PRELIMINARY DESIGN SERVICES: RESEARCH AND DEVELOPMENT REPORT NO. 114. FINAL REPORT

PARSONS (RALPH M.) CO.
PASADENA, CA

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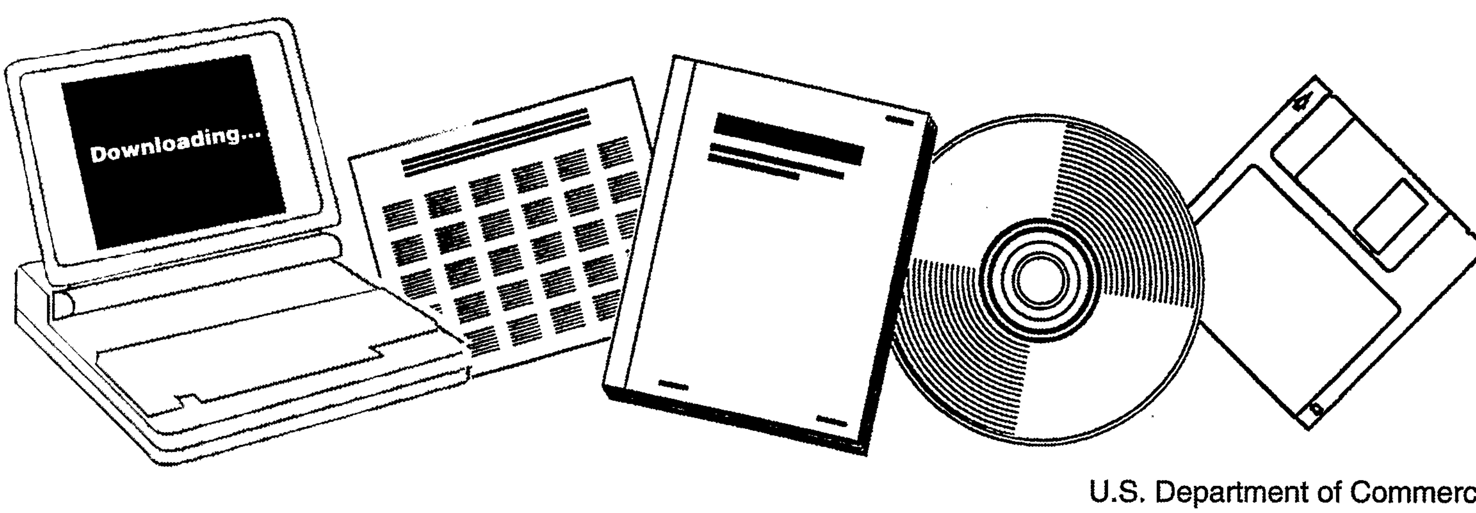

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PRELIMINARY DESIGN SERVICES

RESEARCH AND DEVELOPMENT REPORT NO. 114

FINAL REPORT

Prepared by:
THE RALPH M. PARSONS COMPANY
100 West Walnut Street
Pasadena, California 91124

Under Contract No. EX-76-C-01-1775
November 1978

Prepared for
DEPARTMENT OF ENERGY
OFFICE OF ASSISTANT SECRETARY FOR ENERGY TECHNOLOGY
DIVISION OF COAL CONVERSION
Washington, D.C. 20545

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ABBREVIATIONS

bbl	barrel(s)
BPD	barrels per day
BPSD	barrels per stream day
Btu	British thermal units
COED	Coal - Oil - Energy - Development
DCF and DCFs	Discounted cash flow(s)
DOE	Department of Energy
Dwg	drawing
ERDA	Energy Research and Development Administration
FCI and FCIs	fixed capital investment(s)
F-T	Fischer - Tropsch
HHV	higher heating value
KSI	Killograms per square inch
kWh	Killowatt hour
lb	pound(s)
LPG and LPGs	liquified petroleum gas(es)
LTPD	long tons per day
MAF	moisture and ash free
MF	moisture free
MM	million
MPDP	Multi-Process Demonstration Plant
MW	megawatt(s)
OCR	Office of Coal Research
O/G	Oil/Gas
PVPV and PVPVs	prestressed concrete veactor vessel (s)
POGO	Power - Oil - Gas - Other
psig	pounds per square inch gauge
ROM	run-of-mine
RPSP and RPSPs	required product selling price (s)
scf	standard cubic feet
scfd	standard cubic feet per day
SNG	substitute natural gas
SRC	solvent refined coal
syngas	synthesis gas

ABBREVIATIONS

TPD	tons per day
TPSD	tons per stream day
TPY	tons per year
USAEDH	U. S. Army Engineer Division,of Huntsville, Alabama
wt %	weight percent

SECTION 1

INTRODUCTION

The U.S. Office of Coal Research (OCR) and The Ralph M. Parsons Company executed a three-year Contract, EX-76-01-1775, on December 31, 1974; under the terms of this contract Parsons was to supply Preliminary Design Services in the field of conversion of coal to synthetic fuels and electricity. Responsibility for the contract was subsequently assumed by OCR's successors, the U.S. Energy Research and Development Administration (ERDA) and then the U.S. Department of Energy (DOE).

The prime objective of the contract was to develop conceptual designs and economic evaluations for multiple types of coal conversion plants. Secondary objectives were development of supporting information in the fields of equipment development, materials of construction and environmental factors required for future commercial plants.

Responsibility for completion of a conceptual design for a COED-based pyrolysis plant was transferred from Contract EX-76-C-01-1234, titled "Technical Evaluation Services," to this contract. A final report describing Parsons prior work on the COED design under Contract -1234 has been published.[1]

The contract scope was expanded and the period of performance was extended by seven contract modifications. The period of performance was extended to November 1, 1978.

The contract defined a number of comprehensive task assignments. The results of the work were intended for use to assist OCR/ERDA/DOE in their programs to develop firm bases for design, construction and operation of viable commercial coal conversion plants to provide the U.S. with acceptable future energy options. General categories of task objectives included:

- Development of conceptual designs and eonomic evaluations for four commercial scale coal conversion complexes.
- Development of a preliminary design, operating requirements and projected economics for a multi-process coal conversion demonstration plant.
- Definition of additional data and equipment requirements to assure reliable performance of the commercial plants.
- Development of conceptual designs and, economic predictions for prestressed concrete pressure vessels PCPVs for use in coal conversion plants.

- Definition of environmental control facilities and procedures required to assure the operation of the commercial plants within applicable environmental requirements.

- Publication and dissemination of the results of the work.

This wide range of activities required broad expertise provided by several hundred people over the course of the contract work. As required, the skills and experience of process engineers, project engineers, discipline engineers, environmental engineers, economists, and many others were applied. Of particular importance is the balance of technical and economic skills required for prediction of constructed value of large coal mines and coal conversion plants; a major international contractor who is daily buying and installing major equipment items is equipped to develop realistic and current economic estimates.

Reports have been transmitted and accepted for all task assignments under this contract. This final report provides a summary of key results and a list of references for reports which have been published; these referenced reports contain detailed designs, data, conclusions and recommendations.

Publication of this report completes the Contract EX-76-C-01-1775 obligations of The Ralph M. Parsons Company.

SECTION 2

SUMMARY

The Contract EX-76-C-01-1775 tasks have been completed and reports describing the results have been accepted by OCR/ERDA/DOE.

The Primary Objectives of this contract work, titled "Preliminary Design Services," were to develop four (4) conceptual designs/economic evaluations for coal conversion complexes with each design to use differing technology, to develop a preliminary design/economic evaluation for a multi-process demonstration plant, to develop a conceptual design/economic evaluation for use of representative prestressed concrete pressure vessels in coal conversion plants, to define equipment development, materials of construction, environmental and data requirements to support the design of future coal conversion plants, and to promptly publish the results. The period of performance was approximately four years.

Key elements of the results of this contractual work are presented in this report.

2.1 CONCEPTUAL DESIGNS/ECONOMIC EVALUATIONS

Four (4) conceptual designs/economic evaluations were developed and the results published. Each of the coal conversion complexes was conceived to be located in the Eastern Region of the Interior Coal Province which encompasses portions of the states of Illinois, Indiana and Kentucky. The project scope consist of a grass roots complex with a captive coal mine. All steam and electricity is captively produced.

The design reports contain a definition of the design basis, the data base used, a process description, preliminary process flow diagrams with heat and material balances, an energy balance, a utility balance, major equipment lists, definition of a plot plan, a definition of the environmental control procedures, a capital investment estimate, estimated operating costs, projected profitability analysis, an economic sensitivity analysis, an analysis of expected plant performance, and recommendations for future improvements. A brief description of the designs and projected economics follows.

The conceptual designs incorporate certain potentially attractive operations which have not yet been proven, or in some cases operated, on a pilot plant scale. The designs are intended to show the potential performance and economics for the configurations used; also to define additional development work required prior to commercial design and operation.

2.1.1 COED-BASED PYROLYSIS PLANT

This design[2] was based on results developed by FMC Corporation, under OCR sponsorship, in a 35-ton-per-day (TPD) pilot plant located at Princeton, New Jersey.

The scope of the complex consists of a large captive coal mine which supplies run-of-mine (ROM) coal to a coal preparation plant which in turn provides approximately 25,000 TPD of clean, washed coal to a COED-based pyrolysis coal conversion plant. The 25,000 TPD of coal is fed to a single-line pyrolysis-gasification process plant. The coal is converted to fuel gases, tar and char in multiple fluid bed pyrolyzers operating in series at atmospheric pressure and over a temperature range of 575 to 1,050^{o}F. The char is gasified by reaction with steam and oxygen to produce a synthesis gas (syngas), primarily a mixture of hydrogen and carbon monoxide, which is purified, supplies heat energy to operate the pyrolyzers and then is consumed as fuel in a large electrical power plant. The fuel gases produced in the pyrolysis step are also used to generate electricity. The pyrolysis tar is filtered to remove solids carried over from the pyrolyzers and then hydrotreated to produce a syncrude; the hydrotreating step reduces sulfur and nitrogen contents as well as the viscosity of the syncrude.

Products from the plant operating under typical conditions include approximately 28,000 barrels per day (BPD) of a 28^{o} API, 0.1 percent sulfur content syncrude and about 830 megawatts of electrical power; commercial grade sulfur is produced as a by-product. The projected thermal efficiency of the process plant, including production of fuel gases as feed to the power plant, was about 58 percent.

The design provided the equipment and operating flexibility to process feed coal with a range of analyses which might be expected over the course of a 20-year operating life using coal typically mined in the site area. This fact distinguishes the design from other designs based on a single typical feed coal analysis and which might be called "point" designs. The use of a fixed coal feed rate and variable coal characteristics requires higher fixed capital investment (FCI) to provide the necessary flexibility; it also results in variable product rates. A very preliminary estimate indicated the provisions for ability to process the variable feed coal compositions would increase the FCI by about 10 percent relative to a "point" design.

2.1.2 OIL/GAS

The term "Oil/Gas" originated during the 1973 Project Independence Blueprint period. It refers to a coal hydroliquefaction process configuration which coproduces liquid and gas fuels.

The design basis was developed in cooperation with ERDA; it used the teachings of the Solvent Refined Coal (SRC) development program. A report describing this conceptual design has been published.[3]

The captive coal mine that serves the complex produces approximately 47,000 TPD of ROM coal as feed to the coal preparation plant. The product of the preparation plant, about 36,000 TPD, is fed to an SRC II-based hydroliquefaction coal conversion plant. Here the feed coal is slurried in a coal-derived recycle liquid containing unreacted coal residues and coal ash and reacted with a hydrogen-rich reducing gas at about 850°F and 2,000 psig. The pressure on hydroliquefaction products is then reduced; the resulting gases are purified, hydrogen recovered for recycle to the hydroliquefaction reactor (dissolver), and the light hydrocarbons consisting of methane through the butanes, recovered and purified for sale. The liquids are fractionated and a portion of the higher boiling fraction is filtered to remove unreacted coal and ash to produce a heavy fuel oil; the unfiltered portion is combined with some filtered heavy solvent and recycled to serve as the slurry agent for the feed coal. The complex produces about 55,000 BPD of 0.4 percent sulfur fuel oil with characteristics roughly equivalent to bunker C, 10,000 BPD of naphtha, 10,000 BPD of liquified petroleum gases (LPGs) and 165 million standard cubic feet per day (MM scfd) of SNG; by-products include about 1,300 TPD of sulfur and 90 TPD of ammonia.

The projected thermal efficiency is about 77 percent; this represents the percentage of energy in the feed coal which is converted to salable products. Facilities to permit operation of the complex to meet environmental standards are included and described.

2.1.3 FISCHER-TROPSCH

Parsons had earlier developed two brief Fischer-Tropsch conceptual designs/economic evaluations.[4] One of these was for a small plant while the second was for a large complex prepared under tight deadline pressure for the Project Independence Blueprint program. These prior efforts provided background for a more comprehensive conceptual design[5] described here.

Based on the results of a preliminary analysis of data sources available, a synthesis reactor configuration was selected which consisted of catalyst applied by a flame-spraying technique, or equivalent, on the external surface of extended surface heat exchangers. This design permits recovery of the majority of the heat of reaction as 1,200 psig steam which in turn is used to generate electrical power and supply utility steam requirements to the complex.

The captive coal mine would produce about 40,000 TPD of ROM coal; the coal preparation plant would in turn provide approximately 30,000 TPD of clean, washed coal feed to the process plant. In the process plant, the coal is gasified at approximately 475 psig by reaction with steam and oxygen in an entrained two-stage, slagging-type gasifier. The gases, containing primarily hydrogen and carbon monoxide, are purified and then catalytically reacted to produce liquid products plus substitute natural gas (SNG). The liquid products are recovered and refined for sale. Plant products are projected to have an energy value in excess of 500 billion Btu/day, which is about twice the energy value of commercial coal gasification plants planned for construction in the U.S. The projected product quantitites are 260 MM scfd of SNG and approximately 50,000 BPD of liquid products consisting of LPGs, light and heavy naphthas, diesel fuel, fuel oil, and oxygenates (containing primarily alcohols). The liquids contain nil sulfur, nitrogen and particulate matter, making them environmentally premium grade fuels. They are primarily alyphatic hydrocarbons, useful as petrochemical feedstocks as well as fuels.

Heat recovered from the process operations is used to generate all utilities required to operate the complex, including the coal mine. A supporting independently fueled power plant is not required for normal plant operation. The projected thermal efficiency, coal to salable products, is of the order of 70 percent, indicating a potential efficiency significantly higher than for alternate Fischer-Tropsch historical designs.

A division of the U.S. Bureau of Mines, now the Pittsburgh Energy Research Center, DOE, had investigated flame-sprayed catalytic Fischer-Tropsch conversions on a small scale over a period of about 15 years. They are now constructing a pilot scale unit at Bruceton, Pennsylvania to obtain further performance data on the reactor construction, catalyst application, catalyst life, and conversion performance. A related pilot test using flame-sprayed catalyst for methanation reaction indicated catalyst life in excess of 6,000 hours without significant deterioration in performance.

2.1.4 POGO

POGO, an acronym developed by DOE, is an abbreviation for Power-Oil-Gas-Other. It is used to describe a coal refinery which coproduces electrical power, liquid fuels, gas fuels and chemical by-products, including a precursor of premium grade coke for use by the aluminum and steel industries, plus sulfur and ammonia.

A conceptual design was completed and published.[8] The design basis selected resulted from an analysis of a number of candidate processes and process combinations; a report describing the results of this predesign analysis was also published.[7] The configuration chosen consisted of SRC II-based hydroliquefaction combined with pressurized flash pyrolysis, entrained two-stage, slagging-type gasification and a combined cycle power plant. The configuration eliminated the use of filters for removal of unconverted coal and ash from the hydroliquefaction step.

The base design for the coal refinery was conceived to be located in the Eastern Region of the Interior Coal Province. Two second-order assessments of the effects of constructing the plant at other locations were also completed; one alternate location was the Southern Appalachian Region of the Eastern Coal Province and the second was the Powder River Region of the Rocky Mountain Coal Province.

For the base design, approximately 60,000 TPD of ROM coal was mined and 45,000 TPD of clean, washed, sized coal produced in a coal preparation plant. Approximately forty-five percent of the coal is fed to the SRC II-based hydroliquefaction plant, 15 percent to the flash pyrolysis plant and about 40 percent to a gasification plant used to generate fuel gases for use in the utility section.

In the hydroliquefaction plant, feed coal is slurried in coal-derived solvent containing some unreacted coal and coal ash. This slurry is mixed with hydrogen-rich reducing gases and reacted at about 850^{o}F and 2,000 psig. The pressure is reduced after reaction and the vapors are recovered, purified, separated into hydrogen-rich gas for recycle to the hydroliquefaction step plus LPGs and SNG; the LPGs and SNG are purified for sale.

The liquids recovered after pressure reduction are fractionated, first at essentially atmospheric pressure and then under vacuum. The distillates are processed to produce a low sulfur fuel oil, pool gasoline and coke. The bottoms product from the vacuum distillation, plus feed coal, are fed to the pressurized flash pyrolysis unit where a significant amount of the liquids are recovered and processed for sale as fuels with the remainder being coked; the char produced in the pyrolyzer is fed to the process gasifier where it is reacted with steam and oxygen to produce the reducing gas used to dissolve the coal in the hydroliquefaction step and also, after further processing, to produce the high purity hydrogen used to hydrotreat naphtha and heavy liquids to upgrade them for sale. Energy required for operation of the pyrolysis unit is provided by a recycle char stream from the process gasifier.

The design incorporated the results of a number of efficiency trade-off studies. The projected thermal efficiency, coal to fuel and chemical products plus fuel gas to the power plant, was approximately 75 percent. Seven alternative power plant configurations were analyzed, including interactions with the coal mine and process plant utilities. The configuration selected resulted in a projected efficiency, fuel gas feed to power at the busbar, of about 44 percent; this indicates a potential efficiency gain of about 5 percentage points resulting from careful selection of state of the art combined cycle power plant components and preferred interaction with the other units in the complex.

Projected products from the base case complex include approximately 150 MM scfd of SNG, 15,000 BPD of LPGs, 35,000 BPD of pool gasoline, 27,000 BPD of low sulfur distillate fuel oil, 1,600 TPD of premium grade coke precursor and 1,000 megawatts of electrical power. For the Southern Appalachian Region of the Eastern Coal Province, less SNG and more liquid products are predicted. For the Powder River Region of the Rocky Mountain Province, a higher percentage of the products are in the middle liquid fuel range and lesser quantities in the lower and higher boiling ranges.

2.1.5 ECONOMIC PROJECTIONS

The predicted time to design, construct and start up the facilities for each of the four designs was in the range of 5 years. Economic evaluations were based on a 20-year operating life. All evaluations were expressed as "instantaneous" current dollars, without inflation or escalation over the project life. The current dollar periods used for the original economic evaluation for each of the four conceptual designs described were:

Design	Current dollar period; economics expressed in:
COED-Based	1st quarter (Q) 1974 dollars
Oil/Gas	4th Q 1975 dollars
Fischer-Tropsch	4th Q 1975 dollars
POGO	Mid-1977 dollars

For uniformity of presentation in this report, the projected economics for each of the designs were escalated to first quarter 1978 dollars. Two separate project financial structures were developed, each to yield a 12 percent discounted cash flow (DCF) rate of return; one was 100 percent equity while the second was based on 65 percent debt financing borrowed at 9 percent interest rate. A summary of the results for the Oil/Gas and Fischer-Tropsch designs which coproduce SNG and liquid fuels is:

ITEM	OIL/GAS		FISCHER-TROPSCH	
Fixed capital investment:				
$ billion	1.4		1.8	
$ per daily barrel oil equivalent	12,750		19,000	
$ per daily ton feed coal	30,000		45,000	
PROFITABILITY	100% Equity	65% Debt 35% Equity	100% Equity	65% Debt 35% Equity
Required annual revenue for 12% DCF	590	465	667	515
Required product selling price:				
$ per million btu	2.70	2.10	3.80	2.90
$ per barrel oil equivalent	16.00	12.50	21.00	16.00

In addition, the market value of the products was estimated for each design. Using these values, the projected DCF rates of return for the 65 percent debt project financing cases were:

Design	DCF
Oil/Gas	19%
Fischer-Tropsch	23%

Similar economic projections for the COED-based and POGO complexes follow; these differ from the Oil/Gas and Fischer-Tropsch cases in that each of these configurations produces significant electrical power for sale in addition to fuels and by-products:

ITEM	COED-BASED		POGO	
Fixed capital investment:				
$ billion	1.5		2.5	
$ per daily ton feed coal	41,000		42,000	
PROFITABILITY	100% Equity	65% Debt 100% Equity	100% Equity	65% Debt 100% Equity
Required annual revenue for 12% DCF	570	470	970	735
Required fuel chemical selling price with electrical power sale at $30/MWh:				
$ per barrel oil equivalent (6MM Btu/bbl)	40	30	20	13
$ per million Btu	6.66	5.00	3.33	2.17

The possible market values of POGO products were estimated by comparison of their characteristics with petroleum-sourced products. The results of this analysis indicated a potential annual revenue of $965 million which would yield a DCF rate of return of approximately 20 percent for the 65 percent debt case. COED would also show improved economics on the same basis.

For orientation in interpretation of the "instantaneous" economics, the effect of inflation on projected DCFs in current dollars was scanned. The results indicate that the use of a 6 percent annual inflation rate for all project factors will predict a significantly higher current dollar DCF rate; for the 65 percent debt case, the projected DCF is about 30 percent.

2.2 MULTI-PROCESS DEMONSTRATION PLANT (MPDP)

The objective of this work was to develop preliminary designs and economic assessments for a facilities complex capable of demonstrating the commercial feasibility of a number of coal conversion processes that show potential viability.

The incentives for design, construction and operation of a MPDP include recognition that time and money could potentially be saved if multiple common facilities and process units were located in a central coal gasification and liquefaction test facility. All coal conversion demonstration plants will, in general, include: a gasification unit, facilities for coal receipt, storage, reclaim and preparation for feed to the coal conversion plant; utilities; shops, labs, personnel support facilities; oxygen supply; gas purification; product recovery and refining; other. The potential savings to accrue from use of common units in a MPDP facility can represent 40 to 50 percent of the alternative costs of building a separate facility to test each unit at a separate location. Another incentive is efficiency in personnel use; when one unit is removed from service for maintenance, turnaround or having achieved its objectives, another unit can be placed in service by the operating staff. For the alternative case of testing a single unit at each location, the operating crew would be less efficiently employed during shutdowns.

The MPDP preliminary design contained the following individual plants:[8]

- An entrained-type gasifier to produce fuel gas. It would process 1,800 TPD of coal, operate at 40 psig, and use air as the prime oxidant; the unit would have the flexibility to also use oxygen as oxidant when required.

- An entrained slagging-type oxygen-blown gasifier. It could process up to 3,750 TPD of coal while operating at 470 psig.

- A fluidized-bed gasifier to also process 3,750 TPD of coal at 470 psig.

- A combined cycle power plant capable of producing 200 megawatts (MW) of electrical power.

- An indirect liquefaction plant using elements of an advanced Fischer-Tropsch concept.[5] This plant would process approximately 44 million scfd of synthesis gas to produce about 900 BPD of liquid fuels and 5.7 million scfd of SNG.

In addition, the MPDP contained facilities to support the operation of the above demonstration scale plants and a plant population of about 530 people.

Key factors were described for design, construction and operation of this facility as a 10-year program. The estimated FCI was approximately 500 million mid-1977 dollars. The annual operating cost was estimated to be about $90 million when all plants are operating. The total project cash outflow, including capital and operating dollars, was estimated to be of the order of $1.15 billion. Based on possible operating and production rates plus estimated revenues from product sale, the net negative cash flow for the project could be about $800 million. If the project losses were tax deductible by the sponsoring organization(s), the net negative cash flow might be of the order of $350 million.

2.2.1 Expected Accomplishments

The key result expected is that the MPDP should provide a major basis for industry decisions regarding investment in the coal conversion technologies tested.

To accomplish its objectives, the facility should be conservatively designed, using experience from all sources to reduce technical risks to an acceptable level and assure reliable, safe, and environmentally acceptable operation. The design effort should continue to be supported by an active research and development program. In parallel with the design, procurement, construction, and startup of the MPDP, components should be tested and improved; this includes cooperative programs with equipment, process development, and instrumentation firms.

The construction and operation of an MPDP would provide hands-on experience with the performance of essential plant components. It would provide data and experience on operation of large scale coal conversion plant units and the interaction of the plant units with their associated supporting facilities and environment. An improved understanding would be developed for the range of costs and other factors pertinent to development of this energy option. The construction and operation experience would also contribute to development of the necessary technical and engineering expertise in safety, reliability, economics, and environmental factors for later use in commercial projects. It would also provide a core of experienced personnel in the design, construction, and operation of this type of synfuels plant; the personnel should be available for contributions on later projects.

Specific results to be expected include:

- Successful development and testing of large components should lead to improvements in commercial plant planning, scheduling, and cost prediction.
- The availability of large components whose performance has been proven should reduce the risks in design of commercial scale plants and, therefore, should encourage industry to invest in the larger plants.

- Acceptance of the performance of the fuel products in consumer applications and agreement that they can be sold at competitive prices.

Importantly, the MPDP described here should provide the operational experience and records needed to evaluate the commercial viability of commercial scale coal conversion plants using the technologies tested.

2.3 PRESTRESSED CONCRETE PRESSURE VESSELS (PCPVs) IN COAL CONVERSION PLANTS

A report describing the results of a study of the conceptual design and projected economics for four types of PCPVs for use in coal conversion plants has been published.[5] The PCPV designs and economics were compared with alternative steel vessels when used in the same service. Parsons was the prime contractor for this work and T. Y. Lin International of San Francisco, California served as subcontractor with responsibility for the structural design of the PCPVs.

The prime incentives for initiating this study were that preliminary assessment indicated:

- The development of PCPVs would permit the use of larger high pressure vessels than presently considered practical in steel construction.

- PCPVs would provide a competitive alternative to the use of steel vessels. This could be a major consideration if a large number of coal conversion complexes were to be constructed simultaneously to meet national alternative energy supply goals as described in U.S. energy plans. This alternative is particularly important because of the limited U.S. capability to produce numerous large high pressure vessels simultaneously, and because of possible shortages of alloy materials for high strength steel alloys.

- PCPVs could reduce the FCI of large coal conversion plants. The profitability of coal conversion plants is highly sensitive to the FCI; therefore a successful PCPV program would assist in making these plants economically viable.

The designs developed in this study were chosen to illustrate the potential of representative vessels selected from a large number of possible uses for PCPVs in coal conversion processes. The four PCPVs studied were: a dissolver-separator used to liquefy coal, an absorber used to purify gases, a coal gasifier reactor and an integrated coal gasifier vessel. The vessels studied range from a 23' 4" to a 33' 4" inside diameter. They were each designed to replace one or more conventional steel pressure vessel with no change in the process flow from conventional practive. Figure 2-1 illustrates the projected size and characteristics of one of the vessels - note the 6-foot man for size comparison.

