURING CONSTRUCTION	325	325	315	315	502	502
PLANT INVESTMENT (1985 \$)	9,610	9,610	8,881	8,881	14,170	14,170
WORKING CAPITAL (1985 \$)	3,100	2,700	3,700	3,000	3,100	2,600
TOTAL CAPITAL INVESTMENT (1985 \$)	\$12,710	\$12,310	\$12,581	\$11,881	\$17,270	\$16,770

Power Plant Operating Cost Basis

- No. 6 Fuel Oil Cost

Niagara Mohawk ²	\$4.56/MM Btu (1980\$) 0.7% sulfur 142,857 Btu/gal
Consolidated Edison ³	\$5.10/MM Btu (1980\$) 0.3% sulfur 143,800 Btu/gal

- Heat Rates, for alternative boiler inputs

Niagara Mohawk	Oil	9228 Btu/kWh
	Medium-Btu gas	9539 Btu/kWh
Consolidated Edison	Oil	8896 Btu/kWh
	Medium-Btu gas	9149 Btu/kWh
	Low-Btu gas	9948 Btu/kWh

- Boiler Efficiencies

The following values are for full-load operation and are assumed constant over the 25-100 percent power plant capacity factor range:

Niagara Mohawk	Oil	90.3%
	Medium-Btu gas	87.2%
Consolidated Edison	Oil	89.7%
	Medium-Btu gas	87.2%
	Low-Btu gas	80.2%

- Power plant original capital cost and first year of service (i.e., date capitalized):

Oswego No. 6	\$330,000,000 ⁽²⁾ (1979)
Arthur Kill No. 3	\$ 79,320,000 ⁽³⁾ (1969)

- Fixed Charge Rate

Niagara Mohawk	19% ⁽²⁾
Consolidated Edison	20% ⁽⁷⁾

- Variable expenses include total production expenses exclusive of fuel,⁶ factored to include overhead burden and general and administrative expenses; they are assumed to escalate at 10 percent per year.

METHODOLOGY

Required revenues for the six gasification plant alternatives (up to the gas output and including the coal cost, credit for byproduct power, and income taxes, but excluding gross receipt taxes) are computed in Supplement K. The resulting gas cost in dollars per million Btu is also calculated. Calculations are performed on a current dollar (year-by-year) basis.

Required revenues, including gross receipts taxes, for the power plants using synthetic gas, and the resulting bus bar electricity costs are computed in Supplement K. Levelized bus bar costs, over the 25-year life of the project, are also calculated. The concept of levelized cost is discussed in Supplement J.

The total required revenue to own and operate the power plant using synthetic gas is comprised of the costs of the retrofit, fixed and operating costs of the existing plant and fuel costs. Required revenue is developed for the retrofit, treated as a stand-alone investment. Fuel charges for synthetic gas are taken directly from the gasification plant required revenues in Supplement K (Figures K-1 through K-6). To this is added the fixed carrying charges and the variable operating expenses for the existing power plant. It is assumed that non-fuel-production costs for the power plants will not change as a result of the conversion from oil to gas firing. This is a conservative assumption because gas-fired generating plants normally have slightly lower production expenses than oil-fired plants, and the remaining lives of both Oswego No. 6 and Arthur Kill No. 3 are greater than the 25-year life of the gasifier.

Fixed costs of the existing power plants are derived from the power plant original capital cost and the utility's fixed charge rate. The resulting fixed charge component for Arthur Kill No. 3, completed in 1969 and using a preexisting coal handling facility and stack, is \$158/kW, compared to \$388/kW for Oswego No. 6, built in 1979.

Required revenue for the case of the power plants continuing to use No. 6 oil and the resulting bus bar electricity costs are estimated in Supplement K for comparison with the synthetic gas-fired bus bar costs.

Sensitivity of 1985 bus bar electricity costs are analyzed with respect to variations in coal price, power plant capacity factor, and byproduct power price. Sensitivity analyses are summarized in Tables 12-18, 12-19, and 12-20, which are based on a series of required revenue computer runs following the same format as those in Supplement K. Computer printouts for these runs are not included with the report because they are too voluminous.

An additional sensitivity analysis is performed on the escalation rate assumed for fuel oil; this analysis assumes 10 percent and 15 percent rates and is summarized in Tables 12-21 through 12-26. The attractiveness of synthetic gas versus oil is due to the high escalation rate for oil relative to the approximately 4 to 5 percent rate calculated for synthetic gas. Gibbs & Hill uses the 15 percent rate in planning to imply that oil will escalate at a rate approximately 5 percent greater than that of long-term general inflation, an assumption that appears necessary in light of present oil price economics. Sensitivity of the analysis to 10 percent oil price escalation is investigated to determine its effect on the recommendation.

Cost of lost production during conversion from oil to synthetic gas firing is assumed to be zero. During the conversion, which is estimated to require one to three months of downtime for the various cases, it is assumed that lost production can be made up by increasing the capacity factor of other oil-fired plants, and that the plant undergoing conversion remains in the rate base. Therefore, overall fixed charges do not change for the utility. O&M costs do not change appreciably because the operating staffs for the converted plant and the plants temporarily replacing the lost power remain at the same level. Fuel costs also remain approximately the same because power from the oil plant being converted would most likely be replaced by power from other oil plants. In fact, there would probably be some temporary incremental cost due to the principles of economic dispatch; however, this increase is assumed to be negligible. In addition, the tie-in can be timed to coincide with the normal yearly power plant shutdown, which would help to minimize actual lost production time.

DISCUSSION OF RESULTS

Initial year (1985) gas costs for the six gasifier cases are summarized below in Table 12-13. Values are taken directly from Figures K-1 through K-6, in Supplement K, which were prepared using a 70-percent power plant load factor; a 6.5¢/kWh by-product power credit; and 1980 coal prices of \$1.56 per million Btu for Oswego and \$1.75 per million Btu for Arthur Kill (both escalating at 8 percent per year). These costs are shown before adjustment for the change in boiler efficiencies caused by the conversion from oil to synthetic gas. Gas cost escalation over the life of the plant is also shown.

Gas costs, adjusted for boiler efficiency changes, are summarized in Table 12-14; these values may be directly compared with the 1985 oil costs on a dollar-per-million-Btu basis as shown in Table 12-15.

Table 12-13

1985 GAS COSTS
(At 70 Percent Power Plant Load)

<u>Case</u>	<u>Gas Cost (\$/mm Btu)</u>	<u>Gas Cost Escalation Rate (%)</u>
OS100%Tex	9.52	4.8
OS70%Tex	7.96	5.2
AK100%Tex	13.83	3.8
AK70%Tex	11.29	4.3
AK100%CE	9.46	3.9
AK70%CE	7.76	4.4

Table 12-14

1985 GAS COSTS
(Adjusted to Oil-Fired Boiler Efficiencies)
(At 70 Percent Power Plant Load)

<u>Case</u>	<u>Gas Cost (\$/mm Btu)</u>
OS100%Tex	9.86
OS70%Tex	8.25
AK100%Tex	14.22
AK70%Tex	11.61
AK100%CE	10.58
AK70%CE	8.68

Table 12-15
1985 OIL COSTS

<u>Case</u>	<u>Oil Cost at 15% escalation (\$/mm Btu)</u>	<u>Oil Cost at 10% escalation (\$/mm Btu)</u>
Oswego No.6	9.17	7.34
Arthur Kill No.3	10.26	8.21

Bus bar electricity costs for the six power plant plus gasifier cases and for the continued oil use cases are shown below in Table 12-16. Values are taken directly from Tables K-7 through K-16, in Supplement K, which are prepared on the same basis as is used for preparation of the gas cost figures previously discussed, plus 1980 oil prices of \$4.56 per million Btu for Oswego and \$5.10 per million Btu for Arthur Kill.

Table 12-16

BUS BAR ELECTRICITY COST SUMMARY
(At 70 Percent Power Plant Load)

<u>Case</u>	<u>1985 Bus Bar Cost (¢/kWh)</u>	<u>Levelized Bus Bar Cost (¢/kWh)</u>
OS100%Tex	11.0	13.4
OS70%Tex	9.4	11.9
AK100%Tex	14.5	16.7
AK70%Tex	12.1	14.5
AK100%CE	11.1	12.9
AK70%CE	9.3	11.3
Oswego No. 6 (cont'd oil use)		
15% escalation	10.3	32.9
10% escalation	8.5	16.7
Arthur Kill No. 3 (cont'd oil use)		
15% escalation	10.6	35.7
10% escalation	8.7	17.9

All of the gasification alternatives shown in Table 12-14 produce electricity at a lower cost than oil on a 25-year levelized basis accounting for inflation over the life of the plant. Gas produces electricity at less than half the cost of oil, for the 15 percent oil escalation case. For 10 percent oil escalation, gas is also less expensive over the life of the plant, but the saving is less than in the case of 15 percent oil.

First year (1985) cost savings from consuming synthetic gas instead of oil occur only for the OS70%Tex and AK70%CE alternatives, and only when compared with the 15 percent oil escalation case. However, it is only a matter of years before all of the synthetic gas alternatives becomes cost effective, compared to oil, on a yearly basis, since the costs of producing gas escalate at a lower rate than the range of escalation rates expected for oil. The number of years until this breakeven point is reached is shown in Table 12-17 for each alternative. These values are developed from a comparison of Figures in Supplement K. Figures K-7 through K-12 show the projected yearly bus bar cost of electricity for each of the alternative gasifiers' lives. Figures K-13 through K-16 show the projected yearly bus bar costs for continued oil use (for both the 10 percent and 15 percent cases) at both existing power plants. A comparison of these cost trends results in the synthetic gas versus oil breakeven points shown in Table 12-17.

Table 12-17

BREAKEVEN YEAR
SYNTHETIC GAS versus OIL
(At 70 Percent Power Plant Load)

<u>Fuel Alternative</u>	<u>15% oil Escalation (year)</u>	<u>10% oil Escalation (year)</u>
OS100%Tex	2nd	5th
OS70%Tex	1st	3rd
AK100%Tex	4th	9th
AK70%Tex	3rd	7th
AK100%CE	2nd	5th
AK70%CE	1st	3rd

Sensitivities of initial year (1985) bus bar electricity costs for the six gasification alternatives are analyzed for variations in power plant steady state load factor, coal price, and by-product power credit. All other factors are held constant, only one parameter varies at a time. The analysis is shown in Tables 12-18, 12-19, and 12-20.

Table 12-18

SENSITIVITY ANALYSIS
OSWEGO NO. 6 WITH TEXACO GASIFIER

<u>Sensitivity Parameter</u>	<u>1985 Bus Bar Cost</u>	
	<u>100-Percent Gasifier (¢/kWh)</u>	<u>70-Percent Gasifier (¢/kWh)</u>
<u>Power Plant Load*</u> <u>Factor (%)</u>		
100	8.6	9.3
90	9.2	9.3
70	11.0	9.4
50	14.2	12.0
25	25.4	21.1
<u>Coal Price*</u> <u>(1979 \$/mm Btu)</u>		
2.00	12.4	10.8
1.44	11.0	9.4
1.00	9.9	8.3
<u>Byproduct Power*</u> <u>Credit (¢/kWh)</u>		
3.1	11.3	9.7
6.5	11.0	9.4
11.0	10.6	9.0

* Boxed cases are based on 70 percent power plant load factor, \$1.44/mmBtu (1979 \$) coal price, and 6.5¢/kWh (1985) by product power credit. Oil escalates at 15 percent per year for 70 percent gasifier alternative load factors above 70 percent.

Table 12-19

SENSITIVITY ANALYSIS
ARTHUR KILL NO. 3 WITH TEXACO GASIFIER

<u>Sensitivity Parameter</u>	<u>1985 Bus Bar Cost</u>	
	<u>100-Percent Gasifier (¢/kWh)</u>	<u>70-Percent Gasifier (¢/kWh)</u>
<u>Power Plant Load*</u>		
<u>Factor (percent)</u>		
100	11.1	11.3
90	12.0	11.5
70	14.5	12.1
50	19.1	15.6
25	35.0	28.1
<u>Coal Price*</u> <u>(1979 \$/mm Btu)</u>		
2.25	16.1	13.6
1.62	14.5	12.1
1.25	13.6	11.1
<u>Byproduct Power*</u> <u>Credit (¢/kWh)</u>		
3.1	15.0	12.5
6.5	14.5	12.1
11.0	14.0	11.5

* Boxed cases are based on 70 percent power plant load factor, \$1.62/mmBtu (1979 \$) coal price, and 6.5¢/kWh (1985) by product power credit. Oil escalates at 15 percent per year for 70 percent gasifier alternative load factors above 70 percent.

Table 12-20

SENSITIVITY ANALYSIS
ARTHUR KILL NO. 3 WITH COMBUSTION ENGINEERING GASIFIER

<u>Sensitivity*</u> <u>Parameter</u>	<u>1985 Bus Bar Cost</u>	
<u>Power Plant Load</u> <u>Factor (percent)</u>	<u>100-Percent</u> <u>Gasifier</u> <u>(¢/kWh)</u>	<u>70-Percent</u> <u>Gasifier</u> <u>(¢/kWh)</u>
100	8.5	9.4
90	9.2	9.4
70	11.1	9.3
50	14.6	12.1
25	26.9	21.9
<u>Coal Price*</u> <u>(1979 \$/mm Btu)</u>		
2.25	12.8	11.0
1.62	11.1	9.3
1.25	10.2	8.4
<u>Byproduct Power*</u> <u>Credit (¢/kWh)</u>		
3.1	12.1	10.3
6.5	11.1	9.3
11.0	9.8	8.0

* Boxed cases are based on 70 percent power plant load factor, \$1.62/mmBtu (1979 \$) coal price, and 6.5¢/kWh (1985) byproduct power credit. Oil escalates at 15 percent per year for 70 percent gasifier alternative load factors above 70 percent.

Bus bar costs are seen to be most sensitive to power plant load factor. Bus bar costs are less sensitive to coal price variations; a 10 percent coal price shift in either direction will cause about a 3 percent cost change. Bus bar costs are least sensitive to by-product power credit variations; a 10 percent credit change will cause less than a 1 percent cost shift for the Texaco cases and about a 2 percent cost shift for the Combustion Engineering cases. The information on these tables is shown graphically on Figures 12-7 through 12-15.

FIG. 12-7
OSWEGO / TEXACO
POWER PLANT LOAD FACTOR SENSITIVITY

FIG. 12-8
OSWEGO/TEXACO
COAL PRICE SENSITIVITY

FIG. 12-9
OSWEGO/TEXACO
BY-PRODUCT POWER CREDIT SENSITIVITY

FIG. 12-10
ARTHUR KILL/TEXACO
POWER PLANT LOAD FACTOR SENSITIVITY

FIG. 12-11
ARTHUR KILL/TEXACO
COAL PRICE SENSITIVITY

FIG. 12-12
ARTHUR KILL/TEXACO
BY-PRODUCT POWER CREDIT SENSITIVITY

FIG. 12-13
ARTHUR KILL/COMBUSTION ENGINEERING
POWER PLANT LOAD
FACTOR SENSITIVITY

⊙ 100% COMBUSTION ENGINEERING GASIFIER
▲ 70% COMBUSTION ENGINEERING GASIFIER WITH SUPPLEMENTAL OIL

FIG. 12-14
ARTHUR KILL/COMBUSTION ENGINEERING
COAL PRICE SENSITIVITY

⊙ 100% COMBUSTION ENGINEERING GASIFIER
▲ 70% COMBUSTION ENGINEERING GASIFIER

FIG. 12-15
ARTHUR KILL/COMBUSTION ENGINEERING
BY-PRODUCT POWER CREDIT SENSITIVITY

Bus bar cost sensitivity to power plant load factor, as shown on Figures 12-16 through 12-19 for 25-year levelized costs, deserves special note. As power plant load factor increases up to 70 percent, the resultant bus bar costs decrease for both the 70- and 100-percent-gasifier alternatives. The 70-percent gasifiers have lower capital and operating costs than the 100 percent gasifiers, and they result in lower bus bar costs for power plant load factors up to 70 percent.

As the power plant load factor increases above 70 percent, the 70-percent-gasifier case consumes increasing amounts of high cost oil, which causes the resultant bus bar cost to increase as power plant load factor increases beyond 70 percent. However, bus bar cost resulting from the 100-percent-gasifier case continues to drop as power plant load increases above 70 percent.

The bus bar cost resulting from the 70 percent gasifier case crosses over the bus bar cost of the 100-percent-gasifier case at load factors ranging from 74 to 86 percent for the various alternatives (see Figures 12-16 through 12-19). For all power plant load factors above this crossover point, the 100-percent gasifier results in the lowest bus bar cost.

The 70 percent gasifier curves are based on the assumption that the power plant operates at a steady load, year-round. In actual practice, the plant would experience hourly, daily, and seasonal load fluctuations. Greater amounts of oil than indicated in the steady state curves would actually be consumed. The steady state curves represent the lowest possible bus bar cost theoretically obtainable. The 70 percent curves would be realized for steady, base load operation, with no outages. These curves would not be realized in a load following mode with load excursions above 70 percent.

FIG. 12-16
 OSWEGO NO.6 LEVELIZED BUS BAR COSTS:
 SYNTHETIC GAS VERSUS OIL
 (15% OIL ESCALATION CASE)

FIG. 12-17
ARTHUR KILL NO.3 LEVELIZED BUS BAR COSTS:
SYNTHETIC GAS VERSUS OIL
(15% OIL ESCALATION CASE)

- 100% TEXACO GASIFIER
- ▲ 70% TEXACO GASIFIER WITH SUPPLEMENTAL OIL
- ⊙ 100% COMBUSTION ENGINEERING GASIFIER
- △ 70% COMBUSTION ENGINEERING GASIFIER WITH SUPPLEMENTAL OIL
- CONTINUED OIL USE (15% OIL ESC.)

FIG. 12-18
OSWEGO NO.6 LEVELIZED BUS BAR COSTS:
SYNTHETIC GAS VERSUS OIL
(10% OIL ESCALATION CASE)

FIG. 12-19
ARTHUR KILL NO.3 LEVELIZED BUS BAR COSTS:
SYNTHETIC GAS VERSUS OIL
(10% OIL ESCALATION CASE)

- 100% TEXACO GASIFIER
- ▲ 70% TEXACO GASIFIER WITH SUPPLEMENTAL OIL
- ⊕ 100% COMBUSTION ENGINEERING GASIFIER
- △ 70% COMBUSTION ENGINEERING GASIFIER WITH SUPPLEMENTAL OIL
- CONTINUED OIL USE (10% OIL ESC.)

Sensitivity of 25-year levelized bus bar electricity costs to power plant load factor for the six gasifier plus power plant cases, as well as the case of continued oil use assuming 15 percent per year oil price escalation, is tabulated in Tables 12-21, 12-22, and 12-23, and is shown graphically on Figures 12-16 and 12-17. Only one parameter varies at a time; all other factors are held constant.

Table 12-21

25-YEAR LEVELIZED BUS BAR COST
(15-PERCENT OIL ESCALATION)
OSWEGO NO. 6 WITH TEXACO GASIFIER

<u>Power Plant*</u> <u>Load Factor</u> <u>(percent)</u>	<u>100-Percent</u> <u>Gasifier</u> <u>(¢/kWh)</u>	<u>70-Percent</u> <u>Gasifier</u> <u>(¢/kWh)</u>	<u>Continued</u> <u>Oil Use</u> <u>(¢/kWh)</u>
100	11.0	17.8	32.4
90	11.6	16.2	32.6
70	13.4	11.9	32.9
50	16.6	14.5	33.6
25	27.9	23.8	35.9

* Boxed cases are based on 70 percent power plant load factor, \$1.44/mmBtu (1979 \$) coal price, and 6.5¢/kWh (1985) by product power credit. Oil escalates at 15 percent per year for 70 percent gasifier alternative load factors above 70 percent.

Table 12-22

25-YEAR LEVELIZED BUS BAR COST
(15-PERCENT OIL ESCALATION)
ARTHUR KILL NO. 3 WITH TEXACO GASIFIER

Power Plant* Load Factor (percent)	100-Percent Gasifier (¢/kWh)	70-Percent Gasifier (¢/kWh)	Continued Oil Use (¢/kWh)
100	13.4	20.3	35.4
90	14.3	18.8	35.5
70	16.7	14.5	35.7
50	21.2	18.0	36.2
25	36.7	30.3	37.8

* Boxed cases are based on 70 percent power plant load factor, \$1.62/mmBtu (1979 \$) coal price, and 6.5¢/kWh (1985) by product power credit.

Table 12-23

25-YEAR LEVELIZED BUS BAR COST
(15-PERCENT OIL ESCALATION)
ARTHUR KILL NO. 3 WITH COMBUSTION ENGINEERING GASIFIER

<u>Power Plant* Load Factor (percent)</u>	<u>100-Percent Gasifier (¢/kWh)</u>	<u>70-Percent Gasifier (¢/kWh)</u>	<u>Continued Oil Use (¢/kWh)</u>
100	10.3	18.1	35.4
90	11.0	16.4	35.5
70	12.9	11.3	35.7
50	16.4	14.1	36.2
25	28.6	24.0	37.8

* Boxed cases are based on 70 percent power plant load factor, \$1.62/mmBtu (1979 \$) coal price, and 6.5¢/kWh (1985) by product power credit.

The sensitivity of 25-year levelized bus bar electricity costs to power plant capacity factor for the six gasifier-plus-power-plant cases, as well as the case of continued oil use, is also analyzed with a 10-percent-per-year oil price escalation assumption. The results are tabulated below in Tables 12-24, 12-25, and 12-26 and are shown graphically on Figures 12-18 and 12-19.

Table 12-24

25-YEAR LEVELIZED BUS BAR COST
(10-PERCENT OIL ESCALATION)
OSWEGO NO. 6 WITH TEXACO GASIFIER

<u>Power Plant*</u> <u>Load Factor</u> <u>(percent)</u>	<u>100-Percent</u> <u>Gasifier</u> <u>(¢/kWh)</u>	<u>70-Percent</u> <u>Gasifier</u> <u>(¢/kWh)</u>	<u>Continued</u> <u>Oil Use</u> <u>(¢/kWh)</u>
100	11.0	12.8	16.3
90	11.6	12.6	16.4
70	13.4	11.9	16.7
50	16.6	14.5	17.3
25	27.9	23.8	19.7

* Boxed cases are based on 70 percent power plant load factor, \$1.62/mmBtu (1979 \$) coal price, and 6.5¢/kWh (1985) by product power credit.

Table 12-25

25-YEAR LEVELIZED BUS BAR COST
(10-PERCENT OIL ESCALATION)
ARTHUR KILL NO. 3 WITH TEXACO GASIFIER

<u>Power Plant* Load Factor (percent)</u>	<u>100-Percent Gasifier (¢/kWh)</u>	<u>70-Percent Gasifier (¢/kWh)</u>	<u>Continued Oil Use (¢/kWh)</u>
100	13.4	15.2	17.6
90	14.3	14.9	17.6
70	16.7	14.5	17.9
50	21.2	18.0	18.4
25	36.7	30.3	20.2

* Boxed cases are based on 70 percent power plant load factor, \$1.62/mmBtu (1979 \$) coal price, and 6.5¢/kWh (1985) by product power credit.

Table 12-26

25-YEAR LEVELIZED BUS BAR COST
(10-PERCENT OIL ESCALATION)
ARTHUR KILL NO. 3 WITH COMBUSTION ENGINEERING GASIFIER

<u>Power Plant* Load Factor (percent)</u>	<u>100-Percent Gasifier (¢/kWh)</u>	<u>70-Percent Gasifier (¢/kWh)</u>	<u>Continued Oil Use (¢/kWh)</u>
100	10.3	13.0	17.6
90	11.0	12.5	17.6
70	12.9	11.3	17.9
50	16.4	14.1	18.4
25	28.6	24.0	20.2

* Boxed cases are based on 70 percent power plant load factor, \$1.62/mmBtu (1979 \$) coal price, and 6.5¢/kWh (1985) by product power credit.

Table 12-27 ranks the six cases in order of decreasing required revenues. Required revenue values are taken from Supplement K. Final year required revenues are also tabulated to show that the first-year relationships continue to hold over the 25-year project life for each case.

Table 12-27

POWER PLANT RETROFIT REQUIRED REVENUE
(For 70 Percent Power Plant Load Factor)

<u>Case</u>	<u>First-year Required Revenue (1985 \$ x 10⁶)</u>	<u>Final-year Required Revenue (2009 \$ x 10⁶)</u>
OS100%Tex	575	1,715
OS70%Tex	495	1,587
AK100%Tex	447	1,171
AK70%Tex	371	1,075
AK100%CE	343	927
AK70%CE	287	855

Total capital investment, initial equity investment and payback for each case is given in Table 12-28. Total capital investment includes total plant and initial working capital investments for the gasification plant as well as for the power plant retro-fit as shown in Tables 12-11 and 12-12. Initial equity investment is the amount of equity invested by the plant owner assuming that plant investments are financed at the owner's capital structure (52 percent equity for Niagara Mohawk and 45 percent equity for Consolidated Edison) and that working capital is provided for from equity funds. Payback period is the number of years until the cumulative yearly return on equity, for both the gasifier and retrofit investments, equals the equity portion of the total capital investment.

Table 12-28

INITIAL EQUITY INVESTMENT AND PAYBACK PERIODS

<u>Case</u>	<u>Total Capital Investment (1985 \$ x 10⁶)</u>	<u>Initial Equity Investment (2009 \$ x 10⁶)</u>	<u>Payback (years)</u>
OS100%Tex	1,222	665	10.9
OS70%Tex	935	511	10.7
AK100%Tex	891	430	7.6
AK70%Tex	681	330	7.5
AK100%CE	665	321	7.6
AK70%CE	512	248	7.5

Section 13

INSTITUTIONAL FACTORS

REGULATORY AND FINANCIAL ASPECTS

The Federal Government is moving to bring about utility conversions from oil to alternative fuels, making it imperative that coal gasification be considered as one of the options.

The Power Plant and Industrial Fuel Use Act of 1978 (PIFA) prohibits existing power plants from burning gas after 1990 and prohibits new plants from burning gas or oil as their main fuel. However, the act contains so many channels for exemptions that actual enforcement is hard to predict.

The Oil Backout Bill, now being considered, would amend the PIFA to mandate conversions of specific oil-fired electric generating plants to direct coal-firing and would issue grants to cover up to 50 percent of the investment and loan guarantees for up to an additional 25 percent. Phase Two of the Oil Backout Bill would offer grants to utilities that reduce oil consumption through other means, including coal gasification, and would provide strong incentives to proceed with the conversion effort by no longer allowing utilities to pass increases in oil prices along to customers through automatic fuel adjustment clauses. The bill is currently facing opposition from environmentalists and from those who feel that utilities should not be offered financial assistance for such conversions. These groups argue that electric utilities should not be offered grants and loan guarantees to make investments that will be forced anyway by current oil/coal economics.

However, electric utility companies are currently faced with difficulties in raising funds for large capital investments. Most utility oil usage is in the Northeast where utilities in general are less able, financially, to undertake major capital projects than those in the faster growing regions of the U.S. However, it seems likely that the Oil Backout Bill will pass in some form, given the national necessity of converting away from oil and make some conversion funds available.

The Synthetic Fuels Bill is also expected to be of some assistance in raising capital to develop coal gasification plants for utilities.

The present analysis includes the standard 10 percent investment tax credit, although a larger credit may be available. The National Energy Act of 1978 established an additional 10 percent credit for alternate fuel projects through 1982, and the Windfall Profits Tax Act, just signed, extends the additional 10 percent

to projects with engineering and environmental studies complete by 1982 and to projects that are at least 50 percent under contract by 1986. Therefore, the additional credit may be available for a gasification plant at Oswego or Arthur Kill.

Greater investment tax credits, although helpful, are probably not the most suitable incentives for potential utility owners of coal gasification plants. Even the largest of utilities often do not have sufficient tax liabilities to take full advantage of tax credits of the size that would be generated by a billion-dollar investment in synthetic fuels. The large oil companies, on the other hand, would more likely be able to use additional tax credits.

Price guarantees are probably more attractive to utilities. If significant cost overruns occur or if competing fuels escalate at a lower rate than predicted, the initial synthetic gas price may prove to be more expensive than competing fuels. A prospective utility owner would most likely want assurances that the synfuel plant could be immediately included in the rate base and its cost passed on to customers. Alternatively, a long-term supply contract with another entity of which the utility could be a part would also reduce utility risk. Either alternative would ease the burden of obtaining the necessary financing. Once the gasification plant is built and operating, if not initially competitive, it would be only a matter of time before the price of competing fuels, natural gas and oil, would escalate beyond that of gas derived from coal.

Section 14

RECOMMENDATIONS FOR FUTURE STUDY

While this Study is useful in assessing the merits of coal gasification in power generation, further investigation is warranted to improve the accuracy of the economics and to provide the fuel-firing flexibility that is required by a large electric utility. To this end, it is recommended that investigations be performed to assess the following:

Load Following and System Capability

The ability of the gasification system to follow the variations in electric load demand should be investigated in detail; this is critical in both the selection and operation of the unit. This could expand the potential use of coal gasification in otherwise marginal applications and provide a more cost-effective gasification plant.

In-Process Steam Utilization and Distribution

The steam utilization and distribution system should be optimized. The interdependence between units should be analyzed, particularly during startup, shutdown, and load following. This could improve the overall thermal efficiency, thereby reducing the coal consumption and capital and operating costs.

Steam Generation - Texaco

Higher steam generation pressures and temperatures within the Texaco unit should be considered. Superheating the steam in the gasification unit rather than with valuable product gas should result in the elimination of byproduct electric power generation, increased efficiency, lower coal consumption, and a reduction in capital costs.

Steam Generation - Combustion Engineering

Consideration should be given to generating the steam at the same pressure and temperature as in the power plant. This would permit the more efficient generation of byproduct power or the integration of the gasifier steam system with the power plant, thus avoiding providing a turbo-generator to produce power. The latter would result in a smaller gasification plant, particularly if there is no need for the excess steam or the power generated therefrom, because over 25 percent of the energy in the coal ends up as byproduct steam. This would reduce both the capital and operating costs of the gasification facility.

Marketing of Byproducts

The sulfur produced at Oswego could be worth more than \$10 million and at Arthur Kill up to \$10 million, depending on the market price of the sulfur and the operating factor of the plant. The location of potential clients, their requirements, and the potential selling price of the sulfur should be investigated for each location.

Cooling Water System

Natural-draft cooling towers were used for Texaco with a 15 F delta increase in the circulating water temperature. The quantity of water circulated is very large. A study of other cooling options should be performed for each site in order to investigate ways to reduce the capital and operating costs of this system.

Boiler Efficiency

The boiler efficiency is reduced about 10 percent when firing low-Btu gas over oil, and about 3 percent when firing medium-Btu gas over oil. This is due primarily to the increase in the flue gas and the inability to recover the low level heat in the air preheater. Boiler studies should be performed by the manufacturer to ascertain the actual efficiency with both low- and medium-Btu gas and the means of increasing the boiler efficiency.

Slag

A study should be made to determine the marketability or disposal costs of slag. The selected coal contains 11.5 percent by weight ash. There is no large source of slag in either area. This material can be used in aggregates, for road or airport subsurfaces, in buildings blocks, or possibly to recover specific elements such as iron. Disposal in an environmentally acceptable manner at a site other than the power plant could be rather expensive.

Power Plant Performance

A study should be made to develop a gas composition most ideally suited for the performance of each boiler. Discussions were held with the boiler manufacturers of both boilers. On the basis of preliminary calculations and previous studies, it was their opinion that both boilers would perform at near-design conditions with medium-Btu gas. The only required modifications would be to the fuel supply system where modifications would have to be made to accommodate the gas feed. Operations and controls would

present no problems, and outage time for maintenances should be less because of the cleaner fuel.

No attempt was made to have the two boiler manufacturers rerate their boilers for low- and medium-Btu gas. However, a brief review on their part did demonstrate the potential benefit of such an investigation.

Modularization of the Gasification System

A study should be prepared to optimize the size and number of gasifiers, the size and number of supporting units and subsystems including the extent of crossovers to increase operating flexibility, as well as the extent of spare standby equipment. The following gasification systems are specified for this Study:

- There are seven parallel trains in the Texaco coal gasification system at Oswego. The number of trains was set, based on the largest size gasifier currently available. When operating at higher gasification pressures, it is possible to reduce the number of trains.
- On the basis of information received from two oxygen plant manufacturers, a 2000-TPD unit is the largest practical size for this type of service.
- To permit greater operating flexibility, complete and independent gasification modules from oxygen plant and coal feed system through acid gas cleanup are used.
- The multimodule concept makes it convenient to prorate to other sizes. For example, for about 70 percent operating capacity, only 5 modules would be required. Four modules are required for Arthur Kill at design capacity and three for the 70-percent option.
- Three modules are required for Combustion Engineering coal gasification on the basis of information supplied by Combustion Engineering. Their tentative standard module corresponds to about 2000 TPD of coal feed. Three full trains were provided from coal preparation through acid gas removal.

Alternative Coal Gasification Processes

An investigation should be made of other gasification processes to the same level as was done for the Texaco medium-Btu gas and Combustion Engineering for low-Btu gas. The selection of these systems does not necessarily represent an endorsement by any of the participants of this Study. They were picked as being

representative of processes that may be applicable to provide gaseous fuel to large power plant steam boilers. Furthermore, they met the basic criteria that they would be commercially available by January 1981 and were suitable for the selected coals.

Texaco expressed an early willingness to work with us and did within very short notice provide us with the basic design data and a cost estimate for the coal selected for the Study.

Combustion Engineering is selected because they expressed a willingness to make a contribution to this project. Additionally, they had previously completed a study of low-Btu gas burning for Arthur Kill Unit 3. This study had shown that low-pressure, low-Btu gas could be burned in Unit 3.

There are other processes that could be used in place of the aforementioned. The Combustion Engineering process can be used to produce low-to-medium-Btu gas. Babcock & Wilcox has a unit similar to the Combustion Engineering unit that can produce low-to-medium-Btu gas. They claim they are ready "to go" commercial immediately. Newer processes under development that should be commercially available in the mid to late 1980s, such as the Westinghouse and Allis-Chalmers systems, may prove to be good economic alternatives, and there are others.

Units such as Lurgi and COGAS, which produce both a gas and a liquid product, may also be considered. The gas could be burned as it is produced, and the liquid products stored for power plant peaking and as emergency fuel.

Sulfur Removal

The Combustion Engineering low-Btu coal gasification system with a Stretford unit for hydrogen sulfide removal may not be able to meet the stringent sulfur oxide emissions required for locations such as New York City. A study should be made to determine the actual percent of the sulfur that is converted to carbonyl sulfide and other organic compounds rather than H₂S. If this is a problem, studies should be made pertaining to the removal or conversion of COS, combustion techniques to minimize COS formation, or the selection of coals that will reduce this problem.

U.S. Department of Energy

**New York State Energy Research
and Development Authority**

**Low/Medium Btu Coal
Gasification Assessment Program
for Specific Sites of Two
New York Utilities**

Volume II Technical and Economic Supplements

December 1980

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Volume IA Executive Summary

Volume IB Technical and Economic Report

Volume II Technical and Economic Supplements

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TECHNICAL AND ECONOMIC SUPPLEMENTS

INTRODUCTION

This volume contains the following supplementary studies, supporting information and backup material for the Technical and Economic Report.

Supplement A - Coal Supply

This supplement outlines the methodology used in the coal supply analysis where coals were identified as to availability, quality, quantity, location, ownership, and cost at the mine.

Supplement B - Coal Transportation

This supplement investigates and identifies modes of transportation, identifies transportation routes, and the cost of transportation on a dollar per ton and dollar per million Btu basis obtained for the coals identified in Supplement A.

The information in Supplements A and B, along with impact on the gasification system costs, comprise the basis for the final coal selection.

Supplement C - Texaco Medium-Btu Gasification System for Oswego

This supplement describes the primary processing units in the Texaco coal gasification system along with those supporting subsystems required to produce a medium-Btu gas product for Niagara Mohawk's Unit No. 6 at Oswego. Coal requirements, supporting utilities, and byproducts are identified. The number of parallel trains with the overall material balances are shown on the tables and figures.

Supplement D - Texaco Medium-Btu Gasification System for Arthur Kill

This supplement describes the differences between the Oswego and Arthur Kill Texaco coal gasification systems and includes the material covered in the Supplement C description.

Supplement E - Combustion Engineering Low-Btu Gasification System for Arthur Kill

This supplement describes the primary processing units in the Combustion Engineering coal gasification system along with those supporting systems required to produce a low-Btu gas for use at Consolidated Edison's Unit 3 at Arthur Kill. The coal requirements, supporting utilities, byproduct ash, sulfur and

electricity and the properties of product gas are described. The number of parallel trains with overall material balances are shown on the tables and figures.

