(NASA-CR-168222) ADVANCED TECHNOLOGY COGENERATION SYSTEM CONCEPTUAL DESIGN STUDY: CLOSED CYCLE GAS TURBINES Final Report (Garrett Turbine Engine Co.) 296 p HC A13/MF A01 CSCL 10B G3/44 N85-16300 Unclas 13417

DOE/NASA/0215-1
NASA CR-168222
GTEC 31-4773

ADVANCED TECHNOLOGY COGENERATION SYSTEM CONCEPTUAL DESIGN STUDY

CLOSED CYCLE GAS TURBINES

E.A. Ted Mock and Howard C. Daudet
Garrett Turbine Engine Company
A Division of The Garrett Corporation

October 1983

Prepared for

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION
Lewis Research Center
Cleveland, Ohio 44135
Under Contract DEN3-215

for

U.S. DEPARTMENT OF ENERGY
Division of Heat Engines and Heat Recovery
Washington, D.C. 20545
Under Interagency Agreement DE-AI01-77ET-13111

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1. Report No. NASA CR-16822	2. Government Accession No.	3. Recipient's Catalog No
4. Title and Subtitle Advanced Technology Cogeneration Systems Conceptual Design Study Closed Cycle Gas Turbines		5. Report Date October 1983
		6. Performing Organization Code
7. Author(s) E. A. Ted Mock and Howard C. Daudet		8. Performing Organization Report No 31-4773
		10. Work Unit No
9. Performing Organization Name and Address Garrett Turbine Engine Company Division of The Garrett Corporation P.O. Box 5217 Phoenix, Arizona		11. Contract or Grant No DEN3-215
		13. Type of Report and Period Covered Final Report
12. Sponsoring Agency Name and Address National Aeronautics and Space Administration Lewis Research Center Cleveland, Ohio 44135		14. Sponsoring Agency Code DOE/NASA/0215-1
15. Supplementary Notes		

16. Abstract

This document reports the results of a three task study performed for the Department of Energy under the direction of the NASA Lewis Research Center. The study surveyed the thermal and electrical energy requirements of three specific industrial plants and compiled cost records for the energies consumed. Preliminary coal fired atmospheric fluidized bed heated closed cycle gas turbine and steam turbine cogeneration system designs were developed for each industrial plant. Preliminary cost and return-on-equity values were calculated and the results compared. The best of the three sites was selected for more detailed design and evaluation of both closed cycle gas turbine and steam turbine cogeneration systems during Task II. Task III involved characterizing the industrial sector electrical and thermal loads for the 48 contiguous states, applying a family of closed cycle gas turbine and steam turbine cogeneration systems to these loads, and conducting a market penetration analysis of the closed cycle gas turbine cogeneration system.

17. Key Words (Suggested by Author(s)) Closed Cycle Gas Turbine; Steam Turbine; Atmospheric Fluidized Bed; Cogeneration System Comparison; Industrial Sector Characterization		18. Distribution Statement Unclassified - Unlimited; Star Category 44; DOE Category UC-90	
19. Security Classif (of this report) Unclassified	20. Security Classif. (of this page) Unclassified	21. No. of Pages 291	22. Price*

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

NASA-C-168 (Rev 10-75)

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FOREWARD

The design and study work described in this report was performed by the Garrett Turbine Engine Co., (Garrett), Phoenix Arizona, a division of the Garrett Corporation under DOE/NASA contract number DEN3-215. Garrett was assisted by three sub-contractors. Gibbs & Hill, Inc., New York, N.Y., served as the Architect-Engineer consultant performing the analytical, design and cost estimating for all of the AFBC/steam turbine cogeneration systems including the Balance of Plant equipment; the design and cost estimating of the Balance of Plant for the AFBC/closed cycle gas turbine cogeneration systems; planning, layout and cost estimating for the siting, yardwork and structural work for all sites as well as the permitting and construction scheduling.

Foster-Wheeler Co., served as the Engineering and Construction Consultant for the AFBC/Boiler for the steam turbine systems performing the analytical work, design and cost estimating for the AFBC/boilers for the steam systems and reviewing the cost estimates for the AFBC/air heaters for the closed cycle gas turbine systems. Arthur D. little Company served as the consultant on the Task III Market Analysis and Penetration work. All three subcontractors contributed significantly to the substance and validity of the work.

Dr. John W. Dunning, Jr., of the NASA Lewis Research Center, Cleveland, Ohio was the NASA project manager. His analytical monitoring and coordination of the effort with DOE contributed substantially to the validity of work and the value of the results to the technical and industrial communities.

The Garrett Turbine Engine Company wishes to acknowledge and express appreciation for the participation of the three major organizations, listed below, whose plants were selected as the primary candidates for this study. These companies were as follows:

(1) Reichhold Chemical Company
North Columbia River Highway
P.O. Box 810
St. Helens, Oregon
Mr. Ed Stipkala, Vice President and General Manager
Mr. John Cramer, Process and Plant Manager

(2) Archer-Daniels-Midland
4666 Faries Parkway
Decatur, Illinois 62525
Mr. George McCauley, Energy Manager
Mr. Anthony Petricola, Chief Process Engineer

(3) The Ethyl Corporation, Houston Plant
Pasadena, Texas
Mr. R.C. Fontenot, Manager of
Corporate Energy Supply
Mr. Joseph E. Douglas, Superintendent Houston Plant

In order to assure validity of results, the study was based on actual operating data in actual plant situations. Without the excellent cooperation, assistance and data provided by the organizations and individuals listed above, the objectives of the study could not have been achieved.

FINAL REPORT

ADVANCED TECHNOLOGY COGENERATION SYSTEMS STUDY NASA CONTRACT DEN3-215

1.0 INTRODUCTION

This report, prepared by the Garrett Turbine Engine Company, presents the results of a 14 month study of coal-fired closed cycle gas turbine cogeneration systems. This effort was conducted under NASA-Lewis Research Center Contract DEN3-215 for the Department of Energy.

Coal-fired steam cogeneration systems are currently commercially available. Use of a coal-fired atmospheric fluidized bed combustion (AFBC) system in conjunction with a steam cogeneration system is an attractive approach to cogenerating the industrial sector of the United States. For purposes of this study, the coal-fired AFBC/Steam Cogeneration System was defined as being commercially available. Therefore, all of the steam cogeneration systems designed during the study were based on adapting commercially available equipment to the individual problem statement.

Coal-fired AFBC/Closed Cycle Gas Turbine (CCGT) cogeneration systems are not currently available but are just emerging from the research or demonstration arena into the commercial arena. The AFBC/CCGT is the advanced technology that the study was to address. Accordingly, all of the CCGT cogeneration systems considered during the study were based on customized and optimized major equipment, such as the turbomachinery, for each of the individual problem statements. Figure 1 schematically shows the AFBC/CCGT cogeneration system which consists of an atmospheric fluidized bed combustion system that supplies all of the required thermal energy to a closed cycle gas turbine. The closed cycle gas turbine is similar to the more familiar open cycle gas turbine but affords several key design flexibilities.

AFB/CCGT COGENERATION SYSTEM
SIMPLIFIED BLOCK DIAGRAM

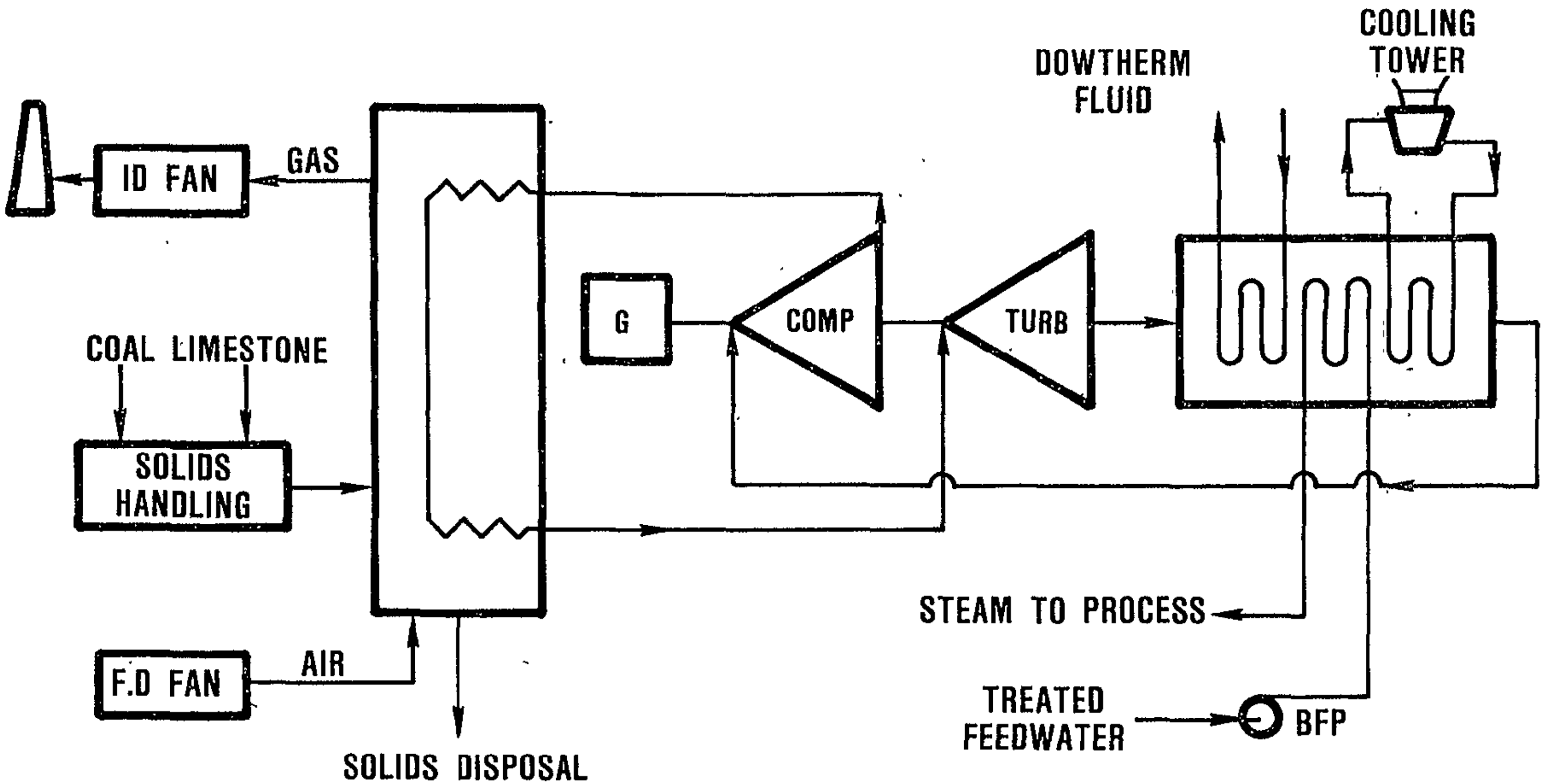

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Figure 1

A. Since the cycle is closed, the cycle working fluid can be any single phase gas. Several gases have been considered but air is the preferred working fluid for megawatt size systems.

B. Since the cycle is closed, the compressor inlet pressure can be any pressure desired. The designs discussed in this report are based on the use of a compressor inlet pressure that will result in a compressor discharge pressure of 600 psia. This results in small component size for a given power level, compared to those of an open cycle gas turbine with the compressor inlet pressure limited to one atmosphere (14.696 psia at sea level).

C. Since the cycle is closed, the compressor inlet temperature is not limited to the atmospheric temperature but can be selected to match the cogeneration thermal and electric loads. This reduces or eliminates the waste heat that is rejected to the atmosphere, reduces the coal flow needed to satisfy the cogeneration loads, and results in a higher return on the capital cost of the cogeneration plant.

The overall objective of the study was to determine the extent of the coal-fired cogeneration system market within the industrial sector of the nation and to evaluate the potential for penetrating that market. Market penetration of the AFBC/CCGT cogeneration system was the major interest, however, the market penetration potential of AFBC/Steam cogeneration systems had to be evaluated so that the significance of the AFBC/CCGT market penetration could be properly judged.

Several previous government sponsored studies compared CCGT versus steam systems for power and/or cogeneration applications. The unique condition of this study is the fact that the atmospheric fluidized bed combustion system is used as the heat source for both the CCGT and the steam systems. In general, the previous studies compared

AFBC/CCGT systems against steam systems that used pulverized coal combustors. The advantages shown for the AFBC/CCGT were often questioned -- were the advantages the result of CCGT versus steam or AFBC versus pulverized coal combustors? Since the current study uses AFBC's for both, the comparative results are clearly CCGT versus steam.

The rationale for the government's sponsoring of this study is the need to establish the national significance of the CCGT technology. It is and was recognized that ultimately the members of the industrial sector will determine if cogeneration is employed in the industrial sector. This decision is based on economics and other considerations. The study was conducted in an attempt to address the economic issue by evaluating the return on the capital invested in the cogeneration plant.

This final report has been organized to summarize the study from two points of view. The report is a contractually required document with the objective of summarizing the significant results for NASA's review and approval. The significance of the study results to the ultimate cogeneration system owner, members of the nations industrial sector, has been highlighted. Accordingly, the report consists of a relatively short main text that summarizes the study results followed by a series of detailed appendices that give details of the study by task.

2.0 EXECUTIVE SUMMARY

The Executive Summary is given in the following paragraphs. This summary is written primarily for the benefit of the reader who is a member of the industrial sector and who is not particularly interested in reading a long description of the study details.

2.1 Study Approach

The study was divided into three tasks as described below

Task I - Site specific screening study
Task II - Site specific conceptual design study
Task III - Market presentation and benefits analysis

The Task I effort involved screening three specific industrial sites to establish which of the three should be addressed during Task II. Both AFBC/Steam and AFBC/CCGT Cogeneration systems were evaluated for each of the three sites, including establishing the capital cost of the cogeneration system and the resulting return on the capital cost. This Task I effort is summarized in detail in Appendix I.

Task II involved the conceptual design of AFBC/CCGT and AFBC/Steam Cogeneration systems for the Ethyl Corporation site. This effort constituted a major part of the study effort and resources and was primarily intended as a verification of the Task I screening study, particularly in the area of the capital cost of the cogeneration plants. The capital costs defined during Task I for the Ethyl site were verified during Task II to within 3.0 percent for the AFBC/CCGT system and to within 11.7 percent for the AFBC/Steam Cogeneration system.

The Task III effort included establishing the technically viable cogeneration loads within the industrial sector and estimating how many of these loads could be economically converted to cogeneration. Both AFBC/CCGT and AFBC/Steam Cogeneration systems were considered in the Task III effort. The Task III effort is of the most significance to the industrial sector and is therefore summarized below.

2.2 Task III Summary

The Task III analysis was organized to provide answers to several layers of questions asked by NASA and DOE and is summarized in Table 1. These questions are based on the premise that steam cogeneration systems are currently available whereas the AFBC/CCGT cogeneration systems are just now emerging from the research/demonstration arena into the commercially available arena. In addition, it should be pointed out that NASA, DOE, Garrett and the subcontractors all understand that the government is not the entity that ultimately decides if any cogeneration plant is built and operated in the industrial sector. The individual industrial plant owner must decide, on the basis of economics and other considerations, whether cogeneration plants will be used in the industrial sector. However, the local utility that supplies electrical power to the industrial site can, by their attitude, influence the industrial site owner's decision.

The Task III analysis was conducted in an attempt to answer at least the technical and economic portions of the questions. The nation's industrial sector was characterized as to steam and electrical loads and coal-fired steam and CCGT cogeneration systems applied to these loads. The return-on-equity (ROE) of each plant was determined and two ROE hurdle rates established, 10 and 20 percent. Any cogeneration plant that exhibited a ROE equal to or greater than the hurdle rate ROE was judged to be economically cogeneratable. The national significance of cogenerating the industrial sector was then established. The answers to the questions of Table 1 form the summary of the Task III analysis.

TABLE 1. TASK III MARKET AND BENEFITS ANALYSIS QUESTIONS

Q1 - Can coal fired cogeneration plants within the industrial sector save energy or displace a significant amount of the more scarce oil and gas fuels?

Q1.1 - Is there sufficient benefit, over the nation as a whole, to warrant continued DOE support of the emerging AFBC/CCGT cogeneration systems?

Q2 - Can the industrial sector afford to cogenerate with coal?

Q2.1 - Is there a sufficient payoff of coal fired AFBC/CCGT cogeneration plants to the industrial sector that the industrial sector will select, or at least consider, AFBC/CCGT cogeneration systems?

Q3 - Are there any technical barriers that will prevent the development of AFBC/CCGT cogeneration systems?

Q3.1 - Are there technologies that will enhance or make more attractive the AFBC/CCGT cogeneration systems?

Q4 - What frame sizes should the closed cycle gas turbine manufacturers offer to the industrial sector?

- Q1 Answer - Use of AFBC/CCGT cogeneration systems will save about 0.66 quads/year of fuel as shown in Figure 2. Converting to coal fired AFBC/steam cogeneration systems, with a minimum return-on-equity (ROE) of 10 percent, actually results in an increase in the total energy needed to satisfy the nations industrial sector electrical and steam needs.

  At a ROE hurdle rate of 10 percent, the AFBC/CCGT cogeneration plants can yearly displace about 1.84 quads of oil and gas with coal. This displacement is almost double that of the equivalent steam system.

- Q1.1 Answer - It appears that continued DOE support of AFBC/CCGT technology is justified, based on the answers to Q1.

- Q2 Answer - This question cannot be answered by any single organization or study. However, the Task III analysis results indicate that at a 10 percent ROE hurdle rate, about 77 percent of the oil and/or gas fired boilers would be cogenerated with the AFBC/CCGT system. Only about 34 percent of the steam cogeneration plants have a ROE of 10 percent or better. These results are drastically reduced at the ROE hurdle rate of 20 percent as shown in Figure 3. Figure 3 shows the Task III results by DOE region, cogeneration system type, and ROE hurdle rate. Note that in the DOE Region X, none of the cogeneration plants have a ROE of 20 percent or greater. This is due to the fact that this region is primarily based on cheap hydroelectric and nuclear utility power.

  A problem with this answer is that it creates another question; is a 10 percent ROE attractive to the industrial sector. It should be noted that some of the cogeneration

NATIONAL AGGREGATE RESULTS

ROE HURDLE RATE	10%		20%	
COGEN SYSTEM	CCGT	STEAM	CCGT	STEAM
TOTAL FUEL SAVED, QUADS/YR	0.66	−0.06	0.26	0.01
TOTAL GAS AND OIL DISPLACED, QUADS/YR	1.84	0.99	0.81	0.11
EMISSION SAVINGS RATIO, %	0.01	−14.92	−1.30	−10.37
EMISSION SAVINGS, 10^6 LB/YR	0.70	−383.2	−25.3	−23.0
ELECTRICAL ENERGY, QUADS/YR	1.14	0.59	0.45	0.05
THERMAL ENERGY, QUADS/YR	1.74	0.90	0.69	0.08
AVG HEAT-TO-POWER RATIO	1.53	1.53	1.53	1.53

Figure 2

NUMBER OF COGENERATION PLANTS

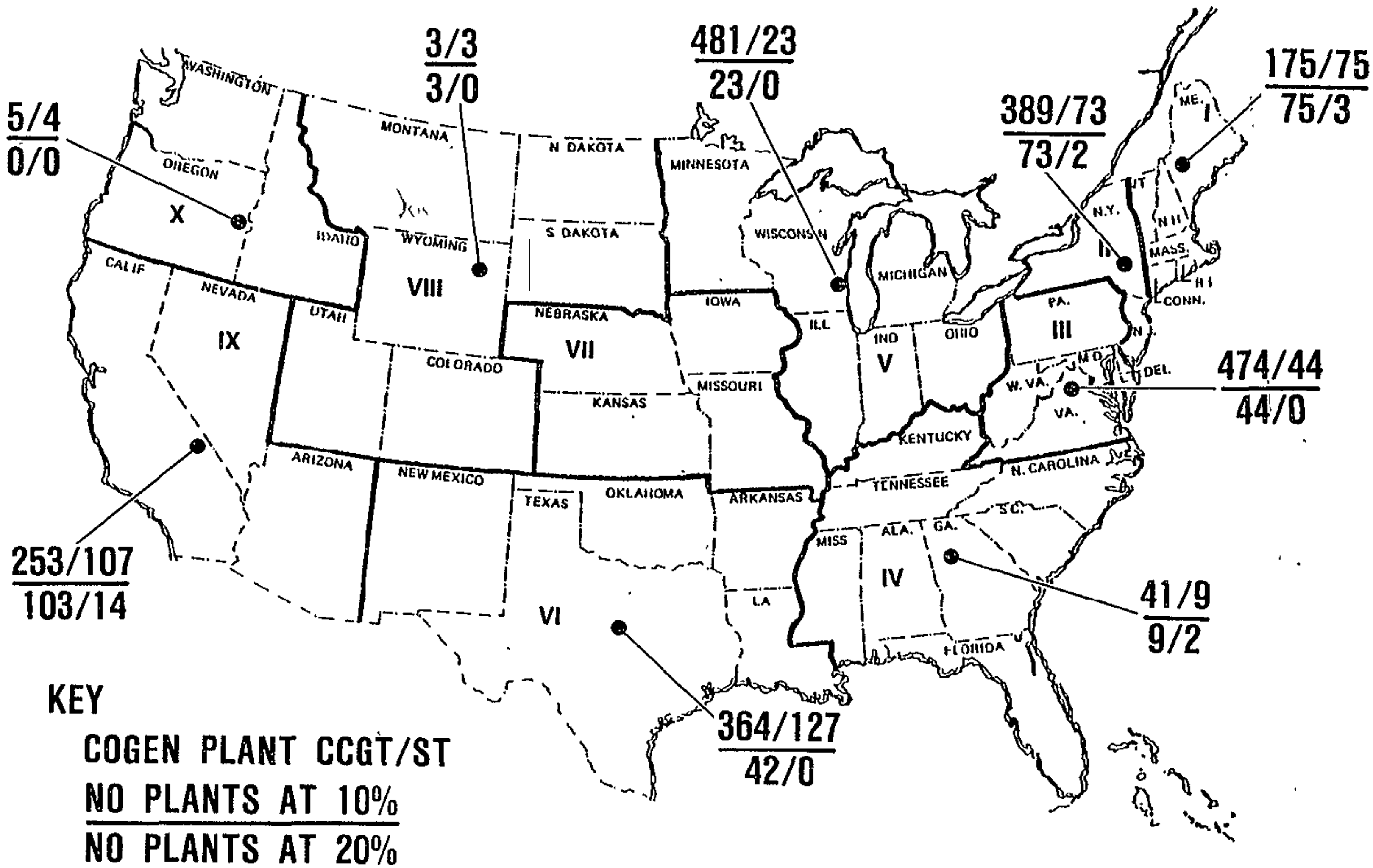

Figure 3

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plants exhibited ROE's in excess of 40 percent and, thus, the question becomes highly site specific.

- Q2.1 Answer - This question has a correlative question to be asked by the AFBC/CCGT manufacturers; is there a sufficient market for AFBC/CCGT cogeneration systems that the manufacturers should develop the technology. On the basis of the 10-percent hurdle rate, there appears to be a significant market. See Q4 answer below.

- Q3 Answer - There are no technical barriers that will prevent development of the AFBC/CCGT cogeneration system. The major enhancement technology is low cost materials for the high temperature heat exchangers.

- Q4 Answer - The AFBC/CCGT cogeneration system is made up from several highly modularized heat exchanger components and the rotating group which includes the generator/gearbox and the turbocompressor unit. The turbocompressor unit output power rating, in MWe, describes the frame size. Two CCGT frame sizes appear to be required to cover the industrial sector, 5 MWe and 50 MWe. The Task III results suggest that, at the 10-percent ROE hurdle rate, the numbers of units for each frame size is as shown below:

Frame Size, MWe	5	50
Number Units Required	1925	1488

Even if only one half of these values ultimately becomes a reality, there appears to be an attractive market.

2.3 Significance of Study to Industrial Sector

The importance of the study results to the industrial sector can best be illustrated by a review and contemplation of the Task III results. The objective of Task III was to apply what was learned about steam and closed-cycle gas turbine cogeneration systems during Tasks I and II, on a site specific basis, to the much broader industrial sector as a whole. The Task III data shows that the industrial sector can benefit, and can afford to benefit, from the use of coal-fired cogeneration systems provided:

a. The industrial site is located in a DOE region that is not predominately based on cheap hydroelectric or nuclear utility power.
b. The specific site is based on using gas and/or oil as the separate generation boiler fuel.
c. The local utility will at least tolerate, or work with, the industrial cogenerator.
d. The industrial site has a minimum heat-to-power ratio of about 1.0 or the local utility will pay a fair price for the power exported from the industrial site.

If all or most of the above conditions are met or approached, the industrial site owners should consider cogeneration. The steam cogeneration systems can provide the industrial owner an attractive return-on-equity and return-on-investment. However, the emerging technology of the closed cycle gas turbine shows a return-on-equity significantly better than that for the equivalent steam cogeneration system as shown in Figure 3.

The significance of the Task I and Task II effort to the industrial sector is that these parts of the study verified the results of Task III by conducting a detailed cost and thermodynamic analysis on a selected industrial site cogeneration system.

2.4 Study Organization

The study was conducted by the Garrett Turbine Engine Company as the prime contractor with the following subcontractors

- o GIBBS & HILL, INC. (G&H) acted as the architect-engineer
- o FOSTER-WHEELER DEVELOPMENT CORP. (F-W) acted as the AFBC Steam Boiler Designer
- o ARTHUR D. LITTLE, INC. (ADL) conducted the market penetration analysis of Task III

A discussion of each organizations responsibilities is presented in Section 4.0, page 42. The significance of this study team to the industrial sector is Garrett is the recognized leader in the field of closed-cycle gas turbine technology. GIBBS & HILL has been designing and building cogeneration and conventional steam systems for many years and FOSTER-WHEELER is a recognized leader in the field of coal-fired combustion systems, both pulverized coal and fluidized beds. ARTHUR D. LITTLE has conducted several design and market studies in the fields of power and cogeneration plants. Thus the team members have a background in their chosen areas, in fact, have participated in several prior studies which lends credability to the study results.

3.0 STUDY SUMMARY

3.1 Program Objectives

The primary objectives of the study were to identify attractive applications for AFBC/Closed Cycle gas turbine cogeneration systems in industrial plant sites and to compare, based on site-specific conceptual designs, the potential benefits of the AFBC/Closed Cycle gas turbine system with an AFBC/steam turbine system at selected plant site(s). Additional goals of the study were to define technology advancements required to achieve the calculated benefits, to define the market to which the AFBC/Closed Cycle gas turbine system is applicable, and to estimate the potential national benefits which could be achieved through implementation of AFBC/Closed Cycle gas turbine systems in industrial cogeneration.

The requirements of plants vary widely across the manufacturing sector of U.S. industry. In fact, even within specialized subclassifications of industry, individual plant requirements vary markedly. Therefore, to better assess the benefits available from the use of both a closed cycle gas turbine and a steam turbine energy conversion system in a particular application, a detailed site-specific analysis was performed.

3.2 Technical Approach

Basically the study was divided into three major tasks as follows:

Task 1 consisted of analyzing three different plant sites for initial evaluation of the technical, economic and environmental consequences of the implementation of both a coal fired AFBC/CCGT cogeneration system and a coal fired AFBC/Steam cogeneration system operating under identical economic constraints and supplying the same site thermal and electrical loads.

An initial group of 10 candidate sites were identified from which three were selected for study in Task I. Each of the 10 sites was visited to obtain first hand data on operational characteristics, electrical and thermal requirements and usage patterns, utility resources and costs, siting considerations, environmental requirements, financial requirements and resources and management attitudes toward implementation of the cogeneration concept. Optimized cogeneration system designs were generated for both AFB/CCGT and AFB/ST concepts to satisfy the requirements for each of the three selected sites, and detailed cost estimates were prepared for each system. Economic analyses were prepared for both the CCGT and steam systems at each site. The Task I effort was concluded by recommending one of the three sites for additional study during Task II.

Task II consisted of performing a more detailed site survey of the selected plant and considerably more detailed design and cost studies of the optimized cogeneration system designs than were developed for that plant. A detailed economic cost/benefits analysis was conducted for both the CCGT and ST systems at the selected site using the ROE as the primary criterion.

The ST systems were predetermined to be state of the art and therefore all components to be commercially available on the current market. An evaluation of the CCGT system was conducted to identify those features or components (if any) which are considered to be beyond todays state of the art and therefore require further development to render them commercially available. Cost and time schedule for the required development program were evaluated.

At this point the ST and CCGT concepts were compared with respect to performance, capital cost, fuel utilization, emissions characteristics and economic benefits (ROE).

Task III consisted of an "in depth" survey of historical and current market data to evaluate the magnitude of the technically potential market for coal fired cogeneration systems in industry. These data were then screened on the basis of established economic factors, with ROE as the primary criterion, to establish the magnitude of the potential economic market. A matrix was generated in which the estimated numerical values for the potential technical market was displayed to show the values pertaining to seven different cogeneration system power classes in each of the ten DOE regions of the U.S.A. on the basis of two levels of ROE.

A similar matrix was generated in which the estimated numerical values for the potential economic market were displayed. These were derived by screening the technical market on the basis of a set of economic factors established by ADL specifically for this market study.

The summary for Task III is included as Section 2.2. The site specific efforts of Tasks I and II are summarized in subsequent sections.

3.3 Task I Summary

The Task I study consisted of optimizing the design of closed cycle gas turbine and steam turbine cogeneration systems for three widely varying specific industrial sites. The results are compared to the non-cogeneration or present method of satisfying plant site energy requirements. One of the three sites was recommended for continued study during the remainder of the program. A summary of the Task I Study is presented herein. Appendix I gives additional details.

3.3.1 Site Definition and Recommendation

The three sites are identified in Table 1 and Appendix I. The Ethyl Corporation is unique in two respects:

TABLE 1.

SITE DATA — GENERAL

NAME:	REICHHOLD CHEMICALS, INC (RCI)	ETHYL CORPORATION (ETH)	ARCHER-DANIELS MIDLAND (ADM)
LOCATION:	ST. HELENS, OREGON	PASADENA, TEXAS	DECATUR, ILL
SIC(S)	2873	2865,2869	2046,2869
PRODUCTS:	AMMONIA, UREA, NITRIC ACID	ZEOLITE, LINEAR ALCOHOL OLEFINS, ETC	CORN AND SOYA FOOD PRODUCTS, FUEL GRADE ALCOHOL
CURRENT FUEL:	NATURAL GAS	NATURAL GAS	NATURAL GAS
UTILITY:	PORTLAND GENERAL ELECTRIC	HOUSTON LIGHT AND POWER	ILLINOIS POWER
UTILITY FUELS:	79% HYDROPOWER 20% NUCLEAR *1% COAL	*85% NATURAL GAS 15% COAL	*70% COAL 30% NUCLEAR

*INDICATES FUEL THAT THE COGENERATED ELECTRICAL POWER WOULD REPLACE

(a) Two types of thermal loads are possible for the Ethyl site, steam and Dowtherm. The cogeneration system could address only the steam loads or both the steam and the Dowtherm heating loads. Both options were considered during the Task I study with the Dowtherm heating case being selected since it exhibits the maximum benefits as a result of cogeneration compared to the non-cogeneration (currently existing) approach.

(b) The Ethyl site exhibits unique economic conditions. The cogeneration system is expected to sell all of its electrical power to the utility (Houston Light and Power), and the site is expected to continue buying all of the electrical power needed. This simultaneous import/export of electrical power results in no stand-by charges being charged by the utility. Other significant differences include the high electrical escalation (7 percent above inflation) which is due to the fact that the utility is predominantly natural gas based and the utility is currently highly capital intensive.

A review of early study results indicated that the site specific fuel and energy costs for the Reichhold site impose an adverse effect on the cogeneration plant for that site. The economics, specified by NASA as being representative of the average industrial sector, were therefore used during the optimization study for the Reichhold site. These "common case" economics are defined in Appendix I.

The site recommended for continuation into Task II was the Ethyl site.

3.3.2 Task I Analytical Approach

The analytical approach for the Task 1 study is summarized in Table 2. The approach for the closed cycle gas turbine cogeneration

TABLE 2

ANALYTICAL APPROACH

CLOSED CYCLE GAS TURBINE

- CCGT COGEN SYSTEM DESIGNED WITH AFBC/GT, DESIGN POINT COMPUTER MODEL THAT:
  - DESIGNS ALL MAJOR COMPONENTS
  - COSTS ALL MAJOR COMPONENTS
  - SCALES BOP ITEMS
  - EVALUATES RETURN ON EQUITY VERSUS SEPARATE-GEN APPROACH
  - 1500 SYSTEMS EVALUATED PER SITE AND LOAD SET
- CHECK SELECTED DESIGN COSTS WITH:
  - AFB MANUFACTURER (FOSTER-WHEELER)
  - BOP AND CONSTRUCTION (GIBBS AND HILL)

STEAM TURBINE

- GIBBS AND HILL DESIGNED SEVERAL STEAM TURBINE SYSTEMS FOR EACH SET OF SITE LOADS
- AFB COSTS BASED ON FOSTER-WHEELER DESIGNS AND COSTS
- REMAINING MAJOR COMPONENTS BASED ON RECENT QUOTES FROM SUPPLIERS
- ROE EVALUATED BY SAME PROGRAM AS USED FOR AFBC/CCGT DESIGNS

system is based on the use of a large computer design point program. In fact, all of the AFBC/CCGT cogeneration systems designs were generated with use of this analytical model described in Appendix I.

The analytical approach for the AFBC/CCGT cogeneration system consisted of establishing a typical cogeneration system design. Over 1100 detailed design parameter decisions were required to be made for each of the site and load set combinations. Once these design choices were made, the remaining design parameters were evaluated over the range of values. Three design figures of merit were established for the cogeneration system optimization procedure as summarized in Figure 4.

The return-on-equity (ROE) is the most important figure of merit since it indicates whether the industrial site owner will consider converting his site to cogeneration. A very significant result of the Task I study was the determination that matching both the thermal and electrical loads results in the highest ROE.

Figure 4 shows a typical example of the computer plotted results for one of the sites with a number of the design variables varied over a selected range. Note that 27 complete AFBC/CCGT cogeneration system designs are summarized in Figure 5. Approximately 7500 complete AFBC/CCGT designs were evaluated in a similar manner during the Task I study.

It should be noted that the AFBC/steam cogeneration systems were evaluated in a more conventional manner as summarized in Table 2.

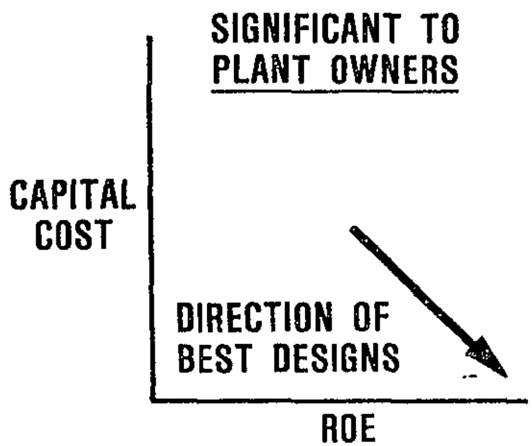
3.3.3 Optimization Study Cycle Characteristics

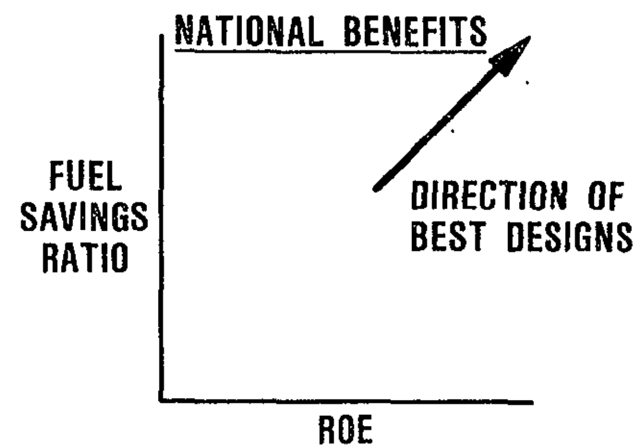
The high power to heat ratio of the Reichhold site lead to the selection of a relatively high recuperator effectiveness for the

ANALYTICAL APPROACH
(AFBC/CCGT SYSTEM ONLY)

ESTABLISH COGENERATION SYSTEM FIGURES-OF-MERIT

- RETURN-ON-EQUITY, ROE
- CAPITAL COST
- FUEL SAVINGS RATIO

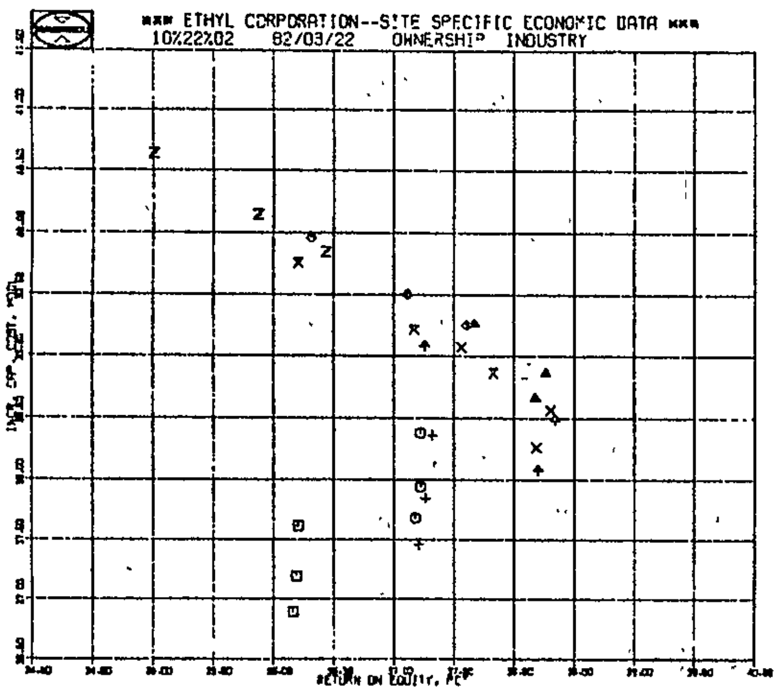




- LOWER CAPITAL COST SYSTEM BREAKS TIES IN ROE
- HIGHER FUEL SAVINGS RATIO BREAKS TIES IN ROE AND CAPITAL COST

Figure 4

EXAMPLE PLOTS



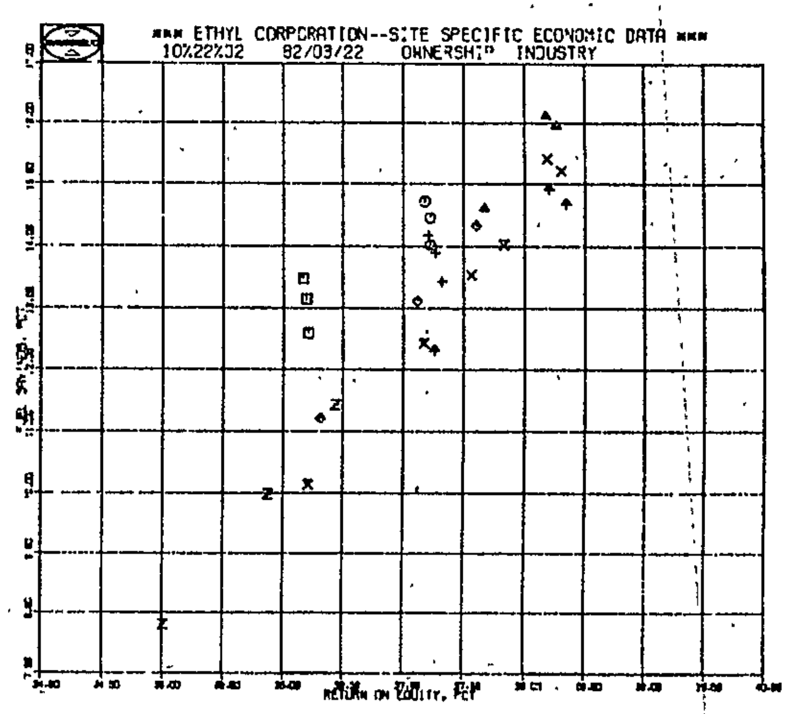


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Figure 5

AFBC/CCGT system and a relatively high primary boiler pressure for the AFBC/steam cogeneration system. The AFBC/CCGT cogeneration systems for the Ethyl and ADM sites do not incorporate recuperators. The importance of recuperation and its effect on the heat-to-power ratio are discussed in Appendix II, page 9.

All of the cogeneration systems match the electrical and thermal loads for the site which maximizes the ROE. The exception was the AFBC/steam cogeneration system for the Ethyl site. The Ethyl steam cogeneration system is a net exporter of electrical power which is the result of using boiler exit steam to satisfy the Dowtherm heating load between Dowtherm temperatures of 550°F and 680°F. An alternative for this steam cogeneration configuration would be to match the steam and electric loads and provide the Dowtherm heating directly from the AFBC instead of with use of high pressure steam. This alternative is discussed in Section 3.3.5.

3.3.4 Cogeneration System Evaluations

Figure 6 presents the most significant comparative evaluation of the steam and closed cycle gas turbine cogeneration systems for the three sites. In each case, the AFBC/CCGT cogeneration system is shown to have lower capital costs and exhibit a significantly higher return on equity. The high ROE for the ETH-G system forms the major reason that the Ethyl site was recommended by Garrett for continued study during Task II.

PERFORMANCE AND BENEFITS ANALYSIS

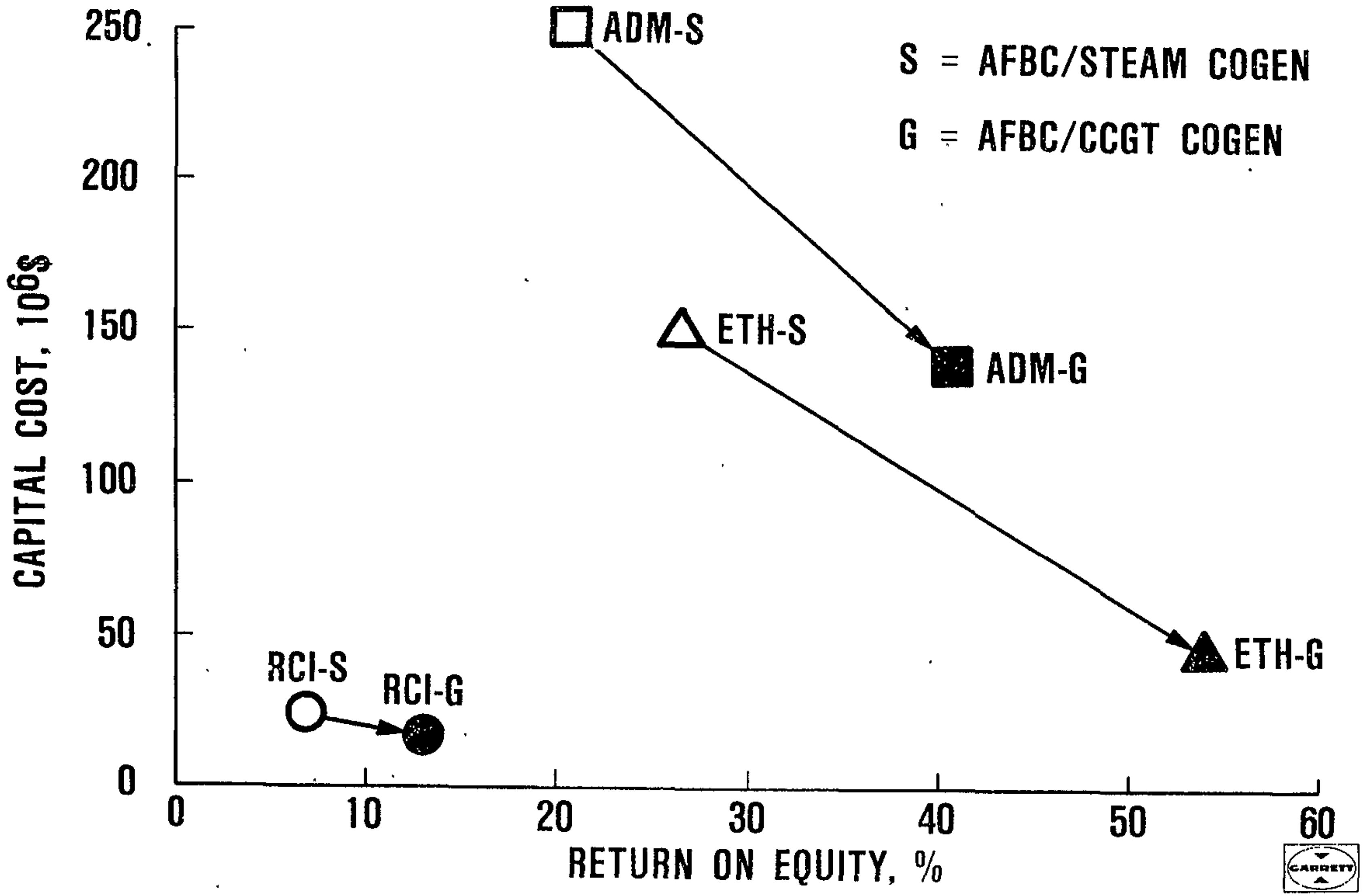


Figure 6

Figure 7 presents the fuel energy savings ratio (FESR) for the six cogeneration systems. The fuel energy saving ratio is defined as:

$$\frac{\text{Fuel used - Separate Generation (Industrial Site + Utility)} - \text{Cogeneration System Fuel Used}}{\text{Fuel used - Separate Generation (Industrial Site + Utility)}}$$

A negative value for the FESR indicates that the cogeneration plant consumes more fuel energy than the industrial site plus the utility consume to satisfy the same electrical and thermal loads.

3.3.5 Task IA - AFBC/STCS for Ethyl Site

The steam system for the Ethyl site delivered 52 MW_e and was therefore a net exporter of electric power. This high electrical output power was the result of using boiler discharge steam to heat the Dowtherm. A new AFBC/STCS was designed for the Ethyl site, based on providing the Dowtherm heat directly from the AFB. Figure 8 show the effect of this design change on return-on-equity and plant capital cost.

3.4 Task II - Conceptual Design Study Summary

3.4.1 Ethyl Site Definition

The Ethyl site was revisited to establish additional details on loads, operating procedures, utility grid conditions, etc. The results of this evaluation, summarized in Appendix II, did not change the average steam and electric loads. Thus the Task I results for the Ethyl site provided an excellent baseline for the cogeneration system conceptual designs.

RELATIVE BENEFITS

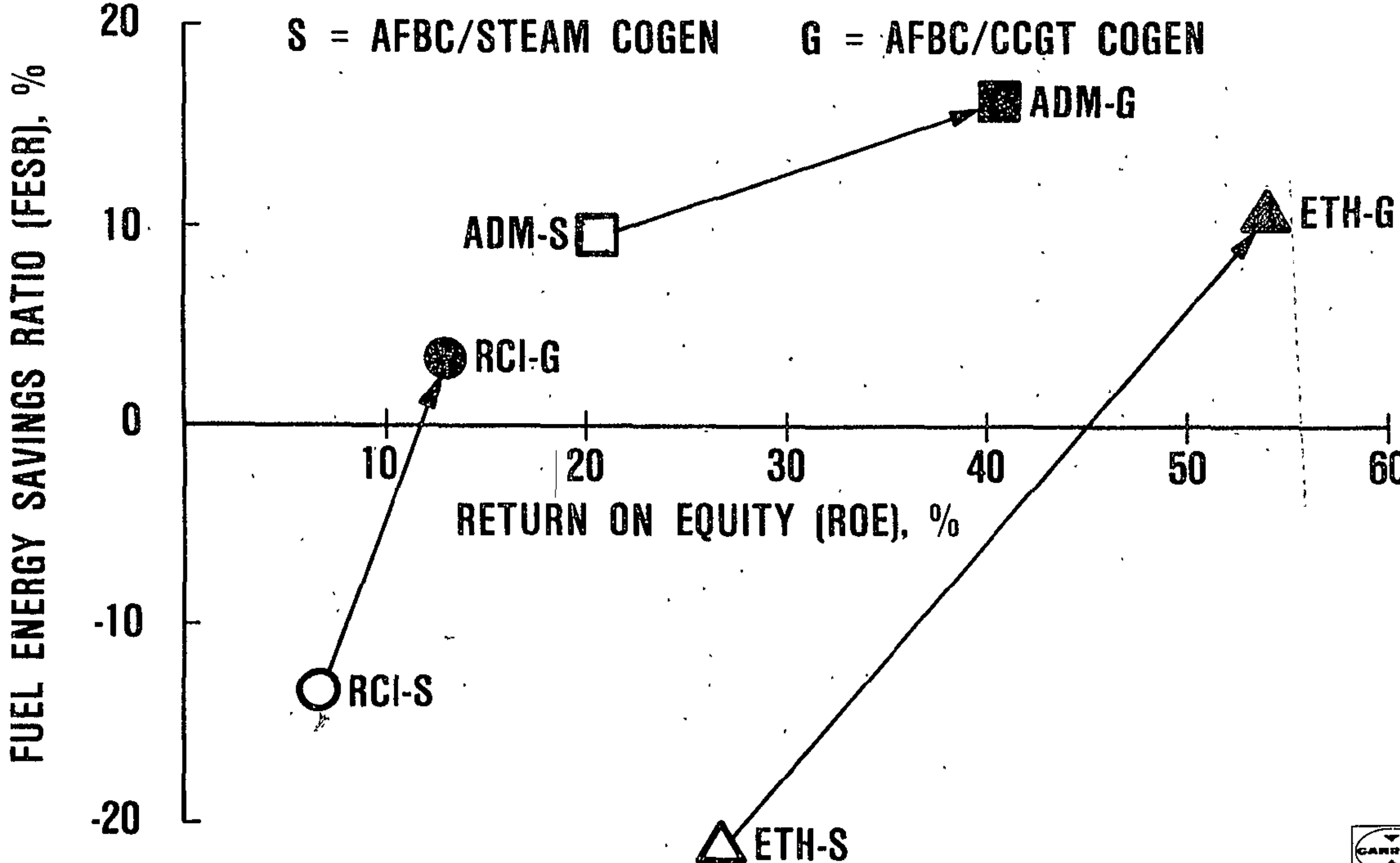


Figure 7

REVISED STEAM COGEN SYSTEM FOR ETHYL

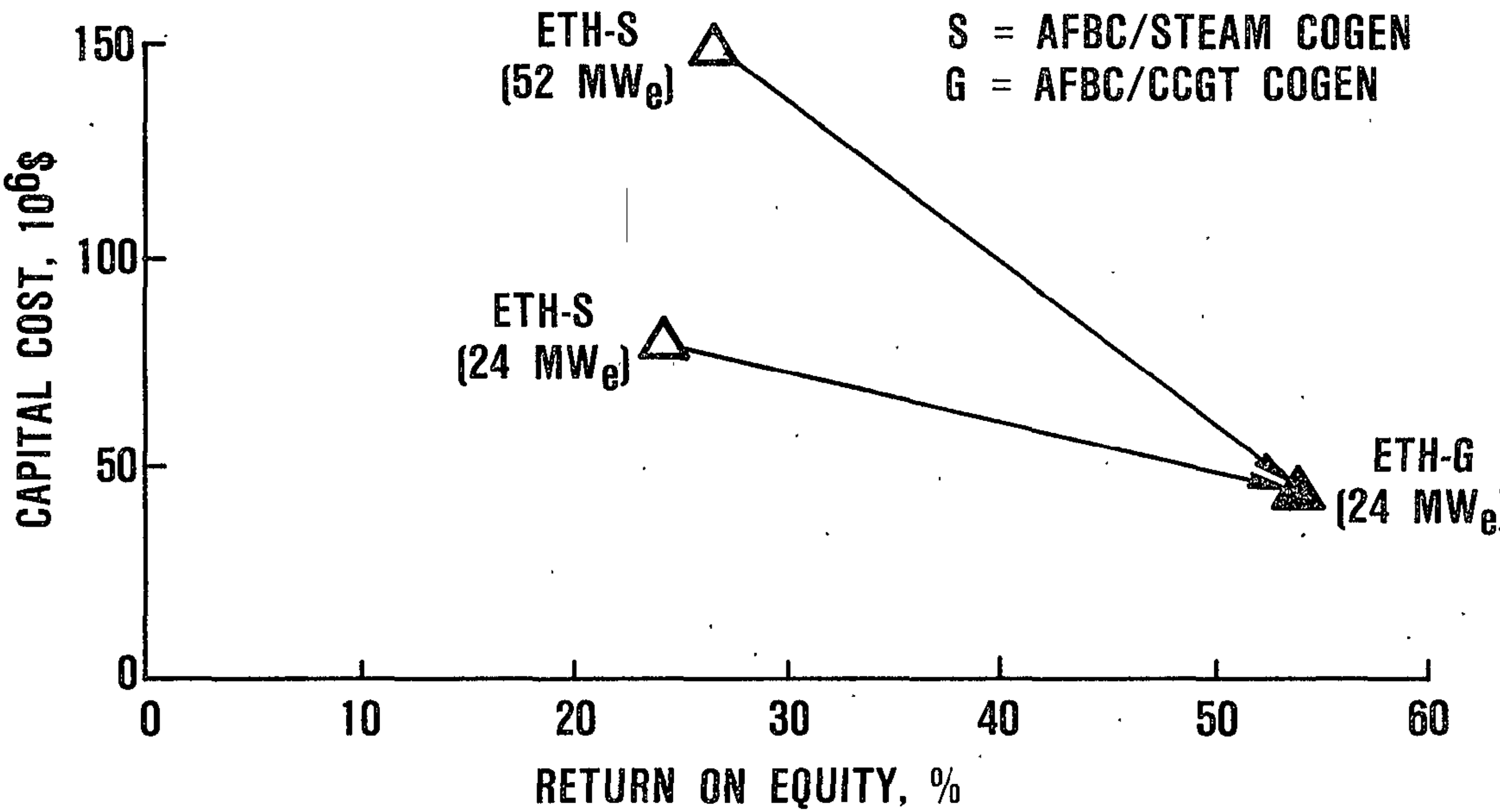


Figure 8

3.4.2 AFBC/Steam Cogeneration System Summary

The basic purpose of the Task II conceptual design was to define the cogeneration system in sufficient detail to provide accurate overall system capital cost estimates.

Figure 9 shows the AFBC/steam cogeneration system simplified schematic and Figure 10 shows the AFBC--boiler design. Details of this conceptual system design are included in Appendix III.

Figure 11 presents a breakdown of capital cost items for the AFBC/Steam cogeneration system. The total capital cost is about 10.5 percent less than the capital cost shown in Figure 24 for the 52 MW_e steam system. Note that the capital cost does not include interest or escalation during construction

3.4.3 AFBC/CCGT Cogeneration System Summary

The conceptual design study on the AFBC/CCGT cogeneration system had two major objectives:

(a) Verify the capital costs
(b) Review the technology to establish if there are any barriers that would prevent the commercialization of AFBC/CCGT cogeneration systems.

Figure 12 shows a simplified schematic of the AFBC/CCGT cogeneration system designed to satisfy the Ethyl site.

Figure 13 shows the CCGT turbocompressor that drives the 3600 rpm generator via a step down gearbox. All of the thermal loads are supplied from the waste heat rejected at the turbine exhaust as shown in Figure 12. Figure 14 shows details of the AFBC-Air Heater which supplies the heat required by the CCGT.

AFB/ST COGENERATION SYSTEM

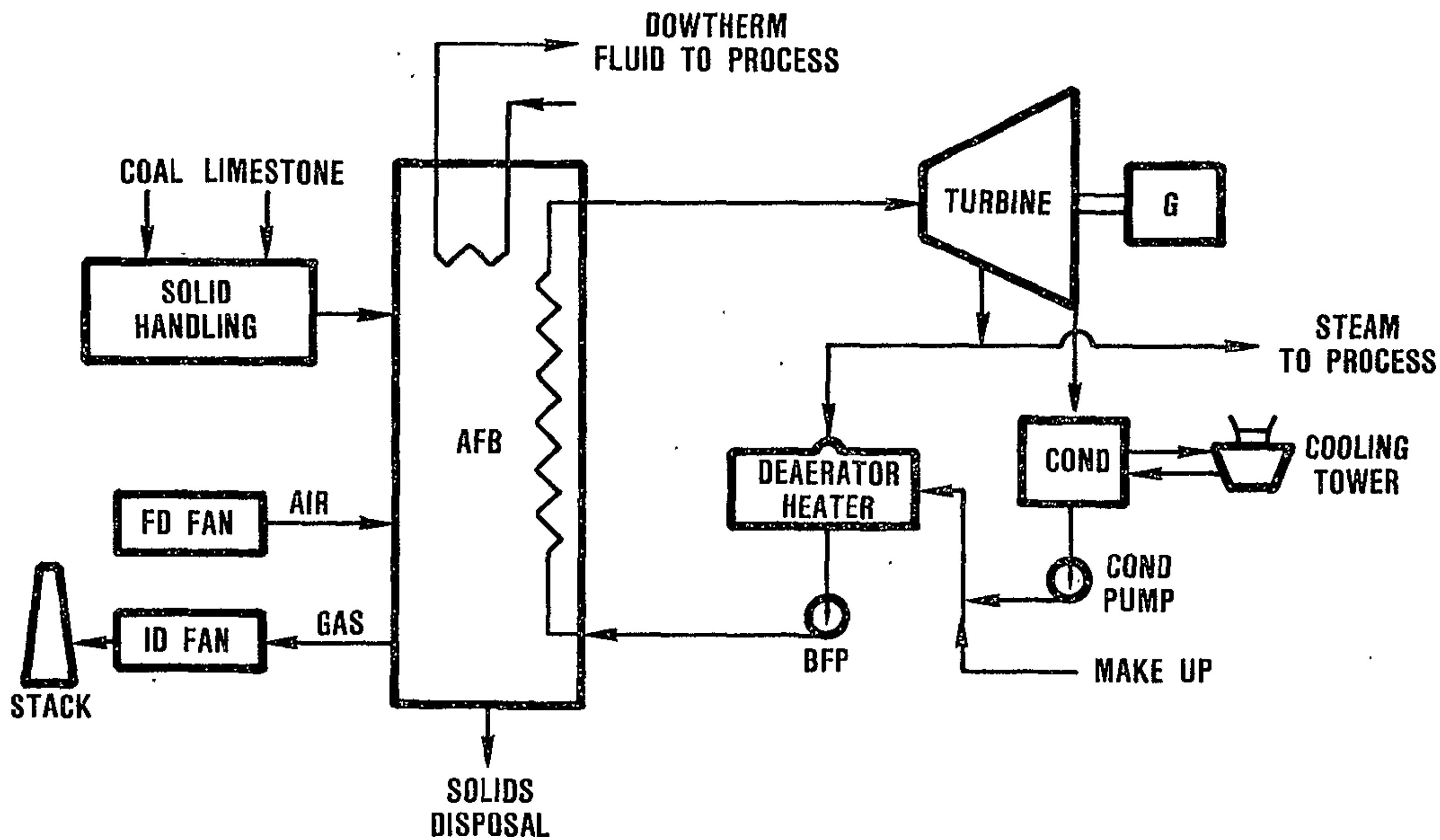
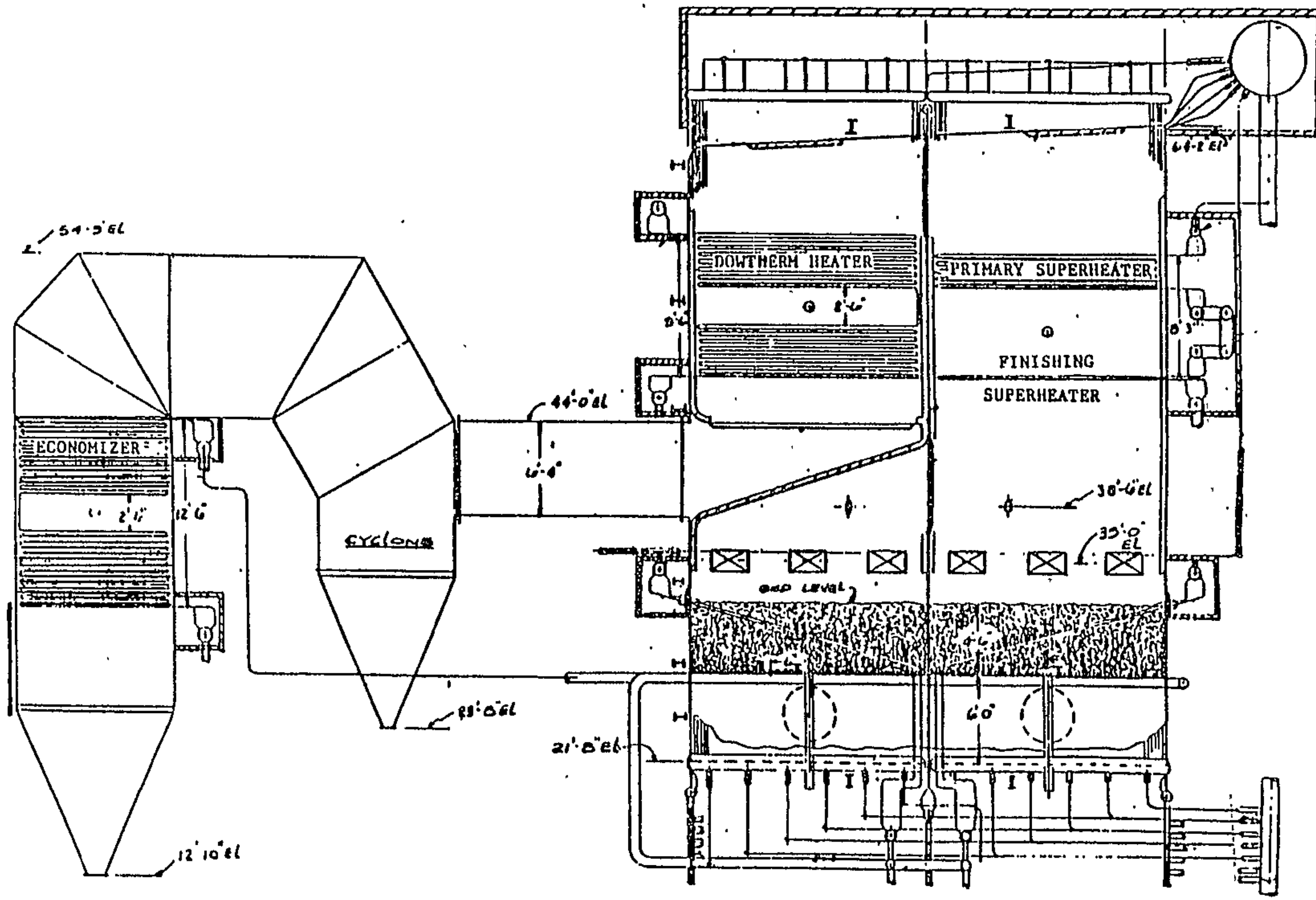


Figure 9



SIMPLIFIED ELEVATION VIEW OF AFBC STEAM GENERATOR

Figure 10

AFB/ST COGENERATION SYSTEM CAPITAL COSTS

(M$)	COMPONENT CAPITAL	DIRECT LABOR	INDIRECT FIELD	MATERIAL	TOTALS
1.0 FURNACE	11.717	3.167	3.167	11.296	29.347
2.0 TURBINE GEN	5.160	0.410	0.410	1.987	7.967
3.0 PROC MECH EQUIP	0.000	0.000	0.000	0.000	0.000
4.0 ELECTRICAL		0.352	0.352	1.418	2.122
5.0 CIVIL + STRUCT		3.733	3.733	4.825	12.291
6.0 PROC PIPE + INST		0.188	0.188	0.213	0.589
7.0 YARDWORK + MISC		0.083	0.083	0.163	0.329
***** TOTALS *****	16.877	7.933	7.933	19.902	52.645
BALANCE OF PLANT (BOP)	(DIRECT + INDIRECT + MATERIAL)			35.768	
A/E HOME OFFICE AND FEE		(AT 15 PCT OF BOP)		5.368	
SUBTOTAL PLANT COST			(TOTAL + A/E)		58.013
CONTINGENCY	(0.157 OF TOTAL PLANT COST, CALC)			9.122	
PLANT COST (1982.0 $)	(SUBTOT PLANT COST + CONTINGENCY)				67.135
CONSTRUCTION ESCAL. AND INTEREST CHARGES					0.000
TOTAL PLANT CAPITAL COST			(1982 $)		67.135

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Figure 11

AFB/CCGT COGENERATION SYSTEM
SIMPLIFIED BLOCK DIAGRAM

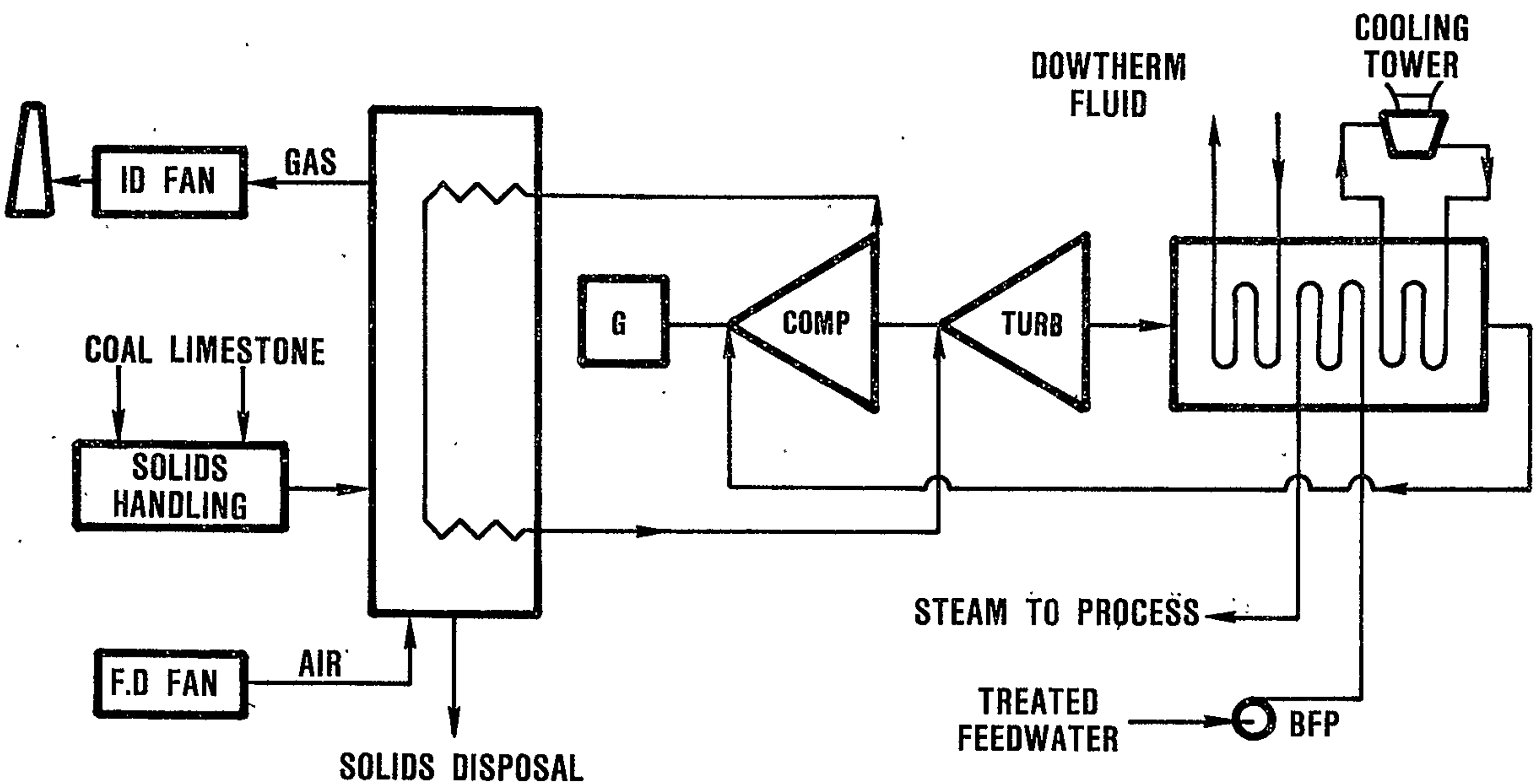

Figure 12

CLOSED CYCLE 30 MW_e TURBOGENERATOR
USES 50 MW_e FRAME SIZE ENGINE

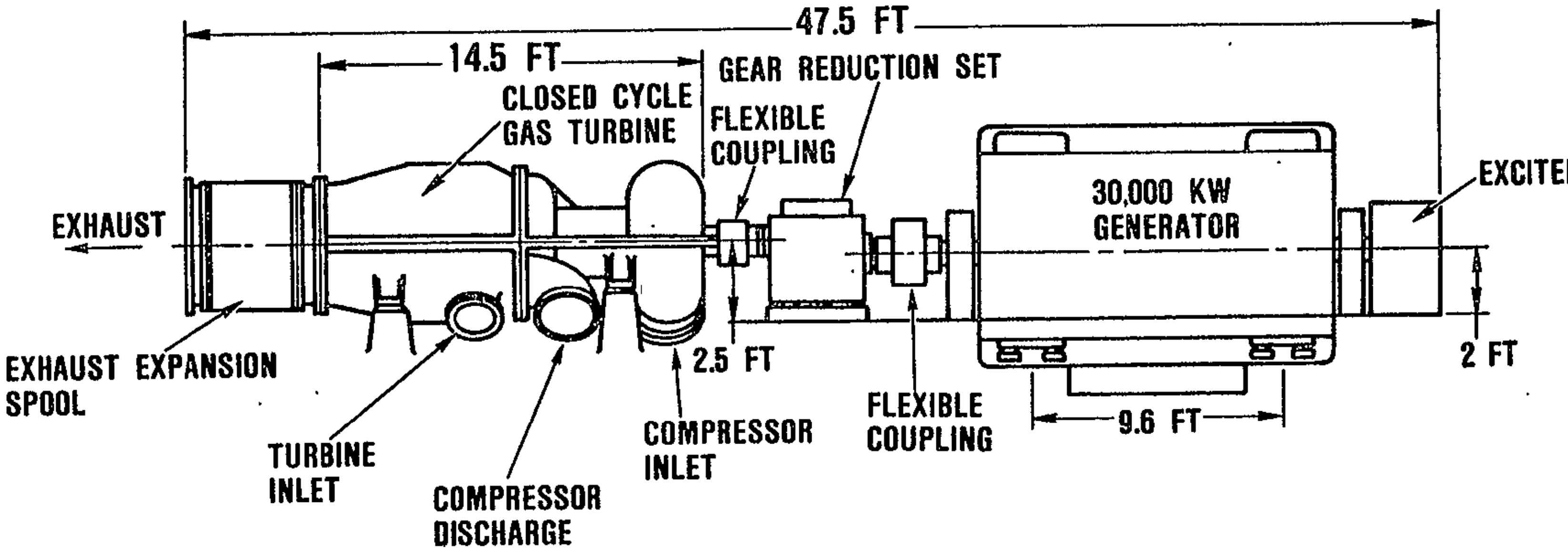

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Figure 13

GARRETT TURBINE ENGINE COMPANY
A DIVISION OF THE GARRETT CORPORATION
PHOENIX, ARIZONA

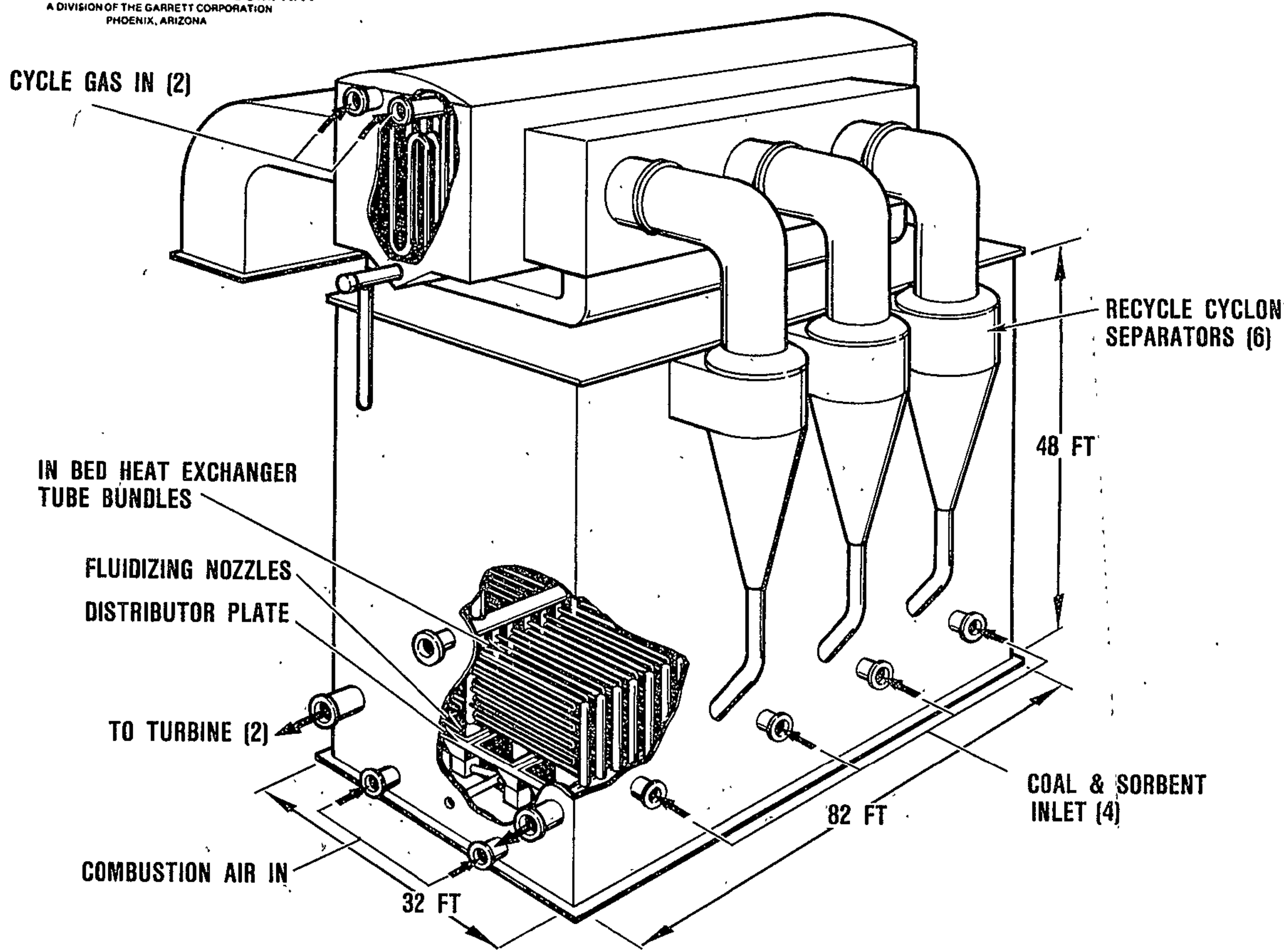

Figure 14

Figure 15 presents a breakdown of capital cost items for the AFBC/CCGT cogeneration system. Note that the capital cost does not include interest or escalation during construction. This total cost is 3 percent greater than the capital cost of essentially the same plant defined during Task I. This is excellent verification of the analytical design model summarized in Section 3.3.2 and Appendix I. This verification results in a high degree of confidence in the Task III results.

