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EVALUATION OF A PRESSURIZED-FLUIDIZED BED COMBUSTION (PFBC) COMBINED CYCLE POWER PLANT CONCEPTUAL DESIGN

FINAL REPORT

EVALUATION OF ALTERNATE PLANT APPROACHES

SUBTASK 1.7

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Abstract

In June, 1976, the U.S. Department of Energy (DOE) awarded a contract to an industry team consisting of Burns and Roe Industrial Services Corporation (BRISC), United Technologies Corporation (UTC), and the Babcock & Wilcox Company (B&W) for an "Evaluation of a Pressurized, Fluidized Bed Combustion (PFBC) Combined Cycle Power Plant Design" (D.O.E. Contract No. EX-76-C-01-2371).

The results of this program indicate that pressurized fluidized bed combustion systems, operating in a combined cycle power plant, offer great potential for producing electrical energy from high sulfur coal within environmental constraints, at a cost less than conventional power plants utilizing low sulfur coal or flue gas desulfurization (FGD) equipment, and at higher efficiency than conventional power plants.

As a result of various trade-off studies, a 600 MWe combined cycle arrangement incorporating a PFB combustor and supplementary firing of the gas turbine exhaust in an atmospheric fluidized bed (AFB) steam generator has been selected for detailed evaluation.

The overall program consists of the following Subtasks:

- 1.1 - Commercial Plant Requirements Definition
- 1.2 - Commercial Plant Design Definition
- 1.3 - System Analysis and Trade-Off Studies
- 1.4 - Reliability and Maintainability Evaluation with Advanced Technology Assessment
- 1.5 - Environmental Analysis
- 1.6 - Economic Analysis
- 1.7 - Evaluation of Alternate Plant Approaches
- 1.8 - PFB/Gas Turbine/Waste Heat Steam Generator Cycle Study
- 1.9 - PFB/Gas Turbine/Power Turbine Reheat Cycle Study

This Final Report discusses the results of studies performed under the contract. The report is divided into four volumes as follows:

Volume I	Executive Summary
Volume II	Subtask 1.2
Volume III	Subtasks 1.3, 1.4, and 1.5
Volume IV	Subtasks 1.7, 1.8, 1.9

The work under Subtask 1.1 has been issued in final form as an Interim Report. Since much of the information is covered in various places throughout the report in the form of design descriptions, no specific section has been devoted to it. Similarly, the economic analysis work performed under Subtask 1.6 is reported with the respective subtasks to which it applies.

REPORT ON SUBTASK 1.7

EVALUATION OF ALTERNATE PLANT APPROACHES

EVALUATION OF A PRESSURIZED FLUIDIZED BED COMBUSTION (PFBC) COMBINED CYCLE POWER PLANT

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1.0 SUMMARY

In this subtask, Evaluation of Alternate Plant Approaches, four different cycles involving fluidized bed combustion have been studied to obtain reasonable plant cost estimates and cost of electricity generated for comparison with the base PFB/AFB plant developed in Subtask 1.2. These cycles are:

- .Steam Cooled PFB Combined Cycle
- .Excess Air Cooled PFB Combined Cycle
- .Devolatilizer/PFB Combined Cycle
- .AFB Steam Cycle

Another promising cycle, AFB/Semi-Closed Gas Turbine Cycle, has been considered, but no cost estimate has been prepared.

Steam Cooled PFB Cycle (Alternate No. 1)

In this cycle, coal is burned in a pressurized fluidized bed (PFB) of sized dolomite. The PFB is cooled by water and steam in tubes; i.e., superheated steam is generated in the combustor. The exiting flue gas from the combustor is cleaned in a dust cleanup system and is routed to the gas turbine at about 1650^{o}F. The gas turbine exhaust is used to heat feedwater in a low level economizer. The superheated steam at 2415 psia and 1000F expands in the high pressure section of a steam turbine to about 584 psia. The high pressure exhaust steam is reheated in the combustor to 1000F. The reheated steam expands in the low pressure section of the steam turbine and exhausts to the condenser at 2" of mercury. Extraction steam from the low pressure turbine is used for the feedwater pump drive and three stages of feedwater heating (one stage being the deaerator). The system is shown schematically in Figure C-1.

Excess Air Cooled PFB Cycle (Alternate No. 2)

In this cycle all the compressor discharge air (less turbine cooling air flow) goes through the PFB Combustor. The bed is maintained at 1650F. The flue gas at 1650F passes through a particulate removal system and then is expanded in the gas turbine. A part of the high temperature gas turbine exhaust is routed to an AFB Combustor (as in the base PFB/AFB Scheme of Subtask 1.2). More coal is burned in the AFB Combustor to generate steam. The exhaust of the AFB Combustor combines with the by-passed turbine exhaust and passes through a high temperature electrostatic precipitator, economizer, I.D. fan and a stack. Figure D-2 shows the schematic diagram of the excess air cooled PFB system configuration. The steam system remains identical to the system used in Subtask 1.2.

Devolatilizer/PFB Scheme (Alternate No. 3)

The process flow schematic diagram Figure E-1 shows the interrelationship of the devolatilizer and PFB combustor in this system. A part of the compressed air from a gas turbine provides the oxygen for combustion of char in the PFB combustor. The rest of the compressor air is routed through bed cooling tubes to maintain the fluidized bed temperature at 1650F. A part of the flue gas from the PFB combustor is used to devolatilize the raw coal in the devolatilizer. The low Btu devolatilizer gas is mixed with the rest of the PFB flue gas and finally burned in a gas/air combustor (GAC) using the hot clean air from the cooling tubes of the PFB combustor.

STEAM-COOLED PFB CONFIGURATION

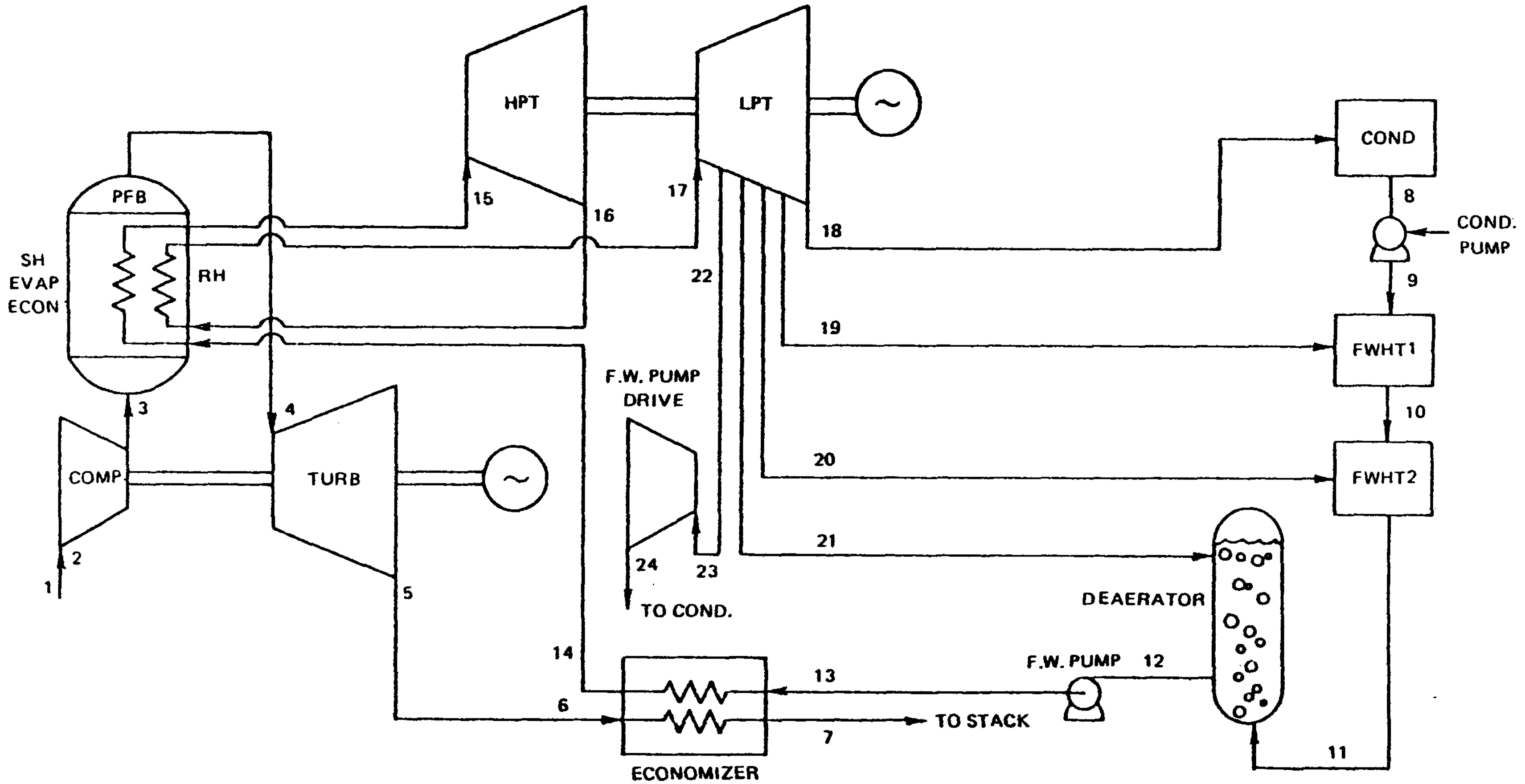

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FIGURE C-1

EXCESS AIR–COOLED PFB CONFIGURATION

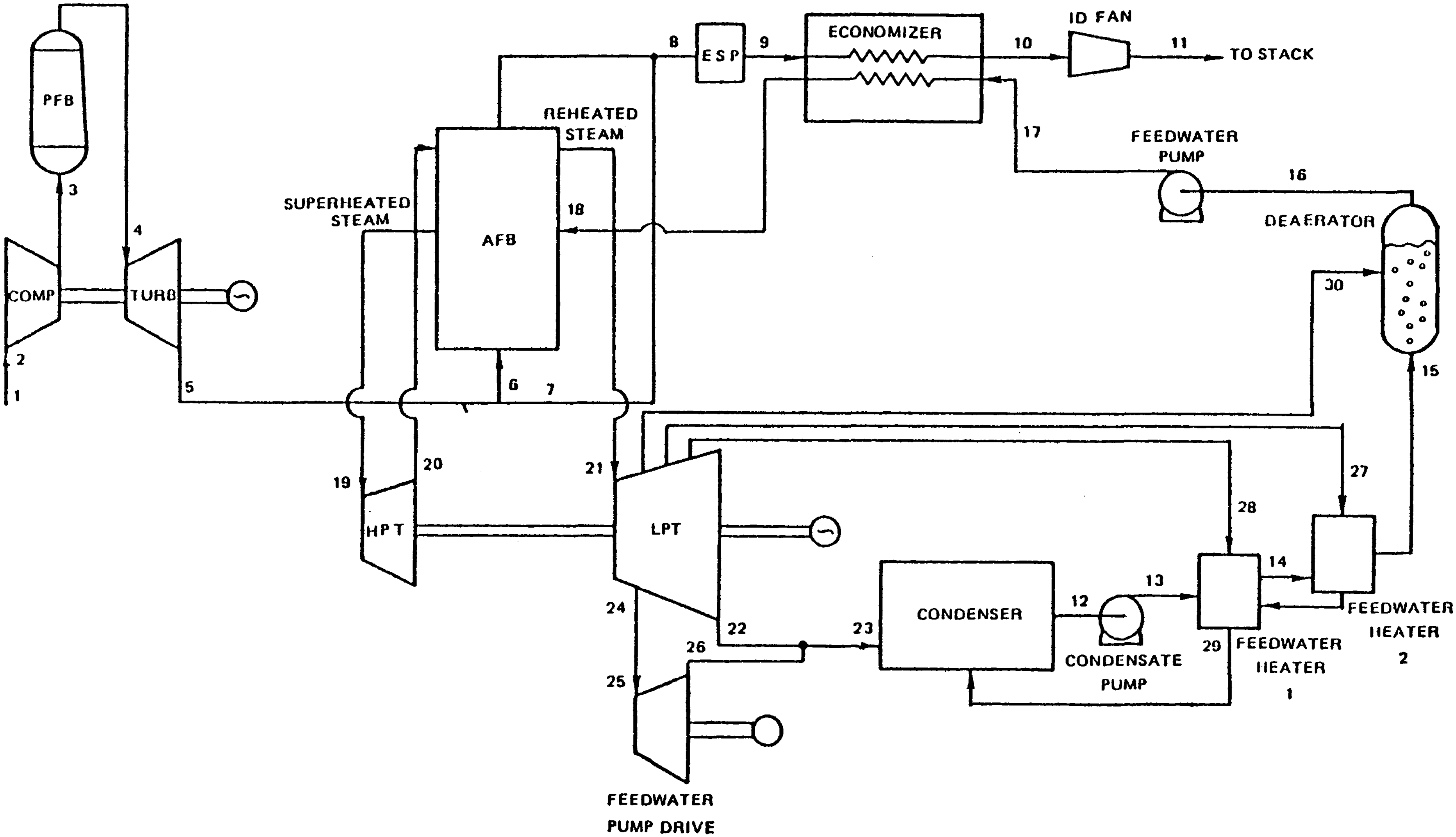

FIGURE D-2

(Reproduced here for convenience)

For the system studied in Subtask 1.7 the gas temperature entering the turbine would be approximately 2178°F, much higher than for other PFB systems studied during this program. A more highly-cooled turbine (21.6 percent cooling air) is required in this system than in the previous systems to expand the gases and generate power.

The exhaust flow from the turbine is approximately 1135°F, so that supplementary firing is not required to generate steam for a high efficiency steam bottoming cycle. A 2400 psig/950°F/950°F steam cycle is used for this system.

Figure E-2 presents a schematic diagram of the devolatilizer/PFB power plant configuration.

Steam Cooled AFB Cycle (Alternate 4)

The steam cycle is a conventional 2400 psig/1000F/1000F cycle. Steam is produced in an AFB steam generator instead of in a convention coal fired steam generator. Figure F-1 shows the mass balance for a 4,300,000 lb/hr AFB steam system burning coal with 3.26% sulfur and using a calcium to sulfur (Ca/S) molar ratio of 4.0. This figure has been excerpted from Reference 4. The actual mass balance for an "as-received" coal with 3.16% sulfur and heating value of 11472 Btu/lb (the reference of Subtask 1.2) will be slightly different.

AFB/Semi-Closed Gas Turbine Cycle

One of the impediments to the realization of the benefits of a combined cycle utility plant with a coal fired pressurized fluidized bed combustor is the current unavailability of a proven reliable and efficient high temperature and high pressure gas cleanup system. A combined cycle system which may be attractive as a backup system has been studied in a very preliminary manner. This system utilizes an atmospheric fluidized bed (AFB) to indirectly heat the air which drives the gas turbine unit. The gas turbine works with dust free air, thereby eliminating the gas turbine corrosion, erosion and deposition problems attendant to PFB systems. In this scheme, the gas turbine will have higher reliability, lower maintenance requirements and longer life. Due to schedule and cost constraints of this project, detailed analysis and cost estimating work have not been done. The concept may be a viable alternative, especially if the development of a reliable high temperature high pressure hot gas cleanup system remains elusive or if such a system is economically impractical. Further study of this cycle is recommended to determine if it would be competitive.

Results: Major equipment necessary for Alternate 1-4 and the base PFB/AFB plant of Subtask 1.2 is shown in Table A-1. Table A-2 depicts the performance estimates for these plants. The capital cost requirements and cost of electricity generated are shown on Table A-3.

Discussion: It must be realized that the cost estimates of alternates 1, 2 and 3 are not as accurate as that of base case. Furthermore, the cost estimate of alternate No. 4 has been developed on the basis of different design and

DEVOLATILIZER/PFB POWER PLANT CONFIGURATION

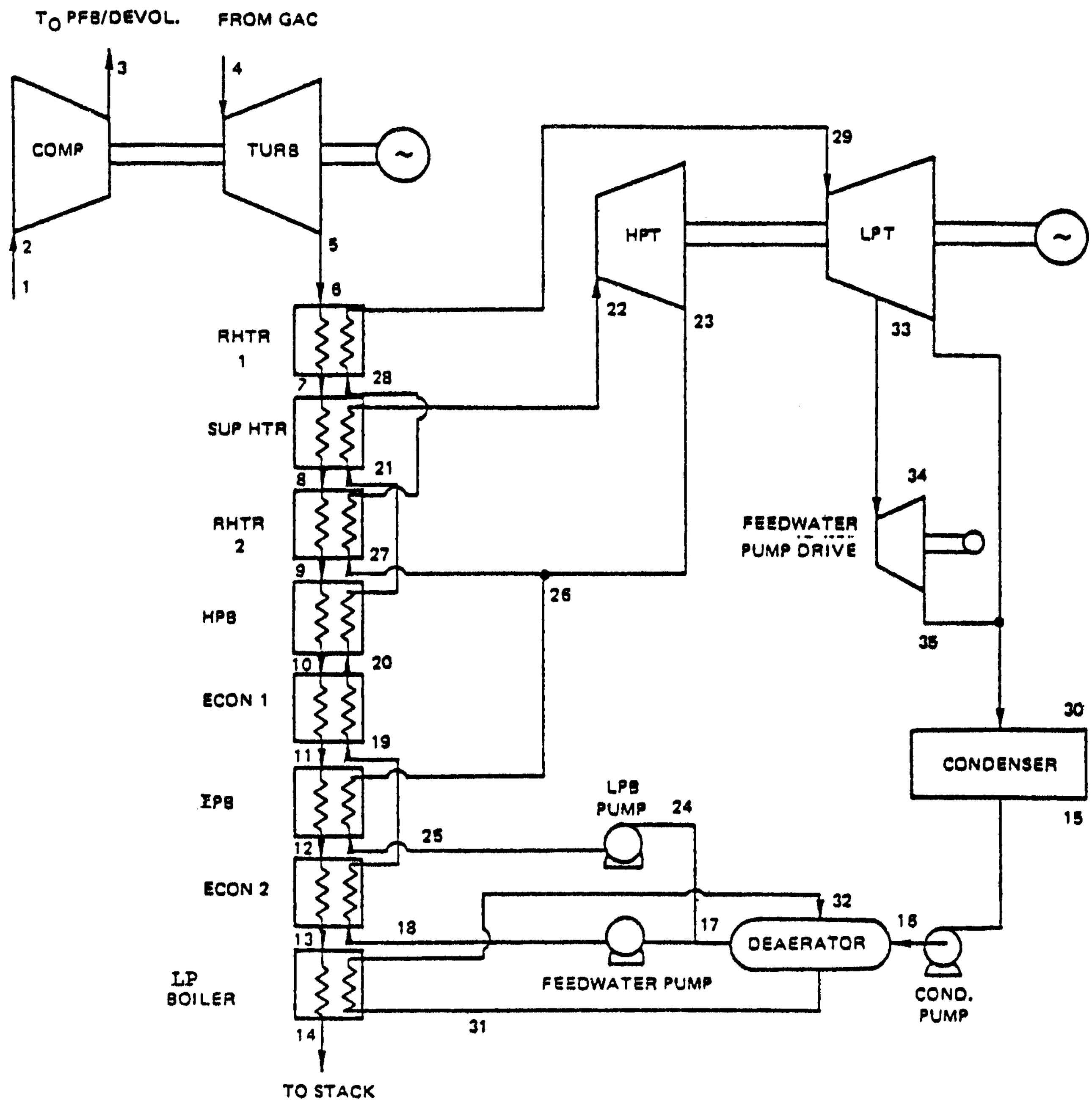

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FIGURE E-2

TABLE A-1

MAJOR EQUIPMENT SUMMARY
FOR THE NOMINAL 600 MW PLANT

		Base PFB/AFB Scheme Subtask 1.2	Steam Cooled PFB Scheme Altern. No. 1	Excess Air Cooled PFB Scheme Altern. No. 2	Devolatilizer/ PFB Scheme Altern. No. 3	Steam Cooled AFB Scheme Altern. No. 4
1.	Number of Gas Turbines	2	2	2	4	0
2.	Number of PFB Combustors	4	8	4	4	0
3.	Number of AFB Combustors	1	0	1	0	1
4.	Number of Devolatilizers	0	0	0	4	0
5.	Number of Steam Turbines	1	1	1	1	1
6.	Number of Waste Heat Boilers	0	0	0	4	0

TABLE A-2

SUMMARY OF PERFORMANCE ESTIMATES

FOR THE NOMINAL 600 MW PLANTS

	Base PFB/AFB Plant of Subtask 1.2	Steam Cooled PFB Plant Alternate #1	Excess Air Cooled PFB Plant Alt. #2	Devolatilizer/ PFB Plant Alternate #3	Steam Cooled AFB Plant Alternate #4
1. Gas Turbine Power, MW	127.2	154.9	137.2	316.4	0
2. Steam Turbine Power, MW	465.7	466.9	465.7	274.8	568.2
3. Gross Total Power, MW	592.9	621.8	602.9	591.2	568.2
4. Auxiliary Power Requirement, MW	18.7	13.9	18.7	13.9	32.3
5. Net Power Generated, MW	574.2	607.9	584.2	577.3	535.9
6. Adjusted Coal ("as-received" coal with HHV cf 11472 Btu/lb) flow rate, tons/h	225.3	229.2	228	210	231.6
7. Steam Flow Rate, lb/h	2,650,000	2,650,000	2,650,000	1,445,760	4,300,000
8. Total Energy Generated, at 65% Cap. Factor, x 10^{-6}kWh	3,268	3,461	3,326	3,287	3,051
9. Net Plant Efficiency, % (based on "as received" coal)	37.91	39.46	38.3	40.88	34.42

TABLE A-3

COST SUMMARY

(in Mid-1977 Dollars)

	Base PFB/AFB Plant of Subtask 1.2	Steam Cooled PFB Plant Alternate #1	Excess Air Cooled PFB Plant Alt. #2	Devolatilizer/ PFB Plant Alternate #3	Steam Cooled AFB Plant Alternate #4
1. Direct Capital Cost, x $10^{-3}\$$	225,010	224,796 (1)	240,023	302,609 (2)	221,420
2. Total Project Cost, x $10^{-3}\$$	325,353	325,045 (1)	347,061	437,558 (2)	320,162
3. Specific Capital Cost, $/kW	567	535 (1)	594	758 (2)	597
4. % Change in specific cost relative to base	+0.0	-6.0	+4.8	+33.7	+5.3
5. Total Annual Cost, x $10^{-3}\$$	93,028	92,997	97,249	108,217	94,531
6. Cost of Electricity, mills/kWh	28.47	26.87	29.24	32.92	30.98
7. % Change in COE relative to Base	+0.0	-6.0	+2.7	+15.6	+8.8

(1) If a final dust collector, e.g., baghouse or electrostatic precipitator, has to be installed to meet EPA limits on particulate emission, the direct capital cost will increase by approximately $8 million, total project cost by approximately $11.52 million and the specific capital cost by $19/kW.

(2) These costs may also increase for same reasons as indicated in note (1). The cost increases have not been estimated, however, they are expected to be significantly larger than those shown in note (1).

economic criteria and by a different group of people; thus, in a strict sense these costs are even less comparable. Therefore, the data on Table A-3 must be evaluated with these factors in mind.

The steam cooled PFB plant (Alternate 1) has the following pros and cons relative to the air cooled PFB/AFB plant:

a. The in-bed heat transfer tube material will experience a lower metal temperature. The task of finding an erosion/corrosion resistant material in a fluidized bed environment will be easier, and mechanical design problems and costs related to the tube bundle are reduced.

b. As with all PFB concepts, for this scheme to be commercially viable, it will be necessary to develop a reliable and cost-effective hot gas cleanup system for the PFB flue gas. However, because of the cycle concept for this alternate, the coal feed to the PFB system per gas turbine is three times as great as for the air cooled PFB concept. The particulate removal requirements to meet the gas turbine loading tolerance are therefore proportionally greater than for the air cooled concepts. In addition, the particulate removal system must handle the total turbine gas flow rather than only one quarter of it as in the split flow air cooled PFB concept of Subtask 1.2. This concept therefore presents a greater degree of uncertainty than the air cooled cycle with respect to particulate loading entering the gas turbine and may require more costly equipment (such as granular bed filters) to achieve acceptable particulate loading for the gas turbine.

Based on the assumptions made for the particulate size distribution and the prediction of cyclone performance, the ability to meet the present emissions limitation of 0.1 lb/10^6 Btu is marginal. It is possible that some form of final removal (baghouse, etc.) would be required to meet the current standards and quite probable that it would be required for the anticipated standards of 0.03 lb/10^6 Btu. The cost of a final particulate removal system has not been included in this study.

c. Another area of concern is the turndown of the steam cooled system. To the level considered in this study, it appears that the bed turndown requirements will result in the gas turbine turning down in parallel or ahead of the steam system. This results in a less favorable efficiency characteristic than the PFB/AFB combined cycle considered under Subtask 1.2.

The conceptual design of the steam cooled PFB has been based on consideration of the system turndown requirements. This results in four combustors being provided for each gas turbine with turndown accomplished by sequential combustor startup or shutdown. The combustors are identical, with each containing boiler, superheater and reheater surface. The design, however, does not consider the system startup requirements. For startup it would be desirable to use separate beds for boiling, superheat and reheat so that steam could first be raised in the boiler bed and the superheat and reheat beds not fired until after sufficient steam flow was available for surface cooling. This is contrary to the desired design for load turndown unless the number of combustors is doubled so that, for each gas turbine, four combustors with boiler surface bed and four combustors with combination superheater/reheater beds are provided. Additional study work is required to develop a system with both a credible turndown capability and startup capability.

The prime advantages and disadvantages of the excess air cooled concept (Alternate 2) are as follows:

a. Aside from the significant cost of the cooling system, the elimination of the cooling system greatly decreases the uncertainties of the PFB combustor. There is currently inadequate data to evaluate corrosion portential for in-bed heat transfer tube materials. In addition, despite the detailed mechanical design analysis of the cooling system done in Subtask 1.2, there are areas in the design that are questionable; e.g., the ability to accommodate the differential thermal expansion that is anticipated, especially if cycling operation is to be the mode of plant operation. The excess air cooled concept would appear to offer the potential for greater reliability of the PFB combustor due to its simplicity.

b. Pressure drop consideration in the bed cooling system is one of the important design constraints on the size of the split flow air cooled PFB. With this cooling system eliminated, the excess air cooled concept offers a great deal more latitude for design optimization. An important factor not yet available for this optimization process is the relationship between gas residence time in the bed (i.e., bed depth divided by superficial velocity) and combustion efficiency and sorbent utilization. With this data, the velocity and bed depth could be varied to study the effect on both equipment cost and cycle performance (i.e., effect of PFB system pressure drop). For instance, doubling the superficial velocity to 12 fps could result in the use of only one PFB combustor per gas turbine.

c. The disadvantage of this concept comes from the fact that all the compressor discharge air passes through the bed and hence must pass through the particulate removal system, thus adding to cost. In addition, several parallel cyclone collectors are required with the ability to alter the number of collectors in service during load changes.

Conclusions: On the basis of this study, the following conclusions can be drawn:

1. The Devolatilizer/PFB plant as described herein displays the highest efficiency. But its specific capital cost and the cost of electricity are also the highest because of the complexity of the plant and the multitude of equipment.

2. The steam cooled PFB plant may generate electricity at the lowest cost, even if a final particulate cleanup system is necessary to meet the current/future EPA limits on particulate emission. However, given the accuracy of these estimates, a more detailed study is required before a firm conclusion can be drawn.

3. The Excess Air Cooled PFB concept is as viable as the Split Flow Air Cooled PFB base plant of Subtask 1.2, both economically and technically.

In addition, the lack of cooling surface in the bed increases the flexibility for optimizing combustor size. Also, uncertainties concerning erosion/corrosion of bed tube materials are eliminated.

4. The three PFB/gas turbine combined cycles (Alternates 1, 2 and the base PFB/AFB plant) are more efficient and, apparently, more economical than the straight AFB steam plant. However, a more detailed study of the straight AFB plant on the same basis as that performed for the PFB/AFB plant in Subtask 1.2 would be required before a final conclusion can be drawn.

Recommendations:

1. It is highly recommended that a detailed design engineering and cost estimating study be done using the same criteria as Subtask 1.2 for conceptual plants employing a steam cooled PFB cycle and an Excess Air Cooled PFB system. A conceptual plant utilizing the steam cooled AFB also should be done using the same design and economical criteria as for Subtask 1.2 to establish the competitive position of that alternative relative to the PFB concepts.

2. The AFB/Semi-Closed Gas Turbine scheme should be further explored, analyzed and developed as a "fall-back" scheme. If a high temperature high pressure gas cleanup system does not become a commercial reality, this particular system may still provide an economical alternative to conventional plants with F.G.D.

3. The Coal Devolatilizer/PFB system (Alternate 3) as defined herein does not appear to be competitive economically with the base PFB/AFB plant of Subtask 1.2 or Alternates 1,2, and 4 as described herein. It is recommended that the design and relative competitive position of Devolatilizer/PFB systems be reevaluated in more detail before additional efforts are expended on its commercialization.

2.0 INTRODUCTION

2.1 GENERAL

Coal fired utility power plants can use the fluidized bed combustion technology in various cycle configurations. The objective of Subtask 1.7 is to identify some of the most promising but diverse cycle configurations which can be profitably employed in a power plant, to develop a reasonable cost estimate for each scheme, to estimate the cost of electricity generated and to identify the advanced technology required for implementation of each cycle. An extensive review of the open literature on fluidized bed technology has been made to select the potential cycles for further study. The list of the literature reviewed for this purpose is given in Appendix 9.1. On the basis of this literature survey the following cycles appeared to deserve further consideration:

a. Steam cooled Pressurized Fluidized Bed (PFB) combined cycle system

b. Excess Air Cooled PFB Combined Cycle Plant

c. Split Flow Air Cooled PFB Combined Cycle Plant

d. Steam Cooled Atmospheric Fluidized Bed (AFB) Combustion Plant

e. Devolatilizer/PFB Combined Cycle Plant

f. AFB/Semi-Closed Gas Turbine Cycle

g. PFB/Gas Turbine/Waste Heat Steam Generator Combined Cycle Plant

h. PFB/Gas Turbine/Power Turbine Reheat Combined Cycle Plant

Of these eight concepts, (c), (g) and (h) have been described in detail in the reports of Subtasks 1.2, 1.8 and 1.9, respectively.

The competitive positions of the remaining cycles relative to the commerical PFB/AFB plant developed in Subtask 1.2 have been assessed during Subtask 1.7. These assessments have included estimates of capital costs, projected maintenance and operating costs and cost of electricity. The design and cost estimates for the alternative plants have been done on a more approximate basis than those of Subtask 1.2, 1.8, and 1.9.

2.2 METHODOLOGY

The five schemes studied in this subtask have been developed to combust the same coal and utilize the same sorbents as of Subtask 1.2. With the exception of the steam cooled AFB plant, all performance estimates have been made on the same assumptions of Subtask 1.2, wherever practicable.

After a cycle configuration was defined, performance estimates were made. If it was a combine cycle plant, then the number of gas turbines required for a nominal 600 MW power station was established. A very preliminary area site plan sketch was made for each plant configuration to help visualize the physical extent of the plant. For the steam cooled AFB plant, the design, performance, and cost data from an earlier Burns and Roe, Inc. study (Ref. 4) were used to develop a relative cost assessment.

2.3 ENVIRONMENTAL ISSUES

Combustion of coal in fluidized bed of sulfur sorbents allows the operation of a plant with a controlled emission of sulfur dioxides to the atmospheres. The operating parameters of the fluidized bed have in all cases been set to meet the current EPA emission limit of 1.2 lbs. of sulfur dioxide per million Btu of heat input. If future standards tighten this limit, as expected, it is likely that all of these plants can achieve 90% sulfur capture by varying the operating parameters of fluidized bed including the calcium to sulfur molar ratios and/or gas residence times.

Because of comparatively low temperature of combustion, in the fluidized beds, the emission of NOx is well within both the present limits of 0.7 lbs/10^6 Btu of heat input, and the anticipated new limit of 0.6 lb/10^6 Btu. In the Devolatilizer/Scheme there remains the possibility that the NOx emission will be higher than from the other schemes because of the higher temperature (2178F) of low Btu coal gas combustor. However, it is reasonable to expect that some variations of current NOx control technology will keep the emission below 0.6 lb/10^6 Btu.

High efficiency cyclones have been used after the PFB combustors to collect the particulates elutriated from the fluidized beds. Based on calculations made in this study, it is anticipated that the emission from these cyclones will marginally satisfy the current EPA limits of 0.1 lb/10^6 Btu input. In the case of the steam cooled PFB plant and the Devolatilizer plant, the uncertainties involved in the calculations leave a possibility that the cyclones alone may not meet the current limits. In addition, there is a high probability that they will not meet the anticipated future standards of 0.03 lb/10^6 Btu. Therefore, it is likely that a more efficient pressurized hot gas clean-up system and/or a final dust collector, e.g., baghouse or electrostatic precipitator would have to be installed on commercial steam cooled PFB plant. For the steam cooled AFB and the Excess Air Cooled PFB plants, a baghouse and precipitator, respectively, have been employed to meet the EPA emission limits on particulates.

2.4 PERFORMANCE ESTIMATES

Babcock and Wilcox Co. has calculated the coal flow to all the combustors and devolatilizers and developed the boiler performance summary, where applicable, except for the AFB steam plant. Using that coal flow rate, the United Technologies Corporation has developed the performance estimates for the different schemes utilizing their proprietary "SOAPP" computer program. Some adjustments have finally been made to provide for the heat losses, not accounted for previously. The net efficiency of the plants have been calculated by using these adjusted coal flow rate and the net power generated. Coal flows to the AFB steam plant were estimated based on data in Ref. 4.

2.5 ECONOMICS

Cost estimates for the: (1) Steam-cooled PFB plant; (2) Excess Air Cooled AFB Plant; and (3) The Devolatilizer/PFB plant have been estimated by modifying the cost of the base PFB/AFB plant of Subtask 1.2.

Proper adjustments in costs have been made to equipment, structure, piping and other material. It is felt that the cost estimates so developed will be less accurate than the preliminary cost estimates of Subtask 1.2, but will be sufficient to assess the relative competitive position of the alternatives.

The total project cost, annual cost and cost of electricity for these plants have been generated using the same economic parameters as has been used in Subtask 1.2.

The direct capital cost estimate for the steam cooled AFB plant has been taken from Ref. 4, with slight modification. The total project cost, annual cost and cost of electricity have been recalculated using the same procedure of Subtask 1.2

No cost estimate has been prepared for AFB/Semi-closed gas turbine cycle, as it was not within the scope of the contractual work.

2.6 ADVANCED TECHNOLOGY IMPACT

Advanced technology required for each scheme has been identified in the description of each scheme. So they are not repeated here.

2.7 AVAILABILITY, TIME & SCHEDULE REQUIREMENTS

The availability of the schemes under consideration is estimated to be of the same order as for the scheme of Subtask 1.2 and explained in the Report on Subtask 1.4

Time and cost requirements for commercialization of schemes are expected to be comparable with those for Subtask 1.2 scheme. The requirements for the devolatilizer (PFB cycle have been discussed in Section 7.0 of the Report on Subtask 1.2 (Commercial Plant Design).

3.0 STEAM COOLED PFB SCHEME

3.1 INTRODUCTION

The steam cooled PFB scheme is a combined cycle plant utilizing pressurized fluidized bed (PFB) combustors for generation of steam and gas turbines for expanding the pressurized flue gas from the PFB combustors. This scheme is being or has been investigated by many investigators. Its advantages include a reduction in boiler volume and sorbent requirements relative to an AFB and higher efficiency than AFB and conventional powerplants.

3.2 DESCRIPTION OF CYCLE

In this scheme, coal is burned in a pressurized fluidized bed (PFB) of sized dolomite in the combustor. The PFB is cooled by water and steam in tubes, i.e., superheated steam is generated in the combustor. The exiting flue gas from the combustor is cleaned in a dust clean-up system and is routed to the gas turbine at about 1650°F. The gas turbine exhaust is used to heat feedwater in a low level economizer. The superheated steam at 2415 psia and 1000F expands in the high pressure section of a steam turbine to about 584 psia. The high pressure exhaust steam is reheated in the combustor to 1000F. The reheated steam expands in the low pressure section of the steam turbine and exhausts to the condenser at 2" of mercury. Extraction steam from the low pressure turbine is used for the feedwater pump drive and three stages of feedwater heating (one stage being the deaerator). The system is shown schematically in Figure C-1.

3.3 PERFORMANCE

Four PFB combustors are used per gas turbine and there are two gas turbines for the conceptual 600 MW plant. The gas turbine chosen for the steam cooled PFB evaluation has the same airflow (840 #/sec) and pressure ratio (10) as the subtask 1.2 gas turbine. The turbine inlet temperature is 1650F, up from 1600F in subtask 1.2 because there are no air tubes in the bed. The bed pressure drop is assumed to be 10%. Each gas turbine would produce 14 MW more than the gas turbines in the subtask 1.2 selected plant configuration. This increase is due to the 50F higher turbine inlet temperature, lower pressure losses, and also to additional mass flow that would be available to the gas turbines resulting from the increased amount of coal combusted.

The system assumptions for performance analysis are shown in Table C-1. Tables C-2 and C-3 provide heat and mass balances for the air/gas and steam systems, respectively. The performance estimates are shown in Table C-4. After the computer calculations were made, adjustments were made to the amount of coal flow to account for the radiation heat losses from the hot gas piping

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STEAM-COOLED PFB CONFIGURATION

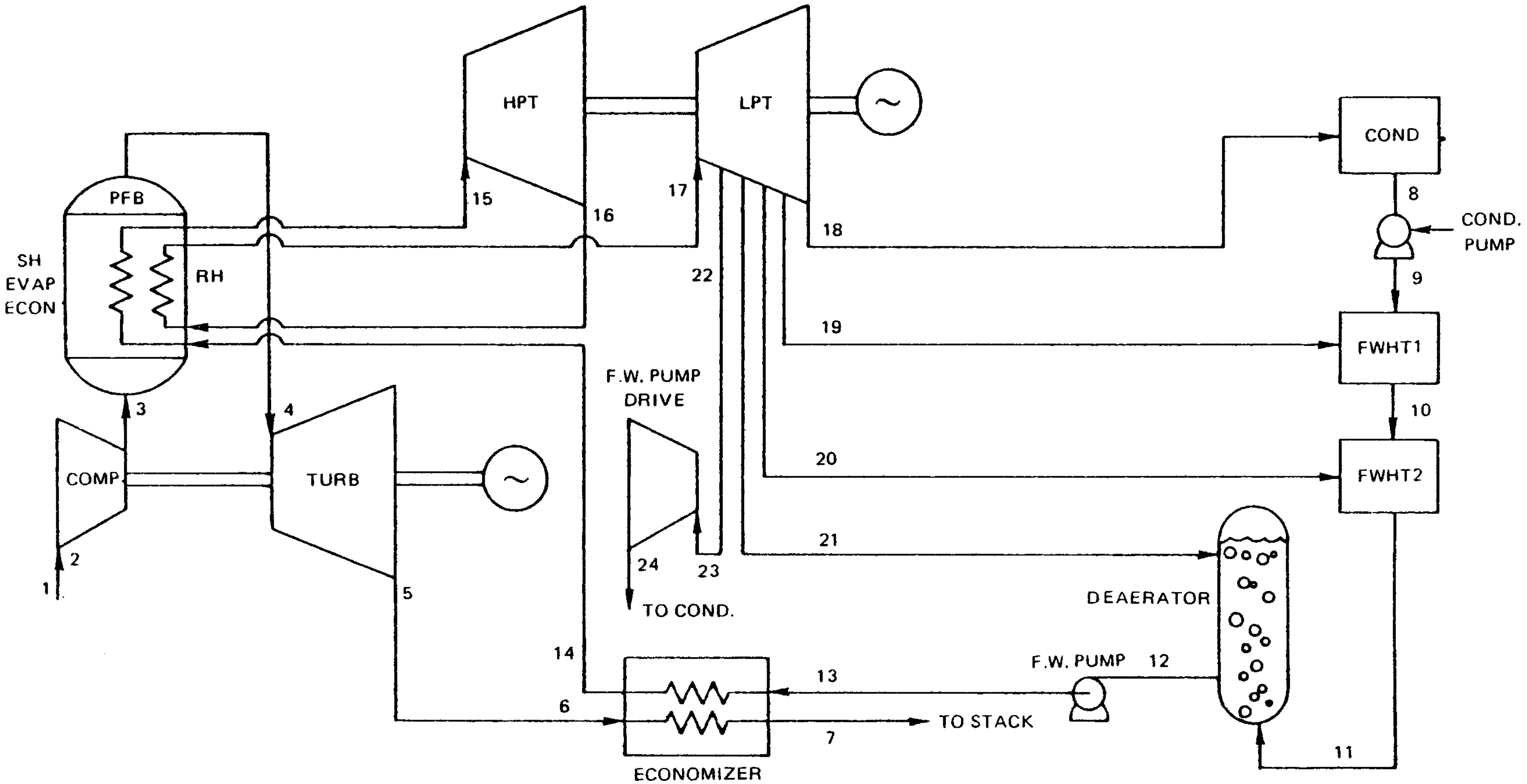


FIGURE C-1

and for unaccounted losses. These adjustments are explained in Table C-5, and these are reflected in the performance estimates shown in Table C-4.

The auxiliary power requirement for this cycle is less than that for the base scheme of subtask 1.2, because there are no electrostatic precipitators or I.D. fans in this scheme.

The total gas turbine power output (2 gas turbines) would be 154.9 MW and the steam system would provide 466.9 MW for a total gross power output of 621.8 MW. The overall net power and efficiency of the powerplant were estimated to be 607.9 MW and 39.46 percent, respectively, after taking into account auxiliary power losses, miscellaneous heat losses and basing the coal rate on "as received" conditions.

TABLE C-1

SYSTEM ASSUMPTIONS FOR PERFORMANCE ANALYSIS

Pressure Loss, % of local gas pressure	
PFB (compressor discharge to turbine inlet)	10.0
PFB Bed Temperature, F	1650
Component Efficiency, %	
Electric generator (steam turbine)	98.4
Electric generator (gas turbine)	98.7
Electric motors	95.0
Boiler feed pump, mechanical	82.0
Boiler feed pump drive turbine, mechanical	75.0
Condensate pump, mechanical	82.0
Energy Losses,	
<u>Percent of Energy Input to PFB</u>	
Sensible heat of solids	1.0
Net heat of reaction (gain)	-0.5
Radiation	0.4
Combustion Losses	1.0
Heat of vaporization	4.0
<u>Percent of Total Energy Input</u>	
Auxiliary power requirement	2.24

TABLE C-2

STEAM-COOLED PFB CONFIGURATION

Heat and Mass Balance for Air/Gas System

Location (1)	Description	W, (2) lb/sec	T, F	P, psia
1	Inlet	840.0	59.0	14.70
2	Compressor Inlet	840.0	59.0	14.55
3	PFB Inlet	810.9	594.4	145.5
4	Turbine Inlet	858.1	1650.0	130.9
5	Turbine Exit	883.0	885.3	15.1
6	Economizer Inlet	883.0	882.3	14.8
7	Stack	883.0	300.0	14.8

(1) Refer to Figure C-1 for locations.

(2) For one gas turbine; multiply by two for total plant

TABLE C-3

STEAM-COOLED PFB CONFIGURATION

Heat and Mass Balance for Steam System

Location (1)	Description	W, (2) lb/sec	T, F	P, psia	H, Btu/lb
8	Condensate Pump Inlet	349.1	101.1	.982	69.1
9	Feedwater Heater 1 Inlet	349.1	101.1	126.7	69.2
10	Feedwater Heater 2 Inlet	349.1	152.4	116.7	120.7
11	Deaerator Inlet	349.1	183.1	30.0	151.5
12	Feedwater Pump Inlet	368.1	238.2	24.4	207.0
13	Economizer Inlet	368.1	243.0	2765.0	223.5
14	PFB Inlet	368.1	573.5	2665.0	585.7
15	HPT Inlet	368.1	1000.0	2415.0	1460.6
16	HPT Exit	368.1	635.0	584.0	1314.1
17	LPT Inlet	368.1	1000.0	526.6	1519.7
18	LPT Exit	307.2	101.1	.982	1024.1
19	Feedwater Heater 1 Extraction	18.4	170.1	6.0	1111.1
20	Feedwater Heater 2 Extraction	10.6	229.6	13.0	1159.7
21	Deaerator Extraction	18.9	382.1	33.0	1228.8
22	Feedwater Pump Drive Extraction	13.0	725.0	175.0	1388.5
23	Feedwater Pump Drive Inlet	13.0	725.0	166.3	1388.5
24	Feedwater Pump Drive Exit	13.0	108.7	.982	1091.5

(1) Refer to Figure C-1 for locations

(2) Multiply flows by two for total plant

TABLE C-4

STEAM-COOLED PFB CONFIGURATION

Performance Estimates

(2 Gas Turbines)

Gas Turbine Power, MW	154.9
Steam Turbine Power, MW	466.9
Total Gross Power, MW	621.8
Power for Auxiliaries, MW	13.9
Total Net Power, MW	607.9
Gross Efficiency[(1)], %	41.64
Net Efficiency[(2)], %	39.46
Coal Feed Rate (as fired), lb/sec	113.68
Coal Feed Rate (as rec'd), lb/sec	125.28
Adjusted Coal Feed Rate (as rec'd), lb/sec[(3)]	127.31

(1) Based on gross total power output and 'as fired' coal rate (HHV=12453.Btu/lb)

(2) Based on net total power output, miscellaneous losses and 'as received' adjusted coal rate (HHV=11472.Btu/lb)

(3) See Table C-5

TABLE C-5

ADJUSTMENTS TO COAL FLOW

After the computer calculations were made, adjustments were made to the coal flow to account for the following:

A.	Radiation loss in hot gas piping		31.6×10^6 Btu/h
		Total	31.6×10^6 Btu/h
B.	Manufacturer's margin and unaccounted for losses for combustors		50.96×10^6 Btu/h

The following adjustment to coal flow was made:

Power Output	Adjustment to Coal Flow (as received) in lbs/sec
100%	+ 2.03

Total Adjusted Coal (as rec'd) flow = 125.28 + 2.03 lbs/sec

= 127.31 lbs/sec

3.4 PLANT DESCRIPTION

3.4.1 General

The steam cooled fluid bed system, as contrasted with the air cooled bed, requires special design considerations in order to achieve load turndown. The steam cooled surface represents a nearly constant heat sink and, because of the narrow band of acceptable bed operating temperature, requires that some means of varying the active surface must be provided in the design to achieve load turndown. In the design of atmospheric pressure fluid bed systems, a multiplicity of bed compartments is provided so that the compartments may be sequentially operated to provide the variable surface needed to accomplish load turndown. A parallel philosophy has been followed for the design of the steam cooled pressurized fluid bed combustors.

The pressurized fluid bed combustor concept, because of the bed geometry, requires that multiple totally separate beds be provided to achieve load turndown rather than the multiple compartments within a bed that are considered for AFB systems. The conceptual plant design is therefore based on the use of four (4) PFB combustors per gas turbine or a total of eight (8) combustors for the 600 MWe plant. Each combustor represents a semi-independent sub-system having its own solids feed system and particulate removal system.

The plant is similar to the base PFB/AFB plant, except that there is no AFB combustor, electrostatic precipitator, I.D. fans and limestone handling system.

The flue gas from the four PFB combustors, after gas cleanup, will combine and expand in the gas turbine. Each combustor along with its feed system, gas cleanup system and hot piping system can be taken out of service independent of the other systems.

The steam system - the steam turbine, generator, condenser, feedwater heaters, deaerator, feedwater pump, condensate pump - remains the same as in the base system of subtask 1.2.

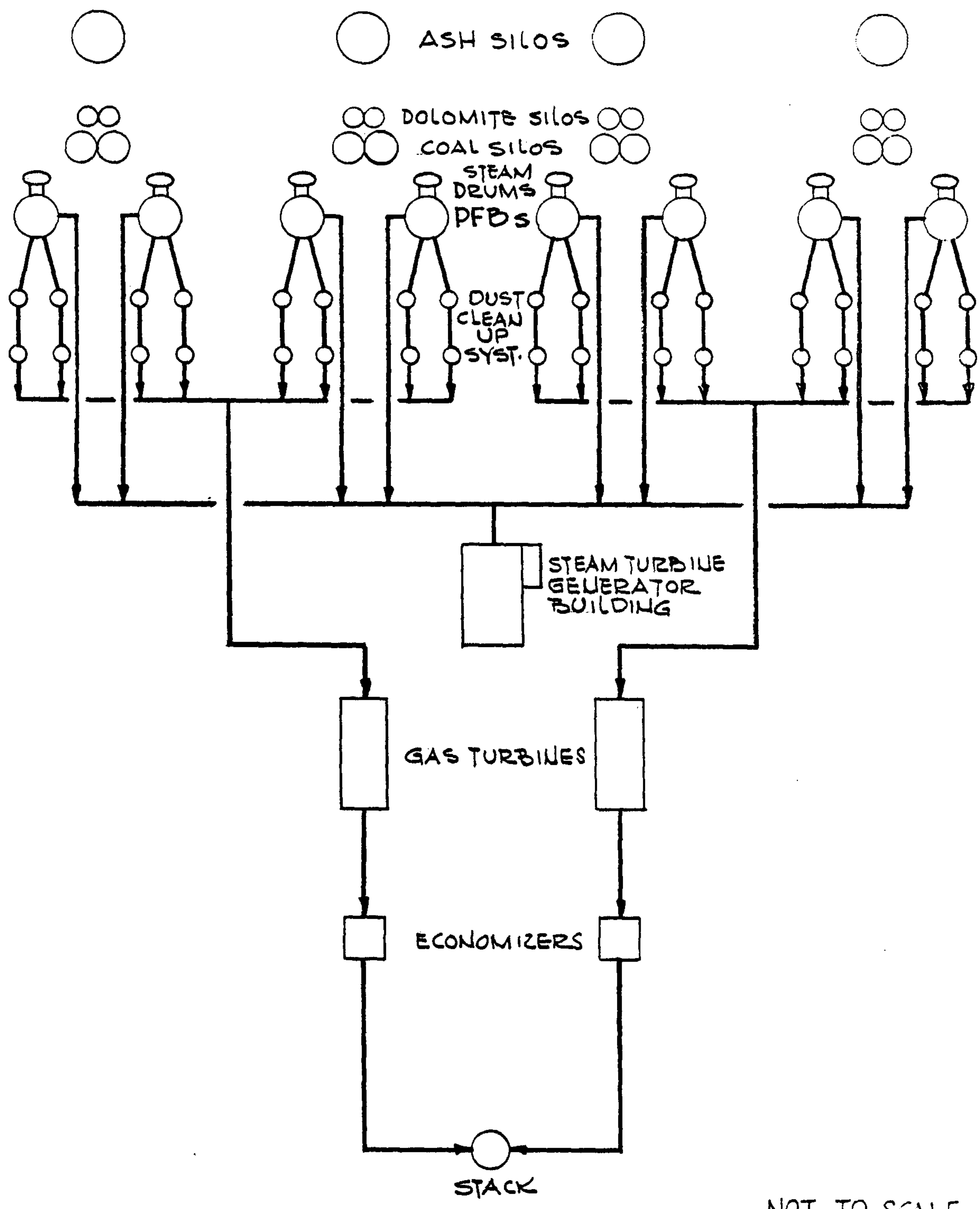
Figure C-1 and Figure C-2, the schematic of the steam cooled PFB plant, together depict this conceptual steam cooled PFB plant. The details of the steam system and other auxiliary systems can be found in Section 4.0, pages 45 to 53 and 109 to 322 of the report on subtask 1.2, Commercial Plant Design.

3.4.2 Major Equipment and Systems

3.4.2.1 PFB Combustors

3.4.2.1.1 PFB Design Parameters

Combustion efficiency, heat transfer and sulfur capture efficiency in the PFB combustor are functions of bed temperature,



NOT TO SCALE

SCHEMATIC OF STEAM COOLED PFB PLANT

FIGURE: C -2

fluidizing velocity and solids feed size. The values of these parameters used in the PFB combustor are based on the reported work of various organizations involved in PFB research. These values are shown in Table C-6 and discussed below:

Bed Operating Temperature: 1650°

The BCURA work comparing the nature of the deposits caused by material elutriated from the bed and escaping through the particulate removal equipment at temperatures of both 1650F and 1750F was a prime consideration in selecting the bed operating temperature. A more complete discussion of this rationale is contained in page 69 of the subtask 1.2 report, Commercial Plant Design.

A contributing factor to the selection of this design operating temperature was the design of the superheater surface. Even at 1650F the design upset heat absorption rates are greater than for conventional boiler. With a 1750F bed operating temperature, these heat absorption rates would be 20% higher still and the ability to satisfactorily design the superheater is in doubt.

Excess Air: 50%

The excess air value is actually set by the cycle configuration and is above the 15% minimum. It should be noted that the performance benefits of the combined cycle arrangement outweigh the efficiency penalty due to higher excess air.

Superficial Velocity: 6 fps

While a low superficial velocity would be desirable in some respects, a compromise of 6 fps has been selected for full load operation to limit the size of the PFB combustors and to provide a means of turndown. For load turndown, this superficial velocity will be lowered to the minimum value consistent with good fluidization.

Coal and Stone Feed Sizing: Coal - 8 mesh, Stone - 8 mesh

The sizes are selected following the rationale contained in page 71 of the subtask 1.2 report with the stone size being increased to agree with the superficial velocity.

Combustion Efficiency: 99%

Calcium/Sulfur Molar Feed Ratio: 1.0

Sulfur Capture: 78%

These three parameters are the same as for the subtask 1.2 PFB design and are based on the feeling that the gas residence time within the bed (2-1/2 seconds) is sufficient to achieve comparable performance.

Heat Transfer Coefficient

Since horizontal tubes are utilized within the fluid bed, the same correlations as used for the horizontal tubes of the atmospheric fluid bed boiler of subtask 1.2 have been utilized in the design. Pages 112 and 113 of the subtask 1.2 report describe these correlations.

TABLE C-6

OPERATING PARAMETERS OF PFB COMBUSTOR

Operating Temperature, ^{o}F	1650
Nominal Operating Pressure, atmos.	10
Fluidizing Velocity	6 fps
Coal Size	-8 mesh
Dolomite Size	-8 mesh
Pressure Drop Through Bed, psia	8.5
Excess Air for Combustion	50%
Combustion Efficiency	99%
Sulfur Capture (for 3.43% sulfur in coal)	78%
Ca/S mole ratio (operating)	1.0

3.4.2.1.2 PFB Combustor Description

Four separate but identical PFB combustors are provided for each gas turbine. The arrangement of one combustor is shown on the following figures.

Figure C-3 Arrgt Steam Cooled PFB Combustor - Front View

Figure C-4 Arrgt Steam Cooled PFB Combustor - Side View

Figure C-5 PFB Combustor - Plan Sections

Figure C-6 PFB Combustor - Plan Sections

a. PFB Combustor Pressure Vessel

The pressure vessel containing the steam cooled fluid bed has an outside diameter of 22'-11" and a length over the heads of 66'-6". The vessel is mounted in the vertical position and is supported from the structural steel by support rings which are positioned close to the center of the unit. This arrangement is chosen to reduce eccentricities in loading when the lateral forces of wind or earthquake are present.

In addition to being the pressure containment vessel for the process, the vessel must be designed to accommodate the support of the steam cooled internals and the bed. The vessel has been designed in accordance with ASME Section VIII Division I Code. The vessel design is based on the use of SA 516 GR 70 carbon steel; the wall thickness is 2-1/2".

The vessel is internally insulated to limit the surface temperature of the combustor to 250F based with an ambient air temperature of 80F. Below the distributor plate, a refractory lining of 3-5/8" of Kaolite 2200HS is used based on the start-up operation with the inlet air being preheated to 1250F. Above the distributor plate, the combustion process is contained in a steam cooled bed with a separately insulated exhaust plenum. The temperature in the annulus between the water cooled combustor and the pressure vessel will be approximately saturation temperature or 700F. The vessel wall in this area is covered with a blanket insulation to achieve the desired surface temperature.

b. Steam Cooled Bed

The fluid bed is contained within a water cooled, membrane wall enclosure which extends from below the distributor plate to slightly above the top of the bed. A refractory lined exhaust plenum conveys the combustion gas from the bed to the outlet nozzle in the upper vessel head.

To minimize the differential expansion problems at the gas exit, the bed enclosure is top supported from the upper vessel head. Since the bed enclosure expands downward, an expansion joint is utilized as a seal between the lower enclosure

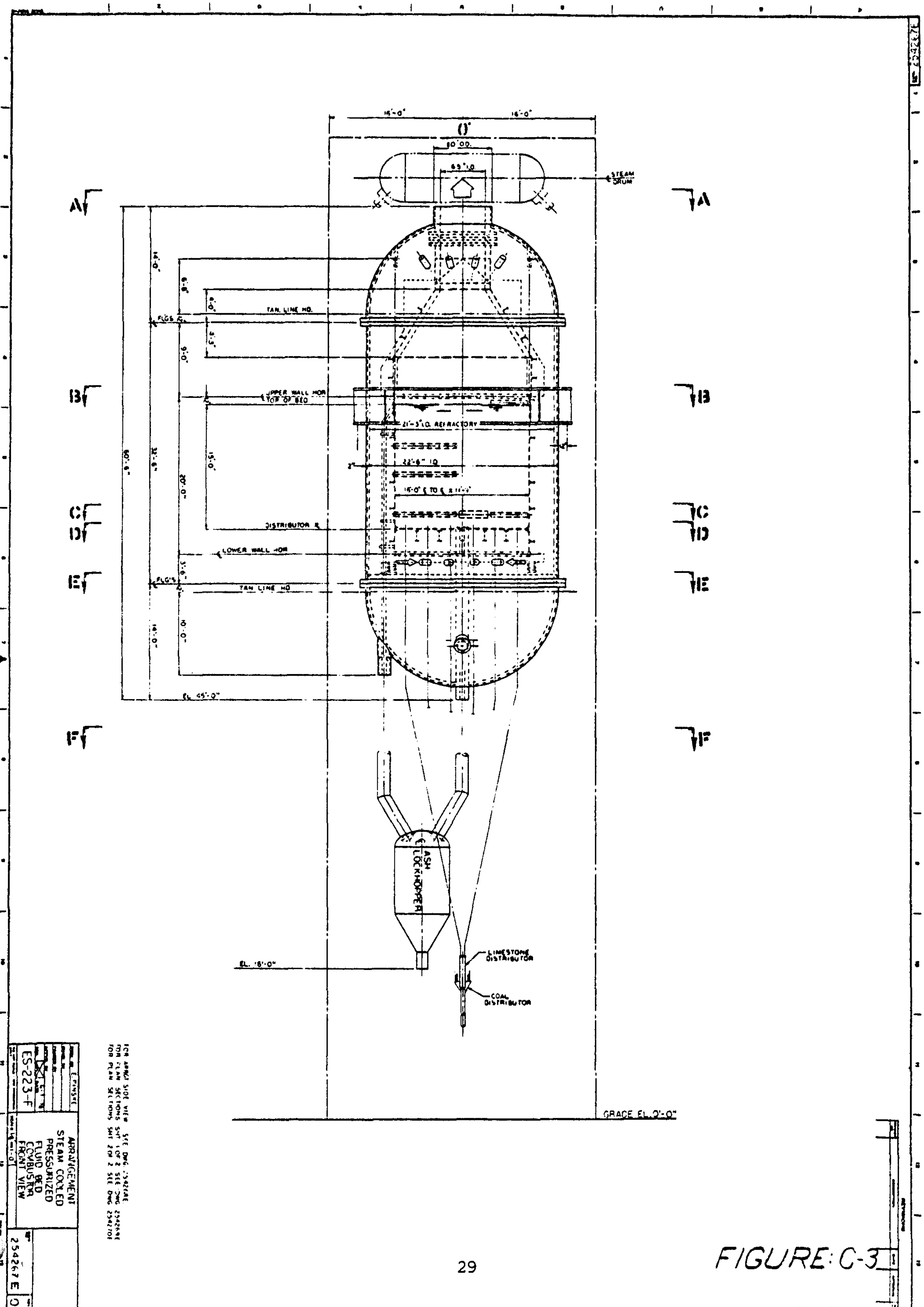

STEAM DRUM
TAN. LINE HO.
FLGS
UPPER WALL HOR
TOP OF BED
21'-3" I.D. REFRACTORY
22'-6" I.D.
DISTRIBUTOR
LOWER WALL HOR
TAN LINE HO
EL. 45'-0"
ASH LOCKHOPPER
EL. 18'-0"
LIMESTONE DISTRIBUTOR
COAL DISTRIBUTOR
GRADE EL. 0'-0"
A
B
C
D
E
F
FOR ARNGT SIDE VIEW SEE DWG 254268E
FOR PLAN SECTIONS SHT 1 OF 2 SEE DWG 254269E
FOR PLAN SECTIONS SHT 2 OF 2 SEE DWG 254270E
E. PINSKE
ES-223-F
ARRANGEMENT
STEAM COOLED
PRESSURIZED
FLUID BED
COMBUSTOR
FRONT VIEW
254267 E
0

FIGURE: C-3

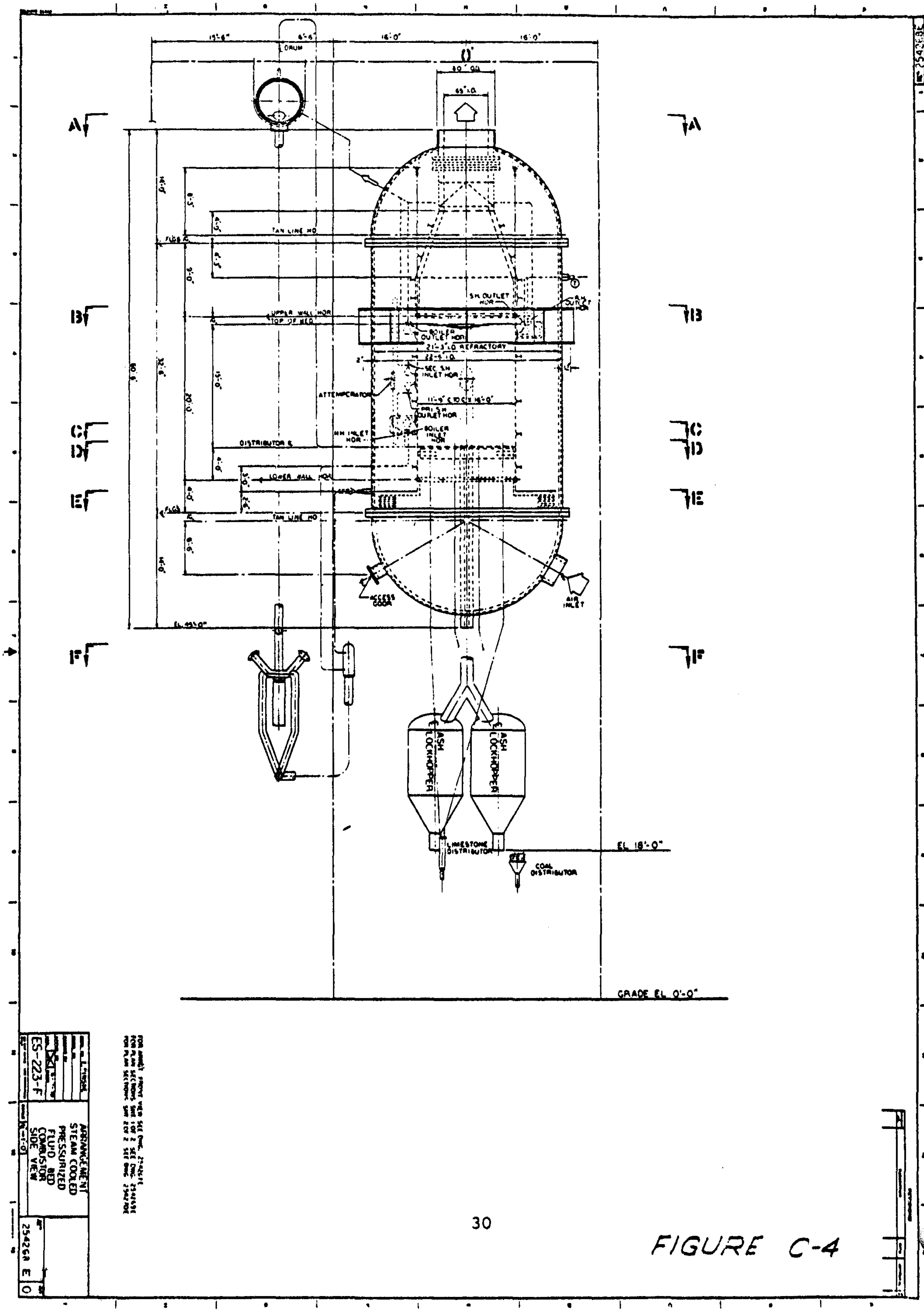

DRUM
ASH LOCKHOPPER
ASH LOCKHOPPER
LIMESTONE DISTRIBUTOR
COAL DISTRIBUTOR
AIR INLET
ACCESS DOOR
ATTEMPERATOR
SH OUTLET HDR
BOILER OUTLET HDR
21'-3" I.D. REFRACTORY
SEC SH INLET HDR
PRI SH OUTLET HDR
BOILER INLET HDR
MH INLET HDR
UPPER WALL HDR
TOP OF BED
DISTRIBUTOR ℄
LOWER WALL HDR
TAN LINE HD
EL 18'-0"
GRADE EL 0'-0"
FOR ARRG'T FRONT VIEW SEE DWG. 2542GYE
FOR PLAN SECTIONS SHT 1 OF 2 SEE DWG. 2542G9E
FOR PLAN SECTIONS SHT 2 OF 2 SEE DWG. 25427OE
ARRANGEMENT
STEAM COOLED
PRESSURIZED
FLUID BED
COMBUSTOR
SIDE VIEW
ES-223-F
2542GA E 0

FIGURE C-4

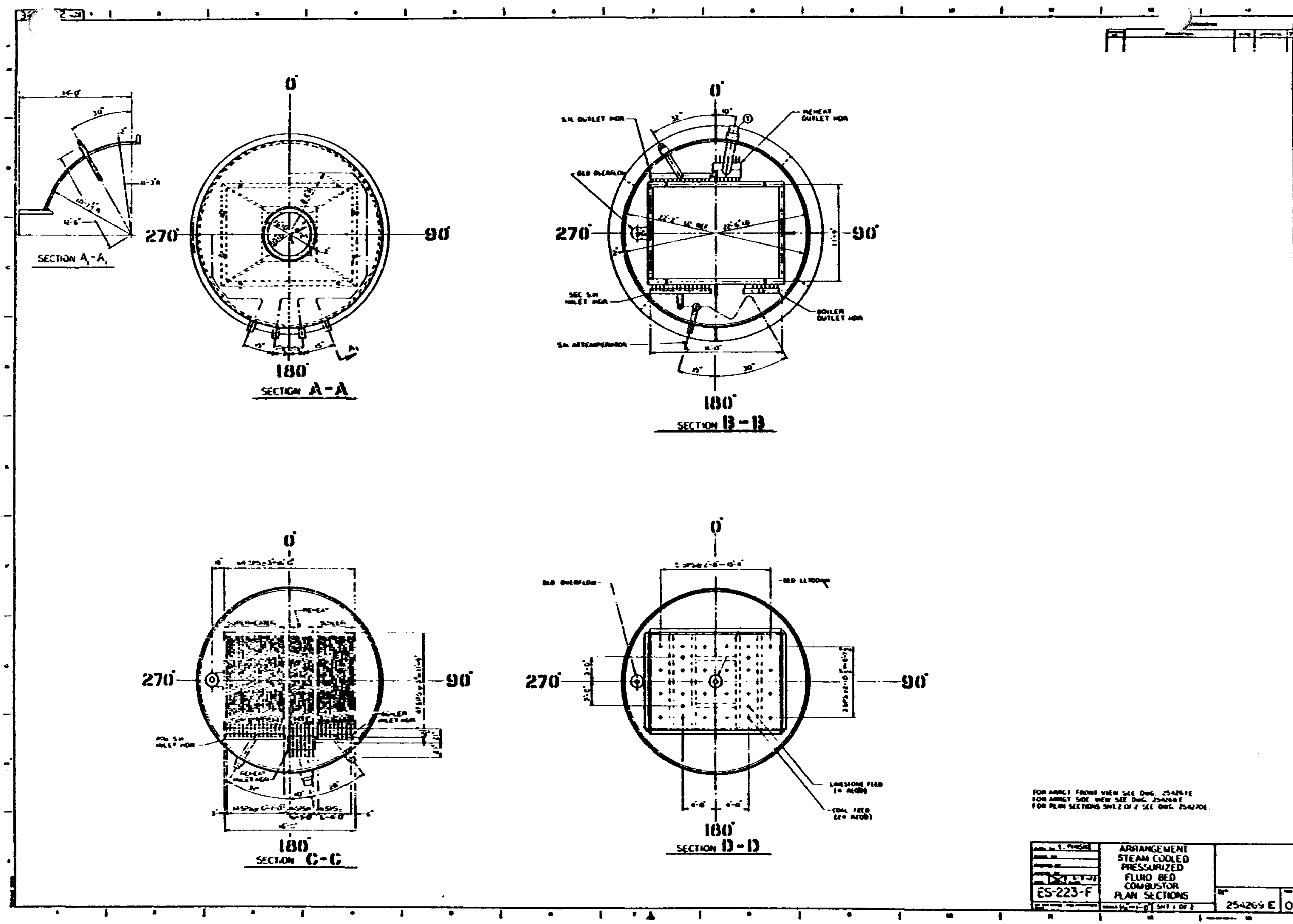

0°
270°
90°
180°
SECTION A-A
SECTION A1-A1
16'-0"
30°
S.H. OUTLET HDR
REHEAT OUTLET HDR
BED OVERFLOW
SEE S.H. INLET HDR
S.H. ATTEMPERATOR
BOILER OUTLET HDR
16'-0"
15°
30°
SECTION B-B
SUPERHEATER
REHEAT
BOILER
BOILER INLET HDR
REHEAT INLET HDR
16'-0"
SECTION C-C
BED OVERFLOW
BED LETDOWN
LIMESTONE FEED (4 REQD)
COAL FEED (24 REQD)
4'-0"
SECTION D-D
ARRANGEMENT
STEAM COOLED
PRESSURIZED
FLUID BED
COMBUSTOR
PLAN SECTIONS
ES-223-F
254269 E
0

FIGURE C-5

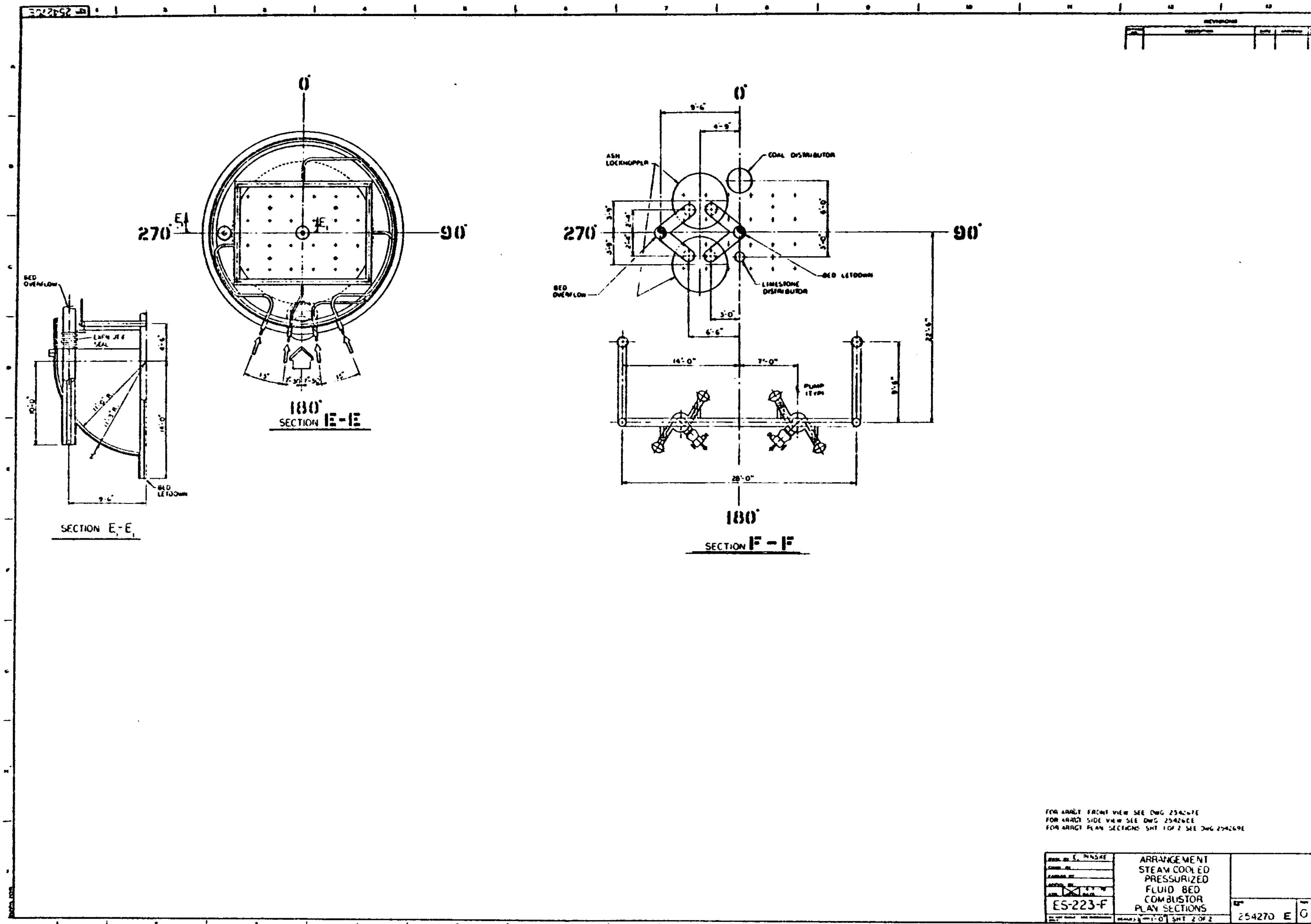

0°
90°
180°
270°
SECTION E-E
E₁
BED OVERFLOW
BED LETDOWN
SECTION E₁-E₁
9'-6"
10'-0"
14'-0"
4'-6"
ASH LOCKHOPPER
COAL DISTRIBUTOR
BED LETDOWN
LIMESTONE DISTRIBUTOR
BED OVERFLOW
PUMP (TYP)
9'-6"
4'-9"
3'-0"
6'-6"
6'-0"
14'-0"
7'-0"
9'-6"
22'-6"
28'-0"
SECTION F-F
FOR ARRGT FRONT VIEW SEE DWG 254267E
FOR ARRGT SIDE VIEW SEE DWG 254268E
FOR ARRGT PLAN SECTIONS SHT 1 OF 2 SEE DWG 254269E
E. PINSKE
ARRANGEMENT
STEAM COOLED
PRESSURIZED
FLUID BED
COMBUSTOR
PLAN SECTIONS
ES-223-F
SHT 2 OF 2
254270 E
0

FIGURE C-6

wall headers and the pressure vessel to prevent the preheated start-up air from entering the annulus between the bed and the pressure vessel.

The bed dimensions are approximately 12'x16' with a depth of 15 feet. The rectangular shape was chosen to minimize the size of the pressure vessel. All headers and connecting piping are located on the 16' side of the bed so that the overall dimensions over the headers approximate a square.

Since the drum boiler philosophy is utilized, the in bed surface is divided into three duties: boiling, superheat and reheat. Because the load turndown concept utilizes the inherent bed level change with fluidizing velocity variation, the surface for these three duties was arranged side by side across the 16' bed dimension and extend the full bed depth of 15'.

<u>Boiling Surface</u> - The boiling duty is split between the enclosure walls (25%) and the in bed surface (75%). The enclosure walls are membraned panels with 2" OD tubes on 3" centers. External buckstays stiffen the wall to withstand the pressure differential between the outer annulus and the bed. The submerged tubes are 2" OD ribbed tubes arranged in a staggered pattern with 6" side spacing and 2-5/8" back spacing.

Each PFB combustor is provided with its own steam drum and circulating system which simplifies the control of water and superheated steam flow for the combustors as the combustors are shut down and restarted during load changes. A pump assisted circulation system is used to achieve the high mass flows required to prevent Departure from Nucleate Boiling (DNB) in the submerged horizontal tubes.

<u>Superheater Surface</u> - The steam from the drum enters the superheater which is made up entirely of in-bed surface. The outlet steam temperature is controlled by an inner stage spray water attemperator and the superheater surface has been initially set to provide 10% attemperation at full load. This provision for attemperation permits some deviation in unit performance from the design parameters while still achieving the rated outlet temperature.

The superheater tubes are 2" OD and are arranged in the same manner as the boiling surface tubes. The metal selection for the superheater is based on an individual combustor turndown from 100% to 85% of full load. Metal temperature is set at this steam flow using upset heat absorption rates to account for local bed temperature variations and for local variations in heat transfer coefficients. The majority of the superheater requires TP304 stainless steel material and the outlet tubes require a minimum wall thickness of 0.460".

Reheat Surface - Pressure drop considerations required the use of 2-1/2" OD tubes in the reheater. The reheater is located near the center of the bed to minimize any effects this larger tube size might have on bed performance. The tube metals are selected in a manner similar to that used for the superheater. Again, most of the tubes require the use of TP 304 material but, due to the lower design pressure, of much lower thickness than for the superheater tubes.

c. Solids Feed System

The coal and sorbent feed to the beds is through nozzles in the air distributor plate. There are twenty-four (24) coal injection points each servicing approximately nine (9) square feet of bed area, and four (4) dolomite injection points per module. Separate pneumatic transport systems are used for the coal and sorbent feed. The systems incorporate lock hoppers for pressurization of the coal and the dolomite. One coal feed system and one dolomite feed system are provided for each PFB combustor. The arrangement of the lock hoppers and feed tanks is shown on Figure M-1 (Page 173) and the system schematic and instrumentation is shown on Figure M-2 (Page 174) of the report on subtask 1.2, Commercial Plant Design.

The crushed solids (coal or dolomite) from the bunker free fall into one of the two lock hoppers. The hopper is pressurized and the solids then free fall into the feed tank. From the feed tank, the solids are pneumatically transported to the boiler module with the feed rate controlled by the speed of the rotary, "air swept" feeder at the feed tank outlet. A single transport line is used from the feed tank to a distributor located beneath each boiler module. At the distributor the solids/air mixture is divided evenly among the individual feed lines to the boiler module.

d. Bed Ash Letdown

Ash letdown is provided by two drains per module. The upper drain is a standpipe arrangement which acts as a solids overflow drain and thus limits the bed height. The lower drain is located at the center of the air distributor plate and provides a means of controlling the bed level. A lock hopper system is provided for depressurization and dumping of solids to the solids cooler.

e. Particulate Removal System

The gas from each boiler module is split into two streams. Each stream passes through two stages of high efficiency cyclones for particulate removal to the dust loading level which satisfies the acceptable limits of the EPA and the gas turbine. For the gas turbine, the allowable gas loading is based on the presumption that particles greater than 10 microns in size would give unsatisfactory turbine life, particles less than 2 microns in size would have negligible effects on turbine life and that some limited amount of particulate in the 2-10 micron size could be tolerated within the gas turbine. The resulting allowable dust loading entering the gas turbine is:

Particle Diameter,d (microns)	Max.Particulate Concentration (grains/SCF)
d 2.0	No limit
2.0-d-10.0	0.0100
d 10.0	0.0000

Concerning EPA limits, the particulate collection system has been designed to achieve a maximum emission of 0.1 $lb/10^6$ Btu.

The high efficiency cyclones are the Aerodyne Development Corporation's "SV-FBC" Series Dust Collectors. Model 22000SV, shown in Figure N-3 (Page 188) of Subtask 1.2 report is capable of handling the combustion gas flow from one-half a boiler module, and is used as a design basis. This design is an extension of the equipment presently used in low temperature, low pressure applications.

Based on the projected particulate loading in the combustion gas and the predicted collection efficiency, two of these collectors operating in series are required for each flow stream to achieve the particulate loading level dictated by the turbine requirements. The predicted performance is

Particle Diameter,d (microns)	Particle Concentration* (grains/SCF)	
	first collector	second collector
d 2.0	.118	.052
2.0-d-10.0	.090	.009
d 10.0	.000	.000
Total emissions,$lb/10^6$ Btu**		.1

* concentration based on gas flow entering turbine

** emissions based on fuel input to combustor (HHV=12,453 Btu/lb,as fired)

A system of holding tanks and lock hoppers is provided for depressurization and dumping of the solids to the solids coolers. The arrangement of the cyclones and associated lock hoppers is shown on Figure D-3 (Page 201) of Subtask 1.2 report.

The particulate collection efficiency for the cyclones in this system is the same as for the cyclones in the base cycle (Task 1.2 report). Since the coal feed rate to the PFB combustors serving one gas turbine is nearly three times that of the base, air cooled cycle, the particulate loading entering the gas turbine are also three times as great. The emissions per unit heat input are the same as for the combustors of the excess air cooled system, again reflecting constant collection efficiency.

It must be remembered that the performance of the particulate removal system is based on both the prediction of the equipment performance and assumptions regarding the particulate sizing. The indicated performance represents better than 99% particulate removal. Seemingly small changes in either predicted collection efficiency or in the particulate size distribution can result in significant changes in both the particulate concentration and the emissions per unit of heat input. This portion of the system design therefore contains one of the greater degrees of uncertainty.

In the case of the particulate concentration, another degree of uncertainty exists namely the turbine tolerance. It is possible that the turbine may tolerate more particulate loading than assumed thereby lessening that degree of uncertainty.

The particulate emission per unit of fuel input is however an absolute limit that is expected to become more stringent with time. It is entirely possible that additional controls will be required in the plant to meet the present limit of 0.1 lb/10^6 Btu and highly probable that they would be required for the anticipated limit of 0.03 lb/10^6 Btu. The additional controls may be either in the form of more sophisticated equipment (granular bed filters, etc.) following the PFB combustors or, if the particulate loading is acceptable for the gas turbine, some type of stack clean-up equipment such as a bag house.

f. <u>Low Level Economizer</u> (LLE)

The exhaust gas from the gas turbines are cooled to the final stack temperature in the final heat trap, the Low Level Economizer. With the selected plant arrangement, two parallel LLE's are provided for the plant, one for each gas turbine. Figure C-7 shows the arrangement of one of the LLE's.

The temperature differentials between the gas and the water are low for the LLE indicating the use of extended surface tubes. The design was based on the use of helically wound fin type surface and follows the design that has been utilized for economizers of conventional oil or gas fired boilers.

3.4.2.2 Gas Turbine Sub System

The gas turbine subsystem remains essentially the same as described in Section 4.3.3 (Pages 127 to 136) of the Subtask 1.2 report. The major change will be an increase in generator size due to the 14 MW increase in gas turbine output.

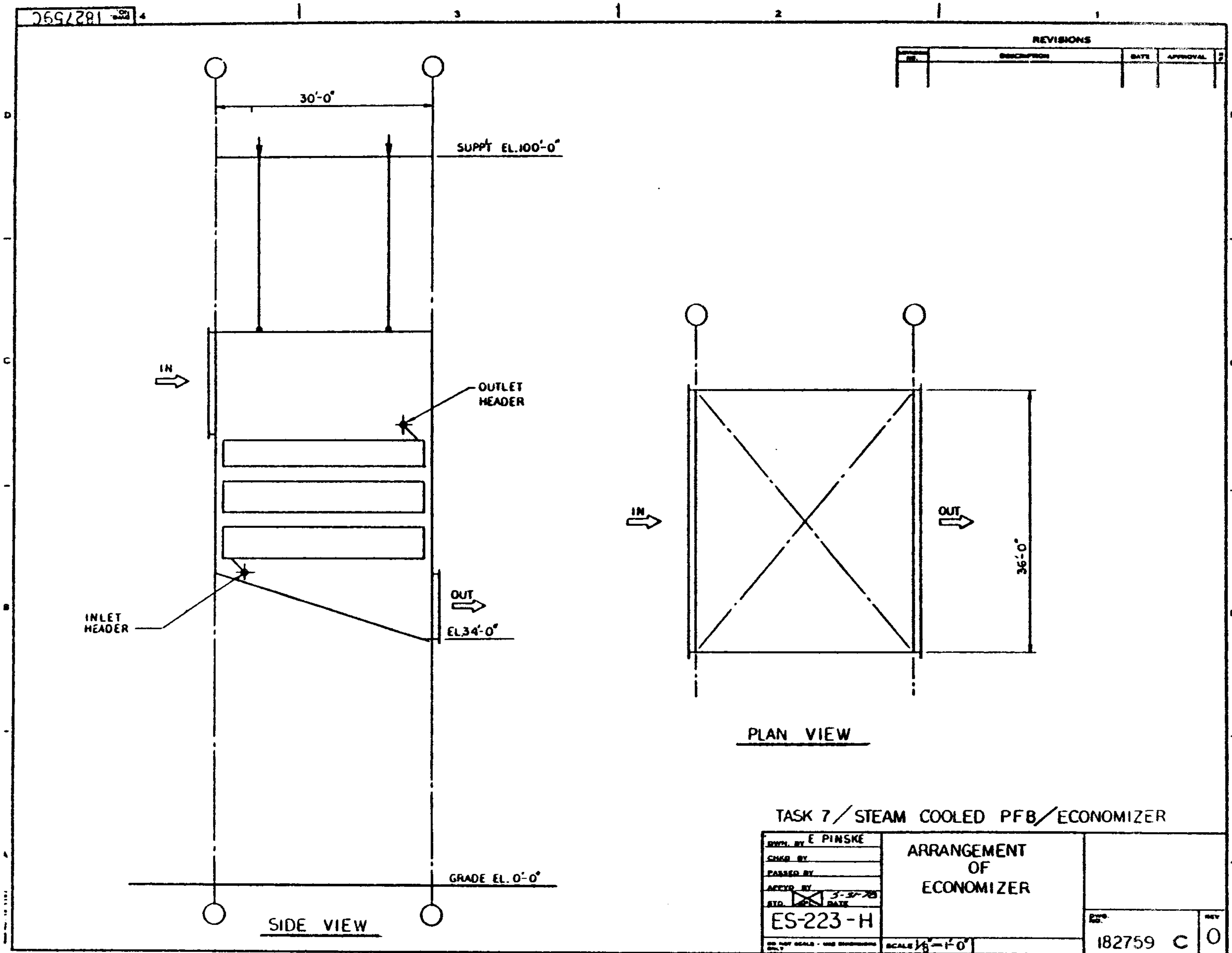

182759C
REVISIONS
DESCRIPTION
DATE
APPROVAL
30'-0"
SUPP'T EL.100'-0"
IN
OUTLET HEADER
INLET HEADER
OUT
EL.34'-0"
GRADE EL. 0'-0"
SIDE VIEW
IN
OUT
36'-0"
PLAN VIEW
TASK 7 / STEAM COOLED PFB / ECONOMIZER
DWN. BY E PINSKE
CHKD BY
PASSED BY
APPVD BY
3-31-78
DATE
ES-223-H
ARRANGEMENT OF ECONOMIZER
SCALE 1/8"=1'-0"
182759 C
0

FIGURE C-7

3.4.3 Operation and Load Turndown

The steam cooled fluidized bed, as contrasted with the air cooled fluidized bed, requires special design considerations to achieve load turndown. The steam cooled surface represents a nearly constant heat sink and, because of the narrow band of acceptable bed operating temperature, requires that some means of varying the active surface must be provided in the design to achieve load turndown.

The Scope of Work in Subtask 1.7 did not provide for a detailed examination of the load turndown design requirements. A cursory study, however, has been made to give direction to the conceptual design.

As noted in the equipment description, the design recognizes the need to provide multiple PFB combustors for sequential operation to achieve wide load control. Two methods have been examined for load turndown on the individual combustors. Because the heat transfer coefficient is rather insensitive to load changes, a reduction of fuel input to the bed results in a rapid lowering of bed temperature unless the amount of surface submerged in the bed is changed. It is desirable to maintain a nearly constant bed temperature both to assure rapid load change response and, more importantly, because combustion efficiency decreases rapidly as bed temperature is lowered.

The first system examined considers the use of constant fluidizing velocity and variable bed depth (i.e., variable inventory) to control bed temperature. The characteristics of this concept are shown on Figure C-8. As can be seen even small load changes require significant changes in bed inventory. It would be desirable to store the solids removed from the bed on load reduction with minimum heat loss so that the solids added back to the bed on load increase would not have a cooling effect on the bed. A system to rapidly transfer solids in and out of the bed and store them with minimum heat loss would be both complicated and expensive. As a point of reference, the dolomite feed system as presently sized for a Ca/S ratio of 3 provide the capability of bed inventory change in the order of 10%/hour and hence, is at least an order of magnitude away from what would be required for load changing.

The second concept considered makes use of the inherent bed level change with changes in fluidizing velocity. Since bed voidage decreases with decreasing velocity, the bed level will decrease as the bed inventory is held constant. Bed inventory may be readily monitored from the total bed pressure drop. As seen on Figure C-9, this concept produces more desirable turndown characteristics than the earlier concept and has been chosen as the design basis.

Another constraint in the turndown consideration is the design of the superheater and reheater tubes. The heat transfer

BED TURNDOWN CHARACTERISTIC
CONSTANT FLUIDIZING VELOCITY
(VARIABLE EXCESS AIR)
BED INVENTORY ADJUSTABLE

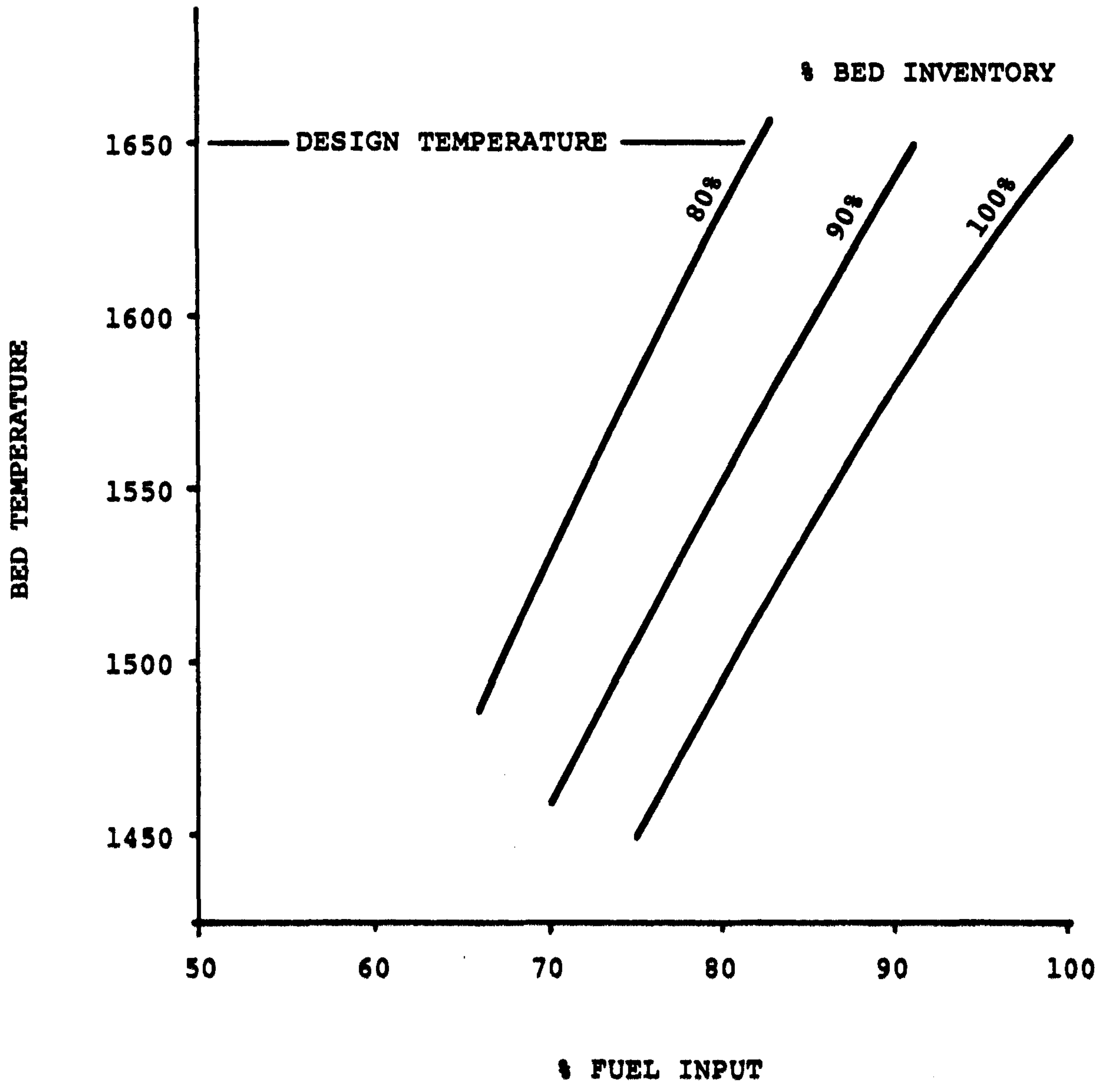


FIGURE C-8

BED TURNDOWN CHARACTERISTIC

CONSTANT EXCESS AIR
(VARIABLE FLUIDIZING VELOCITY)
BED INVENTORY CONSTANT
(LEVEL CHANGES WITH VELOCITY)

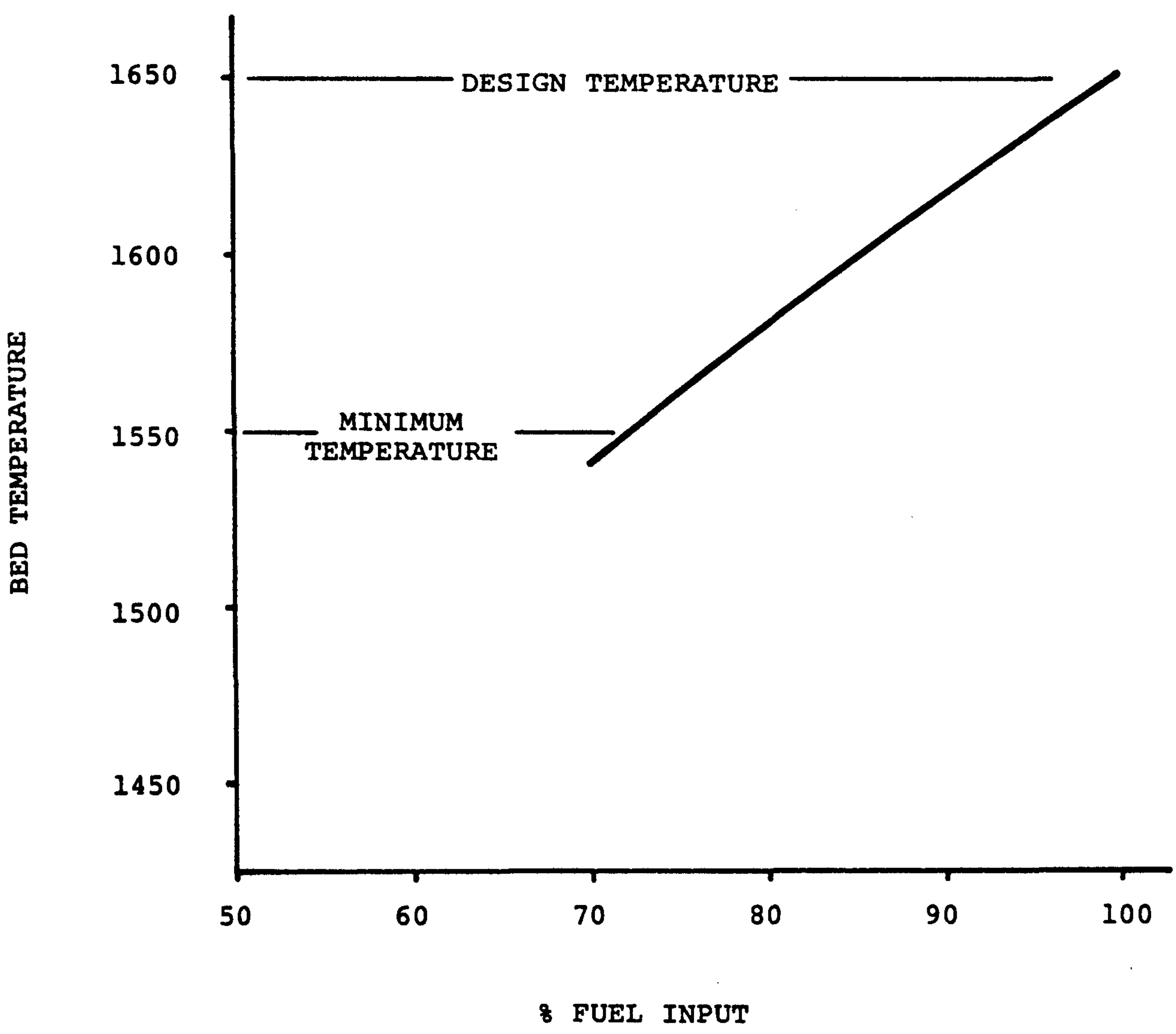
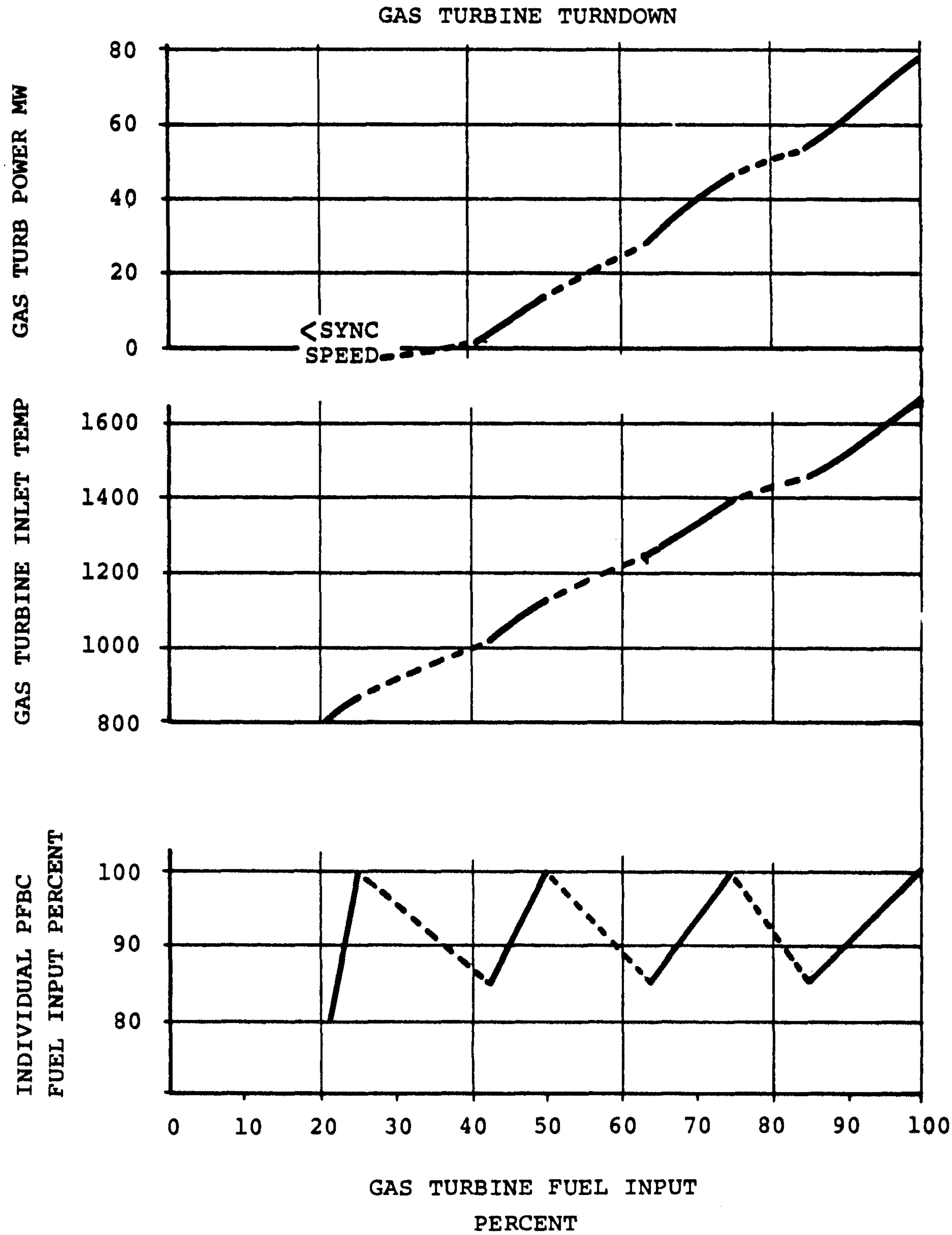


FIGURE C-9

rates from the bed to these tubes vary only slightly with load turndown when the desired goal of nearly constant bed temperature is achieved. The design of these tubes is therefore governed by the lower bed operating loads (as measured by steam flow). This added constraint limited the individual bed turndown to 85% range. As seen in Figure C-10, this yields a discontinuous load control capability when considering only one gas turbine with four combustors. However, the conceptual plant with two gas turbines and eight combustors can achieve nearly continuous load control to 50% fuel input as shown on Figure C-11. Use of a greater number of combustors to achieve smoother load control is not economically justifiable and more detailed system design may indicate that bed turndown to less than the 85% rating may be feasible, yielding smoother turndown.

Figure C-10 also shows the effect that the turndown has on the gas turbine contribution to the cycle. The turndown scheme of constant excess air results in a portion of the compressor discharge air being bypassed around the combustor as load is reduced. This, together with the inherent reduction in bed temperature as load is reduced, results in a significant reduction in gas turbine inlet temperature during the load turndown. The effect is more pronounced as combustors are removed from service on further load reduction. The result is that the gas turbines are turned down at a more rapid rate than the steam turbine so that the overall cycle efficiency vs load characteristic will be much less desirable than the base cycle of Subtask 1.2.

Figure C-10 shows that two of the four combustors for one gas turbine must be in service to achieve synchronous speed on the turbine. Even at 75% fuel input the gas turbine power is only 60% of maximum. This compares to the Subtask 1.2 base cycle where even at 60% fuel input the gas turbine power was still at 100% because the gas turbines were fired separately from the steam system.



GAS TURBINE TURNDOWN
GAS TURB POWER MW
80
60
40
20
0
<SYNC
SPEED
GAS TURBINE INLET TEMP
1600
1400
1200
1000
800
INDIVIDUAL PFBC
FUEL INPUT PERCENT
100
90
80
0
10
20
30
40
50
60
70
80
90
100
GAS TURBINE FUEL INPUT
PERCENT

FIGURE C-10

PLANT TURNDOWN

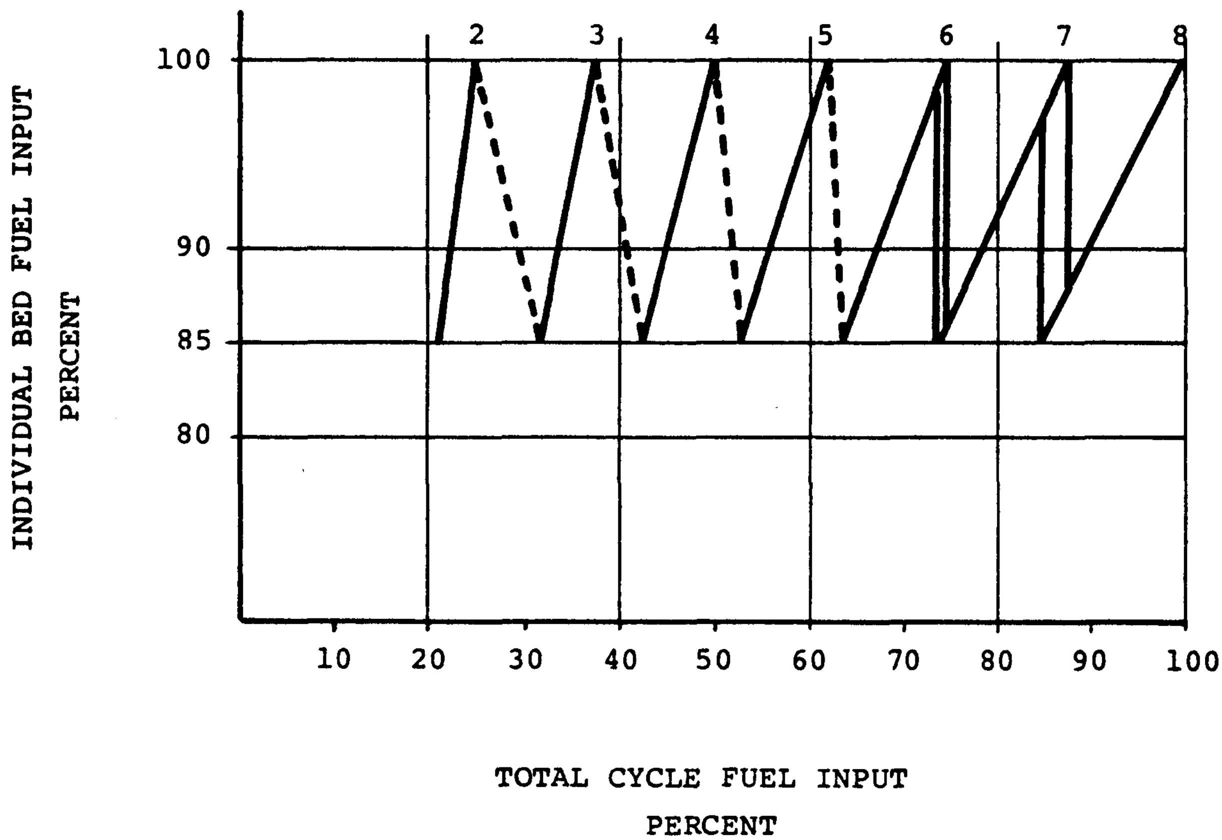


FIGURE C-11

3.5 ECONOMICS

3.5.1 Capital Cost Estimates

3.5.1.1 General

The capital cost for the plant has been estimated by modifying the capital cost of the base PFB/AFB plant of Subtask 1.2 to reflect the differences of the two schemes. Where the cost impact of a change is insignificant, the base cost has not been modified. The assumptions and methodology used in the estimating procedures are the same as described in pages 323 to 329 of the report on Subtask 1.2, Commercial Plant Design.

3.5.1.2 Cost Estimate of the PFB Systems

The costs of the PFB vessel, the feed system, cyclones and other accessories are based on the data developed under the Subtask 1.2 design with appropriate modifications for equipment size. The costs for these items should therefore carry an accuracy comparable to that of the Subtask 1.2 equipment.

The cost estimate for the steam system however has been determined with much less accuracy. The study is not of the depth that would permit the development of the details required to prepare an estimate. Also, there is no established B&W product sufficiently similar to serve as a base for approximation. The only piece of equipment of similar design that has been studied and for which cost estimates are available is a heat recovery boiler for a coal gasification system. The cost of the steam system is therefore approximated using cost per unit weight data from the gasification study. Since design details have not been developed, this process of cost determination also has the potential of overlooking the cost of many of the mechanical design features required for structural integrity.

3.5.1.3 Gas Turbine Subsystem Cost

The gas turbine subsystem cost would increase by about $400,000 to account for the increased generator cost, cooled first stage turbine nozzle, controls and installation costs.

3.5.1.4 Direct Capital Cost

Table C-7 shows the costs of only those items which are different from the commercial plant design of Subtask 1.2, in thousands of mid-1977 dollars.

The data of Table C-7 have been utilized to prepare Table C-8, the direct capital cost estimate. The direct capital cost required for this plant is $224,796,000.

3.5.1.5 Plant Capital Cost Estimated

The plant capital cost is comprised of direct capital cost, engineering and owner's costs, contingency and interest during construction. No escalation of capital cost has been taken into account. The costs shown on Table C-9, Commercial Plant Capital Cost Summary, are in terms of mid-1977 dollars. The total plant capital cost is $325,045,000 and the specific capital cost is $535/kW(net). These costs for the base PFB/AFB scheme are $325,353,000 and $567/kW, respectively.

3.5.2 Annual Cost

The annual cost for running this conceptual plant consists of the following items:

a. Fixed charge for capital cost - this is assumed to be 18% of the capital cost.

b. Cost of Coal - this is calculated at $20/ton at full load net plant heat rate and 65% capacity factor.

c. Cost of Sorbent - this is calculated at $7/ton.

d. Manpower Cost - Manpower need is assumed to be the same as for the base case. Though there is no AFB combustor, electrostatic precipitator and I.D. Fan in this scheme, manpower need is estimated to be the same because of more PFB combustors and associated systems.

e. Other material cost - this cost is also assumed to remain constant for a nominal 600 MW plant.

f. Machinery amortization and replacement parts - this estimate does not change from the base case.

g. Utilities - as same amount of makeup water is used, the water cost remains the same, but fuel oil cost doubles because of more PFB combustors and preheaters.

h. Spent sorbent and ash disposal cost - this cost is calculated at the rate of $3 per ton of disposable material.

