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ENERGY CONVERSION ALTERNATIVES STUDY

—ECAS—

UNITED TECHNOLOGIES PHASE II FINAL REPORT

Integrated Coal Gasifier/Molten Carbonate Fuel Cell Powerplant
Conceptual Design and Implementation Assessment

By: J. M. King, United Technologies Corporation

STUDY TEAM

Burns & Roe, Inc.
United Technologies Corporation
Institute of Gas Technology

Prepared for

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION
ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
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Project Manager, M. M. Bailey	I. L. Chait	J. M. King, Jr.
NASA Lewis Research Center	Program Manager	Program Manager
Cleveland, Ohio 44135	Burns & Roe, Inc	United Technologies Corporation

16. Abstract

This report presents a Conceptual Design and Implementation Assessment for an Integrated Coal Gasifier/Molten Carbonate Fuel Cell Powerplant (ICG/FCP). This effort was carried out as part of the Energy Conversion Alternatives Study (ECAS) Phase II effort being performed by the National Aeronautics and Space Administration in cooperation with the Energy Research and Development Administration and National Science Foundation. This portion of ECAS Phase II was carried out under NASA Contract NAS3-19586 by the Study Team of Burns and Roe, Inc., United Technologies Corporation, and Institute of Gas Technology. Other ECAS Phase II reports are NASA CR-134942 (Westinghouse), NASA CR-134949 (General Electric), and NASA TM X-73515 (NASA-Lewis Research Center).

In the ICG/FCP conceptual design powerplant, coal is gasified in ash agglomerating, fluidized bed gasifiers Gasifier pressure is 200 psia. Sulfur is removed from the product gas in iron oxide beds. The clean gas is fed to molten carbonate fuel cells which operate at 150 psia and a nominal temperature of 1200°F. Direct current power from the fuel cells is converted to alternating current in solid-state inverters Fuel cell exhaust gases drive turbocompressors which pressurize the fuel cells and gasifiers. Waste heat from the fuel cell and the gasifier is used to drive a steam turbine bottoming cycle. Bottoming cycle throttle conditions are 2400 psig and 1000°F; the bottoming cycle incorporates a single preheat to 1000°F. Bottoming cycle heat is rejected in wet mechanical draft cooling towers The gasifier vessels, fuel cell modules inverters and turbocompressors are designed for factory fabrication with rail transport to the plant site The integrated coal gasifier/molten carbonate fuel cell powerplant has a net output of 635 MW; the fuel cell modules produce two thirds of the plant output. Overall plant efficiency based on net ac power delivered and the higher heating value of coal consumed is 49 6 percent. Plant lead time is estimated to be 5 years with capital cost at an estimated $595/kW in 1975 dollars. Pollution emissions are estimated to be less than solid fuel standards. The plant is based on four independent gasifier-fuel cell trains and availability is expected to be 84 to 88 percent

Molten carbonate fuel cells of the type assumed in the study have operated for 5000 hours at ambient pressure at the temperatures assumed in the design. Power density of present experimental configurations at pressure is expected to be two thirds of that assumed in the study. Approaches to improving endurance and performance to the values assumed in the study have been identified and are being evaluated in EPRI Research Project RP114.

A Research, Development, and Demonstration Plan was prepared as part of the ECAS Phase II effort. The plan includes confirmation of fuel cell component technology and design, scaleup to prototype hardware, and demonstration of full-scale dc modules operating with a pilot gasifier and demonstration of a complete 635 MW powerplant. Component technology issues to be addressed in the program include fuel cell performance at pressure, cell tolerance to hydrogen sulfide and other trace gasifier products, and potential for reduction of the fuel cell power section materials requirements. The demonstration plant testing could be completed in mid 1984, and could be transferred to commercial operation during 1985. Construction of the first commercially-designed powerplant could begin at the completion of the demonstration plant testing, and following shakedown testing, the commercial powerplant could be on line in early 1989. Total cost of the Research, Development, and Demonstration Program is estimated at $715 million (1975 Dollars). These costs are exclusive of any Research & Development gasifier/gas clean up costs, and assume a gasifier process development unit and a 5 ton/hour pilot gasifier are available to this program at no cost from other ERDA activities.

An implementation assessment of the ICG/FCP was performed as part of the ECAS Phase II effort. The assessment included technical factors, electric utility application factors, and national interest factors associated with potential commercial implementation of the ICG/FCP.

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FOREWORD

This report covers work performed by the contractors as part of the Energy Conversion Alternatives Study (ECAS). This study is being performed by the NASA-Lewis Research Center in cooperation with the Energy Research and Development Administration and the National Science Foundation. The purpose of the study is to assess, on a common basis, the merits and potential benefits of, and the technology status and development requirements for, advanced energy conversion systems utilizing coal or coal-derived fuels for electric power generation.

The ECAS evaluation of alternate energy conversion systems consisted of two work phases. Phase I involved parametric analyses of many various conversion systems of interest. Phase II involved a conceptual design and implementation assessment effort of selected systems resulting from Phase I studies. ECAS Phase I reports are NASA CR-134941 (Westinghouse), NASA CR-134948 (General Electric), and NASA TM X-71855 (NASA-Lewis Research Center). Phase II reports are NASA CR-134942 (Westinghouse), NASA CR-134949 (General Electric), NASA CR-134955 (United Technologies), and NASA TM X-73515 (NASA-Lewis Research Center).

This report describes the work performed under Phase II of ECAS for a Molten Carbonate Fuel Cell Powerplant operating as in integrated coal-pile-to-busbar central station utility application. The effort was undertaken by a study team of Burns and Roe, Inc., the Power Systems Division of United Technologies, United Technologies Research Center and the Institute of Gas Technology. Since this team did not participate in the ECAS Phase I studies, the selection of system configuration for the integrated Coal Gasifier-Molten Carbonate Fuel Cell Powerplant is included in this report.

The following personnel participated in this study: I. Chait, S. Cavallaro, G. Foley from Burns and Roe, Inc.; J. King, Jr., A. Levy, H. Healy, L. VanDine, R. Wertheim from Power Systems Division of United Technologies Corporation; F. Robson, W. Davison from United Technologies Research Center; J. Patel, K. Burnham from the Institute of Gas Technology.

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UNITS OF MEASURE

Calculations were performed for this project using the English system of units of measure. English units are also used throughout this report for presentation of results. In compliance with form PROC./P-72, the following table of factors for converting to the International System of Units (SI) is included. The SI units are reported in parentheses throughout the text of this report, but are not included in the figures or tables.

FACTORS FOR CONVERSION TO
INTERNATIONAL SYSTEM OF UNITS (SI)

MULTIPLY	BY	TO GET
ATM	101.325	KILOPASCAL
BBL	0.15899	$METRE^3$
BBL/TON	1.7525×10^{-4}	$METRE^3$/KILOGRAM
BHP	0 7457	KILOWATTS
BTU	1.05435	KILOJOULES
BTU/HR	0 29288	WATTS
BTU/LB	2.3244	JOULES/GRAM
BTU/LB MOL	2 3244	JOULES/MOL
BTU/LB MOL, °K	2 3244	JOULES/MOL, °K
BTU/SCF	37.320	KILOJOULES/$METRE^3$
CU FT	0.02832	$METRE^3$
CFH (NTP)	7.8667×10^{-6}	$METRE^3$/SEC
GPM	6.3089×10^{-5}	$METRE^3$/SEC
GAL/TON	$4\ 1727 \times 10^{-6}$	$METRE^3$/KILOGRAM
HP	0.7457	KILOWATTS
KWH	3600	KILOJOULE
KWH/LB	7.9367	KILOJOULE/GM
LB	0.45359	KILOGRAM
LB/CF	16.0185	KILOGRAMS/$METRE^3$
LB/HR	0.12600	GRAMS/SEC
LB/HR, CU FT	4.4491	GRAMS/SEC, $METRE^3$
LB/MM BTU	4.3021×10^{-7}	KILOGRAMS/KILOJOULE
LB/TON	0.500	GRAMS/KILOGRAM
LB/YR	1.4383×10^{-8}	KILOGRAMS/SEC
LB MOL/HR	0.12600	GM MOL/SEC
M LB/HR	0.12600	KILOGRAMS/SEC
MSCF/TON	0.031217	$METRE^3$/KILOGRAM
MSCFH	7.8667×10^{-3}	$METRE^3$/SEC
MM BTU	1.05435×10^{6}	KILOJOULES
MM BTU/BBL	6.6315×10^{6}	KILOJOULES/$METRE^3$
MM BTU/HR	292.88	KILOWATTS
MM CFD	0.32778	$METRE^3$/SEC
MM LB/YR	0.014383	KILOGRAMS/SEC
MM SCFH	7.8667	$METRE^3$/SEC
PSIA	6.89476	KILOPASCAL
SCF/TON	3.1217×10^{-5}	$METRE^3$/KILOGRAM
SCFH	7.8667×10^{-6}	$METRE^3$/SEC
ST/DAY	0.010500	KILOGRAMS/SEC
ST/HR	0.25120	KILOGRAMS/SEC
TON	907.185	KILOGRAMS
TON (OF REFRIGERATION)	3.5145	KILOWATTS
TPD (TONS/DAY)	0.010500	KILOGRAMS/SEC
TON/HR	0.25200	KILOGRAMS/SEC
¢/LB	2 2046	¢/KILOGRAM
¢/MGAL	0.26417	¢/$METRE^3$
¢/MM BTU	9.4845×10^{-7}	¢/KILOJOULE
$/LB	2.2046	$/KILOGRAM
$/MM BTU	9.4845×10^{-7}	$/KILOJOULE
	1.1023×10^{-3}	$/KILOGRAM

$$°K = °C + 273\ 15$$

$$°K = (°F\text{-}32)/1.8 + 273\ 15$$

$$°API = \frac{141.5}{sp\ gr(60°/60°F)} - 131.5$$

I. SUMMARY

This report presents a Conceptual Design and Implementation Assessment for an Integrated Coal Gasifier/Molten Carbonate Fuel Cell Powerplant. This effort was carried out as part of the Energy Conversion Alternatives Study (ECAS) being performed by the National Aeronautics and Space Administration in cooperation with the Energy Research and Development Administration and the National Science Foundation. This portion of ECAS was carried out under NASA Contract NAS3-19586 by the study team of Burns and Roe, Inc.; United Technologies Corporation; and the Institute of Gas Technology.

In the conceptual design powerplant, coal is gasified in ash agglomerating, pressurized fluidized bed gasifiers. Sulfur is removed from the product gas in iron oxide beds. The clean gas is fed to molten carbonate fuel cells. Direct current power from the fuel cells is converted to alternating current in solid-state inverters. Fuel cell exhaust gases drive turbocompressors which pressurize the process air for fuel cells and gasifiers. Waste heat from the fuel cells and the gasifiers is used to drive a steam turbine bottoming cycle. Bottoming cycle heat is rejected in wet mechanical-draft cooling towers. The system thermodynamics was chosen to provide state-of-the-art design conditions for the bottoming cycle and turbocompressors. Fuel cell operating temperature was selected at present experimental levels. Fuel cell pressure was selected at 150 psia; the cell stacks are encapsulated in pressure vessels so that the pressure differential between the cell and ambient is the same as present ambient pressure experimental cells. The gasifier vessels, fuel cell modules, inverters, and turbocompressors are designed for factory fabrication with rail transport to the plant site.

The integrated coal gasifier/molten carbonate fuel cell powerplant design has a net output of 635 MW; the fuel cell modules produce two thirds of the plant output. Overall plant efficiency based on net ac power delivered and the higher heating value of coal consumed is 49.6 percent. Plant capital cost is estimated at $595/KW based on 1975.5 (mid-1975) dollars and including escalation and interest during a five-year design/construction lead time. Pollution emissions are estimated to be less than solid fuel standards. The plant design is based on four independent gasifier-fuel cell trains and availability is expected to be 84 to 88 percent.

Molten carbonate fuel cells of the type assumed in the study have operated for 5000 hours at ambient pressure at the temperatures assumed in the design. Power density of present experimental configurations at pressure is expected to be two thirds of that assumed in the study. Approaches to improving endurance and performance to the values assumed in the study have been identified and are being evaluated in EPRI Research Project RP114.

A Research, Development, and Demonstration Plan was prepared as part of the effort. The plan includes confirmation of fuel cell component technology and design, scaleup to prototype hardware, demonstration of full-scale dc modules operating with a pilot gasifier, and demonstration of a complete 635 MW powerplant. Component technology issues to be addressed in the program include fuel cell performance at pressure, cell tolerance to hydrogen sulfide and other trace gasifier products, and potential for reduction of the fuel cell power section materials requirements. The RD&D plan takes advantage of the ability to test critical technology issues in small research cells and to demonstrate full-scale hardware in single cell stacks or modules.

Demonstration plant testing could be completed in mid-1985, and it could then be transferred to commercial operation. Construction of the first commercially-designed powerplant could begin at the completion of the demonstration plant testing, and following shakedown testing, the commercial powerplant could be on line in early 1989. Total cost of the Research, Development, and Demonstration Program is estimated at $715 million (1975 Dollars). These costs are exclusive of any gasifier/gas clean-up R&D costs, and assume that a gasifier process development unit and a 5 ton/hr pilot gasifier are available to this program from other ERDA activities at no cost.

An implementation assessment of the ICG/FCP was performed as part of the ECAS Phase II effort. The assessment included technical factors, electric utility application factors, and national interest factors associated with potential commercial implementation of the ICG/FCP.

II. INTRODUCTION

A. ECAS Program

The Energy Conversion Alternatives Study (ECAS) was performed by National Aeronautics and Space Administration -- Lewis Research Center in cooperation with the Energy Research and Development Administration and the National Science Foundation. The objective of this study was to develop the information necessary for an assessment of advanced energy conversion systems utilizing coal and coal-derived fuels in base load central station powerplants.

The program was conducted in two phases. Phase I was a parametric study from which a limited number of attractive specific system configurations were selected. Phase II consisted of a Conceptual Design and Implementation Assessment. Conceptual designs were prepared for each of the selected systems in sufficient detail to describe anticipated powerplant performance, capital cost, cost of electricity, natural resource requirements, and environmental impact. Finally a research, development, and demonstration program leading to commercialization of each conceptual design was defined and factors affecting commercial implementation were assessed. Overall control of the ECAS was by an interagency steering committee consisting of members from the government agencies involved. In addition, a technical advisory panel was formed to provide technical advice and a utility advisory panel was formed to inject guidance from the powerplant application viewpoint.

B. Scope of Work

This report describes results of an ECAS Phase II conceptual design and implementation assessment study of an integrated coal gasifier/molten carbonate fuel cell powerplant. This study was carried out by Burns and Roe, United Technologies, and the Institute of Gas Technology under NASA Contract NAS3-19586.

The basic concept of an integrated coal gasifier/molten carbonate fuel cell powerplant was assigned by NASA. The initial study team effort then involved a limited parametric study to specify the gasifier type, bottoming cycle, and system operation conditions. A conceptual design of the specific system was then prepared. The results of the conceptual design include:

- Schematic drawings of the plant showing flow rates and state conditions.
- Performance projections and efficiency calculations for major components.
- Calculation of overall powerplant efficiency including parasitic requirements for auxiliary loads and electrical losses.
- Identification of the materials of construction of the major components.
- Plan and elevation drawings of the major equipment.
- Plan and elevation drawings of the powerplant site including major balance of plant equipment.

- Capital cost estimates for the entire pla
- Estimates of cost of electricity for the plant including the contribution of capital, fuel, and operating and maintenance.
- Estimate of natural resource requireme
- Anticipated environmental intrusions including gaseous, liquid, and solid effluents.

Section III (pages 7 to 68) describes the Conceptual Design and Section IV (pages 69 to 86) provides an estimate of the Design Characteristics. The final effort provides an assessment of the commercial implementation of the integrated coal gasifier/molten carbonate fuel cell powerplant. The results of this phase of the work include:

- As assessment of the present state-of-technology pertinent to the fuel cell portion of the powerplant and a description of the advancements and experiments required to further assess this concept as a utility generation option.
- An estimate of the development schedule required to produce a pilot plant, a demonstration plant, and the first commercial plant.
- Funding estimates for development, pilot plant, and demonstration plant.
- A discussion of a number of factors which may either favorably or unfavorably affect the wide-scale implementation of this powerplant concept.

Section V (pages 87 to 89) presents the Technology and Design Status; Section VI (pages 90 to 102) describes a Research, Development, and Demonstration Plan; and Section VII (pages 103 to 121) discusses Factors Affecting Implementation.

Section VIII (page 122) discusses the Program Results and Section IX (page 123) outlines the Conclusions.

C. Study Team Responsibilities

Burns & Roe Inc. was given the overall management responsibility for the study described in this report. They also provided performance, physical, and economic data for the balance of plant equipment and for the installation of all equipment except the major components within the coal gasification system.

The Institute of Gas Technology (IGT) provided the primary performance and cost data associated with the coal gasification system. This included the close-coupled coal feed and ash removal equipment, the gasifier units, gasifier steam generators, and the subsystem necessary for sulfur removal and recovery. IGT also provided the field cost estimate for erection and installation of this equipment at the site.

The Power Systems Division (PSD) of United Technologies Corporation defined the overall powerplant concept and performed the thermodynamic and fluid flow calculations to define the state conditions necessary for designing the major components. PSD also provided the performance, physical design and fabrication cost estimates for the fuel cell modules, pressure vessels, main reactants piping and valves, controls, and the dc to ac inverter equipment.

United Technology Research Center (UTRC) provided data for the steam bottoming cycle, including the steam turbine – generator, bottoming cycle steam generator, wet cooling towers, and the turbocompressors associated with system pressurization.

The implementation assessment task of the contract was performed by the Power Systems Division of United Technologies Corporation using the data input from all study team members in the conceptual design phase of the program.

D. Study Ground Rules

NASA established a number of common ground rules and goals which were used by all subcontractors in the various advanced system studies. The following list summarizes the major of these input ground rules; a more detailed description of some of the ground rules are included in Appendix I and are indicated below:

- Reference coal was Illinois No. 6 at a base price of $\$1/10^6$ Btu ($\$0.95/10^6$ kilojoules). The coal analysis is presented in Appendix I-A.

- Costs were estimated in 1975.5 dollars and direct site labor was assumed at a composite rate of $11.75/hr.

- Both base emission standards and advanced target goals for solid fuels were provided. These are indicated in Appendix I-B.

- Powerplants were to be designed for an 80 percent capacity factor and economic calculations based on a 65 percent capacity factor.

- Powerplant target availability was set at 90 percent.

- Fixed charge rate for economic calculations was 18 percent.

- Powerplant was to be designed for enclosed construction at the "Middletown, U.S.A." site described in Reference 1.

- NASA supplied a list of critical materials the usage for which were to be identified. The list of critical materials is included as Appendix I-C.

- Site design ambient conditions were set at:

  - 59°F (288°K) dry bulb temperature
  - 60 percent relative humidity
  - 1 atm (101 kilopascal) pressure

- Wet, mechanical-draft cooling towers were to be used for waste heat rejection.
- On-site coal storage capacity for 60 days and emergency waste storage capacity for 15 days was required at 100 percent capacity factor.
- NASA supplied factors for evaluating escalation and interest during construction. The factors are presented in Appendix I-D.

In addition to the above ground rules affecting design, guidelines were established for the Research and Development Plans effort and for the Implementation Assessment:

- The primary emphasis of the study was on the energy conversion portion of the system. Considerably less effort and detail was contemplated on the gasifier/cleanup system. The major emphasis here was on costing and design detail adequate to characterize the interfaces and performance with the prime cycle. As a consequence, there was insufficient information generated with which to prepare detailed development plans and implementation assessment for the gasifier/cleanup subsystem.
- Factors affecting implementation were defined. Fourteen factors were designated for major emphasis and an additional seven factors identified for optional lower emphasis response.

III. CONCEPTUAL DESIGN DESCRIPTION

This section describes the selection of system concept, subsystem approaches, and component ratings for an integrated coal gasification-fuel cell powerplant designed for base load electric utility application. The overall plant arrangement and each subsystem are described in detail. The characteristics of the design are presented in Section IV.

III-A. Overall System

1. Thermodynamic Cycle

The NASA specified the basic concept as an integrated coal gasifier/molten carbonate fuel cell powerplant. The total powerplant cycle was then defined by PSD in initial studies. The powerplant cycle, in its simplest form, consists of three subsystems: a coal gasifier and gas cleanup process; a fuel cell power section; and a bottoming cycle for waste energy recovery. As shown in Figure 1, the subsystems are thermodynamically integrated to achieve high energy conversion efficiency. The entire powerplant configuration is similar to that of a combined cycle plant in which the fuel cell power section is the prime cycle and the bottoming cycle may be either a steam turbine or gas turbine depending on plant application and duty cycle. A steam turbine bottoming cycle was selected for the conceptual design. An alternative design based on a gas turbine bottoming cycle was studied in another program and is discussed in Appendix II.

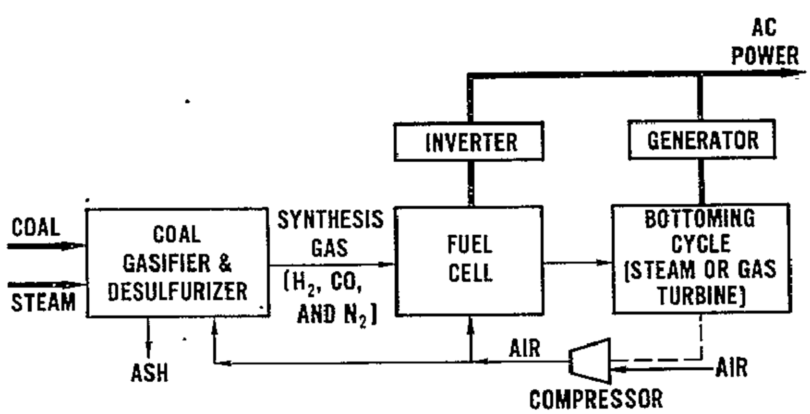


Figure 1 — System Concept

A detailed flow chart of the entire powerplant is shown in Figure 2. The powerplant thermodynamic conditions including flow rates, stream, compositions, pressures, temperatures, and enthalpies corresponding to the numbered stations in Figure 2 are described in Table I. Selected design pressures have been shown. These pressures provide allowances for pressure losses through interconnecting piping and major components. Enthalpies are based on zero enthalpies for the elements at 0° R (0°K) except for the high pressure steam stations for which Keenan and Keyes Steam Tables were used.

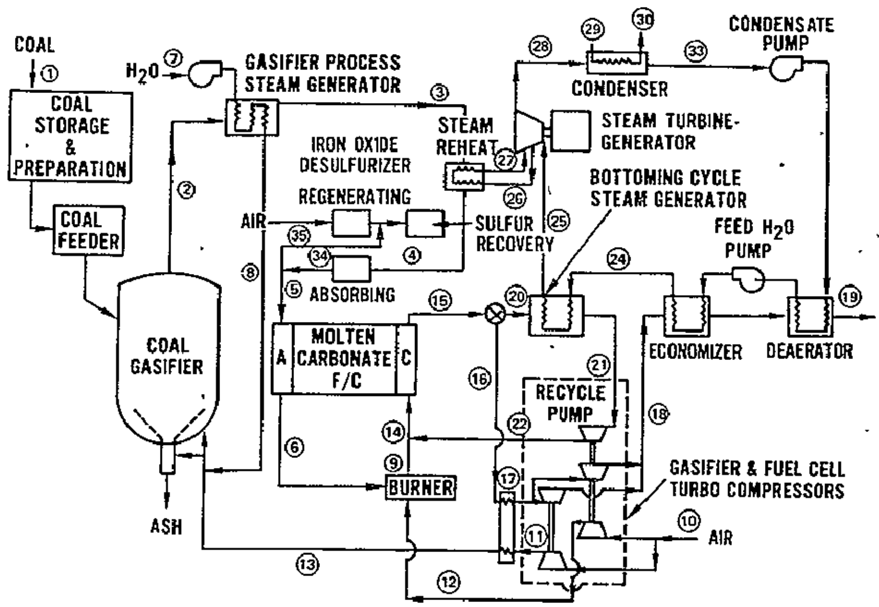


Figure 2 – Powerplant Flow Chart

As shown in the gasifier section in Figure 2, Illinois No. 6 coal is reacted with superheated steam and air in a fluidized bed gasifier to produce a hot LBtu synthesis gas containing primarily hydrogen, carbon monoxide, and nitrogen. The gasifier output is at a temperature of 1900°F (1310°K) and a pressure of 200 psia (1380 kilopascal). Cyclone separators are used to remove particulate matter from the synthesis gas. The ash is removed in the form of ash agglomerates which are funneled through a conical vent at the bottom of the reactor into an ash hopper for subsequent disposal. The hot process gas is partially cooled prior to desulfurization downstream of the gasifier. Sensible heat removed from the synthesis gas provides the thermal energy necessary for generating the gasifier process steam and for reheating steam for the bottoming cycle. The sulfur in the coal fuel appears in the synthesis gas primarily as hydrogen sulfide (H_2S) which is removed by absorption on beds of iron oxide and fly ash. The iron oxide beds are regenerated periodically with air and the sulfur is ultimately recovered in elemental form and stored as a molten liquid.

The clean synthesis gas from the desulfurizer is then passed to the molten carbonate fuel cell power section where the hydrogen in the gas is reacted electrochemically with oxygen from the air to produce useful dc power, product water, and waste heat. The cells are operated at nominal conditions of 1200°F (922°K) and 150 psia (1030 kilopascal). The dc output from the fuel cell is converted to utility quality ac by solid-state, self-commutated inverter equipment and conventional transformers. The molten carbonate fuel cell power section consumes hydrogen at the anode and oxygen and carbon dioxide at the cathode of the cell. Carbon dioxide and water are products of the anode reaction. The anode exhaust, containing the anode products as well as unconsumed hydrogen, carbon monoxide and methane, is mixed with air and burned in a catalytic burner and then fed to the cathode.

The fuel cell product water and waste heat are removed by a cathode recycle gas loop. A portion of the waste heat is utilized in raising superheated steam for the steam turbine bottoming cycle. A vent from the cathode recycle gas loop is expanded through turbocompressor turbine sections to provide the compression power necessary for supplying air to both the coal gasifier and fuel cells. Turbine exhaust gases are cooled to provide feedwater heating for the steam turbine bottoming cycle.

TABLE I

POWERPLANT THERMODYNAMIC CONDITIONS

STA	TEMP DEG F	PRES PSIA	ENTH BTU/HR	H2	H2O	CH4	CO	CO2	O2	N2	H2S	H2O(L)	COAL LBS/HR	TOTAL MOLES/HR	STA
				LB-MOLES/HR											
1	59.	15.	-.5210E+09	0.	0.	0.	0.	0.	0.	0.	0.	0.	404944.	0.	1
2	1900.	200.	-.8843E+09	11750.	6826.	428.	15115.	4337.	0.	33059.	472.*	0.	0.	71988.	2
3	1570.	******	-.1090E+10	11750.	6826.	428.	15115.	4337.	0.	33059.	472.	0.	0.	71988.	3
4	1120.	******	-.1359E+10	11750.	6826.	428.	15115.	4337.	0.	33059.	472.	0.	0.	71988.	4
5	1192.	155.	-.1321E+10	13473.	4689.	408.	12161.	6399.	0.	31544.	14.	0.	0.	68688.	5
6	1300.	******	-.6882E+10	1530.	16631.	408.	2315.	38035.	0.	31544.	14.	-0.	0.	90477.	6
7	59.	******	-.8954E+09	0.	0.	0.	0.	0.	0.	0.	0.	7612.	0.	7612.	7
8	1000.	235.	-.6897E+09	0.	7612.	0.	0.	0.	0.	0.	0.	0.	0.	7612.	8
9	1417.	******	-.6324E+10	0.	19807.	0.	0.	40758.	14218.	95302.	0.	0.	0.	170084.	9
10	59.	******	0.3176E+09	0.	1256.	0.	0.	0.	25727.	96732.	0.	0.	0.	123715.	10
11	804.	******	0.3339E+09	0.	428.	0.	0.	0.	8770.	32974.	0.	0.	0.	42172.	11
12	660.	155.	0.5581E+09	0.	828.	0.	0.	0.	16957.	63758.	0.	0.	0.	81543.	12
13	1000.	235.	0.3964E+09	0.	428.	0.	0.	0.	8770.	32974.	0.	0.	0.	42172.	13
14	1100.	150.	-.1502E+11	0.	64920.	0.	0.	83963.	21786.	312368.	0.	0.	0.	483037.	14
15	1300.	******	-.1101E+11	0.	64920.	0.	0.	62174.	10892.	312368.	0.	0.	0.	450354.	15
16	1300.	******	-.3358E+10	0.	19807.	0.	0.	18969.	3323.	95302.	0.	0.	0.	137401.	16
17	1248.	******	-.3420E+10	0.	19807.	0.	0.	18969.	3323.	95302.	0.	0.	0.	137401.	17
18	722.	******	-.4030E+10	0.	19807.	0.	0.	18969.	3323.	95302.	0.	0.	0.	137401.	18
19	237.	15.	-.4552E+10	0.	19807.	0.	0.	18969.	3323.	95302.	0.	0.	0.	137401.	19
20	1300.	******	-.7648E+10	0.	45113.	0.	0.	43205.	7569.	217066.	0.	0.	0.	312953.	20
21	898.	******	-.8728E+10	0.	45113.	0.	0.	43205.	7569.	217066.	0.	0.	0.	312953.	21
22	912.	******	-.8691E+10	0.	45113.	0.	0.	43205.	7569.	217066.	0.	0.	0.	312953.	22
23	0.	******	0.0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	23
24	547.	******	0.6308E+09	0.	0.	0.	0.	0.	0.	0.	0.	64463.	0.	64463.	24
25	1000.	2400.	0.1698E+10	0.	64463.	0.	0.	0.	0.	0.	0.	0.	0.	64463.	25
26	580.	******	0.1496E+10	0.	64463.	0.	0.	0.	0.	0.	0.	0.	0.	64463.	26
27	1000.	480.	0.1765E+10	0.	64463.	0.	0.	0.	0.	0.	0.	0.	0.	64463.	27
28	101.	1.	0.1192E+10	0.	59628.	0.	0.	0.	0.	0.	0.	4835.	0.	64463.	28
29	72.	25.	0.2227E+10	0.	0.	0.	0.	0.	0.	0.	0.	3086791.	0.	3086791.	29
30	92.	15.	0.3336E+10	0.	0.	0.	0.	0.	0.	0.	0.	3086791.	0.	3086791.	30
31	0.	******	0.0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	31
32	0.	******	0.0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	32
33	101.	******	0.8065E+08	0.	0.	0.	0.	0.	0.	0.	0.	64463.	0.	64463.	33
34	1192.	******	-.1385E+10	14120.	4914.	428.	12746.	6707.	0.	33059.	14.	0.	0.	71988.	34
35	1192.	******	-.6347E+08	647.	225.	20.	584.	307.	0.	1515.	1.	0.	0.	3300.	35

STATIONS 23-30,33 STEAM TABLE ENTHALPY BASE(32 DEG F.)
ALL OTHER STATIONS GIRDLER ENTHALPY BASE(0 DEG R.)
DATE- 01/15/76 TIME- 15:17:51

*H_2S 454 MOLES/HR
COS 18 MOLES/HR
472 MOLES/HR

GASIFIER ASH 43634 #/HR

FCR-0237

The steam turbine bottoming unit utilizes primary steam in the high pressure stage at conventional conditions of 2400 psig (16,600 kilopascal) and 1000°F (811°K). A low pressure turbine stage is employed which uses 470 psig (3340 kilopascal) steam, reheated to 1000°F (811°) by waste heat from the gasification section. This reheat significantly improves the thermal efficiency of the steam turbine cycle. Turbine exhaust steam is condensed in conventional water cooled equipment at a pressure of 2 in. Hg abs. (6.77 kilopascal). The cooling towers are designed to a wet bulb temperature of 52°F (284°K) consistent with the NASA Study Ground Rules.

2. Selection of Component and Powerplant Ratings

The design philosophy used in selecting the individual unit sizes for the gasifier, fuel cell modules, and turbocompressors were based on a maximum of factory fabrication with rail transportation to the site. This approach reduces field construction and permits factory testing to verify specification performance. The ability to transport complete assemblies by rail generally limits the physical size of the components, and frequently results in the use of multiple units to accomplish a given function as compared to a field assembly approach.

Although most of the plant major components are modular in nature, only a single steam turbine bottoming cycle is used. The selection of a single unit was based on achieving the maximum economy of scale for this equipment. While designing for the use of multiple steam turbines would have improved power availability, it would have increased equipment cost.

The overall plant size of 635 megawatts was selected to be typical of present base load fossil plants. Due to the highly modular character of the plant, larger sizes can be constructed by the addition of identical gasifier and fuel cell modules and by a suitable increase in the capacity of the steam turbine plant. Both powerplant efficiency and specific capital cost ($/KW) are expected to be essentially constant for larger plant sizes.

III-B. Plant Layout

1. Guidelines and Criteria

The study guidelines located the integrated coal-gasifier fuel cell plant at a site near Middletown, U.S.A. The topography, general site characteristics, population density, makeup water and public utility services, meteorology and climatology, geology, seismology, and sewage disposal are discussed in Reference 1. The site layout is based on the following considerations:

- Coal delivery is by unit trains of 100 to 110 cars.
- Transmission lines connect to interconnections south of the site. Startup power is available from an outside source.
- Access is provided for coal delivery, fuel oil deliveries, and regular replacement of fuel cell tank assemblies.
- Facility is designed for one unit with no consideration for growth or future capability.

- Provisions for unloading, storing and reclaiming the coal are provided. Sixty days of on-site storage at 100 percent capacity factor is required.

- Heavy equipment would be brought in and removed by railroad.

- Cooling towers are required. River water is adequate for makeup to the plant and properly treated liquid wastes are discharged to the river.

- Ash from combustion of coal is disposed of off site. Only 15 days of on-site ash storage shall be provided for emergencies.

- Safety distances must be provided for fire and explosion hazards.

The layout was developed to obtain a practical and economical arrangement of plant structures and facilities for efficient operation of the coal processing and power generation functions. The arrangement does not necessarily represent an optimized arrangement since evaluation of alternative arrangements was precluded by time and funding.

2. General Plant Arrangement

Figure 3 shows a simplified layout of the plant. The plant occupies 123 acres (499,000 meters^2) of land in a site measuring 1820 feet (555 meters) along the north-south boundaries and 2950 feet (899 meters) along the east-west boundary. The major equipment associated with the thermodynamic cycle is grouped into three main areas: Coal Gasification Island, Fuel Cell Island, and Steam Turbine – Generator Island. Auxiliary areas on the site are: Coal Unloading, Coal Storage, Coal Conveying and Preparation, Ash Removal and Emergency Storage, Cooling Towers, River Water Intake Structure and Equipment Enclosure, Liquid Waste Treatment, Sulfur Recovery Transfer and Storage, Fuel Oil Storage, Electrical Yard, Administrative and Laboratory Building, and Maintenance and Equipment Storage Building.

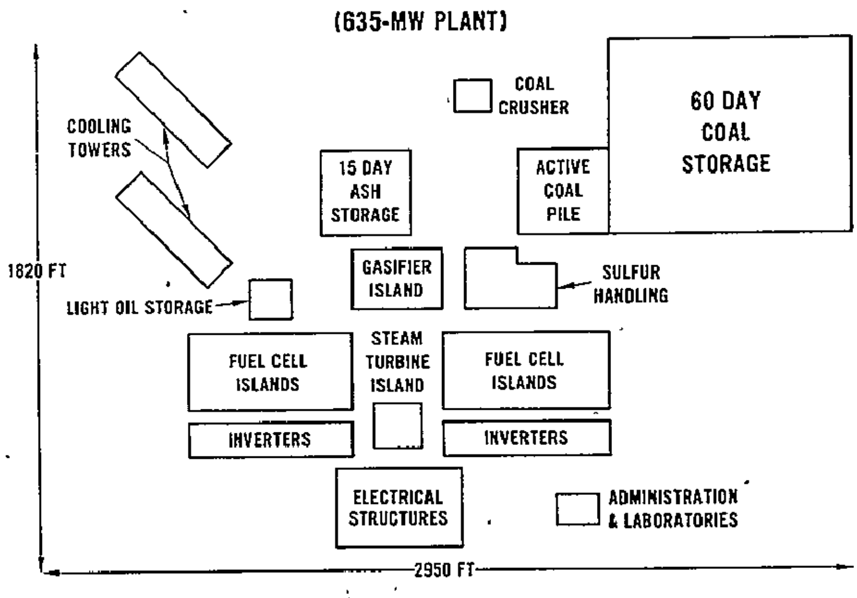


Figure 3 – Simplified Plant Layout

The equipment associated with each island and the relative locations of the islands are grouped in ar attempt to reduce interconnecting piping and wiring costs and for ease of installation, operation anc maintenance. Aisles in the fuel cell buildings, at the lower level of the turbine building and around the islands, permit access of large trailer trucks and mobile cranes. Personnel access aisles are 3 feet 6-inch (1.1 meters) minimum.

The site arrangement considered the safety of personnel and materials. Relatively large safety distances are provided by isolating the gasifier, fuel cell, and steam turbine islands to limit the damage that may result should a fire or explosion occur in a gasifier or fuel cell. The fuel oil storage tanks are located in an earthen dike to isolate and contain a leak or spill. The coal piles are located at a di tance from structures to minimize the likelihood of a coal fire spreading to them. Most administrative and operating personnel will be housed in the Administrative and Laboratory Building and the Steam Turbine Building which are the least hazardous and most remote structures from the major hazard areas. In general, OSHA, NFPA, and other applicable codes were followed in the layout of the plant and in the design of components.

3. Details of Plant Arrangement

Figure 4 shows the details of the plant arrangement. This drawing is shown in Appendix III in a larger size.

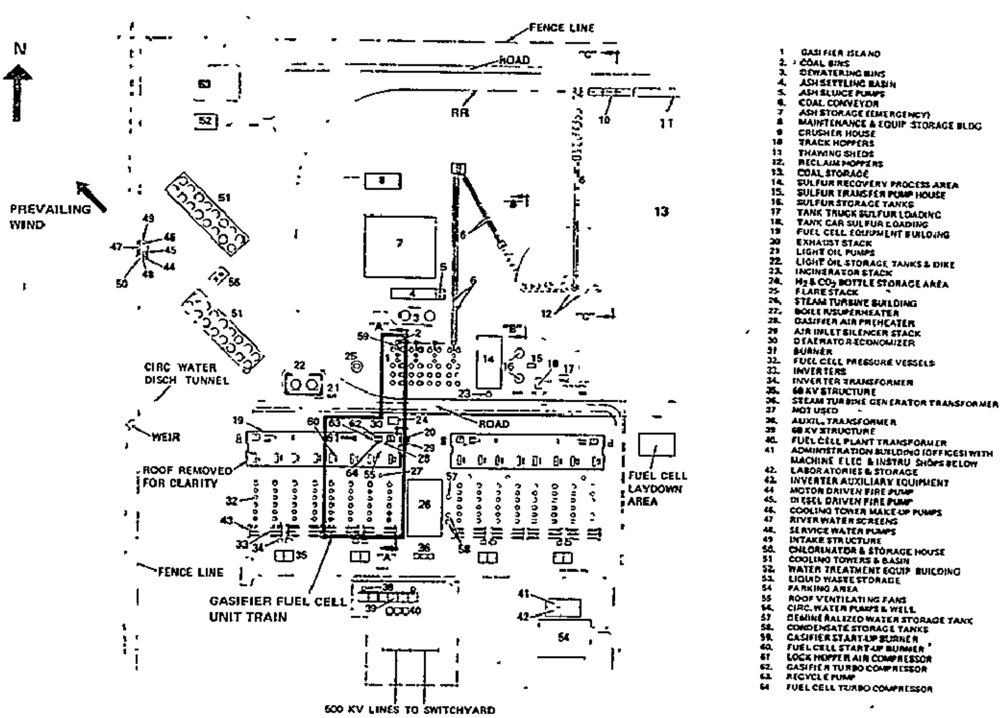


Figure 4 — Detailed Plant Arrangement

Transportation Systems — A railroad spur connecting to the feeder railroad enters the plant from the east. The railroad serves to deliver the coal fuel supply to the plant, to remove sulfur in tank cars, and to deliver and remove large equipment during initial construction and subsequent regular maintenance. The rail spur is designed to handle a unit train of up to 110 hopper cars of 100 ton (907 kilograms) capacity. There are about 8,000 feet (2440 meters) of track on the site.

The spur passes the coal unloading facilities north of the dead coal pile, turns south near the waste treatment area, and swings east between the gasifier, fuel cell and steam turbine generator islands. It then continues east, south of the dead coal pile, and north alongside the incoming spur track. This continuous line is designed to permit the coal unit trains to enter and leave while traveling in one direction on the tracks. Side spurs are provided so that rail cars can be spotted individually to receive sulfur from the recovery plant, and so that fuel cell pressure vessels and other large assemblies in the main equipment areas can be loaded and unloaded without interfering with the coal trains. A special Fuel Cell Laydown Area is allocated to permit fuel cell pressure vessels to be unloaded by a mobile crane and stored temporarily until required during construction and scheduled overhaul operations.

The plant access road connects to a state highway to the south of the plant. The access road is a 20-foot-wide (6.1 meters) paved road and will handle coal trucks and heavy equipment. Roads around the plant provide access to the coal unloading area, water treatment equipment building, maintenance and storage building, ash removal structures, fuel oil storage area, gasification area, sulfur removal area, fuel cell buildings, steam turbine building, switchyard, and the Administration and Laboratory Building. A parking lot for 60 cars is provided at the Administration Building.

Walks and curbs are provided around all buildings and areas requiring personnel access.

Coal Handling and Storage — The coal handling and storage facility is located on the north side of the plant and includes hopper car unloading facilities (10, 11, 6, 12)*, coal storage (13), and the Crusher House (9).

Gasifier Island — The four gasifier islands are located to the southwest of the coal handling area. Each island (1) includes coal bins, gasifiers, boilers, reheaters and iron oxide beds. A flare stack (25) for the gasifiers is located to the west of the gasifier islands. The sulfur recovery plant (14, 23) is to the east of the gasifier island with liquid sulfur storage and handling (15, 16, 17, 18) further to the east. Ash handling facilities (3, 4, 5, 7) are located to the north of the gasifier island.

Fuel Cell Island — The four fuel cell islands are located south of the gasifier island and the sulfur recovery equipment. These islands include the fuel cell pressure vessels (32), waste heat boilers (27) and inverter equipment (33, 34, 35, 43). Two fuel cell equipment buildings (19) in the fuel cell area house the catalytic burners, startup burners, turbocompressors feedwater heaters, lock hopper air compressors, and other equipment.

Steam Turbine Island — The steam turbine island (26) is located between the two pairs of fuel cell islands and directly across from the gasifier island. This location minimizes piping required to transfer waste heat from the fuel cell and gasifier islands.

*Numbers in parentheses indicate callouts on Figure 4.

Other Plant Areas – The electrical switchyard including final step-up transformers (40) is located immediately to the south of the steam turbine island. Two cooling towers (51) and circulating water pumps (56) are located on the west side of the plant and aligned so that the prevailing winds carry the plume away from the plant. Cooling and process water supply systems (46 through 50) are located to the west of the cooling towers and the liquid waste area (52, 53) is located in the northwest corner of the plant. Oil storage tanks (22) for start up oil are located north of the western most fuel cell island and the administration building machine shops and laboratories (41, 42, 54) are located east of the switchyard.

III-C. Gasification and Clean Up System Description

The function of the gasification and clean up system is to convert coal to a clean fuel gas for the fuel cell. A schematic of the system designed for this study is shown in Figure 5. The system consists of coal feed and ash removal systems, the coal gasifier, a source of process steam (boiler/superheater), a source of air or oxygen (turbocompressor), and fuel gas desulfurization and sulfur recovery subsystems. Coal is partially oxidized with air (or oxygen) and steam in the gasifier. The hot product gas is cooled in a gasifier process steam generator and a plant bottoming cycle steam reheater. The resulting fuel gas is fed to the fuel cell system. Sulfur is removed in an iron oxide bed. The bed is regenerated with air and sulfur is recovered in liquid form.

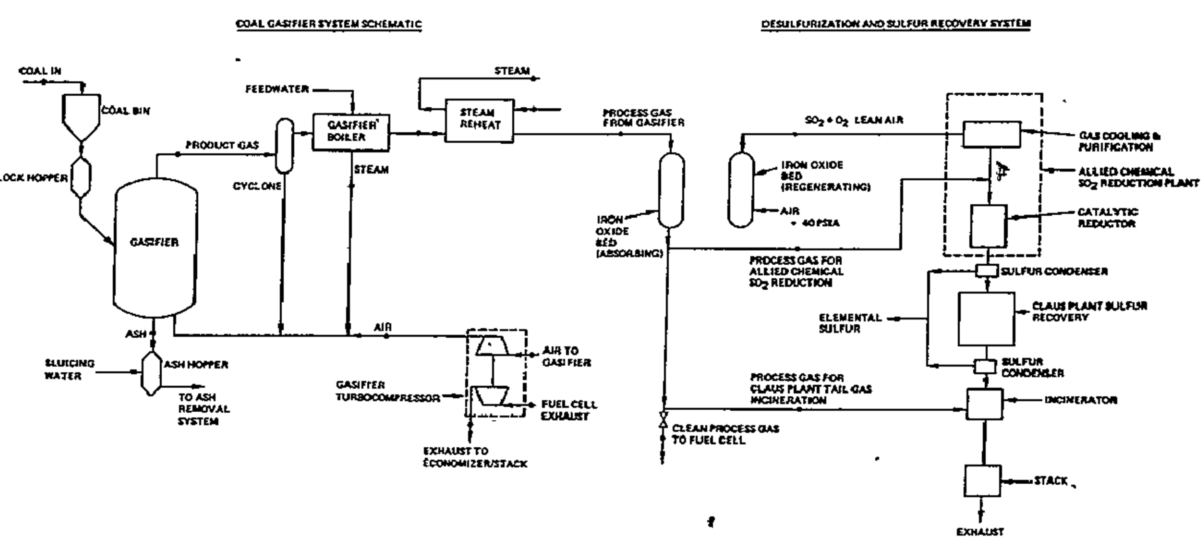


Figure 5 – Coal Gasification and Clean Up System Schematic

1. Selection of Gasifier Type and Operating Conditions

The initial task of the conceptual design studies included selection of a coal gasifier process. Although all gasifier types could be utilized with fuel cells, several gasification characteristics that improve system integration were identified. These characteristics include the level of methane concentration in the synthesis gas and the cold gas efficiency of the gasifier, (defined as the ratio of the heating value of the synthesis gas produced to the heating value of the coal feed). The molten carbonate cell consumes hydrogen and carbon monoxide fuel gases; therefore, high concentrations of these products rather than methane is desired. High cold gas efficiency is desirable since this results in a greater percentage of the energy content of the coal becoming available to the energy conversion cycles.

A review of the state-of-the-art of coal gasification indicated that advanced type gasifiers – fluidized bed, entrained flow and molten salt – offered the most desirable operating characteristics for fuel cell integration. The Institute of Gas Technology (IGT) U-Gas™ fluidized bed gasification process was selected for the conceptual design because it was representative of advanced gasifiers, experimental data were available, and it was familiar to the study team. Fluidized bed gasifiers exhibit good heat transfer characteristics which results in uniform reactant heating and relatively uniform gas compositions. Fluidized beds offer high reaction rates due to the rapid mass and heat exchange between the high relative velocity of the solids and gases. The large inventory of solids that is always present in the fluidized beds contributes to the ability to operate over a wide range of outputs, and, in the event of a coal feed interruption, decreases the potential of a hazardous oxygen breakthrough.

Gasifier operating conditions (oxidant, pressure and temperature) were selected to achieve the best system performance. For this study, an air-blown process was selected. Although an oxygen-blown gasifier yields a higher heating value synthesis gas, studies indicated that fuel cell performance was only minimally affected by the product gas composition, with the result that overall powerplant cost and efficiency of the air-blown approach was similar to the oxygen-blown system. The air-blown system does not require an air separation plant, minimizing impact of powerplant scale, and resulting in a simpler system concept with more flexible operating characteristics for part-load operation. A gasifier nominal operating pressure of 200 psia (1380 kilopascal) was selected, although detailed optimization studies were not performed. In general, undesirable methane production from the gasification process increases with increasing pressure; alternatively, low operating system pressures reduce fuel cell performance, as will be discussed in a later section. Preliminary studies indicated that 200 psia (1380 kilopascal) represented an operating pressure that maximized overall powerplant efficiency Additional study is needed to determine overall impact of pressure level on piping and pressure vessel cost. A gasifier temperature of 1900°F was selected; this temperature minimizes concentrations of tars, oils, and methane in the gasifier exhaust.

2. Gasifier Operating and Physical Characteristics

A gasifier schematic is shown in Figure 6. An ambient pressure gasifier with this configuration has operated at IGT. In the U-Gas™ process (References 2, 3) crushed coal is contacted in a fluidized-bed gasifier with superheated steam and with air. Based on past experience and considering technology appropriate to the 1990 time frame, it is believed that no pretreatment of the Illinois No. 6 coal, other than crushing, is necessary. Other more heavily caking coals could be used after a pretreatment process (see page 112). Present design specifications require a crusher to provide coal with a size distribution of 1/4-inch minus 0 and not more than 10 weight percent minus 200 USS size. The as-received coal moisture content of 13 percent is acceptable for use in the gasifier.

