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DOE/NASA 0257-1
NASA CR-168135
CATALYTIC 43790

(NASA-CR-168135) AFB/OPEN CYCLE GAS TURBINE CONCEPTUAL DESIGN STUDY Final Report (Catalytic, Inc.) 422 p HC A18/MF A01 N84-31784
CSCL 10B Unclas
G3/44 21270

AFB/OPEN CYCLE GAS TURBINE CONCEPTUAL DESIGN STUDY

CATALYTIC, Inc. Final Report

Prepared for
NATIONAL AERONAUTICS AND SPACE ADMINISTRATION
Lewis Research Center
Under Contract DEN 3-257

for
U.S. DEPARTMENT OF ENERGY
Combustion and Heat Systems Division

September 1983

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Catalytic, Inc. Final Report
T.W. Dickinson, R. Tashjian

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Cleveland, OHIO 44135
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U.S. Department of Energy
Combustion and Heat Systems Division
Washington, D.C. 20545
Under Interagency Agreement DE-A101-77ET-13111

1. Report No. NASA CR - 168135	2. Government Accession No.	3. Recipient's Catalog No.
4. Title and Subtitle AFB/OPEN CYCLE GAS TURBINE CONCEPTUAL DESIGN STUDY		5. Report Date JUNE 1983
		6. Performing Organization Code 778-14-10
7. Author(s) T. W. DICKINSON, R. TASHJIAN CATALYTIC, INC.		8. Performing Organization Report No.
		10. Work Unit No.
9. Performing Organization Name and Address NATIONAL AERONAUTICS AND SPACE ADMINISTRATION LEWIS RESEARCH CENTER CLEVELAND, OHIO 44135		11. Contract or Grant No. DEN3-257
		13. Type of Report and Period Covered CONTRACTOR REPORT
12. Sponsoring Agency Name and Address U. S. DEPARTMENT OF ENERGY COMBUSTION AND HEAT SYSTEMS DIVISION WASHINGTON, DC 20545		14. Sponsoring Agency Report No. DOE/NASA 0257-1

15. Supplementary Notes

PREPARED UNDER INTERAGENCY AGREEMENT DE-AI01-77ET-13111

16. Abstract

The AFB/Open Cycle Gas Turbine Conceptual Design Study identifies attractive applications for coal fired atmospheric fluidized bed gas turbine systems in industrial cogeneration. Based on site-specific conceptual designs, the potential benefits of the AFB/gas turbine system is compared with an atmospheric fluidized design steam boiler/steam turbine system. A review was performed of the application of these cogeneration systems at four industrial plant sites. A performance and benefit analysis was made along with a study of the representativeness of the sites both in regard to their own industry and compared to industry as a whole. A site was selected for the conceptual design, which included detailed site definition, AFB/gas turbine and AFB/steam turbine cogeneration system designs, detailed cost estimates and comparative performance and benefit analysis. Market and benefit analyses identified the potential market penetration for the cogeneration technologies and quantified the potential benefits.

17. Key Words (Suggested by Author(s))	18. Distribution Statement
Cogeneration, Atmospheric Fluidized Beds, Gas Turbines, Industrial Power, Air Cycle	Unclassified-Unlimited Star Category 44 DOE Category UC-93

19. Security Classif. (of this report)	20. Security Classif. (of this page)	21. No. of Pages	22. Price*
Unclassified	Unclassified	422	

* For sale by the National Technical Information Service, Springfield, Virginia 22161

NASA-C-168 (Rev. 10-75)

FOREWARD

The AFB/Open Cycle Gas Turbine Conceptual Design Study was performed by the National Aeronautics and Space Administration, Lewis Research Center, for the Department of Energy, Combustion and Heat Systems Division. The primary objectives of this study were to identify attractive applications for coal fired atmospheric fluidized bed/open cycle gas turbine systems in industrial cogeneration and to compare, based on site-specific conceptual designs, the potential benefits of the AFB/gas turbine system with an AFB/steam turbine system at the selected site.

This document describes the work conducted by Catalytic, Inc. under National Aeronautics and Space Administration Contract DEN3-257.

This study was one of two parallel, but independent studies of advanced technology cogeneration by industrial teams along with analysis and evaluations by the National Aeronautics and Space Administration's Lewis Research Center. The AFB/Closed Cycle Gas Turbine Study prepared a conceptual design of the same plant site. This work was performed by the Garrett Turbine Engine Company under Contract No. DEN3-215.

As part of the project team, members of the technical staffs of the following organizations have developed and provided information for the Catalytic AFB/Open Cycle Gas Turbine Conceptual Design Study:

Curtiss-Wright Corporation
Keeler/Dorr-Oliver
General Energy Associates

The contributions of the corporations and electric utilities for each of the sites studied is gratefully acknowledged:

Ethyl Corporation - Houston, Texas
Riegel Products Corporation/James River Corporation - Milford, New Jersey
Georgia-Pacific Corporation - Lovell, Wyoming
Hercules, Inc. - Covington, Virginia
Houston Lighting and Power Company - Houston, Texas
Jersey Central Power and Light Company - Morristown, New Jersey
Pacific Power and Light Company - Lovell, Wyoming
Virginia Electric and Power Company - Richmond, Virginia

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SUMMARY

Coal fired atmospheric fluidized bed gas turbine industrial cogeneration systems offer a means to achieve significant national energy and environmental benefits. On the basis of a site specific analysis comparisons, AFB/gas turbine cogeneration appears significantly more attractive than AFB/steam turbine cogeneration systems. Further, the flexibility of the AFB/gas turbine cycle permits a unique opportunity to closely match the thermal and electrical demands of a wide variety of industrial plants.

The gas turbine technology studied is the open cycle gas turbine using a coal fired atmospheric fluidized bed combustor with inbed vertical tubular metal air heater providing hot air for gas turbine operation. The fluidized bed combustion temperature is limited to about 1,650°F and turbine air inlet temperature is about 1,500°F. With this turbine inlet temperature, it is practical to use existing gas turbines that are available from many manufacturers. No new technology is required for the gas turbine. Many of the system components are standard commercial items, while the "new" items are derived from well-proven technology. There is no technical barrier to the commercialization of open air cycle atmospheric fluidized bed gas turbine cogeneration.

The study first sought to select the specific plant site to be studied in detail. Four existing widely ranging industrial plants were characterized, AFB/gas turbine and AFB/steam turbine cogeneration systems developed and analyzed, and a site recommended for conceptual design. The Ethyl Corporation, Pasadena, Texas chemical plant was the one selected for detailed study.

The conceptual designs and performance analysis for the Ethyl plant site resulted in the AFB/gas turbine ROI of 21.9% in constant (real) dollars exceeding both the site specific required ROI and that developed for the AFB/steam turbine cycle. The levelized annual energy cost saving (including capital charges) was about 12% better than for the plant firing gas or oil and without having any capital charges. The study is based on initial plant operation in 1988. Costs are based on 1981 prices.

The potential national market which could be obtained if AFB/gas turbine cogeneration were implemented at existing steam using plant sites by meeting a ROI of at least 20% (not including inflation) is almost 170 plants. These could provide cogeneration capacity of over 5,000 MW electricity and 103,000,000 lbs./hr. steam. Total potential displacement of utility oil/gas would result in 0.14 QUADS annually. With ROI exceeding 10%, new plants could be implemented as high as 67% of the market in the plant range of 250,000 to 400,000 lbs./hr. steam size with total potential annual displacement of utility oil/gas fuel of 0.28 QUADS.

Chapter 1

INTRODUCTION

1.1 Background

The high fuel conversion efficiencies associated with the cogeneration of electrical and thermal energy have made it the subject of a wide range of studies by both industry and government. Where its practice once supplied a substantial amount of industry's heat and power requirements, its contribution is now small. The factors which have contributed to its decline, as well as the current level of interest, are complex. Although some generalizations may apply, economically and technically attractive cogeneration applications are very site specific in nature. While current and previously available cogeneration technologies are finding many applications in today's industrial community, new technologies are emerging which promise higher efficiencies and better suitability to tomorrow's energy supply and environmental quality requirements.

The Department of Energy (DOE) sponsored the Cogeneration Alternatives Study (CTAS) to evaluate the benefits of advanced technology energy conversion systems for industrial cogeneration. The results of the CTAS study were published in 1980. The study emphasized systems fueled by coal, coal-derived liquids, or the products of coal gasification. Advanced technology energy conversion systems were found to have a significantly greater potential for energy savings than systems commercially available. In addition, the use of coal-fueled advanced technology energy conversion systems offers the opportunity to convert from petroleum fuels to coal while maintaining energy conservation and environmental acceptability.

Among the coal-fueled energy conversion systems studied, the steam turbine system using an atmospheric fluidized bed (AFB) heat source had wide applicability in industrial cogeneration. Open cycle gas turbine and closed cycle gas turbine systems, indirectly coal fired by AFB heat sources, were also found to have significant potential for application in industrial cogeneration.

This DOE sponsored/NASA managed study builds upon the work which DOE/NASA has already accomplished in the Cogeneration Alternatives Study program by developing and analyzing appropriate AFB/open cycle gas turbine, and AFB/steam turbine cogeneration systems for four existing U.S. industrial sites and selecting a "best" application for detailed analysis.

The AFB/steam turbine system is now considered commercially available as an industrial cogeneration system. The relative attractiveness of the various AFB/gas turbine systems and the AFB/steam turbine systems depends primarily on the characteristics of the energy requirements in a specific industrial plant. The strategy used to size the energy conversion system and match the cogeneration system to the industrial plant energy requirements is important to maximize the potential benefits. The requirements of industrial plants vary widely across the manufacturing sector of U.S. industry. Individual plant requirements differ even within specialized classifications. Therefore, a site-specific analysis must be performed to better assess the benefits available from an energy conversion system.

The results of the analysis support conclusions about the ability of AFB/gas turbine cogeneration systems to achieve significant national energy and environmental benefits as compared to existing fuel utilization practices. The study also develops and analyzes the technical, economic, institutional and regulatory barriers which may impede both the technology commercialization and achievement of the projected national benefits.

1.2 Study Objectives

The prime objective of this study is to produce a credible assessment of AFB/open cycle gas turbine cogeneration systems ability to make a substantial contribution to reduction of oil and gas consumption while improving the quality of the country's environment. Intermediate objectives also consider the myriad of direct and indirect factors which affect the credibility of the projected level of achievable results. Recognizing that the vast majority of U.S. industrial plants can purchase all of their electrical energy requirements from their respective utility companies, corporate cogeneration investment decisions are primarily based on the overall economics of the project on a site by site basis. Although previous studies have shown AFB/gas turbine cogeneration systems to be potentially attractive, the current lack of commercially available technology and operating history prevents verification. This study screens four primary industrial plant sites to methodically select the "best" one for conceptual design development. The optimization of the conceptual design and the attendant analyses produced a level of industrial plant site-specific design, performance and economics data which has not previously been available, and thus provides a basis for future development in this area.

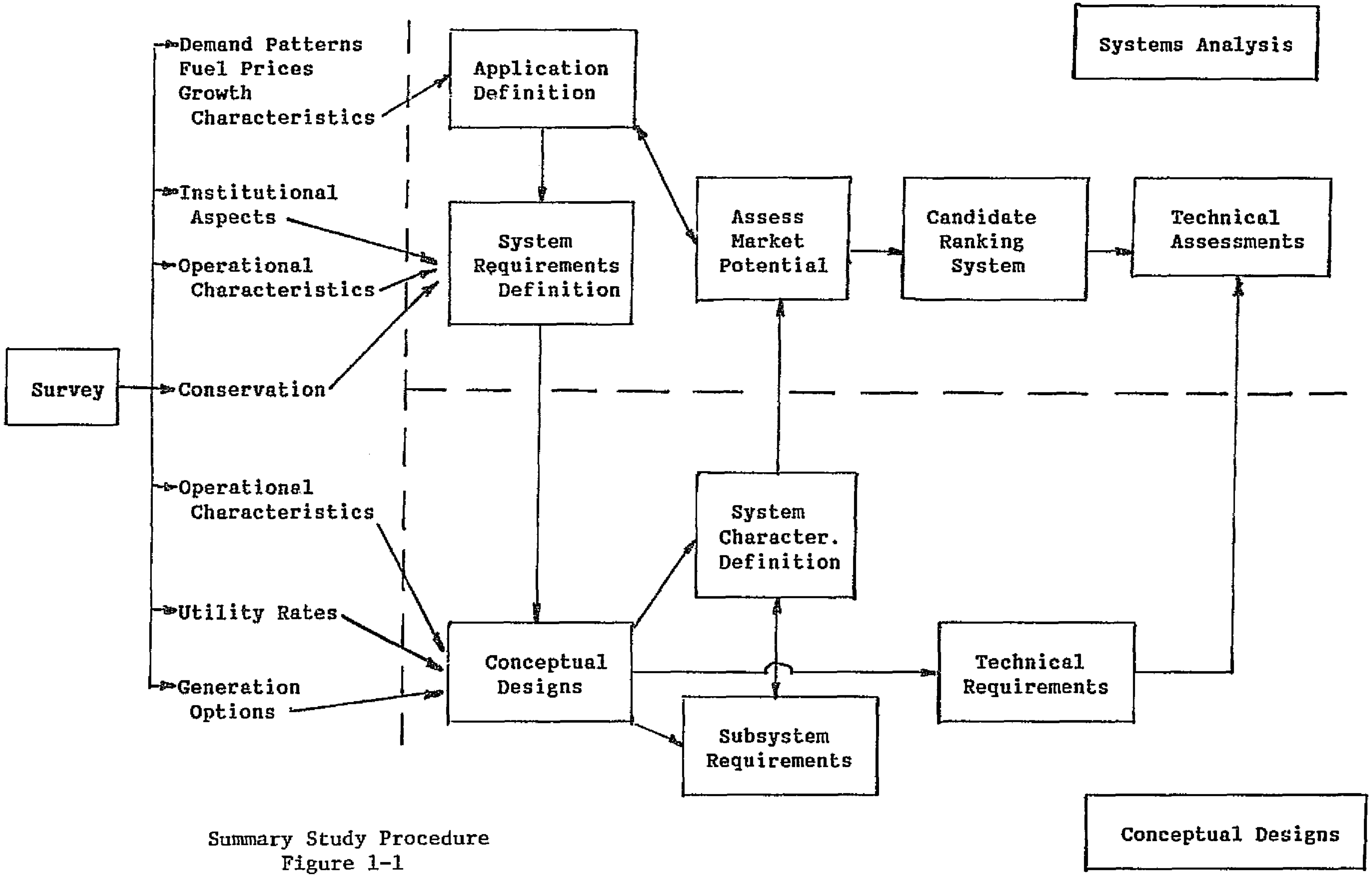
1.3 Technical Approach

The study procedure is summarized by the flow chart shown in Figure 1.1. The study was divided into three tasks as shown in the chart.

1.3.1 Industrial Plant Site Screening - Task 1

The initial task was the evaluation of the four industrial plant sites and the selection of the "best" site for the conceptual design of the AFB /gas turbine cogeneration system. It was necessary to collect a large amount of data on each site to make this screening possible. The data collected for each site came from discussions with the plant operators and corporate staff, the local utilities, and state regulatory agencies.

Site screening provided the plant requirements information necessary to perform preliminary design of cogeneration systems for the proposed sites. Two system designs were developed for each site, an AFB/gas turbine cogeneration system and an AFB/steam turbine cogeneration system. The design effort included studies of the various options for improving system performance and/or efficiency. Systems design was carried to a level of detail that permitted a good estimate of the capital costs for each system. The system designs were also analyzed to identify the operational characteristics, the performance values, the potential for improvement, and the associated costs. An economic analysis was performed using the systems designed. Utility information was used to establish the value of excess electricity (available for export to the utility) plus the values of utility emissions, utility fuel consumption and utility supplied electricity that could be displaced by the cogeneration systems. A survey of institutional barriers was made to identify any non-technical barriers that might exist and limit the use of coal-fired cogeneration. Any differences in the effect on AFB/gas turbine cogeneration systems and AFB/steam turbine cogeneration systems are identified. Performance evaluation criteria included total system fuel energy, emissions, capital cost, and levelized annual costs. Industrial users, utilities, and environmental agencies were contacted to assess non-technical barriers on the proposed sites.



Summary Study Procedure
Figure 1-1

All of the systems design, study evaluation, and industrial plant site information was used to select a "best" application site for the installation of an AFB/gas turbine cogeneration system. The selected site represents an example of the relative advantages of the AFB/gas turbine system compared to the AFB/steam turbine system and also compared to a non-cogeneration mode of operation. This permits a realistic evaluation of the industrial market potential nationwide. The selection also took into consideration the degree to which the industrial plant requirements represent the requirements of other plants nationwide, the non-coal fuel savings potential in similar plants nationally, and the willingness of the plant owner, local utilities, and regulatory agencies to accept the coal-fueled cogeneration concept.

The work in this task was performed by Catalytic with extensive consultation with the plant owners, local utilities, and regulatory agencies plus input from the following Catalytic subcontractors:

Curtiss-Wright - provided cycle arrangement and cycle analysis for the AFB/gas turbine cogeneration system as well as cost input.

Keeler/Dorr-Oliver Boiler Division - provided equipment sizing and costing for the AFB associated with the AFB/steam turbine cogeneration system.

General Energy Associates - performed evaluation of the degree to which the selected sites typify plants nationally.

1.3.2 Cogeneration System Conceptual Design - Task 2

The conceptual designs, an AFB/gas turbine cogeneration system and an AFB/steam turbine cogeneration system, were prepared for the "best" application site. These conceptual designs are more detailed than the system designs used for site selection. They are tailored to the specific site and a detailed performance analysis was conducted for each system. Capital costs were determined for each system, benefits analyzed and institutional barriers assessed at the specific site.

The information collected for site screening and system design was refined. More precise definitions of the load profiles were determined to identify any short duration load spikes. More detailed information was obtained on plant layout, locations of plant interface points (for the cogeneration systems), requirements and restrictions of regulatory agencies that affect the plant and/or cogeneration systems, utility requirements for grid interface, and the specifics of utility involvement in a cogeneration system or purchase of excess power. This additional information was used to develop the conceptual designs for an AFB/gas turbine cogeneration system and an AFB/steam turbine system that meet the requirements of the specific site.

Plant availability requirements and part load performance were also studied to determine the effect on conceptual system design and conversely the conceptual system capability effects on overall plant availability. Natural resource requirements (such as coal, sorbent, water, land area, and materials) are defined along with the projected environmental impacts (exhaust gas emissions, thermal pollution, and waste streams).

Capital costs were developed for the design and construction of each cogeneration system based on the conceptual design and estimate of the construction time.

The conceptual cogeneration systems were analyzed to determine the detailed performance values and benefits. The analysis covers all of the parameters addressed in the systems designs for site screening plus the additional factors (or information) developed in the conceptual design work. A sensitivity analysis was conducted on those parameters affecting the benefits and/or cogeneration system economics. The resulting advantages are listed for both cogeneration systems to permit effective comparison.

For this task, Curtiss-Wright and Keeler/Dorr-Oliver further developed information for a conceptual design for the selected site.

1.3.3 Technical Assessment, Market Analysis and Potential Benefits - Task 3

This task evaluated the magnitude of national benefits to be derived from the implementation of AFB/gas turbine industrial cogeneration systems. A review of currently available technology for AFB/gas turbine cogeneration systems and of existing development programs were conducted to provide information for full scale operation of the conceptual systems by the mid to late 1980s. Areas for development needs were identified.

In assessing the potential market for AFB/gas turbine cogeneration systems, the ability of the AFB/gas turbine system to meet individual plant requirements was considered. Application potential is based on the characteristics of the various industries and the ability of the AFB/gas turbine cogeneration system to meet these requirements by being properly designed (configuration and arrangement). Economic factors, regulatory conditions, utility policies, industry attitudes and other non-technical factors were also considered in the analysis of market potential. An estimate of the market penetration of AFB/gas turbine cogeneration systems was developed based on commercial availability by 1988. The national benefits due to the estimated market penetration were then calculated in terms of fuel savings, cost savings, and environmental impacts. The estimated market penetration and the resultant national benefits were developed as functions of time from 1988 through 2008.

General Energy Associates provided information on industrial plants for the marketing analysis. Suitable models were developed by Catalytic for economics and performance determination of technological assessments and national benefits.

Chapter 2

TECHNOLOGIES

2.1 Basic System Description - AFB Gas Turbine

The AFB/gas turbine cycle uses an indirect fired open cycle utilizing a coal-fueled atmospheric fluidized bed combustor in conjunction with a gas turbine. The basic air cycle system and its major components are shown schematically in Figure 2-1. Fluidizing air is provided to the combustor by a forced draft fan. During cold startup, an oil or gas fired combustor heats the air to warm the bed to coal combustion temperature. Crushed dried coal and prepared limestone enter the bed through feed ports using an underbed feed system via pneumatic transport. Ash is removed through inbed drains passing through a fluidizing column which acts as a seal and into a water cooled fluidized bed ash cooler. The fluidizing air enters the bottom of the bed, passes through the bed, fluidizes it and combines with the coal to form flue gas. The flue gas passes through the freeboard and into a recycle cyclone system where the larger particulates are removed and returned to the bed through a trickle valve. The flue gas then exits the top of the cyclone and goes into an air preheater where heat is transferred from the flue gas to the incoming clean air. The flue gas is then used in the process or in a waste heat boiler to produce steam. Component parts of a typical air cycle fluidized bed unit as offered by Curtiss-Wright are shown in Figures 2-2 and 2-3.

Clean air enters the gas turbine through the inlet silencer and is compressed (and increased in temperature) in the compressor section. Upon exit from the compressor, it is directed through the air preheater, where it obtains additional heat from the flue gas. It then moves through an inbed heat exchanger extracting heat from the bed. The heated air then enters the turbine section, where it powers the compressor and drives the generator to produce electricity. The heat in the clean air from the turbine exit is then available for process use or for conversion to steam in a waste heat boiler.

A detailed component description and a discussion of operation and control during startup, shutdown and operating transients is given in Appendix Section 1. A complete industrial cogeneration system can take several different forms because of the flexibility and adaptability of the gas turbine system to account for different types of plant requirements.

AFB COGENERATION SYSTEM
AIR CYCLE
BASIC FLOW DIAGRAM

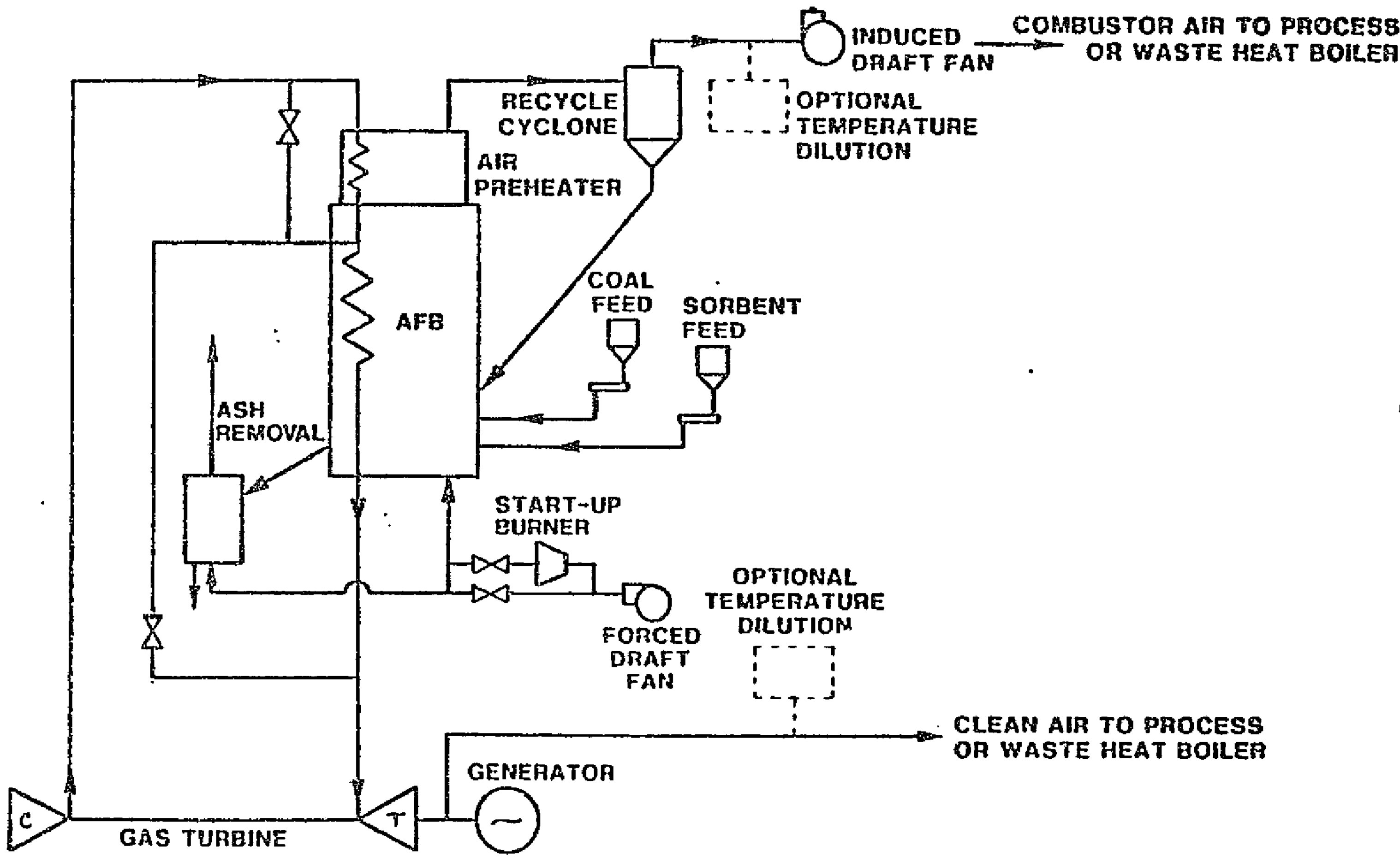


Figure 2-1

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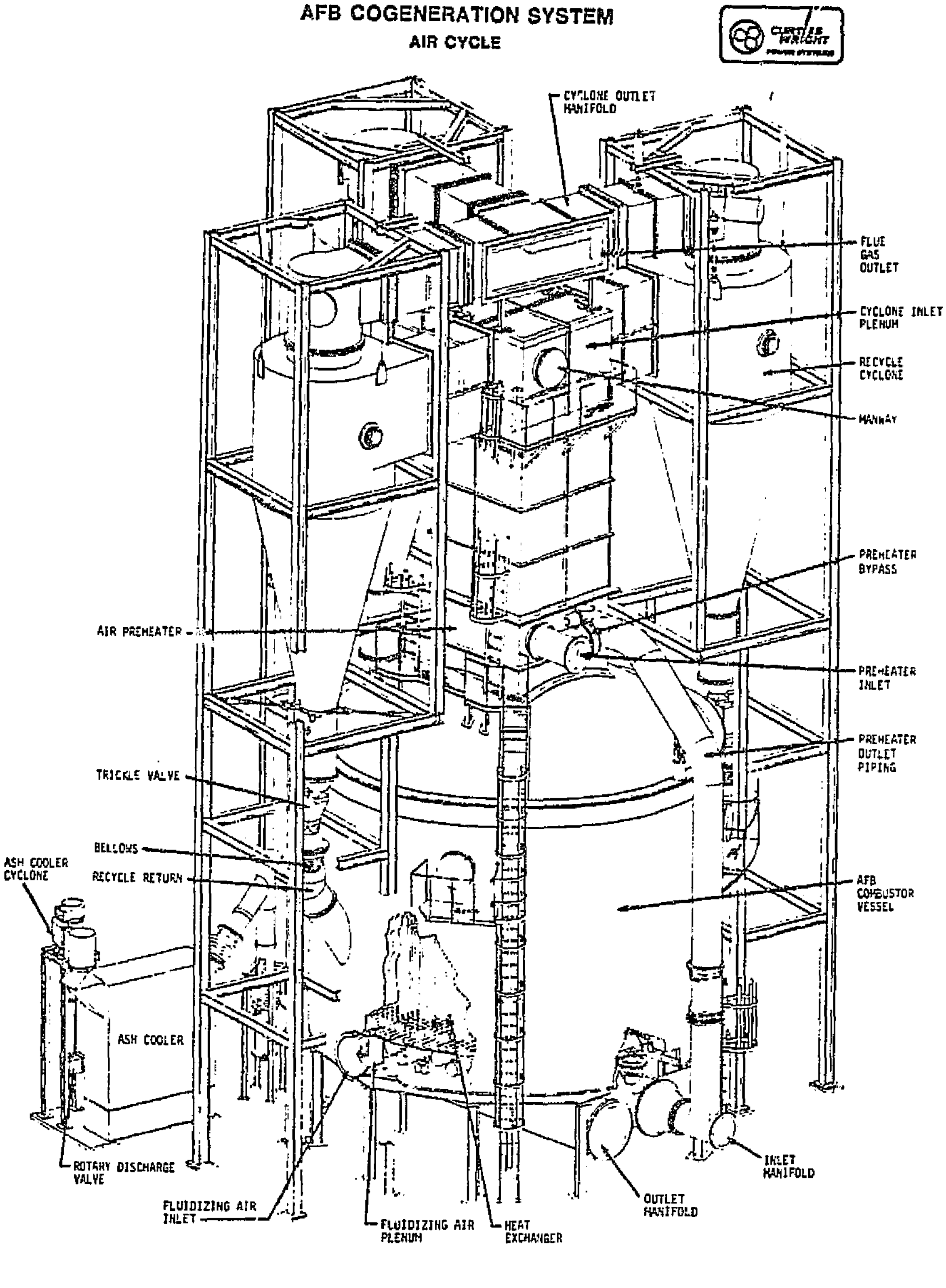

Figure 2-2

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AFB COGENERATION SYSTEM
AIR CYCLE
(SECTIONAL VIEW)

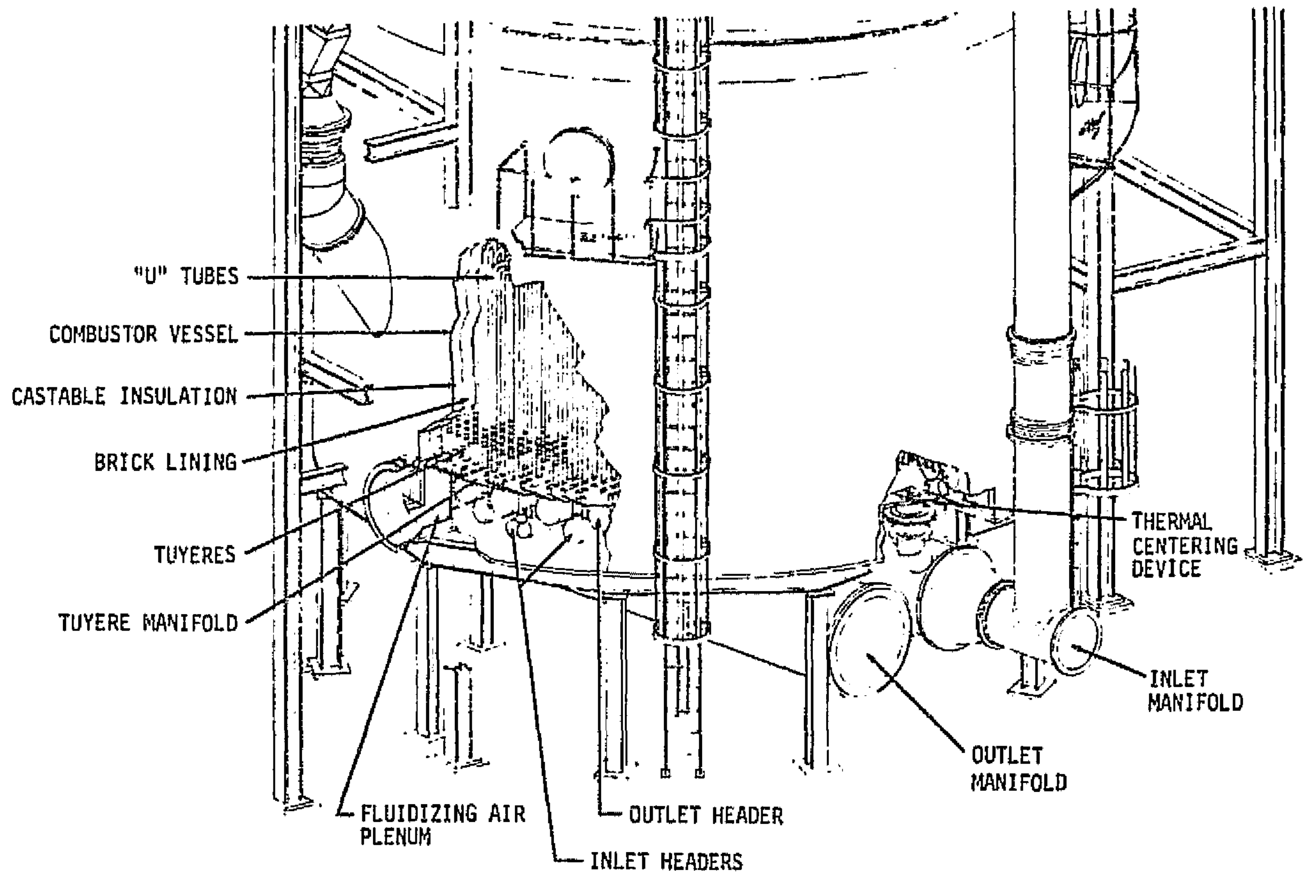

Figure 2-3

The gas turbine technology for this study encompasses several items of interest as noted in Table 2-1.

1) With clean compressed air, the turbine inlet air environment is benign. This is beneficial to gas turbine operation and life. The clean hot air discharge from the turbine can have specialized process uses, such as, direct product heating or use in a hot air waste heat boiler.

2) By limiting the inbed combustion process to about 1,650°F, the turbine air inlet temperature does not exceed about 1,500°F.

3) With turbine inlet temperature in the range of 1,500°F it is practical to use existing gas turbines that are available from many manufacturers. No new technology is required.

Table 2-1

GAS TURBINE SYSTEM TECHNOLOGY

- Clean Air Turbine Cycle - Absence of Combustion Products
- Turbine Air Inlet Temperature of 1,500°F
- Off-the-Shelf Gas Turbine Available from Many Sources. Existing Commercially Available Units were Selected for this Study.

2.2 Basic System Description - AFB/Steam Turbine

The basic steam cycle system and its major components are shown schematically in Figure 2-4. The system resembles a typical coal-fired boiler cogeneration system, with the boiler in this case being a fluidized bed type boiler. Several variations in fluidized bed boiler design are available, depending on manufacturer, capacity and type of fluidized bed design. The type described here was used for the conceptual design.

The forced draft air fan provides fluidizing air which has been preheated in the air preheater to the boiler. The Keeler/Dorr-Oliver design utilizes a sparge pipe air distributor to the fluid bed of the boiler. The sparge and other fluidized bed boiler design elements have been patented by Keeler/Dorr-Oliver.

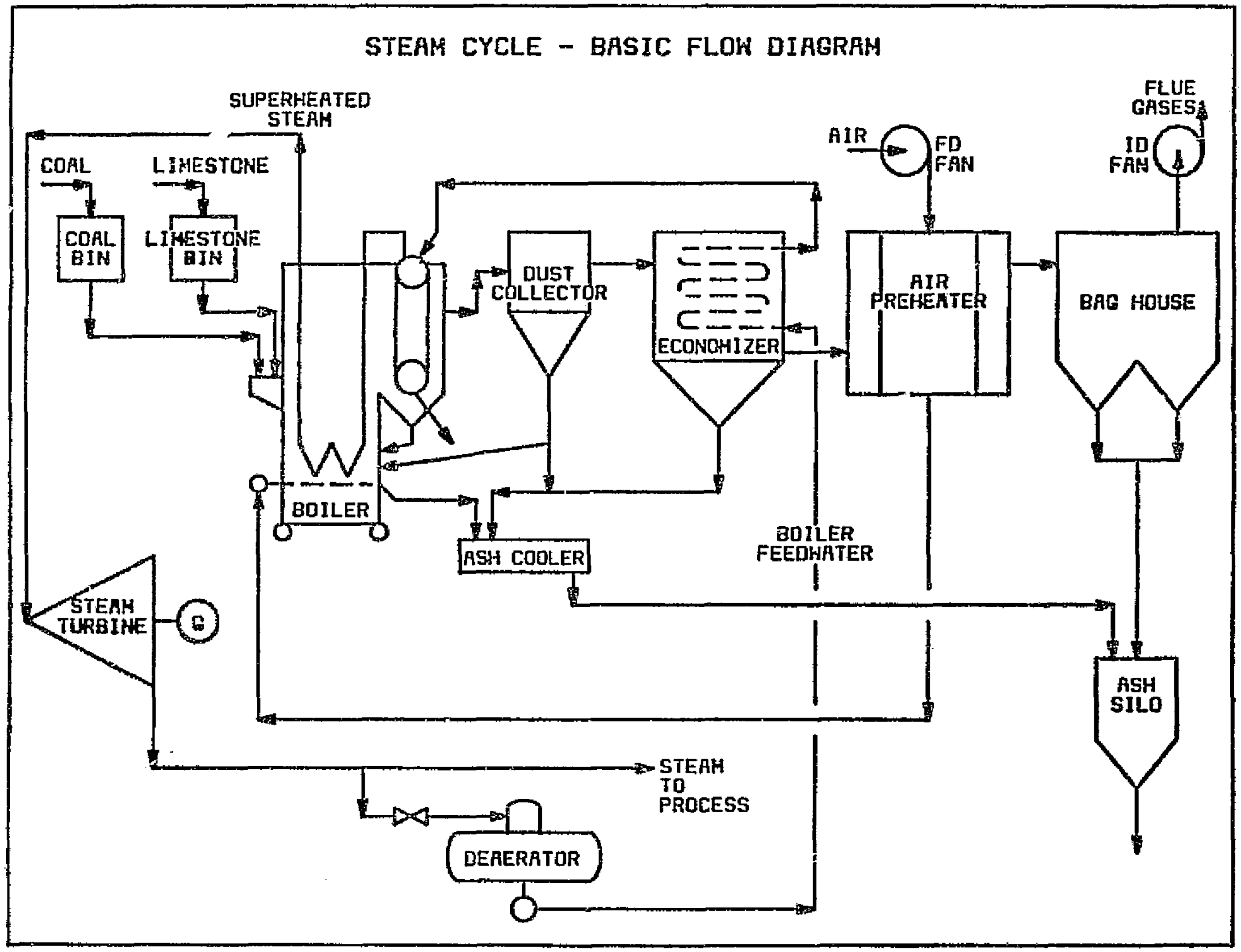
STEAM CYCLE - BASIC FLOW DIAGRAM
SUPERHEATED STEAM
COAL
LIMESTONE
COAL BIN
LIMESTONE BIN
BOILER
DUST COLLECTOR
ECONOMIZER
AIR
FD FAN
AIR PREHEATER
FLUE GASES
ID FAN
BAG HOUSE
ASH COOLER
BOILER FEEDWATER
STEAM TURBINE
G
ASH SILO
STEAM TO PROCESS
DEAERATOR

Figure 2-4

The steam and water drums have been arranged in cross drums providing for a long boiler front wall which can accommodate more than one spreader stoker for overbed feeding of the coal and limestone sorbent. Vertical inbed steam generating tubes provide the bed segmentation between the firing aisles required for the spreaders. The superheater tube banks are also vertical inbed tubes which are supported by the water-cooled, forced circulation generating tubes. This superheater arrangement is expected to result in a virtually flat superheater steam temperature curve with respect to turndown.

Ash withdrawal is accomplished with a set of screw conveyors mounted directly underneath the bottom supply headers running across the width of the fluidized bed. This approach will reduce the discharge temperature of the bottom ash to a level 100-200°F above the saturation temperature of the steam in the boiler generating tubes.

The AFB boiler design is given in further detail in Appendix Section 1.

Chapter 3

STUDY APPROACH AND METHODOLOGY

The primary effort of the study was to compare, based on site-specific designs, the potential benefits of the AFB/gas turbine cogeneration system with an AFB/steam turbine system and also related to a non-cogeneration plant. An additional important goal was to estimate the potential national benefits which could be obtained through implementation of AFB/gas turbine systems in industrial cogeneration.

3.1 Technical Approach to Study

3.1.1 Task 1 - Plant Screening

A. Existing Plants

This task first involved the screening of four industrial plant sites by defining the requirements of these plants to a level of detail which permitted a preliminary assessment of the AFB/gas turbine cogeneration system as compared to an AFB/steam turbine system. Both of these systems were compared to the industrial plant operating in its current mode. The industrial sites evaluated in the study were:

(1) Ethyl Corporation - Pasadena, Texas
(2) Riegel Products Corporation - Milford, New Jersey
(3) Georgia-Pacific Corporation - Lovell, Wyoming
(4) Hercules Incorporated - Covington, Virginia

The primary sites were selected to provide a broad range of characteristics which directly affect the technical and economic success of AFB/gas turbine cogeneration systems, two of the plant sites were found not to provide good comparative cogeneration plant designs. The Georgia-Pacific plant is very amenable to AFB/gas turbine cogeneration because of the need for electricity and hot process air. A steam cogeneration system could not effectively compete because of the need for a complicated steam-to-air heating system. The Hercules plant has a large electrical need but only small seasonally cyclic steam requirements. Accordingly, at this point, work was terminated for these two plants. Data developed for these plants is given in Appendix Section 3. A full comparative analysis was performed on the other two plant sites - Ethyl and Riegel. The actual plant operating data was gathered during site visits by the Catalytic study team, with the cooperation of plant personnel furnishing the raw data. The actual operating data was adjusted to reflect 1985 projected loads. The approach to performance of the cogeneration systems included the following procedure:

The existing plant average and peak energy requirements were established. Cogeneration plants based on both the AFB/gas turbine and AFB/steam turbine cycles were sized for average plant steam requirements, including establishing new powerhouse auxiliary steam and electric loads. Site specific operating and maintenance costs were developed.

B. Capital Costs

Capital investments were developed for the various plant designs first by having delivered and erected costs developed by Curtiss-Wright and Keeler/Door-Oliver for their scope of equipment supply for the cogeneration plants. Then preliminary quotations were obtained by Catalytic for many other items of power plant equipment. Catalytic then developed capital costs for the remaining plant systems to provide a complete system. The desire was to make the capital costs site specific, even for the plant screening phase. A major cost element was providing multiple unit plants in order to realistically account for actual plant design practices. Further, total capital investment was used for evaluation, which included a conservative interest charge during design engineering and construction. This typically added an additional 1/3 of the total capital costs to the estimate.

In order to provide more representative cogeneration plant designs for comparative purposes, a new full steam capacity cogeneration plant was developed including new conventional low pressure oil/gas fired boilers providing backup steam. Thus, a complete new facility was designed for each cogeneration system. Also, for comparison, a new non-cogeneration "all-new" base case using low steam pressure oil/gas fired conventional boilers was designed. Capital costs, performance and other comparisons are based on this "all-new" complete power plant concept to provide better comparisons in selecting a "best" plant which formed the basis for the conceptual design.

C. Performance and Benefits Analyses

Economics and operational performance parameters were used to judge the feasibility and make comparisons of the various plant designs. The primary analytic tools for quantifying economic factors are rate of return analysis, including total capital costs and depreciation using the provisions of the 1981 ERA tax law, and levelized annual costs to account for costs escalating above the general rate of inflation. The primary method used to compare like parameters is graphically with bar charts. As an example, Figure 4-11 summarizes the comparative performance parameters for the Task 1 plant screening effort for the Ethyl and Riegel plant sites. In addition to the quantifiable parameters just discussed, qualitative institutional and other non-technical barriers were also identified and assessed as part of the evaluation and comparison effort.

D. Industry Analysis

An analysis was performed of the energy requirements of industry in general to estimate the portion of industry having requirements similar to the two plants being studies. Chapter 4 shows the results of this analysis. The representativeness of the Ethyl and Riegel plant sites was considered in the selection of "best" plant.

E. Selection of "Best" Plant

The various cost, operating, performance, and institutional factors obtained were considered in the selection of the plant site for which conceptual designs were to be prepared. The Ethyl plant site was selected.

3.1.2 Task 2 - Conceptual Designs

A. Existing Plant

The conceptual design for the "best" plant includes analysis of the effect of plant availability and part load performance. Also accounted for is the effect of preferentially burning waste fuel in the existing boilers.

Regulatory requirements are numerous and several important items had to be addressed. Table 3-1 points out the most important of the regulatory requirements considered for the conceptual designs. Although the plant site is in a non-attainment area regarding particulates, no special design was incorporated into the conceptual design other than meeting the Federal NSPS regulations for boilers. Both AFB combustor designs were assumed to be treated by regulatory agencies as boilers regarding any emission regulations, since standards for indirect fired gas turbines have not been proposed.

Table 3-1

REGULATORY REQUIREMENTS - ETHYL PLANT

AIR	o	Plant Is in Non-Attainment Area (Particulates)
	o	Texas and Federal Regulations (NSPS for Boilers)
WATER	o	Zero Discharge
SOLID WASTE	o	Off-Site Landfill. (Non-Hazardous Material)
SITING	o	Located in Heavy Industrial Area
PERMITS	o	Extensive Permitting Requirements and Procedures.
	o	6 Months to 3 Years Required.
	o	Extensive Pre-Engineering for Permit Applications.

Cogeneration plant water discharge is felt to be readily accommodated by the existing chemical plant waste water treatment. Boiler blowdown is the main steady cogeneration plant discharge. A large quantity of water discharge will come from new water treatment equipment backwash, particularly the demineralizer for the AFB boiler system. Again, this is assumed able to be handled by existing waste water treatment. Covered coal storage essentially eliminates runoff waste water in this area.

With the chemical plant covering a large site and located in a very large, heavily industrial area, local siting restrictions are not probable. Still, obtaining the numerous regulatory permits is time consuming and would require extensive pre-engineering for the permit applications. This permit application time and design effort is considered in the interest charges and adds to the total plant cost. For example, increasing total time for design and construction from four to five years increases total plant cost about 6.5 percent.

B. Capital Costs

As for the plant screening phase, capital cost estimates were based on subcontractor estimates for the AFB/gas turbine and AFB boiler equipment, quotations from equipment manufacturers for other major equipment and Catalytic development of remaining areas of the plant. Capital costs are based on current (1981) dollars.

The conceptual design for each cogeneration system accounts for the fact that these are to be retrofitted into an existing plant. Accordingly, the non-cogeneration base case involves operation of the existing boilers with no capital cost involved. The cogeneration systems for both the AFB/gas turbine and AFB/steam turbine technologies include the effect of the existing boilerhouse remaining. This approach is different from that employed for Task-1 site screening and described in Section 3.1.1.B which used a completely new full size plant including the non-cogeneration base case.

The capital costs were weighed against the projected savings in energy costs over the assumed life of the plant since costs and benefits occur over time.

3.1.3 Task 3 - Market Analysis

A market analysis was performed to assess the potential industrial cogeneration market for coal-fired atmospheric fluidized combustors using gas turbine and steam turbine systems. This is further discussed in Chapter 7. A "bottoms-up" approach was performed by General Energy Associates using plant specific data base to have the market assessment made at the plant site level. These results were used to develop the potential market and national benefits. Capital costs, operaring costs and performance characteristics of the cogeneration systems were developed by Catalytic as input algorithms for the market model. The economic model parameters developed are given in Table 3-2. The performance characteristics developed for market analysis for both AFB systems are presented in Figures 3-1 and 3-2. The AFB/gas turbine was calculated for different values of performance between the ranges noted by the dotted line, and the system with the highest return on investment was selected.

Table 3-2

ECONOMIC MODEL PARAMETERS

- AFB/GT CO-GEN. PLANT CAPITAL COST

  $$\$MILLION = 16 \left(\frac{F,\ PPH}{100{,}000}\right)^{.846} \times \left(\frac{P,\ PSIG}{900}\right)^{.125} + 2.9\ (G,\ MW)^{.8}$$

  TOTAL CAPITAL INVESTMENT IS 1.37 x CAPITAL COST.

- AFB/ST CO-GEN. PLANT CAPITAL COST

  $$\$MILLION = 12.5 \left(\frac{F,\ PPH}{100{,}000}\right)^{.846} \times \left(\frac{P,\ PSIG}{900}\right)^{.125} + 2.3\ (G,\ MW)^{.67}$$

  TOTAL CAPITAL INVESTMENT IS 1.37 x CAPITAL COST

- ZERO CAPITAL COST FOR NO. COGEN. CASE.

- ANNUAL O&M COST (AS PERCENT OF TOTAL CAPITAL INVESTMENT)

  AFB/GT - 8

  AFB/ST - 14

- 15 YEAR EQUIPMENT LIFE.

- 1981 ERA DEPRECIATION METHOD.

- 1988 INITIAL OPERATION.

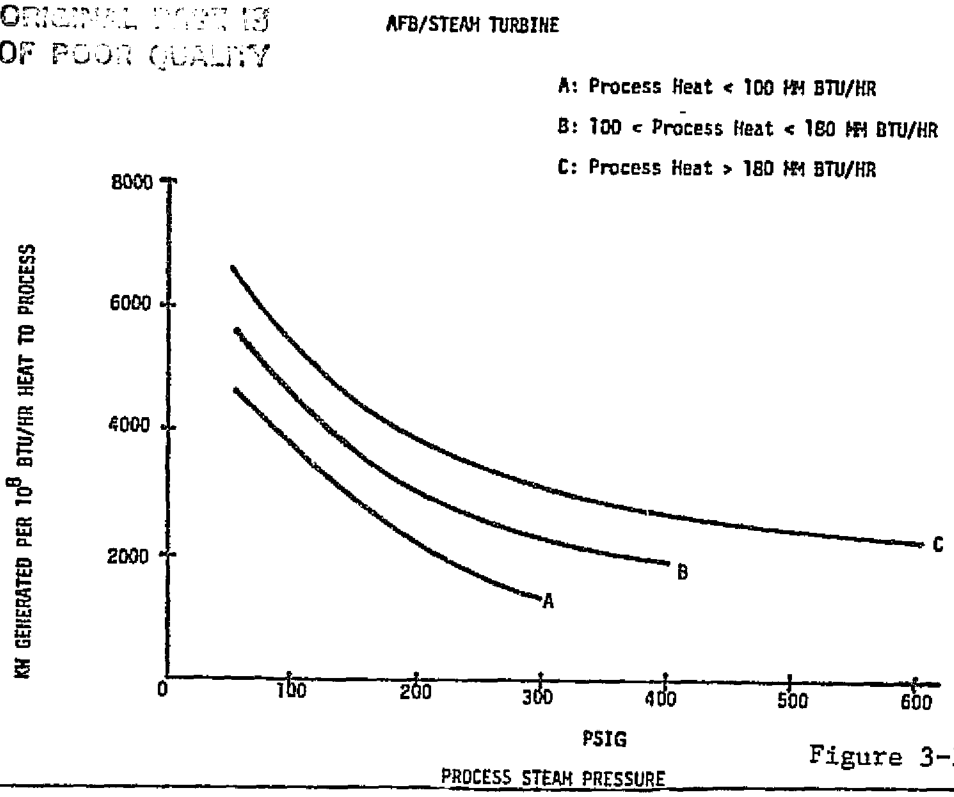

Figure 3-1

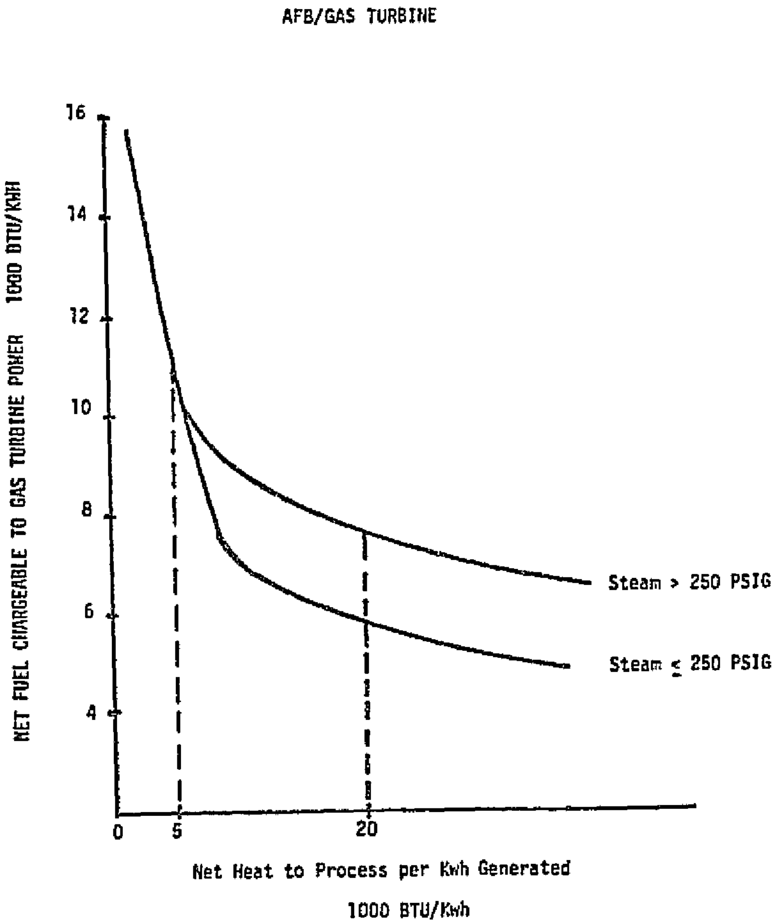

Figure 3-2

3.2 AFB/Gas Turbine Configurations

In considering specific designs for air cycle systems, state-of-the-art technology and current fluid bed design practice was employed. This reduces developmental tasks and produces an achievable design, thus giving credibility. Atmospheric bed temperature was constrained to 1,650°F maximum, based on existing experience in fluid beds and on maintaining good sulfur capture. Turbine inlet temperatures are maintained at about 1,500°F, constrained by the bed temperature and by stresses in the metal heat exchanger tubing and headers. Design point fluidizing velocities are maintained between 3.0 and 4.5 feet per second. Bed depth varies from 6.5 to 8.0 feet. Excess air is maintained at 30 to 40%. Only current commercially available gas turbines which have been configured for external combustors were considered. Only gas turbine pressure ratios of less than 10 have been considered, both because there is no significant performance advantage to the higher cost, high pressure ratio machines and because lower pressures produce lower AFB combustor tube stresses. The result is that, by current standards, the AFB/gas turbine system is designed cost effectively.

There are numerous commercially available gas turbines manufactured by different companies suitable for use with the air cycle AFB. Flow and pressure ratios of standard gas turbines can be changed to match the AFB requirements with the output being somewhat less than normal due to the 1,500°F turbine inlet temperature.

The coal-fired atmospheric fluidized bed combustor is typically sized to provide all of the gas turbine air heating. A flue gas to clean air preheater is sometimes provided to reduce the combustor size and to meet a required electrical output. An air preheater for the fluidizing air may be desirable to extract the maximum energy from the flue gases before they exit to atmosphere.

The AFB/gas turbine cogeneration System Site Applications (Figure 3-3) summarize process heat uses for variations in the basic cycle configuration adapted to the sites studied. This presents the options used for tailoring the configuration to the requirements of a specific site.

3.3 Cogeneration System Strategy

3.3.1 Heat Match, Electric Match

Two types of cogeneration systems are studied for each site - AFB/gas turbine and AFB/steam turbine. The two systems which are being compared for each site need not utilize the same options and strategies. Figure 3-4 shows the atmospheric fluidized bed combustor auxiliaries cycle selection logic diagram. Clearly shown are the

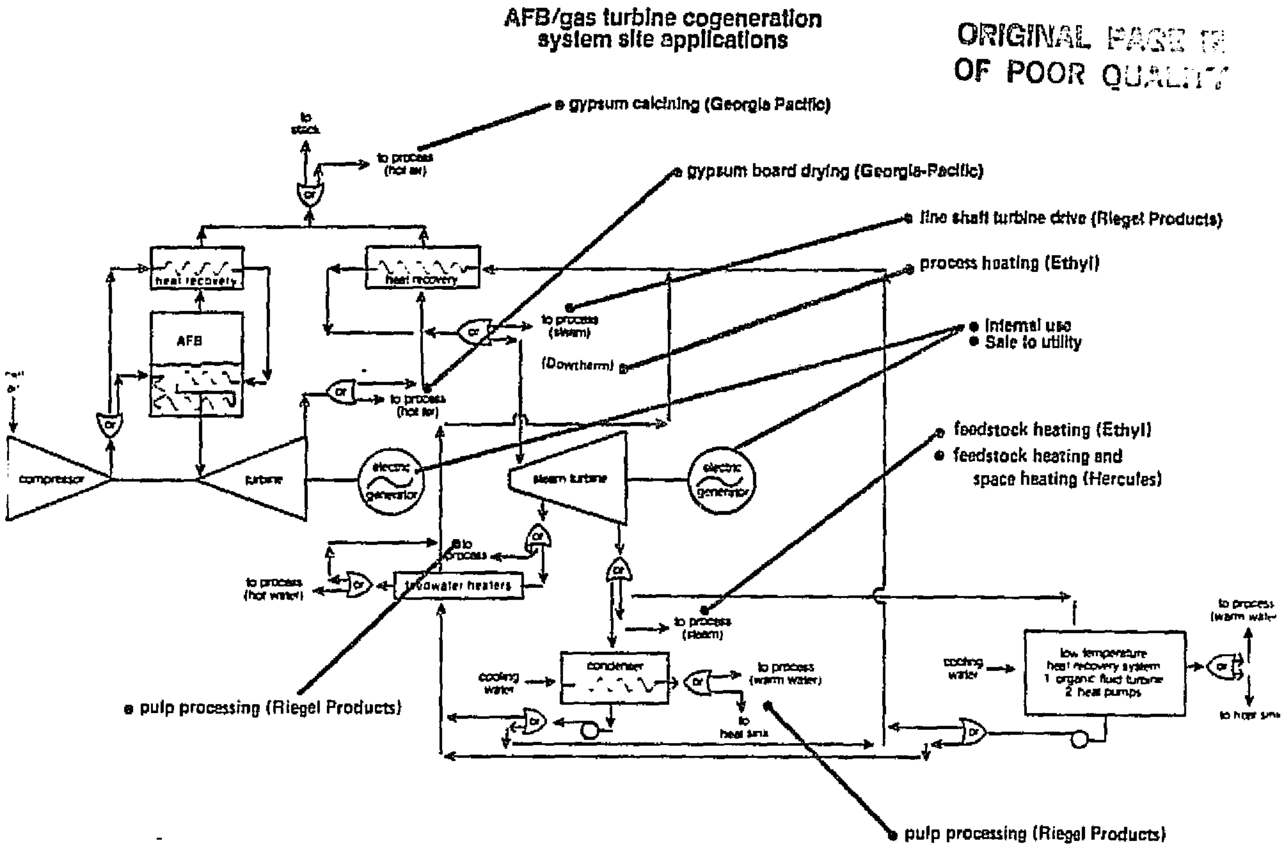

Figure 3-3

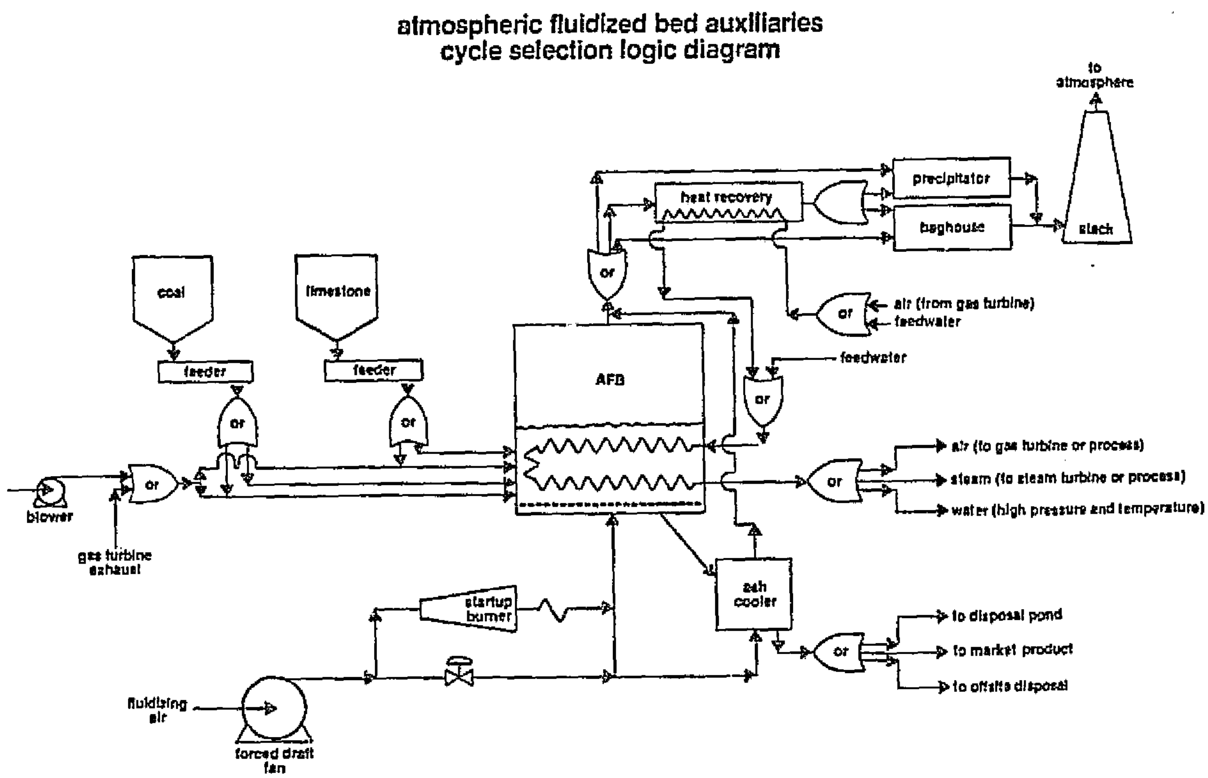

Figure 3-4

number of alternatives available for each component, just for the AFB combustor. Figures 3-5 and 3-6 show alternatives available for AFB/gas turbine and AFB/steam turbine cycle selections, respectively.

Two basic system strategies are available for a cogeneration cycle analysis:

- o Provide the thermal requirement of the plant with any excess electricity sold or deficit of electricity purchased.

- o Provide the total plant electrical need with excess thermal energy wasted or any deficiency provided by oil/gas fuel.

After discussions with plant personnel, the decision was made to concentrate on providing thermal requirements for the plant from the AFB combustors. The following reasoning applied:

- o Rejection of excess useful thermal energy, except through a condensing type steam turbine, is felt to be wasteful and unacceptable to the plants.

- o Provision of thermal energy is the most important function of a boilerhouse, since electricity can be readily purchased. Purchasing steam is not considered viable for most of the plants studied, nor is it considered representative of industry as a whole.

- o If considerable capital is to be spent for a new cogeneration facility, providing adequate thermal energy via the new coal burning equipment appears desirable.

3.3.2 Energy Forms

The dollar value of the form of energy was considered in this study. Tradeoffs were made to provide energy in its most valuable form. For example, should energy best be provided optimally as steam, electricity, or other forms of heat?

3.3.3 Steam Pressures

The current practice of industrial power plant steam turbine throttle pressures is in a range of about 600 to 1,450 psig. There are many possible industrial steam turbine generator configurations. Steam can be expanded into a subatmospheric condenser or exhaust directly into process steam headers. Steam turbines can also be

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AFB/gas turbine cogeneration system
cycle selection logic diagram

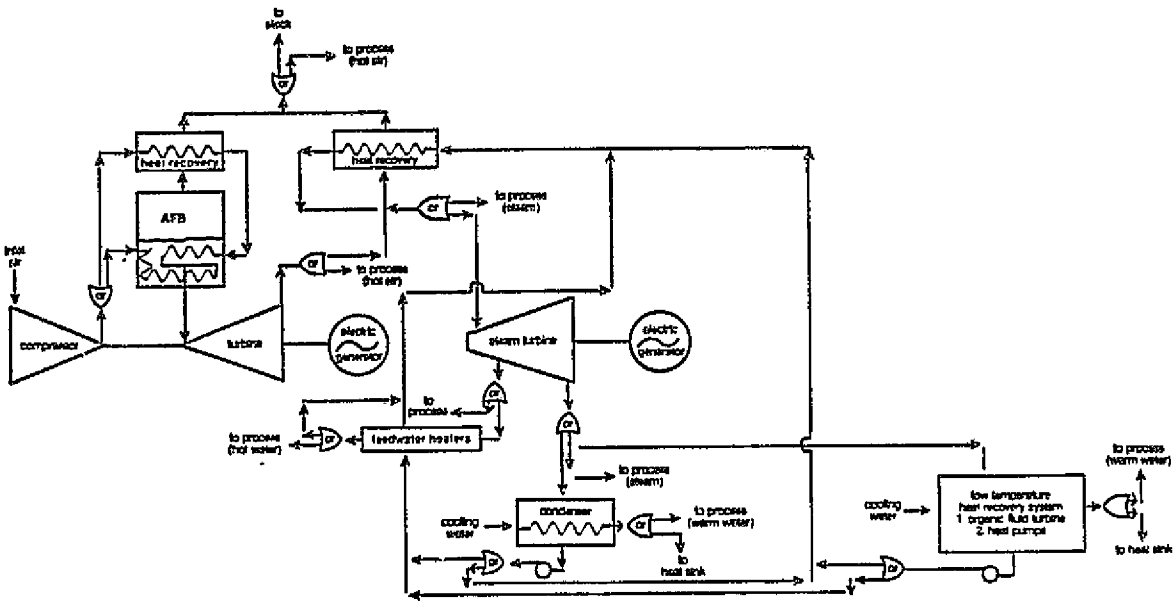


Figure 3-5

AFB/STEAM TURBINE COGENERATION SYSTEM

CYCLE SELECTION LOGIC DIAGRAM

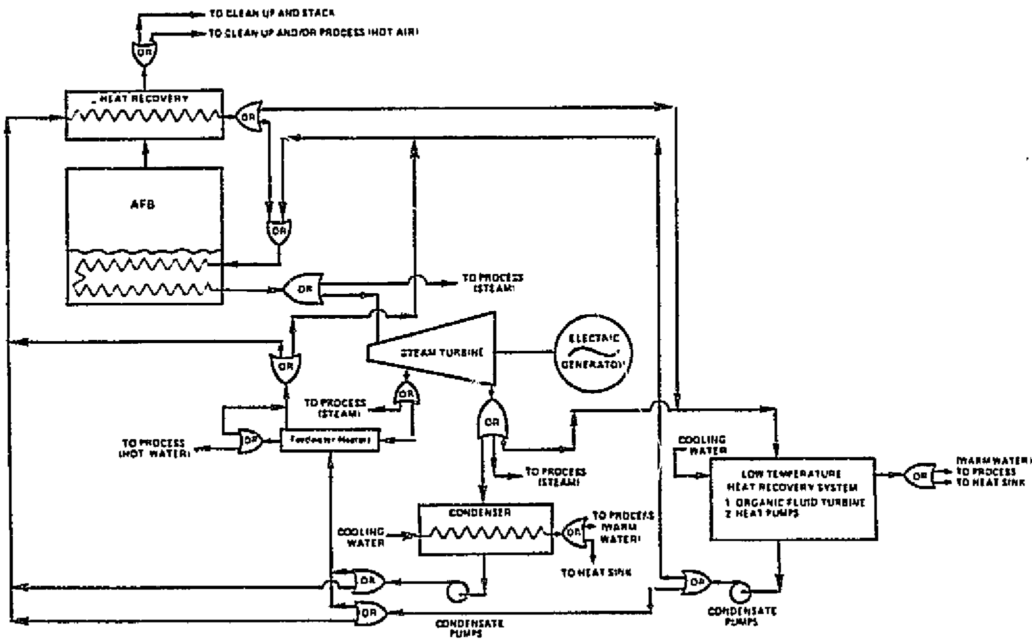


Figure 3-6

straight noncondensing, straight condensing, or include one, two or even three automatically controlled extraction openings. Extraction pressures can be over a range of 600 psig down to 5 psig.

The energy range of the steam in the turbine from throttle to exhaust is a significant factor in the net power generated. A rule of thumb used for this study is selecting the throttle pressure at least twice as high as the highest extraction pressure in order to maintain a practical energy drop range.

A closed feedwater heater, when used in addition to the deaerating heater, raises final feedwater temperature and increases the amount of byproduct power which can be generated from a fixed amount of process flow.

3.3.4 Overall System Strategy

A. Gas Turbine Cycle

The interplay between Catalytic and its equipment subcontractors, Curtiss-Wright and Keeler/Dorr-Oliver, for equipment sizing and selection is very similar to that mostly employed for design projects. System sizing and component selection for the AFB/gas turbine cogeneration cycles were primarily performed by Curtiss-Wright. Basic plant thermal and electric requirements were given to Curtiss-Wright by Catalytic. Curtiss-Wright then selected the gas turbine cogeneration cycle considering the numerous factors involved in the sizing of a coal-fired combustor and a specific gas turbine (as previously described under "Heat Match, Electric Match"). Catalytic reviewed and sometimes modified the thermal heat output to reflect more nearly desired equipment configurations. Curtiss-Wright selected the gas turbine size and configuration most applicable for the system.

B. Steam Turbine Cycle

System sizing for the AFB/steam turbine cogeneration cycle was performed by Catalytic. AFB boiler steam output and steam conditions were given to Keeler/Dorr-Oliver, who sized the AFB boiler and associated equipment. Catalytic selected the AFB boiler size and condition most applicable for the system. The selection of the AFB boiler operating system pressure and temperature not only affects the AFB boiler but also the steam turbine-generator. The steam turbine-generator selection is governed by the operating pressure range of the steam and selection of extraction points. Currently available steam turbine designs from several manufacturers are satisfactory for the conditions which were selected in the study.

The AFB boiler designs were prepared by Keeler/Dorr-Oliver. The AFB boilers are adaptations of current conventional coal fired boiler designs, combined with extrapolation/adaptations of commercial AFB combustors.

Because the AFB combustors for the air and steam cycles heat different working mediums (air versus water/steam), the fluidized bed designs are different in many respects. Table 3-3 compares major parameters for the two AFB combustors.

3.4 Economic Analysis

The detailed defined methodology for the economic analysis is given in Appendix Section 2.

To establish the economic benefits of cogeneration, the capital costs must be weighed against the projected savings in energy costs. The performance of each cogeneration system is analyzed over the life of a plant, since the costs and benefits occur over time.

The rate of return and the annualized energy costs are primary economic evaluation factors. The discounted cash flow analysis method is used, and serves as a measure of economic performance and criterion for decision making.

It is desirable to evaluate the stream of costs and benefits in the present, since the costs and benefits occur over time. Economic evaluation of annual costs includes calculation of levelized costs. Levelized costs are annual costs which have the same present worth of actual costs which may vary annually due to escalation.

Table 3-3

AFB COMBUSTOR PARAMETERS

	ST CYCLE	GT CYCLE
o BED HEIGHT	4 FT.	5-7 FT.
o FREEBOARD HEIGHT	8 FT.	12 FT.
o REINJECTION	FROM BOILER HOPPERS	FROM RECYCLE CYCLONES
o HEAT TRANSFER RATES IN FLUID BED	50-70 $\frac{BTU}{HR.-^{o}F-FT.^{2}}$	50 $\frac{BTU}{HR.-^{o}F-FT.^{2}}$
o COAL AND LIMESTONE FEED	STOKER/OVERBED	PNEUMATIC/ UNDERBED
o TUBE MATERIAL	STANDARD BOILER TYPE CARBON STEEL	300 SERIES STAINLESS STEEL
o TUBE ARRANGEMENT	VERTICAL/PARTLY SUBMERGED	VERTICAL/TOTALLY SUBMERGED
o BED TEMPERATURE	1,600°F	1,650°F
o WORKING FLUID		
o MEDIUM	WATER/STEAM	AIR
o PRESSURE/TEMPERATURE	650 PSIG/750°F	100 PSIG/1,500°F
o CIRCULATION	NATURAL	FORCED

Chapter 4

SITES

4.1 Site Selection

Four actual industrial plant sites were studied to determine their energy requirements. The plants are well dispersed geographically. Refer to Figure 4-1 for plant locations.

The plants represent a diversity of energy requirements and a broad range of characteristics. A summary of the energy requirements is shown in Table 4-1.

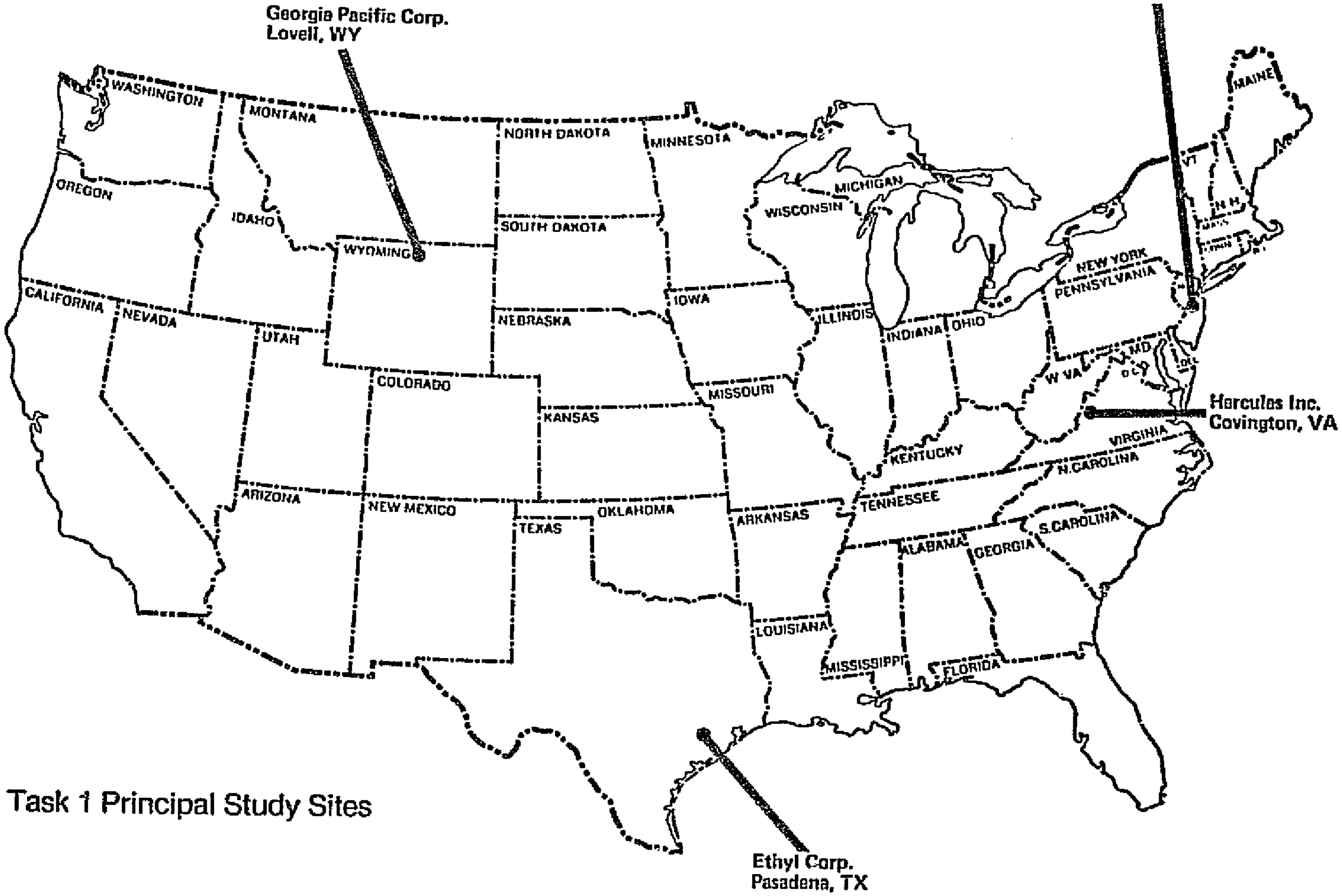
Two of the sites, Hercules and Georgia Pacific, were eliminated because they did not provide good comparative cogeneration plant designs. A brief description of the current mode of utilizing energy at the two sites that were evaluated for selection of the "best" site readily shows the diversity of the sites.

- Ethyl - This chemical plant has a critical minimum steam requirement for process safety reasons, widely and frequently varying steam needs due to plant batch type processes, and a Dowtherm heating load. Electrical use is quite steady, and the plant operates continually. Waste fuel oil is produced by the process and burned in the boilers. A simplified area layout of the Ethyl plant site energy facilities is shown in Figure 4-2.

- Riegel - This specialty paper plant cogenerates electricity, steam, hot water and mechanical power, using mechanical drive, backpressure and extraction/condensing turbines. Process waste paper is burned in the boilers. Waste heat from a gas turbine (on-site, owned by others) is also utilized to generate steam. A summary of the plant survey data is given in Table 4-2, and the summary of utility survey data is given in Table 4-3.

Site data for the plants, which were evaluated against each other to determine the "best" plant for conceptual designs, is shown in Tables 4-4, 4-5 and 4-6.

Plant characteristics relating to the cogeneration potential for these two plants is shown in Table 4-7. This is a preliminary comparison to see if cogeneration should be considered for the plant.



Task 1 Principal Study Sites

Figure 4-1

Table 4-1

SUMMARY OF SITE ENERGY REQUIREMENTS

SITE	HEAT FORM	E/T	TOTAL SYSTEM FUEL ENERGY 10^{12} BTU/YR	ELECTRIC DEMAND MW	HEAT DEMAND
Ethyl	Steam, Dowtherm	.36 steam .19 steam + Dowtherm	6.45 steam + Dowtherm	24	190,000 lbs/hr steam 170 MMBTU/hr Dowth.
Riegel	Steam, Hot Water	.31	1.82	20	160,000 lbs/hr
Georgia-Pacific	Hot Air	.08	.88	2	93 MMBTU/hr
Hercules	Steam	1.05	1.01	8.5	38,000 lbs/hr winter 18,000 lbs/hr summer

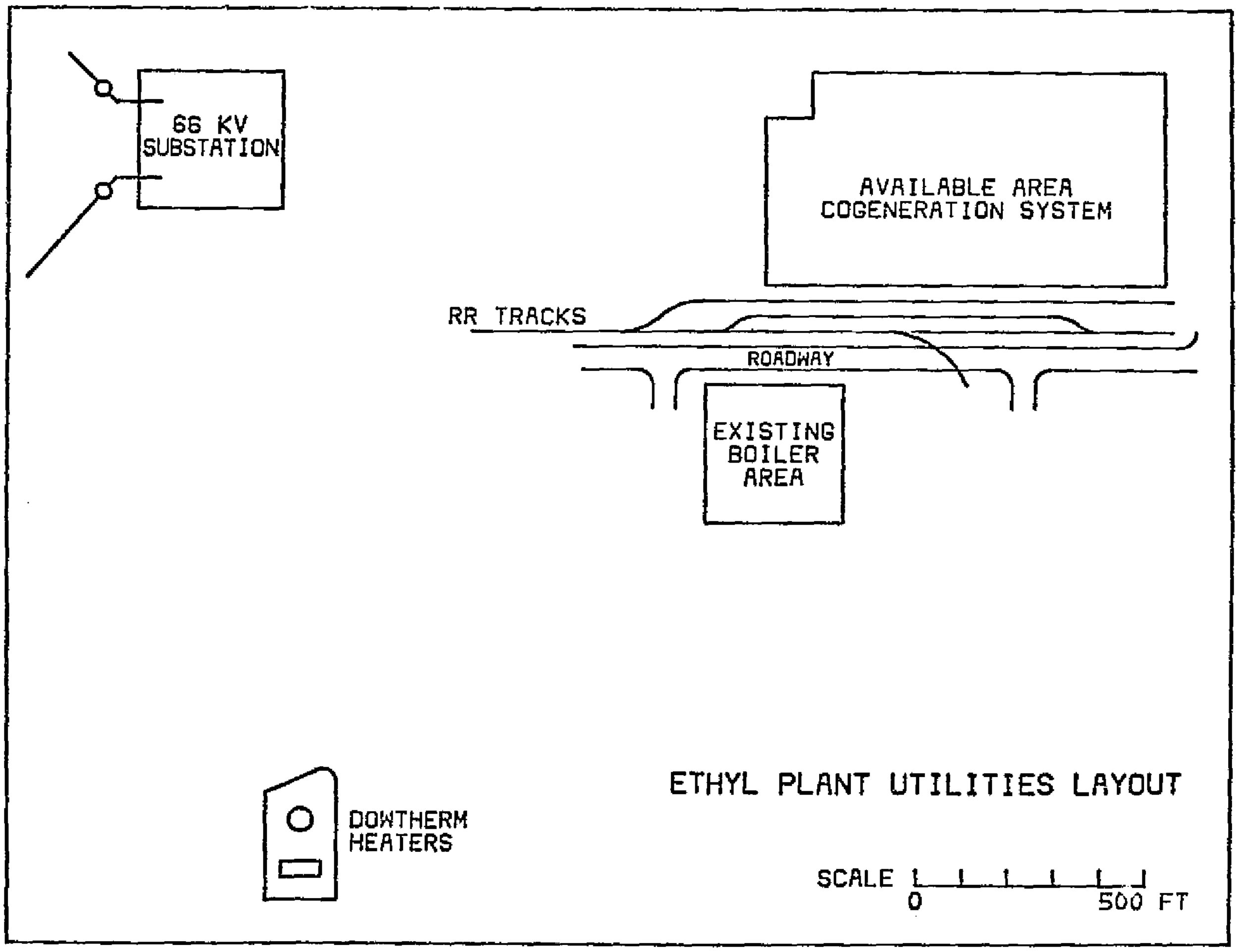


FIGURE 4-2

Table 4-2

PLANT SURVEY

RIEGEL PAPER PRODUCTS, INC. - MILFORD, NEW JERSEY

PRINCIPAL PRODUCT: SPECIALTY PAPER

SURVEY DATE: 30 SEPTEMBER 1981

PLANT AGE: 1940

OPERATING SCHEDULE: 5 DAYS/WEEK - 24 HOURS/DAY

ENERGY REQUIREMENTS:

	ELECTRIC	STEAM	FUEL
UTILITY:	13 MW (AVG) 19 MW (MAX)	100,000 LB/HR*	NATURAL GAS
IN-HOUSE:	6 MW (AVG) 9 MW (MAX)	220,000 LB/HR (MAX) (*75% AVAILABILITY)	RESIDUAL FUEL OIL

UTILITY: JERSEY CENTRAL POWER & LIGHT COMPANY (JCP&L)

COAL SUPPLY: ILLINOIS NO. 6 - HIGH SULFUR @ 12,500 BTU/LB HHV
AMAX COAL COMPANY; INDIANAPOLIS, INDIANA

SORBENT SUPPLY: DOLOMITE - ANL #6401
G&W CORSON, INC.; PLYMOUTH MEETING, PA

POTENTIAL FOR COAL CONVERSION: GOOD

RESTRICTIONS: EXISTING CONTRACT WITH JCP&L FOR COGENERATED STEAM (100,000 LB/HR) AND HOT GAS

E/T < 1

Table 4-3 UTILITY SURVEY

RIEGEL PAPER PRODUCTS, INC. - MILFORD, NEW JERSEY

UTILITY: JERSEY CENTRAL POWER & LIGHT COMPANY (JCP&L)

COGENERATION RATE SCHEDULE: NEGOTIATED; NON-RACHET

COGENERATION SALES RATE:

AVERAGE ON-PEAK	62 MILLS
AVERAGE OFF-PEAK	41 MILLS
STANDBY CHARGE	$3.00/KW/MONTH

PEAK SCHEDULE: 8 AM TO 8 PM, MONDAY THROUGH FRIDAY

UTILITY FUEL SUPPLY:

NUCLEAR	~35%	Approximately 45% Generation By Utility, Rest Is From Interchange
OIL	~30%	
NATURAL GAS/COAL	REMAINDER	

SUPPORT FINANCING: NOT LIKELY

UTILITY POSITION: ENCOURAGES LONG-TERM COGENERATION CONTRACTS
CURRENTLY INVOLVED IN 3-WAY COGENERATION CONTRACT
WITH RIEGEL AND ELIZABETHTOWN GAS COMPANY

Table 4-4

SITE DATA - GENERAL

NAME:	RIEGEL PRODUCTS CORPORATION	ETHYL CORPORATION
LOCATION:	MILFORD, NEW JERSEY	PASADENA, TEXAS
SIC(S):	261	286
PRODUCTS:	SPECIALTY - PAPERS	ZEOLITE, LINEAR OLEFINS, ETC.
CURRENT FUELS:	NATURAL GAS	NATURAL GAS
UTILITY:	JERSEY CENTRAL POWER & LIGHT	HOUSTON LIGHTING & POWER COMPANY
UTILITY FUELS:	33% COAL 19% NUCLEAR 48% OIL/GAS (55% OF GENERATION IS THRU INTERCHANGE)	80% NATURAL GAS 20% COAL

Table 4-5

SITE DATA - LOADS

NAME:	RIEGEL PRODUCTS CORPORATION	ETHYL CORPORATION
ELECTRICAL LOAD:	13 MW AVERAGE 19 MW PEAK	24 MW AVERAGE 29 MW PEAK
THERMAL LOAD:	160,000 #/HR. AVERAGE 220,000 #/HR. PEAK @ 400 PSIG, 150 PSIG, 75 PSIG, 25 PSIG	190,000 #/HR. AVERAGE 310,000 #/HR. PEAK @ 225 PSIG SATURATED 170,000,000 BTU/HR. DOW-THERM
LOAD VARIATION:	FAIRLY STEADY THERMAL LOADS, FAIRLY STEADY ELECTRICAL LOAD, 6192 HR./YR. OPERATION	VERY VARIABLE DAILY THERMAL LOADS, VERY FLAT ELECTRICAL LOAD 8760 HR./YR. OPERATION
POWER/HEAR RATIO:	.3	.36 WITHOUT DOW-THERM .19 WITH DOW-THERM
RELIABILITY:	NEED STEAM TO MAINTAIN MILL OPERATION	MUST MAINTAIN 100,000 #/HR. MINIMUM STEAM FLOW

Table 4-6

SITE DATA - ECONOMICS

(1985 PRICES EXPRESSED IN 1981 DOLLARS)

NAME	RIEGEL PRODUCTS CORPORATION	ETHYL CORPORATION
FUEL PRICES:		
NATURAL GAS	$5.33/MBTU	$5.80/MBTU
COAL	$1.87/MBTU	$2.04/MBTU
ELECTRICITY	*	5.24¢/KWH
STAND-BY POWER	$2.00/KW/MONTH	0
BUY BACK PRICE:		
ELECTRICITY	6.14¢/KWH	5.97¢/KWH
ESCALATION:		
NATURAL GAS	4%	3%
COAL	1%	1%
ELECTRICITY	1%	7%
STAND-BY	0	0
COST OF MONEY: (ABOVE INFLATION)	5%	15%
COST OF COMMON EQUITY:	19.2%	15%
PROJECT LIFE:	20 YEARS	15 YEARS

*VARIES WITH CYCLE USING a) BILLING DEMAND @ $6.66/KW/MONTH AND b) ENERGY CHARGE @ 5.09¢/KWH

Table 4-7

PLANT CHARACTERISTICS AND COGENERATION POTENTIAL

	RIEGEL	ETHYL
COAL COST, $/MM BTU (DELIVERED) LOW FUEL COST FAVORS COGENERATION	1.87	2.29
ELECTRIC COST, MILLS/KWH HIGH COST - PURCHASED OR SOLD - IS A DOMINANT FACTOR	66	46
OPERATING HOURS, HOURS/YR. CONTINUOUS PROCESS OPERATIONS ENHANCE A COGENERATION SYSTEM	6192	8760
AVERAGE ELECTRIC LOAD, MW HIGH LOADS ENHANCE COGENERATION POTENTIAL	13.2	24
STEAM REQUIREMENTS, LBS./HR. LARGER STEAM DEMANDS FAVOR COGENERATION ECONOMICS	220,000	310,000
PROCESS STEAM PRESSURE, PSIG LOWER PROCESS HEADER PRESSURES FAVOR COGENERATION FEASIBILITY	150	225
GAS/OIL COST, $/MM BTU HIGH COST FAVORS SWITCHING TO COAL	5.33	5.24

4.2 Representativeness

Among the factors considered in the selection of the "best" plant for conceptual design is "representativeness." This is covered in detail in Appendix Section 5. Representativeness is the determination of the degree to which the requirements of the plant being considered are representative of other plants in the same industry and/or other industries. General Energy Associates surveyed the plant characteristics of the 10,000 largest industrial plants in the United States. Figures 4-3 through 4-10 show the various plant characteristics for other industries and the location of the Ethyl and Riegel sites in the ranges shown.

These figures are for plants in the total manufacturing sector, excluding those in Standard Industrial Codes (SIC) 26, 28, 32 and 33. SIC 26 is the pulp and paper industry to which the Riegel plant belongs. SIC 28 covers chemicals, which includes the Ethyl plant. SIC 32 is the stone, clay and glass industry, excluded because these plants are not major steam consumers. SIC 33 is the primary metals industry, which is excluded because it is not a representative industry because plants in this code tend to be large cogenerators and heavily use their own waste fuel.

Four of the figures show a Total Number of Plants plotted against:

(a) Plant Power/Heat - Figure 4-3
(b) Plant Power Demand (MW) - Figure 4-5
(c) Plant Steam Demand (lbs/hr) - Figure 4-7
(d) Electric Cost ($/KWH) - Figure 4-9

Two of the figures show Total Plant Power Demand plotted against:

(a) Plant Power/Heat - Figure 4-4
(b) Plant Power Demand (MW) - Figure 4-6

Figure 4-8 shows Total Plant Steam Demand versus Plant Steam Demand.

Figure 4-10 shows Total Plant Power Demand versus Electric Cost.

The result of this effort shows that the Ethyl and Riegel plants are representative of plants both in their respective industries and in other industries.

Industrial Manufacturing Sector
Excluding SIC 26, 28, 32, 33

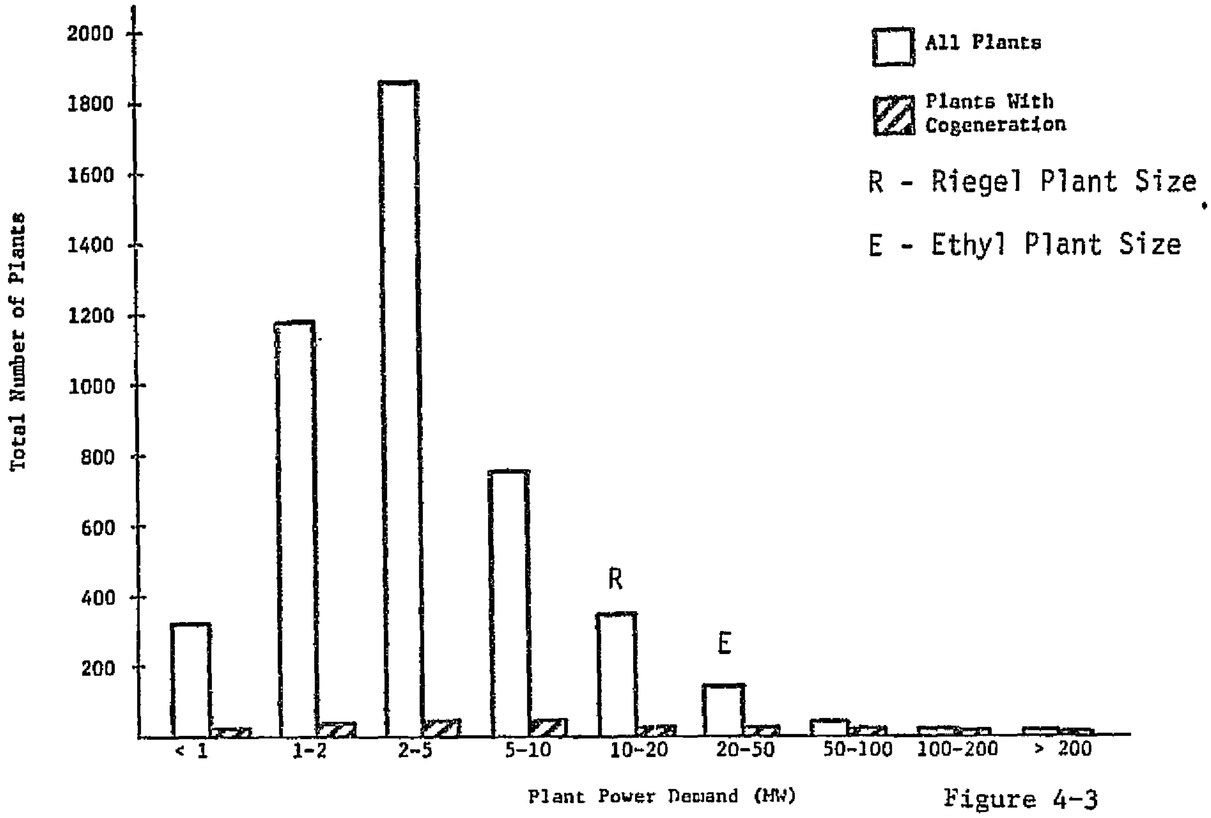


Figure 4-3

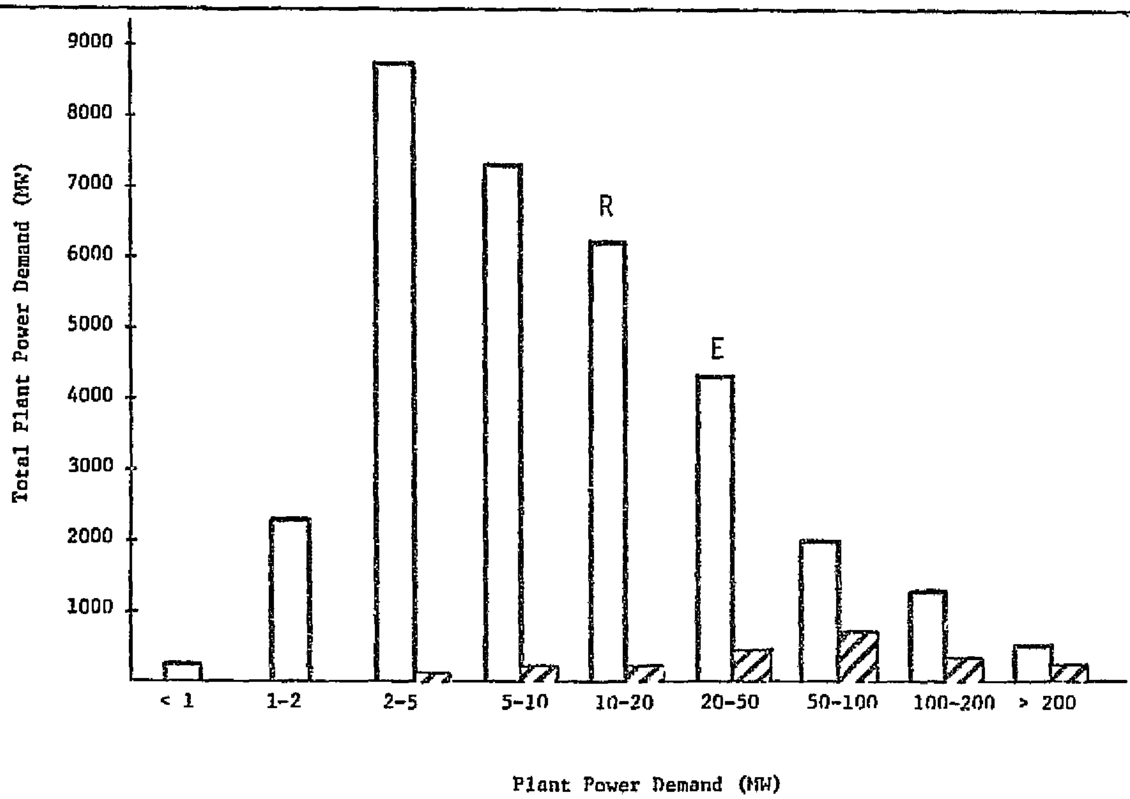


Figure 4-4

Industrial Manufacturing Sector
Excluding SIC 26, 28, 32, 33

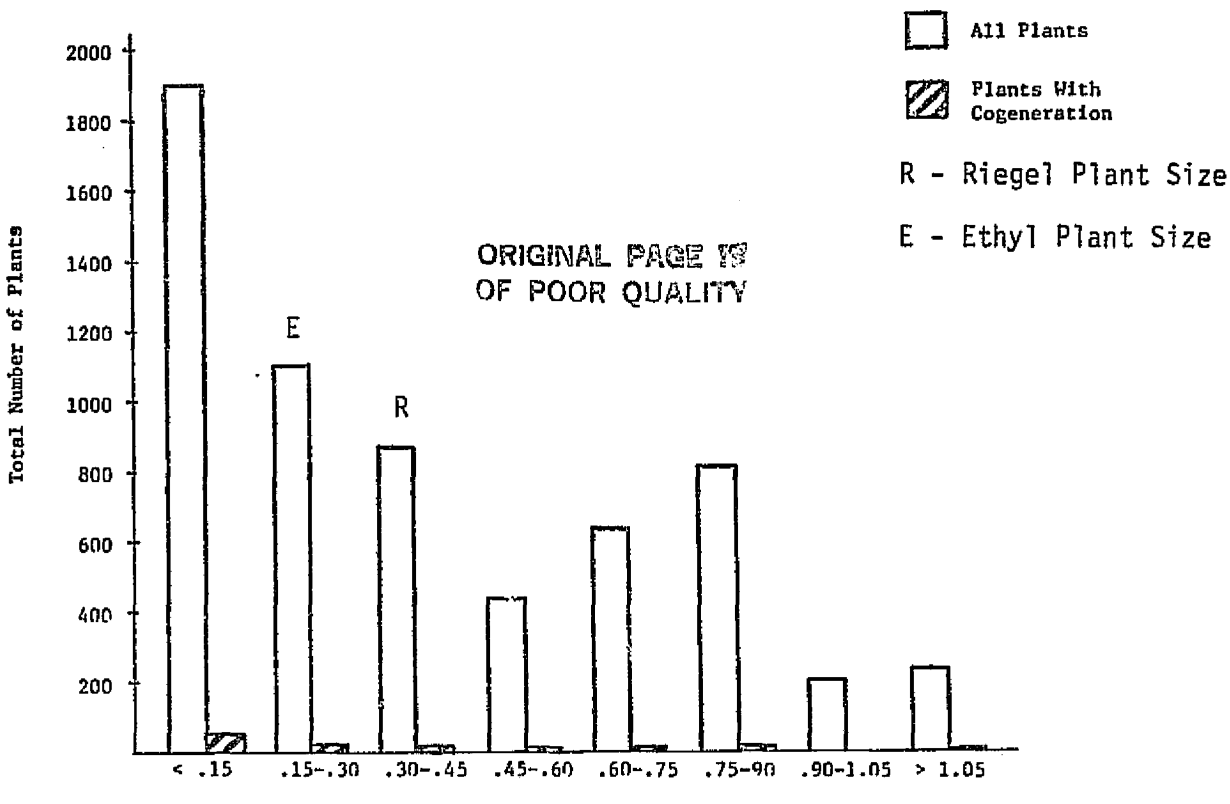


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Figure 4-5

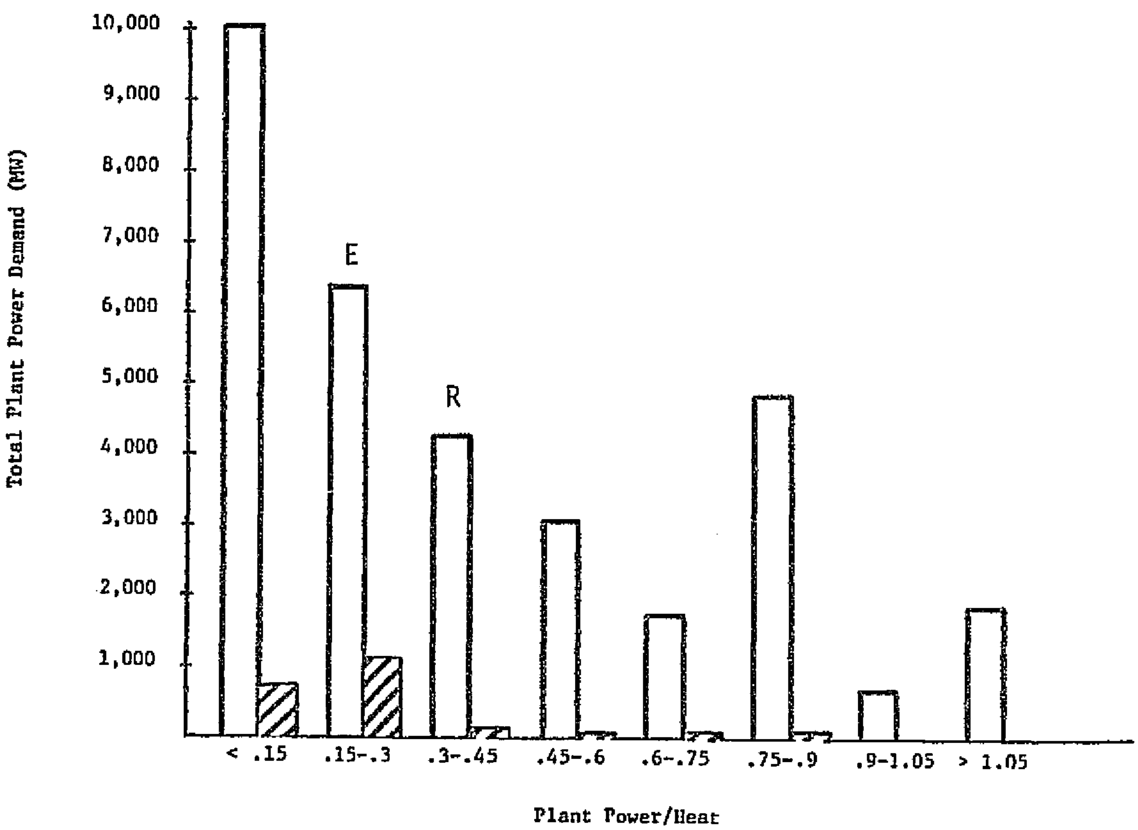

Figure 4-6

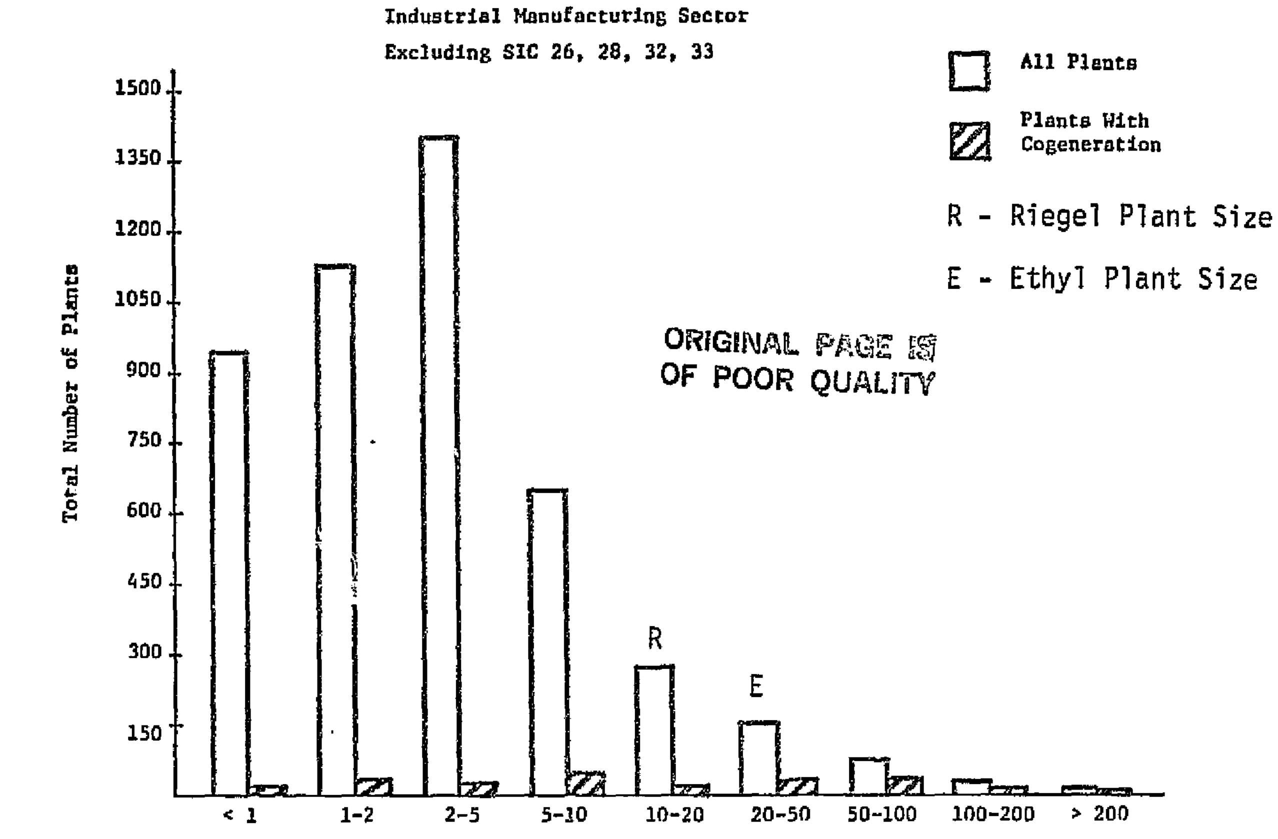

Figure 4-7

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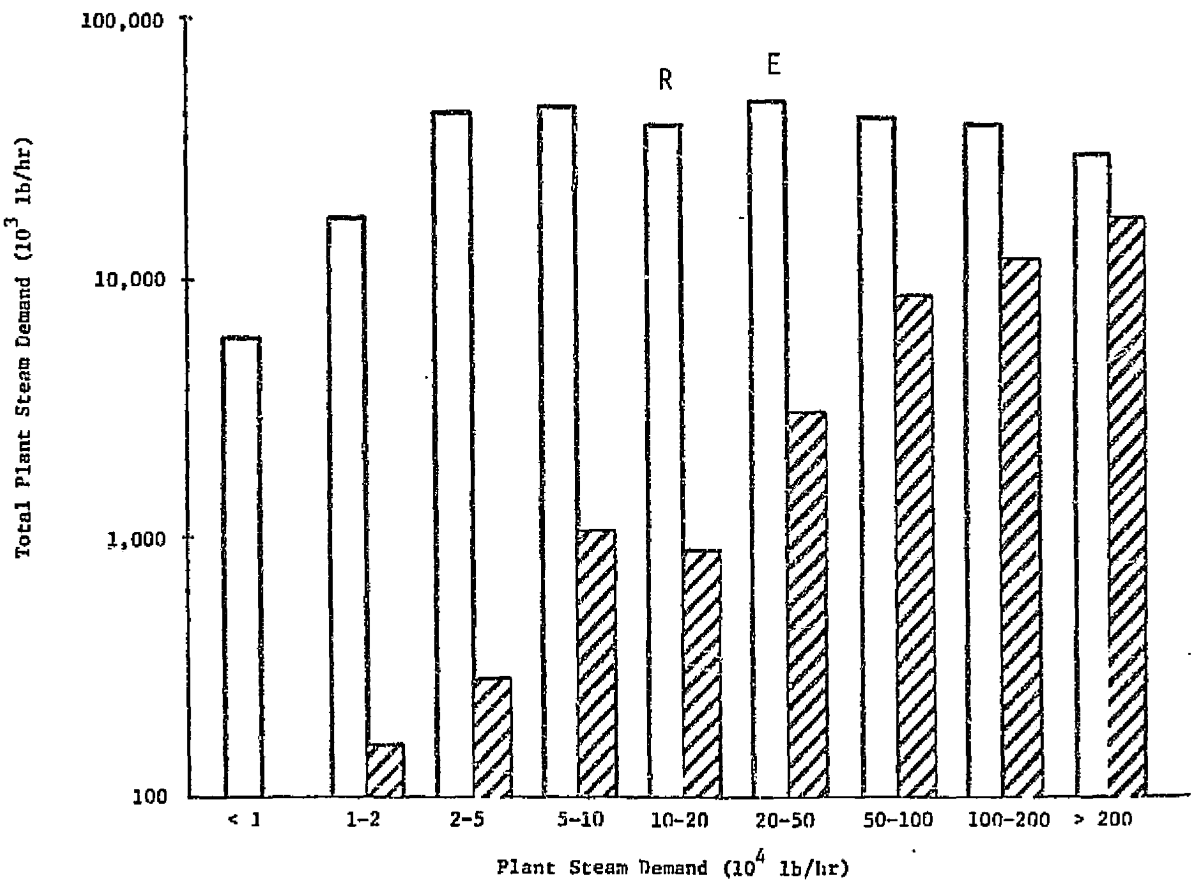

Figure 4-8

Industrial Manufacturing Sector
Excluding SIC 26, 28, 32, 33

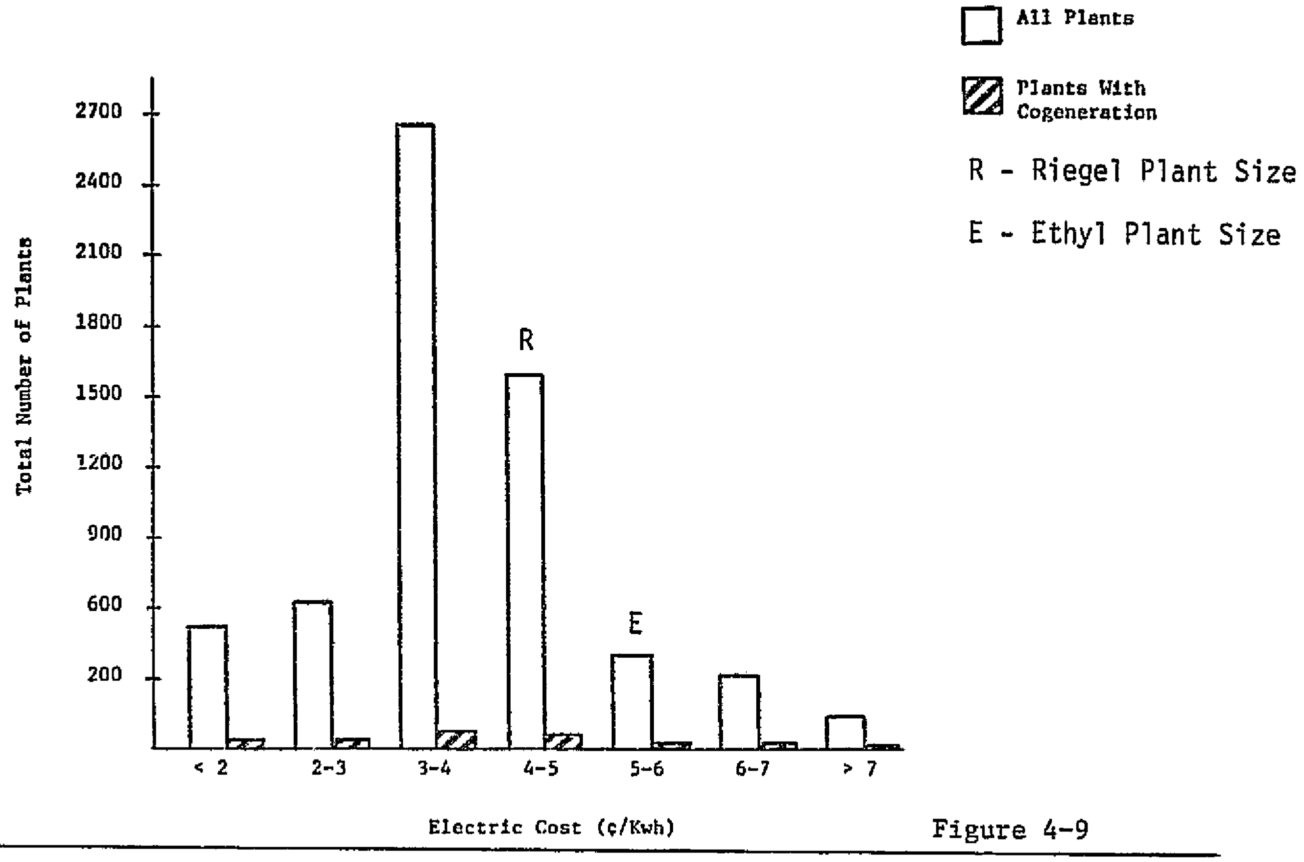

Figure 4-9

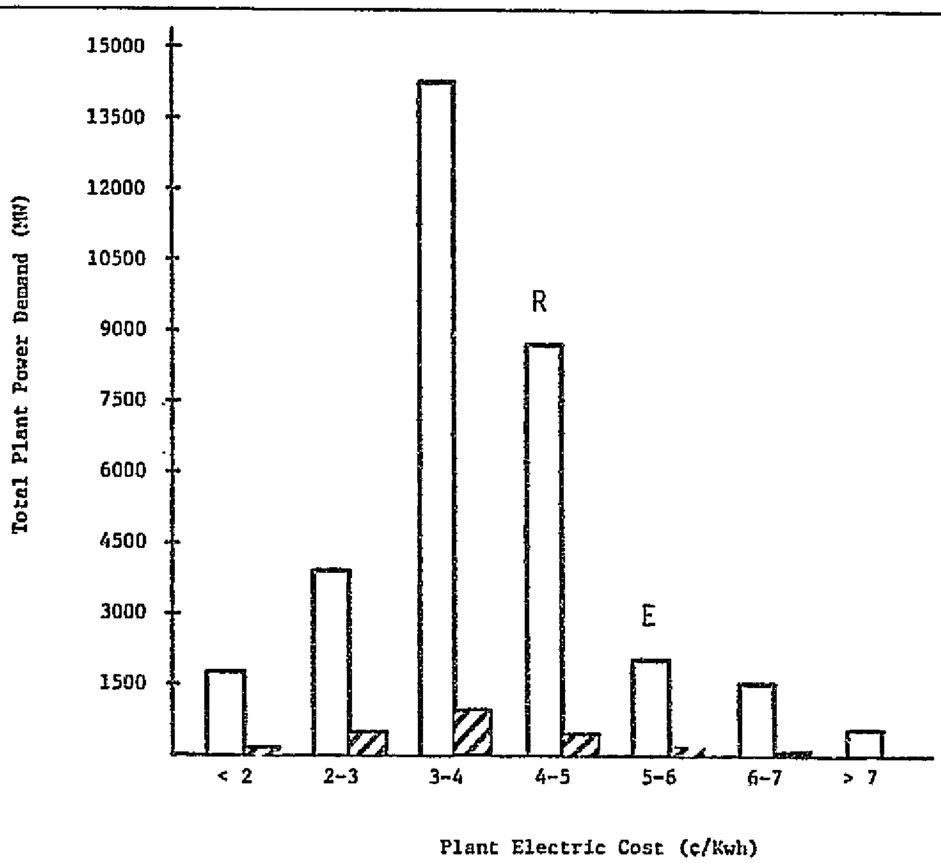

Figure 4-10

4.3 Cogeneration Systems Evaluation and Comparison

Performance and benefits analysis were performed on the cogeneration plants designed for the plant screening effort. Complete AFB/gas turbine, AFB/steam turbine cogeneration plants and new base case non-cogeneration systems were designed for each site. Both the Ethyl and Riegel plant sites were compared against each other in order to determine the "best" cogeneration plant site for the conceptual design effort. Several performance parameters are shown graphically in Figure 4-11. Institutional or non-technical barriers were also assessed in the evaluation and comparison effort. Some items considered are listed in Table 4-8. An assessment of economic and environmental factors is presented in Table 4-9.

The Ethyl Corporation in Pasadena, Texas plant was judged to be the "best" cogeneration site, and was selected for the conceptual design effort.

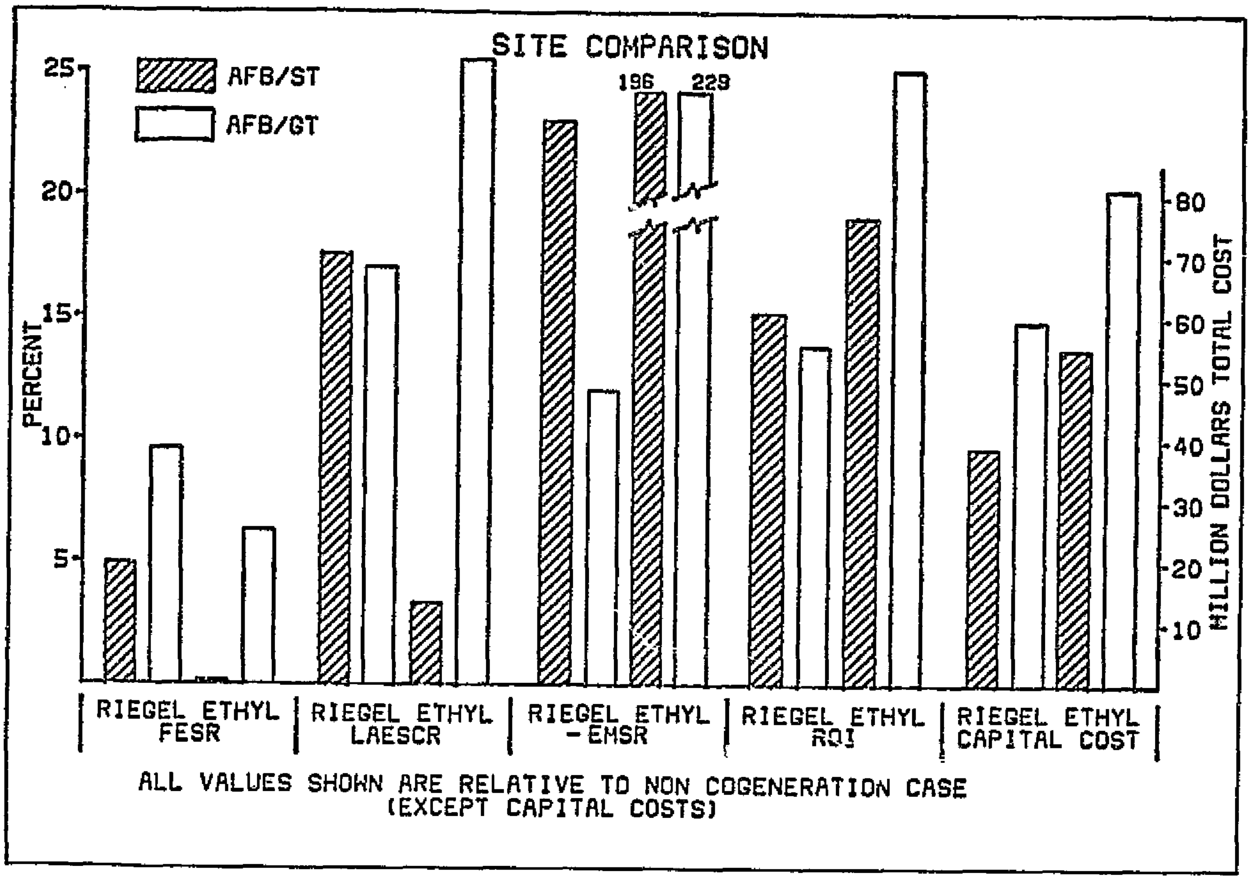

Figure 4-11

DEFINITIONS

FESR - Final Energy Savings Ratio = $\frac{\text{Non-Cogen. Fuel Energy - Cogen. Fuel Energy}}{\text{Non-Cogen. Fuel Energy}}$

LAESCR - Levelized Annual Energy Cost Savings Ratio =

$$\frac{\text{Non-Cogen. Levelized Cost - Cogen. Levelized Cost}}{\text{Non-Cogen. Levelized Cost}}$$

EMSR - Emmissions Savings Ratio = $\frac{\text{Total Non-Cogen. Emissions - Total Cogen. Emission}}{\text{Total Non-Cogen. Emissions}}$

Where Total Emissions = On-site Emissions + Utility Emissions for Purchased Electricity

ROI = Return on Investment, After-Tax Discounted Cash Flow

Table 4-8: BEST SITE SELECTION METHODOLOGY

1. PLANT COMPATIBILITY - AFB GAS TURBINE
2. REPRESENTATION OF PLANTS NATIONWIDE
3. BENEFIT TO NATIONAL ENERGY CONSUMPTION
4 BENEFITS TO SIMILAR PLANTS
5. ACCEPTANCE OF COAL-FIRED COGENERATION CONCEPT
6. SITE COMPATIBILITY - AFB GAS TURBINE
7. GEOGRAPHIC LOCATION/CLIMATOLOGICAL CONDITIONS
8. ECONOMIC ATTRACTIVENESS, PROBABILITY OF SELECTION

Table 4-9: ASSESSMENT OF INSTITUTIONAL CONSTRAINTS

	RIEGEL	ETHYL
Economic Factors		
Large Capital Investment	Reluctance	Less Reluctance
Lack of Proven Track Record	Reluctance	Less Reluctance
General Economic Uncertainty	Severe Impact	Moderate Impact
Inflation Impact	Severe	Less Severe
Environmental		
Air	Attainment Area	Non-Attainment Area
Water	No Problem	No Problem
Solid Waste	Off-Site Disposal	Off-Site Disposal
Permit Problems	Complex	Moderate
Fuel Availability	Supply Source 350 mile distance	Supply Source 350 mile distance
Community Response	May Be Adverse	Probably Approving
Long Lead Time	Doubtful	Acceptable

Chapter 5

CONCEPTUAL DESIGNS

5.1 AFB/Gas Turbine Cogeneration System

5.1.1 Preparation of Conceptual Design

The conceptual design of the AFB/gas turbine system provides a complete thermal match for the selected cogeneration site at the Ethyl-Pasadena, Texas plant. Both process steam needs and direct heat for Dowtherm heating are provided. The resultant electricity generated is a close match to the overall plant requirements including the auxiliary electric requirements of the cogeneration system.

Load variations in electric and direct heat demand are minimal while load variations in steam demand can vary widely due to the plant batch operations requiring steam. The operation of the AFB/gas turbine system provides a steady flow of heat to the Dowtherm heaters and allows the steam flow to vary according to the plant demand. This mode of operation results in a variable supply of electricity, or the production of electricity can also stay steady and the steam production vary according to steam demand.

The overall system flow diagram of the AFB/gas turbine cogeneration system is shown in Figure 5.1. At average load conditions, 190,000 lbs/hr of steam is supplied to process at 225 psig, saturated. Direct heat is supplied to the Dowtherm system at a rate of 170 MM Btu/hr. The resultant electric generation rate for the gas turbine is 28,800 kw net; that is, after accounting for auxiliary powerhouse needs. This average rate of electric generation results in a surplus above average plant electric demands of 24,000 kw. However, the cogeneration system capacity factor of 79.1% negates this surplus condition on an annual basis. A summary of the significant physical parameters of the AFB/gas turbine system is presented in Table 5-1. A more complete listing of the physical parameters is given in Appendix Section 4.