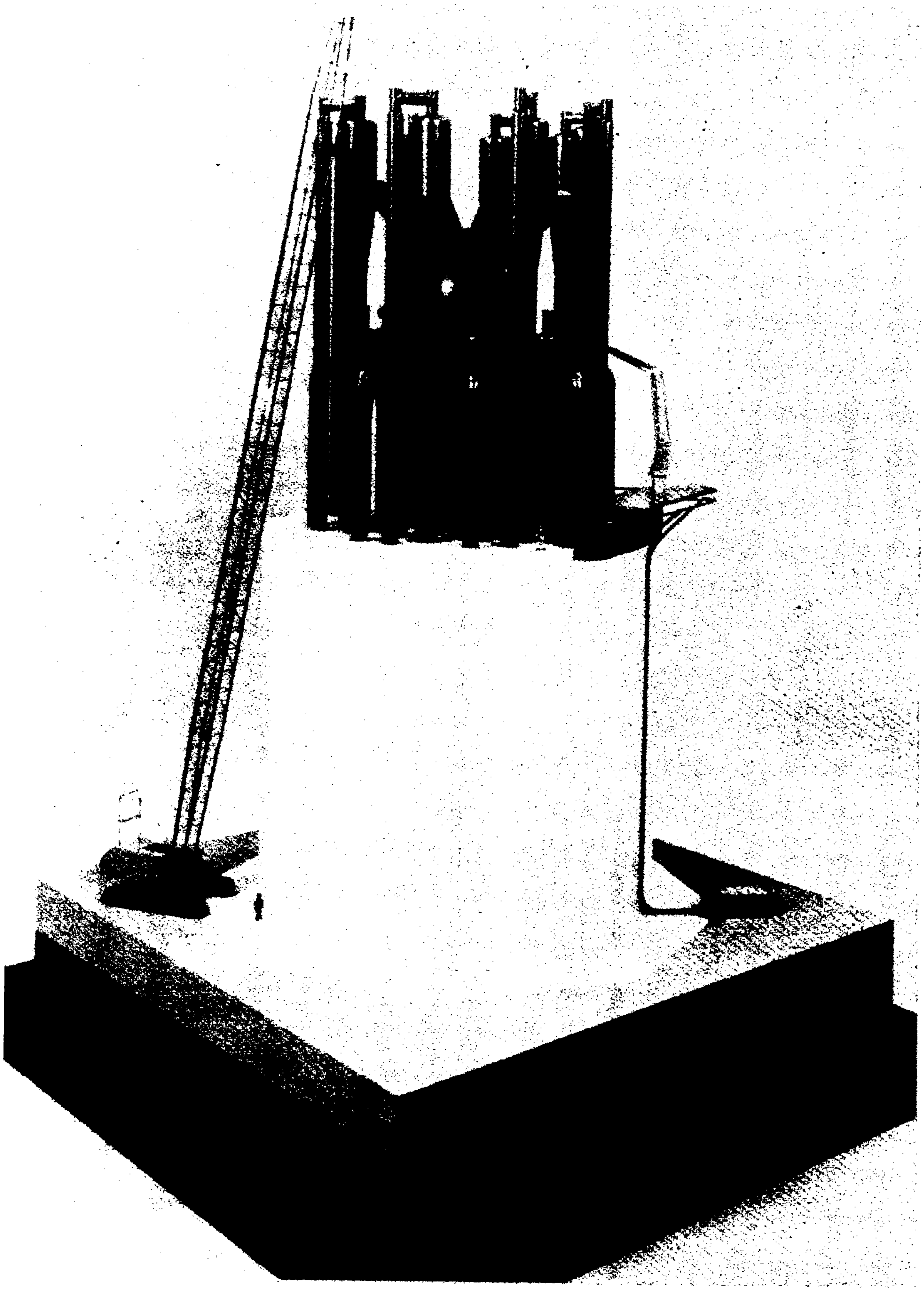


Figure 2-1 - Model - Integrated Gasifier Vessel During Construction

The process duties for each PCPV, and the alternative steel vessels, were defined by development of process designs complete with heat and material balances. The scope of the facilities studied was defined; for the absorbers, it included only the vessels, while for the dissolver-separator and gasifiers it included defined portions of the feed and product recovery facilities. Preliminary designs of the PCPVs in these services were completed followed by preliminary definition of construction procedures, schedules, and estimated FCI and operating costs. A summary of the characteristics of the vessels studied and estimated FCI shows:

Vessel	Type of Construction	Number of Trains	Capacity per Train	Number of Major Vessels per Train	Total Number Of Major Vessels	FCI ($ Million)	Percent Reduction in FCI Compared to Steel Vessel
Dissolver-Separator	Steel	3	20,000 TPD of Coal	6	18	430	0
	PCPV	1	55,000 TPD of Coal	1	1	130	70
Absorber	Steel	3	23 million scf/hr	2	6	10	0
	PCPV	1	69 million scf/hr	1	1	4	60
Gasification	Steel	2	55,000 TPD of Coal	1	2	255	0
	PCPV-Gasifier Reactor only	2	55,000 TPD of Coal	1	2	225	12
	PCPV-Integrated Gasifier	2	55,000 TPD of Coal	1	2	230	10

For the dissolver-separator comparison, one two-cavity PCPV would provide approximately 92 percent of the process capacity of eighteen steel vessels. One PCPV absorber would have capacity equivalent to six steel absorbers; the PCPV gasifier would have the same capacity as a large field-fabricated steel gasifier. The potential reduction in FCIs were predicted to be 70, 60 and 10 percent, respectively, for these cases.

The potential reductions in annual operating costs for the cases studied indicated:

Vessel type	Projected reduction in annual costs to accrue from use of PCPVs rather than steel vessels ($ million)
Dissolver-separator	90
Absorber	2
Gasifier only	10
Integrated gasifier	8

The results of the PCPV study indicated:

- The design and construction of PCPVs was found to be generally within the present state of knowledge. Subscale testing should be performed to confirm some design judgements.

- The use of PCPVs can reduce the FCI requirements. To illustrate, substitution of a single PCPV for as many as 18 steel vessels might reduce the FCI by approximately 70 percent, amounting to as much as $300 million. Replacement of a single steel vessel with a PCPV can reduce the FCI by approximately 10 percent.

  - Thus, there is a definite economic incentive to carry further the development of PCPVs to demonstrate their technical feasibility and economic viability.

- PCPVs offer an alternative for construction of large scale coal conversion plants.

- Improved vessel safety performance is expected because of the benign failure characteristics of PCPVs.

- PCPVs have the potential to be operational in a shorter schedule than steel vessels.

- At the time of this writing, supply projections indicate that the materials of construction of PCPVs can be readily available in the U.S. while the capacity to fabicate and install large numbers of large heavy walled steel pressure vessels was found to be currently limited by the number of suppliers and availability of fabrication facilities.

2.4 SUPPORTING ACTIVITIES

Supporting activities included definition of equipment and control system development programs required to assume reliability and viability of coal conversion processes, a similar program for materials of construction and to define those environmental control facilities to assure the operation within applicable environmental requirements. The prompt presentation and publication of the results of the work was a continuing objective. A summary of the results of these activities follows.

2.4.1 EQUIPMENT DEVELOPMENT

The task objective was to define equipment and control system development programs to assume reliable and viable operation of coal conversion processes.

Preliminary definitions were developed for approximately 6,000 separate major equipment items for use in coal conversion plants during the course of creation of the conceptual and preliminary designs. For each design, opinions regarding the projected performance of the facility, and the equipment used in that facility, were recorded. The resulting listing of equipment types warranting further development, or improvement, served as the basis for communications with equipment vendors and developers. Availability of equipment from domestic and foreign sources to provide the required performance and reliability was a primary objective. Particular areas investigated included solid coal feeders to gasifiers and pyrolyzers, pressure letdown valves, control valves, coal slurry pumps, gas/solid separation devices for performance at high temperature and pressure, large compressors and pressure letdown turbines.

The equipment requirements for scale-up from pilot plants to commercial scale plants were reviewed[10] and we organized and presented, to a national technical meeting, a session titled "Equipment Applications to Coal Conversion Operations" in which specific equipment, instrumentation, control and process unit capabilities were described by 12 major suppliers.[11]

2.4.2 MATERIALS OF CONSTRUCTION

The task objective was to define materials of construction, to assure reliability and viability of coal conversion plants.

To accomplish the objective, we played an active role in the DOE/ERDA/OCR Materials Evaluation program as well as the Materials Property Council (MPC) development programs. We monitored the performance of materials in coal gasification and liquefaction pilot plants, including on-site visits and consultations, and made recommendations where appropriate. We used this background to select the preferred materials for the 6,000-plus equipment items included in the conceptual and preliminary designs developed under this contract.

We responded to requests to present and publish the results of our work in this field; the result was six presentations to technical societies[12,13,14,15,16,17] and seven publications[10,18,19,20,21,22,23] to transmit the results of our work.

2.4.3 ENVIRONMENTAL FACTORS

The objective was to define environmental control procedures and facilities to assure operation of coal conversion plants within applicable environmental requirements.

For each conceptual or preliminary design developed under this contract, the procedures, equipment, estimated costs and projected performance of environmental control facilities were developed. The projected performance was then compared with the relevant emission standards or, if these did not exist, emission standards for related facilities such as oil refineries, petrochemical plants, or coal processing facilities. Where inadequate information was available, consultation and independent analysis was undertaken.

Specific environmental factors studied and reported included the design and operating precautions when handling potential carcinogens, the disposition of trace elements contained in the coal ash, metal carbonyls carbon dioxide exhaust, and the capital costs required for environmental control.

The results of our work in this field were summarized in seven presentations[12,24,25,26,27,28,29] and six publications[10,30,31,32,33,34] in addition to inclusion of a separate section on environmental factor in each of the four conceptual designs and in the MPDP.

2.4.4 PUBLICATION OF CONTRACT WORK RESULTS

The results of the contract work has been placed in the public domain by means of approximately 21 separate publications. In addition, copies of thirty-nine papers which summarize the results of our work are in press in DOE publication titled "Coal Conversion Applications, Collected Works 1972 through 1977."[35]

SECTION 3

CONCEPTUAL DESIGNS

3.1 INTRODUCTION

Four conceptual designs/economic evaluations for coal conversion complexes were completed and reports summarizing the detailed results were published.[2,3,5,6] Each complex contained a captive coal mine. Coal conversion processes incorporated into the designs included pyrolysis, hydroliquefaction, indirect liquefaction and gasification. Two of the designs included large electrical power plants designed to interface with the process plants.[2,6] Three of the designs coproduced gas and liquid synfuels.[3,5,6]

Common characteristics for the designs/economic evaluations include:

(1) The complexes were conceived to be located in the eastern region of the Interior Coal Province, which includes portions of the States of Illinois, Indiana, and Kentucky.

(2) The feed coal was Illinois No. 6 seam coal.

(3) Preliminary process designs complete with heat and natural balances were developed.

(4) All utilities were captively produced.

(5) The complexes were designed to meet applicable environmental requirements.

(6) An equipment list showing all major equipment items, their size, capacity, and, in most cases, materials of construction was developed.

(7) Preliminary fixed capital investment estimates were developed. The expected accuracy was -5, +20%. No contingency was added; sensitivity of project profitability to capital investment was presented to permit a reader to assign a contingency as deemed appropriate.

    The FCIs for the oil/gas, Fischer-Tropsch and POGO designs were independently reviewed by the U.S. Army Engineer Division of Huntsville, Alabama (USAEDH) at the direction of DOE. In each case, USAEDH concluded that the FDI would be less than that reported by Parsons; the USAEDH estimates were in the range of 4-12% lower than Parsons.[36,37,38]

(8) Inspections and projected product specifications were developed for all products and opinions presented regarding their marketability.

(9) Operating costs were estimated for each complex. The contributions of the separate sections of the complex such as coal mine, process plant, and power plant to the operating costs were defined.

(10) The time required to design, engineer, procure and construct the facility was estimated. In each case the total time was approximately 5 years.

(11) The complex was conceived to operate 20 years and have zero scrap value at the end of that time.

(12) The required product selling price (RPSP) was predicted:

(a) The predicted RPSP was based on an "instantaneous" current dollars model.

(b) The base profitability level was 12% DCF rate of return for the oil/gas, Fischer-Tropsch and POGO designs, and 10% for COED. Two financial parameter cases were developed; 100% equity and 65% debt/35% equity with the debt borrowed at 9% interest rate.

(c) For three designs, [3,5,6] the possible product market values of the products, and resulting revenues, were predicted by comparison with analagous petroleum-sourced products. Using the predicted revenues, DCFs were estimated.

(d) Sensitivities of profitability to changes in FCI, operating cost, and coal cost were developed.

(e) Sensitivities of RPSP to DCF rate of return were developed.

(f) A retrospective view of the expected performance of the complex when built was developed.

(g) Recommendations for further improvements and additional data development were presented.

The characteristics of the separate designs will be presented in the following paragraphs.

3.2 COED - BASED PYROLYSIS COMPLEX

3.2.1 FACILITY DESCRIPTION

This section briefly describes general characteristics of the coal conversion complex; an overall block flow diagram is shown in Figure 3-1.

This complex includes captive coal mines with capacity to produce up to approximately 13 million TPY for 20 years. Units are included which will clean, wash, crush, and size the coal and feed it to the process units.

All necessary facilities for production of oxygen, hydrogen, as well as all required utilities, are included in the design. Also included were facilities for treatment and disposal of solid, liquid and gas waste streams. The design is based on a site location capable of providing 45,000 acre-feet of water per year for process requirements and utilities makeup. Well water is used for potable and sanitary water.

The land area required for the life of the project for mining the required coal is estimated to be about 42 square miles; approximately 500 acres would be allotted to the initial plant complex.

The artist's conceptual drawing of the complex is shown in Figure 3-2. A model of the complex has been constructed and a photograph of this model is presented in Figure 3-3.

A. The Pyrolysis Unit

The heart of the coal conversion plant is a multiple-stage atmospheric pressure pyrolysis unit. The vapors generated in the pyrolysis unit are treated to recover a tar and separate the gas. The tar is filtered to remove solids and then hydrotreated to reduce heteroatom content and viscosity. The resulting product is a low-sulfur synthetic crude oil (syncrude). Pyrolysis gases are treated to remove the acid gases hydrogen sulfide and carbon dioxide, and then used in the power generation unit. Elemental sulfur is produced as a by-product of the gas cleaning operations.

The pyrolysis section produces a significant amount of char which is, in turn, essentially completely gasified using steam and oxygen. Recycled char and effluent gases from the gasifier supply energy to the pyrolysis section. The gasifier gases, after purification to remove sulfur compounds, are fed to the power plant, where electrical energy and steam are produced.

B. Plant Capacity

The typical throughput of coal is based on 21,500 TPD of MAF coal; this corresponds to about 24,500 TPD of MF coal and 27,400 TPD of as-is feed coal containing ash and moisture. This throughput will produce the following approximate output rates:

Synthetic crude oil	28,000 BPD
Electric power	830 MW
Sulfur	760 LTPD

Because of the varying content of volatile matter, moisture, and ash in the feed coal, the rate of product output will also vary. Oil output is expected to vary from 24,000 to 32,000 BPD. Electric power maximum exportable output is about 1,150 MW when volatile matter, moisture and ash are lowest. Electrical power output will be lowest under conditions of highest expected content of volatile matter, moisture and ash, in the feed coal, at which point steam demand is high. Efficiency of fuel utilization for electrical generation declines significantly at levels below 825 MW.

C. Energy Balance Factors

Gas, which serves as fuel for the power and steam generation unit, is composed of a mix of high-Btu gas (about 890 Btu/scf) from pyrolysis, and low-Btu gas (250 Btu/scf) from char burning. The total heat content of the combined streams is typically 14,200 million Btu/hr. In addition to the electric power produced with a typical coal composition, this fuel must also produce 5.2 million lb/hr of steam for captive use in the complex. Approximately 3.7 million lb/hr is required in the process units for mechanical drivers and process use of supplement steam which is produced in these units. In addition, 1.5 million lb/hr is required for power plant fuel gas compressor drives. The heating value of fuel gas required to produce this 5.2 million lb/hr of steam, plus the amount required to produce about 80 MW of power required for captive use in the complex, leaves a net quantity of 7,600 million Btu/hr (HHV) for production of electrical power for export.

3.2.2 MATERIAL BALANCE

The overall material balance for the process sections of the complex is depicted in Figure 3-4. The balance is for a typical feed coal composition.

The Figure 3-4 balance reflects the portion of the complex which converts 24,487 TPD of moisture-free coal to a product slate consisting of:

(1) High-Btu gas ($= 890 \frac{Btu}{scf}$ HHV)

(2) Low-Btu gas ($= 250 \frac{Btu}{scf}$ HHV)

(3) Syncrude

(4) Sulfur

(5) CO_2 + ventgas

(6) Ash

The total weight of these products for the typical case is 45,177 TPD.

The revenue producers are syncrude, electricity, and sulfur. The high- and low-Btu gases from the process sections are used to produce the export electricity as well as the steam and electricity required to operate the COED-based complex.

3.2.3 ENERGY BALANCE

The overall energy balance is illustrated in Figure 3-5. All values are based on a typical coal feed and will vary as the characteristics of the coal vary.

Figure 3-5 indicates that of the 25,433 MM Btu/hr energy input from the coal, 15,329 MM Btu/hr, or approximately 60%, is consumed within the complex. Energy value of the products for export are also indicated; these total 10,104 MM Btu/hr, or approximately 40%, of the total energy input. The contributors are:

Product	Energy Content (MM Btu/hr)	Percent Feed Coal	Percent Product
COED syncrude oil	7,005	28	69
Electrical power	2,823	11	28
Sulfur	276	1	3
Total	10,104	40	100

Note that the production of electrical power represents about 28% of the exported energy. The energy efficiency for the process of converting fuel gas to electricity for this case is approximately 35%.

Figure 3-6 depicts the estimated thermal efficiency for the process section. The results indicate a thermal efficiency of approximately 58% for the conversion of feed coal to syncrude, fuel gas, and sulfur.

3.2.4 ECONOMICS

The estimated capital requirements, project and fund drawdown schedules, operating costs and required product selling prices (RPSPs) and sensitivities of RPSP to key parameters, were developed and are summarized here. All economics were based on first quarter 1974 dollars. Economic results for all four conceptual designs were presented in first quarter 1978 dollars in the summary section of this report, for comparison purposes.

Key results of the economic analysis were:

(1) The estimated FCI was approximately $1,000 million.

(2) The estimated total capital requirement, exclusive of interest during construction, was $1,125 million. Elements include:

   (a) Initial raw materials, catalysts and chemicals = $4.5 million

   (b) Allowance for starting costs = $51 million

   (c) Initial working capital - $70 million

   (d) Allowance for land acquisition = $1 million

(3) Capital expenditures for replacement of coal mining equipment were estimated and reported.

(4) Construction financing costs for a project financial structure consisting of 65% debt borrowed at 9% interest rate were estimated to be about $120 million.

(5) The estimated annual operating cost is approximately $125 million.

(6) The predicted project schedule, from project actuation to mechanical completion, was 56 months.

(7) The projected fund drawdown schedule indicates fund requirements would peak at about $240 million during the six month period, 42 to 48 months after project start.

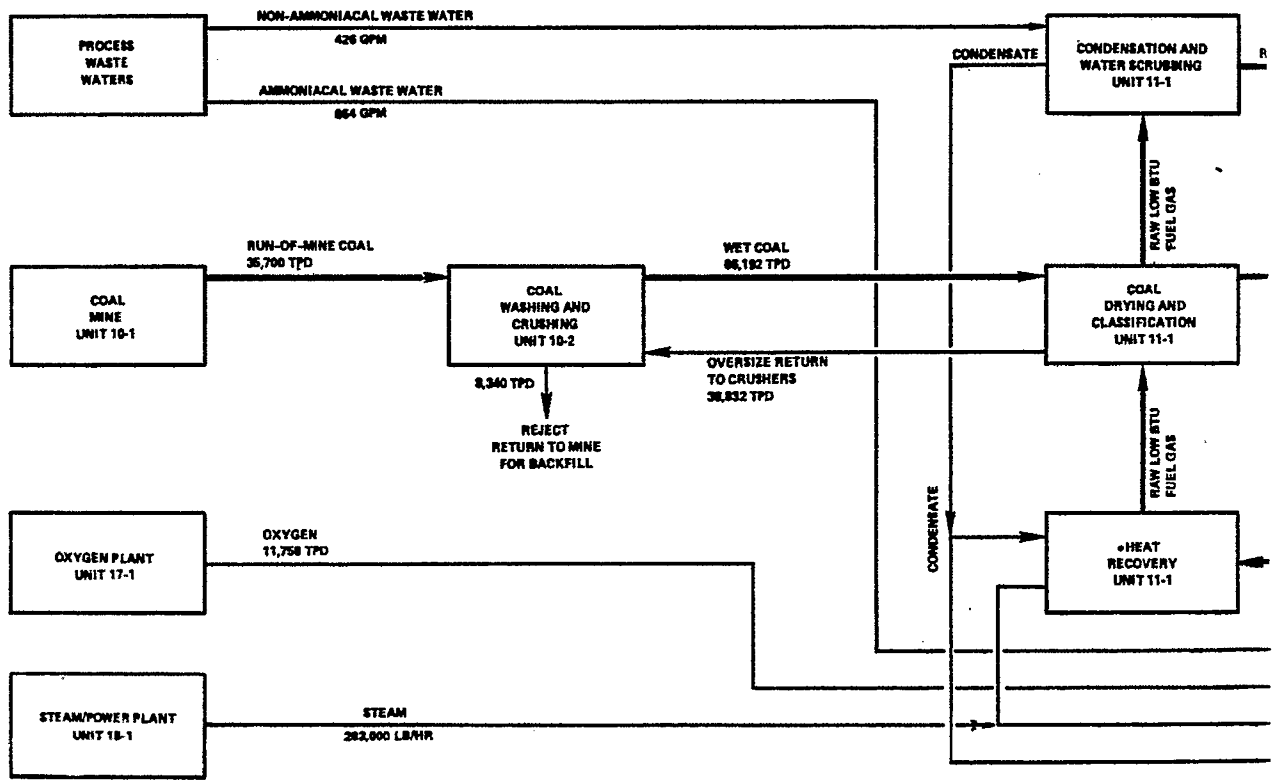
(8) Approximately 1700 people would be directly employed by the complex.

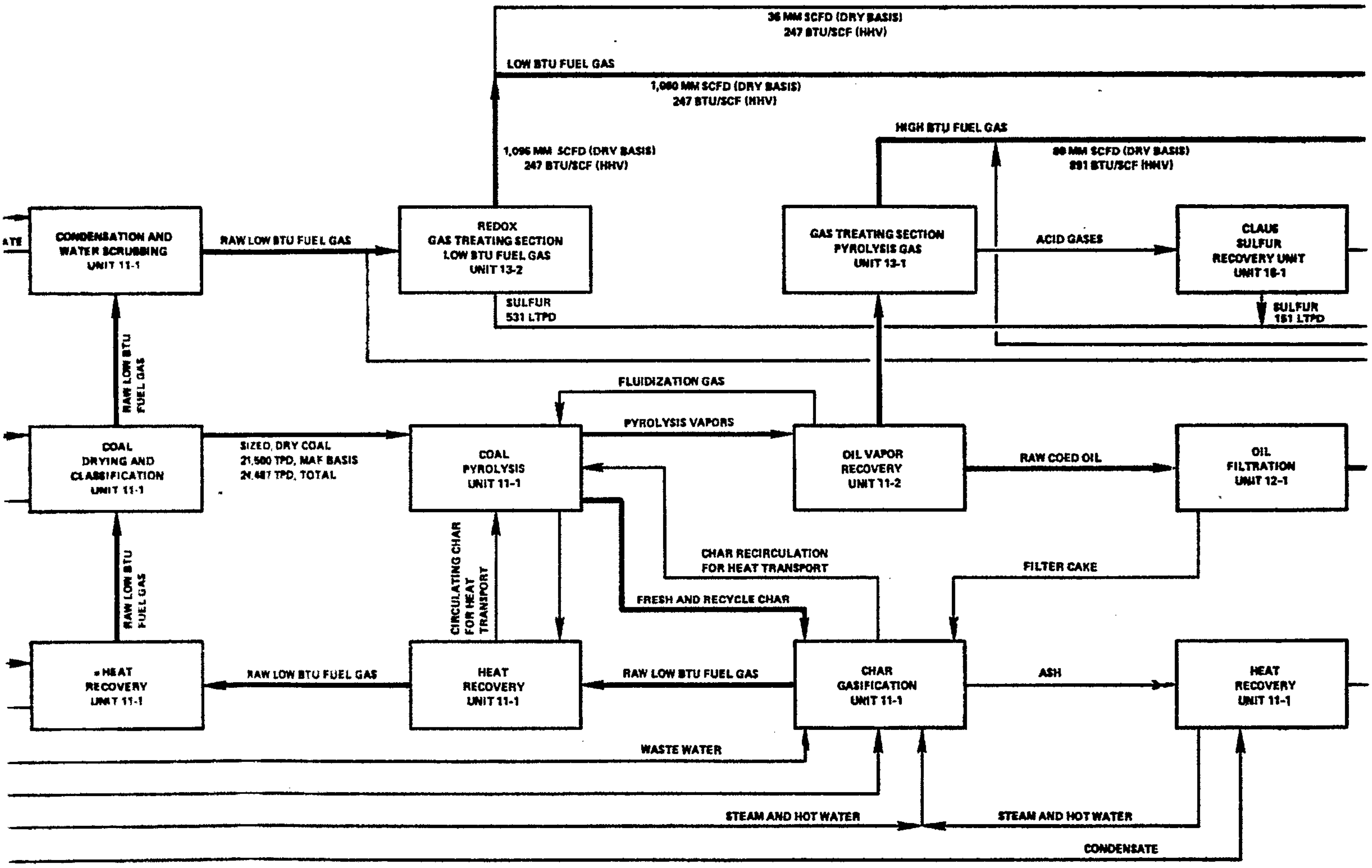
(9) The RPSPs are shown in Figure 3-7 using a "typical" coal analysis and "typical" yields. Here we see that for the 65% debt case with power sales at 30 mils per kWh, syncrude should sell at about $12/barrel to yield a 10% DCF.

(10) The effect of variations in feed coal analysis and method of operation of the complex is shown in Figure 3-8. The difference in required syncrude price to return a 10% DCF for 100% equity financing for the minimum and maximum oil production case is more than a factor of 2.

(11) The profitability is most sensitive to capital investment and least sensitive to operating costs.

(12) Provision of enough flexibility to operate the complex using coals with variations to be expected from use of Illinois No. 6 coal over a 20-year period adds about 10 and 8%, respectively, to the FCI and RPSP, relative to plant designed to handle a single "typical" feed coal composition.


PROCESS
WASTE
WATERS
NON-AMMONIACAL WASTE WATER
426 GPM
AMMONIACAL WASTE WATER
864 GPM
CONDENSATE
CONDENSATION AND
WATER SCRUBBING
UNIT 11-1
RAW LOW BTU
FUEL GAS
COAL
MINE
UNIT 10-1
RUN-OF-MINE COAL
35,700 TPD
COAL
WASHING AND
CRUSHING
UNIT 10-2
WET COAL
66,192 TPD
COAL
DRYING AND
CLASSIFICATION
UNIT 11-1
OVERSIZE RETURN
TO CRUSHERS
38,832 TPD
8,340 TPD
REJECT
RETURN TO MINE
FOR BACKFILL
RAW LOW BTU
FUEL GAS
CONDENSATE
OXYGEN PLANT
UNIT 17-1
OXYGEN
11,758 TPD
•HEAT
RECOVERY
UNIT 11-1
STEAM/POWER PLANT
UNIT 18-1
STEAM
282,000 LB/HR



36 MM SCFD (DRY BASIS)
247 BTU/SCF (HHV)
LOW BTU FUEL GAS
1,060 MM SCFD (DRY BASIS)
247 BTU/SCF (HHV)
HIGH BTU FUEL GAS
1,096 MM SCFD (DRY BASIS)
247 BTU/SCF (HHV)
89 MM SCFD (DRY BASIS)
891 BTU/SCF (HHV)
CONDENSATION AND WATER SCRUBBING UNIT 11-1
RAW LOW BTU FUEL GAS
REDOX GAS TREATING SECTION LOW BTU FUEL GAS UNIT 13-2
GAS TREATING SECTION PYROLYSIS GAS UNIT 13-1
ACID GASES
CLAUS SULFUR RECOVERY UNIT UNIT 16-1
SULFUR 531 LTPD
SULFUR 151 LTPD
RAW LOW BTU FUEL GAS
FLUIDIZATION GAS
PYROLYSIS VAPORS
COAL DRYING AND CLASSIFICATION UNIT 11-1
SIZED, DRY COAL
21,500 TPD, MAF BASIS
24,487 TPD, TOTAL
COAL PYROLYSIS UNIT 11-1
OIL VAPOR RECOVERY UNIT 11-2
RAW COED OIL
OIL FILTRATION UNIT 12-1
CHAR RECIRCULATION FOR HEAT TRANSPORT
FILTER CAKE
RAW LOW BTU FUEL GAS
CIRCULATING CHAR FOR HEAT TRANSPORT
FRESH AND RECYCLE CHAR
HEAT RECOVERY UNIT 11-1
RAW LOW BTU FUEL GAS
HEAT RECOVERY UNIT 11-1
RAW LOW BTU FUEL GAS
CHAR GASIFICATION UNIT 11-1
ASH
HEAT RECOVERY UNIT 11-1
WASTE WATER
STEAM AND HOT WATER
STEAM AND HOT WATER
CONDENSATE