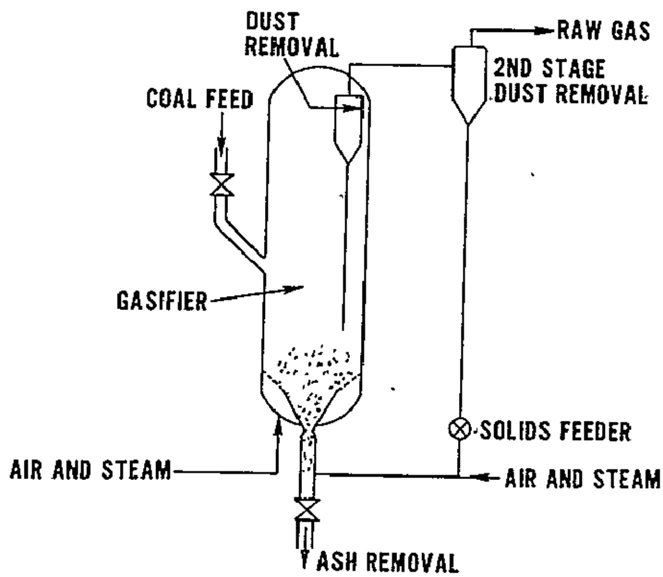


Figure 6 — Simplified Gasifier Schematic

The coal feed system for each pair of gasifier vessels includes a coal bin, lock hoppers, and surge bins. Coal from the coal bin is metered through valves into two feed lock hoppers. The lock hoppers are pressurized with turbine exhaust. Use of the oxygen-dilute exhaust minimizes pre-reaction of the coal feed in the lock hoppers. This exhaust is pressurized with electrically-driven gas compressors. The hoppers operate in thirty-minute cycles and provide the means of transferring coal from ambient pressure into a pressurized surge bin through an interlocking valve system. The valves seal the hopper from ambient air when coal is being fed, and from the raw fuel gas when the hopper is being charged with coal. A single surge bin at the bottom of the lock hoppers smooths out the uneven emptying of coal from the lock hoppers and provides a continuous and controlled feed to the gasifiers.

In the gasifier, coal is contacted with steam and air at about 1900°F (1311°K) and 200 psia (1380 kilopascal). At these conditions, the coal is gasified rapidly to produce a gas stream rich in hydrogen and carbon monoxide with very small quantities of methane. The principal reactions taking place in the fluidized bed are as follows:

$$C + H_2O \rightarrow CO + H_2 - \text{Heat}$$

$$C + CO_2 \rightarrow 2CO - \text{Heat}$$

$$C + 2H_2 \rightarrow CH_4 + \text{Heat}$$

$$C + O_2 \rightarrow CO_2 + \text{Heat}$$

$$CO + H_2O \rightarrow CO_2 + H_2 + \text{Heat}$$

The resultant gas compositions for the conceptual design are given in Table II. This composition, overall gasifier heat and material balance, and gasifier sizing were based on a coal gasification kinetic model developed at IGT (Reference 4). The design of the fluidized bed reactor and method of operation result in high carbon utilization – only 1 percent of the carbon in the coal is lost in the ash. This overall carbon utilization of 99 percent is also based on experimental information developed at IGT (Reference 5). Heat losses are assumed to be 1 percent of the heating value of the coal feed. These operating characteristics result in a cold gas efficiency of 79 percent prior to gas cleanup.

TABLE II

ESTIMATED SYNTHESIS GAS COMPOSITION
(Basis: Illinois Basin #6 Coal)

	WEIGHT PERCENT	VOLUME PERCENT
H_2	1.4	16.3
H_2O	7.2	9.5
CH_4	0.4	0.6
CO	24.8	21.0
CO_2	11.2	6.0
N_2	54.0	45.9
H_2S	0.9	0.6
COS	0.1	0.1
NH_3	TRACE	TRACE
TOTAL	100.0	100.0

The coal is fluidized by a mixture of air and steam using approximately three pounds (1.36 kg) of air and 0.35 pounds (0.16 kg) of steam for each pound of coal fed to the system. Gasification takes place in a nonslagging mode at about 1900°F (1310°K) in the fluid bed. Part of the fluidizing gas enters through a grid that is sloped toward one or more cones contained in the grid. Heavier particles migrate along the sloped grid toward the cones. The rest of the fluidized gas flows upward at high velocity through the throat of the cone apex, creating a submerged jet within the cone. The IGT-designed gasifier utilizes an ash-agglomerating technique. By proper control of air-to-steam ratios, the temperatures generated within the jet are somewhat greater than in the rest of the fluidized bed.

As a result, carbon is gasified in or near the jet area and ash is heated to its softening point. The sticky ash surfaces cling to one another and ash agglomerates grow in the violently agitated jet area. When heavy enough, the ash agglomerates fall counter to the high-velocity gas in the throat and are separated from the fluid bed.

Spherical ash agglomerates, from 1/6 to 1/4-inch (0.42 to 0.64 cm) in size are dropped into a pressurized water filled ash hopper where a circulating stream of water quenches the hot ash agglomerates. A 25 weight percent water-ash slurry at 250°F (395°K) is continuously withdrawn from the hopper and cooled to 150°F (339°K) by cooling water in a coiled slurry cooler. The cooled slurry is then let down in pressure and ducted to the downstream ash-handling subsystem, which is described in Section IIIC.

The principle of ash agglomerating, that is, ash adhering selectively to ash is credited to Godel (Reference 6), and was further developed by Jequier et al (Reference 7). IGT has successfully tested this concept as part of the HYGAS Program.

By appropriate design of the vapor space above the fluidized bed and the method of feeding coal, any tar and oils that may be evolved are thermally cracked to gas and carbon. Elimination of tars and oils in the off-gas stream reduces possible heat exchanger fouling and simplifies byproduct and waste stream cleanup and treatment, as well as increasing the Btu content of the product gases.

Particulates elutriated from the fluid bed — arising either from attrition or from the crushing operation — are returned to the gasifier through cyclones. Most of the particulates in the gases is removed by internal cyclone separators and is returned directly to the fluidized bed. Fine dust is separated in an external cyclone and is returned to the gasifier by injection beneath the gasifier cones. Within the gasifier cones, the carbon contained in the fine dust is gasified and fine ash particles stick to the heavy ash agglomerates and are removed from the system.

The particulates escaping from the cyclones have been estimated to be about 1 grain/SCF (2.29 grams/meter^3). This assumes that the external cyclone of the dual stage units is of a special construction where secondary gas is injected into the cyclone barrel to aid ultrafine particulate removal. Although the technology is not presently available, several organizations, including the Westinghouse Electric Corporation under OCR Contract No. 14-32-0001-1514, are developing hardware to achieve this level of particulate clean-up of hot process gases. The fines escaping the cyclones are not ash particles, but have an analysis similar to the coal feed. It is anticipated that these fines will most likely be trapped in the desulfurization beds included in the powerplant design, and will be subsequently burned off or recovered as solid waste during the sulfur recovery process.

The size of the gasifier vessel was chosen in order to allow shop fabrication of the vessel, and to allow the units to be rail transported to the powerplant site. This limited each gasifier vessel diameter to 13 feet (3.96 meters); the kinetic model results showed that a vessel height of 51 feet (15.5 meters) would be required to achieve the estimated exit gas compositions. A total of eight gasifiers are required for the entire powerplant. The total weight of the coal feed, gasifiers, ash removal, and fines recovery equipment is estimated at 1,080,000 pounds (0.489 x 10^6 kilograms).

The gasifier will be constructed from carbon steel A516 Grade 70, with refractory wall linings on the interior. The lock hoppers and surge bins will be fabricated from carbon steel of A515 Grade 70. Because of the more severe operating environment, the fluidizing cones and internal cyclones will be made from Incoloy 800.

3. Gasifier Heat Recovery

Process steam for the gasifier is required at 1000°F (811°K) and 235 psi (1620 kilopascals). This steam is generated in a boiler utilizing sensible heat available in the process gas. In the first section of the boiler, saturated steam is generated by forced circulation. The steam is then superheated to 1000°F (811°K) in the upper section of the boiler. Four units are required for the overall powerplant. Each unit is designed to transfer 51.5×10^6 Btu/hr (15100 kilowatts) with temperature pinches limited to 1260°F (700°C) in the boiler, and 900°F (500°C) in the superheater. The units will be of special design because of the operating temperature, pressure conditions, and the possibility of particulates accumulation on the boiler tubes. Each unit is fully encapsulated in a cylindrical pressure vessel, with outside dimensions 30 feet (9.14 meters) in length by 10 feet (3.05 meters) in diameter. The superheating section of the boiler will be made of Incoloy 800, with the balance of materials consisting of stainless and carbon steels. Total weight of the four steam generators is estimated at 260,000 pounds (0.118×10^6 kilograms). Process gas leaves the steam generators at 1570°F, (1128°K), and is further cooled to 1120°F (878°K) prior to desulfurization by reheating steam for the bottoming cycle of the powerplant. This bottoming cycle steam reheater is physically located in the gasification island; however, the reheater is considered to be part of the steam bottoming cycle and is discussed in Section III E.

4. Desulfurizer and Sulfur Recovery Selection

It is desirable to desulfurize the synthesis gases at or near design inlet temperature of the prime cycle fuel cells to minimize heat transfer equipment and subsequent heat losses. Since the fuel cell operates at a nominal 1200°F (922°), a high temperature sulfur removal process was selected. The process chosen was a regenerative hot iron oxide process being developed by the Morgantown Energy Research Center (MERC) of the Energy Research and Development Administration (Reference 8). Information on operating conditions and characteristics developed by them have been used in designing the process and it has been assumed that the technology will be perfected and available for application in the mid-1980's.

The system selected for elemental sulfur recovery was Allied Chemical Corporation's SO_2 reduction process (Reference 9). This process has commercial experience and is presently available; in addition, it integrates well with the iron oxide desulfurization process selected above. Information on the operating conditions, including efficiency of sulfur recovery and costs of the plant, was obtained by contact with Allied Chemical Corporation.

5. Desulfurization and Sulfur Recovery Description

The absorbent developed by Morgantown researchers is a mixture of 25 percent iron oxide and 75 percent fly ash, the latter with 3 percent bentonite added as a binder. The absorbent is extruded into pellets 3/16-inch (0.42 cm) diameter and 3/4-Inch (0.64 cm) long, and loaded into an arrangement of packed beds. Necessary valving and controls are provided to operate these beds cyclically between the absorbing and regenerating modes of operation. The absorption reaction is considered to produce two iron sulfides, FeS and FeS_2 with an empirical composition of about $FeS_{1.5}$:

$$3H_2S + Fe_2O_3 \rightarrow 2FeS_{1.5} + 3H_2O$$

Carbonyl sulfide present in the fuel gas is assumed to be absorbed by the iron oxide to the same level as hydrogen sulfide absorption.

The absorption process is capable of operating in the temperature range of 1000 to 1500°F (811 to 1089°K); the temperature range of 1120 to 1190°F (878 to 916°K) was chosen for this study, permitting inlet process gas to the fuels cells near nominal cell operating temperature.

Thermodynamic analysis of the H_2S absorption reactions indicate that at temperatures above 1000°F (811°K) it is not possible to reduce the sulfur level of the clean fuel gas below 200 ppm. The principal barrier to this limit is the water content of the fuel gas which shifts the absorption reaction in the reverse direction. However, the simultaneous water gas shift reaction, which is catalyzed by the iron oxide absorbent, shifts in a favorable direction and reduces the partial pressure of water in the fuel gas. Even so, the H_2S level entering the fuel cells at design was assumed to be 200 ppm. Design cycle time for absorption is 8 hours. Additionally, for design criteria, the absorbent bulk density was assumed to be 93 lbs/ft^3 (1490 KG/meters^3), with a loading capacity of 10 pounds (4.53 KG)sulfur per 100 pounds (45.3 KG) of absorbent at saturation. This design data is based on that provided by MERC.

The saturated absorbent is regenerated by oxidation with air supplied by electrically driven compressors. The overall reaction is represented as follows:

$$4FeS_{1.5} + 9\,O_2 \rightarrow 2Fe_2O_3 + 6SO_2$$

The regeneration cycle is designed for a period of 8 hours, coinciding with the period of absorption on an adjoining bed. The stream leaving the regenerating beds contains 10 to 12 volume percent SO_2, which is fed to the sulfur recovery plant. The ability to regenerate the iron oxide beds has been demonstrated at MERC; however, control of the rate of regeneration is a concern because over-temperature of the beds, with subsequent fusing of the absorbent, can result. This is presently being investigated at MERC.

It is anticipated that particulate carryover from the gasifiers mentioned above would be trapped in the iron oxide beds during absorption. Furthermore, the coal fines in the particulates should be burned off during regeneration of the beds with air, and the remaining trapped ash particulates would be blown out with the SO_2-rich regeneration gases. This has been indicated by lab-scale data at MERC, but remains to be demonstrated in large-scale units (see page 118).

The vessels containing the iron oxide desulfurization beds were sized to be factory fabricated and rail transportable, limiting vessel diameter to 13 feet (3.96 meters). Overall length, including elliptical pressure heads, is 36 feet (11 meters). The units are shipped horizontally, with vertical placement on-site. The unit vessels are constructed of carbon steel SA 515, fully insulated on the interior walls. A total of 24 vessels is required. Total estimated weight, including the iron-oxide absorbent, is 3.23×10^6 pounds (1.46×10^6 kilograms).

Elemental sulfur is recovered from the SO_2 containing gases by the Allied Chemical Corporation SO_2 reduction process. This process converts about 92 percent of the entering SO_2 to elemental sulfur. Prior to the recovery processes, the SO_2-rich gas is cleaned in a combination of liquid scrubbers and electrostatic precipitators. These scrubbing processes will probably remove any of the ash particulates carried over from the regeneration of the desulfurizer beds. However, it was assumed conservatively in this study that none of these particles would be removed in the sulfur recovery process, and would therefore be present as particulate emissions in the tail gas exhaust from the Allied Chemical Plant (see page 74).

Downstream of the scrubbers and precipitators, the sulfur recovery is a two-step process. In the first step, the SO_2 is converted to elemental sulfur and a major portion of the remaining SO_2 to H_2S by the following reactions:

$$SO_2 + 2H_2 \rightarrow 2H_2O + S$$

$$SO_2 + 2CO \rightarrow 2CO_2 + S$$

$$2SO_2 + CH_4 \rightarrow CO_2 + 2H_2O + 2S$$

$$SO_2 + 3H_2 \rightarrow H_2S + 2H_2O$$

$$3SO_2 + 2CH_4 \rightarrow 2CO_2 + 2H_2O + 2H_2S + S$$

The unconverted SO_2 and H_2S are obtained in a mixture closely approximating the ideal ratio required for the subsequent Claus reaction in the second stage of the process:

$$2H_2S + SO_2 \rightarrow 2H_2O + 3S$$

Elemental liquid sulfur is recovered through sulfur condensers located after both stages of the process. Steam generated in the process is sufficient to heat sulfur lines and tanks during normal operation of the powerplant to prevent solidification of the sulfur.

Information on specific component physical dimensions, weights, and materials of construction for the sulfur recovery process were not available because of the proprietary nature of the process. An overall estimate of the footprint for the sulfur recovery plant, as well as costs for the process, were obtained for a battery limits installation from Allied Chemical. Total clean fuel gas requirements for the sulfur recovery process are 4.6 percent of the process gas flow exiting the desulfurizers. The SO_2 reduction process utilizes 3.2 percent of this total, and the remaining 1.2 percent is burned in the tail gas incinerator, which converts all of the remaining sulfur species in the Claus plant exit gas to SO_2 prior to stack exhaust. The SO_2 emission from the tail gas of the sulfur recovery plant is estimated at 0.56 lbs/10^6 Btu (2.409×10^{-7} kilograms/kilojoule), which accounts for approximately 75 percent of the total plant SO_2 emissions. This could be significantly reduced by the addition of tail gas cleanup; this option is discussed in Section VII.

6. Gasifier Turbocompressor and Air Preheater

Process air for the gasifier at 235 psi (1620 kilopascal) and 1000° F (811° K) is supplied by turbocompressor machinery, with preheating of the compressed air in a small heat exchanger located adjacent to the compressor exhaust. The turbocompressor and heat exchanger units are physically located in the fuel cell island building. This arrangement minimizes plant piping, since the gasifier air compressors are driven by tubines using exhaust gases from the fuel cell system.

A description of the physical and operating characteristics of the turbocompressors is given in Table III. The operating characteristics of the gasifier turbocompressor do not require advanced technology components. Required efficiencies of both the turbine and compressor are low. These efficiencies provide adequate exhaust stream energy and do not penalize powerplant efficiency.

Total gasifier air requirements are divided among four identical turbocompressor units each with a power rating of 22,000 shaft horsepower (16,400 kW). Each unit consists of a low-pressure unit and a high-pressure unit in series. This is necessitated primarily because of the compressor pressure ratio requirement of 16 to 1. Lengths of the low-and high-pressure units are 16.3 and 23.3 feet (5 and 10 meters), respectively; total weight for the two units is estimated at 18,900 pounds (8600 kilograms). Since the turbine inlet temperature for the high pressure unit is only 1250° F (950° K), no advanced material technology is required. Although the scope of the study did not permit a search for off-the-shelf turbocompressor machinery, it is anticipated that future design studies could result in design specifications utilizing presently available machinery.

The gasifier air preheater raises the 800°F (700°K), 235 psia (1620 kilopascal) air exiting the compressor to the required gasifier inlet temperature of 1000°F (811°K) utilizing sensible heat from the exhaust gases of the fuel cell system. Four identical units are required for the powerplant, one for each of the gasifier turbocompressor dual units. Design data for the unit is summarized in Appendix V. The heat transferred per unit is 15.6 x 10^6 Btu/hr (4570 kW), with a temperature pinch of 300°F (167°C). Hot-side gases enter and exit the unit at 1300°F (920°K) and 1250°F (950°K), respectively, at a nominal pressure of 150 psia (1030 kilopascal). The unit is designed as a shell-and-tube-type heat exchanger, with the flow of the hotter medium normal to the bare tube bundle. A total of 1680 ft^2 (156 $meters^2$) of heat transfer area is required per unit. The tube material is high alloy steel. Outside dimensions of the unit are 7 feet (2 meters) in diameter by 20 feet (6.1 meters) in height. The pressure vessel is carbon steel, fully insulated on the interior walls with a blanket-type insulating material. Total weight of each unit is estimated at 19,000 pounds (8620 kilograms).

7. Gasification Section Arrangement

The gasification section of the integrated conceptual design molten carbonate powerplant is sized to gasify 202.5 tons (184,000 kilograms) of coal perhour which is accomplished in eight separate gasifier vessels. A total of 69 tons/hr. (17.4 kilograms/second) of process water taken from the powerplant water supply system (described in the balance-of-plant section of the report) and 607.5 tons/hr. (153 kilograms/second) of process air is required for the coal gasification. The process yields 0.45 MM SCFM (212 $meters^3$/second) of raw low-Btu product fuel gas which is fed to an arrangement of 24 separate iron oxide desulfurization beds. Here, an additional 58.6 tons-per-hour (14.8 kilograms/second) ambient air supplied by electrically-driven compressors is required for the regeneration of the iron oxide. Downstream elemental sulfur recovery results in 6.75 tons-per-hour (1.7 kilograms/second) of liquid sulfur byproduct, which is temporarily stored and periodically removed by truck or train.

TABLE III
GASIFIER TURBOCOMPRESSOR DESCRIPTION

A. UNIT DESIGN REQUIREMENTS

COMPRESSOR

- PRESSURE RATIO 16.0
- POLYTROPIC EFFICIENCY 80%

TURBINE

- PRESSURE RATIO 8.9
- INLET TEMPERATURE 1250°F
- ADIABATIC EFFICIENCY 77%
- POWER 22,000 SHP

B. UNIT PHYSICAL CHARACTERISTICS

	No. Per Plant	Overall Length (Ft.)	Max. Diameter(*) (In.)	Weight (Lbs.)	Stages Turbine	Stages Compressor
Gasifier Turbocompressor						
Low Pressure Unit	4	16.3	28	12,215	3	11
High Pressure Unit	4	23.3	23	6,720	1	8

The physical layout of the gasification section is divided into four independent gasifier islands, each island processing one-quarter of the powerplant's total fuel gas requirements. The plot plan and elevation of a gasifier island are shown in Figures 7 and 8. The gasifier island occupies an area approximately 52 feet x 155 feet (15.8 meters x 47.2 meters). Maximum height of the island to the top of the coal bin is 175 feet (53.3 meters). Each island represents a gas processing train capable of operating independently of the others, making the powerplant modular in design and increasing system availability characteristics. No major spare equipment is provided to increase the normal availability of the gasification section. Each island is supplied by its own turbocompressor and feeds one of the four fuel

(*) Does not include diameter of inlet air ducts of gasifier low pressure compressor.

cell islands. Each island contains two gasifiers operating in parallel. The gasifiers are fed from a single elevated coal bin, sized for a capacity equal to approximately one-hour's coal feed to the two gasifiers, or a little over 50 tons (45,400 kilograms). Each gasifier processes about 25 tons (22,700 kilograms) of as-received coal per hour, with an output of 56 M SCFM (26.4 meters^3/second) process gas. Each gasifier is equipped with its own feed lock hoppers, surge bin, ash hopper, and cyclones.

FOUR REQUIRED FOR TOTAL PLANT

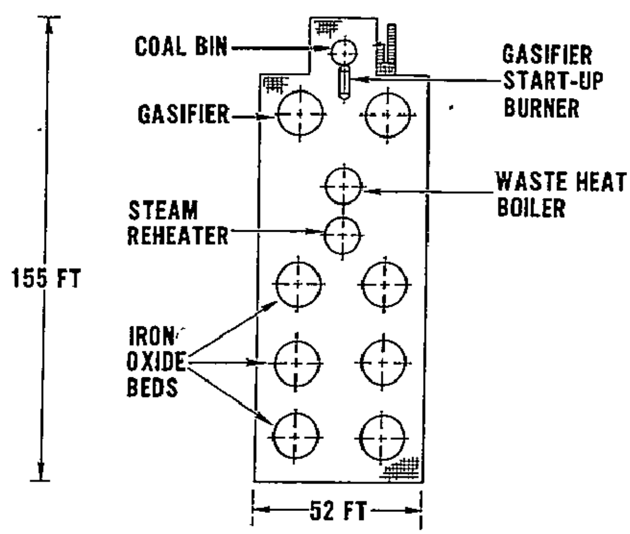


Figure 7 — Coal Gasifier Island Plan

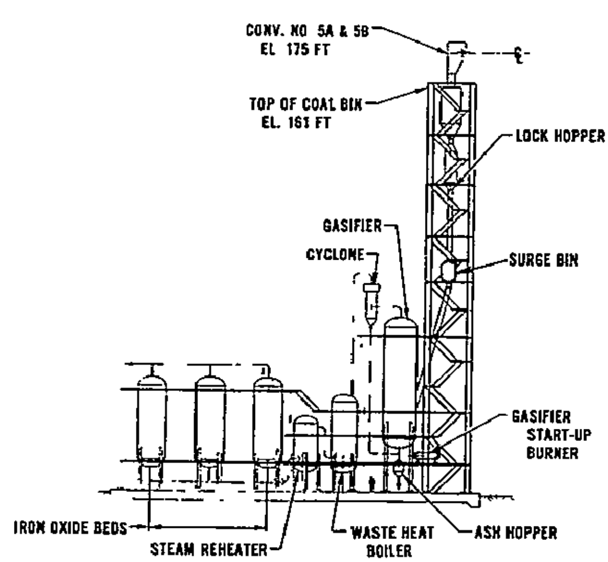


Figure 8 — Coal Gasifier Island Elevation

In addition, each gasifier island contains its own waste heat recovery equipment — which includes the gasifier steam generator and bottoming cycle steam reheater — as well as the process gas desulfurization system. Each gasifier steam generator is sized for a capacity of one-quarter of the total process steam requirements, or approximately 17.2 tons/hr (4.33 kilograms/second). The process gas desulfurization system in each gasifier island consists of six unit iron oxide beds — three absorbing and three regenerating at any given time. The absorbers are on stream in a parallel mode of operation for a period of 8 hours before cycling to the regenerating mode.

The Allied Chemical sulfur recovery facility is shared by the entire gasification section and is not included in the island plan views. As indicated on the plant layout discussed in Section III B, the plant is adjacent to the four gasifier islands and covers an area 70 ft x 150 ft (21.3 meters x 45.7 meters). Included with the plant is a stack for the incinerator used to oxidize any residual sulfur species in the tail gas.

The lock hopper gas compressors and the iron oxide bed regeneration air compressors are included as part of the major component equipment of the gasifier and desulfurization systems respectively, but are not physically located on the gasifier island. For protection and ease of maintenance, these units are housed in the fuel cell building, which is described in Section III D. Four separate lock hopper gas compressors are utilized in the conceptual design, one for each gasifier island. However, a total of two compressors for the total powerplant iron oxide bed regeneration air requirements are used in the design, primarily due to the relatively small capacity and low pressure requirements of the overall process.

The feedwater pumps for the gasifier steam generators are included as major component equipment for that process. Two pumps provide the total gasification process water requirements; each is sized for 75 percent capacity. These pumps are separately enclosed, and are located adjacent to the gasification islands.

Inspection of the plot plan and elevation drawings indicates that a gasifier startup burner is located in each island. The burner operates only during the startup sequence to provide heat to the gasifier, process steam generator, and desulfurizer equipment. One flare stack services the eight gasifiers and is 10 ft (3.05 meters) in diameter x 100 ft (61 meters) high. The unit is utilized during startup, and for flaring off gas from the gasifiers in the event of a sudden loss of powerplant busbar load from the utility network. The use of these units will be described in more detail in Section III H.

8. Balance of Plant Items Associated with Gasifier

In addition to the major components of the gasification process listed above, certain balance-of-plant materials included in the gasifier island contribute to the capital cost of the subsystems described above. These balance-of-plant materials include gasifier islands and Allied Chemical Plant concrete foundations and steel structures, gasification island piping and valves, and instrumentation and controls. All external high temperature process gas piping and valves are austenitic stainless steel, fully wrapped in thermal insulation for protection of operating personnel and to minimize heat losses. Process air and steam piping and reheat steam piping, are high alloy carbon steel and are also insulated. Additional balance-of-plant materials associated with the major components above include the lube oil system and the intake air ducting, silencing, and filters for the gasifier turbocompressor machinery.

Additional Gasification Systems – In order to conform to NASA accounting preferences in determining overall costs of the gasification section, three additional systems are included. These systems include the coal handling and ash handling systems, and the sulfur storage and transfer system.

Coal Supply System – The coal supply system is shown in Figure 9. The physical arrangement of the main sections of the system relative to the remainder of the powerplant layout was illustrated in Section IIIB.

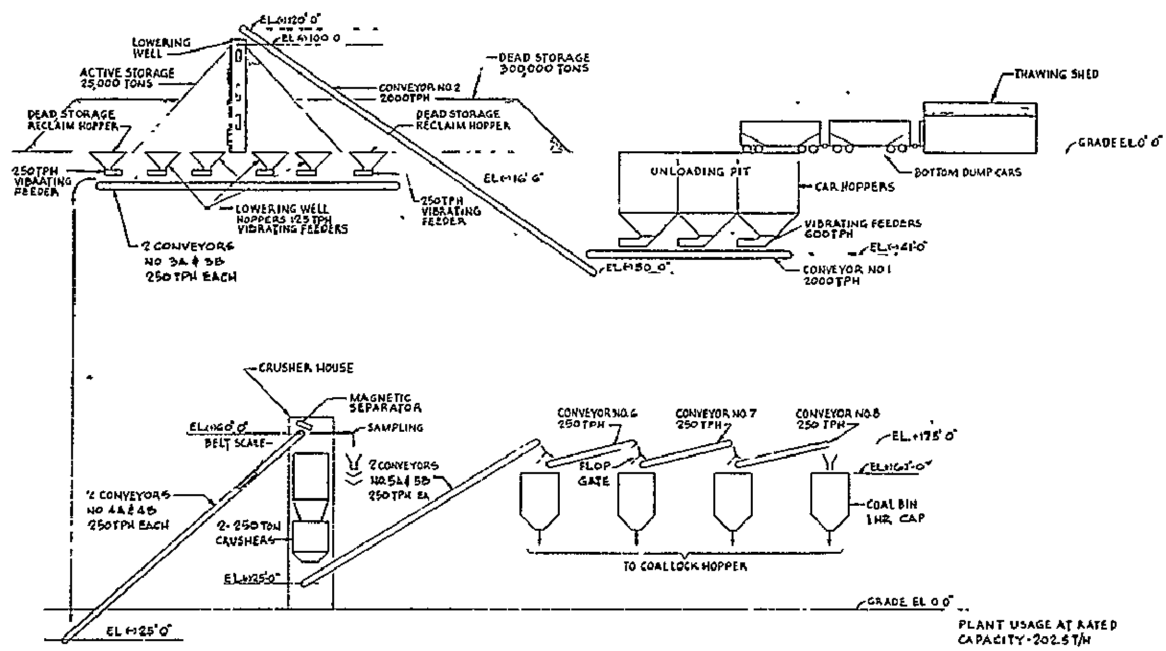


Figure 9 – Coal Supply System Schematic

The design of the coal supply system is based on the plant usage rate at rated plant output of 202.5 tons per hour (51 kilograms/second). Other design parameters are described in Table IV.

The coal is delivered by unit trains of 100 to 110 bottom dump cars per train. Since each car has 100 tons (90,700 kilograms) capacity, a unit train provides about 50 hours of powerplant operating time at rated output.

A thawing shed, 500 feet long (152 meters), divided into 50 foot (15.2 meters) bays, will be provided to thaw frozen coal in three cars simultaneously. The heating will be accomplished by oil-fired heaters. The thawing shed has metal siding, with ventilation, lighting power, and drainage facilities. Three cars are unloaded by shakeout at one time while coupled to the train. The coal is dumped into three receiving hoppers in an unloading pit below grade. Three cars will unload in about 10 minutes.

TABLE IV
COAL SUPPLY SYSTEM DESIGN PARAMETERS

Unloading and Stockout Rate	2000 tons per hour (500 kilograms/second)
Active Pile Volume	25,000 tons (5 days) (22,700 kilograms)
Dead Storage Volume	300,000 tons (60 days) (272,000,000 kilograms)
	700 ft. x 900 ft. x 20 ft. high (213 meters x 274 meters x 61 meters high)
Reclaim Rate	250 tons/hr. (63 kilograms/second)
Crusher Capacity	200-250 tons/hr. (50.4-63 kilograms/second)
Belt Speeds, Stockout	600 FPM (305 centimeters/second)
Belt Speeds, Reclaim	450 FPM (229 centimeters/second)
Belt Sizes, Stockout	60 inches (152 centimeters)
Belt Sizes, Reclaim	36 inches (91 centimeters)
Conveyor Traveling Angle	35 degrees
Maximum Slope of Conveyor	17 degrees
Coal Bin Supply Rate	250 ton/hr. (63 kilograms/second)

Three 600 ton per hour (151 kilograms/second) vibrating feeders deliver the coal to conveyor No. 1. Conveyor No. 1 rated at 2000 tons per hour (500 kilograms/second) delivers the coal to the inclined conveyor No. 2, also rated at 2000 tons per hour (500 kilograms/second), that starts about 50 feet (15.2 meters) below grade and delivers the coal to the top of the lowering well at 100 feet (30.5

meters) elevation. The lowering well is used to distribute the coal over four hoppers to form the active coal storage pile of 25,000 tons (22,700,000 kilograms).

Four 125 tph (31.5 kilograms/second) vibrating feeders receive the coal from the four active pile hoppers under the lowering well. These feeders empty onto either of two 250 tph (63 kilograms/second) conveyors Nos. 3A or 3B. In addition, two 250 tph (63 kilograms/second) vibrating feeders provided under two reclaim hoppers, receiving coal by means of bulldozers from the 300,000 ton (272,000,000 kilograms) dead storage pile, also empty onto the reclaim conveyors 3A or 3B. Conveyors 3A and 3B deliver coal to either conveyors 4A or 4B, each rated at 250 tph (63 kilograms/second), which, in turn, convey the coal to the top of the crusher house. The 25 ft x 20 ft x 70 ft high (7.6 meters x 6.1 meters x 21.3 meters high) crusher house is designed for two crushers, crusher drives, drives for conveyors, and sampling equipment. The crusher house has conventional riveted column and beam framing with high-strength, bolt-field connections. The building has metal siding, and includes necessary ventilation, lighting, power, and drainage facilities. A belt scale on conveyors 4A and 4B weighs the coal fed to the crushers. Magnetic separators remove tramp iron before the coal enters the chute to the crushers. Samples of coal are taken automatically before the coal enters the crusher chute. The coal is then crushed in either of the two 250 tph (63 kilograms/second) hammermill crushers. The crushers are sized to handle Illinois No. 6 run-of-mine coal. Each is a reversible hammermill type, rated to receive 275 tons per hour (69.3 kilograms/second) with 8 percent moisture with a 1000 hp motor operating at 720 rpm. For Illinois No. 6 coal with 13 percent moisture, the crusher is derated to 225 tons per hour (56.7 kilograms/second). For the 203 tons per hour (51 kilograms/second) required for the plant at rated capability, operating brake horsepower will be 902 (673 kilowatts).

The crushed coal is conveyed to the gasifier island via any one of the two parallel conveyors No. 5A or 5B, each rated at 250 tons per hour (63 kilograms/second). Coal is delivered to each of the four coal bins on top of each of the four pair of gasifier lock hoppers by means of cascading belt conveyors Nos. 6, 7 and 8. The atmospheric coal bins are filled sequentially and automatically by means of flop gates.

The bins at the top of the gasifiers have a storage capacity equivalent to one hour operating time at rated output. This may not provide sufficient time for many of the repairs to the upstream coal handling system. To assure that the coal handling system has the necessary reliability and to assure that the availability of the plant will not be reduced because of downtime for equipment repairs, redundancy is built into the system. At least 100 percent standby capability is provided for conveyors 3 and 4, feeders, and crushers so that plant output will not be reduced because of failure of one unit in any stage of the coal feed system after the coal pile. To provide 12 or more hours coal bunker capacity instead would have required bins and supporting structures that would be higher in cost without providing equivalent reliability.

Ash Handling System

Illinois No. 6 coal has about 9.6 percent ash content. Therefore, for coal usage of 202.5 tph (51 kilograms/second), 19.44 tph (4.9 kilograms/second) total or 4.86 tph (1.22 kilograms/second) of ash per gasifier train is generated. The ash handling system is shown in Figure 10. The physical arrangement relative to the powerplant layout has been illustrated in Section IIIB.

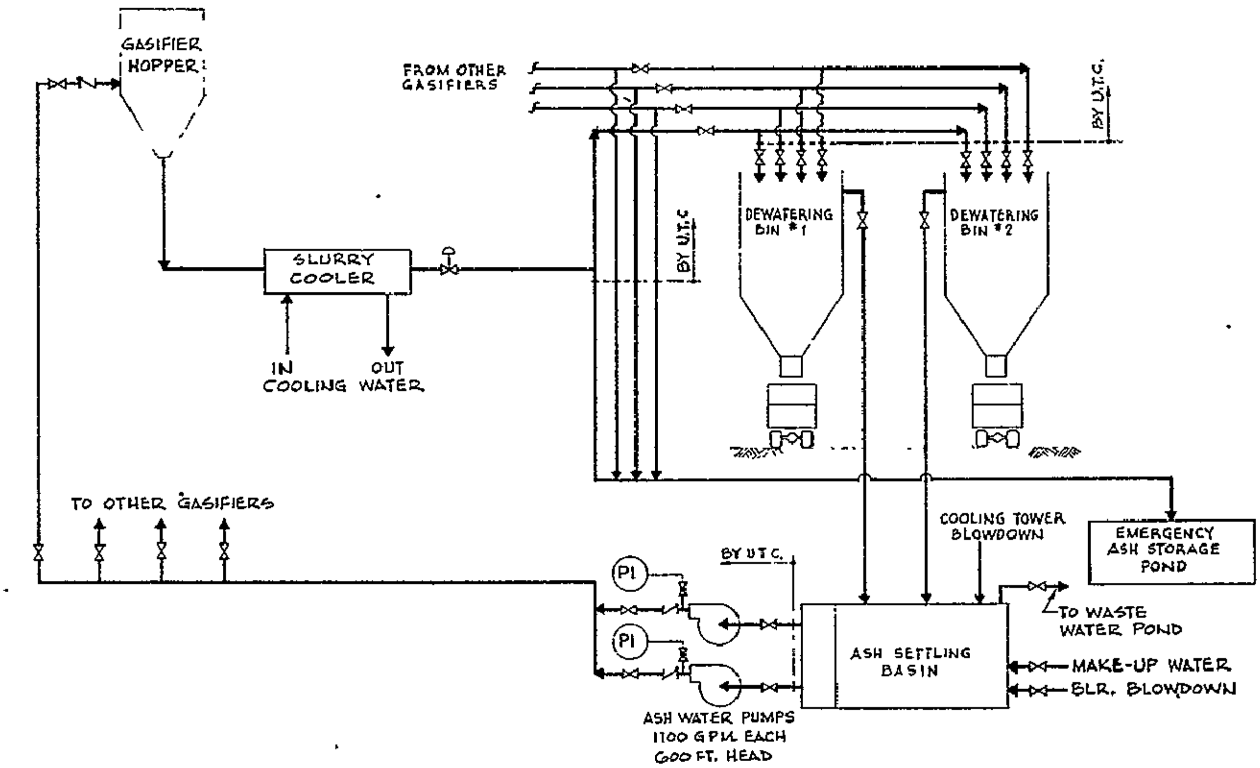


Figure 10 – Ash Handling System Schematic

An ash hopper is provided at the bottom of each gasifier vessel. Each hopper has a capacity of 11.25 tons (10,200 kilograms) of ash or about 2-1/3 hours at rated output. A line from each hopper leads to a slurry cooler. A 25 weight percent water-ash slurry is continuously withdrawn from the hopper under pressure, cooled in the slurry cooler, and ducted through the throttle control valve to one of the two dewatering bins.

The ash settles in the dewatering bins and is removed through a bottom gate into trucks for offsite disposal. The water overflows to the ash settling basin. The two dewatering bins have a capacity of 12,000 cubic feet or 300 tons (272,000 kilograms) of ash – 15 hours at rated output. Bins will have a 30 foot (9.14 meters) diameter and storage sections will be 17 feet (5.2 meters) high. Total height of each bin is 45 feet (13.7 meters).

The ash settling basin is about 125 feet (38.1 meters) x 40 feet (12 meters) and 10 feet (3.05 meters) deep. Overflow water from the dewatering bins empties into the basin. Two ash sluice-water pumps take suction from the settling basin pump sump to provide the sluicing water for the gasifier ash hoppers. Makeup water to the settling basins is from the cooling tower and boiler blowdowns. Should the makeup flows be insufficient to maintain a satisfactory basin level, the level is maintained by water from the service water system. Should the settling basin overflow, excess water is routed to the waste water pond.

In the event truck removal is unavailable for any reason, the ash can be sluiced to an emergency ash storage pond which can store 8250 tons (748,000,000 kilograms) of ash, or about 17 days of ash. The ash storage pond measures 275 feet (83.8 meters) by 200 feet (61 meters), and is 6 feet (1.83 meters) deep. Water will overflow through a weir to a sump where two sump pumps will pump the overflow to the liquid waste storage pond. A pond lining is included to prevent seepage to underground aquifers.

Ash piping is centrifugally cast chrome iron with a Brinell of 500+. The pipe will use sleeve couplings to permit rotation and some relative movement.

Two 100 percent, 250 gpm (0.07 meters^3/second), 800 foot head (2390 kilopascal) vertical ash sluice water pumps take suction from the ash settling basin. Each pump is driven by a 75 hp (50 kilowatt) motor and is constructed of abrasion-resistant material.

Sulfur Storage and Transfer System

The sulfur storage and transfer system equipment is located adjacent to the Allied Chemical sulfur recovery area. It includes the following major items:

- Two 30 ft. (9.14 meters) dia. x 40 ft. (12.22 meters) high storage tanks — 210,000 gal. (796 meters^3) each.
- Two 125 gpm (0.0079 meters^3/second), 30 ft. head (89.7 kilopascal), sulfur transfer pumps
- Rail tank car and tank truck loading facilities.

The performance criteria for the system are given in Table V.

TABLE V

SULFUR STORAGE SYSTEM DESIGN PARAMETERS

Sulfur Supply from Recovery Plant	180 tons per day 7.5 tph (1.89 kilograms/second)
Sulfur Conditions	molten at 265-300°F (403-422°K)
On-site Storage Quantity	15 days
	1600 tons (1,450,000 kilograms) in each of the two storage tanks
Tank Truck Loading Rate	30 minutes

Liquid sulfur is delivered to the storage area from the sulfur recovery area at a temperature between 265°F (403°K) and 300°F (422°K). Interconnecting piping is insulated and steam traced. The sulfur is stored in the two 210,000 gallon (796 $meter^3$) thermally insulated storage tanks which are equipped with steam heating coils which maintain the sulfur in a molten state. Steam is provided from the sulfur recovery plant process during normal operation or from the auxiliary boilers when process steam is unavailable or insufficient.

The molten sulfur in the storage tanks is then pumped to heated rail tank cars or tank trucks for transfer to the market. The sulfur transfer pumps are steam-jacketed all-iron centrifugal units. They discharge to a steam traced header which will feed two filling stations – one for a tank truck of 25 ton (22,700 kilograms) capacity and one for tank cars with 50 tons (45,400 kilograms) capacity per car.

III-D. Fuel Cell System Description

The energy conversion sections of the integrated coal gasifier/fuel cell powerplant consists of two cycles. The prime cycle, described in this section, utilizes a molten carbonate fuel cell power section to convert processed coal gas to electrical power electrochemically. Prime cycle waste heat is utilized in a steam turbine-generator bottoming cycle to produce additional power. Details of the bottoming cycle are discussed in Section IIIE.

1. Fuel Cell Background

The application of the molten carbonate fuel cell for the prime cycle was specified by NASA. This selection is in agreement with results of system studies conducted at PSD prior to this effort. These results are illustrated in Figure 11 in which the overall thermal efficiency of a number of integrated coal gasifier/Fuel Cell Powerplants are plotted as a function of the application time frame. As shown, it is possible to achieve efficiencies greater than 40 percent for systems integrating a coal gasifier with near-term phosphoric acid electrolyte fuel cells. In these, a gas turbine bottoming cycle was incorporated to recover power from the fuel cell exhaust. System studies with molten carbonate cells indicated potential efficiencies in the range of 45 to 60 percent depending on the degree of system integration, the type of bottoming cycle selected for waste heat recovery, and the technology assumed for the coal gasifier and the fuel cell.

The higher powerplant efficiencies of molten carbonate systems result because at reasonable power densities, these cells offer higher efficiency than the near-term phosphoric acid cell. Higher cell performance results from reduced activation polorization at high temperature. In addition, since molten carbonate cells operate at high temperature, they derive increased benefit from integration with the bottoming cycle.

The present conceptual design powerplant study assumes a technology base similar to the mid-range result shown for molten carbonate fuel cells in Figure 11. This technology is based on operating temperatures, cell materials, and electrolyte compositions presently being tested at PSD. The conceptual design is based on pressurized fuel cell operation; present testing is conducted at ambient pressure.

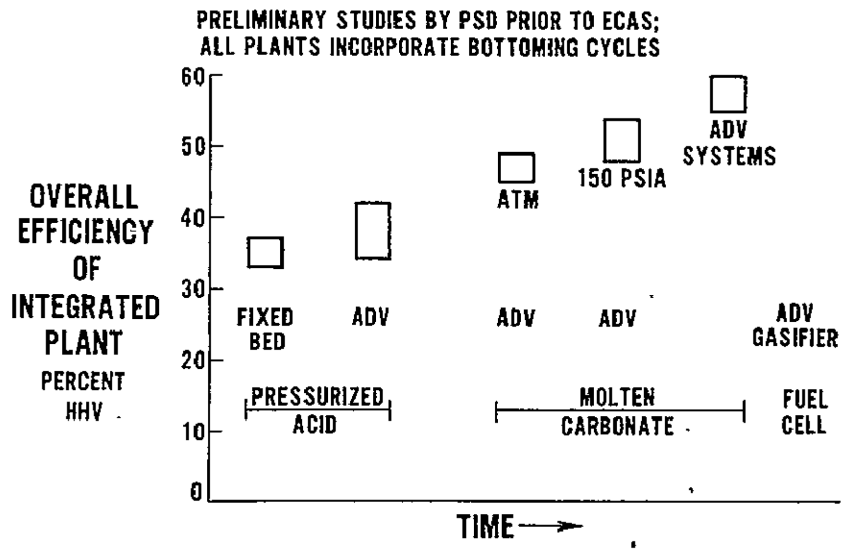


Figure 11 – Evolution of Integrated Coal Gasifier/Fuel Cell Powerplants

A simplified flow schematic of the prime cycle fuel cell system used for this ECAS study is shown in Figure 12. The system consists primarily of a number of fuel cell stacks in which the electrochemical conversion process takes place. Associated equipment includes turbocompressor machinery to provide process air to the fuel cells and a catalytic burner to oxidize vent gas from the fuel cell anode. The heat exchangers for transferring fuel cell waste heat to the steam turbine bottoming cycle are shown in the schematic, but are described in Section IIIE.

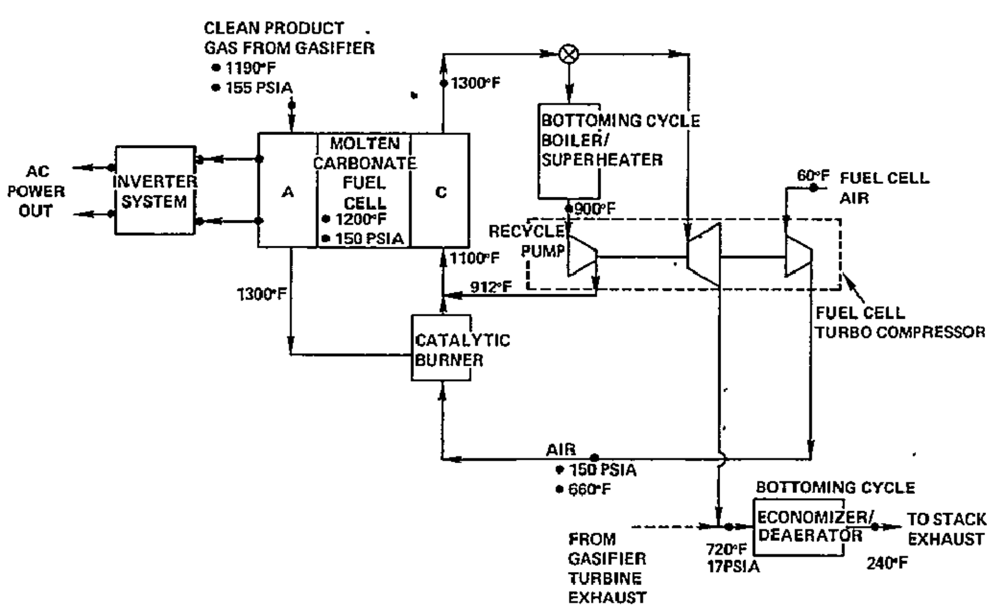


Figure 12 – Fuel Cell System Schematic

2. Fuel Cell Operating Characteristics and Design Assumptions

Fuel cells are electrochemical devices that convert the chemical energy of fuel gases directly into electrical energy. The elemental molten carbonate cell is shown schematically in Figure 13. The cell consists of an anode, an ionically conducting electrolyte, and a cathode. Fuel gas, in the form of H_2 and CO and diluents such as CO_2, H_2O and N_2 are fed to the anode, where the electrochemical oxidation of the H_2 occurs as follows:

$$H_2 + CO_3{}^= \rightarrow H_2O + CO_2 + 2e^-$$

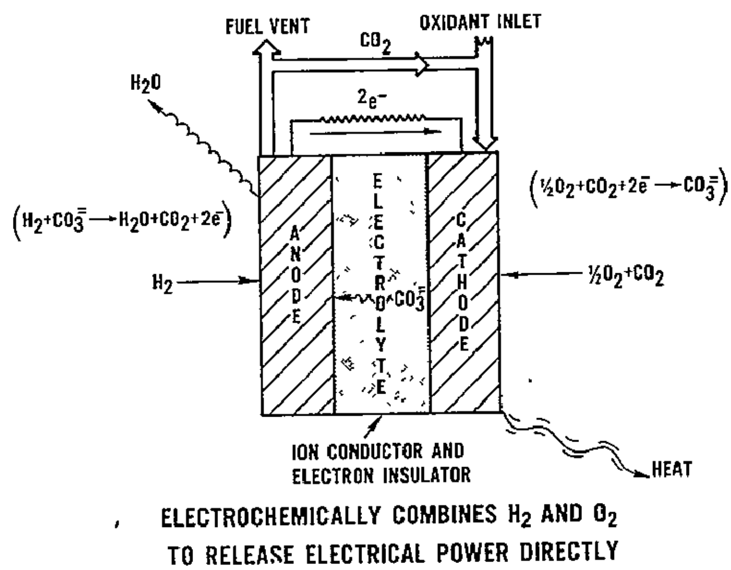


Figure 13 — Elemental Molten Carbonate Cell

Simultaneously, CO is constantly being shifted in the cell anode compartment to make additional H_2, so that the composition across the cell remains in water-gas shift equilibrium. Thus, the H_2, either present in the inlet fuel gas or as a result of the water-gas shift, reacts with the carbonate ion $CO_3^=$ to form byproduct H_2O and CO_2, with an electronic current produced. The electrons are conducted through the load and back to the cathode. At the cathode, oxygen from air, and byproduct CO_2 from the anode reaction, combine electrochemically with the electrons to form the carbonate ion; viz:

$$CO_2 + 1/2\,O_2 + 2e^- \rightarrow CO_3{}^=$$

The carbonate ion thus formed is conducted across the electrolyte and recombines with H_2, completing the circuit. As indicated, the CO_2 formed at the anode must be transferred to the cathode to complete the cycle. This is done in practice by mixing all the anode exhaust gases with process air upstream of the cathode inlet. The overall cell reaction may now be written as:

$$H_2 + 1/2\,O_2 \rightarrow H_2O + \text{Electrical Power} + \text{Heat}$$

Thus, the byproduct of the overall reaction is H_2O which leaves as water vapor in the exhaust gases of the system, and heat. This waste heat is utilized in a bottoming cycle in the conceptual design to increase overall efficiency.

The nominal cell conditions selected for this study were 1200°F (922°K) and 150 psia (1034 kilopascal). The operating temperature is based on a trade-off between ideal cell voltage, cell polarization and endurance. The electrolyte, which is comprised of a mixture of alkali metal carbonates in a ceramic matrix, is a solid at room temperature. The cell must be heated above the electrolyte melt temperature to provide the necessary ionic mobility to sustain cell reactions. As the temperature is increased beyond the melt point, the ideal cell voltage drops but the ionic mobility increases resulting in reduced polarization. The operating temperature range of the cell will be approximately between 1100 and 1300°F (866 and 978°K); this permits waste heat to be removed as sensible heat in the cathode gas stream.