Supplement F - Low-Btu Gas Storage for Arthur Kill

This supplement investigates various gas storage options and the costs of these options.

Supplement G - Low-Btu Gas Transport for Oswego

This supplement investigates the extent and cost of gas compression and the cost of gas transmission to supply Unit No. 6 at Oswego with low-Btu gas.

Supplement H - Medium-Btu Gas Transport for Oswego

This supplement investigates the potential of high and low pressure gas transport from the gasification facility to the power plant.

Supplement I - Power Plant Retrofit

This supplement reviews the general effects of switching to low- or medium-Btu gas firing in boilers designed to burn coal or oil, and how it may impact on the boiler operation, efficiency and rating.

Supplement J - Concept of Levelized Costs

This supplement reviews the concept of levelized costs and includes an illustrative sample.

Supplement K - Required Revenues for Alternative Gasifiers, for Synthetic Gas-fired Power Plant, and for Continued Oil-Fired Power Plant Operation

This supplement contains the tables for the various options considered in the economic evaluation.

Supplement A

COAL SUPPLY

Coal is a heterogeneous material containing combustible organic matter, ash-forming mineral matter, and moisture. Several types of coals are available in the United States. Coal reserves are subdivided into several coal-producing regions based on their geographic locations. Different types of coals from several coal-producing regions are selected in this Study for an evaluation of their delivered costs to the coal gasification plant site and their economic impact on the plant design. The methodology used in securing data on coal sources and coal costs is discussed in the following paragraphs.

CLASSIFICATION OF COALS

The classification of coals by the American Society for Testing and Materials (ASTM) ranking system is shown in Table A-1. Coals are classified by rank according to their percentages of fixed carbon and volatile matter and by calorific value. The system of coal ranking generally accepted is the ASTM rank classification based on the degree of metamorphism of the parent plant material.

Fixed carbon content and calorific value, calculated on a moisture-free, mineral-matter-free basis, are the standard criteria for ranking by the ASTM method. Agglomerating characteristics and percentage volatility are also considered. Coals that have a heating value of 14,000 Btu/lb or more on a moist basis or coals that contain 69 percent or more fixed carbon on a dry basis are all ranked by fixed carbon, regardless of their heating value. All other coals--those with less than 14,000 Btu/lb and those containing less than 69 percent fixed carbon--are ranked by calorific value on a moist basis.

COAL FIELDS AND COAL SUPPLY REGIONS

The Coal Fields of the United States and the Coal Fields and Coal Supply Regions are shown on Figure A-1. Approximately half of the nation's coal reserves are located west of the Mississippi River. The demonstrated coal reserve base of the U.S. by mining method and sulfur content is shown in Table A-2.

Six potential coal sources in Pennsylvania, West Virginia, and Wyoming that are able to meet the projected coal demands of the coal gasification plants at Oswego and Staten Island are identified. The investigation of the location and potential of coal sources, existing mines, their available uncommitted capacities, and undeveloped coal resources is based on in-house information, contacts with major coal companies, and published

data. The preliminary data on coals from various coal sources are shown in Table A-3. Bituminous and anthracite coal sources are selected from the Appalachian region because of their proximity to the plant sites. A source of subbituminous coal is selected from the Powder River Basin for a study of the economic feasibility of using western coals from the Northern Great Plains region.

The identified coal sources are listed below (preliminary information such as their proximate analysis, transportation, and delivered cost is indicated on the Coal Selection Information Matrices, Tables A-4 and A-5):

- Stockton and Coalburg Seams, Boone County, West Virginia
- Compass and Mars Mines, Harrison County, West Virginia
- Dent's Run Mine, Marion County, West Virginia
- Buckskin Mine, Powder River Basin, Wyoming
- Northeastern Anthracite Fields, Wilkes-Barre, Pennsylvania, and South Anthracite Fields, Hazelton, Pennsylvania

Stockton and Coalburg Seams, Boone County, West Virginia

Bituminous coals from the Stockton and Coalburg seams in Boone County, West Virginia, are utility grade coals. Typical proximate analyses of coals from these seams are given below:

	<u>Volatile Matter</u>	<u>Fixed Carbon</u>	<u>Ash</u>	<u>Sulfur</u>	<u>Btu/lb</u>
Median	36	54	6	0.8	13,600
90-% limits	32-40	48-59	3-12	0.6-1.8	12,000 to 14,500

Source: 1978 Keystone Coal Industry Manual.

Eastern Associated Coal Corporation owns and operates six mines in this region, producing approximately 3-1/2 million tons of coal per year. One of the six mines will be upgraded from 1/2 million tons per year to 1-1/2 million tons per year by 1982. A seventh mine will be added in the next 3 to 5 years, producing an additional one million tons per year. Proven coal reserves are estimated at 55 million tons; however, 10 million tons of

coal have been committed as of April 1980. The mined coal is sized to 2 in. x 0 and washed. A typical coal sample from the Wells Plant contains approximately 6.5 percent moisture, 8 percent ash, 1 percent sulfur, and 13,100 Btu/lb. The 1979 market price for this coal is \$38.00 per net ton, FOB mine.

Compass and Mars Mines, Harrison County, West Virginia

Pittsburgh seam coals from Harrison County, West Virginia, are utility and coking grade coals. Typical proximate analyses of coals from this seam are given below:

	<u>Volatile Matter</u>	<u>Fixed Carbon</u>	<u>Ash</u>	<u>Sulfur</u>	<u>Btu/lb</u>
Median	37	53	7	2.2	13,800
90-% limits	34-43	45-57	4-9	0.6-4.0	12,900 to 14,300

Source: 1978 Keystone Coal Industry Manual.

Pittston Coal Sales Corporation owns the Compass and Mars Mines in Harrison County, West Virginia. The 1979 coal production from these mines was 323,000 tons. Their projected coal production in 1980 from these mines is 418,000 tons. The recoverable coal reserve is estimated at 56 million tons on a clean coal basis. A typical coal sample from these mines, sized to 2 in. x 0 and unwashed, contains approximately 4.5 percent moisture, 11.5 percent ash, 3.9 percent sulfur, and 12,500 Btu/lb. The 1979 market price of this coal is \$25.00 per net ton, FOB mine.

Dent's Run Mine, Marion County, West Virginia

Pittsburgh seam coals in Marion County, West Virginia, are utility and coking grade coals, as discussed earlier. Dent's Run Mine, owned by the Consolidation Coal Company, is expected to go into operation in 1982. The estimated coal reserves are 100 million tons. In addition, the Consolidation Coal Company owns other large blocks of property with total estimated coal reserves of over 1 billion tons. The mined coal is sized to 2 in. x 0 and washed. A typical sample contains approximately 4 percent moisture, 6.9 percent ash, 3.2 percent sulfur, and 13,400 Btu/lb. The 1979 market price for this coal is \$31.00 per net ton, FOB mine.

Buckskin Mine, Powder River Basin, Wyoming

The Gillette region is one of the three major coal-producing regions of western coal and is located in the Powder River Basin of the northeastern Wyoming. The total western coal production is approximately 80 million tons per year. The estimated coal reserves in Montana and Wyoming are over 60 billion tons. A typical coal sample from the Buckskin Mine, owned by the Shell Oil Company, contains approximately 29 percent moisture, 6 percent ash, 0.5 percent sulfur, and 8214 Btu/lb. The 1979 market price for this coal is \$9.00 per net ton, FOB mine.

Northeastern Anthracite Fields, Wilkes-Barre and Hazelton, Pennsylvania

Anthracite coal fields of Pennsylvania are subdivided into four major regions--Northern, Southern, Western Middle, and Eastern Middle. Each region contains several seams. Current annual production from all anthracite mines in Pennsylvania is about 5 to 6 million tons. The total estimated anthracite coal reserves in Pennsylvania are 16 billion tons, of which approximately 7-1/2 to 8 billion tons are recoverable. Lehigh Valley Coal Sales Company owns several large blocks of property in this region. A typical prime quality anthracite coal from this region contains approximately 1 percent moisture, 10 percent ash, 0.7 percent sulfur, 13,500 Btu/lb. The 1979 market price of prime quality anthracite coal is \$45.00 per net ton, FOB mine. A mixture of prime quality anthracite coal and refuse, containing approximately 1 percent moisture, 20 percent ash, 0.7 percent sulfur, and 11,500 Btu/lb costs \$30.00 per net ton, FOB mine based on 1979 market price.

FOREIGN COAL SOURCES

Foreign coal sources are not considered in this Study because the purpose of this Study is to lessen our dependency on foreign fuel sources.

SUMMARY

The delivered coal cost for each potential coal is shown in Tables A-4 and A-5 Coal Selection Information Matrices. This investigation indicates that the first five coal sources have adequate uncommitted capacities and undeveloped coal resources. In addition, similar coals from other regions are available at a comparable price. The availability of the mixture of prime quality anthracite coal and refuse from Hazelton, Pennsylvania, is uncertain; hence, this source cannot be considered viable. The least costly coal, based on the delivered cost per million

Btu, is the bituminous coal from Compass and Mars Mines, Harrison County, West Virginia.

TABLE A-1
CLASSIFICATION OF COALS BY ASTM RANKING

CLASS	GROUP	FIXED CARBON LIMITS, PERCENT (DRY, MINERAL- MATTER-FREE BASIS)		VOLATILE MATTER LIMITS, PERCENT (DRY MINERAL- MATTER-FREE BASIS)		CALORIFIC VALUE LIMITS, BTU/LB (MOIST, MINERAL- MATTER-FREE BASIS)		AGGLOMERATING CHARACTER
		EQUAL TO OR GREATER THAN		EQUAL TO OR LESS THAN		EQUAL TO OR GREATER THAN		
			LESS THAN	GREATER THAN	LESS THAN		LESS THAN	
I. ANTHRACITE	1. META-ANTHRACITE	98	--	--	2	--	--	} NONAGGLOMERATING
	2. ANTHRACITE	92	98	2	8	--	--	
	3. SEMIANTHRACITE	86	92	8	14	--	--	
II. BITUMINOUS	1. LOW VOLATILE BITUMINOUS COAL	78	86	14	22	--	--	} COMMONLY AGGLOMERATING
	2. MEDIUM VOLATILE BITUMINOUS COAL	69	78	22	31	--	--	
	3. HIGH VOLATILE A BITUMINOUS COAL	--	69	31	--	14,000	--	
	4. HIGH VOLATILE B BITUMINOUS COAL	--	--	--	--	13,000	14,000	} AGGLOMERATING
	5. HIGH VOLATILE C BITUMINOUS COAL	--	--	--	--	10,500	11,500	
	III. SUBBITUMINOUS	1. SUBBITUMINOUS A COAL	--	--	--	--	10,500	11,500
2. SUBBITUMINOUS B COAL		--	--	--	--	9,500	10,500	
3. SUBBITUMINOUS C COAL		--	--	--	--	8,300	9,500	
IV. LIGNITE	1. LIGNITE A	--	--	--	--	6,300	8,300	} NONAGGLOMERATING
	2. LIGNITE B	--	--	--	--	--	6,300	

SOURCE: ASTM D 388.

TABLE A-2
DEMONSTRATED RESERVE BASE OF COALS
BY MINING METHOD AND SULFUR CONTENT
(MILLIONS OF TONS)

REGION	SULFUR CONTENT, WEIGHT PERCENT									
	LESS THAN 1.0		1.1 TO 3.0		GREATER THAN 3.0		UNKNOWN		TOTAL	
	UNDER- GROUND	SURFACE	UNDER- GROUND	SURFACE	UNDER- GROUND	SURFACE	UNDER- GROUND	SURFACE	UNDER- GROUND	SURFACE
1. NEW ENGLAND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2. NEW YORK/NEW JERSEY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3. MIDDLE ATLANTIC	20,101.9	9,564.3	90,947.9	2,425.9	10,904.2	520.2	7,248.0	680.4	67,999.4	7,190.8
4. SOUTH ATLANTIC	5,771.8	1,816.8	4,254.6	1,954.1	7,555.3	2,161.1	9,182.7	9,721.8	20,764.2	8,853.8
5. MIDWEST	1,598.9	184.6	14,129.8	9,049.7	48,192.9	12,753.6	16,072.0	1,567.3	79,993.0	17,549.2
6. SOUTHWEST	2,092.3	2,499.3	762.8	2,705.2	292.6	940.0	310.9	685.1	9,998.6	6,229.6
7. CENTRAL	1.6	0.0	360.9	357.1	5,696.1	2,331.4	2,899.7	2,113.2	8,958.3	4,801.7
8. NORTH CENTRAL	92,851.0	57,644.0	8,512.5	23,206.6	1,785.9	819.1	9,962.7	2,306.0	113,112.1	83,975.7
9. WEST	0.0	173.2	0.0	176.7	0.0	0.0	0.0	0.0	0.0	349.9
10. NORTHWEST	432.0	173.0	957.7	308.0	13.4	25.8	42.9	2.2	1,446.0	509.0
TOTALS	122,848.1	85,855.2	59,926.2	39,577.9	73,720.4	18,951.2	39,716.8	11,076.0	295,611.6	129,459.7

SOURCE: U.S. DEPARTMENT OF THE INTERIOR, 1977A. MINERALS YEARBOOK 1975, VOLUME 1: METALS, MINERALS, AND FUELS.
BUREAU OF MINES, WASHINGTON, D.C.

TABLE A-3
(SHEET 1 OF 2)

PRELIMINARY COAL DATA

COMPANY	SOURCE	PROXIMATE ANALYSIS		PREPARATION	ESTIMATED COAL RESERVE (MILLION TONS)	COST FOB MINE- (\$/TON)	REMARKS
CONSOLIDATED COAL CO.	1. WESTLAND - 11 MINE, PITTSBURG SEAM, WASHINGTON COUNTY, PA.	MOISTURE - 6%	FUSION TEMP. - 2160 F (INITIAL)	SIZE 2 IN. X O, WASHED, HEAT DRIED.	80	34.00	MINE WILL BE DEVELOPED IN 2 YEARS. NO LONG COMMITMENT.
	2. DENT'S RUN MINE, PITTSBURG SEAM, MARION COUNTY W. VA.	ASH - 8% SULFUR - 2% V.M. - 35.7% F.C. - 50.3% BTU/LB - 12,700	FUSION TEMP. - 2360 F (H = W) - 2370 F (H = 1/2 W) - 2450 F (FLUID) GRINDABILITY - 58	SIZE 2 IN. X O, WASHED, HEAT DRIED	100; ADDITIONAL COAL RESERVE TONS	31.00	MINE WILL GO INTO PRODUCTION IN 1982. NO PRESENT TERM CONTRACT
PITTSBURG COAL SALES CORP.	1. COMPASS/MARS MINES, HARRISON COUNTY, W. VA.	MOISTURE - 4.5% ASH - 11.5% SULFUR - 3.9% V.M. - 38% F.C. - 46%	BTU/LBS - 12,900 FUSION TEMP - 2150 F (H = W)	SIZE 2 IN. X O, UNWASHED	58	25.00	NO LONG-TERM CONTRACT
	2. BADGER MINE, BARBOUR COUNTY, W. VA.	MOISTURE - 4.7% ASH - 7.3% SULFUR - 0.9% V.M. - 32.4% F.C. - 55.6%	BTU/LB - 19,000 FUSION TEMP. - 2800 F (H = W)	SIZE 1-1/4 IN. X O, WASHED.	129	45.00	NO LONG-TERM CONTRACT AFTER MARCH 1981
	3. SEWELL MINE, NICHOLAS COUNTY, W. VA.	MOISTURE - 6% ASH - 8.1% SULFUR - 0.7% V.M. - 27.8% F.C. - 60.1%	BTU/LB - 13,500 FUSION TEMP. - 2785 F (H = W)	SIZE 1-1/4 IN. X O, WASHED.	31	50.00	NO LONG-TERM CONTRACT AFTER MARCH 1981
	4. WIDEN MINE, CLAY COUNTY, W. VA.	MOISTURE - 5% ASH - 8-10% SULFUR - 0.8-1% V.M. - 32-33% F.C. - 52-55%	BTU/LB - 12,500 FUSION TEMP - 2800 F (H = W)	SIZE 1-1/4 IN. X O, WASHED.	65	35.00	LONG-TERM CONTRACT FOR 17 MILLION TONS. BALANCE COAL RESERVE 48 MILLION TONS

TABLE A-3
(SHEET 2 OF 2)
PRELIMINARY COAL DATA

COMPANY	SOURCE	PROXIMATE ANALYSIS		PREPARATION	ESTIMATED COAL RESERVE (MILLION TONS)	COST FOB MINE- (\$/TON)	REMARKS
EASTERN ASSOCIATED COAL CORP.	1. STOCKTON & COALBURG SEAMS, WELLS PREP. PLANT BOONE COUNTY, W. VA.	MOISTURE - 6.5%	BTU/LB - 13,100-13,400	SIZE 2 IN. X 0, WASHED.	55	98.00	NO LONG-TERM CONTRACT PRESENTLY 6 OPERATIONS.
	2. NO. 5 BLOCK STOCKTON & COALBURG SEAMS, BOONE COUNTY, W. VA.	ASH - 8-8% SULFUR - 1% V.M. - 32-34% F.C. - 51.5-55.5%	FUSION TEMP. - 2730 F GRINDABILITY - 53	SIZE 2 IN. X 0, WASHED.	NOT AVAILABLE	95.00-36.00	MINE NOT YET DEVELOPED. EXPECTED PRODUCTION 1 MILLION TONS/YR.
SHELL OIL CO. (SOURCE: BURLINGTON NORTHERN)	BUCKSKIN MINE, WYOMING	MOISTURE - 29% ASH - 6% SULFUR - 0.5% V.M. - 32% F.C. - 33%	BTU/LB - 8214 FUSION TEMP. - 2240 F (REDUCING) 2276 F (OXIDIZING) GRINDABILITY - 62.7	SIZE 2 IN. X 0, UNWASHED	TOTAL IN WYOMING AND MONTANA	7.00-9.00	
LENIGH VALLEY COAL SALES CO.	1. MILKES-BARRE, PA.	MOISTURE - 1% ASH - 10% SULFUR - 0.7% V.M. - 5% F.C. - 84%	BTU/LB - 13,500 FUSION TEMP. - 2900 F GRINDABILITY - 34	SIZE 2 IN. X 0, WASHED	7500-8000-RECOVERABLE FROM ALL PA. MINES	45.00	TOTAL PRODUCTION FROM ALL PA. MINES IS ABOUT 5 MILLION TONS.
	2. HAZELTON, PA.	MOISTURE - 1% ASH - 20% SULFUR - 0.7% V.M. - 5% F.C. - 74%	FUSION TEMP. - 2900 F GRINDABILITY - 32-34	MOSTLY FINES AND REFUSE	NOT AVAILABLE	30.00	

V.M. = VOLATILE MATTER
F.C. = FIXED CARBON

TABLE A-4

COAL GASIFICATION PROJECT—OSWEGO PLANT SELECTION INFORMATION MATRIX

COAL TYPE	LOCATION SEAM	PROXIMATE COAL ANALYSIS (BY WEIGHT)	TRANSPORTATION	DISTANCE BETWEEN MINE AND PLANT SITE (RAIL MILES)	COAL COST FOB MINE \$/TON	TRANSPORTATION COST \$/TON	TOTAL DELIVERED COST 1979 DOLLARS/TON	DOLLARS/MMBTU	REMARKS
BITUMINOUS	BOONE COUNTY, WEST VIRGINIA (SOURCE—EASTERN ASSOCIATED COAL CORP.)	MOISTURE - 6.5% ASH - 6% SULFUR - 1% VOLATILE - 34% MATTER CARBON - 51.5% BTU/LB. - 13100 FUSION TEMP. - 2730 °F GRINDABILITY - 53	CHESSIE SYSTEM AND CONRAIL VIA CHARLESTON, COLUMBUS, TOLEDO, BUFFALO & SYRACUSE	850 (APPROX) UNIT TRAINS	38.00 (QUOTE)	16.5 (ESTIMATED @ \$0.019/TON MILE BASED ON CHESSIE QUOTE)	54.15	2.07	7000-10000 TON UNIT TRAINS ESTIMATED COAL RESERVE = 55 MILLION TONS. CONTRACT FOR 10 MILLION TONS COAL AFTER APRIL 1980
BITUMINOUS	COMPASS & MARS HARRISON COUNTY W. VIRGINIA (SOURCE: PITTSBURGH COAL SALES CORP.)	MOISTURE - 4.5% ASH - 11.5% SULFUR - 3.9% VOLATILE - 38% MATTER CARBON - 46% BTU/LB. - 12,900 FUSION TEMP. - 2150 °F GRINDABILITY - 58	CHESSIE SYSTEM AND CONRAIL VIA CLEARFIELD, BUFFALO AND SYRACUSE	640 (APPROX)	25.00 (QUOTE)	12.16 (SOURCE: CHESSIE SYSTEM)	37.16	1.44	7000-10000 TON UNIT TRAINS ESTIMATED COAL RESERVE = 56 MILLION TONS NO LONG TERM CONTRACT AT PRESENT.
BITUMINOUS	DENT'S RUN MINE PITTSBURGH SEAM MARION COUNTY, W. VA. (SOURCE: CONSOLIDATION COAL CO.)	MOISTURE - 4% ASH - 6.9% SULFUR - 3.2% VOLATILE - 37% MATTER CARBON - 52.1% BTU/LB. - 13,400 FUSION TEMP. - 2260 °F GRINDABILITY - 62	CHESSIE SYSTEM AND CONRAIL VIA CLEARFIELD, BUFFALO AND SYRACUSE	640 (APPROX)	31.00 (QUOTE)	12.16 (SOURCE: CHESSIE SYST.)	43.16	1.61	7000-10000 TON UNIT TRAINS ESTIMATED COAL RESERVE = 100 MILLION TONS NOT YET COMMITTED. ADDITIONAL COAL RESERVE OVER 1 BILLION TONS
SUB-BITUMINOUS	BUCKSKIN MINE, WYOMING (SOURCE: BURLINGTON NORTHERN INC.)	MOISTURE - 29% ASH - 6% SULFUR - 0.5% VOLATILE - 32% MATTER CARBON - 33% BTU/LB. - 8214 FUSION TEMP. - 2240 °F GRINDABILITY - 62.7	BURLINGTON—NORTHERN TO SUPERIOR, MN. FROM SUPERIOR TO OSWEGO BY LAKE VESSELS ALTERNATE: B-N TO CHICAGO, THENCE CONRAIL TO OSWEGO VIA SYRACUSE	BY RAIL - 1100 BY LAKE - 1150 TOTAL - 2250	9.00 (QUOTE) 9.00 (QUOTE)	RAIL \$12.50 LAKE \$9.26 TOTAL \$21.76 (ESTIMATED RAIL TRANS. COST @ \$0.019/TON—MILE BASED ON CHESSIE QUOTE) 36.10 (ESTIMATED @ \$0.019 PER TON-MILE BASED ON CHESSIE SYSTEM QUOTE)	30.76 45.10	1.87 2.75	7000-10000 TON UNIT TRAINS PROPOSED ROUTE OPEN 280 DAYS/YEAR ALTERNATE ALL—RAIL ROUTE OPEN YEAR-ROUND. ESTIMATED COAL RESERVE = 60 BILLION TONS
ANTHRACITE	WILKES-BARRE, PA (SOURCE—LEHIGH VALLEY COAL SALES CO.)	MOISTURE - 1% ASH - 10% SULFUR - 0.7% VOLATILE - 5% MATTER FIXED CARBON - 84% BTU/LB. - 13500 FUSION TEMP. - 2900 °F GRINDABILITY - 34	CONRAIL TO OSWEGO	175 (APPROX)	45.00 (QUOTE)	3.33 (ESTIMATED @ \$0.019/TON-MILE BASED ON CHESSIE QUOTE)	48.33	1.79	7000-10000 TON UNIT TRAINS 7 1/2-8 BILLION TON TOTAL RECOVERABLE COAL CURRENT COAL PRODUCTION 5 MILLION TONS PER YEAR
ANTHRACITE	HAZELTON, PA (SOURCE—LEHIGH VALLEY COAL SALES CO.)	MOISTURE - 1% ASH - 20% SULFUR - 0.7% VOLATILE - 5% MATTER FIXED CARBON - 74% BTU/LB. - 11500 FUSION TEMP. - 2900 °F GRINDABILITY - 32-34	CONRAIL TO OSWEGO	225 (APPROX)	30.00 (QUOTE)	4.28 (ESTIMATED @ \$0.019/TON MILE BASED ON CHESSIE QUOTE.)	34.28	1.49	7000-10000 TON UNIT TRAINS 7 1/2-8 BILLION TON TOTAL RECOVERABLE COAL CURRENT COAL PRODUCTION 5 MILLION TONS PER YEAR

TABLE A-5

COAL GASIFICATION PROJECT—ARTHUR KILL STATION, STATEN ISLAND **SELECTION INFORMATION MATRIX**

COAL TYPE	LOCATION SEAM	PROXIMATE COAL ANALYSIS (BY WEIGHT)	TRANSPORTATION	DISTANCE BETWEEN MINE AND PLANT SITE (RAIL MILES)	COAL COST FOB MINE \$/TON	TRANSPORTATION COST \$/TON	TOTAL DELIVERED COST 1979 DOLLARS/TON	DOLLARS/MMBTU	REMARKS
BITUMINOUS	BOONE COUNTY, W. VIRGINIA (SOURCE: EASTERN ASSOCIATED COAL CORP.)	MOISTURE - 6.5% ASH - 8% SULFUR - 1% VOLATILE - 34% MATTER CARBON - 51.5% BTU/LB. - 13100 FUSION TEMP. - 2730°F GRINDABILITY - 53	CHESSIE SYSTEM TO PHILADELPHIA VIA WASHINGTON, BALTIMORE, THENCE CONRAIL TO PORT READING TO PLANT BY BARGE.	700 (APPROX)	38.0 (QUOTE)	RAIL = 15.60 (QUOTE) BARGE = 1.25 TOTAL = 16.85 (BARGE RATES ESTIMATED—REF. ICF REPORT)	54.85	2.09	7000-10000 TON UNIT TRAINS ESTIMATED COAL RESERVE = 55 MILLION TONS CONTRACT FOR 10 MILLION TONS COAL AFTER APRIL 1980
BITUMINOUS	COMPASS & MARS, HARRISON COUNTY, W. VIRGINIA (SOURCE: PITTSBURGH COAL SALES CORP.)	MOISTURE - 4.5% ASH - 11.5% SULFUR - 3.9% VOLATILE - 38% MATTER CARBON - 46% BTU/LB. - 12,900 FUSION TEMP. - 2150°F GRINDABILITY - 58	CHESSIE SYSTEM TO SHIPPENSBURG, PA., THENCE BY CONRAIL TO PORT READING TO PLANT BY BARGE.	700 (APPROX)	25.00 (QUOTE)	RAIL = 15.60 (QUOTE) BARGE = 1.25 TOTAL = 16.85 (BARGE RATES ESTIMATED—REF. ICF REPORT)	41.85	1.62	7000-10000 TON UNIT TRAINS ESTIMATED COAL RESERVE = 56 MILLION TONS NO LONG TERM CONTRACT AT PRESENT
BITUMINOUS	DENT'S RUN MINE PITTSBURGH SEAM MARION COUNTY, W. VA (SOURCE: CONSOLIDATION COAL CO.)	MOISTURE - 4% ASH - 6.9% SULFUR - 3.2% VOLATILE - 37% MATTER CARBON - 52.1% BTU/LB. - 13,400 FUSION TEMP. - 2260°F GRINDABILITY - 62	CHESSIE SYSTEM TO SHIPPENSBURG, PA., THENCE BY CONRAIL TO PORT READING TO PLANT BY BARGE	700 (APPROX)	31 (QUOTE)	RAIL = 15.60 (QUOTE) BARGE = 1.25 TOTAL = 16.85 (BARGE RATES ESTIMATED—REF. ICF REPORT)	47.85	1.79	7000-10000 TON UNIT TRAINS ESTIMATED COAL RESERVE = 100 MILLION TONS NOT YET COMMITTED ADDITIONAL COAL RESERVE OVER 1 BILLION TONS
SUB-BITUMINOUS	BUCKSKIN MINE, WYOMING (SOURCE: BURLINGTON—NORTHERN INC.)	MOISTURE - 29% ASH - 6% SULFUR - 0.54% VOLATILE - 32% MATTER CARBON - 33% BTU/LB. - 8214 FUSION TEMP. - 2240°F GRINDABILITY - 62.7	BURLINGTON—NORTHERN TO CHICAGO, THENCE CONRAIL TO PORT READING VIA PITTSBURGH & HARRISBURG, PORT READING TO PLANT BY BARGE	1900 (APPROX)	9.00 (QUOTE)	RAIL = \$36.10 (ESTIMATED @ \$0.019/TON-MILE) BARGE = \$1.25 (REF. ICF REPORT) TOTAL = \$37.35	46.35	2.82	7000-10000 TON UNIT TRAINS ESTIMATED COAL RESERVE = 60 BILLION TONS
ANTHRACITE	WILKES-BARRE, PA (SOURCE: LEHIGH VALLEY COAL SALES CO)	MOISTURE - 1% ASH - 10% SULFUR - 0.7% VOLATILE - 5% MATTER FIXED CARBON - 84% BTU/LB. - 13500 FUSION TEMP. - 2900°F GRINDABILITY - 34	CONRAIL TO PORT READING THENCE BY BARGE TO PLANT	150 (APPROX)	45.00 (QUOTE)	RAIL = 2.85 BARGE = 1.25 TOTAL = 4.10 (ESTIMATED RAIL TRANS. COST @ \$0.019/MILE-TON BASED ON CHESSIE QUOTE) (BARGE RATE ESTIMATED—REF. ICF REPORT)	49.10	1.82	7000-10000 TON UNIT TRAINS 7 1/2-8 BILLION TON TOTAL RECOVERABLE COAL CURRENT COAL PRODUCTION 5 MILLION TONS PER YEAR
ANTHRACITE	HAZELTON, PA (SOURCE: LEHIGH VALLEY COAL SALES CO)	MOISTURE - 1% ASH - 20% SULFUR - 0.7% VOLATILE - 5% MATTER FIXED CARBON - 74% BTU/LB. - 11500 FUSION TEMP. - 2900°F GRINDABILITY - 32-34	CONRAIL TO PORT READING THENCE BY BARGE TO PLANT	125 (APPROX)	30.00 (QUOTE)	RAIL = 2.38 BARGE = 1.25 TOTAL = 3.63 (ESTIMATED RAIL TRANS. COST @ \$0.019/MILE-TON BASED ON CHESSIE QUOTE) (BARGE RATE ESTIMATED—REF. ICF REPORT)	33.63	1.46	7000-10000 TON UNIT TRAINS 7 1/2-8 BILLION TON TOTAL RECOVERABLE COAL CURRENT COAL PRODUCTION 5 MILLION TONS PER YEAR

KEYSTONE'S MAP OF THE COAL FIELDS OF THE UNITED STATES

A-12

FIGURE A-1
COAL FIELDS OF THE UNITED STATES

Supplement B

COAL TRANSPORTATION

Coal is transported by several modes; however, only the two major modes--railroads and waterways--are analyzed in this Study. This Study also includes a discussion of factors affecting these modes of transportation, the methodology used in securing data, transportation routes, and costs.

COAL TRANSPORTATION BY RAIL

Coal is transported by rail in four different ways: (1) by single-car movements, (2) by multiple-car movements, (3) by trainload movements, and (4) by unit trains. Each has different operational characteristics and freight rates reflecting specific conditions. Inasmuch as the terminology is not always consistent, the following explanations, quoted from ICC Ex Parte No. 270 (5-1), are adhered to:

Single-Car Rate

A single-car rate is the one that is published based on tonnage requiring the use of only one car. This tonnage is usually 100 tons or less and is frequently based on the marked capacity of the car.

Multiple-Car Rate

Multiple-car rate is based on a sufficient tonnage to require the use of two or more cars moving from one point of origin to one point of destination at one time. A frequently maintained condition for multiple car rates is 1500 tons.

Trainload Rate

A trainload rate is a rate that is published based on sufficient tonnage to make up an entire train, usually 5000 tons or more.

Unit Train Rate

A unit train rate is the one that is published to apply to traffic moving in a sufficient set number of railroad cars and a given number of locomotives dedicated to one unit train, moving in continuously scheduled cycles between one point of loading and one point of unloading.

The combination of dedicated equipment, scheduled operation, absence of switching enroute, and quick turnaround significantly improves the operational efficiency of unit train operation.

This advantage is particularly important during times of shortage of capital and critical materials. High productivity is reflected in unit train rates, as these are the lowest available.

The increase in coal demand would increase the unit train operations. The capability of the railroads to meet this increased demand is determined by two major factors:

- The system capacity includes factors such as rights-of-way, railroad equipment (freight cars and locomotives), and railroad plants.
- The financial capability of the industry to secure the investments required to expand its system capacity.

System Capacity

The system capacity means the volume of traffic that is moved without undue delay because of congestion. Capacity is a function of the type and condition of the right-of-way available, equipment availability, and operating conditions.

The right-of-way is an estimate of the amount of commodity that can be transported. The amount depends upon variable elements such as miles of railroad lines, number of tracks per line, the length and spacing of sidings to permit the passing of trains on the same single track line, the type of signaling system and train control, and the track condition. It is also affected by the distribution of the traffic load. When the traffic volume is fairly even, it moves easily and when the traffic volume alternately peaks and drops off, it causes traffic jams. The condition of the rail tracks dictates the type of equipment and the loads that can be hauled, thus influencing the capacity and train speeds. Increase in coal traffic may require upgrading of rails by laying heavier rail sections, drainage, ballasts, and ties to endure the heavier weight of coal trains. Other means of increasing capacity and reducing potential bottlenecks in coal traffic include double tracking of existing single-track lines, alternating single-track and double-track lines, increasing the length and frequency of passing sidings, and upgrading traffic control systems. Based on ICF Incorporated report dated June 1979 on the analysis of New York State coal supply, demand, and price, 1979 to 1994, coal tonnages projected through 1994 can probably be handled by rail, regardless of the final route selection. Improvements in the rail system capacities on some coal-carrying routes, such as Youngstown-Ashtabula and 12-mile trackage south of Selkirk, may be required. However, the projected tonnages are not likely to create a hopeless situation in the long run, because adequate time for trackage improvement and alternate routing is generally available. The Chessie System and Conrail 7000- to 10,000-ton unit train operation is feasible

to meet the projected coal demand for Oswego and Staten Island Plants.

The equipment needs depend upon the ton-miles of freight movements, and the turnaround time per trip. Increased coal traffic would increase the requirements of equipment such as freight cars and locomotives. The freight cars are available in various sizes; however, commonly used rail cars for unit train operation are 70- to 100-ton capacity. Current capacity to manufacture freight cars is approximately 80,000 per year. Assuming that the freight cars are replaced at an annual rate of 4 percent, the replacement of the freight car fleet would require a production rate of 53,200 cars per year, based on a U.S. Department of Interior 1979 study. A sudden increase in coal demand or an unexpected increase in the rate of replacement of freight car fleet can cause a temporary shortage of railcars. The American Association of Railroads estimates the current fleet size of locomotives at 27,800 as of December 31, 1978. The new units are manufactured at an estimated rate of 1700 units per year, out of which, 200 to 300 units are exported annually. Thus, the manufacturing capacity will have to be expanded 15 to 20 percent per year over the next decade to meet the railroad industry's total requirement (ICC Ex Parte No. 347).

Financial Capability

The financial capability of the railroad industry should be viewed in terms of its total investment required to provide transportation services in terms of rolling stock trackage, and other railroad facilities. Various estimates of railroad industry's future investment needs have been made in recent studies. These estimates have ranged from 4 to 5 billion dollars required through 1985 for increased coal traffic (U.S. Department of Transportation, 1978) to between 50 to 150 billion dollars for the railroad industry as a whole through the year 2000 (National Policy Study Commission, 1979). The financial status of individual railroads varies, but the industry's current financial position is anemic. The shortage of funds lead to deferment of road maintenance and delay in equipment purchase. The ownership of railcars by shipper or the consignee or both may be a stabilizing factor in coal-car availability and also benefits the railroads in conserving their limited revenues.

COAL TRANSPORTATION BY WATERWAYS

Water transportation along the inland waterways and the Great Lakes is the least expensive way to transport coal because of the following:

- Water transportation has a low labor content when compared with rails, trucks, and even conveyors.
- Water carriers do not have to supply or maintain their "right-of-way". All safety and navigation aids, locks, dams, and channel maintenance are government provided and maintained by the Corps of Engineers at no cost to the users.
- Water carriers are largely nonregulated and enjoy a large degree of freedom in rate making.

The annual capacity of the waterway system is a function of mileage, water depth, and lock size. Lock size is the primary limiting factor, affecting the size of the lake vessel and the barge tow; it can also produce a delay each time a lock is negotiated.