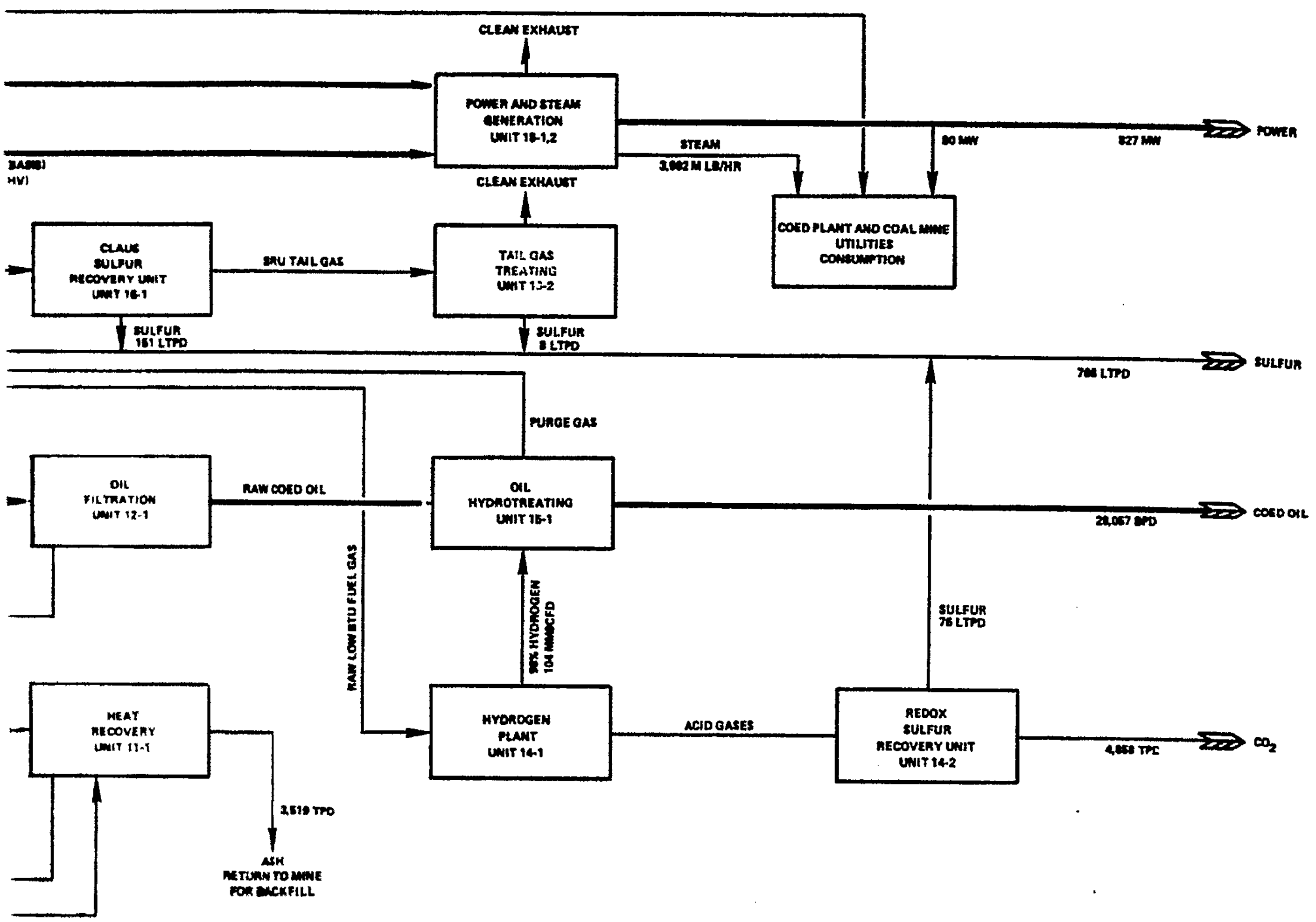


Figure 3-1- Block Flow Diagram -
COED Plant Design

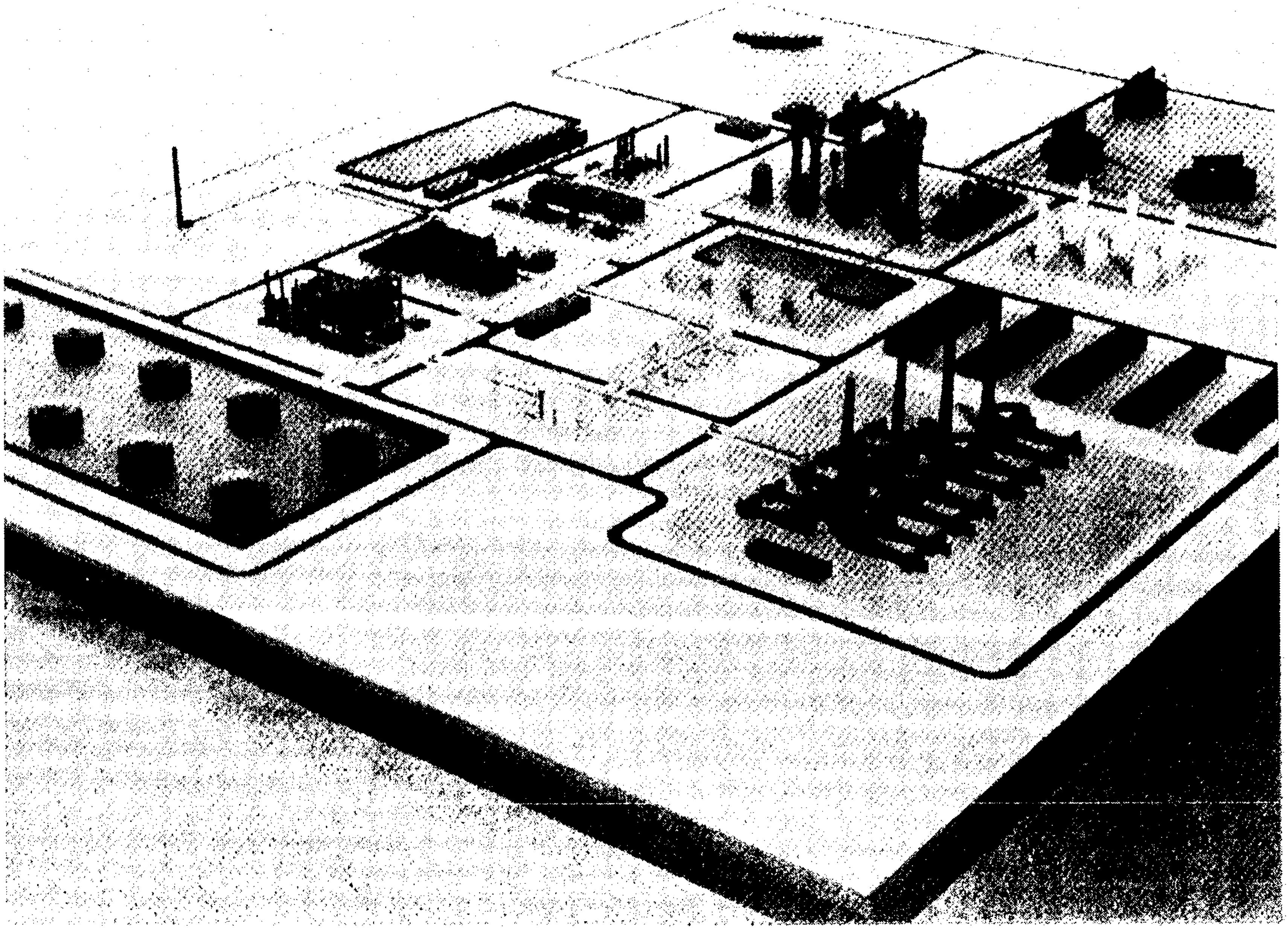


Figure 3-2 - Artist's Concept of COED Plant Design

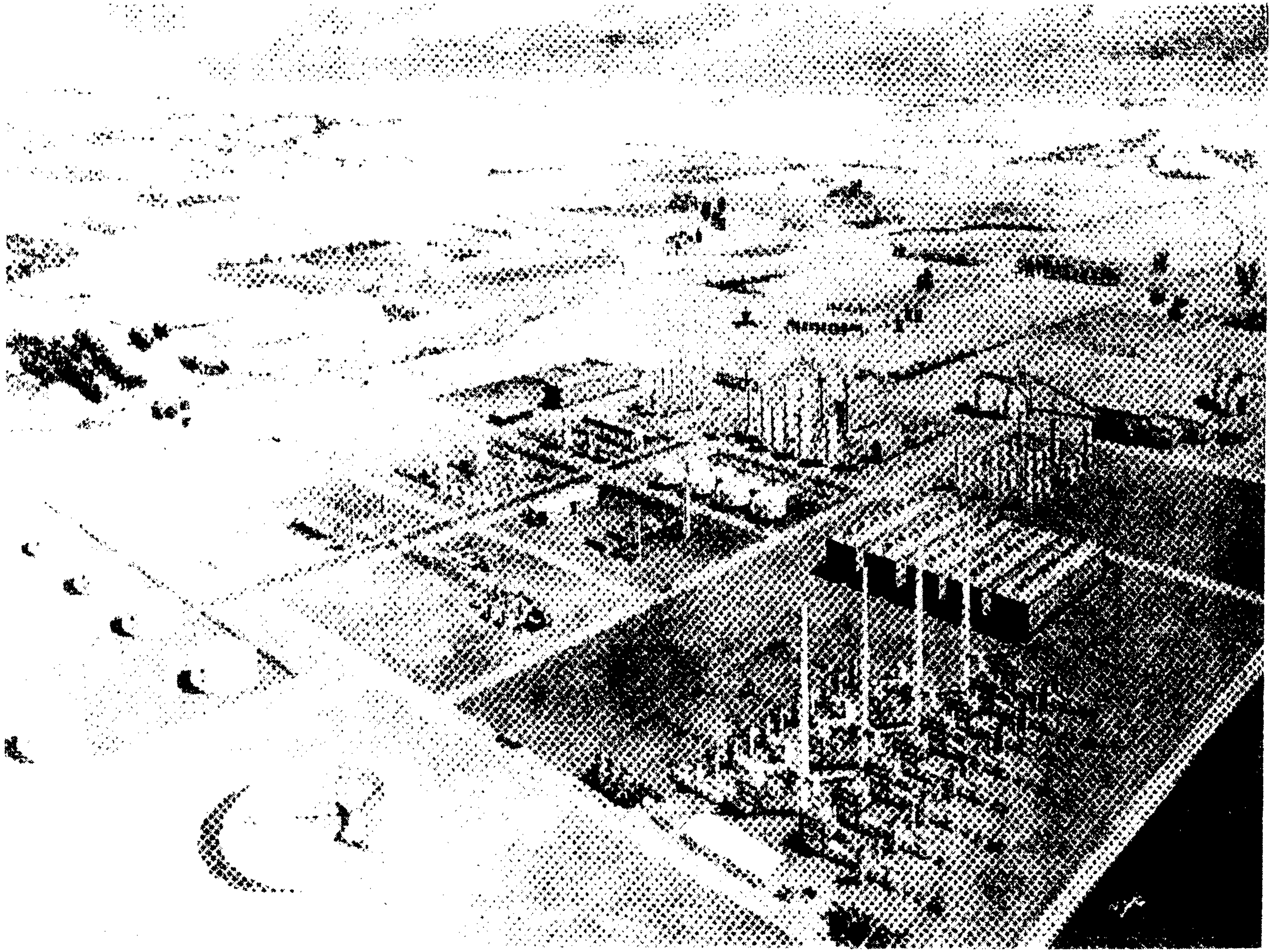


Figure 3-3 - Model of Conceptual COED Plant Design

RMP

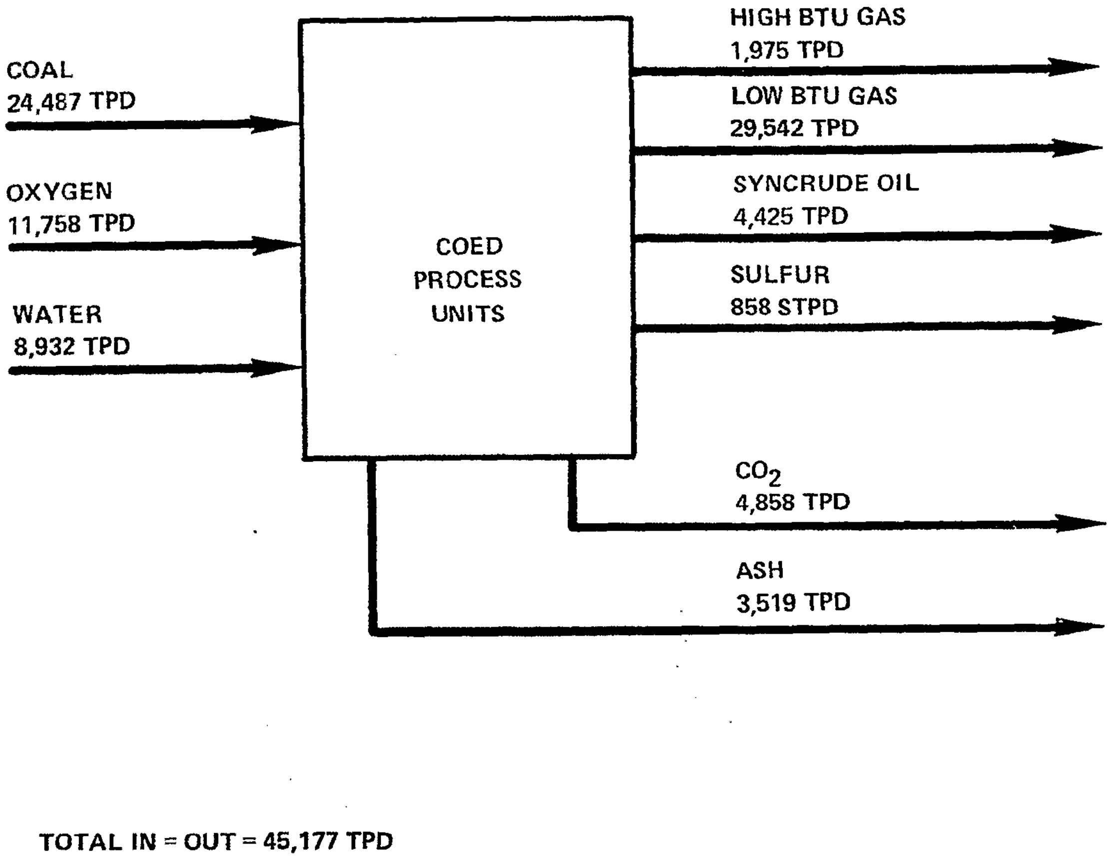
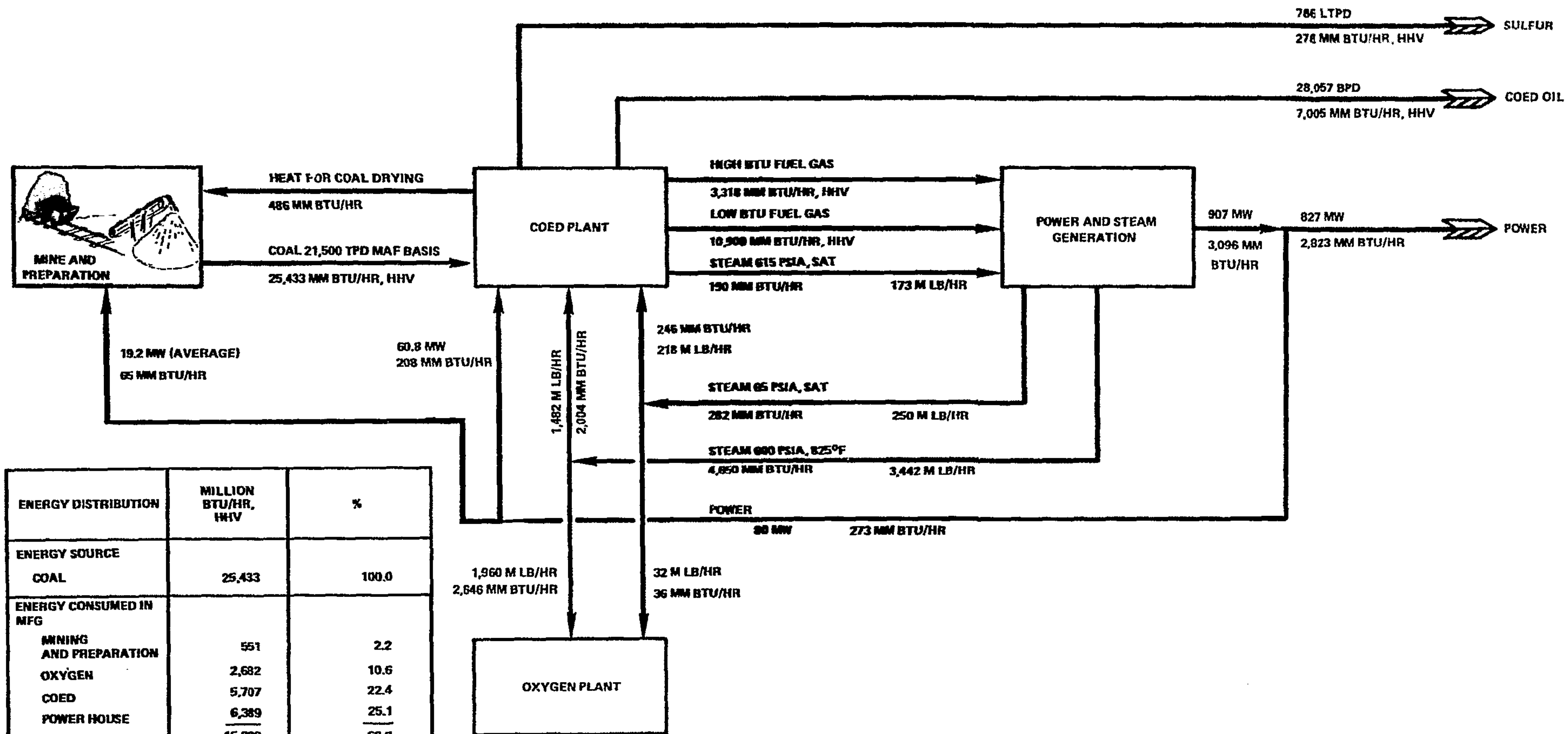


Figure 3-4 - Material Balance
COED Plant Design



ENERGY DISTRIBUTION	MILLION BTU/HR, HHV	%
ENERGY SOURCE		
COAL	25,433	100.0
ENERGY CONSUMED IN MFG		
MINING AND PREPARATION	551	2.2
OXYGEN	2,682	10.6
COED	5,707	22.4
POWER HOUSE	6,389	25.1
TOTAL	15,329	60.3
ENERGY VALUE OF PRODUCT		
COED OIL	7,005	27.5
EXPORT POWER	2,823	11.1
SULFUR	276	1.1
TOTAL	10,104	39.7

Figure 3-5 - Energy Balance - COED Plant Design

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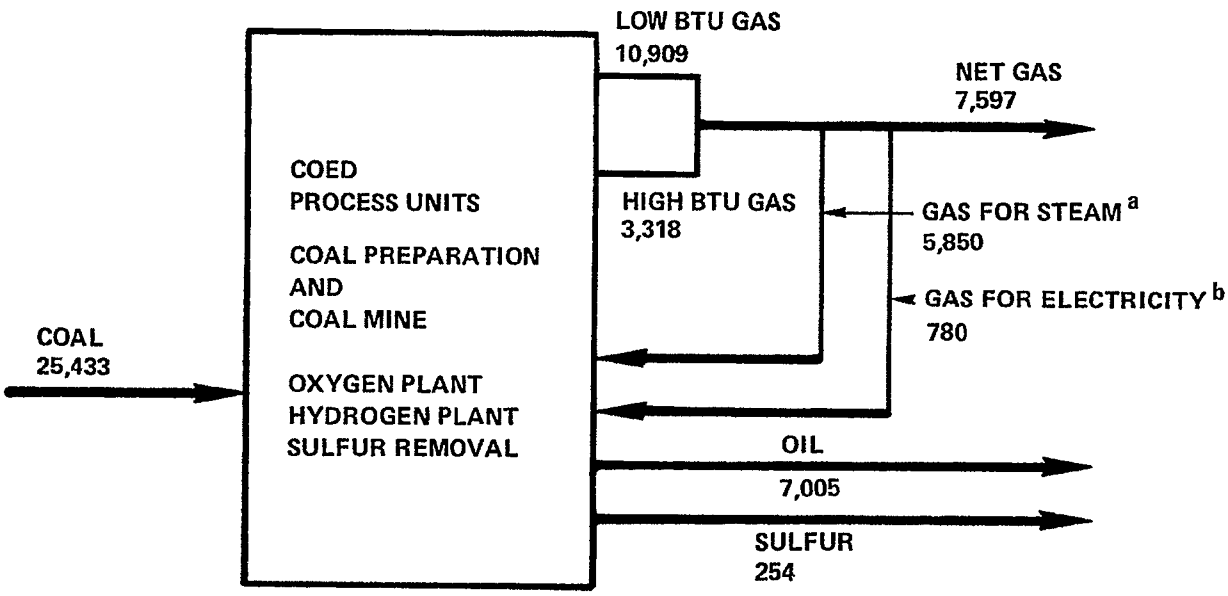


ALL FIGURES ARE MM BTU/HR, HHV

$$\text{THERMAL EFFICIENCY} = \frac{7{,}597 + 7{,}005 + 254}{25{,}433} = 58.4\%$$

a) GAS FOR IN-HOUSE STEAM REQUIRED: $\frac{4{,}970}{0.85\ \text{EFF}} = 5{,}850$

b) GAS FOR IN-HOUSE ELECTRIC POWER REQUIRED: $\frac{80\ \text{MW} \times 3{,}413}{0.35_{\text{EFF}}} = 780$

Note: Based on Export of Fuel Gas

Figure 3-6 - Thermal Efficiency
COED Plant Design

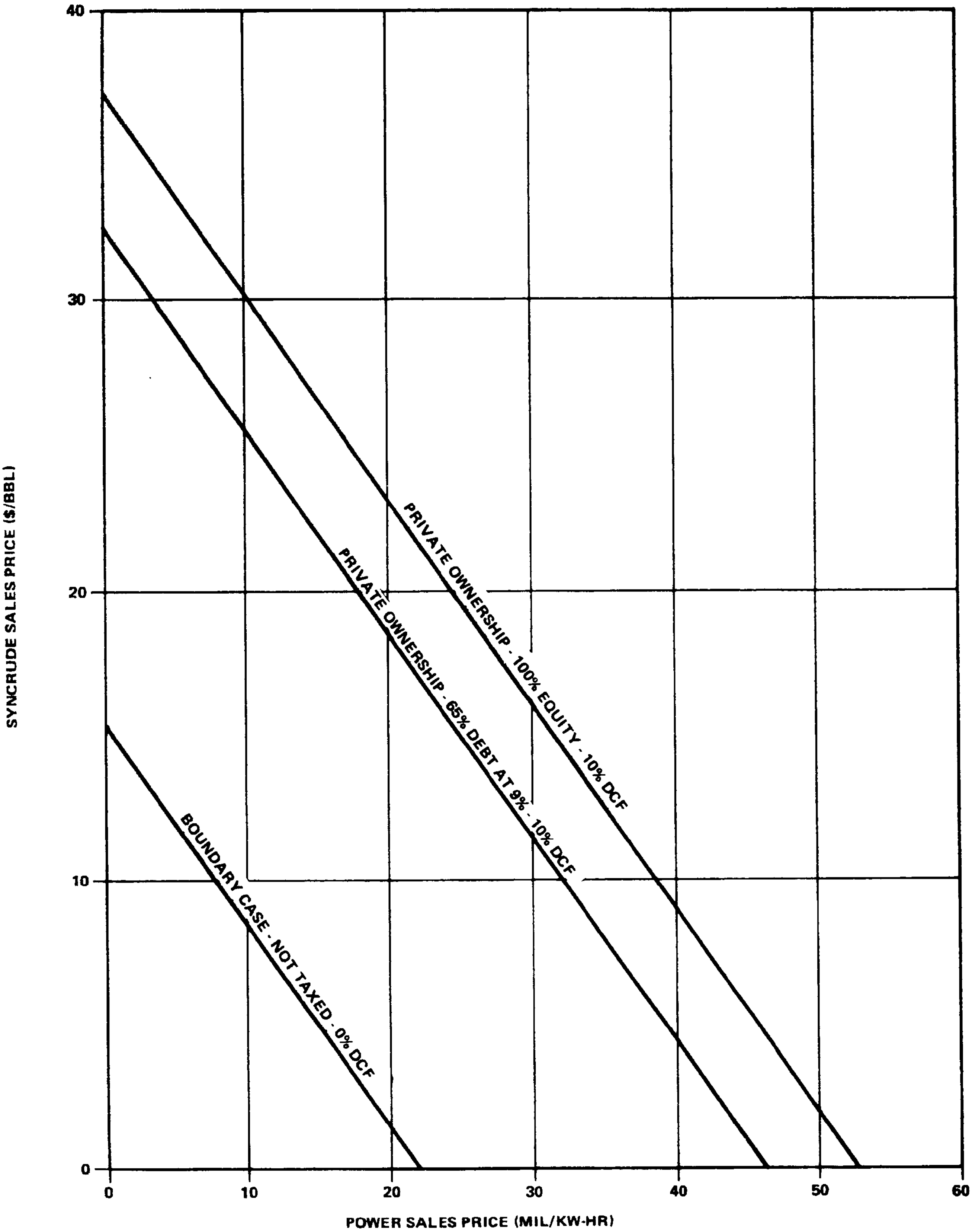


Figure 3-7 - Required Product Selling Prices
Typical Coal Analysis, COED Plant Design

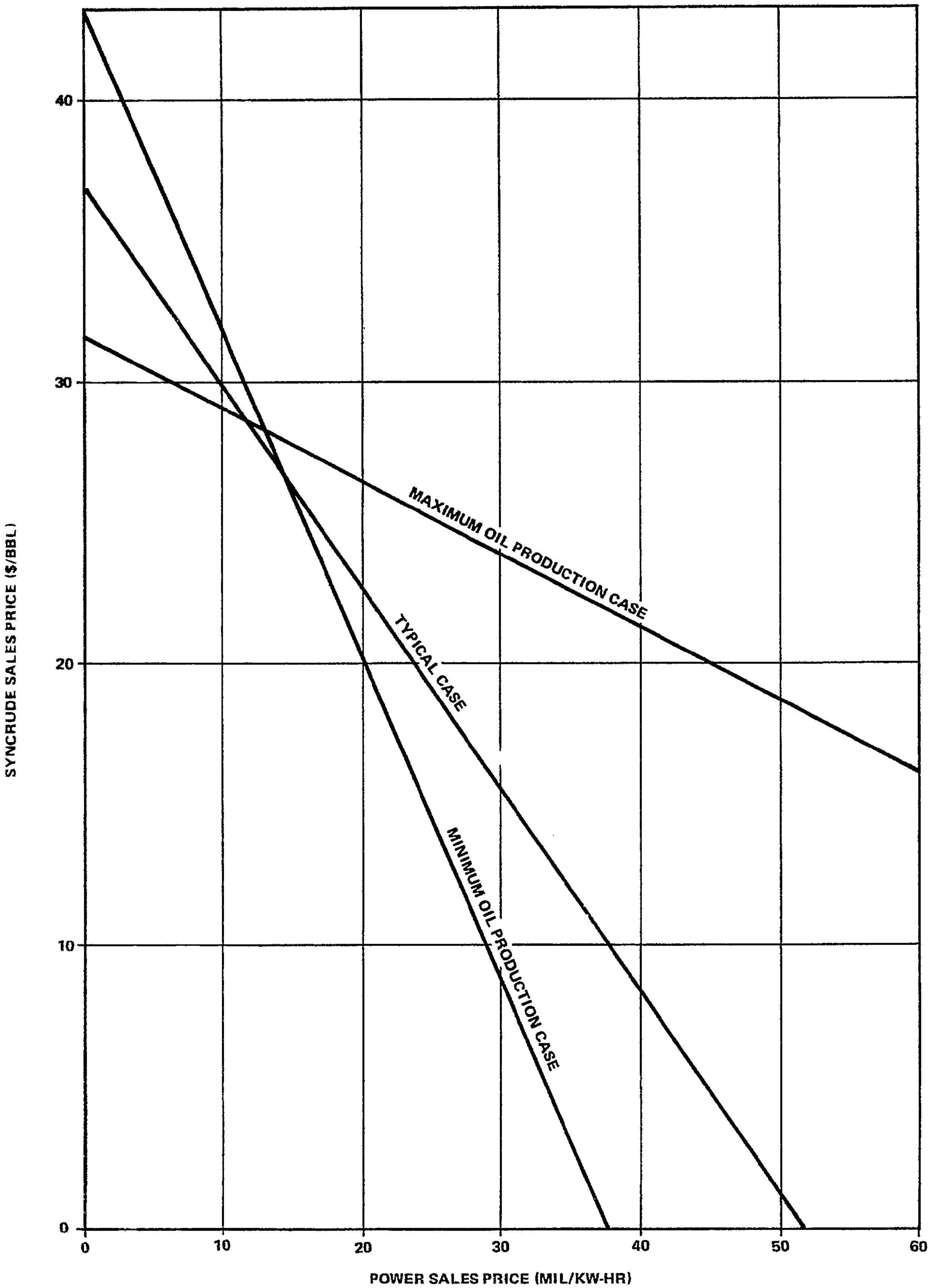


Figure 3-8 - Required Product Selling Prices - 100% Equity 10% DCF for Expected Range of Coal Analysis, COED Plant Design

3.3 OIL/GAS HYDROLIQUEFACTION PLANT

The oil/gas is an SCR II-based hydroliquefaction plant using filters for removal of coal ash and coal residues not converted in the coal dissolving step.[3]

3.3.1 FACILITY DESCRIPTION

A block flow diagram with overall material balance is shown in Figure 3-9. The complex includes a captive coal mine to supply approximately 47,000 tons of ROM coal per stream day, plus facilities to prepare 35,570 tons per stream day (TPSD) clean, sized coal as feed to the process units.

Facilities to produce oxygen and all required utilities are provided, as are facilities for the treatment and disposal of solid, liquid, and gaseous effluent streams.

The land area required for the complex is approximately 600 acres. Over a 20-year project life, approximately 55 square miles would be mined to supply the required feed coal.

A. Process Units

Key coal conversion units are:

(1) A three-train hydroliquefaction unit to convert 20,000 TPSD of feed coal to the primary products: SNG, LPG, naphtha, and fuel oil

(2) A process gasifier to convert 10,000 TPSD of feed coal to methane, syngas, and minor amounts of by-products

(3) A fuel gas gasifier to produce energy for captive use from 5,670 TPSD of coal, plus dry filter cake

Additional process units shown recover and refine the products plus treat waste streams to produce environmentally acceptable effluents.

B. Plant Configuration

Figure 3-10 presents a plot plan, and Figure 3-11 is an artist's conceptual drawing of the complex. A photograph of a model of the complex is shown in Figure 3-12.

C. Plant Capacity

The design coal feed rate to the process section is approximately 30,000 TPD, and the product rate is approximately 75,000 BPD of liquid product and 165 MM scfd of SNG.

3.3.2 MATERIAL BALANCE

The overall material balance for the process sections of the complex is depicted in Figure 3-13. The results predict that approximately 17,500 TPD of fuel products will be produced from about 36,000 TPD of coal fed to the process section of the complex. The fuel output of the plant is approximately 75,000 BPSD of liquids, including the LPGs and 165 scfd of SNG; This output represents a total of about 110,000 equivalent BPSD of fuels based on a 6-million Btu/bbl reference value.