Cell operating pressure was chosen to be 150 psia (1034 kilopascal), although the system was not optimized at this level. This pressure provides good cell performance characteristics, while holding gasifier methane production low. At a given gasifier temperature, lower pressure favors low methane production. Since methane was assumed to be an inert to the cell, low methane results in higher cell efficiency.

In addition to operating temperature and pressure, three other major parameters define cell operation characteristics. These parameters include the fuel and oxidant utilizations and the cell performance. Utilizations define the ratio of the reactant consumed by the cell to the reactant supplied to the cell. Reactant utilizations determine the variation in reactant partial pressure over the cell and therefore the ideal cell voltage and driving forces for reactant diffusion at each point in the cell. This is an important determinant of cell performance. Because CO is shifted to H_2 and consumed in the molten carbonate cell, fuel utilization (U_F) is defined as the ratio of the H_2 consumed in the cell to the total H_2 plus CO supplied to the cell.

Fuel utilization is a partial measure of system efficiency since it indicates the percentage of CO and H_2 in the fuel gas that is consumed electrochemically in the prime cycle. Fuel utilization for the conceptual design powerplant is 85 percent. The O_2 and CO_2 design oxidant utilizations are 50 and 26 percent, respectively.

The unit of performance for fuel cells is the design power density per square foot of active cell area. Cell power density is the product of the voltage measured across the electrodes of each cell and the current density of the cell at that voltage. This unit of performance is analogous to the shaft HP to weight ratio for gas turbines. Since the capital cost of the cell stack is proportional to total cell area, high power densities provide lower cost.

Projected cell performance used in this study was based on an anayltical model developed at PSD (Reference 15). This model is discussed in Appendix IV. Performance improvements were calculated based on operation at higher pressures and an improved cell structure. The assumed performance for this study is shown in the upper curve of Figure 14. The figure also shows the anticipated performance (middle curve) of present technology molten carbonate cells operating on gasifier products at the operating pressure of 150 psia (1034 kilopascal). The lower curve in Figure 14 indicates present experimental cell performance at ambient pressure operating on reformer fuel gas products, and served as a basis for the analytical models performance projections. The cell operating point for the conceptual design was chosen to be 0.85 volts per cell, which results in a current density of 150 amps per square foot (0.16 amps per square centimeter) and a power density of 127 watts per square foot (0.14 watts per square centimeter). At these design conditions, the fuel cell thermal efficiency is 45 percent. Higher power densities are achievable at lower cell voltages, however the thermal efficiency of the fuel cells — defined as the ratio of the heating value of the gross ac power from the inverter to the heating value of the synthesis gases to the fuel cell — would be reduced.

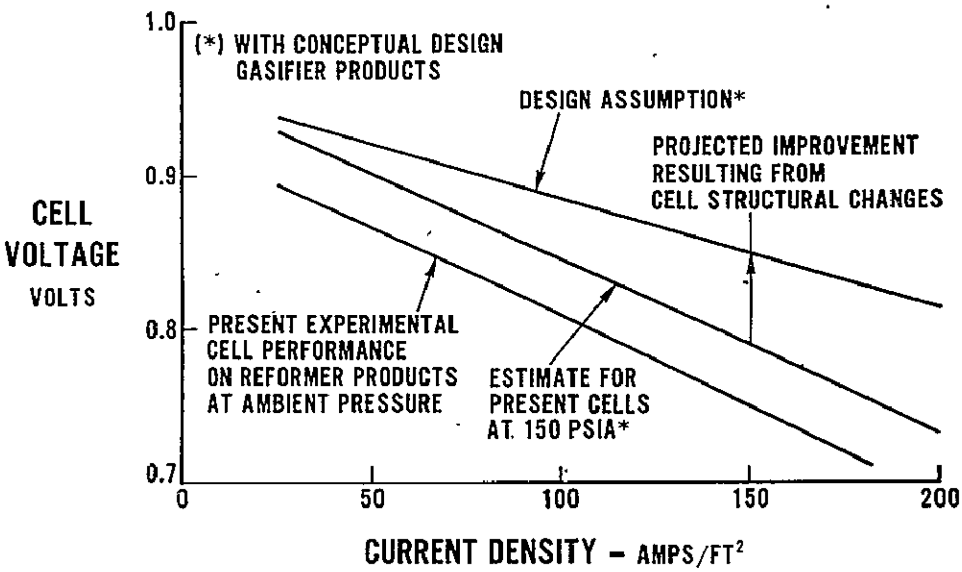


Figure 14 — Cell Performance

Other cell design conditions that affect overall powerplant characteristics are heat losses and cell operating life. The cells are thermally insulated and cell stack heat losses were calculated to be 1 percent of the design gross power output. For purposes of defining economics, cell useful life was assumed to be 40,000 operating hours. This is a goal that has been set for the nearer term acid cells and appears to be a reasonable goal for molten carbonate cells as well. It should be pointed out that after 40,000 hours of operation, the cells will continue to operate, however, at a slightly reduced performance level than assumed for this study. Thus, a utility may choose to replace the fuel cells at this time or it may choose to continue to run the plant with the existing cells, but at a somewhat reduced power level or efficiency.

A final design assumption is that the 1990 molten carbonate cell will be tolerant to 200 ppm sulfur in the fuel gas. If further fuel gas sulfur reduction is required, two approaches are possible. An additional sulfur removal stage downstream of the iron oxide beds could be employed. Regenerable zinc oxide beds are an example of this approach (see page 118). A second approach is to substitute a low-temperature sulfur removal process. This approach is estimated to slightly reduce powerplant efficiency (1 percent), but in addition to lower sulfur levels, would enhance both particulate and trace element removal from the synthesis gas (see page 119).

3. Fuel Cell Physical Characteristics

The arrangement of a single cell and its assembly into a cell stack is shown in Figure 15. In addition to the electrolyte tile, the cell package includes porous nickel electrodes for the anode and cathode. Stainless steel current collectors and separator plate geometry is selected to distribute reactant gases uniformly across the face of the cell and to conduct current through the cell stack. This single cell repeating element is assembled into a multi-cell stack configuration by compressing the cell assemblies between stainless steel end plates and electrical insulating plates. This is accomplished by the use of pressure plates and a follow-up system, such as the tie rods and springs shown in the figure. Cell stack assemblies may be arranged in a series/parallel configuration to give desired output volyage and current.

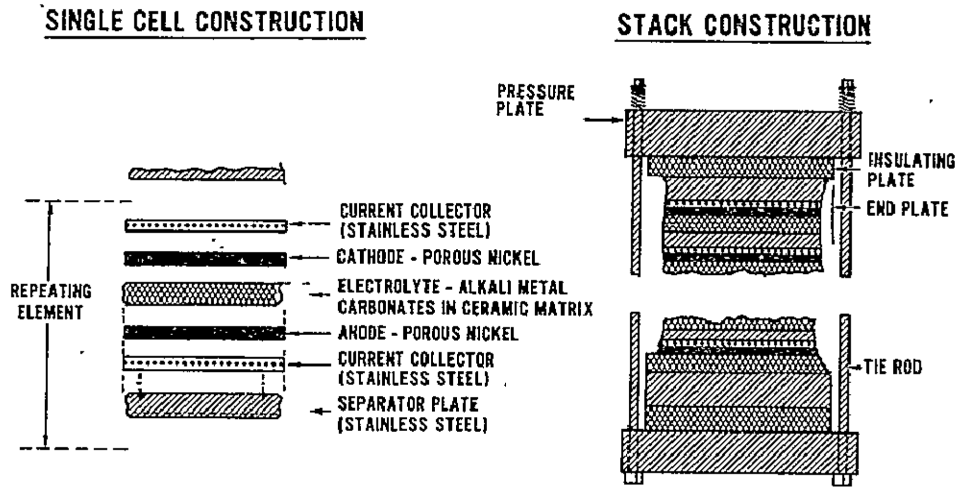


Figure 15 – Cell and Stack Construction

The cell stacks in the conceptual design operate at pressure and pressure vessels are provided to encapsulate cell stack assemblies. As part of the contract effort, one such vessel was designed to permit proper costing. Figure 16 shows the details of the pressure vessel and its enclosed cell stacks. A larger version of this figure appears in Appendix III. The assembly is designed to be factory assembled and tested and transported by rail. Using this criteria, the pressure vessel physical dimensions were limited to an outside diameter of 13 feet (3.96 meters); the height is limited by allowable flat-car load weight and resulted in a dimension of 23 feet (7.01 meters) plus support structures. The vessels are shipped horizontally and erected vertically at the plant. Four lifting tabs are provided for ease of handling. Within the vessels are eight separate fuel cell stack assemblies in a 2-tier arrangement with four stack assemblies per tier. The assemblies are mounted on I-beam support structures, as shown. The assemblies in each tier are connected in parallel electrically with the two tiers connected in series. There are eight penetrations through the pressure vessel; four for the fuel cell cathode (oxidant) manifolding, two for the reactant fuel manifolding, and 2 electrical power take-offs. The stack assemblies are fully insulated thermally, reducing the pressure vessel wall temperature and permitting the vessel construction of low alloy carbon steel, for example, SA515. Expansion joints for the internal manifolding are utilized at critical junctions within the vessel to provide for thermal expansion. All internal manifolding is insulated as well.

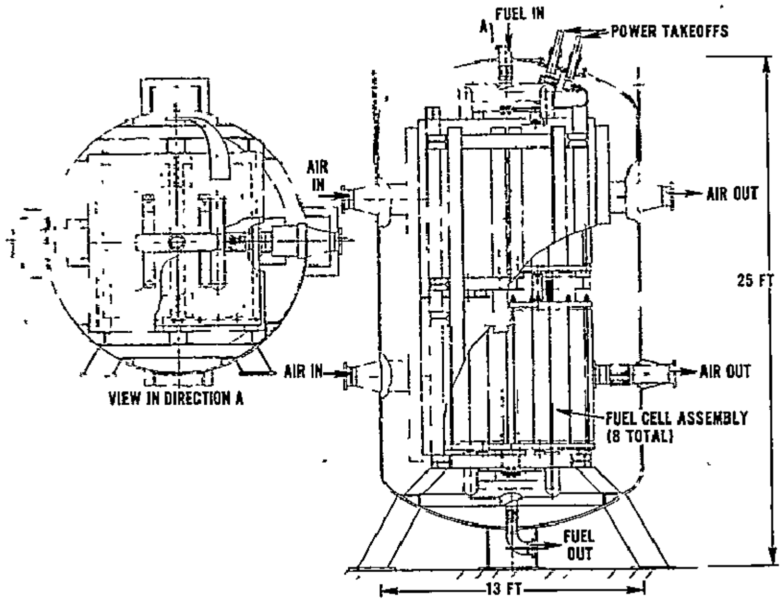


Figure 16 — Fuel Cell Pressure Vessel Assembly

Vessel weight is 20 tons (18,144 kilograms); the total weight of vessel, stacks, and internal structure is approximately 84 tons (76,204 kilograms). Power output of each vessel is 4.7 MW gross dc power — 867 volts at 5410 amps. A total of 96 vessels producing 432 MW of ac power are utilized in the fuel cell section of the powerplant.

4. Fuel Cell Turbocompressor

A second major component in the fuel cell system, shown in Figure 12, is the turbocompressor. This unit derives the necessary power for pumping fuel cell process air to 150 psia, (1034 kilopascal) by expanding the fuel cell exhaust through a turbine. The fuel cell turbine also provides shaft power to the cathode recycle pump. The recycle stream removes cell waste heat and transfers this high quality heat to the bottoming cycle. The split between recycle flow and turbine inlet flow is approximately 2 to 1 (by volume). The recycle head rise is calculated to be 5 psia (34.5 kilopascal) which results in a relatively small shaft power requirement in comparison to the fuel cell air compressor.

The fuel cell turbocompressor operating characteristics are summarized in Table VI. It is important to note that no advanced technology is required. Required efficiencies of both the turbine and compressor are low. Since exhaust stream energy is adequate with these assumptions, the low turbocompressor efficiencies do not penalize the powerplant efficiency.

The fuel cell turbocompressor duty is broken up between four identical units each having a duty of 38,000 SHP (28,337 kilowatts) and providing for one-quarter of the total fuel cell requirements. The physical characteristics for each unit are included in Table VI. Total length is 32 feet; total weight is 26,645 pounds (12,086 kilograms). Because turbine inlet temperatures are limited to 1250° F

(950°K), no advanced material technology is required, and low cost materials can be utilized in fabrication.

TABLE VI

FUEL CELL TURBOCOMPRESSOR DESCRIPTION

Located in Fuel Cell Equipment Building — 4 Per Plant

A. UNIT DESIGN REQUIREMENTS

COMPRESSOR	
• PRESSURE RATIO	10.5
• POLYTROPIC EFFICIENCY	80%
RECYCLE PUMP	
• PRESSURE RATIO	1.03
TURBINE	
• PRESSURE RATIO	8.7
• INLET TEMPERATURE	1250°F
• ADIABATIC EFFICIENCY	77%
POWER	38,000 SHP

B. UNIT PHYSICAL CHARACTERISTICS

	No. Per Plant	Overall Length (Ft.)	Max. Diameters(*) (In.)	Weight (Lbs.)	Stages Turbine	Stages Compressor
Fuel Cell Turbocompressor	4	24.3	48	26,645	3	19
& Recycle Pump		7.7	34		—	1

(*) Does not include diameter of inlet air duct on fuel cell compressor.

5. Fuel Cell Island Burners

The remaining major components located in the prime cycle system are the catalytic and startup burners. The startup burners will be described in a later section of this report dealing with powerplant startup and part power operation. The catalytic burners oxidize H_2, CO, and methane in the fuel cell anode vent. The catalytic burners utilize a precious metal catalyst amounting to 0.3 percent by weight supported on a ceramic material and are enclosed in insulated carbon steel pressure vessels. Design space velocity for the units is 30,000 $ft^3/hr/ft^3$ volume. Adiabatic oxidation temperature for the units is 1400° F (1033° K) with inlet fuel cell anode effluent at 1300° F (978° K), and inlet air at 660° F (622° K). The volume percentages of H_2, CO, and CH_4 entering the burner are 1.7, 2.6, and 0.4 percent, respectively. Oxidation is assumed to be complete including the 200 ppm H_2S present in the fuel gas at cell inlet which is burned to SO_2. Design life for the units is assumed to be 2 years, with replacement of the catalyst bed after this period.

6. Other Fuel Cell Island Components

Waste heat from the prime cycle fuel cells is transferred to the steam turbine bottoming cycle via heat exchangers physcially located within the fuel cell cycle equipment areas. However, they have been included in the steam turbine island equipment costs and will be described in Section III E. This equipment includes the steam turbine cycle economizer/deaerator heat exchangers which recover heat from the turbocompressor turbine exhaust, and the steam turbine boiler/super-heater heat exchangers which recover heat from the fuel cell recycle stream. The fuel cell inverters and associated equipment for converting fuel cell dc power to ac busbar power are also physically located in the fuel cell area. However, their costs are allocated to the electrical plant major component equipment, covered in Section IIIF and these units will be described in detail in that section.

7. Fuel Cell Section Arrangement

The fuel cell conversion section of the integrated conceptual design molten carbonate powerplant generates 432 MW net ac power output, consuming 0.14 x 10^6 SCFM (66.1 meters^3/second) of the H_2-and CO-rich fuel gases supplied from the desulfurization section. The conversion is accomplished in 96 fuel cell pressure vessels. Total process air requirements of 0.51 x 10^6 SCFM (240.7 meters^3/ second) are supplied by four separate fuel cell turbocompressor units. Waste heat transferred from the prime cycle fuel cells to the steam turbine bottoming cycle totals 1.60 x 10^9 Btu/hr (0.47 x 10^6 kW), 67 percent of this heat is transferred from the fuel cell recycle cooling stream through eight boiler/superheater units. The remaining heat is the result of cooling the turbocompressor turbine exhausts, and is transferred through four economizer/dearator units. The fuel cell conversion section occupies 6.5 acres (26,306 square meters) or less than 5 percent of the plant area.

The arrangement of the fuel cell section equipment is divided into four identical islands, each generating 108 MW net ac. Each island is capable of operating independently from the other three islands, and, therefore, represents the primary power building block for the powerplant. Each fuel cell island is fed process gas from one of the four separate gasifier islands, forming an independent coal gasification/desulfurization/fuel cell conversion power train. This modular arrangement permits operation of one or more power trains while others may be down for repair or scheduled maintenance. The plot plan and elevation drawings of one of these fuel cell islands are shown in Figures 17 and 18. Each island is approximately 240 x 300 feet (73 x 91 meters) with the highest elevation of the island 95 feet (29 meters) to the top of the fuel cell exhaust stack.

Two boiler/superheater heat exchanger units are located in each island between the rows of fuel cell pressure vessels and the fuel cell building. Each transfers the waste heat from the two adjacent rows of fuel cell vessels to the steam turbine bottoming cycle. The fuel cell pressure vessels and boiler/ superheater units are located outdoors and supported on a 24-inch reinforced concrete slab on grade by their integral structural steel supports. The slab covers the complete pressure vessel area including the boiler-superheaters. Individual concrete pads are provided on top of the slab under the support legs of the pressure vessels and the support skirts of the boiler-superheaters to level and anchor the units. Access steel platforms are provided at two levels around the pressure vessels and the boiler superheaters.

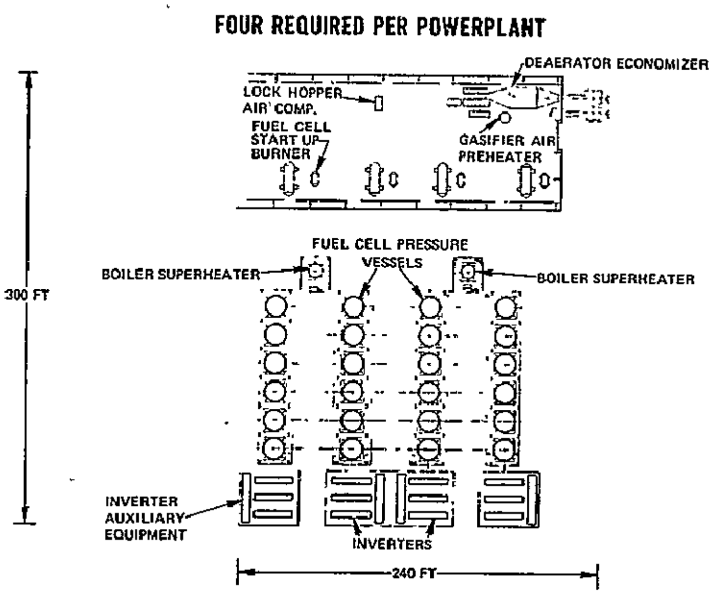


Figure 17 – Fuel Cell Island Plan

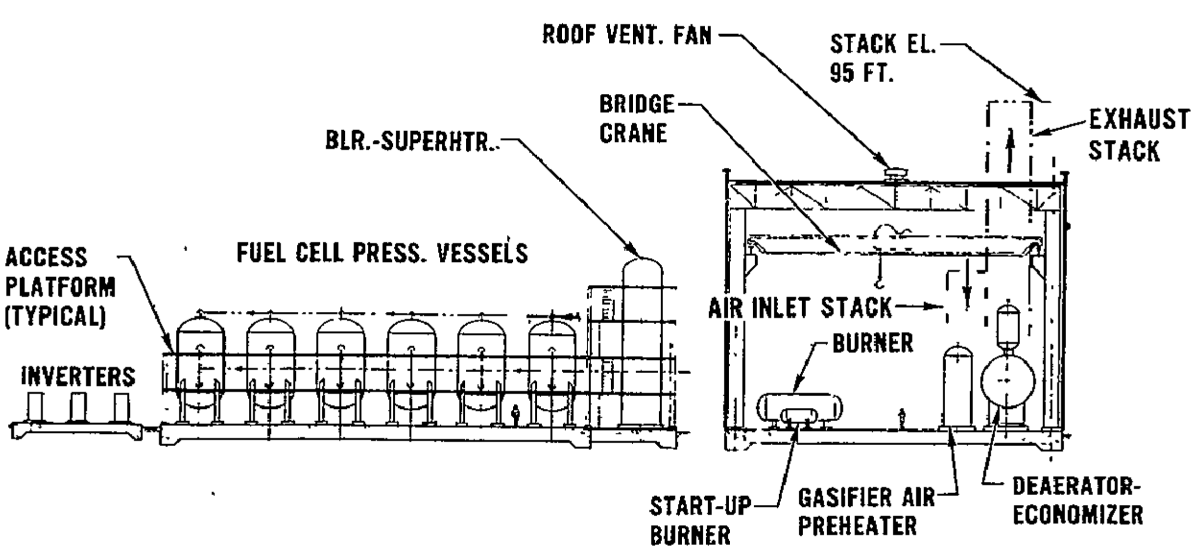


Figure 18 – Fuel Cell Island Elevation

Twelve separate inverter modules and inverter auxiliaries are located at the south end of the fuel cell island. These inverter and inverter auxiliaries are also located outdoors on a concrete slab separate from the fuel cell pressure vessel and boiler/superheater slab. Individual concrete pads are provided on top of the slab under the support skirts of the inverters and inverter auxiliaries as a means to level and anchor the units. A detailed description of the inverter units is presented in Section III F.

One fuel cell turbocompressor unit provides air requirements to the 24 fuel cell pressure vessels in each island. This turbocompressor unit is physically located within a fuel cell building. The gasifier turbocompressor dual unit is located within the fuel cell building adjacent to the fuel cell turbocompressor unit. This placement minimizes plant piping by decreasing the lengths of hot turbine inlet gas piping. The gasifier air preheater unit is located in close proximity to the turbocompressor units as shown in the plot plan. One economizer/deaerator heat exchanger is situated in the building at the turbocompressor turbine exhausts for each fuel cell island in order to transfer waste heat to the steam turbine cycle. Additional components located within the fuel cell building include the four separate catalytic burners and four separate fuel cell startup burners – one for each of the four rows of fuel cell pressure vessels – as well as a gasifier lockhopper gas compressor. Location of all these units with their associated controls and instrumentation within the building provides protection against environmental elements and ensures safety and ease of maintenance during periods of inclement weather.

Two identical fuel cell buildings serve the four fuel cell islands, one building for every two fuel cell islands. The extension of the building for the second contained island is symmetrical to the building section shown in the island plot plan of Figure 17. These two buildings and the four fuel cell islands are divided into two sections placed symmetrically on each side of the Steam Turbine Building, as indicated in the detailed plant arrangement, Figure 4.

The fuel cell equipment buildings have asbestos-protected metal siding; the roof is built-up and insulated and gravel surfaced. Each structure is provided with four roof ventilators. The floor of the building is a concrete slab. The frame is steel, conforming to AISC specifications. A 20-ton (18,144 kilograms) electric single-trolley overhead traveling bridge crane is provided in each building. Roll-up steel doors provide access for trucks at the ends of each building. Personnel doors are provided at each end.

The buildings are heated with steam unit heaters. Other facilities in the building are service air, service and sanitary water, electrical power, lighting, communications, fire protection, and drainage.

At the ends of each building, concrete stacks are provided for air supply and turbine exhaust for the turbocompressors. The intake stacks are 45 feet (13.7 meters) high, and share a wall with the exhaust stacks to this height. The exhaust stacks are 95 feet (29 meters) high. Acoustic treatment is installed in the intake stacks to control the noise level inside the building.

8. Fuel Cell Island Piping

In addition to the major components defined above, other balance-of-plant equipment in the fuel cell section has been defined to provide a basis for capital cost estimates. For the fuel cell islands, this balance-of-plant equipment is primarily identified as the fuel cell controls and instrumentation, and the piping, expansion joints, and support structure for distribution of the reactant gases within the boundaries of the island. All process gas piping to and from the fuel cell pressure vessels, including the cathod recycle cooling loop and the exhaust to the turbine inlets, is austenitic stainless steel, fully jacketed with insulation on the exterior walls to protect plant personnel and minimize heat loss. Steam lines exiting the boiler/superheater units are insulated high alloy steel, while the boiler feedwater, burner air inlet piping, and turbine exhaust ducting are insulated carbon steel.

III-E. Steam Turbine Bottoming Cycle Description

1. Bottoming Cycle Selection

A steam-driven turbo-generator was selected as the bottoming cycle because it resulted in higher overall powerplant efficiency at a cost of electricity comparable to a gas turbine bottoming cycle. The steam turbine integrates well with the fuel cell because fuel cell waste heat can be used to generate steam at conditions suitable for present steam powerplant technology. In addition, the excellent utilization of fuel cell waste heat permits the fuel cell to operate at higher power densities which serves to reduce the initial cost of the prime cycle overall powerplant efficiency.

2. Bottoming Cycle Description

A schematic of the steam bottoming cycle, indicating system operation and sources of heat, is shown in Figure 19. Initially, condensate from the steam condenser is pumped to 10 psig (170.3 kilopascal) and deaerated; the feed water is then pumped to 2600 psig (18,028 kilopascal) and preheated in the economizer, raising the water to 550° F (561° K), somewhat below saturation. The heat for deaeration and preheating is provided by cooling the turbine exhaust streams from the turbocompressor units; no steam extraction for feed water heating is used. The preheated water is fed to the boiler/superheater where steam for throttle conditions of 2400 psig (16,649 kilopascal), and 1000° F (811° K), is raised. This heat is provided by fuel cell waste heat transferred from the cathode recycle loop.

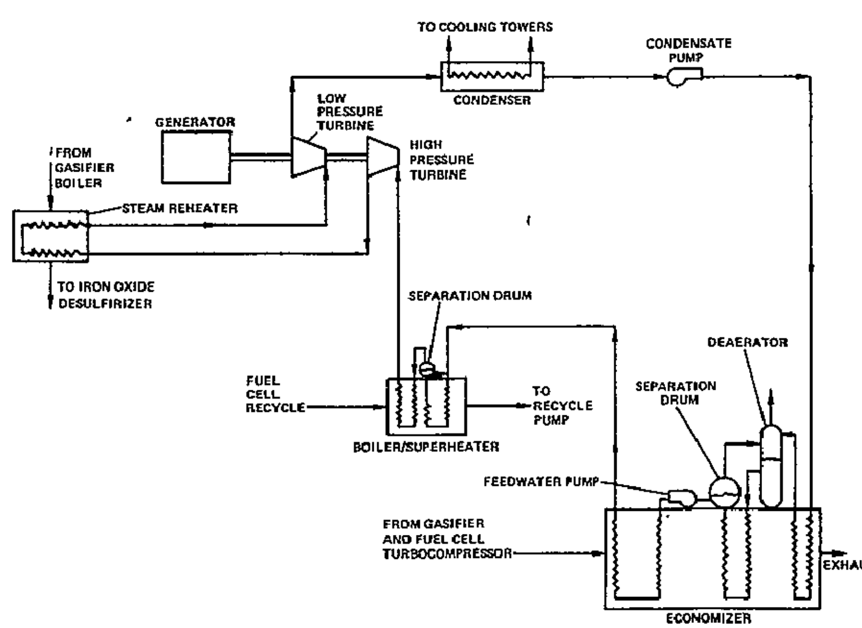


Figure 19 — Steam Turbine System Schematic

The steam is expanded to 470 psig (3342 kilopascal), and 580° F (578° K). Steam is reheated to 1000° F (811° K) and expanded in the reheat turbine down to 2 inches of mercury abs. (6.77 kilopascal), at a saturation temperature of 101° F (311° K). The heat source for the steam reheater is taken as sensible heat from cooling the gasifier product gases prior to desulfurization, as described previously in Section III C.

3. Steam Turbine and Turbine Auxiliaries

The single unit steam turbine-generator is a conventional machine. The turbine is a 3600 rpm, single shaft, compound machine with 26 in. (66 centimeters) last stage blades. The turbine is a condensing unit designed for expansion to 2 in. Hg abs. (6.77 kilopascal). The generator is hydrogen cooled, and includes associated excitation systems. No design data on the unit was generated; existing conventional designs based on unit power output rating for similar operating conditions were examined to obtain the physical characteristics of the unit.

The steam turbine condensing system includes the condenser, condenser vacuum pump, and motor. The condenser is a single pressure, two pass, twin shell unit, with the tubes perpendicular to the turbine center line. The unit is supported from the ground floor. The design condenser pressure of 2 in Hg abs. (6.77 kilopascal) is consistent with the ambient conditions of 59° F (2.88° K) dry bulb/ 52° F (284° K) wet bulb specified by NASA. Condenser cooling water temperature rise is 20° F (11°C), with an inlet cooling water temperature from the cooling towers of 72° F (295° K). This equipment was not specifically designed during this study; conventional design data scaled for the steam turbine rating were utilized.

The condensate and boiler feedwater systems include the condensate polishing systems and storage tank, condensate pump and motor, and the boiler feedwater treatment system. The condensate polisher is located in the condensate pump discharge line. The polishing system consists of a precoat tank and agitator, precoat type filter deionizer tanks with wound filter elements, precoat transfer pumps, a blower for backwashing polishing elements, an air compressor, a control panel, and associated valves, controls, and instrumentation. One 200,000 gallon (758 meters^3) – or approximately 8 hours capacity – carbon steel condensate storage tank is provided. The tank measures 35 ft (10.7 meters) diameter x 28.5 ft (8.69 meters) high and is epoxy coated internally. An automatic control system provides water to the condensate system on low level in the condenser hot well and returns it to the tank on high level. The piping between the condenser and the tank will be epoxy lined.

The boiler chemical feed system will be zero solids type. Ammonia and hydrazine, used to control the feedwater alkalinity and to act as an oxygen scavenger, are injected downstream of the condensate discharge header. A high volume phosphate feed pump is provided in case a relatively large condenser leak develops. Two hydrazine, two ammonia, and two phosphate pumps and three 200 gallon (0.758 meters^3) solution tanks are supplied with the system.

The turbine lube oil purification and transfer system is a bypass, continuous feed, overflow to treatment tank type. A gravity-type purifier is provided. A two-compartment storage tank for clean and dirty oil, and pumps for inlet and discharge are included.

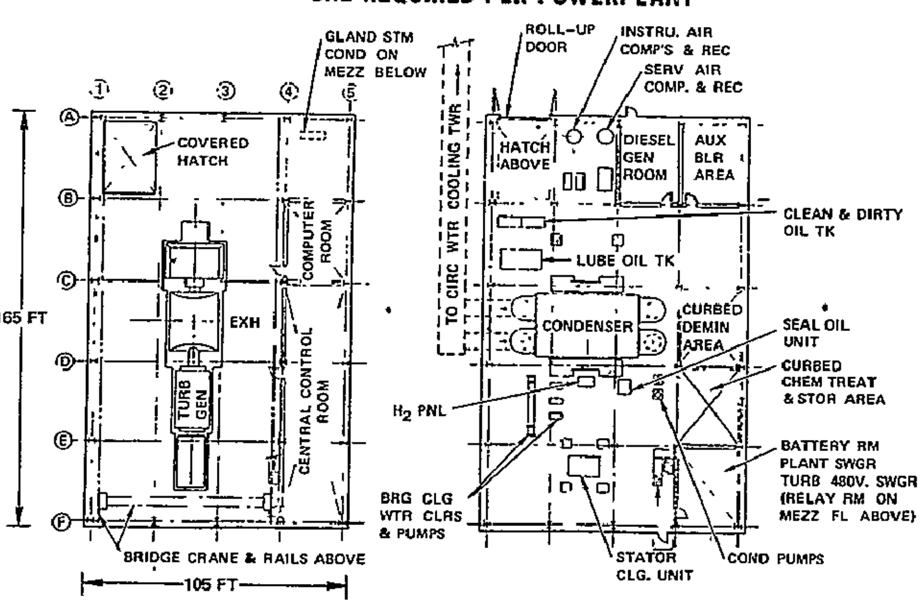
A stator cooling unit, hydrogen panel, seal oil and accessories for the generator are included in the steam turbine plant. The steam turbine piping, valving, and insulation constitute the remainder of the system equipment. All of this equipment is included as balance-of-plant materials in estimating the capital costs of the system discussed in Section IV D.

4. Steam Turbine Island Arrangement

The steam turbine bottoming cycle utilizes 1.87×10^9 Btu/hr. (0.548×10^6 kW) of waste heat from the four gasifier-fuel cell trains described earlier to raise 1.16×10^6 lbs/hr. (0.146×10^6 grams/second] process steam at 2400 psig (16,649 kilopascal) and 1000°F (811°K). Expansion of this steam in the high pressure and reheat steam turbine unit translates 226 MW shaft power to the generator. At 98 percent efficiency, the gross ac power output of the generator is 222 MW, equivalent to a gross therma efficiency of 40 percent.

The steam turbine island plot plan is shown in Figure 20. The unit is enclosed in a building 105 ft x 165 ft (32 meters x 50 meter) located between the two pairs of fuel cell islands described previously. The building has two main levels and a partial mezzanine level. The building is of box-like construction with exterior metal wall panels fabricated of a galvanized steel liner and aluminum exerior with a baked on coating. A base slab at grade level constitutes the ground floor. The operating floor is 38 feet (11.6 meters) above grade. A crane rail is provided in the building about 30 feet (9.14 meters) above the operating floor level. The crane is equipped with a 75 ton (68×10^3 kilograms) hook and a 20 ton (18.1×10^3 kilograms) auxiliary hook, and services both floors of the building. A covered hatch in the north end bay permits equipment to be lifted from grade level to the operating floor. The service areas are located along the east bay of the building.

ONE REQUIRED PER POWERPLANT



STM. TURB. BLDG.-OPER. FLOOR STM. TURB. BLDG.-GROUND FLOOR

Figure 20 – Steam Turbine Island Plan

The steam turbine unit is located on the operating floor level and is supported on a reinforced concrete pedestal foundation which follows the recommendations of the turbine manufacturer for loading, deflection limitations and allowable stresses. The main powerplant control room and computer room are located on the east side of the operating floor. The main control room houses the central powerplant monitoring board as well as the steam turbine operating and control board. Local startup, controls and control boards for the fuel cells and gasifiers are located in the fuel cell buildings and in an enclosure in the gasifier islands. The computer room houses the computer utilized for powerplant data acquisition and annunciation of powerplant alarms. Both of these rooms are air-conditioned for operating personnel. The relay room and electrical cable runs, as well as the gland steam condenser and lube oil storage tank, are located on the mezzanine floor.

The ground floor of the building contains the balance of the steam turbine plant equipment, including the condensing system, the condensate and boiler feedwater systems, the turbine oil purification system, the hydrogen panel, the hydrogen seal oil unit, the stator cooling unit, and miscellaneous generator accessories. In addition, the powerplant auxiliary systems indicated in Table VII are located on the ground floor.

TABLE VII

AUXILIARY POWERPLANT SYSTEMS LOCATED
IN STEAM TURBINE BUILDING

- Service and Instrument Air Compressors
- Auxiliary Boilers and Associated Equipment
- Water Treatment Plant
- Closed Cooling Water Heat Exchangers and Pump
- Emergency Diesel Generator and Auxiliaries

All of these auxiliary systems, except the diesel generator, will be described in the balance-of-plant section of the report. The emergency diesel generator is described on page 57 in the electrical section.

5. Heat Recovery and Rejection Equipment

The heat recovery equipment consists of the economizer/deaerator, the boiler/superheater, and the steam reheater. These units were designed by PSD for the conceptual design task of the ECAS study based on their operational characteristics in the system. A summary of the operational design data for the units is included in Appendix V.

The economizer heat transfer duty is divided between four identical units – one for each fuel cell power train. The hot side medium is clean turbine exhaust, primarily N_2, O_2, CO_2 and H_2O. Inlet and exit temperatures are 722 and 237° F (656 and 387° K) respectively. The total duty is split between the deaeration section and preheat sections of the economizer. To effect deaeration, water is preheated to approximately 150° F (339° K) in a segmented section of the economizer; this water is then run through a deaerator counterflow to steam injection, where the water is preheated to a saturation temperature of 240°F at 10 psig (389°K at 170.3 kilopascal) and deaeration takes place. The saturated water then enters the recirculation boiler section of the economizer where 10 percent quality steam is generated. The steam thus generated is utilized in the deaerator; the saturated water is pumped to desired pressure by feedwater pumps and then heated to 550°F (561°K) in the preheat section of the economizer.

The pinch temperature in the economizer is 50°F (28°C) and occurs in the boiler section. Total heat transferred per unit economizer is 134.8 x 10^6 Btu/hr (39.5 x 10^3 kW). The unit is designed as a vertical finned tube arrangement with turbine exhaust flow normal to the banks of tubes. Tubes and fins are carbon steel, 2 in. (5.08 cm) OD, with 6 in. (15.24 cm) longitudinal and transverse spacing. The fins are 0.028 in. (0.071 cm) thick, 1.0 in. (2.54 cm) in width, with 6 fins/in (2.36 fins/cm). Total fin-side heat transfer area is 153,000 ft^2 (14,215 $meters^2$). The unit measures 14 feet (4.27 meters) in width (normal to gas flow), by 14 feet (4.27 meters) in height, by 20 feet (6.1 meters) in depth, and weighs approximately 100 tons (90.7 x 10^3 kilograms). This physical design data is summarized in Appendix V. The unit is enclosed in a sheet metal frame to provide proper gas manifolding downstream of the turbocompressor units prior to stack exhaust.

The deaerator is a conventionally designed horizontal unit built to ASME code specifications, including a 1/16 inch (0.159 cm) corrosion allowance. Four units are utilized in the powerplant, one for each feedwater économizer. Each tank is made of carbon steel, and measures 12 ft (3.66 meters) in length x 6 ft (1.83 meters) in diameter, with 1200 gallons (4.55 $meters^3$) capacity. The units are situated above the economizer heat exchanger at an elevation of approximately 20 feet (6.1 meters) and both units are located within the fuel cell building. This was illustrated in the fuel cell island elevation, Figure 18 in Section III D.

Four 25 percent capacity two-stage boiler feedwater pumps are provided, one for each economizer/deaerator unit. Each two-stage unit is rated at 600 gpm (0.038 $meters^3$/second) and 2600 psig (18,028 kilopascal) discharge pressure. These pumps are located in the fuel cell building adjacent to the economizer/deaerator units. Two-stage pumps are used to ensure that adequate suction head is maintained to the units. In a conventional fired boiler, this head is supplied as a static head resulting from the elevation of the deaerator tank relative to the feedwater pumps. However, in the conceptual design, the deaerator tank elevation may not be sufficient to ensure the proper head and therefore the two-stage pumps are used.

The boiler/superheater heat transfer duty is divided between eight identical units, as described in Section III D. The hot-side medium is the clean fuel cell cathode recycle cooling loop, primarily O_2, N_2, CO_2 and H_2O. Hot-side temperatures are 1300°F (978°K) inlet and 900°F (755°K) exit and nominal pressure is 150 psia (1034 kilopascal). The total heat duty of each of these units is divided among a small economizer section, a boiler, and a superheater. In the economizing section, water is heated from 550°F (561°K) to saturation at 668°F (626°K) and 2485 psig (17,235 kilopascal). The pinch temperature in this section is 269°F (149°C). Unit heat transferred is 25.9 x 10^6 Btu/hr (7.59 x 10^3 kW). Since the unit is pressurized on the hot side, a shell and tube design was employed. Heat transfer area requirements for the unit economizing section are 1880 ft^2 (175 $meters^2$) on the shell side, with hot gas flow normal to the bank of bare tubes. Because of the low contacting temperatures, carbon steel tubes and headers were used for the design. Additional design data for the unit is summarized in Appendix V.

The boiler and superheater sections are designed similar to the economizer section, using bare, 2-inch OD (5.08 cm) tubes with gas flow normal to the tube bundles. The unit heat transferred and the surface area requirements are 54.4 x 10^6 Btu/hr (15.9 x 10^3 kW) and 2540 ft^2 (236 $meters^2$) for the boiler, and 55.4 x 10^6 Btu/hr (16.2 x 10^3 kW) and 2820 ft^2 (262 $meters^2$) for the superheater. The tubes for the boiler section are made of high alloy steel with upper and lower steam drums of carbon steel; the hotter surface conditions of the superheater tubes and headers require austenitic stainless steel. This design data is illustrated in Appendix V.

A single pressure vessel is utilized to contain the three sections (economizer, boiler and superheater) of the unit heat exchanger. The pressure vessel enclosing the unit is 9 feet (2.74 meters) in diameter, and 49 feet (14.9 meters) in length, including the semi-elliptical pressure heads. It is designed to be factory assembled and rail transportable and placed in a vertically upright position during installation. The vessel is fully insulated on the interior walls with a blanket-like insulating material. This insulation allows the vessel to be fabricated of carbon steel. Unit weight of vessel and contained heat transfer sections is estimated at 54 tons (40 x 10^3 kilograms). Four major penetrations of the unit are required; inlet and exit fuel cell recycle gas flows, inlet water flow, and exit steam flow. The design gas-side ΔP was increased relative to ambient pressure practice to facilitate heat transfer characteristics of the units, but since the units operate at pressure, the $\Delta P/P$ ratio is consistent with units designed for ambient pressure operation.

The third type of heat transfer equipment for the steam turbine is the steam reheater. This unit is located in the gasification island and extracts sensible heat from the process gas stream to provide reheat requirements. Four identical units are required for the powerplant, one for each gasifier island. The reheater is also a pressurized operating unit and is designed similar to the boiler/superheater units above. Total heat transferred per unit is 70.7 x 10^6 Btu/hr (20.7 x 10^3 kW), with a temperature pinch of 540°F (300°C). Heat transfer area is 2385 ft^2 (222 $meters^2$) per unit. Tube material is austenitic stainless steel, due to the high temperature operating conditions of the hot-side gases – inlet to exit hot side temperatures are 1550°F (1116°K) to 1120°F (878°K) respectively. The unit is fully encapsulated in a carbon steel pressure vessel which is completely insulated on the interior walls with blanket-type insulation. The unit is designed to be factory assembled and rail transportable with vertical placement on site. Overall dimensions of the vessel measure 9 feet (2.74 meters) in diameter, by 22 feet (6.71 meters) in height, with a total estimated unit weight of 24,750 pounds (12 tons) (10.9 x 10^3 kilograms). This design data is illustrated in Appendix V.

The cooling towers specified by NASA for the ECAS powerplants are wet mechanical-draft design. The use of the mechanical-draft cooling concept results in fans and fan drives being located outside the towers which increases each of inspection, maintenance, and repair.

The towers were designed for a cooling range of 20°F (11°C) with a 20°F (11°C) approach to 52°F (284°K) ambient wet bulb temperature. This results in a water concentration in the cooling towers of 3 gallons of water/min-ft^2 (0.002 $meters^3$ of water/second-$meters^2$) of tower area at design. The steam turbine condenser heat to be rejected by the cooling towers amounts to 1.11 x 10^9 Btu/hr (325 x 10^3 kW watts). The total circulating water flow to effect a 20°F (11°C) cooling range is 111,000 gpm, (6.99 $meters^3$/second) which result in a total cooling tower ground area of 37,000 ft^2 (3444 $meters^2$).

Two identical cooling tower units were utilized in the powerplant layout. Each unit measures 25 feet (7.62 meters) in height, with rectangular base dimensions of 265 feet (81 meters) by 75 feet (22.9 meters). Each unit consists of 8 cells with two mechanical-draft cooling fans per cell. The cooling water lost to evaporation is replenished by the powerplant circulating water make-up system with proper chlorination facilities included. The total make-up water requirements for the cooling towers are 3890 gpm (0.245 meters^3/second). The cooling towers are located on concrete foundations removed from the energy conversion cycle areas. They are physically located within the powerplant boundaries so that the prevailing winds tend to disperse the humid, warm air away from the powerplant site. The overall plot plan description on Figure 4 illustrates their location relative to the other components of the powerplants.

The major components of the cooling tower system are the unit towers. This equipment was sized for the rating of the present conceptual design powerplant. Additional associated equipment is required to complete the cooling tower system, which includes the water intake structures, circulating and make-up water piping, valves, water pumps, and chlorination facilities. The latter associated equipment was sized for this study based on cooling tower heat rejection duty.

III-F. Electrical System Description

The electrical plant equipment for the integrated coal gasifier/fuel cell powerplant consists of the fuel cell island electrical equipment, which collects the dc output of the fuel cell, converts it to 3-phase 60-Hz ac power, and steps up to transmission voltages; the steam turbine-island electrical equipment, which steps up the ac output voltage of the turbine generator to transmission levels; and the auxiliary system, which distributes power to the various plant electrical auxiliaries.

The fuel cell and steam turbine generator electrical loads and system connections are shown in the simplified one-line diagram provided in Figure 21. Typical 500-kV switchyard switching connections are shown in the diagram, but are not included within the costing scope of this study, as specified by NASA ground rules for the ECAS studies.

1. Fuel Cell Island Electrical System

The fuel cell island electrical system includes the following major equipment: Forty-eight self-commutating type inverter modules and associated harmonic filters, each module with a 9-MW net output nominal rating; eight 54 MVA 69-kV inverter transformers; and three single-phase step-up transformers, each rated at 144 MVA, OA/FOA 65°C rise, and 69 to 500 kV.

The inverter selected for the ICG/FCP utilizes solid-state, self-commutated technology. An identical unit is under development for the near term FCG-1 26-MW phosphoric acid fuel cell powerplant for dispersed generator utility application. This unit will be tested in the 4.8 MW demonstrator program in 1978 or 1979 (Reference 10). This inverter operates at 96 percent efficiency at rated load.

The fuel cell plant electrical arrangement is shown in the main one-line diagram. A total of 432-MW net electrical ac power is supplied by eight identical fuel cell power banks, each bank generating 56.4-MW gross dc power. An enlargement of the electrical arrangement of a single fuel cell power bank is shown in Figure 22. Each bank consists of six 9.4-MW inverter modules, connected in a series/parallel arrangement to 12 fuel cell modules. The 12 fuel cell modules, each rated at 4.7-MW gross

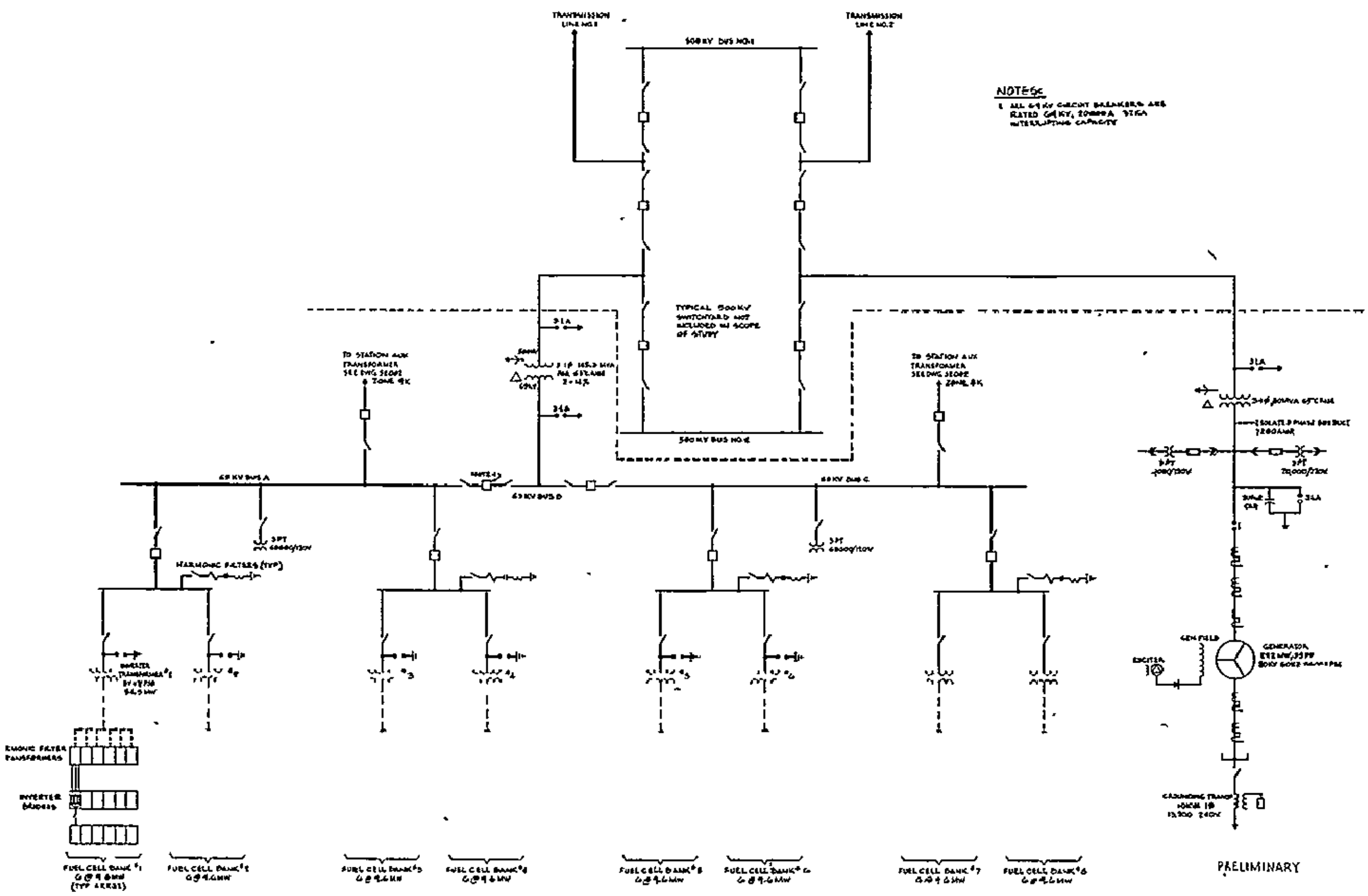


Figure 21 — Fuel Cell and Steam Turbine Generator Electrical Loads and System Connections

dc power, are arranged in four paralleled sets of three series connected modules. Each series connected set supplies 5410 amps at 2600 Vdc. The four fuel cell vessel sets are coupled to the six inverter modules in two paralleled groupings, as illustrated in Figure 22. This arrangement permits electrical isolation of one-half of a fuel cell bank during maintenance or other outage conditions, thereby increasing powerplant availability. As previously described, each fuel cell island consists of 24 fuel cell modules arranged in four rows of six vessels each; thus two fuel cell power banks comprise one fuel cell island.

