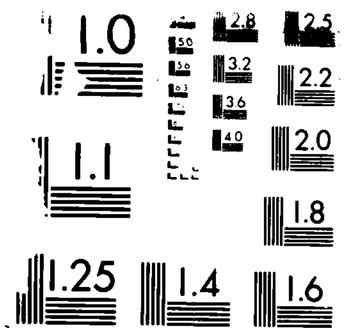
AD-A175 566 FEASIBILITY STUDY OF COAL GASIFICATION/FUEL CELL/COGENERATION ECONOMIC AND FINANCING ASSESSMENT(U) EBASCO SERVICES INC NEW YORK P BOS ET AL. AUG 85 1/2

UNCLASSIFIED DAAG29-85-C-0007 F/G 5/1 NL



RESOLUTION TEST CHART

0

FEASIBILITY STUDY OF

COAL GASIFICATION / FUEL CELL / COGENERATION

ECONOMIC AND FINANCING ASSESSMENT

REPORT CLIN 0004-0005

PREPARED FOR

DEPARTMENT OF THE ARMY

AND

GEORGETOWN UNIVERSITY

AUGUST, 1985

ARS GROUP/EBASCO

FEASIBILITY STUDY OF

COAL GASIFICATION / FUEL CELL / COGENERATION

ECONOMIC AND FINANCING ASSESSMENT

REPORT CLIN 0004-0005

PREPARED FOR

DEPARTMENT OF THE ARMY

AND

GEORGETOWN UNIVERSITY

AUGUST, 1985

ARS GROUP/EBASCO

Unclassified

SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered)

REPORT DOCUMENTATION PAGE		READ INSTRUCTIONS BEFORE COMPLETING FORM
1. REPORT NUMBER CLIN 0004-0005	2. GOVT ACCESSION NO. [redacted]	3. RECIPIENT'S CATALOG NUMBER
4. TITLE (and Subtitle) FEASIBILITY STUDY OF COAL GASIFICATION/ FUEL CELL/COGENERATION, ECONOMIC AND FINANCING ASSESSMENT		5. TYPE OF REPORT & PERIOD COVERED Economic/Financing Analysis 6. PERFORMING ORG. REPORT NUMBER
7. AUTHOR(s) P Bos, B Rossi, P Estreich		8. CONTRACT OR GRANT NUMBER(s) DAAG 29-85-C-0007
9. PERFORMING ORGANIZATION NAME AND ADDRESS Ebasco Services Inc 2 World Trade Center New York, NY 10048 ARS Group, Inc 15 Clark Road Wellesley, MA 02181		10. PROGRAM ELEMENT, PROJECT, TASK AREA & WORK UNIT NUMBERS 611102-BH57-09
11. CONTROLLING OFFICE NAME AND ADDRESS Procurement Office U S Army Research Office P O Box 12211 Research Triangle Park N C 27709-211		12. REPORT DATE August, 1985 13. NUMBER OF PAGES
14. MONITORING AGENCY NAME & ADDRESS(if different from Controlling Office)		15. SECURITY CLASS. (of this report) Unclassified 15a. DECLASSIFICATION/DOWNGRADING SCHEDULE
16. DISTRIBUTION STATEMENT (of this Report) Approved for public release: distribution unlimited		
17. DISTRIBUTION STATEMENT (of the abstract entered in Block 20, if different from Report)		
18. SUPPLEMENTARY NOTES Prepared in cooperation with Georgetown University. The views, opinions and/or findings contained in this report are those of the author(s) and should not be construed as an official Department of the Army position, policy or decision, unless so designated by other documentation.		
19. KEY WORDS (Continue on reverse side if necessary and identify by block number) Fuel Cell/Coal Gasification/Cogeneration/Exemplar Study		
20. ABSTRACT (Continue on reverse side if necessary and identify by block number) Report describes an economic and financing analysis of Coal Gasification/Fuel Cell/Cogeneration (GFC) projects specific to four sites: Washington, D C; Scranton, PA; Ft Hood, Texas; Ft Greely, AL.		

DD FORM 1 JAN 73 1473 EDITION OF 1 NOV 65 IS OBSOLETE

Unclassified

SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered)

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont'd)

8030A

LIST OF FIGURES

8030A

LIST OF TABLES

LIST OF TABLES

1.0 INTRODUCTION

1.1 Purpose

The purpose of this report is to describe the economic and financing feasibility assessment carried out for a Coal Gasification/Fuel Cell/Cogeneration (GFC) Project for 4 specific sites: Scranton Army Ammunition Plant in Pennsylvania, Ft. Greely Army Base in Alaska, Ft. Hood Army Base in Texas, and Georgetown University in Washington, D.C.

Since their respective subjects are closely related and essential to the conclusions drawn for each site, the deliverables, CLIN 0004 (economics) and CLIN 0005 (financing) are combined into this one report.

The assessment presented in this document is part of an overall technical, economic, and financing feasibility study of power generation by a fuel cell using synthetic gas produced from coal. The concept involves selling the electric power and thermal output from the GFC plant to the site facility under a price structure that would produce significant energy-related cost savings for the site for the 20 years, 1990-2009.

Although, the government would partly fund this program, it is intended that the private sector will provide increasingly substantial capital investment and construct, own and operate a more efficient central coal energy facility. The feasibility study is the first stage of a program that links four key objectives to achieve commercialization of GFC technology to more broadly benefit the Army:

1. A technology development cost objective that would reduce the prototype plant capital costs by 1/2 for second stage projects (early 90's) and by 2/3 for commercial stage projects (mid 1990's on).

2. A private ownership/financing objective that has private capital immediately involved in sharing the costs of the prototype plans, and solely involved when the technology is developed to the fully commercial stage. I.e., the initial investment by the

Department of Army would stimulate the inflow of private capital that would with commercialization of this technology, reduce or eliminate DOA capital expenditures.

3. Energy costs that would be equal to or less than the current energy costs of the Department of the Army.

4. Accelerated commercialization of an environmentally sound and efficient coal driven cogeneration technology.

Under this program, the government would fund the R&D-related capital costs of this emerging technology. This funding would cover 70 to 80% of prototype plant costs in the first stage and 50% of plant costs in the second stage. In the last stage, all funding would be from private sources.

The private GFC plant owner would share the savings resulting from the GFC plant energy output (compared to purchasing power from the utility and separating steam and hot water with existing boilers) and would be able to utilize the tax benefits (e.g., depreciation) available to any invester in industrial equipment.

1.2 Organization of Report

The site-specific economic feasibility results, the ownership/financing analysis, and the conclusions and recommendations of the study are presented in the four sections of this report as follows:

- o Section 1.0 outlines the methodology of this report as well as the supporting work that precedes it. It also identifies the risks that are inherent in the economic analysis and the energy price scenarios used to determine ranges for sensitivity analysis. Finally, the conclusions of this analysis are summarized for each site.

- Section 2.0 presents the economic feasibility results for each site, and are organized into the following subsections:

  - Costs benefits for the site
  - Basic economics of the GFC plant
  - Identification of incremental site requirements and capital costs
  - Site conclusions

- Section 3.0 presents the ownership/financing analysis (CLIN 0005) for the two sites found to be viable (Scranton AAP and Fort Greely) and has the following subsections:

  - Potential financing alternatives
  - Interested parties and likely site-specific arrangements
  - Ownership/financial results

- Section 4.0 presents the overall conclusions of the feasibility study and recommendations for further action (or not) for each site.

1.3 Methodology

It is the intent of this study to present results based on representative conditions rather than on technical designs, economics, and financing structures that are fully optimized. The key question is whether the concept could provide benefits to enough (not necessarily all) Army bases to warrant further R&D expenditures on preliminary system design and testing of selected coals and equipment. A subsequent decision would be made after the design and testing stage on whether to proceed into final design and to organize the private ownership and financing component of the concept. Figure 1-1 shows the development stages that would constitute such a program.

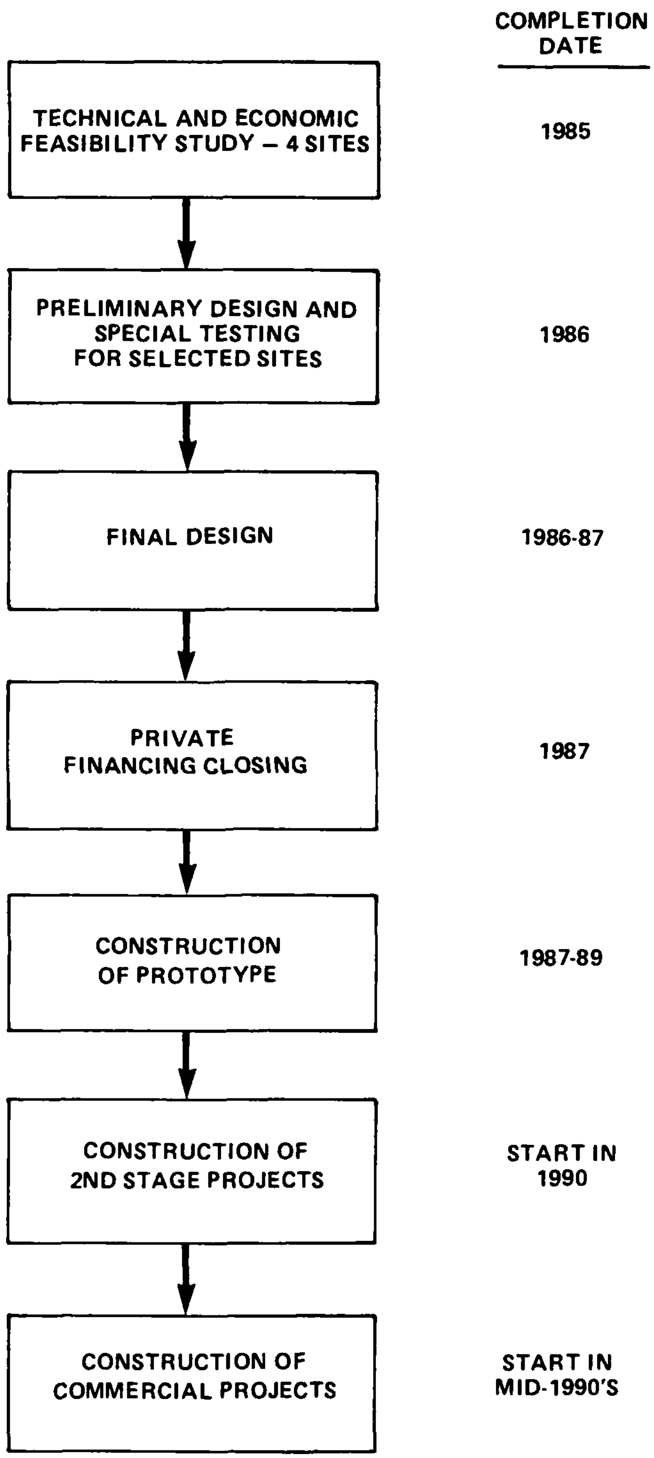


FIGURE 1-1 GFC DEVELOPMENT SCHEDULE

Three steps in the feasibility work preceded this report.

1. Development of a basic system description of the GFC plant, to be used as a point of departure for the feasibility configurations for each site. (CLIN 0001 report)

2. A preliminary survey for each of the four sites, documenting site-specific information to be addressed by the feasibility design and economic evaluation. (CLIN 0002 reports)

3. Development of GFC plant designs for each site (CLIN 0003 reports) to verify technical feasibility and to quantify GFC plant electric and thermal energy production for use in the economic analysis. Site specific incremental plant requirements are determined to provide a complete energy plant defined by site needs.

The analysis of basic economics was carried out in the followng major steps:

a. Estimate capital costs for the GFC plant design developed for each site, including separate costs for the site specific increments.

b. Develop typical operating and maintenance (O&M) costs for the GFC plant.

c. Document current site energy use and costs.

d. Project site energy use and costs under a range of potential energy price scenarios.

e. Assess GFC plant economics for each scenario.

For those sites with strong enough economics, analysis of a potential ownership/financing structure was then carried out.

1.4 Bases and Risks

A number of economic assumptions and GFC plant risk factors are common for all sites and are discussed below.

Major factors in the analysis of existing site future energy costs are as follows:

1. Fuel cost. Since the early 1970s, fossil fuel prices have varied unpredictably, with several sharp increases during this period, followed by relatively flat trends, (see Figure 1-2) or even a decrease in prices.

2. Electric power costs. While somewhat more predictable than fossil fuel prices, electric power prices have also shown sharp changes over the past 15 years as a result of impacts from fossil fuel prices as well as sharp increases in rates when new, and often costly, utility power plants were incorporated into utility rates. (See Figure 1-2)

3. Army base replacement costs. On-site boilers, steam/hot water distribution systems, and electric power distribution lines must periodically be replaced or upgraded by the Army base.

4. O&M costs. The on-site boilers, distribution systems, and other energy-related equipment must be operated and maintained, with an attendant labor and material cost.

GFC plant risks fall into two areas: technical and economic. Technical risks that directly affect the economic analysis are:

- System efficiency. GFC designs for the four sites had system efficiencies ranging from 19.0% to 38.9%.*

---

*System efficiency is defined as the Btu value of the electric power, thermal, and other revenue-producing outputs divided by the Btu value of coal delivered to the plant (minus any coal fines or coal residuals resold).

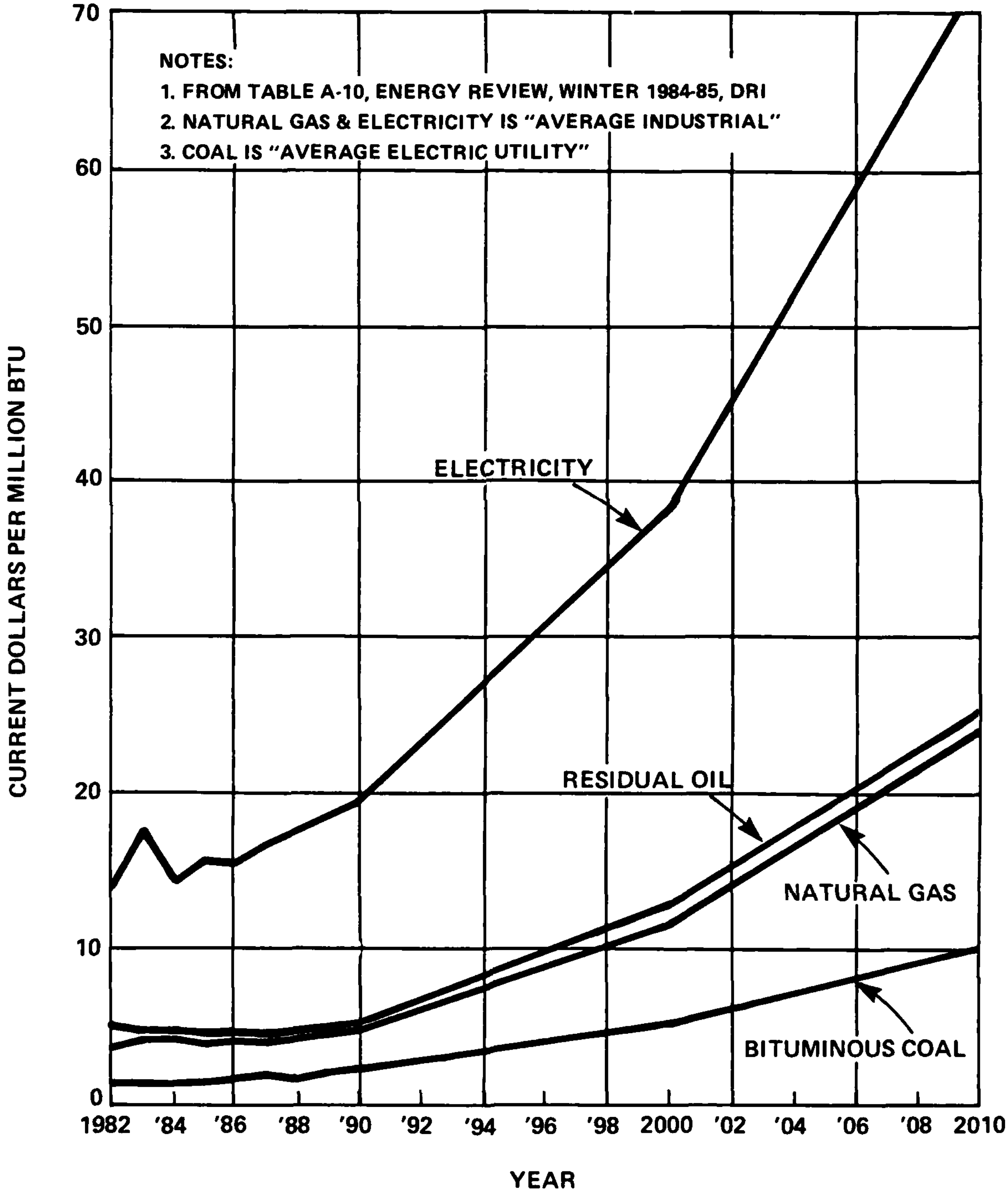


FIGURE 1-2 NATIONAL ENERGY PRICES

- <u>System capacity factor</u>. The plant capacity factor is estimated at 81% for all GFC's but the GFC using the Westinghouse fuel cell at the Scranton, PA. site. Because of its use of anthracite coal, equipment to separate tars and oils from the raw gas was eliminated, raising this factor to 82%. See the CLIN 000303 report, para. 2.4 for details.

- <u>GFC plant lifetime</u>. A minimum 20-year useful technical lifetime and a 10-year economic lifetime were assumed with a complete fuel cell reload every 5 years, starting in the 6th year of plant life.

The economic risks of the GFC plant relate to final plant capital costs, thermal user guarantees, O&M costs, electric power prices, and fossil fuel prices, as follows:

- <u>Final capital costs</u>. The final GFC plant capital costs will be affected by final design and near-term inflation rates. However, the risk from higher capital costs is lower than energy price risks because capital costs become fixed by 1990, whereas the other risks continue throughout the lifetime of the plant. Moreover, the impact of higher capital costs is distributed over a number of years through depreciation and through the private debt financing structure.

- <u>Thermal user guarantees</u>. For some cogeneration plants, the potential loss of the thermal demand (and attendant revenues) represents a significant risk. In this case, since the U.S. Government would be guaranteeing the steam purchase under long term contract (for a guarantee of maximum steam price), the risk is more limited. However, this risk is partially mitigated bythe ability of the thermal Management System to redirect unused thermal energy to the production of electric power.

- <u>Plant O&M costs for GFC facility</u>. Plant O&M costs present two economic risks: the absolute amount of O&M costs as initially established, and the long-term escalation of these costs. The variation in the absolute amount of O&M costs initially established is not considered to be a great risk. For the plant design used (based on the 11 megawatt UTC fuel cell module), a representative set of O&M costs were estimated, and deliberately made the same for all sites. Given the feasibility study accuracy range, regional labor costs and other variations in O&M fall within the accuracy provided in those estimates. The O&M costs as estimated for the first year of operation (1990) approximate $2.5 million (exclusive of any insurance, taxes, and other annual costs). A breakdown of the O&M costs into major components is shown in Table 1-1.

o <u>Electric power and fossil fuel prices</u>. Energy prices and O&M costs present significant risks throughout the life of the project. Given the uncertainty in energy prices and inflation (which are linked), the economic analyses were based on the following three scenarios which were structured to bracket a reasonable range of future energy prices and inflation in terms of near-term (1985-1990) and long-term (1990-2009) average compound growth rates (Refer also to Table 1-2):

<u>SCENARIO 1 -- Fossil Fuel Prices Remain Flat in Near-Term, Increase at Inflation Rate in Long-Term</u>. The specific assumptions used for this scenario are a 0% escalation rate for 1985-1990 (less than the inflation rate) and a 5% escalation rate (equal to assumed inflation) for 1990-2009. Electric power, and O&M costs were assumed to escalate at inflation (5%) in the near-term and long-term. GFC electric and steam prices were assumed to escalate at 5% in the long-term.

While fossil fuel prices have actually decreased in the last 1-2 years, for the 25 year time horizon, the projected energy costs under this scenario would likely be lower than actual. In any event, this scenario is representative of low fossil fuel escalation rate conditions.

SCENARIO 2 -- Fossil Energy Prices Remain Flat in Near-Term, Escalate Significantly in Long-Term. The assumptions for this scenario were 0% escalation for fossil fuel prices for 1985-1990, and 10% for 1990-2009. Electric power costs were assumed to increase at 5% near-term and 10% long-term. GFC electric and steam prices were assumed to escalate at 10% in the long-term. O&M costs and inflation were assumed to escalate at 5% near-term and 8% long-term. (The inflation rate is affected by any long-term energy escalation rates, and therefore was assumed higher to be consistent with the overall scenario.)

This scenario is representative of a situation where energy prices remain flat under stable energy conditions in the near term, but reflect some unforeseen geopolitical event or economic conditions that produce a sustained high growth rate, starting in the early 1990s. While many analysts include such a scenario in their business and contingency planning, and this scenario could be judged to be a "middle", this scenario should just be considered representative of one set of possible conditions.

SCENARIO 3 -- Fossil Fuels Increase at Inflation Rate in Near-Term, Escalate Signifiantly in Long-Term. The specific assumptions under this scenario were a 5% escalation rate for fossil energy prices, electric power, O&M, and inflation for 1985-1990. For the term 1990-2009, a 10% escalation rate was assumed for fossil energy prices, purchsed electric power, and GFC plant electric power and steam prices, with an 8% escalation assumption for O&M costs and inflation.

The combined 25 year growth of energy prices under this scenario is significant. For the 25-year period, the projected energy costs likely are higher than would actually occur.

Exhibit 3 presents a summary of the key assumptions in the three scenarios used in the economic feasibility analysis.

1.5 Conclusions

Based on analyses of the specific energy characteristics for each site and the three economic scenarios, the following conclusions were reached for each site:

1. The Scranton AAP site was found to be viable, and showed a number of improvement opportunities that should be addressed in preliminary design and further economic analysis to improve the economics even further.

2. THE FORT GREELY site was found to be viable, presenting not only strong cost savings but also providing an additional electric power capacity required by the electric utility system in that area.

3. THE FORT HOOD site was found not to be viable for any reasonable level of Army base energy cost savings, mainly due to the relatively low expected cost of future electric power in that area.

4. THE GEORGETOWN UNIVERSITY site was found not to be viable, due to projected electric power prices insufficient to provide suitable GFC plant operating margins, and special site constraints requiring significant increases in the plant capital costs.

TABLE 1-1

ESTIMATED O&M COSTS ($ Million)

Item	1985 Dollars	1990 Dollars*	1995 Dollars*
Labor and Fringes	1.0		
Contract Maintenance	0.2		
Supplies and Parts	0.5		
Site Utilities, Ash/Sludge Disposal and Miscellaneous	0.3		
Subtotal	2.0	2.6	3.3
Annual Fuel Cell Reload Costs**			0.6**
Insurance and Taxes	0.2	.2	.3
TOTAL	2.2	2.8	4.2

* O&M escalated at 5 percent per year in base scenario.

** Start in 6th year of GFC plant operation.

TABLE 1-2

ENERGY PRICE SCENARIOS

	Has Impact on Site	Has Impact on GFC Plant	Scenario 1* 1985-1990 Escal Rate	Scenario 1* 1990-2009 Escal Rate	Scenario 2** 1985-1990 Escal Rate	Scenario 2** 1990-2009 Escal Rate	Scenario 3*** 1985-1990 Escal Rate	Scenario 3*** 1990-2009 Escal Rate
Fuel Oil Price	X		0	5	0	10	5	10
Natural Gas Price	X		0	5	0	10	5	10
Coal Price	X	X	0	5	0	10	5	10
Purchased Electric Power from Utility	X		5	5	5	10	5	10
O&M Cost	X	X	5	5	5	8	5	8
Inflation Rate	X	X	5	5	5	8	5	8
GFC Plant Electric Power Cost	X	X	NA	5	NA	10	NA	10
GFC Plant Steam Cost	X	x	NA	5	NA	10	NA	10

Scenario Definitions:

* Scenario 1 - Flat near-term fossil fuel prices. Inflation rate increases in long-term.

** Scenario 2 - Flat near-term fossil fuel prices. High and sustained longterm escalation rates.

*** Scenario 3 - Inflation increases in near-term fossil fuel prices. High and sustained long-term escalation rates.

2.0 ECONOMIC ANALYSIS

2.1 General

2.1.1 Capital Costs

Order of magnitude capital cost estimates in 1985 dollars are shown in Table 2-1. Each system and facility cost estimate is based on the equipment lists and other information found in Site Specific Project Descriptions, CLIN 000301, 2, 3 and 4, on information from equipment suppliers and on Ebasco Estimating Department records.

Items 1 through 12 in Table 2.1-1 include the following:

a. Cost of equipment with insurance, freight to site and vendor engineering.

b. Cost of direct labor based on craft union agreements, payroll taxes, insurance, fringes and supervision.

   For the Washington DC, Pennsylvania and Texas sites, five eight hour shifts with casual overtime are assumed.

TABLE 2.1-1

CAPITAL COST ESTIMATES[1]
(IN THOUSANDS OF DOLLARS)

Item	Scranton, PA W	Scranton, PA UTC	Fort Greely, AK W	Fort Greely, AK UTC	Fort Hood, TX UTC	Washington, DC UTC
1. UFC Plant Buildings and Site Development[2]	3,400	3,900	10,300	12,700	3,500	14,300
2. Coal Handling & Storage	1,600	1,700	3,000	3,900	1,700	1,700
3. Coal Gasification	5,200	3,600	4,900	6,400	5,000	3,600
4. Gas Cooling, Cleaning and Compression	1,100	1,400	1,800	1,900	1,400	1,400
5. C O Shift	500	600	700	800	600	600
6. Sulfur Removal & Recovery	4,400	5,600	6,100	7,500	5,400	5,600
7. Process Condensate Treatment	1,700	1,700	2,300	2,400	1,660	1,700
8. Fuel Cells & Power Conditioning[3]	15,400	15,400	18,400	18,400	15,400	15,400
9. Thermal Management	2,600	1,900	4,500	4,200	2,400	1,900
10. Cooling Water	700	900	2,100	2,700	800	900
11. Water Treatment	300	400	400	500	400	400
12. Balance of Plant	1,500	2,000	2,800	2,800	1,500	2,000
13. UFC Plant	38,400	39,100	57,300	64,200	39,700	49,500
14. Preproduction Costs	880	940	1,410	1,740	1,000	940
15. Inventory Capital	140	280	230	420	270	280
16. Initial Catalysts & Chemicals	160	720	270	350	450	720
17. Total Plant Investment[4]	39,580	41,040	59,210	66,710	41,420	51,440

Notes: 1. Referenced to mid-1985 dollars; excludes interest during construction.
2. Includes civil work, buildings, building services (HVAC, Electrical, Lighting, Plumbing & Drainage).
3. Costs are based on system being a follow on to the manufacturer's prototype program (semi-production units).
4. Excludes accounts receivable and cash on hand for operating expenses.

For the Alaska site, six ten hour shifts with scheduled overtime are assumed.

c. Indirect construction costs, including temporary construction plant and facilities, nonmanual local hires and subcontractor profit and overhead.

At Fort Greely the cost of incentives to attract and hold craft labor are included. This covers travel allowances, a construction camp and other living accommodations, recreational facilities, food subsidies, etc.

d. Cost of engineering and home office overhead valued at 10% of capital costs.

e. Project contingency which allows for uncertainties in the cost estimate that would be resolved in a detailed design. This contingency which varies with pricing sources and workscope delineation is assigned as follows:

Washington DC - 13%
Scranton, Pa - 11%
Ft Hood, Tx - 12%
Ft Greely, Al - 14%

f. Process contingency of 5.0% which allows for uncertainties in technical performance.

g. An engineering and home office fee of 8% of process capital.

h. Project management

Other costs associated with the initiation of plant operation are as follows:

a. Preproduction cost (Item 14) covers the training of operating personnel, preoperational testing of equipment, extra maintenance and inefficient use of fuel and materials during startup. To approximate these costs, the following items were summed for each GFC plant:

1) one month's fixed and variable operating and maintenance costs.

2) 25% of one month's coal costs.

3) 2% of the plant investment (excluding fixed civil work).

b. Inventory capital (Item 15) is estimated as:

1) one month coal supply based on operation at rated capacity.

2) one month supply of other consumables.

c. Initial catalysts and chemicals (Item 16) are those contained in the process equipment but not in storage.

2.1.2 Operating and Maintenance Costs

As indicated in Section 1.3, typical operating and maintenance costs were estimated for the GFC facility and included the following components:

- Labor and fringes
- Contract maintenance
- Supplies and Parts
- Site Utilities and Waste Disposal
- Fuel Cell Reloads
- Insurance and Taxes

Labor and Fringes - Labor costs were based on the level of staffing outlined in Section 2.5 of CLIN 0003 and an average wage rate of $15 per hour. Fringe benefits were estimated at 10 percent base salary.

Contract Maintenance - Outside maintenance assistance during outages and for specialized tasks was estimated as 25 percent of total maintenance costs. In-house maintenance labor included in "Labor and Fringes" above, was estimated at 15 percent of total maintenance costs for a total maintenance labor component of 40 percent.

Supplies and Parts - Expenses for maintenance materials, tools and spare parts was estimated at 60 percent total maintenance costs. (Total maintenance costs were estimated at an average rate of 2 percent of investment cost).

Site Utilities and Waste Disposal - Expenses were based on estimated quantities presented in CLIN 0003 and the following unit cost factors obtained at the Georgetown site:

- o Water - \$.698/100 cF
- o Sewage - \$1.297/100 cF
- o Electricity - 5.4¢/kWh
- o Ash/Sludge - \$10/ton
- o Natural Gas (option) - \$4.80/10^6 BTU
- o Catalysts/Chemicals - \$175,000/yr

Annual Fuel Cell Reload Costs - Replacement of the fuel cell stack every five years, or 20% annually every year was estimated at \$32/kW-yr.

Insurance and Taxes - Insurance and taxes were estimated at \$200,000/yr or about 1/2 percent of total investment cost.

2.1.3 Natural Gas Standby

A natural gas standby system was considered at all sites but Alaska, as a means for providing a secure source of anode gas for the fuel cell during a major failure in the coal handling, gasification or gas processing systems. Not having an available source of natural gas, this system was not considered for Fort Greely.

The capital cost of a standby system which includes the gas service connection, a methane reformer, hydrodesulfurizer and gas compressor is estimated by Westinghouse to be $4,700,000. An equivalent system for the larger UTC system is estimated to be $6,600,000.

With the plant capacity factor of 81% estimated for this project, avoided costs would have to be above 20¢/kwh to pay for the annual equivalent capital cost and associated fixed charges of the natural gas standby system. For this reason and also noting that all sites can maintain flow of heating steam during a GFC system outage by means of their existing heating plants, the option for a natural gas standby system was rejected.

2.1.4 Site Specific Increments

Site specific increments have been defined and described in the CLIN 0003 report series. These increments represent additional capital costs that are not considered a part of the GFC system or its economics but that are nevertheless, a supplement that is required or that has been requested to satisfy other related site requirements.

A brief description of these increments and their costs are as follows:

Scranton, AAP, Pennsylvania

This increment consists primarily of the acquisition of land and the steam and condensate connections to the existing AAP mains.

Capital Cost - $400,000

It is proposed that the land for the GFC would be purchased from the Scranton City Corporation by the third party owner and given to the Department of the Army.

Fort Greely, Alaska

The major part of this increment is for the purpose of allowing the use of coal to meet all Main Post energy requirements.

The increment consists of additional gasifiers, pressure blowers, an aboveground insulated raw gas pipeline to existing boiler, reworking of an existing boiler to burn the low Btu gas, additional coal handling and storage and the steam and condensate connections (because of unusual length) between the GFC and the existing steam header.

The incremental capital costs imposed by severe cold (e.g., foundation work, space heating and the greater amount of enclosure required) have also been assigned to this category.

Capital Cost, Westinghouse System - $17,500,000
Capital Cost, UTC System - $20,000,000

Fort Hood, Texas

This increment consists of a complete steam absorption unit chilled water plant, a high temperature hot water plant and an extensive underground chilled and hot water piping distribution system with tie-ins and heat exchangers at each building served.

Capital Cost - $17,500,000

Washington, D.C.

Included in this increment are relocation of disrupted facilities, replacement of parking and relocation of athletic playing surface.

Capital Cost - 16 to $20,000,000

2.2 Scranton, Pennsylvania Site

The Scranton Army Ammunition Plant (AAP) site was described in previous reports (CLIN 000202 and CLIN 000302). To verify the economic feasibility of the GFC plant, the costs and benefits must be evaluated for both the site and the GFC plant third party owner. Therefore, this section contains the following:

1. Site costs/benefits.

2. Economics.

3. Conclusions.

Although the "base system" for this site is designed around the Westinghouse fuel cell, it was found that the total system as conceived in CLIN 000302, which includes the use of anthracite coal, resulted in a negative return on investment. (It is believed that with further optimizing and use of another coal type, economics of the Westinghouse based GFC will improve.) By replacing this system with one based on the UTC fuel cell similar to that described for the Washington D.C. site (CLIN 000301) and supplied with an eastern bituminous in lieu of the anthracite coal, the return on investment increased to 11.1%.

For this reason economics of the UTC cell system rather than of the Westinghouse system is analyzed in this section.

2.2.1 Site Costs/Benefits

The benefits to Scranton AAP can occur through savings in electric power use, fuel use, and operating and maintenance (O&M) costs. Each of these is analyzed in the two sections below.

2.2.1.1 Energy Use and Costs Without the GFC

To serve as a base of comparison in the analyis of GFC benefits to the site, 25-year projections were made of energy use and costs without the

GFC for the years 1990-2009. The cost factors projected are discussed as follows:

Electric Energy. Currently, Scranton AAP consumes about 30 million kWhs per year of electric energy. The escalation in kWh use is expected to be moderate. 2% per year was assumed in the near-term, providing somewhat more than 32 million kWh in 1990. A 2% escalation rate was assumed for the long-term as well.

The current electric energy (kWh) rate is 4.3¢/kWh. A 5% annual escalation rate was assumed for all scenarios in the near-term (1985-1990), providing a rate of approximately 5.5¢/kWh in 1990. In the base scenario, a 5% escalation rate was assumed for the long term. For the second and third scenarios, a 10% long-term escalation rate was assumed. (See Table 1-2 for a summary of assumptions made for each scenario.)

The current annual electric energy cost is about $1.3 million. Under the above assumptions, it would increase to $1.8 million in 1990. The long-term projection of electric energy costs depends on escalation rates that vary between 5% and 10% per year.

Electric Demand. Currently, Scranton AAP has a peak electric demand of about 8.5 MW. It was assumed this would increase at a moderate rate of 2% per year, both in the near-term and long-term.

The current demand charge is approximately $3.5/kW/month. In the near-term in all scenarios, it was assumed this would increase at 5% per year, giving a demand charge of $4.4/kW/month in 1990. The long-term escalation rates varied by scenario.

Currently, the total electric demand cost is about $360,000 annually. Under the assumptions used above, this would increase to $500,000 by 1990. In the long-term, a range of escalation rates from 5%-10% were used.

The total electric power costs, then, are currently \$1.6 million, likely to increase to \$2.3 million by 1990.

Natural Gas. Currently, about 350 million cubic feet of natural gas are consumed annually by Scranton AAP. Assuming this usage increases by 2% per year, an assumption consistent with the total energy use projections made for the site, the natural gas required would increase to over 380 million cubic feet by 1990, with a long-term escalation of 2% per year.

The current cost of natural gas is about \$5.80 per mcf (58¢ per therm). Under the first (base) scenario, this price would stay flat through 1990, then increase in the long-term at 5% per year. While near-term decreases in natural gas (and oil) costs could occur, given the current softness of the those prices, the first scenario provides a low level of natural gas prices from 1990 to 2009.

The current annual gas cost of \$2 million would increase to about \$2.2 million by 1990 under the base scenario assumption.

Other Fossil Fuels. Scranton AAP uses a minor amount of fuel oil with usage assumed to increase at 2% per year, both in the near-term and long-term. Its current price of 63¢ per gallon was assumed to stay flat under the first scenario analysis, and increase at 5% per year thereafter. The total annual cost of the fuel oil use is negligible (perhaps \$10,000) compared to the natural gas cost.

Operating and Maintenance Costs. Incomplete information was available on the amount of energy-related O&M costs for Scranton AAP. Based on on available data, a current O&M cost of slightly more than \$500,000 per year was assumed. This was assumed to increase 5% annually (inflation) to \$670,000 per year by 1990, and under the first scenario, to increase by 5% per year thereafter.

Total Site Energy Costs. The total annual energy-related costs for Scranton AAP are currently over \$4.2 million. Under the first scenario, these costs would increase to \$5.2 million in 1990, and would increase to \$9-\$10 million per year in 1999. The total cost for the ten years, 1990-2009, would approximate \$70 million.

Table 2.2-1 shows the projected near-term energy use, rate, and total cost, and the escalation rates assumed for the long-term under the first (base) scenario.

2.2.1.2 Costs/Benefits With the GFC

The cost savings to Scranton AAP can occur through one or more of the following: electric energy savings, electric demand savings, reduced use of gas in their existing boilers, and O&M. The electric power savings would occur if the GFC plant sells power to the site at a cost lower than the purchase price of power from the electric utility.