Details of the AFBC/CCGT conceptual design are included as Appendix IV.

3.4.4 Conceptual Design Comparison

Figures 16 and 17 compare the AFBC/CCGT and AFBC/Steam cogeneration system conceptual designs from the standpoints of performance, efficiency, capital cost, emissions and return-on-equity. The negative emission savings ratios (EMSR) shown in Figure 16 are caused by generating the electricity and thermal loads with coal instead of natural gas. The coal fired cogeneration plant emits more atmospheric pollutants, primarily solids, which results in negative EMSR values. Definitions of EMSR is similar to the fuel savings ratio as discussed on page 25.

The steam system offers an attractive ROE for this application. However, a return-on-equity of nearly 50 percent for the AFBC/CCGT is outstanding.

These ROE values are sensitive to changes in the equipment capital cost and cost of energy as shown in Figures 18 and 19.

AFB/CCGT COGENERATION SYSTEM CAPITAL COSTS

(M$)	COMPONENT CAPITAL	DIRECT LABOR	INDIRECT FIELD	MATERIAL	TOTALS
1.0 FURNACE	8.462	1.414	1.273	0.704	11.853
2.0 TURBINE GEN	7.274	0.058	0.052	0.290	7.674
3.0 PROC MECH EQUIP	0.916	0.402	0.362	7.507	9.187
4.0 ELECTRICAL		0.370	0.333	1.389	2.092
5.0 CIVIL + STRUCT		1.758	1.582	1.803	5.143
6.0 PROC PIPE + INST		0.770	0.693	1.377	2.840
7.0 YARDWORK + MISC		0.000	0.000	0.000	0.000
***** TOTALS *****	16.652	4.772	4.295	13.070	38.789
BALANCE OF PLANT (BOP)	(DIRECT + INDIRECT + MATERIAL)			22.137	
A/E HOME OFFICE AND FEE			(AT 15 PCT OF BOP)	3.320	
SUBTOTAL PLANT COST			(TOTAL + A/E)		42.109
CONTINGENCY	(0.137 OF TOTAL PLANT COST, CALC)			5.786	
PLANT COST (1982.0 $)	(SUBTOT PLANT COST + CONTINGENCY)				47.895
CONSTRUCTION ESCAL. AND INTEREST CHARGES					0.000
TOTAL PLANT CAPITAL COST			(1982 $)		47.895

Figure 15

SYSTEM COMPARISON

	AFB/CCGT	AFB/ST
CAPITAL COST, $M	47.895	67.135
ENERGY — FESR, PERCENT	11.75	1.14
COAL, MBTU/HR	674.9	752.4
ELECTRICITY, MW_e	24.33	24.00
EMISSIONS — EMSR, PERCENT	-37.95	-54.63
ATMOSPHERIC, TONS/DAY	6.11	10.97
SOLID, TONS/DAY	212.1	312.5
ROE, PERCENT	49.26	35.28
LAECSR, PERCENT	61.88	53.08

Figure 16

SYSTEM COMPARISON

	AFB/CCGT	AFB/ST
NET PLANT OUTPUT, MW_e	24.33	24.00
NET PLANT OUTPUT, MW_t	115.34	115.17
FUEL UTILIZATION $\left(\frac{MW_e + MW_t}{MW_{IN}}\right)$, PERCENT	70.65	63.13
AFB HEATER EFFICIENCY, PERCENT	88.37	83.67
COAL CONSUMPTION, TONS/DAY	653	728
LIMESTONE CONSUMPTION, TONS/DAY	152	279
TOTAL SOLID WASTE, TONS/DAY	212.1	312.5
CONSTRUCTION TIME, YEARS *	2.0	2.75

*DOES NOT INCLUDE ENGINEERING OR DESIGN TIME

Figure 17

AFB/CCGT COGENERATION SYSTEM

RESULTS OF SENSITIVITY ANALYSES

ELECTRIC, + 10%	ΔROE = + 4.2%
NATURAL GAS + 10%	ΔROE = + 7.0%
COAL + 10%	ΔROE = -3.0%
TOTAL CAPITAL + 10%	ΔROE = -7.3%

Figure 18

AFB/ST COGENERATION SYSTEM

RESULTS OF SENSITIVITY ANALYSES

ELECTRIC, + 10%	ΔROE = + 4.3%
NATURAL GAS + 10%	ΔROE = + 7.0%
COAL + 10%	ΔROE = -3.3%
TOTAL CAPITAL + 10%	ΔROE = -7.1%

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Figure 19

3.4.5 AFBC/CCGT Technology

The results of the Task II effort show that there are no technological barriers that will prevent the commercialization of AFBC/CCGT cogeneration systems. There are, however, technology advancements that will enhance the commercialization of AFBC/CCGT cogeneration systems. The major enhancement technology is lower cost and/or longer life heat exchanger materials. Development of these technologies by the Department of Energy is justified on the basis that the nation as a whole would benefit.

4.0 STUDY TEAM ORGANIZATION

All of the work conducted under this contract was performed by Garrett Turbine Engine Company as the prime contractor in conjunction with three subcontractors identified as follows:

- GIBBS & HILL, INC.
  393 Seventh Avenue
  New York, NY 10001

- FOSTER-WHEELER DEVELOPMENT CORP.
  12 Peach Tree Hill Road
  Livingston, NJ 07039

- ARTHUR D. LITTLE, INC.
  Acorn Park
  Cambridge, Mass. 02140

GIBBS & HILL, INC. was selected as the Architect-Engineer for the study. Their primary responsibilities included overall cogeneration system layout; siting considerations; integration of cogeneration system with the selected plant site; design/selection, and cost analysis of the BOP equipment for the closed cycle gas turbine cogeneration system; design/selection and cost analysis for the complete steam turbine system. Gibbs & Hill conducted a review and critique of each of the overall cogeneration plant designs.

FOSTER-WHEELER DEVELOPMENT CORP. was selected to perform the engineering, design, and cost estimating work on the fluidized-bed boiler for the steam turbine system. Their sphere of responsibility included the support equipment for the fluidized bed boiler systems. Foster-wheeler also performed a design and cost review and critique for the Garrett designed fluidized bed air heater for the closed cycle gas turbine systems.

ARTHUR D. LITTLE, INC. was selected to perform the commercialization and market analysis for coal fired AFB gas turbine and AFB steam turbine cogeneration systems in the ten DOE regions of the continental USA.

Figure 20 summarizes the responsibility of Garrett and the three subcontractors.

OVERALL PROGRAM ORGANIZATION AND RESPONSIBILITIES

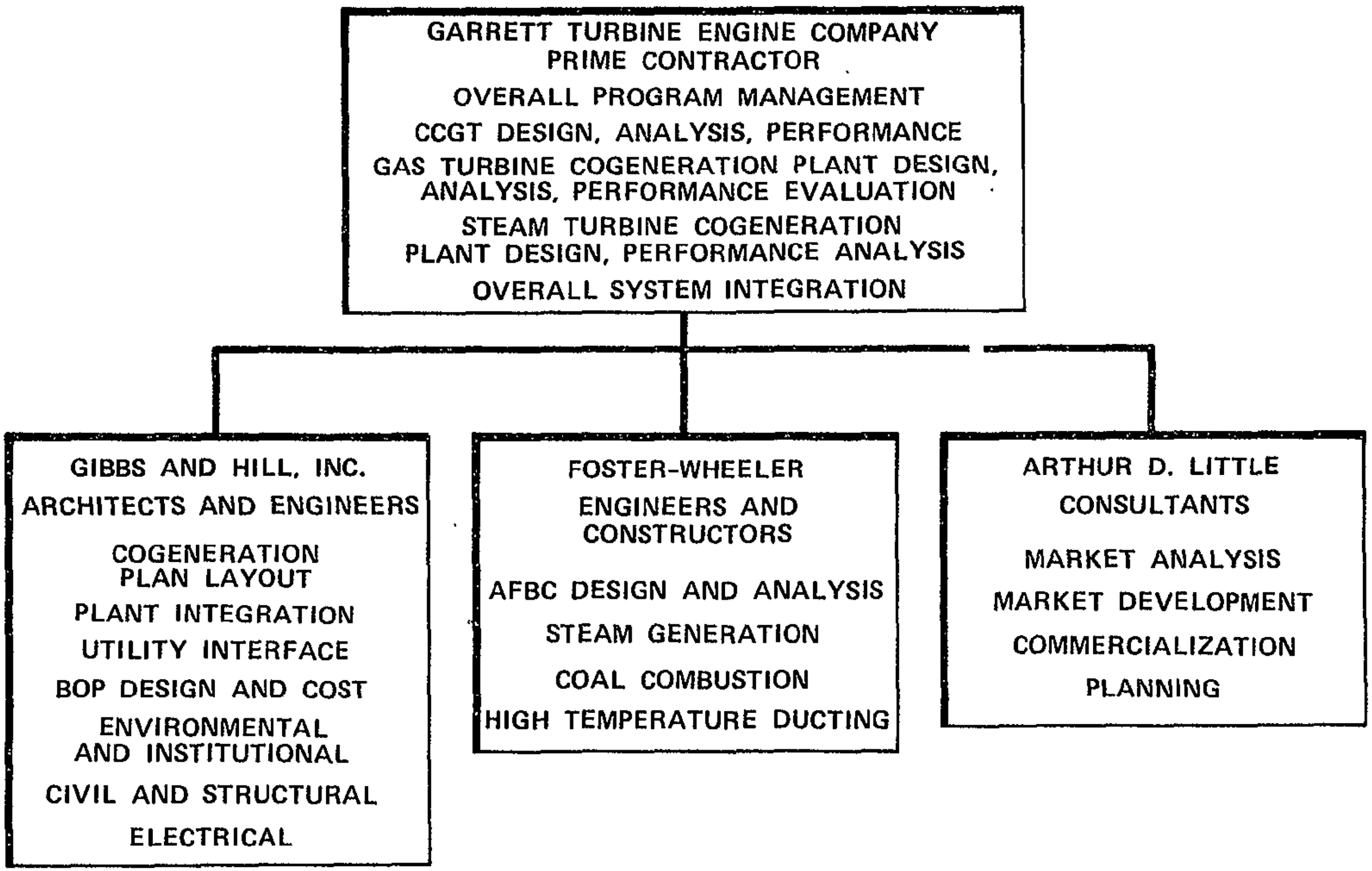

Figure 20

APPENDIX I

TASK I - SITE SCREENING

FINAL REPORT

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(43 pages)

APPENDIX I

TASK 1 - SITE SCREENING

FINAL REPORT

1. INTRODUCTION

This appendix presents the final results of the Task 1 - Cogeneration Specific Site Optimization portion of NASA-Lewis Research Center Contract DEN 3-215.

The Task 1 study consisted of optimizing the design of closed cycle gas turbine and steam turbine cogeneration systems for three widely varying specific industrial sites. The results are compared to the non-cogeneration or present method of satisfying plant site energy requirements. One of the three sites was recommended for continued study during Task II of the program.

2. SITE DEFINITION AND RECOMMENDATION

The significant siting, operational, and economic data for the three sites selected for the initial study are summarized in Tables 1, 2, and 3. The Ethyl Corporation site is unique in two respects:

(a) Two types of thermal and electrical loads are possible for the Ethyl site, steam and Dowtherm. The cogneration system could address only the steam loads or both the steam and the Dowtherm heating loads. Both options were considered during the study with the Dowtherm heating case being selected since it exhibits the maximum benefits as a result of cogeneration compared to the non-cogeneration (currently existing) approach.

Table 1.

SITE DATA — GENERAL

NAME:	REICHHOLD CHEMICALS, INC (RCI)	ETHYL CORPORATION (ETH)	ARCHER-DANIELS MIDLAND (ADM)
LOCATION:	ST. HELENS, OREGON	PASADENA, TEXAS	DECATUR, ILL
SIC(S)	2873	2865,2869	2046,2869
PRODUCTS:	AMMONIA, UREA, NITRIC ACID	ZEOLITE, LINEAR ALCOHOL OLEFINS, ETC	CORN AND SOYA FOOD PRODUCTS, FUEL GRADE ALCOHOL
CURRENT FUEL:	NATURAL GAS	NATURAL GAS	NATURAL GAS
UTILITY:	PORTLAND GENERAL ELECTRIC	HOUSTON LIGHT AND POWER	ILLINOIS POWER
UTILITY FUELS:	79% HYDROPOWER 20% NUCLEAR *1% COAL	*85% NATURAL GAS 15% COAL	*70% COAL 30% NUCLEAR

*INDICATES FUEL THAT THE COGENERATED ELECTRICAL POWER WOULD REPLACE

Table 2.

SITE DATA — LOADS

NAME:	REICHHOLD	ETHYL	ADM
ELECTRICAL LOAD:	10.5 MW AVG 12.0 MW PEAK	24.0 MW AVG 29.0 MW PEAK	63.1 MW AVG 87.5 MW PEAK
THERMAL LOAD:	22,000 LB/HR AVG (6.5 MW) 26,740 LB/HR PEAK (7.9 MW) AT 190 PSIA SATURATED	190,000 LB/HR AVG (65.35 MW) 310,000 LB/HR PEAK (103.36 MW) AT 240 PSIA SATURATED 170,000,000 BTU/HR DOWTHERM (49.8 MW)	1,540,000 LB/HR AVG (469.18 MW) 1,737,850 LB/HR PEAK (529.35 MW) AT 190 PSIA SATURATED
LOAD VARIATION:	FLAT ELECTRICAL LOADS. CYCLIC STEAM LOADS DUE TO TOPPING WASTE HEAT RECOVERY SYSTEM. PLANT SHUTDOWN ONCE PER YEAR FOR REPAIRS. 8760 HR/YR OPERATION	FLAT ELECTRICAL LOADS. HIGHLY CYCLIC STEAM. FLAT DOWTHERM LOADS. 8760 HR/YR OPERATION	FLAT LOADS. 8760 HR/YR OPERATION
POWER/HEAT RATIO:	1.62	0.37 WITHOUT DOWTHERM 0.21 WITH DOWTHERM	0.13
RELIABILITY:	——	MUST MAINTAIN 100,000 LB/HR MINIMUM STEAM FLOW	

Table 3.

SITE DATA — ECONOMICS
(1985 PRICES EXPRESSED IN 1981 DOLLARS)

NAME:	REICHHOLD CHEMICALS	ETHYL CORPORATION	ADM	COMMON CASE
FUEL PRICES				
NATURAL GAS	$4.04/MBTU	$5.80/MBTU	$3.55/MBTU	$5.24/MBTU
COAL	$2.37/MBTU	$2.04/MBTU	$1.51/MBTU	$2.29/MBTU
ELECTRICITY	3.47¢/KWH	5.24¢/KWH	3.66¢/KWH	4.60¢/KWH
STAND-BY POWER	$7.03/KW/MONTH	0	$6.97/KW/MONTH	$4.50/KW/MONTH
BUY-BACK PRICE				
ELECTRICITY	3.56¢/KWH	5.97¢/KWH	2.2¢/KWH	2.8¢/KWH
ESCALATION				
NATURAL GAS	3%	3%	3%	3%
COAL	1%	1%	1%	1%
ELECTRICITY	1.5%	7%	1.5%	1.5%
STAND-BY	1.5%	0	1.5%	1.5%
COST OF MONEY (ABOVE INFLATION)	7%	6%	2%	7%
PROJECT LIFE	30 YEARS	30 YEARS	30 YEARS	30 YEARS

(b) The Ethyl site exhibits unique economic conditions. The cogeneration system is expected to sell all of its electrical power to the utility (Houston Light and Power), and the site is expected to continuing buying all of the electrical power needed. This simultaneous import/export of electrical power results in no stand-by charges being charged by the utility. Other significant differences include the high electrical escalation (7 percent above inflation) which is due to the fact that the utility is predominantly natural gas based and the utility is currently highly capital intensive.

A review of early study results indicated that the site specific fuel and energy costs for the Reichhold site impose an adverse effect on the cogeneration plant for that site. The "common case" economics, specified by NASA as being representative of the industrial sector and shown in Table 3, were therefore used during the optimization study for the Reichhold site.

Figures 1, 2, and 3 show some details of the physical sites. Location of the cogeneration system is shown in Figures 1 and 2. The cogeneration system would be located in the upper left hand quadrant of the photograph of the ADM site.

The site recommended for continuation into Task II is the Ethyl site. The rationale by which this recommendation was selected is presented in Section 6 of this appendix.

REICHHOLD CHEMICALS — ST. HELENS PLANT SITE

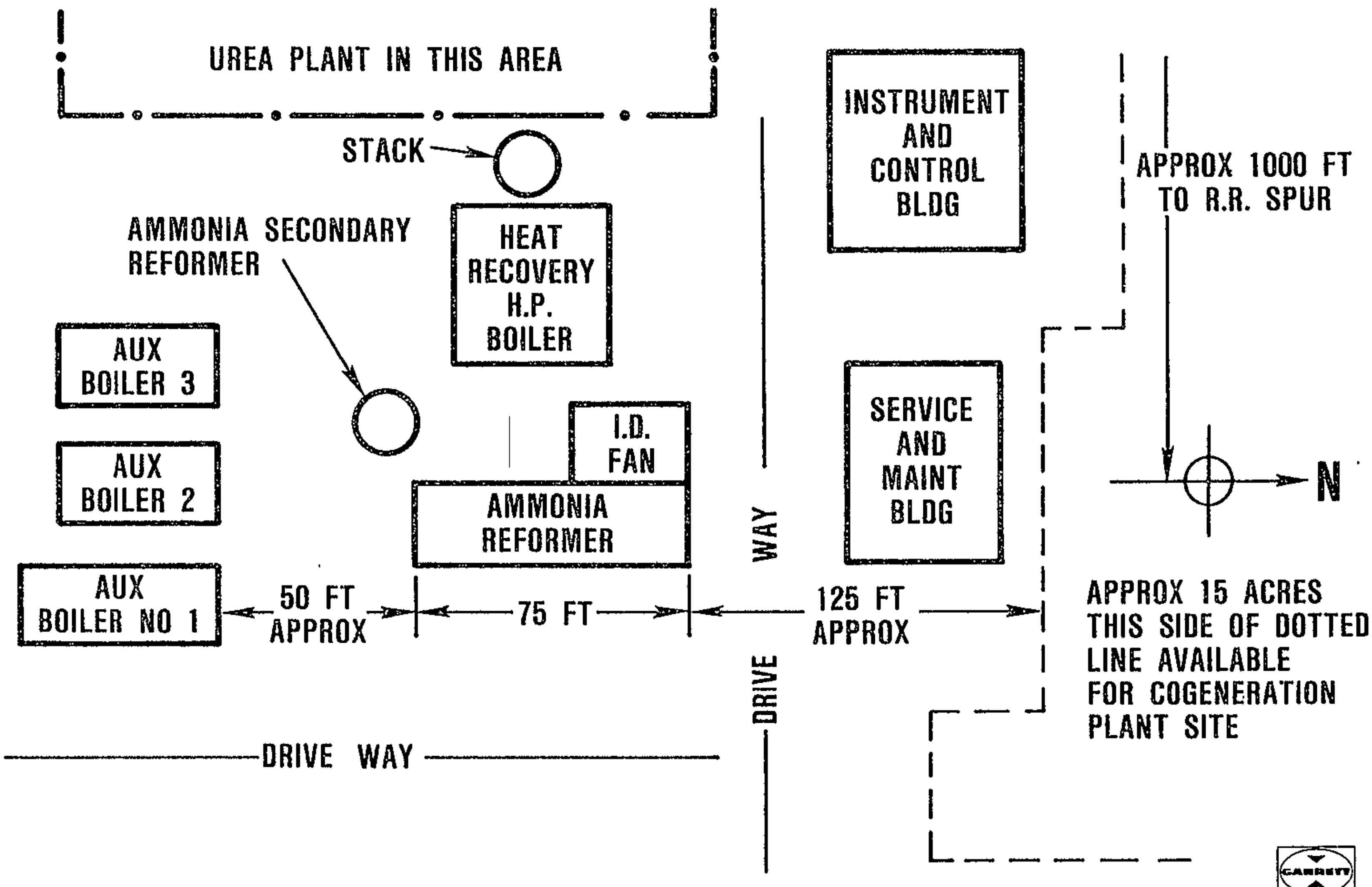

Figure 1.

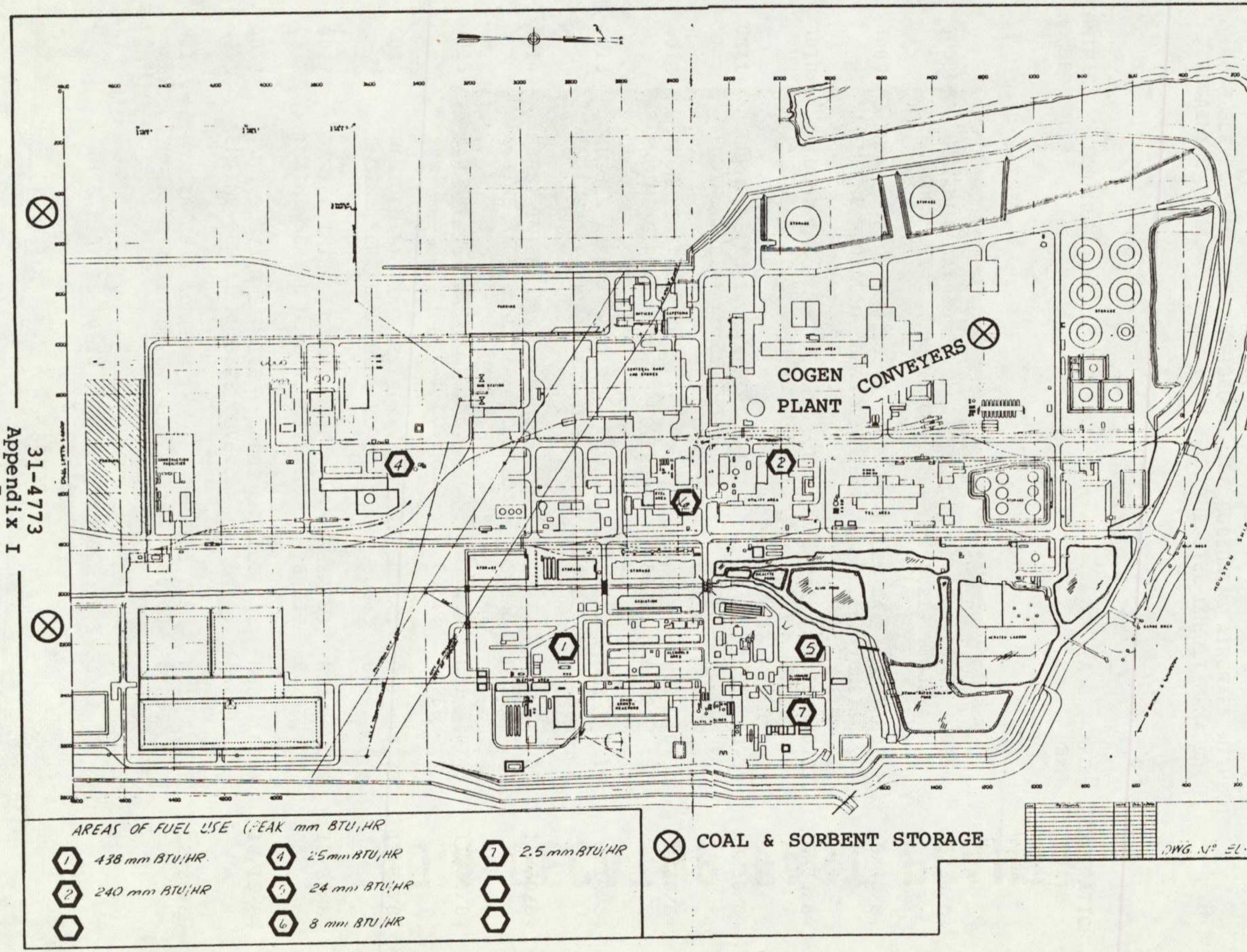
COGEN
PLANT
CONVEYERS
HOUSTON SHIP CHANNEL
AREAS OF FUEL USE (PEAK mm BTU/HR
1 438 mm BTU/HR
2 240 mm BTU/HR
4 2.5 mm BTU/HR
5 24 mm BTU/HR
6 8 mm BTU/HR
7 2.5 mm BTU/HR
COAL & SORBENT STORAGE

Figure 2.

MP-79165

ADM DECATUR EAST PLANT

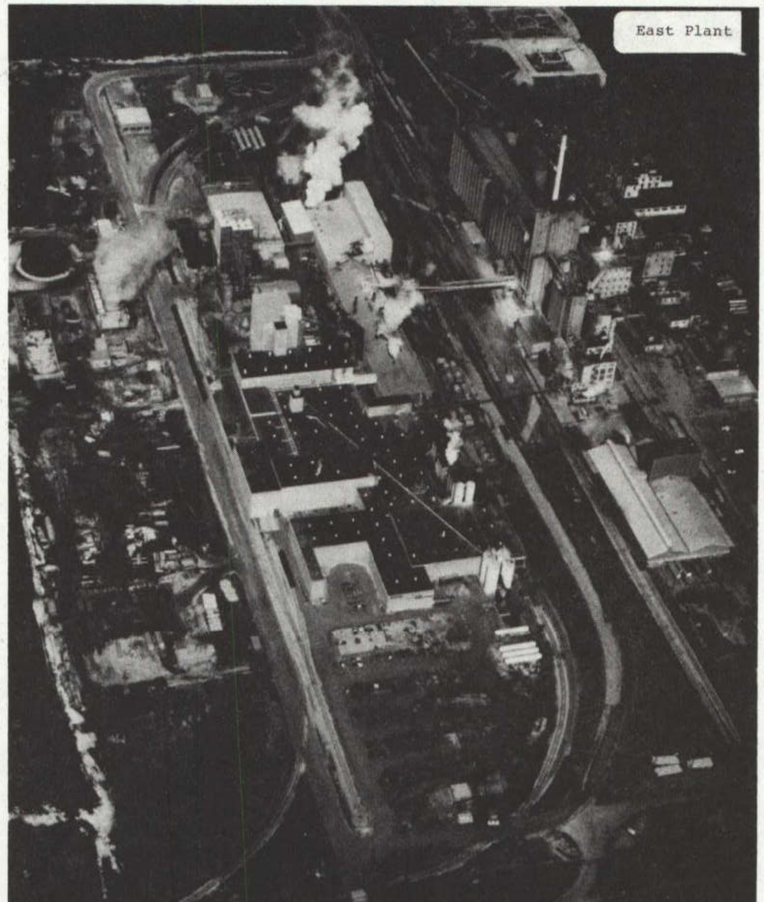

Figure 3.

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Table 4.

ANALYTICAL APPROACH

CLOSED CYCLE GAS TURBINE

- CCGT COGEN SYSTEM DESIGNED WITH AFBC/GT, DESIGN POINT COMPUTER MODEL THAT:
  - DESIGNS ALL MAJOR COMPONENTS
  - COSTS ALL MAJOR COMPONENTS
  - SCALES BOP ITEMS
  - EVALUATES RETURN ON EQUITY VERSUS SEPARATE-GEN APPROACH
  - 1500 SYSTEMS EVALUATED PER SITE AND LOAD SET
- CHECK SELECTED DESIGN COSTS WITH:
  - AFB MANUFACTURER (FOSTER-WHEELER)
  - BOP AND CONSTRUCTION (GIBBS AND HILL)

STEAM TURBINE

- GIBBS AND HILL DESIGNED SEVERAL STEAM TURBINE SYSTEMS FOR EACH SET OF SITE LOADS
- AFB COSTS BASED ON FOSTER-WHEELER DESIGNS AND COSTS
- REMAINING MAJOR COMPONENTS BASED ON RECENT QUOTES FROM SUPPLIERS
- ROE EVALUATED BY SAME PROGRAM AS USED FOR AFBC/CCGT DESIGNS

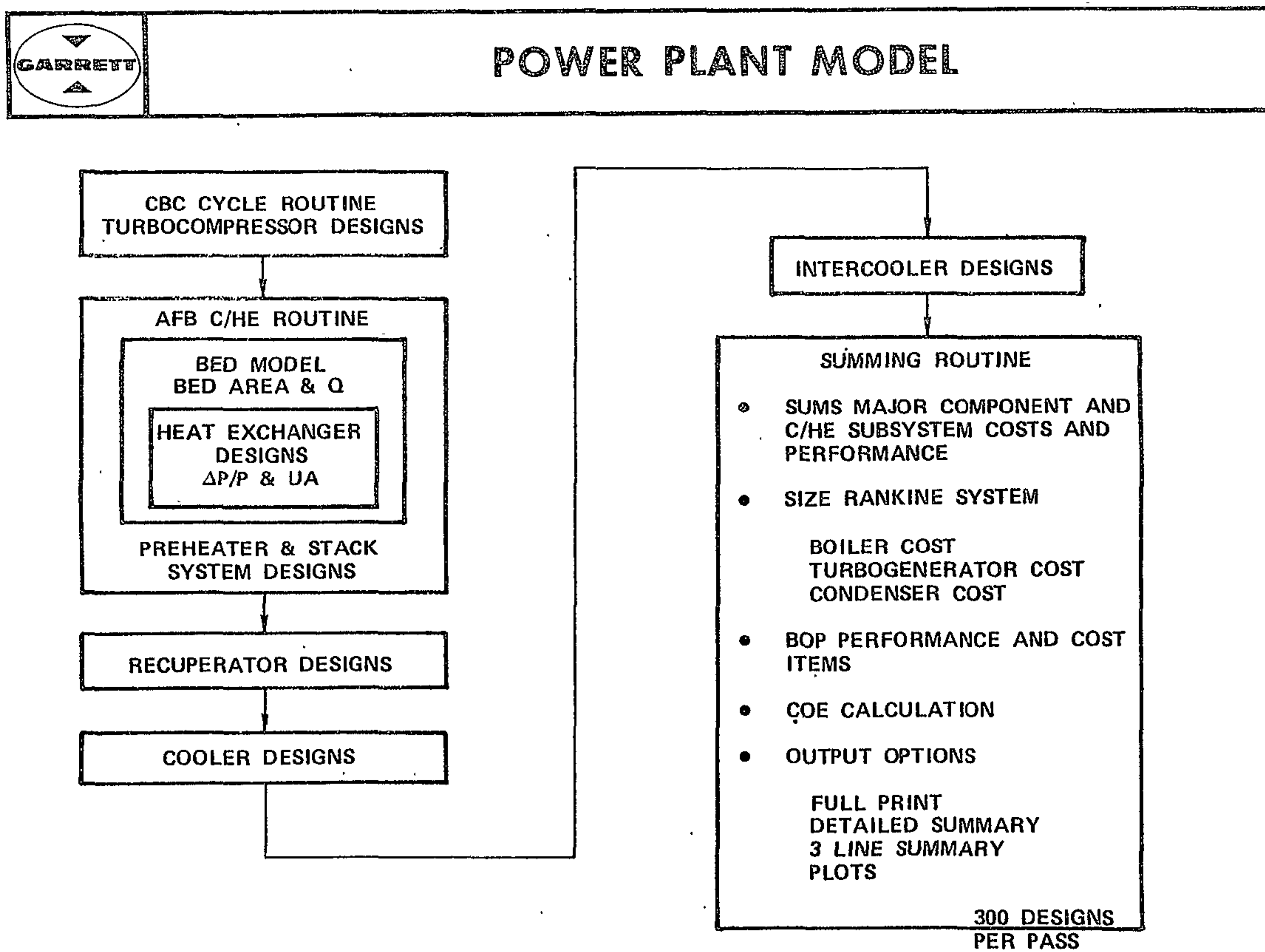

GARRETT
POWER PLANT MODEL
CBC CYCLE ROUTINE
TURBOCOMPRESSOR DESIGNS
AFB C/HE ROUTINE
BED MODEL
BED AREA & Q
HEAT EXCHANGER DESIGNS
ΔP/P & UA
PREHEATER & STACK SYSTEM DESIGNS
RECUPERATOR DESIGNS
COOLER DESIGNS
INTERCOOLER DESIGNS
SUMMING ROUTINE
SUMS MAJOR COMPONENT AND C/HE SUBSYSTEM COSTS AND PERFORMANCE
SIZE RANKINE SYSTEM
BOILER COST
TURBOGENERATOR COST
CONDENSER COST
BOP PERFORMANCE AND COST ITEMS
COE CALCULATION
OUTPUT OPTIONS
FULL PRINT
DETAILED SUMMARY
3 LINE SUMMARY
PLOTS
300 DESIGNS PER PASS

Figure 4.

Table 5.

ANALYTICAL APPROACH
(AFBC/CCGT SYSTEM ONLY)

1. ESTABLISH DETAILED DESIGN PARAMETERS FOR:
   - GAS TURBINE SYSTEM
     - SHAFT SPEED, NO. COMP STAGES, NO. TURB STAGES
     - AERODYNAMIC WORK COEFFICIENTS, CLEARANCES
     - HEAT EXCHANGER (COOLER, RECUPERATOR) CORE GEOMETRY
     - ETC
   - ATMOSPHERIC FLUIDIZED BED SYSTEM
     - BED HEAT EXCHANGER CORE GEOMETRY
     - STACK HEAT EXCHANGER CORE GEOMETRY
     - SUPERFICIAL VELOCITY, PARTICLE DIAMETER
     - PRE-HEATER CONFIGURATION
     - STACK-GAS CLEAN-UP SYSTEM CONFIGURATION
     - ETC
   - TOTAL OF 1120 DESIGN PARAMETERS REQUIRED

Table 6.

ANALYTICAL APPROACH
(AFBC/CCGT SYSTEM ONLY)

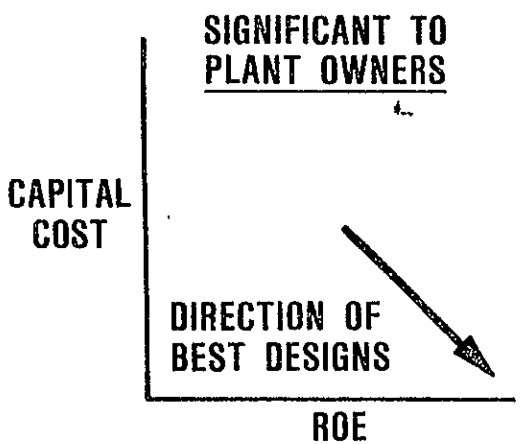
2. ESTABLISH RANGE OF THERMODYNAMIC DESIGN PARAMETERS

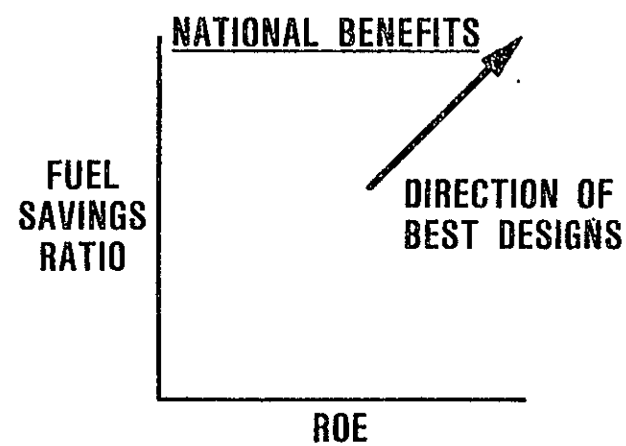
• COMPRESSOR INLET TEMPERATURE, T_1	100°F → T_{SAT}
• COMPRESSOR PRESSURE RATIO, Pr $Pr \leq 3.0$ IF $T_1 \geq 250°F$	2.4 → 3.4
• RECUPERATOR EFFECTIVENESS, E_R	0.0 → 0.925
• WASTE HEAT BOILER EFFECTIVENESS, E_B	0.50 → 0.90
OR	
WASTE HEAT BOILER PINCH TEMPERATURE, ΔT_P	50°F MIN
• TURBINE INLET TEMPERATURE, T_6	1450°F → 1550°F
• NET ELECTRICAL OUTPUT POWER, MW_E	MATCH SITE LOAD $\pm\Delta$

Table 7.

ANALYTICAL APPROACH
(AFBC/CCGT SYSTEM ONLY)

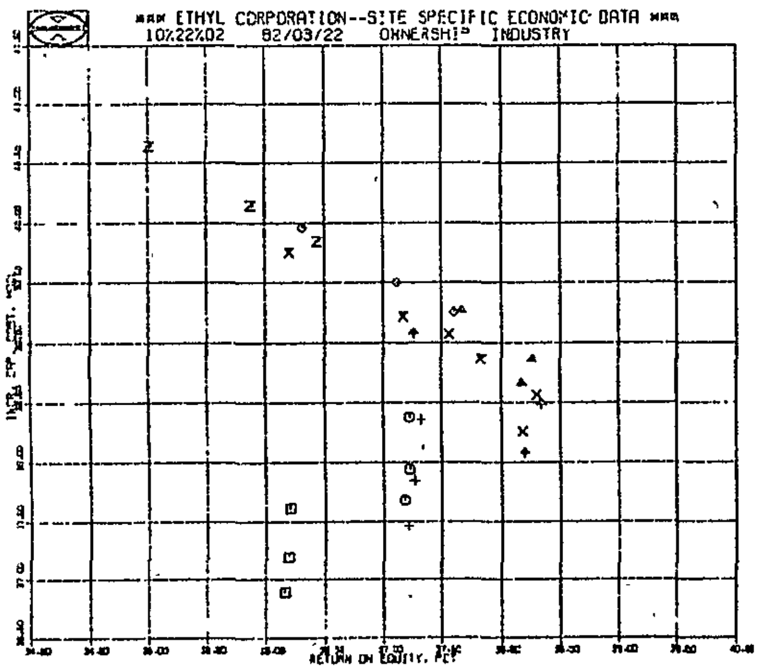
3. ESTABLISH COGENERATION SYSTEM FIGURES-OF-MERIT
   - RETURN-ON-EQUITY, ROE
   - CAPITAL COST
   - FUEL SAVINGS RATIO





- LOWER CAPITAL COST SYSTEM BREAKS TIES IN ROE
- HIGHER FUEL SAVINGS RATIO BREAKS TIES IN ROE AND CAPITAL COST

EXAMPLE PLOTS



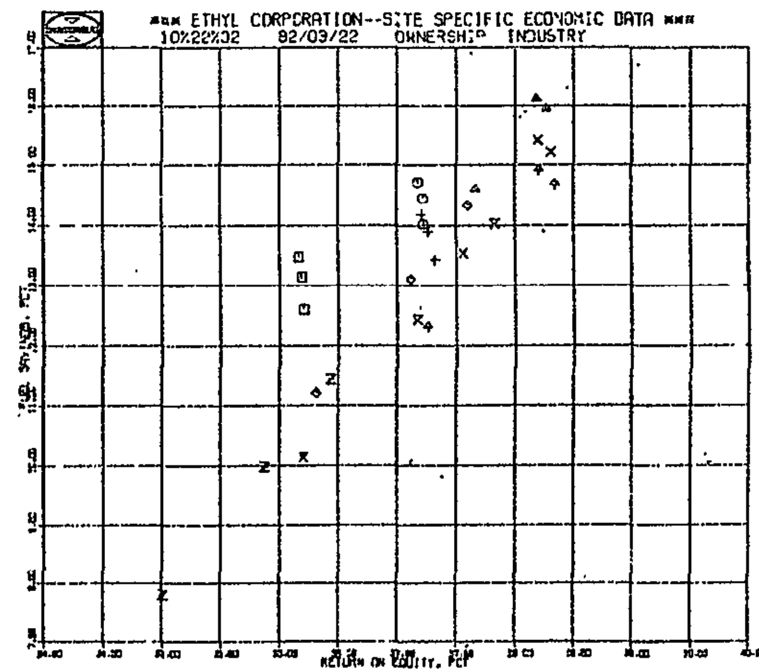


Figure 5.

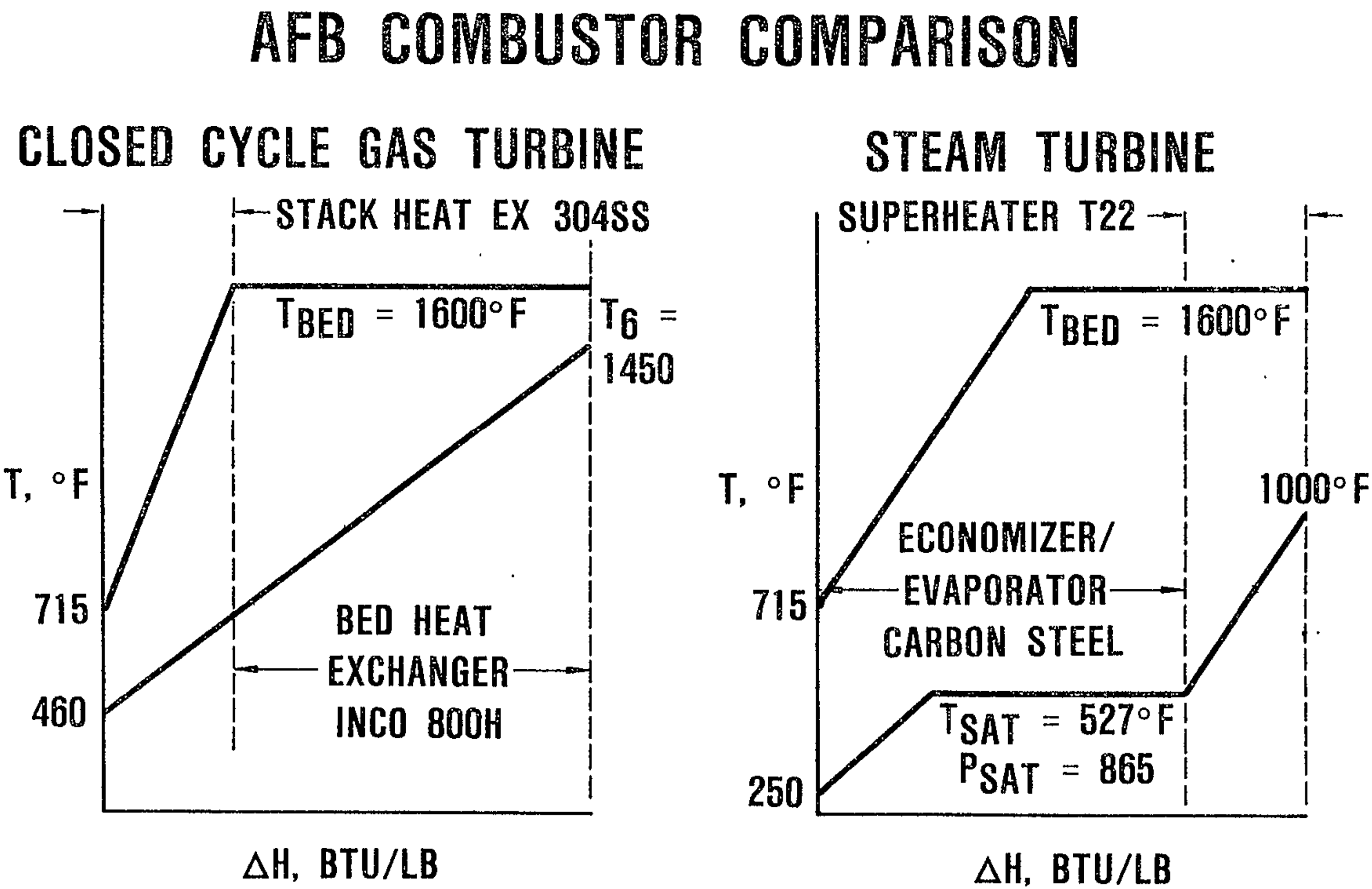

AFB COMBUSTOR COMPARISON
CLOSED CYCLE GAS TURBINE
STACK HEAT EX 304SS
T_{BED} = 1600°F
T_6 = 1450
T, °F
715
460
BED HEAT EXCHANGER INCO 800H
ΔH, BTU/LB
STEAM TURBINE
SUPERHEATER T22
T_{BED} = 1600°F
1000°F
T, °F
715
250
ECONOMIZER/ EVAPORATOR CARBON STEEL
T_{SAT} = 527°F
P_{SAT} = 865
ΔH, BTU/LB

Figure 6.

4. OPTIMIZATION STUDY CYCLE SPECIFICATIONS

Table 8 summarizes the major cycle design parameters selected for the closed gas turbine cogeneration system for each of the three sites. Table 9 summarizes the equivalent parameters selected for the steam turbine system for each of the three sites.

Relatively early in the design study, it became apparent that the most economical systems, those with the highest ROEs, were those that simultaneously matched both electrical and thermal requirements.

Accordingly all of the cogeneration systems match the electrical and thermal loads for the site except for the AFBC/steam cogeneration system for the Ethyl site. The Ethyl steam cogeneration system is a net exporter of electrical power which is the result of using boiler exit steam to satisfy the Dowtherm heating load between Dowtherm temperatures of 550°F and 680°F. An alternative for this steam cogeneration configuration would be to match the steam and electric loads and provide the Dowtherm heating directly from the AFBC instead of with use of high pressure steam. It should be noted that this alternative approach was used for the steam cogeneration systems designed during Task II.

Figures 7 through 12 show the heat balance schematic for each site and cogeneration system. The percentage value for load (or loss) is based on the thermal power input of the coal defined as 100 percent. Waste heat rejected to the atmosphere is a penalty on any cogeneration system. Note that the waste heat rejected to the atmosphere is significantly larger for the Ethyl steam system than the Ethyl closed cycle gas turbine system. Note also that neither cogeneration system rejects waste heat to the atmosphere for the ADM site (Figures 11 and 12).

The key to a successful cogeneration system optimization is directly related to the management of the power system waste heat. For the closed cycle gas turbine, the turbine waste heat can be recovered by the steam boiler in conjunction with a recuperative heat exchanger. This recuperator transfers a portion of the turbine discharge waste heat to the compressor discharge gas, thereby reducing the amount of thermal energy required from the heat source. A high recuperator effectiveness means that a major percentage of the turbine exhaust waste heat is recovered by the recuperator which reduces the amount of thermal energy that can be recovered by the steam boiler. The electrical power to steam (heat) ratio can, therefore, be adjusted by varying the recuperator effectiveness. That is, high power-to-heat ratio loads indicate a high effectiveness recuperator whereas low power-to-heat ratio loads suggest elimination of the recuperator entirely.

The high power-to-heat ratio of the Reichhold site lead to the selection of a relatively high recuperator effectiveness whereas the Ethyl and ADM loads resulted in the elimination of the recuperator as shown in Table 8.

Table 8.

SITE RESULTS
(AFBC/CCGT SYSTEM ONLY)

RCI

T_1 = 150°F   Pr = 3.2 E_R = 0.875 ΔT_P = 50°F T_6 = 1450°F
P_2 = 400 PSIA

MATCH ELECTRICAL AND STEAM LOADS

ETH W/ DOWTHERM

T_1 = 175°F   Pr = 3.2 E_R = 0.0 ΔT_P = 75°F T_6 = 1450°F
P_2 = 600 PSIA

MATCH ELECTRICAL, STEAM AND DOWTHERM LOADS

ADM

T_1 = 313°F   Pr = 3.0 E_R = 0.0 ΔT_P = 75°F T_6 = 1450°F
NO WASTE P_2 = 600 PSIA
HEAT COOLER

MATCH ELECTRICAL AND STEAM LOADS

Table 9.

SITE RESULTS
(AFBC/STEAM TURBINE ONLY)

RCI	P_{SAT} = 1465 PSIA T_{SAT} = 593°F T_{MAX} = 1000°F MATCH ELECTRICAL AND STEAM LOADS
ETH W/ DOWTHERM	P_{SAT} = 865 PSIA T_{SAT} = 527°F T_{MAX} = 1000°F MATCH THERMAL LOADS NET EXPORT 28 MW_e ELECTRICAL POWER
ADM	P_{SAT} = 950 PSIA T_{SAT} = 540°F T_{MAX} = 780°F MATCH ELECTRICAL AND STEAM LOADS

REICHHOLD GAS TURBINE/AFB ENERGY BALANCE

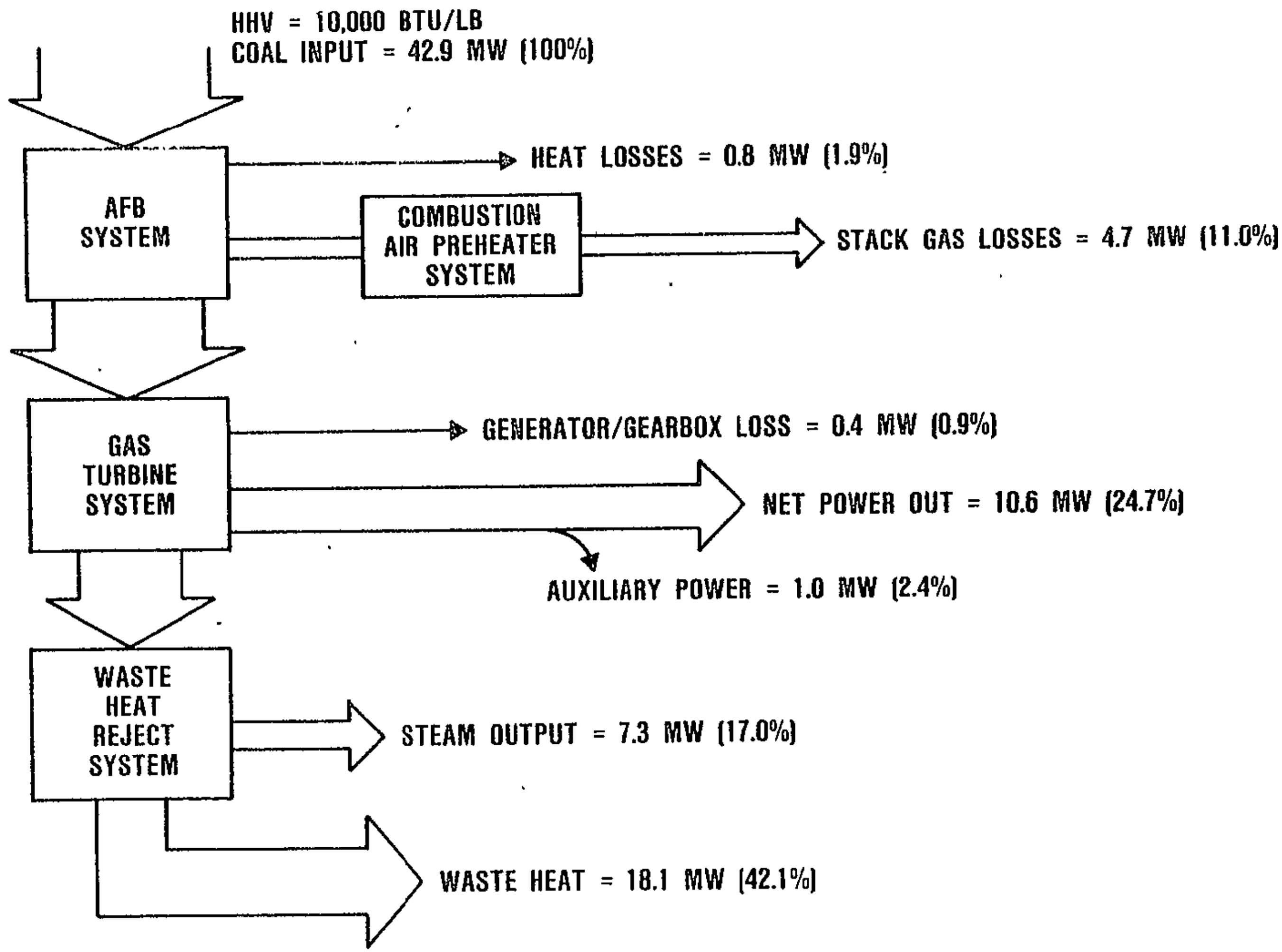


Figure 7.

REICHHOLD STEAM TURBINE/AFB ENERGY BALANCE

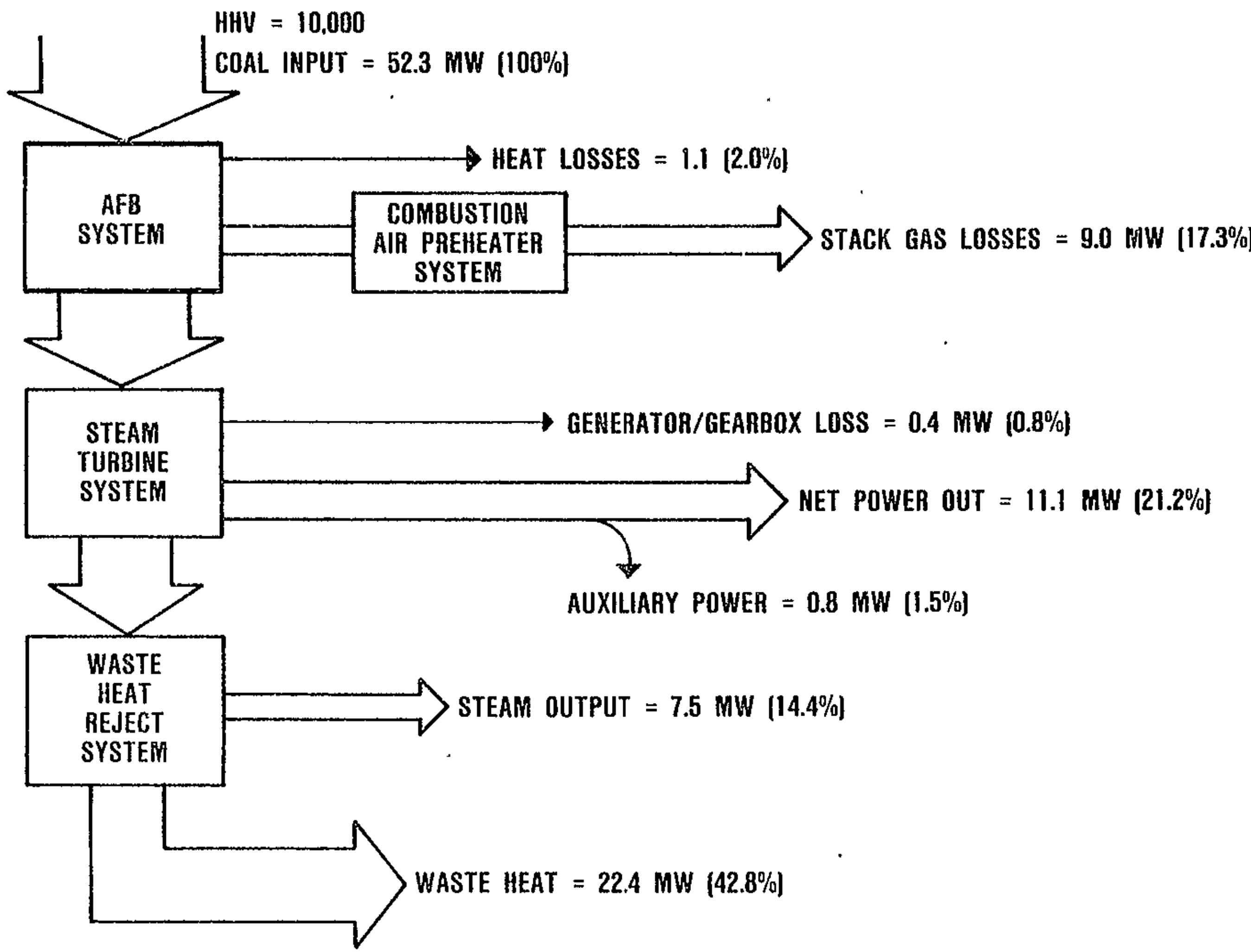


Figure 8.

ETH GAS TURBINE/AFB ENERGY BALANCE

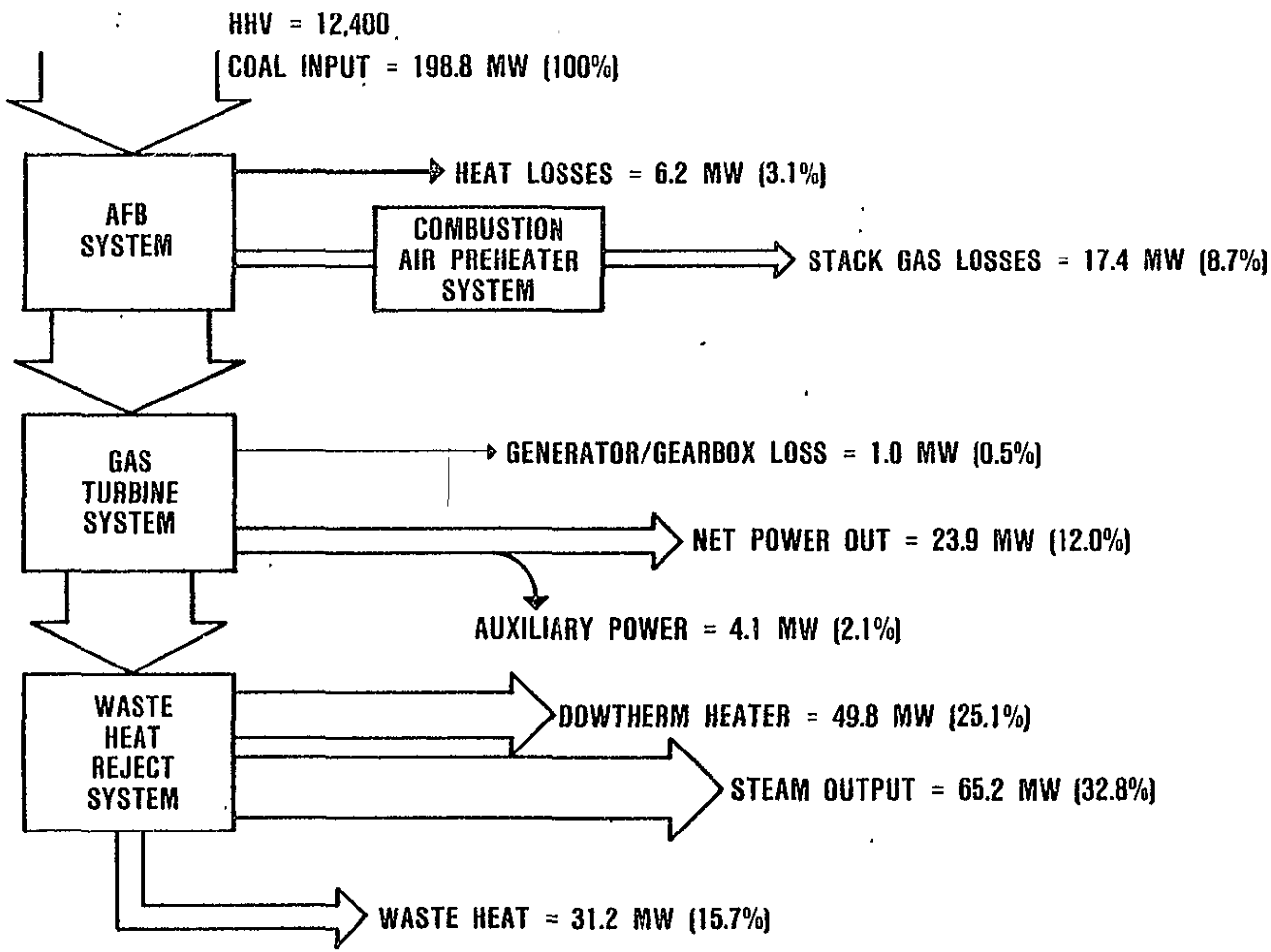


Figure 9.