5.1.2 Operating Strategy

The operating strategy of the AFB/gas turbine system incorporates two (2) AFB combustors and two (2) turbine generator sets. In addition, each AFB combustor includes a separate Dowtherm heater, and each gas turbine exhausts to a separate waste heat steam generator. The two parallel units are each sized at 50% of the average plant capacity. The continuous, uniform demand for Dowtherm heating permits

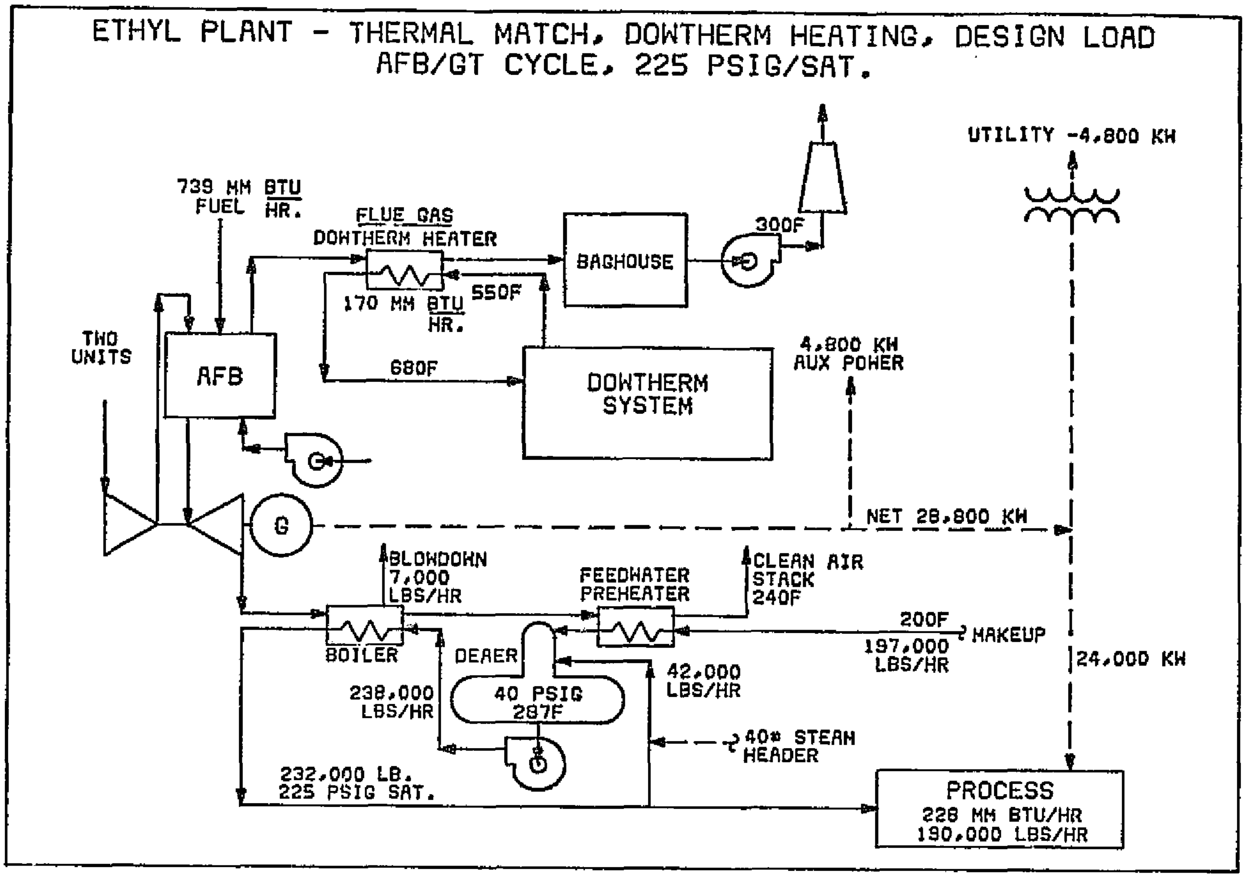

FIGURE 5-1

Table 5-1 AFB/GAS TURBINE SYSTEM PARAMETERS

FUEL: OKLAHOMA BITUMINOUS COAL, 12,400 BTU/#HHV, 3.11%S, $2.10/MBtu, DELIVERED

SORBENT: TEXAS LIMESTONE, 0.297 #/# COAL (3:1 Ca/S MOL RATIO); 39.2% CALCIUM, 11.00 $/TON

AFB/HEATER: (CURTISS-WRIGHT)

BED TEMPERATURE	-1650°F	EXCESS AIR FLOW	- 36%
BED DEPTH	- 8 FT.	FLUIDIZING VELOCITY	- 3.7 FT./SEC.
BED AREA (PER UNIT)	- 1,452 FT.^{2}	TURN-DOWN CAPABILITY, (2.5:1)	40% (TO SUIT SYSTEM MINIMUM)

POWER CYCLE: AIR - BRAYTON TOTAL - 2 GAS TURBINES, WESTINGHOUSE MODEL 191

TURBINE INLET TEMPERATURE - 1500°F

TURBINE INLET PRESSURE - 104.1 PSIA

COMPRESSOR PRESSURE RATIO - 7.47

MASS FLOW - 267 #/SEC. (PER UNIT)

HEAT REJECTION EQUIPMENT: NONE

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both AFB/gas turbine units to operate whenever available. The inherent flexibility of the air cycle provides a steady flow of heat to the Dowtherm system while the steam and electric output vary according to the process steam demand. Backup sources of steam and direct heat are provided by existing boilers and Dowtherm heaters. When both AFB/gas turbine units are operating at design levels there is a net export of electric power; however, the plant capacity factor reduces the annual output from the cogeneration system so that the plant is a small overall buyer of electricity. The plant capacity factor includes an availability factor to account for three weeks of scheduled outage and 5% unscheduled outage (a total of somewhat under 40 days downtime) and a load factor which is a result of instantaneous steam demand in excess of the cogeneration system design capacity.

The system design capacity was selected at the plant annual average demand in order to maximize energy savings while providing the best economics. The design selection necessitates the use of existing equipment to provide steam to meet the maximum plant steam requirements. A complete new plant design would not necessarily select this operating strategy, since the capital charges for auxiliary equipment would be an additional cost item.

5.1.3 Plant Availability

Several items were found to affect the cogeneration system availability at the Ethyl-Pasadena site: (1) equipment availability, (2) demand factor and (3) waste fuel utilization. The combined effect of these three factors results in a system capacity factor of 0.79. Equipment availability is based on a scheduled maintenance outage interval of 21 days and an unscheduled outage amounting to 5% of the scheduled operation. This results in a plant availability factor of 0.90. The demand factor is based on the plant steam demand curve and is a measure of the cogeneration system's ability to satisfy the plant steam demand operating within its design limitations. The demand factor is 0.92 when the cogeneration system is sized to produce a net 190,000 lbs/hr to the process steam demand. The third factor which impacts the plant capacity factor is the waste fuel utilization. An estimated 70 MM Btu/hr of waste oil, equivalent to #5 fuel oil, is produced during process plant operations and must be utilized. At present this fuel is used to generate steam. The cogeneration system operating strategy can use some of this waste fuel in coal and sorbent drying and in the existing steam generators during an outage; however, the remaining quantity of fuel oil will further reduce the cogeneration system capacity factor. As a result, the annual capacity factor is 0.79 for the AFB/gas turbine system.

5.1.4 Resource Requirements

The resource requirements for the AFB/gas turbine cogeneration system are shown in Table 5.2. Design and average values are given to account for the plant capacity factor which will be realized during the course of a typical year of operation.

5.1.5 Environmental Impact

The environmental impact for the AFB/gas turbine system is shown in Table 5-3. Design and rating for the gas turbine system is 739 MM Btu/hr which is the thermal-equivalent feed rate of coal to the combustor. Gaseous emissions of primary concern with the AFB/gas turbine system are SO_x and NO_x. The 90% removal criteria has been applied to the Oklahoma bituminous coal resulting in a SO_x emission rate of 0.50 lbs/MM Btu. The NO_x emission rate of 0.40 lbs/MM Btu is characteristic of an AFB combustor operating under the design conditions incorporated by Curtiss-Wright, Inc. Particulate emission levels are based on the 1978 New Source Performance Standards (NSPS) for utility steam generators. Normally, the 1971 NSPS standards which cover all steam generators would apply; however, the Ethyl-Pasadena plant is located in a non-attainment area for particulates and ozone. Regional, state officials of the Texas Air Control Board have indicated that the more stringent 1978 NSPS standards would apply. This particulate emissions level would be applied to both the power/steam generating function of the AFB/gas turbine system and the direct heat supply function.

Water discharge for the AFB/gas turbine system is a result of the water softening processing required with the boiler makeup water. Filter backwashing is the main contributor.

The siting of an industrial cogeneration system which is not a net annual supplier of electricity outside of the plant boundaries would normally be covered by the 1971 NSPS standards, which require 1.2 lbs SO_x/MM Btu and 0.10 lbs particulate/MM Btu. The site-specific characteristic of a non-attainment area has necessitated the use of the 1978 NSPS standards.

5.1.6 Capital Costs

Cost estimates for the AFB/gas turbine cogeneration system were prepared from budgeting quotations from major equipment suppliers and from material takeoffs as provided by equipment arrangements and plot plans. These estimates are consistent with the conceptual design level of effort. A timetable was prepared to estimate the time interval required for the construction of the cogenerator as shown in Figure 5-2. The time required for permit application and approval cannot be accurately defined; however, 24 months have been assigned to complete this effort.

Table 5-2

RESOURCE REQUIREMENTS

AFB/GAS TURBINE

	DESIGN	AVERAGE (0.791 PLANT FACTOR)
COAL	716 TONS/DAY	566 TONS/DAY
LIMESTONE	213 TONS/DAY	168 TONS/DAY
NATURAL GAS (FOR DOWTHERM HEATING)	0 MBtu/DAY	970 MBtu/DAY
WASTE FUEL	0 MBtu/DAY	1,680 MBtu/DAY
WATER - TOTAL	718,140 GAL./DAY	568,050 GAL./DAY
PROCESS STEAM	230,900 #/HR.	182,640 #/HR.
COOLING - EVAP.	0 GAL./DAY	0 GAL./DAY
BLOWDOWN (3%)	20,580 GAL./DAY	16,280 GAL./DAY

LAND REQUIREMENTS:

POWERHOUSE - 3.0 ACRES

RAILYARD - 1.5 ACRES

Table 5-3

ENVIRONMENTAL IMPACT

EMISSIONS - AFB/GAS TURBINE

(739.32 MBtu/HR. - DESIGN RATING)

	DESIGN	AVERAGE (0.791)
GASEOUS: SO_x - 0.50 #/MBtu	4.44 TONS/DAY	3.51 TONS/DAY
NO_x - 0.40 #/MBtu	3.55 TONS/DAY	2.81 TONS/DAY
PARTICULATE: 0.10/MBtu	0.89 TONS/DAY	0.70 TONS/DAY
THERMAL: COOLING TOWER - 0 BTU/MBtu	--	--
FLUE GAS STACK - 68,250 BTU/MBtu	50.5 MBtu/HR.	39.9 MBtu/HR.
CLEAN AIR STACK - 112,510 BTU/MBtu	83.2 MBtu/HR.	65.8 MBtu/HR.
OTHER - 141,200 BTU/MBtu	104.4 MBtu/HR.	82.6 MBtu/HR.
SOLIDS: TOTAL - 25.19 #/MBtu	223.5 TPD	176.8 TPD
WATER DISCHARGE: 3.06 GALS/MBtu,	54,330 GAL./DAY	42,980 GAL./DAY

The cogeneration system capital costs are summarized in Table 5-4. The AFB/gas turbine subsystem, estimated to cost $27,715,000, includes the following equipment items: coal feed bin; sorbent feed bin; weigh scales; carrier air blower; fluidized bed combustor; ash cooler; startup burner; forced draft fan; air preheater; economizer; recycle system; instrumentation and controls; gas turbine and generator; compressor; inlet silencer; associated duct, piping and conduit; and electrical controls and motor control centers. Dowtherm heating system and heat recovery steam generator costs are estimated to be $4,574,000. Mechanical equipment costs include the following: induced draft fan; baghouse, condensate and feedwater treatment systems; service air, instrument air and service water systems. Material handling includes: rail car unloading equipment, transfer conveyors, storage silos, sampling apparatus, magnetic separators, crushers, dryers, and sizing equipment. A separate baghouse is provided for the crushing and drying systems. Civil and structural costs are estimated to be $3,829.000. This cost includes foundation and structural support for all mechanical equipment. Structural steel for the AFB/gas turbine subsystem is included in the subsystem cost estimate. The civil and structural cost estimate also includes the cost for a concrete stack control building, turbine/generator building, and additional railyard trackage. Process piping estimated at $3,081,000 includes all process pipe, valves and controls for the heat recovery steam generators, Dowtherm heaters, feedwater and condensate systems as well as transfer piping of the Dowtherm fluid to and from the process area at a distance of 1,500 feet. Steam piping is also included at a distance of 200 feet to provide transfer to the existing gas fired steam generator area. Yardwork costs include demolition of the existing warehouse and tank farm as well as adding new railroad tracks and roadway.

The resultant direct, installed capital cost for the AFB/gas turbine cogeneration system is $57,675,000 expressed in 1982 dollars. Architect and engineering costs for a project of this nature are estimated at $9,325,000. The total plant cost is $67,000,000. Labor cost and overhead charges are included in each cost area. Contingency cost estimates are also included for each cost area in accordance with previous experience on similar engineering projects. Interest charges, over the 60 month design and construction period, are $24,723,000, taking a constant interest rate of 15% above inflation furnished by Ethyl Corporation. As stated in the economic groundrules, all costs have been expressed in 1982 dollars. Interest charges are inflation free. The total capital investment, therefore, required for the AFB/gas turbine cogeneration system is $91,723,000.

Table 5-4

AFB/GAS TURBINE

COGENERATION PLANT CAPITAL COSTS
COSTS (THOUSANDS OF DOLLARS)

	TOTAL
1. AFB HEATERS/GAS TURBINES SUB-SYSTEM	27,715
HEATERS & BOILERS	4,574
BAGHOUSE	1,474
2. TURBINE/GENERATOR	INCL. IN #1
3. MECHANICAL EQUIPMENT	5,761
MATERIAL HANDLING	7,488
4. ELECTRICAL	1,946
5. CIVIL & STRUCTURAL	3,829
6. PROCESS PIPING	3,031
INSTRUMENTATION	561
7. YARDWORK & MISC.	1,246
DIRECT COST	57,675
A/E HOME OFFICE & FEES	9,325
TOTAL PLANT COST	67,000
CONTINGENCY	0
TOTAL CAPITAL COST	67,000
INTEREST CHARGE (60 MONTH PROJECT)	24,723
TOTAL CAPITAL INVESTMENT	91,723

PROJECT SCHEDULE

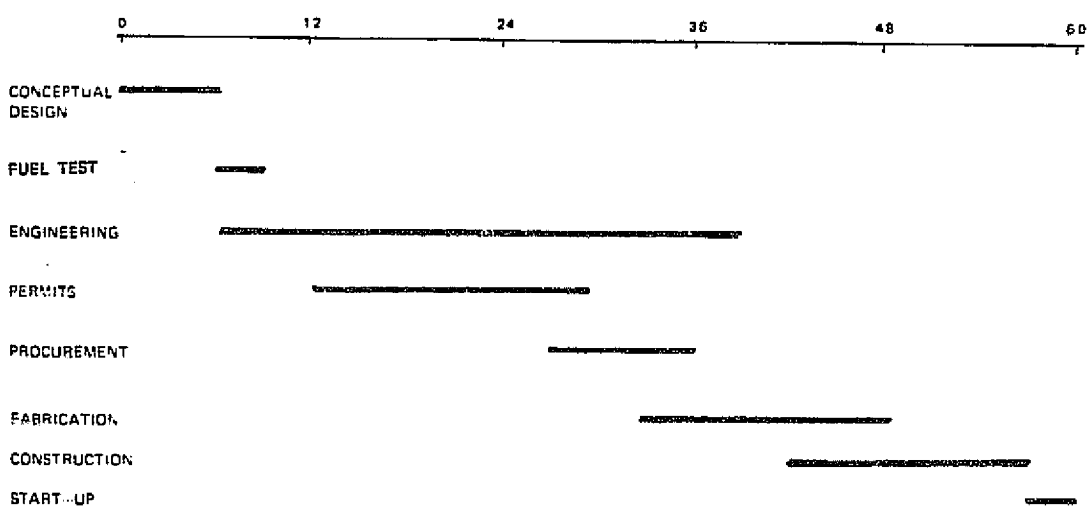

Figure 5-2

5.1.7 Uncertainty Analysis

Measurement was made of the uncertainty in the capital cost estimate. Appendix Section 2.4 describes the evaluation of the assessment of the criticality of the various cost elements.

The overrun profile curves produced are shown in Figures 5-3 and 5-4 for the AFB/gas turbine and AFB/steam turbine systems.

5.1.8 Performance and Benefit Analysis

The detailed plant thermal and electric analysis resulted in a cogeneration system characterized by a steady supply of direct heat for the Dowtherm system and a variable supply of steam and electricity for plant use. The AFB/gas turbine system components are readily adaptable to this arrangement. Equipment flexibility is compatible with part load operating requirements within the steam output range from 230,000 to 100,000 lbs/hr at 225 psig.

Auxiliary electric and thermal energy requirements for the AFB/gas turbine cogeneration system are given in Table 5-5. The major consumers of electricity are the forced draft and induced draft fans in the AFB/gas turbine subsystem, the boiler feedwater and makeup water pumps; and the crushers, dryers and conveyors in the materials handling subsystem. Coal and sorbent drying is shown to be a significant auxiliary thermal energy requirement. Feedwater heating, by low pressure (40 psig) steam, accounts for the auxiliary steam thermal energy. There is no direct use of 225 psig steam for auxiliary use. Steam is not utilized for turbine drive of the boiler feed pumps in order to maximize total electric power output.

Table 5-5

AFB/GAS TURBINE CYCLE

SUMMARY OF AUXILIARY POWER USAGE

	KW
Makeup Feedwater Pump	20
Boiler Feedwater Pump	90
MateriaL Handling	355
Dowtherm Pumping	81
2 Forced Draft Fans	3,082
2 Induced Draft Fans	1,192
	4,820 KW

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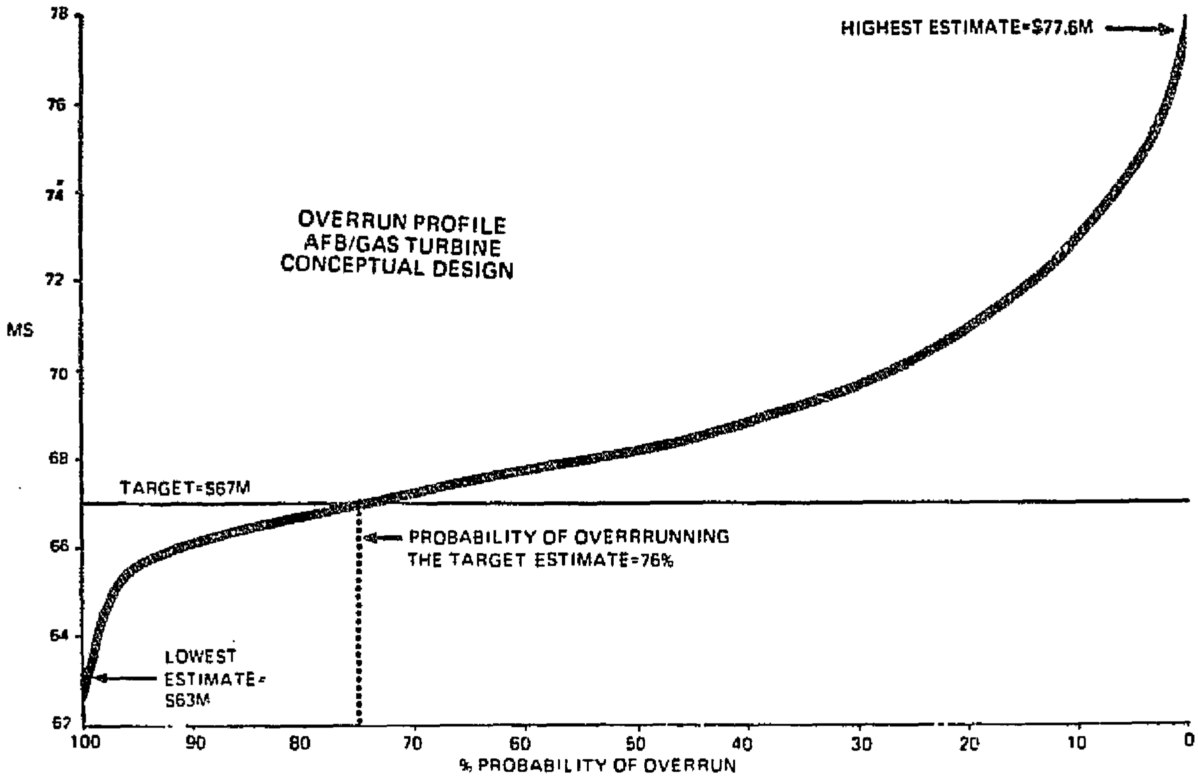

Figure 5-3

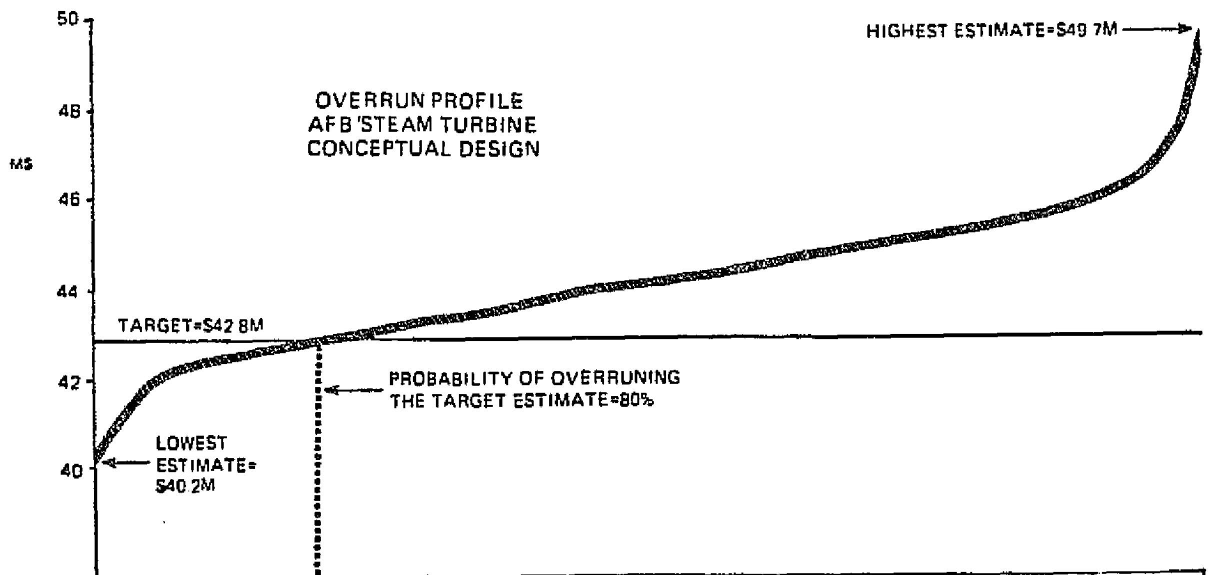

Figure 5-4

The results of a performance and benefits analysis for the AFB/gas turbine system is shown in Table 5-6. The values shown are relative to non-cogeneration. Capital cost for the non-cogeneration cost is zero based, on the assumption that existing steam generating and Dowtherm systems would be utilized without any capital charges.

The ROI for the AFB/gas turbine system is shown to be 21.9%. This value is greater than the minimum acceptable investment ROI required at the Ethyl-Pasadena plant of 20%. The fuel energy savings ratio (FESR) is 5.3%, indicating that the total fuel consumed in the AFB/gas turbine system is less than the non-cogeneration case by the indicated percentage. The levelized annual energy cost savings ratio (LAECSR) at 11.7% reflects the overall economic savings to be realized as a result of utilizing a lower cost fuel supply - coal. The emissions savings ratio (EMSR) at -28% means that the AFB/gas turbine system will result in an overall increase in the amount of pollutants discharged to the environment by 28% on a weight basis. This results from the displacing of natural gas used for both steam and electric generation by coal in the cogeneration system. This analysis includes the primary pollutants: SO_x, NO_x and particulates. All of the economic benefits analyses are based on a total capital investment required of $91,723,500 over the anticipated 60 month project duration.

Sensitivity analyses in terms of return on investment (ROI) for several economic variables and several rates of escalation are summarized in Table 5-7 for the Ethyl site base case. The most sensitive economic variables are shown to be: (1) capital investment changes and (2) gas/oil fuel changes. Economic factors which are secondary in sensitivity are: (1) coal fuel changes and (2) electric rate changes. Operation and maintenance (O&M) changes are not a significant variable.

The sensitivity analysis has identified two divergent and equally important economic variables in the gas/oil fuel changes and the capital changes. The tendency for increases in gas/oil prices to improve plant economics is balanced by equal increases in plant capital investment equally lowering plant economic attractiveness. This analysis illustrates the need for reduced capital charges or government assistance in terms of favorable tax arrangements for industrial cogenerators, or favorable interest rates on capital.

Escalation rates for gas/oil, coal and electric charges were found to be equally sensitive. However, positive increases in the rate of escalation have a small impact on coal costs as compared to

Table 5-6: RESULTS OF PERFORMANCE AND BENEFITS ANALYSES

Item	AFB/Gas Turbine	AFB/Steam Turbine
ROI	21.9%	17.5%
LAESCR	11.7%	- 6.7%
FESR	5.3%	1.2%
EMSR	- 28%	-14.3.%
TOTAL CAPITAL INVESTMENT	$91,723,000	$58,648,000

Values shown are relative to non-cogeneration (except for capital cost).

Table 5-7: SENSITIVITY ANALYSIS

	ROI	
	GT	ST
BASE	21.9	17.5
Variable		
Gas/Oil ± 40%	27.1/17.8	20.9/13.8
Coal ± 40%	20./24.4	16.2/18.9
Capital Investment ± 35%	18.7/29.5	15.1/22.0
Electric ± 25%	24.3/19.9	18.8/16.2
O&M ± 25%	21.4/22.6	16.9/18.2
Escalation		
Gas/Oil + 10%, -2%	34.1/16.8	27.3/12.7
Coal + 10%, -2%	7.4/23.5	5.9/18.6
Electric + 15%, -2%	32.6/15.7	24.6/13.4
O&M + 5%, -2%	21.1/22.2	16.4/17.8

gas/oil and electric changes. The effect of escalation rates on operations and maintenance charges is minimal. Thus, a cogeneration system based on coal is the most economically stable choice of fuel.

Coal fired cogeneration systems in an environment of favorable capital investment is shown by sensitivity analysis to be a viable choice for long term, industrial plant management programs.

5.2 AFB/Steam Turbine Cogeneration System

5.2.1 Preparation of Conceptual Design

The conceptual design of the AFB/steam turbine system provides for process steam needs. Production of steam at high pressure and temperature permits use of a backpressure steam turbine-generator to produce electricity. Dowtherm heating is provided unchanged in the current mode. The wide variations in steam demand due to plant batch operations are provided in part by continuously operating existing boilers and by the use of a deaerator with large storage capacity. This permits the heating steam to the deaerator to be varied according to steam demand.

The overall system flow diagram of the AFB/steam turbine cogeneration system is shown in Figure 5-5. At average load, 190,000 lbs/hr steam at 225 psig saturated is supplied to process and electricity is generated at the rate of 8,700 kw net. The plant electric purchases are thus reduced significantly. A summary of the AFB/steam turbine system's significant system parameters is presented in Table 5-8. Appendix Section 4 provides a more detailed listing of physical parameters.

5.2.2 Operating Strategy

The operating strategy of AFB/steam turbine systems has one new AFB boiler generating high pressure superheated steam at 1,250 psig/950^{o}F which passes through a steam turbine generator of the backpressure type exhausting at 225 psig. The AFB boiler capacity provides 190,000 lbs/hr steam to process plus the steam required for feedwater heating.

The steam conditions of 1,250 psig/950^{o}F represent about the practical maximum for a boiler of the size required. This serves to provide the maximum energy range for the steam passing through the steam turbine, thus maximizing byproduct electricity production since the process plant steam pressure level is set at 225 psig. The backpressure steam turbine is a strict cogenerator and is a simple steam load following device. A radial flow type steam turbine was

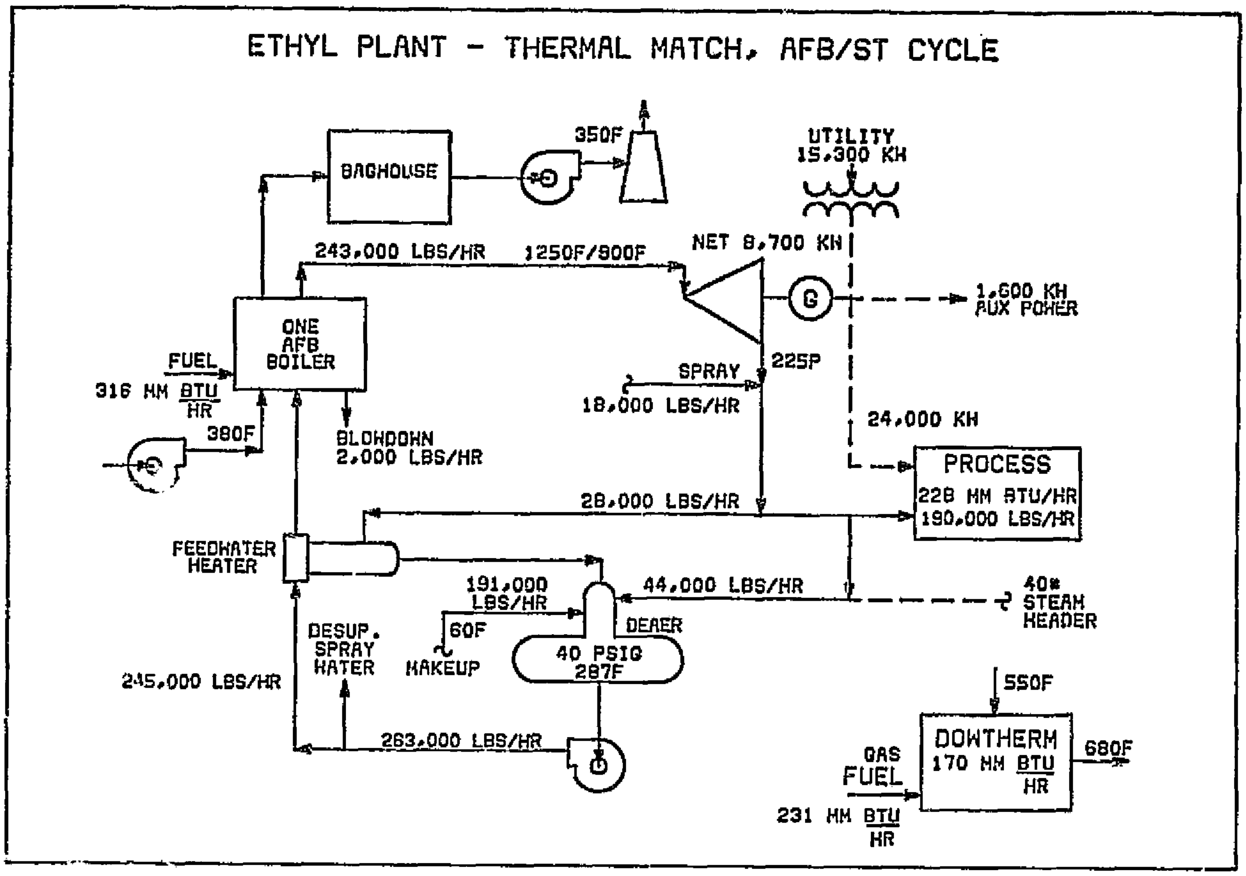

FIGURE 5-5

Table 5-8: AFB/STEAM TURBINE SYSTEM PARAMETERS

FUEL: Oklahoma Bituminous coal; 12,400 BTU/#HHV; 3.11%S; $1.96/MBtu, Delivered

SORBENT: Texas Limestone, 0.297 #/# Coal (3:1 Ca/S MOL RATIO); 39.2% Calcium, $11.00/Ton

AFB/BOILER (KEELER/DORR-OLIVER):

Bed Temperature - 1,600°F
Bed Depth - 4 Ft.
Bed Area - 551 Ft.^{2}
Excess Air Flow - 20%
Fluidizing Velocity - 8.5 Ft./Sec.
Turndown Capability (4:1) - 25% (to suit system minimum)

POWER CYCLE:

Steam-Rankine (Total - 1 Turbine)
Turbine Type: Radial Flow - Backpressure; 11,700 KW Rating
Throttle Conditions - 1,250 Psig/900°F
Exhaust Conditions - 225 Psig/530°F
Mass Flow - 243,000 #/Hr. (Design Rate)

HEAT REJECTION EQUIPMENT: None (Non-Condensing Steam Cycle) selected because of its ability to readily accommodate steam flow swings and because of its indicated higher efficiency. But the system is not very flexible since the electricity generated is a byproduct of steam flow through the turbine. Dowtherm heating is left unchanged since an AFB boiler having Dowtherm heating coils is beyond the state-of-the-art. Also, as opposed to the AFB air heater combustor, the AFB boiler will be varying in steamload.

As noted, the sharp variations in steam demand would directly affect operation of the AFB boiler and must be accounted for. The new steam production facility is designed for 100% cold makeup, and deaerator heating steam is taken from the 225 psig steam header by reduction to 40 psig. A large storage volume deaerator can serve as a type of energy storage accumulator, and the heating steam can be cut back on sudden high steam demand periods and increased during sudden low steam demand periods. This provides load change rates which permit the AFB boiler to respond in a satisfactory manner.

Backup and continuous steam production is provided by the existing boilers. The plant capacity factor and availability factor are taken as identical to that given for the AFB/gas turbine cycle; namely, three weeks of scheduled outage, plus 5% unscheduled downtime and a load factor accounting for instantaneous steam demand variations.

5.2.3 Plant Availability

The description of plant availability for the AFB/gas turbine system in Section 5.1.3 generally applies to the AFB/steam turbine system as well. Waste fuel utilization has impact since this results in direct low pressure steam generation which forces the AFB boiler to produce less steam. The result is an annual capacity factor of 0.786 for the AFB/steam turbine system.

5.2.4 Resource Requirements

The resource requirements for the AFB/steam turbine cogeneration system are shown in Table 5-9 with design and average values given to account for the plant capacity factor.

5.2.5 Environmental Impact

The environmental impact for the AFB/steam system is shown in Table 5-10. The discussion in section 5.1.5 regarding New Source Performance Standards for the AFB/gas turbine system applies for the AFB/steam turbine system.

Table 5-9: RESOURCE REQUIREMENTS - AFB/STEAM TURBINE

	Design	Average (0.791 Plant Factor)
COAL	305 tons/day	240 tons/day
LIMESTONE	91 tons/day	72 tons/day
NATURAL GAS (FOR DOWTHERM HEATING)	5,544 MBtu/day	5,544 MBtu/day
WASTE FUEL	0 MBtu/day	1,680 MBtu/day
WATER - TOTAL	718,950 Gals/day	614,610 Gals/day
Process Steam	234,200 #/hr	184,080 #/hr
Cooling - Evap.	0 Gals/day	0 Gals/day
Blowdown (1%)	6,820 Gals/day	5,350 Gals/day

LAND REQUIREMENTS: POWERHOUSE - 2.0 Acres; RAILYARD - 1.0 Acres

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Table 5-10: ENVIRONMENTAL IMPACT - EMISSIONS - AFB/ STEAM TURBINE (315.95 MBtu/Hr. - Design Rating)

	Design	Average (0.791)
GASEOUS: SO_x - 0.50 #/MBtu	1.90 tons/day	1.49 tons/day
NO_x - 0.40 #/MBtu	1.52 tons/day	1.19 tons/day
PARTICULATE: 0.10/MBtu	0.38 tons/day	0.30 tons/day
THERMAL:		
Cooling Tower - 0 Btu/MBtu	--	--
Flue Gas - 108,400 Btu/MBtu	34.2 MBtu/hr	26.9 MBtu/hr
Other - 133,100 Btu/MBtu	42.1 MBtu/hr	33.1 MBtu/hr
SOLIDS: Total - 28.2 #/MBtu	106.9 TPD	84.0 TPD
WATER DISCHARGE: 14.25 Gals/MBtu	108,070 Gals/day	84,940 Gals/day

5.2.6 Capital Costs

Major design assumptions for this cycle are summarized in Table 5-11. Most of the design assumptions listed also apply to the gas turbine cycle. The AFB/steam turbine cogeneration system capital costs are summarized in Table 5-12. The AFB boiler subsystem is estimated to cost $12,220,000 and includes an erected boiler and associated equipment, including a baghouse. The erected backpressure type steam turbine generator is estimated to cost $2,620,000. The scope of the other cost areas generally follows that described in section 5.1.6 for the AFB/gas turbine system, except that there are no costs associated with the Dowtherm system.

The same 60 month design and construction period is assumed, resulting in a total capital investment of $58,648,000.

5.2.7 Performance and Benefits Analysis

The AFB boiler and steam turbine cogeneration system provides plant process steam and byproduct electricity, reducing the plant's electricity purchase. The system can provide steam which will follow plant demands.

The sensitivity analysis is summarized in Table 5-7. The discussion of the AFB/gas turbine sensitivity analysis given in section 5.1.7 is applicable to the AFB/steam turbine cycle. Table 5-6 shows the results of a performance and benefits analysis for the AFB/steam turbine system.

The ROI for the AFB/steam turbine system is 17.5%. This value is less than the minimum acceptable investment ROI of 20% required by Ethyl Corporation. The Fuel Energy Savings Ratio (FESR) is only 1.2%. This is mainly due to the fact that the existing boilerhouse is quite efficient because of waste steam preheating the boiler makeup water. The negative levelized annual energy cost savings ratio (LAECSR) at -6.7% shows that the combined operating cost savings for the cogeneration plant do not affect the capital cost to produce any savings over the existing high operating cost plant, which does not have a capital charge levied against it. The negative emissions savings ratio (EMSR) is again due to switching to solid fuel combustion.

Table 5-11: AFB/STEAM TURBINE MAJOR DESIGN ASSUMPTIONS

- Railroad delivery of unsized coal and limestone.
- 15 day silo storage for coal and limestone.
- On-site crushing of coal and limestone.
- Drying equipment provided for limestone.
- 10 day silo ash storage/truck removal/off-site landfill.
- Turbine steam inlet condition of 1,250#PSIG/900#F
- Radial flow steam turbine
- 100% makeup water at 60#F from existing plant softeners is demineralized.
- 2 stages of feedwater heating -- deaerator and upstream feedwater heater.

Table 5-12

AFB/STEAM TURBINE COGENERATION PLANT CAPITAL COSTS
(Thousands of Dollars)

			COSTS	TOTAL
1.	AFB Boilers & Baghouse		12,220	
2.	Turbine/Generator		2,620	
3.	Mechanical Equipment		4,578	
	Material Handling		5,372	
4.	Electrical		1,536	
5.	Civil & Structural		2,711	
6.	Process Piping		3,592	
	Instrumentation		987	
7.	Yardwork & Miscellaneous		1,554	
			35,170	
	Direct Cost			35[illegible]70
	A/E Home Office & Fees			7[illegible]0
		TOTAL PLANT COST		42[illegible]0
	Contingency			[illegible]0
		TOTAL CAPITAL COST		42,840
	Interest Charge (60-month project)			15,808
		TOTAL CAPITAL INVESTMENT		58,648

Chapter 6

SYSTEM EVALUATION AND COMPARISON

6.1 Introduction

The comparative analysis between AFB/gas turbine and AFB/steam turbine technologies assumes that both systems have been successfully developed and demonstrated and are commercially available by the mid-1980s. At present, the AFB/steam turbine system is commercially available and proven. The AFB/gas turbine system is commercially available but unproven at the present time.

6.2 System Comparison

A system comparison is presented in Table 6-1. The criteria shown are: net plant output, fuel utilization, AFB heater efficiency, combustion efficiency, coal consumption, limestone consumption, total waste, and construction time. It is important to note that the AFB/gas turbine system provides a match for steam, electricity and Dowtherm heating; whereas the AFB/steam turbine provides a match only for steam with no provision for Dowtherm heating. The use of coal firing in an AFB combustor to provide direct heat for process heating such as Dowtherm heating has not been commercially proven. Therefore, this technology has not been incorporated into the AFB/steam turbine system which is commercially proven.

The provision for direct heat results in a lower fuel utilization value of 65.8% for the AFB/gas turbine system as compared to the AFB/steam turbine system value of 72.8%. The lower fuel utilization for the AFB/gas turbine is due to the optimization for economic performance with maximum Dowtherm heating at the expense of electric production. Otherwise, the AFB/gas turbine and AFB/steam turbine systems have similar efficiencies. The fuel consumption values directly reflect the larger plant sizing criteria and subsequent larger plant output of the AFB/gas turbine system. The estimated construction interval, excluding permitting and design requirements, is 2.5 years for both cogeneration systems.

6.3 Composite System Comparison

Table 6.2 presents a composite system comparison based on economic, resource and environmental evaluation criteria for a typical year of operation. At $91,790,000 total capital investment, the AFB/gas turbine cogeneration system is appreciably more capital intensive compared to the AFB/steam system total capital investment of

$58,691,000. However, the return on investment (ROI) for the AFB/gas turbine system at 21.9% exceeds the site hurdle ROI of 20%. The AFB/steam system ROI at 17.5% does not meet the site hurdle ROI criteria. The hurdle ROI reflects the current industrial market condition, afflicted by high interest rates and low demand for goods produced.

Energy savings for the AFB/gas turbine system is 5.3% for the Ethyl-Pasadena plant compared to 1.2% for the AFB/steam system which represents a minimal savings in fuel consumption between the cogeneration systems and the present non-cogeneration system preheating boiler makeup with waste steam. The actual cost savings is a result of the lower cost associated with high sulfur coal compared to oil or natural gas.

The fuel consumption breakdown in Table 6-2 is shown for the non-cogeneration, AFB/gas turbine, and AFB/steam turbine systems. The waste fuel is consumed preferentially at a rate of 70 MM Btu/hr in all cases. The AFB/gas turbine system requires 40.4 MM Btu/hr of natural gas to fire the supplementary steam generators and Dowtherm heaters on an annual average. The AFB/steam turbine system requires 231.0 MM Btu/hr of natural gas since direct heat for Dowtherm heating is not a provision of the steam system. Electric requirements are shown for each system. The AFB/gas turbine system requires the least amount of electricity purchased from the utility. However, the AFB/gas turbine system is still an annual overall buyer of electricity at a rate of 4.03 MW. The AFB/steam turbine system based strictly on a steam, "thermal" match requires a much larger annual average electric supply of 16.92 MW.

Environmental impact is gauged by the emissions savings ratio (EMSR) which measures all pollutants on a weight basis. The EMSR for the AFB/gas turbine system is -28.0%; this reflects an increase in pollutants as a result of the conversion from natural gas to coal as the primary fuel for plant use as well as electric generation. The AFB/steam turbine value of -14.3% shows a smaller increase in pollutants which directly illustrates the higher use rate of natural gas with a steam, "thermal" match of the AFB/steam turbine cogeneration system. In other words, less coal is burned for the steam turbine versus the gas turbine cycle. The average pollutant loading for each system in terms of tons/day of gas and solids shows the higher pollutant loading of the coal fired systems compared to burning natural gas as the primary fuel in the non-cogeneration case. The utility which has a fuel basis of 80% natural gas and 20% coal similarly has a heavy emphasis on burning natural gas.

Table 6-1

SYSTEM COMPARISON

	AFB/GT (DESIGN)	AFB/ST (DESIGN)
NET PLANT OUTPUT	28.8 MW_e / 112 MW_t (1)	8.7 MW_e / 58.7 MW_t (2)
(3) FUEL UTILIZATION $\left(\frac{MW_e + MW_t}{MW_{IN}}\right)$	65.8%	72.8%
AFB HEATER EFFICIENCY	86.0%	83.7%
COMBUSTION EFFICIENCY	(98%)	(97%)
COAL CONSUMPTION	587 TONS/DAY	251 TONS/DAY
LIMESTONE CONSUMPTION	175 TONS/DAY	75 TONS/DAY
TOTAL WASTE	223.5 TONS/DAY	106.9 TONS/DAY
CONSTRUCTION TIME (EXCLUDING PERMITTING AND DESIGN)	2.5 YEARS	2.5 YEARS

(1) INCLUDING DOWTHERM HEATING

(2) EXCLUDING DOWTHERM HEATING

(3) NON-EQUALIZED FOR DOWTHERM HEATING

Table 6-2

SYSTEM COMPARISON

		NON-COGEN.	AFB/GT	AFB/ST
TOTAL CAPITAL INVESTMENT	($M)	0	91.790	58.691
ENERGY - FESR	(%)	---	5.3	1.2
GAS	(MBtu/HR.)	413.0	40.4	231.0
COAL	(MBtu/HR.)	0	585.0	248.4
WASTE FUEL	(MBtu/HR.)	70.0	70.0	70.0
ELECTRIC	(MW)	24.1	4.03	16.92
EMISSIONS - EMSR	(%)	---	-28	-14.3
GAS	(TONS/DAY)	6.42	8.22	7.34
SOLID	(TONS/DAY)	0	176.8	84.0
ROI	(%)	---	21.9	17.5
LAECSR	(%)	---	11.7	-6.7

6.4 Environmental Regulations

The environmental regulatory guidelines for each cogeneration system would normally fall within the 1971 NSPS criteria. However, the "non-attainment" classification of the plant site at Pasadena, Texas requires compliance with the more stringent 1978 NSPS criteria for all three types of industrial categories: (1) steam generation, (2) electric generation, and (3) direct process heat generation. The 1978 NSPS criteria are reflected in the pollutant emissions levels shown in Table 6-2. Similar cogeneration systems, located in a more favorable environmental location, could operate under less stringent conditions. In terms of capital expenditures, the impact of these environmental regulations is minimal when considering the overall project capital cost.

6.5 Utility Rate Structures

The impact of utility rate structures is a significant factor in determining the feasibility of a cogeneration system. Fortunately, the Houston Power and Light Company has a rate structure which is favorable to cogeneration, with no standby or demand charges for electric supply. Appendix Section 2.2 shows the result of utility rate structures which require consideration of level of electrical cogeneration, size and number of cogenerating units, and electrical rate structure negotiated with the utility.

6.6 Plant Modification to Complement Cogeneration

There are two main areas wherein operating changes would improve the economics of a cogeneration system. These areas are: (1) reduction in the output of waste fuel oil and (2) provision for a more uniform steam demand. The reduction of waste fuel output by inplant utilization would increase the cogeneration plant capacity factor from 78-79% to 82%. The provision for a uniform steam demand would increase the plant capacity factor from 82% up to 90%, which is the estimated cogeneration system availability factor.

The provision for a more uniform steam demand could be accomplished by two primary changes: (1) increased use of mechanical turbine drives for process equipment and (2) provision for an extraction-condensing steam turbine for the AFB/steam turbine system. The increased use of mechanical drives can be accomplished in a phased implementation program at the Ethyl-Pasadena plant. The optimum extent of this conversion from electric to mechanical drive would require a separate detailed analysis.

Provision for an extraction-condensing steam turbine is not cost effective for the Ethyl-Pasadena plant when the existing natural gas-fired steam generators are retained for backup supply. In addition, the "condensing" portion of the system, including all required auxiliaries, would not qualify as cogeneration equipment under current tax and fuel use regulations. A new steam plant, installed to provide the peak steam demand with a 52% load factor which characterizes the Ethyl-Pasadena plant, would require an extraction-condensing unit. However, the groundrules for Task 2 work effort, which include using existing equipment for backup and peaking service, make the use of an extraction-condensing unit capital intensive. The additional electric generation under these conditions does not warrant the additional capital expenditure.

Chapter 7

MARKET AND BENEFIT ANALYSIS

7.1 Introduction

A market and benefits analysis was undertaken to estimate the potential market national benefits assuming full development and commercialization by industry of AFB/gas turbine systems.

The identification and evaluation of industrial cogeneration potential requires three elements:

- o The industrial data base developed by General Energy Associates uses a plant-specific data base which is described in detail in Appendix Section 5.
- o The technology - cost and performance characteristics - was developed by Catalytic.
- o The economic model used by General Energy Associates pulls together the above elements to perform the market assessment.

7.2 Industrial Data Base

General Energy Associates utilizes a plant specific data base as the starting point for the technical/economic analysis of cogeneration viability. This avoids the use of representative plants. The data base contains detailed plant estimates of steam and electric usage, and hours of operation for the top 10,000 existing U.S. industrial plants. Use of plant level estimates allows the application of detailed economic calculations (such as ROI) for each individual plant.

7.3 Cost and Performance Characteristics

Catalytic developed economic model parameters of capital cost for the AFB/gas turbine system, and for the AFB/steam turbine. The non-cogeneration case is for an existing plant as noted in Section 7.2 and has no capital cost. Economic model parameters are given in Table 3-2.

Performance parameters also were developed for both AFB/gas turbine and steam turbine systems. This is shown in Figures 3-1 and 3-2.

7.4 Market Analysis

With the input from Catalytic of cogeneration technology performance parameters and capital costs, plant level ROI has been calculated. Using the AFB/Gas Turbine System Performance and Economic Models, General Energy Associates determined the greatest ROI for each plant site by selecting the best performance between net heat to process per KW between 5 and 20. This range of operation is possible due to the flexibility of the AFB/Gas Turbine system.

For purposes of review, potential plant sites are categorized for ROI greater than 10% and for ROI greater than 20%. The AFB/GT and AFB/ST results represent an independent analysis for each technology at each plant site. Also, the number of plants having incremental ROI's of 10% and 20% for gas turbines relative to steam turbines is given. This can be considered a "hurdle" rate for which gas turbine systems would have to exceed steam turbine economics to be considered for an application.

The summary of analysis given in Appendix Section 5 is presented in several tables:

- Table 7-1 presents the potential national markets for the AFB/gas turbine and AFB/steam turbine.
- Table 7-2 shows over 90% of the AFB/gas turbine and the gas turbine incremental plants are also plants which satisfy the AFB/steam turbine hurdle rates. The incremental plants are those where an analysis of the AFB/GT relative to the AFB/ST at a site satisfies the hurdle rate.
- Table 7-3 shows the market shares of these cogeneration systems as a function of industrial steam production.
- Table 7-4 profiles the market share of systems for 10% ROI.
- Tables 7-5 and 7-6 present the industrial sector profiles.
- Figures 7-1 and 7-2 graphically present the industrial sector profiles.
- Table 7-7 shows the results of a sensitivity analysis to PURPA rates.
- Table 7-8 gives the average system size for the cogeneration plants meeting the economic criteria.
- Tables 7-9 and 7-10 present analysis of the ratio of the cogenerated power to the plant demand.

The geographical summary locating the plants by EIA/DOE Regions shown in Figure 7-3 is given in Tables 7-11 and 7-12 for ROIs of at least 10% and 20% respectively.

7.5 Potential Benefits

The potential national benefits based on the number of industrial plants previously given is summarized in Table 7-13. The total fuel savings include the potential savings at the plant site as well as the utility power plant.

Table 7-1

MARKET SUMMARY

SYSTEM	ROI > 10%		ROI > 20%	
	No. Plants	MW	No. Plants	MW
Steam Turbine	788	8,450	281	5,227
Gas Turbine	776	11,275	167	5,274
Gas Turbine (Incremental)	411	3,813	16	119

Table 7-2

OVERLAPPING PLANTS*

SYSTEM	ROI >10%	ROI >20%
Steam	100%	100%
Gas	95%	99%
Incremental Gas	91%	94%

* Percent of plants in System/ROI group which overlap in Steam/ROI group.

Table 7-3

MARKET SHARE AS A PERCENT OF STEAM USE

SYSTEM	ROI >10%	ROI >20%
Steam	40	27
Gas Turbine	39	19
Incremental Gas Turbine	13	1

Table 7-4

MARKET SHARE AS A FUNCTION OF SIZE
GAS A PERCENT OF STEAM USE IN THAT SIZE RANGE

	SYSTEM	
STEAM SIZE RANGE (10^3 lb/hr)	Steam (> 10%)	Gas (> 10%)
< 50	6	6
50 - 100	34	32
100 - 150	63	60
150 - 200	58	56
200 - 250	67	62
250 - 400	66	67
400 - 600	63	61
600 - 1000	46	46
> 1000	26	26

Table 7-5

INDUSTRIAL SECTOR SUMMARY

ROI > 10%

INDUSTRIAL SECTOR (SIC)	SYSTEM					
	STEAM		GAS		GAS INCREMENTAL	
	No.Plants	MW	No.Plants	MW	No.Plants	MW
Food (20)	40	541	40	629	29	295
Pulp & Paper (26)	212	2,489	232	2,654	198	1,541
Chemicals (28)	276	3,737	276q	4,903	101	1,318
Petro. Refin. (29)	133	1,197	112	2,493	10	318
Steel (33)	49	137	42	221	12	47
Metals Fab.(34-39)	29	172	30	166	29	142
Others	49	177	44	209	32	151
TOTALS	788	8,450	776	11,275	411	3,812

Table 7-6

INDUSTRIAL SECTOR SUMMARY

ROI > 20%

INDUSTRIAL SECTOR (SIC)	STEAM		GAS		GAS INCREMENTAL	
	No.Plants	MW	No.Plants	MW	No.Plants	MW
Food (20)	2	35	2	39	-	-
Pulp & Paper (26)	50	1,190	43	1,068	8	71
Chemicals (28)	129	2,893	75	2,818	1	14
Petro. Refin. (29)	75	942	29	1,223	0	0
Steel (33)	9	45	4	22	3	15
Metals Fab.(34-39)	13	108	11	86	4	19
Others	3	14	3	18	0	0
TOTALS	281	5,227	167	5,274	16	119

C-2

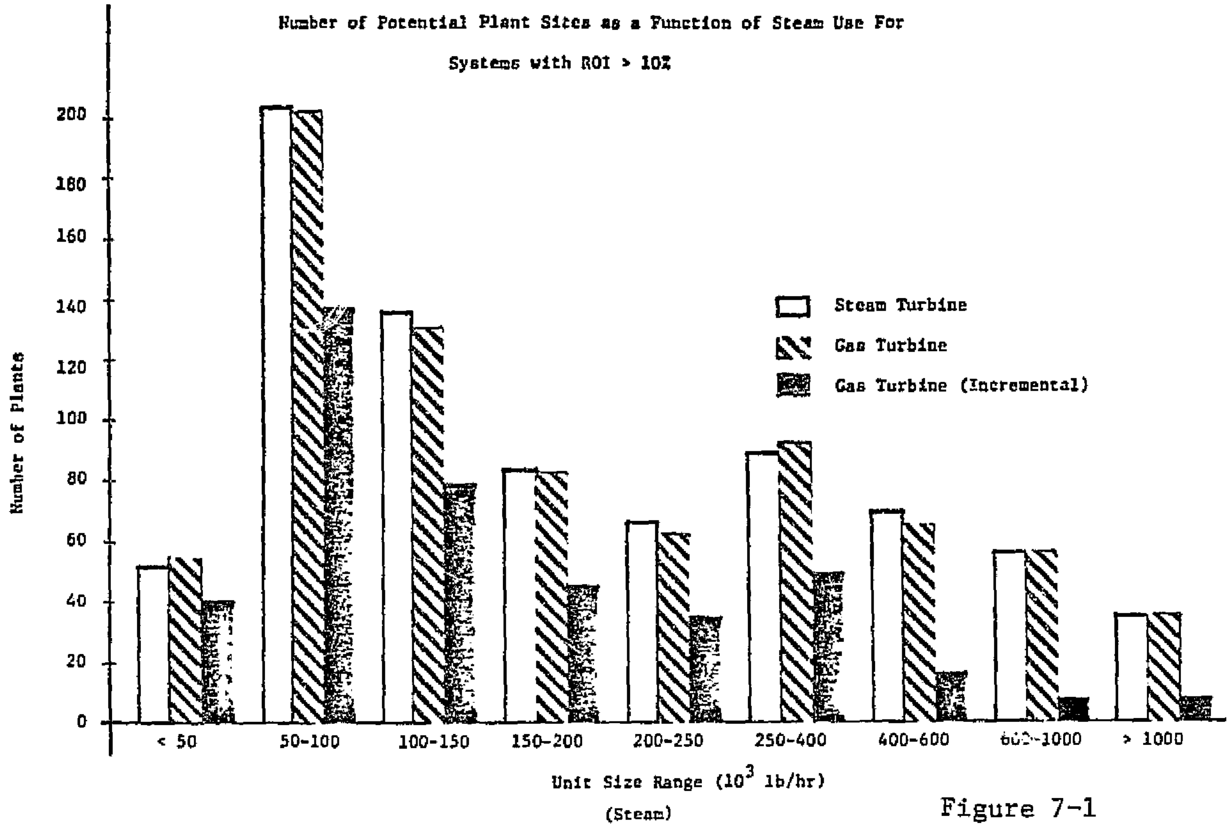


Figure 7-1

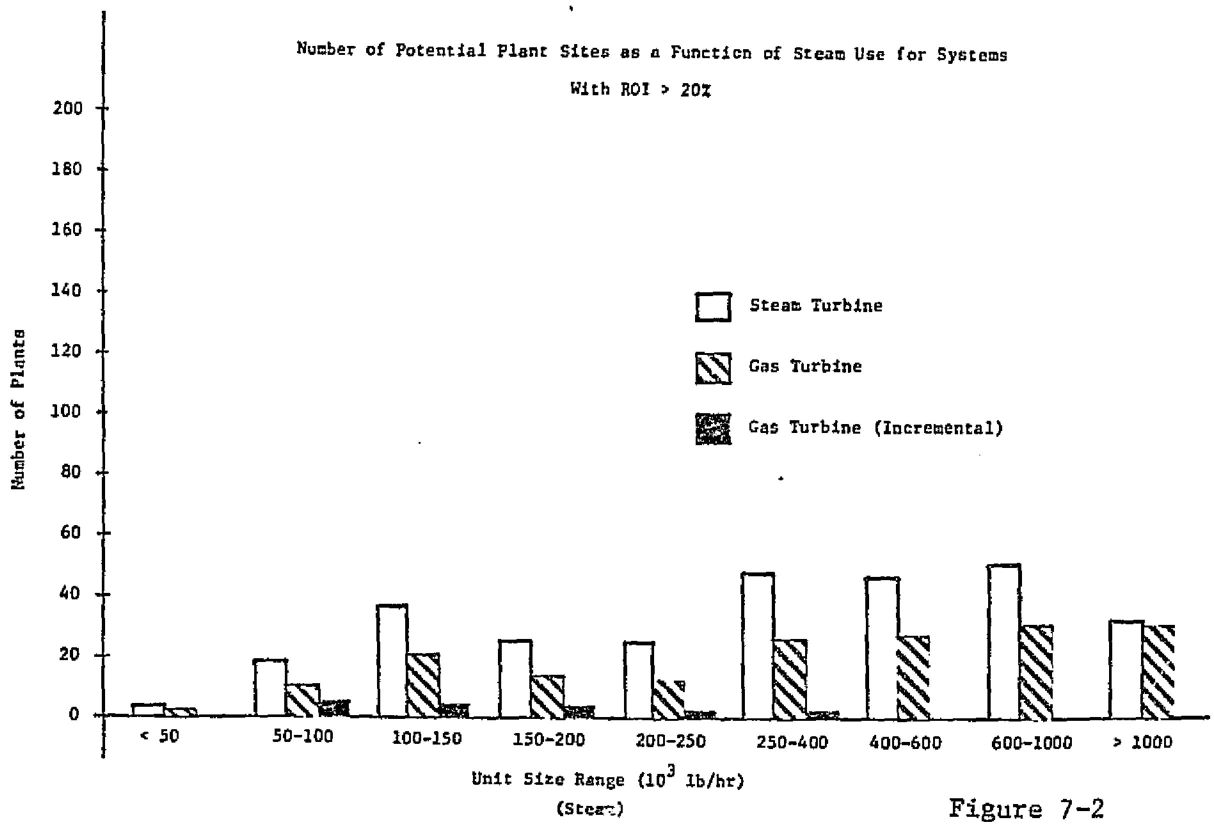


Figure 7-2

Table 7-7

SENSITIVITY TO PURPA

AVERAGE BUY/SELL = .85

% CHANGE IN BUY/SELL RATIO		NUMBER OF PLANTS	MW
+ 20%	STEAM TURBINE	+ 5%	+ 2%
	GAS TURBINE	+ 10%	+ 16%
	INCREMENTAL	+ 23%	+ 51%
- 20%	STEAM TURBINE	- 7%	- 3%
	GAS TURBINE	- 9%	- 6%
	INCREMENTAL	- 20%	- 26%

Table 7-8

AVERAGE SYSTEM SIZE

SYSTEM	ROI > 10%	ROI > 20%
	MW	MW
Steam	11	19
Gas	15	28
Gas (Incremental)	10	12

Table 7-9

RATIO OF $P_{COGEN}/P_{PLANT\ DEMAND}$

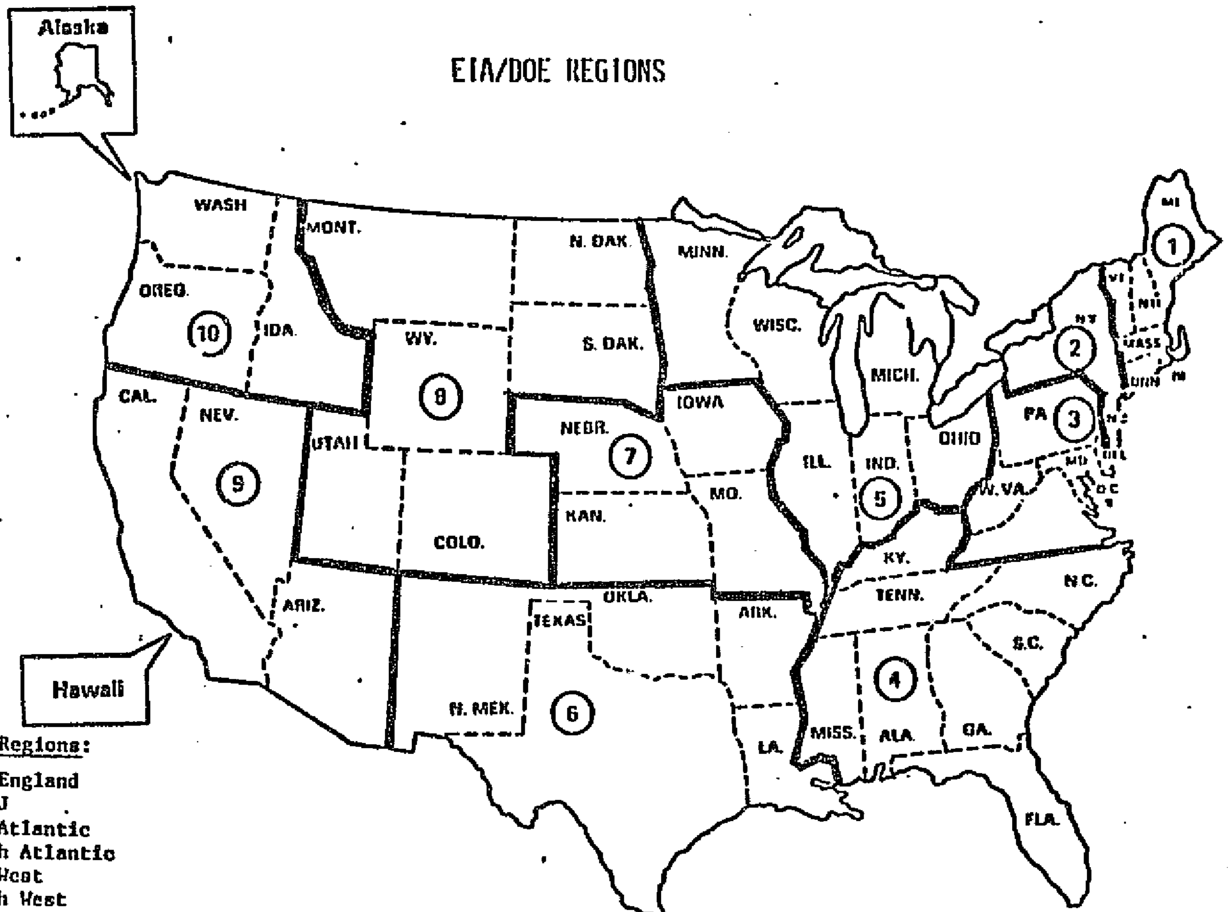
SYSTEM	ROI >10%	ROI >20%
Steam	.33	.35
Gas	.44	.53

Table 7-10

NUMBER OF PLANTS AS A FUNCTION OF RATIO OF $P_{COGEN}/P_{PLANT\ DEMAND}$

P_{COGEN}/P_{PLANT} RATIO	SYSTEM Steam (> 10%)	Gas (> 10%)
< .2	206	89
.2 - .5	245	243
.5 - 1.0	232	274
1.0 - 1.5	66	114
1.5 - 2.0	18	26
2.0 - 5.0	18	27
5 - 10.0	2	1
10 - 20.0	1	2
> 20.0	0	0
	788	776
	Ave. = .33	Ave. = .44

EIA/DOE REGIONS



Regions:

1. New England
2. NY/NJ
3. MID Atlantic
4. South Atlantic
5. MID West
6. South West
7. Central
8. North Central
9. West
10. North West

Figure 7-3

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Table 7-11

REGIONAL SUMMARY - ROI > 10%

REGION	STEAM No.Plants	STEAM MW	GAS No.Plants	GAS MW	GAS INCREMENTAL No.Plants	GAS INCREMENTAL MW
	SYSTEM					
New England	42	359	46	419	40	281
New York/New Jersey	79	478	84	545	73	480
Mid-Atlantic	118	884	118	1,143	71	675
South Atlantic	8	59	142	1,768	66	675
Midwest	75	43	69	934	36	316
Southwest	153	2,758	141	4,102	41	572
Central	51	524	51	711	21	229
North Central	24	212	24	258	6	151
West	60	508	60	756	32	241
Northwest	38	493	41	584	5	296
TOTALS	788	8,450	776	11,275	411	3,811

Table 7-12

REGIONAL SUMMARY - ROI > 20%

REGION	STEAM No.Plants	STEAM MW	GAS No.Plants	GAS MW	GAS INCREMENTAL No.Plants	GAS INCREMENTAL MW
	SYSTEM					
New England	13	222	10	195	0	0
New York/New Jersey	31	320	30	392	4	22
Mid-Atlantic	53	570	41	690	10	80
South Atlantic	42	5	23	785	0	0
Midwest	13	266	4	202	0	0
Southwest	63	2,108	31	2,251	0	0
Central	15	196	4	113	1	10
North Central	17	192	6	163	1	4
West	23	331	13	388	0	0
Northwest	11	183	5	91	0	0
TOTALS	281	5,227	167	5,274	16	118

Table 7-13

POTENTIAL NATIONAL MARKET BENEFITS

	ROI	GT	ST
Number of Plants	10%	776	788
	20%	167	281
Power Generation MW	10%	11,275	8,450
	20%	5,274	5,227
Electrical Cogeneration			
10^6 KWH/YEAR	10%	89,481	66,163
	20%	43,838	43,168
Steam Generation			
Thousands #/HR	10%	222,184	225,569
	20%	102,972	144,140
Total Fuel Savings			
Quads (Oil/Gas)(1)	10%	.28	.34
	20%	.14	.22

(1) Assumes only oil/gas backout of utility fuel.

Chapter 8

STUDY RESULTS

8.1 Plant Screening

The study is based on designing and evaluating cogeneration systems using the characteristics of the energy requirements for a specific industrial plant. The first part of the study - the plant screening effort - involved surveying four industrial plants to determine their energy requirements. Both coal fired atmospheric fluidized bed (AFB) open cycle gas turbine and steam turbine cogeneration systems were sized for these plants. Two of the plants then had estimates of the capital costs prepared for the cogeneration systems and performance and benefits established. An analysis was also made of the energy representativeness of the two plants, both in their own industry and compared to U.S. industry as a whole. Comparisons and evaluations showed key economic parameters, such as return on investment and levelized annual cost savings for the AFB/gas turbine cogeneration systems for both sites, met or exceeded the same parameters for the AFB/steam turbine systems at each site even though there was some increased capital cost required for the AFB/gas turbine cogeneration systems. Comparing the two sites against each other showed the Ethyl Corporation-Pasadena, Texas plant site exhibited better economic and institutional features, even with higher capital costs. The Ethyl Corporation plant site was judged to be the "best" plant site for application of the AFB/gas turbine system.

8.2 Conceptual Designs

A conceptual design was prepared for an AFB/gas turbine cogeneration system and for an AFB/steam turbine cogeneration system for the Ethyl plant. These conceptual designs are more detailed than the designs prepared for site selection. The capital costs and performance values showed that the data developed for the plant screening was valid. Comparisons of the two cogeneration systems again showed the AFB/gas turbine system, despite its higher capital costs, provided better economic performance. The superior ability of the AFB/gas turbine system to meet the specific characteristics of the plant site became readily apparent. This was due to the ease with which Dowtherm heating can be provided with the gas turbine cycle.

8.3 Market Analysis - Potential Benefits

This effort identified and evaluated the potential for new industrial cogeneration using the AFB/gas turbine and AFB/steam turbine technologies. The study showed that the AFB/gas turbine system will compete in the same market as the AFB/steam turbine. The number of plants both technologies that passes a 20% ROI hurdle rate is considerably diminished from that which exceeds a 10% ROI rate. Nevertheless, potential national benefits due to coal fired atmospheric fluidized bed technology is significant.

A potential industrial cogeneration market for the AFB/gas turbine system using direct hot air was not investigated. Direct hot air use could be a significant market for the AFB/gas turbine technology. This market cannot be readily served by steam turbine system

8.4 Findings

a. The AFB/gas turbine systems on a site specific basis show economic returns exceeding those of the AFB/steam turbine, despite increased capital costs.

b. The flexibility of the AFB/gas turbine technology permits matching this system closely to optimum plant thermal conditions.

c. The technology for the AFB/gas turbine system is well advanced and can be considered commercially available.

d. The AFB/gas turbine system should be considered in evaluation of industrial cogeneration alternatives available to those studying and considering the implementation of a cogeneration at an industrial site.

Section 1

TECHNOLOGIES

1.1 GENERIC DESCRIPTION OF AIR CYCLE AFB/GAS TURBINE COGENERATION SYSTEM

1.1.1 Basic System Description

The basic air cycle system and its major components are shown schematically in the process flow diagram of Figure A1-1. Fluidizing air is provided to the combustor by a forced draft fan. During cold startup, an oil or gas fired combustor heats the air to warm the bed to coal combustion temperature. The fluidizing air enters the bottom of the bed, passes through the bed, fluidizing it and combines with the coal to form flue gas. The flue gas passes through the freeboard and into an air preheater where heat is transferred from the flue gas to the incoming clean air. The flue gas next moves to a recycle cyclone system where the larger particulates are removed and returned to the bed through a trickle valve. The flue gas exits the top of the cyclone and is then used in the process or in a waste heat boiler to produce steam.

Clean air enters the gas turbine through the inlet silencer and is compressed (and increased in temperature) in the compressor section. Upon exit from the compressor, it is directed through the air preheater, where it obtains additional heat from the flue gas. It then moves through an inbed heat exchanger extracting heat from the bed. The heated air then enters the turbine section, where it powers the compressor and drives the alternator to produce electricity. The heat in the clean air from the turbine exit is then available for process use or for conversion to steam in a waste steam boiler.

Crushed dried coal and prepared limestone enter the bed through feed ports via an underbed feed system via pneumatic transport. Ash is removed through inbed drains passing through a fluidizing column which acts as a seal and into a water cooled fluidized bed ash cooler.

A detailed component description and a discussion of operation and control during startup, shutdown and operating transients are continued in the following sections.

In considering specific designs for air cycle systems, constraints were imposed based on state-of-the-art technology and current fluid bed design practice. Bed temperature was constrained to 1,650°F maximum, based on existing experience in fluid beds and on maintaining good sulfur capture. Turbine inlet temperatures are maintained at about 1,500°F, constrained by the bed temperature and

AFB COGENERATION SYSTEM
AIR CYCLE
BASIC FLOW DIAGRAM

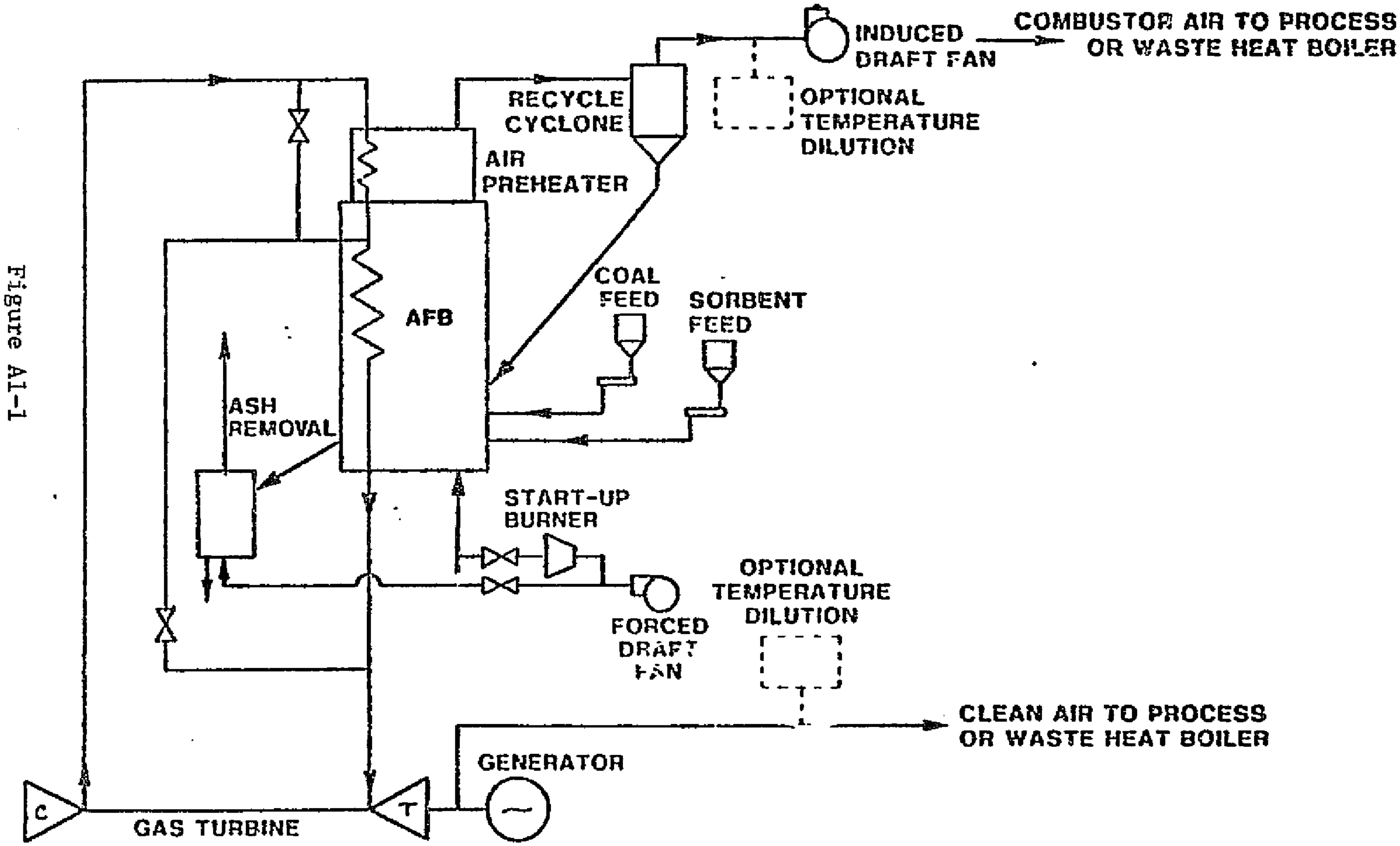

Figure A1-1

by stresses in the heat exchanger tubing and headers. Design point fluidizing velocities are maintained between 3.0 and 4.5 feet per second. Bed depth varies from 6.5 to 8.0 feet. Excess air is maintained at or above 30%. Only current commercially available gas turbines which have been configured for external combustors are considered. Only gas turbines with pressure ratios of less than 10 have been considered, both because there is no significant performance advantage to the higher cost, high pressure ratio machines and because lower pressures produce lower tube stresses.

1.1.2 Component Description

1.1.2.1 Atmospheric Fluidized Bed Combustor

The design concept for the AFB combustor is a single wall pressure vessel lined with refractory insulation with a U-tube heat exchanger in the active bed region. The general arrangement and construction of the AFB combustor is shown in Figure A1-2

The combustor vessel is cylindrical in shape. The roof enclosure is a cone with a rectangular outlet for the combustion gases. The AFB combustor is mounted above grade on a steel structure. The clear space below the vessel permits access for maintenance of the heat exchanger manifolds as well as clearance for removal of the vertical coal guns.

The material of construction is ASTM-A515, Grade 70 carbon steel. Penetrations and reinforcements of the pressure vessel shell are of the same material. Flanged long welding necks are made of ASTM-A105 carbon steel. The steel supporting structure is made of ASTM A-36 structural carbon steel.

The refractory insulation for the active bed region and three feet into the freeboard consists of Harbison-Walker Ufala brick backed with Harbison-Walker HW40-64 castable to maintain a temperature of 250^{o}F at the outer shell wall in the region of the active bed.

The Ufala brick, unlike ordinary 60% alumina brick is characterized by high purity and density and low porosity. At operating temperatures, these qualities make Ufala highly resistant to penetration and reaction by contaminants, including the mineral matter associated with various coals. Its low iron content and high firing temperature during manufacture result in a high degree of resistance to carbon monoxide attack. The brick lining provides a highly abrasion resistant surface in the active bed region.

The backup castable, HW40-64, is a medium density castable refractory (83 lbs/cu.ft.) with a low thermal conductivity (2.5 to 3.5 Btu/sq.ft./hr/^{o}F/in). This backup material has performed successfully as a backup liner on coal gasification applications.

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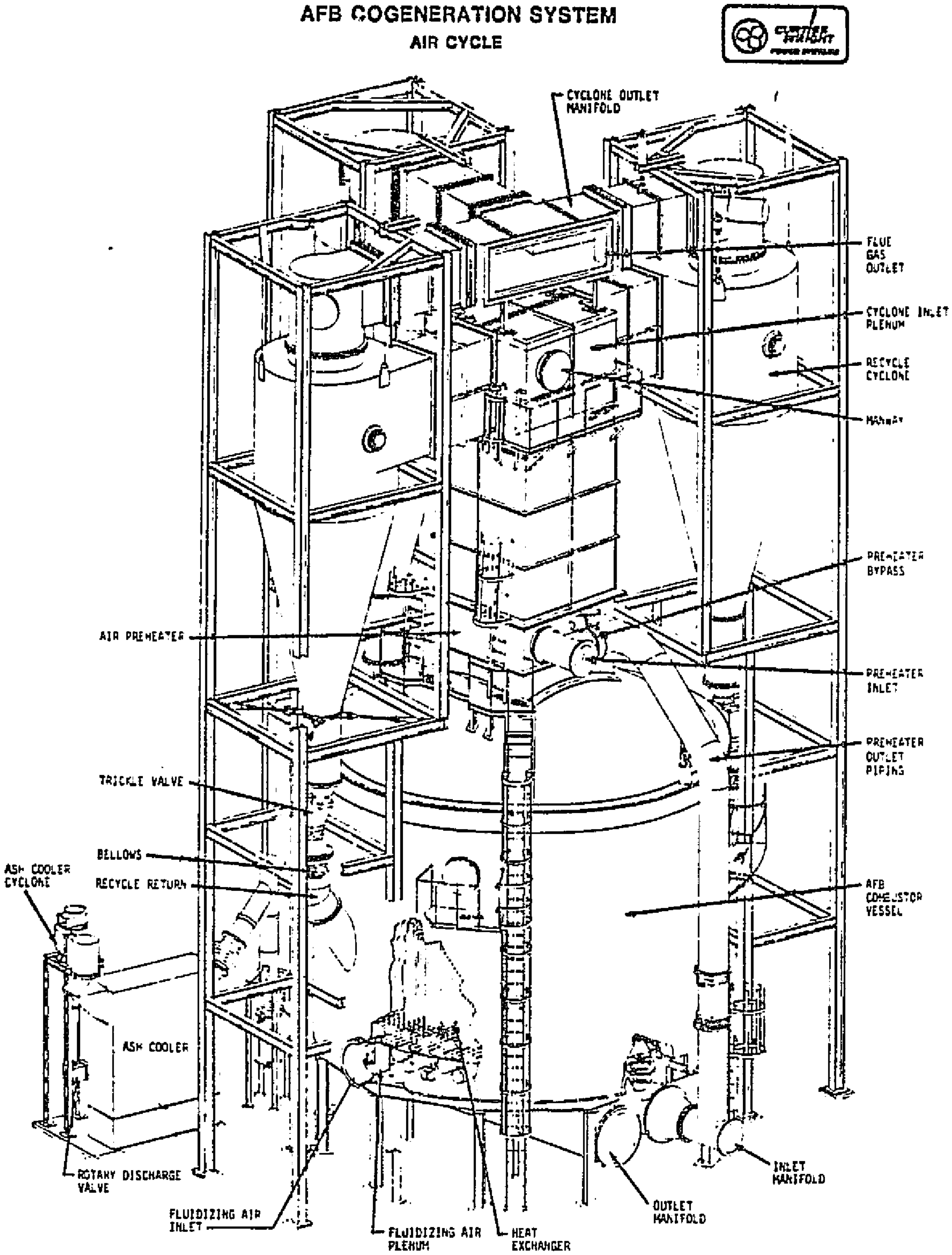

Figure A1-2

Immediately adjacent to the brick and backup castable in the freeboard section is a refractory transition of Hardcast ES. Hardcast ES is an abrasion and erosion resistant low iron castable which provides good protection against particulate laden gas and carbon monoxide. The remainder of the freeboard and the conical roof are lined with a two-component castable, gun applied. Adjacent to the vessel shell HW40-64 is applied. The inner face lining is Hardcast ES. The outer shell wall in the freeboard and conical roof is maintained at 250°F.

The primary recycle cyclone collected particles are returned to the combustor through a 30° angled port, the outlet of which is located one foot below the top of the active bed. The objective of the cyclone return is to maintain fines in the bed, thereby improving bed fluidization, heat transfer characteristics, sulfur sorbent utilization and combustion efficiency. The port is insulated internally with HW40-64 adjacent to the shell. The inner liner of the port is Hardcast ES.

The ash takeoff port is located 1'-6" above the bottom of the active bed. The port is insulated internally with HW40-64 adjacent to the shell. The inner liner of the port is Hardcast ES. Two weld necks are provided at the lower plate of the combustor to permit draining the inactive bed if required.

Circumferential gas barriers are provided adjacent to the vessel shell with a 30" pitch for the active bed and three feet into the freeboard. Each ash return port and the ash removal port have rectangular boxed-in gas barriers.

The monolithic refractory is installed with anchors mounted on studs, the spacing of the studs approximately 10" to 12" and the anchors are oriented at 45 degrees. The fire brick is laid up with super bond mortar with very thin mortar joints.

1.1.2.2 <u>Inbed Heat Exchanger</u>

Vertical heat exchanger tubes within the fluidized bed accomplish final heating of the turbine inlet air. The arrangement of these tubes is shown in Figure A1-3. The tubes are basically inverted U-tubes, 2-3/8" O.D., connected from inlet headers to outlet headers. The vertically oriented inbed tubes minimize the particle impingement angle with the tube wall to eliminate mechanical erosion as a factor in tube durability.

The 2-3/8" O.D. vertical heat exchanger tubes are located with approximately a 1'-6" open annulus adjacent to the I.D. of the brick and arrayed in a square pattern so that a minimum 4" aisle space exists between adjacent tube surfaces. This creates 4" passages which permit good circulation of solids in the combustor bed. Since the tubes are vertical, they occupy only about 8% of the cross-sectional

AFB COGENERATION SYSTEM

AIR CYCLE

(SECTIONAL VIEW)

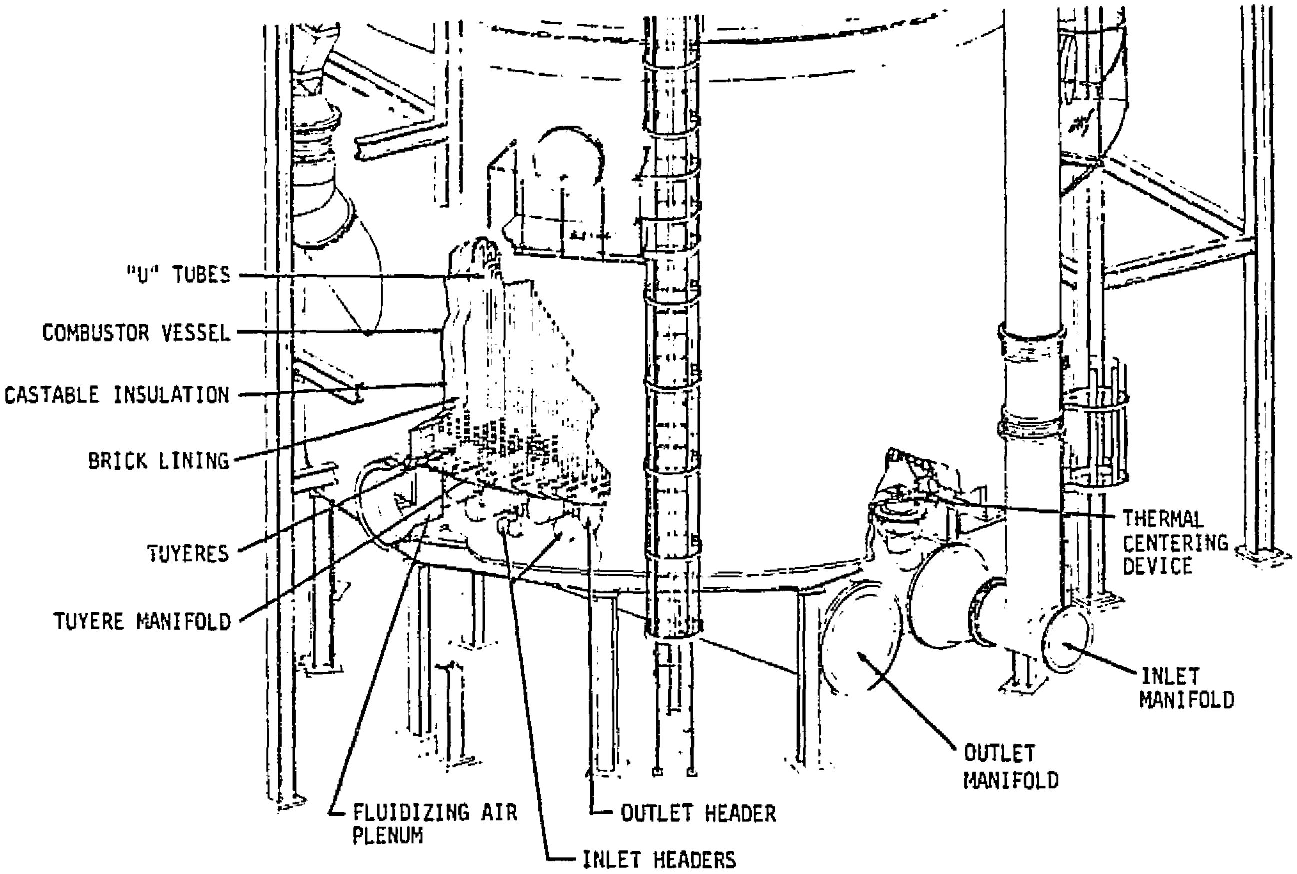

Figure A1-3

area of the combustor bed. This also promotes good circulation of solids which not only enhances combustion efficiency but permits starting of a bed at full slumped depth. This is especially advantageous during startup after bed slumping since the hot bed material does not have to be cooled and discharged and the bed upon restarting will reach operating temperature rapidly.

The U-tubes consist of 2" Sch. 80 pipe with a 2" NPT thread on one end. The tubes are made of controlled chemistry AISI 310 composition material specifying carbon to the high limit of a normal range, limiting the amounts of silicon and manganese and requiring an intentional addition of nitrogen. The U-bend is cast ASTM A351 Type HK 30 material. Two spoilers are integrally cast with the U-bend, one on each leg of the U-bend facing each other. They are semicircular in shape with a radius of 1-11/16". The spoilers are 1/4" in thickness. These spoilers minimize direct impingement of the bed particles on the U-bend, thereby minimizing the potential for erosion.

Each straight portion of tube contains an inner tube that forms an annulus to control the air flow for optimum heat transfer. This inner tube is made from ASTM 312-TP321 material. Three explosure rivet pins, material AISI 321, are provided at both ends to center the tube. This inner tube is positioned at the lower end by a pin, material AISI 310, that is welded into the outer tube wall.

Heat exchangers are shop assembled in modules for the AFB combustor. The module consists of the lower plate (6'-4" wide), a portion of the circular combustor steel wall (8'-5 1/8" high), two single warm air inlet headers, two dual warm air inlet headers, three dual hot air outlet headers, two sectors of the fluidizing inlet plenum and 24 rectangular tuyere manifolds.

That portion of the circular combustor steel wall which is shipped as the heat exchanger module contains all penetrations, gas baffles, insulation support structure, and refractory anchors. The heat exchanger modules are field erected above grade on the AFB combustor steel structure and welded into a single wall circular vessel. The single and dual warm air inlet headers are made of ASTM 312-TP321. The dual hot air outlet headers are made of ASTM B407 (incoloy 800H). The thredolets welded to both the warm air inlet headers and the hot air outlet headers are made of AISI 321 material. Each header has a cast tee/thermal sleeve assembly. The warm air inlet tee/thermal sleeve is made of ASTM A297GR CF-8C, and the hot air outlet tee/thermal sleeve is made of Manurite 900. The single warm air inlet header consists of one tee/thermal sleeve with a length of capped schedule 40 pipe welded to both ends of the run. Along the top of the single header the thredolets are welded to the headers. The warm air inlet dual header and the hot air outlet header construction is identical to the single header design except for the size of the pipe and two rows of thredolets, each row located 3-3/16" from the vertical centerline of the pipe. The straight 2" schedule 80 heat exchanger tube assemblies with the inner tube are threaded into the female thredolets. The 180° U-bends with the spoilers are butt welded to the two upright heat exchanger tubes.

The headers are attached to the AFB combustor lower plate at the upper flange of the tee/thermal sleeve assembly. The location of the attachment point is selected to minimize thermal stresses in the heat exchanger tubes. The headers are supported along their length, as required, in tee slots that permit unrestricted axial thermal expansion. The mounting flange of the tee/thermal sleeve assembly is provided with a groove for a ceramic air seal and a mechanical slip joint to eliminate thermal stresses between the hot flange and the cool base plate. The thermal sleeve section of each tee extends below the combustor base plate and is internally insulated with Keene mono-block and I.D. lined with ASTM A240 TP321 material. The insulation thickness is varied such that the lower flange operates at 250°F. These air header inlet and outlet ports are connected to inlet and outlet manifolds which are located below the vessel base plate.

The hot air outlet manifold operates at an external temperature of 250°F. The carbon steel manifold is internally metal lined and insulated with VSL 50 refractory and a Kaowool blanket wrapped on the O.D. of the inner liner. Each outlet internal liner is a tee with male and female slip joints. The tee is anchored at the centerline of the outlet plane with a double row centering system. This method of construction eliminates any requirements for bellows in the outlet hot air manifold and anchors the hot air header at approximately its center, minimizing the thermal growth.

The warm air inlet manifold also operates at an external temperature of 250°F. The carbon steel manifold is internally metal lined and insulated with VSL 50 refractory and a Kaowool blanket wrapped on the O.D. of the inner liner.

The construction of the warm air inlet manifold is identical to the hot air outlet manifold except for size. This method of construction, as in the hot air outlet manifold, eliminates any requirements for bellows and anchors the inlet header at approximately its center, minimizing the thermal growth.

1.1.2.3 Fluidizing Air Distribution

The combustion air is distributed to the bed through rectangular tubing as shown on Figure A1-3. The fluidizing distributor assembly is designed to handle 1,200°F air during the bed heatup cycle. The fluidizing distributors consist of inlet plenums made from ASTM A167 Type 321 which support the tuyere manifolds which are rectangular tubes (material ASTM A269 GR TP-347) located in the center of the 4" aisle space. Feeding the tuyere manifolds from both ends of the AFB combustors shortens the rectangular box beam, thus minimizing the thermal growth. Welded to the top of the rectangular tubing are tuyeres made of ASTM A351 Type HK-30. Each inlet plenum section is attached to the bottom AFB combustor plate with two round pins. One pin is inserted into a round hole receiver and the other into a slotted receiver to permit radial growth of the plenum. The pins are located to equalize the circumferential growth of the plenums. The plenums are interconnected by bellows. The outer end of each rectangular tube is supported by a vertical plate, material ASTM A167 Type 347, which is pinned to the hot air header and guided by the warm air header. The end of each tube is scarfed to facilitate movement through the bed material due to thermal growth.

1.1.2.4 Air Preheater and Bypass Loop

As shown in Figure A1-2, the air preheater is provided as an integral part of the combustor assembly and mounted on the top of the combustor above the freeboard section. The preheater is a cross flow, counter flow U-tube type exchanger. Tubing is 3" O.D. by .120 wall 304 stainless steel pipe. Tube sheets and manifolds are also of 304 stainless. The casing is of mild steel reinforced with square structural tubing, internally insulated with mineral wool and overlaid with castable refractory. Based on past experience, elutriated material should pass through the heat exchanger and soot blowers will not be required.

The air preheater is provided with a clean air bypass loop. This permits fine tuning of output during operation, and control during part load operation and transients.

The installation of the preheater piping and bypass loop is shown in Figure A1-2. A flanged tee with a branch is mounted on both the inlet and outlet of the air preheater. The two branches with an intermediate butterfly valve provide a bypass of the air preheater for the compressor discharge air. The outlet tee is hard piped parallel to the conical roof and parallel to the vertical wall of the AFB combustor. A double bellows is located in the vertical run upstream of a tee and is connected to the branch. The run of the tee is connected to the warm air header manifold with a thermal sleeve.

A flange is provided in the run concentric with the warm air header manifold connecting to the AFB combustor bypass line.

The hard piping is ASTM A312 GR TP321 with external insulation. A constant force spring hanger and a pipe guide is supplied for the vertical pipe run.

1.1.2.5 Recycle Cyclone Loop

The recycle cyclone loop is designed to handle hot effluent gas from the economizer for primary separation of entrained particles before the waste heat boiler and the baghouse. As the dust laden gas is introduced tangentially to the cyclones, the relatively coarser particles are separated from the gas stream by centrifugal force and discharged through the bottom of the cone section. The cyclones are designed for 93% removal efficiency and constructed with a refractory liner and steel shell.

The cyclone collected particles are returned to the combustor so the unburned carbon and entrained sorbent can be fully reacted. Another objective of the cyclone return is to maintain fines in the bed, thereby improving bed fluidization, heat transfer characteristics, and combustion and sulfur capture efficiency.

Particles collected in the cyclone are recirculated back to the bed through a pipe connection. Due to pressure differential incurred between the reactor bed and the cyclone discharge, collected particles may be flushed back into the cyclone, instead of flowing down to the bed, unless a means is provided to prevent it. A trickle valve mechanism is adopted for this purpose. Attached to the bottom of the cyclone discharge, the valve is normally closed. It remains closed until the static head of accumulated particles in the dipleg exceed the pressure differential. The valve then swings open, discharging the particles, until the pressure differential exceeds the static head of the particles. The valve is externally insulated.

Below the trickle valve assembly is mounted an insulated bellows assembly. This assembly provides for thermal growth variation between the combustor and the cyclone, trickle valve and ash return spool. It also compensates for tolerance variation between these components, including any mismatch between the trickle valve flange and ash return spool flange. The ash is returned to the AFB combustor through a refractory lined spool piece.

As shown in Figure A1-2, the recycle system is composed of cyclones in parallel, with a two-component castable insulation. Adjacent to the shell, AP Green VSL 50 is applied. The inner face lining is AP Green Loabrade.

Each cyclone has a separate discharge pipe provided with a trickle valve to recycle particulates back to the fluid bed.

The trickle valve assembly consists of two thermal sleeves and a Ducon trickle valve Type FA size 12. The trickle valve is externally insulated. Below the trickle valve is an internally refractory lined bellows. A lower ash return spool assembly completes the recycle cyclone loop. It is field fitted prior to installing the internal two-component castable. The dead weight and bellows aerodynamic load are supported by three constant force spring hangers on top of each cyclone.

Access to the recycle cyclones for inspection and refractory maintenance is through a manway located on the front face of the recycle cyclone inlet manifold.

A manway is also provided on the front face of the recycle cyclone outlet manifold for access to the cyclone riser outlet.

1.1.2.6 <u>Coal/Sorbent Feed Systems</u>

Coal and sorbent, previously sized in the preparation system to 1/8" x 0 and dried to less than 6% moisture, are fed into the fluid bed by a pneumatic distribution and injection system.

Feed rates are measured and controlled by use of variable speed drive weigh belt feeders. The two materials feed from their respective live bottom silos, by way of the weigh belt feeders, into a mixing hopper from which the coal/sorbent mixture is discharged through a constant speed rotary feed valve into the pneumatic distribution line. The rotary valve serves as the seal between the positive pressure pneumatic conveying system and the hopper. Air for conveying is generated by a positive displacement blower. The distribution system then provides for a number of flow splits in series through proprietary design flow splitters until the required number of feed point flow paths has been achieved. Flow path piping configuration and sizing is tailored to provide balanced flows in all legs, and provisions are incorporated for verifying this balance in the final installation.

Proper consideration is given in system design, both in equipment and piping systems, to the abrasive qualities of the conveyed materials.

The coal/sorbent mixture is then fed through coal guns into the fluidized bed at multiple locations immediately above the fluidizing air nozzles. The various elements of the system upstream of the rotary valves are vented to the silos which, in turn, are vented to a dust collection system.

1.1.2.7 Ash Cooling System

Ash discharges from the combustor bed by gravity, through a refractory lined pipe, into a vertical pipe column through which the ash is transported by a fluidizing column of air into an ash cooler. The discharge and transport arrangement also serves as a seal between the combustor and the ash cooler. The ash cooler comprises multiple beds in which the ash is further fluidized and cooling coils cool the ash to 300°F or less. Heat may be recovered from the ash by utilizing treated water as the cooling medium and flowing it through the ash cooler immediately prior to its entry into the feedwater heater.

The cooled ash now enters a second fluidizing column/seal system in which the heavier ash particles drop out and are discharged through an ash rotary seal valve into a positive displacement, blower propelled pneumatic conveying system which carries it into an ash bin. The fluidizing air from the ash cooler and seals, with the entrained lighter ash particles, is flowed through a cyclone in which the bulk of the entrained particles are separated and discharged through a second ash rotary valve into the ash conveying system and ash bin. The air is finally discharged through the facility baghouse for removal of the remaining entrained ash particles. In recognition of the abrasive qualities of the ash, abrasion resistant materials and/or linings are used in equipment and piping where required.

1.1.2.8 Forced Draft Fan/Startup Combustor

The forced draft fan is a commercial item and provides fluidizing air for the combustor. During cold starts, forced draft fan output passes through the startup combustor (also a commercial item). This burner is fired with distillate fuel and/or natural gas, and controlled to increase the temperature of the fluidized bed at a rate of 100°F to 200°F per hour to a maximum temperature of 1,200°F.

1.1.2.9 Gas Turbine

In the consideration of the various site cycles discussed in the report, selection of the specific gas turbine was an early and important consideration. Certain constraints were imposed on this selection. Since the AFB air system was to be commercially available in the 1985 timeframe, only engines currently in production and service at the time of this study were considered. To minimize investment, development time and costs, only engines which were configured for external combustion, or which through incorporation of a regeneration cycle, could be readily modified for external combustion, were considered. Engines with pressure ratios greater than 10 were excluded because of their higher cost, because the higher pressure ratio does not provide a significant performance advantage in this mode of operation and, further, because the higher pressure ratios result in higher stress on the tubes of the inbed heat exchanger due to the pressure differential across them. Engines with turbine inlet temperatures greater than 1,700°F were also not considered, since the relatively low clean air temperature provided from the fluid bed would require considerable derating.

1.1.2.10 Instrumentation and Control

A. Control Strategy

Two different control modes can be used to regulate and control the cogeneration plant output. One mode controls electrical generation and allows steam production to vary. Kilowatt output (or turbine inlet temperature) is used as the parameter to control coal injection into the combustor. The second mode controls steam production and allows kilowatt output to vary. With this second method, the steam demand is the controlling parameter for coal injection. The control concept proposed by Curtiss-Wright is capable of efficient operation in either of the above modes.

Turndown to half combustor heat load can be achieved by reducing coal flow while maintaining constant fluidized bed parameters of bed temperature, fluidizing velocity, bed level and coal/dolomite ratio. Further reduction to one-third load requires a scheduled reduction of fluidizing airflow and bed temperature. Minimum values considered acceptable for these variables are 1,450°F bed temperature and 70% of the design fluidizing airflow, which results in 63% of design fluidizing velocity.

The gas turbine is monitored by the Direct Digital Control (DDC) System for control performance, and protection. The interface between the gas turbine and the DDC System is made through computer-automatic-manual (CAM) controllers. This provides a maximum in redundant control in the event of potential component malfunctions.

Parameters that are directly monitored by the analog and digital control systems are speeds, temperature, pressures, and ancillary equipment employed for vibration and fire protection. The electrical generation portion of the gas turbine is controlled by a voltage regulation system provided by the generator manufacturer. Current and potential transformers shall supply the signals for control and protection. Coventional protective relays shall be used for the generator's protection.

The waste heat boiler system is controlled to standard industry practices. A three-element controller is incorporated to control boiler feedwater flow. The digital control system receives status updates of steam pressures and flow, feedwater flow and feedwater level in the boiler drum for overall boiler control. The steam pressure and flow signals interface with the digital control system and provide the feedback for a closed loop steam production control.

All of the equipment in the combustor support system (coal/dolomite handling, coal preparation, ash cooling and removal, instrument and purge air) are controlled and protected as required to provide a totally coordinated and efficiently operated process plant.

B. Control System

The plant control system will consist of a hierarchy of three separate but interacting systems: a Digital Control System, an Analog/Manual Control System and a Safety Interlock System. A three-level system such as this provides the simplest, most cost-effective, and most reliable way of implementing an overall control strategy by using appropriate hardware for each of the three functions.

The Safety Interlock System is active at all times and provides basic safety interlocking during startup, normal operation, normal shutdown, and emergency shutdown. The system consists of process switches and programmable controller/based logic.

The Analog/Manual Control System acts as a backup to the Digital Control System by providing a basic level of monitoring and control of fluidized bed and process parameters to ensure safe and stable, but not necessarily efficient, plant operation. All Digital Control System outputs to final control elements are routed through backup stations to provide control in the absence of Digital Control. Manual backup stations allow manual control of most process parameters. In addition, critical parameters are backed up by analog/manual backup stations to maintain stable conditions. Some non-interacting loops are controlled by analog controllers only.

The Digital Control System provides the highest level of monitoring and control for efficient plant operation. It provides more effective control of process and fluidized bed parameters than that provided by the Analog/Manual Control System, and more effective interlocking and alarming than that provided by the Safety Interlock System.

In addition, the Digital Control System provides optimized combustion and emissions control, and control of power generation and steam production. Multiple AFB/gas turbine facilities can be controlled by a single Digital Control System.

The Digital Control System consists of minicomputer-based hardware. It has appropriate input/output hardware for interfacing with field instrumentation, final control elements, and the Analog/Manual Control System. A color CRT provides extensive process visibility to the operator. Data communications capability will allow interfacing with an existing or future plant energy management computer system for optimum load scheduling, remote data logging and reporting, etc.

The plant control system consists of rugged and reliable electronic components that have established a satisfactory performance and reliability record in industrial process applications.

C. Control Hardware

The control equipment will consist of a digital control center plus additional analog dontrols to be the "front-end". The combination of these controls provides a true DDC control system. The heart of the control system is the digital based mini-computer. The computer has a solid state memory into which the necessary mathematical equations can be stored for control and performance calculations. The memory also maintains the formats for CRT displays and the data logging printer. Memory files store input and output data for the desired manipulation. A CRT operator console will be the plant operator's direct access to the computer. With it, the operator can safely vary process control set points as necessary to increase or decrease the plant output. By utilizing any of the input data, real time performance calculations and plotting can be done by the computer. The computer system is comprised of five major components: Digital Computer (CPU), Input Multiplexer, Output Multiplexer, Power Supplies, and Peripheral Units. The Process Control Computer will be designed for data logging, direct digital control and batch sequencing functions. Its data logging functions include alarming, data printing, special calculations and operator displays.

D. Control Software

Continous control software will provide DDC control for the process utilizing all standard control strategies as well as real time loop optimization. Batch control of software provides the sequencing capability to accomplish automatic plant startup, operation, and shutdown as well as providing subsystem (materials handling, etc.) control.

The control software programs and functions as listed below:

a. Display Control Program
   1. High level language
   2. Real time displays (including colored graphics with dynamic outputs)
   3. Alarming
   4. Logging
   5. Recording
   6. Special calculations

b. Continuous Control Program (DDC)

c. Batch Control Program (Sequencing)

E. Environmental Monitoring

Environmental monitoring equipment will be provided to monitor gas and particulate emissions of the plant. A description of this equipment is as follows:

Gas Analysis

A gas analysis system with on-line capability for the real time analysis of gases such as NO_x, CO_2, O_2, CO, and SO_2 will be provided. The display of data is available at the instruments and through the digital control system on a CRT, a printout on a data logger (hard copy), and continuous trend analysis of a chart recorder.

The typical methods of analysis will be as follows:

NO_x - Chemiluminescence

SO_x - Pulsed fluorescence

CO - Non-dispersive infrared

O_2 - Electrochemical

CO_2 - Non-dispersive infrared

The gas analyzer system will sample the above gases at specified locations so as to provide an index of gas levels and concentrations related to the combustion process. It will also provide pertinent on-line data so that the operator can control the process to remain within the prescribed limits of environmental considerations. Data outputs are used for performance in establishing combustion efficiencies of the process.

The gas analyzer system as described above has been employed by Curtiss-Wright and has demonstrated its technical capability, performance and reliability.

Particulate Grab Sample

The stack will be designed to accomodate a particulate grab sample system in accordance with EPA Method 5. The grab sampler provides sampling capability for off-line detailed particulate analysis.

Filters are provided for extractive isokinetic sampling of particulate emissions. This method of collection will permit laboratory analysis of particulate data meeting the requirements of EPA Test Method 5.

1.1.3 System Operation and Control

The basic mode of operation of the air cycle system has been described in Section 1.0 for design point steady state operation. This section describes operation and control during normal and emergency transients.

1.1.3.1 Cold Startup Sequence

Start forced and induced draft fans to start airflow through the AFB and fluidize it. Fire the startup burner to heat the bed and process piping. Ramp the startup burner at 100°F per hour rate to achieve 1,200°F at the combustor inlet. When the burner temperature and bed temperature reach 1,200°F, start the coal injection system to start feeding coal, and being ramping down the startup burner to shut off. As the bed temperature is increased to 1,400°F, start the gas turbine with a conventional DC electric starter and bring it up to gas generator idle speed.

At this time, with Control Valve CV-2 open, close Control Valve CV-3 to direct compressor discharge air through the air preheater. Use Control Valve CV-2 to modulate airflow through the heat exchanger, increasing turbine inlet temperature until it is self-sustaining and disengage starter. Continue to increase bed temperature, using CV-2 to maintain gas generator speed. At a bed temperature of 1,450°F, the control system will generate a signal to close CV-2 as necessary to achieve turbine synchronous idle speed. At this point, breaker closure is initiated and the gas generator is automatically maintained at synchronous speed by modulation of CV-2.

When generator voltage and phasing has been verified by the Auto-Synchronizer, the breaker is closed. Control Valve CV-2 must immediately respond to accommodate the increase in load on the system. The unit is now available for operation and controlled by feeding coal to match steam demand with 1,650°F bed temperature as an upper limit. Electrical power is produced as a byproduct.

1.1.3.2 Hot Startup Sequence

If the plant has been shut down recently and the bed is still at or above 1,200°F, it is possible to start on coal with no preheat. The bed temperature is important in such a start because of possible overheating of the flue gas boiler. Assuming that the temperature is below 1,476°F to 1,500°F, the procedure can be a simple resumption of the cold startup at that condition. If the temperature is higher, however, a simultaneous start of the gas turbine will be required to maintain boiler temperature at or below design level.

1.1.3.3 Plant Turndown

The primary and most efficient method of reducing the output of the plant is to turn down the combustor. Combustor turndown can be achieved by reducing coal flow. Both fluidizing air and bed cooling airflow are simultaneously reduced. This permits maintaining bed temperatures near the design plant for up to 50% turndown. In order to attain turndown of this nature, steam production demand signal or kilowatt demand signal must be reduced depending on the control mode being used.

1.1.3.4 Steady State Operation

For this discussion, steam production shall be considered the basic operating mode. The combustor is controlled via coal feed to maintain the desired steam demand. Electrical power production will vary depending upon the steam demand.

Other modes of control can be made available depending upon the preference of the customer. In any event, the primary control variable is coal feed and the same safety features in terms of alarms and trips are active for any control mode.

1.1.3.5 Normal Plant Shutdown

For normal shutdown, ramp coal flow to zero and open valve CV-2 to lower the turbine inlet temperature. Generator output and steam production will decrease proportionally to a decrease in turbine inlet temperature. This will continue until the generator is fully unloaded and the breaker is open. When the breaker is open, the forced draft and induced draft fans are shut down and the bed is slumped.

1.1.3.6 Emergency Shutdown Procedure

The most common form of emergency requiring specific corrective action is loss of electrical load. Such an event requires immediate reduction of turbine power to zero to prevent possible catastrophic overspeed of the power turbine and generator. Turbine power can be reduced at an adequate rate by rapid opening of the bypass valves CV-2 and CV-3 to reduce turbine inlet temperature to the synchronous idle level or below. Coal flow must be reduced to minimize bed temperature. The bed need not be slumped and over-temperature of the flue gas boiler can be avoided by closing valve CV-3 and opening CV-2 when the initial crisis is over and the gas turbine has reached synchronous idle temperature. Normal synchronization and load increase can then be executed when the electrical fault is corrected, or a normal shutdown can be carried out if necessary.

An emergency requiring gas turbine shutdown, such as mechanical failure, will require that the bed be slumped to avoid excessive temperature to the flue gas boiler.

Other transients than those mentioned will, in general, reduce system temperatures and pressures with no adverse mechanical consequences. It should be noted, however, that there will be steam production at any time the bed is operating, so that any emergency requiring cutoff of steam flow will require a complete shutdown of the plant.

1.2 MATERIALS OF CONSTRUCTION

1.2.1 Inbed Components

The materials selected for the inbed components of the atmospheric fluid bed are in conformance with the ASME Boiler and Pressure Vessel Division 1 Code. Material selection is based generally on Curtiss-Wright's background in the design of nuclear components and gas turbines, and on testing conducted specifically to evaluate materials operating in fluid bed environments. Curtiss-Wright has conducted over 12,000 hours of such FBC testing, including 4,300 hours in an AFB and 3,500 hours in a PFB. In general, Curtiss-Wright's results have been confirmed by the published results of others, including Oak Ridge National Laboratory (ORNL/TM-7734/P1 - Corrosion of High Temperature Materials in AFBC Environments) and EPRI (EPRI CS-1475 - Materials Problems in Fluidized Bed Combustion Systems).

A. Materials - Heat Exchanger Section

The heat exchanger section of the proposed atmospheric fluidized bed consists of the heat exchanger tubes, 180^{o} elbows, tube extensions from the manifolds, hot and warm headers and hot and warm external manifolds. The material selection for these components is discussed below.

In the "air-heater" fluidized bed concept, the metal temperature of the tubes is essentially the same as the fluidized bed temperature. Material selection for the heat exchanger must consider elevated temperature strength, erosion/corrosion resistance, oxidation/sulfidation resistance and fabricability. Curtiss-Wright's experience has indicated that mechanical erosion is not significant with vertical placement of the heat exchanger tubes, since low impingement angles of the abrasive particles and the low fluidizing velocities employed tend to minimize resultant mechanical erosion. The 180^{o} elbows, which will be subject to impingement of abrasive particles which could cause mechanical erosion, will be protected by "spoilers" which have been shown to be effective, in testing at Exxon's miniplant, in preventing erosion at much higher velocities. Internal oxidation by the clean air is not a significant factor since the material specified for this application is resistant to appreciable scaling to a temperature of 2,000^{o}F.

The major considerations in the selection of a material for the heat exchanger tube application are the ability to withstand the fluidizing bed atmosphere coupled with adequate high temperature strength to permit structural design. This atmosphere is dynamic, fluctuating and non-uniform, which is neither in chemical nor thermodynamic equilibrium. The combustion gases can vary instantaneously between an oxidizing, reducing, carburizing and sulfidizing potential. In addition, it is also possible that areas of low oxygen partial pressure can exist during coal combustion, and this condition in the presence of calcium sulfate can produce high sulfur activity.

Curtiss-Wright has chosen a modified AISI 310 composition material for this heat exchanger tubes. This choice was based on the extensive rig and operating fluid bed testing by Curtiss-Wright and others as noted above. This choice was based on superior corrosion resistance and adequate elevated temperature strength of the 310 material.

Originally, the only limitation that concerned Curtiss-Wright in the use of AISI 310 type material was the possibility of the formation of an embrittling intermetallic phase of chromium-iron, known as "Sigma", after prolonged heating in the range of 1,050-1,700^{o}F. Sigma Phase formation results in a significant drop in room temperature ductility, and there is also concern that oxidation corrosion resistance might be affected in the FBC atmosphere.

The potential susceptibility of the 25 chromium/20 nickel stainless steel (AISI 310 Type) to Sigma Phase prompted Curtiss-Wright to specify an AISI 310 controlled composition which was formulated to retard the formation of Sigma Phase. This composition consisted of specifying carbon to the high limit of a normal range, limiting the amounts of silicon and manganese and requiring an intentional addition of nitrogen.

Recently, a technical report, "Properties of Sandvik 15XRE 19" dated August 24, 1982 and written by H. Wilhelmsson, reported on the formation of Sigma Phase of various type AISI 310 alloys. The materials tested in the report were AISI 310S (low carbon), standard AISI 310 and the modified AISI 310 (15XRE 19 - similar composition to Curtiss-Wright's controlled chemistry 310), all tested by aging for 2,000 hours at 700^{o}, 750^{o}, 800^{o} and 850^{o}C. Microstructure examination of samples of each condition for all materials showed significant Sigma Phase formation for both the AISI 310 and 310S, with very small amounts at the grain boundaries for the modified 310. In the Charpy-V notch tests conducted by Sandvik, marked differences between the three type 310 materials existed. AISI 310S, which forms high amounts of Sigma Phase, has a drastic reduction in impact strength, while the modified AISI 310 showed only a slight decrease in impact strength due to precipitation of carbides and nitrides. The testing conducted by Sandvik indicates that Sigma Phase formation of the AISI 310 material can be controlled by selection of composition.

In the material selection process for the heat exchanger tubes, various other materials were considered. Of particular interest were Inconel 600 (70% nickel), Inconel 671 (50% chromium, 50% nickel) and Incoloy 800H (35% nickel, 20% chromium) because of their superior high temperature strength. However, testing by Curtiss-Wright and others has shown that an alloy with at least 25% chromium content and a limited nickel content was required to provide corrosion resistance in the FBC atmosphere. Many of the nickel alloys, particularly Incoloy 800H and to a lesser extent Inconel 671, are "bellwether" or indicator alloys (see EPRI report previously cited). Testing of these alloys often indicates relatively acceptable corrosion rates in oxygen-rich atmospheres but the onset of rapid corrosion in a reducing atmosphere. Because of the possibility of local or general upsets of the bed during prolonged industrial operation under variable load, Curtiss-Wright has chosen not to use these alloys.

The material specified for the 180° elbows and spoilers will be the same composition as the AISI 310 heat exchanger tubes if fabricated from wrought material. An option to the wrought material fabrication is the use of ASTM A351 Type HK 30 (AISI 310) castings with integral "spoilers." Components internal to the tubes will be fabricated from type 321 18-8 titanium stainless steel.

The hot headers, which operate at approximately 1,600°F but are not in contact with the combustion process, will be fabricated from Incoloy 800H because of its higher strength at elevated temperature. All warm headers will be fabricated from type 321HSS type material (18-8 titanium stabilized) to provide adequate strength, and oxidation and corrosion resistance. Also, all tube connections from the hot and warm headers to the heat exchanger tubes likewise will be fabricated from wrought or cast forms of 18-8 stainless steel.

All manifolds will be constructed of carbon steel ASTM A515 Grade 70 material, with insulation to provide a maximum operating temperature of 250°F and with internal metal liners to protect against refractory spalling. The liners are type 321HSS to provide necessary oxidation and corrosion resistance.

B. Materials - Air Distribution System

The air distribution system consists of tuyeres that operate in the active bed, tuyere manifolds which are in and below the active bed, and tuyere supply headers which are situated below and outside the fluidizing bed.

All tuyere bodies will be cast from AISI A351 (HK-30) material which contains a carbon level of 0.25/0.35. The petrochemical industry has been using this type material operating between 1,500-1,700^{o}F with excellent results with no major problems due to Sigma Phase formation. Industrial experience and previous investigations have concluded that the cast version of AISI 310 material is more resistant to Sigma Phase formation than its wrought counterpart.

The rectangular section of tuyere manifold will be fabricated from type 347HSS columbium (niobium) stabilized 18-8 type stainless steel. Maximum temperature of operation which occurs during cold startup of the unit is 1,200^{o}F. Type 347 material was chosen for this application since air holes on the bottom of the manifold could cause some fluidized combustion below the top of the bed. While this combustion will not result in metal temperatures equivalent to those in the combusted fluidized bed, a material that had been shown by tests to be resistant to inbed corrosion should be specified for this application. Tests conducted at the Stoke Orchard Test Facility by the National Coal Board confirmed the excellent corrosion resistance of the type 347HSS material.

The tuyere supply headers, which will operate at a maximum temperature of 1,200^{o}F (again during cold start) and are not in contact with the products of combustion, will be fabricated from type 321HSS titanium stabilized 18-8 material. This material was chosen to avoid any corrosion problems associated with "sensitization" when exposed to long-term service at 1,200^{o}F operation.

1.3 FLEXIBILITY OF THE AIR CYCLE AFB COGENERATION SYSTEM IN MATCHING INDUSTRIAL PLANT DEMANDS

One of the significant advantages of the air cycle is its ability to match a variety of plant thermal and electrical demands by the modular addition of components and by relatively minor changes to components.

Figures A1-4 through A1-7 demonstrate one type of flexibility. In these figures, the basic components of the air cycle system (those shown in Figure A1-4) have been held constant, as has the coal and dolomite input at 17,400 lbs/hr and 6,200 lbs/hr, respectively. Output variations have been obtained by the addition of ancillary components. The electric power output is 5.8 MW for the processes shown in Figures A1-4 through A1-6, while it is 8.8 MW in Figure A1-7. Clean air flow for all processes is 396,000 lbs/hr.

Still more flexibility is available by variations in some of the components in the design stage, as is illustrated in Table A1-1. Two particular points should be noted from this table. First, the incorporation of supplementary gas firing of the waste heat boiler or the gas turbine can provide, within the basic system, at least partial steam or steam and electric backup when a coal-related component is down for maintenance. Second, the air cycle AFB cogeneration system can serve a wide range of electric to thermal ($E/_T$) plant demand ratios. Note that the values given for each of the configurations is representative and, by combination of the variations, virtually any value of $E/_T$ from 30 to 150 KW/KPPH can be obtained.