The site (AAP) fuel savings would occur if the GFC plant sold steam to the AAP at a price lower than it would otherwise cost the AAP to produce it in their gas fired boilers.

The site would have O&M savings if it did not spend as much operating or maintenance time on its on-site boiler, steam, and electrical systems as it would without the GFC plant. Typically, the O&M savings occur more through reduced boiler and steam system activity, since there is little on-site electric power system maintenance required. Further, under the GFC plant concept, the O&M savings can be more than just the reduced labor and materials cost for on-site boiler and steam systems maintenance. The GFC plant operators could well operate the entire on-site energy plant. In fact, it is preferable to do this, since any integrated energy plant decisions and interface maintenance requirements can be better coordinated. In effect, the site energy plant employees could become employees of the GFC plant.

Site energy cost savings can result from different combinations of lower electric power and/or steam prices. For this study, the site savings to Scranton AAP were primarily the result of the difference in cost between steam purchased from GFC and the fuel and associated O&M costs to generate the same amount of steam in the existing gas fired boilers.

TABLE 2.2-1

SITE ENERGY USE, PRICE AND COST PROJECTIONS

Scenario 1 (Base) Scranton AAP, Pennsylvania

Energy Parameter	1984	1985	1986	1987	1988	1989	1990	1990-2009 Escalation Rate
Electric Power								
Energy (Mil kWh)	28.9	29.5	30.1	30.7	31.3	31.9	32.6	2%
Rate (¢/kWh)	4.1	4.3	4.5	4.8	5.0	5.3	5.5	5%
Demand (MW)	8.4	8.6	8.7	8.9	9.1	9.3	9.5	2%
Rate ($/kW/Mo)	3.3	3.5	3.6	3.8	4.0	4.2	4.4	5%
Overall Rate (¢/kWh)	5.3	5.5	5.8	6.1	6.4	6.7	7.1	
Fuels								
Natural Gas (Mil Mcf)	341	348	355	362	369	376	384	2%
Price ($/Mcf)	5.5	5.8	5.8	5.8	5.8	5.8	5.8	5%
Fuel Oil (Mil gal)	Small	Small	Small	Small	Small	Small	Small	2%
Price ($/Gal)	.60	.63	.63	.63	.63	.63	.63	5%
O&M Cost ($ Mil)	0.5	0.5	0.5	0.6	0.6	0.6	0.7	5%
Total Energy-Related Costs ($ Million)	3.9	4.2	4.4	4.6	4.8	5.0	5.2	

There is an additional advantage to the GFC plant from a savings approach that focuses on steam, and not electric power. If the local electric utility can pay more for the power, depending upon its rate structure and marginal costs of capacity, the GFC plant would derive more value from its power output than it would if it simply displaced the electric power costs for the site. This was the case for the Scranton AAP site feasibility analysis. Pennsylvania Power and Light (PP&L) has an "avoided cost" rate structure (see para. 2.2.2.2) that exceeds the expected rate for purchased power by Scranton AAP which made it possible to correspondingly lower the steam price.

At an assumed 2% growth rate, the current consumption of 90 million pounds of steam per year would increase to approximately 100 million pounds per year by 1990. For the Scranton AAP GFC feasibility design, the GFC plant steam output is 66 million pounds per year (see CLIN 0003). The assumed GFC purchase price by Scranton AAP for this steam (in 1985 dollars) is $4 per thousand pounds, a price set to provide reasonable savings through reduced use of the on-site boilers. At an assumed 5% annual escalation rate, this price would be $5.10 per thousand pounds in 1990, the first year of GFC plant operation and under the base scenario, would also escalate at 5% in the long-term.

With the GFC, Scranton AAP's estimated $2.2 million cost for purchased fuels in 1990 would be reduced to about $2.0 million for purchased steam and remaining fuel requirements, and the 1990 O&M could be reduced from $670,000 to $370,000, or by $300,000.

The total savings in 1990 under these assumptions is estimated at $500,000-$600,000. It is likely to increase, assuming a 5% electric power and fossil fuel escalation rate (first scenario), to over $800,000 per year by 1999, the tenth year of GFC plant operation. The cumulative savings over the first ten years of GFC plant operation (the 1990s) would approximate $7 million.

These savings are conservative since they are based on the first scenario which predicts lower energy costs without the GFC than those forecast by most experts through the year 2000. The estimate of site cost savings under higher escalation rates (scenarios 2 and 3) would be $8-$11 million for the ten-year period. Table 2.2-2 is a summary of the projected site energy use, costs, and savings with the GFC plant. In this exhibit, the current and projected total site energy use is shown. It also shows the total site energy costs without the GFC and with the GFC. However, the GFC savings accrue only to the fuels and O&M costs for the site. Accordingly, on this tabulation, a GFC energy cost comparison is shown next. For 1990, the cost of the GFC thermal energy purchased, combined with the O&M savings that would likely occur is $300,000, whereas the equivalent cost of fuel and O&M without the GFC is estimated at $800,000. Finally, the exhibit shows the estimated GFC related cost savings for the second and third scenarios analyzed.

2.2.2 GFC Plant Economics

The GFC plant economic attractiveness is measured by the financial return on the investment provided. Whether one uses return on total private investment (ROI) or payback, both are affected by the magnitude of investment and the cash savings (after tax) that it can generate. Therefore this section covers the estimated GFC capital cost, GFC O&M costs, GFC energy output characteristics and key assumptions, and the GFC plant return on investment (ROI) results.

In the calculation used, the yearly after-tax cash flows for 10 operating years are discounted to a present value and effectively divided by the present value of private capital investment which occurs over 3 years. A negative return occurs if the total amount of the operating cash flows is less than the total private investment. The ROI of an investment is that discount rate at which the present value of the operating cash flows exactly equals the present value of the private capital investment.

TABLE 2.2-2

PROJECTED SITE ENERGY USE, COSTS AND SAVINGS WITH GFC
($ Million)

Scranton AAP, Pennsylvania

SCENARIO 1 (Base)*	Current 1985	Projected 1990	Projected 1995	10-Yr Total (1990-1999)
Total Site Energy Use				
Electric (million kWh)	29.5	32.6	35.9	356.4
Thermal (billion Btu)	97.3	107.5	118.6	1176
Total Energy Cost				
Cost without GFC		5.2	7.2	71.4
Cost with GFC		4.7	6.5	64.6
GFC Energy Cost Comparison				
Cost of Energy From GFC		.3	.5	4.4
Cost of Same Energy and O&M Without GFC		.8	1.2	11.2
Cost Savings with GFC		.5	.7	6.8
SCENARIO 2:** Cost Savings with GFC		.5	.8	8.2
SCENARIO 3:*** Cost Savings with GFC		.7	1.1	10.7

* Flat near term fossil fuel prices. 5% long-term escalation.

** Flat near term fossil fuel prices. 10% long-term escalation.

*** Fossil fuel prices 5%/year near term, 10%/year long term.

2.2.2.1 Capital Costs

Under the commercialization cost sharing concept of the program, the government would fund 70% of the normal capital cost for the GFC plant, and the private third-party owner the remaining 30% (See Table 2.1-1). Further, the private contribution would be the last 30% required. Under this arrangement, the government capital contribution would be $35.7 million and the private contribution $15.3 million, as shown in Table 2.2-3. These shares are derived as follows:

The estimated GFC plant construction and preproduction costs (1985 dollars) are $40.0 million. Assuming a 5% construction cost escalation until equipment is delivered and construction is completed at various stages, these costs escalate to a total of $46.9 million installed by the end of 1989. The construction costs timing pattern for these is roughly a 20-40-40% allocation for the three construction years, 1987-1989.

In addition to the hard construction costs, there are other capital requirements for any project to begin operation, specifically construction interest, working capital, and development, financing, legal, and other costs. The construction interest is assumed to be zero, for two reasons. First, the basic economic measure is return on total private investment, with no private debt, hence no interest costs. Second, even with a financing structure that assumes debt, since the last capital contribution is the private contribution, the amount of interest during the last few months of construction is small compared to the total capital costs, perhaps a few hundred thousand dollars. However, because of final performance testing and construction certification holdback amounts, it may be that the private contribution would occur virtually at plant startup, with no attendant construction period interest.

Working capital is required for the delay in payment of invoices (i.e., accounts receivable), fuel inventory needed, initial catalyst and chemicals, and other initial inventory. The estimated capital requirements at startup for the Scranton AAP site for these items is $2.3 million.

Finally, for any privately financed entity, there are private development, financing, legal, and other costs associated with that activity. These costs are estimated at $1.8 million (fixed) for the project. These include:

- o Financing fees of $1.2 million, or 8% of the private capital requirement.

- o Third party development fee of $300,000, or 2% of the private capital.

- o Legal and other expenses of $300,000, or 2% of the private development capital.

The total capital requirements, as installed, for the Scranton project, then, are $51.0 million. Table 2.2-3 shows the percentage and timing breakdown of these requirements for the private and governmental portions of $15.3 and $35.7 million respectively.

2.2.2.2 Plant Energy Production

The margin provided by the output revenues and the basic operating cost determines the return on the private capital required. For the Scranton AAP site, the GFC plant outputs are electric power and steam. Any tars and oils or other intermediate outputs of the plant are reused in the process as an auxiliary fuel, or assumed to be unusable and a waste product.

The electric power revenues from the GFC plant are based on its rate of power output, number of operating hours per year and the price received for the power sold. In this case, the entire electric power output is assumed sold to the electric utility, Pennsylvania Power & Light (PP&L). The assumed avoided cost structure, as drawn from projections provided by the utility to the state Public Utilities Commission, is 8.8¢ per kilowatt hour through 1992. From then, and based on projections provided by PP&L, avoided costs escalate to 12.7¢/kWh in 1995. It then is escalated at either 5% or 10% per year, depending on the scenario analyzed.

TABLE 2.2-3

GFC PLANT CAPITAL REQUIREMENTS ($ Million)

Scranton AAP, Pennsylvania

	1985 Dollars	Installed Costs Assuming a 5-Percent Escalation Rate 1987	1988	1989	Total
Construction Costs					
GFC Plant Equipment	35.2				
GFC Plant Civil	3.9				
Preproduction Costs	.9				
Subtotal	40.1	9.0	18.5	19.4	46.9
Other Costs					
Construction Interest				0*	0
Working Capital				2.3	2.3
Development, Financing, Legal and Other				1.8	1.8
Subtotal		—	—	—	4.1
Total Capital Requirements		9.0	18.5	23.5	51.0
At a 30/70 Mix of Capital Contributions:					
Private Capital				15.3*	15.3
Government Capital		9.0	18.5	8.2	35.7

* Private capital would be legally committed at the beginning of construction, but would be contributed as the last funding increment. Therefore, construction interest on any private debt used is assumed to be zero.

The electric energy sold to PP&L is estimated at 88 million kilowatt hours per year in the first five years of operation, increasing to approximately 94 million kilowatt hours thereafter. The assumption behind this increase is that, with operating experience, the plant availability should increase after some period of operation.

The total electric revenues to the GFC plant corresponding to this output are $7.8 million in 1990, increasing to $12.0 million in 1995 in accordance with the increased kWh output and the increased rates. The ten-year revenues for the plant are estimated at $106 million.

The remaining revenues for the plant are steam revenues. The annual amount of steam sold upon startup of the GFC plant is 9200 thousand pounds per hour and 35 million per year, increasing to 38 million pounds per year in 1995 and after. In accordance with the steam price assumptions discussed earlier, the expected annual revenues in 1990 are $340,000, increasing to $460,000 in 1995. The ten year stream of steam revenues is estimated at $4.5 million.

Table 2.2-4 shows the key electric power and other output assumptions for the GFC plant for the first year and sixth year of operation, and cumulatively for the first ten years of operation.

Both the O&M and the fuel operationg costs are significant. The O&M cost assumptions were explained in Section 2.2.2. In addition to the technical O&M, there are other possible annual operating costs that must be considered, mainly taxes and insurance. The amount estimated for these two costs in 1990 is $260,000, assumed to escalate at 5% per year long-term.

Using a coal price of $58 per ton (under the first scenario analysis, fossil fuel prices were assumed flat for five years), the 1990 coal cost for the Scranton GFC plant is estimated at $3.0 million. With a 5% excalation, and an increase in plant operating hours starting in the sixth year, the estimated cost in 1995 is $3.8 million.

TABLE 2.2-4

GFC PLANT ECONOMIC OUTPUTS

Scranton AAP, Pennsylvania

Economic Parameter	First Year (1990)	Sixth Year (1995)	First 10 Years Operation (1990-1999)
Electric Power Output			
Net Power Output (MW)	12.3	12.3	
Operating Hours per year	7096	7596	
Energy Sold to Site (Mil kWhs)	0	0	0
Price (¢/kWh)	NA	NA	
Energy Sold to Utility (Mil kWhs)	87.3	93.4	904
Price (¢/kWh)	8.8	12.7	
Steam Output (at 240 psig)			
Output Rate (000 Lbs/hr)	9200	9200	
Sold to Site (Mil Lbs)	66.1	70.7	684
Price ($/1000 Lbs)	5.10	6.50	

While the basic economic analysis did not focus on financing and ownership structures, it had to incorporate some fundamental tax assumptions in order to derive an after-tax cash flow return on the total investment. While there is currently a substantial focus on potential new tax legislation, in the absence of any new proposals, the current tax laws were assumed.* Therefore, the tax assumptions made were:

- o 10% investment tax credit.
- o 5-year straight line depreciation.
- o 50% combined federal and state marginal annual income tax rate.
- o As a sensitivity analysis, the impact of the annual income tax credit (through 1999) for nonconventional sources of gas was evaluated. Currently, this tax credit is approximately 70¢ per million Btus of synthetic gas produced.

2.2.2.3 Return on Investment

For the basic economic analysis (CLIN 0004 requirement), return on total investment (ROI) was used as the measure of the GFC plant financial performance. With this measure, no private debt is assumed -- i.e., the entire private investment is treated as equity.

---

* With regard to tax factors affecting the GFC plant economics, the overall thrust of the current tax proposals is to eliminate or reduce the investment tax credit and stretch out the depreciation, both measures that would lower the ROI. The proposals would also reduce marginal annual income tax rate, a measure that would increase the ROI in the long-term.

The ROI results of the analysis are not to be considered as final investment-decision results. Rather, they are an indicator of the potential economic attractiveness of the GFC plant. The ROI result is one measure to be used by the Department of the Army to decide which sites warrant further expenditures for preliminary design and detailed economic/financing analysis. Other measures of importance to be used by the Army will be:

- o Benefit from using coal to replace oil and gas use.

- o Increased site power supply reliability.

- o Reduced requirements for other site plant capital expenditures.

- o The value of a maximum price guarantee to be provided by the GFC plant that would not be available from existing electricity and fuel suppliers.

Further, the technical design and economics of the plant were not optimized in this feasibility study. The purpose of the next stage -- preliminary design and testing -- is to identify improvements in the plant efficiency (causing lower operating costs) and reductions in the capital cost. Also, the private cost-sharing component, which is a significant strength of the GFC concept, has been roughly set at 30%, based on an expected production volume capital cost for the GFC plant at 30% of the prototype cost. This number, coupled with revised capital cost estimates, could change somewhat. Therefore, the minimum economic performance required from the analysis to warrant further work should not be as high as the final ROI and other financial requirements that would be desired by investors in any final design plant.

A feasibility ROI criterion of 10%, without the annual syngas income tax credit (which makes the ROI higher), was used to test each of the sites for economic feasibility. While the syngas tax credit has been in effect for several years, and should not be ignored (see Section 6.0), it distorts the ROI such that general comparisons with other ROIs are harder to make. The 10% ROI criterion roughly translates into a 25% or higher return on equity (ROE), assuming a 2/1 private debt/equity ratio. (Alternative financing structures and the ROE results are discussed in Chapter 6.0, Financing and Ownership Analysis.)

As shown in Table 2.2-5, the total GFC plant revenues for Scranton AAP in 1990 are estimated at $8.1 million, and total costs at $5.8 million, resulting in an operating cash flow of $2.3 million. This operating margin increases steadily, with a 10-year total operating cash flow of approximately $34 million.

For the ROI analysis, there is no debt service requirement. Therefore, only a tax saving or payment needs to be applied to the operating cash flow to obtain the after-tax net cash flow.

During the first five years of plant life, the allowed depreciation results in a slight tax savings. Therefore, the net cash flow in 1990 is slightly greater than the operating cash flow. However, starting in 1995, a tax payment of 50% of the operating cash flow occurs.* Overall, the net cash flow is fairly steady at $2.0-$2.5 million during the first ten years of plant life, with a total 10-year cash flow of almost $24 million.

The resulting ROI under the base scenario is approximately 11%. The results under Scenario 2 (flat near-term fossil prices and high, sustained long-term prices) is approximately 10%. Under Scenario 3, with a 5% annual increase in near-term fossil energy prices, and high, sustained long-term escalation rates, the net cash flow would decrease significantly during the first ten years of operation, resulting in a 10-year cash flow of 2/3 that of the first two scenarios and an ROI of about 3%. While this scenario does not appear as likely as either one of the first two, its effects should be evaluated in further financial/economic analysis.

---

* The annual income tax credit for nonconventional sources of gas (called the syngas tax credit) which is in effect through 1999, has not been included in the tax calculation so that the resulting ROI can be compared to other ROIs reflecting conventional tax assumptions.

TABLE 2.2-5

GFC PLANT CASH FLOW SUMMARY

Scranton APP, Pennsylvania

Economic Variable	1990	1995	10-Year Total (1990-1999)
Base Scenario (Flat near-term fuel prices. 5%/year long-term)			
Revenue			
Electric	7.8	12.0	106.0
Other	.3	.5	4.5
Subtotal	8.1	12.5	110.5
Cost			
Fuel	3.0	3.8	37.6
O&M & Other	2.8	4.2	38.8
Subtotal	5.8	8.0	76.4
Operating Cash Flow	2.3	4.4	34.1
Tax Saving (Playment)*	.2	-2.2	-10.4
Net cash flow	2.5	2.2	23.7
ROI	11.1%		
Scenario 2 (Flat near-term fuel prices. 10%/year long term)			
Net Cash Flow	2.5	1.8	22.5
ROI	9.7%		
Scenario 3 (Fuel prices 5%/year near term, 10%/year long term)			
Net Cash Flow	2.1	1.1	16.0
ROI	2.7%		

*Does not include the annual syngas tax credit.

2.2.3 Conclusions

The analysis of the Scranton AAP site led to the following conclusions:

1. Potential site thermal and O&M savings could be significant, approximating 10% of the project site energy costs, and providing a certainty in energy prices not available from other fuel suppliers and the electric utility.

2. The Westinghouse GFC plant as configured for this site for use with anthracite coal, did not provide acceptable economics because of lower economies of scale for the smaller plant and had a lower overall efficiency than the UTC configuration which used bituminous coal. (Accordingly, the analysis of this section was based on the UTC system.)

3. For a set of energy prices that provides the Scranton AAP a 10% cost savings, the minimum GFC plant after-tax return on total investment indicator exceeds 10% with the potential for improvement by optimization in final design.

2.3 Fort Greely, Alaska Site

The Fort Greely site was described in previous reports (CLIN 000204 and CLIN 000304). To verify the economic feasibility of the GFC plant, the cost and benefits must be evaluated for both the site and the GFC plant third party owner. Therefore, this section contains the following:

1. Site costs/benefits.
2. Economics.
3. Conclusions.

Although the "base system" for Fort Greely was in CLIN 000304, designed around the Westinghouse fuel cell, it was found that this system resulted in a negative return on investment. (It is believed that with further optimizing, economics of the Westinghouse based GFC may improve.) By replacing this system with one based on the UTC fuel cell similar to that described for the Fort Hood, Texas site (CLIN000303) and supplied with an eastern bituminous in lieu of the anthracite coal, the return on investment increased to 11.1%.

For this reason economics of the UTC cell system rather than of the Westinghouse system is analyzed in this section.

2.3.1 Site Costs/Benefits

The benefits to Fort Greely can occur through savings in electric power use, fuel use, and operating and maintenance (O&M) costs.

2.3.1.1 Energy Use and Costs Without the GFC

As base of comparison for the analysis of GFC benefits to the site, one must first project the energy use and costs without the GFC plant. The objective of this 25-year projection was to derive reasonable energy use and cost numbers for the years 1990-2009. Therefore, while current and expected near-term energy use and prices were evaluated, there was no attempt to analyze temporary aberrations in electric power or fuel prices. Each of the energy cost factors as projected is discussed in the following paragraphs.

Electric Energy. Currently, Fort Greely consumes about 15 million kWhs per year of electric energy. The expected near-term and long-term escalation in kWh use is almost zero.

The current electric energy rate is 6.8¢/kWh. While scenarios were evaluated with alternative energy price escalation rates, in the near-term (1985-1990), a 5% annual escalation rate was assumed for all scenarios. This would provide a rate of approximately 8.7¢/kWh in 1990. In the base scenario, a 5% escalation rate was assumed for the long term. For the second and third scenarios, a 10% long-term escalation rate was assumed. (See Table 1-2).

The current annual electric energy cost is about $1 million. Under the above assumptions, it would increase to $1.4 million in 1990. The long-term projection of electric energy costs depends on escalation that vary between 5% and 10% per year.

Electric Demand. Currently, Fort Greely has a peak electric demand of about 3 MW, which is not expected to increase materially.

The current demand charges, based on a wheeling charge by Golden Valley Electric Association (GVEA), is approximately $7/kW/month. In the near-term in all scenarios, it was assumed this would increase at 5% per year, giving a demand charge of almost $9/kW/month in 1990. The long-term escalation rates varied by scenario.

Currently, the total electric demand cost is about $250,000 annually. Under the assumptions used above, this would increase to $330,000 by 1990. In the long-term, a range of escalation rates from 5%-10% were used.

The total electric power costs, then, are currently $1.6 million, likely to increase to $1.7 million by 1990.

Fuel Oil. Fort Greely uses about 2.3 million gallons of fuel oil per year as its only fossil fuel consumption (natural gas is not available). As with electric power, the thermal energy and related fuel requirements, are not expected to increase materially over time.

The current cost of No. 2 fuel oil is 95¢ per gallon, assumed flat through 1990 under the base scenario analysis, then increasing in the long-term at 5% per year.

The total annual fuel oil cost is currently about $2.2 million, increasing marginally with time in accordance with the above assumptions.

Operating and Maintenance Costs. Fort Greely's energy plant-related O&M costs are currently about $900,000 per year. These are expected to increase at an inflation rate, (5%) resulting in O&M of $1.1 million in 1990. The long-term escalation rates for O&M were varied between 5-8% across the scenarios analyzed.

Total Site Energy Costs. The total annual energy-related costs for Fort Greely are currently $4.3 million. Under the first scenario, these costs would increase to $5 million in 1990. Under the base scenario analysis (5% per year energy price escalation long-term), the total energy related costs for the site would increase to $8 million per year in 1999 and the total cost for the ten years, 1990-2009, would approximte $6 million.

Table 2.3-1 shows the projected near-term energy use, rate, and total cost, and the escalation rates assumed for the long-term under the first (base) scenario.

2.3.1.2 Site Cost/Benefits With the GFC

The cost savings to Fort Greely can occur through one or more of the following: electric energy savings, electric demand savings, site boiler fuel savings, and O&M. The electric power savings would occur if the GFC plant sells power at a lower cost than the site would otherwise purchase that power from the electric utility. The site fuel savings would occur if the GFC plant sold the site steam at a price lower than it would otherwise cost the site to produce it.

TABLE 2.3-1

SITE ENERGY USE, PRICE AND COST PROJECTIONS - Scenario 1 (Base)

Fort Greely, Alaska

Energy Parameter	1984	1985	1986	1987	1988	1989	1990	1990-2009 Escalation Rate
Electric Power								
Energy (Mil kWhs)	15.7	15.7	15.8	15.8	15.8	15.9	15.9	0.2%
Rate (¢/kWh)	6.5	6.8	7.2	7.5	7.9	8.3	8.7	5%
Demand (MW)	3	3	3	3	3	3	3	0.2%
Rate ($/kW/Mo)	6.7	7.0	7.4	7.7	8.1	8.5	8.9	5%
Overall Rate ($/Kwh)	8.0	8.5	8.8	9.3	9.7	10.2	10.8	
Fuels								
Natural Gas (Mil Mcf) Price ($/Mcf)	NA	NA	NA	NA	NA	NA	NA	NA
Fuel Oil (Mil gal)	2.3	2.3	2.3	2.3	2.3	2.3	2.3	0.2%
(Price ($/Gas))	.95	.95	.95	.95	.95	.95	.95	5%
O&M Cost ($ Mil)	0.8	0.9	0.9	1.0	1.0	1.1	1.1	5%
Total Energy-Related Costs ($ Million)	4.3	4.4	4.5	4.6	4.8	4.9	5.0	

The site would have O&M savings if it did spend as much operating or maintenance time on its on-site boiler, steam, and electrical systems as it would without the GFC plant. Typically, the O&M savings occur more through reduced boiler and steam system activity, since there is little on-site electric power system maintenance required. Further, under the GFC plant concept, the O&M savings can be more than just the reduced labor and materials cost for on-site boiler and steam systems maintenance. The GFC plant operators could well operate the entire on-site energy plant. In fact, it is preferable to do this, since any integrated energy plant decisions and interface maintenance requirements can be better coordinated. In effect, the site energy plant employees could become employees of the GFC plant.

Site energy cost savings can result from different combinations of lower electric power and/or steam prices. For this study, the site savings to Fort Greely were primarily the result of the difference in cost between steam purchased from GFC and the fuel and associated O&M costs to generate the same amount of steam in the existing oil fired boilers.

There is an additional advantage to the GFC plant from a savings approach that focuses on stream, and not electric power. If the local electric utility can pay more for the power, depending upon its rate structure and marginal costs of capacity, the GFC plant would derive more value from its power output than it would if it simply displaced the electric power costs for the site. Our analysis of GVEA capacity and energy requirements in the 1990s indicates that the value of GVEA of new capacity in the Fort Greely area should be substantial. However, we have not assumed it would exceed the projected purchase price of power by Fort Greely. Therefore, the GFC plant was assumed to provide all of the Fort Greely electric power, and then sell its excess to GVEA. The price for GFC power sold to Fort Greely was assumed equal to its purchased cost of power, and the site savings were provided through the sale of lower-cost steam and through savings in O&M.

Fort Greely currently consumes about 230 million pounds of steam per year, expected to increase marginally over time. The expected GFC plant output, as configured for Fort Greely is 67 million pounds per year (see CLIN 3). The assumed purchase price for this steam (in 1985 dollars) is $6 per thousand pounds, clearly less than it costs using the on-site boilers. At an assumed 5% annual escalation rate, this price would be $7.7 per thousand pounds in 1990, the first year of GFC plant operation. Under the base scenario, this price was assumed to escalate at 5% per year in the long-term.

Fort Greely's expected $2.2 million cost for purchased fuels in 1990 would be reduced to about $1.9 million for purchase steam and remaining fuel requirements, and the 1990 O&M could be reduced from $1.1 million to $600,000, or $500,000.

The total estimated site savings in 1990 under these assumptions is estimated at $800,000. It is likely to increase, assuming a 5% electric power and fossil fuel escalation rate (first scenario), to over $1.3 million per year by 1999, the tenth year of GFC plant operation. The cumulative savings over the first ten years of GFC plant operation (the 1990s) would approximate $10.3 million.

These savings are likely to be the minimum that will be achieved, since the first scenario is likely to produce lower energy costs without the GFC plant than is expected through the year 2000. The estimate of site cost savings under higher escalation rates (scenarios 2 and 3) would be $12-20 million for the ten-year period. Table 2.3-2 is a summary of the projected site energy use, costs, and savings with the GFC plant. In this exhibit, the current and projected total site energy use is shown. It also shows the total site energy costs without the GFC and with the GFC. However, the GFC savings accrue only to the fuels and O&M costs for the site. Accordingly, a GFC energy cost comparison is shown next on the exhibit. For 1990, the cost of the GFC electric and thermal energy purchased, is $3.0 million, whereas the cost of these fuels and O&M costs without the GFC is estimated at $3.8 million. Finally, this table shows the estimated GFC-related cost savings for the second and third scenarios analyzed.

TABLE 2.3-2

PROJECTED SITE ENERGY USE, COSTS AND SAVINGS WITH GFC
($ Million)

Fort Greely, Alaska

SCENARIO 1 (Base)*	Current 1985	Projected 1990	Projected 1995	10-Yr Total (1990-1999)
Total Site Energy Use				
Electric (million kWh)	15.7	15.9	16.0	160
Thermal (billion Btu)	240	240	242	2447
Total Energy Cost				
Cost without GFC		5.0	6.5	64.0
Cost with GFC		4.2	5.5	53.7
GFC Energy Cost Comparison				
Cost of Energy from GFC		3.0	4.0	38.5
Cost of Same Energy and O&M Without GFC		3.8	5.0	48.8
Cost Savings with GFC		.8	1.0	10.3
SCENARIO 2:** Cost Savings with GFC		.8	1.2	12.2
SCENARIO 3:*** Cost Savings with GFC		1.3	2.0	19.2

* Flat near-term fossil fuel prices. 5% long-term escalation.

** Flat near-term fossil fuel prices. 10% long-term escalation.

*** Fossil fuel prices 5%/year near term, 10%/year long term.

2.3.2 Economics

The GFC plant economic attractiveness must be measured by the financial return on the investment provided. Whether one uses return on total private investment (ROI) or payback, both are affected by the investment and cash savings (after tax) that it can generate. Therefore this section covers the estimated GFC capital cost, GFC O&M costs, GFC energy output characteristics and key assumptions, and the GFC plant return on investment (ROI) results.

2.3.2.1 Capital Costs

Under the commercialization cost sharing concept of the program, the government would fund 70% of the normal capital cost for the GFC plant, and the private third-party owner the remaining 30%. Further, the private contribution would be the last 30% required. However, noting that there is a substantial premium for construction in Alaska due to higher labor costs, transportation costs and severe climate, it is proposed that this differential of about $28,000,000 be funded by the Federal Government. This would in effect, raise the percentage funded by the government to 80% of capital cost. Under this arrangement, the government capital contribution would be $64.9 million and private contribution $16.2 million, as shown in Table 2.3-3. These shares are derived as follows.

The estimated GFC plant construction and preproduction costs (1985 dollars) are $66.0 million. Assuming a 5% construction cost escalation until equipment is delivered and construction is completed at various states, these costs escalate to a total of $77.2 million installed by the end of 1989. The construction costs timing pattern for these is roughly a 20-40-40% allocation for the three construction years, 1978-1989.

In addition to the hard construction costs, there are other capital requirements for any project to begin operation, specifically construction interest, working capital, and development, financing, legal, and other costs. The construction interest is assumed to be zero, for two reasons. First, the basic economic measure is return on total private investment, with no private debt, hence no interest costs.

Second, even with a financing structure that assumes debt, since the last capital contribution is the private contribution, the amount of interest during the last few months of construction is small compared to the total capital costs, perhaps a few hundred thousand dollars. However, because of final performance testing and construction certification holdback amounts, it may be that the private contribution would occur virtually at plant startup, with no attendent construction period interest.

Working capital is required for the delay in payment of invoices (i.e., accounts receivable), fuel inventory needed, initial catalyst and chemicals, and other initial inventory. The estimated capital requirements at startup for the Fort Greely site for these items is $2.0 million.

Finally, for any privately financed entity, there are private development, financing, legal, and other costs associated with that activity. These costs are estimated at $1.9 million (fixed) for the project. These include:

- Financing fees of $1.3 million, or 8% of the private capital requirement.
- Third party development fee of $300,000, or 2% of the private capital.
- Legal and other expenses of $300,000, or 2% of the private development capital.

The total capital requirements, as installed, for the Ft. Greely project, then, are $81.1 million. Table 2.3-3 shows the percentage and timing breakdown of these requirements for the private and governmental portions of $16.2 and $64.9 million respectively.

TABLE 2.3-3

GFC PLANT CAPITAL REQUIREMENTS ($ Million)

Fort Greely, Alaska

	1985 Dollars	Installed Costs Assuming a 5-Percent Escalation Rate 1987	1988	1989	Total
Construction Costs					
GFC Plant Equipment	51.5				
GFC Plant Civil	12.7				
Preproduction Costs	1.7				
Subtotal	65.9	14.9	30.4	31.9	77.2
Other Costs					
Construction Interest				0*	0
Working Capital				2.0	2.0
Development, Financing, Legal and Other				1.9	1.9
Subtotal					3.9
TOTAL CAPITAL REQUIREMENTS		14.9	30.4	35.8	81.1
At a 20/80 Mix of Capital Contributions: **					
Private Capital				16.2*	16.2
Government Capital		14.9	30.4	19.6	64.9

* Private capital would be legally committed at the beginning of construction, but would be contributed as the last funding increment. Therefore, construction interest on any private debt used is assumed to be zero.

**80 percent government contribution determined as follows:

100% of $28 million special site civil, equipment, and labor costs accruing to Alaskan Army base location		28.0
70% of $53.1 million remaining costs		36.9
	TOTAL	64.9

2.3.2.2 Plant Energy Production

The margin provided by the output revenues and the basic operating cost determines the return on the private capital required. For the GFC site, the GFC plant outputs are electric power, steam and 10% excess coal fines received that cannot be handled by the coal gasification equipment. Any tars and oils or other intermediate outputs of the plant are reused in the process as an auxiliary fuel, or assumed to be unusable and a waste product.

The electric power revenues from the GFC plant are based on its rate of power output, number of operating hours per year, and the price received for the power sold. For Fort Greely the GFC plant provides all of the site power requirements, and the excess GFC plant power is sold to the utility, GVEA. The price for the power is set at the purchased power cost for the site, which currently 8.43¢/kWh (total electric power bill divided by the number of kWhs). It would increase to 10.8¢/kWh by 1990, assuming a 5% escalation rate. The assumed sale price of the power to GVEA in 1990 is 8.9¢/kWh. Under the base scenario, the long-term escalation rate of both the displaced purchased power cost and the sale price to GVEA is assumed at 5%/year. The 8.9¢/kWh 1990 price to GVEA, and the 5%/year escalation escalation rate is based on the minimum value assigned to the cost of new capacity that will be needed on GVEA's system in the 1990s, preferably in the Fort Greely geographic area.

The electric energy produced by the GFC plant is estimated at 72 kWh in 1990, increasing to over 77 million kWhs in 1995 from increase in the number of estimated operating hours. The increase in operating hours is based on the assumption that, with some substantial operatng experience, the plant availability should increase. The electric revenues for the power sold from the GFC plant are estimated at $6.7 million in 1990, increasing to $9.2 million in 1995, and totalling almost $90 million for the first 10 years of plant life.

The amount of steam sold to Fort Greely by the GFC plant is estimated at 167 million pounds per year in 1990, increasing to 179 million pounds per year in 1995. the price assumed for sale of the steam is $6/thousand pounds (1985 dollars), which is less than it costs to produce it on-site. The cost of boiler fuels and labor are significant in Alaska (the fuel oil cost is approximately 40-50% higher than the lower 48 states). The steam price in 1990, assuming a 5% escalation rate, would be $7.7/thousand pounds, increasing to $9.8/thousand pounds by 1995, and escalating at 5% (under the base scenario) in the long-term. The estimated steam revenues in 1990 are $1.3 million, increasing to $1.8 million in 1995, and approximating $16 million for the ten years, 1990-1999.

The excess coal fines contained in the coal received are unusable in the coal gasifier (which can take up to 15% of fines in the coal mix handled). Approximately 10% of the coal received would be resold as excess fines. Assuming a delivered coal price to Fort Wainwight to complete with the $/million Btu delivered prices of other coal, a 1985 coal fines price of $34/ton f.o.b. Greely was assumed. At a 5% per year escalation rate, the 1990 coal price would be over $43/ton. This would provide coal fines sale revenues in 1990 of $420,000, increasing at 5% in the long-term, under the base scenario assumptions.

Table 2.3-4 shows the electric power, and steam production for the GFC plant for the first and sixth years of operation, and cumulatively for the first ten years of operation.

Both O&M and the fuel costs are significant. The O&M cost assumptions were explained in Section 2.1.2. In addition to the technical O&M, there are other possible annual operating costs that must be considered, mainly taxes and insurance. The amount estimated for these two costs in 1990 is $260,000, assumed to escalate at 5% per year long-term.

Using a coal price of $39 per ton (under the first scenario analysis, fossil fuel prices were assumed flat for five years), the 1990 coal cost for the Scranton GFC plant is estimated at $3.2 million. With a 5% escalation, and an increase in plant operaing hours starting in the sixth year, the estimated cost in 1995 is $4.1 million.

TABLE 2.3-4

GFC PLANT ECONOMIC OUTPUT ($ Million)

Fort Greely, Alaska Site

Economic Parameter	First 1985 (1990)	Sixth Year (1995)	First 10 Years Operation (1990-1999)
Electric Power Output			
Net Power Output (MW)	10.2	10.2	
Operating Hours per years	7096	7596	
Energy Sold to Site (Mil kWhs)	15.9	16.0	160
Price (¢/kWh)	10.8	13.7	
Energy Sold to Utility (Mil kWhs)	56.4	61.4	588
Price (¢/kWh)	8.9	11.4	
Steam Output (at 240 psig)			
Output Rate 1000 lb/hr)	23600	23600	
Sold to Site (Mil Lbs)	167.5	179.3	1734
Price ($/000 Lbs)	7.7	9.8	
Other Output			
Coal Fines Sold (Bil Btu)	145	155	1599
Price ($/Ton)	43	55	

While the basic economic analysis did not focus on financing and ownership structures, it had to incorporate some fundamental tax assumptions in order to derive an after-tax cash flow return on the total investment. While there is currently a substantial focus on potential new tax legislation, in the absence of any new proposals, the current tax laws were assumed.* Therefore, the tax assumptions made were:

- 10% investment tax credit.
- 5-year straight line depreciation.
- 50% combined federal and state marginal annual income tax rate.
- As a sensitivity analysis, the impact of the annual income tax credit (through 1999) for nonconventional sources of gas was evaluated. Currently, this tax credit is approximately 70¢ per million Btus of synthetic gas produced.