Each inverter module consists of three inverter bridges connected in parallel to the dc bus. Output voltage harmonics up to 17 times the fundamental are cancelled in harmonic reduction transformers. Any single harmonic voltage output is limited to less than 1 percent of the fundamental. Series reactors are inserted between the bridge output and the harmonic cancelling transformers of each inverter module to provide an inductive impedance to the utility line for control purposes and for buffering the bridge from line transients. The 60-Hz, 3-phase ac output of the six inverter modules is then combined in a 54-MVA inverter transformer for step up to an intermediate ac paralleling voltage of 69-kV. Elimination of remaining harmonics is accomplished by an output filter located on the 69 kV side of the transformer. Lightning arrestors and appropriate ac and dc switchgear and fuses are provided for operational and protective purposes.

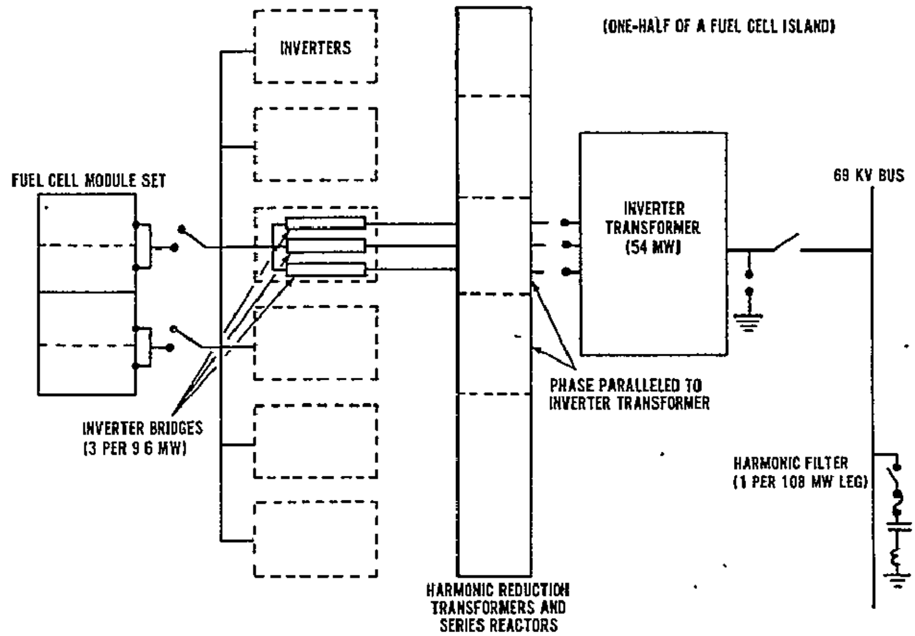


Figure 22 – Fuel Cell Bank Electrical Arrangement

An important characteristic of utilizing self-commutated technology is that both real and reactive power output can be dispatched. The power factor may be operated over the range of 0 to 1.0 within the MVA rating of the inverter modules; this precludes the need for power factor correction capacitors. A feed back controller maintains selected phase angle differences between the inverter bridge output fundamental voltage and the utility line; this phase angle difference is the primary factor in determining real power flow. A second feed back controller maintains a selected voltage difference between the inverter bridge output fundamental and the utility line; this voltage difference is the primary factor in determining the reactive power flow. A feed back regulator system selects and maintains the phase angle and voltage difference required to produce the real and reactive power setting requested by the powerplant supervisory control. The load change response time is set by the magnetics time constant and is less than 0.25 seconds.

The primaries of two 54-MW transformers associated with one fuel cell island are parallel connected through a 69 kV circuit breaker which controls the power from one of the four fuel cell islands. The 69-kV system collects the output of four fuel cell islands, delivers this power to the 432-MV step-up transformer, where the voltage is stepped up to 500-kV for supplying the transmission network.

The 69-kV substations are conventional outdoor type utilizing porcelain insulators for supporting bare conductors on steel framework and air insulation between phases of the bare conductors. A main 69-kV substation and four satellite substations are provided for serving each of the four fuel cell islands. The main 69-kV substation is centrally located and contains the two 12/16 MVA station auxiliary transformers and associated primary circuit breakers, the three 144 MVA single-phase FOA, 69 to 500-kV step-up transformers and two 69-kV bus sectionalizing circuit breakers. The fuel cell island substations each contain two 54 MVA and primary circuit breakers and are connected to main substations via a 69-kV overhead transmission line.

The 69-kV bus is sectionalized with circuit breakers into three parts, namely bus "A", "B" and "C". Buses A and C each receive one-half the fuel cell plant output and also supply one station service transformer which supplies power to the plant electric auxiliaries. This arrangement ensures availability of at least one-half of the fuel cell plant output for maintenance or fault on any bus or transformer, with the exception of the bus "B" sectionalizing breakers and 69 to 500 kV step-up transformer.

The 69-kV circuit breakers are employed for switching each pair of 54-MVA transformers during starting and shutdown of the fuel cells. These circuit breakers are augmented with disconnecting switches on the transformer primary winding which may be used for no-load switching and isolating an inverter transformer during maintenance outages. The 69-kV circuit breakers are also provided with fault sensing relays which initiate tripping of circuit breakers, to automatically isolate faulted bus bars, cables or equipment, thereby keeping to a minimum consequent damages and reduction of plant output. All 69-kV circuit breakers are provided with disconnecting switches to permit isolation of breakers during maintenance, thereby precluding the need to shut down an entire bus.

All transformer windings are provided with surge arresters to protect them from surges which may be caused by lightning or switching. Potential transformers are provided on the 69-kV buses to supply voltage for meters, synchronizing, and protective relays.

2. Steam Turbine Island Electrical System

The steam turbine generator plant electrical system includes the major components indicated in Table VIII.

TABLE VIII

MAJOR COMPONENTS OF STEAM TURBINE ELECTRICAL SYSTEM

- Three One-Phase, 80 MVA, 20 to 500-kV Step-up Transformer Banks
- One Set, Three-Phase, 720 Ampere, 20-kV Isolated Phase Bus
- One Generator, 10 KVA, 13.2 to 240 Grounding Transformer Enclosed in a Steel Compartment
- Two Sets of 3 Potential Transformers, Surge Arresters and Capacitors Enclosed in Steel Compartment

The steam turbine generator electrical plant arrangement is shown in the main one-line diagram of Figure 21. The sychronous steam turbine generator generates 222-MW power at 20-kV, 60 Hz which is transmitted to the step-up transformer bank via the isolated phase bus. The step-up transformer increases the voltage to 500-kV and connects the generator output to the 500-kV network.

The generator grounding transformer is used to ground the neutral of the generator. In conjunction with a voltage relay, it is used to detect grounds in the winding of the generator or connected 20-kV buses and windings which, unless removed, may develop into destructive phase faults. Two sets of potential transformers are provided — one for meters and instruments and one for the voltage regulator. The use of separate transformers for each function ensures greater reliability. This is especially important in the case of the regulator which is vital to the safe operation of the generator. Surge arresters and capacitors protect the generator windings against dielectric stresses caused by surges which may enter the 20-kV generator bus from the 500-kV system through the capacitive coupling of the low and high voltage step-up transformer windings.

The turbine generator is started, accelerated, brought up-to-speed and voltage to match the network and then synchronized to the system by closing the 500-kV circuit breakers. Equipment has been provided to accomplish this either manually or automatically.

3. Plant Auxiliary Electrical System

The plant auxiliary electrical system supplies electrical power required for starting, operating, and shutting down the plant for both normal and emergency conditions. The auxiliary system supplies electric motor-driven auxiliaries for the gasifier, fuel cell and steam turbine islands, coal handling, and cooling towers. It also supplies electric power for many miscellaneous motor drives, lighting, heating, and control of the integrated plant.

A breakdown of the systems' auxilliary power requirements is given in Table IX. Parasite power requirements for each of the major subsystems of the powerplant were estimated by the group responsible for the design of that subsystem. This was done to ensure a complete and detailed listing of the system auxiliary power requirements. IGT provided the power requirements for the coal gasifier and desulfurization subsystems; Burns and Roe — the coal handling equipment, steam plant auxiliaries, and miscellaneous balance of plant machinery; and UTC — the fuel cell subsystem, and the steam cycle cooling towers. Estimates of parasite power were made whenever possible by scaling from available industrial equipment. This was done for a portion of the coal handling equipment such as the crushers and conveyors. System thermodynamics defined the liquid or gas compositions and flowrates for the pumps and compressors. Estimates of the required head rise for each pump were made by calculation of the pressure drops in the appropriate process stream loops. Pumping power estimates were made assuming 80 percent compressor efficiency for gases, 50 percent pump efficiency for water, and 95 percent efficiency for electric motors. Auxiliary power estimates for powerplant auxiliary systems and lighting were based on scaling from present base load powerplants. A detailed breakdown of the assumptions utilized in obtaining powerplant auxiliary power requirements is given in Appendix VI.

The total auxiliary load of 16.4 MW is 2.6 percent of the net ac power output. This is lower than the 4 to 8 percent that is typical of base load steam plants; however, isolating the steam turbine cycle indicates that 4 percent of its gross output would be consumed in associated auxiliary power requirements, consistent with conventional steam plants. One of the inherent advantages of the fuel cell system is that parasite power requirements are generally low. One reason for this is the high system efficiency which results in lower power requirements for coal handling and preparation and for heat rejections. In addition, the coal gasifier/fuel cell powerplant is thermally well integrated. This integration permits major circulating and system pressurization pumps to be driven by turbines utilizing waste heat genrated within the fuel cell system; this reduces the overall parasite power of the powerplant significantly.

TABLE IX
INTEGRATED COAL GASIFIER FUEL CELL POWERPLANT
AUXILIARY POWER BREAKDOWN

	No.	Connected hp	Operating hp	Operating kW
Coal Handling & Processing				
Conveyor No. 1	1	25	–	–
Conveyor No. 2	1	500	400	314
Conveyor No. 3A & 3B	2	15	12	10
Conveyor No. 4A & 4B	2	50	40	33
Conveyor No. 5A & 5B	2	75	60	47
Conveyor No. 6, 7, 8	10 hp Each	30	25	21
Crusher	2	1000	902	673
Magnetic Separator	–	5 kW	5 kW	5
Flop Gates	3	5	–	–
Reclaim Feeders	3 hp Each	18	–	–
Unloading Feeders	10 hp Each	30	–	–
Sampling	1	5	–	–
Thawing Shed	–	–	–	–
Lockhopper Gas Compressors	4	1080 kW	–	1080
Desulfurizer Regeneration Air Pumps	2	1860 kW	–	1860
Gasifier Boiler Feedwater Pumps	2	71 kW	–	71
				4114
Steam Turbine Cycle				
Turbine Generator Auxiliaries				
Hydraulic Fluid HP Pump	2	40	32	27
Lube Oil Pump	2	5	4	3.3
Hydraulic Fluid Heater	2	10 kW	10 kW	10
Turning Gear Oil Pump	1	20	–	–
Turning Gear	1	15	–	–
Filter and Transfer Pump	1	1	0.8	0.7
Main Vapor Extractor	1	3	2.5	2.1
Turbine Drain & Regulating Valves	1	4	–	–
Stator Cooling Water Pump	1	30	25	20.7
Seal Oil Pump	1	10	8	6.6
Steam Packing Exhauster	1	5	4	3.3
Lube Oil Purifier	1	10	8	6.6
Hydrogen Dryer	1	4 kW	4 kW	4.0
				84.0

TABLE IX (Continued)

	No.	Connected hp	Operating hp	Operating kW
Steam Turbine Cycle (Cont.)				
Condensate System				
Feedwater Pumps	2	5679 kW	–	5679
Condensate Pumps	3	64 kW	–	64
Condenser Vacuum Pump	2	125	100	78.5
Condenser Vacuum Seal Pump	2	2	1.6	1.3
Condenser Valves	4	12	–	–
				5823
Miscellaneous Services				
Cooling Tower				
Circulating Water Pumps	2	1053 kW	–	1053
Circulating Water Valves	8	2	–	–
Cooling Tower Fans	32	1132 kW	–	1132
Cooling Tower Makeup Pumps	2	200	160	125.6
Closed Cooling Water (Bearing) Pumps	3	200	160	125.6
Sump Pumps	2	5	–	–
Service Air Compressor	2	75	60	47.1
Instrument Air Compressor	2	50	40	33.2
Turbine Room Crane 30 + 40 + 7 1/2 + 20	1 ea.	97 1/2	–	–
HVAC Air Supply Fans (Total)	–	200	160	125.6
Roof Exhaust Fans (Total)	–	100	80	62.8
Water Treatment Plant	–	100 kW	100 kW	100
Booster Pumps	3	50	40	33.2
Chemical Feed Pumps (Total)	6	1	0.8	0.8
Auxiliary Boiler & Accessories	6	180	144	120
Miscellaneous	–	25	20	16.6
Elevator	1	50	40	33.2
Diesel Oil Pump	1	20	–	–
Fire Pump	1	250	–	–
Screen Wash Pumps	2	150	120	94.2
Traveling Screens	2	50	40	33.2
Ash Sluice Pumps	2	–	–	50
Ash Handling Control	–	1 kW	1 kW	1
Service Water Pumps	2	300	240	188.6
Liquid Waste Treatment	2	50	40	33.2
				3409

TABLE IX (Continued)

	No.	Connected hp	Operating hp	Operating kW
Miscellaneous Utilities				
Lighting				500
Miscellaneous Plant Utilities				2500
				3000
Total Powerplant Auxiliary (MW)				16.4

The auxiliary electrical system one-line diagram is shown in Figure 23. The system includes the major equipment indicated in Table X.

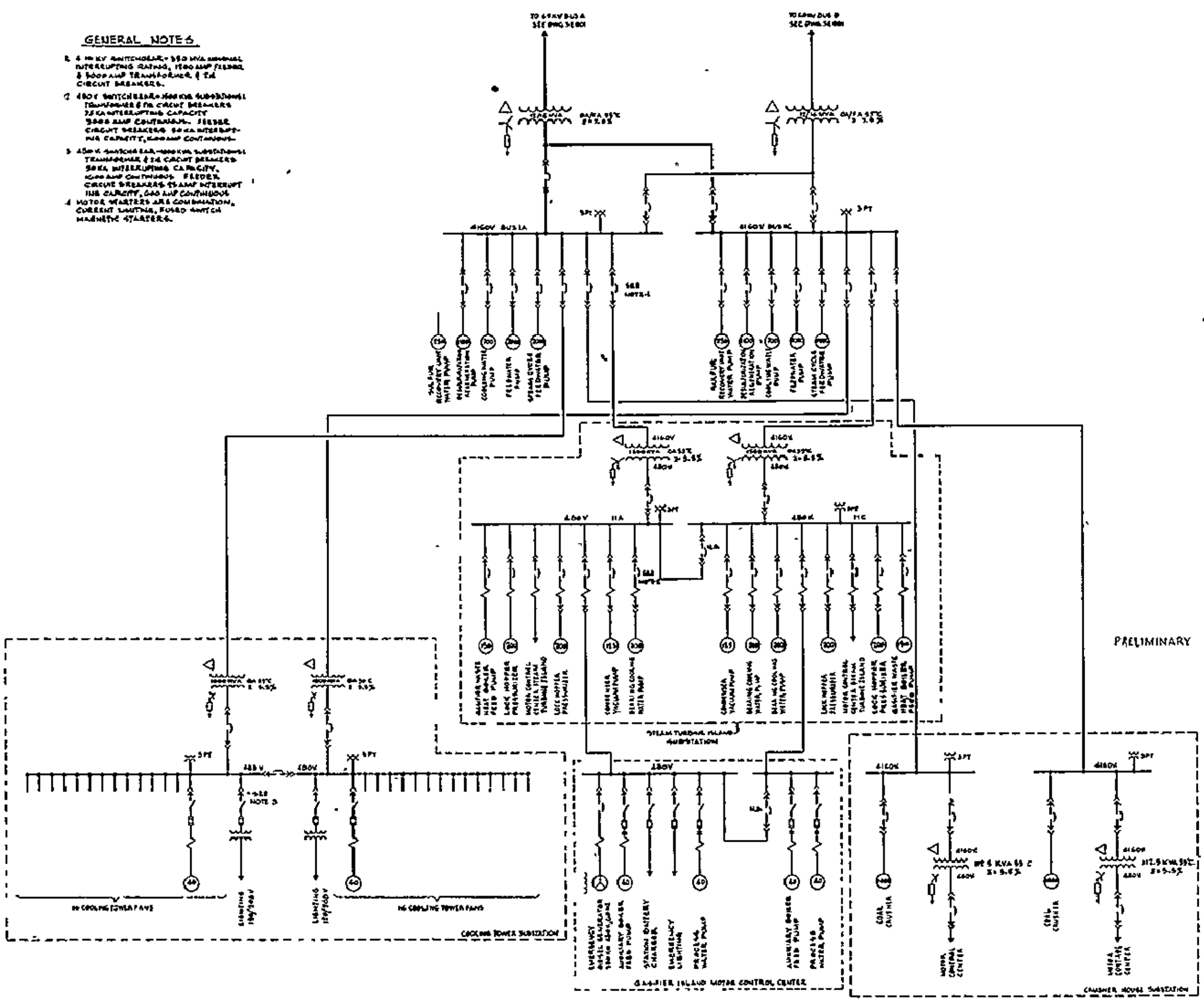


Figure 23 — Auxiliary Electrical System One-Line Diagram

TABLE X

MAJOR EQUIPMENT OF THE AUXILIARY ELECTRIC SYSTEM

- Two – 12/16 MVA OA/FA, 55°C rise, 69 – 4 kV Station Service Transformers
- One Set of 4.16 kV Switchgear with 350 MVA Interrupting Capacity, 1200 amp and 3000 amp Circuit Breakers
- One Double-Ended Unit Substation, 150 kVA, 4160 – 480 Volts, with 75 and 50 kA Interrupting Capacity, Drawout Circuit Breakers, for Main and Feeder Breakers Respectively for Power Distribution to the Steam Turbine Island
- One Double Ended Unit Substation, 1000 kVA, 4160 – 480 Volts for Power Distribution to the Cooling Tower
- Two Dual Voltage 4160 – 480 Volt Substations for Power Distribution to the Crusher House and Coal Handling
- One Gasifier Island Motor Control Center
- Two Turbine Island Motor Control Centers. Motor Control Centers will be of the Combination Across-the-line Magnetic Starters and Fused Switch Type
- One 350 kW, 480 Volt, 60-Hz Diesel Driven Emergency Generator
- One Storage Battery, 125-Volt dc and Approximately 1000 Ampere-hour Capacity, to Supply Normal Station Control Power and Emergency Power to the Turbine Bearing and Seal Oil Pumps and Instrument Supply Inverter.

Each of the two 12/16, OA/FA, 55°C rise, station service transformers supplies power to its respective 4160-volt switchgear section bus "1A" and bus "1C" through normally closed circuit breakers. In addition, a connection is provided from each transformer to the other bus section through a normally open circuit breaker. Upon loss of voltage on one of the buses, the normally open circuit breaker will close automatically to restore power to the affected bus. Each transformer is capable of independently supplying the total plant auxiliary load. The 4160 net switch gear distributes power to unit substations located throughout the plant and large motors of 250 hp (186 kilowatts) and greater. The 4160-volt switchgear is of the indoor type, metal-clad, insulated with air, magnetic drawout type circuit breakers.

The 1500-kVA double ended unit substations, 4160-480 volts, are provided for supplying the steam turbine island auxiliary power. Motors 125 hp (93.2 kilowatts) and larger are supplied directly from the drawout 480-volt air circuit breakers. The two 480-volt buses are fed through their respective normally closed circuit breakers. A normally open bus tie circuit breaker will close automatically upon the loss of voltage on either bus thereby restoring power to the bus.

The 1000-kVA unit substations serving the cooling towers are similar to the above substations except that they utilize motor control centers for distribution of power to motors of 100 hp (74.6 kilowatts) rating, or smaller, in place of 480-volt switchgear.

Two dual voltage substations are provided at the Crusher Tower to supply 4160 volts to the crusher motors and 480 volts to the smaller coal handling conveyer motors and auxiliaries.

All motors, 1/2 hp (0.373 kilowatts) and larger, are across-the-line starting, squirrel cage, 3-phase, 480 or 4160 volts, 60 Hz. Station service transformer impedances are selected to limit the variation of voltage to a range of ±10 percent of rated motor voltage during steady-state electrical conditions and under any combination of powerplant output and auxiliary loading. Voltage dips during starting of large motors will be limited to 15 percent below motor rated voltage.

A 350-kW emergency diesel generator will start automatically upon the complete loss of ac station power, and in less than one minute will provide power to the auxiliaries that must be operative to safely shut down the plant. These auxiliaries include the auxiliary boiler feed pump, station battery charger, emergency lighting and process water pumps that are fed from the gasifier motor control center. The generator is located in the steam turbine building. A 3000-gallon-day (11.4 $meters^3$) tank, fuel pumps, lube oil system, engine cooling system, starting systems, and controls are provided for the diesel and generator.

The 125 volt dc station battery supplies power for the plant process control circuits, motor operated valves, turbine generator emergency bearing oil and seal oil pumps, and instrument power supply inverters. The battery capacity is sufficient to supply these loads for several hours following a complete loss of ac station power.

The instrument power supply inverter is normally powered from the station battery and supplies a closely-regulated, transient-free uninterruptible 120 volt, 60-Hz ac power for instrumentation, recorders and the data logger.

This arrangement avoids the problems that arise from supplying instruments requiring ac power directly from the auxiliary ac power system, which is subjected to transients that may arise from motor starting, switching, and synchronizing.

III-G. Balance-of-Plant Equipment Description

This section of the report describes the balance-of-plant components and subsystems necessary for powerplant operation, but not previously described under the major equipment sections. Costs for all of this equipment were estimated and are reported in Section IV. The items described in this section include two service buildings and auxiliary systems that interface with one or more of the four major subsystems to result in a complete self-contained powerplant facility. Table XI lists the equipment and systems which are discussed in this section.

TABLE XI

BALANCE-OF-PLANT EQUIPMENT

- Service Buildings
- Inter-Island Piping and Wiring
- Water Systems
- Liquid Waste Treatment System
- Compressed Air Systems
- Auxiliary Boilers and Accessories
- Start-up Fuel Oil System
- Powerplant Fire Protection System
- Other Plant Utilities, Including Heating, Ventilating and Air Conditioning; Equipment Handling; and Plant Communications

1. Service Buildings

The administration and laboratory building is located at the southeast quadrant of the site. It is a two story structure, 40 x 100 ft (12.2 meters x 30.5 meters) with an exterior curtain wall construction. A parking lot 100 ft x 100 ft (30.5 meters x 30.5 meters) is located along the south side of the building. The administrative and engineering offices, in addition to the laboratory, are located on the upper floor. This area is completely air conditioned. Shop and storage areas, located on the ground floor, are ventilated and will be provided with large overhead rolling steel doors. Showers, toilets and washroom facilities are provided for personnel.

The maintenance building, located in the northwest quadrant of the site, is 25 ft x 100 ft x 20 ft high (7.6 meters x 30.5 meters x 6.1 meters high). The function of this building is to service the equipment used in the transfer and storage of coal. The building has metal siding with adequate ventilation, lighting, power and drainage facilities necessary for the functions performed.

2. Inter-Island Piping and Wiring

Inter-island piping and wiring is provided between the gasification, fuel cell, and steam turbine islands. The major inter-island pipe lines are summarized in Table XII.

A system of structural steel trestles is provided to support the piping and cable trays. The trestle framework spans the railroad tracks and roads between the islands. Piping is routed to provide expansion loops at each end of a run so that forces and movements at equipment connections, due to thermal expansion, can be expected to be at acceptable levels. All piping handling fluids above 130°F (328°K) is thermally insulated. The insulation finish is weatherproof for outdoor service.

TABLE XII
MAJOR INTER-ISLAND PIPING

Fluid	From	To	No.	Size Inches	Schedule
Gas	Gasifiers	Fuel Cells	4	24	40
			16	12	20
Main Steam	Fuel Cells	Steam Turbine	8	6	XXS
Feedwater	Steam Plant – Condensate Pump	Economizer/ Deaerator	4	6	120
Hot Reheat Steam	Reheater – Gasifier	Low Pressure Steam Turbine – Steam Plant	4	12	40
Cold Reheat Steam	High Pressure Turbine Steam Plant	Reheater – Gasifier	4	10	40
Air	Air Preheater – Fuel Cell	Gasifiers	4	10	3/8 Inch Wall

3. Water Systems

The make-up water and necessary treatment facilities are described schematically in Figure 24. Make up water to the plant is taken from the river. A river water intake structure is provided in which two vertical service water and two cooling tower make-up pumps are mounted.

The screened river water provides the raw make-up to the plant. The travelling water screens are type 304 stainless steel with 1/4 inch (0.635 centimeter) square openings. The velocity of the water through the screens is 2 FPS. A screen wash spray system is provided to clear the screens, the wash system being actuated automatically from a differential pressure across the screens.

The two service water pumps, each rated for 2000 GPM (0.126 meters^3/second), provides make up water for the steam plant, the gasification plant, and the ash handling system. In addition, the service water pumps provide cooling water for certain heat exchangers and miscellaneous services and also provides potable water for sanitary purposes.

The cooling tower pumps, each rated at 2000 GPM (0.126 meters^3/second), provide water primarily for make-up to the cooling towers and for the closed cooling water system. Pumps are cast iron, bronze mounted. Piping is ASTM A53, Grade B.

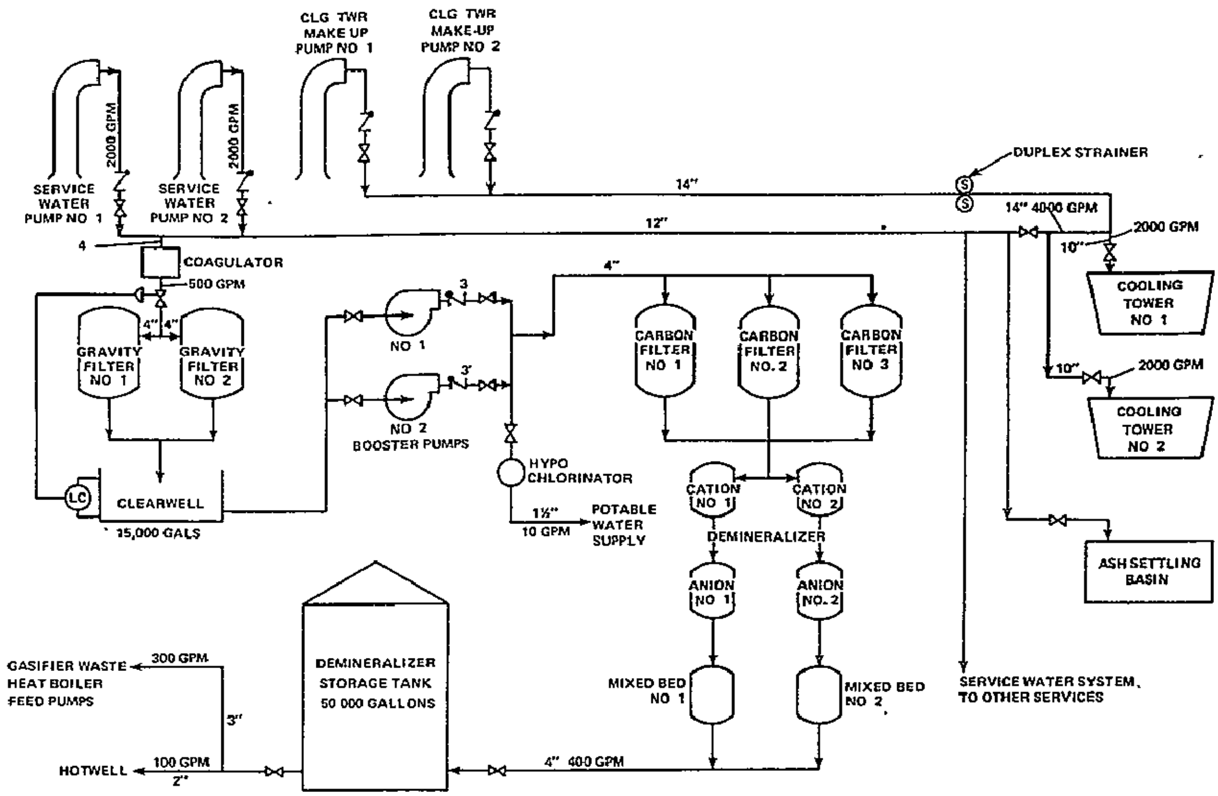


Figure 24 – Make-Up Water and Water Treatment System Schematic

The service water and cooling tower make-up pump discharges are interconnected so that each set of pumps can serve as backup for the other.

Approximately 400 GPM (0.025 meters^3/second) of raw water from the service water pumps is clarified in a coagulator using ferric sulphate and then passed through automatic gravity filters and into the filtered clearwell. The two automatic filters will be in service normally, but the system will operate with one being backwashed while the other is in service. Booster pumps deliver the clarified water to three activated charcoal filters. The carbon filters are reactivated by steam based on pressure differential. The filters are followed by a demineralization system consisting of two strong acid cation exchangers, two strong base anion exchangers, and two mixed bed exchangers.

The demineralization system includes lined interconnecting piping and valves, central control panels, and acid and caustic pumps each fed from a 6000 gallon (22.7 meters^3) concentrated liquid storage tank. An electrically heated hot water tank for heating caustic soda and mixing dilution chambers for the acid and caustic are included. Resin traps are provided at the outlet of the demineralization plant. A recycle pump is provided to maintain the minimum flow rate through the mixed bed. A 50,000 gallon (190 meters^3) carbon steel epoxy lined demineralizer water storage tank is located outside the east wall of the steam turbine building to store the treated water. A small portion of the clarified and filtered water (10 GPM) is not passed through the demineralization system but is chlorinated and used for sanitary purposes in showers, toilets and wash basins.

A chlorinator and bottle storage facility is located adjacent to the river water intake structure. The chlorinator is in a heated shed. Chlorine is added to the river water makeup to the cooling tower on a shock treatment schedule to prevent the formation of algae and slime in the circulation water system. The system includes control devices and distribution headers.

The closed cooling water system supplies water to the bearings of rotating equipment, piping system glands, turbine-generator lube oil coolers, air compressor jackets and aftercoolers, hydrogen coolers, turbine EHC hp fluid coolers, exciter air coolers, boiler feed pump oil coolers, sample coolers, condenser vacuum pumps, air conditioners, and other services. The water is condensate quality which is treated with corrosion inhibitors. The system includes three circulating pumps, two heat exchangers, a head tank, and necessary piping valves and controls.

Three 50 percent capacity horizontal single-stage cooling water pumps are provided, each rated at 1000 gpm (0.063 meters^3/second). The pumps are of cast iron construction and include stainless steel shaft sleeves. The discharge pressure is 100 psig (791 kilopascal).

Two 100 percent capacity single pass water-to-water heat exchangers cool the recirculated water to within 5°F (2.78°C) of the incoming cooling tower circulating water. The recirculated cooling water range is 30°F (16.7°C). The system is designed to provide water that does not exceed 105°F (314°K) at the outlet of the heat exchanger. The heat exchanger design criteria are indicated in Table XIII.

TABLE XIII

CLOSED COOLING WATER SYSTEM HEAT EXCHANGER DESIGN CRITERIA

Shell Material	ASTM A285
Tubes	Admiralty, 18 BWG
Water Boxes	Cast Iron
Shell and Tube Design Pres.	125 psig
Code	ASME and TEMA

One 500 gallon (1.9 meters^3) open top head tank is equipped with a float valve and overflow and telltale. The head tank will tend to maintain a constant head across the closed cooling water system and allow for fluid expansion. The make-up to closed cooling water system is from the condensate pump discharge.

4. Liquid Waste Treatment System

Wastes generated in the plant are collected and treated so they are acceptable for discharge to the river. The system is designed to handle and treat up to 750 GPM (0.047 meters^3/second) of waste liquids.

The waste treatment plant includes the equipment shown in Table XIV.

TABLE XIV

WASTE TREATMENT PLANT EQUIPMENT

- Acid and Caustic Storage and Injection Equipment for pH Correction
- Coagulant Feed
- Oil Skimming
- Recycle Pumps
- Air Sparging Equipment
- Waste Oil Storage Tank
- Waste Water Lift Pumps
- Instrumentation

A 40 ft x 60 ft x 20 ft (12.3 meters x 18.3 meters x 6.1 meters) high waste treatment equipment enclosure is located in the northwest quadrant of the plant adjacent to the liquid waste storage pond and is used to house the pumps, feeders, and chemicals to treat the liquid wastes.

All wastes are collected in a lined liquid waste storage pond — 100 ft x 200 ft by 6 ft deep (30.5 meters x 61.0 meters x 1.8 meters deep) — which has a maximum capacity of 900,000 gallons (3411 meters^3). The pond is located in the northwest sector of the plant. The liquid waste storage pond was sized by assuming that at normal plant operation the pond would be 20 percent full, and that a one-inch-per-hour rainfall occurs for two hours. Also, it was assumed that truck removal of ash is not feasible during the heavy rainfall and the ash is sluiced to the emergency ash storage pond which overflows to the liquid waste storage pond. Treatment of the wastes would be at a maximum flow of 750 gpm by the Liquid Waste Treatment System. The sources of plant liquid waste are indicated in Table XV.

TABLE XV

SOURCES OF PLANT LIQUID WASTE

- Coal Pile Collection Sump
- Crusher House Drains
- Emergency Ash Pond Overflow
- Track Hopper Tunnel Sumps
- Reclaim Hopper Tunnel Sumps
- Ash Settling Basin Overflow
- Storm Water Runoff
- Steam Turbine Building Drain Sumps
- Demineralizer Neutralized Wastes

Wastes are pumped to the pond wherever gravity flow is not feasible. Water treatment plant rinses, backwashes, and blowdown will be collected into a sump and neutralized before being discharged to the waste storage pond. Cooling tower and boiler blowdown discharge to the ash settling basin and the overflow, if any, is discharged to the liquid waste storage pond.

The liquid wastes are treated with sulphuric acid or caustic soda to neutralize them. The pond is sectionalized to permit skimming of oil and to add coagulant to remove suspended solids and clarify the wastes. The wastes are also strained prior to being pumped overboard to the river via the circulating water discharge tunnel.

Cold side circulating water system blowdown does not require treatment and is therefore put back into the line going to the river.

5. Compressed Air System

Two interconnected compressed air systems are provided – one for instrument air and one for service air. Both systems are oil and moisture free. The compressors will be horizontal, motor-driven, single-stage, double-acting, and non-lubricated with intake filter, silencer, and aftercooler.

The instrument air compressor has a capacity of 200 scfm (0.094 meters^3/second), discharging normally at 100 psig (791 kilopascal). The piston rings and packing are Teflon. A distance piece between the crankcase and cylinder prevents the rod from carrying oil into the cylinder. The compressor has a 50 hp (37 kilowatts), three-phase, 480-volt motor operating at 1770 rpm. The unit is equipped with a dual type load-unload control and start-stop control to maintain the required compressed air delivery.

A duplex, automatic-regeneration air dryer, located downstream of the aftercooler, lowers the dew-point of the air to -40°F at 100 psig (233°K at 791 kilopascal). Inlet and outlet filters for the dryer are included. An air receiver tank of 150 cubic feet (4.25 cubic meters) capacity designed to ASME Code for 125 psig (963 kilopascal) is provided.

The service air compressor is rated for 300 scfm (0.142 meters^3/second) and maintains pressure in its receiver at 100 psig (791 kilopascal). The aftercooler lowers the temperature of the service air to within 13°F (7.2°C) of the cooling water from the closed cooling water system. The unit is equipped with dual type control systems.

6. Auxiliary Boilers and Accessories

Two fuel-oil-fired 85,000 lbs/hr auxiliary steam boilers are located in the Steam Turbine Building at grade level. These boilers generate steam at 200 psig and 450°F (1480 kilopascal and 505°K). Two boiler feed pumps and two fuel oil pumps are included for each boiler. Draft fans, condensate collecting tanks, boiler blowdown tanks, and all necessary instrumentation and controls required for each of the units are also provided.

The boilers supply steam for start-up of the gasifiers and to the steam turbine gland seals during start-up. In addition, in the event the powerplant is shut down, the boilers supply steam for building space heating, freeze protection, heating caustic soda for demineralizer resin regeneration, charcoal filter regneration, and chemical cleaning of waste heat and boiler superheaters. During normal operation, these steam requirements are supplied from the excess steam generated by the sulfur recovery plant.

7. Start-Up Fuel Oil System

The No. 2 distillate fuel oil system provides oil to the auxiliary steam boilers, the emergency diesel generator, startup gasifier and fuel cell burners, and coal thawing shed burners whenever those units are in operation.

The fuel oil is delivered by rail or truck. Unloading facilities are provided to transfer the oil to the two 150,000 gallons (569 meters^3) carbon steel, field-erected tanks located west of the gasification plant. The tanks are located inside an earth-diked enclosed area to conform to safety and environmental requirements.

8. Powerplant Fire Protection System

All fire protection systems are designed to conform to the National Fire Protection Association guidelines.

All areas of the plant are protected by two fire pumps supplying water to yard fire hydrants, standpipe and hose stations inside the steam turbine building, spray deluge and sprinkler systems. The water fire protection systems utilize the river as the source of water.

The eight inch (20.3 centimeter) yard fire line is designed as a loop to permit water flow in either direction. Hydrants are provided at the gasification, fuel cell, turbine building, coal storage and handling, and the administration building areas. The loop is sectionalized by valves to permit repairs without the loss of the complete system. Hydrants and NFPA hose houses are located at intervals of about 500 feet (152 meters). A fire line is extended to the crusher house and car dumping station areas.

The system is normally pressurized by the 80 gpm (0.005 meters^3/second) jockey pump taking water from the service water head tank. Two fire pumps — one diesel-driven and one motor-driven — will start automatically in sequence upon loss of pressure, an indication of flow in lines, or when manually actuated. The fire pumps are located in the river water intake structure.

The supply to the steam turbine building standpipe system is provided from the yard header. An indicator valve is provided outside the building. Risers are installed at each corner of the turbine building with hose racks at each level and one and a half inch (3.81 centimeters) linen hose at hose stations. Two and one half gallon (0.009 meters^3) CO_2 and/or foam extinguishers are placed on columns at intervals not to exceed 75 feet (22.9 meters) at all levels. A fire alarm panel with supervisory lights is installed in the Main Control Room.

Deluge systems using fog nozzles protect the steam turbine oil system, and the main and auxiliary transformers. Provisions are made for direct injection of carbon dioxide into the turbine oil reservoir and lube oil storage tank.

Foam water deluge systems will be provided for the turbine front pedestal, governor, and turbine bearings, the gas turbine areas, the hydrogen seal oil systems, the fuel oil tanks and the gasification plant.

9. Other Plant Utilities

The plant is provided with other facility utilities. These include heating, ventilating and air conditioning, material handling, and communications. Steam unit heaters are used for space heating in the Steam Turbine Building, Crusher Building, Maintenance Building, Fuel Cell Buildings and Waste Water Treatment Buildings. The steam is provided from the sulfur recovery plant during normal plant operation, and by the auxiliary boilers during periods of plant shutdown. Roof ventilators are provided for ventilation in these areas. The Administration Building offices and laboratories and main control and computer rooms in the Steam Turbine Building are air-conditioned.

Monorails are provided over large pumps, compressors, and other rotating equipment that is not served by the bridge cranes contained in the various buildings previously described.

An internal plant communication system, including about 100 speakers, 125 handsets and amplifiers and associated monitoring equipment is included in the powerplant design.

III-H. Plant Operation and Control

1. Normal Operation

The powerplant is designed for base load operation at or near full rated power. During normal operation, component temperatures and pressures, and system power output, must be stable and subject to positive controls.

Gasifier temperatures are controlled by varying the coal, steam, and air flow rates. Gasifier outlet temperature, and fuel cell current are sensed to determine the need to change these flow rates.

Bypass valves are used around the gasifier boiler and the steam bottoming cycle heat exchangers to control the temperatures into the desulfurizer, the fuel cell, and the turbocharger subsystems. Since the rate of steam generation varies in removing sufficient waste heat from these sources to maintain required temperatures, the steam cycle power output is determined by the gasifier and fuel cell system controls. Primary power level is accomplished through the fuel cell by changing the real and reactive power output from the inverter subsystem. A change in the inverter output changes the fuel cell output accordingly; temperature controls in the fuel cell and flow rate controls in the gasifier then change to maintain proper operating conditions. Primary control through the fuel cell system is advantageous because it can respond instantly to load changes. A substantial fuel inventory in the stacks and piping permits much faster response times than powerplants using rotating machinery.

System pressure is controlled by bypass valves which divert pressurized gases around the power recovery turbines. Auxilliary burners are also used to maintain key system component temperatures at low load or during shutdowns.

The conceptual design powerplant can be run at part power in two modes. The first mode takes advantage of the fact that the powerplant consists of four independent gasifier-fuel cell trains operated in parallel. In each train, coal is converted to fuel cell power and the waste heat from all trains is available to a single steam bottoming cycle. Any train can be shut down independently of the others; this reduces the fuel cell output by 25 percent. Shutting down a single gasifier-fuel cell train lowers the amount of steam available to the bottoming cycle, thus lowering its output power. This modular unit shutdown approach to turndown has the disadvantage of slow response time to power turnup. It takes two hours or less to bring a hot unit on line. If it has been off line longer than 48 hours and allowed to cool down, it takes a minimum of 12 hours.

The second turndown mode has quick response times and infinitely variable power levels down to about 37 percent of rated power. In this mode, all units remain online and power is reduced by changing the inverter controls and reducing the coal flow to the gasifiers. When the fuel cell is operated at lower loads, it tends to run more efficiently and there is less waste heat available to the steam bottoming cycle. Also, some of the fuel normally used in the fuel cell must be diverted to the fuel cell start-up burners where it is burned prior to expansion in the turbocompressor subsystem in order to maintain system pressurization. The net effect is that the net power turndown is always greater than the coal turndown to the gasifier. The gasifier is the limiting factor in the second turndown mode. It requires at least half of its rated power gas flows to maintain fluidization. At 1/2 of the original coal flow, the system power is down to 37 percent of its rated power.

Component additions and design requirements have been incorporated in the conceptual design powerplant to accommodate this mode of turndown.

2. Startup

Detailed analysis of the startup procedure for the conceptual powerplant was beyond the scope of this program. However, analysis was conducted to identify the startup sequence, define major auxiliary equipment requirements and estimate start times.

When the powerplant is cold, auxiliary distillate oil burners are started in each of the fuel cell islands. The exhaust of these burners, along with starter motors, are used to initiate startup of the turbocompressors. The turbocompressors are brought up to rated speed which bring the fuel cells to full design pressure. A portion of the burner exhaust gases is allowed to circulate through the cathode recycle loop providing sensible heat to the cells. The auxiliary burners are used to heat the cells to their nominal operating temperature of 1200°F (922°K) and to sustain turbocompressor operation during the startup sequence.

During the startup of the fuel cell system, a portion of the turbocompressor compressed air is bled to the gasifier systems and used to start the gasifier turbocompressors. Subsequently, auxiliary distillate oil burners in each gasifier island are fired, and are used to bring the gasifier turbocompressors to full rated speed and to sustain their operation during the gasifier startup sequence. A portion of the burner exhaust gases are used to bring the refractory and internals of the gasifier vessels to an operating temperature between 600 and 800°F (589 and 700°K). At this temperature, a coal char or metallargical coke is fed to the gasifier with only an air flow to the bottom grid of the vessel. As the char begins to burn, steam supplied from the auxiliary steam boilers is introduced to control the temperature rise inside the gasifier. Char or coke is used during startup to avoid the formation and deposition of tarry material inside and upstream of the gasifier when components are cold.

During the initial heatup of the gasifiers using auxiliary burner exhaust, the gases leaving the gasifiers pass through the gasifier waste heat boiler, the steam reheater, and the desulfurizer units, and are expanded in the gasifier turbocompressors before being vented to the stack exhaust. This hot gas stream initiates heatup of these components of the gasification system. When the coke or char feed to the gasifiers begins, the burner exhaust bypasses the gasifiers and continues to heat up the downstream components to operating temperatures, and raises process steam for the gasifiers for normal operation.

When the fluidized bed temperature reaches 1700°F (1200°K), a transition to the normal coal feed is started. Tuning of the coal, steam, and airflows settle the gasifier to its rated power operating conditions. The entire cold startup procedure is estimated to take 12 hours. After gasifier startup, the hot product gas continues to heat the downstream components, and until the fuel gas is needed by the fuel cells, it is flared. Bypass valves are provided on some of the heat exchangers to prevent overtemperature conditions.

During startup, the steam bottoming cycle components utilize heat from both the gasifier and fuel cell subsystems. The main boiler/superheater is heated by sensible heat from the cathode recycle loop. This step is initiated after the fuel cells have reached a predetermined temperature and water is allowed to fill the steam generator and associated components. A bypass loop around the boiler/superheater allows control of heat to this unit.

The exhaust gases from the turbocompressors leave at relatively high temperature. Sensible heat from these gases is used to provide steam cycle feedwater heating in the deaerator/economizer units. As mentioned earlier, steam for reheat is supplied during gasifier startup.

All the steam initially generated by the boilers is vented until the design turbine throttle conditions have been achieved. At this time, steam is admitted to the turbine and turbine speed is slowly increased.

When the gasifier reaches steady-state conditions and the product composition and temperature of the synthesis gas reaches design conditions, the gas is fed to the fuel cells. At this time, the fuel cell inverters begin drawing power from the stacks and feed this power to the utility system. Vent gases leaving the fuel cell are fed to the turbine sections of the turbocompressors which supply the pressurized air for the entire system. The auxiliary burners, which have kept the turbocompressors operating, can now be shut down. The steam turbine is then loaded and synchronized with the line and at this time the powerplant is at full operating condition and the startup sequence has been completed.

The total startup time from cold for the powerplant is limited by heat up of the fuel cell and gasifier sections and requires a minimum of 12 hours. A hot restart of the powerplant is expected to take about two hours or less due to the fact that hot components stay near nominal operating temperatures for up to 48 hours following shutdown.

3. Shutdown

Both complete or partial shutdown of the plant may be accomplished. For partial shutdown to cold condition, the inverters associated with individual fuel cell islands are automatically shut off and disconnected on both the dc and ac sides. Simultaneously, both the coal and air feed to the appropriate gasifiers are stopped causing a halt in the production of synthesis gas. Steam from auxiliary boilers is fed to the gasifiers to control cooling rate. Residual combustible gases in the gasification system and gases formed during the cool down process are burned and vented through the flare stack. After the gasification vessels have cooled sufficiently, they may be depressurized. Residual coal and ash remaining in the vessels is removed through the ash hoppers and carried off through the ash slurry system.

Upon removal of the electrical load, the fuel cells which are being shut down revert to open circuit conditions. Waste heat is no longer being produced and the cathode recycle loop can be shut down. The turbocompressors are shut off and the cells are allowed to cool slowly by natural convection. If faster cooling of the cells is required, the fuel cell turbocompressor may be operated using its auxiliary burner to provide cooling air to the cells.

When the entire plant is to be shut down, the steam bottoming cycle must be removed from the line. Since the steam plant is unfired, it depends on the fuel cell waste heat for process steam production. When the fuel cells are shut down, steam production stops. Residual steam may be either vented to the atmosphere or passed to the turbine condenser unit.

A gasifier/fuel cell island may be shut down for short periods of time and restarted very quickly. In such cases, residual coal is maintained within the gasification vessel in an unfluidized state and periodic blasts of air assure that the bed and vessel temperature are maintained at a high level. After the required shut down period, the bed can be re-fluidized and brought up to operation by re-starting the air and steam flows. The synthesis gas can then be fed to the fuel cells, which, if the shut off period is relatively short, will still be at sufficiently high temperature to support the electrochemical reactions.

IV CONCEPTUAL DESIGN CHARACTERISTICS

This section describes the characteristics of the conceptual design powerplant. The section includes a description of plant output and efficiency, resource requirements, environmental intrusion, capital cost, operating and maintenance cost, and cost of electricity.

A. Power Output and Efficiency

1. Power Output

As indicated in Table XVI, the conceptual design powerplant delivers a gross ac power output of 654 MW. The main transformer loss was estimated at 2 MW based on an efficiency of 99.6 percent. The auxiliary power requirements described in Section III F total 17; therefore, net ac power output is 635 MW. This provides an overall powerplant energy efficiency of 49.6 percent.

TABLE XVI

POWERPLANT OUTPUT SUMMARY

500 KV, 60 Hz Power in MW

Gross ac Power from Fuel Cell/Inverter	432
Gross ac Power from Steam Turbine Generator	222
Total Plant Gross Power	654
Main Transformer Loss	2
Auxiliary Power Requirements	17
Total Net Plant Power Output	635

2. Plant Energy Flow

Figure 25 illustrates the major thermal, mechanical and electrical energy flow throughout the system. For the purposes of simplicity, these flows are given on the basis of a 1 MW net ac powerplant output.

Since the system efficiency is 49.6 percent, the coal feed to the gasifiers is equivalent to 2 MW (based on the higher heating value of the coal). The processed gas leaving the gasifier-cleanup system and flowing to the fuel cells contains 1.82 MW of sensible heat and chemical energy with 1.50 MW available in chemical form for use in the fuel cell. Factors which contribute to inefficiency in the gasification system include carbon loss in the ash, heat losses from the gasifier vessels and piping, electrical parasites, and the consumption of 0.09 MW equivalent of process gas in the sulfur recovery system.