AFB COGENERATION SYSTEM

AIR CYCLE

PROCESS AIR SUPPLY

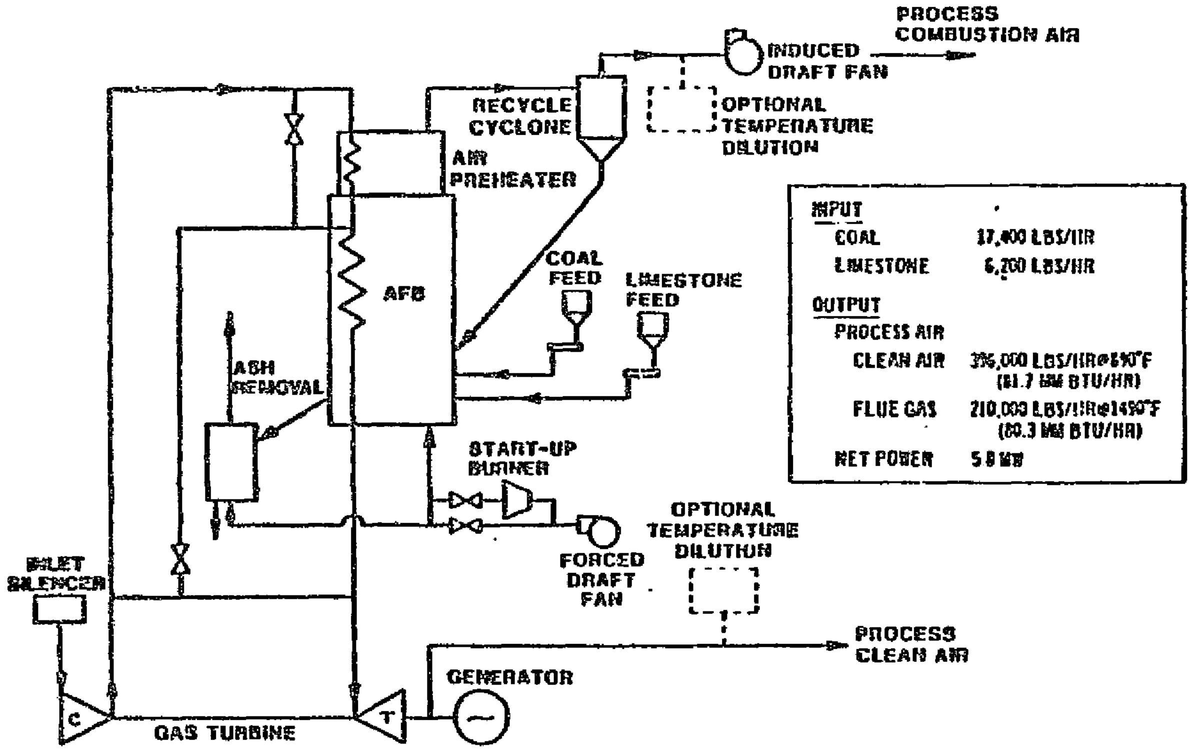

Figure A1-4

AFB COGENERATION SYSTEM
AIR CYCLE
STEAM AND PROCESS AIR SUPPLY

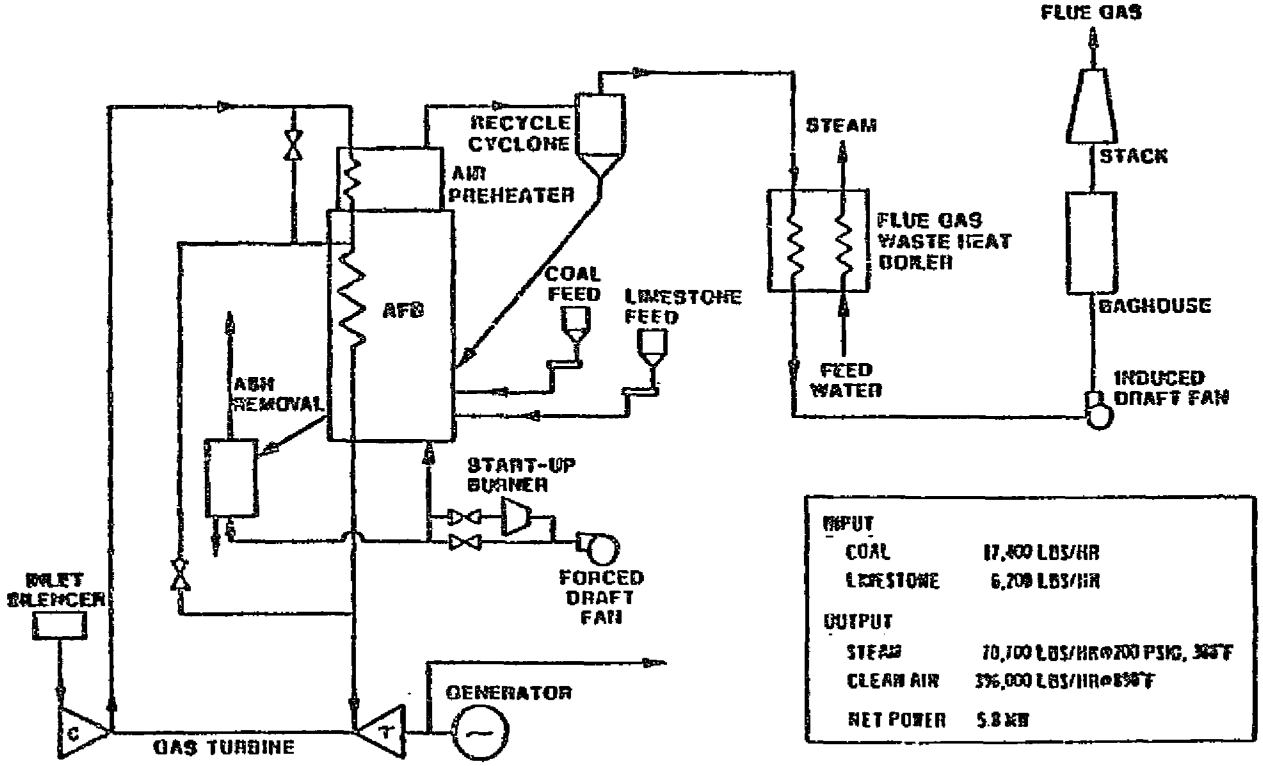

Figure A1-5

AFB COGENERATION SYSTEM

AIR CYCLE

STEAM SUPPLY

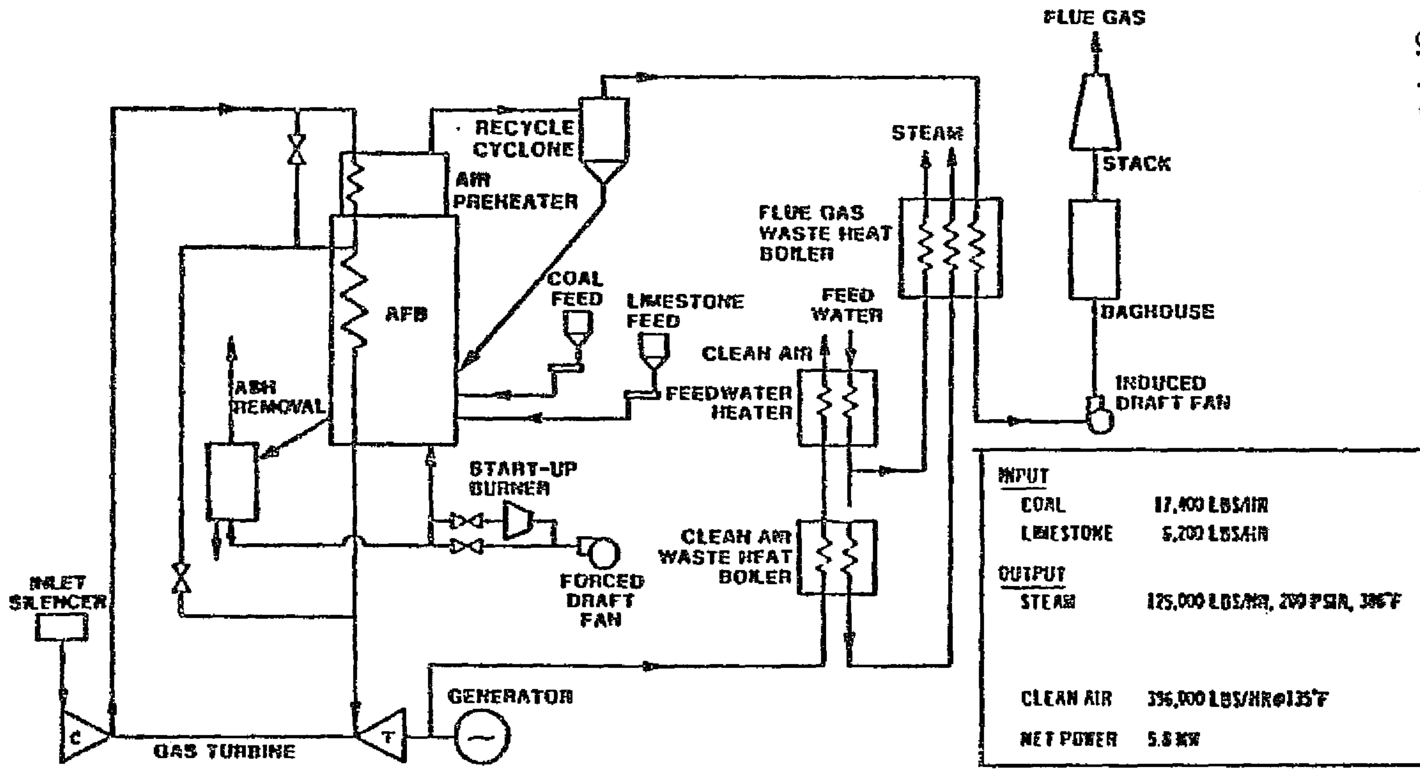

Figure A1-6

AFB COGENERATION SYSTEM
AIR CYCLE
ELECTRIC SUPPLY

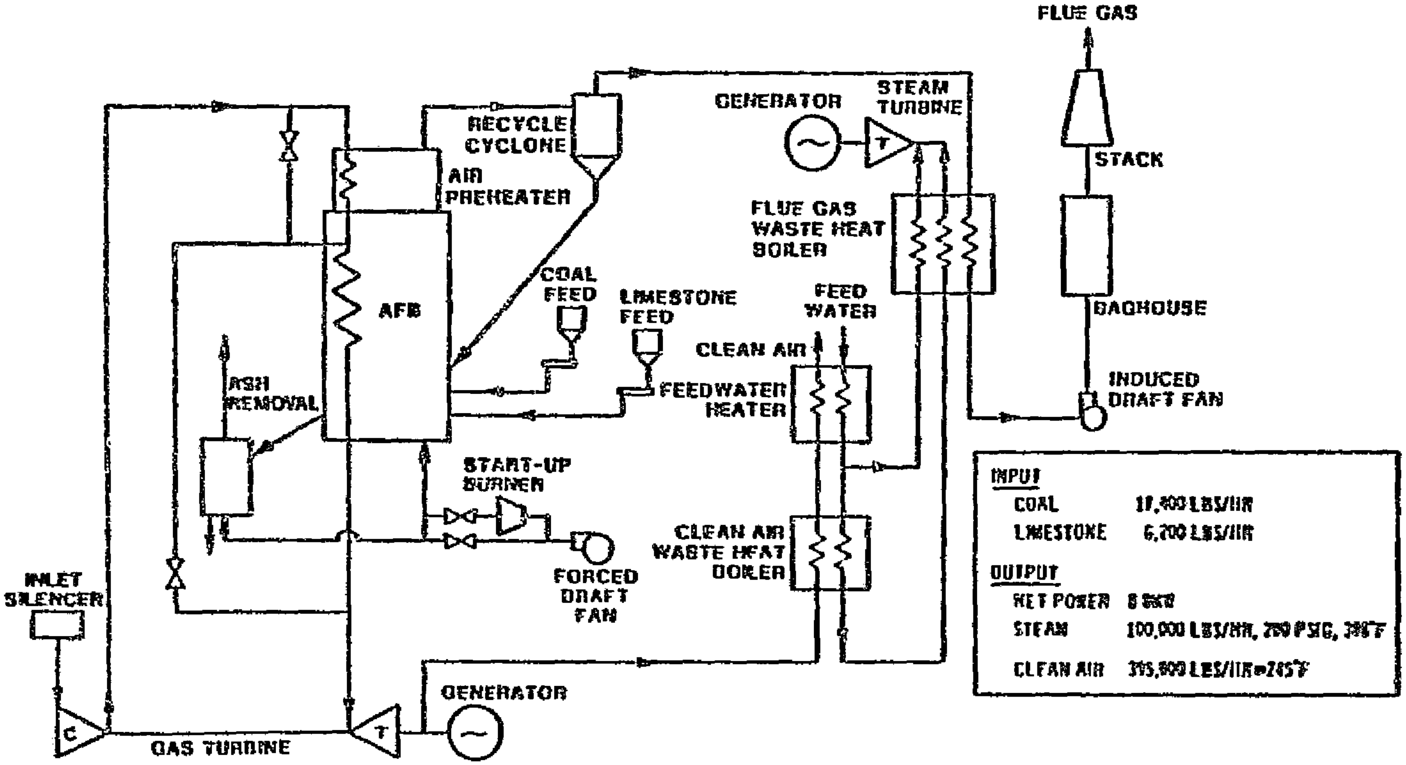

Figure A1-7

A1-29

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Table A1-1
AIR CYCLE OUTPUT FLEXIBILITY

BASIC SYSTEM PRODUCING HIGH TEMPERATURE FLUE GAS, WITH WASTE HEAT BOILERS (WHB) PRODUCING LOW PRESSURE PROCESS STEAM FROM FLUE GAS AND CLEAN AIR E/T = 45 Kw/Kpph

VARIATIONS IN SYSTEM POSSIBLE WITHOUT CHANGING MAJOR COMPONENTS (GAS TURBINE, FBC, COMBUSTOR/HEAT EXCHANGER)

1. GENERATE STEAM AT HIGHER PRESSURE IN WHB AND ADD BACKPRESSURE TURBINE E/T = 115Kw/Kpph

2. MODIFY AIR PREHEATER SO CLEAN AIR EXTRACTS MORE HEAT FROM FLUE GAS E/T = 70Kw/Kpph

3. COMBINE 1 and 2 ABOVE. E/T = 150Kw/Kpph

4. ADD SUPPLEMENTARY FIRING TO WASTE HEAT BOILER (NOTE. IN ACTUAL OPERATION, THIS CAN BE PARTICULARLY ADVANTAGEOUS BY LETTING SUPPLEMENTARY FIRING HANDLE RAPID LOAD SWINGS AND BASIC AFB/GT HANDLE BASE LOAD. WASTE HEAT BOILER CAN ALSO SERVE AS LIMITED STEAM SYSTEM BACKUP BY INDEPENDENT OPERATION) E/T = 30Kw/Kpph

5. ADD SUPPLEMENTARY FIRING TO GAS TURBINE (GT OPERATING ON GAS CAN SERVE AS ELECTRIC AND STEAM BACKUP WHEN AFB IS DOWN FOR MAINTENANCE).

1.4 TECHNOLOGY READINESS OF THE AIR CYCLE AFB

There is no technological barrier to the commercialization of air cycle atmospheric fluid bed/gas turbine cogeneration. Many of the system components are standard commercial items, while the "new" items are derivative from well-proven technology. The remainder of the section will be devoted to demonstrating these statements.

Table A1-2 lists the components of an AFB/gas turbine system. The distinction between integral and ancillary components is somewhat arbitrary, but is made so that it can be simply said that all of the ancillary components are clearly commercially available items.

Table A1-3 describes the status of the integral components. The startup combustor is a duct burner operating on oil or gas, and can be purchased as a packaged item with the forced draft fan. The ash removal system consists of a fluidized column which acts as a seal, and a conventional water-cooled fluid bed heat exchanger. The air preheater is a high-temperature heat exchanger, similar in characteristics to items regularly used in the chemical and petroleum industries, and is commercially available. The gas turbine is also commercially available, since it can be any one of a number of currently sold engines which are adaptable for external combustion, either directly or through a regenerator. Two major points on the gas generator in this cycle must be remembered: It operates on clean air, uncontaminated by any products of combustion; and its turbine inlet temperature is approximately 1,500°F. Thus, its operating regime in the air AFB system is less severe than in normal gas or oil fired operation.

The recycle system consists of cyclones, trickle valves and associated ducting while the coal and sorbent feed system consists of inbed guns fed by a dilute phase pneumatic conveying system, each of which is currently being demonstrated in a variety of AFBs including the B&W 6 x 6 unit, the Great Lakes unit, the TVA 20 MW unit and others. Similarly, control system software for the AFB is being demonstrated in a variety of projects, and specific gas turbine integration with a fluid bed will be demonstrated on Curtiss-Wright's 13 MW PFB pilot plant scheduled for operation in late 1983.

Thus, the "new" technology is the combustor and the inbed heat exchanger. We must now understand from where this technology derives.

Figure A1-8 is a schematic of this derivation. The fluid bed coal combustion technology derives from the variety of operating AFB units, of which the Shamokin boiler is shown as a representative example on this chart. Of course, the basic fluid bed technology extends further back to the thousands of process applications including cat cracking, ore roasting, calcining, etc. The air-cooled heat exchanger derives primarily from the work on air-cooled pressurized fluid beds.

The combustor itself may be divided into two components: The structure itself, and the fluid bed. The structure is a refractory-lined cylindrical steel vessel with a conical roof, similar to many current process vessels and also to the vessels used for the process application of fluid bed technology, and thus represents state-of-the-art technology.

The significant fluid bed parameters used in the various NASA designs are compared on Table A1-4 with Curtiss-Wright experience on operating fluid beds and with the normally accepted range of the parameters for AFB design. As may be seen, the NASA values fall within the accepted range. The bed depth is on the high side of the range, but this is normal for an air-cooled bed. Thus, the NASA designs are not pushing the state-of-the-art.

For the inbed heat exchanger, the normally expressed potential concerns are metallurgical. Structure design is well within state-of-the-art while heat transfer coefficients in fluid beds have been established by test data. (Note that in the basic air AFB design, fine tuning of heat output in the flue gas and clean air is made possible by the incorporation of the air preheater and preheater bypass.) Thus, the items to be addressed are erosion and corrosion.

The potential for erosion is significantly reduced by the use of vertical tubes and by the relatively low fluidizing velocity. Although the U-bends at the top of the tubes do become horizontal, testing for over 1,000 hours at Exxon's miniplant showed that the incorporation of spoilers eliminated a previous erosion problem encountered under the higher fluidizing velocity conditions of that plant.

The potential for corrosion is basically a function of material selection. Curtiss-Wright has conducted over 12,000 hours of testing in the range of 1,650°F on a variety of materials, including 4,300 hours in an operating AFB and 3,500 hours in an operating PFB. Results of the testing show AISI 310 stainless steel to be an acceptable material for heat exchanger tubes. Similar testing reported by ORNL and EPRI confirm the choice of 310 material. (A more complete discussion of these test results and the choice of 310 is contained in the section on Materials Selection.)

Thus, by considering each of the components of the system, we have demonstrated the statement made at the beginning of this section: There are no technology barriers to air cycle AFB/gas turbine steam cogeneration.

Table A1-2

AFB AIR CYCLE

Integral Components

- o AFB Combustor
- o Inbed Heat Exchanger
- o Air Preheater
- o Recycle System
- o Coal/Sorbent Feed System
- o Ash Removal System
- o Startup Combustor/FD Fan
- o Gas Turbine
- o Integrated Control System

Ancillary Components

- o Waste Heat Boilers
- o Coal and Sorbent Receiving
- o Coal Preparation
- o Ash Disposal
- o Feedwater Heater
- o Feedwater Treatment
- o Particulate Removal System/Stack
- o Process Piping and Valving
- o Civil Works
- o Electrical Works

Table A1-3

AFB AIR CYCLE

Integral Components

Commercially Available

- Startup Combustor FD/Fan
- Ash Removal System
- Air Preheater
- Gas Turbine

Commercially Available - In Demonstration

- Recycle System
- Coal/Sorbent Feed System
- Control System Software

"New" Technology

- Combustor
- Inbed Heat Exchanger

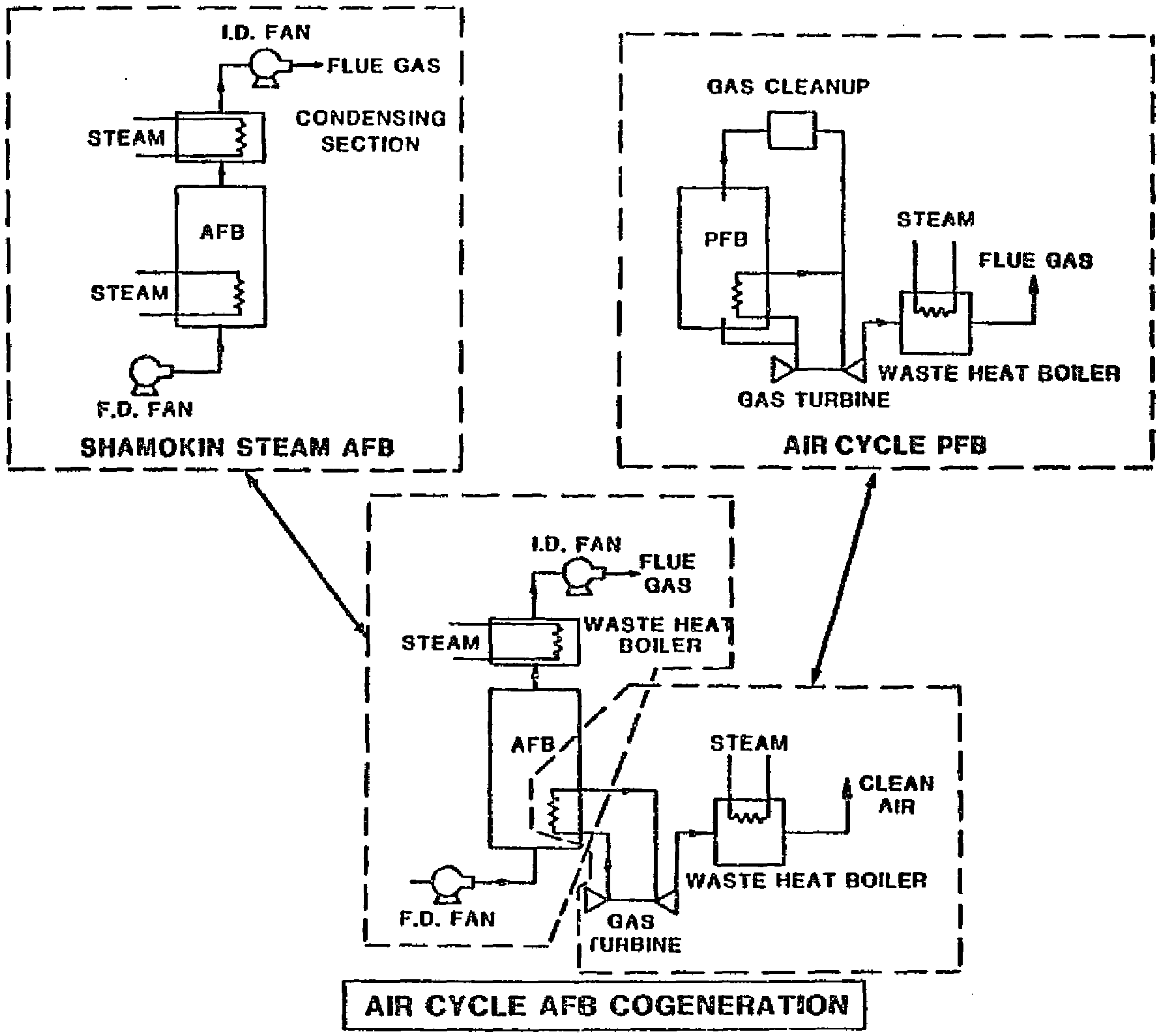
I.D. FAN
FLUE GAS
CONDENSING SECTION
STEAM
AFB
STEAM
F.D. FAN
SHAMOKIN STEAM AFB
GAS CLEANUP
PFB
STEAM
FLUE GAS
WASTE HEAT BOILER
GAS TURBINE
AIR CYCLE PFB
I.D. FAN
FLUE GAS
STEAM
WASTE HEAT BOILER
AFB
STEAM
CLEAN AIR
WASTE HEAT BOILER
F.D. FAN
GAS TURBINE
AIR CYCLE AFB COGENERATION

Figure A1-8

Table A1-4

COMBUSTOR

Comparison of Performance Parameters

PARAMETER	NASA DESIGNS	C-W EXPERIENCE AFB	PFB	NORMAL ACCEPTED RANGE
Fluidizing Velocity (fps)	3.7 (3.0-4.3)	5.3	2.7 (2.2-4.0)	2-8
Excess Air Flow (%)	30 (30-50)	30%	30 (20-40)	20-40
Bed Depth (ft)	7' (6-7.5)	5.0	16	2-8
Bed Temperature	1,625	1,550	1,650 (1,400-1,750)	1,450-1,700
Combustion Efficiency	98	95	99+	92-99

1.5 LOAD TURNDOWN PROCEDURES

1.5.1 Variations in Generic Turndown Procedures

Included in the generic description of the air-cooled AFB/gas turbine system is a discussion of turndown (Section 1.1.3). This basically applies to a plant which produces electricity and steam. The Ethyl plant is unique in that it produces three products - electricity, steam and heat for Dowtherm - and the plant demand is such that direct heat output is to remain constant while steam output is varied. This requires a different turndown methodology than that for simple steam turndown.

In this mode of operation, steam demand is the control on turndown. As steam demand is reduced, control valve CV-2 is opened and a portion of the clean air bypasses the combustor, thus reducing gas turbine inlet and exit temperatures and heat flow to the waste heat boiler. Coal flow is simultaneously decreased, but fluidizing airflow is not altered. Steam output is thus controlled by modulation of CV-2 and by coal flow while direct heat output is unchanged. Turndown characteristics are shown schematically in Figures A1-9 and A1-10.

It should be noted that this method of operation produces lower efficiency, as measured in fuel utilization, than the conventional turndown for a system producing steam due to the higher levels of excess air. Figure A1-11 shows comparative output and efficiency of the Ethyl system with constant fluidizing airflow and a comparable system in which excess air was maintained constant.

Despite the decrease in fuel utilization, an economic analysis by Catalytic shows the system chosen for Ethyl, because of its higher output of premium product, to be superior.

The estimate plant load performance for AFB/gas turbine cycles producing steam by using the gas turbine exhaust gas is shown in Figure A1-12. Such performance is applicable to the Riegel plant site cycles. At 100% heat input, the combustor is operating at 100% design combustor flow and maximum freeboard temperature of 1,650^{o}F. As the heat input is decreased at constant flow and freeboard temperature, electric power and process steam decrease at a slightly faster rate than the heat input. At approximately 60% heat input, the maximum bypass flow is reached, and further reductions in power output are achieved by reducing both fluidizing airflow and freeboard temperature. At the minimum heat load of 33%, electric power is 30% and process steam is 12.5% of design.

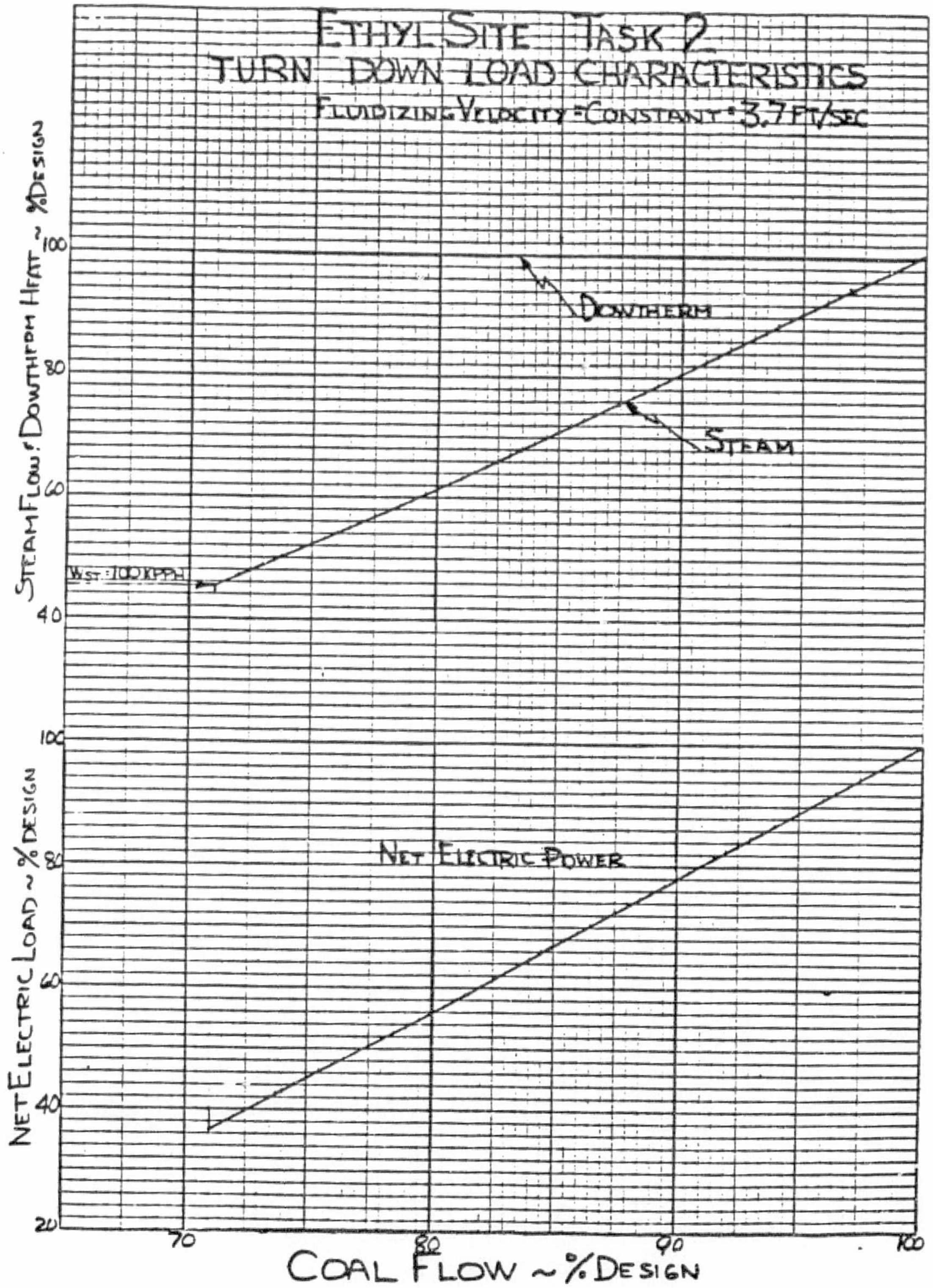
ETHYL SITE TASK 2
TURN DOWN LOAD CHARACTERISTICS
FLUIDIZING VELOCITY = CONSTANT = 3.7 FT/SEC
STEAM FLOW; DOWTHERM HEAT ~ % DESIGN
100
80
60
40
DOWTHERM
STEAM
W_{ST} = 100 KPPH
NET ELECTRIC LOAD ~ % DESIGN
100
80
60
40
20
NET ELECTRIC POWER
70
80
90
100
COAL FLOW ~ % DESIGN

Figure A1-9

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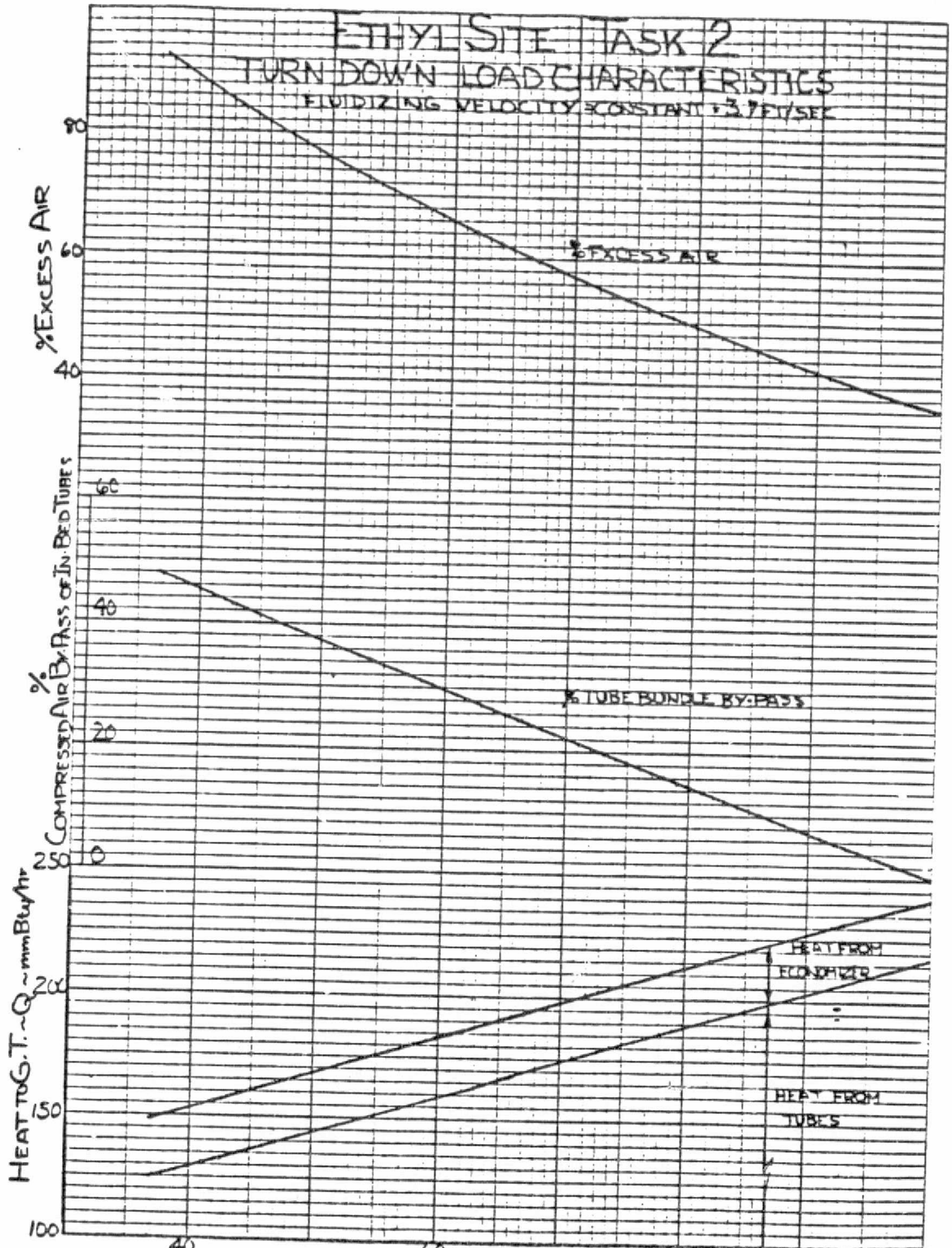

Figure A1-10

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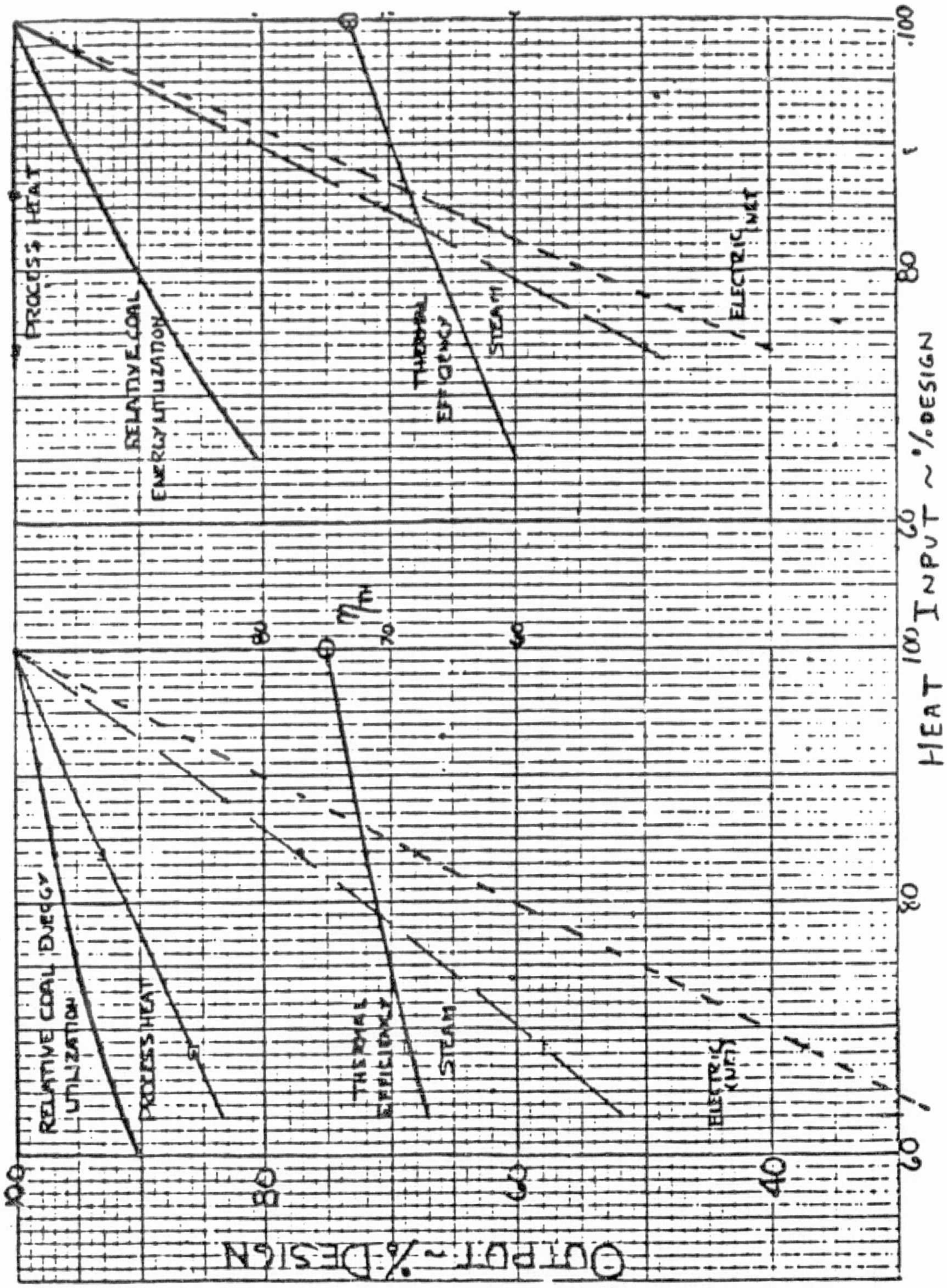

Figure A1-11

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REFERENCE ESTIMATED PERFORMANCE ELECTRIC - STEAM OUTPUT VS HEAT INPUT

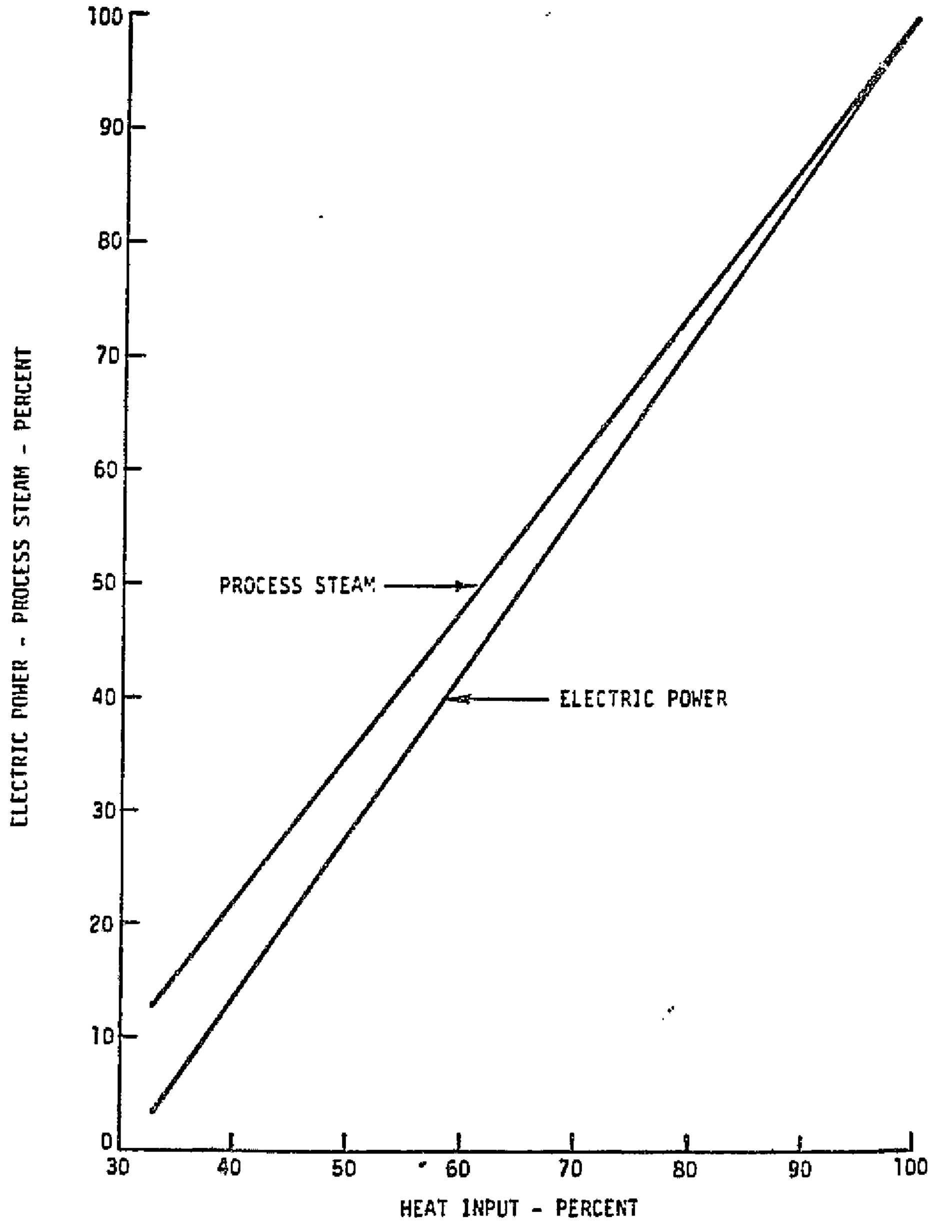


Figure A1-12

1.6 ETHYL PLANT AFB/GAS TURBINE SYSTEM - SIGNIFICANT PHYSICAL PARAMETERS

Table A1-5

Fluid Bed Parameters

Bed Area - 1,452 sq ft total; 1,256 sq ft active

Bed Height - 8'-1"

Freeboard Height - 12'-0"

Fluidizing Velocity - 3.7 fps

Excess Air - 36.2% (Design)

Fluidizing Airflow - 378,000 lbs/hr

Coal Flow - 29,800 lbs/hr (370 MM Btu/hr)

Limestone Flow - 8,860 lbs/hr

Calcium/Sulfur Fuel Ration - 3.0

Number of Coal Feed Points - 64

AFB Combustor

Construction - Refractory Lined Steel (ASTM A515 - GR 70) Cylindrical Vessel with Conical Roof

Vessel O.D. - 45'-8"

Vessel I.D. - 43'-0"

Elevations - Vessel Bottom - 11'-0"

Vessel Top - 58'-11"

System Maximum - 102'-2"

Table A1-5 (continued)

Heat Exchanger

Tubes

Number	-	2188 U-Bend
Size	-	2" Schedule 80
Material	-	AISI 310

Inlet Headers

Number & Size	-	14 - 6" Schedule 40 12 - 10" Schedule 40
Material	-	ASTM A743 Grade CF8C (312 Stainless)

Outlet Headers

Size	-	19 - 12" Schedule 40
Material	-	ASTM B407 (Incoloy 800H)

Manifolds

Inlet	-	66" O.D., 60" Flow Path
Outlet	-	72" O.D., 61-1/8" Flow Path
Material	-	ASTM A515 Grade 70 Pipe with Internal Poured VSL 50 Insulation and Kaowool Blankets lined with AISI 321

Gas Turbine

Model - Westinghouse W-191

Airflow - 961,200 lbs/hr (928,800 through Hx)

Pressure Ratio - 7.5

Turbine Inlet Temperature - 1,500°F

Δ P, Compressor to Turbine - 4.5 psi

Table A1-5 (continued)

Recycle Cyclone

No. Required/Combustor	-	3
Removal Efficiency	-	93%
Total Dust Loading	-	47,600 lbs/hr

Dimensions:

Barrel O.D.	-	12'-10"
Barrel Length	-	15'-4"
Cone Length	-	25'-6"

Recycle Return - 1'-0" below bed through trickle valve

Clean Air Reheater

Q Exchanged	-	24.1 MM Btu/hr
Air Temp., in/out	-	524/626^{o}F
Flue Gas Temp., in/out	-	1,650/1,449^{o}F

FD Fan

Air Flow	-	378,000 lbs/hr
Pressure Drop	-	5.2 psi
Electric Load	-	1,521 Kw

Fluidizing Air Preheater

Q Exchanged	-	43.2 MM Btu/hr
Air Temp., in/out	-	118/590^{o}F
Gas Temp., in/out	-	697/280^{o}F

Table A1-5 (continued)

Major Tie-in Points to AFB/Gas Turbine System

1. Power Turbine Exhaust

   Opening - 6'-9" x 9'-9"
   Elevation from ground level - 11'-9 5/8"

2. Flue Gas Outlet

   Opening - 5'-2" x 18'-3 1/4"
   Flange Face to centerline AFBC - 4'-1 7/8"
   Elevation from ground level to centerline opening - 96'-10 1/2"

3. Coal Silo - 12' Dia. x 56' High

   Dolomite Silo - 9' Dia. x 24' High

4. Fluidizing Air Preheater

   9'-0" x 9'-0" x 6'-0" High

1.7 AFB/STEAM TURBINE COGENERATION SYSTEM

1.7.1 Basic AFB Boiler Design

There are several manufacturers of AFB boilers, each using certain different design features. For this study, Catalytic enlisted as subcontractor for AFB boiler technology the Keeler/Dorr-Oliver Boiler Division. A paper presented jointly by these firms at the Industrial Coal Conference, University of Kentucky, 1981, is reproduced in part to describe the basic AFB boiler design.

1.7.2 Study Approach

After Catalytic surveyed the sites and determined the heat and energy requirements, optimum steam turbine cycle conditions were established by Catalytic within the frame of reference of available plant distribution systems, plant requirements, and the capability of currently available equipment. Site specific conditions, including coal and sorbent properties, were then furnished to Keeler/Dorr-Oliver. The latter studied boiler capacity requirements, load response and turndown requirements. They determined the fluidized bed combustion parameters, calculated heat and material balances, and determined sorbent requirements for SO_2 control. The effect of sorbent requirements in heat and material balances and combustion conditions are reflected in the calculated boiler efficiency. The boiler configuration was adapted to the fluidized bed conditions.

1.7.3 Ethyl Plant Boiler Design - Task 2

The boiler design chosen for the conceptual design is a scale-up of the Keeler/Dorr-Oliver CPFS fluid bed boiler design. The physical arrangement of the boiler is shown Figure A1-13.

The CPFS design utilizes a sparge pipe air distributor patented by Keeler/Dorr-Oliver as well as other fluidized bed boiler design elements also patented by them. The steam and water drums have been arranged as cross drums. This provides for a fairly long boiler front wall, which in turn accommodates three spreader stokers. Vertical in-bed generating tubes provide the bed segmentation between the three firing aisles required for the spreaders. The superheater banks are executed as vertical in-bed tubes. The superheater banks are supported by water cooled forced circulation generating tubes.

The superheater arrangement is expected to result in a virtually flat superheater outlet temperature curve with respect to turndown.

The fluidized bed is 4'-6" deep under normal operating conditions. The dimensions of the plane of the fluidized bed are 19 ft. x 29 ft.

Ash withdrawal is accomplished with a set of screw conveyors mounted directly underneath the bottom supply headers running across the width of the fluidized bed. This approach will reduce the discharge temperature of the bottom ash to a level 100-200^{o} above the saturation temperature of the steam in the generating tubes of the boiler.

1.7.4 Load Control

Turndown and load response is accomplished by proportioning the number of air supply tubes in service to the air flow requirements for a given steam and fuel flow. From the attached Figures A1-14 and A1-15 it can be seen that this approach to load response will give the smoothest possible response curve relative to load.

1.7.5 AFB Boiler Parameters - Ethyl Plant Conceptual Design

A. Design Parameters

1. Capacity: 250,000 lbs/hr
2. Steam Condition: 1,250 Psig/950^{o}F
3. Turndown Ratio: 4:1
4. Bed Temperature: 1,500^{o}F
   (nominal - not to exceed 1,600^{o}F)
5. Air: Ambient, 80^{o}F, 60% RH, Sea Level
6. Feed Water Temperature: 480^{o}F
7. Startup Fuel: Natural Gas
8. Emissions Limitation
   a. SO_x: 90% sulfur capture
   b. NO_x: 0.5% lb/MM BTU
   c. Particulates: To baghouse - 10 grains/ACF

B. Performance

1. Steam Flow: 243,020 lbs/hr
2. Cont. Blowdown: 2,430 lbs/hr
3. Steam at S.H. Outlet: 1,250 Psig/900^{o}F
4. Coal Feed: 25,149 lbs/hr
5. Limestone Feed: 7,474 lbs/hr
6. Fluidizing Air to AFB: 283,396 lbs/hr @ 250^{o}F
7. Bottom Ash Removal: 2,716 lbs/hr
8. Boiler Feedwater to Economizer:
   245,450 lbs/hr @ 480^{o}F
9. Fly Ash: 6,312 lbs/hr
10. Flue Gas to Atmosphere: 306,993 lbs/hr

C. Physical Parameters

1. Fuel Feeders
   a. Type: Overbed, Spreader Stoker
   b. Number: Three (3)
   c. Manufacturer Model No.: Detroit, No. 18
2. Startup Burners: Three (3)
3. Economizer
   a. Manufacturer, Type: Kentube, Bare Tube
   b. Effective Surface Area: 11,360 sq. ft.
   c. Tubes: 2 in. OD, 31 rows x 28 tubes/row, 25 ft effective length
   d. Sootblowers: Two (2) rotary
   e. Tube Fouling Resistance: .001 tube/.005 gas
   f. Heat Transfer: 9.7 BTU/HR/sq. ft. - F
   g. Pressure Drop: 7.6 psi tube/2.49" water gauge
4. Forced Draft Fan: Clarage #120, two stage, 1,500 HP motor
5. Induced Draft Fan: Clarage #17, SW SI, 700 HP motor
6. Mechanical Cyclones: Three (3) plus hopper bottoms
7. Air Heater: Tubular
8. Baghouse:
   a. Manufacturer's Model: C-E Air Preheater, Series 12, pulse-jet type
   b. Gross Filter Ratio: 3.85:1
   c. Net Filter Ratio: One Module Cleansing: 4.62:1
   d. Total Cloth Area, All Modules: 28,773 ft^2
   e. No. Modules, Bags: 6 Modules/252 Bags each, top removal
   f. Bag Data: 6" dia. x 12 ft long, top removal
   g. Bag Material: Woven Fiberglass, 15.5 oz./yd^2, Finish, Teflon B, 10%
   h. Pressure Drop: 5 in. W. G. @ 110,800 ACFM flue gas, 350°F
   i. Outlet Duct: .01 grains/ACFM
   j. Bypass: 100% bypass system
9. Materials of Construction, AFB Boiler
   a. Evaporator Tubes: Carbon steel, SA-178, ERW
   b. Superheater Tubes: Stainless steel, SA-213, Type 304H
   c. Air Distributor Sparge Pipes: Stainless steel, Type 310

1.7.6 AFB Boiler Unit Cost

Probable relationship of unit cost versus capacity for single AFB boilers using the Keeler/Dorr-Oliver Boiler Division design of the 3-furnace, cross drum, 2-drum design as produced for the Ethyl plant is given in Figure A1-16. The cost estimates are to show relationships only.

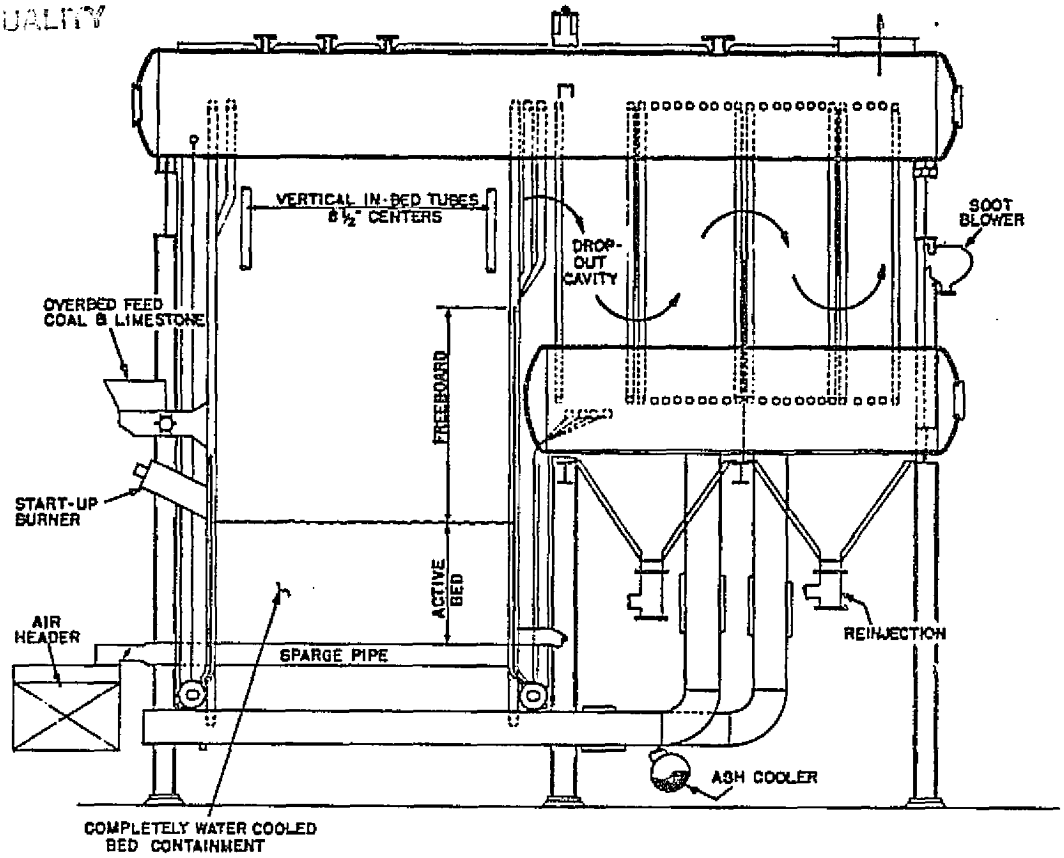


FIG. 6 CPFS — SECTIONAL SIDE

CPFS DESIGN

As the Shamokin design was finalized, the E. Keeler Co. and Dorr-Oliver, Inc. turned to the development of a standard line of boilers to burn normal bituminous and other coals. An evaluation of the industrial boiler market clearly indicated that a shop assembled unit would offer many advantages, at least for the smaller sizes.

The Shamokin unit was designed for a very low grade fuel and it did not lend itself to shop assembly. This prompted a concentrated effort to develop a different concept, eventually called the CPFS. Although it was decided to develop a new conceptual design, it was recognized that many of the desirable features of the Shamokin design should be retained, specifically:

1. Natural circulation.

2. Completely watercooled, seal welded bed containment, including the floor.

3. Vertical in-bed tubes.

4. Zoning of the fluidizing air without zoning or segmenting the bed proper.

As the design developed, care was taken to assure that the basic functional design parameters were not compromised just to have a shop assembled unit.

Fluid beds used for combustion have three basic design parameters: fluidization velocity, bed height, and freeboard height (top of bed to bottom of furnace exit). The optimum fluidizing velocity is determined by the fluidizing characteristics of the bed material realizing that the velocity must be high enough for good mixing but low enough to provide maximum residence time and to minimize carryover. With an established fluidizing velocity, the residence time of the products of com-

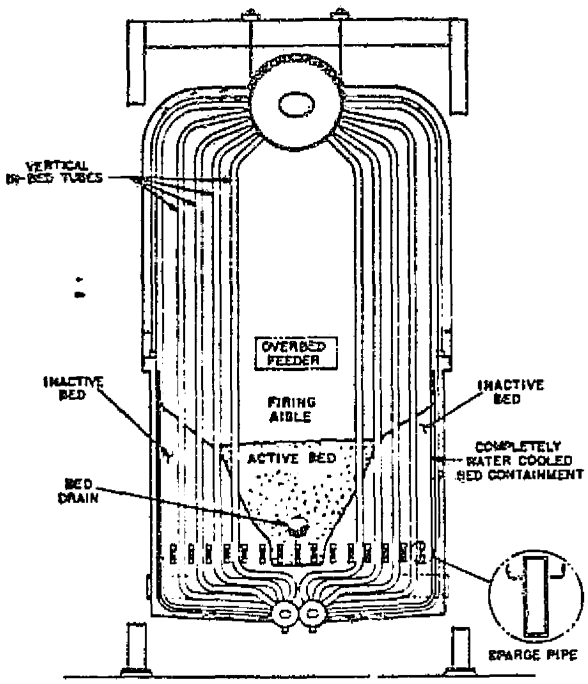


FIG. 7 CPFS — SECTION THRU BED

bustion in the bed, hence completeness of combustion and sulfur capture, is a function of bed height. To assure complete combustion with a minimum of excess air and optimum sulfur capture with a variety of fuels and sorbents, a nominal 4 ft. bed height was selected with the capability to make operating adjustments up to ± 1 ft. (See Fig. 6 and 7).

Particulate carryover from the furnace not only increases carbon and limestone losses, but can cause convection bank erosion and/or fouling. With a particular fluidization velocity, particulate carryover from the furnace is largely dependent upon freeboard height. Naturally a higher freeboard permits more of the entrained particulate to fall back to the bed. After careful review of process bed experience, a minimum freeboard height of 8 ft. was selected. (See Fig. 6).

With a 4 ft. nominal bed height plus an 8 ft. nominal freeboard height, the unit became too high for typical shipping clearances. There were too many compromises to permit a com-

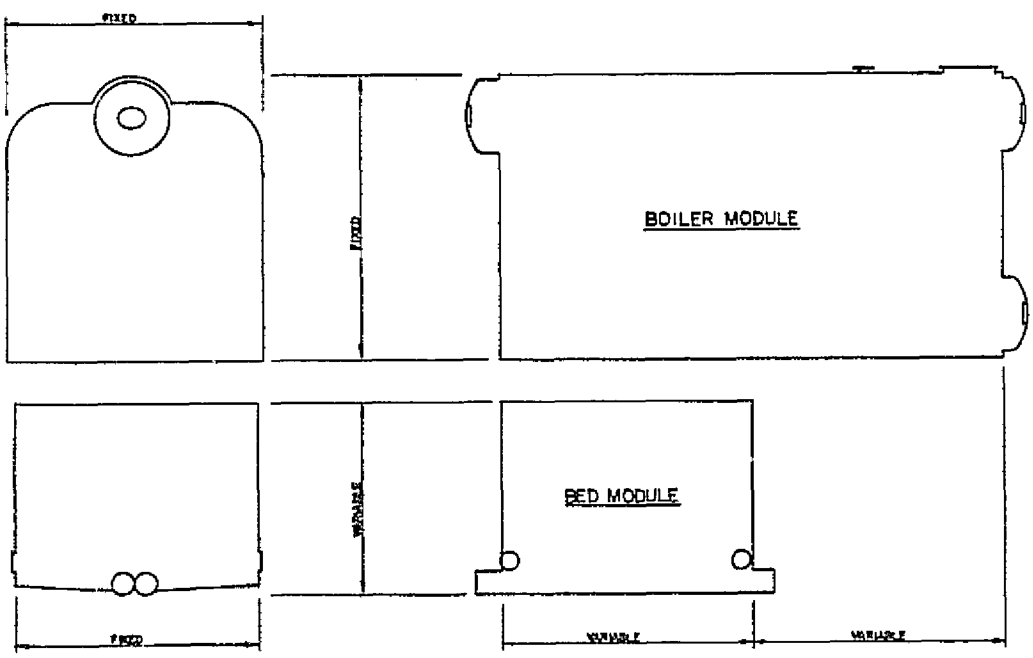


FIG. 8 CPFS MODULAR CONCEPT

pletely shop assembled unit, for even the smaller sizes, but it became apparent that a two module design was feasible and that each module could be completely shop assembled. (See Fig. 8).

With the two module concept, it is practical to custom fit the CPFS boiler/fluid bed to each particular application such as to a particular fuel, sulfur capture, bed carryover characteristic, or desired boiler exit gas temperature. As shown on Fig. 8, the freeboard height, bed height, bed area, and convection surface can be varied, all with a standardized front profile.

Upon initial consideration of fluidized bed firing, two major concerns of most everyone are turndown and load response. To some extent, both can be obtained by permitting bed temperature and bed height to vary, but the range of these techniques is very limited and response is rather slow. Reasonable turndown and load response characteristics can best be obtained by zoning or segmenting the air distribution system so that plan areas of the bed can be slumped. A sufficient number of zones must be supplied to not only permit the required turndown but to also provide for small increments of load change to enhance the load following characteristics.

Instead of windbox segmentation as such, the CPFS design uses sparge (air) pipes, (See Fig. 6 and 7). The sparge pipe arrangement has several advantages:

1. Permits a completely seal welded, watercooled floor without numerous penetrations for the admission of fluidizing air.

2. Permits multiple zones without a cumbersome windbox design with multiple air supplies and dampers.

3. Reduces headroom by eliminating the windbox under the bed.

4. Eliminates sealing requirement between the windbox and fluid bed.

5. Provides for ease of inspection or maintenance (sparge pipe can be withdrawn).

The modular CPFS design utilizes fifteen individual alloy sparge pipes. The sparge pipes are inserted through the watercooled frontwall and bolted in place with a gas tight flanged connection. This makes them removable for inspection or replacement during a boiler outage. Each sparge pipe is equipped with a quick acting damper for control (open or closed) and a manually operated balancing damper. All sparge pipes are connected to a common air header which receives combustion air from the forced draft fan.

The fifteen sparge pipes essentially provide fifteen air zones for turndown and load response. The turndown sequence is that of slumping bed areas from the sidewalls towards the center firing aisle. Operation of only the center three sparge pipes represents the minimum load, as shown pictorially on Fig. 7.

In addition to multiple sparge pipes, turndown capability is complimented by the judicious placement of the in-bed surface along each side of the furnace (See Fig. 7). As individual sparge pipes are shut-off from the sides towards the center, a disproportionate amount of in-bed surface is removed from the active bed area which permits a further reduction in the fuel feed and steam generation per unit of plan area. In other words, in-bed tube density is used to extend the turndown range.

The placement of the in-bed surface along each side of the furnace not only extends turndown capabilities but also provides a center firing aisle for overbed feeding of coal and limestone. The required sizing for normal bituminous coal will be the same as required for spreader stokers. The required limestone sizing will, of course, depend on the analysis and reactivity of the stone used.

The combustion controls for the boiler are similar to those normally furnished with conventional stoker fired units, except there are additional loops for bed temperature control, sparge pipe on-off control, and bed height control. The fuel and air flow are controlled by steam header pressure. The number of sparge pipes in operation is indexed to steam flow. The bed height controls maintain a manually selected bed level by positioning a bed drain valve, and bed level is alarmed for preset high and low conditions. Oxygen and SO_2 trim control are available as options.

A system for the reinjection of flyash collected in the convection bank hoppers is available, and recommended for all except the very small units.

At the present time, the CPFS modular design appears suitable to approximately 80,000 lb/hr. Beyond this capacity the same concept will still be utilized, however, these units will be completely field erected. Operating experience may indicate that greater capacities are possible without going to field erection.

As interest in co-generation grows, higher pressure and superheat will be required. The CPFS is suitable to 800 psig and 750 F. The superheater will be of the drainable, convection type placed in the upper freeboard area.

Fluidized bed fired boilers appear to be rather exotic to those accustomed to conventional solid fuel firing, but if the individual components or systems are examined carefully, they are not that unfamiliar. For example, with the CPFS design, the boiler module is really the CP boiler, and the completely watercooled bed module represents no new technology. The sparge pipe method of introducing fluidizing air has been used in many different process applications. Really, the CPFS fluidized bed fired boiler is a unique adaptation of existing fluidized bed technology and existing solid fuel fired boiler technology.

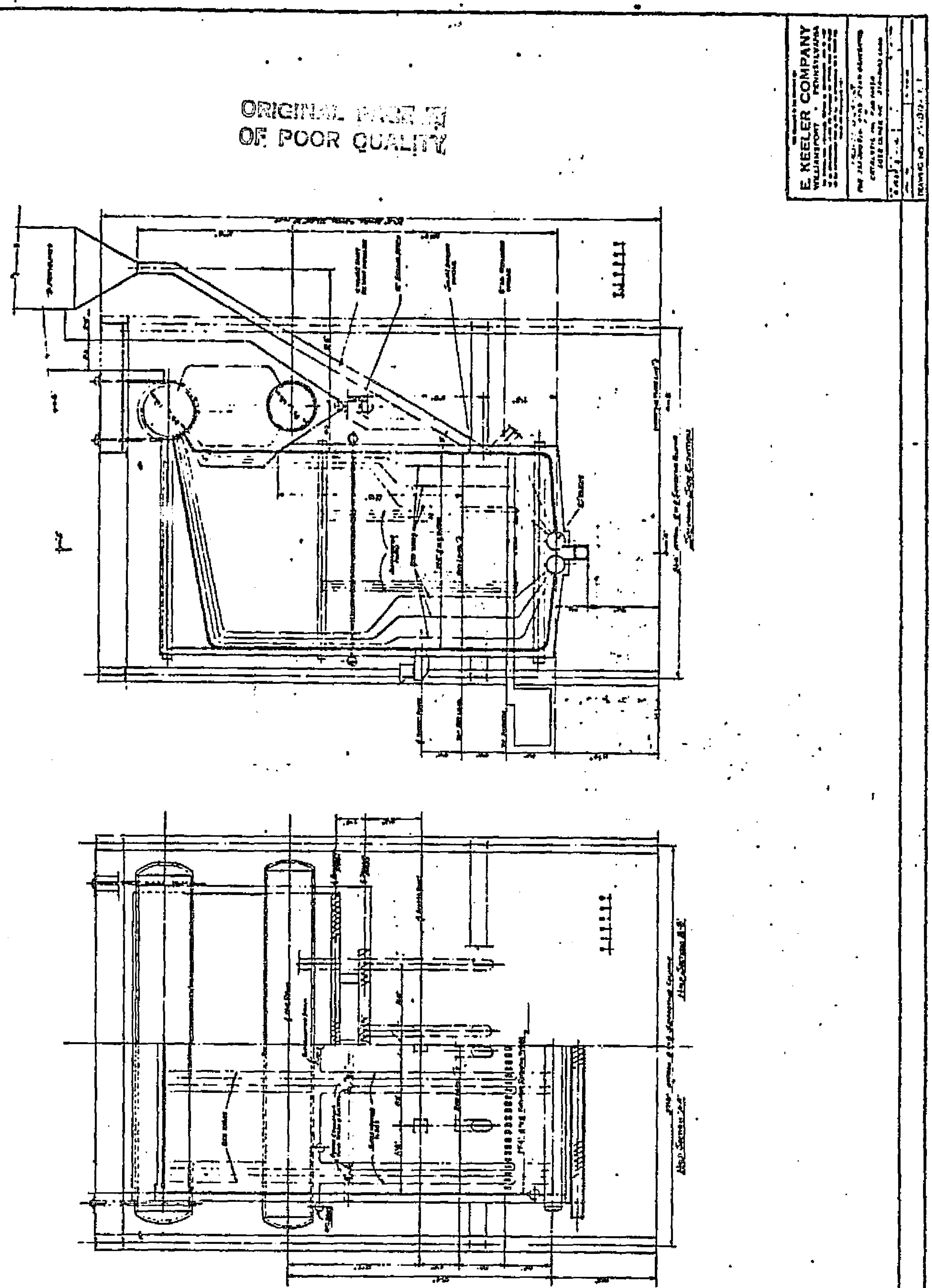
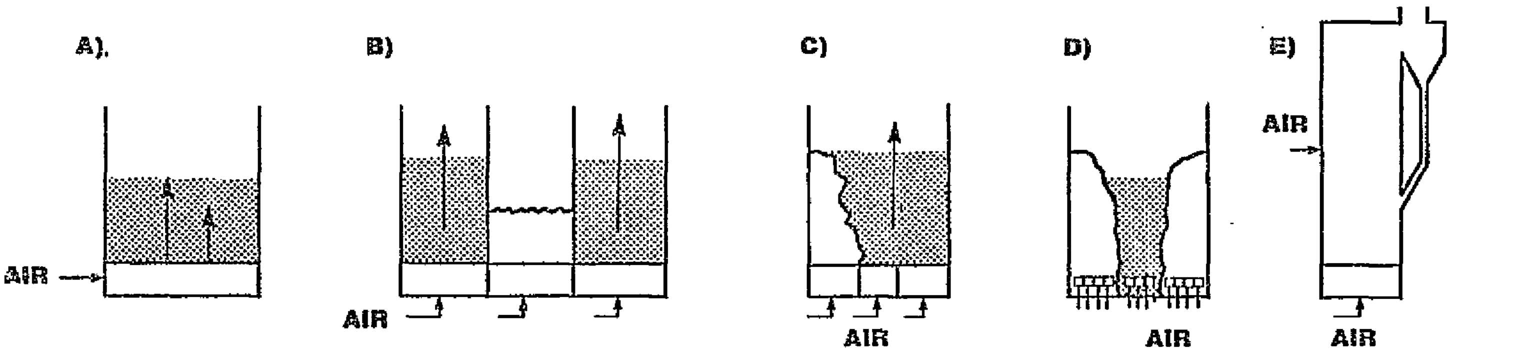


Figure A1-13

TURNDOWN METHODS FOR AFB BOILERS



FLUID BED VELOCITY	BED SEGMENTATION	WINDBOX SEGMENTATION	SPARGE PIPES	RECIRCULATION (TRANSPORT VELOCITY)
70%	LIMITED BY NUMBER OF BEDS TYPICAL 25%	LIMITED BY NUMBER OF CHAMBERS TYPICAL 25%	LIMITED BY NUMBER OF PIPES TYPICAL 20%	COMPLEX LIMITATIONS TYPICAL 30%

TURNDOWN CAPABILITY AS PERCENT OF DESIGN
AT CONSTANT EXCESS AIR

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OF POOR QUALITY

Figure A1-14

LOAD FOLLOWING OF AFB BOILERS DEPENDING ON TURNDOWN DESIGN

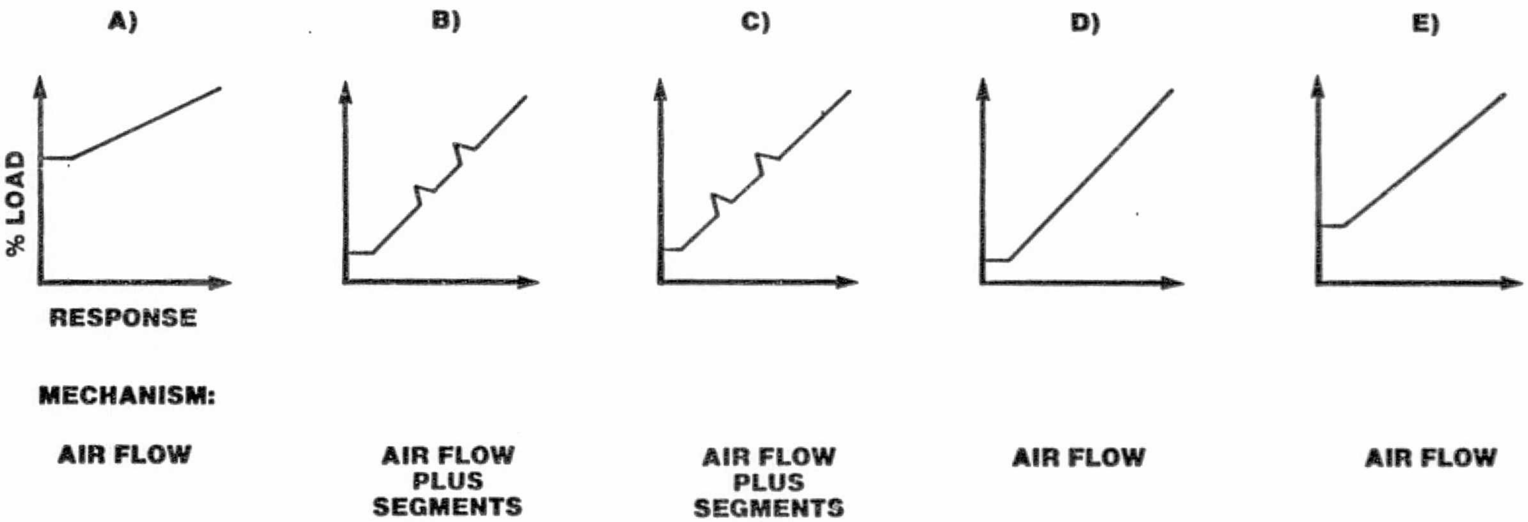


Figure A1-15

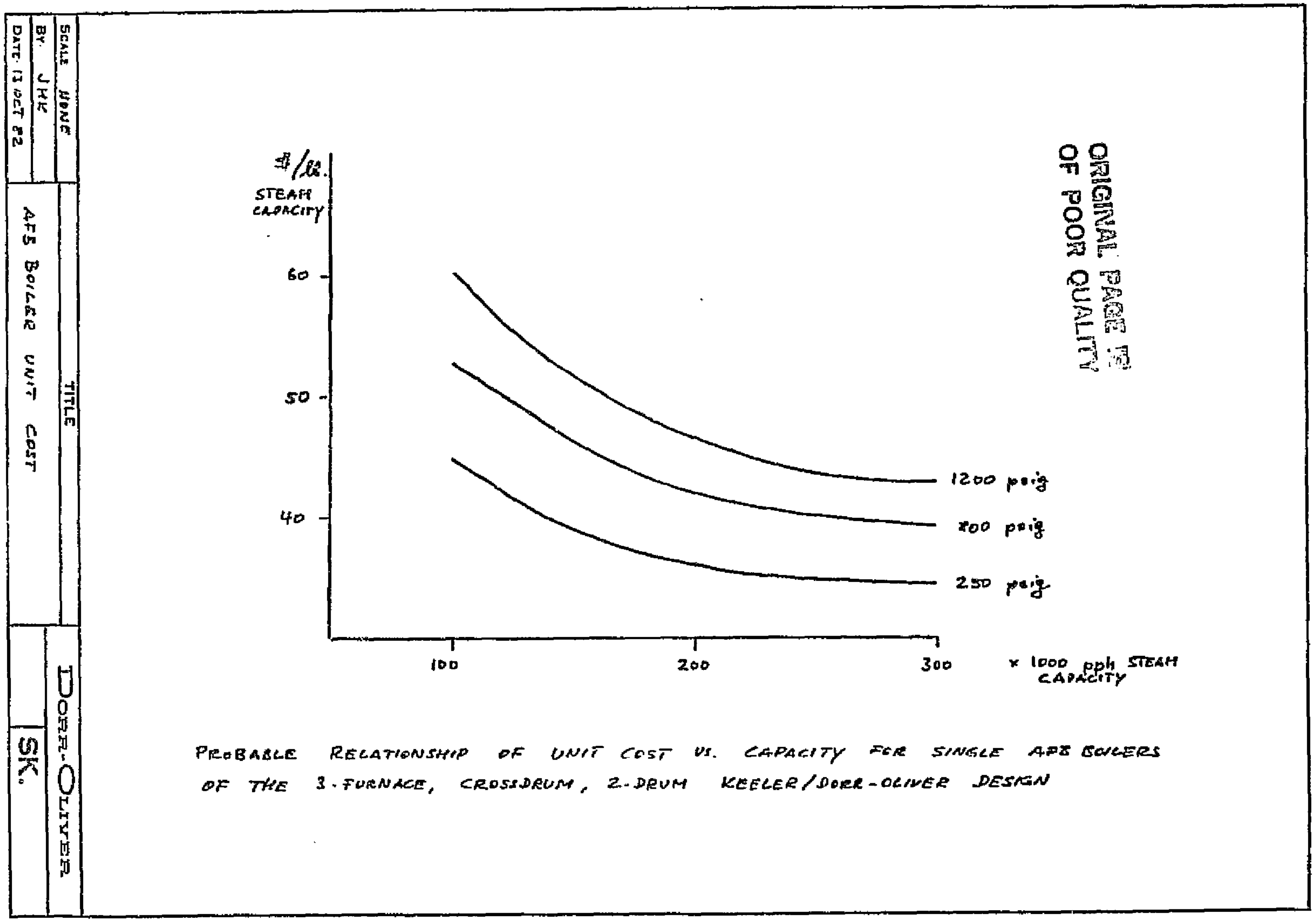


Figure A1-16

Cost estimates are to show relationships only and cannot be used for any commercial or business purpose.

1.8 SOLID WASTE MAKEUP

The predicted analysis of the solid wastes from an AFB combustor is given in the following table. The analysis is based on the coal and limestone specified for the Ethyl plant site.

Table A1-5

SOLID WASTE MAKEUP

EXPECTED ANALYSIS

MATERIAL	BED DRAINS		FLY ASH	
	GT	ST	GT	ST
	% BY WEIGHT		% BY WEIGHT	
COAL ASH	15	28	60	28
CaO + MgO	45	32	10	32
Ca SO_4	40	34	3	33
INERTS	0	1	3	1
CARBON	.3	5	.3	6

NOTES

(1) For ST, the basis is 75% of unburned carbon is contained in fly ash.

Section 2

STUDY APPROACH AND METHODOLOGY

2.1 METHODOLOGY FOR ECONOMIC ANALYSIS

2.1.1 Introduction

A carefully defined methodology for the rate-of-return and the annualized energy cost analysis used was given to Catalytic by NASA for use in this report.

This methodology is being published in the following report:

> Cogeneration Technology Alternatives Study (CTAS) Volume II - Comparison and Evaluation of Results. NASA TM-81401, to be published.

As part of the economic analysis, the following basic computations are required:

(a) the rate of return on an incremental investment using discounted cash flow.

(b) the total annual energy costs for various systems. Total energy cost includes fixed capital charges, fuel costs, O&M costs and any credits for sale of electric power.

2.1.2 Rate of Return Analysis

This study considers an incremental annual rate of return which equates for two investment alternatives the present value of all differential future cash flows with the total incremental capital investment. This study also accounts for the following:

- Start of system operation occurs at the beginning of a year.
- Cash flows are assumed to be annual.
- An after-tax cash flow is used.
- State and local property taxes and insurance costs are approximated as a percent of total capital investment.
- Interest costs or dividends are omitted in the calculation of each annual net cash flow.

- Escalation is accounted for in the computation of both total capital cost and each annual net cash flow. General inflation is assumed to be zero - data is adjusted where needed assuming a 10% inflation rate.

- Investment tax credit of 10% is accounted for as a reduction of first year taxes.

- Salvage or residual values are neglected.

- Land costs are zero.

For those uses where 100% equity financing is considered, return on investment (ROI) is equal to return on equity (ROE).

2.1.3 Total Capital Investment

The capital cost estimate of a system is expressed in mid-1981 dollars and does not include interest (cost of capital) or escalation during construction. For this study, capital cost escalation during construction plus inflation rate are taken as zero. The cost of capital is taken as the following factor: $e^{.418ml}$

with m = before tax cost of money
and 1 = design and construction time, in years.

The effect of engineering and construction periods of varying lengths is shown below. So the total capital investment is greatly impacted by the design and construction time taken. For this study, an engineering and construction period of five (5) years was chosen to account for obtaining of regulatory permits, whereas for the construction period phase perhaps only 2.5 years are needed.

Table A2-1

TOTAL CAPITAL COST FACTOR

Engineering & Construction Period	(1)	(2)	(3)	(4)
	Before-Tax Cost of Money			
	7%	15%	20%	
5 years	1.158	1.368	1.519	1.110
4 years	1.124	1.235	1.397	-
2 1/2 years	1.076	1.170	1.232	1.054

(1) Common Case factors based on NASA criteria
(2) Ethyl Plant Site, Task 1 - Plant Screening
(3) Ethyl Plant Site, Task 2 - Conceptual Design
(4) Riegel Plant Site, Task 1 - Plant Screening

2.1.4 Depreciation

The depreciation method and depreciation life are based on the Economic Recovery Tax Act (ERA) of 1981. The Accelerated Cost Recovery System (ACRS) established by the Act dramatically changes the system of tax depreciation. A five-year tax life is available. The recovery allowances are based on property placed in service after December 31, 1985 and are given below:

Ownership Year	%
1	20
2	32
3	24
4	16
5	8

This depreciation is often larger than the energy savings before taxes, so there is no taxable income and the depreciation is the cash flow for that tax.

As part of the calculation for the fixed charge rate, the levelized depreciation factor must be included. For the ERA, the following term is used:

$$DEP = \sum_{N^1=1}^{5} \frac{\text{RECOVERY ALLOWANCE}}{(1 + m^1)^{N^1}}$$

with m^1 = after-tax cost of money
m^1 = m for 100% equity financing

2.1.5 Levelized Annual Energy Cost

The costs and benefits occur over time, but it is necessary to evaluate the stream of costs and benefits in the present. Levelizing is a method of converting a series of escalating annual costs into an equivalent series of constant annual costs having the same present value. Below is a listing of the levelization used in this study.

Table A2-2

LEVELIZATION FACTORS

	(1) 7%,30 YRS	(2) 15%,15 YRS	(3) 20%,15 YRS	(4) 5%,20 YRS
CHARGE RATE	.0772	.1846	.245	.070
GAS	1.416	1.185	1.163	1.460
COAL	1.115	1.057	1.054	1.095
ELECTRICITY	1.182	1.520	1.446	1.095

(1) Common Case factors based on NASA criteria
(2) Ethyl Plant Site, Task 1 - Plant Screening
(3) Ethyl Plant Site, Task 2 - Conceptual Design
(4) Riegel Plant Site, Task 1 - Plant Screening

2.1.6 Sample Calculations of Economic Factors

Ethyl Corporation Site-Specific Data:

Inflation-free, after-tax Cost of Money, 15%
Inflation-free Hurdle ROE, 20%
100% Equity Financing
Project Life, 15 years
Start of Plant Operation, 1988
Engineering & Construction Period, 5 years

	1985 Prices in 1981 Dollars Cost	Escalation
Natural Gas	$5.80/MM Btu	3%

NOTE: The cost of money at 15% is used to determine the total capital cost for the project. The 20% ROE is the discount factor used in the levelized annual energy cost calculation.

2.1.6.1 Total Capital Cost Factor

For 100% equity financing, before-tax and after-tax cost of money are equal.

Cost of Capital = e.418ml from part 3 of this section of the Appendix.

$$e(.418)(.15)(5) = 1.368$$

2.1.6.2 Fixed Charge Rate

$$FCR = \frac{CRF_{m^1, n_B}}{1-t} \quad (1.0 - (t \times DEP) - C)$$

where CRF_{m^1, n_B} = capital recovery factor for the after-tax cost of money m^1 and the plant life n_B.

t = tax rate
c = investment tax credit rate

$$\text{with } CRF_{m^1} = \frac{.20(1.0 + .20)^{15}}{(1.0 = .20)^{15} - 1.0} = .214$$

$$\text{and DEP} = \frac{.20}{(1.20)} + \frac{.32}{(1.20^2} + \frac{.24}{(1.20)^3} + \frac{.16}{(1.20)^4} + \frac{.08}{(1.20)^5}$$

= .637, levelized depreciation rate using post-1985 depreciation rates of 1981 ERA tax law.

$$FCR = \frac{.214}{1 - .48} \quad (1.0 - (.48 \times .637) - .1) = \underline{.245}$$

2.1.6:3 Levelized Natural Gas Cost

$K_s = \frac{1 + .20}{1 + .03} - 1 = 0.165$, where K_s, = effective cost of money

$$CRF_{gas} = \frac{.165\ (1.0 + .165)^{15}}{(1 + .165^{15} - 1} = .184$$

$$\frac{CRF_{m^1} n_B}{CRF_{gas}} = \frac{.214}{.184} = \underline{1.163}$$

2.2 ELECTRIC UTILITY RATES

The calculation of savings in the cost of electric power is very important in establishing the benefits of cogeneration, since this item plus the fuel cost savings - due to use of coal versus gas/oil - is the total cost savings against which capital costs and increased operation and maintenance costs must be compared.

2.2.1 Ethyl Plant Site

The electric energy cost for this plant site with any type of cogeneration is based on a sell and buyback arrangement. There is no standby rate because of the simultaneous buy/sell rate. The demand is on the buyback at the regular utility rate. So the cogenerator sells to the utility at the latter's marginal energy cost based on gas fuel and buys electricity at the average rate. In consultation with Ethyl Corporation, Houston Lighting and Power and NASA, a 1981 average rate for Ethyl of 4.0¢/Kwh was established with an escalation rate of 7% above inflation. For selling to the utility, a rate of 4.55¢/Kwh is used.

2.2.2 Riegel Plant Site

Cogeneration plant performance is based on an average annual operating rate of 6,192 hours - amounting to 258 days around-the-clock (52 x 5 = 260). Weekend loads are put into the operating hours to account for them. Since the cogeneration cases studied have widely varying quantities of electricity purchased from the utility, the electric rate would also vary considerably since the electric rate structure is composed of several elements.

The rate structure for non-cogeneration is based on a ratcheted billing demand.

The rate structure for cogeneration with steady deficits in electrical requirements made up by purchases from the utility is:

a) A billing demand for an average monthly peak and average generation.
b) A standby charge using average loads and the one largest in-plant electric generator out of service.
c) A resultant combined demand and energy charge that varies considerably depending on the demand and the amount of electricity purchased.

For cogeneration with excess electricity available for sale to the utility the rate structure is composed of:

a) No demand charges.
b) A standby charge using average loads and the one largest in-plant electric generator out of service.
c) A selling rate applied to the electricity.

The following calculations show the various different types of electric rate setting procedures.

<u>BASIS</u> Data from Jersey Central Power & Light Co., 1981 Costs

<u>COSTS</u> Standby @ \$2.00/mth/kw
Demand @ \$6.40/mth/kw
Energy (incl. fuel escal.) @ \$0.0489/kwh
(.04496 energy + .00393 fuel)
Selling Electricity @ \$.05346/kwh
Selling - Capacity @ \$36.05/yr/kw

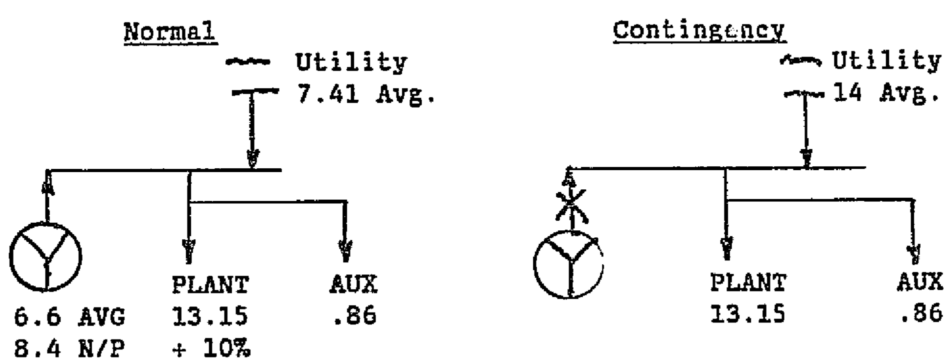
1) Base Case - No Cogeneration

Maximum monthly electric use	15,700 kw
Average electric use	13,820 kw

Demand + Energy =

$$\frac{(15{,}700 \times 6.40 \times 12) + (13{,}820 \times 6{,}192 \times .0489)}{13{,}820 \times 6{,}192} = \$0.063/\text{kwh}$$

2) One Unit Cogenerating at Less than Plant Load



N/P denotes nameplate rating of in-plant generator.

For normal billing demand plant average electric consumption increased by 10% to 14,400 kw.

BILLING 14,400 + 860 - 6,600 ---
DEMAND = 8,660 kw

STANDBY -0- 14,000 - 7,400 = 6,600 kw

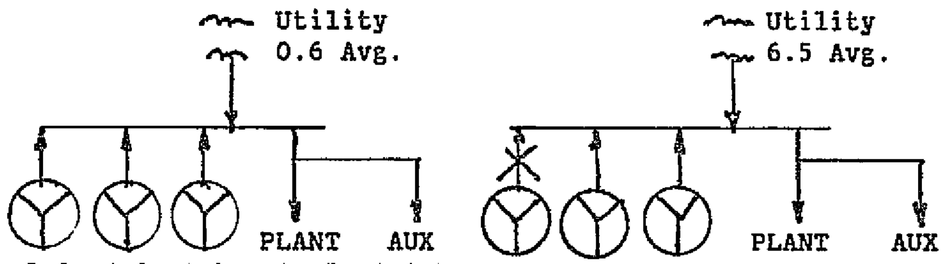
2) <u>One Unit Cogenerating at Less than Plant Load</u> (continued)

DEMAND ENERGY =

$$\frac{(8{,}660 \times 6.40 \times 12) + (7{,}400 \times 6{,}192 \times .0489)}{7{,}400 \times 6{,}192} = \$0.0634/\text{kwh}$$

3) Multiple Units Cogenerating with Small Purchase

<u>Normal</u> <u>Contingency</u>



AVG	5.9	4.3	4.3	13.15	1.995	0	4.3	4.3	13.15	1.995
N/P	8.8	7.0	7.0	+ 10%						

For normal billing demand increase plant and electric by 10% to 14,400 kw.

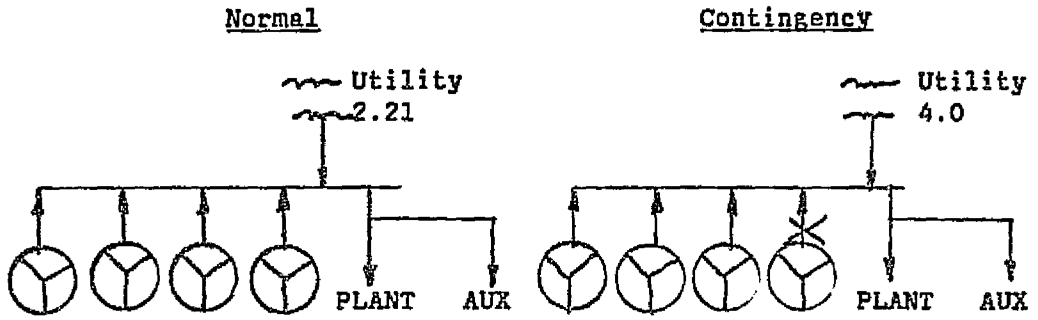
BILLING 14,400 + 1,995 - 14,535
DEMAND = 1,860 kw ---

STANDBY 0 6,500 - 600 = 5,900 kw

Demand + Energy =

$$\frac{(1{,}860 \times 6.40 \times 12) + (610 \times 6{,}192 \times .0489)}{610 \times 6{,}192} = \$0.0867/\text{kwh}$$

4) Multiple Units Cogenerating with Excess Power



					PLANT	AUX					PLANT	AUX
AVG	4.8	4.8	1.7	6.2	13.15	1.03	4.8	4.8	1.7	0	13.15	1.03
N/P	7.0	7.0	2.9	7.0	+ 10%							

	Normal	Contingency
BILLING DEMAND	0	0
STANDBY	0	4,000 kw

Using 1.10 x PURPA RATE (a non-contracted option) = \$0.05346/kw

Demand + Energy =

$$\frac{(2{,}210 \times 36.05) + (2{,}210 \times 6{,}192 \times .05346)}{2{,}210 \times 6{,}192} = \$0.059/\text{kwh}$$

Standby 4,000 x 2 x 12 = \$96,000/yr

2.3 PERFORMANCE AND BENEFITS ANALYSES

2.3.1 Performance Parameter Definitions

A number of economic performance parameters and operational performance parameters are used in this report to judge the feasibility of a cogeneration system. Definitions of the parameters are given in Table A2-3 below.

Table A2-3

PERFORMANCE PARAMETER DEFINITIONS

1) Levelized Annual Energy Costs Savings Ratio =

$$\frac{\text{Non-Cogen. Energy Cost} - \text{Cogen. Energy Cost}}{\text{Non-Cogen. Energy Cost}}$$

2) Capital Cost Ratio = $\dfrac{\text{Cogen. Capital Costs}}{\text{Non-Cogen. Capital Costs}}$

3) Fuel Energy = On-site fuel + utility fuel for purchased electricity

4) Fuel Energy Savings Ratio =

$$\frac{\text{Non-Cogen. Fuel Energy} - \text{Cogen. Fuel Energy}}{\text{Non-Cogen. Fuel Energy}}$$

5) Total Emissions = On-site emissions + utility emissions for purchased electricity

6) Emissions Savings Ratio =

$$\frac{\text{Non-Cogen. Emissions} - \text{Cogen. Emissions}}{\text{Non-Cogen. Emissions}}$$

2.3.2 Economic Feasibility Analysis

The approach to economic feasibility analysis is based on analyzing quantifiable costs and benefits for alternative cogeneration systems. The economic performance of each cogeneration system is analyzed over the assumed life of the power plant since the costs and benefits occur over time. This is best handled by computer analysis, since plant life runs over a typical 15 to 30 year period and several elements of the analysis usually escalate over the time period.

To establish the economic benefits of cogeneration, the capital costs must be weighed against the projected savings in energy costs. A summary of the methodology for economic analysis is shown in Table A2-4. The capital cost elements considered to provide a complete plant are shown in Table A2-5. Such elements are further grouped in 10 major cost areas shown in Table A2-6, which shows the source of the data. Table A2-7 shows the detailed areas of responsibility for the three main parties of the study.

For this study, the Task-1 plant screening effort involved establishing for the no-cogeneration base case an entirely new boilerhouse having oil/gas fired boilers providing only low pressure steam directly to the plant with all electric power needs purchased from the local utility. For the cogeneration cases, the fuel is coal and the combustor and auxiliary equipment needed for a complete system is much different. The difference in capital costs is used in comparing these systems. For the Task-2 conceptual design phase of the study, the no-cogeneration base case is the existing Ethyl plant boilerhouse, so no capital cost is involved for this system.

Other cost elements for performing economic analysis require total annual energy costs for the base case and the main case and is composed of basically the following elements:

- Fuel Cost (Total & Increment)
- Cost of Electric Power (Total & Increment)
- Cost of Operations and Maintenance (Total & Increment)
- Savings Before Taxes (Increment)
- Effect of Taxes and Depreciation

The main economic parameters calculated are:

- Return on Investment
- Levelized Annual Energy Cost

Table A2-4

METHODOLOGY FOR ECONOMIC ANALYSIS

1. CALCULATE TOTAL ANNUAL ENERGY COST WITHOUT COGENERATION AND FOR EACH COGENERATION SYSTEM.

   TOTAL ENERGY COST INCLUDES:

   - FUEL COSTS FOR TOTAL STEAM AND COGENERATED ELECTRICITY
   - COST OF PURCHASED ELECTRIC POWER
   - REVENUE FROM SALE OF ELECTRIC POWER
   - O&M COSTS - ENTIRE POWER SYSTEM
   - FIXED CAPITAL CHARGES - ENTIRE POWER SYSTEM

2. CALCULATE RATE OF RETURN USING INCREMENTAL INVESTMENT (RELATIVE TO THE NON-COGENERATED CASE) FOR THE AFB/STEAM TURBINE CYCLE COGENERATION CASES.

   A. DETERMINE CAPITAL INVESTMENT FOR SYSTEM UTILIZING LOW-PRESSURE STEAM GENERATOR THAT SATISFIES ONLY THERMAL LOAD WITHOUT COGENERATION AND PURCHASE ALL ELECTRICITY.

   B. DETERMINE CAPITAL INVESTMENT FOR COGENERATION CASE AND SUBTRACT COST OF LOW-PRESSURE STEAM ONLY SYSTEM.

3. CAPITAL COST OF AFB/GAS TURBINE CYCLE CALCULATED AND COMPARED TO BASE CASE LOW-PRESSURE STEAM GENERATOR SATISFYING THERMAL LOAD.

4. NUMBER OF UNITS SPECIFIED FOR A NEW PLANT IMPACTS TOTAL CAPITAL COST.

Table A2-5

CAPITAL COST SYSTEM ELEMENTS

FUEL STORAGE & RETRIEVAL
LIMESTONE STORAGE & RETRIEVAL
WASTE HANDLING
HEAT SOURCE
EMISSIONS CONTROL
FEEDWATER SYSTEMS
PRIMARY TURBINE - GENERATOR
SECONDARY TURBINE - GENERATOR
HEAT RECOVERY
CONDENSERS
SUPPLEMENTARY HEAT
HEAT REJECTION
SITE DEVELOPMENT
STRUCTURES
ELECTRICAL

Table A2-6

ECONOMIC DATA BASE

COST ITEM	SOURCE	COMMENT
1. STEAM TURBINE - GENERATOR	CATALYTIC & VENDOR QUOTE	THROTTLE CONDITIONS DIFFER.
2. HEAT SOURCE - STEAM CYCLE	DOOR-OLIVER/ E. KEELER	SAME AS STEAM TURBINE-GENERATOR.
3. AIR CYCLE TURBINE-GENERATOR & HEAT SOURCE	CURTISS-WRIGHT	WASTE HEAT BOILER BY CATALYTIC & VENDOR QUOTE.
4. PARTICULATE REMOVAL EQUIPMENT	CATALYTIC & VENDOR QUOTE	INCLUDE BAGHOUSE AND/OR ESP IF APPROPRIATE.
5. COAL STORAGE & DISTRIBUTION	CATALYTIC & VENDOR QUOTE	INCLUDES CRUSHING TO YIELD CORRECT SIZE.
6. LIMESTONE STORAGE & DISTRIBUTION	CATALYTIC & VENDOR QUOTE	USE SIMILAR EQUIPMENT AS FOR COAL PREPARATION.
7. DRY WASTE SOLIDS DISPOSAL	CATALYTIC & VENDOR QUOTE	OFF-SITE DISPOSAL.
8. BOILER FEEDWATER TREATMENT	CATALYTIC	PROVIDE CHEMICAL ADDITIVES SYSTEM PLUS INCREASE MAKEUP CAPACITY FOR SPECIFIC SITES.
9. HEAT REJECTION SYSTEM	CATALYTIC	ADJUST TO SELECTED TURBINE EXHAUST CONDITIONS.
10. BALANCE OF SYSTEMS	CATALYTIC	PROVIDE COMPLETE WORKING POWER PLANT.

Table A2-7

PRIME CONTRACTOR COMPONENTS RESPONSIBILITY

CATALYTIC

Coal/Dolomite Unloading & Transfer
Coal/Dolomite Crushing
Induced Draft Fan
Bag House/Precipitator
Stack
Stack Monitoring
Waste Heat Boilers/Process Heaters
Cold Ash Handling & Storage
Responsible Equipment Electrical Control/MCC's
All Process Pipe, Valve, Controls
Buildings
Structures
Electric Power Supply
Service Air/Instrument Air
Service Water Systems
Condensate and Feedwater Systems
Civil/Structural Layout
Equipment Arrangement
Step-up/Step-down Power Transformers
Power Connects to Bus
Steam Power Turbine/Generator
Steam Power Turbine Controls

SUBCONTRACTOR COMPONENTS RESPONSIBILITY

CURTISS-WRIGHT
(AFB/Gas Turbine Cycle)

Coal Bin
Dolomite Bin
Weigh Scales
Carrier Air Blower
Fuel Pipe
Boiler
Ash Cooler
Start-up Burner
Forced Draft Fan
Air Heater
Economizer
Recycle System
Boiler Controls
Gas Power Control
Associated Duct, Pipe, Conduit
Responsible Equipment
Electrical Controls/MCC's
Inlet Silencer
Compressor
Gas Turbine/Generator

DORR-OLIVER/E. KEELER
(AFB/Steam Boiler)

Coal Bin
Dolomite Bin
Weigh Scales
Carrier Air Blower
Fuel Pipe
Boiler
Ash Cooler
Start-up Burner
Forced Draft Fan
Air Heater
Economizer
Recycle System
Boiler Controls
Associated Duct, Pipe, Conduit
Responsible Equipment
Electrical Controls/MCC's

2.4 UNCERTAINTY ANALYSIS

This section describes the procedure used by Catalytic to measure the uncertainty in the capital cost estimate for the conceptual designs. A range estimating program (REP) is a method of quantifying the uncertainty in estimating. This computer program is a risk analysis program used to provide information not available with conventional estimating. REP is not a computerized estimating technique. The distinct cost elements of the estimate potentially vary differently, and REP provides information to evaluate an assessment of the criticality of the various cost elements to assure valid results.

Basically, the initial capital cost estimate for a cogeneration plant is composed of a group of line items, or elements. These are called target estimates. Then, an estimate is made of the highest and lowest possible element cost. These estimates represent the estimator's assessment of uncertainty. The values between the high and low estimates are the range for each element. A percent probability - also known as the confidence factor- is assigned to each cost element. This is the assessment of the probability that the actual cost of each line item will be between the lowest estimate and the target estimate, or the estimated probability of underrunning the budget. Probability factor guidelines can be characterized as noted:

0	absolute pessimism
5-10	extreme pessimism
15-35	moderate pessimism
50	ambivalent
55-60	slight optimism
65-85	moderate optimism
90-95	extreme optimism
100	absolute optimism

Judgment determines the confidence factor. REP then performs a Monte Carlo simulation and sensitivity analysis and summarizes results in various output reports.

REP Report No.1 is given in Table A2-8 for the AFB/gas turbine conceptual design, and shows the appropriate elements, their target estimates, the highest and lowest possible element costs assigned by Catalytic and the percent probability assigned to each cost element. REP Report No.2 is not presented since it is input analysis.

Table A2-9 is REP Report No.3, which gives the overrun profile showing the manner in which these total cost combinations compare with one another. The probability curve, Figure A2-1, is a graphical representation of the overrun profile. The risks of the project are quantified by comparing the target with the highest estimate. This amounts to only a 16% increase.

There are relatively few elements that could substantially alter the cost of a project. These elements represent a high degree of uncertainly and/or a high relative cost. The priority analysis, which is REP Report No.4 shown in Table A2-10, pinpoints those elements of major risk and opportunity, and ranks them in order of their importance. The AFBs, piping and material handling are shown to be the three most critical cost elements. Negative impact means the actual cost overruns the target and, conversely, a positive impact means coming in under the estimate. The AFBs have the greatest potential for both negative and positive effect. It has 37% of the total risk of the project and 42% of the total opportunity.

REP Report No.1 for the AFB/steam turbine conceptual design is given in Table A2-11. The present probabilities assigned to the elements are the same as for the gas turbine case. The overrun profile, REP Report No.3, is shown in Table A2-12. The probability curve, Figure A2-2, shows this data graphically. The highest estimate is only 16% above the target estimate.

REP Report No.4, giving the priority analysis, is shown in Table A2-13. The piping, AFBs and turbine-generator (package units subcontract element) are shown as the three most critical cost elements. The AFB boilers have only 9% of the total risk of the project and 25% of the total opportunity.

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Table A2-8

R.E.P. (79.055) - REPORT 1

43790 ADVANCED CO-GEN STUDY GAS RANGE ESTIMATE - 9SEPT82

NO	ELEMENT	UNIT	TARGET EST.	PCT. PROBAB+	LOWEST EST.	HIGHEST EST.
1	BOILERS SUBC	$	32289	60	30000	37575
2	STACKS SUBC	$	250	40	200	500
3	HEAT EXCHANGERS SUBC	$	25	40	20	50
4	VESSELS SUBC	$	159	40	150	200
5	PUMPS SUBC	$	254	40	200	400
6	BLOWERS SUBC	$	296	60	250	400
7	MATERIAL HANDLING EQUIP SUBC	$	7488	60	7000	8900
8	MECHANICAL EQUIP SUBC	$	1474	60	1200	2000
9	SEPARATOR EQUIP SUBC	$	479	60	400	575
10	START-UP SPARE PARTS SUBC 2%	$	800	40	788	1000
11	PIPING SUBC	$	3081	30	3000	5800
12	SEWERS SUBC	$	20.00	30	15.00	40.00
13	INSTRUMENTATION SUBC	$	561	50	500	700
14	ELECTRICAL SUBC	$	1945	50	1500	3000
15	CONCRETE SUBC	$	3772	50	3500	4550
16	STRUCTURAL STEEL SUBC	$	57	30	50	100
17	FIREPROOFING SUBC	$	50	30	40	100
18	BUILDINGS SUBC	$	30	50	20	60
19	SITE DEVELOPMENT & DEMO SUBC	$	426	50	400	550
20	INSULATION SUBC	$	515	40	500	650
21	PAINTING SUBC	$	20.00	40	15.00	40.00
22	FIRE PROTECTION SUBC	$	185	40	150	250
23	MISC SYSTEMS SUBC 6-7%	$	3500	40	3200	4000
24	INSURANCE, TAXES & BOND	$	970	50	800	1050
25	CONSTRUCTION MANAGEMENT	$	1355	50	1150	1414
26	HOME OFFIC ENGINEERING	$	5700	50	4853	5965
27	FEE 2%	$	1300	50	1100	1350
	TOTAL EXPENSE (INPUT TO R.E.P.)		67001		61001	83219
					(THEORETICALS)	

\+ PROBABILITY THAT ACTUAL VALUE WILL BE EQUAL TO OR LESS THAN TARGET
* SUPPLIED BY R.E.P. (BASED ON TARGET, LOWEST AND HIGHEST ESTIMATES)

Table A2-9

R.E.P. (79.055) - REPORT 3

43790 ADVANCED CO-GEN STUDY GAS   OVERRUN PROFILE - 9SEPT82

2 EXAMPLES TO SHOW HOW TO INTERPRET THIS PROFILE

THERE IS A 20 PERCENT PROBABILITY THE TOTAL WILL EXCEED   70834
THERE IS A 80 PERCENT PROBABILITY THE TOTAL WILL EXCEED   66740

77599---- *	74276--- 5	72907---10	71720---15
70834---20	70124---25	69633---30	69217---35
68320---40	68448---45	68219---50	67969---55
67723---60	67510---65	67244---70	67041---75
66740---80	66453---85	66089---90	65731---95
63036---**			

* LESS THAN 0.05 PERCENT PROBABILITY THE TOTAL WILL EXCEED THIS
** GREATER THAN 99.95 PERCENT PROBABILITY THE TOTAL WILL EXCEED THIS

(ABOVE RESULTS DERIVED FROM 1000 SIMULATIONS)

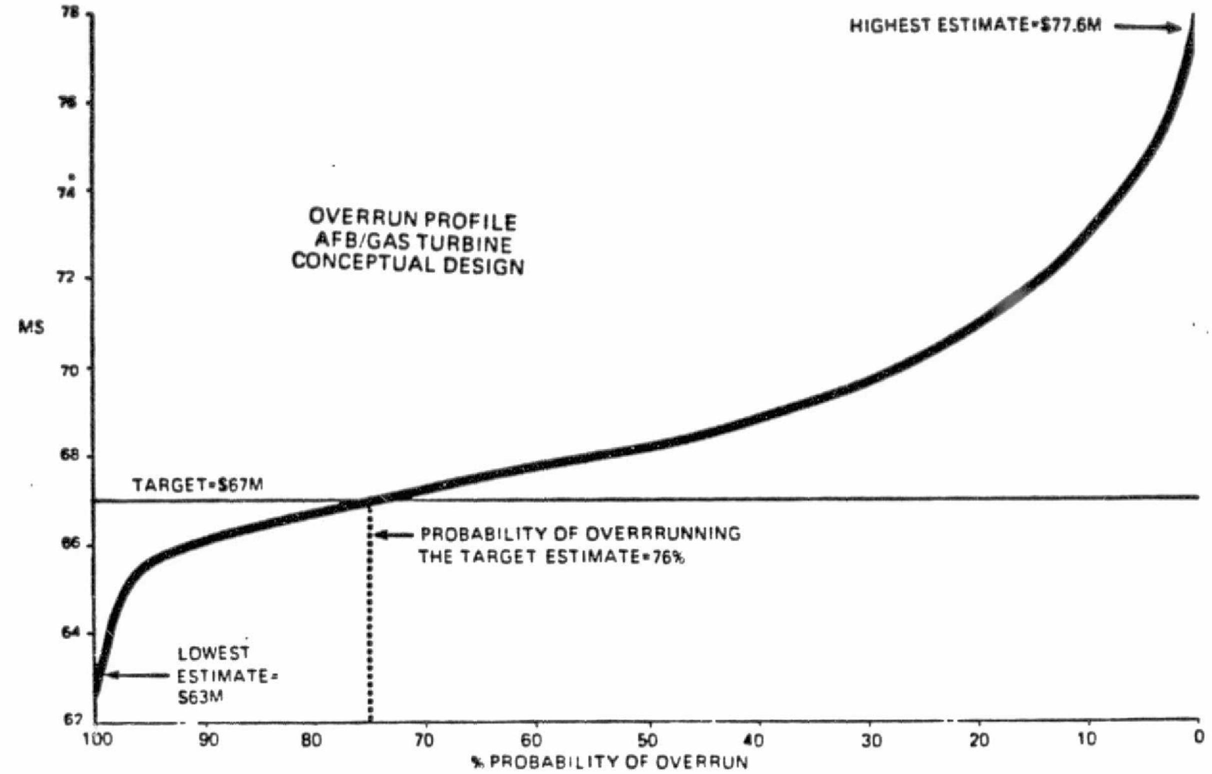

Figure A2-1

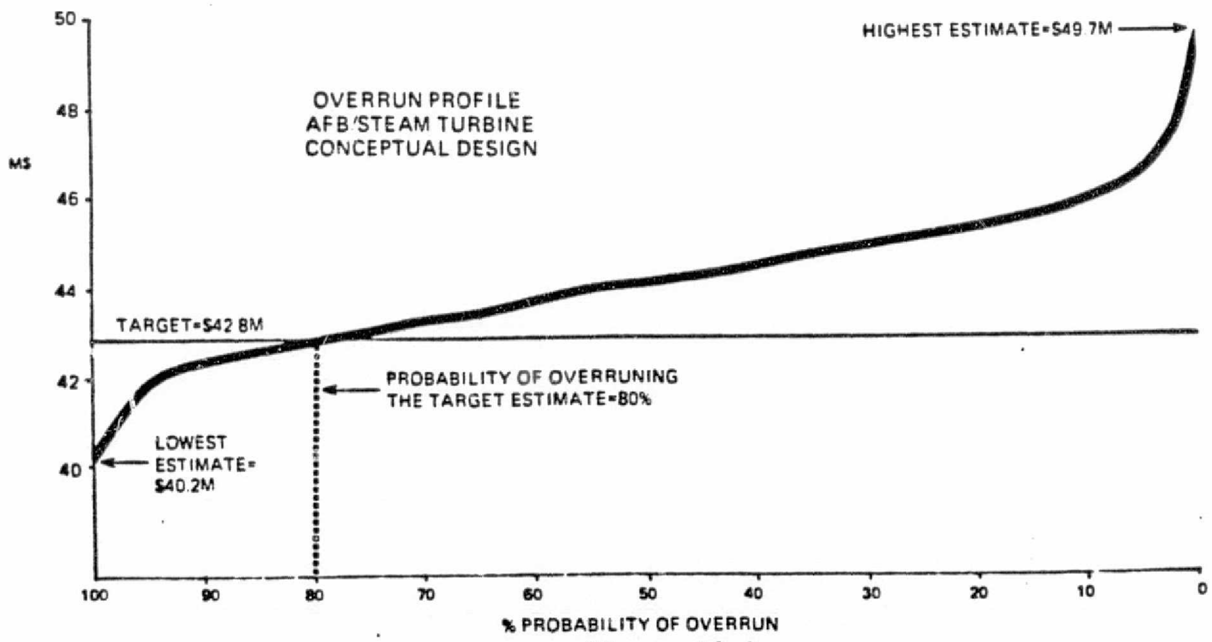

Figure A2-2

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Table A2-10

R.E.P. (79.055) - REPORT 4

43790 ADVANCED CO-GEN STUDY GAS PRIORITY ANALYSIS - 9SEPT82

TOTAL (EXPENSE)	OVERRUN PROBAB.	NET EFFECT OF FROZEN ELEMENTS	WEIGHT FACTOR IN INDEXES
67001	76 PCT.	0 * 0.0 PCT.	1.000000

NO	ELEMENT	UNIT	RANK	-NEGATIVE- PCT.	INDEX	-POSITIVE- PCT.	INDEX
1	BOILERS SUBC	$	1	37.4	1895	42.2	876
11	PIPING SUBC	$	2	23.8	1207	0.8	16
7	MATERIAL HANDLING EQUIP SUBC	$	3	7.2	367	9.0	187
14	ELECTRICAL SUBC	$	4	6.7	339	6.9	143
26	HOME OFFIC ENGINEERING	$	5	1.7	85	13.1	272
15	CONCRETE SUBC	$	6	4.9	250	4.2	87
23	MISC SYSTEMS SUBC 6-7%	$	7	3.8	191	3.8	78
8	MECHANICAL EQUIP SUBC	$	8	2.7	137	5.1	105
2	STACKS SUBC	$	9	1.9	96	0.6	13
25	CONSTRUCTION MANAGEMENT	$	10	0.4	19	3.2	66
24	INSURANCE,TAXES & BOND	$	11	0.5	26	2.6	55
27	FEE 2%	$	12	0.3	16	3.1	64
10	START-UP SPARE PARTS SUBC 2%	$	13	1.5	76	0.1	3
5	PUMPS SUBC	$	14	1.1	56	0.7	14
13	INSTRUMENTATION SUBC	$	15	0.9	45	1.0	20
20	INSULATION SUBC	$	16	1.0	52	0.2	4
9	SEPARATOR EQUIP SUBC	$	17	0.5	25	1.4	30
19	SITE DEVELOPMENT & DEMO SUBC	$	18	0.8	40	0.4	8
6	BLOWERS SUBC	$	19	0.5	27	0.9	18
22	FIRE PROTECTION SUBC	$	20	0.5	25	0.4	9
17	FIREPROOFING SUBC	$	21	0.4	22	0.1	2
16	STRUCTURAL STEEL SUBC	$	22	0.4	19	0.0	1
4	VESSELS SUBC	$	23	0.3	16	0.1	2
18	BUILDINGS SUBC	$	24	0.2	10	0.1	3
3	HEAT EXCHANGERS SUBC	$	25	0.2	10	0.0	1
12	SEWERS SUBC	$	26	0.2	9	0.0	1
21	PAINTING SUBC	$	27	0.2	8	0.0	1
	NET EFFECT OF FROZEN ELEMENTS			0.0	0	0.0	0
	TOTALS			100.0	5068	100.0	2079

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Table A2-11

R.E.P. (79.055) - REPORT 1

43790 ADVANCED CO-GEN STUDY STM RANGE ESTIMATE - 9SEPT82

NO	ELEMENT	UNIT	TARGET EST.	PCT. PROBAB+	LOWEST EST.	HIGHEST EST.
1	BOILERS SUBC	$	12397	60	11000	14000
2	STACKS SUBC	$	250	40	200	500
3	HEAT EXCHANGERS SUBC	$	76	40	50	120
4	VESSELS SUBC	$	63	40	40	110
5	PUMPS SUBC	$	95	40	70	150
6	MATERAIL HANDLING EQIUP SUBC	$	5372	60	5000	7000
7	SEPARATOR EQIUP SUBC	$	1327	60	1000	2000
8	PACKAGE UNITS SUBC	$	2620	60	2000	4000
9	START-UP SPARE PARTS SUBC 2%	$	444	40	390	600
10	PIPING SUBC	$	3592	30	3000	6000
11	SEWERS SUBC	$	20.00	30	15.00	30,00
12	INSTRUMENTATION SUBC	$	987	50	850	1500
13	ELECTRICAL SUBC	$	1536	50	1100	2500
14	CONCRETE SUBC	$	2649	50	2000	3500
15	STRUCTRUAL STEEL SUBC	$	62	30	50	100
16	FIREPROOFING SUBC	$	50	30	40	100
17	BUILDINGS SUBC	$	160	50	110	200
18	SITE DEVELOPMENT & DEMO SUBC	$	426	50	350	500
19	INSULATION SUBC	$	687	40	600	1500
20	PAINTING SUBC	$	25	40	20	40
21	FIRE PROTECTION SUBC	$	185	40	150	250
22	MISC SYSTEMS SUBC 6-7%	$	2146	40	1800	3000
23	INSURANCE,TAXES & BOND	$	700	50	600	830
24	CONSTRUCTION MANAGEMENT	$	1060	50	900	1250
25	HOME OFFIC ENGINEERING	$	5070	50	4200	5800
26	FEE	$	840	50	700	950
	TOTAL EXPENSE (INPUT TO R.E.P.)		42839		36235	56530
					(THEORETICALS)	

+ PROBABILITY THAT ACTUAL VALUE WILL BE EQUAL TO OR LESS THAN TARGET
* SUPPLIED BY R.E.P. (BASED ON TARGET, LOWEST AND HIGHEST ESTIMATES)

Table A2-12

R.E.P. (79.055) - REPORT 3

43790 ADVANCED CO-GEN STUDY STM   OVERRUN PROFILE - 9SEPT82

2 EXAMPLES TO SHOW HOW TO INTERPRET THIS PROFILE

THERE IS A 20 PERCENT PROBABILITY THE TOTAL WILL EXCEED   45386
THERE IS A 80 PERCENT PROBABILITY THE TOTAL WILL EXCEED   42838

49663--- *	46439--- 5	46037---10	45629---15
45386---20	45157---25	44932---30	44730---35
44499---40	44325---45	44133---50	43919---55
43727---60	43529---65	43311---70	43079---75
42838---80	42575---85	42312---90	41918---95
40214---**			

* LESS THAN 0.05 PERCENT PROBABILITY THE TOTAL WILL EXCEED THIS
** GREATER THAN 99.95 PERCENT PROBABILITY THE TOTAL WILL EXCEED THIS

(ABOVE RESULTS DERIVED FROM 1000 SIMULATIONS)

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Table A2-13

R.E.P. (79.055) - REPORT 4

43790 ADVANCED CO-GEN STUDY STM PRIORITY ANALYSIS - 9SEPT82

TOTAL (EXPENSE)	OVERRUN PROBAB.	NET EFFECT OF FROZEN ELEMENTS	WEIGHT FACTOR IN INDEXES
42839	80 PCT.	0 = 0.0 PCT.	1.000000

NO	ELEMENT	UNIT	RANK	-NEGATIVE- PCT.	/INDEX	-POSITIVE- PCT.	/INDEX
10	PIPING SUBC	$	1	23.7	1084	5.4	119
1	BOILERS SUBC	$	2	9.2	423	24.9	542
8	PACKAGE UNITS SUBC	$	3	7.9	364	10.9	241
6	MATERAIL HANDLING EQIUP SUBC	$	4	9.4	430	6.5	144
25	HOME OFFIC ENGINEERING	$	5	5.2	238	12.9	284
14	CONCRETE SUBC	$	6	6.0	277	9.6	212
13	ELECTRICAL SUBC	$	7	6.8	314	6.4	142
22	MISC SYSTEMS SUBC 6-7%	$	8	7.2	331	4.1	91
19	INSULATION SUBC	$	9	6.9	316	1.0	23
7	SEPARATOR EQIUP SUBC	$	10	3.9	178	5.8	127
12	INSTRUMENTATION SUBC	$	11	3.6	167	2.0	45
24	CONSTRUCTION MANAGEMENT	$	12	1.4	62	2.4	52
2	STACKS SUBC	$	13	2.1	97	0.6	13
26	FEE	$	14	0.8	36	2.1	46
23	INSURANCE,TAXES & BOND	$	15	0.9	42	1.5	33
9	START-UP SPARE PARTS SUBC 2%	$	16	1.3	61	0.6	14
18	SITE DEVELLOPMENT & DEMO SUBC	$	17	0.5	24	1.1	25
21	FIRE PROTECTION SUBC	$	18	0.5	25	0.4	9
17	BUILDINGS SUBC	$	19	0.3	13	0.7	16
5	PUMPS SUBC	$	20	0.5	21	0.3	7
16	FIREPROOFING SUBC	$	21	0.5	23	0.1	2
4	VESSELS SUBC	$	22	0.4	18	0.3	6
3	HEAT EXCHANGERS SUBC	$	23	0.4	17	0.3	7
15	STRUCTRUAL STEEL SUBC	$	24	0.4	17	0.1	2
20	PAINTING SUBC	$	25	0.1	6	0.0	1
11	SEWERS SUBC	$	26	0.1	4	0.0	1
	NET EFFECT OF FROZEN ELEMENTS			0.0	0	0.0	0
	TOTALS			100.0	4588	100.0	2204

Section 3

SITES

3.0 PLANT SCREENING

The first task of the study required defining the requirements of specific industrial plant sites. Each industrial site was inspected and studied to determine the site-specific electric and thermal energy requirements. The utility providing electricity to each plant was also visited to assess the impact and potential of industrial cogeneration.

The information gathered was used to determine cogeneration system design and sizing to a level of detail which permitted a preliminary assessment of the benefits of AFB/gas turbine cogeneration as compared to AFB/steam turbine cogeneration and compared to a new non-cogenerating industrial plant.

The industrial sites evaluated are:

1) Ethyl Corporation - Pasadena, Texas
2) Riegel Products Corporation - Milford, New Jersey
3) Georgia-Pacific Corporation - Lovell, Wyoming
4) Hercules Incorporated - Covington, Virginia

All four plants are looking for ways to reduce their energy costs. Combined electric and thermal energy costs are now very significant. Three of the plants have old boilers burning oil and/or natural gas. They have been hurt in the past by cut-offs of gas. Electric costs have also risen sharply in addition to the steep rise in oil and gas prices. These companies do not take an optimistic view of future energy costs.

3.1 EHTYL CORPORATION - PASADENA, TEXAS

3.1.1 Site Definition

A. Site Description

The Ethyl Corporation-Pasadena plant produces a diversified line of intermediate petrochemicals using ethylene as the primary feedstock. General site data is given in Table A3-1. The plant is located in a heavily industrialized area along the Houston Ship Channel. Plant operation is characterized by a large consumption of electricity and natural gas used for steam generation and heating Dowtherm heat transfer fluid. Steam demand typically incorporates substantial swings in steam flow due to frequent cycling of process batch operations. The plant electric demand is quite steady. The entire electric requirement is supplied by Houston Lighting and Power Company. Waste oil is generated in the course of petrochemical processing and is utilized to supplement natural gas firing of the steam generators.

The manufacture of petrochemicals is identified by the Federal government with the Standard Industrial Classification (SIC) number 286. The electric to thermal ratio ($E/_T$) of the Pasadena plant is 0.36, which signifies a large resource requirement for electricity and thermal energy for this large capacity facility.

The site requirements for the Pasadena plant are summarized in Table A3-2 as projected for the mid-1980 level of operation. Average plant electric requirements are 24,000 kw and average thermal requirements are 252 MM Btu/hr as natural gas for steam generation, with a single area requiring on a steady basis 231 MM Btu/hr as natural gas for Dowtherm heating as shown in Figure A3-1. Design peak load operation is shown in Figure A3-2, based on 310,000 lbs/hr steam and 310 MM Btu/hr Dowtherm heating required by the plant. Current plant loads are shown in Figure A3-3 for January, 1982 loads and in Figure A3-4 for the 1981 average load. These two figures serve as the basis for the projected operation. Waste oil, equivalent to a #5 fuel oil, is currently used as a supplementary fuel and is taken to be used in plant energy requirements at a rate of 70 MM Btu/hr. For the selection of the "best" site, the supplemental fuel is not considered. Low pressure steam (40 psig) is currently available from mechanical turbine exhaust and is used to heat makeup water which has been clarified and treated with cold zeolite softeners. All existing steam generating facilities are outdoor installations. The field trip report for the Ethyl Corporation (Pasadena, Texas) is presented in Appendix Section 3.8 and is typical of the reports prepared for each site.

Current plant operation is 7 days per week - 24 hours per day with six boilers, and this level of operation is assumed for the mid-1980s. The variation in electric load, as shown in Figure A3-5, is minimal. Steam demand, however, is cyclic in nature due to the frequency of batch operations as shown in Figure A3-6 for a single steam generator over a typical day. There is a critical need for at least 100,000 lbs/hr steam at all times to prevent unscheduled shutdowns of process units, which is an unsafe practice. There are no condensate returns to the boilers, so there is a 100% makeup water requirement.