ETH STEAM TURBINE/AFB ENERGY BALANCE

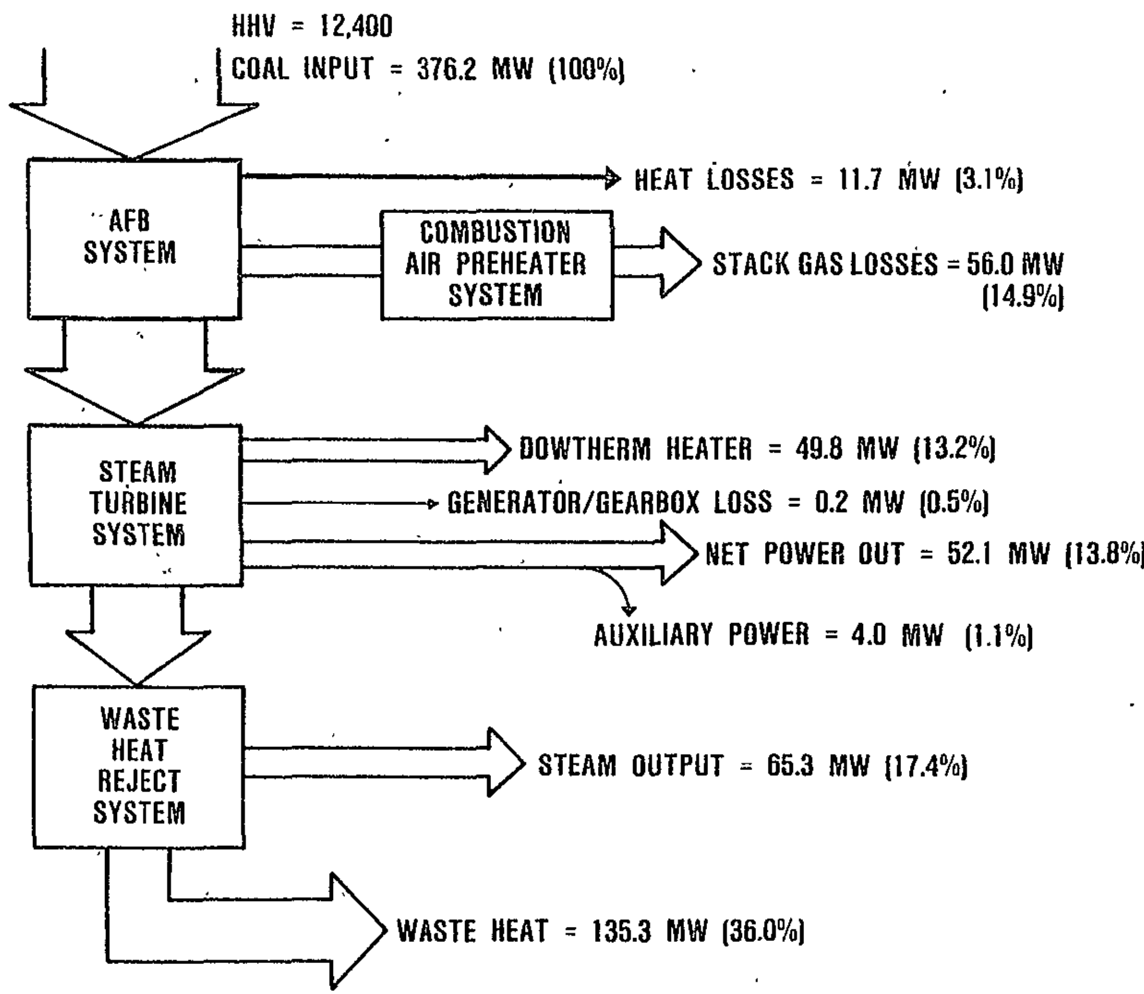


Figure 10.

ADM GAS TURBINE/AFB ENERGY BALANCE

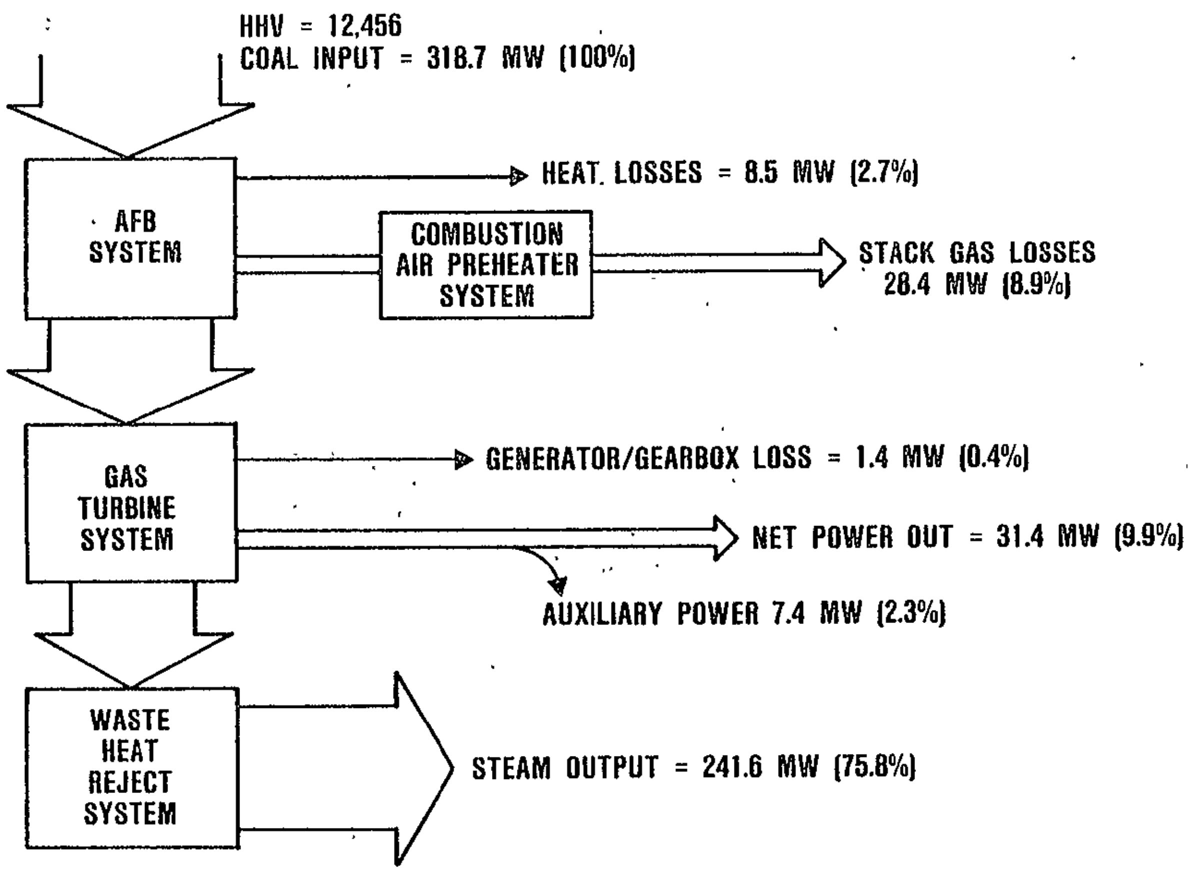


Figure 11.

ADM STEAM TURBINE/AFB ENERGY BALANCE

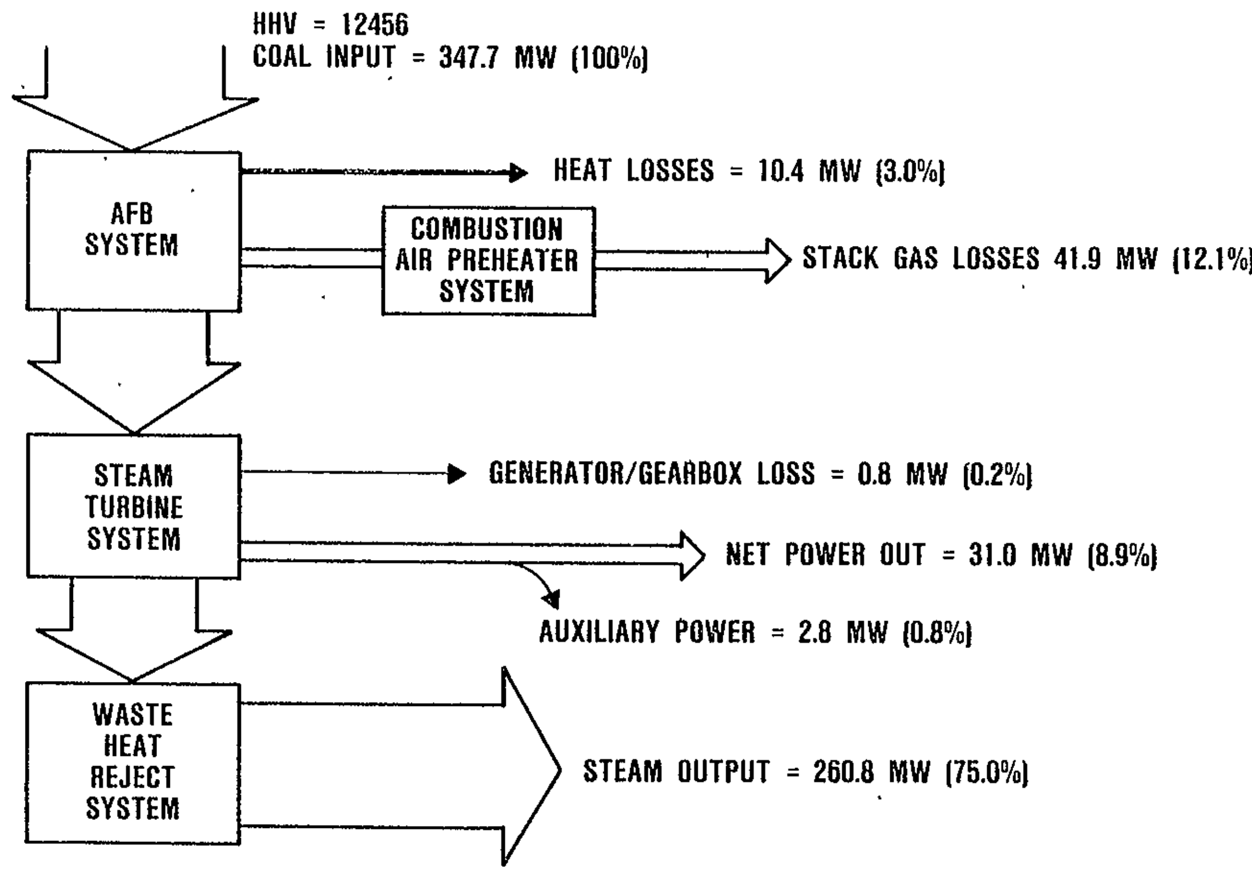


Figure 12.

5. COGENERATION SYSTEM EVALUATIONS

Figure 13 presents the most significant comparative evaluation of the steam and closed cycle gas turbine cogeneration systems for the three sites defined in Section 2. In each case, the AFBC/CCGT cogeneration system is shown to require less capital to procure and exhibits a significantly higher return on equity. The high ROE for the ETH-G system forms the major reason that the Ethyl site was selected for recommendation (by Garrett) for continued study during Task II.

Figure 14 shows a comparison between the non-cogeneration system and the cogeneration system fuel usage during an operating period of 8760 hours. The difference between the two non-cogeneration systems for the Ethyl site is due to the fuel needed for the net export of 28 MW_e from the steam system (see Section 5). Note that the utility fuel replaced is coal for the Reichhold and ADM sites versus natural gas for the Ethyl site.

Figure 15 shows the total emissions as a result of providing the electrical and thermal loads by each of the three methods studied, i.e.: gas turbine cogeneration, steam turbine cogeneration, and non-cogeneration. Total emissions are reduced with use of either cogeneration system for those sites that incorporate some amount of coal based utility that would be off-set by the cogeneration system. The cogeneration systems exhibit higher atmospheric emissions than the non-cogeneration system for the Ethyl site due to the fact that the Ethyl site is serviced by a natural gas based utility.

NO_x is frequently the most significant atmospheric pollutant. Figure 16 shows the impact on NO_x of the cogeneration systems. Note that in each case the cogeneration system produces substantially less NO_x than the non-cogeneration case.

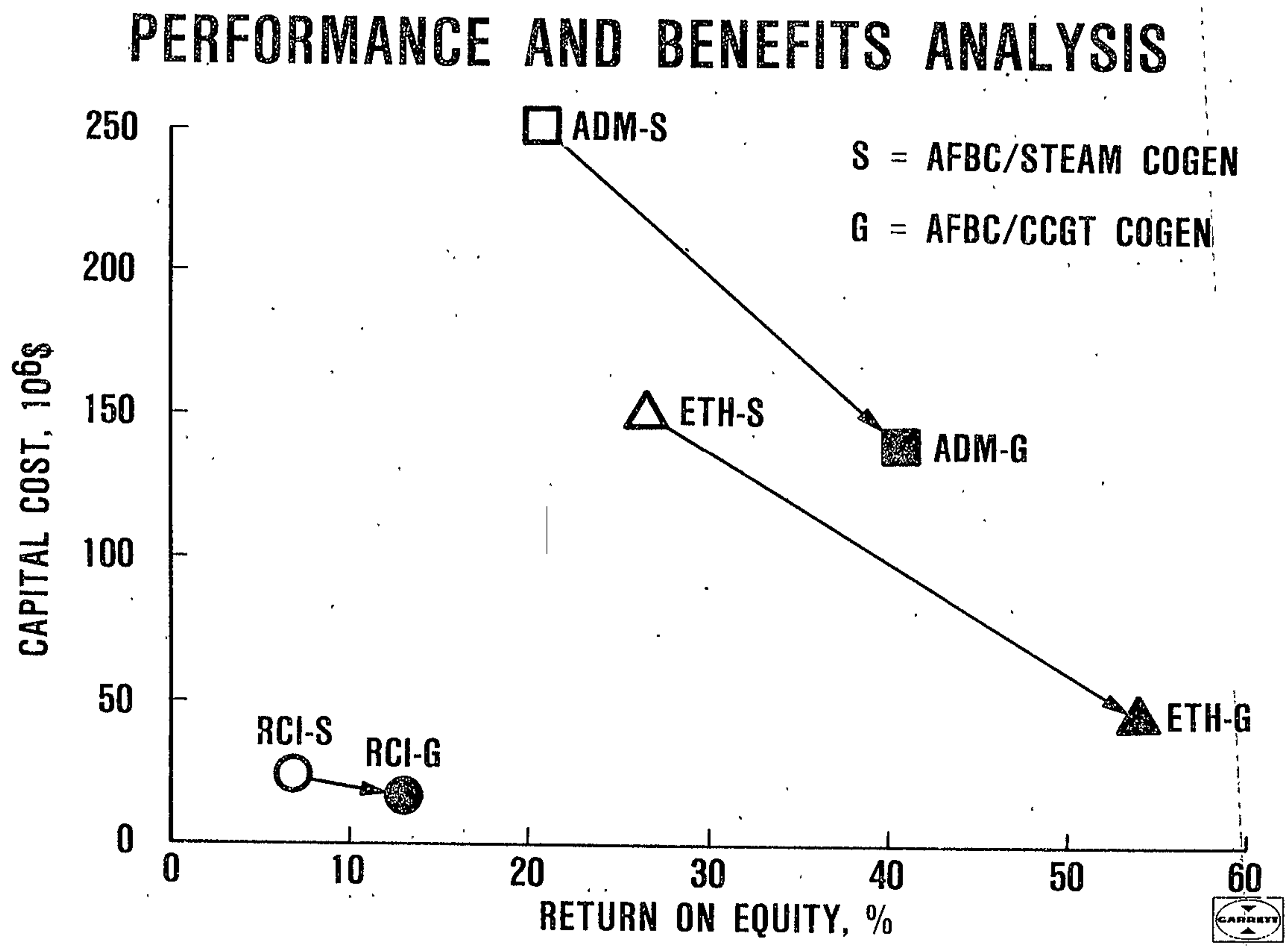

PERFORMANCE AND BENEFITS ANALYSIS
S = AFBC/STEAM COGEN
G = AFBC/CCGT COGEN
ADM-S
ADM-G
ETH-S
ETH-G
RCI-S
RCI-G
CAPITAL COST, $10^6$$
RETURN ON EQUITY, %
0
50
100
150
200
250
0
10
20
30
40
50
60

Figure 13.

PERFORMANCE AND BENEFITS ANALYSIS

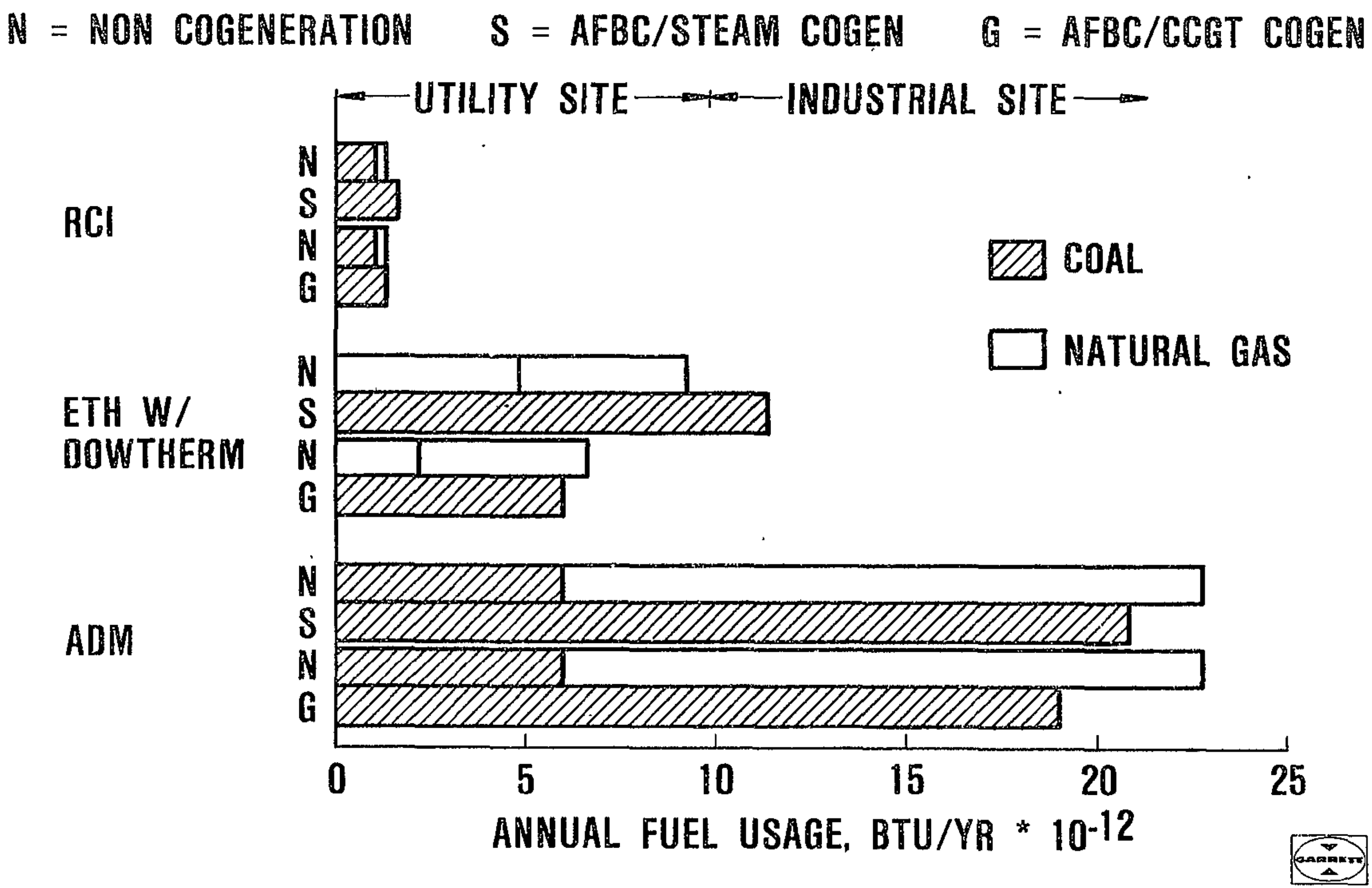


Figure 14.

PERFORMANCE AND BENEFITS ANALYSIS

N = NON COGENERATION S = AFBC/STEAM COGEN G = AFBC/CCGT COGEN

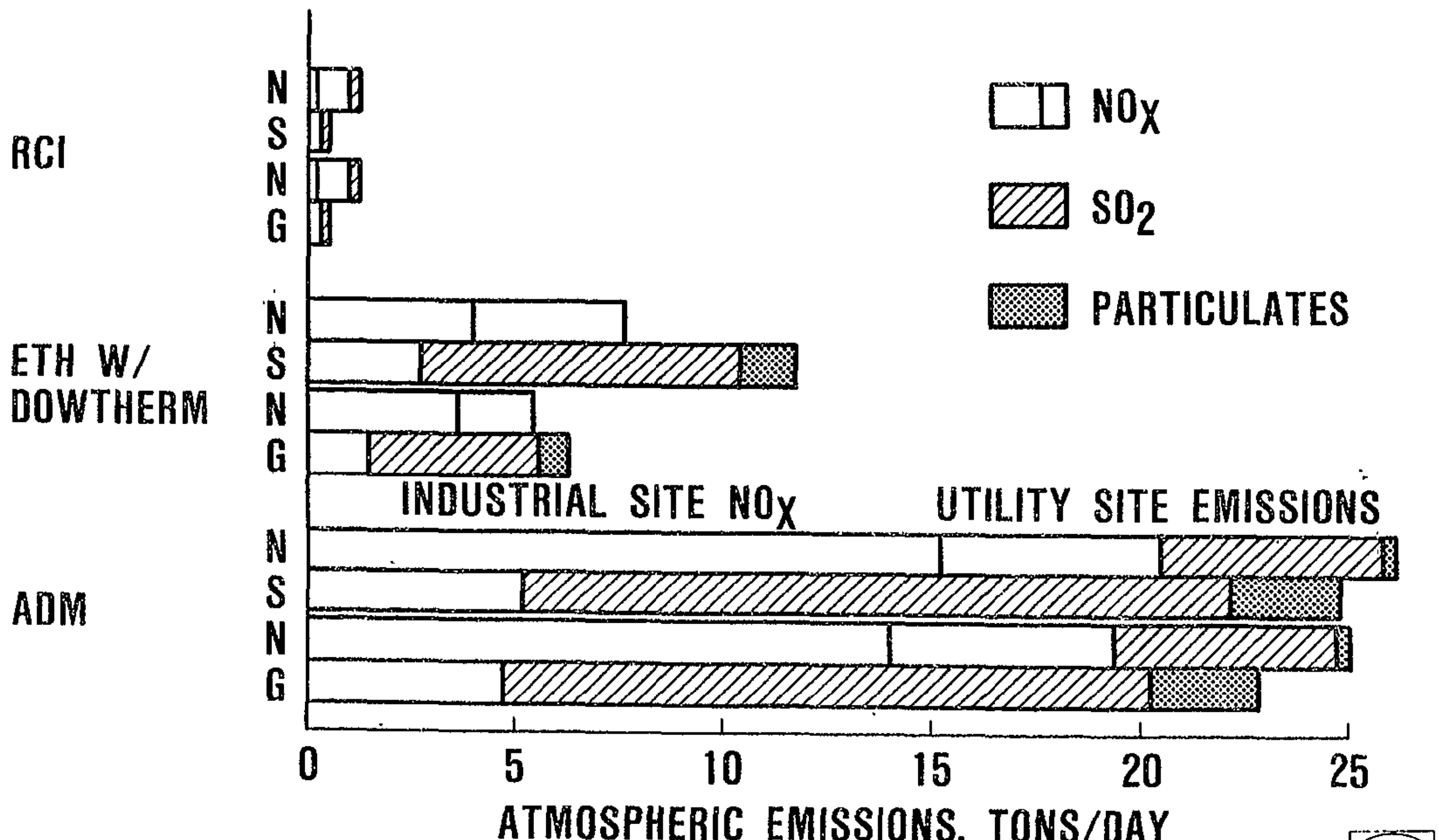


Figure 15.

PERFORMANCE AND BENEFITS ANALYSIS

N = NON COGENERATION   S = AFBC/STEAM COGEN   G = AFBC/CCGT COGEN

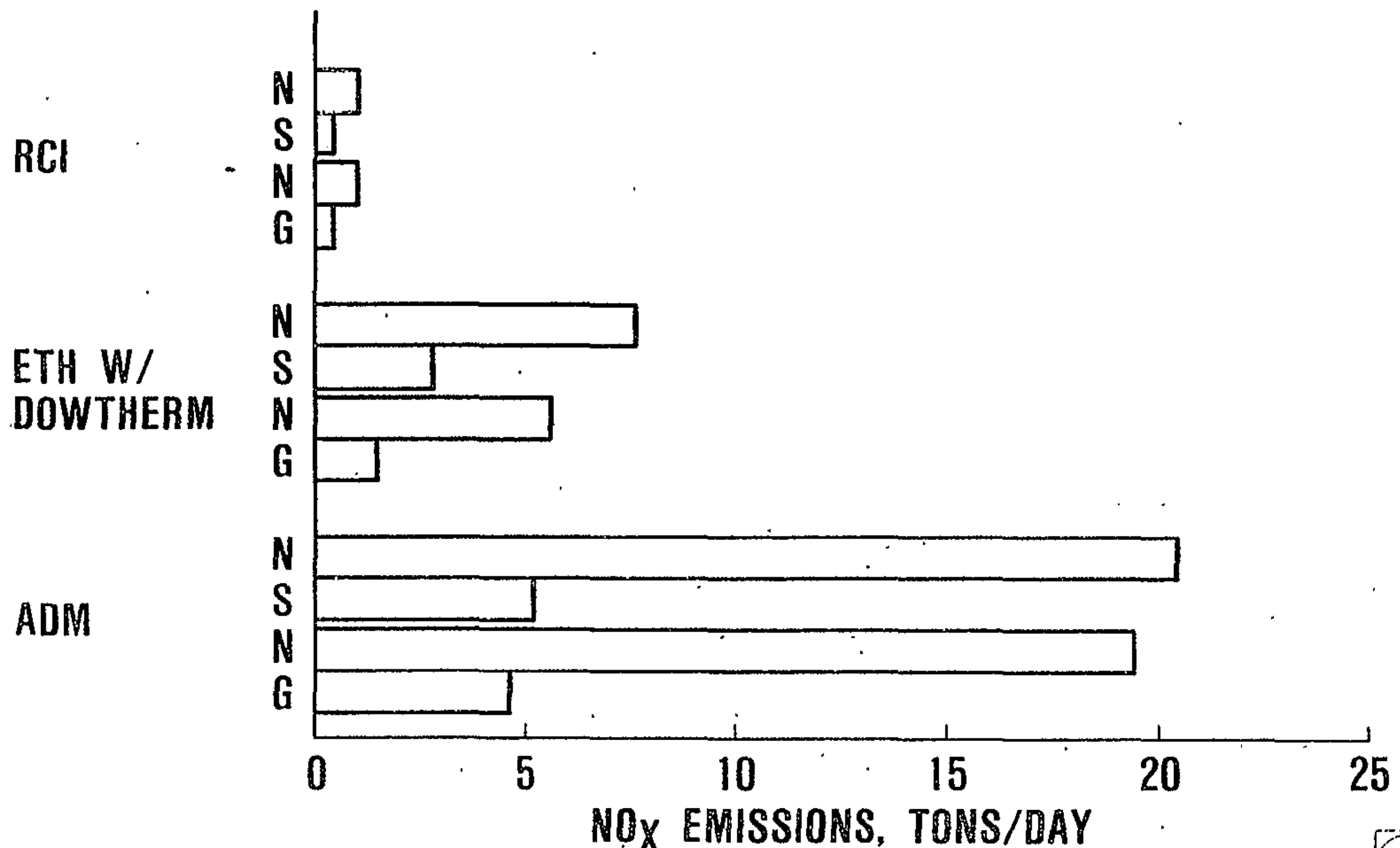


Figure 16.

Figure 17 shows the capital cost and levelized annual energy cost for the cogeneration systems (both gas turbine and steam) compared to the non-cogeneration systems for the three sites. All three sites employ relatively new gas fired boilers that are not scheduled for replacement. The net capital cost for the non-cogeneration system are thus zero as shown in Figure 17. Note that the cost equivalent of producing the total electrical power delivered by the cogeneration system has been incorporated into the two non-cogeneration systems for the Ethyl site.

The benefits of the cogeneration systems relative to the non-cogeneration system are shown in the upper portion of Figure 18. The lower portion of Figure 18 compares the steam cogeneration system to the closed cycle gas turbine cogeneration system.

Figures 19, 20, and 21 show the fuel energy savings ratio and the emission saving ratio for the six cogeneration systems.

Figure 22 shows the comparison of annual operating costs and the levelized annual energy cost savings ratio for the six cogeneration systems.

Figure 23 summarizes the benefits of steam and closed cycle gas turbine cogeneration systems for the three sites studied during Task 1.

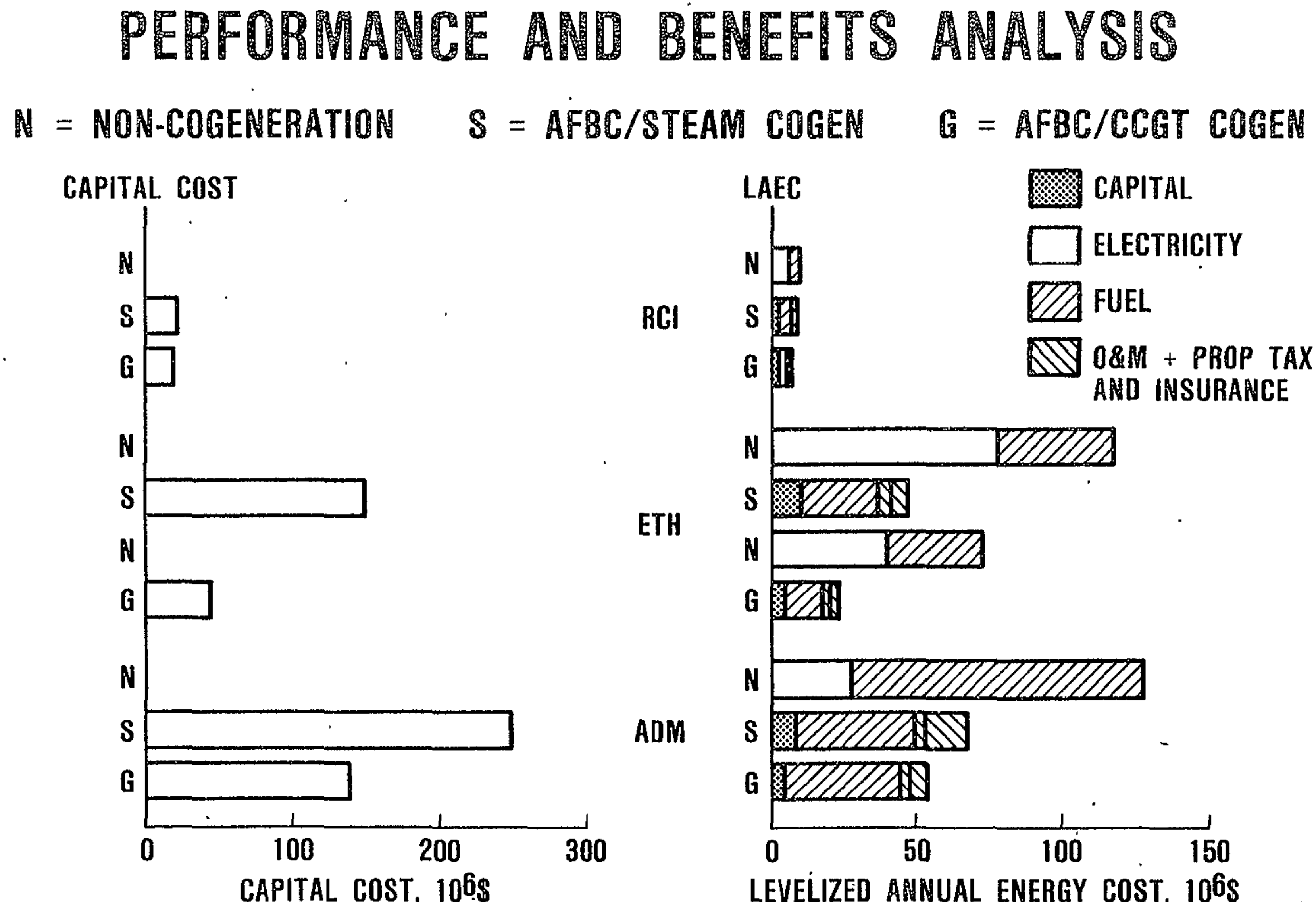

PERFORMANCE AND BENEFITS ANALYSIS
N = NON-COGENERATION
S = AFBC/STEAM COGEN
G = AFBC/CCGT COGEN
CAPITAL COST
LAEC
CAPITAL
ELECTRICITY
FUEL
O&M + PROP TAX AND INSURANCE
RCI
ETH
ADM
N
S
G
0
100
200
300
CAPITAL COST, 10^6$
0
50
100
150
LEVELIZED ANNUAL ENERGY COST, 10^6$

Figure 17.

RELATIVE BENEFITS

S = AFBC/STEAM COGENERATION   G = AFBC/CCGT COGENERATION

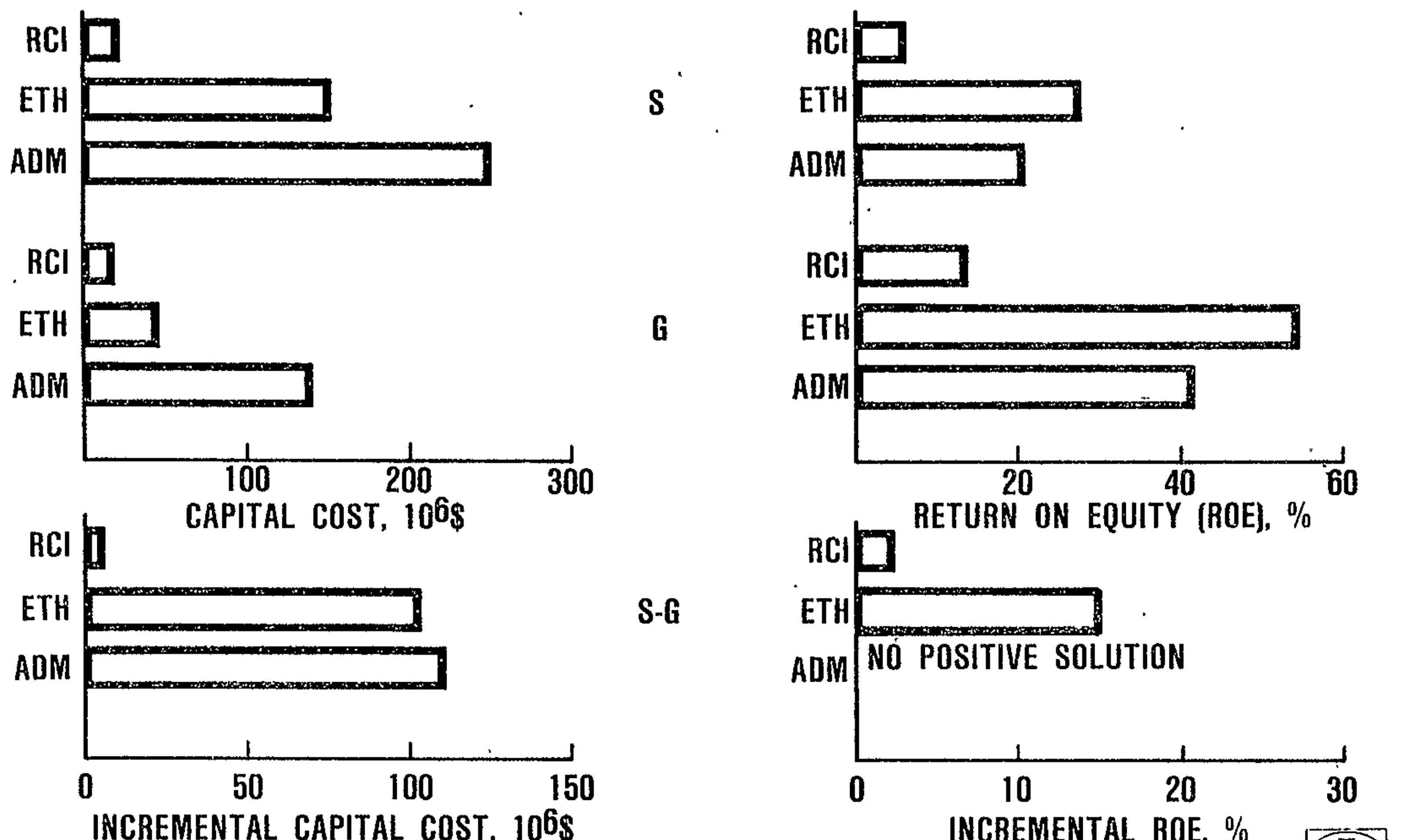


Figure 18.

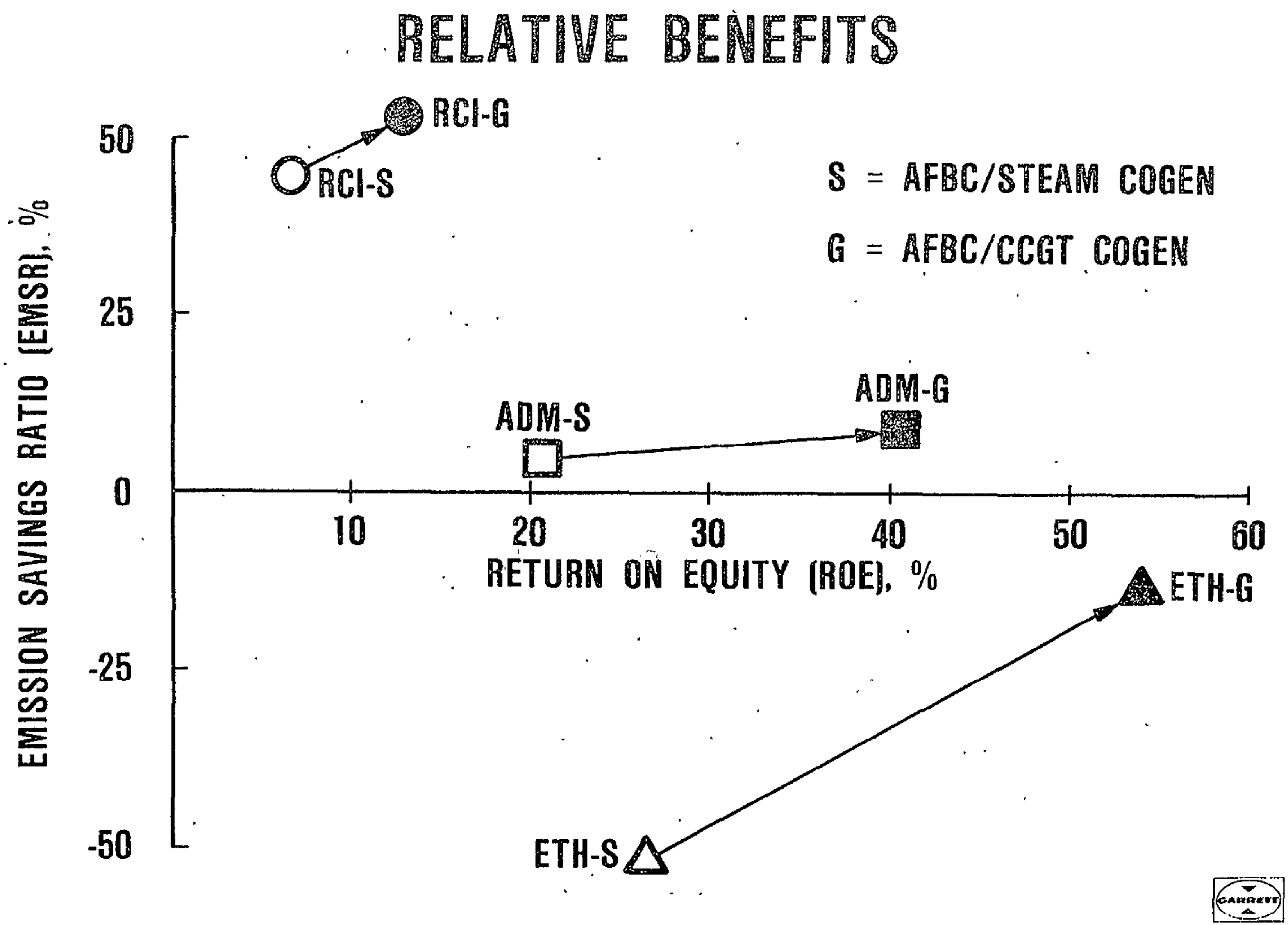

RELATIVE BENEFITS
RCI-G
RCI-S
S = AFBC/STEAM COGEN
G = AFBC/CCGT COGEN
ADM-S
ADM-G
ETH-G
ETH-S
EMISSION SAVINGS RATIO (EMSR), %
RETURN ON EQUITY (ROE), %
50
25
0
-25
-50
10
20
30
40
50
60

Figure 19.

RELATIVE BENEFITS

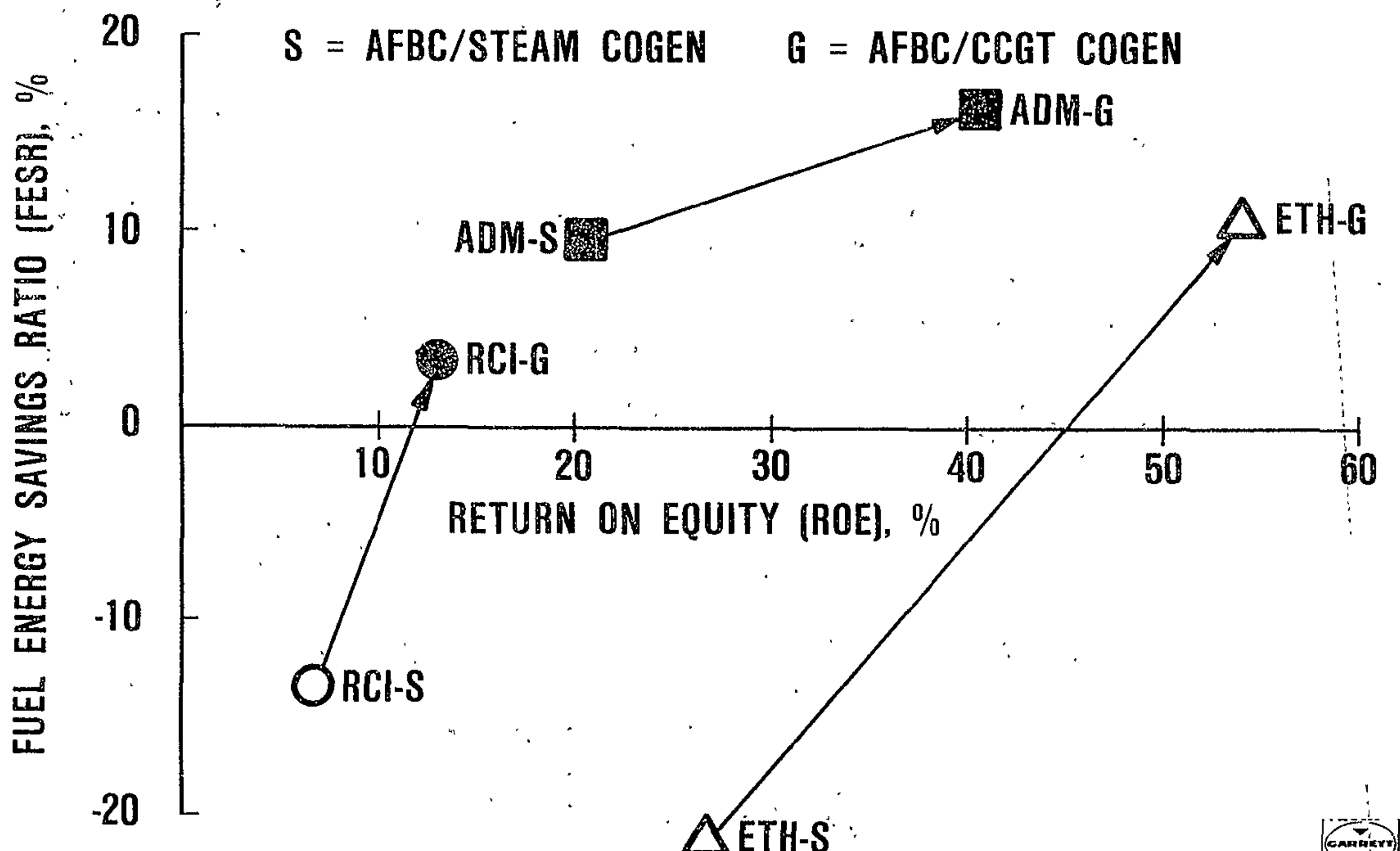


Figure 20.

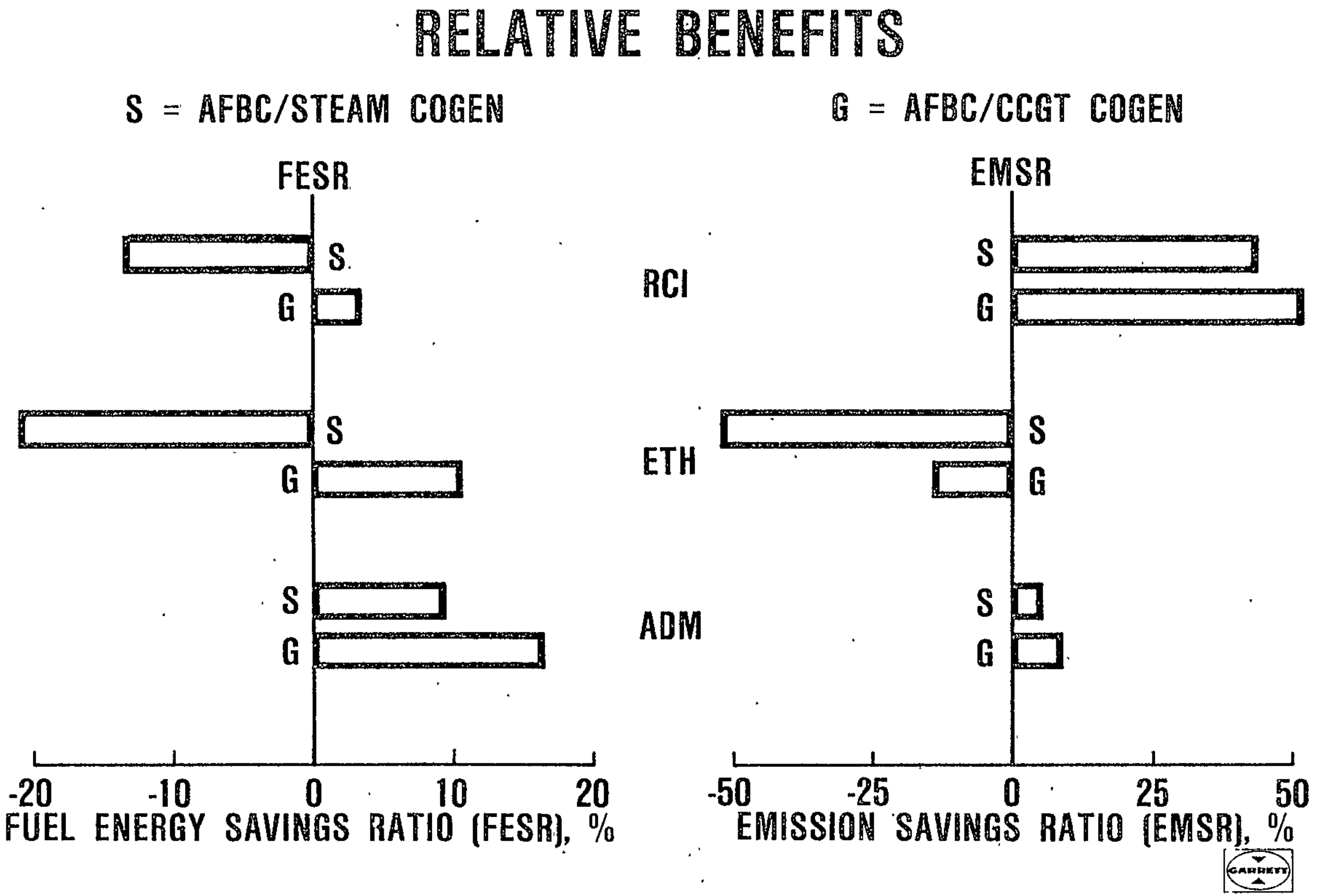

RELATIVE BENEFITS
S = AFBC/STEAM COGEN
G = AFBC/CCGT COGEN
FESR
EMSR
RCI
ETH
ADM
S
G
-20
-10
0
10
20
FUEL ENERGY SAVINGS RATIO (FESR), %
-50
-25
0
25
50
EMISSION SAVINGS RATIO (EMSR), %

Figure 21.

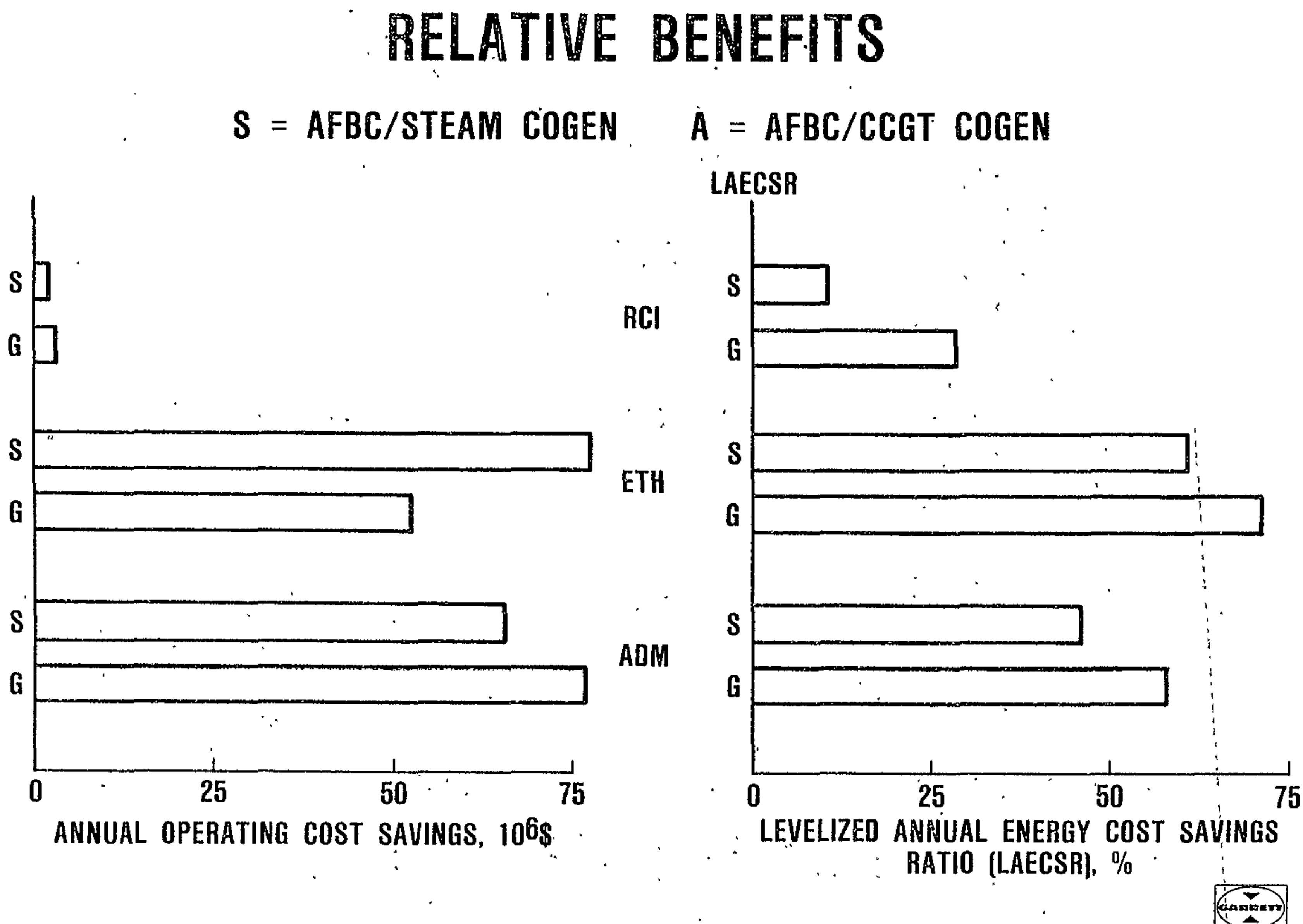

RELATIVE BENEFITS
S = AFBC/STEAM COGEN
A = AFBC/CCGT COGEN
LAECSR
S
G
RCI
S
G
ETH
S
G
ADM
0
25
50
75
ANNUAL OPERATING COST SAVINGS, 10⁶$
LEVELIZED ANNUAL ENERGY COST SAVINGS
RATIO (LAECSR), %

Figure 22.

RELATIVE BENEFITS

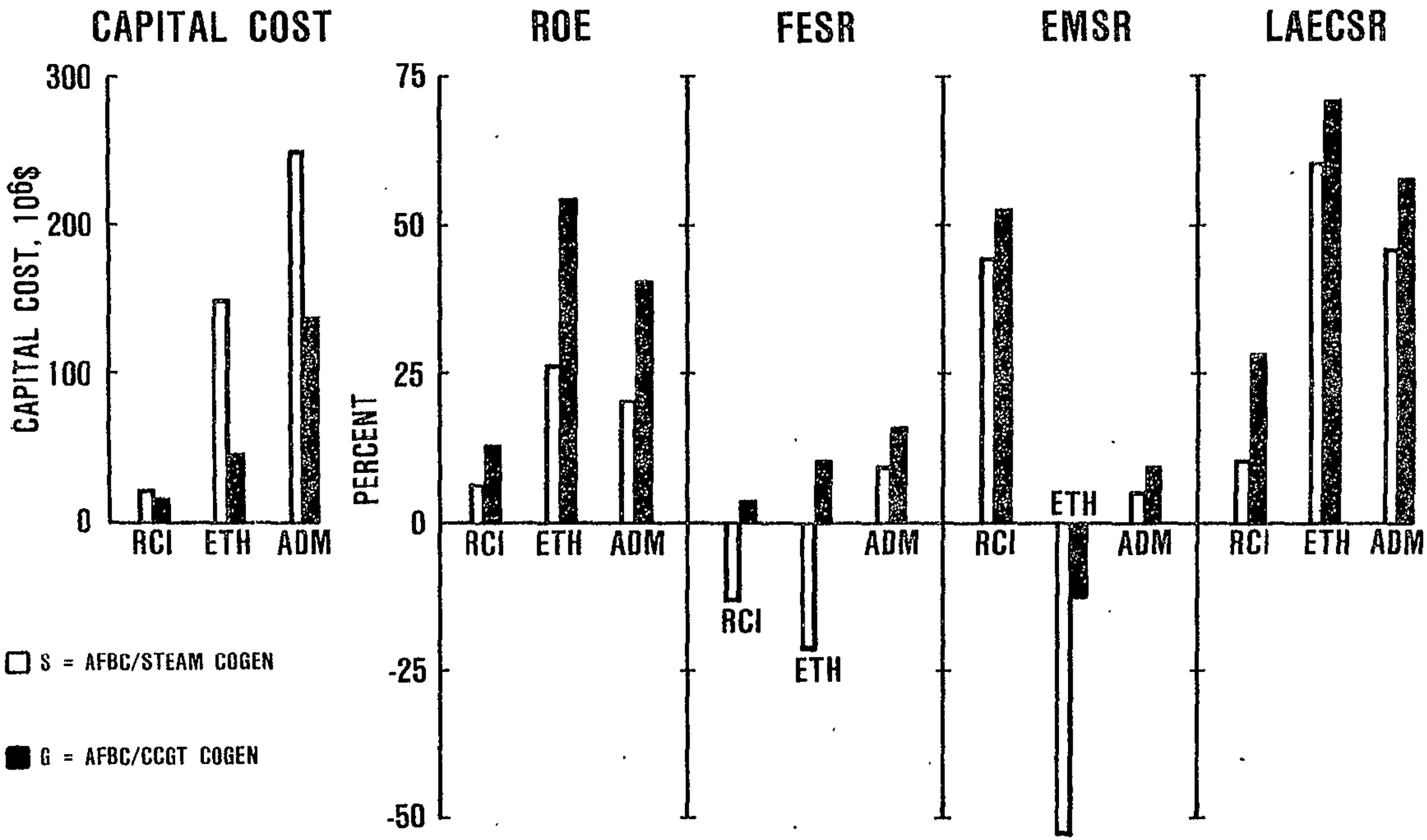


Figure 23.

6. SITE RECOMMENDATION FOR TASK II

A review of Figure 23 reveals that the CCGT systems were more beneficial than the equivalent ST systems in every category in which they were compared.

> THE SITE SELECTION IS BASED ON COMPARING ONLY THE CLOSED CYCLE GAS TURBINE COGENERATION SYSTEM BENEFITS BETWEEN SITES. THE AFBC/STEAM COGENERATION SYSTEMS WERE NOT CONSIDERED DURING THE SELECTION PROCESS.

Figure 24 illustrates the rationale by which the Ethyl site was recommended for continuated study during Task II. Comparative values of 1, 2, and 3 were assigned with lowest value being best.

Return on equity was judged as the most significant figure-of-merit for the cogeneration system. The Ethyl site exhibits the highest ROE, and thus this site was assigned a value of 1 as shown in Figure 24. The Ethyl site exhibits the highest ROE because:

(a) The coal fired cogeneration system is displacing high priced natural gas based electrical and thermal loads (per Figure 3, page 4).
(b) The simultaneous import/export of electrical power eliminates the standby changes (see Figure 3, page 4).

The absolute value of the capital cost required to install the AFBC/CCGT cogeneration system was judged as being almost equal importance compared to the ROE. The Reichhold site has the smallest electrical and cogeneratable thermal loads, and thus its cogeneration system would be the lowest cost. The relative trade-off between ROE and capital cost can best be seen in Figure 13.

SITE SELECTION RATIONALE

IN ORDER OF IMPORTANCE	SITE		
	RCI	ETH	ADM
1. RETURN ON EQUITY	3	1	2
2. CAPITAL COST	1	2	3
3. DISPLACEMENT OF GAS/OIL WITH COAL	3	1	2
4. EMISSION SAVINGS (UMBRELLA)	3	2	1
5. FUEL SAVINGS	3	2	1
6. RELIABILITY AND AVAILABILITY ISSUES	3	1	2
7. REPRESENTATIVE OF INDUSTRY WIDE REQUIREMENTS	2	1	3
	18	10	14

Figure 24.

A major objective of the coal-fired cogeneration system is to replace the use of natural gas. The Ethyl site is the only site in which both the industrial site and its utility are based on natural gas.

The savings in emissions was judged to be the fourth most important figure-of-merit. The ADM-G cogeneration system saves the most total atmospheric emissions and the most NO_x emissions as shown in Figures 15 and 16, respectively. The Ethyl site saves the second most atmospheric emissions with the Reichhold site running a poor third because of the small size of the plant compared to the other two. Note that the comparison is based on the total pounds saved, not the percent saved.

Total fuel savings is a maximum for the ADM site due primarily to the fact that the ADM site has the highest electrical and thermal loads. Note that the comparison is based on the total BTU's saved, not the percent saved.

From the standpoint of reliability and availability issues, the Ethyl site rates substantially better than the other two sites. As pointed out earlier, the Ethyl site is the only one of the three studied that incorporates the concept of simultaneous import and export of the electrical power. In addition, the existing natural gas fired boilers must be in hot standby regardless of the cogeneration system availability to guarantee availability of at least 100,000 pounds per hour of steam. Thus, the criticality of an unavailable cogeneration system due to shut down is minimal at the Ethyl site. The ADM site incorporates two completely separate AFBC/CCGT cogeneration systems, each capable of accomodating one half of the total thermal and electrical load. The ADM site incorporates several totally independent food processing systems that can be selectively shut down, if required. Thus, the ADM site can still operate at partial output without dependence on back-up power, in the event that one of the two cogeneration systems becomes unavailable. By comparison, the Reichhold site incorporates two large synchronous motor driven compressors with narrow band low voltage trips. These motors constitute over 2/3 of the total electric load. Unscheduled shutdown of these compressors causes a complete plant shutdown. These compressors currently average about four shut-downs-per year due to utility power interruptions under present conditions. Criticality of a cogeneration system shut down at the Reichhold site is thus readily seen. The above discussion explains why the Ethyl site was judged as being first with respect to the reliability and availability issues as shown in Figure 24.

The Ethyl site was judged as being most representative of the petrochemical industry as well as the process industry as a whole due to the magnitude of the electrical and thermal loads and the power to heat ratio. By comparison, the ADM plant will, by 1985, be the largest food processing plant in the world and, thus, must be not judged as representative of the food processing industry as a whole.

The totals at the bottom of Figure 24 indicate that the Ethyl site should be selected even when the seven factors are weighed equally. A wider difference would be noted if the order of importance of the seven factors were taken into account. Thus,

THE ETHYL CORPORATION SITE WAS RECOMMENDED FOR CONTINUED STUDY DURING TASK II.

NASA agreed with the above recommendation and thus the Ethyl site was selected for continued study during Task II.

APPENDIX II

THE ETHYL CORPORATION SITE DEFINITION FOR THE TASK II - CONCEPTUAL DESIGN STUDY

GARRETT TURBINE ENGINE COMPANY
A DIVISION OF THE GARRETT CORPORATION
PHOENIX ARIZONA

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(17 pages)

APPENDIX II

THE ETHYL CORPORATION SITE DEFINITION FOR THE TASK II - CONCEPTUAL DESIGN STUDY

1. INTRODUCTION

The objective of Task II was to further evaluate the viability of the coal fired, AFB/CCGT and AFB/ST cogeneration systems on the basis of considerably more detailed design, a more in-depth cost study and more extensive economic analysis. A further objective was to perform a more rigorous comparison of the CCGT and ST systems. In order to achieve these objectives it is imperative that the site be completely defined. Thus

(a) A second visit was made to the Ethyl Corp. plant at Pasadena, Texas to survey existing plant conditions, substantiate the magnitude, nature and profiles of the electrical and steam loads, and to determine the inter-relation of the operation of the plant with the requirements of the utility loads.

(b) All of the information gathered in Step (a) was compiled and analyzed. The resultant data were then used as the basis for establishing two sets of cogeneration system design parameters, one for the CCGT and one for the ST system.

(c) Cogeneration system designs were generated for both systems based upon the system parameters established in Step (b).

(d) Performance analyses were conducted for both systems and some design optimization was accomplished based on resulting R.O.E.

(e) Concept drawings were prepared for the major components as well as system layouts, plot plans, piping and instrumentation diagrams, and one-line electrical schematics for each plant.

(f) Detailed economic analyses were performed for both systems as well as determinations of fuel savings and stack gas emissions.

The AFBC/STCS and AFBC/CCGT conceptual designs are described in Appendices III and IV, respectively.

The plant was toured to obtain first hand information on a number of factors of considerable import to the design of the cogeneration system. Among these were the following:

(a) General layout of the plant.

(b) Nature of the processes constituting the thermal loads.

(c) Interrelation of the processes.

(d) Number, size, type, physical layout, control, fuel, and mode of operation for the existing boilers and steam distribution system.

(e) Same as Item (d) for the Dowtherm System.

(f) Size, location, type, voltages, current ratings, and physical layout of the electrical substation, branch load centers, distribution lines and interconnects of the plant electrical system.

(g) General layout, size, source, storage facilities, treatment and distribution routes for the raw and treated water systems.

(h) Layout, routing, capacities and existing facilities for transportation, loading, unloading and storage of coal, sorbent, and spent bed solids and ash.

(i) A lengthy discussion with management and technical staff members relative to (1) the preferences and priorities in the choice of cogeneration system location; (2) location and method of steam, electricity, gas and water interconnects; (3) modes of operation, scheduling and manpower for the system; (4) the choices and impact of a number of economic factors.

The result of the above approach is discussed herein.

2. PLANT SITE AND LOAD DATA

Table 1 shows the location, SIC numbers, products and other significant data related to the Ethyl plant operation.

Table 2 displays the electrical and thermal plant load data as well as significant information characterizing the loads for cogeneration system design parameters.

As a result of extensive discussions with members of the Ethyl technical staff, a number of significant systems design characteristics and approaches were derived. Among these were the following:

(a) All of the existing gas fired boiler equipment is in excellent condition and good for at least 20 additional years of operation. Because of the imperative requirement for 100,000 lbs/hr of steam at all times, one of the existing natural gas fired boilers will be maintained on hot stand-by. Because one or more of the existing boilers must be maintained "on line" continuously they may be used as peaking units, thereby allowing the cogeneration system to operate as a base loaded steam generator. Although the peak steam loads vary significantly approximately every 20 minutes, the peaks represent only about ±5 percent of the total thermal load (steam plus Dowtherm). Because of that fact, a decision was reached that these peaks may be handled by the stand-by boiler, thereby allowing the process steam load on the cogeneration system boiler to be constant.

(b) The process waste liquid presently being used as boiler supplementary fuel will continue to be used for that purpose for the unit being maintained on-line. For economic purposes it is judged to be equal in cost to the equivalent Btu value of natural gas.

ETHYL CORP. — SITE DATA

GENERAL

NAME:	ETHYL CORPORATION (ETH)
LOCATION:	PASADENA, TEXAS
SIC(S)	2865,2869
PRODUCTS:	ZEOLITE, LINEAR ALCOHOL OLEFINS, ETC
CURRENT FUEL:	NATURAL GAS
UTILITY:	HOUSTON LIGHT AND POWER
UTILITY FUELS:	*85% NATURAL GAS 15% COAL

TABLE 1

ETHYL CORP. — SITE DATA

LOADS

NAME:		ETHYL
ELECTRICAL LOAD:		24.0 MW AVG 29.0 MW PEAK
THERMAL LOAD:		190,000 LB/HR AVG (65.35 MW) 310,000 LB/HR PEAK (103.36 MW) AT 240 PSIA SATURATED 170,000,000 BTU/HR DOWTHERM (49.8 MW)
LOAD VARIATION:		FLAT ELECTRICAL LOADS. HIGHLY CYCLIC STEAM. FLAT DOWTHERM LOADS. 8760 HR/YR OPERATION
POWER/HEAT RATIO:		0.37 WITHOUT DOWTHERM 0.21 WITH DOWTHERM
RELIABILITY:		MUST MAINTAIN 100,000 LB/HR MINIMUM STEAM FLOW

TABLE 2

(c) The existing boiler feedwater treatment plant and storage facility are adequately sized to handle the present steam requirement with an adequate capacity margin. It is in excellent condition and therefore may be used as the treated water supply for the AFBC/CCGT cogeneration system waste heat recovery boiler. Additional water treatment will be required for the AFBC/STCS however.