2.3.2.3 Return on Investment

For the basic economic analysis, return on total investment (ROI) was used as the measure of the GFC plant financial performance. With this measure, no private debt is assumed -- i.e., the entire private investment is treated as equity.

The ROI results of the analysis are not to be considered as final investment decision results. Rather, they are an indicator of the

---

* With regard to tax factors affecting the GFC plant economics, the overall thrust of the current tax proposals is to eliminate or reduce the investment tax credit and stretch out the depreciation, both measures that would lower the ROI. The proposals would also reduce the marginal annual income tax rate, a measure that would increase the ROI in the long-term.

potential economic attractiveness of the GFC plant. The ROI results is one measure to be used by the Department of the Army to decide which sites warrant further expenditures for preliminary design and more refined economic/financing anaysis. Other measures of importance to be used by the Army will be:

- o Benefit from using coal to replace oil and gas use.
- o Increased site power supply reliability.
- o Reduced requirements for other site plant capital expenditures.
- o The value of a maximum price guarantee to be provided by the GFC plant that would not be avaiable from existing electricity and fuel suppliers.

Further, the technical design and economics of the plant were not optimized in this feasibility study. The purpose of the next state -- preliminary design and testing -- is to identify improvements in the plant efficiency (causing lower operting costs) and reductions in the capital cost. Also, the private cost-sharing component, which is a significant strength of the GFC concept, has been roughly set at 30%, based on an expected production volume capital cost for the GFC plant at 30% of the prototype cost. This number, coupled with revised capital cost estimates, could change somewhat. Therefore, the minimum economic performance required from the analysis to warrant further work should not be as high as the final ROI and other financial requirements that would be desired by investors.

Therefore, a feasibility ROI criterion of 10%, without the annual syngas income tax credit (which makes the ROI higher), was used to test each of the sites for economic feasibility. While the syngas tax credit has been in effect for several years, and should not be ignored, it distorts an ROI number such that general comparisons with other ROIs are harder to make. The 10% ROI criterion roughly translates into a 25% or higher return on equity (ROE), assuming a 2/1 private debt/equity ratio.

(Alternative financing structures and the ROE results are discussed in Section 3.0, Financing and Ownership Analysis.)

As shown in Table 2.3-5, the total GFC plant revenues for Fort Greely in 1990 are estimated at $8.4 million, and total costs at $6.0 million, resulting in an operating cash flow of $2.4 million. This operating cash margin increases steadily, with a 10-year total operating cash flow of approximately $34 million.

For the ROI analysis, there is no debt service requirement. Therefore, only a tax saving or payment needs to be applied to the operating cash flow to obtain the after-tax net cash flow.

During the first five years of plant life, the allowed depreciation results in a slight tax savings. Therefore, the net cash flow in 1990 is slightly greater than the operating cash flow. However, starting in 1995, a tax payment of 50% of the operating cash flow occurs.* Overall, the net cash flow is fairly steady at $2.0-$2.5 million during the first ten years of plant life, with a total 10-year cash flow of almost $24 million.

The resulting ROI under the base scenario is approximately 11%. The results under Scenario 2 (flat near-term fossil prices and high, sustained long-term prices) is 16%. Under Scenario 3, with a 5% annual increase in near-term fossil energy prices, and high, sustained long-term escalation rates, the ROI is 10%.

---

* The annual income tax credit for nonconventional sources of gas (called the syngas tax credit) which is in effect through 1999, has not been included in the tax calculation so that the resulting ROI can be compared to other ROIs reflecting conventional tax assumptions.

TABLE 2.3-5

GFC PLANT CASH FLOW SUMMARY

Fort Greely, Alaska Site

Economic Variable	1990)	1995	10-Year Total (1990-1999)
Base Scenario			
Revenue			
Electric	6.7	9.2	87.9
Other	1.7	2.2	21.4
Subtotal	8.4	11.4	109.3
Cost			
Fuel	3.2	4.1	40.2
O&M & Other	2.8	3.6	35.4
Subtotal	6.0	7.7	75.6
Operating Cash Flow	2.4	3.7	33.7
Tax Saving (Payment)	.3	-1.9	-9.5
Net Cash Flow	2.7	1.8	24.2
ROI	11.1%		
Scenario 2			
Net cash flow	2.7	2.5	30.9
ROI	15.7%		
Scenario 3			
Net cash flow	2.2	1.8	23.9
ROI	9.9%		

2.3.3 Conclusions

The analysis of the Fort Greely site led to the following conclusions:

1. Potential site thermal and O&M savings could be significant, approximating 15% of the project site energy costs, and providing a certainty in energy prices not available from other fuel suppliers and the electric utility.

2. The Westinghouse GFC plant configuration did not provide acceptable economics because of lower economies of scale for a smaller plant and a lower efficiency than the UTC configuration.

3. For a set of energy prices that provides Fort Greely a 15% cost savings, the minimum GFC plant after-tax return on total investment indicator exceeds 10%, and promises the potential to exceed 15% through further work that optimzes the technical design and economics.

4. The addition of new GFC capacity in the 1990's in the Fort Greely area would be of significant value to GVEA and would also be available for use by Fort Wainright to handle increased electrical demand with the stationing of additional military personnel.

2.4 Fort Hood, Texas Site

The Fort Hood Texas site was described in previous reports (CLIN 000203 and CLIN 000303). To verify the economic feasibility of the GFC plant, the costs and benefits must be evaluated for both the site and the GFC plant third party owner. Therefore, this chapter contains the following sections:

1. Site costs/benefits
2. Economics
3. Conclusions

2.4.1 Site Costs Benefits

The benefits to Fort Hood can occur through savings in electric power use, fuel use, and operating and maintenance (O&M) costs. Each of these is analyzed in the two sections below.

2.4.1.1 Energy Use and Costs Without the GFC

To serve as a base of comparison in the analysis of GFC benefits to the site, 25-year projections were made of energy use and costs without the GFC for the years 1990-2009.

The cost factors projected are as follows:

Electric Energy. Currently, Fort Hood consumes about 290 million kWhs per year of electric energy. The escalation in kWh use is expected to be moderate. 2% per year was assumed in the near-term, providing about 320 million kWhs in 1990. A 2% escalation rate was assumed for the long-term as well.

The current electric energy (kWh) rate is 3.7¢/kWh in the near-term (1985-1990). A 5% escalation rate was assumed for all scenarios. This would provide a rate of approximately 4.7¢/kWh in 1990. In the base scenario, a 5% escalation rate was assumed for the long term. For the second and third scenarios, a 10% long-term escalation rate was assumed. (See Table 1-2 for a summary of assumptions made for each scenario.)

The current annual electric energy cost is about $10.7 million. Under the above assumptions, it would increase to $15.1 million in 1990. The long-term projection of electric energy costs depends on escalation rates that vary between 5% and 10% per year.

Electric Demand. Currently, Fort Hood has a peak electric demand of about 68 MW. It was assumed this would increase at a moderate rate of 2% per year, both in the near-term and long-term.

The current demand charge is approximately $4.2/kW/month. In the near-term in all scenarios, it was assumed this would increase at 5% per year, giving a demand charge of $5.4/kW/month in 1990. The long-term escalation rates varied by scenario.

Currently, the annual electric demand cost is about $3.5 million. Under the assumotions used above, this would increase to $4.9 million by 1990. In the long-term, a range of escalation rates from 5%-10% were used.

The total electric power costs, then, are currently $1.4 million, likely to increase to $2.0 million by 1990.

Natural Gas. Currently, about 1650 million cubic feet of natural gas are consumed annually by Fort Hood. Assuming this usage increases by 2% per year, an assumption consistent with the total energy use projections made for the site, the natural gas required would increase to over 1830 cubic feet by 1990, with a long-term escalation of 2% per year.

The current cost of natural gas is about $4.2 per mcf (40¢ per therm). Under the first (base) scenario analysis, it was assumed this price would stay flat through 1990, then increase in the long-term at 5% per year. While even near term decreases in natural gas (and oil) costs could occur, given the current softness of those prices, the first scenario provides a reasonably low level of natural gas prices over the 20-year time frame, 1990-2009.

The current annual gas cost of $6.9 million would increase to about $7.6 million by 1990 under the base scenario assumption.

Operating and Maintenance Costs. Incomplete information was available on the amount of energy-related O&M costs for Fort Hood. Based on the experience of the team and on data available from other Army sites, a current O&M cost of $1 million per year was assumed. This was assumed to increase at 5% per year (inflation) to $1.3 million per year by 1990, and to increase by 5% per year thereafter (under the first scenario).

Total Site Energy Costs. The total annual energy-related costs for Fort Hood are currently about $22 million. Under the first scenario, these costs would increase to $29 million in 1990, and would increase to over $50 million per year in 1999. The total cost for the ten years, 1990-2009, would approximate $400 million.

Exhibit 14 shows the projected near-term energy use, rate, and total cost, and the escalation rates assumed for the long-term under the first (base) scenario.

2.4.1.2 Cost/Benefits With the GFC

The cost savings to Fort Hood can occur through one or more of the following: electric energy savings, electric demand savings, site boiler fuel savings, and O&M. The electric power savings would occur if the GFC plant sells power at a lower cost than the site would otherwise purchase that power from the electric utility.

TABLE 2.4-1

SUMMARY - SITE ENERGY USE/UNIT PRICE PROJECTIONS -
Scenario 1 (Base) Fort Hood, Texas

Energy Parameter	1984	1985	1986	1987	1988	1989	1990	1990-2009 Escalation Rate
Electric Power								
Energy (Mil kWhs)	284	290	295	301	307	314	320	2%
Rate (¢/kWh)	3.5	3.7	3.9	4.1	4.3	4.5	4.7	5%
Demand (MW)	66	68	69	71	72	73	75	2%
Rate ($/kW/Mo)	4.0	4.2	4.5	4.7	4.9	5.2	5.4	5%
Overall Rate ($/kW)	4.7	4.9	5.2	5.4	5.7	6.0	6.3	
Fuels								
Natural Gas (Mil Mcf)	1620	1652	1685	1719	1753	1788	1824	2%
Price ($/Mcf)	4.2	4.2	4.2	4.2	4.2	4.2	4.2	5%
Fuel Oil (Mil gal.)	NA	NA	NA	NA	NA	NA	NA	NA
(Price ($/Gal.)	NA	NA	NA	NA	NA	NA	NA	NA
Coal (000 Tons)	NA	NA	NA	NA	NA	NA	NA	NA
Price ($/Ton)								
O&M Cost ($ Mil)	1.0	1.0	1.1	1.2	1.2	1.3	1.3	5%
Total Energy-Related Costs ($ Million)	21.0	22.1	23.3	24.6	26.0	27.4	28.9	

The site fuel savings would occur if the GFC plant sold the site steam at a price lower than it would otherwise cost the site to produce it.

The site would have O&M savings if it did not spend as much operating or maintenance time on its on-site boiler, steam, and electrical systems as it would without the GFC plant. Typically, the O&M savings occur more through reduced boiler and steam system activity, since there is little on-site electric power system maintenance required. Further, under the GFC plant concept, the O&M savings can be more than just the reduced labor and materials cost for on-site boiler and steam systems maintenance. The GFC plant operators could well operate the entire on-site energy plant. In fact, it is preferable to do this, since any integrated energy plant decisions and interface maintenance requirements can be better coordinated. In effect, the site energy plant employees could become employees of the GFC plant.

Site energy cost savings can result from different combinations of lower electric power and/or steam prices. For this study, the site savings to Fort Hood were primarily the result of the difference in cost between steam purchased from the GFC and the fuel and associated O&M costs to generate the same amount of steam in the existing gas fired boilers.

There is an additional advantage to the GFC plant from a savings approach that focuses on steam, and naot electric power. If the local electric utility can pay more for the power, depending upon its rate structure and marginal costs of capacity, the GFC plant would derive more value from its power output than it would if it simply displaced the electric power costs for the site. However, this was not the case for Fort Hood.

Fort Hood currently consumes 1.2 billion pounds of steam per year. At an assumed 2% growth rate, this amount would increase to over 1.3 billion pounds per year by 1990. For the Fort Hood GFC feasibility design, the GFC plant steam output is 144 million pounds per year (see CLIN 000303). The assumed GFC purchase price by Fort Hood for this steam (in 1985 dollars) is $4 per thousand pounds, less than it costs using the on-site boilers. At an assumed 5% annual escalation rate, this price would be $5.10 per thousand pounds in 1990, the first year of GFC plant operation.

Under the base scenario, this price was assumed to escalate at 5% per year in the long-term as well.

With a partial steam purchase from the GFC, Fort Hood's direct cost of purchased fuels in 1990 would be reduced slightly, by about $100,000, and the electric power cost would be reduced $200,000 through the use of steam in an absorption chiller. The 1990 O&M could be reduced by $500,000.

The total savings in 1990 under these assumptions is estimated at $800,000. It is likely to increase, assuming a 5% electric power and fossil fuel escalation rate (first scenario), to over $1.3 million per year by 1999, the tenth year of GFC plant operation. The cumulative savings over the first ten years of GFC plant operation (the 1990s) would approximate $10 million.

These savings are likely the minimum that would be achieved, since the first scenario is likely to produce lower energy costs without the GFC plant than most experts think will occur through the year 2000. The estimate of site cost savings under higher escalation rates (scenarios 2 and 3) would be $12-$16 million for the ten-year period. Table 2.4-2 is a summary of the projected site energy use, costs, and savings with the GFC plant which also shows the total site energy costs without the GFC. However, the GFC savings accrue only to the fuels and O&M costs for the site. Accordingly, a GFC energy cost comparison is shown next on the exhibit. For 1990, the cost of the GFC electric power and thermal energy purchased, combined with the O&M savings that would likely occur is $5.7 million, whereas the cost of these fuels and O&M costs without the GFC is estimated at $6.5 million. Finally, the exhibit shows the estimated GFC-related cost savings for the second and third scenarios analyzed.

TABLE 2.4-2

SUMMARY - PROJECTED SITE ENERGY USE, COSTS AND SAVINGS WITH GFC PLANT
($ Million) Fort Hood, Texas

SCENARIO 1 (Base)*	Current 1985	Projected 1990	Projected 1995	10-Yr Total (1990-1999)
Total Site Energy Use				
Electric (million kWh)	290	320	353	3502
Thermal (billion Btu)	1276	1409	1556	15427
Total Energy Cost				
Cost without GFC		28.9	40.6	400
Cost with GFC		28.1	39.6	390
GFC Energy Cost Comparison				
Cost of Energy From GFC		5.7	7.0	74.0
Cost of Same Energy and O&M Without GFC		6.5	8.1	84.4
Cost Savings with GFC		.8	1.1	10.4
SCENARIO 2: **Cost Savings with GFC		.8	1.3	12.4
SCENARIO 3: ***Cost Savings with GFC		1.0	1.6	16.0

* Flat near-term fossil fuel prices. 5% long-term escalation.

** Flat near-term fossil fuel prices. 10% long-term escalation.

*** Fossil fuel prices 5%/year near term, 10%/year long term.

2.4.2 Economics

The GFC plant economic attractiveness must be measured by the financial return on the investment provided. Whether one uses return on total private investment (ROI) or payback, both are affected by the investment and cash savings (after tax) that it can generate. Therefore this section covers the estimated GFC capital cost, GFC O&M costs, GFC energy output characteristics and key assumptions, and the GFC plant return on investment (ROI) results.

2.4.2.1 Capital Cost

Under the commercialization cost sharing concept of the program, the government would fund 70% of the normal capital cost for the GFC plant, and the private third-party owner the remaining 30%. Further, the private contribution would be the last 30% required. Under this arrangement, the government capital contribution would be $35.7 million and the private contribution $15.3 million. However, because the GFC economics do not provide for a privately financable plant, development of a GFC plant at Fort Hood is not recommended and no governmental funding is warranted.

To appreciate the basic economic analysis, a description of the total capital requirements is provided. The estimated GFC plant construction and preproduction costs (1985 dollars) are $40.7 million. Assuming a 5% construction cost escalation until equipment is delivered and construction is completed at various stages, these costs escalate to a total of $47.6 million installed by the end of 1989. The construction costs timing pattern for these is roughly a 20-40-40% allocation for the three construction years, 1987-1989.

In addition to the hard construction costs, there are other capital requirements for any project to begin operation, specifically construction interest, working capital, and development, financing, legal, and other costs. The construction interest is assumed to be zero, for two reasons. First, the basic economic measure is return on total private investment, with no private debt, hence no interest costs. Second, even with a financing structure that assumes debt, since the last capital contribution is the private contribution, the amount of interest during the last few months of construction is small compared to the total capital costs, perhaps a few hundred thousand dollars. However, because of final performance testing and construction certification holdback amounts, it may be that the private contribution would occur virtually at plant startup, with no attendent construction period interest.

Working capital is required for the delay in payment of invoices (i.e., accounts receivable), fuel inventory needed, initial catalyst and chemicals, and other initial inventory. The estimated capital requirements at startup for the Scranton AAP site for these items is $1.6 million.

Finally, for any privately financed entity, there are private development, financing, legal, and other costs associated with that activity. These costs are estimated at $1.8 million (fixed) for the project. These include:

- o Financing fees of $1.2 million, or 8% of the private capital requirement.

- o Third party development fee of $300,000, or 2% of the private capital.

- o Legal and other expenses of $300,000, or 2% of the private development capital.

The total capital requirements, as installed, for the Fort Hood project, then, are $51.0 million. Table 2.4-3 shows the timing of these capital requirements.

TABLE 2.4-3

SUMMARY - GFC PLANT CAPITAL REQUIREMENTS ($ Million)
Fort Hood, Texas

	1985 Dollars	Installed Costs Assuming a 5-Percent Escalation Rate 1987	1988	1989	Total
Construction Costs					
GFC Plant Equipment	36.2				
GFC Plant Civil	3.5				
Preproduction Costs	1.0				
Subtotal	40.7	9.1	18.8	19.7	47.6
Other Costs					
Construction Interest				0*	0
Working Capital				1.6	1.6
Development, Financing, Legal and Other				1.8	1.8
TOTAL CAPITAL REQUIREMENTS		9.1	18.8	23.1	51.0
Mix of Capital Contributions:					
Private Capital		Not Applicable. GFC plant not recommended on economic grounds.			
Government Capital					

* Private capital would be legally commited at the beginning of constrction, but would be contritubed as the last funding increment. Therefore, construction interest on any private debt used is assumed to be zero.

2.4.2.2 Plant Energy Production

The margin provided by the output revenues and the basic operating cost determines the return on the private capital required. For the Fort Hood site, the GFC plant outputs are electric power and steam. Any tars and oils or other intermediate outputs of the plant are reused in the process as an auxiliary fuel, or assumed to be unusable and a waste product.

The electric power revenues from the GFC plant are based on its rate of power output, number of operating hours per year, and the price received for the power sold. In this case, the entire electric power output is assumed sold to Fort Hood at its cost of displaced power -- 6.2¢ kWh in 1990, escalating at 5 percent/year to 8.0¢/kWh in 1995. In the analysis, the long-term escalation rate was assumed at 5 percent or 10 percent per year, depending on the scenario analyzed.

The GFC electric energy sold to Fort Hood is estimated at 79 million kilowatt hours per year in the first five years of operation, increasing to approximately 84 million kilowatt hours thereafter. The assumption behind this increase is that, with operating experience, the plant availability should increase after some period of operation.

The total electric revenues to the GFC plant corresponding to this output are $4.9 million in 1990, increasing to $6.7 million in 1995 in accordance with the increased kWh output and the increased rates. The ten-year revenues for the plant are estimated at $64 million.

The remaining revenues for the plant are steam revenues. The annual amount of steam sold upon startup of the GFC plant is 20300 thousand pounds per hour and 144 million pounds per year, increasing to 154 million pounds per year in 1995 and after. In accordance with the $5.10/000 lb steam price assumption and discussed earlier, the expected annual revenues in 1990 are $700,000-800,000, increasing to $1 million in 1995. The ten year stream of steam revenues is estimated at $9.6 million.

Table 2.4-4 shows the key electric power and other output assumptions for the GFC plant for the first and sixth years of operation, and cumulatively for the first ten years of operation.

Table 2.4-4

SUMMARY-GFC PLANT ECONOMIC OUTPUTS

Economic Parameter	First Year (1990)	Sixth Year (1995)	First 10 Years Operation (1990-1999)
Electric Power Output			
Net Power Output (MW)	11.1	11.1	
Operating Hours per year	7096	7596	
Energy Sold to Site (Mil kWh)	78.8	84.3	185
Price (¢/kWh)	6.2	8.0	
Energy Sold To Utility (Mil kWhs)	0	0	0
Price (¢/kWh)	NA	NA	
Steam Output (at 240 psig)			
Output Rate (1000 Lbs/hr)	20300	20300	
Sold to Site (Mil Lbs)	144	144	1490
Price ($/1000 Lbs)	5.10	6.50	
Other Output			
Tars/Oils Sold (Bil Btu)	NA	NA	NA
Price ($/Mil Btu)			

Both the O&M and the fuel operating costs are significant. The $2 million 1985 O&M cost estimate was explained in Paragraph 2.1.2. With 5 percent escalation, the 1990 O&M cost would be $2.6 million. In 1995 (sixth operating year), the fuel cell reload costs start, adding ($600,000 per year for a total 1995 O&M of $3.9 million. In addition to the technical O&M, there are other possible annual operating costs that must be considered, mainly taxes and insurance. The amount estimated for these two costs in 1990 is $260,000, assumed to escalate at 5 percent year long-term.

Using a lignite coal price to $35 per ton (under the first scenario analysis, fossil fuel prices were assumed flat for year years), the 1990 coal cost for the GFC plant is estimated at $3.0 million. With a 5 percent escalation, and an increase in plant operating hours starting in the sixth year, the estimated cost in 1995 is $3.8 million.

While the basic economic analysis did not focus on financing and ownership structures, it had to incorporate some fundamental tax assumptions in order to derive an after-tax cash flow return on the total investment. While there is currently a substantial focus on potential new tax legislation, in the absence of any new proposals, the current tax laws were assumed.* Therefore, the tax assumptions made were:

- o 10 percent investment tax credit.
- o 5-year straight line depreciation.
- o 50 percent combined federal and state marginal annual income tax rate.

---

* With regard to tax factors affecting the GFC plant economics, the overall thrust of the current tax proposals is to eliminate or reduce the investment tax credit and stretch out the depreciation, both measures that would lower the ROI. The proposals would also reduce the marginal annual income tax rate, a measure that would increase the ROI in the long-term.

- As a sensitivity analysis, the impact of the annual income tax credit (through (1999) for nonconventional sources of gas was evaluated. Currently, this tax credit is approximately 70¢ per million Btus of synthetic gas produced.

2.4.2.3 Return on Investment

For the basic economic analysis, return on total investment (ROI) was used as the measure of the GFC plant financial performance. With this measure, no private debt is assumed -- i.e., the entire private investment is treated as equity.

The ROI results of the analysis are not to be considered as final investment-decision results. Rather, they are an indicator of the potential economic attractiveness of the GFC plant. The ROI result is one measure to be used by the Department of the Army to decide which sites warrant further expenditures for preliminary design and more refined economic/financing analysis. Other measures of importance to be used by the Army will be:

- Benefit from using coal to replace oil and gas use.

- Increased site power supply reliability.

- Reduced requirements for other site plant capital expenditures.

- The value of a maximum price guarantee to be provided by the GFC plant that would not be available from existing electricity and fuel suppliers.

Further, the technical design and economics of the plat were not optimized in this feasibility study. The purpose of the next stage -- pre:iminary design and teating -- is to identify improvements in the capital cost. Also, the private cost-sharing component, which is a significant strength of the GFC concept, has been roughly set at 30 percent, based on an expected production volume capital cost for the GFC plant at 30 percent of the prototype cost. This number, coupled with revised capital cost estimates, could change somewhat. Therefore, the minimum economic performance required from the analysis to warrant further work should not be as high as the final ROI and other financial requirements that would be desired by investors in any final design plant.

Therefore, a feasibility ROI criterion of 10 percent, without the annual syngas income tax credit (which makes the ROI higher), was used to test each of the sites for economic feasibility. While the syngas tax credit has been in effect for several years, and should not be ignored, it distorts the ROI such that general comparisons with other ROIs are harder to make. The 10 percent ROI criterion roughly translates into a 25 percent or higher return on equity (ROE), assuming a 2/1 private debt/equity ratio.

As shown in Table 2.4-5, the total potential GFC plant revenues for Fort Hood in 1990 are estimated at $5.7 million, and total costs at $5.8 million, resulting in a breakdown cash flow. This operating cash margin is slightly negative over the operating life of the GFC plant.

For the ROI analysis, there is no debt service requirement. Therefore, only a tax saving or payment needs to be applied to the operating cash flow to obtain the after-tax net cash flow.

During the first five years of plant life, the allowed depreciation results in a tax savings. Therefore, the net cash flow in 1990 would be $1.3 million. However, starting in 1995, a tax product of 50 percent of the operating cash flow occurs and the subsequent net cash flows are slightly negative.* The estimated 10-year cash flow is 5-6 million

* The annual income tax credit for nonconventional sources of gas (called the syngas tax credit), which is in effect through 1999, has not been included in the tax calculation so that the resulting ROI can be compared to other ROIs reflecting conventional tax assumptions.

Table 2.4-5

GFC PLANT ECONOMICS SUMMARY

Economic Variable	1990	1995	10-Year Total (1990-1999) -
Base Scenario			
Electric	4.9	6.7	64.4
Other	.8	1.0	9.6
Subtotal	5.7	7.7	74.0
Cost			
Fuel	3.0	3.8	37.3
O&M & Other	2.8	4.2	38.7
Subtotal	5.8	8.0	76.0
Operating Cash Flow	-.1	-.3	-2.0
Tax Saving (Payment)	1.4	.1	7.8
Net Cash Flow	1.3	-.2	5.6
ROI	Negataive		
Scenario 3			
Net Cash Flow	.9	-.3	4.4
ROI	Negative		

2.4.3 Conclusions

The analysis of the Fort Hood site led to the following conclusion:

1. For a set of energy prices that provides Fort Hood any significant cost savings, the GFC plant after-tax return on total investment is unacceptable. Therefore an economically viable application for the GFC plant does not exist.

2.5 WASHINGTON, DC SITE

The Georgetown University site was described in previous (CLIN) 0002 and CLIN 0003). To verify the economic feasibility of the GFC plant, the costs and benefits must be evaluated for both the site and the GFC plant third party owner. Therefore, this chapter contains the following sections:

1. Site costs/benefits.

2. GFC plant economics.

3. Conclusions.

2.5.1 Site Costs/Benefits

The benefits to Georgetown University (GU) can accrue through savings in electric power use, fuel use, and operating and maintenance (O&M) costs. Each of these is analyzed in the two sections below.

2.5.1.1 Energy Use and Costs Without the GFC

To serve as a base of comparison in the analysis of GFC benefits to the site, 25-year projections were made of energy use and costs without the GFC for the years 1990-2009. The cost factors were projected as follows:

Electric Energy. Currently, GU consumes about 75 million kWhs per year of electric energy. Based on GU's 5-year plan, the kWh use is expected to increase steadily, reaching 120 million kWhs by 1990. A 3% escalation rate was assumed for the long-term.

The current average electric energy (kWh) rate is 3.8¢/kWh. While scenarios were evaluated with alternative energy price escalation rates, in the near-term (1985-1990), a 5% annual escalation rate was assumed for all scenarios providing a rate of approximately 4.8¢/kWh in 1990. In the base scenario, a 5% escalation rate was assumed for the long term. For the second and third scenarios, a 10% long-term escalation rate was assumed. (See Table 1-2 for the complete set of assumptions made for each scenario.)

The current annual electric energy cost is about $2.5 million. Under the above assumptions, it would increase to $5.3 million in 1990. The long-term projection of electric energy costs depends on escalation rates that vary between 5% and 10% per year.

Electric Demand. Currently, GU has a peak electric demand of about 11.9 MW. Based on the 5-year plan, it was assumed this would increase to about 16 MW by 1990, escalating at 5% thereafter (Scenario 1).

There are two demand charges -- a ratcheted 12-month distribution charge and a monthly summer charge. These are currently $6/kW/mo and $9.7/kW/mo respectively. In the near-term in all scenarios, it was assumed this would increase at 5% per year. The long-term escalation rates varied by scenario.

Currently, the total electric demand cost is about $1.2 million annually. Under the assumptions used above, this would increase to $2.1 million by 1990. In the long-term, a range of escalation rates from 5%-10% were used.

The total electric power costs, then, are currently $3.6 million, likely to increase to $7.5 million by 1990.

Coal. GU has a fluidized bed coal boiler and a recently completed cogeneration plant. Its intended output is 9.6 million kWh and 600 million pounds of steam per year. This would require an annual coal supply of almost 35,000 tons of bituminous coal. This cogeneration plant would have a steady output, and thus a steady coal requirement.

The current cost of the coal is $51 per ton. In addition, for each ton of coal, a limestone supply cost of $9.30 and an ash removal cost of $2.45 are required, bringing the total fuel-related cost for the plant to approximately $63 per ton. Under the first scenario, it was assumed this cost will stay constant through 1990, increasing at 5% thereafter. Thus, the total annual coal cost under this scenario in 1985 and 1990 is $2.2 million. The largest increase in cost occurs under the third scenario, where a 5% near-term escalation rate and a 10% long-term annual escalation rate were assumed.

Natural Gas. Prior to 1985 only a limited amount of natural gas was used. However, under very competitive prices offered by the natural gas company, GU has contracted for a substantial amount of natural gas in 1985-1986, as much as 400 million cubic feet. This supply arrangement is a year-to-year arrangement. Given the likely continued competitiveness of natural gas with fuel oil, it was assumed for long-term analysis that a fixed annual amount of 155 million cubic feet per year would be contracted for, with the marginal fuel requirements served by No. 6 fuel oil.

The current price paid for natural gas is $4.12 per thousand cubic feet (about 40¢ per therm). Under the first scenario this price is assumed flat through 1990, then escalates at 5% per year. Thus, in 1990 the annual natural gas cost would be between $600,000 and $700,000.

Fuel Oil. Compared with the early 1980s, very little fuel oil is currently used. However, fuel oil will be the marginal fuel over the foreseeable future, and by 1990 approximately 650,000 gallons per year could be required.

The No. 6 fuel oil price is currently 63¢ per gallon ($4.20 per million Btu). As such, the price is roughly equal to the natural gas price per million Btu. The expected cost of fuel oil in 1990 would approximate $400,000.

Since the amount of coal consumed will be fixed, and the price per million Btu of natural gas and fuel oil is approximately the same, a different mix of natural gas versus fuel oil use would not significantly change the results of the energy cost analysis.

Operating and Maintenance Costs. Currently, GU spends $1.9 million for its energy-related O&M. Under the 5-year plan, this is expected to grow to about $2.5 million in 1990. It was assumed that O&M will escalate at

5% annual thereafter. A higher long term escalation rate was analyzed in Scenarios 2 and 3.

Total Site Energy Costs. The total annual energy related costs for GU are almost $8 million. Under the first scenario, these costs would increase to $13.2 million in 1990, and would increase to over $25 million per year by 1999. The total cost for the ten years, 1990-2009, would approximate $190 million.

Table 2.5-1 shows the projected near term energy use, rate, and total cost, and the escalation rates assumed for the long-term under the first (base) scenario.

2.5.1.2 Costs/Benefits With the GFC

The cost savings to GU can occur through one or more of the following: electric energy savings, electric demand savings, site boiler fuel savings, and O&M. The electric power savings would occur if the GFC plant sells power at a lower cost than the site would otherwise purchase that power from the electric utility. The site fuel savings would occur if the GFC plant sold the site steam at a price lower than it would otherwise cost the site to produce it.

The site would have O&M savings if it did not spend as much operating or maintenance time on its on-site boiler, steam, and electrical systems as it would without the GFC plant. Typically, the O&M savings occur more through reduced boiler and steam system activity, since there is little on-site electric power system maintenance required. Further, under the GFC plant concept, the O&M savings can be more than just the reduced labor and materials cost for on-site boiler and steam systems maintenance. The GFC plant operators could well operate the entire on-site energy plant. In fact, it is preferable to do this, since any integrated energy plant decisions and interface maintenance requirements can be better coordinated. In effect, the site energy plant employees could become employees of the GFC plant.

Site energy cost savings can result from different combinations of lower electric power and/or steam prices. For this study, the site savings were primarily the result of the different in cost between steam purchased from GFC and the fuel and associated O&M costs to generate the same amount of steam in the existing boilers.

There is an additional advantage to the GFC plant from a savings approach that focuses on steam, and not electric power. If the local electric utility can pay more for the power, depending upon its rate structure and marginal costs of capacity, the GFC plant would derive more value from its power output than it would if it simply displaced the electric power costs for the site. However, this was not the case for the GU site feasibility analysis. Therefore, it was assumed the GFC plant would displace GU's purchased power at the same price.

GU currently consumes about 600 million pounds of steam per year. At an assumed 5% growth rate, this amount would increase to approximately 770 million pounds per year by 1990. For the GU GFC feasibility design, the GFC plant steam output is small, about 14.2 million pounds per year (see CLIN 3). The assumed purchase price by GU for this steam (in 1985 dollars) is $4 per thousand pounds, less than it costs using the on-site boilers. At an assumed 5% annual escalation rate, this price would be $5.10 per thousand pounds in 1990, the first year of GFC plant operation. Under the base scenario, this price was assumed to escalate at 5% per year in the long-term as well.

Given the small amount of steam purchased from the GFC plant, the $3.2 million cost for purchased fuels in 1990 would be reduced less than $100,000. But the reduction in O&M could be more significant through absorption of O&M costs by the GFC plant, saving $500,000 of the $2.5 million projected O&M.

TABLE 2.5-1

SITE ENERGY USE PRICE AND COST PROJECTIONS - Scenario 1 (Base)

Washington, D.C.

Energy Parameter	1984	1985	1986	1987	1988	1989	1990	1990-2009 Escalation Rate
Electric Power								
Energy (Mil/kWh)	75	75	87	100	108	116	122	3%
Rate (¢/kWh)	3.3	3.7	3.9	4.1	4.4	4.6	4.8	5%
Demand (MW)	12.5	11.9	11.9	13.1	14.4	15.1	15.9	3%
Rate ($/kW/Mo)[1]	5.4	6.0	6.3	6.6	6.9	7.3	7.7	5%
	8.7	9.8	10.8	10.8	11.3	11.9	12.5	5%
Overall Rate ($/kWh)	4.9	4.9	5.0	5.2	5.5	5.8	6.1	
Fuels								
Natural Gas (Mil Ft)[2]	7.1	7.3	31.9	78.2	126.7	155.3	155.3	0%
Price ($/Mcf)	6.4	4.1	4.1	4.1	4.1	4.1	4.1	5%
Fuel Oil (Mil Gal)[2]	3.2	Small	0.1	0.1	0.1	0.3	0.6	Note 2
Price ($/Gal)	.77	.63	.63	.63	.63	.63	.63	5%
Coal (1000 Tons)	11.5	34.6	34.6	34.6	34.6	34.6	34.6	0%
Price ($/Ton)[3]	62.8	62.8	62.8	62.8	62.8	62.8	62.8	5%
O&M Cost ($ Mil)	1.5	1.9	2.0	2.2	2.3	2.4	2.5	5%
Total Energy - Related Costs ($ Million)	8.4	7.8	8.7	9.9	11.0	12.1	13.2	

1 Two demand charges apply, an 11-month ratcheted distribution charge and a monthly summer production/transmission charge.

2 Special natural gas purchase opportunities exist on a year-to-year basis. For purposes of long-term analysis (1990-2009), a maximum of 160 bil Btus (155.3 million ft^3) was assumed, with fuel oil as the marginal fuel. Since the assumed prices ($/Mil Btu) are within 5 percent of each other, a different gas/oil mix would not change the results of the analysis.

3 Coal cost includes coal and the costs per ton for limestone and for ash disposal.

The total estimated savings in 1990 under these assumptions is $600,000. It is likely to increase, assuming a 5% electric power and fossil fuel escalation rate (first scenario), to $800,000 per year by 1999, the tenth year of GFC plant operation. The cumulative savings over the first ten years of GFC plant operation (the 1990s) would approximate $7 million.

These savings are likely the minimum that would be achieved, since the first scenario is likely to produce lower energy costs without the GFC plant than most persons think will occur through the year 2000. The estimate of site cost savings under higher escalation rates (scenarios 2 and 3) would be over $8 million for the ten-year period. Table 2.5-1 is a summary of the projected site energy use, costs, and savings with the GFC plant. In this exhibit, the current and projected total site energy use is shown. It also shows the total site energy costs without the GFC and with the GFC. However, the GFC savings accrue only to the power purchased from the GFC. Accordingly, a GFC energy cost comparison is shown next to the exhibit. For 1990, the cost of the GFC electric and thermal energy purchased, combined with the O&M savings that would likely occur, is $5.2 million, whereas the cost of these fuels and O&M costs without the GFC is estimated at $5.8 million. Finally, the exhibit shows the estimated GFC-related cost savings for the second and third scenarios analyzed.