The transportation of coal via the Great Lakes is done mostly by lake vessels. The locks of the Welland Canal are the smallest and limit the maximum size of the lake vessels to 730 feet long and 75 feet wide (capacity 35,000 tons approximately). The lake vessels are of two types, self-unloading and gearless (Bulkers). The self-unloading type holds about 2000 tons less than the same size of the gearless type, but it has several advantages over the gearless type, such as:

- No shore-unloading equipment
- Faster discharge
- Improved dispatch capabilities

Because of these advantages, the self-unloading vessels are more economical in the long run.

Cold weather also has an impact on the coal transportation via the Great Lakes. The navigational season for the Welland Canal is 280 days per year. For a year-round operation of the plant, either a backup rail transportation is required for the remainder of the year, or an additional 3-month coal storage is required over and above the normal plant coal storage at or near the plant.

The lake vessels are expensive (over 30 million dollars each) and are generally leased on a long-term basis. On the basis of discussions with the American Steam Ship Company, it was determined that the company's available capacity is not adequate to handle additional shipments of coal at present. An estimate by the American Steam Ship Company shows a need for 5 or 6 new self-unloading vessels to meet the projected coal demand of Oswego Plant. Approximate lead time for the delivery of new vessels is 3 years.

Coal transportation via inland waterways is done by several barges, either pulled or pushed by a towboat. The length of the barge tow is limited by the lock capacity. A commonly used barge size for coal transportation is 195 feet long and 35 feet wide, and each barge carries approximately 1500 tons of coal. Currently, up to 10,500-hp towboats are used in coal traffic; however, 5600-hp towboats are most widely used. As in the case of the railways, the use of dedicated equipment, owned by the shipper or the consignee, is increasing.

TRANSPORTATION ROUTES

Figures B-1 and B-2 show the most probable transportation route from each coal source to the Oswego and the Staten Island plants, as suggested by the Chessie System. Specific routings for each of the coals are listed in Tables A-4 and A-5, Coal Selection Information Matrices (Supplement A).

The railway routing depends upon the location of the coal source (originating point) and the plant (delivery point). If the originating point and the delivery point are served by the same railroad, then the railroad selects the routing. If the originating point is served by one railroad and the delivery point is served by another, then the originating railroad delivers coal to a common delivery point, (i.e., one served by both railroads), and the delivering railroad transports the coal to the final delivery point (the plant). The selection of common delivery points is subject to the mutual agreement of the involved railroads. Some of the factors considered in selecting the final routing are the condition of the rail tracks, traffic load on the rail line, availability of passing sidings on the considered route, signalling system, and load rating of rails. Thus, sometimes the shortest route between the coal source and the plant is not a feasible route. Per discussions with the Chessie System, Conrail, and Burlington Northern railroads, different routes are available for the transportation of coal to both Oswego and Staten Island plants. Chessie System is the originating railroad for West Virginia mines and Conrail is the delivering railroad for both Oswego and Staten Island plants. For anthracite coal sources in eastern Pennsylvania, Conrail is both the originating and the delivering railroad. For the

western coal, Burlington Northern is the originating railroad, and Conrail is the delivering railroad. Conrail was unwilling to discuss the final routing at this time.

The combination of rail and water transportation offers an alternate route to coal transportation entirely by rail. The coal, delivered by rail to the transshipping terminals, is reloaded on either barges or lake vessels. A dumping charge at the transshipping terminal is usually added to the transportation cost. A new installation at Lake Superior was completed in 1976 to transship western coal. The Lake Superior terminal has a storage capacity of 11 million tons, of which approximately 6 million tons storage capacity is currently being used. The terminal has a vessel-loading capacity of 11,000 tons per hour. Appalachian coal can be transshipped from Conneaut, Ohio, which has a coal-storage facility, to the Oswego Plant. For Staten Island, the Appalachian coal can be transshipped from either Port Reading, New Jersey, or Newport News, Virginia, by barges. Presently there are plans to upgrade the Port Reading facility to meet future coal demand. The transshipping terminals generally offer improved supply reliability, greater flexibility, and economics of scale when large facilities are shared by several users.

TRANSPORTATION COSTS

The rail transportation costs were obtained from the Chessie System, Conrail, and Burlington Northern railroads. The annual freight rate escalation is currently very high and, hence, the railroads are unwilling to discuss definite rates at this stage. The railroads have, however, published rates for unit train operations. The 1979 published rates for coal transportation by 7,000-ton unit trains from Boone County, West Virginia, to Port Reading, New Jersey, are \$15.60 per ton (for 3 to 5 mines). The dumping charges are included in this rate. The above rate is used in this Study as a base to determine all rail transportation costs. The 1979 published single-car rates from Boone County, West Virginia, to Port Reading, New Jersey, are \$18.47 per ton.

The estimated freight rates, for coal shipment from Lake Superior coal terminal to Oswego via the Great Lakes, by the American Steam Ship company are \$9.00 per ton based on 1979 rates and 30,000 tons of coal per vessel. The estimated rates from Conneaut/Ashtabula to Oswego are \$4.53 per ton based on the above. The Welland canal tolls are \$7700.00 per cargo (i.e., one vessel making a round trip) and are additional to the freight rates.

The barge rates from Port Reading, New Jersey, to Staten Island are estimated at \$1.25 per ton based on the ICF study.

The transportation costs from each coal source to the Oswego and Staten Island plants are shown in Tables A-4 and A-5, Coal Selection Information Matrices (Supplement A).

SUMMARY

Reliable transportation means and costs are as important as the availability of suitable coal in required quantities and at the right price. As the transportation distances increase and the total coal production expands, some rail traffic congestion is likely. A redundant coal transportation system involving both the rail and rail/water transportation can offer an assured coal supply throughout the year, and the economics of such a system may be evaluated further in the detailed engineering phase.

FIGURE B-1
COAL TRANSPORTATION ROUTES FOR OSWEGO PLANT

B-8

FIGURE B-2
COAL TRANSPORTATION ROUTES FOR STATEN ISLAND PLANT

Supplement C

TEXACO MEDIUM-Btu GASIFICATION SYSTEM FOR OSWEGO

GENERAL DESCRIPTION

The Texaco coal gasification process uses a high-pressure, entrained-bed, oxygen-blown reactor to produce medium-Btu gas. The coal feed is finely ground and slurried with water, therefore, virtually all types and sizes of coal can be used. The nonash portion of the coal is gasified by reaction with oxygen and steam to form mainly carbon monoxide, hydrogen, carbon dioxide, and hydrogen sulfide. Small quantities of byproduct tars, phenols, and oils are produced, which are recovered internally and recycled to the gasifier, but trace quantities have to be removed from the wastewater.

High-temperature energy produced by the gasification reactions is recovered as 1200 psig saturated steam, which after superheating is used in turbine drivers on major compressors and pumps. Excess steam is used to generate electricity. High-pressure energy in the product fuel gas is recovered with expander turbines.

The Texaco coal gasification process is expected to be commercially available in the near future. Currently, only pilot and demonstration plants are operating. Table C-1 is a listing of all plants which use Texaco's coal technology. The Texaco coal gasification process is based on their partial oxidation process which gasifies naphthas, gas oils, residual oils, and other organic liquids to produce a medium-Btu gas. Approximately 75 of those plants have been built.

The basic principles and systems for Texaco medium-Btu gas for Oswego are described in Section 10, System Description of the main report. Figure 10-6 in the System Description shows the overall block flow diagram for Texaco coal gasification process.

Table C-2 shows the overall material balance for the Texaco gasification process in lb/hr on an elemental basis. This represents the material balance around the gasifiers, based on information provided by Texaco. Coal, oxidant, and water are fed into the system to yield a dry slag and a hot raw gas. This raw gas is processed further to produce an environmentally acceptable fuel gas product.

Table C-3 shows the individual gas streams of the overall material balance on a component basis in mol/hr for the entire plant. The coal feed and process water is not included. (It is shown in lb/hr in Table C-2.) The raw gas is scrubbed to remove moisture then processed to remove sulfur components.

Figure C-1 shows the overall distribution of the energy in the coal feed. The total gas produced contains approximately 74.53 percent of the energy in the coal feed and another 18.05 percent is available as byproduct energy. The system losses, which include the potential energy in the sulfur, are 7.42 percent. The byproduct energy and a portion of the product gas are used as a source of process heat and for internal power consumption either in the form of direct steam usage in turbines or for the generation of electric power. The quality of the steam produced in the gasification system (1200 psig saturated) is such that some of the product gas must be used to superheat the steam for internal use and efficient production of electric power for export. The internal energy requirements, including the byproduct electric power produced for export, reduce the overall product gas to 66.14 percent of the available energy in the coal feed.

Table C-4 shows the overall electrical power requirements for the gasification plant which consists of 19 percent of total internal energy requirements. In addition to the direct power requirements shown, there are several large energy consumers which utilize steam-driven turbines directly or the energy available from the expansion of the product gas.

COAL RECEIVING AND HANDLING

Complete coal handling facilities are provided for receiving coal from unit trains, storing the coal, and delivering it to the plant coal bunkers at a rate necessary to ensure an uninterrupted supply of coal to the gasification plant under all load conditions.

Coal Requirements

The design criteria for the coal receiving and handling system for coal from Compass and Mars Mines in Harrison County, West Virginia, are as follows:

- Annual coal consumption at the 70 percent gasification capacity factor is 4,250,000 tons per year.
- Allowing for coal supply and transportation interruptions, the installation is designed to receive and unload an average of 17,000 tons of coal per day, based on a 5 days/week, 50 weeks/year operation.

A rotary car dumper is selected to unload rail cars because it can unload any type and size of rail car normally available, thus offering maximum flexibility of operation.

System Description

The coal handling system is shown schematically on Flow Diagram, Figure C-2. The facility comprises the following subsystems designed to operate individually or in combination with others:

- The unloading system includes yard trackage, a thawing shed, a rotary car dumper, a track hopper, frozen coal crushers, feeders, and a sump with sump pumps. Yard trackage allows for unrestricted handling of loaded and empty railcars within the plant property limits. Unit trains of approximately 85 open top railcars, with 100-ton capacity each, are delivered to the plant by main line locomotives twice a day, five days per week. The unloading system is capable of unloading the entire train in less than 6 hours.
- The stackout system includes conveyors, an as-received weigh scale, a magnetic separator, a sampling station, a coal silo, a stacking tube, and all conveyor-system-related chutes and gates.
- Coal is conveyed from the rail unloading area to the coal silo by belt conveyors. Unloaded coal is continuously weighed and sampled. A magnetic separator removes the ferrous impurities from the coal. When the coal silo is full, the unloaded coal is deposited in the coal pile through the stacking tube.
- The reclaim system includes feeders, belt conveyors, a magnetic separator, and an emergency reclaim hopper.
- The silo feed system includes the crushing and sampling station, a magnetic separator, an as-fired sampling system, a crusher, a weigh scale, and all conveyor-system-related chutes and gates. In the crusher and sampling building, reclaimed coal is sampled, and larger than 2-inch size lumps are crushed. The crushed coal is conveyed to the coal bunkers. If the crusher is inoperative, reclaimed coal can be conveyed to the coal bunkers, bypassing the crusher. The coal is continuously weighed prior to storage in the coal bunkers.

OXYGEN PLANT

Figure C-3 shows the process flow diagram for one of the seven parallel operating air separation plants which produces 1470 TPD of 99.5 mol percent oxygen per train. The material balance, however, is based on the total of seven trains. Each train consists of an air compressor, an air separation plant, and an oxygen feed compressor.

Atmospheric air is compressed to about 100 psig by a two-stage centrifugal compressor that is driven by an extracting/condensing steam turbine that uses 440 psig steam. 50 psig steam is extracted for use in other systems with the balance of the steam condensed. Some of the heat of compression is recovered, but most is rejected by means of air fan exchangers and trim water coolers.

The compressed air enters a cold box where reversing heat exchangers chill the gas and freeze out the water and carbon dioxide. The oxygen in the air is cryogenically fractionated to 99.5 percent purity. Product nitrogen and oxygen are expanded to low pressure to supply the needed refrigeration. Some nitrogen is produced at high purity, but most is vented after being used to remove the water and CO₂ from the reversing heat exchangers.

The oxygen gas leaves the cold box at 2 psig and is compressed to 1000 psig in a seven stage centrifugal compressor with intercooler heat rejection by means of air fan exchangers and trim water coolers. The major portion of the horsepower requirement is provided by the expansion of the product fuel gas, and the balance is provided by a 440 psig condensing steam turbine.

The horsepower requirements and prime drive requirements for the oxygen plants to produce 10,289 TPD of 99.5 percent oxygen at 1000 psig are as follows:

<u>Compressor Service</u>	<u>Prime Driver</u>	<u>Horsepower</u>	
		<u>Per Unit</u>	<u>Total</u>
Air	Steam	27,400	191,800
Oxygen	Product gas	7,530	52,710
	Steam	3,770	26,390
		11,300	79,100

GASIFICATION SYSTEM

Figure C-4 shows one of the seven parallel trains for coal grinding, slurry preparation, gasification, ash cooling and dewatering, hot gas cooling, and carbon scrubbing. The drawing is shown in schematic form because the details of these steps are proprietary licensing information of Texaco. An elemental material balance, in lb/hr, around the seven Texaco gasifier reactors is shown in Table C-2.

The coal feed is finely ground in a wet mill, slurried with water to about 60 percent solids concentration, and pumped to the gasifier pressure of 800 psig. The coal/water slurry is reacted with oxygen in a refractory-lined vessel producing a temperature of 2300 F to 2700 F. Partial combustion and the water gas reaction produce a medium-Btu gas (about 300 Btu/scf) consisting mainly of carbon monoxide and hydrogen with some carbon dioxide and unreacted water. The sulfur in the coal is converted to hydrogen sulfide and carbonyl sulfide; nitrogen in the coal is converted mainly to nitrogen gas and a small amount of ammonia.

The water used to slurry the coal feed moderates the gasifier temperature, but the temperature is high enough for slagging of the coal ash. On leaving the reactor, the gas stream is deflected, thereby separating the molten slag. The hot slag is quenched in a water bath and removed via a lock hopper system as a slurry. The granular cooled ash is separated from the water and may be disposed of as landfill in an environmentally acceptable manner or sold as a byproduct. The slag contains about 0.3 weight percent carbon on a dry basis. The separated water is recycled to the coal grinding system. A portion is blown down to the gasification process effluent water system to maintain a specified dissolved solids and chemical constituent level in scrubber water.

The process water blowdown from the Texaco gasifier contains some dissolved H_2S , chloride and sulfide salts, and traces of tars, phenols and oils, as well as traces of dissolved solids. This blowdown water is first depressured to remove the bulk of the sour gases. It is then stripped with steam to remove all traces of hydrogen sulfide. All acid gas is sent to the sulfur plant for sulfur recovery. The effluent water is sent to the waste water treatment for additional processing before being reused in the process or discharged.

The hot raw gas from the gasifier is cooled in waste-heat boilers by the generation of 1200 psig saturated steam. The waste-heat boiler effluent gas is scrubbed with circulating water to remove entrained carbon and fine fly ash. The dirty scrub water is clarified and recirculated to the carbon scrubber with

makeup water. The soot/ash/water suspension which settles out is recycled to the gasifier via the grinding/slurry system to increase the carbon efficiency of the process.

GAS COOLING AND EXPANSION

Process Flow Diagram C-5 shows one of the seven parallel trains in the gas cooling and expansion section. The material balance, however, is based on the total gas production.

The clear effluent gas from the carbon scrubbing section is cooled to 100 F in a series of heat exchangers before being sent to the Selexol acid gas removal system.

First, the gas is cooled by exchange with the sweet product gas from the Selexol unit then cooled by exchange with boiler feedwater (BFW) to 260 F to remove process condensate. It is then cooled further by exchange with sweet gas, BFW, and finally to 100 F with cooling water. The process condensate is returned to the gasifier scrubbing system.

The reheated sweet gas is reduced in pressure from 700 psig to 120 psig in a product gas expander that is direct-connected to an oxygen compressor. The product gas from the expander is sent directly to the Oswego power plant via the gas transmission line without any storage facilities. A slipstream of gas is used as fuel gas for the two steam superheaters and in the tail gas unit on the sulfur plant.

ACID GAS REMOVAL - SELEXOL

Process Flow Diagram C-6 depicts one of the seven parallel acid gas removal trains. The material balance, however, is based on the total plant production rate.

The Allied Chemical's Selexol process is used to produce a sweet product gas and reduce the sulfur components, H₂S and COS, to the level required to meet SO_x emission standards for the Oswego area. The Selexol process can reduce the sulfur content of the gas to less than 0.1 lb SO₂ per million Btu, if required. To achieve this low level of sulfur content, however, it is necessary to increase the size and complexity of the unit and consequently its capital and operating costs.

The Selexol process uses a physical absorbent. Unlike "chemical solvents," such as amines and carbonates, physical solvents selectively absorb sulfur compounds in preference to carbon dioxide.

Besides selectivity, other desirable features of the Selexol process are as follows:

- The solvent is stable, noncorrosive, and nonfoaming.
- The high pressure of the Texaco process makes physical solvents economical because acid gas partial pressures are high.
- Carbonyl sulfide is easily handled.
- Water is absorbed; thus, some dehydration of the gas occurs.

Approximately 25 plants have used the Selexol process for either bulk CO₂ removal or selective sulfur absorption from natural gas or synthetic gas. In several instances, Selexol is used to treat partial oxidation gas similar to that under consideration. These Selexol units are:

<u>Company</u>	<u>Location</u>	<u>Startup</u>	<u>Type</u>	<u>POX Feed</u>	<u>Process</u>
Ammoniaque Syn.	Belgium	1975	CO ₂	Fuel oil	?
ERDA/AGA	Homer City, Pa.	1976	H ₂ S/CO ₂	Coal	Bigas
Texaco	Montebello, Calif.	1978	H ₂ S/CO ₂	Coal	Texaco
TVA	Muscle Shoals, Ala.	1980	H ₂ S/CO ₂	Coal	Texaco

SULFUR RECOVERY - CLAUS UNIT

Process Flow Diagram C-7 depicts one of the two parallel Claus sulfur units. The material balance, however, is based on the total plant production rate.

The sulfur-rich gas from the Selexol units is fed into a common header system and routed to the two 50-percent size Claus units. The Claus sulfur unit is one of the more proven processes in this coal gasification system with many years of reliable service. It is the dominant process used in the oil refining and natural gas processing industries for the production of elemental sulfur from hydrogen sulfide and carbonyl sulfide.

In order to recover the major portion of the sulfur present in the Selexol acid gas, a split-flow, two-stage Claus unit is used.

TAIL GAS CLEANUP - BEAVON/STRETFORD

Process Flow Diagram C-8 depicts one of the two Beavon/Stretford units used to remove and recover residual sulfur compounds present in the Claus unit tail gas. The material balance is based on the total tail gas from the two Claus units. The Beavon section converts all sulfur species to hydrogen sulfide by either hydrogenation or hydrolysis over a cobalt-molybdenum catalyst. The Stretford section chemically oxidizes virtually all of the hydrogen sulfide in the feed gas to elemental sulfur and water.

STEAM, BOILER FEEDWATER, AND CONDENSATE SYSTEM

Figure C-9 shows the process flow diagram for a single steam, boiler feedwater, and condensate system. The steam system operates at three pressure levels:

High pressure	-	1200 psig
Intermediate pressure	-	470 psig
Low pressure	-	50 psig

The highest pressure is based upon Texaco's specification for steam generated by high-temperature gas cooling of the gasifier effluent. This saturated steam is superheated to 900 F in a gas-fired heater and fed to a back-pressure turbine exiting at 470 psig steam pressure level to generate 55.4 MW of electric power. This exhaust steam is combined with 470 psig saturated steam generated in the sulfur plant and reheated to 900 F in a dedicated gas-fired boiler. This steam is used for major steam turbine drivers, as follows:

<u>Service</u>	<u>Total Horsepower</u>
Air compressor - steam turbines	191,700
Oxygen compressors - supplementary steam turbines	26,400
Major pump steam turbines	24,700

All pump drivers are back-pressure turbines producing 50-psig steam. The balance of the 50-psig steam required is produced by the air compressor steam turbines which are combination extracting/condensing turbines. The oxygen compressor supplementary steam turbines are condensing turbines operating at 2-1/2 in. Hg pressure. Excess 470 psig steam is used to generate

an additional 36.7 MW of electric power with a condensing turbine operating at 2-1/2 in. Hg.

The 50-psig process steam supplied by extraction turbines is supplemented by steam generated in waste-heat boilers in the sulfur plant and in the tail gas unit. Most of the 50-psig pressure steam is used in the Selexol stripper reboiler with the balance to other users, which include:

Steam system	-	deaerator stripping
Sulfur plant	-	sulfur sump heating
Tail gas unit	-	sulfur melter
Steam tracing, heating, and miscellaneous		

Hot condensate, collected from process users is fed to the deaerator. Cold condensate from the surface condensers is combined with demineralized makeup water and preheated to the deaerator temperature by heat exchange with the sour fuel gas, the air feed compressor discharge, and the convection sections of the high pressure superheater and reheater. Boiler feedwater, after preheating with the sour gas in the gas cooling section, is fed to the Texaco 1200 psig waste-heat boilers and the sulfur plant 470 psig steam generator. Boiler feedwater from the deaerator is directly fed to the 50 psig steam generator without preheat.

PLANT MAKEUP WATER SYSTEM

Figure C-10 is a schematic block flow diagram of plant water system. One system as shown is required.

Water will be obtained from wells located on the plant site. Each well will have a nominal capacity of 1000 gpm each. The water from the wells will be collected in a common header and transported to a storage tank. The water in this tank is used for:

- Cooling water system makeup
- Gasifier water makeup
- Demineralizer and steam system makeup
- Potable water system
- Firewater System

The plant requires a nominal 8200 gpm of water for normal usage at design conditions when all systems are operating. The cooling water system is the largest single user, requiring 7000 gpm of water. The steam system and demineralizer requires approximately

133 gpm, and the gasification system requires 1055 gpm. A small amount of water is required for the potable water system, general utility usage, and normal plant services. The potable water system is sized for 25,000 gallons per day.

The demineralizer system consists of two 135-gpm, 100-percent trains. Each train consists of a cation, anion, and a mixed-bed demineralizer. Auxiliaries for the demineralizer include a complete regeneration package including bulk chemical tanks and neutralization tank with all required accessories.

WASTEWATER TREATMENT SYSTEM

A system is provided to collect and treat the wastewater generated at the site. The main collection points for waste liquids are the coal pile runoff basin and the wastewater surge basin. The basin's function is to collect and equalize the wastewater flow and to forward the wastewater to the treatment system.

The coal pile runoff basin is an earth-bermed pond, lined with hypalon elastomer sheeting. The hypalon liner prevents waste from seeping into groundwater. The basin holds 24 hours of runoff at a rate of 12 inches of rainfall in 24 hours from the coal pile. The basin pumps are designed to discharge at 1600 gpm, equivalent to the 12 inches of rainfall.

Input to the wastewater surge basin includes cooling tower blowdown, gasifier blowdown, plant drains, and coal pile runoff basin effluent. The wastewater surge basin is sized for a 10-hour holdup of the difference between normal and maximum waste flows. The wastewater surge basin pumps discharge to one of two clarifiers. The clarifiers reduce the suspended solids and precipitate some heavy metals present in the coal pile runoff. The clarifier effluent is then filtered to reduce the suspended solids to acceptable limits. The clarifier sludge is returned to the coal pile runoff basin. The filter effluent is monitored for pH and adjusted to acceptable levels with an in-line chemical injection and mixing system. The filter backwash is routed to the wastewater surge basin.

The effluents from the system are in three forms:

- An acceptable liquid stream for return to the environment.
- Sludges accumulated in the coal pile runoff basin.
- Sludges accumulated in the wastewater surge basin.

COOLING WATER SYSTEM

Figure C-11 shows a schematic of the recirculation cooling water system. The cooling water pumps which require 10,800 hp are driven by 440 psig - 900 F steam back pressure turbines exhausting into the 50 psig system. The cooling water is circulated in parallel through all of the cooling systems and returned to the natural draft cooling tower. Makeup water requirements to replace water lost through evaporation, drift, and windage losses, as well as blow-down, is 7000 gpm.

BYPRODUCT POWER GENERATION

The byproduct power generation systems consists of the 1150 psig - 470 psig back-pressure turbine generator system and the 440 psig condensing turbine-generator system. This includes supporting systems such as lubrication and cooling systems, electrical equipment, including transmission lines, and substations.

The electrical power production and usage at rated boiler plant capacity is as follows:

<u>Description</u>	<u>kW</u>
1150-psig Steam	55,400
440-psig Steam	36,700
Total produced	92,100
Internal usage	23,700
Total available for export	68,400

STARTUP BOILER SYSTEM

Process Flow Diagram C-12 shows a schematic of the equipment required to provide steam for startup.

The startup boiler supplies enough steam to meet the normal requirements of one gasification train.

The system consists of a railroad unloading facility with transfer pumps to receive low-sulfur fuel oil and a 15-day fuel oil storage tank, equipped with a pump suction heater operating on 50 psig steam. The oil is pumped to the burners of a 440 psig - 900 F package type boiler. A second fuel oil heater is provided upstream from the burners to make sure that the oil viscosity is low enough to support good combustion.

During normal operating conditions this boiler is shut down. Furthermore, the onstream time is rather limited, so it is assumed this system does not require any flue gas cleanup facilities. An oil that meets all environmental requirements for intermittent operation is used.

OTHER PLANT SUPPORTING SYSTEMS AND FACILITIES

The following supporting systems are included for the coal gasification plant at Oswego.

Plant Instrument Air

The plant instrument air system includes the following equipment:

- Air Receiver
- Air Coolers
- Air Compressor (100 psig)
- Air Filters
- Instrument Air Dryer

Inert Gas System

Inert gas is supplied by the air separation plant. An additional compressor for compressing the nitrogen from 2 psig to 100 psig is provided.

Flare System

Two smokeless flare systems are provided, which are able in emergency cases to incinerate the total amount of gas produced by two gasifiers. The flare systems are equipped with knockout drum vessels which separate liquid and meet the requirements of EPA, NPA, and insurance regulations.

Fire Protection

The fire protection system meets the requirements of National Fire Protection Association (N.F.P.A.) and insurance regulations. The fire protection system includes a firewater system which delivers the required amount of water at 100 psig. Mobile and stationary equipment is provided. The coal gasification trains are protected by fixed sprays and fire monitor systems.

Water for emergencies is stored in the makeup water storage tank, and is sufficient to provide a 4- to 6-hour supply at the estimated firewater rates.

Sulfur Storage and Loading

Sulfur may be stored in two forms, solid or molten sulfur. Molten sulfur may be cast into 1 yard cubes or stored in a storage sump. The sulfur cubes may be stored in a specially designed warehouse, equipped with loading equipment which permits it to be shipped out to the consumers or to a disposal site.

For this Study, the moten sulfur is stored in a storage sump. The sump is insulated and equipped with temperature controlled bottom and side-steam coils to maintain the temperature of molten sulfur at 275 F. A steam blanket prevents air from entering the sump when it is pumped down. Two steam jacketed pumps (one spare) are provided to deliver the product to the two loading racks which are provided.

Slag Handling System

The coal gasification plant at Oswego disposes about 1360 TPD dry ash or about 1500 TPD wet ash.

A lined ash pond which is able to store the disposed ash for at least one year is provided. The required space for one years' storage is about 25 acres. It is necessary to select a site for the ash pond which permits extending the pond. The pond is equipped with loading facilities, which permit the loading of ash for future disposal elsewhere or for sale to consumers.

The disposal and storage of the ash is performed in an environmentally acceptable manner to comply with all existing Federal and state EPA requirements.

Miscellaneous Plant Supporting Systems

Miscellaneous plant supporting systems include:

- Site cleaning and improvements
- Railroad spur
- Roads and parking lot
- Fencing and gates
- Site drainage systems
- Buildings, turbine-generator, warehouse, workshops, offices, guard houses, garage, and miscellaneous buildings
- Cranes and hoists
- Ambulance and medical equipment

PRODUCT GAS TRANSFER LINE

A product gas transfer line to transport the gas from the coal gasification plant to the power plant is provided. This line is located on supports above grade and is not insulated. It consists of a 48-inch line which increases to 60 inches in diameter at the midpoint. The gas is reduced in pressure from 120 psig to 35 psig as it flows through the line, thereby necessitating a size increase to keep the gas velocity and pressure drop within the required limits.

TABLE C-1
TEXACO COAL GASIFICATION PLANTS

<u>COMPANY</u>	<u>LOCATION</u>	<u>CAPACITY STPD COAL</u>	<u>STARTUP YEAR</u>	<u>PLANT TYPE</u>	<u>FINAL PRODUCT</u>	<u>STATUS</u>
TEXACO	MORGANTOWN, W. VA.	100	1956	DEMO	-	SHUT DOWN 1958
TEXACO	MONTEBELLO, CALIF.	15	1950S	PILOT	-	OPERATING
TEXACO	MONTEBELLO, CALIF.	20	1970S	PILOT	-	OPERATING
RUHRKOHLE/RUHRCHEMIE	OBERHAUSEN-HOLTEN, BRD	160	1978	DEMO	SYN GAS	OPERATING
DOW CHEMICAL	PLAQUAMINE, LA.	250	1979	DEMO	(1)	OPERATING
TVA	MUSCLE SHOALS, ALA.	190	1980	DEMO	AMMONIA	CONSTRUCTION
TEXACO/SO.CAL.EDISON	DAGGETT, CALIF.	1000	1983	COMM	(2)	ENGINEERING
TENNESSEE EASTMAN	KINGSPORT, TENN.		1983	COMM	(3)	ENGINEERING

- NOTES:
1. LOW-BTU GAS FROM LIGNITE USED IN A GAS TURBINE TO MAKE ELECTRICITY.
 2. ELECTRICITY VIA COMBINED CYCLE.
 3. SYN GAS TO MAKE METHANOL AND ACETIC ANHYDRIDE.

TABLE C-2
OSWEGO - TEXACO PROCESS
GASIFIER MATERIAL BALANCE
(LB/HR)

STREAM *	A	B	C		D	E	
DESCRIPTION	<u>COAL FEED</u>	<u>WATER FEED</u>	<u>OXIDANT</u>	<u>TOTAL FEEDS</u>	<u>DRY SLAG</u>	<u>RAW GAS</u>	<u>TOTAL PRODUCTS</u>
CARBON	655,342			655,342	364	654,978	655,342
HYDROGEN	50,582	59,219		109,801		109,801	109,801
NITROGEN	13,251			13,251		13,251	13,251
SULFUR	37,935			37,935		37,935	37,935
OXYGEN	78,669	473,752	852,099	1,404,520		1,404,520	1,404,520
ASH	114,534			114,534	114,534		114,534
ARGON			5,349	5,349		5,349	5,349
TOTAL	950,313	532,971	857,448	2,340,732	114,898	2,225,834	2,340,732
WATER, WT%	4.5	100	-	-	0	17.6	-
STPD**	11,404	-	10,289	-	1,379		-

* DRAWING C-4

** SHORT TONS PER STREAM DAY

C-16

TABLE C-3
OSWEGO - TEXACO PROCESS
GAS MATERIAL BALANCE
(LB - MOLES/HR)

STREAM NUMBER	1	2	3	4	5	6	7	8	9	10	11	12	13
DESCRIPTION	AIR	OXIDANT	SCRUBBED GAS	COOLED GAS	SWEET GAS	STEAM S.H. FUEL	TAIL GAS UNIT FUEL	PRODUCT GAS	ACID GAS	CLAUS FURNACE AIR	TAIL GAS	TGU COMB. AIR	VENT GAS
CO	-	-	42323.6	42323.6	42247.4	4676.6	79.6	37491.2	76.2	-	50.3	-	59.4
H ₂	-	-	91974.0	91974.0	91981.5	9471.6	59.1	27890.8	12.5	-	8.4	-	11.7
CO ₂	-	-	11831.8	11831.8	7099.1	785.8	13.4	6299.9	4732.7	-	4817.8	-	4911.5
H ₂ O	3248.4	-	21718.9	112.4	21.1	2.3	-	18.8	505.9	54.3	1605.7	6.5	674.3
CH ₄	-	-	949.7	949.7	949.7	98.7	0.7	910.9	-	-	-	-	-
N ₂	104483.9	-	473.3	607.0	607.0	67.2	1.2	538.6	-	2126.3	2126.3	211.3	2338.8
AR	1902.1	199.7	199.7	-	-	-	-	-	-	-	68.5	-	0.5
H ₂ S	-	-	1109.0	1109.0	166.0	18.4	-	147.6	943.0	-	9.6	-	0.5
COS	-	-	76.5	76.5	12.0	1.1	-	10.9	64.5	563.4	-	56.0	-
O ₂	28029.6	26628.1	-	-	-	-	-	-	-	-	-	-	-
SO ₂	-	-	-	-	-	-	-	-	-	-	3.6	-	-
S _{7.6}	-	-	-	-	-	-	-	-	-	-	1.2	-	-
TOTAL	137064.0	26761.8	109390.5	87784.0	81863.8	9061.9	154.0	72648.1	6334.8	2755.0	8691.4	273.8	7996.7

TABLE C-4

OSHEGO - ELECTRIC POWER CONSUMPTION

	<u>KW</u>
AIR PLANT	5150
GASIFIER	8530
SELEXOL	500
SULFUR PLANT	720
TAIL GAS UNIT	1340
COOLING WATER SYSTEM	50
STEAM SYSTEM	50
COAL HANDLING	4460
EFFLUENT TREATMENT	1440
DEMINERALIZER	480
MISCELLANEOUS	960
TOTAL KW	23,680

	PERCENT
PRODUCT GAS	66.14
GAS USED IN PROCESS	8.39
TOTAL GAS	74.53
BY-PRODUCT ENERGY	18.05
TOTAL RECOVERABLE ENERGY	92.58
LOSSES	7.42
TOTAL	100.00

OSWEGO - TEXACO PROCESS

OVERALL DISTRIBUTION
OF ENERGY IN COAL

Onge & Hill, Inc.
ENGINEERS DESIGNERS CONSTRUCTORS
NEW YORK

SCALE: NONE

JOB NO. 11-2892 001

FIG. C-1

11/08/80

CADRE/MISC/MISC

MATERIAL BALANCE

STREAM NUMBER	1	2
DESCRIPTION	AIR	OXIDANT
MPH		
O ₂	28029.6	28828.1
N ₂	104483.9	
AR	1902.1	139.7
H ₂ O	3248.4	
TOTAL MPH	137064.0	26,761.8
LB/HR	5,993,052	857,448

NOTES:

1. THIS FLOW DIAGRAM SHOWS ONE OF SEVEN PARALLEL TRAINS.
2. MATERIAL BALANCE SHOWN IS FOR TOTAL OF SEVEN TRAINS.

OSWEGO - TEXACO PROCESS

PROCESS FLOW DIAGRAM
OXYGEN PLANT

Chas. E. Hill, Inc.
ENGINEERS, CHEMICAL, CONSTRUCTORS
NEW YORK

JOB NO. 11-2892-001

SCALE: NONE

FIG. C-3

11/05/80

CRORE/HISC/HISC

MATERIAL BALANCE

STREAM NUMBER	2	3
DESCRIPTION	OXIDANT	SCRUBBED GAS
MPH		
CO		42323.6
H ₂		31374.0
CO ₂		11831.8
H ₂ O		21710.9
CH ₄		349.7
N ₂ +AR	133.7	807.0
H ₂ S		1109.0
CO ₂		76.5
O ₂	26628.1	
TOTAL MPH	26761.8	109390.5
LB/HR	857,448	2,225,834

NOTES:

1. THIS FLOW DIAGRAM SHOWS ONE OF SEVEN PARALLEL TRAINS
2. MATERIAL BALANCE SHOWN IS FOR TOTAL OF SEVEN TRAINS
3. STREAMS WITH LETTER DESIGNATION ARE USED IN GASIFIER MATERIAL BALANCE (TABLE C-1)

OSWEGO - TEXACO PROCESS

PROCESS FLOW DIAGRAM
GASIFICATION SYSTEM

Osaka & Hill, Inc.
ENGINEERS, DESIGNERS, CONSTRUCTORS
NEW YORK

SCALE: NONE

JOB NO. 11-2892-001

FIG. C-4

07/31/80

CADRE/MISC/MISC

MATERIAL BALANCE

STREAM NUMBER	3	4	5	7	8	6
DESCRIPTION	ACRYL. GAS	SOLAR GAS	SWEET GAS	WATER FUEL	100 FUEL	PRODUCT GAS
MPH						
CO	42323.0	42322.6	42247.0	48766.6	76.6	37481.2
H2	31374.0	31374.0	31361.5	3471.6	50.1	27830.8
CO2	11031.6	11031.6	7099.1	785.6	13.4	6299.9
H2O	21718.9	112.4	21.1	2.3	-	16.8
CH4	349.7	349.7	349.7	38.7	0.7	310.3
N2+AR	607.0	607.0	607.0	67.2	1.2	538.6
H2S	1109.0	1109.0	168.0	18.4	-	147.8
COS	76.5	76.5	12.0	1.1	-	10.9
TOTAL MPH	109390.5	87784.0	81863.8	8061.6	154.0	72648.1
LB/HR						

NOTES:

1. THIS FLOW DIAGRAM SHOWS ONE OF SEVEN PARALLEL TRAINS
2. THE MATERIAL BALANCE SHOWN IS THE TOTAL FOR SEVEN FULL TRAINS AT DESIGN CAPACITY.