3.3.3 ENERGY BALANCE

This overall energy balance of the complex is illustrated in Figure 3-14. This figure indicates that of the 36,040-MM Btu/hr energy input from the ground and dried coal, 8,300 MM Btu/hr, or approximately 23%, is consumed within the complex. This consumption includes the power and steam consumed in the mining, coal preparation, and coal grinding and drying operations. The energy value of salable products is projected to total 27,750 MM Btu/hr, or approximately 77% of the total energy input.

3.3.4 ECONOMICS

All economics summarized here are based on fourth quarter 1975 dollars. The results were:

(1) The estimated FCI was approximately $1,225 million

(2) The total capital requirements were estimated to be about $1,600 million, including approximately $175 million for construction financing costs for the 65% debt financing case

(3) The annual operating costs were estimated to be about $195 million

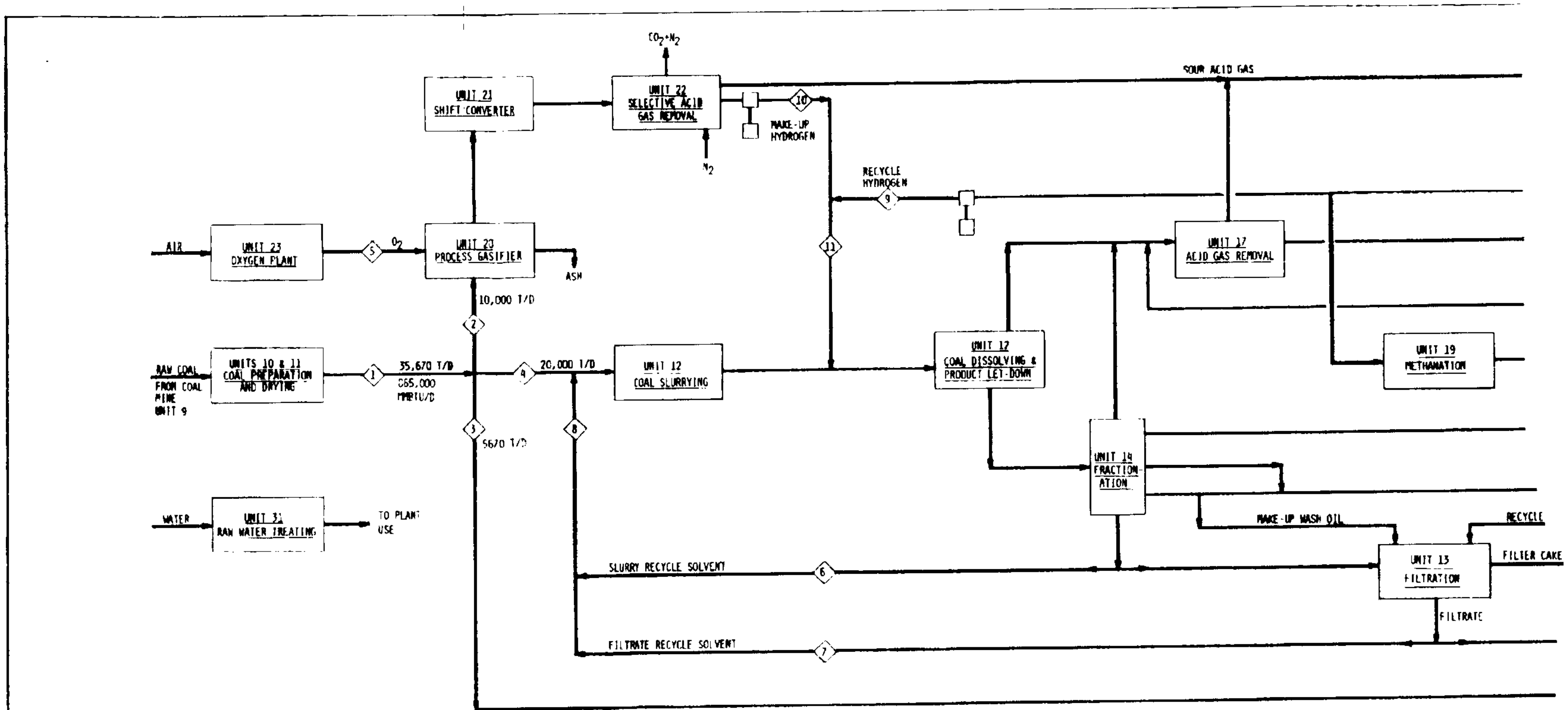
(4) The RPSP, 65% debt borrowed at 9% interest, is slightly less than $2.00 per million Btu; this corresponds to less than $12.00 per nominal 6 million Btu barrel. For the 100% equity funding case, the projected RPSP was of the order of $2.50 million Btu or $15.00 per barrel

(5) The sensitivities of RPSP were:

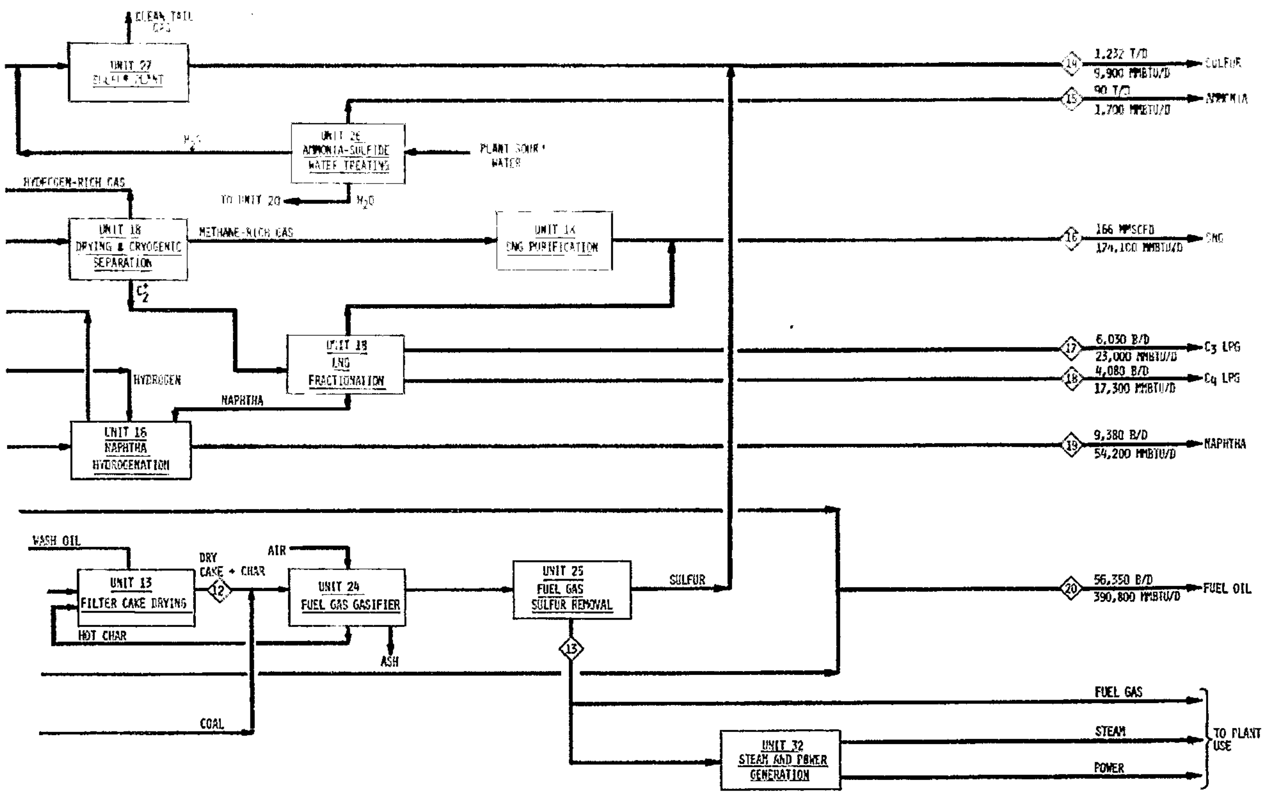
   (a) A 10% reduction in capital associated costs would result in about an 8% reduction in RPSP for the 65% debt financing case

   (b) Similarly, the sensitivity to operating cost is 2.7% reduction in RPSP for a 10% reduction in operating cost

   (c) The sensitivity to coal cost is about 3.5%



STREAM NO.	1	2	3	4	5	6	7	8	9	10
STREAM NAME	CLEAN COAL FEED	COAL TO H.P. GASIFIER	COAL TO L.P. GASIFIER	COAL TO DISSOLVING	OXYGEN TO H.P. GASIFIER	SLURRY SOLVENT	FILTRATE SOLVENT	TOTAL SOLVENT	RECYCLE HYDROGEN	MAKE-UP HYDROGEN
O_2, T/D	-	-	-	-	4,418.8*	-	-	-	-	-
H_2	-	-	-	-	-	-		-	760.50	1,069.20
N_2	-	-	-	-	78.38	-	-	-	105.91	204.70
CO	-	-	-	-	-		-	-	271.32	625.42
CO_2	-			-	-		-		-	29.73
NH_3	-			-		-	-	-	-	11.71
H_2S	-			-	-		-	-	-	9.17
H_2O	963.39	270.00	1[illegible]3.09	540.00	-	-	-	-	49.27	1,6[illegible].71
C_1	-	-	-	-	-	-	-	-	-	
C_2	-	-	-	-	-	-	-	-		-
C_3	-	-	-	-	-	-	-	-	-	-
nC_4	-	-	-	-	-	-	-	-	-	-
IBP 200	-	-	-	-	-	-	-	-	-	-
200-400	-	-	-	-	-	-	-	-	-	-
400-450	-	-		-	-	-	-	-	-	-
450-500	-	-	-	-	-	-	-	-	-	-
500-650	-	-	-	-	-	152.18	84.89	237.07	-	-
650+	-	-	-	-	-	35,701.82	19,915.11	55,616.93	-	-
Residue	-	-	-	-	-	1,485.60	-	1,485.60	-	
Ash	4,209.07	1,180.00	669.07	2,360.00	-	2,660.40	-	2,660.40		-
Coal (MAF)	30,497.96	8,550.00	4,847.96	17,100.00	-	-			-	-
Sulfur	-	-				-	-	-		
Total, T/D	35,670.17	10,000.00	5,670.12	20,000.00	4,497.23	40,000.00	20,000.00	60,000.00	1,187.00	3,638.14
MMSCFD	-	-	-	-	107.1		-	-	299.3	506.8
BPD		-	-	-	-	-	-	-		-
Heating Value, Billion Btu/D	865.0	242.5	137.5	485.0					-	-



(11) TOTAL HYDROGEN	(12) DRY CAKE (ONLY)	(13) PLANT FUEL GAS	(14) SULFUR	(15) AMMONIA	(16) SNG	(17) C_3 LPG	(18) C_4 LPG	(19) NAPHTHA	(20) FUEL OIL
-	-	-	-	-	-	-	-	-	-
1,829.70	-	391.15	-	-	6.80	-	-	-	-
310.61	-	14,684.08	-	-	204.17	-	-	-	-
896.74	-	8,533.99	-	-	5.71	-	-	-	-
29.23	-	1,067.58	-	-	43.83	-	-	-	-
-	-	-	-	90.10	-	-	-	-	-
11.71	-	-	-	-	-	-	-	-	-
9.17	-	488.48	-	-	-	-	-	-	-
1,737.98	-	-	-	-	2,951.04	-	-	-	-
-	-	-	-	-	565.20	11.05	-	-	-
-	-	-	-	-	162.56	514.44	77.82	-	-
-	-	-	-	-	-	6.28	322.02	53.53	-
-	-	-	-	-	-	-	5.88	101.11	
-	-	-	-	-	-	-	-	1,123.49	294.90
-	-	-	-	-	-	-	-	-	532.58
-	2.89	-	-	-	-	-	-	-	510.11
-	51.59	-	-	-	-	-	-	-	1,511.36
-	119.09	-	-	-	-	-	-	-	8,459.93
-	1,318.53	-	-	-	-	-	-	-	-
-	2,465.51	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-
-	-	-	-1,231.70	-	-	-	-	-	-
4,825.14	3,957.61	25,105.28	1,231.70	93.10	3,939.31	531.77	405.72	1,278.43	11,308.96
806.1	-	792.92	-	-	165.9	-	-	-	-
-	-	-	-	-	-	6,030	4,082	9,379	56,348
-	-	114.9	9.9	1.7	174.1	23.0	17.3	54.2	390.8

TOTAL PRODUCTS
671,000 MMBTU/D
77.6% EFFICIENCY

Figure 3-9

ENERGY RESEARCH & DEVELOPMENT ADMINISTRATION (ERDA-FE)
OIL / GAS PLANT
BLOCK FLOW DIAGRAM

REV	DESCRIPTION	COMPANY	JOB NO	DWG NO	REV
0	ISSUED FOR REPORT	THE RALPH M. PARSONS COMPANY, PASADENA, CALIFORNIA	5435-2	R-01-FS-1	0

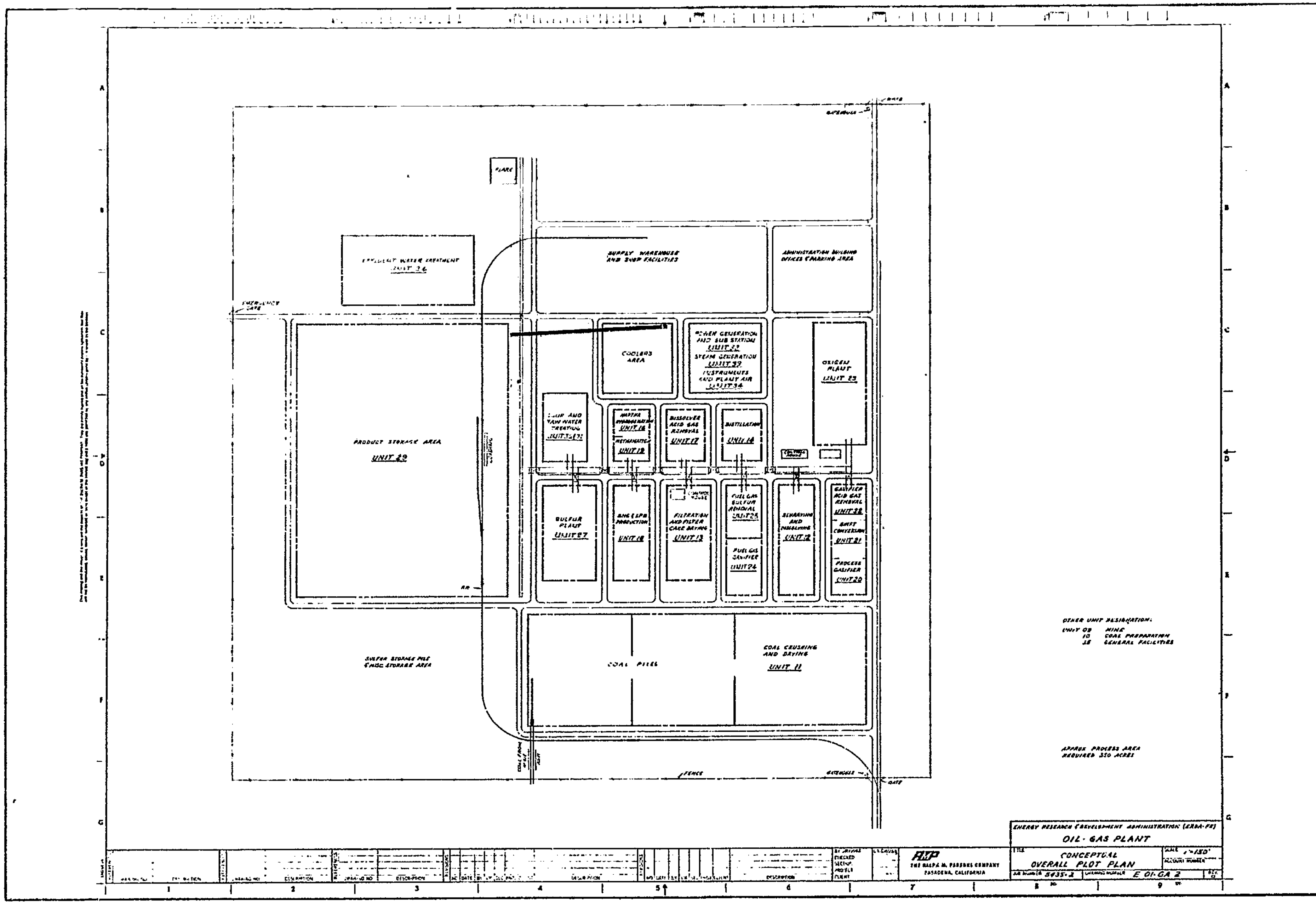


Figure 3-10 - Conceptual Plot Plan
Oil/Gas Plant Design

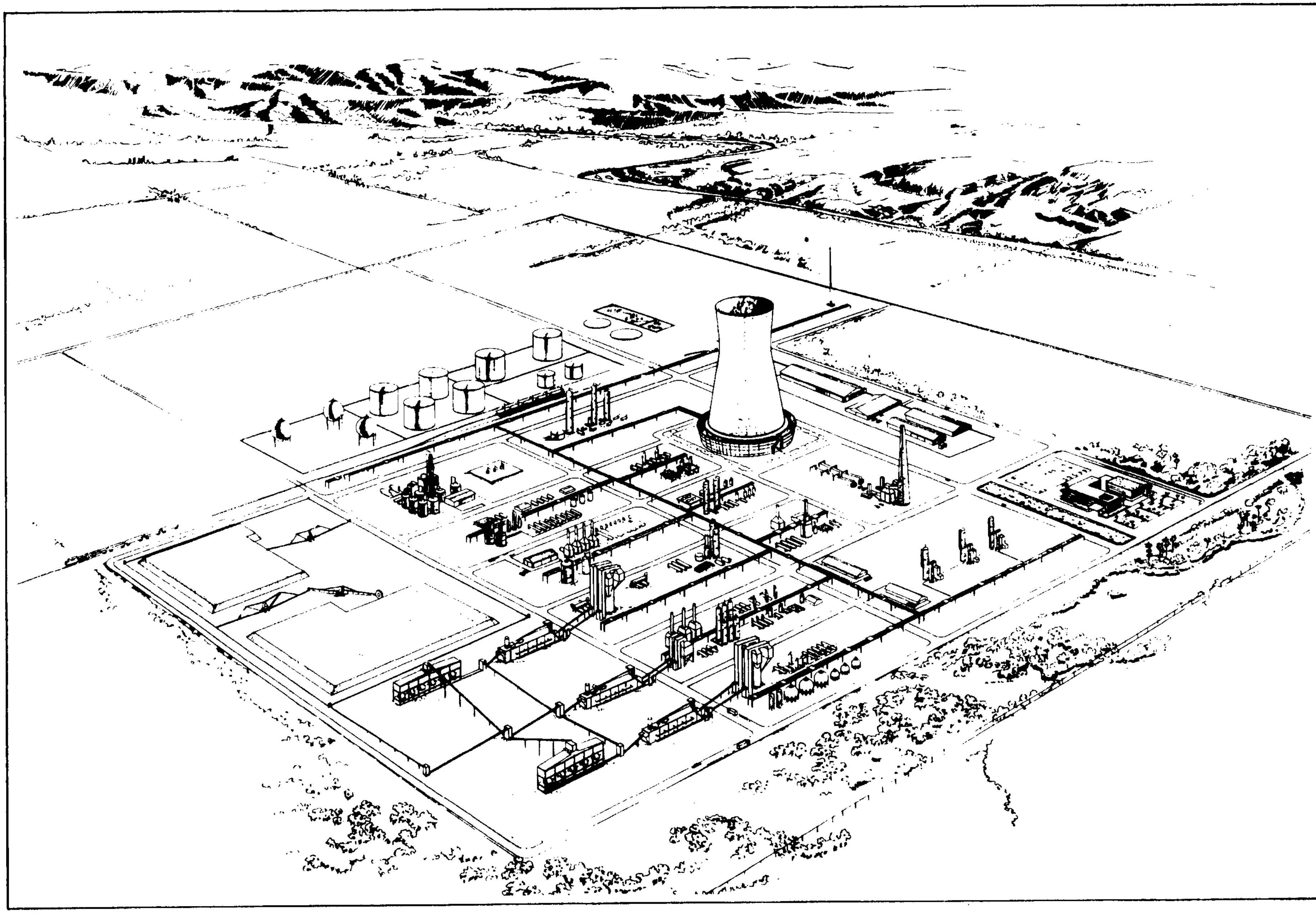


Figure 3-11 - Artist's Concept of Oil/Gas Plant Design

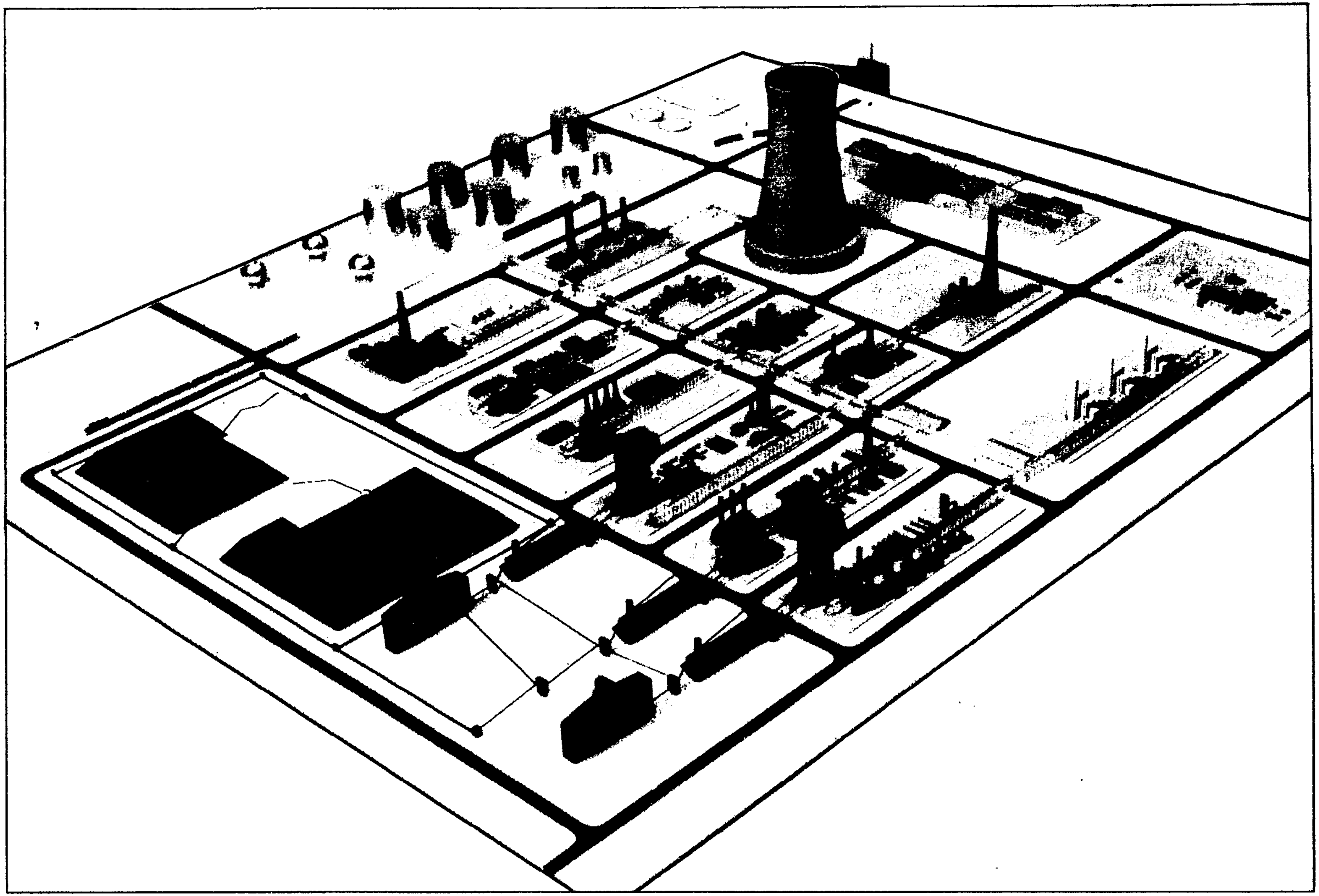


Figure 3-12 - Model of Conceptual Oil/Gas Plant Design

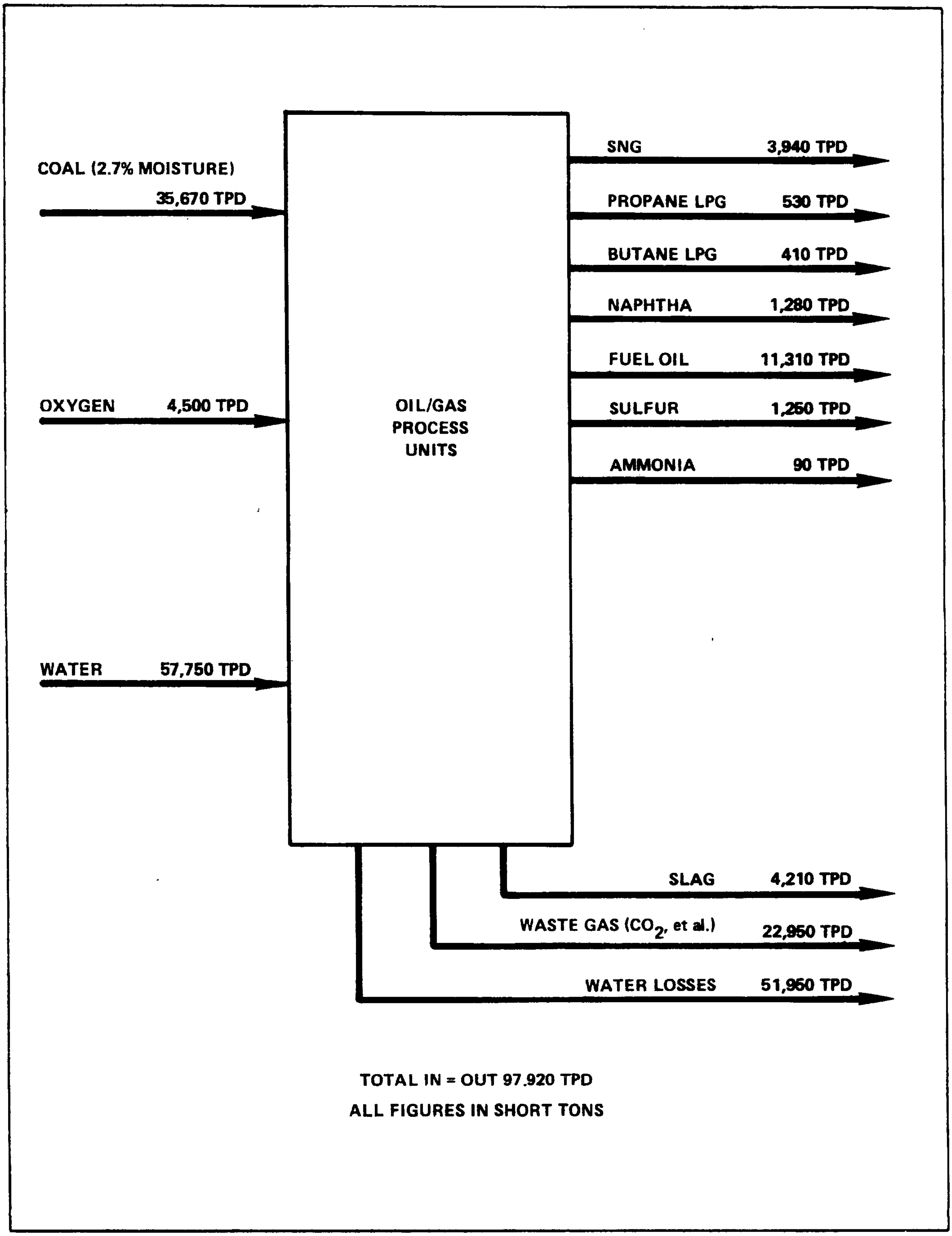


Figure 3-13 - Material Balance
Oil/Gas Plant Design

COAL ENERGY DISTRIBUTION		
STREAM	MM BTU/H	% CLEAN COAL
FEEDS		
COAL TO PROCESS	30,310	84.1
COAL TO UTILITIES	5,730	15.9
TOTAL	36,040	100.0
PROCESS COAL YIELDS		
SALEABLE PRODUCTS	27,951	77.6
FILTER CAKE	844	2.3
REACTION HEATS	1 515	4.2
TOTAL	30 310	84.1

UTILITY ENERGY DISTRIBUTION		
STREAM	MM BTU/H	% CLEAN COAL
INPUTS		
COAL	5,730	15.9
FILTER CAKE	844	2.3
STEAM	632	1.8
TOTAL	7,206	20.0
OUTPUTS		
TO MINING AND PREPARATION		
STEAM	458	1.3
POWER	132	0.4
TOTAL	590	1.7
TO OXYGEN PLANT		
STEAM	1,007	2.8
POWER	8	–
TOTAL	1,015	2.8
TO OIL/GAS PLANT		
POWER	601	1.7
FUEL GAS	1,020	2.8
TOTAL	1,621	4.5
LOSSES TO ATMOSPHERE	3,980	11.0
TOTAL	7,206	20.0

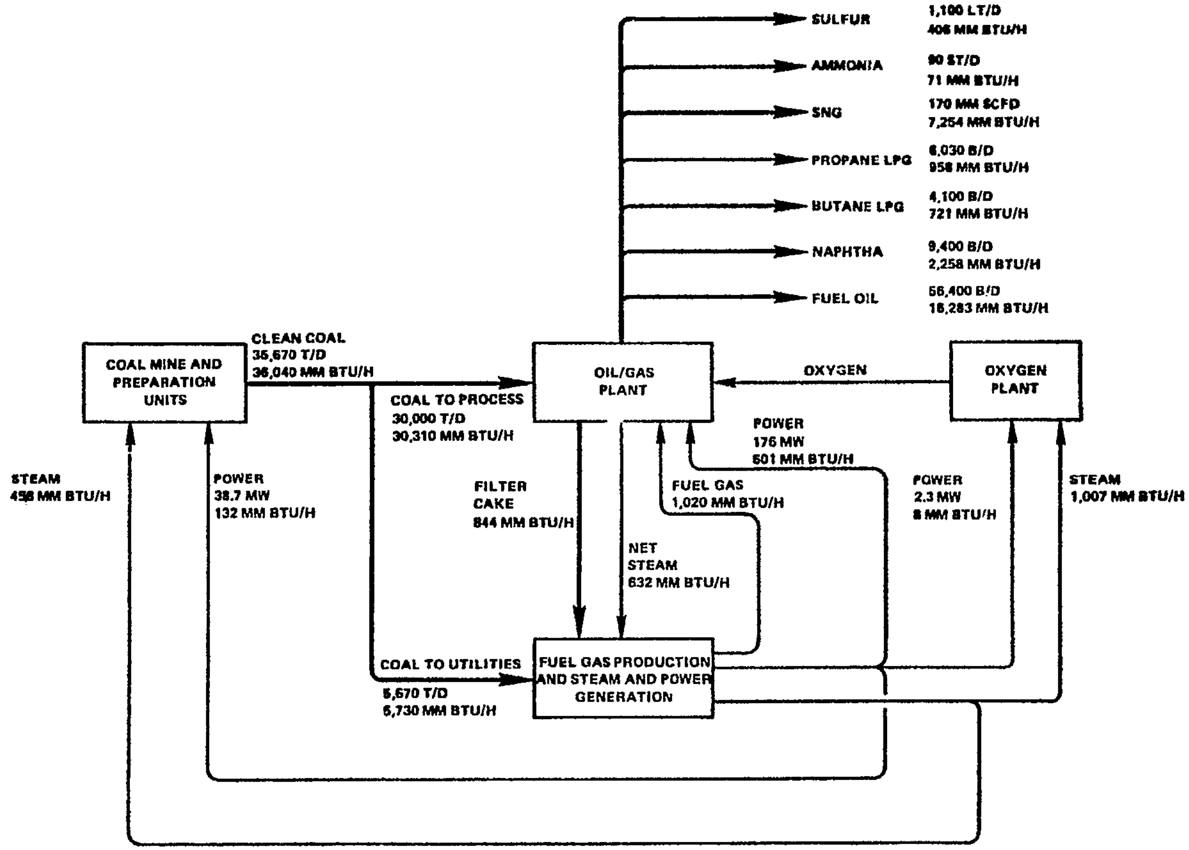


Figure 3-14 - Energy Balance
Oil/Gas Plant Design

3.4 FISCHER-TROPSCH DESIGN

This Fischer-Tropsch design used flame-sprayed catalyst applied to the external surface of finned (extended surface) heat exchangers as the reactors for the Fischer-Tropsch synthesis, shift and methanation reactors. It is based on experimental results developed by a former division of the U.S. Bureau of Mines, now a division of DOE. A pilot scale test unit is under construction at DOE's Bruceton, Pennsylvania laboratories to further test performance of this type of reactor.