The estimated annual cost is $91,901,000 as shown on Table C-10.

3.5.3 Cost of Electricity

Total energy generated in a year is 3,461.4 x 10^6 kWh at 65% capacity factor. So the cost of generated electricity is 26.87 mills/kWh. Cost contribution of each of the items of Section 3.5.2 is shown in Table C-11.

TABLE C-7

STEAM COOLED PFB SYSTEM

COST VARIATIONS IN THE AFFECTED ITEMS ONLY
FOR THE TOTAL PLANT

Account No.	Description	Reference Cost in Subtask 1.2	Cost in This Scheme	Variance
		In Thousands of Mid-1977 Dollars		
2.2.7	Electrostatic Precipitator Fdn. and Structural Steel	232	-	-232
	Total change in A/C 2.0			-232
3.0	Total change in A/C 3.0		-	+400
4.1a	4 PFB Combustors	24,870		-24,870
b	8 PFB Combustors without heat transfer tubes	-	23,900	+23,900
4.2	PFB Gas Cleaning Equip.	7,310	24,795	+17,485
4.3a	Process Solid Waste Hdg.System	1,056	-	-1,056
b	Process Solid Waste Hdg.& Storage	-	6,112	+6,112
4.4	Hot Gas Piping	3,923	11,769	+7,846
4.5	Start-up Combustors-Air Preheaters	853	1,706	+853
4.6	Allowance for PFB System Concrete Work	300	600	+300
	Total change in A/C 4.0			+30,570
5.1	Coal Stackout, Reclaim, Prep., and Silo Storage System	11,392	11,507	+115
5.2a	Dolomite & Limestone - Stackout, Reclaim, Prep., & Silo Storage	1,856	-	-1,856
b	Dolomite - Stackout, Reclaim Prep. & Silo Storage	-	1,943	+1,943
5.3	Coal & Dolomite Feed Systems to PFB	1,960	6,513	+4,553
5.4	Coal & Limestone Feed Systems to AFB	6,600	-	-6,600
	Total change in A/C 5.0			-1,845
6.1a	AFB Steam Generator	30,700	-	-30,700
b	Steam Generator & L.L.Economizer	-	14,874	+14,874
6.2	Electrostatic Precipitator	8,363	-	-8,363
6.3	Mechanical Cyclone Dust Collectors	850	-	-850
6.4	I.D. Fans with Motor Drives	1,007	-	-1,007
6.13	High Pressure Piping	2,385	5,400	+3,015
6.15	Valves	2,237	2,637	+400
6.17	Insulation-Piping & Equip.	705	520	-185
6.27	Process Solid Waste Handling and Storage	5,837	-	-5,837
6.29	Allowance for AFB Concrete Work	500	-	-500
	Total change in A/C 6.0			-29,153
10.2	Instr. for PFB Systems	1,175	2,350	+1,175
10.3	Instr. for PFB Coal Handling System	456	912	+456
10.4	Instr. for AFB Coal Handling System	456	-	-456
10.5	Instr. for Steam Generator System	2,258	1,129	-1,129
	Total change in A/C 10.0			+46

TABLE C-8

DIRECT CAPITAL COST ESTIMATE

STEAM-COOLED PFB

Main Account No.	Description	In Thousands of Mid-1977 Dollars: Material Cost	Installation Cost	Total Cost
1.0	Land & Land Rights	1,020		1,020
2.0	Structures & Improvements	6,585	6,883	13,468
3.0	Gas Turbines & Generators	18,472	2,160	20,400
4.0	PFB Combustor Systems	46,536	22,346	68,882
5.0	Coal & Sorbent Handling Systems	13,900	6,063	19,963
6.0	Boiler Plant Equipment	22,612	11,268	33,880
7.0	Steam Turbine Generator Units	26,453	3,470	29,923
8.0	Accessory Electrical Equipment	12,361	9,997	22,358
9.0	Miscellaneous Power Plant Equipment	450	44	494
10.0	Instrumentation & Control Systems	5,073	1,103	6,176
11.0	Job Distributable Costs	3,955	4,045	8,000
	TOTAL	157,417	67,379	224,796

TABLE C-9

PLANT CAPITAL COST SUMMARY

	$1,000's
1. Direct Capital Cost	$224,796
2. Engineering & Owner's Costs (10% of 1.)	22,480
3. Contingency (10% of 1 + 2)	24,728
4. Interest During Construction (8% Rate; 5 yrs; 19.5% of 1 + 2 +3)	53,041
Total Project Capital Cost	$325,045

Specific Capital Cost = $535/kW(net)

TABLE C-10

ANNUAL COST SUMMARY
AND COST OF ENERGY

Items	Thousands of Dollars
1. Fixed charge (@18%)	58,508
2. Coal	26,097
3. Sorbent	1,664
4. Manpower Cost	2,562
5. Other Material	1,932
6. Machinery Amortization and Replacement Parts	1,075
7. Utilities	79
8. Spent Sorbent & Ash Disposal	1,080
Total	$92,997

Total Energy Output at 65% Capacity Factor $3,461 \times 10^6$ kWh

Cost of Electricity Generated = 26.87 mills/kWh

TABLE C-11

COST OF ELECTRICITY
AT 65% CAPACITY FACTOR

Items		Cost in mills/lWh		Per Cent of Total Cost
Fixed charge @ 18%		16.91		62.91
Fuel - coal		7.54		28.06
Operations & Maintenance Costs				
Sorbent	0.48		1.80	
Spent Sorbent & Ash Disposal	0.31		1.16	
Manpower	0.74		2.75	
Other material	0.56		2.08	
Machinery & Equipment	0.31		1.16	
Utilities	0.02		0.08	
		2.42		9.03
Total		26.87		100.00

Total Energy Output
at 65% Capacity Factor = $3,461 \times 10^6$ kWh

Cost of Electricity Generated = 26.87

3.6 DISCUSSION

This cycle incorporates all the advantages of fluidized bed combustion - high sulfur capture in bed, low boiler surface and higher plant efficiency. The steam cooled PFB scheme has the following advantages over the air cooled PFB/AFB scheme:

a. The in-bed heat transfer tube material will experience a lower metal temperature. The task of finding an erosion/corrosion resistant material in a fluidized bed environment will be easier. Because of lower metal temperature, allowable stresses for the material will be higher. This will reduce mechanical design problems for the tube bundle and cost.

b. As there is no AFB combustor in this scheme, only one kind of sorbent will have to be handled. Mechanical handling system will be simpler.

c. If the performance of the Aerodyne's dust collector is up to the expectation, the emission from the plant will meet the current EPA limits for particulates without any further clean-up system. No final collector, e.g., electrostatic precipitator or baghouse, will be necessary. The hot gas clean-up system is still a major area of concern.

For this scheme to be commercially viable, it will be necessary to develop a reliable and cost-effective hot gas clean-up system for the PFB flue gas.

Because of the cycle concept, the coal feed to the PFB system for a gas turbine is three times as great as for the air cooled PFB concepts. The particulate removal requirements to meet the gas turbine loading tolerance are therefore proportionally greater than for the air cooled concepts. In addition, the particulate removal system must handle the total turbine gas flow rather than only one quarter of it as in the air cooled PFB concept. This concept therefore presents a greater degree of uncertainty than the air cooled cycle with respect to particulate loading entering the gas turbine and the resulting impact on gas turbine performance and plant availability. Additionally, it may require more complex and costly equipment (such as granular bed filters) to achieve acceptable particulate loading for the gas turbine.

Ideally, this plant concept would not require a final particulate removal system to achieve the environmentally acceptable particulate emission levels. Based on the assumptions made for the particulate size distribution and the prediction of cyclone performance, the ability to meet the present emissions limitation of 0.1 $lb/10^6$ Btu is marginal. It is possible that some form of final removal (bag house, etc.) would be required to meet the current standards and quite probable that it would be required for the anticipated standards of 0.03 $lb/10^6$ Btu. The cost of a final particulate removal system has not been included in this study.

The other area of concern is the steam cooled bed itself. As discussed in Section 3.4.3, the turndown of any steam cooled system required special design considerations. To the level considered in this study, it appears that the bed turndown requirements will result in a system operation with the gas turbine turning down in parallel or ahead of the steam system. This results in a less favorable efficiency characteristic than the PFB/AFB combined cycle considered under Subtask 1.2.

The conceptual design of the steam cooled PFB has been based on consideration of the system turndown requirements. This results in four combustors being provided for each gas turbine with turndown accomplished by sequential combustor startup or shutdown. The combustors are identical with each containing boiler, superheater and reheater surface. The design, however, does not consider the system startup requirements. For startup it would be desirable to use separate beds for boiling, superheat and reheat so that steam could first be raised in the boiler bed and the superheat and reheat beds not fired until after sufficient steam flow was available for surface cooling. This is contrary to the desired design for load turndown unless the number of combustors is doubled so that for each gas turbine four combustors with boiler surface bed and four combustors with combination superheater/reheater beds are provided. Additional study work is required to develop a system with both a credible turndown capability and startup capability.

An advantage of the steam cooled PFB concept compared with an AFB is the reduction in both unit size and heating surface. The size reduction is a result of the increased operating pressure which brings with it a proportionate reduction in bed area. The reduction in heating surface is cycle related rather than resulting directly from bed operating pressure as pressure has a negligible impact on heat transfer coefficient.

The in-bed surface for either a PFB or an AFB concept would be similar with the only difference being due to differences in bed temperature and steam cooled tube temperature. In the AFB system, however, most of the total heating surface is in the form of above bed surface used to cool the gas from the bed temperature to the 800F range at the economizer. In the PFB cycle, this gas temperature reduction is accomplished by the pressure expansion through the gas turbine and there is no surface corresponding to the above bed surface of the AFB cycle.

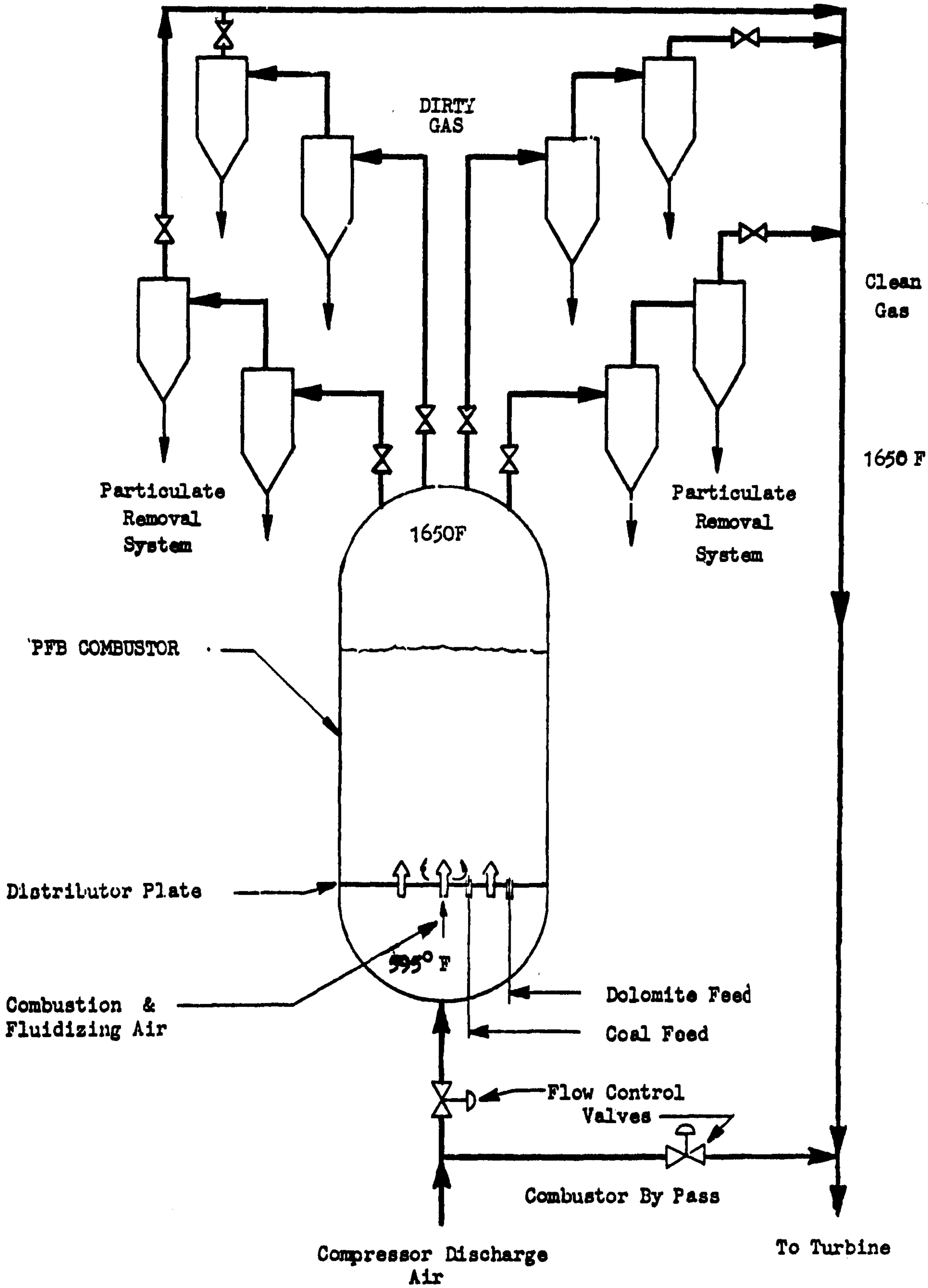
The final heat trap on the PFB cycle is the Low Level Economizer which is comparable to the Low Level Economizer of the PFB/AFB combined cycle of Subtask 1.2.

In summary, the steam cooled PFB scheme looks very promising and may be the most economical approach. It is recommended that further research be carried out to resolve the areas of concern and to develop a more accurate cost estimate for comparison with the PFB/AFB plant developed in Subtask 1.2.

4.0 EXCESS AIR COOLED PFB SCHEME

4.1 INTRODUCTION

The excess air cooled PFB Scheme is a combined cycle plant with PFB Combustor, gas turbine, AFB steam generator & steam turbine. Coal is burned in a pressurized fluidized bed. The fluidized bed is cooled by means of excess air. There are no heat exchanger tubes carrying air (as in Subtask 1.2) or water (as in Section 3.0 of this report) in or above the bed. This is one of the simplest schemes involving pressurized fluidized bed combustion of coal. In this particular study, all effort has been made to obtain a realistic cost estimate of the plant by minor modifications to the base PFB/AFB Scheme of Subtask 1.2 (Commercial Plant Design). The split-flow PFB Combustor, Figure H-1 (page 76) of Subtask 1.2 is replaced by an excess air cooled PFB Combustor, Figure D-1. The hot gas clean up systems are also changed to handle more gas volume. Other systems of Subtask 1.2 remain essentially the same.



Schematic - Excess Air Flow PFB Combustor FIGURE D-1

4.2 DESCRIPTION OF CYCLE

In this scheme, all the compressor discharge air (less turbine cooling air flow) goes through the PFB Combustor. The bed is maintained at 1650F. The flue gas at 1650F passes through a particulate removal system and then is expanded in the gas turbine. A part of the high temperature gas turbine exhaust is routed to an AFB Combustor (as in the base PFB/AFB Scheme of Subtask 1.2). More coal is burned in the AFB Combustor to generate steam. The exhaust of the AFB Combustor combines with the by-passed turbine exhaust and passes through a high temperature electrostatic precipitator, economizer, I.D. fan and to a stack. Figure D-2 shows the schematic diagram of the excess air cooled PFB system configuration. The steam system remains identical to the system used Subtask 1.2.

4.3 PERFORMANCE

The gas turbine chosen for the excess air cooled PFB evaluation has the same airflow (840 lbs/sec) and pressure ratio as the Subtask 1.2 turbine. The turbine inlet temperature is 1650F because there are no air tubes in the bed. The bed pressure drop is assumed to be 10%.

Table D-1 shows the system assumptions made for performance analysis. Tables D-2 and D-3 provide heat and mass balances for the Air/gas and steam systems, respectively. After the computer calculations have been made, some adjustments have been made to the as received coal flow to account for other heat losses. These are explained in Table D-4. Table D-5 provides the power output and plant efficiency estimates.

Each gas turbine would produce 68.6 MW of power output for a total gas turbine (2 gas turbines) participation of 137.2 MW. This power output is 5 MW greater than in the Subtask 1.2 cycle and is due to the 50° higher inlet temperature. The steam cycle portion would contribute an additional 465.7 MW for a total gross plant power output of 602.9 MW. The auxiliary power requirement is 18.7 MW, same as in Subtask 1.2. The net power output of plant is 584.7 MW, and the net plant efficiency is 38.3%. This efficiency includes all the losses and auxiliary power requirement and is based on the higher heating value of as received coal.

EXCESS AIR–COOLED PFB CONFIGURATION

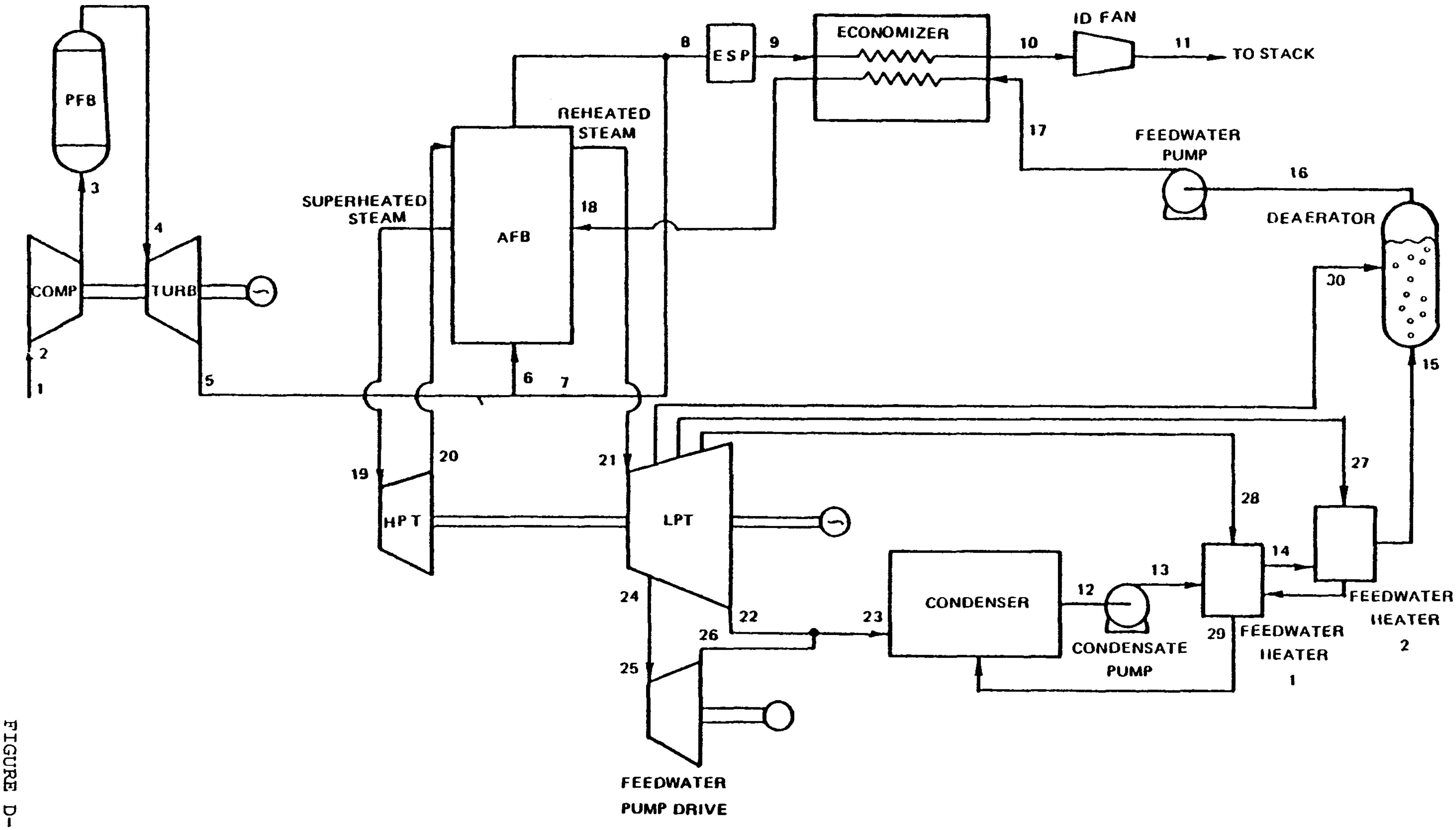


FIGURE D-2

TABLE D-1

SYSTEM ASSUMPTIONS FOR PERFORMANCE ANALYSIS

Pressure Loss, % of local gas pressure	
PFB (compressor discharge to turbine inlet)	10.2
AFB (turbine discharge to top of bed)	9.2
Temperature, F	
	Bed
PFB	1650
AFB	1550
Component Efficiency, %	
Electric generator (steam Turbine)	98.4
Electric generator (gas turbine)	98.7
Electric motors	95.0
Boiler feed pump, mechanical	82.0
Boiler feed pump drive turbine, mechanical	75.0
Condensate pump, mechanical	82.0
ID fan, mechanical	70.0
Energy Losses,	
Percent of Energy Input to AFB	
Sensible heat of solids*	0.7
Net heat of reaction	0.2
Radiation	0.5
Combustion losses	2.7
Heat of vaporization	4.0
Percent of Energy Input ot PFB	
Sensible heat of solids*	1.0
Net heat of reaction (gain)	-0.5
Radiation	0.4
Combustion losses	1.0
Heat of vaporization	4.0

* A large portion of the losses shown can be recovered in the waste solids cooler.

TABLE D-2

EXCESS AIR-COOLED PFB CONFIRURATION

Heat and Mass Balance for Air / Gas System

Location (1)		W, (2) lb/sec	T, F	P, psia	H, Btu/lb
1	Inlet	840.0	59.0	14.70	124.0
2	Compressor Inlet	840.0	59.0	14.55	124.0
3	PFB Inlet	810.8	595.5	145.5	254.8
4	Turbine Inlet	828.0	1650.0	130.9	541.1
5	Turbine Exit	853.0	870.8	15.8	326.7
6	AFB Combustor Inlet	443.3	867.8	15.8	326.7
7	AFB Bypass	409.7	867.8	15.8	326.7
8	Electrostatic Precipitator Inlet	927.1	751.0	14.3	297.0
9	Economizer Inlet	927.1	751.0	14.3	297.0
10	Economizer Exit	927.1	307.0	14.3	184.0
11	Stack	927.1	314.0	14.7	185.5

(1) Refer to Figure D-2 for locations.
(2) For one gas turbine; multiply by two for total plant.

TABLE D-3

EXCESS AIR-COOLED PFB CONFIGURATION

Heat and Mass Balance for Steam System

Location [(1)]	Description	W, [(2)] lb/sec	T, F	P, psia	H, Btu/lb
12	Condensate Pump Inlet	349.1	101.0	.98	69.0
13	Heater No. 1 Inlet (cold)	300.0	101.0	126.7	69.0
14	Heater No. 2 Inlet (cold)	300.0	161.9	116.7	129.0
15	Deaerator Inlet (cold)	300.0	195.6	35.0	164.0
16	Feedwater Pump Inlet	368.0	250.0	30.0	218.8
17	Economizer Inlet	338.7	255.0	2665.0	229.3
18	AFB Inlet	338.7	543.0	2665.0	540.1
19	High Pressure Turbine Inlet	368.0	1000.0	2415.0	1460.6
20	High Pressure Turbine Discharge	368.0	635.0	584.0	1314.1
21	Low Pressure Turbine Inlet	368.0	1000.0	525.6	1519.7
22	Low Pressure Turbine Discharge	307.2	101.0	.98	1025.7
23	Condenser Inlet	349.1	101.1	.98	954.3
24	LP Extraction (Feed. Pump Turbine)	13.0	725.0	175.0	1389.0
25	Feed. Pump Turbine Inlet	13.0	725.0	166.3	1389.0
26	Feed. Pump Turbine Discharge	13.0	109.0	1.23	1091.5
27	LP Extraction (Heater #2)	10.6	230.0	13.0	1160.0
28	LP Extraction (Heater #1)	18.35	170.0	6.0	1111.2
29	Heater No. 2 Discharge (Hot)	28.9	165.8	5.5	134.1
30	LP Extraction (Deaerator)	19.0	382.0	33.0	1229.0

(1) Location numbers identified in Fig. D-2

(2) Per gas turbine, multiply flows shown by 2 to get total plant flow.

TABLE D-4

ADJUSTMENTS TO COAL FLOW

After the computer calculations were made, adjustments were made to the coal flow to account for the following:

A.	Radiation loss in Electrostatic Precipitator	23.87×10^6 Btu/h
	Radiation loss in hot gas piping	31.6×10^6 Btu/h
	Total	55.47×10^6 Btu/h
B.	Manufacturer's margin and unaccounted for losses for combustors	50.48×10^6 Btu/h

The following adjustment to coal flow is made for 100% load.

Power Output	Adjustment to Coal Flow (as received) in lbs/sec
100 %	+ 2.60

Total Adjusted Coal (as received)

Flow Rate = 124.1 + 2.60 lbs/sec
= 126.70 lbs/sec.

TABLE D-5

EXCESS AIR-COOLED PFB PERFORMANCE ESTIMATES

(2 Gas Turbines)

Gas Turbine Power, MW	137.2
Steam Turbine Power, MW	465.7
Total Gross Power, MW	602.9
Power for Auxiliaries, MW	18.7
Total Net Power, MW	584.2
Gross Efficiency (1), %	40.8
Net Efficiency (2), %	38.3
PFB Coal Rate (As Fired), lb/sec	41.22
AFB Coal Rate (As Fired), lb/sec	71.39
Total Coal Rate (As Fired), lb/sec	112.61
Total Coal Rate (As Received), lb/sec (3)	124.1
Total Adjusted Coal Rate (As Received, lb/sec (3)	126.70

---

(1) Based on total gross power and 'as fired' coal rate (HHV = 12453 Btu/lb).

(2) Based on total net power, auxiliary power loss, heat losses and 'as received' adjusted coal rate (HHV = 11472 Btu/lb).

(3) See Table D-4

4.4 PLANT DESCRIPTION

4.4.1 General

The conceptual design of the utility plant employing excess air cooled PFB Combustors is exactly the same as the commercial plant of Subtask 1.2 with the exception of the PFB Combustors themselves and the associated dust clean up and hot gas piping systems. The plot plan for this conceptual design is shown on the Figure D-3. There are two gas turbines in the plant and each gas turbine receives hot pressurized flue gas from two PFB combustors. The flue gas from each combustor passes through four parallel trains of dust clean up systems and then combines before entering the gas turbine. Most parts of the description and drawings of Section 4.1 (pages 45 to 54) of Subtask 1.2 report are applicable to this plant.

4.4.2 Major Equipment and Systems

Only the PFB combustors and the gas clean up systems are described here. Descriptions of all other equipment and systems remain essentially the same as detailed in Subtask 1.2 report.

4.4.2.1 PFB Combustor

4.4.2.1.1 Mechanical Design Considerations

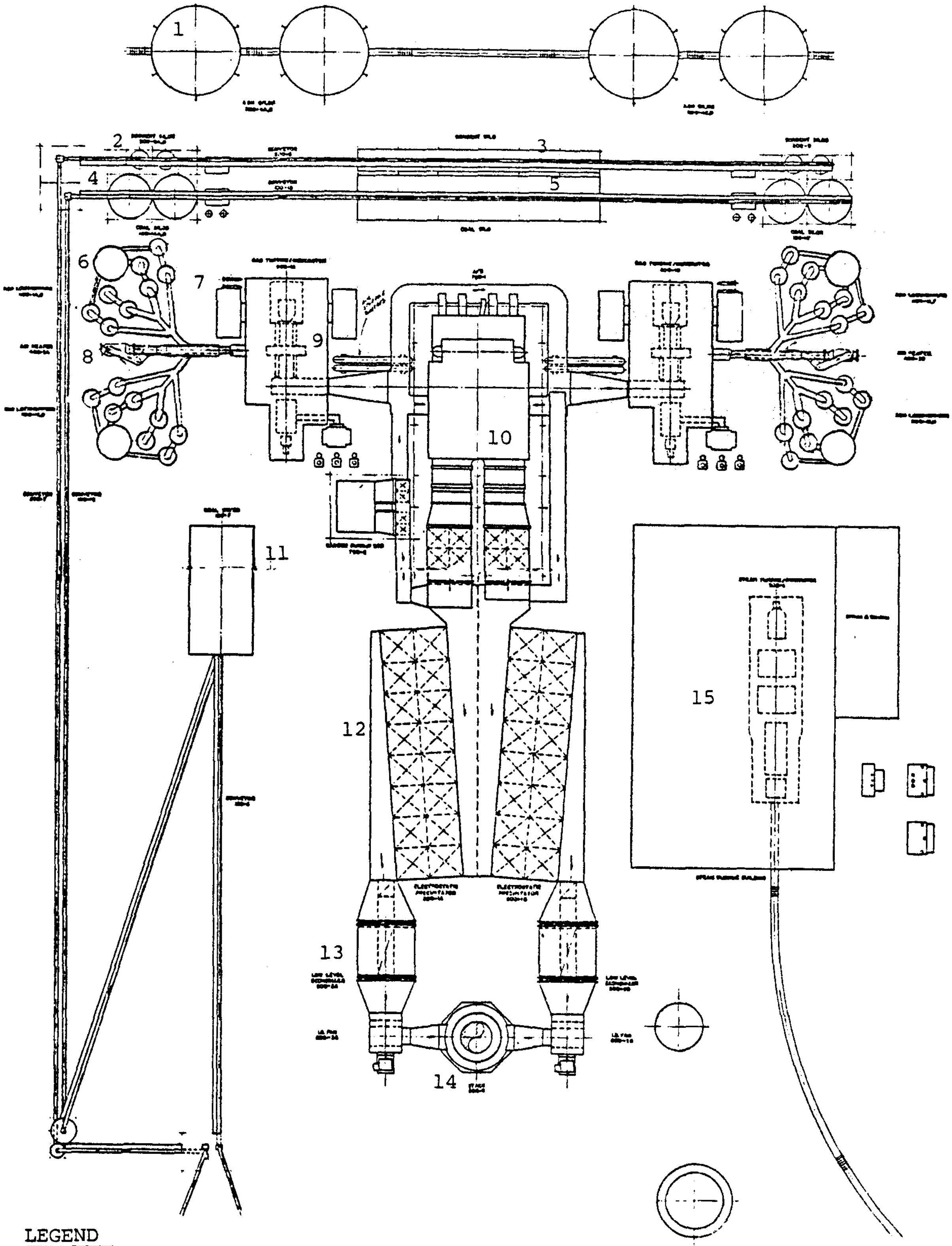
The PFB combustor design is based on the excess air flow concept which is shown schematically in Figure D-1. This concept uses 100% of the compressor discharge air flow for combustion and fluidization. No air cooled or steam cooled surface is immersed in the bed. Consequently, the fuel fired in the combustor is used only to heat the compressor discharge air to the required turbine inlet temperature.

The main advantage of the excess air flow concept is the absence of bed internals (such as heat exchanger tubes) which add weight and cost to the PFB combustor.

Manufacturing capabilities and shipping restrictions limited the diameter of the combustor vessel resulting in the use of two PFB combustors for each gas turbine. Each combustor is a refractory lined pressure vessel having an outside diameter of 23'6" and an overall length of 72 feet. The vessel is mounted in a vertical position and is supported by a support ring. The general arrangement of the vessel and its internals is shown in Figures D-4, D-5 and D-6. The vessel is refractory lined. Mechanical design considerations of the vessel shell, refractory lining, distributor plate, nozzles, coal and dolomite feed systems, lockhopper arrangement for solid material feeding, and spent bed material let down system are described in detail in Sections 4.3.1 and 4.3.6 of the Subtask 1.2 report.

4.4.2.1.2 Operating Parameters

The operating parameters, conditions and performance of PFB Combustors are shown in Table D-6.



LEGEND

1. Ash Silos
2. Dolomite Silos
3. Limestone Bunker
4. Coal Silos
5. Coal Bunker
6. Press.Fluid.Bed Comb.
7. Aerodyne 2-Stage Cyclones
8. Air Preheater
9. Gas Turbine/Gen.
10. Atmos.Flu.Bed Comb.
11. Coal Dryer
12. Electro.Static Precip.
13. Low Level Economizer
14. Stack
15. Steam Turb./Gen.

Plot Plan of
Excess Air-Cooled
PFB/AFB Plant

FIGURE: D-3

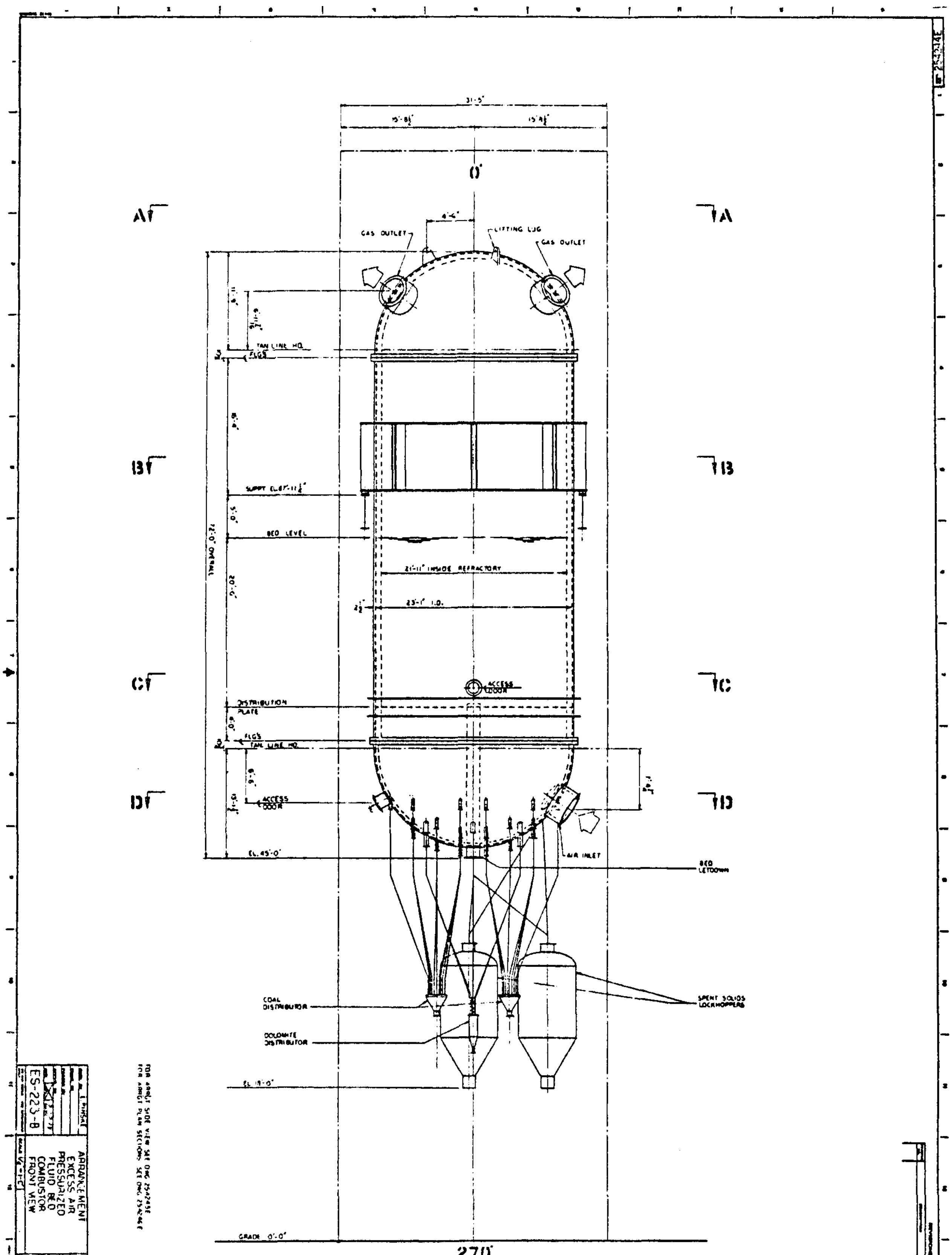
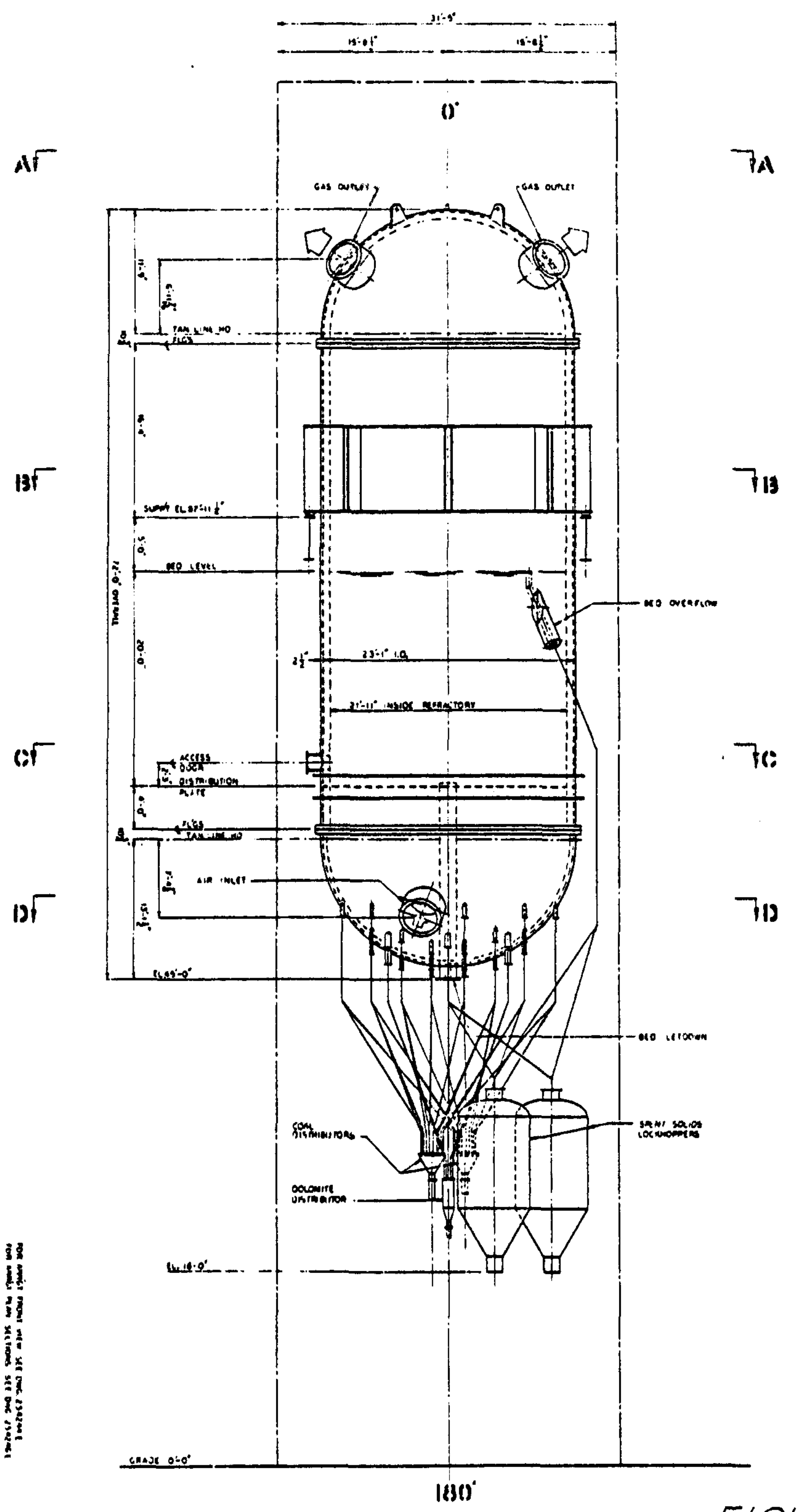

31'-5"
15'-8½"
15'-8½"
0°
A
B
C
D
4'-4"
GAS OUTLET
LIFTING LUG
GAS OUTLET
TAN LINE HD.
FLGS
SUPT ELEV 71'-11½"
BED LEVEL
21'-11" INSIDE REFRACTORY
23'-1" I.D.
72'-0" OVERALL
20'-0"
5'-0"
ACCESS DOOR
DISTRIBUTION PLATE
FLGS
TAN LINE HD.
6'-6"
ACCESS DOOR
EL 45'-0"
AIR INLET
BED LETDOWN
COAL DISTRIBUTOR
DOLOMITE DISTRIBUTOR
SPENT SOLIDS LOCKHOPPERS
EL 19'-0"
GRADE 0'-0"
270°
FOR ARRGT SIDE VIEW SEE DWG 254245E
FOR ARRGT PLAN SECTIONS SEE DWG 254246E
ARRANGEMENT
EXCESS AIR
PRESSURIZED
FLUID BED
COMBUSTOR
FRONT VIEW
ES-223-B
254244 E 0

FIGURE D-4



GAS OUTLET
GAS OUTLET
0°
A
B
C
D
31'-5"
15'-8½"
15'-8½"
TAN LINE HD
FLGS
SUPPT EL.87'-11⅛"
BED LEVEL
BED OVERFLOW
23'-1" I.D.
21'-11" INSIDE REFRACTORY
ACCESS DOOR
DISTRIBUTION PLATE
AIR INLET
EL.45'-0"
BED LETDOWN
COAL DISTRIBUTORS
DOLOMITE DISTRIBUTOR
SPENT SOLIDS LOCKHOPPERS
EL.18'-0"
GRADE 0'-0"
72'-0" OVERALL
16'-4"
5'-0"
20'-0"
4'-0"
11'-9"
13'-1½"
180°
ARRANGEMENT EXCESS AIR PRESSURIZED FLUID BED COMBUSTOR SIDE VIEW
ES-223-B
254245 E 0

FIGURE D-5

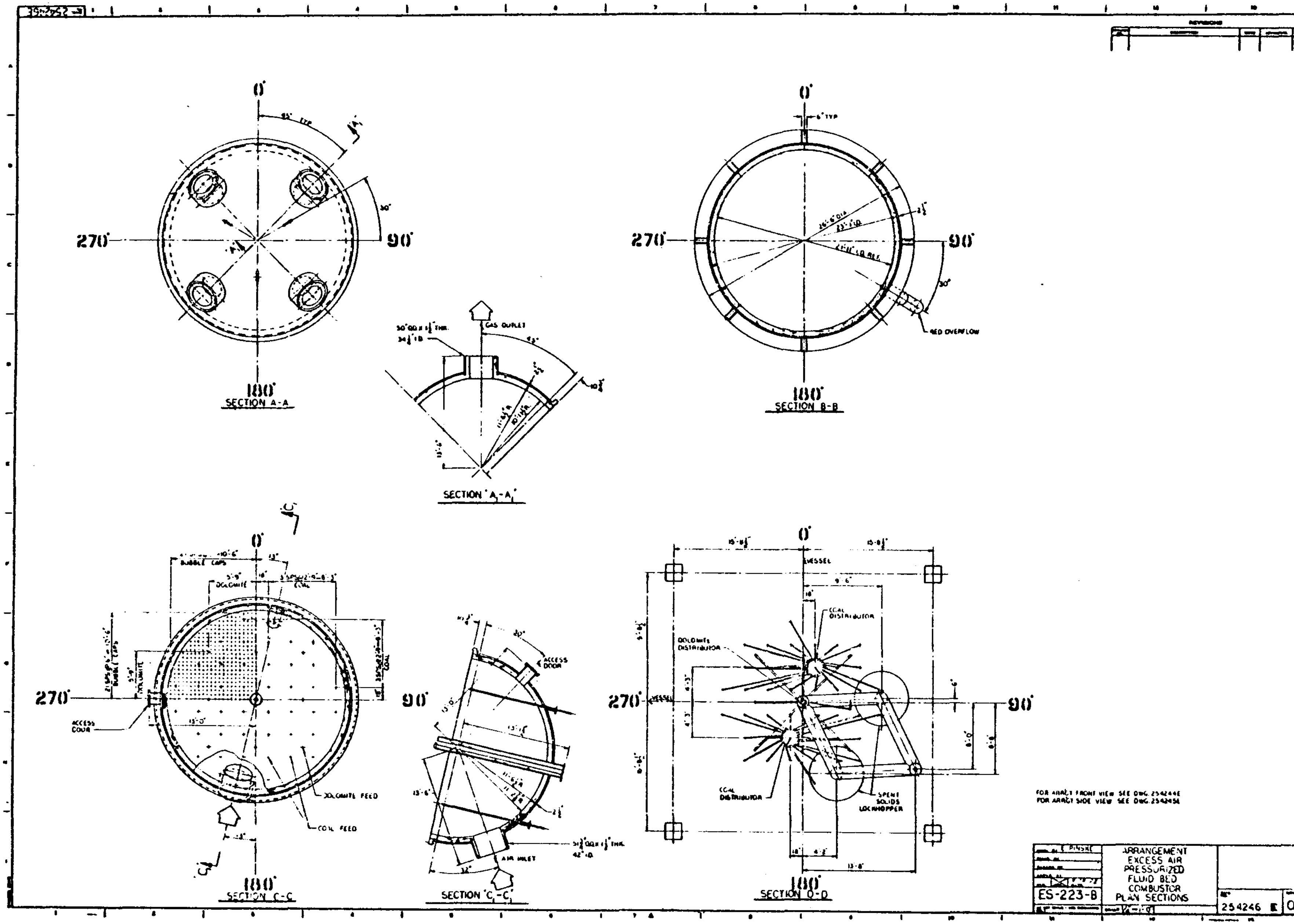

SECTION A-A
SECTION B-B
SECTION 'A₁-A₁'
SECTION C-C
SECTION 'C₁-C₁'
SECTION D-D
GAS OUTLET
BED OVERFLOW
ACCESS DOOR
DOLOMITE FEED
COAL FEED
AIR INLET
COAL DISTRIBUTOR
DOLOMITE DISTRIBUTOR
SPENT SOLIDS LOCKHOPPER
FOR ARR'GT FRONT VIEW SEE DWG 254244E
FOR ARR'GT SIDE VIEW SEE DWG 254245E
ARRANGEMENT EXCESS AIR PRESSURIZED FLUID BED COMBUSTOR PLAN SECTIONS
ES-223-B
254246 E 0

FIGURE D-6

TABLE D-6

PFB Operating Conditions and Performance at 100%

Gas Turbine Load

Coal Flow: 20.606 lbm/sec as fired

Dolomite Flow: 4.133 lbm/sec as fired

Coal Feed Size: -8 mesh

Dolomite Feed Size: -8 mesh

Ca/S = 1.0

Combustion efficiency = 99%

Superficial gas velocity = 6 ft/sec

Bed residence time = 3 sec

Bed voidage = .90

Bed depth = 20 ft.

Location	Air/Gas Flow Rate (lbm/sec)	Air/Gas Temperature $^{\circ}F$)	Air/Gas Pressure (psia)
PFB Combustor Inlet	811.00	595.	144.5
Bottom of Bed	811.00	595.	142.1
PFB Combustor Outlet	829.45	1650.	139.5
Gas Turbine Inlet	829.45	1650.	135.0*

All flow rates are based on two (2) PFB combustors operating in parallel and feeding a single gas turbine. The contribution of each combustor is half of the indicated flow rate.

*This pressure is based upon an assumed pressure drop of 0.5 psi in the piping between the combustor outlet and the gas turbine inlet.

Superficial Fluidizing Velocity: 3 to 6 ft/sec

One of the characteristics of the excess air cooling concept is a superficial fluidizing velocity that varies over the load range (see Section 4.4.3, PFB Combustor Operation, of this report. In order to provide stable operation of the bed and good fluidization over the load range it has been decided that the superficial fluidizing velocity should never be less than 3 ft/sec. Consequently, the PFB combustor was designed for a superficial fluidizing velocity of 3 ft/sec at no load and 6 ft/sec full load.

Coal and Stone Feed Sizing: Coal-8 mesh, Stone-8 mesh

The size of both the coal and stone feed that may be used is related to the superficial gas velocity. The constraints include both maximum size for fluidization and a size distribution to prevent excessive particle elutriation. The test velocity and solids feed sizes used by various researchers are as follows:

	Velocity	Coal Size	Stone Size
BCURA	2-1/2 fps	-12+65 mesh*	-12-65 mesh*
ANL	2-5 fps	-14 mesh	-14+80 mesh
EXXON	4-10 fps	-8 mesh	-6+16 mesh

* Second screen flooded, approximately 1/4 to 1/3 of feed - 65 mesh.

A stone feed size of -8 mesh is selected for use in the PFB combustor because it is felt that this stone size is small enough to provide satisfactory sulfur capture but large enough to prevent excessive particle elutriation.

A coal feed size of -8 mesh is used because fine coal particles have the potential of being carried out of the bed before combustion is completed. It is felt that this coal size would keep more coal particles in the bed thereby increasing combustion efficiency.

The rationale for selecting other parameters, e.g., bed operating temperature, combustion efficiency, sulfur capture, calcium to sulfur mole ratio, is given in pages 69 through 75 of the Subtask 1.2 report.

4.4.2.2 PFB Particulate Removal System

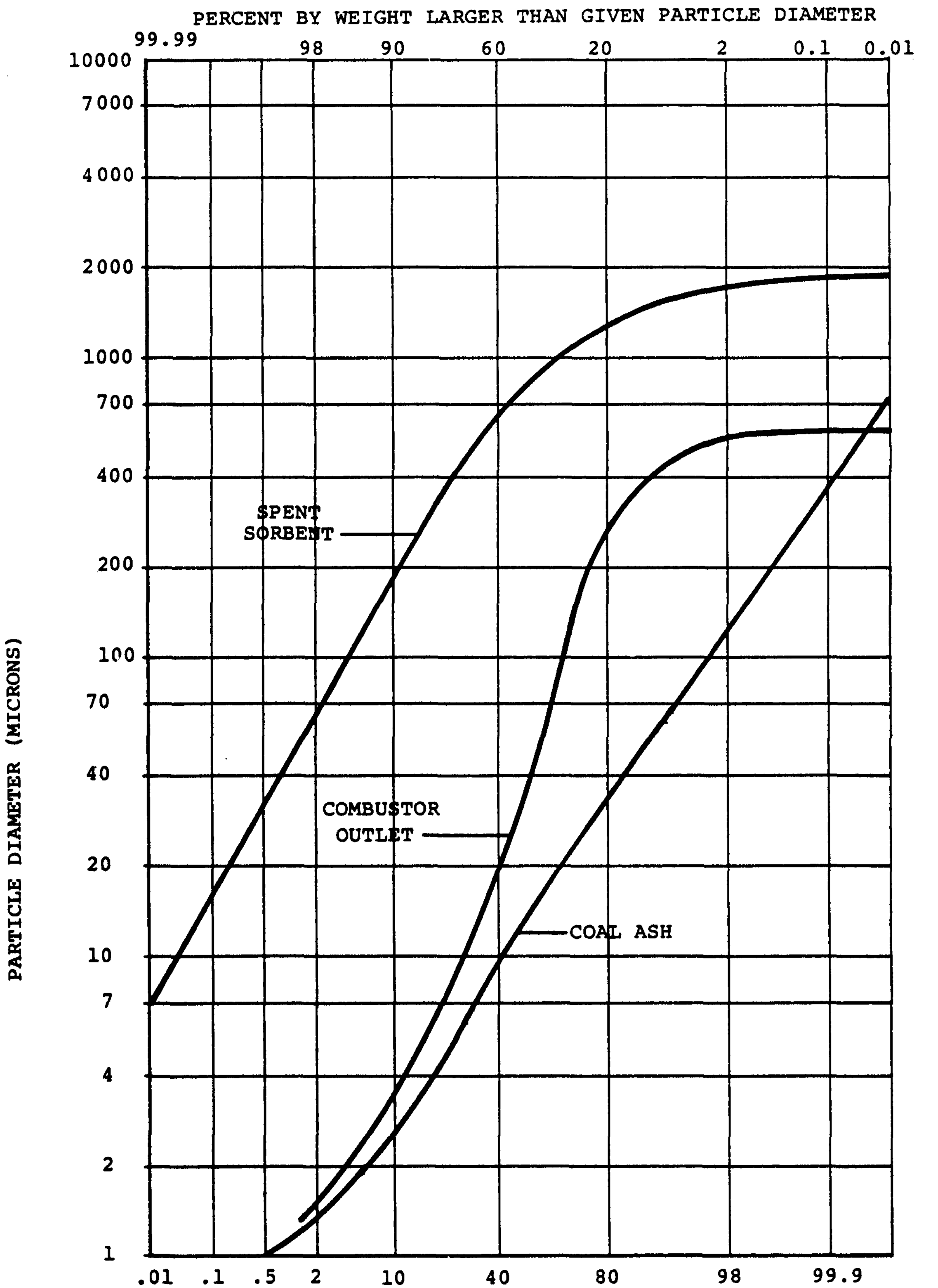
At present, empirical information regarding the particle size distribution of the solids elutriated from a PFB combustor is unavailable. Consequently, assumptions have been made in order to establish the size distribution of the particulates entering the gas cleanup equipment.

The size distribution of the sulfur sorbent elutriated from the bed is based on the size distribution of the stone fed to the bed. To account for abrasion and thermal decrepitation in the bed, a 20% reduction in size distribution has been assumed; the resulting size distribution is shown on Figure D-7. Terminal settling velocity analysis indicated that particles less than 570 micron size would be carried out of the PFB combustor. This results in an elutriation rate of 36% for the spent sorbent. It should be noted that based on these assumptions, less than 0.1% of the elutriated spent sorbent has a size of less than 10 microns.

The size distribution of the coal ash is assumed to be the same as the fly ash size distribution leaving a pulverized coal or stoker fired boiler (Figure D-7). This assumption signifies that essentially all the coal ash is elutriated from the bed with nearly 40% being less than 10 micron size.

The expected operating conditions of the particulate removal system are based on a Ca/S molar feed ratio of 1.0. These conditions are shown in Table D-7 with the corresponding size distribution entering the particulate removal equipment being shown in Figure D-7. Because of the assumptions for the size distribution of the spent sorbent, the dust in the less than 10 micron size range is essentially all coal ash.

As described in the Subtask 1.2 report, the performance requirements for the particulate removal system are based on the following estimated allowable dust loading entering the gas turbine:



PARTICLE SIZE DISTRIBUTION ENTERING THE GAS CLEANUP EQUIPMENT

FIGURE D-7

TABLE D-7

OPERATING CONDITIONS FOR Ca/S = 1.0

Collector Inlet Gas Analysis

Component	lbm/hr	moles/hr
O_2	516080.33	16127.51
N_2	2204108.36	78673.20
Ar	39414.60	986.59
SO_2	1014.43	15.84
CO_2	191262.78	4345.89
H_2O	34128.19	1894.33
Total	2986008.69	102043.36

Collector Inlet Gas Molecular Weight	29.262 lbm/mole
Collector Inlet Gas Temperature	1650°F
Collector Inlet Gas Pressure	141.0 psia
Collector Inlet Gas Density	.1823 lbm/ft^3
Collector Inlet Dust Flow	13806.3 lbm/hr

Collector Inlet Particle Size Distribution:

particle diameter (microns)	% by weight $\geq$ stated particle diameter
100	33.79
80	36.14
60	39.39
40	45.18
20	58.28
10	73.13
8	76.97
6	82.10
4	88.50
2	96.17

All flow rates are based on two (2) PFB combustors operating in parallel and feeding a single gas turbine. The contribution of each combustor is half of the indicated flow rate.

Particle diameter, d (microns)	Max. particulate concentration (grains/SCF)
$d<2.0$	no limit
$2.0\leq d\leq 10.0$	0.0100
$d>10.0$	0.0000

The location of the particulate removal equipment is shown schematically in Figure D-1. With the chosen concept for the PFB combustor, the particulate removal equipment must accommodate 100% of the total gas flow entering the gas turbine. Since the size and cost of this equipment is greatly influenced by the gas volume, the excess air design concept escalates the equipment cost.

It should however be noted that the required particulate removal efficiency is only a function of the solids flow from the bed (i.e., a function of fuel flow) and the permissible solids flow to the gas turbine and is not a function of the proportion of the total gas flow that must be cleaned up. The split flow air cooled cycle considered in Subtask 1.2 requires the same removal efficiency as the excess air cooled cycle but benefits from the smaller volume of gas to be cleaned.

On the basis of predicted performance, system cost and projected operating reliability, Aerodyne Development Corporation's "SV-FBC" Series Dust Collector has been selected for use in the conceptual plant design. The particular "SV-FBC" Dust Collector that would be used is the Model 22000 SV as shown in Figure N-3 (page 186) of Subtask 1.2. report.

The predicted collection efficiency is shown in Figure N-5 (page 188) of the same report. Calculations indicate that four sets of these collectors operating in parallel would be required for each PFB combustor. Each set would consist of two (2) Model 22000 Dust Collectors operating in series. The predicted performance is shown in Table D-8 for a Ca/S ratio of 1.0. The dust loading entering the gas turbine in the critical 2 to 10 micron size range is projected to be 1/3 of allowable level.

TABLE D-8

PARTICULATES REMOVED FOR Ca/S = 1.0

Dust flow entering the first collector = 13806.3 lbm/hr

	First Collector	Second Collector
Particulates removed in first stage (lbm/h)	11301.4	58.88
Particulates removed in second stage (lbm/h)	2098.16	229.21
Dust flow leaving the collector (lbm/h)	406.74	118.65

Dust concentration entering the turbine (grains/SCF) 0.02145

Particle distribution entering the turbine;

Particle diameter, d (Microns)	Particle concentration (Grains/SCF)
$d < 2.0$	0.01826
$2.0 \leq d \leq 10.0$	0.00319
$d > 10.0$	0.00000

All flow rates are based on two (2) PFB combustors operating in parallel and feeding a single gas turbine. The contribution of each combustor is half of the indicated flow rate.

4.4.3 OPERATION AND LOAD TURNDOWN

During normal full load operations, air discharged from the gas turbine compressor enters the bottom of the combustor vessel. All of this incoming air flows upward through bubble caps in the distributor plate and fluidizes the bed solids while at the same time supplying the oxygen needed for combustion. The smaller particulates (less than 570 microns) are elutriated from the top of the bed and flow out the top of the combustor along with the combustion gases. Four dirty gas streams exit the top of the combustor. Each stream flows through a set of two high efficiency centrifugal dust collectors operating in series. After the entrained particulates are removed, the resulting clean gas streams are combined and routed to a gas turbine. The larger particles which form the bed are removed from the combustor through an ash outlet nozzle located at an elevation corresponding to the top surface of the active bed. The complete spent bed material removal system is described in Section 4.3.8 of Subtask 1.2 report.

Part load operation of the gas turbine requires a reduction in the gas turbine inlet gas temperature. This is accomplished by varying the coal flow to the PFB combustor. During part load operation it is desired to maintain the same bed temperature as for full load operation. This keeps the operating temperature in the range needed for efficient sulfur capture and combustion and improves load response since the thermal storage of the bed material need not be changed to change load. In order to maintain a constant bed temperature, the combustion/fluidizing air flow must be reduced as the coal flow is reduced. This is accomplished by bypassing a portion of the compressor discharge air flow around the PFB combustor.

The cooler bypass air is mixed with the hot combustion gases leaving the gas cleanup equipment to achieve the required turbine inlet temperature. Since the compressor discharge air flow is nearly constant over the load range, it follows that the amount of discharge air that bypasses the combustor must increase as the load decreases.

Decreasing the fluidizing air flow in the combustor as the load is reduced results in a decrease in superficial gas velocity. Consequently, the combustor was designed for a superficial gas velocity of 6 ft/sec at full load and 3 ft/sec at no load in order to provide stable operation of the bed and good fluidization over the load range. The decrease in superficial gas velocity causes a decrease in bed voidage which results in a decrease in bed depth.

Since the collection efficiency of the high efficiency cyclones is a function of gas flow rate and velocity, the collection efficiency of the particulate removal system will decrease as the combustion air flow is decreased. This is prevented by sequentially shutting off dirty gas streams as the combustion air flow is decreased thereby maintaining a relatively constant gas flow through the remaining operating cyclones.

4.5 ECONOMICS

4.5.1 Capital Cost Estimates

4.5.1.1 General

The capital cost for the plant has been estimated by modifying the capital cost of the base PFB/AFB plant of Subtask 1.2 to reflect the differences of the two systems. Where the cost impact of a change is insignificant, the base cost has not been modified. The assumptions and methodology used in the estimating procedures are the same as described in pages 323 to 329 of the report on Subtask 1.2, Commercial Plant Design.

4.5.1.2 Cost Estimate of the PFB System

The cost of the PFB combustor has been developed from the design drawings. Material take-offs have been made and the cost of the Alloy 800H materials have been determined from quotations for the various sizes and shapes required. The costs of other materials have been estimated using standard B&W data. The labor and expense estimates have been obtained from the various shops that would be involved in the fabrication of the combustor.

The cost of the solids feed system is based on data developed for Subtask 1.2 with appropriate adjustments for size.

The cost of the dust collection system is based on vendor quotations for the primary removal system and B&W estimates for the ash let down system (hoppers, valves, etc.).

The erection estimates have been developed by the B&W Construction Company based on the various arrangement drawings and on the material weights calculated during the estimating processes.

4.5.1.3 Direct Capital Cost

Table D-9 shows the costs of only those items which are different from the Commercial Plant Design of Subtask 1.2, in thousands of mid-1977 dollars.

The data from Table D-9 has been utilized to prepare Table D-10, the direct Capital Cost estimate. The direct Capital Cost required for this plant is $240,023,000.

TABLE D-9

EXCESS AIR COOLED PFB SYSTEM

COST VARIATIONS IN THE AFFECTED ITEMS ONLY

FOR THE TOTAL PLANT

Acct. No.	Description	Reference Cost In Subtask 1.2	Cost in this Scheme	Variance
		In Thousands of Mid-1977 Dollars		
4.1	PFB Combustors	24,870	15,557	- 9,313
4.2	PFB Gas Cleaning Equip.	7,310	24,795	+17,485
4.4	Hot Gas Piping	3,923	9,536	+ 5,613
	TOTAL CHANGE IN A/C 4.0			+13,785
5.3	Coal & Dolomite Feed Systems to PFB Combustors	1,960	3,188	+ 1,228
	TOTAL CHANGE IN A/C 5.0			+ 1,228

TABLE D-10

DIRECT CAPITAL COST ESTIMATE

Main Acct.No.	Description	Material Cost	Installation Cost	Total Cost
		In Thousands of Mid-1977 Dollars		
1.0	Land & Land Rights	1,020		1,020
2.0	Structures & Improvements	6,709	6,991	13,700
3.0	Gas Turbines & Generators	18,112	2,120	20,232
4.0	PFB Combustor Systems	36,061	16,036	52,097
5.0	Coal and Sorbent Handling Systems	16,617	6,419	23,036
6.0	AFB Boiler Plant Equipment	40,285	22,748	63,033
7.0	Steam Turbine Generator Units	26,453	3,470	29,923
8.0	Accessory Electrical Equipment	12,361	9,997	22,358
9.0	Miscellaneous Power Plant Equipment	450	44	494
10.0	Instrumentation & Control Systems	5,022	1,108	6,130
11.0	Job Distributable Costs	3,955	4,045	8,000
	TOTAL	167,045	72,978	240,023

4.5.1.4 Plant Capital Cost Estimate

The plant capital cost comprises of direct capital cost, engineering and owner's cost, contingency and interest during construction. The plant capital cost is \$347,061,000 in Mid-1977 dollars, as shown on Table D-11. The specific capital cost is \$594/kW(net). These costs for the base PFB/AFB scheme are \$325,353,000 and \$567/kW(net), respectively.

TABLE D-11

PLANT CAPITAL COST SUMMARY

		$1,000's
1.	Direct Capital Cost	$240,023
2.	Engineering & Owner's Costs	24,002
3.	Contingency (10% of 1 + 2)	26,403
4.	Interest During Construction (8% Rate; 5 yrs; 19.5% of 1 + 2 + 3)	56,633
	Total Project Capital Cost	$347,061

Specific Capital Cost = $594/kW(net)

4.5.2 Annual Cost

The annual cost for running the Excess Air Cooled PFB/AFB plant consists of the following items:

a. Fixed charge for the Capital Cost - this is assumed to be 18% of the Capital Cost, consistent with the assumption for the base PFB/AFB plant.

b. Cost of Coal - $25,974,000 per year @ $20.00/ton and 65% capacity factor.

c. Cost of Sorbent - $2,024,000 per year @ $7.00/ton and 65% capacity factor.

d. Manpower cost - Manpower need is assumed to be the same as for the base scheme. So a total of 108 man-years at a total annual cost $2,562,300 is needed.

e. Other Material - this cost is also assumed to remain same as for the base case.

f. Machinery Amortization and Replacement Parts - This cost does not change from the base case.

g. Utilities - Cost is same as for the base scheme.

h. Spent Sorbent & Ash Disposal Cost - Ash and spent sorbent are collected at the rate of 137,000 lbs/h at full load. The disposal cost is $1,170,000 per year @ $3/ton and 65% capacity factor.

The annual cost is estimated to be $97,249,000, as shown on Table D-12.

4.5.3 Cost of Electricity

The total energy generated in a year is 3,326 x 10^6 kWh, at 65% capacity factor. So the cost of generated electricity is 29.24 mills/kWh. In the base scheme, the cost of electricity is 28.47 mills/kWh. Cost contribution of each of the previously discussed items is shown in Table D-13.

TABLE D-12

ANNUAL COST SUMMARY

Items	Thousands of Dollars
1. Fixed charge (@ 18%)	$62,471
2. Coal	25,974
3. Sorbent	2,024
4. Man Power Cost	2,562
5. Other Material	1,932
6. Machinery Amortization and Replacement Parts	1,075
7. Utilities	41
8. Spent Sorbent & Ash Disposal	1,170
TOTAL	$97,249

TABLE D-13

COST OF ELECTRICITY

AT 65% CAPACITY FACTOR

Items	Cost in Mills/kWh		Per Cent of Total Cost	
Fixed charge @ 18%		18.78		64.24
Fuel - Coal		7.81		26.72
Operations & Maintenance Costs				
Sorbent	0.61		2.08	
Spent Sorbent & Ash Disposal	0.35		1.20	
Manpower	0.78		2.63	
Other Material	0.58		1.99	
Machinery & Equipment	0.32		1.10	
Utilities	0.01		0.04	
		2.65		9.04
TOTAL		29.24		100.00

Total Energy Output at 65%

Capacity Factor = 3,326 x 10^6 kWh

Cost of Electricity generated = 29.24 mills/kWh

4.6 DISCUSSION

The prime advantage of the excess air cooled concept as compared to the split flow air cooled concept is the elimination of the bed cooling system. Aside from the significant cost of the cooling system, the elimination of the cooling system greatly decreases the uncertainties of the PFB combustor. There is currently inadequate data to evaluate corrosion potential for in-bed heat transfer tube materials. In addition, despite the detailed mechanical design analysis of the cooling system done in Subtask 1.2, there are areas in the design that are questionable, e.g., the ability to accommodate the differential thermal expansion that is anticipated, especially if cycling operation is to be the mode of plant operation. The excess air cooled concept would appear to offer the potential for greater reliability of the PFB combustor due to its simplicity.

Pressure drop consideration in the bed cooling system is one of the important design constraints for the split flow air cooled PFB. With this cooling system eliminated, the excess air cooled concept offers a great deal more latitude for design optimization. An important factor not yet available for this optimization process is the relationship between gas residence time in the bed (i.e. bed depth divided by superficial velocity) and combustion efficiency and sorbent utilization. With this data, the velocity and bed depth could be varied to study the effect on both equipment cost and cycle performance (i.e. effect of PFB system pressure drop). For instance, doubling the superficial velocity to 12 fps could result in the use of only one PFB combustor per gas turbine.

The disadvantage of this concept comes from the fact that all the compressor discharge air pass through the bed and hence must pass through the particulate removal system. Since the only means of varying the bed turndown is by bypassing a portion of the air around the bed so as to maintain a constant coal/air ratio to the bed, the gas flow to the particulate removal system will change with load. The performance of mechanical separators such as the Aerodyne cyclone however are affected by the gas flow rate. In order to maintain collection efficiency in an acceptable range, several parallel collectors are required with the ability to alter the number of collectors in service to maintain the flow per collector in an acceptable range.

This concept therefore required a significant increase in the size of the particulate collection system as well as provision in that system to maintain acceptable collection efficiency over the system load range. The cost of this larger particulate removal system is greater than the cost savings associated with the elimination of the bed cooling system.

The overall project cost goes up because of higher costs for hot gas clean up systems and hot gas piping. But the cost of electricity increases by only 0.77 mills/kWh (2.7%) from the cost of electricity in the base PFB/AFB scheme.

This scheme has all the advantages of the base PFB/AFB scheme. It deserves consideration as a viable combined cycle power plant if a reliable and cost-effective method of hot gas clean up is found and the development of a high temperature corrosion/erosion resistant in-bed material eludes the research community. The flexibility it affords in design optimization may permit a reduction in cost so that this scheme becomes more competitive, if not cheaper.

5.0 DEVOLATILIZER - PFB SCHEME

5.1 INTRODUCTION

The PFB/Devolatilizer scheme is the most novel of the alternate approaches examined in the Subtask 1.7. The heart of the conceptual design is the interdependency of two fluidized bed processes - the devolatilization of coal and the combustion of devolatilized coal at pressure.

The devolatilization process is based on the principle, that coal heated in temperature range of 1500 to 1700° will release volatile matter from the parent coal. The volatile matter is composed primarily of methane and ethylene, and small amounts of aromatic compounds and tars (Ref. 1). The calcium in the dolomite is utilized in the devolatilization process to capture the sulfur released with the volatile matter and form calcium sulfide; under similar conditions 96% of the sulfur has been demonstrated to be captured (Ref. 2). Based on the ASTM Standard testing procedure for the prediction of the volatile matter in the coal, it is assumed that 100% of the volatile matter reported in the proximate analysis will be released. The design of the Devolatilizer is based primarily on information reported by Westinghouse Electric Corp. (Ref. 3).

The devolatilizer gas is a low Btu coal gas which is further combusted to achieve higher gas turbine inlet temperature than can be attained by direct fluidized bed combustion of coal.

The char leaving the devolatilizer is combusted in a split-flow air cooled PFB combustor. The temperature of the fluidized bed combustor is maintained at 1650°F by cooling tubes carrying air. Some of the flue gas produced in this combustor is then used to devolatilize coal in the devolatilizer. The cooling air from this combustor is used to burn the devolatilizer gas to produce high temperature gas for expansion in the gas turbine. In the oxidizing condition of the char combustor, calcium sulfide (produced in the devolatilizer) converts to calcium sulfate. The increased turbine inlet temperature provides a potential for reducing the system cost by increasing specific power and increasing the system efficiency.

5.2 DESCRIPTION OF CYCLE

The process flow schematic diagram Figure E-1, shows the interrelationship of the devolatilizer and PFB Combustor in this scheme. A part of the compressed air from a gas turbine provides the oxygen for combustion of char in the PFB combustor. The rest of the compressor air is routed through bed cooling tubes to maintain fluidized bed temperature at 1650F. A part of the flue gas from the PFB combustor is used to devolatilize the raw coal in the devolatilizer. The low Btu devolatilizer gas is mixed with the rest of the PFB flue gas and finally burned in a gas/air combustor (GAC) using the hot clean air from the cooling tubes of the PFB combustor.

For the system studied in Subtask 1.7 the gas temperature entering the turbine would be approximately 2178°F, much higher than for other PFB systems studied during this program. A more highly-cooled turbine

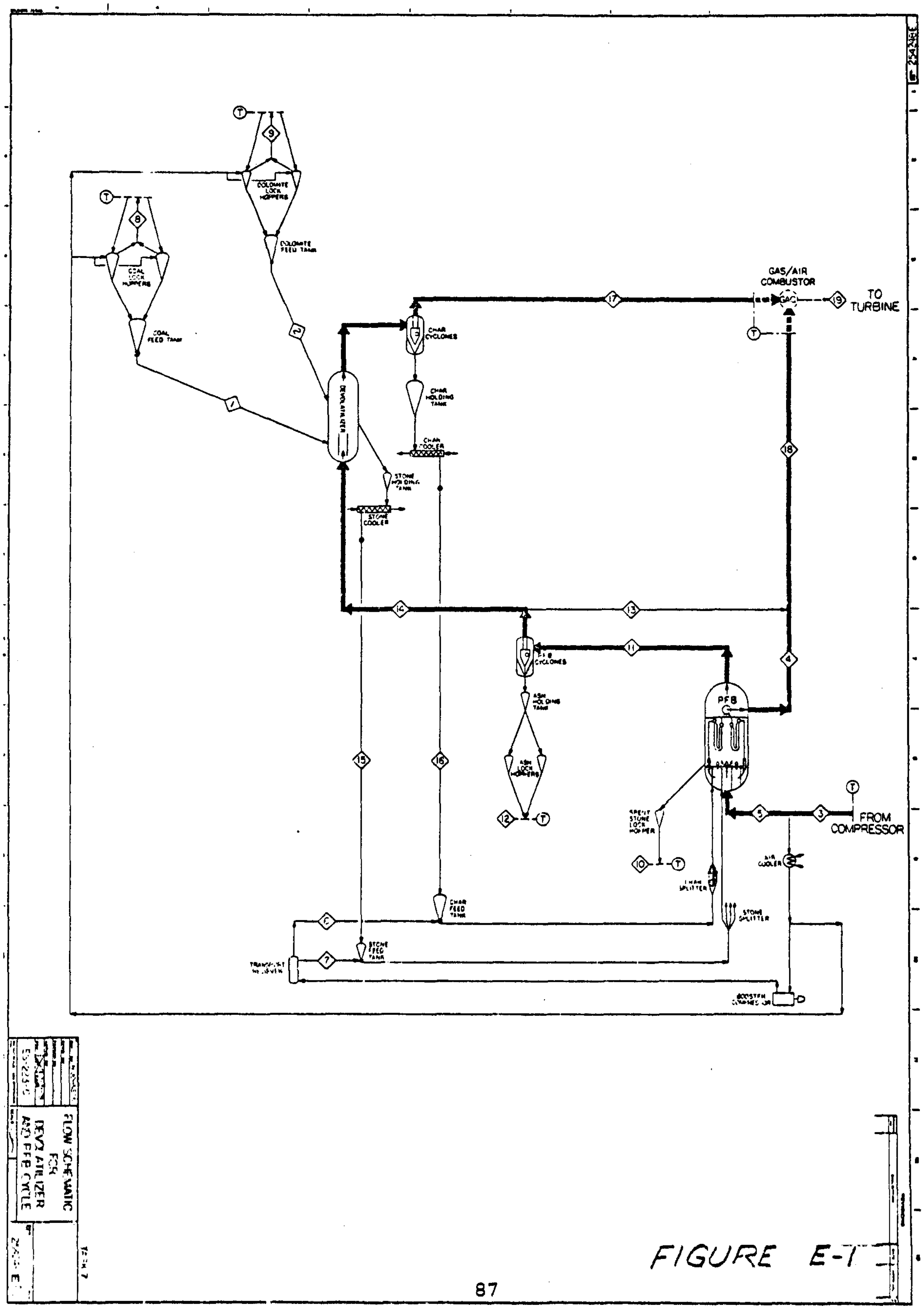

GAS/AIR COMBUSTOR
TO TURBINE
FROM COMPRESSOR
PFB
CHAR CYCLONES
DEVOLATILIZER
STONE COOLER
CHAR COOLER
AIR COOLER
FLOW SCHEMATIC FOR DEVOLATILIZER AND PFB CYCLE

FIGURE E-1

DEVOLATILIZER/PFB POWER PLANT CONFIGURATION

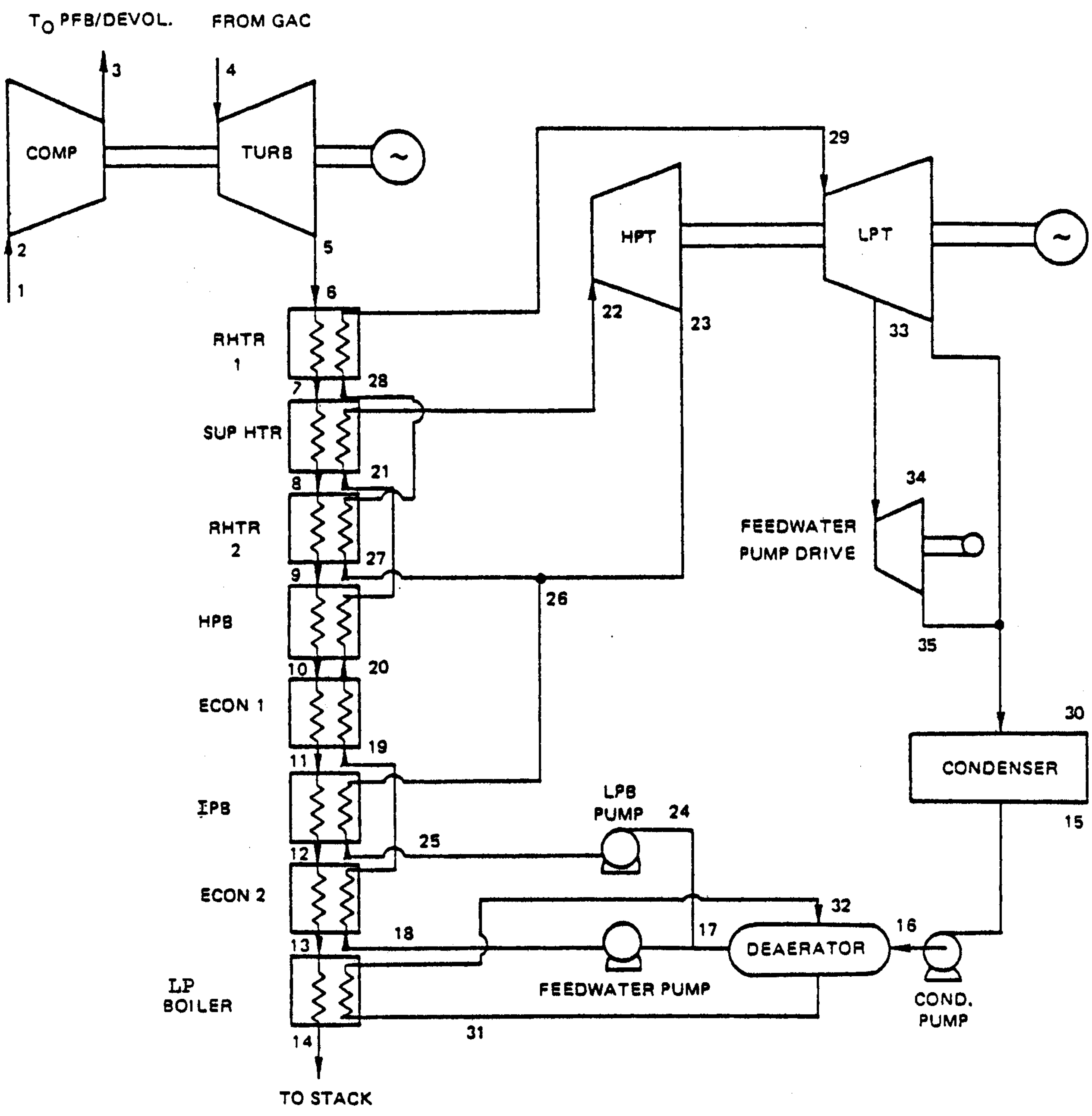


FIGURE E-2

(21.6 percent cooling air) is required in this system than in the previous systems to expand the gases and generate power.

The exhaust flow from the turbine is approximately 1135°F, so supplementary firing is not required to generate steam for a high efficiency steam bottoming cycle. A 2400 psig/950°F/950°F steam cycle is used. for this system.

Figure E-2 presents a schematic diagram of the devolatilizer/PFB power plant configuration.

5.3 PERFORMANCE

The performance of the PFB/devolatilizer is based on very limited study of the important parameters. Subsequent study could result in considerable improvement in performance. The most critical area, however, is the mechanical concept to accomplish devolatilization (or partial gasification) of the coal, and to handle the offgas and the hot char in a practical, but efficient manner.

Tables E-1 and E-2 present heat and mass balances for the air/gas and steam subsystems, respectively.

After making the computer calculations, adjustments have been made to the calculated coal flow to account for radiation heat losses from hot gas piping and "unaccounted for" losses as explained in Table E-3. For a nominal 600 MW plant, four trains of gas turbines, PFB/devolatilizers, and waste heat recovery systems, plus one steam turbine are used.

Each gas turbine in the system would generate 79.1 MW and would provide enough exhaust gas sensible heat to generate steam to produce an additional 68.7 MW for a total of 147.8MW gross power. The corresponding gross plant efficiency is 43.14 percent.

The total gross power for the plant is estimated to be 591.2 MW. The auxiliary power requirement is 13.9 MW, leaving 577.3 MW for net saleable power. Using the adjusted coal flow rate, the net plant efficiency is 40.88%. The performance estimates are shown in Table E-4. For comparison, the net efficiency of the split flow air cooled PFB/AFB scheme of Subtask 1.2 is 37.9%

TABLE E-1

Devolatilizer/PFB Configuration

Heat & Mass Balance for Air/Gas System

Station No.	Description	W,(1) lb/sec	T, F	P, Psia	h, Btu/lb
1	Inlet	840.0	59.0	14.7	124.0
2	Compressor Inlet	840.0	59.0	14.55	124.0
3	Compressor Exit	658.7	595.5	145.5	254.8
4	Turbine Inlet	682.0	2178.0	124.7	712.5
5	Turbine Exit	850.9	1135.2	15.8	403.9
6	Reheater 1 Inlet	850.9	1132.2	15.8	403.1
7	Superheater Inlet	850.9	1090.0	15.8	391.4
8	Reheater 2 Inlet	850.9	944.2	15.8	351.6
9	HPB Inlet	850.9	879.8	15.8	334.2
10	Econ 1 Inlet	850.9	704.0	15.8	287.6
11	LPB Inlet	850.9	591.2	15.8	258.2
12	Econ 2 Inlet	850.9	508.3	15.8	236.9
13	Deaerator Boiler Inlet	850.9	408.0	15.8	211.5
14	Stack	850.9	324.7	14.8	190.6

(1) For one gas turbine system only. For the total plant multiply the figures by four.

TABLE E-2

Devolatilizer/PFB Configuration

Heat & Mass Balance for Steam System

Station No.	Description	W, (1) lb/sec	T, F	P, Psia	h, Btu/lb
15	Condensate Pump Inlet	118.8	101.1	.982	69.1
16	Deaerator Inlet	118.8	101.1	35.0	69.2
17	Deaerator Exit	118.8	250.0	30.0	218.9
18	Econ 2 Inlet	100.4	254.7	2765.0	229.4
19	Econ 1 Inlet	100.4	463.0	2765.0	445.0
20	HPB Inlet	100.4	649.0	2665.0	693.8
21	Superheater Inlet	100.4	669.0	2515.0	1089.1
22	HPT Inlet	100.4	950.0	2415.0	1426.6
23	HPT Exit	100.4	612.2	584.0	1299.9
24	IPB Pump Inlet	18.4	250.0	30.0	218.9
25	IPB Inlet	18.4	250.9	609.0	221.1
26	IPB Exit	18.4	483.3	584.0	1203.2
27	Reheater 2 Inlet	118.8	589.2	584.0	1284.9
28	Reheater 1 Inlet	118.8	800.0	584.0	1409.2
29	IPT Inlet	118.8	950.0	525.6	1492.8
30	Condenser Inlet	118.8	101.1	.982	1033.8
31	LP Boiler Inlet	18.8	250.0	35.0	218.9
32	LP Boiler Exit	18.8	250.0	30.0	1163.3
33	LPT Extraction	3.61	697.9	175.0	1374.7
34	Feedwater Pump Drive Inlet	3.61	697.9	166.3	1374.7
35	Feedwater Pump Drive Exit	3.61	108.7	.982	1083.1

(1) For one gas turbine system only. Multiply by four for full plant.

TABLE E-3

ADJUSTMENTS TO COAL FLOW

After the computer calculations were made, adjustments were made to the coal flow to account for the following:

A.	Radiation loss in hot gas piping	23.7×10^6 Btu/h
B.	Manufacturer's margin and unaccounted for losses for combustors	46.77×10^6 Btu/h
	Total Heat Loss	70.47×10^6 Btu/h

The following adjustment to coal flow has been made:

Power Output	Adjustment to Coal Flow (as received) in lbs/sec
100%	+1.73

Total Adjusted Coal (as received)

Flow Rate = 114.97 + 1.73 lb/sec
= 116.7 lb/sec

TABLE E-4

PERFORMANCE ESTIMATES

Devolatilizer/PFB Configuration

	For Total Plant
Gas Turbine Power, MW	316.4
Steam Turbine Power, MW	274.8
Total Gross Power, MW	591.2
Power for Auxiliaries, MW	13.9
Total Net Power, MW.	577.3
Gross Efficiency, % (1)	43.14
Net Efficiency, % (2)	40.88
Coal Rate (As Fired), lb/sec	104.33
Coal Rate (As Received), lb/sec	114.97
Adjusted Coal Rate (As Received) lb/sec (3)	116.7

(1) Based on 'as fired' coal rate (HHV - 12453 Btu/lb) and gross total power output.

(2) Based on 'as received' adjusted coal rate (HHV - 11472 Btu/lb) and net Power.

(3) See Table E-3.

5.4 PLANT DESCRIPTION

5.4.1 Process Description (see Figure E-1)

Crushed Illinois No. 6 coal (-8 mesh + 0) is introduced into two cycling lock hoppers where it is pressurized to 122 psig. In order to insure constant flow from the cycling lock hoppers the coal drops into a coal feed tank which has sufficient holding capacity. Because the pressurized coal is gravity fed to the devolatilizer, a rotary feeder valve is located underneath the feed tank to control the coal feed rate.

Crushed dolomite (-1/16" + 0) is pressurized and fed to the devolatilizer in an identical fashion.

The devolatilizer is a unique device, where coal, dolomite, and flue gas come together and react to form an essentially sulfur-free combustible gas at 1500°F. Coal is fed into the draft tube located in the lower portion of the devolatilizer. The draft tube permits the dilution of unreacted coal with high concentration of reacted material. This concept makes it possible to operate the devolatilizer with caking coals, such as Illinois No. 6. PFB flue gas is also introduced into the draft tube at a velocity of 20 feet per second as compared to 3 feet per second in the upper portion of the devolatilizer.

The volatile gases from the Devolatilizer, containing all of the char and some of the stone, flow through the cyclone separators where the char and the stone are collected. Char then falls into the char holding tanks and lines before descending into the char coolers. The char enters the screw coolers at 1500°F and exits at 500°F; the char passes through a rotary feeder that controls the char feed rate to the cooler. The char flows by gravity to the char feed tank.

Most of the stone from the devolatilizer is drawn off from the fluidized bed at an intermediate point. The stone is handled and cooled, just as the collected char. It is necessary to cool the solid materials so that they can safely be pneumatically conveyed and distributed to the PFB.

Air at 600°F and 132 psig from the compressor is used for combustion air in the PFB and cooling air for the PFB. A small side stream is taken from the compressed air stream and cooled in an air cooler to 125°F. A part of the air from the air cooler is used for pressurizing the coal and dolomite lock hoppers; the rest of the air from the air cooler passes through a booster compressor which raises the pressure to 140 psig and 150°F. The air from the booster compressor goes to the transport receiver.

The char from the char feed tanks and lines flow by gravity into rotary valves where air from the transport receiver transports the char to the char splitter for distribution to the PFB. The stone from the stone feed tank is distributed to the PFB by a similar method.

The carbon in the char and the calcium sulfide in the stone are completely combusted with 115% stoichiometric air to carbon dioxide and calcium sulfate in the PFB combustor. The temperature in the fluidized bed is maintained at 1650°F by an air cooling circuit. Air from the compressors enters the air cooling circuit of the PFB at 600°F and exits at 1575°F. Most of the spent stone from the PFB flows by gravity to the spent stone lock hoppers. The PFB flue gas enters the PFB cyclones where all of the ash and some of the stone is collected and deposited into ash holding tanks and lines and flows by gravity into the ash lock hoppers and lock lines.

The clean flue gas containing 2.7% oxygen from the PFB cyclones is split into two streams; slightly more than half flows to the devolatilizer where a small amount of oxidation takes place to provide heat for devolatilization. The remaining flue gas from the PFB is mixed with the PFB cooling air which is used for burning the volatile gases from the devolatilizer in gas/air combustor.

The temperature of gas entering the gas turbine can be increased by having both steam and air cooling of the PFB Combustor. Because of steam cooling, more coal is devolatilized and burnt in the combustor. The additional volatile gases permit higher gas turbine inlet temperature to be achieved. The figure in Appendix 9.2 shows gas turbine inlet temperature variation with percentage air cooled. In this conceptual study, the PFB Combustor is 100% air cooled and the gas turbine inlet temperature is approximately 2178F. Appendix 9.2 also contains mass balances for three conditions:

a) 100% Air Cooled PFB Combustor

b) 60% Air Cooled PFB Combustor

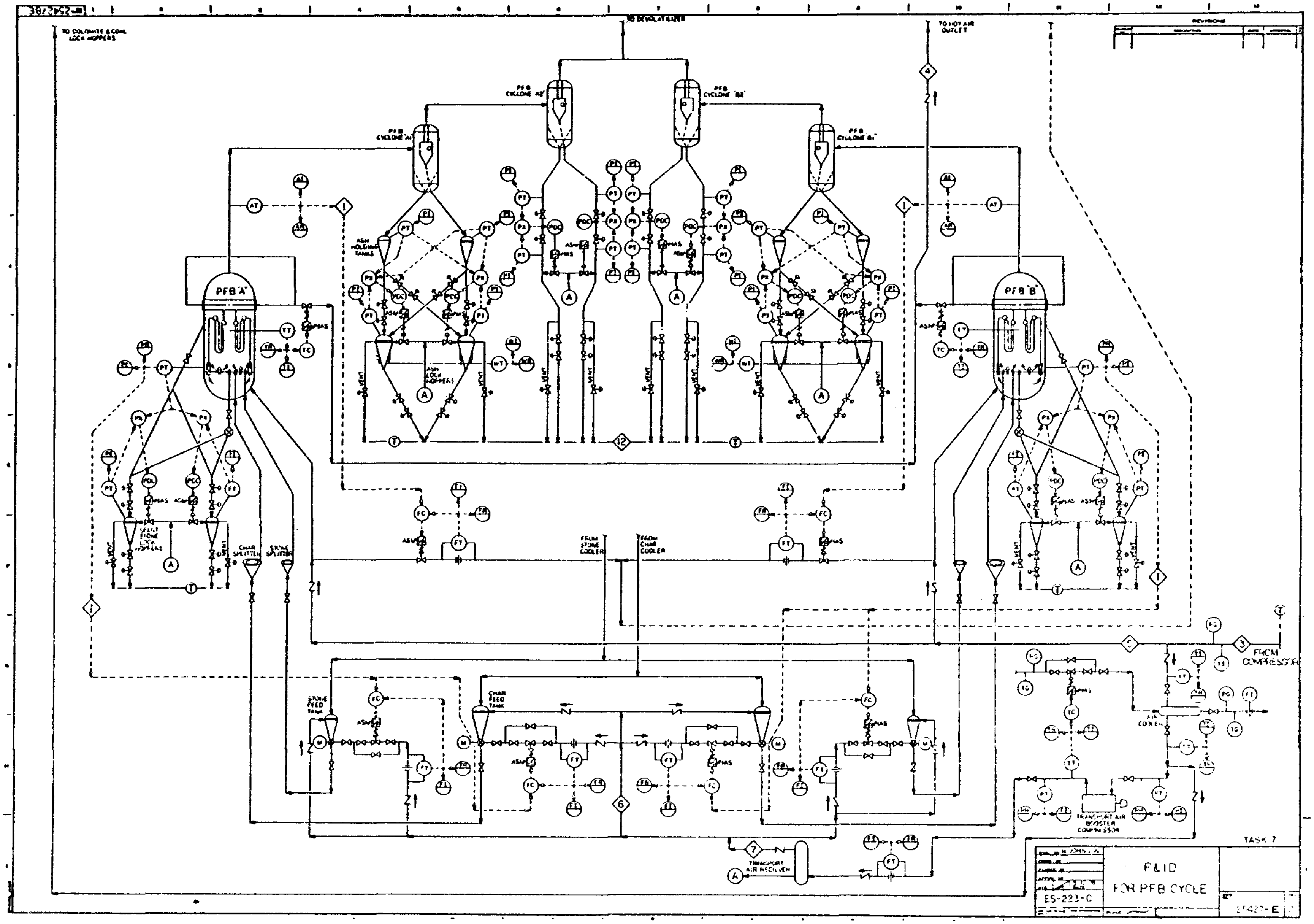
c) 20% Air Cooled PFB Combustor

5.4.2 Control System Description (See Figures E-3 and E-4)

Temperature transmitters, with control room panel indicators and recorders, monitor the compressed air temperature in and out of the air cooler. A temperature transmitter, after the booster compressor, signals the temperature control which controls the flow of cooling water to the air cooler; this temperature transmitter also signals the control room panel indicator and recorder. Local pressure and temperature gauges are available for monitoring the cooling water in and out of the air cooler; also, on the cooling water from the air cooler is a local flow indicator.

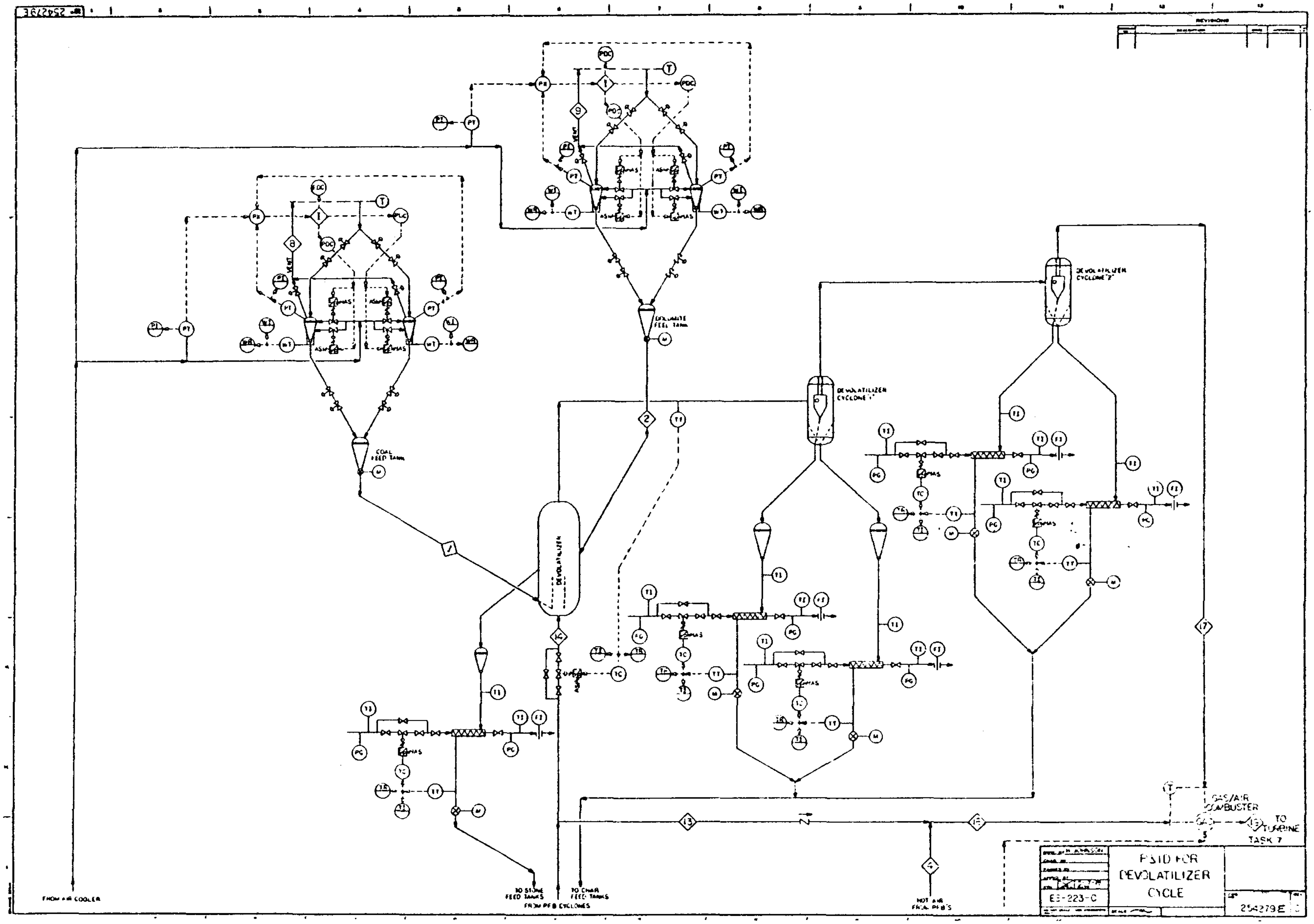
Pressure transmitters with control room panel indicators and recorders before and after the booster compressor, and a flow transmitter with panel board indication and recording of the air flow from the booster compressor, permit monitoring of the booster compressor performance.

The char and stone feed tank pressure is maintained by a line from the transporting air with an in-line check valve. Constant air flow



TO DOLOMITE & COAL LOCK HOPPERS
TO DEVOLATILIZER
TO HOT AIR OUTLET
PFB "A"
PFB "B"
ASH LOCK HOPPERS
FROM STONE COOLER
FROM CHAR COOLER
STONE FEED TANK
CHAR FEED TANK
FROM COMPRESSOR
TRANSPORT AIR RECEIVER
TRANSPORT AIR BOOSTER COMPRESSOR
TASK 7
P&ID FOR PFB CYCLE
ES-223-C

FIGURE: E-3



P&ID FOR
DEVOLATILIZER
CYCLE
E3-223-C
254279E
DEVOLATILIZER
DEVOLATILIZER CYCLONE "1"
DEVOLATILIZER CYCLONE "2"
COAL FEED TANK
DOLOMITE FEED TANK
VENT
FROM AIR COOLER
TO STONE FEED TANKS
TO CHAR FEED TANKS
FROM PFB CYCLONES
HOT AIR FROM PFB'S
GAS/AIR COMBUSTER
TO TURBINE
TASK 7

FIGURE: E-4

to the "air-swept" feeder valve is maintained by a flow control valve. The set point for the flow control valve is influenced by transport system pressure, otherwise the flow transmitter preceding the valve signals the flow controller to maintain constant volume flow.

The "air-swept" feeder valve speed can be modulated to control solids flow rate.

The char splitter distributes the coal to twenty-four points. Likewise, the stone splitter distributes the stone to four feed points, in each PFB combustor.

The PFB cooling air and combustion air are introduced through the same line in the bottom head of the PFB combustor. The cooling air controls the bed temperature to 1650°F. Each PFB cooling air circuit outlet temperature is maintained at 1575°F by a temperature transmitter that signals a temperature control which controls a temperature control valve; the temperature transmitter also signals a temperature indicator and recorder on the control room panel board.

The PFB flue gas outlet contains approximately 2.7% oxygen, this corresponds to approximately 15% excess combustion air in the PFB; this is maintained by an oxygen analyzer transmitter in each PFB flue gas outlet which signals the by-pass air flow control and a panel board composition indicator and recorder.

The by-pass air can be controlled during start-up or turn-down independently of the oxygen analyzer.

The particles carried over from the PFB to the PFB cyclones are disposed of through a depressurizing lock system. Two knife-gate valves before and after each lock hopper and each lock line are remotely operated to permit the passage of solid to and from the lock hoppers and lock lines. All of the lock hoppers and lock lines are equipped with weight transmitters with control room panel indicators for filling and recorders for monitoring solids flow rate over a period of time. Pressure transmitters on the pressurizing lines and lock hoppers and lock lines, give panel board pressure indication and signal the pressure comparators and the differential pressure control valves to control the rate of pressurization. Vent lines, with remote operated control valves, depressurize the lock hoppers and lock lines.

The operating cycle for the lock hoppers and lock lines consist of four steps: pressurizing, filling, venting and dumping. These procedures and their time cycles are the same as described in the pages 172 to 176 of the Report on Subtask 1.2.

The devolatilizer temperature is maintained at 1500°F by a temperature transmitter on the devolatilizer outlet. The temperature transmitter signals the panel board temperature indicator and recorder, and a temperature control which controls the temperature control valve on the flue gas line to the devolatilizer. By directly controlling the gas flow to the devolatilizer inlet the remaining flue gas is by-passed to the gas-air combustor.

The solid carry-over from the devolatilizer (which consists of all the char and some of the stone) is collected in cyclones and deposited in holding tanks and holding lines before descending into the screw coolers. The flow rate of solids through the coolers is controlled by a rotary feeder valve after the cooler.

The stone in the devolatilizer bed is drained off at a continuous rate to a holding tank which feeds a screw cooler followed by a rotary feeder valve to control the stone flow rate.

The solids enter the cooler at 1500°F and exit at 500°F, this is accomplished by a temperature control valve on the cooling water flow-rate. The temperature control receives a signal from the temperature transmitter located at the solid exit from the cooler; the temperature transmitter also signals the panel board temperature indicator and recorder. There are local temperature indicators and pressure gauges on all flow streams to and from the coolers.

The system is presently designed for a full load condition. It is recognized that there are many problems in turn-down that must be resolved.

For startup, the coal and dolomite feed tanks can feed the char and stone feed tanks through direct lines that by-pass the devolalitization step.

5.4.3 Major Equipment & Systems

Figures E-5 and E-6 show the arrangement of devolatilizer, PFB combustor and associated systems for one train of the four trains in the plant. Figure E-7 shows a schematic diagram of the plant. The devolatilizer, PFB combustor, the feed system and lock hopper module for one train as shown in Figures E-5 and E-6 requires an approximate area of 96 ft. by 130 ft. The system requires an approximate height of 167 ft. to the bottom of coal silos. All the equipment in this train has been designed to meet the ASME Code requirements for a 10 atmosphere system. A brief description of some of the equipment is given below:

Coal Lock Hoppers

The coal lock hoppers are made of 3/4" carbon steel which forms a 30° conical bottom with a 12" opening. Welded to the top is an ellipsoidal head which had an outside diameter of 8'6" with an 18" opening.

Dolomite Lock Hoppers

The coal lock hoppers are made of 3/4" carbon steel which forms a 30° conical bottom with a 10" opening. Welded to the top is an ellipsoidal head which has an outside diameter of 6' with an 8" opening.