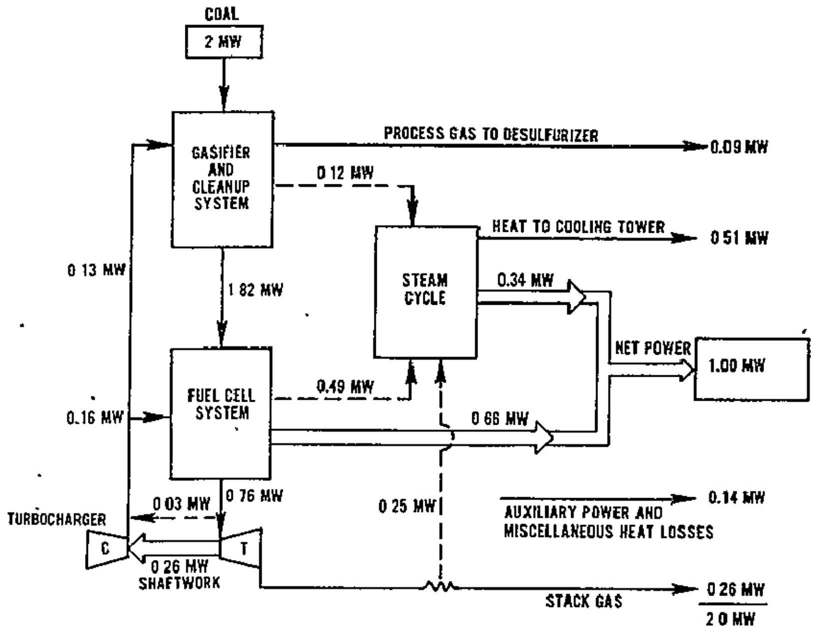


Figure 25 – Approximate System Energy Flow

Heat from cooling the fuel gas before desulfurization is used to raise process steam for the gasifiers, and in addition 0.12 MW of heat is recovered in reheaters of the steam bottoming cycle.

In the fuel cell and inverter, the energy in the fuel gas is converted to 0.66 MW of ac power. Waste heat from the fuel cells amounting to 0.49 MW is recovered and used directly to provide boiling and superheating duty for the steam bottoming cycle. An additional 0.25 MW of heat is recovered in the steam cycle from the cathode exhaust gases after they are expanded through the turbocompressors. Waste heat is also used in the turbocompressors to provide pressurized air to the fuel cells and gasifiers.

The steam bottoming cycle recovers a total equivalent of 0.86 MW of waste heat from the gasifier and fuel cell systems. The bottoming cycle produces a net output of 0.34 MW which results in a 40 percent efficiency for this portion of the plant.

The largest single source of heat rejection in the powerplant is from the cooling towers and amounts to 0.51 MW of heat. The stack gas carries 0.26 MW of heat. Other losses are associated with parasite power required for pumping fluids and for coal handling as well as heat leaks from high temperature vessels and piping.

3. Plant Efficiency Measures

Table XVII summarizes the significant efficiency measures of the powerplant. The gasifier and cleanup system produces fuel gas chemical energy at 75 percent efficiency in addition to thermal energy which is recovered in the bottoming cycle or in the turbocompressors. The fuel cell power section utilizes an electrochemical process which is not limited by the Carnot cycle and, in combination with the 96 percent efficient inverter, converts fuel gas to ac power at an efficiency of 45 percent. Because the fuel cell does not degrade the temperature of the fuel gas, the fuel cell and gasifier waste heat provide good conditions for an efficient steam bottoming cycle. The resulting overall plant efficiency after accounting for auxiliary power requirements is 49.6 percent.

TABLE XVII

POWERPLANT EFFICIENCY MEASURES

	Efficiency — Percent
Gasifier/Clean-up Cold Gas Efficiency[1]	75
Fuel Cell Chemical Energy Conversion Efficiency[2]	47
Inverter Efficiency[3]	96
Fuel Cell/Inverter Chemical Energy Conversion Efficiency[4]	45
Coal Pile to Busbar Powerplant Overall Efficiency[5]	49.6

1. HHV Gases to Fuel Cell/HHV Coal
2. Gross dc Power from Fuel Cell/HHV Gases to Fuel Cell
3. Gross ac Power from Inverter/Gross dc Power to Inverter
4. Gross ac Power from Inverter/HHV Gases to Fuel Cell
5. Net Plant ac Power/HHV Coal

B. Natural Resource Requirements

The natural resource requirements are shown in Table XVIII. The conceptual design powerplant produces a net output of 635 MW, while consuming 202.5 tons/hr (51 kilograms/second) of Illinois No. 6 coal and 4300 gallons of water per minute (0.271 meters^3/second). The land requirements for the powerplant, exclusive of switchyard, is 123 acres (498 x 10^3 meters^2).

Of the total water requirements, 300 gpm (18.9 x 10^3 cm^3/second), or 7 percent of the total is used to provide process steam for the coal gasifiers. About 2 percent, or 94 gpm (5931 cm^3/second) is used for make-up in the steam plant. The remaining 91 percent, or 3900 gpm (0.246 meters^3/second), is required for the wet cooling towers and includes losses associated with evaporation, drift, and blowdown.

TABLE XVIII
POWERPLANT PERFORMANCE SUMMARY
NATURAL RESOURCE REQUIREMENTS

COAL	202.5 TONS/HR	~	0.63 LBS/KWH
WATER	4300 GPM	~	0.40 GALS/KWH
• GASIFIER PROCESS WATER	300 GPM		
• STEAMPLANT MAKE-UP	94 GPM		
• COOLING TOWER MAKE-UP	3900 GPM		
LAND	123 ACRES	~	20 ACRES/ 100 MW

The 123 acres (498 x 10^3 meters^2) of land required for siting is based on a plant layout prepared by Burns & Roe, with input from both PSD and IGT. A significant amount of the acreage is used for the 60-day coal storage supply, coal preparation, emergency ash storage, and cooling towers. Coal storage land requirements could be reduced if a higher coal pile were assumed. This design limited coal pile height to 20 feet (6.1 meters) to permit coal handling via bulldozers.

Only one arrangement of fuel cell modules was studied, utilizing vertical pressure vessels containing 8 fuel cell stack assemblies per vessel. Alternate designs using horizontal vessels with a multiple floor arrangement appear to offer advantages in terms of reduced land requirements. Similarly, the overall plant arrangement includes significant open space which could be reduced with an alternate layout.

C. Environmental Intrusion

A powerplant impacts on the surrounding environment by rejecting heat and by the emission of pollutants in the form of gases, liquids, and solids. These emissions include sulfur and the oxides of sulfur, coal ash and particulates, nitrogen oxides, carbon monoxide, and unburned hydrocarbons. Trace amounts of other elements in the coal feed or compounds formed during the gasification process may also contribute to the powerplant pollution level. Tables XIX and XX show gaseous and thermal emissions and liquid and solid waste respectively for the conceptual design.

The conceptual design powerplant, operating at its design power level, rejects 3430 Btu/kWhr (3616 kilojoules/kWh) of heat. This represents 1 kW of heat for each net kW of electrical power delivered to the systems and reflects the thermal efficiency of 50 percent. This heat rejection rate represents a 20 percent reduction over the most efficent present day fossil fueled plants. In the conceptual design, approximately 50 percent of the waste heat is rejected through the wet cooling towers of the steam bottoming cycle. Heat losses, gases vented from the system, and sensible heat in the ash account for the balance of the thermal emissions.

TABLE XIX
POWERPLANT PERFORMANCE SUMMARY
GASEOUS AND THERMAL EMISSIONS

	PLANT EFFLUENT	SOLID FUEL STANDARDS
SO_2	0.74 LBS/10^6 BTU	1.2 LB/10^6 BTU
NO_X	< 0.03 LBS/10^6 BTU	0.7
HC	NEGLIGIBLE	—
CO	1.6 x 10^{-5} LBS/10^6 BTU	—
PARTICULATE	< 0.09 LBS/10^6 BTU	0.1

THERMAL POLLUTION

HEAT REJECTED — COOLING TOWERS	1730 BTU/KWH
HEAT REJECTED — STACK	875 BTU/KWH
HEAT REJECTED — TOTAL [1]	3430 BTU/KWH

(1) INCLUDES TOTAL PLANT LOSSES

TABLE XX
POWERPLANT PERFORMANCE SUMMARY
LIQUID AND SOLID WASTE

LIQUID			
• BLOWDOWN	670 GPM	~	0.06 GAL/KWH
• GASIFIER BOILER	26		
• STEAMPLANT BOILER	93		
• COOLING TOWER	550		
• SULFUR	13,500 LB/HR	~	0.02 LB/KWH
SOLID (ASH)	22 TONS/HR	~	0.07 LB/KWH

The relative emission levels of ash, particulates, sulfur, and sulfur oxides depend upon the coal composition, the type of gasifier, and the manner of desulfurization. For the conceptual design, Illinois No. 6 coal is gasified in a fluidized bed, ash-agglomerating gasifier. The coal, which contains 9.6 percent ash and is fed at the rate of 405,000 lbs/hr (184 x 10^3 kilograms/hr), requires the removal of 43,630 lbs/hr (19.8 x 10^3 kilograms/hr) of ash. The ash contains large amounts of metal oxides, and small quantities of carbon, nitrogen, and sulfur. The carbon removed with the ash represents a loss in system efficiency and should be minimized.

In the gasification section, coal fines are trapped and recirculated to the gasifier by a series of cyclone separators. The amount of particulates escaping from the cyclones has been estimated by IGT to be about 1 grain/SCF (0.0023 kilograms/Standard Cubic Meter) of product-gas. The particulates are subsequently trapped in the iron oxide desulfurizers. During the regeneration of the desulfurizers, the particulates, which have a composition similar to the coal, are burned off and the ash fines are blown out of the beds with the regeneration air. It is anticipated that the majority of these ash fines will be removed from the system in the cooling water wash step of the sulfur reduction subsystem. Since the actual particulate emission level cannot be accurately estimated at this time, for this study it was conservatively assumed that all of the ash fines would leave in the system exhaust. This represents a maximum particulate emission of 0.09 lbs/10^6 Btu (0.387 x 10^{-7} kilograms/kilojoule) which is lower than the present federal standards permit for a coal fired powerplant.

Illinois No. 6 coal contains 3.9 weight percent sulfur. This sulfur is reacted in the gasifier to form primarily H_2S with trace amounts of COS. The majority of the sulfur compounds are absorbed on the iron oxide beds and then burned off in the air regeneration step, forming primarily SO_2. Using the SO_2 reduction and Claus processes, the SO_2 is converted to elemental sulfur. Approximately 86 percent of the sulfur entering the system is recovered in this manner, which represents 15,900 lbs sulfur per hour (2003 grams/second). In the sulfur recovery system, 7 percent of the sulfur is lost to the atmosphere as SO_2 from the tail gas incinerator.

The iron oxide beds lower the H_2S in the fuel cell process gas down to 200 ppm. The unabsorbed H_2S passes through the fuel cell stacks, is then burned to SO_2 in a catalytic burner, and is finally vented through the powerplant stack. The sulfur leaving the system by this path represents 3 percent of the total sulfur emissions. The balance of the sulfur (4 percent) is lost with the ash removed from the gasifier.

The remaining two critical pollutants are CO and nitrogen oxides. Both are the results of the air combustion of fuel gas. The system includes two catalytic burners in each fuel cell island and a single tail gas incinerator located in the sulfur recovery subsystem. The maximum temperature attained in any of the burners is estimated to be between 1400 and 1800°F (1003 and 1255°K). NOx formation caused by direct combination of N_2 and O_2 from the air is essentially zero at these low burner temperatures. The NOx emission level estimate for this study of <0.03 lbs/10^6 Btu (0.129 x 10^{-7} kilograms/kilojoule) is based on the conservative assumption that all the NH_3 formed during the gasification process is converted to NO_2. Even at this conservative estimate, the NOx emissions are less than 1/20 of the federal standards.

The CO leaving the system comes primarily from the catalytic burner exhausts. CO formation is favored by low burner temperatures; however, the estimated value of 1.6 x 10^{-5} lbs/10^6 Btu (6.88 x 10^{-12} kilograms/kilojoule) for the conceptual design is essentially negligible. Estimates of the emissions of the catalytic burner were based on a kinetic model.

The fate of trace elements present in coal during gasification is not completely known. It is thought that most of these elements will remain in the ash because, in the gasification process chosen, ash is removed at relatively low temperatures compared to slagging gasifiers. Certain volatile elements, such as chlorine, may be completely evolved from the coal and be present in the fuel gas and finally released to the atmosphere. A study of the fate of trace constituents of coal during gasification has been carried out by IGT under EPA contract No. 68-02-1307 (Reference 11). That study concluded that emissions of trace elements from gasifiers will be significantly less than if the same coal were burned in a conventional powerplant.

D. Capital Cost

1. Overall Capital Cost

Capital costs were estimated for all plant equipment. In accordance with NASA ground rules, capital costs were broken down to direct and indirect costs, A and E services, contingency, escalation and interest during construction. Direct costs were the sum of the costs of the major components, plus the systems, components and materials considered as balance-of-plant items, plus direct installation labor. This direct labor is the construction crew team which includes equipment operators, laborers, helpers and foremen. The direct costs for the powerplant components are based on units delivered and installed in mid-1975 in consideration of the fact that escalation beyond mid-1975 will subsequently be included by use of the NASA escalation/interest factors applied to the total plant cost estimate (pages 76, 77).

Indirect costs are associated only with installation labor and include the classes of site labor-related work indicated in Table XXI. These indirect costs were determined by applying a factor of 0.90 to the direct installation labor costs. The sum of direct and indirect field labor costs represents the total site labor for the equipment being installed.

TABLE XXI

INDIRECT COSTS

- Craft support labor, i.e., trade craft members who serve ancillary functions not associated with the construction crews such as unloading materials from common carriers, storing and warehousing materials, cleanup and classification.
- Non-craft support labor: field supervisors, accountants, purchasing agents, clerks, surveyors, etc.
- Payroll taxes and insurance
- Small tools and consumables
- Equipment rentals
- Overhead and profit

Direct installation labor costs of major components were based on their estimated weights and the manhours required to assemble and set the units in place. For general equipment, 60 manhours direct labor per ton (54,431 manhours/kilogram) was assumed. When assembly line procedures were feasible — such as for the ninety-six shop-assembled fuel cell pressure vessels — a more definitive manhour estimate was made so that the average manhours per vessel became considerably lower than the 60 per ton (54,431 manhours/kilogram) basis. For some equipment, such as balance-of-plant equipment, the total site labor is based on a percentage of the overall cost of the equipment, the latter based on a specific dollars per kilowatt figure known from experience for similar equipment. The percentage varies from 60% material — 40% labor for shop assembled packages to 40% material — 60% labor, when more field work is required. Site labor is taken at a composite rate of $11.75 per hour in accordance with NASA's guideline. This is the direct labor rate which includes fringe benefits, such as personnel health and welfare, vacation, apprentice training and industry advancement fund. It is assumed that labor productivity is in the middle of the range of productivities in the U.S.

A&E services and contingency were estimated by Burns and Roe as percentage factors. The percentages for both factors varied by type of direct cost as shown in Table XXII. The contingency estimate is based on the assumption that the design represents a mature powerplant and that several plants of this type have been constructed providing an historical cost base.

TABLE XXII

FACTORS FOR A & E SERVICES AND CONTINGENCY AS A FUNCTION OF MATERIAL AND SITE LABOR COSTS

	MATERIALS — DIRECT COSTS		SITE-LABOR
	MAJOR COMPONENTS	BALANCE-OF-PLANT	(DIRECT PLUS INDIRECT COSTS
	1.0	1.0	1.0
A & E SERVICES	x 0.10	x 0.15	x 0.10
CONTINGENCY	x 0.075	x 0.10	x 0.20
CUMULATIVE TOTALS	1.1825	1.265	1.32

Escalation and interest during construction depend on the lead time for powerplant design and construction. The lead time for this plant has been estimated at 5 years, beginning with initiation of the final design. About one year will be required for site surveys, environmental investigations and reports, permit acquisitions and pre-detailed engineering studies. During this period, engineering on some major and long-delivery items of equipment will be initiated and issued for bidding and soil borings, testing and preliminary construction work will be started. Site preparation will start after receipt of all permits and approvals from regulatory agencies which should be received about 12 months after initiation of the project. Orders for long delivery items such as the steam turbine generator, structural steel, gasifiers, and main transformers will be placed during the latter part of this period. The critical item for plant completion is the steam turbine generator. Deliveries of steam turbines and generators are presently 2 1/2 to 3 years after release of engineering and require six to nine months to complete installation. Other major items such as fuel cell pressure vessels, turbocompressors, gasifiers, coal handling equipment, and special piping and valves do not appear to be on the critical path for plant completion at this time, but will require consideration in planning to avoid construction delays. With allowance for checkout and testing prior to the start of commercial operation, a five year construction period is feasible.

The factors provided by NASA for escalation and interest during construction as a function of plant lead time are shown in Appendix I.' Escalation is assumed to be 6.5 percent per year, and interest is taken as 10 percent on the escalated amounts. With a 5-year design and construction time, these combined costs are 48.7 percent of the sum of direct, plus indirect, plus A and E services and contingency costs.

In keeping with NASA instructions, direct and indirect costs for major equipment, balance-of-plant materials, and installation labor were reported in five major areas: (1) Land, improvements and structures; (2) Fuel handling and processing; (3) Fuel cell system; (4) Steam bottoming cycle; and (5) electrical plant equipment. A and E services, contingency, escalation and interest during construction were then added to these direct costs to obtain total plant cost. Table XXIII summarizes plant capital cost. Total cost is $595/kW with the fuel cell system and fuel handling and processing representing the highest cost areas.

TABLE XXIII
PLANT CAPITAL COST ESTIMATE SUMMARY
(635 MW PLANT)

	MATERIALS			TOTAL	
	MAJOR COMMENTS (MM $'s)	BALANCE OF PLANT (MM $'s)	SITE LABOR (DIRECT & INDIRECT) (MM $'s)	(MM $'s)	$/KW
LAND, IMPROVEMENTS & STRUCTURES	1.5	15.3	14.0	30.8	48.5
COAL HANDLING, GASIFICATION, GAS CLEANUP & ASH HANDLING	17.1	12.1	20 8	50	78.7
FUEL CELL SYSTEM EQUIPMENT	41.7	10.8	6 9	59.4	93 5
STEAM PLANT BOTTOMING CYCLE EQUIPMENT	16.7	4.0	10.8	31-5	49.6
ELECTRICAL PLANT EQUIPMENT	18.4	5.3	9 0	32.7	51-5
SUBTOTALS	95 4	47 5	61.5	204	322
A&E SERVICES & CONTINGENCY	17.4	12.6	19.6	50	78
ESCALATION & INTEREST DURING CONSTRUCTION	(@ 48 7%)			124	195
TOTAL DOLLARS				378	595

2. Capital Cost Breakdown

This section summarizes the installed cost breakdown for each of the five major areas. These are total direct and indirect installed cost numbers, and do not include A and E services, contingency, escalation and interest during construction. Appendix VII defines items included in each cost area.

Land, Improvements and Structures

Table XXIV summarizes the costs of land, improvements, structures and miscellaneous powerplant equipment which were estimated by Burns and Roe. The cost of land is taken as $2,500 per acre ($0.618/meter^2) and the estimate of cost includes all surveys, test borings, and necessary permits.

The other specific items that contribute the major portion of the remaining costs under the category of major equipment are the station buildings and cranes for the fuel cell and steam turbine islands, the exhaust and flare stacks, and the auxiliary plant boilers.

Under balance-of-plant equipment, the major costs are associated with the civil work necessary for the fuel cell and steam turbine islands and inter-island piping. The cost of the main interconnecting piping system between the islands was based on estimating the total lengths and applying the industry experience in cost per foot for the size, schedule and material of the piping. An allowance for bends and fittings and expansion loops was made based on experience. Installation represents the major portion of the total costs in this cost area. As in the balance of plant equipment, the major installation items are associated with the civil works in the fuel cell and steam turbine islands and the inter-island piping. Total installed costs for this entire category are estimated to be 31×10^6 or $48/kW.

TABLE XXIV
COST SUMMARY – LAND, IMPROVEMENTS, STRUCTURES, AND MISCELLANEOUS POWERPLANT EQUIPMENT

(635 MW PLANT)

COMPONENT	COMPONENT OR SUBSYSTEM COSTS (FOB) 1000 $'s	BALANCE OF PLANT MATERIALS 1000 $'s	SITE LABOR (DIRECT & INDIRECT) 1000 $'s	TOTAL INSTALLED COST(*) 1000 $'s	TOTAL INSTALLED COST(*) $/KW
• LAND & LAND RIGHTS	308	N/A	N/A	308	0.5
• IMPROVEMENTS	N/A	450	540	990	1.6
• STRUCTURES	730	7200	8830	16,800	26.4
• MISCELLANEOUS POWERPLANT EQUIPMENT					
INTER-ISLAND PIPING	N/A	6000	4000	10,000	15.7
BALANCE	440	1600	620	2700	4.3
TOTAL	1500	15,300	14,000	30,800	48.5

(*) DOES NOT INCLUDE A&E SERVICES, CONTINGENCY, ESCALATION & IDC

Fuel Handling and Processing

Table XXV summarizes the costs associated with coal handling, gasification, gas cleanup and ash handling. The single costliest major piece of equipment, estimated at $4.9 x 10^6$, is the sulfur recovery system which accepts sulfur dioxide regenerated from the process gas cleanup system and reduces this gas to elemental sulfur for ultimate storage and removal. The cost of this system was supplied by Allied Chemical Co. from whom the process would be licensed. Other pieces of major equipment which represent substantial costs are the gasifiers and associated coal feed and the turbocompressors required to supply compressed air to the gasifiers.

IGT supplied costs for the gasifier reactor vessels, cyclone separators, coal feed bins, lock hoppers, surge hoppers, gasifier process steam generator, gas cleanup equipment and a portion of the ash removal system including ash hoppers and slurry coolers. IGT also supplied balance of plant materials and installation costs for this equipment. Most of the IGT estimates were based on detailed estimates of similar equipment made in previous studies. Costs for the lock hopper gas compressors and air compressors for the regeneration of the iron oxide beds were generated by PSD based on flow rates and head requirements supplied by IGT. The gasifier turbocompressor and auxiliary equipment costs, including the gasifier air preheater, were based on analytical techniques and historical data developed at UTRC for similar equipment. Costs for the gasifier startup burners are included in the turbocompressor system, and were estimated by PSD.

The total installed cost for the entire fuel handling and processing category was estimated at $50 x 10^6. Based on a total powerplant output of 635 MW, the specific cost totals $79/kW.

TABLE XXV
COST SUMMARY – FUEL HANDLING AND PROCESSING
(635 MW PLANT)

SUBSYSTEM	COMPONENT OR SUBSYSTEM COSTS (FOB) 1000 $'s	BALANCE OF PLANT MATERIALS 1000 $'s	SITE LABOR (DIRECT & INDIRECT) 1000 $'s	TOTAL INSTALLED COST(*) 1000 $'s	TOTAL INSTALLED COST(*) $/KW
• COAL HANDLING SYSTEM	2800	N/A	2200	5000	7.9
• COAL FEED & GASIFICATION SYSTEM	3300	3900	6900	14,100	22.2
• ASH REMOVAL SUBSYSTEM	N/A	540	1000	1500	2.4
• GASIFIER PROCESS STEAM GENERATOR	830	730	1200	2800	4.4
• PROCESS GAS CLEANUP	1700	2000	2600	6300	9.9
• SULFUR RECOVERY SYSTEM	4900	4200	6600	15,700	24.7
• SULFUR STORAGE, REMOVAL & TRANSFER	N/A	200	200	400	0.6
• GASIFIER TURBOCOMPRESSOR SUBSYSTEM (INCLUDING PREHEATER)	3600	500	100	4200	6.6
TOTAL	17,100	12,100	20,800	50,000	78.7

(*) DOES NOT INCLUDE A&E SERVICES, CONTINGENCY, ESCALATION & IDC

Fuel Cell System

The fuel cell system costs are summarized in Table XXVI. The costliest item in this system consists of the fuel cell stacks with their associated insulation and pressure vessels for encapsulation. Total installed cost for 96 modules is $\$38 \times 10^6$.

Costs for the cell components were based on PSD and vendor estimates. Specifically, costs for the cell separator plate, the molten carbonate electrolyte tile, and the anode and cathode were based on vendor quotes for large quantities of the finished products. Current collector cost was estimated by PSD based on raw material cost plus an appropriate value added for fabrication. Costs for stack assembly hardware and assembly labor were generated by PSD from raw materials costs plus a factor based on FCG-1 cost estimates.

The high temperature fuel cell stacks are thermally insulated so that the encapsulating pressure vessels can be fabricated from carbon steel. The costs of the vessels were estimated by PSD based on a recent published article (Reference 12) for similar equipment and escalated to 1975.5 dollars. The vessel costs include estimates for stack structural support members internal manifolding, piping, and electrical leads.

Reactant piping, valves, controls, and instrumentation is the second most costly category in the fuel cell system. Piping and valves must handle high temperature gases at 150 psia (1034 kilopascal). The materials used are primarily stainless steel and high alloy steel, all externally insulated to prevent excessive heat loss. Largest piping is 36 inches (91.44 centimeters) in diameter used for recycling cathode gases.

TABLE XXVI
COST SUMMARY – FUEL CELL SYSTI
(635 MW PLANT)

COMPONENT	COMPONENT OR SUBSYSTEM COSTS (FOB) 1000 $'s	BALANCE OF PLANT MATERIALS 1000 $'s	SITE LABOR (DIRECT & INDIRECT) 1000 $'s	TOTAL INSTALLED COST(*) 1000 $'s	TOTAL INSTALLED COST(*) $/KW
• FUEL CELL STACKS, WITH INSULATION	35,000	N/A	1700	38,700	60.9
• FUEL CELL VESSELS	2000	N/A			
• BURNERS & AUX. STARTUP BURNERS	590	N/A	90	680	1.1
• PIPING, VALVES, CONTROLS & INSTRUMENTATION	N/A	10,300	5000	15,000	24.1
• FUEL CELL TURBOCOMPRESSOR SUBSYSTEM	4100	540	60	4700	7 4
TOTAL	41,700	10,800	6900	59,400	93.5

(*) DOES NOT INCLUDE A&E SERVICES, CONTINGENCY, ESCALATION & IDC

Installation costs for the fuel cell vessels and piping were estimated by Burns and Roe based on costs for installing similar equipment. These costs were adjusted lower to account for the large number of identical items to be installed at the ICG/FCP.

Several burners are used in the fuel cell system for startup and normal operation. The primary burner costs, however, are associated with the catalytic burners that are used to oxidize the residual combustible gases leaving the anode compartment of the cells. These burners contain small quantities of platinum and rhodium which promote the oxidation reaction at low temperature. Cost data for the conventional burners were generated from PSD experience. Data for the catalytic burners were generated in conjunction with a vendor involved with similar catalytic burner equipment.

The fuel cell turbocompressor and auxiliary equipment costs, including the cathode recycle compressor, were provided by UTRC. As discussed in the gasifier section, the turbocompressor costs were based on analytical techniques and historical data developed at UTRC and updated to 1975.5 dollars.

The total cost for the components within the fuel cell system, including installation, was estimated to be $\$59 \times 10^6$ or \$94/kW.

Steam Bottoming Cycle

Table XXVII itemizes the costs for the equipment associated with the steam bottoming cycle. As shown on the table, the major cost items include the heat recovery equipment, the steam turbine generator and the mechanical draft wet cooling towers.

TABLE XXVII
COST SUMMARY – STEAM PLANT BOTTOMING CYCLE
(635 MW PLANT)

COMPONENT	COMPONENT OR SUBSYSTEM COSTS (FOB) 1000 $'s	BALANCE OF PLANT MATERIALS 1000 $'s	SITE LABOR (DIRECT & INDIRECT) 1000 $'s	TOTAL INSTALLED COST(*) 1000 $'s	TOTAL INSTALLED COST(*) $/KW
• STEAM TURBINE GENERATOR	7400	N/A	1050	8450	13.3
• HEAT RECOVERY STEAM GENERATOR	5200	N/A	5600	10,800	17 0
• CONDENSERS & ASSOCIATED EQUIPMENT	600	N/A	220	820	1 3
• BOILER FEED & CONDENSATE SYSTEMS	N/A	1240	160	1400	2 2
• PIPING, VALVES, INSULATION	N/A	2000	1400	3400	5.4
• COOLING TOWER SYSTEM	3500	790	2300	6600	10.4
TOTAL	16,700	4000	10,800	31,500	49.6

*) DOES NOT INCLUDE A&E SERVICES, CONTINGENCY, ESCALATION & IDC

The heat recovery steam generation equipment includes the steam turbine boiler-superheaters, the economizer-deaerators and the steam reheaters. Fabricated costs for the overall steam generation equipment were based on dollars per square foot of surface area for similar equipment used in combined cycle powerplants. Allowances were made for the higher hot gas side pressures required in the boiler-superheaters and steam reheaters. Referring to Table XXVII, installation costs for the heat recovery units represent about 50 percent of the total installed costs of this equipment.

Costs for the steam turbine, electrical generator, and cooling towers were supplied by UTRC based on quoted commercially available equipment and were escalated, where necessary, to represent costs for units delivered in 1975.5.

Total installed cost for the steam plant equipment was estimated to be $\$32 \times 10^6$ or \$50/kW.

Electrical Plant Equipment

The costs for the electrical plant equipment are itemized in Table XXVIII. The dc to ac inverter equipment represents approximately 63 percent of the total cost in this area. The inverter system totals 48 modules including solid-state bridges, harmonic filters, 69 kV transformers, output harmonic filters, and associated controls and cabling. The costs for the inverter equipment were based on the designs presently being developed for the FCG-1 powerplant. Cost estimates for major individual components, such as thyristors, transformers, etc., were obtained from vendors, and assembled costs for the entire system were estimated by PSD based on large production quantities using input from a number of subcontractors.

TABLE XXVIII
COST SUMMARY – ELECTRICAL PLANT EQUIPMENT
(635MW PLANT)

COMPONENT	COMPONENT OR SUBSYSTEM COSTS (FOB) 1000 $'s	BALANCE OF PLANT MATERIALS 1000 $'s	SITE LABOR (DIRECT & INDIRECT) 1000 $'s	TOTAL INSTALLED COST(*) 1000 $'s	TOTAL INSTALLED COST(*) $/KW
• INVERTER SYSTEM	16,400	N/A	3490	19,890	31.3
• MAIN & AUX. TRANSFORMERS	1980	N/A	160	2140	3.4
• MOTOR CONTROL CENTERS & CONTROL BOARD	N/A	350	45	400	0 6
• ISOLATED PHASE BUS	N/A	250	100	350	0 5
• DIESEL GENERATOR	N/A	150	30	180	0.3
• CABLES, CONDUITS, & TRAYS	N/A	2400	2600	5000	7.9
• STEAM PLANT ACCESSORY ELECT. EQUIP	N/A	380	1400	1780	2 8
• TOTAL PLANT CONTROLS & INSTRUMENTATION	N/A	1200	900	2100	3 3
• 69 KV STRUCTURE, SWITCHGEAR, CIRCUIT BREAKERS	N/A	590	310	900	1.4
TOTAL	18,400	5300	9000	32,700	51 5

(*)DOES NOT INCLUDE A&E SERVICES, CONTINGENCY; ESCALATION & IDC

The other items contained in the electrical plant equipment are conventional and their costs, estimated by Burns & Roe and UTRC, were based on similar equipment being installed in present day powerplants.

The total installed cost of the electrical equipment was estimated at \$33 x 10^6, or \$52/kW.

E. Operating and Maintenance Costs

One of the contributing costs to the generation of electricity is associated with both the maintenance and operation of the powerplant. Table XXIX summarizes the total estimated operation and maintenance costs, broken down into material and labor fractions. The total estimated cost for operation and maintenance is 3.30 mills/kWh. The following section describes the major assumptions that were made in terms of materials and labor requirements for each of the subsystems associated with the reference powerplant.

TABLE XXIX

OPERATING AND MAINTENANCE COST ESTIMATE

ITEM	MAT. MILLS KW-HR	LABOR MILLS KW-HR	TOTAL MILLS KW-HR
COAL GASIFICATION AND DESULFURIZATION	0.34	0.67	1.01
COAL AND ASH HANDLING EQUIPMENT	0.08	0.09	0.17
FUEL CELL STACKS	1.20	0.09	1.29
CATALYTIC BURNER	0.09	–	0.09
TURBOCOMPRESSORS	0.22	0.01	0.23
STEAM PLT.	0.07	0.20	0.27
B.O.P.	0.14	0.10	0.24
TOTAL	2.14	1.16	3.30

Of the equipment designed by IGT which includes the coal gasifiers and associated feed system, the gas purification equipment and the gasifier process steam generator, there is a yearly estimate for maintenance materials and labor of \$2.07 x 10^6. In addition, there is a requirement for catalyst and chemicals, which includes replacement of the iron oxide beds every three years, of \$195,300 per year. Manpower estimates for operation of the gasification and purification equipment are 14 operators per shift. The total operation and maintenance cost for this equipment operating at a 0.65 capacity factor was calculated at 1.01 mills/kWh. Of the remaining coal and ash handling equipment designed by Burns and Roe, the estimated yearly operating and maintenance cost was \$0.61 x 10^6 or 0.17 mills/kWh.

As discussed in Section III D, the fuel cell modules are assumed to have a useful life of 40,000 operating hours. After this period, each fuel cell vessel will be removed and replaced with a unit containing new fuel cell stacks. The total capital cost for this equipment replacement is estimated at $35 x 10^6. In addition, a cost of $50,000 per vessel was estimated by Burns and Roe to be required for removal of the old and re-installation of the new equipment, totaling about $5 x 10^6 for all 96 fuel cell vessels. Thus the total estimated maintenance cost for fuel cell replacement is 1.2 mills/kWh.

Operating labor requirements for the fuel cell subsystem are estimated at 3 men per shift. If the labor rate specified by NASA for construction labor is assumed applicable to operating labor, an additional yearly cost of $0.31 x 10^6 or 0.09 mills/kWh is added.

The catalytic burners, which oxidize combustible gases vented from the fuel cell anodes, contain catalyst materials which are estimated to require replacement after 2 years of operation. Cost for this catalytic material replacement plus labor requirements was estimated at 0.09 mills/kWh.

Turbocompressors are required to supply pressurized air to both the gasifier and fuel cell subsystems and are also used to recirculate the cathode stream. Each of the four independent gasifier-fuel cell modules contain separate turbocompressor units. The turbocompressors operate at relatively low temperatures and are not required to have high efficiencies. Based on historical data, the estimated yearly maintenance and replacement materials and labor costs for this equipment were determined to be $0.81 x 10^6 or 0.23 mills/kWh.

Operation and maintenance costs of 0.27 mills/kWh for the steam bottoming cycle components were estimated from published data for oil fired steam plants. These values were scaled to account for the fact that the percentage of power generated by the steam plant in the conceptual design represents only 35 percent of the total plant output. This estimate is conservative since the heat transfer equipment associated with the steam plant should require less maintenance than the fired boiler units associated with a conventional plant. The operation and maintenance costs for the remaining balance of plant components amounted to $0.87 x 10^6 per year or 0.24 mills/kWh. Factors for determining these values were supplied by Burns and Roe. Eighty percent of this cost was maintenance associated with the electrical subsystem.

It is anticipated that maintenance procedures requiring teardown and/or periodic replacement in the gasifier, gas clean-up, or fuel cell strings will be performed with that string shut down. Therefore, redundant isolation valves within the independent strings for maintenance worker protection are not necessary and have not been included in powerplant design or cost.

F. Cost of Electricity

The cost of electricity for the integrated coal gasifier-molten carbonate fuel cell powerplant in terms of mills/kWh is shown in Table XXX. The cost is comprised of three basic components: the capital charge, the fuel charge, and the operating and maintenance charge.

The capital charge is the yearly owning cost based on a factor of 18 percent per annum (specified by NASA) applied to the capital cost. This factor includes allowances for amortization, depreciation, interest, insurance and taxes. The fuel charges are based on the design efficiency and the cost of coal, taken as $1/10^6$ Btu. The operating and maintenance costs were described in the section above. Total estimated cost of electricity is 29.0 mills/kWh. Approximately 65 percent of this cost is attributable to capital.

TABLE XXX
POWERPLANT ECONOMIC SUMMARY

• PLANT CAPITAL COST	378 MM$
• PLANT CAPITAL COST	595 $/KW$_e$
• COST OF ELECTRICITY (WITH CAPACITY FACTOR = .65)	
• CAPITAL	18.8 MILLS/KW-HR
• FUEL (AT $1/10^6$ BTU COAL)	6.9 MILLS/KW-HR
• MAINTENANCE & OPERATING	3.3 MILLS/KW-HR
TOTAL	29.0 MILLS/KW-HR
• ESTIMATED TIME OF CONSTRUCTION	5 YEARS[1]
• ESTIMATED DATE OF FIRST COMMERCIAL SERVICE	1985 - 1990

(1) BEGINNING WITH INITIATION OF FINAL DESIGN AND APPROVAL PROCESS - END WITH COMMERCIAL OPERATION

Table XXXI shows the effect on cost of electricity of an arbitrary increase in material or labor charges of 20 percent. An increase in either area results in a rise in electric costs; however, higher materials charges have a more pronounced effect, resulting in a 10 percent increase in total electric costs.

For the purposes of comparison, the cost of electricity as a function of coal price and.plant capacity factor are shown in Table XXXI and in Figures 26 and 27. Because of the high efficiency of the conceptual design, the cost of electricity is relatively insensitive to the price of fuel. The sensitivity of the electric cost to capacity factor is more pronounced due to the relatively large contribution of capital to total owning and operating costs.

TABLE XXXI
COST OF ELECTRICITY SENSITIVITY STUDY
(MILLS/KW-HR)

	BASE CAPACITY FACTOR	BASE CAPACITY CHANGE		FUEL COST INCREASE	MATERIALS INCREASE	LABOR INCREASE
	0 65	0 50	0 8	50%	20%	20%
COE, CAPITAL	18.8	24.5	15.3	18.8	21.4	20.0
COE, FUEL	6.9	6 9	6.9	10.3	6.9	6.9
COE, O&M	3.3	3 7	3.1	3 3	3 7	3.5
TOTAL COE	29.0	35.1	25.3	32.4	32.0	30.4
RELATIVE COE	1.0	1.21	0.87	1.12	1.10	1.05

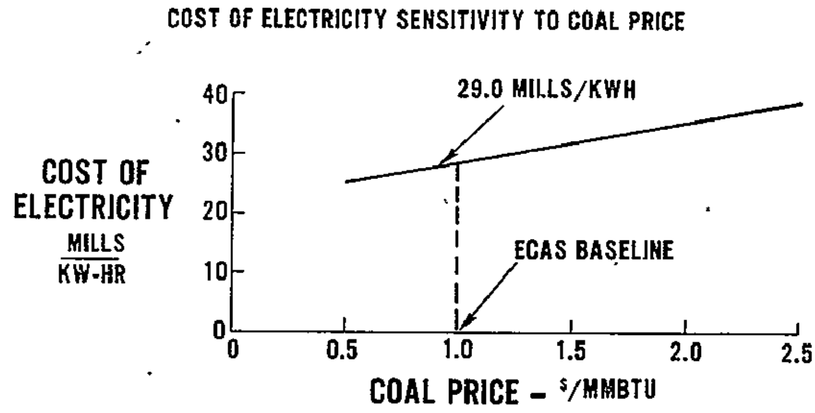


Figure 26 — Cost of Electricity Sensitivity to Study Assumptions

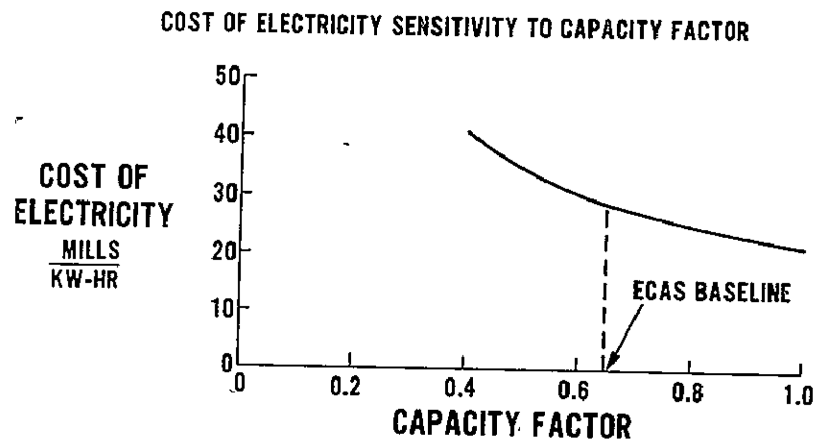


Figure 27 — Cost of Electricity Sensitivity to Study Assumptions

V TECHNOLOGY AND DESIGN STATUS

The conceptual design described in Section III made certain assumptions regarding molten carbonate fuel cell technology and gasifier/gas cleanup technology. The conceptual design system thermodynamic configuration was selected based on preliminary tradeoff studies. Component ratings and configurations were established to fulfill the objective of maximum factory fabrication. This section describes the fuel cell technology and design status and identifies the critical technology issues which form the basis for the Research Development and Demonstration Plan presented in Section VI. The gasifier/gas cleanup technology status is described briefly in Section III C, Gasification and Cleanup System Description.

A. Technology Status

Table XXXII summarizes the critical assumptions used in preparing the conceptual design. The differences between these design assumptions and the present technology status would impact powerplant design and cost but would have only a minor effect on efficiency. A discussion of each assumption and the tests required to verify the assumption follows.

TABLE XXXII
FUEL CELL DESIGN ASSUMPTIONS

	DESIGN ASSUMPTION
• CELL PERFORMANCE (WATTS/FT^2 AT AT 0.85 VOLTS/CELL)	127
• CELL ENDURANCE (HOURS)	40,000
• CELL PRESSURE (PSIA)	150
• CELL TOLERANCE TO H_2S (PPM)	200
• SCALE	4.5 MW

OTHER DESIGN ASSUMPTIONS

- PARTICULATE MATTER IN GASIFIER EXHAUST ASSUMED TO BE TRAPPED IN IRON OXIDE BEDS THEN BURNED OFF OR BLOWN OFF DURING REGENERATION
- FUEL CELL TOLERATES ANY TRACE ELEMENTS CARRIED FROM GASIFIER AND THROUGH GAS CLEAN UP SYSTEM

Based on ambient pressure experimental data, estimated present molten carbonate fuel cell power density at 150 psia (1034 kilopascal) is 85 watts/ft^2, or 67 percent of the power density assumed in the conceptual design. The performance used for the conceptual design is based on projections made using an analytical cell model. The projections are based on the predicted effects of cell structural improvements which are being investigated under the Electric Power Research Institute Research Project 114. After these improvements have been accomplished, verification of cell performance should be obtained in a test of a small research cell operating at the conceptual design conditions.

The conceptual design assumed cell endurance of 40,000 hours. The compatibility of major cell materials has been verified in 40,000-hour tests of early laboratory cells. Present research cells in the same configuration and at the same temperature as the conceptual design have now operated for over 6000 hours, with the test continuing at this writing. The present endurance limitation of the molten carbonate fuel cell is associated with electrolyte losses. An electrolyte management approach with potential for 40,000-hour operation has been identified and testing of that approach is now underway in EPRI Research Project RP114 (Reference 14). Verification of satisfactory endurance can be accomplished in tests of small research cells.

The conceptual design assumed fuel cell operation at 150 psia (1034 kilopascal). Present experimental experience is at 15 psia (103 kilopascal). Since the conceptual design encapsulates the cell stack in a pressure vessel, the pressure differential between the cell and its environment is the same as in the present experimental program. Consequently, operation at pressure is expected to be a straightforward mechanical design issue. Cell design changes may be required to achieve maximum performance at 150 psia (1034 kilopascal). Verification of satisfactory operation at pressure can be accomplished initially in tests of research cells and then in tests of a 20-cell stack.

As Table XXXII indicates, the conceptual design assumes a cell tolerance to 200 ppm hydrogen sulfide in the fuel gas. Present experimental data indicates that at these sulfur levels, fuel cell performance is adversely affected. Alternative anode materials or structures with potential for improved sulfur tolerance should be further investigated and improved sulfur tolerance verified in tests of small research cells. If improved sulfur tolerance cannot be achieved, alternative gas cleanup approaches would be required. Preliminary evaluations indicate that powerplant cost or efficiency penalties with these alternatives would be small (see pages 35, 118).

The conceptual design assumed a 4.7 MW dc module; this is approximately the same size as the dc module for the FCG-1 fuel cell powerplant which uses a phosphoric acid fuel cell. A program is underway with ERDA and EPRI to demonstrate the FCG-1 dc and inverter modules, and a 1-MW pilot plant is scheduled for test in 1977. The largest scale molten carbonate demonstration accomplished to date is a 19-cell stack of 1 square foot (929 cm^2) cells. Experience in other fuel cell programs at United indicates that scale up from this level is a straight forward engineering development problem. Verification of full-scale hardware can be accomplished in laboratory tests of complete cell stacks at simulated powerplant conditions and ultimately in a test of a complete dc module with a 5 ton per hour (1.26 kilograms/second) pilot gasifier.

Another assumption for the conceptual design is that particulate matter in the gasifier exhaust is trapped in the iron oxide beds and carried off during regeneration. This assumption should be verified in tests of the iron oxide sulfur removal process at ERDA's Morgantown Energy Research Center.

Finally, the conceptual design assumed that the fuel cell will tolerate any trace elements carried from the gasifier and through the gas clean up system. This assumption should be verified in tests of research cells with pilot gasifiers.

B. Design Status

The integrated coal gasifier fuel cell powerplant conceptual design prepared in this effort was the initial design of this type of powerplant. Accordingly, tradeoffs and analysis detail were limited by funding and time. Table XXXIII lists several design choices in which further study is needed to ensure that the best powerplant configuration is defined. Some of these choices will be influenced by resolution of the technology issues discussed in the preceeding section.

TABLE XXXIII
DESIGN CHOICES REQUIRING FURTHER STUDY

- OPTIMUM SYSTEM PRESSURE
- GASIFIER TYPE
- GAS CLEAN UP
- OFF DESIGN OPERATION
- FUEL CELL MODULE DESIGN AND RATING
- FUEL CELL ISLAND RATING TO BE COMPATIBLE WITH EXISTING TURBOMACHINERY
- PLANT ARRANGEMENT

Optimum system pressure was defined for this study largely on the basis of fuel cell performance impact. A more detailed study should be conducted which includes the impact on the cost of the coal gasifier, clean up systems, and system piping.

Initial analysis indicated that any advanced gasifier – fluidized bed, entrained flow, or molten salt – would produce similar system thermodynamics. A more detailed analysis should be conducted to determine whether other issues would favor one advanced gasifier and a gasifier type should be selected on that basis. ERDA gasification programs should also be considered in making this selection. Analysis of gasifier alternatives should also consider the merits of oxygen versus air blown gasifiers in greater detail than was possible in this study.

System control functions were provided in the conceptual design but a detailed control design was not prepared and no transient analysis was performed. This analysis should be conducted and off-design performance should be defined.

The fuel cell module configuration and rating was selected on the basis of ability to fabricate the module in a factory and transport it by rail to the plant site. Alternative configurations and ratings should be evaluated to ensure selection of a configuration which minimizes plant construction, piping, and maintenance costs. This evaluation should also include consideration of the rating of a fuel cell island which permits use of existing turbomachinery. Finally, the general plant arrangement should be evaluated to determine the arrangement resulting in lowest plant capital cost and land requirements.

VI RESEARCH, DEVELOPMENT AND DEMONSTRATION PLAN

A plan has been established to resolve the technical issues defined in Section V, to select the best design configuration, to demonstrate the characteristics of integrated coal gasifier/fuel cell powerplants in a utility system, and to commercialize this powerplant concept. This section describes the strategy and assumptions on which the plan is based, the overall plan, more detailed plans for all phases leading up to commercialization, and a preliminary estimate of the overall program cost.

A. Program Strategy and Assumptions

Fuel cell powerplants are modular at many levels. A complete fuel cell powerplant includes a number of dc modules. Each module consists of a number of cell stacks and each stack is made up of several hundred identical cells. Testing of small 4 inch by 4 inch (10.2 cm by 10.2 cm) molten carbonate cells and a 19 cell stack of 1 square foot (929 cm^2) molten carbonate cells has shown that performance in large stacks can be scaled directly from the performance of research cells. This experience verifies earlier scaleup experience with phosphoric acid cells where the performance of 2 inch by 2 inch (5.08 cm by 5.08 cm) research cells is used to predict the performance of a stack of several hundred 3 square foot (2790 cm^2) cells.

As indicated in Section V, the modular nature of fuel cell powerplants allows resolution of technology issues in small scale hardware, and the program plan has been designed to take advantage of this characteristic. This helps minimize program cost and time requirements.

The program plan builds on other efforts. An effort presently underway in EPRI Research Project 114 is focused on developing the basic performance, hardware cost, and endurance of the molten carbonate fuel cell. It is assumed that this program will be followed by an effort to develop and demonstrate a dispersed powerplant based on the molten carbonate fuel cell. The program also assumes that a low Btu gasifier process development unit with a 1000 lb/hour (126 grams/second) coal feed rate is available by 1977, that a pressurized, 5 ton per hour (1.26 kilograms/second) low Btu gasifier pilot plant is available by 1979 and that a low Btu gasifier demonstration plant is in service prior to 1983. The development and demonstration of a gasifier and gas clean-up system suitable for the plant is assumed to be carried out and funded in a separate ERDA effort. No plans or costs for these efforts are included herein. It should be noted that it may be possible to reduce program schedule and/or cost by using the alternative design described in Appendix II for demonstration. This possibility should be considered in Phase I as discussed below. The plan presented herein is based on demonstration with the 635 MW conceptual design.

B. Overall Program Plan

The overall program provides a commercial powerplant specification and design, and a demonstration of a 635 MW integrated coal gasifier/molten carbonate fuel cell powerplant.

A logic diagram showing the means by which requirements of the program are satisfied is shown in Figure 28. A utility expansion model is utilized to define requirements for the powerplant. A reference design is prepared to guide technology development. As indicated above, confirmation of component technology is accomplished in tests of subscale hardware with a process development unit or pilot gasifier. Testing of a complete dc module with a 5 ton per hour (1.26 kilograms/second) pilot gasifier confirms function, scaleup to full-size hardware elements and the ability to meet efficiency goals. The satisfactory operation of the commercial powerplant design and the ability to satisfy the commercial powerplant specification is demonstrated in a 635 MW demonstration plant. Commercial plant designs are prepared concurrently with the demonstration plant and operation of a commercial plant demonstrates commercialization of the technology. The R&D&D plan estimated cost, however, stops at start of construction of the commercial plant — no costs are included for construction or operation of the first commercial plant.