The flame sprayed tubular reactor configuration permits recovery of a significant percentage of the heats of reaction in the form of 1200-psig steam. The result is improved thermal efficiency for the plant design.

Design objectives included production of significant SNG and high thermal efficiency.

3.4.1 FACILITY DESCRIPTION

A block flow diagram is shown in Figure 3-15. The complex includes a captive coal mine with the capacity to produce approximately 15 million TPY for 20 years. Units are included which will clean, wash, crush, and size the coal and feed it to the process units.

Facilities for the production of oxygen and all required utilities are included in the design as well as for the treatment and disposal of solid, liquid, and gaseous effluent streams. The design is based on a site location capable of providing 18,000 acre-feet of water per year for process requirements and utilities makeup. Well water is used for all potable and sanitary water requirements.

The land area required for the life of the project for mining the required coal is estimated to be about 47 square miles; approximately 500 acres should be allotted to the initial plant complex.

A. Process Units

The process consists of the reaction of coal with oxygen and steam at elevated temperature and pressure to produce a synthesis gas, purification and adjustment of composition of the gas, and catalytic reaction of the gas to form principally hydrocarbon liquids. Unreacted tail gas and methane are further processed to produce SNG.

Approximately one-half of the carbon in the coal is reconstituted into hydrocarbons with greater hydrogen content than the feed coal, heat being supplied primarily by heat of reaction released from the gasifier, water gas shift, Fischer-Tropsch synthesis and methanation steps. Efficient heat recovery provides all process needs for power and steam plus salable electric power.

A plot plan is shown at the end of the section as Figure 3-16, and an artist's conceptual drawing of the complex is shown in Figure 3-17. A photograph of a model of the complex appears as Figure 3-18.

B. Plant Capacity

The design feed rate of prepared coal to the gasifier is 30,000 TPSD to produce about 525 billion Btu per stream day of SNG, liquid products, approximately 140 MW of electrical power for sale, and about 1000 TPD of sulfur.

Table 3-1 summarizes product quantities expressed as barrels of fuel oil equivalent; quantities in tons and heating value are also given. The overall thermal efficiency is predicted to be about 70%.

C. Energy Balance Factors

In normal operation all steam is generated by heat recovery from process streams and reactors. Steam generation facilities provided are, therefore, used only during startup and as standby units.

3.4.2 MATERIAL BALANCE

The overall material balance for the process sections of the complex is depicted in Figure 3-19. The results project that approximately 12,500 TPD of premium hydrocarbon and oxygenate products will be produced from 30,000 TPD of bituminous coal. The balance is based on miscellaneous internal consumption equal to approximately 1.2 wt% of the total product quantity.

3.4.3 ENERGY BALANCE

The overall energy balance is illustrated in Figure 3-20. The results indicate that the energy value of products is approximately 525 billion Btu/day, which represents about 70% of the energy contained in the feed coal. The 30.3% energy efficiency loss can be distributed to the user units approximately as shown below:

Units	Percent
Mine	0.9
Coal Preparation	1.4
Gasifier	2.8
Oxygen Plant	7.6
Shift Reactor	1.1
Acid Gas Removal	6.8
Product Recovery	1.1

Units	Percent
Alcohol Recovery - Water Reclamation	0.7
Sulfur Plant - Beavon Unit	0.5
F-T Reactor & Methanation	0.8
Power Plant Auxiliaries	1.8
Power Plant Efficiency Loss	2.9
Miscellaneous & Unaccounted	1.9
TOTAL ENERGY LOSS	30.3

Figure 3-21 presents a simplified summary of the projected thermal efficiency factors.

3.4.4 ECONOMICS

All economics are presented here in fourth quarter 1977 dollars. The results indicate:

(1) The FCI was estimated at approximately $1,550 million.

(2) The total capital requirements, exclusive of construction financing, is approximately $1,770 million

(3) Construction financing for the project structure consisting of 65% debt borrowed at 9% interest rate amounts to about $200 million

(4) It would take an estimated 58 months from project start to mechanical completion

(5) The annual operating cost was estimated to be approximately $190 million

(6) The required product selling price was slightly over $2.50 per million Btu for the 65% debt financial structure; for 100% equity financing, the RPSP was predicted to be slightly over $3.30 per million Btu

(7) The products contain nil sulfur, nitrogen and particulate matter and are therefore premium-grade quality from an environmental standpoint

(8) The possible market values of the product was estimated. Based on this analysis, the potential DCF is 23% for the 65% debt case

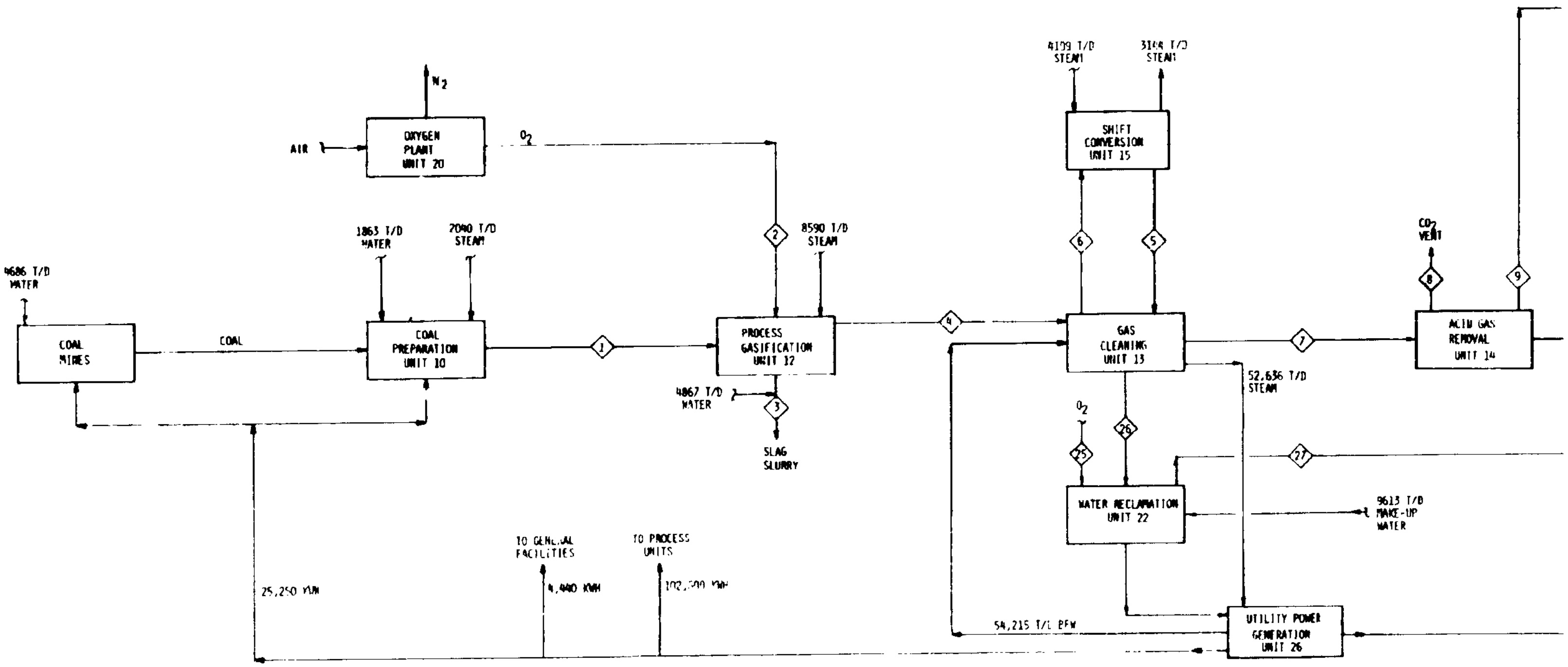
(9) The sensitivity of RPSP to capital associated costs is about 80% for the 65% debt case. For coal costs and operating costs, the sensitivities are about 25 and 20%, respectively.

Table 3-1 - Fischer-Tropsch Products
Projected Quantities and Heating Values

Product	BPSD	TPSD	Product Unit HHV	Total Heating Value (billion Btu/day)	% of Coal HHV
SNG	42,505 [a]	6,588	1,035 Btu/scf	267.78	35.56
C_4s	3,534	343	21,035 BTU/lb	14.42	1.92
Naphthas	20,175	2,378	20,625 Btu/lb	98.08	13.03
Oxygenates	3,913	458	12,505 Btu/lb	11.46	1.52
Diesel Fuel	16,075	2,105	20,255 Btu/lb	85.27	11.32
Premium Fuel Oil	4,959	713	19,865 Btu/lb	28.33	3.76
Subtotal Fuels	91,161	12,585	-	505.34	67.11
Sulfur	1,284 [a]	1,014	3,990 Btu/lb	8.09	1.07
Subtotal Products	92,445	13,599	-	513.43	68.18
Power	1,815 [a]			11.43 [b]	1.56
Total	94,260			524.86	69.70

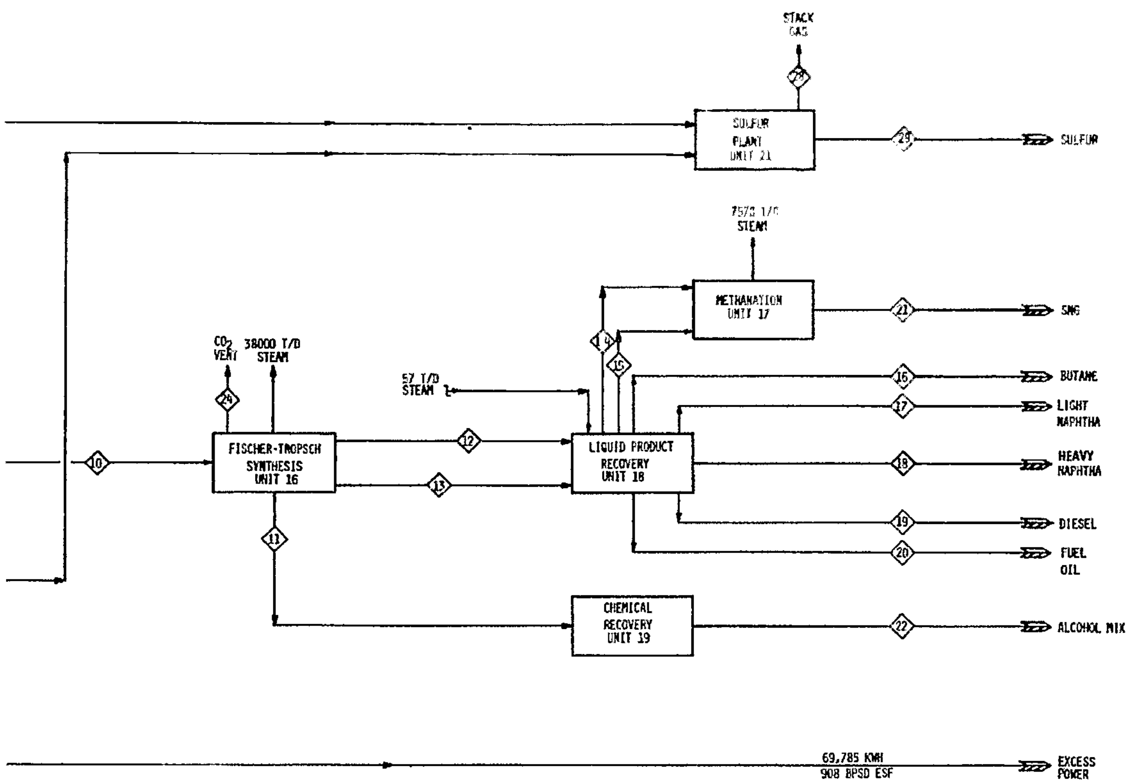
(a) Equivalent fuel oil at 6,300,000 Btu/bbl.

(b) Heating value equivalent to 139.6 MW at theoretical converion of 3415 Btu per kWh. Applicable heat rate would be at least 9,500 per kWh. This would increase thermal efficiency by 2.8 to 72.5%.



STREAM NO.	1	2	3	4	5	6	7	8	9	10
STREAM NAME	COAL FEED	OXYGEN	SLAG SLURRY	RAW SYN GAS	SHIFTED SYN GAS	SYN GAS TO SHIFT	DUST FREE SYN GAS	CO_2 VENT	ACID GAS	SHIFT SYN GAS
Flow, T/D										
H_2	-	-	-	1177	497	363	1513	0.78	-	1512
CO	-	-	-	19172	1213	5006	14499	200 PPMV	-	14376
CO_2	-	-	-	7052	9506	2165	14393	11400	2342	570
CH_4	-	-	-	477	146	146	477	7	-	445
H_2S	-	-	-	526	162	162	519	5 PPMV	519	0.1 PPMV
N_2	-	171	-	329	101	101	329	-	8	321
O_2	-	9580	-	-	-	-	-	-	-	-
H_2O	404	-	4886	1409	2152	1047	188	40	28	41
NH_3	-	-	-	4	1.2	1.2	-	-		-
COS	-	-	-	19	6	6	19		19	-
SO_2	-	-	-	2	0.8	0.8	2	-	2	-
ASH	1070	-	2140	-	-	-	-	-	-	-
CHAR	-	-		351	0.6	0.6	-	-	-	-
COAL (MAF)	13526	-	-	-	-	-	-	-	-	
TOTAL T/D	15000	9751	7026	32518	13986	9074	31860	11527	2918	17265

STREAM NO.	11	12	13	14	15	16	17	18
STREAM NAME	ALCOHOL SOLUTION	F-T GAS	F-T LIQUID	C_3/C_4'S	STRIPPED F-T GAS	BUTANE	LIGHT NAPHTHA	HEAVY NAPHTHA
Flow, T/D								
H_2	-	397	0.5	-	390	-	-	-
CO	-	1632	6	-	1630	-	-	-
CO_2	4	138	0.5	13	126	-	-	-
N_2	-	320	1	-	329	-	-	-
H_2O	2408	27	-	-	-	-		-
C_1	-	1001	8	4	1005		-	
C_2=	-	65	2	6	60	-	-	-
C_2		250	9	42	226	-	-	-
C_3=	-	41	4	26	19	-		-
C_3	-	141	15	102	53	-	-	-
C_4=	-	105	29	106	1	28	-	
C_4	-	304	96	252	1	144	3	-
C_5=	-	74	20	1		1	43	-
C_5	-	103	97	-	2	2	196	-
LIGHT NAPHTHA	-	95	270	-	8	-	354	3
HEAVY NAPHTHA	-	47	551	-	2	-	17	549
DIESEL	-	7	1103	-	-	-	-	41
FUEL OIL	-	-	337		-	-	-	-
ALCOHOLS	271				-	-	-	-
ACID SALTS	41	-	-	-	-	-	-	
TOTAL T/D	2724	4717	2543	552	3869	174	614	593



NOTES:

1. SIZE AND QUANTITY SHOWN HERE FOR ONE TRAIN OF A TWO TRAIN PLANT, EACH TRAIN CHARGING 15,000 T/D COAL TO THE PROCESS PLANT TO MAKE 262 BILLION BTU/D THERMAL PRODUCT OUTPUT.

19	20	21	22
DIESEL	FUEL OIL	SNG	ALCOHOL MIX
-	-	4	-
-	-	5	-
-	-	106	-
-	-	329	-
-	-	-	14
-	-	2318	-
-	-	-	-
-	-	77	-
-	-	-	-
-	-	137	-
-	-	-	-
-	-	362	-
-	-	-	-
-	-	1	-
-	-	-	-
30	-	-	-
1028	41	-	-
10	321	-	-
-	-	-	269
-	-	-	-
1068	362	3344	283

STREAM NO.	24	25	26	27	28	29
STREAM NAME	CO_2 VENT	OXYGEN	PROCESS WATER	SOUR GAS	STACK GAS	SULFUR
Flow, T/D						
H_2	-	-	-	-	-	-
CO	-	-	-	-	*1000 ppmv	-
CO_2	7282	-	-	-	-	-
CH_4	-	-	10 PPM	-	-	-
H_2S	-	-	4	3.5	1 ppmv	-
N_2	-	-	-	-	-	-
O_2	-	7	-	-	-	-
H_2O	192	-	6125	3	-	-
NH_3	-	-	2	1.5	-	-
COS	-	-	-	-	50 ppmv	-
SO_2	-	-	-	-	-	-
COD	-	-	4	-	-	-
ORGANICS	-	-	1	-	-	-
CHLORIDES	-	-	1	-	-	-
CARBONATES	-	-	5	-	-	-
SOLIDS	-	-	2	-	-	-
TOTAL T/D	7474	7	6144	8	4000	507