2.5.2 Economics

The GFC plant economic attractiveness must be measured by the financial return on the investment provided. Whether one uses return on total private investment (ROI) or payback, both are affected by the investment and cash savings (after tax) that it can generate. Therefore this section covers the estimated GFC capital cost, GFC O&M costs, GFC energy output characteristics and key assumptions, and the GFC plant return on investment (ROI) results.

TABLE 2.5-2

PROJECTED SITE ENERGY USE, COSTS AND SAVINGS WITH GFC PLANT ($ Million)

Washington, D.C.

Scenario 1 (Base)*	Current 1985	Projected 1990	Projected 1995	10-Yr Total (1990-1999)
Total Site Energy Use				
Electric (million kWh)	75	122	131	1399
Thermal (billion kWh)	635	811	940	1058
Total Energy Cost				
Cost without GFC		13.2	19.5	192.2
Cost with GFC		12.6	18.8	157.7
GFC Energy Cost Comparison				
Cost of Energy from GFC		5.2	7.1	67.9
Cost of Same Energy and O&M Without GFC		5.8	7.8	75.0
Cost Savings with GFC		.6	.7	7.1
Scenario 2:** Cost Savings with GFC		.6	.8	8.2
Scenario 2:*** Cost Savings with GFC		.6	.8	8.6

* Flat near-term fossil fuel prices. 5 percent long-term escalation.

** Flat near-term fossil fuel prices. 10 percent long-term escalation.

*** Fossil fuel prices 5 percent near term, 10 percent/year long-term.

2.5.2.1 Capital Costs

Under the commercialization cost sharing concept of the program, the government would fund 70% of the normal capital cost for the GFC plant, and the private third-party owner the remaining 30%. Further, the private contribution would be the last 30% required. Under this arrangement, the government capital contribution would be $44.3 million and the private contribution $20 million.

The estimated GFC plant construction and preproduction costs (1985 dollars) are $50.4 million. Assuming a 5% construction cost escalation until equipment is delivered and construction is completed at various stages, these costs escalate to a total of $59 million installed by the end of 1989. The construction cash flow is roughly a 20-40-40% allocation for the three construction years, 1987-1989.

In addition to the hard construction costs, there are other capital requirements for any project to begin operation, specifically construction interest, working capital, and development, financing, legal, and other costs. The construction interest is assumed to be zero, for two reasons. First, the basic economic measure is return on <u>total</u> private investment, with no private debt, hence no interest costs. Second, even with a financing structure that assumed debt, since the last capital contribution is the private contribution, the amount of interest during the last few months of construction is small compared to the total capital costs, perhaps a few hundred thousand dollars. However, because of final performance testing and construction certification holdback amounts, it may be that the private contribution would occur virtually at plant startup, with no attendent construction period interest.

Working capital is required for the delay in payment of invoices (i.e., accounts receivable), fuel inventory needed, initial catalyst and chemicals, and other initial inventory. The estimated capital requirements at startup for the GU site for these items is $2.1 million.

Finally, for any privately financed entity, there are private development, financing, legal, and other costs associated with that activity. These costs are estimated at $2.3 million (fixed) for the project. These include:

- o Financing fee of $1.5 million, or 8% of the private capital requirement.

- o Third party development fee of $380,000, or 2% of the private capital.

- o Legal and other expenses of $380,000, or 2% of the private development capital.

The total capital requirements, as installed, for the Washington, D.C. site, then, are $63.4 million. Table 2.5-3 shows the percentage and timing of these requirements for the private and governmental portions.

2.5.2.2 Plant Energy Production

The margin provided by the output revenues and the basic operating cost determined the return on the private capital required. For the Washington, D.C. site, the GFC plant outputs are electric power, steam and tars and oils.

The electric power revenues from the GFC plant are based on its rate of power output, number of operating hours per year, and the price receivec for the power sold. The entire GFC plant electric output is sold to GU, displacing its purchase oower from the Potomac Electric Power Company (PEPCO). The assumed price for the GFC power sold is the same as GU's cost of purchased power. In 1990 this is 6.7¢/kWh. (This is the total electric power bill divided by the number of kilowatt hours purchased from PEPCO.) At a long-term escalation rate of 5%, this power price increases to 8.5¢/kWh in 1995.

TABLE 2.5-3

GFC PLANT CAPITAL REQUIREMENTS ($ Million)

Washington, D.C.

	1985 Dollars	Installed Costs Assuming a 5-Percent Escalation Rate 1987	1988	1989	Total
Construction Costs					
GFC Plant Equipment	35.2				
GFC Plant Civil	14.3				
Preproduction Costs	.9				
Subtotal	50.4	11.3	23.3	24.4	59.0
Other Costs					
Construction Interest				0*	0
Working Capital				2.1	2.1
Development, Financing, Legal and Other				2.3	2.3
Subtotal	___	___	___	___	4.4
TOTAL CAPITAL REQUIREMENTS		11.3	23.3	28.8	63.4
At a 30/70 Mix of Capital Contributions:					
Private Capital		Not applicable. GFC plant not recommended on economic grounds.			
Government Capital					

* Private capital would be legally committed at the beginning of construction, but would be contributed as the last funding increment. Therefore, construction interest on any private debt used is assumed to be zero.

The amount of electric energy sold annually to GU is 77 million kWhs in the first five years of GFC plant operation, increasing to over 82 million kWhs in the sixth year and later years of operation, for a total of almost 800 million kWhs over the first ten years of plant life. The rationale for the increase in output is that, with some solid operating experience, the GFC plant availability should increase.

The total electric revenues to the GFC plant are estimated at $5.1 million in 1990, $7 million in 1995, and $67 million for the first ten years of plant life.

The other revenues for the GFC plant come from the sale of steam and the sale of tars and oils (similar to residual fuel oil) produced in the process, and not used internally. The limited amount of steam (200 pounds per hour and 14 million pounds per year) would produce 1990 revenues of less than $100,000 per year. The substantial amount of tars and oils produced as a by-produuct of the plant are assumed to be sold at the price of No. 6 fuel oil (63¢ per gallon in 1990), providing revenues of over $1 million. The estimated total GFC plant revenues for 1990, then, are $6.3 million, and over $80 million during the first ten years of plant life.

Exhibit 22 shows the key electric power and other output assumptions for the GFC plant for the first year and sixth year of operation, and cumulatively for the first ten years of operation.

Both the O&M and the fuel operating costs are significant. The basis for the $2 million 1985 O&M cost estimate was given in para. 2.1.2. With 5 percent escalation, the 1990 O&M cost would be $2.6 million. In 1995 (sixth operating year), the fuel cell reload costs start, adding $600,000 per year, for a total 1995 O&M of $3.9 million. In addition to the technical O&M, there are other possible annual operating costs that must be considered, mainly taxes and insurance. The amount estimated for these two costs in 1990 is $260,000, assumed to escalate at 5 percent per year long-term.

TABLE 2.5-4

SUMMARY - GFC PLANT ECONOMIC OUTPUTS

Washington, D.C.

Economic Parameter	First Year (1990)	Sixth Year (1995)	First 10 Years Operation (1990-1999)
Electric Power Outuput			
Net Power Output (MW)	10.8	10.8	
Operating Hours Hours per year	7096	7596	
Energy Sold to Site (Mil kWhs)	77.0	82.4	797
Price (¢/kWh)	6.7	8.5	
Energy Sold to Utility (Mil kWhs)	0	0	0
Price (¢/kWh)	NA	NA	
Steam Output (at 240 psig)			
Output Rate (1000 Lbs/Hr)	2000	2000	
Sold to Site (Mil Lbs)	14.2	15.2	147
Price ($/000 Lbs)	5.1	6.5	
Other Output			
Tars/Oils Sold (Bil Btu)	274	2984	2841
Price ($/gal)	.63	.80	

Using a coal price of $62 per ton (under the first scenario analysis, fossil fuel prices were assumed flat for five years), the 1990 coal cost for the GU GFC plant is estimated at $3.2 million. With a 5 percent escalation, and an increase in plant operating hours starting in the sixth year, the estimated cost in 1995 is $4.0 million.

While the basic economic analysis did not focus on financing and ownership structures, it had to incorporate some fundamental tax assumptions in order to derive an after-tax cash flow return on the total investment. While there is currently a substantial focus on potential new tax legislation, in the absence of any new proposals, the current tax laws were assumed.* Therefore, the tax assumptions made were:

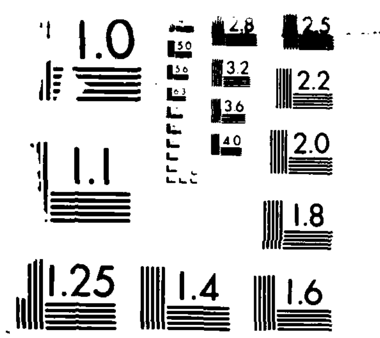
- o 10 percent investment tax credit.
- o 5-year straight line depreciation.
- o 50 percent combined federal and state marginal annual income tax rate.
- o As a sensitivity analysis, the impact of the annual income tax credit (through 1999) for nonconventional sources of gas were evaluated. Currently, this tax credit is approximately 70¢ per million Btus of synthetic gas produced.

---

* With regard to tax factors affecting the GFC plant economics, [illegible] overall thrust of the current tax proposals is to eliminate [illegible] the investment tax credit and stretch out the depreciation [illegible] measures that would lower the ROI. The proposals would also [illegible] marginal annual income tax rate, a measure that would [illegible] in the long-term.

AD-A175 566 FEASIBILITY STUDY OF COAL GASIFICATION/FUEL CELL/COGENERATION ECONOMIC AND FINANCING ASSESSMENT(U) EBASCO SERVICES INC NEW YORK P BOS ET AL. AUG 85 2/2

UNCLASSIFIED DAAG29-85-C-0007 F/G 5/1 NL


1.0
2.8
2.5
3.2
2.2
3.6
4.0
2.0
1.1
1.8
1.25
1.4
1.6

2.5.2.3 Return on Investment

For this analysis, return on total investment (ROI) was used as the measure of the GFC plant financial performance. With this measure, no private debt is assumed -- i.e., the entire private investment is treated as equity.

The ROI results of the analysis are not to be considered as final investment-decision results. Rather, they are an indicator of the potential economic attractiveness of the GFC plant. The ROI result is one measure to be used by the Department of the Army to decide which sites warrant further expenditures for preliminary design and more refined economic/financing analysis. Other measures of importance to be used by the Army will be:

- o Benefit from using coal to replace oil and gas use.
- o Increased site power supply reliability.
- o Reduced requirements for other site plant capital expenditures.
- o The value of a maximum price guarantee to be provided by the GFC plant that would not be available from existing electricity and fuel suppliers.

Further, the technical design and economics of the plant were not optimized in this feasibility study. The purpose of the next step -- preliminary design and testing -- is to identify improvements in the plant efficiency (causing lower operating costs) and reductions in the capital cost. Also, the private cost-sharing component, which is a significant strength of the GFC concept, has been roughly set at 30 percent production volume capital cost for the GFC plant at 30 percent of the prototype cost. This number, coupled with revised capital cost estimates, could change somewhat. Therefore, the minimum economic performance required from the analysis to warrant further work should not be as high as the final ROI and other financial requirements that would be desired by investors in any final design plant.

Therefore, a feasibility ROI criterion of 10 percent, without the annual syngas income tax credit (which makes the ROI higher), was used to test each of the sites for economic feasibility. While the syngas tax credit has been in effect for several years, and should not be ignored, it distorts an ROI number such that general comparisons with other ROIs are harder to make. The 10 percent ROI criterion roughly translates into a 25 percent or higher return on equity (ROE), assuming a 2/1 private debt/equity ratio. (Alternative financing structures and the ROE results are discussed in Chapter 3.0, Financing and Ownership Analysis.)

As shown in Table 2.5-5, the total GFC plant revenues for GU in 1990 are estimated at $6.3 million, and total costs at $6.0 million, resulting in a very limited operating cash flow of $400,000. This operating margin remains at a low level, with a 10-year total operating cash flow of approximately $4 million.

For the ROI analysis, there is no debt service requirement. Therefore, only a tax saving or payment needs to be applied to the operating cash flow to obtain the after-tax net cash flow.

During the first five years of plant life, the allowed depreciation results in a tax savings. Therefore, the net cash flow in 1990 is $1.8 million. However, starting in 1995, a tax payment of 50 percent of the operating cash flow occurs.* After the first 5 years, the net cash flow is limited, with a total 10-year cash flow of $10.4 million.

---

* The annual income tax credit for nonconventional sources of gas (called the syngas tax credit) which is in effect through 1999, has not been included in the tax calculation so that the resulting ROI can be compared to other ROIs reflecting conventional tax assumptions.

TABLE 2.5-5

GFC PLANT CASH FLOW SUMMARY

Washington, D.C.

Economic Variable	1990	1995	10 Year Total (1990-1999)
Base Scenario (Flat near-term fuel prices. 5 percent long-term)			
Revenue			
Electric	5.1	7.0	67.0
Other	1.2	1.5	15.5
Subtotal	6.3	8.5	82.5
Cost			
Fuel	3.2	4.0	39.7
O&M & Other	2.8	4.2	38.8
Subtotal	6.0	8.2	78.5
Operating Cash Flow	.3	.3	4.0
Tax Saving (Payment)*	1.5	-.1	6.4
Net Cash Flow	1.8	.2	10.4
ROI	Negative		
Scenario 2 (Flat near-term fuel prices. 10 percent/year long-term)			
Net Cash Flow			
ROI	Negative		
Scenario 3 (Fuel prices 5 percent/year near term, 10 percent long-term)			
Net Cash Flow			
ROI	Negative		

*Does not include the annual syngas tax credit.

The resulting ROI under the base scenario is negative, as are the ROIs under Scenarios 2 and 3. Sensitivity analysis conducted on electric power and coal prices do not show any potential for improving the economics to an acceptable level.

2.5.2.4 Site Specific Increment

The site specific incremental cost is estimated to be in the range of $16,000,000 to $20,000,000. This additional burden to the basic GFC which is not subject to DOA funding, makes the total plant too costly to continue as the baseline facility.

2.5.3 Conclusions for the Georgetown University Site

The analysis of the Georgetown University site led to the following conclusion:

1. For a set a energy prices that provides Georgetown University any significant cost savings, the GFC plant after-tax return on total investment is unacceptable. Therefore, an economically viable application for the GFC plant does not exist.

With the forecast of oil prices in 1990 (63¢/gal) this project is not feasible at this site for overall electricity costs below 9.7¢/kWh. Since the forecast (Table 2.5-1) indicates the electricity price in 1990 to be 6.1¢/kWh, Georgetown University is not proposed as the baseline site.

3.0 OWNERSHIP AND FINANCING ANALYSIS

3.1 General

In this section, the results of the ownership and financing analysis are presented for the two sites that showed acceptable economic results: Scranton AAP and Fort Greely.

The economic results of both Scranton AAP and Fort Greely indicate that a return on total investment (ROI) of over 10% can be achieved. A summary of the economic results for both sites is shown in Table 3-1.

As with the basic economic analysis, this analysis was intended to determine the financing feasibility of each site, showing that it can or cannot be financed. Financing alternatives selected for each feasible site will be detailed in subsequent stages of GFC project development.

This section also lists key third parties who have indicated serious interest in financing, constructing, owning and operating such a facility.

TABLE 3-1

SUMMARY COMPARISON OF SCRANTON AND FORT GREELY ECONOMICS

	Scranton AAP	Fort Greely
Total Capital Requirement ($ Million)	51.0	81.0
Private Capital Contribution ($ Million)	15.3	16.2
1990 After-Tax Cash Flow ($ Million)	2.5	2.7
10-Year After-Tax Cash Flow ($ Million)	23.7	24.2
Return on Investment		
Scenario 1*	11.1%	11.1%
Scenario 2*	9.7%	15.7%
Scenario 3***	2.78%	9.9%

*Flat near-term fossil fuel prices. 5% long-term esclation.

**Flat near term fossil fuel prices. 10% long-term escalation.

***Fossil fuel prices 5%/year near term, 10%/year long term.

The key steps carried out for the ownership and financing assessement were:

1. Identify types of owners and investment decision criteria.

2. Identify workable financing alternatives.

3. Specify the site financing assumptions.

4. Analysis the financing results.

5. Identify potential owners, financers, and other participants for each site.

The financial analysis had the two following specific objectives:

1. Determine if a Return on Equity (ROE) of at least 25% can be achieved.

2. Determine if a debt coverage ratio greater than 1.5 can be provided for the minimum ROE.

Third party financing is defined as the utilization by other non-participating parties of the available tax, cost recovery and revenue related incentives to invest and own capital ventures. The third-party may embody corporations, individuals, partnerships, or joint ventures, and may emanate from the private or public sector. The distinguishing feature of third-party financing is the capital provided by the investor is targeted on a project-specific or service-specific basis, as in project financing.

Using this project financing approach, lenders finance a specific project and look to the cash flow generated by that project to service and repay the debt. In "pure" project finance, the lenders have no resource to nor support from, the project's sponsors. However, credit support of some sort from the sponsors or interested third parties are sometimes required. The key to "project financing" is to structure the financing with as little recourse as possible to the sponsors while simultaneously providing sufficient credit support so as to induce the lenders to provide the funds.

Thus, the asset of the project itself serves as collateral to secure the loan, but as a practical matter, assets frequently are project/site specific and thereby would have only minimal reusable value to anyone else. Therefore, the sales contracts for project output becomes a key asset.

The second key feature is the sponsors' desire to limit and minimize their risk and liability for the project debt. Given the size and maturity of a project, the sponsors seek to minimize the impact of the project's financing debt on their balance sheets in order to preserve their financial ratios and debt capacity. In short, the sponsors do not want to borrow directly. Instead, they prefer the project entity itself to incur the debt and carry it on the project's balance sheet.

The lenders, however, want to finance a credit rather than a venture capital risk and therefore, require credit support and contractual commitments from the sponsors and/or third parties, which effectively mitigate potentially unacceptable business risks. These supports, whether in the form of guarantees, offtake agreements, supply contracts, completion guarantees, undertakings by a third party, system performance insurance, etc., allow the lenders to shift much of the risks to the sponsors and/or third parties. It is very important to bear in mind the "Project Financing" does not eliminate the risks involved; it merely seeks to disperse the risks among all interested parties. To accommodate both the sponsors and the lenders, the developer of a project must assess the risks inherent in the project and structure a credit support framework which assigns those risks among the participants who have an inherent interest to see the project go ahead.

There are different types of financing structures that can be used to finance the GFC projects. The most straight forward, and most easily understood, structure is direct, 100% ownership of the plant by a single corporation. This single entity receives all of the net cash flow and all of the tax benefits and liabilities of the project. The entity may choose to obtain debt financing to cover a major portion of the project's capital requirements. It trades off the cash required for the debt service (principal plus interest) against the smaller remaining equity investment it has in the project, and then settles on the optimal amount of debt. (The debt financer, of course, has his criteria and limitations on the maximum amount of debt he is willing to provide.)

A variation on the single owner is a joint venture, where several different owners establish a single legal entity, and share the cash returns and tax benefits of the project in an agreed upon proportion.

Another, completely different structure, is a leasing structure, which has been traditionally used for equipment financing by parties who want no responsibilities or risks for management or operation of the equipment. With this structure, the party leasing the equipment (lessor) receives a cash payment for the project manager/operator (lessee) at least as great as the debt service payment required by the debt lendor. The lessor also receives the tax benefits from the project. The manager/operator, or lessee, manages the project, which now has a lease (rental) cost in addition to the operating costs of the project. The residual cash flow after accounting for operating costs and the lease payment is available to the lessee. If the lessor is a financially strong corporation. he can typically obtain a higher amount of debt, and thus more equity leverage, than a directly-owned project financing structure might allow.

There are other, less likely financing structures essentially applicable to the GFC project, such as a large limited partnership, where a special legal entity (the partnership) owns the project and arranges for debt from a lender, much like the direct corporate owner would. But the allocation of the net cash flow and tax benefits to the partnership can be significantly different for different types of partners (e.g. limited vs. general).

Further, the cash flow, tax benefits and liabilities accrue directly to the entities who are the partners and their particular tax positions. These entities can be individuals or corporations.

Regardless of the financing structure, there are two objectives to be met: A minimum ROE of 25%; and a minimum debt service coverage ratio of 1.5.

Pending a further stage of development of the GFC project, and an owner-specific determination of financing interest, the direct 100% corporate ownership structure was assumed, and the results determined under this structure. In the two remaining sections of this chapter, the results of the ownership/financing analyses are discussed for Scranton AAP and Ft Greely.

3.2 Scranton AAP Ownership/Financing

The following assumptions were made for the Scranton AAP financing analysis:

- Private capital contribution of 30% of total required capital
- Debt/equity ratio of 2/1.
- Debt repaid over 15 years with a constant principal repayment (decreasing total debt service payment).
- Average interest rate over the life of the loan of 13%.
- Current tax laws as follows:

    1. Ten percent investment tax credit.
    2. Five year depreciation.
    3. Fifty percent marginal tax rate.
    4. Annual income tax credit for synthetic gas analyzed as an incremental benefit.*

Each of the above financing assumptions could be varied, with a significant impact on the resulting ROE. However, within the range of assumptions currently in use for the analysis of similar energy projects. Using the base scenario for energy prices discussed in para 2.2, the ROE for Scranton was 28.5% when including the syngas tax credit.

Refer to Appendix A for details and annual cash flows.

---

*The annual income tax credit for nonconventional sources of gas (called the syngas tax credit), which is in effect through 1999, has not been included in the tax calculations so that the resulting ROE can be compared to other ROEs reflecting conventional tax assumptions.

Referring to Table 3-2 which summarizes these results, the operating cash flow (revenues minus costs) is the same as for the ROI analysis. However, it was assumed that two-thirds of the private capital contribution would be debt with a maximum debt service payment of $2 million in 1990. Given the interest cost, the taxable income is lower, and the tax savings are higher than for the ROI analysis (no debt). The overall effect on the net cash flow is to reduce it to approximately half of that under the ROI analysis. But, because the equity invested is on-third of the private capital, the return of that cash flow on the equity is 28.5%.

From the debt lender's point of view, a suitable debt coverage ratio is provided. While the minimum debt coverage ratio of 1.5 is not met in the first five years, a coverage ratio of 2.8 - 4.4 is provided in the second five years. The average debt coverage ratio for the first 10 years of plant life is 2.1, as shown in Table 3-2. Thus, the debt structure could be worked around and tailored to the cash flows of the project to provide an acceptable debt coverage ratio for the entire debt service life.

TABLE 3-2

GFC PLANT ECONOMICS SUMMARY ($ Million)
SCRANTON AAP, PENNSYLVANIA

Economic Variable		1990	1995	10-Year Total (1990-1999
Base Scenario (Flat near-term fuel prices. 5% year long-term)				
Revenues:	Electric	7.8	12.0	106.0
	Other	.3	.5	4.5
	Subtotal	8.1	12.5	110.5
Costs:	Fuel	3.0	3.8	37.6
	O&M & Other	2.8	4.2	38.8
	Subtotal	5.8	8.0	76.4
Operating Cash Flow		2.3	4.4	34.1
Tax Saving (Payment)*		.2	-2.2	-10.4
Net cash flow		2.5	2.2	23.7
ROI		11.1%		
Scenario 2 (Flat near-term fuel prices. 10%/year long-term)				
Net Cash Flow		2.5	1.8	22.5
ROI		9.7%		
Scenario 3 (Fuel prices 5%/year near term, 10%/year long-term)				
Net Cash Flow		2.1	1.1	16.0
ROI		2.7%		

ROE ANALYSIS: Base Scenario

Operating Cash Flow	2.3	4.4	34.1
Total Debt Service	-2.0	-1.6	-16.2
Tax Saving (payment)*	.8	-1.7	- 5.7
Net cash flow	1.1	1.1	12.2

Debt coverage ratio**	1.1	2.8	2.1
ROE (2/1 debt/equity ratio):	28.5%		(Average)
ROE with syngas tax credit:	57.9%		

*Does not include the annual syngas tax credit.

**Operating cash flow divided by total debt service.

To assure the practical viability of the project after demonstrating acceptable economics, key participants are required, namely-a coal supplier who can deliver coal at the price indicated, the supplier of a suitable parcal of land, an electric utility to buy power, a purchaser of the steam and/or electric power, an engineer/constructor who can provide the required engineering, various equipment suppliers, and an owner/ operator who will manage and guarantee the operating availability and performance of the plant. For the Scranton AAP site, some of the potential participants are:

- o Coal Supplier: Unionvale Coal Company; American Natural Resources.
- o Land Supplier: University of Scranton
- o Electric Utility: Pennsylvania Power & Light
- o Long Term Steam Purchaser: Scranton AAP.
- o Owner/Operator: Foster-Wheeler Corporation; American Natural Resources; King Smith

The expression of interest of the above participants at this stage confirms the potential of the GFC project, should its economics and financiability be born out in further design and testing work.

3.3 Fort Greely Ownership/Financing

The following assumptions were made for the Fort Greely financing analysis:

- o Private capital contribution of 20% of total required capital
- o Debt/equity ratio of 2/1.
- o Debt repaid over 15 years with a constant principal repayment (decreasing total debt service payment).

- o Average interest rate over the life of the loan of 13%.

- o Current tax laws as follows:

  1. Ten percent investment tax credit.
  2. Five year depreciation.
  3. Fifty percent marginal tax rate.
  4. Annual income tax credit for synthetic gas analyzed as an incremental benefit.*

Each of the above financing assumptions are within the range typically used for analyzing the financing attractiveness of this type of energy project. Using the base scenario for energy prices discussed in paragraph 2.3, the ROE for Fort Greely was 33% which increases to 60% when considering the annual syngas tax credit.

Referring to Table 3-3, operating cash flow (revenues minus costs) is the same as for the ROI analysis. However, it was assumed that two-thirds of the private capital contribution would be debt with a maximum debt service payment of $2 million in 1990. Given the interest cost, the taxable income is lower, and the tax savings are higher, than for the ROI analysis (no debt). But, because the equity invested is one-third of the private capital, the return of that cash flow on the equity is 33%.

Refer to Appendix A for details and annual cash flows.

---

*The annual income tax credit for nonconventional sources of gas (called the syngas tax credit), which is in effect through 1999, has not been included in the tax calculations so that the resulting ROE can be compared to other ROEs reflecting conventional tax assumptions.

From the debt lender's point of view, a suitable debt coverage ratio is provided. While the minimum debt coverage ratio of 1.5 is not met in the first three years, a coverage ratio of 1.5 - 3.5 is provided in the remaining years. The average debt coverage ratio for the first 10 years of plant life is 2.0, as shown in Table 3-3. Thus, the debt structure could be worked around and tailored to the cash flows of the project to provide an acceptable debt coverage ratio for the entire debt service life.

TABLE 3-3

GFC PLANT ECONOMICS SUMMARY

FT. GREELY, ALASKA

Economic Variable		1990	1995	10-Year Total (1990-1999
Base Scenario				
Revenues:	Electric	6.7	9.2	86.9
	Other	1.7	2.2	21.4
	Subtotal	8.4	11.4	109.3
Costs:	Fuel	3.2	4.1	40.2
	O&M & Other	2.8	3.6	35.4
	Subtotal	6.0	7.7	75.6
Operating Cash Flow		2.4	3.7	33.7
Tax Saving (Payment)*		.3	-1.9	- 9.5
Net cash flow		2.7	1.8	24.2
ROI		11.1%		
Scenario 2				
Net Cash Flow		2.7	2.5	30.9
ROI		15.7%		
Scenario 3				
Net Cash Flow		2.2	1.8	23.9
ROI		9.9%		

ROE ANALYSIS: Base Scenario

Operating Cash Flow	2.4	3.7	33.7
Total Debt Service	-2.1	-1.6	-16.9
Tax Saving (payment)	1.0	-1.4	- 4.6
Net cash flow	1.1	.7	12.2

Debt coverage ratio	1.1	2.2	2.0

ROE (2/1 debt/equity ratio): 33%

ROE with syngas tax credit: 60%

To assure the practical viability of the project after demonstrating acceptable economics, key participants are required, namely-a coal supplier who can deliver coal at the price indicated, the supplier of a suitable parcal of land, an electric utility to buy power, a purchaser of the steam and/or electric power, an engineer/constructor who can provide the required engineering, various equipment suppliers, and an owner/operator who will manage and guarantee the operating availability and performance of the plant. For the Ft Greely site, some of the potential participants are:

- Land Supplier: Department of Army
- Electric Utility Power Purchaser: Golden Valley Electric Association.
- Coal Supply: Usibelli; Owen
- Long Term Steam Purchaser: Department of Army
- Owner/Operator: Foster-Wheeler; American Natural Resources; King-Smith; Owen.

The expression of interest of the above participants at this stage confirms the potential of the GFC project, should its economic be born out further design and testing work.

4.0 CONCLUSION AND RECOMMENDATIONS

This report has presented the analysis and findings for an economic and financing feasibility study of the Coal Gasification/Fuel Cell/ Cogeneration (GFC) project federal and private third party cost-sharing concept -- a concept designed to shift Army fuel use from oil or gas to coal and reduce energy costs in doing so. As a feasibility study, the intent was not to provide an optimal design or economic/financing structure, but to arrive at reasonable conclusions regarding the viability of the GFC cost-sharing concept. The third party would own, finance, construct and operate the facility under a long term contract with the Army.

Overall, the GFC concept appears economically feasible. Two of the three Army bases evaluated provide the conditions for an economically viable GFC plant, with potential benefits for a number of Army bases. Specifically, the GFC concept was found to be economically viable for the Scranton Army Ammunition Plant (AAP) and Fort Greely, Alaska, but not for Fort Hood, Texas or for the baseline site, Washington, D.C.

Beyond the direct cost savings that could be provided by a GFC plant at an Army base, there are other indirect benefits that would accrue to GFC plants as well. The site-specific conclusions, general GFC plant conclusions, conclusions regarding broader benefits from GFC plants, and the recommendations based on these conclusions are presented in the four sections below.

4.1 Site-Specific Conclusions

Capital costs referred to in this paragraph are referenced to the date, 1/1/90.

The SCRANTON ARMY AMMUNITION PLANT site was found to be economically feasible and financable for a GFC plant application. This conclusion is the result of the following economic findings:

- o Total capital requirement of $51 million.
- o Federal capital contribution of $36 million (70%).

- Private capital contribution of $15 million (30%).
- Ten-year site savings (1990-1999) of $7-11 million
- Basic economics and financing characteristics that would provide the GFC third party owner with a 25-30% or higher return on equity

FORT GREELY, ALASKA was found to be economically viable for a GFC plant application. This conclusion was based on the following economic findings:

- Total capital requirement of $81 million which includes significant additional construction costs required for an Alaskan Army base location
- Federal capital contribution of $65 million (80%)
- Private capital contribution of $16 million(20%)
- Ten year site savings (1990-1999) of $10-20 million
- Economic and financing characteristics providing the GFC third party owner with a 30-35% or higher return on equity.

FORT HOOD, TEXAS was found not to be economically feasible for a GFC plant application, based on the following findings:

- Total capital requirement of $51 million
- Federal capital contribution of $36 million (70%)
- Private capital contribution of $15 million (30%)
- A negative return on total investment for the GFC plant under any reasonable level of site savings, even with an 80% federal and 20% private capital contribution

The GEORGETOWN UNIVERSITY, WASHINGTON, D.C. site was found not to be economically feasible for a GFC plant application, based on the following findings:

- o Plant capital requirement of $63 million which includes significant special construction costs due to site constraints
- o Federal capital contribution of $44 million (70%)
- o Private capital contribution of $19 million (30%)
- o A low or negative return on total investment for the GFC plant under any reasonable level of site savings

4.2 General Conclusions

The key to achieving a suitable return on total investment or on the private equity required for a GFC project is the operating cash flow available for debt service and for the plant owner. Below, the conclusions on the factors affecting operating cash flow are summarized.

The potential to lower the O&M costs below the estimated $2.0-2.5 million range is believed to be limited, since these costs are based on well understood and historically confirmed labor and material requirements. Delivered coal prices were received from suppliers and are considered a reliable basis for this analysis.

Analysis of the revenues shows that the electric power revenues dominate the cash flow, comprising 80-95% of the total depending on the site. Revenues from steam and the sale of other products (e.g., tars/oils or coal fines) help, but their total impact is limited. However, with the sale of steam there is a leveraged effect on the Army base energy-related O&M costs. The ability of the base to shut down its on-site boilers, if enough steam is supplied, can result in a significant reduction in labor and related boiler and steam system maintenance and materials expenses. Therefore, at the margin, a configuration that provides more steam and less electricity from the GFC plant is better for the site. (However, depending on the relative price for electricity versus steam, it may not be more advantageous to the economics of the GFC plant itself.)

The price paid by the electric utility for power from privately-owned power plants will be key to the GFC plant economics at many Army bases, either because the GFC plant must sell part of its power to the utility, or the utility may offer higher prices than the cost of purchased power to the Army base. The reason the utility's price can be higher than the Army base's purchased power rate is that the utility price is based on its marginal and most expensive cost of power, whereas the Army base purchased power rate reflects an average utility system cost.

The areas where utility purchased power costs (termed avoided costs under the law) are likely to be highest are electric utility service areas where substantial new capacity will be needed in the early to mid '90s. After a decade (1980s) of likely limited additions of utility capacity, most electric power demand forecasters believe that substantial new capacity will be needed throughout the United States during the 1990s.

In terms of absolute rates, a GFC plant application would make economic sense in utility areas where the current purchased power or avoided cost rate is at least 6¢/Kwh with escalation expected to be the same as inflation over the medium to long term. Alternatively, if the current electric power rate is lower, but the escalation rate is 2-3 percent above inflation, the GFC economics would still be viable.

Since forecasted electric power and fossil fuel prices have been so uncertain over the past 15 years, and significant long-term uncertainty will continue, a careful look at the economic conditions that would strengthen or weaken the GFC plant economics is useful.

<u>Factors That Would Strengthen GFC Plant Economics.</u> The following trends would strengthen the GFC plant economics if they occurred:

- Lower coal price escalation than electric power price escalation (All scenarios analyzed assumed the same longterm escalation rate, although the absolute rate itself was varied from five to 10 percent).

- For Army bases that use significant amounts of oil or gas, higher oil and natural gas escalation rates than zero percent per year in the near term and five percent per year in the long term.

- Special, long-term coal contracts at lower than open market prices, guaranteed by the government. (These would be easy to sell off if the Army base closed, since the price is lower than the open market.)

- Optimization of GFC plant design efficiency.

- Retention of the synthetic gas annual income tax credit through 1999 (currently available but not assumed in the basic economic analysis).

<u>Factors That Would Weaken GFC Plant Economics.</u>

- Higher coal price excalation than electric power price escalation.

- Lower oil and natural gas escalation rate than zero percent per year in the near term and five percent per year in the long term.

- Degradation in the GFC plant operating efficiency and availability.

- Inability to lower the GFC plant capital cost by 50% by the early '90s, and by a total of 70% by the mid '90s. (Regardless of the judgement about this factor, the GFC economic concept is not necessarily weakened for other coal-using technologies).

- Elimination of the 10% investment tax credit.

It is believed that the factors likely to strengthen GFC plant economics are more likely to occur than those that would weaken the economics. Few experts believe that the long-term coal price escalation will be as high as electric power price escalation, and few believe that the 20-25 year time horizon for oil and natural gas prices would see a lower price than the zero percent and five percent escalation rates assumed under the base scenario analysis.

With further optimizing, the efficiency of the GFC plant should be improved, reducing coal costs. Also, the fuel cell and other equipment manufacturers will have invested tens of millions of dollars into the technology components of the GFC plant on the basis of a market requiring capital costs of one-third or less than the prototype capital costs (same year dollars).

It therefore, seems reasonable to conclude that these factors in combination will improve GFC plant economics.

4.3 Indirect Benefits

Indirect benefits which do not affect Owner/Operator or Army costs are as follows:

1. The Army would be able to concentrate its resources more on Army activities, and less on site utilities -- i.e., apply the personnel more to the main mission of each base. Further, the security of energy supply would be increased over the existing electric and fuel power supply.

2. The nation would benefit from a shift to coal from oil or natural gas, improving national energy security as well as making a positive contribution to the national balance of payments. Further, there would be technology-related benefits to the nation from the development of the gasification and fuel cell technology.

3. This is a key opportunity for the Army to commercialize effectively a more efficient, near term, coal fired, environmentally sound technology. This flexible technology produces electricity, heat and steam (water) directly.

4. The coal industry would benefit from an additional market for its coal. It would also benefit indirectly through the coal-using technology development supported by the GFC program.

5. The electric utilities involved would benefit in several ways. First, an electric utility can be a partial third party owner. The utility would also have a reduced need for new plant construction with attendant capital savings, and power prurchased at a price no higher than the costs they avoid. The GFC plant would also improve electric system reliability and reduce utility line losses, compared to the development of the same capacity at one central station location. This would be of particular benefit at those Army bases located in relatively remote areas. Finally, the development of small power plants on a utility system would help the public image of the utility in each of the localities where the GFC plant is situated could develop.