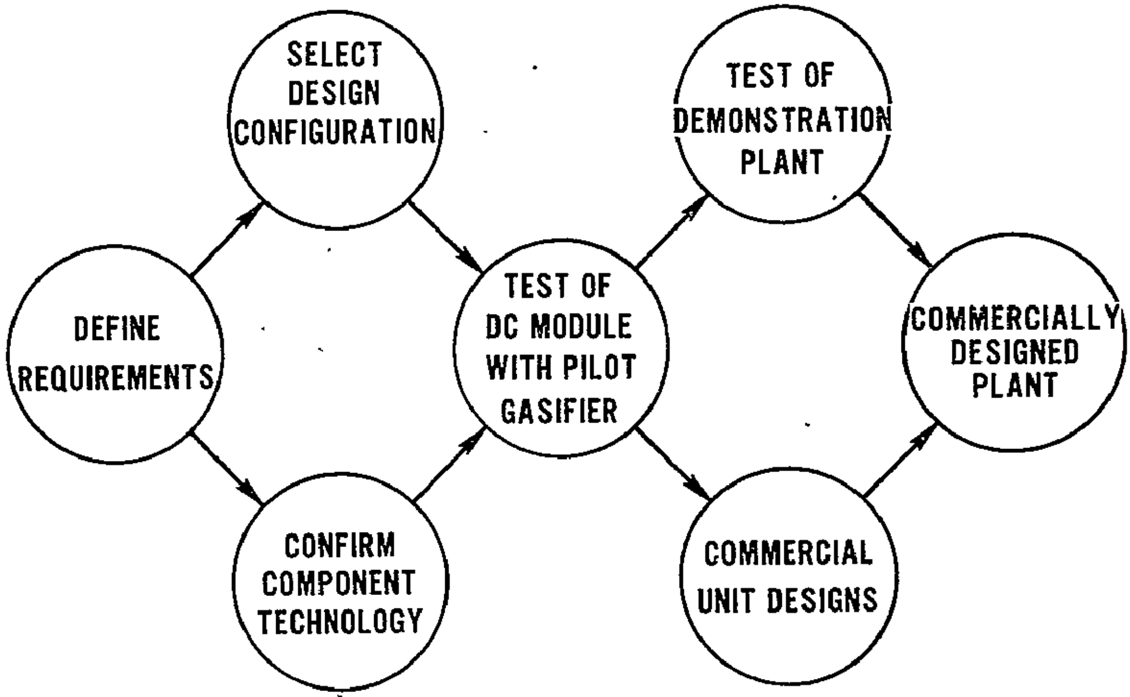


Figure 28 — Program Logic

Figure 29 summarizes the major program milestones. As shown, the commercial powerplant specification is demonstrated 9 years after program start and a commercially-designed plant could be on line in early 1989, 12 years after program start. Some improvement to this schedule would be possible with an increased funding rate and with acceptance of a higher program risk. A shorter program schedule would require more overlap between program phases. A shorter program schedule in which a commercial plant is on line 1 to 2 years earlier is possible if the demonstration powerplant and/or the first commercial powerplant uses the alternative design (see Appendix 11).

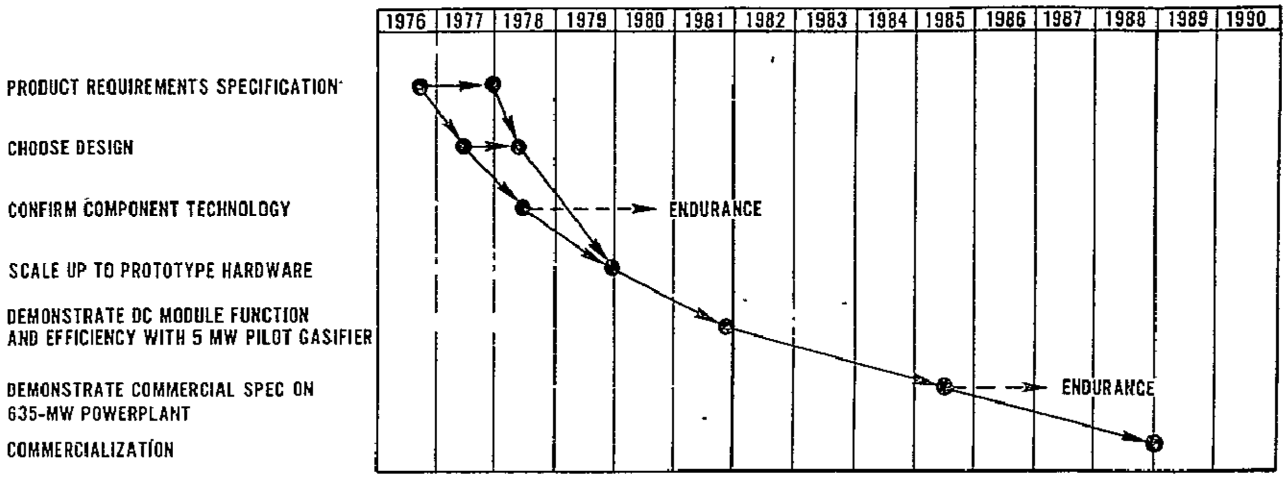


Figure 29 — Program Milestone Summary

Figure 30 shows the overall Research Development and Demonstration Plan. This figure also indicate assumed dates for availability of experimental gasifiers. The program consists of five-phases. Phase I is a 2 year effort to confirm component technology and design. Phase II is a 2 year effort to scale up to prototype hardware. Phase III tests 5-MW prototype hardware with a pilot gasifier. Demonstration of full scale equipment in a 635 MW plant occurs in Phase IV. Finally in Phase V, schedules for construction and operation of a commercially-designed plant are shown for information. Costs for this Phase are not included in the overall R&D&D cost estimate.

Significant program dates include the start of testing with a pilot gasifier at the beginning of 1980, start of construction for the demonstration plant in 1981 with the demonstration plant shakedown and testing beginning in 1984. Transfer of the demonstration powerplant to commercial operation could occur in mid-1985. Construction of the first commercially designed plant and transfer to commercial operation occurs in early 1989.

The program schedule has been designed so that significant commitments are preceeded by appropriate technology demonstrations. One example of this is that demonstration plant construction is timed to begin one year after the start of pilot plant testing and after 10,000-hour endurance on simulated gasifier products has been demonstrated in subscale hardware. The second important example is that construction of the first commercially-designed plant does not begin until completion of testing on the demonstration plant.

Discussion of Phases I through IV follows.

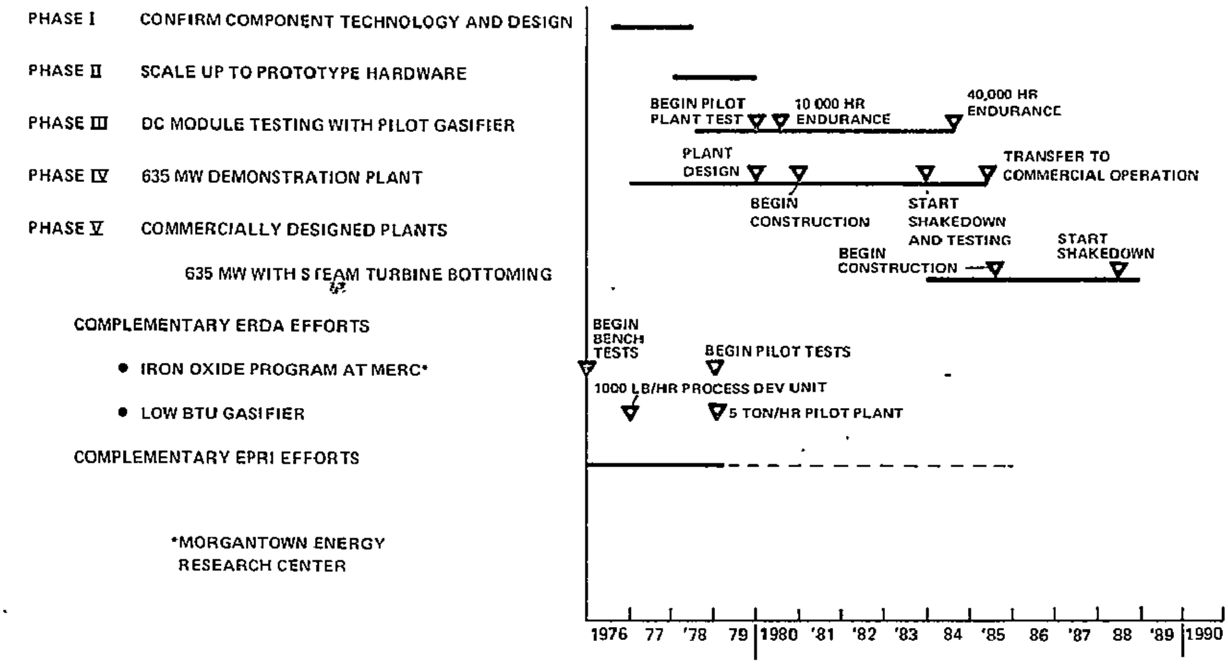


Figure 30 — Overall Research, Development and Demonstration Plan Integrated Coal Gasifier/Molten Carbonate Fuel Cell Powerplant

C. Phase I — Confirm Component Technology and Design

Phase I is a 2-year effort leading to definition of powerplant specification requirements and an initial reference design. Critical technical issues are addressed and the component technology associated with the reference design is confirmed. Finally, the research development and demonstration plan is updated in Phase I to take changes in the design and technology status into account and to prepare a more detailed plan for the remainder of the program. The Phase I program plan is shown in Figure 31.

Task 1 of the first phase defines product requirements for the integrated coal gasifier/fuel cell powerplant based on a utility system 20-year expansion analysis. The starting point for this analysis will be the design characteristics described in Section IV of this report. Variations around these characteristics will be evaluated to determine the best design point. The results of this analysis will define, among other factors, desired unit size, the capital cost vs. efficiency tradeoff, and the need for part load operation. These results will be used to guide the design effort in Task 2.

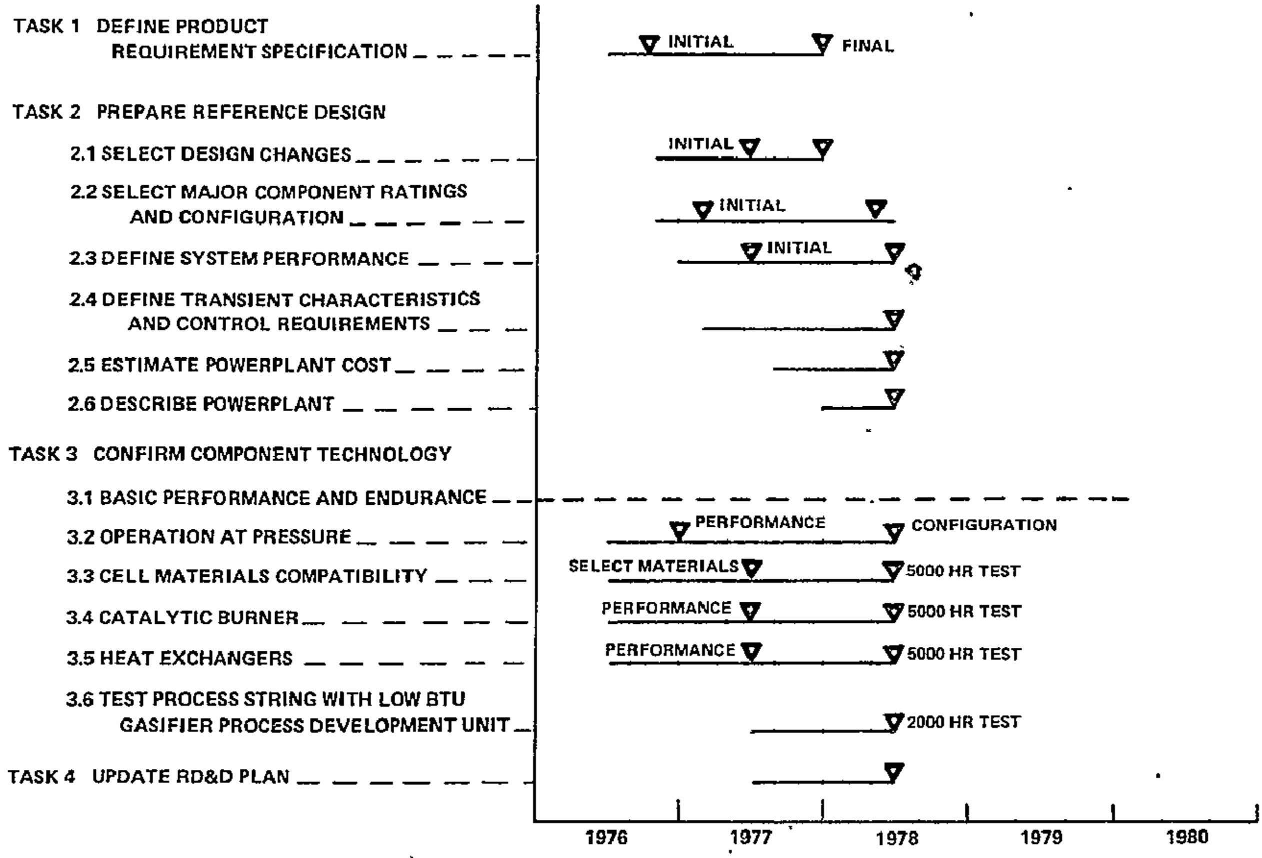


Figure 31 — Phase I Plan - Confirm Component Technology and Design

Task 2 prepares a reference design of a commercial powerplant to meet the specification established in Task 1. The first subtask selects the system thermodynamic configurations based on the choices described in Section V. These choices include type of gasifier, type of gas clean up, system pressure and oxygen vs. air blown gasifiers. The choices will be made in part on the basis of the results of experimental programs carried out in Task 3. Then component ratings and configurations are established for the major system components considering the overall plant arrangement and preliminary capital and maintenance costs (Subtask 2.2). The system performance at rated load is then estimated (Subtask 2.3). A dynamic analytical model of the system is constructed and the system transient characteristics and control requirements are defined in Subtask 2.4. In Subtask 2.5, auxiliary components are selected and a plant layout is prepared along with other drawings required for cost estimating purposes. This subtask concludes with a powerplant cost estimate. In Subtask 2.6, a written description of the powerplant and its characteristics is prepared along with a scale model of the plant. As indicated in the plan, initial definitions of the system design choices and performance estimates are prepared in mid 1977 to provide input for early planning of the demonstration plant.

Task 3 of Phase I confirms the component technology. As indicated in Section VI-A, basic performance and endurance of the molten carbonate cell is planned to be established in a separate ongoing effort funded by EPRI, but this activity is shown here as Subtask 3.1 for completeness. Performance of the molten carbonate cell at pressure is investigated in Subtask 3.2 along with the development of specific configurations for pressurized operation. Cell materials compatability and specifically the compatability of the cell with gasifier products such as hydrogen sulfide is investigated in Subtask 3.3. Development of alternate materials and configurations resulting in lower nickel consumption are also included in this Subtask. Catalytic burners and heat exchangers are evaluated in Subtasks 3.4 and 3.5. As shown in Figure 31, the fuel cell, catalytic burner, and heat exchangers are operated for 5000 hours as part of this Task. In Subtask 3.6, a complete bench scale process string — cleanup, fuel cell, catalytic burner and heat exchanger — is tested for 2000 hours with a low Btu gasifier/gas cleanup process development unit to ensure compatibility of the fuel cell power system with the gasifier. As the plan indicates, initial performance characteristics are established midway through each task to provide input to the Task 2 design effort.

The final Task in Phase I is to prepare an updated Research, Development and Demonstration Plan. This updated plan will reflect a more definitive design, a better appraisal of the technology and more detailed planning than was possible in this effort reported herein. The updated plan will consider the use of the alternative design presented in Appendix II for demonstration purposes.

D. Phase II — Scale Up to Prototype Hardware

Phase II is a two year effort which demonstrates scale up of the dc module and powerplant ancillaries unique to the fuel cell powerplant. This Phase consists of three tasks as shown in Figure 32.

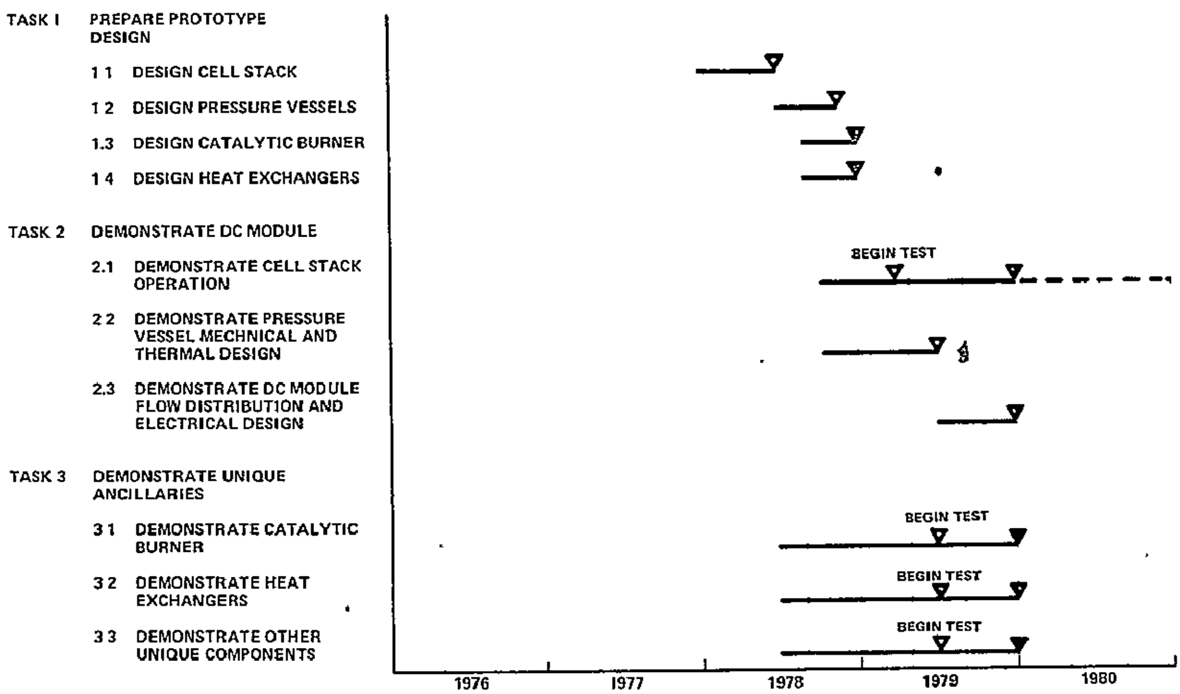


Figure 32 — Phase II Plan - Scale up to Prototype Hardware

The first Task in Phase II prepares designs of a prototype cell stack, pressure vessel, catalytic burner and heat exchangers. In Task 2, the dc module is demonstrated to the extent possible in a test facility. Initially, this testing involves tests of a complete cell stack at full power and thermal and mechanical tests of the dc module pressure vessel. Following these tests, the dc module will be assembled and flow testing will be conducted to demonstrate that internal manifolding and electrical connections are satisfactory. The dc module will then be operated at low power up to the facility limits on gas sup ply and electric power dissipation. These facility limits are expected to limit full dc module operation to about 1 megawatt or one quarter load. However, since complete stacks will have run at full power, this is considered to be an adequate test. Following completion of this testing, the dc module is readie for shipment to the pilot gasifier site where testing will proceed in the third program phase.

Task 3 in Phase II consists of full-scale tests of prototype ancillary hardware unique to the fuel cell. This hardware will include the catalytic burner and the heat exchanger equipment which removes heat from the fuel cell recycle loop. A turbocompressor and recycle pump will be selected from presently available equipment. This hardware will be sized to match, as closely as possible, the requirements of one 4.5-MW dc module. Following laboratory testing, it too will be readied for shipment to the pilot gasifier site for field testing in Phase III.

E. Phase III — DC Module Testing With Pilot Gasifier

Phase III focuses on endurance testing of subscale hardware with a pilot gasifier and on testing of a complete dc module with a pilot gasifier. As shown in Figure 33, Phase III consists of four tasks.

Tasks 1 and 2 prepare a design and test plan for a test facility incorporating a full-scale dc module and appropriately sized ancillary equipment together with a 5 ton per hour (1.26 kilograms/second) pilot gasifier. The design and test plan will take advantage of another ERDA effort to test a pilot gasifier and testing of the fuel cell module will not commence until testing of the basic gasifier is complete. It is assumed that a pilot gasifier can be made available.

In Task 3, subscale process trains consisting of fuel cells on the order of 1 ft^2 or less, catalytic burners, and heat exchangers will be tested. Initial tests will be in laboratory conditions with simulated gasifier clean-up products. Additional testing will include the process train with the gasifier process development unit (PDU) or the pilot gasifier. Since very small hardware can be used, only a small fraction of the pilot gasifier output would be required. The laboratory test with the PDU or pilot gasifier will operate for at least 10,000 hours, with a goal of 40,000 hours. Endurance testing with the gasifier will depend on whether testing with gasifier shows results different from the laboratory tests and on the cost of operating the gasifier unit.

Task 4 is the test of a facility consisting of a 5 ton per hour (1.26 kilograms/second) pilot gasifier and gas cleanup system, the 4.5 MW dc module and appropriately sized ancilliary equipment. Waste heat from the dc module will be rejected to a cooling tower via an intermediate boiler/superheater and steam loop simulating the rejection of dc module heat to the bottoming cycle. The facility will include turbocompressors to provide pressurized air to the fuel cell and gasifier. The facility will also include a dc to ac inverter identical to that to be fabricated for the 4.8 MW demonstrator under ERDA contract E(44-18)2102. In this test, full power operation will be demonstrated and measurements taken to permit projection of the efficiency of a complete powerplant. Off design operation including both normal and abnormal conditions will then be carried out to establish design data for both demonstration and commercial powerplants. It is anticipated that several dc module configurations may be tested in the process of establishing the best design for commercial use.

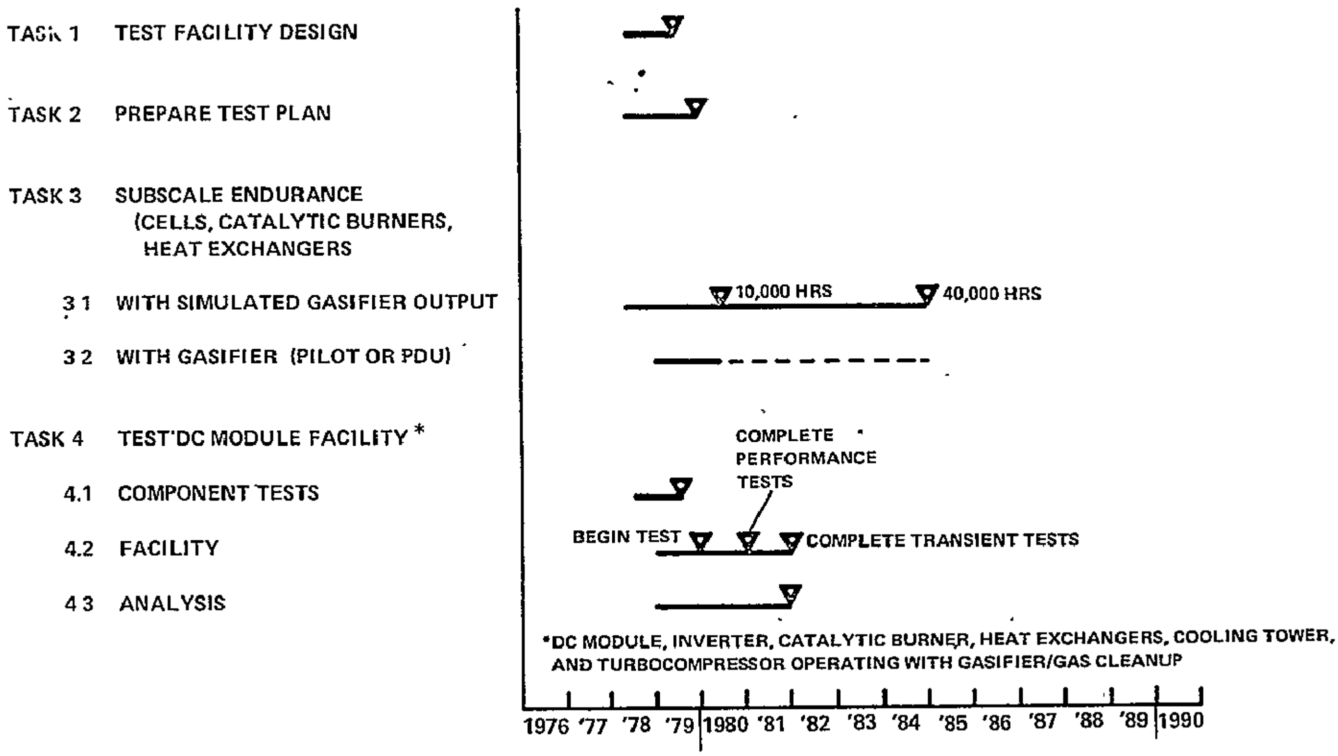


Figure 33 – Phase III Plan - DC Module Testing with Pilot Gasifier

F. Phase IV – 635-MW Demonstration Plant

Phase IV provides demonstration of a complete 635-MW powerplant which incorporates eight gasifiers, a gas clean up system, 96 fuel cell modules, turbocompressors, a steam turbine bottoming cycle and associated ancillaries. It also provides preliminary designs of two commercial plants – one incorporating a gas turbine bottoming cycle and the other incorporating a steam turbine bottoming cycle. This Phase completes the effort leading to committment to the first commercial plant. As Figure 34 shows, this Phase consists of 7 tasks.

Task 1 is associated with securing approvals for the demonstration plant. A conceptual design of the demonstration plant draws on design work in Phase I as does the preparation of an environmental impact statement. An initial demonstrator plant conceptual design and environmental impact statement are available one year after the start of the task with final versions available in two years. An activity in support of the approval process continues until final approval is obtained.

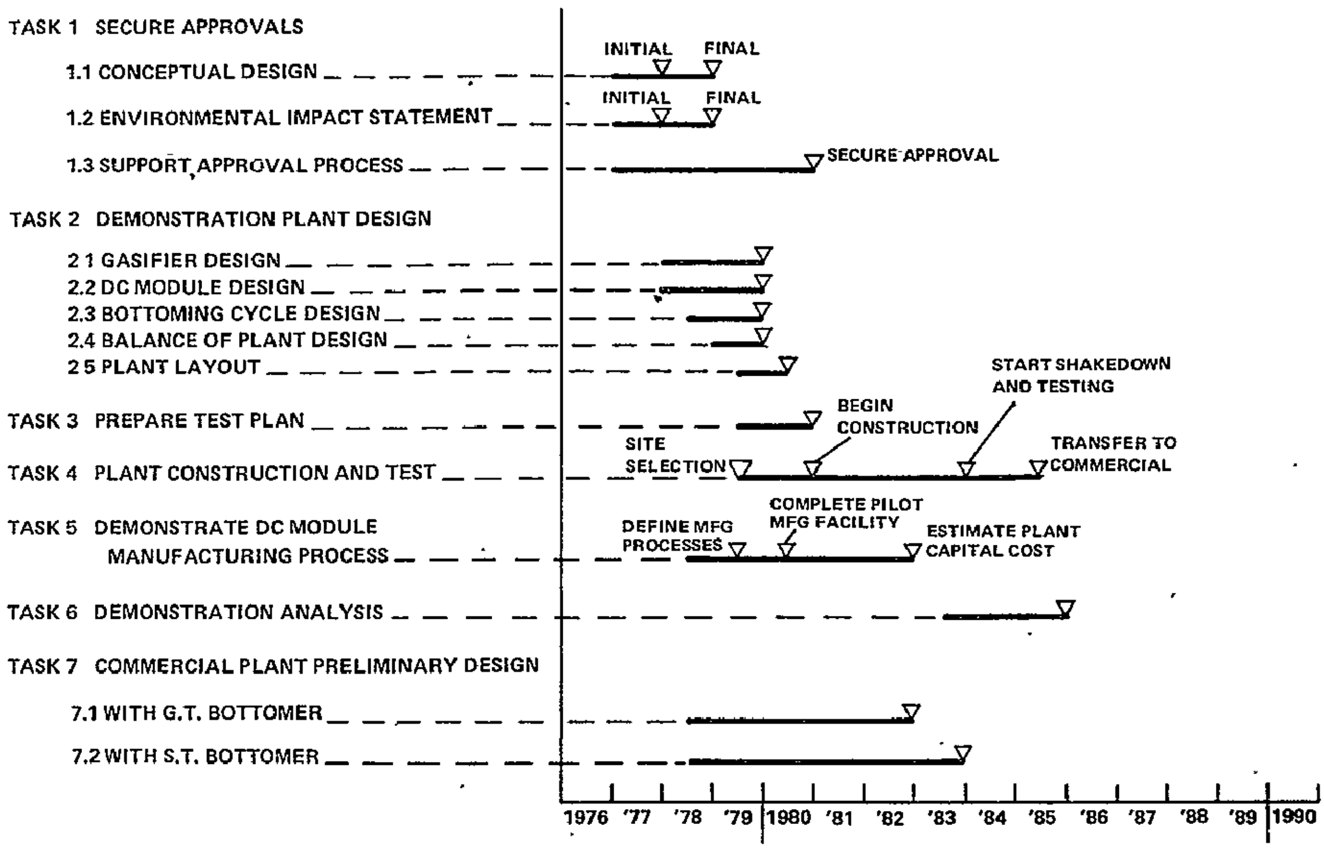


Figure 34 – Phase IV - 635-MW Demonstration Plant

Task 2 prepares a design of the demonstration plant. Major subsystems are designed first (gasifier, dc module, bottoming cycle) followed by balance of plant design and plant layout. The demonstration plant design will reflect design choices made in Phase I and will be as close as possible to commercial plant designs prepared in Task 7.

Task 3 prepares a test plan for the demonstration plant.

Demonstration plant construction and operation are carried out in Task 4. Site selection is made in mid-1979, which complements the plant layout design effort of Task 2, and permits site preparation prior to the start of plant construction in 1981. Shakedown and testing begins 6 years after the start of final design and the complete range of normal and abnormal system operation is investigated in an 18-month test period. After completion of the test plan, the demonstration plant could be transferred to commercial operation. As part of the demonstration program, the dc module manufacturing processes will be verified. This activity is carried out in Task 5 which also provides production of the 96 dc modules for the demonstration plant. An estimate of plant capital cost is made at the end of Task 5. Analysis of the results of demonstration plant testing is carried out in Task 6.

Task 7 prepares preliminary designs for two commercial plants. One plant design will have a gas turbine bottoming cycle and represents an outgrowth of the alternative design described in Appendix II. The other plant has a steam turbine bottoming cycle and is an outgrowth of the ECAS conceptual designs described in Sections II and III.

The results of the demonstration program, the results of endurance testing carried out in Phase IV, the plant capital cost estimate, and these commercial plant designs provide the basis for decisions to commit to commercial powerplants by individual utilities. If the timetable presented in this plan is followed, the first commercially-designed plant could be in operation at the beginning of 1989.

G. Estimated Program Cost

The cost of the Research, Development and Demonstration Program was estimated based on the following assumptions:

- Gasifier and gas cleanup development and demonstration, the gasifier PDU and the 5 ton/hr gasifier pilot equipment used in the program are funded separately. If a new 5 ton/hr pilot gasifier is needed for Phase III, an estimated additional cost of 15-25 million dollars would be incurred. The cost estimate presented below assumes the PDU and pilot-gasifiers are available from other ERDA programs at no cost.

- A concurrent program exists to develop dispersed generators based on the molten carbonate fuel cell.

- Costing of the demonstrator plant is based on the following assumptions:

    1. Components identical to standard commercial items (e.g., steam bottoming cycle, most balance of plant equipment) are at commercial unit cost.

    2. Components involving commercial technology but adapted to fuel cell ratings (e.g., turbocompressors) are at a cost 50 percent higher than commercial unit cost.

    3. Components employing new technology and used for the first time in the demonstration plant (e.g., fuel cell stacks, gasifier, etc.) are at a cost 100 percent higher than the estimated commercial unit cost.

    These assumptions result in material and site labor costs for the demonstration plant which are 58 percent higher than for a commercial plant.

The total estimated cost of the program without fee or profit is $715 million in 1975 dollars. The estimate is based on historical and projected data for fuel cell programs at the United Technologies Corporation, Power Systems Division and the assumptions noted. Table XXXIV shows the breakdown of program cost by Phase by year. Also included is the escalated cost by Phase. Escalated costs were computed at the rate of 6.5 percent per year, compounded annually at year end. A breakdown of program cost by Task (in 1975 dollars) is presented in Table XXXV. Figure 35 is an estimate of cumulative expenditures vs. time with and without the cost of the Phase IV 635-MW demonstration plant included.

The total estimated RD&D program cost could be significantly reduced with the use of the alternative design (Appendix II) for the demonstration powerplant. Use of the alternative design permits demonstration of all the advanced technology features of the ICG/FCP conceptual design in a complete unit of the alternative powerplant at the 145-MW level. This reduces the cost of Phase IV of the RD&D program to 202 million dollars (in 1975 dollars), which represents a savings of 440 million dollars. The total estimated RD&D program cost (without escalation) using the alternative design for the demonstration powerplant is estimated at 275 million dollars. The cost summary for this RD&D program is presented in Appendix II.

TABLE XXXIV
PROGRAM COST SUMMARY
(1975 Dollars – Millions)

	PHASE	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	TOTALS 1975 $'s	TOTALS Estimate $'s
I	Confirm Component Technology and Design	3	8	3	–	–	–	–	–	–	–	$ 14	16
II	Scale Up to Prototype Hardware	–	–	7	18	–	–	–	–	–	–	25	33
III	DC Module Testing with Pilot Gasifier	–	–	–	14	11	6	1	1	1	–	34	48
	SUBTOTAL	3	8	10	32	11	6	1	1	1	–	73	97
IV	635 MW Demonstration Plant	–	1	6	23	108	172	158	118	38	18	642	1010
	TOTAL	3	9	16	55	119	178	159	119	39	18	715	1107

TABLE XXXV
PROGRAM COST BY TASK

		TOTAL 1975 $'s (MILLIONS)	
Phase I Confirm Component Technology and Design			
Task 1	Define Product Requirement Specification	0.3	
Task 2	Prepare Reference Design	1.1	
Task 3	Confirm Component Technology	12.4	
Task 4	Update RD&D Plan	0.2	
			14
Phase II Scale-up to Prototype Hardware			
Task 1	Prepare Prototype Design	1.1	
Task 2	Demonstrate DC Module	18.7	
Task 3	Demonstrate Unique Ancilliaries	5.2	
			25
Phase III DC Module Testing with Pilot Gasifier			
Task 1	Test Facility Design	0.2	
Task 2	Purpose Test Plan	0.1	
Task 3	Subscale Testing	6.0	
Task 4	Test DC Module with Pilot Gasifier	27.7	
			34
Phase IV 635 MW Demonstration Plant			
Task 1	Secure Approval	2.5	
Task 2	Demonstration Plant Design	11.3	
Task 3	Prepare Test Plan	0.2	
Task 4	Plant Construction and Test	575.	
Task 5	Demonstrate DC Module Manufacturing Process	35.	
Task 6	Demonstration Analysis	1.0	
Task 7	Commercial Plant Preliminary Design	17.0	
			642
	TOTAL PROGRAM 1975 DOLLARS ~ MILLIONS		715

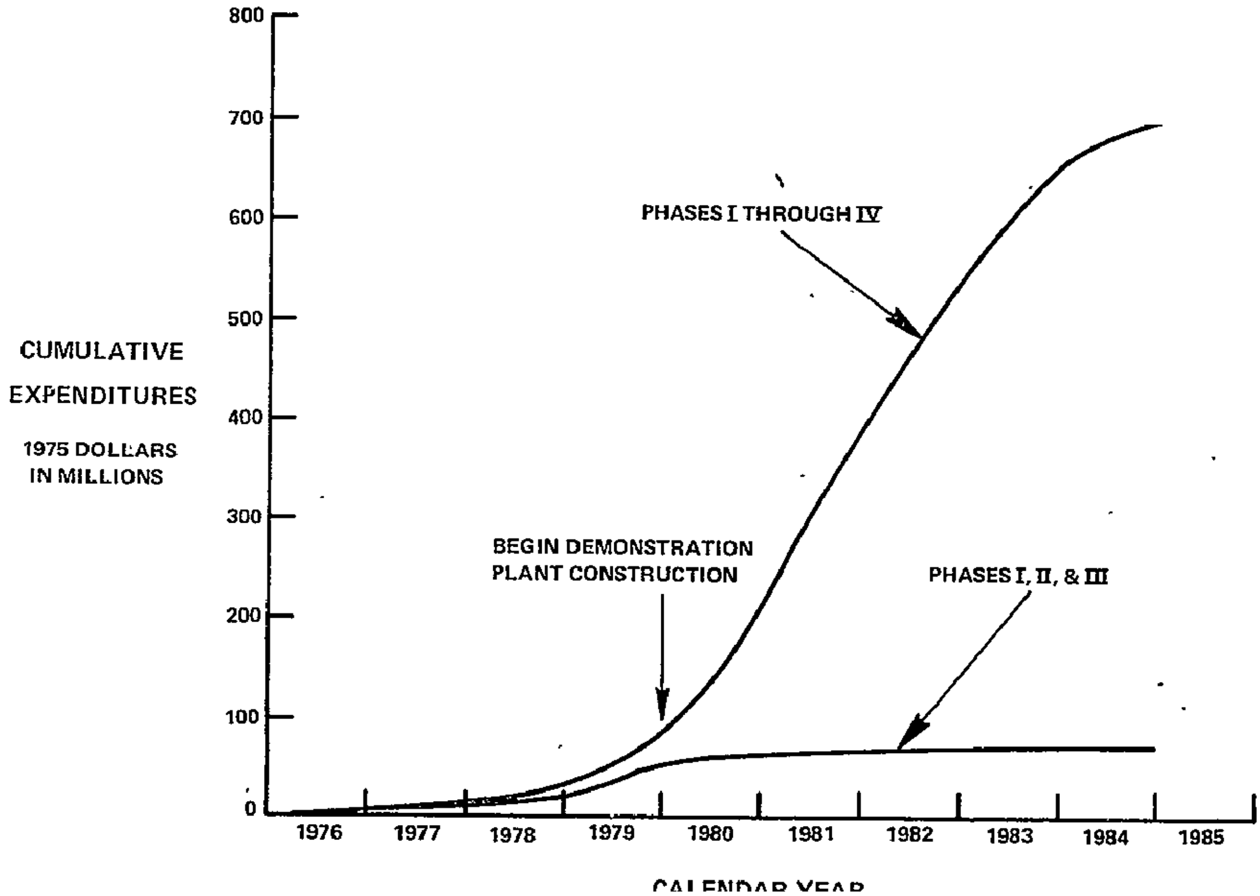


Figure 35 – Program Expenditure Pattern

VII FACTORS AFFECTING IMPLEMENTATION

The purpose of this section is to identify and evaluate those factors which could influence the development and application of the integrated coal gasifier fuel cell powerplant, ICG/FCP. This involves the assessment of a wide range of factors which have been grouped into technical considerations, electric utility application considerations, and national interest factors. A complete list of the factors considered in the assessment and the major conclusions for each item are noted in Table XXXVI. For the most part, these factors would tend to enhance the implementation of the ICG/FCP, relative to conventional equipment. The major constraints to the implementation would be the use of additional critical materials and the need to extend present technology to achieve life and cost objectives.

A. Technical Factors

This section covers the technical factors associated with the implementation of the ICG/FCP. Among the factors considered are the use of critical materials in the high technology areas, the life limiting factors in the powerplant, any unique safety requirements or considerations, and the potential for manufacturing and construction savings due to the unique features of the ICG/FCP.

1. Critical Materials

The critical materials usage requirements unique to the Integrated Coal Gasifier/Fuel Cell Powerplant (ICG/FCP) have been identified. This evaluation includes a quantitative assessment of the critical advanced technology components including the fuel cell stacks and associated pressure vessels, the inverters used to convert fuel cell dc output into ac power, and the catalytic burners required to combust the low-Btu fuel cell anode exhaust. The critical materials required for the remaining equipment in the fuel cell island, such as the turbocompressor machinery for the gasifiers and fuel cells, the heat recovery steam generation equipment, and the fuel cell island piping, are also identified. In addition, a qualitative discussion of the material requirements for other sections of the powerplant is presented with emphasis on the significant usage difference between the ICG/FCP and conventional powerplants. However, the remaining sections of this powerplant concept should have critical materials usage similar to other advanced coal powerplants.

The analysis of the conceptual design indicates that the primary critical materials requirements of the ICG/FCP are nickel, chromium, and aluminum. Molybdenum and small amounts of platinum are also required.

Nickel and stainless steel are the basic building materials of the high temperature molten carbonate fuel cell. Both fuel cell electrodes are composed of porous nickel, while fuel cell structural members such as current collectors, separator plates, and pressure plates are made of stainless steel which contains nickel. The nickel requirement, primarily in the fuel cell stacks, is 7.82 lb/kW (3.55 kilograms/kW. The stainless steel also contains chromium and molybdenum. The chromium usage is 3.76 lb/kW (1.71 kilograms/kW) of plant output and the molybdenum usage is 0.706 lb/kW (0.320 kilogram/kW).

TABLE XXXVI
IMPLEMENTATION ASSESSMENT FACTORS

FACTOR	COMPARISON OF INTEGRATED COAL GASIFIER-FUEL CELL POWERPLANT (ICG/FCP) TO CONVENTIONAL COAL FIRED STEAM PLANT	COMMENTS
TECHNICAL FACTORS		
1. – CRITICAL MATERIALS USE	(–)	• ICG/FCP WILL USE NICKEL, ALUMINUM, CHROMIUM, MOLYBDENUM AND SMALL QUANTITIES OF PLATINUM
2. – LIFE LIMITING FACTORS	(–)	• MAJOR FACTORS ARE GASIFIER LINERS AND COMPONENTS, FUEL CELL ENDURANCE, ECONOMICALLY ACCEPTABLE ENDURANCE CAN BE DEVELOPED
3. – SAFETY CONSIDERATIONS	(+)	• NO TOXIC OR HAZARDOUS MATERIALS, PLANT DESIGNED TO MINIMIZE HARARDS TO PERSONNEL
4. – POTENTIAL FOR MODULAR CONSTRUCTION	(+)	• NATURE OF FUEL CELL PERMITS FACTORY ASSEMBLY AND CHECKOUT OF MAJOR SUBSYSTEMS
ELECTRIC UTILITY APPLICATION FACTORS		
1. – MARKETABILITY	(+)	• FLEXIBILITY WITH REGARD TO SIZE, DUTY CYCLE AND FUEL CAPABILITY ENHANCES MARKETABILITY
2 – ECONOMIC VIABILITY	(+)	• ICG/FCP GENERATES POWER AT COMPETITIVE COST
3 – FUEL FLEXIBILITY	(+)	• CONFIGURATIONS AVAILABLE FOR EFFICIENT USE OF WIDE RANGE OF COAL AND LIQUID FUELS
4 – SITING	(+)	• POWERPLANT FEATURES MINIMIZE SITING RESTRICTIONS, CONFIGURATIONS AVAILABLE TO SUBSTANTIALLY REDUCE WATER REQUIREMENTS AND PLOT SIZE REQUIRED
5 – RETROFITTING OLD STEAM PLANTS	(+)	• GOOD POTENTIAL FOR RETROFITTING DUE TO HIGH TEMPERATURE HEAT SOURCE AVAILABILITY
6 – DUTY CYCLE FLEXIBILITY	(+)	• GOOD PART-LOAD EFFICIENCY CHARACTERISTICS
7. – OPERATION AND CONTROL	(–)	• COLD START-UP TIMES COMPARABLE TO CONVENTIONAL; INTEGRATED SYSTEM MORE COMPLEX THAN CONVENTIONAL; HOWEVER FUEL CELL OPERATION SIMPLE, NO SPECIAL SKILLS REQUIRED
8. – MAINTENANCE	(+)	• POWERPLANT DESIGNED FOR MAINTENANCE WITH PARTIAL POWER CAPABILITY, STATIC CONVERSION PROCESS REDUCES FAILURES, NO NEW LABOR SKILLS REQUIRED
9. – RELIABILITY AND AVAILABILITY	(+)	• MODULAR CONFIGURATION PERMITS HIGH PART POWER AVAILABILITY, STATIC CONVERSION PROCESS MINIMIZES FAILURES
NATIONAL INTEREST FACTORS		
1. – ENVIRONMENTAL INTRUSION AND CONSTRAINTS	(+)	• ICG/FCP MEETS OR BETTERS STANDARDS FOR SOLID FUELED POWERPLANTS, APPROACHES EXIST FOR ACHIEVING TARGET THREE GOALS
2. – EFFICIENCY AND FUEL CONSERVATION POTENTIAL	(+)	• HIGH EFFICIENCY MINIMIZES COAL USE; POTENTIAL FOR IMPROVEMENT WITH ADDITIONAL DEVELOPMENT
3 – NATURAL RESOURCE REQUIREMENTS	(+)	• ICG/FCP MINIMIZES USE OF LAND, WATER AND COAL

The critical material in the fuel cell dc/ac inverter is aluminum; the aluminum usage in the ICG/FCP is 2.06 lb/kW (0.934 kilogram/kW) of plant output. The fuel cell catalytic burners use trace quantities of platinum to catalyze the combustion process at the low temperatures required for the ICG/FCP design. The platinum requirements amount to 7×10^{-5} lb/kW (3.18×10^{-7} kilogram/kW).

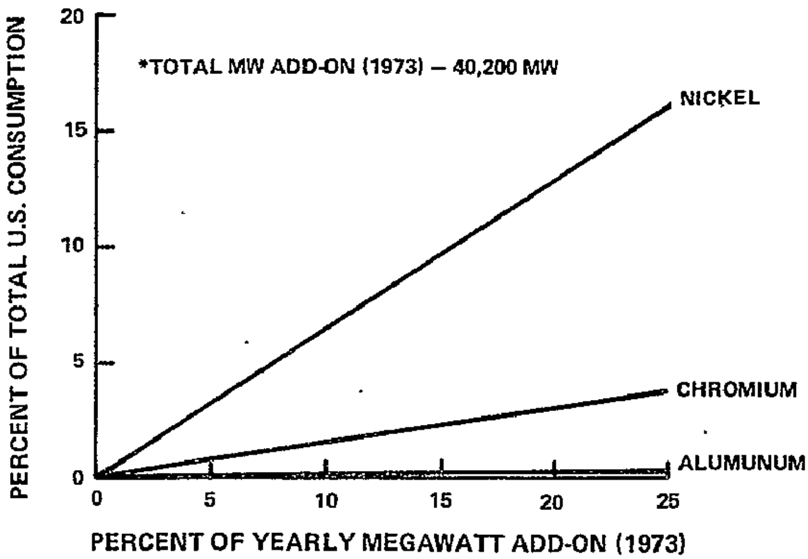
The remaining, non-advanced-technology components of the fuel cell island contain stainless steel for fuel cell piping and heat recovery steam generation equipment. The additional materials requirements are 0.702 lb/kW (0.318 kilogram/kW) of chromium, 0.448 lb/kW (0.203 kilogram/kW) of nickel, and 0.072 lb/kW (0.033 kilogram/kW) of molybdenum. The turbocompressor requires small amounts of other materials such as aluminum, cobalt, copper, manganese, and tungsten. A complete list of the critical materials usage for all components is presented in Table XXXVII.

TABLE XXXVII
CRITICAL MATERIALS

CRITICAL MATERIALS	ADVANCED TECHNOLOGY COMPONENTS OF THE ICG/FCP • FUEL CELL STACKS AND VESSELS • FUEL CELL DC/AC INVERTER • FUEL CELL CATALYTIC BURNERS		OTHER COMPONENTS • ALL TURBOCOMPRESSOR MACHINERY • ALL HEAT RECOVERY STEAM GENERATION EQUIPMENT • FUEL CELL ISLAND PIPING	
	LBS/kW	(kilograms/kW)	LBS/kW	(kilograms/kW)
ALUMINUM	2.06	0.934	0.0018	0.0008
CHROMIUM	3.76	1.71	0.702	0.318
COBALT	–		0.005	0.002
COLUMBIUM	–		NEGLIGIBLE	
COPPER	–		0.0009	0.0004
MANGANESE	–		0.001	0.0005
MERCURY	–		–	
MOLYBDENUM	0.706	0.320	0.072	0.033
NICKEL	7.82	3.55	0.448	0.203
PLATINUM	0.00007	0.00003	–	
TIN	–		NEGLIGIBLE	
TITANIUM	–		NEGLIGIBLE	
TUNGSTEN	–		0.005	0.002
VANADIUM	–		NEGLIGIBLE	
ZIRCONIUM	–		NEGLIGIBLE	

To assess the impact of the implementation of the ICG/FCP design in terms of critical materials, the usage of nickel, chromium, and aluminum in the ICG/FCP, relative to the yearly production rates of these materials, was considered.

Figure 36 illustrates the critical materials usage by the ICG/FCP relative to the annual U.S. material consumption rate. Using 1973 as a reference year, a market penetration of 25 percent of the U.S. generating capacity addition would require up to 16 percent of the total U.S. nickel consumption. This is similar to the percent total demand for the electric industry which represents 17 percent of the total nickel consumption (Reference 14). The use of chromium and aluminum is a much lower percentage of the annual consumption. The actual impact of the fuel cell would depend, of course, upon the amount of these materials used by the plants to be replaced.



*REFERENCES

1. EDISON ELECTRIC INSTITUTE STATISTICAL YEAR BOOK 1974
2. MINERALS IN THE U.S. ECONOMY; BUREAU OF MINES

Figure 36 – Critical Materials Usage Relative to Annual U.S. Consumption Rate

Several approaches can be considered to reduce the usage of critical materials in the advanced technology components. If the fuel cell performance; i.e., its power density, is increased, the nickel and chromium requirements per kW of output power are decreased due to the reduced cell area per kW of output. Modifications to the molten carbonate fuel cell design which reduce material requirements significantly are possible and should be studied. Stainless steel required for high temperature piping can be reduced if internally insulated piping is substituted for the externally insulated piping used in the conceptual design. Finally, if alternate, non-critical substitute materials can be used for fuel cell electrodes, structural members, or inverters, critical materials requirements can be alleviated.

The steam turbine bottoming cycle is a 2400 psig/1000°F/1000°F (16,600 kilopascal/811°K/811°K) system with a single reheat and without feedwater extraction. This concept is within the range of present technology steam systems and can be utilized in the ICG/FCP without introducing any increase in critical materials.