*MAXIMUM

Figure 3-15

ENERGY RESEARCH & DEVELOPMENT ADMINISTRATION (ERDA-FE)
U.S.A. FISCHER-TROPSCH PLANT
BLOCK FLOW DIAGRAM

REV NO.	DATE	REVISION	BY
0		ISSUED FOR REPORT	LS

THE RALPH M. PARSONS COMPANY, PASADENA, CALIFORNIA — JOB NO. 5935-3 — DWG. NO. R-01-FS-1 — REV 0

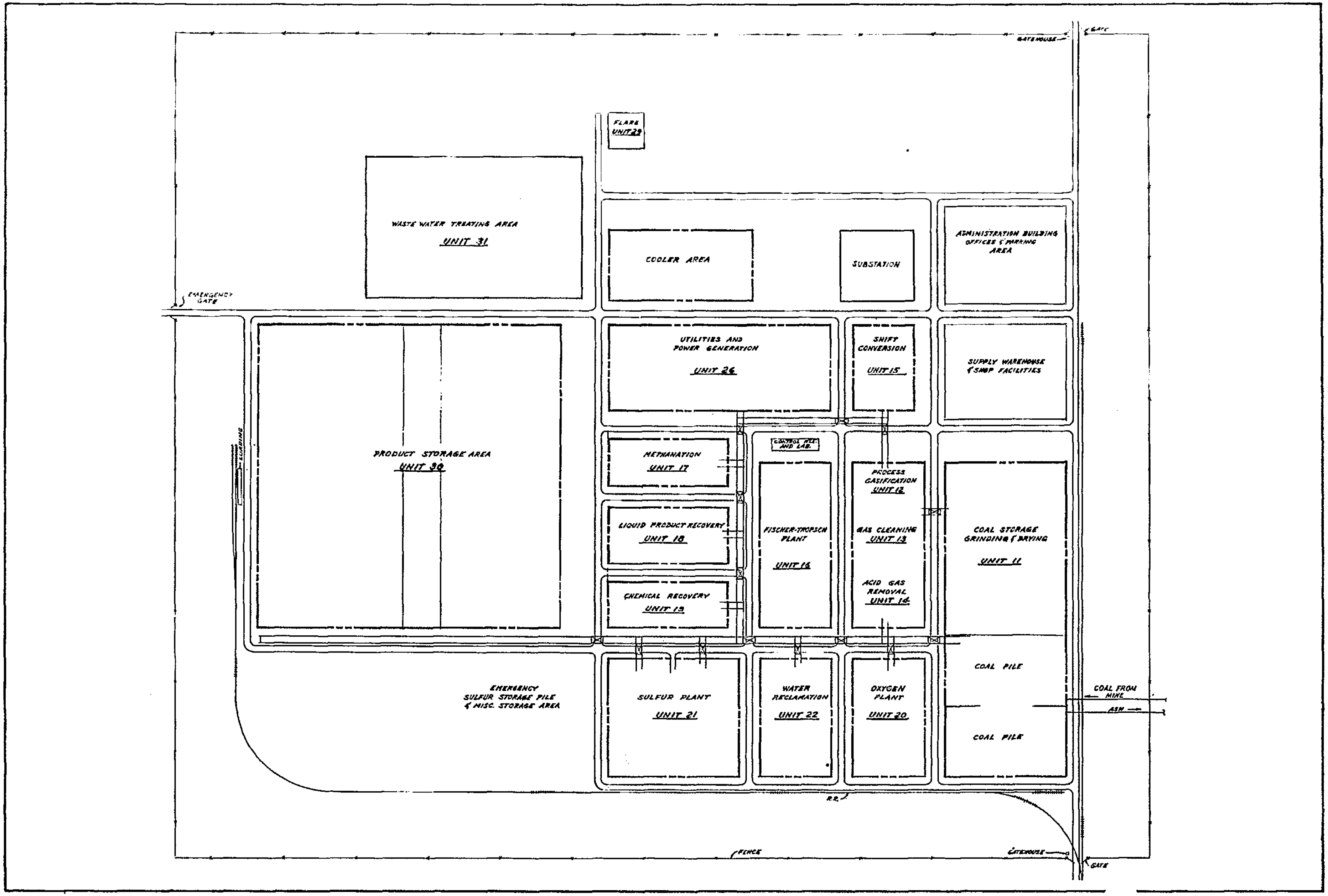


Figure 3-16 - Conceptual Plot Plan
Fischer-Tropsch Plant Design

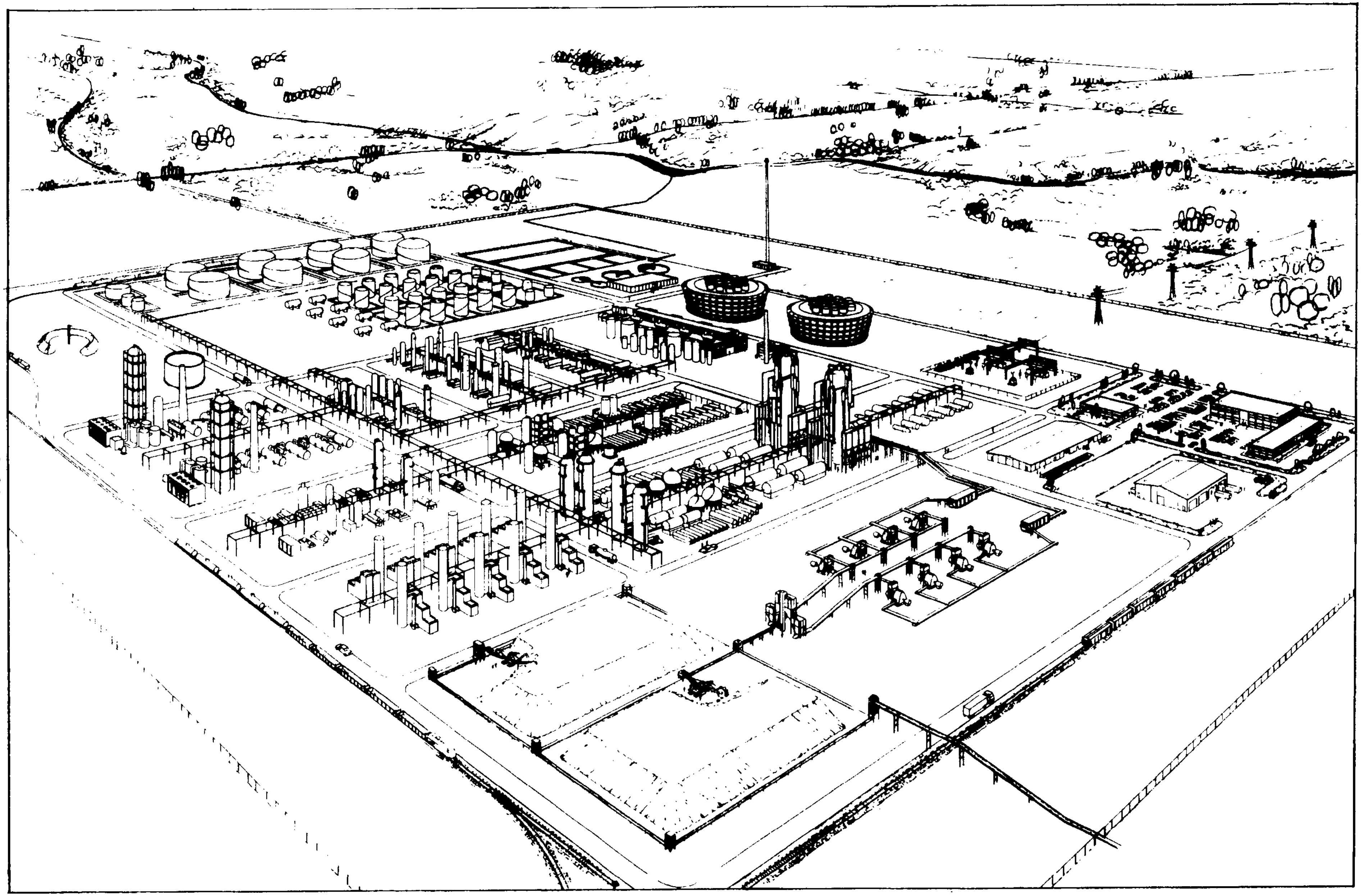


Figure 3-17 - Artist's Concept of Fischer-Tropsch Design

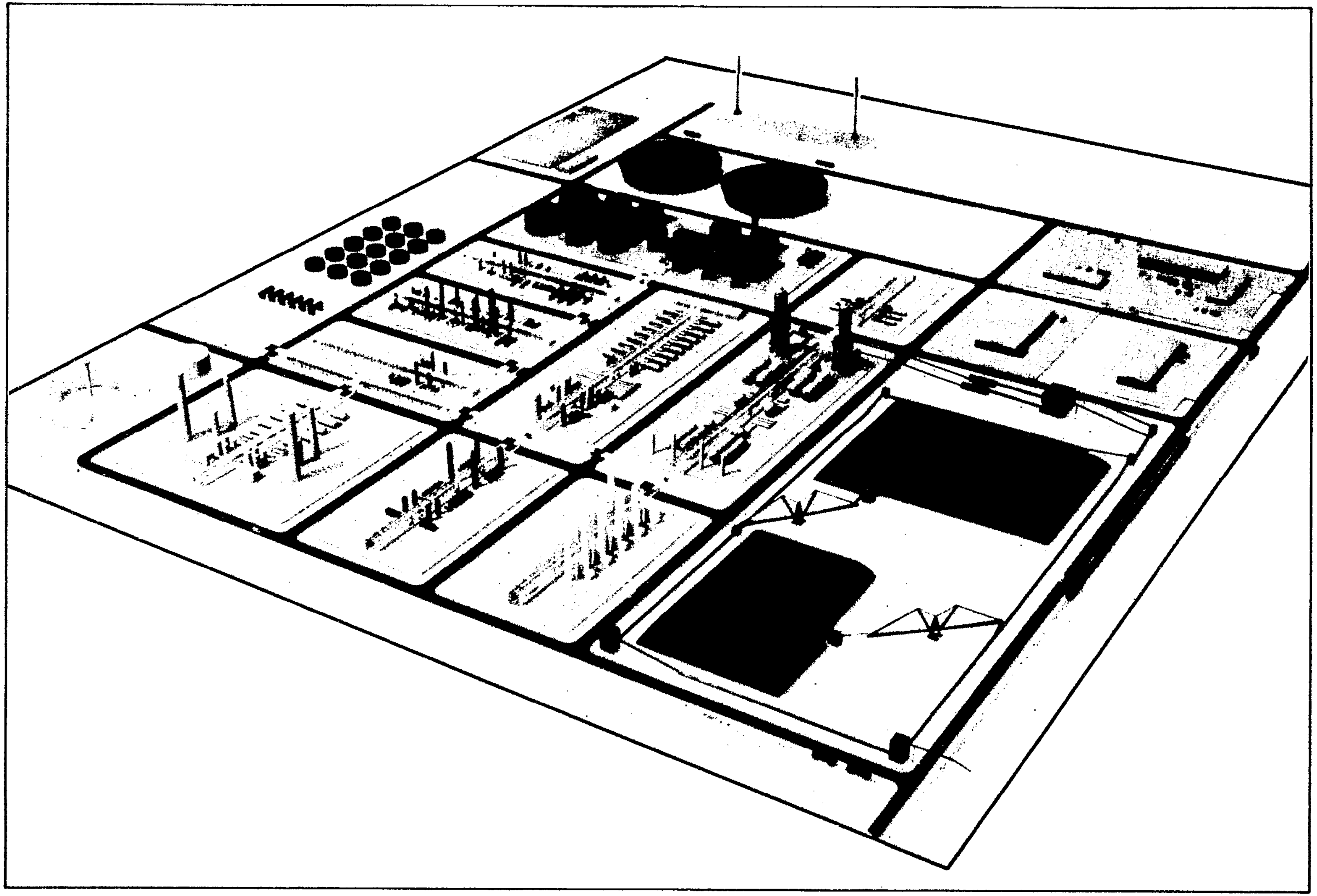


Figure 3-18 - Model of Conceptual Fischer-Tropsch Plant Design

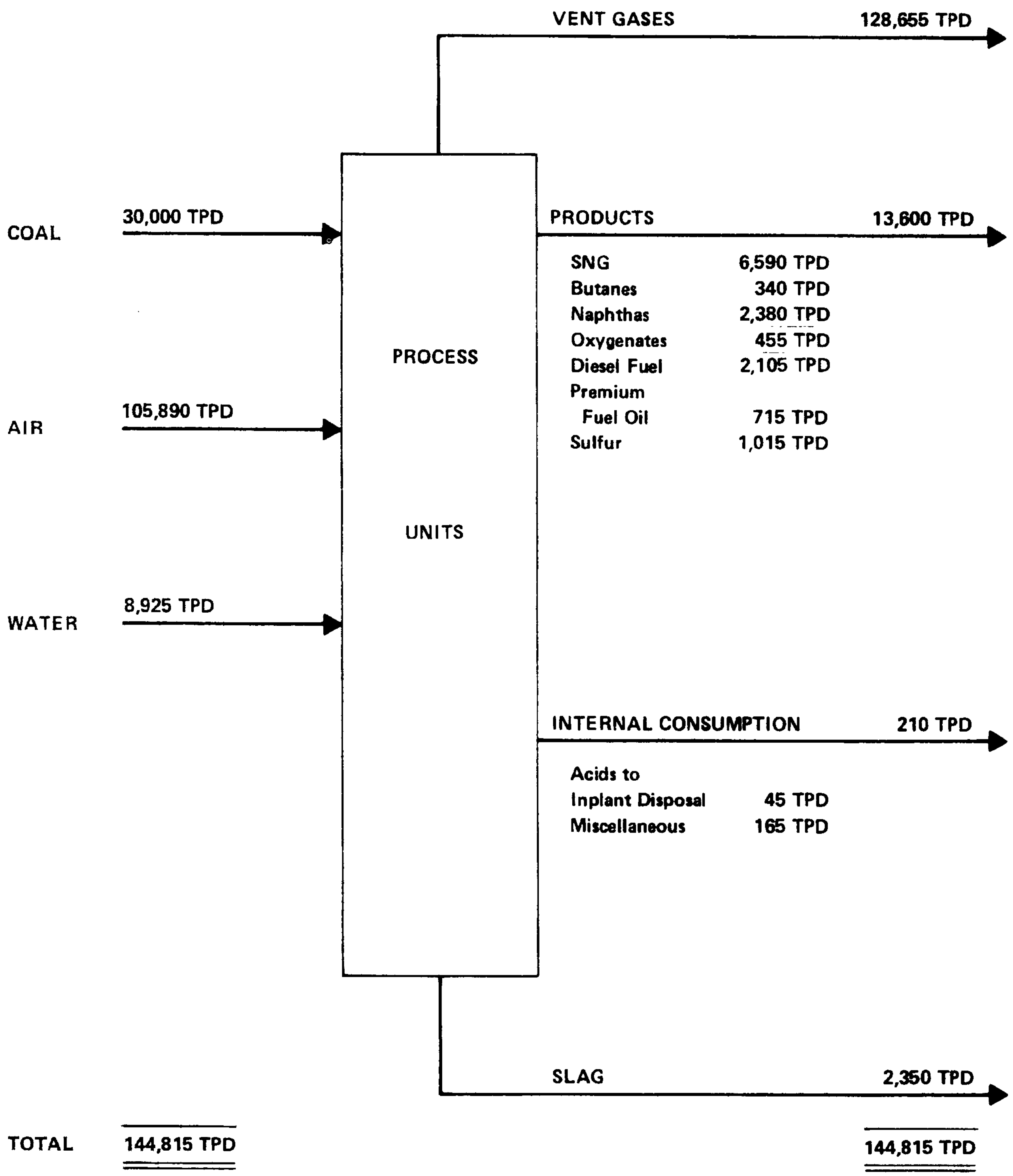
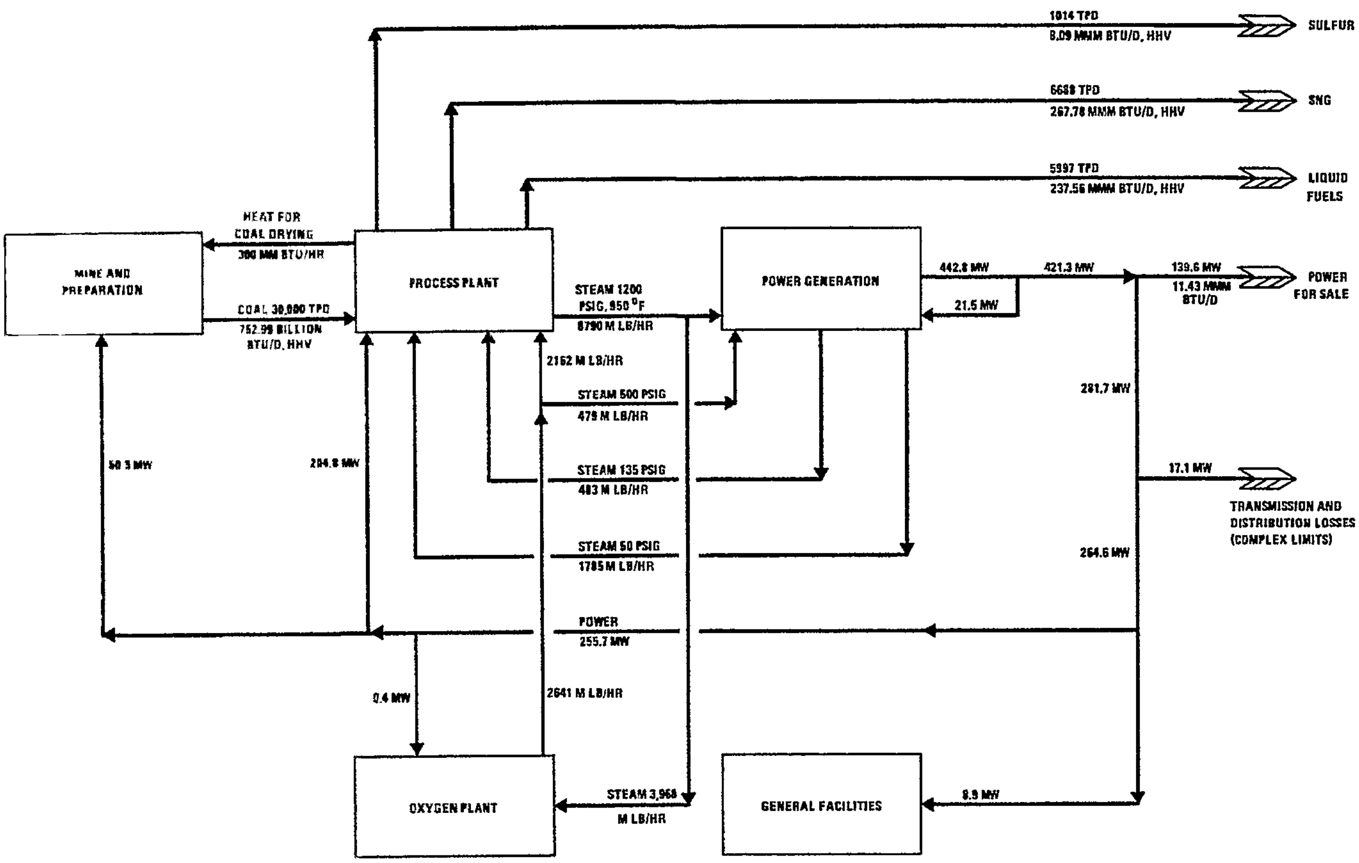


Figure 3-19 - Material Balance
Fischer-Tropsch Plant Design



ENERGY DISTRIBUTION	BILLION BTU/D HHV	%
ENERGY SOURCE	752.99	100.00
COAL		
ENERGY CONSUMED IN MFG		
MINING AND PREPARATION	17.32	2.30
OXYGEN	56.46	7.50
PROCESS	154.05	20.46
TOTAL	227.83	30.26
ENERGY VALUE OF PRODUCT		
SNG	267.78	35.56
LIQUID FUELS	237.56	31.55
POWER FOR SALE	11.43	1.52
SULFUR	8.09	1.07
TOTAL	524.86	69.78

Figure3-20 Energy Balance

Fischer-Tropsch Plant Design

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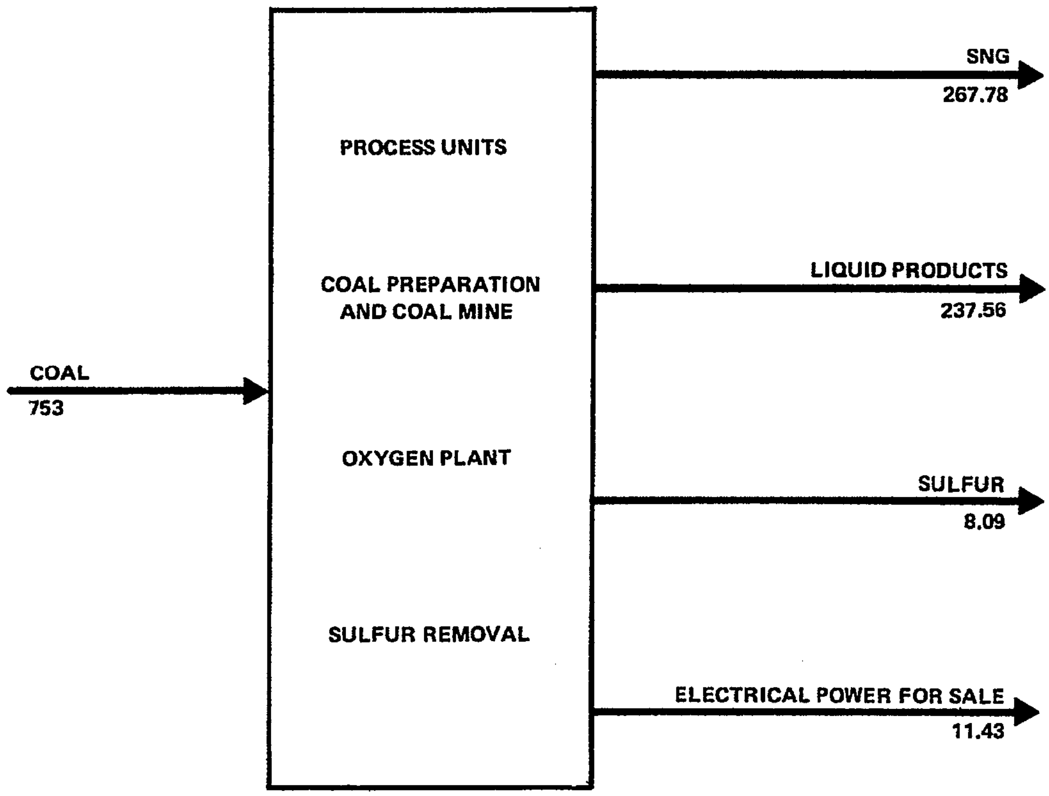


ALL FIGURES ARE MMM BTU/D, HHV

$$\text{THERMAL EFFICIENCY} = \frac{267.78 + 237.56 + 8.09 + 11.43}{753} = 69.7\%$$

Figure 3-21 - Thermal Efficiency
Fischer-Tropsch Plant Design

3.5 POGO DESIGN

POGO, a DOE-generated acronym for power-oil-gas-other, is a conceptual design of a coal refinery which coproduces gas and liquid synfuels, significant electrical power, and chemical by-products.

One design objective was to define the configuration of a coal refinery in which an efficient electrical power generation plant interfaces with the coal mining and process plant operations as an integral part of the complex.

3.5.1 FACILITY DESCRIPTION

A block flow diagram of the POGO process base case is shown in Figure 3-22. The complex includes a captive coal mine with the capacity to produce approximately 20 million TPY for 20 years. Units are included that will clean, wash, crush, and size the coal and feed it to the process units.

Facilities for the production of oxygen and all required utilities, as well as for the treatment and disposal of solid, liquid, and gaseous effluent streams, are included in the design. The design is based on a site location capable of providing nearly 35,000 acre-feet of water per year for process requirements and utilities makeup. Well water is used for all potable and sanitary water requirements.

The land area required for the life of the project for mining the required coal is estimated to approximate 70 square miles. Close to 640 acres or one square mile should be allotted for the plant complex. Figure 3-23 is a conceptual plot plan of the process, power plant, and general facilities area.

A. Process Units

The processes include the liquefaction of coal at elevated temperature and pressure, the pyrolysis of coal and heavy oils at intermediate temperature and pressure, and the reaction of resultant chars with oxygen and steam at elevated temperature and intermediate pressure. These operations produce synthesis produce synthesis gas and crude hydrocarbon liquids. Further processing includes catalytic reactions of gases and liquids and separation by distillation to form final upgraded salable products.

A second oxygen-blown entrainment gasifier is included to produce an intermediate-Btu fuel gas. Following particulates and sulfur removal, the fuel gas is used in the plant-fired heaters and in a large steam and power generation plant. Electrical power is supplied to operate the plant and mine; in addition, significant power is produced for sale.

B. Plant Capacity

The design feed rates of prepared coal to the coal consuming processes are as follows:

SRC reactors	20,000 TPD
Pyrolyzer	7,000
Fuel gas gasifier	16,700
Total	43,700 TPD

A total of 566 billion Btu per stream day of SNG and liquid fuel products is produced. Other products include approximately 1000 MW of electrical power for sale, a special crystalline coke, sulfur, and anhydrous ammonia.

Table 3-2 summarizes product quantities; heating values are also given. The overall thermal efficiency is predicted to be about 74%.

C. Power Plant

A number of power plant configurations were analyzed before finalizing the design. Following a screening analysis of candidate power plant configurations, seven generating cycles were selected for more detailed analysis. Each of these included gas turbines in the combined cycle mode capable of providing a portion of the air separation plant's compressed air requirements plus a steam system able to accept steam generated in the process area. For reference, the primary energy flows between the power plant and other parts of the complex are summarized in Figure 3-24.

The seven systems studied are listed in Table 3-3. Three basic types of cycles were included:

(1) Seventeen gas turbines, zero supplementary firing of 17 steam boilers, four steam turbines, and variable air extraction from the gas turbine compressors; this system is illustrated in Figure 3-25

(2) Thirteen gas turbines with supplementary firing of 13 steam boilers, four steam turbines, and variable air extraction from the gas turbine compressors; see Figure 3-25

(3) Four gas turbines, four fully-fired waste heat steam generators, two steam turbines, and zero air extraction from the gas turbine compressors. The system uses the highest Rankine cycle efficiency currently available; see Figure 3-26.

Key heat rate results are summarized in Table 3-4. All results are based on 1,000 MW power for sale. Credit is included for the power equivalent of the compressed air supplied to the oxygen plant.

Table 3-4 results indicate that the number Ic cycle has the lowest heat rate - 8,885 based on coal fed to the gasifier, and 7,810 based on fuel gas to the power system. These correspond to net power plant fuel to electricity efficiencies of 38 and 44%, respectively. These efficiencies have been improved by about 5% over more conventional power cycles because of the integration of the compressed air and steam supply systems between the power and process areas.

An economic comparison for the separate systems is summarized in Table 3-5. Tables 3-4 and 3-5 results show that cycle I has the best efficiency and lowest total energy cost per kWh. Within the cycle I group, system Ic has the best efficiency, a power cost as low as any system studied, and also provides 40% of the feed air requirement for the oxygen plant. It therefore was selected for inclusion in the final design.

The results also indicate that significant variations in quantity of extracted compressed air can be tolerated without seriously affecting overall efficiency or operating cost. This provides desired flexibility during transient operating periods.

System Ic also offers advantages because reduced mass flow through the gas turbines minimizes NO_x control requirements. Additional definitions of advantages for the Ic system include:

(1) The compressed air supplied to the oxygen plant saves approximately 140 MW; this is about 30% of the total power required to operate the complex

(2) The combined-cycle plants offer low installed cost when compared to other power plant alternatives; for example, the Ic system fixed capital investment is about 30% less than a comparable conventional steam-cycle system

(3) Use of standard gas turbines offers full dual fuel capability. This is important during startup and also during times when supplementary fuel must be used to produce maximum power when production of fuel gas is curtailed

(4) The gas turbine portion can be in service within 10 to 15 minutes from cold start; it then can provide the power needs for operation of the complex. The waste heat steam generators can produce maximum

(5) It can provide steam to the process during startup when fuel gas generating facilities are shut down

(6) The cooling water requirements are significantly less than other power generation alternatives; for example, they are about 700,000 gal/min, less than required for a conventional steam cycle system.

The projected thermal efficiency for conversion of coal to synfuels and by-products, plus fuel gas feed to the power plant, is approximately 75%. Distribution of energy between feed and product streams is shown in Figure 3-27. The efficiency for conversion of the fuel gas to electricity is about 44%.

The high thermal efficiency is the result of analysis of key factors in the 30 major units in the complex. A number of these analyses included development of comparative economics for candidate configurations, in addition to process and performance factors.

3.5.2 MATERIAL BALANCE

The overall material balance for the process sections of the complex is depicted in Figure 3-28. The results project that approximately 17,500 TPD of fuel products and crystalline coke products, with by-product sulfur and anhydrous ammonia, will be produced from 43,700 TPD of bituminous coal feed.

3.5.3 ENERGY BALANCE

The overall energy balance is illustrated in Figure 3-29. The results indicate that the energy value of products is approximately 820 million Btu/day, which represents about 74% of the energy contained in the feed coal.

Figure 3-30 presents a simplified summary of the projected overall thermal efficiency factors including power generation, heat rate based on fuel gas, along with the process products and byproducts.

Figure 3-27 presents the thermal efficiencies for the process operations and for power generation separately. The process thermal efficiency, based on the apportioned fuel gas required to generate the net electrical power for sale of 970 MW, is 43%.

3.5.4 ECONOMICS

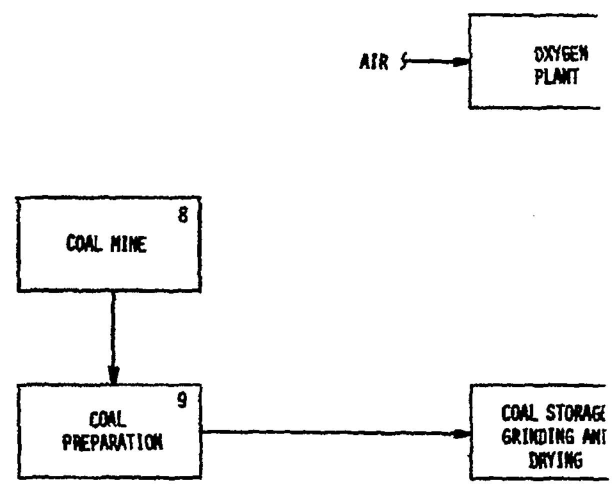
All economics presented here are expressed as mid-1977 dollars. The economic analysis results were:

(1) The estimated fixed capital investment was $2.4 billion

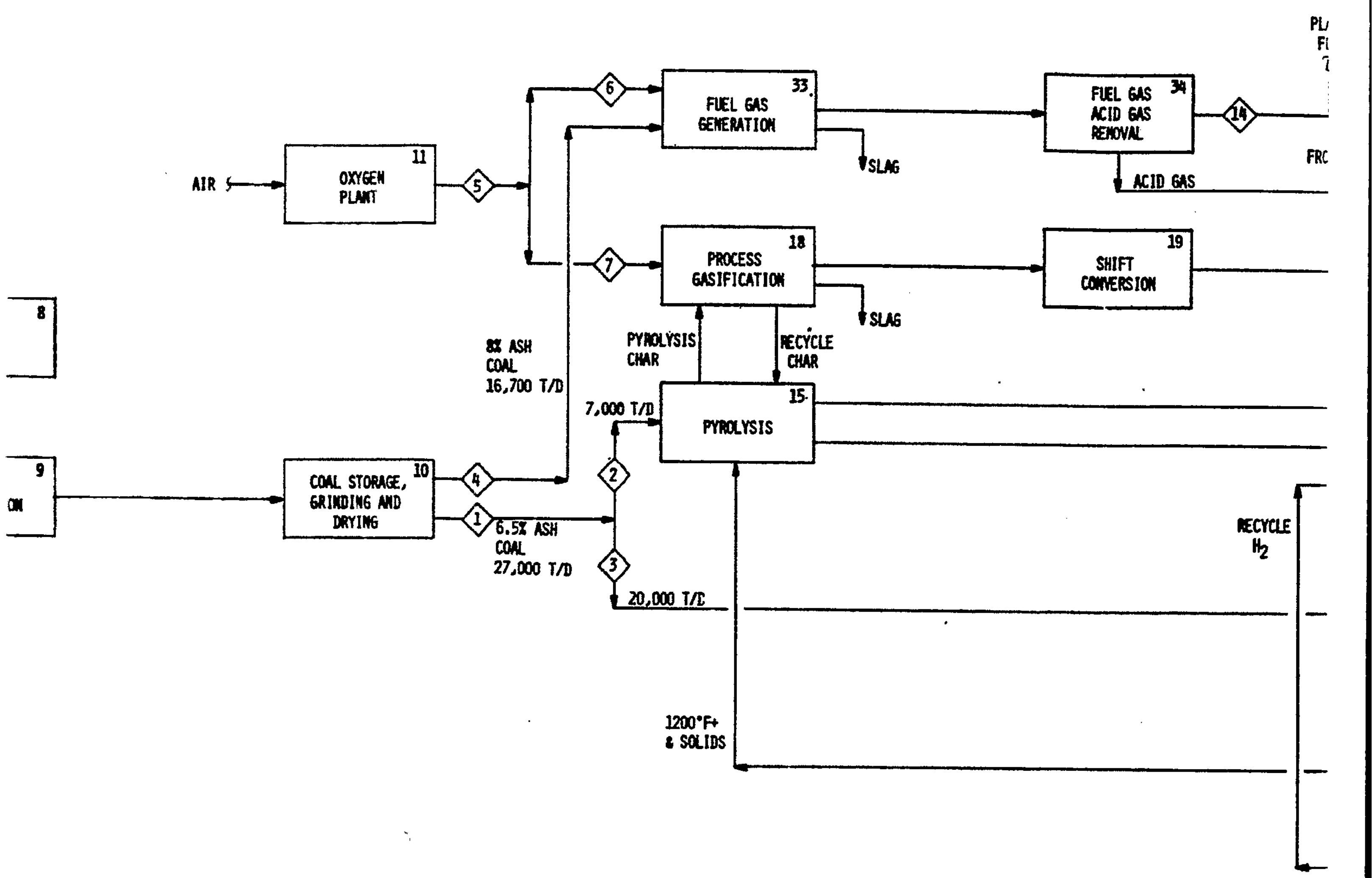
(2) The estimated total capital investment, exclusive of construction financing costs, was $2.75 billion

(3) The estimated project schedule to design, engineer, procure and construct the facility was 60 months

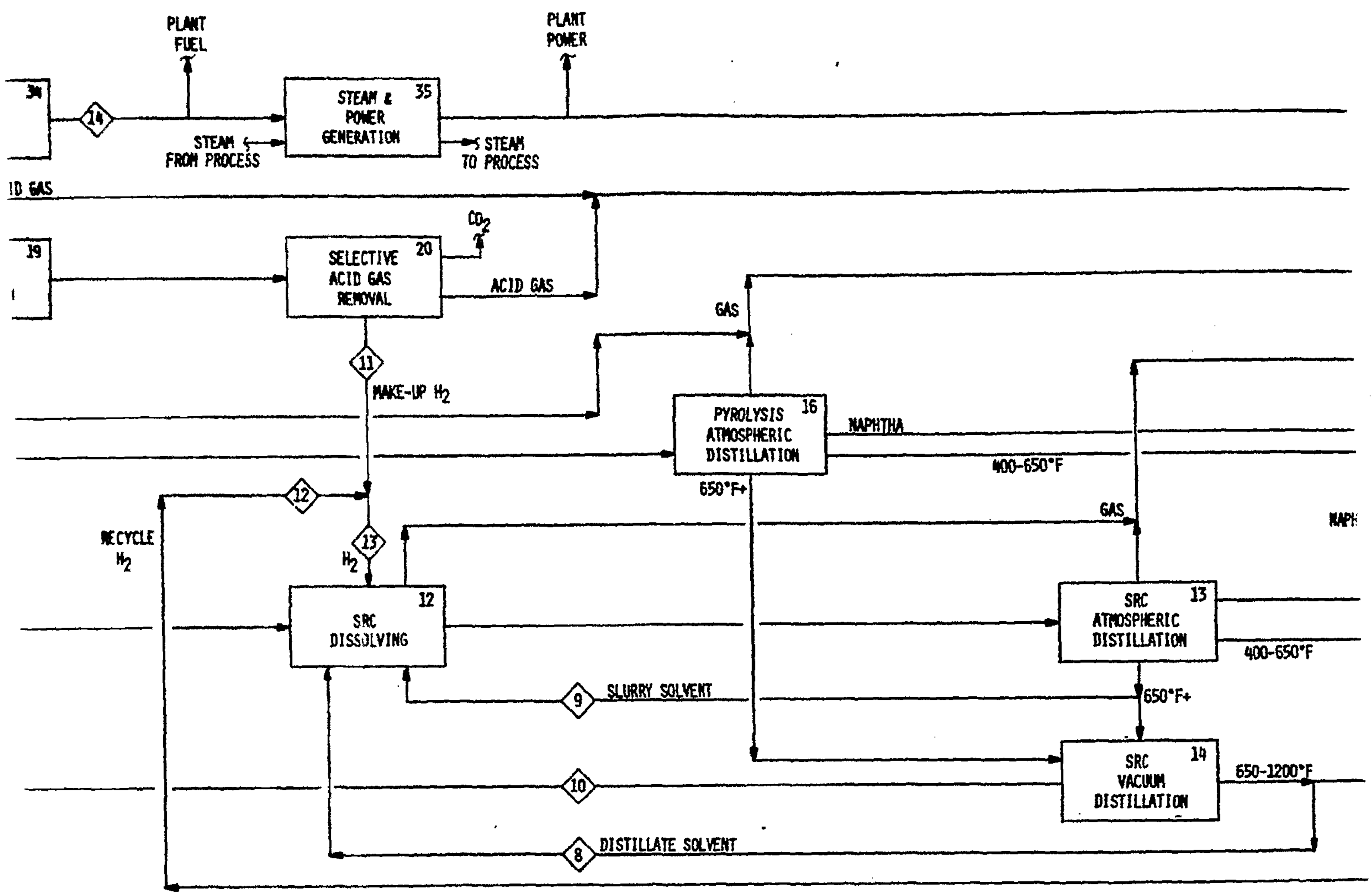
(4) Construction financing costs for a project financial structure consisting of 65% debt borrowed at 9% interest rate were estimated at approximately $300 million