Coal Feed Tank

The coal feed tank is made of 3/4" carbon steel which forms

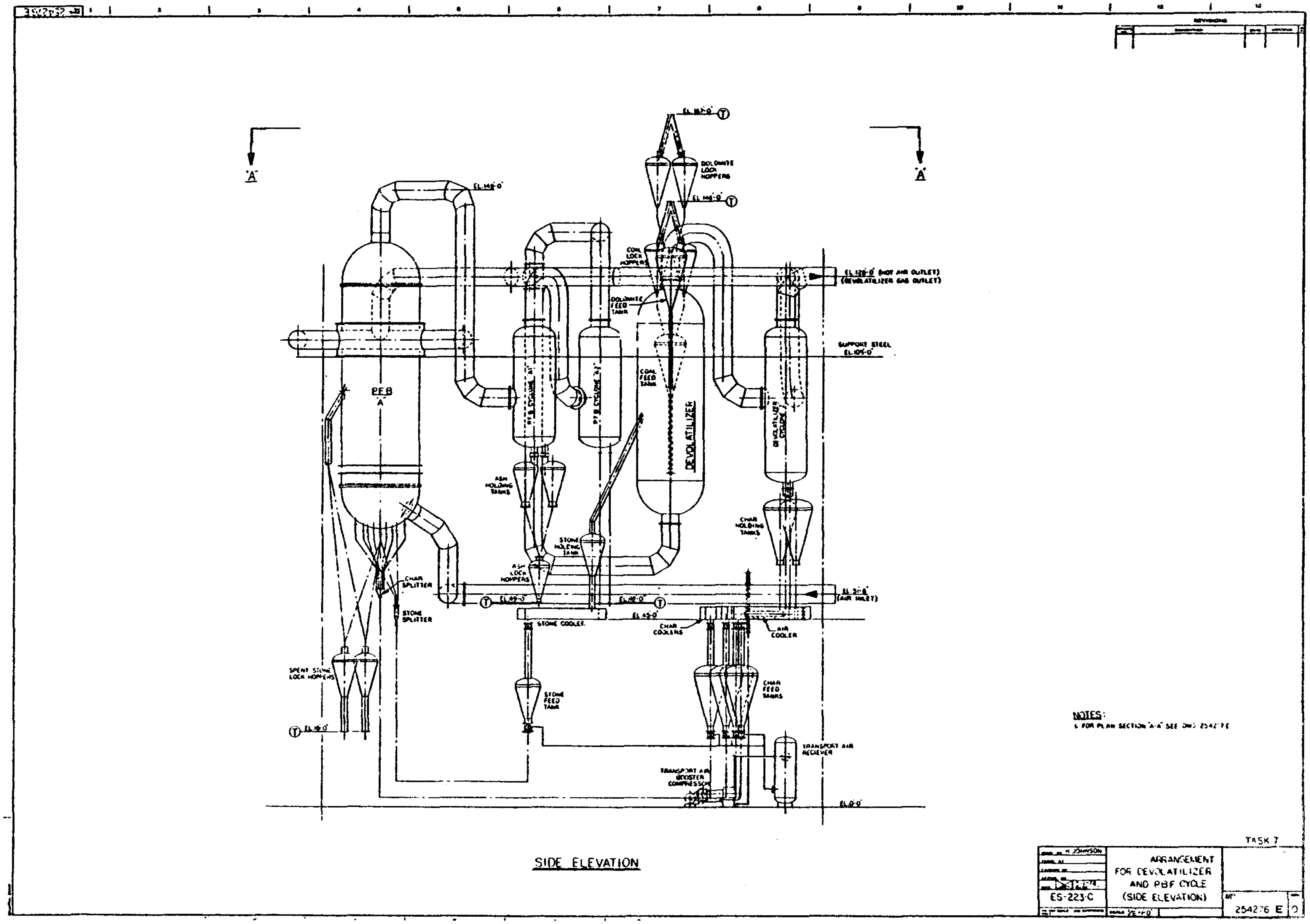

DOLOMITE LOCK HOPPERS
COAL LOCK HOPPERS
DOLOMITE FEED TANK
COAL FEED TANK
SUPPORT STEEL
PFB A
DEVOLATILIZER
DEVOLATILIZER CYCLONE
ASH HOLDING TANKS
ASH LOCK HOPPERS
STONE HOLDING TANK
CHAR HOLDING TANKS
CHAR SPLITTER
STONE SPLITTER
STONE COOLER
CHAR COOLERS
AIR COOLER
SPENT STONE LOCK HOPPERS
STONE FEED TANK
CHAR FEED TANKS
TRANSPORT AIR RECIEVER
TRANSPORT AIR BOOSTER COMPRESSOR
NOTES:
SIDE ELEVATION
TASK 7
H. JOHNSON
ARRANGEMENT FOR DEVOLATILIZER AND PBF CYCLE (SIDE ELEVATION)
ES-223-C
254276 E

FIGURE: E-5

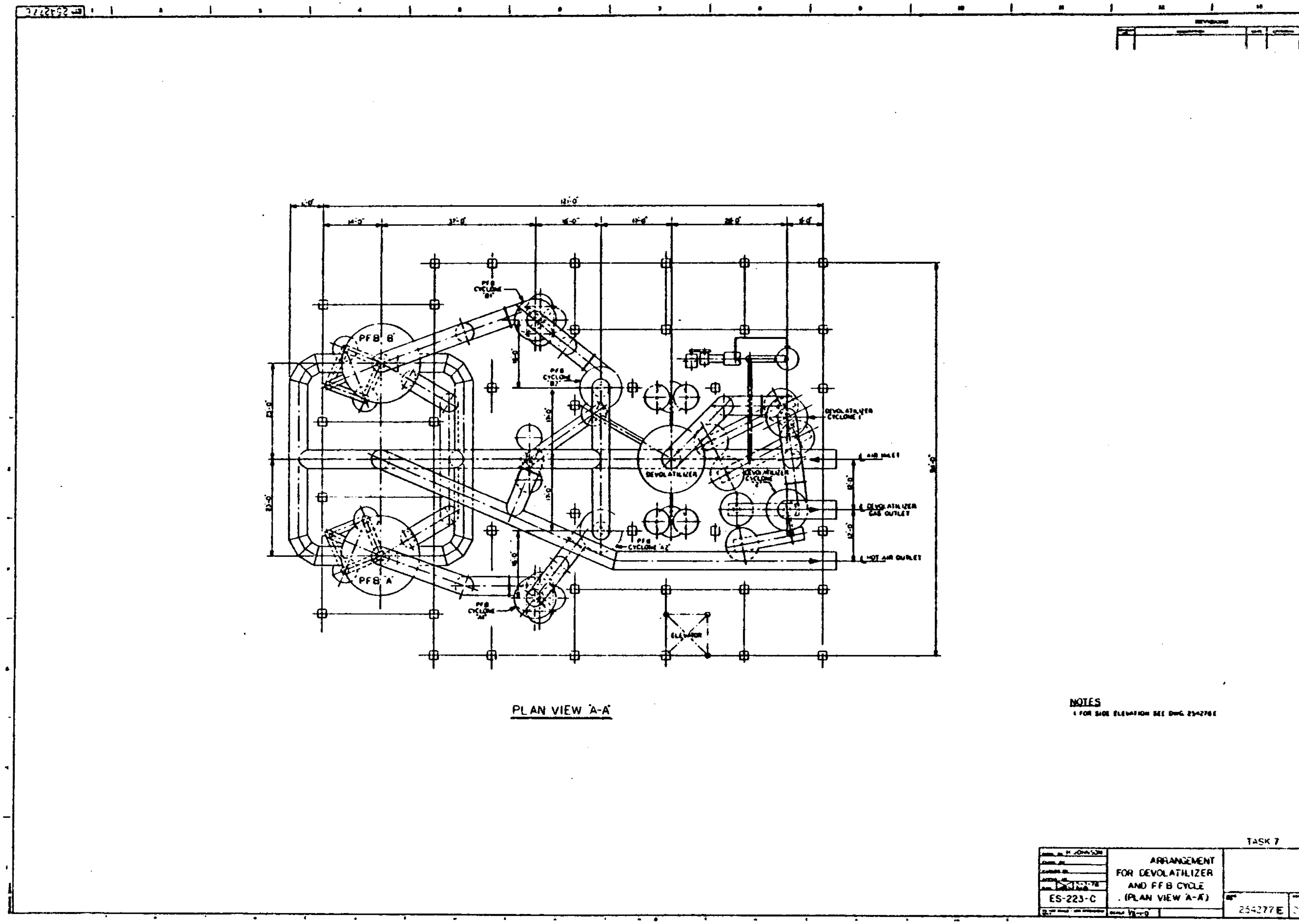


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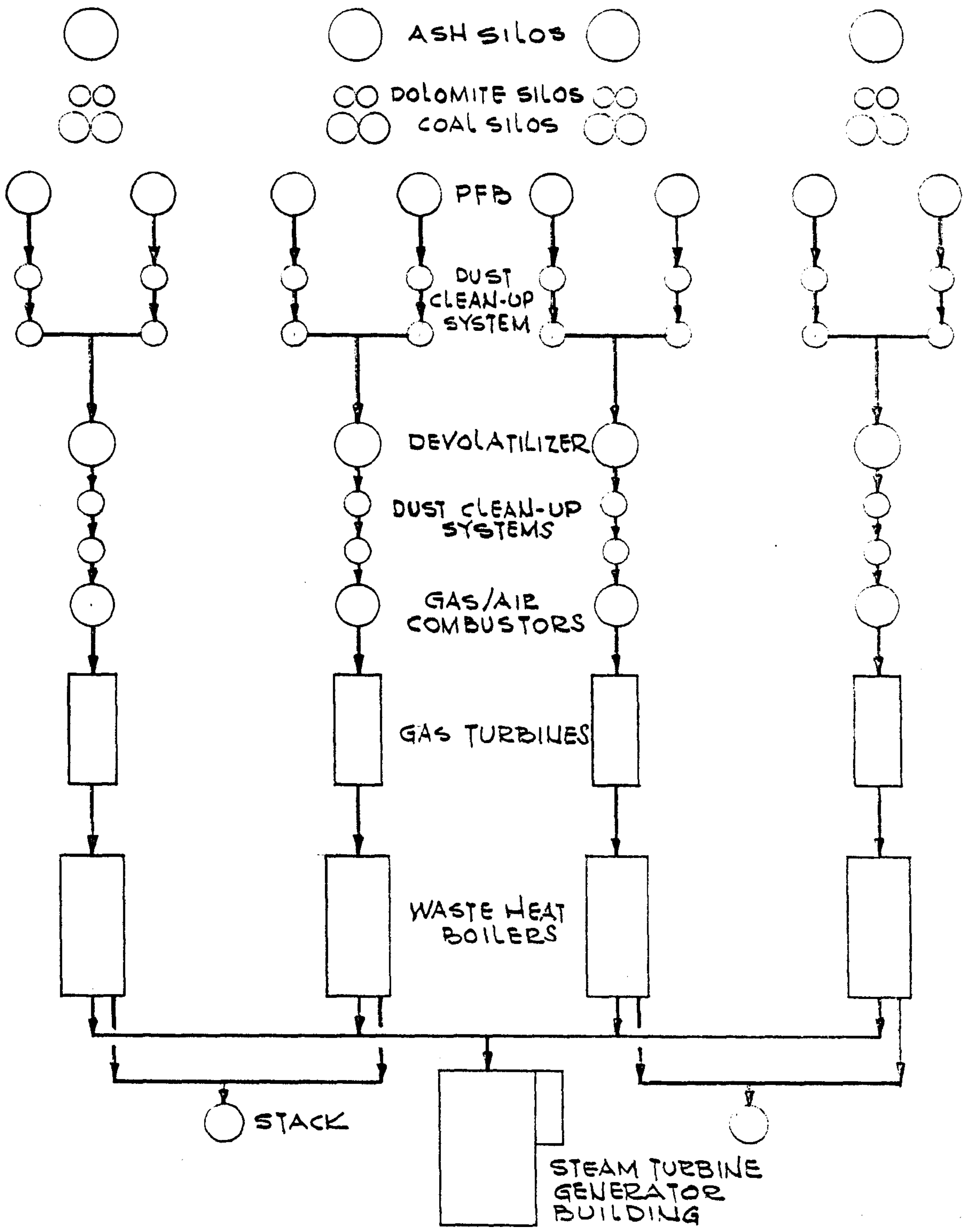
FIGURE: E-6



SCHEMATIC OF DEVOLATILIZER/PFB PLANT

FIGURE E-7

a 30° conical bottom with an 8" opening. Welded to the top is an ellipsoidal head which has an outside diameter of 10'6" with a 12" opening.

Dolomite Feed Tank

The dolomite feed tank is made of 3/4" carbon steel which forms a 30° conical bottom with a 6" opening. Welded to the top is an ellipsoidal head which has an outside diameter of 6'6" with an 8" opening.

Devolatilizer

The devolatilizer is a cylindrical vessel with a 16'6" outside diameter made of 2-1/2" thick carbon steel, with 6" of refractory lining. Flanged to the top is a hemispherical head with an outlet opening having an inside diameter of 40". Flanged to the bottom is a hemispherical head with an inlet having an inside diameter of 36". Supported in the bottom section of the devolatilizer is the draft tube; the draft tube is a cylindrical section having an inside diameter of 5'-10" and a length of 16' made of 1" alloy 800 H.

Devolatilizer Cyclones

The devolatilizer cyclones are an Aerodyne Development Corp. design with an overall length of 40'6" and an outside diameter of 12'-6" Each cyclone contains two stages of separation. The first stage of separation is a pressure vessel made of 1" thick carbon steel with 6" of refractory lining. The second stage is contained inside of the first.

Char Holding Tanks & Char Feed Tanks

The char holding tanks and char feed tanks are made of 3/4" carbon steel which forms a 30° conical bottom with an 18" opening. Welded to the top is an ellipsoidal head which has an outside diameter of 8'6" with an 18" opening. The tanks are lined with 6" of refractory.

Stone Holding Tank, Stone Feed Tanks, Spent Stone Lock Hoppers and Ash Hold-Up Tanks

The stone holding tank, the stone feed tanks, the spent stone lock hoppers and the ash hold-up tanks are made of 3/4" carbon steel which forms a 30° conical bottom with an 18" opening. An ellipsoidal head is welded to the top which has an outside diameter of 6' with an 18" opening. All tanks are lined with 6" of refractory.

Char and Stone Coolers

The char and stone coolers are stainless steel Holo-Flite Processors a product of Denver Equipment Division of Joy Manufacturing Company. The Holo-Flite Processors cool the solids through the surfaces of rotating screw as the material is driven through a trough by the screw helices. The flights and shaft of the screw and the jacketed trough are hollow to permit circulation of cooling water. Char Splitters - The char splitter takes char from a 5" SCH 80 stainless steel transport line and splits it into four 2" SCH 80 lines.

Pressurized Fluidized Bed Combustor

The PFB combustor is a pressure vessel made of 2-1/2" thick carbon steel with an outside diameter of 20'1" and a length of 68'6" and 6" of composite refractory lining. The vessel consists of three main sections: the lower head, cylindrical shell, and upper head. Since the internals of the vessel must be accessible, each of the heads are flanged to the cylindrical shell.

The internal arrangement of the pressure vessel consists of two compartments separated by a horizontal distributor plate. The lower compartment is essentially an inlet air plenum which receives discharge air from the gas turbine compressor. The upper compartment contains the fluidized bed and the heat exchanger surface which is submerged in the bed.

The division between the air inlet plenum and the fluid bed is the distributor plate. The distributor plate distributes the fluidizing air flow evenly over the bed; it supports the bed solids in the slumped state, and provides a flow path via connecting pipes from the inlet air plenum to the bed cooling system. The bed cooling system is made of 3040 U-tubes with an outside diameter of 1" and a wall thickness of 0.125 inches. Welded to the distributor plate are 848 bubble caps on a 6 inch square pitch arrangement which provides combustion air distribution.

PFB Cyclones

The PFB cyclones are an Aerodyne Development Corporation design. Each cyclone contains two stages of separation. The first stage of separation is a pressure vessel made of 1" thick carbon steel with 6" of refractory lining. The second stage is contained inside of the first.

Ash Lock Hoppers

The ash lock hoppers are made of 3/4" carbon steel which forms a 30° conical bottom with an 18" opening. An ellipsoidal head is welded to the top which has an outside diameter of 5' with an 18" opening. The tanks are lined with 6" of refractory.

Air Cooler

The air cooler is shell and tube type heat exchanger designed by Yuba Heat Transfer Corporation. The air cooler is made of carbon steel and utilizes fin tubes. The vessel is 1'3" in diameter with an overall length of 11'.

Booster Compressor

The booster compressor is a reciprocating compressor manufactured by Ingersoll-Rand. The compressor is 3'5" wide, 4'10" high, and 13'3" long and has a brake horsepower requirement of 86.4.

Transport Receiver

The transport receiver is manufactured by Ingersoll-Rand. The receiver is a pressure vessel with an outside diameter of 5' and an overall length of 16'; it is equipped with a manhole, a safety valve, air gauge, and discharge ports.

Gas Turbine Subsystem

The gas turbine subsystem for the PFB/Devolatilizer scheme is very similar to the Subtask 1.2 system. There is a need for ducting the fuel gas to the secondary combustion chambers. It is expected that the secondary combustors can be located in the scrolls without changing the external envelope. Some additional functions are needed in the control system. The increased power output of about 15 MW per gas turbine requires a slightly larger electric generator. Internally the gas turbine would be changed to provide for turbine cooling, necessary at the higher turbine inlet temperature.

Waste Heat Boiler Arrangement

The boiler is a bottom supported, natural circulation drum type, that makes extensive use of helically finned tubes to utilize the low level heat of the turbine exhaust gas for steam generation. The basic boiler component is the section consisting of an inlet and outlet header connected by two rows of closely spaced, finned tubes. In the boiler design the sections are arranged as required to achieve the designed performance. For ease of shipping and erection the sections are shop assembled into shipping units termed modules.

In the economizer, reheater and superheater modules, all interconnections between tube sections are shop installed. As a result, only the module inlet and outlet connections, and the drain and vent lines require field installation. The generating bank sections are shop assembled into modules for convenience in shipping and erection. These sections are designed for connection to the downcomers and drum using supply and riser tubes which are field installed.

The boiler for this cycle actually consists of three separate boilers within a common causing. The high pressure boiler generates 2400 psig, 950°F steam for the steam turbine. This boiler consists of a superheater, a generating bank and two banks of economizer. The remainder of the boiler design description is similar to that contained in Section 4.3.3 of the Report on Subtask 1.9 (PFB/Gas Turbine/Power Turbine Reheat Cycle Study). The predominant change is a 10% reduction in steam flow for the devolatilizer cycle.

The boiler arrangement is shown on Figures E-8 and E-9. The boiler performance and design conditions are shown on the Performance Summary Sheet, Figure E-10.

The Steam Subsystem

All the equipment in this subsystem is similar to the subsystem of Subtask 1.9 cycle- PFB/Gas Turbine/Power Turbine Reheat Cycle. The equipment in this cycle is about 10% smaller than those described in Subtask 1.9.

5.5 ECONOMICS

5.5.1 Capital Cost Estimates

5.5.1.1 General

The capital cost for this plant has been estimated by modifying the capital cost of the base scheme of Subtask 1.2 and the gas turbine reheat scheme of Subtask 1.9. The assumptions and methodology used in the estimating procedures are the same as described in pages 323 to 329 of the Report on Subtask 1.2 (Commerical Plant Design Description and Economic Analysis).

5.5.1.2 Devolatilizer/PFB System

The costs of the PFB combustor systems (combustor, cyclones, feed system, etc.) have been approximated by appropriate adjustments to the estimates of Subtask 1.2 equipment.

The devolatilizer itself, due both to the level of effort of the study and to the lack of design data, exists only as a very preliminary conceptual design consisting of a refractory lined pressure vessel with an internal draft tube. The cost has been estimated on a cost per unit weight basis using the data developed in the Subtask 1.2 equipment cost estimate as a guide.

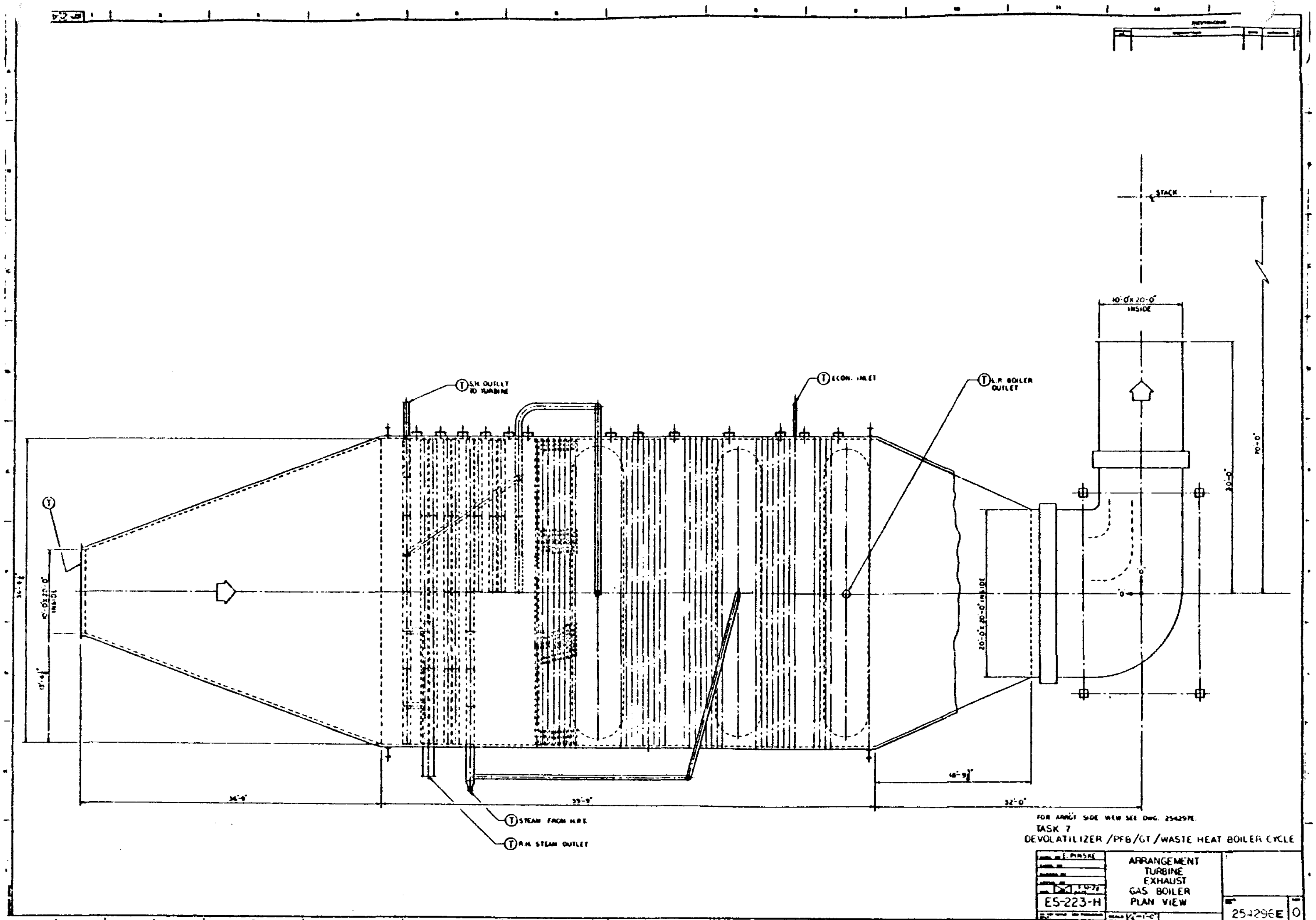

S.H. OUTLET TO TURBINE
ECON. INLET
L.P. BOILER OUTLET
STACK
10'-0" x 20'-0" INSIDE
20'-0" x 20'-0" INSIDE
STEAM FROM H.P.T.
R.H. STEAM OUTLET
36'-9"
39'-9"
32'-0"
FOR ARR'GT SIDE VIEW SEE DWG. 254297E.
TASK 7
DEVOLATILIZER /PFB/GT /WASTE HEAT BOILER CYCLE
ARRANGEMENT
TURBINE
EXHAUST
GAS BOILER
PLAN VIEW
ES-223-H
254296E
0

FIGURE: E-8

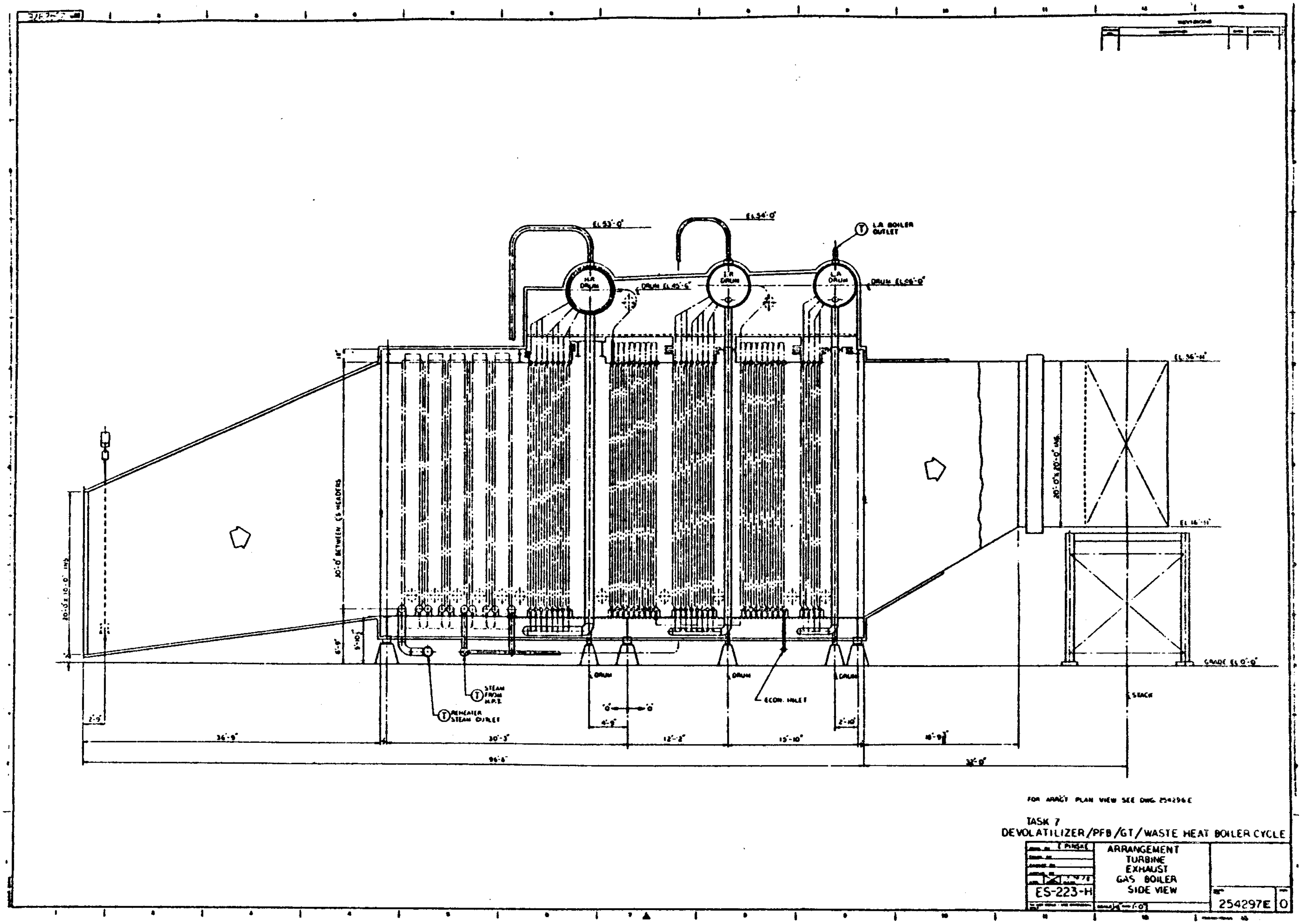

EL 53'-0"
EL 54'-0"
LA BOILER OUTLET
HP DRUM
IP DRUM
LA DRUM
DRUM EL 45'-6"
DRUM EL 46'-0"
EL 36'-11"
EL 16'-11"
GRADE EL 0'-0"
30'-0" BETWEEN C/L HEADERS
20'-0"x10'-0" INS.
20'-0"x20'-0" INS.
DRUM
ECON. INLET
STACK
STEAM FROM H.P.T.
REHEATER STEAM OUTLET
2'-9"
36'-9"
30'-3"
12'-2"
15'-10"
18'-9"
4'-9"
2'-10"
96'-6"
32'-0"
FOR ARR'GT PLAN VIEW SEE DWG 254296 E
TASK 7
DEVOLATILIZER/PFB/GT/WASTE HEAT BOILER CYCLE
ARRANGEMENT
TURBINE
EXHAUST
GAS BOILER
SIDE VIEW
ES-223-H
254297E
0

FIGURE: E-9

P&S 32972

A. FUEL & TURBINE EXHAUST GAS

TURBINE EXHAUST GAS

ANALYSIS				
SOURCE OF ANALYSIS				
LOAD REF.	1			
FUEL	-			
% BY	WEIGHT			
N_2	73.96			
O_2	17.81			
CO_2	5.84			
H_2O	1.04			
SO_2	0.03			
Ar	1.32			
Total	100.00			

SUPPLEMENTARY FUEL

ULTIMATE ANALYSIS				
SOURCE OF ANALYSIS				
FUEL				
% BY				
ASH				
S				
H_2				
C				
CH_4				
C_2H_4				
C_2H_6				
C_3H_8				
C_4H_{10}				
C_5H_{12}				
C_6H_{14}				
CO				
CO_2				
SO_2				
H_2O				
N_2				
O_2				
TOTAL				
BTU/LB				
BTU/CU. FT. AT 60 F., 30 IN. HG.				

TEG HEAT RECOVERY BOILER PERFORMANCE SUMMARY

BY H. Doss | DATE 5-19-78 | APPD.

THE BABCOCK & WILCOX COMPANY

P-

B. PREDICTED PERFORMANCE

GAS TURBINE LOAD CONDITION	LOAD REFERENCE	1
	AIR TEMP (°F)	59
	FUEL	PFB COAL COMBUSTION
	GAS TURBINE LOAD	100 %
	GAS FLOW (MLB/HR)	3063.3
	EXHAUST TEMP (°F)	1132.2
	% INJECTION	-
	BY PASS STACK LEAKAGE (MLB/HR)	-
SUPP. FIRING	TYPE OF SUPP FUEL	NONE
	FUEL INPUT (MKB/HR)	-
	SUPP FUEL (MLB/HR OIL, MCFH N.G)	-
	SUPP AIR FLOW (MLB/HR)	-
	GAS FLOW ENT. BOILER (MLB/HR)	3063.3
HP BOILER	STEAM FLOW LVG SH (MLB/HR)	362.6
	STEAM TEMP AT SH (°F)	950.0
	STM PRESS. AT SH (PSIG)	2400
	PRESS. DROP - ECON. (PSI)	30
	PRESS. DROP-DRUM TO SH (PSI)	100
	FEED WATER TEMPERATURE (°F)	250
	BLOW DOWN (MLB/HR)	-
	SOLIDS IN STEAM (PPM)	1
	MAX ALLOWABLE BOILER CONC. (PPM)	400
IP BOILER	STEAM FLOW LVG DRUM (MLB/HR)	66.2
	STM PRESS. AT DRUM (PSIG)	610
	PRESS DROP - ECON. (PSI)	-
	FEED WATER TEMPERATURE (°F)	250
	BLOW DOWN (MLB/HR)	-
	SOLIDS IN STEAM (PPM)	1
	MAX ALLOWABLE BOILER CONC. (PPM)	1500
LP BOILER	STEAM FLOW LVG (MLB/HR)	67.7
	STM. PRESS. AT DRUM (PSIG)	20
	PRESS DROP - ECON. (PSI)	-
	FEED WATER TEMPERATURE (°F)	250
	BLOW DOWN (MLB/HR)	-
	MOISTURE IN STEAM %	0.5
	MAX ALLOWABLE BOILER CONC. (PPM)	3500
	GAS TEMPERATURE TO STACK (°F)	314.2
RESISTANCE IN. OF WATER	BURNER	-
	CONVECTION BANKS	6.5
	FLUES & STACK	3.5
	PRESS. AT GT EXH. ("WG)	10

PREDICTED PERFORMANCE IS BASED ON TEG ENTERING UNIT AT SPECIFIED TEMPERATURE, ON IN.HG. BAROMETRIC PRESSURE, ON 80F REFERENCE TEMPERATURE, ON CONDITIONS AND EQUIPMENT GIVEN ON THIS SUMMARY SHEET AND ON ARRANGEMENT SHOWN ON DRAWING

C. EQUIPMENT PER UNIT

TYPE PFB COMBINED CYCLE HEAT RECOVERY BOILER

SIZE 30' x 40'

HP BOILER	SHTR	HS 135,194 SQ.FT.	TUBES, OD 2 IN.	4 FINS/INCH
		DESIGN PRESS. 2800	20 ROWS AT 4 IN.	48 WIDE AT 4.5 IN.
	BOILER	HS 270,268 SQ.FT.	TUBES. OD 2 IN.	4 FINS/INCH
		DESIGN PRESS. 2800	20 ROWS AT 4 IN.	96 WIDE AT 4.5 IN.
		DRUM INTERNALS CYCLONE SEPARATORS & SECONDARY SCRUBBERS		
	EC.	HS 432,428 SQ.FT.	TUBES. OD 2 IN.	4 FINS/INCH
		DESIGN PRESS. 2800	32 ROWS AT 4 IN.	96 WIDE AT 4.5 IN.
	STEAM TEMP CONTROL	TYPE ATTEMPERATOR SPRAY		
IP BOILER	BOILER	HS 135,134 SQ.FT.	TUBES. OD 2 IN.	4 FINS/INCH
		DESIGN PRESS 700	10 ROWS AT 4 IN.	96 WIDE AT 4.5 IN.
		DRUM INTERNALS CYCLONE SEPARATORS & SECONDARY SCRUBBERS		
	EC.	HS SQ.FT.	TUBES. OD IN.	FINS/INCH
		DESIGN PRESS.	ROWS AT IN.	WIDE AT IN.
LP BOILER	BOILER	HS 135,134 SQ.FT.	TUBES. OD 2 IN.	4 FINS/INCH
		DESIGN PRESS. 300	10 ROWS AT 4 IN.	96 WIDE AT 4.5 IN.
		DRUM INTERNALS 'B' BAFFLES & DRY PAN		
RH		HS 108,107 SQ.FT.	TUBES, OD 2 IN.	4 FINS/INCH
		DESIGN PRESS. 700	16 ROWS AT 4 IN.	48 WIDE AT 4.5 IN.
BURNER	INPUT - MKB/HR -			

REVISIONS NO.	DESCRIPTION	BY	DATE

TASK-7

DEVOLATILIZER/PFB/GT/WASTE HEAT BOILER CYCLE

PFB/GT/WASTE HEAT BOILER PERFORMANCE SUMMARY

FIGURE E-10

The cost of the waste heat boiler following the gas turbine has been developed by Babcock and Wilcox following standard estimating procedures for that product line.

5.5.1.3 Gas Turbine Subsystem

The gas turbine subsystem cost is increased by about 5% because of the addition of turbine cooling, the secondary combustor, control system functions and larger electric generators.

5.5.1.4 Steam System

The cost of the system has been scaled down from the cost of the steam system of Subtask 1.9, PFB/Gas Turbine/Reheat Power Turbine Cycle by 8% to reflect lower steam flow in this scheme.

5.5.1.5 Direct Capital Cost

Table E-5 shows the costs of only those items which are different from the Commercial Plant Design of Subtask 1.2, in thousands of mid-1977 dollars.

Table E-6, the direct capital cost estimate has been, prepared with the help of Table E-5 and detailed cost estimate of Subtask 1.2. The direct capital cost required for this conceptual design is $302,609.000.

5.5.1.6 Plant Capital Cost Estimate

The total plant capital cost required is $437,558,000, which includes appropriate dollar amounts for contingency, engineering and owner's cost and interest during construction. Table E-7 gives the breakdown of these costs. The specific capital cost is $758/kW (net). For the base PFB/AFB scheme, the total plant capital cost and the specific costs are $325,353,000 and $567/kW (net), respectively.

TABLE E-5

COST VARIATIONS IN THE AFFECTED ITEMS ONLY
For The Total Plant
Devolatilizer/PFB Scheme

Acct. No.	Description	In Thousands of mid-1977 dollars: Reference Cost In Subtask 1.2	Cost In Devol/PFB	Variance
2.2.4	Stack Foundation	150	300	+ 150
2.2.5	Gas Turbine Bldg. Concrete only	278	556	+ 278
2.2.7a	E.P. Fdn. & Structure. Steel	232	-	- 232
2.2.7b	Struct. Steel for Devolatilizer/PFB's	-	2,190	+ 2,190
	TOTAL CHANGE IN A/C 2.0			+2,386
3.1	Gas Turbines & Assoc. Systems	14,490	29,780	+15,290
3.2	Elec. Gen. & Assoc. Systems	3,780	8,948	+ 5,168
3.3	Control Package, Relay	1,512	3,112	+ 1,600
3.4	Enclosure including 25 ton travelling crane	294	588	+ 294
3.5	60-65 MW, Low Voltage Circuit Breakers	55	130	+ 75
3.6	Breeching with dampers & Insulation	101	210	+ 109
	TOTAL CHANGE IN A/C 3.0			+22,536
4.1	PFB Combustors	24,870	-	-24,870
	PFB Combustors & Devolatilizers	-	67,680	+67,680
4.2	PFB Gas Clean-up Equip.	7,310	21,140	+13,830
4.3a	Proc. Solid Waste Handling	1,056	-	- 1,056
4.3b	Proc. Solid Waste Handling & Storage	-	6,112	+ 6,112
4.4	Hot Gas Piping	3,923	15,692	+11,769
4.5	Start-up Combustors, Air Preheaters	853	1,706	+ 853
4.6	Allowance for PFB System - Concrete Work	300	1,200	+ 900
	TOTAL CHANGE IN A/C 4.0			+75,218
5.1	Coal Stackout, Reclaim, Prep., and Silo Storage Systems	11,392	12,507	+ 1,115
5.2a	Dolomite & Limestone - Stackout,Reclaim, Prep, & Silo & Bunker System	1,856	-	- 1,856
5.2b	Dolomite & Stackout, Reclaim Prep, and Silo Systems	-	2,243	+ 2,243

TABLE E-5 (Con't.)

COST VARIATIONS IN THE AFFECTED ITEMS ONLY
For The Total Plant

Acct. No.	Description	In Thousands of mid-1977 dollars Reference Cost In Subtask 1.2	Cost In Devol/PFB	Variance	
5.3	Coal & Dolomite Feed Systems to PFB	1,960	7,088	+ 5,128	
5.4	Coal & Limestone Feed Systems to AFB	6,600	-	- 6,600	
	TOTAL CHANGE IN A/C 5.0				+ 30
6.1a	AFB Steam Generators	30,700	-	- 30,700	
6.1b	Waste Heat Boilers	-	28,995	+ 28,995	
6.2	Electrostatic Precipitators	8,363	-	- 8,363	
6.3	Mech. Cyclone Dust Separators	850	-	- 850	
6.4	I.D. Fans with Motor Drives	1,007	-	- 1,007	
6.5	Boiler Feed Pumps	510	310	- 200	
6.6	Boiler Feed Pump Turbine Drives	1,632	1,284	- 348	
6.8	L.P. Feed Water Heaters	253	-	- 253	
6.9	Deaerating Heaters	196	143	- 53	
6.11	Concrete Chimney	1,400	2,745	+ 1,345	
6.12	Breeching, Including Insulation & Jacket	1,446	98	- 1,348	
6.13	High Pressure Piping	2,385	4,914	+ 2,529	
6.14	Int. & Low Press. Piping	2,579	2,852	+ 273	
6.15	Valves	2,237	1,645	- 592	
6.16	Piping Specialty Items	214	156	- 58	
6.17	Insulation - Piping & Equip.	705	520	- 185	
6.18	Water Treatment Equip.	1,175	883	- 292	
6.27	Proc. Solid Waste Handling Systems & Storage	5,837	-	- 5,837	
6.28	Finish Painting	405	1,117	+ 712	
6.29a	Allowance for AFB Concrete Work	500	-	- 500	
b	Allowance for WHB Concrete Work	-	300	+ 300	
	TOTAL CHANGE IN A/C 6.0				-16,432

TABLE E-5 (Con't.)

COST VARIATIONS IN THE AFFECTED ITEMS ONLY
For The Total Plant

Acct. No.	Description	Reference Cost In Subtask 1.2	Cost In Devol/PFB	Variance
		In Thousands of mid-1977 dollars		
7.1	Steam Turbine Generator with Exciter & Accessories	22,770	15,969	- 6,801
7.2	Condensers and Tubes	2,064	1,840	- 224
7.3	Vacuum Pumps w/motors	242	111	- 131
7.4	Condensate Pumps w/motors	200	142	- 58
7.5	Cooling Tower	2,790	2,163	- 627
7.6	Cooling Tower Chlorination Systems	121	111	- 10
7.9	Circulating Water Pumps w/motors	608	460	- 148
7.10	Circulating Water Booster Pumps w/motors	18	15	- 3
7.11	Circulating Water Piping	720	582	- 138
7.12	Make-up Water Pumps w/motors	43	40	- 3
	TOTAL CHANGE OF A/C 7.0			-8,143
10.2a	Instrumentation for PFB System	1,175	-	- 1,175
10.2b	Instrumentation for PFB & Devolatilizers	-	2,937	+ 2,937
10.3	Instrumentation for PFB Coal & Sorbent Handling System	456	912	+ 456
10.4	Instrumentation for AFB Coal & Sorbent Handling System	456	-	- 456
10.5a	AFB Stm. Generator System	2,258	-	- 2,258
10.5b	WHB Stm. Generator System	-	2,500	+ 2,500
	TOTAL CHANGE IN A/C 10.0			+2,004

TABLE E-6

DIRECT CAPITAL COST ESTIMATE
Devolatilizer/PFB Scheme

MAIN ACCT. NO.	DESCRIPTION	IN THOUSANDS OF MID-1977 DOLLARS MATERIAL COST	INSTALLATION COST	TOTAL COST
1.0	LAND & LAND RIGHTS	1,020		1,020
2.0	STRUCTURES & IMPROVEMENTS	8,107	7,979	16,086
3.0	GAS TURBINES & GENERATORS	38,376	4,392	42,768
4.0	DEVOLATILIZER/PFB COMBUSTOR SYSTEMS	83,572	29,958	113,530
5.0	COAL & SORBENT HANDLING SYSTEMS	16,222	5,616	21,838
6.0	WASTE HEAT BOILER PLANT EQUIPMENT	34,491	12,110	46,601
7.0	STEAM TURBINE GENERATOR UNITS	19,069	2,711	21,780
8.0	ACCESSORY ELECTRICAL EQUIPMENT	12,361	9,997	22,358
9.0	MISCELLANEOUS POWER PLANT EQUIPMENT	450	44	494
10.0	INSTRUMENTATION & CONTROL SYSTEMS	6,645	1,489	8,134
11.0	JOB DISTRIBUTABLE COSTS	3,955	4,045	8,000
	TOTAL	224,268	78, 341	302,609

TABLE E-7

PLANT CAPITAL COST SUMMARY
Devolatilizer/PFB Scheme

		$1,000's
1.	Direct Capital Cost	$302,609
2.	Engineering & Owner's Costs (10% of 1.)	30,261
3.	Contingency (10% of 1 + 2)	33,287
4.	Interest During Construction (8% Rate; 5 yrs. 19.5% of 1+2+3)	71,401
		$437,558

Specific Capital Cost = $758/kW (net)

5.5.2 Annual Cost

The annual cost for running the Devolatilizer/PFB plant consists of the following items:

a. Fixed charge for the capital cost - This is assumed to be 18% of the capital cost, consistent with the assumption for the base PFB/AFB scheme.

b. Cost of Coal - This is lower than the base scheme, reflecting higher efficiency of this scheme. For a capacity factor of 65% and net plant heat rate of 8,349 Btu/kWh, total coal needed is 1,069,265 tons per year. Total coal cost is $21,385,296 per year.

c. Cost of Sorbent - Under the same conditions dolomite needed per year is 214,607 tons, at a cost of $1,502,248.

d. Manpower Cost - The plant is a complex one to run. It is assumed that same number of men as in Subtask 1.2 would be able to run this plant, as there is no AFB generator, electrostatic precipitator and I.D. fan in this plant.

e. Other Material and Machinery Amortization and Replacement Costs - These costs are assumed to remain the same as in Subtask 1.2.

g. Utilities - The water cost will be a bit less than in Subtask 1.2, because of less make-up water requirements. The amount of fuel oil needed for PFB Combustor start-ups will remain the same. The annual cost is estimated to be $40,000.

h. Spent Sorbent and Ash Disposal Cost- Ash and Spent sorbents are collected at the rate of 112,468 lbs/h at full load running condition. The disposal cost of this material is $960,589 per year at 65% capacity factor and $3/ton for disposal.

The estimated annual cost is $108,217,000, as shown in Table E-8.

TABLE E-8

ANNUAL COST SUMMARY

AND COST OF ENERGY

ITEMS	Thousands of Dollars
1. Fixed charge (@ 18%)	78,760
2. Coal	21,385
3. Sorbent	1,502
4. Man Power Cost	2,562
5. Other Material	1,932
6. Machinery Amortization & Replacement Parts	1,075
7. Utilities	40
8. Spent Sorbent & Ash Disposal	961
Total	$108,217

Total Energy Output at 65% Capacity Factor		$3,287 \times 10^6$ kWh
Cost of Electricity Generated	=	32.92 mills/kWh

5.5.3 Cost of Electricity

At 65% capacity factor, the total net energy generated is 3,287 x 10^6 kWh. So the cost of electricity generated is 32.92 mills/kWh. The cost contribution of each of the items mentioned in Subsection 5.5.2 towards the total cost of electricity is shown in Table E-9. The generation cost of electricity in the base scheme is 28.47 mills/kWh.

5.6 DISCUSSION

The main contribution of the devolatilizer to the PFB scheme is the higher gas turbine inlet temperature. Higher gas turbine inlet temperature increases the gas turbine power output and the specific work available per pound of air flow through the turbine. Though in this scheme we have 2178F inlet temperature, the gas turbine power did not increase correspondingly, because of more turbine cooling air flow (21.6% of total air flow) and higher system pressure drops. This suggests that further work is necessary to develop high temperature gas turbine blade material and/or more efficient turbine cooling systems.

This cycle concept circumvents the temperature limitations of the fluidized bed cycles while still maintaining the advantages attendant to fluidized beds such as high carbon utilization and the ability to burn a wide variety of coals in an environmentally acceptable manner. Potentially, a turbine inlet temperature of over 2200F can be achieved with this approach.

Unfortunately there is no directly applicable data to guide the performance determination or equipment design. This system utilizes a slightly oxidizing gas as a devolatilizing medium as opposed to a reducing gas used in the experimental work that guided the estimate of performance for this study. A development program would be required to produce the information needed to confirm the design assumptions.

The conceptual design did not consider a means of temperature control for the devolatilizer itself. At the full load point a heat balance exists. As load is reduced, however, the gas from the PFB combustor to the devolatilizer will become more oxidizing and the devolatilizer temperature would be expected to rise. Additional study work would be required to develop a conceptual design with load turndown capability which would include a system to control the devolatilizer temperature.

The design of the particulate removal system for this concept has been based on the same performance criteria as for the simple PFB cycles. This is probably not adequate for two reasons:

1. Any ash leaving the particulate removal system is exposed to the final combustion temperature of 2200F or greater. This approaches the initial deformation (oxidizing basis) temperature for most coals and hence the concern for deposition and erosion in the gas turbine is considerably increased.

TABLE E-9

COST OF ELECTRICITY

AT 65% CAPACITY FACTOR

Items	Cost in mills/kWh		Per cent of Total Cost	
Fixed charge @ 18%		23.96		72.78
Fuel - coal		6.51		19.76
Operations & Maintenance Costs				
Sorbent	0.46		1.39	
Spent Sorbent & Ash Disposal	0.30		0.89	
Manpower	0.78		2.37	
Other material	0.59		1.78	
Machinery & Equipment	0.33		0.99	
Utilities	0.01		0.04	
		2.47		7.46
Total		32.92		100.00

2. Of greater concern, however, is the potential vaporization of alkaline metals contained in the coal ash. The reference coal contains more than 2000 ppm of sodium plus potasium. Even with the 99+% removal efficiency projected for the two stages of Aerodyne cyclones, the Na+K level to the final combustor would be approximately 20 ppm of the total fuel flow. This is more than an order of magnitude higher than the current, conventional gas turbine fuel specifications for liquid fuels (which have nearly double the heat content per unit weight as compared to coal). UTC specification FR-1 recommends that total Na+K be less than 0.6 ppm while General Electric specification GEI-41047E recommends that total Na+K+Pb be less than 2.0 ppm.

It should be remembered that it was not possible to address all the areas of concern within the scope of this study or to optimize the plant cycle configuration.

After estimating the performance of the base PFB/devolatilizer system it was noted that the main air stream through the PFB cooling tubes was subjected to a 12 psi pressure loss which may not be necessary, in order to match the low Btu fuel gas supply pressure from the devolatilizer and cyclones. To compensate for this pressure differential, it was decided to place a small booster compressor (pressure ratio=1.089) in the combustion air stream feeding the devolatilizer. In that way the resulting gas pressure entering the turbine would be 12 psi higher or 136.7 psia (vs. 124.7 psia). The air entering the PFB boost compressor was precooled to about 560°F so that the compressor exit temperature would be equal to the previous PFB air inlet temperature (595.9°F). In this way the PFB coal rate should be unchanged. The small amount of heat rejected from the precooler was used to generate additional low pressure (609 psia) steam.

Table E-10 shows the revised performance estimates for this scheme. The total net power increases by 6.86 MW to 584.16 MW and the net efficiency increases by 0.5 points to 41.37% over the scheme detailed in tables E-1 through E-4. The base split flow air-cooled PFB/AFB scheme had an efficiency of 37.9%.

The plant described in this Section, however, does not include the booster compressor. The process description and the cost estimate also neglect the booster compressor.

Of all the schemes considered in this contract, the devolatilizer/PFB scheme displays the highest efficiency. To realize this high efficiency in a utility plant, further studies and experiments have to be made to resolve all the uncertainties and reduce capital costs which at this point appear uncompetitive with the base PFB/AFB plant developed in Subtask 1.2.

TABLE E-10

REVISED DEVOLATILIZER/PFB SYSTEM PERFORMANCE ESTIMATES

	One Gas Tubrine	Total Plant
Gas Turbine Power, MW	85.7	342.8
Steam Turbine Power, MW	65.5	262.0
Total Gross Power, MW	151.2	604.8
Booster Compressor Power, MW	1.68	6.72
Total Auxiliary Power, MW	5.16	20.64
Total Net Power, MW	146.04	584.16
Gross Efficiency, % (1)	44.14	44.14
Net Efficiency, % (2)	41.37	41.37
Coal Rate (As Fired), lb/sec	26.08	104.33
Coal Rate (As Received), lb/sec	28.74	114.97
Adjusted Coal (As Received) Rate, no/sec (3)		116.7

(1) Based on 'as fired' coal rate (HHV - 12453 Btu/lb)

(2) Based on 'as received' adjusted coal rate (HHV - 11472 Btu/lb), and net power generation

(3) See Table E-3

6.0 ATMOSPHERIC FLUIDIZED BED (AFB) COMBUSTION SCHEME

6.1 INTRODUCTION

Atmospheric fluidized bed combustion of coal has been studied extensively in recent years. There are quite a few experimental setups around the world, and a 30 MWe pilot plant is in the debugging stage in Rivesville, Virginia. Many Architectural/Engineering firms have done conceptual studies on a commercial utility plant utilizing AFB boilers. For this Subtask 1.7, the findings and cost data of an earlier Burns and Roe, Inc. Study (4) have been modified to be comparable with the findings and cost data of the other alternatives investigated during this study. Stone and Webster Company has estimated costs for an "add-on" AFB unit to an existing utility plant. Since all other estimates in the present study are based on a "grass roots" plant, the data developed by Stone and Webster has not been used for this comparison.

Burns and Roe, Inc. designed their AFB plant to burn a non-compliance low sulfur Western coal. It is felt that the AFB combustor size will not change significantly for high sulfur Illinois coal, because of the unique nature of the fluidized bed combustion process.

6.2 DESCRIPTION OF CYCLE

The steam cycle is a conventional 2400 psig/1000F/1000F cycle, with the steam being produced in an AFB steam generator. Figure F-1 shows the mass balance for a 4,300,000 lb/hr of steam system burning coal with 3.26% sulfur and calcium-to-sulfur molar ratio of 4.0. This figure has been excerpted from Reference 4. The actual mass balance for an "as-received" coal with 3.16% sulfur and heating value of 11472 Btu/lb (the reference fuel for Subtask 1.2) will be slightly different.

6.3 PERFORMANCE

For purposes of estimating annual operating costs (coal, sorbent, etc.) and cost of electricity, the net plant heat rate (9916 Btu/kWh) as calculated for the commercial AFB plant in Reference 4 has been used, along with the coal and sorbent analyses of Subtask 1.2 of this study. Changes in heat rate which would result from the difference in fuel have been neglected. The performance estimates of the steam cooled AFB plant are shown on Table F-1. Total gross power generated and net power output are 568.215 MWe and 535.905 MWe, respectively. The net plant efficiency is 34.42%. The corresponding net plant efficiency of the base PFB/AFB plant of Subtask 1.2 is 37.9%.

6.4 PLANT DESCRIPTION

The plant is described in detail in Volume II of Reference 4. A short description of the plant is given in the Executive Summary of Reference 4 and is appended here for convenience in Section 9.3 Figure F-2 shows a schematic diagram of the plant equipment (excerpted from Reference 4).

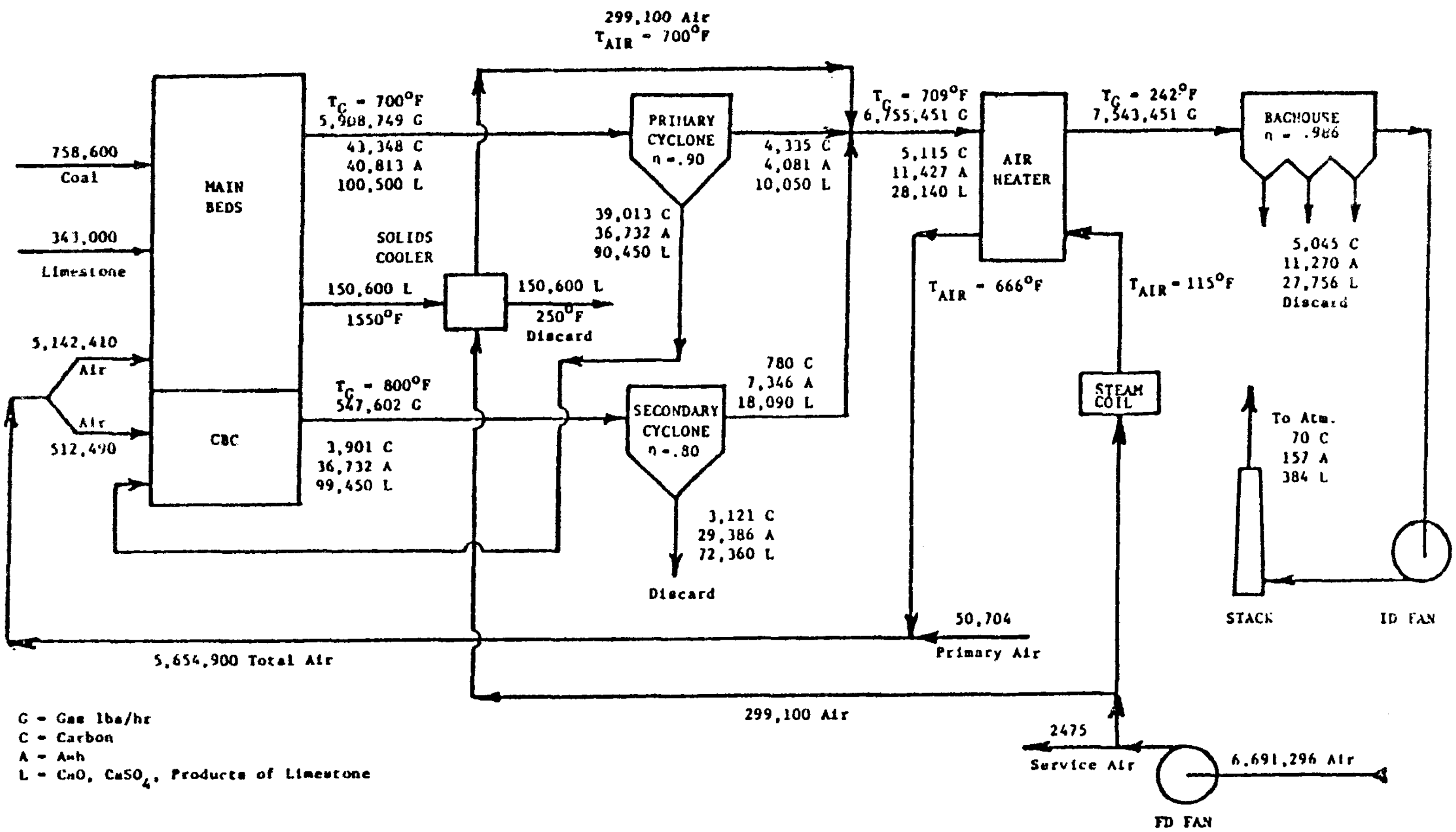


EXHIBIT 3-4. MASS BALANCE 4,300,000 LB/HR OF STEAM FOR COAL WITH 3.26% SULFUR, Ca/S = 4/1

MASS BALANCE FOR AFBC SCHEME

FIGURE F-1

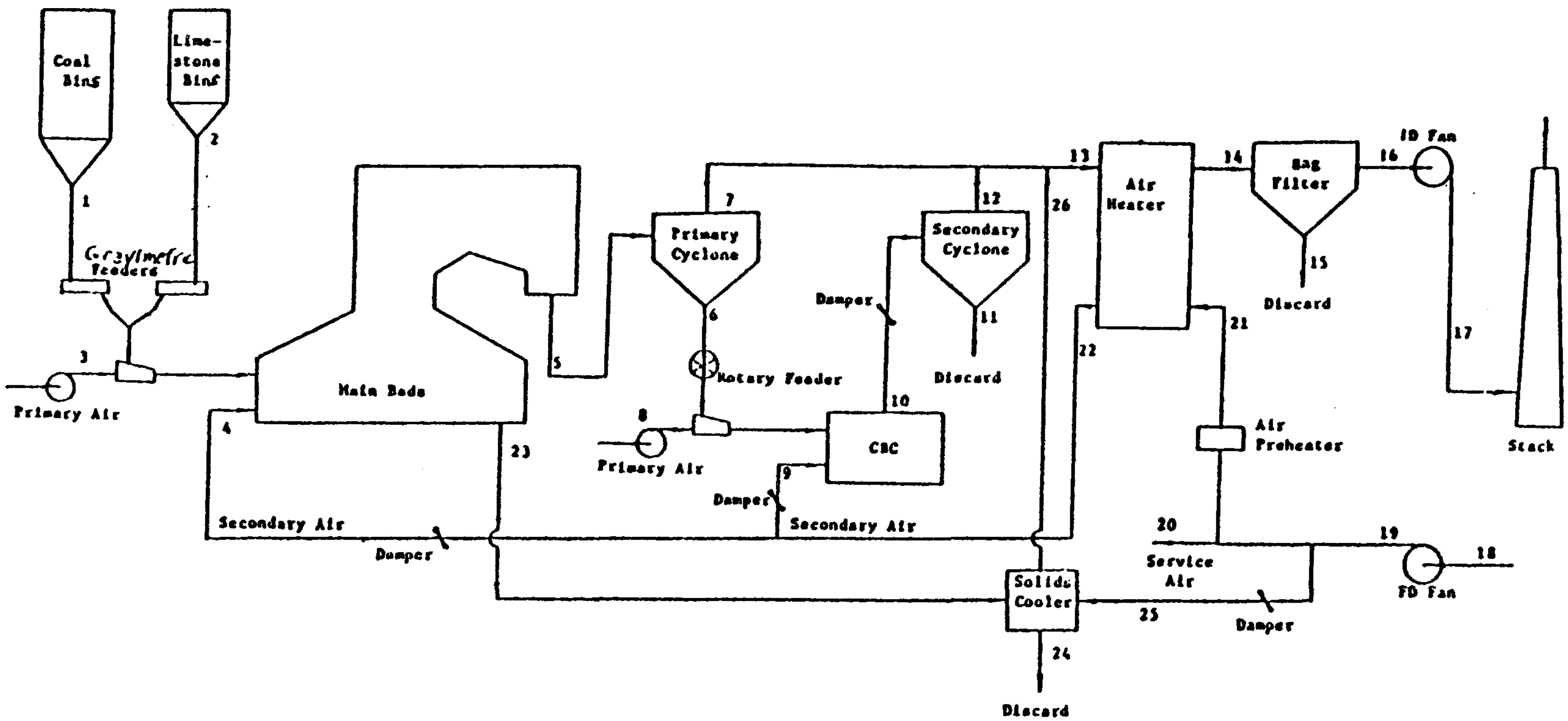


EXHIBIT 3-5. AFBC STEAM GENERATOR AND AUXILIARIES SYSTEM SCHEMATIC

FIGURE F-2

TABLE F-1

STEAM-COOLED AFB PLANT PERFORMANCE ESTIMATES
(From Executive Summary of Reference 4)

Gross Power, MW	568.215
Auxiliaries, MW	32.310
Net Power Output, MW	535.905
Net Plant Heat Rate, Btu/kWh	9916
Net Plant Efficiency, %	34.42
*Coal Feed Rate, As Received, lb/sec	128.67

*Calculated from net plant heat rate of Reference 4 and 11472 Btu/lb, which is the HHV of the "as received" coal used in Subtask 1.2.

6.5 ECONOMICS

6.5.1 Capital Cost Estimate

6.5.1.1 General

The capital cost estimate for this plant has been derived from the capital cost estimate of Reference 4 with some minor modifications.

6.5.1.2 Direct Capital Cost

Table F-2 shows the Direct Capital Cost Estimate for the AFB plant. Reference 4 has a boiler house enclosing the steam generator. But the Subtask 1.2 AFB steam generator is an outdoor installation. For proper comparison, the cost of the boiler house has been deducted from Account 311.0. Reference 4 AFB plant does not have a switchyard. Therefore, a switchyard at a cost of $2,264,000 has been added to Account No. 315.0. The direct capital cost of a comparable AFB plant is $221,420,000 in mid-1977 dollars.

6.5.1.3 Plant Capital Cost Estimate

The total plant capital cost has been estimated in Reference 4 in a manner different from that used in this study. The plant capital cost of $278,065,000 (in mid-1977 dollars) as calculated in Reference 4 does not include any interest during construction. But the total capital cost at the startup date of January, 1985 is $505,594,000 in January, 1985 dollars. This cost includes escalation, interest during construction at 8% discount rate, and working capital of 8.15%.

For comparison of the plant capital costs, it has been decided to develop this cost for the AFB plant using the assumptions of Subtask 1.2. Table F-3 shows the plant capital cost to be $320,162,000 in mid-1977 dollars. This cost includes interest during construction, contingency and engineering and owner's cost. The specific capital cost is estimated to be $597/kW (net). This compares with $567/kW (net) for the base PFB/AFB scheme of Subtask 1.2.

6.5.2 Annual Cost

The annual cost for running this conceptual steam cooled AFB plant consists of the following items. The derivation of this cost is different from that used in Reference 4.

a. Fixed Charge: This is assumed to be 18% of the capital cost, consistent with the assumption for other schemes studied in this program.

b. Cost of Coal: For the net plant heat rate of 9916 Btu/kWh, 231.6 tons of coal are needed per hour. At $20/ton and 65% capacity factor, annual coal cost is $26,375,000.

c. Cost of Sorbent: For a Ca/S mole ratio of 3.7, limestone is needed at the rate of 87.5 tons/hr at full load. For 65% capacity factor and limestone cost of $7/ton, the annual cost for sorbents is $3,488,000.

TABLE F-2

DIRECT CAPITAL COST ESTIMATE

(In Thousands of Mid-1977 Dollars)

Acct. No.	Description	Material	Labor	Total	Remarks
310.0	Land & Land Rights	$ 2,200	-	$ 2,200	
311.0	Structures & Improvements	10,105	$ 5,628	15,733	Except Boiler House, Account 311.2
312.0	Boiler Plant Equip.	100,500	22,305	122,805	
314.0	Turbo Generator Units	38,213	8,829	47,042	
315.0	Accessory Elect. Equipment	9,530	6,723	16,253	Added Switchyard, $2,264,000
316.0	Misc. Power Plant Equipment	1,287	488	1,775	
353.1	Main Power Transformer	2,528	200	2,728	
	Temp. Facilities & Construction Equip. & Services			12,884	Similar to Acct. 11.0 of PFB Study
	Total	$164,363	$44,173	$221,420	

TABLE F-3

COMMERCIAL PLANT CAPITAL COST SUMMARY

STEAM COOLED AFB PLANT

		$1,000's
1.	Direct Capital Cost	$221,420
2.	Engineering & Owner's Costs (10% of 1.)	22,142
3.	Contingency (10% of 1 + 2)	24,356
4.	Interest During Construction (8% Rate; 5 years; i.e., 19.5% of 1 + 2 + 3)	52,244
	Total Project Capital Cost (In Mid-1977 dollars)	$320,162

Specific Capital Cost = $597/kW (net)

d. Manpower Cost: The maintenance and operating manpower cost is \$3,700,000 as estimated in Reference 4.

e. Maintenance Material Cost: This cost is \$887,000/year per Reference 4.

f. Supplies and Expenses: Reference 4 cites this cost as \$833,000/year.

g. Spent Sorbent and Ash Disposal: Approximately 95 tons/hr of spent sorbent and ash has to be disposed. At \$3/ton, the disposal cost is \$1,619,000 Annually.

The total estimated annual cost is \$94,531,000 as shown in Table F-4.

6.5.3 Cost of Electricity

At 65% capacity factor, the total net energy generated is 3,051 X 10^6 kWh. Therefore, the cost of electricity generated is 30.98 mills/kWh. The Table F-5 shows the cost contribution of each of the items of Section 5.5.2 toward the total cost of electricity. The cost of electricity in the base scheme is 28.47 mills/kWh.

6.6 DISCUSSION

The steam cooled AFB scheme may be viewed as a near-term solution to both the energy and environmental problems besetting the utility industry. But before a commercial plant can be constructed, a lot of developmental work is necessary in the following areas to insure economic and reliable systems operation:

Fuel Feed System: Reliable system of coal and limestone injection to the AFB at multitude of points.

Hot Bed Material Handling: Effective collection, processing and transporting of the spent sorbent material.

Flue Gas Particulate Removal System: Further development of suitable equipment to capture particulates from hot flue gas with low sulfur dioxide concentration.

Instrumentation and Control: Reliable means of instrumenting the FBC for determination of bed parameters and simplified control system for the multi-bed FBC.

It must be mentioned that improvements in all these areas are also the prerequisites for commercialization of all the schemes studied under this contract.

The basic design, performance, and cost estimates for the PFB/AFB combined cycle plant of Subtask 1.2 and the AFB plant of Reference 4 have been developed using different criteria and assumptions. Therefore, the 8.8% lower C.O.E. for the PFB/AFB plant (See Section 5.5.3) estimated herein is not

TABLE F-4

ANNUAL COST SUMMARY
AND COST OF ENERGY

Items		Thousands of Dollars
1.	Fixed Charge (@ 18%)	$57,629
2.	Coal	26,375
3.	Sorbent	3,488
4.	Manpower Cost (Operationgs and Maintenance)	3,700
5.	Maintenance Material	887
6.	Supplies and Expenses	833
7.	Spent Sorbent & Ash Disposal	1,619
	Total	$94,531

Total Energy Output at 65% Capacity Factor $3,051 \times 10^6$ kWh

Cost of Electricity Generated = 30.98 mills/kWh

TABLE F-5

COST OF ELECTRICITY
AT 65% CAPACITY FACTOR

Items	Cost in mills/kWh		Percent of Total Cost	
Fixed Charge @ 18%		18.89		60.97
Fuel - Coal		8.64		27.89
Operations & Maintenance Costs:				
Sorbent	1.14		3.68	
Spent Sorbent & Ash Disposal	.53		1.71	
Manpower	1.21		3.91	
Maintenance Material	.29		.94	
Supplies & Expenses	.28		.90	
		3.45		11.14
Total		$30.98		100.00%

considered conclusive. While the results indicate a good probability that the PFB/AFB combined cycle plant would be significantly more economical than the AFB steam plant, the estimate for the latter would have to be performed on the same basis used in Subtask 1.2 before a firm conclusion could be drawn. It is recommended that this study be sponsored by the D.O.E. as soon as possible.

7.0 AFB/SEMI-CLOSED GAS TURBINE CYCLE

7.1 INTRODUCTION

One of the impediments to the realization of the benefits of a combined cycle utility plant with a coal fired pressurized fluidized bed combustor is the current unavailability of a reliable and efficient high temperature and high pressure gas cleanup system. A combined cycle system which may be attractive as a backup system has been studied in a very preliminary manner. This system utilizes an atmospheric fluidized bed (AFB) to indirectly heat the air which drives the gas turbine unit. The gas turbine works with dustfree air, thereby eliminating the gas turbine corrosion, erosion and deposition problems attendant to PFB systems. In this scheme, the gas turbine will have higher reliability, lower maintenance requirements and longer life. Due to schedule and cost constraints of this project, detailed analysis and cost estimating work have not been done. The concept appears very promising, especially if the development of a reliable high temperature high pressure hot gas cleanup system remains elusive or if such a system is economically impractical.

7.2 CYCLE DESCRIPTION

An AFB coal combustor is used both to supply energy to the gas turbine and provide supplementary firing of the gas turbine exhaust for a high efficiency steam system. One of the various possible schemes of the AFB/Semi-Closed Gas Turbine cycle is depicted on Figure G-1. Compressor discharge air is heated in tubes immersed in the bed. After being heated in the tubes, the high pressure air is expanded in a turbine which produces enough power to run both the compressor and the electric generator. One stream of the turbine exhaust gas is used as the combustion air for coal in the AFB. The rest of the turbine exhaust gas goes to the boiler-economizer module. The flue gas from the combustor supplies heat to superheat and reheat steam. The enthalpy of the gas is high enough to support a 2400 psig/1000°F/1000°F steam system.

7.3 GENERAL NOTES ON PERFORMANCE

The performance of this cycle has been estimated in a very preliminary way over various operating pressure ratios (OPR) of the gas turbine. As a result of this crude performance evaluation, the following observations can be made:

a. The gross combined cycle plant efficiency remains in the band of 39 to 41 percent, as the OPR changes from 14 to 6. The peak overall efficiency (about 41%) occurs at a pressure ratio of 8.

b. As OPR is increased, the overall system and steam system power output decrease. The gas turbine power output reaches a maximum at the OPR of 8.

c. A dual pressure steam system is required to efficiently utilize the enthalpy of the gas turbine exhaust and the AFB flue gas.

AFB/SEMI-CLOSED GAS TURBINE CYCLE

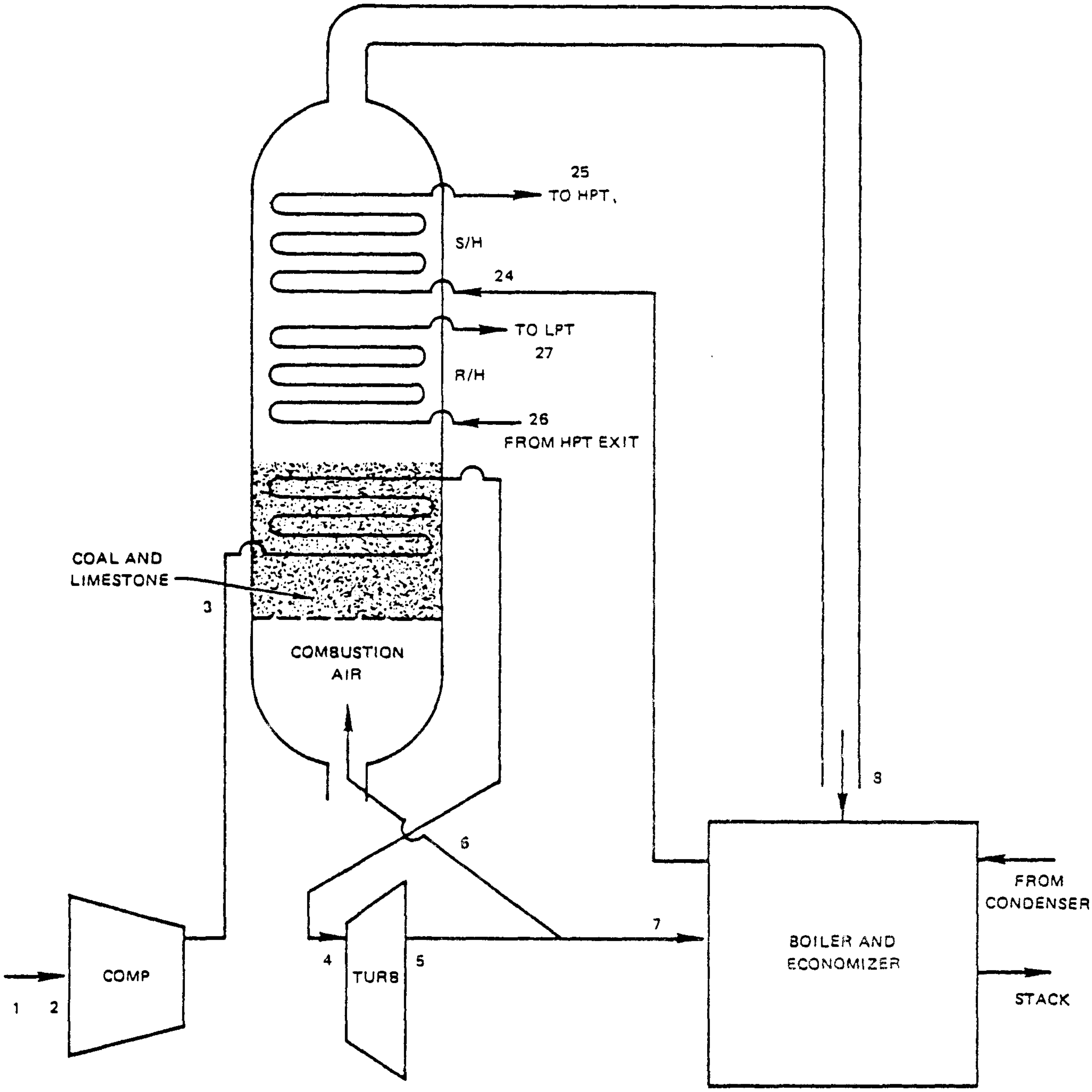


FIGURE G-1

7.4 DISCUSSION

The AFB/Semi-Closed Turbine cycle offers an efficiency higher than a conventional pulverized coal fired utility station with flue gas desulfurization and is comparable to that of the PFB/AFB scheme studied in Subtask 1.2. In addition to the problems associated with the steam cooled AFB units, a major technical problem facing this concept is the development of high temperature (1500F-1700F) corrosion/erosion resistant heat transfer materials suitable for use in a coal fired fluidized bed environment.

On the basis of this preliminary study, the following actions are recommended:

a. Design and develop a conceptual utility sized power plant utilizing the AFB/Semi-Closed Turbine Cycle.

b. Develop a cost estimate for the plant to compare with the other alternatives discussed herein.

c. Compare development effort required to commercialize this concept to that required for other alternatives studied.

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9.0 APPENDICES

Following three sections are appended herein:

9.1 LITERATURE SURVEYED

9.2 MASS BALANCES FOR DEVOLATILIZER SCHEMES

9.3 AFBC POWER PLANT DESIGN DESCRIPTION

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9.2 DEVOLATILIZER/PFB SCHEME

Figure H-1 depicts the gas turbine inlet temperature attainable with various combinations of air cooling and steam cooling.

Tables H-1, H-2 and H-3 show the mass balances for 100%, 60% and 20% air cooling, respectively, of the pressurized fluidized bed.

TEMPERATURE TO GAS TURBINE VERSUS

% AIR COOLING OF PFB COMBUSTOR

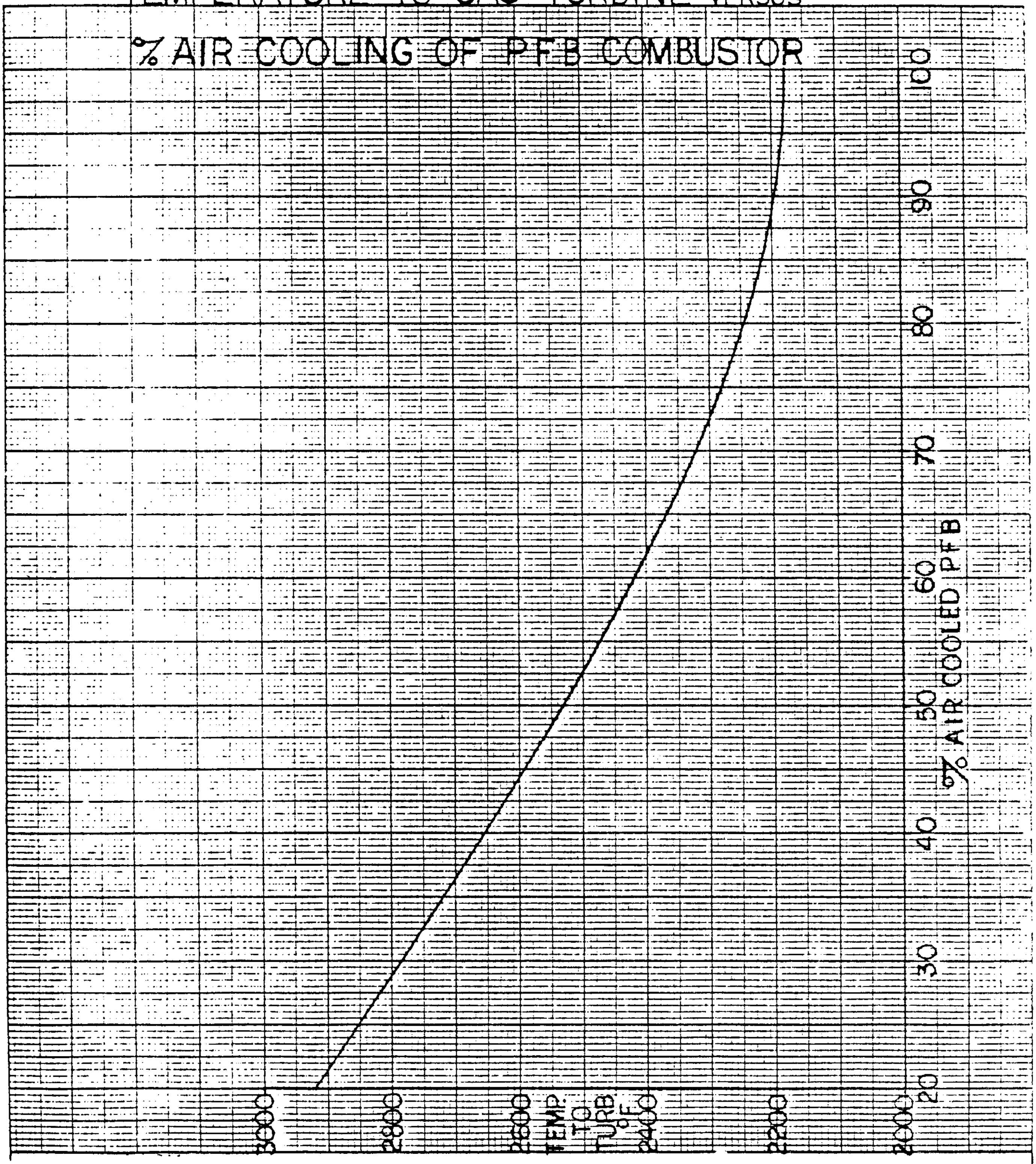

FIGURE H-1

TABLE H-1

MASS BALANCE FOR 100% AIR COOLING

100% AIR COOLED PFB

	1	2	3	4	5
	COAL LB/HR	DOLOMITE LB/HR	TURBINE AIR LB/HR	COMBUSTION AIR GAC LB/HR	COMBUSTION AIR PFB LB/HR
CO	-	-	-	-	-
CO_2	-	-	-	-	-
C_v	-	-	-	-	-
H_v	-	-	-	-	-
H_2	4,563	-	-	-	-
H_2O	2,188	190	30,455	22,452	29,846
H_2S	-	-	-	-	-
SO_2	-	-	-	-	-
O_2	7,676	34	545,681	402,291	534,785
N_2	1,780	114	1,797,489	1,325,188	1,761,635
C	64,833	-	-	-	-
S	3,221	-	-	-	-
$MgCO_3$	-	7,728	-	-	-
$CaCO_3$	-	10,056	-	-	-
MgO	-	-	-	-	-
CaO	-	-	-	-	-
CaS	-	-	-	-	-
$CaSO_4$	-	-	-	-	-
INERT	-	873	-	-	-
ASH	10,347	-	-	-	-
TOTAL	94,608	18,995	2,373,625	1,749,931	2,326,266
GAS	714	150	2,373,625	1,749,931	2,326,266
SOLID	93,894	18,845	-	-	-
TEMP.	77° F	77° F	600° F	1575° F	600° F
PRESS.	122 PSIG	122 PSIG	132 PSIG	125 PSIG	132 PSIG

100% AIR COOLED PFB

	6	7	8	9	10
	TRANSPORT AIR CHAR LB/HR	TRANSPORT AIR STONE LB/HR	VENT AIR COAL LB/HR	VENT AIR DOLOMITE LB/HR	SPENT STONE LB/HR
CO	-	-	-	-	-
CO_2	-	-	-	-	-
C_v	-	-	-	-	-
H_v	-	-	-	-	-
H_2	-	-	-	-	-
H_2O	504	64	24	6	-
H_2S	-	-	-	-	-
SO_2	-	-	-	-	-
O_2	9,033	1,134	418	103	-
N_2	29,754	3,738	1,375	342	-
C	-	-	-	-	-
S	-	-	-	-	-
$MgCO_3$	-	-	-	-	-
$CaCO_3$	-	-	-	-	-
MgO	-	-	-	-	2,329
CaO	-	-	-	-	140
CaS	-	-	-	-	-
$CaSO_4$	-	-	-	-	8,272
INERT	-	-	-	-	551
ASH	-	-	-	-	-
TOTAL	39,291	4,936	1,817	451	11,292
GAS	39,291	4,936	1,817	451	-
SOLID	-	-	-	-	11,292
TEMP.	150° F	150° F	150° F	150° F	1650° F
PRESS.	140 PSIG	140 PSIG	130 PSIG	130 PSIG	ATM

100% AIR COOLED PFB

	11	12	13	14	15
	PFB FLUE GAS LB/HR	ASH LB/HR	BY PASSED FLUE GAS LB/HR	FLUE GAS TO DEVOL. LB/HR	STONE TO PFB LB/HR
CO	-	-	-	-	-
CO_2	162,116	-	78,851	83,264	-
C_v	-	-	-	-	-
H_v	-	-	-	-	-
H_2	-	-	-	-	-
H_2O	7,962	-	3,868	4,094	-
H_2S	-	-	-	-	-
SO_2	-	-	-	-	-
O_2	18,610	-	9,052	9,558	-
N_2	469,898	-	228,545	241,353	-
C	-	-	-	-	-
S	-	-	-	-	-
$MgCO_3$	-	-	-	-	-
$CaCO_3$	-	-	-	-	-
MgO	1,371	1,371	-	-	2,329
CaO	84	84	-	-	140
CaS	-	-	-	-	4,385
$CaSO_4$	4,854	4,854	-	-	-
INERT	319	319	-	-	551
ASH	10,347	10,197	73	77	-
TOTAL	675,561	16,825	320,389	338,346	7,405
GAS	658,586	-	320,316	338,269	-
SOLID	16,975	16,825	73	77	7,405
TEMP.	1650° F	1650° F	1650° F	1650° F	500° F
PRESS.	125 PSIG	ATM	122 PSIG	122 PSIG	115 PSIG

100% AIR COOLED PFB

	16	17	18	19
	CHAR TO PFB LB/HR	VOLATILE GAS LB/HR	COMBUSTION AIR GAC LB/HR	TURBINE GAS LB/HR
CO	-	8,396	-	-
CO_2	-	91,720	78,851	248,394
C_v	-	16,990	-	-
H_v	-	2,991	-	-
H_2	-	-	-	-
H_2O	-	20,515	26,320	73,637
H_2S	-	137	-	-
SO_2	-	-	-	257
O_2	-	-	411,344	335,623
N_2	-	243,246	1,553,733	1,796,980
C	44,243	647	-	-
S	-	-	-	-
$MgCO_3$	-	-	-	-
$CaCO_3$	-	-	-	-
MgO	1,371	-	-	-
CaO	84	-	-	-
CaS	2,572	-	-	-
$CaSO_4$	-	-	-	-
INERT	319	-	-	-
ASH	10,347	150	73	223
TOTAL	58,936	384,792	2,070,321	2,455,114
GAS	-	383,995	2,070,248	2,454,891
SOLID	58,936	797	73	223
TEMP.	500° F	1500° F	1587° F	2178° F
PRESS.	112 PSIG	110 PSIG	122 PSIG	110 PSIG

Q	MM Btu/HR
AIR COOLER	5.32
STONE COOLER	1.76
CHAR COOLER	19.15

TABLE H-2

MASS BALANCE FOR 60% AIR COOLING

60% AIR COOLED PFB ⇒ 184.5 MM Btu/hr TO STEAM

	1	2	3	4	5
	COAL LB/HR	DOLOMITE LB/HR	TURBINE AIR LB/HR	COMBUSTION AIR GAC LB/HR	COMBUSTION AIR PFB LB/HR
CO	-	-	-	-	-
CO_2	-	-	-	-	-
C_v	-	-	-	-	-
H_v	-	-	-	-	-
H_2	6,472	-	-	-	-
H_2O	3,103	269	30,455	19,104	29,608
H_2S	-	-	-	-	-
SO_2	-	-	-	-	-
O_2	10,888	48	545,681	342,303	530,512
N_2	2,525	162	1,797,489	1,127,579	1,747,557
C	91,959	-	-	-	-
S	4,569	-	-	-	-
$MgCO_3$	-	10,961	-	-	-
$CaCO_3$	-	14,263	-	-	-
MgO	-	-	-	-	-
CaO	-	-	-	-	-
CaS	-	-	-	-	-
$CaSO_4$	-	-	-	-	-
INERT	-	1,238	-	-	-
ASH	14,676	-	-	-	-
TOTAL	134,192	26,941	2,373,625	1,488,986	2,307,677
GAS	1,013	213	2,373,625	1,488,986	2,307,677
SOLID	133,179	26,728	-	-	-
TEMP.	77° F	77° F	600° F	1575° F	600° F
PRESS.	122 PSIG	122 PSIG	132 PSIG	125 PSIG	132 PSIG

60% AIR COOLED PFB

	6	7	8	9	10
	TRANSPORT AIR CHAR LB/HR	TRANSPORT AIR STONE LB/HR	VENT AIR COAL LB/HR	VENT AIR DOLOMITE LB/HR	SPENT STONE LB/HR
CO	-	-	-	-	-
CO_2	-	-	-	-	-
C_v	-	-	-	-	-
H_v	-	-	-	-	-
H_2	-	-	-	-	-
H_2O	715	91	34	9	-
H_2S	-	-	-	-	-
SO_2	-	-	-	-	-
O_2	12,812	1,608	593	146	-
N_2	42,203	5,302	1,950	485	-
C	-	-	-	-	-
S	-	-	-	-	-
$MgCO_3$	-	-	-	-	-
$CaCO_3$	-	-	-	-	-
MgO	-	-	-	-	3,303
CaO	-	-	-	-	199
CaS	-	-	-	-	-
$CaSO_4$	-	-	-	-	11,733
INERT	-	-	-	-	782
ASH	-	-	-	-	-
TOTAL	55,730	7,001	2,577	640	16,017
GAS	55,730	7,001	2,577	640	-
SOLID	-	-	-	-	16,017
TEMP.	150° F	150° F	150° F	150° F	1650° F
PRESS.	140 PSIG	140 PSIG	130 PSIG	130 PSIG	ATM

60% AIR COOLED PFB

	11	12	13	14	15
	PFB FLUE GAS LB/HR	ASH LB/HR	BY PASSED FLUE GAS LB/HR	FLUE GAS TO DEVOL. LB/HR	STONE TO PFB LB/HR
CO	-	-	-	-	-
CO_2	229,945	-	111,842	118,101	-
C_v	-	-	-	-	-
H_v	-	-	-	-	-
H_2	-	-	-	-	-
H_2O	11,293	-	5,486	5,807	-
H_2S	-	-	-	-	-
SO_2	-	-	-	-	-
O_2	26,396	-	12,839	13,557	-
N_2	666,502	-	324,168	342,334	-
C	-	-	-	-	-
S	-	-	-	-	-
$MgCO_3$	-	-	-	-	-
$CaCO_3$	-	-	-	-	-
MgO	1,945	1,945	-	-	3,303
CaO	119	119	-	-	199
CaS	-	-	-	-	6,220
$CaSO_4$	6,885	6,885	-	-	-
INERT	452	452	-	-	782
ASH	14,676	14,463	104	109	-
TOTAL	958,213	23,864	454,439	479,908	10,504
GAS	934,136	-	454,335	479,799	-
SOLID	24,077	23,864	104	109	10,504
TEMP.	1650° F	1650° F	1650° F	1650° F	500° F
PRESS.	125 PSIG	ATM	122 PSIG	122 PSIG	115 PSIG

60% AIR COOLED PFB

	16	17	18	19
	CHAR TO PFB LB/HR	VOLATILE GAS LB/HR	COMBUSTION AIR GAC LB/HR	TURBINE GAS LB/HR
CO	-	11,909	-	-
CO_2	-	130,095	111,842	352,321
C_v	-	24,099	-	-
H_v	-	4,242	-	-
H_2	-	-	-	-
H_2O	-	29,098	24,591	91,705
H_2S	-	194	-	-
SO_2	-	-	-	365
O_2	-	-	355,143	247,740
N_2	-	345,019	1,451,747	1,796,766
C	62,754	918	-	-
S	-	-	-	-
$MgCO_3$	-	-	-	-
$CaCO_3$	-	-	-	-
MgO	1,945	-	-	-
CaO	119	-	-	-
CaS	3,648	-	-	-
$CaSO_4$	-	-	-	-
INERT	452	-	-	-
ASH	14,676	213	104	316
TOTAL	83,594	545,787	1,943,427	2,489,213
GAS	-	544,656	1,943,323	2,488,897
SOLID	83,594	1,131	104	316
TEMP.	500° F	1500° F	1593 ° F	2419 ° F
PRESS.	112 PSIG	110 PSIG	122 PSIG	110 PSIG

Q	MM Btu/HR
AIR COOLER	7.55
STONE COOLER	2.50
CHAR COOLER	27.16

TABLE H-3

MASS BALANCE FOR 20% AIR COOLING

20% AIR COOLED PFB => 369 MM Btu/hr To STEAM

	1	2	3	4	5
	COAL LB/HR	DOLOMITE LB/HR	TURBINE AIR LB/HR	COMBUSTION AIR GAC LB/HR	COMBUSTION AIR PFB LB/HR
CO	-	-	-	-	-
CO_2	-	-	-	-	-
C_v	-	-	-	-	-
H_v	-	-	-	-	-
H_2	11,124	-	-	-	-
H_2O	5,334	463	30,455	10,946	29,001
H_2S	-	-	-	-	-
SO_2	-	-	-	-	-
O_2	18,714	83	545,681	196,118	519,620
N_2	4,340	278	1,797,489	646,027	1,711,651
C	158,059	-	-	-	-
S	7,853	-	-	-	-
$MgCO_3$	-	18,840	-	-	-
$CaCO_3$	-	24,516	-	-	-
MgO	-	-	-	-	-
CaO	-	-	-	-	-
CaS	-	-	-	-	-
$CaSO_4$	-	-	-	-	-
INERT	-	2,128	-	-	-
ASH	25,225	-	-	-	-
TOTAL	230,649	46,308	2,373,625	853,091	2,260,272
GAS	1,741	365	2,373,625	853,091	2,260,272
SOLID	228,908	45,943	-	-	-
TEMP.	77° F	77° F	600° F	1575° F	600° F
PRESS.	122 PSIG	122 PSIG	132 PSIG	125 PSIG	132 PSIG

20% AIR COOLED PFB

	6	7	8	9	10
	TRANSPORT AIR CHAR LB/HR	TRANSPORT AIR STONE LB/HR	VENT AIR COAL LB/HR	VENT AIR DOLOMITE LB/HR	SPENT STONE LB/HR
CO	-	-	-	-	-
CO_2	-	-	-	-	-
C_v	-	-	-	-	-
H_v	-	-	-	-	-
H_2	-	-	-	-	-
H_2O	1,229	156	59	15	-
H_2S	-	-	-	-	-
SO_2	-	-	-	-	-
O_2	22,022	2,765	1,019	251	-
N_2	72,538	9,113	3,352	834	-
C	-	-	-	-	-
S	-	-	-	-	-
$MgCO_3$	-	-	-	-	-
$CaCO_3$	-	-	-	-	-
MgO	-	-	-	-	5,678
CaO	-	-	-	-	341
CaS	-	-	-	-	-
$CaSO_4$	-	-	-	-	20,167
INERT	-	-	-	-	1,343
ASH	-	-	-	-	-
TOTAL	95,789	12,034	4,430	1,100	27,529
GAS	95,789	12,034	4,430	1,100	-
SOLID	-	-	-	-	27,529
TEMP.	150° F	150° F	150° F	150° F	1650° F
PRESS.	140 PSIG	140 PSIG	130 PSIG	130 PSIG	ATM

20% AIR COOLED PFB

	11	12	13	14	15
	PFB FLUE GAS LB/HR	ASH LB/HR	BY PASSED FLUE GAS LB/HR	FLUE GAS TO DEVOL. LB/HR	STONE TO PFB LB/HR
CO	-	-	-	-	-
CO_2	395,229	-	192,234	202,993	-
C_v	-	-	-	-	-
H_v	-	-	-	-	-
H_2	-	-	-	-	-
H_2O	19,411	-	9,430	9,981	-
H_2S	-	-	-	-	-
SO_2	-	-	-	-	-
O_2	45,370	-	22,068	23,302	-
N_2	1,145,583	-	557,179	588,404	-
C	-	-	-	-	-
S	-	-	-	-	-
$MgCO_3$	-	-	-	-	-
$CaCO_3$	-	-	-	-	-
MgO	3,342	3,342	-	-	5,678
CaO	205	205	-	-	341
CaS	-	-	-	-	10,690
$CaSO_4$	11,834	11,834	-	-	-
INERT	778	778	-	-	1,343
ASH	25,225	24,860	178	188	-
TOTAL	1,646,977	41,019	781,089	824,868	18,052
GAS	1,605,593	-	780,911	824,680	-
SOLID	41,384	41,019	178	188	18,052
TEMP.	1650° F	1650° F	1650° F	1650° F	500° F
PRESS.	125 PSIG	ATM	122 PSIG	122 PSIG	115 PSIG

20% AIR COOLED PFB

	16	17	18	19
	CHAR TO PFB LB/HR	VOLATILE GAS LB/HR	COMBUSTION AIR GAC LB/HR	TURBINE GAS LB/HR
CO	-	20,469	-	-
CO_2	-	223,608	192,234	605,570
C_v	-	41,421	-	-
H_v	-	7,292	-	-
H_2	-	-	-	-
H_2O	-	50,014	20,376	135,732
H_2S	-	334	-	-
SO_2	-	-	-	627
O_2	-	-	219,420	34,816
N_2	-	593,019	1,203,207	1,796,226
C	107,862	1,577	-	-
S	-	-	-	-
$MgCO_3$	-	-	-	-
$CaCO_3$	-	-	-	-
MgO	3,342	-	-	-
CaO	205	-	-	-
CaS	6,270	-	-	-
$CaSO_4$	-	-	-	-
INERT	778	-	-	-
ASH	25,225	366	178	544
TOTAL	143,682	938,100	1,635,415	2,573,515
GAS	-	936,157	1,635,237	2,572,971
SOLID	143,682	1,943	178	544
TEMP.	500° F	1500° F	1612° F	2920° F
PRESS.	112 PSIG	110 PSIG	122 PSIG	110 PSIG

Q	MM Btu/HR
AIR COOLER	12.97
STONE COOLER	4.29
CHAR COOLER	46.69

B&W EQUIPMENT SCOPE OF SUPPLY

	Weights Per System		
	Wt. per Unit Lbs.	No. Units	Total Wt. Lb.
Coal Lock Hoppers	9,110	2	18,220
Dolomite Lock Hoppers	4,637	2	9,274
Coal Feed Tank	12,081	1	12,081
Dolomite Feed Tank	7,079	1	7,079
Devolatilizer	368,911	1	368,911
Devolatilizer Cyclones	194,250	2	388,500
Char Holding Tanks	9,110	2	18,220
Stone Holding Tank	4,637	1	4,637
Char and Stone Coolers			
1Q2424-6	26,790	1	26,790
1S2420-6	7,650	2	15,300
1S714-4	1,670	1	1,670
1S710-4	1,350	1	1,350
Char Feed Tanks	9,110	2	18,220
Stone Feed Tanks	4,637	2	9,274
Char Splitters	200	2	400
Stone Splitters	150	2	300
PFB	1,062,354	2	2,124,708
Spent Stone Lock Hopper	4,637	4	18,548
PFB Cyclones	126,000	4	504,000
Ash Holding Tanks	4,637	4	18,548
Ash Lock Hoppers	3,100	4	12,400
Air Cooler	5,828	1	5,828
Booster Compressor	7,245	1	7,245
Transport Receiver	8,337	1	8,337
Valves		Lot	54,771
Structural Steel		Lot	669,608
			4,324,219

9.3 AFBC POWER PLANT DESIGN

This section has been excerpted from the Executive Summary of Reference 4.

SECTION 4

AFBC POWER PLANT DESIGN

The conceptual design of the AFBC plant was completed in sufficient detail to permit a technical and economic comparison of the AFBC plant with an equivalent pulverized coal-fired (PCF) plant with a flue gas desulfurization (FGD) system.

The plant site is a representative location, situated in the western half of the United States with available utilities and transportation. The site acreage is approximately 443 acres with a river on its east boundary. The plant structures include a boiler house, turbine generator building, service building, bag filter house, stack, and mechanical draft cooling towers. Other facilities include a transformer yard, electrical switch-yard, live and dead coal piles, live and dead limestone piles, make-up water treatment area, pretreatment area, sewage treatment plant, and ash and spent sorbent area. An artist's rendering of the plant site is shown on the cover of this report, and drawings of the plant site and plant island arrangement are included in Appendix A.

The AFBC plant is a nominal 600 MWe plant utilizing a 2400 psig/1000^{o}F/1000^{o}F steam cycle. A summary description of the major plant systems is presented in this section.

4.1 The AFBC Steam Generator

Six conceptual boiler designs were developed and evaluated by Combustion Engineering, Inc. The arrangement of all beds at a single elevation - "ranch style" - was selected for the conceptual design of the commercial plant as the most economic and technically attractive alternate.

The "ranch style" design was selected for the following reasons:

a. Access to the beds is easier. In the event that major maintenance operations are necessary (such as replacement of bed tube bundles or replacement of complete modules), such operations can be carried out more easily with the ranch design.

b. Access to the coal/limestone feed lines is convenient, as all feed lines are near ground level. Long vertical runs of coal/limestone handling equipment are eliminated.

c. Fewer sealing problems exist. The coal feed lines penetrate air plenum ductwork instead of a wall of tubes.

d. Fewer buckstay problems exist. Internal tie tubes can be used for buckstay support of the bed modules.

e. CE performed cost comparisons for pressure parts, support steel, and erection, and found the ranch style design to be approximately 1.5 million dollars (1977 price levels) less expensive than the other designs considered.

General arrangement and sectional view drawings of the AFBC boiler building are presented in Appendix A.

The principal features of this design are the bottom-supported beds, a vertical-surface top-supported convection pass, and a separate water-cooled carbon burn-up cell (CBC) enclosure.

The design is based on the utilization of non-compliance western coal from the Felix coal bed in the Powder River Basin in Wyoming. It has a design sulfur content of 0.89% and a heating value of 8053 Btu/lb, and thus requires 46% SO_2 removal to meet the emission standard of 1.2 lbs $SO_2/10^6$ Btu fired.

A main bed superficial velocity of 12 ft/sec was selected as an optimum design velocity based on obtaining proper bed operating performance with minimum costs. Based on this fluidizing velocity and the 46% sulfur removal requirement, a Ca/S mole ratio of 2.3 to 1 was determined.

The unit is capable of meeting emission standards while burning 3.26%S coal (the upper sulfur content of the design coal). This maximum sulfur condition would require 85% sulfur removal which results in a required Ca/S mole ratio of 4 to 1. The economic analysis is based on design - not maximum sulfur - operation.

The boiler is sized for main steam output of 4,300,000 lb/hr at maximum continuous rating (MCR) condition. This covers the turbine requirements at maximum calculated capacity with the throttle valves wide open and 5% overpressure and a margin of 68,000 lbs/hr for auxiliary services.

4.1.1 Bed Modules

The steam generator combustor is of modular design. The total main bed area is 6408 ft^2, divided into twenty (20) independent 9' x 36' beds, designed in two rows of ten beds each. The beds include eight 9' x 36' evaporator modules, eight 9' x 36' superheater modules and eight 9' x 17' reheater modules. The total CBC bed area is 1080 ft^2, divided into four 9' x 30' beds.

The main beds operate at 1550°F, 12 ft/sec. and 20% excess air. The CBC beds operate at 2000°F, 9 ft/sec. and 25% excess air.

Each bed module is an independent, bottom supported, fluidized-bed unit and is formed from horizontal wrap-around waterwall tubes, submerged bed surfaces and a grid plate. Each is designed for proper bed performance, shop fabrication and rail shippability and also for ease of maintenance. The modular design requires no waterwall to waterwall seals between the air and gas passes that the stacked bed design would require.

4.1.2 Furnace Hood and Convection Pass

The main bed area of the AFBC boiler is enclosed by a single, top-supported, water cooled hood. Furnace width remains constant at 76 ft while furnace depth is 112 ft at the level of the beds, decreasing to 36 ft at the throat where the gas velocity increases to 30 ft/sec.

Convection pass surface is provided for intermediate and finishing superheater duty, intermediate and finishing reheater duty and economizer duty.

The maximum gas velocity in the convection pass is 50 ft/sec. This velocity is selected to minimize tube erosion from particulates in the gas stream while achieving satisfactory convective heat transfer rates. Although the particulate loading in the flue gas is high, erosion is not expected to be a problem at this velocity since the combustor operating temperature is maintained well below the coal ash fusion point and the coal ash is relatively soft.

4.1.3 Boiler Seals

Because the hood area is top-supported, and the bed modules are bottom supported, expansion joints are required to allow for differential thermal expansion. Seals are also provided at the interface between the hood and the bed walls. Expansion joints are also provided at gaps between the modules.

The peripheral seal between the bed modules and the furnace hood is made of a sloping refractory shelf, supported by stainless steel plates and brackets attached to the bed module waterwalls, and a flexible seal expansion joint. The refractory shelf shields the expansion joint from direct gas radiation exposure and from dust and solids that would otherwise accumulate on the seal.

The seal between the bed modules is made of a removable refractory shelf, a supporting plate and a stainless steel seal plate placed on the attachments to the bed module waterwalls.

4.1.4 Circulation System

Controlled-circulation (using boiler water circulating pumps) is selected for this boiler to insure maintenance of proper boiler water flow rates across heat transfer surfaces.

Four circulating pumps take suction from the downcomers and convey the water through the evaporation tubes in the beds and furnace walls returning the steam-water mixture to the drum.

4.2 Steam Generator Auxiliary Systems

4.2.1 Air and Gas Handling System

a. Forced Draft and Induced Draft Fans

Two (2) forced draft fans are provided to supply combustion air to the main beds and CBC beds as well as to supply auxiliary air. Centrifugal fans are selected to meet the design requirements of high air volume and high static pressures.

Four (4) induced draft fans are provided to handle the flue gas from the main beds and CBC beds, through the air heater and particulate removal equipment to the stack. Axial fans are selected based on the relatively clean gas leaving the bag filter, the low static pressure required, and total installed cost.

All fans are driven with electric motors. The two FD fan motors are of 12,500 hp each, while four 4,000 hp motors are required for the ID fans.

b. Primary and Secondary Cyclones

The primary and secondary cyclones (mechanical dust collectors) handle the first stage of particulate removal in the AFBC boiler flue gas stream. The two (2) primary cyclones collect particles elutriated from the main beds while the two (2) secondary cyclones collect particles elutriated from the CBC beds.

The primary cyclones have a guaranteed removal efficiency of 98%, based on the assumed inlet particle size distribution and a 3.1" w.g. pressure drop. Due to the lack of operating data on cyclones collecting fluidized bed particles with extensive variation in particle size distribution, a conservative design efficiency of 90% is assumed. The secondary cyclones have a guaranteed efficiency of 95% with a 2.9" w.g. pressure drop. However, a conservative collection efficiency of 80% is assumed.

c. Air Heaters

Two (2) 33-VI-112 Ljungstrom regenerative type air heaters are provided for the AFBC unit. These air heaters are suitable for the high differential pressure and high dust loadings that they will be subjected to in this AFBC application.

d. Baghouse

A baghouse is selected for final particulate emission control over an electrostatic precipitator (ESP). This selection is based on the uncertainty of ESP collection characteristics with low sulfur content flue gas and high limestone loading, as well as higher ESP power requirements. Baghouse performance is independent of flue gas sulfur content, and is comparable in overall cost to an ESP. The baghouse selected has a 99% + collection efficiency which is more than sufficient to meet the particulate emission requirements.

4.2.2 Fuel Feed Systems

a. Coal and Limestone Feed System

The coal and limestone feed system transports sized coal (¼" x 0) and limestone (1/8" x 0) from the coal and limestone bunkers to the main beds and CBC beds as required. These two feed streams, one from each bunker, are mixed in a surge hopper at the entrance to a Fuller-Kinyon pump. At this point the feed material is placed in a semi-dense phase transport system utilizing a screw conveyor/seal and compressed air as the conveying media. The feed material then undergoes a 4:1 split and then a 9:1 split; so that 36 feed lines are supplied from each pair of bunkers. These 36 lines feed material from below the grid plate into two beds, (each bed having 18 feed points, or one feed point for every 18 sq. ft. of bed area).

b. CBC Recycle Feed System

The carbon rich particulates are collected in the primary cyclones and transported into the CBC beds from below the grid plates by two Fuller-Kinyon pumps.

c. Warm-Up/Ignitor Systems

In order to start up an individual fluidized-bed from ambient temperature, an oil-fired bed preheat and an ignition system are provided. Warm-up ignitors are located in the main duct-work to increase the overall gas temperature to 400°F and a second ignitor system is located in the toggle section to provide additional heat capable of raising the gas temperature to 750°F before entering the bed.

When the bed solids have reached a temperature of 600°F, a positive ignition source is provided by oil burners firing into the bed. As a stable coal fire rate is obtained, oil firing is cut back.

4.2.3 Bed Ash Handling System

The bed ash handling system is provided to remove spent hot bed material, recover some of its heat, meter the flow rate and transport waste solids to a silo. Drain holes are located in the grid plates of the beds at a spacing of one drain hole for every 100-110 square feet of bed area. The high temperature bed ash handling system drains the bed material through high temperature rotary feed valves to the bed solids cooler. The bed solids cooler utilizes ambient air to cool the solids. The air exhausts from the cooler at about $700^{\circ}F$ and is returned to the boiler flue gas system for heat recovery. The bed solids are cooled to $250^{\circ}F$ and pneumatically transported to the plant solid waste storage silo.

4.3 Balance of Plant

4.3.1 Turbine Generator

The turbine generator selected for the AFBC plant is guaranteed for a 568,215 kW gross output at 2.5 in Hg back pressure and 0 percent makeup. The maximum capability of this turbine generator is 620,180 kW with valves wide open and 5 percent overpressure at the throttle. The turbine is a tandem compound four flow machine with 30 inch last stage blade length. The turbine speed is 3600 rpm and the throttle conditions are 2400 psig and 1000°F with one reheat to 1000°F. The generator is rated at 683,000 kVa at 60 psig H_2 pressure and 0.90 power factor with 24 kV terminal voltage.

4.3.2 Heat Rejection Systems

A heat rejection system optimization study was performed evaluating various types and sizes of cooling towers and surface condensers. As a result of this evaluation, a single pass condenser of 324,000 sq. ft. heat transfer surface with 45 ft. long, 1¼ inch O.D. 18 BWG admiralty tubes, was selected.

The cooling towers are of the rectangular, wooden, mechanical induced draft type, constructed in two sections of seven cells each.

Make-up water for the circulating water system is screened, clarified river water.

Cooling water for most plant auxiliary equipment is provided by a closed cooling water system which is cooled by circulating water. The closed cooling water system is comprised of a surge tank, two-100% capacity heat exchangers and two-100% cooling water pumps.

Large cooling water users such as main turbine lube oil, hydrogen coolers are cooled directly by circulating water supplied by two circulating water booster pumps.

4.3.3 Condensate-Feedwater System

The power cycle uses seven stages of feedwater heating. Three 50% capacity electric motor driven can-type condensate pumps take suction from the condenser hotwell and forward the condensate through the condensate polishing demineralizer, steam packing exhauster, low pressure feedwater heaters No. 1, 2, 3 and 4 to the deaerator.

Feedwater heater No. 1 is located in the condenser neck. All others are external to the condenser.

Two 60% capacity steam turbine driven boiler feed pumps take suction from the deaerator storage tank and forward the feedwater through the high pressure feedwater heaters No. 6 and 7 to the boiler economizer inlet.

The boiler feed pump turbine drives normally use extraction steam with main steam backup for low load operation and start-up.

4.3.4 Coal and Limestone Handling System

Coal and limestone is normally delivered to the plant by river barges of 1500 ton capacity. As a back-up for emergencies such as a frozen river, work stoppages or other interruptions of regular supply of coal and limestone by barge, a rail and truck delivery system is provided. This system uses bottom hopper unloading to underground track hoppers from which coal and limestone are transported by belt conveyors to the storage piles.

Coal and limestone arriving by barges are unloaded by a vertical bucket type barge unloader and transfer station. From there the material is transported by conveyors through sampling and weighing stations to a traveling stacker which discharges to either the coal or limestone live piles.

Dead storage piles for 60 day operation are provided for both coal and limestone.

Separate reclaim systems are used for coal and limestone, each consisting of reclaim tunnels, vibrating feeders, conveyors, crusher-dryers, sampling and weighing equipment, discharging into the boiler house coal or limestone bunkers.

The live storage piles are sized for 72 hour operation, while the boiler house bunkers have a storage capacity of approximately 12 hour full load operation.

The entire coal and limestone handling system is designed to minimize fire hazards and dust emissions to the environment.

4.3.5 Spent Sorbent and Ash Handling System

The spent sorbent extracted from the fluidized beds is cooled by air and conveyed dry by a pneumatic conveying system to a spent sorbent silo.

Flyash collected from the baghouse, secondary cyclone and air preheater are conveyed to the flyash silo by a pneumatic conveying system.

Both the bed discards and the flyash silos are designed for 72 hours storage capacity. The pneumatic conveyors are connected in parallel to both silos to provide for flexibility in operation.

Normal disposal of bed discards and flyash is by trucking this material away either for commercial utilization or for depositing in a suitable and ecologically acceptable location.

For temporary or emergency disposal an ash pond is provided on the plant site to which material is transported by means of a pneumatic conveying system.

For this purpose each silo is equipped with two aerated discharge hoppers and dust conditioning unloaders for trucks and a third hopper directly connected by means of an air lock valve to the pressure conveyor.

4.4 Plant Performance

4.4.1 Turbine-Generator Output

The designs for both the AFBC and PCF plants compared in this study are based on the same turbine generator output and power cycle arrangement. The maximum guaranteed (rated) turbine generator output is 568,215 kW.

4.4.2 Auxiliary Power Requirements

The electric power required for the motor driven auxiliary equipment of each plant is taken from the auxiliary power transformers and, therefore, must be subtracted from the generator output to calculate the net plant output. A summary of auxiliary power requirements for the AFBC plant and for the PCF plant with FGD are presented in Exhibit 4-1.

Exhibit 4-1 shows that the total auxiliary electric power requirements for the PCF plant with FGD are substantially larger than those of the AFBC plant.

The AFBC boiler requires much larger FD fans and additional fuel feeding equipment such as Fuller-Kinyon pumps, conveying air compressors, baghouse fan, etc. However, the fact that it does not require coal mills, primary air fans, precipitators and flue gas desulfurization equipment leads to the overall lower auxiliary power requirement of the AFBC plant.

4.4.3 Net Plant Output

The net plant output is the power available for ultimate delivery from the plant. The net plant output is obtained by subtracting the auxiliary power from the generator output. Although the turbine-generator output for both the AFBC and PCF plants are the same, the different auxiliary power requirements of these plants result in differences in net plant power output. The net plant output at maximum guaranteed turbine operation is shown in Exhibit 4-2 to be 535,905 kW and 532,219 kW for the AFBC and PCF plants, respectively.

4.4.4 Net Plant Heat Rate

The ratio of boiler heat input to net plant power output is defined as the net plant heat rate. Due to differing boiler efficiencies and plant auxiliary power requirements, the net plant heat rates for the AFBC plant and the PCF plant with FGD differ. A summary of performance data and the net plant heat rates for the AFBC and PCF plants is presented in Exhibit 4-2.

In the calculation of the net plant heat rates the auxiliary steam requirements are taken into account.

4.5 Environmental Aspects

An Environmental Analysis Report for the AFBC Electric Power Generating Plant is presented in Volume III of this report.

The report evaluates the overall environmental impact of the 600 MWe AFBC plant design. To accomplish this, the following are considered:

a. Sources of emissions/effluents
b. Characteristics of gaseous, liquid and solid wastes
c. Capability for compliance with existing and projected environmental regulations
d. Options for environmental control
e. Land use
f. Health and safety
g. Socioeconomic impacts

The report concludes that AFBC technology is an effective means of burning non-compliance coal in an environmentally acceptable manner.