(d) The Dowtherm heat load to be applied to the cogeneration system heat recovery system is limited to that presently supplied by the two large Dowtherm heaters.

(e) The electrical load is nearly constant but experiences some deviation as plant processes vary. Because of an arrangement negotiated with HL&P, the Ethyl plant electrical system will remain on the utility bus as is. All net electrical power generated by the cogeneration plant will be fed to the utility bus through a power meter. All power used by the Ethyl plant will continue to be fed from HL&P through existing meters. HL&P will buy all of the cogenerated power at a negotiated price and will sell all of the power used by the plant at a negotiated price. On the average, the HL&P purchase rate will be 1.14 times the sell rate.

(f) The plant site is immediately adjacent to the Houston Ship Channel and has its own dock facilities. It also is served by a network of roads and good rail facilities throughout the major plant areas so that fuel and sorbent may be shipped to the site by barge, railcar or motor truck.

As a result ground rules were established with NASA and Ethyl Corp. which were used to direct the course of the study and to assist in making the study approach consistent between the two, cogenerator systems. Table 3 presents the common ground rules as approved by NASA.

TABLE 3. ETHYL CORPORATION, PASADENA, TEXAS
1985 Loads and Fuel Prices

Site data as determined by NASA-LeRC on March 24, 1982, after discussion with the Ethyl Corp.

Item	Value
Steam load, net to plant, average	190,000 lbs/hr at 225 psig saturated
Steam load, net to plant, peak	310,000 lbs/hr at 225 psig, saturated
Minimum steam required to operate plant	100,000 lbs/hr
Electrical load, net to plant, average	24,000 kw
Electrical load, net to plant, peak	29,000 kw
Natural gas price	$5.80/10**6 Btu (1985 price in 1981 dollars)
Natural gas price escalation (above inflation)	3.0%/year
Electricity price	5.24¢/kwh (1985 price in 1981 dollars)
Electrical price escalation (above inflation)	7.0%/year
Electricity buy-back price	5.97¢/kwh (1985 price in 1981 dollars)
Coal price	$2.04/10**6 Btu/(1985 price in 1981 dollars)
Coal price escalation (above inflation)	1%/year
DOW-THERM	230 x 10**6 Btu installed capacity deemed cogenerateable
DOW-THERM	170 x 10**6 Btu expected usage in 1985

Figure 1 illustrates the specific area of the plant selected for the cogeneration system site. Among the reasons for selecting this area are the following:

(a) It is within 150 feet of a main steam transmission line serving the major steam loads in the plant area.

(b) It is within 500 feet of a major electrical substation that can be utilized for the utility and plant bus inter-ties.

(c) It is bordered on two sides by a major rail spur as well as two of the major plant roadways, thus facilitating fuel and sorbent delivery and ash disposal. It also facilitates equipment delivery for system erection.

(d) In one corner of this site is the main storage tank for treated boiler feedwater.

(e) It provides adequate space for the coal and sorbent covered storage areas and ash storage silos in addition to the AFB/cogeneration system.

(f) The major buildings shown adjacent to the selected area are residuals from an obsolete process plant that has been shut down. These buildings are scheduled for removal whether or not a decision is made to cogenerate so the cost of removal is not to be charged to the cogeneration system site preparation costs.

As dictated by the foregoing system design parameters, plant electrical and thermal loads were characterized as illustrated in Figure 2 for both the gas turbine and steam turbine cogeneration systems. Note that the electrical load selected was a constant 24 MW_e. This allows the turbogenerator unit to operate base loaded at all times. Thus, the cogeneration system is base loaded from both an electrical and a thermal load standpoint. Because the steam production rate of the CCGT system is dependent upon the heat available in the turbine exhaust gas, a system design was generated in which the steam produced at the base electrical load is equal to the average steam demand of 115 MW_t which is equal to the sum of the steam and Dowtherm loads.

GARRETT TURBINE ENGINE COMPANY
A DIVISION OF THE GARRETT CORPORATION
PHOENIX ARIZONA

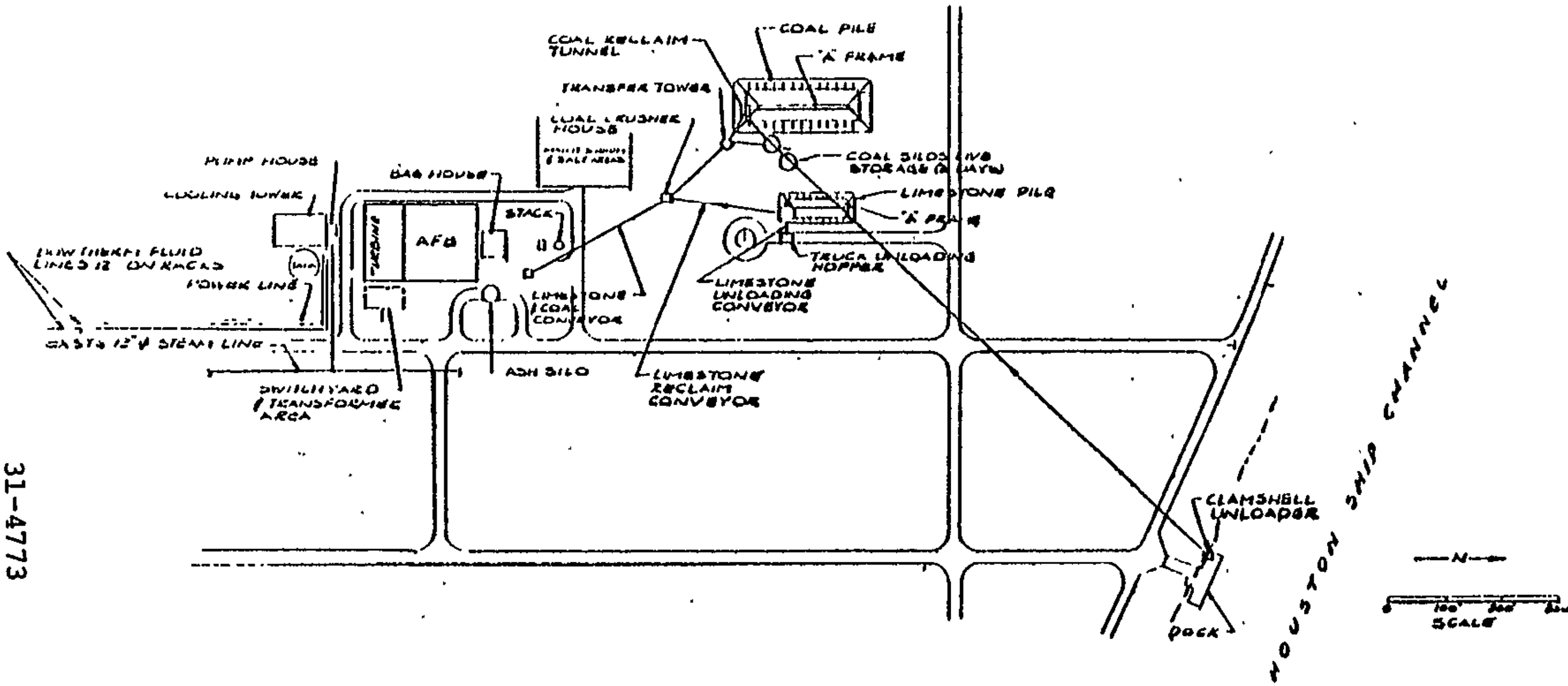

FIGURE 1

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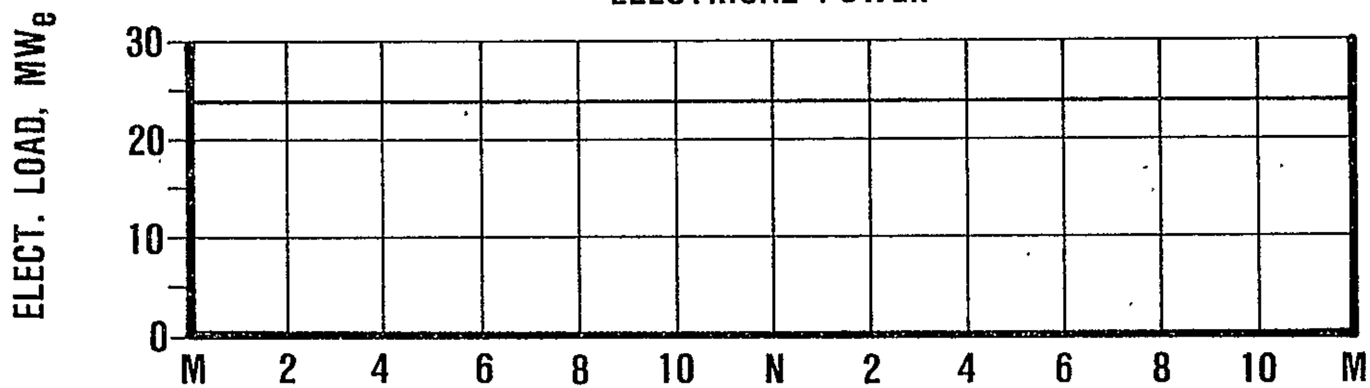
Appendix II
9

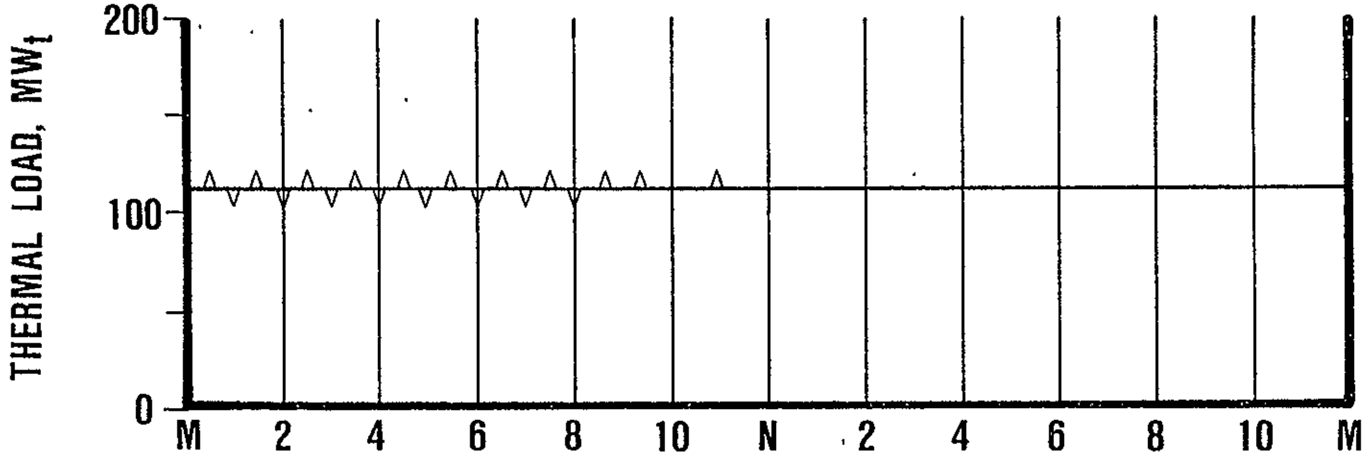
ADVANCED TECHNOLOGY COGENERATION SYSTEMS STUDY

ETHYL CORP. PLANT LOAD PROFILES

ELECTRICAL POWER



THERMAL LOAD



Based upon these load profiles and the study guidelines, concept designs were established for both the CCGT and ST cogeneration systems. In order to avoid confusion these design concepts are presented separately in Appendices III and IV.

3. FUEL SOURCE AND COST

In order to maintain commonality between the CCGT and the STC plants, it was decided to use the same coal for both the CCGT and ST systems and to utilize essentially identical handling and storage facilities.

This section discusses the coal source, coal specification and coal and limestone transportation to the plant site.

3.1 Coal Source and Specification

Oklahoma bituminous coal, from a coal mine located in Rogers County, Oklahoma, was selected for the design of this cogeneration plant. The coal has a higher heating value of 12,400 Btu/lb and sulfur content of 3.11 percent on as-received basis. The coal analysis shown in Table 4 indicates that this bituminous coal has low total moisture content of 8.46 percent on as-received basis. Thus, it is considered that coal drying is an unnecessary process for the cogeneration plant.

3.2 Coal Transportation

The bituminous coal will be transported from Rogers County, Oklahoma by rail to a site near Houston, Texas, from where the coal will be transported by barge to a docking facility near the Ethyl Corporation site. At the docks, the coal will be off loaded from the barge and conveyed to a storage area at the Ethyl Corporation facility where the coal will be reclaimed and delivered to the coal bunkers and fed into the AFBC boiler. The docking location for the barges is shown in Figure 1.

TABLE 4. COAL ANALYSIS

Oklahoma Bituminous

1. Location - Rogers County, Oklahoma
2. Scan - Iron Post/Fort Scott
3. Proximate Analysis (As-Received Basis - Typical)

o Moisture	8.46%
o Volatile Matter	40.66%
o Fixed Carbon	40.79%
o Ash	10.09%
o Sulfur	3.40%
o Btu/lb	12,400

4. Ultimate Analysis

Ultimate Analysis	Dry Basis	As-Rec'd Basis
o Hydrogen	4.97%	4.55%
o Carbon	73.90%	67.65%
o Nitrogen	1.32%	1.21%
o Oxygen (By Difference)	5.39%	4.93%
o Sulfur	3.40%	3.11%
o Chlorine	-	-
o Moisture, Total	-0-	8.46%
o Ash	11.02%	10.09%

3.3 Limestone

Limestone will be brought to the Ethyl facility site by trucks from a local source and will be unloaded to the storage area where the limestone will be reclaimed to the limestone bunker and fed into the AFBC boiler. The limestone analysis is shown below:

Limestone Analysis (% by Weight)	
CaCO	93.9
$MgCO_3$	1.4
H_2O_3	3.0
Other	1.7

*Includes surface moisture

4. ENVIRONMENTAL CONSIDERATIONS

The proposed cogeneration facility is subject to both federal and state environmental regulations.

4.1 Federal Emission Regulations

The cogeneration facility is subject to "Subpart Da - Standards of Performance for Electric Utility System Generating Units" of 40 CFR 60. The facility is subject to the more stringent requirements for electric generating stations for the following reasons:

(a) The facility generates a gross output power of more than 25 MW.
(b) The facility sells all of its net electrical output power.

4.1.1 Sulfur Dioxide Emissions

The design coal for the facility is Oklahoma bituminous coal with a typical as-received proximate sulfur content of 3.40 percent and a 12,400 Btu/lb heating value. Such a coal yields an uncontrolled SO_2 emission level of 5.5 lb/MBtu. This level of potential emission would ordinarily require a controlled SO_2 emission level of 0.6 lb/MBtu (equivalent to 89 percent reduction in SO_2 level). However, the regulation provides an exemption for facilities that qualify for commercial demonstration permits. An atmospheric fluidized bed combustor is one type of facility that could qualify for such a permit. If the facility so qualified, required SO_2 emission reduction would be 85 percent (equivalent to 0.8 lb/MBtu).

Since the performance data for the facility indicates that the AFB combustors are capable of attaining an SO_2 emission level of 0.50 lb/MBtu, the facility easily meets the federal emission criteria for sulfur dioxide.

4.1.2 Particulate Matter

The proposed facility must achieve an emission level for particulate matter no greater than 0.03 lb/MBtu. The performance data for the equipment shows an expected AFBC/STCS emission level of 0.026 lb/MBtu, again in compliance with federal emission limits. AFBC/CCGT cogeneration system particulate emissions level is 0.029 lb/MBtu.

4.1.3 Nitrogen Oxides

The emission limit for nitrogen oxides (expressed as nitrogen dioxide) is 0.60 lb/MBtu bituminous coal. The performance data shows that the AFBC/STCS facility is capable of attaining a nitrogen oxide emission level of 0.33 lb/MBtu, again well below the limit. AFBC/CCGT cogeneration system NO_x emissions level is 0.18 lb/MBtu.

In summary, it can be stated that the proposed facility would be in compliance with all applicable federal emission limitations.

4.2 State Emission Regulations

The state emission regulations for particulate matter, sulfur dioxide and nitrogen oxide are less stringent than the federal limits - therefore, the federal regulations are governing.

4.3 Ambient Air Quality and Prevention of Significant Deterioration (PSD)

The proposed plant would be considered a major source (of atmospheric pollutants) because it would emit more than 100 tons per year of pollutants which are covered by the Clean Air Act. The facility is located in Harris County in Pasadena, Texas which is in Air Quality Control Region 216. This part of the region is classified as better than the National Standard for Sulfur Dioxide and Nitrogen Oxides but the ambient air quality does not satisfy the primary standard for total suspended particulates. Because of these factors, PSD and new source permits must be obtained and it must be proven that the facility is capable of achieving Lowest Achievable Emission Rate (LAER). Since the facility is capable of achieving emission levels equal to or better than that achievable by the application of Best Available Control Technology (BACT) on conventional plants, the facility should not have any unexpected difficulty in receiving these permits.

APPENDIX III

TASK II - AFBC/STEAM TURBINE COGENERATION PLANT DETAILED CONCEPTUAL DESIGN STUDY

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TABLE OF CONTENTS (Contd)

APPENDIX III

TASK II - AFBC/STEAM TURBINE COGENERATION PLANT DETAILED CONCEPTUAL DESIGN STUDY

1.0 INTRODUCTION AND SUMMARY

The overall objective of the conceptual design of the AFBC/Steam Turbine Cycle System (STCS) in Task II is to expand in greater detail the study of the Ethyl site and to evaluate more adequately its potential for both fuel and cost savings than was accomplished in Task I. This involves considerably more detailed system and site definitions, specifications and drawings, detailed cost analyses and estimates, detailed thermal distribution values, and more accurate performance evaluations.

1.1 Conceptual Design Approach of AFBC/STCS

During the conduct of the Task I cycle selection and optimization for the AFBC/STCS, the approach taken on the Dowtherm thermal load was to locate the Dowtherm heat exchangers in series with the throttle steamline and use superheated steam from the AFBC to heat Dowtherm fluid. This design approach matched the process steam load (190,000 lbs/hr saturated steam at 240 psia), but generated 52 MW_e net power output, which is more than the plant electrical load (24 MW_e) specified in the design criteria. This high power output is due to the higher throttle steam flow rate dictated by the Dowtherm thermal load. As a result, the overgeneration of electrical output requires a larger steam turbine, large heat rejection system, larger AFBC boiler and larger balance-of-plant equipment, thus, requiring a higher capital investment for the cogeneration plant. The generation of excess electrical power also complicated the comparison of AFBC/STCS with AFBC/CCGS.

Since many commercial Dowtherm heaters, including those in operation at the Ethyl site, are direct fired, and because Foster-Wheeler already markets direct fired Dowtherm heaters, a decision was made to adopt this approach in the AFBC/STCS. This design incorporates the Dowtherm heat exchangers in the convective section of the AFBC. This method resulted in a smaller AFBC, which simultaneously matches the Dowtherm thermal load, process steam load and electrical power demand. This approach is the basis for the conceptual design of the AFBC/STCS, which has been chosen as the most cost effective and is described in detail in this Appendix.

1.2 Design Methodology

The AFBC/steam system was considered to be state-of-the-art commercially available technology. Accordingly, commercially available equipment was selected and adapted to the Ethyl site problem statement. The design and evaluation of the cogeneration plant using AFBC/STCS was conducted in the following steps:

(a) A single automatic extraction condensing steam turbine with a nominal rating of 30 MW_e was selected for the steam cycle performance analysis.

(b) Throttle steam flow rate was determined to match both process steam load (i.e., 190,000 lb/hr of saturated steam at 240 psia) and net electrical load (i.e., 24 MW_e). Optimization was achieved by an iterative procedure using a series of different throttle and extraction conditions.

(c) Atmospheric fluidized bed boiler was designed to match both throttle steam flow and Dowtherm thermal duty. Dowtherm duty is 170 x 10^6 Btu/hr with 550°F inlet and 680°F outlet. Coal and limestone consumption rates were also determined for the overbed fed AFBC.

(d) Coal and limestone handling systems were designed based on their consumption rates. Spent sorbent and ash were determined from coal and limestone consumption rates and combustion air requirements.

(e) The balance-of-the-plant was sized to match the AFBC and steam turbine cycle systems. The auxiliary power requirement was calculated, and incorporated to determine exact throttle steam flow and power output.

(f) Budgetary prices for all major components and systems were obtained from vendors' quotation. In order to achieve the greater accuracy in the determination of cogeneration plant cost, quoted prices of major equipment and systems were obtained from at least two vendors.

1.3 AFBC/STCS Conceptual Design Summary

Figure 1-1 shows a simplified schematic of the AFBC/STCS Conceptual Design. Figure 1-2 summarizes the conceptual design. Details of the equipment operating conditions are shown in Figure 1-3.

A two unit-cell atmospheric fluidized bed combustion boiler was designed by Foster-Wheeler to provide 360,000 lbs/hr of superheated steam to the turbine. The steam turbine cycle system consists of one single extraction, condensing type steam turbine, one deaerator, one surface condenser, one mechanical-draft wet cooling tower, one desuperheater and associated pumps. The cycle is non reheat type with some extraction steam conveyed to the deaerator for feedwater heating. All process steam is non-recoverable, therefore 100 percent make-up water is required.

The total system is tied into the existing boilers; thus, the thermal redundancy for the process steam can be achieved by using existing boilers when the cogeneration plant is shut down for scheduled or non-scheduled maintenance.

Figures 1-4 and 1-5 show the cogeneration plant site and typical equipment arrangement.

AFB/ST COGENERATION SYSTEM

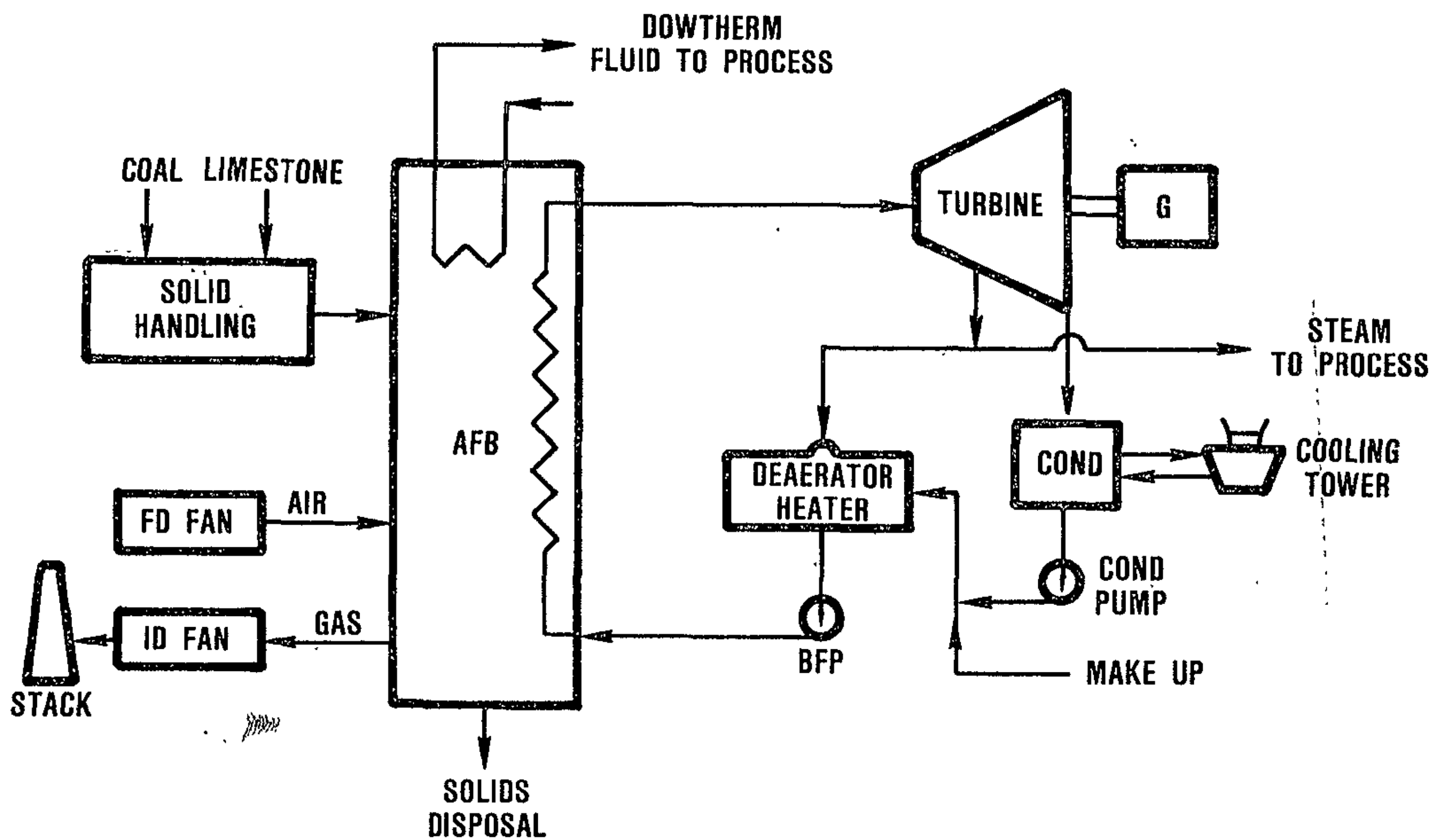


FIGURE 1-1

AFB/ST COGENERATION SYSTEM PARAMETERS

FUEL: COAL — BITUMINOUS, 12,400 BTU/LB HHV, 3.11%S, $2.1018/MBTU

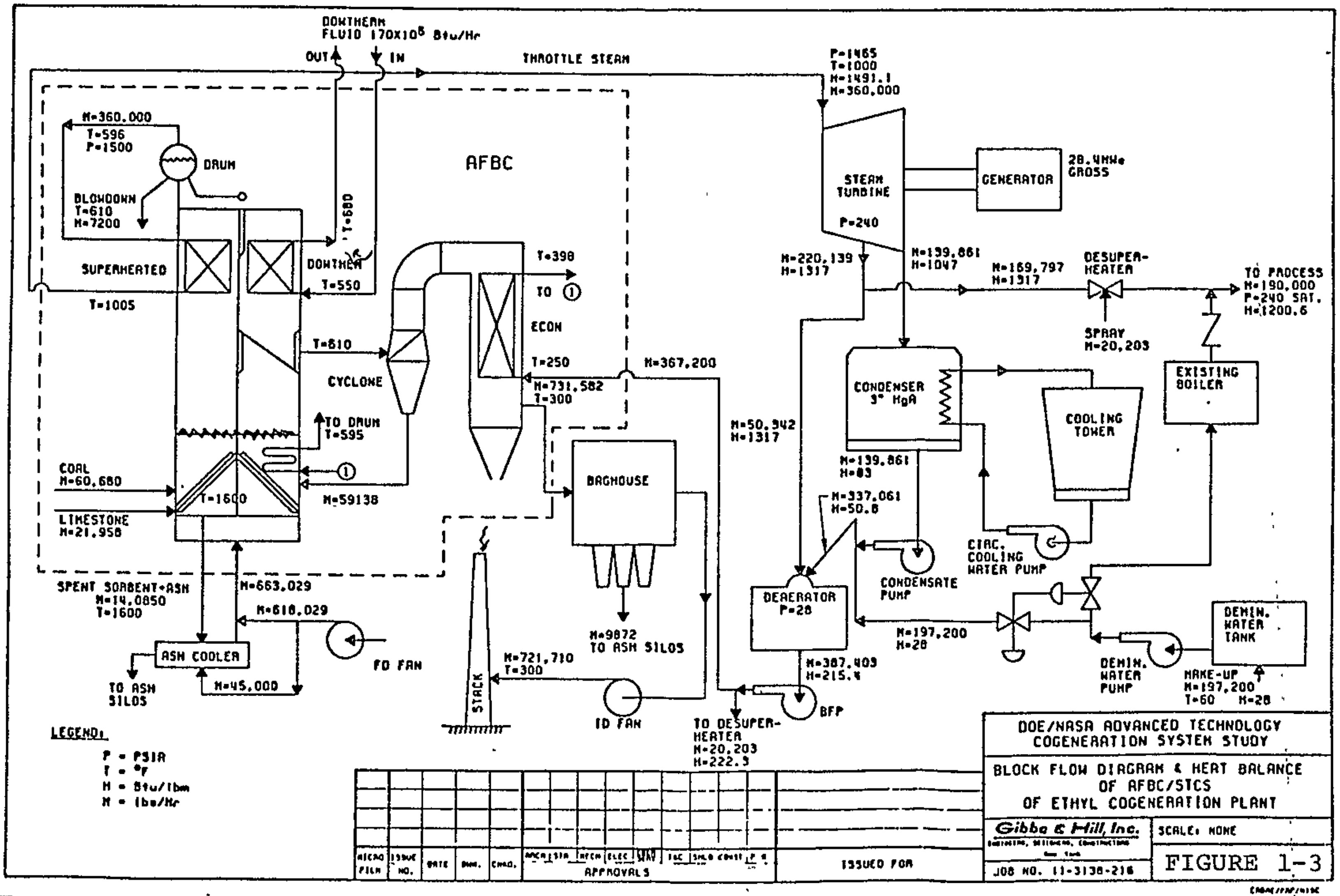
SORBENT: LIMESTONE, 0.383 LB/LB COAL, 93.9% Ca, $13.90/TON

AFB HEATER:
- BED TEMPERATURE — 1600°F
- BED DEPTH — 4.5 FT
- BED AREA — 1344 FT^2
- FREEBOARD TEMP = 1880°F
- EXCESS AIR FLOW — 21.0%
- SUPERFICIAL VELOCITY — 7.5 FT/SEC
- DUTY — 465.9 MBTU/HR TO STEAM
  170.0 MBTU/HR TO DOWTHERM
  635.9 MBTU/HR TOTAL

POWER CYCLE: STEAM-RANKINE
- TURBINE TYPE — SINGLE EXTRACTION
- THROTTLE CONDITIONS — 1465 PSIA, 1000°F
- EXHAUST CONDITIONS — 3 IN HgA, 115°F
- MASS FLOW — 360,000 LB/HR

HEAT REJECTION:
- WET COOLING TOWER — 2 CELLS
- STACK GAS TEMPERATURE — 300°F

FIGURE 1-2


DOWTHERM FLUID 170X10^6 Btu/Hr
OUT
IN
THROTTLE STEAM
P=1465
T=1000
H=1491.1
M=360,000
AFBC
M=360,000
T=596
P=1500
DRUM
BLOWDOWN
T=610
M=7200
T=680
SUPERHEATED
DOWTHERM
T=550
T=1005
T=398
TO ①
ECON
T=610
CYCLONE
T=250
M=731,582
T=300
M=367,200
TO DRUM
T=595
COAL
M=60,680
LIMESTONE
M=21,958
T=1600
M=59138
BAGHOUSE
SPENT SORBENT+ASH
M=14,0850
T=1600
M=663,029
M=618,029
ASH COOLER
M=45,000
TO ASH SILOS
FD FAN
STACK
M=721,710
T=300
ID FAN
M=9872
TO ASH SILOS
STEAM TURBINE
P=240
GENERATOR
28.4MWe GROSS
M=220,139
H=1317
M=139,861
H=1047
M=169,797
H=1317
DESUPER-HEATER
TO PROCESS
M=190,000
P=240 SAT.
H=1200.6
SPRAY
M=20,203
EXISTING BOILER
CONDENSER
3" HgA
COOLING TOWER
M=50,942
H=1317
M=139,861
H=83
M=337,061
H=50.8
CONDENSATE PUMP
CIRC. COOLING WATER PUMP
DEAERATOR
P=28
M=197,200
H=28
M=387,403
H=215.4
BFP
TO DESUPER-HEATER
M=20,203
H=222.3
DEMIN. WATER PUMP
DEMIN. WATER TANK
MAKE-UP
M=197,200
T=60
H=28
LEGEND:
P = PSIA
T = °F
H = Btu/lbm
M = lbs/Hr
DOE/NASA ADVANCED TECHNOLOGY COGENERATION SYSTEM STUDY
BLOCK FLOW DIAGRAM & HEAT BALANCE OF AFBC/STCS OF ETHYL COGENERATION PLANT
Gibbs & Hill, Inc.
SCALE: NONE
JOB NO. 11-3138-216
MICRO FILM
ISSUE NO.
DATE
DWN.
CHKD.
APPROVALS
ISSUED FOR
FIGURE 1-3

31-4773
Appendix III
1-7

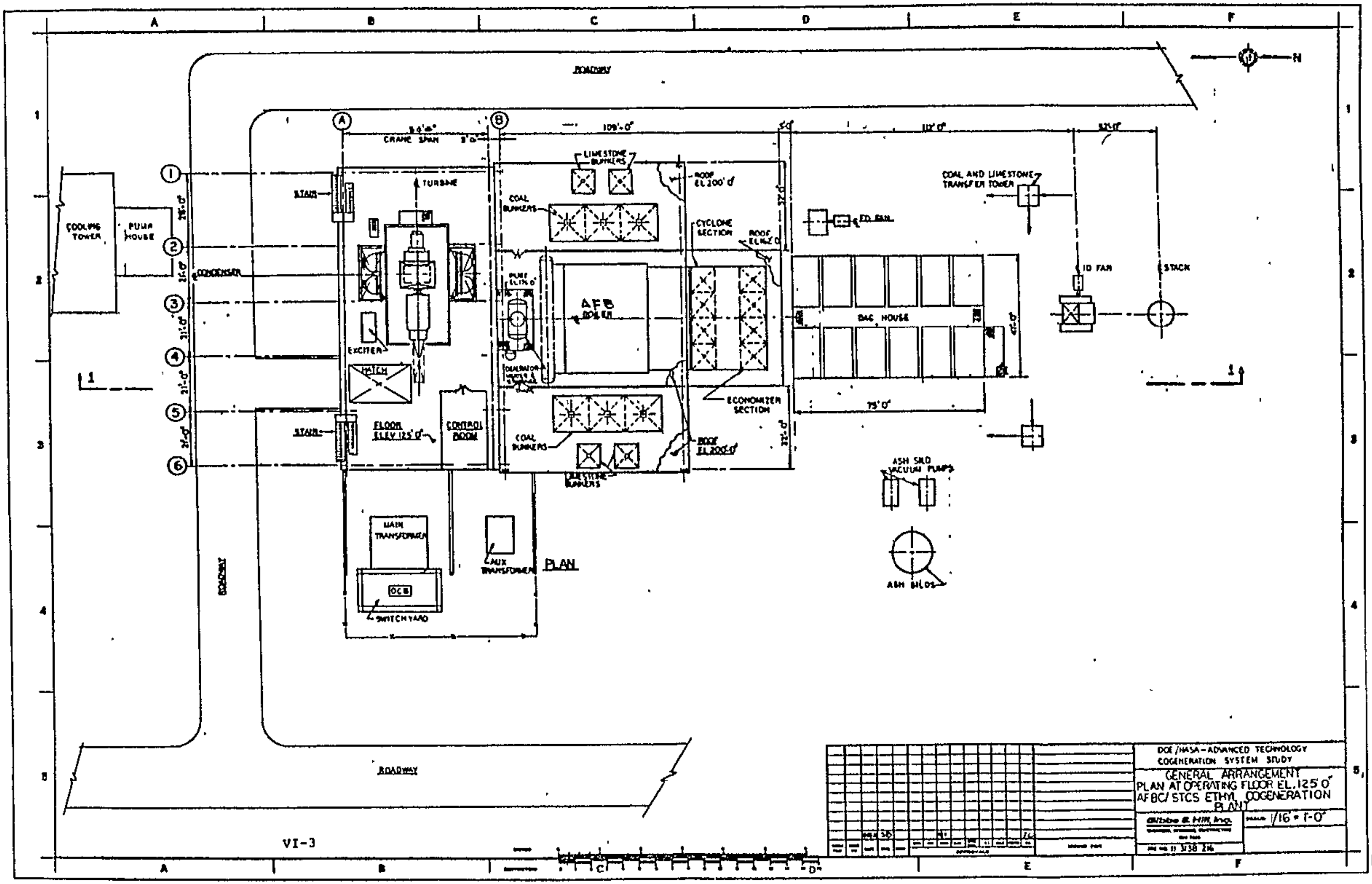


FIGURE 1-4

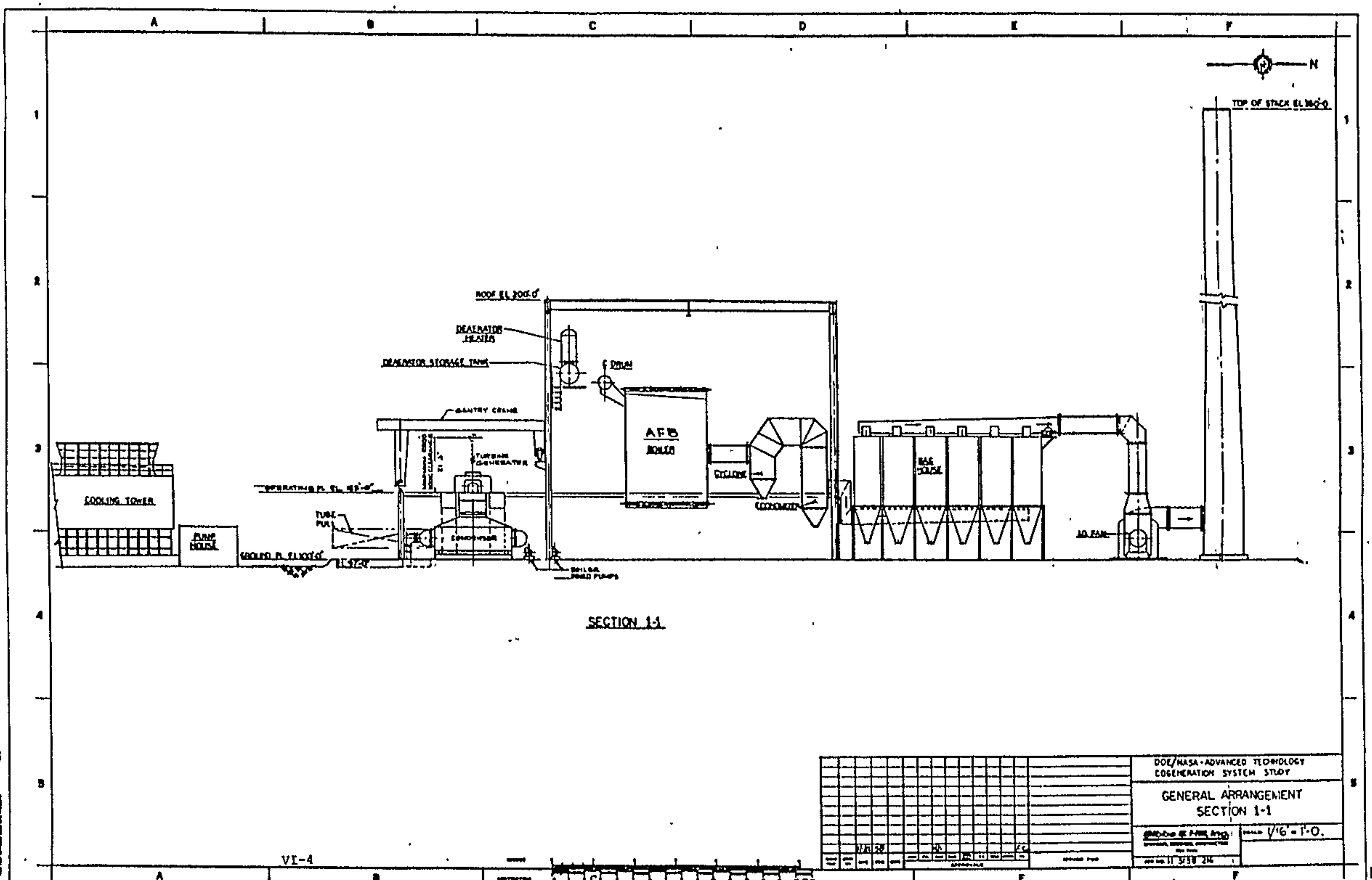

N
COOLING TOWER
PUMP HOUSE
ROOF EL 200'-0"
DEAERATOR HEATER
DEAERATOR STORAGE TANK
GANTRY CRANE
TURBINE GENERATOR
CONDENSER
TUBE PULL
BOILER FEED PUMPS
AFB BOILER
CYCLONE
ECONOMIZER
BAG HOUSE
ID FAN
SECTION 1-1
DOE/NASA-ADVANCED TECHNOLOGY COGENERATION SYSTEM STUDY
GENERAL ARRANGEMENT SECTION 1-1
1/16" = 1'-0.
VI-4

FIGURE 1-5

Figures 1-6 and 1-7 summarize the plant output characteristics and resource requirements. Atmospheric emissions, spent solids and thermal heat rejection conditions are summarized in Figure 1-8.

The Task II detailed conceptual design study was conducted to determine, with reasonable certainty, the cost of a plant design for a specific site. The plant capital cost is summarized in Figure 1-9.

Figure 1-10 compares the AFBC/STCS Conceptual design against the existing separate generation plant at the Ethyl site. The return-on-equity value (ROE) is quite attractive. The fuel energy savings ratio (FESR) is defined as:

$$\frac{\begin{array}{c}\text{Separate Generation}\\ \text{Fuel Used}\\ \text{(Utility Plus Industrial Site)}\end{array} - \begin{array}{c}\text{Cogeneration}\\ \text{Plant Fuel Used}\end{array}}{\text{Separate Generation Fuel Used (Utility Plus Industrial Site)}}$$

A positive FESR shows that the total energy used to satisfy the loads is less with the cogeneration plant. The emission savings ratio (EMSR) is defined similar to the FESR. A negative EMSR shows that the cogeneration plant rejects significantly (in this case) more emissions into the atmosphere. This is generally the case when the industry and the utility are based on natural gas and the cogeneration system is coal fuel. The oxides of nitrogen are reduced but the particulate emissions associated with coal more than offset the reduced NO_x emissions.

The remainder of this appendix provides details of the results shown above.

AFB/ST COGENERATION SYSTEM

NET PLANT OUTPUT, MW_e	24.00
NET PLANT OUTPUT, MW_t	115.17
FUEL UTILIZATION $\left(\frac{MW_e + MW_t}{MW_{IN}}\right)$, PERCENT	63.13
AFB HEATER EFFICIENCY, PERCENT	83.67
COAL CONSUMPTION, TONS/DAY	728
LIMESTONE CONSUMPTION, TONS/DAY	279
TOTAL SOLID WASTE, TONS/DAY	312.5
CONSTRUCTION TIME, YEARS	2.75
PRE-ENGINEERING & PERMITS TIME, YEARS	0.75

FIGURE 1-6

AFB/ST COGENERATION SYSTEM
RESOURCE REQUIREMENTS

COAL — 80.64 LB/MBTU$_{\text{FIRED}}$, 728 TONS/DAY

LIMESTONE — 30.92 LB/MBTU$_{\text{FIRED}}$, 279.1 TONS/DAY

NATURAL GAS — NONE

WATER —

COOLING — EVAP.	558,000 GAL/DAY
BLOWDOWN	164,160
TOTAL	722,160

LAND REQUIREMENTS — 10 ACRES (INCLUDES COAL, LIMESTONE AND ASH STORAGE)

FIGURE 1-7

AFB/ST COGENERATION SYSTEM EMISSIONS

	$LB/MBTU_{FIRED}$	TONS/DAY
ATMOSPHERIC		
SO_2	0.50	4.51
NO_X	0.33	2.98
HC	0.16	1.44
CO	0.20	1.81
PARTICULATES	0.026	0.23
TOTAL		10.97
SPENT SOLIDS		
CALCIUM SULFATE	9.60	86.66
ASH AND DIRT	10.02	90.48
UNREACTED SORBENT	13.62	123.00
CARBON	1.37	12.36
TOTAL		312.5

THERMAL	BTU/MBTU
COOLING TOWER	179,186
STACK	55,686
OTHER	2,389
TOTAL	237,261

AFB/ST COGENERATION SYSTEM CAPITAL COSTS

(M$)	COMPONENT CAPITAL	DIRECT LABOR	INDIRECT FIELD	MATERIAL	TOTALS
1.0 FURNACE	11.717	3.167	3.167	11.296	29.347
2.0 TURBINE GEN	5.160	0.410	0.410	1.987	7.967
3.0 PROC MECH EQUIP	0.000	0.000	0.000	0.000	0.000
4.0 ELECTRICAL		0.352	0.352	1.418	2.122
5.0 CIVIL + STRUCT		3.733	3.733	4.825	12.291
6.0 PROC PIPE + INST		0.188	0.188	0.213	0.589
7.0 YARDWORK + MISC		0.083	0.083	0.163	0.329
***** TOTALS *****	16.877	7.933	7.933	19.902	52.645
BALANCE OF PLANT (BOP)	(DIRECT + INDIRECT + MATERIAL)			35.768	
A/E HOME OFFICE AND FEE	(AT 15 PCT OF BOP)			5.368	
SUBTOTAL PLANT COST	(TOTAL + A/E)				58.013
CONTINGENCY	(0.157 OF TOTAL PLANT COST, CALC)			9.122	
PLANT COST (1982.0 $)	(SUBTOT PLANT COST + CONTINGENCY)				67.135
CONSTRUCTION ESCAL. AND INTEREST CHARGES					0.000
TOTAL PLANT CAPITAL COST	(1982 $)				67.135

FIGURE 1-9

AFB/ST COGENERATION SYSTEM
PERFORMANCE AND BENEFITS ANALYSES

ROE	35.28 PERCENT
FESR	1.14 PERCENT
EMSR	–54.63 PERCENT
CAPITAL COST	67.135 MILLION $

VALUES SHOWN ARE RELATIVE TO NON-COGENERATION

FIGURE 1-10

2.0 ATMOSPHERIC FLUIDIZED BED COMBUSTOR (AFBC)

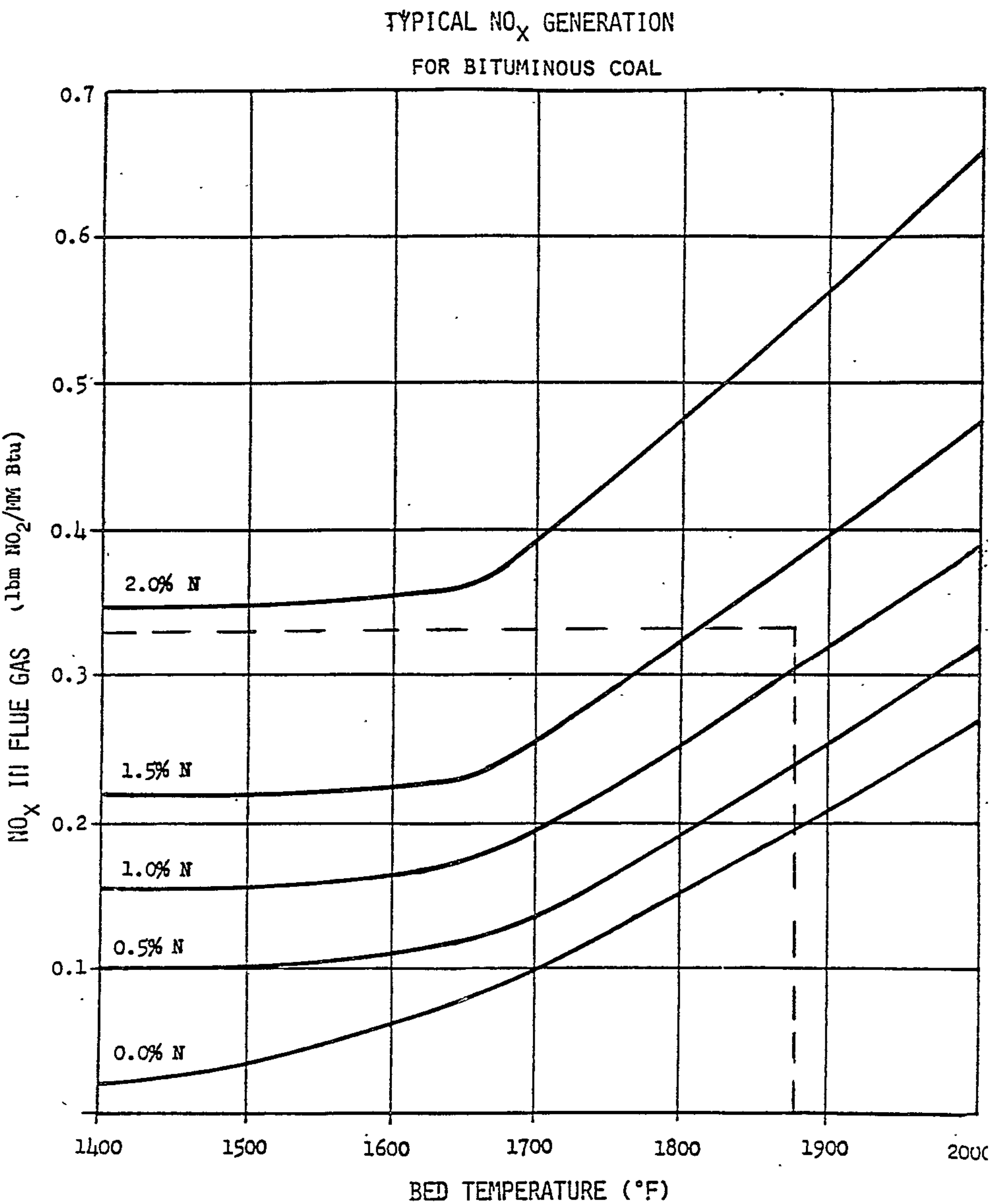
2.1 Design and Arrangement

The atmospheric fluidized bed combustor (AFBC) is designed to generate 360,000 lb/hr of steam at 1490 psia and 1005°F, while simultaneously heating Dowtherm from 550°F to 680°F as shown in Figure 1-3. In the AFB, a finely granulated material is enclosed in an airtight box, the floor of which is perforated so as to admit combustion air. By passing sufficient air through the floor and into the bed material, the bed can be made to behave in a fluid-like manner, promoting intense mixing and high heat transfer rates.

For the current application, coal is fed over the bed in order to provide the necessary thermal input. The bed material, which is initially comprised of limestone sized to 1/8 inch x 0, serves to remove the fuel bound sulfur directly during the combustion process, resulting in a dry, free flowing by-product which primarily contains calcium oxide (un-reacted limestone) and calcium sulfate. By utilizing this approach, the need for expensive flue gas scrubbers is eliminated, and the overall plant simplified.

The actual limestone feed rate required to remove 90 percent of the sulfur contained in the fuel is affected by several factors, including superficial velocity, Ca/S molar feed ratio, bed depth and bed temperature. For the current design, a Ca/S ratio of 3.56 is employed to remove 90 percent of the sulfur in the fuel.

In addition to removing fuel sulfur directly, the fluidized bed combustor also enables the emissions of oxides of nitrogen to be reduced substantially, compared to a pulverized coal fired combustor of the same capacity. As can be seen in Figure 2-1, NO_x emissions from the AFB are predominantly influenced by the maximum temperature attained, as well as the amount of nitrogen in th fuel. The current



DOE/NASA ATCS. STUDY
NOx IN FLUE GAS VS. BED TEMPERATURE
FIGURE 2-1

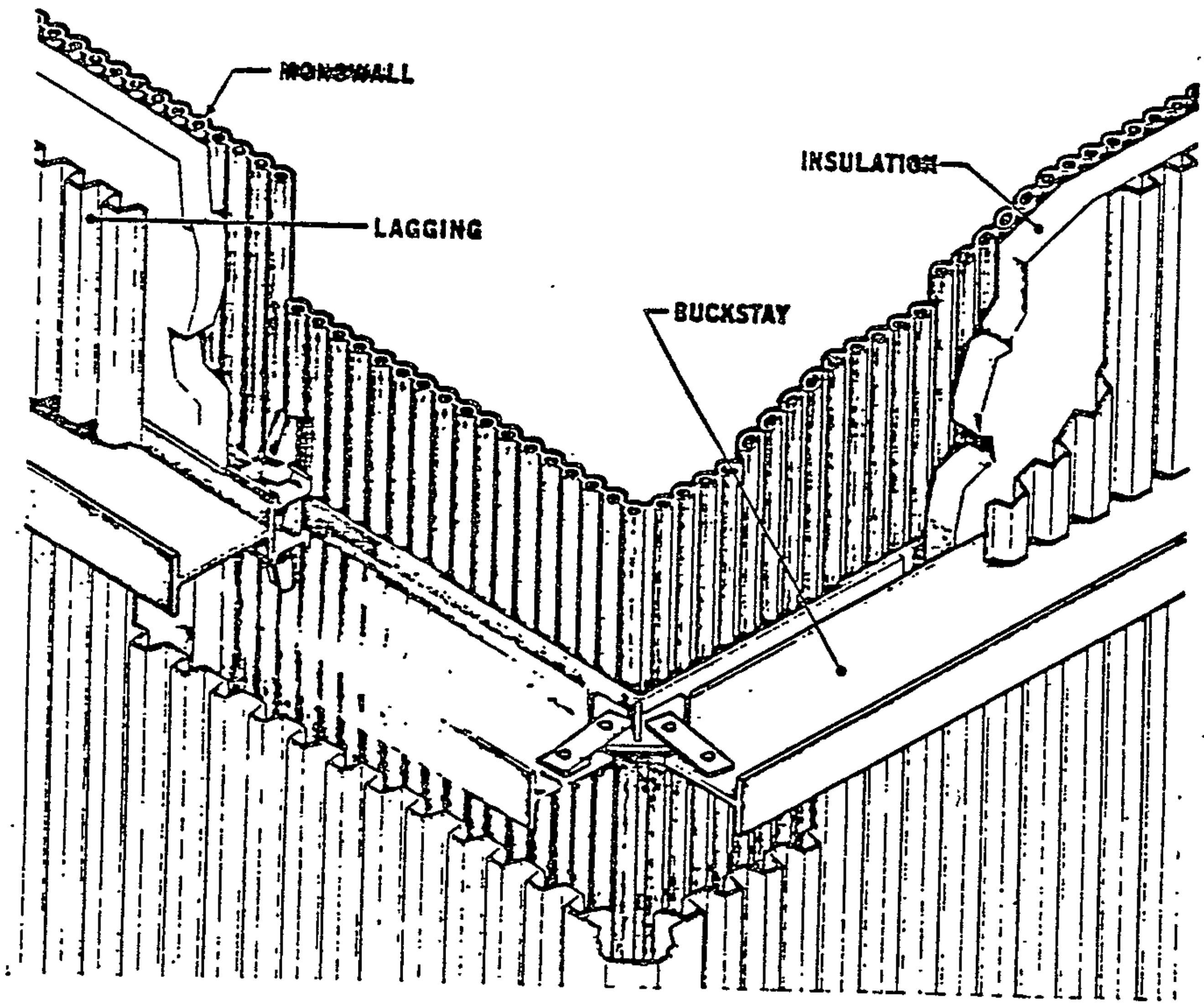
design, which employs fuel feed over the surface of the 4-1/2 feet deep bed, attains a maximum temperature just above the bed surface of 1880°F, which is substantially above the nominal bed temperature of 1600°F. This higher temperature yields NO_x emissions, as shown in Figure 2-1, of about 0.33 lb NO_x/MBtu which is substantially below the EPA mandated maximum of 0.7 lb NO_x/MBtu.

The AFBC consists of two independently controllable fluidized beds (front and rear) in common enclosure and separated by a single partition wall. Each bed has a plan area of 42 feet, 6 inches x 16 feet, 3 inches, and a full-load bed height of 4 feet, 6 inches. The partition wall separating the two beds is located along the 42 feet, 6 inches bed dimension.

The enclosure consists of four walls: front wall, left side wall, right side wall, and rear wall. The entire enclosure utilizes Monowall construction throughout, with the majority of the wall surfaces employing 2 inches OD tubes located on 3 inch centers. Typical wall construction is shown in Figure 2-2. A general arrangement of the steam generator is shown in a simplified elevation in Figure 2-3.

In forming the enclosure, the right side wall is split six feet from the plenum floor in order to form the air distributor, right and left plenum side wall, and plenum floor. These four surfaces, because of the split wall, are comprised of 2 inches OD tubes on 6 inch centers. The remaining two plenum walls (front and rear) consist of 2 inch OD tubes on 3 inch centers.

The partition wall, running parallel to the front wall and extending the entire height of the enclosure, also consists of 2 inch OD tubes on 3 inch centers. The partition wall tubes are bent out of plane to form tube screens at two locations, in order to provide flue gas passages. The first screen is located in the freeboard section of both beds, thus allowing the flue gas from the rear bed to be directed



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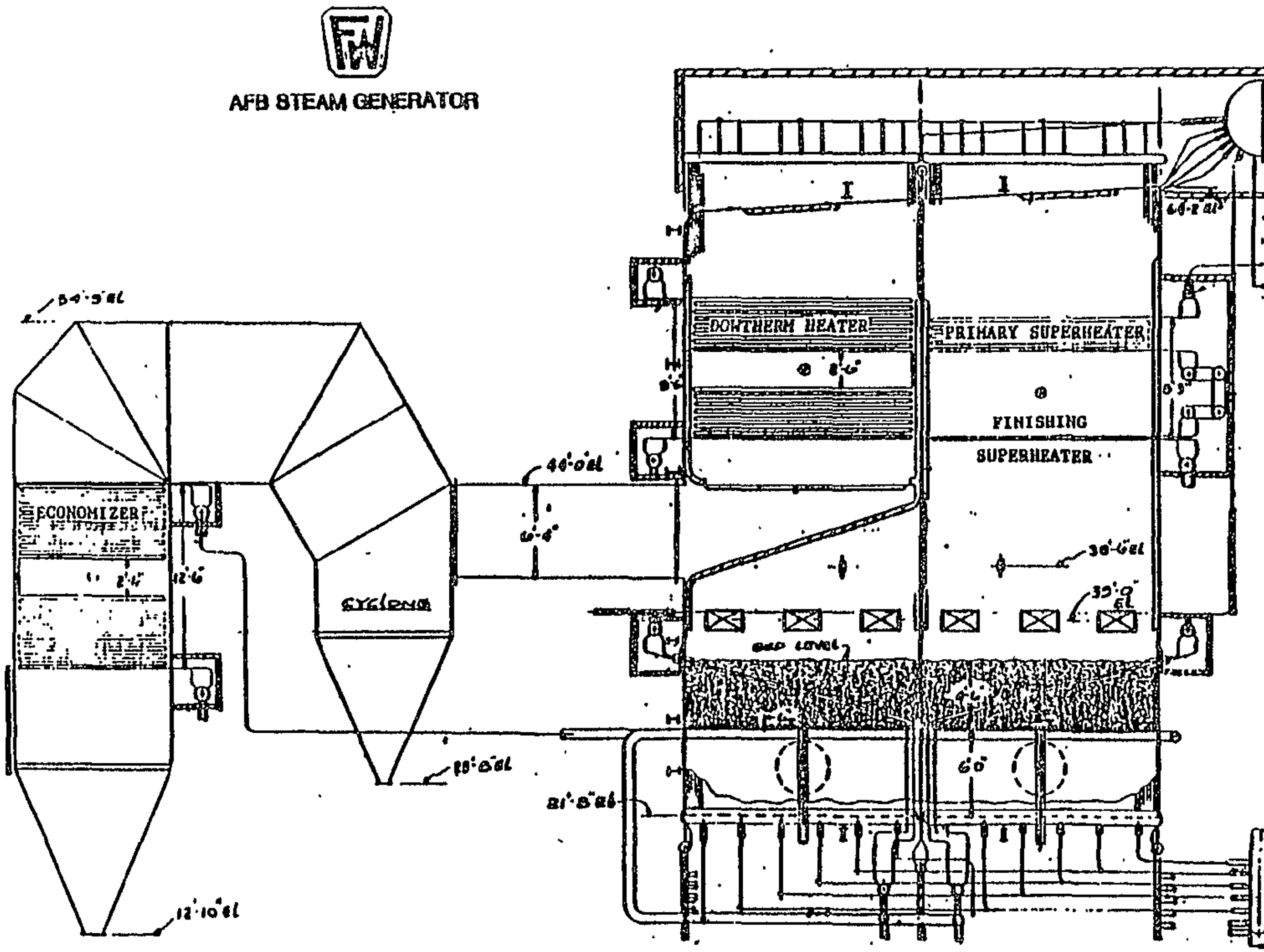
COGENERATION SYSTEM STUDY

TYPICAL BOILER MONOWALL
SECTION

FIGURE 2-2



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SIMPLIFIED ELEVATION VIEW OF AFB STEAM GENERATOR

FIGURE 2-3

to the convective section. The second screen is located at the outlet of the convection superheater, thus permitting the combined flue gas flow from both beds to be passed over the Dowtherm heating surface.

The rear wall is bent at a point 10 feet above the distributor in order to form the roof of the rear bed. This roof extends from the rear wall to the partition wall at an angle of 15 degrees.

The tubes are then bent approximately 180 degrees at the partition wall and return to form the remainder of the rear wall. These return tubes are bent out of plane before reaching the rear wall, in order to form a flue gas outlet screen. At the top of the rear wall, the tubes are bent to form the enclosure roof before terminating at the drum.

The plenum is divided into four zones by both the partition wall and a refractory lined steel wall running perpendicular to the partition wall. Each zone is individually supplied with air via a 3-foot, 6-inch diameter duct. Two of the ducts (one for each bed) contain oil fired in-line start-up burners. The air distributer is supported by 6-inch schedule 120-piping which connects the economizer to the steam generator. Air is admitted to the beds by means of A-6272 stainless steel tee nozzles which are located uniformly along the 4-inch wide bins connecting the distributor steam tubes.

Bed cooling/steam generation is attained by the placement of heat transfer surface within the fluidized zone. This surface is comprised of 2-inch OD tubes located on a 3-inch triangular pitch. Each bed contains a total of 335 tubes which enter through the distributor near the partition wall, slope upward at about 15 degrees, and exit through openings in the front and rear walls.

The convection superheater is located above the front bed, and is arranged in a general counterflow arrangement. Flue gas from both beds enters the finishing superheater first, where a final steam outlet temperature of 1005°F is attained. The tube surface in this zone consists of 84 tube elements, each of which consists of two rows of 1.5-inch OD tubes located on 6-inch transverse centers and 3-inch lateral centers.

After passing through this zone, the flue gas enters the primary superheater, which takes saturated steam and raises its temperature to about 949°F, prior to entering the spray attemperator. Heat transfer surface in this zone is comprised of 168 tube elements, each of which contains rows of 1.5-inch OD tubes located on a rectangular pitch with a transverse spacing of 3 inches and a lateral spacing of 3 inches. Upon passing through this zone, the combined flue gas flow passes through the partition wall screen and then flows downward through the Dowtherm heat transfer surface.

A major design feature of the steam generator is the placement of the Dowtherm convective surface. Since this fluid is subject to thermal degradation at temperatures above 750°F, care was taken to ensure that all Dowtherm heat transfer surfaces would be shielded from directly viewing the burning fluidized beds. By placing superheat convective surface between the beds and the Dowtherm convective surface, additional flue gas cooling is achieved prior to heating the Dowtherm, thus further reducing the danger of thermal degradation.

The Dowtherm heat transfer surface is arranged as a counterflow heat exchanger. Flue gas, passing down, flows over a total of 168 tube elements, each of which contains a total of 30 rows of 2-inch OD tubes located on 3-inch lateral centers. The tube elements are located on 3-inch transverse centers, resulting in a square tube pitch. The heat transfer surface is divided equally into two zones, in order that a cavity may be provided for retractable soot blowers.

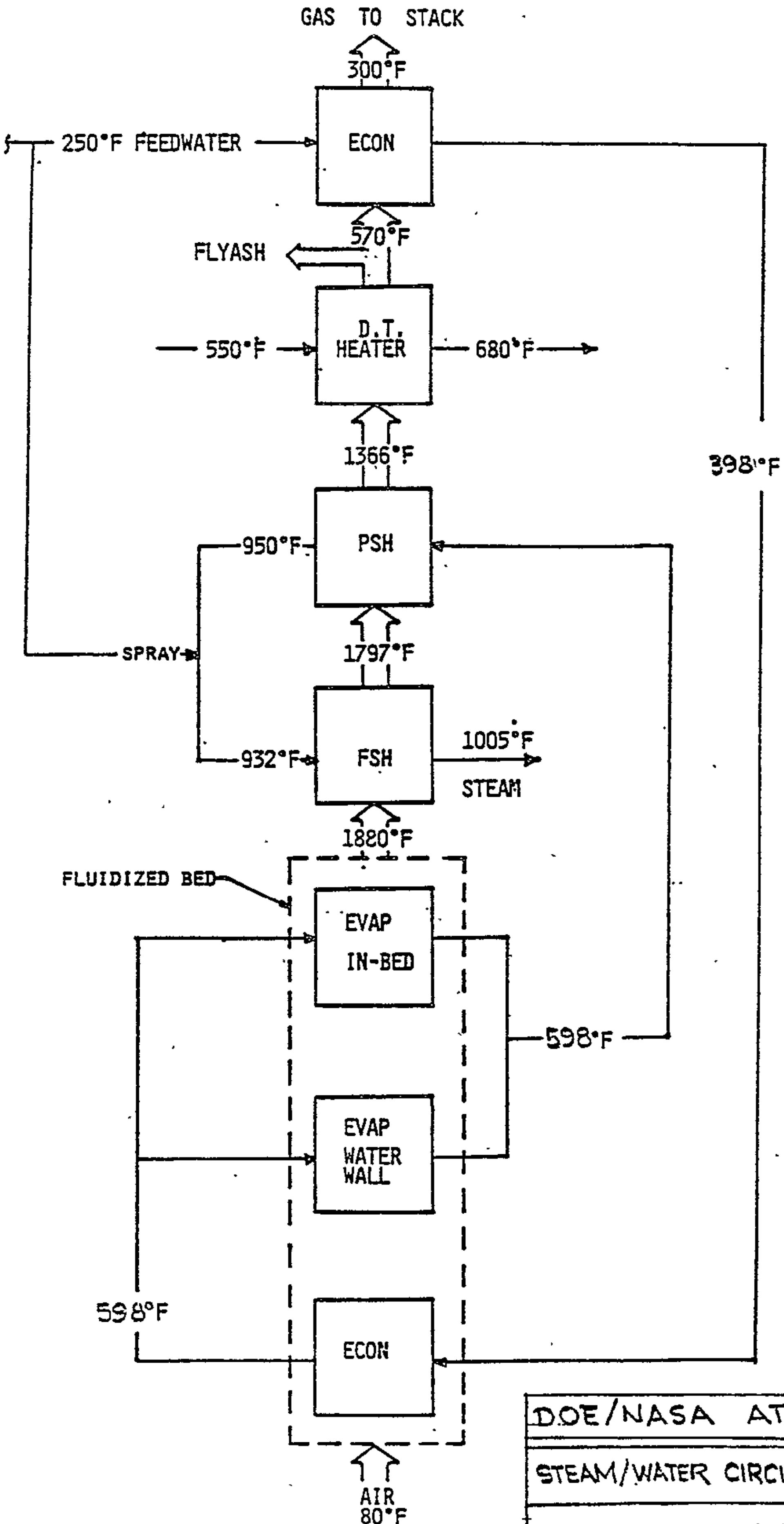
After exiting from the Dowtherm convective surface, the flue gas is passed through cyclone separators in order to reduce the particulate loading and enable a large portion of the unburned combustible matter in the ash to be recycled for further burning. The relatively clean gas leaving the cyclones is then ducted to an economizer which cools the flue gases down to 300°F.