6. As a result of the plant construction and operation, as well as the related coal activities, there would be a number of economic benefits for each of the communities and surrounding areas for each GFC plant location.

   a. There would be 34 direct employees of the plant.

   b. The number of additional jobs created by the economic activity could approximately 25-35 jobs, in accordance with commonly accepted economic multipliers.

      The additional jobs would occur not only through supplier activities (e.g., coal transportation and coal mining), but also more indirectly through additional retail purchases by the employees of the plant and the plant entity itself.

And, if properly implemented by the private owner entity, there could be special training and educational benefits provided by this new technology energy plant to the primary and secondary educational institutions in the area.

4.4 Recommendation

On the basis of positive economic feasibility results for two of three Army bases, and the broader benefits that can accrue to GFC plant development, it is recommended that the Department of the Army proceed to the next stage of development for Scranton AAP and Fort Greely. More specifically, it is recommended that the Department of the Army initiate funding for:

1. Preliminary design and initial optimization studies.

2. Refined economic analysis including comparison with alternative energy systems.

3. Selective testing of alternative coals with gasifier technology options.

4. Initial ownership discussions and conceptual negotiations on the cost-sharing participation with potential owners.

5. Identification of total number of Army bases that would satisfy GFC viability criteria.

5.0 APPENDICES

A. Cash Flow Analyses

1. Georgetown University Site Analysis without GFC Plant
2. Georgetown University GFC Plant Analysis
3. Scranton AAP Site Analysis without GFC Plant
4. Scranton AAP GFC Plant Analysis - Westinghouse Fuel Cell
5. Scranton AAP GFC Plant Analysis - UTC Fuel Cell
6. Fort Greely Site Analysis without GFC Plant
7. Fort Greely GFC Plant Analysis - Westinghouse Fuel Cell
8. Fort Greely GFC Plant Analysis - UTC Fuel Cell
9. Fort Hood Site Analysis without GFC Plant
10. Fort Hood GFC Plant Analysis

SITE COSTS AND BENEFITS ANALYSIS DC

Site August 19, 1985

Avail Hours of GFC 7096 (Input

13000 Coal Btu Content

Steam Output:
Thou lbs/hr @ 240 psia: Input) 2000
Net Enthalpy Gain in Btus/lb: Input) 1050

A.1-1

Georgetown University
Site Analysis w/o GFC Plant

	1985 Cost		Esc Rate 1985-1990	1990 Cost	Esc Rate 1990-2010
		(1990 Inp			
Purch El Pwr Cost (c/kwh)	5.59	from	5.00	6.66	5.00
GFC Elec En Pr (cts/kwh)		below-1202)		6.66	5.00
Electric Demand($/kw/Mo)	0.00		5.00	0.00	5.00
Natural Gas($/mcf)	4.12		0.00	4.12	5.00
Fuel Oil($/gal)	0.63		0.00	0.63	5.00
Existing Cogen	(Input from below-see b120)				
Coal Price($/Ton)	62.76		0.00	62.76	5.00
Coal Heat Content (Btu/lb)	13000		NA	13000	NA
Coal Price($/Mil.Btu)	2.41		0.00	2.41	5.00
Steam Pr & Esc Rate(%/yr)	4.00		5.00	5.11	5.00
O & M Esc Rate(% per Yr)	N.A.		5.00	N.A.	5.00

ELECTRIC POWER DEMAND WITHOUT GFC	DC 1984	Esc Rate 1984-90	1985	1986	1987	1988	1989	1990	Esc Rate 1990-2009	1991	1992	1993	1994	1995	1996	1997	1998	1999	Subtotal Yrs 1-10
KWH Amount (Mil kwhs)																			
On-peak																			
Intermediate																			
Off-peak																			
Subtotal	73.90		75.00	87.00	100.00	108.00	116.00	122.00		125.66	129.43	133.31	137.31	141.43	145.67	150.04	154.55	159.18	1,398.59
									Inputs										
Campus	50.60	Annual	51.00	60.00	70.00	75.00	79.00	82.00	3.00	84.46	86.99	89.60	92.29	95.06	97.91	100.85	103.88	106.99	940.04
Hospital	23.30	Annual	24.00	27.00	30.00	33.00	37.00	40.00	3.00	41.20	42.44	43.71	45.02	46.37	47.76	49.19	50.67	52.19	458.56
KWH Rates(Cts/kwh)																			
Average On-peak																			
Average intermediate																			
Average off peak																			
Overall Average	3.30	Annual	3.76	3.95	4.14	4.35	4.57	4.80	5.00	5.04	5.29	5.56	5.83	6.13	6.43	6.75	7.09	7.45	--
Summer(4 Mos)	4.33		4.52																
Rest of Year	2.78		3.38																
Peak MW									Inputs										
Distribution(12-Mo Pat)	12.63	Annual	11.90	11.90	13.10	14.40	15.10	15.90	3.00	16.38	16.87	17.37	17.90	18.43	18.99	19.55	20.14	20.75	--
Prod/Transm(4-Mo Avg)	12.34	Annual	11.90	11.90	13.10	14.40	15.10	15.90	3.00	16.38	16.87	17.37	17.90	18.43	18.99	19.55	20.14	20.75	--
Peak MW Rate($/kw/Mo)																			
Distribution(12 Mos)	5.77	5.00	6.00	6.30	6.62	6.95	7.29	7.66	5.00	8.04	8.44	8.86	9.31	9.77	10.26	10.78	11.31	11.88	--
Prod/Transm(4 Mos)	8.74	5.00	7.80	10.29	10.80	11.34	11.91	12.51	5.00	13.13	13.79	14.48	15.20	15.96	16.76	17.60	18.48	19.40	--
		(1986 On)																	
THERMAL DEMAND																			
Steam Demand(Mil lbs)																			
Summer (4 Ms)	262.00	5.00	220.00	231.00	242.55	254.68	267.41	280.78	3.00	289.21	297.88	306.82	316.02	325.50	335.27	345.33	355.69	366.36	3,218.85
Rest of Yr	418.00	5.00	385.00	404.25	424.45	445.69	467.97	491.37	3.00	506.11	521.29	536.93	553.04	567.63	586.72	604.32	622.45	641.12	5,632.99
Total Year	680.00		605.00	635.25	667.00	700.36	735.38	772.15											

A 1 - 2

Page 3

Peak Dem(000 Lbs/Hr)	120.00	Annual	120.00	122.00	130.00	137.00	143.00	145.00	3.00	149.35	153.83	158.45	163.20	168.09	173.14	178.33	183.68	189.19	
Avg Btu/Lb(Net)	1050		1050	1050	1050	1050	1050	1050		1050	1050	1050	1050	1050	1050	1050	1050	1050	
Bil Btus Required	714.00		635.25	667.01	700.36	735.38	772.15	810.76		835.08	860.13	885.94	912.52	939.89	968.09	997.13	1027.04	1057.86	9,294.43
Hot Water (Mil Gals)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Avg Btu/Gal	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Bil Btus Required	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EXISTING COGENERATION																			
Elect Energy(Mil Kwhs)																			
Summer	0.00	(Input)	4.28	4.28	4.28	4.28	4.28	4.28		4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	42.82
Rest of Yr	0.00	(Input)	5.32	5.32	5.32	5.32	5.32	5.32		5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	53.18
Subtotal	0.00		9.60	9.60	9.60	9.60	9.60	9.60		9.60	9.60	9.60	9.60	9.60	9.60	9.60	9.60	9.60	96.00
Min Annual MW Output	0.00	(Input)	1.15	1.15	1.15	1.15	1.15	1.15		1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	
Avg Min Summer MW Outpt	0.00	(Input)	1.15	1.15	1.15	1.15	1.15	1.15		1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	
Steam Supply(Mil Lbs)																			
Summer	0.00	(Input)	250.00	250.00	250.00	250.00	250.00	250.00		250.00	250.00	250.00	250.00	250.00	250.00	250.00	250.00	250.00	2,500.00
Rest of Yr	0.00	(Input)	350.00	350.00	350.00	350.00	350.00	350.00		350.00	350.00	350.00	350.00	350.00	350.00	350.00	350.00	350.00	3,500.00
Subtotal	0.00		600.00	600.00	600.00	600.00	600.00	600.00		600.00	600.00	600.00	600.00	600.00	600.00	600.00	600.00	600.00	6,000.00
Avg Btu/Lb(Net)	1050		1050	1050	1050	1050	1050	1050		1050	1050	1050	1050	1050	1050	1050	1050	1050	
Steam Btus(Bils)	0.00		630.00	630.00	630.00	630.00	630.00	630.00		630.00	630.00	630.00	630.00	630.00	630.00	630.00	630.00	630.00	6,300.00
TG Heat Rate	0.00	(Input)	3700	3700	3700	3700	3700	3700		3700	3700	3700	3700	3700	3700	3700	3700	3700	
Boiler Efficiency	0.70	(Input)	0.70	0.70	0.70	0.70	0.70	0.70		0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	
Coal Btus Required(Bil)	0.00		900.04	900.04	900.04	900.04	900.04	900.04		900.04	900.04	900.04	900.04	900.04	900.04	900.04	900.04	900.04	9,000.36
COSTS-Elect Energy($Mil)																			
On-peak																			
Intermed																			
Off-peak																			
Subtot(Net of Cogen)	2.44		2.46	3.06	3.74	4.28	4.86	5.40		5.85	6.34	6.87	7.45	8.08	8.75	9.49	10.28	11.14	79.64
COSTS-Elect Demand($Mil)																			
Distribution(Net)	0.81		0.77	0.81	0.95	1.10	1.22	1.36		1.47	1.59	1.73	1.87	2.03	2.20	2.38	2.58	2.79	19.99
Fred/Transm(Nat)	0.43		0.42	0.44	0.52	0.60	0.66	0.74		0.80	0.87	0.94	1.02	1.10	1.20	1.30	1.40	1.52	10.88
Subtot(Net of Cogen)	1.25		1.20	1.26	1.47	1.71	1.89	2.09		2.27	2.46	2.67	2.89	3.13	3.39	3.68	3.98	4.31	30.87
TOTAL ELECT COSTS	3.68		3.65	4.31	5.21	5.99	6.75	7.49		8.12	8.80	9.54	10.34	11.21	12.15	13.16	14.26	15.45	110.51
SITE FUEL REQS & COSTS WITHOUT EFC																			
Existing Cogen Coal Reqs																			
Btus Required(Bils)	0.00		900.04	900.04	900.04	900.04	900.04	900.04		900.04	900.04	900.04	900.04	900.04	900.04	900.04	900.04	900.04	9,000.36
Btu/Lb	13000		13000	13000	13000	13000	13000	13000		13000	13000	13000	13000	13000	13000	13000	13000	13000	
Total Tons(000)	0.00		34.62	34.62	34.62	34.62	34.62	34.62		34.62	34.62	34.62	34.62	34.62	34.62	34.62	34.62	34.62	346.17
$/Ton Coal	51.00	0.00	51.00	51.00	51.00	51.00	51.00	51.00	5.00	53.55	56.23	59.04	61.99	65.09	68.34	71.76	75.35	79.12	
$/Ton Limestone	9.31	0.00	9.31	9.31	9.31	9.31	9.31	9.31	5.00	9.78	10.27	10.78	11.32	11.89	12.48	13.11	13.76	14.45	
$/Ton Ash Removal	2.45	0.00	2.45	2.45	2.45	2.45	2.45	2.45	5.00	2.57	2.70	2.84	2.98	3.13	3.28	3.45	3.62	3.80	
Total $/Ton	62.76		62.76	62.76	62.76	62.76	62.76	62.76		65.90	69.20	72.66	76.29	80.10	84.11	88.32	92.73	97.37	

A 1-3

$/Mil Btus	2.41		2.41	2.41	2.41	2.41													
Cogen Coal Cost($Mil)	0.00		2.17	2.17	2.17	2.17	2.17	2.17		2.28	2.40	2.52	2.64	2.77	2.91	3.06	3.21	3.37	27.33
Supplemental Fuel Reqs																			
Suppl Steam Btus(Bil)	714.00		5.25	37.01	70.36	105.38	142.15	180.76		205.08	230.13	255.94	282.52	309.89	338.09	367.13	397.04	427.86	2,994.43
Site Boiler Effics	0.70	(Input)	0.70	0.70	0.70	0.70	0.70	0.70		0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	
Suppl Fuel Btus(Bil)	1020.00		7.50	52.88	100.52	150.54	203.07	258.23		292.97	328.76	365.62	403.59	442.70	482.98	524.47	567.21	611.72	4,277.76
Coal(Same cogen boiler)																			
Btus Required(Bil)	298.66	(Input)	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Btu/Lb	13000		13000	13000	13000	13000	13000	13000		13000	13000	13000	13000	13000	13000	13000	13000	13000	
Total Tons(000)	11.49		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
$/Ton-Coal	51.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Ton-Limestone	9.31		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Ton-Ash Removal	2.45		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Total $/Ton	62.76		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Mil Btu	2.41		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Coal Cost($Mil)	0.72		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas																			
Btus Required(Bil)	7.33	(Input)	7.50	32.88	80.52	130.54	160.00	160.00		160.00	160.00	160.00	160.00	160.00	160.00	160.00	160.00	160.00	1,600.00
Btu/Cubic Ft	1030	(Input)	1030	1030	1030	1030	1030	1030		1030	1030	1030	1030	1030	1030	1030	1030	1030	
Total (Mil Cu Ft)	7.12		7.28	31.92	78.17	126.74	155.34	155.34		155.34	155.34	155.34	155.34	155.34	155.34	155.34	155.34	155.34	1,553.40
$/Mcf	6.39	0.00	4.12	4.12	4.12	4.12	4.12	4.12		4.33	4.54	4.77	5.01	5.26	5.52	5.80	6.09	6.39	
$/Mil Btu	6.20		4.00	4.00	4.00	4.00	4.00	4.00	5.00	4.20	4.41	4.63	4.86	5.11	5.36	5.63	5.91	6.21	
Gas Cost($Mil)	0.05		0.03	0.13	0.32	0.52	0.64	0.64		0.67	0.71	0.74	0.78	0.82	0.86	0.90	0.95	0.99	8.05
Fuel Oil																			
Btus Required(Bil)	474.66	(Input)	0.00	20.00	20.00	20.00	43.07	98.23		132.97	168.76	205.62	243.59	282.70	322.98	364.47	407.21	451.22	2,677.76
Btu/Bbl(Mil)	6.30	(Input)	6.30	6.30	6.30	6.30	6.30	6.30		6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	
Total Gals(Mil)	3.16		0.00	0.13	0.13	0.13	0.29	0.65		0.89	1.13	1.37	1.62	1.88	2.15	2.43	2.71	3.01	17.85
$/Gal	0.77	0.00	0.63	0.63	0.63	0.63	0.63	0.63	5.00	0.66	0.69	0.73	0.77	0.80	0.84	0.89	0.93	0.98	
$/Mil Btu	5.15		4.20	4.20	4.20	4.20	4.20	4.20		4.41	4.63	4.86	5.11	5.36	5.63	5.91	6.21	6.52	
Oil Cost($Mil)	2.44		0.00	0.08	0.08	0.08	0.18	0.41		0.59	0.78	1.00	1.24	1.52	1.82	2.15	2.53	2.94	14.98
TOTAL FUEL COST($Mil)																			
Non-GFC Cogen Coal	0.00		2.17	2.17	2.17	2.17	2.17	2.17		2.28	2.40	2.52	2.64	2.77	2.91	3.06	3.21	3.37	27.33
Suppl Steam Fuels																			
Coal	0.72		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	0.05		0.03	0.13	0.32	0.52	0.64	0.64		0.67	0.71	0.74	0.78	0.82	0.86	0.90	0.95	0.99	8.05
Oil	2.44		0.00	0.08	0.08	0.08	0.18	0.41		0.59	0.78	1.00	1.24	1.52	1.82	2.15	2.53	2.94	14.98
Total Fuel Cost	3.21		2.20	2.39	2.58	2.78	2.99	3.23		3.54	3.88	4.26	4.66	5.11	5.59	6.11	6.68	7.30	50.36
Non GFC Case O & M ($Mil)																			
Non-GFC Cogen O & M	0.40		0.44	0.44	0.50	0.55	0.60	0.65	5.00	0.68	0.72	0.75	0.79	0.83	0.87	0.91	0.96	1.01	8.18
Suppl Thermal O & M	1.10		1.50	1.55	1.65	1.71	1.77	1.84	5.00	1.93	2.03	2.13	2.24	2.35	2.47	2.59	2.72	2.85	23.14
Subtotal O & M	1.50		1.94	1.99	2.15	2.26	2.37	2.49		2.61	2.75	2.88	3.03	3.18	3.34	3.50	3.68	3.86	31.32

TOTAL NON-GFC CASE COSTS																		
Purch Elect Power	3.68	3.65	4.31	5.21	5.99	6.75	7.49		8.12	8.80	9.54	10.34	11.21	12.15	13.16	14.26	15.45	110.51
Purch Fuels	3.21	2.20	2.39	2.58	2.78	2.99	3.23		3.54	3.88	4.26	4.66	5.11	5.59	6.11	6.68	7.30	50.36
O & M	1.50	1.94	1.99	2.15	2.26	2.37	2.49		2.61	2.75	2.88	3.03	3.18	3.34	3.50	3.68	3.86	31.32
Total Costs	8.39	7.80	8.69	9.94	11.02	12.11	13.20		14.27	15.43	16.68	18.03	19.49	21.07	22.78	24.62	26.62	192.19
ENERGY COSTS WITH GFC																		
GFC Availability(Hrs/ Yr)							7096		7096	7096	7096	7096	7596	7596	7596	7596	7596	
GFC KWhs Purchased(Mil)							76.95		76.95	76.95	76.95	76.95	82.37	82.37	82.37	82.37	82.37	796.60
Price (c/KWh)				(Cost of purchased electric energy)			6.66		7.00	7.34	7.71	8.10	8.50	8.93	9.37	9.84	10.33	
Min GFC Annual MW Output							10.84 (Input		10.84	10.84	10.84	10.84	10.84	10.84	10.84	10.84	10.84	
GFC Avg Min Summer MW							10.84 (Input		10.84	10.84	10.84	10.84	10.84	10.84	10.84	10.84	10.84	
Total Elect Costs($Mil)							5.13		5.38	5.65	5.93	6.23	7.00	7.35	7.72	8.10	8.51	67.01
GFC Steam Purch (Mil Lbs)							14.19		14.19	14.19	14.19	14.19	14.19	14.19	14.19	14.19	14.19	141.92
GFC Steam Btus (Bil)							14.90		14.90	14.90	14.90	14.90	14.90	14.90	14.90	14.90	14.90	149.02
Price ($/000 Lbs)							5.11	5.00	5.36	5.63	5.91	6.21	6.52	6.84	7.18	7.54	7.92	
Hot Water Purch(Mil gals)							0.00											
Price (c/ Gal)							0.00											
Total Therm Costs($Mil)							0.07		0.08	0.08	0.08	0.09	0.09	0.10	0.10	0.11	0.11	0.91
Subtotal GFC En Costs							5.20		5.46	5.73	6.02	6.32	7.09	7.45	7.82	8.21	8.62	67.92
Existing Cogen Fuel Costs							2.17		2.28	2.40	2.52	2.64	2.77	2.91	3.06	3.21	3.37	27.33
Supplemental Energy Reqs																		
Elect Energy(Mil KWhs)							35.45		39.11	42.88	46.76	50.76	49.46	53.70	58.07	62.57	67.21	505.99
Rate (c/KWh)							4.80		5.04	5.29	5.56	5.83	6.13	6.43	6.75	7.09	7.45	
Energy Cost($Mil)							1.70		1.97	2.27	2.60	2.96	3.03	3.45	3.92	4.44	5.00	31.35
Elect Demand Annual(MW)							3.91		4.39	4.88	5.38	5.91	6.44	7.00	7.56	8.15	8.76	
Rate($/KW/Mo)-12 Mo							7.66		8.04	8.44	8.86	9.31	9.77	10.26	10.78	11.31	11.88	
Elect Demand Summer(MW)							3.91		4.38	4.87	5.38	5.90	6.44	6.99	7.56	8.15	8.75	
Rate($/KW/Mo)-4 Mo							12.51		13.13	13.79	14.48	15.20	15.96	16.76	17.60	18.48	19.40	
Demand Cost($Mil)							0.55		0.65	0.76	0.88	1.02	1.17	1.33	1.51	1.71	1.93	11.52
Elect Cost($Mil)							2.26		2.62	3.03	3.48	3.98	4.20	4.78	5.43	6.15	6.93	42.87
Suppl Steam (Mil Lbs)							150.78		172.89	195.66	219.12	243.29	268.17	293.81	320.21	347.40	375.41	2,586.74
Hot Water (Mil Gals)							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Thermal Btus (Bil)							165.86		190.18	215.23	241.04	267.61	294.99	323.19	352.23	382.14	412.95	2,845.41

A.7-5

Fuel Btus Req (Bil)	236.94		271.68	307.47	344.34	382.31	421.4					
Non-GFC Fuel Reqs												
Btus Req (Bil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal (000 Tons)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Price ($/Ton)	62.76		65.90	69.20	72.66	76.29	80.10	84.11	88.32	92.73	97.37	
Cost ($Mil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Btus Req (Bil)	160.00		160.00	160.00	160.00	160.00	160.00	160.00	160.00	160.00	160.00	1,600.00
Nat Gas (Mil Cu Ft)	155.34		155.34	155.34	155.34	155.34	155.34	155.34	155.34	155.34	155.34	1,553.40
Price ($/Mcf)	4.12		4.33	4.54	4.77	5.01	5.26	5.52	5.80	6.09	6.39	
Cost ($Mil)	0.64		0.67	0.71	0.74	0.78	0.82	0.86	0.90	0.95	0.99	8.05
Btus Req (Bil)	76.94		111.68	147.47	184.34	222.31	261.41	301.69	343.18	385.92	429.93	2,464.88
Fuel Oil (Mil Gals)	0.51		0.74	0.98	1.23	1.48	1.74	2.01	2.29	2.57	2.87	16.43
Price ($/Gal)	0.63		0.66	0.69	0.73	0.77	0.80	0.84	0.89	0.93	0.98	
Cost ($Mil)	0.32		0.49	0.68	0.90	1.13	1.40	1.70	2.03	2.39	2.80	13.85
Suppl Fuel Cost($Mil)	0.96		1.16	1.39	1.64	1.91	2.22	2.56	2.93	3.34	3.79	21.90
O & M Cost ($Mil)												
Existing Cogen Plant	0.65		0.68	0.72	0.75	0.79	0.83	0.87	0.91	0.96	1.01	8.18
Suppl Therm Plant	1.84	5.00	1.93	2.03	2.13	2.24	2.35	2.47	2.59	2.72	2.85	23.14
O & M Savings	0.50	Esc Rate	0.53	0.55	0.58	0.61	0.64	0.67	0.70	0.74	0.78	6.29
Suppl O & M Cost	1.99		2.09	2.19	2.30	2.42	2.54	2.67	2.80	2.94	3.09	25.03

COST/BENEFIT SUMMARY

Without GFC Facility											
Purch Elect Pwr	7.49	8.12	8.80	9.54	10.34	11.21	12.15	13.16	14.26	15.45	110.51
Purch Fuels	3.23	3.54	3.88	4.26	4.66	5.11	5.59	6.11	6.68	7.30	50.36
O & M	2.49	2.61	2.75	2.88	3.03	3.18	[illegible]	3.50	3.68	3.86	31.32
Subtotal-No GFC	13.20	14.27	15.43	16.68	18.03	19.49	21.07	22.78	24.62	26.62	192.19
With GFC Facility											
Purch GFC Elect Pwr	5.13	5.38	5.65	5.93	6.23	7.00	7.35	7.72	8.10	8.51	67.01
Purch GFC Thermal	0.07	0.08	0.08	0.08	0.09	0.09	0.10	0.10	0.11	0.11	0.91
Subtotal	5.20	5.46	5.73	6.02	6.32	7.09	7.45	7.82	8.21	8.62	67.92
Existing Cogen Fuel Costs	2.17	2.28	2.40	2.52	2.64	2.77	2.91	3.06	3.21	3.37	27.33

A,1-6

Suppl Elect Pwr	2.26	2.62	3.03	3.48	3.98	4.20	4.78	5.43	6.15	6.93	42.87
Suppl Fuels	0.96	1.16	1.39	1.64	1.91	2.22	2.56	2.93	3.34	3.79	21.90
Subtotal	3.22	3.79	4.42	5.12	5.89	6.41	7.34	8.36	9.49	10.73	64.77
O & M	1.99	2.09	2.19	2.30	2.42	2.54	2.67	2.80	2.94	3.09	25.03
Subtotal-With GFC	12.58	13.62	14.74	15.96	17.27	18.82	20.37	22.04	23.85	25.81	157.73
NET GFC SAVINGS ($Mil)	0.62	0.65	0.69	0.72	0.76	0.67	0.70	0.74	0.77	0.81	7.14
Avoided cost w/ GFC	5.82	6.11	6.42	6.74	7.08	7.76	8.15	8.56	8.99	9.43	75.06

FINANCIAL EVALUATION OF SAVINGS:

	Cumulative Savings	1990 NPV at Discount Rate of 20.00 %
10-Years	7.14	2.50

A.2-1

Georgetown University
GFC Plant Analysis

GFC PLANT ANALYSIS	Site: DC	Rated Output (MW):	11.00	Bil Btus Coal:	1,323.69	at Mil Btus/hr of	186.54 (Input
	August 19, 1985	Avail(Hrs per Yr):	7096 (Input	Btus/Lb:	13,000.00 (Input		
				Annual Tons Coal:	50,911.07		
				Tons/ Day:	172.19		

ENERGY BALANCE SUMMARY

				Mil Btus/hr	Bil Btus/Yr
Steam Output:					
Thou lbs/hr @ 240 psia:	Input>	2000	600 Lbs/hr		
Net Enthalpy Gain:	Input>	1050	Btus/lb	2.10	14.90
Electric Pwr Output:					
Fuel Cell Output	Input>	11.60	MW	39.59	280.94
Gas Expander Output	Input>	2.54	MW	8.67	61.52
Thermal Mgt System	Input>	0.89		3.04	21.55
Power Conditioner Losses	Input>	(0.60)	MW	(2.05)	(14.53)
Aux Pwr Reqs	Input>	(3.59)	MW	(12.24)	(86.85)
Net Pwr Out		10.84		37.01	262.63
Other Outputs:					
Tars/Oils	at	38.68	Mil Btus/hr (Input		274.47
Other(e.g., Sul,Ammon)	at	0.00	Mil Btus/hr (Input		
Losses					9.30
Ash	at	1.31	Mil Btus/hr (Input		17.67
Cyclone Carbon Dust	at	2.49	Mil Btus/hr (Input		0.00
Heat Rejected by Cooling Tower	at	47.00	Mil Btus/hr (Input		333.51
CO Shift Air Cooler	at	14.70	Mil Btus/hr (Input		104.31
HSRG Stack Loss	at	25.20	Mil Btus/hr (Input		178.82
Miscellaneous	at	18.05	Mil Btus/hr (Input		128.08
TOTAL BTUS:				186.54	1,323.69

GFC PLANT EFFICIENCY:

Hourly Calc (mil Btus)					Annual Calc (bil Btus)			
Net Pwr Out	+ Steam	+ Tars/Oils	+ Other		Net Pwr Out	+ Steam	+ Tars/Oils	+ Other
37.01	2.10	38.68	0.00	Equals:	262.63	14.90	274.47	0.00
	186.54 Coal In					1,323.69 Coal In		

Net Heat Rate:	13,441.53		Gross Heat Rate:	9,697.94	
145.76 (Coal minus Steam & Tars)	Divided by	10.84 (Net Pwr)	145.76 (Coal minus Steam & Tars)	Divided by	15.03 (Gross power out)

Hrly Efficiency Equals: 41.70 Percent
Annual Efficiency Equals: 41.70 Percent

A.2-2.

ECONOMIC & FINANCIAL ASSUMPTIONS   July 30

	All Inputs	All Inputs		All Inputs
	1985 Energy Cost	Annual Escal. Rate 1985-1990	Energy Price 1990	Annual Escal. Rate 1990-2010
GFE Elect En Pr (cts/kwh)	5.22	5.00	6.66	5.00
Fuel Oil($/Mil Btu)	4.20	0.00	4.20	5.00
Coal Price($/Ton)	62.00	0.00	62.00	5.00
Coal Heat Content (Btu/lb)	13000	NA	13000	NA
Coal Price($/Mil.Btu)	2.38	NA	2.38	5.00
Steam Price & Esc Rate	4.00	5.00	5.11	5.00
O & M Esc Rate(% per Yr)	N.A.	5.00	N.A.	5.00

	1985 Existing	1990-2010	Percent of Equip	
Depreciation Method	ACRS	SL		
Depreciation Term(Years)				
Equipment	5.00	5.00	100.00	Percent
Utilities & Other	15.00	15.00	0.00	Percent
Investment Tax Credit	10.00 %	10.00 %		
Nonconventional Gas Annual Income Tax Credit ($/Mil. Btu)	0.70	0.00 (thru 1999)	5.00 Percent Esc Rate	
Investor's Annual Income Tax Rate (Combined Fed. & State)	50.00 %	50.00 %		

OWNERSHIP AND FINANCING STRUCTURE

Parameter	Assumption		
Percent Government Funding	70.00		<Input
Percent Private Funding	30.00		
Percent equity		33.00	<Input
Percent debt		67.00	
Interest rate		13.00	<Input
Loan term(years)		15	<Input
Constr int rate		13.00	<Input
Constr loan amount($Mil)		0.00	<Input
1st yr portion		0.10	<Input
2nd yr portion		0.40	<Input
3rd yr portion		0.50	<Input

A.2-3

CONSTRUCTION COST BREAKDOWN ($Mil)   SITE: OC   GFC SIZE: 11 MW

	5.00 % Esc Rate	1985$	1989$	Period When Costs Will Occur 1987	1988	1989
Coal Hndlg & Gasif.	5.27			20.00	40.00	40.00
Gas Processing & Systems	9.26					
Fuel Cell/Pwr Cond.	15.43					
Thermal Mgt Syst.	3.16					
Balance of Plant	2.08					
Subtotal		35.20	41.18	7.76	16.30	17.11
Prototype Investment(Incl above)		0.00	0.00	0.00	0.00	0.00
Unique Site Costs		14.30	16.73	3.15	6.62	6.95
General Conditions(Incl above)		0.00	0.00	0.00	0.00	0.00
Design & Engineering(Incl above)		0.00	0.00	0.00	0.00	0.00
Preproduction Costs(Incl above)		0.94	1.14	0.38	0.38	0.38
Contingency at a Percent of:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL CONSTRUCTION COST:		50.44	59.05	11.30	23.30	24.45
Land		0.00	0.00	0.00	0.00	0.00
Other Special		1.00	1.22	0.41	0.41	0.41
TOTAL CONSTRUCTION + SPECIAL:		51.44	60.26	11.70	23.71	24.85
OTHER CAPITAL COSTS						
Working Capital						
Accts Receivable at	45 days		0.78	0.00	0.00	0.78
Fuel Inventory at	15 days		0.13	0.00	0.00	0.13
Other Inventory/Supplies			0.10	0.00	0.00	0.10
Accnts Payable at	10 days		(0.16)	0.00	0.00	(0.16)
Subtotal Working Capital			0.85	0.00	0.00	0.85
Priv Fin Fees at Percent of:	8.00 %		1.47	0.00	0.00	1.47
3rd Pty Own Fee at Percent of:	2.00 %		0.37	0.00	0.00	0.37
Other Expenses at Percent of:	2.00 %		0.37	0.00	0.00	0.37
Subtotal			2.20	0.00	0.00	2.20
TOTAL OTHER CAPITAL COSTS:			3.05	0.00	0.00	3.05
CONSTRUCTION INTEREST:			0.00	0.00	0.00	0.00

GFC O & M COST BREAKDOWN($Mil)

	Escal. Rate:	5.00 % 1985$	1990$	1995$
Direct Labor	0.80			
Fringes @ 20%	0.16			
Contract Oper Fee	0.10			
Contract Maint.	0.22			
Chem & Supplies	0.18			
Spare Pts/Maint Sup	0.30			
Water & Site Utils	0.10			
Ash/Sludge Disp.	0.08			
Miscel	0.07			
Subtotal		2.01	2.56	3.27
Wheeling Charge		0.00	0.00	0.00
Fuel Cell Reloading Costs in 1985$ of	32 $/kw/yr	NA	NA	0.60
TOTAL O & M		2.01	2.56	3.87
OTHER ANNUAL EXPENSES				
Legal/Account.		0.00	0.00	0.00
Insurance		0.20	0.26	0.33
Prop. Taxes		0.00	0.00	0.00
TOTAL OTHER		0.20	0.26	0.33

A-2-4

ENERGY PRODUCTION	In 1985 $	In 1990 $	In 1995 $
Net Amount of Electric Power Sold			
kWh(Mil)	76.95	76.95	82.37
Avg Monthly Max. MW	10.84	10.84	10.84
Avg Monthly Min. MW	8.00	8.00	8.00
Price(cts/kWh)	5.22	6.66	8.50
Price/kW/Mo	0.00	0.00	0.00
Annual Energy Revenues ($ Mil)	4.02	5.13	7.00
Annual Capacity Revenues ($ Mil)	0.00	0.00	0.00
Subtotal Elect Revs	4.02	5.13	7.00
Steam/Hot Water Sold			
Amount(Mil lbs)	14.19	14.19	15.19
Energy Content(Bil Btus)	14.90	14.90	15.95
Price per Unit ($/000 lb)	4.00	5.11	6.52
Thermal Revenues	0.06	0.07	0.10
Other Revenues: Esc Rate:		(Tars Based on of retail fuel oil price)	100 percent
Tars/Oils	1.15	1.15	1.47
Sulfur	0.00	0.00	0.00
Ammonium Sulfate	0.00	0.00	0.00
Other Revs:	1.15	1.15	1.47
GFF Total Revs ($Mil)	5.23	6.75	8.57
Fuel Use			
Energy Content(Bil Btus)	1,323.69	1,323.69	1,323.69
Amount(Mil Tons)	50,911.07	50,911.07	50,911.07
Cost			
Fuel Cost($/ton)	62.00	62.00	79.13
Total Fuel Cost($ Mil)	3.16	3.16	4.03
O & M Costs	2.01	2.56	3.87
Other Annual Costs	0.20	0.26	0.33
GFF OPER COSTS ($Mil)	5.36	5.97	8.23

A.2-5

COAL GASIFICATION-FUEL CELL-COGENERATION PLANT AT: DC SITE   GFC CF ANALYSIS   DC SITE

FINANCIAL ANALYSIS ($MIL)

Priv Eqty: 6.27 = 30.00 33.00 Percent
Priv Debt: 12.73 = 30.00 67.00 Percent
Tot Cap Costs of 63.31 times

Item	Engineering/Construction 1987	1988	1989		Operating Period 1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Subtotal Yrs 1-10		2000
Revenues																	
Electric	0.00	0.00	0.00		5.13	5.38	5.65	5.93	6.23	7.00	7.35	7.72	8.11	8.51	67.03		8.94
Thermal	0.00	0.00	0.00		0.07	0.08	0.08	0.08	0.09	0.10	0.10	0.11	0.11	0.12	0.95		0.13
Other	0.00	0.00	0.00		1.15	1.21	1.27	1.33	1.40	1.47	1.54	1.62	1.70	1.79	14.50		1.88
Subtotal	0.00	0.00	0.00		6.35	6.67	7.00	7.35	7.72	8.57	9.00	9.45	9.93	10.42	82.47		10.94
Operating Costs																	
Fuel	0.00	0.00	0.00		3.16	3.31	3.48	3.65	3.84	4.03	4.23	4.44	4.66	4.90	39.70		5.14
O & M	0.00	0.00	0.00		2.56	2.69	2.82	2.96	3.11	3.87	4.07	4.27	4.48	4.71	35.54		4.94
Other	0.00	0.00	0.00		0.26	0.27	0.28	0.30	0.31	0.33	0.34	0.36	0.38	0.40	3.21		0.42
Subtotal	0.00	0.00	0.00		5.97	6.27	6.58	6.91	7.26	8.23	8.64	9.07	9.52	10.00	78.46		10.50
OPERATING CASH FLOW	0.00	0.00	0.00		0.38	0.40	0.42	0.44	0.46	0.35	0.36	0.38	0.40	0.42	4.02		0.44
Debt Service: Principal				15	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	8.48		0.85
Interest	0.00	0.00	0.00	Yrs	1.65	1.54	1.43	1.32	1.21	1.10	0.99	0.88	0.77	0.66	11.58		0.55
	(Constr	Loan	Interest)														
Subtotal	0.00	0.00	0.00		2.50	2.39	2.28	2.17	2.06	1.95	1.84	1.73	1.62	1.51	20.06		1.40
Coverage Ratio					0.15	0.17	0.18	0.20	0.22	0.18	0.20	0.22	0.25	0.28	0.20		0.32
Debt Svc Reserve					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00
Cumul Reserve					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N.A.		0.00
RESIDUAL CASH FLOW	0.00	0.00	0.00		(2.12)	(1.99)	(1.86)	(1.73)	(1.60)	(1.60)	(1.48)	(1.35)	(1.22)	(1.09)	(16.04)		(0.96)
Management Fee					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00
		(Private share															
Tax Adjustments		of equipment)															
Depr 5-yr Equip(SL) at	0.95	30.00	Percent)		3.37	3.37	3.37	3.37	3.37						16.83		
Depr 15-yr Equip(SL) at	1.00	30.00	Percent)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00
Amort Startup Cost	0.00	0.00	0.00														
Principal Payment					0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	8.48		0.85
Debt Svc Reserve					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00
Taxable Income/Loss(-)	0.00	0.00	0.00		(4.64)	(4.51)	(4.38)	(4.25)	(4.12)	(0.76)	(0.63)	(0.50)	(0.37)	(0.24)	(24.39)		(0.11)
Tax Saving or Payment(-)	0.00	0.00	0.00		2.32	2.26	2.19	2.12	2.06	0.38	0.31	0.25	0.18	0.12	12.19		0.05
11 % Inv Tax Credit at	30.00 Percent)		1.81														
Syngas Tax Credit at	0.00 $/Mil Btu to 1999)				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Priv Capital Requirement			(18.99)														
Priv Perm Debt Financing			12.73														
NET CASH FLOW	0.00	0.00	:	(4.46)	0.20	0.26	0.33	0.39	0.46	(1.23)	(1.16)	(1.10)	(1.03)	(0.97)	(0.90)	(0.84)	(0.77)
Cumulative Cash Flow	0.00	0.00	(4.46)		(4.26)	(4.00)	(3.67)	(3.28)	(2.82)	(4.05)	(5.21)	(6.31)	(7.34)	(8.31)	(9.21)	(10.05)	(10.82)