Table A3-1: SITE DATA - GENERAL

	RIEGEL PRODUCTS CORP. Milford, New Jersey	ETHYL CORP. Pasadena, Texas
SIC(s)	261	286
PRODUCTS	Specialty Papers	Zeolite, Linear Olefins, etc.
CURRENT FUELS	Natural Gas	Natural Gas
UTILITY	Jersey Central Power & Light	Houston Lighting & Power Company
UTILITY FUELS	33% Coal; 19% Nuclear; 48% Oil/Gas; (55% of generation is through interchange)	80% Natural Gas; 20% Coal

Table A3-2: SITE DATA - LOADS

	RIEGEL PRODUCTS CORP.	ETHYL CORPORATION
ELECTRICAL LOAD	13 MW Average; 19 MW Peak	24 MW Average; 29 MW Peak
THERMAL LOAD	160,000 #/Hr. Average 220,000 #/Hr. Peak @ 400 Psig, 150 Psig, 75 Psig, 25 Psig	190,000 #/Hr. Average 310,000 #/Hr. Peak @ 225 Psig saturated 170,000,000 Btu/Hr. Dowtherm
LOAD VARIATION	Fairly steady thermal loads, fairly steady electrical load, 6,192 Hr./Yr. Operation	Very variable daily thermal loads, very flat electrical load 8,760 Hr./Yr. Operation
POWER/HEAT RATIO	.3	.36 without Dowtherm .19 with Dowtherm
RELIABILITY	Need steam to maintain mill operation.	Must maintain 100,000 #/Hr. minimum steam flow.

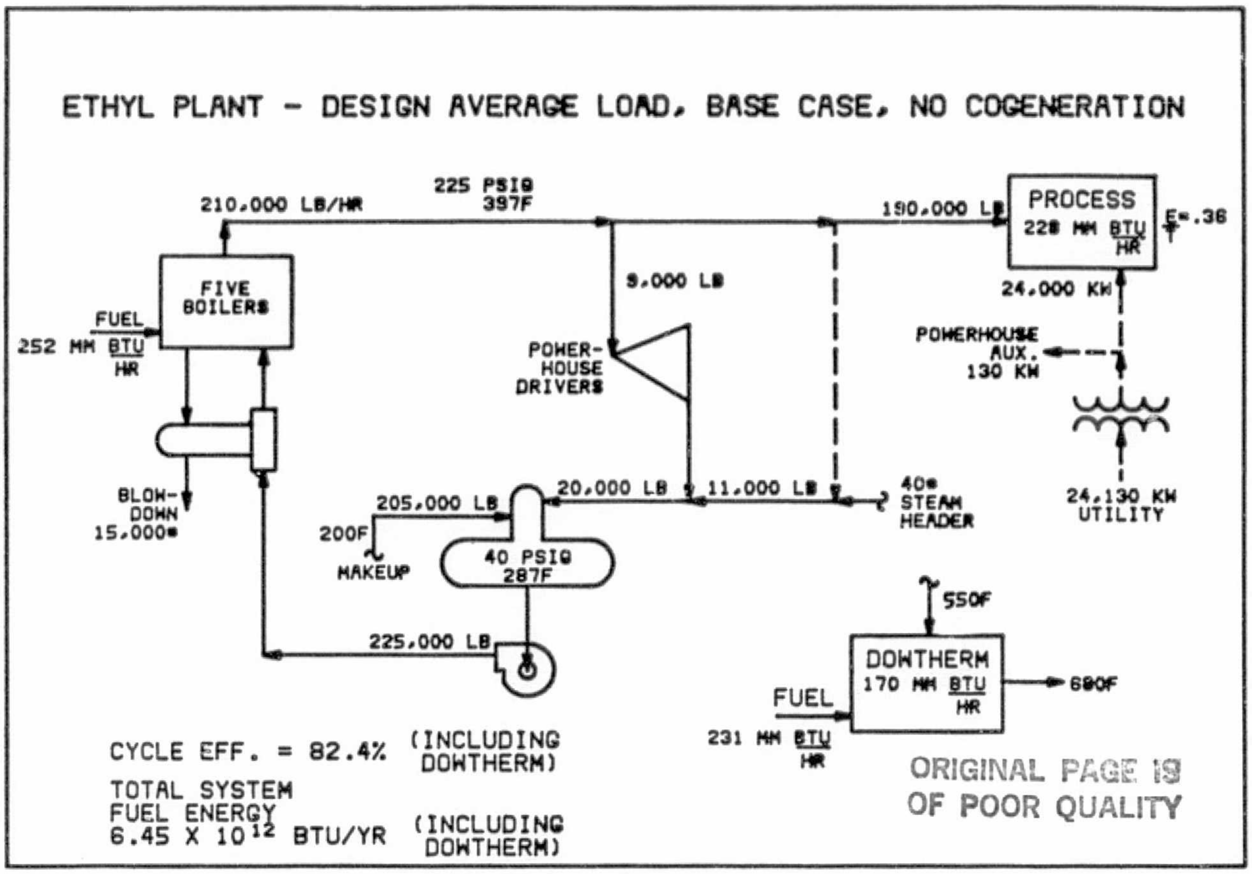

FIGURE A3-1

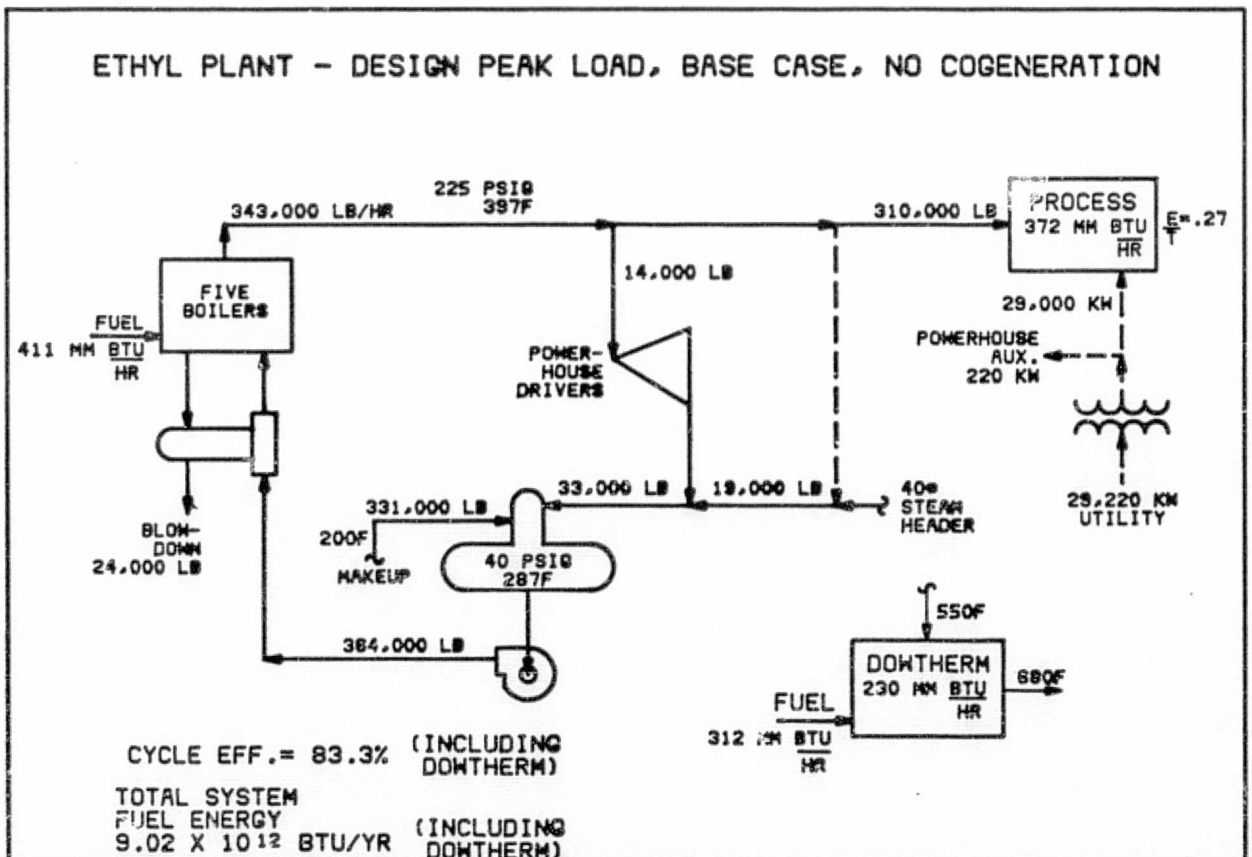

FIGURE A3-2

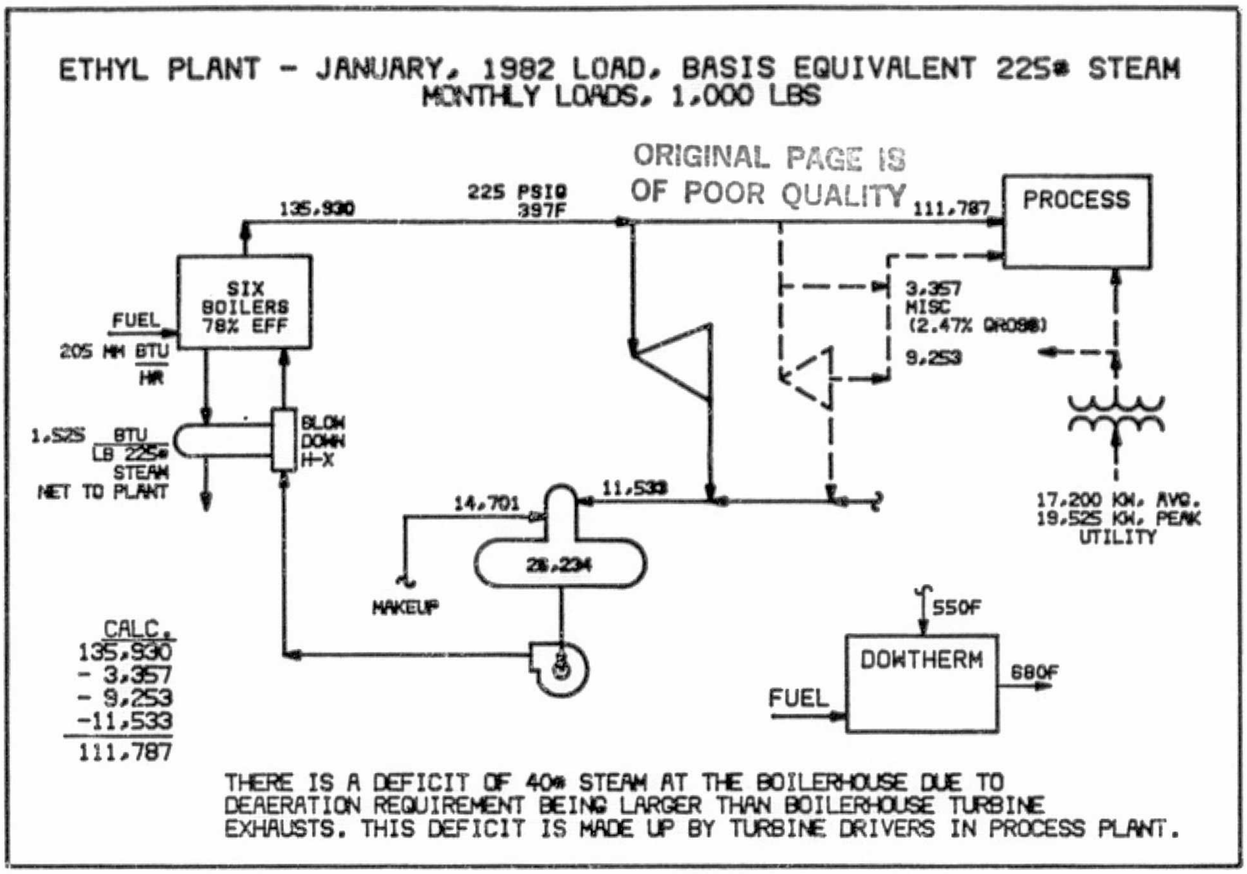

FIGURE A3-3

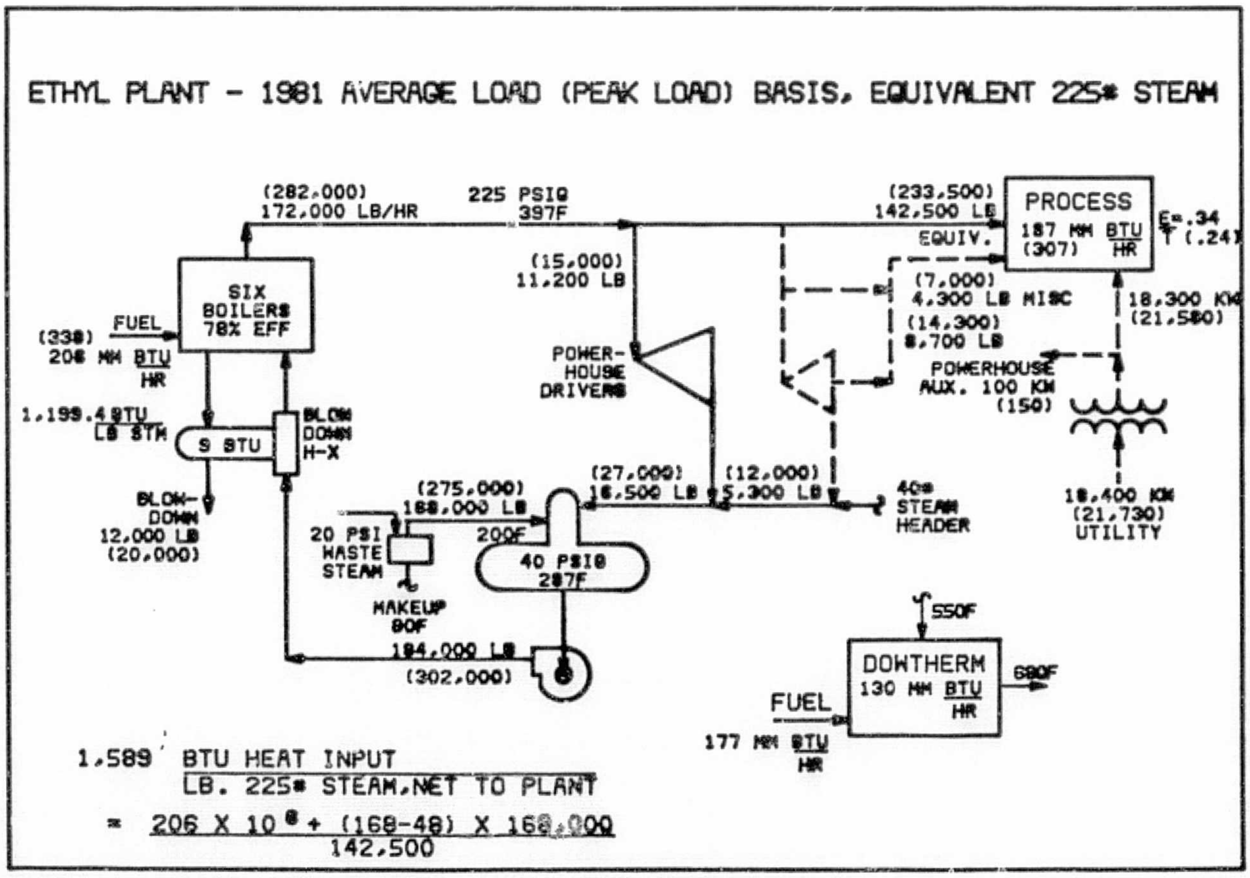

FIGURE A3-4

typical day
plant electric consumption

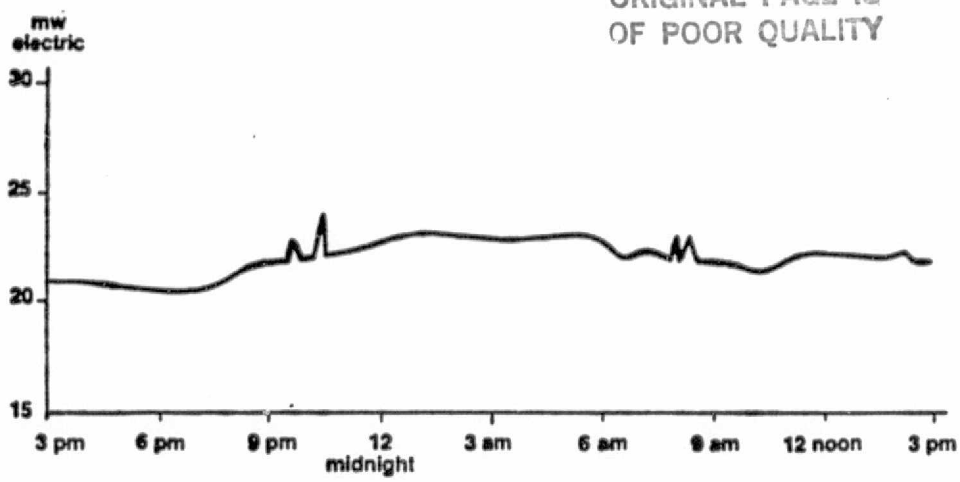

Figure A3-5

TYPICAL DAY
SINGLE BOILER
STEAM OUTPUT

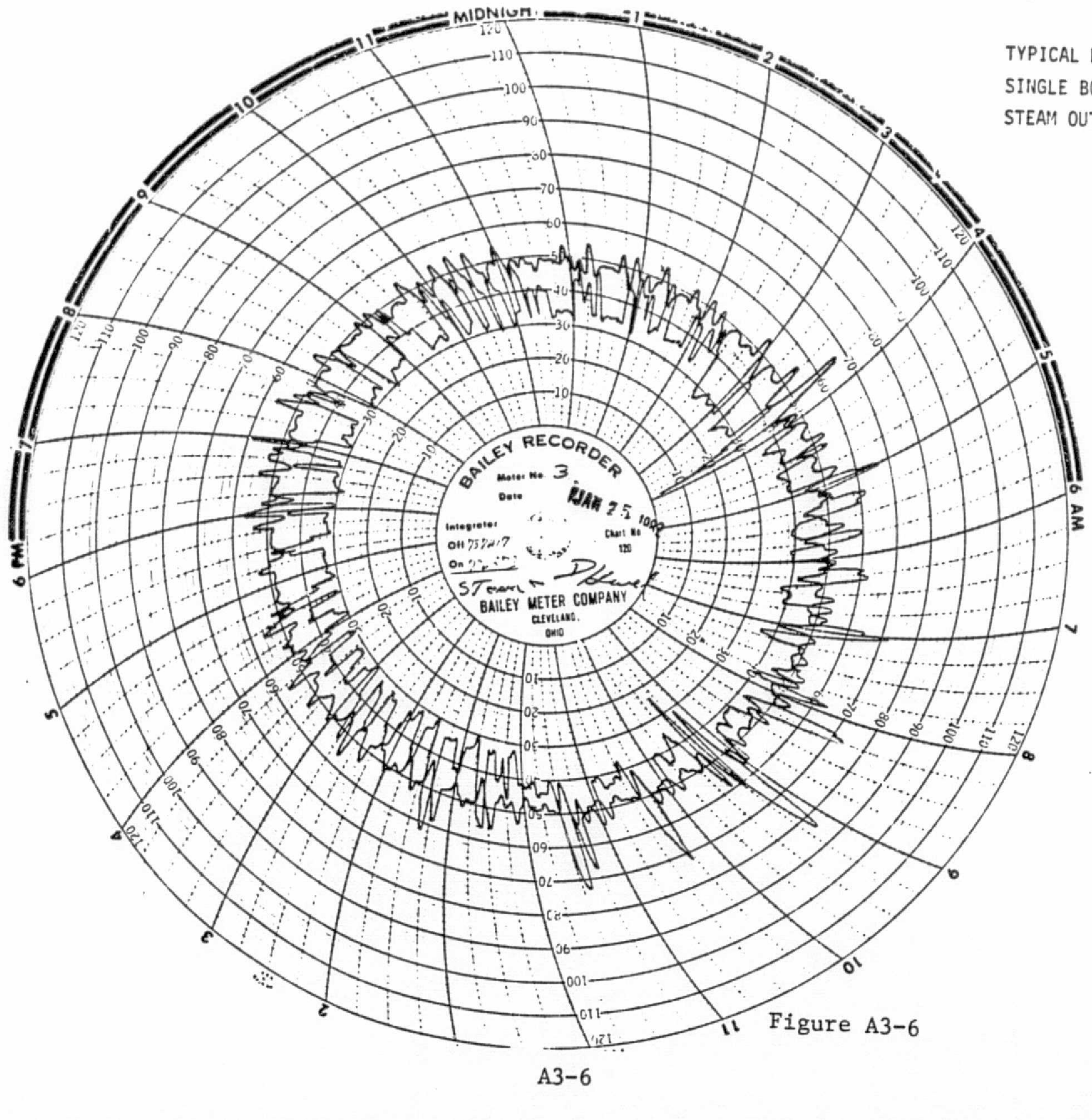

Figure A3-6

There is a considerable Dowtherm heat demand throughout the plant provided by several scattered gas fired heaters. One portion of Dowtherm heat demand is quite steady and is provided by two large fired heaters located about 1,000 feet from the boilers. An overall operating efficiency of 74.6% is assumed since the one larger unit has an air preheater. Ethyl Corporation provided the projected average and maximum Dowtherm heat demands of 170 and 230 MM Btu/hr. The heating of this Dowtherm by the cogeneration system is a possibility, but not a necessity. The displacement of gas firing is an economic and technical consideration.

The Pasadena plant energy requirements are compatible with the AFB/gas turbine cogeneration system. Both electricity, steam and direct heat (Dowtherm) are required in proportions that can be satisfied by the AFB/gas turbine system flexibility. Process use of steam to power mechanical drives, such as chillers and extruders, is currently utilized at a rate of 11,000 lbs/hr as 225 psig steam. The projected level of mechanical drive steam usage is 44,000 lbs/hr for the mid-1980s. A new plant would not differ significantly from the current plant operation at the Pasadena site. A rearrangement of process areas to maximize the availability of direct heat from an AFB/gas turbine cogeneration system would be incorporated into a new plant layout in order to minimize transfer distances. There is currently an ample amount of land available at the Pasadena site to incorporate the cogeneration system and the necessary requirements for coal and sorbent storage and rail transfer of this material. The properties of the coal and sorbent selected for the site are listed in Table A3-3. Again, site specific items are used for this study to further provide a meaningful selection of AFB combustors for both the gas turbine and steam turbine cycles for each site. The AFB designers considered this in the design and performance of their combustors for the site.

Site specific economic parameters are listed in Table A3-4. There are some changes in certain figures used in Task-1 plant screening and Task-2 conceptual design, but these changes do not have a severe impact on overall economics.

B. Houston Lighting and Power Company (HL&P)

A meeting was arranged with regional and local representatives of HL&P to evaluate the feasibility of cogeneration at the Pasadena plant and the utility's philosophy toward cogeneration in general. Information on electric rates is given in Appendix Section 2.2.1

Power generation stations for HL&P are fueled by 80% natural gas and 20% coal. The coal is mostly Texas Lignite.

Table A3-3

COAL AND LIMESTONE CHARACTERISTICS

		ETHYL PLANT
Coal:	Name	Oklahoma
	Type	Iron Post/ Ft. Scott
Ultimate Analysis:	% Moisture	8.46
	% Ash	10.09
	% Sulfur	3.11
	% C	67.65
	% H	4.55
	% N	1.21
	% O	4.93
H.H.V. Btu/lb (as delivered)		12,400

Table A3-4: ECONOMIC PARAMETERS
(1985 Price in 1981 Dollars)

		ETHYL TASK 1	RIEGEL (SECTION 3.2)	COMMON CASE (SECTION 3.4)
	I			
1.	General Inflation Rate (%) (10% actual)	0	0	0
2.	Local Taxes & Insurance (% of Capital Investment)	1.5	3.0	3.0
3.	Federal & State Corporate Income Tax Rate (%)	48	46	50
4.	Cost of Money (%)	15	5	7
	a. Debt to Equity Ratio	0/100	1.81	0/100
	b. Cost of Debt above inflation (%) (before taxes)	-	1.5	3
	c. Cost of Common Equity above inflation (%)	15	19.2	7
5.	Cogeneration System Investment Tax Credit Rate (%)	10	10	10
6.	Life of Facility for Tax Purposes (Years)	5	5	5
7.	Life of Project (Years)	15	20	30
8.	Tax Depreciation Method	PER ERA	PER ERA	PER ERA
9.	Initial Operation Date	1988	1986	1988
	II			
1.	Annual Charge for Standby Power ($/Kw/Month)	-	2.00	4.50
2.	Composite Price of Electricity purchased from a Utility ($/Kwh)	0.0524	Varies with cycle (see below)	0.0046
	Price of:			
3.	Elect. sold to a Utility ($/Kwh)	0.0597	0.0614	0.028
4.	Coal ($/MM/Btu) (Delivered)	2.04	1.87	2.29
5.	Distillate Oil ($/MM/Btu)	-	-	7.66
6.	Residual Oil ($/MM/Btu)		5.58	6.69
7.	Natural Gas ($/MM/Btu)	5.80	5.33	5.24
8.	Limestone ($/ton) (Delivered)	18.00	-	13.90
9.	Dolomite ($/ton) (Delivered)	-	16.65	17.40
10.	Direct Installation Labor Rate ($/Hr)	-	19.00	17.10

No Cogeneration - 6.56 ¢/Kwh
AFB/ST 600 P/750#F - 6.60 ¢/Kwh
AFB/ST 1250 P/900F - 6.64¢ /Kwh

AFB/GT 600 P/750°F - 9.02 ¢/Kwh
AFB/GT 150 P/480°F - 6.84 ¢/Kwh
AFB/GT 900 P/825°F - 6.14 ¢/Kwh

Table A3-4: ECONOMIC PARAMETERS - continued
(1985 Price in 1981 Dollars)

III	ETHYL	RIEGEL	COMMON CASE
Price Escalation for:			
1. Electrical Energy (%)	7.0	1.0	1.5
2. Distillate & Residual Oil (%)	-	3.0	4.0
3. Natural Gas (%)	3.0	4.0	3.0
4. Coal (%)	1.0	1.0	1.0
5. Sorbent (%)	0	0	0
6. Cost Escalation for O&M Expenses	0	0	0

3.1.2 Base Case System

In order to provide better comparisons between the non-cogeneration system and the cogeneration systems for the Task-1 plant screening effort, a complete new non-cogeneration base case is considered using low steam pressure conventional boilers. This provides a minimum investment against which all the cogeneration cases are measured. Five 115,000 lbs/hr oil/gas fired package boilers are felt needed to provide steam continuously and also provide for peak loads. Basically, three boilers would normally continually operate. The performance is unchanged from the current plant operation projected for the mid-1980s in Figures A3-1 and A3-2. Powerhouse auxiliary electric and steam loads are accounted for to develop base case performance data to properly evaluate alternative systems. Refer to Figure A3-7 describing the approach to accounting for auxiliary power consumption. The preliminary capital cost estimate is shown in Table A3-5. Operating costs on a levelized annual basis are shown in Table A3-6 for the site specific case. Operating and maintenance costs were developed by Catalytic with minimal input from Ethyl Corporation.

Consideration was given to having an AFB boiler as the no-cogeneration base case, but this was decided against because of the following reasons:

- o One important output of the study is the displacement (saving) of oil and gas by coal.
- o The least expensive plant to build but most costly plant to operate is a new oil/gas fired boilerhouse.

Figure A3-7

AUXILIARY POWER CONSUMPTION

- Miscellaneous small power users which are common to any power plant are neglected. This includes small pumps, lighting, compressors, controls.

- Large power users are accounted for, such as forced draft and induced draft fans, barter feed pump (turbine or motor driven), coal handling, circulating water pump for AFB/gas turbine cycle with feedwater preheating.

- For the no-cogeneration base case, 94 kw/100,500 lbs/hr steam output is taken as the auxiliary power.

- For the AFB boiler cogeneration case, 560 kw/100,000 lbs/hr steam output is used for fans and material handling power needs.

- For the AFB/gas turbine system material handling, 140 kw/100,000 lbs/hr steam is used, or 0.476 kw/MM Btu/hr heat input, which is felt to be an equivalent figure.

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Table A3-5

ETHYL PLANT SITE
CAPITAL COST ESTIMATE

COST ITEM (THOUS. $)	BASE CASE 5-115,000 LB/HR OIL/GAS PACKAGE BOILERS,225 PSIG	AFB/ST 3-110,000 LB/HR AFB'S,600P/750F 2-110K BOILERS	AFB/GT 3-AFB'S 3-97K BOILERS, 225 PSIG	AFB/GT 4-AFB'S SUPPL. FIRING WHB'S
PACKAGE BOILERS, DELIVERED & ERECTED	2,185	1,480	1,794	-
AFB'S	-	12,600	21,620	28,654
FOUNDATIONS & STEEL	-	1,800	2,162	2,865
DUCTS & STACKS	-	1,200	1,425	1,740
BAGHOUSE	-	Incl.	2,375	2,967
FUEL OIL HANDLING & STORAGE	2,052	1,449	1,449	663
SOLID MATERIAL HANDLING & STORAGE	-	5,607	6,350	7,303
PIPING	874	4,000	3,200	3,600
FEEDWATER	182	400	360	360
WATER TREATMENT	250	250	250	250
TURBINE - GENERATOR	-	1,650	-	-
DOWTHERM PIPING & PUMPS	-	-	349	349
WASTE HEAT BOILERS & FW HEATERS	-	-	3,350	6,050
DOWTHERM HEATERS	-	-	1,002	1,336
ELECTRICAL EQUIPMENT	1,289	1,468	1,506	1,624
MISC. STRUCTURES	437	550	465	544
DIRECT COST	7,269	32,454	47,657	58,305
23% INDIRECTS	1,672	7,464	10,961	13,410
C-W ENGINEERING & SUPPORT	-	-	700	780
TOTAL CAPITAL	8,941	39,918	59,318	72,495
UNIT COST	$15.55/PPH STM	$ 5,468/KW	$ 2,785/KW	$ 2,553/KW

Table A3-6

ETHYL PLANT
LEVELIZED ANNUAL ENERGY COST ANALYSIS
SITE SPECIFIC ECONOMIC PARAMETERS

COST ITEM MILLION $	LEVELIZING FACTORS	1988 COSTS IN 1981 DOLLARS				LEVELIZED COSTS IN NOMINAL $			
		BASE CASE	AFB/ST 600/750	AFB/GT 3 UNITS	AFB/GT 4 UNITS	BASE CASE	AFB/ST 600/750	AFB/GT 3 UNITS	AFB/GT 4 UNITS
CAPITAL COST	-	8.941	39.918	59.318	72.495	-	-	-	-
CAPITAL INVESTMENT	-	10.461	54.608	81.47	99.173	-	-	-	-
LEVELIZED CAPITAL INVESTMENT	.1846	-	-	-	-	1.931	10.081	14.980	18.307
FUEL COST - GAS	1.185	26.402	12.627	4.685	1.115	31.286	14.963	5.552	1.321
FUEL COST - COAL	1.057	-	5.273	9.795	11.241	-	5.574	10.353	11.882
ELECTRIC PURCHASE	1.52	13.127	13.676	15.275	15.656	19.953	20.788	23.218	23.797
ELECTRIC BUY BACK	1.52	-	(2.787)	(13.192	(14.071)	-	(4.236)	(20.052)	(21.388)
SORBENT	1.0	-	1.435	1.311	1.419	-	-	-	-
WASTE DISPOSAL	1.0	-	.306	.375	.430	-	-	-	-
UTILITIES, LABOR & MAINTENANCE	1.0	.845	2.576	3.052	3.348	-	-	-	-
INSURANCE & LOCAL TAXES	1.0	0.157	.819	1.217	1.488	-	-	-	-
SUM OF CONSTANT ANNUAL COSTS	1.0	1.002	5.136	5.955	6.685	1.002	5.136	5.955	6.685
LEVELIZED ANNUAL ENERGY COST (NOMINAL $)	-	-	-	-	-	54.172	52.306	40.006	40.604
LEVELIZED ANNUAL ENERGY COST SAVING	-	-	-	-	-	-	1.866	14.166	13.568
PERCENT SAVING	-	-	-	-	-	-	3.4%	26.2%	25%

3.1.3 AFB/Gas Turbine Cogeneration System

A. Approach to Performance

Because of the flexibility of this cycle, the following criteria are applied:

- o Flue gas from the AFB is used to provide process heat for Dowtherm units. This involves pumping Dowtherm about 1,100 feet from the heaters to the AFB/ gas turbine unit, preheating the Dowtherm since process loads are considerably in excess of heat available from the flue gas, pumping back to the Dowtherm heaters for final heating. So, part of the economics involves pricing new piping, pumps, and process modifications and accounting for pressure drop. But heating gas is displaced.
- o Steam is provided by the waste heat from the gas turbines.
- o The waste heat boilers use clean gas turbine exhaust to produce additional steam through supplemental firing.
- o A standby package boiler is provided for low pressure (non-cogeneration) operation for taking load swings. This is kept on standby to provide additional steam when an AFB/gas turbine unit is not operational. Sized at about 125,000 lbs/hr, it plus an AFB/gas turbine unit can handle normal operating loads.
- o Three AFB/gas turbine units, each capable of providing about 60,000 lbs/hr steam, in normal operation would provide a good range of steam output, and if one generating unit were suddenly lost, then the remaining two can still provide plant safe steam requirements.
- o By providing about 65,000 lbs/hr supplemental firing capability at each waste heat boiler, two AFB/gas turbine units with supplemental firing (or one AFB/gas turbine unit with supplemental firing plus the package boiler) can provide steam requirements to 250,000 lbs/hr with remaining spikes in load handled by the low pressure boiler.
- o Clean gas turbine exhaust air exiting from the waste heat boiler preheats the feedwater.

The AFB/gas turbine cycle design parameters noted in Table A3-8 are applied for all Task-1 systems. Physical parameters for the fluidized bed boilers (combustors) are summarized in Table A3-9 for both AFB cycles - steam and air. Consideration was also given to the commercial

Table A3-8: AFB/GAS TURBINE SYSTEM

AFB DESIGN PARAMETERS

- Bed Temperature - 1,650°F, Maximum
- Turbine Inlet Temperature - 1,500°F
- Air Heat Exchanger - Inbed Vertical Metal U-Tubes
- Relatively Deep Bed
- Relatively Low Fluidizing Velocities
- Flue Gas to Combustion Air Preheater Included
- High Efficiency Recycle Cyclone
- Only Currently Available Gas Turbines Considered

Table A3-9: AFB COMBUSTOR PARAMETERS

	ST CYCLE	GT CYCLE
o BED HEIGHT	4 FT.	5-7 FT.
o FREEBOARD HEIGHT	8 FT.	12 FT.
o REINJECTION	FROM BOILER HOPPERS	SAME
o HEAT TRANSFER RATES IN FLUID BED	50-70 BTU / HR.-°F-FT.^{2}	50 BTU / HR.-°F-FT.^{2}
o COAL AND LIMESTONE FEED	STOKER/OVERBED	PNEUMATIC/ UNDERBED
o TUBE MATERIAL	STANDARD BOILER TYPE CARBON STEEL	300 SERIES STAINLESS STEEL
o TUBE ARRANGEMENT	VERTICAL/PARTLY SUBMERGED	VERTICAL/TOTALLY SUBMERGED
o BED TEMPERATURE	1,600°F	1,650°F
o WORKING FLUID		
o MEDIUM	WATER/STEAM	AIR
o PRESSURE/TEMPERATURE	650 PSIG/750°F	100 PSIG/1,500°F
o CIRCULATION	NATURAL	FORCED

availability of air-cycle components as shown in Tables A3-10 and A3-11. Of all the components listed, only the AFB combustor, heat exchanger and manifolds, recycle system and system controls represent "new" equipment.

Refer to Figures A3-8 and A3-9 for cycle diagrams for average and maximum load performance. A partial steam match and substantial Dowtherm heating are provided. An energy flow diagram, Figure A3-10, shows distribution of energy for average load. Figures A3-11 and A3-12 show cycle performance for four units of AFB/gas turbines providing average and maximum plant requirements. Curtiss-Wright prepared the mass and energy balances and the process flow sheet for this cycle, which is denoted as Cycle C, and is shown in Figure A3-13 and Tables A3-12 and A3-13. Capital costs and levelized annual costs are prepared for the three and four unit Cycle C systems.

Cycle A, with detailed performance data given in Tables A3-16 and A3-17, is the first cycle produced for the Ethyl site. Cycle B, is shown in Figures A3-14 and A3-15 for average and maximum load operation, and has increased Dowtherm heating over cycle A. Mass and energy balance and process flow data are given in Tables A3-14 and A3-15. Cycle C is a variation of Cycle B and is the cycle selected for the screening evaluation. Cycles C and B are based on the same equipment with equal steam output maintained from the gas turbine, with Cycle C having increased output of process heat to the Dowtherm system. This requires additional fluidizing air flow and larger FD and ID fans; hence, Cycle C produces less net electricity.

B. Capital Cost Estimate

Curtiss-Wright provided not only major technical input for the AFB/gas turbine systems, but also provided cost estimates of their scope of supply. The basis of costing is for technologically established "nth-of-a-kind" units without development costs. Refer to Table A2-7 for the listing of contractor areas of responsibility for equipment. Table A3-18 gives the detailed costing summary for Curtiss-Wright's scope of equipment for the Ethyl site. N-rate costing in price includes all items within their scope of supply, including all interconnecting ducting and piping between these components, and overall control for the entire system. Costs are inclusive from site specific design through fabrication and erection to checkout and commissioning. Not included are civil works, including foundations, and the system control building. Also not included are the Dowtherm heaters and the ducting

Table A3-10: AVAILABILITY OF COMPONENTS - AIR CYCLE AFB

COMPONENT	AVAILABILITY STATUS
COMBUSTOR	o Curtiss-Wright Design
HEAT EXCHANGER & MANIFOLDS	o Currently available
RECYCLE SYSTEM	o Currently available
STARTUP COMBUSTOR & FORCED DRAFT FAN	o Commercial Item
SYSTEM CONTROLS	o Currently available
COAL & SORBENT FEED SYSTEM	o Commercial Item
AIR PREHEATER	o Commercial Item
ASH-COOLING SYSTEM	o Commercial Item
AIR PIPING	o Commercial Item
GAS TURBINE	o Commercial Item

ALL ITEMS CURRENTLY AVAILABLE

Table A3-11: AVAILABILITY OF OTHER MAJOR COMPONENTS

The following major components are all available commercially:

- o STEAM TURBINE GENERATOR
- o COAL STORAGE & DISTRIBUTION SYSTEM
- o WASTE-HEAT RECOVERY UNITS
- o SOLIDS DISPOSAL EQUIPMENT
- o PARTICULATE-REMOVAL EQUIPMENT
- o ELECTRICAL EQUIPMENT
- o STANDBY BOILER(S)

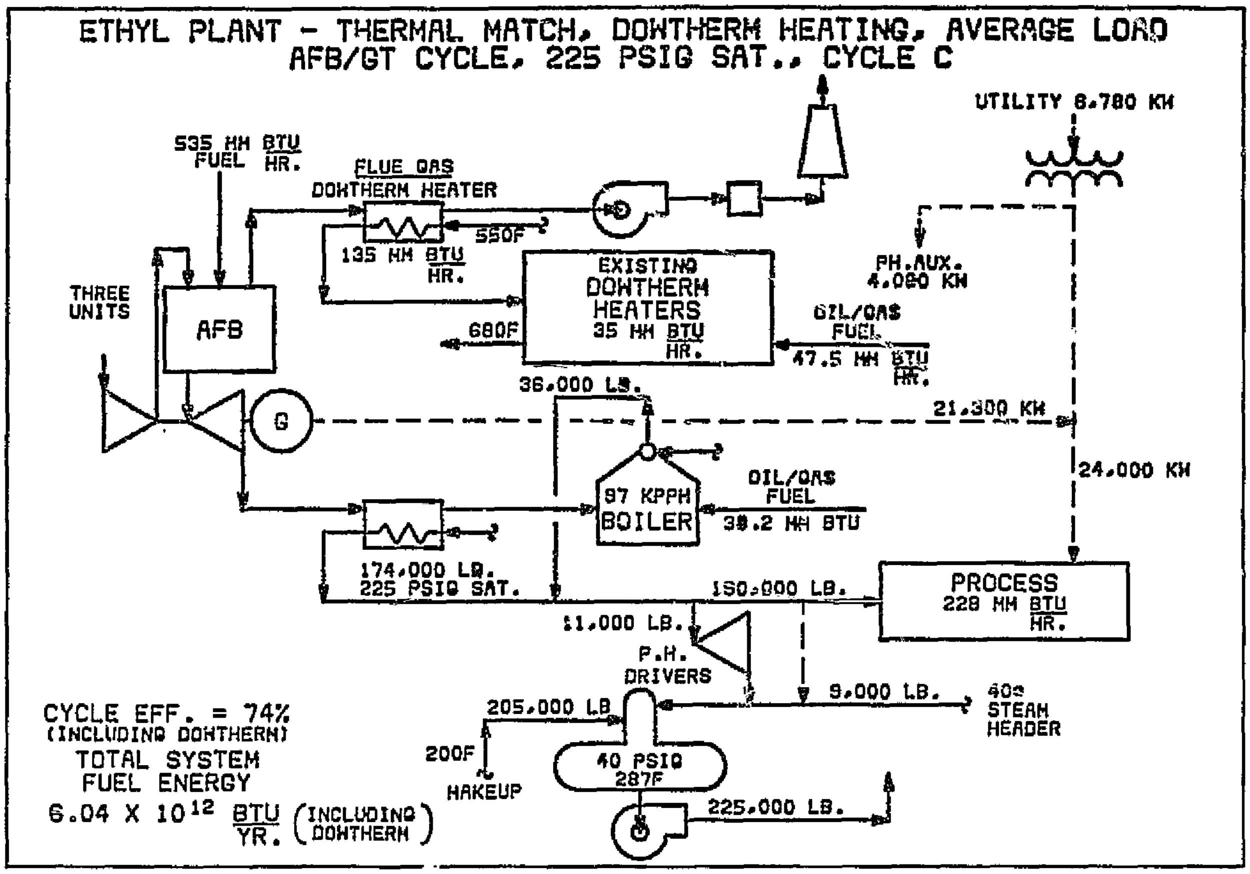

FIGURE A3-8

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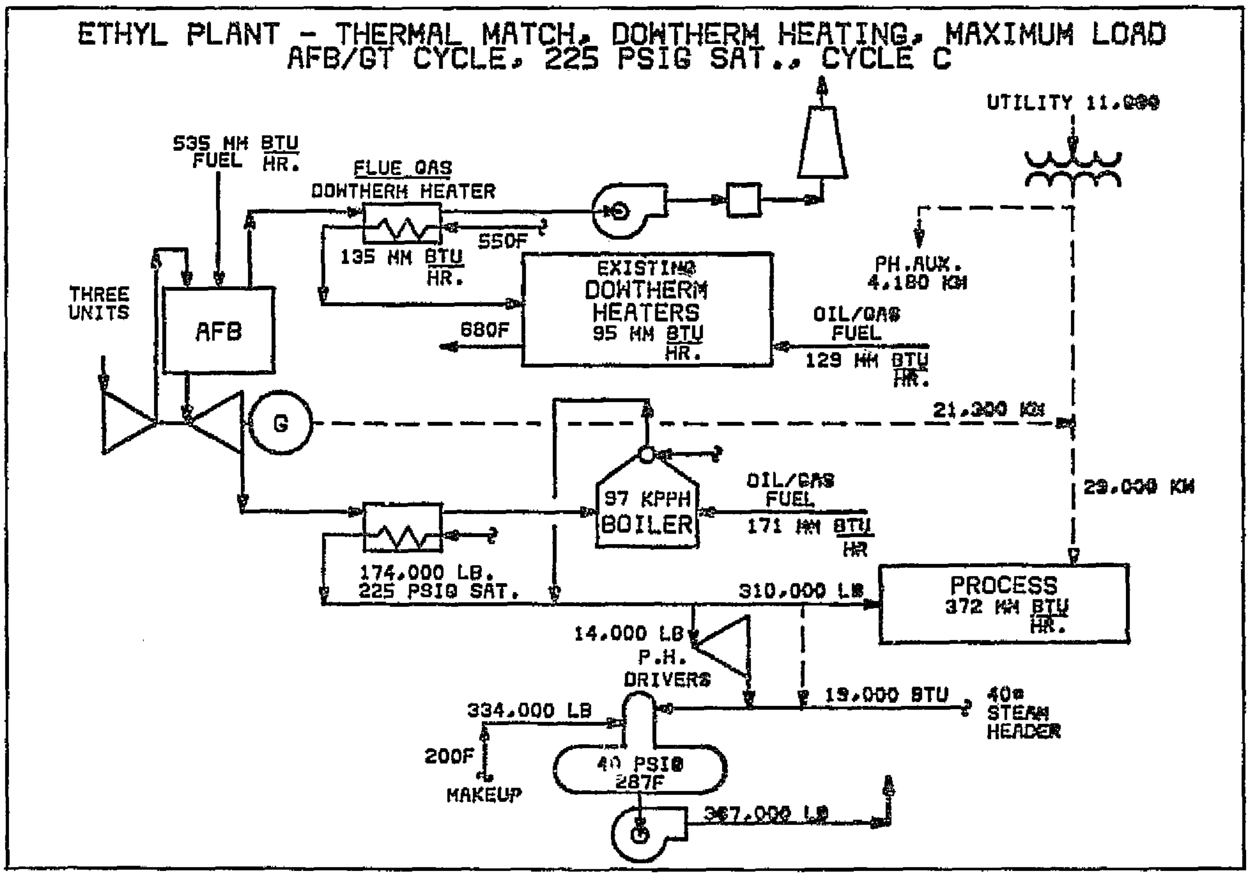

FIGURE A3-9

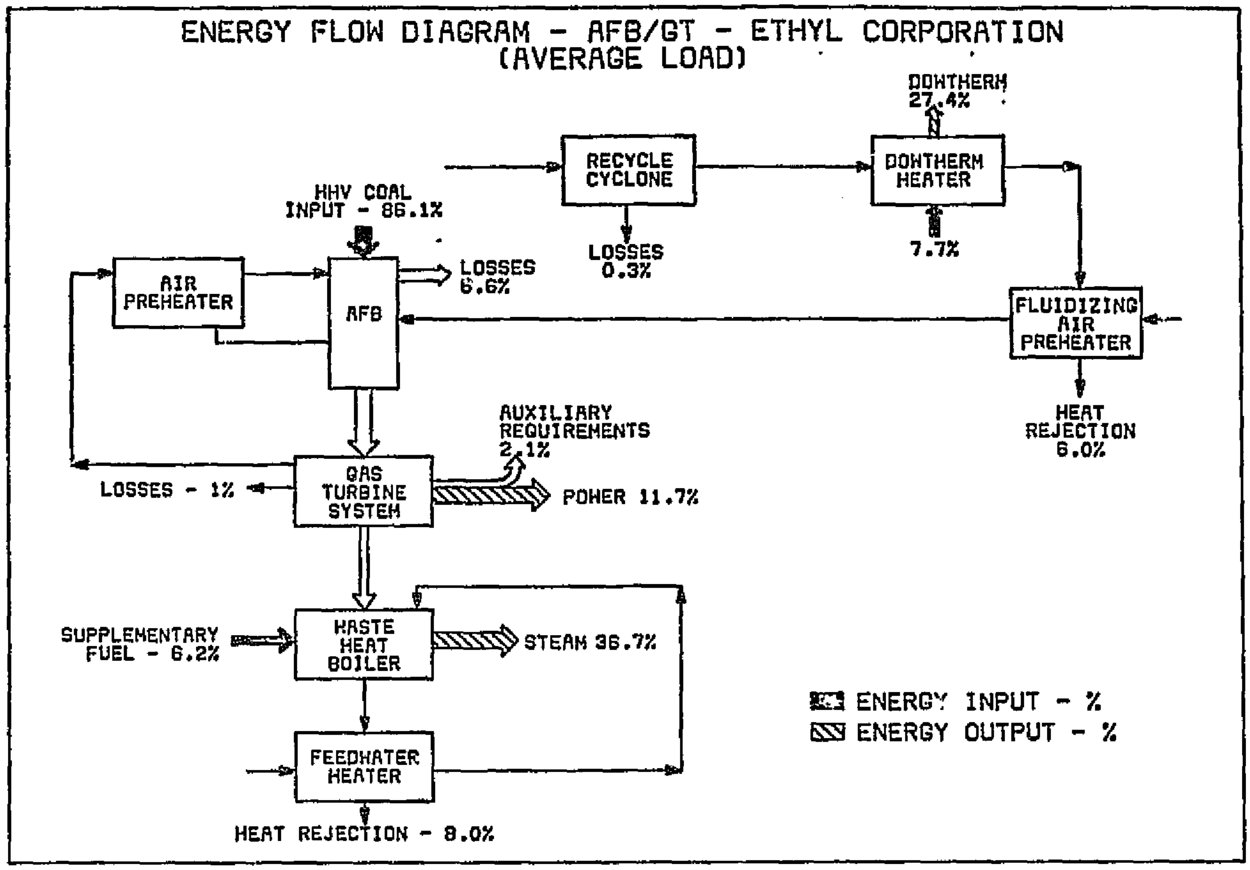

FIGURE A3-10

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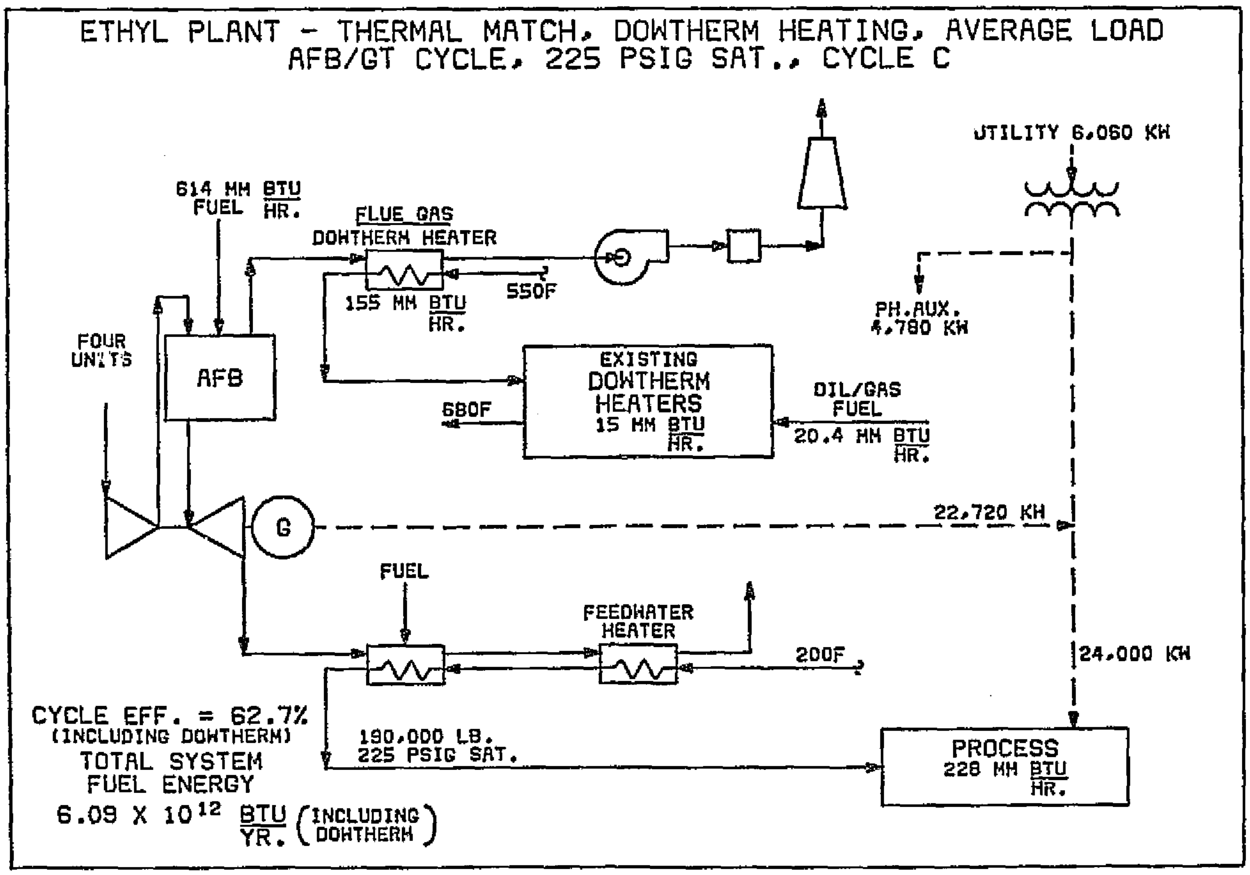

FIGURE A3-11

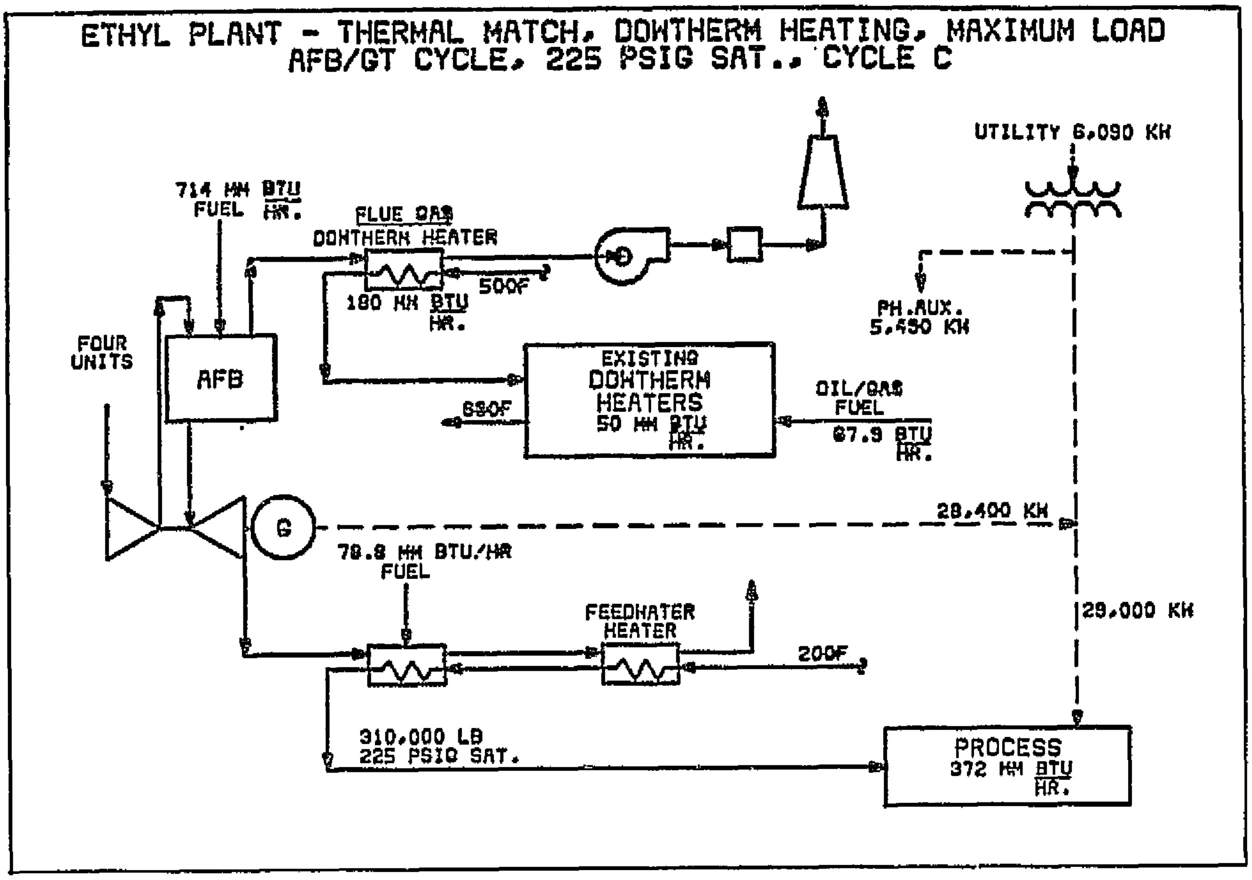

FIGURE A3-12

AIR CYCLE AFB COGENERATION SYSTEM
ETHYL PLANT

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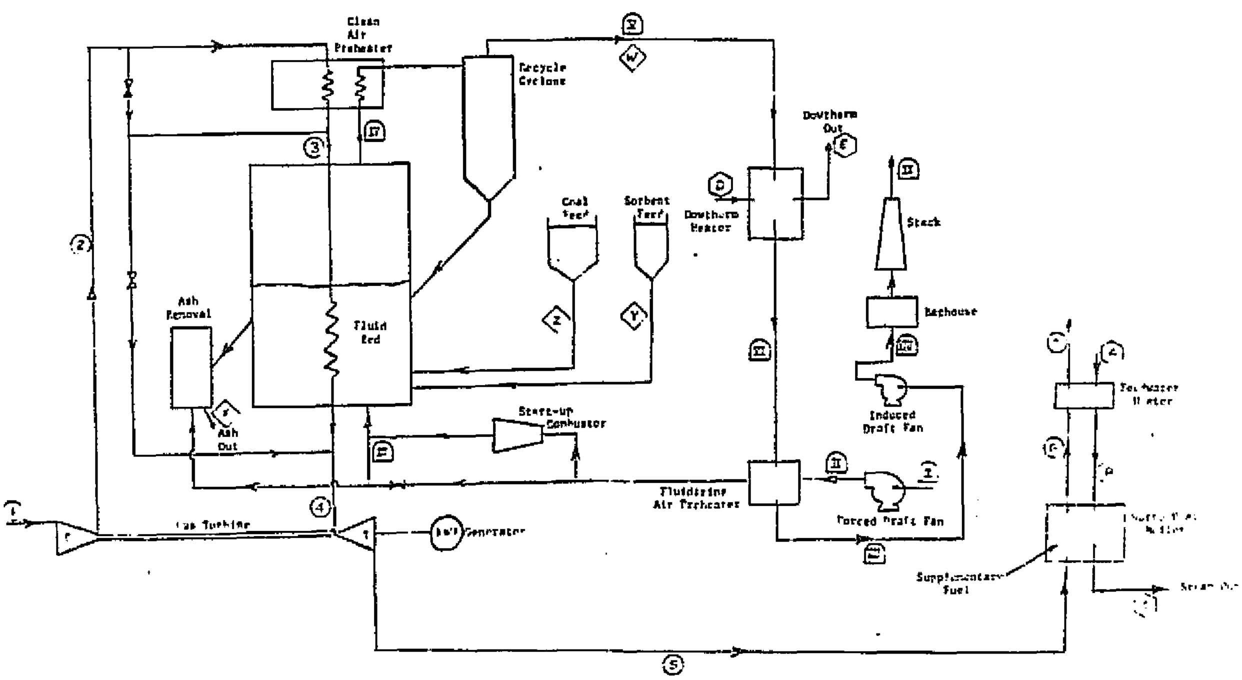

Figure A3-13

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Table A3-12

AIR CYCLE AFB COGENERATION SYSTEM

MASS AND ENERGY BALANCE FOR ONE AFB/GT SYSTEM

ETHYL PLANT - CYCLE C

	Mass PPH	Energy Million Btu/Hr	%	Electricity Kw
FEEDS				
Coal, delivered	15225	178.37		
Limestone, #9801	5542	0		
Clean Air	438550	0		
Fluidizing Air	194400	0		
Feedwater (60°F)	58000	0		
	711717	178.37	100.0	
PRODUCTS				
1525°F Flue Gas to 700°F	208027	45.00		
Solids Off-take	3808	1.57		
Fly Ash	1904	0.79		
Steam, 295 psig/397°F	58000	68.00		
	271739	115.36	64.7	
ELECTRICAL				
Gas Turbine, Gross		-24.23		-7100
Forced Draft Fan		+ 2.66		+ 778
Induced Draft Fan		+ 1.60		+ 468
Total Electrical, Net		19.97	11.2	5854
LOSSES				
Feedwater + Economizer Heat, 1%		.20		
Evaporator, 2%		.96		
Combustion Process, HHV-LHV		6.46		
98% Comb. Eff.		3.51		
Water Vapor, Coal Drying	1370	-		
Gas Turbine Bleed Air	4390	.46		
Gas Turbine Gr. Box + Gen.		1.59		
Recycle Cyclone Separator		.59		
Flue Gas Stack, 300°F		12.40		
Clean Air Stack, 218°F	434160	16.52		
Fluidizing Air Preheater, 1%		.21		
	439920	42.90	24.1	
	711659	178.23	100.0	

Table A3-13

AIR AFB COGENERATION SYSTEM
ETHYL SITE - CYCLE C
PROCESS FLOW DATA

CLEAN AIR CIRCUIT[1]

	1	2	3	4	5	6	7
W	1,315,650	1,263,039	1,263,039	1,263,039	1,302,480	1,302,480	1,302,480
P	14.7	99.9	98.9	96.8	15.23	14.87	14.7
T	59	494	565	1500	852	407	218

COMBUSTION AIR CIRCUIT[1]

	I	II	III	IV	V	VI	VII	VIII	IX
W	583,200	583,200	583,200	629,793	629,793	629,793	629,793	629,793	624,081
P	14.7	19.5	19.1	14.7	14.3	13.6	13.2	14.7	14.7
T	59	118	567	1650	1525	700	270	300	300

SOLIDS FLOW[1]

	Z	Y	X	W
W	45,675	16,626	11,424	5712

DOWTHERM A CIRCUIT

STEAM CIRCUIT

	A	B	C	D	E
W	174,000	174,000	174,000	1,890,000	1,890,000
P	ATM	40	225		
T	60	287	397	680	550

ELECTRIC OUTPUT

KW1[1] = 17560

NOTE: Values shown are for three combustor/gas turbine units

W = Flow Rate, Pounds Per Hour
P = Pressure, PSIA for Air Circuits, PSIG for Steam
T = Temperature, °F
KW = Net Electrical Output, Kilowatts

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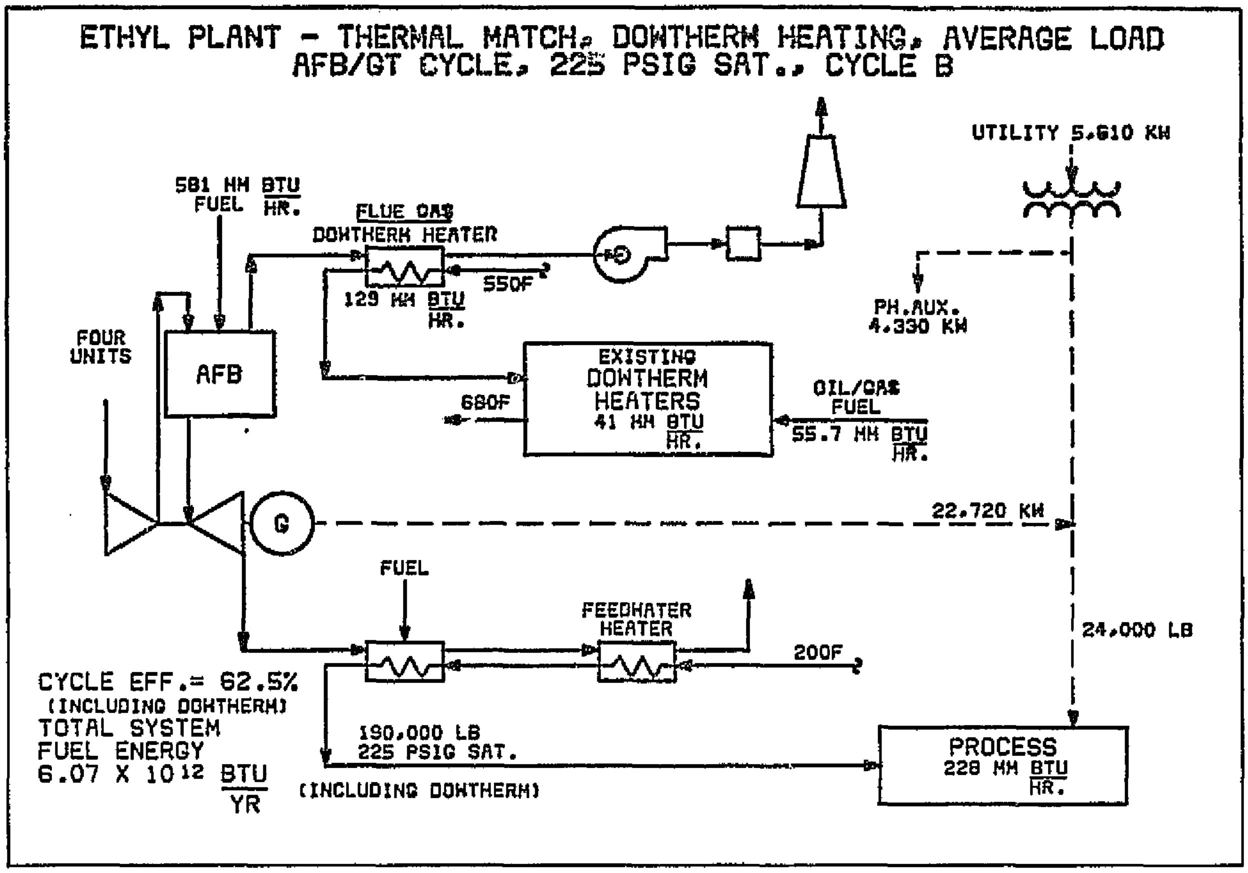

FIGURE A3-14

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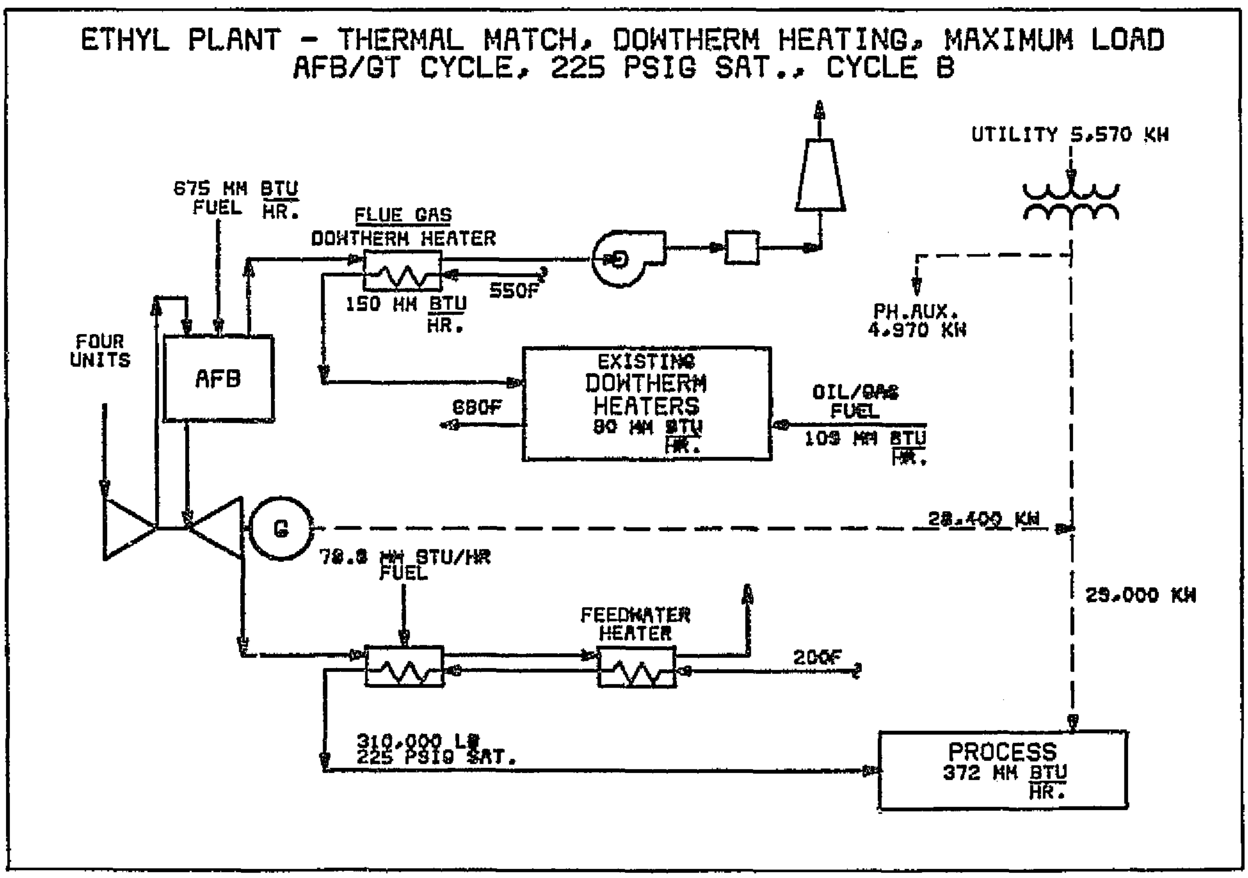

FIGURE A3-15

Table A3-14

AIR CYCLE AFB COGENERATION SYSTEM

MASS AND ENERGY BALANCE FOR ONE AFB/GT SYSTEM

ETHYL PLANT - CYCLE B

	Mass PPH	Energy Million Btu/Hr	%	Electricity Kw
FEEDS				
Coal, delivered	14375	168.82		
Limestone, #9801	5232	0		
Clean Air	438550	0		
Fluidizing Air	174960	0		
Feedwater (60°F)	58000	0		
	697117	168.82	100.0	
PRODUCTS				
1410°F Flue Gas to 700°F	187837	37.50		
Solids Off-take	3595	1.49		
Fly Ash	1798	0.75		
Steam, 295 psig/397°F	58000	68.00		
	251230	107.74	63.8	
ELECTRICAL				
Gas Turbine, Gross		-24.23		-7100
Forced Draft Fan		+ 2.40		+ 702
Induced Draft Fan		+ 1.44		+ 421
Total Electrical, Net		20.39	12.1	5977
LOSSES				
Feedwater + Economizer Heat, 1%		.20		
Evaporator, 2%		.96		
Combustion Process, HHV-LHV		5.98		
98% Comb. Eff.		3.25		
Water Vapor, Coal Drying	1294	-		
Gas Turbine Bleed Air	4390	.46		
Gas Turbine Gr. Box + Gen.		1.59		
Recycle Cyclone Separator		.53		
Flue Gas Stack, 300°F		11.09		
Clean Air Stack, 218°F	434160	16.52		
Fluidizing Air Preheater, 1%		.19		
	439844	40.77	24.1	
	691074	168.90	100.0	

Table A3-15

AIR AFB COGENERATION SYSTEM
ETHYL SITE - CYCLE B
PROCESS FLOW DATA

CLEAN AIR CIRCUIT[1]

	1	2	3	4	5	6	7
W	1,315,650	1,263,039	1,263,039	1,263,039	1,302,480	1,302,480	1,302,480
P	14.7	99.9	98.9	96.8	15.23	14.87	14.7
T	59	494	615	1500	852	407	218

COMBUSTION AIR CIRCUIT[1]

	I	II	III	IV	V	VI	VII	VIII	IX
W	524,880	524,880	524,880	568,905	568,905	568,905	568,905	568,905	563,511
P	14.7	19.5	19.1	14.7	14.3	13.6	13.2	14.7	14.7
T	59	118	567	1650	1410	700	270	300	300

SOLIDS FLOW[1]

	Z	Y	X	W
W	43,125	15,696	10,785	5394

STEAM CIRCUIT / DOWTHERM A CIRCUIT

	A	B	C	D	E
W	174,000	174,000	174,000	1,575,000	1,575,000
P	ATM	40	225		
T	60	287	397	680	550

ELECTRIC OUTPUT

KW1[1] = 17930

NOTE: Values shown are for three combustor/gas turbine units

W = Flow Rate, Pounds Per Hour
P = Pressure, PSIA for Air Circuits, PSIG for Steam
T = Temperature, °F
KW = Net Electrical Output, Kilowatts

Table A3-16

AIR CYCLE AFB COGENERATION SYSTEM

MASS AND ENERGY BALANCE FOR ONE AFB/GT SYSTEM

ETHYL PLANT -CYCLE A

	Mass PPH	Energy Million Btu/Hr	%	Electricity Kw
FEEDS				
Coal, delivered	13,653	159.96		
Limestone, #9801	4,968	0		
Clean Air	438,550	0		
Fluidizing Air	155,520	0		
Feedwater (60°F)	58,000	0		
	670,691	159.96	100.0	
PRODUCTS				
1350°F Flue gas to 700°F	167,868	30.00		
Solids Off-take	3,363	1.39		
Fly Ash	1,681	.70		
Steam, 295 psig/397°F	58,000	68.00		
	23[illegible],912	100.09	62.6	
ELECTRICAL				
Gas Turbine, Gross		-24.23		-7,100
Forced Draft Fan		+ 2.13		+ 623
Induced Draft Fan		+ 1.28		+ 374
Total Electrical, Net		20.82	13.0	6,103
LOSSES:				
Feedwater + Economizer Heat, 1%		.20		
Evaporator, 2%		.96		
Combustion Process, HHV-LHV		5.68		
98% Comb. Eff.		3.09		
Water Vapor, Coal Drying	1,229	-		
Gas Turbine Bleed Air	4,390	.46		
Gas Turbine Gr. Box + Gen		1.59		
Recycle Cyclone Separator		.47		
Flue Gas Stack, 300°F		9.91		
Clean Air Stack, 218°F	434,160	16.52		
Fluidizing Air Preheater, 1%		.17		
	439,779	39.05	24.4	
	670,691	159.96	100.0	

Table A3-17

AIR AFB COGENERATION SYSTEM
ETHYL SITE - CYCLE A
PROCESS FLOW DATA

CLEAN AIR CIRCUIT[1]

	1	2	3	4	5	6	7
W	1,315,650	1,263,039	1,263,039	1,263,039	1,302,480	1,302,480	1,302,480
P	14.7	99.9	98.9	96.8	15.23	14.87	14.7
T	59	494	624	1500	852	407	218

COMBUSTION AIR CIRCUIT[1]

	I	II	III	IV	V	VI	VII	VIII	IX
W	466,560	466,560	466,560	503,604	503,604	503,604	503,604	503,604	498,561
P	14.7	19.5	19.1	14.7	14.3	13.6	13.2	14.7	14.7
T	59	118	567	1650	1350	700	270	300	300

SOLIDS FLOW[1]

	Z	Y	X	W
W	40,959	14,904	10,089	5,043

STEAM CIRCUIT / DOWTHERM A CIRCUIT

	A	B	C	D	E
W	174,000	174,000	174,000	1,260,000	1,260,000
P	ATM	40	225		
T	60	287	397	680	550

ELECTRIC OUTPUT

KW1[1] = 18,300

Note: Values shown are for three combustor/gas turbine units

W = Flow Rate, Pounds Per Hour
P = Pressure, PSIA for Air Circuits, PSIG for Steam
T = Temperature, °F
KW = Net Electrical Output, Kilowatts

Table A3-18

AIR CYCLE AFB COGENERATION SYSTEM

Costing Summary - Go Rate Units

ETHYL SITE

	Cycle A	Cycle B	Cycle C
A. Combustor	966,300	966,300	966,300
B. Hx and Manifolds	1,467,800	1,474,600	1,479,900
C. Recycle System	284,900	312,300	337,000
D. Start Up Combustor/FD Fan	325,100	351,000	375,900
E. System Controls	293,000	293,000	293,000
F. Coal Feed System	352,300	364,200	378,100
G. Air Preheater	143,200	124,400	81,400
H. Ash Cooling System	65,200	68,100	70,600
I. Air Piping	621,900	621,900	621,900
J. Miscellaneous	169,400	169,400	169,400
K. Gas Turbine System	2,538,000	2,538,000	2,538,000
L. Fluidizing Air Preheater	80,600	86,800	92,700
Hardware	7,307,700	7,370,000	7,404,200
Engineering/Software	706,700	706,700	706,700
1st Unit	8,014,400	8,076,700	8,110,900
2nd Unit			
Hardware	7,088,500	7,148,900	7,182,100
Software	223,500	223,500	223,500
	7,312,000	7,372,400	7,405,600
3rd Unit			
Hardware	6,942,300	7,001,500	7,034.000
Software	133,700	133,700	133,700
	7,076,000	7,135,200	7,167,700

from them to the AFB and to the fluidizing air preheaters. In addition to a breakdown of hardware costs by component on the first unit is a summary of costs for second and third units. Gas turbine costs are included as part of the AFB system costs. Secondary equipment and system costs were prepared by Catalytic using preliminary quotations for such equipment and Catalytic's data bases. Capital costs are based on current (1981) dollars. The preliminary capital cost estimates for Cycle C are summarized in Table A3-5. The capital costs reflect the design of a complete new cogeneration plant for screening purposes.

3.1.4 AFB/Steam Turbine Cogeneration System

A. Approach to Performance

Due to widely fluctuating plant steam requirements, three AFB boilers are provided along with two oil/gas fired boilers generating steam at the same pressure as the AFB boilers. The operating criterion of using three boilers (the AFB units) normally continuously operating is the same criterion discussed for the no-cogeneration base case in section 3.1.2.

The energy range of the steam from turbine inlet to exhaust is a significant factor in the net power generated by a backpressure steam turbine. A rule of thumb is to select the steam inlet pressure at least twice as high as the exhaust pressure or highest extraction pressure, as applicable, in order to maintain an adequate energy range. Current practice of industrial power plant steam turbine inlet pressures is in a range of about 600 to 1,450 psig. Table A3-19 lists steam turbine generator efficiencies used in Task 1. Because of the relatively small size of the boilers, steam conditions of 600 psig/750^{o}F was selected. Figures A3-16 and A3-17 show performance of the AFB/steam turbine cogeneration system at average and maximum loads.

Table A3-19: STEAM TURBINE GENERATOR EFFICIENCIES

For Sizes 10 MW maximum-

Overall Efficiences	Efficiency % Non-Condensing	Efficiency % Condensing
a. No extraction	75	75
b. Single extraction	71	70.5
c. Double extraction	69	67.5

Neglect mechanical and generator losses (typically 2-3%).

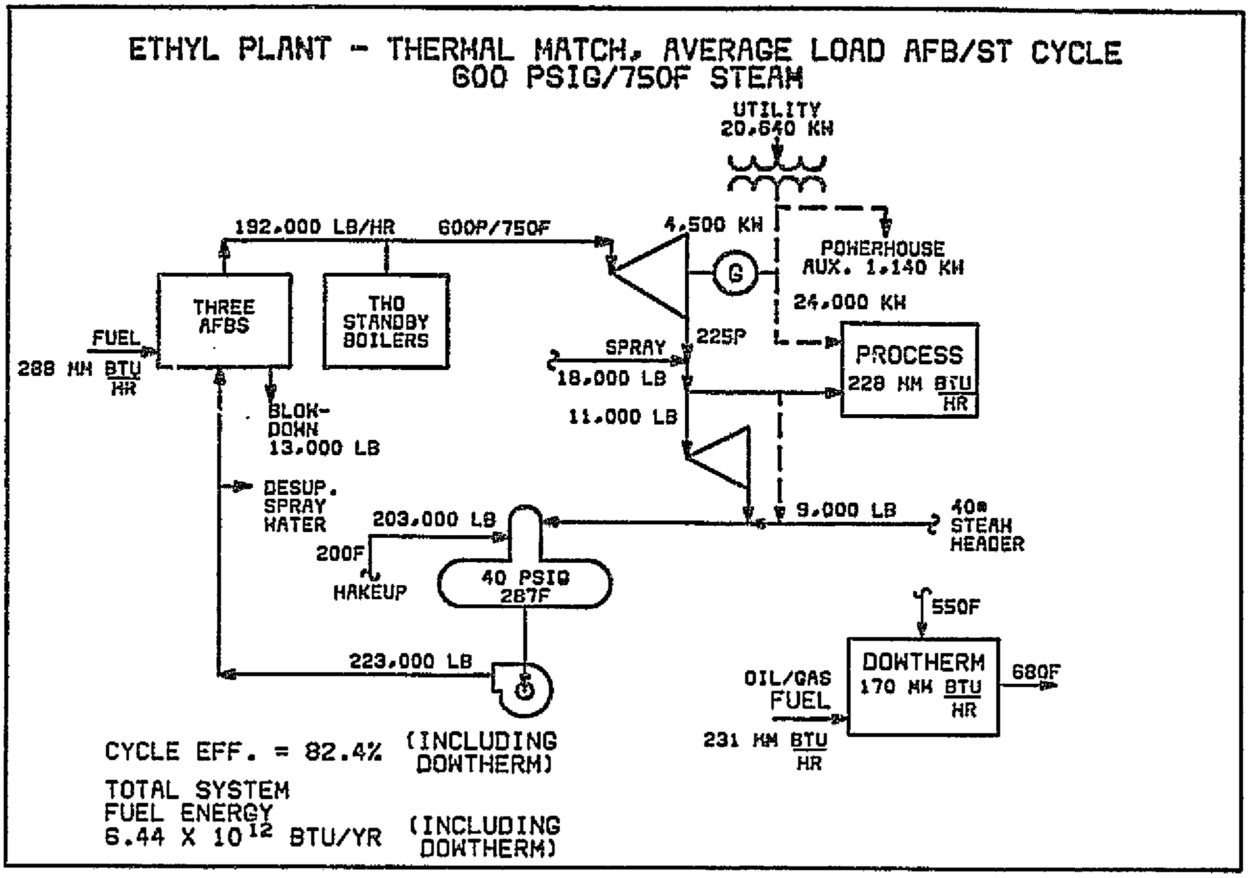

FIGURE A3-16

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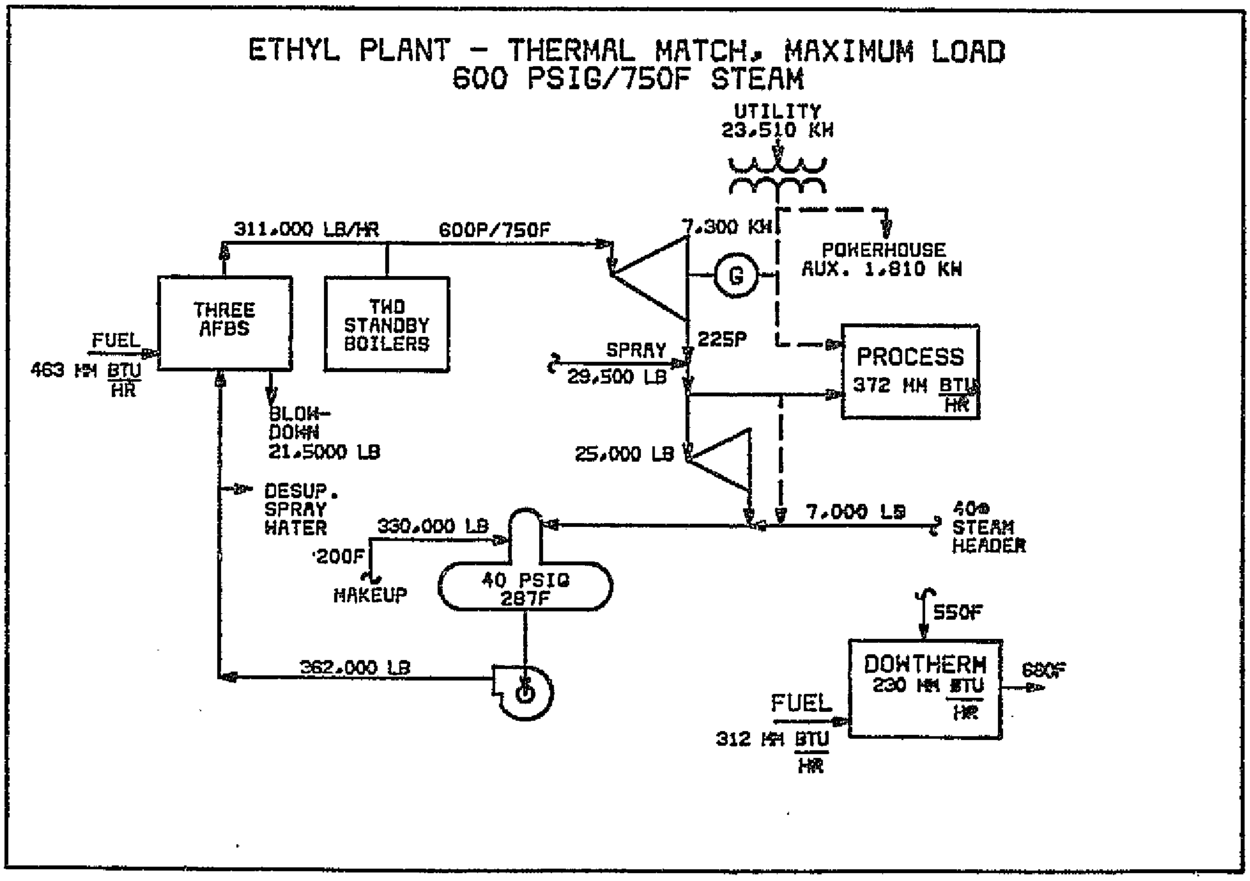


FIGURE A3-17

B. Capital Cost Estimates

Catalytic derived capital costs from information provided by Dorr-Oliver/Keeler. The preliminary capital cost estimate for the cogeneration system is summarized in Table A3-5. Again, a complete new plant is used for screening purposes.

3.2 RIEGEL PRODUCTS CORPOATION - MILFORD, NEW JERSEY

3.2.1 Site Definition

A. Site Description

The Milford plant of the Riegel Products Corporation, a subsidiary of James River Corporation, produces specialty paper as its primary product. The plant is located along the Delaware River in western New Jersey. The Milford plant is part of a four mill complex with a combined nominal capacity of 300 tons per day of specialty paper. The plant capacity at Milford is the largest single producer at a nominal 200 tons per day capacity, and is the mill studied. General site data is given in Table A3-1. Cogeneration is currently utilized to supply a limited portion of the plant electric requirement. Steam is the main form of process heat required at the plant, with some hot water also used. The thermal requirements are supplied by natural gas or oil firing of five existing steam generators and by hot gases from an existing cogeneration gas turbine with a unique ownership arrangement. Many years ago, some of the boilers burned coal, but most coal burning equipment has been removed. The use of natural gas or oil is dependent upon market pricing and availability. Gas is used for this study since, at the time of the survey, it was slightly less expensive than #6 fuel oil.

The manufacture of specialty paper is identified by the SIC number 361. The electric to thermal ratio ($E/_T$) of the Milford plant is 0.31, which is indicative of both large electric and thermal consumption in this high capacity industry.

The site requirements for the Milford plant are summarized in Table A3-2, with Table A3-20 further describing plant operation.

Table A3-20: RIEGEL PLANT OPERATION

1. Electricity: Current cogeneration - 42.5%
   Purchase - 57.5%

2. Mill Steam Cogeneration (adjusted for weekends):

Pressure, psig	Flow Rate, lbs/hr	
150	15,000	35,000 - 40,000
75	23,000	lbs/hr total
25	89,000	
3.5 in. Hg A	10,000 (produces hot water)	

3. Condensate Returns - approximately 50%

4. Mechanical Line Driver in Mill - assume 700 HP load for all uses.

The average electric requirement of 20,000 kw is primarily purchased from the utility. However, a significant portion of the total plant average electric requirement is generated in-house (6,000 kw). The current average operating mode of the Milford plant is shown in Figure A3-18. Thermal energy requirements are supplied by natural gas or oil; however, waste paper is burned as a fuel supplement at a rate of about 5% of the total fuel input. This waste heat content is considered as gas for purposes of analysis. The benefits of cogeneration have been further utilized at the Milford plant in the form of a separately owned natural gas fired turbine supplying to the plant hot exhaust gas fueling a plant-owned heat recovery steam generator, and then supplying hot combustion air to a boiler. The electricity from the gas turbine is taken by the electric company. To simplify the calculation of fuel consumption, the gas turbine heat input to the powerhouse is considered as gas heat input and the gas turbine completely eliminated from this study. Steam is also generated by the other existing plant boilers and powers a large process mechanical driver in the mill, a single extraction backpressure turbine and a single extractor condensing turbine. The end use for the steam generation, other than the condensing turbine quantity, is process heating at line pressures of 150, 75, and 25 psig. There are requirements at the Milford plant for hot water.

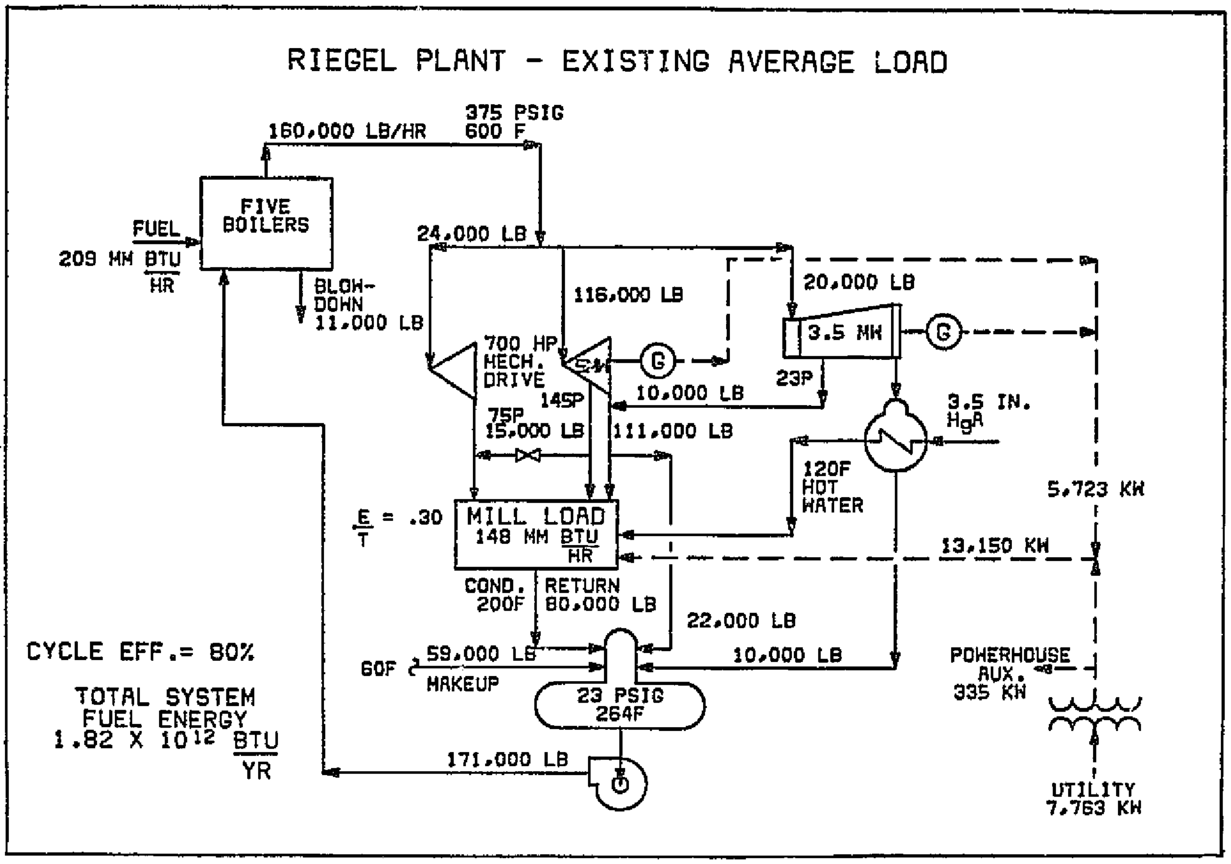


Figure A3-18

Steam demand was found to fluctuate by 40,000 lbs/hr over a five minute interval. Current plant operation is 5 days per week - 24 hours per day. The rate of production is not expected to increase at the Milford plant for the mid-1980's time period, so current operating data is used to evaluate cogeneration potential. Site specific economic parameters are listed in Table A3-4.

Land is presently available at the powerhouse for an AFB/cogeneration system. In addition, the Milford plant has previously utilized coal as the primary fuel for its steam generators. Coal bunkers are still in place and land is available which had been used for coal unloading and storage. However, the original coal conveyors and transfer equipment have been removed. Coal was supplied by rail transport. Coal and sorbent properties selected for this site are given in the field trip report.

Unscheduled energy shutdowns (steam or electricity) would cause immediate loss of plant production. No physically unsafe or unhealthy condition is apparent though. Process plant reliability requirements for both electricity and steam do not appear out of the ordinary, so no special consideration will be given to these needs. With multiple boilers normally operating, and excellent availability of purchased electric power, unscheduled shutdowns are not a consideration.

B. Jersey Central Power and Light Company (JCP&L)

A meeting was arranged with regional representatives of JCP&L to discuss the nature of the cogeneration arrangement which currently exists at the plant and to discuss the utility's philosophy toward cogeneration in general. Schedules were obtained which define the rate structures for standby service and the utility electric buy-sell rates. Table 4-3 in the main body of the report presents a summary of the utility data. These rates are based on avoided costs as detailed in PURPA. The following current (1981) cogeneration electric purchase rates were proposed by JCP&L:

On-peak	62 mills
Off-peak	41 mills
Average	49 mills

The on-peak times are from 0800 to 2000 hours Monday through Friday with off-peak at all other times. A standby charge of $3.00/kw/month will be assessed for cogeneration. The result is average electric rates that very according to the situation occurring. Appendix section 2.2 presents electric utility rates for several options.

The JCP&L power generating stations are primarily nuclear and oil-fired. Natural gas and coal firing amount to 45% of the total electric output. Emission guidelines for the utility are under the jurisdiction of the New Jersey Department of Environmental Protection.

Support financing for any type of ownership option is not likely for a cogeneration facility with JCP&L. However, the utility is engaged in the gas turbine cogeneration facility at the Milford plant. JCP&L is actively negotiating with new cogenerators to establish buy-sell arrangements. Most potential systems have proposed oil or gas-fired turbine cogeneration systems. The utility does not anticipate the construction of any new generation facilities over the next 10 years.

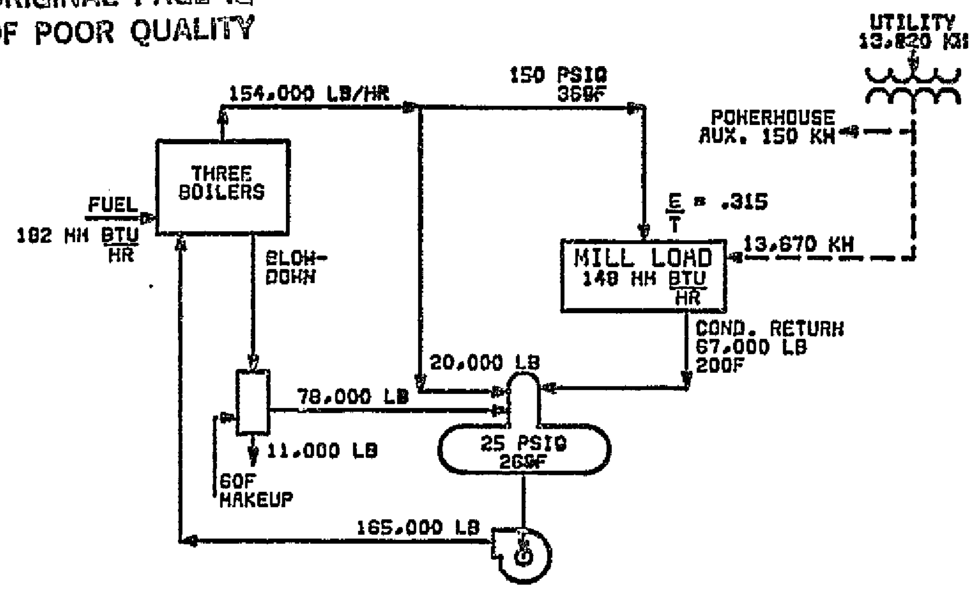
The current cogeneration at the Riegel Products Milford plant consists of a 25 MW gas turbine operating in conjunction with a 120,000 lbs/hr heat recovery steam generator producing steam at 450P/660^{o}F. This system is expected to operate three out of four weeks dependent upon operation of the heat recovery steam generator. Any analysis of the Milford steam demand must consider this prior contract arrangement. The individual parties to this cogeneration agreement are JCP&L, Riegel Products Corporation, and the Elizabethtown Gas Company.

3.2.2 Base Case System

Since the plant currently cogenerates, a no-cogeneration base case was produced for comparison purposes and is shown in Figures A3-19 and A3-20. Even the mechanical drive turbine is replaced by a motor for performance purposes. No economic charge is placed on this latter change. Three 110,000 lbs/hr oil/gas fired package boilers are provided. Figures A3-19 and A3-20 give plant performance data.

The preliminary capital cost estimate is shown in Table A3-21, and the levelized operating cost is shown in Table A3-22.

RIEGEL PLANT - BASE CASE, NO COGENERATION OIL/GAS FIRED BOILERS
AVERAGE LOAD



CYCLE EFF. = 81.5%

TOTAL SYSTEM
FUEL ENERGY
2.05×10^{12} BTU/HR

FIGURE A3-19

RIEGEL PLANT - BASE CASE, NO COGENERATION OIL/GAS FIRED BOILERS
PEAK OPERATING CONDITION

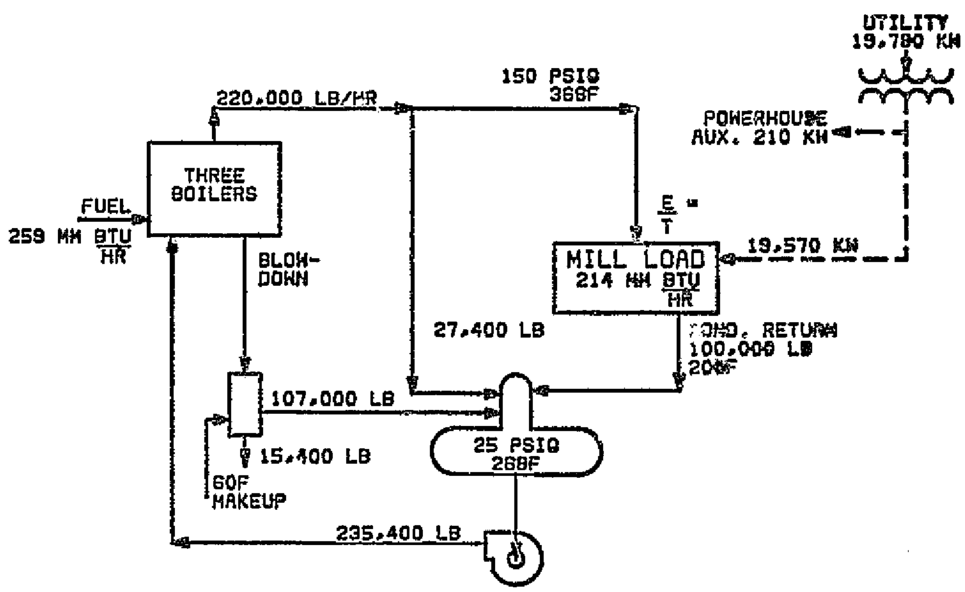


FIGURE A3-20

Table A3-21

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RIEGEL PLANT SITE
CAPITAL COST ESTIMATE

COST ITEM (THOUSAND $)	BASE CASE NO COGENERATION 3-110,000 LB/HR OIL/GAS PACKAGE BOILERS, 150 PSIG	AFB/ST 600P/750F 2-110,000 LB/HR AFB'S, 1T-G, 1-110K BOILER	AFB/ST 1250P/900F 2-100,000 LB/HR AFB S, 2T-G, 1-110K BOILER	AFB/GT 600P/750F 2-110,000 LB/HR AFB'S, 1T-2G 1-110K BOILER	AFB/GT 900P/825F 2-110,000 LB/HR AFB'S, 2T-G, 1-110K BOILER	AFB/GT 150P/480F 2-110,000 LB/HR AFB'S, 1T-G, 1-110K BOILER
PACKAGE BOILERS, DELIVERED & ERECTED	1,272	780	952	780	902	780
AFB'S	-	8,400	9,600	14,743	14,743	14,053
FOUNDATIONS & STEEL	-	1,200	1,200	1,474	1,474	1,405
DUCTS & STACKS	-	800	800	950	950	950
BAGHOUSE	-	INCL.	INCL.	1,900	1,900	1,700
FUEL OIL HANDLING & STORAGE	1,652	947	947	947	947	947
PIPING	509	2,667	4,000	2,667	3,400	2,667
FEEDWATER	106	270	480	351	400	351
WATER TREATMENT	170	170	440	440	440	440
TURBINE-GENERATOR	-	4,125	6,240	4,290	4,640	2,640
WASTE HEATERS & FW HEATERS	-	-	-	5,718	6,833	5,545
ELECTRICAL EQUIPMENT	872	1,101	1,171	974	1,171	974
BUILDING/STRUCTURES	254	1,008	1,323	880	880	473
MISCELLANEOUS STRUCTURES	-	330	330	308	308	308
SOLID MATERIAL HANDLING & STORAGE	-	6,438	6,438	6,438	6,438	6,438
DIRECT COST	4,835	28,236	33,921	42,863	45,429	39,682
23% INDIRECTS	1,112	6,494	7,802	9,858	10,449	9,127
C-W ENGINEERING & SUPPORT	-	-	-	630	630	630
TOTAL CAPITAL	5,947	34,730	41,723	53,351	56,508	49,439
UNIT COST	$18,000/PPASTH	$4,135/KW	$3,311/KW	$2,330/KW	$2,200/KW	$3,190/KW

Table A3-22

RIEGEL PLANT
LEVELIZED ANNUAL ENERGY COST ANALYSIS
SITE SPECIFIC ECONOMIC PARAMETERS

COST ITEM MILLION $	LEVEL FACTOR	1989 COSTS IN 1981 DOLLARS BASE CASE	AFB/ST 600/750	AFB/ST 1250/900	AFB/GT 600/750	AFB/GT 900/825	AFB/GT 150/480	LEVELIZED COSTS IN NOMINAL $ BASE CASE	AFB/ST 600/750	AFB/ST 1250/900	AFB/GT 600/750	AFB/GT 900/825	AFB/GT 150/480
CAPITAL COST	-	5.497	37.73	41.723	53.354	56.508	49.439	-	-	-	-	-	-
CAPITAL INVESTMENT	-	6.267	36.55	46.313	59.22	62.724	54.877	-	-	-	-	-	-
LEVEL CAPITAL INVESTMENT	.070	-	-	-	-	-	-	.439	2.699	3.242	4.145	4.391	3.841
FUEL COST - GAS	1.46	6.117	-	-	-	-	-	8.93	-	-	-	-	-
FUEL COST - COAL	1.095	-	2.732	2.617	3.422	3.705	3.355	-	2.992	2.866	3.735	4.057	3.674
ELECTRIC PURCHASE	1.095	5.391	3.042	2.486	.342	-	1.493	5.903	3.331	2.722	.374	-	1.635
ELECTRIC BUY-BACK	1.095	-	-	-	-	(.807)	-	-	-	-	-	(.884)	-
STAND-BY	1.0	-	.158	.139	.142	.096	.046	-	-	-	-	-	-
SORBENT	1.0	-	.753	.748	.577	.63	.335	-	-	-	-	-	-
WASTE DISPOSAL	1.0	-	.174	.172	.163	.176	.151	-	-	-	-	-	-
UTILITIES, LABOR & MAINTENANCE	1.0	.416	1.84	1.985	2.259	2.346	2.163	-	-	-	-	-	-
INSURANCE & LOCAL TAXES	1.0	.188	1.157	1.389	1.777	1.682	1.646	-	-	-	-	-	-
SUM OF CONSTANT ANNUAL COSTS	1.0	.604	4.082	4.433	4.918	5.132	4.341	.604	4.082	4.433	4.918	5.132	4.341
LEVELIZED ANNUAL ENERGY COST (NOMINAL $)	-	-	-	-	-	-	-	15.876	13.104	13.263	13.172	12.695	13.491
LEVEL ANNUAL ENERGY COST SAVING	-	-	-	-	-	-	-	-	2.772	2.613	2.704	3.18	2.385
PERCENT SAVING	-	-	-	-	-	-	-	-	17.5%	16.46%	17.6%	20%	15%

3.2.3 AFB/Gas Turbine Cogeneration System

A. Approach to Performance

The following criteria are applied:

- o Cogenerated steam is produced in separate, unfired waste heat boilers using flue gas from the AFB combustor and the clean gas turbine exhaust gas. Figure A1-12 is used to determine part load performance.
- o Clean gas turbine exhaust air exiting from the waste heat boiler preheats the combined plant condensate returns and makeup feedwater. Flue gas is kept at about 300°F, minimum, to avoid cold end corrosion. The clean turbine exhaust air can be reduced to temperatures as low as economically practical since the clean air would not produce corrosion. The heated water is flashed in a deaerator, and is then pumped to both waste heat boilers to produce steam.
- o The half-size oil/gas fired standby boiler generates steam at the same pressure as the waste heat boilers.
- o Three systems are investigated to produce steam at different pressures: 600 psig/750°F, 900 psig/825°F, and 150 psig/480°F plus 400 psig/650°F. The steam pressures are high enough to permit use of steam turbines, giving a combined cycle.
- o The 600 psig/750°F steam system has one double extraction condensing steam turbine.
- o The 900 psig/825°F steam system has one single extraction backpressure steam turbine and one double extraction condensing steam turbine. This steam pressure is felt to represent the upper limit possible with the gas turbine exhaust temperature at about 900°F and serves to maximize electrical output. This system uses dual pressure coils in the waste heat boilers. The steam turbine provides both hot water and 25 psig steam. The high pressure steam coil drives the mechanical line turbine.
- o The 150 psig/480°F steam system has a single extraction condensing steam turbine. This is not a combined cycle cogeneration system as are the other two.

Refer to the following figures for cycle diagrams:

- o Figure A3-21 for the 600 psig/750°F system
- o Figure A3-22 for the 900 psig/825°F system
- o Figure A3-23 for the 150 psig/480°F system

An energy flow diagram, Figure A3-24, shows the 600 psig/750°F system. This system is the one used for the performance and benefit analysis described in Section 3.3.

Curtiss-Wright prepared the mass and energy balances and the process flow sheets for these systems. A thermal match is provided and a close electrical match also results for the higher steam pressure systems. Cycle A refers to the 150 psig/480°F system, while Cycle B refers to the other two systems. Cycle B is shown in Figure A3-25 and in Tables A3-23 and A3-24. Cycle A is shown in Figure A3-26 and in Tables A3-25 and A3-26.

B. Capital Cost Estimates

The cost estimate provided by Curtiss-Wright for the two systems noted as Cycles A and B is given in Table A3-27. Complete cogeneration system preliminary capital cost estimates for screening purposes are given in Table A3-21.

3.2.4 AFB/ Steam Turbine Cogeneration System

A. Approach to Performance

Two systems are investigated to produce steam at different pressures, 600 psig/750°F and 1,250 psig/900°F to see if the increased capital cost of the higher pressure system is offset by the increased byproduct electricity. Figure A3-27 shows average performance of the 600 psig/750°F cycle which uses one double extraction-condensing steam turbine. Two AFB boilers and one oil/gas fired standby boiler generate steam at the same pressure. The 600 psig/750°F system is the one used for the performance and benefit analysis described in Section 3.3

The performance of the 1,250 psig/900°F AFB boiler system is shown in Figure A3-28. A single extraction-backpressure steam turbine and a single extraction-condensing steam turbine are used in this cycle to provide the various operating steam pressure levels needed by the paper mill. The standby oil/gas fired boiler is a high pressure unit.