In order to minimize the amount of surface required, the economizer is also arranged for counterflow heat transfer. A total of 168 tube elements, each consisting of 42 rows of 2-inch OD tubes located on 3-inch lateral centers, comprise the bare tube surface arrangement. As in the Dowtherm convective surface, the transverse spacing of the tube elements is 3 inches. Flue gas leaving the economizer is directed, via an ID fan, to the baghouse then to a stack.

Because of the relatively high temperatures (680°F) required by the Dowtherm, and the specified steam requirement, all enclosure surfaces (walls, roofs, partition wall) located above the beds are lined with 4 inches of erosion resistant refractory. This significantly reduces the flue gas temperature drop through the convection superheater, thus ensuring that adequate heat is available in the flue gas as it enters the Dowtherm convective surface.

2.2 Steam/Water Circuitry

Figure 2-4 schematically illustrates the steam and water circuitry. Feedwater passes through the first economizer (ECON 1) before entering the steam generator. From ECON 1 subcooled water passes through a section of in-bed tubes (ECON 2) and then to the steam drum. From the steam drum, downcomers and feeders supply saturated water to the enclosure and partition walls and the remainder of the in-bed tubes (BB1). The transition from saturated water to a steam/water mixture occurs within these tubes. The steam/water mixture leaving the enclosure and partition walls is returned to the steam drum where



DOE/NASA ATCS STUDY
STEAM/WATER CIRCUITRY SCHEMATIC
FIGURE 2-4

the steam and water are separated. The steam leaving the drum is sent through the primary superheater (PSH) located above the front bed. Superheated steam leaving the PSH is cooled by the spray attemperator.

Steam leaving the attemperator then goes to the finishing superheater (FSH) located in the first heat recovery zone where the steam is heated to its final outlet temperature.

Table 2-1 lists the steam/water circuitry material requirements. All pressure part materials indicated are similar to those utilized in a conventional pulverized coal steam generator, and do not represent a significant departure from conventional practice.

2.2.1 Economizer Surface

The economizer surface is concentrated in two areas of the unit: downstream of the cyclone outlet (ECON 1) and in both beds (ECON 2). ECON 1 surface is arranged for counterflow heat transfers, with feedwater passing vertically up through the tubes. At full load, the flue gas temperature is reduced from 570°F to 300°F in this zone.

ECON 2, located in both the front and rear beds, occupies the portion of the inclined immersed tube surface nearest the left side wall. Feedwater, exiting from the convective economizer downstream of the cyclones, is piped, via the piping supporting the air distributor, to the inlet headers of ECON 2. Upon exiting from ECON 2, the feedwater, at a temperature slightly below saturation, is piped directly to the drum.

2.2.2 Boiler Surface

The boiler surface consists of a number of heated circuits operating in parallel. Steam generation is achieved by utilizing natural circulation in all boiling circuits. During operation, slightly sub-

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TABLE 2-1. STEAM/WATER CIRCUITRY MATERIALS LIST

Pressure Part	Quantity	Surface Area, Ft^2 FP = Flat Projected GW = Gas Wetted	Diameter Inches (OD Unless) Noted	Minimum Wall Inches	Material	S_T Inches	S_L Inches
Furnace Wall Tubes	765 ---	1252 GW in Bed 4550 FP is Free-Board	2.00 ---	0.165 ---	210A1 ---	3.0 ---	--- ---
Grid and Floor Tubes	129	---	2.00	0.165	210A1	6.0	---
Immersed Bed Tubes	670	5964 GW	2.00	0.1654	213T2	6.0	---
Primary Superheater Tubes	1344	8445GW	1.50	0.165	213T2	3.0	3.0
	336	2111 GW	1.50	0.165	213T22	3.0	3.0
Finishing SH Tubes	168	1056 GW	1.50	0.165	213T22	6.0	3.0
Dowtherm Tubes	5040	42223 GW	2.00	0.165	213T2	3.0	3.0
Economizer Tubes	6720	38704 GW	2.00	0.165	210A1	3.0	3.0
Steam Drum	1	---	60 ID	7.0	515-60	---	---
Dowcomers	8	---	14	Sch 100	106B	---	---
Feeders and Risers	81 15	--- ---	4.50 6.625	Sch 120 Sch 120	106B 106B	--- ---	--- ---

TABLE 2-1. STEAM/WATER CIRCUITRY MATERIALS LIST (Contd)

Pressure Part	Quantity	Surface Area, Ft^2 FP = Flat Projected GW = Gas Wetted	Diameter Inches (OD Unless) Noted	Minimum Wall Inches	Material	S_T Inches	S_L Inches
Waterwall Headers	7 2	--- ---	8.625 12.750	Sch 140 Sch 160	106B 106B	--- ---	--- ---
Immersed Bed Header	4	---	8.625	Sch 140	106B	---	---
PSH Inlet Header	1	---	8.625	Sch 140	106B	---	---
PSH Outlet	1	---	10.750	1.56	TP304	---	---
FSH Inlet Header	1	---	10.750	1.56	TP304	---	---
FSH Outlet	1	---	10.750	1.61	TP304	---	---
DT In	1	---	10.750	Sch 120	106B	---	---
DT Out	1	---	10.750	Sch 120	335P2	---	---
Economizer	2	---	8.625	Sch 140	106B	---	---

cooled water is admitted to the bottom of the enclosure and in-bed tube circuits via a series of downcomers, feeders and headers. As the tube surface absorbs heat, the water is converted to a mixture of steam and water. This mixture then flows up through the heat absorbing tubing, (either enclosure walls or in-bed tubing) is collected in various headers and then fed, via numerous risers, to the drum. Due to the density difference existing between the steam/water mixture and the slightly subcooled feedwater entering the heat absorbing circuits, a constant flow of fresh feedwater is admitted to the tube circuit inlets. The flow rate in each circuit is estabished by balancing the pressure gained in the downcomer/feeder circuits with that lost in the heat absorbing/riser circuits. Flow rate adjustments are obtained during design by varying the number and size of feeders and/or risers, thus ensuring that each boiling tube circuit has a constantly wetted internal periphery. Thus, by maintaining the proper flow rates, tube hot spots can be eliminated.

For the present configuration, steam is generated in both the bed enclosure walls and a portion of the inclined tube surface immersed in each bed. Due to the presence of the refractory lining above the beds and throughout the convective surface enclosure, only 22 percent of the total design steam flow can be generated within the waterwalls. As a result of this, additional inclined heat transfer surface is placed within the beds to ensure a total steam generation rate of 360,000 lb/hr.

2.2.3 Convection Superheater Surface

The convection superheater, located above the front bed freeboard, is divided into a primary superheater (PHS) and a finishing superheater (FHS). Saturated steam at 598°F and 1505 psig leaves the drum and enters the primary superheater inlet header via 3 feed pipes. The steam then flows down through the PSH, exits through the enclosure wall and passes to the spray attemperator. Heat transfer surface in both the PSH and FSH is arranged for single loop-in-loop operation, whereby the inlet and outlet headers of a particular zone are connected by tube elements consisting of single, serpentine tubes spaced evenly along the length of the headers.

At design conditions, the spray attemperator mixes 0.8 percent of the total feedwater flow, at 250°F, with the superheated steam leaving the PSH. The resulting combined flow is then passed to the FSH. During normal operation, the amount of feedwater admitted to the attemperator varies in order to maintain the FSH steam outlet temperature at 1005°F. This arrangement can be used to neutralize small excursions in final steam outlet temperature resulting from variations in fuel quality, load changes, and transient conditions.

Steam exiting from the spray attemperator finally passes to the FSH, passes down through the two tube passes in this zone, and then is collected in the FSH outlet header.

Because of the downward flow of steam through the superheater, care has been taken to ensure that the frictional pressure drop through the heat transfer surface is significantly greater than the pressure gain which arises due to the differences in elevation between the inlet to the PSH and the outlet from the FSH. By maintaining the ratio of frictional pressure drop to gravity head pressure gain at a high value, the hazards associated with flow instabilities and flow reversals are minimized, and the dangers of superheater tube failure reduced.

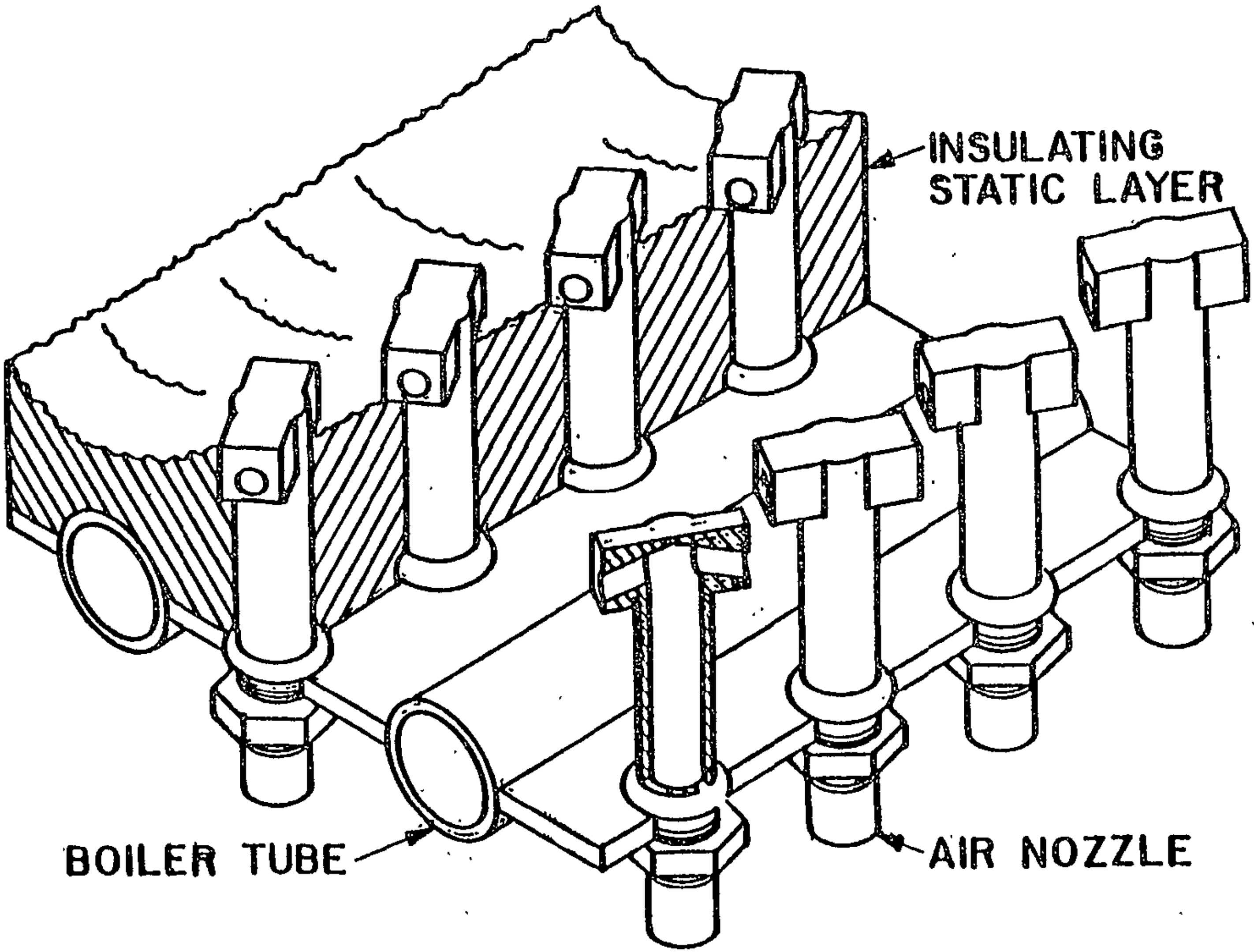
2.3 Dowtherm Circuitry

As noted previously, the Dowtherm heat transfer surface within the steam generator utilizes a counterflow arrangement in which hot flue gases pass down through the serpentine tube bundle while the Dowtherm flows upward. The 550°F liquid Dowtherm enters the tube bundle via a single inlet header, flows up through both heat transfer zones, and exits as a 680°F liquid prior to being piped to the process heat exchangers. Because of the relatively long piping runs between the Dowtherm heater and the point at which the Dowtherm heat is utilized, the Dowtherm heater has been designed to minimize frictional pressure drop at 62 psi. Flow imbalances which would normally occur in a downflow arrangement with this low pressure drop are largely reduced by the large gravity head differences between the inlet and outlet headers. As a result, each convective tube element receives ample Dowtherm flow, thus ensuring that flow stagnation and localized tube hot spots do not occur.

2.4 Air System

Combustion air for both beds is fed from the ID fan, via 4 separate ducts, to the compartmented plenums beneath each bed. Two of these ducts, (one for each bed), contain 30 x 10^6 Btu/hr in-line burners which are utilized during the start-up of the steam generator. These two burner ducts supply air to one third of the total plenum area of each bed, as dictated by the location of the plenum division walls which are perpendicular to the partition wall separating the two beds. After entering the plenums, the air from all four supply ducts (97.0 percent of the total combustion air), is admitted to the beds via the stainless steel tee nozzles located in the water cooled distributor support plate. The remaining 3 percent of the combustion air is admitted to the beds with the pneumatically injected recycled ash.

As described earlier, the distribution through which the fluidizing air is admitted to the beds consists of a series of 2-inch OD water cooled tubes located on 6-inch centers and connected by a continuously welded fin as shown in Figure 2-5. Cast stainless steel tee nozzles, located on 9-3/4-inch centers along each fin, are arranged in a triangular pitch over the entire plan area of both beds. The discharge point of each nozzle is 5 inches above the plate to which it is



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COGENERATION SYSTEM STUDY

WATER COOLED AIR DISTRIBUTOR

FIGURE 2-5

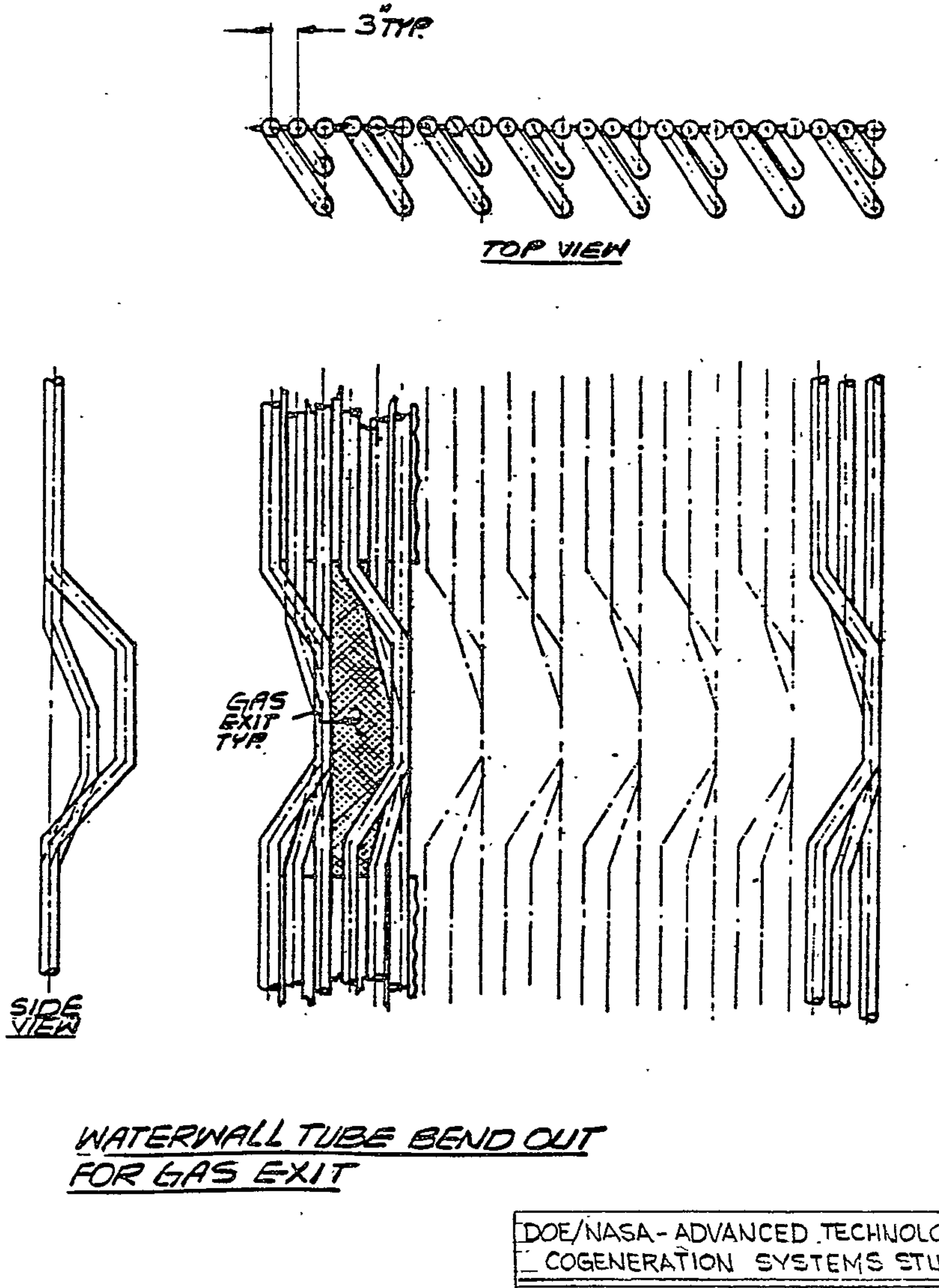
fastened, thus ensuring that the jets emanating from the nozzles do not impinge upon the floor tubes. During operation, a layer of bed material fills this 5-inch gap and effectively insulates the fin/tube floor from the 1600°F bed environment, thus eliminating the thermal expansion problems which would otherwise be encountered with a perforated plate distributor.

The overall tee nozzle geometry is selected to provide a pressure drop of 30 percent of the bed pressure drop. While simultaneously preventing the backflow of bed material into the plenum. This pressure drop ensures that, as load is reduced, sufficient drop is still available across the nozzles to ensure an adequate airflow distribution to the beds.

2.5 Flue Gas System

Because of the use of overbed fuel feed and the presence of a refractory lining in the freeboard, the flue gas temperature just above the beds rises to about 1880°F at full load operation. The dust laden gas from both beds then rises through the convection superheater, turns, and passes through the partition wall and down through the Dowtherm convective surface. A typical wall gas exit is shown in Figure 2-6. Gas exiting from the Dowtherm section is then passed to the recycle ash cyclones, and then to the inlet of the economizer. The flue gas temperatures as they pass through the unit are shown schematically in Figure 1-3.

Because of the high dust loadings in both the superheater and Dowtherm convective surfaces, relatively low maximum intertube gas velocities of 14 and 36 feet/second are employed in the primary and finishing superheater, respectively. Maximum Dowtherm intertube velocities reach 29 feet/second. These velocities provide high gas side film conductances, while minimizing the potential for accelerated tube erosion due to the high dust loadings.



DOE/NASA - ADVANCED TECHNOLOGY COGENERATION SYSTEMS STUDY
AFB SCREEN SECTION DETAILS
FIGURE 2-6

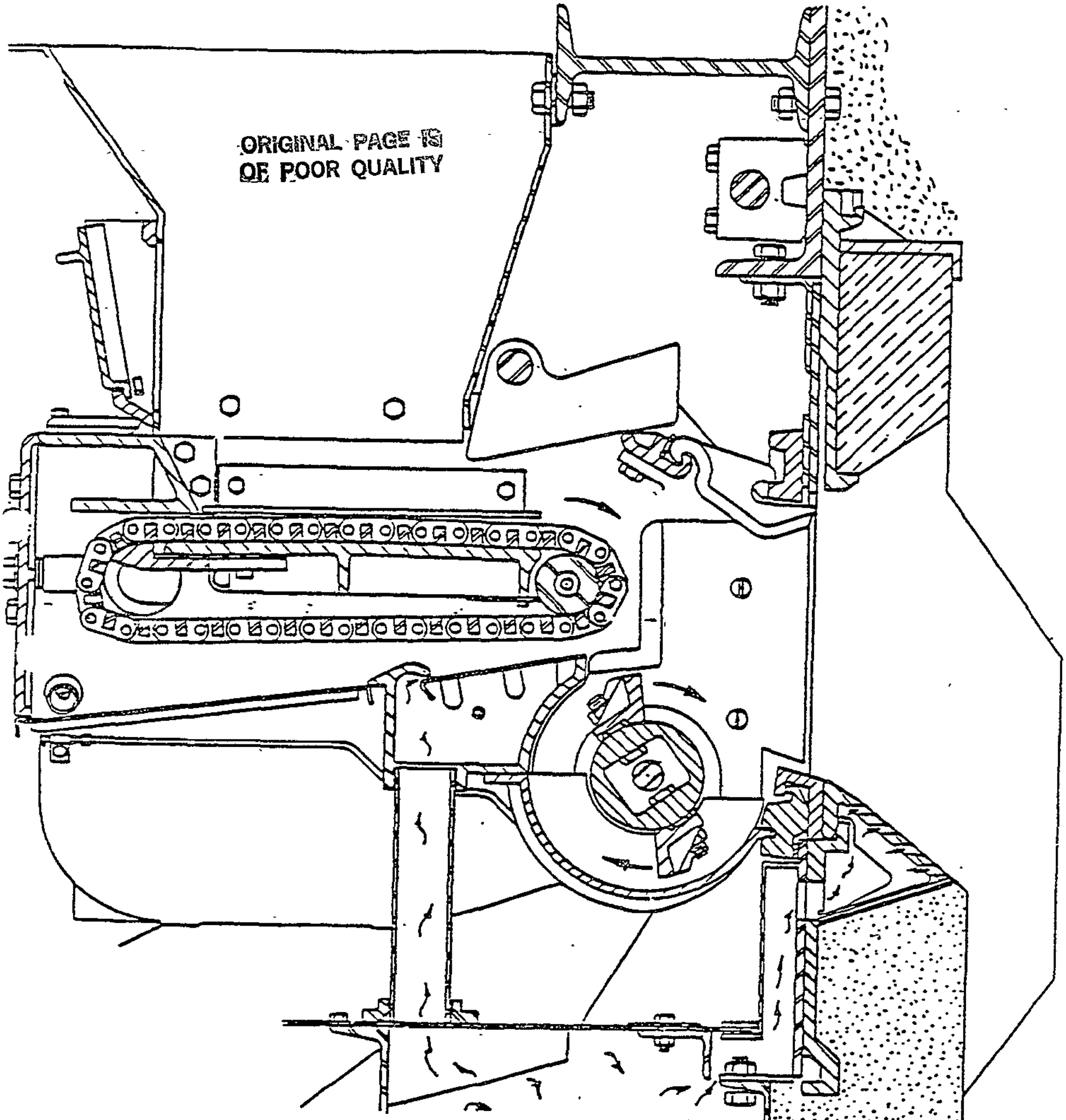
Retractable air blown sootblowers are provided at selected locations throughout the gas path in order to maintain high heat transfer coefficients in the convective sections. The use of air as a cleaning medium was selected in order to eliminate the possibility of reacted and/or agglomerated calcium constituents which could arise with the use of steam sootblowers.

As the dust laden gas exits from the boiler enclosure, it is ducted directly to the ash recycle cyclones. These cyclones are arranged in 4 parallel enclosures, each of which contains 100 cast iron cyclones. The flyash collected by these cyclones falls into 4 separate hoppers, from which it is pneumatically recycled to the beds, in order to improve carbon utilization.

2.6 Fuel Feed System

Fuel is fed to both beds by spreader stoker coal feeders, located in both side walls of the enclosure. A total of 12 feeders are employed in the steam generator, with 3 located in each side wall of both the front and rear beds. These feeders have been used in industrial steam generators for many years and have been extensively developed. A typical feeder is shown schematically in Figures 2-7 and 2-8.

A typical feeder consists of a small hopper which directs coal onto a plate. The plate has a series of 1-inch bars spaced at 2-inch centers, which are attached to a chain on each side. The bars move the coal horizontally and it falls onto a rotor. The rotor has several paddles attached to a 4-inch diameter shaft which rotates and propels the coal into the furnace. The coal dropping onto the rotor slides along the blades outward to provide a varying trajectory of the coal into the furnace. The rotor speed can be varied to suit the coal moisture and size distribution with regard to distance thrown. There are also adjustments available to the feed rate by changing the speed of the chain feeder. Cooling and sealing air is forced through the unit



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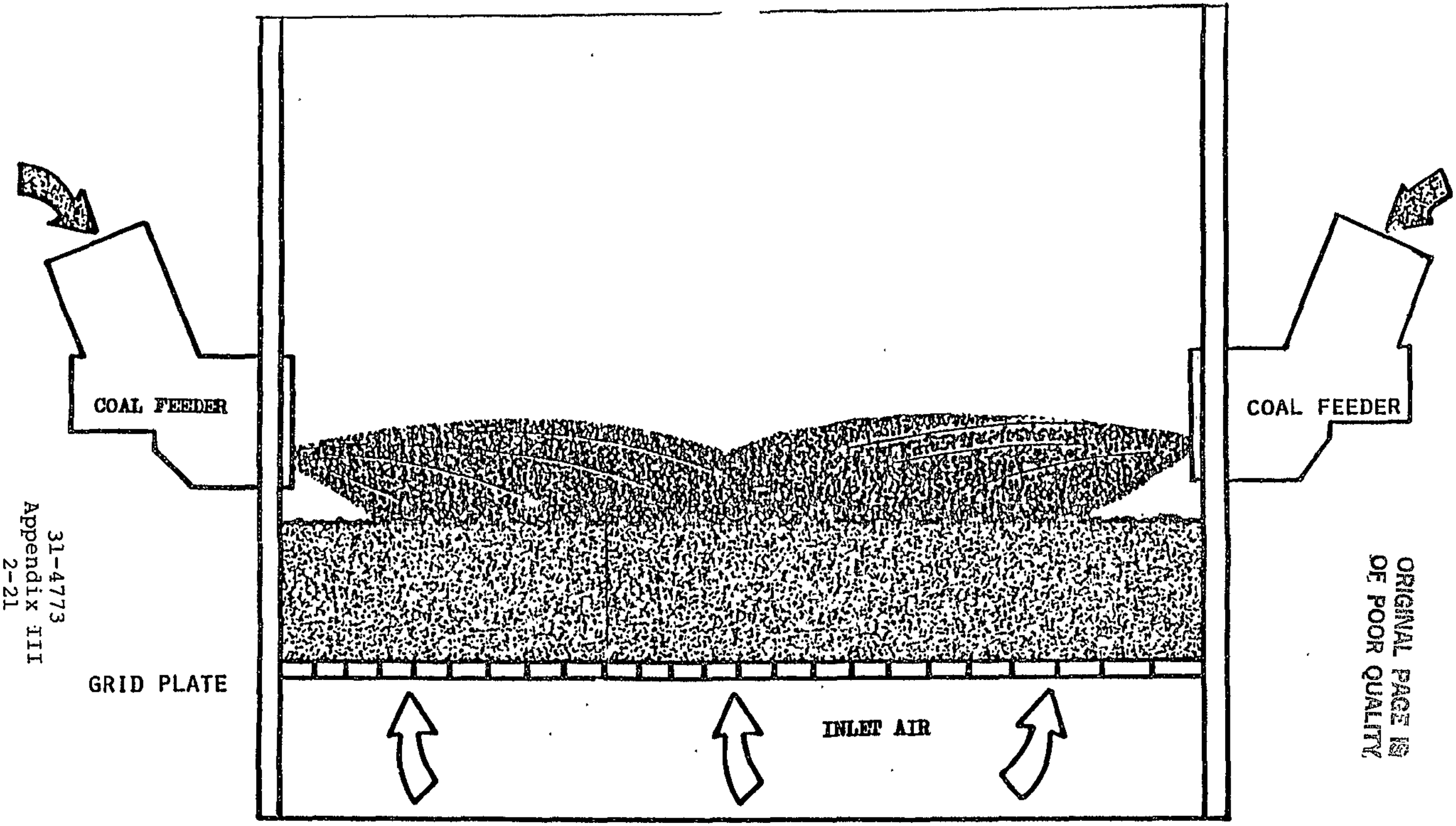
COGENERATION SYSTEMS STUDY

SPREADER FEEDER

FIGURE 2-7



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COAL FEED SCHEMATIC

FIGURE 2-8

to keep coal fines from the operating mechanisms. The principal bearings are water-cooled. A variable speed electric motor powers the spreader feeder. Coal can be thrown from the feeder to a distance in excess of 20 feet, depending upon the size and moisture content. A uniform side to side distribution pattern can be achieved.

One of the principal advantages of spreader units is the relative lack of sensitivity to moisture in the fuel. Wet coal can be handled readily and the moisture, although reducing combustor efficiency somewhat, aids the agglomeration of coal fines to larger particles for injection into the furnace. Since there are no small diameter conveying pipes, coal sized at nominal 1-1/4 inch x 0 is suitable for this type of feed, with not more than 20 percent of the feed lying in the 1/4 inch x 0 size range. Thus, this feed system minimizes the amount of coal crushing required, while simultaneously eliminating the need to dry the coal to any extent.

2.7. Limestone Feed System

Limestone, which serves as the sulfur sorbent during the combustion process, is fed to the beds via 4 feed ports located in each of the 4 side walls above the coal feeders. Limestone, sized to 1/8 inch x 0, is taken from its storage hopper and fed, via a rotary airlock, to each bed. The slope of the pipe through which the limestone flows to the beds is adjusted so as to enable gravity flow to be achieved. The location of the feed port in the boiler side wall was selected so as to provide a maximum bed residence time for the limestone particles, prior to removal from the two bed drain ports.

2.8 Flyash Recycle/Bed Removal System

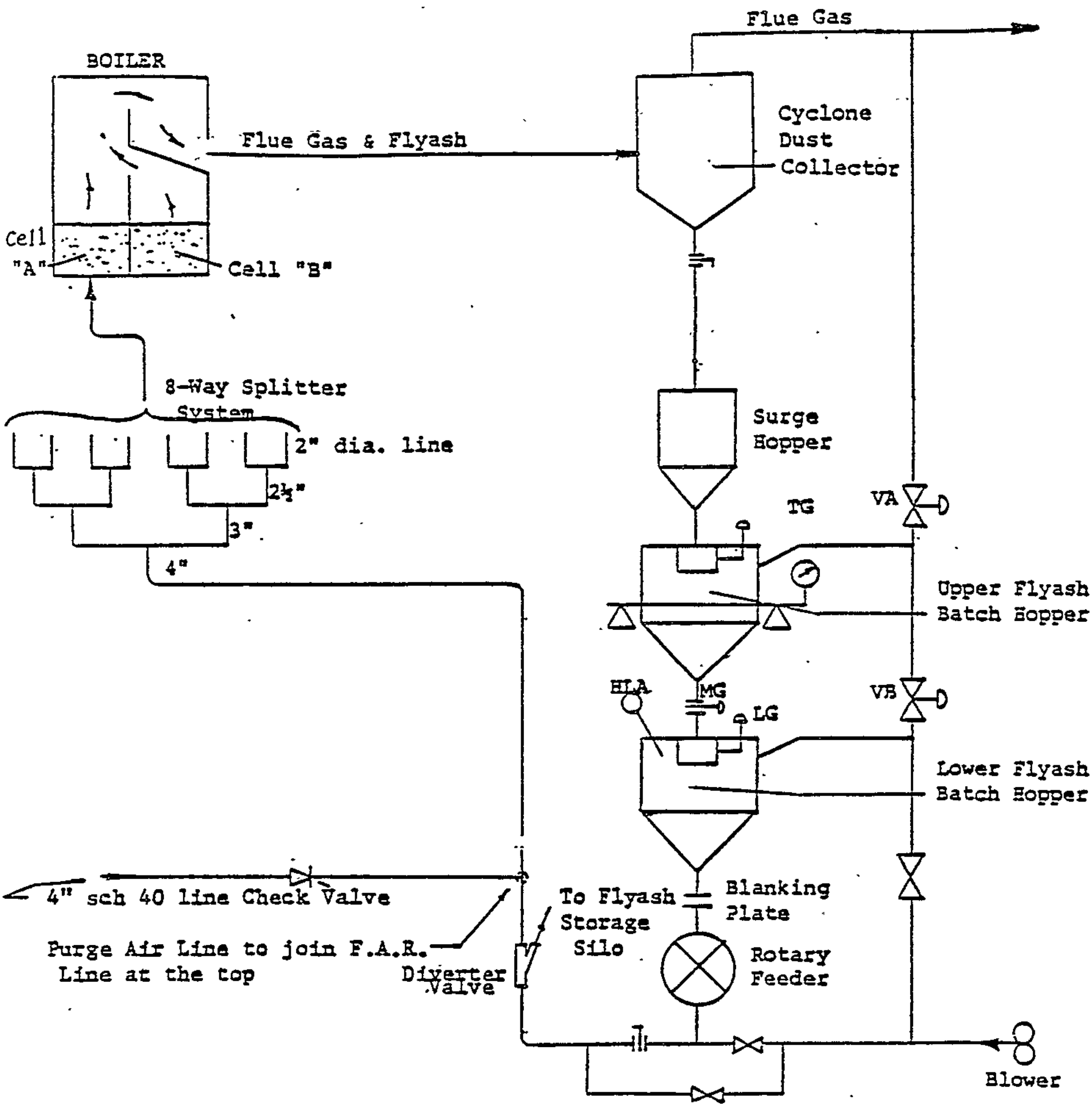
2.8.1 Flyash Recycle

The flyash recycle system is employed to return ash which is captured by the cyclones to the beds, in order to improve carbon burn-up efficiency. A separate recycle train is employed at the outlet of each of the 4 cyclone collection hoppers, and is shown in Figure 2-9. Each train consists of a series of lockhoppers, a rotary air lock, low pressure air blower, and the associated piping connecting the hoppers to the fluidized beds.

During operation, the flyash, which is dry and free flowing, is removed form the cyclone collection hopper in batches. Load cells are provided on the lockhoppers to both enable the recycle flow rate to be determined and to indicate when the hoppers are empty during their cyclic operation. Ash leaving the lockhoppers passes through a rotary feeder and drops into a 4-inch loading tee, where it is pneumatically conveyed to the beds. As the ash is being transported to the beds, the 4-inch line through which it flows from the loading tee is split into 8 separate lines. Each line passes through the plenum and discharges into the bed via a tee nozzle. All transport lines from the loading tee to the boiler enclosure are insulated in order to reduce heat losses and improve thermal efficiency.

2.8.2 Bed Removal System

Bed removal is achieved by two bed drain ports located in the center of each of the beds. The discharge from each of these ports passes through a refractory lined pipe which penetrates the plenum and empties through the bottom of the enclosure. The amount of ash removed is controlled by high temperature knife gate valves which are located in each discharge line and modulated to maintain a constant bed pressure differential. All ash which is removed is deposited into two ash coolers, which reduce the material temperature down to 300°F before it is transported to the ash storage hopper.



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COGENERATION SYSTEMS STUDY

FLYASH RECYCLE SYSTEM

FIGURE 2-9

2.8.3 Combustion Particulate Removal System

The combustion particulate removal system consists of a baghouse for removing flyash and other elutriated bed materials. The bag cleaning is accomplished by reversing the gas flow through one module at a time on a predetermined adjustable program. A more detailed description on the combustion particulate removal system design is included in Section 4.5. The total emission of particulate matter after the baghouse is 0.026 lb/mm Btu input which is below the federal new source performance standards (NSPS) of 0.03 lb/mm Btu input.

2.9 AFBC System Cost

Steam generator capital costs are summarized in Table 2-2. These costs, which are in 1982 dollars and are fully escalatable, include the following components:

(a) Pressure Parts
(b) Refractory and Insulation
(c) Coal Feeders and Drives
(d) Limestone Feeders and Drives
(e) Ash Recycle Cyclones and Conveying Equipment
(f) Start-Up Burners
(g) Combustion Air Control Dampers
(h) Insulation and Lagging
(i) Flues and Ducts Connecting the Economizer, Ash Recycle Cyclones and Boiler Enclosure
(j) Soot Blowers
(k) Controls
(l) Valves (solids let down, safety, drain, etc.)

TABLE 2-2. AFB STEAM GENERATOR COST SUMMARY

	1982 $
Engineering and Administration	2,269,280
Shop Labor	3,719,540
Material	5.728,180
TOTAL	11,717,000

Specifically not included in these costs are the following:

(a) Structural Steel, Platforms and Ladders
(b) FD Fan and Drive
(c) ID Fan and Drive
(d) Baghouse
(e) Electrical Connections and Wiring
(f) Ash Coolers and Ash Handling Equipment
(g) Coal and Limestone Preparation Equipment

3.0 STEAM TURBINE GENERATOR

A single automatic extraction condensing type steam turbine is used in the steam turbine cycle. The turbine is designed for the following conditions:

Throttle steam	:	1450 psig/1000 F
Extraction pressure	:	240 psia
Exhaust pressure	:	3.0 in. HgA
Throttle flow	:	360,000 lbs/hr

The turbine generator has a nameplate rating of 30 MWe.

3.1 Operational Requirements

The basic project requirements are to provide 24 MWe of net power generation and 190,000 lbs.hr of saturated steam at 240 psia for process. The gross electrical production from the cogeneration plant is sold to Houston Light and Power (HL&P) and all on site electrical requirements are purchased from HL&P.

3.2 Sizing of Turbine-Generator

A single automatic extraction turbine was selected for the steam turbine cycle because of the following factors:

(a) Certain areas in the steam path are designed with enlarged sections so that large quantities of steam can be extracted for process requirements.

(b) Additional control devices and linkages have been added to maintain extraction process, load, and flow control automatically.

This type of turbine is used widely in applications demanding continuous process steam at one pressure.

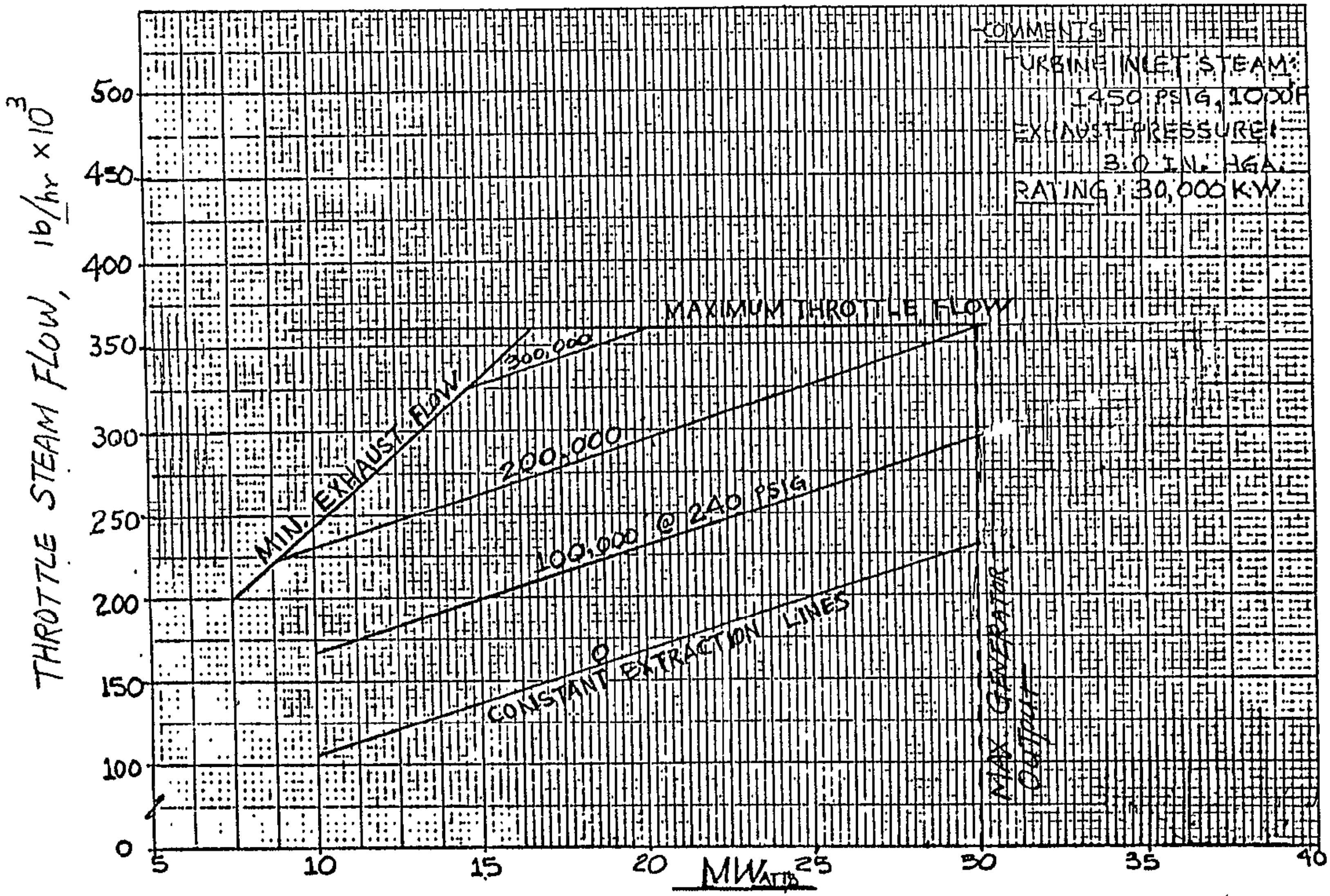
In sizing the turbine-generator, iterative calculations were performed to determine the required throttle steam flow which will provide 190,000 lbs/hr saturated steam at 240 psia and 24 MWe net power output in addition to the auxiliary power requirements with the turbine inlet set at a pressure of 1450 psia and a temperature of 1000°F. The analysis shows that with the throttle flow at 360,000 lbs/hr, the cogeneration plant can generate 28,400 kW gross output which will provide 4,400 kW of net output plus 190,000 lbs/hr of steam at 240 psia for process use. Therefore, a generator rating of 30 MWe (nominal) was selected for the cogeneration plant.

3.3 Steam Turbine Performance

The performance curves for a nominal rating of 30 MW single extraction turbine are shown in Figure 3-1. The family of parallel curves defines required throttle steam flow at kW output as shown on the horizontal axis and extraction flow. Each parallel line represents the constant extraction flow at extraction pressure of 240 psia. At the lower ranges of kW output there is a limitation on the amount of steam that may be extracted; when the output is all produced by extracted steam, the exhaust section of the turbine is idled. For this condition the blades churn the steam entrapped in these stages and rapidly raise the temperature of steam and blades to the point where blades may fail. To prevent this, a small amount of "cooling" steam flow must be maintained through the exhaust section to keep the blading temperature at a safe value; this steam carries off the energy the blade acquires from the churning.

The curve labeled minimum exhaust flow shows the relation between the kW output produced on extracted steam alone and corresponding throttle steam flow. This curve intersects each of the constant extraction curves at the throttle flow equalling the sum of the cooling steam and the extraction flow. For the 30 MW single extraction turbine the minimum exhaust is 25,000 lbs/hr.

ESTIMATED TURBINE PERFORMANCE



DOE/NASA ATCS STUDY

ESTIMATED TURBINE PERFORMANCE

Figure 3-1.

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Other limits are the maximum throttle flow and maximum generator output; these are fixed by the size of the respective parts. For a 30 MW single extraction turbine the maximum throttle flow is 360,000 lbs/hr which will provide 190,000 lbs/hr saturated steam at 240 psia for process, some extraction flow for deaerator heating and also generate 28.4 MWe gross electric output.

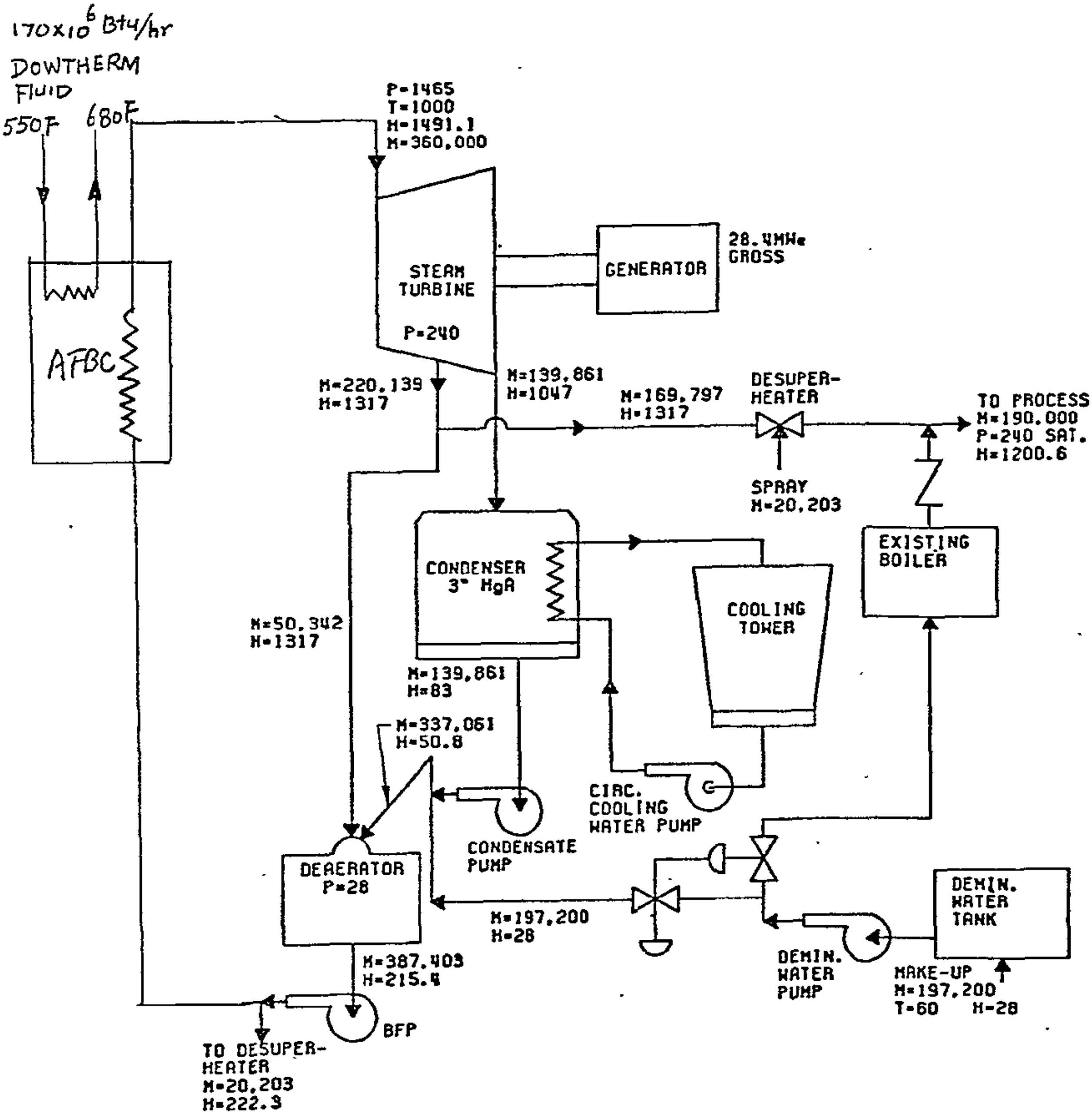
These performance curves indicate that both power demand and steam demand can be met simultaneously within the limits by adjusting the throttle steam flow.

3.4 Heat Balance

The heat balance developed for this study is based on standard equipment and includes the process steam requirement and make up water for the condensate lost during the process. The unit's throttle flow is 360,000 lbs/hr and gross generation is 28.4 MW and 220,139 lbs/hr of extraction steam of which 50,942 lbs/hr is intended for deaerator heating. The superheated extraction steam of 169,797 lbs/hr is desuperheated by mixing it with water to achieve the saturated steam of 190,000 lbs/hr at 240 psia for process. The heat balance of the steam turbine cycle system at design condition is shown in Figure 3-2. Exhaust steam into the condenser is cooled by the closed loop circulating water from the mechanical draft wet cooling tower.

3.5 Generator

The 30 MW nominal rating of the generator is rated at 32,000 kVA, 3600 rpm, 3 phase, 60 Hz, 13.8 kV, with 0.9 power factor. It is a synchronous type, air cooled generator with four corner mounted coolers.



DOE/NASA ATCS STUDY

HEAT BALANCE OF STEAM TURBINE CYCLE SYSTEM (100% LOAD)

Figure 3-2

3.6 Outline Drawing of Steam-Turbine-Generator

The typical outline of a 30 MW single extraction steam turbine-generator is shown in Figure 3-3.

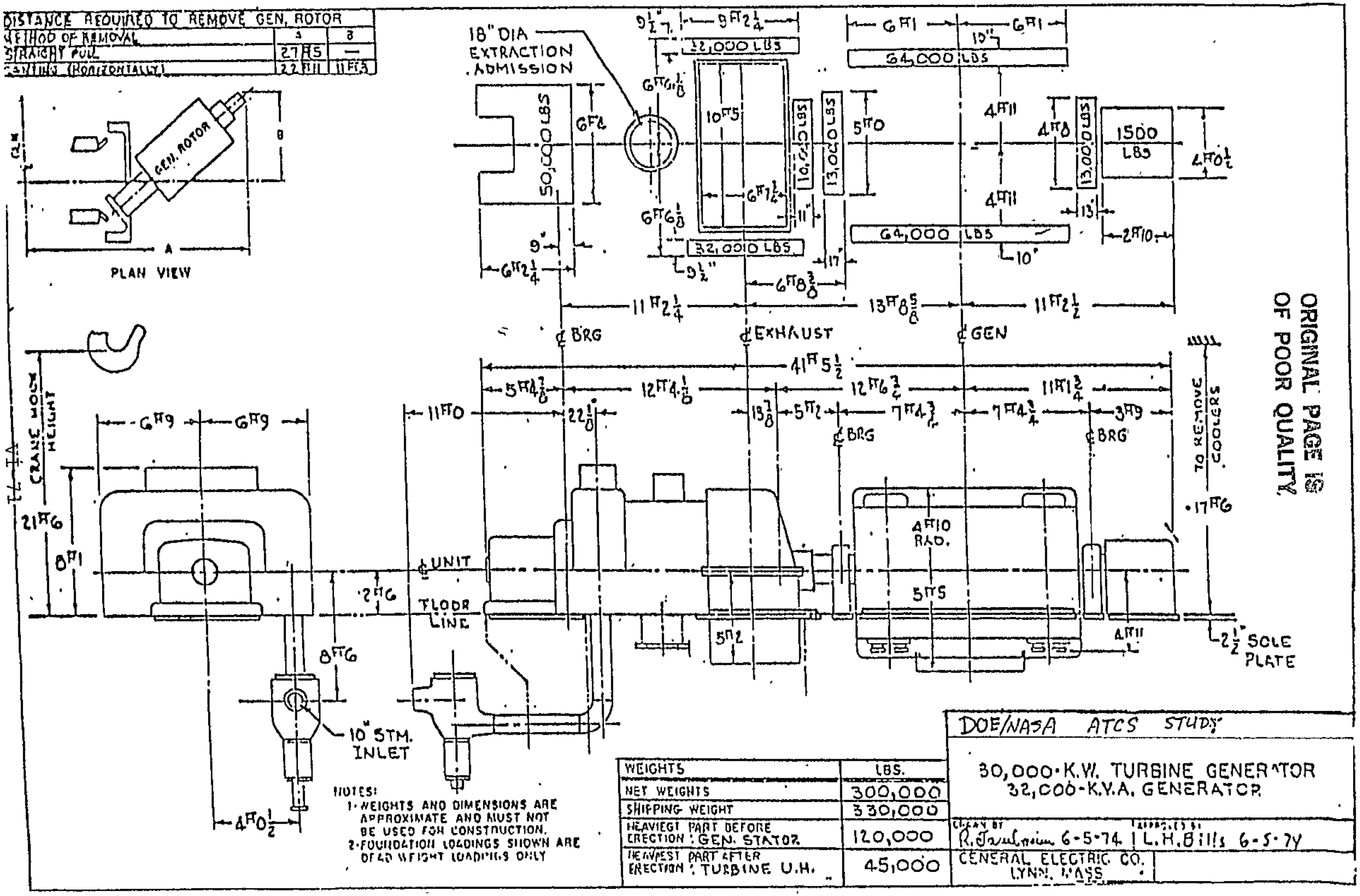

DISTANCE REQUIRED TO REMOVE GEN. ROTOR
METHOD OF REMOVAL
STRAIGHT PULL
SWIVING (HORIZONTALLY)
GEN. ROTOR
PLAN VIEW
18" DIA EXTRACTION ADMISSION
50,000 LBS
32,000 LBS
64,000 LBS
13,000 LBS
1500 LBS
℄ BRG
℄ EXHAUST
℄ GEN
41FT 5 1/2
℄ UNIT
FLOOR LINE
℄ BRG
4FT10 RAD.
CRANE HOOK HEIGHT
TO REMOVE COOLERS
10" STM. INLET
2 1/2" SOLE PLATE
NOTES:
1. WEIGHTS AND DIMENSIONS ARE APPROXIMATE AND MUST NOT BE USED FOR CONSTRUCTION.
2. FOUNDATION LOADINGS SHOWN ARE DEAD WEIGHT LOADINGS ONLY
WEIGHTS | LBS.
NET WEIGHTS | 300,000
SHIPPING WEIGHT | 330,000
HEAVIEST PART BEFORE ERECTION : GEN. STATOR | 120,000
HEAVIEST PART AFTER ERECTION : TURBINE U.H. | 45,000
DOE/NASA ATCS STUDY
30,000-K.W. TURBINE GENERATOR
32,000-K.V.A. GENERATOR
6-5-74
L.H. Bills 6-5-74
GENERAL ELECTRIC CO.
LYNN, MASS.

Figure 3-3.

4.0 BALANCE OF PLANT EQUIPMENT

4.1 Steam and Dowtherm Fluid Distribution System

The process steam (190,000 lbs/hr saturated steam at 240 psia) is extracted from the steam turbine cycle and conveyed in a 10-inch carbon steel pipe which is tied into the existing 10 inch steam header located near the existing boilers. The length of new steam line is 350 feet and is supported by overhead piping racks.

Both inlet and outlet Dowtherm fluid pipes are 10 inch pipe using carbon steel as piping material. The length of Dowtherm line for both inlet and outlet is 1500 feet and is supported by the overhead piping racks.

The distribution of process steam and Dowtherm are shown in Figure 4-1.

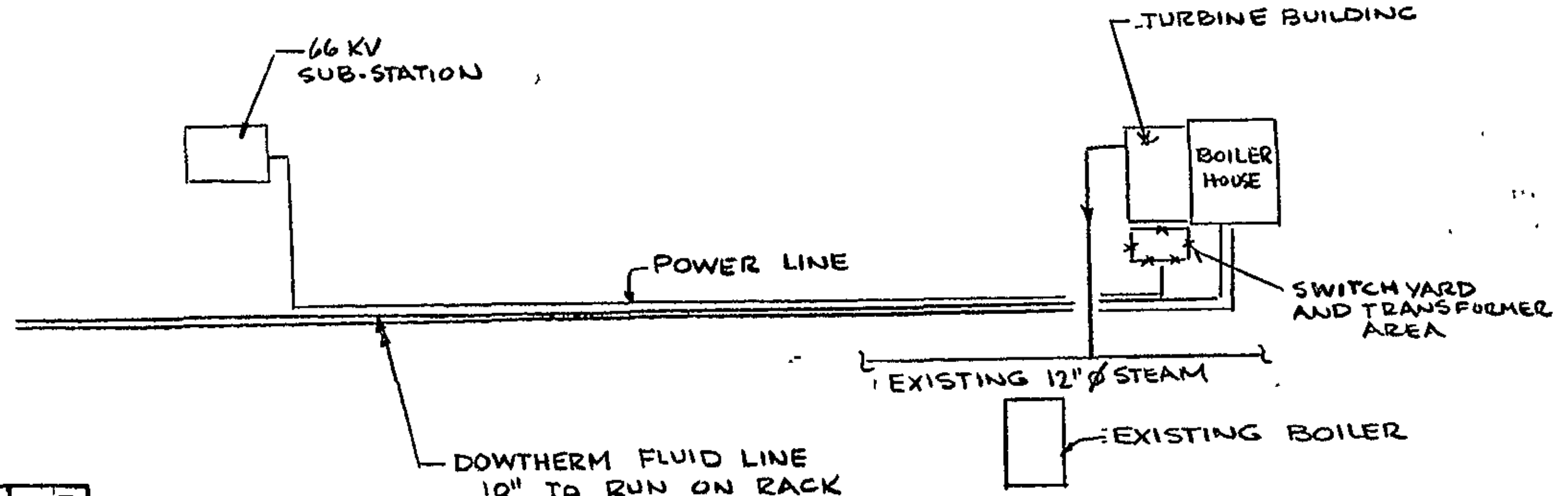
4.2 Coal Handling System

The coal handling facilities encompass three integrated system:

- o Shoreline facilities
- o Coal handling and coal storage
- o Coal reclaiming and bunker fueling

Figure 4-2 outlines these systems. Figure 1 of Appendix II illustrates the overall arrangement of the major equipment.

The maximum coal consumption at full load is 30.3 tons/hr. Coal arrives in 2 barges per week each carrying 2,550 tons per barge. The capacity of the dead coal storage pile is 15 days which is equivalent to 11,000 tons of coal.



DOE/NASA-ADVANCED TECHNOLOGY COGENERATION SYSTEM STUDY

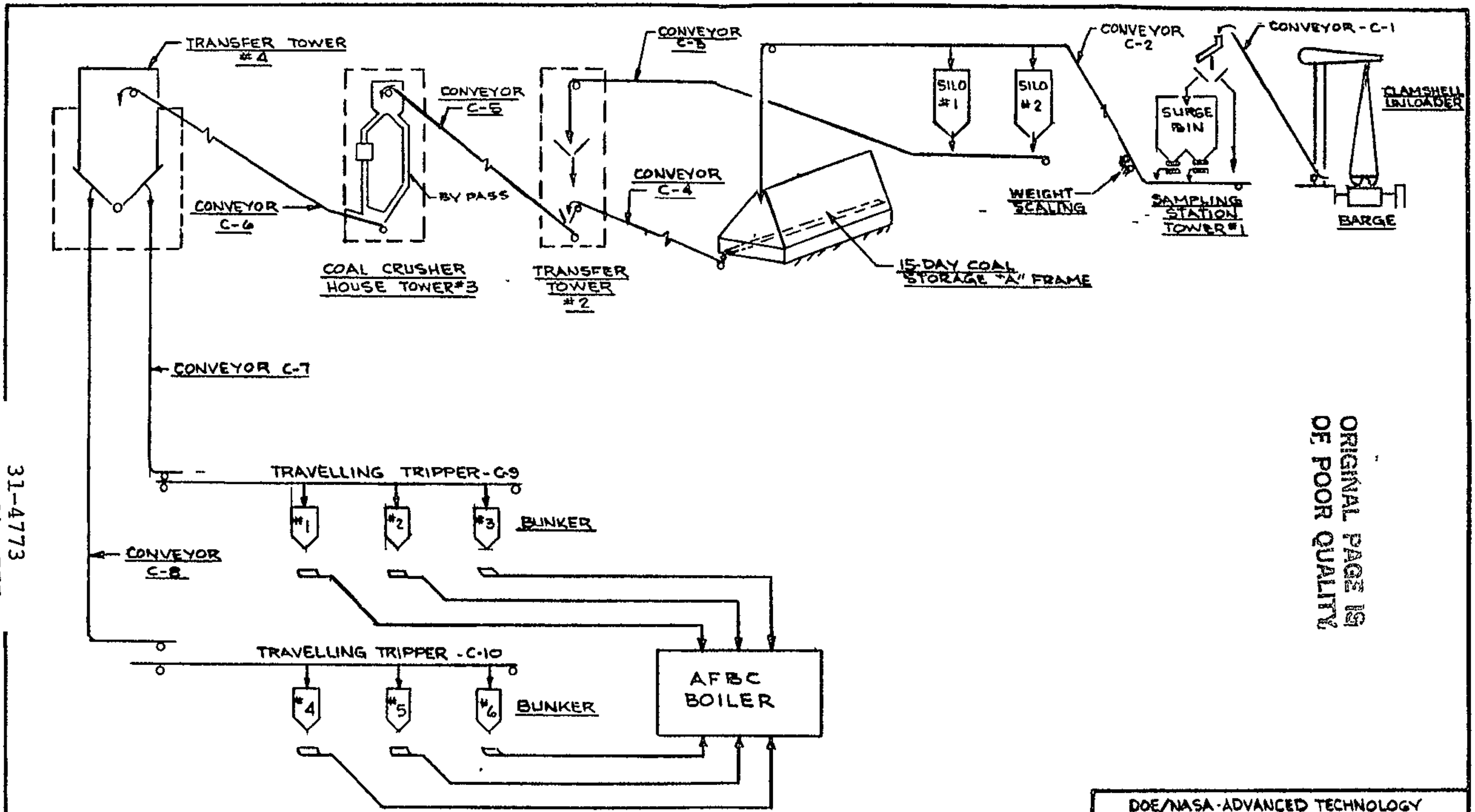
PROCESS STEAM AND DOWTHERM FLUID DISTRIBUTION LINES

Gibbs & Hill, Inc.

JOB NO. 11-3138-216

SCALE - ~

FIGURE 4-1



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Appendix III
4-3

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DOE/NASA-ADVANCED TECHNOLOGY COGENERATION SYSTEM STUDY

COAL HANDLING SYSTEM

Gibbs & Hill, Inc.
ENGINEERS DESIGNERS CONSTRUCTORS NEW YORK

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JOB NO 11-3138-216

FIGURE 4-2

MICRO FILM	ISSUE NO	DATE	DWN	CHKD	ARCH	STR	MECH	ELEC	CHEM SERV	I&C		CONSTR	P.M.	ISSUED FOR

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4.2.1 Shoreline Facilities

The shoreline arrangement has considered the value of water front property by minimizing the space allocated for the unloading of coal barges. Under the present scheme, the barge unloader would remain stationary while barges are moved back and forth along the shoreline, by means of a motor powered cable system propelling one barge at a time.

The barge unloader is a clamshell type, having an average/maximum (free digging) capacity of 250/400 TPH. Coal is unloaded in four day-shifts per week assuming 5 hours per shift of unloading and 3 hours for setup and related activities. One day-shift per week is reserved for normal maintenance and unscheduled outage contingency. Any coal spillage occurring during barge unloading drops back into the barge as it is being emptied. If as a result of the environmental review it becomes necessary to provide additional protective devices, this could be readily incorporated into the design.

4.2.2 Coal Handling and Coal Storage

Coal is transported by conveyor C1, to the sampling station in transfer tower No. 1. The sampling station extracts small but representative quantities from the coal arriving on conveyor C1, and, after further processing, delivers a final sample of approximately 40 lbs for laboratory analysis each day.

Coal transported over conveyor C2 normally discharges into coal silo 1 or 2. Conveyors C1 and C2 have the same 250/400 TPH coal feed rating as the unloader. Each silo is proportioned to store 1100 tons of coal. When both silos are full, they contain sufficient coal to fuel the bunkers for 3 days of operation at rated captivity. Thus, barge unloading or secondary reclaiming from outside storage is not required over the weekend. The silos are designed to feed coal on a first-in first-out basis. This feature prevents coal from remaining in a silo long enough to overheat and catch fire due to spontaneous combustion.

When the silos are filled to capacity before all barges have been unloaded, excess coal is fed into the dead coal pile storage which is housed by an A-Frame type structure. Such an enclosure prevents fugitive dust. Coal placed inside the A-Frame storage pile is reclaimed through a tunnel and conveyed to the transfer tower No. 2.

4.2.3 Coal Reclaiming and Bunker Fueling

Coal is withdrawn from either silo 1 or 2 by means of bottom discharge and transported by conveyor C3 to transfer tower No. 2. At that point it discharges to conveyor C5 and is conveyed to the crusher house. Alternatively, when both silos 1 and 2 are empty, coal is reclaimed from the coal storage piles and transported by conveyor C4 to transfer tower No. 2 and then to the crusher house. Conveyors C3, C4 and C5 and the crusher house process coal at 150/225 TPH average/ maximum feed rates which permits the coal bunkers to be filled for 24-hour operation in 5 hours of a day shift.

Coal is transported from the crusher house to transfer tower No. 4 by conveyor C6. Two conveyors C7 and C8 then transport coal from transfer tower No. 4 to 2 tripper conveyors (C9 & C10) located above the coal bunkers on both sides of AFBC combustor. Conveyors C6 to C10 can feed coal at the same 150/225 TPH rating as the prior coal handling equipment. The travelling trippers fill the 6 bunkers sequentially. If a bunker is taken out of service, a slide gate is closed, preventing coal from entering. As the last bunker reaches a high coal level, a signal shuts down the bunker fueling system at its source. The bunker capacity is designed for one day operation at rated capacity.

All conveyors and related equipment are fully interlocked and controlled from a centrally located control panel. A separate control panel for the unloading system is located in the unloading control cab. Automation would be specified to the extent necessary to relieve operators of non-essential and repetitive functions.

4.3 Limestone Handling System

Limestone is delivered by truck to the plant site. Figure 1 of Appendix II illustrates the overall arrangement of the limestone handling system.

The limestone consumption rate at full load for the steam system is 11 tons per hour and for the CCGT system is 6.66 tons per hour. Assuming 90 percent capacity factor and 100 percent load at all times, the annual limestone consumption is estimated to be 86,700 tons for the steam system and 50,000 tons for the CCGT system. The capacity of limestone storage is designed for 15 days of full load operation. This is equivalent to 3,960 tons of storage.

Limestone is unloaded to the hopper and then conveyed to a storage pile housed in an A-Frame type structure. Such a structure prevents fugitive dust. Limestone placed inside the A-frame structure is reclaimed through a tunnel and conveyed to the transfer tower where two separate conveyors transport limestone to the trippers, and eventually to the limestone bunkers located on both sides of limestone feeding ports. The total capacity of limestone bunkers is designed for one day operation at rated capacity, and is equivalent to 265 tons.

The limestone reclaim rate and conveyor feed rate are designed for up to 60 TPH with an average rate at 40 TPH. Thus the limestone bunkers are filled in 7 hours for 24 hour operation.