ROE= ERR Percent; NPV= ERR at a ERR Percent Disc Rate.
(Using a 10 Year Cash Stream)

A.3-1

Scranton AAP
Site Analysis w/o GFC

SITE COST/BENEFITS ANALYSIS

	FA	Site	Avail	Hours of GFC	
GFC Steam Output:	August 19, 1985			7096 (Input	13000 Coal Btu Content
Thou lbs/hr @ 230 psia:		Input)	9200		
Net Enthalpy (Btus/lb):		Input)	1052		

	1985 Cost		Esc Rate 1985-1990	1990 Cost	Esc Rate 1990-2010
Cost Purch El Pwr(c/kwh)	6.10	(Input fm	5.00	7.06	5.00
Cost GFC El Pwr (c/kwh)		below)	Input)	8.80	5.00
Electric Demand($/kw/Mo)	0.00		5.00	0.00	5.00
Natural Gas($/mcf)	5.79		0.00	5.79	5.00
Fuel Oil($/gal)	0.63		0.00	0.63	5.00
Existing Cogen Coal Price($/Ton)	N.A.		0.00	N.A.	5.00
Coal Heat Content (Btu/lb)	13000		NA	NA	NA
Coal Price($/Mil.Btu)	N.A.		0.00	N.A.	5.00
Steam Fr % Esc Rate(%/yr)	4.00		5.00	5.10	5.00
O & M Esc Rate(% per Yr)	N.A.		5.00	N.A.	5.00

ELECTRIC POWER DEMAND WITHOUT GFC	FA 1984	Esc Rate 1984-90	1985	1986	1987	1988	1989	1990	Esc Rate 1990-2009	1991	1992	1993	1994	1995	1996	1997	1998	1999	Subtotal Yrs 1-10
KWH Amount (Mil kwhs)																			
On-peak																			
Intermediate																			
Off-peak																			
Subtotal	28.90	2.00	29.48	30.07	30.67	31.28	31.91	32.55	2.00 Inputs	33.20	33.86	34.54	35.23	35.93	36.65	37.39	38.13	38.90	356.37
KWH Rates(Cts/kwh)																			
Average On peak																			
Average intermediate																			
Average off-peak																			
Overall Average	4.12	5.00	4.33	4.54	4.77	5.01	5.26	5.52	5.00	5.80	6.09	6.39	6.71	7.05	7.40	7.77	8.16	8.57	--
Summer(4 Mos)																			
Rest of Year																			
Peak MW									Inputs										
Distribution(12 Mo Rat)	8.40	2.00	8.57	8.74	8.91	9.09	9.27	9.46	2.00	9.65	9.84	10.04	10.24	10.44	10.65	10.87	11.08	11.31	--
Peak MW Rate($/kw/Mo)																			
Distribution(12 Mos)	3.30	5.00	3.47	3.64	3.82	4.01	4.21	4.42	5.00	4.64	4.88	5.12	5.38	5.64	5.93	6.22	6.53	6.86	--
THERMAL DEMAND																			
Steam Demand(Mil lbs)																			
Summer (4 Mo)	25.00	2.00	25.50	26.01	26.53	27.06	27.60	28.15	2.00	28.72	29.29	29.88	30.47	31.08	31.71	32.34	32.99	33.65	308.28
Rest of Yr	65.70	2.00	67.01	68.35	69.72	71.12	72.54	73.99	2.00	75.47	76.98	78.52	80.09	81.69	83.32	84.99	86.69	88.42	810.16
Total Year	90.70		92.51	94.36	96.25	98.18	100.14	102.14											

Peak Dem(000 Lbs/Hr)	?	2.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Avg Btu/Lb(Net)	1052		1052	1052	1052	1052	1052	1052		1052	1052	1052	1052	1052	1052	1052	1052	1052	
Bil Btus Required	95.42		97.32	99.27	101.26	103.28	105.35	107.45		109.60	111.80	114.03	116.31	118.64	121.01	123.43	125.90	128.42	1,176.60
Hot Water (Mil Gals)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Avg Btu/Gal	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Bil Btus Required	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EXISTING COGENERATION																			
Elect Energy(Mil kwhs)																			
Summer	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rest of Yr	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Min Annual MW Output	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Avg Min Summer MW Outpt	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam Supply(Mil Lbs)																			
Summer	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rest of Yr	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Avg Btu/Lb(Net)	1052		1052	1052	1052	1052	1052	1052		1052	1052	1052	1052	1052	1052	1052	1052	1052	
Steam Btus(Bils)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TG Heat Rate	0.00	(Input)	3700	3700	3700	3700	3700	3700		3700	3700	3700	3700	3700	3700	3700	3700	3700	
Boiler Efficiency	0.70	(Input)	0.70	0.70	0.70	0.70	0.70	0.70		0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	
Coal Btus Required(Bil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COSTS Elect Energy($Mil)																			
On-peak																			
Intermed																			
Off-peak																			
Subtot(Net of Cogen)	1.17		1.28	1.37	1.46	1.57	1.68	1.80		1.92	2.06	2.21	2.36	2.53	2.71	2.90	3.11	3.33	24.94
COSTS Elect Demand($Mil)																			
Distribution(Net)	0.33		0.36	0.38	0.41	0.44	0.47	0.50		0.54	0.58	0.62	0.66	0.71	0.76	0.81	0.87	0.93	6.97
Prod/Transm(Net)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtot(Net of Cogen)	0.33		0.36	0.38	0.41	0.44	0.47	0.50		0.54	0.58	0.62	0.66	0.71	0.76	0.81	0.87	0.93	6.97
TOTAL ELECT COSTS	1.52		1.64	1.75	1.87	2.00	2.15	2.30		2.46	2.64	2.82	3.02	3.24	3.47	3.72	3.98	4.26	31.91
SITE FUEL REQS & COSTS WITHOUT GFC																			
Existing Cogen Coal Reqs																			
Btus Required(Bils)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Btu/Lb	0		13000	13000	13000	13000	13000	13000		13000	13000	13000	13000	13000	13000	13000	13000	13000	
Total Tons(000)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
$/Ton Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Ton Limestone	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Ton Ash Removal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Total $/Ton	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	

$/Mil Btus	0.00																		
Cogen Coal Cost($Mil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Supplemental Fuel Reqs																			
Suppl Steam Btus(Bil)	95.42		97.32	99.27	101.26	103.28	105.35	107.45		109.60	111.80	114.03	116.31	118.64	121.01	123.43	125.90	128.42	1,176.60
Site Boiler Effics	0.70	<Input>	0.70	0.70	0.70	0.70	0.70	0.70		0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	
Suppl Fuel Btus(Bil)	136.31		139.04	141.82	144.65	147.55	150.50	153.51		156.58	159.71	162.90	166.16	169.48	172.87	176.33	179.86	183.45	1,680.85
Coal(Same cogen boiler)																			
Btus Required(Bil)	0.00	<Input>	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Btu/Lb	13000		13000	13000	13000	13000	13000	13000		13000	13000	13000	13000	13000	13000	13000	13000	13000	
Total Tons(000)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
$/Ton-Coal	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Ton-Limestone	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Ton-Ash Removal	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Total $/Ton	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Mil Btu	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Coal Cost($Mil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas																			
Btus Required(Bil)	348.00	2.00	354.96	362.06	369.30	376.69	384.22	391.90	2.00	399.74	407.74	415.89	424.21	432.69	441.35	450.18	459.18	468.36	4,291.25
Btu/Cubic Ft	1,021.00	<Input	1,021.00	1,021.00	1,021.00	1,021.00	1,021.00	1,021.00		1,021.00	1,021.00	1,021.00	1,021.00	1,021.00	1,021.00	1,021.00	1,021.00	1,021.00	
Total (Mil Cu Ft)	340.84		347.66	354.61	361.70	368.94	376.32	383.84		391.52	399.35	407.34	415.48	423.79	432.27	440.92	449.73	458.73	4,202.98
$/Mcf	5.51	0.00	5.79	5.79	5.79	5.79	5.79	5.79	5.00	6.08	6.38	6.70	7.04	7.39	7.76	8.15	8.55	8.98	
$/Mil Btu	5.40		5.67	5.67	5.67	5.67	5.67	5.67		5.95	6.25	6.56	6.89	7.24	7.60	7.98	8.38	8.80	
Gas Cost($Mil)	1.88		2.01	2.05	2.09	2.14	2.18	2.22		2.38	2.55	2.73	2.92	3.13	3.35	3.59	3.85	4.12	30.85
Fuel Oil																			
Btus Required(Bil)	2.53	2.00	2.58	2.63	2.68	2.74	2.79	2.85	2.00	2.91	2.96	3.02	3.08	3.15	3.21	3.27	3.34	3.41	31.20
Btu/Bbl(Mil)	5.80	<Input	5.80	5.80	5.80	5.80	5.80	5.80		5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	
Total Gals(Mil)	0.02		0.02	0.02	0.02	0.02	0.02	0.02		0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.23
$/Gal	0.60	0.00	0.63	0.63	0.63	0.63	0.63	0.63	5.00	0.66	0.69	0.73	0.77	0.80	0.84	0.89	0.93	0.98	
$/Mil Btu	4.34		4.56	4.56	4.56	4.56	4.56	4.56		4.79	5.03	5.28	5.55	5.82	6.11	6.42	6.74	7.08	
Oil Cost($Mil)	0.01		0.01	0.01	0.01	0.01	0.01	0.01		0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.18
TOTAL FUEL COST($Mil)																			
Non-GFC Cogen Coal	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Suppl Steam Fuels																			
Coal	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	1.88		2.01	2.05	2.09	2.14	2.18	2.22		2.38	2.55	2.73	2.92	3.13	3.35	3.59	3.85	4.12	30.85
Oil	0.01		0.01	0.01	0.01	0.01	0.01	0.01		0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.18
Total Fuel Cost	1.89		2.02	2.07	2.11	2.15	2.19	2.24		2.39	2.56	2.75	2.94	3.15	3.37	3.61	3.87	4.14	31.03
Non GFC Case O & M ($Mil)																			
Existing Cogen O & M	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Suppl Thermal O & M	0.50	5.00	0.53	0.55	0.58	0.61	0.64	0.67	5.00	0.70	0.74	0.78	0.81	0.86	0.90	0.94	0.99	1.04	8.43
Subtotal O & M	0.50		0.53	0.55	0.58	0.61	0.64	0.67		0.70	0.74	0.78	0.81	0.86	0.90	0.94	0.99	1.04	8.43

A.3-4

TOTAL NON-GFC CASE COSTS																		
Purch Elect Power	1.52	1.63	1.75	1.87	2.00	2.15	2.30		2.46	2.64	2.82	3.02	3.24	3.47	3.72	3.98	4.26	31.91
Purch Fuels	1.89	2.02	2.07	2.11	2.15	2.19	2.24		2.39	2.56	2.75	2.94	3.15	3.37	3.61	3.87	4.14	31.03
O & M	0.50	0.53	0.55	0.58	0.61	0.64	0.67		0.70	0.74	0.78	0.81	0.86	0.90	0.94	0.99	1.04	8.43
Total Costs	3.91	4.18	4.36	4.56	4.76	4.98	5.20		5.56	5.94	6.35	6.78	7.24	7.74	8.27	8.84	9.45	71.37
ENERGY COSTS WITH GFC																		
GFC Availability(Hrs/ Yr)							7096		7096	7096	7096	7096	7596	7596	7596	7596	7596	
GFC KWhs Purchased(Mil)							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Price (c/KWh)							8.80	5.00	9.24	9.70	10.19	10.70	11.23	11.79	12.38	13.00	13.65	
Min GFC Annual MW Output							N.A.	<Input	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
GFC Avg Min Summer MW							N.A.	<Input	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Total Elect Costs($Mil)							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GFC Steam Purch (Mil Lbs)							65.28		65.28	65.28	65.28	65.28	65.28	65.28	65.28	65.28	65.28	652.83
GFC Steam Btus (Bil)							68.68		68.68	68.68	68.68	68.68	68.68	68.68	68.68	68.68	68.68	686.78
Price ($/000 Lbs)							5.10	5.00	5.36	5.62	5.90	6.20	6.51	6.83	7.18	7.54	7.91	
Hot Water Purch(Mil gals)							0.00											
Price (c/ Gal)							0.00											
Total Therm Costs($Mil)							0.33		0.35	0.37	0.39	0.40	0.42	0.45	0.47	0.49	0.52	4.19
Subtotal GFC En Costs							0.33		0.35	0.37	0.39	0.40	0.42	0.45	0.47	0.49	0.52	4.19
Existing Cogen Fuel Costs							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Supplemental Energy Reqs																		
Elect Energy(Mil KWhs)							32.55		33.20	33.86	34.54	35.23	35.93	36.65	37.39	38.13	38.90	356.37
Rate (c/KWh)							5.52		5.80	6.09	6.39	6.71	7.05	7.40	7.77	8.16	8.57	
Energy Cost($Mil)							1.80		1.92	2.06	2.21	2.36	2.53	2.71	2.90	3.11	3.33	24.94
Elect Demand-Annual(MW)							9.46		9.65	9.84	10.04	10.24	10.44	10.65	10.87	11.08	11.31	
Rate($/KW/Mo)-12 Mo							4.42		4.64	4.88	5.12	5.38	5.64	5.93	6.22	6.53	6.86	
Elect Demand-Summer(MW)							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Rate($/KW/Mo)-4 Mo							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Demand Cost($Mil)							0.50		0.54	0.58	0.62	0.66	0.71	0.76	0.81	0.87	0.93	6.97
Elect Cost($Mil)							2.30		2.46	2.64	2.82	3.02	3.24	3.47	3.72	3.98	4.26	31.91
Suppl Steam (Mil Lbs)							195.49		191.95	197.03	202.22	207.52	212.92	218.42	224.04	229.77	235.61	2,114.98
Hot Water (Mil Gals)							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Thermal Btus (Bil)							205.66		211.14	216.74	222.45	228.27	234.21	240.27	246.44	252.75	259.18	3,604.47

A.3-5

Fuel Btus Req (Bil)	293.79		301.63	309.63	317.78	326.10	334.58	3				
Non-GFC Fuel Reqs												
Btus Req (Bil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal (000 Tons)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Price ($/Ton)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Cost ($Mil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Btus Req (Bil)	293.79		301.63	309.63	317.78	326.10	334.58	343.24	352.06	361.07	370.25	3,310.13
Nat Gas (Mil Cu Ft)	287.75		295.43	303.26	311.24	319.39	327.70	336.18	344.82	353.64	362.64	3,242.05
Price ($/Mcf)	5.79		6.08	6.38	6.70	7.04	7.39	7.76	8.15	8.55	8.98	
Cost ($Mil)	1.67		1.80	1.94	2.09	2.25	2.42	2.61	2.81	3.03	3.26	23.85
Btus Req (Bil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Oil (Mil Gals)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Price ($/Gal)	0.63		0.66	0.69	0.73	0.77	0.80	0.84	0.89	0.93	0.98	
Cost ($Mil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Suppl Fuel Cost($Mil)	1.67		1.80	1.94	2.09	2.25	2.42	2.61	2.81	3.03	3.26	23.85
O & M Cost ($Mil)												
Existing Cogen Plant	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Suppl Therm Plant	0.67		0.70	0.74	0.78	0.81	0.86	0.90	0.94	0.99	1.04	8.43
		5.00										
O & M Savings	0.30		0.32	0.33	0.35	0.36	0.38	0.40	0.42	0.44	0.47	3.77
Suppl O & M Cost	0.37		0.39	0.41	0.43	0.45	0.47	0.50	0.52	0.55	0.57	4.65
COST/BENEFIT SUMMARY												
Without GFC Facility												
Purch Elect Pwr	2.30		2.46	2.64	2.82	3.02	3.24	3.47	3.72	3.98	4.26	31.91
Purch Fuels	2.24		2.39	2.56	2.75	2.94	3.15	3.37	3.61	3.87	4.14	31.03
O & M	0.67		0.70	0.74	0.78	0.81	0.86	0.90	0.94	0.99	1.04	8.43
Subtotal No GFC	5.20		5.56	5.94	6.35	6.78	7.24	7.74	8.27	8.84	9.45	71.37
With GFC Facility												
Purch GFC Elect Pwr	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Purch GFC Thermal	0.33		0.35	0.37	0.39	0.40	0.42	0.45	0.47	0.49	0.52	4.19
Subtotal	0.33		0.35	0.37	0.39	0.40	0.42	0.45	0.47	0.49	0.52	4.19
Existing Cogen Coal Costs	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Suppl Elect Pwr	2.30	2.46	2.64	2.82	3.02	3.24	3.47	3.72	3.98	4.26	31.91
Suppl Fuels	1.67	1.80	1.94	2.09	2.25	2.42	2.61	2.81	3.03	3.26	23.85
Subtotal	3.97	4.26	4.57	4.91	5.27	5.66	6.08	6.53	7.00	7.52	55.77
O & M	0.37	0.39	0.41	0.43	0.45	0.47	0.50	0.52	0.55	0.57	4.65
Subtotal With GFC	4.67	5.00	5.35	5.72	6.13	6.56	7.02	7.51	8.04	8.61	64.61
NET GFC SAVINGS (M$)	0.54	0.56	0.59	0.62	0.65	0.69	0.72	0.76	0.80	0.84	6.76
Avoided cost w/ GFC	0.87	0.91	0.96	1.01	1.06	1.11	1.17	1.23	1.29	1.35	10.95

FINANCIAL EVALUATION OF SAVINGS:

	Cumulative Savings	1990 NPV at Discount Rate of 20.00 %
10-Years	6.76	2.27

A-1-1

Scranton AAP
GFC Plant Analysis
(Westinghouse Fuel Cell)

GFC PLANT ANALYSIS	Site: FA	Rated Output (MW):	7.50	Bil Btus Coal:	704.35	at Mil Btus/hr of	99.26 <Input
Westinghouse Fuel Cell	August 19, 1985	Avail(Hrs per Yr):	7096 <Input	Btus/Lb:	13,020.00 <Input		
				Annual Tons Coal:	27,048.73		
ENERGY BALANCE SUMMARY				Tons/ Day:	91.48		

				Mil Btus/hr	Bil Btus/Yr
Steam Output:					
Thou lbs/hr @ 240 psia:	Input>	3470	Lbs/hr		
Net Enthalpy Gain:	Input>	1020	Btus/lb	3.54	25.12
Electric Pwr Output:					
Fuel Cell Output	Input>	7.50	MW	25.60	181.64
Gas Expander Output	Input>	1.70	MW	5.80	41.17
Thermal Mgt System	Input>	0.00		0.00	0.00
Power Conditioner Losses	Input>	(0.35)	MW	(1.19)	(8.48)
Aux Pwr Reqs	Input>	(4.12)	MW	(14.06)	(99.78)
Net Pwr Out		4.73	MW	16.14	114.55
Other Outputs:					
Tars/Oils	at	0.00	Mil Btus/hr	<Input	0.00
Other(e.g., Sul,Ammon)	at	0.00	Mil Btus/hr	<Input	0.00
Losses					
Ash	at	0.70	Mil Btus/hr	<Input	4.97
Cyclone Carbon Dust	at	1.30	Mil Btus/hr	<Input	9.22
Heat Rejected by Cooling Tower	at	34.00	Mil Btus/hr	<Input	241.26
CO Shift Air Cooler	at	9.90	Mil Btus/hr	<Input	70.25
HSRG Stack Loss	at	16.72	Mil Btus/hr	<Input	118.65
Miscellaneous	at	16.45	Mil Btus/hr	<Input	116.73
TOTAL BTUS:		98.75	Mil Btus/hr		700.75

GFC PLANT EFFICIENCY: Hourly Calc (mil Btus) — Annual Calc (bil Btus)

	Net Pwr Out	+ Steam	+ Tars/Oils	+ Other		Net Pwr Out	+ Steam	+ Tars/Oils	+ Other
	16.14	3.54	0.00	0.00	Equals:	114.55	25.12	0.00	0.00
		99.26 Coal In					704.35 Coal In		

Net Heat Rate:	20,236.91			Gross Heat Rate:	10,404.41			
95.72 (Coal minus Steam & Tars)	Divided by	4.73 (Net Pwr)		95.72 (Coal minus Steam & Tars)	Divided by	9.20 (Gross power out)		

Hrly Efficiency Equals: 19.83 Percent
Annual Efficiency Equals: 19.83 Percent

A-4-2

ECONOMIC & FINANCIAL ASSUMPTIONS

	All Inputs	All Inputs	All Inputs	All Inputs
	1985 Energy Cost	Annual Escal. Rate 1985-1990	Energy Price 1990	Annual Escal. Rate 1990-2010
PP&L Avoided Cost(cts/kwh	3.20	20.40	8.10	5.00
Electric Demand($/kw/Mo)	0.00	5.00	0.00	5.00
Other Demand($/kw/Mo)	0.00	5.00	0.00	5.00
Natural Gas($/mcf)	5.79	0.00	5.79	5.00
Fuel Oil($/gal)	0.63	0.00	0.63	5.00
Coal Price($/Ton)	58.00	0.00	58.00	5.00
Coal Heat Content (Btu/lb)	13,020.00	NA	NA	NA
Coal Price($/Mil.Btu)	2.23	NA	2.23	NA
Steam Price & Esc Rate	4.00	5.00	5.11	5.00
O & M Esc Rate(% per Yr)	N.A.	5.00	N.A.	5.00

	1985 Existing	1990-2010		
Depreciation Method	ACRS	SL		
Depreciation Term(Years)			Percent of Equip	
Equipment	5.00	5.00	100.00	Percent
Utilities & Other	15.00	15.00	0.00	Percent
Investment Tax Credit	10.00 %	10.00 %		
Nonconventional Gas Annual Income Tax Credit ($/Mil. Btu)	0.70	0.00 (thru 1999)	5.00 Percent Esc Rate	
Investor's Annual Income Tax Rate (Combined Fed. & State)	50.00 %	50.00 %		

OWNERSHIP AND FINANCING STRUCTURE

Parameter	Assumption		
Percent Government Funding	70.00		<Input
Percent Private Funding	30.00		
Percent equity		33.00	<Input
Percent debt		67.00	
Interest rate		13.00	<Input
Loan term(years)		15	<Input
Constr int rate		13.00	<Input
Constr loan amount($Mil)		0.00	<Input
1st yr portion		0.10	<Input
2nd yr portion		0.40	<Input
3rd yr portion		0.50	<Input

CONSTRUCTION COST BREAKDOWN ($Mil) SITE: PA GFC SIZE: 7.5 MW

		5.00 % Esc Rate 1985$	1989$	Period When Costs Will Occur 1987	1988	1989
Coal Hndlg & Gasif.	6.83			20.00	40.00	40.00
Gas Processing & Systems	7.64					
Fuel Cell/Pwr Cond.	22.00					
Thermal Mgt Syst.	3.57					
Balance of Plant	1.52					
Subtotal		41.56	48.61	9.16	19.24	20.21
Prototype Investment(Incl above)		0.00	0.00	0.00	0.00	0.00
Unique Site Costs		3.80	4.45	0.84	1.76	1.85
General Conditions(Incl above)		0.00	0.00	0.00	0.00	0.00
Design & Engineering(Incl above)		0.00	0.00	0.00	0.00	0.00
Preproduction Costs(Incl above)		0.00	0.00	0.00	0.00	0.00
Contingency at a Percent of:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL CONSTRUCTION COST:		45.36	53.06	10.00	21.00	22.05
Land		0.00	0.00	0.00	0.00	0.00
Other Special		0.00	0.00	0.00	0.00	0.00
TOTAL CONSTRUCTION + SPECIAL:		45.36	53.06	10.00	21.00	22.05
OTHER CAPITAL COSTS						
Working Capital						
Accts Receivable @15 days	0.65		0.77	0.00	0.00	0.79
Fuel Inventory @15 days	0.12		0.15	0.00	0.00	0.15
Other Inventory/Supplies	0.10		0.12	0.00	0.00	0.12
Accnts Payable @10 days	(0.11)		(0.13)	0.00	0.00	(0.13)
Subtotal Working Capital			0.92	0.00	0.00	0.92
Priv Fin Fees at Percent of:	8.00 %		1.30	0.00	0.00	1.30
3rd Pty Own Fee at Percent of:	2.00 %		0.32	0.00	0.00	0.32
Other Expenses at Percent of:	2.00 %		0.32	0.00	0.00	0.32
Subtotal			1.94	0.00	0.00	1.94
TOTAL OTHER CAPITAL COSTS:			2.87	0.00	0.00	2.87
CONSTRUCTION INTEREST:			0.00	0.00	0.00	0.00

GFC O & M COST BREAKDOWN($Mil)

	Escal.Rate:	5.00 % 1985$	1990$	1995$
Direct Labor	0.70			
Fringes @ 20%	0.14			
Contract Maint.	0.20			
Chem & Supplies	0.15			
Spare Parts	0.05			
Water/Utilities	0.10			
Ash/Sludge Disp.	0.10			
Miscel	0.06			
Subtotal		1.50	1.91	2.44
Wheeling Charge		0.00	0.00	0.00
Fuel Cell Reloading Costs @$60/kw(1985$) (per year)		NA	NA	0.73
TOTAL O & M		1.50	1.91	3.18
OTHER ANNUAL EXPENSES				
Legal/Account.		0.00	0.00	0.00
Insurance		0.15	0.19	0.24
Prop. Taxes		0.00	0.00	0.00
Contract Oper. Fee		0.10	0.13	0.16
TOTAL OTHER		0.25	0.32	0.41

A.4-4

ENERGY PRODUCTION	In 1985 $	In 1990 $	In 1995 $
Net Amount of Electric Power Sold			
kWh(Mil)	33.56	33.56	35.93
Avg Monthly Max. MW	4.73	4.73	4.73
Avg Monthly Min. MW	4.00	4.00	4.00
Price(cts/kwh)	3.20	8.10	10.33
Price/kW/Mo	0.00	0.00	0.00
Annual Energy Revenues ($ Mil)	1.07	2.72	3.71
Annual Capacity Revenues ($ Mil)	0.00	0.00	0.00
Subtotal Elect Revs	1.07	2.72	3.71
Steam/Hot Water Sold			
Amount(Mil lbs)	24.62	24.62	26.36
Energy Content(Bil Btus)	25.12	25.12	26.89
Price per Unit ($/000 lb)	4.00	5.11	6.52
Thermal Revenues	0.10	0.13	0.17
Other Revenues: Esc Rate:	5.00	(Based on of fuel oil price)	50 percent
Tars/Oils	0.00	0.00	0.00
Sulfur	0.00	0.00	0.00
Ammonium Sulfate	0.00	0.00	0.00
Other Revs:	0.00	0.00	0.00
Fuel Use			
Energy Content(Bil Btus)	704.35	704.35	704.35
Amount(Mil Tons)	27,048.73	27,048.73	27,048.73
Cost			
Fuel Cost($/ton)	58.00	58.00	74.02
Total Fuel Cost($ Mil)	1.57	1.57	2.00
O & M Costs	1.50	1.51	3.18
Other Annual Costs	0.25	0.72	0.41
SUBTOTAL SEF OPERATING COSTS ($Mil)	3.32	3.80	5.59

COAL GASIFICATION-FUEL CELL-COGENERATION PLANT AT: FA SITE

FINANCIAL ANALYSIS ($MIL)

GFC CF ANALYSIS FA SITE

Priv Eqty Equals 5.54 at 30.00 33.00 Percent
Priv Debt Equals 11.24 at 30.00 67.00 Percent
Tot Cap Costs of 55.93

Item	Engineering/Construction 1987	1988	1989	Operating Period 1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Subtotal Yrs 1-10	2000
Revenues															
Electric	0.00	0.00	0.00	2.72	3.06	3.21	3.37	3.54	3.72	3.90	4.10	4.30	4.52	36.41	5.44
Thermal	0.00	0.00	0.00	0.13	0.14	0.15	0.16	0.16	0.17	0.18	0.19	0.20	0.21	1.69	0.22
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00	0.00	0.00	2.84	3.20	3.36	3.53	3.70	3.89	4.08	4.29	4.50	4.73	38.11	5.66
Operating Costs															
Fuel	0.00	0.00	0.00	1.57	1.65	1.73	1.82	1.91	2.00	2.10	2.21	2.32	2.43	19.73	2.56
O & M	0.00	0.00	0.00	1.91	2.01	2.11	2.22	2.33	3.18	3.34	3.50	3.68	3.86	28.13	4.05
Other	0.00	0.00	0.00	0.32	0.34	0.35	0.37	0.39	0.41	0.43	0.45	0.47	0.49	4.01	0.52
Subtotal	0.00	0.00	0.00	3.80	3.99	4.19	4.40	4.62	5.59	5.87	6.16	6.47	6.79	51.88	7.13
OPERATING CASH FLOW	0.00	0.00	0.00	(0.96)	(0.79)	(0.83)	(0.88)	(0.92)	(1.70)	(1.78)	(1.87)	(1.97)	(2.06)	(13.76)	(1.47)
Debt Service: Principal				0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	7.49	0.75
Interest	0.00	0.00	0.00	1.46	1.36	1.27	1.17	1.07	0.97	0.88	0.78	0.68	0.58	10.23	0.49
	(Constr	Loan	Interest)												
Subtotal	0.00	0.00	0.00	2.21	2.11	2.02	1.92	1.82	1.72	1.63	1.53	1.43	1.33	17.72	1.24
Coverage Ratio				(0.43)	(0.38)	(0.41)	(0.46)	(0.50)	(0.99)	(1.10)	(1.22)	(1.37)	(1.55)		(1.19)
Debt S/c Reserve				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Equal Reserve				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N.A.	0.00
RESIDUAL CASH FLOW	0.00	0.00	0.00	(3.17)	(2.91)	(2.85)	(2.79)	(2.74)	(3.42)	(3.41)	(3.40)	(3.40)	(3.40)	(31.49)	(2.71)
Management Fee				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax Adjustments		(Private share of equipment)													
Depr 5-yr Equip(SL) at	0.95	30.00	Percent)	3.02	3.02	3.02	3.02	3.02						15.12	
Depr 15-yr Equip(SL) at	1.00	30.00	Percent)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amort Startup Cost	0.00	0.00	0.00												
Principal Payment				0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	7.49	0.75
Debt S/c Reserve				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income/Loss(-)	0.00	0.00	0.00	(5.44)	(5.18)	(5.12)	(5.07)	(5.02)	(2.67)	(2.66)	(2.65)	(2.65)	(2.65)	(39.12)	(1.96)
Tax Saving or Payment(-)	0.00	0.00	0.00	2.72	2.59	2.56	2.53	2.51	1.34	1.33	1.33	1.32	1.32	19.56	0.98
10 % Inv Tax Credit at	30.00 Percent)		1.59												
Syngas Tax Credit at	0.00 $/Mil Btu to 1997)			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Priv Capital Requirement			(16.78)												
Priv Perm Debt Financing			11.24												
NET CASH FLOW	0.00	0.00	(3.94)	(0.45)	(0.32)	(0.29)	(0.26)	(0.23)	(2.09)	(2.08)	(2.08)	(2.07)	(2.07)		(1.73)
Cumulative Cash Flow	0.00	0.00	(3.94)	(4.39)	(4.71)	(5.00)	(5.26)	(5.49)	(7.57)	(9.65)	(11.73)	(13.80)	(15.87)		(17.60)

Pay Back: Years. ROE= (1.72) Percent and NPV= 43.67 at a (152.07) Percent Disc Rate.
(Using a 10 Year Cash Stream)

A.5-1

Scranton AAP
GFC Plant Analysis
(UTC Fuel Cell)

GFC PLANT ANALYSIS   Site: PA   Rated Output (MW): 11.00   Bil Btus Coal: 1,323.47 at Mil Btus/hr of 186.51 <Input
August 19, 1985   Avail(Hrs per Yr): 7096 <Input   Btus/Lb: 13,000.00 <Input
Annual Tons Coal: 50,902.88
Tons/ Day: 172.16

ENERGY BALANCE SUMMARY

				Mil Btus/hr		Bil Btus/Yr
Steam Output:						
Thou lbs/hr @ 2?0 psia:	Input>	9200	000 Lbs/hr			
Net Enthalpy Gain:	Input>	1052	Btus/lb	9.68		68.68
Electric Pwr Output:						
Fuel Cell Output	Input>	11.60	MW	39.59		280.94
Gas Expander Output	Input>	2.50	MW	8.53		60.55
Thermal Mgt System	Input>	2.40		8.19		58.12
Power Conditioner Losses	Input>	(0.60)	MW	(2.05)		(14.53)
Aux Pwr Reqs	Input>	(3.60)	MW	(12.29)		(87.19)
Net Pwr Out		12.30		41.98		297.89
Other Outputs:						
Tars/Oils	at			0.00	Mil Btus/hr <Input	0.00
Other(e.g., Sul,Ammon)	at			0.00	Mil Btus/hr <Input	
Losses						4.97
Ash	at			0.70	Mil Btus/hr <Input	9.22
Cyclone Carbon Dust	at			1.30	Mil Btus/hr <Input	0.00
Heat Rejected by Cooling Tower	at			66.00	Mil Btus/hr <Input	468.34
CO Shift Air Cooler	at			14.70	Mil Btus/hr <Input	104.31
HSRG Stack Loss	at			26.90	Mil Btus/hr <Input	190.88
Miscellaneous	at			25.25	Mil Btus/hr <Input	179.17
TOTAL BTUS:				186.51		1,323.46

GFC PLANT EFFICIENCY: Hourly Calc (mil Btus)   Annual Calc (bil Btus)

Net Pwr Out	+ Steam	+ Tars/Oils	+ Other		Net Pwr Out	+ Steam	+ Tars/Oils	+ Other
41.98	9.68	0.00	0.00	Equals:	297.89	68.68	0.00	0.00
	186.51 Coal In					1,323.47 Coal In		

Net Heat Rate: 14,?76.55   Gross Heat Rate: 10,717.07

176.8? (Coal minus Steam & Tars) Divided by 12.?? (Net Pwr)   176.83 (Coal minus Steam & Tars) Divided by 16.50 (Gross power out)

Hrly Efficiency Equals: 27.70 Percent
Annual Efficiency Equals: 27.70 Percent

A.5-2.