SO_2 and NO_x levels are maintained below federal emission standard levels by control of limestone feed rate and fluidized bed combustion parameters while particulate emissions are held below federal limits by use of conventional particulate control equipment.

A major concern regarding environmental effects of AFBC technology, however, is the solid waste generated and the disposal of this material in an environmentally acceptable manner. Research is presently underway to find methods of increasing sorbent utilization, thereby minimizing waste production. In addition, studies are being conducted to determine commercial uses for the waste material as well as to find ways to minimize the environmental effects of disposal.

EXHIBIT 4-1

PLANT AUXILIARY POWER SUMMARY

AT MAXIMUM GUARANTEED TURBINE OUTPUT

SYSTEM	POWER (kW)	
	AFBC	PCF
BOILER HOUSE		
Coal Mills	-	3357
Primary Air Fans	-	4476
Forced Draft Fans	10119	3238
Induced Draft Fans	5786	5595
Boiler Circulation Pumps	1938	2133
Feed System Compressor	1255	-
Bed Solids Transport System	531	-
Precipitators	-	1000
Fuller Kinyon Feed System	432	-
Bed Solids Cooler Fans	186	-
Baghouse Fan	100	-
Miscellaneous Motors	159	571
Boiler House Subtotal	20,506	20,370
TURBINE GENERATOR BUILDING		
Condensate Pumps	1399	1399
Circulating Water Booster Pumps	168	168
Station Air Compressors	140	140
Closed Cooling Water Pumps	112	112
Condenser Vacuum Pump	112	112
Miscellaneous Motors	308	308
Turbine Generator Bldg. Subtotal	2,239	2,239
BALANCE OF PLANT		
Coal & Limestone Handling	533	403
Service Building HVAC	64	64
Cooling Towers	5317	5317
Waste Disposal Handling System	170	391
Flue Gas Desulfurization	-	3731
Transformer Losses	2481	2481
Lighting	1000	1000
Balance of Plant Subtotal	9,565	13,287
TOTAL	32,310	35,996

EXHIBIT 4-2

PLANT GENERATION SUMMARY

AT MAXIMUM GUARANTEED TURBINE OUTPUT

PERFORMANCE DATA	AFBC	PCF
GROSS GENERATOR OUTPUT, kW	568,215	568,215
AUXILIARY POWER, kW	32,310	35,996
NET PLANT OUTPUT, kW	535,905	532,219
GROSS TURBINE HEAT RATE, Btu/kWh	7875	7875
BOILER EFFICIENCY, %	84.2	85.0
NET PLANT HEAT RATE, Btu/kWh	9916	9890

EVALUATION OF A PRESSURIZED-FLUIDIZED BED COMBUSTION (PFBC) COMBINED CYCLE POWER PLANT CONCEPTUAL DESIGN

FINAL REPORT

PFB/GAS TURBINE/WASTE HEAT STEAM GENERATOR CYCLE STUDY

SUBTASK 1.8

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Abstract

In June 1976, the U. S. Department of Energy (DOE) awarded a contract to an industry team consisting of Burns and Roe Industrial Services Corp. (BRISC), United Technologies Corp. (UTC), and the Babcock & Wilcox Company (B&W) for an "Evaluation of a Pressurized, Fluidized Bed Combustion (PFBC) Combined Cycle Power Plant Design".

The results of this program indicate that pressurized fluidized bed combustion systems, operating in a combined cycle power plant, offer great potential for producing electrical energy from high sulfur coal within environmental constraints, at a cost less than conventional power plants utilizing low sulfur coal or flue gas desulfurization (FGD) equipment, and at higher efficiency than conventional power plants.

As a result of various trade-off studies, a 600 MWe combined cycle arrangement incorporating a PFB combustor and supplementary firing of the gas turbine exhaust in an atmospheric fluidized bed (AFB) steam generator has been selected for detailed evaluation.

The overall program consists of the following Subtasks:

1.1 - Commercial Plant Requirements Definition

1.2 - Commercial Plant Design Definition

1.3 - System Analysis and Trade-Off Studies

1.4 - Reliability and Maintainability Evaluation with Advanced Technology Assessment

1.5 - Environmental Analysis

1.6 - Economic Analysis

1.7 - Evaluation of Alternate Plant Approaches

1.8 - PFB/Gas Turbine/Waste Heat Boiler Cycle Study

1.9 - PFB/Gas Turbine/Power Turbine Reheat Cycle Study

This Report discusses the results of studies performed under Subtask 1.8.

REPORT ON SUBTASK 1.8

PFB/GAS TURBINE/WASTE HEAT STEAM GENERATOR CYCLE STUDY

EVALUATION OF A PRESSURIZED-FLUIDIZED BED COMBUSTION

(PFBC)

COMBINED CYCLE POWER PLANT

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1.0 SUMMARY

On the basis of studies performed under Subtask 1.3 (Trade-Off Studies) of this contract, the Department of Energy (DOE) has authorized an extension to the scope of work to cover additional studies of a PFB/Gas Turbine (G.T.)/ Waste Heat Steam Generator (WHSG) Combined Cycle. These studies have been performed under Subtask 1.8 of the extended contract and are described in this report.

1.1 OBJECTIVE AND SCOPE OF WORK

The objective of this study is to develop a preliminary cost estimate for a PFB/GT/WHSG plant on the same basis as that prepared for the PFB/AFB Combined Cycle Commercial Plant studied under Subtask 1.2 (Commercial Plant Design). This estimate is then to be used as the basis of an economic comparison of both cycles in which the trade-offs between capital costs, efficiencies, and operability are evaluated.

Prior to preparation of the cost estimates, the scope of work has also included cycle optimization studies and development of a plant conceptual design.

1.2 SELECTION OF CYCLE

The nominal power plant size of 600 MWe has been chosen to provide direct comparison to the PFB/AFB Combined Cycle commercial plant concept developed under Subtask 1.2 of this contract.

The system that has been selected as the primary PFB commercial power plant configuration for Subtask 1.2 utilizes a PFB for combusting coal with the gas turbine compressor discharge air, and a steam-cooled Atmospheric Fluidized Bed (AFB) boiler in which supplementary firing of the gas turbine exhaust flow provides sufficient heat to the steam system so that a high-efficiency steam cycle can be used, thereby increasing the overall efficiency of the power plant. On the basis of work performed under Subtask 1.3, the Department of Energy (DOE) authorized an extension to the contract to cover additional studies on a PFB/Gas Turbine (GT)/Waste Heat Steam Generator (WHSG) Cycle. In the PFB/GT/WHSG cycle only the waste heat from the gas turbine is used to generate steam (See Figures B-3 and F-2). This results in less total output from each gas turbine module (i.e., the gas turbine and its associated portion of the steam cycle which, in this case, consists of one WHSG and one-half steam turbine). However, since there is only one stage of combustion, each module is less complex than the corresponding module from the PFB/AFB plant. While the rough order of magnitude studies under Subtask 1.3 indicate that the large number of PFB/GT/WHSG modules required to produce 600 MWe would result in relatively poor economics compared to the PFB/AFB system, a more detailed effort is justified to check this conclusion. In addition, the PFB/GT/WHSG cycle may be attractive as a smaller interim system to demonstrate technology and bridge the gap between present power plants and more efficient PFB/AFB cycles. Furthermore, the PFB/GT/WHSG system may be more competitive in the smaller plant sizes (say, less than 100 MWe). Since the maximum generating capacity of each gas turbine and associated waste heat steam system is only 90-100 MWe, based on the largest gas turbines available to date, multiple PFB/GT/WHSG modules must be used for plants over 100 MWe. Therefore, reductions in specific cost ($/kW) associated with the "economy of scale" are expected to be relatively small for PFB/GT/WHSG plants over 100 MWe in capacity. However, in the small utility or industrial market, only one module would be required. Hence, these plants should be more competitive with other alternatives which utilize a larger proportion of steam turbine to gas turbine power because the steam power equipment must be reduced to the same scale as the gas turbine equipment. For these reasons, a more detailed analysis of this cycle is further justified in order to develop design and cost data which may be used as a basis for future decisions in the PFB development program.

1.3 CYCLE PERFORMANCE ANALYSIS

In Subtask 1.8 a number of PFB/GT/WHSG cycles have been studied. For all cases, the gas turbine cycle parameters are the same as those used in Subtask 1.2. The major changes considered are in the steam portion of the system. As a result of these studies, the cycle configuration shown schematically on Figures B-3 and F-2 has been selected for more detailed evaluation under this subtask.

The selected alternative utilizes exhaust heat from the gas turbines to raise steam at three pressure levels. The highest is the steam turbine inlet pressure of 615 psia, and the intermediate steam pressure for admission to the low pressure turbine is 165 psia. Steam at the third, or lowest, pressure level (L.P. steam) is generated for use in a deaerating feedwater heater. The detailed heat and mass balance for the air/gas and steam systems for the selected cycle are given in Tables G-3 and G-4, respectively. The corresponding power plant performance is summarized in Table G-5. This system produces a net output power of 590.7 MWe with a net coal pile to busbar efficiency (HHV) of 37.4%. The corresponding values for the PFB/AFB base plant from Subtask 1.2 are 574.2 MWe and 37.91%, respectively.

The coal and dolomite analyses used as the basis for all performance and plant design calculations are the same as used in Subtask 1.2 and are defined herein on Tables D-1 and D-2, respectively. The fuel is an average Illinois Basin bituminous coal with an "as fired" HHV of 12453 Btu/lb and a sulfur content of 3.43%.

1.4 ENVIRONMENTAL EVALUATION

The PFB/GT/WHSG plant described herein has been designed to meet the present environmental air pollution standards. In order to meet the anticipated future federal environmental regulations, changes will be required in the particulate collection system. The following federal New Source Performance Standards (NSPS) are currently applicable to a power plant and have been used as the design basis in this study:

Air Pollutant	Maximum Emissions
1. Particulate Matter	0.1 lb/10^6 Btu input
2. SO_2	1.2 lb/10^6 Btu input
3. NO_x	0.7 lb/10^6 Btu input

This standard is applicable to each generating unit of more than 250 x 10^6 Btu/hr heat input. Standards are for maximum 2 hour average emission. The Clean Air Act Amendment of 1977 requires the EPA to revise these new source performance standards by August, 1978.

The anticipated new EPA limits on the pollutants for coal fired stations are:

Air Pollutant	Maximum Emissions
1. Particulate Matter	0.03 lb/10^6 Btu input
2. SO_2	1.2 lb/10^6 Btu input; Minimum Sulfur removal of 90% required unless emissions are below 0.2 lb/10^6 Btu.
3. NO_x	0.6 lb/10^6 Btu input

With the exception of the particulate emission, the new standards are not expected to significantly affect the design or cost of either the PFB/AFB base plant or the PFB/GT/WHSG plant. The reasons for the minimal impact of the new NO_x and SO_2 standards are indicated in the Subtask 1.2 Report (Commercial Plant Design).

The PFB/GT/WHSG plant has been designed to meet the current EPA requirements for emission of particulates. It is estimated that the particulates emission from the plant will be about 0.1 lb/10^6 Btu. It should be noted, however, that the uncertainty associated with this prediction is quite high. It is very sensitive to assumptions concerning the quantity and size distribution of particulates leaving the PFB combustors and to the performance capability of the cyclones themselves. Even a relatively minor change to any of these factors could result in the need for a final collection device (precipitator or baghouse) prior to the stack. Since no such device is included in this design, the cost would be increased significantly. On the other hand, a precipitator has already been included in the design and cost estimates for the base PFB/AFB plant. Therefore, the cost is much less sensitive to these assumptions.

In order to reduce the emission to the level of 0.03 $lb/10^6$ Btu as per the anticipated future requirements, a final dust collection device would be required in the PFB/GT/WHSG plant between the gas turbine exhaust and the stack in addition to those provided at the gas turbine inlets. As indicated above, the effect of these changes on the estimated cost of the plant would be significant. However, no attempt has been made to estimate the overall cost impact of the new standards on the PFB/GT/WHSG concept. As indicated above, since a precipitator has already been included in the base PFB/AFB plant, the impact of the new EPA standards on its design and cost would be much less significant.

Section 3.3.3 of this report defines the current EPA liquid and thermal effluent standards that have been used as a design basis for the PFB/GT/WHSG plant. These are the same as those used in Subtask 1.2.

1.5 COMMERCIAL PFB/GT/WHSG PLANT DESIGN DESCRIPTION

The hypothetical site is Middletown, U.S.A., and it is described in detail in the Subtask 1.2 Report. Plant design and rating is based on the following average ambient air conditions:

D.B. temperature	59°F
W.B. temperature	51.5°F
Relative Humidity	60%
Barometric Pressure	29.92" Hg.

The PFB/GT/Waste Heat Steam Generator (WHSG) plant (Figure B-3) contains six gas turbines, with each gas turbine exhausting into an individual WHSG. Steam is generated by these WHSG's at two pressure levels for expansion through three (3) steam turbines (one (1) steam turbine for two (2) gas turbines), and at a third pressure level for use in the deaerating feedwater heater.

The overall layout of the main system is shown in the Area Site Plan, Figure F-1. The process flow diagram for the main process fluids in the system is shown on Figure F-2. The six parallel trains of PFB's, gas turbine generator sets, and WHSG's are arranged side-by-side. The gases from two (2) gas turbines are exhausted into one (1) stack. Consequently, three (3) stacks are provided. The steam outputs of the six (6) WHSG's are combined to feed three (3) steam turbine generator sets in any combination.

The arrangement of PFB's, cyclones, and hot gas piping for each gas turbine is identical to the Subtask 1.2 plant. No changes to the layout, piping sizes or other configurational features are required. However, six (6) gas turbines are needed versus two (2) gas turbines in the Subtask 1.2 to produce the same nominal power plant capacity. Therefore, the quantity of associated PFB's, cyclones, hot gas piping, etc. is higher for the PFB/GT/WHSG plant.

The Pressurized Fluid Bed (PFB) System consists of the PFB combustors and their accessories. The system design is based upon the use of two PFB combustors for each gas turbine.

Since the intent of this Task is basically to investigate the effects of an alternate steam bottoming cycle compared to the Subtask 1.2 base plant design, the split-flow, air cooled PFB system design is the same as presented in the Subtask 1.2 report with the exception of the number of units involved. Therefore, only an abbreviated description of the PFB system is included in this report for convenience (See Section 4.3.1).

The exhaust gases from the gas turbine pass through a waste heat boiler which generates steam for the bottoming cycle. No additional fuel is fired in the boiler.

The WHSG is an established commercial product that has been supplied by the Babcock and Wilcox Company for other combined cycle installations. The boiler is based on standard design concepts that are tailored to suit the individual requirements of the specific cycle (See Section 4.3.2).

As in Subtask 1.2, the gas turbine subsystem is based on the UTC FT50 Industrial Gas Trubine design. The main enclosure contains the gas turbine with the electric generator enclosure extending from the main enclosure. The FT50 is a high performance industrial gas turbine consisting of twin-spool gas generator and a free turbine driving the output shaft. The choice of this design for all of the gas turbine subsystem physical and mechanical characteristics permitted using information resulting from a very large engineering design effort. Performance characteristics, however, are based on a comparably sized industrial gas turbine design which may be more appropriate for the commercial PFB application. The component efficiencies for the commercial plant engine are of the same level as those used for the FT50 and are reasonable for a mid-1980's production gas turbine suitable for PFB operation. It is felt that the physical characteristics of weight, size, and systems designed for the FT50 would be close to those required for the commercial plant gas turbine.

The PFB/GT/WHSG plant contains six (6) gas turbine units as compared to two (2) units in the PFB/AFB plant of Subtask 1.2. In both cases, two (2) PFB units and associated cyclones are piped into each gas turbine unit. A schematic arrangement of the piping configuration with valving for each gas turbine is shown on Figure H-6. The valves are refractory lined and water-cooled to reduce the temperature of pressure containing metal parts to 750°F or below. Piping is also refractory lined on its inside surface so as to maintain wall temperatures at 250°F or less. For each gas turbine, the design, sizing, and arrangement of piping and equipment is identical to the PFB/AFB plant. The only difference lies in the number of gas turbines. A complete design description of the high temperature piping and valving for each unit is contained on pages 136-159 of the report on Subtask 1.2. Considerable development work is required in this area to demonstrate commercial feasibility.

The coal and sorbent handling and feed systems are of the same general design as used in Subtask 1.2, except that limestone handling is not required, and more PFB units must be fed. The changes in system configuration are discussed in Section 4.3.5 and 4.3.6.

The gas from the PFB combustor passes through two stages of high efficiency cyclones for particulate removal to the requirements imposed by gas turbine tolerance levels and EPA limitations. The allowable gas turbine particulate loading is based on the assumption that particles greater than 10 microns in size would give unsatisfactory turbine life, particles less than 2 microns in size would have negligible effects on turbine life, and that .01 grains/scf of particulate in the 2-10 micron size could be tolerated within the gas turbine.

The high efficiency cyclones provided are Aerodyne Development Corporation's "SV-FBC" Series Dust Collectors. Two Model 22000SV (shown on page 188, Figure N-3, of the Subtask 1.2 Report) collectors in series handle the combustion gas flow from one PFB combustor. This design is an extension of the equipment presently used in low temperature, low pressure applications.

The solid waste handling system for the PFB/GT/WHSG system is basically the same design as used in Subtask 1.2. Changes have been made in the piping and equipment to account for the elimination of the AFB and its associated cyclones, as well as the electrostatic precipitator. In addition, the system has been revised to reflect the increased number of PFB combustors and their associated Aerodyne Cyclones.

Each of the three steam turbines is a dual pressure admission, condensing steam turbine with control and governing system, lubricating oil system, gland steam system with gland steam condenser, thermal insulation, turbine startup and supervisory panel, standard instrumentation, and integral piping. Each corresponding generator is a 2-pole, air cooled, totally enclosed, synchronous 3-phase, 60 Hz unit designed to produce the required MWe terminal output at a power factor of 0.8. Air coolers, air filters, and space heaters are provided.

The condensers, generator air coolers, turbine oil coolers and closed cooling water heat exchangers reject their heat to the cooling water coming from a mechanical draft cooling tower. The heat rejection system is a closed type circulating water system. The diagram on Figure H-7 shows the general scheme of the circulating water system. River water is used as makeup to compensate for blowdown and evaporation losses.

A mechanical draft, double flow induced draft cooling tower is erected above a concrete basin. One end of the concrete basin has sufficient depth to allow for the installation of vertical circulating water pumps.

Two 50% capacity, vertical motor driven circulating water pumps are installed in the wet pit of the tower basin.

River water is used for cooling tower makeup. The river water intake structure and equipment is similar to that used for Subtask 1.2 with the exception of the capacity of the equipment. The equipment is designed to supply the requirements called for on the flow diagram Figure H-7.

The source of WHSG makeup water is the city water system. This is available at the northeast corner of the site. A 100,000 gallon storage tank is provided.

The analysis of the city water used is the same as that in Subtask 1.2.

The design capacity of the makeup feedwater treatment plant is 150 gpm. Automatic, sodium zeolite, skid mounted water treatment units are used. Three units of 50 gpm capacity each are installed.

Boiler chemical feed systems and a waste water treatment plant are also provided as described in Subsections 4.3.12.1.1 and 4.3.12.2.

1.6 COST ESTIMATES FOR PFB/GT/WHSG PLANT

The estimate is based on the following assumptions: The plant is located in "Middletown", U.S.A., which represents an average U.S.A. geographic location in close proximity to an Eastern Coal Belt. This area lies approximately East of the Mississippi, West of the Appalachian Mountains, South of the Great Lakes, and North of the Gulf of Mexico. All costs in this estimate reflect what is felt to be "average" expected costs for this area of the country.

Estimated costs reflect the theoretical assumptions that sufficient number of plants of the same type have previously been built, therefore, no "development" cost factors have been included.

All costs represent a mid-1977 price level and do not include escalation.

The total project cost is estimated to be $450,086,000 in mid-1977 dollars. This amounts to a specific capital cost of $762 per kW capacity net. The direct capital cost is 71.1% of total cost, and IDC accounts for 16.3%. A 10% contingency has been included on all costs except IDC. A summary of the direct and indirect capital costs is shown on Tables W-3 and W-5, respectively.

The fixed charge has been assumed to be 18% of the total project cost. Under the assumed conditions, the total annual cost of operation is $116,197,000. The annual cost summary is shown in Table W-10.

At 65% capacity factor, the annual energy output is 3,363 x 10^6 kWh. Therefore, the cost of electricity is 34.55 mills/kWh.

1.7 COST COMPARISON - PFB/GT/WHSG PLANT VERSUS PFB/AFB PLANT

1.7.1 Capital Cost Comparison

A comparison of the capital cost estimates for Subtask 1.8 versus those of 1.2 shows that the PFB/GT/WHSG plant ($762/kW) is approximately 34% more costly than the PFB/AFB commercial plant ($567/kW) used as a base. Table W-11 briefly summarizes where the cost differences occur on a main cost account basis. Table W-12 gives a detailed breakdown of the cost differences with a short explanation for each variance. In order to explain the major variances, the following table compares gross power outputs for the steam and gas turbine portions of each plant.

	PFB/GT/WHSG		PFB/AFB (Base)	
	Total Output	No. of Units	Total Output	No. of Units
Gas Turbine/Generators	397.9 MWe	6	127.2 MWe	2
Steam Turbine/Generators	212.0 MWe	3	465.7 MWe	1

Since the gas turbines being used are the largest available to date, the only way to triple their contribution relative to the base case as indicated is to triple the number of gas turbines. Due to allowable stress limitations, the combustor design considered in this study (i.e. 21 ft dia and 69 ft length) cannot be made very much larger. Therefore, identical PFB combustors and associated cyclones have been used for each plant, meaning that the PFB/GT/WHSG plant has three times the number of these units relative to the base case. Thus the costs for these items are about three times higher than base. On the other hand, the cost of the steam plant does not decrease in proportion to the decrease in output. This is due in part to the fact that the PFB/GT/WHSG plant must utilize a low pressure/low temperature steam cycle compared to the base case which necessitates the use of multiple steam turbine/generators in order to achieve the 212.0 MWe output (three have been used in this design). Therefore, while the output has been decreased by a factor of 2.2, the combined cost of the steam turbine/generator and boiler plants only decreases by a factor of 1.5.

For the foregoing reasons, the increased direct capital cost for the PFB/Gas turbine systems is only partly offset by the reduction in Boiler Plant and Steam Turbine Generator cost. In addition, the increased modularization of the PFB/GT/WHSG plant results in increased electrical system and instrumentation/control system costs. After contingency and interest during construction are factored in, the net result of these changes is that the capital cost of the PFB/GT/WHSG plant is $124,734,000 or $195/kW higher than the PFB/AFB plant studied in Subtask 1.2.

As indicated above, a large portion of the increase in relative cost of the PFB/GT/WHSG plant is attributable to the fact that the PFB combustors and gas turbines were not scaled up in size to achieve the increase in capacity required. It is conceivable that the allowable stress limitations that constrained the size of the combustors used in this study would not apply to other designs. Assume that the size of the PFB combustors used in Subtask 1.2 and associated cyclones and piping could be scaled up such that their capacity is increased by a factor of two. This would permit the use of one PFB per gas turbine instead of two as used in this design. Further, assume that the cost of each larger combustor and associated system would increase by the factor $2^{0.6}$. On this basis, as indicated in Section 5.4.1, it is still expected that the PFB/AFB capital cost would be \$150/kW less than that of the PFB/GT/WHSG plant.

1.7.2 COE Comparison

As indicated earlier, the COE for the PFB/GT/WHSG plant is 34.55 mills/kWh which is 21% more than the 28.47 mills/kWh obtained for the PFB/AFB cycle studied in Subtask 1.2. The 6 mill/kWh increase is due almost entirely to the higher Fixed Charges of the PFB/GT/WHSG plant which result from its higher capital cost. The differences in plant performance have an insignificant impact on COE.

2.0 CONCLUSIONS AND RECOMMENDATIONS

2.1 CONCLUSIONS

The following conclusions are drawn from the results of the work performed in the Subtask:

a) For a 600 MWe capacity, the PFB/Gas Turbine(GT)/Waste Heat Steam Generator (WHSG) plant configuration would have a 25% - 35% higher capital cost and a 20% higher cost of electricity than the PFB/AFB combined cycle plant proposed in Subtask 1.2.

b) If the EPA particulate emission limit is reduced to 0.03 lb/10^6 Btu as expected, the PFB/GT/WHSG plant would require the addition of a final collection stage (baghouse, electrostatic precipitator, etc. prior to the stack, or, the use of more efficient collection devices at the gas turbine inlet. The PFB/AFB plant proposed in Subtask 1.2 already incorporates a final stage collection system (precipitators), and costs required to modify that system to meet the new limit are expected to be relatively insignificant. However, the addition of such a system to the PFB/GT/WHSG system would raise the cost of that system by \$40 - \$60/kW over that estimated in this study. (Note: The stack gas flow rate in the PFB/GT/WHSG plant is three times that in the PFB/AFB plant.)

c) The higher cost of the PFB/GT/WHSG system is attributable in great part to the fact that the gas turbines and air cooled PFB systems cannot be scaled-up in size to achieve capacities over 100 MWe with a single unit. The use of multiple units results in a loss of the "economy-of-scale" relative to the steam system. Thus, it appears that the optimum number of gas turbines in a PFB combined cycle from a cost viewpoint may be one or two per plant. (The PFB/AFB plant uses two.)

d) The increased cost of burning supplementary coal to supply heat for the steam bottoming cycle is small compared to the increased output and efficiency gained. Thus, supplementary firing should be incorporated in any large PFB plant.

2.2 RECOMMENDATIONS

On the basis of the conclusions drawn in Section 2.1, the following recommendations are made:

a) The PFB/Gas Turbine/Waste Heat Steam Generator cycle configuration should not be considered for plants over 100-200 MWe in capacity. A more economical choice would be the PFB/AFB plant described in the report on Subtask 1.2, Commercial Plant Design.

b) An effort should be made to determine whether gas turbines and air cooled PFB combustors can be scaled-up in size and capacity so as to obtain the "economies of scale" that have been achieved in the conventional steam turbine and boiler industries. Such an effort could enhance the cost of all PFB combined cycle arrangements.

c) As indicated in the foregoing the "economies of scale" make the PFB/GT/WHSG configuration uneconomical for large plants. However, in the small utility or industrial co-generation market (100 MWe or less) only one gas turbine module would be required. Hence, this arrangement may be more economical than other alternatives which utilize a larger proportion of steam turbine to gas turbine power since the steam power equipment must be reduced to the same scale as the PFB/GT/WHSG equipment. It is recommended, therefore, that this possibility be studied further.

3.0 COMMERCIAL PLANT CRITERIA

3.1 PLANT CAPACITY

The nominal powerplant size of 600 MW has been chosen to provide direct comparison to the PFB/AFB Combined Cycle commercial plant concept developed under Subtask 1.2 of this contract.

3.2 SELECTION OF CYCLE

The system that has been selected as the primary PFB powerplant configuration for Subtask 1.2 utilizes a PFB for combusting coal with the gas turbine compressor discharge air and a steam-cooled Atmospheric Fluidized Bed (AFB) boiler, whereby supplementary firing of the gas turbine exhaust flow provides sufficient heat to the steam system so that a high-efficiency steam cycle can be used, thereby increasing the overall efficiency of the powerplant. On the basis of work performed under Subtask 1.3, the Department of Energy (D.O.E.) authorized an extension to the contract to cover additional studies on a PFB/Gas Turbine (GT)/Waste Heat Steam Generator (WHSG) Cycle. In the PFB/GT/WHSG cycle only the waste heat from the gas turbine is used to generate steam. This results in less total output from each gas turbine module (i.e., the gas turbine and its associated portion of the steam cycle which, in this case, consists of one WHSG and one-half steam turbine). However, since there is only one stage of combustion, each module is less complex than the corresponding module from the PFB/AFB plant. While the rough order of magnitude studies under Subtask 1.3 indicate that the large number of PFB/GT/WHSG modules required to produce 600 MW would result in relatively poor economics compared to the PFB/AFB system, a more detailed effort is justified to check this conclusion. In addition, the PFB/GT/WHSG cycle may be attractive as a smaller interim system to demonstrate technology and bridge the gap between present power plants and more efficient PFB/AFB cycles. Furthermore, the PFB/GT/WHSG system may be more competitive in the smaller plant sizes (say, less than 100 MWe). Since the maximum generating capacity of each gas turbine and associated waste heat steam system is only 90-100 MWe, based on the largest gas turbines available to date, multiple PFB/GT/WHSG modules must be used for plants over 100 MWe. Therefore, reductions in specific cost ($/kW) associated with the "economy of scale" are expected to be relatively small for PFB/GT/WHSG plants over 100 MWe in capacity. However, in the small utility or industrial market, only one module would be required. Hence, these plants should be more competitive with other alternatives which utilize a larger proportion of steam turbine to gas turbine power because the steam power equipment must be reduced to the same scale as the gas turbine equipment. Thus, a more detailed analysis of this cycle is justified in order to develop design and cost data which may be used as a basis for future decisions in the PFB development program.

3.2.1 Comparative Cycle Performance Analyses

In Subtask 1.8 a number of PFB/GT/WHSG cycles have been studied. For all cases, the gas turbine cycle parameters are the same as those used in Subtask 1.2. The major changes considered are in the steam portion of the system.

The first steam system examined (See Figure B-1) raises steam at a single pressure, 250 psia. This is a relatively low pressure and would be a very simple steam system. A detailed heat and mass balance for the air/gas system is given in Table B-1, and the heat and mass balance for the steam system is given in Table B-2. The corresponding powerplant performance estimate is given in Table B-3. As noted in the Table B-3, the net plant output power is 567.9 MWe, and the net plant efficiency is 36.4%.

The second steam system alternative (see Figure B-2) raises steam at two pressures. The higher steam turbine inlet pressure is 615 psia, and the second steam pressure for admission to the low pressure turbine is 165 psia. The detailed heat and mass balance for the air/gas and steam systems for this cycle are given in Tables B-4 and B-5, respectively. The corresponding power plant performance is summarized in Table B-6. This system has slightly improved performance, with net output power being 577.4 MWe and net efficiency being 36.6%.

The estimated gross efficiency of the two-pressure steam system is 39.6%, which is 3.4% (fractional) greater than the 38.3% gross efficiency originally estimated for this system in Subtask 1.3. This difference in efficiency is attributable to three factors:

1. A decrease in gas side pressure drop through the waste heat recovery boiler from 40 to 10 inches of water.

2. A change in steam system pressures from 265 psia to 615 psia with a constant stack temperature.

3. A change in fuel from an HHV/LHV ratio of 1.06 to a coal with HHV/LHV ratio of 1.038.

The increments in plant efficiency due to these changes are summarized in Table B-7.

A revised two-pressure steam system has been selected for the Subtask 1.8 cycle, with changes based on suggestions by Babcock and Wilcox that the steam production rate could be increased by rearranging the low temperature boiler surface (compare Figures B-2 and B-3). In so doing, the stack temperature can be lowered from 342°F to 296°F and the steam power can be increased from 198 MWe to 212MWe. This third, revised cycle has been used for all further Subtask 1.8 studies. The heat and mass balance and performance for the selected cycle is discussed in Section 4.2.

3.3 ENVIRONMENTAL STANDARDS

3.3.1 General

The plant described herein has been designed to meet the present environmental standards. In order to meet the anticipated future federal environmental regulations, changes will be required in the particulate collection system. The following federal standards are currently applicable to a power plant:

TABLE B-1

PFB/GT/WHSG CYCLE

HEAT AND MASS BALANCE FOR AIR/GAS SYSTEM

SINGLE-PRESSURE STEAM SYSTEM

DESCRIPTION	W, * lb/sec	T, °F	P, psia	H, Btu/lb
Inlet	840.	59.	14.7	124.0
Compressor Inlet	840.	59.	14.55	124.0
Compressor Discharge	810.8	595.5	145.5	254.8
PFB Inlet	214.8	595.5	145.5	254.8
PFB Exit	230.9	1650.	130.9	554.6
PFB Cooling Tube Inlet	596	595.5	145.5	254.8
PFB Cooling Tube Exit	596	1575.	130.9	514.4
Turbine Inlet	826.9	1597.	130.9	525.6
Turbine Exit	851.8	828.	16.1	315.4
Superheater Inlet	851.8	828	14.8	315.4
Evaporator Inlet	851.8	756.8	14.8	296.9
Economizer Inlet	851.8	405.7	14.8	208.1
Deaerator Boiler Inlet	851.8	261.9	14.8	197.2
Stack	851.8	300.	14.8	182.0

*Flows are based on one (1) gas turbine; multiply flows by six (6) for total system.

TABLE B-2

PFB/GT/WHSG CYCLE

HEAT AND MASS BALANCE FOR STEAM SYSTEM

SINGLE-PRESSURE STEAM SYSTEM

DESCRIPTION	W, * lb/sec	T, °F	P, psia	H, Btu/lb
Condensate Pump Inlet	86.4	100.8	.982	69.1
Deaerator Boiler Inlet	13.7	250.	30.	218.9
Deaerator Boiler Exit	13.7	250.3	30.	1163.3
Feedwater Pump Inlet	100.1	250.3	276.	218.9
Economizer Inlet	86.4	250.4	276.	219.8
Evaporator Inlet	86.4	354.6	276	326.6
Superheater Inlet	85.6	404.6	260.4	1201.9
Turbine Inlet	85.6	727.9	250.	1386.3
Turbine Exit	85.6	101.1	.982	1019.0
Condenser Inlet	85.6	101.1	.982	1019.0

*Flows are based on one (1) gas turbine; multiply flows by six (6) for total system.

TABLE B-3

PFB/GT/WHSG CYCLE PERFORMANCE ESTIMATES

(Six Gas Turbines)

SINGLE-PRESSURE STEAM SYSTEM

PWR_{GT}, MW	390.6
PWR_{ST}, MW	195.7
$PWR_{TOTAL\ GROSS}$ MW	586.3
AUXILIARIES, MW	18.4
$PWR_{TOTAL\ NET}$ MW	567.9
$EFFICIENCY_{TOTAL\ GROSS}$ % (1)	39.4
$EFFICIENCY_{TOTAL\ NET}$ % (2)	36.4
COAL RATE (AS FIRED), lb/sec	113.4
COAL RATE (AS RECEIVED), lb/sec	129.0

(1) Based on total gross power and "as fired" coal rate (HHV = 12453. Btu/lb)

(2) Based on total net power, 3.14% auxiliary power losses, 3.3% miscellaneous heat losses and "as received" coal rate (HHV = 11472. Btu/lb)

TABLE B-4

PFB/GT/WHSG CYCLE

HEAT AND MASS BALANCE FOR AIR/GAS SYSTEM

TWO-PRESSURE STEAM SYSTEM

DESCRIPTION	W, * lb/sec	T, °F	P, psia	H, Btu/lb
Inlet	840.	59.	14.7	124.0
Compressor Inlet	840.	59.	14.55	124.0
Compressor Discharge	810.8	595.5	145.5	254.8
PFB Inlet	214.8	595.5	145.5	254.8
PFB Exit	230.9	1650.	130.9	554.6
PFB Cooling Tube Inlet	596	595.5	145.5	254.8
PFB Cooling Tube Exit	596	1575.	130.9	514.4
Turbine Inlet	826.9	1597.	130.9	525.6
Turbine Exit	851.8	822.7	15.1	314.0
Superheater Inlet	851.8	819.7	14.8	313.2
HP Boiler Inlet	851.8	764.6	14.8	298.9
HP Economizer Inlet	851.8	528.2	14.8	238.6
LP Boiler Inlet	851.8	448.8	14.8	218.7
LP Economizer Inlet	851.8	402.4	14.8	207.2
Deaerator Boiler Inlet	851.8	396.0	14.8	205.7
Stack	851.8	342.7	14.8	192.5

*Flows are based on one (1) gas turbine; multiply flows by six (6) for total system.

TABLE B-5

PFB/GT/WHSG CYCLE

HEAT AND MASS BALANCE FOR STEAM SYSTEM

TWO-PRESSURE STEAM SYSTEM

DESCRIPTION	W, * lb/sec	T, °F	P, psia	H, Btu/lb
Condensate Pump Inlet	80.2	101.1	.982	69.1
Deaerator Boiler Inlet	11.7	240.	35.	208.3
Deaerator Boiler Exit	11.7	259.3	35.	1166.7
Feedwater Pump Inlet	80.2	240.	25.	208.8
HP Economizer Inlet	68.9	241.2	664.7	211.3
HP Boiler Inlet	68.9	473.2	664.7	456.7
LP Economizer Inlet	11.3	242.2	189.7	211.3
LP Boiler Inlet	11.3	357.4	189.7	329.5
LP Boiler Exit	11.3	377.4	164.7	1197.6
Superheater Inlet	68.9	493.2	639.7	1202.4
High Turbine Inlet	68.9	750.	614.7	1379.8
High Turbine Exit	68.9	481.8	164.7	1263.2
Low Turbine Inlet	80.2	465.	164.7	1253.9
Condenser Inlet	80.2	101.1	.982	959.5

*Flows are based on one (1) gas turbine; multiply flows by six (6) for total system.

TABLE B-6

PFB/GT/WHSG CYCLE PERFORMANCE ESTIMATES

(SIX GAS TURBINES)

TWO-PRESSURE STEAM SYSTEM

PWR_{GT}, MW	397.9
PWR_{ST}, MW	197.6
Gross PWR_{Total}, MW	595.5
Net PWR_{Total}, MW	577.4
Gross $Efficiency_{Total}$,% (1)	39.6
Net $Efficiency_{Total}$,% (2)	36.6
"As Fired" Coal Rate, lb/sec	114.5
"As Received" Coal Rate, lb/sec	130.2

(1) Based on "As Fired" coal rate (HHV = 12453 Btu/lb) and no auxiliary power or heat losses

(2) Based on "As Received" coal rate (HHV = 11472 Btu/lb) including 3.3% miscellaneous heat losses and 3.14% auxiliary power loss.

TABLE B-7

PFB/GT/WHSG EFFICIENCY DIFFERENCES

	Subtask 1.3 Calc. (Base)	Subtask 1.8 Simulation
Gross Efficiency, % (HHV)	38.3	39.6
% Delta Efficiency	-	+3.40
Delta Powerplant (40" $H_2O \rightarrow 10"$ H_2O)	-	+1.00
Steam Cycle (265 psia $\rightarrow$ 615 psia)	-	+ .30
HHV/LHV (1.06 $\rightarrow$ 1.038)	-	+2.10
		+3.40

PFB/GT/WHSG SYSTEM

SINGLE–PRESSURE STEAM SYSTEM

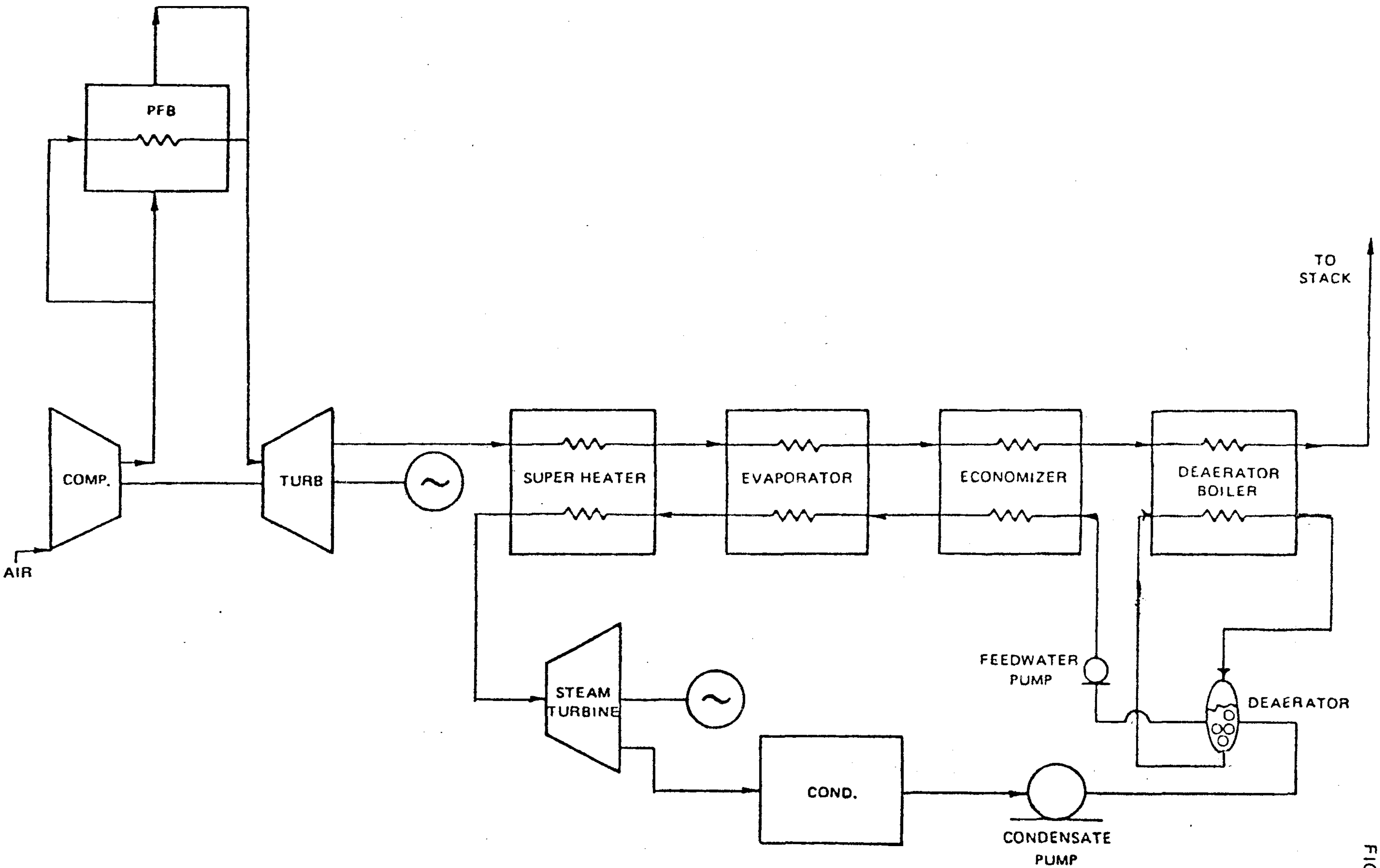


FIG. B-1

PFB/GAS TURBINE/WASTE HEAT STEAM GENERATOR

TWO–PRESSURE STEAM SYSTEM

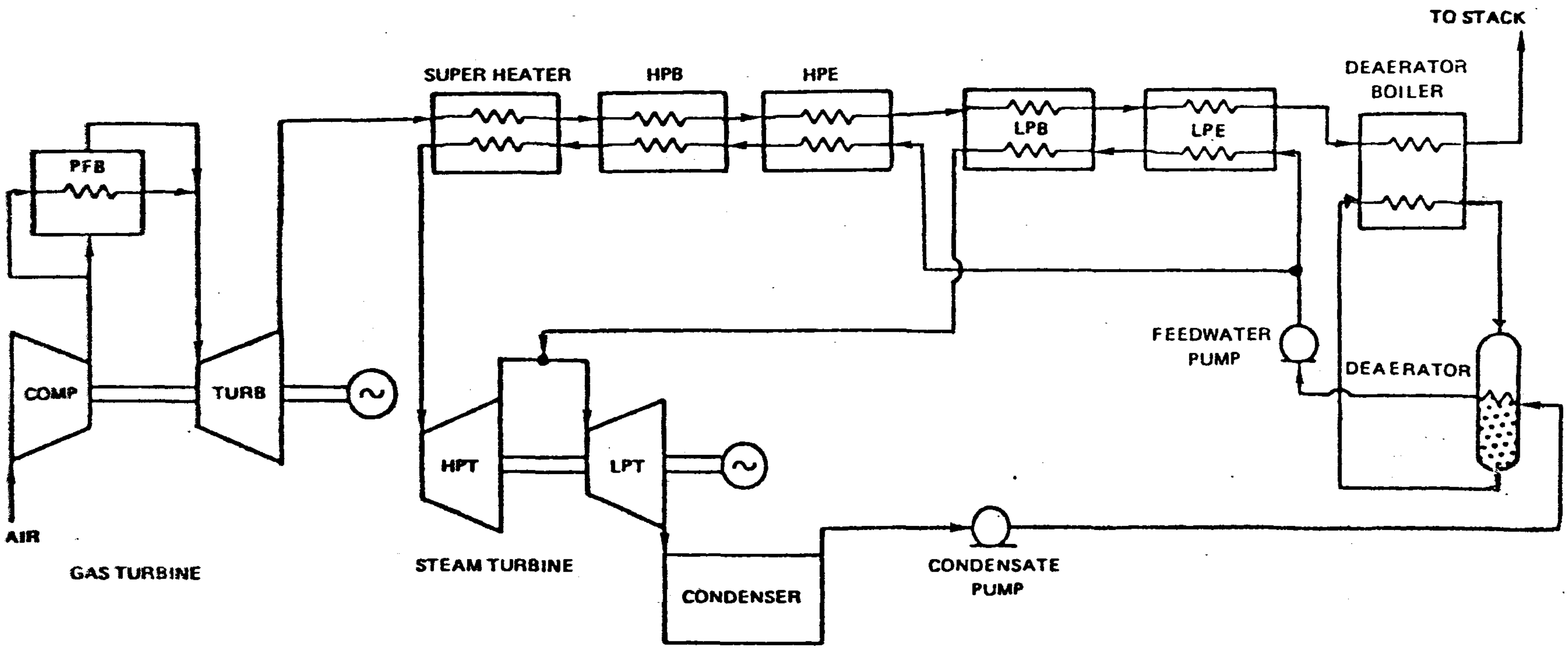


FIG. B–2

SELECTED PFB/GAS TURBINE/WASTE HEAT STEAM GENERATOR

REVISED TWO–PRESSURE STEAM SYSTEM

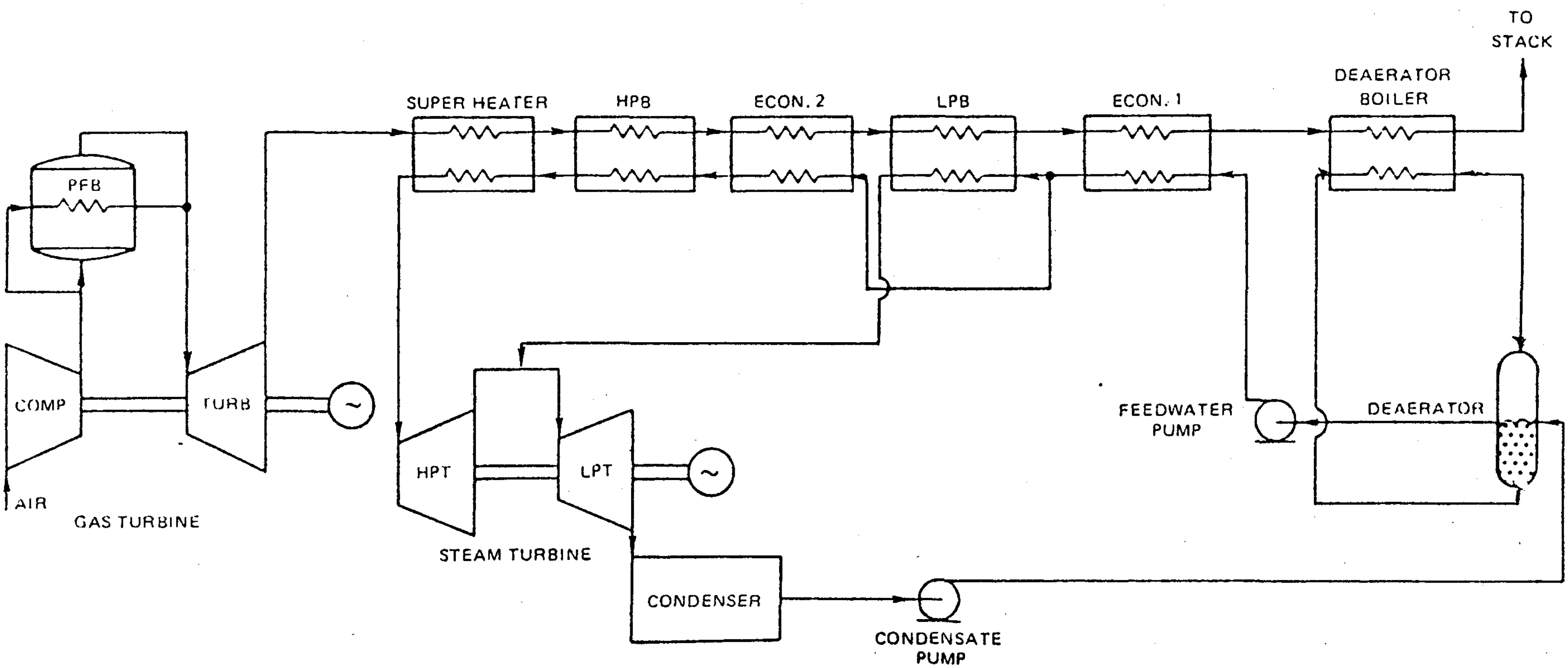


FIG. B-3

A. Standards of Performance for New Stationary Sources (NSPS) - Published in the Federal Register on December 23, 1971.

B. Federal Primary and Secondary Ambient Air Quality Standards - Published in the Federal Register on April 30, 1971. The secondary SO_2 standards for annual arithmetic mean and 24 hour average have been revoked - see Federal Register, September 14, 1973.

C. Standards for Prevention of Significant Air Quality Deterioration (PSD) - Published in Federal Register on December 5, 1974 and as amended in the Clean Air Act of 1977.

D. Effluent Guidelines and Standards for the Steam Electric Power Generating Point Source Category - Published in the Federal Register on October 8, 1974.

Compliance with Standards B and C depends upon the existing concentration of each pollutant in the air and the classification of plant location under the regulations. It has been assumed that the plant location is in a class II area and sufficiently far away from a class I area to avoid possible impact on the class I area. The total allowable increments in the concentration of pollutants in the air since January 6, 1975 are specified by standards for Prevention of Significant Air Quality Deterioration (i.e., Standard C). Hence, the compliance of the plant with respect to these standards may also be dependent upon the time of construction of the plant.

No attempt has been made to evaluate the site specific requirements promulgated in Standards B and C, since the location of plant and the starting date of construction are only hypothetical. Only the requirements in items A and D above have been considered.

3.3.2 Standards of Performance for New Stationary Sources

This standard, published in the Federal Register on December 23, 1971, presents the following air quality emissions standards for coal fired steam generators:

Air Pollutant	Maximum Emissions
1. Particulate Matter	0.1 lb/10^6 Btu input
2. SO_2	1.2 lb/10^6 Btu input
3. NO_x	0.7 lb/10^6 Btu input

This standard is applicable to each generating unit of more than 250 X 10^6 Btu/hr heat input. Standards are for maximum 2 hour average emission. The Clean Air Act Amendment of 1977 requires the EPA to revise these new source performance standards by August, 1978.

The anticipated EPA limits on the pollutants for coal fired stations are:

Air Pollutant	Maximum Emissions
1. Particulate Matter	0.03 lb/10^6 Btu input
2. SO_2	1.2 lb/10^6 Btu input; Minimum Sulfur removal of 90% required unless emissions are below 0.2 lb/10^6 Btu.
3. NO_x	0.6 lb/10^6 Btu input

3.3.2.1 Particulate Emission

The PFB/GT/WHSG plant has been designed to meet the current EPA requirements for emission of particulates. It is estimated that the particulates emission from the plant will be about 0.1 lb/10^6 Btu. It should be noted, however, that the uncertainty associated with this prediction is quite high. It is very sensitive to assumptions concerning the quantity and size distribution of particulates leaving the PFB combustors and to the performance capability of the cyclones themselves. Even a relatively minor change to any of these factors could result in the need for a final collection device (precipitator or baghouse) prior to the stack. Since no such device is included in this design, the cost would be increased significantly.

In order to reduce the emission to the level of 0.03 lb/10^6 Btu as per the anticipated future requirements, a final dust collection device would be required between the gas turbine exhaust and the stack in addition to those provided at the gas turbine inlets. As indicated above, the effect of these changes on the estimated cost of the plant would be significant. However, no attempt has been made to estimate the overall cost impact of the new standards on the PFB/GT/WHSG concept.

3.3.2.2 SO_2 Emissions

The sorbent feed rate in the PFB combustion system has been based on achieving the current SO_2 emission limit of 1.2 lb/10^6 Btu. For the "design coal" with 3.43% sulfur and a higher heating value of 12,453 Btu/lb, a 78% removal of sulfur ensures meeting the current regulation.

It appears feasible to capture 90% of the sulfur in the fuel by changing operational parameters. One approach would be to increase the sorbent feed rates. It is projected that the Ca/S feed ratio for the PFB portion of this system must increase from the present 1.0 to 1.5. Associated with these increased calcium feed rates is an increased coal flow to account for the increased heat to the calcining reactions and the increased heat loss in the sensible heat of the spent stone. The coal flow to the PFB must increase by 0.46%. Other than the increased solids handling requirements, which remain within the design margins presently incorporated in the systems, the impact of this approach on system design and operation is negligible.

Alternate approaches would involve an increase in gas residence time within the fluid beds. This would be relatively ineffective in the PFB since the residence time is already very high (approximately 7 seconds). The effect of these changes on the cost of electricity would be relatively small.

3.3.2.3 NO_x Emissions

The data reported by three investigators (Refs. 2, 3, 4) indicate that NO_x emissions in the range of 0.2 lb/10^6 Btu may be expected from the PFB combustor. There appears to be a reasonably good agreement amont these three investigators, and it is expected that the PFB/GT/WHSG commercial plant would, therefore, meet both the current and the anticipated NO_x emission limits.

3.3.3 Effluent Guidelines and Standards for the Steam Electric Power Generating Point Source Category

This standard, published in the Federal Register on October 3, 1974, presents the following liquid effluent standards for all new steam electric power plants for the following sources: bottom ash transport water; boiler blowdown; and fly ash sluice water. These standards will also be applied to the PFB/GT/WHSG Combined Cycle Plant.

		Allowable Discharge	
Pollutant		Maximum for Any One Day	Avg. only for 30 Consecutive Days
1.	Total Suspended Particles	100 mg/l	30 mg/l
2.	Oil and Grease	20 mg/l	15 mg/l
3.	Free Available Chlorine	0.5 mg/l	0.2 mg/l

For cooling tower blowdown, zinc, chromium, phosphorous, and other corrosion inhibitors shall not be detectable.

Total suspended solids from material storage and construction runoff shall not exceed 50 mg/l, and the pH shall be within the range of 6.0 - 9.0.

FEPA Guidelines state that the discharge of heat from the main condensers will not be allowed except from cold side blowdown from a recirculatory cooling system. Although exceptions are possible (Section 316a of the Act), this study assumes no exceptions shall be taken for this plant.

3.4 RAW MATERIAL DATA

The specifications for all raw materials used in this study are identical to those used for corresponding materials in the Subtask 1.2 study.

3.4.1 Fuel

High sulfur Illinois bituminous coal has been used as a design basis. The average composition of this coal is shown in Table D-1. On an "as-fired" basis, approximately 208.5 tons/hr would be consumed at full load.

3.4.2 Sorbent

Dolomite is used as the sulfur sorbent in the PFB combustors. Table D-2 shows the composition of the dolomite. With a Ca/S ratio of 1, approximately 41.9 tons/hr would be consumed at full load.

TABLE D-1

FUEL ANALYSIS

AVERAGE OF 82 COALS FROM ILLINOIS BASIN

	% By Wt.-Dry	% By Wt.-As Rec'd.	% By Wt.-As Fired
PROXIMATE ANALYSIS:			
Volatiles	39.78%	35.79%	38.86%
Fixed Carbon	48.95%	44.05%	47.81%
Ash	11.27%	10.14%	11.01%
Moisture	-	10.02%	2.32%
	100.00%	100.00%	100.00%
HHV	12,749 Btu/lb	11,472 Btu/lb	12,453 Btu/lb
ULTIMATE ANALYSIS:			
C	70.69%	63.61%	69.05%
S	3.51%	3.16%	3.43%
H	4.98%	4.48%	4.86%
N	1.35%	1.21%	1.32%
O	8.19%	7.37%	8.00%
Ash	11.28%	10.15%	11.02%
H_2O	-	10.02%	2.32%
	100.00%	100.00%	100.00%
RANGE OF VARIATION:			
C	62.49% - 79.94%	55.83% - 71.42%	61.04% - 78.09%
S	1.12% - 5.59%	1.00% - 4.99%	1.09% - 5.46%
H	4.19% - 5.76%	3.74% - 5.15%	4.09% - 5.63%
N	0.95% - 1.84%	0.85% - 1.64%	0.93% - 1.80%
O	4.15% - 14.36%	3.71% - 12.83%	4.05% - 14.03%
Ash	4.60% - 16.00%	4.11% - 14.30%	4.49% - 15.63%
H_2O	-	1.60% - 18.20%	0.20% - 2.50%

TABLE D-2

DOLOMITE ANALYSES

	% By Weight (Dry)
$CaCO_3$	53.9%
$MgCO_3$	41.4%
SiO_2	3.1%
Al_2O_3	0.5%
Fe_2O_3	0.8%
Na_2CO_3, K_2CO_3, etc.	0.3%
	100.0%
Moisture	1.0%

3.4.3 Auxiliary Fuel Oil

No. 2 distillate oil is used for starting-up the PFB combustors an the gas turbines. See Table D-3 for analysis.

3.5 SITE DESCRIPTION

The hypothetical site is Middletown, U.S.A., and it is described in detail in the Subtask 1.2 Report. Only a brief description is repeated here for convenience.

3.5.1 Topography and General Features

Figure E-1 describes the location of the site.

3.5.2 Site Access

Access to the site is provided by roads, a railroad spur, and the North River.

3.5.3 Population Density and Land Use

The site is in an area of low population density.

3.5.4 Cooling Water and Public Utility Services

Sufficient water from the North River and city water is available to supply all plant needs. Electric power is also available.

3.5.5 Meteorology and Climatology

Prevailing Winds

Surface winds are predominantly southwesterly, four to ten knots during the warm months of the year and westerly six to thirteen knots during the cold months.

Atmospheric Diffusion Properties

During the warm months of the year, the atmospheric conditions near the surface are 25% unstable, 4% neutral and 35% stable.

Severe Meteorological Phenomena

None of any significance.

Ambient Background Concentrations

Background concentrations of SO_2, NO_x, and particulates are typical of a rural area approximately 30 miles from a major industrial metropolitan center.

3.5.6 Geology and Seismology

TABLE D-3

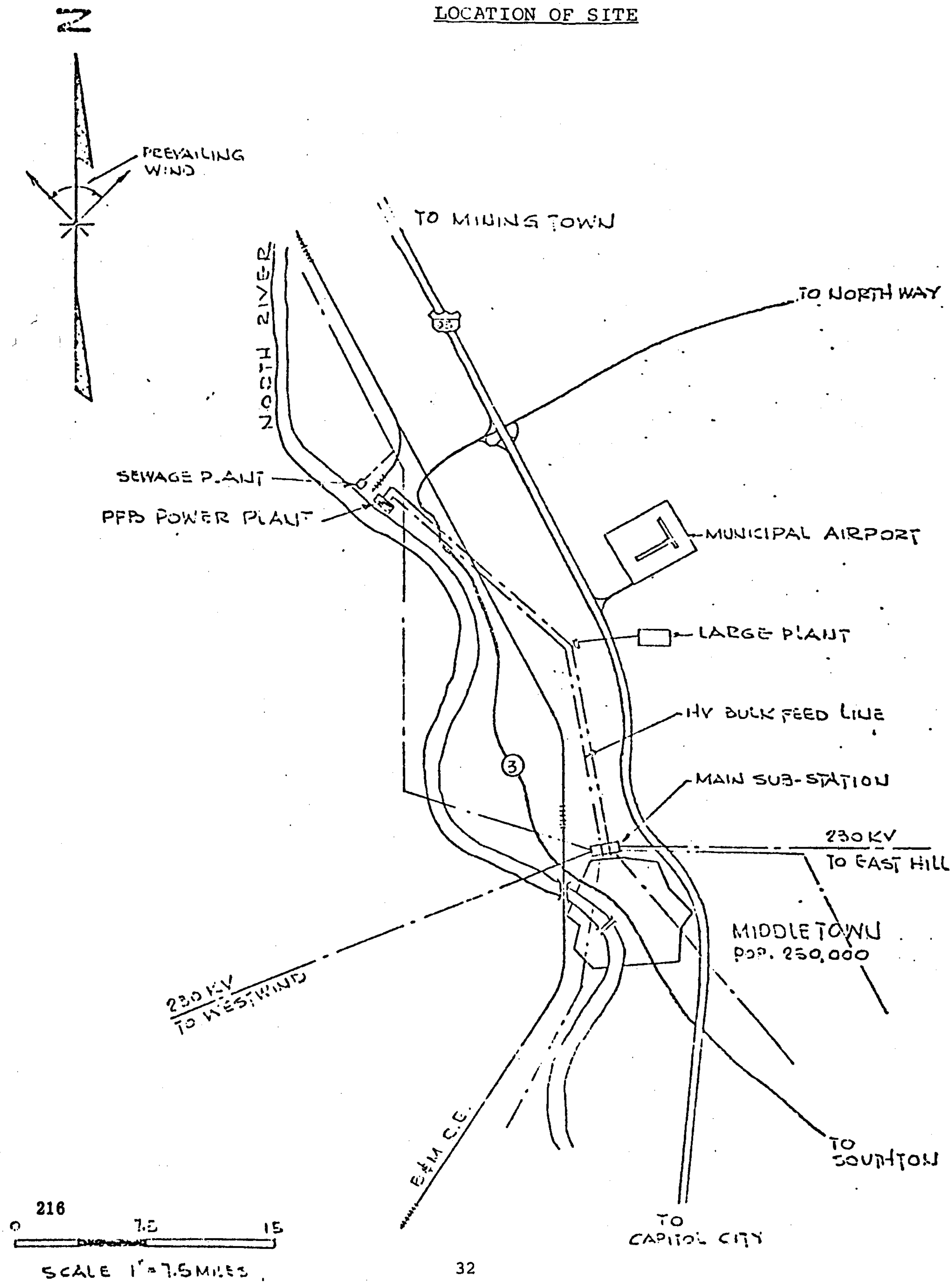
NO. 2 FUEL OIL ANALYSIS

Composition	% By Weight
Sulfur	0.3
Hydrogen	12.5
Carbon	87.2
Nitrogen	0.02
Oxygen	Nil
Ash	Nil

Gravity	32 degrees API
Specific Gravity	0.865
Pounds per Gallon	7.21
Pour Point	$-5^{\circ}F$
Viscosity	34 ssu @ $100^{\circ}F$
Water and Sediment	Nil
Heat Value	19,430 (Gross) Btu/lb

Fig. E-1

LOCATION OF SITE



Soil Profiles and Load Bearing Characteristics

Allowable soil bearing is 6000 psf, rock bearing characteristics are 18,000 psf.

Seismology

The site is Zone 1 as designated by the Uniform Building Code.

3.5.7 Sewage

Sewage would receive primary and secondary treatment prior to discharge to the North River. Treatment would be the same as outlined in the Subtask 1.2 Report.

3.5.8 Ambient Conditions

Plant design and rating is based on the following average ambient air conditions:

D.B. temperature	$59^{\circ}F$
W.B. temperature	$51.5^{\circ}F$
Relative Humidity	60%
Barometric Pressure	29.92" Hg.

4.0 COMMERCIAL PLANT DESIGN

4.1 PLANT CONFIGURATION

The PFB/GT/Waste Heat Steam Generator (WHSG) plant (Fig. B-3) contains six gas turbines, with each gas turbine exhausting into an individual WHSG. Steam is generated by these WHSG's at two pressure levels for expansion through steam turbines (one steam turbine for two gas turbines), and at a third pressure level for use in the deaerating feedwater heater.

The overall layout of the main systems is shown in the Area Site Plan, Figure F-1. The process flow diagram for the main process fluids in the system is shown on Figure F-2. The six parallel trains of PFB's, gas turbine generator sets, and WHSG's are arranged side-by-side. The gases from two (2) gas turbines are exhausted into one (1) stack. Consequently, three (3) stacks are provided. The steam output of the six (6) WHSG's are combined to feed three (3) steam turbine generator sets in any combination.

The arrangement of PFB's (two per gas turbine), cyclones, and hot gas piping for each gas turbine is identical to the Subtask 1.2 plant. No changes to the layout piping sizes or other configurational features are required. However, 6 gas turbines are needed versus two gas turbines in the Subtask 1.2 cycle to produce the same nominal powerplant capacity. Therefore, the quantity of associated PFB's, cyclones, hot gas piping, etc. is higher for the PFB/GT/WHSG plant.

4.2 PERFORMANCE

4.2.1 Full Load Plant Output and Efficiency

Each gas turbine selected for the PFB/GT/WHSG cycle is an axial-flow, single-spool machine having a flow rate of 840 lb/sec and an overall pressure ratio of 10:1. Two air-cooled PFB's are required for each gas turbine. In the PFB's, approximately 25% of the compressor discharge air passes through the bed and is heated to 1650°F while the remaining 75% of the compressor discharge air is being heated to 1575°F as it passes through cooling tubes immersed in the bed. The mixed temperature is approximately 1600°F entering the turbine, where the gases are expanded and exhausted to the WHSG. The gas pressure loss through the WHSG is 10 inches of water. Power produced by the turbine drives the compressor and an electric generator. The gas turbine cycle studies in this task incorporate all of the refinements developed for the Subtask 1.2 cycle. The major gas turbine performance change for the PFB/GT/WHSG cycle is a lower pressure loss in the WHSG than in the AFB used in the PFB/AFB cycle. As a result, the gas turbine power output is 2.7 MW per turbine higher in the PFB/GT/WHSG case.

The steam cycle has a 615 psia throttle pressure and 755°F superheat temperature. There is no reheat section in this steam cycle, but 165 psia steam raised in an intermediate pressure boiler is mixed with the main steam flow prior to expansion in the low pressure turbine. The steam turbine

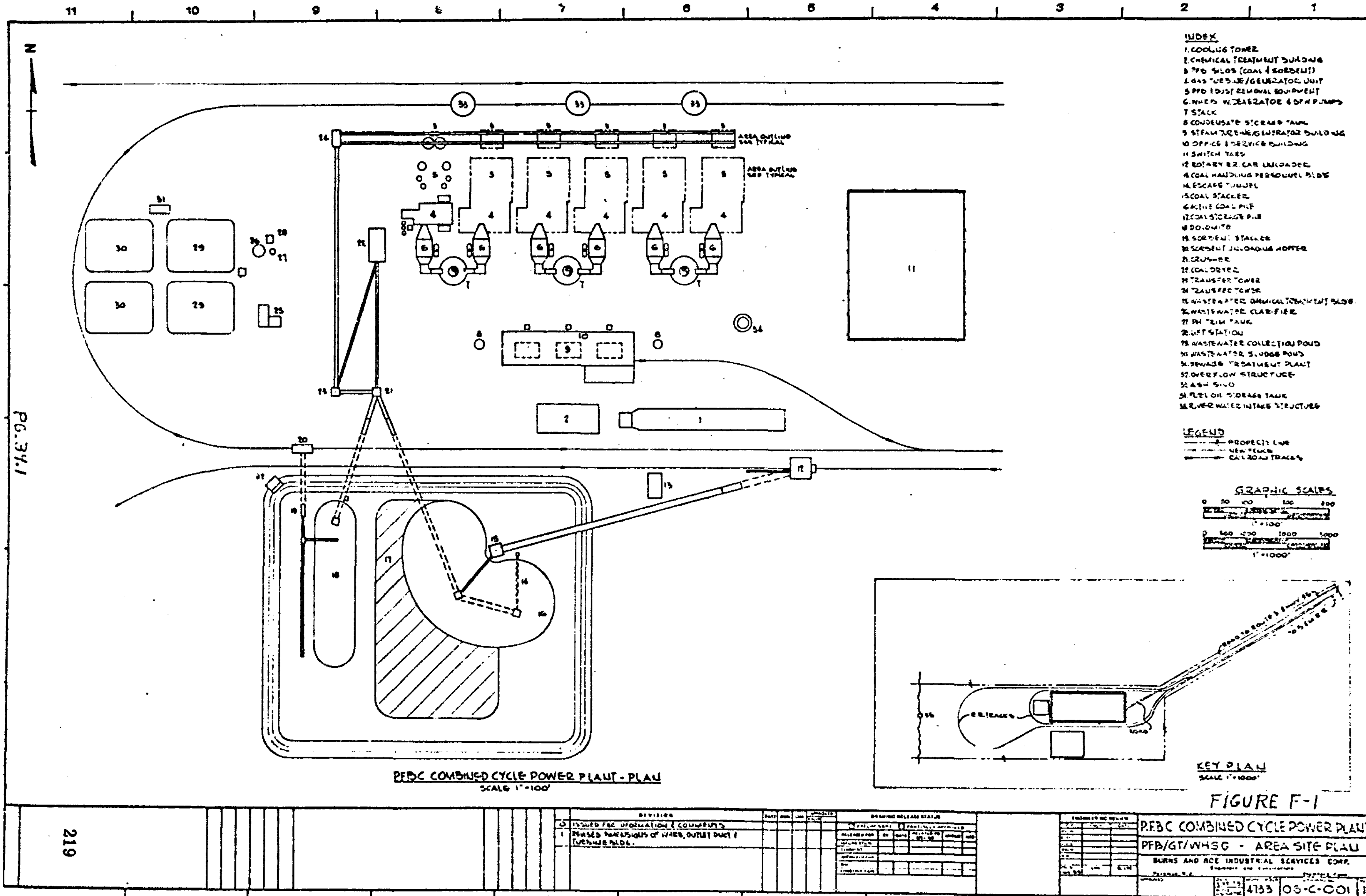
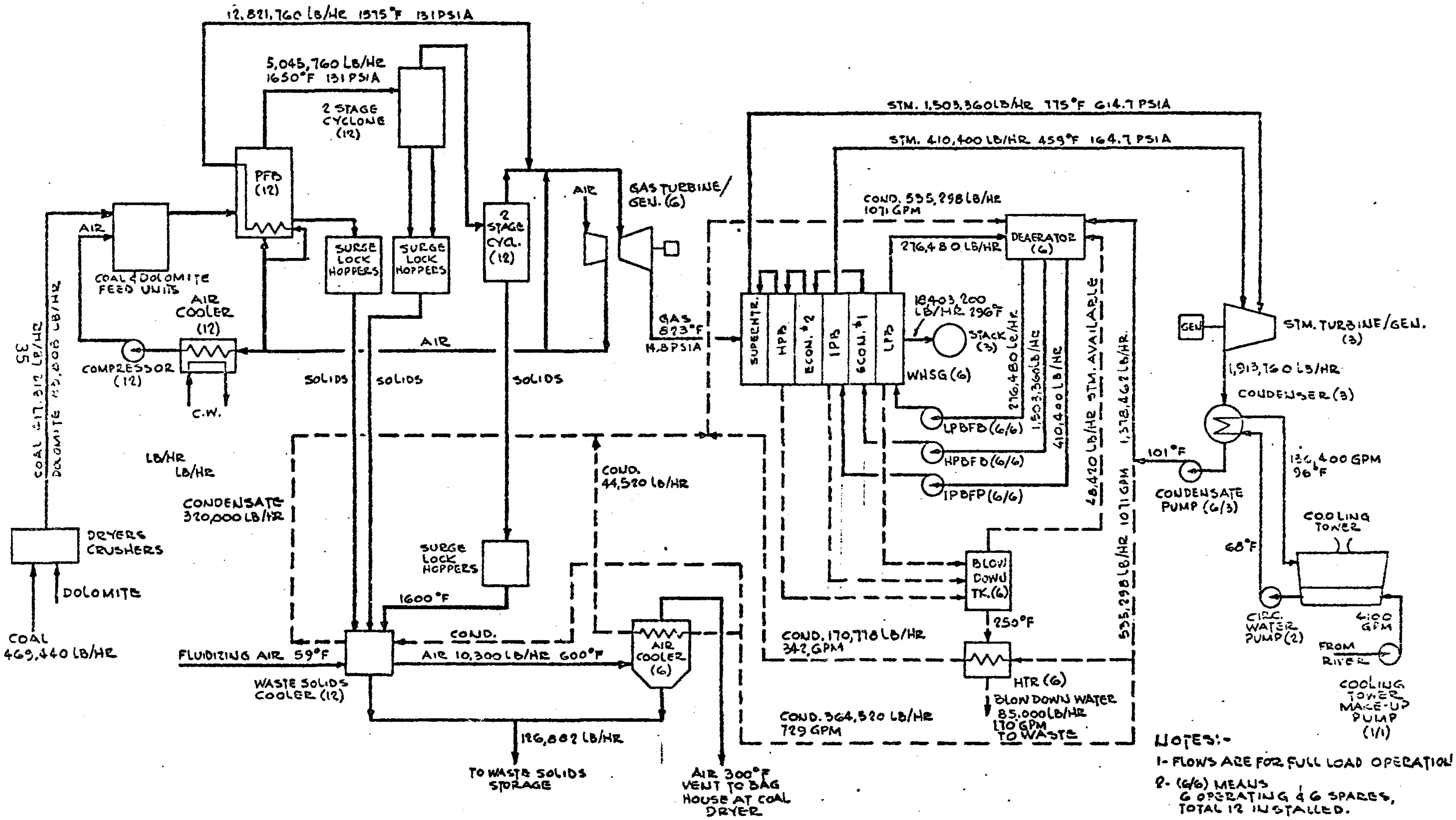

INDEX
1. COOLING TOWER
2. CHEMICAL TREATMENT BUILDING
3. PFB SILOS (COAL & SORBENT)
4. GAS TURBINE/GENERATOR UNIT
5. PFB & DUST REMOVAL EQUIPMENT
6. WHSG W/DEAERATOR & SFW PUMPS
7. STACK
8. CONDENSATE STORAGE TANK
9. STEAM TURBINE/GENERATOR BUILDING
10. OFFICE & SERVICE BUILDING
11. SWITCH YARD
12. ROTARY R.R. CAR UNLOADER
13. COAL HANDLING PERSONNEL BLDG
14. ESCAPE TUNNEL
15. COAL STACKER
16. ACTIVE COAL PILE
17. COAL STORAGE PILE
18. DOLOMITE
19. SORBENT STACKER
20. SORBENT UNLOADING HOPPER
21. CRUSHER
22. COAL DRYER
23. TRANSFER TOWER
24. TRANSFER TOWER
25. WASTEWATER CHEMICAL TREATMENT BLDG.
26. WASTEWATER CLARIFIER
27. PH TRIM TANK
28. LIFT STATION
29. WASTEWATER COLLECTION POND
30. WASTEWATER SLUDGE POND
31. SEWAGE TREATMENT PLANT
32. OVERFLOW STRUCTURE
33. ASH SILO
34. FUEL OIL STORAGE TANK
35. RIVER WATER INTAKE STRUCTURE
LEGEND
PROPERTY LINE
NEW FENCE
RAILROAD TRACKS
GRAPHIC SCALES
1" = 100'
1" = 1000'
AREA OUTLINE SEE TYPICAL
PFBC COMBINED CYCLE POWER PLANT - PLAN
SCALE 1" = 100'
KEY PLAN
SCALE 1" = 1000'
R.R. TRACKS
ROAD
ISSUED FOR INFORMATION & COMMENTS
REVISED DIMENSIONS OF WHSG, OUTLET DUCT & TURBINE BLDG.
P.F.B.C COMBINED CYCLE POWER PLANT
PFB/GT/WHSG - AREA SITE PLAN
BURNS AND ROE INDUSTRIAL SERVICES CORP.
4133
05-C-001
1
PG. 37.1
219

FIGURE F-1



PFB/GT/WHSG POWER PLANT
PROCESS FLOW DIAGRAM

FIG. F-2 PG.

exhaust pressure is 2 inches of mercury. Power produced by the steam turbines is used to generate electricity. A high efficiency steam system, such as the one used in PFB/AFB plant, cannot be used with this system since the gas turbine exhaust temperature (823°F) is too low.

The Babcock and Wilcox Company (B&W) calculated the coal flow requirements for the PFB Combustors. Based on this data, United Technologies Corporation (UTC) did the performance calculations for the total plant using their State-of-the-Art-Performance Program (SOAPP). The key assumptions for the performance calculations are summarized in Table G-1. Some adjustments were made to the total coal flow to account for the radiation heat losses from hot gas piping, etc. The adjustments made are explained in Table G-2, and they are reflected in the performance figures discussed below.

The full load plant heat and mass balances are shown in Tables G-3 and G-4 for the air/gas and steam systems, respectively.

The full load power output and efficiency estimates for the powerplant are shown in Table G-5. The total gross power output is 609.9 MW, with a total gas turbine power output of 397.9 MW (66.3 MW per gas turbine) and a steam turbine output of 212.0 MW. Overall system gross efficiency is 40.1 percent based on the "as fired" coal rate (HHV = 12453 Btu/lb).

The net plant output after adjusting for 3.14 percent auxiliary power losses is 590.7 MW. After adjusting the coal rate to account for drying losses (HHV = 11472 Btu/lb) and miscellaneous heat losses, the "as received" coal rate is 130.4 lb/sec, and the corresponding net plant efficiency is 37.4 percent.

4.2.2 Part Load Performance

The part load performance for the PFB/GT/WHSG cycle has not been calculated. Based upon the PFB/AFB part load performance studies (See Subtask 1.2), however, it would be expected that the characteristic "sawtooth" performance curve would be obtained over the load range. At some part load points the increased number of gas turbine and steam turbine units in the PFB/GT/WHSG plant may result in a smaller percentage reduction in efficiency from the full load value than is obtained in the PFB/AFB plant. However, 100% load efficiency in the PFB/GT/WHSG plant is slightly lower than in the PFB/AFB plant (37.9% vs. 37.4%). Therefore, the average efficiency characteristic over the load range fore, the average efficiency characteristic over the load range may be about the same in both cases.

4.3 MAJOR MECHANICAL SYSTEMS AND EQUIPMENT DESCRIPTIONS

4.3.1 Pressurized Fluidized Bed System

The Pressurized Fluid Bed (PFB) System consists of the PFB combustors and their accessories. The system design is based upon the use of two PFB combustors for each gas turbine.

Since the intent of this Task is to investigate the effects of an alternate steam bottoming cycle compared to the Subtask 1.2 base plant design, the PFB system design is the same as presented in the Subtask 1.2 report.

TABLE G-1

SYSTEM ASSUMPTIONS FOR PERFORMANCE ANALYSIS

Pressure Loss, % of local gas pressure		
PFB (compressor discharge to turbine inlet)		10.2
WHSG		2.4
Temperature, F		
	Bed	Cooling Tubes
PFB	1650	1575 (air)
Component Efficiency, %		
Electric generator (steam turbine)		98.4
Electric generator (gas turbine)		98.7
Electric motors		95.0
Boiler feed pump, mechanical		82.0
Condensate pump, mechanical		82.0
Energy Losses, % of total energy input to PFB		
Sensible heat of solids*		1.0
Net heat of reaction (gain)		-0.5
Radiation		0.4
Unburned combustibles		1.0
Heat of vaporization		4.0
Auxiliary power requirement		3.14

*A large portion of the losses shown here is recovered in the waste solids cooler.

TABLE G-2

ADJUSTMENTS TO COAL FLOW

After the computer calculations were made on the assumptions on Table G-1, adjustments were made to the reported coal flow and efficiency to account for the following:

A.	Radiation loss in hot gas piping	23.7×10^6 Btu/h
	Radiation loss in PFB (over and above that already taken into account. The outside metal temperature was raised to 250°F from 130°F)	39.6×10^6 Btu/h
	Total	63.6×10^6 Btu/h
B.	Manufacturer's margin and unaccounted for losses for combustors.	52.0×10^6 Btu/h

The following adjustments to coal flow were made:

Power Output	Adjustment to Coal Flow (as received) in lb/sec
100%	+2.7

TABLE G-3

SELECTED PFB/GT/WHSG PLANT

HEAT AND MASS BALANCE FOR AIR/GAS SYSTEM

REVISED TWO-PRESSURE STEAM SYSTEM

DESCRIPTION	W * lb/sec	T, °F	P, psia	H, Btu/lb
Inlet	840.	59.	14.7	124.0
Compressor Inlet	840.	59.	14.55	124.0
Compressor Discharge	810.8	595.5	145.5	254.8
PFB Inlet	217.3	595.5	145.5	254.8
PFB Exit	233.6	1650.	130.9	554.6
PFB Cooling Tube Inlet	593.6	595.5	145.5	254.8
PFB Cooling Tube Exit	593.6	1575.	130.9	514.4
Turbine Inlet	827.1	1597.2	130.9	525.6
Turbine Exit	852.0	823.1	15.1	314.0
Superheater Inlet	852.0	820.1	14.8	313.4
HP Boiler Inlet	852.0	763.5	14.8	298.6
2nd Economizer Inlet	852.0	524.8	14.8	237.8
IP Boiler Inlet	852.0	483.4	14.8	227.4
1st Economizer Inlet	852.0	405.3	14.8	207.9
Deaerator Boiler Inlet	852.0	355.1	14.8	195.6
Stack	852.0	296.4	14.8	181.4

*Flows are based on one (1) gas turbine; multiply flows by six (6) for total system.

TABLE G-4

SELECTED PFB/GT/WHSG PLANT

HEAT AND MASS BALANCE FOR STEAM SYSTEM

REVISED TWO-PRESSURE STEAM SYSTEM

DESCRIPTION	W, lb/sec *	T, °F	P, psia	H, Btu/lb
Condensate Pump Inlet	88.6	101.1	.982	69.1
Deaerator Boiler Inlet	12.8	240.	35.	208.3
Deaerator Boiler Exit	12.8	259.3	35.	1166.7
Feedwater Pump Inlet	88.6	240.	25.	208.8
1st Economizer Inlet	88.6	240.4	664.7	210.6
2nd Economizer Inlet	60.6	357.4	664.7	329.5
HP Boiler Inlet	69.6	473.2	664.7	456.7
IP Boiler Inlet	19.1	357.0	189.7	329.5
IP Boiler Exit	19.1	377.4	164.7	1197.6
Superheater Inlet	69.6	493.2	639.7	1202.4
High Turbine Inlet	69.6	755.	614.7	1382.6
High Turbine Exit	69.6	485.8	164.7	1262.9
Low Turbine Inlet	88.6	459.3	164.7	1248.9
Condenser Inlet	88.6	101.1	.982	954.4

*Flows are based on one (1) gas turbine; multiply flows by six (6) for total system.

TABLE G-5

SELECTED PFB/GT/WHSG PLANT PERFORMANCE EVALUATION

(SIX GAS TURBINES)

REVISED TWO-PRESSURE STEAM SYSTEM

	100% Load
PWR_{GT}, MW	397.9
PWR_{ST}, MW	212.0
Gross PWR_{TOTAL}, MW	609.9
Net PWR_{TOTAL}, MW	590.7
Gross $Efficiency_{TOTAL}$, %(1)	40.1
Net $Efficiency_{TOTAL}$, %(2)	37.4
"As Fired " Coal Rate, lb/sec	115.9
"As Received" Coal Rate, lb/sec(3)	130.4
Dolomite Feed Rate, lb/sec	23.3
Solid Waste Discharge Rate, lb/sec	35.2

(1) Based on "As Fired" coal rate (HHV = 12453 Btu/lb) and no auxiliary power or heat losses

(2) Based on "As Received" coal rate (HHV = 11472 Btu/lb), including miscellaneous heat losses and 3.14% auxiliary power loss.

(3) Adjusted as indicated on Table G-2

Therefore, only an abbreviated description of the PFB system is included in this report.

4.3.1.1 PFB Combustor Concept

The PFB combustor design is based upon the split air flow concept; the concept is shown schematically on Figure H-1. The fuel fired in the bed is used only to heat the compressor discharge air to the turbine inlet temperature; no additional coal is fired for steam generation within the PFB combustor. In the split air flow design approximately ¼ of the compressor discharge air flow is used for combustion and fluidizing air; the remaining 3/4 of the air flow is routed to a bed cooling system. This concept provides the following advantages:

1. Since only ¼ of the total air flow is used for combustion and fluidizing air, the sizes of both the combustor and the gas clean-up system are smaller than if all the compressor discharge air flow were used for fluidizing air.

2. Since the bed cooling system consists of both heating surface within the bed and a bypass around this heating surface, the heat extraction from the fluidized bed may be controlled by varying the air flow split between the heating surface and the bypass. This concept provides turndown control of the PFB combustor from 0% to 100% gas turbine load, while permitting the combustor to operate at constant fluidizing velocity and constant bed level.

4.3.1.2 PFB Combustor Design Parameters

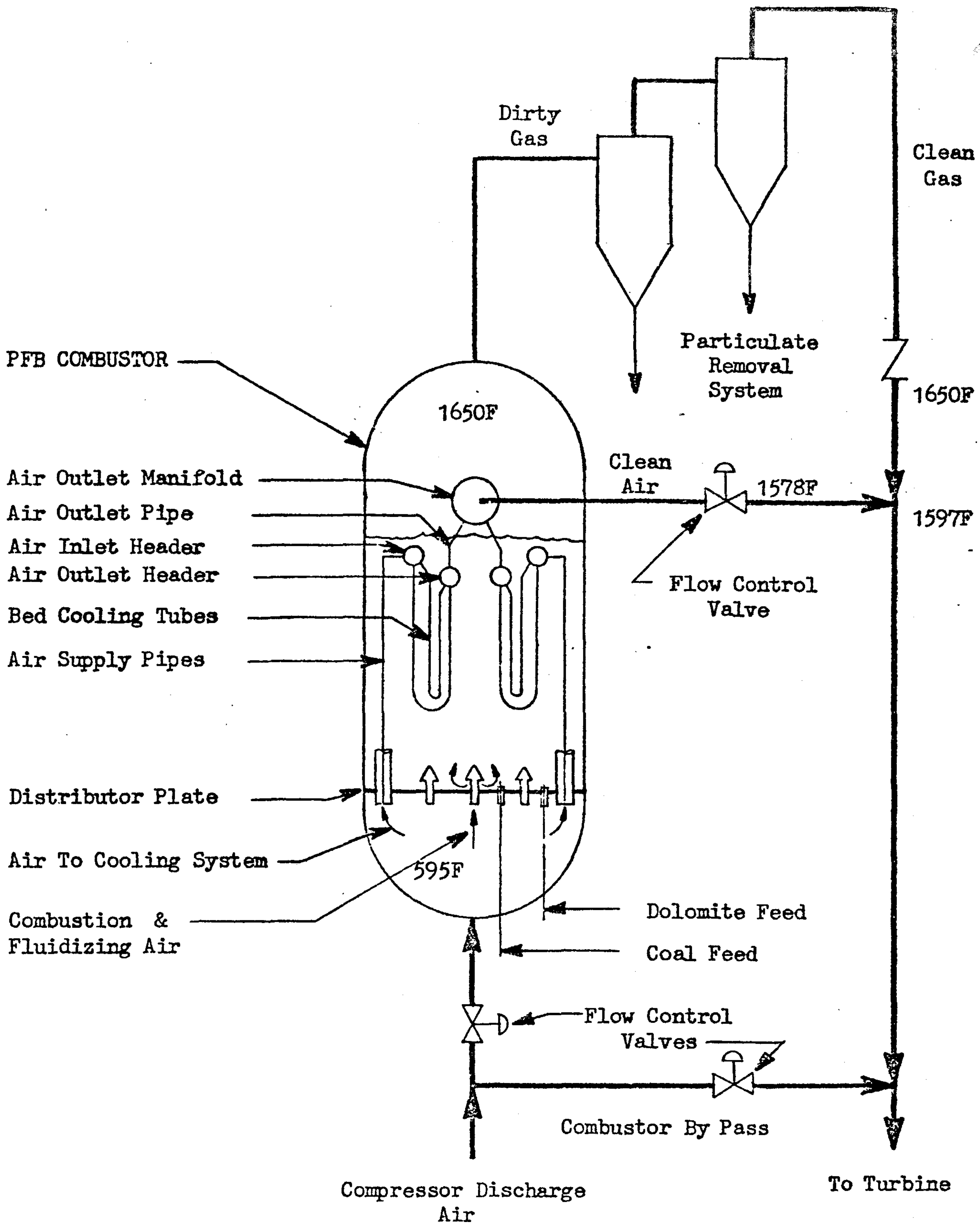
Combustion efficiency, heat transfer and sulfur capture efficiency in the PFB combustor are functions of bed temperature, fluidizing velocity and solids feed size. The values of these parameters used in the design of the PFB combustor are based on the reported work of various organizations involved in PFB research. These values are listed below.

Bed Temperature	$1650^{\circ}F$
Excess Air	15%
Superficial Velocity	<3 fps
Coal feed size	-8 mesh
Sorbent feed size	-10 mesh
Combustion efficiency	99%
Calcium/Sulfur Molar Feed Ratio	1.0
Sulfur Capture	~80% (1.2 lb $SO_2/10^6$ Btu)

4.3.1.3 PFB Combustor Description

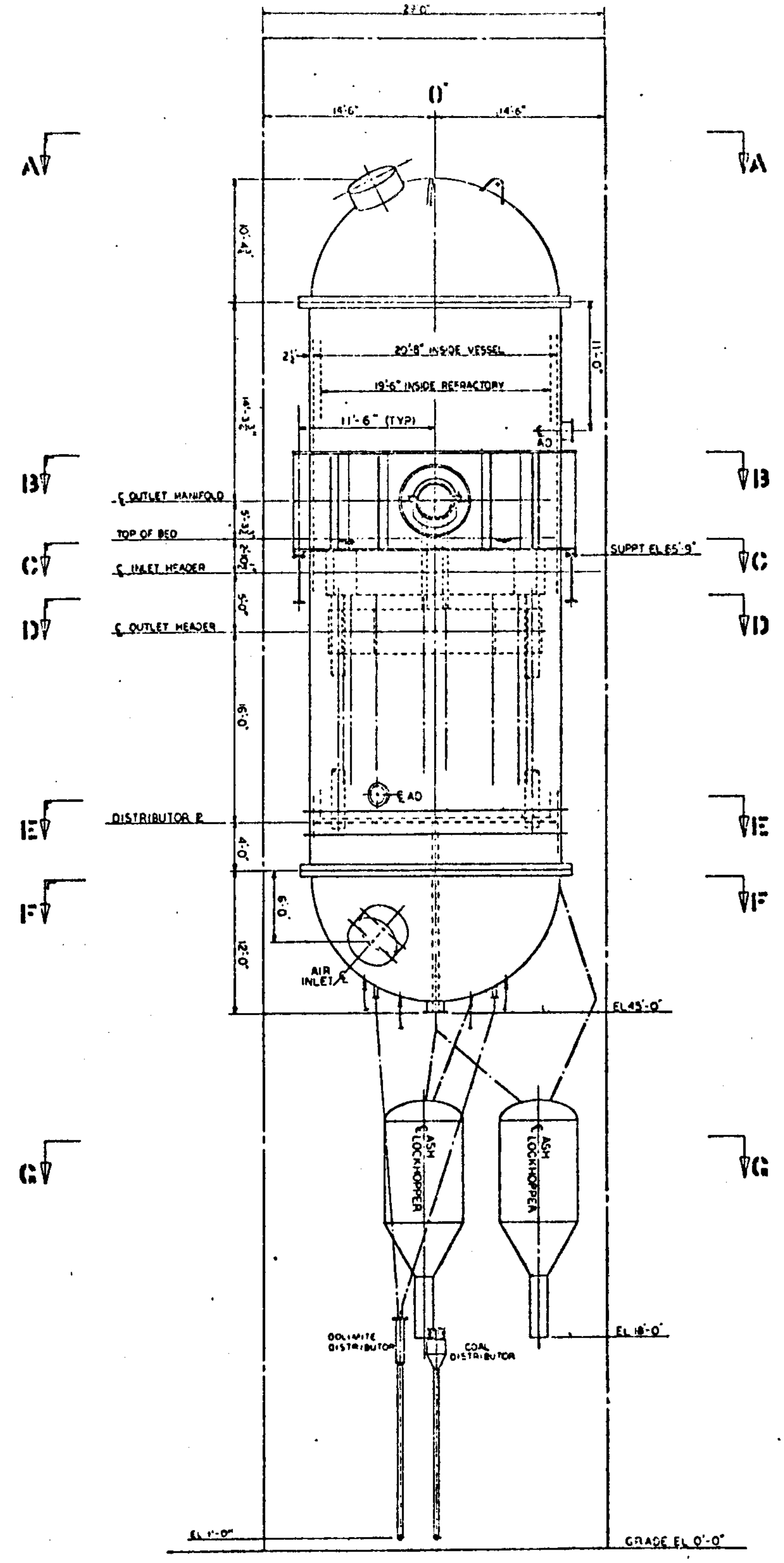
Arrangement drawings of the PFB combustors are contained in the report on Subtask 1.2 (See pages 89 through 95, Figures H-5 through H-11 of the report on Subtask 1.2). Two of these drawings are included here for convenience. They are:

Figure H-2	Arrangement PFB Combustor - Front View
Figure H-3	Arrangement PFB Combustor - Side View



Schematic - Split Air Flow PFB Combustor

FIGURE: H-1



ARRG'T. PRESSURIZED FLUID BED COMBUSTOR FRONT VIEW

FIGURE H-2

ES-223	ARRGT PRESSURIZED FLUID BED COMBUSTOR FRONT VIEW
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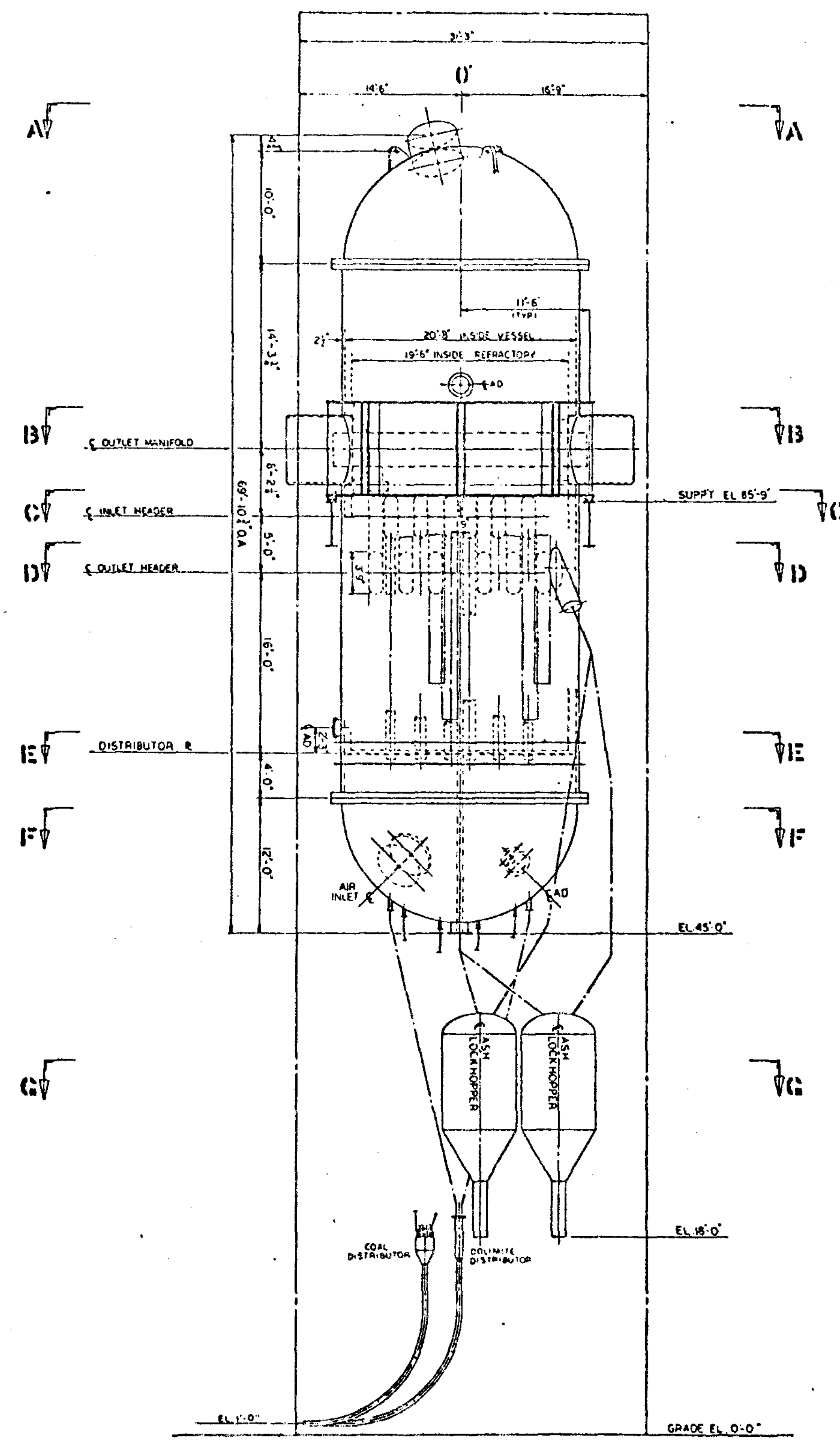


ARRG'T. PRESSURIZED FLUID BED COMBUSTOR SIDE VIEW

FIGURE H-3

The PFB Combustor is a refractory lined pressure vessel with an outside diameter of 21'1" and a length of 69'10-3/4". The vessel is mounted in the vertical position and is supported from structural steel by support rings which are positioned near the mid point of the length. The vessel design is based upon the use of SA516 GR 70 carbon steel; the wall thickness is 2½".

The vessel is internally lined with insulating refractory to limit the surface temperature of the combustor to 250°F based on an ambient air temperature of 80°F. Below the distributor plate the lining is 3-5/8" of Kaolite 2200-HS. Above the distributor plate a two-component refractory lining is used, with the design based on a bed maximum operating temperature of 1700°F. A minimum thickness of 5" of Kaolite 2200-HS insulating refractory is used, covered by a 2" thick layer of Kao-Phos 93 dense refractory to provide erosion protection.

The distributor plate utilizes bubble caps to provide uniform fluidization and yet prevent the bed solids from sifting back into the air inlet plenum. The distributor plate is also refractory covered to limit its operating temperature. The plate is supported by a series of stiffeners in the air inlet plenum. The support system design is based both upon the dead load of a slumped bed and the uplift equivalent to the pressure loss through the plate during normal operation.

The bed cooling system consists of the heat exchanger tubes, together with the associated headers and connecting pipes. Cooling air enters the bed cooling system by way of supply pipes which connect the distributor plate with the inlet headers. The bed cooling tubes are arranged in a U-tube configuration between the inlet and outlet headers. The U-tube arrangement was chosen to accommodate the differential expansion along the tube length as the air is heated from 600°F to nearly 1600°F. Both the tubes and the headers are made of Alloy 800H material. From the outlet header the air flows to the air outlet manifold which spans the vessel diameter and connects to the hot air piping.

4.3.2 Waste Heat Steam Generators (WHSG's)

4.3.2.1 Introduction

The exhaust gases from the gas turbine pass through a waste heat boiler which generates steam for the bottoming cycle. No additional fuel is fired in the boiler.

The WHSG is an established commercial product that has been supplied by the Babcock and Wilcox Company for other combined cycle installations. The boiler is based on standard design concepts that are tailored to suit the individual requirements of the specific cycle.

4.3.2.2 Boiler Arrangement

The boiler is a bottom supported, natural circulation drum type boiler that makes extensive use of helically finned tubes to recover the low level heat of the gas turbine exhaust gas for steam generation. The basic boiler component is the section consisting of an inlet and outlet header connected by two rows of closely spaced, finned tubes. In the boiler design the sections are arranged as required to achieve the desired performance. For ease of shipping and erection the sections are shop assembled into shipping units termed modules.

In the economizer and superheater modules, all interconnections between tube sections are shop installed. As a result, only the module inlet and outlet connections, and the drain and vent lines require field installations. The generating bank sections are shop assembled into modules for convenience in shipping and erection. These sections are designed for connection to the downcomers and drum using supply and riser tubes which are field installed.

The boiler for this cycle actually consists of three separate boilers within a common casing. The high pressure boiler generates 625 psig, 755^{o}F steam for the steam turbine. This boiler consists of a superheater, a generating bank and two banks of economizer.

The intermediate pressure boiler generates 175 psig, saturated steam which is inducted into an intermediate pressure point on the steam turbine. To make maximum use of the energy available in the gas turbine exhaust, the intermediate pressure boiler is located between the two banks of the high pressure boiler economizer. The location is such that the water temperature in the high pressure boiler economizer on either side of the intermediate pressure boiler is approximately the same as the saturation temperature within the intermediate pressure boiler at the design load. The intermediate pressure boiler consists only of a generating bank, and no economizer or superheater surface is included.

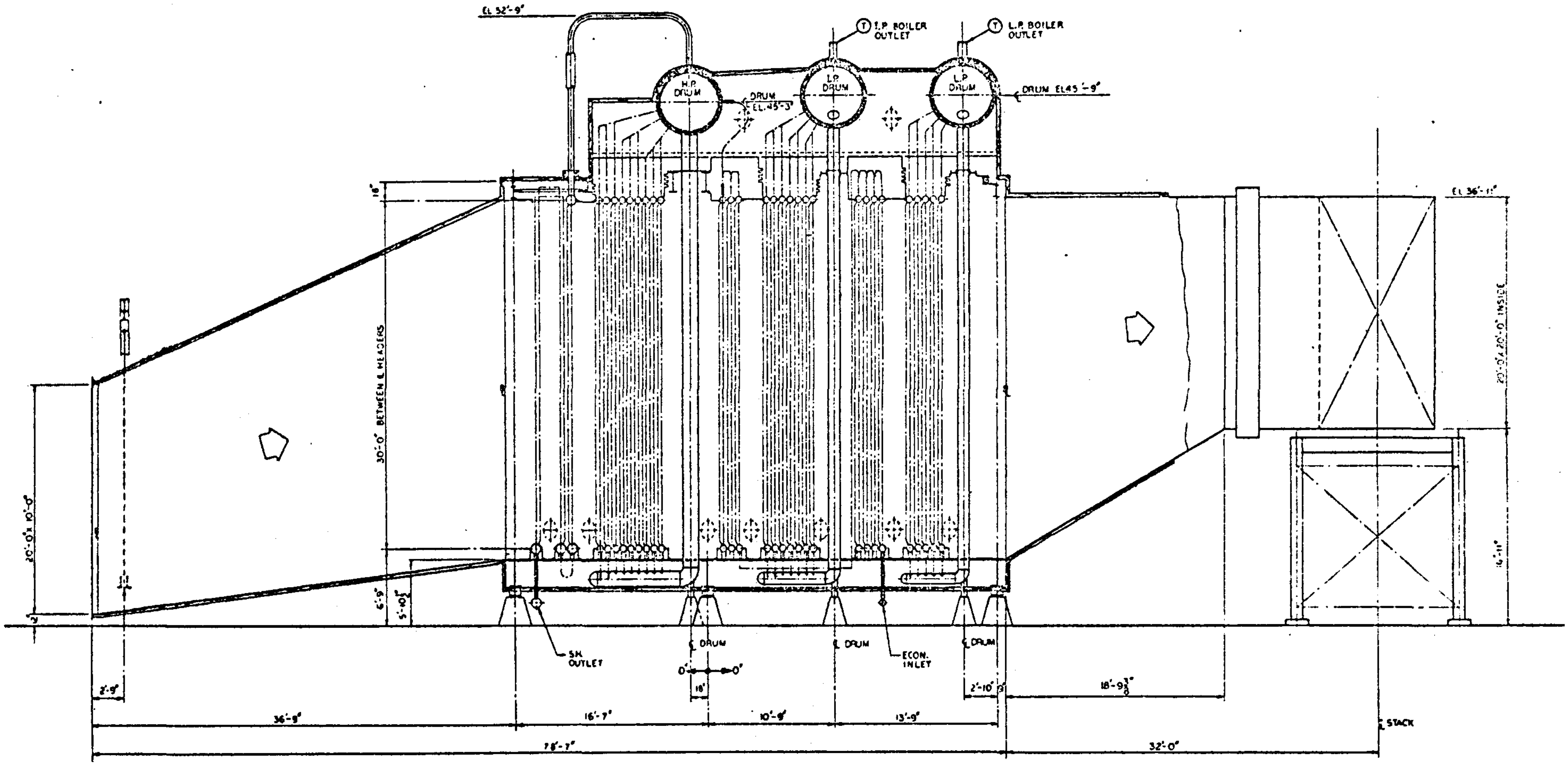
The final heat trap is the low pressure boiler which also consists of only a generating bank. This boiler generates 24 psig steam which is used for deaeration and feedwater heating, since the cycle optimization favors the use of a non-extraction steam turbine.

The boiler arrangement is shown on Figures H-4 and H-5. The boiler performance and design conditions are shown on the Performance Summary Sheet, Table H-1.

4.3.2.3 High Pressure Boiler Design

The superheater consists of three modules located side by side across the width of the boiler. The modules, each six rows deep, are arranged in parallel to minimize the superheater pressure drop. The superheater surface was set to achieve the design steam temperature at the design load condition. No means of steam temperature control is provided because of the modest temperature, and the superheat temperature will vary as the gas turbine exhaust temperature varies.

The lower superheater headers rest on the support grid and are positioned by alignment guides on the connection penetration of the lower gas

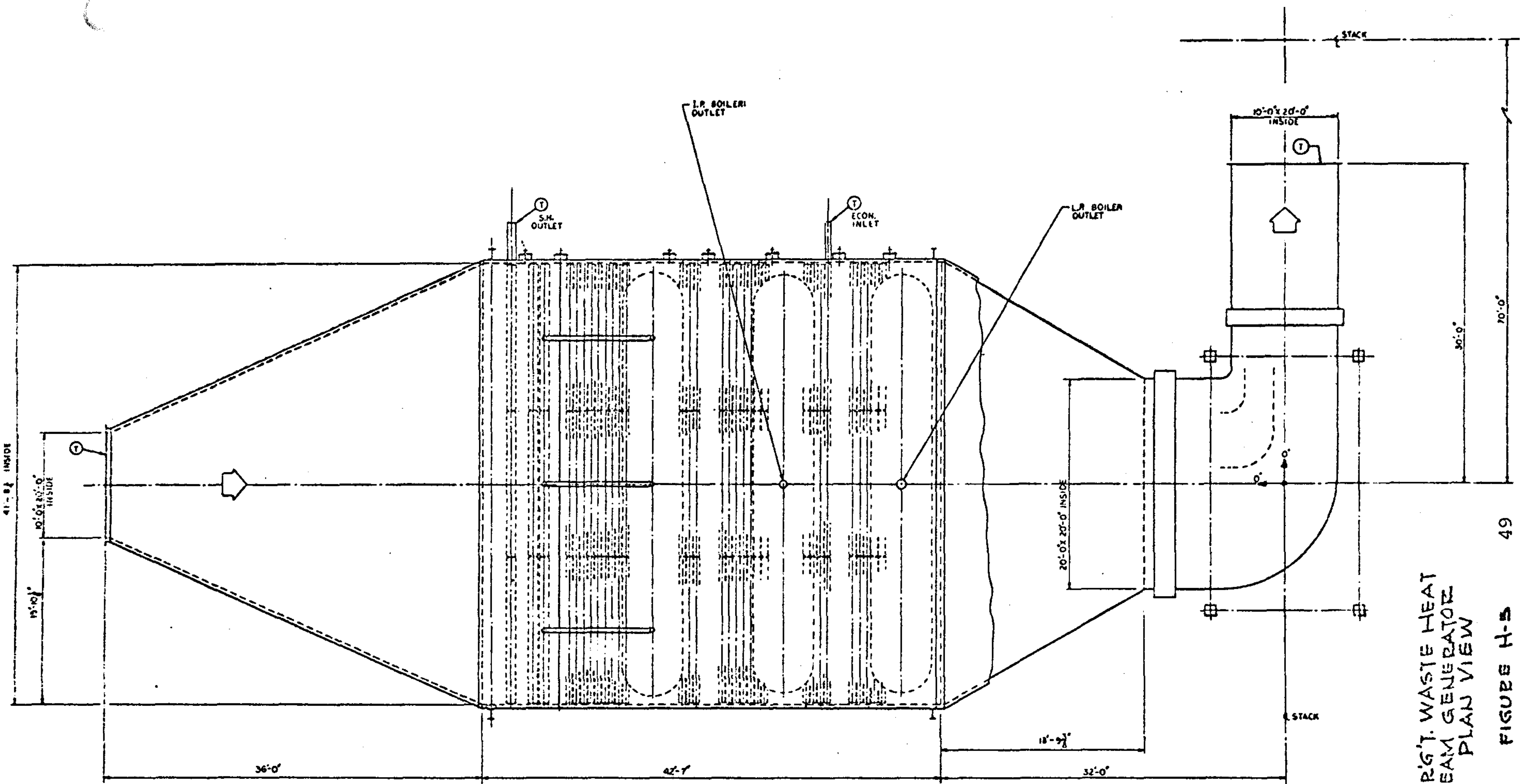


FOR ARRGT PLAN VIEW SEE DWG 254251E

ARRANGEMENT
WASTE HEAT STEAM GENERATOR
SIDE VIEW

FIGURE H-4

ES-223-E



ARR'G'T. WASTE HEAT
STEAM GENERATOR
PLAN VIEW

FIGURE H-5

FOR ARR'GT SIDE VIEW SEE DWG. 254250E

TASK 8
P.F.B./GT./WASTE HEAT BOILER CYCLE

ARRANGEMENT
TURBINE
EXHAUST
GAS BOILER
PLAN VIEW

ES-223-E

254251

PGS 32972

A — FUEL & TURBINE EXHAUST GAS

TURBINE EXHAUST GAS @ 820°F.