4.4 Solids Removal System

The solids removal system is composed of the following:

(a) Bed material removal system
(b) Flyash reinjection system
(c) Flyash removal system

Bed material consisting of spent sorbent and ash is drained by gravity from each bed. Bed material at 1600°F is cooled to about 300°F in an air cooled bed drain cooler located below each of the two boiler beds. Material discharging from the bed drain cooler passes through an air lock into a pneumatic transport line which carries the material to a storage silo. The normal drain rate of bottom ash and spent sorbent from the fluidized bed at the full load is 14,000 lb/hr.

In the event of plant shutdown under an emergency condition, it may be necessary to drain the spent sorbent and bottom ash as fast as possible to remove the heat stored inside the fluidized bed boiler and to avoid the overheating of the tubes. Thus a maximum bed drain rate of 28,000 lb/hr, which doubles the normal production rate of 14,000 lb/hr, has been designed for the bed material removal system.

Flyash reinjection is provided from a mechanical collector (cyclone) located immediately downstream from the combustor. The intent of the reinjection system is to reinject unburned carbon into the boiler for more complete combustion. Reinjection is pneumatic with the collected flyash dropping into an eductor from which it is impelled into the combustor bed by pressure blowers.

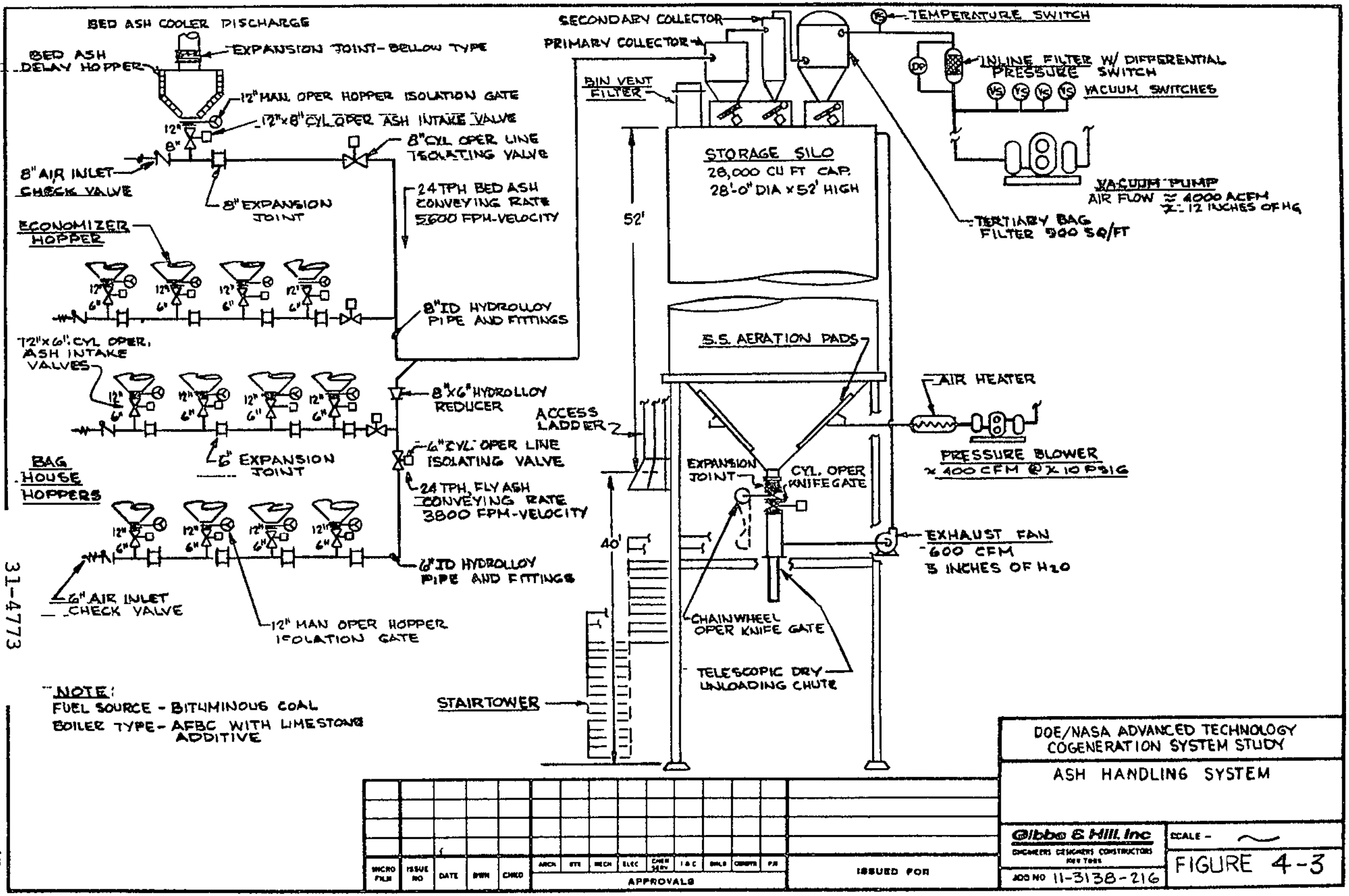
Flyash passing beyond the mechanical collector partially drops out in 4 hoppers located below the economizer; the remainder is collected in a baghouse. Particulates trapped on the bags in the baghouse drop into hoppers. From the hoppers they are conveyed into air locks from which they are picked up by a pneumatic transport system for delivery to a flyash silo. The normal removal rate of flyash from the baghouse is 9872 lb/hr.

Based on the system described above, a vacuum system with a solids transporting capability of 24 TPH was designed for the removal of spent sorbent and bottom ash from the bed drain and flyash from the economizer section and the baghouse. The schematic flow diagram of the solid removal system is shown in Figure 4-3. A vacuum or negative pressure was chosen over a pressure system due to the simplicity of equipment at the hoppers and the short travelling distance for ash from drain point to the storage silo. A vacuum conveying system carries the material through a pipeline in an air stream at less than atmospheric pressure. The airflow is induced by an air exhauster located at the distant end of the pipe. The exhauster is powered by a mechanical blower. Air enters the pipe through an air intake (8 inch check valve) at the upstream end of the conveying pipe and the material enters the pipe through ash intakes located along the pipe including drains from bed, economizer and baghouse hoppers. Material is fed from only one ash intake at a time, and is carried through the pipe by the air stream induced by the exhauster at the far end of the line.

Hoppers are emptied one at a time, in sequence, along the conveyor row. Conveying proceeds from hopper to hopper and row to row until the dust collector hoppers are all emptied.

An ash silo of 28 foot diameter x 52 foot high with net volume of 28,000 feet^3 was designed to provide 3 days of storage at full load.

The two bottom ash coolers are designed to cool 14,000 lb/hr each of bed drain from the fluidized bed boiler from 1600°F down to 300°F using a 33,150 lb/hr of air at 100°F. In reducing the ash temperature to 300°F, the bottom ash can be transported in a manageable way


BED ASH COOLER DISCHARGE
EXPANSION JOINT - BELLOW TYPE
BED ASH DELAY HOPPER
12" MAN. OPER HOPPER ISOLATION GATE
12"x8" CYL OPER ASH INTAKE VALVE
8" CYL OPER LINE ISOLATING VALVE
8" AIR INLET CHECK VALVE
8" EXPANSION JOINT
24 TPH BED ASH CONVEYING RATE 5600 FPM-VELOCITY
ECONOMIZER HOPPER
8" ID HYDROLLOY PIPE AND FITTINGS
12"x6" CYL OPER. ASH INTAKE VALVES
8"x6" HYDROLLOY REDUCER
6" EXPANSION JOINT
6" CYL. OPER LINE ISOLATING VALVE
24 TPH FLY ASH CONVEYING RATE 3800 FPM-VELOCITY
BAG HOUSE HOPPERS
6" ID HYDROLLOY PIPE AND FITTINGS
6" AIR INLET CHECK VALVE
12" MAN OPER HOPPER ISOLATION GATE
NOTE:
FUEL SOURCE - BITUMINOUS COAL
BOILER TYPE - AFBC WITH LIMESTONE ADDITIVE
SECONDARY COLLECTOR
PRIMARY COLLECTOR
TEMPERATURE SWITCH
BIN VENT FILTER
INLINE FILTER W/ DIFFERENTIAL PRESSURE SWITCH
VACUUM SWITCHES
STORAGE SILO
28,000 CU FT CAP.
28'-0" DIA x 52' HIGH
52'
VACUUM PUMP
AIR FLOW ≅ 4000 ACFM
≅ 12 INCHES OF HG
TERTIARY BAG FILTER 500 SQ/FT
S.S. AERATION PADS
AIR HEATER
ACCESS LADDER
PRESSURE BLOWER
≈ 400 CFM @ ≈ 10 PSIG
EXPANSION JOINT
CYL. OPER KNIFE GATE
40'
EXHAUST FAN
600 CFM
5 INCHES OF H2O
CHAINWHEEL OPER KNIFE GATE
TELESCOPIC DRY UNLOADING CHUTE
STAIRTOWER
DOE/NASA ADVANCED TECHNOLOGY COGENERATION SYSTEM STUDY
ASH HANDLING SYSTEM
Gibbs & Hill, Inc
ENGINEERS DESIGNERS CONSTRUCTORS
SCALE -
FIGURE 4-3
JOB NO 11-3138-216
MICRO FILM
ISSUE NO
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through the handling system to the storage silo. To cool the bottom ash, 5 percent of the combustion airflow, equivalent to 33,150 lb/hr, is diverted from the combustion airflow path to the cooler. The final air temperature leaving the cooler will be in the range of 620°F. The heated airflow from the ash cooler is then mixed with the other 95 percent of combustion air. The general layout of the ash cooler is shown in Figure 4-4.

4.5 Combustion Particulate Removal System

The combustion particulate removal system consists of a baghouse for removing flyash. The fabric filter type collector system is a continuous cleaning, high efficiency, multiple bag, glass filter design. The collector has a rectangular configuration of modular design with fabric filter cleaning by reverse airflow. A sufficient number of modules are furnished such that performance criteria are met with one module out of service for cleaning with reverse airflow.

The baghouse is designed for negative pressure to operate at a draft loss of 6 to 8 inches w.g. from baghouse inlet to outlet when operating continuously at the flue gas flow and dust loading specified below:

Gas Flow:	233,000 ACFM at 300°F
Inlet Concentration:	5.02 gr/ACFM
Outlet Concentration:	0.01 gr/ACFM
Removal Efficiency:	99.8 percent
Baghouse Drain:	9,815 lb/hr
Average Particle Size:	100-150 microns

The total emission of particulate matter after the baghouse is 0.026 lb/mm Btu input, which is below the federal new source performance standard (NSPS) of 0.03 lb/mmBtu input.

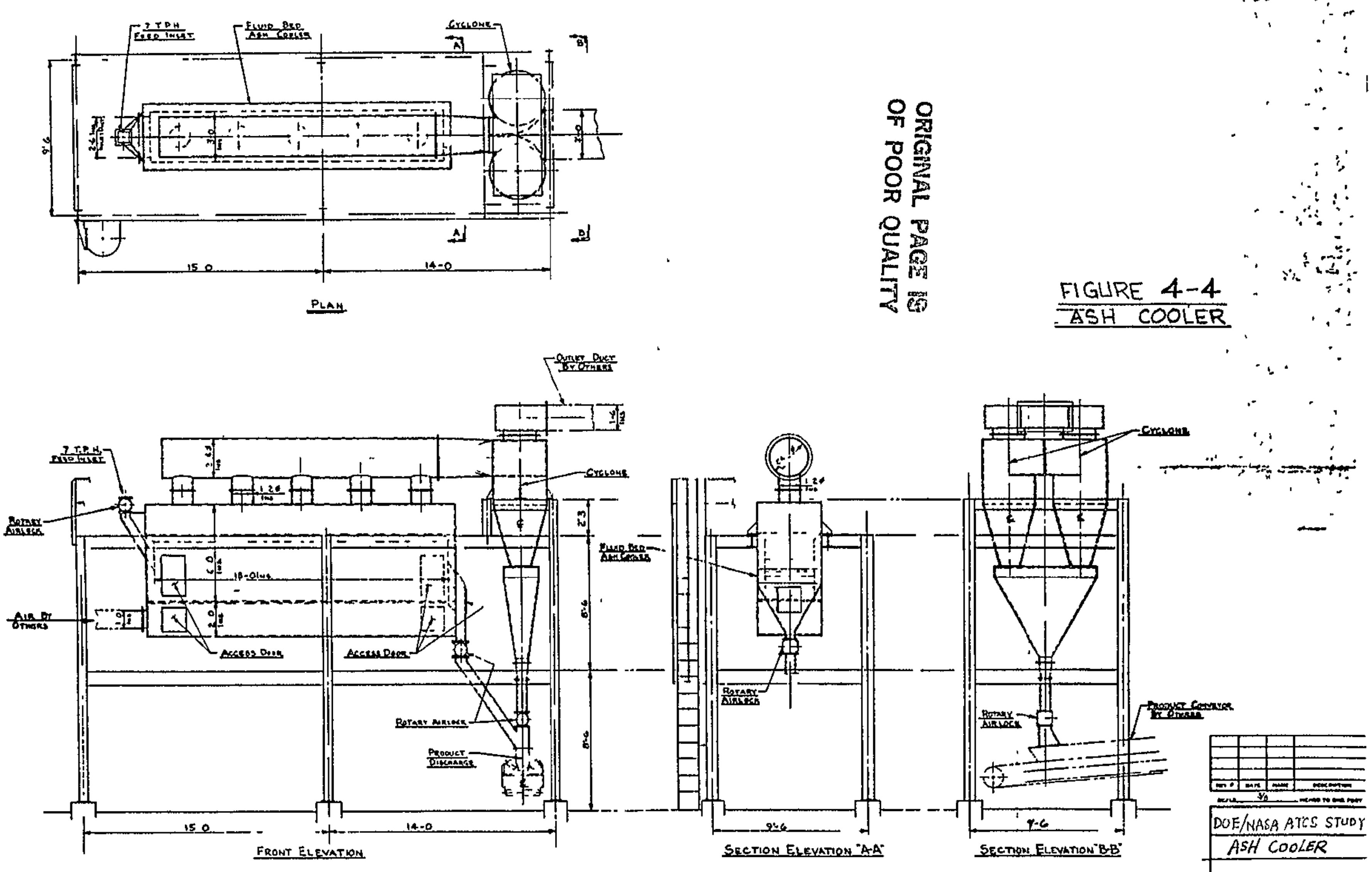

FIGURE 4-4
ASH COOLER

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(NOTE: THIS DRAWING WAS PROVIDED BY HEYL & PATTERSON, INC. PITTSBURGH)

The exterior housing, hoppers, tubesheet and ductwork consist of 3/16 inch minimum thickness, ASTM A36 carbon steel. The baghouse and hoppers are welded construction stiffened as necessary with structural steel shapes. Bags are glass fiber construction with acid resistant Teflon "8" finish and have anticollapse rings sewn into each bag.

The baghouse design consists of:

Number of modules per baghouse:	12
Number of bags per module:	212
Total number of bags:	2544
Bag size:	8 inch diameter x 24 feet long
Cloth area per bag:	50.16 square feet
Total cloth area:	127,607 square feet
Gross air to cloth ratio:	1.85
Net air to cloth ratio (one module out for cleaning, including reverse air)	2.15

The arrangement of baghouse design is shown in Figure 4-5. The bag cleaning is accomplished by reversing the clean gas flow through one module at a time on a predetermined adjustable program cycle. A completely automatic control system is used to regulate the reverse air cleaning cycle for each module. The controls provide capability to adjust all phases, sequences and cleaning cycle time as required.

Each hopper has a heater to maintain the internal hopper temperature above the ambient dew point during start-up. The hopper heater system is thermostatically controlled and includes starters, controls and alarms.

The baghouse housing, hoppers, reverse air ductwork, hot gas inlet and outlet duct and roof are insulated with 3 inch thick mineral wool block or mineral wool blanket material.

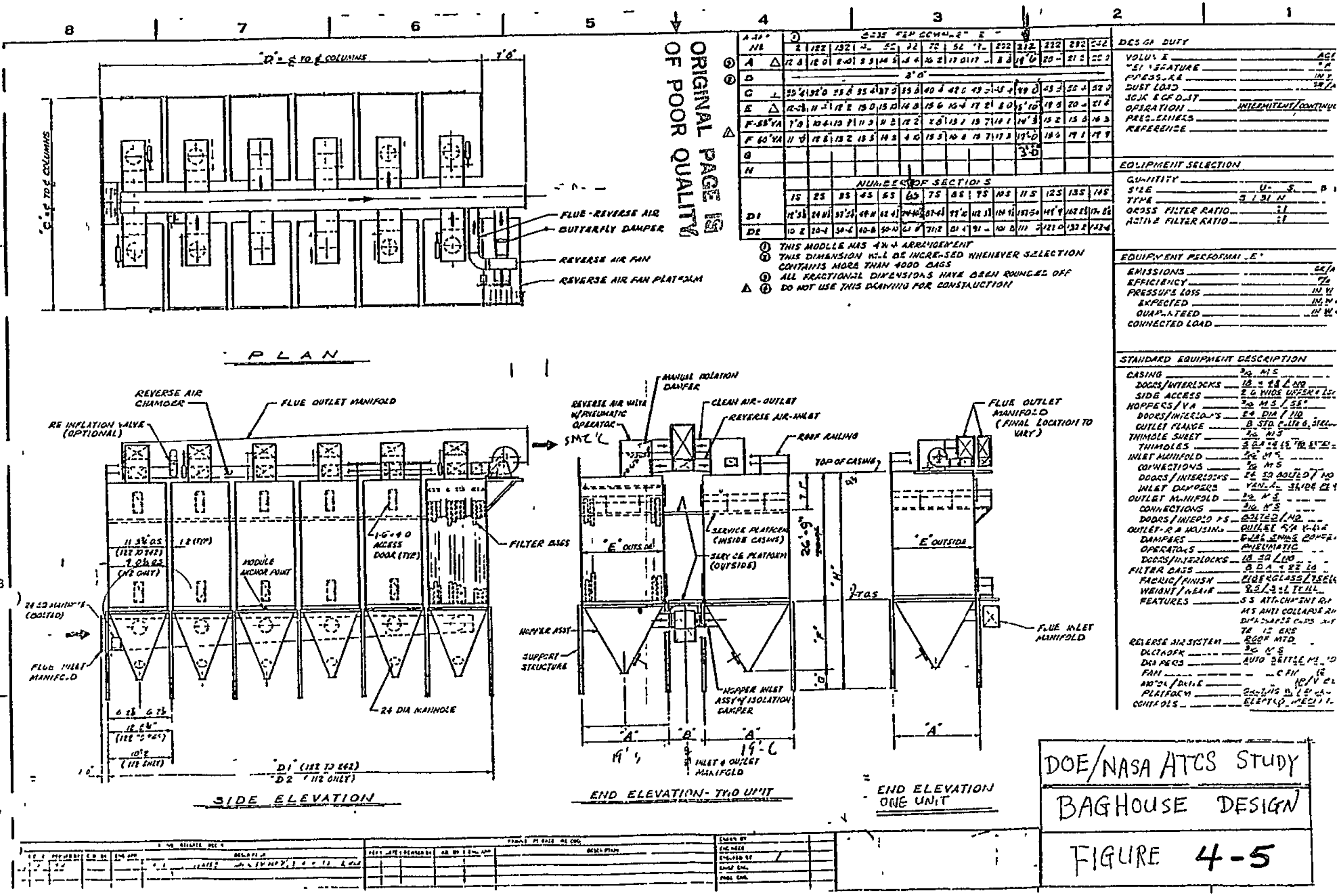

ORIGINAL PAGE IS OF POOR QUALITY
PLAN
FLUE - REVERSE AIR
BUTTERFLY DAMPER
REVERSE AIR FAN
REVERSE AIR FAN PLATFORM
NUMBER OF SECTIONS
THIS MODULE HAS 4 X 4 ARRANGEMENT
THIS DIMENSION WILL BE INCREASED WHENEVER SELECTION CONTAINS MORE THAN 4000 BAGS
ALL FRACTIONAL DIMENSIONS HAVE BEEN ROUNDED OFF
DO NOT USE THIS DRAWING FOR CONSTRUCTION
DESIGN DUTY
EQUIPMENT SELECTION
GROSS FILTER RATIO
ACTIVE FILTER RATIO
EQUIPMENT PERFORMANCE
EMISSIONS
EFFICIENCY
PRESSURE LOSS
EXPECTED
GUARANTEED
CONNECTED LOAD
STANDARD EQUIPMENT DESCRIPTION
CASING
DOORS/INTERLOCKS
SIDE ACCESS
HOPPERS
OUTLET FLANGE
THIMBLE SHEET
THIMBLES
INLET MANIFOLD
CONNECTIONS
INLET DAMPERS
OUTLET MANIFOLD
DAMPERS
OPERATORS
FILTER BAGS
FABRIC/FINISH
FEATURES
REVERSE AIR SYSTEM
DUCTWORK
FAN
PLATFORM
CONTROLS
REVERSE AIR CHAMBER
FLUE OUTLET MANIFOLD
RE INFLATION VALVE (OPTIONAL)
MODULE ANCHOR POINT
ACCESS DOOR (TYP)
FILTER BAGS
FLUE INLET MANIFOLD
24 DIA MANHOLE
SIDE ELEVATION
MANUAL ISOLATION DAMPER
REVERSE AIR VALVE W/PNEUMATIC OPERATOR
CLEAN AIR - OUTLET
REVERSE AIR - INLET
ROOF RAILING
TOP OF CASING
SERVICE PLATFORM (INSIDE CASING)
SERVICE PLATFORM (OUTSIDE)
HOPPER ASSY
SUPPORT STRUCTURE
HOPPER INLET ASSY W/ ISOLATION DAMPER
INLET & OUTLET MANIFOLD
END ELEVATION - TWO UNIT
FLUE OUTLET MANIFOLD (FINAL LOCATION TO VARY)
FLUE INLET MANIFOLD
END ELEVATION ONE UNIT
DOE/NASA ATCS STUDY
BAGHOUSE DESIGN

FIGURE 4-5

4.6 Heat Rejection System

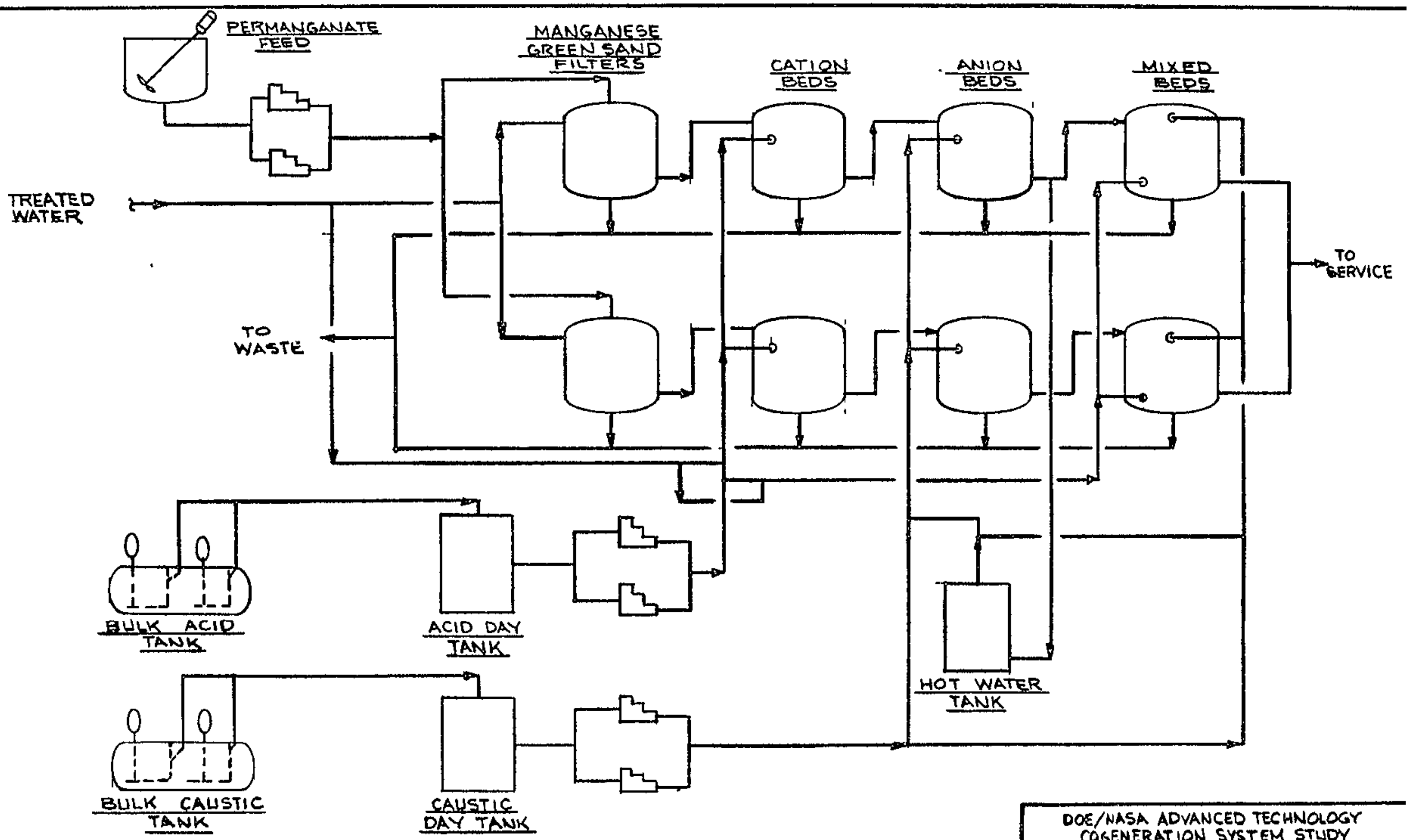
Waste heat from the exhaust steam will be cooled in the condenser by circulating cooling water from cooling tower. The design thermal duty for the heat rejection system is 222 x 10^6 Btu/hr. The condenser design vacuum pressure is 3 inches HgA, which results in a saturation temperature of 115°F. Based on 15°F temperature rise of circulating water, and 10°F approach with ambient wet-bulb temperature of 80°F, the required circulating water flow rate is 31,000 gpm. A mechanical draft, wet, counter flow cooling tower has been chosen for this study.

4.7 Water Treatment System

4.7.1 Makeup Water Treatment System

A makeup water treatment system is provided to condition treated water for boiler makeup at a rate of 400 gpm from an existing 400,000 gallon storage (see Figure 4-6). The analysis of the water is as follows:

Constituent	mg/l as $CaCO_3$
Ca	0.15
Mg	0.05
Na	No reading
HCO_3	28
CO_3	2
Cl	21
SO_4	No reading
Total Hardness	0.3
Silica as S_1O_2	5
pH	8.1
Copper as Cu	0.1
Copper as Cr	No reading
Conductivity as μmhos/cm	230
Iron (Fe)	3.5



DOE/NASA ADVANCED TECHNOLOGY COGENERATION SYSTEM STUDY

MAKE UP WATER TREATMENT

Gibbs & Hill, Inc.
ENGINEERS DESIGNERS CONSTRUCTORS
NEW YORK

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JOB NO 11-3138-216

FIGURE 4-6

MICRO FILM	ISSUE NO	DATE	DWN	CHKD	ARCH	STR	MECH	ELEC	CHEM SERV	I & C	BLDG	CONSTR	P.E.	ISSUED FOR

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The system consists of two parallel trains of manganese greensand filters for iron removal, strong acid cation and strong base anion exchangers and mixed bed anion effluent polishers. Each train has a flow capacity to provide 100 percent makeup requirements.

The iron removal filters are regenerated with potassium permanganate. Cation and anion exchange resins are respectively regenerated with sulfuric acid and caustic soda. Regenerant day tanks, chemical metering pumps and related equipment are installed. Sulfuric acid and caustic soda are received in bulk, stored as 66-degree Baume' sulfuric acid and 50 percent caustic soda.

The makeup water treatment system consists of the following skid-mounted equipment:

Two (2) 8-foot diameter x 6-foot straight side greensand filters

Two (2) 8-foot diameter x 6-foot straight side cation beds

Two (2) 8-foot diameter x 6-foot straight side anion beds

Two (2) 6-foot diameter x 6-foot straight side mixed beds

One (1) 5000 gallon acid storage tank with two (2) transfer pumps

Acid regenerating equipment consisting of one (1) day tank, two (2) regenerant pumps, mixing tees, interconnecting piping, valves, and controls

Caustic regenerating equipment consisting of one (1) day tank, one (1) hotwater tank, two (2) regenerant pumps, mixing tees, interconnecting piping, valves and controls

Two (2) low flow recycle pumps

One (1) 5000-gallon caustic storage with two (2) transfer pumps

One (1) control panel with annunciator

4.7.2 Boiler Feed System

Internal treatment of the boiler feedwater to control scale formation will be accomplished by injecting disodium and/or trisodium phosphate solution into the boiler drum. The phosphate feed system will include a mixing solution tank and two metering pumps.

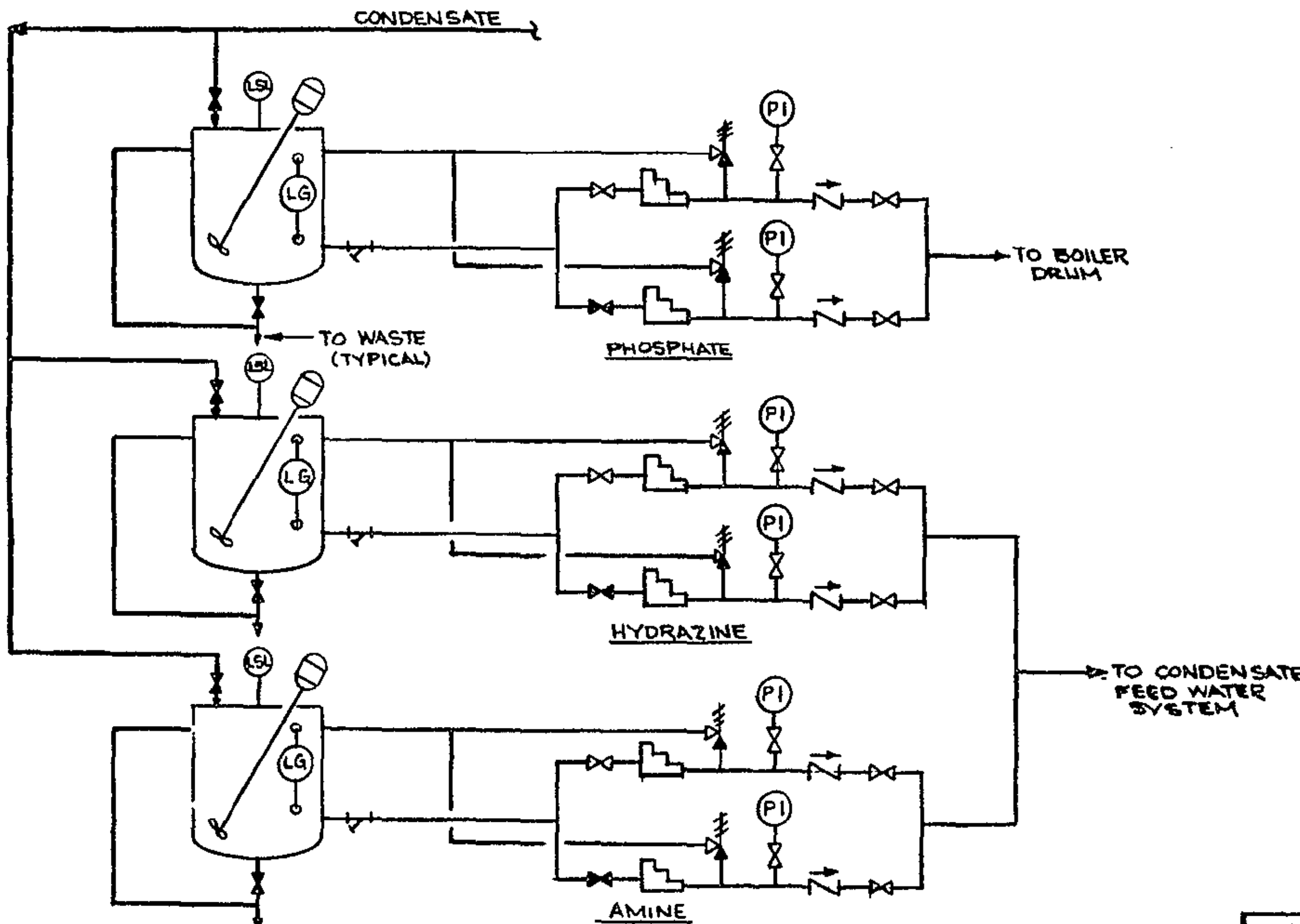
Amine and hydrazine dilute solutions will be fed continuously for pH control and oxygen scavening. A solution tank and two metering pumps will be provided for each chemical. (See Figure 4-7.)

The boiler feed system consists of the following skid-mounted equipment:

One (1) 100-gallon stainless steel phosphate solution tank with removable dissolving basket, agitator, gauge glass, low-level pump cut-off switch, two (2) metering pumps with stroke control valves, interconnecting piping, suction strainers, fittings, and controls.

One (1) 100-gallon stainless steel hydrazine solution tank with agitator, gauge glass, low-level pump cut-off switch; two (2) metering pumps with stroke control, valves, interconnecting piping suction strainers, fittings and controls

One (1) 100-gallon stainless steel amine solution tank with agitator, gauge glass, low-level pump cut-off switch; two (2) metering pumps with automatic stroke control, valves, interconnection piping suction strainers, fittings and controls.



DOE/NASA ADVANCED TECHNOLOGY COGENERATION SYSTEM STUDY

BOILER FEED SYSTEM

Gibbs & Hill, Inc.
ENGINEERS DESIGNERS CONSTRUCTORS
NEW YORK

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JOB NO 11-3138-216

FIGURE 4-7

MICRO FILM	ISSUE NO	DATE	DWN	CHKD	ARCH	STR	MECH	ELEC	CHEM MECH	I & C	BHLD	COORD	P.M.	ISSUED FOR

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One (1) control panel, skid mounted, with pump and agitator, on-off switches and running lights, motor starters and alarms.

4.7.3 Cooling Tower Corrosion Inhibitor Feed System

The cooling tower corrosion inhibitor feed system is provided to control exposed circulating system carbon steel surfaces from the agressive nature of the essentially completely softened treated water with a low alkalinity. The system includes a mixing solution tank and two metering pumps. (See Figure 4-8.)

The corrosion inhibitor system consists of the following skid-mounted equipment:

One (1) 300-gallon inhibitor solution tank with cover constructed of ASTM 285 Gr.C steel at least 1/4 inch thick with gauge, glass, agitator, removable stainless steel dissolving basket and low level pump cut-off switch

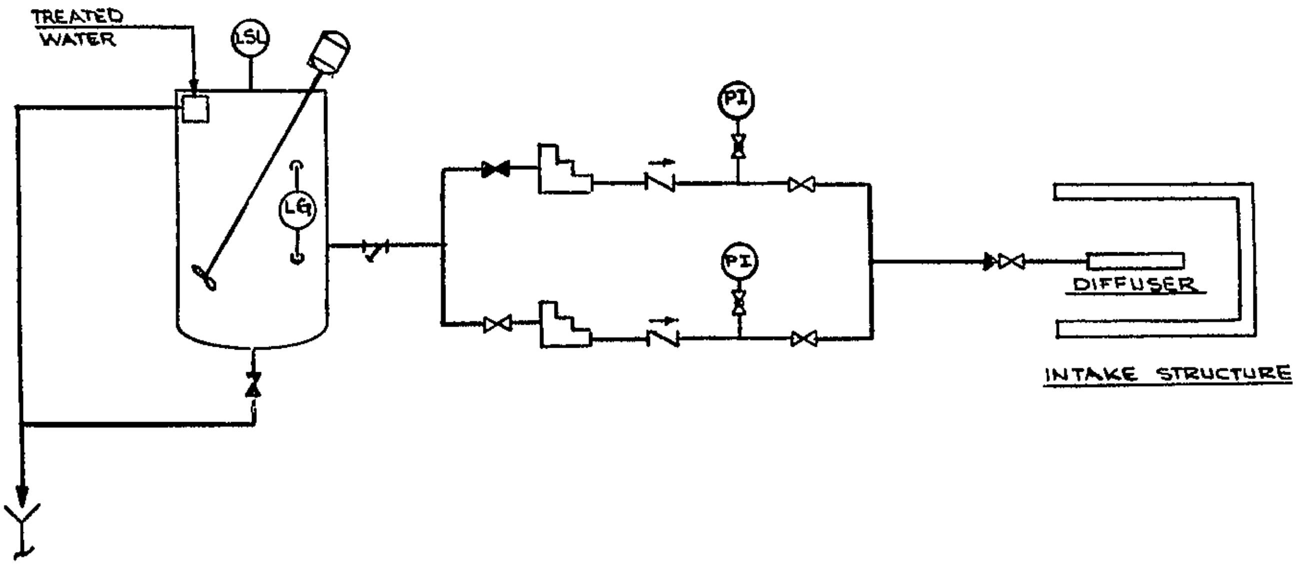
Two (2) cast iron metering pumps with motor, suction strainer and manual stroke adjustment with vernier and locking device

One (1) lot interconnecting piping, valves, fittings

One (1) control box with on-off-auto selector switches, running lights for motors and one low level warning system.

4.7.4 Anti-Fouling-Anti-Scaling

Western Chemical Bromocide is used as a biocide to reduce fouling in the surface condenser of a circulating water system. Bromocide is fed intermittently by automatic timer at the appropriate rate to the circulating system. The feed rate is manually set on the automatic feeders which have an adjustable range.



DOE/NASA ADVANCED TECHNOLOGY COGENERATION SYSTEM STUDY

COOLING TOWER CORROSION INHIBITOR FEED SYSTEM

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NEW YORK

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FIGURE 4-8

JOB NO 11-3138-216

MICRO FILM	ISSUE NO	DATE	DWN	CHKD	APPROVALS	ISSUED FOR

5/76

Chlorine, under pressure, is withdrawn from manifolded one ton containers to the chlorine evaporators. The motivating force for withdrawing chlorine from the evaporators is the vacuum created by the flow of water through the chlorine solution ejectors, which are located downstream of the chlorinators. To assure sufficient head at the point of chlorine application in the circulating water intake bay two 100-percent capacity booster pumps are provided. An automatic 24-hour program is used to control the duration and intervals of chlorine application, which is known as "shock chlorination." (See Figure 4-9.)

The chlorination system consists of the following skid-mounted equipment:

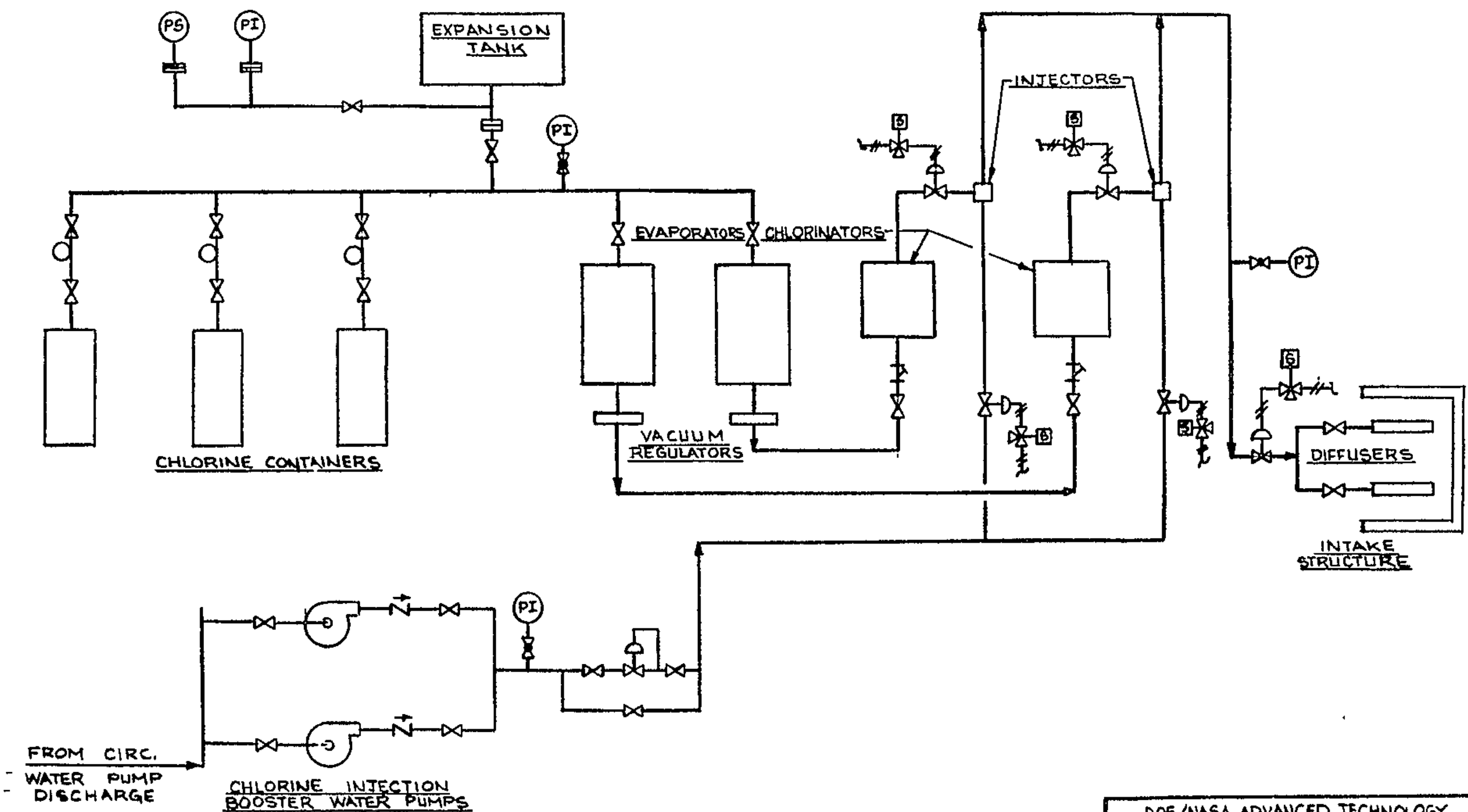
Two (2) evaporators with expansion tank
Two (2) 2000-pound per day chlorinators with ejectors
Two (2) booster pumps
Two (2) chlorine detectors
One (1) chlorine residual analyzer
One (1) control panel with annunciator
One (1) lot piping, valves and controls

4.8 Civil/Structural Considerations

The site plan shows an extensive parcel of property already occupied by many buildings of the Ethyl Corporation facility complex.

The existing facilities that will be expanded into the new construction area are the network of roads and sidewalks, the storm drainage system, the potable water, firelines and sewers.

The necessary earthworks are included in the estimate. The cost of extending roads and parking area is also included.



DOE/NASA ADVANCED TECHNOLOGY COGENERATION SYSTEM STUDY

CHLORINATION SYSTEM CIRCULATING WATER

Gibbs & Hill, Inc. ENGINEERS DESIGNERS CONSTRUCTORS NEW YORK

JOB NO 11-3138-216

SCALE – ~

FIGURE 4-9

MICRO FILM	ISSUE NO	DATE	DWN	CHKD	ARCH	STR	MECH	ELEC	CHEM	I&C			P.E.	ISSUED FOR
					APPROVALS									

Not included in the estimate are the following civil items:

(a) Any work in and around the barge handling facilities that would include dredging, construction of dolphins, quays or riprap of shorelines.
(b) The disposal of any solid waste resulting from the new construction, spoil or the disposal of demolished structures.
(c) Excluded also is landscaping, planting or installation of sod anywhere on the site.

The principal buildings and structures that are to be considered are as follows:

(a) Turbine/boiler house, baghouse, stack and electrical switchyard-transformer area
(b) Coal handling system, including foundations for all conveyors, unloading and reclaim hopper, coal storage silos, and "A" frame coal storage building, crusher building, transfer tower
(c) Limestone handling system including foundations for conveyors, unloading and reclaim hoppers, "A: frame storage building
(d) Ash silo
(e) Pipe racks

The general foundation concept for all structures on this cogeneration project is assumed to be spread footing and mats since soils data is not available. A basic approximation of 3000 psf soil bearing value was assumed.

The turbine/boiler building is conceived to be a braced steel frame structure, metal siding enclosure around the turbine building only below the operating floor. The turbine building structure supports a gantry crane of 25 tons lifting capacity. There are two concrete slab floors in this portion of the building; the mezzanine floor for supporting of electrical gear and an operating floor with the same elevation as the top of the generator pedestal. The generator is supported on a reinforced concrete pedestal and foundation mat. The boiler, coal bunkers and limestone bunkers are supported by the boiler structure steel frame. A roof of metal decking sloped for drainage purposes is provided over the boiler and coal room. The six bunkers provide for one day of coal storage and 4 bunkers provide for one day of limestone storage. The space above the bunkers is a dustproof enclosure for the conveyors and unloading trippers. The boiler is serviced by several levels of platforms for the operators use. These floors are either concrete slab or grating construction. All building columns are founded on spread footings for reinforced concrete mats. The F.D. fan is located in this area.

The boiler flue gases are handled in a steel plate duct work proceeding from the boiler outlet, through the baghouse and ID fan, and to the atmosphere by way of a 10-foot diameter steel stack. All structures are supported on reinforced concrete mats.

The cooling tower is a mechanical draft two cell system constructed on a reinforced concrete base combined with a pump pit at one end. The tower base forms a shallow basin capable of storing a small supply of water for the pump surge. The pump pit forms the base for the vertical type pumps required for the cooling water system. The foundation structure will be integral with the basin and pump pit, monolithically constructed to minimize leakage through joints.

A galvanized steel frame superstructure will be provided for the electrical switchyard and transformer area. Heavy reinforced concrete bases will be available for the large electrical equipment located there.

The area will be fenced with cyclone type fencing, and a crushed stone base will overlay the enclosed area.

4.9 Electrical System

4.9.1 Electrical Equipment and Systems Description

The section gives a brief description of the electrical system and major electrical equipment.

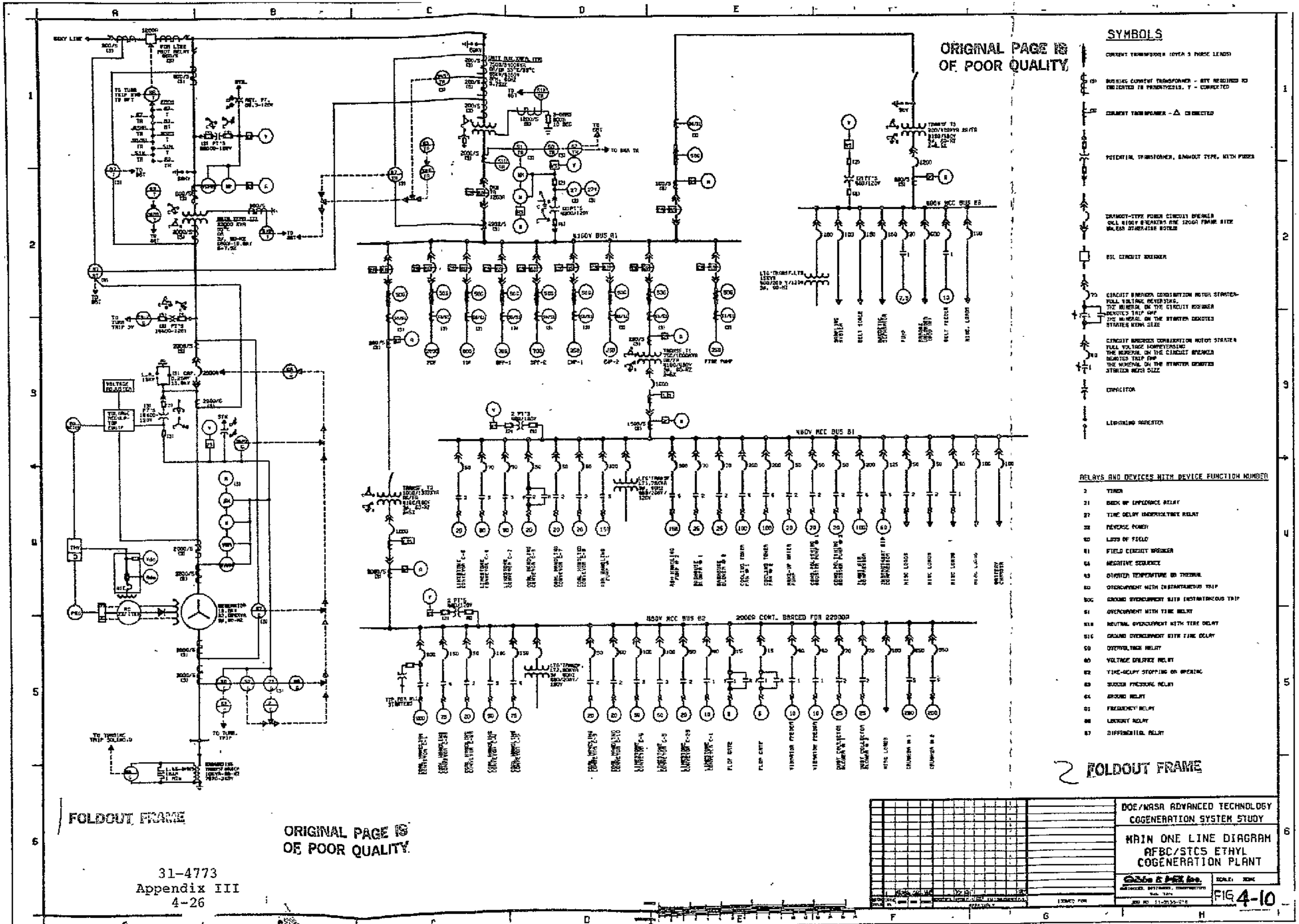
The plant consists of one turbine generator unit with a capacity of 30 megawatts. Power is generated at 13.8 kV, 3 phase, 60 Hz and is stepped up to 66 kV by a main transformer (T). Power is supplied to the HL&P network through a 66 kV overhead transmission line. The plant auxiliaries are supplied from an auxiliary transformer which steps down the voltage to 4160 V. Large motors are fed from the 4160 V. Three power center transformers step-down the voltage to 480 V to supply small motors and lighting transformers.

The accompanying one line diagram (Figure 4-10) shows the plant electrical distribution system.

In accordance with the project design criteria, the auxiliary transformer is supplied from the 66 kV line instead of the 13.8 kV generator bus. Consequently, the main transformer capacity has to be sized the same as the generator rated capacity.

It is to be noted that the common practice is to supply the auxiliary transformer directly from the generator but because it reduces the capacity requirement of the main transformer and requires lower primary voltage rating of the auxiliary transformer, it is supplied from the 66 kV line in this system.

However, based on the project design criteria, the auxiliary transformer power supply and the revenue metering are arranged on the basis that the gross generated power is saleable power and the plant auxiliary power consumption will be purchased from the utility company.



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SYMBOLS
RELAYS AND DEVICES WITH DEVICE FUNCTION NUMBER
4160V BUS A1
480V MCC BUS B2
480V MCC BUS A1
480V MCC BUS A2
2000A CONT. BRACED FOR 22000A
GENERATOR
FIRE PUMP
FOLDOUT FRAME
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DOE/NASA ADVANCED TECHNOLOGY COGENERATION SYSTEM STUDY
MAIN ONE LINE DIAGRAM AFBC/STCS ETHYL COGENERATION PLANT
FIG 4-10

The plant has no provision for blackout start. Start-up power will be supplied by the utility company through the 66 kV line.

In the event of failure of the utility power supply, while the cogeneration plant is in operation, the plant will supply power to the station auxiliaries and the Ethyl facilities. However, if simultaneous failure of the utility supply and the cogeneration plant occurs, the plant will not be able to start until the utility supply is restored.

A generator circuit breaker is provided for synchronizing and tying the generator with the utility network.

4.9.1.1 Generator

The turbine generator is rated 32,000 kva, 30,000 kw, 13.8 kv, 3 phase, 60 Hz wye connected, air cooled.

The generator neutral is connected to a single phase neutral grounding transformer rated 10 kva, 7970/240 v. A 1.45 ohm, 166 Amp loading resistor is connected across the secondary of the grounding transformer. The grounded leg of the grounding transformer will be connected to the station ground grid. In the event of a generator ground fault, a ground relay, 64/G connected in parallel with the ground resistor, will initiate an alarm and simultaneously trip the turbine trip solenoid.

The exciter is a shaft driven brushless type excitation system utilizing silicon diodes to supply rectified current to the generator field. The exciter components are: a main exciter, a pilot exciter and a rotating rectifier. The pilot exciter is a permanent magnet generator that provides high frequency, 3 phase power to the voltage regulator. The voltage regulator varies the excitation of the stationary field of the AC exciter through a thyristor amplifier. The output from the rotor (armature) of the AC exciter is rectified by the rotating rectifier and fed to the field of the AC generator.

One set of three 14,400/120 V potential transformers connected WYE-WYE with grounded neutral are provided at the line side of the generator for metering and relaying. The surge protection equipment consists of three 0.25 Mfd 15 kV capacitors paralleled with three sets of 15 kV station type lightning arresters.

The connections from the generator terminals to the generator breaker and from the generator breaker to the main transformer secondary and auxiliary transformer primary consist of indoor generator breaker to the main transformer secondary and auxiliary transformer primary consist of indoor and outdoor type non-segregated phase buses rated for 2000 A, three phase, 13.8 kV braced for 750 MVA.

The generator breaker is a 2000 A, 15 kV indoor type vacuum power circuit breaker.

4.9.1.2 Main Transformer

The plant will supply power to the HL&P network through a main transformer (T) which will step-up the 13.8 kV generated voltage to 66 kV. The main transformer is a two winding three phase 32,000 kVA, 13.8 kV/66 kV 60 Hz, OA oil immersed self-cooled transformer.

4.9.1.3 Unit Auxiliary Transformer

The plant auxiliaries and coal handling system will be supplied power from one unit auxiliary transformer which will step down the voltage from 66 kV to 4.16 kV.

The unit auxiliary transformer (TA) is a two winding, three phase, 7500/8400 VA 55 C/65 C, OA/OA oil immersed self-cooled transformer.

4.9.1.4 480 V Power Center and Motor Control Centers

The 480 V plant auxiliaries and limestone conveyor system will be fed from a power center with a three phase 750/1000 kVA, AA/FA, 4.16 kV/480 V self-ventilated/forced air cooled, dry type transformer (T1) and a main power air circuit breaker. The motor feeders will be fed from a 480 V motor control center.

The coal handling system will be fed from two locations. One power center transformer (T2) will be located at the transfer tower to the coal crusher. This transformer is rated 1000/1333 kVA, AA/FA, 4160V/480V, 3 phase, 60 Hz. The other power center will be located at the pier area to feed the barge unloader and the conveyors near the pier. This transformer (T3) is rated at 300/400 kVA, AA/FA, 4160V/480V, 3 phase, 60 Hz.

4.9.2 Protective Relaying

The connections of the protective relays are shown schematically on the one line diagram.

4.9.2.1 Generator Protection

The generator is protected from phase to phase and three phase faults by the generator differential relay 87/G.

The generator is grounded through a 10 kVa 7970V/240V single phase transformer and a 1.45 ohm secondary resistor. The calculated ground fault current is 3.46 A. The corresponding secondary current is 166 A and the secondary voltage is 230 V. A ground relay 64/G is used to detect generator ground fault.

The generator is protected against damage from loss of excitation by a "loss of field" relay (40/G) in combination with a time delay relay 62 to provide a time delay trip so that false tripping will be avoided during severe system swings.

A negative sequence relay (46/G) is used to protect the generator from thermal heating caused by negative sequence currents which flow during unbalanced fault on the system.

A volts-per-Hertz relay (59/81) is used to protect the generator from overheating during overexcitation conditions.

A reverse power relay (32/G) is used to detect reverse power flow in the generator which may cause "motoring" upon loss of input from the prime mover and thus results in damage to the prime mover.

An impedance relay 921/G) in combination with a timer (2/G) is used as a generator backup protection.

4.9.2.2 Transformer Protection

The main transformer and auxiliary transformer are each provided with a percentage differential relay 87/T and 87/TA, respectively, for phase to phase protection. Each transformer is also provided with sudden pressure relay 63 and an overcurrent relay 51N for phase to ground fault. The auxiliary transformer is provided with an overcurrent relay 50/51 for backup protection in case of internal fault.

4.9.2.3 Bus Protection

An overall differential relay 87/BT is provided as backup protection to the main transformer and to protect the non-segregated bus to the auxiliary transformer and main transformer buses up to the generator circuit breaker.

C-3

5.0 MAJOR EQUIPMENT LIST

The major mechanical and electrical equipment required for the STCS are the following:

Mechanical Equipment

Item	Description	Quantity
1	Atmospheric Fluidized Bed Boiler: Steam capacity of 360,000 lb/hr at 1490 psia and 1005°F and simultaneously heating Dowtherm from 550°F to 680°F for total maximum Dowtherm duty of 170 x 10^{-6} Btu/hr. Fluidized bed coal fired with the injection of limestone, balanced draft unit including forced draft and induced draft fans, ash recyclone, economizer, air-driven soot blowers to burn Oklahoma bituminous coal.	1
2	Steam Turbine-Generator: 30 MWe nominal rating, single automatic extraction turbine: Throttle conditions are 1450 psig/1000°F, single extraction at 240 psia. 360,000 lb/hr of design throttle flow, design exhaust pressure at 3.0 in. Hg abs. The generator is rated 32,000 kVA, 30,000 kW, 13.8 kV, 3-phase, 60 Hz, 3600 rpm.	1
3	Condenser: Approximate heat transfer surface area 20,820 sq. ft. with admiralty tubes.	1
4	Motor Driven Boiler Feed Pump: Approximately 500 gpm, 4160 ft TDH with motor.	2
5	Condenser Pump: 570 gpm, 65 ft TDH with motor.	2

Item	Description	Quantity
6	Demineralized Water Pump: 400 gpm, 120 ft TDH with motor	2
7	Circulating Water Pump: 18,600 gpm, 50 ft TDH with motor	2
8	Condenser Cooling Water Tower: Mechanical-draft, wet cooling tower with counter flow design for 80°F wet-bulb temperature dissipating 222.4 x 10^6 Btu/hr with a circulating water flow of 31,000 gpm. Cooling water inlet temperature 90°F and outlet temperature 105°F.	1
9	Desuperheater: Capable of reducing the temperature of 240 psia steam from 600°F inlet of 400°F outlet. Maximum inlet steam flow 250,000 lb/hr.	1
10	Circulating Water Piping System: Including steel piping with motor operated shutoff valves, expansion joints, and elbows.	1
11	Makeup Water Treatmènt System: To condition treated water at a rate of 400 gpm from the existing 400,000 gallon storage tank. Including 2 parallel trains of manganese greens and filter for iron removal, strong acid cation and strong base anion exchange and mixed bed anion effluent polishers; also included are demineralized water storage tank, piping, valves and fittings.	1
12	Boiler Feed System: Injecting disodium and/or trisodium phosphate solution into the boiler drum. Including tanks for phosphate solution, hydrozine solution, amine solution, and valves, gauges, agitators and pumps.	1

Item	Description	Quantity
13	<u>Cooling Tower Corrosion Inhibitor Feed System</u>:	1
	Including 300 gallon inhibitor solution tank with agitors, valve, switch, pump, and strainer.	
14	<u>Chlorination Biological Control System</u>:	1
	Chlorination supply tanks, controls, residual chlorine detector, motor-driven shutoff valves, piping and fittings. Chlorinator capacity is 2000 lb/day with two required.	
15	<u>Deaerating Feedwater Heater</u>:	1
	Internal direct contact, spray type vent condensing - 387,400 lb/hr flow, storage capacity of 6300 gal.	
16	<u>Baghouse</u>:	1
	Reverse air type, to operate at a draft loss of 6 to 8 in. w.g. Gas flow of 233,000 ACFM of 300°F. Inlet concentration at 5.02 gr/ACFM, outlet concentration at 0.01 gr/ACFM. Removal efficiency 99.8 percent and drain rate at 9815 lb/hr. Number of modules per baghouse is 12; number of bags per module is 212, average particle size is 100-150 microns.	
17	<u>Stack</u>:	1
	10 ft diameter at top and 250 ft tall steel structures. The lower portion is tapered slightly, so that the chimney will not require any wire bracing for stability. Chimney is resting on a concrete mat.	
18	<u>Coal Unloading, Handling and Storage System</u>:	1
	Including barge unloading facility, conveyors, transfer towers, 3-day storage silo, A-Frame structure for 15-day coal storage, crushers, scaling, sampling stations, bunkers, and gate valves. Coal bunker capacity is 724.2 tons and is designed for one day full load operation.	

Item	Description	Quantity
19	Limestone Unloading, Handling and Storage System: Including unloading hoppers, conveyors, A-Frame structure for limestone storage, transfer towers, bunkers, gate valves. A maximum design capacity of 60 TPH is sized for unloading hopper, reclaim tunnel and conveyors. Average operating capacity for limestone handling system is 40 TPH.	1
20	Ash Handling System: A 24 TPH vacuum system is sized for ash handling system including 8 in. and 9 in. conveying pipes, rotary slide gates, hoppers, valve, elbow, vacuum blower with 100 hp motor and 20 hp motor for silo fluidization, bag filter, surge tank and 28 ft dia x 52 ft high ash silo.	1
21	Bottom Ash Cooler: Designed to cool 14,000 lb/hr of bottom ash from 1600°F to 300°F, including fluid bed cooler, cycle dust collector, exhaust air manifold, rotary air lock, and refractory linings.	2
22	Process Steam Piping: 10 in. schedule 40 carbon steel piping for 240 psia saturated steam supply tied to the existing steam header. Motor operator shutoff valves, fittings and controls.	350 ft
23	Dowtherm Piping: 10 in. schedule 40 carbon steel piping for inlet and outlet Dowtherm fluid. Motor operator shutoff valves, fittings and controls.	3000 ft
24	Turbine Oil Filter Systems: Including pumps, filters, storage tanks, and piping.	1

Item	Description	Quantity
25	Plant Air Compressor:	1
	300 SCFM at 100 psig discharge pressure.	
26	Circulating Water Make-up System:	1
	50 percent capacity pumps and motors, isolation valves, piping, expansion joints and fittings.	
27	Cooling Tower Blowdown System:	1
	Including overflow control Weir, piping and high velocity nozzle.	
28	Fire Protection and Raw Water Storage System:	1
	Including water storage tanks, fire pumps, mains, laterals, headers, sprinklers, control valves, and electric motor.	
29	Compressed Air Receiver: (Surge Tank)	1
	300 psig working pressure	
30	Plant Lighting:	1 lot
31	Control Room:	1 lot
	Including instruments, gauges, computer, recorders, sensors wiring, relays, etc.	
32	Local Plant Instruments, Transmitters, etc.:	Lots
33	Instrument Air Receiver:	1
34	Pipe Insulation and Hangers:	As required

Electrical Equipment

Item	Description	Quantity
1	Step-Up Transformer: 13.8 kV/66 kV, 3 phase, 60 Hz, 32,000 kVA, OA, 55C with no load tap changer, 2-2 1/2 percent above, and 2-2 1/2 percent below rated voltage, to be equipped with 7-600/5A primary bushing C.Ts and 3-2000/5 A sec. busing CTs.	1
2	Auxiliary Transformer: 66 kV/4.16 kV, 3 phase, 60 Hz, 7,500 kVA/8,400 kVA, OA/FA with no load tap changer, 2-2 1/2 percent above and 2-2 1/2 percent below rated voltage to be equipped with 6-200/5A primary bushing CTs.	1
3	Power Center Transformer 4.16 kB/480B, 3 phase, 60 Hz, 750 kVA/1000 kVA, dry type, AA/FA indoor enclosure.	1
4	Power Center Transformer: Same as Item 3 except 1000 kVA/1333 kVA	1
5	Power Center Transformer: 4.16 kV/480 V, 3 phase, 60 Hz, 300 kVA/400 kVA, dry type, AA/FA indoor	1
6	Lighting Distribution Transformer: 480 V/208 V/120 V, 3 phase, 60 Hz, 30 kVA dry type indoor enclosure	1
7	Lighting Distribution Transformer: Same as Item 6, except 75 kVA	1
8	Lighting Distribution Transformer: 480 V/208 V wye/120 V, 3 phase, 60 Hz 30 kVA totally enclosure indoor/outdoor enclosure.	1

Item	Description	Quantity
9	Air Break Switches:	4 sets
	3 poles gang operated, 60 kV, 1200 A, complete with manual operating handle.	
10	Power Circuit Breaker:	1
	60 kV oil circuit breaker, 3 poles, 1200 A, 3500 MVA interrupting rating, outdoor, to be equipped with 6-600/5 bushing CTs.	
11	Power Circuit Breaker:	1
	13.8 kV vacuum breaker, 3 poles 2000 A, 750 MVA indoor type enclosure.	
12	Lighting Arrester:	3
	60 kV lighting arresters station type, outdoor	
13	Potential Transformer:	3
	Outdoor potential transformer 60 kV/120 V.	
14	Substation Structure:	1 lot
	Steel structure, galvanized steel, for: 1 - Main transformer 1 - Auxiliary transformer 1 - Oil circuit breaker 4 - Three-pole, gang operated air brake switches	
15	4160 V Switchgear:	1 lot
	416V switchgear, indoor, consisting of 11 vertical sections equipped with electrical operated circuit breakers, 1200 A, frame, 150 MVA interrupting rating, as follows: a. One incoming main breaker section b. Seven motor feeder breaker sections c. Three transformer feeder breaker sections d. 1 - instrument and potential transformer compartment equipped with the following:	

Item	Description	Quantity
	2 - Potential transf. 420 V/120 V 3 - Time delay undervoltage relays 3 - Auxiliary relays type MG-6 1 - AC voltmeter and voltmeter switch 1 - AC ammeter and ammeter switch	
16	Boiler Turbine-Generator Control Board	1 lot
17	Generator Surge Protection and Potential Transformer Equipment:	
	13.8 kV Station type lighting arresters and surge capacitors, 0.75 uf	3
	Potential transformer, indoor type 14,100 V/ 120 V complete with current limiting fuses	3
18	Generator Grounding Transformer and Resistor:	
	a. Generator ground transformer, 10 kVA 13.8 kV wye/7970 V-240 V	3
	b. Grounding resistor 1.45 ohms, 166 A, 1 min, 230 V	3
19	Nonsegregated Phase Bus:	1 lot
	2000 A, 3 phase, 13.8 kV braced for 750 MVA, with taps for 1200 A, consisting of:	
	24 ft - straight section, outdoor 1 - vertical "L" corner section, outdoor 1 - transformer termination, outdoor 1 - expansion joint, outdoor 1 - connector with vapor barrier for outdoor/ indoor transition	
	54 ft - straight section, indoor 3 - vertical "L" corner section, indoor 1 - expansion joint, indoor 2 - circuit breaker termination indoor	
20	Nonsegregated Phase Bus:	1 lot
	2000 A, 3 phase, 4.16 kV braced for 150 MVA, consisting of:	

Item	Description	Quantity
	24 ft - straight section, outdoor 10 ft - straight section, indoor 1 - vertical "L" section, outdoor 1 - vertical "L" section, indoor 1 - transformer termination, outdoor 1 - switchgear termination, indoor 1 - expansion joint, outdoor 1 - connector with vapor barrier for indoor/ outdoor transition	
21	<u>480 V MCC, B1</u>:	1
	Indoor NEMA 12 dust tight enclosures, with 1600 A main bus braced for 22,000A. Starters shall be in combination with circuit breakers.	
	MCC shall consist of 8 vertical sections equipped with starters as shown on the one line diagram.	
22	<u>480 V MCC B2</u>:	1 lot
	Same as MCC B1 except it shall have 2000 A main bus and shall consist of 9 vertical sections equipped with starters as shown on the one line diagram.	
23	<u>480 V MCC B3</u>:	1 lot
	Same as MCC B1 except it shall have 1200 A main bus and shall consist of 3 vertical sections equipped with starters as shown on the one line diagram.	
24	<u>Power Cables</u>:	
	a. 5 kV power cable, 3-conductor, copper, Class B stranded, EPR insulated, neoprene or hypalon potential shielded	1
	1. No. 1/0 AWG -	2000 ft
	2. 500 MCM -	2500 ft
	b. 600 V power cable, 3-conductor, copper, Class B stranded, EPR insulated, neoprene or hypalon jacketed.	1

Item	Description	Quantity
25	Control Cable:	
	600 V control cable, tin coated copper insulated with thermosetting, fire retardant oil and heat resistant compound neoprene or hypalon jacketed.	
	a. 2 conductor No. 12 AWG	20,000 ft
	b. 2 conductor No. 12 AWG	15,000 ft
	c. 5 conductor No. 12 AWG	10,000 ft
26	Instrument Cable:	
	a. Electronic instrument cable 300 V class No. 16 AWG stranded copper, twisted pairs or triads, insulated and jacketed with thermosetting compound with flame retardant characteristics.	
	1. 1 pair	20,000 ft
	2. 2 pairs	6,000 ft
	3. 1 pair shielded	10,000 ft
	b. Thermocouple extension wire and cable, 300 V class chromel-constantan, insulated and jacketed with thermosetting compound.	
	1. 1 pair	5,000 ft
	2. 2 pairs	5,000 ft
27	Communication Cable:	5,000 ft
	Communication cable for single page and five party channels with supplemental control circuit conductor and a ground conductor. Consisting of 3 No. 14 AWG and 13 No. AWG conductor 600 V class, EPR insulated, neoprene or hypalon jacketed.	
28	Ground Wires:	
	a. Bare copper conductor, No. 4/0 AWG, Class A stranded, medium drawn	1,000 ft
	b. Bare copper conductor, 500 MCM Class A stranded medium drawn	2,000 ft

Item	Description	Quantity
29	Communication Equipment:	
	Low level public address system solid state design, for operation on 120 V ac, 60 Hz with one page and 5-party channels, consisting of:	1 lot
	6 - Indoor stations 3 - Weatherproof wall stations 2 - Explosion proof stations 6 - Indoor loudspeakers 6 - Weatherproof speaker/amplifier 2 - Explosion proof loudspeaker 1 - Test and distribution panel	
30	Station Battery and Battery Charger:	1 set
	Station battery consisting of 58 cells, Lead-Calcium, 825 ampere hours capacity, complete with one battery rack and one 20A 125 V dc battery charger	
31	Main dc Distribution Switchgear and Panelboards:	
	a. Distribution switchgear 250 V dc class, indoor equipped with 1-800 A, 2-pole main breaker 2-100 A 2-pole and 8-60 A, 2-pole branch breakers	1
	b. Dc distribution panelboard, 250 V dc class, indoor equipped with 1-100 A, 2-pole main breaker and 12-15 A, 2-pole branch breakers	2
32	Lighting Distribution Panels, as follows:	
	a. Main Distribution panel 3 ph, 4 wire 208 V/120 V ac NEMA 12 enclosure, with: 1 - main breaker 3-pole, 400 A 10 - branch breakers, 3 pole, 325 A	1
	b. Lighting panel board 3 ph, 4 wire, 208 V/120 V ac NEMA 12 enclosure with 1-100 A, 3-pole main breaker and 24 - 20 A branch circuit breakers	5

Item	Description	Quantity
	c. Same as item 32b except 225 A, 3-pole main breaker and 42 - 20 A branch circuit breakers	3
33	Lighting Fixture, as follows:	
	a. 400 W, 208 V ac mercury vapor flood outdoor	30
	b. 400 W, 208 V ac mercury vapor lamp fixture, indoor	20
	c. 100 W, 208 V ac mercury vapor lamp fixture, outdoor	250
	d. 2-40 W 120 V ac fluorescent fixture indoor	100
	e. 1-40 W 120 V ac fluorescent fixture indoor	50
	f. 100 W explosionproof incandescent lamp fixture	20
34	Cable Trays	1 lot
35	Conduit and Fittings	1 lot

3. Large Electric Motors (4.16 kV)

	Driven Equipment	Motor HP	Quantity
1.	FD Fan	2800	1
2.	ID Fan	850	1
3.	Boiler Feed Pump	700	2
4.	Circulating Cooling Water Pump	250	2
5.	Baghouse	60	2
6.	Cooling Tower Fan	60	2
7.	Condensate Polishing Booster Pump	50	1
8.	Plant Air Compressor	100	1
9.	Fire Pump	350	1
10.	Ash Handling Vacuum Pump	150	1
11.	Clamshell Pump of Coal Handling System	300	
12.	Coal Conveyor	400	1
13.	Coal Conveyor	75	2
14.	Coal Crusher	300	1
15.	Limestone Conveyor	50	2

6.0 CAPITAL COST ESTIMATE

The cost estimate of the AFBC/STCS cogeneration plant has been prepared in accordance with NASA's format and synthesized from the following:

- o Major component costs
- o Balance-of-plant (BOP) material costs
- o BOP direct and indirect labor costs
- o Architect/Engineer fee
- o Contingency

The major components, BOP materials, and BOP labor costs are divided into the following seven categories:

- o AFBC boiler plant
- o Turbine generator
- o Cogeneration process mechanical equipment
- o Electrical
- o Civil and structural
- o Cogeneration process piping and instrumentation
- o Yardwook and miscellaneous

The breakdown of total plant capital cost is shown in Figure 6-1. The results indicate that the plant is estimated to cost $67,135,000 in 1982 dollars.