OSWEGO - TEXACO PROCESS

PROCESS FLOW DIAGRAM
GAS COOLING/EXPANSION

Cabot & Hill, Inc.
ENGINEERING, DESIGN, CONSTRUCTION
FOR TOL.

SCALE: NONE

FIG. C-5

JOB NO. 11-2892-001

07/31/80 CORE/HISC/HISC

OSWEGO - TEXACO PROCESS

PROCESS FLOW DIAGRAM
TAIL GAS UNIT (TGU)

Osbe & Hill, Inc.
 ENGINEERS, CHEMISTS, CONSTRUCTORS
 NEW YORK

SCALE: NONE

JOB NO. 11-2892-001

FIG. C-8

NOTES:

1. MAJOR PUMP DRIVES ARE:
 -HP BFW 4100 BHP
 -SELEXOL HELPER 7900 BHP
 -SULFUR 1900 BHP
 -COOLING WATER 10800 BHP
2. 79100 BHP TOTAL 52700 BHP SUPPLIED BY PRODUCT GAS EXPANDER.1
3. THIS DRAWING SHOWS THE OVERALL STEAM AND CONDENSATE BALANCE

OSWEGO - TEXACO PROCESS

PROCESS FLOW DIAGRAM
STEAM, BFW & CONDENSATE SYSTEM

Osco & Hill, Inc.
 ENGINEERS, DESIGNERS, CONSTRUCTORS
 NEW YORK

JOB NO. 11-2892-001

SCALE: NONE

FIG. C-9

10/08/80

CADRE/HISC/HISC

NOTE:
FIGURES GIVEN ARE MLB/HR EXCEPT
WHERE NOTED

OSWEGO - TEXACO PROCESS

BLOCK FLOW DIAGRAM
PLANT WATER SYSTEM

Osco & Hill, Inc.
ENGINEERS, DESIGNERS, CONSTRUCTORS
NEW YORK

JOB NO. 11-2892-001

SCALE: NONE

FIG. C-10

7/31/80

CADRE/NISC/NISC

OSWEGO - TEXACO PROCESS

PROCESS FLOW DIAGRAM
COOLING WATER SYSTEM

Chas. E. Hill, Inc.
ENGINEERING, DESIGN, CONSTRUCTION
NEW YORK

JOB NO. 11-2892-001

SCALE: NONE

FIG. C-11

11/07/80

CADRE/MISC/MISC

OSWEGO - TEXACO PROCESS

PROCESS FLOW DIAGRAM
STARTUP BOILER SYSTEM

Chas. & Hill, Inc.
ENGINEERS, DESIGNERS, CONSTRUCTORS
NEW YORK

JOB NO. 11-2892-001

SCALE: NONE

FIG. C-12

7/31/80 CADRE/MISC/MISC

Supplement D

TEXACO MEDIUM-Btu GASIFICATION SYSTEM FOR ARTHUR KILL

GENERAL DESCRIPTION

The Texaco coal gasification process used for Arthur Kill is essentially the same as that described in detail for Oswego in Supplement C.

Figure 10-7 in Section 10, System Description, of the main report shows the overall Block Flow Diagram with the number of parallel units required for each processing step, the coal requirements, the quality and quantity of product gas, and the byproduct electricity available for export. The basic systems in the overall coal gasification plant are summarized therein.

This Supplement highlights the differences between the Oswego and Arthur Kill Texaco processes and, where required, compares the similarities between the two alternatives for Arthur Kill.

The main differences between Oswego and Arthur Kill are:

- Quantity of gas required
- Number of processing trains
- Distance between the gas processing plant and the power plant
- Gas delivery pressure
- SOx emission requirements
- Source and type of cooling water
- Site conditions
- Available utilities
- Existing coal receiving and handling facilities
- Type of power plant boiler

The material balance for each of the processing steps is shown on the respective flow sheet, with the overall material balance shown on Block Flow Diagram 10-7. The individual gas streams of the overall material balance are summarized in Table D-1.

The Arthur Kill plant is 56.4 percent as large as the Oswego plant. Therefore, electrical power requirements, steam requirements, and coal consumption are reduced over Oswego by the same percentage. The overall efficiency of the system, however, is the same as for Oswego with one general exception. The gasification plant is located adjacent to the power plant so that the energy required to transport the gas from the gasification system to the power plant is minimized. This results in an additional increase in electric power production which is available for export.

COAL UNLOADING AND HANDLING

The coal handling system for Texaco at Arthur Kill is described in Supplement E, Combustion Engineering Low Btu Gasification for Arthur Kill, subsection Coal Receiving and Handling.

The coal slurry preparation system, which is a proprietary Texaco process, is described in Supplement C, Texaco Medium-Btu Gasification for Oswego, subsection Gasification System. The coal feed rate is 6434 TPD.

OXYGEN PLANT

The coal gasification plant at Arthur Kill requires 5618 TPD of oxygen and is essentially the same as that described in Supplement C. Figure D-1 shows one of the four parallel processing units and the total material balance for the four units.

The only variation with Oswego is that an additional exchanger has been added to the air compressor intercooling system to reheat the product gas between the first and second stage product gas expanders.

GASIFICATION SYSTEM

The gasification system at Arthur Kill is the same as that described in Supplement C. Figure D-2 shows one of the four parallel processing units and the total material balance for the system.

GAS COOLING AND EXPANSION

Figure D-3 shows one of the four parallel processing units and the total material balance for Arthur Kill. These units are the same as that described in Supplement C, except for the product gas depressurization and energy recovery system.

At Arthur Kill, the gasification plant is adjacent to the power plant. The pressure drop consumed in the gas transmission line

at Oswego is recovered at Arthur Kill in a second stage product gas expander, which is used to generate 17,800 kW of electricity.

ACID GAS REMOVAL - SELEXOL

Figure D-4 shows one of the four parallel processing units and the total material balance for Arthur Kill.

The SO_x emission requirements at Arthur Kill are much more stringent than those at Oswego. To achieve this high level of sulfur removal, a more efficient Selexol unit is provided. This results in a longer solution circulation rate per volume of gas, and, consequently, larger equipment and utility requirements than the system specified for Oswego.

SULFUR RECOVERY - CLAUS UNIT

Figure D-5 shows one of the two parallel Claus units. The material balance, however, is based on the total plant capacity at rated conditions.

This system is the same as that described in Supplement C.

TAIL GAS CLEANUP - BEAVON/STRETTFORD UNIT

Figure D-6 shows one of the two parallel Beavon/Stretford units which remove sulfur components from the Claus unit tail gas and convert it to elemental sulfur.

This system is the same as that described in Supplement C.

STEAM, BOILER FEEDWATER, AND CONDENSATE SYSTEM

The steam, boiler feedwater, and condensate system for Texaco at Arthur Kill is similar to that described in Supplement C. Figure D-7 shows the overall steam and condensate balance for this system.

PLANT MAKEUP WATER SYSTEM

Figure D-8 is a schematic block flow diagram of a plant water system which will obtain water from two sources:

- One system uses 67,000 gpm of saltwater from the Arthur Kill to provide cooling water for the surface condensers on the condensing steam turbines.
- A second system uses 4000 gpm of city water (1) as makeup for cooling tower, (2) to meet gasification process water requirements, (3) as demineralized water

for the waste-heat steam system, and (4) for potable water usage.

The freshwater system is similar to that described in Supplement C, except for the reduced size of the cooling water makeup system, because saltwater is used to replace major cooling systems at Arthur Kill.

WASTEWATER TREATMENT SYSTEM

The wastewater treatment systems will be similar to that described in Supplement C. Treated wastewater will overflow into Arthur Kill.

COOLING WATER SYSTEMS

The Arthur Kill cooling water requirements are similar to those described in Supplement C, except that the surface condensers on the condensing steam turbines are cooled by a separate system using saltwater. The balance of the system uses freshwater cooling as per Oswego.

BYPRODUCT POWER GENERATION

There are three sources of byproduct electric power for the Texaco coal gasification at Arthur Kill, as compared to two for Oswego. The sources of byproduct electric power as shown on Figure D-3, Gas Cooling and Expansion, and on Figure D-7, Steam, BFW, and Condensate System, follows:

<u>Description</u>	<u>kW</u>
Product gas expander No. 2	17,800
1150 to 470 psig steam turbines	31,200
470 psig condensing steam turbine	<u>20,700</u>
Total power generated	69,700
Less internal consumption	<u>13,500</u>
Power available for export	56,200

STARTUP BOILER SYSTEM

A startup boiler system is provided for Arthur Kill similar to that described in Supplement C for Oswego.

The startup boiler is a fuel oil-fired, package-type boiler with a capacity of 300,000 lb/hr at 440 psig and 900 F steam.

OTHER PLANT SUPPORTING SYSTEMS AND FACILITIES

The plant supporting systems and facilities for the Texaco coal gasification process at Arthur Kill are similar to those at Oswego, with modifications where required based on site-specific requirements. The following systems are included:

- Plant instrument air
- Inert gas system utilizing nitrogen from the air separation plant.
- Flare system
- Fire protection system
- Sulfur storage and loading
- Slag storage and handling
- Site cleaning and improvements
- Foundations and piling
- Roads and fencing
- Drainage system
- Building and offices
- Electrical distribution system
- Maintenance shops and laboratory equipment
- Turbine room and miscellaneous cranes and hoists
- Communications systems
- Makeup water storage tank

TABLE D-1
ARTHUR KILL - TEXACO PROCESS
GAS MATERIAL BALANCE

STREAM NUMBER	(LB. - MOLES/HR.)												
	1	2	3	4	5	6	7	8	9	10	11	12	13
DESCRIPTION	AIR	OXIDANT	SCRUBBED GAS	COOLED GAS	SWEET GAS	STEAM S.H. FUEL	TAIL GAS UNIT FUEL	PRODUCT GAS	ACID GAS	CLAUS FURNACE AIR	TAIL GAS	TGU COMB AIR	VENT GAS
D-6 CO			23870.5	23870.5	23827.5	2637.6	44.9	21145.0	43.0		28.4		33.5
H ₂			17694.9	17694.9	17687.9	1958.1	33.3	15696.0	7.0		4.7		6.6
CO ₂			6673.1	6673.1	4003.9	443.2	7.6	3553.7	2669.2		2717.2		2770.1
H ₂ O	1832.1		12249.5	63.4	11.9	1.3	-	10.6	285.3	36.8	905.6	3.7	380.3
CH ₄			197.2	197.2	197.2	21.8	0.4	175.0					
N ₂	58928.9		266.9	266.9	266.9	37.9	0.7	303.7		1199.2	1199.2	119.2	1319.1
AR	734.4	75.4	75.4	75.4	75.4						38.6		0.3
H ₂ S			625.5	625.5	18.0	2.0	-	16.0	607.5		5.4		0.3
COS			43.4	43.4	3.0	0.3	-	2.6	40.4	317.7		31.6	
O ₂	15808.7	15018.2	-	-	-	-							-
SO ₂			-	-	-	-					2.3		-
S _{7.6}			-	-	-	-					0.7		-
TOTAL	77304.1	15093.6	61696.4	49510.3	46091.7	5102.1	86.9	40902.6	3652.4	1553.7	4902.1	154.5	4510.2

MATERIAL BALANCE

STREAM NUMBER	1	2
DESCRIPTION	AIR	OXIDANT
MPH		
O ₂	15808.7	15018.2
N ₂	58928.9	
Ar	734.4	75.4
H ₂ O	1832.1	
TOTAL MPH	77304.1	15093.6
LB/HR	2,255,455	483600

NOTES:

1. THIS FLOW DIAGRAM SHOWS ONE OF FOUR PARALLEL TRAINS.
2. MATERIAL BALANCE SHOWN IS FOR TOTAL OF FOUR TRAINS.

ARTHUR KILL - TEXACO PROCESS

PROCESS FLOW DIAGRAM OXYGEN PLANT

Onco & Hill, Inc.
ENGINEERS, DESIGNERS, CONSTRUCTORS
New York

SCALE: NONE

JOB NO. 11-2892-001

FIG. D-1

11/03/80

CADRE/MISC/M111

MATERIAL BALANCE

STREAM NUMBER	2	3
DESCRIPTION	OXIDANT	SCRUBBED GAS
NPH		
C0		25870.5
H2		17894.9
CO2		6679.1
H2O		12249.5
CH4		187.2
N2+AR	75.4	342.5
H2S		625.5
CDS		43.4
O2	15018.2	
TOTAL NPH	15093.6	61898.1
LB/HR	46,3600	1,255,370

NOTES:

1. THIS FLOW DIAGRAM SHOWS ONE OF FOUR PARALLEL TRAINS
2. MATERIAL BALANCE SHOWN IS FOR TOTAL OF FOUR TRAINS
3. STREAMS WITH LETTER DESIGNATION ARE USED IN GASIFIER MATERIAL BALANCE (TABLE D-01)

ARTHUR KILL - TEXACO PROCESS

PROCESS FLOW DIAGRAM
GASIFICATION SYSTEM

Chas. & H. Inc.
ENGINEERS, DESIGNERS, CONSTRUCTORS
NEW YORK

JOB NO. 11-2892-0C1

SCALE: NONE

FIG. D-2

07/31/80

CADRE/MISC/MISC

MATERIAL BALANCE

STREAM NUMBER	3	4	5	7	8	6
DESCRIPTION	SCRUB. GAS	SOUR GAS	SWEET GAS	SPWIA FUEL	TEU FUEL	PRODUCT GAS
MPH						
CO	23870.5	23870.5	23872.5	2637.6	44.9	21145.0
H ₂	17694.9	17694.9	17687.9	1958.1	35.3	15696.0
CO ₂	6673.1	6673.1	4003.9	449.2	7.6	3553.7
H ₂ O	12249.5	63.4	11.9	1.3	-	10.6
CH ₄	197.2	197.2	197.2	21.0	0.4	175.0
N ₂ +AR	342.5	342.3	342.3	37.9	0.7	303.7
H ₂ S	825.5	825.5	10.0	2.0	-	16.0
COS	49.4	43.4	3.0	0.3	-	2.6
TOTAL MPH	81898.4	49510.4	48091.7	5102.2	86.9	40902.8
LB/HR						

NOTES:

1. THIS FLOW DIAGRAM SHOWS ONE OF FOUR PARALLEL TRAINS
2. THE MATERIAL BALANCE SHOWN IS THE TOTAL FOR FOUR FULL TRAINS AT DESIGN CAPACITY.

ARTHUR KILL - TEXACO PROCESS

PROCESS FLOW DIAGRAM
GAS COOLING/EXPANSIONArthur Kill, Inc.
ENGINEERS, DESIGNERS, CONSTRUCTORS
NEW YORK

SCALE: NONE

JOB NO. 11-2892-001

FIG. D-3

STREAM NUMBER	4	5	9
DESCRIPTION	COOLIDGE GWS	SHEET GWS	AC10 GWS
MPH			
C0	23870.5	23827.5	43.0
M2	17894.9	17867.3	7.0
C02	6673.1	4003.8	2689.2
H20	83.4	11.9	205.3
CH4	197.2	197.2	
N2+AR	342.3	342.3	
H2S	825.5	18.0	807.5
C05	43.4	3.0	40.4
TOTAL MPH	49510.3	48091.7	3852.4

NOTES:

1. THIS FLOW DIAGRAM SHOWS ONE OF FOUR PARALLEL TRAINS
2. MATERIAL BALANCE SHOWN IS FOR TOTAL OF FOUR TRAINS

ARTHUR KILL - TEXACO PROCESS

PROCESS FLOW DIAGRAM ACID GAS REMOVAL-SELEXOL

Cole & Hill, Inc.
EXPERT DESIGNERS, CONSTRUCTORS
Salem, Mass.

SCALE: NONE

JOB NO. 11-2892-001

FIG. D-4

07/31/60

CRORE/MISC/MISC

NOTES:

1. THIS FLOW DIAGRAM SHOWS ONE OF TWO PARALLEL TRAINS
2. THE MATERIAL BALANCE SHOWN IS FOR TWO PARALLEL TRAINS

ARTHUR KILL - TEXACO PROCESS

PROCESS FLOW DIAGRAM
TAIL GAS UNIT (TGU)

CH2M HILL Inc.
DESIGN, CONSTRUCTION
NEW YORK

SCALE: NONE

JOB NO. 11-2892-001

FIG. D-6

8-1-80 CADRE/MISC/MISC

NOTES:

1. MAJOR PUMP DRIVES ARE:
-HP BFW 2310 BHP
-SELEXOL HELPER 4455 BHP
-SLURRY 1070 BHP
-COOLING WATER 4700 BHP
2. 44600 BHP TOTAL, 29700 BHP SUPPLIED BY PRODUCT GAS EXPANDER. 1
3. THIS DRAWING SHOWS THE OVERALL STEAM AND CONDENSATE BALANCE

ARTHUR KILL - TEXACO PROCESS

PROCESS FLOW DIAGRAM
STEAM, BFW & CONDENSATE SYSTEM

Arthur Kill, Inc.
ENGINEERS, DESIGNERS, CONSTRUCTORS
New York

SCALE: NONE

JOB NO. 11-2892-001

FIG. D-7

NOTE:
FIGURES GIVEN ARE MLB/MR EXCEPT
WHERE NOTED

ARTHUR KILL - TEXACO PROCESS

BLOCK FLOW DIAGRAM PLANT WATER SYSTEM

Chas. E. Hill, Inc.
ENGINEERS, DESIGNERS, CONSTRUCTORS
NEW YORK

SCALE: NONE

JOB NO. 11-2892-001

FIG. D-8

11/05/80

CADRE/MISC/MISC

Supplement E

COMBUSTION ENGINEERING LOW-Btu GASIFICATION SYSTEM FOR ARTHUR KILL

GENERAL DESCRIPTION

The Combustion Engineering gasification process used in this Study uses air rather than oxygen in a low-pressure entrained-flow gasifier to produce low-Btu gas. Pulverized coal is fed to a two-stage unit. In the lower stage, about a third of the coal is completely combusted in a cyclone-type slagging combustor. The hot effluent gases therefrom are reacted with the remaining coal in the upper section to produce a gas that is rich in both hydrogen and carbon monoxide. After cooling, char removal, and acid gas cleanup, the product gas has a heating value of 104.4 Btu/scf.

One coal storage system and three coal pulverizing units supply coal to the three coal gasification trains. In addition to the three main processing trains, the coal gasification plant includes all necessary offsite utility and environmental facilities.

High temperature energy in the form of 1450 psig, 900 F steam is produced as a byproduct in the gasification reactor. The bulk of the steam is used to generate 141,000 kWh; 9000 kWh are used internally, and the balance of 132,000 kWh is available for export. The power recovery plant also supplies the required amount of 600-psig steam for the mechanical steam-driven turbines and 600-psig, 240-psig, and 50-psig steam for processing and heating. Major equipment sections are shown in Table E-1.

Figure 10-8 in Section 10, System Description, shows the Overall Block Flow Diagram with the number of parallel units required for each processing step, the coal requirements, the quality and quantity of product gas, and the byproduct electricity available for export. The basic systems in the overall coal gasification plant are summarized therein. This Supplement contains a more detailed description of the same systems.

Table E-2 shows the overall material balance for the gasifier in lb/hr on an elemental basis. This represents the material balance around the gasifiers based on information provided by Combustion Engineering which was adjusted for the specific coal used in the Study.

Table E-3 shows the distributions of energy in the coal feed. The product gas contains 67.11 percent of the energy in the coal feed, and another 28.84 percent is available as byproduct energy. The gasification losses which include the potential energy in the

sulfur are 4.05 percent. The byproduct energy is used to provide heat to the air preheater, and the balance is converted to 1450 psig, 900 F steam. This steam is used to meet process requirements for direct usage in steam turbine, and the balance is used to produce electricity.

Table E-4 shows the overall distributions of energy. This shows that the gas efficiency is 67.11 percent; the overall efficiency is 84.5 percent with internal consumption and losses of 15.5 percent. This overall efficiency is higher than that found in an oxygen-fed gasification process.

Table E-5 shows the internal power requirements as equivalent kW's, with a distribution of direct steam users or electric power users.

COAL RECEIVING AND HANDLING

Facilities are available at Arthur Kill to receive and unload coal from railroad cars and move it to the existing power plant or to the dead storage pile. The existing facilities do not allow the use of unit trains. The system could be modified for unit train operation. It is, however, not considered as a part of this Study.

As an alternative to rail delivery, a barge receiving and unloading system was investigated. Coal would be delivered to the site by shuttle barges which operate between the power plant site and Port Reading on the Jersey side of the Arthur Kill.

Coal Requirements

The design criteria for the coal receiving and handling system for coal from Compass and Mars Mines in Harrison County, West Virginia, is as follows:

- Annual coal consumption at the 70-percent gasification capacity factor is 2,500,000 tons per year.
- Allowing for coal supply and transportation interruptions, the installation is designed to unload an average of 10,000 tons of coal per day based on a 5 days/week, 50 weeks/year operation.

System Description

Coal receiving and handling system layout and equipment selection varies with the final coal transportation mode. For rail delivery, the coal-handling system is as shown schematically on attached Flow Diagram E-1. For coal delivery by barges, the coal receiving and handling system is as shown schematically on

attached Flow Diagram E-2. In either case, the coal-handling system consists of the following subsystems, designed to operate individually or in combination with others:

Rail Unloading System. Arthur Kill Station at Staten Island has an existing coal unloading facility. The existing facility includes yard trackage, a thawing shed, a rotary car dumper, a frozen coal crusher (moving hammer mill type), a receiving hopper, and downstream collecting conveyors. The existing facility is in excellent working condition and can be used as is. The dumper is capable of unloading up to 100-ton-capacity railcars. The yard trackage is capable of accommodating sixty to seventy 70-ton-capacity railcars. By laying additional trackage, the unloading system can be upgraded to handle unit trains. In this Study, no changes to the existing rail unloading system are proposed.

Barge Unloading System. The optional barge unloading system has been specified to handle and unload seven 1500-ton barges per day. Coal will be unloaded at an average rate of 1500 tons per hour on a 5-day/week basis. A stationary continuous bucket ladder type barge unloader will be located at the center of a dock. While unloading, a loaded coal barge will be positioned under the unloader by a work boat and drawn past the rotating bucket(s) of the unloader by cables attached to power winches. When empty, a second barge will be positioned under the unloader and unloaded in a similar manner as described above. Unloaded barges are moved to an empty barge fleeting area by the work boat.

Coal will be conveyed from the unloading area to the coal silo by belt conveyors. When the coal cannot be deposited in the coal silo, the unloaded coal will be deposited in the active coal pile. The active coal pile will be used either to reclaim coal by bypassing the silo, or to build a dead coal storage inventory.

The coal receiving and handling system will include the following supporting facilities: an electric power supply for instrumentation and control of the system; water for washdown; compressed air for maintenance; instrument air for air-operated valves (if furnished); heating, ventilating, and air-conditioning; and a fire detection and protection system. Adequate dust and noise control systems will be provided to minimize fugitive dust and noise pollution.

Coal Preparation. The gasification process requires ground coal, 70 percent, passing a 200-mesh screen. The coal is ground and dried simultaneously in the pulverizers.

The drying gas is 325 F process air from the primary air heater. The pulverized coal is pneumatically conveyed to the gasifiers by the drying gas. Each pulverizer train consists of two pulverizers. One of the pulverizers supplies coal to the upper reducing section of the gasifier. The second supplies coal to the combustion chamber of the gasifier.

COAL GASIFICATION

The gasifier shown on Process Flow Diagram, Gasification and Ash Handling, Figure E-3, is a two-stage unit. The lower chamber is an ash-slugging combustor into which one-third of the coal and a near stoichiometric amount of air is injected. The combustor is located beneath a substantially air deficient reduction section. The remaining two-thirds of coal is injected into the diffuser portion of the reduction section with very little air--only enough to transport the coal into the gasifier.

Pulverized coal about 70 percent through 200 mesh and recycled char are fed through the combustion nozzles and oxidized in the combustion zone. The resulting hot gas rises into the reduction section, while the molten slag is removed from the bottom and quenched.

The hot gases rising from the combustor provide the heat necessary to devolatilize the coal and initiate and continue the endothermic gasification reactions which proceed throughout the height of the gasifier.

Pulverized coal and recycled char are injected tangentially into the hot gases rising from the combustion section.

The feed coal is devolatilized, and the volatile substance is cracked in the lower, high-temperature section of the gasifier. As the gases rise through the remainder of the gasifier, they are cooled to 1700 F by the endothermic gasification reaction.

The gasifier is enclosed with water-cooled, fin-welded, studded, refractory-covered walls. Boiler feedwater is pumped through walls, and high-pressure saturated steam is generated. Air to the gasifier is compressed to 19.5-in. water gauge pressure in a single-stage blower. The air is heated in the primary process heater to 325 F. Approximately 35 percent of the preheated air is used to transport the coal and char to the gasifier and to dry the pulverized coal. Process air is further preheated to 600 F in the secondary heater before being fed to the gasifier

combustion zone. Entrainment is about 27 lb char per 100 lb of coal. Complete coal gasification is not obtained in one pass through the gasifier. Unreacted char is swept out of the gasifier in the hot effluent gas and recovered after gas cooling in the char recovery system. Molten slag collects on the combustion walls and drains into a water-filled slag quench vessel, where it is quenched and fragmented under controlled conditions. The resultant slurry is educted and emptied into a common transfer tank using recycled process water as the motive fluid. Slag grinders prevent large chunks of slag from plugging transfer lines. The slag slurry is dewatered in dewatering bins, producing an ash ready for disposal. Final cleaning of the water overflowing the dewatering bin is accomplished in a settling tank, where slag fines are settled and pumped back to a dewatering bin.

The gas cooling and char recovery sections are shown on Process Flow Diagram, Figure E-4. Gases exiting the top of the reduction section of the gasifier are directed downward into the waste-heat recovery unit, where the temperature is reduced to 220 F by tubular heat transfer surfaces.

The following four heat recovery coils are stacked from top to bottom:

- High-pressure steam superheating coil
- High temperature heating coil
- Boiler feedwater heating coils
- Condensate heating coil

The waste-heat recovery boiler is designed to generate and superheat the steam to 950 F at 1450 psig. Only a small amount of waste heat is used to heat high temperature heating coil for the secondary air preheater.

High-pressure saturated steam is generated by continuously circulating boiler feedwater through the gasifier's walls.

The mixture of high-pressure saturated steam and high-temperature water is directed to the high-pressure steam drum where steam from the gasifier is separated and then superheated to 950 F in the superheater coil.

In order to recover the maximum amount of available heat and to cool the gas to 220 F, cold condensate from the surface condenser is heated from 109 to 200 F and flows to the deaerator. The superheated high-pressure 1450-psig, 950 F steam is directed to the power recovery unit to generate electrical power and extract

the required amount of 600-psig and 240-psig steam for heating and for mechanical steam drive turbines for the primary pumps, blowers, and so forth. The cooled gas effluent (220 F) containing char flows through the spray dryer into which a 33-percent char slurry is sprayed from the secondary char recovery unit.

The purpose of the spray dryer is to dry and agglomerate the solids which are collected in the wet secondary char recovery unit before they are recycled to the combustion section of the gasifier. A part of these solids is collected in the hopper bottom of the spray dryer, and the rest is collected in a char recovery cyclone. Recovered char is pneumatically transported to the gasifier with process air. Eighty-five percent of the solids is recovered by a spray dryer and cyclone; therefore, the remaining 15 percent is recovered in a Venturi scrubber. The cooled gas stream from the char recovery cyclone flows through a Venturi scrubber, where it is washed with water to remove the remaining particulate matter. Scrubber water, which contains about 2 percent char, is pumped from the bottom of the scrubber knockout vessel to the secondary char recovery unit. Hydrocyclones thicken the bottoms to about 33 percent slurry. The filtrate from the recovery unit is recycled back to the Venturi scrubbers.

GASIFICATION PROCESS EFFLUENT WATER SYSTEM

The major consumers of water in the coal gasification units are:

- The ash handling system
- The char recovery system

In order to avoid the generation of wastewater, these two systems are closed with a zero discharge.

Ash Handling System

A portion of the clarified water is recycled for slag quenching after cooling in an induced draft cooling water.

Char Recovery System

The Venturi scrubber is the main consumer of makeup water.

The filtrate from the recovery unit is recycled back to the venturi scrubbers. Raw water makeup maintains the scrubbing system in water balance and the discharge is zero.

SULFUR REMOVAL - STRETTFORD

The Stretford sulfur removal process is shown on Process Flow Diagram, Figure E-5. The Stretford process is used for removal of hydrogen sulfide, and it is a highly efficient process at atmospheric pressure. The Stretford process removes hydrogen sulfide (H_2S) and recovers the sulfur in its elemental form.

Process Description

The char-free crude gas flows up through an H_2S absorber, where the H_2S is absorbed by countercurrent contact with an alkaline solution. The desulfurized product gas from the H_2S absorber is compressed by a product gas blower to 46 in. H_2O , and then transported to the boiler.

Chemicals in the solution oxidize the absorbed H_2S to elemental sulfur. The retention time in the absorber allows the reaction to elemental sulfur to proceed essentially to completion. The reacted solution flows from the bottom of the absorber to oxidizing tanks, where it is regenerated with air sprayed into the tanks. The air also provides a medium for flotation of the sulfur to the top of the oxidizers, where it overflows into a slurry tank. The underflow from the oxidizers flows to a tank from which it is pumped back to the absorber. Sulfur from the slurry tank is pumped to the primary centrifuge which produces a wet sulfur cake that is reslurried and fed to a secondary centrifuge. The filtrate from the two centrifuges is recycled to the primary oxidizer through a filtrate tank. The sulfur cake from the secondary centrifuge is reslurried and pumped through an ejector mixer, where the sulfur is melted by the injection of steam. The molten sulfur is separated from the slurry medium (water) in a sulfur separator, and then pumped to the sulfur sump.

Published data suggests that the amount of sulfur (S) and carbonyl sulfide (COS) in the gasification process can exceed 5 percent of the total sulfur in the coal. The emissions limitation at Arthur Kill cannot be met if the S as COS exceeds only 3 percent of the total amount of sulfur in the product gas. The content of the COS in the gasifier effluent is a significant factor in the design of the Stretford unit. In the Stretford process, the content H_2S in the purified gas can be reduced to 1 ppm, but the COS cannot be removed to any significant degree.

The Stretford process is designed to remove 99.82 percent of the H_2S (22 ppm in purified gas) to meet the local sulfur oxide (SO_x) emission requirements from the combustion of H_2S and COS in the gas. This is achieved by increasing the amount of circulating absorbent and increasing the size of the H_2S absorber, oxidizing,

and supporting equipment, thereby increasing both the capital and operating cost of this system.

STEAM, BOILER FEEDWATER, AND CONDENSATE SYSTEM

Process Flow Diagram, Figure E-6, shows the overall steam, boiler feedwater, and condensate system. Twenty-eight percent of the heat input to the gasifiers is recovered by the waste-heat boiler. The waste heat is used for steam generation (1450 psig, 950 F) with a small fraction used for heating high temperature solution for the air preheaters.

The power recovery unit is a cogeneration plant which supplies 600-psig, 240-psig, and 50-psig steam for the coal gasification plant and for the mechanical drive steam turbines that drive the basic pumps and blowers with a capacity higher than 500 kW. The power recovery unit supplies the necessary amount of steam, power for internal use, and 132,000 kW for export.

Boiler feedwater from the deaerator is pumped through the waste-heat boiler to the high-pressure steam drum, where the steam is separated. Boiler feedwater is circulated through the gasifier walls and returned to the high-pressure steam drum, where the steam is separated. The high-pressure saturated steam from the steam drum is superheated to 950 F in the waste-heat boiler, and fed to the high-pressure steam header. The total high-pressure steam production is 1,547,000 lb/hr. The high-pressure steam is used (1) to drive the product gas blower and (2) in the condensing steam turbine-generator. 600 psig and 240 psig steam is extracted to meet the demand of the coal gasification plant, and 600-psig steam is used for the mechanical steam driven turbines and for the air preheater. Steam at 240 psig is used for heating air to the gasifier and melting sulfur in the Stretford unit. Steam at 50 psig is supplied by mechanical steam driven exhausts and condensate flashed from the 600-psig, 240-psig pressure level. 50 psig steam is used for heating boiler feedwater from 200 F to 250 F and for steam tracing and heating.

PLANT MAKEUP WATER SYSTEM

Figure E-7 is a schematic block flow diagram of the plant's fresh water system. A second system uses saltwater from the Arthur Kill to provide cooling water for the surface condenser on the byproduct electric power steam turbine on a once-through basis. This is a dedicated system that requires about 78,000 gpm with the saltwater returned to the Arthur Kill after usage.

The plant requires 1000 gpm of water for makeup to the gasifier cooling tower, waste-heat power cycle, and for potable water. Most of the water is required for the gasifier cooling tower.

For the purpose of this Study it was assumed that New York City water is available for makeup.

A demineralizer system is provided to meet the demands of the boiler feedwater system. It is the same as that described for Oswego, except the flow required is 100 gpm per train.

WASTEWATER TREATMENT SYSTEM

The wastewater is treated in two subsystems. One subsystem is used to treat coal pile runoff and consists of a clarifier and filters to treat the maximum anticipated runoff, based on 12 inches of rainfall in 24 hours. The clarifier and filters remove suspended solids and precipitate heavy metals in the runoff water. A second subsystem treats the waste from demineralizer regeneration, waste-heat power plant building drains, and gasifier cooling tower blowdown.

The wastewater from the demineralizer is neutralized, and passes through an oil-water separator before being discharged to the wastewater system. These wastes are mixed with the gasifier tower blowdown in the wastewater holding tank and forwarded to filters for suspended solids removal. The total wastewater flow passes through the on-line neutralization system for adjustment to an acceptable pH for discharge. The discharge complies with the requirements of the Federal and State codes.

COOLING WATER SYSTEM

The major consumer of cooling water is the surface condensor on the steam turbine. The required amount of cooling water, 78,000 gpm, is supplied from the Arthur Kill. The saltwater is sent to a primary filtration system and then to the surface condenser. The water from the condenser is returned to the Arthur Kill.

The ash handling system requires about 2000-2500 gpm of fresh water to quench the slag. The ash handling system is provided with an induced-draft mechanical cooling tower which reduces the temperature of the outgoing water from the quench vessel and dewatering bin from 120 to 80 F, and is sent back to the slag quench vessel. This system is a closed system without any discharge, and requires about 400 to 500 gpm for makeup.

BYPRODUCT POWER GENERATION

Process Flow Diagram E-8 shows the overall byproduct power generation system. Excess heat and steam generated in the gas processing units are converted into electric power. Thus, although the primary purpose of the plant is the production of

low-Btu gas, 141,000 kW is generated as a byproduct at a 100-percent loading factor.

A total of 9000 kW are consumed by the gasification plant and 132,000 kW are available for export.

The byproduct power generation system is a cogeneration plant in that 600-psig and 240-psig steam are extracted to meet the process requirements. The steam turbine is a condensing double-extraction unit.

Eighty percent of the 600-psig extraction steam is used to drive pumps and turbines. This steam exhausts into a 50-psig system. The rest of 600-psig steam is used for air heating.

The 240-psig extraction steam is used to preheat the air to the gasifier and to melt sulfur in the acid gas removal unit.

The selection of 1450 psig and 900 F for steam generating is not the most economical alternative, but is based on published reports. The amount of electrical power could be increased by generating steam at a higher pressure, 2400 psig, and temperature 1000 F.

OTHER PLANT SUPPORTING SYSTEMS AND FACILITIES

The following supporting systems and facilities are included for the coal gasification plant at Arthur Kill.

The plant instrument air system includes air receivers, air coolers, air compressors, air filters, and an instrument air dryer.

Inert Gas Generator

This system is a packaged inert gas generation unit designed to produce an inert gas by the combustion of low-Btu gas. The major pieces of equipment are the inert gas generator, two gas compressors, two drying units (dessicant type), and two receivers. The inert gas is supplied to the plant at 100 psig at the maximum capacity. The maximum oxygen content is about 500 ppm.

Flare System

A smokeless flare system is provided which is able in an emergency to incinerate the total gas production of one gasifier train. The flare system is equipped with specially designed knockout drum which permits the separation of the entrained char and liquid.