ANALYSIS

SOURCE OF ANALYSIS	
LOAD REF.	1
FUEL	
% BY	WEIGHT
N_2	73.960
O_2	17.805
CO_2	5.839
H_2O	1.042
SO_2	0.031
AR	1.321
TOTAL	100

SUPPLEMENTARY FUEL

ULTIMATE ANALYSIS

SOURCE OF ANALYSIS	
FUEL	
% BY	
ASH	
S	
H_2	
C	
CH_4	
C_2H_4	
C_2H_6	
C_3H_8	
C_4H_{10}	
C_5H_{12}	
C_6H_{14}	
CO	
CO_2	
SO_2	
H_2O	
N_2	
O_2	
TOTAL	
BTU/LB	
BTU/CU. FT. AT 60 F., 30 IN. HG.	

B — PREDICTED PERFORMANCE

2	GAS TURBINE LOAD CONDITION	LOAD REFERENCE	1
3		AIR TEMP (°F)	59
4		FUEL	PFB COAL COMBUSTION
5		GAS TURBINE LOAD	100 %
6		GAS FLOW (MLB/HR)	3071.50
7		EXHAUST TEMP (°F)	823
8		% INJECTION	-
9		BY PASS STACK LEAKAGE (MLB/HR)	0
10	SUPP FIRING	TYPE OF SUPP FUEL	NONE
11		FUEL INPUT (MKB/HR)	-
12		SUPP FUEL (MLB/HR OIL, MCFH N.G)	-
13		SUPP AIR FLOW (MLB/HR)	-
14		GAS FLOW ENT. BOILER (MLB/HR)	3071.50
15	HP BOILER	STEAM FLOW LVG SH (MLB/HR)	250.46
16		STEAM TEMP AT SH (°F)	755
17		STM PRESS. AT SH (PSIG)	625
18		PRESS. DROP - ECON. (PSI)	24
19		PRESS. DROP-DRUM TO SH (PSI)	25
20		FEED WATER TEMPERATURE (°F)	240°F.
21		BLOW DOWN (MLB/HR)	0
22		SOLIDS IN STEAM (PPM)	1
23		MAX ALLOWABLE BOILER CONC. (PPM)	1500
24			
25	IP BOILER	STEAM FLOW LVG DRUM (MLB/HR)	68.63
26		STM PRESS. AT DRUM (PSIG)	175
27		PRESS DROP - ECON. (PSI)	-
28		FEED WATER TEMPERATURE (°F)	240°F.
29		BLOW DOWN (MLB/HR)	0
30		SOLIDS IN STEAM (PPM)	3
31		MAX ALLOWABLE BOILER CONC. (PPM)	3000
32			
33	LP BOILER	STEAM FLOW LVG (MLB/HR)	46.2
34		STM. PRESS. AT DRUM (PSIG)	24
35		PRESS DROP - ECON. (PSI)	-
36		FEED WATER TEMPERATURE (°F)	240
37		BLOW DOWN (MLB/HR)	
38		MOISTURE IN STEAM %	0.5
39		MAX ALLOWABLE BOILER CONC. (PPM)	3500
40			
41		GAS TEMPERATURE TO STACK (°F)	299.0
42	RESISTANCE IN. OF WATER	BURNER	
43		CONVECTION BANKS	6
44		FLUES & STACK	4
45			
46		PRESS. AT GT EXH. ("WG)	10

PREDICTED PERFORMANCE IS BASED ON TEG ENTERING UNIT AT SPECIFIED TEMPERATURE, ON IN.HG. BAROMETRIC PRESSURE, ON 80F REFERENCE TEMPERATURE, ON CONDITIONS AND EQUIPMENT GIVEN ON THIS SUMMARY SHEET AND ON ARRANGEMENT SHOWN ON DRAWING

C — EQUIPMENT PER UNIT

2			TYPE PFB COMBINED CYCLE HEAT RECOVERY BOILER		
3			SIZE 30' x 41.8'		
7	HP BOILER	SHTR	HS 68,990 SQ.FT.	TUBES, OD 2 IN.	3 FINS/INCH
8			DESIGN PRESS. 750	6 ROWS AT 4 IN.	105 WIDE AT 4.5 IN.
11		BOILER	HS 266,400 SQ.FT.	TUBES, OD 2 IN.	4 FINS/INCH
12			DESIGN PRESS. 750	18 ROWS AT 4 IN.	105 WIDE AT 4.5 IN.
15			DRUM INTERNALS CYCLONE SEPARATORS & SECONDARY SCRUBBERS		
17		EC.	HS 207,200 SQ.FT.	TUBES, OD 2 IN.	4 FINS/INCH
18			DESIGN PRESS. 750	14 ROWS AT 4 IN.	105 WIDE AT 4.5 IN.
19		STEAM TEMP CONTROL	TYPE UNCONTROLLED		
22	IP BOILER	BOILER	HS 207,200 SQ.FT.	TUBES, OD 2 IN.	4 FINS/INCH
23			DESIGN PRESS 300	14 ROWS AT 4 IN	105 WIDE AT 4.5 IN.
24			DRUM INTERNALS "B" BAFFLE & SECONDARY SCRUBBER		
26		EC.	HS SQ.FT.	TUBES, OD IN.	FINS/INCH
27			DESIGN PRESS.	ROWS AT IN.	WIDE AT IN.
28	LP BOILER	BOILER	HS 148,000 SQ.FT.	TUBES, OD 2 IN.	4 FINS/INCH
29			DESIGN PRESS. 300	10 ROWS AT 4 IN.	105 WIDE AT 4.5 IN.
30			DRUM INTERNALS "B" BAFFLES & DRY PAN		
32		EC.	HS SQ.FT.	TUBES, OD IN.	FINS/INCH
33			DESIGN PRESS.	ROWS AT IN.	WIDE AT IN.
36	BURNER		INPUT - MKB/HR -		

REVISIONS

NO.	DESCRIPTION	BY	DATE

TASK 8
PFB/GT/WASTE HEAT BOILER CYCLE

TEG HEAT RECOVERY BOILER PERFORMANCE SUMMARY

BY H. Doss | DATE 3-10-78 | APPD.

THE BABCOCK & WILCOX COMPANY

P-

TABLE H-1
PFB/GT/WHSG CYCLE
WHSG SUMMARY PERFORMANCE SHEET

tight casing. To accommodate the differential expansion of the tubes and the casing, the modules are free to expand vertically. They are stabilized at the top at the upper inlet header and upper screen header by alignment guides on the connection penetrations of the upper gas tight casing.

The generating bank consists of three modules and follows the superheater in direction of gas flow. These modules, each eighteen rows deep, are located side by side across the width of the unit. The generating bank is designed for natural circulation; no circulating pumps are required in the boiler. The water from the drum flows down three downcomer pipes located in the gas stream behind the generating bank. The downcomers penetrate the lower gas tight casing. Below this casing, supply tubes are routed to the lower headers of the generating sections. Riser tubes carry the steam-water mixture from the upper headers into the drum. The drum internals include cyclone steam separators to separate the steam-water mixture entering the drum from the generating bank. The water is discharged from the bottom of the cyclone steam separators and is mixed with the feedwater from the economizer discharge. The feedwater from the economizer also passes through independent cyclone steam separators as it enters the drum to provide steam-water separation during operation at the lower loads when the economizer is steaming.

The lower generating bank headers rest on the support grid. Both the upper and lower headers are integrated into the gas tight casing so that the numerous supply and riser tubes need not penetrate the casing. The lower headers are attached directly to the casing. The upper headers are attached to the casing by a metallic expansion joint.

The drum is supported on the downcomers which, in turn, are bottom supported. In this manner, the generating sections, drum and downcomer are all supported from the same elevation. Since these components are always at saturation temperature, they expand together. With the use of the expansion joints at the upper headers and at the downcomer penetrations of the upper gas tight casing, these pressure parts are free to expand independently of the casing.

The economizer outlet bank follows the generating bank and consists of three modules, each with three of the two-row sections connected in series. The economizer inlet bank follows the intermediate pressure boiler generating bank and consists of three modules, each with four of the two-row sections connected in series. Because of the potential for steam generation in the economizer at the lower loads, upflow is desired in the multiple finned tubes of each section. The connection between successive upflow sections is accomplished by a single, non-finned tube routed, inside the gas stream, from the upper header of one section to the lower header of the next section. This arrangement provides for stable water flow through the economizer at all loads.

The lower economizer headers are supported from the support grid with the gas tight casing located between the headers and support grid. The upper gas tight seal is located above the upper headers. This allows the modules to expand independently of the casing. In addition, the flexibility of the connecting tube between modules allows for free expansion of the modules relative to one another. This is required due to the increasing water temperature through the economizer and because this temperature profile changes with load. Each economizer section is provided with a drain connection on the lower header and a vent connection on the upper header so that the economizer may be completely drained.

4.3.2.4 Intermediate Pressure Boiler

The intermediate pressure boiler consists only of a generating bank located between the high pressure boiler economizer banks. The bank consists of three modules, each fourteen rows deep, located side by side across the width of the unit.

The design parallels that of the high pressure boiler except for the drum internals. Because feedwater is supplied directly from the feed pump, rather than through an economizer, the water enters the drum through a feed distribution pipe. Because of the lower operating pressure, a baffle arrangement, rather than cyclone separators, is used for steam-water separation.

4.3.2.5 Low Pressure Boiler

The low pressure boiler also consists of only a generating bank. It consists of three modules, each ten rows deep, located side by side across the width of the unit following the high pressure boiler economizer inlet bank. The design is similar to that of the Intermediate Pressure Boiler.

4.3.3 Gas Turbine Subsystem Equipment Description

4.3.3.1 Introduction

As in subtask 1.2, the gas turbine subsystem is based on the UTC FT50 Industrial Gas Turbine design. A typical layout of the FT50 gas turbine powerplant package is shown in the Subtask 1.2 report (Commercial Plant Design). The main enclosure contains the gas turbine with the electric generator enclosure extending from the main enclosure. Various other systems are located adjacent to the main enclosure. The FT50 is a high performance industrial gas turbine consisting of twin-spool gas generator and a free turbine driving the output shaft. The choice of this design for all of the gas turbine subsystem physical and mechanical characteristics permitted using information resulting from a very large engineering design effort. Performance characteristics, however, are based on a comparably sized industrial gas turbine design. After a performance optimization study, the selected cycle performance was based on gas turbine assumed to have slightly higher airflow (840 vs. 815), lower pressure ratio (10 vs. 16) and of single spool design (i.e., one rotor at 3600 rpm). The single spool engine efficiencies are of the same level as those used in the FT50 and are reasonable for a mid-1980's production gas turbine suitable for PFB operation. It is felt that the physical characteristics of weight, size, and the support systems required for the FT50 would be similar to those required for the selected commercial gas turbine.

4.3.3.2 Gas Turbine Subsystem

The gas turbine subsystem is similar to today's "packaged power-plants". It is assumed to be a pre-engineered power plant of standard design, modified for delivering compressed air to the PFB combustor and returning the hot pressurized gas to the turbine for expansion. The hot exhaust gases would then be ducted to the WHSG to produce steam.

All gas turbine system components are assumed to be part of the gas turbine subsystem. A complete list of equipment has been used to generate system costs. This list is made up of the Gas Turbine Package, the Generator and Exciter Package and the Control Package. The Main Air Circuit Breaker, Lubrication systems, starting systems, electrical systems and protection system are all included in the above packages. A complete design description of the gas turbine used in the PFB/GT/WHSG cycle study is contained on pages 127 through 136 of the report on Subtask 1.2.

4.3.4 High Temperature Piping and Valving

The PFB/GT/WHSG plant contains six gas turbine units as compared to two units in the PFB/AFB plant of Subtask 1.2. In both cases, two PFB units and associated cyclones are piped into each gas turbine unit. A schematic arrangement of the piping configuration with valving for each gas turbine is shown on Figure H-6. The valves are refractory lined and water-cooled to reduce the temperature of pressure containing metal parts to 750^{o}F or below. Piping is also refractory lined on its inside surface so as to maintain wall temperatures at 250^{o}F or less. For each gas turbine, the design, sizing, and arrangement of piping and equipment relative to the respective gas turbine are identical to the PFB/AFB plant. The only difference lies in the number of gas turbines. A complete design description of the high temperature piping and valving for each unit is contained on pages 136-159 of the report on Subtask 1.2. Considerable development work is required in this area to demonstrate commercial feasibility.

4.3.5 Coal and Sorbent Handling Systems

The coal and sorbent handling systems are of the same general design as used in Subtask 1.2, except that limestone handling is not required. The changes in system configuration are indicated by comparing Figure F-1, Area Site Plan, with the corresponding figure in the Subtask 1.2 report (i.e., Fig. C-1, page 253). Briefly, these changes are as follows:

- The limestone storage pile is removed.
- The sorbent stacker does not have capability to swivel.
- The underground reclaim system for limestone is removed.
- The length of the coal and dolomite storage silo feed conveyors is increased since the east-to-west dimension between the first and last silos is increased to accommodate the greater number of gas turbines.
- Some minor changes to the crushers are required since it is no longer necessary to produce two different coal sizes (i.e., one for AFB and one for PFB) and sorbent sizes.

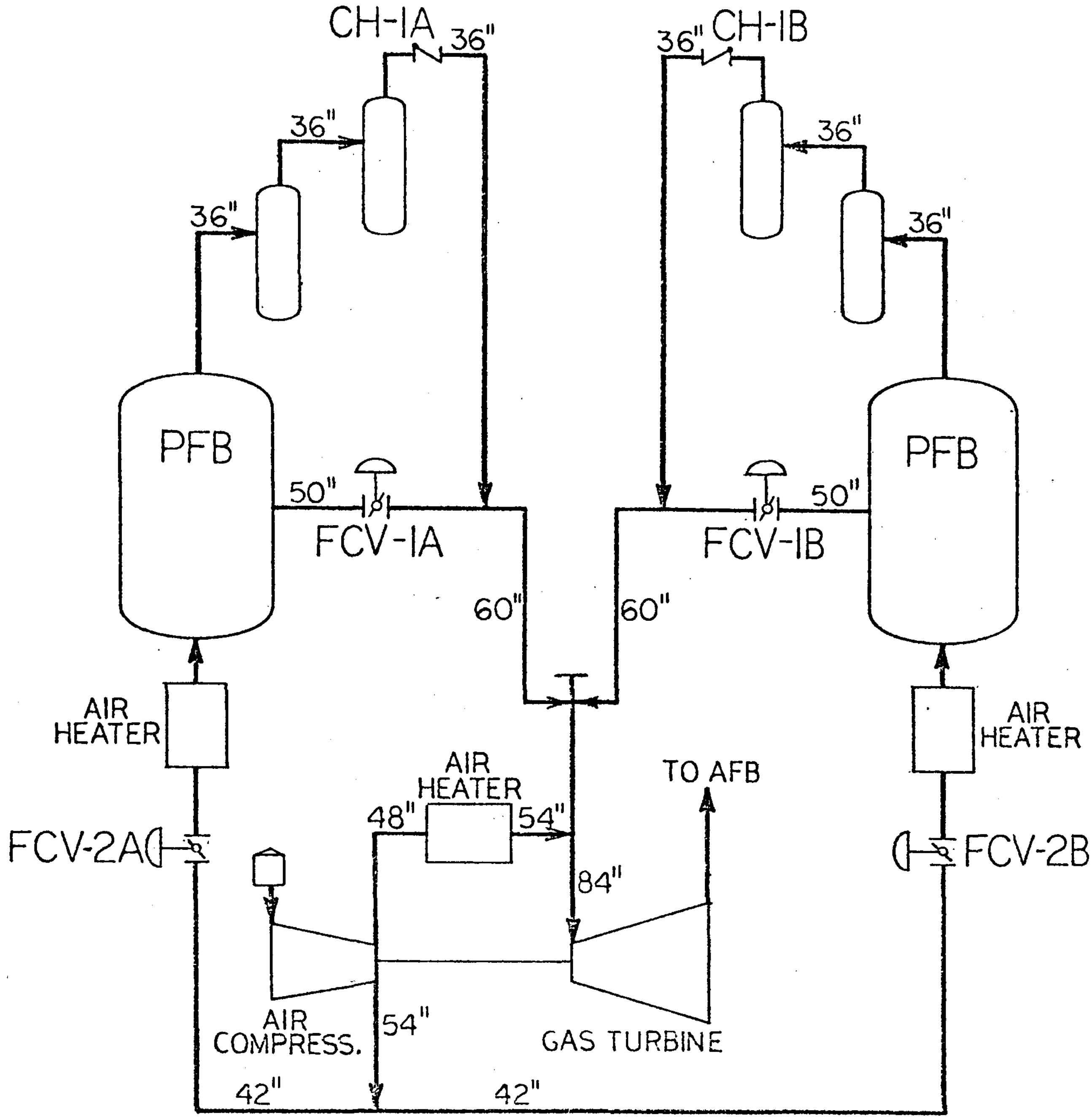


FIGURE: H-6

PFBC COMBINED CYCLE POWER PLANT
HIGH TEMPERATURE VALVE LOCATIO
BURNS AND ROE INDUSTRIAL SERVICES CORP. Engineers and Constructors Paramus, N. J. Stamford, Conn.

Approved	Date 2-15-78	Work Order 4733	Drawing No. OLM-24	R

With the exception of these changes, the system design description and criteria contained on pages 160 to 171 of the report on Subtask 1.2 also apply to the PFB/GT/WHSG study.

4.3.6 Solids Feed System

Separate pneumatic transport systems are used for the coal and sorbent feed. The systems incorporate lock hoppers for pressurization of the coal and the dolomite. One coal feed system and one dolomite feed system are provided for each PFB combustor. The arrangement of the lock hoppers and feed tanks is shown in the Subtask 1.2 report on page 173 (Figure M-1), and the system schematic and instrumentation are shown on page 174 (Figure M-2).

The crushed solids (coal or dolomite) from the bunker free fall into one of the two lock hoppers. The lock hopper is pressurized, and the solids then free fall into the feed tank. From the feed tank the solids are pneumatically transported to the PFB combustor, with the feed rate controlled by the speed of the rotary "air swept" feeder at the feed tank outlet. A single transport line is used from the feed tank to a feed distributor located beneath the PFB combustor. At the distributor, the solids/air mixture is divided evenly among the individual feed lines which enter the combustor. Twenty-four coal feed lines (each servicing approximately 9 square feet of bed area) and four dolomite feed lines are used.

4.3.7 Particulate Removal System

The gas from the PFB combustor passes through two stages of high efficiency cyclones for particulate removal as required to satisfy the requirements of both the EPA and the gas turbine. The allowable gas turbine particulate loading is based on the assumption that particles greater than 10 microns in size would give unsatisfactory turbine life, particles less than 2 microns in size would have negligible effects on turbine life, and that some limited amount of particulate in the 2-10 micron size could be tolerated within the gas turbine. The assumed allowable dust loading entering the gas turbine is:

particle diameter, d (microns)	maximum particulate concentration (grains/SCF)
$d < 2.0$	no limit
$2.0 < d < 10.0$	0.0100
$d > 10.0$	0.0000

The high efficiency cyclones provided are Aerodyne Development Corporation's "SV-FBC" Series Dust Collectors. Two Model 22000SV (shown on page 188, Figure N-3, of the Subtask 1.2 report) units in series are used to process the combustion gas flow from one PFB combustor. This design is an extension of the equipment presently used in low temperature, low pressure applications. Each unit is essentially a two-stage cyclone contained in one vessel. Based on the estimated particulate loading in the combustion gas and the predicted collection efficiency, two of these "two-stage" collectors operating in series are required to achieve the particulate loading level dictated by the turbine requirements. The predicted performance is:

particle diameter, d (microns)	particle concentration* (grains/SCF) leaving first collector	leaving second collector
$d < 2.0$	0.0403	0.0176
$2.0 < d < 10.0$	0.0307	0.0031
$d > 10.0$	0.0000	0.0000
total emissions, lb/10^6 Btu**	0.347	0.1

* concentration based on total gas flow entering turbine
**emissions based on fuel input to combustor (HHV = 12,453 as fired)

It should be noted, however, that the uncertainty associated with these predictions is quite high. They are very sensitive to assumptions concerning the quantity and size distribution of particulates leaving the PFB combustors, and to the performance capability of the cyclones themselves. Even a relatively minor change to any of these factors could result in the need for an additional stage of collection or an alternate collection technology, either of which would significantly increase the plant cost.

A system of holding tanks and lock hoppers is provided for depressurization and dumping of the solids to the solids coolers. The arrangement of the cyclones and associated lock hoppers is shown in the Subtask 1.2 report on page 201 (Figure O-3).

4.3.8 Solid Waste Handling System

The solid waste handling system for the PFB/GT/WHSG system is basically the same design as used in Subtask 1.2. Changes have been made in the piping and equipment to account for the elimination of the AFB and its associated cyclones, as well as the electrostatic precipitator. In addition, the system has been revised to reflect the increased number of PFB combustors and their associated Aerodyne Cyclones.

The solid waste from each PFB unit and its corresponding dust removal system is piped to a Fuller Fluidized Bed Hydroaire solid waste cooler. Each gas turbine unit has two PFB combustors and two solid waste coolers. The total plant arrangement consists of six similar gas turbine units (Figure F-1).

The solid waste is transferred from each solid waste cooler to a storage silo by means of a positive pressure pneumatic transport system. The solid waste from two gas turbine modules is transferred to a single storage silo. This results in the use of three solid waste storage silos for the total plant. The design features and details of each silo except for capacity are the same as those described under Subtask 1.2. Each silo has been increased in size so that the total plant storage capacity is unchanged from the PFB/AFB plant.

The unloading and removal of the solid waste from the silos is similar to the method described in the Subtask 1.2 report.

4.3.8.1 PFB Combustor Spent Bed Material Letdown System

Two solids drains are provided on the PFB combustor. The upper drain is a standpipe arrangement at the side of the pressure vessel at the normal bed operating level. This drain is used for level control during normal operation of the combustor. The lower drain at the distributor plate provides both low bed level control during startup and a means of lowering the bed level during the unit shutdown. A lock hopper system is provided for depressurization and dumping of the solids to the solids cooler. See pages 197-199 of the Subtask 1.2 report for a more detailed description of this system.

4.3.9 Steam Turbine/Generator

Each of the three (3) steam turbine-generator sets has a nominal rating of 70 MWe and takes throttle steam at 615 psia, 755°F and induction steam at 165 psia, 377°F (saturated). Condenser vacuum is 2 inches of Hg absolute. Generator voltage is 13,800 kV. Power factor is 0.8. Each set can be independently operated.

4.3.9.1 Steam Turbine

Each turbine is a dual pressure admission, condensing steam turbine with control and governing system, lubricating oil system, gland steam system with gland steam condenser, thermal insulation, turbine startup and supervisory panel, standard instrumentation, and integral piping.

4.3.9.2 Generators

Each generator is a 2-pole, air cooled, totally enclosed, synchronous 3-phase, 60 Hz unit designed to produce the required MWe terminal output at a power factor of 0.8. Air coolers, air filters, and space heaters are provided.

4.3.9.3 Excitation Equipment and Electrical Auxiliaries

The excitation equipment consists of brushless exciters with rotating diodes, main rotary exciter and permanent pole pilot exciter, automatic voltage regulator, neutral resistor, rectifier and compound transformer, and lightning arrestors.

4.3.10 Steam and Boiler Feedwater System

In the PFB/GT/WHSG cycle, hot exhaust gas from each gas turbine unit passes through a waste heat steam generator. The WHSG is designed to produce steam at three pressure levels. Superheated steam at the high pressure level is routed from each of the six WHSG's to a common steam header. From the header, the H.P. steam is piped to the throttles of the three steam turbines or to the condenser via a turbine bypass line and control valve. Similarly, saturated steam at the intermediate pressure (I.P.) level is routed from each WHSG, via a header, to the induction points on the dual admission steam turbine/

generators, or through a bypass line and control valve to the condenser. Saturated steam at the low pressure (L.P.) level is piped to the deaerating feedwater heater.

Since this plant consists of six modular units, each waste heat boiler is provided with a separate deaerating feedwater heater and three sets of boiler feedwater pumps, all located adjacent to each waste heat boiler unit.

The waste heat boiler units have three separate steam drums. Each steam drum operates at a different pressure level. Each steam pressure level is fed from a different feedwater pump system. Each pump is designed for 100% capacity, with a 100% capacity spare unit as backup.

The low pressure boiler provides 20 psig saturated steam to each of the deaerating feedwater heaters.

The intermediate pressure boiler supplies 175 psig saturated steam and is sent to the 175 psig header which connects the intermediate pressure boilers with the intermediate pressure steam induction connections of the steam turbine generating units.

The high pressure steam generator produces 625 psig and 755°F. This steam is sent to a header which connects all the high pressure boilers with the inlets to the high pressure sections of the steam turbine generating units.

Each waste heat boiler module is provided with a blowdown tank. The boiler blowdown flow is controlled so that drum water solids and chemistry is maintained within proscribed operating limits.

Flashed steam from the blowdown tank and waste heat is recovered and put back into the steam cycle for better plant efficiency.

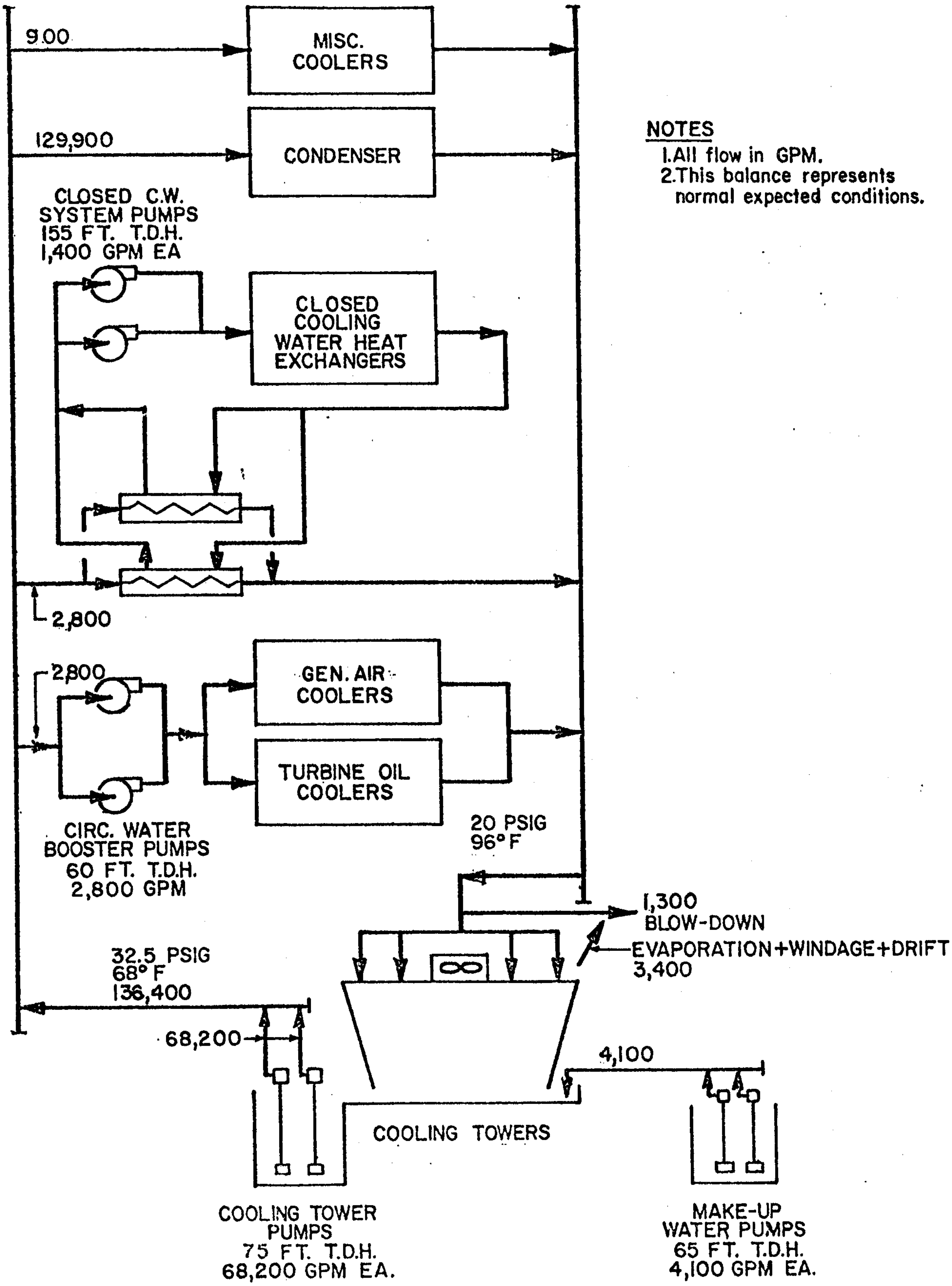
4.3.11 Heat Rejection System

4.3.11.1 General

The condensers, generator air coolers, turbine oil coolers and closed cooling water heat exchangers reject their heat to the cooling water coming from a mechanical draft cooling tower. The heat rejection system is a closed type circulating water system. The diagram on Figure H-7 shows the general scheme of the circulating water system. River water is used as makeup to compensate for blowdown and evaporation losses. The equipment is designed for full load operation at ISO ambient conditions.

4.3.11.2 Selection of Design Parameters

The design parameters used in selecting the cooling tower are based on the studies made during Subtask 1.2 (See pages 215-218 of Subtask 1.2 report). The only changes made for this study are the quantities of water required for the equipment used in the PFB/GT/WHSG cycle.



FLOW DIAGRAM
FOR COOLING WATER

FIGURE H-7

4.3.11.3 Cooling Tower

A mechanical draft, double flow induced draft cooling tower is erected above a concrete basin. One end of the concrete basin has sufficient depth to allow for the installation of vertical circulating water pumps.

Two 50% capacity, vertical motor driven circulating water pumps are installed in the wet pit of the tower basin.

4.3.11.4 Makeup Water

River water is used for cooling tower makeup. The river water intake structure and equipment is similar to that used for Subtask 1.2 with the exception of the capacity of the equipment. The equipment is designed to supply the requirements called for on the flow diagram Figure H-7.

4.3.12 Water Treatment Systems

4.3.12.1 Makeup Feedwater System

The source of plant makeup water is the city water system. This is available at the northeast corner of the site. The city water pressure varies from 112 psig at zero flow to 30 psig at a line flow of 390 gpm. A 100,000 gallon storage tank is provided.

The analysis of the city water used is the same as that in Subtask 1.2.

The design capacity of the makeup feedwater treatment plant is 150 gpm. Automatic, sodium zeolite, skid mounted water treatment units are used. Three units of 50 gpm capacity each are installed.

4.3.12.1.1 Boiler Chemical Feed System

The internal surfaces of the boiler in contact with water and steam must be kept free of scale and corrosion products to assure an efficient transfer of heat. In order to keep the total solids in the feedwater and boiler cycles at a minimum, a zero solids type chemical treatment is provided with phosphate backup.

The primary chemical feed system consists of two hydrazine-ammonia pumps, with necessary accesory equipment and control for each waste heat boiler unit.

The secondary chemical feed system consists of two phosphate pumps per boiler drum at each waste heat boiler unit. The phosphate solution feed is necessary in order to convert any contamination from condenser or other leakage such as calcium and magnesium salts to the more desirable phosphate forms of sludge. The phosphate sludge is readily dispersed and removed by blowdown.

4.3.12.2 Wastewater Treatment and Disposal System

Cooling tower blowdown is one of the major liquid waste streams produced by the plant. The blowdown from the cooling tower is metered and continuously monitored for residual chlorine before being returned to the river.

The treatment and softening of makeup boiler feedwater also generates process wastewater. This water, along with the wastewater produced in boiler blowdown, equipment drains, floor drains, oil spills, coal pile runoff, etc. is collected by various piping systems and flows to a central wastewater treatment plant.

The wastewater treatment plant consists of a plant similar to the one described in the Subtask 1.2 report (pages 223-225). The plant has a design operating range of from 150 gpm to 300 gpm maximum flow. It is estimated that wastewater will be generated at an average flow rate of 127 gpm.

4.4 ELECTRICAL SYSTEM AND COMPONENT DESCRIPTION

4.4.1 Scope

The power generation output of the plant is 610MW gross. The plant, having no independent start-up capabilities, is tied to the regional network to provide start-up power. The main one line diagram for the PFB/GT/WHSG plant is shown on Figure H-8.

4.4.2 Power Generation

Six gas turbine driven generators rated at 75MVA and three steam turbine driven generators rated at 70MVA are provided for electrical energy generation. The generators will be 2 pole, totally enclosed, air cooled, 13.8kV, 3Ø, 60 Hz. Generator output will be transmitted via bus to a dedicated main 13.8kV breaker and unit step-up transformer 13.8/69kV.

4.4.3 Power Transmission

Several alternative schemes have been considered for transmitting the generator output to the main 230kV switchyard. The use of 230kV for directly transmitting power to the switchyard is deemed unacceptable. The running of open bus structures at 230kV through the plant has been rejected. SF_6 insulated bus or pressurized oil filled pipe type cable operating at 230kV is too costly. Cable bus or metal enclosed bus operating at 13.8kV is also too costly and not practical because of excessive operating currents. A more satisfactory arrangement is found by choosing an intermediate voltage of 69kV. Because of the availability and good service record of solid dielectric cable in this voltage, 69kV has been selected. Cables are installed in cable bus systems which are routed on pipe bridges above mechanical piping.

4.4.4 Switchyard and Transmission Terminal

Nine 69kV cable bus connections, one from each generator step up transformer, are used to bring power to the 69kV switchyard. At this switchyard generator outputs are synchronized in groups of three and stepped up for connection to the adjacent 230kV switchyard.

The 69kV switchyard is arranged on a simple radial scheme. In order to limit fault levels to within the breaker ratings, three separate buses are used, each bus controlling two gas turbines, one steam turbine, one auxiliary transformer, and one power transformer (69/230kV). The auxiliary transformer provides power for start up and operation of the auxiliaries associated with the three turbines. The switchyard is of outdoor open bus construction with 2500MVA oil circuit breakers.

The 230kV switchyard employs the breaker and one-half bus configuration as defined for Subtask 1.2. At this level, the outputs of all power transformers are synchronized and long distance power transmission originates via two 230kV lines.

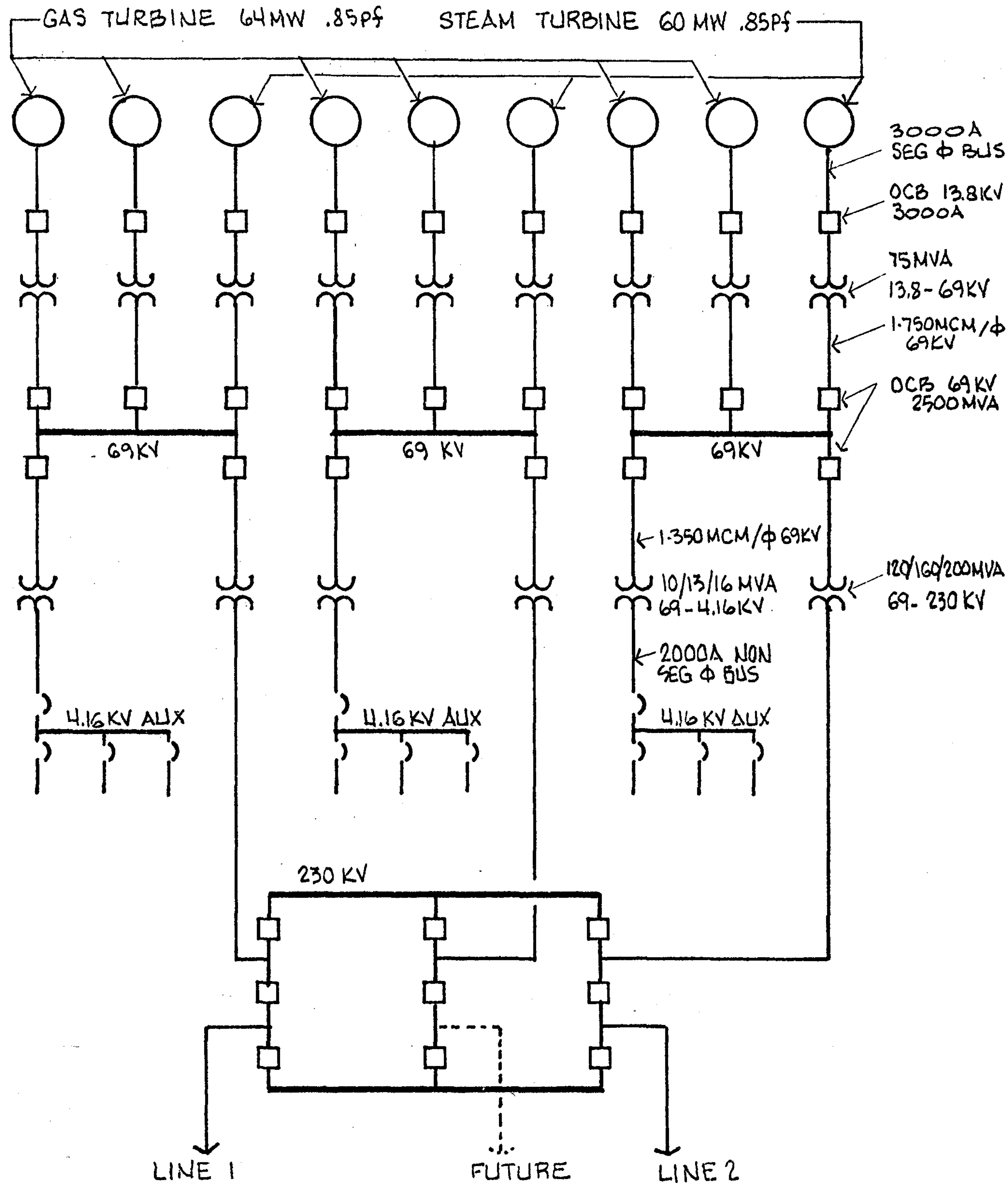


FIGURE H-8 PFB/GT/WHSG PLANT MAIN ONE LINE DIAGRAM

4.4.5 Equipment Comparison, Subtask 1.2 Versus Subtask 1.8

Subtask 1.8 equipment is generally smaller and in greater quantity than that used in Subtask 1.2. For example, the PFB/AFB plant (Subtask 1.2) utilized three generator step-up transformers, where nine are used in the PFB/GT/WHSG plant. The smaller size of the generators in Subtask 1.8 as well as the site arrangement, necessitated the use of an intermediate voltage of 69kV between the generator terminals and the 230kV switchyard. The introduction of this intermediate voltage increased cost by the addition of: 69kV power cable, 69kV switchyard, 69-230kV power transformers. The introduction of this additional equipment was partly offset by a reduction in the quantity of motors and auxiliary equipment required by the large turbine in Subtask 1.2. Differences in 5kV switchgear and unit substation are negligible.

4.5 CIVIL/STRUCTURAL/ARCHITECTURAL DESIGN DESCRIPTION

4.5.1 General

The Middletown site proposed for location of the Subtask 1.8 PFBC Combined Cycle Power plant has been treated extensively in the Subtask 1.2 report. Although there are some important differences in the sizes, location and orientation of various facilities of the two subtasks, provisions for site preparation work, sanitary facilities, service roads, access and site railroad, parking areas, and major structural features and types of construction for the Subtask 1.8 PFBC plant are essentially the same as those of the Subtask 1.2 plant. Accordingly, area plans, structural layouts, material quantities and capital cost estimates of similar systems or subsystems of this subtask are based on the findings, where applicable, of earlier work developed in detail and presented in the Subtask 1.2 report. New or different structural systems were designed, as required, in sufficient detail to enable the preparation of specific plans for material takeoff purposes.

4.5.1.1 Site Development

The area site plan for the PFB/GT/WHSG combined cycle powerplant is shown in Figure F-1. As in Subtask 1.2, a total of 340 acres of land is required for the plant. The principal area allocations for the major plant components are the same as for Subtask 1.2. Moreover, provisions for site preparation, sanitary facilities, service roads, access and site railroad and parking areas are essentially the same as in Subtask 1.2.

4.5.2 Types of Construction

4.5.2.1 Foundations and Substructures

As in Subtask 1.2, spread-footing type foundations are assumed for all plant island structures and equipment including the coal and sorbent yard structures. Use of piles may be necessitated if atypical or non-uniform soil conditions, or greater overburden depths than anticipated, are encountered. However, the design and capital cost estimates herein make no allowance for piles.

4.5.2.2 Steam Turbine-Generator Building and Control Room

This building houses the three steam turbine-generator units, condensers and the auxiliary equipment for these systems. The building consists of a ground floor, a mezzanine floor at elevation 16 feet and an operating floor at elevation 33 feet. An overhead crane and craneway are provided to serve the turbine-generator. Roof elevation is 80 feet in the crane bay. The control room is located at the operating floor level. Three separate pedestals supported on concrete foundation mats have been provided. The ground floor is a structural slab on grade. The superstructure is steel framed with welded shop connections and high strength bolted field connections. The remaining construction features are identical to the Subtask 1.2 turbine-generator building.

4.5.2.3 Office and Service Building

A 40 ft by 120 ft office and service building attached to the south side of the steam turbine-generator building has been provided. Except for its orientation relative to the steam turbine-generator building, the office and service building is the same as provided and detailed in Subtask 1.2.

4.5.2.4 Gas Turbine-Generator Building

Provision is made to house each of the six gas turbine-generator assemblies in a separate pre-engineered metal enclosure building. In each case, the turbine-generator pedestal is supported on a concrete foundation mat and the ground floor is a structural slab or grade.

4.5.2.5 Other Buildings

Provision has also been made for the following buildings which are described in detail in the Subtask 1.2 report.

- Garage, Carpenter Shop, Paint Shop and Oil and Grease Storage Building
- Warehouse Building
- Water Treatment Building
- Personnel Building in Coal Yard Area
- Miscellaneous Buildings

4.5.2.6 Circulating Water System

A concrete basin and pump pit for the mechanical draft cooling tower have been provided. The structural details are the same as described in Subtask 1.2, with the exception that the basin length has been reduced to 400 feet. The concrete intake structure for makeup water to be installed at the North River is the same as in Subtask 1.2.

4.5.2.7 Coal and Dolomite Handling Structures

The layout for the coal and dolomite handling structures is shown in Figure F-1. All structures, towers, conveyor belt supports, pits and tunnels have been designed using the same structural criteria and arrangements as in Subtask 1.2 with the exception that limestone handling structures are eliminated. Similarly, the structural configuration and construction details of coal and limestone silos are identical to those of Subtask 1.2. The support structure is steel framing on spread footings.

4.5.2.8 Wastewater Treatment Plant

The plant waste streams and intermittent rainwater runoff from the coal yard area are to be accommodated and treated as required in a wastewater treatment plant which is of the same size and design as in Subtask 1.2. Similarly, rainwater runoff from the diked coal and dolomite storage area is sent to the treatment plant through an overflow structure.

4.5.2.9 Equipment Foundations

Spread footings have been used as foundations for all major elevated equipment. The ground floor, where required, is a concrete slab on grade with welded wire fabric reinforcement.

4.5.3. Loads

The criteria described in the Subtask 1.2 report have been used for each of the following loading categories:

Dead Loads
Wind Load
Seismic Load
Crane Loads
Hoist Loads
Elevator Loads
Thermal Loads
Loads from Mechanical Equipment
Vehicular Loading
Surcharge
Temporary Construction Loads
Loads Imposed on Stairs and Platforms
Turbine Bay Floor and Roof Loads
Live Load Reductions
Load Combinations

4.5.4 Codes, Materials and Design

The criteria used in each of the following categories are identical to those of Subtask 1.2:

General Codes
Structural Steel Publications
Structural Concrete Publications
Reinforcing Steel for Concrete Structures
Miscellaneous Steel and Iron

4.5.5 Cranes and Hoists

4.5.5.1 Turbine-Generator Building

An overhead crane and craneway serve the turbine-generator building. Lift capacity of the main hook is 80 tons, and the auxiliary hook 25 tons. A hoist well is provided in the center of the building from the ground floor level to the operating floor level.

4.5.5.2 Machine Shop

A 25-ton crane is furnished for the machine shop with a total lift of 25 feet.

4.5.5.3 Hoists

Suitable monorails, trolleys, hoists and other lifting equipment have been provided as required to service equipment.

4.6 Instrumentation, Control, and Operation

It should be recognized that even on conventional power plants, there are divided opinions concerning the control requirements. On fluid bed systems there is undoubtedly an even greater diversity of opinions since there are presently virtually no such systems in commercial operation to provide an indication of the true control system requirements. In addition to the novelty offered by the fluid bed systems, the control of the commercial plant described herein is complicated by the fact that it is a combined cycle plant utilizing a coal-fired PFB/Gas Turbine System which exhausts to a Waste Heat Steam Generator (WHSG). Utilizing current technology, it is feasible to design a reliable and practical control system that is capable of control for base load or swing operation. By changing the number of gas turbines and WHSG's in operation, the plant can operate over a load turndown range of more than 10 to 1. This is better than conventional power plants. It is anticipated that load changes of 5% per minute over the turndown range of the equipment in service can be accomplished. This rate of change capability is comparable with other types of large power plants.

This PFB/WHSG Combined Cycle power plant consists of six gas turbines (with two coal-fired PFB combustors, and one oil-fired start-up combustor, and one Waste Heat Steam Generator (WHSG) per gas turbine), three steam turbines, associated mechanical and electrical station auxiliaries, and a control system designed to minimize operator requirements. This section discusses in detail the functions and requirements for operation of the station. Figure V-1 is a flow sheet which indicates the relationship of the various components in the cycle.

The power plant is flexible in its modes of operation. Basically, there are two operating modes:

1. Simple Cycle
2. Combined Cycle

The plant can be operated in one of the above-mentioned modes or a combination thereof.

The mode of operation for each Gas Turbine (GT) and WHSG must be selected. When operating the station in the Simple Cycle mode, the "steam side" portion of the plant is not in operation; therefore, maintenance, repairs, etc. may be readily performed on that portion of the plant while the gas turbines are providing significant power output.

Any combination of GT/WHSG units selected can operate in the combined cycle mode. Those gas turbine(s) not selected to operate in combined cycle are available for simple cycle operation or maintenance. The three steam turbines are supplied from common high pressure and intermediate pressure steam headers and, therefore, they may be started and shut down in any order, regardless of which GT/WHSG modules are in operation.

4.6.1 General Control System Description

The goal in the development of Direct Digital Control, is a system more powerful, yet as dependable as any analog control system available. The

P&I DIAGRAM
FOR PFB/GT/WHSG SYSTEM

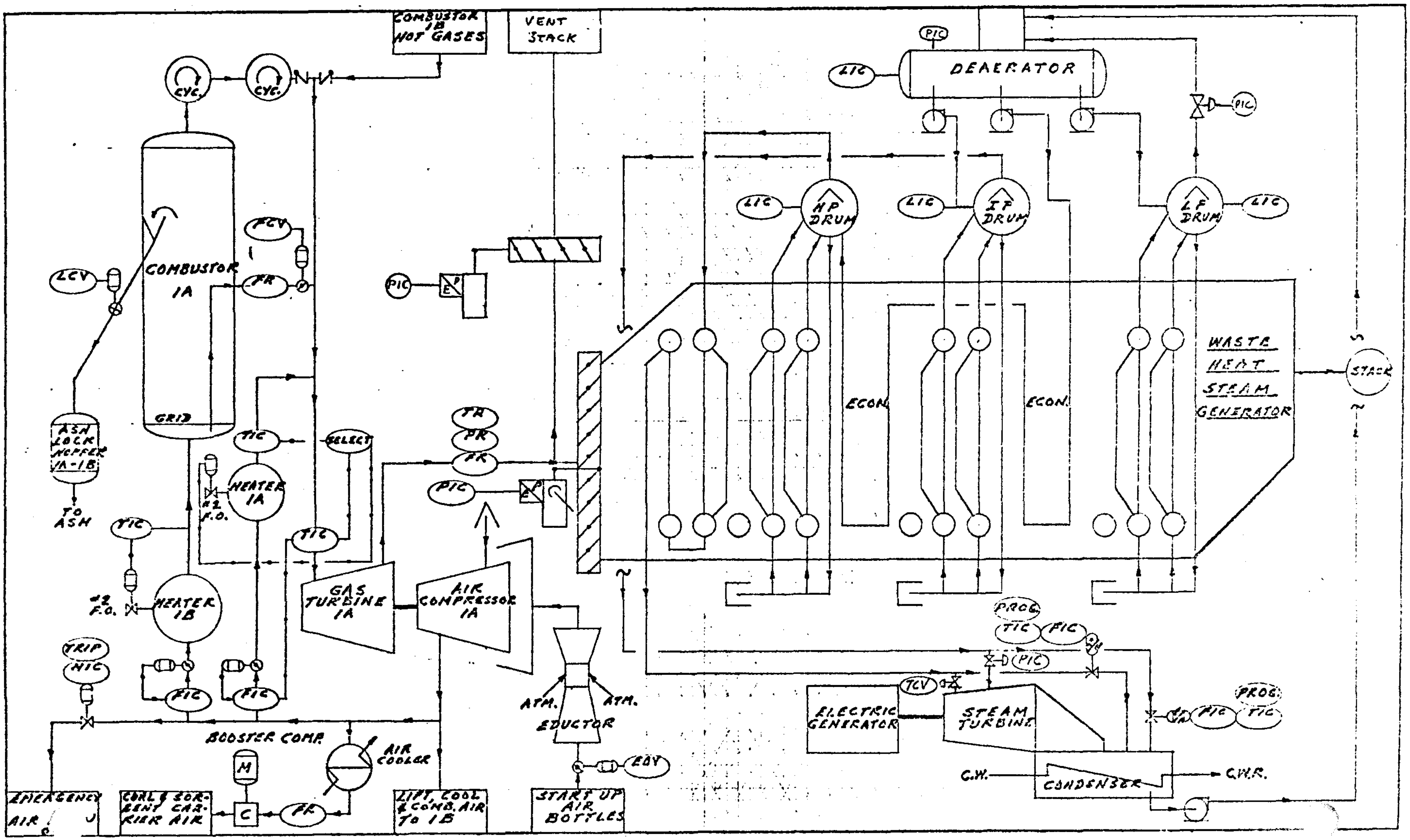


FIGURE V-1

main criterion is that no single failure shall result in loss of the ability to control the majority of the PFB/WHSG subsystems on automatic. Major elements that provide the ability to meet this goal are:

1. A powerful, reliable, all-core memory computer specifically designed for process control applications.
2. Dual-ported I/O modules distributed on a subsystem level with distinct failure modes.
3. A simplified programming language designed specifically for direct digital control.

The system proposed for Direct Digital Control of this power plant is a distributed hierarchical, microprocessor configuration. (See Figures V-2, V-3, and V-4 for a general system overview.) At the heart of the systems is an all-core memory computer dedicated to control. The PFB and WHSG Control Computers are programmed to provide a fully coordinated control system. Communication with the measuring devices, control devices and the operator is via a distributed Communication Control Master (CCM) and Central Processing Unit (CPU). Communication with the Turbine Controls is via a CCM-CPU data link. A data link is also provided for communication with a Remote Dispatch Computer.

4.6.2 Plant Master Control System (ADS)

All complex power plants require a Master Control System to direct the control systems or the various plant components, to provide central automation, to accept demand signals from the load dispatcher and to provide a common point for operator interface. The Master System controls total plant load in response to a remote dispatcher set point or an operator set value. It distributes the load demand to the various plant components to provide the desired type of operation. It also provides the automation commands to start or stop plant components as required to meet the desired load. Plant contingency situations are handled from the Master System with the necessary action commands sent to the respective control systems and subsystems.

A system of panel interfaces with permissive and reject logic is provided to permit the operator to select safe operating modes and configurations.

The input signals to the Master are plant load and load rate of change from the dispatcher or operator, limits from the plant components or the operator, runback or run-up demands from the plant components, mode selection requests from the operator and operating status information from the operator.

Figure V-5 is a block diagram of the plant master. Once all plant subloops are placed in auto, all plant operations by the operator are initiated from the plant master panel. This panel combines the functions required to run the plant. The plant master panel includes all of the display and operator control devices associated with the PFB, Gas Turbine, WHSG and the Steam Turbine Masters. From this control panel the operator interfaces with the ADC, changes plant load, selects mode of plant operation or selects manual control for the PFB, Gas Turbines, WHSG or Steam Turbine. Displays indicate the desired generation in megawatts, the actual megawatts and relative loading of the plant units. Subloop status and sequence logic lights are included on this plant master panel.

CPU & MICROPROCESSOR INTERFACE FLOW SHEET FOR PFB/GT/WHSG PLANT

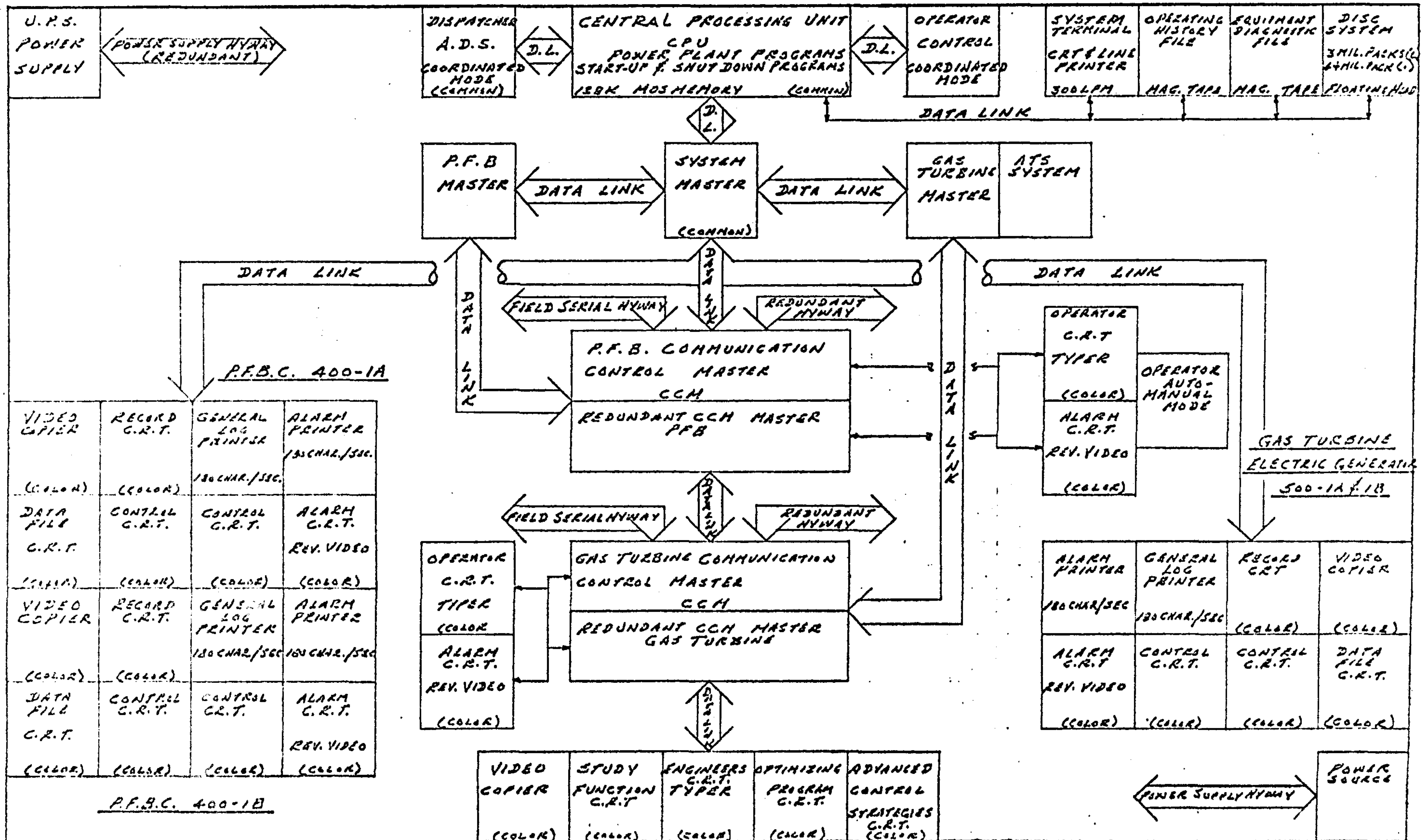


FIGURE V-2

CPU & MICROPROSSER
INTERFACE FLOWSHEET FOR WHSG

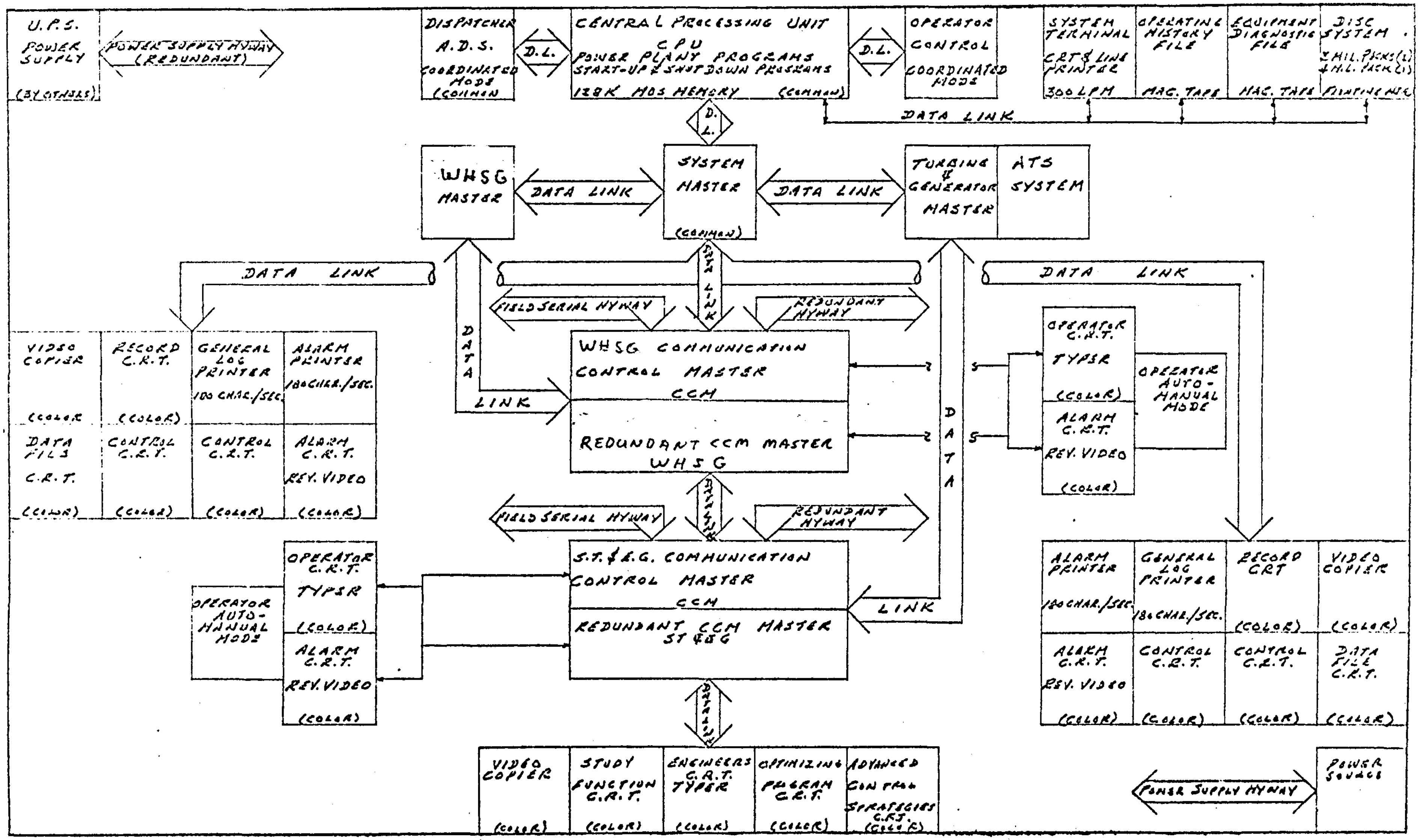


FIGURE V-3

TYPICAL FIELD TRANSMITTER
CABINET LOCATION & MICROPROCESSOR

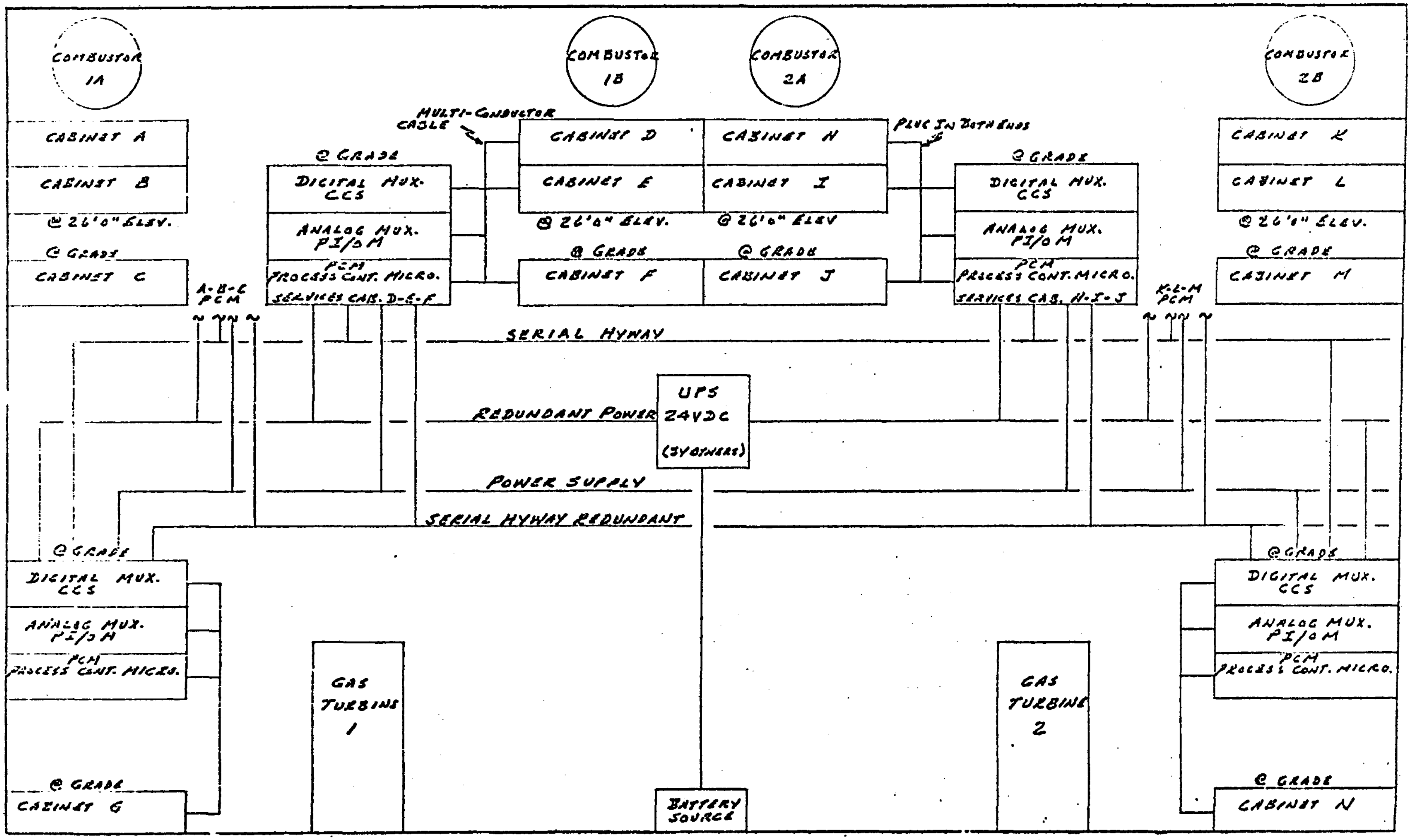


FIGURE V-4

WHSG + PFB PLANT MASTER

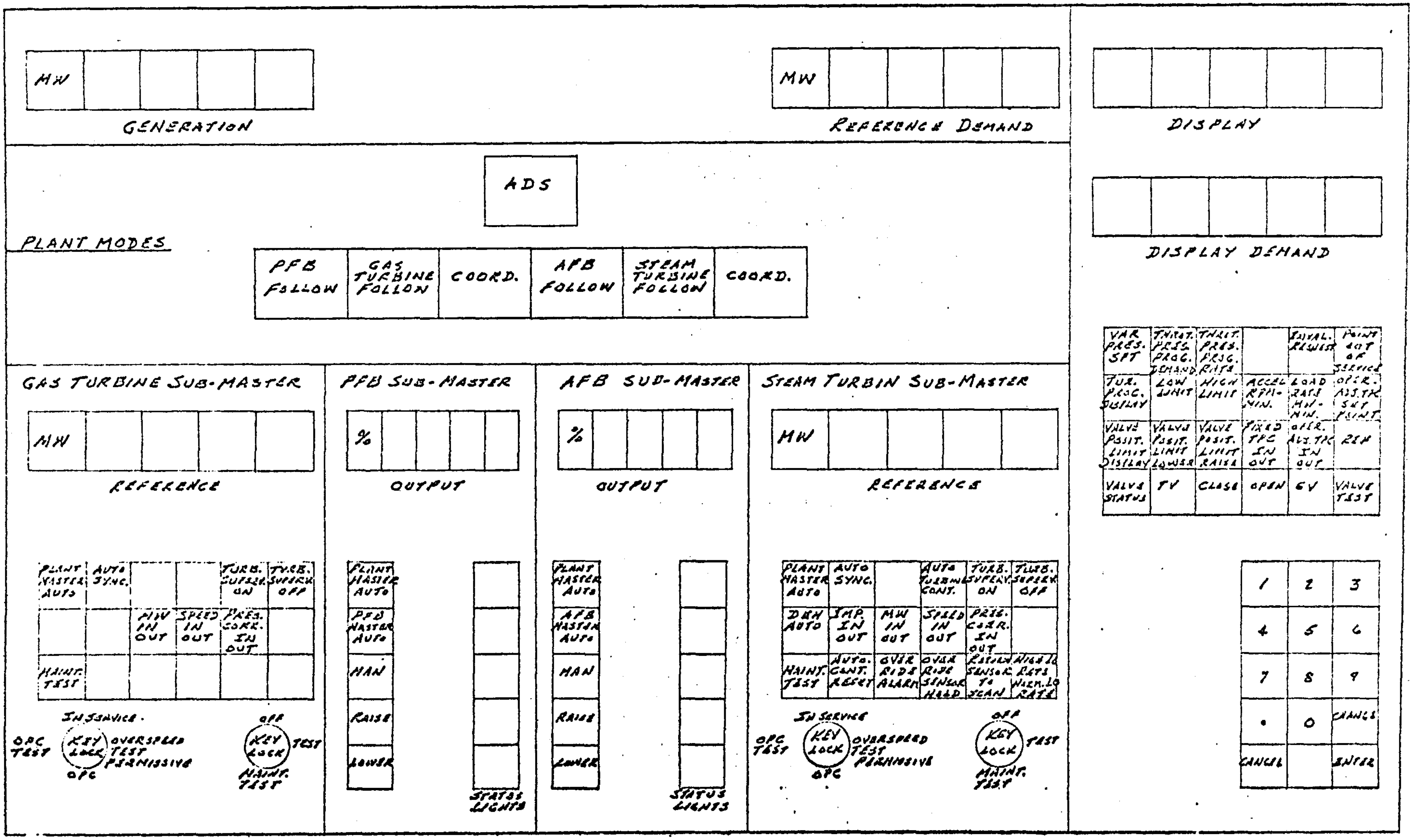


FIGURE V-5

4.6.2.1 Plant Startup Procedures

A gas turbine, say Turbine 1A on Figure V-1, is started independently of the PFB combustors through the use of stored compressed air and a blown-air start system in conjunction with oil fired startup heater 1A. The gas turbine starts and proceeds to gas generator idle conditions (i.e., no electrical output) and is held at this point by a turbine inlet temperature controller which controls oil input to startup heater 1A to maintain 760F at the turbine inlet.

The WHSG isolation and bypass dampers are operated so that a specified portion of the gas turbine exhaust flow is routed through the WHSG for warmup, while the remainder is passed directly to the atmosphere. At this point, the WHSG drains are opened and, if the pressures in the three steam drums (i.e., the HP, I.P., and Deaerator Evaporator Steam Drum) are less than specified values, the WHSG vents are also opened. If desired, all six gas turbine/WHSG units may be started in parallel according to methods described herein for one unit. In accordance with a procedure to be described later, the first gas turbine is accelerated at a controlled rate to full speed and is automatically synchronized. Upon gas turbine breaker closure, a loading ramp is initiated until a specified gas turbine exhaust temperature is reached. In the meantime, a second gas turbine may also be synchronized following similar procedures. The motor-operated header non-return valve for the first WHSG is opened to pressurize the steam header up to the three closed steam turbine stop valves and the closed steam bypass control valve. Steam header drains and the steam turbine stop valve above seat drain (for the first steam turbine to be started) are then opened.

The WHSG vents are closed when pressures in the three WHSG steam drums reach specified values. When the temperature at the WHSG superheater outlet reaches a pre-established value, the gas turbine bypass dampers are closed, and the GT then resumes loading to full output, at which point the exhaust temperature is about 820^{o}F. The remaining WHSG drains are closed at a predetermined drum pressure.

The steam turbine stop valve is opened automatically when the header steam pressure and temperature reach the preestablished values. The steam header pressure continues to rise, as does the flow through the header drain valves, until a predetermined pressure setting of the steam bypass valve is reached. The bypass valve then opens and permits steam to flow to the condenser, so as to automatically maintain the steam header pressure at the startup level.

When the steam bypass control valve opens and there is sufficient steam flow to roll the steam turbine off the turning gear, the startup control rolls the turbine and limits turbine speed in accordance with the established acceleration schedule.

The steam turbine acceleration schedule is selected automatically by the cold, warm or hot steam plant temperature conditions at the beginning of the startup. The steam turbine accelerates to the predetermined hold point, which is approximately 1000 RPM. The turbine remains at this speed for sufficient time to allow the operator to verify that such conditions as vibration, shell and rotor differential expansion, and condenser vacuum are within the prescribed limits. At the end of the timing period the turbine is automatically released and the acceleration schedule then continues to control the events until the turbine is at rated speed.

The steam turbine generator is automatically synchronized when the voltage is matched and the unit reaches system frequency. When the generator breaker is closed, the Steam Turbine initial load step is applied (3%). The startup control then continues loading the steam turbine on a ramp basis (dependent upon a hot, warm or cold start). At this point, the steam bypass control valve is still controlling header pressure and gradually closes as more steam is admitted to the turbine. This continues until the turbine throttle control valve is wide open. Then the loading stops and the initial pressure setpoint is ramped from its start-up level to the minimum operating level. The steam turbine control transfers from speed control to minimum pressure control. The steam bypass control valves are transferred from pressure control at this point and ramped closed to continue loading at an appropriate rate, and the start-up speed control setpoint is moved quickly up and out of the way. This action permits the steam turbine to accept all the steam produced by the WHSG's.

The amount of load accepted by the steam turbine-generators depends upon the amount of steam generated by the WHSG's, which in turn follows gas turbine load. The control system is designed to utilize all the steam generated by the WHSG's to produce power from the steam turbine generator at the appropriate loading rate (hot, warm or cold). Above the minimum pressure setpoint, the plant operates in a variable pressure mode. The steam turbine valves are fixed in the open position, and the throttle pressure varies in proportion to WHSG steam production.

The PFB/Gas Turbine subsystem warm-up and loading sequence takes place in parallel with the steam system startup just described. When the gas turbines reach the gas generator idle point, the valve at the air inlet of PFB 1A is opened to permit sufficient air flow for startup of Heater 1B (See Fig. V-1). The outlet temperature from heater 1B is ramp-controlled to 1250°F over a certain time period. The bed temperature should reach 1000°F in less than two hours. This is sufficiently high for coal ignition. During this period air entering the PFB combustor is routed both through the bed and the cooling tubes. When heater 1B is put into operation, the turbine inlet temperature controller adjusts oil flow to heater 1A to maintain gas generator idle conditions. The PFB combustor hot air bypass valve (FCV) is adjusted to obtain the necessary flow rate through the combustor bed and the hot air exchanger. During this period, the bed level is maintained at 5 feet (expanded). As the bed temperature increases with mass flow rate constant, the superficial velocity increases, and the bed gradually becomes fluidized. When the bed temperature reaches 1000°F, coal is added to the bed, with its flow rate controlled on the basis of a bed temperature demand signal. A temperature controller stops fuel oil to heater 1B when the bed temperature reaches 1500°F. At this point, the set point on the bed level controller is programmed to the operating bed height of 24 feet, and the bed temperature set point is programmed to 1650°F.

In order to synchronize the gas turbine generator, the gas turbine control is switched to a turbine inlet temperature mode of control. The turbine inlet temperature set point is increased. The PFB control responds by decreasing the PFB bypass air flow and increasing the air flow to the PFB, which increases the required coal feed rate. The gas turbine then accelerates toward synchronizing speed (3600 revolutions per minute). As the synchronizing speed is approached, heater 1A may be used if required as a trimming device through the gas turbine control to regulate the turbine speed. After attaining synchronizing speed and after generator phase relationship has occurred, the breaker is closed and the system is controlled on the MW power loop used for on-line operation. Heater 1A phase-out is then completed.

4.6.2.2 On-line Operation and Load Control

Various options are available for operation of this combined cycle power plant.

1. The gas turbines may all be run in the simple cycle mode with the steam portion of the plant shut down. That is, one to six gas turbines are operated as individual generating units.

2. All of the gas turbines, steam turbines and WHSG's may be run in the combined cycle mode.

3. One or more gas turbines may be run simple cycle and the remaining gas turbine(s) run in conjunction with their respective WHSG's and steam turbines in the combined cycle mode.

In order to turn down plant output from the 100% load point, one gas turbine's bypass dampers are opened, and permissive interlocks detect that the dampers are open and energize a timer which, after a time delay, closes the isolation damper of the respective WHSG. Sequentially, the second gas turbine bypass dampers are opened before the WHSG isolation damper is closed, followed sequentially by the dampers of the third, fourth, fifth and sixth WHSG's. When steam header pressure decays to the minimum set point, the initial pressure controller closes turbine control valves. At any point in the steam plant turndown gas turbines may also be turned down and/or taken off-line as required in order to achieve the desired plant output.

The following alternative procedure may be used which would result in higher part load efficiency. Fuel input to one gas turbine is decreased, thereby reducing its output, as well as that of the steam turbines. When coal flow to the first gas turbine cannot be reduced further, that unit is shut down, and reduction of coal flow to a second unit is begun. In order to prevent an unacceptable reduction in steam header pressure, one of the three steam turbines may be shut down while load on the second gas turbine is being reduced. The plant turndown then proceeds sequentially to the remaining units.

4.6.2.3 Plant Shutdown Procedures

The motor-operated non-return valve in the steam header from each WHSG is energized to close a short time after the respective WHSG isolation damper is closed. The steam being generated as the steam turbines are shut down may raise the header pressure until the bypass valve opens on pressure control. As the steam generation ceases, the bypass valve closes.

When the last WHSG isolation damper is closed, each operating gas turbine is unloaded in succession by reduction in coal flow to the corresponding PFB combustors.

As described in the above two paragraphs, at the point in WHSG sequence where the opening bypass damper of the last operating WHSG is reached, the WHSG sequence is held while the auxiliary steam is prepared for the steam turbine gland seals and for pegging the deaerator.

After the steam turbine control valves (as regulated by the steam turbine initial pressure controller) close to the "Minimum Steam Flow" position, or after all isolation dampers are closed, the steam turbine is tripped.

4.6.3 Pressurized Fluid Bed (PFB) System Control (On-Line Operation)

P&ID sheets for the PFB Combustors and the gas turbine systems are shown on Figures V-6 and V-7, respectively.

4.6.3.1 PFB Combustion Controls

The PFB Combustion Control system is shown on Figure V-8. The concept for the PFB combustion control is based upon constant fluidizing velocity within the combustor bed. With essentially constant compressor outlet pressure over the load range, this results in the requirement for a constant fluidizing air flow and, hence, results in a variation in excess oxygen content of the combustion gases with load. A measurement of excess oxygen is used to trim the limiting coal-air ratio to assure that coal flow does not exceed that quantity which can be properly burned by the existing combustion air flow.

The control system also utilizes the unique relationship between heat input to the gas turbine (i.e., coal flow) and megawatts. It is of course recognized that this relationship requires on-line calibration to reflect changing gas turbine component efficiency and changes in coal heating value (Coal flow is measured by mass or volume; hence, an exact Btu flow cannot be determined.). The system compares coal flow demand and coal flow. The demand is generated by a feed forward signal based upon megawatts with appropriate trim based on megawatt deviations from set point. In addition, override controls are provided based upon maximum allowable turbine inlet temperature, maximum allowable bed temperature, and excess O_2 in the combustion gases leaving the bed.

The actual fluidizing air flow is indirectly measured in the following way. The total air flow to the bottom head of the combustor is measured by an annubar flow element. The hot air flow leaving the cooling tubes is also measured by an annubar element. These two flows are subtracted, and the difference is added to the sorbent and coal transport air flows. The resultant flow measurement is the air flow used to fluidize the bed and combust the coal. A differential pressure indicating controller (PdIC) measuring grid delta P will constrain the fuel air velocity. All of the above measurements are compensated as required to account for the temperature and pressure variations in the system.

BASIC PFB COMBUSTOR FLOW SHEET

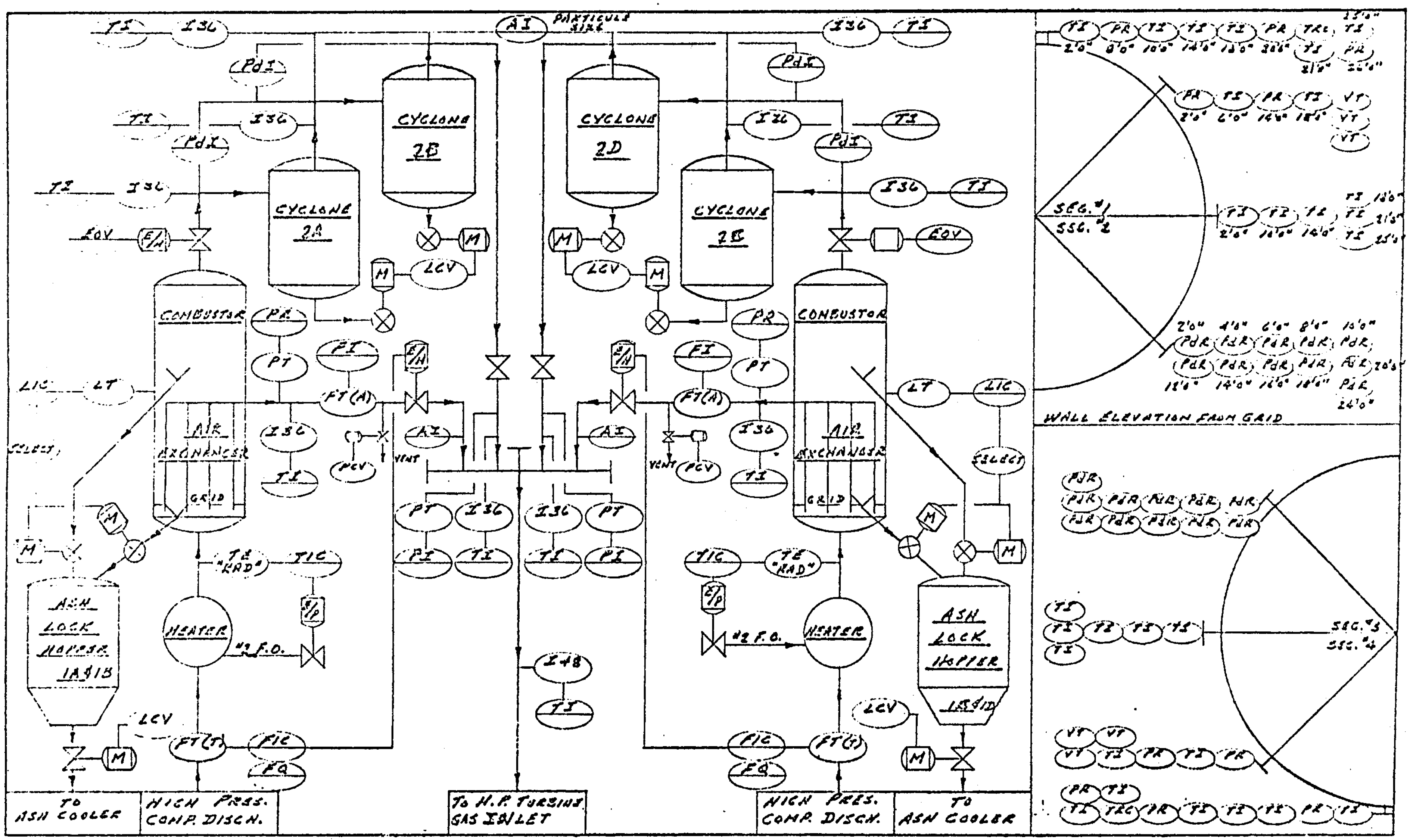


FIGURE V-6

BASIC GAS TURBINE FLOW SHEET

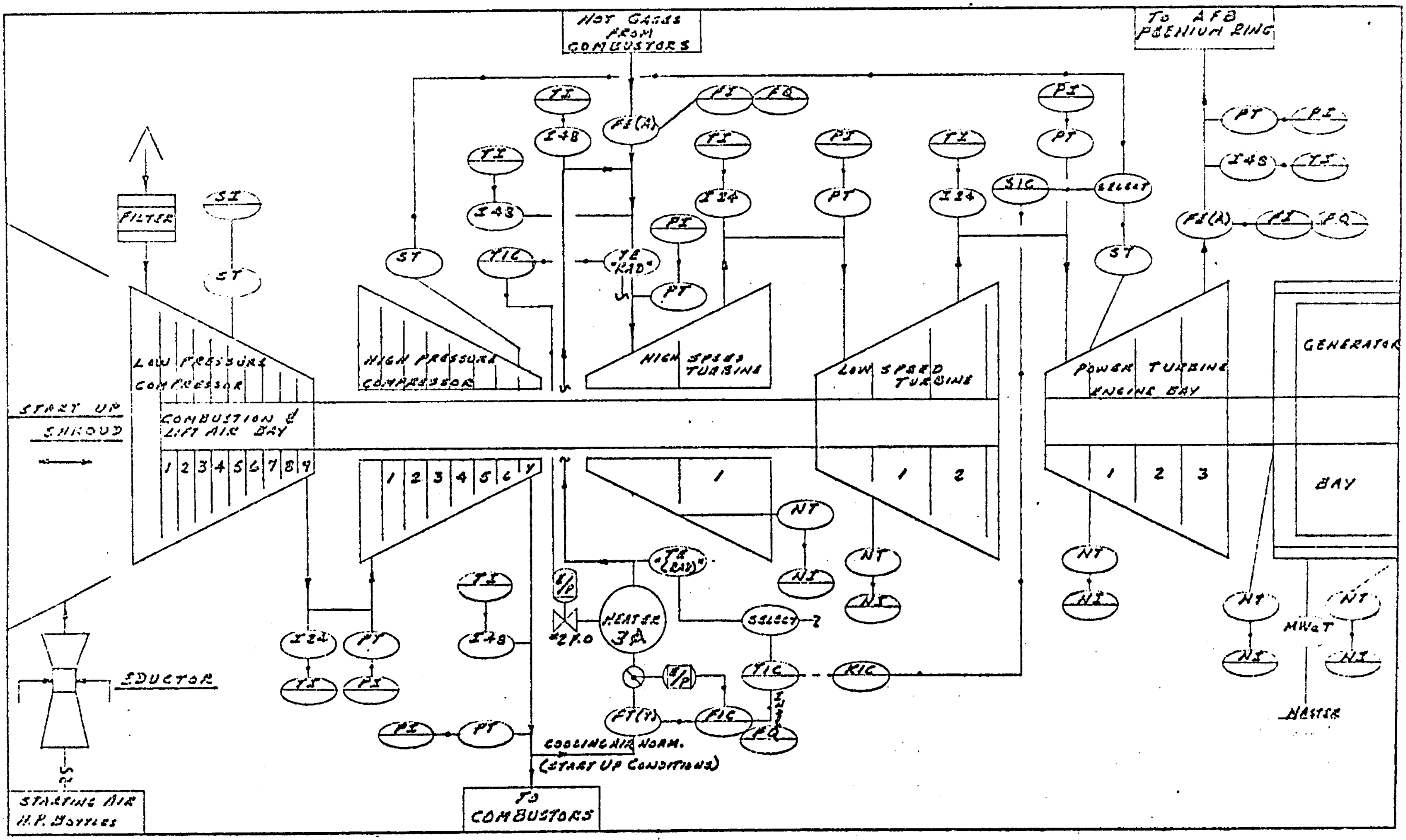


FIGURE V-7

BASIC COMBUSTION CONTROL
FOR A PFB COMBUSTOR

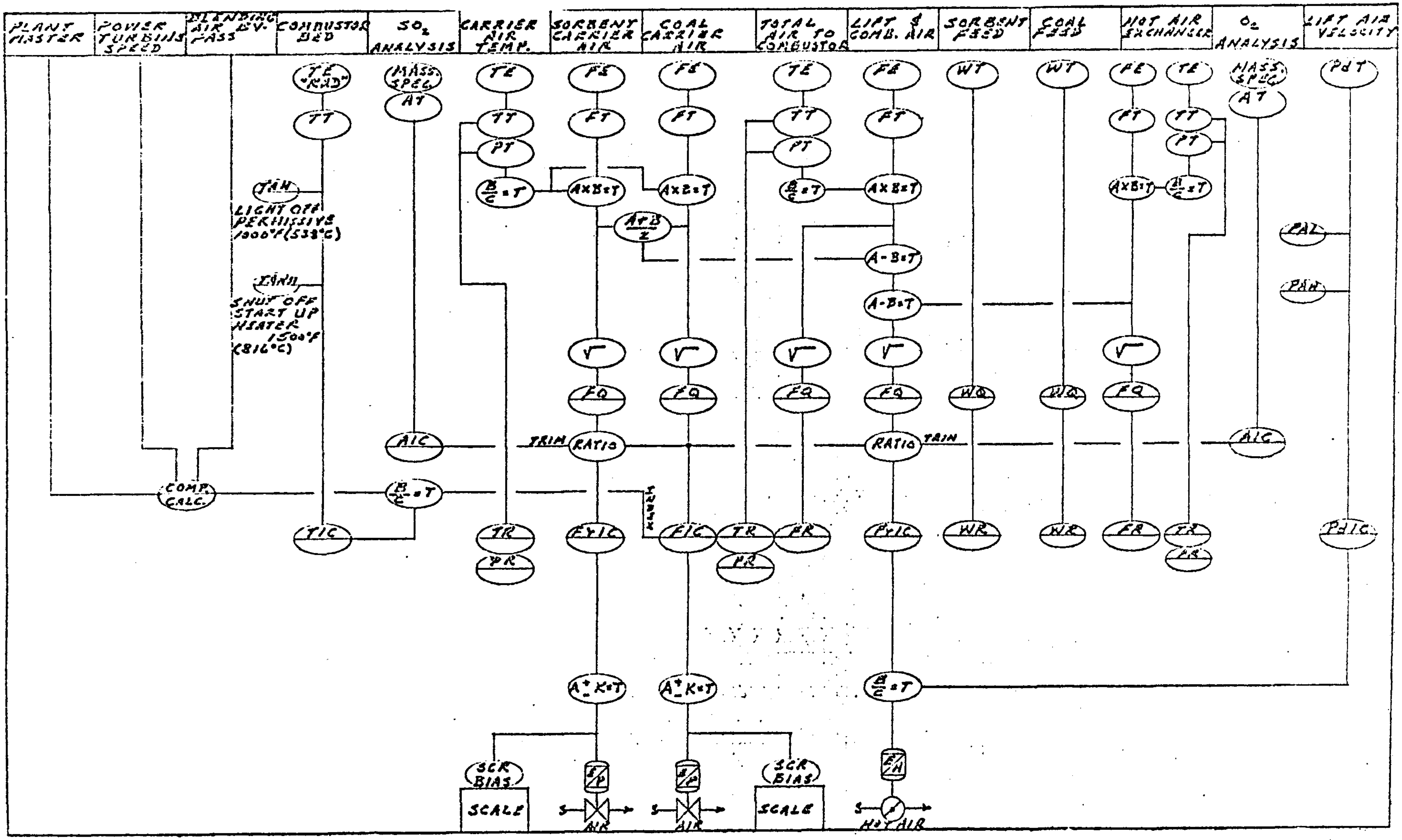


FIGURE V-8

Coal flow to each of the combustors is measured directly via load cells (WIC) on the respective coal feed tanks. In addition, an inferred flow measure could be taken by correlating coal flow with the speed of the rotary feeders at the discharge of the feed tanks.

The valve at the outlet of the bed cooling circuits is modulated to vary the distribution of the air entering the lower head of the combustor between the bed (fluidizing air) and the cooling circuits.

Coal flow rate to the combustors is controlled by varying the speed of the air swept rotary feeders located at the outlet of each feed tank. (See Figures M-1 and M-2 in subsection 4.3.6.1 of the report on Subtask 1.2).

4.6.3.2 PFB Bed Temperature Control

Bed temperature is controlled by changing the total air flow to the combustors. A decrease in total air flow to the combustor would tend to increase bed temperature and vice versa. That portion of the compressor discharge flow not required in the combustor is routed to the combustor air bypass line. Overrides are provided to insure adequate fluidizing/combustion air flow to the beds. If a high gas temperature is being generated in the combustor, in spite of the above controls, a TIC would send a signal to the coal feed controller, which would lower the fuel rate to the combustor to hold a 1650°F (889°C) temperature in the bed.

The bed temperature is measured by a radiation pyrometer. Magnesium oxide thermocouples are also located at various points in the bed for backup (See figure V-9). Air flow measurements at combustor inlets and in the bypass lines are made by annubar type elements with proper temperature and pressure compensation.

4.6.3.3 PFB SO_2 Sorbent (Dolomite) Feed Rate Control

The feed rate of dolomite into the combustor is controlled to maintain a certain dolomite/coal ratio. The required ratio is initially selected as a function of fuel sulfur content and higher heating value, as well as the EPA SO_2 emission limits. In the suggested control system, the SO_2 concentration (corrected for O_2) in the combustion gas stream is measured and is used to trim the dolomite/coal ratio as required to maintain the SO_2 concentration within the desired range. Since the dolomite feed rate is small compared to bed inventory, a relatively long time will be required for a change in dolomite feed rate to be reflected by a corresponding change in SO_2 concentration. Care must be taken in the design of the system to prevent instabilities. An alternate but less desirable system would be based on manual correction to the preselected ratio based on the operator's observations of trends in the measured SO_2 concentration.

Dolomite flow to the combustors is measured directly by load cells on the respective dolomite feed tanks. An alternate approach would be to correlate dolomite flow with the speed of the rotary feeders at the discharge feed tanks. Combustion gas SO_2 and O_2 concentrations are measured by standard mass spectrometer gas analyzing systems and plotted on a recording CRT.

TEMPERATURE MEASUREMENT
PFB COMBUSTOR

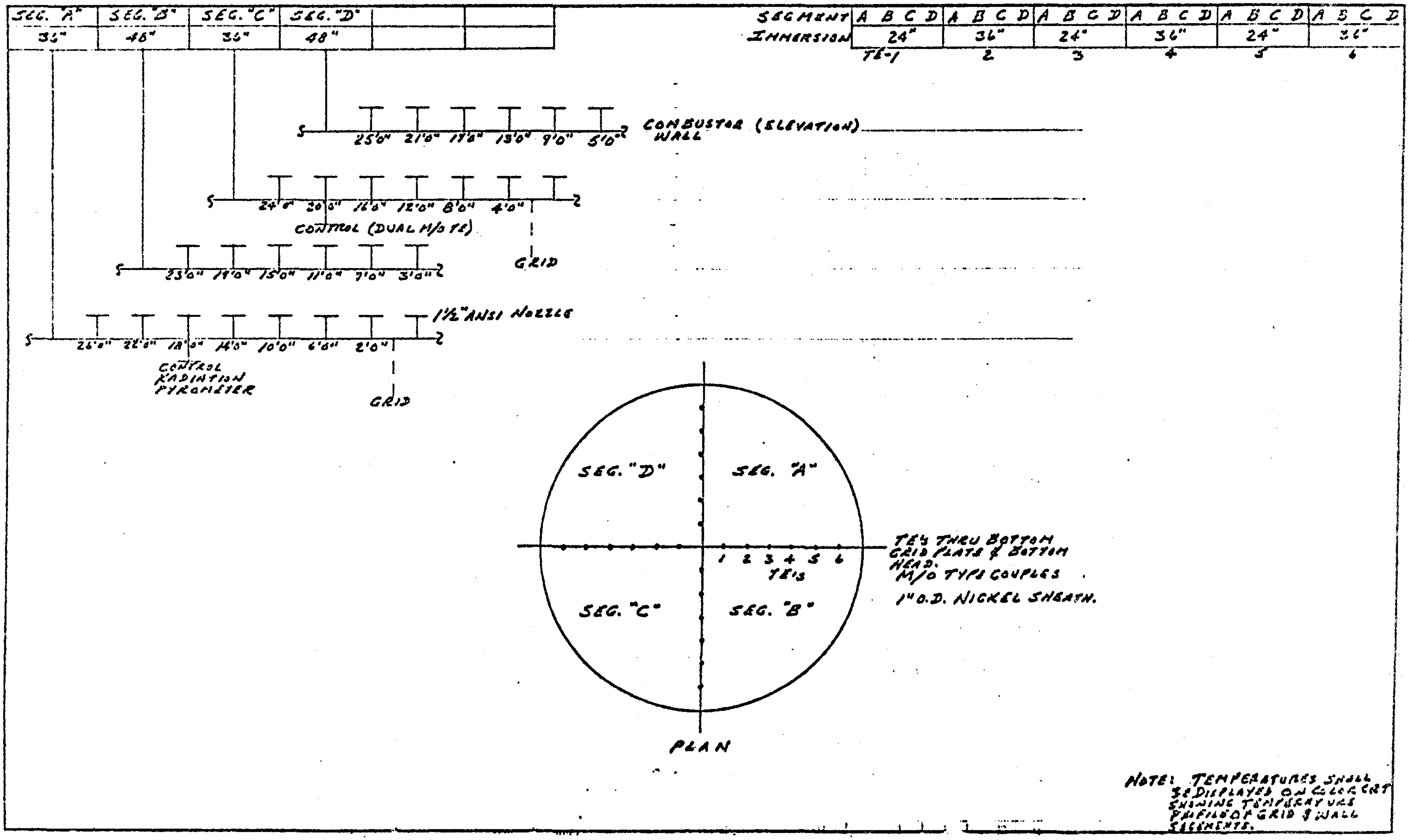


FIGURE V-9

Dolomite flow rate to the combustors is controlled by varying the speed of the air swept rotary feeders located at the outlet of each dolomite feed tank (See Figures M-1 and M-2 in subsection 4.3.6.1 of the report on Subtask 1.2).

4.6.3.4 PFB Bed Level Control

During normal operation a constant bed level is maintained at a point just above the top of the bed cooling tube banks (i.e., 24 feet above the air distribution plate). This level does not vary with load. During startup a reduced bed height of about five feet (expanded) is maintained so that the bed can be heated to the coal ignition temperature within a reasonable time and with reasonable oil consumption. After coal ignition the bed is raised to the normal operating level of 24 feet by feeding dolomite at the maximum capacity of the feed system.

The bed level measurement is accomplished by a series of pressure differential measurements made at various elevations along the side of the combustor as shown on Figure V-10. An alternative system which could also be used as a backup is shown on Figure V-11. This system would use the minimum instrumentation required for bed level measurement which would be a pair of differential pressure transmitters connected to three pressure taps on the vessel. One pressure tap would be located slightly above the distributor plate, the second between the distributor plate and the level control point, and the third located above the level control point. The level is algebraically determined by comparing the ratio of differentials between the first and second taps and the first and third taps to the distances between the taps.

Control of bed level in the combustor is accomplished through use of the two solids drains provided on the PFB combustor. The upper drain is a standpipe arrangement which is located at the side of the pressure vessel, the entrance to which is positioned at the normal bed operating level. This drain is used for level control during normal operation of the combustor. The lower drain at the distributor plate is to provide for low bed level control during startup and as a means of lowering the bed level during the unit shutdown.

During normal operation the level control is provided by the elevation of the bed material discharge standpipe within the pressure vessel. Knife valves are provided in the bed drain line to the lock hopper system. These knife valves are controlled by lock hopper level (load cells). During normal operation, the two lock hoppers are operated sequentially to provide continuous control of combustor bed level.

The lower bed drain is used for startup or to empty the bed for shutdown or maintenance purposes. Since the startup level need not be controlled to an absolute point, knife valves are again contemplated. The knife valve operation is regulated by both the level in the lock hoppers or by the operator based upon the desired PFB bed level.

4.6.4 Gas Turbine Controls

Figure V-12 presents a simplified schematic of the control functions and measurement requirements for the plant. Table V-1 defines the symbols used on Figure V-12.

BED LEVEL OR DENSITY MEASUREMENT
PFB COMBUSTOR

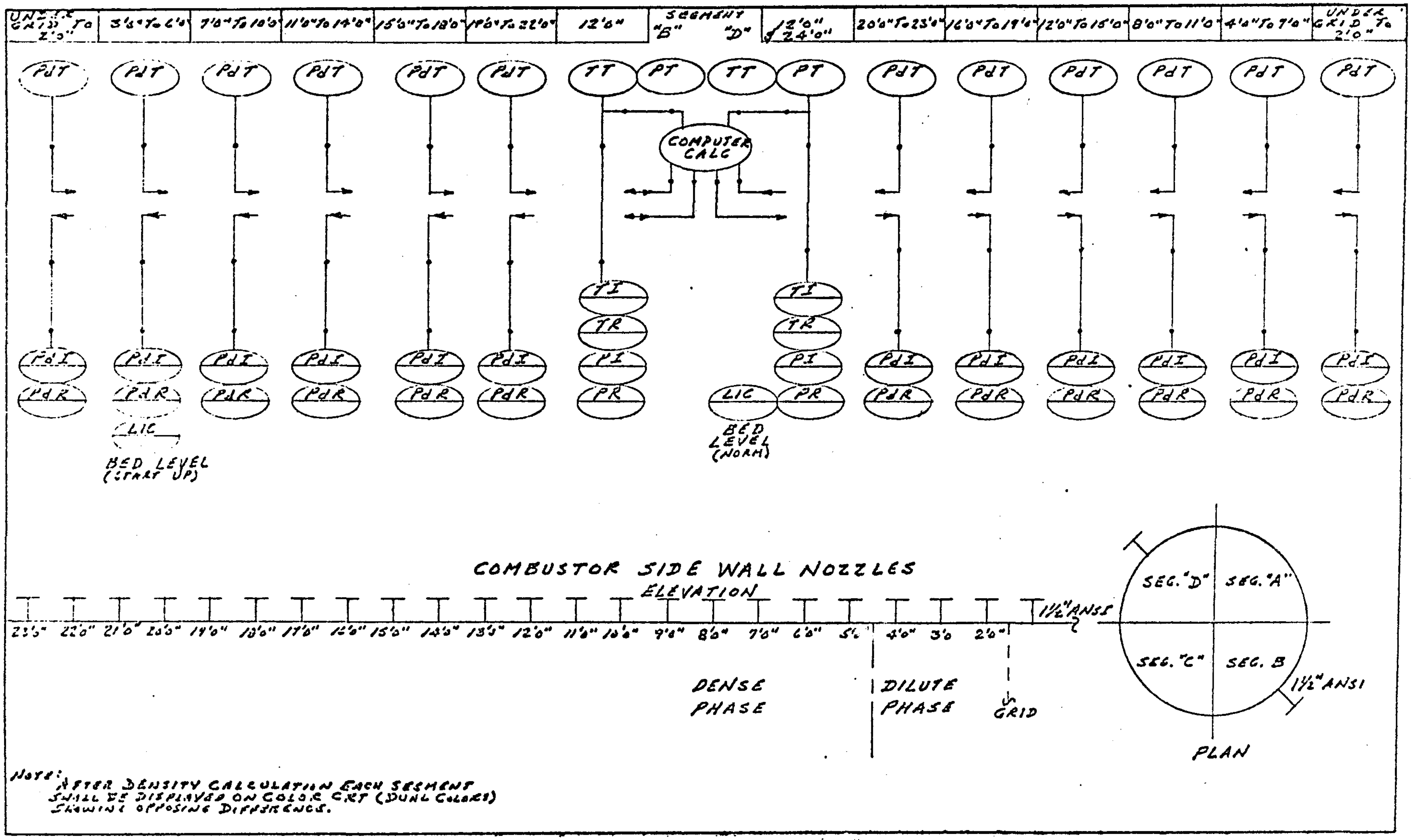


FIGURE V-10

ALTERNATE BED LEVEL MEASUREMENT
PFB COMBUSTOR

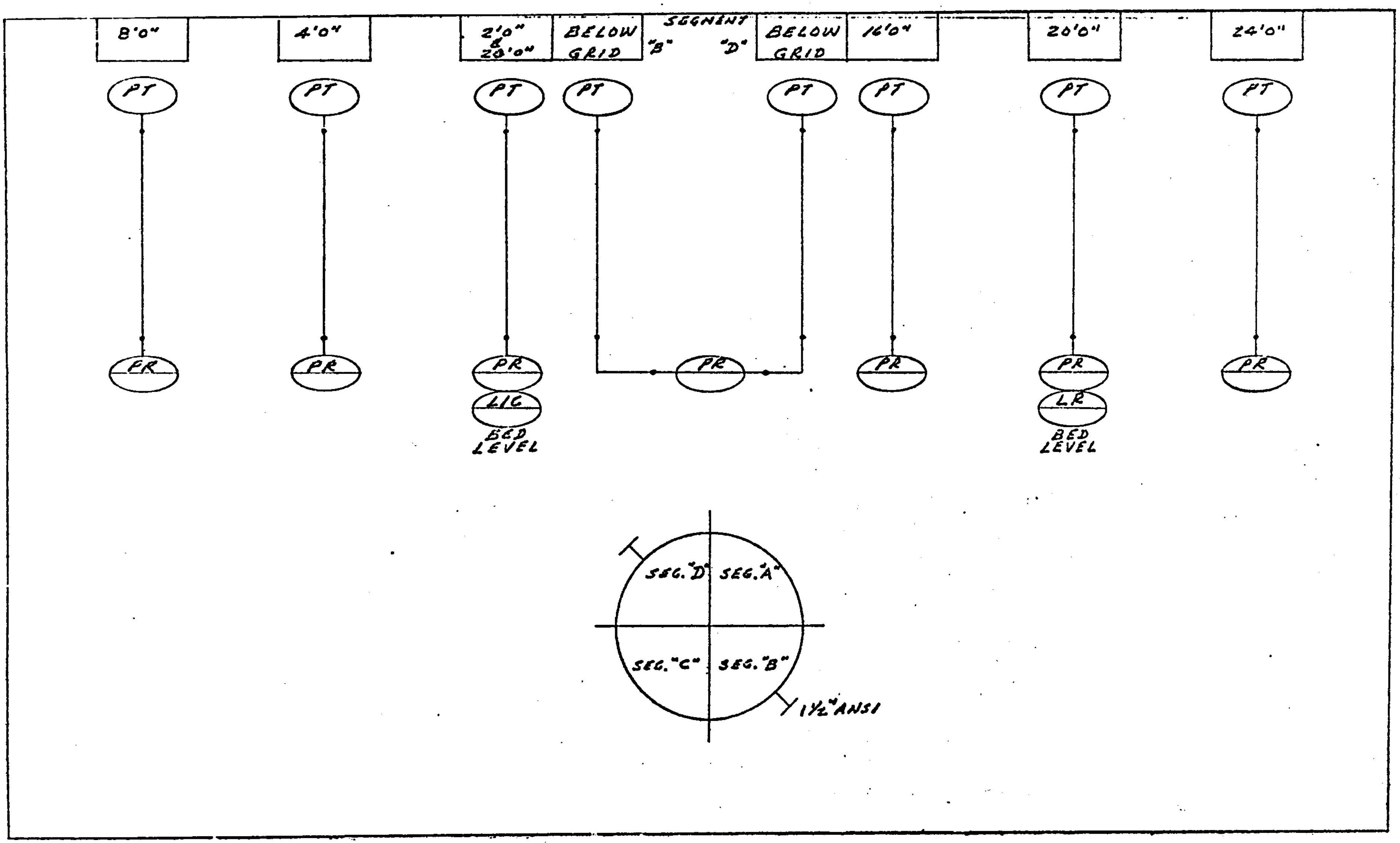


FIGURE V-11

TABLE V-1

Temperature	Pressures and Rotor Speeds	Valves
T1 - Engine Inlet Temp.	Pb - Gas Turbine Compressor Discharge Pressure	V1 - Gas Turbine Surge Bleed Shutoff
T2 - Compressor Discharge Temperature	N1 - Low Rotor Speed	V2 - PFB Bypass Modulation
T3 - PFB Inlet Temperature	N2 - High Rotor Speed	V3 - PFB Air Inlet Modulation
T4 - PFB Outlet Temperature	N3 - Power Turbine Speed	V4 - PFB Air Coolant Modulation
T5 - PFB Outlet Temperature		V5 - Overspeed Protection Dump Valve
T6 - (TIT) - Turbine Inlet Temperature		V6 - PFB Discharge Check Valve
T7 - PFB Coolant Temp.		V7 - WHSG System Bypass Damper
		V8 - Startup Combustor A Oil Modulation
		V9 - Startup Combustor B Oil Modulation
		V10 - PFB Coal Feed
		V11 - Air Storage Shutoff Valve

FT50/PFB COMBINED CYCLE START-UP SCHEMATIC

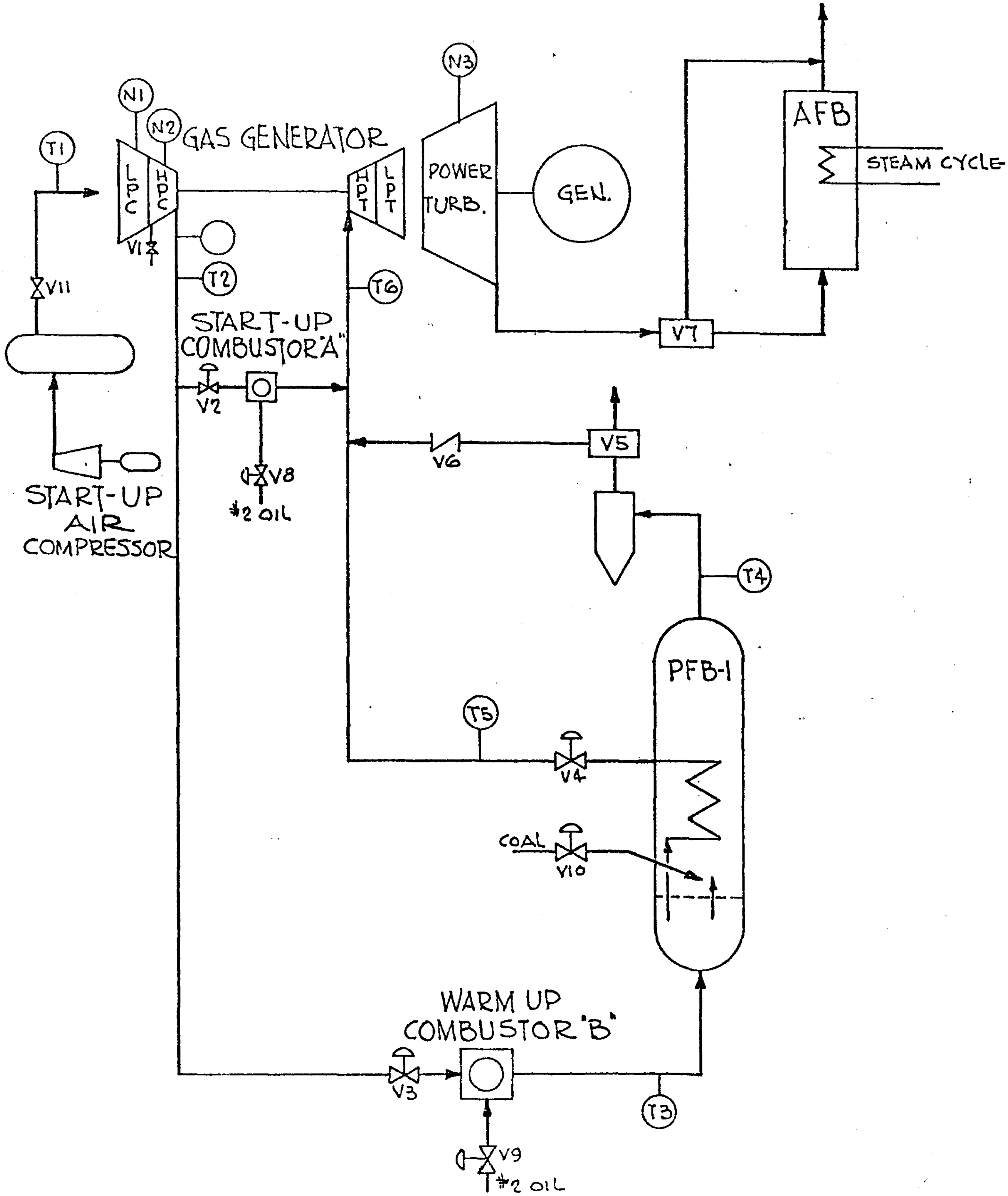


FIGURE V-12

The gas turbine control system modulates the engine compressor stability bleeds and provides signals to the PFB control system and to the startup combustor (A) control system. The gas turbine element senses the following parameters: low pressure spool rotor speed (N1), high pressure spool rotor speed (N2), power turbine rotor speed (N3), sensed power from the gas turbine generator (MW), turbine inlet temperature (T6), compressor discharge pressure (Pb), and an optical probe for sensing turbine blade and vane metal temperature levels. The sensed parameters are compensated for dynamics and then compared with reference values. The lowest or safest error term is selected for governing purposes. A control mode diagram of the overall plant control concept is shown in Figure V-13 to illustrate the relationship between control functions and measurements. The Turbine is controlled by changing the coal flow demand to the PFB (V10) and then changing the proportion of PFB bypass airflow (V2) to PFB total airflow (V3) to maintain the proper PFB bed temperature.