The major components and BOP material costs are reported in mid-1982 dollars. The major component costs result from detailed component designs. The BOP material and equipment costs are determined from vendor's budgetary quotations and from recent power plant construction field cost reports. No provision for escalation to commercial operation or interest during construction has been included.

AFB/ST COGENERATION SYSTEM CAPITAL COSTS

(M$)	COMPONENT CAPITAL	DIRECT LABOR	INDIRECT FIELD	MATERIAL	TOTALS
1.0 FURNACE	11.717	3.167	3.167	11.296	29.347
2.0 TURBINE GEN	5.160	0.410	0.410	1.987	7.967
3.0 PROC MECH EQUIP	0.000	0.000	0.000	0.000	0.000
4.0 ELECTRICAL		0.352	0.352	1.418	2.122
5.0 CIVIL + STRUCT		3.733	3.733	4.825	12.291
6.0 PROC PIPE + INST		0.188	0.188	0.213	0.589
7.0 YARDWORK + MISC		0.083	0.083	0.163	0.329
***** TOTALS *****	16.877	7.933	7.933	19.902	52.645
BALANCE OF PLANT (BOP)			(DIRECT + INDIRECT + MATERIAL)	35.768	
A/E HOME OFFICE AND FEE			(AT 15 PCT OF BOP)	5.368	
SUBTOTAL PLANT COST			(TOTAL + A/E)		58.013
CONTINGENCY			(0.157 OF TOTAL PLANT COST, CALC)	9.122	
PLANT COST (1982.0 $)			(SUBTOT PLANT COST + CONTINGENCY)		67.135
CONSTRUCTION ESCAL. AND INTEREST CHARGES					0.000
TOTAL PLANT CAPITAL COST			(1982 $)		67.135

Figure 6-1

The A/E fee and contingency factor are expressed as fractions of the BOP and plant cost, respectively.

Information used in preparing the estimate was based on the following:

- o Site plan
- o Electrical one-line diagram and list of electrical equipment
- o List of mechanical equipment
- o Quantities of civil and structural materials developed on a conceptual basis

More detailed discussion of each plant capital cost element is given below.

6.1 Major Components

The following two items are considered as major components in the AFBC/STCS cogeneration plant:

1. AFBC steam boiler
2. Steam turbine-generator

The cost estimate of AFBC steam boiler was provided by Foster-Wheeler who is subcontractor to G&H and is responsible for the design and development of AFBC boiler. As to the capital cost of steam turbine-generator, its budgetary estimates were received from the following two vendors:

1. General Electric Co.
2. Westinghouse Canada

Other components and systems other than AFBC boiler and turbine-generator are grouped into the category of the BOP material.

6.2 Balance-of-Plant

The balance-of-plant material items include all other equipment and bulk materials not included in the major components that are necessary to construct the cogeneration plant. The BOP direct labor costs include all the costs for installing the major components in addition to the costs associated with constructing the plant and installing the BOP material items.

6.3 Indirect Field Costs

The BOP indirect field costs account for costs that cannot be directly identified with any specific direct account item, but rather are distributed over all direct items. Items that are in the indirect field account include:

- Temporary buildings and utilities
- Warehousing
- Construction supervision
- Administrator and field engineering
- Field office expenses
- Unallocable labor costs
- Construction equipment and maintenance
- Small tools and consumables
- Insurance and payroll taxes
- Preliminary operations and testing

6.4 Engineering, Home Office Costs and Fees

The A/E fees are estimated to be 15 percent of the total BOP costs. This is in accordance with the approach used in several previous NASA and DOE sponsored studies. Included in the costs are:

- Design engineering
- Estimating, scheduling and cost control
- Purchasing, expediting, and inspection
- Construction management and administration
- Engineering, procurement, and construction management fees

6.5 Contingency

Contingency is the amount of money that construction experience has demonstrated must be added to an estimate to provide for uncertainties in pricing and productivity. In this study, the following contingency factors are used:

Material:	11 percent
Subcontractor:	15 percent
Labor:	25 percent

By applying above contingency factors to the plant cost, it is found that the overall contingency factor is equivalent to 15.7 percent of total plant cost, as shown in Figure 6-1.

6.6 Subcontracts

Subcontracts are not stated as such in the cost estimates. BOP items such as cooling towers and stacks that are usually listed as a single subcontract cost were divided into direct labor and material to facilitate a proper accounting of all field labor manhours.

APPENDIX IV

TASK II - AFBC/CCGT COGENERATION SYSTEM DETAILED CONCEPTUAL DESIGN STUDY

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APPENDIX IV

TASK II - AFBC/CCGT COGENERATION SYSTEM DETAILED CONCEPTUAL DESIGN STUDY

1.0 INTRODUCTION AND SUMMARY

This Appendix provides the details of the results of an intense system optimization and performance study as well as a more detailed design, cost, and economic evaluation than that performed during Task I on the AFBC/CCGT Cogeneration Plant for the Ethyl site.

Following Task I an intensive effort was launched to define the performance requirements, operating conditions, economic data and physical requirements related to the Ethyl Corporation site. The significant results of this effort are presented in Appendix II. Detailed optimization of the AFBC/CCGT Cogeneration System was then conducted to match the system to the revised site requirements.

1.1 Conceptual Design Approach of AFBC/CCGT

The conceptual design approach for the AFBC/CCGT Cogeneration System for Task II was to refine the design that resulted from the Task I effort on the Ethyl site. The refinements were evaluated on the basis of the effect of design changes on the return-on-equity. The analysis was accomplished with use of the methods described in Appendix I, Page 9.

The conceptual design approach led to two changes. The major change was the elimination of coal drying capability from the AFBC system. This resulted in a small increase in the required coal flow but a significant reduction in the cost of the AFBC system. The other change involved a 10°F decrease in the compressor inlet temperature to better match the revised site loads.

1.2 Conceptual Design Methodology

The design and evaluation of the AFBC/CCGT Cogeneration Plant was conducted in the following steps.

(a) Design the CCGT system to match the Ethyl site average electrical and thermal loads. The CCGT is required to produce a gross electrical power equal to the site average electrical power plus the AFBC/CCGT auxiliary power.
(b) Design the AFBC system to provide the heat needed by the CCGT system.
(c) Design a combined dowtherm heater, waste-heat boiler, and cooler that produces the required thermal loads and delivers the engine airflow to the compressor at the proper temperature.
(d) Establish the cost of the above major components and use and/or scale the balance-of-plant equipment of the steam system (see Appendix III, Section 4.0) as required and as appropriate.
(e) Compare the AFBC/CCGT conceptual design to the existing Ethyl approach to providing the electrical and thermal loads.

1.3 AFBC/CCGT Cogeneration System Conceptual Design Summary

Figure 1-1 schematically illustrates the AFBC/CCGT Cogeneration System conceptual design, a summary of which is shown in Figure 1-2. The AFBC is designed to provide the required heat to the CCGT system which, in turn, satisfies the electrical and thermal (steam and dowtherm) loads. Details of the equipment operating conditions are shown in Figures 1-3 and 1-4. Figures 1-5 and 1-6 show the AFBC/CCGT Cogeneration System installation on the Ethyl site and the equipment arrangement.

AFB/CCGT COGENERATION SYSTEM
SIMPLIFIED BLOCK DIAGRAM

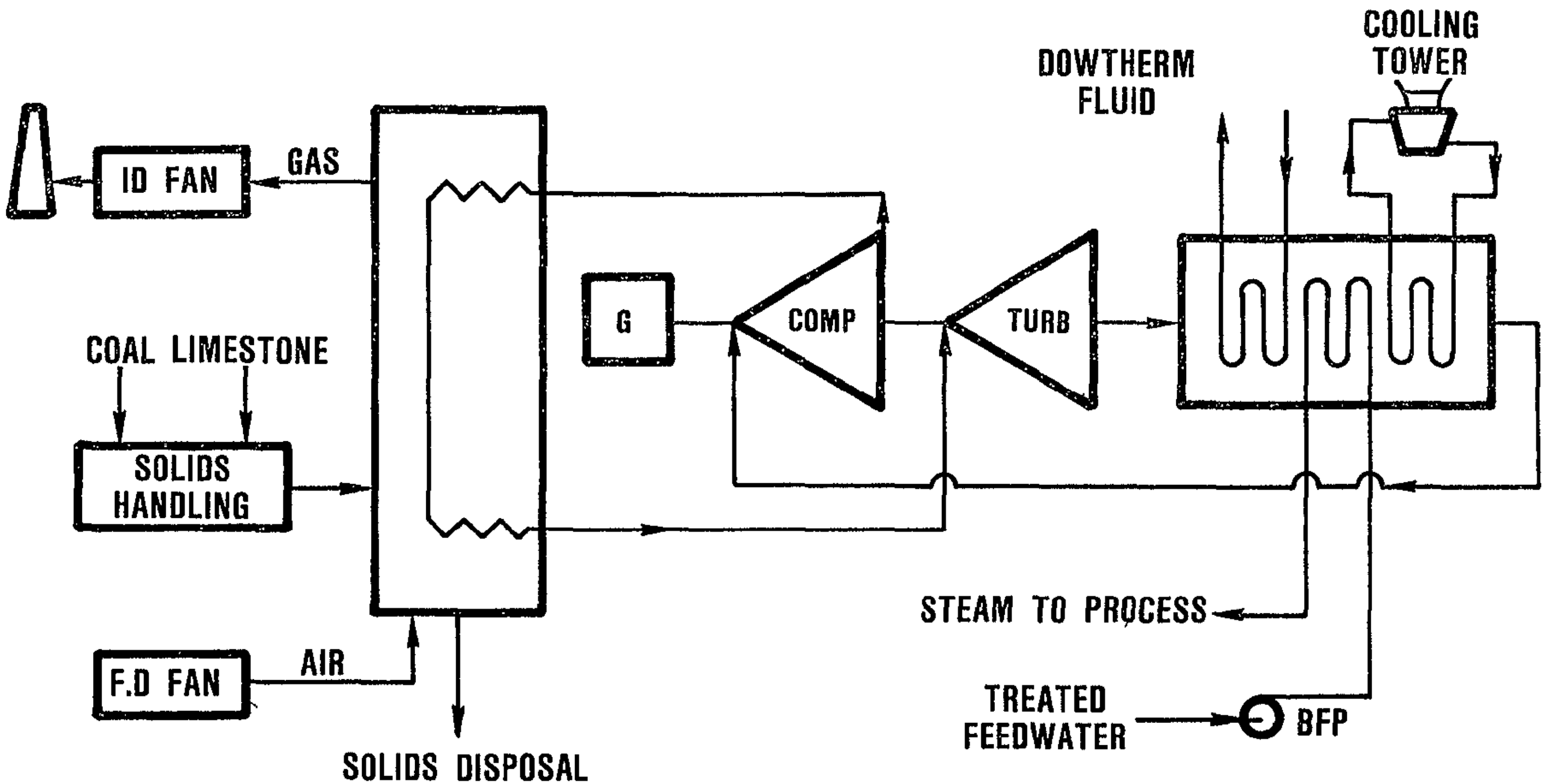

FIGURE 1-1

AFB/CCGT COGENERATION SYSTEM PARAMETERS

FUEL: COAL — BITUMINOUS, 12,400 BTU/LB HHV, 3.11%S, $2.1018/MBTU

SORBENT: LIMESTONE, 0.233 LB/LB COAL, 93.9% Ca, $13.90/TON

AFB HEATER:
- BED TEMPERATURE — 1600°F
- BED DEPTH — 5.4 FT
- BED AREA — 1975 FT^2
- EXCESS AIR FLOW — 15.0%
- SUPERFICIAL VELOCITY — 4.5 FT/SEC
- DUTY — 596.3 MBTU/HR TO AIR

POWER CYCLE: AIR-BRAYTON
- TURBINE INLET TEMPERATURE — 1450°F
- COMPRESSOR DISCHARGE PRESSURE — 600 PSIA
- COMPRESSOR PRESSURE RATIO — 3.0
- MASS FLOW — 629.4 LB/SEC

HEAT REJECTION:
- WET COOLING TOWER — 1 CELL
- STACK GAS TEMPERATURE — 300°F

FIGURE 1-2

TASK II AFBC SYSTEM FOR THE ETHYL CORPORATION CCGT COGENERATION SYSTEM

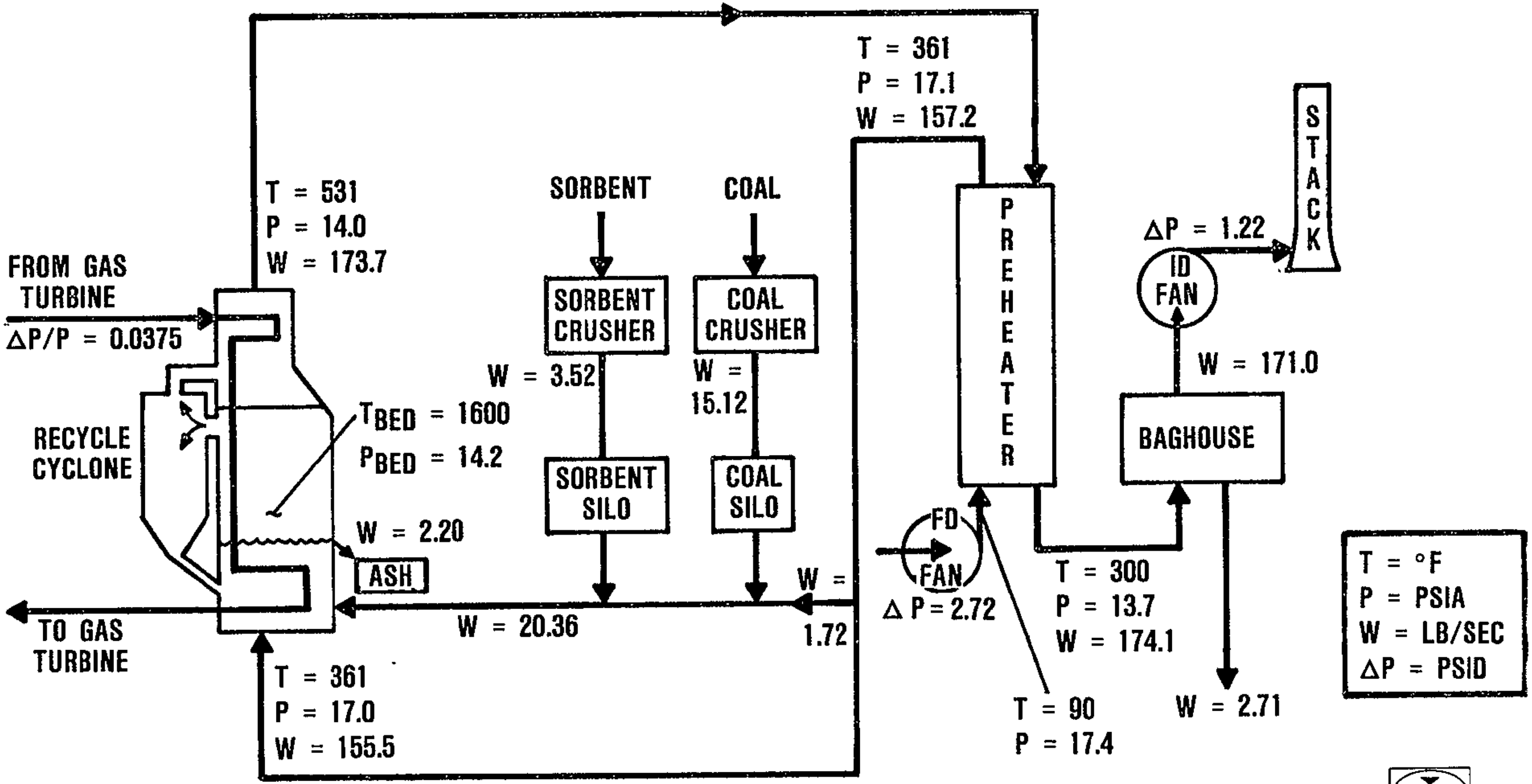

FIGURE 1-3

TASK II AFBC/CCGT COGENERATION SYSTEM FOR THE ETHYL CORPORATION

BOILER CONDITIONS

P_{SAT} = 240 PSIA
STEAM FLOW = 190,000 LB/HR
ΔH = 1173.62
WATER INLET TEMP = 60°F

DOWTHERM HEATER CONDITIONS

HEAT TRANSFERRED = 170 · 10^6 BTU/HR
DOWTHERM INLET TEMP = 550°F
DOWTHERM DISCH TEMP = 680°F

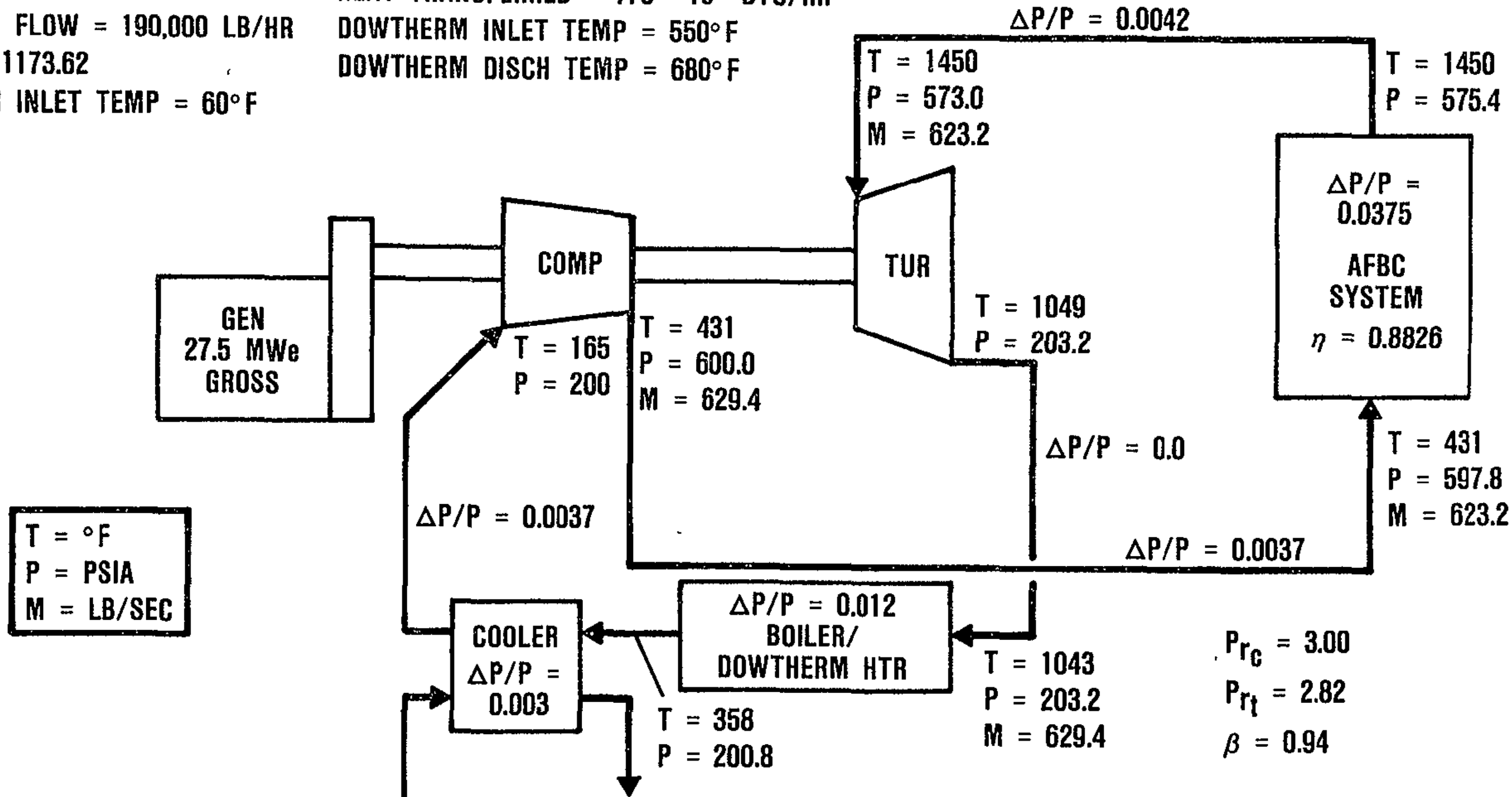

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FIGURE 1-4

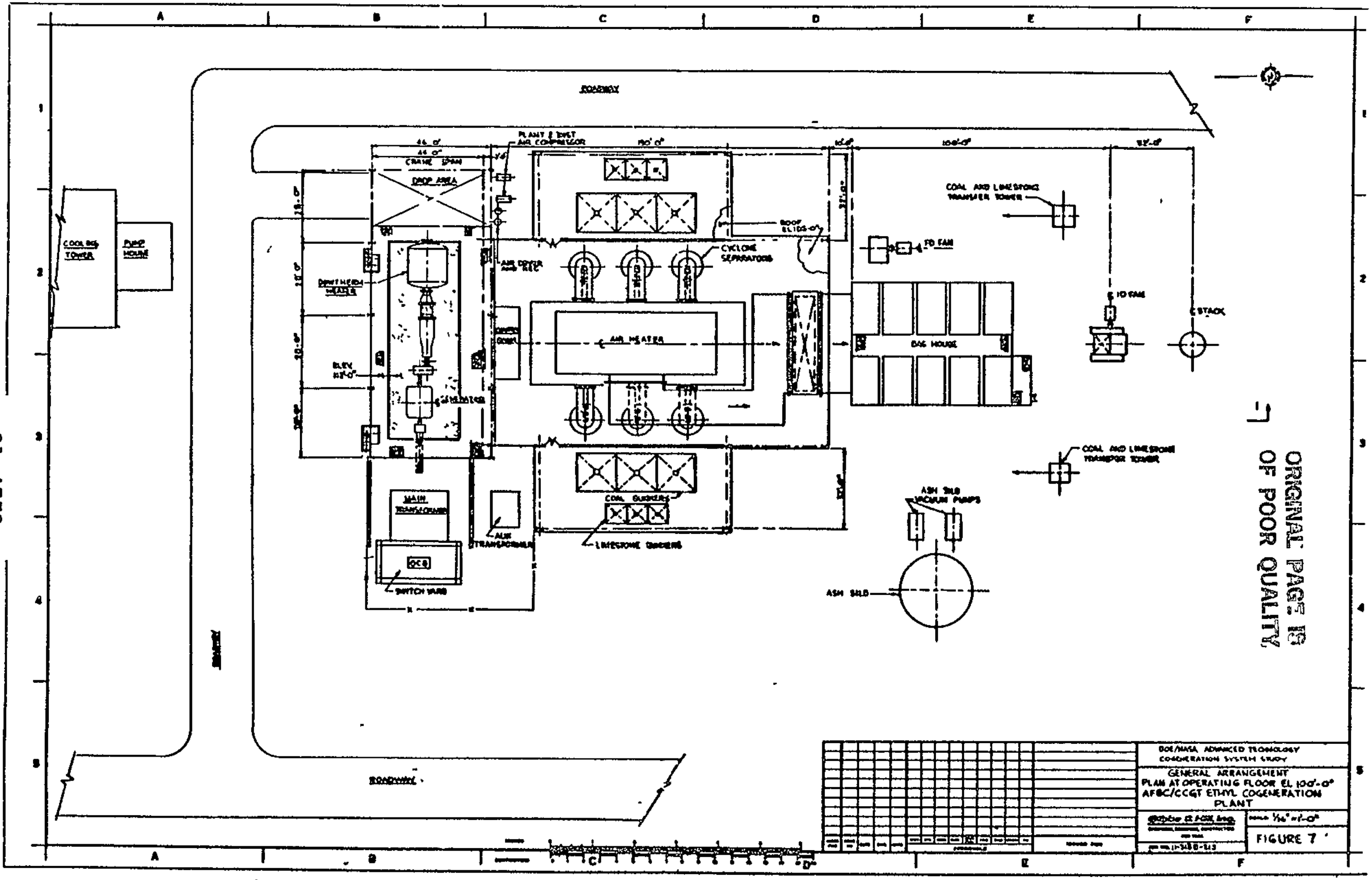
ROADWAY
COOLING TOWER
PUMP HOUSE
CRANE SPAN
DROP AREA
PLANT & INST AIR COMPRESSOR
AIR DRYER AND REC.
CYCLONE SEPARATORS
AIR HEATER
BAG HOUSE
FD FAN
ID FAN
STACK
COAL AND LIMESTONE TRANSFER TOWER
GENERATOR
MAIN TRANSFORMER
AUX TRANSFORMER
OCB
SWITCH YARD
COAL BUNKERS
LIMESTONE BUNKERS
ASH SILO VACUUM PUMPS
ASH SILO
ROADWAY
DOE/NASA ADVANCED TECHNOLOGY COGENERATION SYSTEM STUDY
GENERAL ARRANGEMENT PLAN AT OPERATING FLOOR EL 100'-0" AFBC/CCGT ETHYL COGENERATION PLANT
FIGURE 7

FIGURE 1-5

GARRETT TURBINE ENGINE COMPANY
A DIVISION OF THE GARRETT CORPORATION
PHOENIX ARIZONA

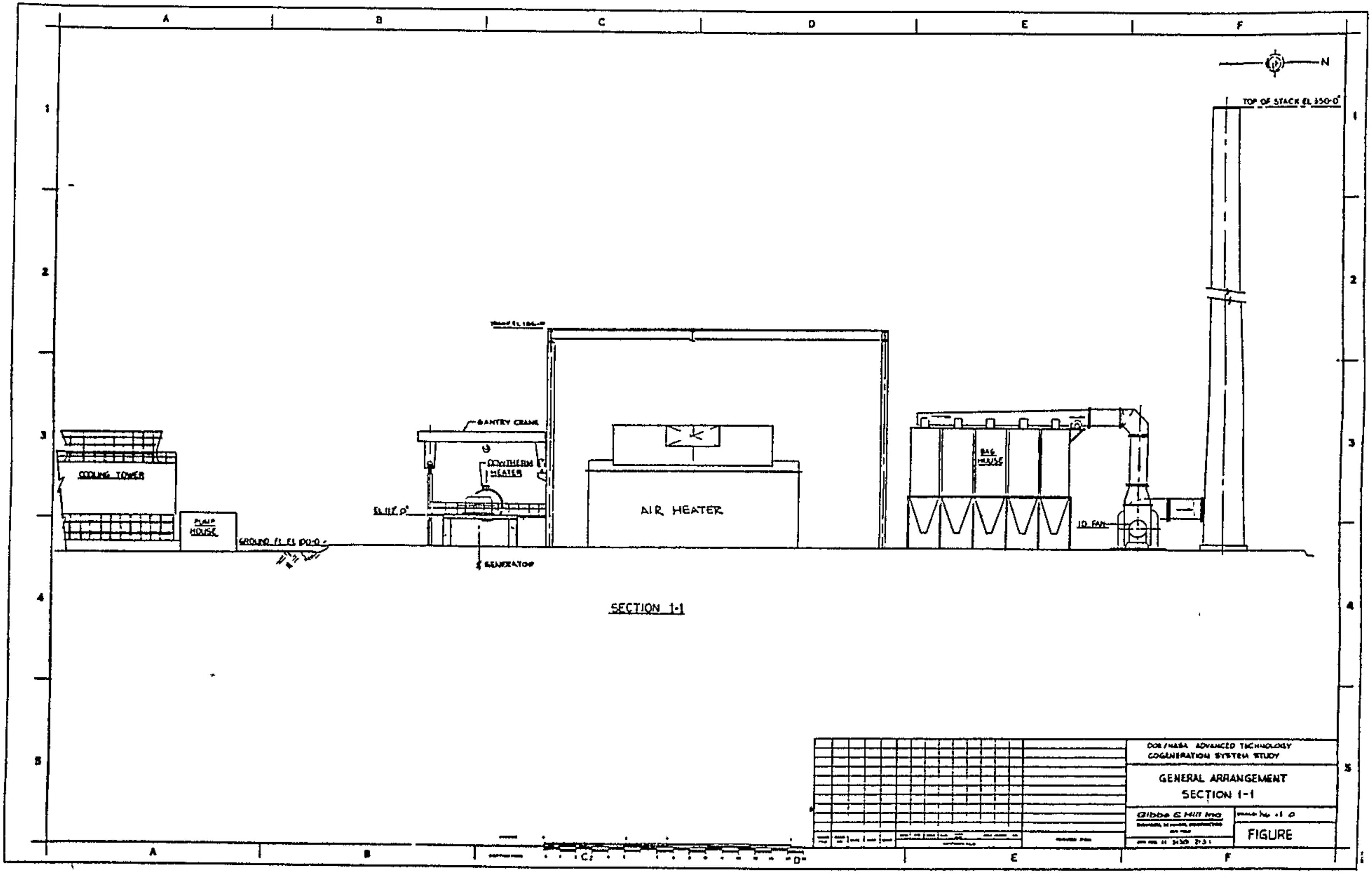

FIGURE 1-6

Figure 1-6 illustrates an elevation view of the complete AFBC/CCGT Cogeneration System. The turbogenerator deck is elevated about 12 feet above the ground elevation to accommodate the location and support of the cycle gas ducts to and from the AFBC heater. All other major components, except the combustion air preheater, are ground mounted for which adequate concrete and steel foundations have been cost estimated. It should be made clear that the foregoing system design is conceptual in nature. In the course of the study a great deal of emphasis was placed on realism and, therefore, reliability of results. Although fabrication and erection type design drawings were not either a requisite or an objective of the study, the design study was done in sufficient detail to support realistic performance and cost estimates.

Figure 1-7 summarizes the plant output characteristics. Figure 1-8 presents the values of the requirements for the five major resources required to support the AFBC/CCGT Cogeneration System at full load, full time operation. Note that a basic assumption of full time, base loaded operation was established early in the analytical study which is consistent with the constant loads of the Ethyl site. Atmospheric emissions, spent solids and thermal heat rejection values are summarized in Figure 1-9.

The Task II detailed conceptual design study was conducted to determine, with reasonable certainty, the cost of a plant designed for a specific site. The plant capital cost is summarized in Figure 1-10. Note that the plant cost does not include interest or escalation during construction.

Figure 1-11 compares the AFBC/CCGT conceptual design against the existing separate generation plant at the Ethyl site. The return-on-equity (ROE) value is very attractive. The fuel energy savings ratio (FESR) is defined as:

AFB/CCGT COGENERATION SYSTEM

NET PLANT OUTPUT, MW_e	24.33
NET PLANT OUTPUT, MW_t	115.34
FUEL UTILIZATION $\left(\frac{MW_e + MW_t}{MW_{IN}}\right)$, PERCENT	70.65
AFB HEATER EFFICIENCY, PERCENT	88.37
COAL CONSUMPTION, TONS/DAY	653
LIMESTONE CONSUMPTION, TONS/DAY	152
TOTAL SOLID WASTE, TONS/DAY	212.1
CONSTRUCTION TIME, YEARS	2.0
PRE-ENGINEERING & PERMITS TIME, YEARS	0.75

FIGURE 1-7

AFB/CCGT COGENERATION SYSTEM
(RESOURCE REQUIREMENTS)

COAL — 80.64 LB/$MBTU_{FIRED}$, 653 TONS/DAY

LIMESTONE — 18.77 LB/$MBTU_{FIRED}$, 152 TONS/DAY

NATURAL GAS — NONE

WATER —

COOLING — EVAP.	279,000 GALS/DAY
BLOWDOWN	82,080
TOTAL	361,080

LAND REQUIREMENTS — 10 ACRES (INCLUDES COAL, LIMESTONE AND ASH STORAGE)

FIGURE 1-8

AFB/CCGT COGENERATION SYSTEM EMISSIONS

	$LB/MBTU_{FIRED}$	TONS/DAY
ATMOSPHERIC		
SO_2	0.50	4.06
NO_X	0.18	1.46
HC	$\simeq$0.0	0.0
CO	$\simeq$0.0	0.0
PARTICULATES	0.029	0.23
TOTAL		5.75
SPENT SOLIDS		
CALCIUM SULFATE	9.60	77.73
ASH AND DIRT	9.86	79.89
UNREACTED SORBENT	5.61	45.46
CARBON	1.11	9.02
TOTAL		212.1

THERMAL	BTU/MBTU
COOLING TOWER	156,383
STACK	52,951
OTHER	5,776
TOTAL	215,100

FIGURE 1-9

AFB/CCGT COGENERATION SYSTEM CAPITAL COSTS

(M$)	COMPONENT CAPITAL	DIRECT LABOR	INDIRECT FIELD	MATERIAL	TOTALS
1.0 FURNACE	8.462	1.414	1.273	0.704	11.853
2.0 TURBINE GEN	7.274	0.058	0.052	0.290	7.674
3.0 PROC MECH EQUIP	0.916	0.402	0.362	7.507	9.187
4.0 ELECTRICAL		0.370	0.333	1.389	2.092
5.0 CIVIL + STRUCT		1.758	1.582	1.803	5.143
6.0 PROC PIPE + INST		0.770	0.693	1.377	2.840
7.0 YARDWORK + MISC		0.000	0.000	0.000	0.000
***** TOTALS *****	16.652	4.772	4.295	13.070	38.789
BALANCE OF PLANT (BOP)	(DIRECT + INDIRECT + MATERIAL)			22.137	
A/E HOME OFFICE AND FEE		(AT 15 PCT OF BOP)		3.320	
SUBTOTAL PLANT COST			(TOTAL + A/E)		42.109
CONTINGENCY	(0.137 OF TOTAL PLANT COST, CALC)			5.786	
PLANT COST (1982.0 $)	(SUBTOT PLANT COST + CONTINGENCY)				47.895
CONSTRUCTION ESCAL. AND INTEREST CHARGES					0.000
TOTAL PLANT CAPITAL COST			(1982 $)		47.895

FIGURE 1-10

AFB/CCGT COGENERATION SYSTEM
PERFORMANCE AND BENEFITS ANALYSES

ROE	49.26 PERCENT
FESR	11.75 PERCENT
EMSR	-37.95 PERCENT
CAPITAL COST	47.895 MILLION $

VALUES SHOWN ARE RELATIVE
TO NON-COGENERATION

FIGURE 1-11

$$\frac{\text{Separate Generation Fuel Used (Utility Plus Industrial Site)} - \text{Cogeneration Fuel Used}}{\text{Separate Generation Fuel Used (Utility Plus Industrial Site)}}$$

A positive FESR shows that the total energy used to satisfy the loads is less with the cogeneration system. The emissions savings ratio (EMSR) is defined similar to the FESR. A negative EMSR shows that the cogeneration plant rejects more emissions into the atmosphere. This is generally the case when the industry and the utility are based on natural gas and the cogeneration system is based on the use of coal. The oxides of nitrogen are reduced but the particulate emissions associated with coal more than offset the reduced NO_x emissions.

The remainder of this appendix provides details of the results shown above.

2.0 CLOSED CYCLE GAS TURBINE

2.1 Turbine - Generator

As noted earlier in this report the main objective in the cogeneration system design was to provide output that would simultaneously match both the electrical and thermal requirements of the Ethyl Plant. In the course of developing a CCGT design to meet those goals it became evident that the resulting turbomachinery configuration was very similar to that of a unit designed earlier for 50 MW_e capability at somewhat different operating conditions. An analysis of the operating conditions required to satisfy the Ethyl load requirements revealed that they are well within the range of conditions suitable for the heater and heat recovery systems. Additional analyses were conducted to optimize the performance for this application. Figure 2-1 illustrates the turbocompressor unit in cross section. Refer to Table 2-1 and Figure 2-2 for configuration details and dimensions. The output shaft speed is constant at 10,000 rpm, therefore a gear reducer is required to match the shaft speed with the 60 Hz generator.

Two different configurations of industrial gear reducers designed specifically for this service were investigated. One is a parallel shaft, double helical gear set with integral, full pressure lubricating oil system with external, dual filter and cooling system. The other is an axial shaft, two stage planetary gear set also complete with full pressure lubricating system with external, dual filter and cooling system. Both units satisfy the operating conditions with ample margin. The two stage planetary system is felt to offer greater strength and longer life because of inherently lower tooth to tooth contact pressure and the elimination of gear thrust loads. The parallel shaft system is somewhat simpler construction and is lower in cost. Outline configuration and dimensions for the parallel shaft unit are presented in Figure 2-3. Price and delivery information on this unit were provided by:

GARRETT TURBINE ENGINE COMPANY
A DIVISION OF THE GARRETT CORPORATION
PHOENIX ARIZONA

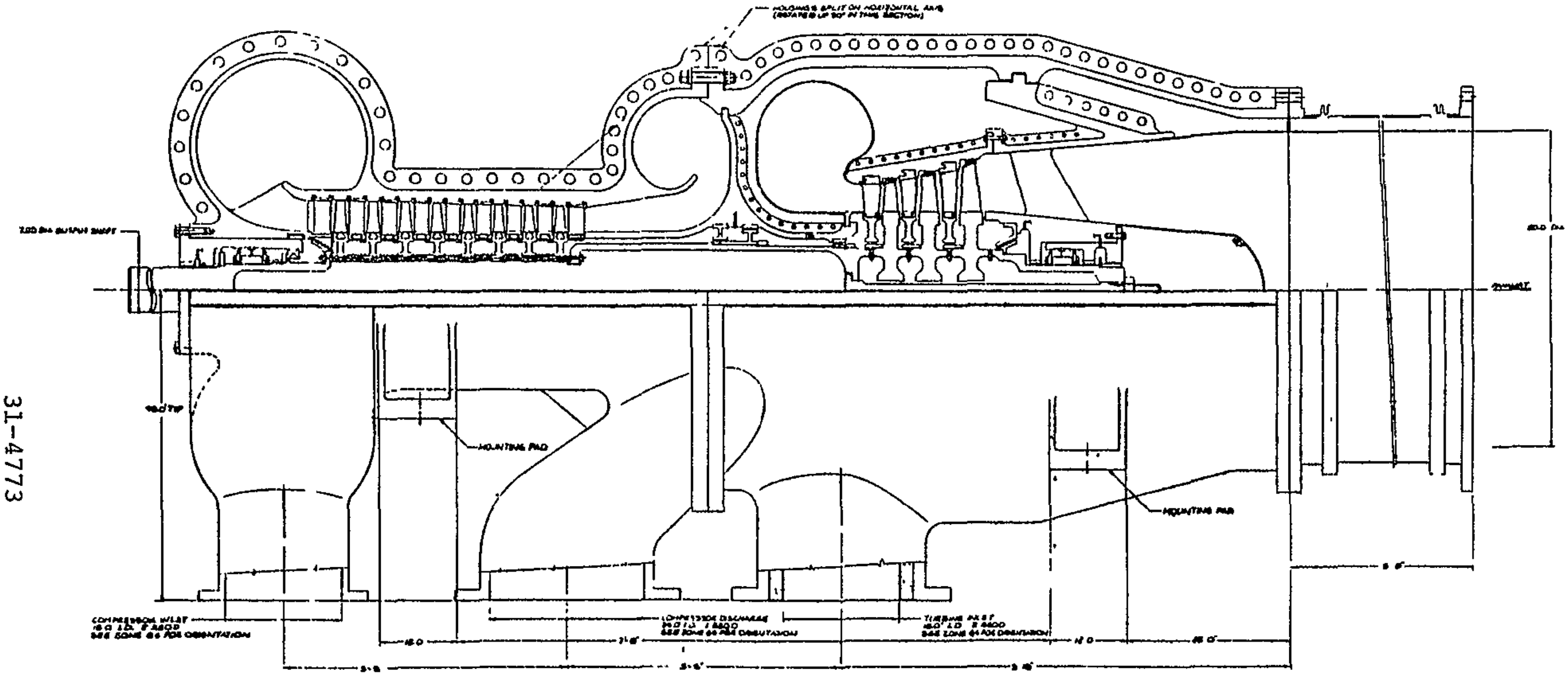

FIGURE 2-1

TABLE 2-1. CCGT TURBOCOMPRESSOR DESIGN SUMMARY

Shaft Speed, rpm	10,000
Shaft Output Power, kw	28,590
Compressor Section	
Inlet Temperature, °F	165
Inlet Pressure, psia	200
Inlet Flow, lb/sec	629.4
Pressure Ratio	3.00
8 stage axial design	
Hub Diameter, in	16.3
First Stage Tip Diameter, in	23.0
Turbine Section	
Inlet Temperature, °F	1450
Inlet Pressure, psia	573
Inlet Flow, lb/sec	623.2
Pressure Ratio	2.82
3 Stage Axial Design	
Hub Diameter, in	19.9
Last Stage Tip Diameter, in	34.8

CLOSED CYCLE 30 MW_e TURBOGENERATOR

USES 50 MW_e FRAME SIZE ENGINE

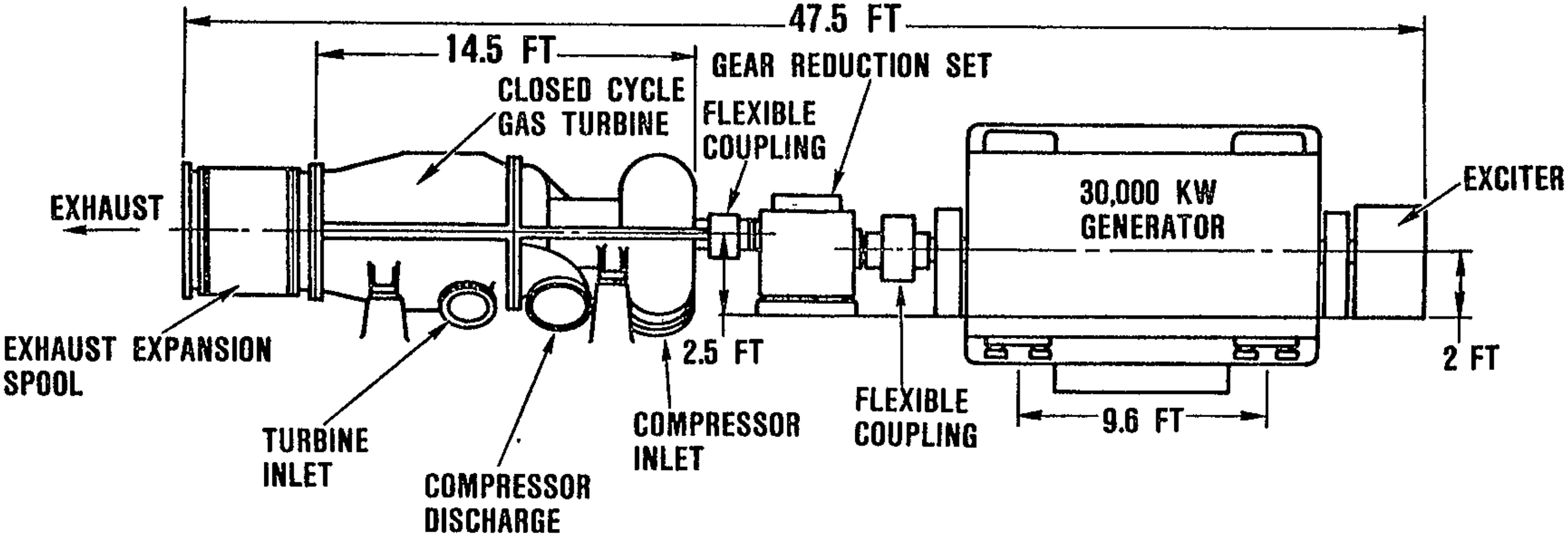

FIGURE 2-2

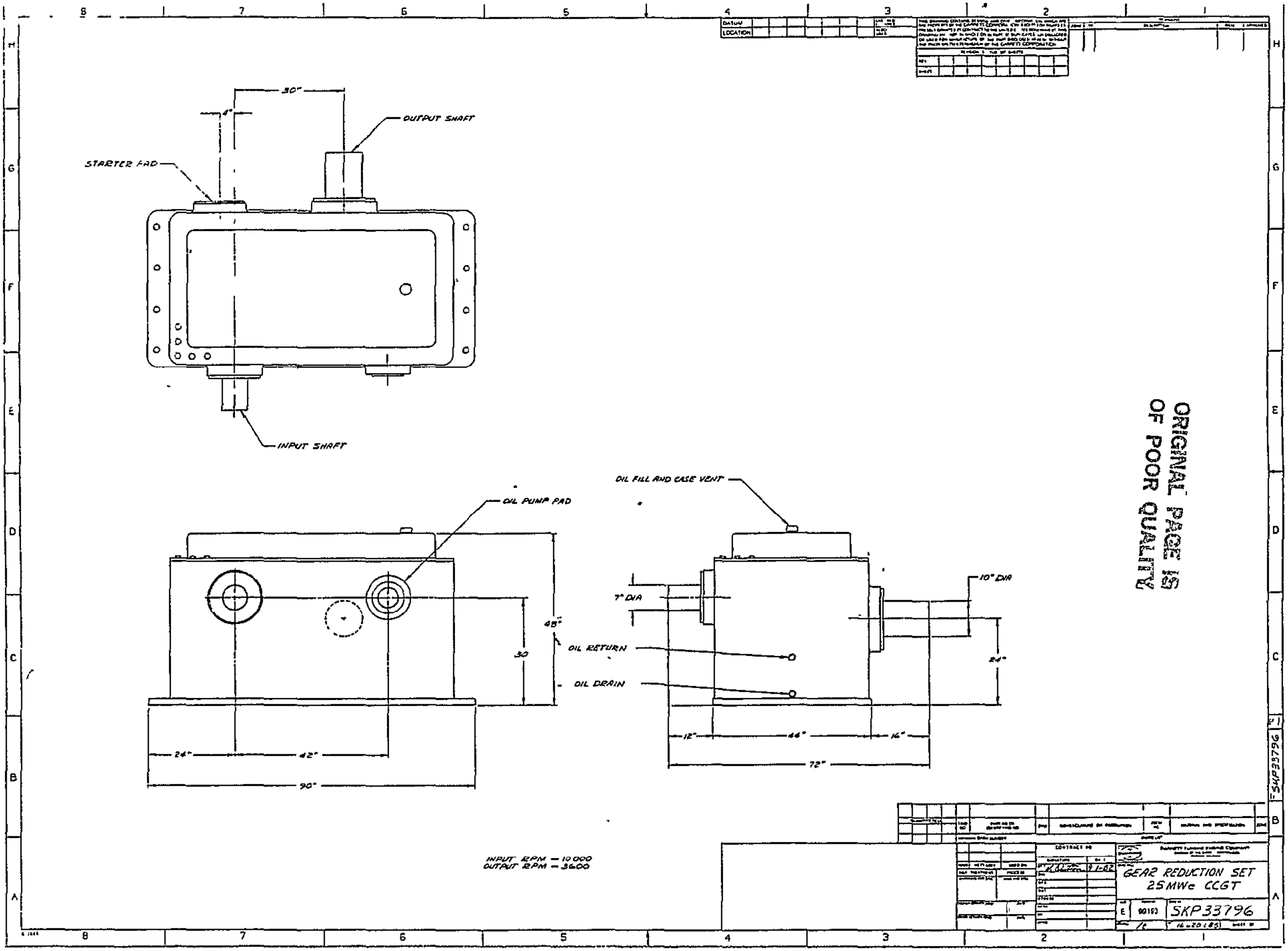
STARTER PAD
30"
4"
OUTPUT SHAFT
INPUT SHAFT
OIL PUMP PAD
OIL FILL AND CASE VENT
48"
30
OIL RETURN
OIL DRAIN
7" DIA
10" DIA
24"
24"
42"
90"
12"
44"
16"
72"
INPUT RPM = 10 000
OUTPUT RPM = 3600
GEAR REDUCTION SET
25MWe CCGT
SKP33796
ORIGINAL PAGE IS
OF POOR QUALITY

FIGURE 2-3

Philadelphia Gear Corp.
181 South Gulph Road
King of Prussia, PA 19406

Price and delivery data for the two stage planetary system were provided by:

American Lohman Corp.
74 Industrial Avenue
Little Ferry, NJ 07643

Both units are comparable in performance while the parallel shaft unit is somewhat larger and heavier than the planetary unit.

Starting of the gas turbine is planned to be accomplished by connecting the generator across the utility bus. Therefore neither gear reducer is equipped with a separate starter pad. This feature can be added to either unit with the parallel shaft unit somewhat easier and less expensive to adapt.

Both units are designed for handling torque transient loads equal to 7-1/2 times full load torque for short duration spikes without failure.

Both units are designed for base mounting. Input and output shafts are equipped with standard keys for connection to the prime mover and the load.

The gas turbine, gearbox and generator are all mounted to a common fixed foundation. Flexible couplings are used to couple the turbine output shaft to the gearbox and the gearbox output shaft to the generator. Sources for these couplings are as follows:

Philadelphia Gear Corp
181 South Gulph Road
King of Prussia, PA 19406

Zurn Industries, Inc.
Mechanical Drives Div.
1801 Pittsburgh Avenue
Erie, PA 16512

Figure 2-2 shows the closed cycle gas turbine, gearbox, coupling and generator arrangement for the Ethyl Corp. system. It should be noted that the overall length of the unit from the exit of the gas turbine exhaust expansion spool to the end of the generator exciter is only 47 ft-5 in. The highest point above the floor line is approximately 6 ft.

The generator is the same as that used for the AFBC/STCS as described in Appendix III, Page 3-6.

2.2 Waste Heat Recovery System

2.2.1 General Description

All of the heat energy for heating the Dowtherm fluid, generating the process steam and heating the boiler feedwater is provided by the gas turbine exhaust gas. This is accomplished by enclosing the three separate heat exchanger bundles in a common pressure vessel. An inlet duct on the pressure vessel is connected by an expansion duct to the discharge duct of the gas turbine housing. A cross sectional view of this unit is shown in Figure 2-4.

2.2.2 Design Details

Reference to Figure 2-4 will show that the heat recovery pressure vessel is nearly spherical in shape with a diameter of 12 ft-10 in. This shape is to minimize the shell metal thickness required to withstand the internal air pressure of 194 psig. The rectangular internal duct which contains the heat exchanger bundles is of relatively light metal construction because the pressure across that element is equal only to the ΔP created by the airflow across the tubes. However, this duct is insulated with 8 inches of refractory insulation as the entering air temperature is 1050°F and the leaving temperature at the discharge of the cooler heat exchanger is 165°F. This feature permits the inside surface of the pressure vessel to be swept with 165°F air, thus keeping the walls cool and minimizing the required metal thickness. All of the heat exchangers are constructed of stainless steel, 0.75 in OD finned tubing. Fin count is 11 fins per inch with fin OD of 1.05 in. The finned tubes have a heat transfer surface area of 105.7 ft^2 per cubic foot of core volume.

The tube bundles are supported from the top of the inner structure and the vertical wall supporting the manifolds. Clearance for

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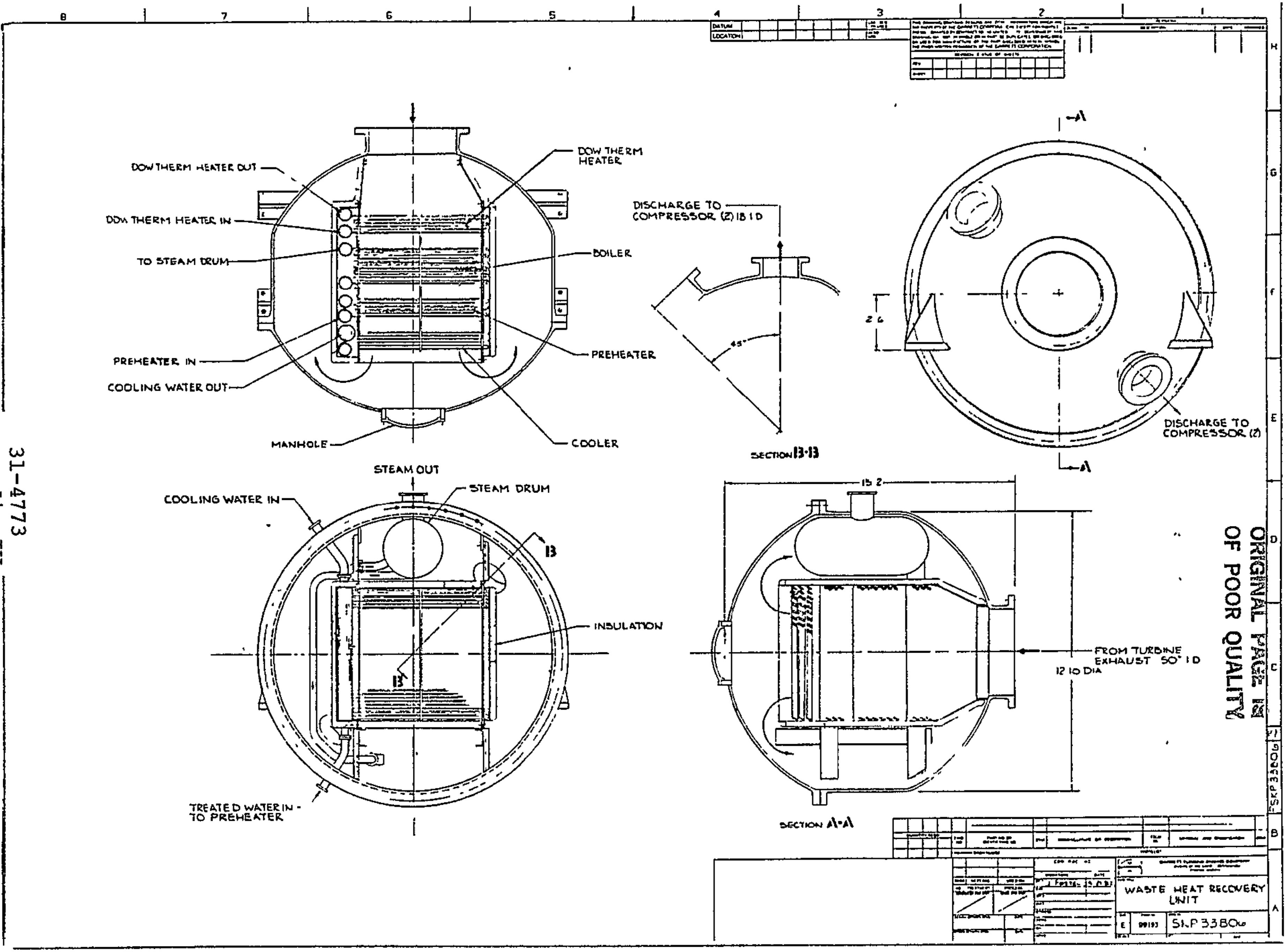


FIGURE 2-4

expansion is provided in baffles along the bottom and opposite vertical wall. The manifolds for each of the heat exchanger sections are constructed of stainless steel and supported from the structural steel skeleton that supports the rectangular inner duct.

The steam drum is housed inside the pressure vessel which reduces the inside to outside pressure differential on the drum and shortens the interconnecting lines to the feedwater heater.

One end of the pressure vessel is flanged to accommodate a hemispherical end cover which is bolted to the shell. This provides access to the internal components for maintenance, repair or replacement.

Reference to Figure 1-5 in Section 1.0 will show the location of the cogeneration site at the Ethyl Corp. plant. Figure 1-6 illustrates a plan view of the CCGT cogeneration system within the specified site.

3.0 AFBC - HEATER SYSTEM

3.1 General Description

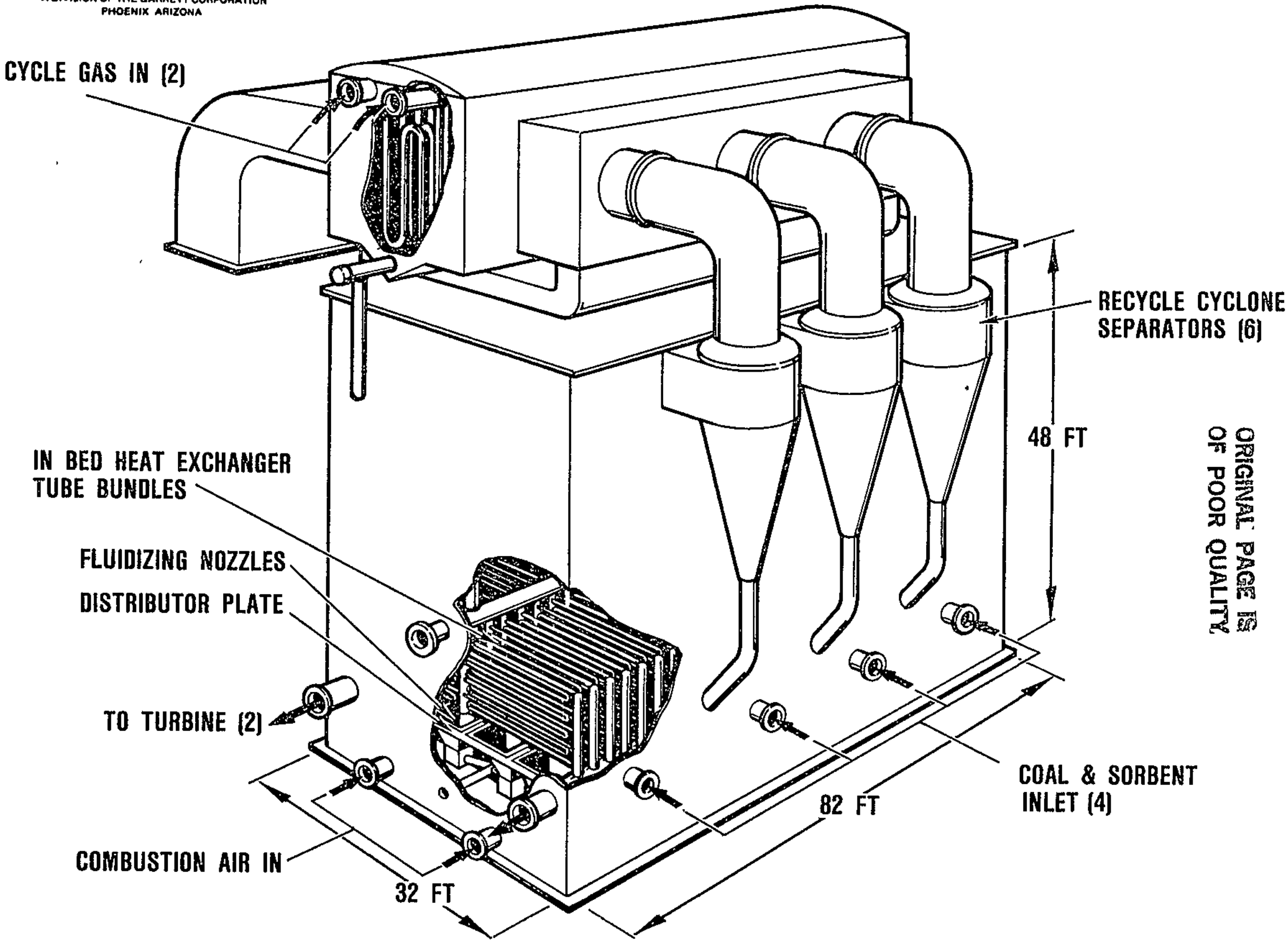
The cycle gas (air) for the CCGT system is heated remotely from the gas turbine in a fluidized bed combustor/heater. An isometric, cutaway illustration of the unit is shown in Figure 3-1. The combustor, or furnace, section is a rectangular, thermally insulated vessel approximately 82 ft long x 32 ft wide x 48 ft high. The lower section provides a space for combustion air ducting to a distributor system that supplies the air evenly to the bottom of the bed. The bed consists of crushed limestone and ash particles about 5.4 ft deep supported on a grid above the distributor. Crushed coal and limestone are pneumatically injected into the bottom portion of the bed through eight feed ducts, four on each of the long sides of the furnace. The coal ignites immediately on contact with the hot bed particles, maintained at 1600°F. Combustion gases and coal ash particles are levitated upward through the freeboard space above the bed and through six cyclone separators mounted on the long sides of the furnace, three on each side. The heavier, unspent particles separated out of the gases are ducted back into the bed. The partially cleaned flue gas is ducted upward from the cyclone separator to the top-mounted cycle gas preheater chamber where it passes through the tubular heat exchanger then through the combustion air preheater. The combustion air preheater is shown on Figure 3-2.