The IGT U-Gas^{TM} low-Btu coal gasifier is representative of advanced gasifier technology. Although the major material requirement for the gasifier is carbon steel, critical materials are required for its construction. The need for advanced coal gasification technology is not unique to the ICG/FCP design however, and its integration into the fuel cell system concept does not affect the gasifier design. In addition, the use of a specific advanced technology gasifier, such as the IGT U-Gas^{TM}, is not required by the fuel cell system; other advanced gasifiers could be integrated with the fuel cell system with only slight adjustment to the fuel cell system design. Because the fuel cell powerplant has high efficiency, coal processing requirements are reduced. This helps minimize gasifier materials requirements.

2. Life Limiting Factors

The life limiting factors in the ICG/FCP will be primarily in the areas of the coal gasifier and the fuel cell subsystem. The factors limiting the steam turbine and its associated equipment should be similar to those of a conventional steam plant, with the exception of the fired boiler.

Several possible areas of concern have been identified in the coal gasification subsystem. These problems will be common to all advanced systems employing a coal gasification process. The use of solids handling equipment — such as lockhoppers, conveyors, and pumps — entails the possibility of mechanical failure. These failures could constitute life limiting factors to the ICG/FCP. In addition, the refractory linings in the coal gasifiers are subject to erosion and this requires periodic maintenance of the gasifier vessels. There are also two gas to gas heat exchangers associated with the gasifier island. The tubes of both the gasifier waste heat boiler and the steam reheater are subject to fouling, slagging, and/or erosion.

Fuel cell life is expected to be 40,000 hours or more. The 40,000-hour goal has been set as a reasonable compromise between desires for longer life for economic reasons and the need to demonstrate endurance in a development program prior to commercialization. As discussed in Section V, experimental results indicate that the 40,000-hour goal will be achieved. Technology growth beyond this life is expected once commercialization is achieved. Finally, it should be noted that fuel cell performance drops gradually with time. Beyond 40,000 hours, the output power capability or efficiency will be reduced compared to design values, but the powerplant will continue to be serviceable.

3. Safety Considerations

The ICG/FCP has no unique safety problems; it does not contain toxic or radioactive materials. In addition, the powerplant design and operating philosophy have been selected to minimize the safety hazards for both operating personnel and the general public.

All pressure containment vessels and piping were designed to meet the ASME pressure vessel codes. Observance of these codes, which contain an inherent safety factor of four on the allowable stress, insures the safety of the ICG/FCP in terms of the pressure containment vessels. Additionally, the safety-considerations for high pressure operation are somewhat reduced relative to other proposed gasification processes, due to the low pressure operation of 200 psia (1380 kilopascal) for the ICG/FCP coal gasifier.

The temperature level, in both the gasification and fuel cell power conversion processes, necessitates the use of high temperature piping in the ICG/FCP. This high temperature piping is externally insulated both to reduce heat loss and for the protection of plant personnel.

The modular nature of the powerplant limits the extent of any hazardous occurrences. For example, a fire occurring in a fuel cell pressure vessel would be contained to that vessel alone, rather than affecting the entire fuel cell power section.

Operation of the prime cycle fuel cells in the ICG/FCP is to a large degree automatic. This factor limits the number of operating personnel at the powerplant site. This is, of course, desirable, especially in the event of a hazard. Fire protection equipment is provided in the ICG/FCP conceptual design and cost estimates for this equipment are included under balance-of-plant costs.

4. Potential for Factory Modular Construction

The fuel cell modules, gasifiers, desulfurizers, turbocompressors, and the steam generation equipment of the ICG/FCP were designed to be factory constructed and tested, and to be rail transportable to the plant site. This increased factory fabrication reduces the cost and time required for field construction and mass production techniques and production learning reduce component fabrication costs. Additional advantages associated with factory fabrication include the utilization of factory check-out and testing prior to field installation. This should favorably affect the reliability of the components of the ICG/FCP.

The steam turbine, which is not modular nor factory fabricated, represents the largest lead time item in the ICG/FCP; however, the overall powerplant lead time is reduced due to the factory fabrication and modularity of the rest of the powerplant. The effect of reducing the lead time is a reduction in overall system capital cost due to reduced interest during construction.

An approach which further increases the modularity of the ICG/FCP is the alternative gas turbine bottoming cycle system described in Section V. Since the steam turbine is the only major, non-modular piece of equipment in the ICG/FCP, its replacement by multiple gas turbine generators would completely modularize the powerplant. The substitution of a gas turbine bottomer could decrease overall lead time of the powerplant to four years. The reduction in field labor and interest during construction is mainly responsible for the slightly reduced capital cost of the gas turbine bottoming system.

B. Electric Utility Application Factors

This section covers those factors which would influence the implementation of the ICG/FCP from the viewpoint of the electric utility industry. These factors include those related to the integration and operation of the ICG/FCP in the utility system, those concerned with the siting of the powerplant within the systems, and those factors related to the overall costs of owning and operating the ICG/FCP.

1. Marketability

The design point of a fuel cell powerplant can be selected from a range of possibilities for any given technology status. The selection will depend on the cost efficiency trade off for the application considered. In addition, since the fuel cell itself operates on hydrogen and carbon-monoxide, any fossil fuel can be processed to a suitable fuel gas.

The basic fuel cell technology can be adapted to a variety of powerplant types operating on a wide range of fuels. In addition to the baseload steam turbine bottoming configuration of the ICG/FCP conceptual design, an alternate configuration with a gas turbine bottoming cycle can be made available.

The fuel cell shows good efficiency characteristics over a wide range of load. This enables a utility to operate the fuel cell at part power conditions with attractive operating costs. The good part-power efficiency of the fuel cell enables the utility to operate their system in the most cost effective manner. For example, the "spinning reserve" mode runs the fuel cells at low power levels where they operate efficiently and permit the other units on the line to be operated closer to their optimum efficiency. If additional power is required, the fuel cell can respond rapidly to meet the requirement. This factor, combined with the fuel cell's high availability, can serve to improve the overall system economics. Capital requirements additions to utility generating capacity also influence the marketability of powerplants. Fuel cells offer the potential for reducing the utilities' problems in this area. The modular characteristics and high availability of fuel cells tend to reduce utilities' reserve margin requirements, reducing the capital outlays for generation equipment. The modular nature of the fuel cell also permits their introduction in small blocks, comparable to annual growth increments, thus limiting capital expenditures to the minimum required. Finally, the ICG/FCP has a five year lead time (or four years if the gas turbine bottomer is used), which is equal to or better than current steam plants.

2. Economic Viability

The economic viability of a powerplant concept is dependent upon the cost of research and the development required to advance the technology, the cost of electricity from a mature powerplant, and the scope of application of powerplants incorporating the results of the technology effort.

The fuel cell independence from scale effects is an important factor in determining research and development requirements. Scale independence permits performance and life characteristics to be determined on small scale hardware. In addition, this modularity permits design and testing of the basic powerplant building block in 4.5 MWe modules rather than as a single unit of 432 MWe. This facilitates research and development scheduling and minimizes overall program costs.

The research and development costs for the coal gasifiers should be similar for all advanced power cycles incorporating advanced technology gasifiers. In addition, the ICG/FCP is not dependent on the development of a specific gasifier. Since there are no unique interface requirements between the fuel cell and gasifier, fuel cells can be integrated with all advanced-type gasifiers.

The equipment associated with the steam turbine bottoming cycle should have minimal research and development requirements, since it is presently a commercial item. The turbocompressors represent an existing technology and as such, should require no new research and development expenditures.

The goal of this ECAS study effort was to develop conceptual designs of alternate energy systems that could be ready for commercialization by the 1990 time frame. In this respect, molten carbonate fuel cell research and development is scheduled so that the ICG/FCP could be in commercial operation within this time frame.

The timing of the molten carbonate fuel cell research and development effort also coincides with the advanced coal gasification R&D effort that is presently underway.

The second element in determining the economic viability of a proposed powerplant to a utility lies in the cost of the electricity produced by the powerplant. The factors which define the cost of electricity include the component capital costs and operating costs, and the cost of fuel. The cost of electricity produced by the ICG/FCP is determined by its design point characteristics. The capital cost of the powerplant including escalation and interest during construction commensurate with a five year lead time comes to $595/kW. For a thirty year plant life, and the 65% capacity factor specified for the ECAS study, the powerplant capital costs are 18.8 mils/kWh. The fuel costs, based on a coal price of $\$1/10^6$ Btu ($0.948 \$/10^6$ kilojoules), and the ICG/FCP thermal efficiency of 50 percent, are 6.9 mils/kWh. The operating and maintenance costs, based on estimated individual component lives and thirty year overall plant life, are 3.3 mils/kWh. The overall cost of electricity of the ICG/FCF is 29.0 mils/kWh.

The capital costs of the ICG/FCP breakdown as follows: the fuel cell system, including the dc/ac inverters, 39 percent; the gasification system, 25 percent; the steam turbine bottoming cycle system, 15 percent; and the balance-of-plant costs, 21 percent.

There exists a capital cost versus efficiency trade-off for the ICG/FCP. Subsequent to selection of the ICG/FCP design point, rough cost estimates were made for the system operating at other design efficiencies. From this data, an optimization was made between cost of electricity and system heat rate or efficiency. Results of this study are shown in Figure 37 and indicate that while the conceptual design is near the minimum cost of electricity for the 65 percent capacity factor, a small reduction in C.O.E. can be made at a slightly lower efficiency point. A design at lower efficiency would also reduce materials consumption. Rapid increases in cost occur as efficiency is increased beyond the design point because this requires higher cell area. Other capacity factors and fuel costs would change the optimum efficiency; designs to meet these other requirements could be based on standard fuel cell and gasifier modules. Among the major fuel cell parameters affecting the capital cost component of the ICG/FCP are cell manufacturing costs, cell performance, and cell life. Decreases in cell manufacturing costs can be used to reduce capital cost. The effects of increasing cell performance would be similar to those of decreasing manufacturing costs. Increasing cell life would reduce cell stack replacement costs and result in lower operating and maintenance costs.

Sensitivity studies were undertaken to assess the relative effects of the above parameters on the powerplant cost of electricity. Figure 38 illustrates that if cell manufacturing costs were to disappear totally, a 15 percent decrease in cost of electricity could be realized, while, if the manufacturing costs were to double, this would increase the C.O.E. by 15 percent. The other parameters do not follow this linear functional relationship. For example, in the area of cell performance, a two-fold improvement yields only an 7 percent decrease in C.O.E., but the halving of performance would produce an approximately 14 percent increase in C.O.E.

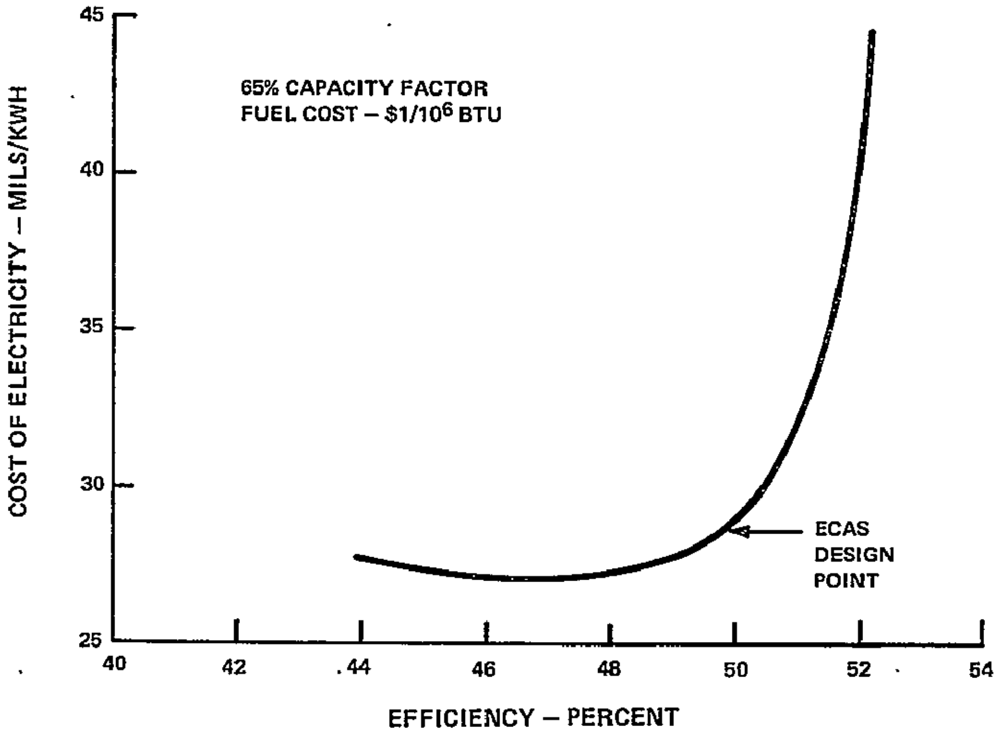


Figure 37 – C.O.E. vs. Heat Rate

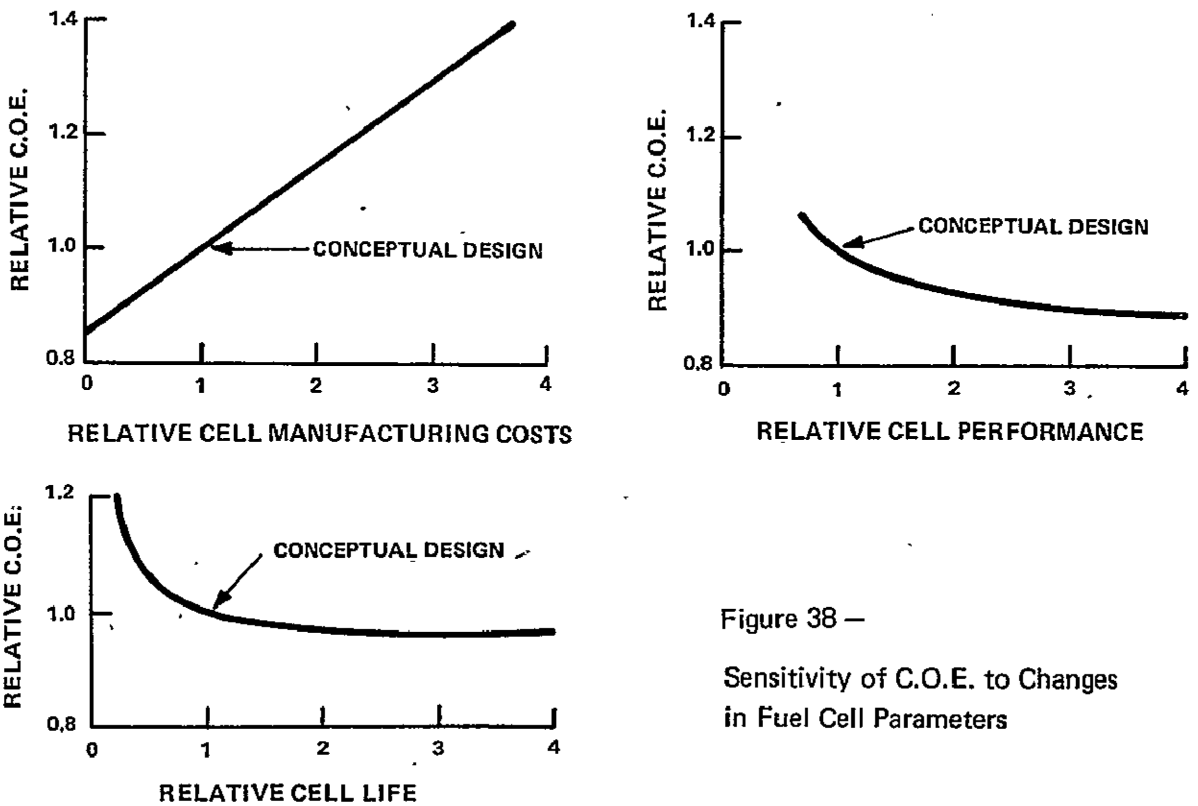


Figure 38 –

Sensitivity of C.O.E. to Changes in Fuel Cell Parameters

Additionally, performance projections for molten carbonate cells utilizing present-day cell technology indicate performance of 85 watts/ft^2 (915 watts/meter^2) at ICG/FCP design conditions. If no improvement over present performance could be achieved, the C.O.E. would be increased by 7 percen In the area of cell life, a four-fold increase in life yields only a 4 percent decrease in C.O.E., while a four-fold decrease causes a 17 percent increase. Thus, especially in the areas of cell performance and life, it is important that a development effort be made to insure that the ICG/FCP meets its design specifications. Moreover since the gains to be realized by improvement in these factors are relatively small, the study shows that the design specifications are cost effective.

3. Fuel Flexibility

The IGT U-Gas^{TM} gasifier is used to convert the raw Illinois No. 6 coal into synthesis gas suitable for the molten carbonate fuel cell. This gasifier is designed to operate on Illinois No. 6 coal without pretreatment or drying. The Illinois No. 6 coal is mildly caking; however, other more heavily caking coal (i.e., Eastern bituminous coals) could be utilized by the U-Gas Process with the addition of pretreatment. Pretreatment consists of feeding the coal through a lock-hopper system to a pretreater, where the coal is contacted with air in a fluidized bed at system pressure and at a temperature of 700° to 800° F (644° to 700° K). This process causes an oxidized "skin" to be produced on the surface of crushed coal, eliminating caking during gasification. This pretreatment would cause a reduction in gasifier efficiency; therefore, use of more heavily caking coals would result in efficiency reduction in the ICG/FCP. Fuel flexibility is enhanced by the compatibility of the molten carbonate fuel cell technology with all types of coal gasifier configurations. Ambient pressure gasifiers, for example, can be integrated with ambient pressure fuel cells without any inherent decrease in efficiency but with an increase in overall powerplant costs because cell performance would be reduced at low pressure. The use of an oxygen blown gasifier may reduce the cost increase for an ambient pressure design.

A range of feedstock coal properties such as fines, ash, moisture, and sulfur can be handled by the gasifier unit. (The effects of varying these properties are relatively minor changes in the overall power plant efficiency.) Increased moisture content in the coal causes a derating of the crusher, which increases the auxiliary power requirements. Increased sulfur content in the coal increases the duty for the iron oxide desulfurizer beds and necessitates more frequent desulfurizer recycling. The process gas requirements for the sulfur recovery system are also increased, thus reducing the useful gas output for the power cycles of the ICG/FCP. In the case of increased ash, efficiency loss would be caused by increased carbon loss in the ash. This carbon represents unconverted fuel which cannot be used for power generation in the powerplant.

4. Siting

Three major factors which determine the siting flexibility for a powerplant are: (1) the type of fuel used and the cost of fuel delivery; (2) the amount and quality of water used for operation; and (3) the degree to which the powerplant impacts on its immediate surrounding in terms of noise, air pollution emissions, and the need for waste product disposal.

From a fuels delivery viewpoint, siting flexibility for the ICG/FCP is similar to other advanced cycles which utilize coal as a fuel. Delivery of coal to a powerplant is best performed by railroad car, necessitating either the location of the powerplant adjacent to an existing railroad line or the construction of a new railroad spur to serve the powerplant.

Since heat rejection for the steam bottoming cycle is by means of an evaporative cooling tower, as specified in the ground rules of the study, sites for the ICG/FCP must be near a source of water. However, the use of indirect cooling towers for ECAS powerplants alleviates the thermal pollution problems entailed with the use of the once-through or direct water cooling approach, still common among many powerplants today.

If desired, the water requirements of the ICG/FCP can be substantially reduced. The alternate approach to the ICG/FCP conceptual design is to integrate a gas turbine bottoming cycle with the molten carbonate fuel cell. With this approach, waste heat from the bottoming cycle would be released directly via the gas turbine exhaust obviating the need for indirect cooling towers. Since makeup for these towers and the steam turbine comprise some 92 percent of the total water requirements, it is quite possible that with this alternative approach, well water supply could be used and location near a body of water would not be necessary. Thus the siting flexibility would be increased.

The alternate gas turbine bottoming cycle system would also have a small module block, since gas turbines are quite cost effective at small sizes (approximately 50 MWe). The fuel cell/gas turbine powerplants could thus be utilized in building blocks as small as 150 MWe, a feature that may well increase siting flexibility in land-short areas. These siting features would be achieved at a reduced efficiency (45 vs. 50) relative to the conceptual design.

Siting locations may also be limited by the noise level. The bulk of the ICG/FCP power output is produced by the prime cycle fuel cells which are static, noise free devices. Although the ICG/FCP contains two major rotating devices, the steam turbine and the gas turbocompressor, the size, and thus, the noise output of these units is small relative to the power rating of the plant. The steam turbine produces 34 percent of the powerplant output and in this respect is similar to the steam turbine component of a combined cycle plant. The combined rating of the turbocompressors is only 178 MWe so that their size and noise output is relatively low.

5. Retrofitting Old Steam Plants

Another aspect of the ICG/FCP siting flexibility involves the potential for retrofitting existing old steam plants with this configuration. Integration of old steam turbines with the ICG/FCP will have multiple benefits: firstly, it will serve as a vehicle for utilizing existing sites; secondly, it will provide a source of new capacity; and thirdly, it will permit an upgrading of the existing capacity.

The modularity of the ICG/FCP design particularly lends itself to the retrofitting of old steam plants into the powerplant. One or more of the four individual fuel cell/gasifier islands can be combined with an appropriately sized steam turbine to produce a self sufficient powerplant. At design conditions, approximately 35 percent of the power output comes from the steam bottoming cycle. Since a string represents approximately 160 MWe of power, steam plants with as low a power rating as 55 MWe or any multiple above can be integrated into the ICG/FCP.

The steam conditions in the ICG/FCP are ideal for the retrofit application, since it is designed to provide 2400 psig (16,649 kilpascal) steam at 1000°F (811°K) with a single 1000°F (811°K) reheat to the steam turbine. This is made possible because two high temperature sources of sensible heat are available. Heat for the primary boiling and superheating is provided by the 1300°F (978°K) molten carbonate fuel cell exhaust. The reheat duty is provided by the high temperature 1570°F (1128°K) gasifier boiler effluent.

The suitability of this approach for any given existing plant depends on the specific plant design, plant age, land availability, etc.

6. Duty Cycle Flexibility

The load following characteristics of the ICG/FCP are determined by the characteristics of each of the three major subsystems of the integrated plant, i.e., the fuel cell, the gasifier and the steam turbine.

The response of the prime cycle fuel cells to changes in load is instantaneous, since the changes to fuel cell output power are made by changing power density at constant temperature.

The inverters, designed to convert fuel cell dc output into ac power, are solid-state devices whose no load to full load response time is set by the magnetics time constant and is less than 0.25 seconds.

The steam turbine bottoming cycle, which depends on fuel cell waste heat as its energy source, will follow the fuel cell load changes due to the reduction in fuel cell waste heat at part power. In fact, the steam plant output will be reduced by a greater percentage than the fuel cell power due to the increased fuel cell efficiency and the attendent reduction in fuel cell waste heat.

The IGT U-Gas^{TM} coal gasifier is designed to operate as a load-following unit with a turndown rating up to 50 percent of the full capacity of the gasifier. The changes in gasifier throughput are achieved by a combination of gas velocity, temperature and steam/coal and air/coal ratios. Initial investigations at IGT have suggested that the gasifier product gas heating value is reduced by less than ten percent through a capacity change from a full load to 50 percent load. A more detailed investigation of the gasifier in combination with the other plant components is required before a definite strategy of load following can be developed. However, the unit train concept of the powerplant should make it possible to achieve reduction in plant capacity by taking an entire train out of production.

An important factor in assessing the duty cycle flexibility of a powerplant is its' part-load efficiency characteristics. Rough part-power thermodynamic analysis indicates that the efficiency vs. load curve for the overall powerplant is relatively flat. This is due to the combination of the part-power efficiency characteristics of both the fuel cell and the steam turbine with some additional effects due to the greater impact of auxiliary parasite power requirements at part power. The fuel cell actually becomes more efficient at part load (a characteristic not found in Carnot cycles); additionally, its available heat sources are reduced for reasons discussed above. A more detailed part load analysis, beyond the scope of this study, is necessary to assess the effects of turndown on the ICG/FCP.

An additional factor in assessing the duty cycle flexibility is the time required for getting the powerplant on load from a hot or cold condition. The coal gasifier can be shut off for periods up to 48 hours and restarted very quickly. The fuel cells can be restarted from a hot condition (defined as any time up to 48 hours after shutdown) in a maximum of two hours. Thus, with a two hour maximum time required for a hot start, the ICG/FCP would offer a good potential for intermediate use. The time needed for a cold start of the ICG/FCP is estimated to be a minimum of twelve hours. This time is determined by the heatup rates of the gasifiers and fuel cells. Although this time period is comparable to that required for conventional coal-fired steam plants, considerable energy will be required for a cold start, consisting of the heat equivalent power input to the ICG/FCP. Thus, it would be advantageous to thermally cycle the ICG/FCP as little as possible.

7. Operation and Control

The procedure utilized for operation and control of the ICG/FCP has been described in Section III H of the main text of the report. The major impact of the operation and control on the implementation of the design is that no special operator skills, over and above those required for operation of conventional powerplants, are required.

8. Maintenance

The ICG/FCP is composed of four trains or strings, each of which contains 24 fuel cell pressure vessels, two gasifiers, two steam generators, one fuel cell turbocompressor and one gasifier turbocompressor, along with other ancillary components. Only the steam turbine portion of the plant is not modular due to the performance and cost penalties which would be associated with multiple small steam turbines.

The modular nature of the powerplant permits maintenance on a section of the powerplant without interrupting the power output capability of the remaining sections of the powerplant. The maintenance procedures and schedules for the ICG/FCP can be established to maximize the availability of the powerplant.

The maintenance tasks for the coal gasifier and bottoming cycle portion of the powerplant will be similar to those required for conventional steam plants and combined cycle units with gasifiers. The major maintenance task in the fuel cell section involves the overhaul of the cell stacks at the end of their useful life. The present approach for this task would be to remove the used stacks and replace them with new factory assembled units. This approach minimizes field labor and associated costs for the major overhaul.

With the present maintenance approach, the ICG/FCP should not impose any additional burden on the skilled labor requirements for the maintenance crews.

With the exception of the fuel cell stacks, the cost of maintenance for the ICG/FCP powerplant should be similar to the costs for conventional steam plants or combined cycle powerplants with coal gasifiers. The fuel cell overhaul represents approximately 36 percent of the total maintenance cost.

9. Reliability and Availability Potential

The modular concept of the ICG/FCP permits partial power operation during individual outages in either the coal gasification, fuel cell, or turbocompressor subsystems. Only a major failure of the steam turbine could cause a powerplant shutdown. This possibility can be avoided if cooling tower capacity is sufficient to remove all of the fuel cell waste heat. With this contingency, the powerplant could remain in operation at reduced efficiency and output. The additional capital cost expenditure involved with this option has been estimated at $13/kW of output power.

Fuel cells possess an inherent overload capability which can be utilized to make up a power deficit caused by failed cells. In the event of random cell failures, the remaining cells are operated at increased power densities and lower cell voltages. The decreased cell voltage reduces the cell efficiency and consequently, the overall efficiency is somewhat lower. For the ICG/FCP, full power operation is possible with up to 10 percent random fuel cell failures.

Redundant components are included in the design to avoid forced shutdowns of the ICG/FCP caused by failures of pumps, conveyors, and similar type equipment. This equipment represents a minor increase in powerplant capital costs to effect a substantial increase in powerplant availability.

Studies were performed at PSD to assess the availability potential of the ICG/FCP. The effects of both corrective and preventive maintenance procedures on the availability of the powerplant were evaluated. The conceptual design is modular and most failures or planned maintenance actions affect only a portion of the powerplant. A power profile showing percent available power vs. percent time was generated for two cases representing a range of possible component downtimes. Figure 39 illustrates that the range of equivalent power availability is 84 to 88 percent. Equivalent power availability is defined as maximum kWh which could be delivered in a period divided by powerplant rating and by clock time. These values fall slightly short of the NASA goal of 90 percent availability.

The major factor limiting the availability of the ICG/FCP is the steam turbine bottoming cycle. Due to the steam turbine not being modular, (only one is incorporated into the ICG/FCP due to the cost ineffectiveness of small steam turbines), a failure of this single component can cause shutdown of the entire plant. The major preventive maintenance performed on the ICG/FCP involves annual maintenance which requires shutdown of the powerplant. With regard to auxiliary, balance-of-plant components, the philosophy was adopted that the loss of any one auxiliary unit of equipment shall not reduce the availability of the generating units below that set by the major components. This is accomplished by the use of multiple, redundant or excess capacity units for each of the auxiliary units.

Several approaches for increasing the availability potential of the ICG/FCP have been identified. One involves the adoption of the alternate gas turbine bottoming cycle system. This would enhance the modularity of the powerplant, removing the major item that is not modular; i.e., the steam turbine. Thus an improvement in powerplant availability would be expected, since the powerplant would no longer have to be shutdown due to the failure of a single component. An additional alternative is to include additional cooling tower capacity in the baseline steam turbine bottoming ICG/FCP. This would permit operation of the prime cycle fuel cells without the bottomer in the event of steam cycle failure although at much reduced overall system efficiency. Studies indicate that with this option, a

91 percent power availability could be achieved, meeting the NASA goal of 90 percent availability. This option would entail a nominal capital cost increase of \$13/kW.

TWO GRAPHS REPRESENT THE RANGE OF POSSIBLE COMPONENT DOWNTIMES

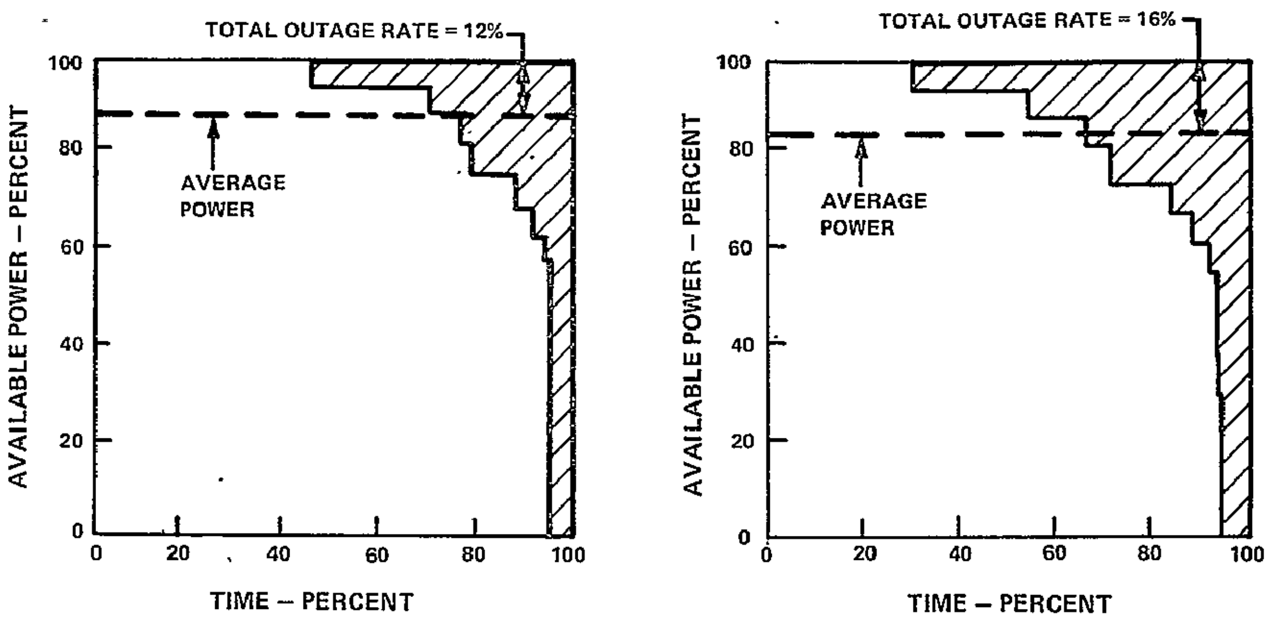


Figure 39 – Power Profile

C. NATIONAL INTEREST FACTORS

The implementation factors discussed in this section have an impact on both the technical and electric utility application factors. They are also important from a national interest standpoint since they influence the air quality, and the requirements for and allocation of natural resources such as fuel, land, and water.

1. Environmental Intrusion and Constraints

The ICG/FCP operating on Illinois No. 6 coal will have emissions of sulfur dioxide, oxides of nitrogen and particulates. The estimated level of these emissions meets or betters the emissions standards for solid fueled powerplants. Several approaches are available for reducing the emissions to the Target 1, 2 or 3 goals listed in Appendix I-B with modest penalties in capital cost and/or heat rate.

The estimated level of sulfur dioxide emissions from the ICG/FCP is 0.74 lb $SO_2/10^6$ Btu (3.18 kilograms SO_2/kilojoule). The emissions are contained in two exhaust streams. The exhaust from the Allied Chemical sulfur recovery plant contains 73 percent of the SO_2 emission while the remaining 27 percent is contained in the fuel cell exhaust (specifically the exhaust from the economizer). This level of emission is lower than the sulfur dioxide gaseous emission standards for solid fueled powerplants of 1.2 lb $SO_2/10^6$ Btu (5.16 kilograms SO_2/kilojoule), but it exceeds the Target 1, 2 and 3 goals for SO_2 emissions from solid fueled powerplants.

Various approaches to reduce the sulfur dioxide emissions to meet the Target 3 goals have been identified. Addition of a tail gas cleanup subsystem downstream of the Allied Chemical plant could remove on the order of 90 percent of the sulfur dioxide emissions from the sulfur recovery subsystem. The tail gas cleanup system would increase capital cost by $13/kW and reduce overall sulfur dioxide emissions to 0.25 lb $SO_2/10^6$ Btu (1.08 kilograms SO_2/kilojoule). This reduction, while significant, is not sufficient to meet the Target 1 goals.

Regenerable zinc oxide adsorption beds can be added downstream of the iron oxide desulfurizer beds to remove the bulk of the emissions which appear in the fuel cell exhaust gases of the ICG/FCP. The incorporation of these zinc oxide beds in addition to the tail gas cleanup system could reduce sulfur dioxide emissions to 0.04 lb $SO_2/10^6$ Btu (0.17 kilogram SO_2/kilojoule), a level that would meet Target 3 goals. Addition of the zinc oxide beds would entail a small additional cost expenditure of $0.4/kW.

The estimated oxides of nitrogen emission levels for the ICG/FCP are lower than the Target 3 goals. The emission level of 0.03 lb $NO_2/10^6$ Btu (0.13 kilogram NO_2/kilojoule) represents a maximum thermodynamic limit for NOx formation in the fuel cell catalytic burner. In actuality, the emission levels could be considerably lower, since kinetics would probably indicate lower NOx yields than attained at thermodynamic equilibrium. The very low NOx emission levels from the ICG/FCP are due to low temperatures in the catalytic combustor. This low temperature is a result of the dilute nature of the anode exhaust, which consists of low Btu gasifier product gas from which 85 percent of the combustibles have already been utilized in the fuel cell. Another possible source of NOx emissions could be from the combustion of by-product ammonia gas from the coal gasifier. Since ammonia production is very low, the effect on NOx emissions is negligible.

Maximum particulate emissions from the ICG/FCP have been estimated at 0.09 lb/10^6 Btu (0.39 kilogram/kilojoule). This maximum estimate would meet the present standard of 0.1 lb/10^6 Btu (0.43 kilogram/kilojoule), but it is considerable above the Target 3 goal of 0.001 lb/10^6 Btu (0.004 kilogram/kilojoule). Particulate emissions from the ICG/FCP appear as carryover from the gasifier cyclones. Experimental data indicates that this carryover consists of one grain of particulates per standard cubic foot of gasifier effluent. These emissions have been determined to have the same composition as the feedstock and are, therefore, approximately 10 percent ash or particulates. The particulate emission estimate is based on the assumption that ash is not removed in either the iron oxide desulfurizer beds or in the Allied Chemical sulfur recovery unit. Bench scale data, based on experiments performed at IGT, indicated that all of the ash would be removed in the iron oxide beds. Experimental data on large-scale equipment is required to confirm this data. Therefore, the assumption of near zero particulate emissions was not made for the ICG/FCP design.

Actual particulate emissions levels depend on a number of factors which have yet to be totally confirmed. First, the efficiency of ash removal by the high temperature cyclones has yet to be finally determined; second, the effectiveness of the iron oxide beds in trapping particulates has yet to be demonstrated on a large-scale rig; and last, the effectiveness of the sulfur recovery unit in cleaning up particulate matter has not been determined. The net effect of these factors should tend to reduce the emission level below the values estimated for the ICG/FCP.

In addition, if the alternative low temperature desulfurization approach is selected for the ICG/FCP, the particulates would be reduced to low levels, since the removal of particulates can be achieved by contacting the particulate containing gases with the liquid washes. Thus Target 3 goals on particulate emissions from the ICG/FCP could be met with only a slight (1 percent) decrease in powerplant efficiency.

Any trace element emissions from the ICG/FCP result from the coal gasification process. An EPA-sponsored program at IGT indicated that the trace element emissions from coal gasification to high Btu gas are less than the emissions resulting from the environmentally acceptable direct combustion of coal (Reference 11).

The appearance of trace elements in the fuel gas depends to a large extent on the relative volatility or boiling point of these elements or their associated compounds. Ligher, lower boiling point elements or compounds will tend to volatize and appear in the fuel product gas. Heavier, non-volatile elements will more likely agglomerate with the ash and be removed as part of the powerplant solid waste.

In the IGT U-Gas^{TM} gasifier design, trace element removal with the ash would be probable since slagging temperatures are not approached in the gasifier. The ash agglomerating temperature of 1900°F (1311°K) is far lower than the slagging temperature of 2800°F (1811°K) leading to a lower degree of volatization of trace elements.

Actual trace element carryover has not been established, and experimental data will be required to determine the degree of this carryover from the gasifier and desulfurizer.

If trace elements should prove to be a problem, an alternative approach to fuel cleanup is the utilization of a low-temperature desulfurization scheme. Low-temperature desulfurization processes are more likely to clean up volatized trace elements in the gasifier product gas since vapor pressures are sufficiently low at the low desulfurization temperatures to cause condensation of the trace elements.

2. Efficiency and Fuel Conservation Potential

The ICG/FCP is designed to operate at 49.6% overall thermal efficiency (heating value of net plant electrical power output/higher heating values of coal feed stock) at rated power conditions.

To assess the coal conservation potential associated with implementation of the ICG/FCP design, its fuel usage should be compared to that of a conventional coal fired powerplant, designed to meet present pollution standards with Illinois No. 6 coal. Coal fired steam plants typically operate at a full power efficiency of about 36 percent overall. Use of the ICG/FCP in place of the steam plant would result in a 28 percent savings in coal usage, if both were operated at equal capacity factors. Of course, the actual fuel conservation potential of the ICG/FCP would depend upon its usage and the generation mixture within the particular utility.

If desired, higher efficiencies can be achieved with the ICG/FCP at some capital expense. Two approaches can be considered for improving efficiency. The first is within the technology projections for the ICG/FCP, while the second involves technology advances in fuel cell and gasifier technology.

Fuel cell efficiency can be increased, without any changes in cell technology, by increasing the rated power design cell operating voltage (Figure 14). This involves a decrease in fuel cell design power density; thus more cell area is required to produce a unit of power, and capital cost increases. (See Figure 37 for effect on C.O.E.) It is an inherent characteristic of the fuel cell that it can be designed for a range of efficiencies at rated power with variance only in the capital cost of the powerplant. Thus, unlike Carnot cycle powerplants, (where the maximum design efficiency is limited by materials technology), an efficiency/capital cost trade-off exists for the fuel cell for a given technology level and efficiency can be selected to reflect current fuel prices without changing powerplant technology.

The second approach to increasing ICG/FCP efficiency is to develop advanced fuel cell technology. While increasing efficiency with the current technology involved an increased capital cost investment, advancing fuel cell technology would require additional investment in research and development. With additional funding, cell performance could be increased, which would allow for efficiency improvement over the conceptual design without capital cost increase, or could provide for even further efficiency increase with a smaller corresponding capital cost increase than would be possible with the conceptual design.

Additionally, higher powerplant efficiencies could be obtained using higher temperature fuel cells integrated with more advanced gasification processes.

3. Natural Resource Requirements

The natural resources required for the implementation of the ICG/FCP design include coal to fuel the powerplant; water for cooling and processing; and land for siting the powerplant. Since the desulfurization process is regenerable, there is no requirement for waste disposal from this process.

At rated power of 635 MW, coal consumption is 202.5 tons per hour (51.03 kilograms/second), or a specific fuel consumption of 0.63 pound per kilowatt-hour (0.29 kilogram/kW). The 49.6 percent overall efficiency for the ICG/FCP offers 50 percent conservation of this natural resource relative to present technology plants, with efficiencies in the 33 percent range.

Water is required in the ICG/FCP for cooling and as process feed in the coal gasification step. The total water requirement at rated power is 0.4 gallon per kilowatt-hour (0.0015 meters^3/kWh). Ninety percent of this requirement is make-up water for the cooling tower subsystem; the remainder is used primarily to provide the process water for the gasifier (0.03 gallon per kilowatt-hour) (114 x 10^{-6} meters^3/kW) and make-up for the steam turbine (0.009 gallon per kilowatt-hour) (34.1 x 10^{-6} meters^3/kWh).

Wet cooling towers were used in the ICG/FCP design, as specified by NASA as a ground rule for the ECAS study. There are three major sources of water loss inherent in the use of wet cooling towers. The first is evaporation into the cooling air; the second is water blowdown, a procedure by which water is intentionally discharged from the system to control concentration of salts and other impurities in the cooling water; and the third is drift loss which is water lost from the tower as liquid droplets entrained in the air.

An approach for limiting water usage in the ICG/FCP is to replace the evaporative cooling towers by dry cooling towers. Dry towers, although widely used in Europe, have not been used in U.S. powerplants due to the penalty in both powerplant initial cost and efficiency that their use entails. Their advantage, of course, is in the siting flexibility provided by the fact that large quatities of make-up water would not be required with their use.

Dry cooling towers generally have greater first capital cost due to the poor heat transfer characteristics of air as a cooling medium. Their cost can range anywhere from two to three times that of evaporative cooling towers.

The land requirement for the ICG/FCP is 20 acres per 100 megawatts (809.4 meters^2/MW) of plant capacity. This requirement includes the land for the plant and the storage area for the sixty day coal supply. The coal storage area accounts for a significant portion of the total land requirement. This could be reduced by either increasing the height of the coal piles, or reducing the amount of coal storage below the sixty day requirement.

The ICG/FCP has a minimal impact on natural resources requirements, relative to conventional options, since it has a high conversion efficiency. This reduces both the coal consumption and the amount of make-up-water required for the wet cooling towers. Further substantial reductions could be made in the water requirement through the use of dry cooling towers. This would however, cause a moderate increase in the overall plant capital cost.

VIII STUDY RESULTS

The conceptual design and implementation assessment indicate the following potential features of an integrated coal gasifier/molten carbonate fuel cell powerplant:

- This concept offers the potential of very high electric generation efficiency (49.6 percent) because of the high efficiency of the electrochemical prime cycle and the effective utilization of high quality waste heat in an integrated steam bottoming cycle. Consequently resource requirements are low relative to conventional steam powerplants.
- The relatively high efficiency coupled with modular design result in competitive powerplant capital cost ($595/kW) and busbar cost of power (29 mils/kWh) which can be achieved in plant ratings as low as 635 MW.
- The estimated pollution levels are lower than solid fuel standards and could be reduced further with moderate cost impact.
- The modular nature of the plant results in an estimated energy availability of 84 to 88 percent.
- Technology issues which must be resolved with this technology include fuel cell performance and endurance, and operation of the cell at pressure with gasifier/cleanup system products.
- The modular character of fuel cell powerplants permits addressing technology issues in small scale research cells or cell stacks. Full scale dc powerplant modules are rated at 4.5 MW, and can be demonstrated with 5 ton/hour gasifiers.
- The estimated development program cost is $715 million (1975 dollars), including $642 million for demonstration of a complete 635 MW powerplant. The demonstration could be completed in mid 1985. The first commercially designed powerplant could be on line in early 1989.
- An alternative design employing a gas turbine bottoming cycle has somewhat lower efficiency (45 percent) but could be constructed in 145 MW plants. The potential reduced plant size coupled with reduced water requirements improve siting flexibility relative to the conceptual design powerplant. (Appendix II)

IX CONCLUDING REMARKS

The conceptual design and implementation assessment identified several features of the Integrated Coal Gasifier – Molten Carbonate Fuel Cell Powerplant. These features include the potential for high efficiency, good economic characteristics, and a high degree of system modularity. The major factors influencing these design features are discussed below.

The overall coal pile to busbar efficiency of the conceptual design powerplant is 49.6 percent. This high efficiency is the result of the high efficiency fuel cell prime cycle utilized in the powerplant. Fuel cells are electrochemical energy conversion devices and are not, therefore, limited to Carnot efficiency. The chemical energy conversion efficiency of the conceptual design fuel cell is 45 percent, based on the ratio of the gross ac power output of the cycle to the higher heating value of the fuel gases fed to the cycle. Because the fuel cells are not Carnot limited, this efficiency is not dependent on a high temperature heat source, nor is it dependent on the absolute difference of the heat source and heat sink available. Since the fuel cell waste heat is available at the cell operating temperature, it can be utilized at high efficiency in a Carnot engine bottoming cycle. The waste heat conditions are especially well suited for use in a steam cycle, permitting use of conventionally available units.

Since the fuel cell is not an expansion device, the fuel cell exhaust streams are available at the operating pressure of the cell. This could permit expansion of pressurized fuel cell exhaust in a turbocompressor to provide the energy of compression for both the fuel cell and gasifier process air requirements. Thus, no parasitic electric power would be required for these two compression duties. Another aspect of operating the fuel cells at pressure is that the high quality cell waste heat would be available in pressurized gas streams. This offers the potential of improved heat transfer characteristics and, therefore, smaller heat transfer equipment for transferring heat between the energy cycles.

The high powerplant efficiency impacts on the system economics of the conceptual design by decreasing the upstream coal processing costs. The high efficiency of the powerplant would require less coal per kilowatt-hour to be processed, which could result in smaller and lower cost coal handling, gasification, and gas cleanup facilities. High efficiency could also reduce heat rejection costs.

The integrated coal gasifier-fuel cell conceptual design powerplant is a modular designed system which could impact favorably on the development requirements and the economic and operating characteristics of the powerplant. Modularity is an inherent characteristic of electrochemical devices such as the fuel cell because increased power is obtained simply by increasing total cell area. The unit cell forms a repeating element and is the modular building block of the fuel cell energy conversion device. Operating and endurance characteristics can be demonstrated in small single cells. The complete fuel cell module for this powerplant design is only 4.5 MW, and could fully demonstrate the operational characteristics of the fuel cell power section design.

The modular characteristic of the fuel cell could permit the unit cells to be mass produced and tested at a factory prior to rail transportation to the powerplant site. Designing the gasification, gas cleanup, and turbocompressor equipment of the powerplant to be modular, as discussed in Sections III-C and III-D, could result in a powerplant with a high degree of factory fabrication and decreased site construction costs.

APPENDICES

APPENDIX I

INPUT GROUND RULES PROVIDED BY NASA

The following sections of Appendix I provide a detailed description of several of the input ground rules provided by NASA and common for all of the ECAS Phase II studies. All of the ground rules are summarized in Section II-B of the report. The following appendixes are included in Appendix I:

APPENDIX I-A
ECAS COAL PROPERTIES

Illinois No. 6
(Macoupin County)

Reference BOM TP – 641

Higher Heating Value (As Received)

10,788 Btu/lb

Proximate Analysis (As Received)

Moisture	13.0
Volatile	36.7
Fixed Carbon	40.7
Ash	9.6

Ultimate Analysis (As Received)

Ash	9.6
Sulfur	3.9
Hydrogen	5.9
Carbon	59.6
Nitrogen	1.0
Oxygen	20.0

Grindability H. G. I.

Range	52-66
Average	55

Free Swelling Index

Range	1-6.5
Average	4.5

APPENDIX I-A (Cont'd.)

Ash Analysis, %

SiO_2	46.6
Al_2O_3	19.3
Fe_2O_3	20.8
TiO_2	0.8
P_2O_5	0.24
CaO	7.7
MgO	0.9
Na_2O	0.2
K_2O	1.7
SO_3	2.4

Ash Fusability

Initial Deformation Temperature °F	1990 - 2130
Softening (Average) Temperature °F	1979
Fluid Temperature °F	2090 - 2440

Trace Element Analysis, ppm in Coal

Beryllium	0.6-7.6
Fluorine	50-167
Arsenic	8-45
Selenium	—
Cadmium	—
Mercury	0.04-0.49
Lead	8-14
Boron	13-198
Vanadium	8.7-67
Chromium	5-54
Cobalt	1.2-10
Nickel	5-37
Copper	3.1-25
Zinc	0-53
Gallium	1.5-8

APPENDIX I-A (Cont'd.)

Trace Element Analysis, ppm in Coal (Cont'd.)	
Germanium	0.4-27
Molybdenum	0.6-8.5
Tin	0.1-5
Yttrium	1-13
Lanthanum	0.2-24
Uranium	10

Trace Element Analysis %W in Ash	
Lithium	.017-.039
Scandium	.007-008
Manganese	.020-.062
Strontium	.058-.070
Barium	.029-.047
Ytterbium	.0003-.0011
Bismuth	.0001-.0002

APPENDIX I-B

EMISSIONS STANDARDS AND TARGET GOALS

Emissions standards applicable to integrated gasifier plants are the solid fuel standards. The solid fuel standards (base) and targets for sensitivity investigations are as follows:

		Emissions (lbs/million Btu heat input)		
Pollutant	Base	Target 1	Target 2	Target 3
SO_x	1.2	0.2	0.1	0.1
NO_x	0.7	0.3	0.12	0.12
Particulates*	0.1	0.01	0.005	0.001
Hydrocarbons	–	0.01	0.01	0.01
CO	–	0.04	0.02	0.02

*For Targets 1, 2, and 3 particulates are specified as smaller than 1 micron.