The following control measurements would be used for gas turbine protection: N1, N2, N3, Pb, TIT, blade/vane metal temperature.

The compressor surge bleeds (V1) are used to maintain engine compressor stability. The bleed valves are actuated as a function of N1 and T2 to an open position during lower power operation, including startup as well as for dropload or emergency unload transients.

It is anticipated that trimming devices such as valves will be used to permit constant power output to be achieved in steady state. Regulation of frequency during transients such as substantial rapid load changes can be met partially by using or dissipating stored energy in the system and partially by rapid response in the combustion system. During a dropload condition, stored heat and pressure in the PFB can cause rapid overspeed of the power turbine/generator. A rapid actuation valve is required to bypass the power turbine to prevent overspeed.

Figure V-14 defines the gas turbine control system in more detail than previous figures.

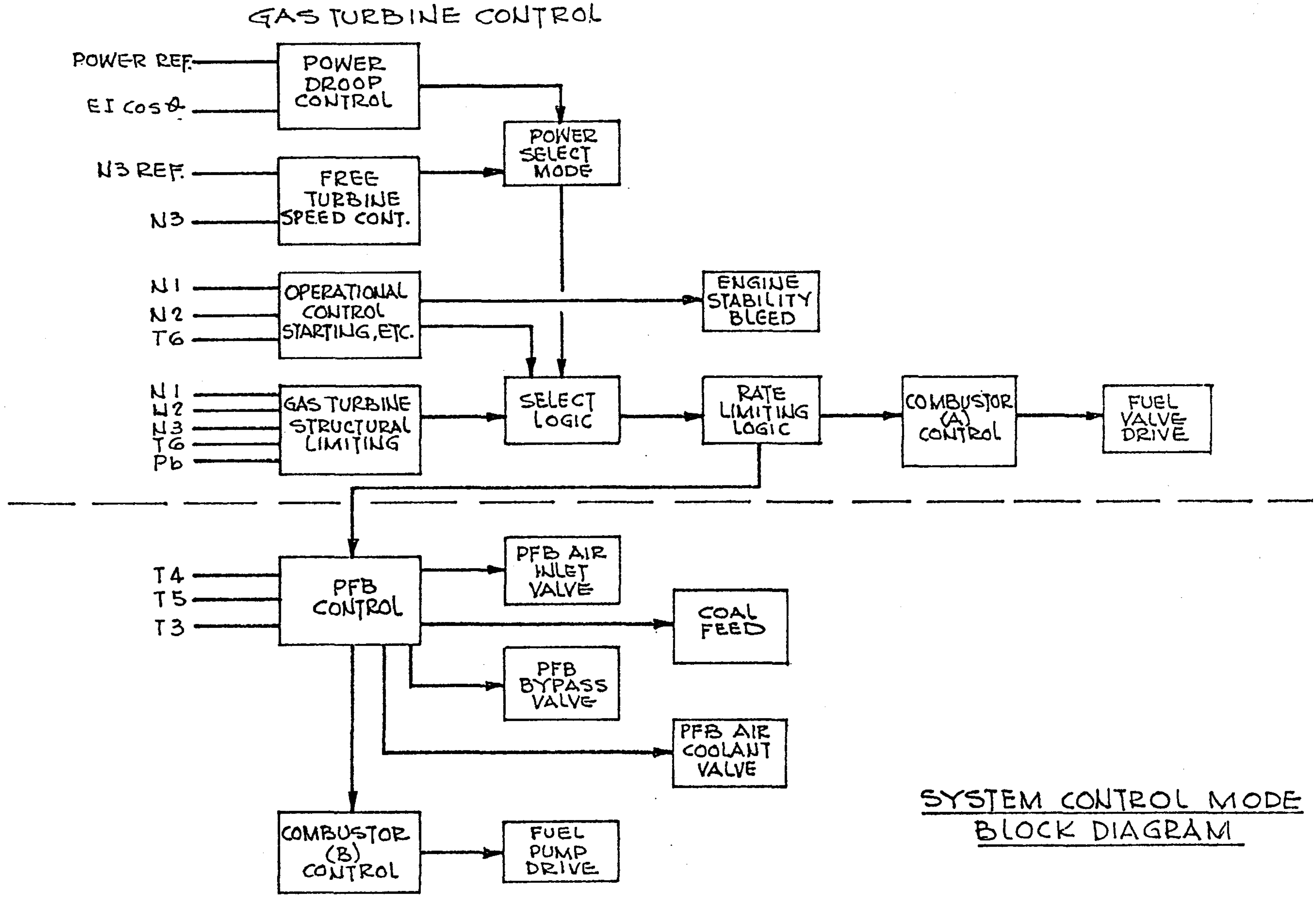
4.6.5 Waste Heat Steam Generator (WHSG) On-Line Operation

A process flow diagram for WHSG/steam turbine/electric generator is shown on Figure V-15.

4.6.5.1 Basic Feedwater Control Systems

Feedwater flow is required at all loads to replace the water which has been converted to steam and sent to the steam turbine. The feedwater flow control subloop (See Figure V-16) uses a cascade feed forward type of control system to regulate the feedwater pumps. Shrink and swell effects are minimized by using a feed forward load index based on steam flow.

The startup drum level control signal is transmitted to an indicating control system whose signal has been conditioned by an inverse derivative relay that levels out shrink and swell signal distortion. The indicating controller then modulates the bypass and startup feedwater in split range action to hold drum level.



SYSTEM CONTROL MODE BLOCK DIAGRAM

FIGURE V-13

OVERSPEED PROTECTION SYSTEM
GAS TURBINE CONTROLS

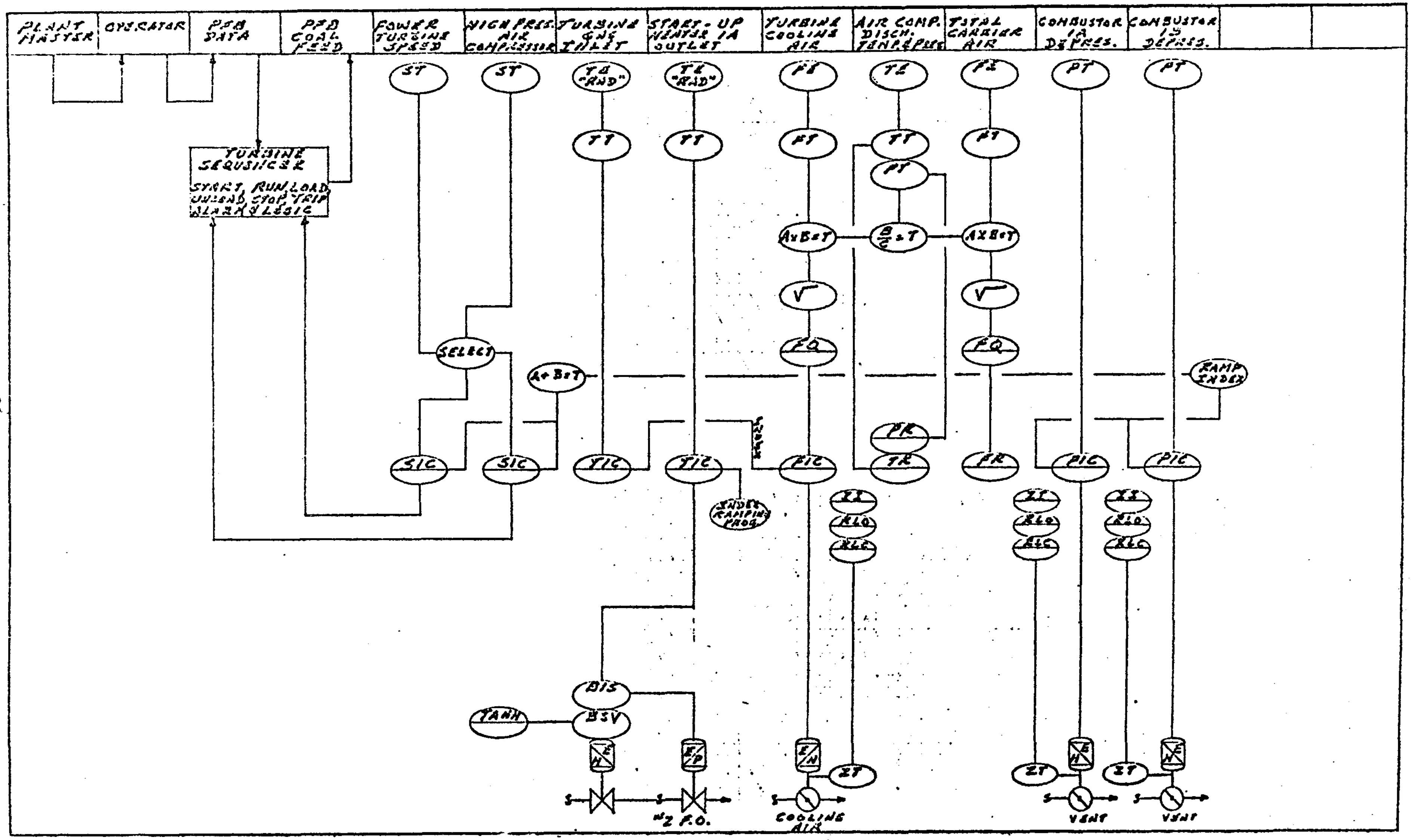


FIGURE V-14

PROCESS FLOW DIAGRAM FOR A
PFBC & WASTE HEAT STEAM
GENERATOR - STEAM TURBINE - ELECTRIC GENERATOR

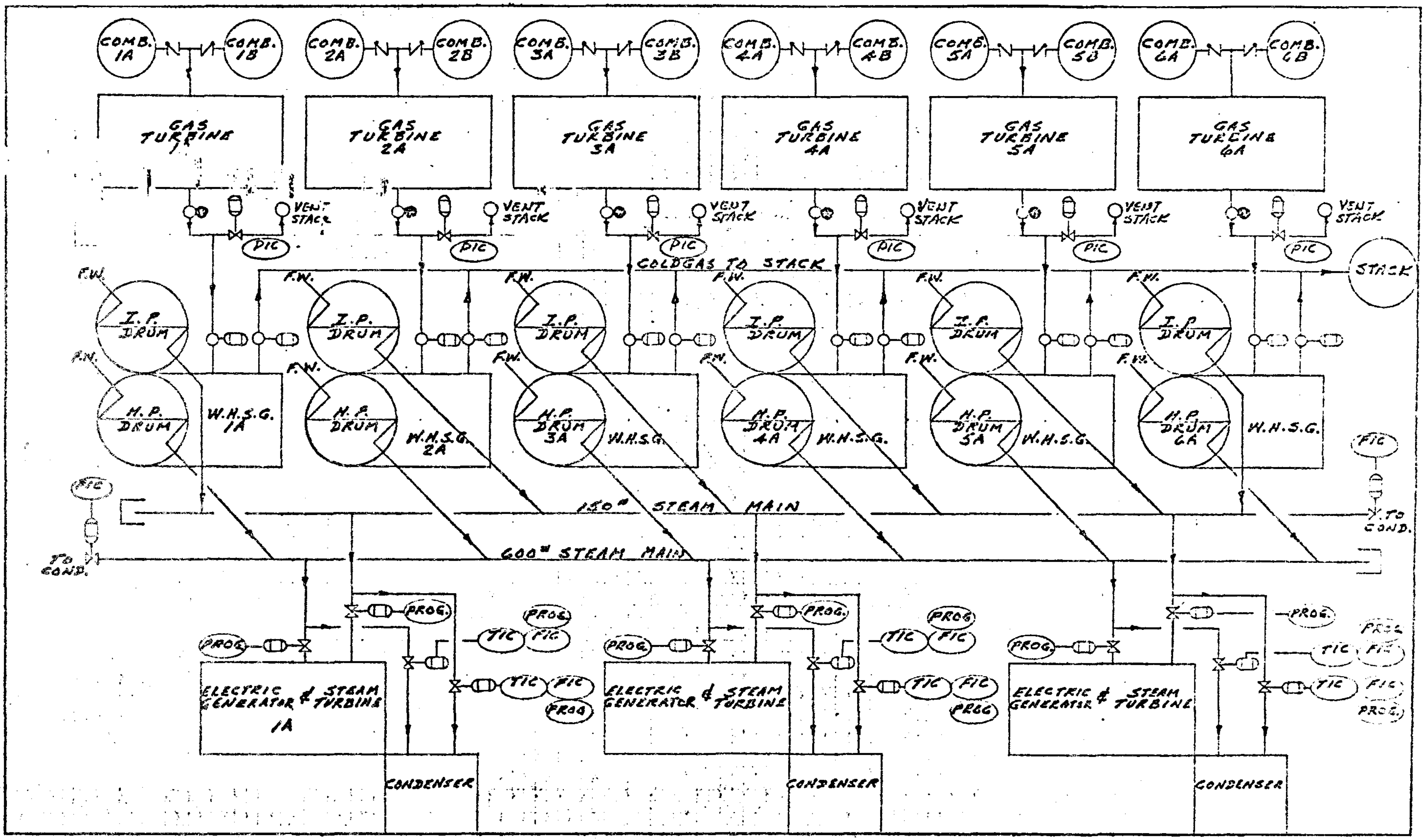


FIGURE V-15

TYPICAL
FEED WATER CONTROL SYSTEM
FOR EACH STEAM DRUM

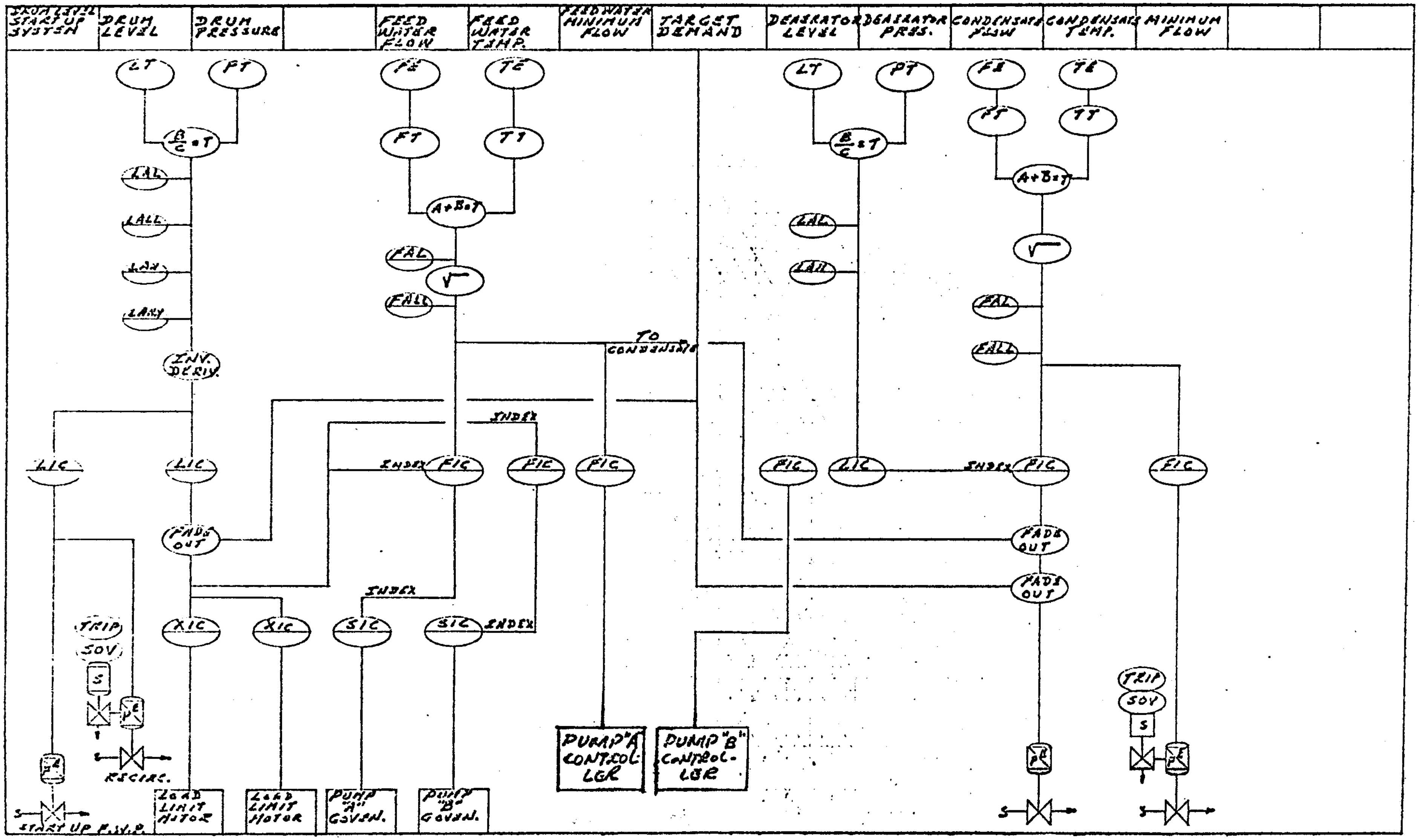


FIGURE V-16

Steam flow is used as the feed forward signal to generate the basic demand for feedwater flow. The operator selects the high pressure drum (This system duplicates for the intermediate pressure drum.) level set point which is compared to the actual drum level. Any error (errors due to blowdown, meter error, etc.) is used to correct the feed forward program. Since the basic demand for feed forward is developed base on load, shrink and swell have only minimal effect on the control system.

Low pressure drum (i.e., deaerator boiler drum) level is temperature compensated and its signal sent to an indicating control station. The LIC sets a control valve in the feedwater makeup to hold drum level. The deaerator drum level sends a signal to an indicating controller, controlling system condensate flow and maintaining minimum flow protection of the condensate pump.

4.6.6 Steam Turbine Control System

Figure V-17 should be referenced to supplement the following steam turbine control description.

4.6.6.1 The Steam Turbine Bypass System Control

This system must function to permit a buildup in superheat before the steam can be fed to the turbine. In addition, in response to the Digital Electro Hydraulic Turbine Control (DEH), the turbine bypass valve is gradually closed off as load is being increased to permit all steam produced to flow through the turbine.

At startup the steam temperature at turbine inlet is measured and sent to an indicating control station. This station's output feeds to a flow controller, controlling the steam bypass to the condenser. The controller is limited to prevent overloading the condenser with too much steam flow. An attemperator system is required downstream of the steam bypass valve to desuperheat the steam flowing to the condenser.

When steam superheat conditions are met, this indicating flow controller comes under the control of the DEH. The basic DEH control system is a turbine valve positioning system. The Coordinated Control System provides two modes of automatic turbine operation: "DEH Auto" and "Plant Master Auto". In DEH Auto, the turbine valves are set at a constant position by the DEH control program with an additional minimum pressure control set point entered from the plant master panel as a function of load. Steam turbine output varies with throttle pressure. The controls also govern the admission of intermediate pressure induction steam, which produces a portion of the total turbine output. In either of these modes, several feedback or corrective loops can be active in the DEH, such as those described below.

4.6.6.2 Speed Loop

A high grain proportional feedback loop compares the actual turbine speed to a speed set point and controls valve position to adjust speed to the desired set point.

STEAM TURBINE 600 & 150 PSIG
STAGE CONTROL SYSTEM

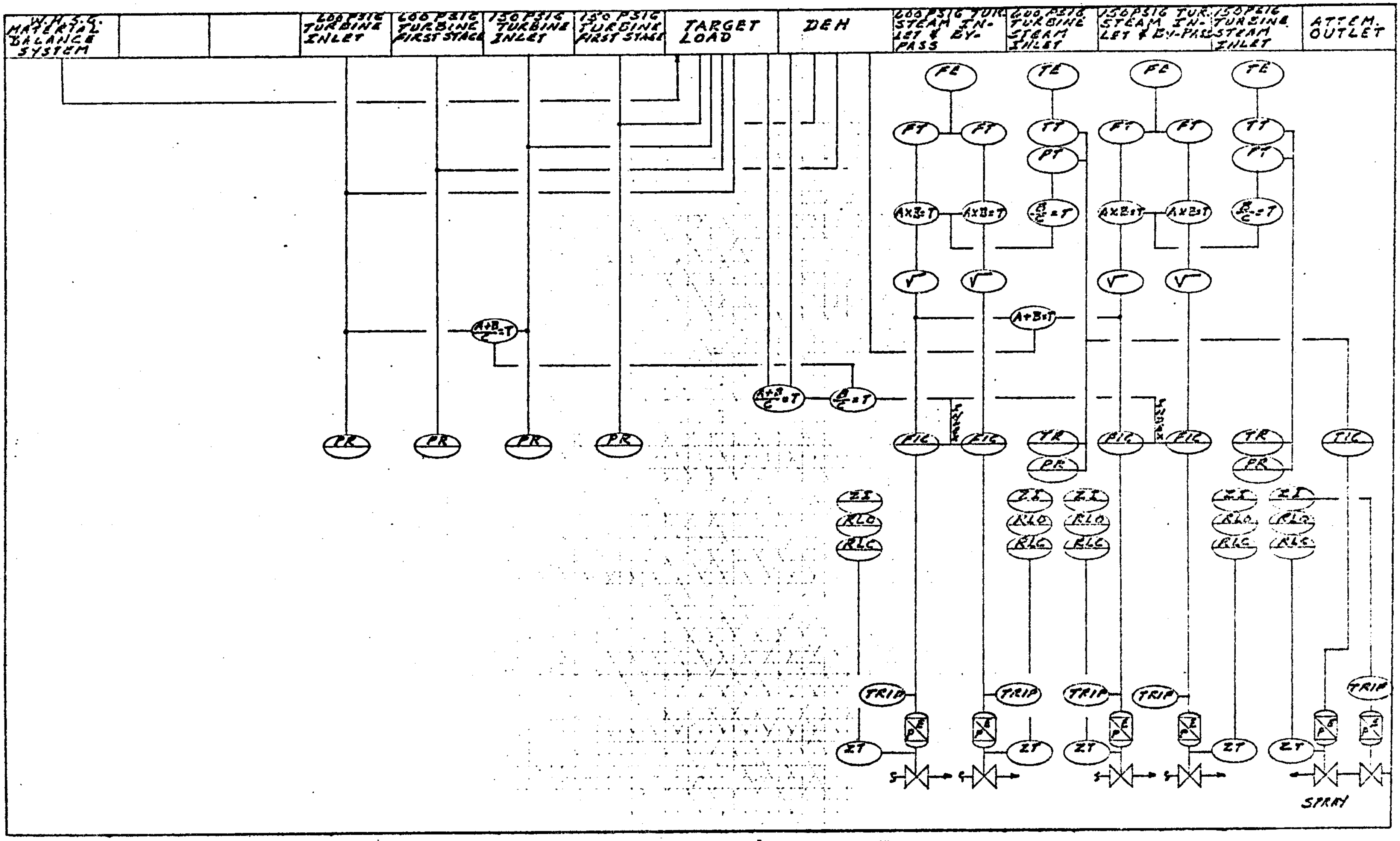


FIGURE V-17

4.6.6.3 Throttle Pressure Limit Loop

The DEH demand is decreased and tends to close the governor valves if throttle pressure falls below the minimum set point.

4.6.6.4 Valve Management Program

The flow capability of each valve is calculated and valve position is corrected for nonlinearities between flow through the valve and valve position. The net result is to linearize the turbine-generator so that MW load output is linear with throttle pressure. The steam bypass valve is backed off line on increasing load and is ramped open on turbine trip.

4.6.6.5 Pressure Correction

In the pressure correction loop, valve position is compensated for changes in throttle pressure so that a relatively constant impulse pressure is maintained should throttle pressure go into fluctuation. This program needs to be tuned such that the bypass valve control has time to return throttle pressure to set point before low pressure causes large changes in valve position. It is important that pressure correction not become interactive with the bypass valve control.

5.0 COST ESTIMATES

5.1 CAPITAL COST ESTIMATES

5.1.1 Methodology

The format adopted for the development and presentation of the Capital Cost Estimate is similar to and patterned after the "Uniform System of Accounts," established by the Federal Power Commission. The estimate is comprised of ten (10) major direct cost accounts. Each item of work associated with a given account is identified with a "sub-account" number prefixed with the major account number. Major accounts 1.0 to 10.0 inclusive represent "direct cost" items.

Job distributable costs covered under Account 11.0, together with the items listed below, represent "indirect cost" items:

a) Engineering and Owner's costs
b) Contingency
c) Interest during Construction

Items a, b and c are described later. The definition of items a and b are exactly the same as given by Westinghouse (Ref. 5) for professional services and contingency respectively.

5.1.1.1 Assumptions

The estimate is based on the following assumptions: The plant is located in "Middletown" U.S.A., which represents an average U.S.A. geographic location, in close proximity to an Eastern Coal Belt. This area lies approximately East of the Mississippi, West of the Appalachian Mountains, South of the Great Lakes and North of the Gulf of Mexico. All costs in this estimate reflect what is felt to be "average" expected costs for this area of the country.

All major items of equipment are procured by the owner.

All items of construction are covered by a series of construction packages, placed by the owner with qualified contractors. Contractors are responsible for furnishing all materials, equipment other than furnished by the owner, craft labor, field supervision, construction equipment, small tools, consumables, trailers, water and electric hook-ups, etc. necessary for a complete installation. All construction costs in our estimate therefore, reflect "contractor cost."

Estimated costs reflect the theoretical assumption that sufficient number of plants of the same type have previously been built, therefore, no "development" cost factors have been included.

All costs represent a mid-1977 price level and do not include escalation.

5.1.1.2 Quantification

Detailed quantity take-offs for the major portion of the work have been performed from plot plans, equipment lists, equipment and piping arrangement drawings, electrical drawings, one (1) line diagrams and other data prepared especially for this project. In addition, take-offs for some systems have been obtained from drawings made for other "in house" projects having similar systems. In these instances, adjustments or modifications have been marked on the drawings to insure compatibility with this project.

5.1.1.3 Price Development

5.1.1.3.1 Gas Turbines/Generators

United Technologies Corporation has estimated the price of the gas turbines and generators using their normal costing procedures with allowance for manufacturers' normal mark-up. The price reflects the turbine inlet temperature of 1600^{o}F and the corresponding reduction in the rating of each turbine to 66.3 MWe. These gas turbine package costs have been checked against current prices of gas turbine packaged powerplants and appear to be realistic for commercially available units.

5.1.1.3.2 PFB System

The cost of the PFB combustor has been developed from the design drawings. Material take-offs have been made and the cost of the Alloy 800H materials have been determined from quotations for the various sizes and shapes required. The cost of other materials has been estimated using standard B&W data. The labor and expense estimates have been obtained from the various shops that would be involved in the fabrication of the combustor with the coordination of the shop estimating being done by the Production Control Department. In many areas the design drawings are not of sufficient detail to define fabrication details. In these areas, Product Control has worked with the shops to develop approximations of the labor and expense costs.

The cost for the solids feed system has been developed from the design drawings using standard B&W estimating procedures. Quotations have been obtained for the rotary feeders. The costs of other purchased items (load cells, valves, etc.) have been based on data developed on earlier studies with approximate adjustments for size and time.

The cost for the dust collection system has been based on vendor quotations for the primary removal systems and B&W estimates for the ash let down systems (hoppers, valves, etc.).

The erection estimates have been developed by the B&W Construction Company based on the various arrangement drawings and on the material weights calculated during the estimating processes.

5.1.1.3.3 Waste Heat Steam Generators (WHSG's)

The WHSG is an established commercial product that has been supplied by B&W for other combined cycle installations. The costs for these units were estimated by the group at B&W which normally markets these units.

5.1.1.3.4 Hot Gas Piping

Since the hot gas piping system is unique to the PFB/G.T. plant, a relatively detailed material take-off has been made during Subtask 1.2 and is repeated here for convenience on Tables W-1 and W-2. It should be noted that the quantities shown are for a two gas turbine plant, therefore, for the PFB/GT/WHSG plant discussed in this report, they should be multiplied by 3.

5.1.1.3.5 Balance of Plant

In general, brief specifications have been prepared for the major items on the equipment list and "budget" prices have been solicited from vendor sources. In those cases where "in house" pricing data are available, the same have been used and adjusted to reflect a 1977 pricing level.

Materials

Material costs have been taken from various estimating publications, manufacturer's price lists, and from BRISC's "in house" cost data bank. Adjustments to these costs have been made as required to adapt this data for this project. The costs for special items have been solicited from vendor sources who have had familiarity and experience with the products involved.

Installation Costs

In general, installation manhours have been estimated for each task. These hours have been multiplied by a developed "average" craft rate including fringe benefits for the discipline involved and to which an allowance for the following has been added to yield a total "Contractor" installation cost:

- Field Supervision
- Unemployment insurance, workman's compensation, Social Security and Liability insurance
- Construction equipment
- Small tools and consumables
- Home office costs including purchasing, estimating, administrative bonds, permits and other costs
- Profit

The following is a listing by discipline, of construction installation rates used in the development of this estimate:

MATERIAL TAKE-OFF FOR HOT PIPING SYSTEM

Table W-1

.I.D. Of Pipe, Inches	Pipe O.D. x Wall Thickness, Inches	Length, Feet	No. of Slip-On Flanges	No. of Shop Butt-welds	No. of Field Butt-welds	No. of 90° Nozzles	No. of Mitre Butt-welds
31	40 x 1/2	63	-	2	8	2	4
36	45 x 1/2	972	36	8	44	4	88
42	51 x 1/2	332	16	8	16	4	16
48	57 1/4 x 5/8	120	2	2	2	-	16
50	59 1/4 x 5/8	240	10	12	12	4	8
54	63 1/4 x 5/8	162	2	6	4	-	8
55	64 1/4 x 5/8	90	-		12	2	4
60	69 1/4 x 5/8	120	-	4	4	4	-
84	93 1/2 x 3/4	120	-	4	8	-	-

REDUCERS

Size, Inches	No. Needed	Size, Inches	No. Needed
45 x 36 x 1/2	8	69 1/4 x 54 x 5/8	4
51 x 42 x 1/2	8	93 1/2 x 63 1/4 x 3/4	2
59 1/4 x 45 x 5/8	8	93 1/2 x 64 1/4 x 3/4	2
59 1/4 x 54 x 5/8	4		
63 1/4 x 40 x 5/8	2		
63 1/4 x 57 1/4 x 5/8	2		

VALVES

Type	No. Needed	No. of Field Buttwelds
36" - Check	4	8
42" - Butterfly	4	8
54" - Butterfly	4	8

MATERIAL TAKE-OFF FOR HOT PIPING SYSTEM

TABLE W-2

REFRACTORY MATERIAL

TYPE	SQ.FT.
1" Thick Insulation Mineral Block	33,800
3" Thick Kast-o-Lite Refractory	32,600
Shop Installation of Ins. & Refrac.	33,200

EXPANSION JOINTS

DESCRIPTION	QTY.
55" I.D., 150# Weld End Expansion Joint For 3/4" Expansion	2
55" I.D., 150# FLG, Weld End Balanced Universal Expansion Joint for 1/2" Lateral Expansion	4
31" I.D., 150# FLG, Weld End Expansion Joint for 3/4" Expansion	2
31" I.D., 150# FLG, Weld End Balanced Universal Expansion Joint for 1/2" Lateral Expansion	4

LINERS

DESCRIPTION	QTY.
3/16" Thick Incoloy 800H Plate	22,000 lbs

Civil, Structural, Architectural -	$22.00/h
Mechanical -	
Piping and Instrumentation -	$26.00/h
Heavy Equipment -	23.00/h
Light Equipment -	21.00/h
Electrical -	26.00/h

In some cases, manhours have not been used to determine installation costs. Instead, a percentage of the equipment or material costs, commensurate with the complexity of the installation considered, has been taken to represent Contractor's installation cost.

5.1.2 Direct Capital Cost

The direct capital cost is summarized by main cost account in Table W-3. A detailed capital cost breakdown is shown in Table W-4.

The items in account 11.0, Job Distributable Cost, may be considered as indirect costs since they are expenditures associated with common temporary construction facilities. These are applicable in varying degrees to all accounts and cannot in any practical way be apportioned equitably among the other direct accounts. It should be noted that a certain amount has been included in accounts 1.0 to 10.0 for items which are sometimes covered in the job distributable category by other investigators.

5.1.3 Total Project Cost

The total project cost which includes both the direct capital costs and the indirect costs are shown in Table W-5. The economic parameters assumed for this study are shown in Table W-6.

5.1.3.1 Engineering and Owner's Costs (E&O Costs)

Engineering and Owner's costs include project management, preliminary engineering, detail engineering and design, construction management, procurement services, architectural design, shop inspection and expediting, supervision of construction, start-up and testing. If these services are performed by a combination of professional firms, or a single professional engineering/ construction firm, the costs include the resulting fees.

Other owner's costs include general office expense, owner's field operation costs, legal fees, taxes during construction, capitalized start-up costs, insurance, spare parts, and special tools for operation and maintenance of the completed project.

This cost breakdown is similar to that described in the ECAS study (Ref. 5). For the present study, 7% of the total of direct costs (accounts 1.0 - 11.0) has been used for the E&O cost. This is less than the 10% used in Subtask 1.2 in recognition of the fact that the PFB/GT/WHSG plant is more modular in nature.

TABLE W-3

PFB/GT/WHSG PLANT
DIRECT CAPITAL COST ESTIMATE
BY MAIN COST ACCOUNT

Main Account No.	Description	In Thousands of Mid-1977 Dollars Material Cost	Installation Cost	Total Cost
1.0	Land & Land Rights	1,020		1,020
2.0	Structures & Improvements	6,790	6,980	13,770
3.0	Gas Turbines & Generators	54,162	6,231	60,393
4.0	PFB Combustor Systems	79,296	35,641	114,937
5.0	Coal & Sorbent Handling Systems	14,495	5,724	20,219
6.0	Boiler Plant Equipment	27,742	12,193	39,935
7.0	Steam Turbine Generator Units	18,687	3,506	22,193
8.0	Accessory Electrical Equipment	16,117	10,580	26,697
9.0	Miscellaneous Powerplant Equipment	432	44	476
10.0	Instrumentation & Control Systems	7,769	2,492	10,261
11.0	Job Distributable Costs	4,945	5,055	10,000
	TOTAL	231,455	88,446	319,901

TABLE W-4

PFB/GT/WHSG COMBINED CYCLE POWER PLANT
DETAILED DIRECT CAPITAL COST ESTIMATE

Account No.	Description	Material	Installation	Total
		Cost in Thousand Dollars		
1.0	Land & Land Rights			
1.1	Land	747	-	747
1.2	Land Rights	273	-	273
	Totals Acct. 1.0	1,020	-	1,020
2.0	Structures & Improvements			
2.1	Site Improvements			
2.1.1	Site Grading	-	2,180	2,180
2.1.2	Building Excavation		120	120
2.1.3	Landscaping	65	35	100
2.1.4	Fresh Water Supply	43	40	83
2.1.5	Fire Protection	282	262	544
2.1.6	Drainage & Sewage Disposal	98	30	123
2.1.7	Wastewater Treatment System	342	169	511
2.1.8	Flagpole	4	1	5
2.1.9	Guard House	2	4	6
2.1.10	Railroad	1,165	635	1,800
2.1.11	Roads, Paved Areas & Parking Lots	283	213	496
2.1.12	Fencing	65	35	100
	Subtotal Acct. 2.1	2,349	3,724	6,073
2.2	Structures			
2.2.1	Office & Service Building	571	376	947
2.2.2	Steam T/G Building	2,400	1,600	4,000
2.2.3	Circ. Water System (Concrete Struct)	268	332	600
2.2.4	Stack Foundation	294	156	450
2.2.5	Gas Turbine Bldg. (Concrete Only)	371	462	833
2.2.6	Chemical Treatment Building	52	63	115
2.2.7	Miscellaneous Buildings	135	117	252
2.2.8	Pipe Rack	350	150	500
	Subtotal Acct. 2.2	4,441	3,256	7,697
	Totals Acct. 2.0	6,790	6,980	13,770

TABLE W-4 Continued

Account No.	Description	Cost in Thousand Dollars Material	Installation	Total
3.0	Gas Turbines & Generators			
3.1	Gas Turbines & Associated Systems (6)	39,123	4,347	43,470
3.2	Electrical Generators & Associated Systems (6)	10,206	1,134	11,340
3.3	Control Package, Relays, Breakers, etc. (6)	4,083	453	4,536
3.4	Enclosure Including 25-ton Traveling Crane (6)	618	264	882
3.5	60-65 MW Low Voltage Circuit Breakers (6)	132	33	165
	Total Acct. 3.0	54,162	6,231	60,393
4.0	PFB Combustor Systems			
4.1	PFB Combustors (12)	50,010	24,600	74,610
4.2	PFB Gas Cleaning Equipment	14,850	7,080	21,930
4.3	Process Solid Waste Handling System	2,640	528	3,168
4.4	Hot Gas Piping	9,216	2,553	11,769
4.5	Start-up Combustors-Air Preheaters	2,220	340	2,560
4.6	Allowance for PFB System Concrete Work	360	540	900
	Total Acct. 4.0	79,296	35,641	114,937
5.0	Coal and Sorbent Handling Systems			
5.1	Coal Stackout, Reclaim, Preparation and Silo Storage Systems	8,562	3,671	12,233
5.2	Dolomite Stackout, Reclaim, Preparation and Silo Storage Systems	1,463	643	2,106
5.3	Coal and Dolomite Feed Systems to PFB	4,470	1,410	5,880
	Total Acct. 5.0	14,495	5,724	20,219

TABLE W-4 Continued

Account No.	Description	Material	Installation	Total
		Cost in Thousand Dollars		
6.0	Boiler Plant Equipment			
6.1	Waste Heat Steam Generators (6)	18,295	5,586	23,881
6.2	Boiler Feed Pumps:			
6.2.1	H.P.-500 gpm, 1640'TDH, 300 HP Motors (12)	848	202	1,050
6.2.2	I.P.-140 gpm, 415'TDH, 30 HP Motors (12)	126	25	151
6.2.3	L.P.-100 gpm, 46'TDH, 3 HP Motors (12)	120	20	140
6.3	Deaerating Heaters (6)	162	38	200
6.4	Air Compressors - Service & Instr.	111	6	117
6.5	Concrete Chimneys (3)	2,520	1,512	4,032
6.6	Breeching, including Insulation & Jacket	84	62	146
6.7	High Pressure, Intermediate and Low Pressure Piping:			
6.7.1	High Pressure Steam Piping	100	256	356
6.7.2	Boiler Feed Discharge Piping	172	418	590
6.7.3	Intermediate Steam Piping	52	127	179
6.7.4	Low Pressure Steam Piping	38	100	138
6.7.5	Boiler Feed Suction Piping	17	50	67
6.7.6	Condensate Piping	18	47	65
6.7.7	Condensate Piping for Solids Cooler and Condenser Heating	40	92	132
6.7.8	Continuous Blowdown Piping	17	64	81
6.7.9	Intermittant Blowdown Piping	14	49	63
6.7.10	Fuel Oil Piping	26	96	122
6.7.11	Bearing Cooling Water Piping	68	82	150
6.7.12	Boiler Vents and Drain Piping	40	60	100
6.7.13	Condenser Vacuum & Air Extraction Piping	40	40	80
6.7.14	Sodium Zeolite & Cooling Tower Chlor.Piping	39	49	88
6.7.15	Drain and Vent Piping	27	31	58
6.7.16	Safety Relief Valve Vent Piping	45	55	100
6.7.17	Instrument Air Piping	20	30	50
6.7.18	Service Air piping	24	36	60
6.7.19	Lube Oil Piping	26	39	65
6.7.20	Main and Auxiliary Turbine Piping	43	57	100
6.7.21	Plant Waste Piping	27	39	66
6.7.22	Roof Drain Piping	32	38	70
6.7.23	Service Water Piping	113	137	250
6.8	Valves:			
6.8.1	High Pressure (600# cast steel gate and globe valves)	263	87	350
6.8.2	Low Pressure (Gate, globe & check valves)	325	108	433

TABLE W-4 Continued

Account No.	Description	Cost in Thousand Dollars Material	Installation	Total
6.8.3	Forged Steel (Gate, globe & check valves)	420	139	559
6.8.4	Safety and Relief Valves	20	7	27
6.8.5	Control Valves	269	89	358
6.9	Piping Specialty Items	88	126	214
6.10	Insulation - Piping & Equipment	375	125	500
6.11	Water Treatment Equipment:			
6.11.1	Sodium Zeolite Equipment (3)	68	22	90
6.11.2	Chemical Feed Equipment	32	8	40
6.12	Shop Fabricated Tanks, including Condensate Heaters and Coolers	133	3	136
6.13	Condensate Storage Tanks (2)	50	30	80
6.14	Light Oil Storage Tank	41	27	68
6.15	Fuel Oil Transfer Pumps and Drives	4	1	5
6.16	Fuel Oil Unloading Pump with Motor	2	1	3
6.17	Fuel Oil Strainers	4	1	5
6.18	Sump Pumps	12	3	15
6.19	Air Compressors for Waste Ponds	22	3	25
6.20	Concrete Ash Silos with Dust Collector Rotary Unloaders and Panel Control (3)	2,000	1,200	3,200
6.21	Finish Painting	80	425	505
6.22	Allowance for Equipment Concrete Work	230	345	575
	TOTAL Acct. 6.0	27,742	12,193	39,935

TABLE W-4 Continued

Account No.	Description	Cost in Thousand Dollars Material	Installation	Total
7.0	Steam Turbine Generator Units			
7.1	Steam Turbine Generator with Exciter & Accessories (3), 65,000-70,000 kW	13800	2070	15870
7.2	Condenser & Tubes (3), 85,000 ft^2 Surface Area, Single Condenser Shells & Boxes, w/Steam Jet Air Ejectors & Access.	1575	525	2100
7.3	Condensate Pumps w/Motors, 640 gpm, 217' TDH, 60 HP Motors (9)	114	28	142
7.4	Cooling Tower including Sprinkler System	1900	500	2400
7.5	Cooling Tower Chlorination System	96	25	121
7.6	Chlorinator Booster Pumps w/Motors (2), 800 gpm, 184' TDH, 50 HP Motors	6	1	7
7.7	Cooling Tower Acid Feed System	35	8	43
7.8	Circulating Water pumps w/Motors (2) 68,200 gpm, 72'TDH, 2100 HP Motors	480	55	535
7.9	Circulating Water Booster Pumps, w/Motors (2)	8	2	10
7.10	Circulating Water Piping	400	233	633
7.11	C.T. Makeup Water Pumps w/Motors (2), 4100 gpm, 65'TDH, 115 HP Motors	28	7	35
7.12	Sluice Gates w/Floor Stands	12	3	15
7.13	Traveling Screens	50	13	63
7.14	Screen Wash Pumps w/Motors	9	2	11
7.15	Closed Cooling Water Heat Exchangers	60	15	75
7.16	Closed Cooling Water Pumps w/Motors	10	3	13
7.17	Lube Oil Purification Equipment	80	13	93
7.18	Lube Oil Pumps w/Motors	24	3	27
	TOTAL Acct. 7.0	18687	3506	22193

TABLE W-4 Continued

Account No.	Description	Material	Installation	Total
		Cost in Thousand Dollars		
8.0	Accessory Electric Equipment			
8.1	Generator Accessories & Equipment	3439	455	3894
8.2	Station Service Equipment	1009	447	1456
8.3	Switchgear Unit Substation & M.C.C.	3656	676	4332
8.4	Switchyards	4104	1126	5230
8.5	Grounding & Misc. Systems	162	413	575
8.6	Emergency Gener. & UPS Equipment	171	65	236
8.7	Raceways	1497	4789	6286
8.8	Conductors	1715	1813	3528
8.9	Lighting & Communications	364	796	1160
	TOTAL Acct. 8.0	16117	10580	26697
9.0	Miscellaneous Power Plant Equipment			
9.1	Laboratory Equipment	82	8	90
9.2	Steam & Water Sampling Equipment	135	15	150
9.3	Shop Tools & Equipment	80	8	88
9.4	Lockers	5	1	6
9.5	Office Furniture & Machines	30	2	32
9.6	Lunch Room Equipment	25	3	28
9.7	Portable Fire Extinguishing Equipment	20	1	21
9.8	Miscellaneous Cranes & Hoists	50	5	55
9.9	Emergency Equipment	5	1	6
	TOTAL Acct. 9.0	432	44	476
10.0	Instrumentation and Control Systems			
10.1	Gas Turbines & Elect. Generator Systems	921	265	1186
10.2	PFB Systems	2017	780	2797
10.3	PFB Coal & Sorbent Feed System	996	344	1340
10.4	Waste Heat Steam Generator Systems	1835	707	2542
10.5	Computer & CRT. Display Systems	1707	293	2000
10.6	Coal & Sorbent Receiving Storage, Reclaim and Transfer to Silos	293	103	396
10.7	Steam & Water Sampling	(Included in Account 9.0)		
	TOTAL Acct. 10.0	7769	2492	10261

TABLE W-4 Continued

Account No.	Description	Cost in Thousand Dollars Material	Installation	Total
11.0	Job Distributable Costs			
	Temporary Facilities: Field Office, Field Office Supplies, Warehouses & Shops, Change House, Toilets, First Aid, Job Cleanup	750	2250	3000
	Heat, Light & Power, Water, Air	1875	625	2500
	**Roads & Parking Areas	500	1000	1500
	Sewers and Drainage	250	250	500
	Fire Protection, Security Guards, and Communications	250	375	625
	Motor Pool & Garage	1125	375	1500
	Fences	70	30	100
	Miscellaneous	125	150	275
	TOTAL Account 11.0	4945	5055	10000

Note: Costs Include:

1. Maintenance Personnel
2. Dismantling & Removal

**Includes Snow Removal Costs

TABLE W-5

PFB/GT/WHSG COMMERCIAL PLANT CAPITAL COST SUMMARY

		$1,000's
1.	Direct Capital Cost	$319,901
2.	Engineering & Owner's Costs (7% of 1.)	22,500
3.	Contingency (10% of 1+2)	34,240
4.	Interest During Construction (8% Rate; 5 yrs; i.e.; 19.5% of 1+2+3)	73,445
	Total Project Capital Cost	$450,086

Specific Capital Cost = $762/kW (Net)

TABLE W-6

ECONOMIC PARAMETERS

PFB/GT/WHSG CYCLE STUDY

Plant Life	30 years
Capacity Factor	65%
Output Factor	100%
Dollar Base Used	Mid-1977
Escalation	0
Discount Rate	8%
Interest During Construction	8%
Period of Construction	5 years
S-curved Expenditure Schedule	
Fixed Capital Charge	18%
Replacement Energy Cost	25 mills/kwh
Cost of Coal	$0.87/mmBTU $20.00/ton
Cost of Limestone & Dolomite	$7.00/ton
Cost of Disposal of Ash & Spent Sorbent	$3.00/ton

5.1.3.2 Contingency

As stated in Ref. 5, "Contingency is an allowance for costs which may be incurred as a result of factors which cannot be specifically anticipated and, therefore, cannot be included in the direct accounts. Contingency includes the additional costs likely to be encountered due to incompletely specified designs, estimating errors and omissions, unanticipated site conditions, minor scope changes, inability to predict actual productivity and unforeseen construction problems. Forced station additions or modifications due to revised statutory requirements (particularly environmental), major scope changes, Force Majeure, and unanticipated changes in escalation and interest during construction are not included as contingency costs."

In the present study, an allowance of 10 percent of the direct capital cost and engineering and owner's cost has been made to cover contingency costs.

5.1.3.3 Interest During Construction (IDC)

The total capital investment is assumed to be spent according to an S-curve expenditure schedule. This particular schedule is used by Burns and Roe, Inc. in estimating the construction costs of power plants. For zero escalation, 8 percent interest rate and a construction period of 5 years, the total interest during construction becomes 19.5 percent of the sum of direct capital cost, engineering and owner's cost and contingency. Under the same conditions, except for an interest rate of 10 percent, IDC becomes 24.9 percent.

5.1.3.4 Total Project Cost

The total project cost is estimated to be $450,086,000 in mid-1977 dollars. This amounts to a specific capital cost of $762 per kW capacity net. The direct capital cost is 71.1% of total cost and IDC accounts for 16.3%.

If the interest rate is 10%, the IDC cost becomes $93,784,000. The total project cost and specific capital cost becomes $470,425,000 and $796 respectively. IDC cost becomes 19.9% of total project cost.

5.2 OPERATING AND MAINTENANCE COSTS

The operating and maintenance costs include the costs for manning, coal, sorbents, utilities, solid waste disposal, chemicals for water treatment, spare parts, replacement of tools and equipment, etc.

It is needless to say that extimating these costs for a complex utility plant verges on conjecture. In consideration of the overall accuracy of these estimates, it is reasonable to assume that the total O&M costs for the PFB/GT/WHSG plant would be the same as for the PFB/AFB plant of Subtask 1.2. Estimates for the Subtask 1.2 study have been based on data and criteria from a document (Ref. 6) prepared by Stanford Research Institute (SRI) for Bechtel Corporation. The two cases from the SRI document which form the bases of that estimate are as follows:

a) A coal fired 800 MWe station with capacity factor 70%, and

b) A gas turbine plant, 133 MWe station, with 1000 hours per year operation.

The reported data have been prorated and modified for this study. The costs have been updated to reflect the values of mid-1977 dollars. Estimated manpower needs are shown in Table W-7. Man-hours needed for accounting, personnel, warehousing and sales activity are not accounted for here under the assumption that these functions would be performed by personnel the utility company already has employed. A total of 108 people are required to operate this plant. Total manpower cost is estimated to be $2,562,300 per year, allowing 30% of salary as fringe benefits. The assumed salary scale and manpower cost are shown in Table W-8.

The costs of materials and supplies have been based on a capacity factor of 65% and on the maintenance of full load heat rate at all loads. These estimates are shown in Table W-9 in the same format as was given in the SRI document (Ref. 6). Equipment requirements were based on several criteria. First, equipment was segregated into items that were expected to have a life equal to, or greater than, that of the energy facility, and those with a shorter life. Examples of these two categories are the rotary car dumper and the trucks, scrapers, and other mechanical transport equipment used at the plant. With appropriate maintenance, the railroad car dumper is expected to last for the 30-year life of the plant. The trucks, scrapers, and similar transport equipment are expected to last for 5 to 7 years before replacement. Equipment costs for the car dumper are those for replacement and repair supplies. (Manpower requirements were included in the overall manpower requirements for the facility). For the transport equipment whose life was less than the facility, the cost reported is a combination of an amortized replacement cost and the materials and supplies required to keep the equipment in operation over its normal lifetime.

5.3 COST OF ELECTRICITY (COE)

5.3.1 The Basic Cost

The cost of electricity is calculated from the total energy output in a year and the total annual cost. The total annual cost is the sum of the following: (1) fixed charge, (2) fuel and (3) other operating and maintenance costs, including the sorbent cost.

The fixed charge has been assumed to be 18% of the total project cost. The annual cost summary is shown in Table W-10. Under the assumed conditions, the total annual cost of operation is $116,197,000.

At 65% capacity factor, the annual energy output is 3,363 x 10^6 kWh. Therefore, the cost of electricity is 34.55 mills/kWh.

5.4 COST COMPARISON OF PFB/GT/WHSG (SUBTASK 1.8) CYCLE VERSUS PFB/AFB CYCLE (SUBTASK 1.2)

5.4.1 Capital Cost Comparison

A comparison of the capital cost estimates for Subtask 1.8 versus those of 1.2 shows that the PFB/GT/WHSG plant ($762/kW) is approximately 34% more costly than the PFB/AFB commercial plant ($567/kW) used as a base. Table W-11 briefly summarizes where the cost differences occur on a main cost account basis. Table W-12 gives a detailed breakdown of the cost differences with a short explanation for each variance.

TABLE W-7

CONCEPTUAL PFB PLANT ESTIMATED MANPOWER NEED FOR OPERATION AND MAINTENANCE

MAN-POWER	NUMBER/YR.
A. NON-MANUAL	
1. Technical	
a) Engineers	
Electrical	6
Mechanical	5
Instrumentation	2
b) Designers & Draftsmen	1
c) Supervisors & Managers	11
2. Non-technical	10
3. Total Non-Manual	35
B. MANUAL LABOR	
1. Craftsmen	
Pipe fitter	6
Pipe fitter/Welder	10
Electrician	10
Boiler Maker/Welder	6
Operator	20
Millwright	6
2. Teamsters & Laborers (Contract)	15
3. Total Manual Labor	73
TOTAL MAN-YRS NEEDED	108

TABLE W-8

COST OF MANPOWER

OPERATION AND MAINTENANCE

TYPE OF PERSONNEL	NUMBER	BASIC ANNUAL SALARY RATE, $	TOTAL SALARY $
1. Supervisors & Managers	11	25,000	275,000
2. Engineers	13	22,000	286,000
3. Designers & Draftsman	1	20,000	20,000
4. Non-technical non-manual	10	12,000	120,000
5. Craftsmen	38	20,000	760,000
6. Operators	20	18,000	360,000
7. Contract labor	15	10,000	150,000
TOTAL	108		1,971,000

Total Manpower Cost with 30% for fringe benefits is $2,562,300/year.

TABLE W-9

ANNUAL COST FOR MATERIALS, EQUIPMENT AND UTILITIES

		Thousands of Dollars
I.	Materials	
	A. Major Raw Material	
	1. Coal, 1,336,496 tons/yr	26,730
	2. Dolomite, 238,601 tons/yr	1,670
	3. TOTAL	28,400
	B. Other Significant Material & Supplies	
	1. Chemicals & Other Material (27-32)*	
	Water Treatment	42.9
	Other	101.9
	2. Stone, Clay and Glass Products (35,36)	96.9
	3. Non-ferrous metals (38)	82.2
	4. Metal Products (39-42)	
	Fabricated Structural Steel	619.3
	Fabricated Plate Work	316.6
	Pipes, Valves & Miscellaneous	542.0
	Other	71.4
	5. Miscellaneous	58.8
	6. TOTAL	1,932

* Numbers in parentheses are Bureau of Economic Analysis Industry category numbers.

TABLE W-9 Cont.

ANNUAL COST FOR MATERIALS, EQUIPMENT AND UTILITIES

		Thousands of Dollars
II	Machinery & Equipment (Amortization and Replacement Parts)	
1.	Non-electrical Machinery (43-50,52)	
	Steam engines and turbines	135.3
	Internal combustion engine	9.0
	Contruction Machinery	65.6
	Conveyors	144.3
	Hoists and Cranes	29.6
	Industrial Trucks and Tractors	27.0
	Metal Working Machinery	68.1
	Blowers and Fans	9.0
	Industrial Machinery & Equipment	112.1
	Sub-Total	600.0
2.	Electrical Equipment (53-58)	
	Electrical machinery	9.0
	Transformers	18.0
	Switchgear & Switchboards	40.6
	Motors & Generators	170.9
	Controls	27.0
	Electrical Lighting	4.5
	Miscellaneous Electrical	34.0
	Sub-Total	304.0
3.	Transportation Equipment (59-61)	39.0
4.	Instruments & Controls (62,63)	
	Engineering & Scientific Instruments	71.8
	Measuring Devices	22.2
	Sub-Total	94.0
5.	Miscellaneous (64)	38.0
6.	TOTAL	1,075.0

TABLE W-9 Cont.

ANNUAL COST FOR MATERIALS, EQUIPMENT AND UTILITIES

		Thousands of Dollars
III	Utilities	
	1. Fuel (68) 300,000 gals @ $0.38 gal.	114
	2. Water (68) 58,000,000 gals @ $ 0.25/m gal	15
	3. Total	129
IV	Spent Sorbent & Ash Disposal	
	Removal & Disposal of Solid Waste Material 361,233 tons/yr @ $3/ton	1,084

TABLE W-10

ANNUAL COST SUMMARY

AND COST OF ELECTRICITY

ITEMS	Thousands of Dollars
1. Fixed charge (@ 18%)	81,015
2. Coal	26,730
3. Sorbent	1,670
4. Man Power Cost	2,562
5. Other Material	1,932
6. Machinery Amortization and Replacement Parts	1,075
7. Utilities	129
8. Spent Sorbent & Ash Disposal	1,084
Total	$ 116,197

Total Energy Output at 65% Capacity Factor $3,363 \times 10^6$ kWh

Cost of Electricity Generated = 34.55 mills/kWh

TABLE W-11

COMPARATIVE CAPITAL COST ANALYSIS BY MAIN COST ACCOUNT

PFB/GT/WHSG vs. PFB/AFB

Account No.	Description	COSTS, $1000 574 MW PFB/AFB (Base)	COSTS, $1000 591 MW PFB/GT/WHSG	Variance Over or Under () Base
	SUMMARY			
1.0	Land and Land Rights	1020	1020	0
2.0	Structures & Improvements	13700	13770	70
3.0	Gas Turbines/Generators	20232	60393	40161
4.0	PFB Combustor Systems	38312	114937	76625
5.0	Coal & Sorbent Handling Systems	21808	20219	(1589)
6.0	Boiler Plant Equipment	63033	39935	(23098)
7.0	Steam Turbine Generator Units	29923	22193	(7730)
8.0	Accessory Electric Equipment	22358	26697	4339
9.0	Misc. Power Plant Equipment	494	476	(18)
10.0	Instrumentation & Control Systems	6130	10261	4131
11.0	Job Distributable Costs	8000	10000	2000
	Sub-Total	225010	319901	94891
	Engineering & Owner Costs	22501	22501	0
	Sub-Total	247511	342402	94891
	Contingency	24751	34240	9489
	Sub-Total	272262	376642	104380
	Interest During Construction	53091	73445	20354
	Totals	325353	450087	124734
		$567/kW	$762/kW	$195/kW

TABLE W-12
DETAILED COMPARISON OF CAPITAL COSTS
PFB/GT/WHSG CYCLE VERSUS PFB/AFB CYCLE

PFB/AFB CYCLE (Subtask 1.2)-Base Case Acct. No.	Item Description	Amount $1,000	PFB/GT/WHSG CYCLE (Subtask 1.8) Acct. No.	Item Description or Change	Amount $1,000	Variance Over or Under () Base
1.0	Land & Land Rights					
1.1	Land	747	1.1	No Change	0	
1.2	Land Rights	273	1.2	No Change	0	
				Acct. 1.0 Total Variance	0	
2.0	Structures & Improvements					
2.1	Site Improvements	6073	2.1	No Change	0	
2.2	Structures:					
2.2.1	Office & Service Bldg.	947	2.2.1	No Change	0	
2.2.2	Steam T/G Bldg.	5025	2.2.2	Smaller T/G Bldg.	4000	(1025)
2.2.3	Circ.WaterSys.ConcreteStruct.	628	2.2.3	Smaller Concrete Struct.	600	(28)
2.2.4	One Stack Foundation	150	2.2.4	Three Stack Foundations	450	300
2.2.5	Two Gas Turbine Bldg.Concrete	278	2.2.5	Six Gas Turbine Bldg.Conc.	833	555
2.2.6	Chemical Treatment Bldg.	115	2.2.6	No Change	0	
2.2.7	Electrostatic Precip. Fdn. and steel	232		None Required		(232)
2.2.8	Misc. Bldgs. & Pipe Rack	252	2.2.7&8	Longer Pipe Rack	752	500
				Acct. 2.0 Total Variance		70
3.0	Gas Turbines/Generators					
3.1	Two Gas Turbines& Assoc.Sys.	14490	3.1	Six GasTurbines&Asso.Sys.	43470	28980
3.2	Two elect.Gen.&Assoc. Sys.	3780	3.2	Six Elec. Gen.&Assoc.Sys.	11340	7560
3.3	Control Pkg. Relays, Breakers etc. for 2 Sys.	1512	3.3	Control Pkg. Relays, Breakers for 6 Sys.	4636	3024
3.4	Two GT Encs.w/25 T Crane	294	3.4	Six GT Encs. w/25 T Crane	882	588
3.5	Two 60-65 MW low Volt.C.B.	55	3.5	Six 60-65 MW low Volt. C.B.	165	110
3.6	Breeching, incl. Isolating Dampers & Insulation to AFB	101	3.6	None Required		(101)
				Acct. 3.0 Total Variance		40161

TABLE W-12 (continued)

PFB/AFB CYCLE (Subtask 1.2)-Base Case Acct. No.	Item Description	Amount $1,000	PFB/GT/WHSG CYCLE (Subtask 1.8) Acct. No.	Item Description or Change	Amount $1,000	Variance Over or Under () Base
4.0	PFB Combustor Systems					
4.1	Four PFB Combustors	24870	4.1	Twelve PFB Combustors	74610	49740
4.2	PFB Gas Cleaning Equip. for Four Combustors	7310	4.2	PFB Gas Cleaning Equip. for Twelve Combustors	21930	14620
4.3	Proc. Solid Waste Handling Sys. for 4 Combustors	1056	4.3	Proc. Solid Waste Handling Sys. for 12 Combustors	3168	2112
4.4	Hot Gas Piping for 4 Comb.	3923	4.4	Hot Gas Piping for 12 Comb.	11769	7846
4.5	Startup Comb. Air Preheaters for 4 PFB Systems	853	4.5	Startup Comb. Air Preheaters for 12 PFB Systems	2560	1707
4.6	Concrete work for 4 PFB Comb.	300	4.6	Concrete Work for 12 PFB Comb.	900	600
				Acct. 4.0 Total Variance		76625
5.0	Coal & Sorbent Handling Systems					
5.1	Coal Stackout, Reclaim,, Prep. for 4 Silo & Catenary Bunker Storage	11392	5.1	Coal Stackout, Reclaim, Prep. for 12 Silo Storage System	12233	841
5.2	Dolomite & Limestone Stackout, Reclaim/4 Silo & Catenary Bunker Storage	1856	5.2	Dolomite only Stackout,Reclaim, Prep. /12 Silo Storage System Also longer Conveyors (ST)	2106	250
5.3	Coal & Dolomite Feed Sys. to 4 PFB's	1960	5.3	Coal & Dolomite Feed Systems to 12 PFB's	5880	3920
5.4	Coal & Limestone Feed Systems to AFB	6600	5.4	None Required		(6600)
				Acct. 5.0 Total Variance		(1589)

TABLE W-12 (continued)

PFB/AFB CYCLE (Subtask 1.2)-Base Case Acct. No.	Item Description	Amount $1,000	PFB/GT/WHSG CYCLE (Subtask 1.8) Acct. No.	Item Description or Change	Amount $1,000	Variance Over or Under () Base
6.0	Boiler Plant Equipment					
6.1	One AFB Steam Generator	30700	6.1	Six Waste Heat Recovery Blrs.	23881	(6819)
6.2	Electrostatic Precipitators	8363		None Required		(8363)
6.3	Mech. Cyclone Dust Separators	850		None Required		(850)
6.4	I.D. Fans w/Motor Drives	1007		None Required		(1007)
6.5	Two Boiler Feed Pumps	501	6.2	36 Boiler Feed Pumps w/Motors	1341	840
6.6	Boiler Feed Pump Turb.Drive	1632		None Required		(1632)
6.7	Startup Boiler Feed Pump	174		None Required		(174)
6.8	L.P. Feedwater Heaters	253		None Required		(253)
6.9	Deaerating Heater, one @ 3,000,000 lb/hr	196	6.3	Deaerating Heaters six @ 2,191,758 lb/hr Total	200	4
6.10	Air Compressors (Serv.&Inst.)	117	6.4	No Change		0
6.11	One Concrete Chimney	1400	6.5	Three Concrete Chimneys	4032	2632
6.12	Breeching, incl. Insulation & Jacket	1446	6.6	Breeching, incl. Ins. & Jacket Less Req'd due to No Electro- static Precipitators	146	(1300)
6.13 &.14	High Pressure, Int. & Low Pressure Piping	4964	6.7	No Reheat Systems, No Alloy, GenerallyLessExpens.PipingSys.	3030	(1934)
6.15	Valves	2237	6.8	Valves (Less Expens. as above)	1727	(510)
6.16	Piping, Specialty Items	214	6.9	No Change		0
6.17	Insulation,Piping & Equip.	705	6.10	LesserEquip.Req.per 6.7 above	500	(205)
6.18	Water Treat. Equip. Demineralizer System	1175	6.11	Water Treat. Equip. Zeolite Sys. less Expens. than Demin.Sys.	130	(1045)
6.19	Shop Fab. Tanks incl. one Boiler Blowdown Tank	86	6.12	Shop Fab. Tanks incl. Heaters & Coolers & 9 Blr.BlowdownTanks	136	50
6.20	Two 150,000 gal. Condensate Storage Tanks	150	6.13	Two 60,000 gal. Condensate Storage Tanks	80	(70)
6.21	Light Oil Storage Tanks	68	6.14	No Change		0
6.22	F.O. Transfer Pumps&Drives	5	6.15	No Change		0
6.23	F.O. Unloading Pump w/Motor	3	6.16	No Change		0
6.24	F.O. Strainers	5	6.17	No Change		0
6.25	Sump Pumps	15	6.18	No Change		0
6.26	Air Compressors for Waste Ponds	25	6.19	No Change		0
6.27	AFB Proc. Solid Waste Hand- ling & Storage Systems	5837	6.20	No AFB Solid Waste Hand- ling-Concrete Ash Silos only	3200	(2637)
6.28	Finish Painting	405	6.21	Longer Pipe Rack & more equip.	505	100
6.29	Equip. Concrete Work	500	6.22	More Equip. Foundations	575	75
				Acct. 6.0 Total Variance		(23098)

TABLE W-12 (continued)

PFB/AFB CYCLE (Subtask 1.2)-Base Case Acct. No.	Item Description	Amount $1,000	PFB/GT/WHSG CYCLE (Subtask 1.8) Acct. No.	Item Description or Change	Amount $1,000	Variance Over or Under () Base
7.0	Steam Turbine Generator Units					
7.1	Stm. T/G, One @ 480,000 kW	22770	7.1	Three @ 65,000-70000kW ea.	15870	(6900)
7.2	One twin Condenser & Tubes	2064	7.2	Three Single Condenser & Tubes w/S.J.A.E.	2100	36
7.3	Condenser Vac. Pumps&Motors	242		None Required		(242)
7.4	Condensate Pumps w/Motors	200	7.3	Smaller Pumping Cap. Reqs.	142	(58)
7.5	Cooling Tower, 168,000 gpm, 18 cells	2790	7.4	Cooling Tower, 136,400 gpm, 14 cells	2400	(390)
7.6	C.T. Chlorination System	121	7.5	No Change		0
7.7	Chlorinator Booster Pumps	7	7.6	No Change		0
7.8	C.T. Acid Feed System	43	7.7	No Change		0
7.9	Circ. Water Pumps	608	7.8	Smaller Capacity Pumps	535	(73)
7.10	Circ. Water Booster Pumps	18	7.9	Smaller Capacity Pumps	10	(8)
7.11	Circ. Water Piping	720	7.10	Smaller Size Piping	633	(87)
7.12	C.T. Makeup Water Pumps	43	7.11	Smaller Capacity Pumps	35	(8)
7.13	Sluice Gates w/Floor Stands	15	7.12	No Change		0
7.14	Travelling Screens	63	7.13	No Change		0
7.15	Screen Wash Pumps	11	7.14	No Change		0
7.16	Closed Cooling Water Heat Exc.	75	7.15	No Change		0
7.17	Closed Cooling Water Pumps	13	7.16	No Change		0
7.18	Lube Oil Purification Equip.	93	7.17	No Change		0
7.19	Lube Oil Pumps	27	7.18	No Change		0
				Acct. 7.0 Total Variance		(7730)

TABLE W-12 (continued)

PFB/AFB CYCLE (Subtask 1.2)-Base Case			PFB/GT/WHSG CYCLE (Subtask 1.8)			Variance
Acct. No.	Item Description	Amount $1,000	Acct. No.	Item Description or Change	Amount $1,000	Over or Under () Base
8.0	Accessory Electric Equipment					
8.1	Generator Accessories & Equip.	2753	8.1	Increased Quantity of Step-up Transformers from 2 to 9. Added 3 large circuit breakers	3894	1141
8.2	Station Service Equipment	1180	8.2	Increased Quantity & Size of Aux. Transformers & Related Accessories & Equip.	1456	276
8.3	Switchgear, Unit Substation & M.C.C.	4205	8.3	Increase in number of Unit Substations	4332	127
8.4	Switchyard	2264	8.4	Addition of 69 kV Switchyard	5230	2966
8.5	Grounding & Misc. Systems	531	8.5	Increase in Amt. of Equip. to be Grounded	575	44
8.6	Emergency Gen. & UPS Equip.	236	8.6	No Change		0
8.7	Raceways	6410	8.7	Less Motor Requirements	6286	(124)
8.8	Conductors	3619	8.8	Less Motor Requirements	3528	(91)
8.9	Lighting & Communications	1160	8.9	No Change		0
				Acct. 8.0 Total Variance		4389
9.0	Miscellaneous Power Plant Equipment					
9.1	Laboratory Equipment	90	9.1	No Change		0
9.2	Steam & Water Sampling Equip.	168	9.2	Slightly Less Required	150	(18)
9.3	Shop Tools & Equip.	88	9.3	No Change		0
9.4	Lockers	6	9.4	No Change		0
9.5	Office Furniture & Machines	32	9.5	No Change		0
9.6	Lunch Room Equipment	28	9.6	No Change		0
9.7	Portable Fire Exting. Equip.	21	9.7	No Change		0
9.8	Misc. Cranes & Hoists	55	9.8	No Change		0
9.9	Emergency Equip.	6	9.9	No Change		0
				Acct. 9.0 Total Variance		(18)

TABLE W-12 (continued)

PFB/AFB CYCLE (Subtask 1.2)-Base Case Acct. No.	Item Description	Amount $1,000	PFB/GT/WHSG CYCLE (Subtask 1.8) Acct. No.	Item Description or Change	Amount $1,000	Variance Over or Under () Base
10.0	Instrumentation & Control Systems					
10.1	Two Gas Turbines & Electric Generator Systems	284	10.1	Six Gas Turbines & Electric Generator Systems	1186	902
10.2	Four PFB Systems	1175	10.2	Twelve PFB Systems	2797	1622
10.3	Four PFB Coal & Sorbent Handling Systems	456	10.3	Twelve PFB Coal & Sorbent Handling Systems	1340	884
10.4	AFB Coal&Sorbent HandlingSys.	456		None Required		(456)
10.5	AFB Steam Generator Sys.	2258		None Required		(2258)
-	None Required		10.4	Waste Heat Steam Gen. Sys.	2542	2542
10.6	Computer & CRT Displays	1105	10.5	More Data to Process & More Complicated Control Functions Dealing with 6 WHSG to 3 Steam Turbine Units	2000	895
10.7	Coal & Sorbent Receiving Storage, Reclaim & Transfer to Silos	396	10.6	No Change		0
10.8	Steam & Water Sampling In Acct. 9.0		10.7	No Change		0
				Acct. 10.0 Total Variance		4131
11.0	Job Distributable Costs					
	All Costs	8000		Increase is Directly Related to Increase in Project Field Labor Force Requirements	10000	2000
	Engineering & Owner's Costs	22501		No Change		0
	Contingency	24751		Increase is Directly Related to Increase in Project Costs	33863	9112
	Interest During Construction	53091		Increase is Directly Related to Increase in Total Project Costs	72637	19546

The reason for the large difference in cost can be explained with the help of the following table which compares the comparative gross power outputs for the two cycles:

	PFB/GT/WHSG		PFB/AFB (Base)	
	Total Output	No. of Units	Total Output	No. of Units
Gas Turbine/Generators	397.9 MW	6	127.2 MW	2
Steam Turbine/Generators	212.0 MW	3	465.7 MW	1

Since the gas turbines being used are the largest available to date, the only way to triple the total contribution of the gas turbines relative to the base as indicated is to triple the number of gas turbines. Due to allowable stress limitations, the combustor design considered in this study (i.e. 21 ft dia and 69 ft length) cannot be made very much larger. Therefore, identical PFB combustors and associated cyclones have been used for each plant, meaning that the PFB/GT/WHSG plants have three times the number relative to the base case. Thus, as shown on Table W-11, the costs for these items (accounts 3.0 and 4.0) are about three times higher than base. On the other hand, the cost of the steam plant (accounts 6.0 and 7.0) does not decrease in proportion to the decrease in output. This is due in part to the fact that the PFB/GT/WHSG plant must utilize a low pressure/low temperature steam cycle compared to the base case (600 psig/750 F versus 2400 psig/1000 F) which necessitates the use of multiple steam turbine/generators in order to achieve the 212.0 MW output (three have been used in this design). Therefore, while the output has been decreased by a factor of 2.2, the combined cost of the steam turbine/generator and boiler plants only decreases by a factor of 1.5.

For the foregoing reasons, Table W-11 shows that the $116,788,000 increase in direct capital cost for the PFB/Gas turbine Systems (accounts 3.0 and 4.0) is only partly offset by the $30,828,000 reduction in the combined Boiler Plant and Steam Turbine Generator (accounts 6.0 and 7.0) cost. The result is a net increase of $85,960,000 for the PFB/GT/WHSG relative to the base case. In addition, the increased modularization of the PFB/GT/WHSG plant results in increased electrical system and instrumentation/control system (accounts 8.0 and 10.0) costs of $8,470,000 relative to the base case. All other variations are relatively small. As indicated on Table W-11, after contingency and interest during construction are factored in, the net result of these changes is that the capital cost of the PFB/GT/WHSG plant is $124,734,000 or $195/kW higher than the PFB/AFB plant studied in Subtask 1.2.

As indicated above, a large portion of the increase in relative cost of the PFB/GT/WHSG plant is attributable to the fact that the PFB combustors and gas turbines were not scaled up in size to achieve the increase in capacity required. It is conceivable that the allowable stress limitations that constrained the size of the combustors used in this study would not apply to other designs. Assume that the size of the PFB combustors used in Subtask 1.2 and associated cyclones could be scaled up such that their capacity is increased by a factor of two. This would permit the use of one PFB per gas turbine instead of two as used in this design. Further, assume that the cost of each larger combustor and associated cyclone and piping systems (account 4.0) would increase by the factor $2^{0.6}$. Then, the cost of the PFB combustor systems for the

PFB/GT/WHSG cycle would decrease to $87,000,000 and the same cost for the PFB/AFB base case would also decrease to $29,000,000. Therefore, the difference in costs (or variance) between the two systems would be $58,000,000 which is $18,000,000 less than the value shown on Table W-11. Allowing for a $2,000,000 decrease in the relative costs of the electrical and I&C systems, the total decrease in direct capital cost for the PFB/GT/WHSG system relative to the PFB/AFB system would be $20,000,000. After factoring in contingency and interest during construction, the total reduction in capital cost of the PFB/GT/WHSG system relative to the base case would be $26,000,000 or $44/kW. Thus, even if the PFB combustor systems could be sealed up in capacity by a factor of two, it is still expected that the PFB/AFB plant capital cost would be about $150/kW less than that of the PFB/GT/WHSG plant.

5.4.2 Cost of Electricity (COE)

As indicated earlier, the COE for the PFB/GT/WHSG plant is 34.55 mills/kWh which is 21% more than the 28.47 mills/kWh obtained for the PFB/AFB cycle studied in Subtask 1.2. The 6 mill/kWh increase is due almost entirely to the higher Fixed Charges of the PFB/GT/WHSG plant. Difference in coal and sorbent costs due to variations in plant performance are relatively insignificant.

6.0 REFERENCES

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EVALUATION OF A PRESSURIZED-FLUIDIZED BED COMBUSTION (PFBC) COMBINED CYCLE POWER PLANT CONCEPTUAL DESIGN

Final Report
PFB/Gas Turbine/Power Turbine Reheat Cycle Study
Subtask 1.9

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ABSTRACT

In June 1976, the U.S. Department of Energy (DOE) awarded a contract to an industry team consisting of Burns and Roe Industrial Services Corp. (BRISC), United Technologies Corp. (UTC), and the Babcock & Wilcox Company (B&W) for an "Evaluation of a Pressurized, Fluidized Bed Combustion (PFBC) Combined Cycle Power Plant Design".

The results of this program indicate that pressurized fluidized-bed combustion systems, operating in a combined-cycle power plant, offer great potential for producing electrical energy from high sulfur coal within environmental constraints and at a cost less than conventional power plants utilizing low sulfur coal or flue gas desulfurization (FGD) equipment.

As a result of various trade-off studies, a 600 MWe combined cycle arrangement, incorporating a PFB combustor and supplementary firing of the gas turbine exhaust in an atmospheric fluidized bed (AFB) steam generator, has been selected for detailed evaluation.

The overall program consists of the following subtasks:

1.1 - Commercial Plant Requirements Definition

1.2 - Commercial Plant Design Definition

1.3 - System Analysis and Trade-Off Studies

1.4 - Reliability and Maintainability Evaluation with Advanced Technology Assessment

1.5 - Environmental Analysis

1.6 - Economic Analysis

1.7 - Evaluation of Alternate Plant Approaches

1.8 - PFB/Gas Turbine/Waste Heat Steam Generator Cycle Study

1.9 - PFB/Gas Turbine/Power Turbine Reheat Cycle Study

This report discusses the results of studies performed under Subtask 1.9.

REPORT ON SUBTASK 1.9

PFB/GAS TURBINE/POWER TURBINE REHEAT CYCLE STUDY

EVALUATION OF A PRESSURIZED-FLUIDIZED BED COMBUSTION

(PFBC)

COMBINED CYCLE POWER PLANT

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1.0 SUMMARY

On the basis of studies performed under Subtask 1.3 (Trade-Off Studies) of this contract, the Department of Energy (DOE) has authorized an extension to the scope of work to cover additional studies of a PFB/Gas Turbine (G.T.)/Power Turbine Reheat (RH) Combined Cycle. These studies have been performed under Subtask 1.9 of the extended contract and are described in this report.

1.1 Objective and Scope of Work

The primary emphasis for the PFB/GT/RH studies under Subtask 1.9 has been placed upon the conceptual design of the 16 atmosphere main PFB combustors and the 2-1/2 atmosphere reheat PFB combustors and particulate removal equipment. Order of magnitude cost estimates have also been developed for the PFB/GT/RH plant and compared to the PFB/AFB combined cycle plant developed under Subtask 1.2 (Commerical Plant Design).

In addition, the scope of work has included cycle optimization studies and development of a plant conceptual design. Areas of required technology development have also been identified.

1.2 Selection of Cycle

A PFB/Gas Turbine (GT)/Power Turbine Reheat (RH) cycle using a high pressure PFB for initial heating of the working fluid and a moderate pressure PFB for reheating the working fluid has been selected for study in Subtask 1.9. The PFB/GT/RH cycle has been briefly investigated in Subtask 1.3 and identified as having higher efficiency and potentially equal or lower specific cost than the PFB/AFB cycle selected for study in Subtask 1.2. On the basis of studies performed under Subtask 1.3 (Trade-Off Studies), the Department of Energy (DOE) has authorized an extension to the scope of work to permit a more detailed analysis of this cycle under Subtask 1.9.

The nominal power plant capacity of 600 MWe has been chosen to provide a direct comparison to the PFB/AFB Combined Cycle commerical plant concept developed under Subtask 1.2.

An an alternative to the PFB/AFB configuration, the PFB/GT/RH system utilizes a PFB as the main combustor, a reheat PFB which combusts coal with the compressor drive turbine exhaust flow prior to expansion in the power turbine, and a WHSG to generate steam. The main combustor operates at the compressor exit pressure (10 to 16 atmospheres), and the reheat fluidized bed operates at the compressor drive turbine exhaust pressure of (2 to 3 atmospheres). The exit temperature leaving the reheat turbine is high enough to provide a high efficiency steam cycle.

To select the cycle parameters for the Subtask 1.9 Commercial Plant Design, a cycle study varying overall pressure ratio (OPR) from 10:1 to 18:1 and power turbine reheat temperature from 1400°F to 1500°F has been performed. The results of the cycle study indicate that efficiency is relatively insensitive to OPR, therefore a 16:1 pressure ratio gas turbine has been selected to provide a relatively high pressure for the reheat PFB. A reheat temperature of 1500°F has been selected since this temperature level provides the highest power output and efficiency for the gas turbine reheat configuration consistent with gas turbine design limits.

The effect of reheat bed pressure loss has also been evaluated in the cycle selection process in order to provide data for use during the combustor design phase when trade-off between plant performance, vessel size, and number of vessels had to be evaluated. Table B-2 presents a performance comparison for several power turbine reheat cases where the pressure loss in the reheat fluid bed (RFB) is varied.

1.3 Plant Configuration and Performance Estimates

The coal and dolomite analyses used as the basis for all performance and plant design calculations are the same as used in Subtask 1.2 and are not repeated herein. The fuel is an average Illinois Basin bituminous coal with an "as fired" HHV of 12453 Btu/lb and a sulfur content of 3.43%.

The overall layout of the main systems is shown on the Area Site Plan, Figure F-1. The flow of main process fluids through the system is shown on Process Flow Diagram, Figure F-2.

The PFB/GT/Power Turbine Reheat (PFB/GT/RH) cycle contains four (4) gas turbine-compressor (gas generator) sets and four (4) gas turbine-generator (power turbine) sets. Each gas generator is supplied with hot gas by 2 main PFB (16 atm.) combustors. Each gas generator set exhausts into two (2) reheat PFB (RHPFB) combustors which in turn exhaust into one (1) power turbine set. Each power turbine exhausts into an individual waste heat steam generator (WHSG). In the WHSG, steam is produced at three (3) pressure levels. High pressure steam from all WHSG's is collected in a header and routed to the throttle of a single high pressure (HP) steam turbine/generator set. Steam generated at the intermediate pressure (IP) is combined with the HP turbine exhaust flow and routed to a steam reheater. From the reheater, the IP steam is routed to the inlet of the low pressure turbine. Steam generated at the lowest pressure (LP) level in the WHSG is used in the deaerating feedwater heater. The steam turbine is a single shaft condensing unit. Steam is extracted from the low pressure section and used for the steam turbines driving the high pressure boiler feed pumps. One stack takes exhaust gases from two (2) waste heat steam generators. Thus, there are two (2) stacks in the plant.

The gas turbine subsystem incorporates several changes relative to the Subtask 1.2 PFB/AFB cycle. The higher pressure ratio of 16:1 from the gas turbine necessitates using a compressor with several variable stages or a dual spool gas generator design. Reheating between turbine stages favors using a free power turbine.

The reheat cycle also requires ducting from the exit of the compressor drive turbine to the combustors and ducting of the hot air to the entry of the power turbine.

A set of two aerodyne cyclones in series is located at the outlet of each of the 8 main PFB combustors. In addition, three sets of two cyclones in series are provided at the outlet of each of the 8 reheat combustors. Thus, the PFB/GT/RH plant contains a total of 16 PFB combustors (Main and Reheat) and 64 individual cyclone units with accompanying pressurized coal, sorbent, and solid waste handling systems. The added complexity of this system relative to the 8 PFB's and 16 cyclones of the PFB/AFB plant is reflected in the costs to be discussed later.

In the main PFB combustors, coal is burned to heat the compressor discharge air to approximately 1600°F for use in the compressor drive turbine where the gas is expanded and exhausted to the Reheat PFB (RHPFB).

In the RHPFB a portion of the gas is combusted to 1650°F and the remaining gas is heated in tubes immersed in the bed much the same as was done in the main PFB. Due to power turbine design limitations, the gas temperature exiting the tubes is substantially reduced, and the mixed gas temperature entering the power turbine is 1500°F. This temperature is 543°F higher than would enter the power turbine without reheat resulting in increased power output and improved efficiency. Also since the gas temperature exiting the power turbine is high enough to raise high quality steam, supplementary firing in the gas turbine exhaust is not used.

An OPR of 16:1 is utilized as discussed earlier.

The steam cycle (2400 psig throttle pressure) has been changed slightly from the steam system used in the Subtask 1.2 cycle. Steam superheat and reheat temperatures have been lowered from 1000°F to 950°F to facilitate boiler design, and an intermediate pressure boiler is used to generate 584 psig steam. This steam is mixed with the high pressure turbine exhaust steam prior to being reheated to 950°F (See Figure B-1). The final steam turbine exhaust pressure is 2" Hg.

In Table B-9, selected performance parameters for the PFB/GT/RH plant are compared against those of the PFB/AFB plant proposed in Subtask 1.2 (Commercial Plant Design). The 37.9% net efficiency of the PFB/AFB plant is significantly lower than the corresponding 40.9% efficiency of the PFB/GT/RH plant. The effect of this difference on overall cost of electricity is indicated later in this report. The net power outputs are 603.4 MWe for the PFB/GT/RH plant and 574.2MWe for the PFB/AFB plant.

1.4 Environmental Evaluation

The PFB/GT/RH plant described herein has been designed to meet the present environmental air pollution standards. The following federal New Source Performance Standards (NSPS) are currently applicable to a power plant and have been used as the design basis in this study:

Air Pollutant	Maximum Emissions
1. Particulate Matter	0.1 lb/10^6 Btu input

2. SO_2	1.2 $lb/10^6$ Btu input
3. NO_x	0.7 $lb/10^6$ Btu input

The anticipated new EPA limits on the pollutants for coal fired stations are:

Air Pollutant	Maximum Emissions
1. Particulate Matter	0.03 $lb/10^6$ Btu input
2. SO_2	1.2 $lb/10^6$ Btu input; Minimum Sulfur removal of 90% required unless emissions are below 0.2 $lb/10^6$ Btu.
3. NO_x	0.6 $lb/10^6$ Btu input

With the exception of the particulate emission, the new standards are not expected to significantly affect the design or cost of either the PFB/AFB base plant or the PFB/GT/WHSG plant. The reasons for the minimal impact of the new NO_x and SO_2 standards are indicated in the Subtask 1.2 Report (Commercial Plant Design).

The PFB/GT/RH plant has been designed to meet the current EPA requirements for emission of particulates. It is estimated that the particulates emission from the plant will be about 0.1 $lb/10^6$ Btu. It should be noted, however, that the uncertainty associated with this prediction is quite high. It is very sensitive to assumptions concerning the quantity and size distribution of particulates leaving the PFB combustors and to the performance capability of the cyclones themselves. Even a relatively minor change to any of these factors could result in the need for a final collection device (precipitator or baghouse) prior to the stack, and/or use of a more efficient pressurized hot gas cleanup system. Since no such provision is included in this design, the cost would be increased significantly. On the other hand, a precipitator has already been included in the design and cost estimates for the base PFB/AFB plant. Therefore, the cost for that plant is much less sensitive to these assumptions. The same comments apply when evaluating the impact of the anticipated new EPA limit of .03 $lb/10^6$ Btu on plant costs. It is highly probable that in order to reduce the emission to the level of 0.03 $lb/10^6$ Btu as per the anticipated future requirements, one of the changes discussed earlier would be required in the PFB/GT/RH plant. As indicated above, the effect of these changes on the estimated cost of the plant would be significant. However, no attempt has been made to estimate the overall cost impact of the new standards on the PFB/GT/RH concept. Since a precipitator has already been included in the base PFB/AFB plant, the impact of the new EPA standards on its design and cost would be much less significant.

Section 3.3.3 of the Report on Subtask 1.8 (PFB/Gas Turbine/ Waste Heat Steam Generator Cycle Study) defines the current EPA liquid and thermal effluent standards that have been used as a design basis for the PFB/GT/RH plant. These are the same as those used in Subtask 1.2.

1.5 Raw Material Data

The specifications for all raw materials (coal, sorbent, etc.) used in this study are identical to those used for corresponding materials in the Subtask 1.2 study and in the Subtask 1.8 study, and they are not repeated in this report.

1.6 Site Description

The same "Middletown, U.S.A." site used in Subtask 1.2 has been used in this study. Refer to Page 41 of the Report on Subtask 1.2 (Commercial Plant Design) for a detailed site description.

1.7 Major Mechanical Systems And Equipment Descriptions

1.7.1 Main PFB Combustors (16 Atmospheres)

The Main Pressurized Fluid Bed (PFB) System consists of the main PFB combustors (16 atm.) and their accessories. The system design is based on the use of two main PFB combustors for each gas turbine.

The intent of this subtask is to investigate the design of the PFB combustors required for the gas turbine reheat cycle. However, since the only significant difference between the 16 atmosphere combustor and the Subtask 1.2 combustor (10 atm.) is operating pressure, only an abbreviated description of the 16 atmosphere PFB system is included in this report.

The main PFB combustor design is based on the split air flow concept; the concept is shown schematically in Figure H-1. The fuel fired in the bed is used only to heat the compressor discharge air to the turbine inlet temperature. This concept provides advantages which are detailed in section 4.3.1.1.

The combustor design parameters are based on the reported work of various organizations involved in PFB research. These values are listed below:

Bed Temperature	1650F
Excess Air	60%
Superficial Velocity	<3 fps
Coal feed size	-8 mesh
Sorbent feed size	-10 mesh
Combustion efficiency	99%
Calcium/Sulfur Molar Feed Ratio	1.0
Sulfur Capture	~80% (1.2 lb $SO^2/10^6$ Btu)

Only the excess air is different from the value used in Subtask 1.2. The increase in bed excess air is a consequence of the fact that, at the higher operating pressure (16 Atm. vs. 10 Atm.), the vessel diameter required to contain the bed cooling surface is larger than that required to achieve the desired superficial velocity. Therefore, more air is passed through the bed to raise the velocity thereby increasing the excess air.

The arrangement of the PFB Combustors is shown on the following B&W drawings:

254235E Arrgt. 16 Atm. PFB Combustor - Front View (Fig. H-2)
254236E Arrgt. 16 Atm. PFB Combustor - Side View (Fig. H-3)
254237E Arrgt. 16 Atm. PFB Combustor - Plan Sections, 1 of 2, (Fig. H-4)
254238E Arrgt. 16 Atm. PFB Combustor - Plan Sections, 2 of 2, (Fig. H-5)

The PFB Combustor is a refractory lined pressure vessel with an outside diameter of 19' and a length of 72'-11". The vessel is mounted in the vertical position and is supported from structural steel by support rings which are positioned near the mid-point of the length. The vessel design is based on the use of SA516 GR 70 carbon steel; the wall thickness is 3".

The vessel is internally lined with insulating refractory to limit the surface temperature of the combustor to 250F based on an ambient air temperature of 80F.

The distributor plate utilizes bubble caps to provide uniform fluidization and, yet, prevent the bed solids from sifting back into the air inlet plenum. The distributor plate is also refractory covered to achieve an acceptable operating temperature. The bed cooling tubes are arranged in a U-tube configuration between the inlet and outlet headers. The U-tube arrangement was chosen to accommodate the differential expansion along the tube length as the air is heated from 752F to 1576F. Both the tubes and the headers are made of Alloy 800H material.

1.7.2 Reheat PFB Combustors (2-1/2 Atmospheres)

The reheat pressurized fluidized bed (PFB) system consists of the reheat PFB (RHPFB) combustors and their accessories. The system design is based on the use of two reheat combustors for each gas turbine.

Combustion efficiency, heat transfer, and sulfur capture efficiency in the PFB combustor are functions of bed temperature, fluidizing velocity, and solids feed size. The numerical values for the parameters used in the design of the reheat PFB combustor are based on the reported work of various organizations involved in PFB research.

The RHPFB combustor design is based on the split air flow concept; the concept is shown schematically in Figure H-6. The fuel fired in the bed is used only to heat the gas generator discharge air to the required power turbine inlet temperature; no additional coal is fired for steam generation within the PFB combustor. In the split air flow concept approximately 16% of gas generator discharge air flow is used for combustion and fluidizing air; the remaining 84% of the air flow is routed to a bed cooling system.

The initial design concept consisted of a vertical combustor having an internal arrangement similar to that of the PFB combustor design of Subtask 1.2. The bed depth required to submerge the tubes with this type of arrangement results in a relatively high pressure loss which was judged unsatisfactory from the cycle efficiency viewpoint. Consequently, a study was undertaken to find an arrangement that would produce a shallower bed and a higher pressure at the power turbine inlet. The arrangement that has finally been selected consists of four bed modules placed inside a horizontal combustor vessel. Each bed module is composed of straight horizontal tubes connecting an inlet header to an outlet header (see Figure H-7).

Manufacturing capabilities, shipping restrictions, and structural considerations limited the diameter of the combustor vessel resulting in the use of two reheat combustors for each gas turbine. Each combustor is a refractory lined pressure vessel having an outside diameter of 28'-4" and an overall length of 55'-2". The vessel is mounted in a horizontal position by means of two support saddles. The general arrangement of the vessel and its internals is shown in Figure H-7.

The arrangements and details of the reheat PFB combustor are shown on the following drawings:

Fig. H-7 Reheat PFB Combustor
Fig. H-8 Arrgt. Reheat PFB Combustor
Fig. H-9 Reheat PFB Combustor Details - Sheet 1
Fig. H-10 Reheat PFB Combustor Details - Sheet 2

Incoloy 800 is used for all combustor internals exposed to hot bed gases and solids. The reason for its selection as the design basis is covered in Section 4.3.1.4 of the Subtask 1.2 Report. SA516 GR 70 carbon steel is used for the pressure vessel itself. The vessel is 2" thick.

Coal and dolomite are fed to the bed through sixty-four (64) coal feed pipes and sixteen (16) dolomite feed pipes which penetrate the lower half of the combustor vessel and pass vertically upward through the lower compartment and distributor plate. The feed pipes are made of SA-310 stainless steel and are welded to the lower half of the combustor vessel. Provisions for differential expansion of components are described in the main body of the report.

1.7.3 Waste Heat Steam Generator (WHSG)

The exhaust gases from the gas turbine pass through a waste heat steam generator (WHSG) which generates steam for the bottoming cycle. No additional fuel is fired in the WHSG.

The WHSG is an established commercial product that has been supplied by the Babcock and Wilcox Company for other combined cycle installations. The boiler is based on standard design concepts that are tailored to suit individual requirements.

1.7.4 Gas Turbine

The gas turbines are generally of the same size as that of Subtask 1.2, but there are several internal and external changes necessary to match the reheat cycle. The selected cycle has a pressure ratio of 16 and an airflow of 840 #/sec. These parameters are consistent with FT50 gas generator design values. For Subtask 1.9, therefore, the FT50 gas generator has been assumed for all mechanical studies.

Ducting for the exhaust gases from the compressor drive turbine (gas generator) to the reheat PFB is located at the exhaust end of the FT50 gas generator. The reheated gas from the PFB can then be ducted to a power turbine similar to the FT50 in design. The power turbine and electric generator are located at different locations for convenience in the general plant layout. The flow area of the turbine would be increased to accommodate the higher volume flow at the higher reheat temperature of 1500F. This increase is not too large in the case of the FT50 because the original turbine design was based on a relatively high turbine inlet temperature.

1.7.5 High Temperature Gas Piping and Valving

Except for smaller diameters (see Fig. J-1), the high temperature refractory lined piping and valving around each configuration of main PFB's (16 atm.), cyclones, and gas generator sets are of the same configuration, and quantity as used in Subtask 1.2. In addition to being refractory lined, certain parts of the valves must be water cooled. See Pages 136-159 of the report on Subtask 1.2 (Commercial Plant Design) for more details. Appropriately sized (see Fig. H-6) refractory lined piping and high temperature valves of the same design as used for the main PFB system are provided for the various streams entering and leaving the reheat combustor. A significant amount of development effort is required to demonstrate commercial feasibility in this area.

1.7.6 Coal and Sorbent Handling and Feed Systems

The coal and sorbent handling and feed systems are of the same general design as used in Subtask 1.2, except that limestone handling is not required and more PFB units must be fed. The changes in system design and configuration are discussed in Section 4.3.6 and 4.3.7.

1.7.7 Particulate Removal Systems

1.7.7.1 Main PFB Particulate Removal System

The gas from each main PFB combustor passes through two stages of high efficiency cyclones for particulate removal to the requirements of the EPA and of the gas turbine. The allowable gas turbine particulate loading is based on the presumption that particles greater than 10 microns in size would give unsatisfactory turbine life, particles less than 2 microns in size would have negligible effects on turbine life and that .01 grain/SCF of particulate in the 2-10 micron size range could be tolerated within the gas turbine. In addition, the total amount of particulate entering the turbine is not to exceed the current EPA emission limit of 0.1 lb/10^6 Btu of fuel input.

Aerodyne Development Corporation's Model 15000SV, which is capable of handling the combustion gas flow from one PFB combustor, is used as the design basis. This design is an extension of the equipment presently used in low temperature, low pressure applications and is actually a two-stage cyclone contained within a single pressure vessel. Based on the projected particulate loading in the combustion gas and the predicted collection efficiency, two of these collectors operating in series are required to achieve the particulate loading level which complies with both the EPA emission limit and the gas turbine requirements.

1.7.7.2 Reheat PFB Particulate Removal System

Aerodyne's Model 18000 SV, is used as the design basis. This design is the same as the 15000 SV except for size. Calculations indicate that three sets of these collectors operating in parallel would be required for each Reheat PFB combustor. Each set would consist of two (2) Model 18000 Dust Collectors operating in series. The dust loading entering the gas turbine in the critical 2 to 10 micron size range is projected to be 36% of the gas turbine allowable level the total loading is virtually equal to the current EPA emission limit of 0.1 lb/10^6 Btu (when particles under 2 microns are considered).

It must be remembered that the performance of the particulate removal system is based on both the prediction of the equipment performance and assumptions regarding the particulate sizing. The indicated performance represents better than 99% particulate removal. Seemingly small changes in either predicted collection efficiency or in the assumed particulate size distribution leaving the PFB's result in significant changes in both the particulate concentration entering the gas turbines and the plant emissions per unit of heat input. This portion of the system design therefore contains one of the greater degrees of uncertainty.

In the case of the particulate concentration, another degree of uncertainty exists; namely the turbine tolerance. It is possible that the turbine may be more tolerable to particulate loading then assumed thereby lessening that degree of uncertainty.

The particulate emission per unit of fuel input is however an absolute limit that is expected to become more stringent with time. Due to the uncertainty involved in the predictions, it is possible that additional controls will be required in the plant to meet the present limit of 0.1 lb/10^6 Btu and highly probable that they would be required for the anticipated limit of 0.03 lb/10^6 Btu. The additional controls may be either in the form of more sophisticated equipment (granular bed filters, etc.) following the PFB combustors, or, if the particulate loading is acceptable for the gas turbine, some type of stack clean-up equipment such as a bag house or electrostatic precipitator. Either of these alternatives would result in significantly higher costs for the PFB/GT/RH plant then have been established in this study. However, by comparison, the PFB/AFB plant developed in Subtask 1.2 already includes a final stack clean-up device (an electrostatic precipitator). Therefore, even if the particulate loading entering the gas turbine did exceed the EPA limit for any of the reasons discussed above, the cost of that plant would not be significantly affected. Also, since there are less PFB combustors involved in the PFB/AFB plant, a requirement for more efficient hot gas clean-up equipment to satisfy gas turbine limits would have a much less severe impact on cost relative to the PFB/GT/RH plant.

1.7.8 <u>Solid Waste Handling System</u>

The solid waste handling system for the PFB/GT/RH is basically the same design as used in Subtask 1.2. Changes have been made in the piping and equipment to account for the elimination of the AFB and its associated cyclones, as well as the electrostatic precipitator. The system has also been revised to reflect the increased number of PFB combustors (both main PFB's and RHPFB's) and their associated Aerodyne Cyclones.

1.7.9 Steam Turbine - Generator

The steam turbine is a 3600 rpm single reheat, tandem coupound unit with a four flow exhaust and 30 inch last row blades. An extraction is included to provide steam for the WHSG feed water pump drive turbines.

The generator design is based on 400000 KVA, 0.90 pf, 0.85 SCR (at 60 psig hydrogen pressure), 3 phase, 60 Hz, 24,000 volt, and 3,600 rpm.

1.7.10 Heat Rejection System

The condensers, generator air coolers, turbine oil coolers and closed cooling water heat exchangers reject their heat to the cooling water coming from a mechanical draft cooling tower. The heat rejection system is a closed type circulating water system. The diagram, Figure R-1, shows the general scheme of the circulating water system. River water is used as make-up to compensate for blowdown and evaporation losses. The equipment is designed for full load operation at ISO ambient conditions.

A mechanical draft, double flow induced draft cooling tower is erected above a concrete basin. One end of the concrete basin has sufficient depth to allow for the installation of vertical circulating water pumps.

Two 50% capacity, vertical motor driven circulating water pumps are installed in the wet pit of the tower basin.

River water is used for cooling tower make-up. The river water intake structure and equipment is similar to that used for Subtask 1.2 with the exception of the capacity of the equipment. The equipment is designed to supply the requirements called for on the flow diagram Figure R-1.

1.7.11 Water Treatment Systems

The source of plant make-up feedwater is the city water system. This is available at the northeast corner of the site. A 100,000 gallon storage tank is provided.

The design capacity of the make-up feedwater treatment plant is 150 gpm. Automatic demineralizing skid mounted, water treatment units are used. Two units of 150 gpm capacity each are provided.

Boiler chemical feed systems and a waste water treatment plant are also provided as described in Subsection 4.3.13.

1.8 Cost Estimates for PFB/GT/RH Plant

The estimate is based on the following assumptions: The plant is located in "Middletown," U.S.A., which represents an average U.S.A. geographic location in close proximity to an Eastern Coal Belt. This area lies approximately East of the Mississippi, West of the Appalachian Mountains, South of the Great Lakes, and North of the Gulf of Mexico. All costs in this estimate reflect what is felt to be "average" expected costs for this area of the country.

Estimated costs reflect the theorectical assumptions that a sufficient number of plants of the same type have previously been built, therefore, no "development" cost factors have been included.

All costs represent a mid-1977 price level and do not include escalation.

The total project cost is estimated to be $607,275,000 in mid-1977 dollars. This amounts to a specific capital cost of $1006 per kW capacity net. The direct capital cost is 69.1% of total cost, and IDC accounts for 16.3%. A 10% contingency has been included on all costs except IDC. A summary of the direct and indirect capital costs is shown on Tables W-3 and W-5, respectively.

The fixed charge has been assumed to be 18% of the total project cost. Under the assumed conditions, the total annaul cost of operation is $142,575,000. The annual cost summary is shown in Table W-10.

At 65% capacity factor, the annual energy output is 3,436 x 10^6 kWh. Therefore, the cost of electricity is 41.49 mills/kWh.

1.9 Cost Comparison - PFB/GT/RH Plant versus PFB/AFB Plant

1.9.1 Capital Cost Comparison

A comparison of the capital cost estimates for Subtask 1.9 versus those of 1.2 shows that the PFB/GT/RH plant ($1006/kW) is approximately 77% more costly than the PFB/AFB commercial plant ($567/kW) used as a base. Table W-11 briefly summarizes where the cost differences occur on a main cost account basis. Table W-12 gives a detailed breakdown of the cost differences with a short explanation for each variance.

The hugh difference in capital costs is due to the large number of PFB combustors (with associated cyclones, solids feed systems, and solid waste letdown systems) required for the PFB/GT/RH plant as compared to the PFB/AFB plant (see accounts 3.0 and 4.0 on Table W-11).

1.9.2 COE Comparison

As indicated earlier, the COE for the PFB/GT/RH plant is 41.49 mills/kWh which is 46% more than the 28.47 mills/kWh obtained for the PFB/AFB cycle study in Subtask 1.2. The 13/mill/kWh increase is due almost entirely to the higher Fixed Charges of the PFB/GT/RH plant which result from its higher capital cost. The differences in plant performance have a relatively insignificant impact on COE. The annual costs for coal and sorbent are 0.7 mills/kWh lower in the PFB/GT/RH plant.

1.10 Technology Development Requirements

The technology development requirements for the PFB/GT/RH plant are essentially the same as those defined for the PFB/AFB plant on pages 355 and 356 of the Report on Subtask 1.2 (Commercial Plant Design). In addition, the PFB/GT/RH plant would require the development of a design data base for combustors operating at 2-1/2 atmospheres.

2.0 CONCLUSIONS AND RECOMMENDATIONS

2.1 Conclusions

The following conclusions are drawn from the results of the work performed in the Subtask:

a) For a 600 MWe capacity, the PFB/Gas Turbine (GT) Power Turbine Reheat (RH) plant configuration would have a 75%-80% higher capital cost and a 45%-50% higher cost of electricity than the PFB/AFB combined cycle plant proposed in Subtask 1.2.

b) If the EPA particulate emission limit is reduced to 0.03 lb/10^6 Btu as expected, the PFB/GT/RH plant would require the addition of a final collection stage (baghouse, electrostatic precipitator, etc., prior to the stack, or, the use of more efficient collection devices at the gas turbine inlet. The PFB/AFB plant proposed in Subtask 1.2 already incorporates a final stage collection system (precipitators), and costs required to modify that system to meet the new limit are expected to be relatively insignificant. However, the addition of such a system to the PFB/GT/RH system would raise the cost of that system over that estimated in this study. (Note: The stack gas flow rate in the PFB/GT/RH plant is two times that in the PFB/AFB plant.)

2.2 Recommendations

On the basis of the conclusions drawn in Section 2.1, the PFB/Gas Turbine/Power Turbine Reheat cycle configuration described in this report should not be considered for future plants. A more economical choice would be the PFB/AFB plant described in the report on Subtask 1.2, Commercial Plant Design.

3.0 COMMERCIAL PLANT CRITERIA

3.1 PLANT CAPACITY

The gas turbine reheat cycle configuration (Fig.B-1) contains four (4) gas turbines with each exhausting into an individual waste heat steam generator (WHSG). Steam generated by the gas turbine exhaust heat is expanded through one (1) steam turbine. The nominal power plant size of 600 MWe has been chosen to provide direct comparison to the Subtask 1.2, Commercial Plant.