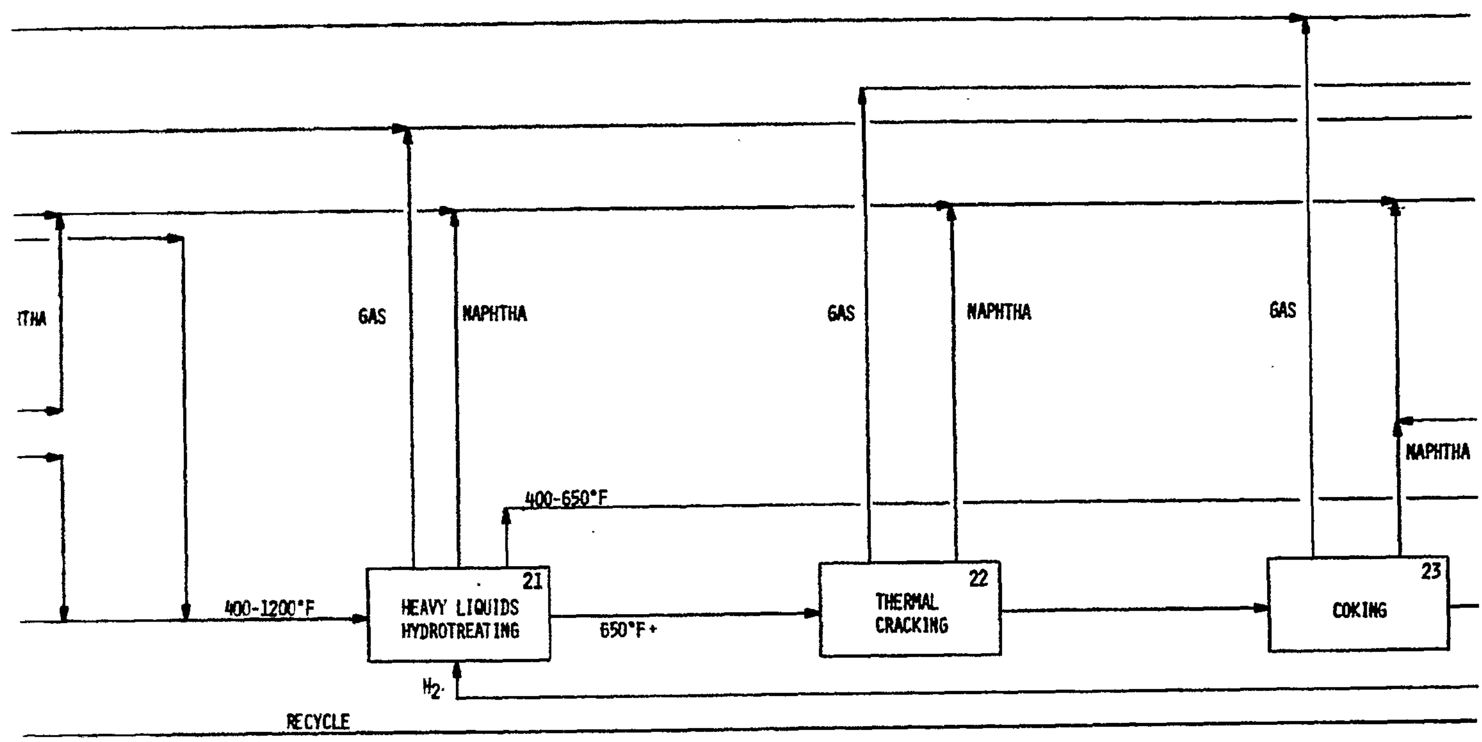
STREAM NO.	1	2	3	4
DESCRIPTION	COAL TO PROCESS	COAL TO PYROLYSIS	COAL TO SRC	COAL T[O] FUEL G[AS] GENERAT[ION]
COMPONENT				
O_2, T/D	-	-	-	-
H_2	-	-	-	-
N_2	-	-	-	-
CO	-	-	-	-
CO_2	-	-	-	-
NH_3	-	-	-	-
H_2S	-	-	-	-
H_2O	729.0	1[illegible].0	540.0	450.[illegible]
CH_4	-	-	-	-
C_2H_4	-	-	-	-
C_2H_6	-	-	-	-
C_3H_6	-	-	-	-
C_3H_8	-	-	-	-
C_4H_8	-	-	-	-
C_4H_{10}	-	-	-	-
IBP-400	-	-	-	-
400-650	-	-	-	-
650-950	-	-	-	-
950-1200	-	-	-	-
1200+	-	-	-	-
RESIDUE	-	-	-	-
ASH	1706.4	442.4	1264.0	1416.[illegible]
COAL (MAF)	24564.6	6368.6	18196.0	14832.[illegible]
COKE	-	-	-	-
SULFUR	-	-	-	-
TOTAL, T/D	27000.0	7000.0	20000.0	15700.[illegible]
MMSCFD	-	-	-	-
BPD	-	-	-	-
HEATING VALUE, BILLION BTU/D	684.11	177.36	506.75	412.7[illegible]



O.	1	2	3	4	5	6	7	8	9	10	11	12	13
ION	COAL TO PROCESS	COAL TO PYROLYSIS	COAL TO SRC	COAL TO FUEL GAS GENERATION	TOTAL OXYGEN	O_2 TO FUEL GAS GENERATION	O_2 TO PROCESS	DISTILLATE SOLVENT	SLURRY SOLVENT	SRC VACUUM BOTTOMS	MAKEUP HYDROGEN	RECYCLE HYDROGEN	TOTAL HYDROGEN
	-	-	-	-	18428.3	11665.6	6762.7	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	1268.1	675.9	1944.0
	-	-	-	-	329.2	208.4	120.8	-	-	-	261.9	94.1	356.0
	-	-	-	-	-	-	-	-	-	-	969.2	241.1	1210.3
	-	-	-	-	-	-	-	-	-	-	34.9	-	34.9
	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	13.6	-	13.5
	729.0	189.0	540.0	450.9	-	-	-	-	-	-	12.3	-	12.3
	-	-	-	-	-	-	-	-	-	-	125.2	43.8	169.0
	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-		-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	567.4	916.5	8.3	-	-	-
	-	-	-	-	-	-	-	11264.1	18229.7	182.5	-	-	-
	-	-	-	-	-	-	-	8150.6	14104.2	[illegible]	-	-	-
	-	-	-	-	-	-	-	17.9	3309.8	[illegible]	-	-	-
	-	-	-	-	-	-	-	-	1768.8	1404.0	-	-	-
	1706.4	442.4	1264.0	1416.8	-	-	-	-	1591.4	1272.8	-	-	-
)	24564.6	6368.6	18196.0	14832.3	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
D	27000.0	7000.0	20000.0	16700.0	18757.5	11874.0	6883.5	20000.0	40000.0	6206.1	2685.1	1054.9	3740.0
	-	-	-	-	446.00	282.33	163.67	-	-	-	519.30	286.62	784.92
	-	-	-	-	-	-	-	-	-	-	-	-	-
VALUE, TU/D	684.11	177.36	506.75	412.76	-	-	-	-	-	-	-	-	-



〉	13	14	STREAM NO.	15	16	17	18	19	20	21	22
E EN	TOTAL HYDROGEN	TOTAL FUEL GAS	DESCRIPTION	AMMONIA	SULFUR	SNG	C_3-LPG	C_4-LPG	POOL GASOLINE	FUEL OIL	COKE
			COMPONENT								
	-	-	O_2, T/D	-	-	-	-	-	-	-	-
9	1944.0	1393.5	H_2	-	-	28.9	-	-	-	-	-
1	356.0	427.0	N_2	-	-	248.8	-	-	-	-	-
1	1710.3	21153.1	CO	-	-	-	-	-	-	-	-
	34.9	823.7	CO_2	-	-	276.9	-	-	-	-	-
	-	-	NH_3	183.2	-	-	-	-	-	-	-
	19.5	0.1	H_2S	-	-	-	-	-	-	-	-
	12.3	62.6	H_2O	-	-	0.2	-	-	-	-	28.7
9	169.0	150.1	CH_4	-	-	2097.9	-	-	-	-	-
	-	-	C_2H_4	-	-	115.0	0.4	-	-	-	-
	-	-	C_2H_6	-	-	921.4	29.6	TR	TR	-	-
	-	-	C_3H_6	-	-	7.9	74.5	0.1	0.3	-	-
	-	-	C_3H_8	-	-	63.0	1023.9	25.0	53.7	-	-
	-	-	C_4H_8	-	-	-	3.9	14.2	30.7	-	-
	-	-	C_4H_{10}	-	-	-	19.6	169.0	674.0	-	-
	-	-	IBP-400	-	-	-	-	4.0	3712.4	343.0	-
	-	-	400-650	-	-	-	-	-	-	3849.8	-
	-	-	650-950	-	-	-	-	-	-	276.9	-
	-	-	950-1200	-	-	-	-	-	-	-	-
	-	-	1200+	-	-	-	-	-	-	-	-
	-	-	RESIDUE	-	-	-	-	-	-	-	-
	-	-	ASH	-	-	-	-	-	-	-	-
	-	-	COAL (MAF)	-	-	-	-	-	-	-	-
	-	-	COKE	-	-	-	-	-	-	-	1596.4
	-	-	SULFUR	-	1709.9	-	-	-	-	-	-
(	3740.0	24010.5	TOTAL, T/D	183.2	1709.9	3760.0	1151.9	212.3	4471.1	4429.7	1625.1
	784.92	1133.47	MMSCFD	-	-	149.0	-	-	-	-	-
	-	-	BPD	-	-	-	13040	2114	34822	27020	-
	-	360.72	HEATING VALUE, BILLION BTU/D	3.54	13.65	153.87	49.83	9.05	181.24	172.01	46.91



THA
GAS
NAPHTHA
GAS
NAPHTHA
GAS
NAPHTHA
400-650°F
400-1200°F
HEAVY LIQUIDS HYDROTREATING
21
650°F+
THERMAL CRACKING
22
COKING
23
H_2
RECYCLE

(5) Annual operating costs were estimated to be about $295 million

(6) The plant population during operations was estimated to be approximately 2,800 people

(7) The estimated required product selling prices for a 12% DCF, 65% debt borrowed at 9% interest, and a 20 year project life, were:

Electricity Bus Bar Selling Price in mils/kWh	Average Fuel F.O.B. Selling Price	
	$/MM Btu	$/Bbl 6 MM Btu/bbl
20	2.50	15.00
30	2.10	12.60
40	1.75	10.50

The RPSPs are approximately 50% higher than for 100% equity financing.

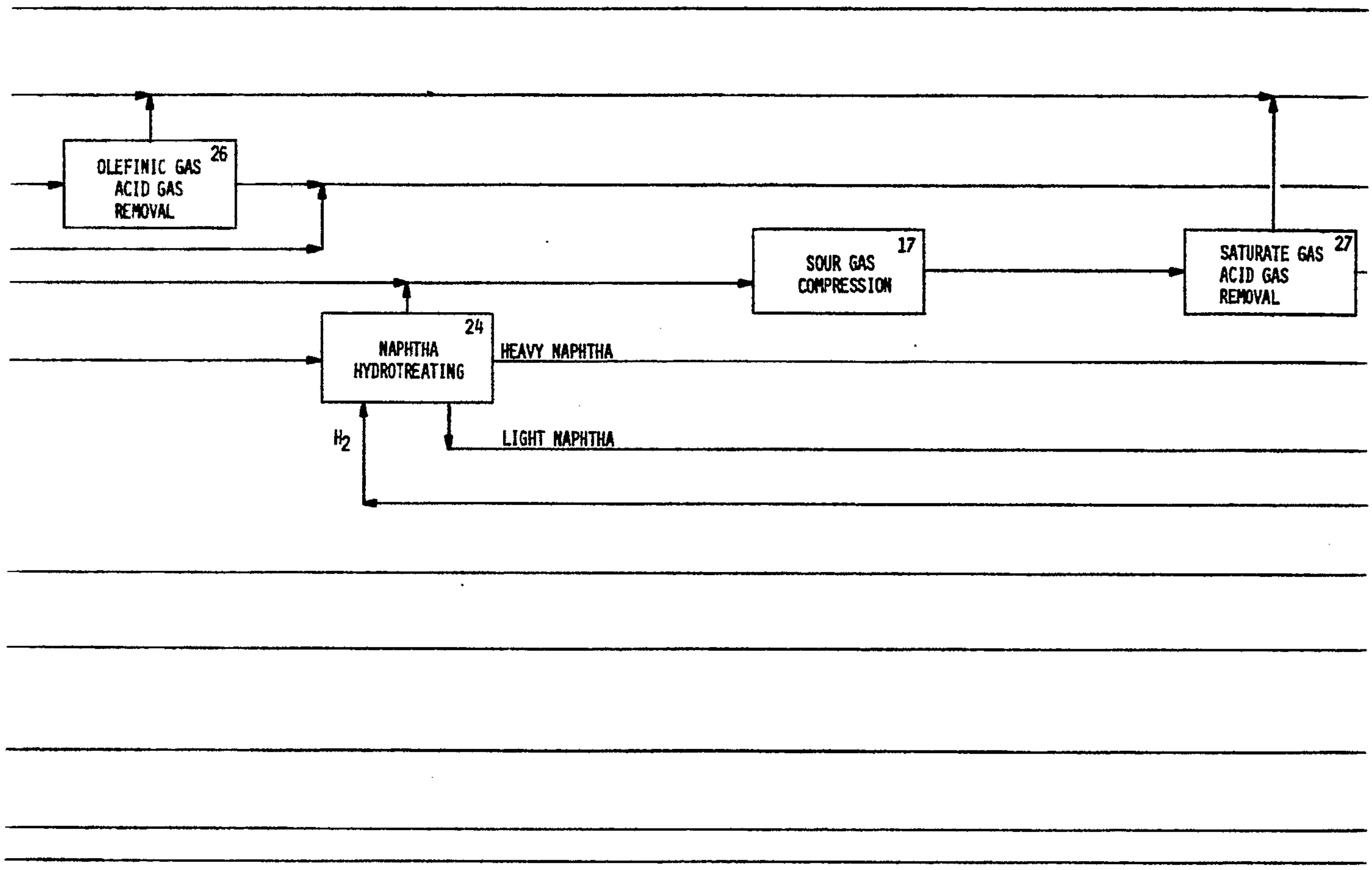
(8) The sensitivities of RPSP to 10% changes in the cost elements were predicted to be:

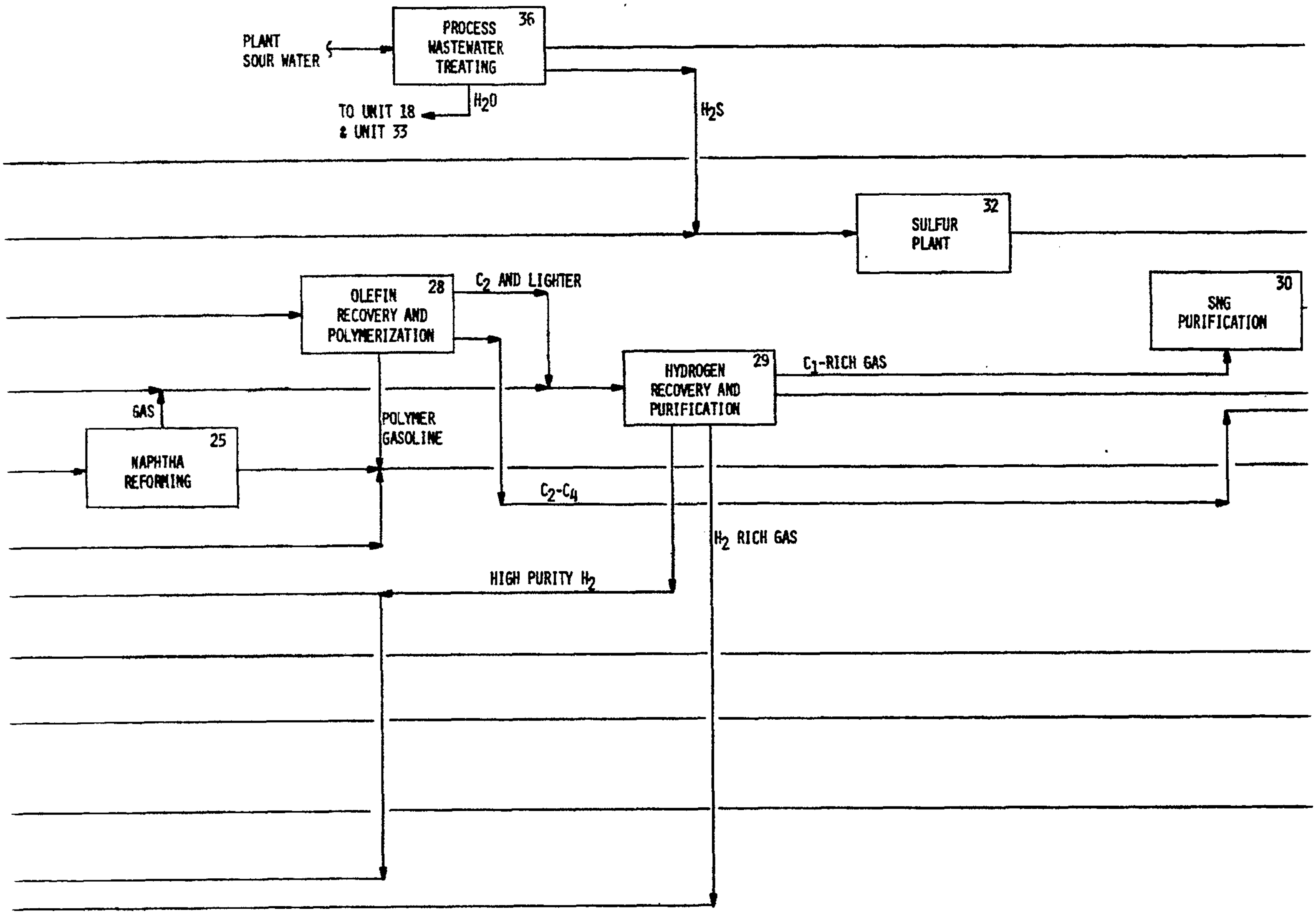
	% Change in RPSP	
Cost Element	100% Equity	65% Debt
Capital associated costs	8.5	8.0
Operating costs	3.3	4.2
ROM coal costs	2.3	3.7
Clean coal costs	2.5	4.0

(9) Possible product market values were predicted. Using these projected revenues would result in the following DCFs:

65% debt - 20% DCF

100% equity - 13% DCF


OLEFINIC GAS
ACID GAS
REMOVAL
26
SOUR GAS
COMPRESSION
17
SATURATE GAS
ACID GAS
REMOVAL
27
NAPHTHA
HYDROTREATING
24
HEAVY NAPHTHA
LIGHT NAPHTHA
H2


PLANT SOUR WATER
PROCESS WASTEWATER TREATING 36
H_2O
TO UNIT 18 & UNIT 33
H_2S
SULFUR PLANT 32
OLEFIN RECOVERY AND POLYMERIZATION 28
C_2 AND LIGHTER
SNG PURIFICATION 30
HYDROGEN RECOVERY AND PURIFICATION 29
C_1-RICH GAS
GAS
NAPHTHA REFORMING 25
POLYMER GASOLINE
C_2-C_4
H_2 RICH GAS
HIGH PURITY H_2

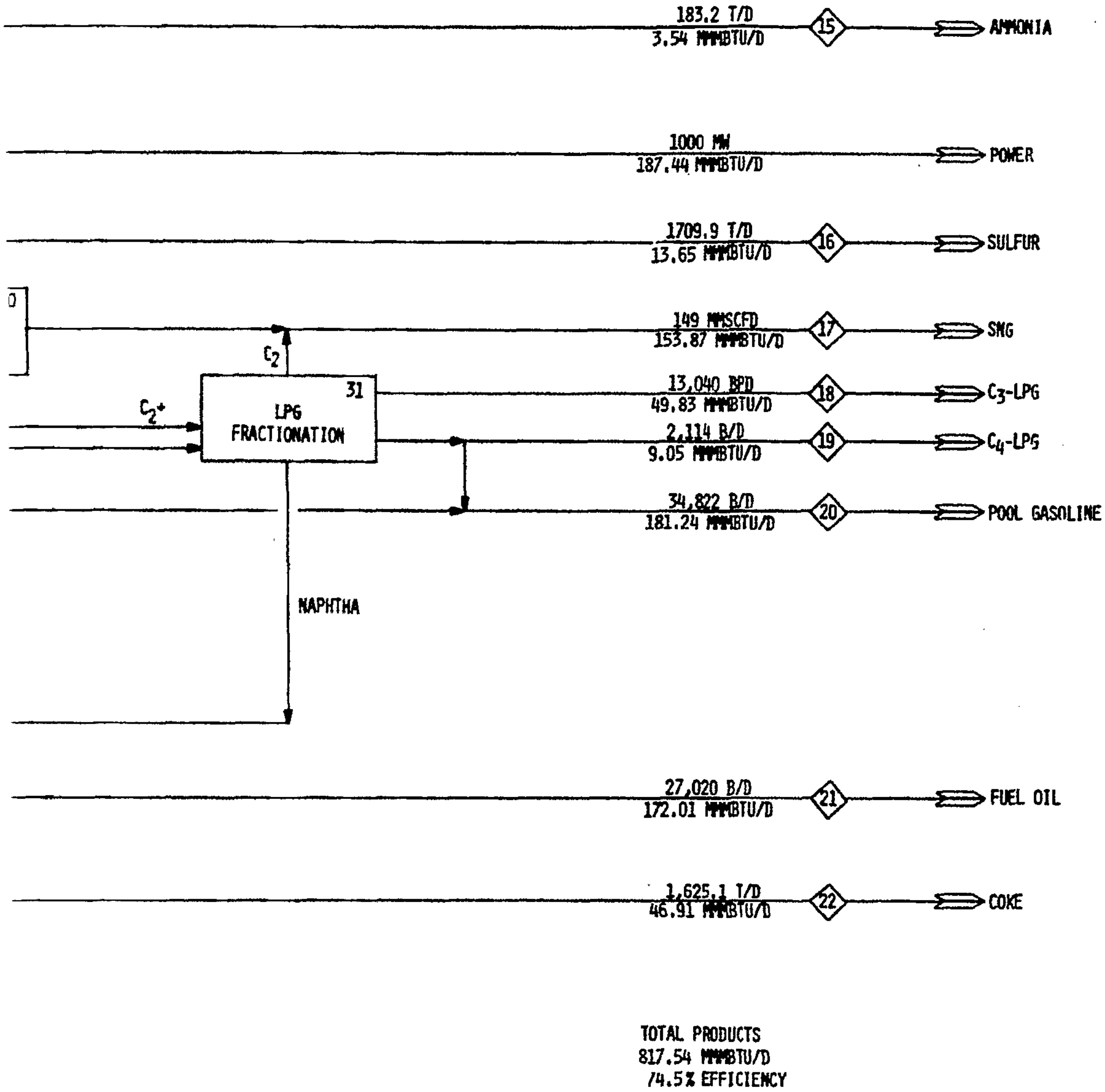


FIGURE 3-22

REV. NO.	SUPT. APPR.	DATE	REVISION	BY	PROC. ENGR.	CHECK	CHIEF PROC. ENGR.	CHIEF OPER. ENGR.	PROJ. DIR.
0			ISSUED FOR REPORT						