RIEGEL PLANT - THERMAL AND ELECTRICAL MATCH, AVERAGE LOAD
AFB/GT CYCLE - 600 PSIG/750F STEAM, COMBINED CYCLE

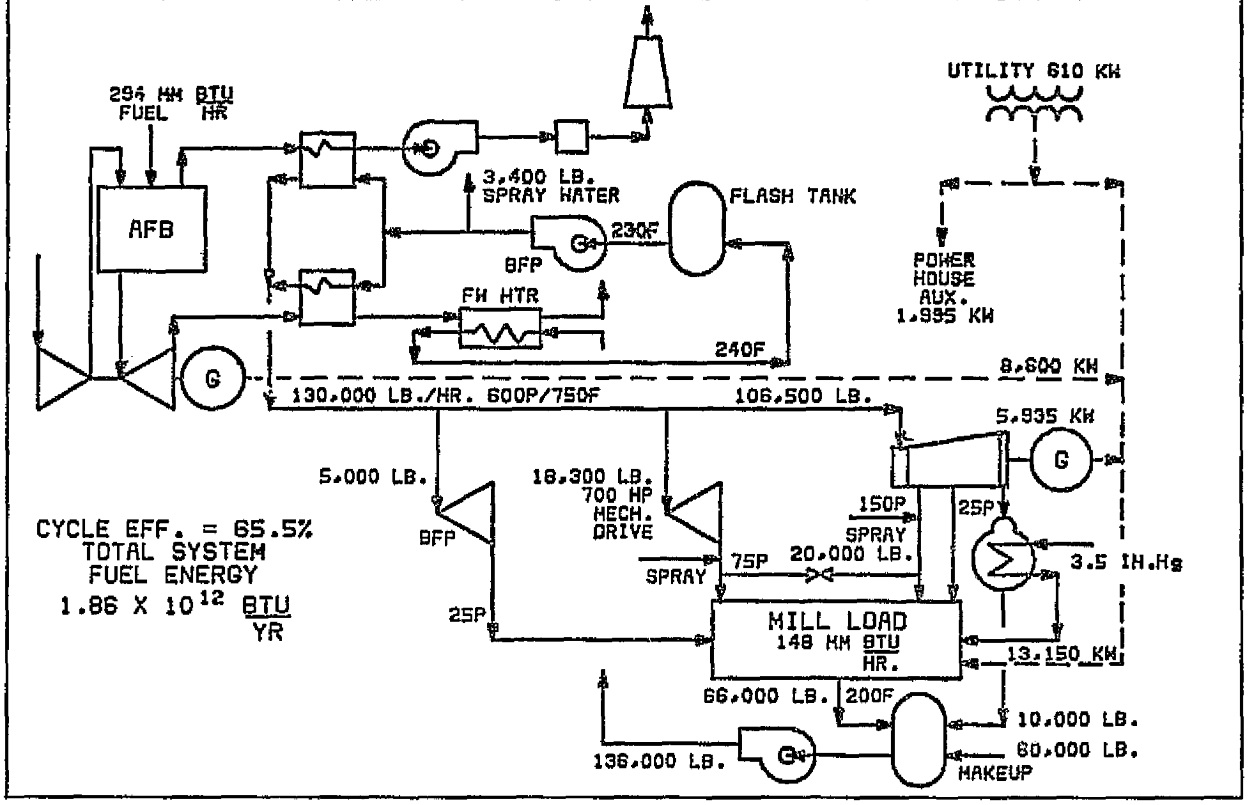

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FIGURE A3-21

RIEGEL PLANT - THERMAL MATCH, EXCESS ELECTRICITY, AVERAGE LOAD
AFB/GT CYCLE - 900 PSIG/825F STEAM, COMBINED CYCLE

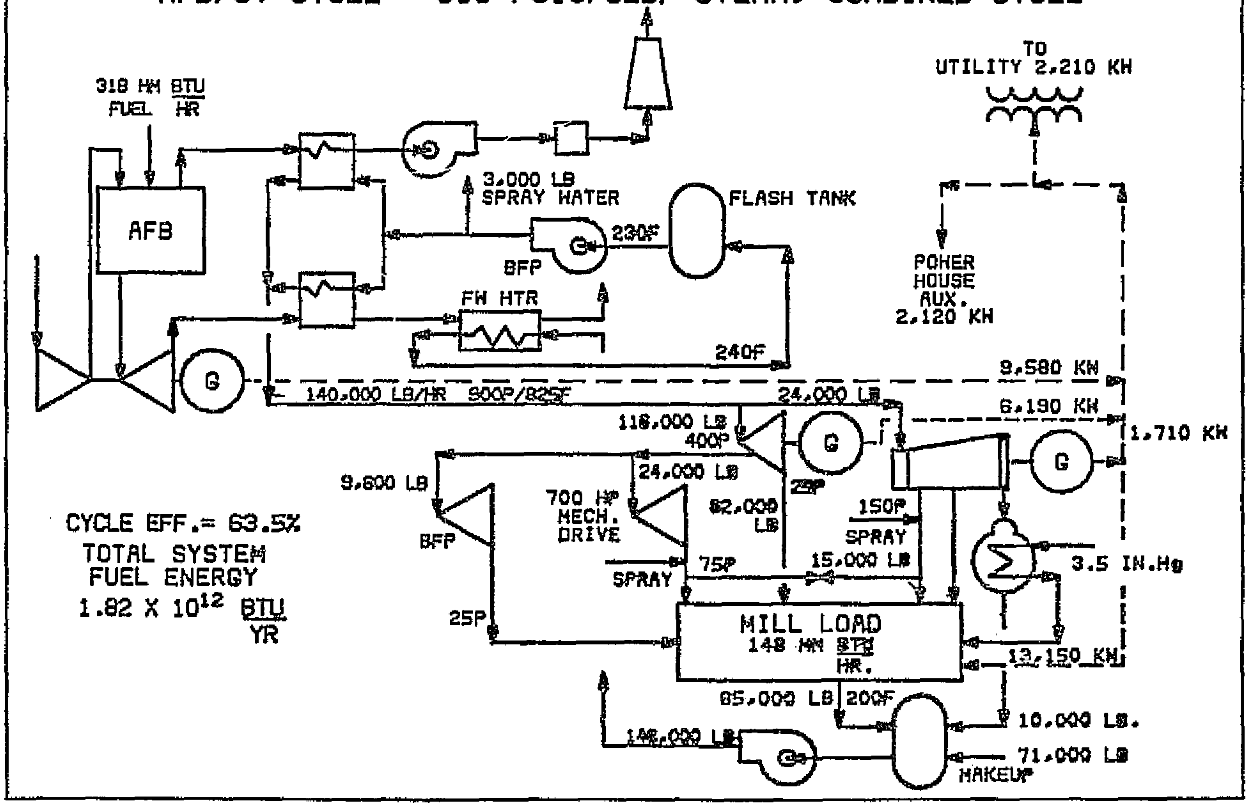

FIGURE A3-22

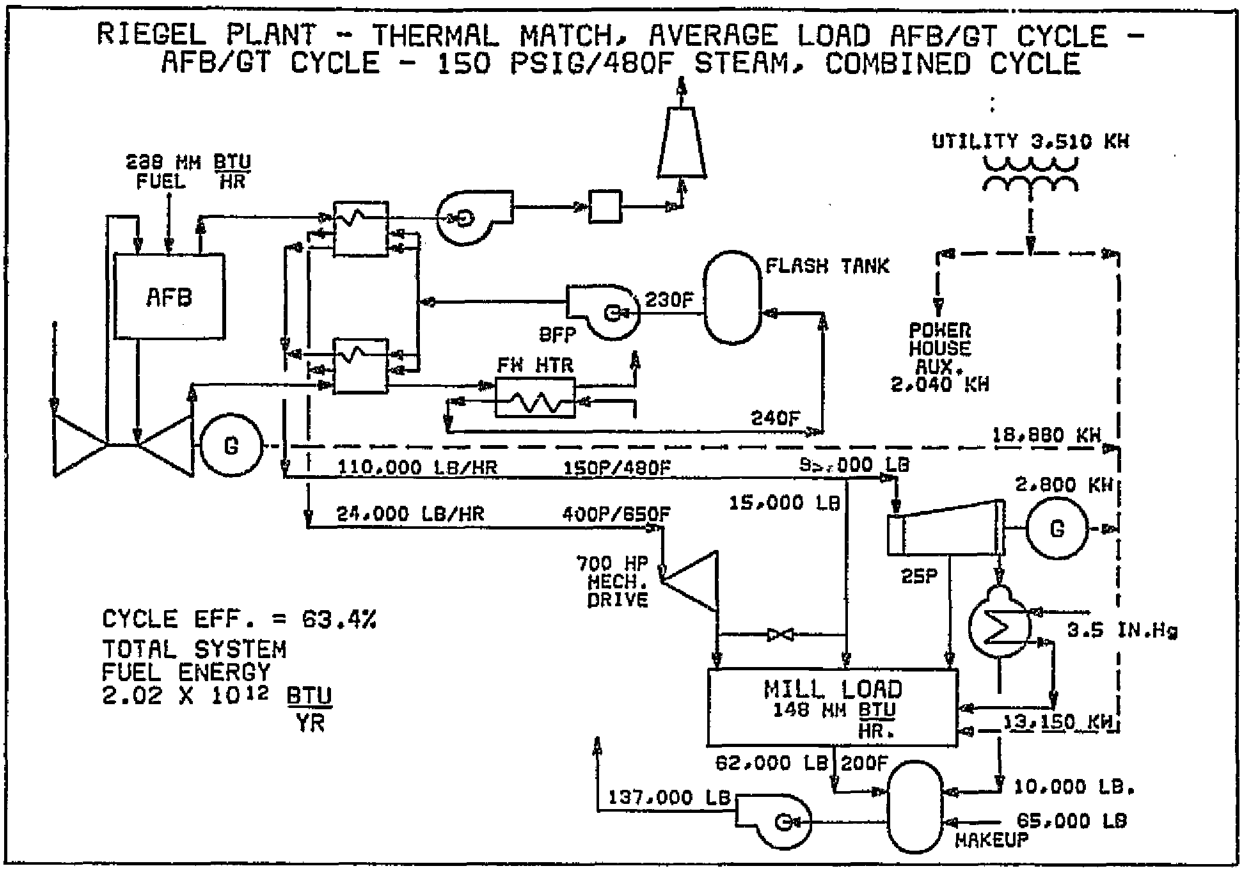

FIGURE A3-23

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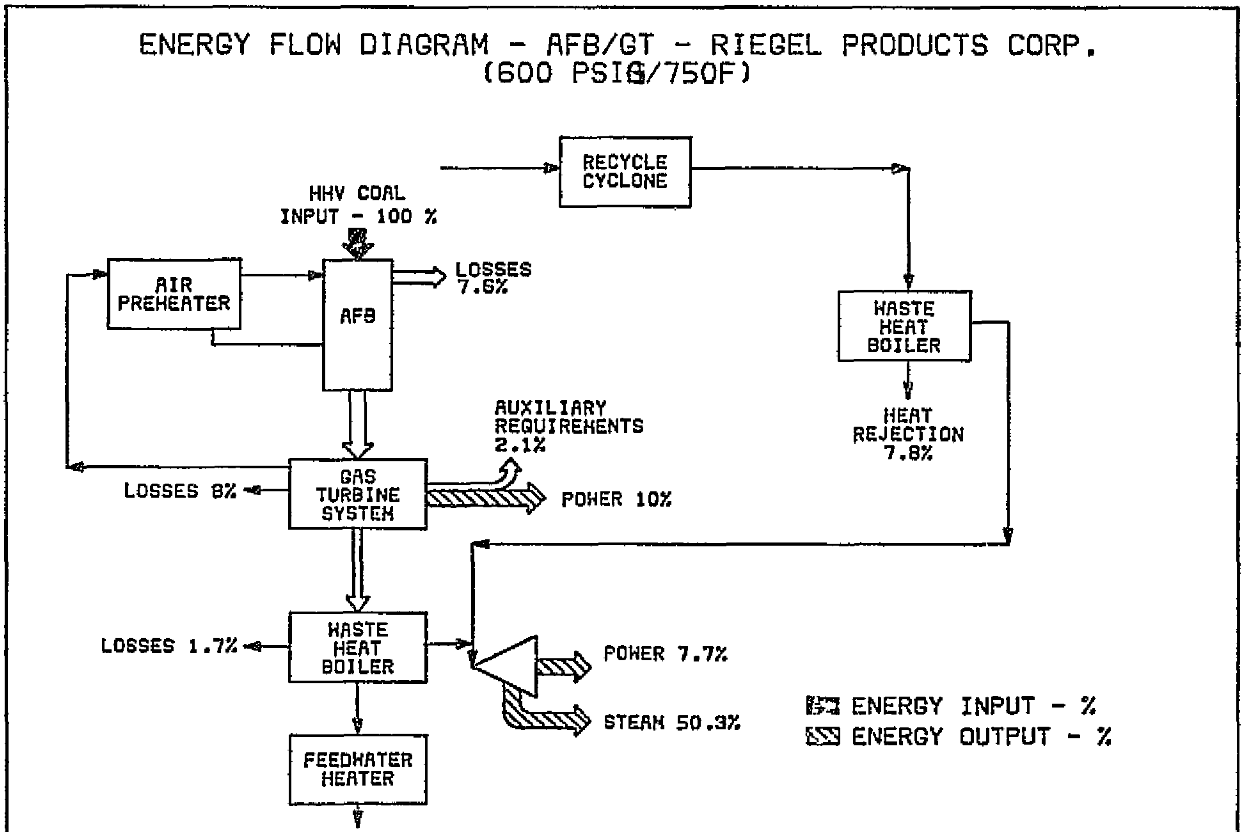

FIGURE A3-24

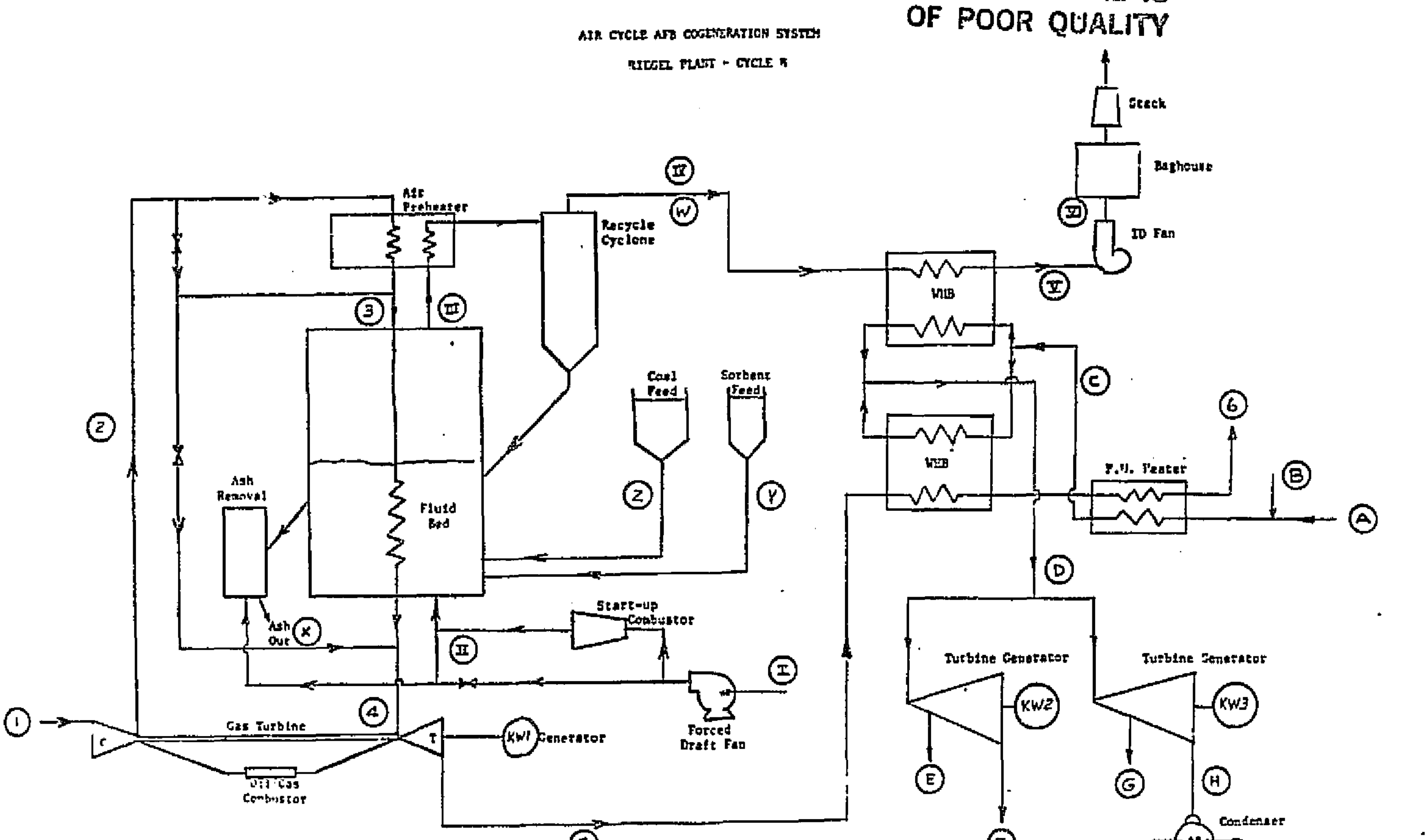

Figure A3-25

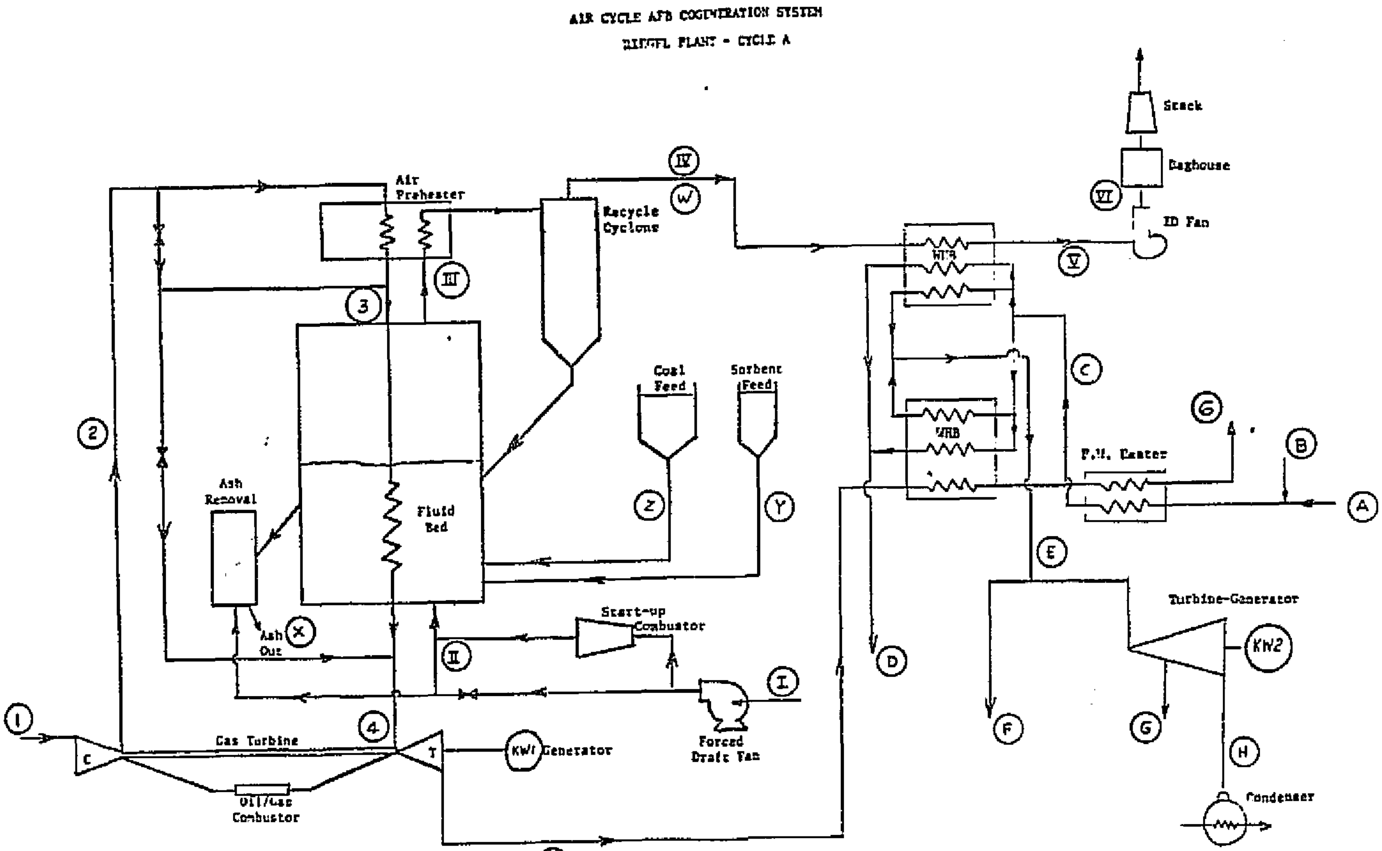

Figure A3-26

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Table A3-23

AIR CYCLE AFB COGENERATION SYSTEM
MASS AND ENERGY BALANCE

RIEGEL PLANT - CYCLE B

	Mass Pounds/Hour	Energy Million Btu/Hr	%	Electricity KW
Feeds				
Coal, (as delivered)	34385	402.85	96.7	118043
Limestone, #6401	15459	0.0		
Clean Air	792000	0.0		
Fluidizing Air	398000	0.0		
Feedwater (Process) 200°F	99000	13.86	3.3	
(Make-Up) 60°F	99000	0.0		
	1437844	416.71	100.0	
Products				
Clean Air Stack, T = 255°F	792000	37.49		
Flue Gas Stack, T = 334°F	430342	28.89		
Solids Off-Take	9605	3.97		
Flyash	4802	1.99		
Steam, 150 psig/510°F	50000	63.97		
Steam, 25 psig/324°F	118000	141.44		
Steam, 400 psig/646°F	20000	26.10		
Steam, 3.5 In.Hg.ABS	10000	10.62		
		314.47	75.5	
Electrical				
Gas Turbine, Gross		-48.10		-14094
Forced Draft Fan		+ 6.09		+ 1784
Induced Draft Fan		+ 1.55		+ 454
Steam Turbine, Net		-30.19		- 8848
		70.65	17.0	20704
Losses				
Feedwater Heater + Ecoomizer Heat 1%		0.76		
Evaporator + Super Heat 2%		3.58		
Combustion Process,				
HHV - LHV		14.27		
98% Comb. Eff.		8.05		
Gas Turbine Gear + Generator Losses		2.95		
Deaerator Temp. Drop, 240-230°F		1.98		
		31.59	7.5	
Water Vapor from Coal Drying	3095			
	1437844	416.71	100.0	

Table A3-24

AIR AFB COGENERATION SYSTEM
RIEGEL SITE - CYCLE B
PROCESS FLOW DATA

CLEAN AIR CIRCUIT[1]

	1	2	3	4	5	6
W	792000	776196	776196	776196	792000	792000
P	14.7	95	94	92.15	15.1	14.7
T	59	469	564	1517	893	255

COMBUSTION AIR CIRCUIT[1]

	I	II	III	IV	V
W	398000	398000	430342	430342	425540
P	14.7	19.5	14.7	14.3	14.7
T	59	129	1650	1500	334

SOLIDS FLOW [1]

	Z	Y	X	W
W	34385	15459	9605	4802

STEAM CIRCUIT

	A	B	C	D	E	F	G	H
W	99000	99000	198000	198000	20000	118000	50000	10000
P	ATM	ATM	ATM	600	400	25	150	3.5"Hg
T	200	60	230	750	646	324	510	120

ELECTRIC OUTPUT

KW1[1]	11,860
KW2	6,450
KW3	2,400
Total -	20,710

Note 1 - Values shown are for two combustor gas turbine units with output to a single boiler system

W = Flow Rate, Pounds Per Hour
P = Pressure, PSIA for Air Circuits, PSIG for Steam
T = Temperature, $^{\circ}F$
KW = Net Electrical Output, Kilowatts

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Table A3-25

AIR CYCLE AFB COGENERATION SYSTEM
MASS AND ENERGY BALANCE

RIEGEL PLANT - CYCLE A

	Mass Pounds/Hour	Energy Million Btu/Hr	%	Electricity Kw
Feeds				
Coal, (as delivered)	31103	364.00	96.3	108092
Limestone, #6401	14154	0.0	0.0	
Clean Air	792000	0.0	0.0	
Fluidizing Air	359182	0.0	0.0	
Feedwater (Process) 200°F	99000	13.86	3.7	
(Make-Up) 60°F	99000	0.0	0.0	
	1394439	378.26	100.0	
Products				
Stack Clean Air, 180°F	792000	23.12		
Stack Flue Gas, 416°F	388475	33.91		
Solids Off-Take	8776	3.65		
Flyash	4388	1.82		
Steam, 150 psig/480°F	50000	61.70		
Steam, 25 psig/267°F	118000	134.73		
Steam, 400 psig/650°F	20000	26.14		
Steam, 3.5 In.Hg.ABS.	10000	10.38		
		295.45	78.1	
Electrical				
Gas Turbine, Gross		-48.10		14094
Forced Draft Fan		+ 6.03		+ 1768
Induced Draft Fan		+ 1.40		+ 410
Steam Turbine, Net		-12.16		- 3564
Total Electrical, Net		52.83	14.0	15480
Losses				
Feedwater + Economizer Heat, 1%		.51		
Evaporator + Superheat, 2%		3.65		
Combustion Process, HHV - LHV		12.91		
98% Comb. Eff.		7.29		
Gas Turbine Gear + Generator Losses		2.95		
Deaerator Temp Drop 240-230°F		1.98		
Unaccounted		.69		
		29.98	7.9	
Water Vapor from Coal Drying	2800			
	1394439	378.26	100.0	

Table A3-26

AIR AFB COGENERATION SYSTEM
RIEGEL SITE - CYCLE A
PROCESS FLOW DATA

CLEAN AIR CIRCUIT[1]

	1	2	3	4	5	6
W	792000	776196	776196	776196	792000	792000
P	14.7	95	94	91.7	15.1	14.7
T	59	469	640	1517	893	180

COMBUSTION AIR CIRCUIT[1]

	I	II	III	IV	V
W	359182	359182	388476	388476	384084
P	14.7	19.4	14.7	14.3	14.7
T	59	129	1650	1350	416

SOLIDS FLOW[1]

	Z	Y	X	W
W	31103	14154	8776	4388

STEAM CIRCUIT

	A	B	C	D	E	F	G	H
W	99000	99000	198000	20000	178000	50000	118000	10000
P	ATM	ATM	ATM	400	150	150	25	3.5"Hg
T	200	60	230	650	480	480	267	120

ELECTRIC OUTPUT

KW1[1]	11,920
KW2	3,560
Total -	15,480

Note 1 - Values shown are for two combustor/gas turbine units with output to a single boiler system

W = Flow Rate, Pounds Per Hour
P = Pressure, PSIA For Air Circuits, PSIG for Steam
T = Temperature, °F
KW = Net Electrical Output, Kilowatts

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Table A3-27

AIR CYCLE AFB COGENERATION SYSTEM

Costing Summary - Go Rate Units

		Riegel A	Riegel B
A.	Combustor	916,400	980,500
B.	Hx and Manifolds	1,339,800	1,504,300
C.	Recycle System	326,900	366,100
D.	Start Up Combustor/FD Fan	357,000	381,700
E.	System Controls	293,000	293,000
F.	Coal Feed System	345,300	345,300
G.	Air Preheater	128,100	87,700
H.	Ash Cooling System	97,900	104,700
I.	Air Piping	621,900	621,800
J.	Miscellaneous	169,400	169,400
K.	Gas Turbine System	2,538,000	2,538,000
	Hardware	7,133,700	7,392,500
	Engineering/Software	706,700	706,700
	1st Unit	7,840,400	8,099,200
	2nd Unit		
	Hardware	6,919,700	7,170,700
	Software	223,459	223,459
		7,143,159	7,394,159
	3rd Unit		
	Hardware	6,777,000	7,022,900
	Software	133,740	133,740
		6,910,740	7,156,640

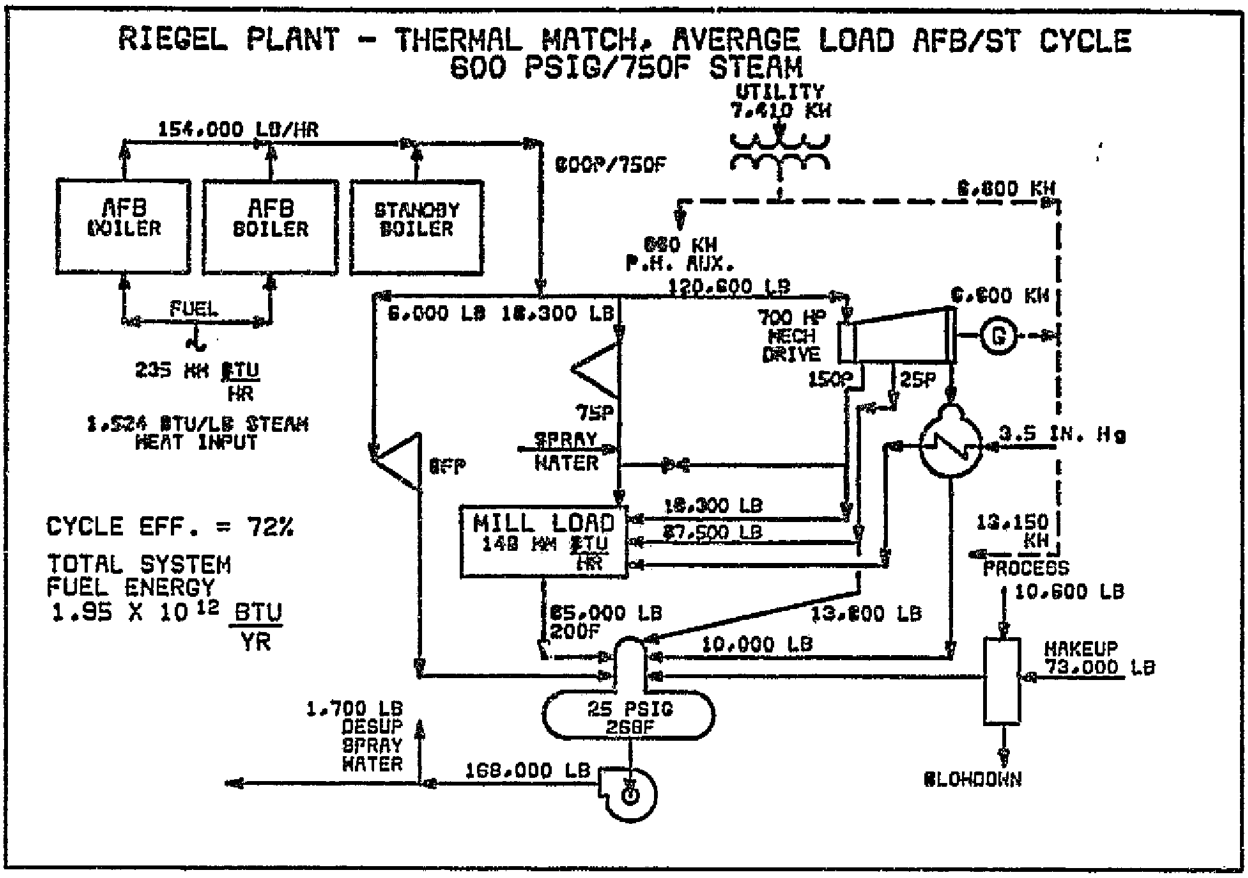

FIGURE A3-27

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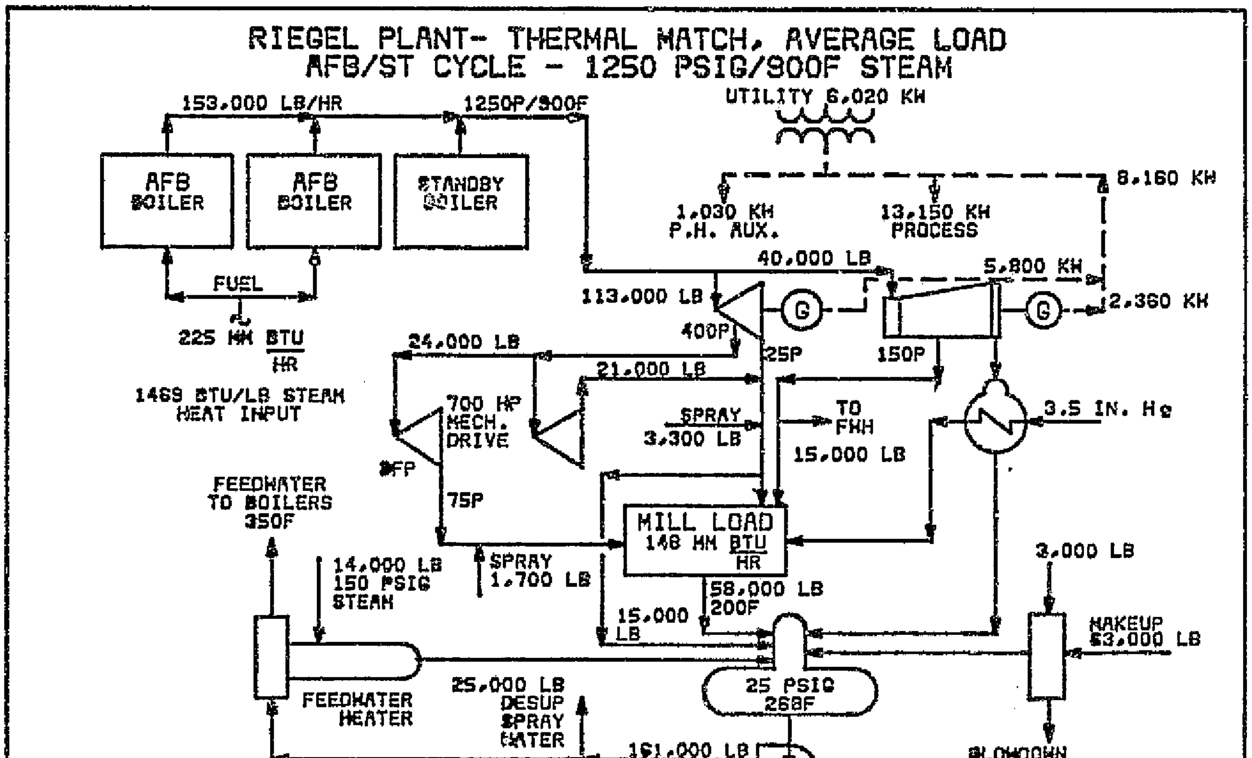

FIGURE A3-28

AFB boiler performance is derived from data provided by Dorr-Oliver/Keeler shown in Tables A3-28, I and II. For the AFB boilers in each system, the performance data listed is adjusted for the different steam conditions finally selected. The AFB boiler performance data for the Task-1 Ethyl plant site was also based on this performance data. A boiler of this size and for steam conditions not in excess of the 600 psig/750°F range is felt by Dorr-Oliver/Keeler to look as the one shown in Figures A3-29 and A3-30.

For both the steam turbine and gas turbine cycles producing 600 psig/750°F steam, it is assumed that the existing mechanical line drive turbine can operate successfully at this pressure. Since the unit currently operates at about 375 psig/600°F, this assumption is felt to be reasonable.

B. Capital Cost Estimates

The preliminary capital cost estimates for the two systems are summarized in Table A3-21 for entirely new, complete cogeneration facilities for screening purposes.

3.3 PERFORMANCE AND BENEFITS ANALYSIS

Appendix Section 2 provides background on the elements involved in performance and benefits analysis. This permits the evaluation and comparison of the cogeneration systems considered. The evaluation of the benefits of each cogeneration system is established relative to the non-cogeneration base case. The following parameters have been calculated and are discussed in this section.

- o emissions (total and by constituent)
- o capital costs
- o return on investment
- o levelized annual energy costs
- o fuel energy (by fuel type)

3.3.1 Emissions

Calculations have been performed to derive both on-site emissions and total emissions, which include utility emissions associated with generating purchased electricity. Table A3-29 shows allowable regulatory emissions based on applicable regulatory requirements for both the Ethyl and Riegel sites. On-site emissions for the AFB cogeneration cases assumes 90% sulfur reduction. Utility particulate emissions are taken as meeting regulations.

RIEGEL PAPER PRODUCTS COMPANY

Table A3-28I

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Site Data

Steam demand @ 400 psig/650°F TT:

Summer	200,000 pph
Winter	220,000 pph
Minimum	80,000 pph
Load change	8,000 lb/min @ 3.6% of MCR/min
Turn-down	36%
Coal to be used:	Illinois No. 6 high sulfur 12,520 Btu/lb
Hydrogen	4.6%
Carbon	67.4%
Nitrogen	1.3%
Oxygen	7.9%
Sulfur	3.5%
Ash	10.3%
Water	5.0%
Altitude	137.18 ft AMSL
Limestone to be used:	Argonne No. 6401
$CaCO_3$	64.2%
$MgCO_3$	29.5%
Inerts	6.4%
Water	None

Table A3-28II

Performance Data

Steam generation rate	110,000 pph
Air inlet temperature	70°F
Economizer outlet (gas) temperature	320°F
Combustion efficiency	95%
Ca/S mol ratio	5:1
Sulfur capture	90%
Excess air for combustion	20%
Dust loading to baghouse	6 gr/ACF
Boiler efficiency	76.2%
Coal feed rate	12,263 pph
Dolomite feed rate	10,434 pph
Bottom ash rate	7,000 pph
Fly ash rate	1,000 pph
Boiler feedwater temperature	268°F
Ash discharge temperature	540°F
Fluid bed depth (fluidized)	4.5 ft

Equipment Selection

2 - 110,000 pph AFB boilers, 450 psig. pressure rating

Turn-down capability 15%

Auxiliary equipment (each boiler):

FD fan (test block) 160,000 pph @ 104" WG with 900 HP motor

ID fan (test block) 174,000 pph @ 25"WG with 500 HP motor

Separate Detroit stoker spreader feeder and dolomite feeder.

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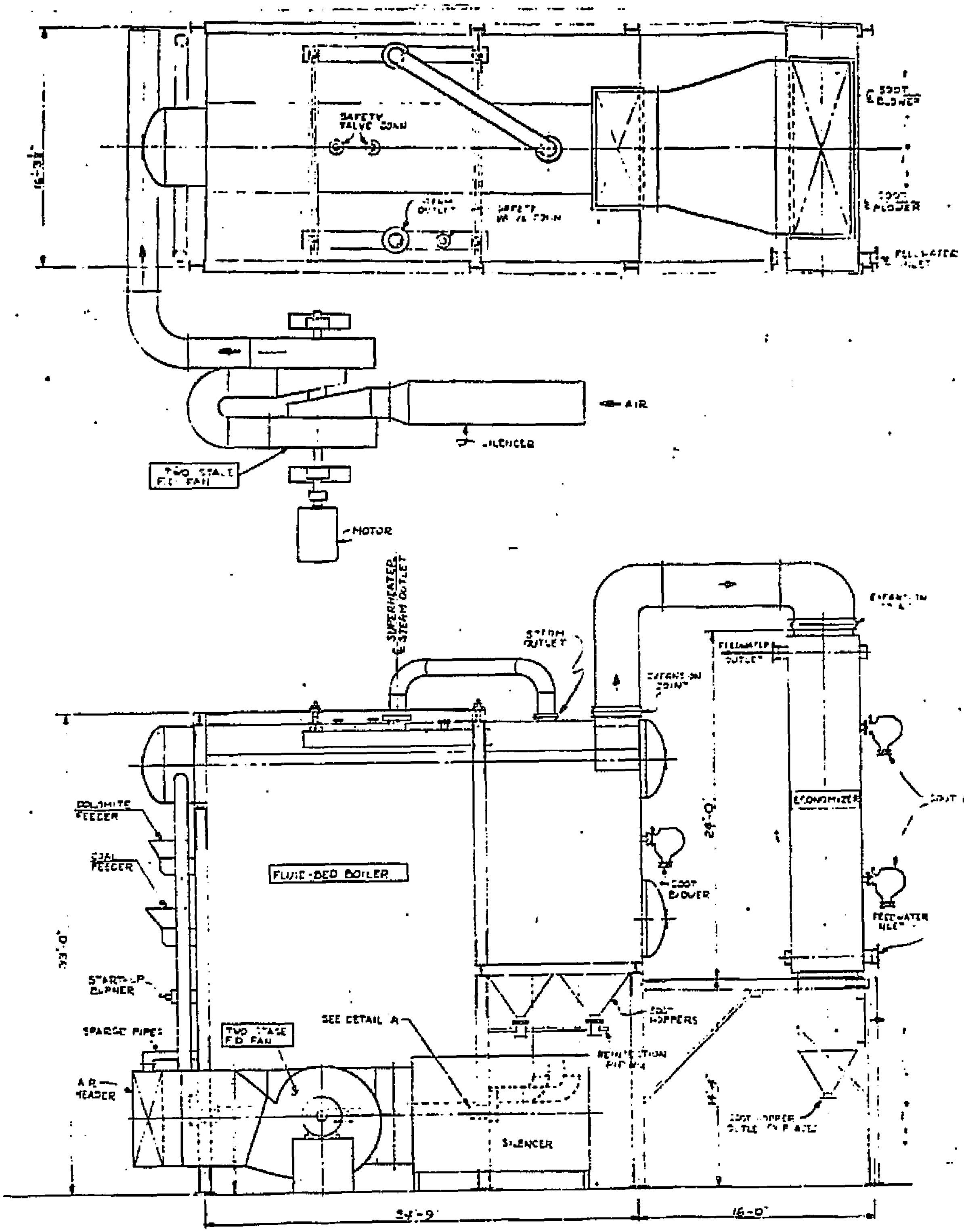
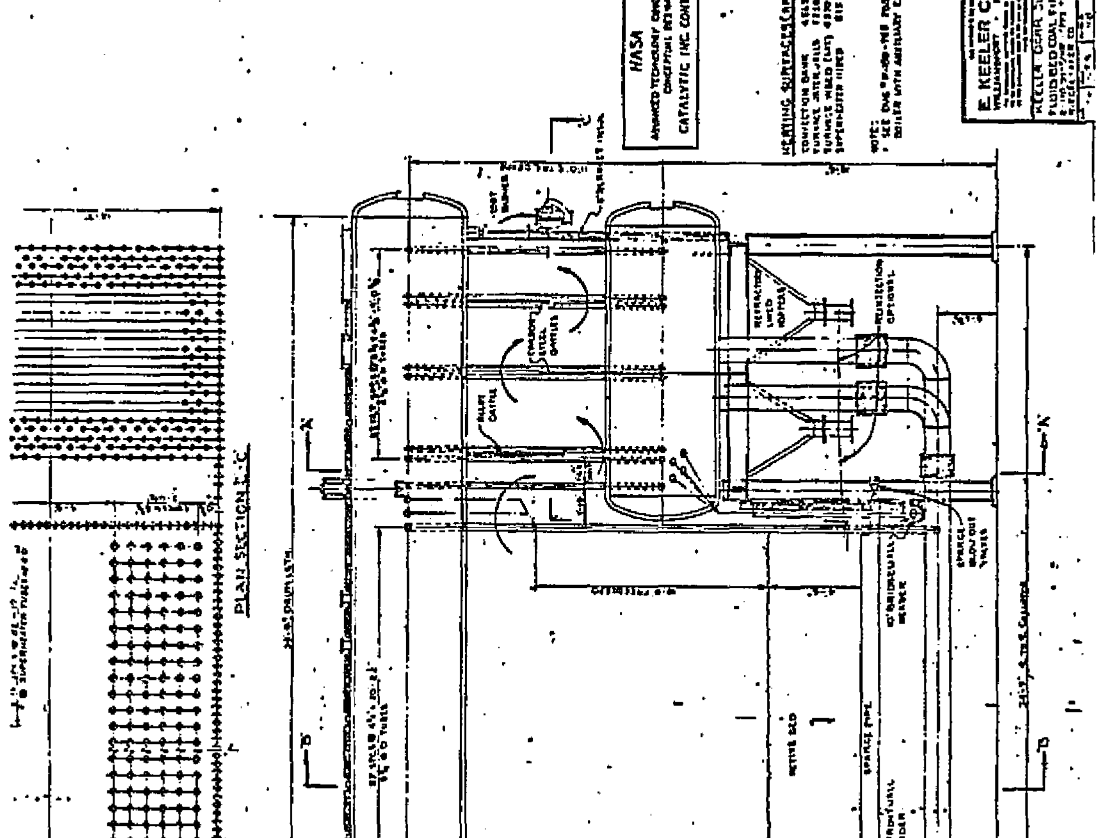


SIDE ELEVATION

Figure A3-29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NASA
E. KEELER COMPANY
HALF SECTION B-B
HALF SECTION A-A
OPERATING FLOOR
AIR HEADER

Figure A3-30

Table A3-29: EMISSIONS DATA

REGULATORY BASIS	ETHYL Federal Standards	RIEGEL New Jersey Standards
SO_x, lbs/MM Btu heat input	1.2	1.2
NO_x, lbs/MM Btu heat input	0.5	0.5
Particulates, lbs/MM Btu heat input	0.1	0.03
AFB EMISSIONS		
SO_x coal	90% removal with 3.1% S	
NO_x, lbs/MM Btu heat input	0.4	0.4
Particulates, lbs/MM Btu heat input	0.01	0.03
UTILITY		
Heat Rate, Btu/kwh	10,500	10,624
Fuel Usage by Type		
Coal %	20	32.5
Oil %	---	37.1
Gas %	80	11.0
Other %	---	19.4
SOLID WASTE		
Ash Content of Coal, %	10	10
Coal Heating Value, Btu/#		
Utility	7,300	12,500
Industry	12,400	12,500
AFB/Gas Turbine System, TPH	8.57	5.30
AFB/Steam Turbine System, tons/100 KPPH steam	3.64	3.64

Figure A3-31 shows in graphical form the predicted emissions for both plant sites for the non-cogeneration base case and for both AFB/gas turbine and AFB/steam turbine cogeneration systems. The increased SO_x emissions for the cogeneration cases is due to coal burning.

The increase in solid wastes for the cogeneration cases, which is shown in Figure A3-32, is due to the use of an AFB combustor which increases solid wastes due to use of sorbent in the furnace, as compared to burning oil or gas in a boiler.

The emissions savings ratio (EMSR), both on-site and total, is shown in Figure A3-33. The large negative savings (increase) is due to displacing gas with coal firing at the industrial plant.

3.3.2 Capital Costs

A graphical summary of the capital costs is given in Figure A3-34. The capital cost ratio and incremental capital costs are plotted in Figure A3-35 for the various cases.

3.3.3 Return on Investment

The return on investment on the incremental capital investment (ROI) for the cogeneration system relative to the non-cogeneration base case and also for the AFB/gas turbine relative to the AFB/steam turbine case for the two sites is shown in Figure A3-34. A copy of some of the computer based cash flow/ROI calculations for the Ethyl site are given in Appendix Section 3.9.

Some of the factors for calculating the operating and maintenance costs are given in Table A3-30. Table A3-31 lists the ROIs calculated for various cases.

3.3.4 Levelized Annual Energy Costs

The levelized annual energy costs for the systems considered for the Ethyl plant are shown in Table A3-6, and for the Riegel plant in Table A3-22. The various operating cost items are for the first year of operation in 1988. Figure A3-36 shows these cost items graphically.

The levelized cost savings and the cost savings ratios given in the above tables are shown graphically in Figure A3-37.

3.3.5 Fuel Energy

Total electrical and thermal energy requirements for both plant sites are shown in Figure A3-38 by fuel type. The total system fuel energy includes both the fuel consumed on-site and the fuel consumed by the utility to generate the purchased electricity. The fuel energy savings ratio (FESR) is shown in Figure A3-36.

3.3.6 Site Comparison

Figure A3-39 shows at one look the five main comparison parameters given previously. A brief listing of pertinent technical and economic factors that influence site selection are listed in Table A3-32.

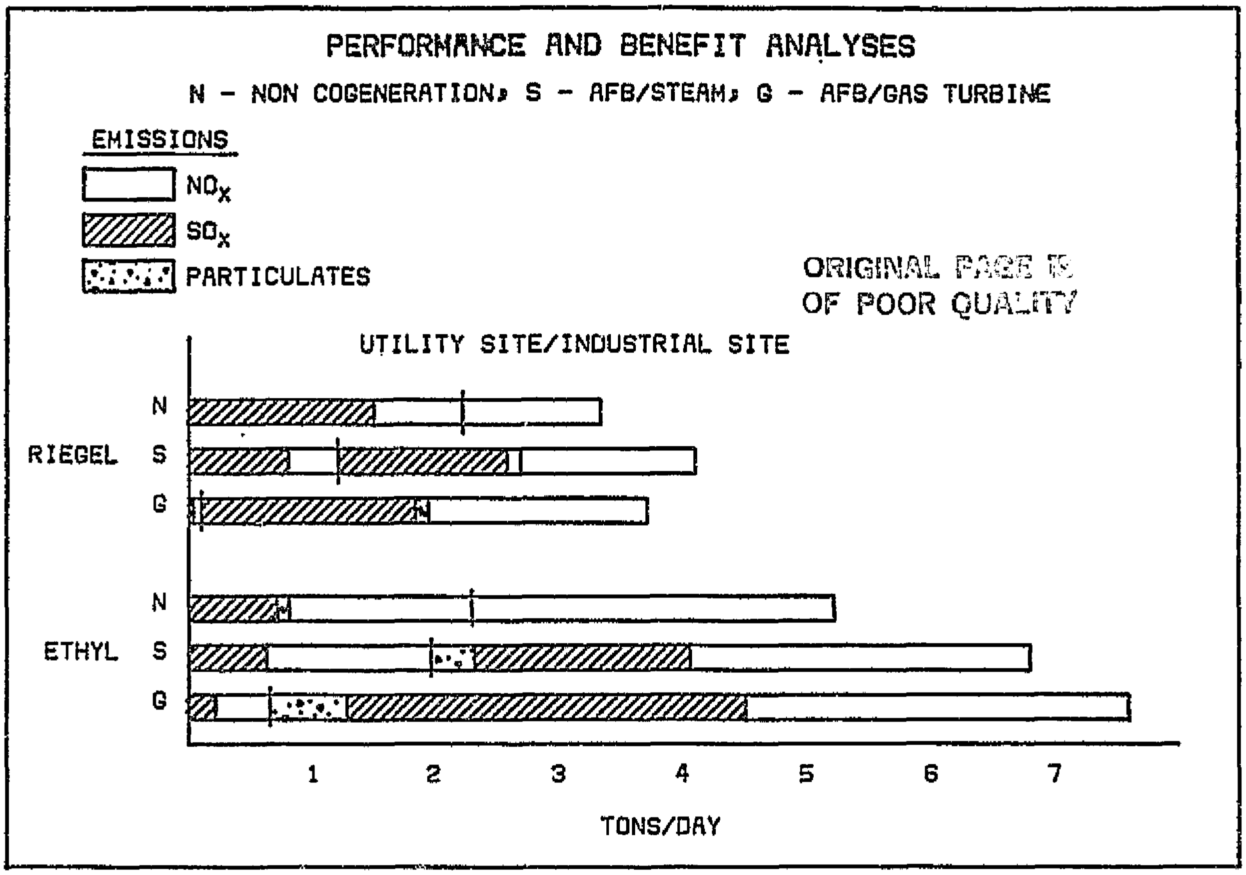

FIGURE A3-31

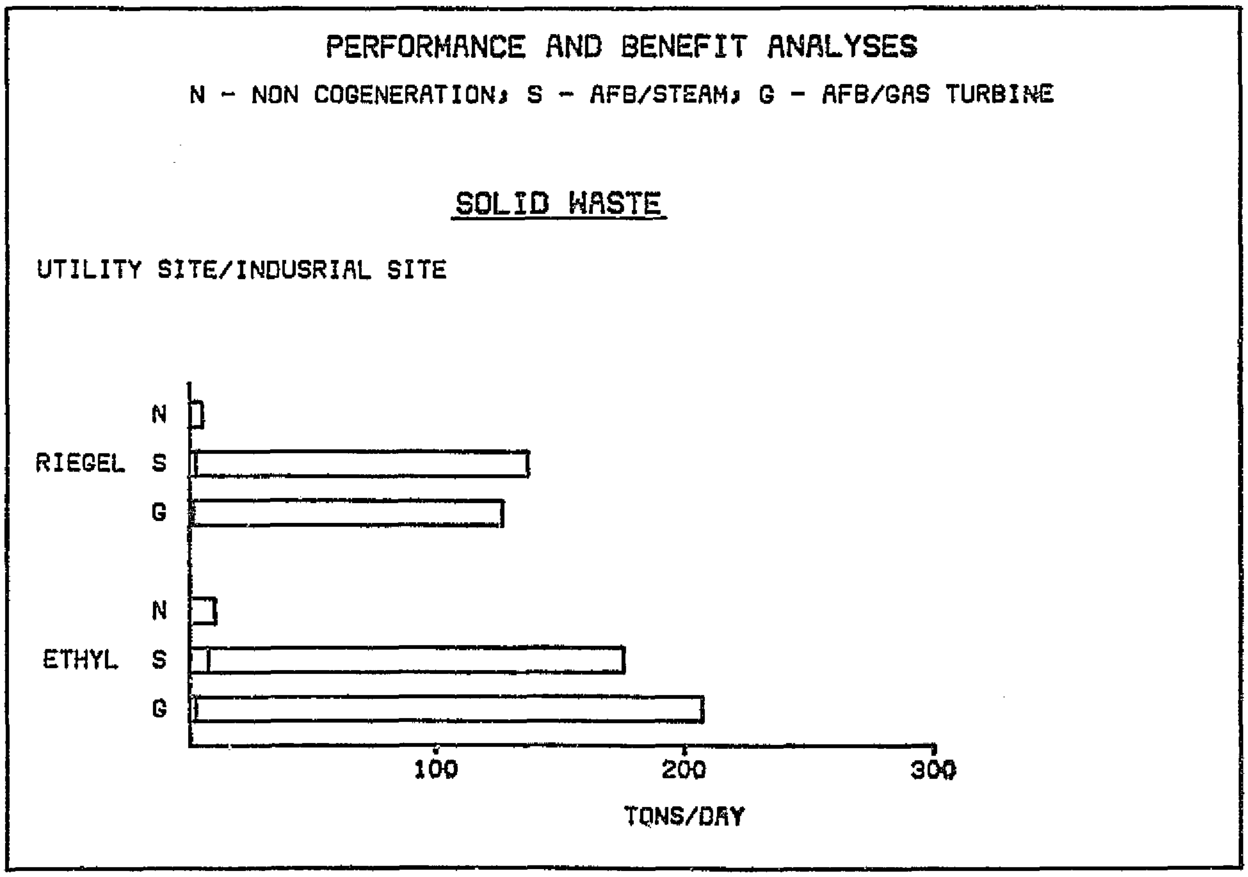

FIGURE A3-32

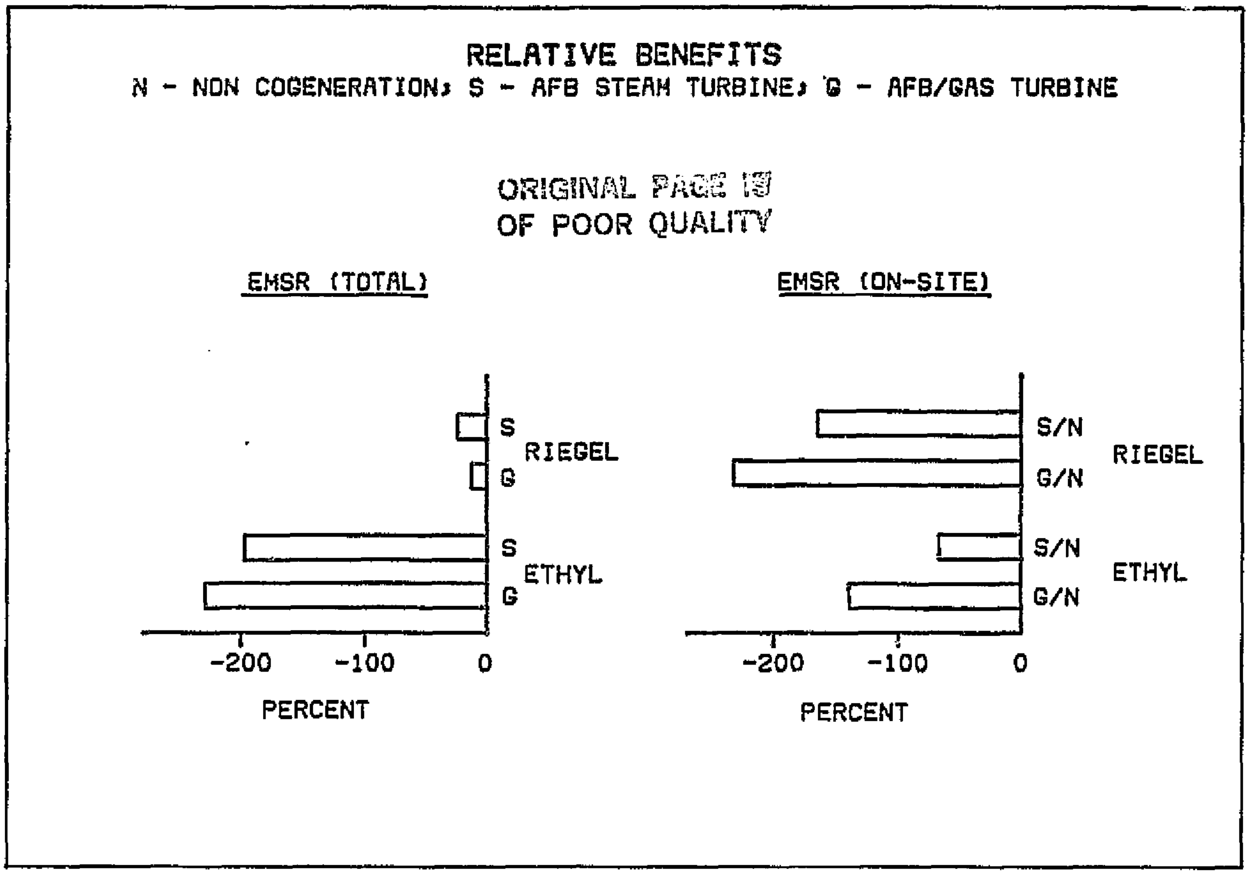

FIGURE A3-33

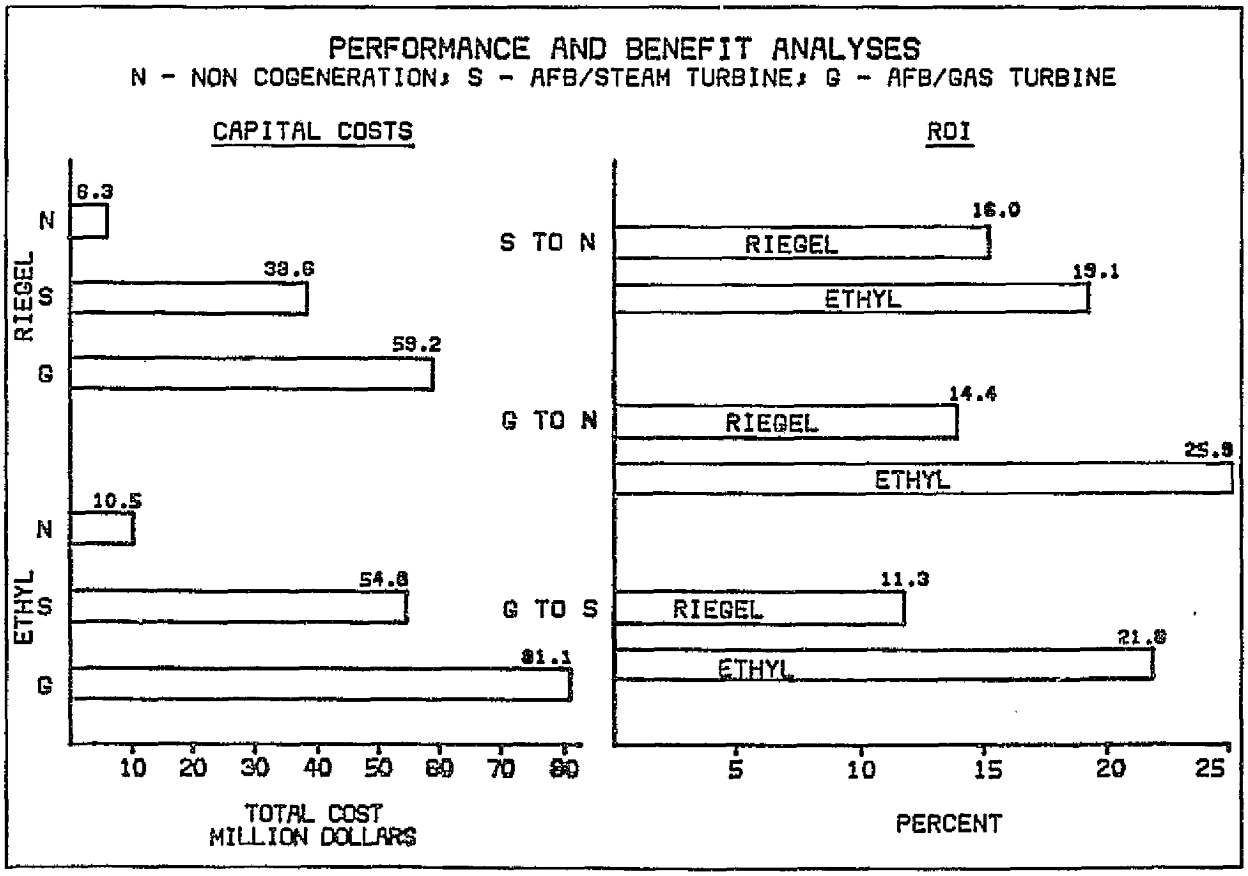

FIGURE A3-34

Table A3-30: FACTORS FOR OPERATING AND MAINTENANCE COSTS

	ETHYL	RIEGEL
1. SOLID WASTE REMOVAL	$5.00/ton	Same
2. ANNUAL MAINTENANCE		
No-Cogeneration Base Case	$87,000	$52,000
Cogeneration Cases	3% Direct Capital	

3. SORBENT

Sorbent consumption is taken as an operating and maintenance item since it does not escalate. None of the operating and maintenance items escalate.

	ETHYL	RIEGEL
4. OPERATING LABOR		
Manpower per Shift (5 shifts)		
Base Case	2.0(1)	1.5
Cogeneration Cases	5.0	5.0
Annual Cost/Man	$70,000(1)	$44,350

(1) Ethyl Corporation Input

Table A3-31: ROI'S FOR VARIOUS CASES

ETHYL SITE	ROI
AFB/Steam Turbine vs. No-Cogeneration	19.1
AFB/Gas Turbine, 3 Units vs. No-Cogeneration	25.9
AFB/Gas Turbine, 4 Units vs. No-Cogeneration	23.6
AFB/Gas Turbine, 3 Units vs. AFB/Steam Turbine	21.8
AFB/Gas Turbine, 4 Units vs. AFB/Steam Turbine	14.2
RIEGEL SITE	
AFB/Steam Turbine, 600/750 vs. No-Cogeneration	16.0
AFB/Steam Turbine, 1,250/900 vs. No-Cogeneration	15.1
AFB/Gas Turbine, 600/750 vs. No-Cogeneration	14.4
AFB/Gas Turbine, 900/825 vs. No-Cogeneration	14.7
AFB/Gas Turbine, 150/480 vs. No-Cogeneration	13.9
AFB/Gas Turbine, 600/750 vs. AFB/Steam Turbine, 600/750	11.3
AFB/Gas Turbine, 600/750 vs. AFB/Steam Turbine, 1,250/900	12.0
AFB/Gas Turbine, 900/825 vs. AFB/Steam Turbine, 600/750	12.7

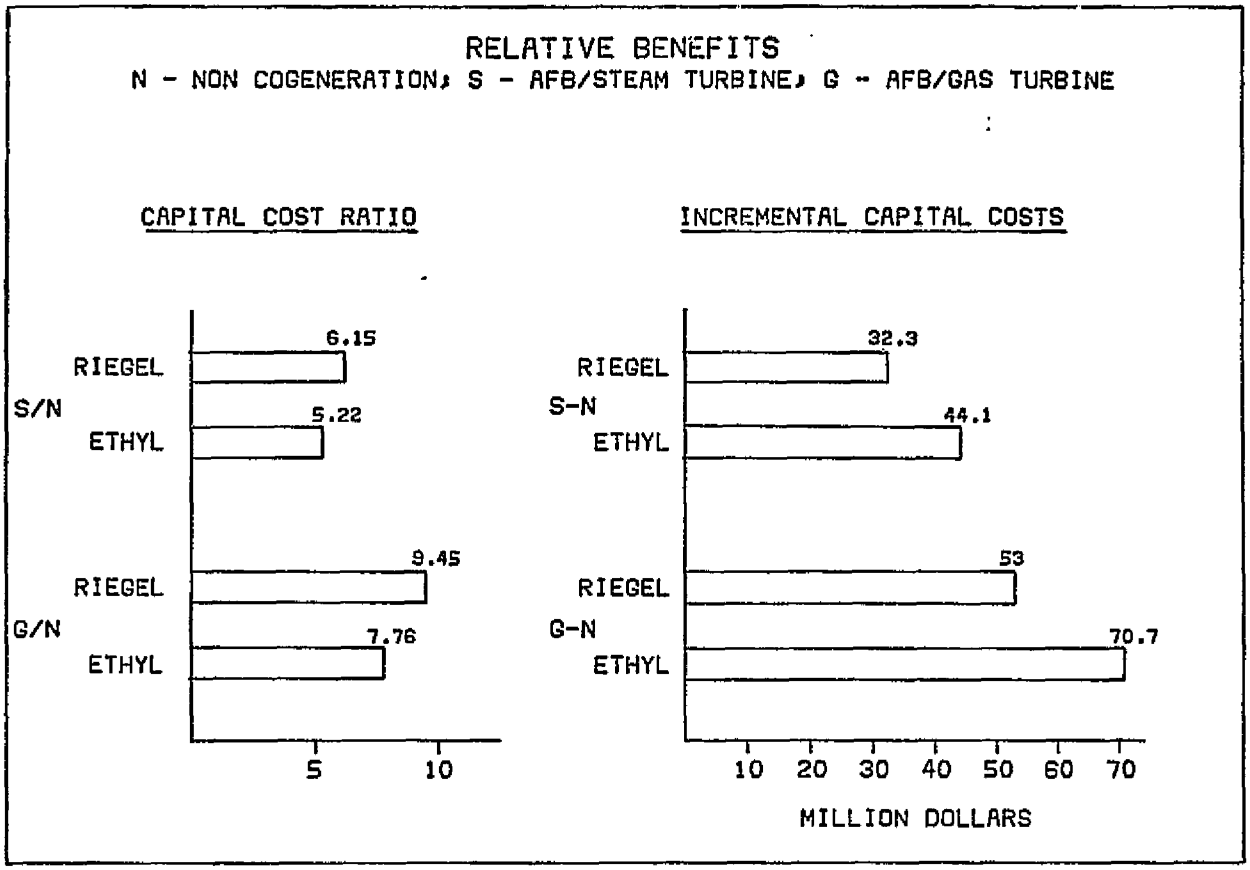

FIGURE A3-35

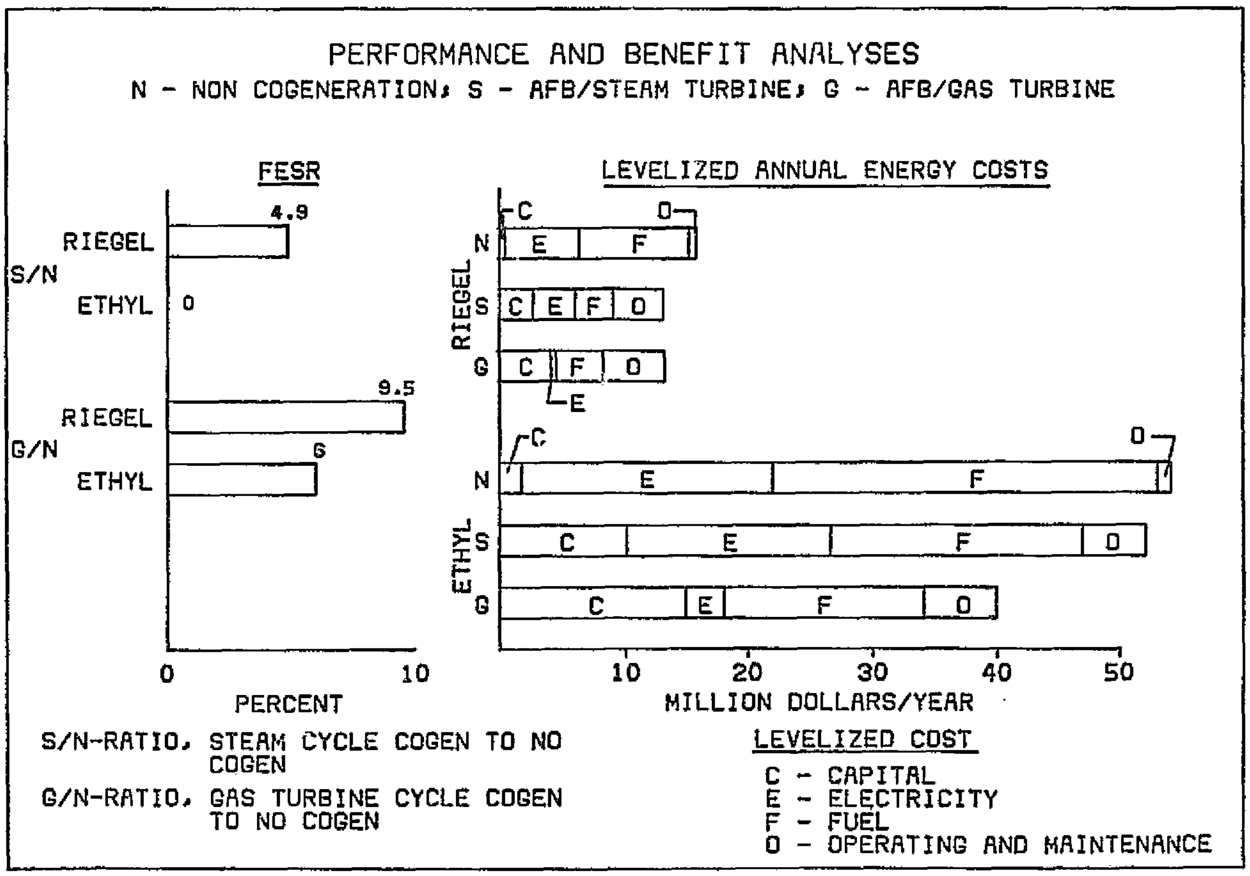

FIGURE A3-36

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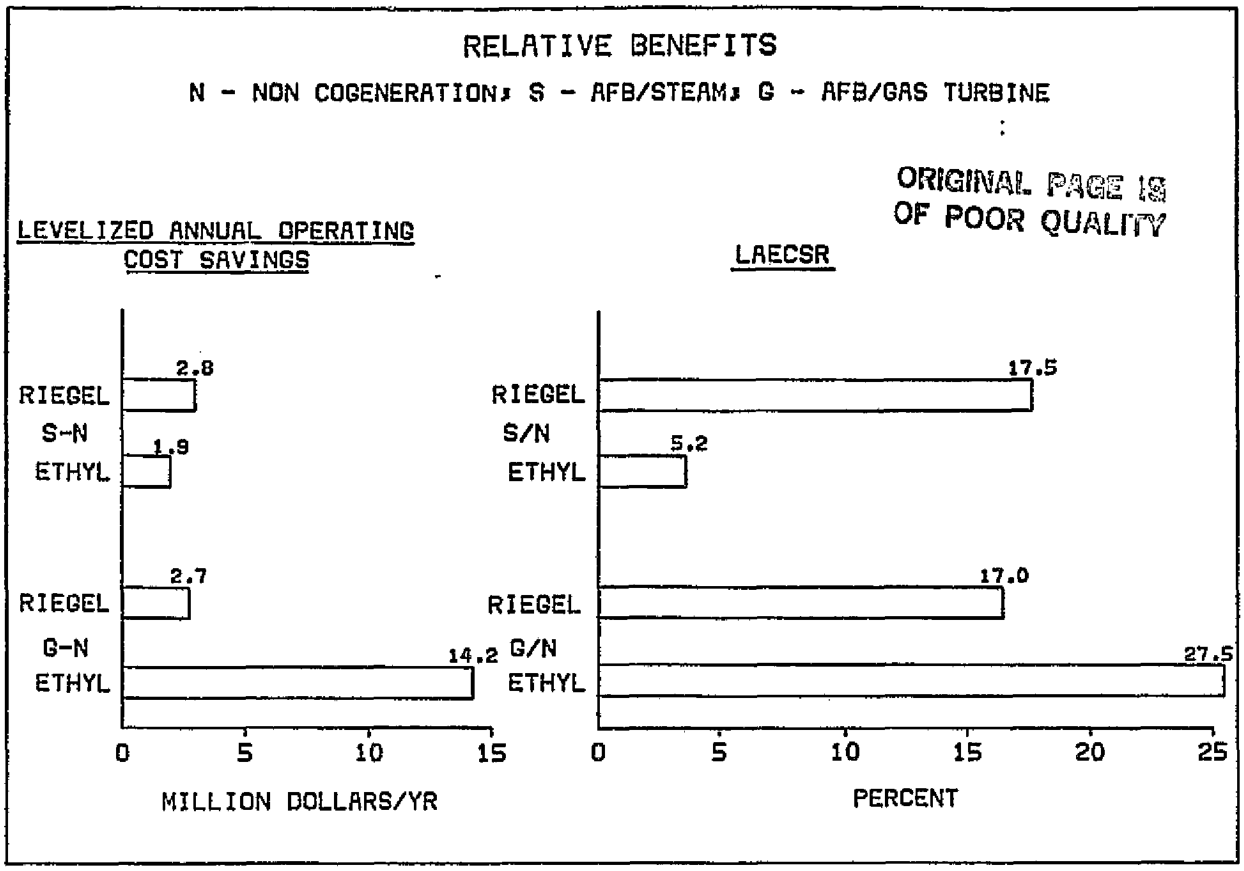

FIGURE A3-37

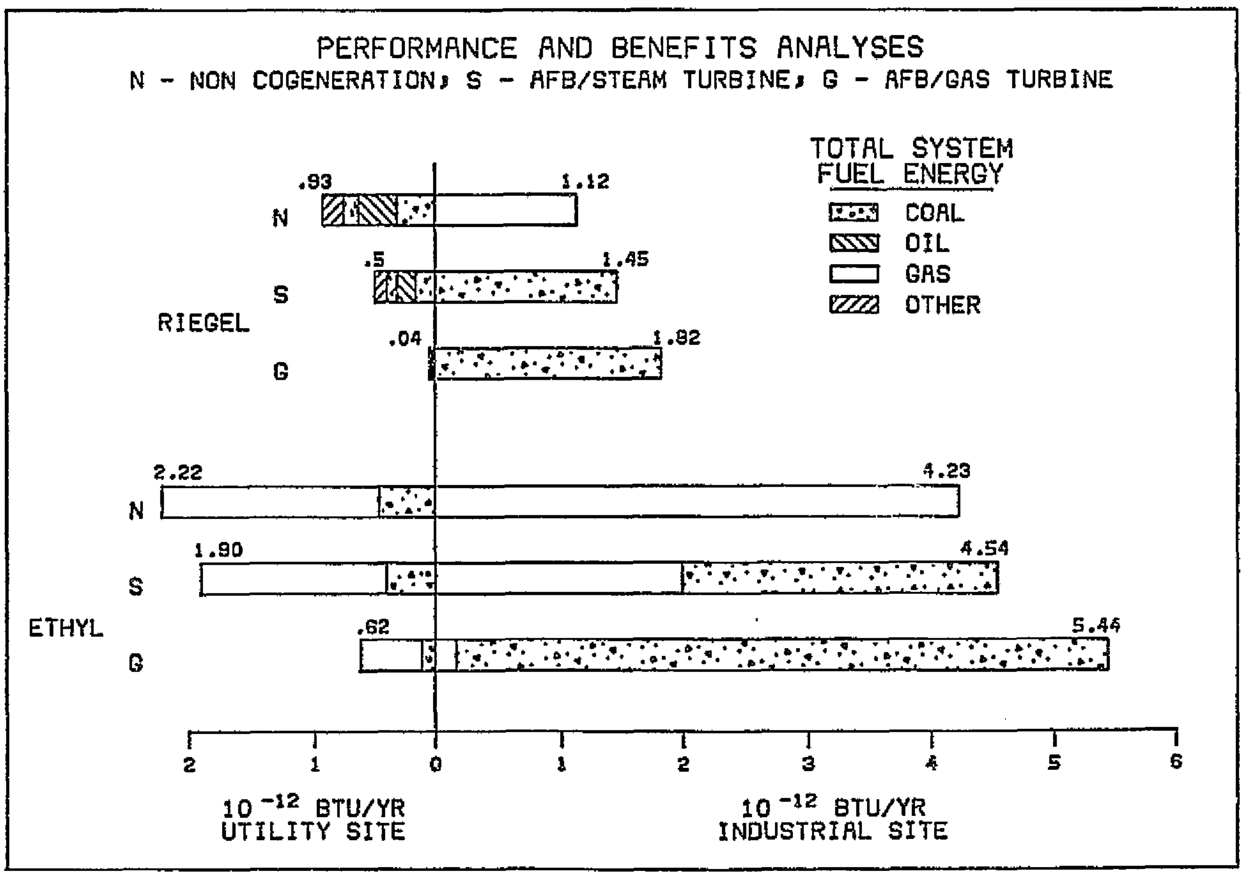

FIGURE A3-38

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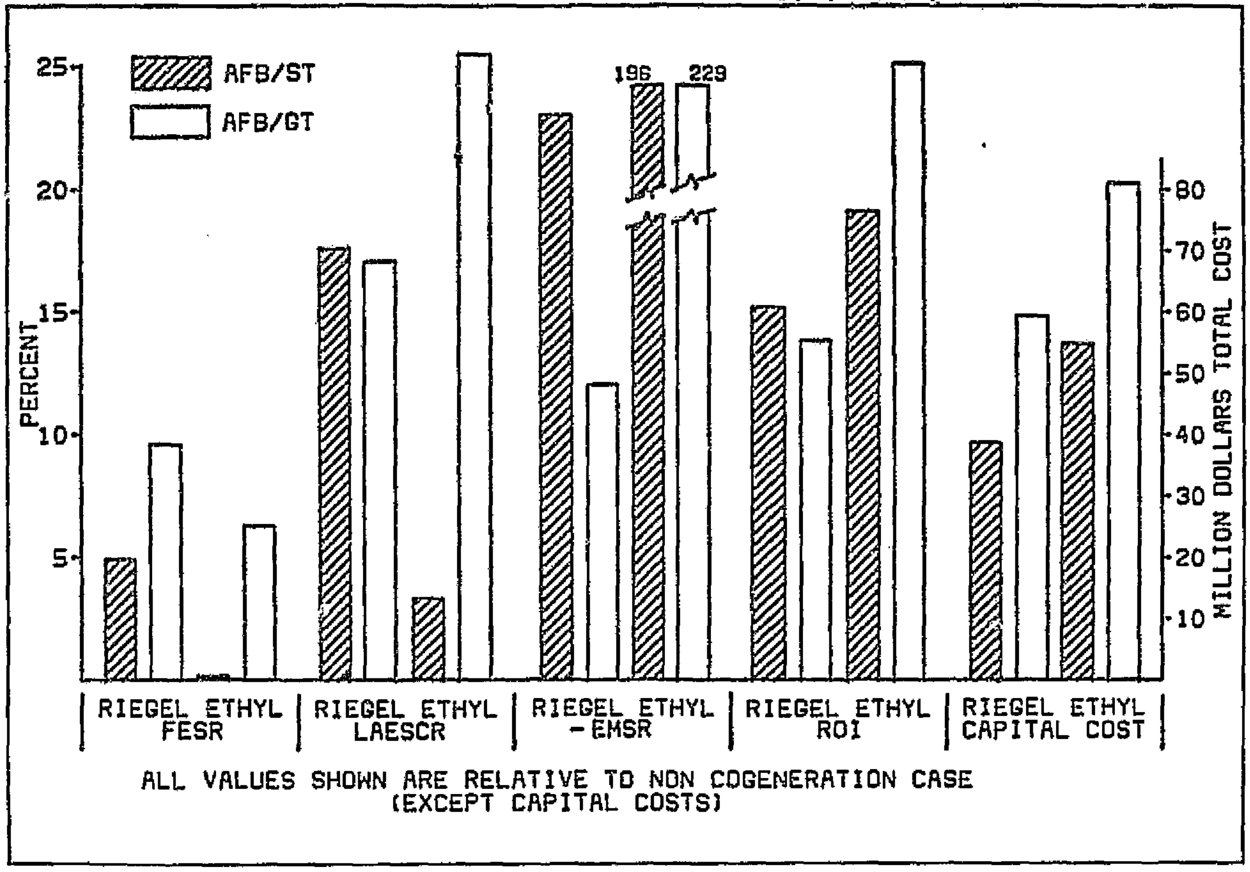

Figure A3-39: SITE COMPARISON

Table A3-32: SITE SELECTION CRITERIA - TECHNICAL AND ECONOMIC

	RIEGEL	ETHYL
ROI PERCENT	14.4	25.9
TOTAL CAPITAL INVESTMENT - $MM	59.2	81.5
THERMAL EFFICIENCY - PERCENT	65.0	64.0
E/T	.3	0.36
COGENERATION/ELECTRICAL - MW	14.5	21.3
ANNUAL ENERGY CONSUMPTION - BTU x 10^{12}	1.86	6.06

3.4 TASK 1 - COMMON CASE DATA

As part of the Task-1 plant screening, common case economic parameters were prepared by NASA to produce an economic evaluation of each site using a consistent set of economic criteria. This evaluation is in addition to that using site specific data which is the main output of this study. The common case economic factors given are shown in Table A3-4. All prices are for a base year of 1985 expressed in 1981 dollars. The given calculation rates are assumed constant from 1985 throughout the time period of interest. The fuel prices and escalation represent DOE energy price forecasts in February 1982.

Levelized annual energy cost analysis using the common case economic parameters is given in Table A3-33 for the Ethyl plant and in Table A3-34 for the Riegel plant. The results of the benefits comparison using the common case economic parameters are shown in the following Figures:

Figure A3-40	Capital Costs/ROI
Figure A3-41	Capital Cost Ratio/Incremental Capital Costs
Figure A3-42	Levelized Annual Energy Costs/FESR
Figure A3-43	Levelized Annual Energy Operating Cost Savings/LAECSR

3.5 ASSESSMENT

Section 3.3. determined benefits and advantages of quantifiable items as part of the Task-1 plant screening effort. An assessment of institutional or non-technical barriers is presented in this section.

Three broad classes of qualitative restraints are identified:

- o Restraints generic to coal-fired cogeneration.
- o Restraints that pertain to application of a particular technology.
- o Restraints that are site specific.

Table A3-33

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ETHYL PLANT

LEVELIZED ANNUAL ENERGY COST ANALYSIS

COMMON CASE ECONOMIC PARAMETERS

COST ITEM MILLION $	LEVELIZING FACTORS	1988 COSTS IN 1981 DOLLARS				LEVELIZED COSTS IN NOMINAL $			
		BASE CASE	AFB/ST 600/750	AFB/GT 3 UNITS	AFB/GT 4 UNITS	BASE CASE	AFB/ST 600/750	AFB/GT 3 UNITS	AFB/GT 4 UNITS
CAPITAL COST	-	8.941	39.918	59.318	72.495	-	-	-	-
CAPITAL INVESTMENT	-	9.620	46.213	68.672	83.927	-	-	-	-
LEVELIZED CAPITAL INVESTMENT	.0772	-	-	-	-	.742	3.56	5.30	6.479
FUEL COST - GAS	1.416	23.876	11.412	4.234	1.008	33.80	16.159	5.995	1.427
FUEL COST - COAL	1.1148	-	5.904	10.966	12.586	-	6.580	12.220	14.030
ELECTRIC PURCHASE	1.182	10.082	10.505	11.733	12.026	11.917	12.41	13.868	14.187
ELECTRIC BUY BACK	1.182	-	(1.145)	(5.422)	(5.784)	-	(1.353)	(6.408)	(6.836)
SORBENT	1.0	-	1.108	1.102	1.461	-	-	-	-
WASTE DISPOSAL	1.0	-	.306	.375	.430	-	-	-	-
UTILITIES, LABOR & MAINTENANCE	1.0	.845	2.576	3.052	3.348	-	-	-	-
INSURANCE & LOCAL TAXES	1.0	.289	1.386	2.060	2.517	-	-	-	-
SUM OF CONSTANT ANNUAL COSTS	1.0	1.134	5.376	6.589	7.326	1.134	5.376	6.589	7.326
LEVELIZED ANNUAL ENERGY COST (NOMINAL $)	-	-	-	-	-	47.59	42.732	37.56	36.613
LEVELIZED ANNUAL ENERGY COST SAVING	-	-	-	-	-	-	4.86	10.03	10.977
PERCENT SAVING	-	-	-	-	-	-	10%	21.1%	23.1%

Table A3-34

RIEGEL PLANT

LEVELIZED ANNUAL ENERGY COST ANALYSIS

COMMON CASE ECONOMIC PARAMETERS

COST ITEM MILLION $	LEVEL FACTOR	1988 COSTS IN 1981 DOLLARS						LEVELIZED COSTS IN NOMINAL $					
		BASE CASE	AFB/ST 600/750	AFB/ST 1250/900	AFB/GT 600/750	AFB/GT 900/825	AFB/GT 150/480	BASE CASE	AFB/ST 600/750	AFB/ST 1250/900	AFB/GT 600/750	AFB/GT 900/825	AFB/GT 150/480
CAPITAL COST	-	5.497	37.73	41.723	53.354	56.508	49.439	-	-	-	-	-	-
CAPITAL INVESTMENT	-	6.398	40.207	41.904	61.764	59.021	50.038	-	-	-	-	-	-
LEVEL CAPITAL INVESTMENT	.0772	-	-	-	-	-	-	.493	3.104	3.235	4.768	7.556	3.925
FUEL COST - GAS	1.416	6.342	-	-	-	-	-	8.98	-	-	-	-	-
FUEL COST - COAL	1.1148	-	3.401	3.257	4 .26	4.612	4.176	-	3.791	3.631	4.75	5.141	4.655
ELECTRIC PURCHASE	1.182	4.082	2.188	1.778	.180	-	1.037	4.825	2.587	2.102	.213	-	1.226
ELECTRIC BUY-BACK	1.182	-	-	-	-	(.397)	-	-	-	-	-	(.469)	-
STAND-BY	1.0	-	.356	.313	.318	.216	.103	-	-	-	-	-	-
SORBENT	1.0	-	.629	.748	.482	.524	.276	-	-	-	-	-	-
WASTE DISPOSAL	1.0	-	.174	.172	.163	.176	.151	-	-	-	-	-	-
UTILITIES, LABOR & MAINTENANCE	1.0	.416	1.84	1.985	2.259	2.348	2.163	-	-	-	-	-	-
INSURANCE & LOCAL TAXES	1.0	.192	1.206	1.389	1.853	1.963	1.717	-	-	-	-	-	-
SUM OF CONSTANT ANNUAL COSTS	1.0	.608	4.205	4.607	5.075	5.227	4.41	.608	4.205	4.607	5.075	5.227	4.41
LEVELIZED ANNUAL ENERGY COST (NOMINAL $)	-	-	-	-	-	-	-	14.906	13.687	13.575	14.806	14.455	14.216
LEVEL ANNUAL ENERGY COST SAVING	-	-	-	-	-	-	-	-	1.219	1.331	.10	.451	.69
PERCENT SAVING	-	-	-	-	-	-	-	-	8.1%	8.9%	0.7%	3%	4.6%

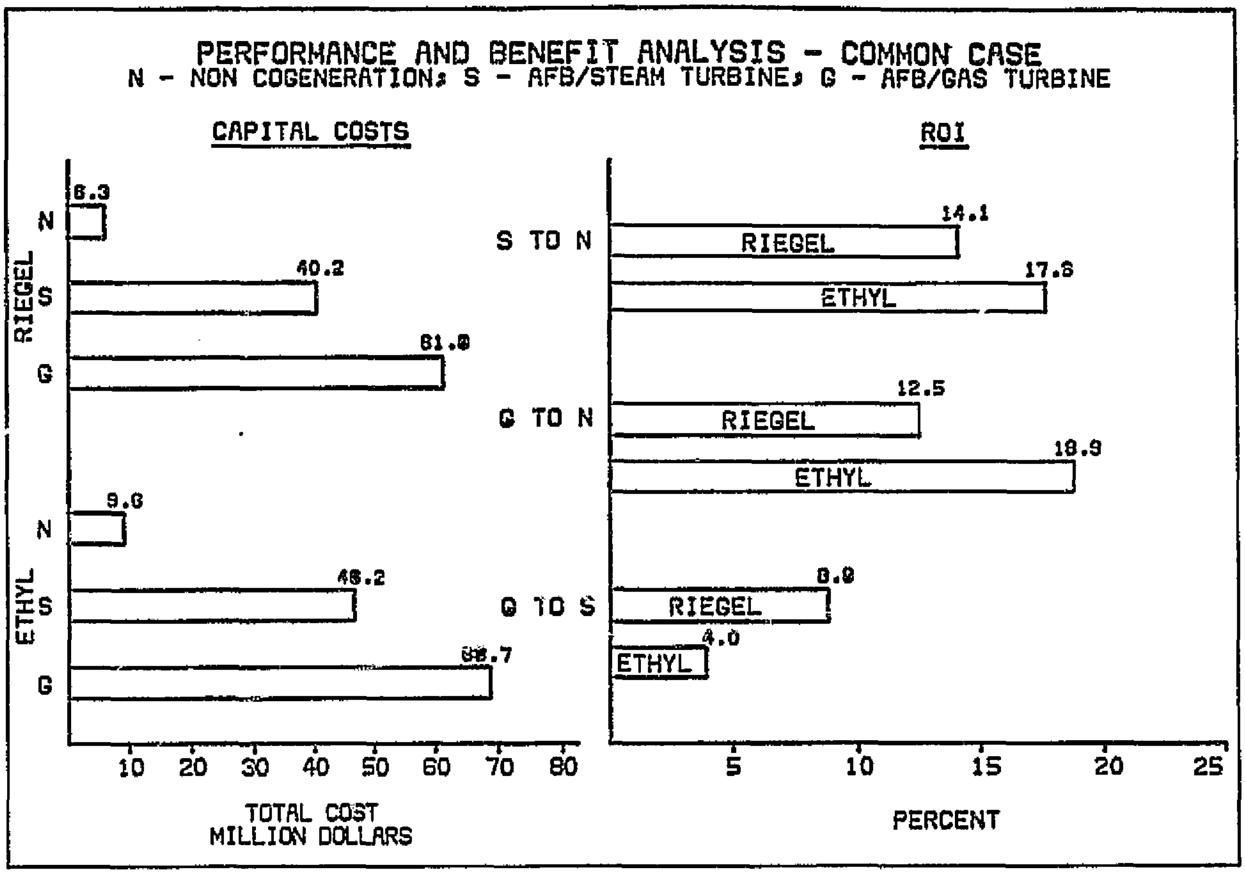

FIGURE A3-40

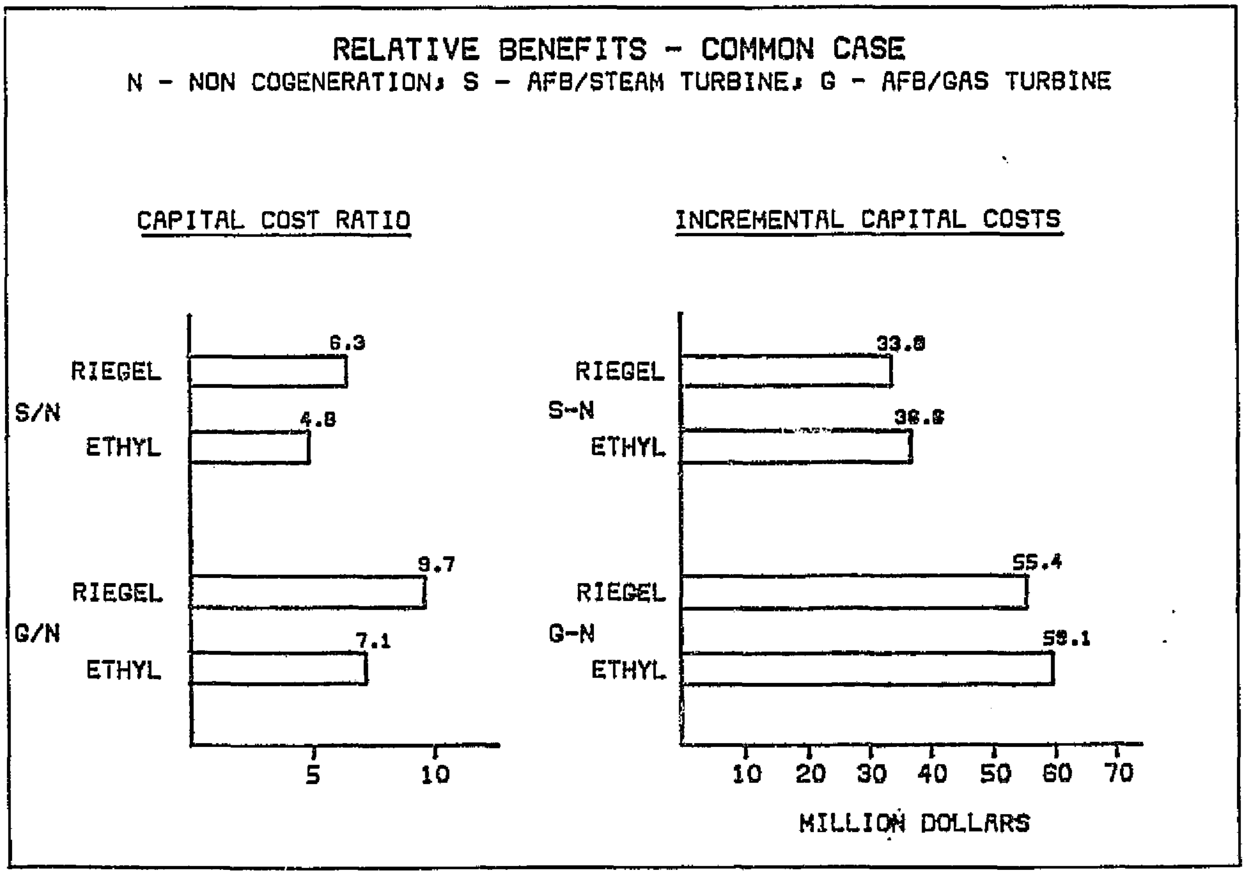

FIGURE A3-41

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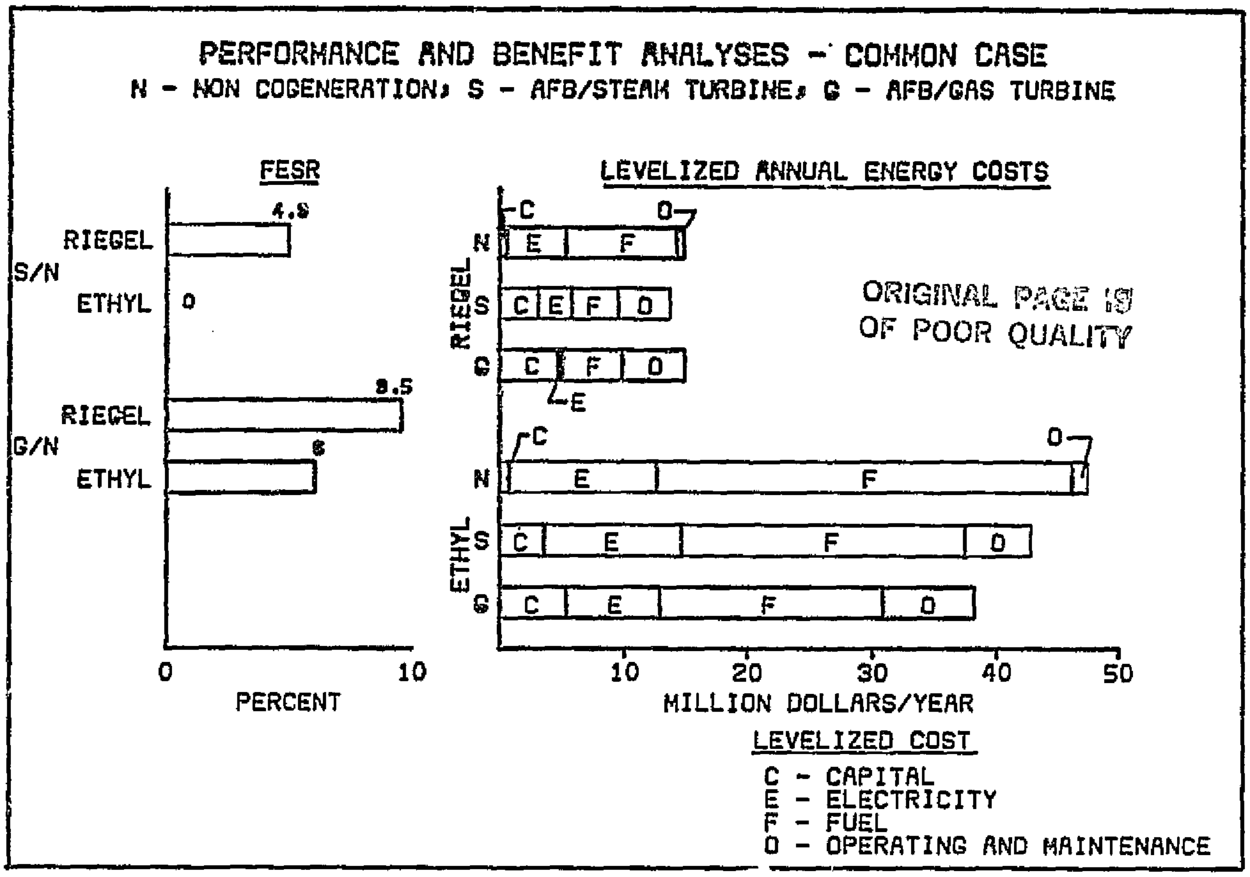

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FIGURE A3-42

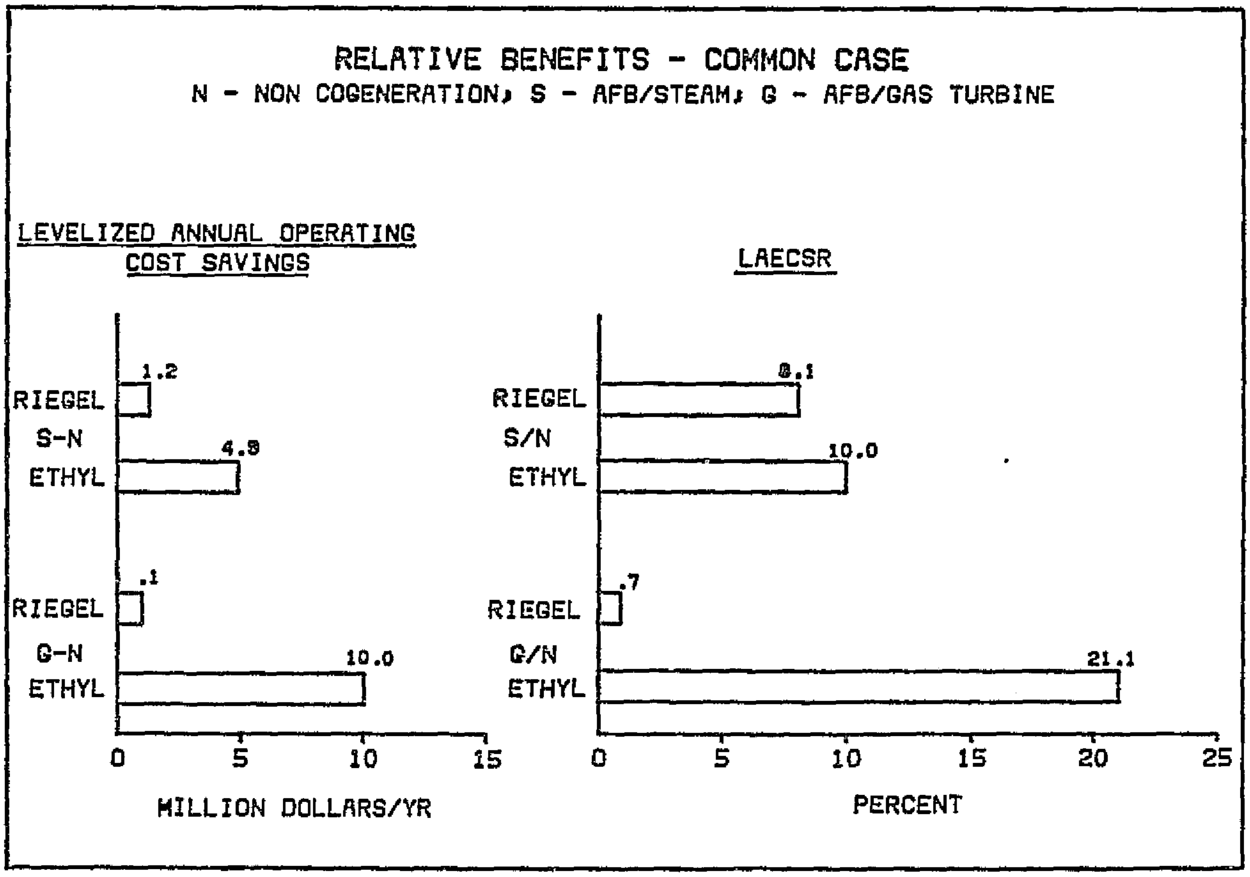

FIGURE A3-43

Restraints generic to coal-fired cogeneration are identified.

- o Larger capital investment.
- o Longer lead times required to develop a project.
- o The concept is directly competitive with existing energy sources and must vie with these alternatives in the open market.
- o Government rules and regulations still are not settled.

Some restraints against a particular technology:

- o The use of a "new" fuel - coal - introduces a degree of uncertainty to coal-fired technologies where industry has not previously used coal.
- o The atmospheric fluidized bed concept - particularly AFB/gas turbine technology - does not have a proven track record.

Institutional restraints pertaining to the two sites being compared are listed in Table A3-35.

Some of the numerous factors concerning coal use that affect the industrial user but are beyond its control and that act as driving forces in industry are:

- o Coal Cost

- o Coal Availability
  - -Uneven quality
  - -Poor infrastructure
  - -Poor service by suppliers

- o Government Energy Policy
  - -Fuel Use Act
  - -Cogeneration

- o Environmental Policies
  - -Clean Air Act
  - -SIP
  - -NSPS

Some of the items considered in the best site selection methodology are shown in Table A3-36.

Table A3-35: BEST SITE SELECTION METHODOLOGY

1. PLANT COMPATIBILITY - AFB GAS TURBINE
2. REPRESENTATION OF PLANTS NATIONWIDE
3. BENEFIT TO NATIONAL ENERGY CONSUMPTION
4 BENEFITS TO SIMILAR PLANTS
5. ACCEPTANCE OF COAL-FIRED COGENERATION CONCEPT
6. SITE COMPATIBILITY - AFB GAS TURBINE
7. GEOGRAPHIC LOCATION/CLIMATOLOGICAL CONDITIONS
8. ECONOMIC ATTRACTIVENESS, PROBABILITY OF SELECTION

Table A3-36: ASSESSMENT OF INSTITUTIONAL CONSTRAINTS

	RIEGEL	ETHYL
Economic Factors		
Large Capital Investment	Reluctance	Less Reluctance
Lack of Proven Track Record	Reluctance	Less Reluctance
General Economic Uncertainty	Severe Impact	Moderate Impact
Inflation Impact	Severe	Less Severe
Environmental		
Air	Attainment Area	Non-Attainment Area
Water	No Problem	No Problem
Solid Waste	Off-Site Disposal	Off-Site Disposal
Permit Problems	Complex	Moderate
Fuel Availability	Supply Source 350 mile distance	Supply Source 350 mile distance
Community Response	May Be Adverse	Probably Approving
Long Lead Time	Doubtful	Acceptable

3.6 GEORGIA-PACIFIC CORPORATION - LOVELL, WYOMING

3.6.1 Site Definition

A. Site Description

The Lovell plant of the Georgia-Pacific Corporation produces gypsum wallboard as its primary product. The plant is located in an isolated area in northern Wyoming adjacent to a source of gypsum. The Lovell plant has a "typical" product capacity of 100 feet per minute of 5/8-inch wallboard. The entire electric requirement is purchased from Pacific Power and Light Company. Thermal requirements are supplied by natural gas firing of various process heaters and dryers. Steam is not required in the manufacturing process for gypsum wallboard. Oil is used as the backup fuel supply. The electric to thermal ratio ($E/_T$) of the Lovell plant is 0.08, which is indicative of the high consumption of thermal energy required for this industry.

The current site requirements for the Lovell plant are summarized in Table A3-37. The estimated future average electric requirement of 1,300 kw and an average thermal requirement of 93 MM Btu/hr in the form of clean and dirty hot gases make this site an obvious candidate for the implementation of an AFB/gas turbine cogeneration system. The peak energy requirements are based on operation at 100% plant capacity. This condition is expected to be attained by the mid-1980s. Peak loads are taken at 20% above current design loads. Plant operation is characterized as continuous at a predetermined production level. Electric consumption for a typical 12 month period is steady. The natural gas consumption includes 3% for non-process heating. Wallboard drying requires 50% of the natural gas usage to produce hot air at 600°F. This hot air must be maintained free of particulate matter. The remaining process heating demands require hot gases at 1,500°F and 1,180°F, respectively. The particulate matter contained in the flue gas of an AFB system following mechanical cyclone solids removal is compatible with the process requirements.

The variation in both electrical and thermal load profiles with time is minimal. Current plant operation is 4 days per week - 24 hours per day; the mid-1980 level of operation is anticipated to be 6-2/3 days per week - 24 hours per day. In addition, the rate of production will increase by 12.4% with an increase in the rate of energy consumption.

The current plant operation at Lovell is very compatible with the AFB/gas turbine cogeneration system. No plant modifications were necesary or desirable to better fit the AFB/GT system at this site. Unscheduled energy shutdowns cause immediate loss of all plant production, although no physically unsafe or unhealthy condition appears apparent. Restart might take place over some days due to the need to remove damaged production goods. Unscheduled shutdowns of the cogeneration system would be minimized at the Lovell plant by maintaining standby electric supply with the utility and standby natural gas supply or oil storage, which is the present means of standby fuel supply. The capability of direct-firing of the process heater and dryers would be maintained throughout the plant. Land is readily available adjacent to the process plant. This land is partially used as a staging area for the rail transport of product and manufacturing goods. Site specific coal and limestone data is given with the field trip report.

B. Pacific Power and Light Company (PP&L)

A meeting was arranged with regional and local representatives of PP&L to evaluate the feasibility of cogeneration at the Lovell plant and the utility's philosophy toward cogeneration in general. Schedules were obtained which define the rate structure concerning the purchase of surplus energy, the rate structure for standby electricity supply and electric use rates. Table A3-38 provides a summary of the utility data. The buy-sell rates are based on avoided cost as detailed in the Public Utilities Regulatory and Policy Act of 1978. Rates for the purchase of electricity from a cogenerator are dependent upon availability. For firm supply, the capacity credit is $6.00/kw in 1981 and $8.00 to $8.50/kw estimated for 1987. For intermittent supply, the capacity credit has not been finalized. The electric usage rate is shown in Table A-3-38.

Table A3-37

PLANT SURVEY

GEORGIA-PACIFIC, INC. - GYPSUM PLANT - LOVELL, WYOMING

PRINCIPAL PRODUCT: GYPSUM WALLBOARD

SURVEY DATE: 7 OCTOBER 1981

PLANT AGE: 1960

OPERATING SCHEDULE: 6-2/3 DAYS/WEEK - 24 HOURS/DAY (ANTICIPATED 1985)

ENERGY REQUIREMENTS:

	ELECTRIC	HOT AIR	FUEL
UTILITY:	1.5 MW (AVG) - 2 MW (MAX)	50 MMBTU/HR (AVG) (CLEAN)	NATURAL GAS
IN-HOUSE:		30 MMBTU/HR (AVG) (DIRTY)	(DISTILLATE FUEL OIL)

UTILITY: PACIFIC POWER & LIGHT COMPANY (PP&L)

COAL SUPPLY: WESTERN COAL - LOW SULFUR @ 8,800 BTU/LB HHV
COAL CREEK MINING COMPANY; ASHLAND, MONTANA

SORBENT SUPPLY: LIMESTONE - ANL #8901
HOPPER BROTHERS QUARRY, WEEPING WATER, NEBR.*
(*LOCAL SUPPLY WITHIN 40 MILES)

POTENTIAL FOR COAL CONVERSION: EXCELLENT

RESTRICTIONS: SMALL PLANT SIZE

E/T $<<1$

Table A3-38 UTILITY SURVEY

GEORGIA-PACIFIC, INC. - GYPSUM PLANT - LOVELL, WYOMING

UTILITY: PACIFIC POWER & LIGHT COMPANY (PP&L)

COGENERATION RATE SCHEDULE: NEGOTIATED; NON-RACHET

COGENERATION SALES RATE:

AVERAGE ON-PEAK	25 MILLS
AVERAGE OFF-PEAK	16 MILLS
STANDBY CHARGE	$1.31/KW/MONTH

PEAK SCHEDULE: 6 AM TO 10 PM, MONDAY THROUGH FRIDAY

UTILITY FUEL SUPPLY: LOW SULFUR, WESTERN COAL (100%)

SUPPORT FINANCING: NOT LIKELY

UTILITY POSITION: ENCOURAGES LONG-TERM, FIRM SUPPLY COGENERATION PROJECTS SUCH AS PULP AND PAPER PLANTS.

All of the Wyoming regional power generating stations are coal-fired with coal supplied from nearby Wyoming-Montana mines. The coal has a lower heating value of 8,000 Btu/lb and a sulfur content of 0.5 to 1.0%. Current electric rates for the existing coal-fired generating stations is about 3¢/kw hr. This is due primarily to higher capital charges and the operating constraints of a power station located in an area of limited water supply. Emission guidelines for the utility are under the jurisdiction of the Wyoming Department of Environmental Quality.

PP&L has no interest in ownership options in cogeneration facilities due to the scarcity of capital within PP&L. However, the utility does not reject the possibility of ownership options under favorable conditions. As an example, PP&L is currently involved in an ownership arrangement with a Weyerhaeuser linerboard plant in Springfield, Oregon. A turbine generator, owned by PP&L, generates electricity from high pressure steam and then passes the lower pressure steam on to the process area. A power sales agreement was signed between the utility and three cities in California. The negotiations began late in 1974 and the plant started up in the Fall of 1976. The single most difficult hurdle in these negotiations was receiving approval from the EPA. Although State and County approval was obtained, the EPA approval delayed the project by four months.

There are currently five cogenerators in the Wyoming region. Three plants are involved in the production of soda ash and are cogenerating at a rate of 5,000 to 15,000 kw of electricity. There are no utility ownership options involved in these industrial sites. The general policy of the PP&L utility is favorable to industrial cogeneration plants in the Wyoming region. Long line distances to isolated industrial users, such as the Lovell plant, enhance the appeal of on-site power generation.

3.6.2 Gas Turbine Cogeneration System

With hot air leaving the kettles at 750°F, recapture of this waste heat is even now of considerable interest to Georgia-Pacific. No use of steam for direct process use is considered practical. Even with cogeneration, the use of gas fired burners as in the present installation would be needed for supplemental and/or backup firing, and one AFB/gas turbine would be used.

A thermal balance is possible, as shown in Figure A3-44, with the AFB flue gas going to the mills and kettles. The flue gas from the kettles, being 750°F, passes through an air preheater prior to being cleaned. The forced draft air to the AFB is preheated. Because clean drying air need not exceed 600°F, a regenerator can be effectively provided at the outlet of the gas turbine to preheat the gas turbine compressed air. The result is a combined cycle unit providing over 2 MM excess electricity for sale to the electric utility. Even with the wet, low sulfur coal and no need for steam, the AFB/gas turbine shows simplicity, readily providing a thermal match and generating excess electricity. The mass and energy balance is shown in Table A3-39 and the process flow data in Table A3-40.

3.6.3 AFB/Steam Turbine Cogeneration System

This cycle is not sufficiently flexible to readily provide a viable cogeneration system. An arrangement is shown in Figure A3-45, with one AFB at full rating and gas burners providing backup. The cycle utilizes the hot flue gases at the mills and kettles with supplemental gas firing. A closed steam loop with straight condensing type turbine generator produces electricity. No cooling water can be considered available for condensing purposes; air-cooled condensers are needed. Some of the heated air from the air-cooled condenser is further heated by the hot flue gas exiting from the kettles. Supplemental firing of the clean air is still required before use for drying wallboard. The sequential generation of electricity and use of the condenser cooking air constitute the cogeneration feature of this plant. Consideration was given to using an AFB only as a hot flue gas source, but this was ruled out as not being a cogeneration cycle.

3.7 HERCULES INCORPORATED - COVINGTON, VIRGINIA

3.7.1 Site Definition

A. Site Description

The Hercules-Covington plant produces polypropylene films. A recent fire destroyed the fiber production facilities, reducing its operating requirements by 50 percent. The polypropylene films are used in tobacco and food packaging. Most of the electric power requirement is purchased from Virginia Electric and Power Company (VEPCO) except for a small diesel generator which is used for peak sharing purposes. Thermal requirements include steam for process requirements and area heating and hot air for film drying. The plant currently uses natural gas as the primary fuel with oil used only as a standby fuel supply.

AIR CYCLE AFB COGENERATION SYSTEM

GEORGIA PACIFIC SITE

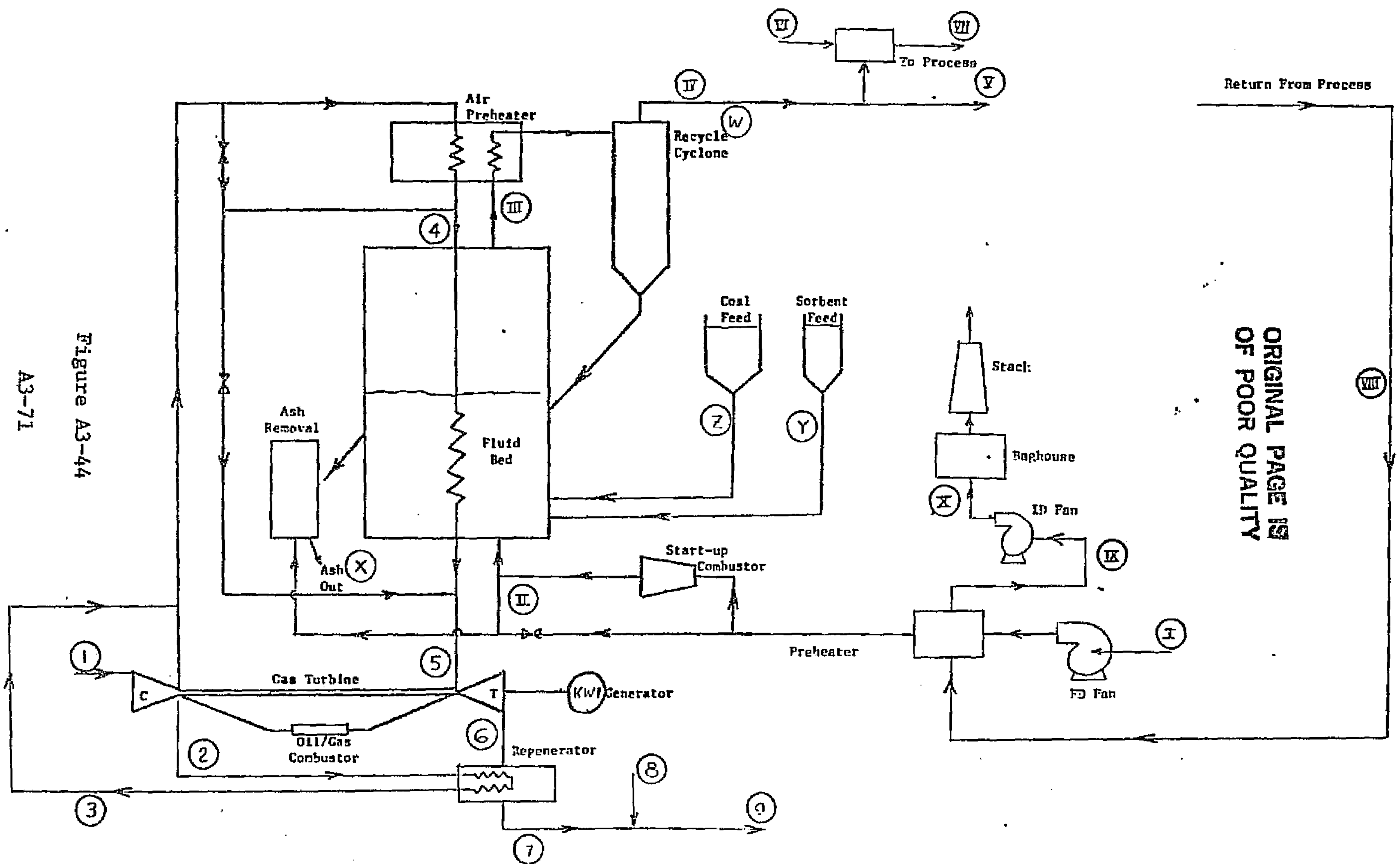

Figure A3-44

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Table A3-39

AIR CYCLE AFB COGENERATION SYSTEM
MASS AND ENERGY BALANCE

GEORGIA PACIFIC PLANT

	Mass Pounds/Hour	Energy Million Btu/Hr	%	Electricity KW
Feeds				
Coal, (as delivered)	15137	133.04		
Limestone, #8901	950	-.34		
Clean Air, 45°F Gas Turbine	358560	0.0		
Clean Air, 45°F Diluent C.A.	120166	0.0		
Clean Air, 45°F Diluent F.G.	3398	0.0		
Fluidizing Air	138060	0.0		
	636271	132.70	100.0	
Products				
Clean Air, 600°F(Dryer/Kilns)	478726	65.10		
Flue Gas, 1500°F - 750°F (Kettles)	141791	28.50*		
Flue Gas, 1100°F (Mills)	13000	3.50		
Solids Off-Take	1059	.43		
Flyash	530	.22		
	635106	97.75	73.7	
Electrical				
Gas Turbine, Gross		18.51		5425
Forced Draft Fan		+ 2.67		+ 784
Induced Draft Fan		+ 1.05		+ 308
Net		14.79	11.2	4333
Losses				
Water Vapor - Coal Dryer	1165	-		
Flue Gas Stack, 283°F-45°F		8.12		
Combustion Process, HHV - LHV		5.36		
98% Comb. Eff.		2.66		
Gas Turbine Generator + Gear Box Losses		1.21		
Unaccounted		2.81		
		20.16	15.1	
	636271	132.70	100.0	

*750°F flow returns to system

Table A3-40

AIR AFB COGENERATION SYSTEM
GEORGIA PACIFIC SITE
PROCESS FLOW DATA

CLEAN AIR CIRCUIT

	1	2	3	4	5	6	7	8	9
W	358560	350424	350424	350424	358560	358560	358560	120166	478726
P	12.7	-	83.5	82.5	80.5	14.1	13.4	12.7	13.06
T	45	459	590	660	1505	896	786	45	600

COMBUSTION AIR CIRCUIT

	I	II	III	IV	V	VI	VII	VIII	IX	X
W	138060	138060	151393	151393	141791	3598	13000	141791	141791	141261
P	12.7	16.9	12.7	12.34	12.34	12.7	12.34	11.98	11.62	12.7
T	45	630	1650	1510	1500	45	1100	750	255	283

SOLIDS FLOW

	Z	Y	X	W
W	15137	950	1059	530

ELECTRIC OUTPUT

KW1 4330

W = Flow Rate, Pounds Per Hour
P = Pressure, PSIA for Air Circuits, PSIG for Steam
T = Temperature, °F
KW = Net Electrical Output, Kilowatts

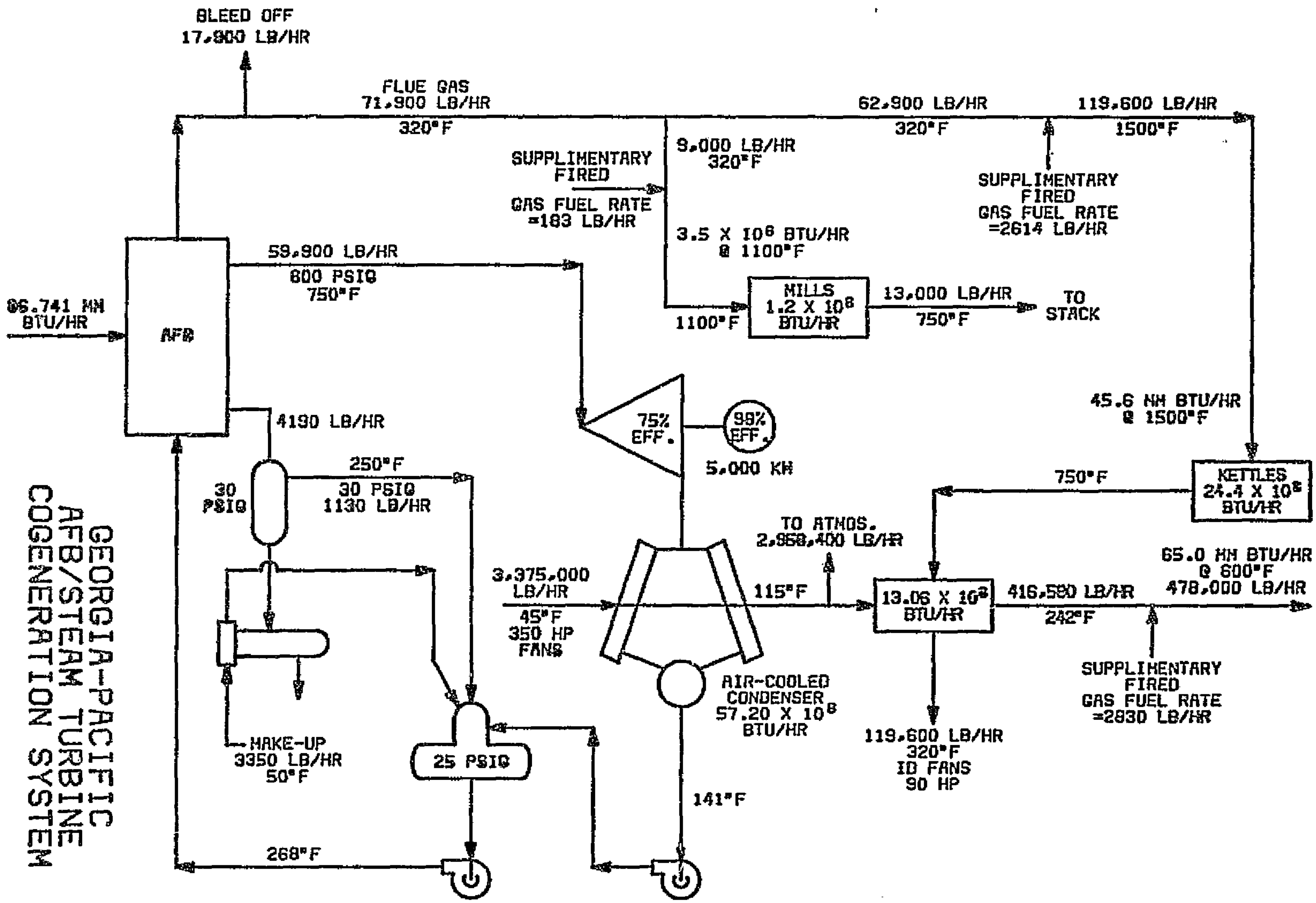

FIGURE A3-45

GEORGIA-PACIFIC
AFB/STEAM TURBINE
COGENERATION SYSTEM

The electric to thermal ($E/_T$) ratio for the Covington plant is 1.05, typical of an industry primarily dependent upon electrical energy. Thermal energy requirements at the plant are seasonal, increasing significantly during the winter months due to steam demand for area heating.

The site requirements for the Covington plant are summarized in Table A3-41. The average electric requirement of 8,500 kw and an average thermal requirement of 27 MM Btu/hr in the form of 100 psig steam and clean hot gases (10%). The normal steam rate is 18,000 lbs/hr with a seasonal peak of 38,000 lbs/hr in the winter months. The small, widely varying steam load does not lend itself to cogeneration. Plant operation is characterized as continuous, 24 hours per day - 365 days per year. Electric consumption for the Covington plant is quite steady. Variations in the steam load occur in the area of 3,000 lbs/hr. The amount of gas required for film drying averages 3 MM Btu/hr.

The variation in electric demand is minimal throughout the year; however, steam demand has a significant increase during the winter months. The current rate of operation is not expected to change during the mid-1980s. Electric load swings of 1,000 kw are normal during plant operations, with peak sharing of electrical loads by the diesel generator.

Due to the high electric to thermal ratio, there exist possible modifications at the Covington plant which would benefit from cogeneration. Several large electric motors with continuous duty can be changed to turbine drives powered by the cogeneration steam supply. Three candidate areas have been identified; two air compressors and two chillers in the powerhouse area with on-line horsepower requirements of 450 HP and 400 HP respectively for each motor. In the process area there exist three extruders with an on-line horsepower requirement of 600 HP each.

Existing steam generators would be maintained as backup for the cogeneration system. The Covington plant still has space and storage provisions for a coal-fired system. The plant did burn coal up to 1960 and remnants of the coal feeders and floor areas exist within the boilerhouse. Area adjacent to the existing boilerhouse is available for a new cogeneration system. Site specific coal and limestone data is given in the rear of this Appendix.

The Covington plant requires 100% electric availability and 60% steam availability for process equipment. The need for a firm supply of electricity and the prevailing rate structure for electricity place a heavy burden on the cogeneration system. Unscheduled shutdowns would cripple the plant because of the numerous electric motors.

B. Virginia Electric and Power Company (VEPCO)

A meeting was arranged with regional and local representatives of VEPCO to evaluate the feasibility of cogeneration at the Covington plant and the utility's philosophy toward cogeneration in general. Schedules were obtained which define the rate structure concerning the purchase of surplus energy, the rate structure for standby electricity supply and electric use rates. Table A3-42 provides a summary of the utility data. The buy-sell rates are based on avoided cost as detailed in the Public Utilities Regulatory and Policy Act of 1978. Rates for the purchase of electricity from a cogenerator are dependent upon on-peak or off-peak generation. The average of 1981 and 1982 avoided costs are 5.203¢/kw hr on-peak and 3.132¢/kw hr off-peak. On-peak is from 0700 to 2200 hours Monday through Friday with off-peak being all other times.

The VEPCO regional power generating stations are primarily nuclear and coal-fired. The present fraction of nuclear power is 45% and is expected to rise to 52%. Coal is typically supplied from Kentucky and West Virginia. Approximately 5% of the generating capacity is derived from oil and 1% from natural gas when available. The installed capacity of VEPCO is 11,154 MW with an actual generation of 8,500 MW in 1980.

Emission guidelines for the utility are controlled primarily by the Commonwealth of Virginia; however, one generating station is under West Virginia state regulations. The new source limitations under Virginia regulations are 2.64 pounds of sulfur/MM Btu and 0.10 pound of particulate/MM Btu.

VEPCO has no interest in ownership options in cogeneration facilities due to a prohibition from joint ventures with industry mandated by Virginia law #19.1-2.1.

Table A3-41

PLANT SURVEY

HERCULES, INC. - FORSTER PLANT - COVINGTON, VIRGINIA

PRINCIPAL PRODUCT: POLYPROPYLENE FILM

SURVEY DATE: 12 OCTOBER 1981

PLANT AGE: 1940

OPERATING SCHEDULE: 7 DAYS/WEEK - 24 HOURS/DAY

ENERGY REQUIREMENTS:

	ELECTRIC	STEAM	FUEL
UTILITY:	9 MW (AVG.) - 10 MW (MAX.)		
IN-HOUSE:	1 MW (DIESEL)	38,000 LB/HR (MAX) 100 PSIG D&S 15 PSIG	NATURAL GAS (STEAM) RESIDUAL OIL (DIESEL)

UTILITY: VIRGINIA ELECTRIC & POWER COMPANY (VEPCO)

COAL SUPPLY: PITTSBURGH SEAM - HIGH SULFUR @ 13,000 BTU/LB HHV
CARBONFIELD COAL COMPANY, CHARLESTON, W. VA.

SORBENT SUPPLY: LIMESTONE - ANL #9501
GROVE LIME COMPANY, STEPHENS CITY, VA.

POTENTIAL FOR COAL CONVERSION: GOOD

RESTRICTIONS: LOW THERMAL ENERGY REQUIREMENT
SMALL PLANT SIZE
LARGE SEASONAL VARIATIONS IN THERMAL LOAD

E/T $>$ 1

Table A3-42 UTILITY SURVEY

HERCULES, INC. - FORSTER PLANT - COVINGTON, VIRGINIA

UTILITY: VIRGINIA ELECTRIC POWER COMPANY (VEPCO)

COGENERATION RATE SCHEDULE: NEGOTIATED - RACHET

COGENERATION SALES RATE:

AVERAGE ON-PEAK	53.4 MILLS
AVERAGE OFF-PEAK	30.9 MILLS
STANDBY CHARGE	$9.02/KW/MONTH

PEAK SCHEDULE: 7 AM TO 10 PM, MONDAY THROUGH FRIDAY

UTILITY FUEL SUPPLY:

NUCLEAR	45%
COAL	40%
OIL/NATURAL GAS	REMAINDER

SUPPORT FINANCING: NOT LIKELY

UTILITY POSITION: ENCOURAGES LONG-TERM - FIRM SUPPLY
COGENERATION PROJECTS SUCH AS PULP AND PAPER
PLANTS.

Currently there are 25 cogeneration systems in the VEPCO region in the range of 300 to 127,000 kw. Papermills are typically the large cogenerators. Schedule #19 has been developed by VEPCO to cover all cogenerators greater than 100 kw. In addition, a set of relay protection guidelines has been developed for parallel generation and/or synchronous motors by VEPCO.

The single most difficult hurdle for the Covington plant to overcome is the electric use rate which is based on a "rachet" type schedule. This schedule would require a base billing rate in accordance with a peak annual electric use rate. Therefore, any downtime or unscheduled outage requiring backup electricity in large quantities from the utility would result in excessive electric charges from the utility over the entire year period. The Covington plant regularly uses a 700 kw diesel generator for peak-sharing purposes in its current operating mode.

3.7.2 AFB/Gas Turbine Cogeneration System

Three cycles have been prepared by Curtiss-Wright. Cycle 1, for a single AFB unit, shown in Figure A3-46 and Tables A3-43 and A3-44, provides only 18,000 lbs/hr steam. Cycle 2, consisting of two modules, shown in Figure A3-47 and Tables A3-45 and A3-46, is a combined cycle system with double extraction-condensing steam turbine generator providing entire plant steam requirements year-round. A significant quantity of steam, about 35,000 lbs/hr, is condensed even in the winter. Cycle 3, consisting of three modules, is shown in Figure A3-47 and Tables A3-47 and A3-48. Like Cycle 2, it is a combined cycle unit, but is overall a smaller system since only a small quantity of steam is condensed during the winter.