3.2 SELECTION OF CYCLE

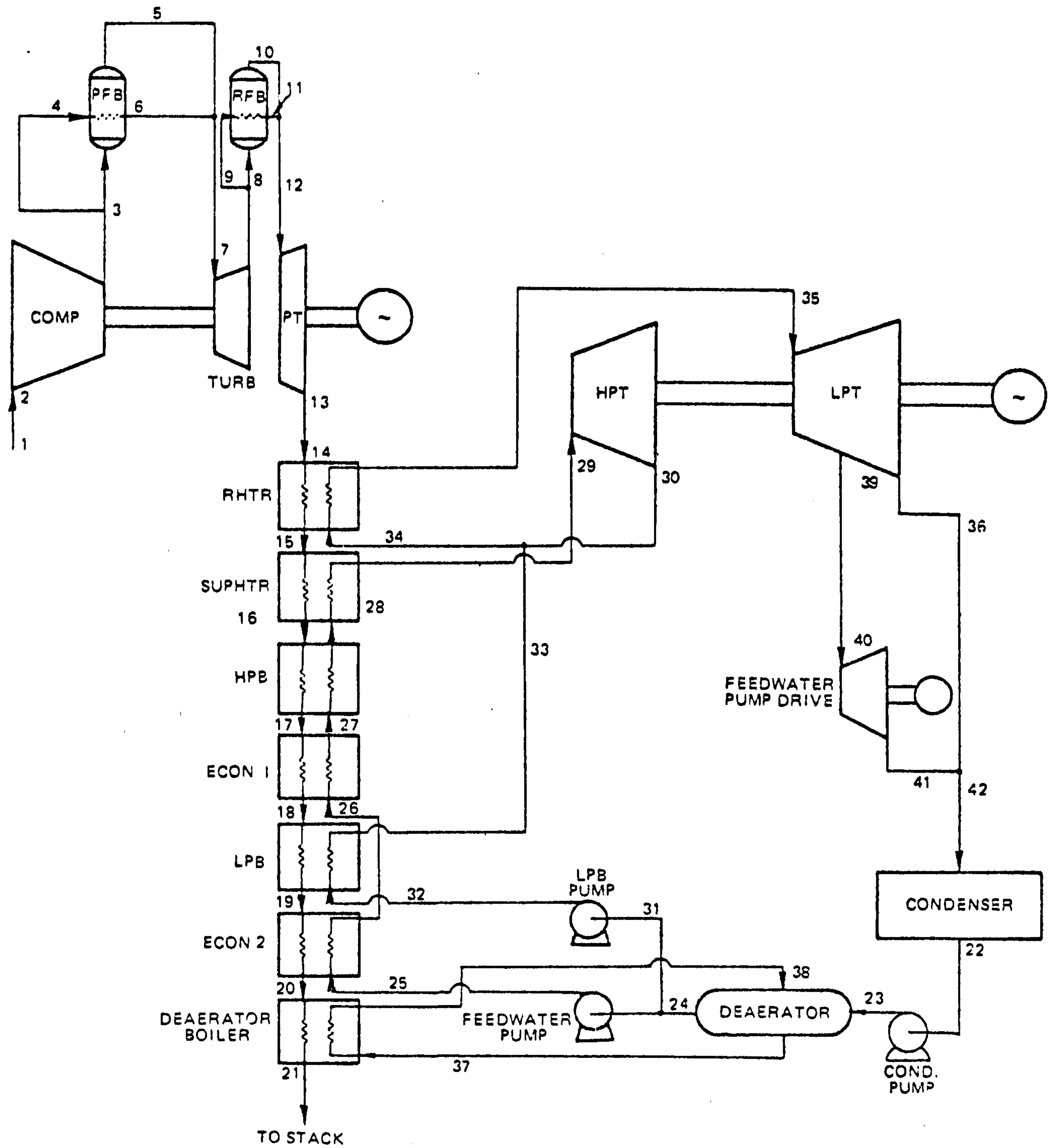
A PFB/Gas Turbine (GT)/Power Turbine Reheat (RH) cycle using a high pressure PFB for initial heating of the working fluid and a moderate pressure PFB for reheating the working fluid has been selected for study in Subtask 1.9. The PFB/GT/RH cycle has been briefly investigated in Subtask 1.3 and identified as having higher efficiency and potentially equal or lower specific cost than the PFB/AFB cycle selected for study in Subtask 1.2. On the basis of studies performed under Subtask 1.3 (Trade-Off Studies), the Department of Energy (DOE) has authorized an extension to the scope of work to permit a more detailed analysis of this cycle under Subtask 1.9.

The system selected as the primary PFB power plant configuration for Subtask 1.2 uses a PFB for combusting coal with the gas turbine compressor discharge air. In addition, a steam cooled atmospheric fluidized bed (AFB) boiler is utilized to burn additional coal with the gas turbine exhaust gas. This supplementary firing permits a high-efficiency steam cycle to be used, thereby increasing the overall efficiency of the power plant.

As an alternative to the PFB/AFB configuration, the PFB/GT/RH system has been selected for study in Subtask 1.9. This system utilizes a PFB as the main combustor, a reheat PFB (RFB) which combusts coal with the compressor drive turbine exhaust flow prior to expansion in the power turbine, and a WHSG to generate steam. The main combustor operates at the compressor exit pressure (10 to 16 atmospheres), and the reheat fluidized bed operates at the compressor drive turbine exhaust pressure (of 2 to 3 atmospheres). The exit temperature leaving the reheat turbine is high enough to provide a high efficiency steam cycle.

Alternatives to the basic reheat system configuration have been considered, but not studied in depth in Subtask 1.9. For example, the reheat could be accomplished in a bed where the combustion takes place at atmospheric pressure. The air cooled bed design would be similar to the AFB semi-closed cycle discussed in Subtask 1.7. Part of the exhaust gas from the free turbine would be used for combustion air in the reheat AFB.

FIG. B-1
GAS TURBINE REHEAT CONFIGURATION



To select the cycle parameters for the Subtask 1.9 Commercial Plant Design, a cycle study varying overall pressure ratio (OPR) from 10:1 to 18:1 and power turbine reheat temperature from 1400°F to 1500°F has been performed. The performance estimates for the various cycle parameters are presented in Table B-1. The overall power plant efficiency is basically independent of the OPR variation due to the power turbine reheat effect. As the reheat temperature is decreased from 1500°F to 1400°F, overall power plant efficiency and power output decrease due to the lower energy level entering the power turbine. The gas turbine exhaust temperature also decreases. Consequently, the steam system will generate less steam and produces less electrical power. The results of the cycle study indicate that efficiency is relatively insensitive to OPR, therefore a 16:1 pressure ratio gas turbine has been selected to provide a relatively high pressure for the reheat PFB. A reheat temperature of 1500°F has been selected since this temperature level provides the highest power output and efficiency for the gas turbine reheat configuration consistent with gas turbine design limits.

The effect of bed pressure loss has also been evaluated in the cycle selection process in order to provide data for use during the combustor design phase when trade-offs between plant performance, vessel size, and number of vessels had to be evaluated. Table B-2 presents a performance comparison for several power turbine reheat cycles where the pressure loss in the reheat fluid bed (RFB) is increased. Detailed heat and mass balances for the base reheat cycle shown in Table B-2 are presented in Table B-3 (air/gas system) and Table B-4 (steam system).

As the pressure loss is increased the gas turbine power output decreases since the expansion ratio across the power turbine is lower. Gas turbine exhaust temperature increases as pressure loss increases since less energy is extracted from the gas stream, and this benefits the steam system. More steam is now generated since the energy level into the steam system is greater, and the steam power output increases with increasing pressure loss. However, the combined effect of decreasing gas turbine power and increasing steam power results in a net overall power decrease and decreasing overall efficiency.

The final pressure losses in the main PFB and RFB have been determined to be 17 psi and 5.8 psi, respectively. These pressure losses have been used in the final gas turbine reheat cycle evaluation calculations described in Section 4.0.

TABLE B-1

PFB GAS TURBINE REHEAT CYCLE STUDY

(per gas turbine)

Power Turbine Inlet Temp. °F	OPR	PWR_{GT} MW	PWR_{PT} MW	Gross PWR_{TOT} MW	Net PWR_{TOT} MW	$\dot{W}$ Coal PFB lb/sec	$\dot{W}$ Coal RFB lb/sec	η_{TOTAL}[1] Gross, %	η_{TOTAL}[2] Net, %	$\dot{W}$ HPF lb/sec	$\dot{W}$ LPB lb/sec	Temp GT Exit °F	Temp RFB Tube Exit °F	$\dot{W}$ RFB Exit lb/sec	$\dot{W}$ RFB Tube Exit lb/sec	Steam Conditions
1500	10	81.9	75.8	157.6	152.7	19.1	8.12	44.1	41.7	108.5	19.0	1166	1474	122.2	732.6	2400 psig/1000F/1000F
	12	83.4	75.0	158.3	153.4	18.0	9.22	44.3	41.9	106.7	19.7	1160	1470	136.6	718.2	
	14	83.5	74.9	158.4	153.4	17.0	10.2	44.2	41.8	106.6	19.7	1160	1466	149.0	705.8	
	16	82.6	75.4	158.0	153.0	16.1	11.1	44.1	41.7	107.7	19.3	1164	1463	159.9	694.9	
	18	80.9	76.4	157.2	152.3	15.3	11.9	43.9	41.5	109.8	18.5	1171	1461	169.6	685.1	
1450	10	79.7	69.8	149.5	144.8	19.1	7.05	43.5	41.1	95.5	23.9	1123	1420	106.2	747.7	
	12	81.2	69.0	150.2	145.4	18.0	8.16	43.7	41.3	93.8	24.6	1117	1415	120.8	733.1	
	14	81.2	69.0	150.2	145.4	17.0	9.14	43.7	41.3	93.7	24.6	1117	1411	133.4	720.5	
	16	80.4	69.5	149.9	145.1	16.1	10.0	43.6	41.0	94.8	24.2	1120	1407	144.5	709.4	
	18	78.7	70.4	149.1	144.4	15.3	10.8	43.3	40.9	96.8	23.4	1127	1403	154.5	699.4	
1400	10	77.5	63.6	141.1	136.7	19.1	6.0	42.8	40.5	85.2	27.8	1080	1369	90.2	762.7	2400 psig/975F/975F
	12	78.9	62.8	141.8	137.3	18.0	7.10	43.0	40.7	83.4	28.5	1074	1363	105.1	747.9	
	14	79.0	62.8	141.8	137.4	17.0	8.08	43.0	40.7	83.3	28.5	1074	1357	118.0	735.0	
	16	78.2	63.3	141.5	137.0	16.1	9.00	42.8	40.5	84.4	28.1	1077	1352	129.3	723.7	
	18	76.5	64.2	140.7	136.3	15.3	9.78	42.6	40.3	86.4	27.3	1084	1348	139.4	713.6	

(1) Based on 'As Fired' coal rate (HHV = 12453 Btu/lb) and no auxiliary power or heat losses.

(2) Based on 'As Received' coal rate (HHV = 11472 Btu/lb), 3.14% auxiliary power loss and 1% miscellaneous pipe loss.

NOTE: 'As Received' coal rate is ~10% greater than 'As Fired' coal rate.

TABLE B-2

PFB POWER TURBINE REHEAT CYCLE PERFORMANCE ESTIMATES
RFB PRESSURE LOSS EFFECTS

(Four Gas Trubines)

	BASE ΔP = 4 psi	ΔP_{RFB} = 7 psi	ΔP_{RFB} = 10 psi
PWR_{GT}, MWe	330.4	298.9	263.9
PWR_{ST}, MWe	306.1	320.6	339.4
Gross PWR_{TOTAL}, MWe	636.5	619.5	603.3
Net PWR_{TOTAL}, MWe	616.5	600.0	584.4
Gross $\eta^{(1)}_{TOTAL}$, %	44.5	43.3	42.2
Net $\eta^{(2)}_{TOTAL}$, %	41.1	40.0	39.0
PFB Coal Rate (as Fired), lb/sec	64.6	64.6	64.6
RFB Coal Rate (as Fired), lb/sec	44.3	44.3	44.3
TOTAL Coal Rate (As Fired), lb/sec	108.9	108.9	108.9
TOTAL Coal Rate (As Received), lb/sec	123.8	123.8	123.8
T_{T} exhaust, ^{o}F	703.6	735.6	771.1

(1) Based on "As Fired" coal rate (HHV = 12453 Btu/lb) and no auxiliary power or heat losses.

(2) Based on "As Received" coal rate (HHV = 11472 Btu/lb), 3.14% auxiliary power losses, and 3.33% miscellaneous heat losses.

TABLE B-3

BASE GAS TURBINE REHEAT CYCLE

Heat and Mass Balance for Air/Gas System

Description	W,[1] lb/sec	T, F	P, psia	H, Btu/lb
Gas Turbine Inlet	840.0	59.0	14.70	124.0
Compressor Inlet	840.0	59.0	14.55	124.0
PFB Combustor Inlet	175.9	754.2	232.8	294.9
PFB Cooling Tube Inlet	634.9	754.2	232.8	294.9
PFB Combustor Exit	189.6	1650.0	209.5	555.3
PFB Cooling Tube Exit	634.9	1575.0	209.5	514.4
Turbine Inlet	824.5	1593.2	209.5	523.8
RFB Combustor Inlet	150.4	956.7	39.7	349.0
RFB Cooling Tube Inlet	694.9	956.7	39.7	349.0
RFB Combustor Exit	159.9	1650.0	35.7	555.9
RFB Cooling Tube Exit	694.9	1463.3	35.7	487.2
PT Inlet	854.8	1500.0	35.7	500.0
PT Exit	854.8	1163.6	14.69	406.2
Reheater Inlet	858.9	1160.6	14.33	405.4
Superheater Inlet	858.9	1041.6	14.33	373.0
HPB Inlet	858.9	880.7	14.33	330.0
2nd Economizer Inlet	858.9	712.6	14.33	285.9
LPB Inlet	858.9	587.9	14.33	253.9
1st Economizer Inlet	858.9	508.3	14.33	233.8
Feedwater Heater Inlet	858.9	380.3	14.33	201.8
Feedwater Heater Exit	858.9	290.8	14.33	179.7
Stack	858.9	298.1	14.70	181.5

---

(1) Multiply flows by 4 to obtain total plant flows.

TABLE B-4

BASE GAS TURBINE REHEAT CYCLE

Heat and Mass Balance for Steam System

Description	W,(1) lb/sec	T, F	P, psia	H, Btu/lb
Condensate Pump Inlet	127.9	101.1	.982	69.1
Feedwater Heater Inlet	127.9	101.1	106.7	69.5
Feedwater Pump Inlet	127.9	250.3	30.0	218.9
1st Economizer Inlet	127.9	254.9	2765.0	229.4
2nd Economizer Inlet	105.5	463.3	2665.0	445.4
LPB Inlet	22.4	463.3	584.0	445.4
LPB Exit	22.4	483.3	584.0	1203.2
HPB Inlet	105.5	657.6	2665.0	709.1
Superheater Inlet	105.5	677.6	2515.0	1011.8
HPT Inlet	105.5	950.0	2415.0	1460.6
HPT Exit	105.5	596.2	584.0	1315.8
Reheater Inlet	127.9	573.0	584.0	1293.4
LPT Inlet	127.9	950.0	525.6	1519.7
Feedwater Pump Drive Extraction	123.3	683.0	175.0	1389.2
Feedwater Pump Drive Inlet	4.6	683.0	166.3	1389.2
Feedwater Pump Drive Exit	4.6	108.7	1.23	1092.0
Condenser Inlet	127.9	101.1	.982	1024.7

---

(1) Multiply flows by 4 to obtain total plant flows.

3.3 ENVIRONMENTAL STANDARDS

The PFB/GT/RH plant described herein has been designed to meet the present environmental air pollution standards. In order to meet the anticipated future federal environmental regulations, changes will be required in the particulate collection system. The following federal New Source Performance Standards (NSPS) are currently applicable to a power plant and have been used as the design basis in this study:

Air Pollutant	Maximum Emissions
1. Particulate Matter	0.1 lb/10^6 Btu input
2. SO_2	1.2 lb/10^6 Btu input
3. NO_x	0.7 lb/10^6 Btu input

The anticipated new EPA limits on the pollutants for coal fired stations are:

Air Pollutant	Maximum Emissions
1. Particulate Matter	0.03 lb/10^6 Btu input
2. SO_2	1.2 lb/10^6 Btu input; Minimum Sulfur removal of 90% required unless emissions are below 0.2 lb/10^6 Btu.
3. NO_x	0.6 lb/10^6 Btu input

With the exception of the particulate emission, the new standards are not expected to significantly affect the design or cost of either the PFB/AFB base plant or the PFB/GT/WHSG plant. The reasons for the minimal impact of the new NO_x and SO_2 standards are indicated in the Subtask 1.2 Report (Commercial Plant Design).

The PFB/GT/RH plant has been designed to meet the current EPA requirements for emission of particulates. It is estimated that the particulates emission from the plant will be about 0.1 lb/10^6 Btu. It should be noted, however, that the uncertainty associated with this prediction is quite high. It is very sensitive to assumptions concerning the quantity and size distribution of particulates leaving the PFB combustors and to the performance capability of the cyclones themselves. Even a relatively minor change to any of these factors could result in the need for a final collection device (precipitator or baghouse) prior to the stack and/or a more efficient pressurized hot gas clean-up system. Since no such provision is included in this design, the cost would be increased significantly. On the other hand, a precipitator has already been included in the design and cost estimates for the base PFB/AFB plant. Therefore, the cost is much less sensitive to these assumptions.

In order to reduce the emission to the level of 0.03 $lb/10^6$ Btu as per the anticipated future requirements, a final dust collection device would be required in the PFB/GT/RH plant between the gas turbine exhaust and the stack in addition to those provided at the gas turbine inlets. As indicated above, the effect of these changes on the estimated cost of the plant would be significant. However, no attempt has been made to estimate the overall cost impact of the new standards on the PFB/GT/RH concept. As indicated above, since a precipitator has already been included in the base PFB/AFB plant, the impact of the new EPA standards on its design and cost would be much less significant.

Section 3.3.3 of the Report on Subtask 1.8 (PFB/Gas Turbine/ Waste Heat Steam Generator Cycle Study) defines the current EPA liquid and thermal effluent standards that have been used as a design basis for the PFB/GT/RH plant. These are the same as those used in Subtask 1.2.

3.4 RAW MATERIAL DATA

The specifications for all raw materials (coal, sorbent, etc.) used in this study are identical to those used for corresponding materials in the Subtask 1.2 study and in the Subtask 1.8 study, and they will not be repeated in this report.

3.5 SITE DESCRIPTION

The same "Middletown, U.S.A." site used in Subtask 1.2 has been used in this study. Refer to Page 41 of the Report on Subtask 1.2 (Commercial Plant Design) for a detailed site description.

4.0 COMMERCIAL PLANT DESIGN

4.1 PLANT CONFIGURATION

The overall layout of the main systems is shown on the Area Site Plan, Figure F-1. The flow of main process fluids through the system is shown on Process Flow Diagram, Figure F-2.

The PFB/GT/Power Turbine Reheat (PFB/GT/RH) cycle contains four (4) gas turbine-compressor (gas generator) sets and four (4) gas turbine-generator (power turbine) sets. Each gas generator set exhausts into two (2) reheat PFB (RHPFB) combustors which in turn exhaust into one (1) power turbine set. Each power turbine exhausts into an individual waste heat steam generator (WHSG). In the WHSG, steam is produced at three (3) pressure levels. High pressure steam from all WHSG's is collected in a header and routed to the throttle of a single high pressure (HP) steam turbine/generator set. Steam generated at the intermediate pressure (IP) is combined with the HP turbine exhaust flow and routed to a steam reheater. From the reheater, the IP steam is routed to the inlet of the low pressure turbine. Steam generated at the lowest pressure (LP) level in the WHSG is used in the deaerating feedwater heater. The steam turbine is a single shaft condensing unit. Steam is extracted from the low pressure section and used for the steam turbines driving the high pressure boiler feed pumps. One stack takes exhaust gases from two (2) waste heat steam generators. Thus, there are two (2) stacks in the plant.

The gas turbine subsystem incorporates several changes relative to the Subtask 1.2 PFB/AFB cycle. The higher pressure ratio of 16:1 from the gas turbine necessitates using a compressor with several variable stages or a dual spool gas generator design. Reheating between turbine stages favors using a free power turbine. The increased temperature into the free turbine necessitates a larger gas flow annular area (longer blades) and upgrading of material requirements. In the largest sizes, a double flow free turbine might be used.

The reheat cycle also requires ducting from the exit of the compressor drive turbine to the combustors and ducting of the hot air to the entry of the power turbine.

4.2 PERFORMANCE

The performance discussed below has been calculated using parameters selected after the parametric studies discussed in Section 3.2 were completed.

4.2.1 Full Load Plant Output and Efficiency-Commercial Plant

Each gas turbine selected for the PFB/GT/RH cycle is an axial-flow, dual-spool machine having a flow rate of 840 lb/sec and an overall pressure ratio of 16:1. Two air cooled main PFB's are required for each gas turbine. These heat part of the compressor discharge air

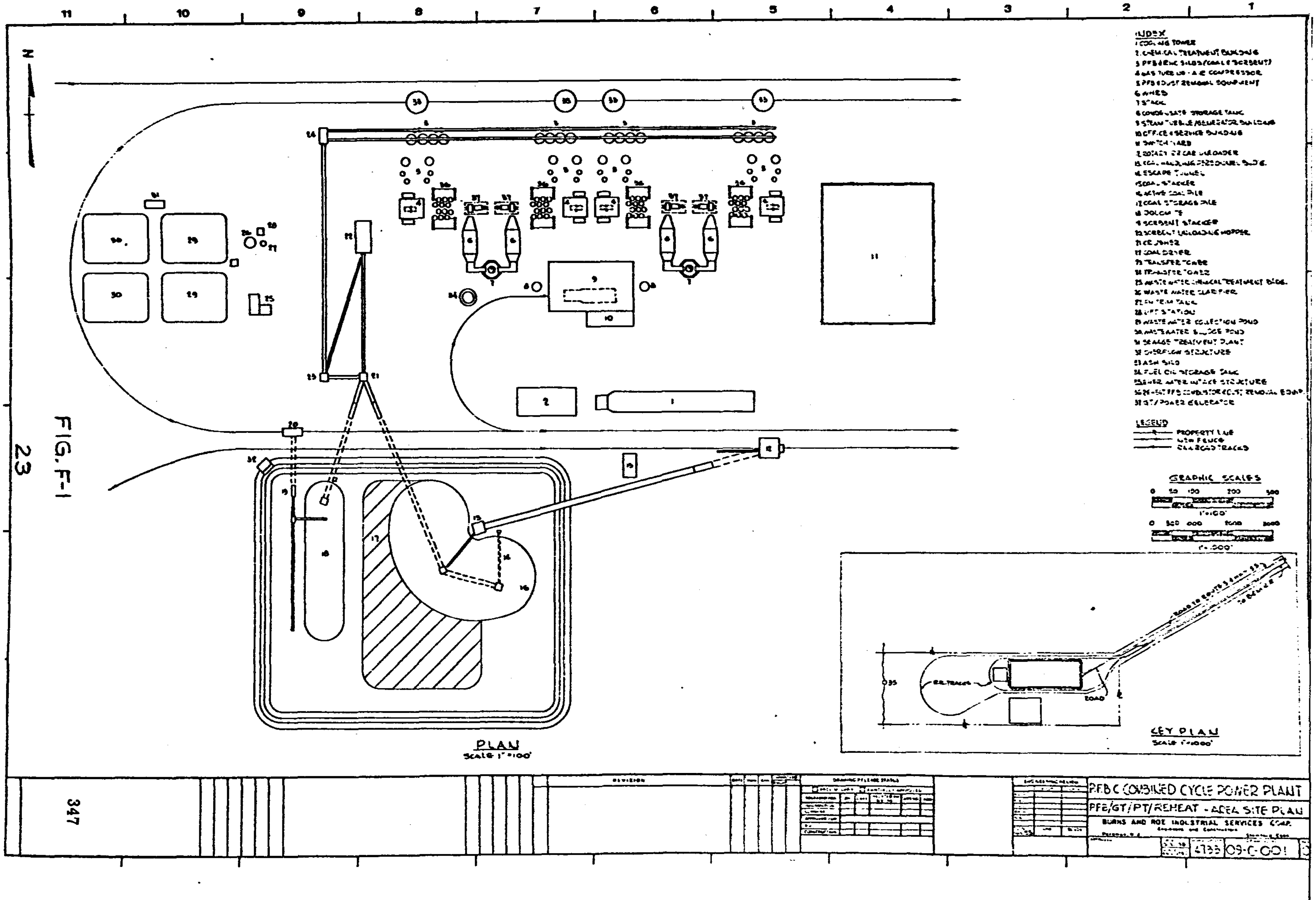

PLAN
SCALE 1"=100'
GRAPHIC SCALES
LEGEND
PROPERTY LINE
KEY PLAN
P.F.B.C COMBINED CYCLE POWER PLANT
PFB/GT/PT/REHEAT - AREA SITE PLAN
BURNS AND ROE INDUSTRIAL SERVICES CORP.
4733
09-C-001

FIG. F-1

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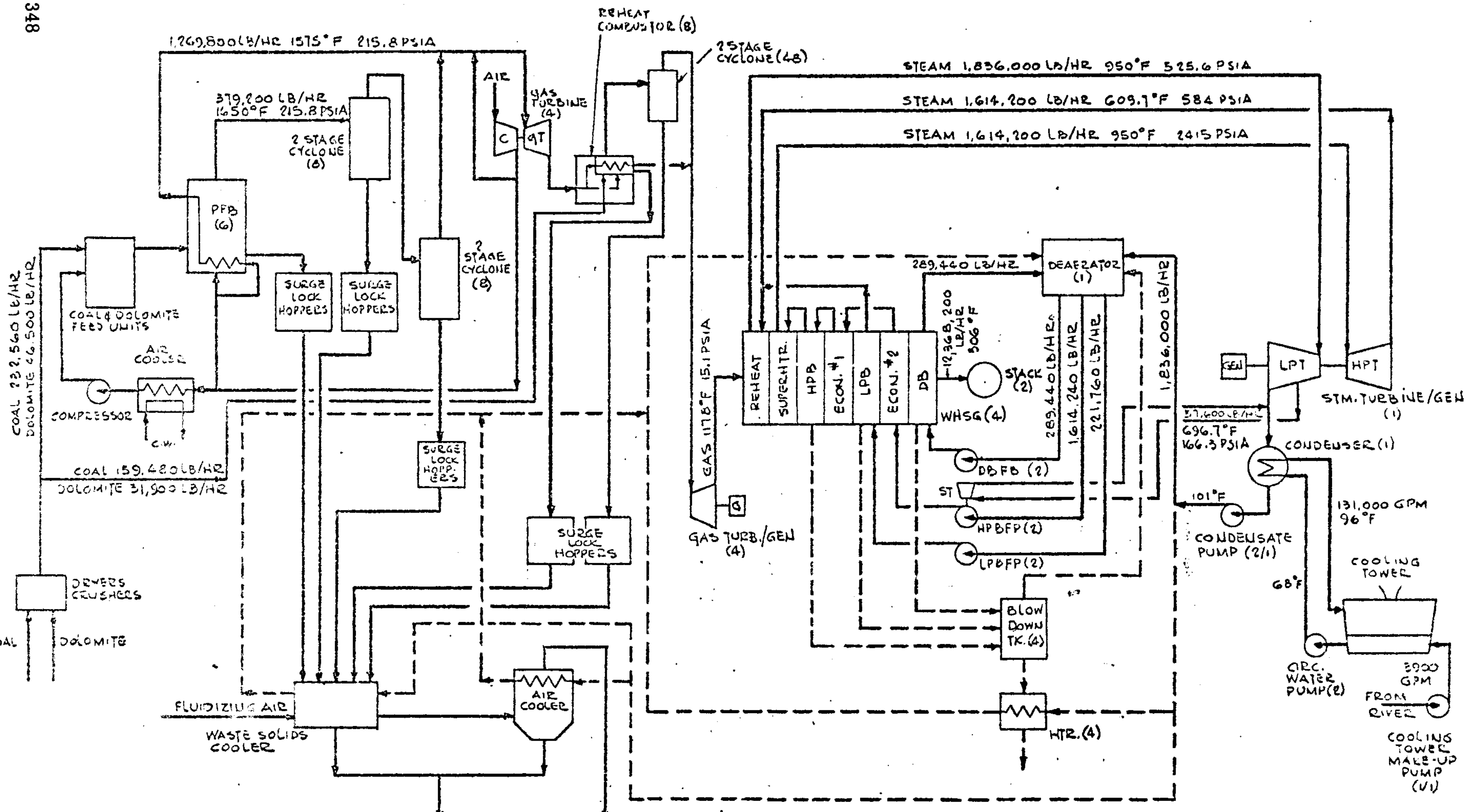


NOTES:

1. FLOWS ARE FOR FULL LOAD OPERATION
2. (2/1) MEANS 2 OPERATING, 1 SPARE TOTAL 3 INSTALLED

PFB/GT/POWERTURBINE REHEAT CYCLE
PROCESS FLOW DIAGRAM
FIG. F-2

to 1650°F, while the remainder of the air flow is heated to 1575°F in cooling tubes immersed in the bed. The mixed gas temperature is approximately 1600°F entering the compressor drive turbine where the gases are expanded and exhausted to the Reheat Fluidized Bed (RHPFB).

In the RHPFB a portion of the gas is combusted to 1650°F and the remaining gas is heated in tubes immersed in the bed much the same as was done in the main PFB. Due to power turbine design limitations, the gas temperature exiting the tubes is substantially reduced, and the mixed gas temperature entering the power turbine is 1500°F. This temperature is 543°F higher than would enter the power turbine without reheat resulting in increased power output and improved efficiency. Also, since the gas temperature exiting the power turbine is high enough to raise high quality steam, supplementary firing in the gas turbine exhaust is not used.

An OPR of 16:1 is utilized, as discussed in Section 3.2, to provide a relatively high operating pressure for the RHPFB.

The steam cycle (2400 psig throttle pressure) has been changed slightly from the steam system used in the Subtask 1.2 cycle. Steam superheat and reheat temperatures have been lowered from 1000°F to 950°F to facilitate boiler design, and a low pressure boiler (LPB) is used to generate 584 psia steam. This steam is mixed with the high pressure turbine exhaust steam prior to being reheated to 950°F (See Figure B-1). The final steam turbine exhaust pressure is 2" Hg. Power produced by the steam turbine is used to generate electricity.

Tables B-5 and B-6 present detailed heat and mass balances for the air/gas and steam systems respectively. Table B-7 presents the estimated power output and efficiency for the overall reheat power plant and subsystems.

The total gross power output is 623.0 MWe with the four gas turbines producing 313.2 MWe (78.3 MWe per gas turbine) and the steam turbine producing 309.8 MWe. Overall system gross efficiency is 43.6 percent based on the "as fired" coal rate (HHV = 12453 Btu/lb).

The net plant output after adjusting for 3.14 percent auxiliary power losses is 603.4 MWe. Adjusting the coal rate to account for drying losses (HHV = 11472 Btu/lb) and miscellaneous heat losses (See Table B-8) the "as received" coal rate is 121.9 lb/sec, and the corresponding net plant efficiency is 40.9 percent.

4.2.2 Performance Comparison - PFB/AFB Plant Versus PFB/GT/RH Plant

In Table B-9, selected performance parameters for the PFB/GT/RH plant are compared against those of the PFB/AFB plant proposed in Subtask 1.2 (Commercial Plant Design). The 37.9% net efficiency of the PFB/AFB plant is significantly lower than the corresponding 40.9% efficiency of the PFB/GT/RH plant. The effect of this difference on overall cost of electricity will be indicated in Section 5.0 of this report.

TABLE B-5

SELECTED PFB/GT/RH PLANT CONFIGURATION

Heat and Mass Balance for Air/Gas System

Location	Description	W,(2) lb/sec	T, F	P, psia	H, Btu/lb
1	Inlet	840.0	59.0	14.70	124.0
2	Compressor Inlet	840.0	59.0	14.55	124.0
3	PFB Inlet	175.9	754.2	232.8	294.9
4	PFB Cooling Tube Inlet	634.9	754.2	232.8	294.9
5	PFB Exit	189.6	1650.0	215.8	555.3
6	PFB Cooling Tube Exit	634.9	1575.0	215.8	514.4
7	Turbine Inlet	824.6	1593.2	215.8	523.8
8	RFB Inlet	150.4	956.7	40.9	349.0
9	RFB Cooling Tube Inlet	694.6	956.7	40.9	349.0
10	RFB Exit	159.9	1650.0	35.0	555.8
11	RFB Cooling Tube Exit	694.6	1463.3	35.0	487.2
12	PT Inlet	854.8	1500.0	35.0	500.0
13	PT Exit	858.9	1181.0	15.1	411.0
14	Reheater Inlet	858.9	1178.0	15.1	410.1
15	Superheater Inlet	858.9	1065.8	15.1	379.5
16	HPB Inlet	858.9	893.2	15.1	333.3
17	Economizer 1 Inlet	858.9	712.6	15.1	286.0
18	LPB Inlet	858.9	578.2	15.1	251.5
19	Economizer 2 Inlet	858.9	508.3	15.1	233.8
20	Deaerator Boiler Inlet	858.9	395.7	15.1	205.6
21	Stack	858.9	306.0	14.8	183.5

(1) Refer to Figure B-1 for locations.

(2) For one gas turbine; multiply flows by four for entire plant.

TABLE B-6

SELECTED PFB/GT/RH PLANT CONFIGURATION

Heat and Mass Balance for Steam System

Location (1)	Description	W,(2) lb/sec	T, F	P, psia	H, Btu/lb
22	Condensate Pump Inlet	127.5	101.1	.982	69.1
23	Deaerator Inlet	127.5	101.1	106.7	69.5
24	Deaerator Exit	127.5	250.0	30.0	218.9
25	Economizer 2 Inlet	112.1	254.9	2765.0	229.4
26	Economizer 1 Inlet	112.1	463.0	2665.0	445.0
27	HPB Inlet	112.1	657.6	2665.0	709.1
28	Superheater Inlet	112.1	677.6	2515.0	1071.8
29	HPT Inlet	112.1	950.0	2415.0	1426.2
30	HPT Exit	112.1	609.7	584.0	1289.3
31	LPB Pump Inlet	15.4	250.0	30.0	218.9
32	LPB Inlet	15.4	250.0	584.0	218.9
33	LPB Exit	15.4	483.3	584.0	1203.2
34	Reheater Inlet	127.5	592.0	584.0	1278.6
35	LPT Inlet	127.5	950.0	525.6	1492.8
36	LPT Exit	119.0	101.1	.982	1012.2
37	Deaerator Boiler Inlet	20.1	250.0	35.0	218.9
38	Deaerator Saturated Steam	20.1	255.0	30.0	1166.7
39	LPT Extraction	4.0	696.7	175.0	1367.6
40	Feedwater Pump Drive Inlet	4.0	696.7	166.3	1367.6
41	Feedwater Pump Drive Exit	4.0	108.7	1.228	1078.7
42	Condenser Inlet	127.5	101.1	.982	1014.3

(1) Refer to Figure B-1 for locations.

(2) For one gas turbine; multiply flows by four for entire plant.

TABLE B-7

SELECTED PFB/GT/RH PLANT CONFIGURATION PERFORMANCE ESTIMATES

(4 Gas Turbines)

PWR_{GT}, MW	313.2
PWR_{ST}, MW	309.8
PWR_{TOT} (Gross), MW	623.0
Auxiliaries, MW	19.6
PWR_{TOT} (Net), MW	603.4
η_{TOT} (1) (Gross), %	43.6
η_{TOT} (2) (Net), %	40.9
PFB Coal Rate (As Fired), lb/sec	64.6
RFB Coal Rate (As Fired), lb/sec	44.3
Total Coal Rate (As Fired), lb/sec	108.9
Total Coal Rate (As Received), lb/sec	121.9

(1) Based on 'as fired' coal rate (HHV = 12453 Btu/lb) and gross power output.

(2) Based on 'as received' coal rate (HHV ≐ 11472 Btu/lb), 3.14% auxiliary power losses and miscellaneous losses, shown on Table B-8

TABLE B-8

ADJUSTMENTS TO COAL FLOW FOR MISCELLANEOUS HEAT LOSSES

After the computer calculations were made, adjustments were made to to the reported coal flow and efficiency to account for the following:

A.	Radiation loss in hot gas piping		31.6×10^6 Btu/h
B.	Manufacturer's margin and unaccounted for losses for combustors.		48.8×10^6 Btu/h
		TOTAL	80.4×10^6 Btu/h

The following adjustments to "as received" flow were made:

Power Output	Adjustment to Coal Flow (as received) in lb/sec
100%	+1.9

TABLE B-9

PERFORMANCE COMPARISON - PFB/AFB PLANT (SUBTASK 1.2)

VERSUS PFB/GT/RH PLANT (SUBTASK 1.9)

	PFB/GT/RH	PFB/AFB
PWR (GT), MW	313.2	127.2
PWR (ST), MW	309.8	465.7
Gross PWR (Total), MW	623.0	592.9
Net PWR (Total), MW	603.4	574.2
Gross Efficiency (Total), % (1)	43.6	39.73
Net Efficiency (Total), % (2)	40.9	37.91
"As-Fired" Coal Rate,Tons/Hr	196.0	200.7
"As-Received" Coal Rate, Tons/Hr	219.4	225.3
Dolomite, Tons/Hr	38.98	13.97
Limestone, Tons/Hr	NONE	36.91
Waste Solids, Tons/Hr	59.6	63.4

(1) Based on "As-Fired" coal rate (HHV = 12,453 Btu/lb) and gross power output

(2) Based on "As-Received" coal rate (HHV = 11,472 Btu/lb) and net power output.

4.3 MAJOR MECHANICAL SYSTEMS AND EQUIPMENT DESCRIPTIONS

4.3.1 Main PFB Combustors (16 Atmospheres)

The Main Pressurized Fluid Bed (PFB) System consists of the main PFB combustors (16 atm.) and their accessories. The system design is based on the use of two main PFB combustors for each gas turbine.

The intent of this subtask is to investigate the design of the PFB combustors required for the gas turbine reheat cycle. Since the only significant difference between the 16 atmosphere combustor and the Subtask 1.2 combustor (10 atm.) is operating pressure, only an abbreviated description of the 16 atmosphere PFB system is included in this report.

4.3.1.1 Main PFB Combustor Concept

The main PFB combustor design is based on the split air flow concept; the concept is shown schematically in Figure H-1. The fuel fired in the bed is used only to heat the compressor discharge air to the turbine inlet temperature; no additional coal is fired for steam generation within the PFB combustor. In the split air flow design approximately 30% of the compressor discharge air flow is used for combustion and fluidizing air; the remaining 70% of the compressor discharge air is routed to a bed cooling system. This concept provides the following advantages:

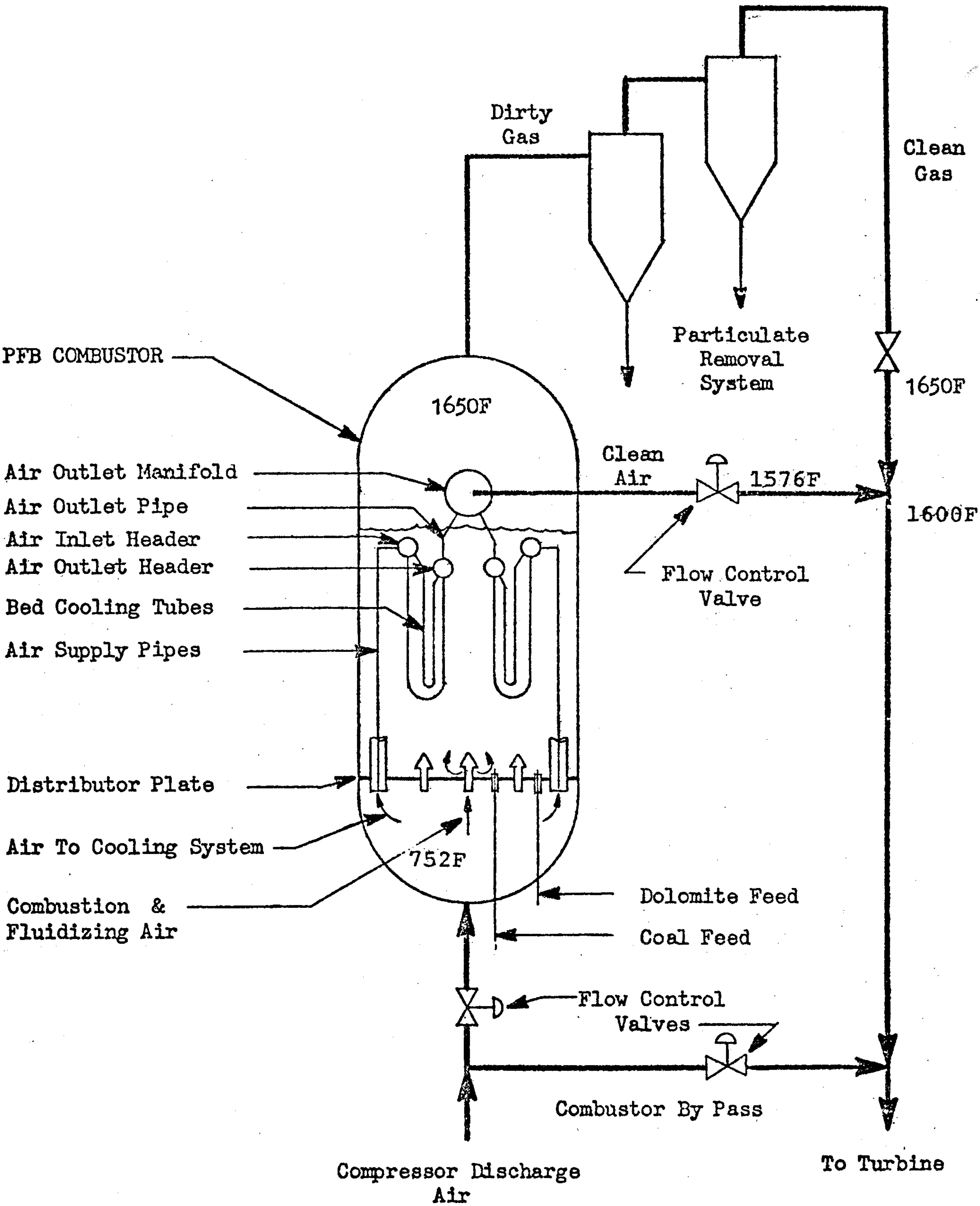
1. Since only 30% of the total air flow is used for combustion and fluidizing air, the sizes of both the combustor and the gas clean-up system are smaller than if all the compressor discharge air flow were used for fluidizing air.

2. Since the bed cooling system consists of both heating surface within the bed and the by-pass around this heating surface, the heat extraction from the fluidized bed may be controlled by the air flow split between the heating surface and the by pass. This concept provides turndown control of the PFB combustor from 0% to 100% gas turbine load while permitting the combustor to operate at constant fluidizing velocity and constant bed level.

4.3.1.2 Main PFB Combustor Design Parameters

Combustion efficiency, heat transfer and sulfur capture efficiency in the PFB combustor are functions of bed temperature, fluidizing velocity and solids feed size. The values of these parameters used in the design of the PFB combustor are based on the reported work of various organizations involved in PFB research. These values are listed below:

Bed Temperature	1650F
Excess Air	60%



Schematic - Split Air Flow Main PFB Combustor (16 atm)

FIG. H-1

Superficial Velocity	<3 fps
Coal feed size	-8 mesh
Sorbent feed size	-10 mesh
Combustion efficiency	99%
Calcium/Sulfur Molar Feed Ratio	1.0
Sulfur Capture	~80% (1.2 lb $SO^2/10^6$Btu)

Because of the possibility of tube leaks, it is desirable to keep the tube side static pressure greater than the bed side static pressure. This requires that the unrecoverable tube side pressure loss be less than the total distributor plate and bed losses at each point along the tube. It is also desired to operate the combustor at 15% excess air and a superficial gas velocity of 3 ft/sec. However, the diameter of the combustor vessel necessary to contain the required number of tubes results in an inadequate superficial velocity. In order to reduce the number of tubes required and to raise the superficial velocity to 3 ft/sec., it was decided to pass more air through the bed and less through the tubes. Consequently, the combustion/fluidizing air flow was increased and the combustor operates at 60% excess air rather than 15% excess air as is the case in the Subtask 1.2 design.

4.3.1.3 Main PFB Combustor Description

The arrangement of the PFB combustors is shown on the following B&W drawings:

254235E	Arrgt. 16 Atmosphere PFB Combustor - Front View (Figure H-2)
254236E	Arrgt. 16 Atmosphere PFB Combustor - Side View (Figure H-3)
254237E	Arrgt. 16 Atmosphere PFB Combustor - Plan Sections, 1 of 2 (Figure H-4)
254238E	Arrgt. 16 Atmosphere PFB Combustor - Plan Sections, 2 of 2 (Figure H-5)

The PFB Combustor is a refractory lined pressure vessel with an outside diameter of 19' and a length of 72'-11". The vessel is mounted in the vertical position and is supported from structural steel by support rings which are positioned near the mid point of the length. The vessel design is based on the use of SA516 GR 70 carbon steel; the wall thickness is 3".

The vessel is internally lined with insulating refractory to limit the surface temperature of the combustor to 250F based on an ambient air temperature of 80F. Below the distributor plate the lining is 3-5/8" of Kaolite 2200-HS. Above the distributor plate, a two component refractory lining is used with the design based on a bed maximum operating temperature of 1700F. A minimum thickness of 5" of Kaolite 2200 HS insulating refractory is used covered by a 2" thick layer of Kao-Phos 93 dense refractory to provide erosion protection.

The distributor plate utilizes bubble caps to provide uniform fluidization and yet prevent the bed solids from sifting back into the air inlet plenum. The distributor plate is also refractory covered to achieve an acceptable operating temperature. The plate is supported by a series of stiffeners in the air inlet plenum. The support system design is based

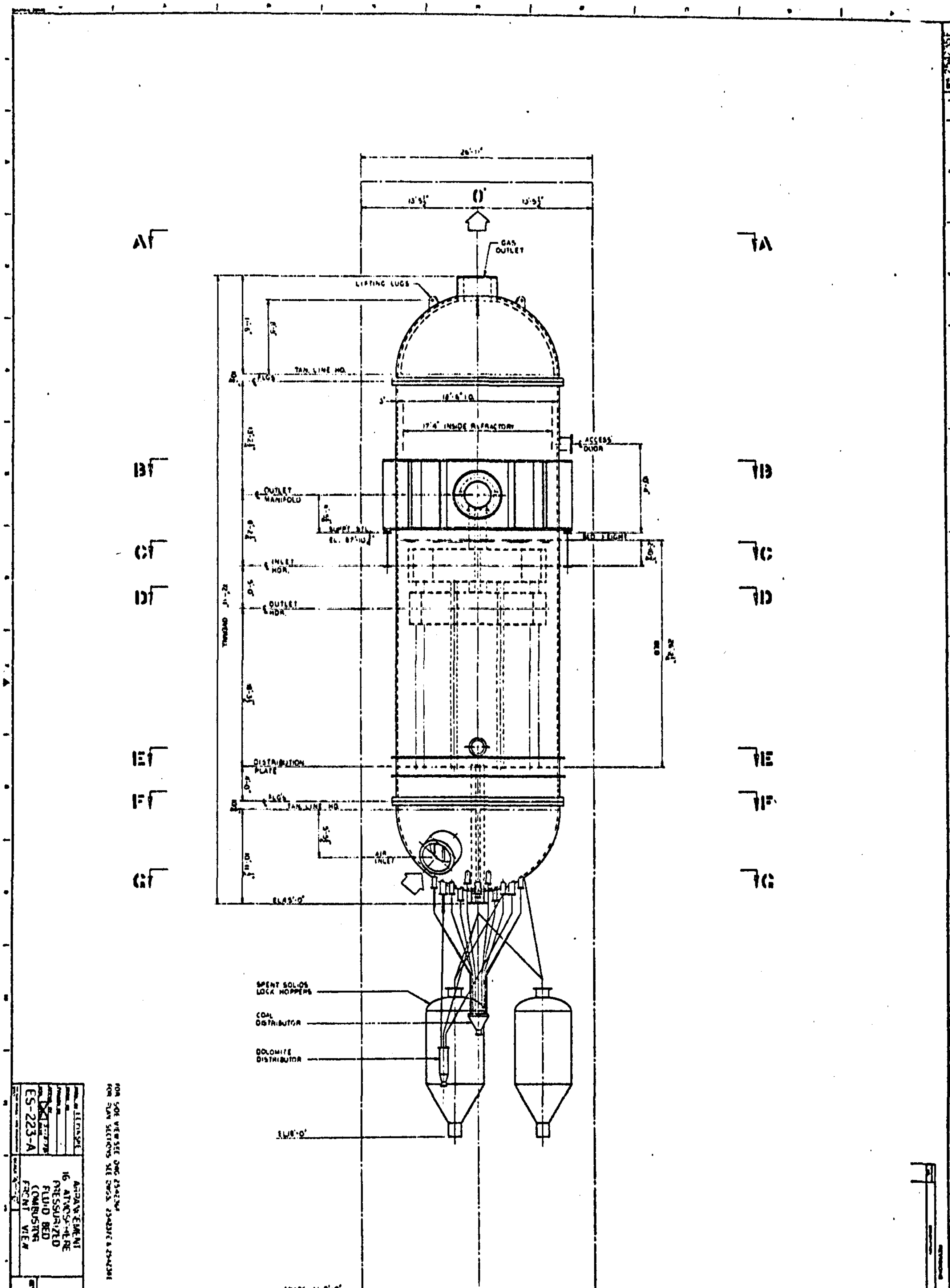


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FIG. H-2
ARRGT.-16 ATM. PFB COMBUSTOR-FRONT VIEW

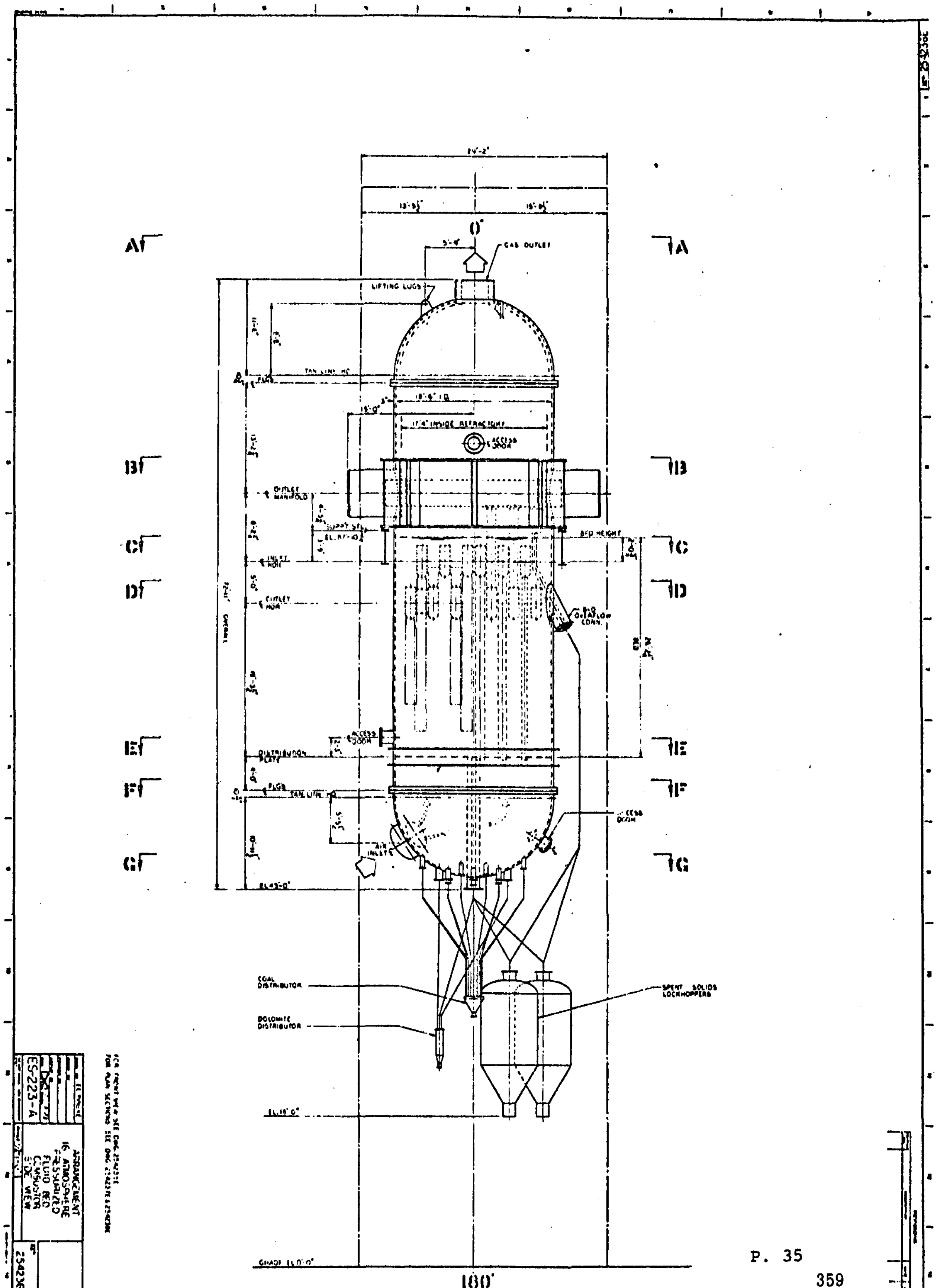


FIG. H-3
APRG'T.-16 ATM. PFB COMBUSTOR-SIDE VIEW

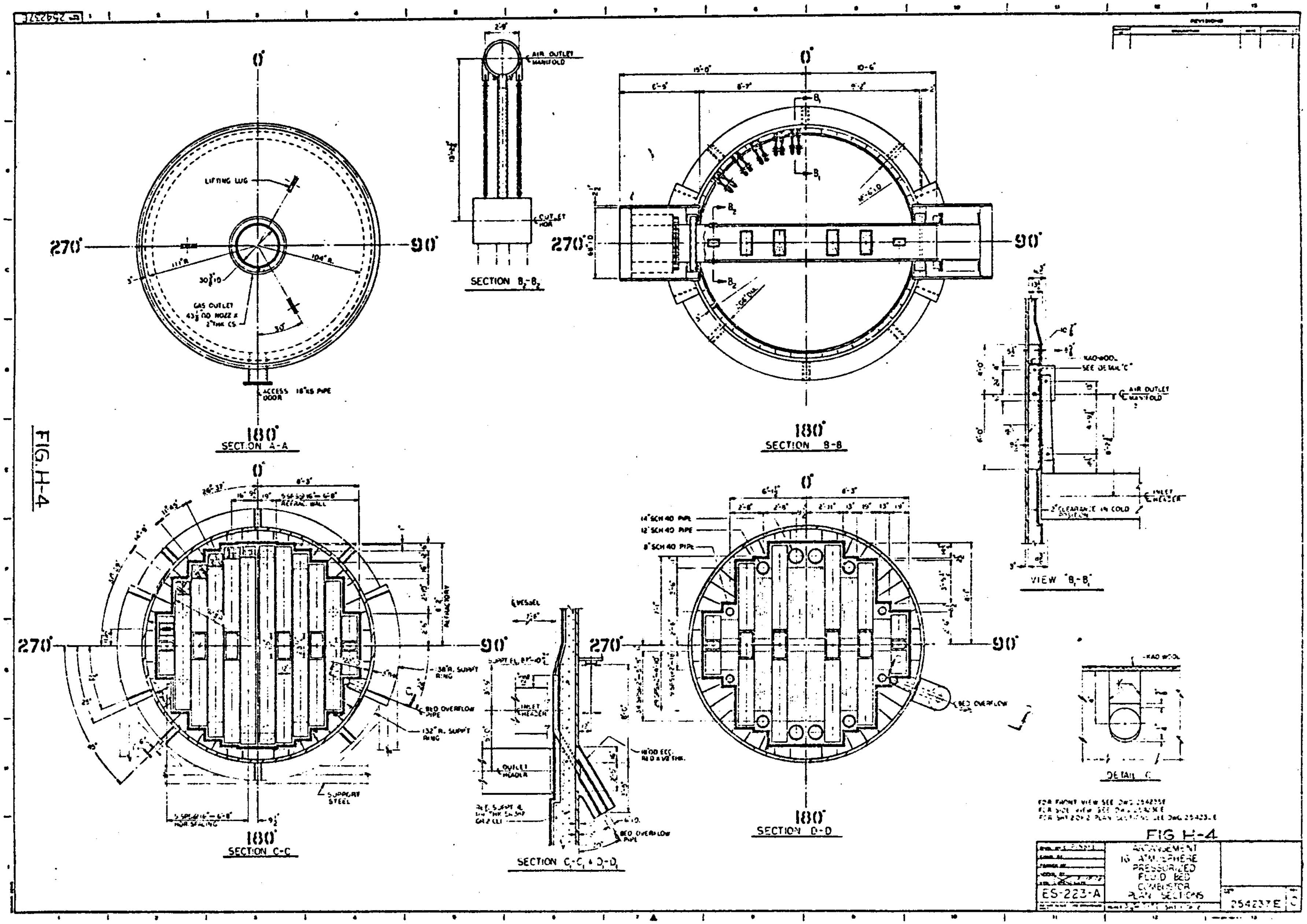
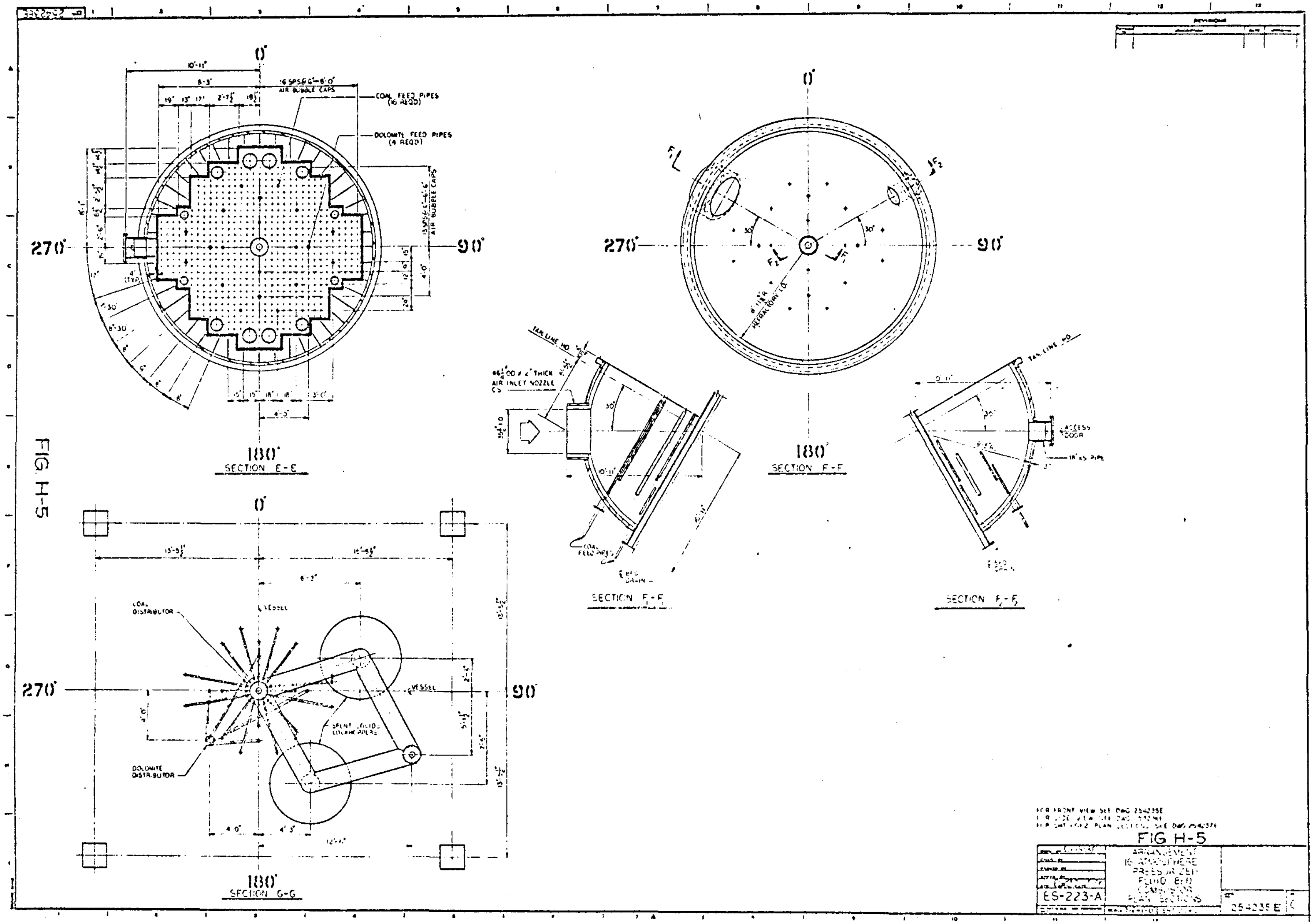

0°
270°
90°
180°
LIFTING LUG
GAS OUTLET
ACCESS DOOR
SECTION A-A
AIR OUTLET MANIFOLD
OUTLET HDR
SECTION B2-B2
SECTION B-B
VIEW "B1-B1"
INLET HEADER
SECTION C-C
BED OVERFLOW PIPE
SUPPORT STEEL
SECTION C1-C1 & D1-D1
SECTION D-D
DETAIL "C"
ARRANGEMENT
16 ATMOSPHERE
PRESSURIZED
FLUID BED
COMBUSTOR
PLAN SECTIONS
ES-223-A
254237E

FIG. H-4



0°
270°
90°
180°
COAL FEED PIPES (16 REQD)
DOLOMITE FEED PIPES (4 REQD)
AIR BUBBLE CAPS
SECTION E-E
SECTION F-F
SECTION F1-F1
SECTION F2-F2
TAN. LINE HD.
AIR INLET NOZZLE
ACCESS DOOR
COAL FEED PIPES
COAL DISTRIBUTOR
DOLOMITE DISTRIBUTOR
VESSEL
SECTION G-G
FIG H-5
ARRANGEMENT
16 ATMOSPHERE
PRESSURIZED
FLUID BED
COMBUSTOR
PLAN SECTIONS
ES-223-A
254235 E

FIG. H-5

both on the dead load of a slumped bed and the uplift equivalent to the pressure loss through the plate during normal operation.

The bed cooling system consists of the heat exchanger tubes together with the associated headers and connecting pipes. Cooling air enters the bed cooling system by way of supply pipes which connect the distributor plate with the inlet headers. The bed cooling tubes are arranged in a U-tube configuration between the inlet and outlet headers. The U-tube arrangement was chosen to accommodate the differential expansion along the tube length as the air is heated from 752F to 1576F. Both the tubes and the headers are made of Alloy 800H material. (Its selection as the design basis is covered in Section 4.3.1.4 of the Subtask 1.2 Report.) From the outlet header the air flows to the air outlet manifold which spans the vessel diameter and connects to the hot air piping.

4.3.2 Reheat PFB Combustors (2½ atmospheres)

The reheat pressurized fluidized bed (PFB) system consists of the reheat PFB (RHPFB) combustors and their accessories. The system design is based on the use of two reheat combustors for each gas turbine.

4.3.2.1 RHPFB Combustor Design Parameters

Combustion efficiency, heat transfer, and sulfur capture efficiency in the PFB combustor are functions of bed temperature, fluidizing velocity, and solids feed size. The numerical values for the parameters used in the design of the reheat PFB combustor are based on the reported work of various organizations involved in PFB research. The rationale used in determining these values is the same as that described on Pages 69-75 of the Report on Subtask 1.2 (Commercial Plant Design) with the exception of the following discussion on sulfur capture. In addition, due to small differences in tube temperatures and the lower operating pressure, the bed to tube heat transfer coefficient is about 10% higher than the corresponding value in Subtask 1.2. All other design parameters for the RHPFB are the same as those listed in Section 4.3.1.2 above except for the bed excess air which is 15% instead of 60%.

4.3.2.1.1 Sulfur Capture

The type of sulfur sorbent and its feed rate is set by the sulfur removal requirements. In order to achieve the EPA limit of 1.2 lb $SO_2/10^6$ BTU input, approximately 80% of the sulfur in the proposed coal (3.43% sulfur 12450 BTU/lbm HHV) must be removed.

There is no test data comparable to the operating conditions of the reheat combustor. The operating pressure of the reheat combustor is approximately 2-1/2 atmospheres. The lowest operating pressure of PFB test facilities is the 5 atmosphere work done by BCURA (Ref. 1). Since operating pressure will affect both the partial pressure of SO_2 and CO_2 (with the latter affecting the rate of calcining), pressure may be expected to affect the sulfur capture.

As noted in Section 4.3.1.1 of Subtask 1.2 Report (Commercial Plant Design), the 5 atmosphere BCURA test work and the 8 atmosphere ANL test work are in close agreement on sulfur capture. With the lack of test work at 2-1/2 atm., it is assumed that the sulfur capture at 2-1/2 atm. would be the same as observed at the higher pressures and a Ca/S ratio of 1.0 using dolomite has been selected as the design basis.

The gas residence time in the reheat bed (9 ft. depth and 3 fps velocity yielding 3 seconds residence time) is comparable to the residence times of the BCURA and ANL test facilities adding further credibility to the assumption for sulfur capture. This increased residence time, as suggested by Exxon (Ref. 2), explains much of the apparent improvement in sulfur capture as compared to the various atmospheric pressure investigations.

4.3.2.2 Reheat PFB Combustor (RHPFB) General Description

The RHPFB combustor design is based on the split air flow concept; the concept is shown schematically in Figure H-6. The fuel fired in the bed is used only to heat the gas generator discharge air to the required power turbine inlet temperature; no additional coal is fired for steam generation within the PFB combustor. In the split air flow concept approximately 16% of gas generator discharge air flow is used for combustion and fluidizing air; the remaining 84% of the air flow is routed to a bed cooling system.

The initial design concept consisted of a vertical combustor having an internal arrangement similar to that of the PFB combustor design of Subtask 1.2. The bed depth required to submerge the tubes with this type of arrangement results in a relatively high pressure loss which was judged unsatisfactory from the cycle efficiency viewpoint. Consequently, a study was undertaken to find an arrangement that would produce a shallower bed and a higher pressure at the power turbine inlet. The arrangement that has finally been selected consists of four bed modules placed inside a horizontal combustor vessel. Each bed module is composed of straight horizontal tubes connecting an inlet header to an outlet header (see Figure H-7).

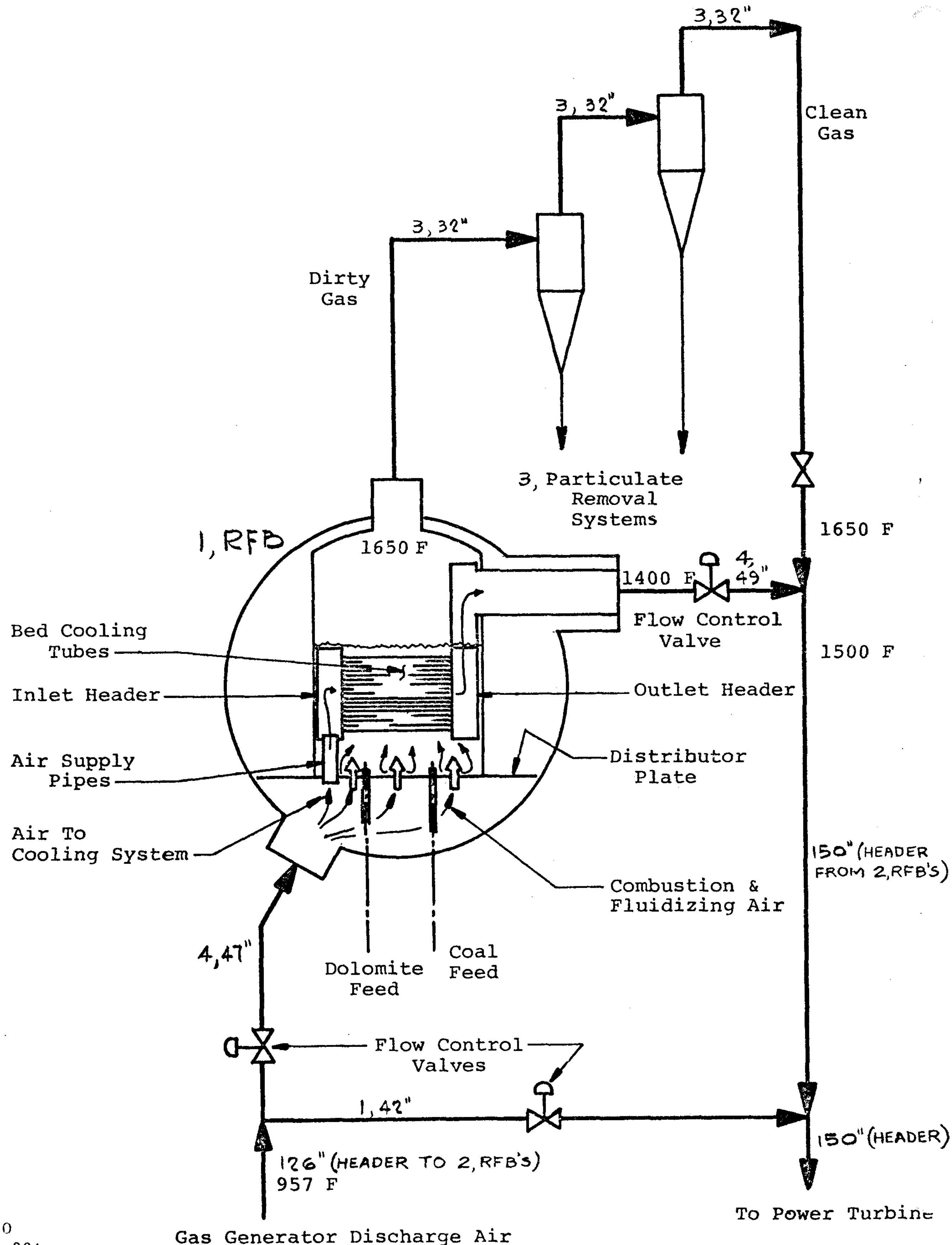


FIGURE H-6 Schematic - Split Air Flow Reheat PFB Combustor (2 1/2 ATM.)

Manufacturing capabilities, shipping restrictions, and structural considerations limited the diameter of the combustor vessel resulting in the use of two reheat combustors for each gas turbine. Each combustor is a refractory lined pressure vessel having an outside diameter of 28'-4" and an overall length of 55'-2". The vessel is mounted in a horizontal position by means of two support saddles. The general arrangement of the vessel and its internals is shown in Figure H-7.

4.3.2.3 RHPFB Combustor Operation

During normal full load operation, air discharged from the gas generator enters the bottom of the PFB pressure vessel. Approximately 16% of this incoming air flows upward through bubble caps in the distributor plate and fluidizes the bed solids while at the same time supplying the oxygen needed for combustion. The smaller particulates (less than 250 microns) are elutriated from the top of the bed and flow out the top of the combustor along with the combustion gases. Three dirty gas streams exit the top of the combustor. Each stream flows through a set of two high efficiency centrifugal dust collectors operating in series.

The remaining incoming compressed air flows through pipes and tubes immersed in the bed where it undergoes an increase in temperature. The hot compressed air is collected in the outlet headers and routed out through the side of the vessel. It is then mixed with the combustion gases after the latter have passed through the gas cleanup equipment. The resulting clean gas mixture is then routed to the power turbine.

The larger particles which form the bed are removed from the combustor through two ash outlet nozzles located at an elevation corresponding to the top surface of the active bed. The complete spent bed material removal system is described in Section 4.3.9.

4.3.2.4 RHPFB Internals-Material Selection

Incoloy 800 is used for all combustor internals exposed to hot bed gases and solids. The reason for its selection as the design basis is covered in Section 4.3.1.4 of the Subtask 1.2 Report.

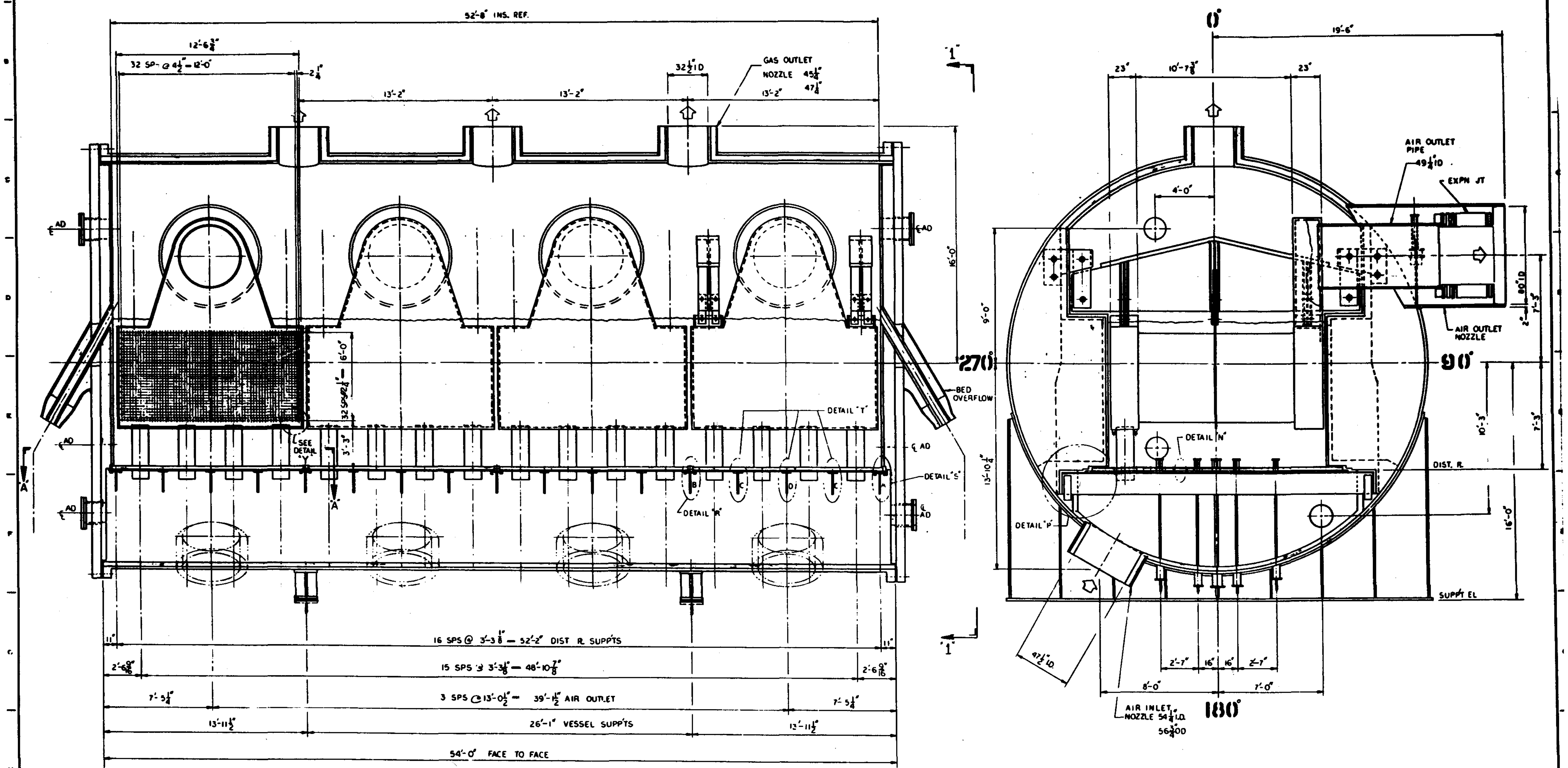
4.3.2.5 RHPFB Combustor Detailed Design Description

The arrangements and details of the reheat PFB combustor are shown on the following B&W drawings:

Fig. H-7 Reheat PFB Combustor
Fig. H-8 Arrgt. Reheat PFB Combustor
Fig. H-9 Reheat PFB Combustor Details - Sheet 1
Fig. H-10 Reheat PFB Combustor Details - Sheet 2

4.3.2.5.1 RHPFB Combustor Pressure Vessel

The PFB Combustor is a refractory lined pressure vessel with an outside diameter of 28'-4" and a length of 55'-2". The vessel is mounted in the horizontal position and is supported from structural steel by two saddles. The saddle supports are designed to support the



FOR DETAIL DWG. SHT. 1 OF 2 SEE DWG. 254294E.
FOR DETAIL DWG. SHT. 2 OF 2 SEE DWG. 254295E.

FIG H-7

E. PINSKE	REHEAT P. F. B. COMBUSTOR
ES-223-D	254293 E 0

SCALE 3/8" = 1'-0"

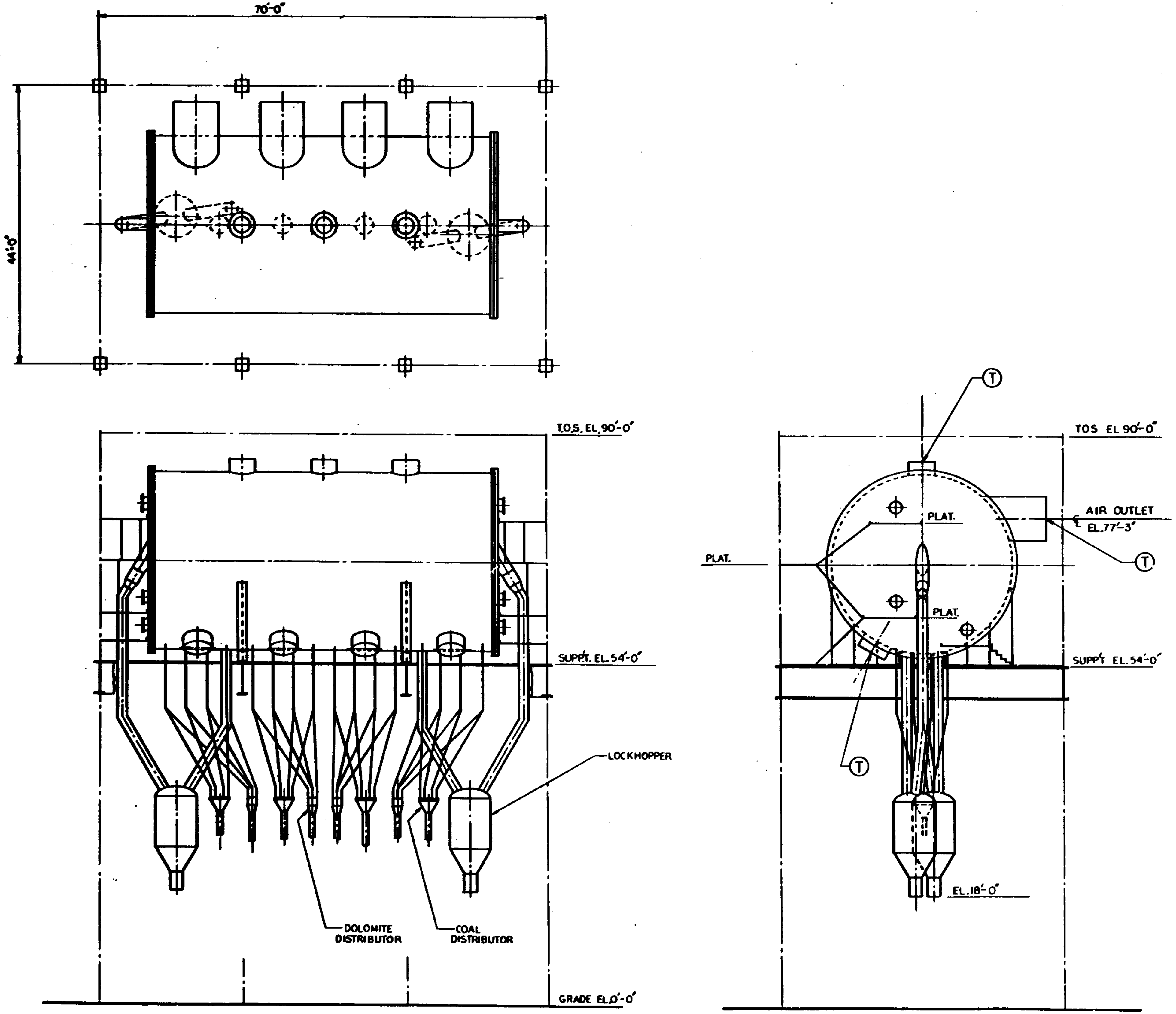


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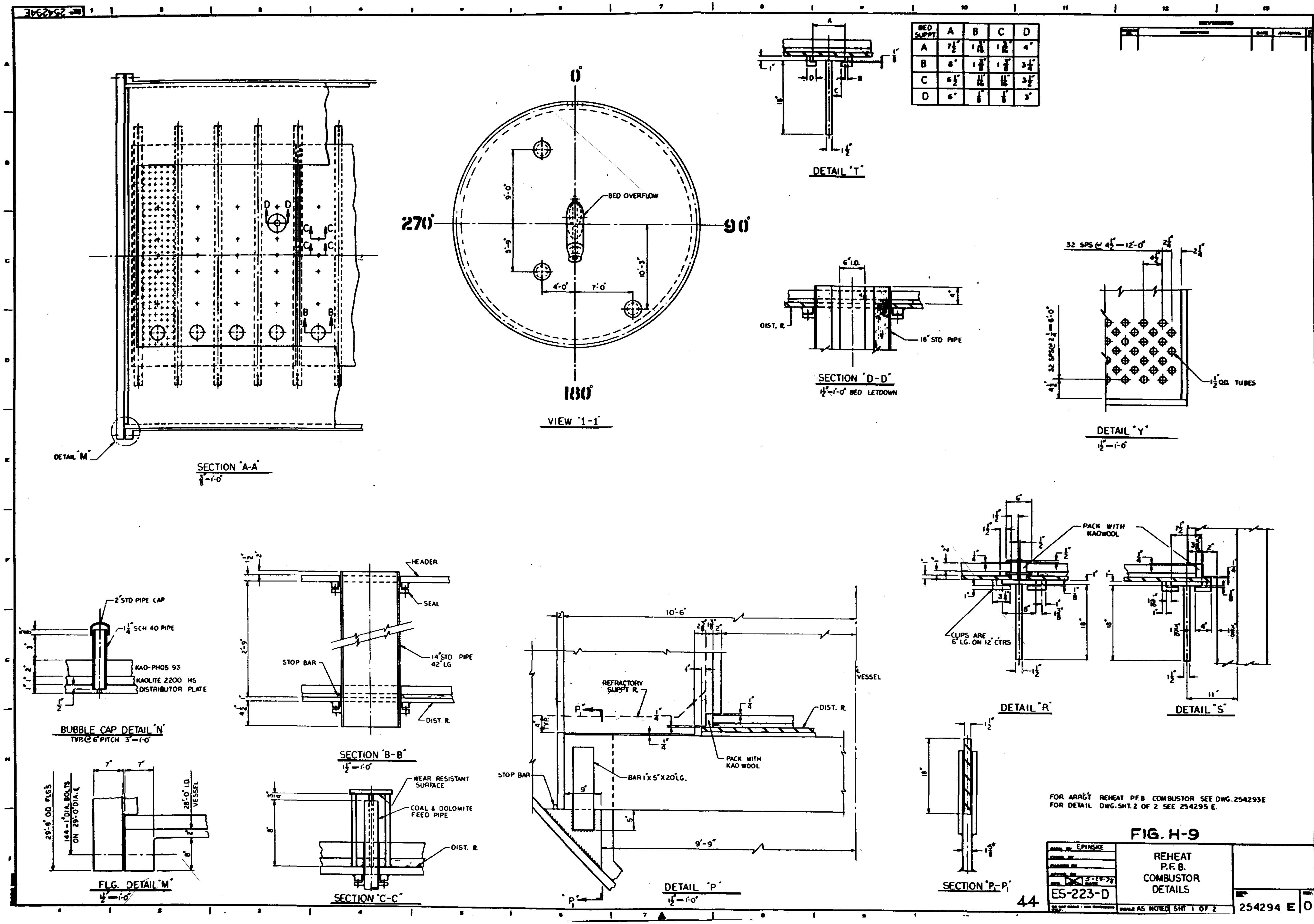
FIG. H-8

DWN. BY E. PINSKE ES-223-D	ARRANGEMENT REHEAT P.F.B. COMBUSTOR	367 151212 D 0



BED SUPP'T	A	B	C	D
A	7½"	1 [illegible]	1 [illegible]	4"
B	8"	1 [illegible]	1 [illegible]	3¼"
C	6½"	[illegible]	[illegible]	3½"
D	6"	[illegible]	[illegible]	3"

FIG. H-9

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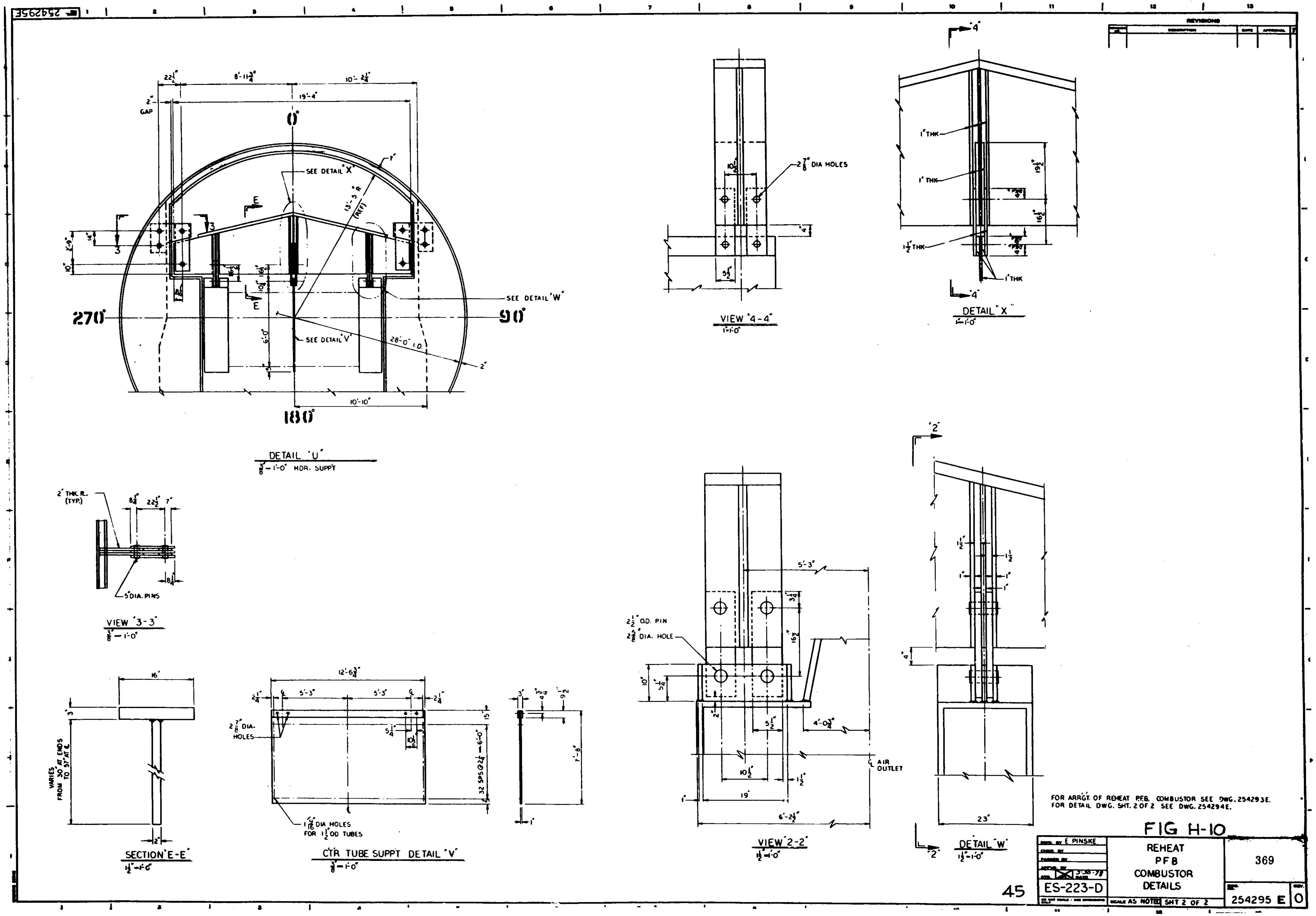


DETAIL 'U'
3/8" = 1'-0" HOR. SUPP'T
VIEW '4-4'
1" = 1'-0"
DETAIL 'X'
1" = 1'-0"
VIEW '3-3'
3/8" = 1'-0"
SECTION 'E-E'
1 1/2" = 1'-0"
CTR TUBE SUPP'T DETAIL 'V'
3/8" = 1'-0"
VIEW '2-2'
1 1/2" = 1'-0"
DETAIL 'W'
1 1/2" = 1'-0"
FOR ARR'GT. OF REHEAT PFB COMBUSTOR SEE DWG. 254293E.
FOR DETAIL DWG. SHT. 2 OF 2 SEE DWG. 254294E.
FIG H-10
E. PINSKE
3-30-78
ES-223-D
REHEAT
PFB
COMBUSTOR
DETAILS
369
SCALE AS NOTED SHT 2 OF 2
254295 E 0
45

dead load of the vessel and its contents, wind and earthquake forces, and externally applied forces and moments as well as the dead loads applied during hydrostatic testing.

Low friction plates are used as the interface points between the combustor support saddles and the structural steel to reduce the longitudinal and tangential friction loads on the vessel wall. Each of the support points is blocked and guided to fix the combustor centerline in space regardless of any external force applied to the vessel.

Internally, the pressure vessel consists of two compartments separated by a horizontal distributor plate. The lower compartment is essentially an inlet air plenum which receives air from the gas generator. The upper compartment contains the fluidized bed and the heat exchanger surface which is submerged in the bed.

In addition to being the containment vessel for the pressurized combustion process, the vessel must be designed to accommodat the support of the internal heating surface and the distributor plate. The vessel has been designed in accordance with ASME Section VIII Division I Code.

The vessel design is based on the use of SA 516 GR70 carbon steel. The vessel consists of three main sections; two flat heads and a cylindrical shell. The nozzle openings in each section have been examined for pressure and, if required, any externally applied forces and moments. Since the internals of the vessel must be accessible for assembly and maintenance, each of the heads is fastened to the middle cylinder using flanged connections.

A uniform wall thickness of 2" is used for the vessel and is a function of several parameters including:

1. The capacity of the cylindrical shell to absorb the thermal forces and moments produced by the associated piping.

2. The strength requirements of the two support saddles to support the combustor.

3. The local stresses at the flanges produced by both gasket seating and design pressure.

All pressure part welds will undergo radiographic inspect

The design of the vessel is based on an average wall temp ture of 250F. Local hot spots exist opposite certain internal support attachments to the vessel wall. These hot spots do not require special design consideration for the vessel itself.

4.3.2.5.2 PFB Combustor Vessel Refractory Lining

Insulating refractory is used to limit the outside surfac temperature of the combustor vessel to 250F when the ambient air temperature is 80F and the air velocity is 50 feet per minute. Below the distributor plate, a minimum thickness of 3 5/8" of Kaolite 2200-HS is used to insulate the vessel wall from the hot compressed air entering the combustor (Figure H-7). This thickness is based on the 1250F air temperature that exists in the lower compartment during bed warm up.

Above the distributor plate, a two component refractory lining is used with the thickness based on a bed design temperature of 1700F. The components consist of a layer of insulating refractory covered by a layer of abrasion resistant refractory.

The insulating refractory is Kaolite 2200-HS with a minimum thickness of 5 inches (Figure H-10). In the area of the bed cooling surface, the refractory thickness is increased to follow the outline of the surface as shown in Figure H-7. The Kaolite 2200-HS is a light weight, high strength, insulating castable refractory that is manufactured by Babcock & Wilcox's Refractories Division. It is resistant to thermal shock and has a maximum temperature use limit of 2200F.

Erosion and abrasion of the Kaolite refractory by coal and dolomite particles is prevented by a 2 inch thick layer of Kao-Phos 93 which is applied to the hot surface of the Kaolite refractory in the bed compartment (Figure H-10). The Kao-Phos is a dense castable refractory that is manufactured by Babcock & Wilcox and which is highly resistant to erosion and abrasion. It has a maximum temperature use limit of 3000F.

A 2 inch thick layer of Kao-Phos 93 on top of a 1 inch thick layer of Kaolite 2200-HS (Figure H-9) prevents the metal temperature of the distributor plate from exceeding its 1300F design temperature during normal operation and when a hot bed is slumped.

4.3.2.5.3 Distributor Plate

The division between the air inlet plenum and the fluid bed is the distributor plate. The plate serves several functions including:

1. Distributing the fluidizing air flow evenly over the bed area.

2. Supporting the bed solids in the slumped state.

In addition, coal and dolomite are fed into the fluid bed through nozzles penetrating the distributor plate and provision is included for draining the bed solids through the lower solids drain pipes which pass through the plate and out through the bottom of the vessel.

Air distribution is provided by a system of bubble caps welded to the distributor plate. In designing the bubble caps, the following criteria must be considered:

1. Prevent bed solids from sifting through the air nozzles.

2. Produce uniform fluidization throughout the bed.

3. Provide sufficient pressure drop to assure that the bed side operating pressure is lower than the tube side operating pressure.

This minimizes the concern for leaks in the heat exchanger tubes since the pressure differential prevents bed solids from entering the clean air stream which flows directly to the power turbine. To achieve this objective an unrecoverable pressure loss of 1.8 psig is required across the distributor plate and bubble cap at full load operating conditions.

Uniform fluidization is achieved throughout the bed by using a large number of bubble caps. Studies indicate that a 6 inch square pitch arrangement would yeild the desired quantity of bubble caps and at the same time provide sufficient space for installation and maintenance.

The requirement that bed solids not sift through the air nozzles precluded the use of vertical air nozzles or a perforated distributor plate. Although horizontal air nozzles as used in the bubble caps tested by Pope, Evans and Robbins (Ref. 3) would satisfy this requirement, jet penetration theory (Ref. 4) indicates that horizontal nozzles are not suitable for our design. This is due to the fact that the velocity associated with the required pressure drop would cause the horizontal air jets of adjacent bubble caps to interfere with one another resulting in premature air bubble coalescence. It is felt that this would cause large air bubbles to form which would lead to non-uniform fluidization and unstable bed operation. Consequently, a unique bubble cap was designed (Detail N of Figure H-9) to produce a low velocity downward air jet thereby preventing premature bubble coalescence. In addition, this type of bubble cap has the following advantages:

1. Simplified manufacturing process; the new bubble cap does not require any air nozzles to be drilled.

2. More readily available; the new bubble cap is made up of commonly available components - a piece of pipe welded to a standard pipe cap.

The required pressure drop is achieved by the drilling in the distributor plate at the inlet of the bubble cap. The air jet from the hole impinges on the underside of the bubble cap and is turned downward, exiting from the bubble cap as a low velocity downward jet.

Coal and dolomite are fed to the bed through sixty-four (64) coal feed pipes and sixteen (16) dolomite feed pipes which penetrate the lower half of the combustor vessel and pass vertically upward through the lower compartment and distributor plate. The feed pipes are made of SA-310 stainless steel and are welded to the lower half of the combustor vessel. High temperature packing between the feed pipes and the distributor plate (Figure H-9) allows the pipes to expand and contract axially. A deflector plate located above each of the feed pipes provides a horizontal velocity component to solids entering the bed, thereby aiding uniform mixing of the coal and the dolomite in the bed. Erosion of the deflector plates is minimized by an abrasion resistant ceramic coating applied to the bottom surface of the plates. The stress analysis of the feed pipes included an analysis for flexibility to accommodate the relative motion of the distributor plate with respect to the vessel wall.

The lower solids drains consist of two 18 inch O.D. pipes which penetrate the bottom of the combustor vessel and pass upward through the lower compartment and distributor plate. The drain pipes are made of SA-310 stainless steel and are lined on the inside with insulating refractory (approximately 3-5/8 inches of Kaolite 2200 HS). Erosion of the insulating refractory by the bed solids is prevented by a layer of abrasion resistant refractory (2 inches of Kao-Phos 93) applied to the inside surface of the insulating refractory. The drain pipes are welded to the lower half of the vessel and a high temperature packing gland arrangement between the drain pipes and the distributor plate allows the pipes to expand and contract axially. The packing gland arrangement also eliminates any problems that might arise because of the differential expansion of the distributor plate with respect to the vessel shell.

The structural analysis of the distributor plate examined two conditions; a 1.8 psi pressure load acting upward on the plate when the bed is fluidized and a dead load acting downward when the bed is slumped. The more severe case occurs when the combustor has just come down after a period of operation and the heat transfer to the distributor plate from the slumped bed has reached a steady state condition. The design temperature for this condition is 1300F.

Calculations indicated that a 1 inch thick plate of Incoloy 800, strengthened and supported by horizontal stiffeners, would be structurally adequate. The stiffeners, located on 39-1/8 inch centers and running parallel to one another, are not welded to the plate. Instead, a slot type arrangement (Detail "T" of Figure H-9) is used to limit upward movement of the distributor plate during uplift conditions. This arrangement also permits differential expansion between the plate and the vessel in both the longitudinal and transverse directions.

To support the weight of the distributor plate and its load, the stiffeners were extended beyond the edges of the plate. Each end of the stiffener rests on a pad attached to the vessel wall (Detail "P" of Figure H-9). The pads form a restraint for the dead load design condition. Vertical bars attached to both sides of the pad prevent the stiffener from moving off the pad. In addition, they add lateral stability to the stiffener and restrict its motion in a direction parallel to the vessel's longitudinal axis. A horizontal bar attached to both of the vertical bars and located above the stiffener forms a restraint for the uplift design condition. A two inch gap, between the end of the stiffener and the refractory, allows the stiffener to expand and contract along its longitudinal axis.

Air is prevented from leaking around the perimeter of the distributor plate by a Kaowool packing (Details "P" and "S" of Figure H-9). This packing is designed to withstand a 1.8 psi pressure differential while having sufficient compressibility to accommodate the differential expansion between the distributor plate and the vessel.

The differential expansion between the distributor plate and the vessel is minimized by using four adjacent plates instead of one long continous plate. A tight fit between the stiffener and slot on the centerline of each plate (Detail "T" of Figure H-9) restrains the motion of the plate's centerline and forces the plate to expand outward. Kaowool packing between adjacent plates (Detail "R" of Figure H-9) allows the plates to expand towards one another thereby dividing the overall expansion into components that are small enough to be easily handled.

4.3.2.5.4 Bed Cooling System

The bed cooling system consists of the heat exchanger tubes and associated headers and connecting pipes. The primary goal in designing the bed cooling system was to achieve an arrangement having minimum differential expansion between the system components and their support systems. In addition, the design had to recognize the low allowable stress of the material at the design temperature of 1700F.

Cooling air enters the bed cooling system by way of supply pipes which connect the distributor plate to the inlet header. Four supply pipes penetrate each inlet header and pass through the bed compartment and the distributor plate. These pipes are at a higher temperature than the vessel wall which supports both the inlet header and the distributor plate. A packing gland arrangement with high temperature packing at the penetration of both the distributor plate and the inlet header (Section "B-B" of Figure H-9) allows differential expansion while minimizing air leakage across the distributor plate.

The heat exchanger tubes are supported at their ends by an inlet header and an outlet header and in the middle by a tube support plate (Figure H-7). The box shape of the headers does not present a design problem because the pressure differential that exists across the header walls is quite low. In addition, internal stays prevent excessive stresses from occurring in the sides of the headers.

The inlet and outlet headers, tube support plates and heat exchanger tubes form a unit called a bed module. The headers and support plate act as simply supported beams since each end is connected by a pin and linkage assembly to a large, tapered, structural member (Figure H-10). There are two members per bed module and each carries half of the load. This load is transmitted to the vessel shell by a pin and linkage system that connects each end of the member to support plates that are welded to the inside of the vessel shell. Figure H-10 shows the arrangement of the support plates and linkage systems used to support the bed module. Croloy 2-1/4 material is used for the support plates welded to the vessel shell. Cantilever plates are supported from these support plates by 5 inch diameter pins and are made from Incoloy 800 material as is the rest of the support system. The use of pins between the support plates and cantilever plates simplifies the installation of the bed module in the pressure vessel and reduces the contact area available for heat flow between the support system and the vessel wall. By supporting the outlet header at the same elevation on the vessel wall as the air outlet pipe, the differential expansion between them is eliminated.

Since the operating temperature of the air outlet pipe is approximately 1525F compared to a minimum vessel temperature of 250F, a roller support was required for the pipe in order to accommodate the differential expansion (Figure H-7). The rollers also provide a minimum contact point between the pipe and the vessel shell to limit the amount of heat transfer and to provide an area of materials interface (Incoloy 800 to Croloy 2-1/4).

Because of the large relative motion between the air outlet pipe and the vessel wall, it was decided to use an expansion joint rather than a packing gland arrangement to provide the seal between the hot air and the combustion gases. The expansion joint is located in the combustor's external piping to facilitate removal for maintenance (Figure H-7).

Since the bed gases flow upward and across the horizontal heat exchanger tubes, the tubes are arranged on a triangular pitch (Detail "Y" of Figure H-9). It is felt that this type of arrangement promotes better mixing in the bed because there is no continuous bed-side flow path from bottom to top of the tube bundle as is the case in a square pitch arrangement. In addition, the triangular pitch arrangement enables more tubes to be fitted into a given volume than did a comparable square pitch arrangement. This helps to minimize the bed depth and bed side pressure drop as well as the tube length and tube side pressure drop.

The heat exchanger tubes have an outside diameter of 1.5" and a minimum wall thickness of 0.125". There are 4356 tubes per combustor and each has a length of approximately 10'-7". The wall thickness has been selected to assure high quality welds rather than for pressure stress reasons. The 1.5" tube size has been selected because it results in an acceptable (short enough) tube length and (small enough) tube-side pressure drop.

The 36 inch space above the distributor plate is free of heat exchanger tubes in order to provide access for inspection and maintenance of the distributor plate, bubble caps and solids feed pipes. Furthermore, a space free of restriction is required above the distributor plate to aid rapid and thorough mixing of the coal and dolomite.

4.3.3 Waste Heat Steam Generators

The exhaust gases from the gas turbine pass through a waste heat steam generator (WHSG) which generates steam for the bottoming cycle. No additional fuel is fired in the WHSG.

The WHSG is an established commercial product that has been supplied by the Babcock and Wilcox Company for other combined cycle installations. The boiler is based on standard design concepts that are tailored to suit individual requirements.

4.3.3.1 WHSG Arrangement

The boiler is a bottom supported, natural circulation drum type, that makes extensive use of helically finned tubes to utilize the low level heat of the turbine exhaust gas for steam generation. The basic boiler component is the section consisting of an inlet and outlet header connected by two rows of closely spaced, finned tubes. For ease of shipping and erection the sections are shop assembled into shipping units termed modules.

In the economizer, reheater and superheater modules, all interconnections between tube sections are shop installed. As a result, only the module inlet and outlet connections, and the drain and vent lines require field installation. The generating bank sections are shop assembled into modules for convenience in shipping and erection. These sections are designed for connection to the downcomers and drum using supply and riser tubes which are field installed.

The boiler for this cycle actually consists of three separate boilers within a common casing. The high pressure boiler generates 2500 psig, 955F steam for the steam turbine. This boiler consists of a superheater, a generating bank and two banks of economizer.

The intermediate pressure boiler generates 630 psig, saturated steam which is mixed with exhaust steam from the high pressure steam turbine at 555 psig and 596F and then introduced into the reheater. Steam from the reheater (950F) is utilized at the intermediate pressure point on the steam turbine. To make maximum use of the energy available in the gas turbine exhaust, the intermediate pressure boiler is located between the two banks of the economizers.

The final heat trap is the low pressure boiler which also consists of only a generating bank. This boiler generates 20 psig steam which is used for deaeration and feedwater heating.

The boiler arrangement is shown on Figure H-11 and H-12. The boiler performance and design conditions are shown on the Performance Summary Sheet, Table H-5.

4.3.3.2 High Pressure Boiler Design

The superheater and the reheater consist of four modules located side by side across the width of the boiler, two allocated to the reheater and the other two to the superheater. The superheater modules are each twenty rows deep. The two superheater modules are connected in series. The superheater surface is set to achieve the design steam temperature at the design load condition. A spray attemperator is located between the cold and hot superheater modules to control temporary excursions of steam temperature. Water from the high pressure boiler feed line is utilized as feed to the spray attemperator.

The two reheater modules located in the same trap as the superheaters are twelve rows deep. Steam from intermediate pressure boiler and high pressure turbine outlet are mixed and fed into the reheater. Steam from the reheater is eventually utilized in the turbine at an intermediate pressure point.