Fire Protection

Fire prevention is essential to the gasification plant, and this system will meet the requirements of National Fire Protection Association (N.F.P.A.) and the insurance companies. The fire protection system includes a fire water system which delivers the required amount of water at 100 psi. The coal gasification trains are protected by fixed sprays and fire monitor systems. A distribution system of large diameter pipes is provided.

Sulfur Storage and Loading

Sulfur may be stored in two forms, as solid and as molten sulfur.

Molten sulfur may be cast into 1-yard cubes or stored in a storage sump. The sulfur cubes may be stored in a specially designed warehouse, equipped with loading equipment which permits it to be shipped out to the consumers or to the future disposal site. For this Study, sulfur is stored in the molten form.

The sulfur storage sump is insulated and equipped with temperature controlled bottom- and side-steam coils to maintain the temperature of molten sulfur at 275 F. A steam blanket prevents air from entering the sump when it is pumped down. Two steam jacketed pumps (one spare) are provided to deliver the product to the two loading racks which are also provided.

Slag Handling

The coal gasification plant disposes of about 825 TPD dry ash or about 1000 TPD wet ash. It is provided with a lined ash pond, which is sized to store one year's production of ash.

The Arthur Kill site has a limited available space; therefore, the size of the ash pond is limited. The ash will be sent out to other disposal sites if no markets for the material are developed. Fifty percent of the ash is stored above the grade and 50 percent below grade. The total volume of the pond (assuming bulk density of 40 lb/ft³) is about 20 million ft³. The pond is to be equipped with loading facilities which permit the ash to be removed for transfer to a future disposal site or to consumers.

The disposal and storage of the ash is performed in an environmentally acceptable manner and complies with all existing Federal and State EPA requirements.

Foundations and Piling

The coal gasification plant is located next to the Arthur Kill Power Plant. The Arthur Kill Power Plant is located near the shoreline; therefore, the geologic formation and stratifications are indigenous to shorelines.

A limited number of borings in this area are available. The following observations are noted:

- Soils down to a depth of about 30 feet are very soft organic silts, with nodules of clay.
- Below this strata are clay sands that appear to be moderately stiff to very stiff.
- Rock was not reached in the boring at a depth of about 105 feet.

A total of 1977 piles were used for the construction of the No. 3 power plant (500 MW); it is estimated that about 1200 piles would be required for the construction of the coal gasification plant.

Electrical Distribution System

The total byproduct power generation is 142,000 kW. Nine thousand kW are consumed internally by the coal gasification plant; the balance is available to Con Edison. The byproduct power would be into the existing Consolidated Edison substations at Arthur Kill.

In order to have a reliable electrical system, the coal gasification plant would be provided with an independent self-contained system which includes two main substations and substations at 3000 kVA each. Provisions are made to import power during startup, shutdown, and emergency situations.

Buildings

The following buildings are provided:

- Offices, medical services
- Central control and computer room, chemical laboratory
- Warehouse with mechanical and electrical shops, and a central meeting room

- Two heated guard shacks

Miscellaneous Plant Supporting System

The construction of the coal gasification plant requires additional construction services:

- Site clearing and improvements
- Roads, drainage system, and fencing
- Onsite construction of the sanitary system and connection with the existing city sanitary system.

TABLE E-1

MAJOR EQUIPMENT SECTIONS

OPERATING

COAL HANDLING	1
COAL PULVERIZING AND DRYING	3
AIR COMPRESSION	3
AIR PREHEAT	3
GASIFICATION	3
ASH HANDLING	1
GAS COOLING AND CHAR RECOVERY	3
ACID GAS REMOVAL	3
POWER RECOVERY	1
WASTEWATER TREATING	1
WATER TREATING	1
CONDENSATE COLLECTION AND DEAERATION	1
COOLING WATER SYSTEM	1

TABLE E-2

AIR BLOWN GASIFIER MATERIAL BALANCE

INPUT				OUTPUT			
	TEMPERATURE (F)	(LB/HR)	(LB MOL/HR)		(LB/HR)	(LB MOL/HR)	PERCENT MOLES
<u>COAL</u>	77			<u>GASIFIER EFFLUENT</u>			
MOISTURE		24,162	1,341	H2	27,843	13,811	11.37
ASH		68,595		CO	753,340	26,905	22.15
CARBON		397,525	33,099	CO2	270,952	6,158	5.07
HYDROGEN		27,800	13,788	H2O	75,438	4,181	3.45
OXYGEN		24,602	1,538	H2S	23,524	690	0.56
NITROGEN		8,037	286	COS	1,394	23	0.02
SULFUR		23,009	717	N2	1,951,572	69,698	57.38
CHLORINE		880	25	TOTAL	3,104,063	121,466	100.00
TOTAL		574,610		<u>RECYCLE CHAR</u>			
<u>RECYCLE CHAR</u>				ASH	54,336		
ASH		54,336		CARBON	114,027		
CARBON		114,027		TOTAL	168,363		
MOISTURE		30,210	1,679				
TOTAL		198,573					
<u>OXIDANT</u>							
OXYGEN		567,296	17,728	SLAG	68,600		
NITROGEN		1,966,984	70,209				
MOISTURE		33,563	1,863				
SUBTOTAL		2,567,843	89,800				
TOTAL		3,341,026		TOTAL	3,341,026		

TABLE E-3

DISTRIBUTION OF ENERGY IN THE COAL

<u>INPUT</u>	<u>10⁶ BTU/HR</u>	<u>PERCENT</u>
COAL HHV	7412	100.00
<u>OUTPUT</u>		
PRODUCT GAS	4974	167.11
HEAT RECOVERED	2137	28.84
LOSSES (RADIATION AND SENSIBLE HEAT OF SLAG CHAR, AND GAS LEAVING THE WASTE-HEAT BOILER	301	4.05
TOTAL	7412	100.00
GAS EFFICIENCY - 67.1 PERCENT		
OVERALL EFFICIENCY - 95.95 PERCENT		

TABLE E-4

OVERALL DISTRIBUTION OF ENERGY
(HEAT RATE = 9788 BTU/KWH)

<u>INPUT</u>	<u>10⁶ BTU/HR</u>	<u>PERCENT</u>
COAL HHV	7412	100.00
<u>OUTPUT</u>		
PRODUCT GAS	4974	67.11
AIR PREHEATER	306	4.13
BOILER FEEDWATER PREPARATION	152	2.05
OTHER STEAM USERS	78	1.05
CONSUMPTION OF ELECTRICAL POWER	309	4.18
ELECTRICAL POWER FOR EXPORT	1292	17.43
LOSSES (RADIATION, SENSIBLE HEAT, AND OTHERS)	301	4.05
TOTAL	7412	100.00

$$\text{GAS EFFICIENCY} = \frac{4974 \times 10^6 \text{ BTU/HR}}{7412 \times 10^6 \text{ BTU/HR}} = 67.11 \text{ PERCENT}$$

$$\begin{aligned} \text{OVERALL EFFICIENCY} &= \frac{4974 \times 10^6 \text{ BTU/HR} + 1292 \times 10^6 \text{ BTU/HR}}{7412 \times 10^6 \text{ BTU/HR}} \\ &= 84.5 \text{ PERCENT} \end{aligned}$$

TABLE E-5
CONSUMPTION OF POWER

<u>DESCRIPTION</u>	<u>REQUIRED POWER (KV)</u>	<u>TYPE OF DRIVER</u>
PROCESS AIR BLOWER	2.200	MECHANICAL STEAM DRIVEN TURBINE
PRODUCT GAS BLOWER	15.000	MECHANICAL STEAM DRIVEN TURBINE
CIRCULATING PUMP BOILER FEEDWATER TO GASIFIER	1.750	MECHANICAL STEAM DRIVEN TURBINE
HIGH-PRESSURE BOILER FEEDWATER PUMP	3.500	MECHANICAL STEAM DRIVEN TURBINE
SLAG QUENCHING	170	MOTOR
CHAR RECOVERY	1.215	MOTOR
STRETTFORD	875	MOTOR
COAL PREPARATION	2.660	MOTOR
COOLING WATER TO THE SURFACE CONDENSER	1.700	MOTOR
LIGHTING	500	MOTOR
MISCELLANEOUS (WATER SUPPLY, WATER TREATMENT, WASTEWATER TREATMENT, AND OTHERS)	<u>2.000</u>	
TOTAL CONSUMPTION OF POWER	31,570

STREAM NUMBER COMPONENT	3	MOL%
	MPH	
CH ₄	0.6	
H ₂	13810.2	11.37
CO	26905.2	22.15
CO ₂	6158.4	5.07
H ₂ O	4190.7	3.45
H ₂ S	692.1	0.56
CO ₂	22.2	0.02
N ₂	69697.8	57.38
TOTAL	121475.1	100.0

NOTES:

1. THIS FLOW DIAGRAM SHOWS ONE OF THREE PARALLEL TRAINS
2. THE MATERIAL BALANCE SHOWN IS THE TOTAL FOR THREE FULL TRAINS AT DESIGN CAPACITY
3. H.T. HIGH TEMPERATURE

ARTHUR KILL
COMBUSTION ENGINEERING PROCESSPROCESS FLOW DIAGRAM
GAS COOLING &
CHAR RECOVERY

Arthur Kill Inc.
ENGINEERS DESIGNERS CONSTRUCTORS
NEW YORK

SCALE: NONE

JOB NO. 11-2892-001

FIG. E-4

11/05/80

CRDR/MISC/MISC

STREAM NUMBER	4	
COMPONENT	MPH	MOL%
CO	26909.1	21.41
CO ₂	6158.7	4.90
H ₂	13800	10.98
H ₂ S	1.2	0.00
COS	21.9	0.02
H ₂ O	69692.4	55.46
	9087	7.23
TOTAL	125670.3	100.0

NOTES:

1. THIS FLOW DIAGRAM SHOWS ONE OF THREE PARALLEL TRAINS
2. THE MATERIAL BALANCE SHOWN IS THE TOTAL FOR THREE FULL TRAINS AT DESIGN CAPACITY

ARTHUR KILL
COMBUSTION ENGINEERING PROCESSPROCESS FLOW DIAGRAM
ACID GAS REMOVAL -
STRET福德

Arthur Kill Inc.
ENGINEERING, DESIGN, CONSTRUCTION
NEW YORK

JOB NO. 11-2892-001

SCALE: NONE

FIG. E-5

NOTE
 1. THIS SYSTEM CONSISTS OF ONE FLOW DIAGRAM
 2. FIGURES GIVEN ARE LB/HR

**ARTHUR KILL
 COMBUSTION ENGINEERING PROCESS
 PROCESS FLOW DIAGRAM
 STEAM BFW &
 CONDENSATE SYSTEM**

Arthur Kill Inc.
 ENGINEERS, DESIGNERS, CONSTRUCTORS
 NEW YORK

JOB NO. 11-2892-001

SCALE: NONE

FIG. E-6

11/03/80 CADRE/MISC/MISC

NOTE:
FIGURES GIVEN ARE MLB/HR.
EXCEPT WHERE NOTED

ARTHUR KILL
COMBUSTION ENGINEERING PROCESS

BLOCK FLOW DIAGRAM
PLANT WATER SYSTEM

Chas. E. Hill, Inc.
ENGINEERS, DESIGNERS, CONSTRUCTORS
NEW YORK

SCALE: NONE

JOB NO. 11-2892-001

FIG. E-7

11/07/80

CADRE/MISC/MISC

ARTHUR KILL -
COMBUSTION ENGINEERING PROCESS
BYPRODUCT ELECTRIC POWER
GENERATOR SYSTEM

Gate & Hill, Inc.
ENGINEERS, DESIGNERS, CONSTRUCTORS
NEW YORK

JOB NO. 11-2892-001

SCALE: NONE

FIG E-8

11/03/80

CADRE/HISC/HISC

Supplement F

COMBUSTION ENGINEERING LOW-Btu GAS STORAGE FOR ARTHUR KILL

Unit No. 3 at Arthur Kill is a 500-MW Combustion Engineering (CE) tangentially fired, radiant reheat controlled circulation, balanced draft steam generator.

The flow of gas to the boiler must be controlled to meet the desired electric load demand in the same way in which the existing combustion control system controls the supply of fuel oil. With the existing controls on boiler No. 30, Unit No. 3, the change of load from 25 percent to full load can be accomplished at a rate of 3 MW/min. The required time to change the load from 25 percent to 100 percent is about 125 minutes.

Combustion Engineering contends that the gasifier load range and rate of load change capabilities are adequate to respond to the load changes required by the boiler. The CE gasification system, however, has no commercial or demonstration plant experience on load following of an electric power plant. Therefore, it is difficult to predict the technical performance of the gasifiers. Under these circumstances, it is necessary to provide some preventive measures and to investigate storage systems which ensure the continuous supply of low-Btu gas to the existing boiler No. 30.

The basic purposes of the storage system are:

- To meet the required load change for the boiler
- To ensure a continuous supply of low-Btu gas to the boiler during short-term disturbances of gasifiers, etc.
- To prevent incineration of excess low-Btu gas during load changes

In order to determine the technical and economical feasibility of a storage system, the following storage times and pressures are analyzed:

Storage Time				
	<u>10 minutes</u>	<u>1 hour</u>	<u>6 hours</u>	<u>24 hours</u>
Pressures	atm.	atm.	atm.	atm.
	25 psig	25 psig	25 psig	25 psig
	100 psig	100 psig	100 psig	100 psig

The type and size of the selected storage tanks for different pressures are shown below:

<u>Storage Pressure (psig)</u>	<u>Type</u>	<u>Diameter (ft)</u>	<u>Height or Length (ft)</u>
atm.	Gas holders	200	150
25	Spherical tanks	100	-
100	Spherical tanks	80	-
100	Shop fabricated bullets		60
100	Field erected bullet	12	120

The required storage capacity and number of vessels for the specified storage options are presented in Table F-1.

Two basic alternatives to supplying the low-Btu gas to the storage system and boilers are analyzed:

System I

The low-Btu gas from the gasifiers is sent continuously to the storage system which supplies the gas to the boiler.

System II

The low-Btu gas from the gasifiers is sent directly to the boiler with a small side stream sent to storage to meet variations in supply and demand.

System I, having an adequate amount of gas in the vessels, eliminates any possible fluctuations in the supply of the gas from the gasification system to the boiler, but requires the consumption of electrical power for pressure storage systems higher than atmospheric (25 psig or higher); therefore, the overall efficiency of the gasification system is decreased.

System II, which only periodically compresses the gas as required to fill out the system consumes significantly less energy than System I. The capacity of the compressors is smaller than for System I; therefore, the capital cost is also reduced.

The maximum electrical power requirements and the capacity of the compressors for the different alternatives are shown in Table F-2.

The atmospheric storage system does not require any additional electrical power or compressors for each of the alternatives.

The product gas is delivered to the gas holders or the boilers at 40 in. H₂O pressure.

As can be seen from Table F-2, the consumption of electrical power for System I is high; for System II, it is much lower because of the intermittent requirements to compress the gas.

The high consumption of electrical power required for 25 psig and 100 psig gas storage eliminates the possibility of applying System I for high pressure storage of low-Btu gas. System I, however, is suitable for atmospheric storage.

The total capital costs for a low-Btu gas storage system at atmospheric and 25 and 100 psig for 10 minutes, 1 hour, and 24 hours storage are estimated and shown in Table F-3. A low-Btu gas storage system includes two basic elements: compression and storage.

Tables F-4, F-5, and F-6 present the capital costs for the two basic elements--compression and storage--for different storage systems, at atmospheric pressure and 25 and 100 psig for 10 minutes, 1 hour, and 24 hours storage.

As can be seen from these tables, the capital cost for a storage system above 1 hour is very high and therefore cannot be justified.

TABLE F-1

THE REQUIRED STORAGE CAPACITY AND NUMBER OF VESSELS

STORAGE PRESSURE (PSIQ)	STORAGE TIME TYPE OF VESSELS	10 MINUTES		1 HOUR		6 HOURS		24 HOURS	
		STORAGE CAPACITY (MM FT ³)	NUMBER OF VESSELS	STORAGE CAPACITY (MM FT ³)	NUMBER OF VESSELS	STORAGE CAPACITY (MM FT ³)	NUMBER OF VESSELS	STORAGE CAPACITY (MM FT ³)	NUMBER OF VESSELS
0 (ATM)	LARGE CYLINDRICAL FLCAT. ROOF TANKS 200 FT DIAMETER 152 FT LENGTH	9.5	2	57.2	12	343.2	72	1372	288
25	SPHERE TANKS 100 FT DIAMETER	3.36	7	20.2	39	121.0	231	484	924
100	SPHERE TANKS 80 FT DIAMETER	1.14	5	6.84	26	41.0	154	164	614
100	BULLETS SHOP FABRICATED 12 FT DIAMETER 60 FT LENGTH	1.14	168	6.84	1010	41.0	6056	164	24,239
100	BULLETS FIELD ERECTED 12 FT DIAMETER 120 FT LENGTH	1.14	84						

F-4

TABLE F-2

<u>STORAGE PRESSURE</u>	<u>SYSTEM I</u>	<u>SYSTEM II</u>
	<u>CAPACITY OF COMPRESSORS IN BHP</u>	<u>CAPACITY OF COMPRESSORS IN BHP</u>
ATM.*	0	0
25 PSIG	4 COMPRESSORS 21,800 BHP EACH	2 COMPRESSORS 10,400 BHP EACH
100 PSIG	4 COMPRESSORS 50,400 BHP EACH	2 COMPRESSORS 25,000 BHP EACH

* THE ATMOSPHERIC STORAGE DOES NOT REQUIRE ANY ADDITIONAL ELECTRICAL POWER OR COMPRESSORS FOR EACH OF THESE SYSTEMS.

NOTE: THE PRODUCT GAS IS DELIVERED TO THE GAS HOLDERS OR THE BOILERS AT 40 IN. H₂O PRESSURE.

TABLE F-3
TOTAL CAPITAL COST
FOR LOW-BTU GAS STORAGE
(\$1,000,000)

<u>TIME OF STORAGE</u>	<u>ATMOSPHERIC PRESSURE</u>		<u>25 PSIG</u>		<u>100 PSIG</u>	
	<u>SYSTEM I</u>	<u>SYSTEM II</u>	<u>SYSTEM I</u>	<u>SYSTEM II</u>	<u>SYSTEM I</u>	<u>SYSTEM II</u>
10 MINUTES	39	39	60	30	85	40
1 HOUR	222	222	121	91	149	104
24 HOURS	4,928	4,928	1,698	1,677	1,660	1,628

TABLE F-4
CAPITAL COST
FOR LOW-BTU GAS STORAGE AT ATMOSPHERIC PRESSURE
(\$ 1,000,000)

<u>TIME OF STORAGE</u>	<u>SYSTEM I</u>			<u>SYSTEM II</u>		
	<u>COMPRESSION*</u>	<u>STORAGE</u>	<u>TOTAL COST</u>	<u>COMPRESSION*</u>	<u>STORAGE</u>	<u>TOTAL COST</u>
10 MINUTES	—	39	39	—	39	39,000
1 HOUR	—	222	222	—	222	222,000
24 HOURS	—	4,928	4,928	—	4,928	4,928,000

* THE PRODUCT GAS IS DELIVERED TO THE GAS HOLDERS OR THE BOILERS AT 40 IN. H₂O PRESSURE.

F-8

TABLE F-5
CAPITAL COST
FOR LOW-BTU GAS STORAGE AT 25 PSIG
(\$ 1,000,000)

<u>TIME OF STORAGE</u>	<u>SYSTEM I</u>			<u>SYSTEM II</u>		
	<u>COMPRESSION*</u>	<u>STORAGE</u>	<u>TOTAL COST</u>	<u>COMPRESSION*</u>	<u>STORAGE</u>	<u>TOTAL COST</u>
10 MINUTES	43	17	60	13	17	30
1 HOUR	43	78	121	13	78	91
24 HOURS	43	1,655	1,698	22	1,655	1,677

TABLE F-6
CAPITAL COST
FOR LOW-BTU GAS STORAGE AT 100 PSIG
(\$ 1,000,000)

<u>TIME OF STORAGE</u>	<u>SYSTEM I</u>			<u>SYSTEM II</u>		
	<u>COMPRESSION</u>	<u>STORAGE</u>	<u>TOTAL COST</u>	<u>COMPRESSION</u>	<u>STORAGE</u>	<u>TOTAL COST</u>
10 MINUTES	67	18	85	22	18	40
1 HOUR	67	82	149	22	82	104
24 HOURS	67	1,593	1,660	35	1,593	1,628

Supplement G

LOW-Btu GAS TRANSPORT FOR OSWEGO

The economics of low-Btu gas transport are considered as part of the gasification process evaluation for Oswego. For gasification processes such as the Combustion Engineering (CE) process, where the gas is generated at near-atmosphere pressure, the gas has to be compressed prior to transportation; whereas, for high-pressure low-Btu gas options, compression is not required.

Figure G-1, Low-Btu Gas Transport Systems for Oswego, shows that two lines are required to meet the design gas requirements for Oswego. For a pressure drop of 70 psi, two 54-inch inside-diameter pipelines are required; for a 100-psi pressure drop, two 48-inch pipelines are required. The gas transport lines are calculated using conventional pipeline pressure drop criteria.

A total of four two-stage compressor trains, based on the largest size commercially available, are required for either option. The energy requirements for the two 54-inch pipeline option are about 240 MW, whereas for the two 48-inch pipeline option it is about 270 MW. These values represent approximately 28 to 32 percent of the rated electrical generating capacity of the power plant. Furthermore, this energy requirement is greater than the total available byproduct energy from a low-Btu CE gasification system which provides gas to an 850-MW power plant.

Figure G-2, Low-Btu Pipeline Gas Compression System for Oswego, shows one of the four gas compression systems and the common cooling tower system. Steam is delivered to the turbines and condensate is returned to the boiler feedwater system.

The estimated total plant investment costs in mid 1986 dollars for the two schemes are as follows:

	<u>Scheme I</u>	<u>Scheme II</u>
Gas Compression System	\$101 x 10 ⁶	\$107.8 x 10 ⁶
Gas Pipeline System	\$ 29 x 10 ⁶	\$ 30.8 x 10 ⁶
Steam Supply and Condensing System	Not included	Not included

The cost of the steam generation system, condensate system, and boiler feedwater makeup systems are not included. This, added to the above, appears to make this system uneconomical for

low-pressure low-Btu gas generation such as the Combustion Engineering system.

It is one of the major contributing factors along with boiler derating and lower boiler efficiency leading to the decision not to evaluate low-Btu gas at Oswego.

FIGURE G-1
LOW-BTU GAS TRANSPORT
SYSTEMS FOR OSWEGO

FIGURE G-2
 LOW-BTU PIPELINE
 GAS COMPRESSION SYSTEM FOR OSWEGO
 FOUR - 2 STAGE PARALLEL GAS COMPRESSION UNITS
 WITH SINGLE COOLING TOWER SYSTEM

Supplement H

MEDIUM-Btu GAS TRANSPORT FOR OSWEGO

Figure H-1, Medium-Btu Gas Transmission Options for Oswego, depicts options considered for the transmission of the medium-Btu gas from the coal gasification site to the power plant, which is located about 5 miles away.

Figure H-1 shows that there are two alternatives for transmission of the gas at the pressure at which it is generated and one alternative for transmission of the gas after it has been partially depressured, with byproduct energy recovery, at the coal gasification site.

For transmission at the gas generation pressure, the line size is 24 in., with the options to recover or not recover power from the gas at the power plant site. To recover power at the power plant site requires that the gas be reheated to about 450 F. This could be done with high temperature steam from the power plant, but the quantity of steam required is large and may not be available. The other alternative is indirect heating in a fired heater, which consumes a portion of the product gas, or direct heating by combusting a portion of the gas. The latter reduces the Btu content of the gas.

There is no direct means of using the energy available from the depressurization of the gas at the power plant; therefore, electric power would have to be generated.

By partially depressuring the gas at the gas generation site, the energy recovered is used directly rather than converted to electric power. The recommended choice is to use this power to supply a portion of the oxygen compressor power requirements. With high pressure gas transmission, this power cannot be used directly for the oxygen compressor. This results in additional capital costs at both the coal gasification and power plant sites. An additional electric generator is required at the power plant site to recover the energy in the gas, and electric motor drivers and supporting facilities are required for the oxygen compressor.

The transmission line for the lower pressure case is larger than for the higher pressure alternative (42 in. versus 24 in.). The weight of metal in the higher pressure gas transmission line, however, is greater than for the lower pressure line; therefore, its cost is greater than for the low pressure line.

Considering the potential extra costs for byproduct energy recovery and the extra cost for the gas transmission line, it

appears that the lower pressure gas transmission is the most cost effective option. As such, it is used in this Study.

FIGURE H-1
**TRANSMISSION OPTIONS FOR OSWEGO
MEDIUM-BTU GAS**

Supplement I

POWER PLANT RETROFIT

PHYSICAL AND FUNCTIONAL CHANGES IN THE POWER PLANT

The gasification plant is a completely independent fuel production plant which delivers a clean, desulfurized fuel gas at specified pressure and temperature and closely controlled heating value to the power plant boiler. From the standpoint of the power plant operator, an additional boiler fuel has been added. The only operational changes required are: (1) instrumentation and control equipment to integrate this new fuel in the existing fuel and air flow control system; (2) protective interlock, monitoring, and alarm systems, which involves additional instrumentation in the control room; and (3) the new fuel supply pipes (or ducts).

The only obvious external physical change to the existing power plant is the addition of a fuel gas supply system which conveys the gas from the gas production plant to the power plant boiler in one or more ducts or large pipelines and distributes it to the burners of the boiler designated for the retrofit. This requires modifications of the existing burners and windboxes. Less obvious changes may involve modifications of heat transfer surface in the steam generator and/or in its circulation system and provisions for increasing induced-draft fan capacity including possible replacement with a larger fan and increasing the capacity of the desuperheating spray water system.

The need for these boiler modifications and the extent of these modifications are determined, case by case, for each retrofit application. The parameters which determine these decisions are described below.

Consistent with the basic objective of a coal gasifier retrofit, which is to replace fuel oil or natural gas, the existing boiler has to be capable of burning this gas to the exclusion of any other fuels, with the exception of ignition and flame stabilization requirements during startup and shutdown.

Accordingly, the flow of gas to the boiler is controlled to meet the desired electric load demand of the turbine generator unit in the same way in which the existing combustion control system controls the supply of fuel oil or natural gas. The manufacturers of the coal gasification plants involved in this study claim that the gasifier load range and rate of load change capabilities are adequate to respond to the load changes required of the turbine generator units (about one-quarter load to full load range with a rate of load change of 3 MW/min). Transmission

of the load demand signal to the gasifier feed controls should present no problem using modern electronic controls, even where large distances between the gas plant and the power plant are involved. On the other hand, the additional lag time in transmitting the increased gas flow over a long distance to the power plant may be of sufficient magnitude to render the response of the system unacceptable. The problem should be studied and resolved in each case where long distances between the gasifier plant and the power plant are involved. However this is not considered to be a problem at Oswego. In most instances where large drum type boilers are involved and distances are not excessive, the heat stored in the boiler may be sufficient to maintain turbine throttle pressure during a load increase until fuel gas supply pressure at the boiler is restored. In other cases, control system modifications can be introduced to compensate for this lag; supplementary fuel could be introduced temporarily or turbine extraction flow could be reduced temporarily. In an extreme case a limited volume of fuel gas could be stored at the power plant site.

Other controls required to assure that the heating value and temperature of the fuel gas are maintained within permissible limits are the complete responsibility of the gas production plant. The power plant operator can expect to deal with a gas supply system which functions in the same manner as those in most utilities burning natural gas. The gas pressure is controlled within prescribed limits at the entrance to the power plant, and the existing combustion control system (supplemented with the necessary equipment for gas burning) modulates the gas supply on the boiler side of the pressure-reducing station, to follow load. The combustion air flow is automatically adjusted to result in the desired fuel/air ratio for the particular low- or medium-Btu gas. Automatic burner monitoring and safety controls for tripping burners or preventing light-off when hazardous conditions exist, are required. Double valving at the burners and in the main supply with intervalve vents, assures that no leakage gas enters the furnace after a burner or fuel trip. Gas vents are carried to a safe location outside the boiler plant. These safety measures, established in the code of the National Fire Protection Association, have been in use on natural gas-fired utility power boilers for many years.

The limits of flammability of coal gas in air or oxygen mixtures are much wider apart than those for natural gas (i.e., methane) in the same mixtures (Ref. 1). This allows a much wider variation in fuel/air ratio before unstable flame conditions are encountered. This reduces the probability of a furnace explosion well below that for a similar natural gas-fired boiler.

Coal gas, unlike natural gas, contains a high percentage of CO. The possibility of gas escaping to atmosphere in the proximity of

personnel must be avoided because inhalation of this odorless, tasteless gas can lead to suffocation. Where it is necessary to vent gas in significant quantities for extended periods, the vented gas is flared. The boiler-turbine steam and feedwater cycle are physically unaffected by the introduction of the coal-derived gas fuel, and operation of this equipment takes place in the same manner as before with oil or natural gas firing.

The capacity of the unit is derated in some cases because the boiler steaming capacity is reduced when changing to low- or medium-Btu gas fuel. In other cases the boiler is able to retain its original maximum continuous rating (MCR) and virtually no performance changes or limitations occur in the turbine cycle.

The net station heat rate of the unit is higher in all cases because the boiler efficiency is lower and its auxiliary power consumption is higher. The severity of these penalties varies from case to case from almost negligible increments in the most favorable cases to penalties which are sufficiently large to become a major economic deterrent to the adoption of a retrofit project.

It is clear that the introduction of gas from a coal gasification plant as a retrofit power plant boiler fuel, requires minimal changes in the operating practices of the plant, and the physical changes which are required to accommodate this fuel are confined to the boiler and its auxiliary equipment.

The remainder of this section is devoted to an examination of the effects of burning low- and medium- Btu coal-derived gases in the two existing power plant boilers analyzed in this study and an analysis of the technical and economic feasibility of the two specific applications.

BURNING LOW- AND MEDIUM-Btu GAS IN LARGE UTILITY STEAM BOILERS

Use of a low- or medium-Btu gas as a fuel in large steam boilers does not represent a new technology. Many large boilers in the United States and abroad have operated for many years burning industrial waste gases. In the steel industry, gases derived from coal, such as blast furnace gas (500-600 Btu/scf), are commonly used as supplementary fuels for steam generation; most of the larger boiler manufacturers in this country have designed and built boilers for these applications. Their files are replete with information identifying the relationship between the properties of these gases and the associated boiler design requirements and performance results. The cleanliness of the gases in most of these industrial applications is inferior to that of the product gases considered in this Study. It follows that a boiler can be modified for burning any specified low- or

medium-Btu coal-derived gas, with the same assurance of meeting performance guarantees and operating availability as a natural gas-fired boiler.

While perhaps self-evident, this observation is made to emphasize that the questions to be addressed do not require an appraisal of the behavior of a new unknown fuel gas in a boiler, but merely an appraisal of the behavior of a known fuel gas in a boiler which was designed for another fuel.

A number of appraisals have been performed by the major boiler manufacturers on the basis of coal derived gases ranging from a low-Btu gas of about 100 Btu/scf to a medium-Btu gas of about 400 Btu/scf, fueling selected utility steam generating units designed for coal, fuel oil, and natural gas, respectively (Ref. 2 to 6). These studies have helped to improve the understanding of the properties of low- and medium-Btu coal-derived gases which are most significant for boiler design.

The most common gaseous fuel for which power boilers are designed is natural gas, which has a heating value of approximately 1000 Btu/scf. It is, therefore, natural to compare the performance of the low- and medium-Btu gases in a boiler with that of natural gas. The difference between the two types of gases is that the prime combustible substance in natural gas is methane, whereas in the coal-derived gases, it is carbon monoxide and hydrogen. Of greater significance for boiler fuel applications is the fact that while the composition of natural gas is virtually the same with only small differences in heating value, the composition of coal-derived gases varies widely according to the type of coal and the gasification process employed and hence the heating value also varies widely.

Evidently, the heating value is of primary concern in appraising the feasibility of burning a fuel in a steam generator that had been designed for a different fuel, because it determines the quantity of the new fuel which must be burned in order to achieve the same steam generation (or nearly the same) as with the original design fuel.

Although differing widely in heating value, the coal-derived gases may be divided into two classes which differ sharply with respect to feasibility for retrofit:

- Medium-Btu gas (292 Btu/scf) produced by the oxygen fed Texaco gasifiers
- Low-Btu gas (104.4 Btu/scf) produced by the air fed Combustion Engineering gasifiers

The reason for this pronounced difference lies in the fact that the low-Btu gases contain large quantities of inert nitrogen which is not present in medium-Btu gases, causing an increase in the amount of fuel gas which must be supplied to the boiler for the same Btu input. Figure I-1 taken from Reference 5 illustrates the drastic increase in fuel flow when changing from medium-Btu gas to low-Btu gas. Figure I-2 shows the variation in flue gas rate with the Btu content of the gas. Typical flue gas rates for gas and oil fired units and for coal fired units are superimposed on Figure I-2 for reference.

The effect of this increase in fuel flow and its large component of inert gas on the thermal performance of a steam generator designed for one of the common fossil fuels is twofold:

- The presence of large quantities of inert gas in the fuel reduces the flame temperature and radiant heat transfer in the furnace, reducing the heat absorption in the boiler.
- The large quantity of fuel produces correspondingly large quantities of flue gas, thereby increasing the heat absorption in the convection zones (superheater, reheater, economizer, and air heater).

These two effects therefore result in a shift in heat absorption in the steam generator, by reducing the heat absorbed in the boiler and increasing it in the convection zones. Figures from Reference 5 show the trends in heat absorption rates in the various components of a steam generating unit designed for coal, Figure I-3, and gas, Figure I-4, firing, when fueled with low-, medium-, and high-Btu gas. The sharp decrease of absorption in the furnace and boiler and the corresponding increase in the absorption rates in the convection gases when changing from medium- to low-Btu gas is clearly evident.

Reduction of heat absorption in the furnace and boiler reduces the steaming capacity, while an increase in heat absorption in the convection zones may cause temperatures to exceed allowable limits and reduces the efficiency of the boiler.

In addition to the change in heat transfer characteristics, the large volume of flue gas of the low-Btu gas fuels causes the draft losses through the steam generator unit to increase significantly.

The extent to which the performance changes and the extent to which a steam generator should be modified, depends on:

- Whether medium- or low- Btu gas is contemplated and its Btu value.

- Whether the boiler to be retrofitted is designed for coal, oil, or natural gas and the specific design of its components.

As evident from the curves on Figures I-3 and I-4, the problems of retrofit become increasingly severe as the heating value of the gas diminishes.

Boilers designed for coal firing have large furnaces and widely spaced convection surfaces, offering a greater potential for the acceptance of low-Btu gas as a fuel than boilers designed for oil or natural gas firing.

Parameters which have a major impact on the economics are:

- Steam Generator Capacity
Is the boiler seriously derated?
- Steam Generator Efficiency
Is the fuel consumption excessive?

In general, the modifications indicated and their capital cost have less economic impact than the above performance parameters. These changes involve burner modifications and the addition of a fuel gas supply duct or piping system and its associated controls. Additional changes such as modification of superheater surface, increase of desuperheating spray water capacity, or increase of induced draft (ID) fan size and ductwork may become necessary with low-Btu gas in boilers designed for oil or natural gas or both.

By summarizing the results of detailed investigations (References 2 to 6) by boiler manufacturers of burning medium- and low-Btu gases of various heating values in selected utility steam generating units designed for coal, oil, or natural gas firing, the following general conclusions can be drawn:

- A boiler designed for oil or gas burning can be converted to fire a medium-Btu gas with a high probability of retaining its design output and only a moderate loss in its efficiency.
- A medium Btu gas can be burned with less conversion cost and less, if any, deterioration in boiler performance and output, than a low Btu gas.
- Boilers designed for burning coal have the greatest potential for accepting low Btu gas; the progressively

smaller furnaces of oil- and gas-fired boilers present increasing problems in both performance and magnitude of alterations. Thus, a retrofit of a boiler designed for oil or gas fuel to low Btu gas can rarely, if ever, be justified.

- As the heating value of the proposed fuel gas diminishes below about 300 Btu/scf, the increase in the mass flow of fuel over that for which the boiler had been designed becomes so great that the heat transfer characteristics throughout the unit begin to change significantly. Heat absorption diminishes in the furnace and increases in the convection passes. The increased fuel flow and flue gas flow causes some of the convection surfaces to become overloaded, as the flow of the fluids being heated (feedwater, steam, and air, respectively) remains constant. This causes the cold fluids to be heated to higher temperatures than the original design values and when the heat transfer limits of the surface are exceeded the excess is passed on in the form of higher flue gas exit temperature (Figure I-5). This results in an overall decrease in the unit efficiency (Figure I-6).