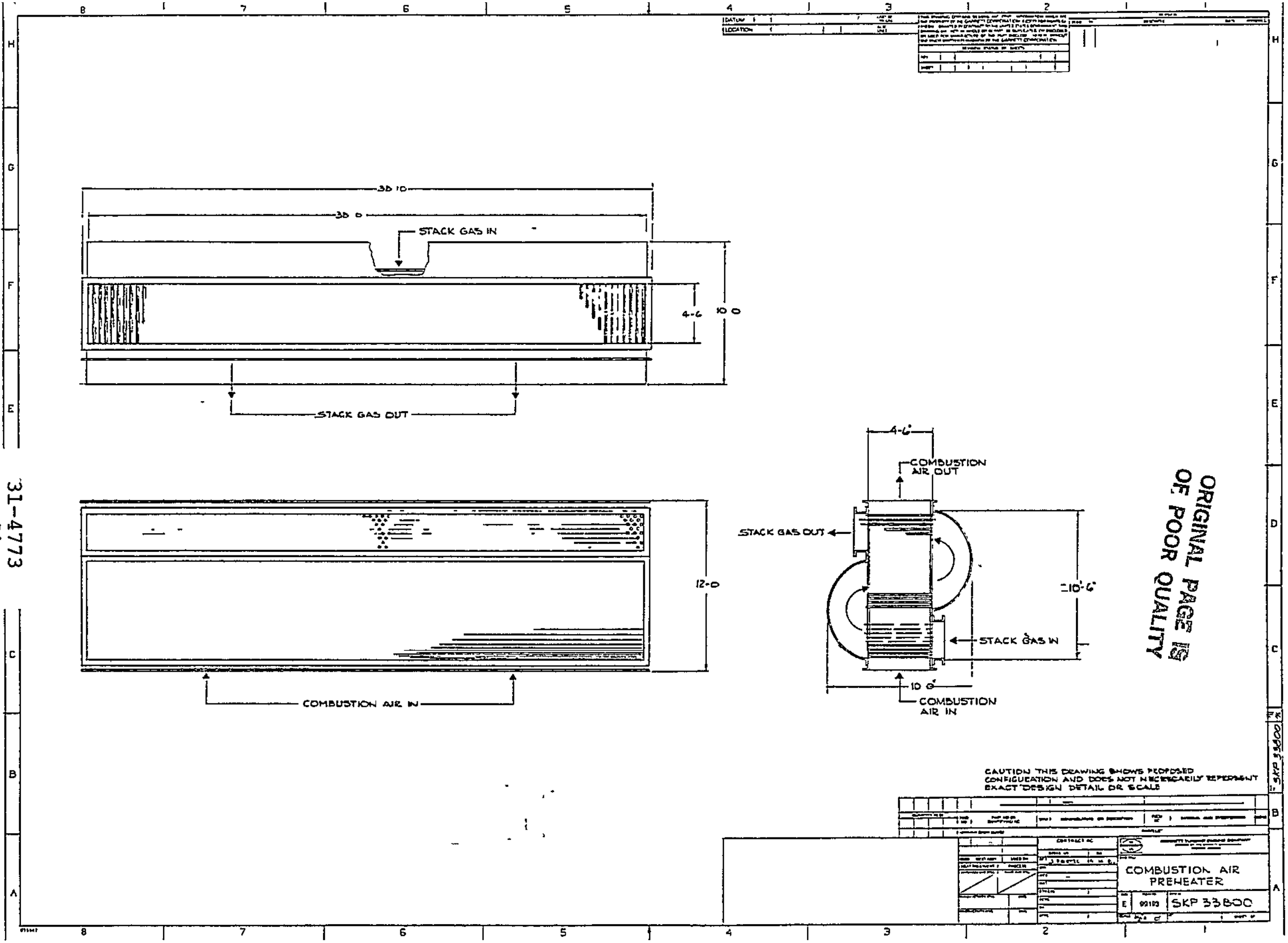
An orthographic view of the AFBC is shown in Figure 3-3.

3.2 AFBC System Design Details

Details of the cycle state points throughout the AFBC System are shown in Figure 1-3. Specific details of the AFBC heat exchangers are presented in Table 3-1.

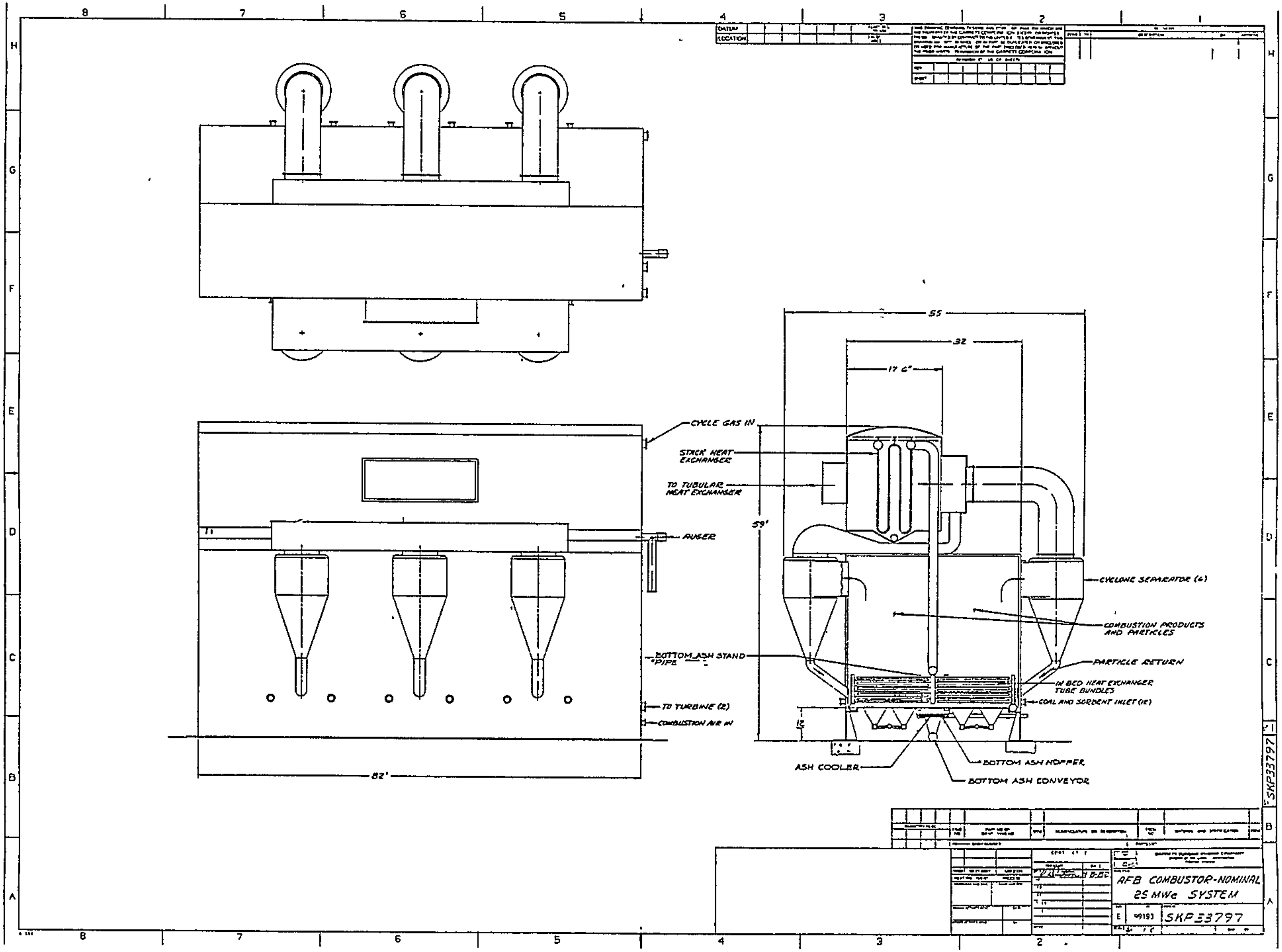
GARRETT TURBINE ENGINE COMPANY
A DIVISION OF THE GARRETT CORPORATION
PHOENIX ARIZONA





38 10
38 0
STACK GAS IN
4-6
10 0
STACK GAS OUT
12-0
COMBUSTION AIR IN
4-6
COMBUSTION AIR OUT
STACK GAS OUT
10-6
STACK GAS IN
10 0
COMBUSTION AIR IN
ORIGINAL PAGE IS OF POOR QUALITY
CAUTION THIS DRAWING SHOWS PROPOSED CONFIGURATION AND DOES NOT NECESSARILY REPRESENT EXACT DESIGN DETAIL OR SCALE
COMBUSTION AIR PREHEATER
SKP 33800

FIGURE 3-2



CYCLE GAS IN
STACK HEAT EXCHANGER
TO TUBULAR HEAT EXCHANGER
AUGER
BOTTOM ASH STAND PIPE
TO TURBINE (2)
COMBUSTION AIR IN
82'
55
32
17 6"
59'
CYCLONE SEPARATOR (6)
COMBUSTION PRODUCTS AND PARTICLES
PARTICLE RETURN
IN BED HEAT EXCHANGER TUBE BUNDLES
COAL AND SORBENT INLET (12)
ASH COOLER
BOTTOM ASH HOPPER
BOTTOM ASH CONVEYOR
AFB COMBUSTOR-NOMINAL 25 MWe SYSTEM
SKP 33797

FIGURE 3-3

TABLE 3-1. AFBC HEAT EXCHANGER SUMMARY FOR TASK II - AFBC/CCGT COGENERATION SYSTEM

In-Bed Heat Exchanger	
Three Passes on CCGT Cycle Side Cross-Counterflow Arrangement	
Heat Transfer, Btu/sec	113,364
Tube Outside Diameter, in	1.258
Tube Length, ft	12.0
Total Number of Tubes	4077
Tube Material	INCO 800H
Convective Heat Exchanger	
Five Passes on CCGT Cycle Side Cross-Counterflow Arrangement	
Heat Transfer, Btu/sec	52,273
Tube Outside Diameter, in	1.125
Tube Length, ft	12.0
Total Number of Tubes	11,700
Tube Material	AISI 304
Preheater	
Three Passes on Stack Gas Side Cross-Counterflow Arrangement	
Heat Transfer, Btu/sec	10,227
Tube Outside Diameter, in	1.000
Tube Length, ft	4.5
Total Number of Tubes	25,560
Tube Material	AISI 304

It should be noted that coal and sorbent hoppers are provided on either side of the AFBC which have capacities to maintain operation at full load for 30 hours. Ash transport equipment and storage silos are located near the baghouse particle separator where most of the rejected solids are collected. The forced draft fan is electrically driven and is mounted on a concrete foundation near the combustion air inlet duct of the air preheater which is located in the vertical exhaust duct section between the AFBC and the baghouse. The induced draft fan and its electric motor drive are mounted on a concrete foundation between the baghouse exit and the stack.

3.3 CCGT System Emissions

One of the significant objectives of this study was to evaluate the impact on local air quality as a result of the emissions generated by the CCGT cogeneration system. Three areas of concern with respect to pollutants generated were specified as follows:

(a) Sulfur dioxide (SO_2)
(b) Oxides of nitrogen (NO_x)
(c) Particulates

Limits for permissible emission of the above pollutants were established as discussed in Appendix II.

3.3.1 SO_2 Levels

Among the inherent advantages of the AFBC when fired with coal is its capability to reduce the generation of SO_2 by introducing a sulfur sorbent with the fuel. For this system crushed limestone is used as the SO_2 sorbent. Characteristics of the limestone are presented earlier in Appendix II. The chemical processes by which the calcium in the limestone combines with the sulfur in the fuel during the combustion process has been covered in a great deal of detail in many publications. Test results have indicated that SO_2 levels in the exhaust gas stream of AFBCs burning coal can be kept within acceptable limits by exercising care in the design procedure and adhering to several well founded AFBC design principles. Critical design aspects which act to control SO_2 are as follows:

(a) Incorporation of specially designed, hot recycle cyclones
(b) Maintain relatively low superficial velocity
(c) Controlling raw sorbent feedstock particle size distribution within desirable limits
(d) Maintain bed temperature limits between 1450°F and 1650°F
(e) Limit above-bed temperature to a value not higher than bed temperature, achieved by using underbed feed.

The design of the Ethyl Corp. AFBC incorporates all of the design features listed above and as a result SO_2 levels will be maintained well below the federal standards for the area. Key to this successful design approach is the use of under bed feed of the coal and sorbent.

3.3.2 NO_x Levels

A second inherent feature of the AFBC when fired with coal is its capability to maintain low levels of NO_x in the flue gas. This feature is enhanced when underbed coal feeding is used. The thermochemical process by which NO_x is formed when burning coal in conventional stoker fed and pulverized coal furnaces has been well established as a result of nearly a century of experience. Combustion temperatures exceed 3000°F in those processes and the very steep rise in the rate of NO_x formation at temperatures above 2200°F has been accurately determined. The formation of NO_x in the flue gases from a coal fired AFBC is significantly reduced in comparison to that in the traditional combustors because of the marked reduction in the maximum combustion temperatures reached. Empirical data from well designed AFBCs indicate temperature distribution profiles throughout the bed with a spread of 20°F or less. Because of the intimate, solid to solid contact of raw fuel particles with the hot bed particles ignition is initiated within a few milliseconds after injection. The combustion process is completed with bed particles extracting the heat energy from the burning fuel particles at an extremely rapid rate, thus limiting the fuel particle temperature to only a narrow margin above bed temperature. Maximum combustion temperature in the bed thus never reaches the critical 2000°F level where NO_x is generated at an appreciable rate.

Therefore NO_x levels in the flue gas are maintained well below the federal standards for coal fired units.

3.3.3 Particulates

One of the characteristics of the type of AFBC designed for the Ethyl Corp. cogeneration system is that more than 70 percent of the ash resulting from combustion is carried out of the bed with the flue gas. Less than 30 percent is carried out through the gravity bed drain system. This is due primarily to three different operational factors.

(a) The fuel fed to the bed is crushed to 3/6 in minus size prior to injection
(b) Abrasive action in the bed with hot bed particles reduces the particle size during combustion to approximately 100 microns maximum
(c) Recycle cyclones separate the larger particles from the flue gas stream and recycle them through the bed as many times as necessary to reduce the size small enough that they are carried out with the gas stream.

Because the gas stream is highly contaminated with fine coal ash particles and spent sorbent particles, it is passed through banks of baghouses to remove the partiulates prior to entering the stack. With this system 99.8 percent of the particulates are removed. This maintains particulate levels within the federal standards.

Actual emission levels predicted for this system are presented in Figure 1-9.

One of the national benefits that may be achieved through the application of coal fired cogeneration systems burning coal is a reduction in emission levels over the more traditional coal burning utility plants. This is a result of the inherently lower emission levels of the AFBC as discussed in the foregoing paragraphs. As a measure of the improvement in emissions as compared to traditional utility systems the actual levels predicted for the cogeneration system were compared to those generated by the utility plant for the same level of electrical output plus that generated on site for producing the same thermal output. As a convenient means of expressing the improvement, a factor was developed by NASA which was termed the "emission savings ratio" (EMSR) and was defined as follows:

$$EMSR = \frac{\begin{pmatrix}\text{Total Emissions for} \\ \text{Non Cogeneration}\end{pmatrix} - \begin{pmatrix}\text{Total Emissions} \\ \text{for Cogeneration}\end{pmatrix}}{\begin{pmatrix}\text{Total Emissions for} \\ \text{Non Cogeneration}\end{pmatrix}}$$

The value for Ethyl Corp. system is -37.95 percent as shown in Figure 1-11. This negative EMSR value shows that the total emissions are higher for the cogeneration case. The reason for this is that coal is being used for fuel in the cogeneration case as opposed to natural gas for both the public utility and the on-site thermal units. The oxides of nitrogen are reduced but the sulfur dioxide and particulate emissions associated with coal more than offset the reduced NO_x emissions.

4.0 CCGT SYSTEM BALANCE OF PLANT (B.O.P.)

In structuring the overall approach to the specific system design studies, experience gained on prior studies of similar systems was utilized. A major reason for engaging Gibbs & Hill, Inc. in this study was to take advantage of their long experience and proven successful record in the analysis, design, and erection of coal fired steam turbine generating plants including all of the BOP and site work. As the analysis and design iteration process evolved for both the CCGT and ST systems it became evident that designs were feasible for both systems that would perform identical tasks; that is, to satisfy essentially identical electrical and thermal loads. Thus most of the BOP; for example, the equipment to support the AFB combustor heaters, the entire electrical system, the steam distribution system, boiler feedwater, spent solids disposal, and other similar equipment is essentially identical for both systems. Because Gibbs & Hill had the responsibility for the design and cost analysis of the entire ST system it was deemed most effective to pursue that design first and to complete it through the specification and cost estimating of the site work and balance of plant. Due to the similarities of the systems, the sizes, capacities and specifications for a large percentage of the BOP equipment for the CCGT system are either identical with or similar to those for the ST system. In cases where specifications were essentially identical, the cost estimates used for both the CCGT and ST systems were identical. In cases where sufficient technical differences exist in the BOP for the two systems, cost estimates for the CCGT system were derived by scaling the comparable ST system estimates based on factors derived from a careful comparison of loads, capacities, materials handling rates, etc. In cases where substantial differences exist or where there is no comparable component in the ST system, separate specifications and costs were developed for the CCGT system.

Included in this account were such components as:

- High temperature - high pressure, internally insulated cycle air ducting
- Reduced temperature - high pressure, externally insulated cycle air ducting
- Cycle air inventory storage accumulators
- Cycle air inventory high pressure compressors, filters, dryers and controls
- Non common foundations
- Gear reducer oil cooling system
- Cycle air loop control equipment
- Turbine starting support equipment.

5.0 MAJOR EQUIPMENT LIST

The major mechanical and electrical equipment required for the AFBC/CCGT are the following:

Mechanical Equipment

Item	Description	Quantity
1	Atmospheric Fluidized Bed Air Heater Fluidized bed coal fired with pneumatic underbed injection of coal and limestone, balanced draft unit including forced draft and induced draft fans, ash recycle cyclones, air preheater, blowers motors, piping and controls to burn Oklahoma bituminous coal.	1
2	Gas Turbine-Generator: The generator is rated 32,000 kVA, 30,000 kW, 13.8 kV, 3-phase, 60 Hz, 3600 rpm. Closed cycle gas turbine with 1450°F turbine inlet temperature, 600 psi max pressure with air as the cycle fluid.	1
3	Waste Heat Recovery Unit 4 element, shell and tube exchanger unit. Four separate tube bundles in series as follows: Dowtherm heater, steam generator, feedwater preheater and cycle gas cooler. Stainless steel, modified spherical shell with integral manifolding, receiver and feedwater supply systems. Includes boiler and circulating water feed pumps.	1
5	Cooling Water Tower: Mechanical-draft, wet cooling tower with counter flow design for 80°F wet-bulb temperature. Cooling water inlet temperature 90°F and outlet temperature 105°F.	1

Item	Description	Quantity
6	Circulating Water Piping System: Including steel piping with motor operated shutoff valves, expansion joints, and elbows.	1
7	Cooling Tower Corrosion Inhibitor Feed System: Including 300 gallon inhibitor solution tank with agitors, valve, switch, pump, and strainer.	1
8	Chlorination Biological Control System: Chlorination supply tanks, controls, residual chlorine detector, motor-driven shutoff valves, piping and fittings. Chlorinator capacity is 2000 lb/day with one required.	1
9	Baghouse: Reverse air type, to operate at a draft loss of 6 to 8 in. w.g. Removal efficiency 99.8 percent. Number of modules per baghouse is 12; number of bags per module is 212, average particle size is 100-150 microns.	1
10	Stack: 10 ft diameter at top and 250 ft tall steel structures. The lower portion is tapered slightly, so that the chimney will not require any wire bracing for stability. Chimney is resting on a concrete mat.	1
11	Coal Unloading, Handling and Storage System: Including barge unloading facility, conveyors, transfer towers, 3-day storage silo, A-Frame structure for 15-day coal storage, crushers, scaling, sampling stations, bunkers, and gate valves. Coal bunker capacity is designed for one day full load operation.	1

Item	Description	Quantity
12	Limestone Unloading, Handling and Storage System: Including unloading hoppers, conveyors, A-Frame structure for limestone storage, transfer towers, bunkers, gate valves. A maximum design capacity of 40 TPH is sized for unloading hopper, reclaim tunnel and conveyors. Average operating capacity for limestone handling system is 20 TPH.	1
13	Ash Handling System: A vacuum system is sized for ash handling system including 8 in. and 9 in. conveying pipes, rotary slide gates, hoppers, valve, elbow, vacuum blower with 100 hp motor and 20 hp motor for silo fluidization, bag filter, surge tank and 28 ft dia x 52 ft high ash silo.	1
14	Bottom Ash Cooler: Designed to cool bottom ash from 1600°F to 300°F, including fluid bed cooler, cycle dust collector, exhaust air manifold, rotary air lock, and refractory linings.	2
15	Process Steam Piping: 10 in. schedule 40 carbon steel piping for 240 psia saturated steam supply tied to the existing steam header. Thermally insulated and sheathed. Motor operated shutoff valves, fittings and controls.	350 ft
16	Dowtherm Piping: 10 in. schedule 40 carbon steel piping for inlet and outlet Dowtherm fluid. Motor operator shutoff valves, fittings and controls. Piping thermally insulated and sheathed.	3000 ft
17	Turbine Oil Filter Systems: Including pumps, filters, storage tanks, and piping. Dual filters and switching valve for filter maintenance "on-the-run".	1

Item	Description	Quantity
18	Plant Air Compressor:	
	300 SCFM at 100 psig discharge pressure.	
19	Circulating Water Make-up System:	1
	50 percent capacity pumps and motors, isolation valves, piping, expansion joints and fittings.	
20	Cooling Tower Blowdown System:	1
	Including overflow control Weir, piping and high velocity nozzle.	
21	Fire Protection and Raw Water Storage System:	1
	Including water storage tanks, fire pumps, mains, laterals, headers, sprinklers, control valves, and electric motor.	
22	Compressed Air Receiver: (Surge Tank)	1
	300 psig working pressure	
23	Plant Lighting:	1 lot
24	Control Room:	1 lot
	Including instruments, gauges, computer, recorders, sensors wiring, relays, etc.	
25	Local Plant Instruments, Transmitters, etc.:	Lots
26	Instrument Air Receiver:	1
27	Pipe Insulation and Hangers:	As required

Electrical Equipment

Item	Description	Quantity
1	Step-Up Transformer: 13.8 kV/66 kV, 3 phase, 60 Hz, 32,000 kVA, OA, 55C with no load tap changer, 2-2 1/2 percent above, and 2-2 1/2 percent below rated voltage, to be equipped with 7-600/5A primary bushing C.Ts and 3-2000/5 A sec. busing CTs.	1
2	Auxiliary Transformer: 66 kV/4.16 kV, 3 phase, 60 Hz, 7,500 kVA/8,400 kVA, OA/FA with no load tap changer, 2-2 1/2 percent above and 2-2 1/2 percent below rated voltage to be equipped with 6-200/5A primary bushing CTs.	1
3	Power Center Transformer 4.16 kV/480V, 3 phase, 60 Hz, 750 kVA/1000 kVA, dry type, AA/FA indoor enclosure.	1
4	Power Center Transformer: Same as Item 3 except 1000 kVA/1333 kVA	1
5	Power Center Transformer: 4.16 kV/480 V, 3 phase, 60 Hz, 300 kVA/400 kVA, dry type, AA/FA indoor	1
6	Lighting Distribution Transformer: 480 V/208 V/120 V, 3 phase, 60 Hz, 30 kVA dry type indoor enclosure	1
7	Lighting Distribution Transformer: Same as Item 6, except 75 kVA	1
8	Lighting Distribution Transformer: 480 V/208 V wye/120 V, 3 phase, 60 Hz 30 kVA totally enclosed indoor/outdoor enclosure.	1

Item	Description	Quantity
9	Air Break Switches: 3 poles gang operated, 60 kV, 1200 A, complete with manual operating handle.	4 sets
10	Power Circuit Breaker: 60 kV oil circuit breaker, 3 poles, 1200 A, 3500 MVA interrupting rating, outdoor, to be equipped with 6-600/5 bushing CTs.	1
11	Power Circuit Breaker: 13.8 kV vacuum breaker, 3 poles 2000 A, 750 MVA indoor type enclosure.	1
12	Lighting Arrester: 60 kV lighting arresters, station type, outdoor	3
13	Potential Transformer: Outdoor potential transformer 60 kV/120 V.	3
14	Substation Structure: Steel structure, galvanized steel, for: 1 - Main transformer 1 - Auxiliary transformer 1 - Oil circuit breaker 4 - Three-pole, gang operated air break switches	1 lot
15	4160 V Switchgear: 416V switchgear, indoor, consisting of 11 vertical sections equipped with electrical operated circuit breakers, 1200 A, frame, 150 MVA interrupting rating, as follows: a. One incoming main breaker section b. Seven motor feeder breaker sections c. Three transformer feeder breaker sections d. 1 - instrument and potential transformer compartment equipped with the following:	1 lot

Item	Description	Quantity
	2 - Potential transf. 420 V/120 V 3 - Time delay undervoltage relays 3 - Auxiliary relays type MG-6 1 - AC voltmeter and voltmeter switch 1 - AC ammeter and ammeter switch	
16	Heater, Turbine-Generator Control Board	1 lot
17	Generator Surge Protection and Potential Transformer Equipment:	
	13.8 kV Station type lightning arresters and surge capacitors, 0.75 uf.	3
	Potential transformer, indoor type 14,100 V/ 120 V complete with current limiting fuses	3
18	Generator Grounding Transformer and Resistor:	
	a. Generator ground transformer, 10 kVA 13.8 kV wye/7970 V-240 V	3
	b. Grounding resistor 1.45 ohms, 166 A, 1 min, 230 V	3
19	Nonsegregated Phase Bus:	1 lot
	2000 A, 3 phase, 13.8 kV braced for 750 MVA, with taps for 1200 A, consisting of:	
	24 ft - straight section, outdoor 1 - vertical "L" corner section, outdoor 1 - transformer termination, outdoor 1 - expansion joint, outdoor 1 - connector with vapor barrier for outdoor/ indoor transition	
	54 ft - straight section, indoor 3 - vertical "L" corner section, indoor 1 - expansion joint, indoor 2 - circuit breaker termination indoor	
20	Nonsegregated Phase Bus:	1 lot
	2000 A, 3 phase, 4.16 kV braced for 150 MVA, consisting of:	

Item	Description	Quantity
	24 ft - straight section, outdoor 10 ft - straight section, indoor 1 - vertical "L" section, outdoor 1 - vertical "L" section, indoor 1 - transformer termination, outdoor 1 - switchgear termination, indoor 1 - expansion joint, outdoor 1 - connector with vapor barrier for indoor/ outdoor transition	
21	480 V MCC, B1: Indoor NEMA 12 dust tight enclosures, with 1600 A main bus braced for 22,000A. Starters shall be in combination with circuit breakers. MCC shall consist of 8 vertical sections equipped with starters as shown on the one line diagram.	
22	480 V MCC B2: Same as MCC B1 except it shall have 2000 A main bus and shall consist of 9 vertical sections equipped with starters as shown on the one line diagram.	1 lot
23	480 V MCC B3: Same as MCC B1 except it shall have 1200 A main bus and shall consist of 3 vertical sections equipped with starters as shown on the one line diagram.	1 lot
24	Power Cables:	
	a. 5 kV power cable, 3-conductor, copper, Class B stranded, EPR insulated, neoprene or hypalon potential shielded	1
	1. No. 1/0 AWG -	2000 ft
	2. 500 MCM -	2500 ft
	b. 600 V power cable, 3-conductor, copper, Class B stranded, EPR insulated, neoprene or hypalon jacketed.	1

Item	Description	Quantity
25	Control Cable:	
	600 V control cable, tin coated copper insulated with thermosetting, fire retardant oil and heat resistant compound neoprene or hypalon jacketed.	
	a. 2 conductor No. 12 AWG	20,000 ft
	b. 2 conductor No. 12 AWG	15,000 ft
	c. 5 conductor No. 12 AWG	10,000 ft
26	Instrument Cable:	
	a. Electronic instrument cable 300 V class No. 16 AWG stranded copper, twisted pairs or triads, insulated and jacketed with thermosetting compound with flame retardant characteristics.	
	1. 1 pair	20,000 ft
	2. 2 pairs	6,000 ft
	3. 1 pair shielded	10,000 ft
	b. Thermocouple extension wire and cable, 300 V class chromel-constantan, insulated and jacketed with thermosetting compound.	
	1. 1 pair	5,000 ft
	2. 2 pairs	5,000 ft
27	Communication Cable:	5,000 ft
	Communication cable for single page and five party channels with supplemental control circuit conductor and a ground conductor. Consisting of 3 No. 14 AWG and 13 No. AWG conductor 600 V class, EPR insulated, neoprene or hypalon jacketed.	
28	Ground Wires:	
	a. Bare copper conductor, No. 4/0 AWG, Class A stranded, medium drawn	1,000 ft
	b. Bare copper conductor, 500 MCM Class A stranded medium drawn	2,000 ft

Item	Description	Quantity
29	Communication Equipment:	
	Low level public address system solid state design, for operation on 120 V ac, 60 Hz with one page and 5-party channels, consisting of: 6 - Indoor stations 3 - Weatherproof wall stations 2 - Explosion proof stations 6 - Indoor loudspeakers 6 - Weatherproof speaker/amplifier 2 - Explosion proof loudspeaker 1 - Test and distribution panel	1 lot
30	Station Battery and Battery Charger:	1 set
	Station battery consisting of 58 cells, Lead-Calcium, 825 ampere hours capacity, complete with one battery rack and one 20A 125 V dc battery charger	
31	Main dc Distribution Switchgear and Panelboards:	
	a. Distribution switchgear 250 V dc class, indoor equipped with 1-800 A, 2-pole main breaker 2-100 A 2-pole and 8-60 A, 2-pole branch breakers	1
	b. Dc distribution panelboard, 250 V dc class, indoor equipped with 1-100 A, 2-pole main breaker and 12-15 A, 2-pole branch breakers	2
32	Lighting Distribution Panels, as follows:	
	a. Main Distribution panel 3 ph, 4 wire 208 V/120 V ac NEMA 12 enclosure, with: 1 - main breaker 3-pole, 400 A 10 - branch breakers, 3 pole, 325 A	1
	b. Lighting panel board 3 ph, 4 wire, 208 V/120 V ac NEMA 12 enclosure with 1-100 A, 3-pole main breaker and 24 - 20 A branch circuit breakers	5

Item		Description	Quantity
	c.	Same as item 32b except 225 A, 3-pole main breaker and 42 - 20 A branch circuit breakers	3
33	Lighting Fixture, as follows:		
	a.	400 W, 208 V ac mercury vapor flood outdoor	30
	b.	400 W, 208 V ac mercury vapor lamp fixture, indoor	20
	c.	100 W, 208 V ac mercury vapor lamp fixture, outdoor	250
	d.	2-40 W 120 V ac fluorescent fixture indoor	100
	e.	1-40 W 120 V ac fluorescent fixture indoor	50
	f.	100 W explosionproof incandescent lamp fixture	20
34	Cable Trays		1 lot
35	Conduit and Fittings		1 lot

3. Large Electric Motors (4.16 kV)

	Driven Equipment	Motor HP	Quantity
1.	FD Fan	2065	1
2.	ID Fan	1470	1
3.	Boiler Feed Pump	400	2
4.	Circulating Cooling Water Pump	125	2
5.	Baghouse	60	2
6.	Cooling Tower Fan	50	2
7.	Plant Air Compressor	100	1
8.	Fire Pump	350	1
9.	Ash Handling Vacuum Pump	100	1
10.	Clamshell Pump of Coal Handling System	300	
11.	Coal Conveyor	400	1
12.	Coal Conveyor	75	2
13.	Coal Crusher	300	1
14.	Limestone Conveyor	50	2

6.0 CAPITAL COST ESTIMATE

The cost estimate of the AFBC/CCGT cogeneration plant has been prepared in accordance with NASA's format and synthesized from the following:

- Major component costs
- Balance-of-plant (BOP) material costs
- BOP direct and indirect labor costs
- Architect/Engineer fee
- Contingency

The major components, BOP materials, and BOP labor costs are divided into the following seven categories:

- AFBC air heater plant
- Turbine generator
- Cogeneration process mechanical equipment
- Electrical
- Civil and structural
- Cogeneration process piping and instrumentation
- Yardwork and miscellaneous

The breakdown of total plant capital cost is shown in Figure 6-1. The results indicate that the plant is estimated to cost $47,895,000 in 1982 dollars. Note that the capital cost does not include interest or escalation during construction.

The major components and BOP material costs are reported in mid-1982 dollars. The major component costs result from detailed component designs. The BOP material and equipment costs are determined from vendor's budgetary quotations and from recent power plant construction field cost reports. No provision for escalation to commercial operation or interest during construction has been included.

AFB/CCGT COGENERATION SYSTEM CAPITAL COSTS

(M$)	COMPONENT CAPITAL	DIRECT LABOR	INDIRECT FIELD	MATERIAL	TOTALS
1.0 FURNACE	8.462	1.414	1.273	0.704	11.853
2.0 TURBINE GEN	7.274	0.058	0.052	0.290	7.674
3.0 PROC MECH EQUIP	0.916	0.402	0.362	7.507	9.187
4.0 ELECTRICAL		0.370	0.333	1.389	2.092
5.0 CIVIL + STRUCT		1.758	1.582	1.803	5.143
6.0 PROC PIPE + INST		0.770	0.693	1.377	2.840
7.0 YARDWORK + MISC		0.000	0.000	0.000	0.000
***** TOTALS *****	16.652	4.772	4.295	13.070	38.789
BALANCE OF PLANT (BOP)	(DIRECT + INDIRECT + MATERIAL)			22.137	
A/E HOME OFFICE AND FEE	(AT 15 PCT OF BOP)			3.320	
SUBTOTAL PLANT COST	(TOTAL + A/E)				42.109
CONTINGENCY	(0.137 OF TOTAL PLANT COST, CALC)			5.786	
PLANT COST (1982.0 $)	(SUBTOT PLANT COST + CONTINGENCY)				47.895
CONSTRUCTION ESCAL. AND INTEREST CHARGES					0.000
TOTAL PLANT CAPITAL COST	(1982 $)				47.895

FIGURE 6-1

The A/E fee and contingency factor are expressed as fractions of the BOP and plant cost, respectively.

Information used in preparing the estimate was based on the following:

- o Site plan
- o Electrical one-line diagram and list of electrical equipment
- o List of mechanical equipment
- o Quantities of civil and structural materials developed on a conceptual basis

More detailed discussion of each plant capital cost element is given below.

6.1 Major Components

The following two items are considered as major components in the AFBC/CCGT cogeneration plant:

1. AFBC air heater system
2. A closed cycle gas turbine-generator

The cost estimate of AFBC air heater was provided by GTEC based on cost estimates generated for this and prior studies, and reviewed by Foster-Wheeler Corp. As to the capital cost of the turbine-generator, its budgetary estimates were generated by submitting detailed drawings to the GTEC Manufacturing Engineering Department which generated costs on a production scale basis.

Other components and systems other than AFBC air heater and turbine-generator are grouped into the category of the BOP material.

6.2 Balance-of-Plant

The balance-of-plant material items include all other equipment and bulk materials not included in the major components that are necessary to construct the cogeneration plant. The BOP direct labor costs include all the costs for installing the major components in addition to the costs associated with constructing the plant and installing the BOP material items.

6.3 Indirect Field Costs

The BOP indirect field costs account for costs that cannot be directly identified with any specific direct account item, but rather are distributed over all direct items. Items that are in the indirect field account include:

- Temporary buildings and utilities
- Warehousing
- Construction supervision
- Administrator and field engineering
- Field office expenses
- Unallocable labor costs
- Construction equipment and maintenance
- Small tools and consumables
- Insurance and payroll taxes
- Preliminary operations and testing

6.4 Engineering, Home Office Costs and Fees

The A/E fees are estimated to be 15 percent of the total BOP costs. This is in accordance with the approach used in several previous NASA and DOE sponsored studies. Included in the costs are:

- Design engineering
- Estimating, scheduling and cost control
- Purchasing, expediting, and inspection
- Construction management and administration
- Engineering, procurement, and construction management fees

6.5 Contingency

Contingency is the amount of money that construction experience has demonstrated must be added to an estimate to provide for uncertainties in pricing and productivity. In this study, the following contingency factors are used:

Material:	11 percent
Subcontractor:	15 percent
Labor:	25 percent

By applying the above contingency factors to the plant cost, it is found that the overall contingency factor is equivalent to 13.7 percent of total plant cost, as shown in Figure 6-1.

6.6 Subcontracts

Subcontracts are not stated as such in the cost estimates. BOP items such as cooling towers and stacks that are usually listed as a single subcontract cost were divided into direct labor and material to facilitate a proper accounting of all field labor manhours.

APPENDIX V

TASK III - MARKET AND BENEFITS ANALYSIS

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APPENDIX V

TASK III - MARKET AND BENEFITS ANALYSIS

1.0 INTRODUCTION AND SUMMARY

This appendix describes the Task III - Market and Benefits Analysis effort which was conducted by Arthur D. Little, Inc. as a subcontractor to, and in concert with, The Garrett Turbine Engine Company.

The Task III analysis was organized to provide answers to several layers of questions asked by NASA and DOE and is summarized in Table 1. These questions are based on the premise that steam cogeneration systems are currently available whereas the AFBC/CCGT cogeneration systems are just now emerging from the research/demonstration arena into the commercially available arena. In addition, it should be pointed out that NASA, DOE, Garrett and the subcontractors all understand that the government is not the entity that ultimately decides if any cogeneration plant is built and operated in the industrial sector. The individual industrial plant owner must decide, on the basis of economics and other considerations, whether cogeneration plants will be used in the industrial section. However, the local utility that supplies electrical power to the industrial site can, by their attitude, influence the industrial site owner's decision.

The Task III analysis was conducted in an attempt to answer at least the technical and economic portions of the questions. The nation's industrial sector was characterized as to steam and electrical loads and coal-fired steam and CCGT cogeneration systems were applied to these loads. The return-on-equity (ROE) of each plant was determined and two ROE hurdle rates established, 10 and 20 percent. Any cogeneration plant that exhibited a ROE equal to or greater than the hurdle rate ROE was judged to be economically cogeneratable. The

TABLE 1. TASK III MARKET AND BENEFITS ANALYSIS QUESTIONS

Q1 - Can coal fired cogeneration plants within the industrial sector save energy or displace a significant amount of the more scarce oil and gas fuels?

Q1.1 - Is there sufficient benefit, over the nation as a whole, to warrant continued DOE support of the emerging AFBC/CCGT cogeneration systems?

Q2 - Can the industrial sector afford to cogenerate with coal?

Q2.1 - Is there a sufficient payoff of coal fired AFBC/CCGT cogeneration plants to the industrial sector that the industrial sector will select, or at least consider, AFBC/CCGT cogeneration systems?

Q3 - Are there any technical barriers that will prevent the development of AFBC/CCGT cogeneration systems?

Q3.1 - Are there technologies that will enhance or make more attractive the AFBC/CCGT cogeneration systems?

Q4 - What frame sizes should the closed cycle gas turbine manufacturers offer to the industrial sector?

national significant of cogenerating the industrial sector was then established. The answers to the questions of Table 1 form the summary of the Task III analysis.

- <u>Q1 Answer</u> - Use of AFBC/CCGT cogeneration systems will save about 0.66 quads/year of fuel as shown in Figure 1. Converting to coal fired AFBC/steam cogeneration systems, with a minimum return-on-equity (ROE) of 10 percent, actually results in an increase in the total energy needed to satisfy the nations industrial sector electrical and steam needs.

  At a ROE hurdle rate of 10 percent, the AFBC/CCGT cogeneration plants can yearly displace about 1.84 quads of oil and gas with coal. This displacement is almost double that of the equivalent steam system.

- <u>Q1.1 Answer</u> - It appears that continued DOE support of AFBC/CCGT technology is justified, based on the answers to Q1.

- <u>Q2 Answer</u> - This question cannot be answered by any single organization or study. However, the Task III analysis results indicate that at a 10 percent ROE hurdle rate, about 77 percent of the oil and/or gas fired boilers would be cogenerated with the AFB/CCGT system. Only about 34 percent of the steam cogeneration plants have a ROE of 10 percent or better. These results are drastically reduced at the ROE hurdle rate of 20 percent as shown in Figure 2. Figure 2 shows the Task III results by DOE region, cogeneration system type, and ROE hurdle rate. Note that in the DOE Region X, none of the cogeneration plants have a ROE of 20 percent or greater. This is due to the fact that this region is primarily based on cheap hydroelectric and nuclear utility power.

NATIONAL AGGREGATE RESULTS

ROE HURDLE RATE	10%		20%	
COGEN SYSTEM	CCGT	STEAM	CCGT	STEAM
TOTAL FUEL SAVED, QUADS/YR	0.66	−0.06	0.26	0.01
TOTAL GAS AND OIL DISPLACED, QUADS/YR	1.84	0.99	0.81	0.11
EMISSION SAVINGS RATIO, %	0.01	−14.92	−1.30	−10.37
EMISSION SAVINGS, 10^6 LB/YR	0.70	−383.2	−25.3	−23.0
ELECTRICAL ENERGY, QUADS/YR	1.14	0.59	0.45	0.05
THERMAL ENERGY, QUADS/YR	1.74	0.90	0.69	0.08
AVG HEAT-TO-POWER RATIO	1.53	1.53	1.53	1.53

FIGURE 1

NUMBER OF COGENERATION PLANTS

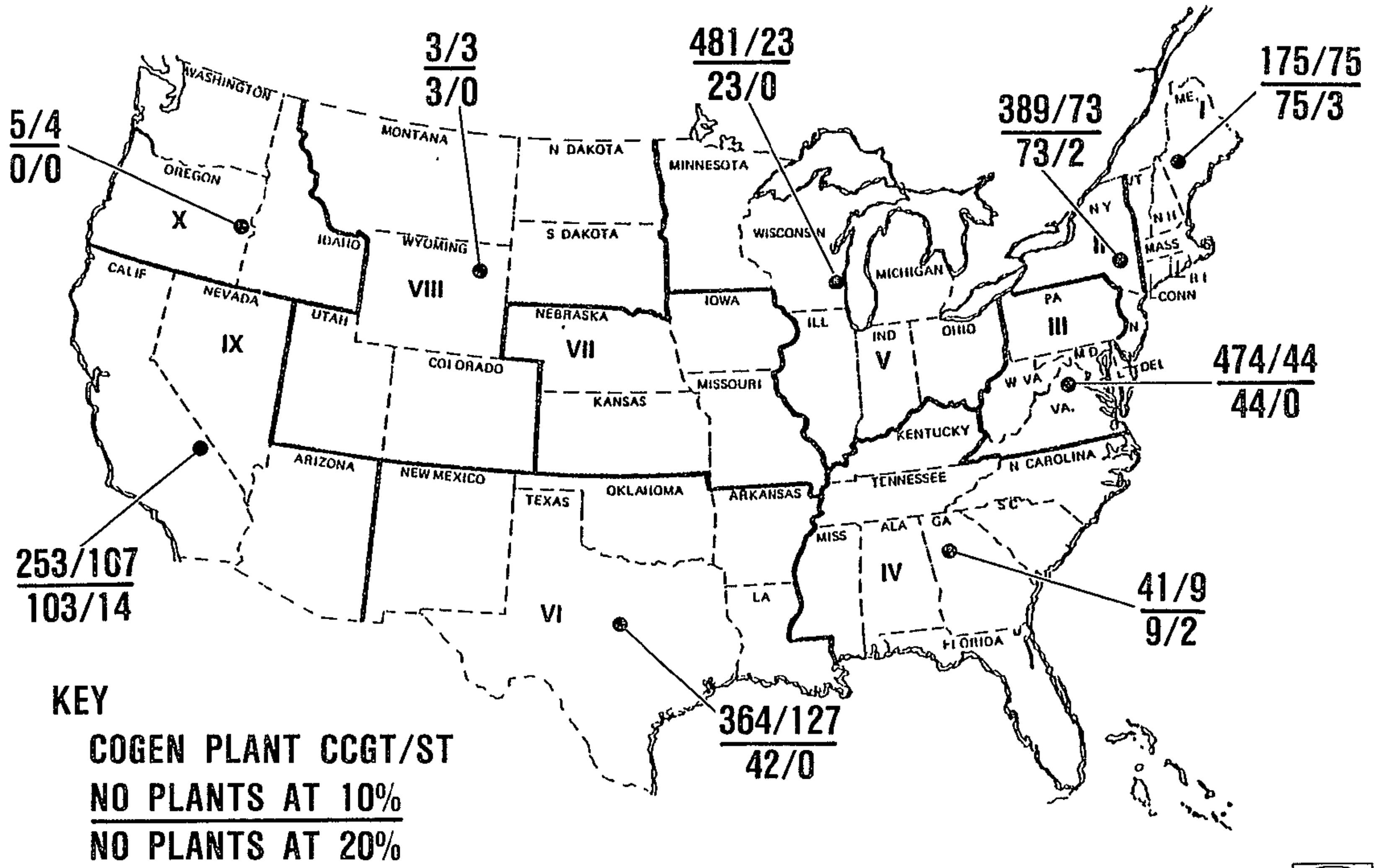

FIGURE 2

31-4773
Appendix V
5

A problem with this answer is that it creates another question; is a 10 percent ROE attractive to the industrial sector. It should be noted that some of the cogeneration plants exhibited ROE's in excess of 40 percent and, thus, the question becomes highly site specific.

- Q2.1 Answer - This question has a correlative question to be asked by the AFBC/CCGT manufacturers; is there a sufficient market for AFBC/CCGT cogeneration systems that the manufacturers should develop the technology. On the basis of the 10-percent hurdle rate, there appears to be a significant market. See Q4 answer below.

- Q3 Answer - There are no technological barriers that will prevent development of the AFBC/CCGT cogeneration system. The major enhancement technology is low cost materials for the high temperature heat exchangers.

- Q4 Answer - The AFBC/CCGT cogeneration system is made up from several highly modularized heat exchanger components and the rotating group which includes the generator/gearbox and the turbocompressor unit. The turbocompressor unit output power rating, in MWe, describes the frame size. Two CCGT frame sizes appear to be required to cover the industrial sector, 5 MWe and 50 MWe. The Task III results suggest that, at the 10-percent ROE hurdle rate, the numbers of units for each frame size is as shown below:

Frame Size, MWe	5	50
Number Units Required	1925	1488

Even if only one half of these values ultimately becomes a reality, there appears to be an attractive market.

Significance of Study to Industrial Sector

The importance of the study results to the industrial sector can best be illustrated by a review and contemplation of the Task III results. The objective of Task III was to apply what was learned about steam and closed-cycle gas turbine cogeneration systems during Tasks I and II, on a site specific basis, to the much broader industrial sector as a whole. The Task III data shows that the industrial sector can benefit, and can afford to benefit, from the use of coal-fired cogeneration systems provided:

a. The industrial site is located in a DOE region that is not predominately based on cheap hydroelectric or nuclear utility power.
b. The specific site is based on using gas and/or oil as the separate generation boiler fuel.
c. The local utility will at least tolerate, or work with, the industrial cogenerator.
d. The industrial site has a minimum heat-to-power ratio of about 1.0 or the local utility will pay a fair price for the power exported from the industrial site.

If all or most of the above conditions are met or approached, the industrial site owners should consider cogeneration. The steam cogeneration systems can provide the industrial owner an attractive return-on-equity and return-on-investment. However, the emerging technology of the closed cycle gas turbine shows a return-on-equity significantly better than that for the equivalent steam cogeneration system as shown in Figure 2.

The significance of the Task I and Task II effort to the industrial sector is that these parts of the study verified the results of Task III by conducting a detailed cost and thermodynamic analysis on a selected industrial site cogeneration system.

Details of the Task III analysis are discussed in the following paragraphs.

2.0 TASK III APPROACH

Figure 3 illustrates the objectives of the Task III analysis. These objectives are restatements of the questions summarized in Table 1.

Figure 4 illustrates the approach taken during the Task III effort. The majority of the Task III effort involved the characterization of the industrial sector. The Arthur D. Little, Inc., hereafter referred to as ADL, data on boiler size were used to establish, for each of the ten DOE regions, the thermal and electrical power loads within the industrial sector. The ADL data distinguished between the boiler fuel, coal, oil and/or gas, waste heat, and other fuels. The steam generation capacity that was generated with coal or oil and/or gas was separated from the total steam generation capacity and termed the 'technical potential' for cogeneration. That is, only those industrial sector plants that currently generate steam with coal or oil and/or gas were judged to be candidates for cogeneration. If these 'technical potential' plants survive the economic screening, then the plants are described as the 'economic potential'. The average plant heat-to-power ratio and average electrical load were then estimated. Thus, the results of the industrial sector characterization included a description of the industrial sector as shown in Figure 5.

Figure 6 shows a typical example of the industrial sector characterization data. This figure shows the thermal steam loads, generated with gas and/or oil as the boiler fuel, for the ten DOE regions and for seven boiler size ranges. The fuel needed to generate these steam loads can be estimated based on the assumption that the boiler operates with a thermal efficiency of 85 percent. It should be noted that the boilers were assumed to be operating at full capacity for the percent of the year shown in Figure 7 on the basis that small plants tend to operate less than 24 hours per day and also tend to shut down on week-ends.

TASK III — MARKET AND BENEFITS ANALYSIS

OBJECTIVES

- ESTABLISH THE MARKET PENETRATION POTENTIAL OF AFB/CCGT COGENERATION SYSTEMS

- COMPARE AFB/CCGT VERSUS AFB/STEAM COGENERATION SYSTEMS FOR

  - MARKET PENETRATION POTENTIAL

  - RELATIVE NATIONAL BENEFITS

- ESTABLISH AFB/CCGT COGENERATION SYSTEM FRAME SIZE

FIGURE 3

MARKET PENETRATION ANALYSIS

APPROACH

- CHARACTERIZE THE INDUSTRIAL SECTOR BY DOE REGION AND BOILER SIZE FOR
  - THERMAL AND ELECTRICAL POWER LOADS
  - BOILER FUEL
  - AVERAGE PLANT HEAT-TO-POWER RATIO AND AVERAGE PLANT ELECTRICAL LOAD
- ESTABLISH FUEL AND ENERGY PRICES BY DOE REGION
- ESTABLISH ROE BY DOE REGION AND BOILER SIZE FOR
  - AFB/CCGT COGENERATION SYSTEM
  - AFB/STEAM COGENERATION SYSTEM
- SCREEN THE ROE RESULTS TO DETERMINE ECONOMICALLY VIABLE COGENERATION SYSTEMS FOR
  - 10-PERCENT ROE HURDLE RATE
  - 20-PERCENT ROE HURDLE RATE

FIGURE 4

TASK III — INDUSTRIAL SECTOR CHARACTERIZATION

(AVAILABLE DATA IN FOLLOWING FORMS)

SEPARATE BOILER FUEL: COAL OIL AND/OR GAS

<table>
<tr><th rowspan="2">DOE REGION</th><th colspan="7">THERMAL SIZE RANGE MW_t</th><th rowspan="2">TOTALS*</th></tr>
<tr><th>2.5-10</th><th>11-20</th><th>21-35</th><th>36-60</th><th>61-100</th><th>101-200</th><th>>200</th></tr>
<tr><td>I
II
III
IV
V
VI
VII
VIII
IX
X</td><td colspan="7">• THERMAL POTENTIAL (MW_t)*
• ELECTRICAL POTENTIAL (MW_e)*
• REPRESENTATIVE HEAT-TO-POWER RATIO
• REPRESENTATIVE ELECTRICAL LOADS (MW_e)
• NUMBER OF REPRESENTATIVE PLANTS*
• RETURN ON EQUITY (ROE) FOR
  ▪ CLOSED CYCLE GAS TURBINE SYSTEM
  ▪ STEAM TURBINE SYSTEM</td><td></td></tr>
<tr><td colspan="9">TOTALS*
*TOTALS ONLY FOR STARRED PARAMETERS</td></tr>
</table>

FIGURE 5

REPRESENTATIVE DATA SET

ADJUSTED TECHNICAL POTENTIAL FOR COGENERATION:
THERMAL POTENTIAL IN MEGAWATTS
FUEL: GAS AND OIL
YEAR: 1988

DOE REGION	SIZE CATEGORY (MW) 2.5-10	11-20	21-35	36-60	61-100	101-200	>200	TOTAL
I	266.5	825.4	1038.0	1449.1	302.1	433.8	0.0	4314.9
II	826.5	2821.6	3205.7	2869.1	623.7	276.2	473.7	11096.4
III	822.2	2925.2	3411.8	5283.9	2901.4	1256.0	0.0	16600.4
IV	1304.5	4710.9	4442.2	5179.2	2591.8	1031.5	631.2	19891.4
V	529.8	2559.4	4281.5	6182.7	1604.5	420.8	0.0	15578.6
VI	392.8	2107.3	2670.5	6139.5	6660.7	4955.8	2715.8	25642.4
VII	162.9	842.7	889.5	811.4	437.0	0.0	0.0	3093.5
VIII	178.0	688.4	486.6	1159.9	440.2	412.2	0.0	3365.4
IX	331.3	1332.6	1286.2	2012.3	880.5	376.6	0.0	6219.4
X	131.6	577.3	339.9	576.2	307.5	162.9	0.0	2095.4
TOTAL	4943.1	19390.7	22001.9	31663.2	16749.3	9325.8	3820.7	107897.6

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FIGURE 6

TASK III — PLANT OPERATING TIME

SIZE CATEGORY (MW_t)	OPERATING TIME, %
2.5 — 10	30
11 — 20	40
21 — 35	50
36 — 60	60
61 — 100	75
101 — 200	90
>200	100

FIGURE 7

The fuel and electrical power prices were then established for each of the DOE regions. It should be noted that these prices reflected such conditions as hydroelectric and/or nuclear based utility power and varied transportation cost for the coal and sorbent.

Two families of coal-fired cogeneration plants (AFBC/STCS and AFBC/CCGT) were then established with a range of design output electrical powers and a range of heat-to-power ratios. These cogeneration plants were based on the study results of Task I and the first part of the Task II effort. The cogeneration plant return-on-equity (ROE) was then determined for each of the DOE regions and cogeneration plant type, AFBC/STCS and AFBC/CCGT. These ROE data were then used to establish the ROE of each cogeneration plant by DOE region, boiler size, and boiler fuel type. Figure 8 shows the ROE results for the oil and/or gas boiler fuel and Figure 9 shows the ROE results for the coal fired boilers.

Two ROE levels were established by NASA as 'hurdle rates' for the purpose of screening the ROE data.

RETURN ON EQUITY CALCULATION
FUEL: GAS AND OIL
SYSTEM: CCGT

	Size Category (MW)						
DOE Region	2.5-10	11-20	21-35	36-60	61-100	101-200	>200
I	12.5	17.0	20.7	23.6	30.1	37.8	0.0
II	9.9	13.9	17.0	20.3	23.7	28.7	47.6
III	8.7	12.6	16.2	18.2	22.4	26.1	0.0
IV	1.5	3.8	6.3	9.4	12.6	29.0	39.1
V	7.2	10.7	12.8	15.4	22.7	27.4	0.0
VI	6.4	9.7	12.7	15.6	19.6	24.2	26.1
VII	12.9	18.6	22.2	25.3	29.8	0.0	0.0
VIII	0.7	2.9	3.4	7.7	7.5	25.5	0.0
IX	11.7	16.2	20.4	25.8	33.6	35.7	0.0
X	0.0	0.0	6.8	4.9	16.8	11.6	0.0

RETURN ON EQUITY CALCULATION
FUEL: GAS AND OIL
SYSTEM: STEAM TURBINE

	Size Category (MW)						
DOE Region	2.5-10	11-20	21-35	36-60	61-100	101-200	>200
I	4.8	7.8	10.5	12.6	18.1	24.6	0.0
II	3.5	6.9	6.1	10.7	13.8	18.0	32.1
III	3.0	5.4	7.9	9.5	13.1	16.2	0.0
IV	0.0	0.4	2.0	4.3	6.9	18.7	25.9
V	2.4	4.5	6.8	7.5	13.4	17.7	0.0
VI	1.9	3.8	5.8	8.0	11.3	15.4	16.8
VII	5.2	9.3	11.7	14.0	17.8	0.0	0.0
VIII	0.0	0.5	0.6	3.7	3.7	16.3	0.0
IX	4.8	7.6	10.8	15.0	20.9	23.3	0.0
X	0.0	0.0	3.2	2.0	10.1	7.3	0.0

FIGURE 8

RETURN ON EQUITY CALCULATION
FUEL: COAL
SYSTEM: CCGT

DOE Region	Size Category (MW) 2.5-10	11-20	21-35	36-60	61-100	101-200	>200
I	0.0	6.6	0.0	0.0	10.1	0.0	0.0
II	0.2	1.8	4.3	6.7	10.1	13.2	0.0
III	0.0	0.0	0.4	2.5	5.6	9.4	10.9
IV	0.0	0.0	0.0	0.0	1.2	5.5	8.0
V	0.0	0.0	0.1	2.0	5.4	9.1	11.2
VI	0.0	4.9	7.1	9.2	10.8	15.3	17.9
VII	0.0	0.0	0.0	3.7	12.1	0.0	0.0
VIII	0.0	0.0	0.0	0.0	0.1	1.7	3.4
IX	0.0	0.0	0.0	10.9	0.0	0.0	19.5
X	0.0	0.0	0.0	0.0	0.0	0.0	0.0

RETURN ON EQUITY CALCULATION
FUEL: COAL
SYSTEM: STEAM TURBINE

DOE Region	Size Category (MW) 2.5-10	11-20	21-35	36-60	61-100	101-200	>200
I	0.0	1.9	0.0	0.0	6.2	0.0	0.0
II	0.0	0.0	1.0	2.6	5.4	7.7	0.0
III	0.0	0.0	0.0	0.3	3.0	6.0	6.7
IV	0.0	0.0	0.0	0.0	0.0	3.2	5.3
V	0.0	0.0	0.0	0.1	2.6	5.7	7.3
VI	0.0	0.9	2.4	4.1	6.3	9.9	11.0
VII	0.0	0.0	0.0	2.1	6.7	0.0	0.0
VIII	0.0	0.0	0.0	0.0	0.0	0.7	2.1
IX	0.0	0.0	0.0	5.0	0.0	0.0	12.6
X	0.0	0.0	0.0	0.0	0.0	0.0	0.0

FIGURE 9

3.0 TASK III RESULTS

The ROE data was screened to eliminate those plants that do not exhibit a ROE equal to or greater than the ROE hurdle rate. That is, if the ROE value is equal to or exceeds the hurdle rate the plant is judged to be economically cogeneratable. The results of this screening process were available by the classifications summarized in Figure 10.

Figure 11 shows an example of the results by boiler size for the case of a ROE hurdle rate of 10 percent and oil and/or gas boiler fuel. Figure 2 shows an example of the results of the screening process as a function of DOE region, cogeneration plant type and ROE hurdle rate.

Figure 12 shows the AFBC/CCGT Task III results that established the average plant electrical size, heat-to-power ratio and average thermal size. The number of plants are illustrated for both ROE hurdle rates. These results were used to establish the number of plants of the two AFBC/CCGT frame sizes that are necessary to accommodate the industrial sector. An unexpected result of the data presented in Figure 11 was the average heat-to-power (HPR) ratio of the average plant. Originally the expected HPR was thought to be in the range of 3 to 5 and to vary more as a function of the plant size.

Figure 1 summarized the results of Task III having national significance. It should be noted that the results of Figures 1, 2, and 12 are for all boiler fuels.

A review of the Task III results indicates that the economic viability of coal-fired cogeneration systems is sensitive to the non-cogeneration boiler fuel and operating time and relatively insensitive to the cogeneration system capital cost. These sensitivities are discussed below and summarized in Figure 13.

MARKET POTENTIAL RESULTS

TASK III RESULTS AVAILABLE BY

- DOE REGION
- THERMAL SIZE
- SEPARATE BOILER FUEL
  - COAL
  - OIL AND GAS
- ROE HURDLE RATE
  - 10%
  - 20%
- COGENERATION SYSTEM
  - CLOSED CYCLE GAS TURBINE (CCGT)
  - STEAM TURBINE

FIGURE 10

TASK III TYPICAL RESULTS

SUMMARY OF THE POTENTIAL FOR COGENERATION THERMAL POTENTIAL IN MEGAWATTS

FUEL: GAS AND OIL

HURDLE: 10.

YEAR: 1988

SIZE CATEGORY (MW)	TECHNICAL	ECONOMIC	
		CCGT SYSTEMS	STEAM SYSTEMS
2.5-10	4946.1	760.7	0.0
11-20	19390.7	11306.8	0.0
21-35	22001.9	16733.1	3163.0
36-50	31663.2	24747.9	7141.9
61-100	16749.3	16309.1	13717.3
101-200	9325.8	9325.8	9162.9
>200	3820.7	3820.7	3820.7
TOTAL	107897.6	83004.1	37006.4

FIGURE 11

NO COGEN CCGT VS AVG PLANT LOADS

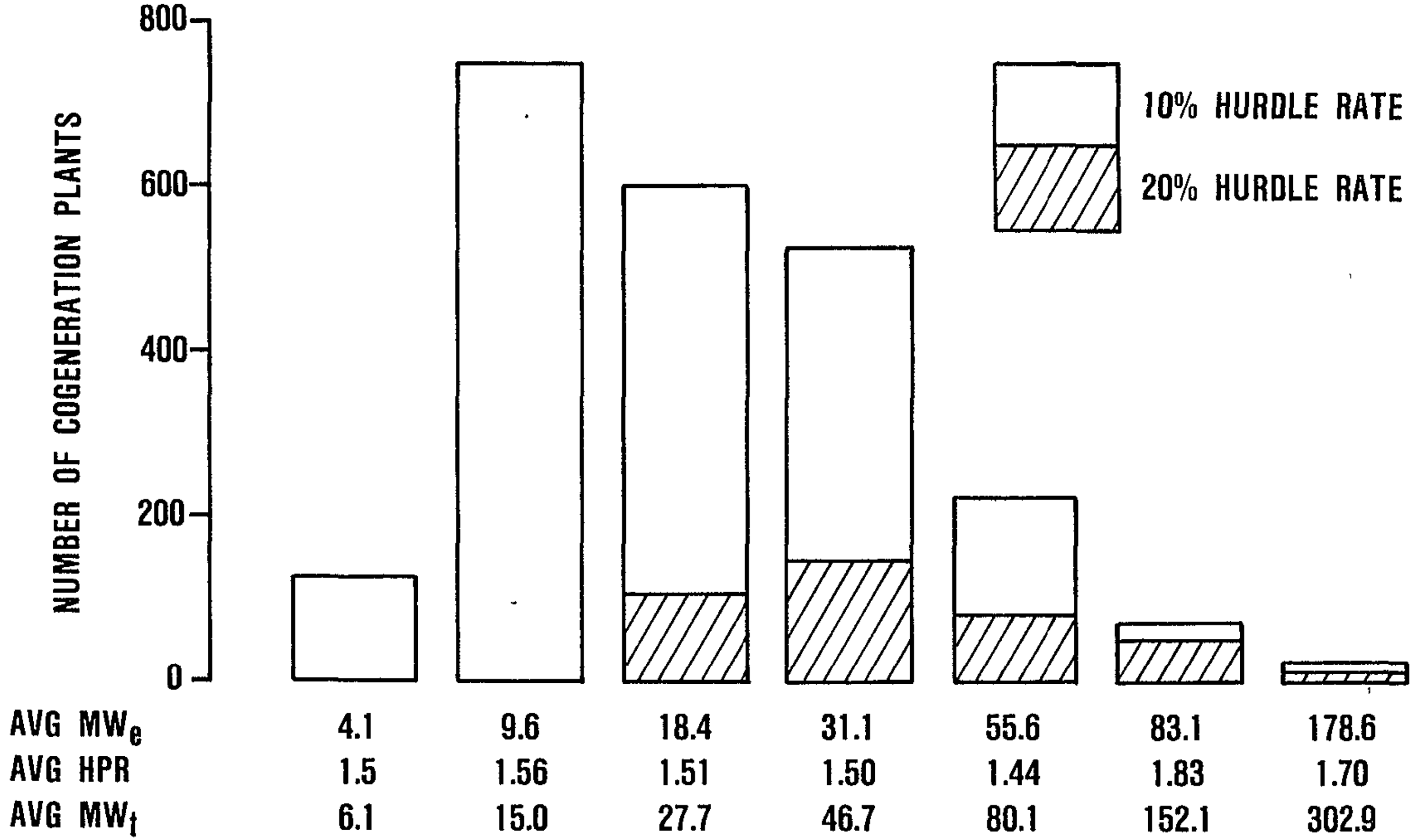

FIGURE 12

TASK III — RESULTS SENSITIVITY

RESULTS SENSITIVE TO

- SEPARATE BOILER FUEL
  AT 10% HURDLE RATE CCGT WILL CONVERT
  - 20.5% OF THE COAL FIRED BOILERS
  - 76.9% OF THE OIL AND GAS FIRED BOILERS

- PLANT OPERATING TIME
  - 2.5 TO 10 MW_t SIZE CLASS OPERATES 30% OF TIME
  - 10% HURDLE RATE EQUIVALENT TO 33% ROE FOR SAME PLANT OPERATING 100% OF TIME

RESULTS INSENSITIVE TO

- PLANT CAPITAL COST
  20% REDUCTION IN PLANT CAPITAL COST (REMOVING CONTINGENCY COST) RESULTS IN A 20.8% INCREASE IN ROE

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FIGURE 13

- o Boiler Fuel - Only about 20 percent of the coal-fired boiler capacity is judged to be economically cogenerateable but almost 77 percent of the oil and/or gas-fired boiler capacity is cogenerateable with the AFBC/CCGT system. These results suggest that a major advantage of cogeneration is fuel switching, ie, converting from the high cost oil and gas to the lower cost coal.

- o Operating Time - The data shown in Figure 11 suggest that the Task III results are sensitive to boiler size, ie, only about 15 percent of the smallest size category boiler capacity would be economically cogeneratable with the AFBC/CCGT system. This apparent sensitivity is, however, largely due to the assumed operating time as defined by Figure 7. If operating time were 100 percent instead of 30 percent for the smallest size boilers, the ROE values shown in column 1 of Figure 8 would increase by a factor of 3.33 and the results shown in Figure 11 would be 67.4 percent cogeneratable for the AFBC/CCGT and 48.7 percent cogeneratable for the AFBC/STCS. Alternatively, the 10 percent ROE hurdle rate with an operating time of 30 percent is equivalent to an ROE of 33.3 percent for a system operating 100 percent of the time as summarized in Figure 13.

- o Capital Cost - All of the cogeneration plants defined for Task I and Task III included a 20 percent capital cost contingency. Elimination of this contingency results in the ROE values shown in Figure 8 being increased by a factor of 1.208 or the 10 percent hurdle rate is equivalent to 10/ 1.208 = 8.3. This change would not significantly change the results as summarized in Figure 11 and thus, Task III results and conclusions are insensitive to plant capital cost variations.

The significant results of the Task III study are summarized in Figure 14. Closed-cycle gas turbine cogeneration systems are more attractive that the steam turbine alternative because the CCGT will result in a higher return on equity at a lower capital cost. There are no technical barriers against CCGT cogeneration systems. There are, however, several economic and regulative barriers to coal-fired cogeneration and cogeneration systems in general. If these barriers are eliminated or modified, then the market penetration potential of CCGT cogeneration systems is very good.

SUMMARY

QUESTION FROM DOE

- HOW DOES CCGT COMPARE TO STEAM TURBINE IN COGENERATION APPLICATION?
  - BETTER ROE
  - LOWER COST
- WHAT ARE THE TECHNOLOGICAL BARRIERS AGAINST CCGT COGENERATION SYSTEMS?
  - NONE
- WHAT IS MARKET PENETRATION POTENTIAL FOR CCGT COGENERATION SYSTEMS?
  - GOOD

FIGURE 14