AIR CYCLE AFB COGENERATION SYSTEM

HERCULES PLANT - CYCLE 1

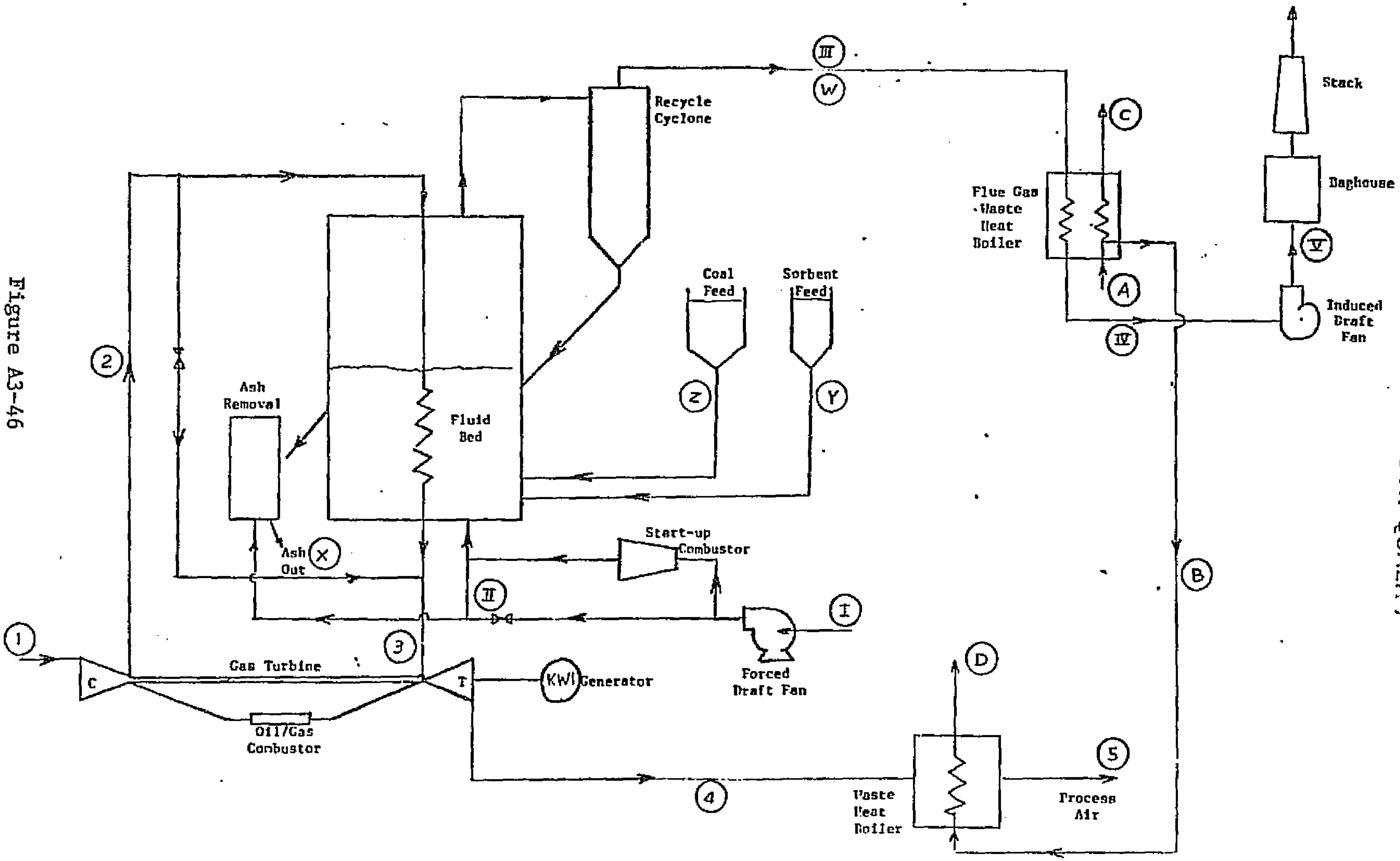

Figure A3-46

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Table A3-43

AIR CYCLE AFB COGENERATION SYSTEM
MASS AND ENERGY BALANCE

HERCULES PLANT - CYCLE 1

	Mass Pounds/Hour	Energy Million Btu/Hr	%	Electricity KW
Feeds				
Coal (as delivered)	2444	30.18		
Limestone, #9501	612	0.00		
Clean Air, 59°F	47186	0.00		
Fluidizing Air, 59°F	37224	0.00		
Feedwater, 238°F	18000	3.71		
	105466	33.89	100.0	
Products				
Flue Gas, Stack - 300°F	39578	- 2.23		
Clean Air, (575°F-250°F)	47186	- 3.76		
Steam (100 Psia Sat.)	18000	-21.31		
Solids Off-Take	468	- .20		
Flyash	234	- .10		
		27.60	81.4	
Electrical				
Gas Turbine, Gross		-2.72		- 798
Forced Draft Fan		+ .51		+ 150
Induced Draft Fan		+ .11		+ 31
Net		2.10	6.2	617
Losses				
Generator & Gear Box Losses		.19		
Clean Air, 250°F (Process Loss)		2.16		
Combustion Process,				
HHV - LHV		1.13		
98% Comb. Eff.		.60		
Cleanup System, 1650-1640		.11		
		4.19	12.4	
	105466	33.89	100.0	

Table A3-44

AIR AFB COGENERATION SYSTEM
HERCULES PLANT - CYCLE 1
PROCESS FLOW DATA

One of Two Duplicate Plants

CLEAN AIR CIRCUIT

	1	2	3	4	5
W	47186	47186	47186	47186	47186
P	14.1	87.4	83.0	14.8	14.45
T	59	475	1450	830	575

COMBUSTION AIR CIRCUIT

	I	II	III	IV	V
W	37224	37224	39600	39600	39366
P	14.1	18.3	14.0	13.6	14.1
T	59	130	1640	300	310

SOLIDS FLOW

	Z	Y	X	W
W	2444	612	468	234

STEAM CIRCUIT

	A	B	C	D
W	18000	3540	14460	3540
P	9	100	115	115
T	238	338	338	338

ELECTRIC

KW1 617

W = Flow Rate, Pounds Per Hour
P = Pressure, PSIA for Air Circuits, PSIG for Steam
T = Temperature, °F
KW = Net Electrical Output, Kilowatts

AIR CYCLE AFB COGENERATION SYSTEM

HERCULES PLANT

CYCLES 2 & 3

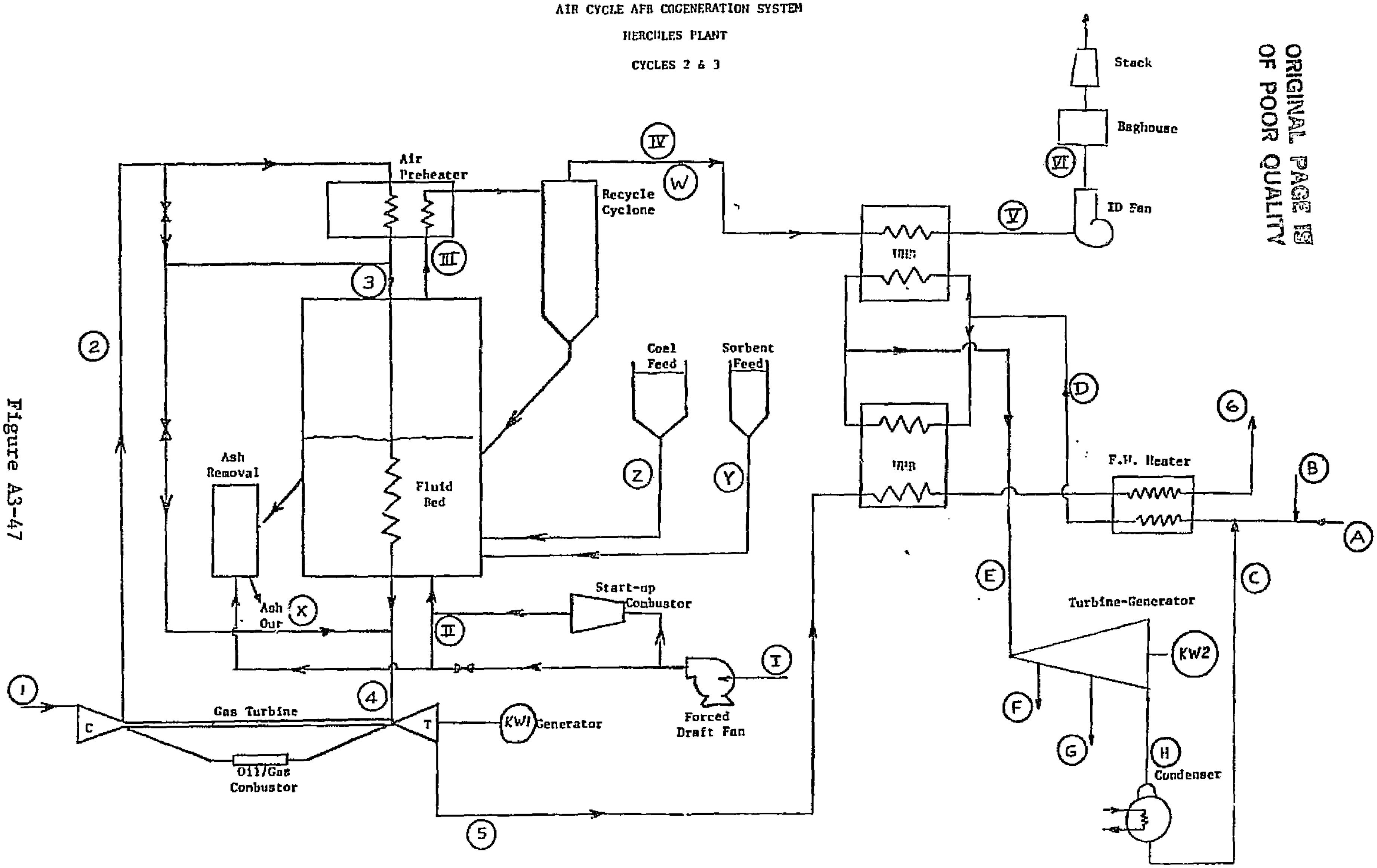

Figure A3-47

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Table A3-45

AIR CYCLE AFB COGENERATION SYSTEM
MASS AND ENERGY BALANCE

HERCULES PLANT - CYCLE 2

	Mass Pounds/Hour	Energy Million Btu/Hr	%	Electricity KW
Feeds				
Coal, (as delivered)	12118	149.66		
Limestone, #9501	3031	0.0		
Clean Air	332000	0.0		
Fluidizing Air	154800	0.0		
Feedwater (Process) 212°F	28000	4.26		
(Make-up) 60°F	12000	0.0		
(Condensate) 120°F	35000	2.10		
	576949	156.02	100.0	
Products				
Stack Clean Air, 205°F	332000	11.59		
Stack Flue Gas, 518°F	166536	18.63		
Solids Off-Take	2275	.94		
Flyash	1138	.47		
Steam, 100 psig/437°F	12000	14.60		
Steam, 15 psig/265°F	28000	32.02		
Wet Steam, 3.5 In.Hg.ABS, 120°F	35000	35.75		
	576949	114.00	73.1	
Electrical				
Gas Turbine, Gross		-16.40		-4800
Forced Draft Fan		+ 2.53		+ 740
Induced Draft Fan		+ .84		+ 246
Steam Turbine, Net		-15.70		4600
Total Electrical, Net		28.73	18.4	8414
Losses				
Feedwater + Economizer Heat, 1%		.24		
Evaporator + Superheat, 2%		1.36		
Combustion Process,				
HHV - LHV		5.65		
98% Comb. Eff.		2.88		
Gas Turbine Gear Box + Generator Losses		2.25		
Unaccounted		.91		
		13.29	8.5	
		156.02	100.0	

Table A3-46

AIR AFB COGENERATION SYSTEM
HERCULES PLANT - CYCLE 2
PROCESS FLOW DATA

CLEAN AIR CIRCUIT [1]

	1	2	3	4	5	6	7
W	332000	332000	332000	332000	332000	332000	332000
P	14.09	85.67	84.87	82.78	14.45	-	14.09
T	59	514	703	1500	873	498	205

COMBUSTION AIR CIRCUIT [1]

	I	II	III	IV	V	VI
W	154800	154800	166536	166536	166536	166398
P	14.09	18.22	14.09	13.73	13.37	14.09
T	59	130	1650	1328	498	518

SOLIDS FLOW [1]

	Z	Y	X	W
W	12118	3031	2275	1138

STEAM CIRCUIT

	A	B	C	D	E	F	G	H
A	12000	28000	35000	75000	75000	12000	28000	35000
P	-	-	-	400	400	100	15	3.5"Hg
T	60	212	120	145	650	437	265	120

ELECTRICAL OUTPUT

KW1 [1]	3814
KW2	4600
Total -	8414

Note 1 - Values shown are for two combustor/gas turbine units with output to a single boiler system

W = Flow Rate, Pounds Per Hour
P = Pressure, PSIA for Air Circuits, PSIG for Steam
T = Temperature, °F
KW = Net Electrical Output, Kilowatts

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Table A3-47

AIR CYCLE AFB COGENERATION SYSTEM
MASS AND ENERGY BALANCE

HERCULES PLANT - CYCLE 3

	Mass Pounds/Hour	Energy Million Btu/Hr	%	Electricity KW
Feeds				
Coal, (as delivered)	9238	114.08		
Limestone, #9501	2311	0.0		
Clean Air	332000	0.0		
Fluidizing Air	121104	0.0		
Feedwater (Process) 212°F	28000	4.26		
(Make-up) 60°F	12000	0.0		
(Condensate) 120°F	3000	0.18		
	507653	118.52	100.0	
Products				
Stack Clean Air, 340°F	332000	22.35		
Stack Flue Gas, 518°F	130032	14.47		
Solids Off-Take	1747	.72		
Flyash	874	.36		
Steam, 100 psig/437°F	12000	14.60		
Steam, 15 psig/265°F	28000	32.02		
Net Steam, 3.5 In.Hg.ABS, 120°F	3000	3.15		
	507653	87.67	74.0	
Electrical				
Gas Turbine, Gross		-16.40		-4800
Forced Draft Fan		+ 1.92		+ 564
Induced Draft Fan		+ .71		+ 207
Steam Turbine, Net		- 6.51		1907
Total Electrical, Net		20.28	17.1	5936
Losses				
Feedwater + Economizer Heat, 1%		.13		
Evaporator + Superheat, 2%		.78		
Combustion Process,				
HHV - LHV		4.30		
98% Comb. Eff.		2.28		
Gas Turbine Gear Box + Generator Losses		2.25		
Unaccounted		.83		
		10.57	8.9	
		118.52	100.0	

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AIR AFB COGENERATION SYSTEM
HERCULES PLANT - CYCLE 3
PROCESS FLOW DATA

Table A3-48

CLEAN AIR CIRCUIT[1]

	1	2	3	4	5	6	7
W	332000	332000	332000	332000	332000	332000	332000
P	14.09	85.67	84.87	81.81	14.45	-	14.09
T	59	514	909	1500	752	498	340

COMBUSTION AIR CIRCUIT[1]

	I	II	III	IV	V	VI
W	121104	121104	130032	130032	130032	129158
P	14.09	18.11	14.09	13.73	13.37	14.09
T	59	130	1650	735	498	518

SOLIDS FLOW[1]

	Z	Y	X	W
W	9238	2311	1747	874

STEAM CIRCUIT

	A	B	C	D	E	F	G	H
W	12000	28000	3000	43000	43000	12000	28000	30000
P	-	-	-	10	400	100	15	3.5"Hg
T	60	212	120	238	650	437	265	120

ELECTRICAL OUTPUT

KW1[1] 4030
KW2 1910
Total-5940

Note 1 - Values shown are for two combustor/gas turbine units with output to a single boiler system

W = Flow Rate, Pounds Per Hour
P = Pressure, PSIA for Air Circuits, PSIG for Steam
T = Temperature, °F
KW = Net Electrical Output, Kilowatts

3.7.3 AFB/Steam Turbine Cogeneration System

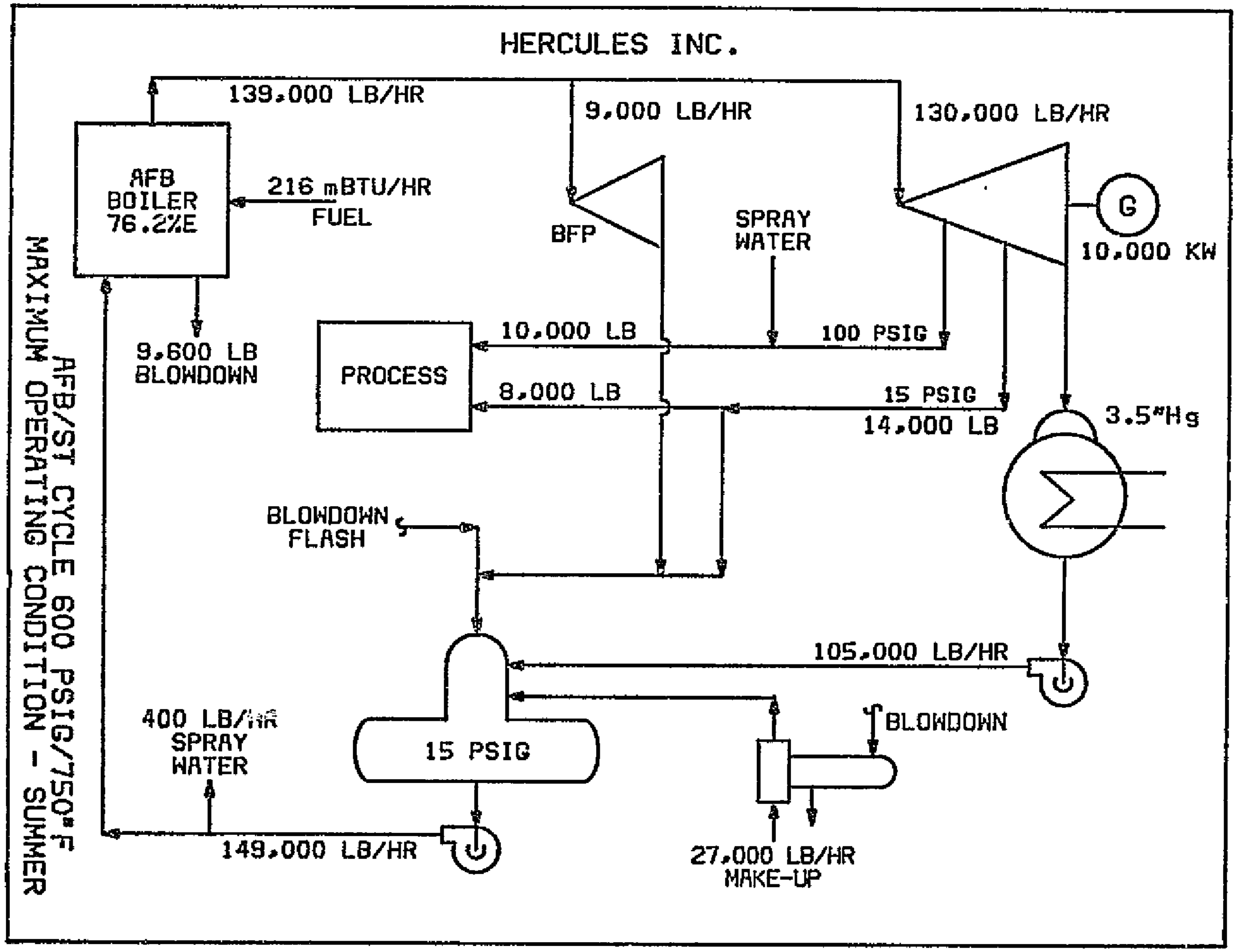
As shown for two of the gas turbine cycles, employing a condensing type steam turbine generator accommodates the large seasonal fluctuations in plant thermal requirements. Two strategies are employed for sizing the condenser steam flow:

- Winter steam production results in minimum flow to the condenser. Summer steam production gives maximum condenser steam flow. A year-round thermal match is provided with only a small quantity of steam generated in the winter. Cycle 3 of the AFB/gas turbine cases also uses this approach.

- Provide for high electrical output with an electric match even in the winter, resulting in considerable steam condensed in the winter. The even electric production results in a smaller percentage reduction in steam production between summer and winter. Cycle 2 of the AFB/gas turbine cases also uses this approach.

Figure A3-48 shows the basic cycle as discussed above, whereby winter steam production results in significant flow to the condenser . Table A3-49 gives the calculated performance data for the two cases operating in summer and winter. The table shows greater year-round steam generation to maximize electric generation.

AFB boiler performance is derived from data provided by Dorr-Oliver/Keeler shown in Tables A3-50 I and II, adjusted for the steam conditions finally selected. Physical appearance of the boiler is shown in Figures A3-49 and A3-50.



AFB/ST CYCLE 600 PSIG/750°F
MAXIMUM OPERATING CONDITION - SUMMER

FIGURE A3-48

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Table A3-49: CALCULATED PERFORMANCE DATA

FLOW DIAGRAM	A WINTER	B SUMMER	C WINTER	D SUMMER
BOILER STEAM #/HR	46,273	46,273	145,939	139,300
HEAT INPUT TO BOILER MM BTU/HR	71.581	71.581	225.757	215.796
OVERALL PLANT HEAT RATE BTU/KW HR	35,366	26,571	22,576	21,580
T/G THROTTLE FLOW #/HR	43,017	43,017	136,616	130,097
100PSI EXTRACTION KW	400	333	400	333
FLOW #/HR	11,519	9,597	11,516	9,597
15PSI EXTRACTION KW	1,552	582	1,552	333
FLOW #/HR	28,000	10,500	28,000	9,597
CONDENSER KW	179	1,921	8,574	9,417
FLOW #/HR	2,000	21,420	95,600	10,500
KW HR NET GENERATED	2,024	2,024	10,000	10,000
BOILERHOUSE	2,342	2,342	7,387	7,061
LOSES #/HR	500	500	500	500
BLD-VENT-T/6	1,500	1,500	1,500	1,500
PROCESS USE 100 PSI & 15 PSI	12,000	10,000	12,000	10,000
#/HR	24,675	8,000	21,347	8,000
MAKEUP #/HR	41,071	22,342	42,734	27,061
BF PUMP HP	110 HP	110 HP	315 HP	310 HP
STEAM FLOW	3,256 #	3,256 #	9,323 #	9,203 #

Table A3-50I HERCULES, INCORPORATED

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Site Data

Steam demand @ 650 psig/750°F TT:	
Peak	49,600 pph
Minimum	25,000 pph
Load change	1,500 pph = 25 lb/min or 0.05% of MCR/min
Turn-down	50%
Coal to be used:	West Virginia (Pittsburgh seam) high sulfur 13,500 Btu/lb
Hydrogen	5.0%
Carbon	75.0%
Nitrogen	1.5%
Oxygen	6.7%
Sulfur	2.3%
Ash	7.0%
Water	2.5%
Altitude	1,220 ft AMSL
Limestone to be used:	Argonne No. 9501
$CaCO_3$	95.3%
$MgCO_3$	1.3%
Inerts	3.4%
Water	None

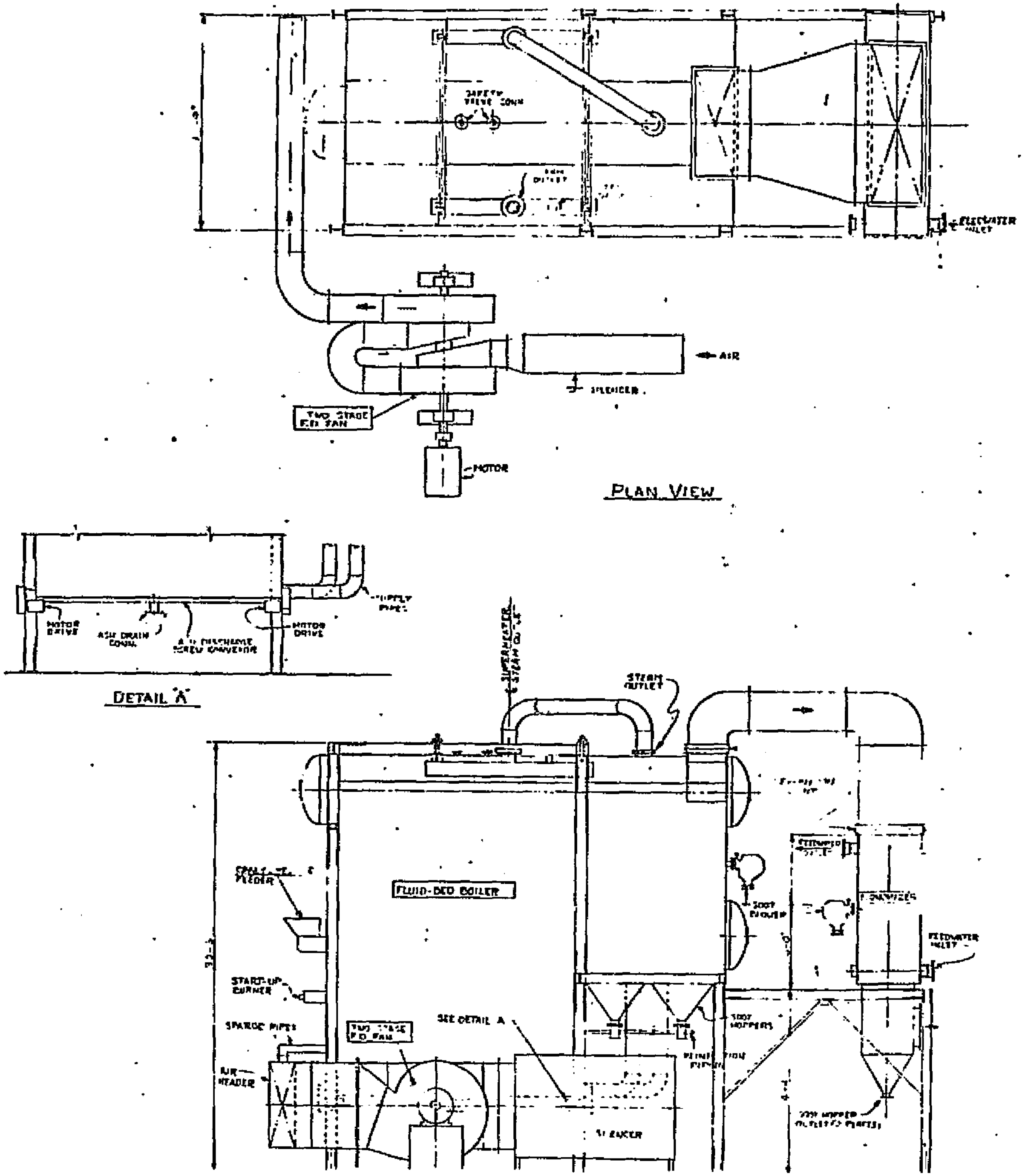
Table A3-50II

Performance Data

Steam generation rate	50,000 pph
Air inlet temperature	70°F
Economizer outlet (gas) temperature	350°F
Combustion efficiency	95%
Ca/S mol ratio	6:1
Sulfur capture	90%
Excess air for combustion	20%
Dust loading to baghouse	6 gr/SCF
Boiler efficiency	76.2%
Coal feed rate	5,630 pph
Limestone feed rate	2,545 pph
Bottom ash rate	1,570 pph
Fly ash rate	580 pph
Boiler feedwater temperature	238°F
Ash discharge temperature	600°F
Fluid bed depth (fluidized)	4.5 ft

Equipment Selection

1 - 50,000 pph AFB boiler, 700 psig. pressure rating	
Turn-down capability	15%
Auxiliary equipment:	
FD fan (test block) with 400 HP motor	83,200 pph @ 91"HG
ID fan (test block) with 200 HP motor	90,000 pph @ 25"HG
Single Detroit stoker spreader feeder for combined coal and limestone	



DESIGN DATA

FUEL .... PITTSBURGH SEAM, WEST VA.
STEAM CAPACITY .... [illegible]000#/HR
SUPERHEATER OUTLET TEMP .... 750°F
STEAM PRESSURE .... 650 PSIG
DESIGN PRESSURE .... 725 PSIG
FEEDWATER TEMP .... 235°F
SORBENT .... LIMESTONE

NOTE:
1. FOR BOILER ARRGT SEE DWG # P-140-1159

NASA
ADVANCED TECHNOLOGY COGENERATION SYSTEM
CONCEPTUAL DESIGN STUDY
CATALYTIC INC. CONTRACT NO. 43790

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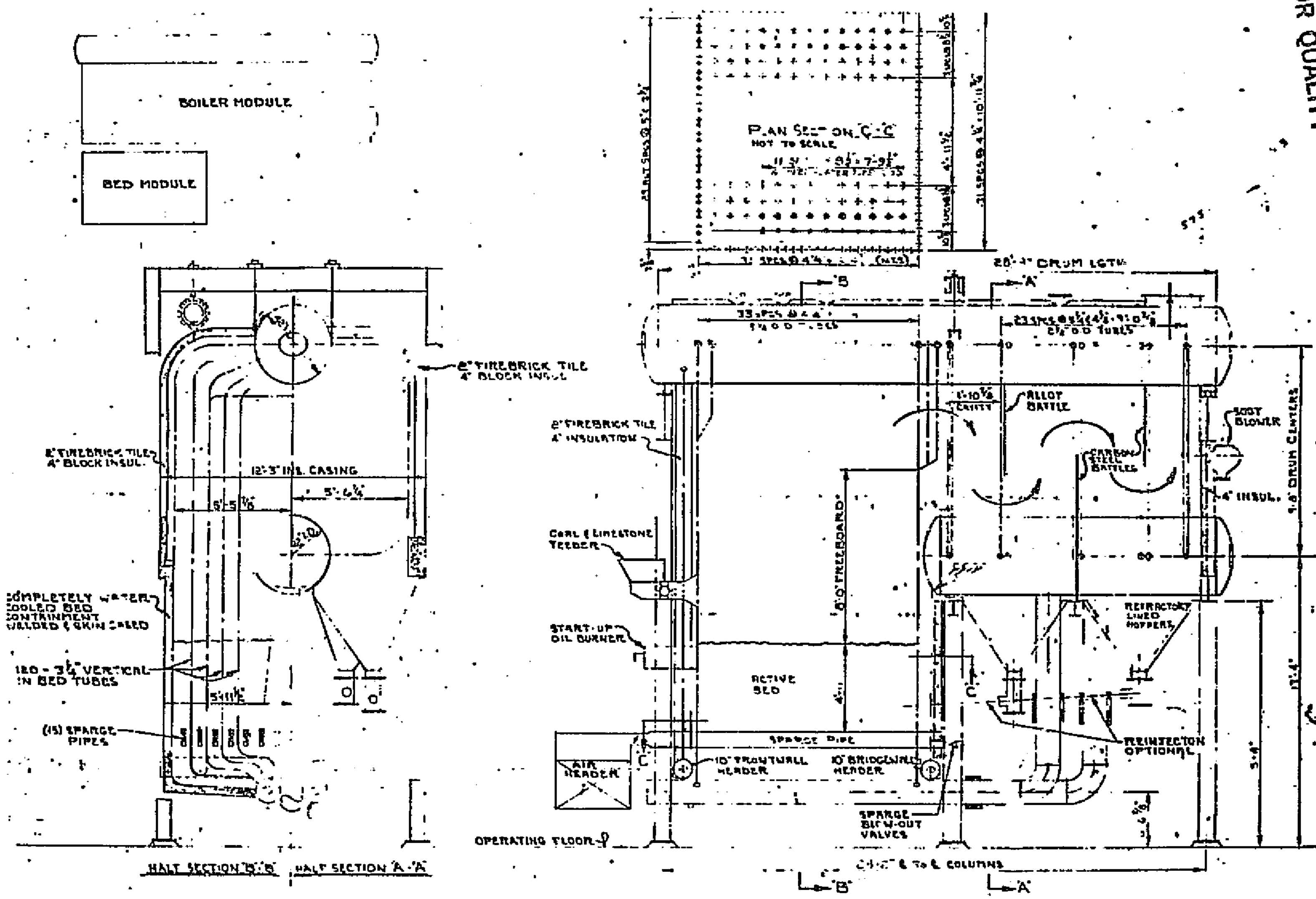
Figure A3-49



BOILER MODULE
BED MODULE
PLAN SECTION "C-C"
NOT TO SCALE
28'-4" DRUM LGTH
2" FIREBRICK TILE
4" BLOCK INSUL.
12'-3" INS. CASING
5'-4¼"
COMPLETELY WATER-COOLED BED CONTAINMENT WELDED & SKIN CASED
120 - 3¼" VERTICAL IN BED TUBES
(15) SPARGE PIPES
HALF SECTION "B-B"
HALF SECTION "A-A"
2" FIREBRICK TILE
4" INSULATION
COAL & LIMESTONE FEEDER
START-UP OIL BURNER
ACTIVE BED
SPARGE PIPE
AIR HEADER
10" FRONTWALL HEADER
10" BRIDGEWALL HEADER
SPARGE BLOW-OUT VALVES
OPERATING FLOOR
ALLOY BAFFLE
CARBON STEEL BAFFLES
SOOT BLOWER
4" INSUL.
REFRACTORY LINED HOPPERS
REINJECTION OPTIONAL
DRUM CENTERS
TO COLUMNS

Figure A3-50

APPENDIX

SECTION 3 - SITES

3.8

FIELD TRIP REPORTS,

OPERATING DATA

ADVANCED TECHNOLOGY COGENERATION SYSTEM

CONCEPTUAL DESIGN STUDY

BASIC DATA SURVEY FORM

COMPANY INFORMATION:

1. Company Name:

   ETHYL CORPORATION

2. Plant Name:

   HOUSTON PLANT

3. Plant Location:

   P. O. BOX 472
   PASADENA, TEXAS 77501

4. Principal Product:

   Linear Alcohols, Alpha Olefins, Aluminum Alkyls, Zeolite A, Orthoalkylated Anilines

5. Principal Contact & Position:

   J. E. Douglas - Energy Coordinator

6. Telephone Number:

   (713) 475-6177

7. Date Information Gathered:

   March 4, 1982

The information supplied to Catalytic, Inc. through this survey data form is to be used for NASA/LEWIS RFP3-154953Q Advanced Technology Cogeneration System Conceptual Design Study. Information of a proprietary nature should be designated with an asterisk (*) to designate that it should not be transmitted to anyone not directly associated with this study.

POWER PLANT ECONOMIC PARAMETERS FOR INVESTMENTS

A. Year power plant was built: 1952

B. Remaining service life of plant: Unknown

C. Operation of power plant:

Shifts/Day 3

Days/Week 7

Weeks/Year 52

Manpower/Shift ______

D. Method of calculating depreciation (check those which apply):

___ Straight line

___ Double declining balance

___ Sum of the year digits

___ Sinking fund method

___ Largest of the above for any given year

___ Depreciation period

E. If your power plant were redesigned for cogeneration:

Economic criteria to be satisfied:

Satisfactory return on investment.

How might the redesigned plant differ from the existing plant?

20-30% increase in power and steam requirements.

Economic impact of unscheduled shutdowns on the overall operation of the process plant:

Very negative - can be devastating from safety point of view.

Minimum return on investment that would be considered for replacement of the present power plant:

POWER PLANT ECONOMIC PARAMETERS FOR INVESTMENTS

Yearly Real Estate, State & Local Taxes (% Adjusted Income).

Federal Income Taxes (% Adjusted Income).

Yearly Insurance charge (% Adjusted income).

Scheduled shutdown frequency and duration.

No total shutdown of boilers.

Present Fuel Price:

Fuel		Price $/MM BTU	Anticipated Esc. Rate %/Yr.
Gas	1981 average	3.25	25%/yr
Oil			
Coal			
Other:	Liquid hydrocarbon waste valued at gas price. Similar properties to #5 fuel oil.		

(Note: Attach Chemical Analysis)

Present Electricity Purchase Price or Schedule — 4.08 ¢/KW (1981 Avg.) Based on 10,000 Btu/KwH

Anticipated Escalation Rate — 15%/Year, incl. inflation

Utility Company Supplying Electricity:

Name: HOUSTON LIGHTING & POWER COMPANY

Address: 611 Walker Street., P. O. Box 1700

City & State: Houston, Texas Zip Code: 77001

Phone No.: (713) 228-9211, X-3554

Person to Contact: J. Bickham

Utility Supply Voltage: 66 KV

Electrical Supply profile with respect to time:

Very steady = 10% Range
20,000 Kw Avg.; 24,000 Kw Max., with 4-15 minute peaks/month

PROCESS DATA

Steam Requirements (each main supply steam):

Flow Lbs/Hr.:	150,000	Ave.	250,000	Peak
Pressure PSIG:	225	Ave.	--	Peak
Temperature °F:	SAT	Ave.	--	Peak

Efficiency % : 1,600 Btu/#Steam net to plant

Pressure Reductions: 40 psig

Generating Equipment: None

No. Days operated at 100% MCR: Frequently for parts of days

Hot Water Requirements (each main supply steam): NONE

Flow Lbs/Hr.:	Ave.	Peak
Pressure PSIG:	Ave.	Peak
Temperature °F:	Ave.	Peak

Necessary Purity:

Heating Equipment:

Hot Air Requirements: NONE

Flow Lbs/Hr.:	Ave.	Peak
Pressure PSIG:	Ave.	Peak
Temperature °F:	Ave.	Peak

Necessary Purity:

Heating Equipment:

PROCESS DATA

Power Requirements

Generated KW	NONE	Ave.	Peak
Consumed KW	20,000	Ave.	Peak
Purchased KW	24,000	Ave.	Peak
Sold KW	NONE	Ave.	Peak

Generating Equipment (Describe):

NONE

Reliability: Excellent for purchased electricity.

Response Time Requirements: Not unique

Backup Equipment (Redundancy Requirements) - Explain, giving Equipment Type and Equipment Ratings:

None for electricity (can be purchased).
Steam generation equipment is required.

Nearest Coal Supplier(s)

Name: OKLAHOMA BITUMINOUS

Address: 1 Ron Post/Fort Scott Seam

City & State: Zip Code:

Phone No.:

Cost: - Delivered 49.00 $/Ton (Attach Analysis)

Nearest Limestone Supplier(s):

Name: CHEMICAL LIME COMPANY, Clifton, Texas

Address: c/o Mr. D. Hoffman

City & State: Fort Worth, Texas Zip Code:

Phone No.: (817) 732-8164

Cost: 18-20 $/Ton (Attach Analysis)

or: TEXAS CRUSHED STONE
Ms. Dana Tucker (512) 255-4405 15 $/Ton

PROCESS DATA

Maintenance Schedules:

Yearly inspection and maintenance.

Electrical Load Profiles with time:

Steady

Thermal Load Profiles with time:

Erratic but at indeterminate times.

Availability of Land on or near site for expansion:

Land for new power plant available near present boilers.
Land nearby available for coal storage.

Planned changes to plant:

NONE

Suggested modifications to permit better use of
AFB/Gas Turbine System in plant:

Heating Dowtherm with flue gas from AFB.

Environmental Requirements:

Non-attainment area - offsets required. 0.7% oil is base for offsets - basis total fuel input to entire plant.

Environmental Constraints:

Internal Utility Arrangements:

13.8 KV throughout plant - reduced to 2,400V or 480V.

External Utility Arrangements:

Waste Stream Disposal:

Non-hazardous solids (ash) would have to be disposed of off-site.

Available Transportation:

Rail, truck, barge.

Climatic Conditions: Mild

AIR CYCLE AFB COGENERATION STUDY

COAL AND LIMESTONE CHARACTERISTICS

Site		Riegel	Hercules	Georgia-Pacific
Coal: Name		Illinois #6	Pittsburgh #8	Western
Type			Hi.Vol. Bit.A	Sub Bit
Ultimate Anal.	% Moist.	9.0	5.0	8.4 + 16.0
	% Ash	9.36	7.0	6.95
	% Sulphur	3.18	3.0	0.52
	% C	63.65	72.0	51.98
	% H	4.47	5.0	3.69
	% N	1.18	1.0	0.70
	% O	9.15	7.0	11.76
H.H.V.	Btu/lb (as delivered)	11716	12350	8789
L.H.V.		11301	11884	8447
H.H.V.	Dry % H_2O = 0	12875	13000	11652
Limestone Type		# 6401	# 9501	# 8901
% CaO/% CO_2		36.0/43.6	53.24/41.79	50.3/39.49
W Limestone/W Coal		.494	.250	.068
Ca/S		3.25	2.5	5.0
W Solids/W Coal		.46515	.2874	.1144

APPENDIX

SECTION 3 - SITES

3.9

CASH FLOW/ROI
CALCULATIONS

TASK 1 PLANT SCREENING

ADVANCED TECHNOLOGY COGENERATION-CONCEPTUAL DESIGN STUDY
NASA-LEWIS RESEARCH CENTER   CATALYTIC JOB NO.43790

PLANT SPECIFIC CASE,NO-COGENERATION VS. AFB/ST 600P/750F
ETHYL PLANT SITE COMPARATIVE ANNUAL COSTS

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
PLANT INVESTMENT($M)	(54.632)	-	-	-	-	-	-	-	-	-
PLANT INVESTMENT BASE CASE	(10.460)	-	-	-	-	-	-	-	-	-
INCREMENTAL PLANT INVESTMENT($M)	(44.172)	-	-	-	-	-	-	-	-	-
FUEL USED MMBTU/HR	288.000	288.000	288.000	288.000	288.000	288.000	288.000	288.000	288.000	288.000
ADDITIONAL STEAM DUTY MMBTU/HR	231.000	231.000	231.000	231.000	231.000	231.000	231.000	231.000	231.000	231.000
BASE CASE FUEL USE MMBTU/HR	483.100	483.100	483.100	483.100	483.100	483.100	483.100	483.100	483.100	483.100
PRICE OF OIL/GAS ($/MMBTU)	6.240	6.427	6.620	6.819	7.024	7.235	7.452	7.676	7.906	8.143
PRICE OF COAL ($/MMBTU)	2.090	2.111	2.132	2.153	2.175	2.197	2.219	2.241	2.263	2.286
COST OF OIL/GAS ($M)	26.407	27.199	28.016	28.858	29.725	30.618	31.537	32.484	33.458	34.461
COST OF COAL ($M)	5.273	5.326	5.379	5.432	5.487	5.543	5.598	5.654	5.709	5.767
COST OF OIL/GAS FOR STEAM($M)	12.627	13.005	13.396	13.799	14.213	14.640	15.080	15.533	15.998	16.478
TOTAL FUEL COST($M)	17.900	18.331	18.775	19.231	19.700	20.183	20.678	21.187	21.707	22.245
INCREMENTAL FUEL COST($M)	8.507	8.868	9.241	9.627	10.025	10.435	10.859	11.297	11.751	12.216
AVERAGE ELECTRIC GEN. MW/HR	4.500	4.500	4.500	4.500	4.500	4.500	4.500	4.500	4.500	4.500
STANDBY POWER MW/HR	-	-	-	-	-	-	-	-	-	-
AVERAGE PURCHASED ELECTRICITY MW/HR.	25.140	25.140	25.140	25.140	25.140	25.140	25.140	25.140	25.140	25.140
DEMAND & ENERGY CHARGE ($/KW-HR)	0.0621	0.0664	0.0710	0.0760	0.0813	0.0870	0.0931	0.0996	0.1066	0.1141
STANDBY CHARGE $/KW/MON	-	-	-	-	-	-	-	-	-	-
BASE CASE ELECTRICITY PURCHASED MW/HR	24.130	24.130	24.130	24.130	24.130	24.130	24.130	24.130	24.130	24.130
ELECTRICITY SOLD TO UTILITY MW/HR	4.500	4.500	4.500	4.500	4.500	4.500	4.500	4.500	4.500	4.500
PRICE FOR SELLING ELECTRICITY $/KW-HR	0.0707	0.0756	0.0809	0.0866	0.0927	0.0992	0.1061	0.1135	0.1214	0.1299
REVENUE FROM ELECTRIC SALE ($M)	2.787	2.980	3.189	3.414	3.656	3.910	4.182	4.474	4.786	5.121
COST OF PURCHASED ELECTRICITY($M)	13.676	14.623	15.636	16.737	17.904	19.160	20.503	21.935	23.476	25.128
COST OF ELECTRIC ENERGY ($M)	10.889	11.643	12.447	13.323	14.250	15.250	16.321	17.461	18.690	20.007
BASE CASE COST ELECTRICITY ($M)	13.127	14.036	15.009	16.065	17.185	18.390	19.679	21.053	22.533	24.118
INCREMENTAL COST OF ELECTRICITY $M	2.238	2.393	2.561	2.742	2.935	3.140	3.358	3.592	3.843	4.111
ANNUAL ENERGY COST ($M)	28.789	29.974	31.222	32.554	33.950	35.433	36.999	38.648	40.397	42.252
ANNUAL ENERGY SAVINGS($M)	10.745	11.261	11.802	12.369	12.960	13.575	14.217	14.885	15.594	16.327
PRICE OF SORBENT $/TON	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000
COST OF SORBENT($M)	1.387	1.387	1.387	1.387	1.387	1.387	1.387	1.387	1.387	1.387
COST OF WASTE DISPOSAL($M)	0.306	0.306	0.306	0.306	0.306	0.306	0.306	0.306	0.306	0.306
UTILITIES,LABOR,MAINT.($M)	2.576	2.576	2.576	2.576	2.576	2.576	2.576	2.576	2.576	2.576
INSURANCE AND LOCAL TAXES($M)	0.819	0.819	0.819	0.819	0.819	0.819	0.819	0.819	0.819	0.819
ANNUAL OPER,MAIN&TAXES ($M)	5.088	5.088	5.088	5.088	5.088	5.088	5.088	5.088	5.088	5.088
BASE COST OPER MAINT & TAXES ($M)	1.002	1.002	1.002	1.002	1.002	1.002	1.002	1.002	1.002	1.002
INCREMENTAL COST OF OPER.&MAINT. ($M)	(4.086)	(4.086)	(4.086)	(4.086)	(4.086)	(4.086)	(4.086)	(4.086)	(4.086)	(4.086)
SAVINGS BEFORE TAXES ($M)	6.659	7.175	7.716	8.283	8.874	9.489	10.131	10.803	11.508	12.241
DEPRECIATION $M	8.834	14.135	10.601	7.068	3.534	-	-	-	-	-
NET TAXABLE INCOME($M)	-	-	-	1.215	5.340	9.489	10.131	10.803	11.508	12.241
INCOME TAX ($M)	-	-	-	0.583	2.563	4.555	4.863	5.185	5.524	5.876
INCOME TAX CREDIT ($M)	4.417	-	-	-	-	-	-	-	-	-
NET INCOME AFTER TAXES($M)	4.417	-	-	0.632	2.777	4.934	5.268	5.618	5.984	6.365
DEPRECIATION ADDED BACK($M)	8.834	14.135	10.601	7.068	3.534	-	-	-	-	-
CASH FLOW ($M)	13.251	14.135	10.601	7.700	6.311	4.934	5.268	5.618	5.984	6.365
CALCULATION OF ROI	(44.172)	13.251	14.135	10.601	7.700	6.311	4.934	5.268	5.618	5.984

RETURN ON INVESTMENT = 19.117%

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ADVANCED TECHNOLOGY COGENERATION-CONCEPTUAL DESIGN STUDY
NASA-LEWIS RESEARCH CENTER   CATALYTIC JOB NO.43790
PLANT SPECIFIC CASE,NO-COGENERATION VS. AFB/ST 600P/750F
ETHYL PLANT SITE COMPARATIVE ANNUAL COSTS

	1998	1999	2000	2001	2002
PLANT INVESTMENT($M)	-	-	-	-	-
PLANT INVESTMENT BASE CASE	-	-	-	-	-
INCREMENTAL PLANT INVESTMENT($M)	-	-	-	-	-
FUEL USED MMBTU/HR	288.000	288.000	288.000	288.000	288.000
ADDITIONAL STEAM DUTY MMBTU/HR	231.000	231.000	231.000	231.000	231.000
BASE CASE FUEL USE MMBTU/HR	483.100	483.100	483.100	483.100	483.100
PRICE OF OIL/GAS ($/MMBTU)	8.387	8.639	8.898	9.165	9.440
PRICE OF COAL ($/MMBTU)	2.309	2.332	2.355	2.379	2.403
COST OF OIL/GAS ($M)	35.493	36.560	37.656	38.786	39.950
COST OF COAL ($M)	5.825	5.883	5.941	6.002	6.062
COST OF OIL/GAS FOR STEAM($M)	16.972	17.482	18.006	18.546	19.102
TOTAL FUEL COST($M)	22.797	23.365	23.947	24.548	25.164
INCREMENTAL FUEL COST($M)	12.696	13.195	13.709	14.238	14.786
AVERAGE ELECTRIC GEN. MW/HR	4.500	4.500	4.500	4.500	4.500
STANDBY POWER MW/HR	-	-	-	-	-
AVERAGE PURCHASED ELECTRICITY MW/HR.	25.140	25.140	25.140	25.140	25.140
DEMAND & ENERGY CHARGE ($/KW-HR)	0.1221	0.1306	0.1397	0.1495	0.1600
STANDBY CHARGE $/KW/MON	-	-	-	-	-
BASE CASE ELECTRICITY PURCHASED MW/HR	24.130	24.130	24.130	24.130	24.130
ELECTRICITY SOLD TO UTILITY MW/HR	4.500	4.500	4.500	4.500	4.500
PRICE FOR SELLING ELECTRICITY $/KW-HR	0.1390	0.1487	0.1591	0.1702	0.1821
REVENUE FROM ELECTRIC SALE ($M)	5.479	5.062	6.272	6.709	7.178
COST OF PURCHASED ELECTRICITY($M)	26.890	28.762	30.766	32.924	35.236
COST OF ELECTRIC ENERGY ($M)	21.411	22.900	24.494	26.215	28.058
BASE CASE COST ELECTRICITY ($M)	25.809	27.606	29.530	31.601	33.821
INCREMENTAL COST OF ELECTRICITY $M	4.398	4.706	5.036	5.386	5.763
ANNUAL ENERGY COST ($M)	44.208	46.265	48.441	50.763	53.222
ANNUAL ENERGY SAVINGS($M)	17.094	17.901	18.745	19.674	20.549
PRICE OF SORBENT $/TON	18.000	18.000	18.000	18.000	18.000
COST OF SORBENT($M)	1.387	1.387	1.387	1.387	1.387
COST OF WASTE DISPOSAL($M)	0.306	0.306	0.306	0.306	0.306
UTILITIES,LABOR,MAINT.($M)	2.576	2.576	2.576	2.576	2.576
INSURANCE AND LOCAL TAXES($M)	0.819	0.819	0.819	0.819	0.819
ANNUAL OPER.MAIN&TAXES ($M)	5.088	5.088	5.089	5.088	5.088
BASE COST OPER MAINT & TAXES ($M)	1.002	1.002	1.002	1.002	1.002
INCREMENTAL COST OF OPER.&MAINT. ($M)	(4.086)	(4.086)	(4.086)	(4.096)	(4.086)
SAVINGS BEFORE TAXES ($M)	13.008	13.815	14.659	15.538	16.463
DEPRECIATION $M	-	-	-	-	-
NET TAXABLE INCOME($M)	13.008	13.815	14.659	15.538	16.463
INCOME TAX ($M)	6.244	6.631	7.036	7.458	7.902
INCOME TAX CREDIT ($M)	-	-	-	-	-
NET INCOME AFTER TAXES($M)	6.764	7.184	7.623	8.080	8.561
DEPRECIATION ADDED BACK($M)	-	-	-	-	-
CASH FLOW ($M)	6.764	7.184	7.623	8.080	8.561
CALCULATION OF ROI	6.365	6.764	7.184	7.623	8.080

ADVANCED TECHNOLOGY COGENERATION-CONCEPTUAL DESIGN STUDY
NASA-LEWIS RESEARCH CENTER CATALYTIC JOB NO.43790

PLANT SPECIFIC CASE,NO-COGENERATION VS.AFB/GT
THREE UNITS FOR ETHYL CORP.

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
PLANT INVESTMENT($M)	(81.183)	-	-	-	-	-	-	-	-	-
PLANT INVESTMENT BASE CASE	(10.460)	-	-	-	-	-	-	-	-	-
INCREMENTAL PLANT INVESTMENT($M)	(70.723)	-	-	-	-	-	-	-	-	-
FUEL USED MMBTU/HR	535.000	535.000	535.000	535.000	535.000	535.000	535.000	535.000	535.000	535.000
ADDITIONAL STEAM DUTY MMBTU/HR	85.700	85.700	85.700	85.700	85.700	85.700	85.700	85.700	85.700	85.700
BASE CASE FUEL USE MMBTU/HR	483.100	483.100	483.100	483.100	483.100	483.100	483.100	483.100	483.100	483.100
PRICE OF OIL/GAS ($/MMBTU)	6.240	6.427	6.620	6.819	7.024	7.235	7.452	7.676	7.906	8.143
PRICE OF COAL ($/MMBTU)	2.090	2.111	2.132	2.153	2.175	2.197	2.219	2.241	2.263	2.286
COST OF OIL/GAS ($M)	26.407	27.199	28.016	28.858	29.725	30.618	31.537	32.484	33.458	34.461
COST OF COAL ($M)	9.795	9.893	9.992	10.090	10.193	10.296	10.400	10.503	10.606	10.714
COST OF OIL/GAS FOR STEAM($M)	4.685	4.825	4.970	5.119	5.273	5.432	5.594	5.763	5.935	6.113
TOTAL FUEL COST($M)	14.480	14.718	14.962	15.209	15.466	15.728	15.994	16.266	16.541	16.827
INCREMENTAL FUEL COST($M)	11.927	12.491	13.054	13.649	14.259	14.890	15.543	16.218	16.917	17.634
AVERAGE ELECTRIC GEN. MW/HR	21.300	21.300	21.300	21.300	21.300	21.300	21.300	21.300	21.300	21.300
STANDBY POWER MW/HR	-	-	-	-	-	-	-	-	-	-
AVERAGE PURCHASED ELECTRICITY MW/HR.	28.080	28.080	28.080	28.080	28.080	28.080	28.080	28.080	28.080	28.080
DEMAND & ENERGY CHARGE ($/KW-HR)	0.0621	0.0664	0.0710	0.0760	0.0813	0.0870	0.0931	0.0996	0.1066	0.1141
STANDBY CHARGE $/KW/MON	-	-	-	-	-	-	-	-	-	-
BASE CASE ELECTRICITY PURCHASED MW/HR	24.130	24.130	24.130	24.130	24.130	24.130	24.130	24.130	24.130	24.130
ELECTRICITY SOLD TO UTILITY MW/HR	21.300	21.300	21.300	21.300	21.300	21.300	21.300	21.300	21.300	21.300
PRICE FOR SELLING ELECTRICITY $/KW-HR	0.0707	0.0756	0.0809	0.0866	0.0927	0.0992	0.1061	0.1135	0.1214	0.1299
REVENUE FROM ELECTRIC SALE ($M)	13.192	14.106	15.095	16.159	17.297	18.510	19.797	21.178	22.652	24.238
COST OF PURCHASED ELECTRICITY($M)	15.275	16.333	17.465	18.695	19.998	21.400	22.901	24.500	26.222	28.066
COST OF ELECTRIC ENERGY ($M)	2.083	2.227	2.370	2.536	2.701	2.890	3.104	3.322	3.570	3.828
BASE CASE COST ELECTRICITY ($M)	13.127	14.036	15.009	16.065	17.185	18.390	19.679	21.053	22.533	24.118
INCREMENTAL COST OF ELECTRICITY $M	11.044	11.809	12.638	13.529	14.484	15.500	16.575	17.731	18.963	20.290
ANNUAL ENERGY COST ($M)	16.563	16.945	17.332	17.745	18.167	18.618	19.098	19.588	20.111	20.655
ANNUAL ENERGY SAVINGS($M)	22.971	24.290	25.692	27.178	28.743	30.390	32.118	33.949	35.880	37.924
PRICE OF SORBENT $/TON	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000
COST OF SORBENT($M)	1.267	1.267	1.267	1.267	1.267	1.267	1.267	1.267	1.267	1.267
COST OF WASTE DISPOSAL($M)	0.375	0.375	0.375	0.375	0.375	0.375	0.375	0.375	0.375	0.375
UTILITIES,LABOR,MAINT.($M)	3.052	3.052	3.052	3.052	3.052	3.052	3.052	3.052	3.052	3.052
INSURANCE AND LOCAL TAXES($M)	1.218	1.218	1.218	1.218	1.218	1.218	1.218	1.218	1.218	1.218
ANNUAL OPER.MAINGTAXES ($M)	5.912	5.912	5.912	5.912	5.912	5.912	5.912	5.912	5.912	5.912
BASE COST OPER MAINT & TAXES ($M)	1.002	1.002	1.002	1.002	1.002	1.002	1.002	1.002	1.002	1.002
INCREMENTAL COST OF OPER.&MAINT. ($M)	(4.910)	(4.910)	(4.910)	(4.910)	(4.910)	(4.910)	(4.910)	(4.910)	(4.910)	(4.910)
SAVINGS BEFORE TAXES ($M)	18.061	19.380	20.782	22.268	23.833	25.480	27.208	29.039	30.970	33.014
DEPRECIATION $M	14.145	22.631	16.974	11.316	5.658	-	-	-	-	-
NET TAXABLE INCOME($M)	3.916	-	3.808	10.952	18.175	25.480	27.208	29.039	30.970	33.014
INCOME TAX ($M)	1.880	-	1.828	5.257	8.724	12.230	13.060	13.939	14.866	15.847
INCOME TAX CREDIT ($M)	7.072	-	-	-	-	-	-	-	-	-
NET INCOME AFTER TAXES($M)	9.108	-	1.980	5.695	9.451	13.250	14.148	15.100	16.104	17.167
DEPRECIATION ADDED BACK($M)	14.145	22.631	16.974	11.316	5.658	-	-	-	-	-
CASH FLOW ($M)	23.253	22.631	18.954	17.011	15.109	13.250	14.148	15.100	16.104	17.167
CALCULATION OF ROI	(70.723)	23.253	22.631	18.954	17.011	15.109	13.250	14.148	15.100	16.104

RETURN ON INVESTMENT = 25.876(

ADVANCED TECHNOLOGY COGENERATION-CONCEPTUAL DESIGN STUDY
NASA-LEWIS RESEARCH CENTER   CATALYTIC JOB NO.63790
PLANT SPECIFIC CASE,NO-COGENERATION VS.AFB/GT
THREE UNITS FOR ETHYL CORP.

	1998	1999	2000	2001	2002
PLANT INVESTMENT($M)	-	-	-	-	-
PLANT INVESTMENT BASE CASE	-	-	-	-	-
INCREMENTAL PLANT INVESTMENT($M)	-	-	-	-	-
FUEL USED MMBTU/HR	535.000	535.000	535.000	535.000	535.000
ADDITIONAL STEAM DUTY MMBTU/HR	85.700	85.700	85.700	85.700	85.700
BASE CASE FUEL USE MMBTU/HR	483.100	483.100	483.100	483.100	483.100
PRICE OF OIL/GAS ($/MMBTU)	8.387	8.635	8.899	9.165	9.440
PRICE OF COAL ($/MMBTU)	2.309	2.332	2.355	2.379	2.403
COST OF OIL/GAS ($M)	35.493	36.560	37.656	38.786	39.950
COST OF COAL ($M)	10.821	10.929	11.037	11.149	11.262
COST OF OIL/GAS FOR STEAM($M)	6.296	6.486	6.680	6.880	7.087
TOTAL FUEL COST($M)	17.117	17.415	17.717	18.029	18.349
INCREMENTAL FUEL COST($M)	18.376	19.145	19.939	20.757	21.601
AVERAGE ELECTRIC GEN. MW/HR	21.300	21.300	21.300	21.300	21.300
STANDBY POWER MW/HR	-	-	-	-	-
AVERAGE PURCHASED ELECTRICITY MW/HR.	28.080	28.080	28.080	28.080	28.080
DEMAND & ENERGY CHARGE ($/KW-HR)	0.1221	0.1306	0.1397	0.1495	0.1600
STANDBY CHARGE $/KW/MON	-	-	-	-	-
BASE CASE ELECTRICITY PURCHASED MW/HR	24.130	24.130	24.130	24.130	24.130
ELECTRICITY SOLD TO UTILITY MW/HR	21.300	21.300	21.300	21.300	21.300
PRICE FOR SELLING ELECTRICITY $/KW-HR	0.1390	0.1487	0.1591	0.1702	0.1821
REVENUE FROM ELECTRIC SALE ($M)	25.936	27.746	29.686	31.757	33.978
COST OF PURCHASED ELECTRICITY($M)	30.034	32.125	34.364	36.774	39.357
COST OF ELECTRIC ENERGY ($M)	4.098	4.379	4.678	5.017	5.379
BASE CASE COST ELECTRICITY ($M)	25.809	27.606	29.530	31.601	33.821
INCREMENTAL COST OF ELECTRICITY $M	21.711	23.227	24.852	26.584	28.442
ANNUAL ENERGY COST ($M)	21.215	21.794	22.395	23.046	23.728
ANNUAL ENERGY SAVINGS($M)	40.087	42.372	44.791	47.341	50.043
PRICE OF SORBENT $/TON	18.000	18.000	18.000	18.000	18.000
COST OF SORBENT($M)	1.267	1.267	1.267	1.267	1.267
COST OF WASTE DISPOSAL($M)	0.375	0.375	0.375	0.375	0.375
UTILITIES,LABOR,MAINT.($M)	3.052	3.052	3.052	3.052	3.052
INSURANCE AND LOCAL TAXES($M)	1.218	1.218	1.218	1.218	1.218
ANNUAL OPER,MAIN&TAXES ($M)	5.912	5.912	5.912	5.912	5.912
BASE COST OPER MAINT & TAXES ($M)	1.002	1.002	1.002	1.002	1.002
INCREMENTAL COST OF OPER.&MAINT. ($M)	(4.910)	(4.910)	(4.910)	(4.910)	(4.910)
SAVINGS BEFORE TAXES ($M)	35.177	37.462	35.881	42.431	45.133
DEPRECIATION $M	-	-	-	-	-
NET TAXABLE INCOME($M)	35.177	37.462	35.881	42.431	45.133
INCOME TAX ($M)	16.885	17.982	19.143	20.367	21.664
INCOME TAX CREDIT ($M)	-	-	-	-	-
NET INCOME AFTER TAXES($M)	18.292	19.480	20.738	22.064	23.469
DEPRECIATION ADDED BACK($M)	-	-	-	-	-
CASH FLOW ($M)	18.292	19.480	20.738	22.064	23.469
CALCULATION OF ROI	17.167	18.292	19.480	20.738	22.064

ADVANCED TECHNOLOGY COGENERATION-CONCEPTUAL DESIGN STUDY
NASA-LEWIS RESEARCH CENTER CATALYTIC JOB NO.43790
PLANT SPECIFIC CASE,NO-COGENERATION VS.AFB/GT 600P/750F
AFB/ST VS AFB/GT THREE UNIT PLANT SPEC.DATA

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
PLANT INVESTMENT($M)	(81.183)	-	-	-	-	-	-	-	-	-
PLANT INVESTMENT BASE CASE	(54.632)	-	-	-	-	-	-	-	-	-
INCREMENTAL PLANT INVESTMENT($M)	(26.551)	-	-	-	-	-	-	-	-	-
FUEL USED MMBTU/HR	535.000	535.000	535.000	535.000	535.000	535.000	535.000	535.000	535.000	535.000
GAS/OIL STEAM DUTY MMBTU/HR	85.700	85.700	85.700	85.700	85.700	85.700	85.700	85.700	85.700	85.700
BASE CASE COAL USE MMBTU/HR	288.000	288.000	288.000	288.000	288.000	288.000	288.000	288.000	288.000	288.000
GAS/OIL BASE CASE STEAM DUTY	231.000	231.000	231.000	231.000	231.000	231.000	231.000	231.000	231.000	231.000
PRICE OF OIL/GAS ($/MMBTU)	6.240	6.427	6.620	6.819	7.024	7.235	7.452	7.676	7.906	8.143
PRICE OF COAL ($/MMBTU)	2.090	2.111	2.132	2.153	2.175	2.197	2.219	2.241	2.263	2.286
COST OF GAS/OIL (STEAM) ($M)	5.273	5.326	5.379	5.432	5.487	5.543	5.598	5.654	5.709	5.767
BASE COST OF GAS/OIL(STEAM) ($M)	12.627	13.005	13.396	13.799	14.213	14.640	15.080	15.533	15.998	16.478
COST OF COAL ($M)	9.795	9.893	9.992	10.090	10.193	10.296	10.400	10.503	10.606	10.714
COST OF OIL/GAS FOR STEAM($M)	4.685	4.825	4.970	5.119	5.273	5.432	5.594	5.763	5.935	6.113
TOTAL FUEL COST($M)	14.480	14.718	14.962	15.209	15.466	15.728	15.994	16.266	16.541	16.827
BASE CASE FUEL COST	17.900	18.331	18.775	19.231	19.700	20.183	20.678	21.187	21.707	22.245
INCREMENTAL FUEL COST($M)	(3.420)	(3.613)	(3.813)	(4.022)	(4.234)	(4.455)	(4.684)	(4.921)	(5.166)	(5.418)
AVERAGE ELECTRIC GEN. MW/HR	21.300	21.300	21.300	21.300	21.300	21.300	21.300	21.300	21.300	21.300
STANDBY POWER MW/HR	-	-	-	-	-	-	-	-	-	-
AVERAGE PURCHASED ELECTRICITY MW/HR.	28.080	28.080	28.080	28.080	28.080	28.080	28.080	28.080	28.080	28.080
DEMAND & ENERGY CHARGE ($/KW-HR)	0.0621	0.0664	0.0710	0.0760	0.0813	0.0870	0.0931	0.0996	0.1066	0.1141
STANDBY CHARGE $/KW/MON	-	-	-	-	-	-	-	-	-	-
BASE CASE ELECTRICITY PURCHASED MW/HR	24.130	24.130	24.130	24.130	24.130	24.130	24.130	24.130	24.130	24.130
ELECTRICITY SOLD TO UTILITY MW/HR	21.300	21.300	21.300	21.300	21.300	21.300	21.300	21.300	21.300	21.300
PRICE FOR SELLING ELECTRICITY $/KW-HR	0.0707	0.0756	0.0809	0.0866	0.0927	0.0992	0.1061	0.1135	0.1214	0.1299
REVENUE FROM ELECTRIC SALE ($M)	13.192	14.106	15.095	16.159	17.297	18.510	19.797	21.178	22.652	24.238
COST OF PURCHASED ELECTRICITY($M)	15.275	16.333	17.465	18.695	19.998	21.400	22.901	24.500	26.222	28.066
COST OF ELECTRIC ENERGY ($M)	2.083	2.227	2.370	2.536	2.701	2.890	3.104	3.322	3.570	3.828
BASE CASE COST ELECTRICITY ($M)	10.889	11.651	12.467	13.340	14.274	15.273	16.342	17.486	18.710	20.020
INCREMENTAL COST OF ELECTRICITY $M	8.806	9.424	10.097	10.804	11.573	12.383	13.238	14.164	15.140	16.192
ANNUAL ENERGY COST ($M)	16.563	16.945	17.332	17.745	18.167	18.618	19.098	19.588	20.111	20.655
ANNUAL ENERGY SAVINGS($M)	5.386	5.811	6.284	6.782	7.339	7.928	8.554	9.243	9.974	10.774
PRICE OF SORBENT $/TON	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000
COST OF SORBENT($M)	1.267	1.267	1.267	1.267	1.267	1.267	1.267	1.267	1.267	1.267
COST OF WASTE DISPOSAL($M)	0.375	0.375	0.375	0.375	0.375	0.375	0.375	0.375	0.375	0.375
UTILITIES,LABOR,MAINT.($M)	3.052	3.052	3.052	3.052	3.052	3.052	3.052	3.052	3.052	3.052
INSURANCE AND LOCAL TAXES($M)	1.218	1.218	1.218	1.218	1.218	1.218	1.218	1.218	1.218	1.218
ANNUAL OPER,MAIN&TAXES ($M)	5.912	5.912	5.912	5.912	5.912	5.912	5.912	5.912	5.912	5.912
BASE COST OPER MAINT & TAXES ($M)	5.136	5.136	5.136	5.136	5.136	5.136	5.136	5.136	5.136	5.136
INCREMENTAL COST OF OPER.&MAINT. ($M)	(0.776)	(0.776)	(0.776)	(0.776)	(0.776)	(0.776)	(0.776)	(0.776)	(0.776)	(0.776)
SAVINGS BEFORE TAXES ($M)	4.610	5.035	5.508	6.006	6.563	7.152	7.778	8.467	9.198	9.998
DEPRECIATION $M	5.310	8.496	6.372	4.248	2.124	-	-	-	-	-
NET TAXABLE INCOME($M)	-	-	-	1.758	4.439	7.152	7.778	8.467	9.198	9.998
INCOME TAX ($M)	-	-	-	0.844	2.131	3.433	3.733	4.064	4.415	4.799
INCOME TAX CREDIT ($M)	2.655	-	-	-	-	-	-	-	-	-
NET INCOME AFTER TAXES($M)	2.655	-	-	0.914	2.308	3.719	4.045	4.403	4.783	5.199
DEPRECIATION ADDED BACK($M)	5.310	8.496	6.372	4.248	2.124	-	-	-	-	-
CASH FLOW ($M)	7.965	8.496	6.372	5.162	4.432	3.719	4.045	4.403	4.783	5.199
CALCULATION OF ROI	(26.551)	7.965	8.496	6.372	5.162	4.432	3.719	4.045	4.403	4.783

RETURN ON INVESTMENT = 21.838(

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ADVANCED TECHNOLOGY COGENERATION-CONCEPTUAL DESIGN STUDY
NASA-LEWIS RESEARCH CENTER CATALYTIC JOB NO.43790
PLANT SPECIFIC CASE,NO-COGENERATION VS.AFB/GT 600P/750F
AFB/ST VS AFB/GT THREE UNIT PLANT SPEC.DATA

	1998	1999	2000	2001	2002
PLANT INVESTMENT($M)	-	-	-	-	-
PLANT INVESTMENT BASE CASE	-	-	-	-	-
INCREMENTAL PLANT INVESTMENT($M)	-	-	-	-	-
FUEL USED MMBTU/HR	535.000	535.000	535.000	535.000	535.000
GAS/OIL STEAM DUTY MMBTU/HR	85.700	85.700	85.700	85.700	85.700
BASE CASE COAL USE MMBTU/HR	288.000	288.000	288.000	288.000	288.000
GAS/OIL BASE CASE STEAM DUTY	231.000	231.000	231.000	231.000	231.000
PRICE OF OIL/GAS ($/MMBTU)	8.387	8.639	8.898	9.165	9.440
PRICE OF COAL ($/MMBTU)	2.309	2.332	2.355	2.379	2.403
COST OF GAS/OIL (STEAM) ($M)	5.825	5.883	5.941	6.002	6.062
BASE COST OF GAS/OIL(STEAM) ($M)	16.972	17.482	18.006	18.546	19.102
COST OF COAL ($M)	10.821	10.929	11.037	11.149	11.262
COST OF OIL/GAS FOR STEAM($M)	6.296	6.486	6.680	6.880	7.087
TOTAL FUEL COST($M)	17.117	17.415	17.717	18.029	18.349
BASE CASE FUEL COST	22.797	23.365	23.947	24.548	25.164
INCREMENTAL FUEL COST($M)	(5.680)	(5.950)	(6.230)	(6.519)	(6.815)
AVERAGE ELECTRIC GEN. MW/HR	21.300	21.300	21.300	21.300	21.300
STANDBY POWER MW/HR	-	-	-	-	-
AVERAGE PURCHASED ELECTRICITY MW/HR.	28.080	28.080	28.080	28.080	28.080
DEMAND & ENERGY CHARGE ($/KW-HR)	0.1221	0.1306	0.1397	0.1495	0.1600
STANDBY CHARGE $/KW/MON	-	-	-	-	-
BASE CASE ELECTRICITY PURCHASED MW/HR	24.130	24.130	24.130	24.130	24.130
ELECTRICITY SOLD TO UTILITY MW/HR	21.300	21.300	21.300	21.300	21.300
PRICE FOR SELLING ELECTRICITY $/KW-HR	0.1390	0.1487	0.1591	0.1702	0.1821
REVENUE FROM ELECTRIC SALE ($M)	25.936	27.746	29.686	31.757	33.978
COST OF PURCHASED ELECTRICITY($M)	30.034	32.125	34.364	36.774	39.357
COST OF ELECTRIC ENERGY ($M)	4.098	4.379	4.678	5.017	5.379
BASE CASE COST ELECTRICITY ($M)	21.421	22.920	24.524	26.241	28.078
INCREMENTAL COST OF ELECTRICITY $M	17.323	18.541	19.846	21.224	22.699
ANNUAL ENERGY COST ($M)	21.215	21.794	22.395	23.046	23.728
ANNUAL ENERGY SAVINGS($M)	11.643	12.591	13.616	14.705	15.884
PRICE OF SORBENT $/TON	18.000	18.000	18.000	18.000	18.000
COST OF SORBENT($M)	1.267	1.267	1.267	1.267	1.267
COST OF WASTE DISPOSAL($M)	0.375	0.375	0.375	0.375	0.375
UTILITIES,LABOR,MAINT.($M)	3.052	3.052	3.052	3.052	3.052
INSURANCE AND LOCAL TAXES($M)	1.218	1.218	1.218	1.218	1.218
ANNUAL OPER,MAIN&TAXES ($M)	5.912	5.912	5.912	5.912	5.912
BASE COST OPER MAINT & TAXES ($M)	5.136	5.136	5.136	5.136	5.136
INCREMENTAL COST OF OPER.&MAINT. ($M)	(0.776)	(0.776)	(0.776)	(0.776)	(0.776)
SAVINGS BEFORE TAXES ($M)	10.867	11.815	12.840	13.929	15.108
DEPRECIATION $M	-	-	-	-	-
NET TAXABLE INCOME($M)	10.867	11.815	12.840	13.929	15.108
INCOME TAX ($M)	5.216	5.671	6.163	6.686	7.252
INCOME TAX CREDIT ($M)	-	-	-	-	-
NET INCOME AFTER TAXES($M)	5.651	6.144	6.677	7.243	7.856
DEPRECIATION ADDED BACK($M)	-	-	-	-	-
CASH FLOW ($M)	5.651	6.144	6.677	7.243	7.856
CALCULATION OF ROI	5.199	5.651	6.144	6.677	7.243

Section 4

CONCEPTUAL DESIGNS

4.0 CONCEPTUAL DESIGN OBJECTIVES

The preparation of site-specific conceptual designs for an AFB/gas turbine industrial cogeneration system and an AFB/steam turbine system permits fulfillment of a primary objective of the study: the comparison of the potential benefits of the two systems. This section of the Appendix covers the preparation of the conceptual designs of the two cogeneration systems for the Ethyl Corporation, Pasadena, Texas plant site.

4.1 DETAILED SITE DEFINITION

Preparation of the conceptual plant designs requires further definition of the plant characteristics and requirements, beyond those employed in the plant screening task.

4.1.1 Electrical Requirements

The steadiness of the plant electric consumption is shown clearly by Figure A4-1, showing a typical 24-hour use chart of the plant. Figure A4-2 is a plot of the data presented in Figure A4-1, and more clearly shows no load variation in varying parts of a day. So, the 24 MW average plant load for the future is taken at a steady rate.

4.1.2 Steam Requirements

The plant steam load varies considerably and requires further analysis. Figure A4-3 shows current 24-hour performance of a single boiler. Review of other boiler charts for the same day shows the load swings occur simultaneously with them, too. Also, the steam header pressure remains quite steady, so the load swings shown are indeed typical and must be addressed, since Ethyl has said that chemical plant operation cannot be modified to smooth out the steam load swings. The load is continuous and does not have any seasonal, weekend, shift or any other type of long duration swings in steam demand. The short (5 to 15 minute) durations of the load swings provide steady cumulative steam flow as shown in Figure A4-4. Typical load swings fall within the range of ± 60,000 lbs/hr steam (± 30% steam send out), but because of the short duration only about 9,000 to 10,000 pounds of steam actually is sent to process. Rate of change of steam load is about 5% per minute of boiler output. This permits consideration of using an oversized deaerator storage tank with proper controls functioning as a constant pressure accumulator, providing steam needed for the short load swings. This approach is felt to be realistic for the Ethyl site. This is discussed further in this Appendix, section 4.3.1.

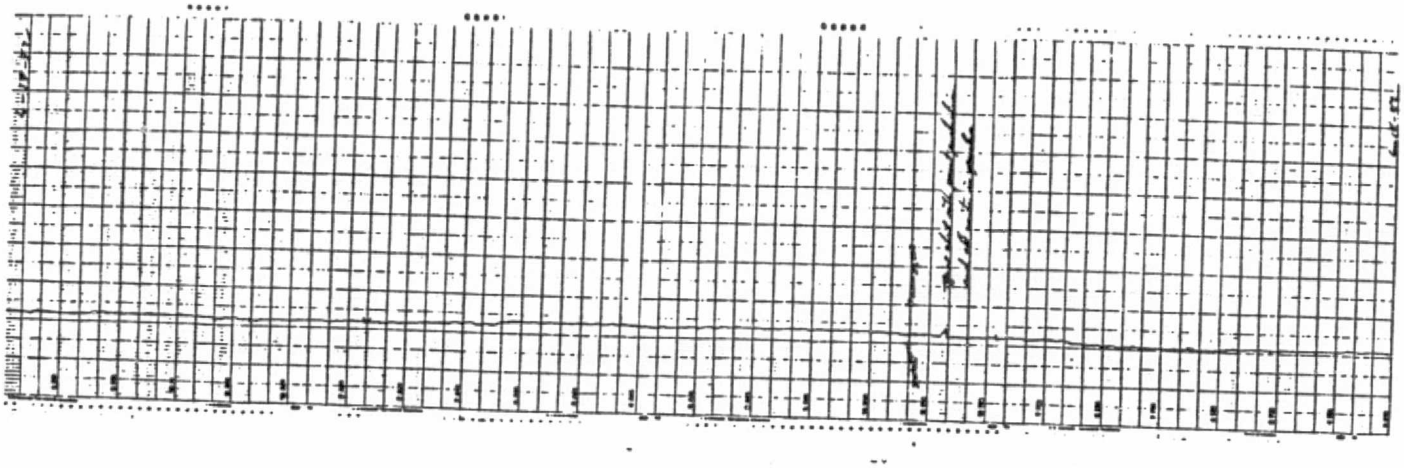

Figure A4-1

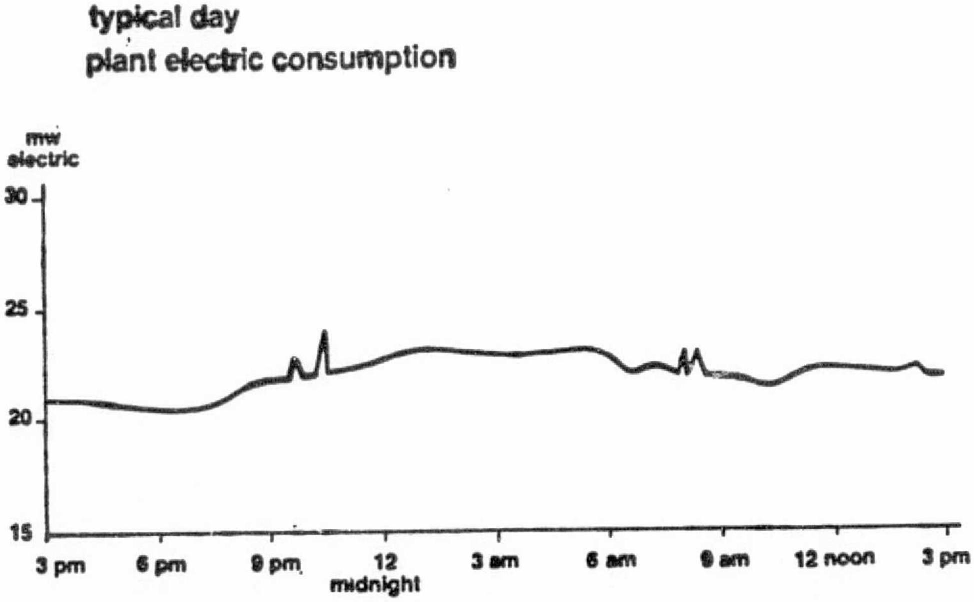

Figure A4-2

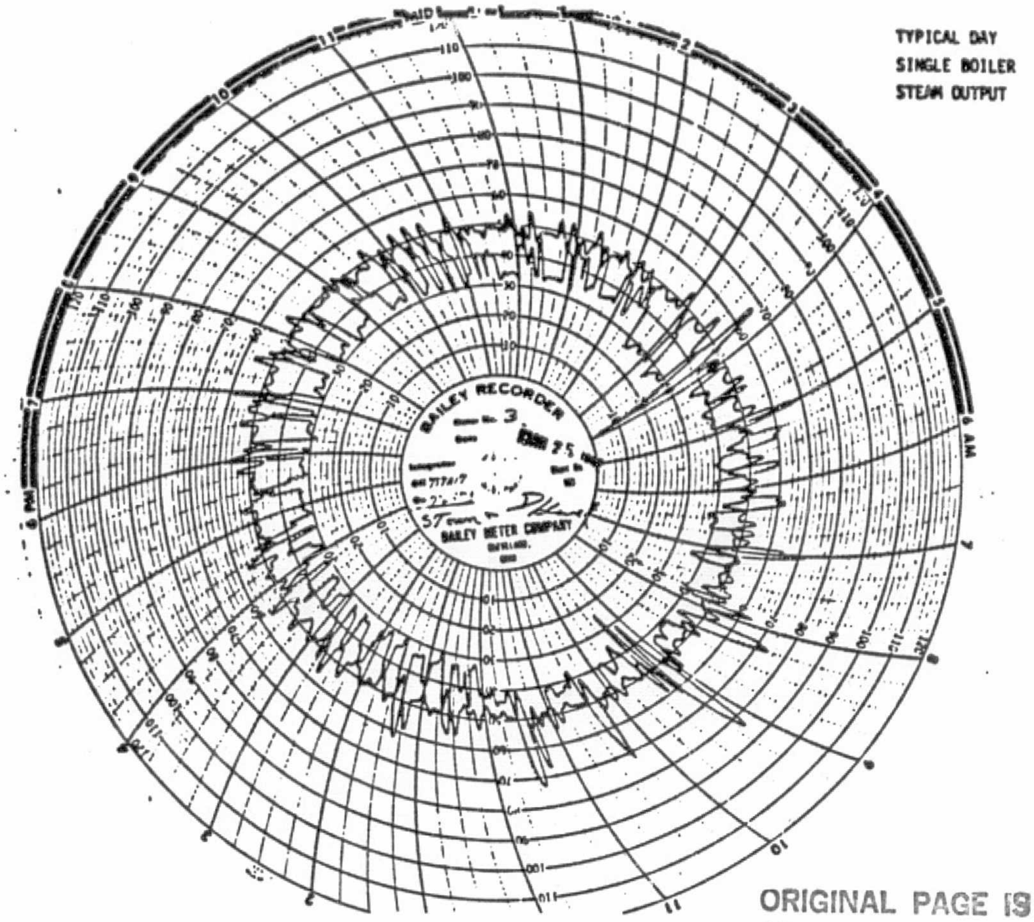

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Figure A4-3

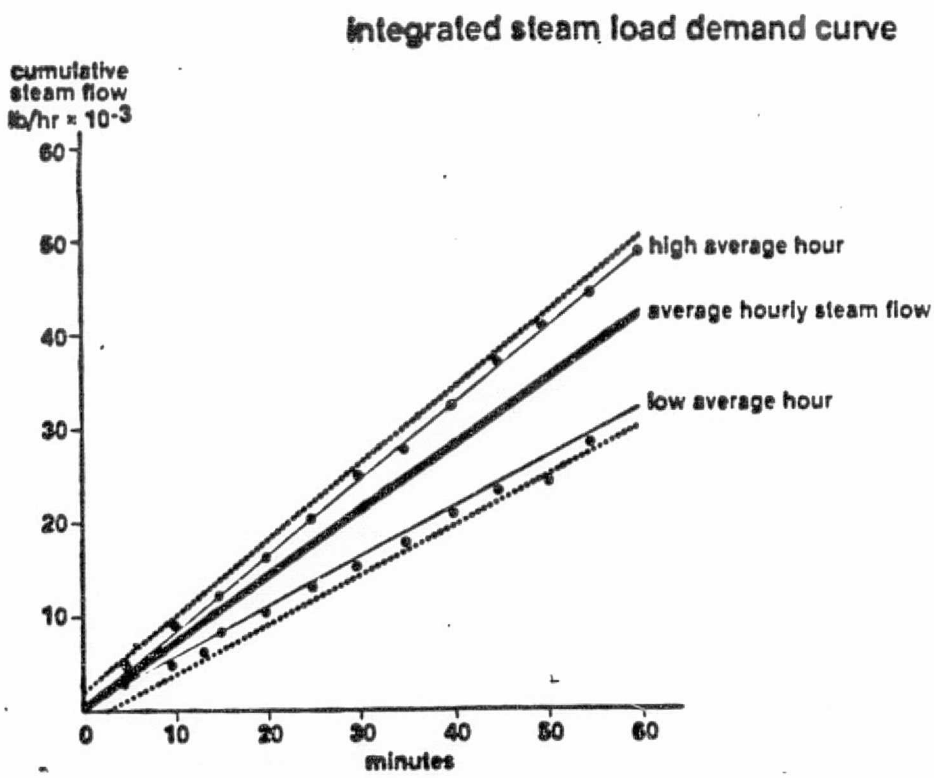

Figure A4-4

For the AFB/gas turbine system, a waste heat boiler can be taken to operate as the existing boilers to satisfactorily handle load swings, and is discussed further in section 4.2.1.

The steam load duration curve constructed from the boiler steam output curve is shown in Figure A4-5, resulting in about 52% annual load factor (area under the curve versus area of rectangle within curve boundaries). Maximum steam flow of about 100,000 lbs/hr must be maintained for plant safety considerations by preventing upsets in the process. Scheduled shutdowns are acceptable.

4.1.3 Dowtherm Heating

There is a steady Dowtherm heating load of 170 x 10^6 Btu/hr located at two existing Dowtherm heaters some distance from the existing boiler area. Dowtherm heating is considered for cogeneration systems. This Dowtherm heating load requires 231 x 10^6 Btu/hr gas fuel at the existing Dowtherm heaters as shown in Table A4-1.

4.1.4 Existing Boilers

For the conceptual designs, the existing boilers remain. Performance and benefits for the cogeneration systems will be compared to the current boiler system, which has no capital cost associated with it. This is a departure from the Task-2 plant screening analysis, which assumed new boilers. Further, the existing boilers form part of the overall cogeneration system, since they can provide backup and load swinging capability. Each cogeneration system approach will be covered.

4.1.5 Waste Fuel

A liquid waste fuel is produced by the process plant at a rate assumed to become a steady 70 x 10^6 Btu/hr on an annual basis in the future. This amounts to about 280 bbl/day equivalent #6 fuel oil, or about double current production. This fuel is unsaleable and cannot be assumed burnable in the AFBs. Further, this fuel cannot be handled by the existing Dowtherm heaters without unknown modifications. However, this fuel does burn readily in the existing boilers. For purposes of the study, the waste fuel is burned preferentially to any cogeneration fuel, and is priced the same as natural gas. Existing storage facilities are taken as adequate for handling this waste fuel.

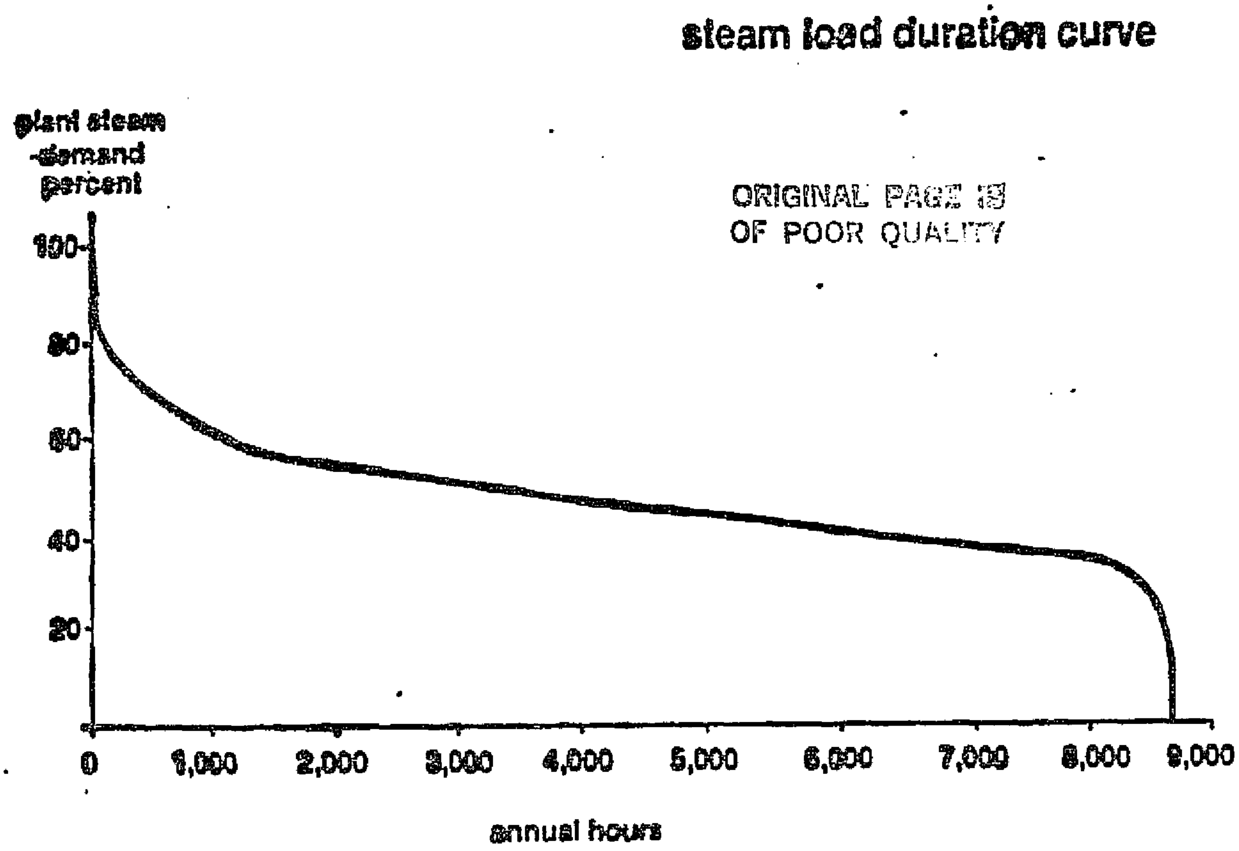

Figure A4-5. - STEAM LOAD DURATION CURVE

Table A4-1

DOWTHERM HEATING

BASIS

170 x 10^6 Btu/hr heat to Dowtherm

Existing Dowtherm heaters, assume:

65% for unit with no air preheater
82% for unit with air preheater

Weighing different sizes of the Dowtherm

Heaters give overall 73.6% E.

170 x 10^6 Dowtherm heating requires $\frac{170}{.736}$ = 231 MM Btu/hr gas input

4.1.6 Site Considerations

Several other site-specific items were provided by Ethyl Corporation.

A. Cogeneration Facility Site

An area north of the existing boilers by railroad tracks and a road, is available for the cogeneration plant, about 200 feet away. It is now occupied by miscellaneous storage tanks and a large storage building, which can be removed. This is the preferred site. A much larger site is also available further to the northeast, and is a large flat open field.

The Dowtherm heaters, which can be displaced, are in the process plant about 1,500 feet from the preferred cogeneration site. Pipe racks exist along much of the route.

A 66 KV electrical substation for the plant is about 1,500 feet west of the cogeneration site.

B. Material Delivery

Coal and limestone can be delivered to the site by rail, truck or barge. Rail delivery is considered because:

- Tracks are in place next to the cogeneration site.
- Quantities of incoming material are too great for economic truck delivery.
- Material is not enough to warrant barge unloading. Also, the distance from the barge facility to the cogeneration site adds to the cost.

Ethyl also specified that run of mine coal should be considered for delivery. This necessitates on-site crushing. Limestone is also delivered not sized, so on-site crushing is also needed for this material. Solid wastes, both fly ash and bottom ash, from the AFBs would be disposed off-site with removal by trucks.

As a result of open railroad car delivery of both coal and limestone, material drying facilities are considered for the systems.

C. Material Storage

A client requirement is for 15 day on-site covered storage of both coal and limestone. This is taken to be 15 days full load operation. Ash storage for 10 days capacity is also needed.

D. Water

The existing plant water softeners can remain in use with 100% makeup water still a requirement for steam production. For the new cogeneration facility, no credit will be given for preheating the makeup water with waste steam. Further, the cogeneration facility will provide its own auxiliary steam for feedwater/deaerating heating. But any new deaerator will operate at 40 psig, the same as the existing one, and a low-pressure steam connection will be provided, connecting the two deaerators.

The Coast Industrial Water Authority (CIWA) supply is apparently softened by lime-soda ash-magnesium process followed by zeolite softening. This produces water of low hardness and alkalinity. The iron concentration (3.5 ppm) is too high for use as boiler feedwater makeup and requires installation of an iron removal system (0.1 ppm). The dissolved solids concentration in the supply (210 ppm) mandates a boiler blowdown rate of 8% in order to observe the 3,500 ppm limit recommended by the ABMA for boilers operating in the projected pressure range.

4.2 AFB/GAS TURBINE COGENERATION SYSTEM

4.2.1 Approach to Performance

A. Operating Strategy

The strategy adopted for this operating system employs a heat match approach, providing average steam and Dowtherm heat needs. An approximate electrical match also results. Two half-size AFB combustors and gas turbines are employed. Each AFB combustor is a 43 ft. ID vessel about 45 ft. high. Refer to Appendix Section 1 for significant physical parameters of the AFB provided by Curtiss-Wright. The gas turbine would be Westinghouse Model W-191. Employing two half-size units results from the use of currently made gas turbines which do not require major modifications to be employed in this cycle with an AFB combustor. A steam match and a near electrical match also result. Also, a single AFB combustor size would be quite large. The cycle data provided by Curtiss-Wright is shown in Figure A4-6, and in Tables A4-2 and A4-3 for the mass and energy balance and process flow data. The design philosophy for the AFB/gas turbine system is summarized in Table A4-4.

B. Dowtherm Heating

The flexibility of the AFB/gas turbine system permits providing for Dowtherm heating, using the dirty 1,400°F flue gas to heat the Dowtherm, displacing natural gas at the process fired heaters. Consultation with fired-heater design specialists and manufacturers provided positive indications that this is a workable scheme, since the flue gas temperature is at a suitable level with regard to the Dowtherm. Heater designs can be provided to account for the dirty flue gas. Note that the flue gas, upon leaving the cycle Dowtherm heater, then proceeds to preheat the forced draft combustion air. Because of the value of displacing natural gas, a control scheme was developed by Curtiss-Wright to have Dowtherm heating remain constant while steam output is varied. Table A4-5 shows the basis for determining that Dowtherm heating is the valuable heating product. The control scheme is described in Appendix Section 1.

C. Steam Pressure

The clean hot gas turbine exhaust air produces steam in an unfired waste heat boiler. Since the air is clean, there is no minimum gas temperature that needs to be maintained. Feedwater preheating is provided in the waste heat boiler by this air. The concept shown has steam generated at 225 psig, saturated - the level required by the plant. A simple steam production arrangement is provided. Production of high pressure steam in conjunction with a backpressure steam turbine-generator is not provided. Steam generation at this pressure does not require significantly greater water treatment than the existing plant water softeners. Because a high iron content is indicated in the softened water, new iron removal filters are provided. Other than the deaerator, no further feedwater heating is provided.

AIR CYCLE AFB COGENERATION SYSTEM
ETHYL PLANT

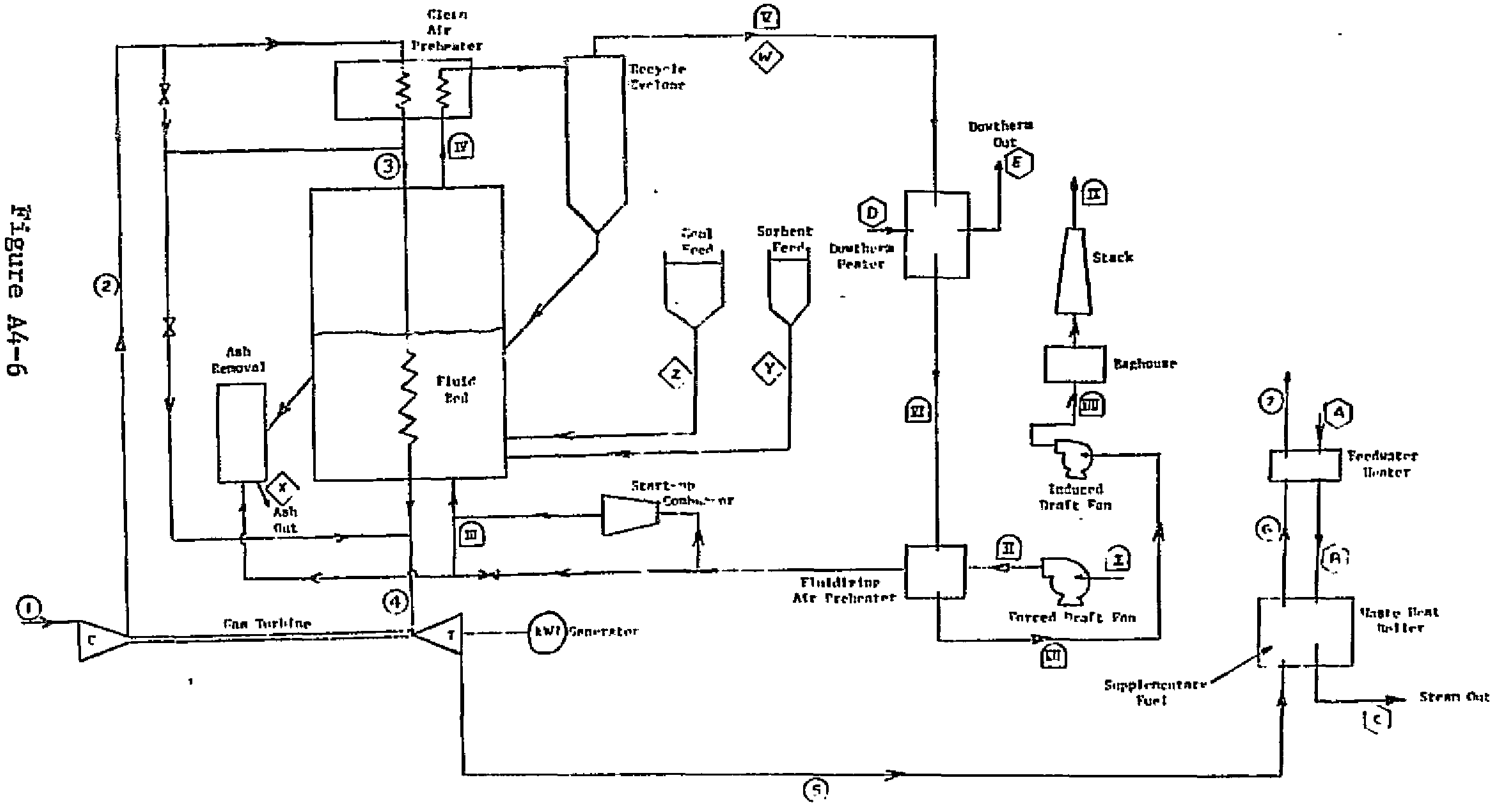

Figure A4-6

Table A4-2

AIR CYCLE AFB COGENERATION SYSTEM
MASS AND ENERGY BALANCE FOR ONE AFB/GT SYSTEM
ETHYL PLANT - TASK II

	Mass PPH	Energy Million Btu/Hr	%	Electricity Kw
FEEDS				
Coal, delivered	29811	369.66		
Limestone,	8860	-1.43		
Clean Air	961200	0.00		
Fluidizing Air	378000	0.00		
Feedwater (60^oF)	115439	0.00		
	1,493310	368.23	100.0	
PRODUCTS				
1439^oF Flue Gas to 697^oF	406679	85.00		
Solids Off-take	6661	2.75		
Fly Ash	3331	1.38		
Steam, 225 psig/397^oF	115439	135.34		
	532110	224.47	61.0	
ELECTRICAL				
Gas Turbine, Gross		-57.03		-16,712
Forced Draft Fan		+ 5.26		+ 1,541
Induced Draft Fan		+ 2.03		+ 596
Total Electrical, Net		49.74	13.5	14,575
LOSSES				
Feedwater + Economizer Heat, 1%		0.40		
Evaporator, 2%		1.91		
Combustion Process, HHV-LHV		12.58		
98% Comb. Eff.		7.13		
Gas Turbine Air				
Gas Turbine Gr. Box + Gen.		3.54		
Recycle Cyclone Separator		1.20		
Flue Gas Stack, 300^oF		25.23		
Clean Air Stack, 238^oF	961200	41.59		
Fluidizing Air Preheater, 1%		0.44		
	961200	94.02	25.5	
	1,493,310	368.23	100.0	

Table A4-3

AIR AFB CO NERATION SYSTEM
ETHYL . E - TASK II
PROCESS FLOW DATA

CLEAN AIR CIRCUIT[1]

	1	2	3	4	5	6	7
W	1,922,400	1,857,600	1,857,600	1,857,600	1,922,400	1,922,400	1,922,400
P	14.6	109.0	108.0	104.5	15.1	14.8	14.7
T	59	524	628	1500	807	407	238

COMBUSTION AIR CIRCUIT[1]

	I	II	III	IV	V	VI	VII	VIII	IX
W	756,000	756,000	756,000	820,020	820,020	820,020	820,020	820,020	813,358
P	14.7	19.9	19.6	14.7	14.3	13.6	13.4	14.9	14.7
T	59	117	590	1650	1439	69.7	280	300	300

SOLIDS FLOW[1]

	Z	Y	X	W
W	59,622	17,720	13,322	6662

DOWTHERM A CIRCUIT

STEAM CIRCUIT

	A	B	C	D	E
W	230,878	230,878	230,878	2,378,000	2,378,000
P	ATM	40	225		
T	60	287	397	680	550

ELECTRIC OUTPUT

KWI[1] = 29150

NOTE: Values shown are for two combustor/gas turbine units

W = Flow Rate, Pounds Per Hour
P = Pressure, PSIA for Air Circuits, PSIG for Steam
T = Temperature, °F
KW = Net Electrical Output, Kilowatts

Table A4-4

AFB/GAS TURBINE SYSTEM DESIGN PHILOSOPHY

- HEAT MATCH APPROACH (STEAM AND DOWTHERM).
- TWO HALF-SIZE AFB COMBUSTORS AND GAS TURBINES.
- STEAM LOAD OF 190,000 #/HR. AT 91.7% CAPACITY FACTOR.
- EXISTING BOILERS CONTINUOUSLY STEAMING.
- 90% AVAILABILITY FACTOR.
- DOWTHERM HEATING BY AFB COMBUSTOR FLUE GAS.
- SIMULTANEOUS BUY/SELL APPROACH EMPLOYED FOR ELECTRIC POWER.

D. Plant Availability and Waste Fuel Use

This section draws from ASME Paper 80-IPC/Pwr-1, Boiler Size Selection for Industrial Plants with Multiple Boilers by Lace, Nolte and Wainwright. The availability of a boiler (or AFB combustor) is a combination of scheduled outage and forced outage. For this study, a coal fired industrial installation has a scheduled outage of about three weeks each year for each AFB (combustor or boiler) in addition to a forced outage rate of 5%. With these data, an AFB has an overall availability of 90%.

The 190,000 lbs/hr average plant steam consumption requirement for a full year (8,760 hours) results in a .917 load factor from the analysis of the modified Steam Load Duration Curve, Figure A4-7. The product of 90% availability and 91.7% load factor is 82.5% capacity factor. Using the existing boilers firing waste oil to provide the remainder of the average plant steam needs, and using waste oil to fuel the coal and limestone drying still results in an excess of waste fuel. This excess waste fuel is preferentially burned to produce steam for process use. The remainder of the process steam is provided by the cogeneration system. The calculations in Table A4-6 show the procedure used.

Table A4-5: DETERMINATION OF LOAD CONTROL METHOD

Two ways to reduce load on AFB:
- o SCHEME A Drop coal flow
- o SCHEME B Increase air flow

Basis: 70% Steam Load

	SCHEME A			SCHEME B	
Item	Percent	MM BTU		Percent	MM BTU
Coal Flow	86.5	319.7	= 24.9 MM BTU	79.8	294.8
Dowtherm	100.0	66.7	= 18.3 MM BTU	78.5	85.0
Net Electric	66.5	33.1	= -1.5 MM BTU	69.3	34.5

Is it worth using an additional 24.9 MM Btu/hr fuel to get an additional 18.3 MM Btu Dowtherm heating, while losing 1.5 MM Btu (439.5 Kw) electricity?

	1988 COSTS	LEVELIZING FACTORS
Coal	$2.09/MM BTU	1.054
Gas	6.24/MM BTU	1.163
Sell Electric	.0707/KW	1.446

Assume existing Dowtherm heater has maximum 82% efficiency:

$24.9 \times 2.09 \times 1.054$ = $ 54.85/HR COAL

$\frac{1.5 \times 10^6}{3{,}413} \times .0707 \times 1.446$ = $ 44.93/HR ELECTRIC

$\frac{18.3}{.82} \times 6.24 \times 1.163$ = $161.98 GAS (DOWTHERM)

COAL	- $ 54.85
ELECTRIC	- 44.93
GAS SAVING	+ 161.98
	+ $ 62.20/HR x 8,760 = $545,000/YR LEVELIZED

It is cost effective to use additional coal fuel to keep Dowtherm heating even while losing electric power.

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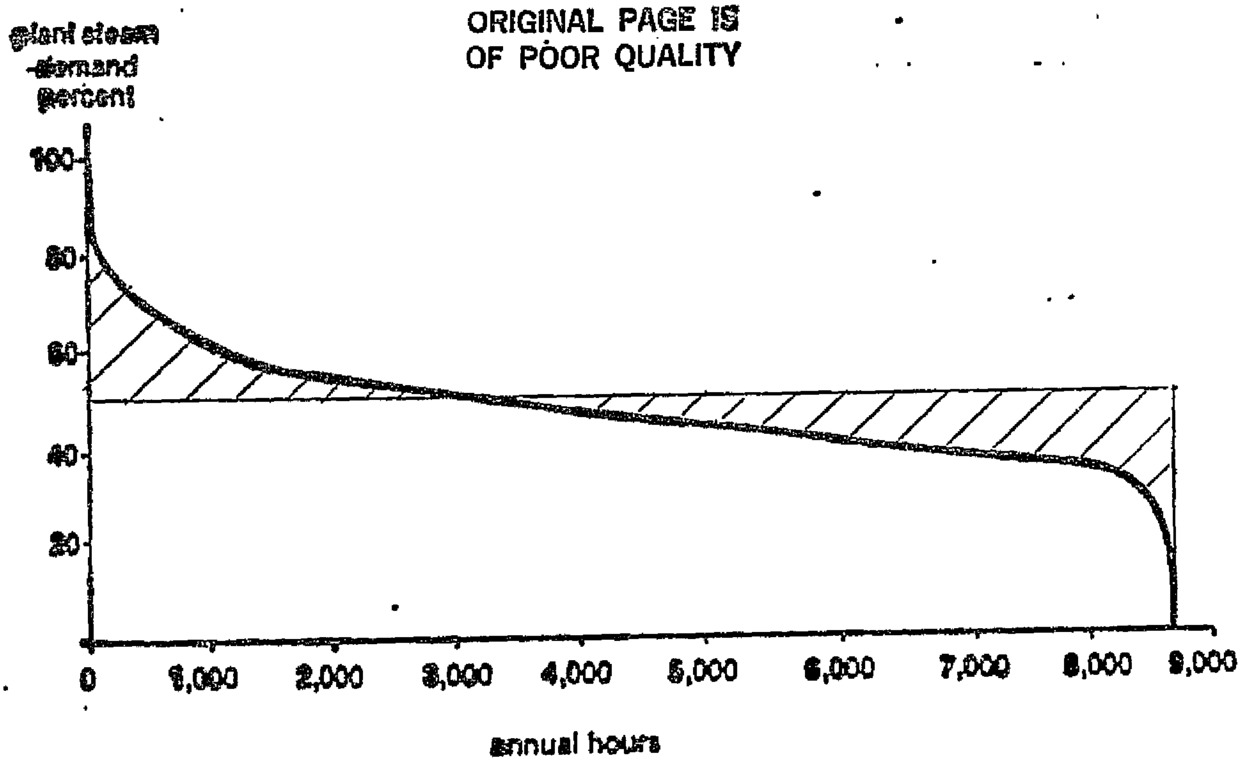


Figure A4-7. - MODIFIED STEAM LOAD DURATION CURVE

Table A4-6. - WASTE OIL BURNING — AFB/GAS TURBINE SYSTEM

<u>BASIS</u>: 90% Availability
91.7% Load Factor
70 MM Btu/Hr Waste Oil
1,326 Btu/lb steam heat input, existing boilers
14 MM Btu/Hr drying fuel
190,000 lbs/hr process steam
8,760 hrs/yr operation

1) .90 x .917 = .825 CAPACITY FACTOR, AFB

2) 190,000 x 1,326 x (1 -.825) = 44.1 MM Btu/hr waste fuel burned to account for capacity factor

3) 44.1 + (14 x .825, drying fuel requirement = 11.6) = 55.7 MM Btu/hr

4) 70 - 55.7 = 14.3 MM Btu/hr excess waste fuel to be preferentially burned in boilers

5) $14.3 \times 10^6 / 1,326$ = 10,800 lbs/hr steam to process

6) 190,000 - 10,800 / 190,000 = .94 OPERATING FACTOR

The Curtiss-Wright heat balance data allows for losses in their scope of supply. In order to account for heat losses in the remainder of the plant, an overall 98% realization ratio is applied to the coal fuel use. The product of the .825 capacity factor and .94 operating factor, divided by the .98 realization factor is a .791 plant factor. This figure is the factor by which design data is multiplied to obtain a single average running hour year-round.

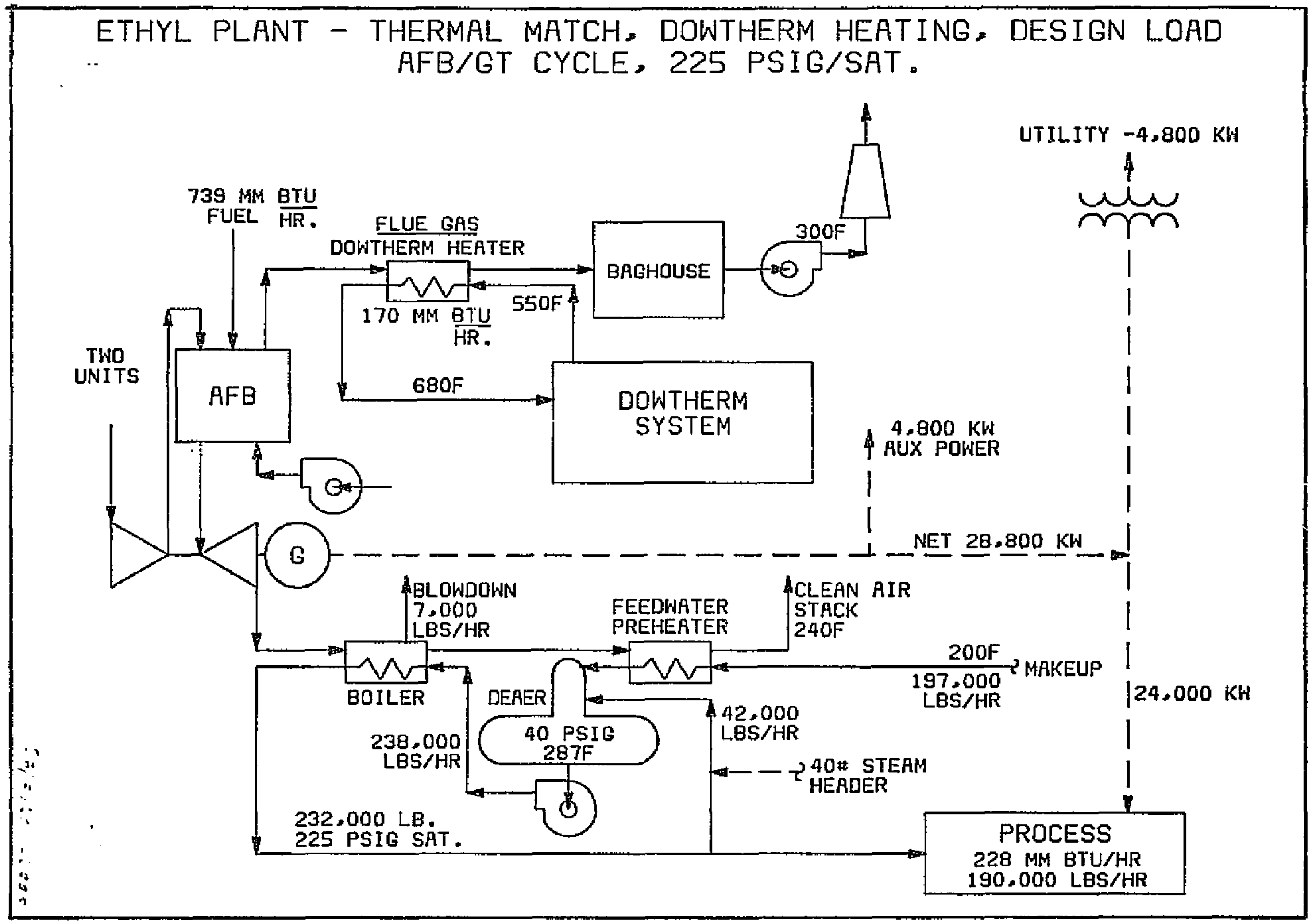
E. System Operation

The overall system flow diagram for the AFB/gas turbine is shown in Figure A4-8. The major design assumptions are summarized in Table A4-7. Some physical and operating parameters of the AFB combustor and some gas turbine operating parameters are summarized in Table A4-8. Additional items are given in Appendix Section 1.

The resource requirements of the AFB/gas turbine system are shown in Table A4-9. The average data is on the basis of one hour operation for 8,760 hours per year. The total water requirements given are based on 100% makeup water converted to steam and blowdown, plus an allowance for backwashing the iron removal filters.

The environmental impact of the AFB/gas turbine system is given in Table A4-10. The water discharge is the sum of the steam generator blowdown and the filter backwash. The process flow diagram, drawing A-202, of the cogeneration system is shown in Figure A4-9. The auxiliary power use for this system is dominated by the fan power requirements, as shown in Table A4-11.

Because the coal and limestone are shipped to the plant site in open railroad cars, with resultant surface moisture, drying equipment is deemed necessary. Table A4-12 gives the drying requirements. The underbed pneumatic feed system for the air cycle AFB combustor is shown having drying provided for both coal and limestone. The overbed stoker feed system for the steam cycle AFB boiler can handle "wet" coal, but limestone drying is provided because of on-site crushing and storage requiring some drying to avoid formation of large lumps of limestone.



ETHYL PLANT - THERMAL MATCH, DOWTHERM HEATING, DESIGN LOAD
AFB/GT CYCLE, 225 PSIG/SAT.
UTILITY -4,800 KW
739 MM BTU/HR.
FUEL
FLUE GAS
DOWTHERM HEATER
BAGHOUSE
300F
550F
170 MM BTU/HR.
TWO UNITS
AFB
680F
DOWTHERM SYSTEM
4,800 KW
AUX POWER
G
NET 28,800 KW
BLOWDOWN
7,000
LBS/HR
FEEDWATER PREHEATER
CLEAN AIR
STACK
240F
200F
MAKEUP
197,000
LBS/HR
BOILER
DEAER
40 PSIG
287F
42,000
LBS/HR
24,000 KW
238,000
LBS/HR
40# STEAM
HEADER
232,000 LB.
225 PSIG SAT.
PROCESS
228 MM BTU/HR
190,000 LBS/HR

Figure A4-8

Table A4-7: AFB/GAS TURBINE SYSTEM MAJOR DESIGN ASSUMPTIONS

- RAILROAD DELIVERY OF UNSIZED COAL AND LIMESTONE.
- 15 DAY SILO COVERED STORAGE FOR COAL AND LIMESTONE.
- ON-SITE CRUSHING OF COAL AND LIMESTONE. GREATER CRUSHING REQUIRED FOR COAL.
- DRYING EQUIPMENT PROVIDED FOR COAL AND LIMESTONE.
- 10 DAY SILO ASH STORAGE/TRUCK REMOVAL/OFF-SITE LANDFILL.
- STEAM GENERATION AT 225 PSIG USING GAS TURBINE EXHAUST AIR.
- 100% MAKEUP WATER AT 60°F FROM EXISTING PLANT SOFTENERS FILTERED FOR IRON REMOVAL.
- 1 STAGE OF FEEDWATER HEATING BY DEAERATOR.

Table A4-8: AFB/GAS TURBINE SYSTEM PARAMETERS

FUEL: Oklahoma Bituminous coal; 12,400 BTU/#HHV; 3.11%S; $1.96/MBtu, Delivered

SORBENT: Texas Limestone, 0.297 #/# Coal (3:1 Ca/S MOL RATIO); 39.2% Calcium, $11.00/Ton

AFB/HEATER (CURTISS-WRIGHT):

Bed Temperature - 1,650°F
Bed Depth - 8 Ft.
Bed Area (per unit) - 1,452 Ft.^{2}
Excess Air Flow - 36%
Fluidizing Velocity - 3.7 Ft./Sec.
Turndown Capability (2.5:1) - 40% (to suit system minimum)

POWER CYCLE: Air - Brayton Total - 2 Gas Turbines, Westinghouse Model 191
Turbine Inlet Temperature - 1,500°F
Turbine Inlet Pressure - 104.1 Psia
Compressor Pressure Ratio - 7.47
Mass Flow - 267 #/Sec. (per unit)

HEAT REJECTION EQUIPMENT: None

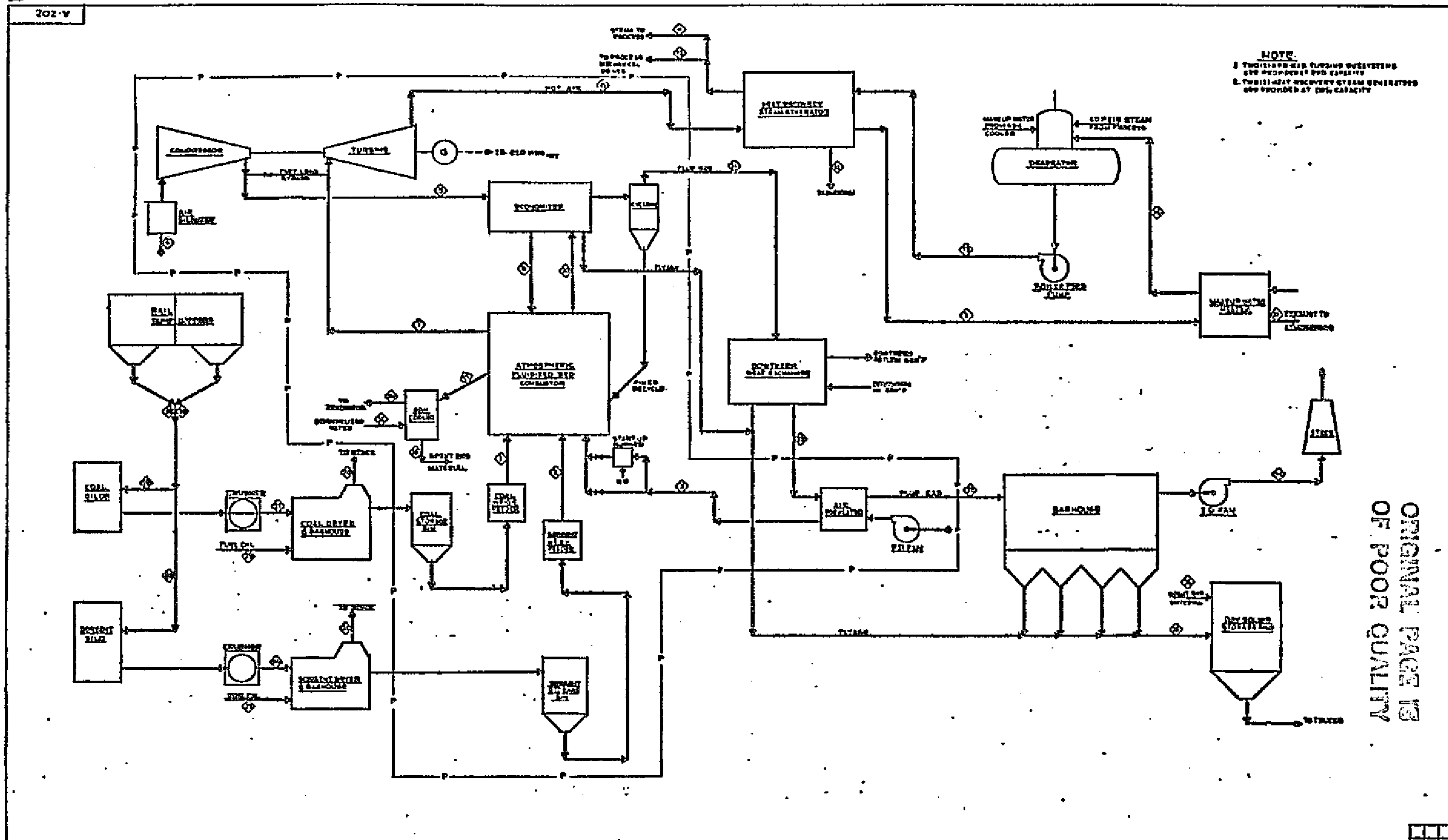
Table A4-9: RESOURCE REQUIREMENTS - AFB/GAS TURBINE

	Design	Average (0.791 Plant Factor)
COAL	716 tons/day	566 tons/day
LIMESTONE	213 tons/day	168 tons/day
NATURAL GAS (FOR DOWTHERM HEATING)	0 MBtu/day	970 MBtu/day
WASTE FUEL	0 MBtu/day	1,680 MBtu/day
WATER - TOTAL	718,140 Gals/day	568,050 Gals/day
Process Steam	230,900 #/hr	182,640 #/hr
Cooling - Evap.	0 Gals/day	0 Gals/day
Blowdown (3%)	20,580 Gals/day	16,280 Gals/day

LAND REQUIREMENTS: POWERHOUSE - 3.0 Acres; RAILYARD - 1.5 Acres

Table A4-10: ENVIRONMENTAL IMPACT - EMISSIONS - AFB/ GAS TURBINE
(739.32 MBtu/Hr. - Design Rating)

	Design	Average (0.791)
GASEOUS: SO_x - 0.50 #/MBtu	4.44 tons/day	3.51 tons/day
NO_x - 0.40 #/MBtu	3.55 tons/day	2.81 tons/day
PARTICULATE: 0.10/MBtu	0.89 tons/day	0.70 tons/day
THERMAL:		
Cooling Tower - 0 Btu/MBtu	--	--
Flue Gas Stack - 68,250 Btu/MBtu	50.5 MBtu/hr	39.9 MBtu/hr
Clean Air Stack - 112,510 Btu/MBtu	83.2 MBtu/hr	65.8 MBtu/hr
Other - 141,200 Btu/MBtu	104.4 MBtu/hr	82.6 MBtu/hr
SOLIDS: Total - 25.19 #/MBtu	223.5 TPD	176.8 TPD
WATER DISCHARGE: 3.06 Gals/MBtu	54,330 Gals/day	42,980 Gals/day



STREAM NO	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
CLASSIFICATION	COAL	LIMESTONE	AIR	AIR	AIR	AIR	AIR	AIR	AIR	AIR	STEAM	STEAM	FEEDWATER	[illegible]	[illegible] WATER	MAKEUP WATER
PRESSURE PSIA	14.7	14.7	[illegible]	14.7	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	14.7	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
TEMPERATURE °F	AMBIENT	AMBIENT	[illegible]	[illegible]	[illegible]	[illegible]	1500	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	
DENSITY, LB/CU FT	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	
MAT'L FLOW, LB/HR	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			
ENERGY FLOW MMBTU/HR	[illegible]	0		0						[illegible]	[illegible]	[illegible]	[illegible]			
PARTICULATE CONTENT GR/ACF	—	—	0	0	0	0	0	0	0	0	—	—	—	—	—	—
MOISTURE CONTENT %	0.0	0	1.30	1.30	1.30	1.30	1.30	1.30	1.30	[illegible]	0	0	—	—	—	—

STREAM NO	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
CLASSIFICATION	SPENT BED MATERIAL	SPENT BED MATERIAL	FLYASH	FLUE GAS	FLUE GAS	FLUE GAS	FLUE GAS	FLUE GAS	NATURAL GAS	LIMESTONE	COAL	LIMESTONE	COAL	FLUE GAS	FLUE GAS	[illegible]
PRESSURE PSIA	[illegible]	14.7	14.7	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		14.7	14.7			[illegible]	[illegible]	
TEMPERATURE °F	[illegible]	[illegible]	350	[illegible]	[illegible]	[illegible]	[illegible]	300		AMBIENT	AMBIENT	AMBIENT	AMBIENT			
DENSITY, LB/CU FT	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]			
MAT'L FLOW, LB/HR	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]					[illegible]
ENERGY FLOW MMBTU/HR								[illegible]		0	[illegible]	0				
PARTICULATE CONTENT GR/ACF	—	—	—	—	[illegible]	[illegible]	[illegible]	[illegible]	—	—	—	—	—			—
MOISTURE CONTENT %	—	—	—	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]			—

A-202

Figure A4-9

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Table A4-11

AFB/GAS TURBINE CYCLE

SUMMARY OF AUXILIARY POWER USAGE

	KW
MAKEUP FEEDWATER PUMP	20
BOILER FEEDWATER PUMP	90
MATERIAL HANDLING	355
DOWTHERM PUMPING	81
2 FORCED DRAFT FANS	3,082
2 INDUCED DRAFT FANS	1,192
	4,820 KW

Table A4-12

MATERIAL DRYING

COAL MOISTURE: 8.5% Avg.
15.0% Max.

Heat Input, MM Btu/Hr	Air Cycle	Steam Cycle
Coal	10	--
Limestone	4	2
Total	14	2

4.2.2 Cost Estimate and Economics

A. Capital Cost Estimate

A summary of the capital cost estimate is shown in Table A4-13. Note the large interest charge equal to 37% of the capital cost, which is due to the economic groundrules stipulating the interest charge be assigned to the entire engineering, permitting and construction time. Figure A4-10 shows the anticipated project schedule, including the time required to obtain the necessary permits for coal firing. Probably no major expenditures would be made until all permits have been obtained. The summary and sub-summary sheets providing details of the costs shown in Table A4-13 are given in Tables A4-14 and A4-15. The largest material cost item, code 0100, consists of the two half-size AFB units costed by Curtiss-Wright in Table A4-16, with 5% additional costs for miscellaneous extras plus brushing, waste heat boilers and Dowtherm heaters. The second largest cost item is code 1100, the material handling equipment, which includes coal, limestone, ash, drying, and the storage silos.

B. Uncertainty Analysis

A description of the procedures used in quantifying the uncertainty in the cost estimate is provided in Appendix Section 2, using the AFB/gas turbine cycle as the example.

C. Economic Performance

The predicted cash flow/ROI calculation over the economic life of the cogeneration plant is given in the computer printout shown in Table A4-17. Levelized annual energy cost analysis is presented in Table A4-18 for the Base Case (no cogeneration), AFB/Gas Turbine Case, and AFB/Steam Turbine Case.