In the superheater surfaces, this increases steam and metal temperatures, requiring increased spray and possibly a change of metallurgy. In the economizer, it may lead to steaming; in the air heater, the gas exit temperature increases the dry gas loss and thereby lowers the boiler efficiency.

An examination of air heater performance changes due to increased gas flue gas flows is covered in Supplement J.

- From an economic viewpoint, the significant results of these performance and equipment changes may be summarized as follows. As the Btu value of the gas diminishes, the following penalties are suffered with increasing severity:

- Unit rated output may be reduced primarily because of reduced furnace heat absorption.
- Unit efficiency may be reduced because of higher air heater gas exit temperature and higher hydrogen and moisture content in the fuel.
- ID fans and gas ductwork may have to be increased in size and structural strength to handle the increased flue gas flow. This increases auxiliary power requirements.

- Pressure parts including superheaters may have to be modified to keep temperatures and other parameters within permissible limits.
- Desuperheating spray capacity may have to be increased.
- The extent of modifications to the boiler and the burner system that may be required to accommodate the new fuel.

It follows from the above that an evaluation of the feasibility of retrofitting a specific boiler for a designated low- or medium-Btu fuel requires an in-depth performance analysis of each component of the steam generating unit. Preferably, this analysis should be performed by the designer/manufacture of the boiler.

A preliminary evaluation for the two steam generators under consideration is made on the basis of published studies, related prior investigations, and discussions with the manufacturers of the two boilers. In the event a specific feasibility study for retrofit of one or the other of these two steam generators is carried out, it is recommended that a detailed performance evaluation by the manufacturer of the boiler be undertaken at the outset.

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FIGURE 1-1

POUNDS OF FUEL GAS/1000 BTU
VS
HEATING VALUE OF FUEL GAS

FIGURE 1-2
POUNDS OF AIR & FLUE GAS
VS
HEATING VALUE OF GAS

FIGURE I-3
HEAT ABSORPTION
IN COAL FIRED BOILERS

FIGURE I-4
HEAT ABSORPTION
IN GAS FIRED BOILERS

FIGURE 1-5

FIGURE I-6
BOILER EFFICIENCY

Supplement J

CONCEPT OF LEVELIZED COST

Most investments are characterized by series of unequal annual cash flows, which complicate direct economic comparisons of alternative investments. For example, it is difficult to compare directly one investment alternative with a given set of initial and operating costs to a competing alternative with a lower initial cost but higher future operating costs. The complicating factor is inflation, which decreases the value today of cash flows that will occur in the future. The levelized cost method, however, solves this problem by converting a series of unequal annual costs into the equivalent series of constant annual costs having the same present value. This permits direct economic comparison of engineering alternatives.

Levelized cost is defined as follows: The levelized cost of a series of unequal annual costs is that constant annual cost which has a net present value equal to the net present value of the stream of unequal costs, when both are discounted at the same percentage rate and over the same number of time periods.

A discount rate of 14 percent is used in this analysis because it approximates the weighted average cost of capital of both Niagara Mohawk and Consolidated Edison.

While levelizing is useful for comparison of alternatives, individual levelized values are not as meaningful. This is because an individual levelized value is sensitive to the discount rate and project life used in its derivation. The relative ranking of levelized values for several alternatives, however, is comparatively insensitive to the discount rate and project life as long as all of the alternatives are evaluated at the same rate and life.

Levelized costs are calculated from the following formula:

$$L_{i,n}(\text{PWFA}) = \sum_{t=1}^n \frac{F_{i,t}(\text{PWF})}{(1+i)^t} \quad (1)$$

As an example, the levelized bus bar electricity cost for alternative 1, Oswego No. 6 with 100-percent Texaco gasifier, is derived below:

n = project life = 25 years

i = discount rate = 14%

F_t = estimated bus bar cost of electricity for each year of the 25-year project (from Table K-7)

L = levelized cost

PWFA = present worth factor for an annuity

$$= \frac{(1+i)^n - 1}{i(1+i)^n} = 6.87$$

PWF = present worth factor

$$= \frac{1}{(1+i)^t}$$

Solving equation (1) for L gives,

$$L = \frac{\sum_{t=1}^n \frac{F_t}{(1+i)^t}}{\frac{(1+i)^n - 1}{i(1+i)^n}} \dots \dots \dots (2)$$

The numerator of equation (2) is calculated as follows

<u>t</u> Period	<u>F_t</u> Bus Bar Electricity Cost	<u>F_t</u> <u>(1 + 0.14)^t</u>
1985	11.0	9.6
1986	11.1	8.5
1987	11.3	7.6
1988	11.5	6.8
1989	11.7	6.1
1990	12.0	5.5
1991	12.3	4.9
1992	12.7	4.5
1993	13.1	4.0
1994	13.6	3.7
1995	14.2	3.4
1996	14.8	3.1
1997	15.5	2.8
1998	16.2	2.6
1999	17.1	2.4
2000	18.1	2.2
2001	19.1	2.1
2002	20.3	1.9
2003	21.6	1.8
2004	23.1	1.7
2005	24.7	1.6
2006	26.4	1.5
2007	28.4	1.4
2008	30.5	1.3
2009	32.9	1.2

$$\sum_{t=1}^n \frac{F_t}{(1 + 0.14)^t} = 92.2$$

$$t = 1 \quad (1 + 0.14)$$

Substituting back into equation (2),

$$L = \frac{92.2}{6.87} = 13.4\text{¢/kWh}$$

Supplement K

REQUIRED REVENUES FOR ALTERNATIVE GASIFIERS, FOR SYNTHETIC GAS-FIRED POWER PLANT OPERATION, AND FOR CONTINUED OIL- FIRED POWER PLANT OPERATION

Required revenues for the six gasification plant alternatives, up to the gas output and including the coal cost, credit for byproduct power, and income tax, but excluding gross receipt taxes, are estimated herein. The resulting gas costs in dollars per million Btu are also calculated. The analyses are based on a 70-percent power plant load factor; 1980 coal prices of \$1.56 per million Btu for Oswego, and \$1.75 per million Btu for Arthur Kill (both escalating at 8 percent per year); and 1980 oil prices of \$4.56 per million Btu for Oswego and \$5.10 per million Btu for Arthur Kill (two oil price escalation rates are analyzed: 15 and 10 percent per year).

Gasification plant required revenues are developed in the following tables:

Table	Title		
K-1	Required Revenue Oswego Texaco	100%	Gasifier Base Case
K-2	Required Revenue Oswego Texaco	70%	Gasifier Base Case
K-3	Required Revenue Arthur Kill Texaco	100%	Gasifier Base Case
K-4	Required Revenue Arthur Kill Texaco	70%	Gasifier Base Case
K-5	Required Revenue Arthur Kill CE	100%	Gasifier Base Case
K-6	Required Revenue Arthur Kill CE	70%	Gasifier Base Case

Required revenue, including income and gross receipts taxes for the power plants using synthetic gas, and the resulting bus bar electricity costs are estimated herein for the six gasifier cases. Levelized bus bar costs, over the 25-year life of the project, are also calculated. The concept of levelized cost is discussed in Supplement J.

Synthetic gas-fired, power plant required revenues are developed in the following tables:

<u>Table</u>	<u>Title</u>	
K-7	Required Revenue Oswego Power Plant with Base Case	100% Tex Gasif
K-8	Required Revenue Oswego Power Plant with Base Case	70% Tex Gasif
K-9	Required Revenue Arthur Kill Power Plant with Base Case	100% Tex Gasif
K-10	Required Revenue Arthur Kill Power Plant with Base Case	70% Tex Gasif
K-11	Required Revenue Arthur Kill Power Plant with Base Case	100% CE Gasif
K-12	Required Revenue Arthur Kill Power Plant with Base Case	70% CE Gasif

Required revenues for the cases of the power plants continuing to use No. 6 oil, and the resulting bus bar electricity costs, are estimated, in the following tables, for comparison with the synthetic gas-fired bus bar costs:

<u>Table</u>	<u>Title</u>	
K-13	Required Revenue Oswego Power Plant Cont'd Oil Use Base Case	15% Oil Esc.
K-14	Required Revenue Oswego Power Plant Cont'd Oil Use Base Case	10% Oil Esc.
K-15	Required Revenue Arthur Kill Power Plant Cont'd Oil Use Base Case	15% Oil Esc.
K-16	Required Revenue Arthur Kill Power Plant Cont'd Oil Use Base Case	10% Oil Esc.

TABLE K-1
(Sheet 1 of 3)

GIBBS & HILL, INC.

R E Q U I R E D R E V E N U E
OSWEGO TEXACO 100% GASIFIER BASE CASE

	YEAR									
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
INVESTMENT	1150,075	1150,075	1150,075	1150,075	1150,075	1150,075	1150,075	1150,075	1150,075	1150,075
WORKING CAPITAL	59,100	62,055	65,157	68,414	71,834	75,425	79,196	83,155	87,312	91,677
GROSS CAPITAL INVESTMENT	1209,175	1212,130	1215,232	1218,489	1221,909	1225,500	1229,271	1233,230	1237,387	1241,752
CUMULATIVE DEPRECIATION	46,003	92,006	138,009	184,012	230,015	276,018	322,021	368,024	414,027	460,030
OUTSTANDING LOAN BALANCE	549,002	545,543	541,599	537,103	531,978	526,135	519,474	511,880	503,223	493,354
PROJECT EQUITY	614,170	574,581	535,624	497,374	459,916	423,347	387,776	353,326	320,137	288,368
RETURN ON EQUITY	85,983	80,441	74,987	69,632	64,388	59,268	54,288	49,465	44,819	40,371
INTEREST	77,286	76,861	76,376	75,824	75,195	74,477	73,659	72,726	71,663	70,451
INVESTMENT TAX CREDIT	4,589	4,589	4,589	4,589	4,589	4,589	4,589	4,589	4,589	4,589
DEPRECIATION	46,003	46,003	46,003	46,003	46,003	46,003	46,003	46,003	46,003	46,003
INSURANCE	1,147	1,147	1,147	1,147	1,147	1,147	1,147	1,147	1,147	1,147
PROPERTY TAX	11,473	12,390	13,381	14,451	15,607	16,855	18,203	19,659	21,231	22,929
OPERATION AND MAINTENANCE	37,308	41,038	45,141	49,655	54,620	60,082	66,090	72,699	79,968	87,964
COAL	171,822	185,567	200,412	216,444	233,759	252,459	272,655	294,467	318,024	343,465
WATER	000	000	000	000	000	000	000	000	000	000
CATALYST & CHEMICALS	802	882	970	1,067	1,173	1,290	1,419	1,560	1,716	1,887
BY-PRODUCT POWER CREDIT	27,223	29,400	31,752	34,292	37,035	39,997	43,196	46,651	50,383	54,413
BY-PRODUCT SULFUR CREDIT	000	000	000	000	000	000	000	000	000	000
BY-PRODUCT ASH CREDIT	000	000	000	000	000	000	000	000	000	000
INCOME TAX	73,244	68,522	63,877	59,314	54,848	50,497	46,244	42,135	38,177	34,388
GROSS RECEIPTS TAX	000	000	000	000	000	000	000	000	000	000
REQUIRED REVENUE	473,256	478,862	485,953	494,656	505,116	517,482	531,923	548,621	567,776	589,603
GAS COST (\$ / MMBTU)	9.518	9.631	9.773	9.949	10.159	10.408	10.698	11.034	11.419	11.858

LEVELIZED REQ'D REVENUE
(AT 14.0% DISCOUNT RATE)

581627.6567

TABLE K-1
(Sheet 2 of 3)
GIBBS & HILL, INC.
R E Q U I R E D R P V E N U E
OSWEGO TEXACO 100% GASIFIER BASE CASE

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
INVESTMENT	1150,075	1150,075	1150,075	1150,075	1150,075	1150,075	1150,075	1150,075	1150,075	1150,075
WORKING CAPITAL	96,260	101,073	106,126	111,432	117,003	122,853	128,995	135,444	142,216	149,326
GROSS CAPITAL INVESTMENT	1246,335	1251,148	1256,201	1261,507	1267,078	1272,928	1279,070	1285,519	1292,291	1299,401
CUMULATIVE DEPRECIATION	506,033	552,036	598,039	644,042	690,045	736,048	782,051	828,054	874,057	920,060
OUTSTANDING LOAN BALANCE	482,103	469,277	454,655	437,986	418,984	397,321	372,625	344,472	312,377	275,789
PROJECT EQUITY	258,199	229,835	203,507	175,479	158,049	139,559	124,394	112,993	105,857	103,552
RETURN ON EQUITY	36,147	32,176	28,490	25,127	22,126	19,538	17,415	15,819	14,819	14,497
INTEREST	69,069	67,494	65,698	63,651	61,318	58,657	55,624	52,167	48,225	43,732
INVESTMENT TAX CREDIT	4,589	4,585	4,589	4,589	4,589	4,589	4,589	4,589	4,589	4,589
DEPRECIATION	46,003	46,003	46,003	46,003	46,003	46,003	46,003	46,003	46,003	46,003
INSURANCE	1,147	1,147	1,147	1,147	1,147	1,147	1,147	1,147	1,147	1,147
PROPERTY TAX	24,763	26,744	28,883	31,193	33,688	36,383	39,293	42,436	45,830	49,496
OPERATION AND MAINTENANCE	96,760	106,436	117,079	128,786	141,664	155,830	171,413	188,554	207,409	228,149
COAL	370,942	400,617	432,666	467,279	504,661	545,033	588,635	635,725	686,583	741,509
WATER	000	000	000	000	000	000	000	000	000	000
CATALYST & CHEMICALS	2,075	2,282	2,510	2,761	3,037	3,340	3,674	4,041	4,445	4,889
BY-PRODUCT POWER CREDIT	58,766	63,467	68,544	74,027	79,949	86,344	93,251	100,711	108,767	117,468
BY-PRODUCT SULFUR CREDIT	000	000	000	000	000	000	000	000	000	000
BY-PRODUCT ASH CREDIT	000	000	000	000	000	000	000	000	000	000
INCOME TAX	30,790	27,407	24,268	21,403	18,846	16,642	14,833	13,474	12,622	12,348
GROSS RECEIPTS TAX	000	000	000	000	000	000	000	000	000	000
REQUIRED REVENUE	614,341	642,250	673,611	708,734	747,952	791,640	840,197	894,066	953,727	1019,713
GAS COST (\$ / MMBTU)	12.356	12.917	13.548	14.254	15.043	15.922	16.898	17.982	19.182	20.509

TABLE K-1
(Sheet 3 of 3)
GIBBS & HILL, INC.
R E Q U I R E D R E V E N U E
OSWEGO TEXACO 100% GASIFIER BASE CASE
YEAR
2005 2006 2007 2008 2009

INVESTMENT	1150,075	1150,075	1150,075	1150,075	1150,075
WORKING CAPITAL	156,792	164,631	172,862	181,505	190,580
<hr/>					
GROSS CAPITAL INVESTMENT	1306,867	1314,706	1322,937	1331,580	1340,655
CUMULATIVE DEPRECIATION	966,063	1012,066	1058,069	1104,072	1150,075
OUTSTANDING LOAN BALANCE ¹	234,079	186,529	132,322	70,526	078
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PROJECT EQUITY	106,725	116,111	132,546	156,982	190,502
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RETURN ON EQUITY	14,941	16,255	18,556	21,977	26,670
INTEREST	38,610	32,770	26,113	18,524	9,872
INVESTMENT TAX CREDIT	4,589	4,589	4,589	4,589	4,589
DEPRECIATION	46,003	46,003	46,003	46,003	46,003
INSURANCE	1,147	1,147	1,147	1,147	1,147
PROPERTY TAX	53,455	57,731	62,349	67,336	72,722
OPERATION AND MAINTENANCE	250,963	276,059	303,664	334,030	367,433
COAL	800,829	864,895	934,086	1008,812	1089,516
WATER	000	000	000	000	000
CATALYST & CHEMICALS	5,377	5,914	6,505	7,155	7,870
BY-PRODUCT POWER CREDIT	126,865	137,014	147,975	159,813	172,598
BY-PRODUCT SULFUR CREDIT	000	000	000	000	000
BY-PRODUCT ASH CREDIT	000	000	000	000	000
INCOME TAX	12,725	13,846	15,605	18,720	22,718
GROSS RECEIPTS TAX	000	000	000	000	000
<hr/>					
REQUIRED REVENUE	1092,596	1173,017	1261,664	1359,302	1466,764
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GAS COST (\$ / MBTU)	21.975	23.592	25.375	27.339	29.501

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
INVESTMENT	873,371	873,371	873,371	873,371	873,371	873,371	873,371	873,371	873,371	873,371
WORKING CAPITAL	49,400	51,870	54,463	57,186	60,045	63,047	66,199	69,508	72,983	76,632
GROSS CAPITAL INVESTMENT	922,771	925,241	927,834	930,557	933,416	936,418	939,570	942,879	946,354	950,003
CUMULATIVE DEPRECIATION	34,934	69,869	104,802	139,736	174,670	209,604	244,538	279,472	314,406	349,340
OUTSTANDING LOAN BALANCE	416,914	414,287	411,293	407,879	403,987	399,550	394,492	388,726	382,153	374,659
PROJECT EQUITY	470,923	441,085	411,739	382,942	354,759	327,264	300,540	274,681	249,795	226,004
RETURN ON EQUITY	65,929	61,752	57,643	53,611	49,666	45,816	42,075	38,455	34,971	31,640
INTEREST	58,691	58,368	58,001	57,581	57,103	56,558	55,937	55,229	54,422	53,501
INVESTMENT TAX CREDIT	3,484	3,484	3,484	3,484	3,484	3,484	3,484	3,484	3,484	3,484
DEPRECIATION	34,934	34,934	34,934	34,934	34,934	34,934	34,934	34,934	34,934	34,934
INSURANCE	871	871	871	871	871	871	871	871	871	871
PROPERTY TAX	8,709	9,405	10,157	10,969	11,846	12,793	13,816	14,921	16,114	17,403
OPERATION AND MAINTENANCE	28,786	31,664	34,830	38,313	42,144	46,358	50,993	56,092	61,701	67,871
COAL	171,822	185,567	200,412	216,444	233,759	252,459	272,655	294,467	318,024	343,465
WATER	000	000	000	000	000	000	000	000	000	000
CATALYST & CHEMICALS	802	882	970	1,067	1,173	1,290	1,419	1,560	1,716	1,887
BY-PRODUCT POWER CREDIT	27,223	29,400	31,752	34,292	37,035	39,997	43,196	46,651	50,383	54,413
BY-PRODUCT SULFUR CREDIT	000	000	000	000	000	000	000	000	000	000
BY-PRODUCT ASH CREDIT	000	000	000	000	000	000	000	000	000	000
INCOME TAX	56,161	52,601	49,101	45,668	42,307	39,027	35,840	32,757	29,788	26,951
GROSS RECEIPTS TAX	000	000	000	000	000	000	000	000	000	000
REQUIRED REVENUE	395,998	403,160	411,683	421,682	433,284	446,625	461,860	479,151	498,674	520,626
GAS COST (\$ / MMBTU)	7.964	8.108	8.280	8.481	8.714	8.982	9.289	9.637	10.029	10.471

LEVELIZED REQ'D REVENUE	507253.5115
(AT 14.0% DISCOUNT RATE	

TABLE K-2
(Sheet 2 of 3)
GIBBS & HILL, INC.
R E Q U I R E D R E V E N U E
OSWEGO TEXACO 70% GASIFIER BASE CASE

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
INVESTMENT	873,371	873,371	873,371	873,371	873,371	873,371	873,371	873,371	873,371	873,371
WORKING CAPITAL	80,463	84,486	88,710	93,145	97,802	102,692	107,826	113,217	118,877	124,820
GROSS CAPITAL INVESTMENT	953,834	957,857	962,081	966,516	971,173	976,063	981,197	986,588	992,248	998,191
CUMULATIVE DEPRECIATION	384,274	419,208	454,142	489,076	524,010	558,944	593,878	628,812	663,746	698,680
OUTSTANDING LOAN BALANCE	366,116	356,377	345,275	332,618	318,189	301,740	282,988	261,611	237,241	209,459
PROJECT EQUITY	203,444	182,272	162,664	144,822	128,974	115,379	104,331	96,165	91,261	90,052
RETURN ON EQUITY	28,482	25,518	22,772	20,275	18,056	16,153	14,606	13,463	12,776	12,607
INTEREST	52,452	51,256	49,893	48,338	46,566	44,546	42,243	39,618	36,625	33,213
INVESTMENT TAX CREDIT	3,484	3,484	3,484	3,484	3,484	3,484	3,484	3,484	3,484	3,484
DEPRECIATION	34,934	34,934	34,934	34,934	34,934	34,934	34,934	34,934	34,934	34,934
INSURANCE	871	871	871	871	871	871	871	871	871	871
PROPERTY TAX	18,795	20,298	21,921	23,674	25,567	27,612	29,820	32,205	34,781	37,563
OPERATION AND MAINTENANCE	74,658	82,123	90,335	99,368	109,304	120,234	132,257	145,482	160,030	176,033
COAL	370,942	400,617	432,666	467,279	504,661	545,033	588,635	635,725	686,583	741,509
WATER	000	000	000	000	000	000	000	000	000	000
CATALYST & CHEMICALS	2,075	2,282	2,510	2,761	3,037	3,340	3,674	4,041	4,445	4,889
BY-PRODUCT POWER CREDIT	58,766	63,467	68,544	74,027	79,949	86,344	93,251	100,711	108,767	117,468
BY-PRODUCT SULFUR CREDIT	000	000	000	000	000	000	000	000	000	000
BY-PRODUCT ASH CREDIT	000	000	000	000	000	000	000	000	000	000
INCOME TAX	24,261	21,737	19,398	17,270	15,379	13,759	12,440	11,466	10,881	10,738
GROSS RECEIPTS TAX	000	000	000	000	000	000	000	000	000	000
REQUIRED REVENUE	545,220	572,685	603,272	637,259	674,942	716,654	762,745	813,610	869,675	931,405
GAS COST (\$ / MMBTU)	10.966	11.518	12.133	12.817	13.575	14.414	15.341	16.364	17.491	18.733

TABLE K-2
(Sheet 3 of 3)
GIBBS & HILL, INC.

	R E Q U I R E D R E V E N U E				
	OSWEGO	TEXACO	70% GASIFIER	BASE CASE	YEAR
	2005	2006	2007	2008	2009
INVESTMENT	873,371	873,371	873,371	873,371	873,371
WORKING CAPITAL	131,061	137,614	144,494	151,718	159,303
GROSS CAPITAL INVESTMENT	1004,432	1010,985	1017,865	1025,089	1032,674
CUMULATIVE DEPRECIATION	733,614	768,548	803,482	838,416	873,350
OUTSTANDING LOAN BALANCE	177,788	141,683	100,523	53,601	109
PROJECT EQUITY	93,030	100,754	113,860	133,072	159,215
RETURN ON EQUITY	13,024	14,105	15,940	18,630	22,290
INTEREST	29,324	24,890	19,835	14,073	7,503
INVESTMENT TAX CREDIT	3,484	3,484	3,484	3,484	3,484
DEPRECIATION	34,934	34,934	34,934	34,934	34,934
INSURANCE	871	871	871	871	871
PROPERTY TAX	40,568	43,613	47,318	51,103	55,191
OPERATION AND MAINTENANCE	193,636	212,599	234,298	257,727	283,499
COAL	800,829	864,695	934,086	1008,812	1089,516
WATER	000	000	000	000	000
CATALYST & CHEMICALS	5,377	5,614	6,505	7,155	7,870
BY-PRODUCT POWER CREDIT	126,865	137,614	147,975	159,813	172,598
BY-PRODUCT SULFUR CREDIT	000	000	000	000	000
BY-PRODUCT ASH CREDIT	000	000	000	000	000
INCOME TAX	11,094	12,614	13,577	15,868	18,987
GROSS RECEIPTS TAX	000	000	000	000	000
REQUIRED REVENUE	999,308	1073,537	1155,905	1245,876	1344,579
GAS COST (\$ / MMBTU)	20.099	21.600	23.248	25.058	27.043

TABLE K-3
(Sheet 1 of 3)

GIBBS & HILL, INC.

REQUIRED REVENUE

ARTHUR KILL TEXACO 100% GASIFIER BASE CASE

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
INVESTMENT	830,205	830,205	830,205	830,205	830,205	830,205	830,205	830,205	830,205	830,205
WORKING CAPITAL	48,400	50,820	53,361	56,029	58,830	61,771	64,859	68,101	71,506	75,081
GROSS CAPITAL INVESTMENT	878,605	881,025	883,566	886,234	889,035	891,976	895,064	898,306	901,711	905,286
CUMULATIVE DEPRECIATION	33,208	66,416	99,624	132,832	166,040	199,248	232,456	265,664	298,872	332,080
OUTSTANDING LOAN BALANCE	453,188	449,353	445,058	440,247	434,859	428,824	422,065	414,495	406,016	396,520
PROJECT EQUITY	392,209	365,256	338,884	313,155	288,136	263,904	240,543	218,147	196,823	176,686
RETURN ON EQUITY	70,597	65,746	60,999	56,367	51,864	47,502	43,297	39,266	35,428	31,803
INTEREST	54,794	54,383	53,923	53,407	52,830	52,183	51,459	50,648	49,739	48,722
INVESTMENT TAX CREDIT	3,313	3,313	3,313	3,313	3,313	3,313	3,313	3,313	3,313	3,313
DEPRECIATION	33,208	33,208	33,208	33,208	33,208	33,208	33,208	33,208	33,208	33,208
INSURANCE	828	828	828	828	828	828	828	828	828	828
PROPERTY TAX	57,980	57,980	57,980	57,980	57,980	57,980	57,980	57,980	57,980	57,980
OPERATION AND MAINTENANCE	25,706	28,276	31,103	34,213	37,634	41,397	45,536	50,089	55,097	60,606
COAL	109,171	117,904	127,336	137,522	148,523	160,404	173,236	187,094	202,061	218,225
WATER	910	982	1,060	1,144	1,235	1,333	1,439	1,554	1,678	1,812
CATALYST & CHEMICALS	617	678	745	819	900	990	1,089	1,197	1,316	1,447
BY-PRODUCT POWER CREDIT	22,799	24,622	26,591	28,718	31,015	33,496	36,175	39,069	42,194	45,569
BY-PRODUCT SULFUR CREDIT	000	000	000	000	000	000	000	000	000	000
BY-PRODUCT ASH CREDIT	000	000	000	000	000	000	000	000	000	000
INCOME TAX	60,137	56,005	51,961	48,014	44,179	40,462	36,881	33,448	30,177	27,090
GROSS RECEIPTS TAX	000	000	000	000	000	000	000	000	000	000
REQUIRED REVENUE	387,836	388,055	389,239	391,471	394,853	399,478	405,465	412,930	422,005	432,839
GAS COST (\$ / MMBTU)	13.826	13.833	13.876	13.955	14.076	14.241	14.454	14.720	15.044	15.430
LEVELIZED REQ'D REVENUE (AT 14.0% DISCOUNT RATE)	437622.5976									

TABLE K-3
(Sheet 2 of 3)
GIBBS & HILL, INC.
R E Q U I R E D R E V E N U E
ARTHUR KILL TEXACO 100% GASIFIER BASE CASE

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
INVESTMENT	830,205	830,205	830,205	830,205	830,205	830,205	830,205	830,205	830,205	830,205
WORKING CAPITAL	78,835	82,776	86,914	91,259	95,821	100,612	105,642	110,924	116,470	122,293
GROSS CAPITAL INVESTMENT	909,040	912,981	917,119	921,464	926,026	930,817	935,847	941,129	946,675	952,498
CUMULATIVE DEPRECIATIONS	365,289	398,496	431,704	464,912	498,120	531,328	564,536	597,744	630,952	664,160
OUTSTANDING LOAN BALANCE	385,884	373,972	360,630	345,687	328,951	310,207	289,214	265,701	239,367	209,873
PROJECT EQUITY	157,868	140,513	124,785	110,865	98,955	89,282	82,097	77,684	76,356	78,465
RETURN ON EQUITY	28,416	25,292	22,461	19,955	17,811	16,070	14,777	13,983	13,744	14,123
INTEREST	47,582	46,306	44,876	43,275	41,482	39,474	37,225	34,705	31,884	28,724
INVESTMENT TAX CREDIT	3,313	3,313	3,313	3,313	3,313	3,313	3,313	3,313	3,313	3,313
DEPRECIATION	33,208	33,208	33,208	33,208	33,208	33,208	33,208	33,208	33,208	33,208
INSURANCE	828	828	828	828	828	828	828	828	828	828
PROPERTY TAX	57,980	57,980	57,980	57,980	57,980	57,980	57,980	57,980	57,980	57,980
OPERATION AND MAINTENANCE	66,666	73,332	80,665	88,731	97,604	107,364	118,100	129,910	142,901	157,191
COAL	235,683	254,537	274,899	296,890	320,641	346,292	373,995	403,914	436,227	471,125
WATER	1,956	2,112	2,280	2,462	2,658	2,870	3,099	3,346	3,613	3,902
CATALYST & CHEMICALS	1,591	1,750	1,925	2,117	2,328	2,560	2,816	3,097	3,406	3,746
BY-PRODUCT POWER CREDIT	49,214	53,151	57,403	61,995	66,954	72,310	78,094	84,341	91,088	98,375
BY-PRODUCT SULFUR CREDIT	000	000	000	000	000	000	000	000	000	000
BY-PRODUCT ASH CREDIT	000	000	000	000	000	000	000	000	000	000
INCOME TAX	24,205	21,544	19,133	16,998	15,172	13,688	12,587	11,911	11,707	12,029
GROSS RECEIPTS TAX	000	000	000	000	000	000	000	000	000	000
REQUIRED REVENUE	445,588	460,425	477,539	497,136	519,445	544,711	573,208	605,228	641,097	681,168
GAS COST (\$ / MMBTU)	15.884	16.413	17.023	17.722	18.517	19.418	20.434	21.575	22.854	24.283

TABLE K-3
(Sheet 3 of 3)
GIBBS & HILL, INC.

	REQUIRED REVENUE					BASE CASE
	ARTHUR KILL	TEXACO	100% GASIFIER			
	2005	2006	2007	2008	2009	
INVESTMENT	830,205	830,205	830,205	830,205	830,205	
WORKING CAPITAL	128,407	134,827	141,568	148,646	156,078	
GROSS CAPITAL INVESTMENT	958,612	965,032	971,773	978,851	986,283	
CUMULATIVE DEPRECIATION	697,368	730,576	763,784	796,992	830,200	
OUTSTANDING LOAN BALANCE ¹	176,839	139,841	98,403	51,993	013	
PROJECT EQUITY	84,405	94,615	109,586	129,866	156,070	
RETURN ON EQUITY	15,192	17,030	19,725	23,375	28,092	
INTEREST	25,184	21,220	16,780	11,808	6,238	
INVESTMENT TAX CREDIT	3,313	3,313	3,313	3,313	3,313	
DEPRECIATION	33,208	33,208	33,208	33,208	33,208	
INSURANCE	828	828	828	828	828	
PROPERTY TAX	57,980	57,980	57,980	57,980	57,980	
OPERATION AND MAINTENANCE	172,910	190,201	209,221	230,143	253,157	
COAL	508,815	549,520	593,481	640,959	692,235	
WATER	4,214	4,551	4,915	5,308	5,732	
CATALYST & CHEMICALS	4,120	4,532	4,905	5,483	6,031	
BY-PRODUCT POWER CREDIT	106,245	114,744	123,923	133,836	144,542	
BY-PRODUCT SULFUR CREDIT	000	000	000	000	000	
BY-PRODUCT ASH CREDIT	000	000	000	000	000	
INCOME TAX	12,940	14,505	16,801	19,911	23,929	
GROSS RECEIPTS TAX	000	000	000	000	000	
REQUIRED REVENUE	725,833	775,518	830,608	891,854	959,575	
GAS COST (\$ / MMBTU)	25.875	27.646	29.613	31.794	34.208	

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TABLE K-4

(Sheet 1 of 3)
GIBBS & HILL, INC.REQUIRED REVENUE
ARTHUR KILL TEXACO 70% GASIFIER

BASE CASE

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
INVESTMENT	629,576	629,576	629,576	629,576	629,576	629,576	629,576	629,576	629,576	629,576
WORKING CAPITAL	39,500	41,475	43,548	45,725	48,011	50,411	52,931	55,577	58,355	61,272
GROSS CAPITAL INVESTMENT	669,076	671,051	673,124	675,301	677,587	679,987	682,507	685,153	687,931	690,848
CUMULATIVE DEPRECIATION	25,183	50,366	75,549	100,732	125,915	151,098	176,281	201,464	226,647	251,830
OUTSTANDING LOAN BALANCE	343,670	340,763	337,507	333,860	329,776	325,201	320,077	314,338	307,911	300,712
PROJECT EQUITY	300,223	279,922	260,068	240,709	221,896	203,688	186,149	169,351	153,373	138,306
RETURN ON EQUITY	54,040	50,385	46,812	43,327	39,941	36,663	33,506	30,483	27,607	24,895
INTEREST	41,552	41,241	40,892	40,501	40,064	39,573	39,024	38,409	37,721	36,949
INVESTMENT TAX CREDIT	2,512	2,512	2,512	2,512	2,512	2,512	2,512	2,512	2,512	2,512
DEPRECIATION	25,183	25,183	25,183	25,183	25,183	25,183	25,183	25,183	25,183	25,183
INSURANCE	628	628	628	628	628	628	628	628	628	628
PROPERTY TAX	43,953	43,953	43,953	43,953	43,953	43,953	43,953	43,953	43,953	43,953
OPERATION AND MAINTENANCE	19,931	21,924	24,116	26,527	29,179	32,096	35,305	38,835	42,718	46,989
COAL	109,171	117,904	127,336	137,522	148,523	160,404	173,236	187,094	202,061	218,225
WATER	910	982	1,060	1,144	1,235	1,333	1,439	1,554	1,678	1,812
CATALYST & CHEMICALS	617	678	745	819	900	990	1,089	1,197	1,316	1,447
BY-PRODUCT POWER CREDIT	22,799	24,622	26,591	28,718	31,015	33,496	36,175	39,069	42,194	45,569
BY-PRODUCT SULFUR CREDIT	000	000	000	000	000	000	000	000	000	000
BY-PRODUCT ASH CREDIT	000	000	000	000	000	000	000	000	000	000
INCOME TAX	46,053	42,920	39,875	36,907	34,022	31,229	28,540	25,966	23,516	21,205
GROSS RECEIPTS TAX	000	000	000	000	000	000	000	000	000	000
REQUIRED REVENUE	316,707	318,664	321,497	325,281	330,101	336,044	343,216	351,721	361,675	373,205
GAS COST (\$ / MBTU)	11.290	11.360	11.461	11.596	11.767	11.979	12.235	12.538	12.893	13.304
LEVELIZED REQ'D REVENUE (AT 14.0% DISCOUNT RATE)	372326.5578									

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TABLE K-4
(Sheet 2 of 3)

GIBBS & HILL, INC.