APPENDIX I-C
CRITICAL MATERIALS LIST

Aluminum	Nickel
Chromium	Platinum
Cobalt	Tin
Columbium	Titanium
Copper	Tungsten
Manganese	Vanadium
Mercury	Zirconium
Molybdenum	

APPENDIX I-D
ESCALATION AND INTEREST COST FACTORS

(Escalation + Interest = Total)
Annual Rates: 6.5% Escalation, 10% Interest

Years[1]	Escalation	Interest[2]	Total
0.0	1.000	1.000	1.000
0.5	1.018	1.022	1.040
1.0	1.037	1.044	1.081
1.5	1.056	1.069	1.125
2.0	1.076	1.094	1.170
2.5	1.096	1.122	1.218
3.0	1.116	1.151	1.267
3.5	1.137	1.182	1.319
4.0	1.158	1.214	1.372
4.5	1.179	1.249	1.428
5.0	1.202	1.285	1.487
5.5	1.224	1.324	1.548
6.0	1.247	1.365	1.612
6.5	1.270	1.409	1.679
7.0	1.294	1.454	1.748
7.5	1.319	1.503	1.822
8.0	1.344	1.554	1.898
8.5	1.369	1.609	1.978
9.0	1.395	1.666	2.061
9.5	1.422	1.726	2.148
10.0	1.449	1.790	2.239

(1) Time from start of design to first commercial service.

(2) Interest on escalated amount.

APPENDIX II

ALTERNATIVE DESIGN DESCRIPTION

Substitution of a gas turbine bottoming cycle for the steam turbine used in the conceptual design was evaluated under a separate contract (EPRI Research Project RP114 – see reference 14). In that evaluation, the gasifiers, clean-up system and fuel cell modules were assumed to be the same as those used in the conceptual design and described in Section III. A discussion of this alternative design and its features are included here to provide context for discussions of the R&D Program Plan and Implementation Assessment in Sections VII and VIII.

A. Description of Alternative Design

Figure II-A shows the bases for the alternative powerplant design relative to the conceptual design described in Section III. In the alternative powerplant design the major change involves the substitution of a gas turbine-generator bottoming cycle for the steam cycle utilized in the conceptual design. Fuel cell waste heat is used to heat compressed air which is expanded through a turbine. The turbine powers its own compressor and and an electric generator. Since waste heat is not used as effectively, the alternative design has lower powerplant efficiency than the steam turbine bottoming cycle approach. Overall powerplant efficency is 45 percent compared to 50 percent for the conceptual design.

- **UTILIZE ECAS DESIGN DATA AND RESULTS WHEREVER POSSIBLE**
- **SAME PHYSICAL AND OPERATING CHARACTERISTICS FOR THE GASIFIERS, GAS CLEANUP, AND FUEL CELL MODULES AS CONCEPTUAL DESIGN POWERPLANT**
- **TURBOCOMPRESSOR COMPONENT EFFICIENCY INCREASED RELATIVE TO CONCEPTUAL DESIGN**
- **SUBSTITUTES GAS TURBINE BOTTOMING CYCLE FOR STEAM BOTTOMER**
- **MODIFICATION OF WASTE HEAT REMOVAL EQUIPMENT AND BALANCE-OF-PLANT EQUIPMENT CONSISTENT WITH BOTTOMING CYCLE APPROACH**

Figure II-A
Basis for Alternative Design

To provide a good basis for comparison with the conceptual design and to minimize effort, the coal handling, gasifiers, clean-up systems and fuel cell modules of the conceptual design were utilized in the alternative design. Turbocompressor component efficiency was increased because, unlike the conceptual design, higher turbocompressor efficiency is of benefit with a gas turbine bottoming cycle powerplant design. A gas turbine bottoming cycle was incorporated into each gasifier-fuel cell train. This is possible because the gas turbine equipment is not so sensitive to scale as the steam turbine equipment. Having a bottoming cycle with each of the four gasifier-fuel cell trains minimizes inter island piping, provides higher plant reliability, and permits the use of one train as a complete powerplant.

B. Comparison of Alternative Design Characteristics to Conceptual Design

Figure II-B compares the characteristics of the alternative design to the conceptual design. As indicated previously, the gas turbine bottoming cycle cannot utilize fuel cell waste heat as effectively and consequently its efficiency is 45 percent compared to the 50 percent efficiency achieved by the conceptual design.

	CONCEPTUAL DESIGN (STEAM TURBINE BOTTOMING)	ALTERNATE DESIGN (GAS TURBINE BOTTOMING)
OVERALL THERMAL EFFICIENCY	50% (HEAT RATE = 6850 BTU/KWH)	45% (HEAT RATE = 7580 BTU/KWH)
POWERPLANT RATING	635 MW	145 - 578 MW
POWERPLANT LEAD TIME	5 YRS	4 YRS
CAPITAL COST	$595/KW	$575/KW *
BUSBAR COST @ 0.65 CAPACITY FACTOR AND $\$1/10^6$ BTU COAL	29 MILLS/KWH	30 MILLS/KWH
WATER REQUIREMENTS	0.4 GAL/KWH	0.07 GAL/KWH
RELATIVE GASEOUS EMISSIONS/10^6 BTU	1.0	1.0

*AT 578 MW

Figure II-B
Comparison of Powerplant Characteristics

Because the alternative design uses the same coal processing equipment, gasifiers, and fuel cell modules the lower efficiency reduces output power from 635 MW for the conceptual design to 578 MW for the alternative design. However, the 578 MW is associated with a complete plant based on all four of the gasifier-fuel cell trains. Because each gasifier-fuel cell train has its own bottoming cycle with the alternative design, a plant as small as 145 MW could be constructed using the same building blocks except for the coal handling and sulfur recovery systems. Efficiency would remain the same at 145 MW, but specific cost ($/kW) will increase slightly because of higher specific costs for coal handling and sulfur recovery equipment.

Because the alternative design uses a gas turbine bottoming cycle and because the steam bottoming cycle was the pacing item for the conceptual design lead time, powerplant lead time is expected to be reduced from 5 years to 4 years for the alternative design. The reduced need for site construction will also contribute to this improvement. Because of the shorter lead time, escalation and interest during construction are lower for the alternative design and slightly lower plant capital cost is obtained. This lower capital cost does not offset increased fuel costs associated with lower efficiency and busbar cost of power increases slightly for the conceptual design.

The alternative design does not require a cooling tower and therefore, as shown in Figure II-B, water requirements are only 18 percent of those of the conceptual design, and siting flexibility is improved. Because the alternative design is based on the same coal specification and fuel processing equipment, emissions measured on the basis of pollution per fuel heating value are the same.

The potential for smaller complete unit powerplant sizes (145 MW) using the alternative design provides advantages in development program schedule and cost, as discussed in Section VI. A shorter program schedule is possible using the alternative design as the demonstration powerplant. In this case, construction of the demonstration powerplant is reduced by one year which permits completion of demonstration testing and initiates construction of the first commercial powerplant one year earlier in the program. This approach permits the first commercially-designed powerplant using the conceptual design with the steam bottoming cycle to be on line in early 1988, one year earlier than the schedule presented in Section VI. In addition, if the first commercially-designed powerplant were to use the alternative design, the design/construction time of the commercial unit is reduced, permitting the powerplant to be on line as early as 1987.

Use of the alternative design could also reduce program development cost. Use of the alternative design at the 145 MW level as the demonstration powerplant in the RD&D program would reduce the cost of the Phase IV Demonstration Plant to 202 million dollars (1975 dollars), for a savings of 440 million dollars as compared to Phase IV of the RD&D program presented in Section VI. The cost summary of the RD&D program by Phase by year using the alternative design as the demonstration powerplant is presented in Table II-A. It should be noted that the Task breakdowns of Phases I-III are identical to those presented in Section VI with respect to both schedule and funding. The assumptions used in estimating the RD&D program cost presented in Table II-A are identical to those listed in Section VI, with the following exceptions for costing the demonstrator powerplant:

1. The gas turbine bottoming cycle with its associated balance-of-plant equipment is at commercial unit cost.

2. Coal handling and sulfur recovery equipment, due to their reduced ratings, are added to the list of components costed 50 percent higher than commercial unit cost.

These assumptions result in specific material and site labor costs ($/kW) for the 145 MW demonstration plant which are 62 percent higher than for a commercial plant using the alternative design.

Other advantages due to the potential of smaller powerplant sizes using the alternative design include siting flexibility, powerplant availability, system reserve margin, and utility load growth matching. These topics are discussed in Section VII.

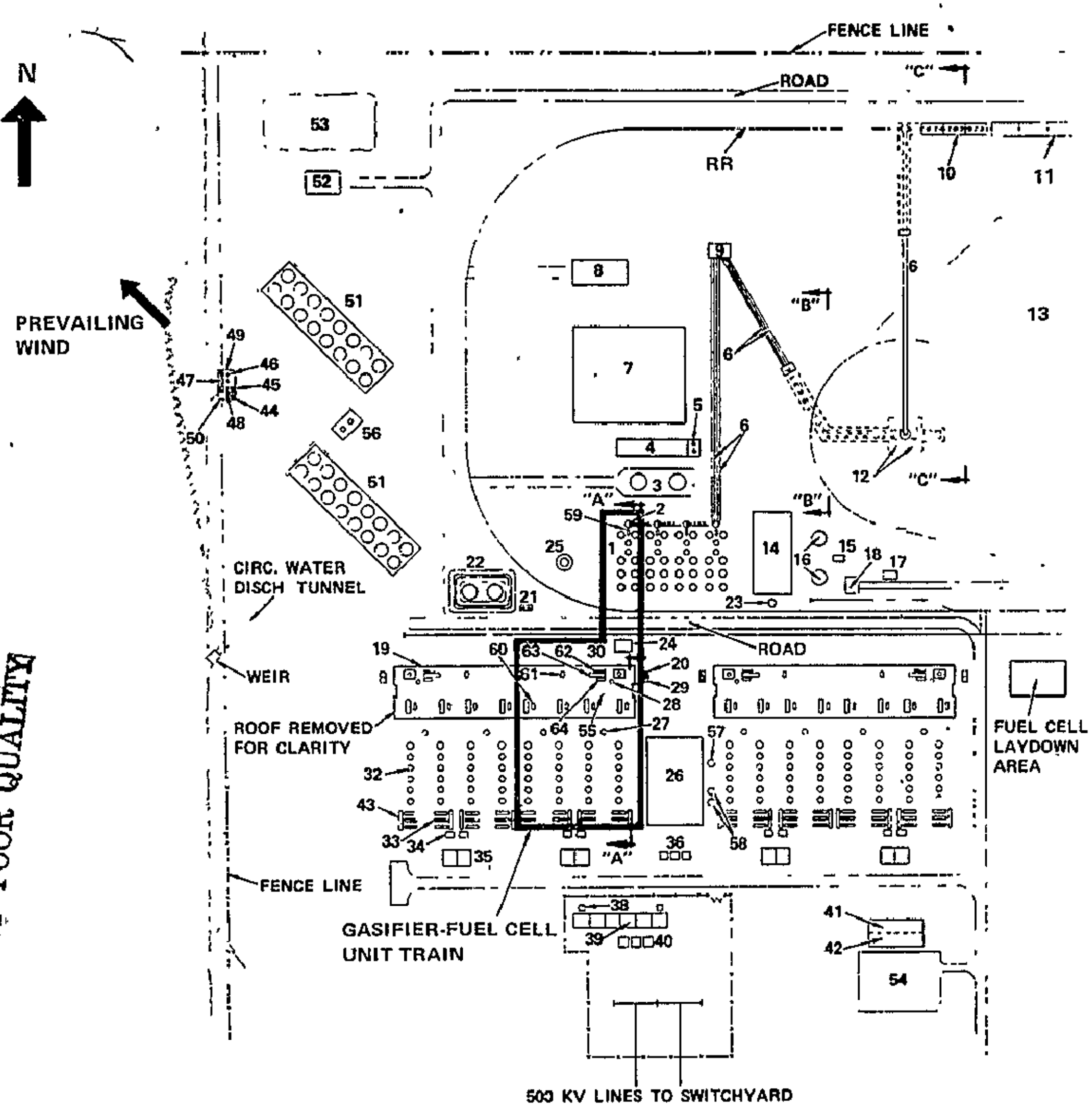
TABLE 11-A

PROGRAM COST SUMMARY ∿ 1975 DOLLARS (WITH ALTERNATIVE DESIGN DEMONSTRATION PLANT)

	PHASE	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	TOTAL $'s 1975	TOTAL $'s ESCALATED
I	Confirm Component Technology & Design	3	8	3	— —	— —	— —	— —	— —	— —	— —	$ 14	16
II	Scale Up to Prototype Hardware	— —	— —	7	18	— —	— —	— —	— —	— —	— —	25	33
III	DC Module Testing With Pilot Gasifier	— —	— —	— —	14	11	6	1	1	1	— —	34	48
	SUBTOTAL	3	8	10	20	11	10	9	1	1	— —	73	97
V	145 MW Demonstrator Plant	— —	1	6	23	40	49	49	28	6	— —	202	307
	TOTAL	3	9	16	55	51	55	50	29	7	— —	$275	404

APPENDIX III

DRAWINGS



1. GASIFIER ISLAND
2 COAL BINS
3 DEWATERING BINS
4. ASH SETTLING BASIN
5. ASH SLUICE PUMPS
6 COAL CONVEYOR
7. ASH STORAGE (EMERGENCY)
8 MAINTENANCE & EQUIP STORAGE BLDG
9. CRUSHER HOUSE
10. TRACK HOPPERS
11 THAWING SHEDS
12. RECLAIM HOPPERS
13. COAL STORAGE
14 SULFUR RECOVERY PROCESS AREA
15. SULFUR TRANSFER PUMP HOUSE
16 SULFUR STORAGE TANKS
17. TANK TRUCK SULFUR LOADING
18 TANK CAR SULFUR LOADING
19. FUEL CELL EQUIPMENT BUILDING
20. EXHAUST STACK
21 LIGHT OIL PUMPS
22. LIGHT OIL STORAGE TANKS & DIKE
23 INCINERATOR STACK
24 H_2 & CO_2 BOTTLE STORAGE AREA
25 FLARE STACK
26. STEAM TURBINE BUILDING
27. BOILER/SUPERHEATER
28 GASIFIER AIR PREHEATER
29. AIR INLET SILENCER STACK
30. DEAERATOR ECONOMIZER
31 BURNER
32. FUEL CELL PRESSURE VESSELS
33. INVERTERS
34 INVERTER TRANSFORMER
35 69 KV STRUCTURE
36. STEAM TURBINE GENERATOR TRANSFORMER
37 NOT USED
38 AUXIL. TRANSFORMER
39. 69 KV STRUCTURE
40 FUEL CELL PLANT TRANSFORMER
41. ADMINISTRATION BUILDING (OFFICES) WITH MACHINE, ELEC & INSTRU SHOPS BELOW
42 LABORATORIES & STORAGE
43. INVERTER AUXILIARY EQUIPMENT
44 MOTOR DRIVEN FIRE PUMP
45 DIESEL DRIVEN FIRE PUMP
46. COOLING TOWER MAKE UP PUMPS
47 RIVER WATER SCREENS
48. SERVICE WATER PUMPS
49 INTAKE STRUCTURE
50 CHLORINATOR & STORAGE HOUSE
51. COOLING TOWERS & BASIN
52 WATER TREATMENT EQUIP. BUILDING
53 LIQUID WASTE STORAGE
54. PARKING AREA
55 ROOF VENTILATING FANS
56. CIRC. WATER PUMPS & WELL
57 DEMINERALIZED WATER STORAGE TANK
58 CONDENSATE STORAGE TANKS
59 GASIFIER START-UP BURNER
60 FUEL CELL START UP BURNER
61 LOCK HOPPER AIR COMPRESSOR
62 GASIFIER TURBO COMPRESSOR
63 RECYCLE PUMP
64 FUEL CELL TURBO COMPRESSOR

Figure III-A — Detailed Plant Arrangement

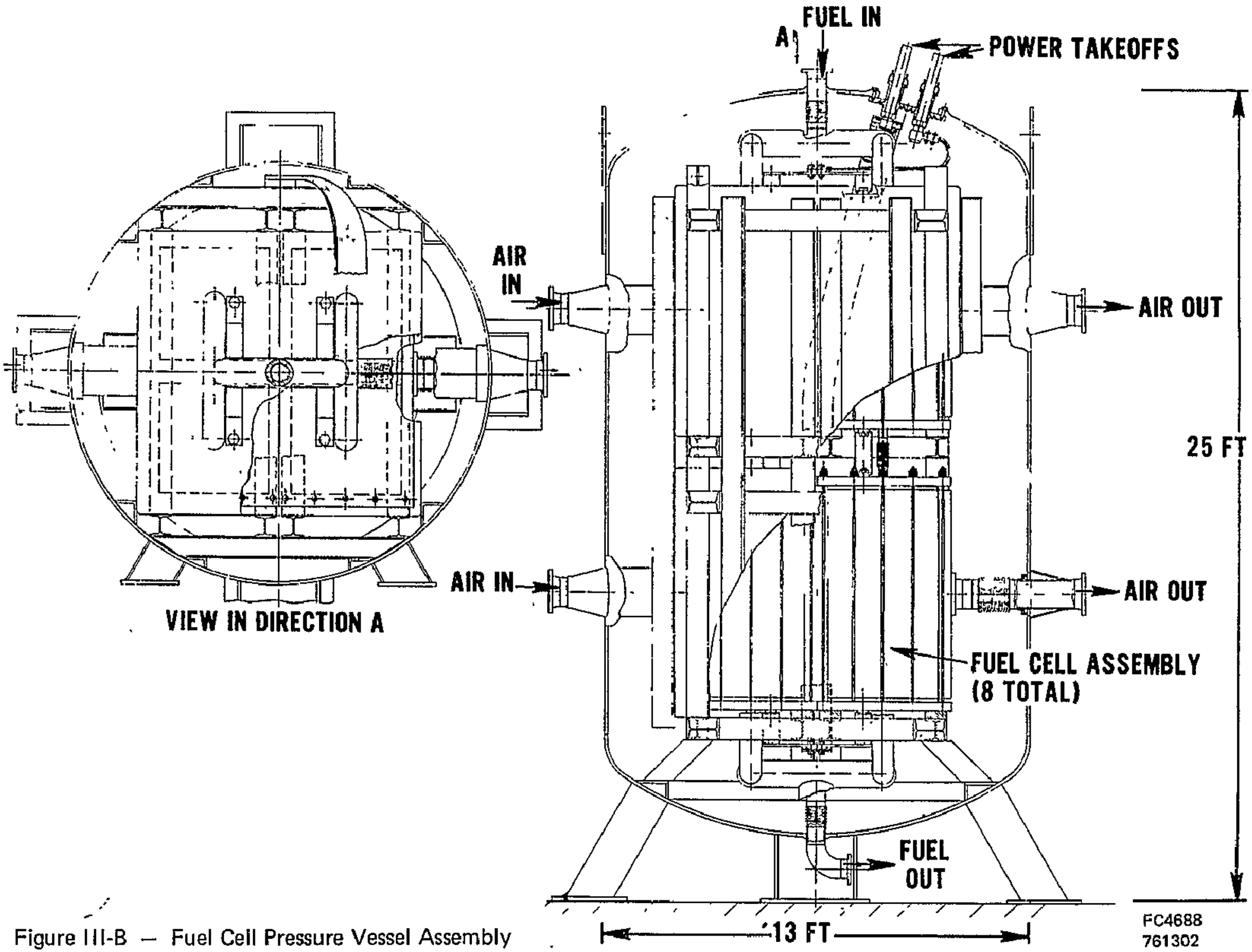


Figure III-B — Fuel Cell Pressure Vessel Assembly

APPENDIX IV

DESCRIPTION OF CELL ANALYTICAL MODEL

In EPRI project RP114, a mathematical model of the molten carbonate fuel cell was developed (Reference 14), and is presented herein.

The molten carbonate fuel cell produces direct current electrical power by the electrochemical combination of hydrogen and oxygen. The half-cell reactions are:

Anode	$H_2 + CO_3^{=} \rightleftharpoons H_2O + CO_2 + 2e^-$
Cathode	$1/2\ O_2 + CO_2 + 2e^- \rightleftharpoons CO_3^{=}$
Overall	$1/2\ O_2 + H_2 \rightleftharpoons H_2O$

Separate anode and cathode computer programs simulate the performance of porous, sintered gas diffusion electrodes as functions of reactant gas composition and utilization, cell operating temperature, electrolyte composition and the electrode structural and catalytic properties. The models for the anode and cathode are combined with experimentally determined values of electronic and conic resistance losses to provide a model of the entire cell.

An idealized illustration of the thin electrolyte film model is shown in Figure A. Here the pores are assumed to consist of an array of straight uniform cylinders of some constant mean radius. A thin layer of electrolyte extends from a flat meniscus and covers the wall of the pore for a distance equal to many times its constant thickness, δ. The electrode reaction takes place beneath this film where the dissolved reactants and electrolyte are both available at the active site. The performance of this single pore is scaled-up to represent that of the entire electrode. Voltage losses associated with diffusional transport of reactant and product gases across the electrolyte film, the electrochemical reaction occuring at the electrolyte/electrode interface and ohmic losses due to ionic resistance in the film are considered.

By postulating various reaction mechanisms and comparing theoretical trends with experimental data, an identification of the most likely mechanism and rate determining step (RDS) at each electrode becomes possible. This information is used to determine the relationship between the local current density (i) and the electrode polarization (η) for a multi-step electrochemical reaction. Combining this relationship with equations describing the flux of dissolved gases across the electrolyte film and the ohmic effect along the film length, a set of differential equations is generated which when solved simultaneously with the use of a digital computer yields the following information for a given overall cell current density:

- Anode and cathode IR-free potentials
- Local current density profile along the film
- Local electrolyte potential profile along the film
- Reactant and product concentration gradients across the film

A comparison of the model with a set of IR-free, low utilization (5% fuel and 10% oxidant), isothermal, half-cell performance data is shown in Figure B. The local exchange current density, i_o is used as the fitting parameter. As can be seen, the comparison between model and experiment is excellent.

In actual cell operation, the fuel and oxidant utilizations are much higher than those used in half cell tests, resulting in partial pressure gradients across the faces of the electrodes. The present model assumes that a single set of mean gas partial pressures can be used for each electrode to correctly predict the cell voltage for a given set of inlet compositions and utilizations. This means, in effect, that each electrode "sees" a uniform composition over its entire surface and it is this composition which will determine the half cell open circuit potential and electrode activity as measured by the exchange current density. At a given temperature, the exchange current density for both electrodes is, in general, directly proportional to some function of the gas partial pressures. This function in turn is dependent on the sequence of steps and the RDS chosen to represent the half-cell reaction. The proportionality constant in these relationships is what is varied in order to obtain a correlation with a particular set of data.

In order to test the model to see if it could correctly predict the effect of various reactant gas compositions and utilizations on cell performance at constant temperature, the individual values of the exchange current densities are varied until the best correspondence is obtained between model and experimental data for the performance curve based on 15% utilization of both fuel and oxidant. The proportionality constants are then determined. At this point the gas partial pressures are changed according to the variation in the fuel and oxidant utilizations and model predictions are made. All electrode and electrolyte parameters (electrode thickness, porosity, tortuosity, conductivity, etc.) are kept constant. A comparison between model and experiment is shown in Figure C (Cell Performance as a Function of Fuel Utilization) and Figure D (Cell Performance as a Function of Oxidant Utilization). In all cases the correspondence between model and experiment is very good.

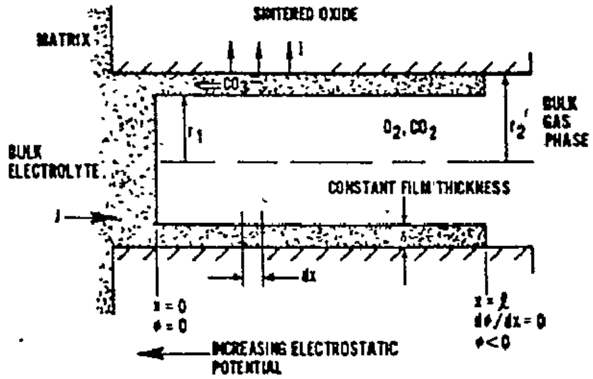


Figure A — Thin Film Model Applied to an Idealized Pore of the Cathode

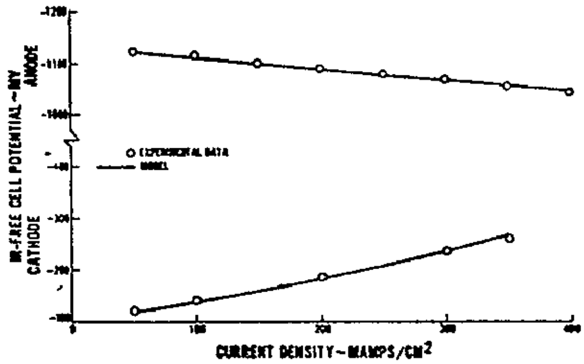


Figure B — Comparison of Half Cell Experimental IR-Free Data with Model Utilization of Fuel = 5 Percent. Utilization of Oxidant = 10 Percent. Reference Electrode Au/CO_2:O_2 (67%:33%) Isothermal Conditions

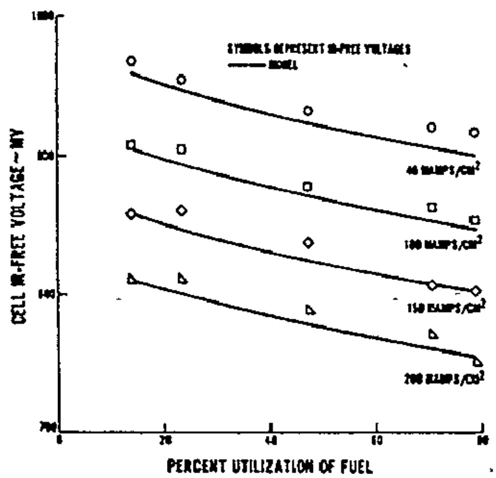
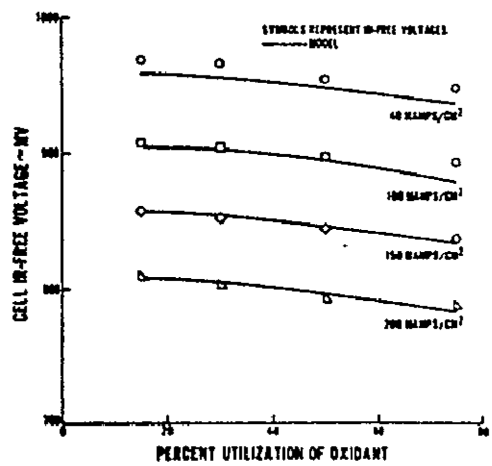


Figure C — Cell Performance as a Function of Fuel Utilization. Oxidant Utilization Kept Constant at 15 Percent

Figure D — Cell Performance as a Function of Oxidant Utilization. Fuel Utilization Kept Constant at 15 Percent.



APPENDIX V

OPERATING AND PHYSICAL CHARACTERISTICS OF HEAT EXCHANGER EQUIPMENT FOR THE INTEGRATED COAL GASIFIER/FUEL CELL POWERPLANT

TABLE A
UNIT HEAT EXCHANGER CHARACTERISTICS

Heat Exchanger	No. Units Per Powerplant	Vessel Size and Type	Heat Transferred Per Unit (10^6 Btu/Hr)	Surface Area Per Unit (Ft^2)	Weight Per Unit (1000 lbs)	Cost Per Unit FOB (1000$'s)	Cost Per Unit Duty ($/$10^6$ Btu)
Steam Bottoming Plant Boiler/Superheater	8	9' Diam x 49' Shell & Tube	477	170,000	440	1300	2730
Steam Reheater	4	9' Diam x 22' Shell & Tube					
Economizer	4	14' x 20' x 14' Finned Tubes					
Gasifier Air Preheater	4	7' Diam x 20' Shell & Tube	15.6	1680	19	29	1860
Gasifier Steam Generator	4	10' Diam x 30'	51.5		65	205	3980

Materials of Construction (except for Gasifier Steam Generator, designed by IGT)

- Tubes for Steam Reheater, and Superheater section of Boiler/Superheater: Stainless Steel, Austenetic
- Tubes for Boiler section of Boiler-Superheater, Air Preheater: High Alloy Steel
- Tubes for Economizer and Economizer section of Boiler/Superheater: Carbon Steel
- All pressure vessels: Carbon Steel

(*) Gasifier steam generator design was by IGT – Surface areas (Ft^2) were not available

TABLE B
HEAT EXCHANGER COMPONENT CHARACTERISTICS

Heat Exchanger	Hex Component	Temperatures, °F Approach	Temperatures, °F Pinch	Component Heat Transferred (10^6 Btu/hr)	Component Surface Area (Ft^2)	Tube Spacing (In) Long'tdl	Tube Spacing (In) Transverse	Tube Pitch (In)	Weight of Component Tubes (Lbs)
Boiler/ Superheater	Superheater	449	300	55.4	2820	4	4	2	17,370
	Boiler	449	269	54.4	2540	5	4	2	7,830
	Economizer	290	269	25.9	1880	4	5	2	11,415
Steam Reheater	N/A	570	540	70.7	2385	4	4	2	3,350
Economizer	N/A	175	50	134.8	153,060 (Finned – 6 fins/in; 1" fin width; .028" fin thickness)	6	6	2	131,180
Gasifier Air Preheater	N/A	449	300	15.6	1680	4	4	2	1,990
Gasifier Steam Generator	Superheater	1435	900	51.5	* →				
	Boiler	1435	1259						
	Economizer	1511	1259						

(*) Gasifier steam generator design by IGT – surface area and other details not available.

APPENDIX VI

ASSUMPTIONS USED IN ESTIMATING AUXILIARY POWER REQUIREMENTS

ITEM	ASSUMPTIONS	# OF UNITS	kW EACH	TOTAL kW
1. Lockhopper Gas Compressors	— Compressor ΔP rise (total)=235 psi — Inlet gas temperature = 260°F — 2-stage compressor w/ intercooling to 200°F — Flow per unit = 150 moles/hr of fuel cell exhaust — Compressor efficiency = 80% — Motor efficiency = 95%	4	270	1080
2. Desulfurizer Regeneration Air Pumps	— Pump ΔP rise = 25 psi — Flow per unit = 58,000 lb/hr — Pump efficiency = 80% — Motor efficiency = 95%	2	930	1860
3. Gasifier Boiler Feedwater Pumps	— Pump ΔP rise = 260 psi — Flow per unit = 150 gpm — Pump efficiency = 50% — Motor efficiency = 95%	2	36	71
4. Gasifier Process Air Compressors	— Driven by turbocharger			
5. Ash Sluice Pumps	— Pump ΔP rise = 205 psi — 25 wt % ash in ash/water slurry — Process water flow/unit = 264 gpm — Pump efficiency = 50% — Motor efficiency = 95%	2	25	50
6. Fuel Cell Recycle Pumps	— Driven by turbocharger			
7. Fuel Cell Process Air Compressors	— Driven by turbocharger			
8. Condensate Pumps	— Pump ΔP rise = 24 psi — Flow per unit = 1160 gpm — Pump efficiency = 50% — Motor efficiency = 95%	2	32	64

AUXILIARY POWER (CONT'D)

ITEM	ASSUMPTIONS	#OF UNITS	kW EACH	TOTAL kW
9. Steam Turbine Boiler Feedwater Pump (Staged)	– Pump ΔP rise = 2575 psi – Flow per unit = 1207 gpm – Pump efficiency = 50% – Motor efficiency = 95%	4	1420	5680
10. Cooling Tower Circulating Pum	– Pump ΔP rise = 10 psi – Flow per unit = 55,000 gpm – Pump efficiency = 50% – Motor efficiency = 95%	2	530	1050
11. Cooling Tower Fans	– Horsepower requirements = .041 hp/ft^2 tower area	32	35	1130
12. Steam Turbine Auxiliaries	Connected hp based on the same size and type unit provided for the 277 Mw Unit No. 1 at the Georgetown Steam Electric Station of the South Carolina Public Service Authority			84.3
13. Condensate Cycle, including: Condenser Vacuum Pump Condenser Vacuum Seal Pump Condenser Valves	On same basis as Item 12			79.8
14. Miscellaneous Services				
a. Closed Cooling Water System Pumps	GPM = 1000 Head = 233 ft. Pump eff. = 0.60 Motor eff. = 0.90	3	62.8	125.6
b. Sump Pumps	On same basis as Item 12	2	–	Not normally in operation
c. Service Air Compressor	300 scfm 100 psig discharge pres. 75 hp motor – same as Fort Martin Unit No. 1 Motor eff. = 0.95	2	47.1	47.1

AUXILIARY POWER (CONT'D)

ITEM	ASSUMPTIONS	# OF UNITS	kW EACH	TOTAL kW
d. Instrument Air Compressor	200 scfm 100 psig discharge pres. 50 hp motor — same as Fort Martin Unit No. 1 Motor eff. = 0.9	2	33.2	33.2
e. Bridge Crane	Main hook: 75 tons; travelling @ 4½ fpm – 30 hp	1		
	Auxiliary hook: 25 tons; travelling at 20 fpm – 40 hp	1		Normally not in operation
	Bridge: travelling at 100 fpm – 7½ hp	1		
	Trolley: travelling at 50 fpm — 20 hp	1		
f. HVAC Air Supply Fans	200 hp connected hp, based on the same size and type unit provided for the 400 Mw Leland Olds Unit No. 2 of Basin Electric Power Co.			125.6
g. Roof Exhaust Fans	100 hp connected load on same basis as Item 14f			62.8
h. Water Treatment Plant	Electric heating of concentrated caustic soda storage tank — based on same source as Item 14f	1		100
1) Booster Pump	250 gpm 220 head pump efficiency = 0.70 motor efficiency = 0.90	3	16.6	33.2
2) Chemical Feed Pumps				
Hydrazine	Based on same source as Item 12 3 gph, 850 ft. head	2	.02	0.02

AUXILIARY POWER (CONT'D)

ITEM	ASSUMPTIONS	#OF UNITS	kW EACH	TOTAL kW
Ammonia	½ hp based on same source as Item 12 3 gph, 850 ft. head	2	.02	0.02
Phosphate	Based on same source as Item 12.10 gph, 5750 ft. head	2	0.5	0.5
i. Auxiliary Boiler & Accessories	Based on same source as Item 14c for 85,000 pph boiler			
	Fan = 100 hp Fuel oil Pump = 20 hp Feedwater Pump = 60 hp	2 2	– –	
	Total connected hp 180	–		120
j. Miscellaneous	Misc. fans, pumps, instruments & controls less than 1 hp — Based on same source as Item 14c	25-50		16.6
k. Elevator	Motor-generator set, hp based on same source as Item 14c	1		33.2
l. Diesel Oil Pump	Based on same source as Item 14c for same size unit	1		Normally not in operation
m. Fire Pump	1500 gpm 300 ft. head Pump eff. = 0.50 Motor eff. = 0.75	1		Normally not in operation
n. Screen Wash Pumps & Travelling Screens	Based on same source as Item 12	2 2		94.2 33.2
o. Cooling Tower Makeup Pump	2000 gpm each 135 ft. head Pump eff. = 0.75 Motor eff. = 0.95	2	62.8	125.6

ITEM	ASSUMPTIONS	# OF UNITS	Kw EACH	TOTAL Kw
p. Service Water Pumps	2000 gpm, each 230 ft. head Pump eff. = 0.75 Motor eff. = 0.95	2	62.8	125.6
q. Liquid Waste Treatment	Based on proportioned hp for waste treatment plant for same source as Item 12	–	–	33.2
15. Coat Handling				
a. Conveyor No. 1	2000 tph, 600 fpm Horizontal hp = $C_f$xt(tph)xd d = center to center distance 35^{o} idlers C_f from U.S. Rubber Handbook M6314-B-17 Conveyor Belt Engineering, with Supplement, 1963	1	–	Normally not in operation
b. Conveyor No. 2	200 tph, 600 fpm Horizontal hp from same formula as item 15a $\text{Lift hp} = \frac{\text{tph x height of lift}}{990}$ from U.S. Rubber Conveyor Belt Engineering Handbook Height = 170 ft. Total hp = horizon. hp + lift hp	1	–	314
c. Conveyor Nos. 3A & 3B	250 tph, 600 fpm, horizontal – from same source as Item 15a	2	–	10
d. Conveyor Nos. 4A & 4B	250 tph, 450 fpm, horizontal + lift hp from same source as Item 15b	2	–	33

APPENDIX VII

Tables A through E in this Appendix list a detailed breakdown of the items included in the corresponding component categories listed in Tables XXIV thru XXVIII inclusive, in Section IV-D, of this report. These items are listed either as major components or balance-of-plant materials, corresponding to the way they were cost accounted in the study. Also, for each component category, the cost totals for the major components and the balance-of-plant materials are given, corresponding to the cost breakdown given in the above referenced report section. With one exception, the site labor costs included in the powerplant capital cost estimates correspond to site installation of only the items listed within each component category. The exception is under the category of improvements to the powerplant land siting wherein site labor includes the cost of initial land clearing and grading, in addition to site labor for landscaping, drainage, roads, etc.

TABLE A

LAND, IMPROVEMENTS, STRUCTURES, AND MISCELLANEOUS POWERPLANT EQUIPMENT

COMPONENT	MAJOR COMPONENTS	BALANCE-OF-PLANT MATERIALS
1.0 LAND	123 ACRES	
COST TOTAL	$308,000	
2.0 IMPROVEMENTS		
		2.1 FINISH GRADING AND LANDSCAPING 2.2 SITE DRAINAGE AND SEWAGE DISPOSAL 2.3 ROADS, WALKS, AND PARKING AREAS 2.4 RAILROAD ACCESS TRACK AND TRACK SITE 2.5 BALANCE (FENCING, ETC.)
COST TOTAL		$450,000
3.0 STRUCTURES		
	3.6 STATION CRANES IN F/C AND S/T BUILDINGS 3.7 STACKS – TURBOCOMPRESSOR/ ECONOMIZER STACKS (FOUR EXHAUSTS), FLARING STACK FOR GASIFIERS	3.1 FUEL CELL ISLAND CIVIL WORKS 3.2 STEAM TURBINE ISLAND CIVIL WORKS, INCLUDING TURBINE PEDESTAL 3.3 MISCELLANEOUS EQUIPMENT FOUNDATIONS 3.4 ADMINISTRATION BUILDING, INCLUDING STRUCTURE, UTILITIES, MACHINE SHOP, OFFICE EQUIPMENT 3.5 MAINTENANCE BUILDING, INCLUDING STRUCTURE UTILITIES AND SERVICE EQUIPMENT
COST TOTALS	$730,000	$7,200,000

TABLE A (Cont.)

COMPONENT	MAJOR COMPONENTS	BALANCE-OF-PLANT MATERIALS
4.0 MISCELLANEOUS POWERPLANT EQUIPMENT		
	4.1 AUXILIARY BOILERS AND ACCESSORIES	4.2 INTER-ISLAND PIPING, INCLUDING SUPPORTS, INSULATION, AND FOUNDATION 4.3 SERVICE WATER SYSTEM — PUMPS AND PIPING 4.4 WATER TREATMENT SYSTEM INCLUDING: COAGULATORS, FILTERS, DEMINERALIZATION SYSTEM, BOILER FEEDWATER TREATMENT, DEMINERALIZED STORAGE TANK, AND PUMPS 4.5 CLOSED COOLING WATER SYSTEM INCLUDING HEX., PUMPS, TANK 4.6 LIQUID WASTE TREATMENT SYSTEM, INCLUDING WASTE TREATMENT FACILITIES AND WASTE STORAGE POND 4.7 COMPRESSED AIR SYSTEM INCLUDING INSTRUMENTATION AND SERVICE AIR SYSTEMS 4.8 START-UP FUEL OIL SYSTEM INCLUDING TANKS AND FACILITIES 4.9 FIRE PROTECTION SYSTEM 4.10 OTHER PLANT UTILITIES, INCLUDING HEATING, VENTILATING, AND AIR CONDITIONING, AND COMMUNICATIONS
COST TOTALS	$440,000	$7,600,000

TABLE B

FUEL HANDLING AND PROCESSING

COMPONENT	MAJOR COMPONENTS	BALANCE-OF-PLANT MATERIALS
1.0 COAL HANDLING SYSTEM		
	1.1 CONVEYORS, FEEDERS, THAWING SHED, HEATERS, CRUSHERS, CRUSHER BUILDING, AND ACCESSORIES, HOPPERS, TUNNELS, LOWERING WELL	
COST TOTAL	$2,800,000	
2.0 COAL FEED AND GASIFICATION SYSTEM		
	2.1 LOCKHOPPER AIR COMPRESSORS, 22 LOCKHOPPERS, COAL BINS, SURGE HOPPERS, GASIFIER VESSELS CYCLONES, ASH HOPPERS, SLURRY COOLER, ASH SLUICE PUMPS	2.3 CONTROLS INSTRUMENTATION, PIPING AND AND VALVES (P&V) AND STEEL SUPPORT STRUCTURES AND CONCRETE FOUNDATION
COST TOTALS	$3,300,000	$3,900,000
3.0 ASH REMOVAL SUBSYSTEMS		3.1 ASH SETTLING BASIN, DEWATERING BINS, PIPING, AND EMERGENCY STORAGE POND
COST TOTAL		$540,000

TABLE B (Cont.)

COMPONENT	MAJOR COMPONENTS	BALANCE-OF-PLANT MATERIALS
4.0 GASIFIER PROCESS STEAM GENERATOR		
	4.1 BOILER-SUPERHEATER HEAT EXCHANGERS 4.2 BOILER FEEDWATER PUMPS	4.3 CONTROLS AND INSTRUMENTATION, PIPING AND VALVES, AND STRUCTURES AND FOUNDATIONS
COST TOTALS	\$830,000	\$730,000
5.0 PROCESS GAS CLEANUP		
	5.1 IRON OXIDE BEDS AND VESSELS 5.2 REGENERATION AIR PUMPS	5.3 CONTROLS AND INSTRUMENTATION, PIPING AND VALVING, AND FOUNDATIONS AND STRUCTURAL STEEL
COST TOTALS	\$1,700,000	\$2,000,000
6.0 SULFUR RECOVERY SYSTEM		
	6.1 ALLIED CHEMICAL SO_2 REDUCTION PLANT 6.2 CLAUS PLANT, SULFUR CONDENSERS AND PUMPS	6.3 CONTROLS AND INSTRUMENTATION, PIPING AND VALVES, FOUNDATIONS AND STRUCTURAL STEEL
COST TOTALS	\$4,900,000	\$4,200,000
7.0 SULFUR STORAGE, REMOVAL AND TRANSFER		
		7.1 STORAGE TANKS WITH STEAM COILS, TRANSFER PUMPS, STEAM TRACING, LOADING FACILITIES, AND PIPING
COST TOTAL		\$200,000

TABLE B (Cont.)

COMPONENT	MAJOR COMPONENTS	BALANCE-OF-PLANT MATERIALS
8.0 GASIFIER TURBOCOMPRESSOR SUBSYSTEM		
	8.1 TURBINE/AIR COMPRESSOR UNITS 8.2 GASIFIER AIR PREHEATER HEX'S 8.3 GASIFIER START-UP BURNERS	8.4 LUBE OIL SYSTEM AND BREACHING DUCT 8.5 INTAKE STACKS, SILENCING, INSULATION, AND INLET AIR FILTERS 8.6 COMPUTER CONTROLS, AND CONTROL PANELS
COST TOTALS	\$3,600,000	\$500,000

TABLE C
FUEL CELL SYSTEM

COMPONENT	MAJOR COMPONENTS	BALANCE-OF-PLANT MATERIALS
1.0 FUEL CELL STACKS		
	1.1 FUEL CELL STACKS, WITH INSULATION	
COST TOTAL	$35,000,000	
2.0 FUEL CELL VESSELS		
	2.1 FUEL CELL PRESSURE VESSELS AND INTERNAL SUPPORT STRUCTURES	
COST TOTAL	$2,000,000	
3.0 BURNERS AND AUXILIARY STARTUP BURNER		
	3.1 CATALYTIC BURNERS 3.2 STARTUP BURNERS, IGNITION, AND CONTROLS	
COST TOTAL	$590,000	
4.0 PIPING, VALVES, CONTROLS, AND INSTRUMENTATION		
		4.1 DISTRIBUTION PIPING AND VALVING, CONTROLS AND INSTRUMENTATION WITHIN FUEL CELL ISLANDS
COST TOTAL		$10,300,000

TABLE C (Cont.)

COMPONENT	MAJOR COMPONENTS	BALANCE-OF-PLANT MATERIALS
5.0 FUEL CELL TURBOCOMPRESSOR SUBSYSTEM		
	5.1 TURBOCOMPRESSOR UNITS WITH RECYCLE PUMP 5.2 STARTER MOTORS	5.3 LUBE OIL SYSTEM 5.4 INTAKE STACKS, SILENCING, AND INSULATION AND INLET AIR FILTERS 5.5 COMPUTER CONTROLS AND CONTROL PANELS
COST TOTAL	$4,100,000	$550,000

TABLE D

STEAM PLANT BOTTOMING CYCLE

COMPONENT	MAJOR COMPONENT	BALANCE-OF-PLANT MATERIALS
1.0 STEAM TURBINE GENERATOR		
	1.1 TURBINE-GENERATOR UNIT, W/AUXILIARIES: EXCITATION SYSTEM, TURBINE OIL PURIFICATION SYSTEM, LUBE OIL SYSTEM, H_2 AND CO_2 BOTTLE STORAGE AREA AND PANELS, STATOR COOLING UNIT, AND GLAND STEAM CONDENSER	
COST TOTAL	$7,400,000	
2.0 HEAT RECOVERY STEAM GENERATOR		
	2.1 STEAM TURBINE HEAT EXCHANGERS, INCLUDING: BOILER-SUPERHEATERS, AND STEAM REHEATERS, WITH HEADERS, PRESSURE VESSELS, AND INTERNAL SUPPORT STRUCTURE, ECONOMIZERS WITH HEADERS AND DUCTING	
COST TOTAL	$5,200,000	
3.0 CONDENSERS AND ASSOCIATED EQUIPMENT		
	3.1 CONDENSER 3.2 CONDENSER VACUUM PUMP AND MOTOR	
COST TOTAL	$600,000	

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TABLE D (Cont.)

COMPONENT	MAJOR COMPONENT	BALANCE-OF-PLANT MATERIALS
4.0 BOILER FEED AND CONDENSATE SYSTEMS		
		4.1 STEAM TURBINE BOILER FEEDWATER PUMPING 4.2 TANK DEAERATORS 4.3 CONDENSATE POLISHING SYSTEM 4.4 CONDENSATE STORAGE TANK 4.5 PUMPS AND MOTORS
COST TOTAL		$1,200,000
5.0 PIPING, VALVES, INSULATION		
		5.1 STEAM TURBINE ISLAND PIPING, VALVES, AND INSULATION FOR SAME
COST TOTAL		$2,000,000
6.0 COOLING TOWER SYSTEM		
	6.1 COOLING TOWERS W/FANS	6.2 COOLING TOWER FOUNDATIONS 6.3 CIRCULATING WATER PUMPS, PIPING, AND VALVES 6.4 MAKE UP PUMPS 6.5 INTAKE STRUCTURE INCLUDING SCREENS AND WASH PUMPS 6.6 CHLORINATION FACILITY
COST TOTALS	$3,500,000	$790,000

TABLE E

ELECTRICAL PLANT EQUIPMENT

COMPONENT/SUBSYSTEM	MAJOR COMPONENT	BALANCE-OF-PLANT MATERIALS
1.0 INVERTER SYSTEM		
	1.1 INVERTER MODULES, SERIES REACTORS AND HARMONIC REDUCTION TRANSFORMERS, INVERTER TRANSFORMERS AND ARRESTORS, HARMONIC FILTERS, DC AND AC SWITCHGEAR AND FUSES, FUEL CELL ISLAND CABLE, CONDUITS AND TRAYS	
COST TOTAL	$16,400,000	
2.0 MAIN AND AUXILIARY TRANSFORMERS		
	2.1 FUEL CELL MAIN TRANSFORMERS 2.2 STEAM TURBINE MAIN TRANSFORMERS 2.3 STATION AUXILIARY TRANSFORMERS, WITH ARRESTORS	
COST TOTAL	$2,000,000	
3.0 MOTOR CONTROL CENTERS AND CONTROL BOARD		
		3.1 MOTOR CONTROL CENTERS 3.2 CONTROL AND RELAY BOARDS LOCATED IN GASIFIER, FUEL CELL, STEAM TURBINE ISLANDS, AND COOLING TOWERS
COST TOTAL		$350,000

TABLE E (Cont.)

COMPONENT/SUBSYSTEM	MAJOR COMPONENT	BALANCE-OF-PLANT MATERIALS
4.0 ISOLATED PHASE BUS		
		4.1 STEAM, TURBINE ISOLATED PHASE BUS
COST TOTAL		$250,000
5.0 DIESEL GENERATOR		
		5.1 DIESEL MOTOR, GENERATOR, FUEL TANK AND PUMPS, STARTING, COOLING, AND LUBING SYSTEMS, AND CONTROLS
COST TOTAL		$150,000
6.0 CABLES, CONDUITS AND TRAYS		
		6.1 ALL INTER-ISLAND WIRING, DUCTING AND SUPPORTS. (SOME TRESTLES SHARED WITH INTER-ISLAND PIPING)
COST TOTAL		$2,400,000
7.0 STEAM PLANT ACCESSORY ELECTRIC EQUIPMENT		
		7.1 GROUNDING TRANSFORMER, TURBINE ISLAND CABLE, CONDUIT, AND TRAYS, STATION BATTERY, INSTRUMENT POWER SUPPLY INVERTER
COST TOTAL		$380,000

TABLE E (Cont.)

COMPONENT/SUBSYSTEM	MAJOR COMPONENTS	BALANCE-OF-PLANT MATERIALS
8.0 TOTAL PLANT CONTROLS AND INSTRUMENTATION		8.1 CENTRAL CONTROL ROOM FOR CENTRALIZED POWERPLANT MONITORING BOARD, INCLUDING INSTRUMENATION 8.2 POWERPLANT COMPUTER
COST TOTAL		$1,200,000
9.0 69 KV STRUCTURE, SWITCH-GEAR AND CIRCUIT BREAKERS		9.1 POTENTIAL TRANSFORMERS, ARRESTORS, SURGE CAPACITORS, SWITCHGEAR 9.2 CIRCUIT BREAKERS 9.3 69 KV STRUCTURES
COST TOTAL		$590,000

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