4.2.3 Reference Plant System Description

A. Site

The proposed site, about 200 feet from the present boilers, is acceptable for the AFB/gas turbine cogeneration system. Equipment arrangement drawing A-102, Figure A4-11, shows the proposed equipment is readily

Table A4-13

AFB/GAS TURBINE COGENERATION PLANT CAPITAL COSTS
(Thousands of Dollars)

		COSTS	TOTAL
1.	AFB Heaters/Gas Turbines Subsystem	27,715	
	Heaters & Boilers	4,574	
	Baghouse	1,474	
2.	Turbine/Generator	Included in #1	
3.	Mechanical Equipment	5,761	
	Material Handling	7,488	
4.	Electrical	1,946	
5.	Civil & Structural	3,829	
6.	Process Piping	3,081	
	Instrumentation	561	
7.	Yardwork & Miscellaneous	1,246	
		57,675	
	Direct Cost		57,675
	A/E Home Office & Fees		9,325
	TOTAL PLANT COST		67,000
	Contingency		0
	TOTAL CAPITAL COST		67,000
	Interest Charge (60-month project)		24,723
	TOTAL CAPITAL INVESTMENT		91,723

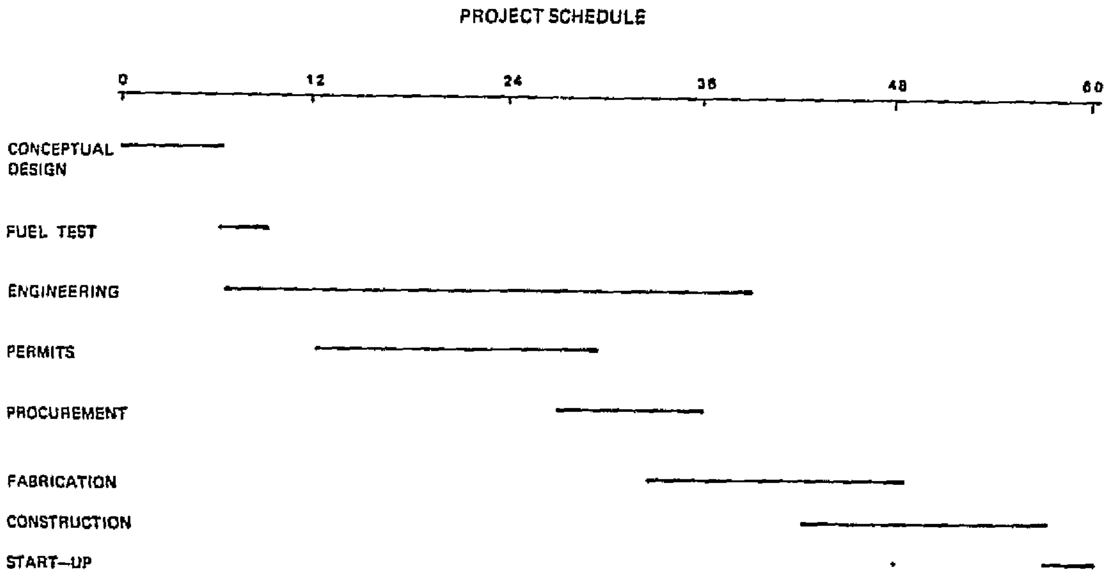

Figure A4-10

Table A4-14

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CATALYTIC, INC.
Philadelphia, Pennsylvania 19102

13045-0976P

SUMMARY SHEET "STUDY ESTIMATE"

Estimate/Job Number 43790 Date 9-20-82

Customer NASA

Location PASADENA, TEXAS

Description ADVANCED CO-GENERATION STUDY - GAS CYCLE

Process Equipment						
Materials						
Subcontracts and Shop Labor	57	675	000			
All Risk Insurance, Legal Liability, etc. .25%		150	000			
Special Taxes, (sales, use, etc.) 6% on Material		220	000			
Bond 1%		600	000			
Total Material, Subcontracts and Shop Labor	58	645	000			
Field Labor						
Payroll Burden						
Total Field Labor	-	0	-			
Field Supervision, Field Office Personnel, Field Office Expense, Field Planning, Start-up Operators } Construction Management	1	355	000			
Construction Equipment and Tools						
Total Other Field Charges	1	355	000			
Mechanical Engineering, Process Engineering, Estimating, Planning, and Cost Analysis 8.6%, Purchasing, Expediting and Shop Inspection, Accounting, Industrial Relations, General Administration & Construction Mgmt.	5	700	000			
Total Home Office Expenses	5	700	000			
Sub-Total	65	700	000			
Contingencies						
Escalation						
Sub-Total	65	700	000			
Overhead						
Fee 2%	1	300	000			
Grand Total	67	000	000			

Remarks: Study Estimate (+) 35% - Present Day Cost.
Demolition - Items to be cleaned and safed by owner prior to demolition.

Table A4-15

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CATALYTIC
F15021-982P

Sub-Summary

Client NASA Estimate No. 43790

Location PASADENA, TEXAS Date 9-17-82

Page ___ of ___

GAS CYCLE

Code	Description	Material	Labor	Subcontract
0100	Fired Heaters and Boilers			32,288,600
0200	Stacks			250,000
0400	Reactors and Internals			
0500	Towers and Internals			
0600	Heat Exchange Equipment			25,300
0700	Cooling Towers			
0800	Vessels, Tanks, Drums and Internals			158,900
0900	Pumps and Drivers			253,900
1000	Blowers and Compressors			295,600
1100	Elevators, Conveyors, Materials Handling Equipment			7,487,600
1200	Miscellaneous Mechanical Equipment			1,474,000
2500	Tankage			
2800	Filters, Centrifuges, Separator Equipment			478,500
2900	Agitators and Mixers			
3000	Scrubbers and Entrainment Separators			
3100	Machine Tools and Machine Shop Equipment			
3200	Heating, Ventilation, Air Conditioning, Dust Control (Process Only)			
3400	Package Units			
	Start-up Spare Parts 2%			800,000
Sub-Total — Major Equipment		- 0 -	- 0 -	43,512,400
1300	Piping			3,001,000
1400	Sewers			20,000
1500	Instrumentation			561,200
1600	Electrical			1,945,500
1700	Concrete			3,772,000
1800	Structural Steel			57,000
1900	Fireproofing			50,000
2000	Buildings			30,000
2100	Site Development and Demolition			426,000
2200	Insulation			514,900
2300	Painting and Protective Coatings			20,000
2400	Field Testing			
2600	Chemicals and Catalyst			
2700	Piling			
3300	Fire Protection			185,000
3500	Miscellaneous Systems 6.5%			3,500,000
Sub-Total		- 0 -	- 0 -	57,675,000
3700	Miscellaneous Direct Charges			
3800	Storehouse Accounts			
3900	Construction Supplies and Petty Tools			
1300	Testing Welders			
3600	Temporary Piping and Electrical Facilities			
3600	Temporary Construction Buildings			
3600	Temporary Site Development			
Total Direct Costs		- 0 -	- 0 -	57,675,000

Table A4-16

AIR CYCLE AFB COGENERATION SYSTEM

Costing Summary - Go Rate Units

ETHYL SITE - Task 2

		Cycle A
A.	Combustor	1,543,400
B.	Hx and Manifolds	2,442,500
C.	Recycle System	612,800
D.	Start Up Combustor/FD Fan	580,000
E.	System Controls	171,000
F.	Coal Feed System	497,200
G.	Air Preheater	225,700
H.	Ash Cooling System	66,700
I.	Air Piping	1,334,200
J.	Miscellaneous	430,900
K.	Gas Turbine System	4,860,000
L.	Fluidizing Air Preheater	162,700
	Hardware	12,927,100
	Engineering/Software	706,700
	1st Unit	13,633,800
	2nd Unit	
	Hardware	12,539,300
	Software	223,500
		12,762,800

ADVANCED TECHNOLOGY COGENERATION-CONCEPTUAL DESIGN STUDY
NASA-LEWIS RESEARCH CENTER CATALYTIC JOB NO.43790
SUBTASK 2D NO COGEN VS AFB/GT SENSITIVITY ANALYSIS

Table A4-17

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
PLANT INVESTMENT($M)	(91.723)	-	-	-	-	-	-	-	-	-
INCREMENTAL PLANT INVESTMENT($M)	(91.723)	-	-	-	-	-	-	-	-	-
COAL USE MMBTU/HR	585.040	585.040	585.040	585.040	585.040	585.040	585.040	585.040	585.040	585.040
COGEN OIL/GAS USE MMBTU/HR	70.000	70.000	70.000	70.000	70.000	70.000	70.000	70.000	70.000	70.000
COGEN DOWTHERM FUEL MMBTU/HR	40.425	40.425	40.425	40.425	40.425	40.425	40.425	40.425	40.425	40.425
NO COGEN FUEL INCL DOWTHERM MMBTU/HR	483.000	483.000	483.000	483.000	483.000	483.000	483.000	483.000	483.000	483.000
PRICE OF OIL/GAS ($/MMBTU)	6.240	6.427	6.620	6.819	7.024	7.235	7.452	7.676	7.906	8.143
PRICE OF COAL ($/MMBTU)	2.090	2.111	2.132	2.153	2.175	2.197	2.219	2.241	2.263	2.286
COST NO COGEN FUEL ($M)	26.402	27.193	28.010	28.852	29.719	30.612	31.530	32.478	33.451	34.454
COST OF COAL ($M)	10.711	10.819	10.926	11.034	11.147	11.260	11.372	11.485	11.598	11.716
COST COGEN OIL/GAS + DOWTHERM ($M)	6.036	6.217	6.404	6.596	6.794	6.999	7.208	7.425	7.648	7.877
TOTAL COST COGEN FUEL ($M)	16.747	17.036	17.330	17.630	17.941	18.259	18.580	18.910	19.246	19.593
INCREMENTAL FUEL COST($M)	9.655	10.157	10.680	11.222	11.778	12.353	12.950	13.568	14.205	14.861
AVERAGE ELECTRIC GEN. MW/HR	23.973	23.973	23.973	23.973	23.973	23.973	23.973	23.973	23.973	23.973
POWERHOUSE ELECTRIC USE MW/HR	4.000	4.000	4.000	4.000	4.000	4.000	4.000	4.000	4.000	4.000
PLANT AVERAGE ELECTRIC USE MW/HR	24.000	24.000	24.000	24.000	24.000	24.000	24.000	24.000	24.000	24.000
ELECTRIC BUY RATE ($/KW-HR)	0.0621	0.0664	0.0710	0.0760	0.0813	0.0870	0.0931	0.0996	0.1066	0.1141
BASE CASE ELECTRICITY PURCHASED MW/HR	24.130	24.130	24.130	24.130	24.130	24.130	24.130	24.130	24.130	24.130
PRICE FOR SELLING ELECTRICITY $/KW-HR	0.0707	0.0756	0.0809	0.0866	0.0927	0.0992	0.1061	0.1135	0.1214	0.1299
REVENUE FROM ELECTRIC SALE ($M)	14.847	15.876	16.989	18.186	19.467	20.832	22.281	23.835	25.494	27.279
COST OF PURCHASED ELECTRICITY($M)	15.232	16.287	17.415	18.641	19.941	21.339	22.836	24.430	26.147	27.986
COST OF ELECTRIC ENERGY ($M)	0.385	0.411	0.426	0.455	0.474	0.507	0.555	0.595	0.653	0.707
BASE CASE COST ELECTRICITY ($M)	13.127	14.036	15.008	16.065	17.185	18.390	19.679	21.053	22.533	24.118
INCREMENTAL COST OF ELECTRICITY $M	12.742	13.625	14.582	15.610	16.711	17.883	19.124	20.458	21.880	23.411
ANNUAL ENERGY COST ($M)	17.132	17.447	17.756	18.085	18.415	18.766	19.135	19.505	19.899	20.300
ANNUAL ENERGY SAVINGS($M)	22.397	23.782	25.262.	26.832	28.489	30.236	32.074	34.026	36.085	38.272
PRICE OF SORBENT $/TON	11.000	11.000	11.000	11.000	11.000	11.000	11.000	11.000	11.000	11.000
COST OF SORBENT($M)	0.676	0.676	0.676	0.676	0.676	0.676	0.676	0.676	0.676	0.676
COST OF WASTE DISPOSAL($M)	0.346	0.346	0.346	0.346	0.346	0.346	0.346	0.346	0.346	0.346
UTILITIES,LABOR,MAINT.($M)	3.321	3.321	3.321	3.321	3.321	3.321	3.321	3.321	3.321	3.321
INSURANCE AND LOCAL TAXES($M)	1.376	1.376	1.376	1.376	1.376	1.376	1.376	1.376	1.376	1.376
ANNUAL OPER,MAIN&TAXES ($M)	5.719	5.719	5.719	5.719	5.719	5.719	5.719	5.719	5.719	5.719
BASE COST OPER MAINT & TAXES ($M)	1.095	1.095	1.095	1.095	1.095	1.095	1.095	1.095	1.095	1.095
INCREMENTAL COST OF OPER.&MAINT. ($M)	(4.624)	(4.624)	(4.624)	(4.624)	(4.624)	(4.624)	(4.624)	(4.624)	(4.624)	(4.624)
SAVINGS BEFORE TAXES ($M)	17.773	19.158	20.638	22.208	23.865	25.612	27.450	29.402	31.461	33.648
DEPRECIATION $M	18.345	29.351	22.014	14.676	7.338	-	-	-	-	-
NET TAXABLE INCOME($M)	-	-	-	7.532	16.527	25.612	27.450	29.402	31.461	33.648
INCOME TAX ($M)	-	-	-	3.615	7.933	12.294	13.176	14.113	15.101	16.151
INCOME TAX CREDIT ($M)	9.172	-	-	-	-	-	-	-	-	-
NET INCOME AFTER TAXES($M)	9.172	-	-	3.917	8.594	13.318	14.274	15.289	16.360	17.497
DEPRECIATION ADDED BACK($M)	18.345	29.351	22.014	14.676	7.338	-	-	-	-	-
CASH FLOW ($M)	27.517	29.351	22.014	18.593	15.932	13.318	14.274	15.289	16.360	17.497
CALCULATION OF ROI	(91.723)	27.517	29.351	22.014	18.593	15.932	13.318	14.274	15.289	16.360

RETURN ON INVESTMENT = 21.916%

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Table A4-17 (Cont.)

ADVANCED TECHNOLOGY COGENERATION-CONCEPTUAL DESIGN STUDY
NASA-LEWIS RESEARCH CENTER CATALYTIC JOB NO.43790
SUBTASK 2D NO COGEN VS AFB/GT SENSITIVITY ANALYSIS

	1998	1999	2000	2001	2002
PLANT INVESTMENT($M)	-	-	-	-	-
INCREMENTAL PLANT INVESTMENT($M)	-	-	-	-	-
COAL USE MMBTU/HR	585.040	585.040	585.040	585.040	585.040
COGEN OIL/GAS USE MMBTU/HR	70.000	70.000	70.000	70.000	70.000
COGEN DOWTHERM FUEL MMBTU/HR	40.425	40.425	40.425	40.425	40.425
NO COGEN FUEL INCL DOWTHERM MMBTU/HR	483.000	483.000	483.000	483.000	483.000
PRICE OF OIL/GAS ($/MMBTU)	8.387	8.639	8.898	9.165	9.440
PRICE OF COAL ($/MMBTU)	2.309	2.332	2.355	2.377	2.403
COST NO COGEN FUEL ($M)	35.486	36.552	37.648	38.778	39.941
COST OF COAL ($M)	11.834	11.951	12.069	12.192	12.315
COST COGEN OIL/GAS + DOWTHERM ($M)	8.113	8.357	8.607	8.866	9.132
TOTAL COST COGEN FUEL ($M)	19.947	20.308	20.676	21.058	21.447
INCREMENTAL FUEL COST($M)	15.539	16.244	16.972	17.720	18.494
AVERAGE ELECTRIC GEN. MW/HR	23.973	23.973	23.973	23.973	23.973
POWERHOUSE ELECTRIC USE MW/HR	4.000	4.000	4.000	4.000	4.000
PLANT AVERAGE ELECTRIC USE MW/HR	24.000	24.000	24.000	24.000	24.000
ELECTRIC BUY RATE ($/KW-HR)	0.1221	0.1306	0.1397	0.1495	0.1600
BASE CASE ELECTRICITY PURCHASED MW/HR	24.130	24.130	24.130	24.130	24.130
PRICE FOR SELLING ELECTRICITY $/KW-HR	0.1390	0.1487	0.1591	0.1702	0.1821
REVENUE FROM ELECTRIC SALE ($M)	29.190	31.228	33.412	35.743	38.242
COST OF PURCHASED ELECTRICITY($M)	29.949	32.034	34.266	36.669	39.245
COST OF ELECTRIC ENERGY ($M)	0.759	0.806	0.854	0.926	1.003
BASE CASE COST ELECTRICITY ($M)	25.809	27.606	29.530	31.601	33.821
INCREMENTAL COST OF ELECTRICITY $M	25.050	26.800	28.676	30.675	32.818
ANNUAL ENERGY COST ($M)	20.706	21.114	21.530	21.984	22.450
ANNUAL ENERGY SAVINGS($M)	40.589	43.044	45.648	48.395	51.312
PRICE OF SORBENT $/TON	11.000	11.000	11.000	11.000	11.000
COST OF SORBENT($M)	0.676	0.676	0.676	0.676	0.676
COST OF WASTE DISPOSAL($M)	0.346	0.346	0.346	0.346	0.346
UTILITIES,LABOR,MAINT.($M)	3.321	3.321	3.321	3.321	3.321
INSURANCE AND LOCAL TAXES($M)	1.376	1.376	1.376	1.376	1.376
ANNUAL OPER,MAIN&TAXES ($M)	5.719	5.719	5.719	5.719	5.719
BASE COST OPER MAINT & TAXES ($M)	1.095	1.095	1.095	1.095	1.095
INCREMENTAL COST OF OPER.&MAINT. ($M)	(4.624)	(4.624)	(4.624)	(4.624)	(4.624)
SAVINGS BEFORE TAXES ($M)	35.965	38.420	41.024	43.771	46.688
DEPRECIATION $M	-	-	-	-	-
NET TAXABLE INCOME($M)	35.965	38.420	41.024	43.771	46.688
INCOME TAX ($M)	17.263	18.442	19.692	21.010	22.410
INCOME TAX CREDIT ($M)	-	-	-	-	-
NET INCOME AFTER TAXES($M)	18.702	19.978	21.332	22.761	24.278
DEPRECIATION ADDED BACK($M)	-	-	-	-	-
CASH FLOW ($M)	18.702	19.978	21.332	22.761	24.278
CALCULATION OF ROI	17.497	18.702	19.978	21.332	22.761

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Table A4-18

ETHYL PLANT SITE

LEVELIZED ANNUAL ENERGY COST ANALYSIS

TASK 2 - CONCEPTUAL PLANT DESIGN

COST ITEM MILLION $	LEVELIZING FACTORS	1988 COSTS IN 1981 DOLLARS			LEVELIZED COSTS		
		EXISTING PLANT	AFB/ST	AFB/GT	EXISTING PLANT	AFB/ST	AFB/GT
CAPITAL COST	---	---	42.840	67.000	---	---	---
CAPITAL INVESTMENT (1.37)	---	---	58.646	91.723	---	---	---
LEVELIZED CAPITAL INVESTMENT	.245	---	---	---	---	14.369	22.472
FUEL COST - GAS	1.163	13.775	3.826	3.826	16.020	4.450	4.450
FUEL COST - COAL	1.054	---	4.548	10.711	---	4.794	11.290
FUEL COST - DOWTHERM HEATING	1.163	12.627	12.627	2.210	14.685	14.685	2.570
ELECTRIC PURCHASE	1.446	13.127	13.780	15.232	18.981	19.925	22.043
ELECTRIC BUY-BACK	1.446	---	(5.212)	(14.847)	---	(7.536)	(21.469)
SORBENT	1.0	---	.292	.676	---	---	---
WASTE DISPOSAL	1.0	---	.177	.346	---	---	---
UTILITIES, LABOR & MAINTENANCE	1.0	.845	2.387	1.457	---	---	---
INSURANCE & LOCAL TAXES	1.0	.250	.643	1.005	---	---	---
SUM OF CONSTANT ANNUAL COSTS	1.0	1.095	3.499	3.484	1.095	3.499	3.484
LEVELIZED ANNUAL ENERGY COST (NOMINAL $)	---	---	---	---	50.781	54.186	44.840
LEVELIZED ANNUAL ENERGY COST SAVING	---	---	---	---	---	(3.405)	5.941
PERCENT SAVING	---	---	---	---	---	(6.71)	11.70

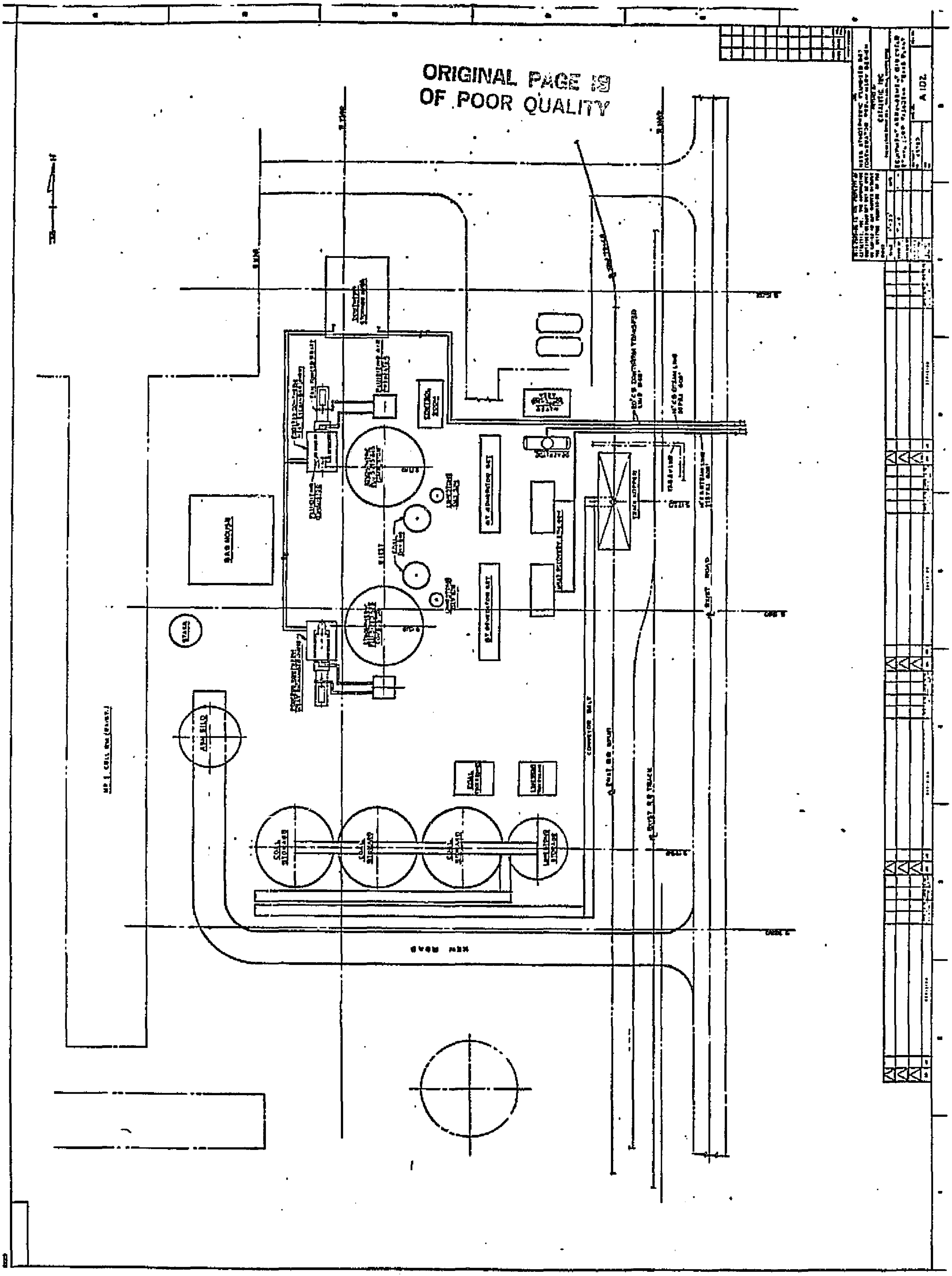

Figure A4-11

accommodated by the site after removal of existing tanks and buildings. It is assumed that the existing railroad tracks and spur can accommodate coal and limestone cars. Some new railroad track also is required to accommodate coal and limestone unloading. A portion of new roadway is needed to provide access to the ash silo. The site is about 1,500 feet from the main plant electrical substation. Necessary tie-ins to the existing boiler area can be readily made.

B. Air Cycle AFB Components

Appendix Section 1 provides detailed physical parameters for the AFB system components under Curtiss-Wright's scope of supply.

C. Dowtherm System

Having Dowtherm heated by the air cycle AFB combustor flue gas requires new equipment which is required to connect to the existing Dowtherm equipment and provide a workable scheme. Figure A4-12 schematically shows the extent of the new equipment required. This has been allowed for in the cost estimate.

The design criteria for the Dowtherm heating system is given in Table A4-19. In designing a heating system, four main safety factors have to be considered:

1) Low flow of Dowtherm
2) Uneven flow to each pass
3) Overheating of Dowtherm
4) Ruptured or leaking Dowtherm tubes

Table A4-19: DOWTHERM HEATING SYSTEM DESIGN CRITERIA

DOWTHERM A		FLUE GAS	
Flow Per Unit	1,085,700 lbs/hr	Flow Rate	406,679 lbs/hr
Inlet Temperature	550°F	Inlet Temperature	1,439°F
Outlet Temperature	680°F	Outlet Temperature	697°F
Inlet Pressure	200 psig	Inlet Pressure	14.3 psia
Outlet Pressure	190 psig	Outlet Pressure	13.6 psia
		Heat Transfer	85 MM Btu/hr

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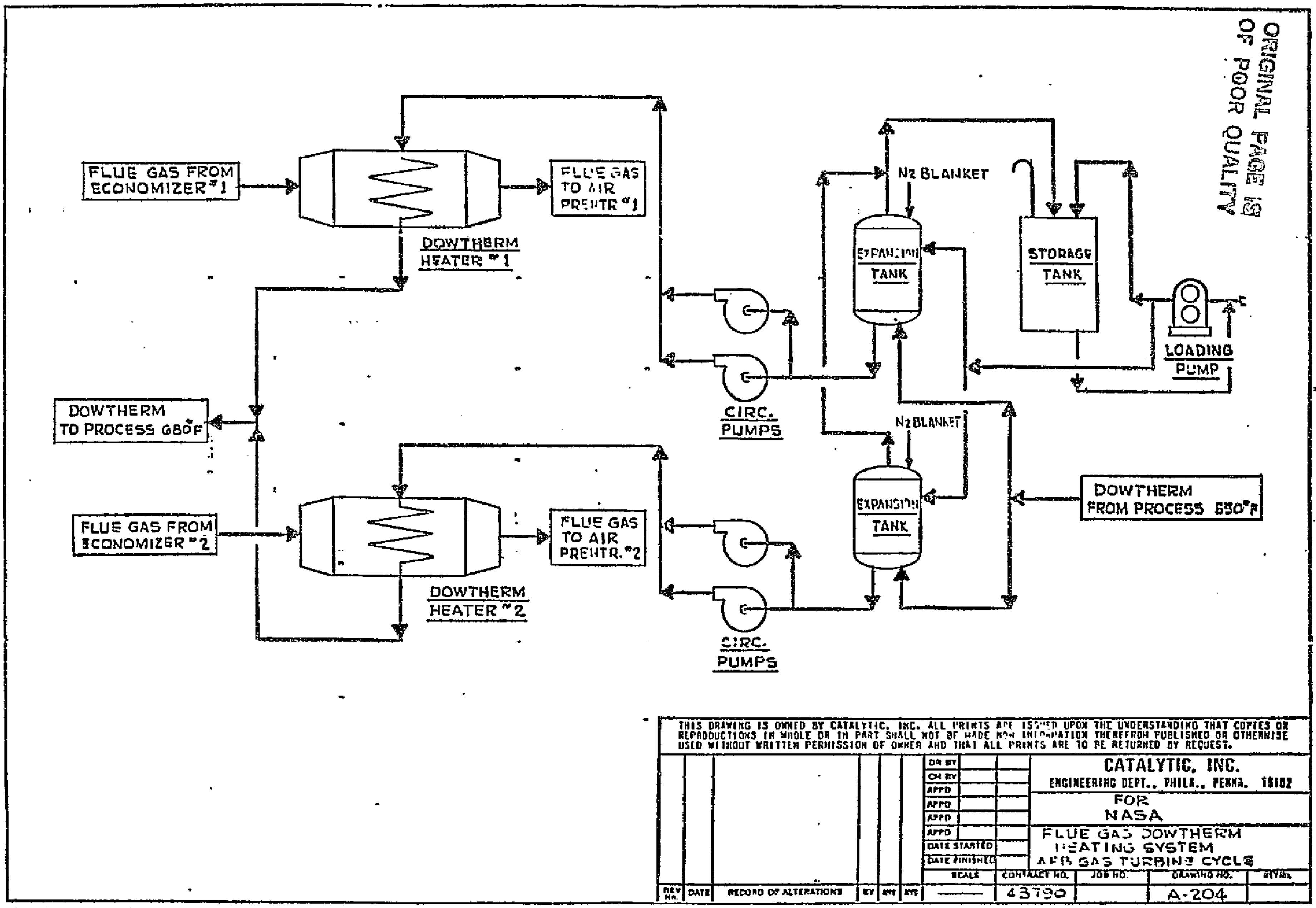

BARCLAY BROS., INC. 4-75

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Figure A4-12

Loss of flow to a heater would most likely result from a pump failure, so a standby pump which would automatically start on failure of the main pump is provided. Also provided are manual balancing valves at the inlet of each heater tube pass with thermocouples measuring individual pass exist Dowtherm temperatures.

A reduction of Dowtherm process heat absorption of 25% could increase the Dowtherm outlet temperature to about 750°F. At this temperature the Dowtherm could rapidly degrade. Then, there is also the risk of tube ruptures caused by coking of the tube internals. Two alternate schemes for safe operation were examined. First, an air cooled exchanger would overcome the danger of overheating, but would not allow the Dowtherm coil to be isolated in the event of a tube rupture or during maintenance. Alternately, a flue gas bypass control arrangement would provide reasonable control of Dowtherm temperature, and would enable the coil to be isolated when necessary. The flue gas bypass damper system was selected, and a modulating damper and controls are included in the cost estimate.

D. Steam Generation

This plant is designed for 100% makeup water at 60°F and providing internal steam needs for deaeration. This is not the procedure used for the existing boilers, which use waste steam to preheat the 100% makeup water to about 200°F, and then use 40 psig plant steam for deaerating steam. Because the gas turbine exhaust is clean air (no products of combustion), the use of makeup water preheating is considered since the new deaerator is designed for the same 40 psig operating pressure as the existing unit. Curtiss-Wright data shows an apparent pinch point of 10°F for steam generation. This is not considered practical, so less steam would be generated than shown in their heat balance. Catalytic obtained prices for waste heat boilers with 50° and 25°F pinch points. A 25°F pinch point unit would cost aobut 60% more than the 50°F pinch point boiler, but increased steam production is available. A 25°F pinch point waste heat boiler would produce about 107,000 lbs/hr steam per AFB.

E. Emissions Controls

The flue gas clean up is accomplished with one baghouse serving both AFBs. Table A4-20 lists pertinent design criteria.

F. Material Handling

Because of its importance, complexity and cost, emphasis was placed on material handling. This facet of the study encompassed rail reception of coal and limestone, conveying to covered storage, including in-transit processing and weighed reclamation from storage to size reduction and drying, terminating in conveying materials to day bins (by others). The day bins provide 12 hours supply of materials for pneumatic conveying feed to fluid bed units (by others). The pneumatic conveying of fly ash from process to a storage silo is also covered.

The information contained in this report is specifically applicable to the materials handling requirements for the gas turbine energy conversion system. However, except as conveying rates and storage volumes would be lower, consistent with lower use rates required for the alternate steam turbine energy conversion system, the design philosophy and materials handling system components and arrangement of same would be essentially very comparable.

1. <u>Design Parameters</u>

Plant Location: Pasadena, Texas
Reference Flow Sheet: Figure A4-13 (Dwg. No. A-203)
Railcars: 100 ton size open top, hopper bottom

Raw Materials, as received (typical):

<u>Bituminous Coal</u>
Size: 4" x 0" (6" maximum size occasional lump)
Bulk Density: 50 lb./cu.ft.
Maximum Moisture Content: 9%, design for 15%
Hardgrove Grindability Index: 52

<u>Limestone</u>
(Chemical Scrubber Lime)
Size: 1-3/4" and under
Bulk Density: 76 lb./cu.ft.
Maximum Moisture Content: 7%, design for 12%

Table A4-20

BAGHOUSE DESIGN CRITERIA

	Gas Turbine	Steam Turbine
Flue Gas Rate, lbs/hr	820,000	432,000
Temperature, ^{o}F	350	350
Inlet Loading GR/ACF (1)	6 (Max)	6 (Max)
Heat Input Rate, MM Btu/hr	739	739
Outlet Loading, lbs/MM Btu	0.10	0.10
Gas Density, lbs/cu.ft.	0.05	0.05
Air to Cloth Ratio - Gross	4.5	3.95
Net	5.0	4.74
Cleaning Method		Pulse Jet (3)
Overall Dimensions	55'L x 52'W x 33'H	32'L x 48'W x 33'H

Particulate Concentration for Both Cases:

Size is	%
0-8	14
8-16	32
16-32	34
32-64	16
64-128	4
>128	0

Particulate Composition for Both Cases:

Constituent	Wt.%
Sulfates (Ca, Mg)	32
Oxides (Ca, Mg)	12
FeO	16
Al	13
Si	23
Carbonates	3
NaO	0.2
KO	0.4
Chlorides	0.1

NOTES

(1) Inlet loading is absolute most case and would occur only for short duration.
2) Assume particle size is not biased to extremely fine end.
3) Off-line cleaning method.

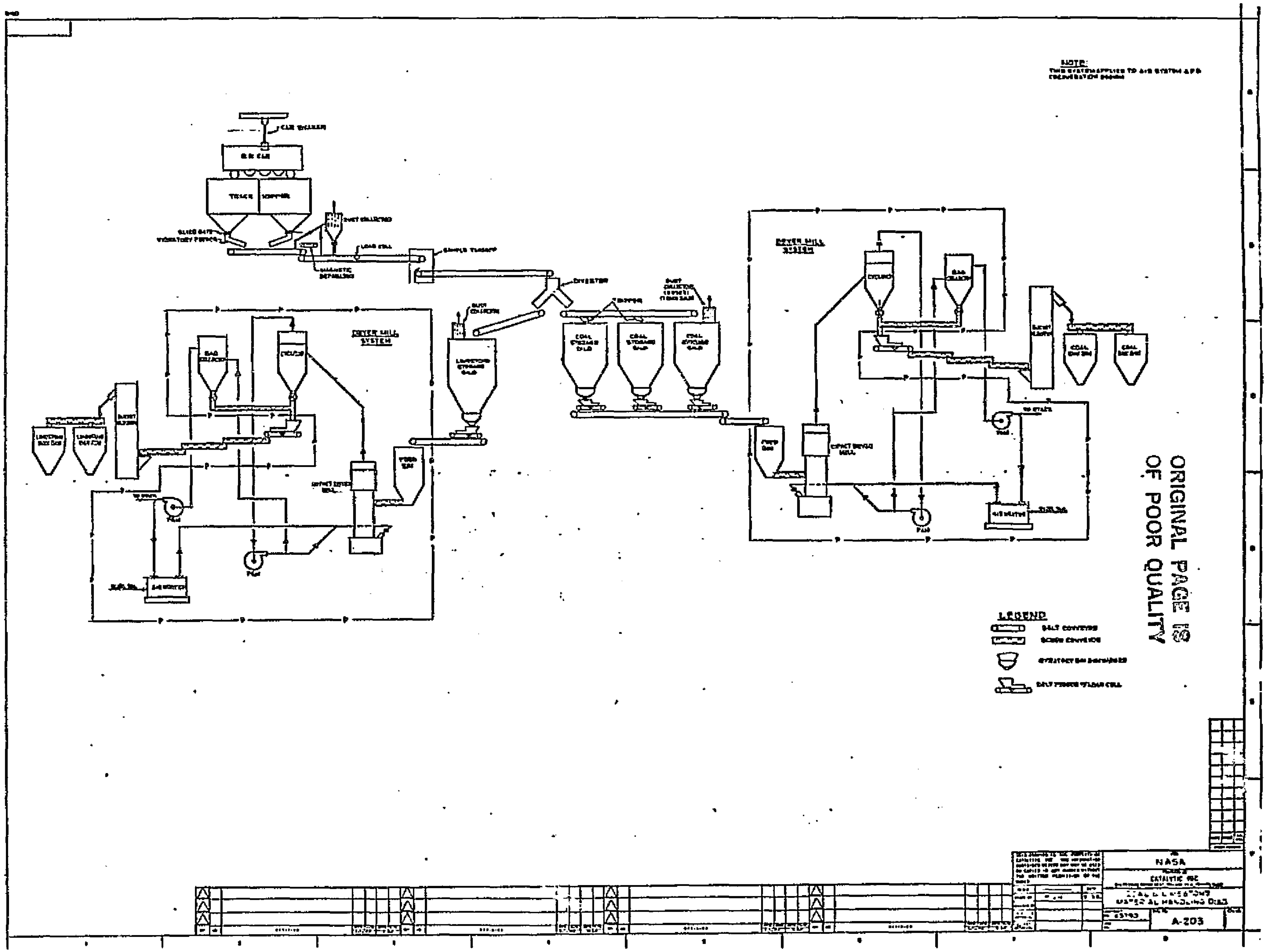

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Figure A4-13

Design Parameters (continued)

Operation: 24 hr./day, 7 days per week

Coal Consumption: 44,958 lb./hr.
Size Required: 1/8" x 0"
Maximum Moisture: 6%

Limestone Consumption: 16,365 lb./hr.
Size Required: 1/8" x 0"
Maximum Moisture: 0% surface

Storage Requirement: 15 days covered storage

Ash Handling System:
Quantity to Convey: 15% of coal and all limestone
Quantity to Store in Silo: minimum of 3 days

2. Raw Materials Reception/Unloading Requirements

Coal Use Rate:

44,958 lb./hr. x 24 = 1,078,992 lb./day

or $\frac{1,078,992 \text{ lbs.}}{2,000}$ = 539.5 tons/day

539.5 tons/day x 7 = 3,776.5 tons of coal required per week

$\frac{3,776.5 \text{ tons}}{100 \text{ ton railcar}}$ = 37.77 cars of coal/week

Limestone Use Rate:

16,365 lb./hr. x 24 = 392,760 lb./day

or $\frac{392,760}{2,000}$ = 196.4 tons/day

196.4 tons/day x 7 = 1,374.8 tons of limestone required per week

$\frac{1,374.8 \text{ tons}}{100 \text{ ton railcar}}$ = 13.75 cars of limestone/week

Summary =

38 Cars of Coal and 14 Cars of Limestone weekly.

Suggested Twice Weekly Delivery =

19 Cars of Coal and 7 Cars of Limestone

Recommended Unloading System

A track hopper with dual unloading compartments, utilizing vibratory feeders to *belt conveyor system. At normal design loadings and operating speeds this system will alternately serve to unload either raw material, without operating modification, at flow rates consistent with bulk densities of 500 T.P.H. of coal and 760 T.P.H. of limestone.

Unloading Times:

19 Cars of Coal @ 100 tons =

$$\frac{1{,}900 \text{ tons}}{500 \text{ T.P.H.}} = 3.80 \text{ hrs.}$$

7 Cars of Limestone @ 100 tons =

$$\frac{700 \text{ tons}}{760 \text{ T.P.H.}} = 0.92 \text{ hrs.}$$

Actual Unloading Time = 4.72 hrs.

Approximate actual unloading time of 4.72 hours should also permit spotting cars over track hopper and repositioning empty cars with suggested trackmobile so that total unloading can be achieved by the dayshift.

N.B. A vibratory type car shaker, suspended from a twin hook hoist mounted on an I-beam track over the hopper is also recommended to accelerate the flow of materials from railcars.

* See Notes following section 3, "Storage Requirements and Recommendations," for explanation of requirements for belt conveyor system.

7. <u>Storage Requirements and Recommendations</u>
(15 days covered storage required)

<u>Coal</u>: use 539.5 tons per day x 15 = 8,092.5 tons

$$50 \text{ lb./cu.ft. or } \frac{2{,}000}{50} = 40 \text{ cu.ft./ton} \times 8{,}092.5$$

$$= \underline{323{,}700 \text{ cu.ft. required}}$$

<u>Recommended</u>: 3 slip form concrete silos, each 50 ft. dia. x 108 ft., skirted to grade, each with 60^{o} steel cone bottom outlet, fitted with bin activator to promote flow.
(Approx. Volume = 324,000 cu.ft. total)

<u>Limestone</u>: use 196.4 tons per day x 15 = 2,946 tons

$$76 \text{ lb./cu.ft. or } \frac{2{,}000}{76} = 26.32 \text{ cu.ft./ton} \times 2{,}946$$

$$= \underline{77{,}539 \text{ cu.ft. required}}$$

<u>Recommended</u>: 1 concrete stave silo 38 ft. dia. x 108 ft., skirted to grade with a 60^{o} steel cone bottom outlet, fitted with bin activator to promote flow. (Approx. Volume = 77,600 cu.ft.)

<u>NOTES</u>

a. As an alternate to silo storage, investigation was made of storing the respective materials in relatively economical "A" shaped buildings. Each storage pile would be formed by a belt conveyor equipped with an automatic tripper and reclamation to processing would utilize a scraper reclaimer to a belt conveyor at grade, along one side of the storage pile.

This concept has the advantages of somewhat lower cost, with appreciably lower structures and a correspondingly shorter run of belt conveyor from track hopper to storage area. Both the required unloading rates and the lump size of incoming coal rule out use of a bucket elevator for this transfer. In that 18^{o} is the maximum safe angle of inclination for a belt conveyor handling these materials, each foot of height required reflects approximately 3 feet of conveyor required.

Notes, continued:

Unfortunately, the A-shaped buildings storage concepts required additional square footage, which simply is not available at the site.

b. In that the coal and limestone are transported to the plant site in open top hopper cars, the drying equipment must be and is designed to process materials saturated with moisture. Under these given conditions, the requirement for "covered" storage of materials with the attendant considerable expense would seem to warrant further consideration.

4. Size Reduction and Drying Systems with Conveying

For the required size reduction and drying of coal and limestone, Williams impact dryer mill systems are recommended. These systems simultaneously dry, grind, size and convey the respective materials. In that the cost of this or any comparable grinding/drying system is so significantly affected by the throughput rate (HP and BTU), it is recommended that these systems should be operated only at rates commensurate with the requirements of the fluid beds. Since all of the materials in the silos are in live storage, the required weighed feeds to the Williams systems may be readily programmed to suit.

From the Williams systems processing, screw conveyors and bucket elevators provide dust tight conveying systems to day bins.

5. Conveying and Processing from Track Hopper to Silos

The conveying run from track hopper to diverter alternately transports coal or limestone via inclined belt conveyors with carrying belts protected by weather enclosures. The belt conveyors will be mounted on bridges with supports to grade and walkways one side of each conveyor.

The following equipment will be provided for essential processing of materials in transit:

a. A magnetic separator to provide for tramp iron removal.

b. An electronic type belt scale to weigh, totalize and record weights of incoming materials.

c. A sampling system to analyze pertinent properties of incoming materials.

From the diverter, coal and limestone is transported to silo storage via a horizontal weather protected belt conveyor dedicated to service on that particular material.

6. Ash Conveying and Silo Storage
(Not shown on Referenced Flow Sheet)

a. Quantity to Convey = 15% of coal and all limestone

44,958 lb./hr. Coal Use x 15 = 6,744 lbs./hr. Ash
+ Limestone Ash = 16,365 lb./hr.
Total Ash = 23,109 lb./hr.

= 11.55 T.P.H.

Equipment Provided

Conventional pneumatic conveying systems operate approximately half the time or 4 Hrs. each 8 Hr. shift, conveying at approximately twice the production rate. Correspondingly, the pneumatic conveying system will be designed to transport ash from four locations at the two fluid bed units and multiple outlets on the baghouse to the storage silo at the rate of 24 T.P.H. System will be vacuum pressure type.

b. Quantity to Store in Silo = 3 Days Ash

$$23{,}109 \text{ lb./hr.} \times 24 \times 3 = \frac{1{,}663{,}848 \text{ lbs.}}{2{,}000} = 832 \text{ tons}$$

At 45 lb./cu.ft. or 44.444 cu.ft./ton = 36,978 cu.ft.

Equipment Provided

One 38 ft. dia. x 49 ft. high concrete stave silo mounted on a 22 ft. high pedestal, with bottom of silo fitted with airslides to promote material flow to a rotary ash conditioner, mounted on platform below silo, at proper height for truck loadout.

7. <u>Dust Control</u>

To control dust generated in dumping materials from open top hopper cars a wet type dust suppression system is required. This system encompasses spray assemblies on a header above the unloading railcar and spray assemblies at each of two material discharges from hopper. Systems are complete with compound tanks, pumps, piping and controls to provide automatic mode of operation.

A bag type dust collector will be provided at each material transfer point (hood) from conveyor to conveyor.

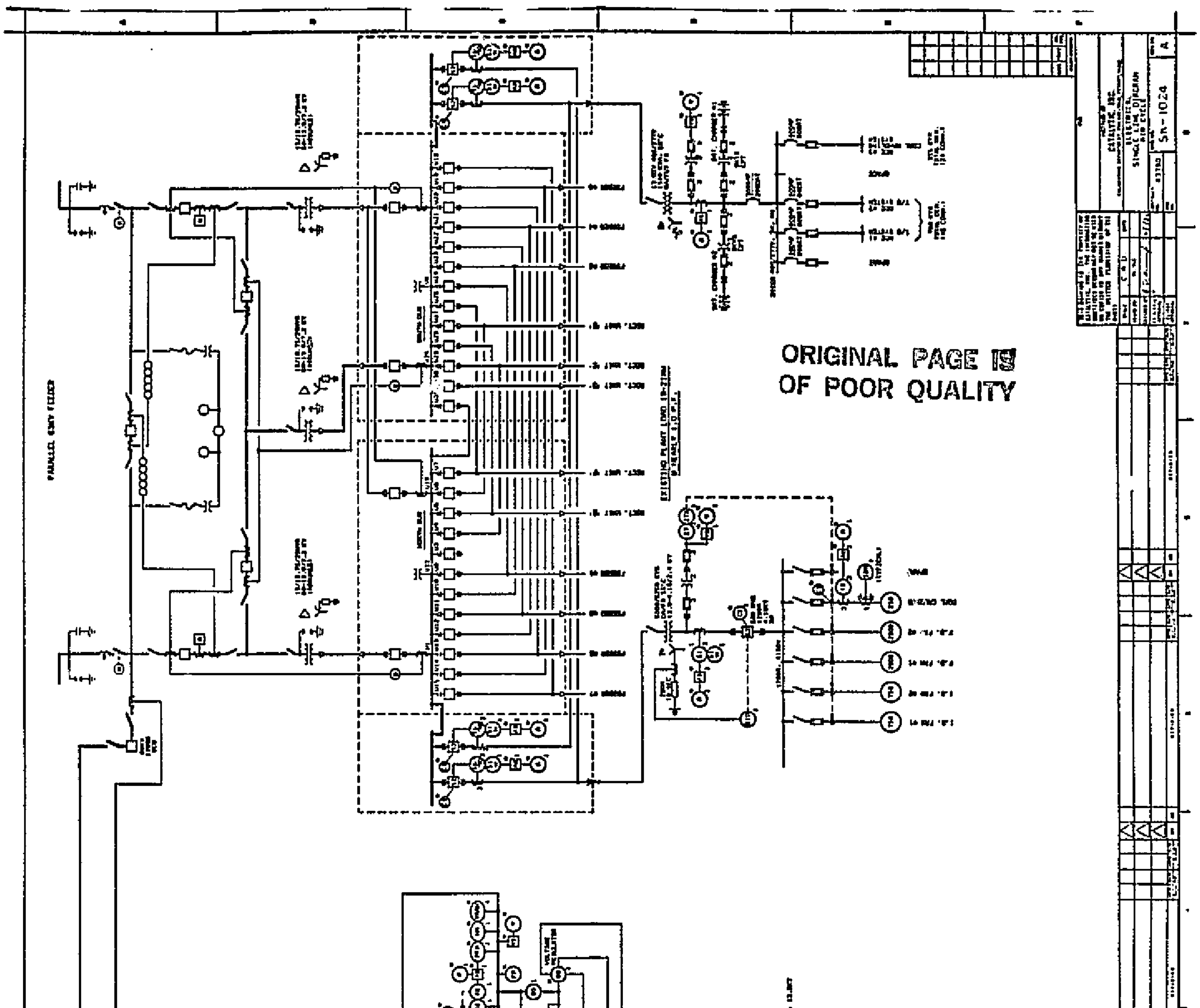
Bag type dust collectors, bin vent type, are provided on tops of all silos.

Ash discharged from storage silo is provided with an ash conditioner which sufficiently moistens dry ash as to preclude nuisance dusting in loadout to trucks and transport to disposal.

G. Electrical Facilities

Electric generation utilizing steam requires a single 10 MW turbine generator, while that of a gas cycle requires two 17 MW turbine generators. The system utilizing the gas cycle is depicted in Figure A4-14 (Drawing No. SK.1024) while the steam cycle is depicted in Figure A4-15 (Drawing No. SK.1025). Both designs for generation utilize solid state voltage regulators, solid state excitation equipment, automatic synchronizing devices, and low resistance grounding.

Both designs require an outdoor oil-filled power transformer to step-up the generated voltage of 13.8 KV to 69 KV for transmission to the existing 69 KV substation over a new aerial line. The steam cycle requires a 12/18 MVA forced-cooled unit, while the gas cycle requires a 50 MVA self-cooled unit. Both transformers will be connected delta on the generator side and solidly grounded on the transmission side.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CATALYTIC, INC.
ELECTRICAL
SINGLE LINE DIAGRAM
SR-1024

Figure A4-14

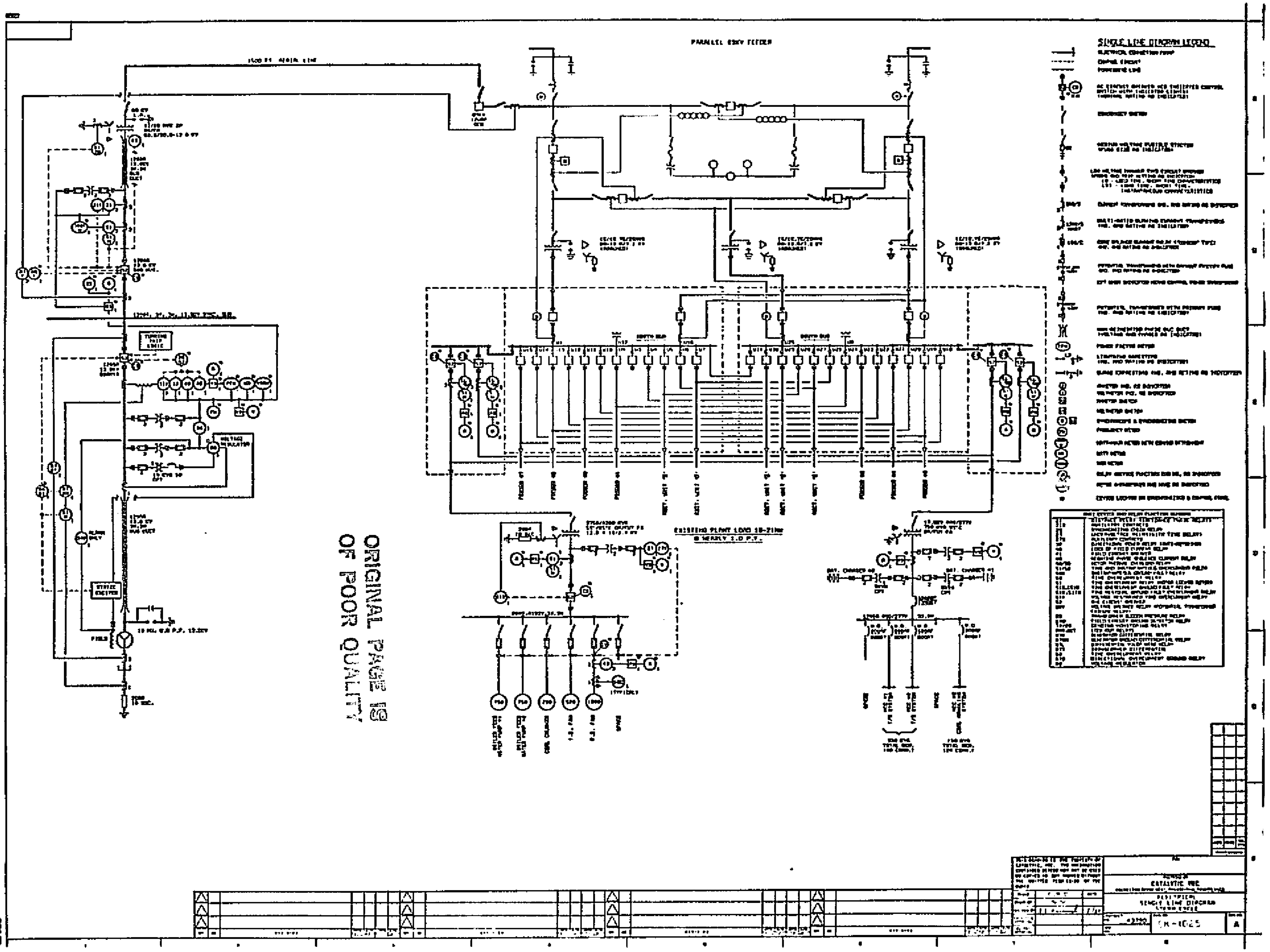


Figure A4-15

The relaying as depicted is that as recommended by the IEEE standards and established engineering practice. The generators' primary protection will be with phase and ground differential relaying with time overcurrent relays as back-up protection. The differential relays set up a zonal protection around the generator and are used for instantaneous and sensitive response to generator internal faults.

The generators are further protected against negative phase sequence currents which flow during unbalanced faults, against motoring which could occur if the steam or gas supply were in low supply, against the loss of excitation, and against failure of one of the potential transformer's fuses. Additionally, an alarm is sounded on the main control panel when a ground appears in the generator field circuits. The relays associated with the generator are tied into lock-out relays in the main control panel. The breakers cannot be re-closed until these lock-out relays are deliberately reset.

The primary protection for the main step-up transformer will be with phase differential relays and with phase and ground relays as a back-up. Like the generator circuit, a zone of protection is set up around the unit. The differential relays are tied into a lock-out relay in the main control panel; the breaker also will not be able to be closed without deliberate action.

Directional power relays are used to immediately isolate the transformer circuit in the event of a 69 KV system fault. The advantage is that the transformer breaker will trip before the generator circuit; this keeps the generators operating until the 69 KV fault can be cleared. Transformers of this magnitude are also designed with a sudden pressure relay which will trip the transformer when there is an abrupt rise in the transformer internal pressure.

The cogeneration plant station utilities are shown taken from an addition to the existing 13.8 KV substation. The design follows the same philosophy in utilizing two feeder breakers, one from each bus. Two separate substations are required, one for 4160 volt services and one for 480/277 volt services. In the case of the steam turbine the 4160 volt service would be from a 3750/4200 KVA transformer; the gas cycle would use a 5000/6250 KVA unit. For the 480/277 volt service the steam turbine utilizes a 750 KVA unit, while for a gas cycle, a 1500 KVA unit is required.

The transformer for the 4160 volt services will be low resistance grounded. Its primary form of protection will then be phase and ground time overcurrent relays. The switchgear will consist of a main breaker directly connected to a lineup of fusible medium voltage controllers. Each of the controllers is designed with motor thermal overload protection and instantaneous ground fault protection. The entire lineup is further protected against undervoltage; upon undervoltage all the starters will be tripped.

The 480/277 volt substation will utilize self-contained manually operated drawout type circuit breakers. These breakers in team will feed each of the motor control centers for the balance of plant load. The station battery chargers will receive their power from this 480 volt bus; each battery is completely redundant and will have an automatic throwover switch to transfer the 125 volt DC power.

The main control panel will be a graphic type with all the main breaker control switches mounted on it. The panel will also contain the necessary electrical instrumentation to properly operate the facility. The voltage regulation equipment and automatic synchronizing equipment will be mounted in the panel as well.

4.3 AFB/STEAM TURBINE COGENERATION SYSTEM

4.3.1 Approach to Performance

A. Operating Strategy

The strategy adapted for this system is the heat match approach, whereby the cogeneration facility satisfies plant steam needs and cogenerates electricity as a byproduct. With the plant's steam demand satisfied, electricity deficits can be purchased as necessary. There is no need to match the thermal and electrical loads both in terms of magnitude and timing.

There are two opposing operating requirements:

- o That the process operation have frequent and rapid variations in steam demand
- o Optimum coal-fired AFB boiler operation and economy requires constant steam generation.

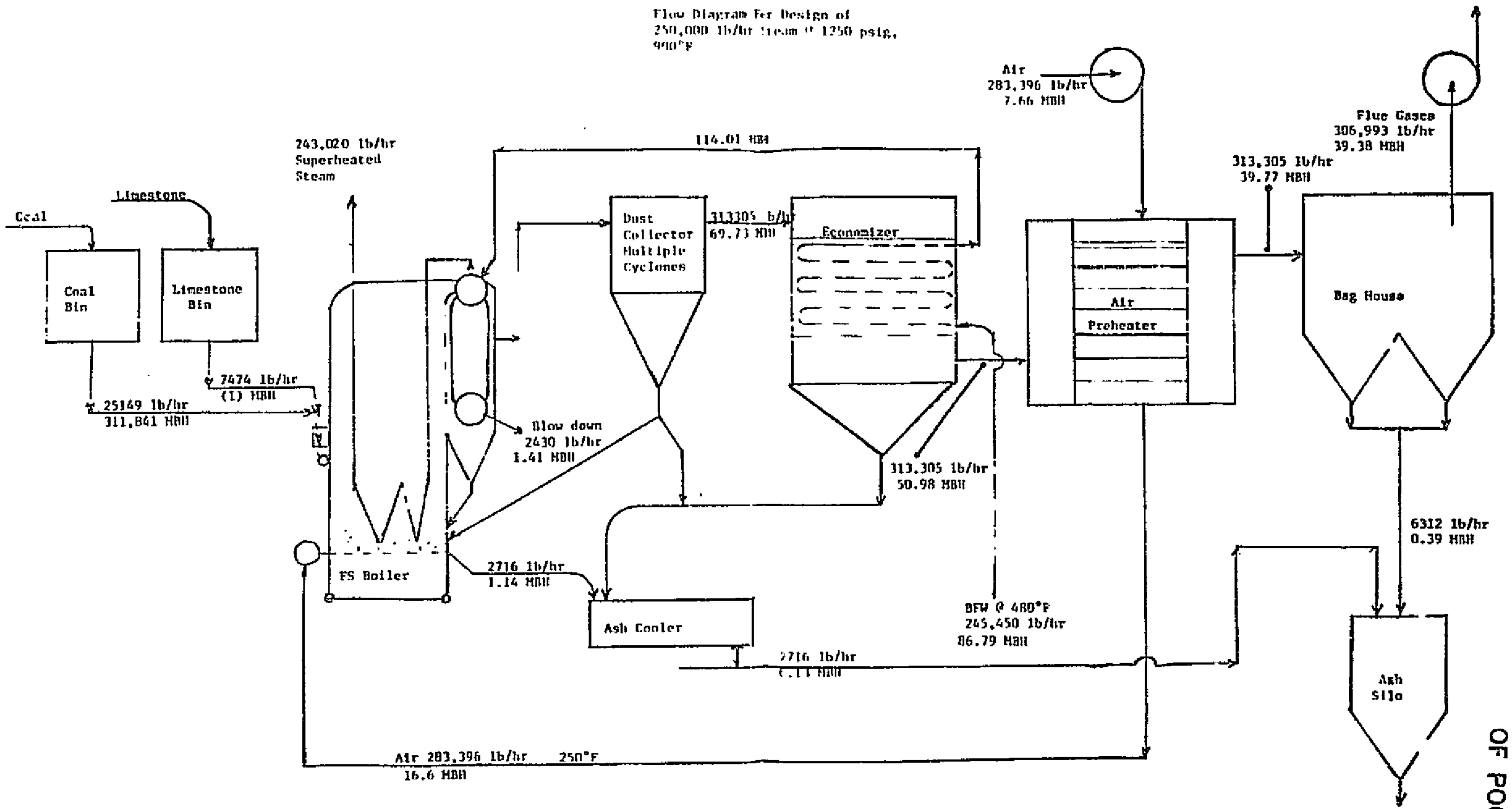
One AFB boiler operating at a constant level, and one or more oil/gas fired boilers operating as swing boilers to meet the variations in steam demands, meets the plant operating requirements. Refer to Appendix Section 1 for the AFB boiler parameters provided by Keeler/Dorr-Oliver. Figure A4-16 shows the basic cycle data prepared by Keeler/Dorr-Oliver, and Table A4-21 gives the predicted performance data for 250,000 lbs/hr output.

B. Dowtherm Heating

For this cycle, Dowtherm heating is provided by the existing system, which remains unchanged. So, no natural gas is displaced for heating the Dowtherm for this cycle. Dowtherm heating with the AFB boiler was not considered to be currently applicable technology and was rejected for the following reasons:

- o Combined Dowtherm heating and steam generation in one integrated unit is not believed to be practical anywhere.
- o While using coal as a Dowtherm fuel heating supply has been investigated by others and appears feasible, the use of high inlet temperature Dowtherm (500°F) would probably entail a Dowtherm coil set in parallel with the superheater coil. Practical design problems may be quite difficult.
- o The potential large Dowtherm heating load (up to 170 MM Btu/hr) in relation to the steam heating load (= 250 MM Btu/hr) could cause further design problems. If preheating of the Dowtherm to less than 680°F were employed, there could be problems with control and service operation with the existing Dowtherm heaters.

Flow Diagram For Design of
250,000 lb/hr Steam @ 1250 psig,
900°F



Keeler/Dorr-Oliver Fluidized Bed Boiler

Note: Gas wt. into econ, air heater and baghouse includes wt. of flyash

Oct. 1982

Figure A4-16

Table A4-21

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DORR-OLIVER

DESIGN CALCULATIONS

PROJECT NO. J-1798

SUBJECT CATALYTIC INC

MKFS BOILER 250,000 lb/hr

PREDICTED PERFORMANCE DATA — REVISION I

LOAD % OF DESIGN	100	75	50	25
1 FEED WATER (Lb/Hr)	263,160	197,370	131,580	65790
2. EVAPORATION (Lb/Hr)	250,000	187,500	125,000	62,500
3 STEAM TEMP °F	900			
4 STEAM PRESS. (Psig)	1250	1250	1250	1250
5 GAS TEMP OUT BOILER (°F)	690	655	655	670
6 GAS TEMP OUT ECON. (°F)	480	420	405	395
7 GAS TEMP OUT AIR HTR (°F)	350	340	330	325
8 FW TEMP OUT ECON °F	480	480	480	490
9. EXCESS AIR (%)	20	20	20	20
10 HEAT RELEASE (Btu/hr)	330,882,000	245,586,000	162,068,000	80,972,000
11 WT FLUE GASES (Lbs/Hr)	326,250	240,060	159,720	79,800
12 WT. AIR (Lbs/Hr)	300,670	221,240	147,200	73,544
13 WT FUEL (Lbs/Hr)	26,685	19,644	13,070	6530
14. WT LIMESTONE (Lbs/Hr)	7,928	5,836	3883	1940
15 LOSSES (%)				
DRY GASES	6.06	5.83	5.61	5.49
H_2O IN AIR	0.15	0.15	0.14	0.14
$H_2 + H_2O$ IN FUEL	4.63	4.61	4.12	4.58
UNBURNT COMB	3.00	3.00	3.00	3.00
RADIATION	0.61	0.82	1.23	2.47
Mfg. MARGIN	1.00	1.00	1.00	1.00
SORBENT REACTIONS	0.32	0.32	0.32	0.32
Fly ASH	0.13	0.09	0.05	0.03
BOTTOM ASH	0.32	0.52	0.73	0.84
TOTAL LOSSES	16.22	16.34	16.20	17.87
BOILER EFF. %	83.78	83.66	83.80	82.13

BY WMJ DATE 12 Aug 82 CHKD ______ DATE ______ SHEET ____ OF ____

C. Steam Pressure

For a steam turbine cycle, the incremental cost of having higher boiler steam outlet pressure and temperature is generally warranted because of the increased electrical generation. Also, a closed feedwater heater, used in addition to the deaerating heater, raises the final feedwater temperature to the boiler and increases the amount of byproduct electric power which can be generated from a fixed amount of process steam flow. Considering the size range of the AFB boilers in addition to the above factors, a steam turbine inlet condition of 1,250 psig/ 900^{o}F was selected. Steam generation at this condition requires a new demineralizer to provide suitable quality makeup feedwater. The process flow diagram of the cogeneration system is given in Figure A4-17 (Drawing No. A-201).

D. Plant Availability and Waste Fuel Use

The same approach employed for the AFB/gas turbine cycle, and discussed in section 4.2.1 -D, is used for this cycle. This AFB has the same 90% overall availability factor accounting for both scheduled and forced outages. With the 91.7% load factor, the same 82.5% capacity factor results. With the existing boilers firing waste oil on a preferential basis, and with reduced drying needs of only 2 MM Btu/hr, about 18,000 lbs/hr steam to process is produced (versus 10,800 lbs/hr for the AFB/gas turbine cycle in Figure A4-6). The result would be operating a 250,000 lbs/hr nominal design rate AFB boiler at about 220,000 lbs/hr. In order to account for heat losses in the entire cycle, an overall 95% realization factor is applied to the coal use. A .786 plant factor is used to obtain a single average running hour year-round.

E. System Operation

The overall system flow diagram for the AFB/steam turbine cogeneration system is shown in Figure A4-18. Major design assumptions for this cycle are summarized in Table A4-22. Most of the design assumptions listed also apply to the gas turbine cycle. Some physical and operating parameters of the AFB boiler are summarized in Table A4-23.

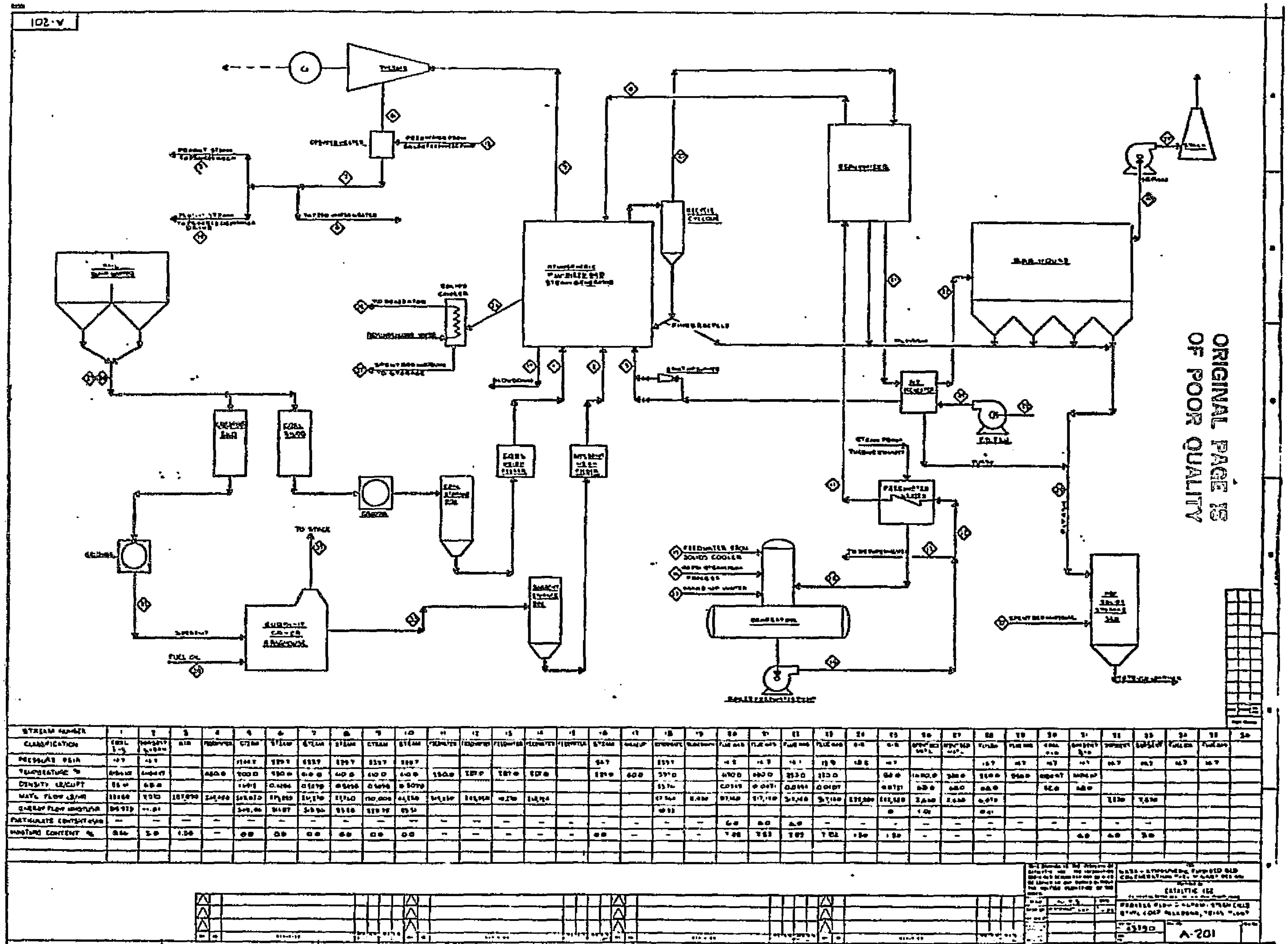

Figure A4-17

A4-50

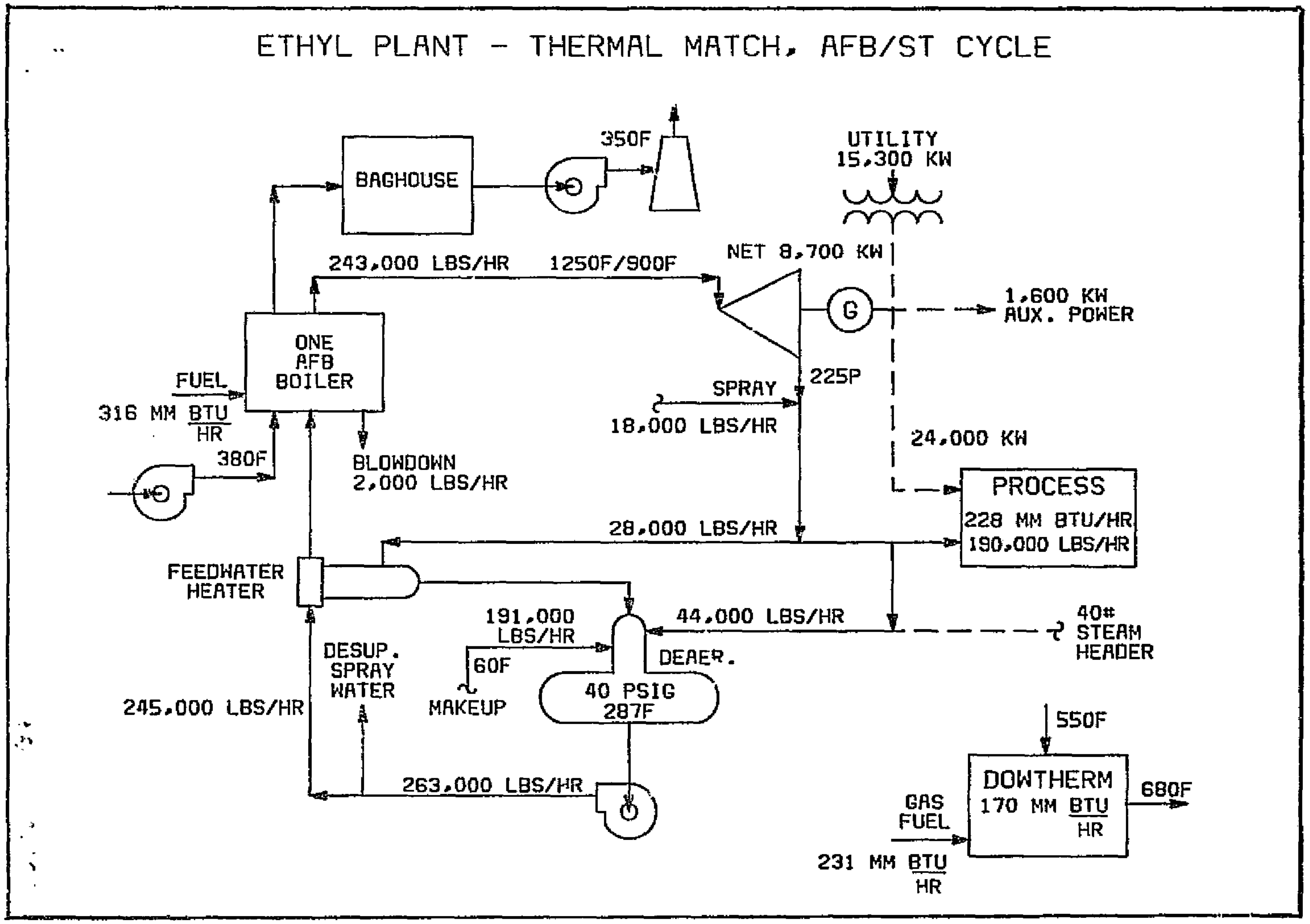
ETHYL PLANT - THERMAL MATCH, AFB/ST CYCLE
BAGHOUSE
350F
UTILITY
15,300 KW
243,000 LBS/HR
1250F/900F
NET 8,700 KW
G
1,600 KW
AUX. POWER
ONE
AFB
BOILER
FUEL
316 MM BTU/HR
SPRAY
225P
18,000 LBS/HR
24,000 KW
380F
BLOWDOWN
2,000 LBS/HR
PROCESS
228 MM BTU/HR
190,000 LBS/HR
28,000 LBS/HR
FEEDWATER
HEATER
191,000
LBS/HR
44,000 LBS/HR
40#
STEAM
HEADER
DESUP.
SPRAY
WATER
60F
MAKEUP
DEAER.
40 PSIG
287F
245,000 LBS/HR
550F
263,000 LBS/HR
DOWTHERM
170 MM BTU/HR
680F
GAS
FUEL
231 MM BTU/HR

Figure A4-18

Table A4-22: AFB/STEAM TURBINE MAJOR DESIGN ASSUMPTIONS

- o RAILROAD DELIVERY OF UNSIZED COAL AND LIMESTONE.
- o 15 DAY SILO STORAGE FOR COAL AND LIMESTONE.
- o ON-SITE CRUSHING OF COAL AND LIMESTONE.
- o DRYING EQUIPMENT PROVIDED FOR LIMESTONE.
- o 10 DAY SILO ASH STORAGE/TRUCK REMOVAL/OFF-SITE LANDFILL.
- o TURBINE STEAM INLET CONDITION OF 1,250°PSIG/900°F
- o RADIAL FLOW STEAM TURBINE
- o 100% MAKEUP WATER AT 60°F FROM EXISTING PLANT SOFTENERS IS DEMINERALIZED.
- o 2 STAGES OF FEEDWATER HEATING -- DEAERATOR AND UPSTREAM FEEDWATER HEATER.

Table A4-23: AFB/STEAM TURBINE SYSTEM PARAMETERS

FUEL: Oklahoma Bituminous coal; 12,400 BTU/#HHV; 3.11%S; $1.96/MBtu, Delivered

SORBENT: Texas Limestone, 0.297 #/# Coal (3:1 Ca/S MOL RATIO); 39.2% Calcium, $11.00/Ton

AFB/BOILER (KEELER/DORR OLIVER):

Bed Temperature - 1,600°F
Bed Depth - 4 Ft.
Bed Area - 551 Ft.^{2}
Excess Air Flow - 20%
Fluidizing Velocity - 8.5 Ft./Sec.
Turndown Capability (4:1) - 25% (to suit system minimum)

POWER CYCLE:

Steam-Rankine (Total - 1 Turbine)
Turbine Type: Radial Flow - Backpressure; 11,700 KW Rating
Throttle Conditions - 1,250 Psig/900°F
Exhaust Conditions - 225 Psig/530°F
Mass Flow - 243,000 #/Hr. (Design Rate)

HEAT REJECTION EQUIPMENT: None (Non-Condensing Steam Cycle)

The resource requirements of the AFB/steam turbine system are shown in Table A4-24. The average data is on the basis of one hour operation for 8,760 hours per year.

The total water requirements are based on 100% makeup water converted to steam and blowdown plus about 100,000 gpd (70 gpm) for demineralizer regeneration.

The environmental impact of the AFB/steam turbine system is given in Table A4-25. The water discharge is the sum of the boiler blowdown and the demineralizer regeneration. The auxiliary power requirements for this system consist largely of the four power requirements shown in Table A4-26.

The low drying requirements of 2 MM Btu/hr shown in Table A4-12 is only for the limestone sorbent, which would be shipped to the plant in open railroad cars.

Table A4-24: RESOURCE REQUIREMENTS - AFB/STEAM TURBINE

	Design	Average (0.791 Plant Factor)
COAL	305 tons/day	240 tons/day
LIMESTONE	91 tons/day	72 tons/day
NATURAL GAS (FOR DOWTHERM HEATING)	5,544 MBtu/day	5,544 MBtu/day
WASTE FUEL	0 MBtu/day	1,680 MBtu/day
WATER - TOTAL	718,950 Gals/day	614,610 Gals/day
Process Steam	234,200 #/hr	184,080 #/hr
Cooling - Evap.	0 Gals/day	0 Gals/day
Blowdown (1%)	6,820 Gals/day	5,350 Gals/day

LAND REQUIREMENTS: POWERHOUSE - 2.0 Acres; RAILYARD - 1.0 Acres

Table A4-25: ENVIRONMENTAL IMPACT - EMISSIONS - AFB/ STEAM TURBINE (315.95 MBtu/Hr. - Design Rating)

		Design	Average (0.791)
GASEOUS:	SO_x - 0.50 #/MBtu	1.90 tons/day	1.49 tons/day
	NO_x - 0.40 #/MBtu	1.52 tons/day	1.19 tons/day
PARTICULATE:	0.10/MBtu	0.38 tons/day	0.30 tons/day
THERMAL:			
	Cooling Tower - 0 Btu/MBtu	--	--
	Flue Gas - 108,400 Btu/MBtu	34.2 MBtu/hr	26.9 MBtu/hr
	Other - 133,100 Btu/MBtu	42.1 MBtu/hr	33.1 MBtu/hr
SOLIDS:	Total - 28.2 #/MBtu	106.9 TPD	84.0 TPD
WATER DISCHARGE:	14.25 Gals/MBtu	108,070 Gals/day	84,940 Gals/day

Table A4-26

AFB/STEAM TURBINE CYCLE

Summary of Auxiliary Power Usage

	KW
BOILER FEEDWATER PUMP	580
MATERIAL HANDLING	105
FORCED AND INDUCED DRAFT FANS	900
	1,585 Kw

4.3.2 Cost Estimate and Economics

A. Capital Cost Estimate

Table A4-27 summarizes the capital cost estimate, with the interest charge amounting to 37% of the capital cost. The summary and sub-summary sheets giving more details of the capital costs are shown in Tables A4-28 and A4-29. The largest material cost item consists of the one AFB unit cost estimate provided by Keeler/Dorr-Oliver, with 10% additional costs for miscellaneous extras plus breeching. The second largest cost item is the material handling and storage equipment.

Table A4-27

AFB/STEAM TURBINE COGENERATION PLANT CAPITAL COSTS
(Thousands of Dollars)

		COSTS	TOTAL
1.	AFB Boilers & Baghouse	12,220	
2.	Turbine/Generator	2,620	
3.	Mechanical Equipment	4,578	
	Material Handling	5,372	
4.	Electrical	1,536	
5.	Civil & Structural	2,711	
6.	Process Piping	3,592	
	Instrumentation	987	
7.	Yardwork & Miscellaneous	1,554	
		35,170	
Direct Cost			35,170
A/E Home Office & Fees			7,670
	TOTAL PLANT COST		42,840
Contingency			0
	TOTAL CAPITAL COST		42,840
Interest Charge (60-month project)			15,808
	TOTAL CAPITAL INVESTMENT		58,648

Table A4-28

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CATALYTIC, INC.
Philadelphia, Pennsylvania 19102

15045-0574P

SUMMARY SHEET "STUDY ESTIMATE"

Estimate/Job Number 43790 Date 9-20-82
Customer NASA
Location PASADENA, TEXAS
Description ADVANCED CO-GENERATION STUDY - STEAM CYCLE

Process Equipment						
Materials						
Subcontracts and Shop Labor	35	170	000			
All Risk Insurance, Legal Liability, etc. .25%		100	000			
Special Taxes, (sales, use, etc.) 6% on Material		200	000			
Bond 1%		400	000			
Total Material, Subcontracts and Shop Labor	35	870	000			
Field Labor						
Payroll Burden						
Total Field Labor	-	0	-			
Field Supervision						
Field Office Personnel						
Field Office Expense — Construction Management	1	060	000			
Field Planning						
Start-up Operators						
Construction Equipment and Tools						
Total Other Field Charges	1	060	000			
Mechanical Engineering						
Process Engineering						
Estimating, Planning, and Cost Analysis 11.9%	5	070	000			
Purchasing, Expediting and Shop Inspection						
Accounting, Industrial Relations, General Administration & Construction Mgmt.						
Total Home Office Expenses	5	070	000			
Sub-Total	42	000	000			
Contingencies						
Escalation						
Sub-Total	42	000	000			
Overhead						
Fee 2%		840	000			
Grand Total	42	840	000			

Remarks: Study Estimate (+) 35% - Present Day Cost.
Demolition - Items to be cleaned and safed by owner prior to demolition.

Table A4-29

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CATALYTIC
P15021-982P

Sub-Summary

Client NASA Estimate No. 43790

Location PASADENA, TEXAS Date 9-16-82

STEAM CYCLE Page ____ of ____

Code	Description	Material	Labor	Subcontract
0100	Fired Heaters and Boilers			12,397,000
0200	Stacks			250,000
0400	Reactors and Internals			
0500	Towers and Internals			
0600	Heat Exchange Equipment			76,000
0700	Cooling Towers			
0800	Vessels, Tanks, Drums and Internals			63,300
0900	Pumps and Drivers			95,000
1000	Blowers and Compressors			
1100	Elevators, Conveyors, Materials Handling Equipment			5,371,700
1200	Miscellaneous Mechanical Equipment			
2500	Tankage			
2800	Filters, Centrifuges, Separator Equipment			1,327,000
2900	Agitators and Mixers			
3000	Scrubbers and Entrainment Separators			
3100	Machine Tools and Machine Shop Equipment			
3200	Heating, Ventilation, Air Conditioning, Dust Control (Process Only)			
3400	Package Units			2,620,200
	Start-up Spare Parts 2%			444,000
Sub-Total — Major Equipment		- 0 -	- 0 -	22,644,200
1300	Piping			3,592,000
1400	Sewers			20,000
1500	Instrumentation			987,300
1600	Electrical			1,536,400
1700	Concrete			2,649,000
1800	Structural Steel			62,000
1900	Fireproofing			50,000
2000	Buildings			160,000
2100	Site Development and Demolition			426,000
2200	Insulation			687,100
2300	Painting and Protective Coatings			25,000
2400	Field Testing			
2600	Chemicals and Catalyst			
2700	Piling			
3300	Fire Protection			185,000
3500	Miscellaneous Systems 6.5%			2,146,000
Sub-Total		- 0 -	- 0 -	35,170,000
3700	Miscellaneous Direct Charges			
3800	Storehouse Accounts			
3900	Construction Supplies and Petty Tools			
1300	Testing Welders			
3600	Temporary Piping and Electrical Facilities			
3600	Temporary Construction Buildings			
3600	Temporary Site Development			
Total Direct Costs		- 0 -	- 0 -	35,170,000

B. Uncertainty Analysis

Refer to Appendix Section 2 for presentation of this analysis.

C. Economic Performance

Table A4-30 presents the predicted cash flow/ROI calculations for the economic life of the cogeneration facility. Levelized annual energy cost analysis is given in Table A4-18.

4.3.3 Reference Plant System Description

A. Site

The site described for the gas turbine cycle is also suitable for the steam turbine cycle. Equipment arrangement drawing A-101, Figure A4-19, shows the proposed layout for the site.

B. Steam Cycle AFB Boiler Components

Detailed physical parameters for the AFB boiler components under Keeler/Dorr-Oliver's scope of supply are given in Appendix Section 1.

C. Steam Turbine-Generator

A radial flow type, backpressure steam turbine appears to offer high operating efficiency for this service, and is considered suitable for this application. A backpressure type steam turbine produces fully cogenerated electricity and steam.

This plant is designed for 100% makeup water at 60°F and providing internal steam needs for deaerator and feedwater heating.

D. Emissions Controls

The flue gas cleanup for the AFB boiler is performed with one baghouse. Table A4-20 lists the design data.

ADVANCED TECHNOLOGY COGENERATION-CONCEPTUAL DESIGN STUDY
NASA-LEWIS RESEARCH CENTER CATALYTIC JOB NO.43790
SUBTASK 2D NO COGEN VS AFB/ST SENSITIVITY ANALYSIS

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
PLANT INVESTMENT($M)	(58.648)	-	-	-	-	-	-	-	-	-
INCREMENTAL PLANT INVESTMENT($M)	(58.648)	-	-	-	-	-	-	-	-	-
COAL USE MMBTU/HR	248.400	248.400	248.400	248.400	248.400	248.400	248.400	248.400	248.400	248.400
COGEN OIL/GAS USE MMBTU/HR	70.000	70.000	70.000	70.000	70.000	70.000	70.000	70.000	70.000	70.000
COGEN DOWTHERM FUEL MMBTU/HR	231.000	231.000	231.000	231.000	231.000	231.000	231.000	231.000	231.000	231.000
NO COGEN FUEL INCL DOWTHERM MMBTU/HR	483.000	483.000	483.000	483.000	483.000	483.000	483.000	483.000	483.000	483.000
PRICE OF OIL/GAS ($/MMBTU)	6.240	6.427	6.620	6.817	7.024	7.235	7.452	7.676	7.906	8.143
PRICE OF COAL ($/MMBTU)	2.090	2.111	2.132	2.153	2.175	2.197	2.219	2.241	2.263	2.286
COST NO COGEN FUEL ($M)	26.402	27.193	28.010	28.852	29.719	30.612	31.530	32.478	33.451	34.454
COST OF COAL ($M)	4.548	4.594	4.639	4.685	4.733	4.781	4.829	4.876	4.924	4.974
COST COGEN OIL/GAS + DOWTHERM ($M)	16.453	16.945	17.455	17.980	18.521	19.077	19.649	20.240	20.846	21.471
TOTAL COST COGEN FUEL ($M)	21.001	21.540	22.094	22.665	23.254	23.858	24.478	25.116	25.770	26.445
INCREMENTAL FUEL COST($M)	5.401	5.653	5.916	6.187	6.465	6.754	7.052	7.362	7.681	8.009
AVERAGE ELECTRIC GEN. MW/HR	8.415	8.415	8.415	8.415	8.415	8.415	8.415	8.415	8.415	8.415
POWERHOUSE ELECTRIC USE MW/HR	1.330	1.330	1.330	1.330	1.330	1.330	1.330	1.330	1.330	1.330
PLANT AVERAGE ELECTRIC USE MW/HR	24.000	24.000	24.000	24.000	24.000	24.000	24.000	24.000	24.000	24.000
ELECTRIC BUY RATE ($/KW-HR)	0.0621	0.0664	0.0710	0.0760	0.0813	0.0870	0.0931	0.0996	0.1066	0.1141
BASE CASE ELECTRICITY PURCHASED MW/HR	24.130	24.130	24.130	24.130	24.130	24.130	24.130	24.130	24.130	24.130
PRICE FOR SELLING ELECTRICITY $/KW-HR	0.0707	0.0756	0.0809	0.0866	0.0927	0.0992	0.1061	0.1135	0.1214	0.1299
REVENUE FROM ELECTRIC SALE ($M)	5.212	5.573	5.964	6.384	6.833	7.313	7.821	8.367	8.949	9.576
COST OF PURCHASED ELECTRICITY($M)	13.779	14.734	15.754	16.864	18.040	19.304	20.658	22.100	23.654	25.318
COST OF ELECTRIC ENERGY ($M)	8.567	9.161	9.790	10.480	11.207	11.991	12.837	13.733	14.705	15.742
BASE CASE COST ELECTRICITY ($M)	13.127	14.036	15.009	16.065	17.185	18.390	19.679	21.053	22.533	24.118
INCREMENTAL COST OF ELECTRICITY $M	4.560	4.875	5.219	5.585	5.978	6.399	6.842	7.320	7.828	8.376
ANNUAL ENERGY COST ($M)	29.568	30.701	31.884	33.145	34.461	35.849	37.315	38.849	40.475	42.187
ANNUAL ENERGY SAVINGS($M)	9.961	10.529	11.134	11.772	12.443	13.153	13.894	14.682	15.509	16.385
PRICE OF SORBENT $/TON	11.000	11.000	11.000	11.000	11.000	11.000	11.000	11.000	11.000	11.000
COST OF SORBENT($M)	0.292	0.292	0.292	0.292	0.292	0.292	0.292	0.292	0.292	0.292
COST OF WASTE DISPOSAL($M)	0.177	0.177	0.177	0.177	0.177	0.177	0.177	0.177	0.177	0.177
UTILITIES,LABOR,MAINT.($M)	2.387	2.387	2.387	2.387	2.387	2.387	2.387	2.387	2.387	2.387
INSURANCE AND LOCAL TAXES($M)	0.880	0.880	0.880	0.880	0.880	0.880	0.880	0.880	0.880	0.880
ANNUAL OPER,MAINT&TAXES ($M)	3.736	3.736	3.736	3.736	3.736	3.736	3.736	3.736	3.736	3.736
BASE COST OPER MAINT & TAXES ($M)	1.095	1.095	1.095	1.095	1.095	1.095	1.095	1.095	1.095	1.095
INCREMENTAL COST OF OPER.&MAINT. ($M)	(2.641)	(2.641)	(2.641)	(2.641)	(2.641)	(2.641)	(2.641)	(2.641)	(2.641)	(2.641)
SAVINGS BEFORE TAXES ($M)	7.320	7.987	8.493	9.131	9.802	10.512	11.253	12.041	12.868	13.744
DEPRECIATION $M	11.730	18.767	14.076	9.384	4.692	-	-	-	-	-
NET TAXABLE INCOME($M)	-	-	-	-	5.110	10.512	11.253	12.041	12.868	13.744
INCOME TAX ($M)	-	-	-	-	2.453	5.046	5.401	5.780	6.177	6.597
INCOME TAX CREDIT ($M)	5.865	-	-	-	-	-	-	-	-	-
NET INCOME AFTER TAXES($M)	5.865	-	-	-	2.657	5.466	5.852	6.261	6.691	7.147
DEPRECIATION ADDED BACK($M)	11.730	18.767	14.076	9.384	4.692	-	-	-	-	-
CASH FLOW ($M)	17.595	18.767	14.076	9.384	7.349	5.466	5.852	6.261	6.691	7.147
CALCULATION OF ROI	(58.648)	17.595	18.767	14.076	9.384	7.349	5.466	5.852	6.261	6.691

RETURN ON INVESTMENT = 17.493%

Table A4-30

ADVANCED TECHNOLOGY COGENERATION-CONCEPTUAL DESIGN STUDY
NASA-LEWIS RESEARCH CENTER CATALYTIC JOB NO.43790
SUBTASK 2D NO COGEN VS AFB/ST SENSITIVITY ANALYSIS

Table A4-30 (Cont.)

	1998	1999	2000	2001	2002
PLANT INVESTMENT($M)	-	-	-	-	-
INCREMENTAL PLANT INVESTMENT($M)	-	-	-	-	-
COAL USE MMBTU/HR	248.400	248.400	248.400	248.400	248.400
COGEN OIL/GAS USE MMBTU/HR	70.000	70.000	70.000	70.000	70.000
COGEN DOWTHERM FUEL MMBTU/HR	231.000	231.000	231.000	231.000	231.000
NO COGEN FUEL INCL DOWTHERM MMBTU/HR	483.000	483.000	483.000	483.000	483.000
PRICE OF OIL/GAS ($/MMBTU)	8.387	8.639	8.898	9.165	9.440
PRICE OF COAL ($/MMBTU)	2.309	2.332	2.355	2.379	2.403
COST NO COGEN FUEL ($M)	35.486	36.552	37.649	38.778	39.941
COST OF COAL ($M)	5.024	5.074	5.124	5.177	5.229
COST COGEN OIL/GAS + DOWTHERM ($M)	22.115	22.779	23.462	24.166	24.891
TOTAL COST COGEN FUEL ($M)	27.139	27.853	28.536	29.343	30.120
INCREMENTAL FUEL COST($M)	8.347	8.699	9.062	9.435	9.821
AVERAGE ELECTRIC GEN. MW/HR	8.415	8.415	8.415	8.415	8.415
POWERHOUSE ELECTRIC USE MW/HR	1.330	1.330	1.330	1.330	1.330
PLANT AVERAGE ELECTRIC USE MW/HR	24.000	24.000	24.000	24.000	24.000
ELECTRIC BUY RATE ($/KW-HR)	0.1221	0.1306	0.1397	0.1495	0.1600
BASE CASE ELECTRICITY PURCHASED MW/HR	24.130	24.130	24.130	24.130	24.130
PRICE FOR SELLING ELECTRICITY $/KW-HR	0.1390	0.1487	0.1591	0.1702	0.1821
REVENUE FROM ELECTRIC SALE ($M)	10.246	10.961	11.728	12.546	13.424
COST OF PURCHASED ELECTRICITY($M)	27.093	28.979	30.999	33.173	35.503
COST OF ELECTRIC ENERGY ($M)	16.847	18.013	19.270	20.627	22.079
BASE CASE COST ELECTRICITY ($M)	25.809	27.606	29.530	31.601	33.921
INCREMENTAL COST OF ELECTRICITY $M	8.962	9.588	10.260	10.974	11.742
ANNUAL ENERGY COST ($M)	43.986	45.971	47.856	49.970	52.199
ANNUAL ENERGY SAVINGS($M)	17.309	18.287	19.322	20.409	21.563
PRICE OF SORBENT $/TON	11.000	11.000	11.000	11.000	11.000
COST OF SORBENT($M)	0.292	0.292	0.292	0.292	0.292
COST OF WASTE DISPOSAL($M)	0.177	0.177	0.177	0.177	0.177
UTILITIES,LABOR,MAINT.($M)	2.387	2.387	2.387	2.387	2.387
INSURANCE AND LOCAL TAXES($M)	0.880	0.880	0.880	0.880	0.880
ANNUAL OPER,MAIN&TAXES ($M)	3.736	3.736	3.736	3.736	3.736
BASE COST OPER MAINT & TAXES ($M)	1.095	1.095	1.095	1.095	1.095
INCREMENTAL COST OF OPER.&MAINT. ($M)	(2.641)	(2.641)	(2.641)	(2.641)	(2.641)
SAVINGS BEFORE TAXES ($M)	14.668	15.646	16.681	17.768	18.922
DEPRECIATION $M	-	-	-	-	-
NET TAXABLE INCOME($M)	14.668	15.646	16.681	17.768	18.922
INCOME TAX ($M)	7.041	7.510	8.007	8.529	9.083
INCOME TAX CREDIT ($M)	-	-	-	-	-
NET INCOME AFTER TAXES($M)	7.627	8.136	8.674	9.239	9.839
DEPRECIATION ADDED BACK($M)	-	-	-	-	-
CASH FLOW ($M)	7.627	8.136	8.674	9.239	9.839
CALCULATION OF ROI	7.147	7.627	8.136	8.674	9.239

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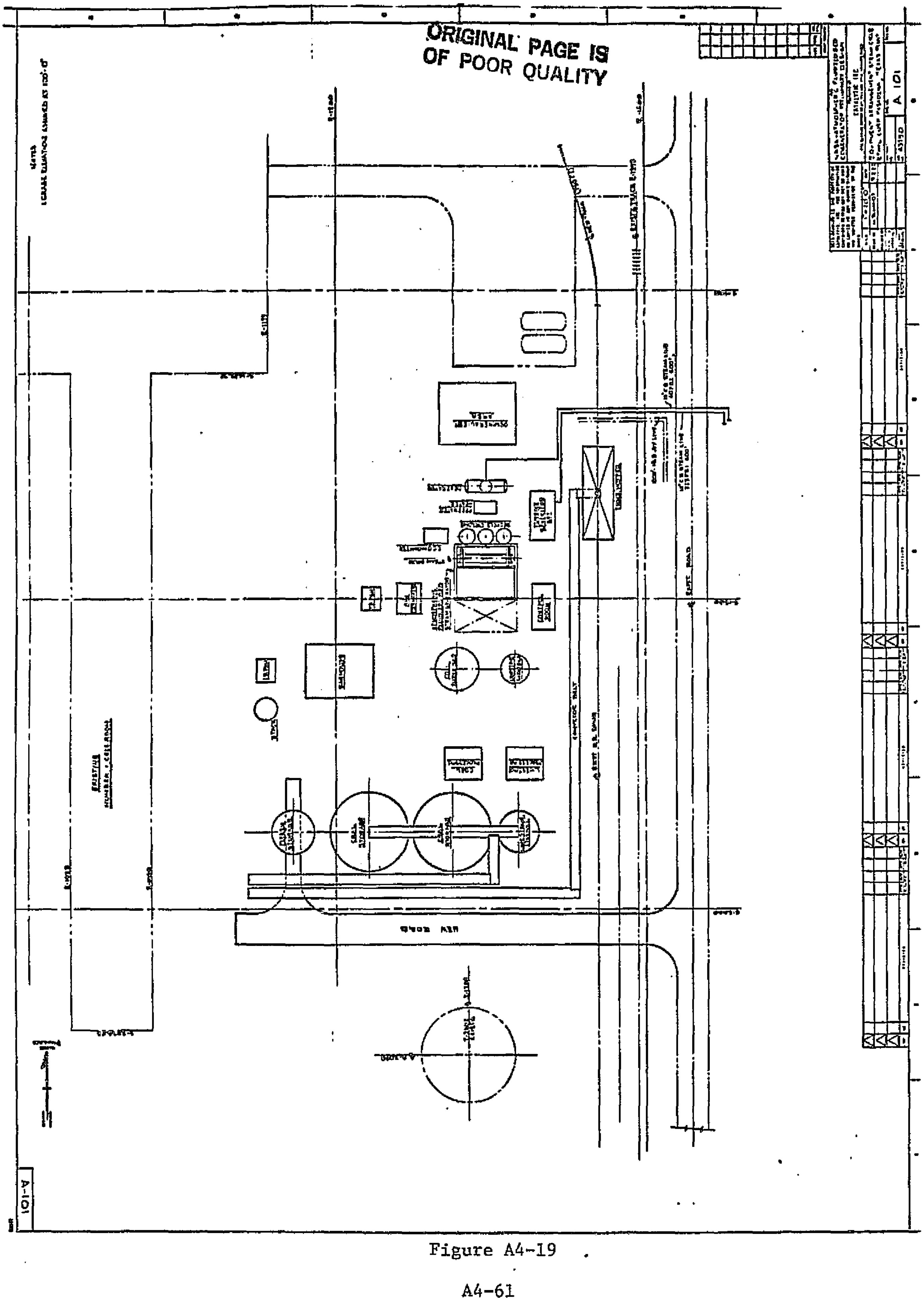

Figure A4-19

E. Material Handling

The description provided for the AFB/gas turbine cycle in this Appendix, section 3.2.3-F, also applies to this system. The same items of equipment are used; just the size is smaller because of the lower heat input.

F. Electrical Facilities

The description provided for the AFB/gas turbine cycle in this Appendix, section 3.2.3-G, also applies to this system.

G. Instrumentation

1. Control Room

An electronic distributed control system will be installed for monitoring and controlling the fluidized bed boiler and the balance of the cogeneration systems.

Increased reliability and safety are obtained with: a back-up controller file which automatically switches on-line when primary controller fails; battery back-up to maintain programs and controls loops in advent of loss of normal AC supply; auto/manual stations for critical parameters if CRT display or control is lost.

Improved efficiencies are otainable through selection or modification of computational algorithms when boiler actual dynamics are evaluated after start-up, without hardware or wiring changes.

System check-out, commissioning, trouble shooting and management logs are simplified with CRT's and a printer capable of digitally showing trend, historical data and alarm status.

2. Local Panels

Separate panels for turbine generator, ash handling, air compressor, demineralizers and material handling will be located near their respective units. Systems will be designed for automatic operation with malfunction and trouble alarms annunciated in the main control room.

3. Control Operations

Two CRT's with keyboards will normally be used by an operator to monitor the cogeneration facility. One CRT will normally be set for alarm monitoring while the other would be used to monitor analog functions and change control settings as required.

A printer would list all alarm activities with time of occurrence, and log real time, trend and historical data as desired.

Boiler controls will consist of a 3-element feedwater control system for drum stability; oxygen trim for fuel efficiency; and parallel metering with cross-limiting and flow tieback combustion controls to ensure minimal air supply without smoking.

Coal handling equipment design will necessitate that the upstream device is operating before the immediate downstream conveyor, hopper, etc. is running to avoid plugging and spilling. All malfunctions or stoppages will be alarmed in the control room.

4. Safety

Each vessel will be protected from over pressure by use of safety and relief valves sized according to applicable ASME codes.

Instruments, hook-up material and valves will be designed to withstand the design pressure of its associated mechanical system and piping.

A flame safeguard security system (FSSS) will be furnished in accordance with NFPA standards to provide explosion protection.

Redundant furnace pressure transmitters and switches will be monitored for trip logic and control restraints such as directional blocking of FD or ID dampers and damper limit positioning for implosion protection of boiler baghouse and ducting in accordance with NFPA 85G.

Diaphragm seals and purges will be used to isolate corrosive liquids from instruments used for demineralizer regeneration and waste neutralization. This will protect maintenance workers and reduce project costs by eliminating the need for long delivery non-standard materials of construction.

4.4 PERFORMANCE AND BENEFITS ANALYSES

4.4.1 Results of Analyses

Performance and benefits analyses were performed on the conceptual designs. Appendix Section 3 provides background for the various items of importance which are summarized in Table A4-31.

4.4.2 Sensitivity Analysis

Economic feasibility analysis addresses certain specific factors which create risks for new cogeneration projects:

- o Long lead times are required to develop a project, implement it and make it a viable ongoing entity.
- o Projections of future energy prices are just that - a projection - which is uncertainty.
- o Future levels of inflation, that are unknown and can only be guessed at, particularly regarding capital costs.

Sensitivity analysis is used as a basis for directing the detailed challenging of economic assumptions.

Sensitivity analysis helps indicate which economic assumptions are critical to the success of the project.

Table A4-32, summarized by economic data, shows the range of sensitivity applied, and the effect on ROI. The focus of the review using sensitivity analysis is determining the practicality of the project in the real world.

Table A4-31: RESULTS OF PERFORMANCE AND BENEFITS ANALYSES

Item	AFB/Gas Turbine	AFB/Steam Turbine
ROI	21.9%	17.5%
LAESCR	11.7%	- 6.7%
FESR	5.3%	1.2%
EMSR	- 2.8%	-14.3.%
TOTAL CAPITAL INVESTMENT	$91,723,000	$58,648,000

Values shown are relative to non-cogeneration (except for capital cost).

Table A4-32: SENSITIVITY ANALYSIS

	ROI	
	GT	ST
BASE	21.9	17.5
Variable (1 -8 1)Variable		
Gas/Oil ± 40%	27.1/17.8	20.9/13.8
Coal ± 40%	20./24.4	16.2/18.9
Capital Investment ± 35%	18.7/29.5	15.1/22.0
Electric ± 25%	24.3/19.9	18.8/16.2
O&M ± 25%	21.4/22.6	16.9/18.2
Escalation		
Gas/Oil + 10%, -2%	34.1/16.8	27.3/12.7
Coal + 10%, -2%	7.4/23.5	5.9/18.6
Electric + 15%, -2%	32.6/15.7	24.6/13.4
O&M + 5%, -2%	21.1/22.2	16.4/17.8

Curves showing the effect of the full range of sensitivity of the various parameters have been prepared:

<u>Figure A4-20</u>: <u>Electric Cost Sensitivity</u>

Two pairs of curves are shown: cogeneration selling price 14% above the buying price, and cogeneration selling price 43% below the buying price. This shows a range of anticipated costs. The first operating year electrical cost is the item being sensitized.

<u>Figure A4-21</u>: <u>Oil/Gas Price Sensitivity</u>

The first year fuel price is sensitized. The value used for the cash flow and levelized cost analyses is shown by the dots on all the curves.

<u>Figure A4-22</u>: <u>Coal Price Sensitivity</u>

The more the curve leans to the horizontal, the more sensitive this item is to variations.

<u>Figure A4-23</u>: <u>Capital Cost Sensitivity</u>

The ROI base scale is the same for all the sensitivity curves.

<u>Figure A4-24</u>: <u>Operations and Maintenance Cost Sensitivity</u>

Items such as cost of sorbent and cost of solid waste disposal are part of the annual O&M cost.

<u>Figure A4-25</u>: <u>Energy Cost Escalation Sensitivity</u>

The rate of escalation assumed has strong effect on the ROI.

<u>Figure A4-26</u>: <u>Operating Parameter Sensitivity</u>

These curves show the effect of:
1) production of electricity
2) amount of coal consumption

Table A4-33 shows the range of capital cost factors resulting from different engineering and construction periods, and varying after-tax cost of money. Also, varying levelization factors result from different cost of money and economic life.

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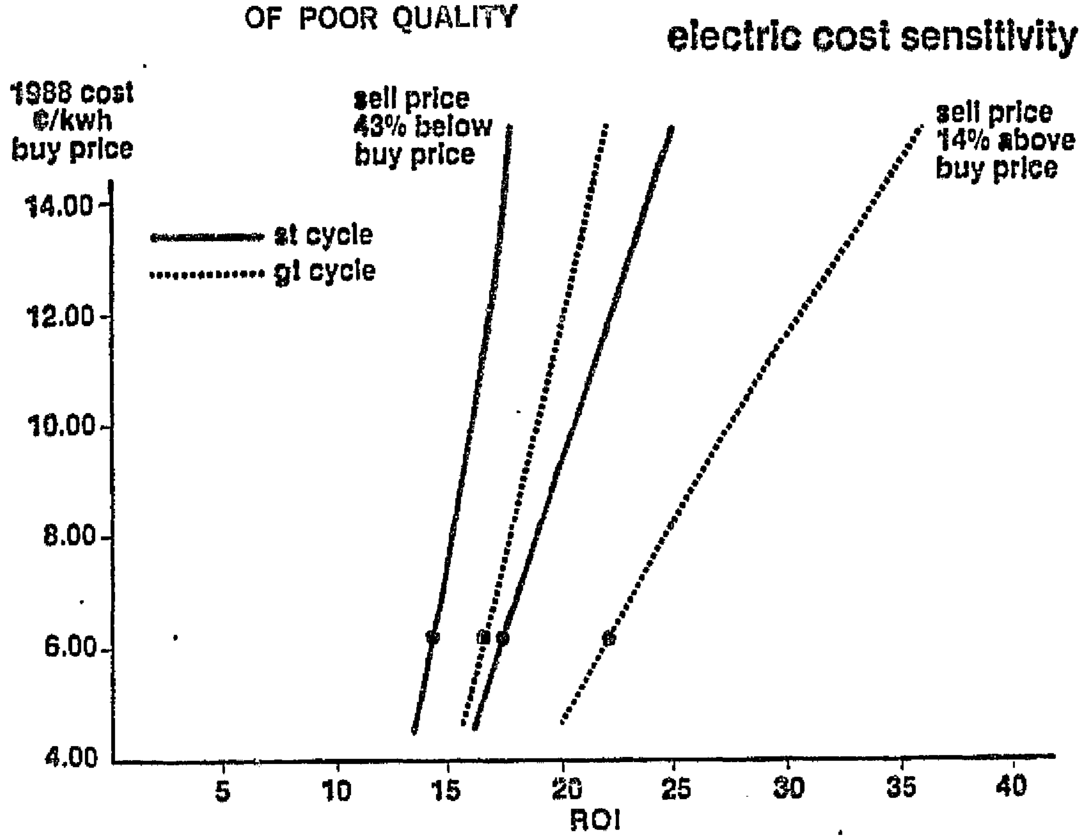
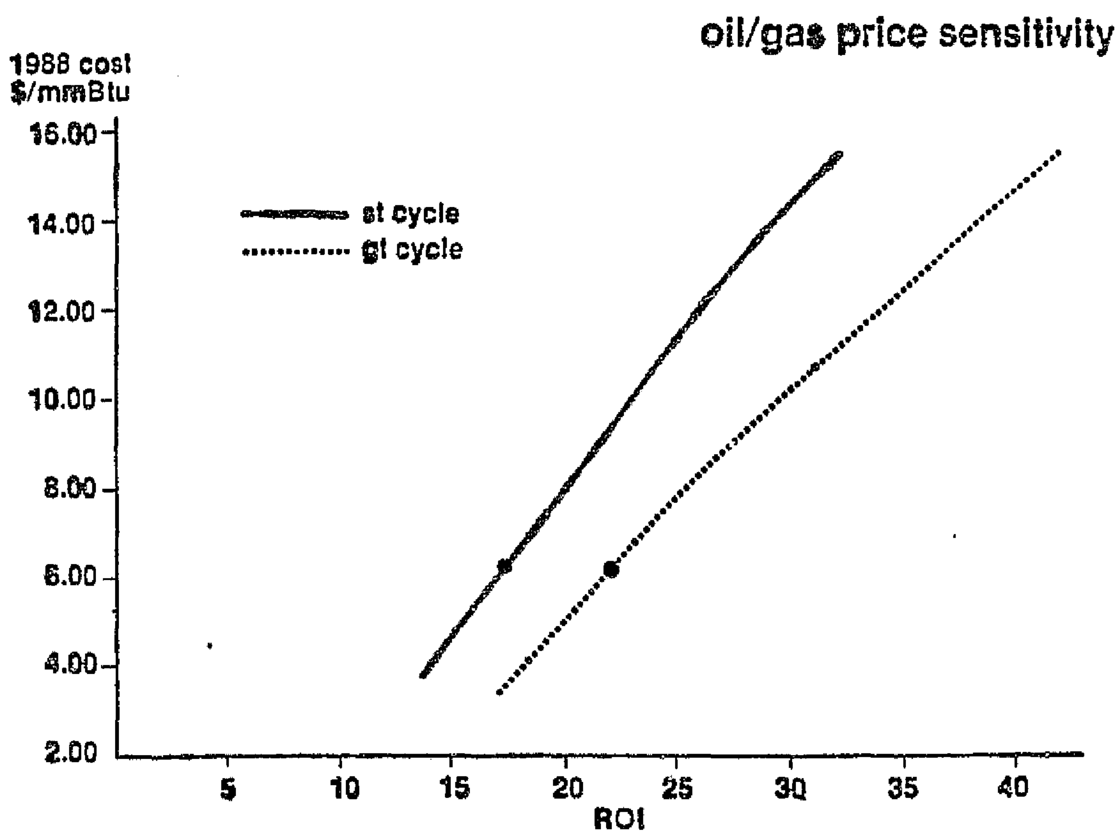


Figure A4-20



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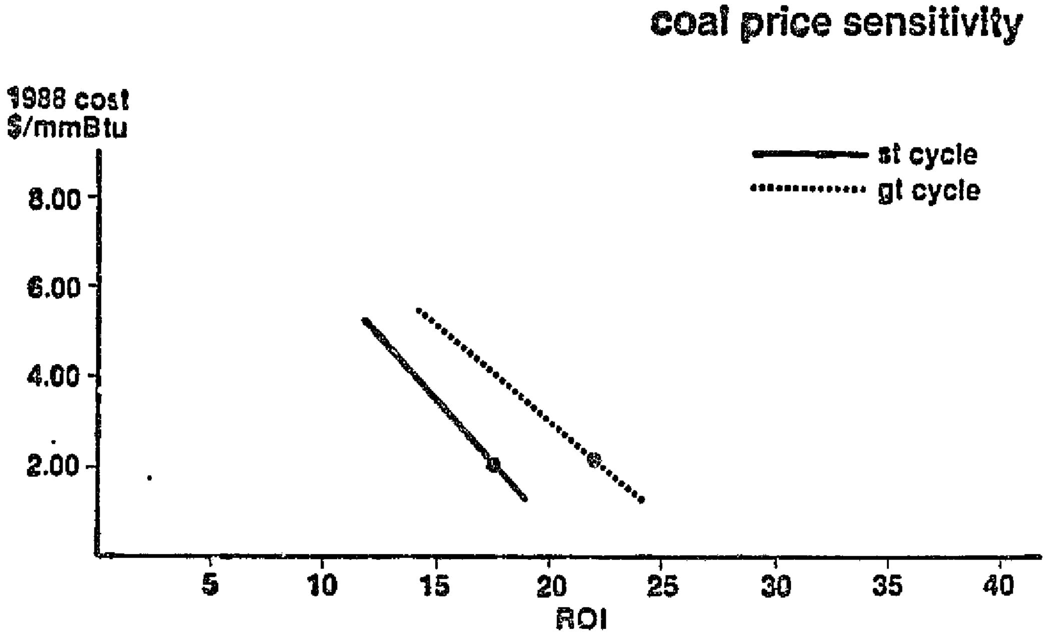

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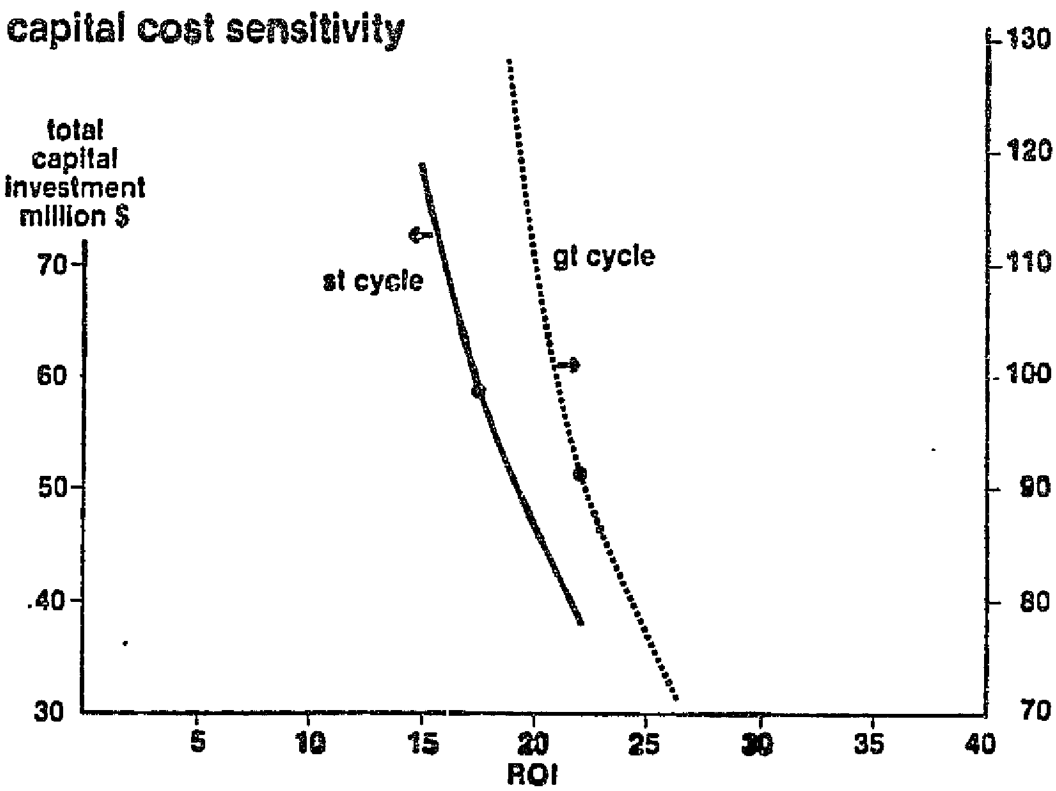

Figure A4-23

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operations & maintenance cost sensitivity

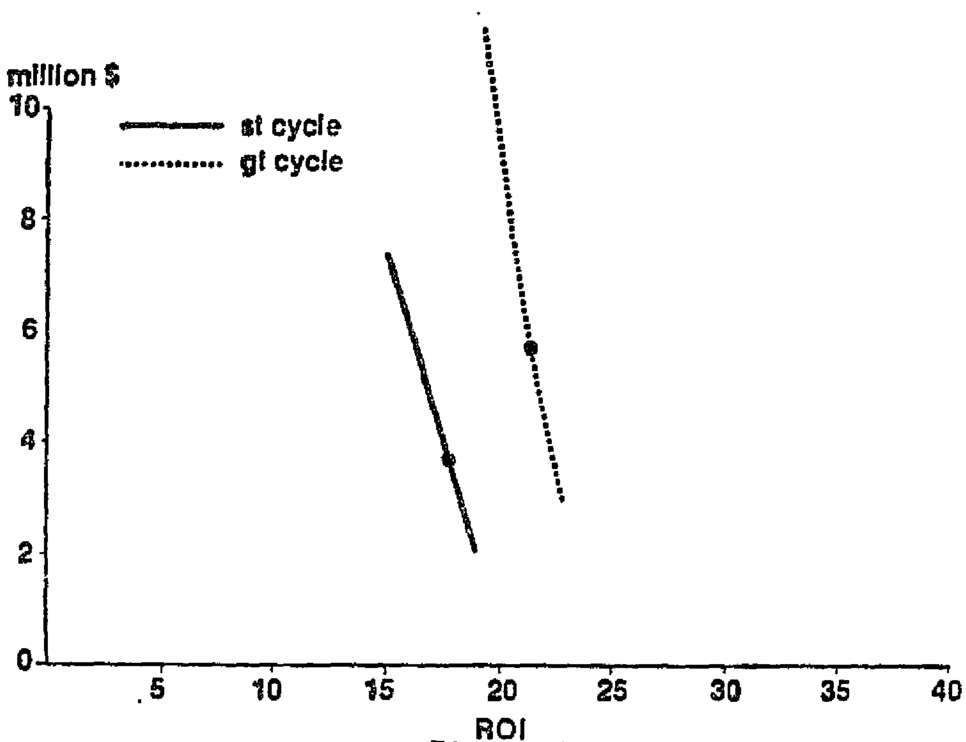

Figure A4-24

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energy cost escalation sensitivity

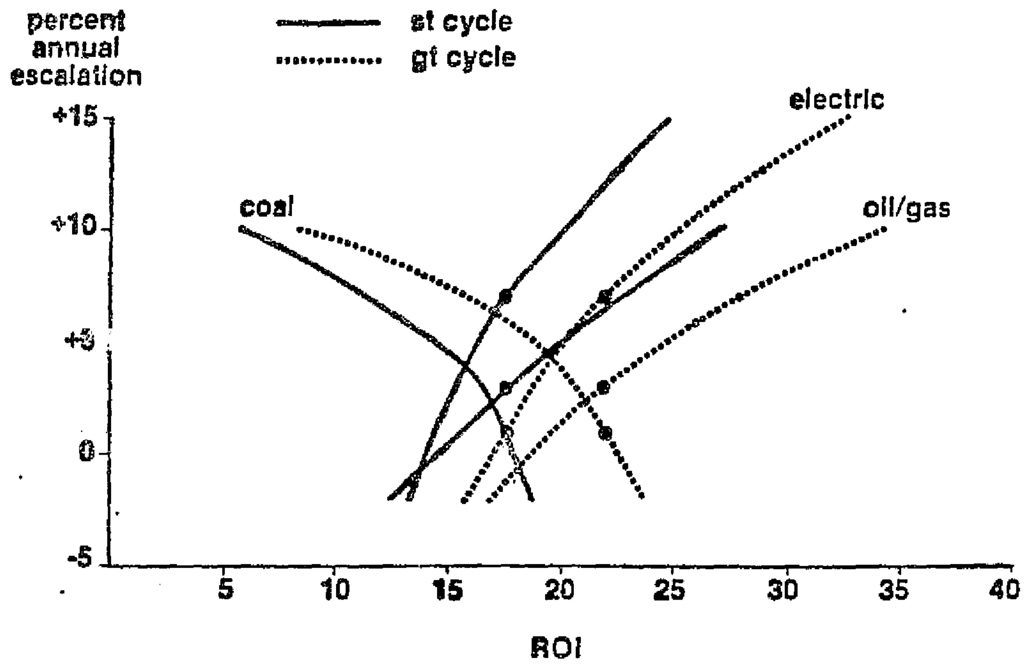


Figure A4-25

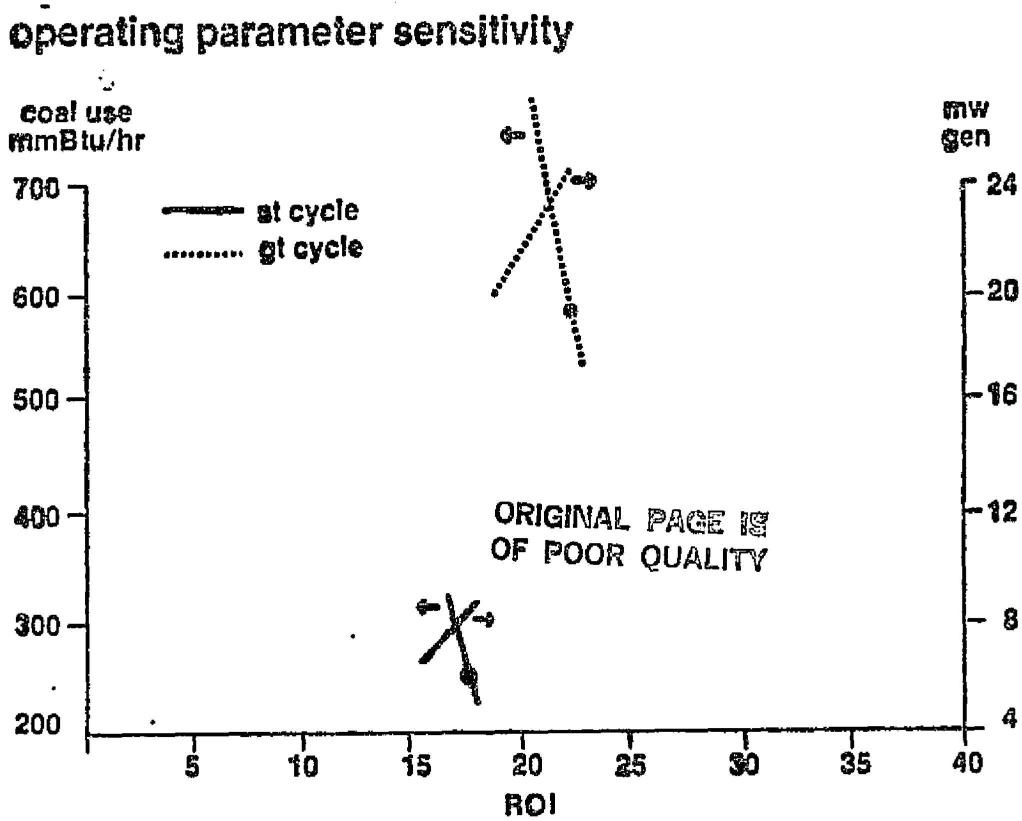


Figure A4-26

Table A4-33

I. TOTAL CAPITAL COST FACTOR

ENGINEERING & CONSTRUCTION PERIOD	AFTER-TAX COST OF MONEY		
	7%	15%	20%
5 YEARS	1.158	1.368	1.519
4 YEARS	1.124	1.285	1.397
2½ YEARS	1.076	1.170	1.232

II. LEVELIZATION FACTORS

	7%, 30 YRS.	15%, 15 YRS.	20%, 15 YRS.
FCR	.083	.185	.245
GAS	1.416	1.185	1.163
COAL	1.115	1.058	1.054
ELECTRICITY		1.520	1.446

4.4.3 System Comparison

The operating parameters' comparison for the two cogeneration systems is summarized in Table A4-34. The fuel utilization efficiency for the AFB/gas turbine system refelects the effect of cost effectiveness in the system design to provide increased Dowtherm heating at the expense of electric generation. The gas turbine cycle plant is much larger than the steam turbine cycle plant as readily seen by the net plant output and fueld and sorbent consumption. Other system comparisons are made in Table A4-35, which shows economic energy and emissions performance for the two cogeneration systems.