DEPARTMENT OF ENERGY - DIVISION OF COAL CONVERSION
POGO PLANT
BLOCK FLOW DIAGRAM
BASE CASE

THE RALPH M. PARSONS COMPANY PASADENA, CALIFORNIA	JOB NO. 5435-4	DWG. NO. R-01-FS-1	REV. 0

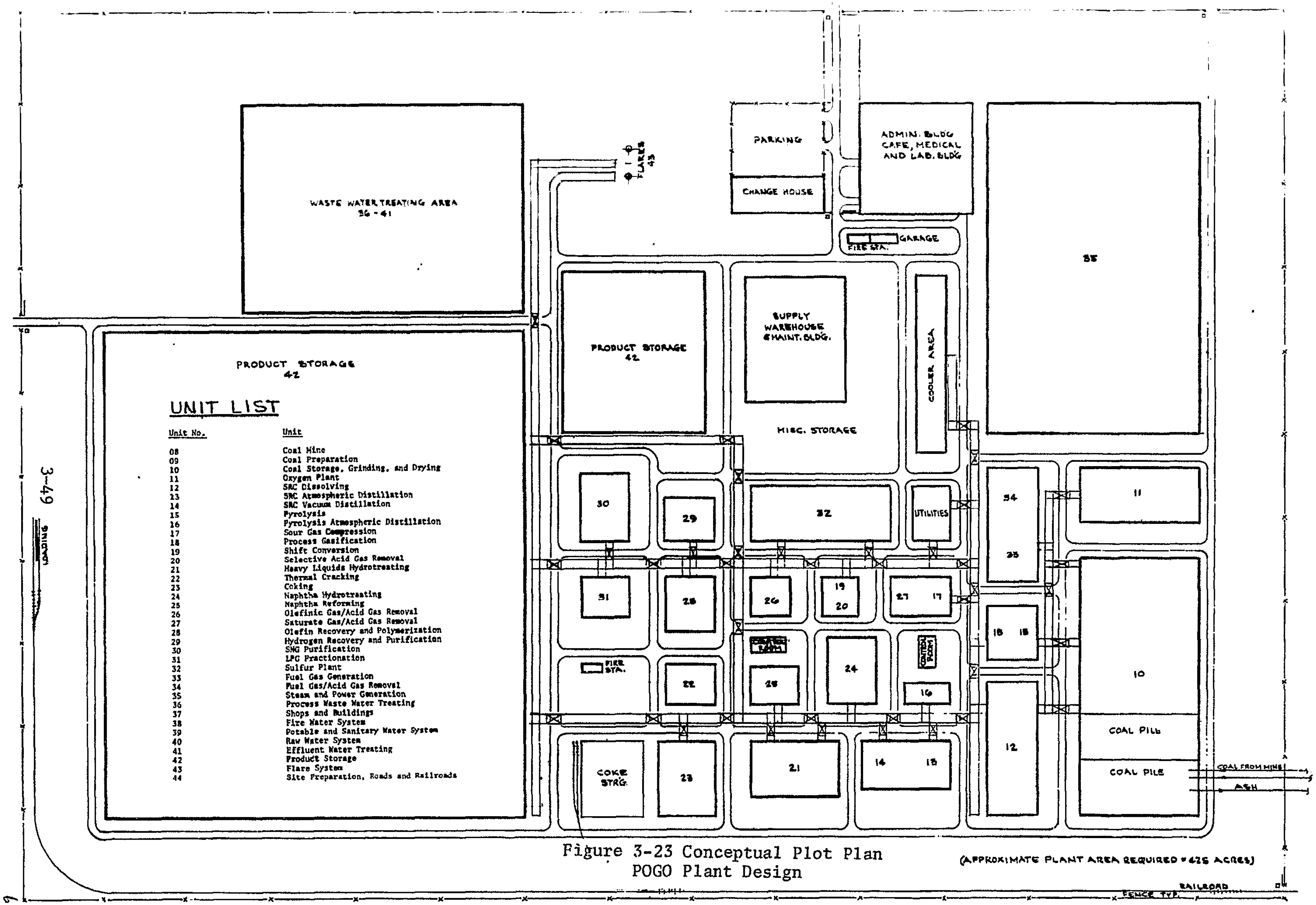


Figure 3-23 Conceptual Plot Plan
POGO Plant Design

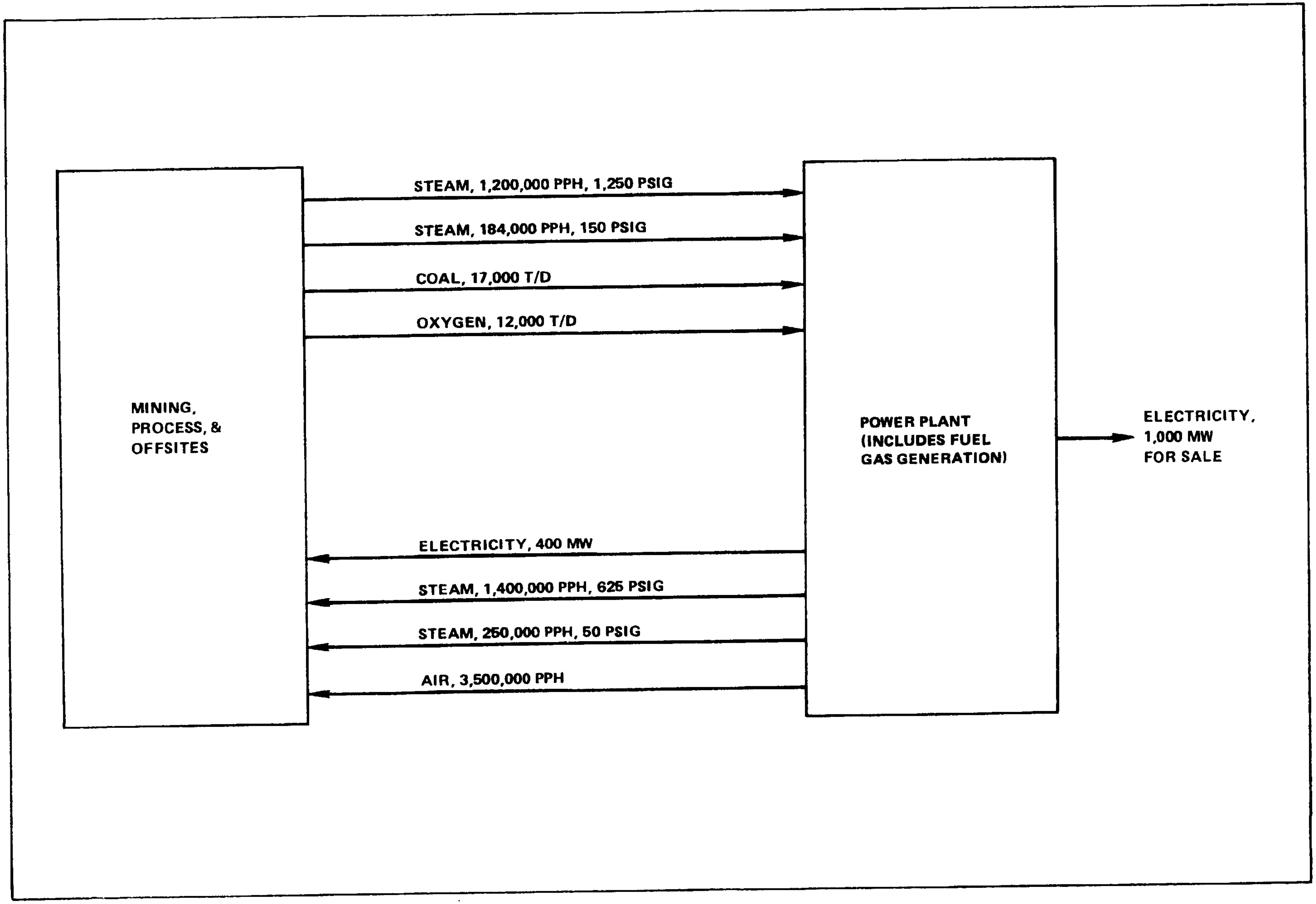


Figure 3-24 - Major Flows To/From Power Plant
POGO Plant Design

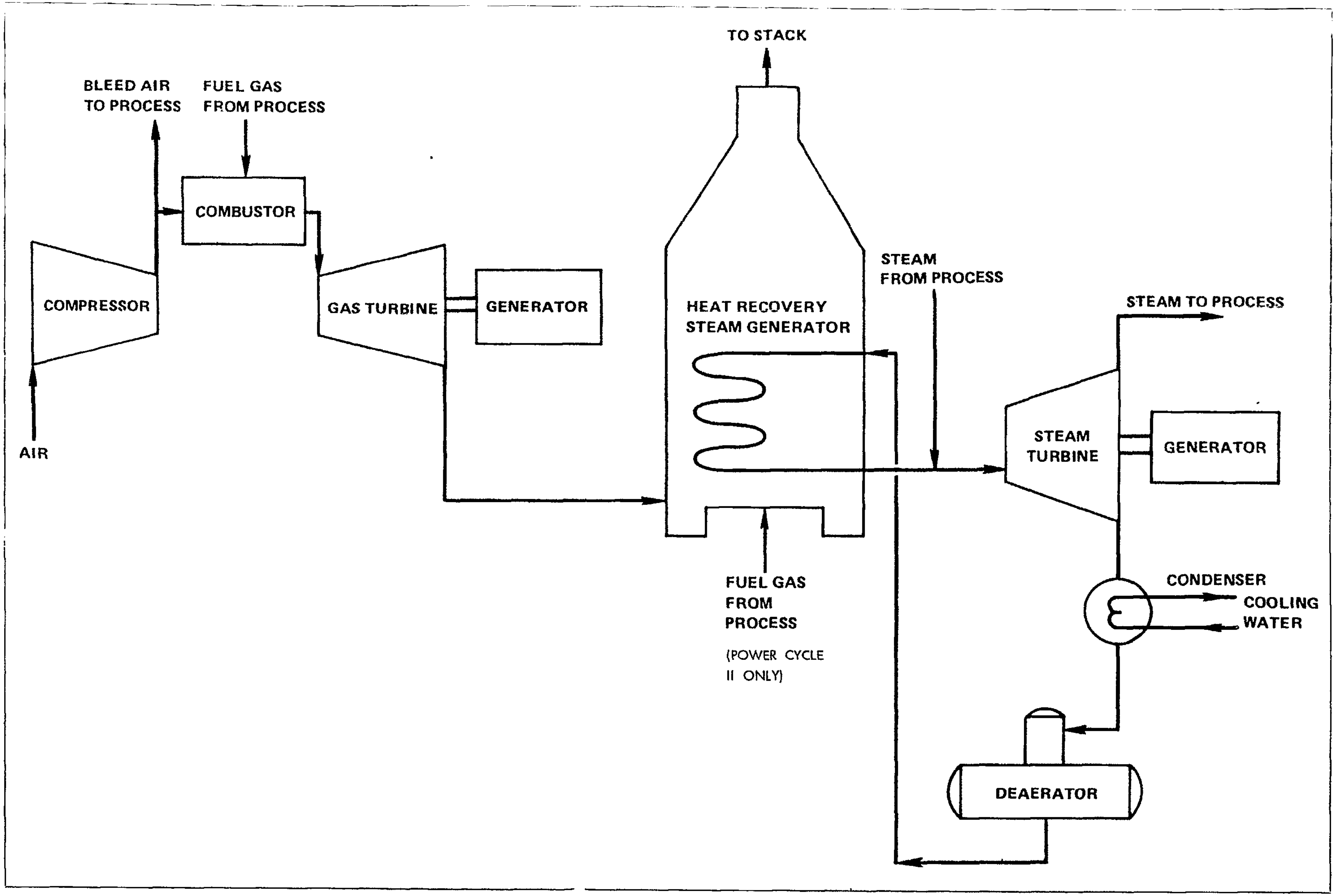


Figure 3-25 - Schematic Diagram of Power Cycles 1 and 11.
POGO Plant Design

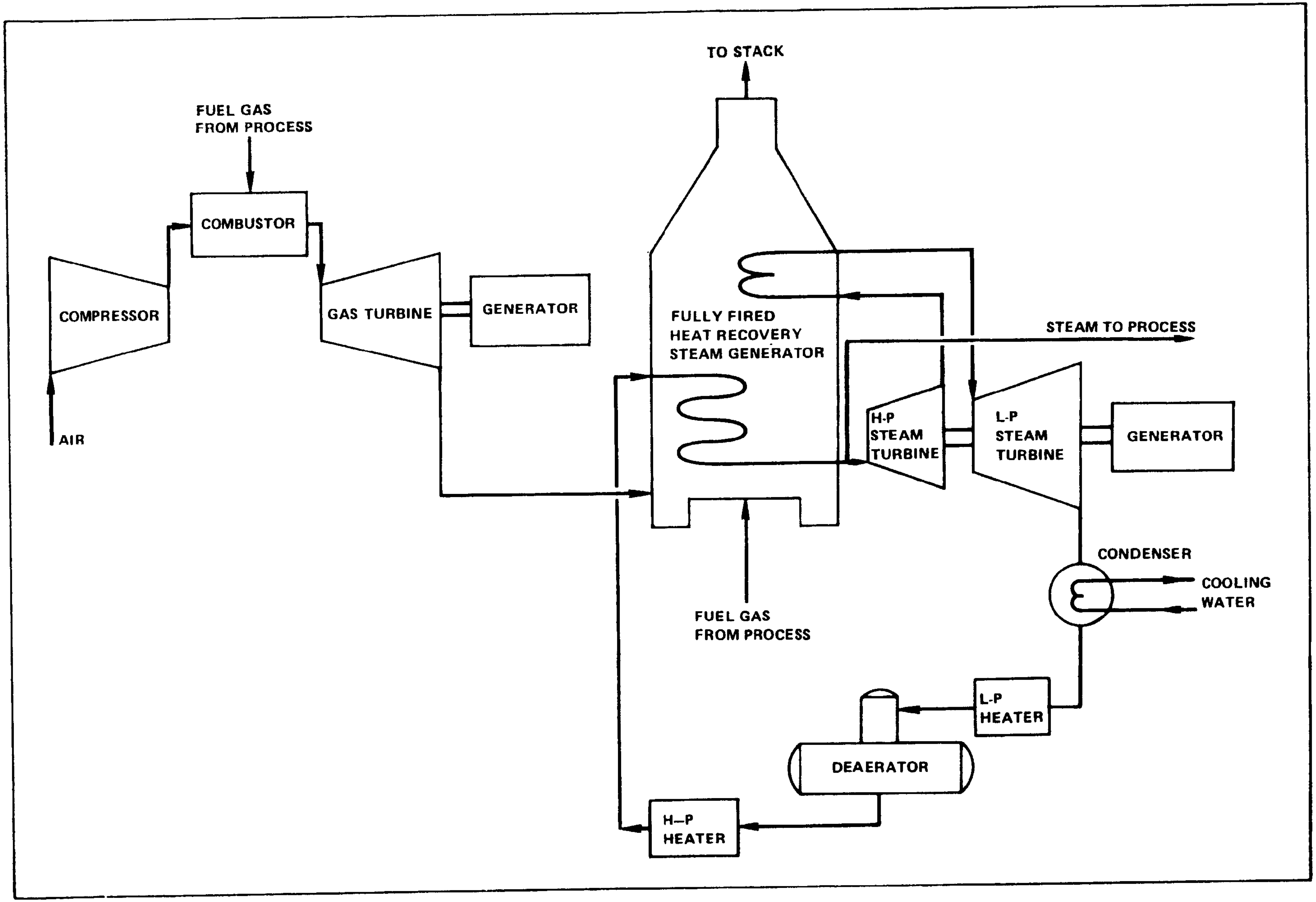
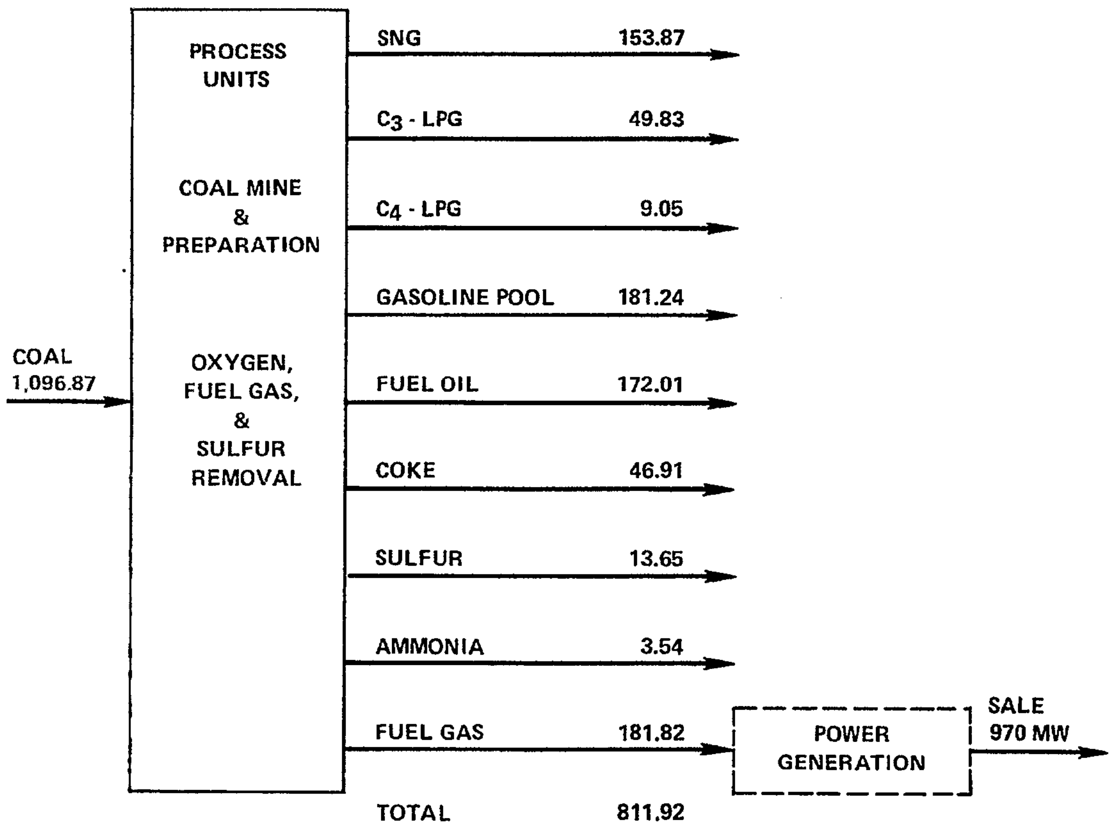


Figure 3-26 - Schematic of Power Cycle No. 111
POGO Plant Design



ALL FIGURES ARE MMM Btu/D HHV

PROCESS THERMAL EFFICIENCY:

$$\frac{811.92}{1{,}096.87} \times 100 = 74.0\%$$

POWER GENERATION EFFICIENCY (BASED ON GAS)

$$\frac{970{,}000 \text{ kW} \times 24 \times 3{,}413 \text{ Btu/kWh}}{181{,}820{,}000{,}000} \times 100 = 43.7\%$$

Figure 3-27 - Projected Thermal Efficiencies
POGO Plant Design

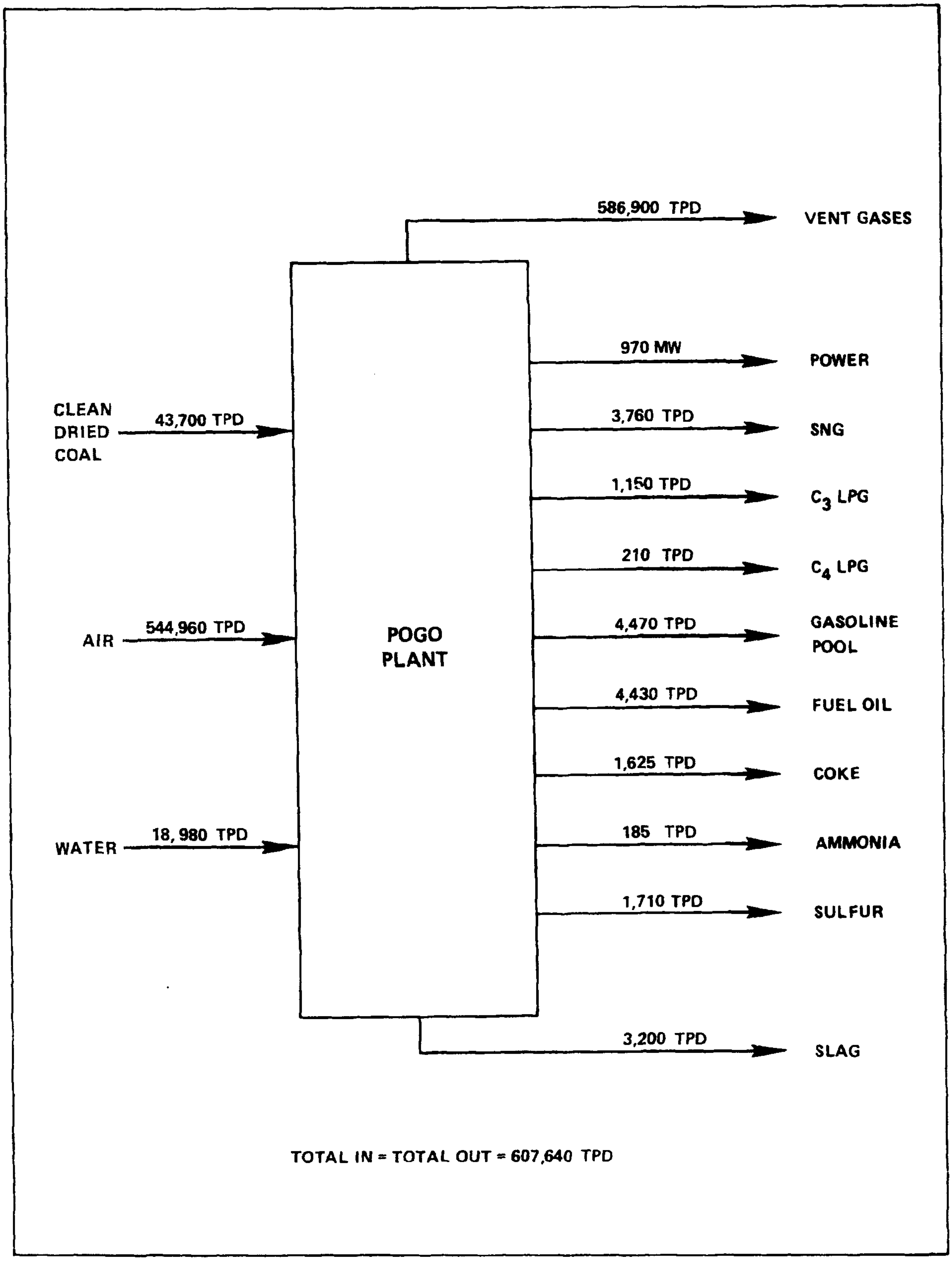
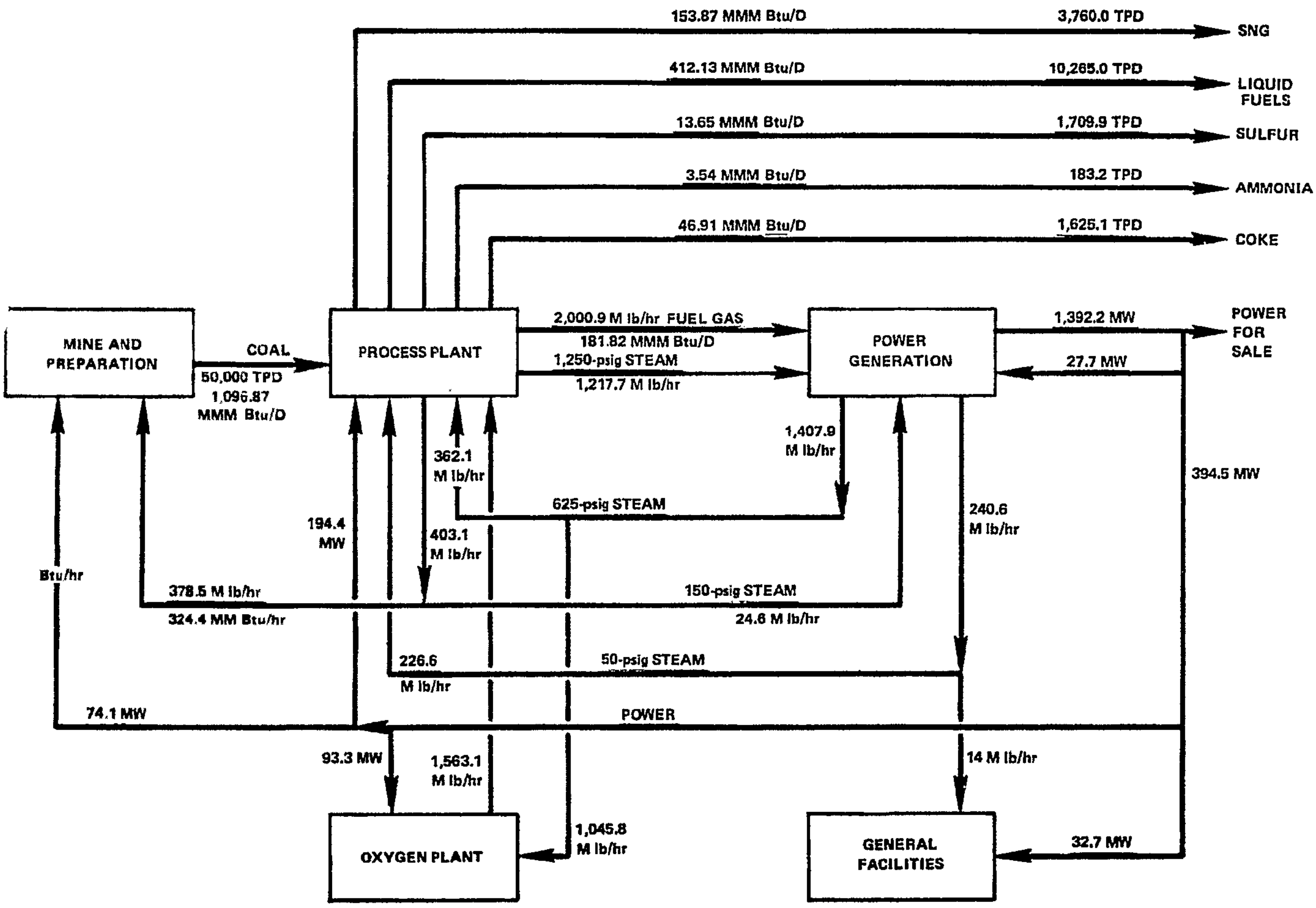
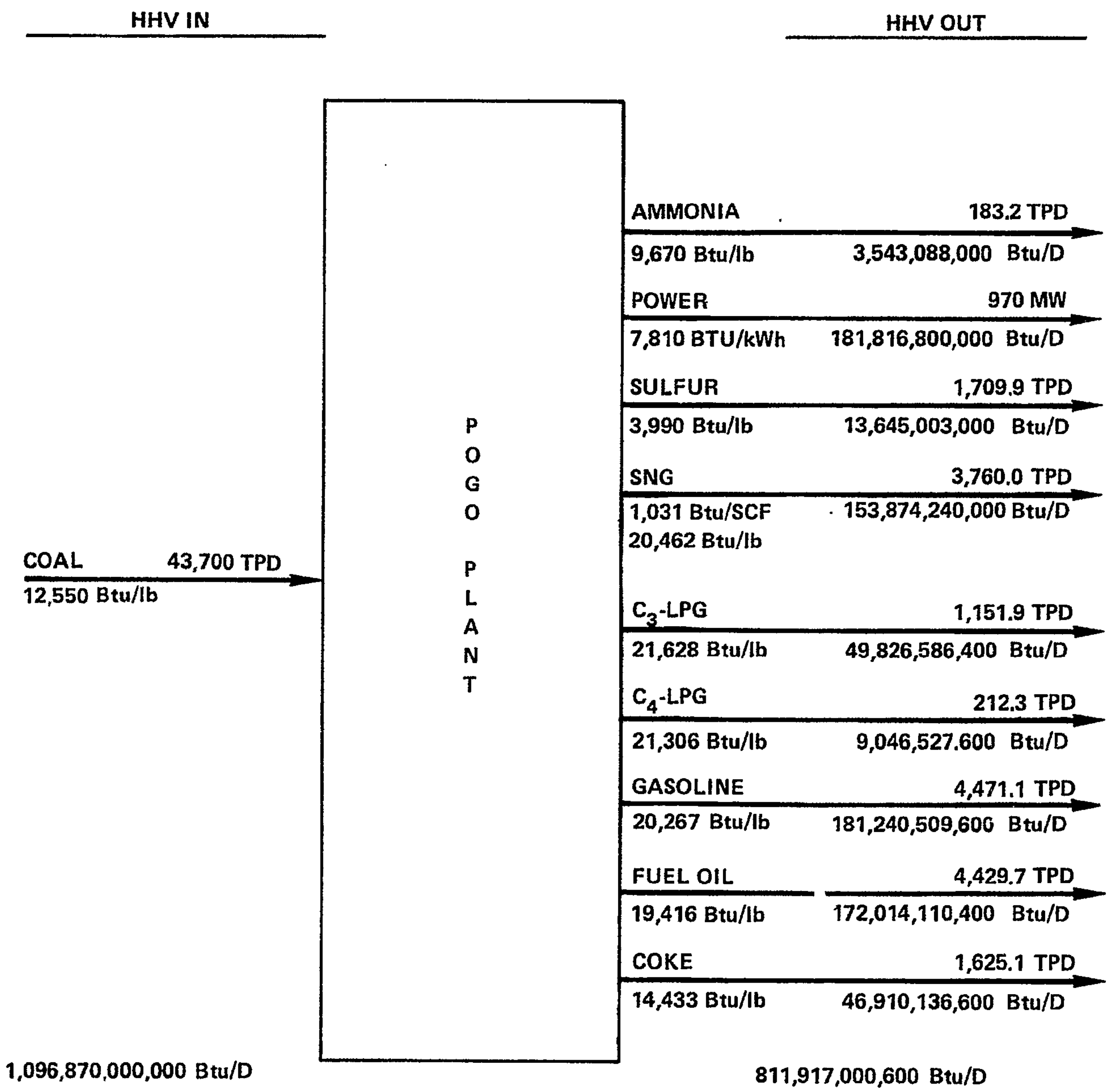


Figure 3-28 - Material Balance
POGO Plant Design



ENERGY DISTRIBUTION	BILLION Btu/D	PERCENT
ENERGY SOURCE		
COAL	1,096.87	100
ENERGY CONSUMED		
MINING AND PREPARATION	23.59	2.15
PROCESS	210.43	19.19
OXYGEN	38.03	3.47
GENERAL FACILITIES	7.28	.66
TOTAL	279.33	25.47
ENERGY VALUE OF PRODUCT		
SNG	153.87	14.03
LIQUID FUELS	412.13	37.57
SULFUR	13.65	1.24
AMMONIA	3.54	.32
COKE	46.91	4.28
FUEL GAS TO STEAM & POWER	181.82	16.58
TOTAL	811.92	74.02

Figure 3-29 Energy Balance
POGO Plant Design



$$\text{OVERALL THERMAL EFFICIENCY} = \frac{811{,}917}{1{,}096{,}870} \times 100 = 74.0\%$$

Figure 3-30 - Overall Thermal Efficiency
POGO Plant Design

Table 3-2 - POGO Products
Projected Quantities and Heating Values

Product	Production Rate			Product Unit HHV	Total Heating Value[a] (Billion Btu/Day)	% of Coal HHV
	Common Units	as BPSD	as TPSD			
Fuels						
SNG	149.24 MM SCFD	26,312[b]	3,760	1,031 Btu/scf (20,462 Btu/lb)	153.87	14.69
C_3-LPG		13,040	1,152	21,628 Btu/lb	49.83	4.75
C_4-LPG		2,114	212	21,306 Btu/lb	9.05	0.86
Gasoline		34,822	4,471	20,268 Btu/lb	181.24	17.30
Fuel Oil		27,020	4,430	19,416 Btu/lb	172.01	16.42
Subtotal		103,308	14,025		566.00	54.02
Power	970 MW	24,242[b]			145.45[c]	13.88
Total Energy Products		127,550			711.45	67.90
Byproducts						
Coke		7,818[b]	1,625	14,433 Btu/lb	46.91	4.48
Sulfur		2,275[b]	1,710	3,990 Btu/lb	13.65	1.30
Ammonia		590[b]	183	9,760 Btu/lb	3.54	0.34
Subtotal		10,683	3,518		64.10	6.12
Total		138,233	17,543		775.55	74.02

[a]Values are per stream day. The process plant operates 330 days per year; the power plant operates 365 days per year.

[b]Barrels of Oil Equivalent (BOE) at 6,000,000 Btu/bbl.

[c]Heat rate of 7,810 Btu/kWh, based on fuel gas and 0.8 load factor.

Table 3-3 - Power Cycle Characteristics

System Number	Number of Gas Turbines with Steam Boilers	Number of Steam Turbines	Percent Air Extraction (Feed to Oxygen Plant)	Supplementary Firing
I-a	17	4	0	No
I-b	17	4	5	No
I-c	17	4	10	No
II-a	13	4	0	Yes
II-b	13	4	5	Yes
II-c	13	4	10	Yes
III	4	2	0	Yes

Table 3-4 - Summary of Power Production and Heat Rate Preference Studies

System Number	Net Power Produced (MW)			Power to Process	Power for Sale	Compressed Air to Oxygen Plant		Net Power Produced (Electricity + Air)	Heat Rate[a] in Btu/kWh Produced, Based on	
	Gas Turbine	Steam Turbine	Total	MW	MW	MM PPH	MW Equivalent	MW	Coal to Fuel Gasifier	Fuel Gas to Power Plant
I-a	1069	463	1532	532	1000	0	0	1532	8890	7815
I-b	993	463	1465	456	1000	1.6	71	1527	8915	7835
I-c	905	470	1375	375	1000	3.3	147	1522	8885	7810
II-a	832	702	1534	534	1000	0	0	1534	9365	8235
II-b	779	693	1472	472	1000	1.3	55	1527	9345	8215
II-c	714	692	1406	406	1000	2.5	116	1522	9280	8160
III	247	1295	1542	542	1000	0	0	1542	10,000	8795

[a] Includes Credit for Power Equivalent for Compressed Air to Process

Table 3-5 - Preliminary Economics Summary - Power Plant Preference Studies

System Number	Net Power Produced[a] MW	Fixed Capital Investment $MM	Operating Costs (Mils/kWh) Fuel[b]	Labor	Maintenance	Other[c]	Total	Fixed Charges[d] Mils/kWh	Total Cost Mils/kWh
I-a	1532	405	19.54	1.5	2.0	0.20	23.24	5.4	28.6
I-b	1527	405	19.59	1.5	2.0	0.20	23.29	5.4	28.7
I-c	1522	405	19.53	1.5	2.0	0.20	23.23	5.4	28.6
II-a	1534	389	20.59	1.5	2.1	0.24	24.43	5.1	29.5
II-b	1527	389	20.54	1.5	2.1	0.24	24.38	5.1	29.5
II-c	1522	389	20.40	1.5	2.1	0.24	24.24	5.1	29.3
III	1542	575	21.99	1.5	3.0	0.36	26.85	7.5	34.4

[a] From Table 2
[b] Fuel Gas at $2.50 per million Btu
[c] Includes cost of water at $0.20 per 1000 gallons
[d] 16% fixed charges