ECONOMIC & FINANCIAL ASSUMPTIONS   July 30

32.26

	All Inputs 1985 Energy Cost	All Inputs Annual Escal. Rate 1985-1990	Energy Price 1990	All Inputs Annual Escal. Rate 1990-2010
Avoided El Costs (c/kwh)	3.20	1990	8.90	5.00
		1991	8.80	(beginning in 1995)
		1992	8.80	
		1993	9.20	
		1994	9.30	
		1995	12.71	
Fuel Oil($/gal)	0.63 (Not used	0.00	0.63	5.00
Coal Price($/Ton)	58.00	0.00	58.00	5.00
Coal Heat Content (Btu/lb)	13,020.00	NA	13,020.00	NA
Coal Price($/Mil.Btu)	2.23	NA	2.23	NA
Steam Price & Esc Rate	4.00	5.00	5.11	5.00
O & M Esc Rate(% per Yr)	N.A.	5.00	N.A.	5.00

	1985 Existing	1990-2010	Percent of Equip	
Depreciation Method	ACRS	SL		
Depreciation Term(years)				
Equipment	5.00	5.00	100.00	Percent
Utilities & Other	15.00	15.00	0.00	Percent
Investment Tax Credit	10.00 %	10.00 %		
Nonconventional Fuel Annual Income Tax Credit ($/Mil. Btu)	0.70	0.00 (thru 1999)	5.00 Percent Esc Rate	
Investor's Annual Income Tax Rate (Combined Fed. & State)	50.00 %	50.00 %		

OWNERSHIP AND FINANCING STRUCTURE

Parameter	Assumption		
Percent Government Funding	70.00		<Input
Percent Private Funding	30.00		
Percent equity		33.00	<Input
Percent debt		67.00	
Interest rate		13.00	<Input
Loan term(years)		15	<Input
Constr int rate		13.00	<Input
Constr loan amount($Mil)		0.00	<Input
1st yr portion		0.10	<Input
2nd yr portion		0.40	<Input
3rd yr portion		0.50	<Input

CONSTRUCTION COST
BREAKDOWN ($Mil)

SITE: FA   GFC SIZE:11 MW

		1985$	1988$	Period When Costs Will Occur 1987	1988	1989
Coal Hndlg & Prep.	5.27			20.00	40.00	40.00
Gas Processing & Systems	9.26			(Percent of 1985 capital costs		
Fuel Cell-Pwr Cond.	15.43			incurred by construction year)		
Thermal Mgt Syst.	3.16					
Balance of Plant	2.08	5.00 % Esc Rate				
Subtotal		35.70	41.18	7.76	16.30	17.11
Prototype Investment(Incl above)		0.00	0.00	0.00	0.00	0.00
Unique Site Costs		3.90	4.56	0.86	1.81	1.90
General Conditions(Incl above)		0.00	0.00	0.00	0.00	0.00
Design & Engineering(Incl above)		0.00	0.00	0.00	0.00	0.00
Preproduction Costs(Incl above)		0.94	1.14	0.38	0.38	0.38
Contingency at a Percent of:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL CONSTRUCTION COST:		40.04	46.88	9.00	18.49	19.39
Land		0.00	0.00	0.00	0.00	0.00
Other Special		1.00	1.22	0.41	0.41	0.41
TOTAL CONSTRUCTION + SPECIAL:		41.04	48.10	9.41	18.89	19.80
OTHER CAPITAL COSTS						
Working Capital						
Accounts Receivable:	45	days	0.99			0.99
Fuel Inventory:	15	days	0.12			0.12
Other Inventory/Supplies:			0.10			0.10
Accounts Payable:	10	days	(0.16)			(0.16)
Subtotal Working Capital			1.05			1.05
Priv Fin Fees at Percent of:	8.00 %		1.18			1.18
3rd Pty Own Fee at Percent of:	2.00 %		0.29			0.29
Other Expenses at Percent of:	2.00 %		0.29			0.29
Subtotal			1.77			1.77
TOTAL OTHER CAPITAL COSTS:			2.82			2.82
CONSTRUCTION INTEREST:			0.00	0.00	0.00	0.00
TOTAL:			[illegible]			

GFC O & M COST
BREAKDOWN ($Mil)

		1985$	1990$	1995$
Direct Labor	0.80			
Fringes @ 20%	0.16			
Contr Oper Fee	0.10			
Contract Maint.	0.22			
Chem & Supplies	0.18			
Spare Pts/Maint Sup	0.30			
Water & Site Utils	0.10			
Ash/Sludge Disp.	0.08			
Miscel	0.07		Escal.Rat	5.00
Subtotal		2.01	2.57	3.27
Wheeling Charge		0.00	0.00	0.00
Fuel Cell Reloading Costs 1985 $ of:	32	NA	NA	0.60
TOTAL O & M		2.01	2.57	3.88
OTHER ANNUAL EXPENSES				
Legal/Account.		0.00	0.00	0.00
Insurance		0.20	0.26	0.33
Prop. Taxes		0.00	0.00	0.00
TOTAL OTHER		0.20	0.26	0.33

A.5-4

ENERGY PRODUCTION	In 1985 $	In 1990 $	In 1995 $
Net Amount of Electric Power Sold			
kWh(Mil)	87.28	87.28	93.43
Avg Monthly Max. MW	12.30	12.30	12.30
Avg Monthly Min. MW	10.00	10.00	10.00
Price(cts/kwh)	7.20	8.80	12.71
Price/kW Mo	0.00	0.00	0.00
Annual Energy Revenues ($ Mil)	2.79	7.68	11.87
Annual Capacity Revenues ($ Mil)	0.00	0.00	0.00
Subtotal Elect Revs	2.79	7.68	11.87
Steam/Hot Water Sold			
Amount(Mil lbs)	65.28	65.28	69.88
Energy Content(Bil Btus)	68.68	68.68	73.52
Price per Unit ($/000 lb)	4.00	5.11	6.52
Thermal Revenues	0.26	0.33	0.46
Othe Revenues: Esc Rate:			
Tars/Oils	0.00	0.00	0.00
Sulfur	0.00	0.00	0.00
Ammonium Sulfate	0.00	0.00	0.00
Other Revs:	0.00	0.00	0.00
Fuel Use			
Energy Content(Bil Btus)	1,323.47	1,323.47	1,323.47
Amount(Mil Tons)	50,902.88	50,902.88	50,902.88
Cost			
Fuel Cost($/ton)	58.00	58.00	74.02
Total Fuel Cost($ Mil)	2.95	2.95	3.77
O & M Costs	2.01	2.57	3.88
Other Annual Costs	0.20	0.26	0.33
SUBTOTAL GFC OPERATING COSTS ($Mil)	5.16	5.77	7.97

A.5-5

COAL GASIFICATION-FUEL CELL-COGENERATION PLANT AT: FA SITE

GFC CF ANALYSIS FA SITE

Tot Cap Costs of 50.92
5.04 times 30.00 33.00 Percent Priv Eqty
10.23 times 30.00 67.00 Percent Priv Debt

FINANCIAL ANALYSIS ($MIL)

Item	Engineering/Construction 1987	1988	1989		Operating Period 1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Subtotal Yrs 1-10	2000
Revenues																
Electric	0.00	0.00	0.00		7.68	7.68	7.68	8.03	8.12	11.87	12.46	13.09	13.74	14.43	104.78	15.15
Thermal	0.00	0.00	0.00		0.33	0.37	0.39	0.41	0.43	0.46	0.48	0.50	0.53	0.55	4.47	0.58
Other	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00	0.00	0.00		8.01	8.06	8.07	8.44	8.55	12.33	12.94	13.59	14.27	14.98	109.25	15.73
Operating Costs																
Fuel	0.00	0.00	0.00		2.95	3.10	3.25	3.42	3.59	3.77	3.96	4.15	4.36	4.58	37.13	4.81
O & M	0.00	0.00	0.00		2.57	2.69	2.83	2.97	3.12	3.88	4.07	4.28	4.49	4.71	35.61	4.95
Other	0.00	0.00	0.00		0.26	0.27	0.28	0.30	0.31	0.33	0.34	0.36	0.38	0.40	3.21	0.42
Subtotal	0.00	0.00	0.00		5.77	6.06	6.36	6.68	7.02	7.97	8.37	8.79	9.23	9.69	75.95	10.19
OPERATING CASH FLOW	0.00	0.00	0.00		2.24	1.99	1.71	1.76	1.53	4.35	4.57	4.80	5.04	5.29	33.29	5.56
Debt Service: Principal				15	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	6.82	0.68
Interest	0.00	0.00	0.00	Yrs	1.33	1.24	1.15	1.06	0.98	0.89	0.80	0.71	0.62	0.53	9.31	0.44
	(Constr	Loan	Interest)													
Subtotal	0.00	0.00	0.00		2.01	1.92	1.84	1.75	1.66	1.57	1.48	1.39	1.30	1.21	16.14	1.13
Coverage Ratio					1.11	1.04	0.93	1.01	0.93	2.77	3.09	3.45	3.87	4.36	2.06	4.94
Debt Svc Reserve					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumul Reserve					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N.A.	0.00
RESIDUAL CASH FLOW	0.00	0.00	0.00		0.23	0.07	(0.13)	0.01	(0.12)	2.78	3.09	3.41	3.74	4.08	17.16	4.43
Management Fee					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		(Private share														
Tax Adjustments		of equipment)														
Depr 5-yr Equip(SL) at	0.95	30.00	Percent)		2.67	2.67	2.67	2.67	2.67						13.36	
Depr 15 yr Equip(SL) at	1.00	30.00	Percent)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amort Startup Cost	0.00	0.00	0.00													
Principal Payment					0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	6.82	0.68
Debt Svc Reserve					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income/Loss(-)	0.00	0.00	0.00		(1.76)	(1.92)	(2.12)	(1.98)	(2.11)	3.47	3.77	4.09	4.42	4.76	10.62	5.11
Tax Saving or Payment(-)	0.00	0.00	0.00		0.88	0.96	1.06	0.99	1.06	(1.73)	(1.89)	(2.04)	(2.21)	(2.38)	(5.31)	(2.56)
10 % Inv Tax Credit at	30.00 Percent)		1.44													
Syngas Tax Credit at	0.00 $/Mil Btu to 1999)				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Priv Capital Requirement			(15.27)													
Priv Perm Debt Financing			10.23													
NET CASH FLOW	0.00	0.00		(3.60)	1.11	1.03	0.93	1.00	0.93	1.05	1.20	1.36	1.53	1.70		1.87
Cumulative Cash Flow	0.00	0.00	(3.60)		(2.49)	(1.46)	(0.53)	0.48	1.41	2.46	3.66	5.03	6.55	8.25		10.12

ROE= 27.43 Percent and NPV= (0.13) at a 27.43 Percent Disc Rate.
(Using a 10 Year Cash Stream)

SITE ENERGY USE AND BENEFITS ANALYSIS At Site August 19, 1985

Steam Output:		Avail	Hours of GFC	
Thou lbs/hr @ 120 psia:	Input: 23600	2096	Input	7510 Coal Btu Content
Net Enthalpy Gain in Btus/lb:	Input: 1051			

	1985 Cost	(Part Sold to Grid)	Esc Rate 1985-1990	1990 Cost	Esc Rate 1990-2010
GFC El Pwr Price(c/kwh)	N.A.		5.00	10.76	5.00
Total Purch El Pwr Cost (c/kwh)	8.43		5.00	10.76	5.00
Natural Gas Price($/mcf)	N.A.		0.00	N.A.	5.00
Fuel Oil Price($/gal)	0.95		0.00	0.95	5.00
Existing Cogen Coal Price($/Ton)	N.A.		5.00	N.A.	5.00
Coal Heat Content (Btu/lb)	7510		NA	NA	NA
Coal Price($/Mil.Btu)	0.00		5.00	0.00	5.00
GFC Stm Price & Esc Rate	6.00		5.00	7.66	5.00
O & M Esc Rate(% per Yr)	N.A.		5.00	N.A.	5.00

ELECTRIC POWER DEMAND WITHOUT GFC	AK 1984	Esc Rate 1984-90	1985	1986	1987	1988	1989	1990	Esc Rate 1990-2009	1991	1992	1993	1994	1995	1996	1997	1998	1999	Subtotal Yrs 1-10
KWH Amount (Mil kwhs)																			
On peak																			
Intermediate																			
Off peak																			
Total	15.69	0.20	15.72	15.75	15.78	15.82	15.85	15.88	Input 0.20	15.91	15.94	15.97	16.01	16.04	16.07	16.10	16.14	16.17	160.23
Fm Ft. Wainwright	14.63																		
On site	1.06																		
KWH Rates(Cts/kwh)																			
Average On peak																			
Average intermediate																			
Average off peak																			
Overall Average	6.50	5.00	6.83	7.17	7.52	7.90	8.30	8.71	5.00	9.15	9.60	10.08	10.59	11.12	11.67	12.26	12.87	13.51	--
Summer(4 Mos)																			
Rest of Year																			
Peak MW Demand	3.00	0.20	3.01	3.01	3.02	3.02	3.03	3.04	Input 0.20	3.04	3.05	3.05	3.06	3.07	3.07	3.08	3.09	3.09	--
	(Effective wheeling demand charge)																		
Peak MW Rate($/kw/Mo)	6.67	5.00	7.00	7.35	7.72	8.10	8.51	8.93	5.00	9.38	9.85	10.34	10.86	11.40	11.97	12.57	13.20	13.86	--
THERMAL DEMAND																			
Steam Demand(Mil lbs)																			
Summer (4 Mo)	50.00	0.20	50.10	50.20	50.30	50.40	50.50	50.60	0.20	50.70	50.81	50.91	51.01	51.11	51.21	51.32	51.42	51.52	510.61
Rest of Yr	177.95	0.20	178.31	178.66	179.02	179.38	179.74	180.10	0.20	180.46	180.82	181.18	181.54	181.90	182.27	182.63	183.00	183.36	1,817.26
Total Year	227.95		228.41	228.86	229.32	229.78	230.24	230.70		231.16	231.62	232.09	232.55	233.02	233.48	233.95	234.42	234.89	2,327.87

Peak Dem(000 Lbs/Hr)	50.00	0.20	50.10	50.20	50.30	50.40	50.50	50.60	0.20	50.70	50.81	50.91	51.01	51.11	51.21	51.32	51.42	51.52	
Avg Btu/Lb(Net)	1051		1051	1051	1051	1051	1051	1051		1051	1051	1051	1051	1051	1051	1051	1051	1051	
Bil Btus Required	239.58		240.05	240.53	241.02	241.50	241.98	242.46		242.95	243.44	243.92	244.41	244.90	245.39	245.88	246.37	246.86	2,446.59
Hot Water (Mil Gals)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Avg Btu/Gal	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Bil Btus Required	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EXISTING COGENERATION (For this analysis assume all is purchased from Ft. Wainwright)																			
Elect Energy(Mil kwhs)																			
Summer	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rest of Yr	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Min Annual MW Output	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Avg Min Summer MW Outpt	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Steam Supply(Mil Lbs)																			
Summer	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rest of Yr	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Avg Btu/Lb(Net)	0		0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	
Steam Btus(Bils)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TG Heat Rate	0.00	(Input)	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	
Boiler Efficiency	.00	(Input)	.00	.00	.00	.00	.00	.00		.00	.00	.00	.00	.00	.00	.00	.00	.00	
Coal Btus Required(Bil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COSTS-Elect Energy($Mil)																			
On-peak																			
Intermed																			
Off-peak																			
Subtotal	1.02		1.07	1.13	1.19	1.25	1.31	1.38		1.46	1.53	1.61	1.69	1.78	1.88	1.97	2.08	2.18	17.57
COSTS-Elect Demand($Mil)																			
Distribution(Net)	0.24		0.25	0.27	0.28	0.29	0.31	0.33		0.34	0.36	0.38	0.40	0.42	0.44	0.46	0.49	0.51	4.13
Subtotal	0.24		0.25	0.27	0.28	0.29	0.31	0.33		0.34	0.36	0.38	0.40	0.42	0.44	0.46	0.49	0.51	4.13
TOTAL ELECT COSTS	1.26		1.33	1.39	1.47	1.54	1.62	1.71		1.80	1.89	1.99	2.09	2.20	2.32	2.44	2.57	2.70	21.70
SITE FUEL REQS & COSTS WITHOUT GFC																			
Existing Cogen Coal Reqs																			
Btus Required(Bils)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Btu/Lb	7510		7510	7510	7510	7510	7510	7510		7510	7510	7510	7510	7510	7510	7510	7510	7510	
Total Tons(000)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
$/Ton Coal	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Ton Limestone	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Ton Ash Removal	.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Total $/Ton	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	

$/Mil Btus	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Cogen Coal Cost($Mil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Reqs																			
Site Steam Btus(Bil)	239.58		240.05	240.53	241.02	241.50	241.98	242.46		242.95	243.44	243.92	244.41	244.90	245.39	245.88	246.37	246.86	2,446.59
Site Boiler Effic	0.74	(Input)	0.74	0.74	0.74	0.74	0.74	0.74		0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	
Site Fuel Btus(Bil)	323.75		324.40	325.05	325.70	326.35	327.00	327.66		328.31	328.97	329.62	330.28	330.94	331.61	332.27	332.93	333.60	3,306.20
Coal																			
Btus Required(Bil)	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Btu/Lb	7510		7510	7510	7510	7510	7510	7510		7510	7510	7510	7510	7510	7510	7510	7510	7510	
Total Tons(000)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
$/Ton-Coal	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Ton-Limestone	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Ton-Ash Removal	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Total $/Ton	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Mil Btu	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Coal Cost($Mil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas																			
Btus Required(Bil)	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Btu/Cubic Ft	1,030.00	(Input)	1,030.00	1,030.00	1,030.00	1,030.00	1,030.00	1,030.00		1,030.00	1,030.00	1,030.00	1,030.00	1,030.00	1,030.00	1,030.00	1,030.00	1,030.00	
Total (Mil Cu Ft)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
$/Mcf	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Mil Btu	0.00		0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Gas Cost($Mil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Oil		(See Fuel Reqs																	
Btus Required(Bil)	323.75	above)	324.40	325.05	325.70	326.35	327.00	327.66		328.31	328.97	329.62	330.28	330.94	331.61	332.27	332.93	333.60	3,306.20
Btu/Bbl(Mil)	5.95	(Input	5.95	5.95	5.95	5.95	5.95	5.95		5.95	5.95	5.95	5.95	5.95	5.95	5.95	5.95	5.95	
Total Gals(Mil)	2.29		2.29	2.29	2.30	2.30	2.31	2.31		2.32	2.32	2.33	2.33	2.34	2.34	2.35	2.35	2.35	23.34
$/Gal	0.95	0.00	0.95	0.95	0.95	0.95	0.95	0.95	5.00	1.00	1.05	1.10	1.15	1.21	1.27	1.34	1.40	1.47	
$/Mil Btu	6.71		6.71	6.71	6.71	6.71	6.71	6.71		7.04	7.39	7.76	8.15	8.56	8.99	9.44	9.91	10.40	
Oil Cost($Mil)	2.17		2.18	2.18	2.18	2.19	2.19	2.20		2.31	2.43	2.56	2.69	2.83	2.98	3.14	3.30	3.47	27.91
TOTAL FUEL COST($Mil)																			
Existing Cogen Fuel	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Boiler Fuels																			
Coal	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	2.17		2.18	2.18	2.18	2.19	2.19	2.20		2.31	2.43	2.56	2.69	2.83	2.98	3.14	3.30	3.47	27.91
Total Fuel Cost	2.17		2.18	2.18	2.18	2.19	2.19	2.20		2.31	2.43	2.56	2.69	2.83	2.98	3.14	3.30	3.47	27.91
Non GFC Case O & M ($Mil)																			
Site Elect O & M	0.53	5.00	0.55	0.58	0.61	0.64	0.67	0.70	5.00	0.74	0.78	0.81	0.86	0.90	0.94	0.99	1.04	1.09	8.85
Site Thermal O & M	0.33	5.00	0.34	0.36	0.38	0.40	0.42	0.44	5.00	0.46	0.48	0.51	0.53	0.56	0.59	0.61	0.65	0.68	5.49
Subtotal O & M	0.85		0.87	0.94	0.99	1.03	1.09	1.14		1.20	1.26	1.32	1.39	1.46	1.53	1.60	1.69	1.77	14.34

A.C 4

TOTAL NON-GFC CASE COSTS																		
Purch Elect Power	1.26	1.33	1.39	1.47	1.54	1.62	1.71		1.80	1.89	1.99	2.09	2.20	2.32	2.44	2.57	2.70	21.70
Purch Fuels	2.17	2.18	2.18	2.18	2.19	2.19	2.20		2.31	2.43	2.56	2.69	2.83	2.98	3.14	3.30	3.47	27.91
O & M	0.85	0.89	0.94	0.99	1.03	1.09	1.14		1.20	1.26	1.32	1.39	1.46	1.53	1.60	1.68	1.77	14.34
Total Costs	4.28	4.39	4.51	4.64	4.77	4.90	5.05		5.31	5.58	5.87	6.17	6.49	6.83	7.18	7.55	7.94	63.96
ENERGY COSTS WITH GFC																		
GFC Availability(Hrs/ Yr)							7096		7096	7096	7096	7096	7596	7596	7596	7596	7596	
GFC kWhs Purchased(Mil)							15.88		15.91	15.94	15.97	16.01	16.04	16.07	16.10	16.14	16.17	160.23
Price (c/kWh)						(Cost of purchased electric energy)	10.76	5.00	11.30	11.86	12.46	13.08	13.73	14.42	15.14	15.90	16.69	16.69
Min GFC Annual MW Output							10.20 (Input		10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	
GFC Avg Min Summer MW							10.20 (Input		10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	10.20	
Total Elect Costs($Mil)							1.71		1.80	1.89	1.99	2.09	2.20	2.32	2.44	2.57	2.70	21.70
GFC Steam Purch (Mil Lbs)							167.47		167.47	167.47	167.47	167.47	167.47	167.47	167.47	167.47	167.47	1,674.66
GFC Steam Btus (Bil)							176.01		176.01	176.01	176.01	176.01	176.01	176.01	176.01	176.01	176.01	1,760.06
Price ($/000 Lbs)							7.66	5.00	8.04	8.44	8.86	9.31	9.77	10.26	10.78	11.31	11.88	11.88
Hot Water Purch(Mil gals)							0.00											
Price (c/ Gal)							0.00											
Total Therm Costs($Mil)							1.28		1.35	1.41	1.48	1.56	1.64	1.72	1.80	1.89	1.99	16.13
Subtotal GFC En Costs							2.99		3.14	3.31	3.47	3.65	3.84	4.04	4.24	4.46	4.69	37.83
Existing Cogen Fuel Costs							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Supplemental Energy Reqs																		
Elect Energy(Mil kWhs)							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rate (c/kWh)							8.71		9.15	9.60	10.08	10.59	11.12	11.67	12.26	12.87	13.51	
Energy Cost($Mil)							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Elect Demand-Annual(MW)							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Rate($/kW/Mo)-12 Mo							8.93		9.38	9.85	10.34	10.86	11.40	11.97	12.57	13.20	13.86	
Elect Demand-Summer(MW)							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Rate($/kW/Mo) 4 Mo							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Demand Cost($Mil)							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Elect Cost($Mil)							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Suppl Steam (Mil Lbs)							60.42		60.86	61.30	61.74	62.19	62.63	63.08	63.52	63.97	64.42	624.11
Hot Water (Mil Gals)							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Thermal Btus (Bil)							66.46		66.94	67.43	67.92	68.40	68.89	69.38	69.87	70.37	70.86	686.52

A.c. 5

Fuel Btus Req (Bil)	89.81		90.46	91.12	91.78	92.44	93.10	93.76	94.42	95.09	95.75	927.73
Non-GFC Fuel Reqs												
Btus Req (Bil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal (000 Tons)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Price ($/Ton)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Cost ($Mil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Btus Req (Bil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nat Gas (Mil Cu Ft)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Price ($/Mcf)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Cost ($Mil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Btus Req (Bil)	89.81		90.46	91.12	91.78	92.44	93.10	93.76	94.42	95.09	95.75	927.73
Fuel Oil (Mil Gals)	0.63		0.64	0.64	0.65	0.65	0.66	0.66	0.67	0.67	0.68	6.55
Price ($/Gal)	0.95		1.00	1.05	1.10	1.15	1.21	1.27	1.34	1.40	1.47	
Cost ($Mil)	0.60		0.64	0.67	0.71	0.75	0.80	0.84	0.89	0.94	1.00	7.85
Suppl Fuel Cost($Mil)	0.60		0.64	0.67	0.71	0.75	0.80	0.84	0.89	0.94	1.00	7.85
O & M Cost ($Mil)												
Site Elect O & M	0.70		0.74	0.78	0.81	0.86	0.90	0.94	0.99	1.04	1.09	8.85
Site Thermal O & M	0.44		0.46	0.48	0.51	0.53	0.56	0.59	0.61	0.65	0.69	5.49
O & M Savings	0.50	5.00	0.53	0.55	0.58	0.61	0.64	0.67	0.70	0.74	0.78	6.29
Suppl O & M Cost	0.64		0.67	0.71	0.74	0.78	0.82	0.86	0.90	0.95	0.99	8.06
COST/BENEFIT SUMMARY												
Without GFC Facility												
Purch Elect Pwr	1.71		1.80	1.89	1.99	2.09	2.20	2.32	2.44	2.57	2.70	21.70
Purch Fuels	2.20		2.31	2.43	2.56	2.69	2.83	2.98	3.14	3.30	3.47	27.91
O & M	1.14		1.20	1.26	1.32	1.39	1.46	1.53	1.60	1.68	1.77	14.34
Subtotal-No GFC	5.05		5.31	5.58	5.87	6.17	6.49	6.83	7.18	7.55	7.94	63.96
With GFC Facility												
Purch GFC Elect Pwr	1.71		1.80	1.89	1.99	2.09	2.20	2.32	2.44	2.57	2.70	21.70
Purch GFC Thermal	1.28		1.35	1.41	1.48	1.56	1.64	1.72	1.80	1.89	1.99	16.13
Subtotal	2.99		3.14	3.31	3.47	3.65	3.84	4.04	4.24	4.46	4.69	37.83
Existing Cogen Coal Costs	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Suppl Elect Pwr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Suppl Fuels	0.60	0.64	0.67	0.71	0.75	0.80	0.84	0.89	0.94	1.00	7.85
Subtotal	0.60	0.64	0.67	0.71	0.75	0.80	0.84	0.89	0.94	1.00	7.85
O & M	0.64	0.67	0.71	0.74	0.78	0.82	0.86	0.90	0.95	0.99	8.06
Subtotal-With GFC	4.23	4.45	4.68	4.93	5.18	5.45	5.74	6.03	6.35	6.68	53.74
NET GFC SAVINGS ($Mil)	0.81	0.85	0.90	0.94	0.99	1.04	1.09	1.14	1.20	1.26	10.22
Avoided cost w/ GFC	3.80	4.00	4.20	4.42	4.64	4.88	5.12	5.39	5.66	5.95	48.05

FINANCIAL EVALUATION OF SAVINGS:

	Cumulative Savings	1990 NPV at Discount Rate of 20.00 %
10-Years	10.22	3.44

A.1-1

Fort Greely
GFC Plant Analysis
(Westinghouse Fuel Cell)

GFC PLANT ANALYSIS — Site: AK — August 19, 1985 — Westinghouse Fuel Cell

Rated Output (MW):	7.10	Bil Btus Coal:	884.16 at Mil Btus/hr of 124.60 <Input
Avail(Hrs per Yr):	7096 <Input	Btus/Lb:	7,510.00 <Input
		Annual Tons Coal:	58,865.62
		Tons/ Day:	199.09

ENERGY BALANCE SUMMARY

					Mil Btus/hr	Bil Btus/Yr
Steam Output:						
Thou lbs/hr @ 120 psia:	Input>	13776	000 Lbs/hr			
Net Enthalpy Gain:	Input>	1044	Btus/lb		14.38	102.06
Electric Pwr Output:						
Fuel Cell Output	Input>	7.50	MW		25.60	181.64
Gas Expander Output	Input>	2.80	MW		9.56	67.81
Thermal Mgt System	Input>	0.00			0.00	0.00
Power Conditioner Losses	Input>	(0.40)	MW		(1.37)	(9.69)
Aux Pwr Reqs	Input>	(4.80)	MW		(16.38)	(116.25)
Net Pwr Out		5.10			17.41	123.52
Other Outputs:						
Tars/Oils	at	0.00	Mil Btus/hr	<Input		0.00
Other(e.g., Sul,Ammon)	at	0.00	Mil Btus/hr	<Input		
Losses						3.41
Ash	at	0.48	Mil Btus/hr	<Input		13.70
Cyclone Carbon Dust	at	1.93	Mil Btus/hr	<Input		0.00
Heat Rejected by Cooling Tower	at	30.00	Mil Btus/hr	<Input		212.88
CO Shift Air Cooler	at	9.90	Mil Btus/hr	<Input		70.25
HSRG Stack Loss	at	19.50	Mil Btus/hr	<Input		138.37
Miscellaneous	at	16.40	Mil Btus/hr	<Input		116.37
Coal Fines	at	14.60				103.60
TOTAL BTUS:					124.60	884.15

GFC PLANT EFFICIENCY:

Hourly Calc (mil Btus)

Net Pwr Out	+ Steam	+ Tars/Oils	+ Other
17.41	14.38	0.00	0.00

divided by 110.00 (Coal In - Fines)

Equals:

Annual Calc (bil Btus)

Net Pwr Out	+ Steam	+ Tars/Oils	+ Other
123.52	102.06	0.00	0.00

divided by 780.56 (Coal In - Fines)

Net Heat Rate: 21,611.34 — 110.22 (Coal minus Steam & Tars) Divided by 5.10 (Net Pwr)

Gross Heat Rate: 10,700.76 — 110.22 (Coal minus Steam & Tars) Divided by 10.30 (Gross power out)

Hrly Efficiency Equals: 28.90 Percent
Annual Efficiency Equals: 28.90 Percent

ECONOMIC & FINANCIAL ASSUMPTIONS

	All Inputs 1985 Energy Cost		All Inputs Annual Escal. Rate 1985-1990	All Inputs Energy Price 1990	Annual Escal. Rate 1990-2010
BFC Elect En Pr (cts/kwh)	7.57	Wtd Avg	5.00	9.66	5.00
Displaced Wainwright	8.43	0.40	5.00	10.76	
Sell to GVEA	7.00	0.60	5.00	8.93	
Fuel Oil($/Mil Btu)	4.20		0.00	4.20	5.00
Coal Price($/Ton)	39.00		0.00	39.00	5.00
Coal Heat Content (Btu/lb)	7,510.00		NA	7,510.00	NA
Coal Price($/Mil.Btu)	2.60		NA	2.60	NA
Coal Fines Price ($/ton)	34.00		0.00	34.00	5.00
Steam Price & Esc Rate	6.00		5.00	7.66	5.00
O & M Esc Rate(% per Yr)	N.A.		5.00	N.A.	5.00

	1985 Existing	1990-2010		
Depreciation Method	ACRS	SL		
Depreciation Term(Years)			Percent of Equip	
Equipment	5.00	5.00	100.00	Percent
Utilities & Other	15.00	15.00	0.00	Percent
Investment Tax Credit	10.00 %	10.00 %		
Nonconventional Gas Annual Income Tax Credit ($/Mil. Btu)	0.70	0.00 (thru 1999)	5.00 Percent Esc Rate	
Investor's Annual Income Tax Rate (Combined Fed. & State)	50.00 %	50.00 %		

OWNERSHIP AND FINANCING STRUCTURE

Parameter	Assumption		
Percent Government Funding	80.00		<Input
Percent Private Funding	20.00		
Percent equity		33.00	<Input
Percent debt		67.00	
Interest rate		13.00	<Input
Loan term(years)		15	<Input
Constr int rate		13.00	<Input
Constr loan amount($Mil)		0.00	<Input
1st yr portion		0.10	<Input
2nd yr portion		0.40	<Input
3rd yr portion		0.50	<Input

CONSTRUCTION COST BREAKDOWN ($Mil) SITE: AK GFC SIZE: 11 MW

		5.00 % Esc Rate 1985$	1989$	Period When Costs Will Occur 1987	1988	1989
Coal Hndlg & Gasif.		7.90		20.00	40.00	40.00
Gas Processing & Systems		10.90				
Fuel Cell/Pwr Cond.		18.40				
Thermal Mgt Syst.		7.00				
Balance of Plant		2.80				
Subtotal		47.00	54.98	10.36	21.76	22.85
Prototype Investment(Incl above)		0.00	0.00	0.00	0.00	0.00
Unique Site Costs		10.30	12.05	2.27	4.77	5.01
General Conditions(Incl above)		0.00	0.00	0.00	0.00	0.00
Design & Engineering(Incl above)		0.00	0.00	0.00	0.00	0.00
Preproduction Costs(Incl above)		1.41	1.71	0.57	0.57	0.57
Contingency at a Percent of:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL CONSTRUCTION COST:		58.71	68.74	13.21	27.10	28.43
Land		0.00	0.00	0.00	0.00	0.00
Other Special		0.00	0.00	0.00	0.00	0.00
TOTAL CONSTRUCTION + SPECIAL:		58.71	68.74	13.21	27.10	28.43
OTHER CAPITAL COSTS						
Working Capital						
Accts Receivable at	45 days		0.55	0.00	0.00	0.55
Fuel Inventory at	15 days		0.09	0.00	0.00	0.09
Other Inventory/Supplies		0.40 (1985)	0.49	0.00	0.00	0.49
Accnts Payable at	10 days		(0.14)	0.00	0.00	(0.14)
Subtotal Working Capital			0.99	0.00	0.00	0.99
Priv Fin Fees at Percent of:	8.00 %		1.12	0.00	0.00	1.12
3rd Pty Own Fee at Percent of:	2.00 %		0.28	0.00	0.00	0.28
Other Expenses at Percent of:	2.00 %		0.28	0.00	0.00	0.28
Subtotal			1.67	0.00	0.00	1.67
TOTAL OTHER CAPITAL COSTS:			2.67	0.00	0.00	2.67
CONSTRUCTION INTEREST:			0.00	0.00	0.00	0.00

GFC O & M COST BREAKDOWN($Mil)

	Escal.Rate:	5.00 % 1985$	1990$	1995$
Direct Labor	0.80			
Fringes @ 20%	0.16			
Contract Oper Fee	0.10			
Contract Maint.	0.22			
Chem & Supplies	0.18			
Spare Pts/Maint Sup	0.30			
Water & Site Utils	0.10			
Ash/Sludge Disp.	0.08			
Miscel	0.07			
Subtotal		2.01	2.56	3.27
Wheeling Charge		0.00	0.00	0.00
Fuel Cell Reloading Costs in 1985$ of	32 $/kw/yr	NA	NA	0.39
TOTAL O & M		2.01	2.56	3.66
OTHER ANNUAL EXPENSES				
Legal/Account.		0.00	0.00	0.00
Insurance		0.20	0.26	0.33
Prop. Taxes		0.00	0.00	0.00
TOTAL OTHER		0.20	0.26	0.33

A 7-4

ENERGY PRODUCTION	In 1985 $	In 1990 $	In 1995 $
Net Amount of Electric Power Sold			
kWh(Mil)	36.19	36.19	38.74
Avg Monthly Max. MW	5.10	5.10	5.10
Avg Monthly Min. MW	5.10	5.10	5.10
Price(cts/kwh)	7.57	9.66	12.33
Price/kW/Mo	0.00	0.00	0.00
Annual Energy Revenues ($ Mil)	2.74	3.50	4.78
Annual Capacity Revenues ($ Mil)	0.00	0.00	0.00
Subtotal Elect Revs	2.74	3.50	4.78
Steam/Hot Water Sold			
Amount(Mil lbs)	97.75	97.75	104.64
Energy Content(Bil Btus)	102.06	102.06	109.25
Price per Unit ($/000 lb)	6.00	7.66	9.77
Thermal Revenues	0.59	0.75	1.02
Other Revenues: Esc Rate:			percent
Tars/Oils	0.00	0.00	0.00
Coal Fines	0.23	0.23	0.30
Other Revs:	0.23	0.23	0.30
Fuel Use			
Energy Content(Bil Btus)	884.16	884.16	884.16
Amount(Mil Tons)	58,865.62	58,845.62	58,865.62
Cost			
Fuel Cost($/ton)	39.00	39.00	49.77
Total Fuel Cost($ Mil)	2.30	2.30	2.93
O & M Costs	2.01	2.56	3.66
Other Annual Costs	0.20	0.26	0.33
SUBTOTAL GFC OPERATING COSTS ($Mil)	4.50	5.11	6.91

COAL GASIFICATION-FUEL CELL-COGENERATION PLANT AT: AK SITE

FINANCIAL ANALYSIS ($MIL)

GFC CF ANALYSIS AK SITE

Tot Cap Costs of 71.41 times

Priv Eqty: 4.71 = 20.00 33.00 Percent

Priv Debt: 9.57 = 20.00 67.00 Percent

Total Private Cap: 14.28

Item	Engineering/Construction 1987	1988	1989		Operating Period 1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Subtotal Yrs 1-10	2000
Revenues																
Electric	0.00	0.00	0.00		3.50	3.67	3.86	4.05	4.25	4.78	5.02	5.27	5.53	5.81	45.73	6.10
Thermal	0.00	0.00	0.00		0.75	0.79	0.83	0.87	0.91	0.96	1.00	1.05	1.11	1.16	9.42	1.22
Other	0.00	0.00	0.00		0.23	0.25	0.26	0.27	0.29	0.30	0.31	0.33	0.35	0.36	2.95	0.38
Subtotal	0.00	0.00	0.00		4.48	4.70	4.94	5.19	5.45	6.03	6.33	6.65	6.98	7.33	58.09	7.70
															12.37	
Operating Costs																
Fuel	0.00	0.00	0.00		2.30	2.41	2.53	2.66	2.79	2.93	3.08	3.23	3.39	3.56	28.88	3.74
O & M	0.00	0.00	0.00		2.56	2.69	2.82	2.96	3.11	3.27	3.43	3.60	3.78	3.97	32.20	4.17
Other	0.00	0.00	0.00		0.26	0.27	0.28	0.30	0.31	0.33	0.34	0.36	0.38	0.40	3.21	0.42
Subtotal	0.00	0.00	0.00		5.11	5.37	5.64	5.92	6.21	6.52	6.85	7.19	7.55	7.93	64.29	8.33
OPERATING CASH FLOW	0.00	0.00	0.00		(0.63)	(0.66)	(0.70)	(0.73)	(0.77)	(0.49)	(0.52)	(0.54)	(0.57)	(0.60)	(6.20)	(0.63)
Debt Service: Principal				15	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	6.38	0.64
Interest	0.00	0.00	0.00	Yrs	1.24	1.16	1.08	1.00	0.91	0.83	0.75	0.66	0.58	0.50	8.71	0.41
	(Constr	Loan	Interest)													
Subtotal	0.00	0.00	0.00		1.88	1.80	1.72	1.63	1.55	1.47	1.38	1.30	1.22	1.14	15.09	1.05
Coverage Ratio					(0.34)	(0.37)	(0.41)	(0.45)	(0.49)	(0.33)	(0.37)	(0.42)	(0.47)	(0.53)	(0.41)	(0.59)
Debt Svc Reserve					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumul Reserve					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N.A.	0.00
RESIDUAL CASH FLOW	0.00	0.00	0.00		(2.51)	(2.46)	(2.41)	(2.36)	(2.32)	(1.96)	(1.90)	(1.84)	(1.79)	(1.73)	(21.28)	(1.68)
Management Fee					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax Adjustments		(Private share of equipment)														
Depr 5-yr Equip(SL) at	0.95	20.00	Percent)		2.61	2.61	2.61	2.61	2.61						13.06	
Depr 15-yr Equip(SL) at	1.00	20.00	Percent)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amort Startup Cost	0.00	0.00	0.00													
Principal Payment					0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	6.38	0.64
Debt Svc Reserve					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income/Loss(-)	0.00	0.00	0.00		(4.49)	(4.44)	(4.39)	(4.34)	(4.29)	(1.32)	(1.26)	(1.20)	(1.15)	(1.09)	(27.96)	(1.04)
Tax Saving or Payment(-)	0.00	0.00	0.00		2.24	2.22	2.19	2.17	2.15	0.66	0.63	0.60	0.57	0.55	13.98	0.52
10 % Inv Tax Credit at	20.00	Percent)	1.37													
Syngas Tax Credit at	0.00	$/Mil Btu	to 1999)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Priv Capital Requirement			(14.28)													
Priv Perm Debt Financing			9.57													
NET CASH FLOW	0.00	0.00	)	(3.34)	(0.27)	(0.24)	(0.22)	(0.19)	(0.17)	(1.30)	(1.27)	(1.24)	(1.21)	(1.18)		(1.16)
Cumulative Cash Flow	0.00	0.00	(3.34)		(3.61)	(3.85)	(4.07)	(4.26)	(4.44)	(5.73)	(7.00)	(8.24)	(9.45)	(10.64)		(11.80)