REQUIRED REVENUE
ARTHUR KILL TEXACO 70% GASIFIER

BASE CASE

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
INVESTMENT	629,576	629,576	629,576	629,576	629,576	629,576	629,576	629,576	629,576	629,576
WORKING CAPITAL	64,335	67,551	70,928	74,474	78,197	82,106	86,211	90,521	95,047	99,799
GROSS CAPITAL INVESTMENT	693,911	697,127	700,504	704,050	707,773	711,682	715,787	720,097	724,623	729,375
CUMULATIVE DEPRECIATION	277,013	302,196	327,379	352,562	377,745	402,928	428,111	453,294	478,477	503,660
OUTSTANDING LOAN BALANCE	292,649	283,619	273,505	262,178	249,491	235,282	219,368	201,544	181,581	159,222
PROJECT EQUITY	124,249	111,312	99,620	89,310	80,537	73,472	68,308	65,259	64,565	66,493
RETURN ON EQUITY	22,364	20,036	17,931	16,075	14,496	13,224	12,295	11,746	11,621	11,968
INTEREST	36,005	35,110	34,034	32,821	31,461	29,939	28,234	26,324	24,185	21,789
INVESTMENT TAX CREDIT	2,512	2,512	2,512	2,512	2,512	2,512	2,512	2,512	2,512	2,512
DEPRECIATION	25,183	25,183	25,183	25,183	25,183	25,183	25,183	25,183	25,183	25,183
INSURANCE	628	628	628	628	628	628	628	628	628	628
PROPERTY TAX	43,953	43,953	43,953	43,953	43,953	43,953	43,953	43,953	43,953	43,953
OPERATION AND MAINTENANCE	51,687	56,855	62,540	68,794	75,673	83,240	91,564	100,720	110,792	121,871
COAL	235,683	254,537	274,899	296,890	320,641	346,292	373,995	403,914	436,227	471,125
WATER	1,956	2,112	2,280	2,462	2,658	2,870	3,099	3,346	3,613	3,902
CATALYST & CHEMICALS	1,591	1,750	1,925	2,117	2,328	2,560	2,816	3,097	3,406	3,746
BY-PRODUCT POWER CREDIT	49,214	53,151	57,403	61,995	66,954	72,310	78,094	84,341	91,088	98,375
BY-PRODUCT SULFUR CREDIT	000	000	000	000	000	000	000	000	000	000
BY-PRODUCT ASH CREDIT	000	000	000	000	000	000	000	000	000	000
INCOME TAX	19,050	17,066	15,274	13,692	12,348	11,264	10,472	10,005	9,898	10,194
GROSS RECEIPTS TAX	000	000	000	000	000	000	000	000	000	000
REQUIRED REVENUE	386,454	401,575	418,732	438,108	459,903	484,331	511,633	542,063	575,906	613,472
GAS COST (\$ / MBTU)	13.776	14.315	14.927	15.618	16.395	17.266	18.239	19.324	20.530	21.869

TABLE K-4
(Sheet 3 of 3)
GIBBS & HILL, INC.
REQUIRED REVENUE
ARTHUR KILL TEXACO 70% GASIFIER BASE CASE

	2005	2006	2007	2008	2009
INVESTMENT	629,576	629,576	629,576	629,576	629,576
WORKING CAPITAL	104,788	110,027	115,528	121,304	127,369
GROSS CAPITAL INVESTMENT	734,364	739,603	745,104	750,880	756,945
CUMULATIVE DEPRECIATION	528,843	554,036	579,209	604,392	629,575
OUTSTANDING LOAN BALANCE	134,180	106,133	74,720	39,538	134
PROJECT EQUITY	71,341	79,444	91,175	106,950	127,236
RETURN ON EQUITY	12,841	14,299	16,411	19,251	22,902
INTEREST	19,106	16,101	12,735	8,966	4,744
INVESTMENT TAX CREDIT	2,512	2,512	2,512	2,512	2,512
DEPRECIATION	25,183	25,183	25,183	25,183	25,183
INSURANCE	628	628	628	628	628
PROPERTY TAX	43,953	43,953	43,953	43,953	43,953
OPERATION AND MAINTENANCE	134,058	147,463	162,209	178,429	196,271
COAL	508,815	549,520	593,481	640,959	692,235
WATER	4,214	4,551	4,915	5,308	5,732
CATALYST & CHEMICALS	4,120	4,532	4,985	5,483	6,031
BY-PRODUCT POWER CREDIT	106,245	114,744	123,923	133,836	144,542
BY-PRODUCT SULFUR CREDIT	000	000	000	000	000
BY-PRODUCT ASH CREDIT	000	000	000	000	000
INCOME TAX	10,937	12,179	13,979	16,398	19,507
GROSS RECEIPTS TAX	000	000	000	000	000
REQUIRED REVENUE	655,098	701,153	752,044	808,210	870,132
GAS COST (\$ / MMBTU)	23.353	24.995	26.809	28.812	31.019

TABLE K-5
(SHEET 1 of 3)
GIBBS & HILL, INC.
R E Q U I R E D R E V E N U E
ARTHUR KILL C. E. 100 % GASIFIER BASE CASE

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
INVESTMENT	611,596	611,596	611,596	611,596	611,596	611,596	611,596	611,596	611,596	611,596
WORKING CAPITAL	36,000	37,800	39,690	41,674	43,757	45,944	48,241	50,653	53,185	55,844
GROSS CAPITAL INVESTMENT	647,596	649,396	651,286	653,270	655,353	657,540	659,837	662,249	664,781	667,440
CUMULATIVE DEPRECIATION	24,463	48,926	73,389	97,852	122,315	146,778	171,241	195,704	220,167	244,630
OUTSTANDING LOAN BALANCE	333,855	331,030	327,866	324,322	320,353	315,908	310,929	305,352	299,106	292,111
PROJECT EQUITY	289,278	269,440	250,031	231,096	212,685	194,854	177,667	161,193	145,508	130,699
RETURN ON EQUITY	52,070	48,499	45,005	41,597	38,283	35,073	31,980	29,014	26,191	23,525
INTEREST	40,366	40,063	39,724	39,344	38,919	38,443	37,909	37,311	36,642	35,893
INVESTMENT TAX CREDIT	2,439	2,439	2,439	2,439	2,439	2,439	2,439	2,439	2,439	2,439
DEPRECIATION	24,463	24,463	24,463	24,463	24,463	24,463	24,463	24,463	24,463	24,463
INSURANCE	610	610	610	610	610	610	610	610	610	610
PROPERTY TAX	42,690	42,690	42,690	42,690	42,690	42,690	42,690	42,690	42,690	42,690
OPERATION AND MAINTENANCE	20,303	22,333	24,566	27,022	29,724	32,696	35,965	39,561	43,517	47,868
COAL	116,993	126,352	136,460	147,376	159,166	171,899	185,650	200,502	216,542	233,865
WATER	910	982	1,060	1,144	1,235	1,333	1,439	1,554	1,678	1,812
CATALYST & CHEMICALS	788	866	952	1,047	1,151	1,266	1,392	1,531	1,684	1,852
BY-PRODUCT POWER CREDIT	52,613	56,822	61,367	66,276	71,578	77,304	83,488	90,167	97,380	105,170
BY-PRODUCT SULFUR CREDIT	000	000	000	000	000	000	000	000	000	000
BY-PRODUCT ASH CREDIT	000	000	000	000	000	000	000	000	000	000
INCOME TAX	44,355	41,312	38,337	35,433	32,611	29,875	27,240	24,714	22,309	20,038
GROSS RECEIPTS TAX	000	000	000	000	000	000	000	000	000	000
REQUIRED REVENUE	288,496	288,909	290,061	292,011	294,835	298,605	303,411	309,344	316,507	325,007
GAS COST (\$ / MMBTU)	9.458	9.472	9.509	9.573	9.666	9.790	9.947	10.142	10.376	10.655
LEVELIZED REQ'D REVENUE (AT 14.0% DISCOUNT RATE)	327958.0525									

TABLE K-5
(Sheet 2 of 3)
GIBBS & HILL, INC.
REQUIRED REVENUE
ARTHUR KILL C. E. 100 % GASIFIER BASE CASE

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
INVESTMENT	611,596	611,596	611,596	611,596	611,596	611,596	611,596	611,596	611,596	611,596
WORKING CAPITAL	58,636	61,567	64,645	67,877	71,270	74,833	78,574	82,502	86,627	90,958
GROSS CAPITAL INVESTMENT	670,232	673,163	676,241	679,473	682,866	686,429	690,170	694,098	698,223	702,554
CUMULATIVE DEPRECIATION	269,093	293,556	318,019	342,482	366,945	391,408	415,871	440,334	464,797	489,260
OUTSTANDING LOAN BALANCE	284,276	275,501	265,673	254,665	242,336	228,528	213,063	195,742	176,343	154,616
PROJECT EQUITY	116,863	104,106	92,549	82,326	73,585	66,493	61,236	58,022	57,083	58,678
RETURN ON EQUITY	21,035	18,739	16,658	14,818	13,245	11,968	11,022	10,443	10,274	10,562
INTEREST	35,053	34,113	33,060	31,880	30,559	29,080	27,423	25,567	23,489	21,161
INVESTMENT TAX CREDIT	2,439	2,439	2,439	2,439	2,439	2,439	2,439	2,439	2,439	2,439
DEPRECIATION	24,463	24,463	24,463	24,463	24,463	24,463	24,463	24,463	24,463	24,463
INSURANCE	610	610	610	610	610	610	610	610	610	610
PROPERTY TAX	42,690	42,690	42,690	42,690	42,690	42,690	42,690	42,690	42,690	42,690
OPERATION AND MAINTENANCE	52,654	57,919	63,710	70,081	77,089	84,797	93,276	102,603	112,863	124,149
COAL	252,574	272,779	294,601	318,169	343,622	371,111	400,799	432,862	467,490	504,889
WATER	1,956	2,112	2,280	2,462	2,658	2,870	3,099	3,346	3,613	3,902
CATALYST & CHEMICALS	2,037	2,240	2,464	2,710	2,981	3,279	3,606	3,966	4,362	4,798
BY-PRODUCT POWER CREDIT	113,583	122,669	132,482	143,080	154,526	166,888	180,239	194,658	210,230	227,048
BY-PRODUCT SULFUR CREDIT	000	000	000	000	000	000	000	000	000	000
BY-PRODUCT ASH CREDIT	000	000	000	000	000	000	000	000	000	000
INCOME TAX	17,918	15,961	14,188	12,622	11,281	10,194	9,388	8,894	8,751	8,996
GROSS RECEIPTS TAX	000	000	000	000	000	000	000	000	000	000
REQUIRED REVENUE	334,968	344,518	359,803	374,986	392,233	411,735	433,698	458,347	485,936	516,733
GAS COST (\$ / MBTU)	10.982	11.360	11.796	12.294	12.859	13.499	14.219	15.027	15.931	16.941

TABLE K-5
(Sheet 3 of 3)
GIBBS & HILL, INC.
REQUIRED REVENUE
ARTHUR KILL C. E. 100 % GASIFIER BASE CASE

	2005	2006	2007	2008	2009
INVESTMENT	611,596	611,596	611,596	611,596	611,596
WORKING CAPITAL	95,505	100,280	105,294	110,558	116,085
GROSS CAPITAL INVESTMENT	707,101	711,876	716,890	722,154	727,681
CUMULATIVE DEPRECIATION	513,723	538,186	562,649	587,112	611,575
OUTSTANDING LOAN BALANCE	130,281	103,026	72,500	38,311	019
PROJECT EQUITY	63,097	70,664	81,741	96,731	116,087
RETURN ON EQUITY	11,357	12,719	14,713	17,411	20,895
INTEREST	18,553	15,633	12,362	8,699	4,596
INVESTMENT TAX CREDIT	2,439	2,439	2,439	2,439	2,439
DEPRECIATION	24,463	24,463	24,463	24,463	24,463
INSURANCE	610	610	610	610	610
PROPERTY TAX	42,690	42,690	42,690	42,690	42,690
OPERATION AND MAINTENANCE	136,563	150,219	165,240	181,764	199,940
COAL	545,280	588,902	636,014	686,895	741,846
WATER	4,214	4,551	4,915	5,308	5,732
CATALYST & CHEMICALS	5,277	5,004	6,384	7,022	7,724
BY-PRODUCT POWER CREDIT	245,211	264,827	286,013	308,894	333,605
BY-PRODUCT SULFUR CREDIT	000	000	000	000	000
BY-PRODUCT ASH CREDIT	000	000	000	000	000
INCOME TAX	9,674	10,833	12,531	14,831	17,798
GROSS RECEIPTS TAX	000	000	000	000	000
REQUIRED REVENUE	551,031	589,158	631,470	678,360	730,250
GAS COST (\$ / MMBTU)	18.065	19.316	20.703	22.240	23.941

TABLE K-6
(Sheet 1 of 3)
GIBBS & HILL, INC.
R E Q U I R E D R E V E N U E
ARTHUR KILL C. E. 70 % GASIFIER BASE CASE

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
INVESTMENT	466,122	466,122	466,122	466,122	466,122	466,122	466,122	466,122	466,122	466,122
WORKING CAPITAL	29,500	30,975	32,523	34,149	35,856	37,648	39,530	41,506	43,581	45,760
GROSS CAPITAL INVESTMENT	495,622	497,097	498,645	500,271	501,978	503,770	505,652	507,628	509,703	511,882
CUMULATIVE DEPRECIATION	18,644	37,288	55,932	74,576	93,220	111,864	130,508	149,152	167,796	186,440
OUTSTANDING LOAN BALANCE	254,446	252,234	249,884	247,184	244,160	240,773	236,980	232,732	227,974	222,645
PROJECT EQUITY	222,532	207,515	192,829	178,511	164,598	151,133	138,164	125,744	113,933	102,797
RETURN ON EQUITY	40,055	37,352	34,709	32,131	29,627	27,203	24,869	22,633	20,507	18,503
INTEREST	30,765	30,534	30,276	29,986	29,662	29,299	28,893	28,438	27,928	27,357
INVESTMENT TAX CREDIT	1,858	1,858	1,858	1,858	1,858	1,858	1,858	1,858	1,858	1,858
DEPRECIATION	18,644	18,644	18,644	18,644	18,644	18,644	18,644	18,644	18,644	18,644
INSURANCE	465	465	465	465	465	465	465	465	465	465
PROPERTY TAX	32,521	32,521	32,521	32,521	32,521	32,521	32,521	32,521	32,521	32,521
OPERATION AND MAINTENANCE	15,892	17,481	19,229	21,151	23,266	25,592	28,151	30,966	34,062	37,468
COAL	116,993	126,352	136,460	147,376	159,166	171,899	185,650	200,502	216,542	233,865
WATER	910	982	1,060	1,144	1,235	1,333	1,439	1,554	1,678	1,812
CATALYST & CHEMICALS	788	866	952	1,047	1,151	1,266	1,392	1,531	1,684	1,852
BY-PRODUCT POWER CREDIT	52,613	56,822	61,367	66,276	71,578	77,304	83,488	90,167	97,380	105,170
BY-PRODUCT SULFUR CREDIT	000	000	000	000	000	000	000	000	000	000
BY-PRODUCT ASH CREDIT	000	000	000	000	000	000	000	000	000	000
INCOME TAX	34,120	31,876	29,566	27,370	25,237	23,172	21,183	19,279	17,468	15,761
GROSS RECEIPTS TAX	000	000	000	000	000	000	000	000	000	000
REQUIRED REVENUE	236,682	238,333	240,657	243,701	247,538	252,232	257,861	264,508	272,261	281,220
GAS COST (\$ / MMBTU)	7.759	7.813	7.890	7.989	8.115	8.269	8.454	8.672	8.926	9.220
LEVELIZED REQ'D REVENUE (AT 14.0% DISCOUNT RATE)	280112.3423									

TABLE K-6
(Sheet 2 of 3)
GIBBS & HILL, INC.
REQUIRED REVENUE
ARTHUR KILL C. E. 70 % GASIFIER BASE CASE

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
INVESTMENT	466,122	466,122	466,122	466,122	466,122	466,122	466,122	466,122	466,122	466,122
WORKING CAPITAL	48,048	50,450	52,972	55,620	58,401	61,321	64,387	67,606	70,986	74,535
GROSS CAPITAL INVESTMENT	514,170	516,572	519,094	521,742	524,523	527,443	530,509	533,728	537,108	540,657
CUMULATIVE DEPRECIATION	205,084	223,728	242,372	261,016	279,660	298,304	316,948	335,592	354,236	372,880
OUTSTANDING LOAN BALANCE	216,676	209,991	202,504	194,118	184,726	174,207	162,425	149,229	134,450	117,897
PROJECT EQUITY	92,410	82,853	74,218	66,608	60,137	54,932	51,136	48,907	48,422	49,880
RETURN ON EQUITY	16,633	14,913	13,359	11,989	10,824	9,887	9,204	8,803	8,715	8,978
INTEREST	26,717	26,001	25,199	24,300	23,294	22,167	20,904	19,490	17,907	16,133
INVESTMENT TAX CREDIT	1,858	1,858	1,858	1,858	1,858	1,858	1,858	1,858	1,858	1,858
DEPRECIATION	18,644	18,644	18,644	18,644	18,644	18,644	18,644	18,644	18,644	18,644
INSURANCE	465	465	465	465	465	465	465	465	465	465
PROPERTY TAX	32,521	32,521	32,521	32,521	32,521	32,521	32,521	32,521	32,521	32,521
OPERATION AND MAINTENANCE	41,214	45,335	49,868	54,854	60,339	66,372	73,009	80,309	88,339	97,172
COAL	252,574	272,779	294,601	318,169	343,622	371,111	400,799	432,862	467,490	504,889
WATER	1,956	2,112	2,280	2,462	2,658	2,870	3,099	3,346	3,613	3,902
CATALYST & CHEMICALS	2,037	2,240	2,464	2,710	2,981	3,279	3,606	3,966	4,362	4,798
BY-PRODUCT POWER CREDIT	113,583	122,669	132,482	143,080	154,526	166,888	180,239	194,658	210,230	227,048
BY-PRODUCT SULFUR CREDIT	000	000	000	000	000	000	000	000	000	000
BY-PRODUCT ASH CREDIT	000	000	000	000	000	000	000	000	000	000
INCOME TAX	14,168	12,701	11,379	10,211	9,220	8,422	7,838	7,498	7,422	7,646
GROSS RECEIPTS TAX	000	000	000	000	000	000	000	000	000	000
REQUIRED REVENUE	291,488	303,184	316,440	331,387	348,184	366,992	387,992	411,388	437,390	466,242
GAS COST (\$ / HHBTU)	9.556	9.940	10.374	10.864	11.415	12.032	12.720	13.487	14.340	15.286

TABLE K-6
(Sheet 3 of 3)
GIBBS & HILL, INC.
REQUIRED REVENUE
ARTHUR KILL C. E. 70 % GASIFIER BASE CASE

	2005	2006	2007	2008	2009
INVESTMENT	466,122	466,122	466,122	466,122	466,122
WORKING CAPITAL	78,261	82,174	86,282	90,596	95,125
GROSS CAPITAL INVESTMENT	544,383	548,296	552,404	556,718	561,247
CUMULATIVE DEPRECIATION	391,524	410,168	428,812	447,456	466,100
OUTSTANDING LOAN BALANCE	99,358	78,594	55,338	29,291	119
PROJECT EQUITY	53,501	59,534	68,254	79,971	95,028
RETURN ON EQUITY	9,630	10,716	12,285	14,394	17,105
INTEREST	14,147	11,922	9,430	6,639	3,514
INVESTMENT TAX CREDIT	1,858	11,358	1,858	1,858	1,858
DEPRECIATION	18,644	18,644	18,644	18,644	18,644
INSURANCE	465	465	465	465	465
PROPERTY TAX	32,521	32,521	32,521	32,521	32,521
OPERATION AND MAINTENANCE	106,889	117,577	129,334	142,267	156,493
COAL	545,280	588,902	636,014	686,895	741,846
WATER	4,214	4,551	4,915	5,308	5,732
CATALYST & CHEMICALS	5,277	5,804	6,384	7,022	7,724
BY-PRODUCT POWER CREDIT	245,211	264,827	286,013	308,894	333,605
BY-PRODUCT SULFUR CREDIT	000	000	000	000	000
BY-PRODUCT ASH CREDIT	000	000	000	000	000
INCOME TAX	8,201	9,127	10,464	12,261	14,570
GROSS RECEIPTS TAX	000	000	000	000	000
REQUIRED REVENUE	498,199	533,544	572,585	615,664	663,151
GAS COST (\$ / MMBTU)	16.333	17.492	18.772	20.185	21.741

TABLE K-7
(Sheet 1 of 3)
GIBBS & HILL, INC.

	R E Q U I R E D R E V E N U E									
	OSWEGO		POWER PLANT WITH		100% GASIFIER		BASE CASE			
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
INVESTMENT	9,610	9,610	9,610	9,610	9,610	9,610	9,610	9,610	9,610	9,610
WORKING CAPITAL	3,100	3,255	3,417	3,587	3,766	3,954	4,151	4,358	4,575	4,803
GROSS CAPITAL INVESTMENT	12,710	12,865	13,027	13,197	13,376	13,564	13,761	13,968	14,185	14,413
CUMULATIVE DEPRECIATION	384	768	1,152	1,536	1,920	2,304	2,688	3,072	3,456	3,840
OUTSTANDING LOAN BALANCE	4,587	4,559	4,527	4,490	4,448	4,400	4,345	4,282	4,210	4,128
PROJECT EQUITY	7,739	7,538	7,348	7,171	7,008	6,860	6,728	6,614	6,519	6,445
ROE (NETEC-FIT)	1,083	1,055	1,028	1,003	981	960	941	925	912	902
INTEREST (" ")	646	643	639	634	629	623	616	608	599	589
INVESTMENT TAX CREDIT	038	038	038	038	038	038	038	038	038	038
DEPRECIATION (" ")	384	384	384	384	384	384	384	384	384	384
INSURANCE (" ")	010	010	010	010	010	010	010	010	010	010
PROPERTY TAX (" ")	096	103	111	119	128	138	149	160	172	185
OPER. & MAINT. (" ")	000	000	000	000	000	000	000	000	000	000
GAS	473,256	478,862	485,953	494,656	505,116	517,482	531,923	548,621	567,776	589,603
OIL	000	000	000	000	000	000	000	000	000	000
FIXED EXP. (EXISTING PLNT)	53,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000
VARI. EXP. (" ")	10,800	11,880	13,068	14,374	15,811	17,392	19,131	21,044	23,148	25,462
INCOME TAX	922	898	874	853	835	816	800	787	775	766
GROSS RECEIPTS TAX	25,321	25,626	26,005	26,464	27,010	27,650	28,393	29,249	30,226	31,336
REQUIRED REVENUE	575,480	582,423	591,034	601,459	613,866	628,417	645,309	664,750	686,964	712,199
BUS BAR COST (\$/KWH)	0.110	0.111	0.113	0.115	0.117	0.120	0.123	0.127	0.131	0.136
LEVELIZED REQ'D REVENUE (AT 14.0% DISCOUNT RATE)	701644.6279									

K-21

TABLE K-7
(Sheet 2 of 3)

GIBBS & HILL, INC.

	R E Q U I R E D R E V E N U E									
	OSWEGO	POWER PLANT WITH	100% GASIFIER	BASE CASE	YEAR					
	1995	1995	1997	1998	1999	2000	2001	2002	2003	2004
INVESTMENT	9,610	9,510	9,610	9,610	9,610	9,610	9,610	9,610	9,610	9,610
WORKING CAPITAL	5,043	5,295	5,559	5,836	6,127	6,433	6,754	7,091	7,445	7,817
GROSS CAPITAL INVESTMENT	14,653	14,805	15,169	15,446	15,737	16,043	16,364	16,701	17,055	17,427
CUMULATIVE DEPRECIATION	4,224	4,608	4,992	5,376	5,760	6,144	6,528	6,912	7,296	7,680
OUTSTANDING ICAM BALANCE	4,035	3,928	3,807	3,668	3,510	3,330	3,124	2,890	2,623	2,318
PROJECT EQUITY	6,394	6,369	6,370	6,402	6,467	6,569	6,712	6,899	7,136	7,429
ROE (BETEC-FIT)	895	891	891	896	905	919	939	965	999	1,040
INTEREST (" ")	578	564	550	532	513	491	465	437	404	366
INVESTMENT TAX CREDIT	038	038	038	038	038	038	038	038	038	038
DEPRECIATION (" ")	384	384	384	384	384	384	384	384	384	384
INSURANCE (" ")	010	010	010	010	010	010	010	010	010	010
PROPERTY TAX (" ")	199	214	231	249	268	289	312	336	362	390
OPER. & MAINT. (" ")	000	000	000	000	000	000	000	000	000	000
GAS	614,341	642,250	673,611	708,734	747,952	791,640	840,197	894,066	953,727	1019,713
OIL	000	000	000	000	000	000	000	000	000	000
FIXED EXP. (EXISTING PLNT)	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000
VARI. EXP. (" ")	28,008	30,808	33,888	37,276	41,003	45,103	49,613	54,574	60,031	66,034
INCOME TAX	761	157	757	762	770	781	798	820	850	885
GROSS RECEIPTS TAX	32,592	34,605	35,590	37,363	39,340	41,541	43,985	46,694	49,694	53,010
REQUIBED REVENUE	740,730	772,845	808,874	849,168	894,107	944,120	999,665	1061,248	1129,423	1204,794
BUS BAR COST (\$/KWH)	0.142	0.148	0.155	0.162	0.171	0.181	0.191	0.203	0.216	0.231

TABLE K-7
(Sheet 3 of 3)
GIBBS & HILL, INC.

	R E Q U I R E D R E V E N U E					BASE CASE
	OSWEGO	POWER PLANT WITH	100% GASIFIER	YEAR		
	2005	2006	2007	2008	2009	
INVESTMENT	9,610	9,610	9,610	9,610	9,610	
WORKING CAPITAL	8,207	8,617	9,047	9,499	9,973	
GROSS CAPITAL INVESTMENT	17,817	18,227	18,657	19,109	19,583	
CUMULATIVE DEPRECIATION	8,064	8,448	8,832	9,216	9,600	
OUTSTANDING LOAN BALANCE	1,971	1,575	1,123	608	021	
PROJECT EQUITY	7,782	8,204	8,702	9,285	9,962	
ROE (EBTBC-FIT)	1,089	1,148	1,218	1,299	1,394	
INTEREST (" ")	324	275	219	156	084	
INVESTMENT TAX CREDIT	038	038	038	038	038	
DEPRECIATION (" ")	384	384	384	384	384	
INSURANCE (" ")	010	010	010	010	010	
PROPERTY TAX (" ")	421	454	490	529	571	
OPER. & MAINT. (" ")	000	000	000	000	000	
GAS	1092,596	1173,017	1261,664	1359,302	1466,764	
OIL	000	000	000	000	000	
FIXED EXP. (EXISTING PLNT)	63,000	63,000	63,000	63,000	63,000	
VARI. EXP. (" ")	72,637	79,900	87,890	96,679	106,346	
INCOME TAX	925	977	1,037	1,105	1,187	
GROSS RECEIPTS TAX	56,672	60,712	65,165	70,069	75,467	
REQUIRED REVENUE	1288,020	1379,839	1481,039	1592,495	1715,169	
BUS BAR COST (\$/KWH)	0.247	0.264	0.284	0.305	0.329	

TABLE K-8
(Sheet 1 of 3)

GIBBS & HILL, INC.

	R E Q U I R E D R E V E N U E									
	OSWEGO	POWER PLANT WITH				70% GASIFIER	BASE CASE			
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
INVESTMENT	9,610	9,610	9,610	9,610	9,610	9,610	9,610	9,610	9,610	9,610
WORKING CAPITAL	2,700	2,835	2,976	3,124	3,280	3,444	3,616	3,796	3,985	4,184
GROSS CAPITAL INVESTMENT	12,310	12,445	12,586	12,734	12,890	13,054	13,226	13,406	13,595	13,794
CUMULATIVE DEPRECIATION	384	768	1,152	1,536	1,920	2,304	2,688	3,072	3,456	3,840
OUTSTANDING LOAN BALANCE	4,587	4,559	4,527	4,490	4,448	4,400	4,345	4,282	4,210	4,128
PROJECT EQUITY	7,339	7,118	6,907	6,708	6,522	6,350	6,193	6,052	5,929	5,826
ROB (FETBC-FIT)	1,027	956	966	939	913	889	867	847	830	815
INTEREST (" ")	646	643	639	634	629	623	616	608	599	589
INVESTMENT TAX CREDIT	038	038	038	038	038	038	038	038	038	038
DEPRECIATION (" ")	384	384	384	384	384	384	384	384	384	384
INSURANCE (" ")	010	010	010	010	010	010	010	010	010	010
PROPERTY TAX (" ")	096	103	111	119	128	138	149	160	172	185
OPER. & MAINT. (" ")	000	000	000	000	000	000	000	000	000	000
GAS	395,998	403,160	411,683	421,682	433,284	446,625	461,860	479,151	498,674	520,626
OIL	000	000	000	000	000	000	000	000	000	000
FIXED EXP. (EXISTING PLNT)	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000
VARI. EXP. (" ")	10,800	11,880	13,068	14,374	15,811	17,392	19,131	21,044	23,148	25,462
INCOME TAX	874	848	822	798	775	755	737	720	705	692
GROSS RECEIPTS TAX	21,760	22,137	22,581	23,100	23,698	24,383	25,162	26,044	27,039	28,154
REQUIRED REVENUE	494,557	503,123	513,226	525,002	538,594	554,161	571,878	591,930	614,523	639,879
BUS BAR COST (\$/KWH)	0.094	0.096	0.098	0.100	0.103	0.106	0.109	0.113	0.117	0.122
LEVELIZED REQ'D REVENUE (AT 14.0% DISCOUNT RATE)	623687.4180									

TABLE K-8

(Sheet 2 of 3)
GIBBS & HILL, INC.

	REQUIRED REVENUE									
	OSWEGO	POWER PLANT WITH			70% GASIFIER		BASE CASE			
	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
INVESTMENT	9,610	9,610	9,610	9,610	9,610	9,610	9,610	9,610	9,610	9,610
WORKING CAPITAL	4,393	4,612	4,842	5,084	5,338	5,604	5,884	6,178	6,486	6,810
GROSS CAPITAL INVESTMENT	14,003	14,222	14,452	14,694	14,948	15,214	15,494	15,788	16,096	16,420
CUMULATIVE DEPRECIATION	4,224	4,608	4,992	5,376	5,760	6,144	6,528	6,912	7,296	7,680
OUTSTANDING LOAN BALANCE	4,035	3,928	3,807	3,668	3,510	3,330	3,124	2,890	2,623	2,318
PROJECT EQUITY	5,744	5,686	5,653	5,650	5,678	5,740	5,842	5,986	6,177	6,422
ROE (BETRC-FIT)	804	796	791	791	794	803	817	838	864	899
INTEREST (" ")	578	564	550	532	513	491	465	437	404	366
INVESTMENT TAX CREDIT	038	038	038	038	038	038	038	038	038	038
DEPRECIATION (" ")	384	384	384	384	384	384	384	384	384	384
INSURANCE (" ")	010	010	010	010	010	010	010	010	010	010
PROPERTY TAX (" ")	199	214	231	249	268	289	312	336	362	390
OPER. & MAINT. (" ")	000	000	000	000	000	000	000	000	000	000
GAS	545,220	572,685	603,272	637,259	674,942	716,259	762,745	813,610	869,675	931,405
OIL	000	000	000	000	000	000	000	000	000	000
FIXED EXP. (EXISTING PLNT)	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000
VARI. EXP. (" ")	28,008	30,808	33,888	37,276	41,003	45,103	49,613	54,574	60,031	66,034
INCOME TAX	683	677	672	672	675	683	694	712	735	764
GROSS RECEIPTS TAX	29,403	30,795	32,344	34,064	35,970	38,062	40,410	42,981	45,814	48,934
REQUIRED REVENUE	668,251	699,895	735,104	774,199	817,521	865,046	918,412	976,844	1041,241	1112,148
BUS BAR COST (\$/KWH)	0.128	0.134	0.141	0.148	0.156	0.165	0.176	0.187	0.199	0.213

TABLE K-8

(Sheet 3 of 3)

GIBBS & HILL, INC.

	R E Q U I R E D R E V E N U E					BASE CASE
	OSWEGO	POWER PLANT WITH	70% GASIFIER	YEAR		
	2005	2006	2007	2008	2009	
INVESTMENT	9,610	9,610	9,610	9,610	9,610	
WORKING CAPITAL	7,150	7,507	7,882	8,276	8,689	
GROSS CAPITAL INVESTMENT	16,760	17,117	17,492	17,886	18,299	
CUMULATIVE DEPRECIATION	8,064	8,443	8,832	9,216	9,600	
OUTSTANDING LOAN BALANCE	1,971	1,575	1,123	608	021	
PROJECT EQUITY	6,725	7,094	7,537	8,062	8,678	
ROE (RETRC-FIT)	941	993	1,055	1,128	1,214	
INTEREST (" ")	324	275	219	156	084	
INVESTMENT TAX CREDIT	038	033	038	038	038	
DEPRECIATION (" ")	384	384	384	384	384	
INSURANCE (" ")	010	010	010	010	010	
PROPERTY TAX (" ")	421	454	490	529	571	
OPER. & MAINT. (" ")	000	000	000	000	000	
GAS	999,308	1073,937	1155,905	1245,876	1344,579	
OIL	000	000	000	000	000	
FIXED EXP. (EXISTING PLNT)	63,000	63,000	63,000	63,000	63,000	
VARI. EXP. (" ")	72,637	79,900	87,890	96,679	106,346	
INCOME TAX	800	844	898	959	1,033	
GROSS RECEIPTS TAX	52,366	56,139	60,284	64,834	69,828	
REQUIRED REVENUE	1190,153	1275,398	1370,097	1473,517	1587,011	
BUS BAR COST (\$/KWH)	0.228	0.244	0.262	0.282	0.304	

TABLE K-9

(Sheet 1 of 3)
GIBBS & HILL, INC.R E Q U I R E D R E V E N U E
ARTHUR KILL POWER PLANT WITH 100% TEX. GASIF. BASE CASE

	YEAR									
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
INVESTMENT	8,881	8,881	8,881	8,881	8,881	8,881	8,881	8,881	8,881	8,881
WORKING CAPITAL	3,700	3,885	4,079	4,282	4,496	4,720	4,956	5,203	5,463	5,736
GROSS CAPITAL INVESTMENT	12,581	12,766	12,960	13,163	13,377	13,601	13,837	14,084	14,344	14,617
CUMULATIVE DEPRECIATION	355	710	1,065	1,420	1,775	2,130	2,485	2,840	3,195	3,550
OUTSTANDING LOAN BALANCE1	4,849	4,809	4,764	4,714	4,658	4,595	4,525	4,446	4,358	4,259
PROJECT EQUITY	7,377	7,247	7,131	7,029	6,944	6,876	6,827	6,798	6,791	6,808
ROE (RETRO-FIT)	1,327	1,304	1,283	1,265	1,249	1,237	1,228	1,223	1,222	1,225
INTEREST (" ")	587	582	577	572	566	559	552	543	534	523
INVESTMENT TAX CREDIT	036	036	036	036	036	036	036	036	036	036
DEPRECIATION (" ")	355	355	355	355	355	355	355	355	355	355
INSURANCE (" ")	009	009	009	009	009	009	009	009	009	009
PROPERTY TAX (" ")	622	622	622	622	622	622	622	622	622	622
OPER. & MAINT. (" ")	000	000	000	000	000	000	000	000	000	000
GAS	387,836	388,055	389,239	391,471	394,853	399,478	405,465	412,930	422,005	432,839
OIL	000	000	000	000	000	000	000	000	000	000
FIXED EXP. (EXISTING PLNT)	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864
VARI. EXP. (EXISTING PLNT)	12,084	13,292	14,621	16,083	17,691	19,460	21,406	23,546	25,900	28,490
INCOME TAX	1,129	1,109	1,092	1,075	1,062	1,053	1,044	1,040	1,040	1,042
GROSS RECEIPTS TAX	27,269	27,359	27,519	27,757	28,079	28,492	29,006	29,629	30,371	31,242
REQUIRED REVENUE	447,046	448,515	451,145	455,037	460,314	467,093	475,515	485,725	497,886	512,175
BUS BAR COST (\$/KWH)	0.145	0.146	0.147	0.148	0.150	0.152	0.155	0.158	0.162	0.167
LEVELIZED REQ'D REVENUE (AT 14.0% DISCOUNT RATE)	514727.9083									

TABLE K-9
(Sheet 2 of 3)
GIBBS & HILL, INC.
REQUIRED REVENUE
ARTHUR KILL POWER PLANT WITH 100% TEX. GASIF. BASE CASE

	1995	1996	1997	1998	YEAR 1999	2000	2001	2002	2003	2004
INVESTMENT	8,881	8,881	8,881	8,881	8,881	8,881	8,881	8,881	8,881	8,881
WORKING CAPITAL	6,022	6,323	6,639	6,970	7,318	7,683	8,067	8,470	8,893	9,337
GROSS CAPITAL INVESTMENT	14,903	15,204	15,520	15,851	16,199	16,564	16,948	17,351	17,774	18,218
CUMULATIVE DEPRECIATION	3,905	4,260	4,615	4,970	5,325	5,680	6,035	6,390	6,745	7,100
OUTSTANDING LOAN BALANCE	4,148	4,024	3,885	3,729	3,554	3,358	3,138	2,892	2,616	2,307
PROJECT EQUITY	6,850	6,920	7,020	7,152	7,320	7,526	7,775	8,069	8,413	8,811
ROE (RETRC-PIT)	1,233	1,245	1,263	1,287	1,317	1,354	1,399	1,452	1,514	1,585
INTEREST (" ")	511	498	483	466	447	426	402	376	346	313
INVESTMENT TAX CREDIT (" ")	036	036	036	036	036	036	036	036	036	036
DEPRECIATION (" ")	355	355	355	355	355	355	355	355	355	355
INSURANCE (" ")	009	009	009	009	009	009	009	009	009	009
PROPERTY TAX (" ")	622	622	622	622	622	622	622	622	622	622
OPER. & MAINT. (" ")	000	000	000	000	000	000	000	000	000	000
GAS	445,588	460,425	477,539	497,136	519,445	544,711	573,208	605,228	641,097	681,168
OIL	000	000	000	000	000	000	000	000	000	000
FIXED EXP. (EXISTING PLNT)	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864
VARI. EXP. (EXISTING PLNT)	31,339	34,472	37,919	41,710	45,881	50,469	55,515	61,066	67,172	73,889
INCOME TAX	1,050	1,059	1,074	1,096	1,120	1,151	1,190	1,235	1,288	1,350
GROSS RECEIPTS TAX	32,256	33,424	34,761	36,282	38,004	39,947	42,130	44,575	47,307	50,353
REQUIRED REVENUE	528,791	547,937	569,853	594,791	623,028	654,872	690,658	730,746	775,538	825,472
BUS BAR COST (\$/KWH)	0.172	0.178	0.185	0.193	0.203	0.213	0.225	0.238	0.252	0.269