Advantages of each of the two cogeneration systems are summarized in Table A4-36.

Table A4-34: SYSTEM COMPARISON

	AFB/GT (DESIGN)	AFB/ST (DESIGN)
Net Plant Output	28.8 MW_e (1)	8.7 MW_e (2)
	112.0 MW_t	58.7 MW_t
(3) Fuel Utilization $\frac{(MW_e + MW_t)}{MW_{IN}}$	65.8%	72.8%

MW_e - plant electric power use, megawatts

MW_t - plant thermal heat use, expressed in megawatts

MW_{IN} - plant fuel and electric consumption, expressed in megawatts

AFB Heater Efficiency	86.0%	83.7%
Combustion Efficiency	(98%)	(97%)
Coal Consumption	587 tons/day	251 tons/day
Limestone Consumption	175 tons/day	75 tons/day
Total Waste	223.5 tons/day	106.9 tons/day
Construction Time (excluding permitting and design)	2.5 years	2.5 years

(1) Including Dowtherm Heating (2) Excluding Dowtherm Heating

(3) Non-Equalized for Dowtherm Heating

Table A4-35

SYSTEM COMPARISON

		NON-COGEN.	AFB/GT	AFB/ST
TOTAL CAPITAL INVESTMENT	($M)	0	91.790	58.691
ENERGY - FESR	(%)	---	5.3	1.2
GAS	(MBtu/HR.)	413.0	40.4	231.0
COAL	(MBtu/HR.)	0	585.0	248.4
WASTE FUEL	(MBtu/HR.)	70.0	70.0	70.0
ELECTRIC	(MW)	24.1	4.03	16.92
EMISSIONS - EMSR	(%)	---	-28	-14.3
GAS	(TONS/DAY)	6.42	3.22	7.34
SOLID	(TONS/DAY)	0	176.8	84.0
ROI	(%)	---	21.9	17.5
LAECSR	(%)	---	11.7	-6.7

Table A4-36

COGENERATION SYSTEMS COMPARISON

ETHYL PLANT SITE

	SYSTEM ADVANTAGE
AFB/GAS TURBINE	o CONSTANT DOWTHERM HEATING o HEAT AND ELECTRICITY MATCH o GREATER NATURAL DISPLACEMENT o HIGHER ROI o HIGHER LAECSR
AFB/STEAM TURBINE	o HIGH SYSTEM EFFICIENCY (EXCLUDES DOWTHERM HEATING) o LOWER CAPITAL COST

Section 5

MARKET AND BENEFIT ANALYSIS

5.1 REPRESENTATIVENESS

Among the factors considered in plant screening for the selection of the "best" site for the AFB/gas turbine is degree of representativeness to other plants:

a. in the same industry
b. in other industries

The two sites were analyzed to develop criteria which can be extended to industry at large. The criteria to define likeness are plant parameters such as:

a. Power/Heat ratio against plants in the same industry
b. Plant electric use against plants in the same industry
c. Steam load against plants in the same industry
d. Electric power cost against plants in the same industry
e. Existing cogeneration (capacity and number of plants)

The above elements are also defined for plants in the total "other" industrial manufacturing sector, excluding SIC 26, 28, 32 and 33. The above elements (criteria) define sameness to determine degree of representativeness to other plants in that same industry or other industries.

SIC 32 is stone, clay and glass industry and is excluded because these plants are not major steam consumers.

SIC 33 is primary metals industry and is excluded because it is not a representative type industry. Plants in this SIC code tend to be larger cogenerators and heavily use their own waste fuel.

SIC 26 is the pulp and paper industry, to which the Riegel plant belongs. SIC 28 covers chemicals, which includes the Ethyl plant.

A series of graphical displays follows which shows where the two plant sites fit with reference to other plants in its own industry and to other industries for each criteria. The plants profiled are the largest 10,000 plants (out of about 300,000 total in the U.S.A.), but these represent 85% to 90% of total industry energy requirements. The largest plants require at least 50,000 lbs/hr steam and 2 MW power needs.

General Energy Associates produced the graphs using their GEA/IPEP Plant Site Data Base, which is described in Appendix Section 5.2. The figures are arranged to show the bar charts and histograms for Ethyl and Riegel for each plant parameter. The array of figures is for the two plant sites for their respective industries. Chapter 4 of the report gives figures for plant characteristics for other industries.

In Figure A5-1, two of the charts have as the ordinates the number of plants in SIC 26 (top left chart) and in SIC 28 (lower left chart) that are within the top 10,000 plants profiled. The other two charts have as ordinates the total plant load for these plants.

For Figure A5-2, the abscissa for these four charts is the actual plant electrical use. These charts confirm the expectation that more large-size plants (percentage wise) currently cogenerate.

The four charts in Figure A5-3 show that plants with larger steam loads have a larger percent cogenerating, as expected. The effect of purchased electric power costs is shown in Figure A5-4.

The histograms are plots of the bar charts. SIC 26 is the pulp and paper industry, and it encompasses about 600 plants. Figure A5-7 shows that a significant number of the plants currently cogenerate, and that a large percentage of the total plant power is provided by cogenerating plants in this industry. This confirms expectations for this industry. SIC 28 is for all chemical plants, and is a diverse industry of about 750 plants. The histogram given in Figure A5-8 corresponds to the bar charts in Figures 4-3 and 4-4. The histogram given in Figure A5-9 corresponds to the bar charts in Figures 4-7 and 4-8, while the histogram in Figure A5-10 corresponds to the bar charts in Figures 4-9 and 4-10 of the main part of the report.

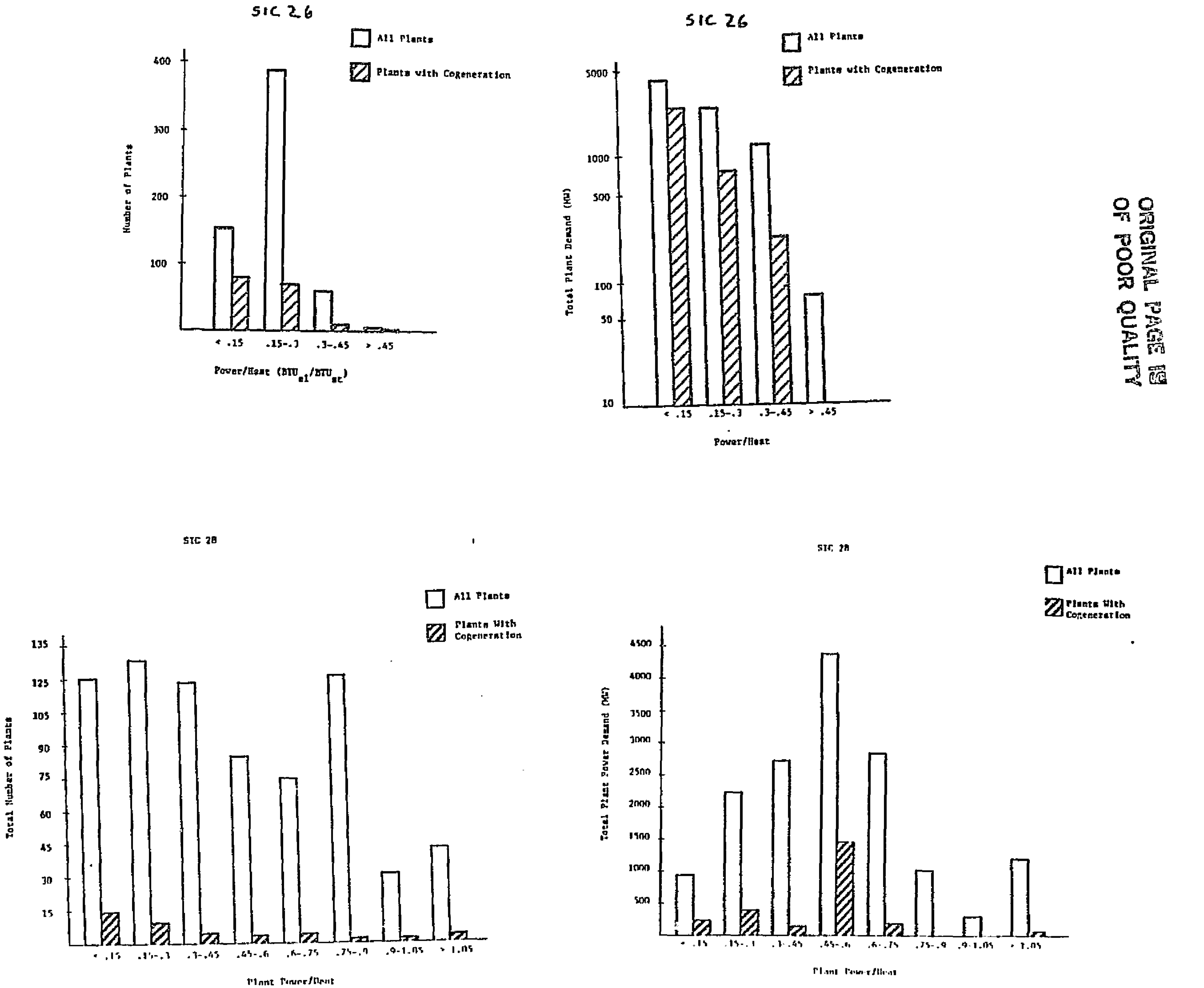
Site representativeness based on the number of plants for each of the plant parameters is rated in Table A5-1. The result of this profiling shows the two plant sites are representative of their respective industry.

Table A5-1

SITE REPRESENTATIVENESS
(Based on Number of Plants)

CRITERIA	RIEGEL (SIC 26/Others)	ETHYL (SIC 28/Others)
Power/Heat	1 / 2	1 / 2
Electrical Demand (MW)	2 / 3	2 / 3
Steam Demand (LBS/HR)	2 / 3	1 / 3
Electrical Cost (¢/KWH)	3 / 3	3 / 3

1 = High 2 = Moderate 3 = Low



SIC 26
All Plants
Plants with Cogeneration
Number of Plants
400
300
200
100
< .15
.15-.3
.3-.45
> .45
Power/Heat (BTU_{el}/BTU_{st})
SIC 26
All Plants
Plants with Cogeneration
Total Plant Demand (KW)
5000
1000
500
100
50
10
< .15
.15-.3
.3-.45
> .45
Power/Heat
SIC 28
All Plants
Plants With Cogeneration
Total Number of Plants
135
125
105
90
75
60
45
30
15
< .15
.15-.3
.3-.45
.45-.6
.6-.75
.75-.9
.9-1.05
> 1.05
Plant Power/Heat
SIC 28
All Plants
Plants With Cogeneration
Total Plant Power Demand (KW)
4500
4000
3500
3000
2500
2000
1500
1000
500
Plant Power/Heat

Figure A5-1

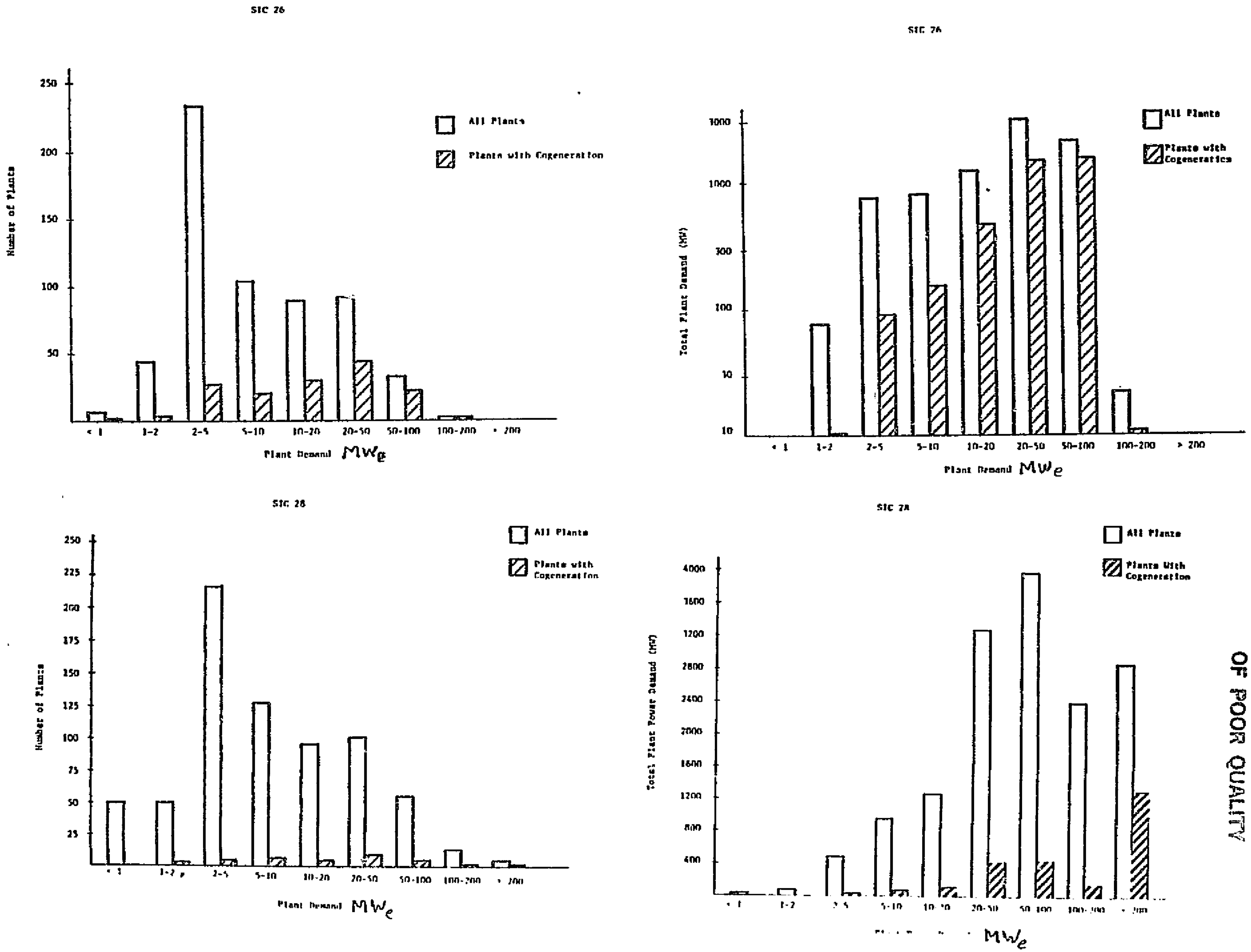
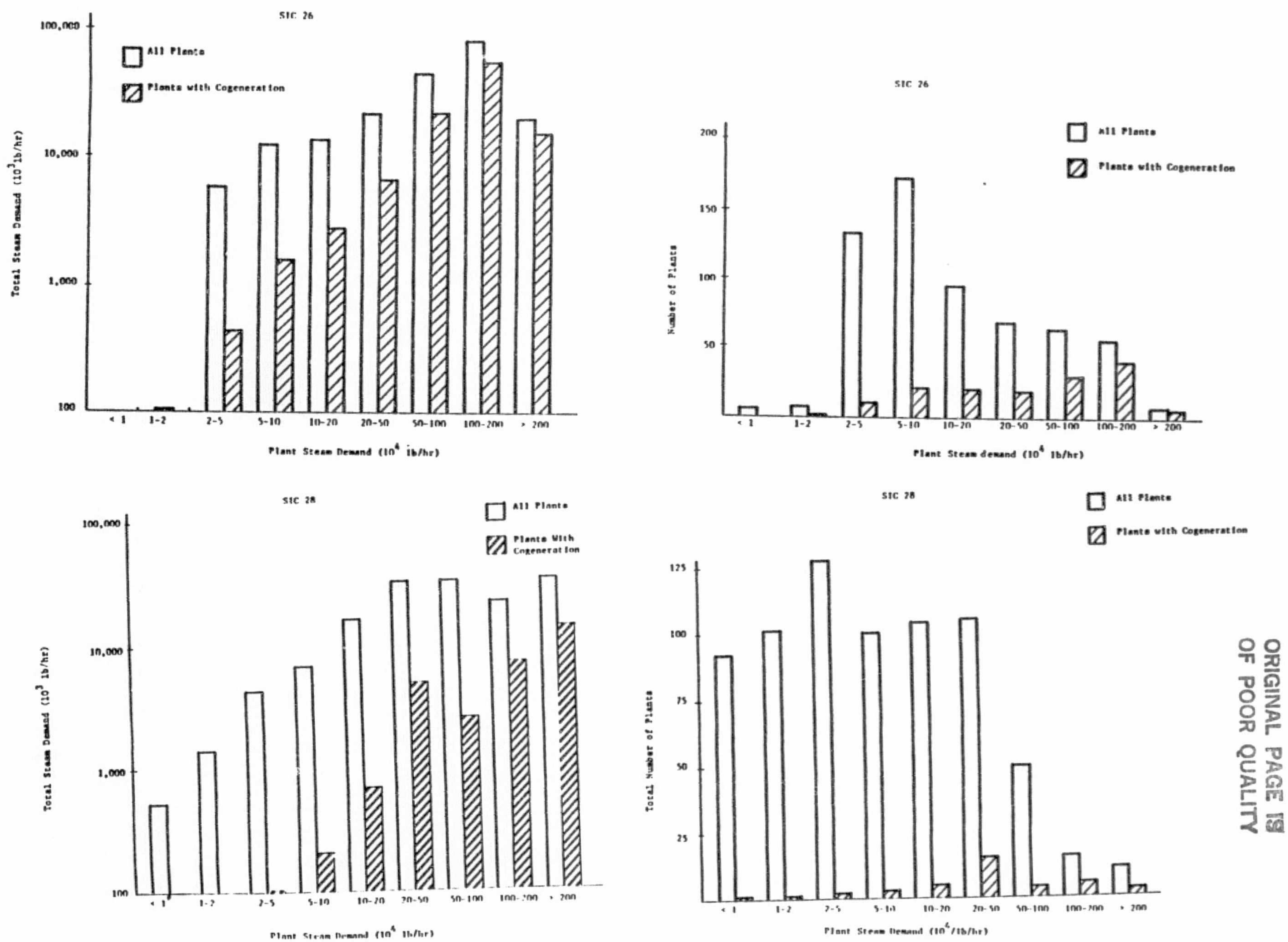
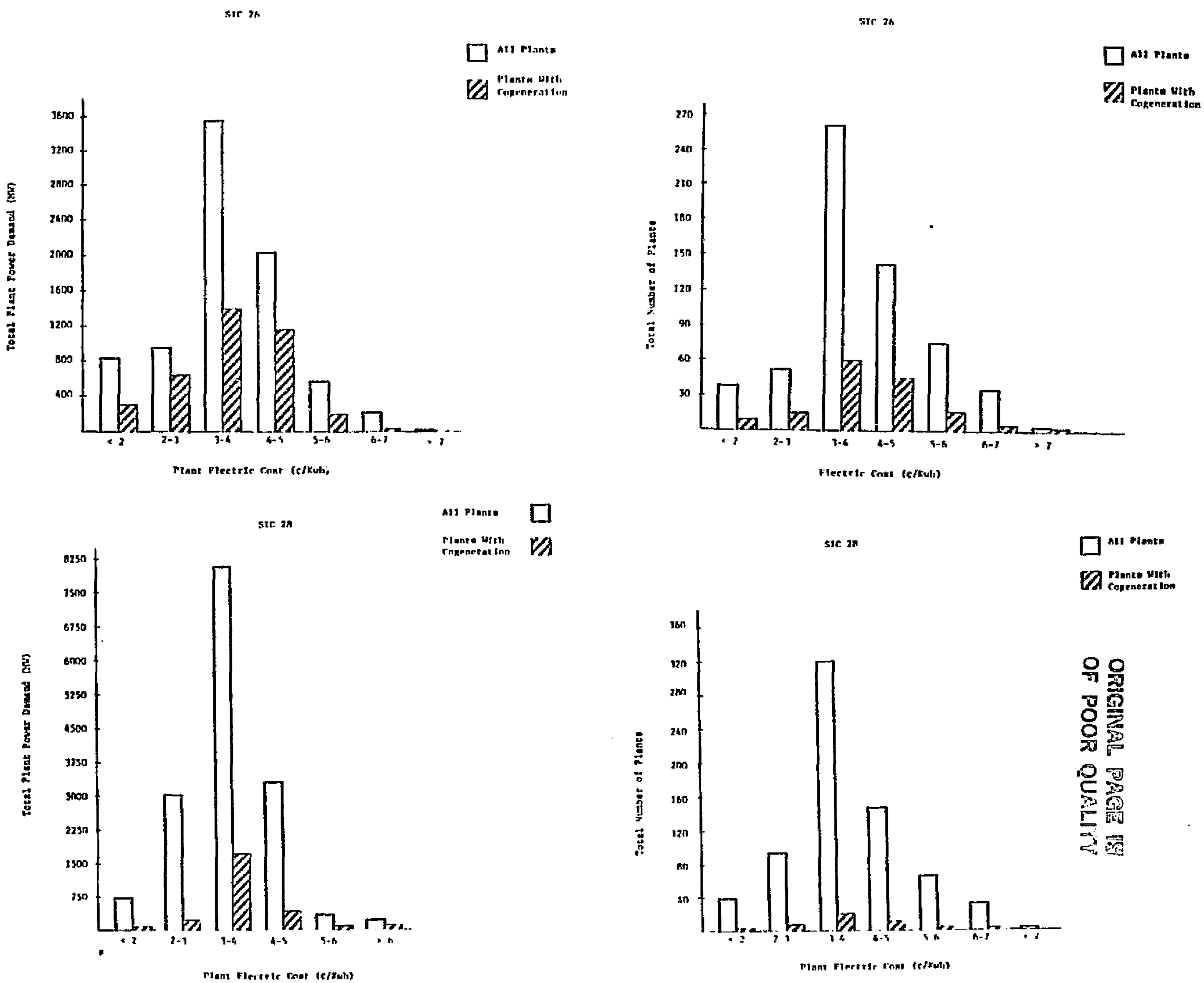

SIC 26
Number of Plants
All Plants
Plants with Cogeneration
Plant Demand MWe
SIC 26
Total Plant Demand (MW)
All Plants
Plants with Cogeneration
Plant Demand MWe
SIC 28
Number of Plants
All Plants
Plants with Cogeneration
Plant Demand MWe
SIC 28
Total Plant Power Demand (MW)
All Plants
Plants With Cogeneration
MWe

Figure A5-2



SIC 26
All Plants
Plants with Cogeneration
Total Steam Demand (10^3 lb/hr)
100,000
10,000
1,000
100
< 1
1-2
2-5
5-10
10-20
20-50
50-100
100-200
> 200
Plant Steam Demand (10^4 lb/hr)
SIC 26
All Plants
Plants with Cogeneration
Number of Plants
200
150
100
50
Plant Steam demand (10^4 lb/hr)
SIC 28
All Plants
Plants With Cogeneration
Total Steam Demand (10^3 lb/hr)
100,000
10,000
1,000
100
Plant Steam Demand (10^4 lb/hr)
SIC 28
All Plants
Plants with Cogeneration
Total Number of Plants
125
100
75
50
25
Plant Steam Demand (10^4/lb/hr)

Figure A5-3



SIC 26
All Plants
Plants With Cogeneration
Total Plant Power Demand (MW)
Plant Electric Cost (¢/Kwh)
SIC 26
All Plants
Plants With Cogeneration
Total Number of Plants
Electric Cost (¢/Kwh)
SIC 28
All Plants
Plants With Cogeneration
Total Plant Power Demand (MW)
Plant Electric Cost (¢/Kwh)
SIC 28
All Plants
Plants With Cogeneration
Total Number of Plants
Plant Electric Cost (¢/Kwh)

Figure A5-4

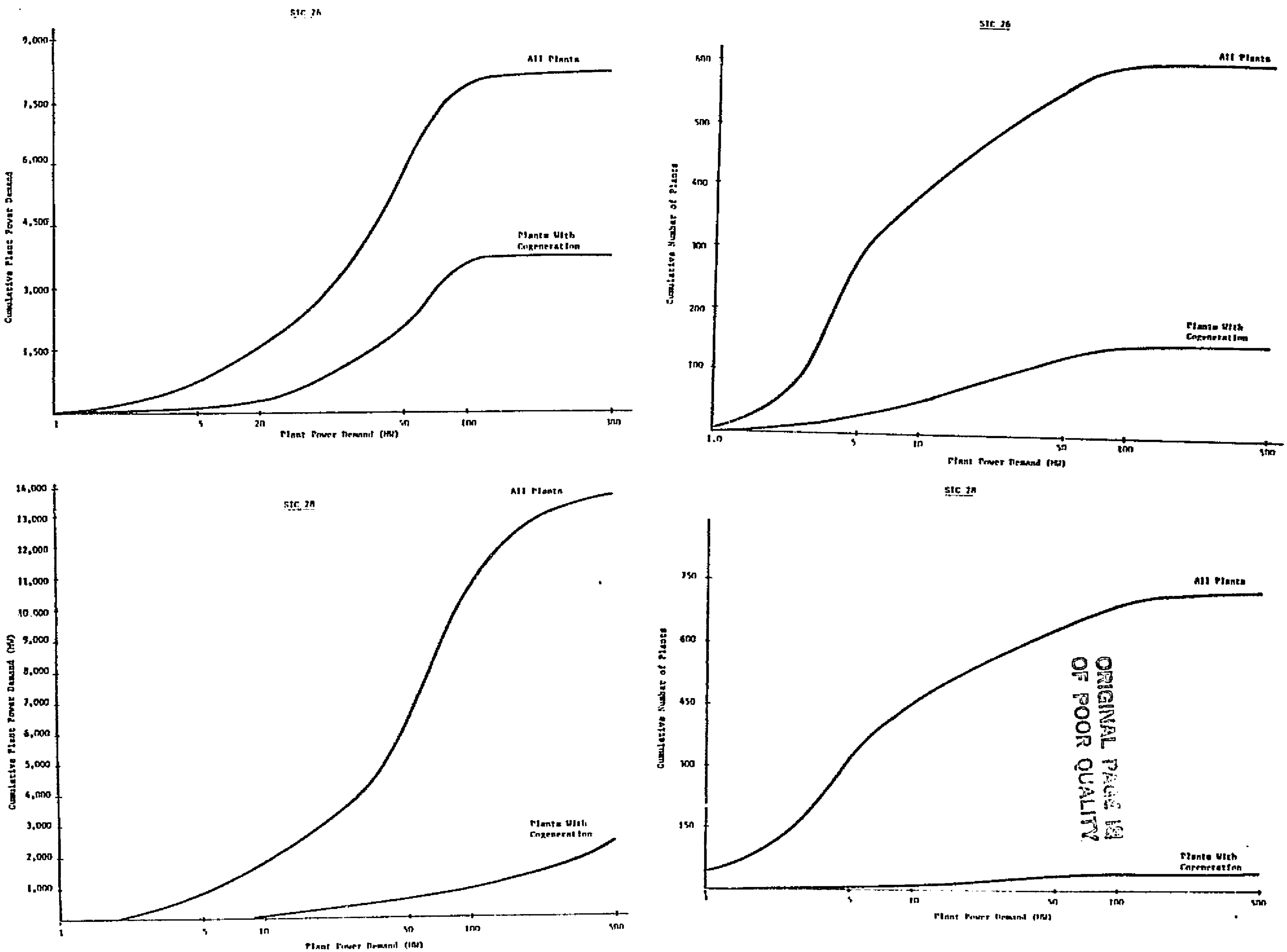

SIC 26
All Plants
Plants With Cogeneration
Cumulative Plant Power Demand
Plant Power Demand (MW)
Cumulative Number of Plants
SIC 26
All Plants
Plants With Cogeneration
Plant Power Demand (MW)
SIC 28
All Plants
Plants With Cogeneration
Cumulative Plant Power Demand (MW)
Plant Power Demand (MW)
SIC 28
All Plants
Plants With Cogeneration
Cumulative Number of Plants
Plant Power Demand (MW)

Figure A5-5

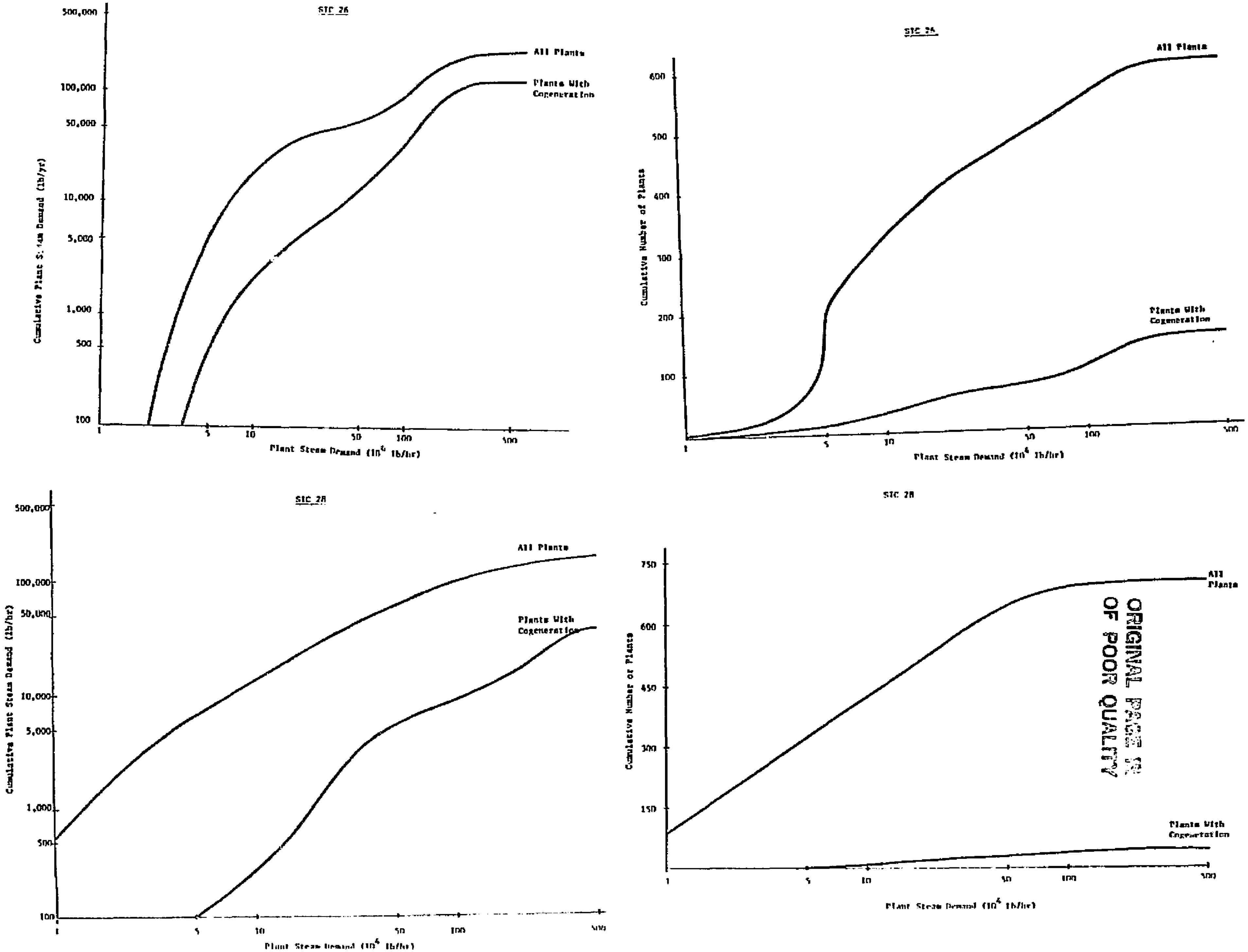

SIC 26
500,000
100,000
50,000
10,000
5,000
1,000
500
100
Cumulative Plant Steam Demand (lb/yr)
All Plants
Plants With Cogeneration
1
5
10
50
100
500
Plant Steam Demand (10⁶ lb/hr)
SIC 26
600
500
400
300
200
100
Cumulative Number of Plants
All Plants
Plants With Cogeneration
1
5
10
50
100
500
Plant Steam Demand (10⁶ lb/hr)
SIC 28
500,000
100,000
50,000
10,000
5,000
1,000
500
100
Cumulative Plant Steam Demand (lb/hr)
All Plants
Plants With Cogeneration
1
5
10
50
100
500
Plant Steam Demand (10⁶ lb/hr)
SIC 28
750
600
450
300
150
Cumulative Number of Plants
All Plants
Plants With Cogeneration
1
5
10
50
100
500
Plant Steam Demand (10⁶ lb/hr)

Figure A5-6

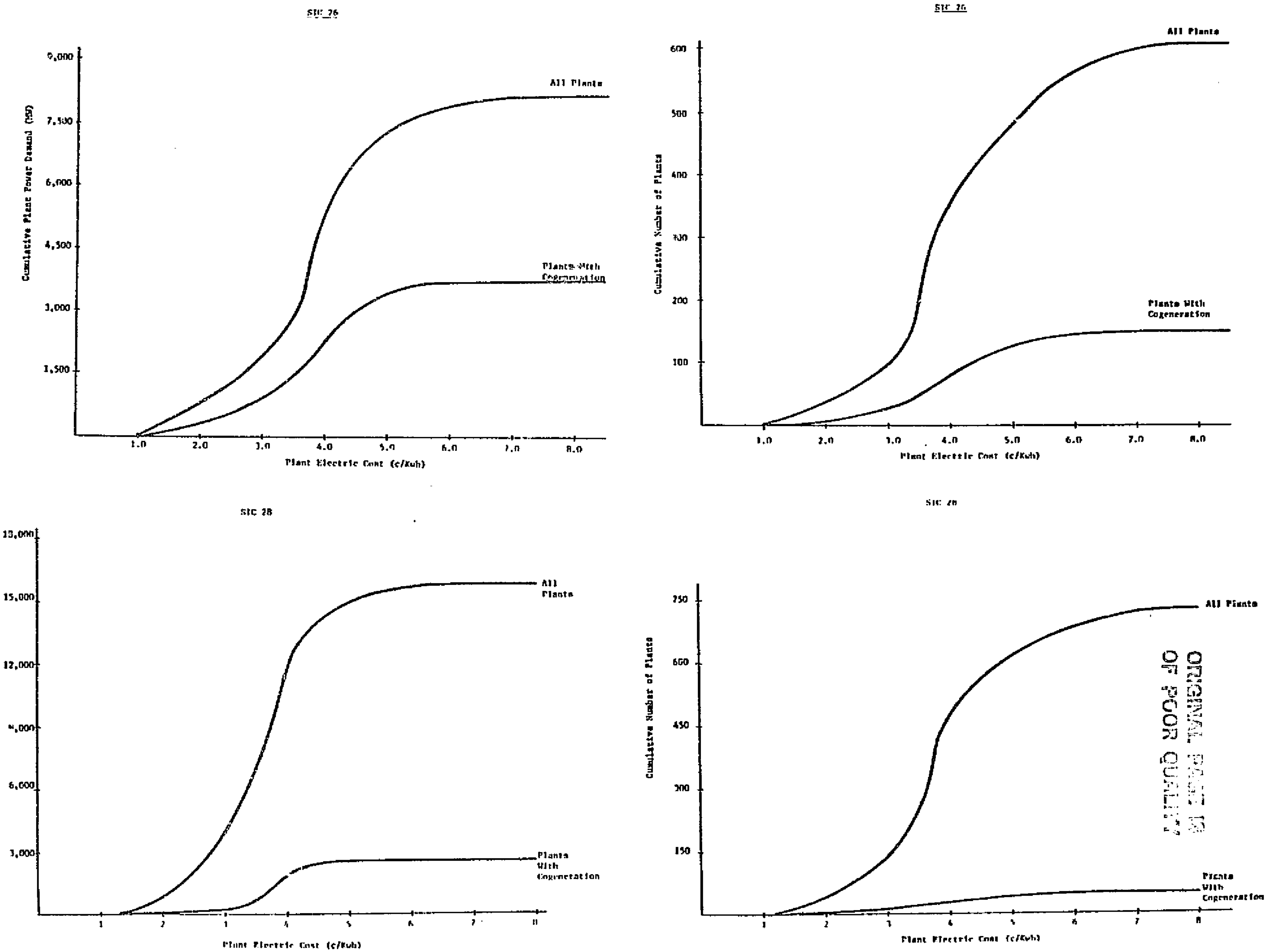


Figure A5-7

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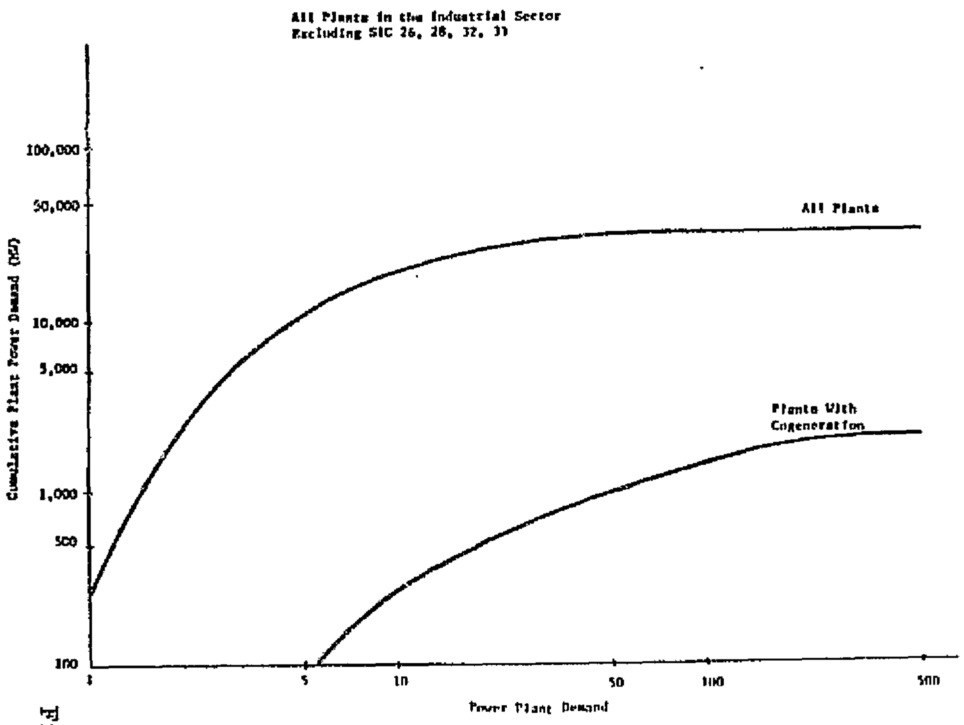

All Plants in the Industrial Sector
Excluding SIC 26, 28, 32, 33
Cumulative Plant Power Demand (MW)
100,000
50,000
10,000
5,000
1,000
500
100
All Plants
Plants With Cogeneration
1
5
10
50
100
500
Power Plant Demand

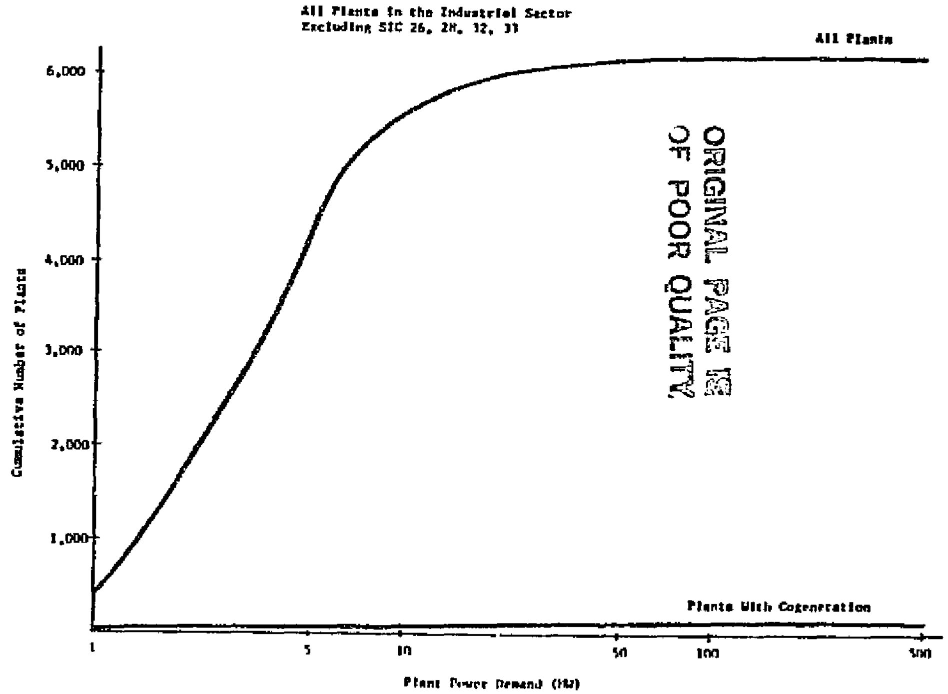
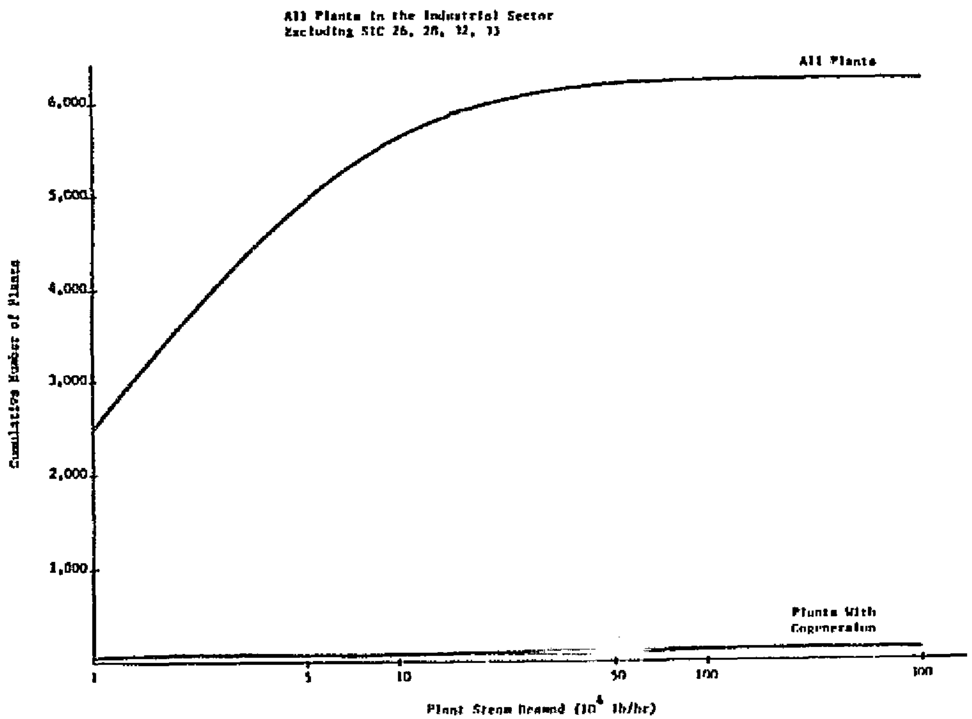

All Plants in the Industrial Sector
Excluding SIC 26, 28, 32, 33
All Plants
Cumulative Number of Plants
6,000
5,000
4,000
3,000
2,000
1,000
Plants With Cogeneration
1
5
10
50
100
500
Plant Power Demand (MW)

Figure A5-8



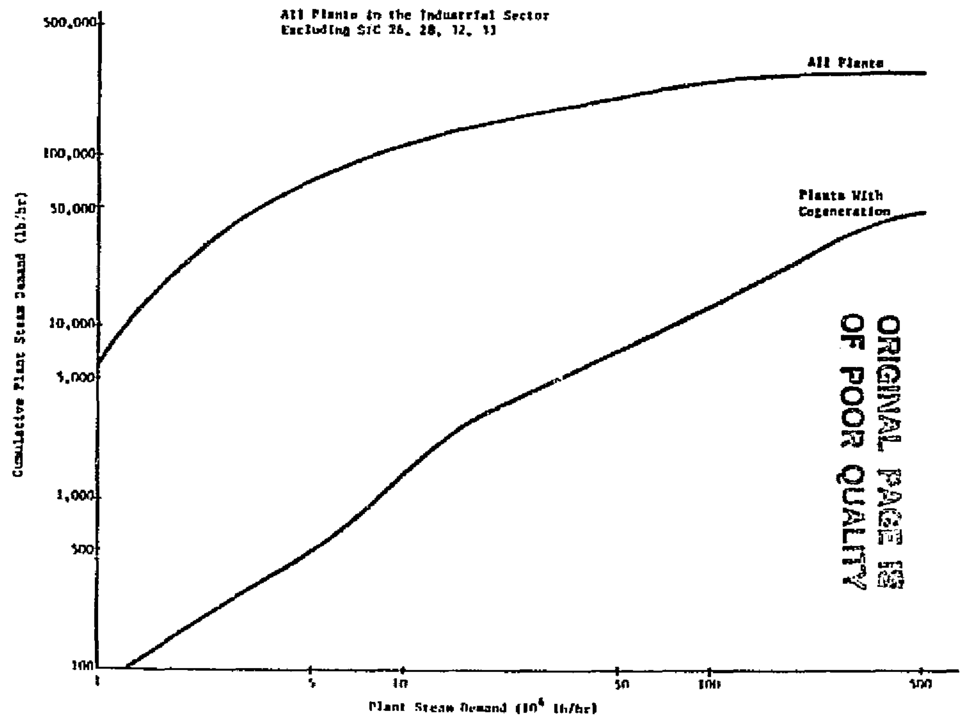


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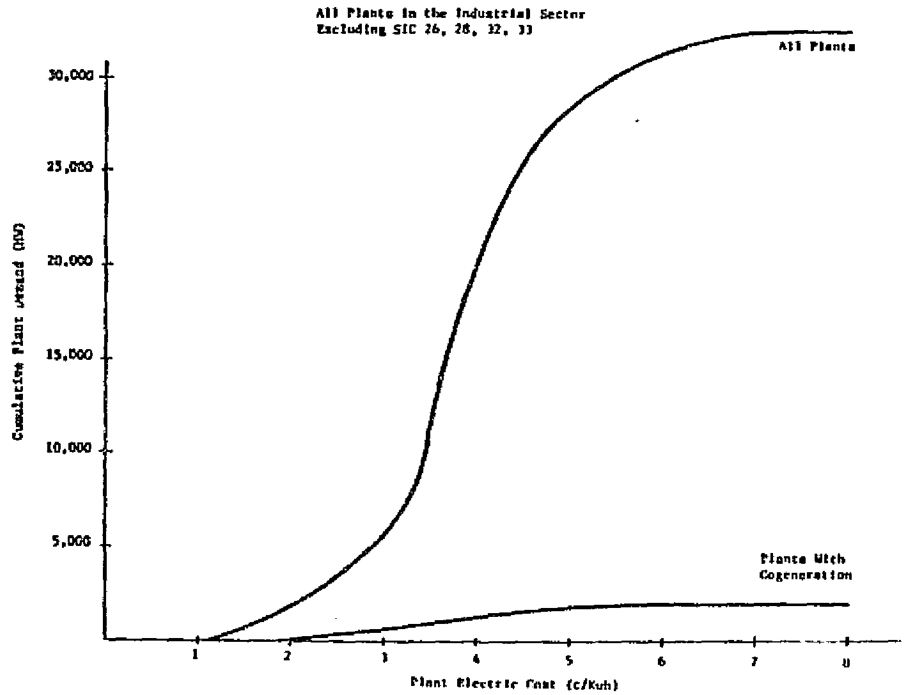
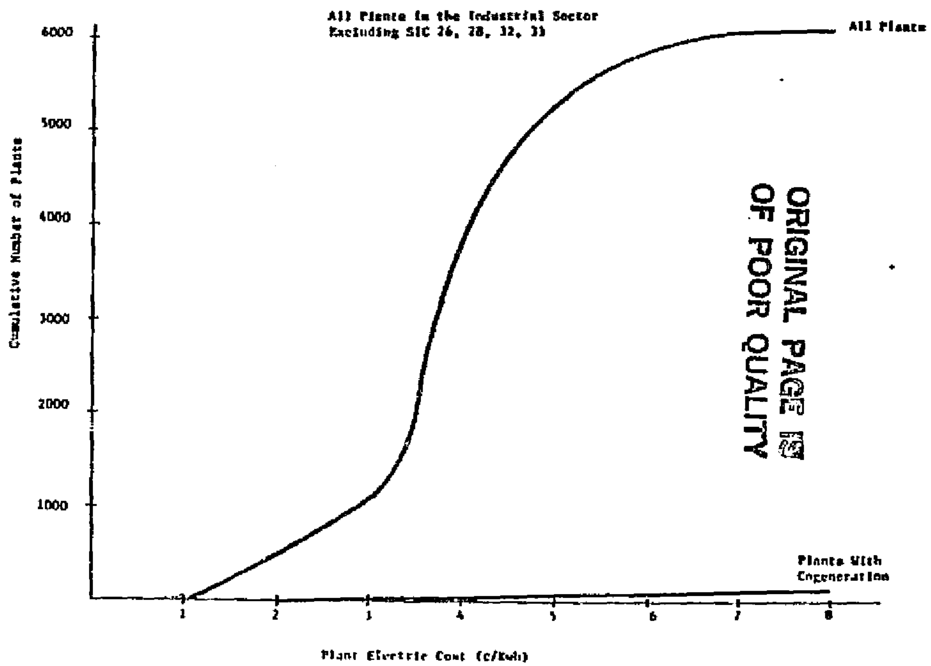
Figure A5-9



All Plants in the Industrial Sector
Excluding SIC 26, 28, 32, 33
All Plants
Plants With Cogeneration
30,000
25,000
20,000
15,000
10,000
5,000
Cumulative Plant Demand (MW)
1
2
3
4
5
6
7
8
Plant Electric Cost (¢/Kwh)



All Plants in the Industrial Sector
Excluding SIC 26, 28, 32, 33
All Plants
Plants With Cogeneration
6000
5000
4000
3000
2000
1000
Cumulative Number of Plants
1
2
3
4
5
6
7
8
Plant Electric Cost (¢/Kwh)

Figure A5-10

5.2 GEA/IPEP PLANT SITE DATA BASE

A description of the methodology in the construction of the General Energy Associated Industrial Plant Energy Profile (GEA/IPEP) Data Base for the top 10,000 plants used in the study is presented.

The basic premise used to construct the data base is that, while differences exist in energy use between plants in a given industrial sector, these differences may be quantified by estimating the processes and production levels in each plant. Plants with common processes may be grouped into generic plant types. For these generic plant types, a process data base is used to estimate the processes and energy use per unit product for that generic plant. Key to this is the ability to recognize, and classify, each actual plant into a generic plant type and to determine production levels for the plant. Trade association data sources are used . Central to the success of this approach are three key data bases (Exhibits 1 and 2).

- An accurate list of plants by industrial sector: the Dun and Bradstreet plant list, state directories, and trade association plant sites.

- A process data base to establish generic plant types and energy intensity: the Drexel 108 Process Data Base with the addition of a significant number of processes by GEA.

- A method for classifying actual plants by generic type and production level by plant: trade association sources are used.

It is clear that two plants in the same generic type may differ in their energy intensity per unit product owing to age of equipment, efficiency of overall plant operation and percent capacity of plant production. Because of these factors, estimates will deviate from actual plant operation. In order to account for this in this study, field verification and validation of plant estimates were conducted.

This has contributed to the use of a very broad and reasonable set of plant estimates in the technology/ROI models for estimation of market share.

Exhibit 1

GENERAL INDUSTRIAL DATA BASE APPROACH

FOR TOP 10,000 U.S.A. PLANTS

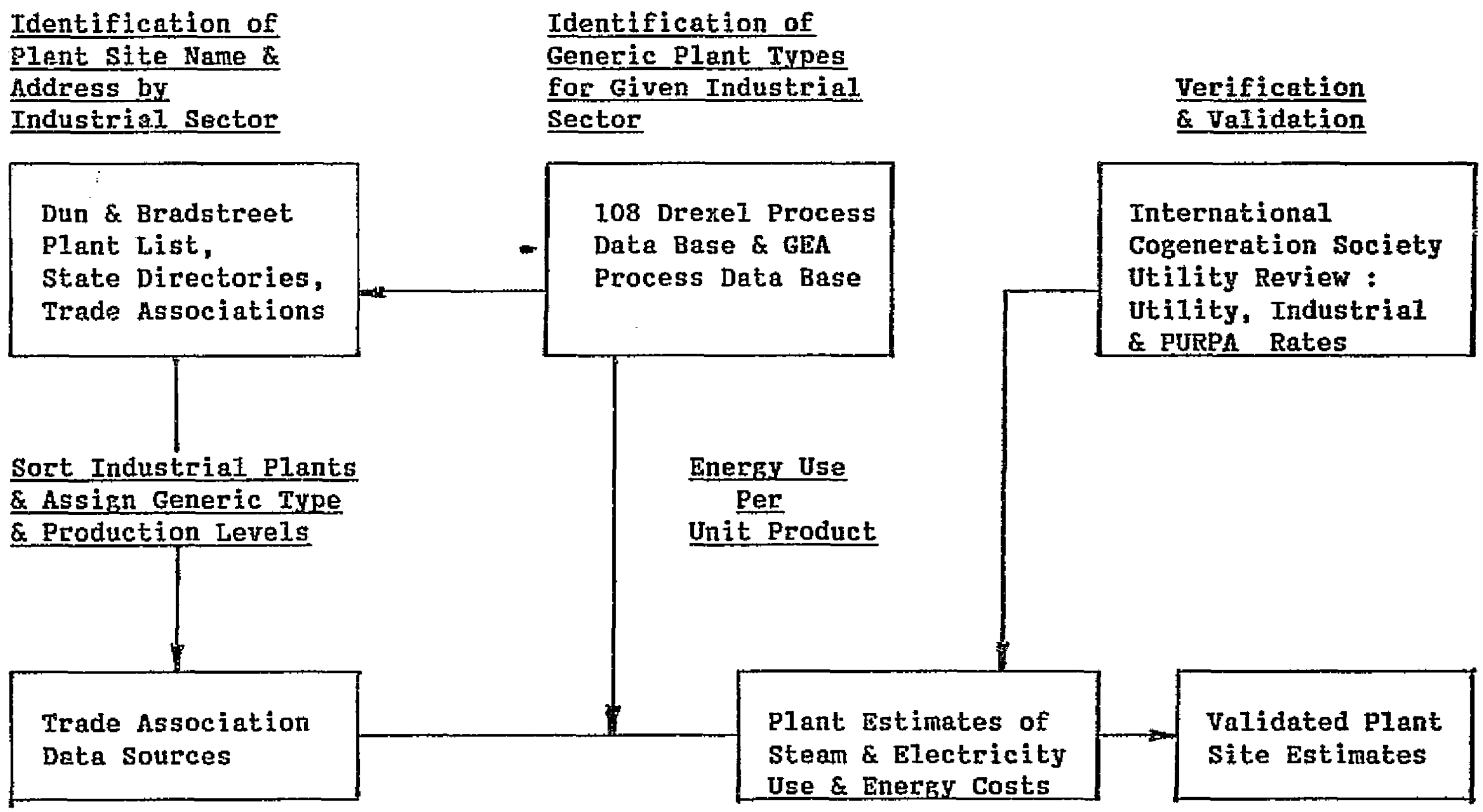
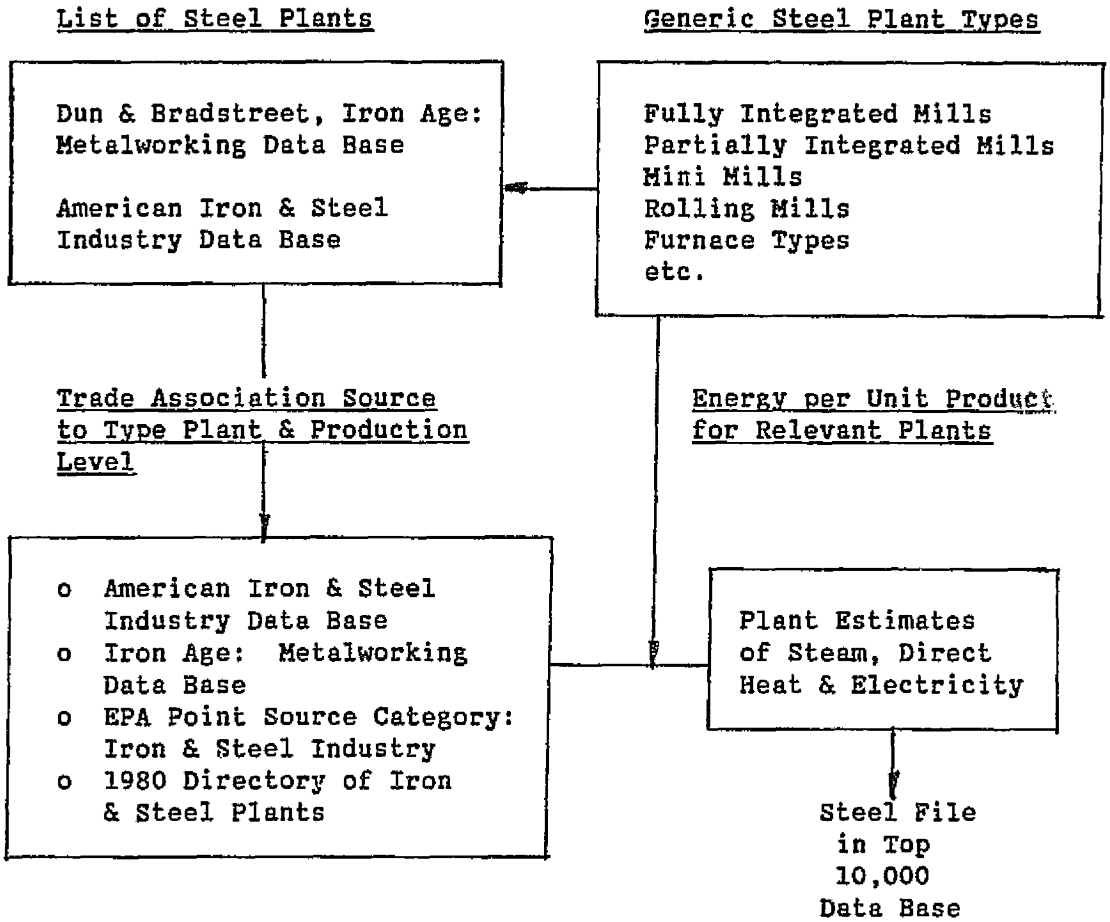


Exhibit 2

INDUSTRIAL DATA BASE APPROACH: EXAMPLE

Below is shown in summary fashion the data base methodology for a sample industry: steel.



It is useful in understanding the methodology to consider an example. The steel plants in New York State are used to focus on the key elements in the methodology.

A. Plant List

Using a uniform set of plant names, addresses and employees from cited references, a subfile of plants in this SIC* is created:

Plant	City	Employees
Al Tech Steel	Dunkirk	840
Al Tech Steel	Watervliet	720
Al Tech Steel	Watervliet	703
Bethlehem Steel	Lackawanna	8,500
Crucible Steel	Syracuse	165
Hanna Steel	Buffalo	265
Markin Tube	Wyoming	150
Portec Inc.	Troy	160
Ramco Steel	Buffalo	210
Republic Steel	Buffalo	1,400
Roblin Steel	Dunkirk	155
Roblin Steel	N. Tonawanda	165
Simonds Steel	Lockport	450
Special Metals	New Hartford	405
Washburn Wire	New York	175
		13,993

While companies with less than 100 employees exist, the thrust of this data base is to address energy use for the largest plant sites.

B. Process Data Base

One of the great difficulties in developing a plant energy data base is that even within a 4-digit SIC sector*, a variety of processes and products may exist. To deal with this problem, we have made extensive use of the process energy data base developed at Drexel University under Department of Energy contract as well as significantly expanded this data base to additional processes.

*Standard Industrial Classification (SIC)

For a given SIC, such as 3312 - Blast Furnace and Steel processes, the Process Data Base has a complete description of the energy requirements by unit operation (Exhibit 3), defined in terms of energy/unit product for all relevant processes within this SIC. In examining energy use at the plant level, two difficulties arise:

- o Any given steel mill will, in general, not have all the unit operations shown in Exhibit 3. They will have some mix of these operations, depending on their products and the input materials.

- o To use the process data, it is necessary to obtain units of production for each plant.

Although any given plant within a 4-digit SIC may have an arbitrary mix of unit operations, trade association data and industry consultants indicate a given number of <u>generic plant types</u> into which most plants fit. For steel mills, it appears that nine plant types are quite adequate. These are shown in Exhibit 4. It can be noted that some 245 major steel mills exist in the United States, of which 15 are in New York State. For each mill the trade association data give the major products, production levels, processes and equipment type. This affords a mechanism for selecting a generic type for each of these mills.

For each of these generic plant types, a specific mix of unit operations can be defined. So that for SIC 3312, the process data base contains a listing of generic plant types, and the specific unit operations are defined on an energy use per unit product basis. For example, those unit operations typical of, say, generic types 3, 4, 5, 6 would have the following entries for energy use at the unit operation level:

<u>Generic Types 3, 4, 5, 6</u>

Unit Operation	Btu/lb Product Electric	Btu/lb Product Fossil Fuel
Electric Arc	255	-
Rolling Mill	300	-
Reheat Furnace	-	2,500
Lights	15	-
Auxiliary Equipment	50	-
Boiler*	-	170

*Only for boilers in plants with no coking or blast furnaces.

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Exhibit 3

3312 - BLAST FURNACES AND STEEL MILLS

PROCESS FLOW

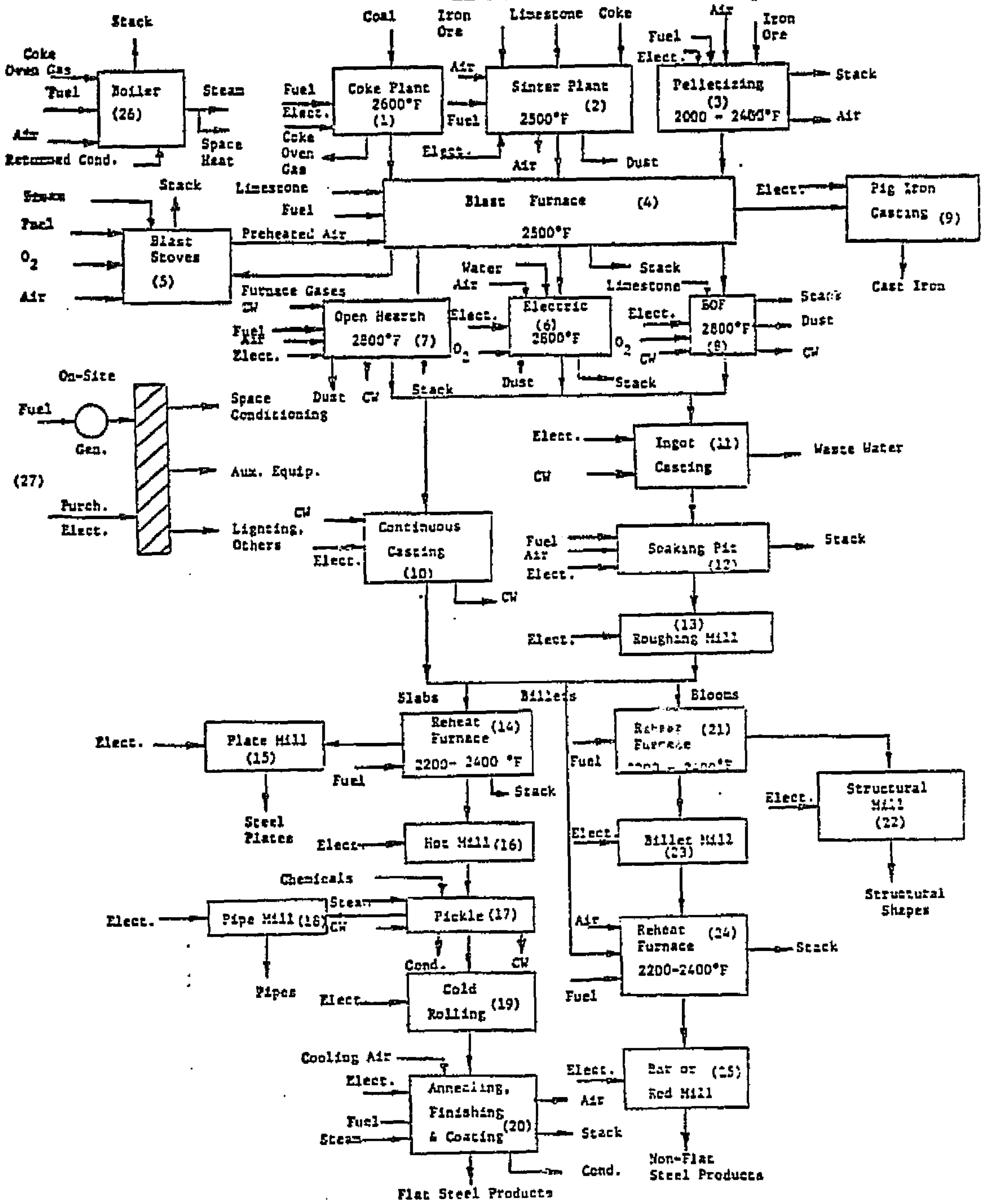

Exhibit 4

GENERIC PLANT TYPES IN STEEL

1. Completely integrated through rolling mill, process fraction BOF - %; electric - %; open hearth arc - %.
2. Completely integrated without coke, process fraction.
3. Electric arc, only casting.
4. Electric arc casting and rolling mills.
5. Rolling mills only - types not specified.
6. Rolling mills only - product fraction specified.
7. Coke and blast furnace only.
8. Blast furnace only.
9. Coke only.

The important point to make is that if one knows that a steel mill fits generic type 5, for example, its energy use can be well characterized whether in New York or Ohio. In this industry, as in others, the major regional differences are product and process mix that tend to be characteristic of the region. The remaining differences in energy intensity are due to plant age, capacity of operation and degree of plant efficiency. The validation effort is used to account for these factors.

The estimation of plant production level again makes use of trade association sources.

C. <u>Estimation of Plant Energy Usage</u>

In order to make use of the Process Data Base described in B, it is desirable to have plant specific data so that a plant can be categorized into a particular generic type. Trade association information becomes invaluable here.

As noted, for steel, 245 steel mills exist in the U.S. with more than 20 employees; detailed information on 220 of these mills exists in trade association publications. Using this information, the New York State steel mills can be classified as follows:

Steel Mills	Type	Steel Mills	Type
Al Tech Steel	4	Ramco Steel	6
Al Tech Steel	4	Republic Steel	2 BOF*
Al Tech Steel	4	Roblin Steel	3
Bethlehem Steel	1 BOF*	Roblin Steel	6
Crucible Steel	4	Simonds Steel	4
Hanna Steel	8	Special Metals	3
Markin Tube	6	Washburn Wire	6
Portec Inc.	4		

<u>Description of Types with Unit Operation</u>

1 BOF: Coking, Blast Furnace, Basic Oxygen Furnace, Reheat Furnaces, Rolling Mills, Boilers, Lights, Auxiliary Equipment

2 BOF: Blast Furnace, Basic Oxygen Furnace, Reheat Furnace, Rolling Mills, Boilers, Lights, Auxiliary Equipment.

3: Electric Arc, Boilers, Lights, Auxiliary Equipment.

4: Electric Arc, Rolling Mills, Reheat Furnace, Auxiliary Equipment, Boiler.

*BOF refers to basic oxygen furnace.

In order to classify each plant, the specific processes, equipment types and products are examined in the trade association source.*

To proceed with the SIC 3312 example, the following are the unit operations that fit the steel mill generic types in New York State:

Direct Heat

- o Coking
- o Blast Furnace
- o Basic Oxygen Furnace
- o Reheat Furnace

Steam

- o Steam used in Prime Mover
- o Process Steam
- o Miscellaneous
- o Space Heat

Electric

- o Electric Arc
- o Auxiliary Process Drives
- o Rolling Mill
- o Lights

To estimate the energy use for any unit operation ("i") in a given plant, the following algorithm is then utilized to find the Btu/hr used by this operation:

$$\frac{\text{Btu}}{\text{Hr}}(\text{Unit Operation})_i = \left(\frac{\text{Tons of Steel}}{\text{Year}}\right) \times \left(\frac{\text{Btu}}{\text{Ton}}\right)_i \times \left(\frac{\text{Yr}}{\text{Hrs}}\right)$$

This equation applies equally well to direct heat, steam or electric operations.

The energy use in steam in SIC 3312 is now examined in detail. In general, those plant types that have the largest amounts of steam use are types 1 and 2. This is because coal or coke is used directly in these plants - with the attendant generation of large amounts of byproduct gas. It is this gas that is burned in boilers. For type 1, the following is the relevant process data base entry for steam use in lb/ton:

*Trade association sources include Directory of Iron and Steel Works of the U.S. and Canada, American Iron and Steel Institute.

	lb Steam/Ton	Electric
Type #1	1,420	-

For the Bethlehem plant (Type 1 BOF):

$$\frac{lb}{hr} = \frac{Tons}{Yr} \times \frac{lb/Steam}{Ton} \times \frac{Yr}{Hrs}$$

The amount of steam = $2,300 \times 10^3 \times 1,420 \times \frac{1}{8,600}$

which yields the entry: 38,000 lb/hr for this plant.

This methodology has been used in each of the relevant industrial sectors. Exhibit 5 presents the number of generic plant types in each sector.

Exhibit 5

GENERIC PLANT TYPES

SECTOR	PLANT TYPES	REMARKS & REFERENCES
Food (SIC 20)	Relevant 6-Digit SIC was used to create Generic Plant Types	
Textiles (SIC 22)	10 Generic Types	Each plant is placed in relevant category.
Wood Products (SIC 24)	10 Product Types	Plants are then built using these products - each plant individually modeled.
Paper (SIC 26)	7 Process Types with: % bleaching % cogeneration % integration from wood to paper	Plants classified by process, with the appropriate process variables used for each plant.
Chemicals (SIC 28)	250 Individual Chemicals	Each plant is built up from the relevant chemicals in the process data base.
Petrorefining (SIC 29)	10 Processes	Each refinery is built from bbl processed by each unit operation.
Plastics & Rubber (SIC 30)	Relevant 4-digit SIC used for each plant. Plant employment to scale.	Employment & 4-Digit SIC taken from References.
Stone/Clay/Glass (SIC 32)	Relevant 4-digit SIC used for each plant. Plant employment used to scale relevant process energy.	
Steel (SIC 331)	9 Generic Types.	Plants classified.
Primary Metals (SIC 33) other than steel and Metals (SIC 34-39)	6-digit SIC used to create generic plants. Plant employment used to scale relevant process energies.	

C-5

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3. "The Potential for Industrial Cogeneration Development by 1990." Resource Planning Associates, Inc., RA-81-1455; July 31, 1981.

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7. "Energy Analysis of 108 Industrial Processes." Drexel University; October, 1980.

8. "Utility Purchase Rates for Interconnected Small Power Producers: The Current Status of PURPA 201 and 210 Implementation." Argonne National Laboratory; May, 1981.

9. "Typical Residential, Commercial and Industrial Bills: Investor-Owned Utilities." Edison Electric Institute; Winter, 1981.

10. "Preliminary 1985, 1990, and 1995 Energy Forecasts for the Annual Report to Congress, 1980." Energy Information Administration, DOE, SR/IA/80-16;; November, 1980.

11. "1980 Annual Report to Congress." Energy Information Administration, DOE, DOE/EIA-0173(80)/1,2,3; March, 1981.

12. Personal Communication, Howard Gerlaugh, General Electric; 1981.

13. Personal Communication, Sherif Fam, Thermoelectron; 1981.

14. Personal Communication, Thom Dickenson, Catalytic Construction Company; 1981.

<u>References</u> (continued)

15. Personal Communication, Robert Tarves, Monarch Boiler Construction Company; 1981.

16. Personal Communication, Dale Brown, General Electric; 1981.

17. "1981 U. S. Industrial Outlook for 200 Industries with Projection for 1985." U. D. Department of Commerce; January, 1981.

18. <u>Chemical Engineering News</u>; 1981.

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General Energy Associates
Industrial Plant Energy Profile Data Base
(GEA/IPEP)

References

FOOD: SIC 20

SIC 201: Meat Packing

1. U.S. Directory of Meat Processing Plants.

   Lists 4,000 major meat processing plants engaged in manufacturing sausages, cured meats, frozen meats, natural casings and other prepared meats and meat specialties. Sausage kitchens and other prepared meat plants operated by packing houses as separate establishments are also included. 230 pp. Yearly. Food Industry Directories, 25 Broad St., New York, N.Y. 10004.

2. U.S. Directory of Meat Slaughtering Plants.

   Contains over 3,000 plants engaged in slaughtering of cattle, hogs, sheep, lambs, and calves for meat to be sold or used in curing and canning, plus making sausage, lard and other products. Food Industries Directories, 25 Broad St., New York, N.Y. 10004.

3. U.S. Directory of Renderers.

   Contains over 825 plants engaged in rendering fats and oils from meat and poultry and reprocessing same into lards, shortening and commercial products. Food Industries Directories, 25 Broad St., New York, N.Y. 10004.

4. Poultry Industry Directory.

   Provides a geographical listing of approximately 800 chicken, egg turkey producers, processors, wholesalers, feed, pharmaceutical and other suppliers to the industry. Annually in spring Southeastern Poultry and Egg Association 1456 Church St., Decatur, Ga. 20020.

SIC 202: Dairy Products.

1. Dairy Credit Book.

   A listing of 25,000 American milk and ice cream processing plants, mix manufacturers, creameries, condenseries, cheese factories, powdered milk plants and dairy jobbers; executive names and financial ratings given. Annually. Dairy Credit Bureau, 3540 W. Peterson Ave., Chicago, Ill. 60645.

SIC 203: Canning and Frozen Foods.

1. The Directory of the Canning, Freezing, Preserving Industries.

   Nearly 500 pages listing approximately 1,700 food processors in four cross-reference lists as follows: SECTION I - alphabetical list containing full zip code address, telephone numbers, pack volume, names and responsibilities of company executives, brands, container sizes, servicing railroads, plant managers, products by factory and process (cans, glass, frozen), divisions and subsidiaries. SECTION II - geographical list showing full zip code, firm address, alphabetically by state. SECTION III - product list showing full zip code address, with packers listed alphabetically under 375 product heads. Type of pack designated as (C) cans, (G) glass, (F) frozen. SECTION IV - brand list, alphabetically with company identification. Published biennially in April of even numbered years. Edward E. Judge & Son, Inc., P.O. Box 866, Westminister, Md. 21157.

General References in Development of GEA/IPEP Data Base

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2. Energy Consumption in Manufacturing, The Conference Board, Ballinger, 1974.

3. A Technical Basis for Energy Conservation, Federal Power Commission, April, 1974.

4. Study of Industrial Uses of Energy Relative to Environmental Effects, Fejer, M.E., and Larson, D.H., July, 1974.

5. Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Hittman Associates, Inc., Vol. 1, November,1974, NTIS: HIT593.

6. Alternative Cycles: The U.S. Energy Problem, Inter Technology Corporation, Vol. II, Appendices - Part B, PB 207-519, November, 1971, Report No. NSF-RANN 71-1-3, NTIS.

7. Advanced Heat Processing, LeMay, Robert, Associates, seminar materials,1974.

8. The Potential for Energy Conservation, Office of Emergency Preparedness, a staff study, October, 1972.

9. Energy Conservation by Industries in Support of National Defense, Rand Corporation, report to the Defense Advanced Research Projects Agency, August, 1974, NTIS: AD784-964.

10. Energy Consumption: Paper, Stone/Clay/Glass/Concrete, and Food Industries, Reding, J.T., and Shepherd, B.P., EPA, Research Triangle Park, N.C., publication number EPA-650/2-75-032-C, April, 1975.

11. Patterns of Energy Consumption in the U.S., Stanford Research Institute,1972.

12. Potential for Effective Use of Fuel in Industry, Thermo Electron Corporation, Ballinger, 1974.

13. Industrial Furnaces, Trinks, W., and M.H. Mawhinney, 5th Edition, John Wiley, New York, 1961.

14. U.S. Statistical Abstract, U.S. Department of Commerce, 1974.

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17. The U.S. Energy Problems,Vol. II, Appendices - Part B by InterTechnology Corporation (November, 1971), Distributed by National Technical Information Service, 5285 Port Royal Road, Springfield, Va. 22151, NTIS No. PB-207519.

5.3 MARKET ASSESSMENT

5.3.1 Summary

This study represents a unique approach to the identification of technology potential in the complex U.S. industrial energy marketplace. By using a plant specific data base, the market assessment is made directly at the plant site level. From this level, a bottoms-up approach is used to develop the aggregate market potential and national benefits.

A summary of the market share and national benefits is presented in Table A5-2 as a function of the uninflated ROI hurdle rates for both the AFB/steam turbine and the AFB/gas turbine.

Table A5-2

POTENTIAL NATIONAL MARKET BENEFITS

	ROI	GT	ST
Number of Plants	10%	776	788
	20%	167	281
Power Generation MW	10%	11,275	8,450
	20%	5,274	5,227
Electrical Cogeneration 10^6 KWH/YEAR	10%	89,481	66,163
	20%	43,838	43,168
Steam Generation Thousands #/HR	10%	222,184	225,569
	20%	102,972	144,140
Total Fuel Savings Quads (Oil/Gas)(1)	10%	.28	.34
	20%	.14	.22

(1) Assumes only oil/gas backout of utility fuel.

5.3.2 Market Assessment Methodology

5.3.2.1 Introduction

The evaluation of cogeneration potential in U.S. industry has been the subject of a number of studies. These studies have been characterized by the use of sectorial models to describe the economics of cogeneration technologies in given industries and/or geographic regions. The structure of the U.S. industrial sector, however, is significantly more complex than a description afforded by representative plants or sectorial models. The economics of cogeneration depend critically on the individual plant steam use, hours of operation, utility rates, and whether the plant already cogenerates.

The GEA effort offers a unique approach to the identification of technology potential in the complex U.S. industrial energy marketplace. By using a plant specific data base, technology and economic estimates can be made directly at the plant site level.

The basic approach is to utilize a data base at the plant level for all large U.S. industrial plants, with appropriate field verification, to serve as the starting point for the technical/economic analysis of cogeneration viability. The approach has the obvious advantage of avoiding the use of representative plants and utility rates - but rather using <u>actual</u> plant sites with the appropriate utility costs. In addition, the existing industrial plants that already cogenerate are identified individually; these will not be included in producing final estimates for potential cogeneration. The objectives, basic approach and assumptions are outlined in Tables A5-3 and A5-4. The model is presented in Figure A5-11. The plant data base used is the GEA/IPEP* data base. This data base contains detailed plant estimates of steam use, electricity use, and hours of operation for the top 10,000 U.S. industrial plants. Each plant is identified in the data file by name, address, SIC, products and electric utility. Use of <u>plant level</u> estimates allows the application of detailed economic calculations for each <u>individual plant</u>. Those plants that pass some minimum plant economic return on investment become potential sites.

*The General Energy Associates Industrial Plant Energy Profile (GEA/IPEP) Data Base is described in detail in Appendix Section 5.2.

Table A5-3

MARKET AND BENEFITS ANALYSIS

<u>OBJECTIVES</u>

- o Determine the Amenable Market
- o Estimate Potential Savings and Benefits

<u>APPROACH</u>

- o ROI Driven Investments (10% and 20% Hurdles)
- o Existing Site Emphasis
- o Best Technology and Site Fit Emphasis
- o Heat Demand as Steam
- o Direct Heat Requirements Excluded
- o Construct Integrated ROI Model

Table A5-4

MARKET AND BENEFIT ANALYSIS

<u>METHODOLOGY AND APPROACH</u>

- o Site Specific Data Base
- o Existing Cogenerating Plants Excluded
- o Heat Match
- o Simultaneous Buy-Sell/Site Specific Electric Rates
- o Steam produced by On-Site Waste Fuel Excluded
- o All Market Sectors (SIC Codes) Included
- o Excludes Plants below 40,000 lbs/hr net steam to Process - No upper limit on steam flow
- o Modified EIA Fuel and Electric Cost Calculations

5.3.2.2 Economic (ROI) Model

The basic model in determining the return-on-investment (ROI) is that presented in the CTAS studies (References 1 and 2). This is based on total system capital costs. The computer flow model is presented in Figure A5-20. The basic formulation is presented below:

$$C_{cogen} = \sum_{n=1}^{15} \frac{S_{cogen} - S_{nocogen}}{(1 + ROI)^n}$$

where,

C = TOTAL CAPITAL (installation plus equipment plus interest) for appropriate technology (AFB steam or gas turbine cogeneration systems; the no-cogeneration [boiler] system assumes existing boiler operation, and therefore no capital costs).

The no-cogeneration basis represents boilers supplying plant steam using gas/oil fuel and the purchase of plant electricity needs.

S = CASH FLOW for appropriate technology (cogeneration or no cogeneration).

and

S = REVENUES - CASH OPERATING EXPENSE - TAX

The revenues represent income from the sale of all electricity generated by the plant back to the utility; cash operating expenses represent system fuel cost, overhead and maintenance, and the cost of electricity purchased by the plant. The tax is defined as follows:

TAX = INCOME TAX RATE (Revenue - Cash Operating Expense - Tax Depreciation) - Investment Tax Credit.

Figure A5-11

ROI MODEL

GEA/IPEP

Read Individual Plant Profile — SIC, Address, Kwh, MW, Steam Temp., Steam (lb/hr). Appendix 5.2

Load Electric & Fuel Prices from Appropriate Region & Utility — GEA (Regional Energy Costs). Appendix 5.3.4

Size Systems Based on Average Steam Load & Check System Limits — Cogeneration Technology Performance Parameters. Appendix 5.3.5

Calculate System Capital Investment: C_{GT}, C_{ST}, C_{NO} — Cogeneration Technology Capital Costs. Appendix 5.3.5

Calculate all parameters for Gas System (GT), steam system (ST) and boiler-nocogen system (NO) & use final ROI & incremental ROI as basis for market assessments. Do for each year, i, to end of equipment life.

Calculate O&M Expenses: OM_{GT}, OM_{ST}, OM_{NO} — Cogeneration Technology O&M Costs $OM_i = f(C)$

Calculate Depreciation: D_{GT}, D_{ST}, D_{NO} — Depreciation per Schedule in ERA. Table A5-5.

GEA (PURPA Rate) Appendix 5.3.4 → Calculate Revenue: R_{GT}, R_{ST}, R_{NO} — Revenue: Sale of all Generated Power to Utility. $R_i = (Kwh_{Gen})$ PURPA $Rate_i$

GEA (Elec. Rate) Appendix 5.3.4 → Calculate Purchased Power: P_{GT}, P_{ST}, P_{NO} — $P_i = (Kwh_{Plant})$ Elec. $Rate_i$

GEA (Fuel Costs) Appendix 5.3.4 → Calculate Purchased Fuel: F_{GT}, F_{ST}, F_{NO} — $F_i = \dfrac{\text{System Output} \quad \text{Fuel Cost}}{n}$

$n = \dfrac{\text{Elect. or Steam Output}}{\text{Fuel Input}}$

(System Characteristics)

Calculate Cash Operating Expenses: E_{GT}, E_{ST}, E_{NO} — $E_i = R_i - P_i - F_i - OM_i$

Calculate Cash Flow: S_{GT}, S_{ST}, S_{NO} — $S_i = E_i$ − TAX RATE $(E_i - D_i)$ + INVESTMENT TAX CREDIT

ROI MODEL (continued):

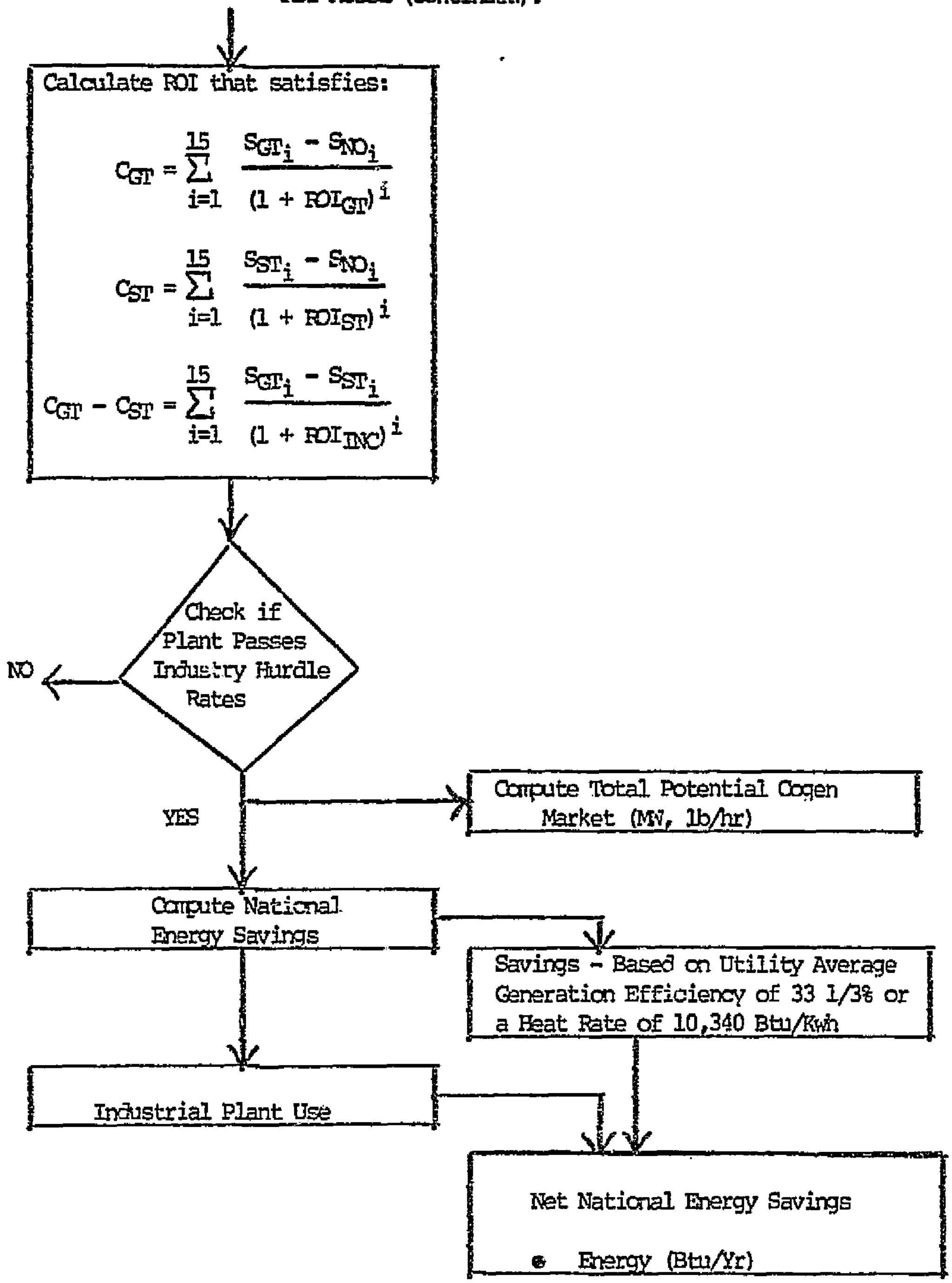


Table A5-5

ECONOMIC GROUNDRULES

Annual Inflation Rate*		0
Income Tax Rate		50%
Investment Tax Credit		10%
Depreciation	Year	Percent
	1	20
	2	32
	3	24
	4	16
	5	8
Equipment Life		15 Years
Initial Operation Date		1988
Fuel and Electric Costs (see section 5.0)		Modified EIA Projections

*All costs are in 1981 dollars.

5.3.2.3 Waste Fuel

The following table (A5-6) summarizes waste fuel available in the industrial sector used in steam production. In this study, systems are sized on the fraction of plant steam load supplied by purchased fuels.

Table A5-6

SIC	INDUSTRY	WASTE FUEL
2062	Cane Sugar	Bagasse
2421	Saw Mills	Wood
26	Pulp Mills (Kraft)	Wood (Black Liquor)
28	Chemicals	Off Gas
2911	Petroleum Refining	Refinery Gas
3312	Steel Mills	Coke Oven Gas Blast Furnace Gas

5.3.3 Results

5.3.3.1 Summary of Analysis

Based on the methodology described in Appendix Section 2 and the industrial plant data base described in Appendix 5.3.2, the potential national markets for the AFB/steam turbine (AFB/ST) and AFB/gas turbine (AFB/GT) are presented in Table A5-7. The AFB/GT and AFB/ST results represent an independent analysis of each technology at each plant site which satisfies the 10% and 20% hurdle rates. The AFB/Gas Turbine (Incremental) represents an analysis for each plant site of the AFB/GT relative to the AFB/ST. This incremental ROI then must additionally satisfy the respective 10% and 20% hurdle rates to be included in that category.

The detailed analysis was performed by General Energy Associates as a function of system size (steam range) and industrial sector (2-digit SIC). Seven parameters were analyzed for each ROI hurdle rate and technology:

- o Number of Plants
- o Power Production (MW)
- o Electric Production (Kwh/yr)
- o Annual Steam Generation (lb/yr)
- o Total Hourly Steam Generation (lb/hr)
- o Energy Savings (Btu/yr)
- o Capital Costs ($)

Tables A5-7 to A5-21 represent the summary of data generated by General Energy Associates. As shown in Table A5-8, over 90% of the AFB/GT and AFB/GT (Incremental) plants are also plants which satisfy the AFB/steam turbine hurdle rates.

The market shares of these cogeneration systems as a function of the industrial steam production are shown in Table A5-9. The 10% hurdle rate shows a 39-40% share of the steam generation market, and this is profiled as a function of the steam size range in Table A5-10.

The industrial sector profiles are presented in Tables A5-11 and A5-12, and Figures A5-12 and A5-13. These clearly define the major sectors:

- o Food (SIC 20)
- o Pulp and Paper (SIC 26)
- o Chemicals (SIC 28)
- o Petro Refining (SIC 29)
- o Steel (SIC 33)

Additional Analysis of the market is presented in Tables A5-13 through A5-16. The average electric buy/sell ratio in the U.S. is .95. Since this ratio and electric rates are significant parameters, a sensitivity analysis was performed. A change of 20% in this ratio was examined. The % charge in the number of plants and power generation (MW) vary significantly with the greater impact on the AFB/GT and a more significant impact on those "incremental" AFB/GT.

An additional consideration is the ratio of the cogenerated power to the Plant Demand:

$$P_{cogen}/P_{plant\ demand}$$

for each of the systems. This ratio is presented in Tables A5-15 and A5-16 and averages between .33 to .53 for the two systems.

Table A5-7

MARKET SUMMARY

SYSTEM	ROI > 10%		ROI > 20%	
	No. Plants	MW	No. Plants	MW
Steam Turbine	788	8,450	281	5,227
Gas Turbine	776	11,275	167	5,274
Gas Turbine (Incremental)	411	3,813	16	119

Table A5-8

OVERLAPPING PLANTS*

SYSTEM	ROI >10%	ROI >20%
Steam	100%	100%
Gas	95%	99%
Incremental Gas	91%	94%

* Percent of plants in System/ROI group which overlap in Steam/ROI group.

Table A5-9

MARKET SHARE AS A PERCENT OF STEAM USE

SYSTEM	ROI >10%	ROI >20%
Steam	40	27
Gas Turbine	39	19
Incremental Gas Turbine	13	1

Table A5-10

MARKET SHARE AS A FUNCTION OF SIZE
AS A PERCENT OF STEAM USE IN THAT SIZE RANGE

	SYSTEM	
STEAM SIZE RANGE (10^3 lb/hr)	Steam (> 10%)	Gas (> 10%)
< 50	6	6
50 - 100	34	32
100 - 150	63	60
150 - 200	58	56
200 - 250	67	62
250 - 400	66	67
400 - 600	63	61
600 - 1000	46	46
> 1000	26	26

Table A5-11

INDUSTRIAL SECTOR SUMMARY

ROI > 10%

INDUSTRIAL SECTOR (SIC)	SYSTEM					
	STEAM		GAS		GAS INCREMENTAL	
	No.Plants	MW	No.Plants	MW	No.Plants	MW
Food (20)	40	541	40	629	29	295
Pulp & Paper (26)	212	2,489	232	2,654	198	1,541
Chemicals (28)	276	3,737	276q	4,903	101	1,318
Petro. Refin. (29)	133	1,197	112	2,493	10	318
Steel (33)	49	137	42	221	12	47
Metals Fab.(34-39)	29	172	30	166	29	142
Others	49	177	44	209	32	151
TOTALS	788	8,450	776	11,275	411	3,812

Table A5-12

INDUSTRIAL SECTOR SUMMARY

ROI > 20%

INDUSTRIAL SECTOR (SIC)	STEAM		GAS		GAS INCREMENTAL	
	No.Plants	MW	No.Plants	MW	No.Plants	MW
Food (20)	2	35	2	39	-	-
Pulp & Paper (26)	50	1,190	43	1,068	8	71
Chemicals (28)	129	2,893	75	2,818	1	14
Petro. Refin. (29)	75	942	29	1,223	0	0
Steel (33)	9	45	4	22	3	15
Metals Fab.(34-39)	13	108	11	86	4	19
Others	3	14	3	18	0	0
TOTALS	281	5,227	167	5,274	16	119

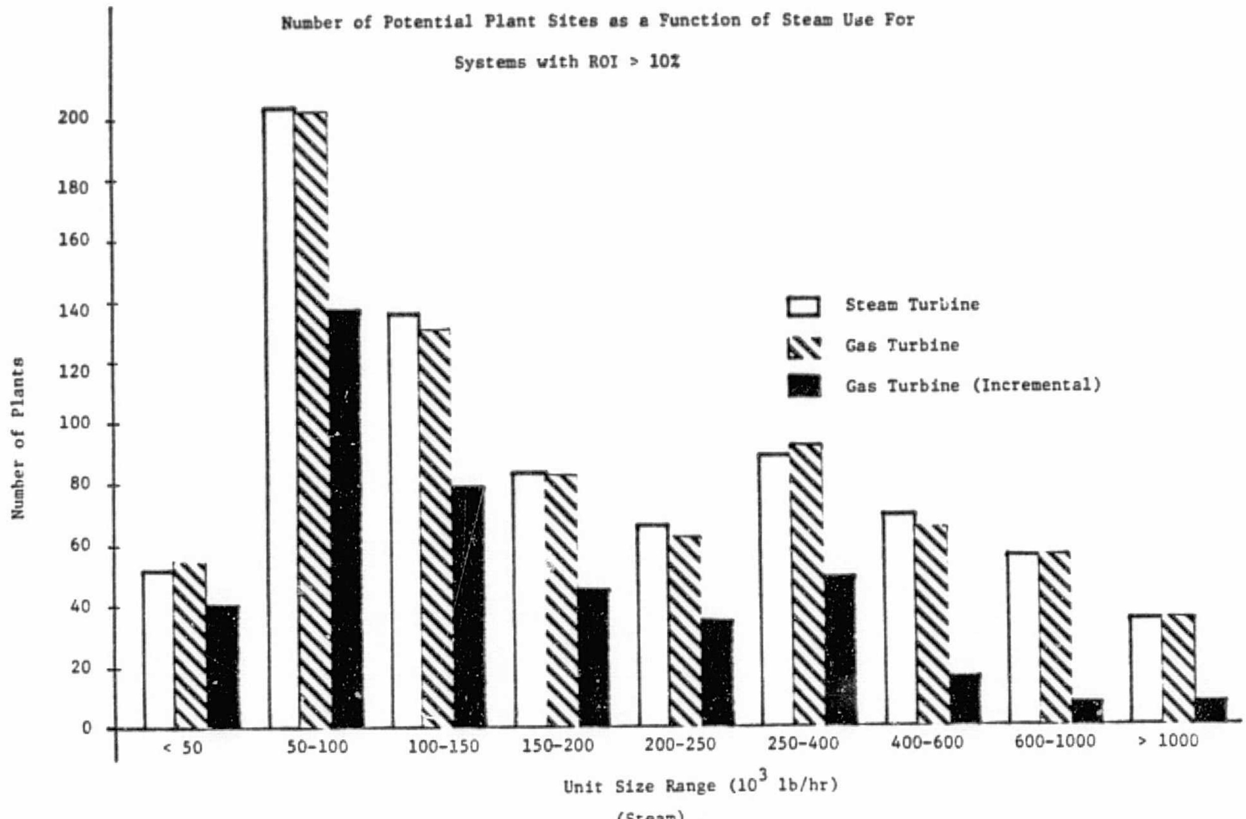


Figure A5-12

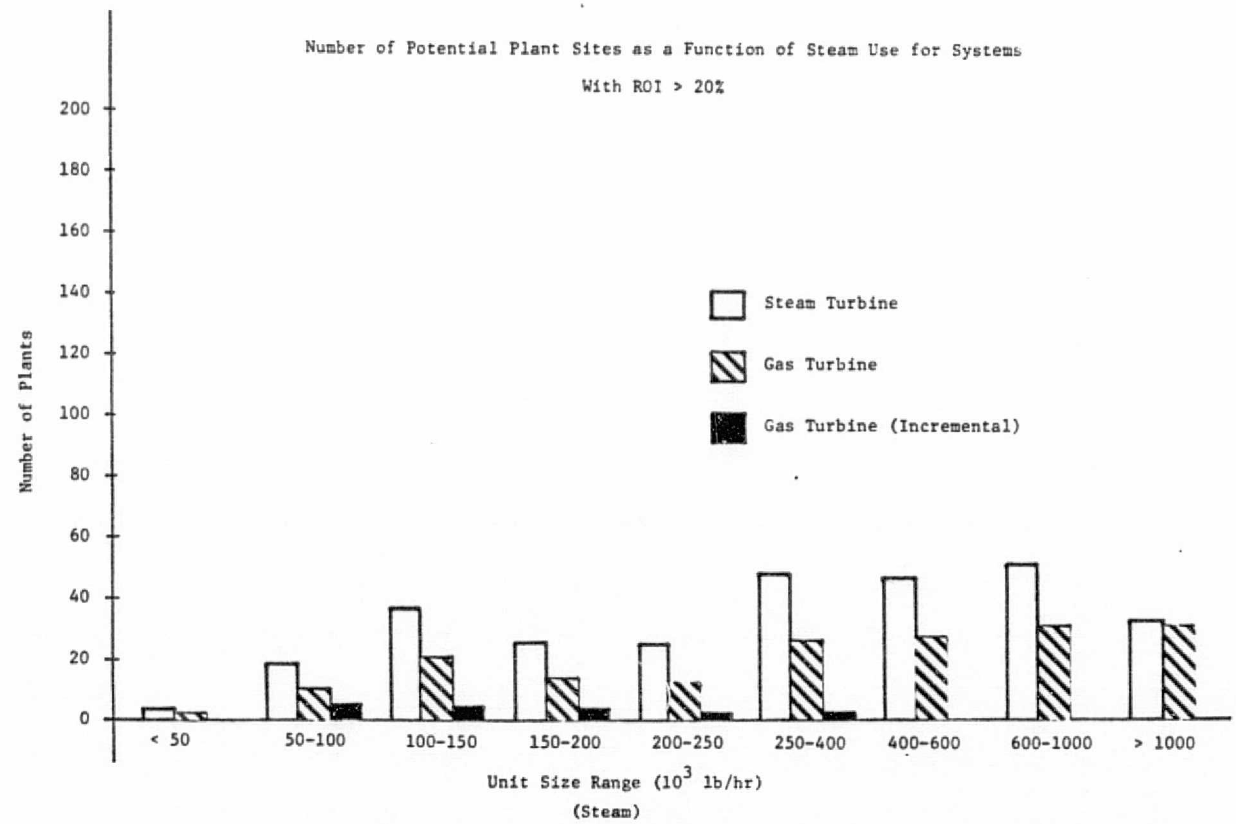


Figure A5-13

Table A5-13

SENSITIVITY TO PURPA

AVERAGE BUY/SELL = .85

% CHANGE IN BUY/SELL RATIO		NUMBER OF PLANTS	MW
+ 20%	STEAM TURBINE	+ 5%	+ 2%
	GAS TURBINE	+ 10%	+ 16%
	INCREMENTAL	+ 23%	+ 51%
- 20%	STEAM TURBINE	- 7%	- 3%
	GAS TURBINE	- 9%	- 6%
	INCREMENTAL	- 20%	- 26%

Table A5-14

AVERAGE SYSTEM SIZE

SYSTEM	ROI > 10% MW	ROI > 20% MW
Steam	11	19
Gas	15	32

Table A5-15

RATIO OF $P_{COGEN}/P_{PLANT\ DEMAND}$

SYSTEM	ROI >10%	ROI >20%
Steam	.33	.35
Gas	.44	.53

Table A5-16

NUMBER OF PLANTS AS A FUNCTION OF
RATIO OF $P_{COGEN}/P_{PLANT\ DEMAND}$

P_{COGEN}/P_{PLANT} RATIO	SYSTEM Steam (> 10%)	SYSTEM Gas (> 10%)
< .2	206	89
.2 – .5	245	243
.5 – 1.0	232	274
1.0 – 1.5	66	114
1.5 – 2.0	18	26
2.0 – 5.0	18	27
5 – 10.0	2	1
10 – 20.0	1	2
> 20.0	0	0
	788	776
	Ave. = .33	Ave. = .44

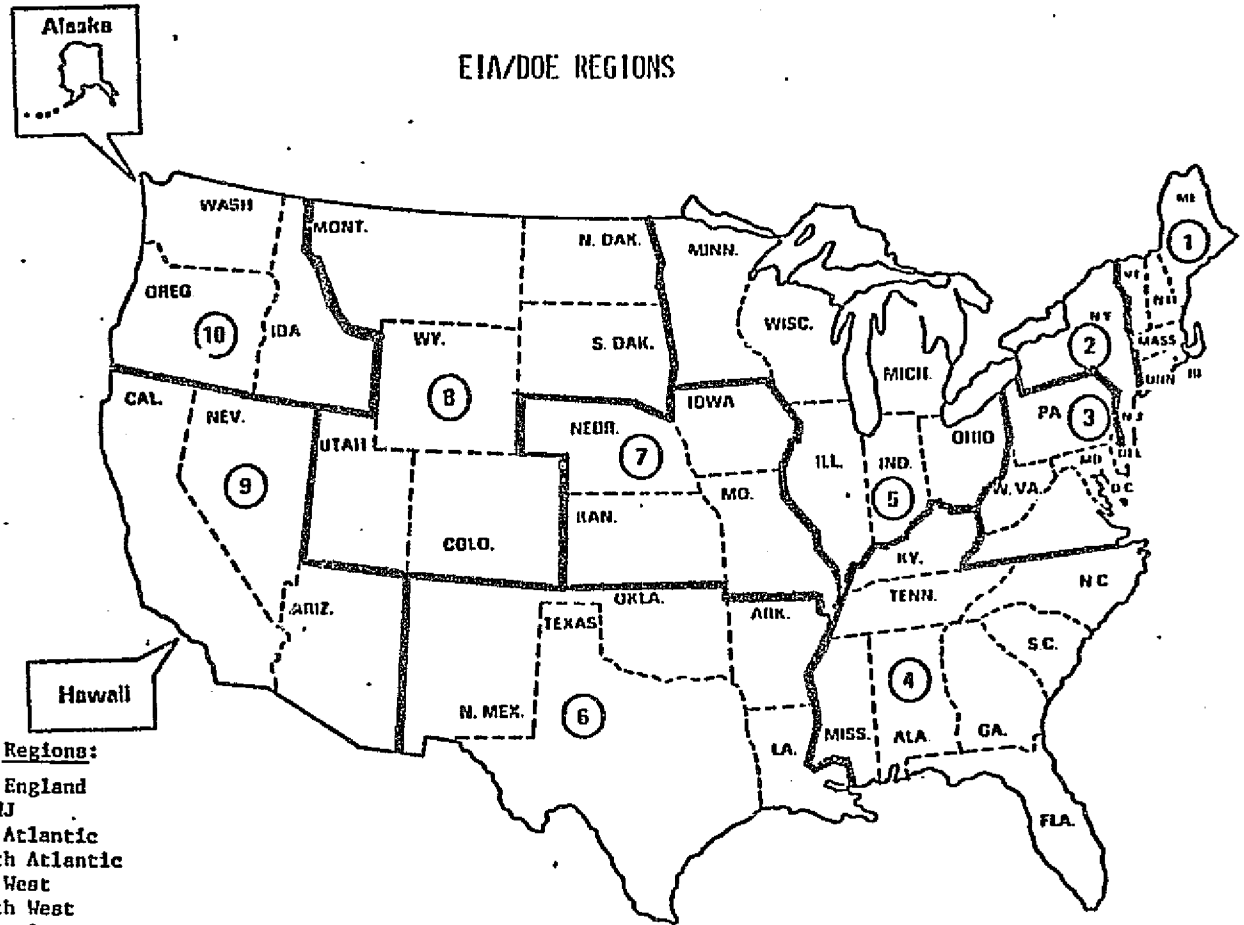
5.3.3.2 Regional Summary

The potential market is also aggregated by the ten EIA/DOE regions shown on the map in Figure A5-14. Tables A5-17 and A5-18 present the market by regions for ROIs of at least 10% and 20% respectively.

5.3.3. Potential National Benefits

The potential national market benefits based on the plants given in Table A5-17 and A5-18 is summarized in Table A5-19. The total fuel savings includes the potential savings at the plant site as well as with the power company.

EIA/DOE REGIONS



Regions:

1. New England
2. NY/NJ
3. MID Atlantic
4. South Atlantic
5. MID West
6. South West
7. Central
8. North Central
9. West
10. North West

Figure A5-14

Table A5-17

REGIONAL SUMMARY - ROI > 10%

REGION	SYSTEM: STEAM No.Plants	STEAM MW	GAS No.Plants	GAS MW	GAS INCREMENTAL No.Plants	GAS INCREMENTAL MW
New England	42	359	46	419	40	281
New York/New Jersey	79	478	84	545	73	480
Mid-Atlantic	118	884	118	1,143	71	675
South Atlantic	8	59	142	1,768	66	675
Midwest	75	43	69	934	36	316
Southwest	153	2,758	141	4,102	41	572
Central	51	524	51	711	21	229
North Central	24	212	24	258	6	151
West	60	508	60	756	32	241
Northwest	38	493	41	584	5	296
TOTALS	788	8,450	776	11,275	411	3,811

Table A5-18

REGIONAL SUMMARY - ROI > 20%

REGION	SYSTEM: STEAM No.Plants	STEAM MW	GAS No.Plants	GAS MW	GAS INCREMENTAL No.Plants	GAS INCREMENTAL MW
New England	13	222	10	195	0	0
New York/New Jersey	31	320	30	392	4	22
Mid-Atlantic	53	570	41	690	10	80
South Atlantic	42	5	23	785	0	0
Midwest	13	266	4	202	0	0
Southwest	63	2,108	31	2,251	0	0
Central	15	196	4	113	1	10
North Central	17	192	6	163	1	4
West	23	331	13	388	0	0
Northwest	11	183	5	91	0	0
TOTALS	281	5,227	167	5,274	16	118

Table A5-19

POTENTIAL NATIONAL MARKET BENEFITS

	ROI	GT	ST
Number of Plants	10%	776	788
	20%	167	281
Power Generation MW	10%	11,275	8,450
	20%	5,274	5,227
Electrical Cogeneration			
10^6 KWH/YEAR	10%	89,481	66,163
	20%	43,838	43,168
Steam Generation			
Thousands #/HR	10%	222,184	225,569
	20%	102,972	144,140
Total Fuel Savings			
Quads (Oil/Gas)[1]	10%	.28	.34
	20%	.14	.22

(1) Assumes only oil/gas backout of utility fuel.

5.3.4 Fuel and Electricity Costs

The electricity costs (industrial plant purchase and industrial sell-back or PURPA rates) are based upon information generated from surveys of specific utilities and References 8 and 9. The information for specific utilities is utilized for specific plants within that utility. Where information is not available, averages are generated for the region (defined in Figure A5-14) from the data provided by the specific utilities. These averages are presented (¢/Kwh) in Table A5-20, and are projected to the year 2000.

These projections are based upon the 1978 EIA projections (References 10 and 11) which were modified in this study to reflect natural gas deregulation by the year 1985. The EIA projections were regionally developed and are based upon international oil prices and exclusion of the system compliance option of the Power Plant and Industrial Fuels Use Act (PIFUA). The medium case scenario was used and then modified to reflect deregulation by 1985.

These modified projections were analyzed along with the utility data. The resultant projections used in this study are presented in Table A5-21 for the 10 regions in the U.S. for the period 1980 to the year 2000.

5.3.5 Technology Performance and Costs

The economic parameters of the AFB/Gas Turbine and AFB/Steam Turbine are presented in Table A5-22. The performance characteristics for each of the systems are presented in Figures A5-15 and A5-16. These data and curves were incorporated into the model as outlined in Figure A5-11.

The performance curve of the AFB/Gas Turbine was modeled for discrete values (5, 9, 12, 15, 18, 20) of net heat to process per Kwh Generated (1,000 Btu/kwh). Thus, for each plant, an AFB system was calculated for each of the six values. That system which provided the highest ROI was considered the "best" in this analysis. This optimization routine, based on the ROI criterion, was required since the AFB/GT system has the flexibility of a wide range of heat/power ratio.

Table A5-20

INDUSTRIAL ELECTRIC AND BUYBACK RATES

CENTS PER KWH

(1980 DOLLARS)

REGIONS	1980 INDUSTRIAL RATE	1980 BUYBACK RATE	1985 INDUSTRIAL RATE	1985 BUYBACK RATE	1990 INDUSTRIAL RATE	1990 BUYBACK RATE	1995 INDUSTRIAL RATE	1995 BUYBACK RATE	2000 INDUSTRIAL RATE	2000 BUYBACK RATE
NEW ENGLAND	5.63	8.06	7.51	10.73	6.08	9.84	5.58	7.98	4.53	6.48
NY / NJ	4.70	3.15	6.26	4.19	5.69	3.81	5.94	3.98	6.19	4.15
MID ATLANTIC	3.48	2.61	4.64	3.48	4.94	3.70	5.06	3.80	5.19	3.89
S. ATLANTIC	3.06	2.70	4.08	3.59	4.62	3.89	4.49	3.95	4.57	4.02
MID WEST	3.33	2.00	4.44	2.67	4.68	2.81	4.52	2.71	4.37	2.62
S. WEST	4.67	3.32	6.22	4.42	5.50	3.90	5.65	4.01	5.81	4.13
CENTRAL	3.87	2.09	5.15	2.78	4.66	2.52	4.74	2.56	4.82	2.61
N. CENTRAL	3.27	2.45	4.35	3.27	3.19	2.39	2.44	1.83	1.87	1.40
WEST	4.59	4.30	6.10	5.73	5.73	5.38	5.63	5.29	5.54	5.21
N. WEST	1.04	1.60	1.39	2.13	1.98	3.04	1.75	2.70	1.56	2.39

Table A5-21

1980 ENERGY PRICES

(1980 DOLLARS PER MILLION BTU)

REGIONS

	NEW-ENG	NY/NJ	MID-ATL	S.-ATL	MIDWEST	S.-WEST	CENTRAL	N-CNTRL	WEST	N.-WEST
ELECTRIC	16.31	13.77	10.20	8.90	9.77	13.49	11.33	9.58	13.41	3.05
DIST. OIL	4.93	4.98	5.09	5.09	4.83	4.93	4.80	4.84	4.65	4.65
RES. OIL	3.67	3.75	3.83	3.63	3.64	3.63	3.66	3.54	3.47	3.44
COAL	2.63	1.70	1.45	2.07	1.49	2.06	1.29	1.00	2.16	1.29
NAT. GAS	3.34	3.43	3.51	3.31	3.32	2.39	3.34	2.32	3.14	3.56

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Table A5-21 (Cont.)

1985 ENERGY PRICES

(1980 DOLLARS PER MILLION BTU)

REGIONS

	NEW-ENG	NY/NJ	MID-ATL	S.-ATL	MIDWEST	S.-WEST	CENTRAL	N-CNTRL	WEST	N.-WEST
ELECTRIC	22.00	18.35	13.60	11.97	13.02	10.24	15.09	12.74	17.87	4.06
DIST. OIL	8.25	8.32	8.51	8.51	8.07	8.24	8.02	8.09	7.78	7.78
RES. OIL	7.29	7.45	7.42	7.22	7.24	7.26	7.20	7.02	6.89	6.84
COAL	3.01	2.51	2.14	3.06	2.21	3.04	1.90	1.48	3.20	1.91
NAT. GAS	7.29	7.46	7.62	7.27	7.24	7.25	7.28	7.04	6.09	6.83

1990 ENERGY PRICES

(1980 DOLLARS PER MILLION BTU)

	REGIONS									
	NEW-ENG	NY/NJ	MID-ATL	S.-ATL	MIDWEST	S.-WEST	CENTRAL	N-CNTRL	WEST	N.-WEST
ELECTRIC	20.16	16.69	14.47	12.94	13.71	16.11	13.67	9.35	16.70	5.79
DIST. OIL	9.16	9.24	9.44	9.43	9.01	9.16	8.95	8.99	8.70	8.70
RES. OIL	8.03	8.20	8.36	7.96	8.00	8.01	8.03	7.75	7.44	7.59
COAL	3.29	2.77	2.43	3.54	2.46	3.27	2.10	1.48	3.40	3.42
NAT. GAS	8.09	8.25	8.41	8.01	8.04	7.89	8.08	7.70	7.71	6.74

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Table A5-21 (Cont.)

1995 ENERGY PRICES

(1980 DOLLARS PER MILLION BTU)

REGIONS

	NEW-ENG	NY/NJ	MID-ATL	S.-ATL	MIDWEST	S.-WEST	CENTRAL	N-CNTRL	WEST	N.-WEST
ELECTRIC	16.36	17.40	14.84	13.16	13.24	16.57	13.90	7.16	16.52	5.24
DIST. OIL	10.88	10.74	11.16	11.22	10.79	10.95	10.74	10.70	10.41	10.41
RES. OIL	9.52	9.69	9.86	9.46	6.35	7.34	6.63	9.31	9.11	9.07
COAL	3.34	2.83	2.48	3.52	2.44	3.53	2.14	1.52	3.46	3.13
NAT. GAS	9.54	9.70	9.05	9.46	6.49	8.29	6.31	7.83	9.14	8.00

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Table A5-21 (Cont.)

2000 ENERGY PRICES

(1980 DOLLARS PER MILLION BTU)

REGIONS

	NEW-ENG	NY/NJ	MID-ATL	S.-ATL	MIDWEST	S.-WEST	CENTRAL	N-CNTRL	WEST	N.-WEST.
ELECTRIC	13.20	18.14	15.21	13.39	12.79	17.04	14.14	5.40	16.23	4.57
DIST. OIL	12.93	12.40	13.18	13.35	12.93	13.10	12.89	12.93	12.46	12.46
RES. OIL	12.29	11.45	11.62	11.23	5.03	4.73	5.15	11.13	10.67	10.04
COAL	3.30	2.80	2.52	3.49	2.41	3.81	2.17	1.57	3.53	2.86
NAT. GAS	11.25	11.39	11.54	11.17	5.23	8.71	4.93	7.97	10.88	9.50

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Table A5-22

ECONOMIC MODEL PARAMETERS

- o AFB/GT CO-GEN. PLANT CAPITAL COST

$$\$\text{Million} = 16\left(\frac{F,\ PPH}{100{,}000}\right)^{.846} \times \left(\frac{P,\ PSIG}{900}\right)^{.125} + 2.9\ (G,\ MW)^{.8}$$

Total Capital Investment is 1.37 x Capital Cost

- o AFB/ST CO-GEN. PLANT CAPITAL COST

$$\$\text{Million} = 12.5\ \left(\frac{F,\ PPH}{100{,}000}\right)^{.846} \times \left(\frac{P,\ PSIG}{900}\right)^{.125} + 2.3\ (G,\ MW)^{.67}$$

Total Capital Investment is 1.37 x Capital Cost

- o ZERO CAPITAL COST FOR NO-COGEN CASE

- o ANNUAL O&M COST (AS PERCENT OF TOTAL CAPITAL INVESTMENT)

AFB/GT = 8

AFB/ST = 14

- o 15 YEAR EQUIPMENT LIFE
- o 1981 ERA DEPRECIATION METHOD
- o 1988 INITIAL OPERATION

AFB/STEAM TURBINE

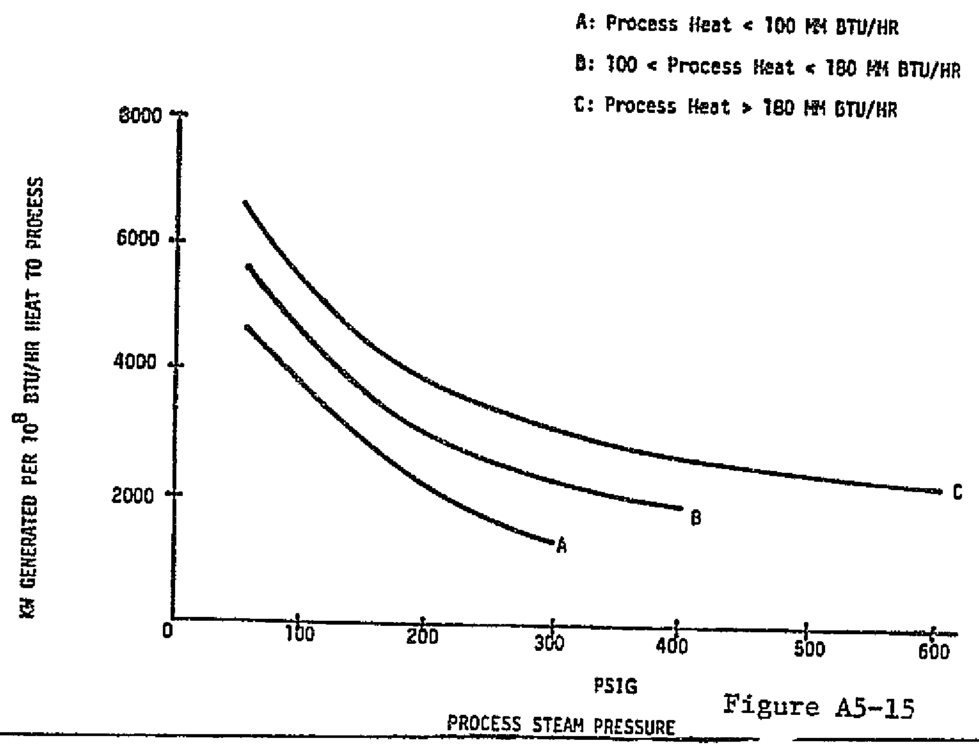

Figure A5-15

AFB/GAS TURBINE

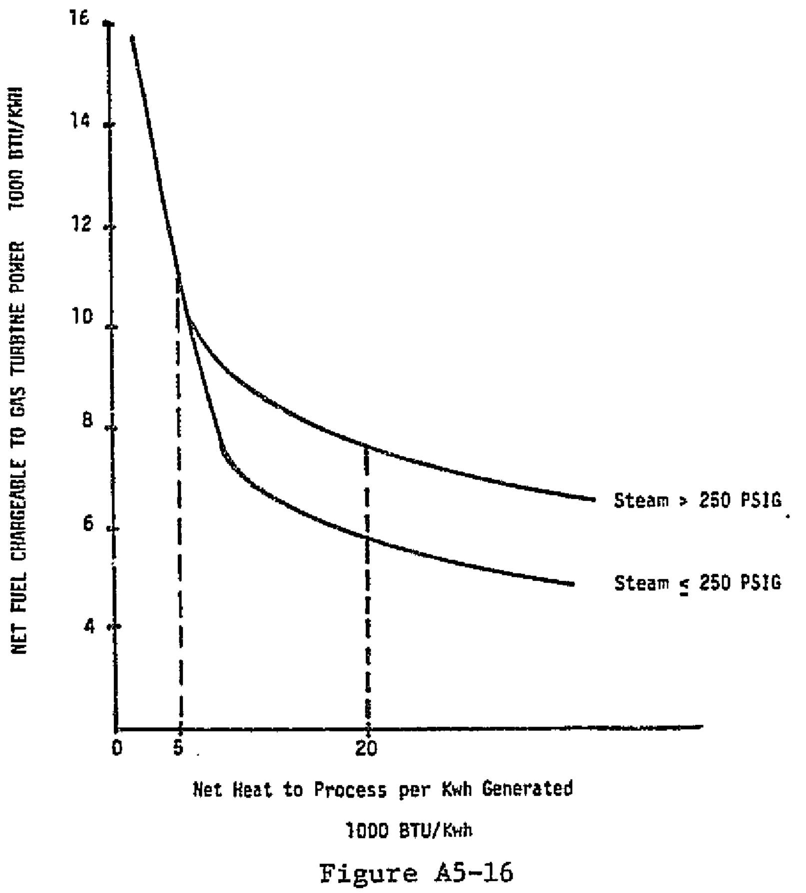

Figure A5-16