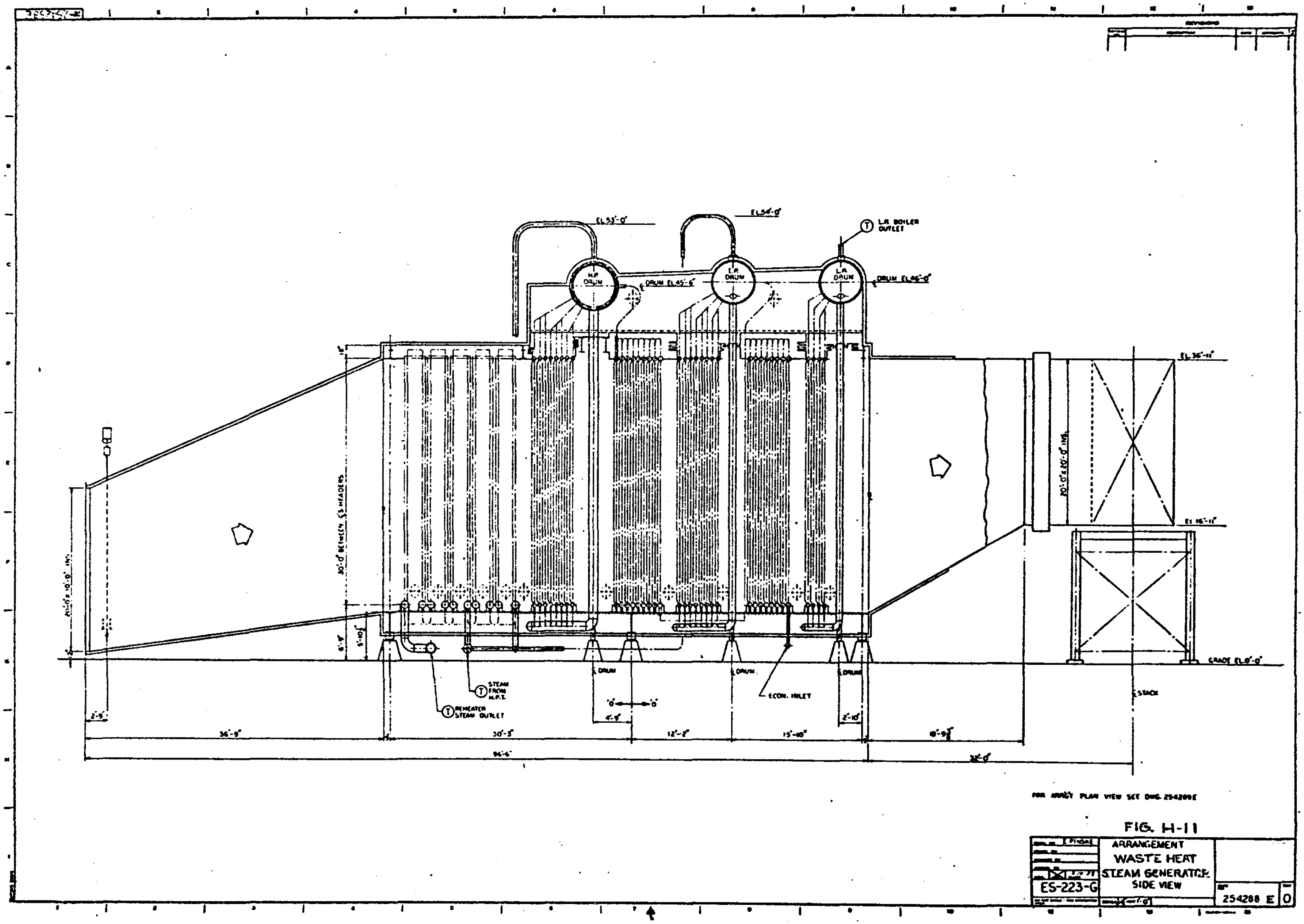

EL 53'-0"
EL 54'-0"
L.P. BOILER OUTLET
H.P. DRUM
I.P. DRUM
L.P. DRUM
DRUM EL 45'-6"
DRUM EL 46'-0"
EL 36'-11"
EL 16'-11"
30'-0" BETWEEN ℄ HEADERS
GRADE EL 0'-0"
℄ DRUM
ECON. INLET
℄ STACK
STEAM FROM H.P.T.
REHEATER STEAM OUTLET
2'-9"
36'-9"
30'-3"
4'-9"
12'-2"
15'-10"
2'-10"
18'-9"
96'-6"
32'-0"
FOR ARR'GT PLAN VIEW SEE DWG. 254289E
ARRANGEMENT
WASTE HEAT
STEAM GENERATOR
SIDE VIEW
ES-223-G
254288 E
0

FIG. H-11

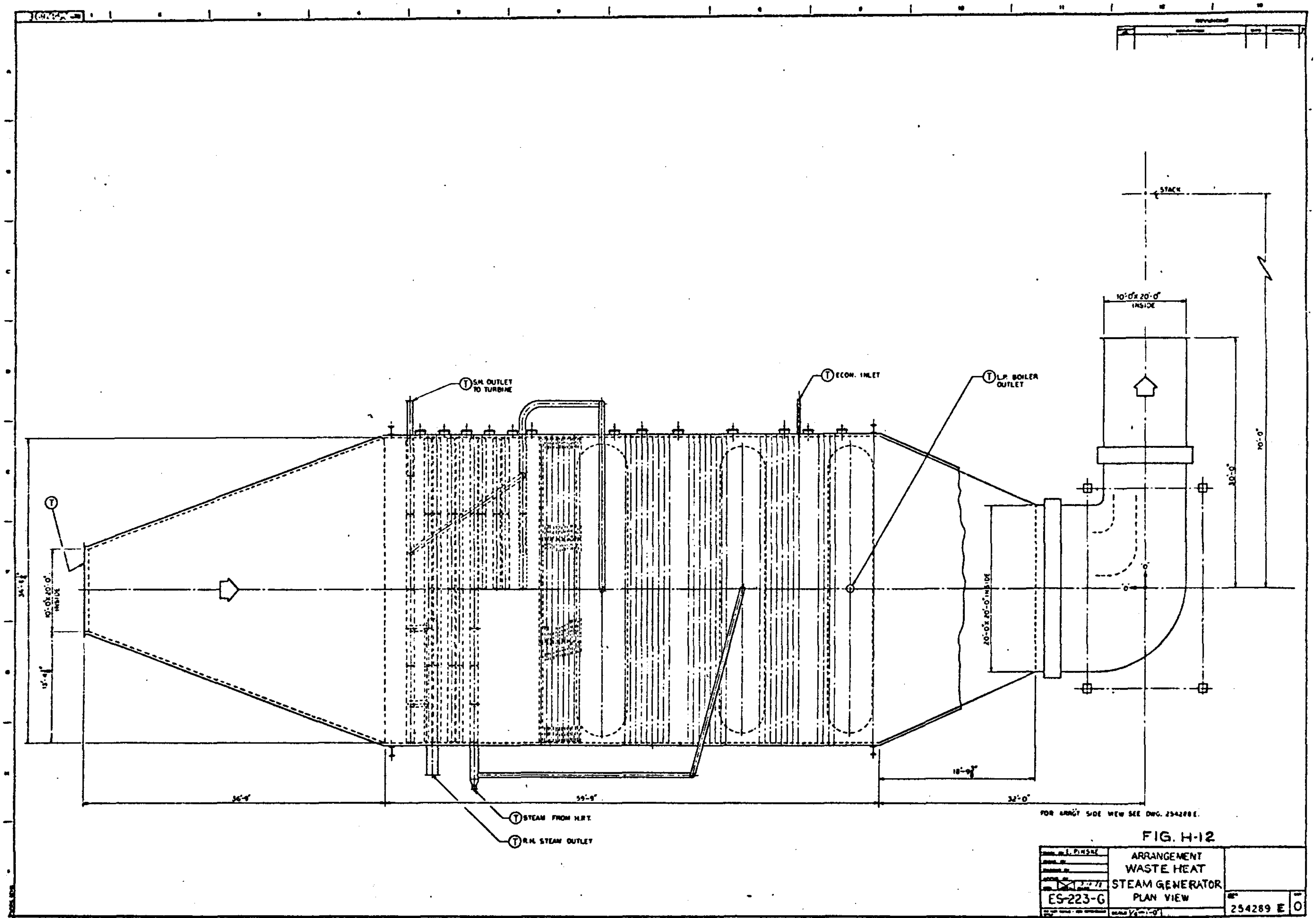

S.H. OUTLET TO TURBINE
ECON. INLET
L.P. BOILER OUTLET
STACK
10'-0" x 20'-0" INSIDE
20'-0" x 20'-0" INSIDE
30'-0"
70'-0"
36'-9"
59'-9"
32'-0"
18'-9½"
STEAM FROM H.P.T.
R.H. STEAM OUTLET
FOR ARRG'T SIDE VIEW SEE DWG. 254288 E.
ARRANGEMENT
WASTE HEAT
STEAM GENERATOR
PLAN VIEW
ES-223-G
254289 E
0

FIG. H-12

A — FUEL & TURBINE EXHAUST GAS

TURBINE EXHAUST GAS @ 1161 °F

ANALYSIS					
SOURCE OF ANALYSIS					
LOAD REF.	1				
FUEL					
% BY					
N_2	73.960				
O_2	17.805				
CO_2	5.839				
H_2O	1.042				
SO_2	0.031				
AR	1.323				
TOTAL	100				

SUPPLEMENTARY FUEL

ULTIMATE ANALYSIS				
SOURCE OF ANALYSIS				
FUEL				
% BY				
ASH				
S				
H_2				
C				
CH_4				
C_2H_4				
C_2H_6				
C_3H_8				
C_4H_{10}				
C_5H_{12}				
C_6H_{14}				
CO				
CO_2				
SO_2				
H_2O				
N_2				
O_2				
TOTAL				
BTU/LB				
BTU/CU. FT. AT 60 F., 30 IN. HG.				

B — PREDICTED PERFORMANCE

2	GAS TURBINE LOAD CONDITION	LOAD REFERENCE	1
3		AIR TEMP (°F)	59
4		FUEL	PFB COAL COMBUSTION
5		GAS TURBINE LOAD	100%
6		GAS FLOW (MLB/HR)	3077.30
7		EXHAUST TEMP (°F)	1161
8		% INJECTION	–
9		BY PASS STACK LEAKAGE (MLB/HR)	0
10	SUPP. FIRING	TYPE OF SUPP FUEL	NONE
11		FUEL INPUT (MKB/HR)	–
12		SUPP FUEL (MLB/HR OIL, MCFH N.G)	–
13		SUPP AIR FLOW (MLB/HR)	–
14		GAS FLOW ENT. BOILER (MLB/HR)	3077.3
15	HP BOILER	STEAM FLOW LVG SH (MLB/HR)	379.06
16		STEAM TEMP AT SH (°F)	955
17		STM PRESS. AT SH (PSIG)	2500
18		PRESS. DROP - ECON. (PSI)	25
19		PRESS. DROP-DRUM TO SH (OUTLET) (PSI)	100
20		FEED WATER TEMPERATURE (°F)	240
21		BLOW DOWN (MLB/HR)	0
22		SOLIDS IN STEAM (PPM)	1.0
23		MAX ALLOWABLE BOILER CONC. (PPM)	400
24			
25	IP BOILER	STEAM FLOW LVG DRUM (MLB/HR)	70.56
26		STM PRESS. AT DRUM (PSIG)	630
27		PRESS DROP - ECON. (PSI)	–
28		FEED WATER TEMPERATURE (°F)	240
29		BLOW DOWN (MLB/HR)	–
30		SOLIDS IN STEAM (PPM)	1
31		MAX ALLOWABLE BOILER CONC. (PPM)	1500
32			
33	LP BOILER	STEAM FLOW LVG (MLB/HR)	43.8
34		STM. PRESS. AT DRUM (PSIG)	20
35		PRESS DROP - ECON. (PSI)	
36		FEED WATER TEMPERATURE (°F)	240
37		BLOW DOWN (MLB/HR)	–
38		MOISTURE IN STEAM %	0.5
39		MAX ALLOWABLE BOILER CONC. (PPM)	3500
40			
41		GAS TEMPERATURE TO STACK (°F)	328.3
42	RESISTANCE IN. OF WATER	BURNER	–
43		CONVECTION BANKS	6
44		FLUES & STACK	4
45			
46		PRESS. AT GT EXH. ("WG)	10

C — EQUIPMENT PER UNIT

2	TYPE		PFB COMBINED CYCLE HEAT RECOVERY BOILER		
3	SIZE		30' x 40'		
7	HP BOILER	SHTR	HS 135,369 SQ.FT.	TUBES, OD 2 IN.	4 FINS/INCH
8			DESIGN PRESS. 2800	20 ROWS AT 4 IN.	46 WIDE AT 4.5 IN.
11		BOILER	HS 216,590 SQ.FT.	TUBES, OD 2 IN.	4 FINS/INCH
12			DESIGN PRESS. 2800	16 ROWS AT 4 IN.	96 WIDE AT 4.5 IN.
15			DRUM INTERNALS CYCLONE SEPARATORS & SECONDARY SCRUBBERS		
17		EC.	HS 459,878 SQ.FT.	TUBES, OD 2 IN.	4 FINS/INCH
18			DESIGN PRESS. 2800	34 ROWS AT 4 IN.	96 WIDE AT 4.5 IN.
19		STEAM TEMP CONTROL	TYPE ATTEMPERATOR SPRAY		
22	IP BOILER	BOILER	HS 216,590 SQ.FT.	TUBES, OD 2 IN.	4 FINS/INCH
23			DESIGN PRESS 700	16 ROWS AT 4 IN.	96 WIDE AT 4.5 IN.
24			DRUM INTERNALS CYCLONE SEPARATORS & SECONDARY SCRUBBERS		
26		EC.	HS SQ.FT.	TUBES, OD IN.	FINS/INCH
27			DESIGN PRESS.	ROWS AT IN.	WIDE AT IN.
28	LP BOILER	BOILER	HS 108,107 SQ.FT.	TUBES, OD 2 IN.	4 FINS/INCH
29			DESIGN PRESS. 300	8 ROWS AT 4 IN.	96 WIDE AT 4.5 IN.
30			DRUM INTERNALS 'B' BAFFLES & DRY PAN		
32	RH		HS 81,221 SQ.FT.	TUBES, OD 2 IN.	4 FINS/INCH
33			DESIGN PRESS. 700	12 ROWS AT 4 IN.	48 WIDE AT 4.5 IN.
36	BURNER		INPUT - MKB/HR -		

REVISIONS NO.	DESCRIPTION	BY	DATE

TEG HEAT RECOVERY BOILER PERFORMANCE SUMMARY

BY H. DOSS | DATE 5-18-78 | APPD.

THE BABCOCK & WILCOX COMPANY

P-

PREDICTED PERFORMANCE IS BASED ON TEG ENTERING UNIT AT SPECIFIED TEMPERATURE, ON IN.HG. BAROMETRIC PRESSURE, ON 80F REFERENCE TEMPERATURE, ON CONDITIONS AND EQUIPMENT GIVEN ON THIS SUMMARY SHEET AND ON ARRANGEMENT SHOWN ON DRAWING

TABLE H-5
PFB/GT/POWER TURBINE REHEAT CYCLE WHSG PERFORMANCE SUMMARY

The lower superheater and reheater headers rest on the support grid and are positioned by alignment guides on the connection penetration of the lower gas tight casing. To accommodate the differential expansion of the tubes and the casing, the modules are free to expand vertically. They are stablized at the top at the upper inlet header and upper screen header by alignment guides on the connection penetrations of the upper gas tight casing.

The generating bank consists of three modules and follows the superheater-reheater section in direction of gas flow. These modules, each twenty rows deep, are located side by side across the width of the unit. The generating bank is designed for natural circulation; no circulating pumps are required in the boiler. The water from the drum flows down three downcomer pipes located in the gas stream behind the generating bank. The downcomers penetrate the lower gas tight casing. Below this casing, supply tubes are routed to the lower headers of the generating sections. Riser tubes carry the steam-water mixture from the upper headers into the drum. The drum internals include cyclone steam separators to separate the steam-water mixture entering the drum from the generating bank. The water is discharged from the bottom of the cyclone steam separators and is mixed with the feed water from the economizer discharge. The feed water from the economizer also passes through independent cyclone steam separators as it enters the drum to provide steam-water separation during operation at the lower loads when the economizer is steaming.

The lower generating bank headers rest on the support grid. Both the upper and lower headers are integrated into the gas tight casing so that the numerous supply and riser tubes need not penetrate the casing. The lower headers are attached directly to the casing. The upper headers are attached to the casing by a metallic expansion joint.

The drum is supported on the downcomers which, in turn, are bottom supported. In this manner, the generating sections, drum and downcomer are all supported from the same elevation. Since these components are always at saturation temperature, they expand together. With the use of the expansion joints at the upper headers and at the downcomer penetrations of the upper gas tight casing, these pressure parts are free to expand independently of the casing.

The economizer outlet bank follows the generating bank and consists of three modules, each with nine of the two row sections connected in series. The economizer inlet bank follows the intermediate pressure boiler generating bank and consists of three modules, each with eight of the two row sections connected in series. Because of the potential for steam generation in the economizer at the lower loads, up flow is desired in the multiple finned tubes of each section. The connection between successive upflow sections is accomplished by a single, non-finned tube routed, inside the gas stream, from the upper header of one section to the lower header of the next section. This arrangement provides for stable water flow through the economizer at all loads.

The lower economizer headers are supported from the support grid with the gas tight casing located between the headers and support grid. The upper gas tight seal is located above the upper headers. This allows the modules to expand independent of the casing. In addition, the flexibility of the connecting tube between modules allows for free expansion of the modules relative to one another. This is required due to the increasing water temperature through the economizer and because this temperature profile changes with load. Each economizer section is provided with a drain connection on the lower header and a vent connection on the upper header so that the economizer may be completely drained.

4.3.3.3 Intermediate Pressure Boiler

The intermediate pressure boiler consists of a generating bank located between the high pressure boiler economizer banks. The bank consists of three modules, each sixteen rows deep, located side by side across the width of the unit.

The design parallels that of the high pressure boiler except for the drum internals. The feed water enters the economizer located between the intermediate and low pressure boilers. The outlet from this section of the economizer splits into two streams, one feeding the IP boiler steam drum and another lead into the next section of the economizer located between the intermediate and the high pressure boiler. The drum internals include cyclone steam separators to separate steam-water mixture entering the drum from the generating banks.

4.3.3.4 Low Pressure Boiler (Deaerator Boiler)

The low pressure boiler consists of only a generating bank. It consists of three modules, each eight rows deep, located side by side across the width of the unit following the high pressure boiler economizer inlet bank. The design is similar to that of the Intermediate Pressure Boiler. A baffle arrangement is provided for steam-water separation.

4.3.4 Gas Turbine

The gas turbine subsystem is generally of the same size as that of Subtask 1.2, but there are several internal and external changes necessary to match the reheat cycle. The selected cycle has a pressure ratio of 16 and an airflow of 840 #/sec. These parameters are consistent with FT50 gas generator design values. For Subtask 1.9, therefore, the FT50 gas generator has been assumed for all mechanical studies.

Ducting for the exhaust gases from the compressor drive turbine to the reheat PFB is located at the exhaust end of the FT50 gas generator. The reheated gas from the PFB can then be ducted to a power turbine similar to the FT50 in design. The power turbine and electric generator can be located at any location convenient to the reheat PFB and general plant layout. The flow area of the turbine would be increased to accommodate the higher volume flow at the higher reheat temperature of 1500F. This increase is not too large in the case of the FT50 because the original turbine design was based on a relatively high turbine inlet temperature.

In addition to the gas turbine changes, the electric output per gas turbine in 78.3 MW which is nearly 15 MW greater than the gas turbine output of the Subtask 1.2 cycle. A slightly larger generator is required to accommodate this increase in power.

The other gas turbine systems such as the lube system, start system, etc., are affected to a small degree by the configuration changes.

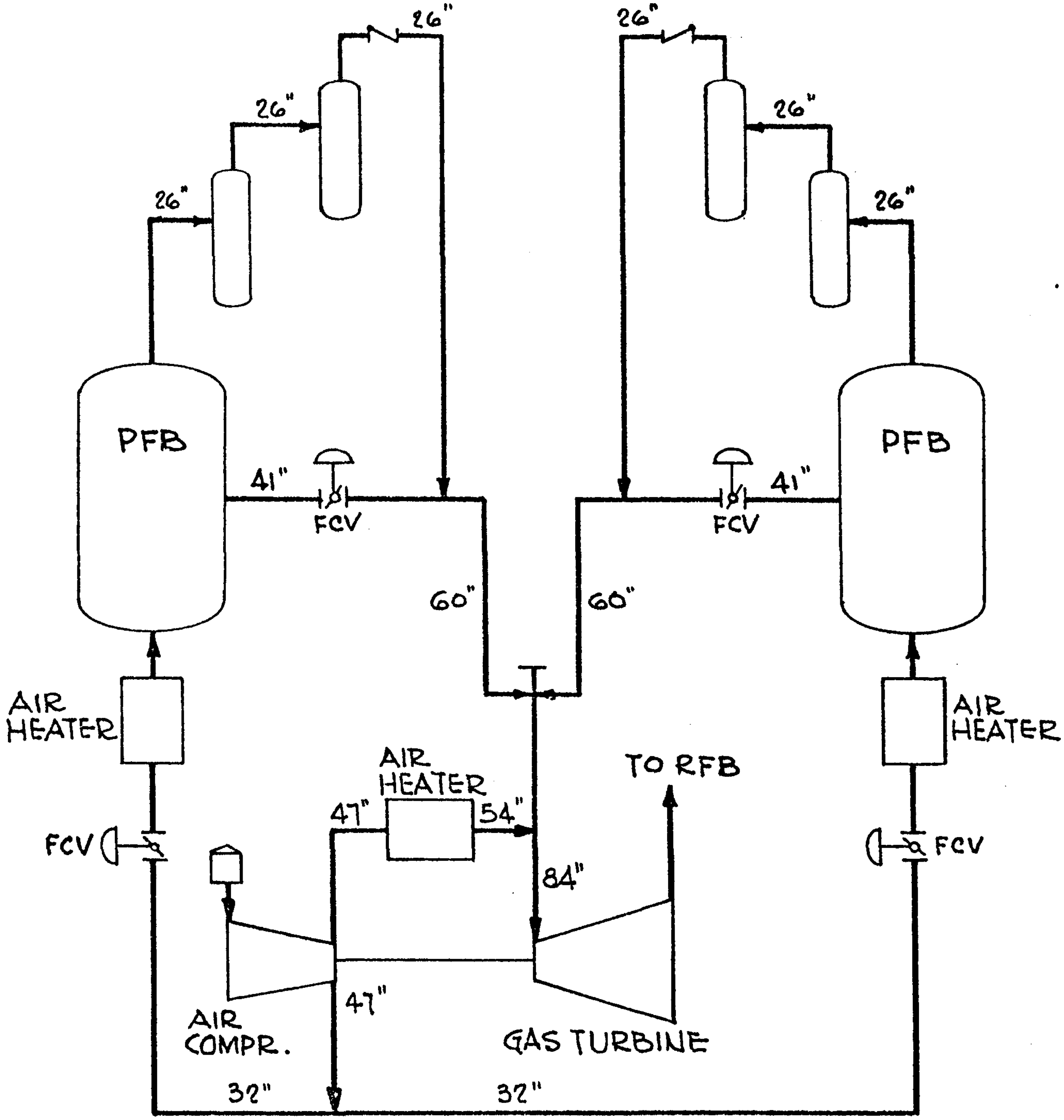
4.3.5 High Temperature Gas Piping and Valving

Except for smaller diameters (see Fig. J-1), the high temperature refractory lined piping and valving around each configuration of main PFB's (16 atm.), cyclones, and gas generator sets are of the same configuration, and quantity as used in Subtask 1.2. See Pages 136-159 of the report on Subtask 1.2 (Commercial Plant Design) for more details. The exhaust gases from each gas generator are piped to two reheat PFB combustors in each of which the gas stream is split so that approximately 16% of the stream is reheated in the fluidized bed and 84% is reheated in coils in the fluidized bed. The gas streams are combined, after clean-up of the 16% stream, and piped to the separate gas turbine-generator set. Appropriately sized (see Fig. H-6) refractory lined piping and high temperature valves of the same design as used for the main PFB system are provided for the various streams entering and leaving the reheat combustor.

4.3.6 Coal and Sorbent Handling Systems

The coal and sorbent handling systems are of the same general design as used in Subtask 1.2, except that limestone handling is not required. The changes in system configuration are indicated by comparing Figure F-1, Area Site Plan, with the corresponding figures in the Subtask 1.2 report (i.e., Fig. C-1, page 253). Briefly, these changes are as follows:

- The limestone storage pile is removed.
- The sorbent stacker does not have capability to swivel.
- The underground reclaim system for limestone is removed.
- The length of the coal and dolomite storage silo feed conveyors is increased since the east-to-west dimension between the first and last silos is increased to accommodate the greater number of gas turbines and the addition of the reheat combustors.
- Some minor changes to the crushers are required since it is no longer necessary to produce two different coal sizes (i.e., one for AFB and one for PFB) and sorbent sizes.



MAIN PFB COMBUSTOR/GAS GENERATOR SYSTEM

HIGH TEMPERATURE PIPING & VALVE SCHEMATIC

FIGURE J-1

4.3.7 Coal and Sorbent Feed Systems

4.3.7.1 Main PFB Combustor Feed System

Separate pneumatic transport systems are used for the coal and sorbent feed. The systems incorporate lock hoppers for pressurization of the coal and the dolomite. One coal feed system and one dolomite feed system are provided for each PFB combustor.

The arrangement of the lock hoppers and feed tanks is similar to that shown on page 173 of the Report on Subtask 1.2 (Commercial Plant Design) and the system schematic and instrumentation are similar to that shown on page 174.

The crushed solids (coal or dolomite) from the bunker free fall into one of the two lock hoppers. The hopper is pressurized and the solids then free fall into the feed tank. From the feed tank the solids are pneumatically transported to the PFB combustor with the feed rate controlled by the speed of the rotary, "air swept" feeder at the feed tank outlet. A single transport line is used from the feed tank to a feed distributor located beneath the PFB combustor. At the distributor the solids/air mixture is divided evenly among the individual feed lines to the combustor. Sixteen coal feed lines (each servicing approximately 9 square feet of bed area) and four dolomite feed lines are used.

4.3.7.2 Reheat PFB Combustor Feed System

Separate pneumatic transport systems are used for the coal and sorbent feed. The systems incorporate lock hoppers for pressurization of the coal and the dolomite. One coal feed system and one dolomite feed system are provided for each PFB combustor. The arrangement of the lock hoppers and feed tanks as well as the system schematic and instrumentation are similar to those described for the main PFB. The major exceptions are in the number of distributors and feed lines for each combustor. There are four coal feed distributors and four dolomite feed distributors per combustor. At the distributor the solids/air mixture is divided evenly among the individual feed lines to the combustor. Sixty-four coal feed lines (each servicing approximately 9 sq. ft. of bed area) and sixteen dolomite feed lines are used per combustor.

4.3.8. Particulate Removal Systems

4.3.8.1 Main PFB Particulate Removal System

The gas from the PFB combustor passes through two stages of high efficiency cyclones for particulate removal to the requirements projected for the gas turbine. The allowable gas turbine particulate loading is based on the presumption that particles greater than 10 microns in size would give unsatisfactory turbine life, particles less than 2 microns in size would have negligible effects on turbine life and that some limited amount of particulate in the 2-10 micron size range could be tolerated within the gas turbine. The resulting allowable dust loading entering the gas turbine is:

particle diameter, d (microns)	max. particulate concentration (grains/SCF)
d<2.0	no limit
2.0<d<10.0	0.0100
d>10.0	0.0000

The high efficiency cyclones are Aerodyne Development Corporation's "SV-FBC" Series Dust Collectors. This is actually a two-stage cyclone contained within a single pressure vessel. The Model 15000SV, which is capable of handling the combustion gas flow from one PFB combustor, is used as the design basis. This design is an extension of the equipment presently used in low temperature, low pressure applications. Based on the projected particulate loading in the combustion gas and the predicted collection efficiency, two of these collectors operating in series are required to achieve the particulate loading level which complies with both the EPA emission limit and the gas turbine requirements. The predicted performance is shown in Table H-1.

A system of holding tanks and lock hoppers is provided for depressurization and dumping of the solids to the solids coolers. The arrangement of the cyclones and associated lock hoppers is similar to that shown on page 201 of the Report on Subtask 1.2 (Commercial Plant Design).

4.3.8.2 RHPFB Particulate Removal System

At the present time empirical information regarding the particle size distribution of the solids elutriated from a PFB combustor is unavailable. Consequently, assumptions have been made in order to establish the size distribution of the particulates elutriated from the RHPFB Combustors. See pages 180-184 on the Report on Subtask 1.2 (Commercial Plant Design) for a description of these assumptions.

In addition to the particles of spent sorbent and coal ash that are elutriated from the reheat combustors, consideration must also be given to the particulates discharged from the gas generator. The sources of these particulates are the two Sixteen Atmosphere PFB Combustors located upstream from the gas generator. Particulates elutriated by these combustors and not removed by their gas cleanup systems eventually reach the inlet nozzles of the reheat combustors. Since 16% of the gas generator discharge air flow is used for combustion and fluidizng air in the bed of the reheat combustor, it was assumed that 16% of the particulates entering the reheat combustors are routed to their beds. These particulates will place an additional loading on the reheat combustors' gas cleanup systems. The remaining 84% of the particulates entering the reheat combustors will be routed through the cooling tubes and flow to the power turbine without passing through any gas cleanup equipment.

TABLE H-1

Projected Removal Of Particulates In The Aerodyne 15000 SV System
For Ca/S Ratio of 1.0

Dust flow entering the first collector = 11590 lbm/hr

	First Collector	Second Collector
particulates removed in the first stage (lbm/hr)	9574	47.1
particulates removed in the second stage (lbm/hr)	1690.5	183.5
dust flow leaving the collector (lbm/hr)	325.5	94.9
dust concentration entering the turbine (grains/SCF)		.0175

particle distribution entering the turbine

particle diameter, d (microns)	particle concentration (grains/SCF)
$d<2.0$	0.0149
$2.0 \le d \le 10.0$	0.0026
$d > 10.0$	0.0000

All flow rates are based on two (2) PFB combustors operating in parallel and feeding a single gas turbine. The contribution of each combustor is half of the indicated flow rate.

The expected operating conditions of the reheat combustors particulate removal systems are based on a Ca/S molar feed ratio of 1.0. These conditions are shown in Table H-2. Because of the assumption for the size distribution of the spent sorbent, the dust in the less than 10 micron size range is essentially all coal ash.

As explained on page 184 of the Subtask 1.2 Report (Commerical Plant Design), an estimate of allowable gas turbine particulate loading has been made and is shown in the previous section (4.3.8.1). These estimates consider the fact that PFB particulates are expected to be less errosive than particulates used in tests reported to date. The performance requirements for the particulate removal system are based on these permissible dust loadings entering the gas turbine:

particle diameter, d (microns)	max. particulate concentration (grains/SCF)
$d<2.0$	no limit
$2.0 \leq d \leq 10.0$	0.0100
$d>10.0$	0.0000

Additional design requirements for the equipment are shown in Table H-3.

The location of the particulate removal equipment is shown schematically in Figure H-6. With the choosen concept for the PFB combustor, the particulate removal equipment need only accommodate approximately 16% of the total gas flow entering the gas turbine. Since the size and cost of this equipment is greatly influenced by the gas volume, this design concept helps minimize the equipment cost.

It should, however, be noted that the required particulate removal efficiency is only a function of the solids flow from the bed (i.e., a function of fuel flow) and the permissible solids flow to the gas turbine and is not a function of the proportion of the total gas flow that must be cleaned up. The air cooled PFB cycles consume less fuel per unit of turbine gas flow than the steam cooled PFB cycles and hence require lower particulate removal efficiency for the same absolute turbine limits. The split flow air cooled combustor considered here requires the same removal efficiency as the steam cooled and excess air cooled concepts of Subtask 1.7 but benefits from the smaller volume of gas to be cleaned.

On the basis of predicted performance, system cost and projected operating reliability, Aerodyne Development Corporation's "SV-FBC" Series Dust Collector has been selected for use in the conceptual plant design. The Model 18000 SV, is used as the design basis. This design is the same as that described in the Subtask 1.2 Report (Commerical Plant Design) except for size.

TABLE H-2

REHEAT PFB PARTICULATE REMOVAL EQUIPMENT

OPERATING CONDITIONS FOR Ca/S = 1.0

Collector Inlet Gas Analysis

Component	lbm/hr	moles/hr
O_2	11684.5	365.14
N_2	358494.4	12796.06
Ar	6403.1	160.31
SO_2	619.5	9.67
CO_2	116799.2	2653.92
H_2O	20841.2	1156.82
Total	514841.9	17141.92

Collector Inlet Gas Molecular Weight	30.034 lbm/mole
Collector Inlet Gas Temperature	1650°F
Collector Inlet Gas Pressure	37.0 psia
Collector Inlet Gas Density	0.0491 lbm/ft^3
Collector Inlet Dust Flow	6361.28 lbm/hr

Collector Inlet Particle Size Distribution

particle diameter (microns)	% by weight ≥ stated particle diameter
100	23.60
80	27.86
60	32.74
40	40.20
20	55.40
10	71.42
8	75.50
6	80.93
4	87.67
2	95.77

Air Flow Through Cooling Tubes	2561984 lbm/hr
Air Flow Temperature	1400°F
Air Flow Pressure	37.0 psia
Dust Flow Through Cooling Tubes	79.74 lbm/hr

Dust Flow Particle Size Distribution

particle diameter (microns)	% by weight ≥ stated particle diameter
8	0.00
6	0.09
4	1.34
2	14.90

All flow rates are based on two (2) reheat PFB combustors operating in parallel and feeding a single power turbine.

TABLE H-3

REHEAT PFB COMBUSTOR PARTICULATE REMOVAL EQUIPMENT

DESIGN REQUIREMENTS

1. The maximum allowable unrecoverable pressure loss that can exist between the inlet and outlet of the dust collection equipment is 1.00 psi.

2. All insulation is to be located adjacent to the inside surface of the exterior walls of the dust collection equipment.

3. The metal temperature of the outside surface of the exterior walls of the dust collection equipment is to be maintained at 250°F when the ambient air temperature is 80°F and the flue gas temperature is 1650° F.

4. Each pressurized fluidized bed combustor is to have its own dust collection system.

The predicted collection efficiency is shown in Figure N-4 of the Report on Subtask 1.2 (Commercial Plant Design). Calculations indicate that three sets of these collectors operating in parallel would be required for each Reheat PFB combustor. Each set would consist of two (2) Model 18000 Dust Collectors operating in series. The predicted performance is shown in Table H-4 for a Ca/S ratio of 1.0. The dust loading entering the gas turbine in the critical 2 to 10 micron size range is projected to be 36% of the gas turbine allowable level.

It must be remembered that the performance of the particulate removal system is based on both the prediction of the equipment performance and assumptions regarding the particulate sizing. The indicated performance represents better than 99% particulate removal. Seemingly small changes in either predicted collection efficiency or in the assumed particulate size distribution leaving the PFB's result in significant changes in both the particulate concentration entering the gas turbines and the plant emissions per unit of heat input. This portion of the system design therefore contains one of the greater degrees of uncertainty.

In the case of the particulate concentration, another degree of uncertainty exists; namely the turbine tolerance. It is possible that the turbine may be more tolerable to particulate loading then assumed thereby lessening that degree of uncertainty.

The particulate emission per unit of fuel input is however an absolute limit that is expected to become more stringent with time. Due to the uncertainty involved in the predictions, it is possible that additional controls will be required in the plant to meet the present limit of 0.1 lb/10^6 Btu and highly probable that they would be required for the anticipated limit of 0.03 lb/10^6 Btu. The additional controls may be either in the form of more sophisticated equipment (granular bed filters, etc.) following the PFB combustors, or, if the particulate loading is acceptable for the gas turbine, some type of stack clean-up equipment such as a bag house or electrostatic precipitator.

TABLE H-4

AERODYNE DEVELOPMENT CORP. MODEL 18000 SV DUST COLLECTORS

PARTICULATES REMOVED FOR Ca/S = 1.0

dust flow entering the first collector = 6361.3 lbm/hr

	First Collector	Second Collector
particulates removed in the first stage (lbm/hr)	5127.1	28.9
particulates removed in the second stage "	1031.2	114.1
dust flow leaving the collector (lbm/hr)	203.0	60.0
dust flow bypassing the cleanup system (lbm/hr)	79.7	
*total emissions (lbm dust/10^6BTU)	0.1	
dust concentration entering the turbine (grains/SCF)	0.0244	

particle distribution entering the turbine:

particle diameter, d (microns)	particle concentration (grains/SCF)
$d < 2.0$	0.0208
$2.0 \leq d \leq 10.0$	0.0036
$d > 10.0$	0.0000

*based on fuel input to combustor (HHV = 12453 BTU/lbm as fired).

All flow rates are based on two (2) reheat PFB combustors operating in parallel and feeding a single power turbine.

4.3.9 Solid Waste Handling System

The solid waste handling system for the PFB/GT/Power Turbine Reheat Cycle is basically the same design as used in Subtask 1.2. Changes have been made in the piping and equipment to account for the elimination of the AFB and its associated cyclones, as well as the electrostatic precipitator. The system has been revised to reflect the increased number of PFB combustors (both main PFB's and RHPFB's) and their associated Aerodyne Cyclones.

The solid waste from each main PFB and RHPFB unit and its corresponding dust removal system is piped to a Fuller Fluidized Bed Hydroaire solid waste coolers. Each gas turbine unit has two PFB combustors, two RFB combustors, and four solid waste coolers. The total plant arrangement consists of four similar gas turbine modules (Figure F-1).

The solid waste is transferred from each solid waste cooler to a storage silo by means of a positive pressure pneumatic transport system. The solid waste from each gas turbine module is transferred to a single storage silo. This results in the use of four solid waste storage silos for the total plant. The design features, details and size of each silo are the same as those described under Subtask 1.2.

The unloading and removal of the solid waste from the silos is similar to the method described in the Subtask 1.2. report.

4.3.9.1 PFB Combustor Spent Bed Material Letdown Systems

4.3.9.1.1 Main PFB Combustor (16 atm.) Letdown System

Two solids drains are provided on the PFB combustor. The upper drain is a standpipe arrangement at the side of the pressure vessel at the normal bed operating level. This drain is used for level control during normal operation of the combustor. The lower drain at the distributor plate provides both low bed level control during startup and a means of lowering the bed level during the unit shutdown. A lock hopper system is provided for depressurization and dumping of the solids to the solids cooler. See pages 197-199 of the Subtask 1.2 report for a more detailed description of this system.

4.3.9.1.2 RHPFB Combustor (2-1/2 Atm.) Letdown System

Four solids drains are provided on each Reheat PFB combustor. The two upper drains are standpipe arrangements (See Figure H-7). One drain is located on each head at the normal bed operating level. These drains are used for level control during normal operation of the combustor. The two lower drains at the distributor plate (Section "D-D" of Figure H-9) are used for low bed level control during start-up and provide a means of lowering the bed level during the unit shut-down. Two lock hopper systems are provided for depressurization and dumping of the solids to the solids cooler (Figure H-8). Each system serves one upper drain and one lower drain.

4.3.10 Steam Turbine - Generator and Auxiliaries

4.3.10.1 Steam Turbine Type

The steam turbine is a 3600 rpm single reheat, tandem coupound unit with a four flow exhaust and 30 inch last row blades. The turbine provides steam for the WHSG feed water pump drive turbines.

4.3.10.2 Turbine Performance Parameters

The nominal rating and steam conditions are as follows:

Generation, KW- 320,000
Throttle Steam Flow, lb/hr. - 1,620,000
Inlet Pressure, psig - 2,400
Inlet Temp., ^{o}F - 950
Hot Reheat Temp., ^{o}F - 950
Condenser backpressure,
  in HG abs -2

4.3.10.3 Generator

The generator design is based on 400,000 KVA, 0.90 pf, 0.85 SCR (at 60 psig hydrogen pressure), 3 phase, 60 Hz, 24,000 volt, and 3,600 rpm.

4.3.10.4 Excitation Equipment

The generator has one shaft driven, suitably rated compact excitation system.

4.3.10.5 Accessories

4.3.10.5.1 Auxiliary Heat Exchangers

The auxiliary heat exchangers are provided with admiralty tubes designed for the use of closed cooling water supplied at 95^{o}F maximum. Four Hydrogen Coolers and two lube oil coolers are provided.

4.3.10.5.2 Gland Steam System

The gland steam system is complete with a gland steam regulator and a gland steam exhauster with stainless steel tubes. The exhauster is designed for cooling with condensate. The design temperature and pressure are 105^{o}F and 400 psig respectively. All necessary piping and accessories are provided.

4.3.10.5.3 Lubrication System

The lubricating oil system consists of an oil reservoir with float-type level indicator, vapor extractor and mist eliminator. The main oil pump is turbine shaft driven. An a-c motor driven auxiliary pump and a d-c motor driven emergency oil pump are also provided.

Two full size oil coolers are also provided with manual valves to permit a change over from one to the other without coming off line.

4.3.10.5.4 Main Steam and Reheat Valves

Separately mounted throttle stop and governing control vavles are provided. The throttle stop valves are capable of withstanding cold boiler hydrostatic test pressure of 4,000 psig. Reheat stop and interceptor valves are also provided.

4.3.10.5.5 Turbine Controls

The turbine shall be provided with an electrohydraulic governing system comprising a high pressure fluid reservoir, fluid supply system pumps, filters and coolers. The governing valve controller shall provide for automatic and manual speed control and bumpless transfer from auto to manual. Protective devices shall be provided to trip the turbine on abnormal conditions including overspeed, low oil pressure, excessive vibration, high bearing or turbine metal temperatures.

4.3.11 Steam and Boiler Feedwater System

4.3.11.1 General

For the steam plant, a conventional 2415 psia, 950^{o}FSH, 950^{O}RH high pressure steam cycle is used. The high pressure steam is collected from the four waste heat steam generators and piped to the high pressure section of the steam turbine where it is expanded to and exhausted at a pressure of 584 psia. The exhausted steam is returned to the four waste heat steam generators where it is reheated to a temperature of 950^{o}F. The steam is collected again and piped to the low pressure section of the turbine where it is expanded from 526 psia to .982 psia and 101^{o}F at the condenser. Low pressure steam at 166 psia and 697^{o}F is extracted from the turbine to drive the high pressure feedwater pump turbine. Steam for the single deaerator is provided by the low pressure boiler (deaerator boiler) of each of the four waste heat steam generators.

4.3.11.2 Main Steam Piping System

Piping other than those portions under the jurisdiction of the ASME Power Boiler code are designed to ANSI Power Piping Code B31.1.

The main steam piping from the superheater outlet to the turbine stop valves is designed in accordance with the ASME Power Boiler Code. No stop valves other than the turbine stop valves are provided. The turbine stop valves are designed to meet boiler code requirements including boiler hydrostatic test.

The pressure drop from superheater outlet to turbine throttle is 100 psi. A 5^{o}F temperature drop occurs between these two points. The piping is designed for a maximum temperature of 960^{o}F.

4.3.11.3 Hot and Cold Reheat System

The hot and cold reheat system piping is designed in accordance with ANSI Piping Code B31.1. The maximum flow velocity is 18,000 FPM at full load output. The hot reheat piping is designed for a maximum temperature of 960°F. Welded piping is provided where seamless is not available due to size.

The cold reheat lines have provisions for blowing out of the lines with steam prior to start up to prevent contamination.

Attemperators supplied by the boiler manufacturer are located in the cold reheat lines to control reheat temperature. Spray water to the attemperators is supplied from the interstage connections on the boiler feed pumps. The movement of the reheat piping in relation to the spray water piping has been considered.

Safety valves are supplied by the boiler manufacturer for the inlet and outlet piping to the reheater. Nozzle designs for the relief valves and pipe supports are adequate for the forces developed when the safety valves are actuated.

4.3.11.4 Condensate Feedwater System, and Heater Drain System

4.3.11.4.1 Condensate System

a. Condensate System Arrangement

The condensers are interconnected in the steam space by a connection sized to prevent tripping of the turbine due to excessive pressure and/or temperature difference caused by loss of cooling water to one of the condensers when the plant is operating at a load compatible with one condenser operation.

The hotwells are interconnected by piping to maintain equal level in both condenser hotwells. This enables the suction connections to the condensate pumps to be taken from the nearest hotwell. Level controls and instrumentation are located on this hotwell.

Suction piping to the pumps is sized to provide the NPSH required. Air pockets are avoided in the suction lines. Butterfly valves are provided on the suction of each pump ahead of a temporary strainer and rubber expansion joint. A relief valve is provided on the suction side of each pump.

The condensate pumps discharge to the turbine gland exhauster, polishing demineralizer, and then to the deaerator.

The minimum condensate flow quantity is the greater of the condensate pump minimum flow requirements or the turbine gland exhauster minimum flow requirements. Minimum flow is controlled by condensate flow measurement.

The condenser high level dump is routed to the condensate storage tank. Condenser low level makeup comes from the condensate storage tank through a connection located above the tube bank to provide for deaeration. Chemical feed connections for hydrazine and ammonia are provided.

b. Condensate Storage

Two condensate storage tanks of 150,000 gallon capacity each are located at grade outdoors. They are lined with epoxy. An automatic control system provides make-up water to the condensate system on low level in the condenser hot well and returns it to the tanks on high level.

The condensate storage tanks are designed and fabricated in accordance with AWWA Specification D-100 for field erected tanks.

c. Condensate Polishing System

A full capacity condensate polishing system, consisting of a mixed bed exchanger is installed on a bypass between the condensate pumps and the deaerator. Semiautomatic regeneration is provided.

The unit is complete with acid and caustic storage tanks and pumps. Instruments, controls, alarms, and electrical equipment are mounted on a control panel located near the exchanger.

4.3.11.4.2 Feedwater System

a. Feedwater System Arrangement

The feed pumps and deaerator are located in the steam turbine-generator building. By a system of headers and manifolds, the four waste heat steam generators are fed by one set of high pressure, intermediate pressure and low pressure feed pumps taking water from one deaerator. Each suction line from the deaerator for each pressure level is a single line with parallel conections to two feed pumps. Each pump is equipped with a flow measuring device, recirculation valves for minimum flow protection, suction relief valve, a temporary strainer, and a warm-up orifice. Oxygen scavenging chemicals and pH control chemicals are fed into the suction lines. Three element feedwater controls are used for the three separate boilers on each waste heat steam generator. The high pressure pumps are multi-stage barrel type with double volute or diffuser type impellers. The outer barrel is carbon steel; but all other parts are 11-13 percent chrome steel.

Superheat attemperator spray water is taken from the high pressure feed discharge lines. The superheater attemperator system has sufficient capacity to account for the low pressure differentials that exist during part load operation.

The boiler feed pump discharge piping is sized for a maximum flow velocity of 20 fps. Piping 8 inches and over is fabricated from A106 GrC carbon steel, and pipe smaller than 8 inches from A 106 GrB carbon steel. Swing checkvalves and motor operated stop valves are provided in the discharge lines from each pump.

b. Makeup Feed Water

The source of makeup water for the boiler feedwater system is from the city water system. This is available at the northeast corner of the site. The city water pressure varies from 112 psig at zero flow to 30 psig at a line flow of 390 gpm. A 100,000 gallon storage tank is provided.

The city water is demineralized to the purity required for the steam cycle make-up using conventional equipment and technology. The system and equipment provided to treat the makeup water is described in 4.3.13.

4.3.12 Heat Rejection System

4.3.12.1 General

The condensers, generator air coolers, turbine oil coolers and closed cooling water heat exchangers reject their heat to the cooling water coming from a mechanical draft cooling tower. The heat rejection system is a closed type circulating water system.

The diagram, Figure R-1, shows the general scheme of the circulating water system. River water is used as make-up to compensate for blowdown and evaporation losses. The equipment is designed for full load operation at ISO ambient conditions.

4.3.12.2 Selection of Design Parameters

The design parameters used in selecting the cooling tower were based on the studies made in the Subtask 1.2 Report. The only changes made for this study are the quantities of water required for the equipment used in this cycle study which are shown on Figure R-1.

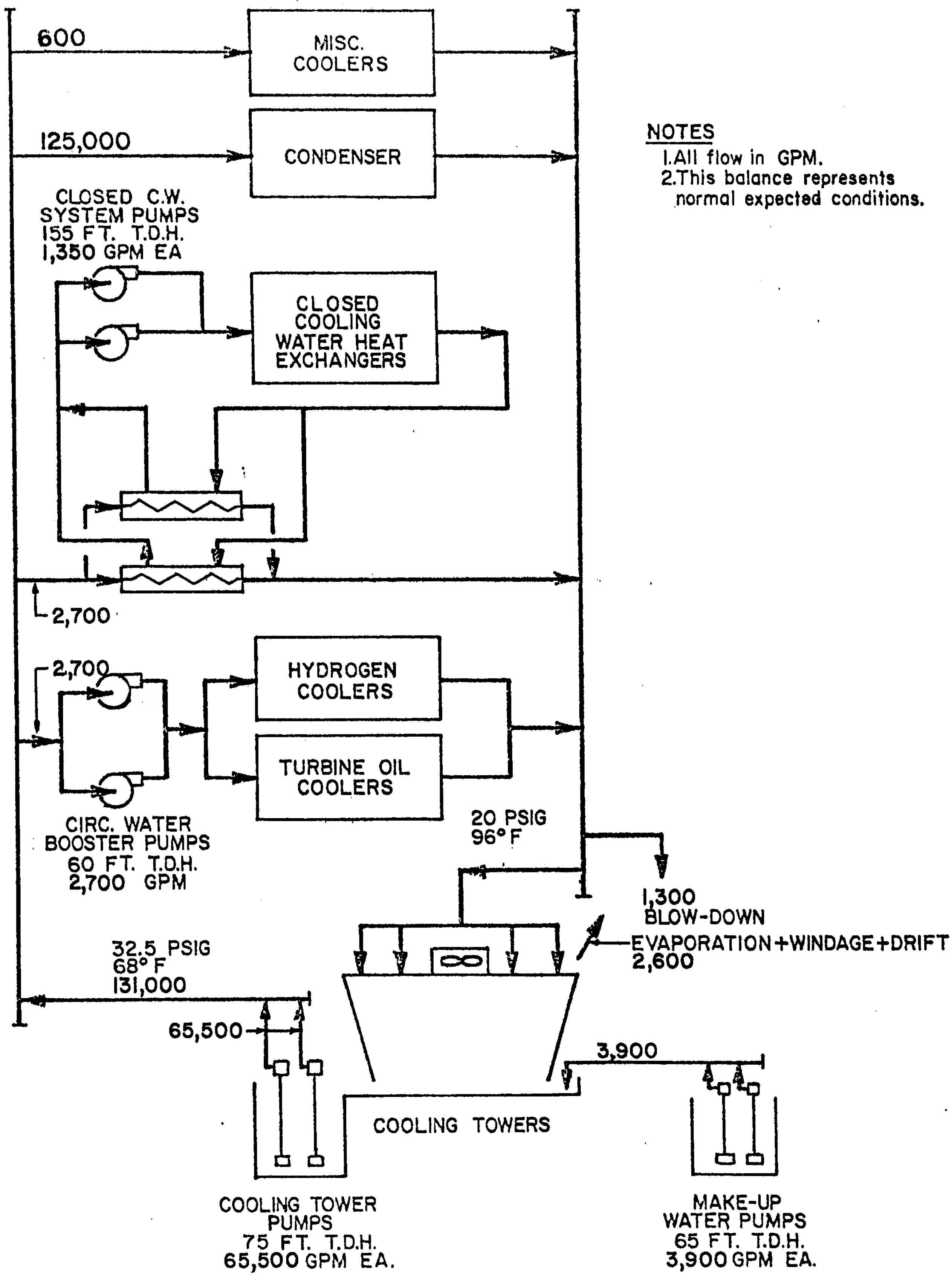
4.3.12.3 Cooling Tower

A mechanical draft, double flow induced draft cooling tower is erected above a concrete basin. One end of the concrete basin has sufficient depth to allow for the installation of vertical circulating water pumps.

Two 50% capacity, vertical motor driven circulating water pumps are installed in the wet pit of the tower basin.

4.3.12.4 Make-Up Water

River water is used for cooling tower make-up. The river water intake structure and equipment is similar to that used for Subtask 1.2 with the exception of the capacity of the equipment. The equipment is designed to supply the requirements called for on the flow diagram Figure R-1.



NOTES
1. All flow in GPM.
2. This balance represents normal expected conditions.

FLOW DIAGRAM FOR COOLING WATER

FIGURE R-1

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4.3.13 Water Treatment Systems

4.3.13.1 Make-up Feedwater System

The source of plant make-up feedwater is the city water system. This is available at the northeast corner of the site. The city water pressure varies from 112 psig at zero flow to 30 psig at a line flow of 390 gpm. A 100,000 gallon storage tank is mounted at the roof of the heater bay structure.

The analysis of the city water used is the same as that in Subtask 1.2.

The design capacity of the make-up feedwater treatment plant is 150 gpm. Automatic demineralizing skid mounted, water treatment units are used. Two units of 150 gpm capacity each will be installed.

4.3.13.2 Condensate Polishing System

The condensate demineralizing system is designed for semi-automatic operation and consists of a number of mixed-bed ion exchange designed to demineralize all of the station condensate. The term "demineralizing" is used interchangeably with the word "polishing." One of the total number of exchangers shall serve as a standby unit.

4.3.13.3 Boiler Chemical Feed System

The internal surfaces of the boiler in contact with water and steam must be kept free of scale and corrosion products to assure an efficient transfer of heat. In order to keep the total solids in the feedwater and boiler cycles at a minimum, a zero solids type chemical treatment is provided with phosphate backup.

4.3.13.4 Waste Water Treatment and Disposal System

Cooling tower blowdown is one of the major liquid waste streams produced by the plant. The blowdown from the cooling tower is metered and continously monitored for residual chlorine before being returned to the river.

The treatment and softening of make-up boiler feedwater also generates process waste water. This water, along with the waste water produced in boiler blowdown, equipment drains, floor drains, oil spills, coal pile run-off, etc. is collected by various piping systems and flows to a central waste water treatment plant.

The waste water treatment plant consists of a plant similar to the one described in the Subtask 1.2 Report. The plant has a design operating range of from 150 gpm to 300 gpm maximum flow. It is estimated that waste water will be generated at an average flow rate of 127 gpm.

4.4 Electrical System and Component Description

Subtask 1.2 utilizes two (2) gas turbine driven generators rated at 75 MVA and one (1) steam turbine driven generator rated at 534 MVA. The PFB/GT/Power Turbine Reheat Cycle utilizes four (4) gas turbine driven generators rated at 75 MVA and one (1) steam turbine driven generator rated at 387 MVA. Electrically, the configuration of the Subtask 1.9 plant is the same as Subtask 1.2 with the addition of the two (2) gas turbine/unit transformer modules.

The addition of two (2) gas turbine generators for the Subtask 1.9 package requires an additional two (2) generator step-up transformers, 2-230 KV lines to transmit power from these transformers to the switchyard, and one (1) three (3) breaker bay in the switchyard.

The increased cost of this equipment is partially offset by a reduction in the auxiliary power requirements of the steam turbine driven generator. The generator step-up transformer, generator auxiliary transformers, and start up transformer are reduced in proportion to the Subtask 1.9 generator rating. Figure K-1 shows a one-line diagram for the PFB/GT/Power Turbine Reheat Plant.

4.5 Civil/Structural/Architectural Design Description

4.5.1 General

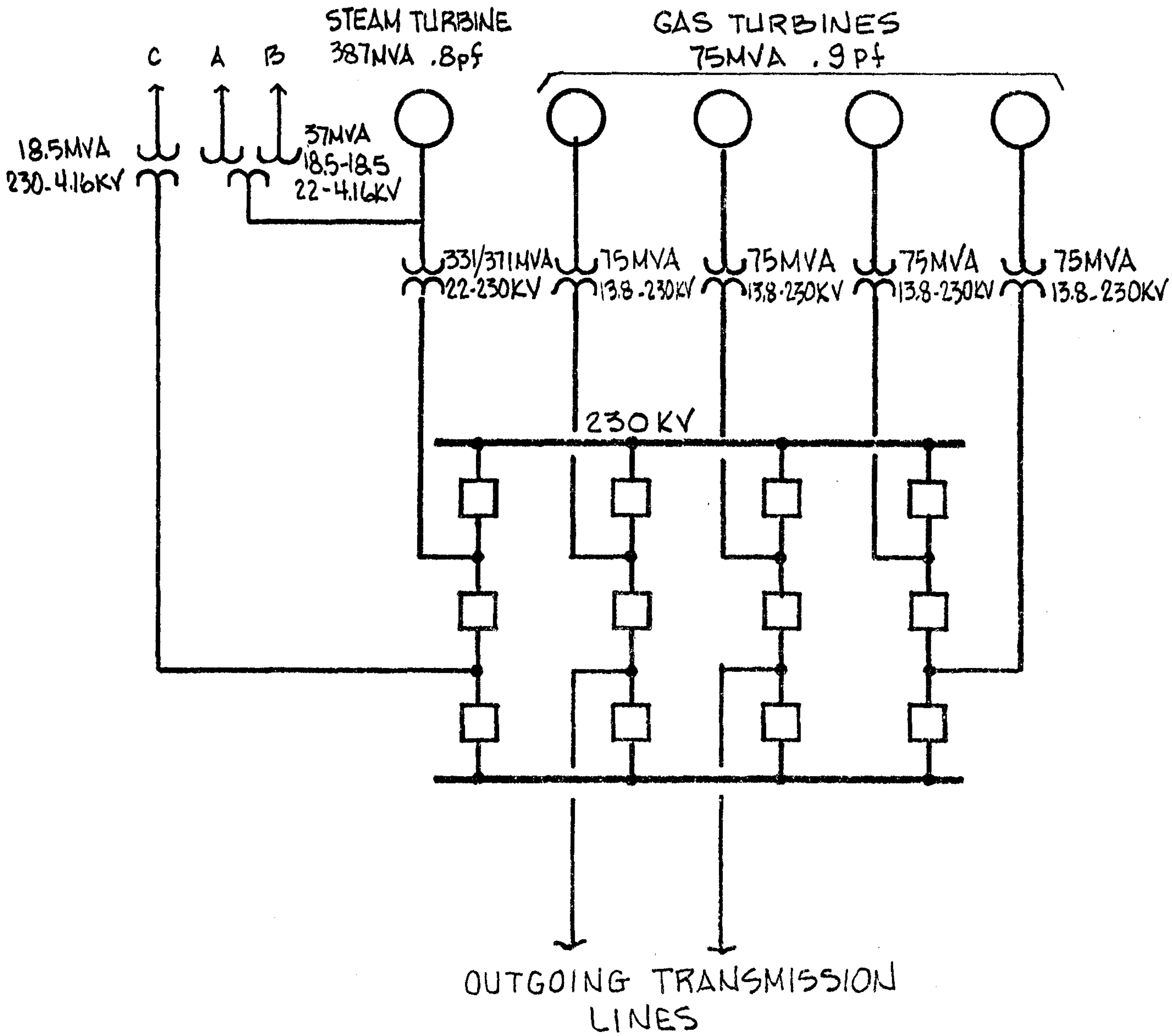
The Middletwon site proposed for location of the Subtask 1.9 PFBC Combined Cycle Power Plant has been treated extensively in the Subtask 1.2 report. Although there are some important differences in the sizes, location and orientation of various facilities of the two subtasks, provisions for site preparation work, sanitary facilities, service roads, access and site railroad, parking areas, and major structural features and types of construction for the Subtask 1.9 PFBC plant are essentially the same as those of the Subtask 1.2 plant. Accordingly, area plans, structural layouts, material quantities and capital cost estimates of similar systems or subsystems of this subtask are based on the findings, where applicable, of earlier work developed in detail and presented in the Subtask 1.2 report. New or different structural systems were designed, as required, in sufficient detail to enable the preparation of specific plans for material takeoff purposes.

4.5.1.1 Site Development

The area site plan for the PFB/GT/RH cycle power plant is shown in Figure F-1. As in Subtask 1.2, a total of 340 acres of land required for the plant. The principal area allocations for the major plant components are the same as for Subtask 1.2. Moreover, provisions for site preparation, sanitary facilities, service roads, access and site railroad and parking areas are essentially the same as in Subtask 1.2.

4.5.2 Types of Construction

4.5.2.1 Foundations and Substructures



PFB / GT / RH PLANT
ELECTRICAL MAIN ONE LINE DIAGRAM
FIGURE K-1

As in Subtask 1.2, spread-footing type foundations are assumed for all plant island structures and equipment including the coal and sorbent yard structures. Use of piles may be necessitated if atypical or non-uniform soil conditions, or greater overburden depths than anticipated, are encountered. However, the design and capital cost estimates herein make no allowance for piles.

4.5.2.2 Steam Turbine-Generator Building and Control Room

This building houses the three steam turbine-generator units, condensers and the auxiliary equipment for these systems. The building consists of a ground floor, a mezzanine floor at elevation 20 feet and an operating floor at elevation 40 feet. An overhead crane and craneway are provided to serve the turbine-generator. Roof elevation is 90 feet in the crane bay. The control room is located at the operating floor level. A turbine-generator pedestal supported on a concrete foundation mat has been provided. The ground floor is a structural slab on grade. The superstructure is steel framed with welded shop connections and high strength bolted field connections. The remaining construction features are identical to the Subtask 1.2 turbine generator building.

4.5.2.3 Office and Service Building

A 40 ft by 120 ft office and service building attached to the south side of the steam turbine-generator building has been provided. Except for its orientation relative to the steam turbine-generator building, the office and service building is the same as provided and detailed in Subtask 1.2.

4.5.2.4 Gas Turbine - Air Compressor and Power Generator Buildings

Provision is made to house each of the four gas generator assemblies as well as the four power turbines in a separate pre-engineered metal enclosure building. The turbine-generator pedestals are supported on concrete foundation mats. The ground floor is a structural slab on grade.

4.5.2.5 Other Buildings

Provision has also been made for the following buildings which are described in detail in the Subtask 1.2 report.

Garage, Carpenter Shop, Paint Shop and Oil and Grease Storage Building
Warehouse Building
Water Treatment Building
Personnel Building in Coal Yard Area
Miscellaneous Buildings

4.5.2.6 Circulating Water System

A concrete basin and pump pit for the mechanical draft cooling tower have been provided. The structural details are the same as described in Subtask 1.2, with the exception that the basin length has been reduced to 400 feet. The concrete intake structure for makeup water to be installed at the North River is the same as in Subtask 1.2.

4.5.2.7 Coal and Dolomite Handling Structures

The layout for the coal and dolomite handling structures is shown in Figure F-1. All structures, towers, conveyor belt supports, pits and tunnels have been designed using the same structural criteria and arrangements as in Subtask 1.2 with the exception that limestone handling structures are eliminated. Similarly, the structural configuration and construction details of coal and limestone silos are identical to those of Subtask 1.2. The support structure is steel framing on spread footings.

4.5.2.8 Wastewater Treatment Plant

The plant waste streams and intermittent rainwater runoff from the coal yard area are to be accommodated and treated as required in a wastewater treatment plant which is of the same size and design as in Subtask 1.2. Similarly, rainwater runoff from the diked coal and dolomite storage area is sent to the treatment plant through an overflow structure.

4.5.2.9 Equipment Foundations

Spread footings have been used as foundations for all major elevated equipment. The ground floor, where required, is a concrete slab on grade with welded wire fabric reinforcement.

4.5.3. Loads

The criteria described in the Subtask 1.2 report have been used for each of the following loading categories:

Dead Loads
Wind Load
Seismic Load
Crane Loads
Hoist Loads
Elevator Loads
Thermal Loads
Loads from Mechanical Equipment
Vehicular Loading
Surcharge
Temporary Construction Loads
Loads Imposed on Stairs and Platforms
Turbine Bay Floor and Roof Loads
Live Load Reductions
Load Combinations

4.5.4 Codes, Materials and Design

The criteria used in each of the following categories are identical to those of Subtask 1.2:

General Codes
Structural Steel Publications
Structural Concrete Publications
Reinforcing Steel for Concrete Structures
Miscellaneous Steel and Iron

4.5.5 Cranes and Hoists

4.5.5.1 Turbine-Generator Building

An overhead crane and craneway serve the turbine-generator building. Lift capacity of the main hook is 80 tons, and the auxiliary hook 25 tons. A hoist well is provided in the center of the building from the ground floor level to the operating floor level.

4.5.5.2 Machine Shop

A 25-ton crane is furnished for the machine shop with a total lift of 25 feet.

4.5.5.3 Hoists

Suitable monorails, trolleys, hoists and other lifting equipment have been provided as required to service equipment.

4.6 Instrumentation and Controls

The scope of work for this Subtask did not include a design effort on the instrumentation and controls system for the PFB/GT/RH plant. The order of magnitude cost estimate for the PFB/GT/RH plant is based on the estimate prepared for Subtask 1.8 (PFB/GT/WHSG Cycle Study). The I&C costs for the main PFB combustors, gas turbines, and waste heat steam generators were estimated at 2/3 of the corresponding costs from Subtask 1.8 reflecting the difference in the number of units involved.

It was assumed that requirements for the reheat PFB combustor systems, and the RFB coal and sorbent handling systems, would be the same as those for the main PFB's. Therefore, the same estimated costs were used for both.

The computer and CRT display system requirements for Subtask 1.9 were estimated on the basis of judgment factors applied to the Subtask 1.8 costs.

5.0 COST ESTIMATES

5.1 CAPITAL COST ESTIMATES

5.1.1 Methodology

The format adopted for the development and presentation of the Capital Cost Estimate is similar to and patterned after the "Uniform System of Accounts," established by the Federal Power Commission. The estimate is comprised of ten (10) major direct cost accounts. Each item of work associated with a given account is identified with a "sub-account" number prefixed with the major account number. Major accounts 1.0 to 10.0 inclusive represent "direct cost" items.

Job distributable costs covered under Account 11.0, together with the items listed below, represent "indirect cost" items:

a) Engineering and Owner's costs
b) Contingency
c) Interest during Construction

Items a, b and c are described later. The definition of items a and b are exactly the same as given by Westinghouse (Ref. 5) for professional services and contingency respectively.

5.1.1.1 Assumptions

The estimate is based on the following assumptions: The plant is located in "Middletown" U.S.A., which represents an average U.S.A. geographic location, in close proximity to an Eastern Coal Belt. This area lies approximately East of the Mississippi, West of the Appalachian Mountains, South of the Great Lakes and North of the Gulf of Mexico. All costs in this estimate reflect what is felt to be "average" expected costs for this area of the country.

All major items of equipment are procured by the owner.

All items of construction are covered by a series of construction packages, placed by the owner with qualified contractors. Contractors are responsible for furnishing all materials, equipment other than furnished by the owner, craft labor, field supervision, construction equipment, small tools, consumables, trailers, water and electric hook-ups, etc. necessary for a complete installation. All construction costs in our estimate therefore, reflect "contractor cost."

Estimated costs reflect the theoretical assumption that sufficient number of plants of the same type have previously been built, therefore, no "development" cost factors have been included.

All costs represent a mid-1977 price level and do not include escalation.

5.1.1.2 Quantification

Detailed quantity take-offs for the major portion of the work have been performed from plot plans, equipment lists, equipment and piping arrangement drawings, electrical drawings, one (1) line diagrams and other data prepared especially for this project. In addition, take-offs for some systems have been obtained from drawings made for other "in house" projects having similar systems. In these instances, adjustments or modifications have been marked on the drawings to insure compatibility with this project.

5.1.1.3 Price Development

5.1.1.3.1 Gas Turbines/Generators

United Technologies Corporation has estimated the price of the gas turbines and generators. This cost increases relative to Subtask 1.2 due to changes in gas turbine configuration, enclosure changes, generator output increase, ducting changes and control system modifications.

5.1.1.3.2 PFB System

The cost of the PFB combustor has been developed from the design drawings. Material take-offs have been made and the cost of the Alloy 800H materials have been determined from quotations for the various sizes and shapes required. The cost of other materials has been estimated using standard B&W data. The labor and expense estimates have been obtained from the various shops that would be involved in the fabrication of the combustor with the coordination of the shop estimating being done by the Production Control Department. In many areas the design drawings are not of sufficient detail to define fabrication details. In these areas, Product Control has worked with the shops to develop approximations of the labor and expense costs. The cost of the solids feed system is based on the costs of similar feed systems from earlier studies (Subtask 1.2) with appropriate adjustments for size and time.

The cost of the dust collection system is based on previous vendor quotations for high efficiency cyclone dust collectors (Subtasks 1.2 and 1.3) appropriately adjusted for size and time and on B&W estimates for the ash letdown system (hoppers, valves, etc.).

The erection estimates have been developed by the B&W Construction Company based on the various arrangement drawings and on the material weights calculated during the estimating processes. The conversion of the costs to price is based on the same factors that B&W has found to be competitive in the current utility marketplace.

5.1.1.3.3 Waste Heat Steam Generators (WHSG's)

The WHSG is an established commercial product that has been supplied by B&W for other combined cycle installations. The costs for these units were estimated by the group at B&W which normally markets these units.

5.1.1.3.4 Hot Gas Piping

The main PFB 16 (atm) hot gas piping has been estimated from costs taken from the detailed Subtask 1.2 estimate and prorated on a per bound basis to reflect the costs for the pipe sizes and wall thicknesses established for Subtask 1.9.

Since the hot gas piping system is unique to the PFB/G.T. plant, a relatively detailed material take-off has been made for the Reheat PFB System (2½ atm) and is shown on Table W-1.

5.1.1.3.5 Balance of Plant

In general, brief specifications have been prepared for the major items on the equipment list. Costs for this equipment have been estimated from pricing data taken from the Subtask 1.2 and 1.8 estimates. In those cases where "in house" pricing data are available, the same have been used and adjusted to reflect a 1977 pricing level.

Materials

Material costs have been taken from various estimating publications, manufacturer's price lists, and from BRISC's "in house" cost data bank. Adjustments to these costs have been made as required to adapt this data for this project. The costs for special items have been solicited from vendor sources who have had familiarity and experience with the products involved.

Installation Costs

In general, installation manhours have been estimated for each task. These hours have been multiplied by a developed "average" craft rate including fringe benefits for the discipline involved and to which an allowance for the following has been added to yield a total "Contractor" installation cost:

- Field Supervision
- Unemployment insurance, workman's compensation, Social Security and Liability insurance
- Construction equipment
- Small tools and consumables
- Home office costs including purchasing, estimating, administrative bonds, permits and other costs
- Profit

The following is a listing by discipline, of construction installation rates used in the development of this estimate:

MATERIAL TAKE-OFF FOR RFB HOT PIPING SYSTEM

TABLE W-1

PIPE

Pipe O.D. x Wall Thickness, Inches	Length, Feet	No. of Shop Mitre Butt-welds	No. of Field Butt-welds	No. of 90° Nozzles
20 x 1/2	3,600	-	180	-
36 x 1/4	2,760	384	276	32
57 x 1/4	1,600	96	160	32
60 x 1/4	1,440	-	144	32
66 x 1/4	480	-	48	32
138 x 3/8	720	24	72	-
162 x 1/2	840	24	84	-

REFRACTORY MATERIAL

TYPE	SQ. FT.
1" Thick Insulation Mineral Block	160,000
3" Thick Kast-o-Lite Refractory	152,000
Shop Installation of Insul. & Refractory	156,000

EXPANSION JOINTS

DESCRIPTION	QUANTITY
138" O.D., Weld End, Balanced Universal Expansion Joint	4

LINERS

DESCRIPTION	QUANTITY
3/16" Thick Incoloy 800H Plate	960,000

408

Civil, Structural, Architectural - $22.00/h

Mechanical -

Piping and Instrumentation -	$26.00/h
Heavy Equipment -	23.00/h
Light Equipment -	21.00/h

Electrical - 26.00/h

In some cases, manhours have not been used to determine installation costs. Instead, a percentage of the equipment or material costs, commensurate with the complexity of the installation considered, has been taken to represent Contractor's installation cost.

5.1.2 Direct Capital Cost

The direct capital cost is summarized by main cost account in Table W-3. A detailed capital cost breakdown is shown in Table W-4.

The items in account 11.0, Job Distributable Cost, may be considered as indirect costs since they are expenditures associated with common temporary construction facilities. These are applicable in varying degrees to all accounts and cannot in any practical way be apportioned equitably among the other direct accounts. It should be noted that a certain amount has been included in accounts 1.0 to 10.0 for items which are sometimes covered in the job distributable category by other investigators.

5.1.3 Total Project Cost

The total project cost which includes both the direct capital costs and the indirect costs is shown in Table W-5. The economic parameters assumed for this study are shown in Table W-6.

5.1.3.1 Engineering and Owner's Costs (E&O Costs)

Engineering and Owner's costs include project management, preliminary engineering, detail engineering and design, construction management, procurement services, architectural design, shop inspection and expediting, supervision of construction, start-up and testing. If these services are performed by a combination of professional firms, or a single professional engineering/ construction firm, the costs include the resulting fees.

Other owner's costs include general office expense, owner's field operation costs, legal fees, taxes during construction, capitalized start-up costs, insurance, spare parts, and special tools for operation and maintenance of the completed project.

This cost breakdown is similar to that described in the ECAS study (Ref. 5). For the present study, 10% of the total of direct costs (accounts 1.0 - 11.0) has been used for the E&O cost.

TABLE W-3

DIRECT CAPITAL COST ESTIMATE
BY MAIN COST ACCOUNT
PFB/GT/RH PLANT

MAIN ACCOUNT NO.	DESCRIPTION	IN THOUSANDS OF MID-1977 DOLLARS MATERIAL COST	INSTALLATION COST	TOTAL COST
1.0	LAND & LAND RIGHTS	1,020		1,020
2.0	STRUCTURES & IMPROVEMENTS	7,136	7,259	14,395
3.0	GAS TURBINES & GENERATORS	43,732	4,936	48,668
4.0	PFB & RFB COMBUSTOR SYSTEMS	137,956	69,071	207,027
5.0	COAL & SORBENT HANDLING SYSTEMS	18,041	6,503	24,544
6.0	BOILER PLANT EQUIPMENT	38,827	14,820	53,647
7.0	STEAM TURBINE GENERATOR UNITS	20,704	2,940	23,644
8.0	ACCESSORY ELECTRICAL EQUIPMENT	12,405	10,102	22,507
9.0	MISCELLANEOUS POWER PLANT EQUIPMENT	450	44	494
10.0	INSTRUMENTATION & CONTROL SYSTEMS	7,543	2,495	10,038
11.0	JOB DISTRIBUTABLE COSTS	6,923	7,077	14,000
	TOTAL	294,737	125,247	419,984

TABLE W-4

PFB/GT/RH POWER PLANT
DETAILED DIRECT CAPITAL COST ESTIMATE

Acct. No.	Description	Cost in Thousand Dollars Material	Installation	Total
1.0	Land & Land Rights			
1.1	Land	747	-	747
1.2	Land Rights	273	-	273
	TOTALS ACCT. 1.0	1,020	-	1,020
2.0	Structures & Improvements			
2.1	Site Improvements			
2.1.1	Site Grading		2,180	2,180
2.1.2	Building Excavation		120	120
2.1.3	Landscaping	65	35	100
2.1.4	Fresh Water Supply	43	40	83
2.1.5	Fire Protection	282	262	544
2.1.6	Drainage & Sewage Disposal	98	30	128
2.1.7	Wastewater Treatment System	342	169	511
2.1.8	Flag Pole	4	1	5
2.1.9	Guard House	2	4	6
2.1.10	Railroad	1,165	635	1,800
2.1.11	Roads, Paved Areas & Parking Lots	283	213	496
2.1.12	Fencing	65	35	100
	SUBTOTAL ACCT. 2.1	2,349	3,724	6,073
2.2	Structures			
2.2.1	Office & Service Building	571	376	947
2.2.2	Steam T/G Building	2,987	2,038	5,025
2.2.3	C.W.S. (Concrete Struct.)	268	332	600
2.2.4	Stack Foundation	196	104	300
2.2.5	Gas Turb. Building (Concrete Only)	315	393	708
2.2.6	Chemical Treatment Building	52	63	115
2.2.7	Miscellaneous Buildings	135	117	252
2.2.8	Pipe Rack	263	112	375
	SUBTOTAL ACCT. 2.2	4,787	3,535	8,322
	TOTALS ACCT. 2.0	7,136	7,259	14,395

TABLE W-4 (continued)

Acct. No.	Description	Cost in Thousand Dollars: Material	Installation	Total
3.0	Gas Turbines/Generators			
3.1	4 Gas Turbines & Associated Systems	32,098	3,426	35,524
3.2	4 Electrical Generators & Associated Systems	8,052	896	8,948
3.3	Control Package, Relays, Breakers, etc.	2,802	310	3,112
3.4	Enclosure Including 25 Ton Travelling Crane	492	184	676
3.5	60-65 MW Low Voltage Circuit Breaker	106	24	130
3.6	Breeching, Including Isolating Dampers & Insulation	182	96	278
	TOTALS ACCT. 3.0	43,732	4,936	48,668
4.0	PFB & RFB Combustor Systems			
4.1	8 PFB Combustors & Ash Letdown Systems	31,075	18,266	49,341
4.2	8 PFB Aerodyne Particulate Removal Systems	12,342	4,227	16,569
4.3	PFB Process Solid Waste Handling System	1,760	352	2,112
4.4	PFB Hot Gas Piping	5,873	1,627	7,500
4.5	PFB Start-up Combustors - Air Preheaters	1,480	226	1,706
4.6	Allowance For PFB System Concrete Work	240	360	600
4.7	8 Reheat Combustors	45,860	30,114	75,974
4.8	Reheat Aerodyne Particulate Removal Systems	28,394	8,738	37,132
4.9	RFB Hot Gas Piping	8,852	4,328	13,180
4.10	RFB Process Solid Waste Handling System	1,760	353	2,113
4.11	Allowance For RFB System Concrete Work	320	480	800
	TOTALS ACCT. 4.0	137,956	69,071	207,027
5.0	Coal and Sorbent Handling Systems			
5.1	Coal Stackout, Reclaim, Preparation and Silo Storage Systems	9,103	4,098	13,201
5.2	Dolomite Stackout, Reclaim, Preparation and Silo Storage Systems	1,609	743	2,352
5.3	Coal and Dolomite Feed Systems to PFB	4,369	1,146	5,515
5.4	Coal and Dolomite Feed Systems to RFB	2,960	516	3,476
	TOTALS ACCT. 5.0	18,041	6,503	24,544
6.0	Boiler Plant Equipment			
6.1	Waste Heat Steam Generators (4)	24,489	4,506	28,995
6.2	Boiler Feed Pumps	270	67	337
6.3	Boiler Feed Pump Turbine Drives	1,270	126	1,396
6.4	Start-up Boiler Feed Pump w/Motor	151	23	174
6.5	Deaerating Heater	135	20	155
6.6	Air Compressors - Service & Instr.	110	6	116
6.7	Concrete Chimney (2)	1,680	1,065	2,745

TABLE W-4 (continued)

Acct. No.	Description	Cost in Thousand Dollars: Material	Installation	Total
6.8	Breeching, including Insulation & Jacket	56	41	97
6.9	High Pressure Piping:			
6.91	Main Steam	1,250	1,750	3,000
6.92	Boiler Feed Discharge	730	817	1,547
6.93	Cold Reheat	182	255	437
6.94	Hot Reheat	223	134	357
6.10	Int. & Low Pressure Piping:			
6.101	Boiler Feed Suction	32	35	67
6.102	600# Steam	49	65	114
6.103	175# Steam	6	8	14
6.104	30# Steam	282	371	653
6.105	Bleed Steam	134	177	311
6.106	Bearing Cooling Water	109	131	240
6.107	Steam Blowout	65	80	145
6.108	Boiler Vents & Drain	40	55	95
6.109	Condensate	52	73	125
6.1010	Condenser Vacuum & Air Extraction	85	82	167
6.1011	Demineralized Water	39	49	88
6.1012	Hydrogen Vent	2	3	5
6.1013	Safety & Relief Valve Vent	30	40	70
6.1014	Instrument Air	9	14	23
6.1015	Lube Oil	26	39	65
6.1016	Main & Auxiliary Turbine	47	63	110
6.1017	Plant Waste	27	39	66
6.1018	Roof Drain	79	97	176
6.1019	Service Air	12	18	30
6.1020	Service Water	237	298	535
6.11	Valves:			
6.111	High Pressure (Gates)	232	76	308
6.112	High Pressure (Globes)	405	134	539
6.113	Low Pressure (Gates, Globes, Checks)	396	131	527
6.114	Forged Steel (Gates, Globes, Checks)	512	168	680
6.115	Safety & Relief	24	10	34
6.116	3-Way & Reverse Flow Check	91	31	122
6.117	Steam Conditioning	58	20	78
6.118	Control	328	108	436
6.12	Piping Specialty Items	100	150	250
6.13	Insulation Piping & Equipment	884	277	1,161
6.14	Water Treatment Equipment:			
6.141	Demineralizer & Condensate Polisher	840	100	940
6.142	Chemical Feed Equipment	16	4	20

TABLE W-4 (continued)

Acct. No.	Description	Cost in Thousand Dollars: Material	Installation	Total
6.15	Shop Fabricated Tanks	83	3	86
6.16	Condensate Storage Tanks	90	60	150
6.17	Light Oil Storage Tank	41	27	68
6.18	Fuel Oil Transfer Pumps & Drives	4	1	5
6.19	Fuel Oil Unloading Pump w/Motor	2	1	3
6.20	Fuel Oil Strainers	4	1	5
6.21	Sump Pumps	12	3	15
6.22	Air Compressors For Waste Ponds	22	3	25
6.23	Process Solid Waste Handling & Storage Systems	2,400	1,600	4,000
6.24	Finish Painting	195	1,020	1,215
6.25	Allowance for W.H.R.B. Concrete Work	180	345	525
	TOTALS ACCT. 6.0	38,827	14,820	53,647
7.0	Steam Turbine Generator Units			
7.1	Steam Turbine Generator with Exciter and Accessories	16,300	1,058	17,358
7.2	Condenser and Tubes	1,478	522	2,000
7.3	Condenser Vacuum Pumps with Motors	220	22	242
7.4	Condensate Pumps with Motors	120	34	154
7.5	Cooling Tower	1,301	929	2,230
7.6	Cooling Tower Chlorination System	96	25	121
7.7	Chlorinator Booster Pumps with Motors	6	1	7
7.8	Cooling Tower Acid Feed Systems	35	8	43
7.9	Circulating Water Pumps with Motors	455	45	500
7.10	Circulating Water Booster Pumps with Motors	13	3	16
7.11	Circulating Water Piping	400	233	633
7.12	Make-up Water Pumps with Motors	35	8	43
7.13	Sluice Gates with Floor Stands	12	3	15
7.14	Travelling Screens	50	13	63
7.15	Screen Wash Pumps with Motors	9	2	11
7.16	Closed Cooling Water Heat Exchanges	60	15	75
7.17	Closed Cooling Water Pumps with Motors	10	3	13
7.18	Lube Oil Purification Equipment	80	13	93
7.19	Lube Oil Pumps with Motors	24	3	27
	TOTALS ACCT. 7.0	20,704	2,940	23,644

TABLE W-4 (continued)

Acct. No.	Description	Cost in Thousand Dollars Material	Installation	Total
8.0	Accessory Electric Equipment			
8.1	Generator Accessories and Equipment	2,228	416	2,644
8.2	Station Service Equipment	861	165	1,026
8.3	Switchgear, Unit Sub-station and M.C.C.	2,975	546	3,521
8.4	Switchyard	2,372	988	3,360
8.5	Grounding and Miscellaneous Systems	157	374	531
8.6	Emergency Generator and UPS Equipment	171	65	236
8.7	Raceways	1,527	4,883	6,410
8.8	Conductors	1,750	1,869	3,619
8.9	Lighting and Communications	364	796	1,160
	TOTALS ACCT. 8.0	12,405	10,102	22,507
9.0	Miscellaneous Power Plant Equipment			
9.1	Laboratory Equipment	82	8	90
9.2	Steam and Water Sampling Equipment	153	15	168
9.3	Shop Tools and Equipment	80	8	88
9.4	Lockers	5	1	6
9.5	Office Furniture and Machines	30	2	32
9.6	Lunch Room Equipment	25	3	28
9.7	Portable Fire Extinguishing Equipment	20	1	21
9.8	Miscellaneous Cranes and Hoists	50	5	55
9.9	Emergency Equipment	5	1	6
	TOTALS ACCT. 9.0	450	44	494
10.0	Instrumentation and Control Systems			
10.1	Gas Turbine and Electric Generator Systems	617	178	795
10.2	PFB Systems	1,352	523	1,875
10.3	PFB Coal and Sorbent Handling Systems	667	230	897
10.4	RFB Systems	1,352	523	1,875
10.5	RFB Coal and Sorbent Handling Systems	667	230	897
10.6	Waste Heat Steam Generator Systems	1,229	474	1,703
10.7	Computer and CRT Display Systems	1,366	234	1,600
10.8	Coal and Sorbent Receiving, Storage, Reclaim and Transfer to Silos	293	103	396
10.9	Steam and Water Sampling	- Included in Acct. 9.0 -		
	TOTALS ACCT. 10.0	7,543	2,495	10,038

TABLE W-4 (continued)

Acct. No.	Description	Material	Installation	Total
		Cost in Thousand Dollars		
11.0	Job Distributable Costs			
	Temporary Facilities:			
	Field Office) Field Office Supplies) Warehouses & Shops) Change House) - Toilets) First Aid) Job Cleanup)	1,050	3,150	4,200
	Heat) Light & Power) - Water) Air)	2,625	875	3,500
**	Roads & Parking Areas	700	1,400	2,100
	Sewers and Drainage	350	350	700
	Fire Protection) Security Guards) - Communications)	350	525	875
	Motor Pool and Garage	1,575	525	2,100
	Fences	98	42	140
	Miscellaneous	175	210	335
	TOTALS ACCT. 11.0	6,923	7,077	14,000

Note: Costs Include:
1) Maintenance Personnel
2) Dismantling & Removal

**: Includes Snow Removal Costs

TABLE W-5

PFB/GT/RH COMMERCIAL PLANT CAPITAL COST SUMMARY

		$1,000's
1.	Direct Capital Cost	$419,984
2.	Engineering & Owner's Costs (10% of 1.)	41,998
3.	Contingency (10% of 1+2)	46,198
4.	Interest During Construction (8% Rate; 5 yrs; i.e.; 19.5% of 1+2+3)	99,095
	Total Project Capital Cost	$607,275

Specific Capital Cost = $1006/kW (Net)

603.4 MW net

TABLE W-6

ECONOMIC PARAMETERS

PFB/GT/RH CYCLE STUDY

Plant Life	30 years
Capacity Factor	65%
Output Factor	100%
Dollar Base Used	Mid-1977
Escalation	0
Discount Rate	8%
Interest During Construction	8%
Period of Construction	5 years
S-curved Expenditure Schedule	
Fixed Capital Charge	18%
Replacement Energy Cost	25 mills/kwh
Cost of Coal	\$0.87/mmBTU \$20.00/ton
Cost of Dolomite	\$7.00/ton
Cost of Disposal of Ash & Spent Sorbent	\$3.00/ton

5.1.3.2 Contingency

As stated in Ref. 5, "Contingency is an allowance for costs which may be incurred as a result of factors which cannot be specifically anticipated and, therefore, cannot be included in the direct accounts. Contingency includes the additional costs likely to be encountered due to incompletely specified designs, estimating errors and omissions, unanticipated site conditions, minor scope changes, inability to predict actual productivity and unforeseen construction problems. Forced station additions or modifications due to revised statutory requirements (particularly environmental), major scope changes, Force Majeure, and unanticipated changes in escalation and interest during construction are not included as contingency costs."

In the present study, an allowance of 10 percent of the direct capital cost and engineering and owner's cost has been made to cover contingency costs.

5.1.3.3 Interest During Construction (IDC)

The total capital investment is assumed to be spent according to an S-curve expenditure schedule. This particular schedule is used by Burns and Roe, Inc. in estimating the construction costs of power plants. For zero escalation, 8 percent interest rate and a construction period of 5 years, the total interest during construction becomes 19.5 percent of the sum of direct capital cost, engineering and owner's cost and contingency. Under the same conditions, except for an interest rate of 10 percent, IDC becomes 24.9 percent.

5.1.3.4 Total Project Cost

The total project cost is estimated to be $607,275,000 in mid-1977 dollars. This amounts to a specific capital cost of $1006 per kW capacity net. The direct capital cost is 69.1% of total cost and IDC accounts for 16.3%.

If the interest rate is 10%, the IDC cost becomes $126,537,000. The total project cost and specific capital cost becomes $634,717,000 and $1052/kW, respectively. IDC cost becomes 19.9% of total project cost.

5.2 OPERATING AND MAINTENANCE COSTS

The operating and maintenance costs include the costs for manning, coal, sorbents, utilities, solid waste disposal, chemicals for water treatment, spare parts, replacement of tools and equipment, etc.

It is needless to say that extimating these costs for a complex utility plant verges on conjecture. In consideration of the overall accuracy of these estimates, it is reasonable to assume that the total O&M costs for the PFB/GT/RH plant would be the same as for the PFB/AFB plant of Subtask 1.2. Estimates for the Subtask 1.2 study have been based on data and criteria from a document (Ref. 6) prepared by Stanford Research Institute (SRI) for Bechtel Corporation. The two cases from the SRI document which form the bases of that estimate are as follows:

a) A coal fired 800 MWe station with capacity factor 70%, and

b) A gas turbine plant, 133 MWe station, with 1000 hours per year operation.

The reported data have been prorated and modified for this study. The costs have been updated to reflect the values of mid-1977 dollars. Estimated manpower needs are shown in Table W-7. Man-hours needed for accounting, personnel, warehousing and sales activity are not accounted for here under the assumption that these functions would be performed by personnel the utility company already has employed. A total of 108 people are required to operate this plant. Total manpower cost is estimated to be $2,562,300 per year, allowing 30% of salary as fringe benefits. The assumed salary scale and manpower cost are shown in Table W-8.

The costs of materials and supplies have been based on a capacity factor of 65% and on the maintenance of full load heat rate at all loads. These estimates are shown in Table W-9 in the same format as was given in the SRI document (Ref. 6). Equipment requirements were based on several criteria. First, equipment was segregated into items that were expected to have a life equal to, or greater than, that of the energy facility, and those with a shorter life. Examples of these two categories are the rotary car dumper and the trucks, scrapers, and other mechanical transport equipment used at the plant. With appropriate maintenance, the railroad car dumper is expected to last for the 30-year life of the plant. The trucks, scrapers, and similar transport equipment are expected to last for 5 to 7 years before replacement. Equipment costs for the car dumper are those for replacement and repair supplies. (Manpower requirements were included in the overall manpower requirements for the facility). For the transport equipment whose life was less than the facility, the cost reported is a combination of an amortized replacement cost and the materials and supplies required to keep the equipment in operation over its normal lifetime.

5.3 COST OF ELECTRICITY (COE)

5.3.1 The Basic Cost

The cost of electricity is calculated from the total energy output in a year and the total annual cost. The total annual cost is the sum of the following: (1) fixed charge, (2) fuel and (3) other operating and maintenance costs, including the sorbent cost.

The fixed charge has been assumed to be 18% of the total project cost. The annual cost summary is shown in Table W-10. Under the assumed conditions, the total annual cost of operation is $142,575,000.

At 65% capacity factor, the annual energy output is $3{,}436 \times 10^6$ kWh. Therefore, the cost of electricity is 41.49 mills/kWh.

5.4 COST COMPARISON OF PFB/GT/RH (SUBTASK 1.9) CYCLE VERSUS PFB/AFB CYCLE (SUBTASK 1.2)

5.4.1 Capital Cost Comparison

A comparison of the capital cost estimates for Subtask 1.9 versus those of 1.2 shows that the PFB/GT/RH plant ($1006/kW) is approximately 77% more costly than the PFB/AFB commercial plant ($567/kW) used as a base. Table W-11 briefly summarizes where the cost differences occur on a main cost account basis. Table W-12 gives a detailed breakdown of the cost differences with a short explanation for each variance.

The huge difference in capital costs is due to the large number of PFB combustors (with associated cyclones, solids feed systems and solid waste letdown systems) required for the PFB/GT/RH plant as compared to the PFB/AFB plant (See Accounts 3.0 and 4.0 on Table W-11).

5.4.2 Cost of Electricity (COE)

As indicated earlier, the COE for the PFB/GT/RH plant is 41.49 mills/kWh which is 46% more than the 28.47 mills/kWh obtained for the PFB/AFB cycle studied in Subtask 1.2. The 13 mill/kWh increase is due almost entirely to the higher Fixed Charges of the PFB/GT/RH plant. Differences in coal and sorbent costs due to variations in plant performance are relatively insignificant (the PFB/GT/RH plant is 0.74 mills/kWh less).

TABLE W-7

CONCEPTUAL PFB PLANT ESTIMATED MANPOWER NEED FOR OPERATION AND MAINTENANCE

	MAN-POWER	NUMBER/YR.
A.	NON-MANUAL	
	1. Technical	
	a) Engineers	
	Electrical	6
	Mechanical	5
	Instrumentation	2
	b) Designers & Draftsmen	1
	c) Supervisors & Managers	11
	2. Non-technical	10
	3. Total Non-Manual	35
B.	MANUAL LABOR	
	1. Craftsmen	
	Pipe fitter	6
	Pipe fitter/Welder	10
	Electrician	10
	Boiler Maker/Welder	6
	Operator	20
	Millwright	6
	2. Teamsters & Laborers (Contract)	15
	3. Total Manual Labor	73
	TOTAL MAN-YRS NEEDED	108

TABLE W-8

COST OF MANPOWER

OPERATION AND MAINTENANCE

TYPE OF PERSONNEL	NUMBER	BASIC ANNUAL SALARY RATE, $	TOTAL SALARY $
1. Supervisors & Managers	11	25,000	275,000
2. Engineers	13	22,000	286,000
3. Designers & Draftsman	1	20,000	20,000
4. Non-technical non-manual	10	12,000	120,000
5. Craftsmen	38	20,000	760,000
6. Operators	20	18,000	360,000
7. Contract labor	15	10,000	150,000
TOTAL	108		1,971,000

Total Manpower Cost with 30% for fringe benefits is $2,562,300/year.

TABLE W-9

ANNUAL COST FOR MATERIALS, EQUIPMENT AND UTILITIES

I. Materials	Thousands of Dollars
A. Major Raw Material	
1. Coal, 1,249,400 tons/yr	24,988
2. Dolomite, 223,143 tons/yr	1,562
3. TOTAL	26,550
B. Other Significant Material & Supplies	
1. Chemicals & Other Material (27-32)*	
Water Treatment	42.9
Other	101.9
2. Stone, Clay and Glass Products (35,36)	96.9
3. Non-ferrous metals (38)	82.2
4. Metal Products (39-42)	
Fabricated Structural Steel	619.3
Fabricated Plate Work	316.6
Pipes, Valves & Miscellaneous	542.0
Other	71.4
5. Miscellaneous	58.8
6. TOTAL	1,932

* Numbers in parentheses are Bureau of Economic Analysis Industry category numbers.

TABLE W-9 Cont.

ANNUAL COST FOR MATERIALS, EQUIPMENT AND UTILITIES

		Thousands of Dollars
II	Machinery & Equipment (Amortization and Replacement Parts)	
1.	Non-electrical Machinery (43-50,52)	
	Steam engines and turbines	135.3
	Internal combustion engine	9.0
	Contruction Machinery	65.6
	Conveyors	144.3
	Hoists and Cranes	29.6
	Industrial Trucks and Tractors	27.0
	Metal Working Machinery	68.1
	Blowers and Fans	9.0
	Industrial Machinery & Equipment	112.1
	Sub-Total	600.0
2.	Electrical Equipment (53-58)	
	Electrical machinery	9.0
	Transformers	18.0
	Switchgear & Switchboards	40.6
	Motors & Generators	170.9
	Controls	27.0
	Electrical Lighting	4.5
	Miscellaneous Electrical	34.0
	Sub-Total	304.0
3.	Transportation Equipment (59-61)	39.0
4.	Instruments & Controls (62,63)	
	Engineering & Scientific Instruments	71.8
	Measuring Devices	22.2
	Sub-Total	94.0
5.	Miscellaneous (64)	38.0
6.	TOTAL	1,075.0

TABLE W-9 Cont.

ANNUAL COST FOR MATERIALS, EQUIPMENT AND UTILITIES

III	Utilities		Thousands of Dollars
	1. Fuel	300,000 gals @ $0.38 gal.	114
	2. Water	58,000,000 gals @ $ 0.25/m gal	15
	3. Total		129
IV	Spent Sorbent & Ash Disposal		
	Removal & Disposal of Solid Waste Material 339,100 tons/yr @ $3/ton		1,084

TABLE W-10

PFB/GT/RH PLANT ANNUAL COST SUMMARY

AND COST OF ELECTRICITY

ITEMS	Thousands of Dollars
1. Fixed charge (@ 18%)	109,310
2. Coal	24,988
3. Sorbent	1,562
4. Man Power Cost	2,562
5. Other Material	1,932
6. Machinery Amortization and Replacement Parts	1,075
7. Utilities	129
8. Spent Sorbent & Ash Disposal	1,017
Total	$ 142,575

Total Energy Output at 65% Capacity Factor $3{,}436 \times 10^6$ kWh

Cost of Electricity Generated = 41.49 mills/kWh

TABLE W-11

COMPARATIVE CAPITAL COST ANALYSIS BY MAIN COST ACCOUNT

PFB/GT/RH vs. PFB/AFB

Account No.	Description	COSTS, $1000 574 MW PFB/AFB (Base)	COSTS, $1000 603 MW PFB/GT/RH	Variance Over or Under () Base
	SUMMARY			
1.0	Land and Land Rights	1020	1020	0
2.0	Structures & Improvements	13700	14395	695
3.0	Gas Turbines/Generators	20232	48668	28436
4.0	PFB Combustor Systems	38312	77828	39516
	RFB Combustor Systems	-	129199	129199
5.0	Coal & Sorbent Handling Systems	21808	24544	2736
6.0	Boiler Plant Equipment	63033	53647	(9386)
7.0	Steam Turbine Generator Units	29923	23644	(6279)
8.0	Accessory Electric Equipment	22358	22507	149
9.0	Misc. Power Plant Equipment	494	494	0
10.0	Instrumentation & Control Systems	6130	10038	3908
11.0	Job Distributable Costs	8000	14000	6000
	Sub-Total	225010	419984	194974
	Engineering & Owner Costs	22501	41998	19497
	Sub-Total	247511	461982	214471
	Contingency	24751	46198	21447
	Sub-Total	272262	508180	235918
	Interest During Construction	53091	99095	46004
	Totals	325353	607275	281922
		$567/kW	$1007/kW	$440/kW

TABLE W-12
DETAILED COMPARISON OF CAPITAL COSTS
PFB/GT/RH CYCLE VERSUS PFB/AFB CYCLE

PFB/AFB CYCLE (Subtask 1.2)-Base Case Acct. No.	Item Description	Amount $1,000	PFB/GT/RH CYCLE (Subtask 1.9) Acct. No.	Item Description or Change	Amount $1,000	Variance Over or Under () Base
1.0	Land & Land Rights					
1.1	Land	747	1.1	No Change		0
1.2	Land Rights	273	1.2	No Change		0
				Acct. 1.0 Total Variance		0
2.0	Structures & Improvements					
2.1	Site Improvements	6073	2.1	No Change		0
2.2	Structures:					
2.2.1	Office & Service Bldg.	947	2.2.1	No Change		0
2.2.2	Steam T/G Bldg.	5025	2.2.2	No Change		0
2.2.3	Circ.WaterSys.ConcreteStruct.	628	2.2.3	Smaller Concrete Struct.	600	(28)
2.2.4	One Stack Foundation	150	2.2.4	Two Stack Foundations	300	150
2.2.5	Two Gas Turbine Bldg.Concrete	278	2.2.5	Four GT Air Compr. & Four Gen. Building Concrete	708	430
2.2.6	Chemical Treatment Building	115	2.2.6	No Change		0
2.2.7	Electrostatic Precip. Fdn. and steel	232		None Required		(232)
2.2.8	Misc. Bldgs. & Pipe Rack	252	2.2.7&8	Longer Pipe Rack	627	375
				Acct. 2.0 Total Variance		695
3.0	Gas Turbines/Generators					
3.1	Two Gas Turbines& Assoc.Sys.	14490	3.1	Four Gas Turbines (Split). Higher Gas Temp. - More Expensive Materials	35524	21034
3.2	Two elect.Gen.&Assoc. Sys.	3780	3.2	Four Elec.Gen.(Split) Larger Generating Capacity	8948	5168
3.3	Control Pkg. Relays, Breakers etc. for 2 Sys.	1512	3.3	Control Pkg. Relays, Breakers for 4 Sys.	3112	1600
3.4	Two GT Encs.w/25 T Crane	294	3.4	Four GT Encs. w/25 T Crane (Split)	676	382
3.5	Two 60-65 MW low Volt.C.B.	55	3.5	Four 75-80 MW low Volt. C.B	130	75
3.6	Breeching, incl. Isolating Dampers & Insulation to AFB	101		None Required		(101)
	None Required		3.6	Breeching, including isolating Dampers & Insulation to WHSG	278	278
				Acct. 3.0 Total Variance		28436

TABLE W-12 (continued)

PFB/AFB CYCLE (Subtask 1.2)-Base Case			PFB/GT/RH CYCLE (Subtask 1.9)			Variance
Acct. No.	Item Description	Amount $1,000	Acct. No.	Item Description or Change	Amount $1,000	Over or Under () Base
4.0	PFB Combustor Systems					
4.1	Four PFB Combustors	24870	4.1	Eight PFB Combustors	49341	24471
4.2	PFB Gas Cleaning Equip. for Four Combustors	7310	4.2	PFB Gas Cleaning Equip for 8 Combustors	16569	9259
4.3	Proc. Solid Waste Handling Sys. for 4 Combustors	1056	4.3	Proc. Solid Waste Handling Sys. for 8 Combustors	2112	1056
4.4	Hot Gas Piping for 4 Comb.	3923	4.4	Hot Gas Piping for 8 Comb.	7500	3577
4.5	Startup Comb. Air Preheaters for 4 PFB Systems	853	4.5	Startup Comb. Air Preheaters for 8 PFB Systems	1706	853
4.6	Concrete work for 4 PFB Comb.	300	4.6	Concrete Work for 8 PFB Comb.	600	300
				PFB Combustor System Variance		39616
4.0	RFB Combustor Systems					
-	None Required		4.7	8 RFB Combustors	75974	75974
-	None Required		4.8	GasCleaning Equip.for 8 RFB's	37132	37132
-	None Required		4.9	Hot Gas Piping/8 RFB's	13180	13180
-	None Required		4.10	Proc. Solid Waste Handling Sys. for 8 RFB's	21130	21130
-	None Required		4.11	Concrete Work/8 RFB's	800	800
				RFB Combustor System Variance		129199
				Acct. 4.0 Total Variance		168315

TABLE W-12 (continued)

PFB/AFB CYCLE (Subtask 1.2)-Base Case Acct. No.	Item Description	Amount $1,000	PFB/GT/RH CYCLE (Subtask 1.9) Acct. No.	Item Description or Change	Amount $1,000	Variance Over or Under () Base
5.0	Coal & Sorbent Handling Systems					
5.1	Coal Stackout, Reclaim, Prep. for 4 Silo & Catenary Bunker Storage	11392	5.1	Coal Stackout, Reclaim, Prep. for 16 Silo Storage System Longer Conveyor (C-9)	13201	1809
5.2	Dolomite & Limestone Stackout, Reclaim/4 Silo & Catenary Bunker Storage	1856	5.2	Dolomite onlyStackout,Reclaim Prep./16 Silo Storage System Longer Conveyor (S-7)	2352	496
5.3	Coal & Dolomite Feed Sys. to 4 PFB's	1960	5.3	Coal & Dolomite Feed Systems to 8 PFB's	5515	3555
5.4	Coal & Limestone Feed Systems to AFB	6600	-	None Required		(6600)
-	None Required		5.4	Coal & Dolomite Feed Systems to RFB	3476	3476
				Acct. 5.0 Total Variance		2736

TABLE W-12 (continued)

PFB/AFB CYCLE (Subtask 1.2)-Base Case Acct. No.	Item Description	Amount $1,000	PFB/GT/RH CYCLE (Subtask 1.9) Acct. No.	Item Description or Change	Amount $1,000	Variance Over or Under () Base
6.0	Boiler Plant Equipment					
6.1	One AFB Steam Generator	30700	6.1	Four Waste Heat Steam Gens.	28995	(1705)
6.2	Electrostatic Precipitators	8363		None Required		(8363)
6.3	Mech. Cyclone Dust Separators	850		None Required		(850)
6.4	I.D. Fans w/Motor Drives	1007		None Required		(1007)
6.5	Two 3314gpm Boiler Feed Pumps	501	6.2	Two 1800gpm Boiler Feed Pumps	337	(164)
6.6	5500 HP Boiler Feed Pump Turbine Drives	1632	6.3	4170 HP Boiler Feed Pump Turbine Drives	1396	(236)
6.7	Startup Boiler Feed Pump	174	6.4	No Change		0
6.8	L.P. Feedwater Heaters	253		None Required		(253)
6.9	Deaerating Heater, one @ 3,000,000 lb/hr	196	6.5	Deaerating Heater, 1@ 2,000,000 lb/hr	155	(41)
6.10	Air Compressors - Serv.&Inst.	117	6.6	No Change		0
6.11	One Concrete Chimney	1400	6.7	Two Concrete Chimneys	2745	1345
6.12	Breeching, incl. Insulation & Jacket	1446	6.8	Less Reqd. due to Elimination of Electrostatic Precipitators	970	(1349)
6.13 &.14	High Pressure, Int. & Low Pressure Piping	4964	6.9 &.10	Greater Quant. of Piping Reqd. to span the 4 WHSG's	8440	3476
6.15	Valves	2237	6.11	Valves-greater quant. reqd. due to increased piping reqs.	2724	487
6.16	Piping, Specialty Items	214	6.12	Piping Spec. increased due to greater piping reqs.	250	36
6.17	Insulation,Piping & Equip.	705	6.13	Increased surface area due to greater quant. of piping	1161	456
6.18	Water Treat. Equip. Demineralizer System	1175	6.14	Less water treatment equip. requirements	960	(215)
6.19	Shop Fabricated Tanks	86	6.15	No Change		0
6.20	Condensate Storage Tanks	150	6.16	No Change		0
6.21	Light Oil Storage Tanks	68	6.17	No Change		0
6.22	Fuel Oil Transfer Pumps	5	6.18	No Change		0
6.23	Fuel Oil Unloading Pumps	3	6.19	No Change		0
6.24	Fuel Oil Strainers	5	6.20	No Change		0
6.25	Sump Pumps	15	6.21	No Change		0
6.26	Air Compressors for Waste Ponds	25	6.22	No Change		0
6.27	AFB Proc. Solid Waste Handling & Storage Systems	5837	6.23	No AFB Solid Waste Handling,Concrete Ash Silos only	4000	(1837)
6.28	Finish Painting	405	6.24	Increase due to longer pipe rack, greater quant. Equip. and piping	1215	810
6.29	AFB Sys. Concrete Work	500	6.25	More concrete req. for WHSG System	525	25
				Acct. 6.0 Total Variance		9385

TABLE W-12 (continued)

PFB/AFB CYCLE (Subtask 1.2)-Base Case Acct. No.	Item Description	Amount $1,000	PFB/GT/RH CYCLE (Subtask 1.9) Acct. No.	Item Description or Change	Amount $1,000	Variance Over or Under () Base
7.0	Steam Turbine Generator Units					
7.1	Stm. T/G, One @ 480,000 kW	22770	7.1	Stm. T/G, One @ 310,000 kW	17358	(5412)
7.2	257,851 sq.ft. Twin Conden-ser & Tubes	2064	7.2	246,000 sq.ft. Twin Conden-ser & Tubes	2000	(64)
7.3	Condenser Vac. Pumps& Motors	242	7.3	No Change		0
7.4	2813 gpm Condensate Pumps	200	7.4	1840 gpm Condensate Pumps	154	(46)
7.5	Cooling Tower, 168,000 gpm	2790	7.5	Cooling Tower, 131,000 gpm	2230	(560)
7.6	C.T. Chlorination System	121	7.5	No Change		0
7.7	Chlorinator Booster Pumps	7	7.7	No Change		0
7.8	C.T. Acid Feed System	43	7.8	No Change		0
7.9	90,000 gpm Circ. Water Pumps w/2000 HP Motors	608	7.9	65,500 gpm Circ. Water Pumps w/1500 HP Motors	500	(108)
7.10	3500 gpm Circ. Water Booster Pumps	18	7.10	2700 gpm Circ. Water Booster Pumps	16	(2)
7.11	Circ. Water Piping	720	7.11	Smaller Size Piping	633	(87)
7.12	C.T. Makeup Water Pumps	43	7.12	No Change		0
7.13	Sluice Gates w/Floor Stands	15	7.13	No Change		0
7.14	Traveling Screens	63	7.14	No Change		0
7.15	Screen Wash Pumps	11	7.15	No Change		0
7.16	Closed Cooling Water Heat Exch.	75	7.16	No Change		0
7.17	Closed Cooling Water Pumps	13	7.17	No Change		0
7.18	Lube Oil Purification Equip.	93	7.18	No Change		0
7.19	Lube Oil Pumps	27	7.19	No Change		0
				Acct. 7.0 Total Variance		(6279)

TABLE W-12 (continued)

PFB/AFB CYCLE (Subtask 1.2)-Base Case Acct. No.	Item Description	Amount $1,000	PFB/GT/RH CYCLE (Subtask 1.9) Acct. No.	Item Description or Change	Amount $1,000	Variance Over or Under () Base
8.0	Accessory Electric Equipment					
8.1	Generator Accessories&Equip.	2753	8.1	Elim. Underground 230 kV cable to Switchyard	2644	(109)
8.2	Station Serv. Equip.	1180	8.2	Elim. 2 Aux. Transformers	1026	(154)
8.3	Switchgear, Unit Substation & MCC	4205	8.3	Elim. 2 Outdoor & 4 Indoor Substations	3521	(684)
8.4	Switchyard	2264	8.4	3 Bays added to accommodate Feeders for 2 Additional Gas Turbine Generators	3360	1096
8.5	Grounding & Misc. Sys.	531	8.5	No Change		0
8.6	Emergency Gen. & UPS Equip.	236	8.6	No Change		0
8.7	Raceways	6410	8.7	No Change		0
8.8	Conductors	3619	8.8	No Change		0
8.9	Lighting & Communications	1160	8.9	No Change		0
			Acct. 8.0	Total Variance		149
9.0	Misc. Power Plant Equipment					
9.1	Laboratory Equipment	90	9.1	No Change		0
9.2	Steam & Water Sampling Equip	168	9.2	No Change		0
9.3	Shop Tools & Equip.	88	9.3	No Change		0
9.4	Lockers	6	9.4	No Change		0
9.5	Office Furniture & Machines	32	9.5	No Change		0
9.6	Lunch Room Equipment	28	9.6	No Change		0
9.7	Portable Fire Exting. Equip.	21	9.7	No Change		0
9.8	Misc. Cranes & Hoists	55	9.8	No Change		0
9.9	Emergency Equip.	6	9.9	No Change		0
				Acct. 9.0 Total Variance		0

TABLE W-12 (continued)

PFB/AFB CYCLE (Subtask 1.2)-Base Case Acct. No.	Item Description	Amount $1,000	PFB/GT/RH CYCLE (Subtask 1.9) Acct. No.	Item Description or Change	Amount $1,000	Variance Over or Under () Base
10.0	Instrumentation & Control Systems					
10.1	Two Gas Turbines & Elect. Generator Systems	284	10.1	Four Gas Turbines & Electric Generator Systems	795	511
10.2	Four PFB Systems	1175	10.2	Eight PFB Systems	1875	700
10.3	Four PFB Coal & Sorbent Handling Systems	456	10.3	Eight PFB Coal & Sorbent Handling Systems	897	441
10.4	AFB Coal & Sorbent Hand.Sys.	456	-	None Required		(456)
10.5	AFB Steam Generator Systems	2258	-	None Required		(2258)
-	None Required		10.4	RFB Systems	1875	1875
-	None Required		10.5	RFB Coal & Sorbent Hand.Sys.	897	897
-	None Required		10.6	Waste Heat Steam Gen. Sys.	1703	1703
10.6	Computer & CRT Displays	1105	10.7	More Data to Process & More Control Functions Dealing with 4 WHSG to Steam Turbine	1600	495
10.7	Coal & Sorbent Receiving Storage, Reclaim & Transfer to Silos	396	10.8	No Change		0
10.8	Steam & Water Sampling	InAcct. 9.0	10.9	No Change		0
				Acct. 10.0 Total Variance		3908
11.0	Job Distributable Costs					
	All Costs	8000		Increase is Directly Related to increase in project field labor force requirements.	14000	6000
	Engineering & Owner Costs	22501		GreaterEngineeringEffort to be Expended due to addition of RFB Sys. Also general increase in other Equip. & Piping Reqs.	42033	19532
	Contingency	24751		Increase is Directly Related to Increase in Project Cost	46236	21485
	Interest During Construction	53091		Increase is Directly Related toIncrease inTotal Proj.Costs	99177	46086

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