TABLE K-9
(Sheet 3 of 3)
GIBBS & HILL, INC.
R E Q U I R E D R E V E N U E
ARTHUR KILL POWER PLANT WITH 100% TEX. GASIF. BASE CASE

	2005	2006	2007	2008	2009
INVESTMENT	8,881	8,881	8,881	8,881	8,881
WORKING CAPITAL	9,803	10,293	10,807	11,347	11,914
GROSS CAPITAL INVESTMENT	18,684	19,174	19,688	20,228	20,795
CUMULATIVE DEPRECIATION	7,455	7,810	8,165	8,520	8,875
OUTSTANDING LOAN BALANCE	1,961	1,573	1,139	653	108
PROJECT EQUITY	9,268	9,791	10,384	11,055	11,812
ROE (RETRC-FIT)	1,568	1,762	1,869	1,989	2,126
INTEREST (" ")	276	234	188	136	077
INVESTMENT TAX CREDIT	036	036	036	036	036
DEPRECIATION (" ")	355	355	355	355	355
INSURANCE (" ")	009	009	009	009	009
PROPERTY TAX (" ")	622	622	622	622	622
OPER. & MAINT. (" ")	000	000	000	000	000
GAS	725,833	775,518	830,688	891,854	959,575
OIL	000	000	000	000	000
FIXED EXP. (EXISTING PLNT)	15,864	15,864	15,864	15,864	15,864
VARI. EXP. (EXISTING PLNT)	81,277	89,404	98,344	108,178	118,995
INCOME TAX	1,420	1,500	1,590	1,692	1,809
GROSS RECEIPTS TAX	53,742	57,507	61,681	66,305	71,419
REQUIRED REVENUE	881,030	942,739	1011,174	1086,968	1170,815
BUS BAR COST (\$/KWH)	0.287	0.307	0.329	0.354	0.381

TABLE K-10
(Sheet 1 of 3)
GIBBS & HILL, INC.
R E Q U I R E D R E V E N U E
ARTHUR KILL POWER PLANT WITH 70% TEX. GASIF. BASE CASE

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
INVESTMENT	8,881	8,881	8,881	8,881	8,881	8,881	8,881	8,881	8,881	8,881
WORKING CAPITAL	3,000	3,150	3,307	3,472	3,645	3,827	4,018	4,218	4,428	4,649
GROSS CAPITAL INVESTMENT	11,881	12,031	12,188	12,353	12,526	12,708	12,899	13,099	13,309	13,530
CUMULATIVE DEPRECIATION	355	710	1,065	1,420	1,775	2,130	2,485	2,840	3,195	3,550
OUTSTANDING LOAN BALANCE	4,849	4,809	4,764	4,714	4,658	4,595	4,525	4,446	4,358	4,259
PROJECT EQUITY	6,677	6,512	6,359	6,219	6,093	5,983	5,889	5,813	5,756	5,721
ROE (BETSC-FIT)	1,201	1,172	1,144	1,119	1,096	1,076	1,060	1,046	1,036	1,029
INTEREST (" ")	587	582	577	572	566	559	552	543	534	523
INVESTMENT TAX CREDIT	036	036	036	036	036	036	036	036	036	036
DEPRECIATION (" ")	355	355	355	355	355	355	355	355	355	355
INSURANCE (" ")	009	009	009	009	009	009	009	009	009	009
PROPERTY TAX (" ")	622	622	622	622	622	622	622	622	622	622
OPER. & MAINT. (" ")	000	000	000	000	000	000	000	000	000	000
GAS	316,707	318,664	321,497	325,281	330,101	336,044	343,216	351,721	361,675	373,205
OIL	000	000	000	000	000	000	000	000	000	000
FIXED EXP. (EXISTING PLNT)	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864
VARI. EXP. (EXISTING PLNT)	12,084	13,292	14,621	16,083	17,691	19,460	21,406	23,546	25,900	28,490
INCOME TAX	1,022	998	974	951	933	914	901	890	881	875
GROSS RECEIPTS TAX	22,633	22,835	23,102	23,439	23,854	24,352	24,942	25,631	26,429	27,345
REQUIRED REVENUE	371,048	374,357	378,729	384,259	391,055	399,219	408,891	420,191	433,269	448,281
BUS BAR COST (\$/KWH)	0.121	0.122	0.123	0.125	0.127	0.130	0.133	0.137	0.141	0.146
LEVELIZED REQ'D REVENUE (AT 14.0% DISCOUNT RATE)	444840.0152									

TABLE K-10
(Sheet 2 of 3)
GIBBS & HILL, INC.
REQUIRED REVENUE
ARTHUR KILL POWER PLANT WITH 70% TEX. GASIF. BASE CASE

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
INVESTMENT	8,881	8,881	8,881	8,881	8,881	8,881	8,881	8,881	8,881	8,881
WORKING CAPITAL	4,881	5,125	5,381	5,650	5,932	6,228	6,539	6,865	7,208	7,568
GROSS CAPITAL INVESTMENT	13,762	14,006	14,262	14,531	14,813	15,109	15,420	15,746	16,089	16,449
CUMULATIVE DEPRECIATION	3,905	4,260	4,615	4,970	5,325	5,680	6,035	6,390	6,745	7,100
OUTSTANDING LOAN BALANCE	4,148	4,024	3,885	3,729	3,554	3,358	3,138	2,892	2,616	2,307
PROJECT EQUITY	5,709	5,722	5,762	5,832	5,934	6,071	6,247	6,464	6,728	7,042
BOE (BETHC-FIT)	1,027	1,029	1,037	1,049	1,068	1,092	1,124	1,163	1,211	1,267
INTEREST (" ")	511	498	483	466	447	426	402	376	346	313
INVESTMENT TAX CREDIT (" ")	036	036	036	036	036	036	036	036	036	036
DEPRECIATION (" ")	355	355	355	355	355	355	355	355	355	355
INSURANCE (" ")	009	009	009	009	009	009	009	009	009	009
PROPERTY TAX (" ")	622	622	622	622	622	622	622	622	622	622
OPER. & MAINT. (" ")	000	000	000	000	000	000	000	000	000	000
GAS	386,454	401,575	418,732	438,108	459,903	484,331	511,633	542,063	575,906	613,472
OIL	000	000	000	000	000	000	000	000	000	000
FIXED EXP. (EXISTING PLNT)	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864
VARI. EXP. (EXISTING PLNT)	31,339	34,472	37,919	41,710	45,881	50,469	55,515	61,066	67,172	73,889
INCOME TAX	874	875	883	892	909	929	957	988	1,031	1,077
GROSS RECEIPTS TAX	28,389	29,575	30,913	32,418	34,106	35,993	38,097	40,437	43,036	45,917
REQUIRED REVENUE	465,408	484,838	506,781	531,457	559,128	590,054	624,542	662,907	705,516	752,749
BUS BAR COST (\$/KWH)	0.151	0.158	0.165	0.173	0.182	0.192	0.203	0.216	0.230	0.245

TABLE K-10
(Sheet 3 of 3)
GIBBS & HILL, INC.
R E Q U I R E D R E V E N U E
ARTHUR KILL POWER PLANT WITH 70% TEX. GASIF. BASE CASE

	2005	2006	2007	2008	YEAR 2009
INVESTMENT	8,881	8,881	8,881	8,881	8,881
WORKING CAPITAL	7,946	8,343	8,760	9,198	9,657
GROSS CAPITAL INVESTMENT	16,827	17,224	17,641	18,079	18,538
CUMULATIVE DEPRECIATION	7,453	7,810	8,165	8,520	8,875
OUTSTANDING LOAN BALANCE	1,961	1,573	1,139	653	108
PROJECT EQUITY	7,411	7,841	8,337	8,906	9,555
ROE (EBTRC-FIT)	1,133	1,411	1,500	1,603	1,719
INTEREST (" ")	276	234	188	136	077
INVESTMENT TAX CREDIT	036	036	036	036	036
DEPRECIATION (" ")	355	355	355	355	355
INSURANCE (" ")	009	009	009	009	009
PROPERTY TAX (" ")	622	622	622	622	622
OPER. & MAINT. (" ")	000	000	000	000	000
GAS	655,098	701,153	752,044	808,210	870,132
OIL	000	000	000	000	000
FIXED EXP. (EXISTING PLNT)	15,864	15,864	15,864	15,864	15,864
VARI. EXP. (EXISTING PLNT)	81,277	89,404	98,344	108,178	118,995
INCOME TAX	1,135	1,201	1,277	1,364	1,462
GROSS RECEIPTS TAX	49,107	52,633	56,528	60,824	65,560
REQUIRED REVENUE	805,040	862,850	926,695	997,129	1074,759
BUS BAR COST (\$/KWH)	0.262	0.281	0.302	0.325	0.350

TABLE K-11
(Sheet 1 of 3)
GIBBS & HILL, INC.
R E Q U I R E D R E V E N U E
ARTHUR KILL POWER PLANT WITH 100% C.E. GASIP. BASE CASE

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
INVESTMENT	14,170	14,170	14,170	14,170	14,170	14,170	14,170	14,170	14,170	14,170
WORKING CAPITAL	3,100	3,255	3,417	3,587	3,766	3,954	4,151	4,358	4,575	4,803
GROSS CAPITAL INVESTMENT	17,270	17,425	17,587	17,757	17,936	18,124	18,321	18,528	18,745	18,973
CUMULATIVE DEPRECIATION	566	1,132	1,698	2,264	2,830	3,396	3,962	4,528	5,094	5,660
OUTSTANDING LOAN BALANCE ¹	7,736	7,672	7,600	7,519	7,428	7,327	7,213	7,086	6,943	6,783
PROJECT EQUITY	8,968	8,621	8,289	7,974	7,678	7,401	7,146	6,914	6,708	6,530
BOE (BETHC-FIT)	1,614	1,551	1,492	1,435	1,382	1,332	1,286	1,244	1,207	1,175
INTEREST (" ")	936	929	921	912	902	892	879	866	850	833
INVESTMENT TAX CREDIT	057	057	057	057	057	057	057	057	057	057
DEPRECIATION (" ")	566	566	566	566	566	566	566	566	566	566
INSURANCE (" ")	014	014	014	014	014	014	014	014	014	014
PROPERTY TAX (" ")	992	992	992	992	992	992	992	992	992	992
OPER. & MAINT. (" ")	000	000	000	000	000	000	000	000	000	000
GAS	288,496	288,909	290,061	292,011	294,835	298,605	303,411	309,344	316,507	325,007
OIL	000	000	000	000	000	000	000	000	000	000
FIXED EXP. (EXISTING PLNT)	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864
VARI. EXP. (EXISTING PLNT)	12,084	13,292	14,621	16,083	17,691	19,460	21,406	23,546	25,900	28,490
INCOME TAX	1,374	1,320	1,270	1,222	1,175	1,133	1,094	1,059	1,027	1,000
GROSS RECEIPTS TAX	20,910	21,007	21,161	21,375	21,656	22,009	22,441	22,960	23,573	24,288
REQUIRED REVENUE	342,793	344,387	346,905	350,417	355,020	360,810	367,896	376,398	386,443	398,172
BUS BAR COST (\$/KWH)	0.111	0.112	0.113	0.114	0.115	0.117	0.119	0.122	0.126	0.129
LEVELIZED REQ'D REVENUE (AT 14.0% DISCOUNT RATE)	399008.0644									

TABLE K-11
(Sheet 2 of 3)
GIBBS & HILL, INC.
REQUIRED REVENUE
ARTHUR KILL POWER PLANT WITH 100% C.E. GASIF. BASE CASE

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
INVESTMENT	14,170	14,170	14,170	14,170	14,170	14,170	14,170	14,170	14,170	14,170
WORKING CAPITAL	5,043	5,295	5,559	5,836	6,127	6,433	6,754	7,091	7,445	7,817
GROSS CAPITAL INVESTMENT	19,213	19,465	19,729	20,006	20,297	20,603	20,924	21,261	21,615	21,987
CUMULATIVE DEPRECIATION	6,226	6,792	7,358	7,924	8,490	9,056	9,622	10,188	10,754	11,320
OUTSTANDING LOAN BALANCE	6,604	6,403	6,178	5,926	5,644	5,328	4,974	4,577	4,133	3,635
PROJECT EQUITY	6,383	6,270	6,193	6,156	6,163	6,219	6,328	6,496	6,728	7,032
ROE (BETBC-FIT)	1,148	1,128	1,114	1,108	1,109	1,119	1,139	1,169	1,211	1,265
INTEREST (" ")	814	792	768	741	711	677	639	596	549	495
INVESTMENT TAX CREDIT	057	057	057	057	057	057	057	057	057	057
DEPRECIATION (" ")	566	566	566	566	566	566	566	566	566	566
INSURANCE (" ")	014	014	014	014	014	014	014	014	014	014
PROPERTY TAX (" ")	992	992	992	992	992	992	992	992	992	992
OPER. & MAINT. (" ")	000	000	000	000	000	000	000	000	000	000
GAS	334,968	346,518	359,803	374,986	392,233	411,735	433,698	458,347	485,936	516,733
OIL	000	000	000	000	000	000	000	000	000	000
FIXED EXP. (EXISTING PLNT)	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864
VARI. EXP. (EXISTING PLNT)	31,339	34,472	37,919	41,710	45,881	50,469	55,515	61,066	67,172	73,889
INCOME TAX	977	959	948	942	944	951	968	994	1,031	1,075
GROSS RECEIPTS TAX	25,116	26,065	27,149	28,380	29,769	31,333	33,087	35,050	37,241	39,681
REQUIRED REVENUE	411,741	427,314	445,080	465,246	488,026	513,663	542,425	574,601	610,519	650,517
BUS BAR COST (\$/KWH)	0.134	0.139	0.145	0.151	0.159	0.167	0.176	0.187	0.199	0.212

TABLE K-11

(Sheet 3 of 3)
GIBBS & HILL, INC.R E Q U I R E D R E V E N U E
ARTHUR KILL POWER PLANT WITH 100% C.E. GASIF. BASE CASE

	2005	2006	2007	2008	YEAR 2009
INVESTMENT	14,170	14,170	14,170	14,170	14,170
WORKING CAPITAL	8,207	8,617	9,047	9,499	9,973
GROSS CAPITAL INVESTMENT	22,377	22,787	23,217	23,669	24,143
CUMULATIVE DEPRECIATION	11,886	12,452	13,018	13,584	14,150
OUTSTANDING LOAN BALANCE	3,078	2,454	1,755	972	095
PROJECT EQUITY	7,413	7,881	8,444	9,113	9,898
ROE (RETRC-FIT)	1,334	1,418	1,519	1,640	1,781
INTEREST (" ")	436	369	294	210	116
INVESTMENT TAX CREDIT (" ")	057	057	057	057	057
DEPRECIATION (" ")	566	566	566	566	566
INSURANCE (" ")	014	014	014	014	014
PROPERTY TAX (" ")	992	992	992	992	992
OPER. & MAINT. (" ")	000	000	000	000	000
GAS	551,031	589,158	631,470	678,360	730,250
OIL	000	000	000	000	000
FIXED EXP. (EXISTING PLNT)	15,864	15,864	15,864	15,864	15,864
VARI. EXP. (EXISTING PLNT)	81,277	89,404	98,344	108,178	118,995
INCOME TAX	1,135	1,207	1,292	1,396	1,516
GROSS RECEIPTS TAX	42,394	45,404	48,741	52,435	56,519
REQUIRED REVENUE	694,986	744,339	799,039	859,598	926,556
BUS BAR COST (\$/KWH)	0.226	0.242	0.260	0.280	0.302

TABLE K-12
(Sheet 1 of 3)
GIBBS & HILL, INC.
R E Q U I R E D R E V E N U E
ARTHUR KILL POWER PLANT WITH 70% C.E. GASIF. BASE CASE

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
INVESTMENT	14,170	14,170	14,170	14,170	14,170	14,170	14,170	14,170	14,170	14,170
WORKING CAPITAL	2,600	2,730	2,866	3,009	3,159	3,316	3,481	3,655	3,837	4,028
GROSS CAPITAL INVESTMENT	16,770	16,900	17,036	17,179	17,329	17,486	17,651	17,825	18,007	18,198
CUMULATIVE DEPRECIATION	566	1,132	1,698	2,264	2,830	3,396	3,962	4,528	5,094	5,660
OUTSTANDING LOAN BALANCE	7,736	7,672	7,600	7,519	7,428	7,327	7,213	7,086	6,943	6,783
PROJECT EQUITY	8,468	8,096	7,738	7,396	7,071	6,763	6,476	6,211	5,970	5,755
AGE (BETBC-PIT)	1,524	1,457	1,392	1,331	1,272	1,217	1,165	1,117	1,074	1,035
INTEREST (" ")	936	929	921	912	902	892	879	866	850	833
INVESTMENT TAX CREDIT	057	057	057	057	057	057	057	057	057	057
DEPRECIATION (" ")	566	566	566	566	566	566	566	566	566	566
INSURANCE (" ")	014	014	014	014	014	014	014	014	014	014
PROPERTY TAX (" ")	992	992	992	992	992	992	992	992	992	992
OPEB. & MAINT. (" ")	000	000	000	000	000	000	000	000	000	000
GAS	236,682	238,333	240,657	243,701	247,538	252,232	257,861	264,508	272,261	281,220
OIL	000	000	000	000	000	000	000	000	000	000
FIXED EXP. (EXISTING PLNT)	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864
VARI. EXP. (EXISTING PLNT)	12,084	13,292	14,621	16,083	17,691	19,460	21,406	23,546	25,900	28,490
INCOME TAX	1,298	1,240	1,185	1,133	1,083	1,035	990	950	914	881
GROSS RECEIPTS TAX	17,533	17,710	17,939	18,224	18,570	18,983	19,468	20,032	20,682	21,427
REQUIRED REVENUE	287,436	290,320	294,094	298,763	304,435	311,198	319,148	328,398	339,060	351,265
BUS BAR COST (\$/KWH)	0.093	0.094	0.095	0.097	0.099	0.101	0.104	0.107	0.110	0.114
LEVELIZED REQ'D REVENUE (AT 14.0% DISCOUNT RATE)	347803.9021									

TABLE K-12
(Sheet 2 of 3)
GIBBS & HILL, INC.
REQUIRED REVENUE
ARTHUR KILL POWER PLANT WITH 70% C.E. GASIF. BASE CASE

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
INVESTMENT	14,170	14,170	14,170	14,170	14,170	14,170	14,170	14,170	14,170	14,170
WORKING CAPITAL	4,229	4,440	4,662	4,895	5,139	5,395	5,664	5,947	6,244	6,556
GROSS CAPITAL INVESTMENT	18,399	18,610	18,832	19,065	19,309	19,565	19,834	20,117	20,414	20,726
CUMULATIVE DEPRECIATION	6,226	6,792	7,358	7,924	8,490	9,056	9,622	10,188	10,754	11,320
OUTSTANDING LOAN BALANCE	6,604	6,403	6,178	5,926	5,644	5,328	4,974	4,577	4,133	3,635
PROJECT EQUITY	5,569	5,415	5,296	5,215	5,175	5,181	5,238	5,352	5,527	5,771
ROE (RETBC-FIT)	1,002	974	953	938	931	932	942	963	994	1,038
INTEREST (" ")	814	792	768	741	711	677	639	596	549	495
INVESTMENT TAX CREDIT	057	057	057	057	057	057	057	057	057	057
DEPRECIATION (" ")	566	566	566	566	566	566	566	566	566	566
INSURANCE (" ")	014	014	014	014	014	014	014	014	014	014
PROPERTY TAX (" ")	992	992	992	992	992	992	992	992	992	992
OPER. & MAINT. (" ")	000	000	000	000	000	000	000	000	000	000
GAS	291,488	303,184	316,440	331,367	348,184	366,992	387,992	411,388	437,390	466,242
OIL	000	000	000	000	000	000	000	000	000	000
FIXED EXP. (EXISTING PLNT)	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864	15,864
VARI. EXP. (EXISTING PLNT)	31,339	34,472	37,919	41,710	45,881	50,469	55,515	61,066	67,172	73,889
INCOME TAX	851	829	811	798	792	792	801	818	846	883
GROSS RECEIPTS TAX	22,273	23,232	24,313	25,527	26,886	28,404	30,095	31,975	34,061	36,374
REQUIRED REVENUE	365,146	380,862	398,583	418,480	440,764	465,645	493,363	524,185	558,391	596,300
BUS BAR COST (\$/KWH)	0.119	0.124	0.130	0.136	0.143	0.151	0.160	0.170	0.182	0.194

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TABLE K-12
(Sheet 3 of 3)

GIBBS & HILL, INC.
REQUIRED REVENUE
ARTHUR KILL POWER PLANT WITH 70% C.E. GASIF. BASE CASE

	2005	2006	2007	2008	YEAR 2009
INVESTMENT	14,170	14,170	14,170	14,170	14,170
WORKING CAPITAL	6,883	7,227	7,588	7,967	8,365
GROSS CAPITAL INVESTMENT	21,053	21,397	21,758	22,137	22,535
CUMULATIVE DEPRECIATION	11,886	12,452	13,018	13,564	14,150
OUTSTANDING LOAN BALANCE	3,078	2,454	1,755	972	095
PROJECT EQUITY	6,089	6,491	6,985	7,581	8,290
ROE (RETBC-FIT)	1,096	1,168	1,257	1,364	1,492
INTEREST (" ")	436	369	294	210	116
INVESTMENT TAX CREDIT	057	057	057	057	057
DEPRECIATION (" ")	566	566	566	566	566
INSURANCE (" ")	014	014	014	014	014
PROPERTY TAX (" ")	992	992	992	992	992
OPER. & MAINT. (" ")	000	000	000	000	000
GAS	498,199	533,544	572,585	615,664	663,151
OIL	000	000	000	000	000
FIXED EXP. (EXISTING PLNT)	15,864	15,864	15,864	15,864	15,864
VARI. EXP. (EXISTING PLNT)	81,277	89,404	98,344	108,178	118,995
INCOME TAX	933	994	1,070	1,161	1,270
GROSS RECEIPTS TAX	38,933	41,761	44,884	48,329	52,126
REQUIRED REVENUE	638,253	684,619	735,813	792,285	854,529
BUS BAR COST (\$/KWH)	0.208	0.223	0.239	0.258	0.278

TABLE K-13
(Sheet 1 of 3)

GIBBS & HILL, INC.

REQUIRED REVENUE
OSWEGO POWER PLANT CONT'D OIL USE BASE CASE (15% OIL ESC.)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000
INVESTMENT										
GROSS CAPITAL INVESTMENT	000	000	000	000	000	000	000	000	000	000
CUMULATIVE DEPRECIATION	000	000	000	000	000	000	000	000	000	000
PROJECT EQUITY	000	000	000	000	000	000	000	000	000	000
	000	000	000	000	000	000	000	000	000	000
INCOME TAX	000	000	000	000	000	000	000	000	000	000
OIL	441	507	583	670	770	885	1,017	1,169	1,344	1,545
VARIABLE EXPENSES	011	012	013	014	016	017	019	021	023	025
FIXED EXPENSES	063	063	063	063	063	063	063	063	063	063
GROSS RECEIPTS TAX	023	026	030	034	039	044	050	057	065	075
REQUIRED REVENUE	538	608	689	781	888	1,009	1,149	1,310	1,495	1,708
BUS BAR COST (\$/KWH)	0.103	0.116	0.132	0.149	0.170	0.193	0.220	0.251	0.286	0.327
LEVELIZED REQ'D REVENUE (AT 14.0% DISCOUNT RATE)	1720.7327									

TABLE K-13
(Sheet 2 of 3)
GIBBS & HILL, INC.
R E Q U I R E D R E V E N U E
OSWEGO POWER PLANT CONT'D OIL USE BASE CASE (15% OIL ESC.)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
INVESTMENT	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000
GROSS CAPITAL INVESTMENT	000	000	000	000	000	000	000	000	000	000
CUMULATIVE DEPRECIATION	000	000	000	000	000	000	000	000	000	000
PROJECT EQUITY	000	000	000	000	000	000	000	000	000	000
	000	000	000	000	000	000	000	000	000	000
INCOME TAX	000	000	000	000	000	000	000	000	000	000
OIL	1,776	2,042	2,348	2,700	3,105	3,570	4,105	4,720	5,428	6,242
VARIABLE EXPENSES	028	031	034	037	041	045	050	055	060	066
FIXED EXPENSES	063	063	063	063	063	063	063	063	063	063
GROSS RECEIPTS TAX	085	098	112	128	147	169	194	222	255	293
REQUIRED REVENUE	1,952	2,234	2,557	2,928	3,356	3,847	4,412	5,060	5,806	6,664
BUS BAR COST (\$/KWH)	0.374	0.428	0.490	0.561	0.643	0.738	0.846	0.970	1.113	1.278

TABLE K-13
(Sheet 3 of 3)

GIBBS & HILL, INC.

R E Q U I R E D R E V E N U E
OSWEGO POWER PLANT CONT'D OIL USE

BASE CASE

(15% OIL ESC.)

	2005	2006	2007	2008	YEAR 2009
INVESTMENT	0,000	0,000	0,000	0,000	0,000
GROSS CAPITAL INVESTMENT	000	000	000	000	000
CUMULATIVE DEPRECIATION	000	000	000	000	000
PROJECT EQUITY	000	000	000	000	000
	000	000	000	000	000
	000	000	000	000	000
INCOME TAX	000	000	000	000	000
OIL	7,178	8,254	9,492	10,915	12,552
VARIABLE EXPENSERS	073	080	088	097	106
FIXED EXPENSES	063	063	063	063	063
GROSS RECEIPTS TAX	336	386	443	509	585
REQUIRED REVENUE	7,650	8,783	10,086	11,584	13,306
BUS BAR COST (\$/KWH)	1.467	1.685	1.935	2.222	2.552

TABLE K-14
(Sheet 1 of 3)

GIBBS & HILL, INC.

REQUIRED REVENUE
OSWEGO POWER PLANT CONT'D OIL USE

BASE CASE

(10% OIL ESC.)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
INVESTMENT	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000
GROSS CAPITAL INVESTMENT	000	000	000	000	000	000	000	000	000	000
CUMULATIVE DEPRECIATION	000	000	000	000	000	000	000	000	000	000
PROJECT EQUITY	000	000	000	000	000	000	000	000	000	000
	000	000	000	000	000	000	000	000	000	000
INCOME TAX	000	000	000	000	000	000	000	000	000	000
OIL	353	388	426	468	514	565	621	683	751	826
VARIABLE EXPENSES	011	012	013	014	016	017	019	021	023	025
FIXED EXPENSES	063	063	063	063	063	063	063	063	063	063
GROSS RECEIPTS TAX	019	021	023	025	027	029	032	035	038	042
REQUIRED REVENUE	446	434	525	570	620	674	735	802	875	956
BUS BAR COST (\$/KWH)	0.085	0.092	0.100	0.109	0.118	0.129	0.141	0.153	0.167	0.183
LEVELIZED REQ'D REVENUE (AT 14.0% DISCOUNT RATE)	876.6737									

TABLE K-14
(Sheet 2 of 3)
GIBBS & HILL, INC.
R E Q U I R E D R E V E N U E
OSWEGO POWER PLANT CONT'D OIL USE BASE CASE (10% OIL ESC.)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
INVESTMENT	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000
GROSS CAPITAL INVESTMENT	000	000	000	000	000	000	000	000	000	000
CUMULATIVE DEPRECIATION	000	000	000	000	000	000	000	000	000	000
PROJECT EQUITY	000	000	000	000	000	000	000	000	000	000
	000	000	000	000	000	000	000	000	000	000
INCOME TAX	000	000	000	000	000	000	000	000	000	000
OIL	908	998	1,097	1,206	1,326	1,458	1,603	1,763	1,939	2,132
VARIABLE EXPENSES	028	031	034	037	041	045	050	055	060	066
FIXED EXPENSES	063	063	063	063	063	063	063	063	063	063
GROSS RECEIPTS TAX	045	050	054	060	065	072	078	086	094	104
REQUIRED REVENUE	1,044	1,142	1,248	1,366	1,495	1,638	1,794	1,967	2,156	2,365
BUS BAR COST (\$/KWH)	0.200	0.219	0.239	0.262	0.286	0.314	0.344	0.377	0.413	0.453

TABLE K-14 (Sheet 3 of 3) GIBBS & HILL, INC. REQUIRED REVENUE OSWEGO POWER PLANT CONT'D OIL USE BASE CASE (10% OIL ESC.)					
	2005	2006	2007	2008	YEAR 2009
INVESTMENT	0,000	0,000	0,000	0,000	0,000
GROSS CAPITAL INVESTMENT	000	000	000	000	000
CUMULATIVE DEPRECIATION	000	000	000	000	000
PROJECT EQUITY	000	000	000	000	000
	000	000	000	000	000
INCOME TAX	000	000	000	000	000
OIL	2,345	2,579	2,836	3,119	3,430
VARIABLE EXPENSES	073	030	088	097	106
FIXED EXPENSES	063	053	063	063	063
GROSS RECEIPTS TAX	114	125	137	150	165
REQUIRED REVENUE	2,595	2,847	3,124	3,429	3,764
BUS BAR COST (\$/KWH)	0.497	0.546	0.599	0.657	0.722

TABLE K-15

(Sheet 1 of 3)

GIBBS & HILL, INC.

R E Q U I R E D R E V E N U E
A. K. POWER PLANT CONT'D OIL USE

BASE CASE

(15% OIL ESC.)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
INVESTMENT	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000
GROSS CAPITAL INVESTMENT	000	000	000	000	000	000	000	000	000	000
CUMULATIVE DEPRECIATION	000	000	000	000	000	000	000	000	000	000
PROJECT EQUITY	000	000	000	000	000	000	000	000	000	000
	000	000	000	000	000	000	000	000	000	000
	000	000	000	000	000	000	000	000	000	000
OIL	280	322	370	425	488	561	645	741	852	979
VARIABLE EXPENSES	012	013	015	016	018	019	021	024	026	028
FIXED EXPENSES	016	016	016	016	016	016	016	016	016	016
GROSS RECEIPTS TAX	020	022	026	029	033	038	044	050	058	066
REQUIRED REVENUE	328	373	427	486	555	634	726	831	952	1,089
BUS BAR COST (\$/KWH)	0.106	0.121	0.139	0.158	0.181	0.206	0.236	0.271	0.310	0.355
LEVELIZED REQ'D REVENUE (AT 14.0% DISCOUNT RATE)	1095.5223									

K-45

TABLE K-15
(Sheet 2 of 3)
GIBBS & HILL, INC.
R E Q U I R E D R E V E N U E
A. E. POWER PLANT CONT'D OIL USE BASE CASE (15% OIL ESC.)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
INVESTMENT	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000
GROSS CAPITAL INVESTMENT	000	000	000	000	000	000	000	000	000	000
CUMULATIVE DEPRECIATION	000	000	000	000	000	000	000	000	000	000
PROJECT EQUITY	000	000	000	000	000	000	000	000	000	000
	000	000	000	000	000	000	000	000	000	000
	000	000	000	000	000	000	000	000	000	000
	000	000	000	000	000	000	000	000	000	000
OIL	1,125	1,293	1,486	1,708	1,964	2,258	2,596	2,985	3,432	3,946
VARIABLE EXPENSES	031	034	038	042	046	050	056	061	067	074
FIXED EXPENSES	016	016	016	016	016	016	016	016	016	016
GROSS RECEIPTS TAX	076	087	100	114	131	150	173	198	228	262
REQUIRED REVENUE	1,248	1,430	1,640	1,880	2,157	2,474	2,841	3,260	3,743	4,298
BUS BAR COST (\$/KWH)	0.407	0.466	0.534	0.613	0.703	0.806	0.926	1.063	1.220	1.401

TABLE K-15
(Sheet 3 of 3)
GIBBS & HILL, INC.

	R E Q U I R E D R E V E N U E					BASE CASE	(15% OIL ESC.)
	A. K. POWER PLANT CONT'D OIL USE						
	2005	2006	2007	2008	YEAR 2009		
INVESTMENT	<u>0,000</u>	<u>0,000</u>	<u>0,000</u>	<u>0,000</u>	<u>0,000</u>		
<hr/>							
GROSS CAPITAL INVESTMENT	000	000	000	000	000		
CUMULATIVE DEPRECIATION	000	000	000	000	000		
<hr/>							
PROJECT EQUITY	000	000	000	000	000		
	000	000	000	000	000		
	000	000	000	000	000		
	000	000	000	000	000		
OIL	4,537	5,217	5,999	6,898	7,932		
VARIABLE EXPENSES	081	089	098	108	119		
FIXED EXPENSES	016	016	016	016	016		
GROSS RECEIPTS TAX	301	345	397	456	524		
<hr/>							
REQUIRED REVENUE	4,935	5,667	6,510	7,478	8,591		
BUS BAR COST (\$/KWH)	1.609	1.848	2.123	2.439	2.802		

TABLE K-16
(Sheet 1 of 3)
GIBBS & HILL, INC.
REQUIRED REVENUE
A. F. POWER PLANT CONT'D OIL USE

	YEAR					BASE CASE		(10% OIL ESC.)		
	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
INVESTMENT	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000
GROSS CAPITAL INVESTMENT	000	000	000	000	000	000	000	000	000	000
CUMULATIVE DEPRECIATION	000	000	000	000	000	000	000	000	000	000
PROJECT EQUITY	000	000	000	000	000	000	000	000	000	000
	000	000	000	000	000	000	000	000	000	000
	000	000	000	000	000	000	000	000	000	000
OIL	224	246	270	297	326	358	393	432	475	522
VARIABLE EXPENSES	012	013	015	016	018	019	021	024	026	028
FIXED EXPENSES	016	016	016	016	016	016	016	016	016	016
GROSS RECEIPTS TAX	016	017	019	021	023	025	027	030	033	036
REQUIRED REVENUE	268	292	320	350	383	418	457	502	550	602
RUS BAR COST (\$/KWH)	0.087	0.095	0.104	0.114	0.124	0.136	0.149	0.163	0.179	0.196

LEVELIZED REQ'D REVENUE
(AT 14.0% DISCOUNT RATE)

551.2067

TABLE K-16
(Sheet 2 of 3)
GIBBS & HILL, INC.

	R E Q U I R E D R E V E N U E									
	A. K. POWER PLANT					CONT'D OIL USE		BASE CASE		(10% OIL ESC.)
	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000
INVESTMENT										
GROSS CAPITAL INVESTMENT	000	000	000	000	000	000	000	000	000	000
CUMULATIVE DEPRECIATION	000	000	000	000	000	000	000	000	000	000
PROJECT EQUITY	000	000	000	000	000	000	000	000	000	000
	000	000	000	000	000	000	000	000	000	000
	000	000	000	000	000	000	000	000	000	000
OIL	574	631	694	763	839	922	1,014	1,115	1,226	1,348
VARIABLE EXPENSES	031	034	038	042	046	050	056	061	067	074
FIXED EXPENSES	016	016	016	016	016	016	016	016	016	016
GROSS RECEIPTS TAX	040	044	048	053	058	064	070	077	085	093
REQUIRED REVENUE	661	725	796	874	959	1,052	1,156	1,269	1,394	1,531
BUS BAR COST (\$/KWH)	0.215	0.236	0.259	0.285	0.312	0.343	0.377	0.413	0.454	0.499

TABLE K-16
(Sheet 3 of 3)

GIBBS & HILL, INC.
REQUIRED REVENUE
A. K. POWER PLANT CONT'D OIL USE BASE CASE (10% OIL ESC.)

	2005	2006	2007	2008	YEAR 2009
INVESTMENT	0,000	0,000	0,000	0,000	0,000
GROSS CAPITAL INVESTMENT	000	000	000	000	000
CUMULATIVE DEPRECIATION	000	000	000	000	000
PROJECT EQUITY	000	000	000	000	000
	000	000	000	000	000
	000	000	000	000	000
	000	000	000	000	000
CIL	1,482	1,630	1,793	1,972	2,169
VARIABLE EXPENSES	081	089	098	108	119
FIXED EXPENSES	016	016	016	016	016
GROSS RECEIPTS TAX	102	112	123	136	149
REQUIRED REVENUE	1,681	1,847	2,030	2,232	2,453
BUS BAR COST (\$/KWH)	0.548	0.602	0.662	0.727	0.800

UNITED STATES
DEPARTMENT OF ENERGY
WASHINGTON, D.C. 20585

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