ROE= ERR Percent; NPV= ERR at a ERR Percent Disc Rate.
10 Year Cash Stream)

A. 3 - 1

Fort Creely
GFC Plant Analysis
(UTC Fuel Cell)

GFC PLANT ANALYSIS Site: AK
August 19, 1985

Rated Output (MW): 11.00
Avail(Hrs per Yr): 7096 <Input

Bil Btus Coal: 1,231.87 at Mil Btus/hr of 173.60 <Input
Btus/Lb: 7,510.00 <Input
Annual Tons Coal: 82,015.02
Tons/ Day: 277.39

ENERGY BALANCE SUMMARY

			Mil Btus/hr	Bil Btus/Yr
Steam Output:				
Thou lbs/hr @ 120 psia:	Input>	23600 000 Lbs/hr		
Net Enthalpy Gain:	Input>	1051 Btus/lb	24.80	176.01
Electric Pwr Output:				
Fuel Cell Output	Input>	11.60 MW	39.59	280.94
Gas Expander Output	Input>	2.60 MW	8.87	62.97
Thermal Mgt System	Input>	0.40	1.37	9.69
Power Conditioner Losses	Input>	(0.60) MW	(2.05)	(14.53)
Aux Pwr Reqs	Input>	(3.81) MW	(13.00)	(92.27)
Net Pwr Out		10.19	34.78	246.79
Other Outputs:				
Tars/Oils	at	0.00 Mil Btus/hr <Input		0.00
Other(e.g., Sul,Ammon)	at	0.00 Mil Btus/hr <Input		
Losses				4.97
Ash	at	0.70 Mil Btus/hr <Input		9.22
Cyclone Carbon Dust	at	1.30 Mil Btus/hr <Input		0.00
Heat Rejected by Cooling Tower	at	35.00 Mil Btus/hr <Input		248.36
CO Shift Air Cooler	at	13.40 Mil Btus/hr <Input		95.09
HRSG Stack Loss	at	25.10 Mil Btus/hr <Input		178.11
Miscellaneous	at	18.13 Mil Btus/hr <Input		128.65
Coal Fines	at	20.40	==========	144.76 ==========
TOTAL BTUS:			173.61	1,231.95

GFC PLANT EFFICIENCY: Hourly Calc (mil Btus)

Net Pwr Out	+ Steam	+ Tars/Oils	+ Other
34.78	24.80	0.00	0.00

153.20
Coal In - Fines

Equals:

Annual Calc (bil Btus)

Net Pwr Out	+ Steam	+ Tars/Oils	+ Other
246.79	176.01	0.00	0.00

1,087.11
Coal In - Fines

Net Heat Rate: 14,602.20

148.80 (Coal minus Steam & Tars) Divided by 10.19 (Net Pwr)

Gross Heat Rate: 10,191.53

148.80 (Coal minus Steam & Tars) Divided by 14.60 (Gross power out)

Hrly Efficiency Equals: 38.89 Percent
Annual Efficiency Equals: 38.89 Percent

SITE: AK GFC SIZE: 11 MW

CONSTRUCTION COST BREAKDOWN ($Mil)

		5.00 % Esc Rate 1985$	1989$	Period When Costs Will Occur 1987	1988	1989
Coal Hndlg & Gasif.		7.87		20.00	40.00	40.00
Gas Processing & Systems		11.01				
Fuel Cell/Pwr Cond.		22.93	Save NG Bk-up sys			
Thermal Mgt Syst.		6.91				
Balance of Plant		2.78				
Subtotal		51.50	60.24	11.36	23.85	25.04
Prototype Investment(Incl above)		0.00	0.00	0.00	0.00	0.00
Unique Site Costs		12.70	14.86	2.80	5.88	6.17
General Conditions(Incl above)		0.00	0.00	0.00	0.00	0.00
Design & Engineering(Incl above)		0.00	0.00	0.00	0.00	0.00
Preproduction Costs(Incl above)		1.74	2.11	0.70	0.70	0.70
Contingency at a Percent of:	0.00	0.77	0.00	0.00	0.00	0.00
TOTAL CONSTRUCTION COST:		66.71	77.21	14.86	30.43	31.92
Land		0.00	0.00	0.00	0.00	0.00
Other Special		0.00	0.00	0.00	0.00	0.00
TOTAL CONSTRUCTION + SPECIAL:		66.71	77.21	14.86	30.43	31.92
OTHER CAPITAL COSTS						
Working Capital						
Accts Receivable at	45 days		1.04	0.00	0.00	1.04
Fuel Inventory at	15 days		0.13	0.00	0.00	0.13
Other Inventory/Supplies			0.10	0.00	0.00	0.10
Accnts Payable at	10 days		(0.16)	0.00	0.00	(0.16)
Subtotal Working Capital			1.11	0.00	0.00	1.11
Priv Fin Fees at Percent of:	8.00 %		1.25	0.00	0.00	1.25
3rd Pty Own Fee at Percent of:	2.00 %		0.31	0.00	0.00	0.31
Other Expenses at Percent of:	2.00 %		0.31	0.00	0.00	0.31
Subtotal			1.88	0.00	0.00	1.88
TOTAL OTHER CAPITAL COSTS:			2.98	0.00	0.00	2.98
CONSTRUCTION INTEREST:			[illegible]	0.00	0.00	0.00

GFC O & M COST BREAKDOWN ($Mil)

	Escal.Rate:	5.00 % 1985$	1990$	1995$
Direct Labor	0.80			
Fringes @ 20%	0.16			
Contract Oper Fee	0.10			
Contract Maint.	0.22			
Chem & Supplies	0.18			
Spare Pts/Maint Sup	0.30			
Water & Site Utils	0.10			
Ash/Sludge Disp.	0.08			
Miscel	0.07			
Subtotal		2.01	2.56	3.27
Wheeling Charge		0.00	0.00	0.00
Fuel Cell Reloading Costs in 1985$ of	32 $/kw/yr	NA	NA	0.60
TOTAL O & M		2.01	2.56	3.87
OTHER ANNUAL EXPENSES				
Legal/Account.		0.00	0.00	0.00
Insurance		0.20	0.26	0.33
Prop. Taxes		0.00	0.00	0.00
TOTAL OTHER		0.20	0.26	0.33

ECONOMIC & FINANCIAL ASSUMPTIONS

	All Inputs 1985 Energy Cost		All Inputs Annual Escal. Rate 1985-1990	Energy Price 1990	All Inputs Annual Escal. Rate 1990-2010
GFC Elect En Pr (cts/kwh)	7.29	Wtd Avg	5.00	9.30	5.00
Displaced Wainwright	8.43	0.20	5.00	10.76	
Sell to GVEA	7.00	0.80	5.00	8.93	
Fuel Oil($/Mil Btu)	4.20		0.00	4.20	5.00
Coal Price($/Ton)	39.00		0.00	39.00	5.00
Coal Heat Content (Btu/lb)	7,510.00		NA	7,510.00	NA
Coal Price($/Mil.Btu)	2.60		NA	2.60	NA
Coal Fines Price ($/ton)	34.00		5.00	43.39	5.00
Steam Price & Esc Rate	6.00		5.00	7.66	5.00
O & M Esc Rate(% per Yr)	N.A.		5.00	N.A.	5.00

	1985 Existing	1990-2010	Percent of Equip	
Depreciation Method	ACRS	SL		
Depreciation Term(Years)				
Equipment	5.00	5.00	100.00	Percent
Utilities & Other	15.00	15.00	0.00	Percent
Investment Tax Credit	10.00 %	10.00 %		
Nonconventional Gas Annual Income Tax Credit ($/Mil. Btu)	0.70	0.00 (thru 1999)	5.00	Percent Esc Rate
Investor's Annual Income Tax Rate (Combined Fed. & State)	50.00 %	50.00 %		

OWNERSHIP AND FINANCING STRUCTURE

Parameter	Assumption		
Percent Government Funding	80.00		(Input
Percent Private Funding	20.00		
Percent equity		33.00	(Input
Percent debt		67.00	
Interest rate		13.00	(Input
Loan term(years)		15	(Input
Constr int rate		13.00	(Input
Constr loan amount($Mil)		0.00	(Input
1st yr portion		0.10	(Input
2nd yr portion		0.40	(Input
3rd yr portion		0.50	(Input

A.3-4

ENERGY PRODUCTION	In 1985 $	In 1990 $	In 1995 $
Net Amount of Electric Power Sold			
kWh(Mil)	72.31	72.31	77.40
Avg Monthly Max. MW	10.19	10.19	10.19
Avg Monthly Min. MW	10.19	10.19	10.19
Price(cts/kwh)	7.29	9.30	11.87
Price/kW/Mo	0.00	0.00	0.00
Annual Energy Revenues ($ Mil)	5.27	6.72	9.19
Annual Capacity Revenues ($ Mil)	0.00	0.00	0.00
Subtotal Elect Revs	5.27	6.72	9.19
Steam/Hot Water Sold			
Amount(Mil lbs)	167.47	167.47	179.27
Energy Content(Bil Btus)	176.01	176.01	188.41
Price per Unit ($/000 lb)	6.00	7.66	9.77
Thermal Revenues	1.00	1.28	1.75
Other Revenues: Esc Rate:		(Tars Based on of retail fuel oil price)	N.A. percent
Tars/Oils	0.00	0.00	0.00
Coal Fines	0.33	0.42	0.53
Other Revs:	0.33	0.42	0.53
Fuel Use			
Energy Content(Bil Btus)	1,231.87	1,231.87	1,231.87
Amount(Mil Tons)	82,015.02	82,015.02	82,015.02
Cost			
Fuel Cost($/ton)	39.00	39.00	49.77
Total Fuel Cost($ Mil)	3.20	3.20	4.08
O & M Costs	2.01	2.56	3.87
Other Annual Costs	0.20	0.26	0.33
SUBTOTAL EFC OPERATING COSTS ($Mil)	5.40	6.01	8.28

A.3-5

COAL GASIFICATION-FUEL CELL-COGENERATION PLANT AT: AK SITE — SFC CF ANALYSIS — AK SITE

FINANCIAL ANALYSIS ($MIL)

Priv Eqty: 5.29 = 20.00 33.00 Percent
Priv Debt: 10.75 = 26.00 67.00 Percent
Total Private Cap: 16.04
Tot Cap Costs of 80.20 times

Item	Engineering/Construction 1987	1988	1989		Operating Period 1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Subtotal Yrs 1-10	2000
Revenues																
Electric	0.00	0.00	0.00		6.72	7.06	7.41	7.78	8.17	9.19	9.65	10.13	10.63	11.17	87.91	11.72
Thermal	0.00	0.00	0.00		1.28	1.35	1.41	1.48	1.56	1.64	1.72	1.80	1.89	1.99	16.13	2.09
Other	0.00	0.00	0.00		0.42	0.44	0.46	0.48	0.51	0.53	0.56	0.59	0.62	0.65	5.26	0.69
Subtotal	0.00	0.00	0.00		8.42	8.85	9.29	9.75	10.24	11.36	11.92	12.52	13.15	13.80	109.30	14.49
															21.39	
Operating Costs																
Fuel	0.00	0.00	0.00		3.20	3.36	3.53	3.70	3.89	4.08	4.29	4.50	4.73	4.96	40.23	5.21
O & M	0.00	0.00	0.00		2.56	2.69	2.82	2.96	3.11	3.27	3.43	3.60	3.78	3.97	32.20	4.17
Other	0.00	0.00	0.00		0.26	0.27	0.28	0.30	0.31	0.33	0.34	0.36	0.38	0.40	3.21	0.42
Subtotal	0.00	0.00	0.00		6.01	6.31	6.63	6.96	7.31	7.68	8.06	8.46	8.89	9.33	75.64	9.80
OPERATING CASH FLOW	0.00	0.00	0.00		2.41	2.53	2.66	2.79	2.93	3.68	3.87	4.06	4.26	4.47	33.66	4.70
Debt Service: Principal				15	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	7.16	0.72
Interest	0.00	0.00	0.00	Yrs	1.40	1.30	1.21	1.12	1.02	0.93	0.84	0.75	0.65	0.56	9.78	0.47
	(Constr	Loan	Interest)													
Subtotal	0.00	0.00	0.00		2.11	2.02	1.93	1.83	1.74	1.65	1.55	1.46	1.37	1.28	16.94	1.18
Coverage Ratio					1.14	1.25	1.38	1.52	1.68	2.23	2.49	2.78	3.11	3.51	1.99	3.97
Debt Svc Reserve					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cumul Reserve					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N.A.	0.00
RESIDUAL CASH FLOW	0.00	0.00	0.00		0.30	0.51	0.73	0.96	1.19	2.03	2.31	2.60	2.89	3.20	16.72	3.52
Management Fee					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	(Private share	of equipment)														
Tax Adjustments																
Depr 5-yr Equip(SL) at	0.95	20.00	Percent)		2.93	2.93	2.93	2.93	2.93						14.67	
Depr 15-yr Equip(SL) at	1.00	20.00	Percent)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amort Startup Cost	0.00	0.00	0.00													
Principal Payment					0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	7.16	0.72
Debt Svc Reserve					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taxable Income/Loss(-)	0.00	0.00	0.00		(1.92)	(1.71)	(1.49)	(1.26)	(1.03)	2.75	3.03	3.31	3.61	3.92	9.21	4.23
Tax Saving or Payment(-)	0.00	0.00	0.00		0.96	0.85	0.74	0.63	0.51	(1.37)	(1.51)	(1.66)	(1.80)	(1.96)	(4.61)	(2.12)
10 % Inv Tax Credit at	20.00 Percent)		1.54													
Syngas Tax Credit at	0.00 $/Mil Btu to 1999)				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Priv Capital Requirement			(16.04)													
Priv Perm Debt Financing			10.75													
NET CASH FLOW	0.00	0.00	>	(3.75)	1.26	1.36	1.47	1.59	1.70	0.66	0.80	0.94	1.09	1.24		1.40
Cumulative Cash Flow	0.00	0.00	(3.75)		(2.49)	(1.13)	0.35	1.93	3.64	4.30	5.09	6.03	7.12	8.36		9.76

ROE= 32.88 Percent; NPV= (0.11) at a 32.88 Percent Disc Rate.
10 Year Cash Stream)

SITE COST/BENEFITS ANALYSIS

	TX	? te	Avail	Hours of GFC	
GFC Steam Output:	August 19, 1985			7096 (Input	6719 Coal Btu Content
Thou lbs/hr @ 230 psia:		Input)	20300		
Net Enthalpy (Btus/lb):		Input)	1054		

Total	1985 Cost		Esc Rate 1985-1990	1990 Cost	Esc Rate 1990-2010	
Cost Purch El Pwr(c/kwh)	4.90	(Input in below)	5.00	6.26	5.00	
Cost GFC El Pwr (c/kwh)			Input)	NA	5.00	(Sold to grid at 6.26 c/kWh)
Electric Demand($/kw/Mo)	0.00		5.00	0.00	5.00	
Natural Gas($/mcf)	4.16		0.00	4.16	5.00	
Fuel Oil($/gal)	0.63		0.00	0.63	5.00	
Existing Cogen Coal Price($/Ton)	N.A.		0.00	N.A.	5.00	
Coal Heat Content (Btu/lb)	6719		NA	NA	NA	
Coal Price($/Mil.Btu)	N.A.		0.00	N.A.	5.00	
Steam Pr & Esc Rate(%/yr)	4.00		5.00	5.11	5.00	
O & M Esc Rate(% per Yr)	N.A.		5.00	N.A.	5.00	

A.1-1

Fort Hood
Site Analysis
w/o GFC Plant

ELECTRIC POWER DEMAND WITHOUT GFC (TX)	1984	Esc Rate 1984-90	1985	1986	1987	1988	1989	1990	Esc Rate 1990-2009	1991	1992	1993	1994	1995	1996	1997	1998	1999	Subtotal Yrs 1-10
KWH Amount (Mil kwhs)																			
On peak																			
Intermediate																			
Off-peak																			
Subtotal	284.00	2.00	289.68	295.47	301.38	307.41	313.56	319.83	2.00 Inputs	326.23	332.75	339.41	346.19	353.12	360.18	367.38	374.73	382.23	3,502.05
KWH Rates(Cts/kwh)																			
Average On-peak																			
Average intermediate																			
Average off-peak																			
Overall Average	3.53	5.00	3.71	3.89	4.09	4.29	4.51	4.73	5.00	4.97	5.22	5.48	5.75	6.04	6.34	6.66	6.99	7.34	--
Summer(4 Mos)																			
Rest of Year																			
Peak MW Distribution(12-Mo Rat)	66.50	2.00	67.83	69.19	70.57	71.98	73.42	74.89	Inputs 2.00	76.39	77.92	79.47	81.06	82.68	84.34	86.02	87.75	89.50	--
Peak MW Rate($/kw/Mo) Distribution(12 Mos)	4.05	5.00	4.25	4.47	4.69	4.92	5.17	5.43	5.00	5.70	5.98	6.28	6.60	6.93	7.27	7.64	8.02	8.42	--
THERMAL DEMAND																			
Steam Demand(Mil lbs)																			
Summer (4 Mo)	387.00	2.00	394.74	402.63	410.69	418.90	427.28	435.82	2.00	444.54	453.43	462.50	471.75	481.19	490.81	500.63	510.64	520.85	4,772.16
Rest of Yr	800.00	2.00	816.00	832.32	848.97	865.95	883.26	900.93	2.00	918.75	937.33	956.07	975.20	994.70	1,014.59	1,034.89	1,055.58	1,076.69	9,864.93
Total Year	1,187.00		1,210.74	1,234.95	1,259.65	1,284.85	1,310.54	1,336.75											

A.9-2

Peak Dem(000 Lbs/Hr)	50.00	2.00	51.00	52.02	53.06	54.12	55.20	56.31	2.00	57.43	58.58	59.75	60.95	62.17	63.41	64.68	65.97	67.29	
Avg Btu/Lb(Net)	1054		1054	1054	1054	1054	1054	1054		1054	1054	1054	1054	1054	1054	1054	1054	1054	
Bil Btus Required	1251.10		1276.12	1301.64	1327.68	1354.23	1381.31	1408.94		1437.12	1465.86	1495.18	1525.08	1555.58	1586.69	1618.43	1650.80	1683.81	15,427.49
Hot Water (Mil Gals)	0.00	(Steam	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		used to																	
Avg Btu/Gal	0.00	generate	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Bil Btus Required	0.00	hot water	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

EXISTING COGENERATION

Page 3

Elect Energy(Mil kwhs)																			
Summer	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rest of Yr	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Min Annual MW Output	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Avg Min Summer MW Outpt	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Steam Supply(Mil Lbs)																			
Summer	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rest of Yr	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Avg Btu/Lb(Net)	1054		1054	1054	1054	1054	1054	1054		1054	1054	1054	1054	1054	1054	1054	1054	1054	
Steam Btus(Bils)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TG Heat Rate	0.00	(Input)	3700	3700	3700	3700	3700	3700		3700	3700	3700	3700	3700	3700	3700	3700	3700	
Boiler Efficiency	0.70	(Input)	0.70	0.70	0.70	0.70	0.70	0.70		0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	
Coal Btus Required(Bil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COSTS-Elect Energy($Mil)																			
On-peak																			
Intermed																			
Off-peak																			
Subtot(Net of Cogen)	10.03		10.74	11.50	12.32	13.19	14.13	15.13		16.20	17.35	18.59	19.91	21.32	22.83	24.45	26.19	28.05	210.03
COSTS-Elect Demand($Mil)		(Actual																	
Distribution(Net)	3.23	4.30	3.46	3.71	3.97	4.25	4.55	4.88		5.22	5.59	5.99	6.42	6.87	7.36	7.88	8.44	9.04	67.71
		in 1984?)																	
Subtot(Net of Cogen)	3.23		3.46	3.71	3.97	4.25	4.55	4.88		5.22	5.59	5.99	6.42	6.87	7.36	7.88	8.44	9.04	67.71
TOTAL ELECT COSTS	13.26		14.20	15.21	16.29	17.44	18.68	20.01		21.43	22.95	24.58	26.32	28.19	30.19	32.34	34.63	37.09	277.74

SITE FUEL REQS & COSTS
WITHOUT GFF

Existing Cogen Coal Reqs																			
Btus Required(Bils)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Btu/Lb	0		6719	6719	6719	6719	6719	6719		6719	6719	6719	6719	6719	6719	6719	6719	6719	
Total Tons(000)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
$/Ton Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Ton-Limestone	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Ton-Ash Removal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Total $/Ton	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	

$/Mil Btus	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Cogen Coal Cost($Mil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Supplemental Fuel Reqs																			
Suppl Steam Btus(Bil)	1251.10		1276.12	1301.64	1327.68	1354.23	1381.31	1408.94		1437.12	1465.86	1495.18	1525.08	1555.58	1586.69	1618.43	1650.80	1683.81	15,427.49
Site Boiler Effics	0.75	(Input)	0.75	0.75	0.75	0.75	0.75	0.75		0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	
Suppl Fuel Btus(Bil)	1668.13		1701.49	1735.52	1770.23	1805.64	1841.75	1878.59		1916.16	1954.48	1993.57	2033.44	2074.11	2115.59	2157.90	2201.06	2245.08	20,569.99
Coal(Same cogen boiler)																			
Btus Required(Bil)	0.00	(Input)	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Btu/Lb	6719		6719	6719	6719	6719	6719	6719		6719	6719	6719	6719	6719	6719	6719	6719	6719	
Total Tons(000)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
$/Ton-Coal	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Ton Limestone	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Ton-Ash Removal	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Total $/Ton	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
$/Mil Btu	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Coal Cost($Mil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas																			
Btus Required(Bil)	1,668.13		1,701.49	1,735.52	1,770.23	1,805.64	1,841.75	1,878.59		1,916.16	1,954.48	1,993.57	2,033.44	2,074.11	2,115.59	2,157.90	2,201.06	2,245.08	20,569.99
Btu/Cubic Ft	1,030.00	(Input	1,030.00	1,030.00	1,030.00	1,030.00	1,030.00	1,030.00		1,030.00	1,030.00	1,030.00	1,030.00	1,030.00	1,030.00	1,030.00	1,030.00	1,030.00	
Total (Mil Cu Ft)	1,619.54		1,651.94	1,684.97	1,718.67	1,753.05	1,788.11	1,823.87		1,860.35	1,897.55	1,935.51	1,974.22	2,013.70	2,053.97	2,095.05	2,136.95	2,179.69	19,970.87
$/Mcf	4.16	0.00	4.16	4.16	4.16	4.16	4.16	4.16	5.00	4.37	4.59	4.82	5.06	5.31	5.57	5.85	6.15	6.45	
$/Mil Btu	4.04		4.04	4.04	4.04	4.04	4.04	4.04		4.24	4.45	4.68	4.91	5.15	5.41	5.68	5.97	6.27	
Gas Cost($Mil)	6.74		6.87	7.01	7.15	7.29	7.44	7.59		8.13	8.70	9.32	9.98	10.69	11.45	12.26	13.13	14.07	105.33
Fuel Oil																			
Btus Required(Bil)	0.00	2.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Btu/Bbl(Mil)	5.80	(Input	5.80	5.80	5.80	5.80	5.80	5.80		5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	
Total Gals(Mil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
$/Gal	0.63	0.00	0.63	0.63	0.63	0.63	0.63	0.63	5.00	0.66	0.69	0.73	0.77	0.80	0.84	0.89	0.93	0.98	
$/Mil Btu	4.56		4.56	4.56	4.56	4.56	4.56	4.56		4.79	5.03	5.28	5.55	5.82	6.11	6.42	6.74	7.08	
Oil Cost($Mil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL FUEL COST($Mil)																			
Non-GFC Cogen Coal	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Suppl Steam Fuels																			
Coal	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	6.74		6.87	7.01	7.15	7.29	7.44	7.59		8.13	8.70	9.32	9.98	10.69	11.45	12.26	13.13	14.07	105.33
Oil	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Fuel Cost	6.74		6.87	7.01	7.15	7.29	7.44	7.59		8.13	8.70	9.32	9.98	10.69	11.45	12.26	13.13	14.07	105.33
Non-GFC Case O & M ($Mil)(Conservative estimate made)																			
Existing Cogen O & M	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Suppl Thermal O & M	1.00	5.00	1.05	1.10	1.16	1.22	1.28	1.34	5.00	1.41	1.48	1.55	1.63	1.71	1.80	1.89	1.98	2.08	16.86
Subtotal O & M	1.00		1.05	1.10	1.16	1.22	1.28	1.34		1.41	1.48	1.55	1.63	1.71	1.80	1.89	1.98	2.08	16.86

TOTAL NON-GFC CASE COSTS																		
Purch Elect Power	13.26	14.20	15.21	16.29	17.44	18.68	20.01		21.43	22.95	24.58	26.32	28.19	30.19	32.34	34.63	37.09	277.74
Purch Fuels	6.74	6.87	7.01	7.15	7.29	7.44	7.59		8.13	8.70	9.32	9.98	10.69	11.45	12.26	13.13	14.07	105.33
O & M	1.00	1.05	1.10	1.16	1.22	1.28	1.34		1.41	1.48	1.55	1.63	1.71	1.80	1.89	1.98	2.08	16.86
Total Costs	20.99	22.12	23.32	24.59	25.95	27.40	28.93		30.96	33.13	35.45	37.94	40.59	43.44	46.49	49.75	53.24	399.92
ENERGY COSTS WITH GFC																		
GFC Availability(Hrs/ Yr)							7096		7096	7096	7096	7096	7596	7596	7596	7596	7596	
GFC KWhs Purchased(Mil)							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Price (c/KWh)							NA	5.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Min GFC Annual MW Output							NA (Input		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
GFC Avg Min Summer MW							NA (Input		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Total Elect Costs($Mil)							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GFC Steam Purch (Mil Lbs)							144.05		144.05	144.05	144.05	144.05	144.05	144.05	144.05	144.05	144.05	1,440.49
GFC Steam Btus (Bil)							151.83		151.83	151.83	151.83	151.83	151.83	151.83	151.83	151.83	151.83	1,518.27
Price ($/000 Lbs)							5.11	5.00	5.36	5.63	5.91	6.21	6.52	6.84	7.18	7.54	7.92	
Hot Water Purch(Mil gals)							0.00											
Price (c/ Gal)							0.00											
Total Therm Costs($Mil)							0.74		0.77	0.81	0.85	0.89	0.94	0.99	1.03	1.09	1.14	9.25
Subtotal GFC En Costs							0.74		0.77	0.81	0.85	0.89	0.94	0.99	1.03	1.09	1.14	9.25
Existing Cogen Fuel Costs							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Supplemental Energy Reqs																		
Abs A/C Pwr Displ							5.09		5.09	5.09	5.09	5.09	5.09	5.09	5.09	5.09	5.09	
Elect Energy(Mil KWhs)							314.74		321.14	327.66	334.32	341.11	348.03	355.09	362.30	369.64	377.14	3,451.18
Rate (c/KWh)							4.73		4.97	5.22	5.48	5.75	6.04	6.34	6.66	6.99	7.34	
Energy Cost($Mil)							14.89		15.95	17.09	18.31	19.61	21.01	22.51	24.12	25.84	27.68	207.00
Elect Demand-Annual(MW)							74.89		76.39	77.92	79.47	81.06	82.68	84.34	86.02	87.75	89.50	
Rate($/KW/Mo)-12 Mo							5.43		5.70	5.98	6.28	6.60	6.93	7.27	7.64	8.02	8.42	
Demand Cost($Mil)							4.88		5.22	5.59	5.99	6.42	6.87	7.36	7.88	8.44	9.04	67.71
Elect Cost($Mil)							19.77		21.17	22.68	24.30	26.03	27.89	29.87	32.00	34.28	36.72	274.71
Suppl Steam (Mil Lbs)							1,192.71		1,168.45	1,194.58	1,221.23	1,248.41	1,276.14	1,304.42	1,333.27	1,362.70	1,392.71	12,694.62
Hot Water (Mil Gals)							0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Thermal Btus (Bil)							1,237.11		1,295.29	1,314.03	1,343.35	1,373.25	1,403.76	1,434.87	1,466.60	1,498.97	1,531.99	19,051.72

Fuel Btus Req (Bil)	1,676.15		1,713.72	1,752.04	1,791.13	1,831.01	1,871.67	1,913.16	1,955.47	1,998.63	2,042.65	18,545.63
Non-GFC Fuel Reqs												
Btus Req (Bil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal (000 Tons)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Price ($/Ton)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Cost ($Mil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Btus Req (Bil)	1,676.15		1,713.72	1,752.04	1,791.13	1,831.01	1,871.67	1,913.16	1,955.47	1,998.63	2,042.65	18,545.63
Nat Gas (Mil Cu Ft)	1,627.33		1,663.81	1,701.01	1,738.97	1,777.68	1,817.16	1,857.43	1,898.51	1,940.41	1,983.15	18,005.46
Price ($/Mcf)	4.16		4.37	4.59	4.82	5.06	5.31	5.57	5.85	6.15	6.45	
Cost ($Mil)	6.77		7.27	7.80	8.37	8.99	9.65	10.35	11.11	11.93	12.80	95.04
Btus Req (Bil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Oil (Mil Gals)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Price ($/Gal)	0.63		0.66	0.69	0.73	0.77	0.80	0.84	0.89	0.93	0.98	
Cost ($Mil)	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Suppl Fuel Cost($Mil)	6.77		7.27	7.80	8.37	8.99	9.65	10.35	11.11	11.93	12.80	95.04
O & M Cost ($Mil)												
Existing Cogen Plant	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Suppl Therm Plant	1.34		1.41	1.48	1.55	1.63	1.71	1.80	1.89	1.98	2.08	16.86
		5.00										
O & M Savings	0.50		0.53	0.55	0.58	0.61	0.64	0.67	0.70	0.74	0.78	6.29
Suppl O & M Cost	0.84		0.88	0.93	0.97	1.02	1.07	1.13	1.18	1.24	1.30	10.57

COST/BENEFIT SUMMARY

Without GFC Facility											
Purch Elect Pwr	20.01	21.43	22.95	24.58	26.32	28.19	30.19	32.34	34.63	37.09	277.74
Purch Fuels	7.59	8.13	8.70	9.32	9.98	10.69	11.45	12.26	13.13	14.07	105.33
O & M	1.34	1.41	1.48	1.55	1.63	1.71	1.80	1.89	1.98	2.08	16.86
Subtotal-No GFC	28.93	30.96	33.13	35.45	37.94	40.59	43.44	46.49	49.75	53.24	399.92
With GFC Facility											
Purch GFC Elect Pwr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Purch GFC Thermal	0.74	0.77	0.81	0.85	0.87	0.94	0.99	1.03	1.09	1.14	9.25
Subtotal	0.74	0.77	0.81	0.85	0.89	0.94	0.99	1.03	1.09	1.14	9.25
Existing Cogen Coal Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Suppl Elect Pwr	19.77	21.17	22.68	24.30	26.03	27.89	29.87	32.00	34.28	36.72	274.71
Suppl Fuels	6.77	7.27	7.80	8.37	8.99	9.65	10.35	11.11	11.93	12.80	95.04
Subtotal	26.54	28.44	30.49	32.67	35.02	37.53	40.23	43.11	46.20	49.52	369.75
O & M	0.84	0.88	0.93	0.97	1.02	1.07	1.13	1.18	1.24	1.30	10.57
Subtotal-With GFC	28.11	30.10	32.22	34.50	36.93	39.54	42.34	45.33	48.53	51.96	389.57
NET GFC SAVINGS ($Mil)	0.82	0.86	0.91	0.95	1.00	1.05	1.10	1.16	1.22	1.28	10.35

FINANCIAL EVALUATION OF SAVINGS:

	Cumulative Savings	1990 NPV at Discount Rate of 20.00 %
10-Years	10.35	3.48

COAL GASIFICATION-FUEL CEGFC PLANT ANALYSIS   Site: TX   August 19, 1985

A.10-1

Fort Hood
GFC Plant Analysis

Rated Output (MW):	11.00	Bil Btus Coal:	1,137.49	at Mil Btus/hr of 160.30 <Input
Avail(Hrs per Yr):	7096 <Input	Btus/Lb:	6,719.00 <Input	
		Annual Tons Coal:	84,647.18	
		Tons/ Day:	286.29	

FINANCIAL ANALYSIS ($MIL)

Item

Revenues
Electric
Thermal
Other

Subtotal

Operating Costs
Fuel
O & M
Other

Subtotal

OPERATING CASH FLOW

Debt Service: Principal
Interest

Subtotal
Coverage Ratio

Debt Svc Reserve
Cumul Reserve

RESIDUAL CASH FLOW

Management Fee

Tax Adjustments
Depr 5-yr Equip(SL) at
Depr 15-yr Equip(SL) at
Amort Startup Cost
Principal Payment
Debt Svc Reserve

Taxable Income/Loss(-)

Tax Saving or Payment(-)
10 % Inv Tax Credit at
Syngas Tax Credit at
Priv Capital Requirement
Priv Pare Debt Financing

NET CASH FLOW

Cumulative Cash Flow

ENERGY BALANCE SUMMARY

					Mil Btus/hr	Bil Btus/Yr
Steam Output:						
Thou lbs/hr @ 240 psia:	Input>	20300	000 Lbs/hr			
Net Enthalpy Gain:	Input>	1054	Btus/lb		21.40	151.83
Electric Pwr Output:						
Fuel Cell Output	Input>	11.60	MW		39.59	280.94
Gas Expander Output	Input>	2.34	MW		7.99	56.67
Thermal Mgt System	Input>	1.28			4.37	31.00
Power Conditioner Losses	Input>	(0.60)	MW		(2.05)	(14.53)
Aux Pwr Reqs	Input>	(3.52)	MW		(12.01)	(85.25)
Net Pwr Out		11.10			37.88	268.83
Other Outputs:						
Tars/Oils	at	0.00	Mil Btus/hr	<Input		0.00
Other(e.g., Sul,Ammon)	at	0.00	Mil Btus/hr	<Input		
Losses						29.24
Ash and Coal Dust	at	4.12	Mil Btus/hr	<Input		0.00
Cyclone Carbon Dust	at	0.00	Mil Btus/hr	<Input		0.00
Heat Rejected by Cooling Tower	at	51.00	Mil Btus/hr	<Input		361.90
CO Shift Air Cooler	at	13.40	Mil Btus/hr	<Input		95.09
HSRG Stack Loss	at	25.10	Mil Btus/hr	<Input		178.11
Miscellaneous	at	8.04	Mil Btus/hr	<Input		57.05
TOTAL BTUS:					160.94	1,142.03

GFC PLANT EFFICIENCY:

Hourly Calc (mil Btus)

Net Pwr Out	+ Steam	+ Tars/Oils	+ Other
37.88	21.40	0.00	0.00

160.30
Coal In

Equals:

Annual Calc (bil Btus)

Net Pwr Out	+ Steam	+ Tars/Oils	+ Other
268.83	151.83	0.00	0.00

1,137.49
Coal In

Net Heat Rate:	12,513.86	Gross Heat Rate:	9,126.40
138.90 (Coal minus Steam & Tars) Divided by 11.10 (Net Pwr)		138.90 (Coal minus Steam & Tars) Divided by 15.22 (Gross power out)	

Hrly Efficiency Equals: 36.98 Percent
Annual Efficiency Equals: 36.98 Percent

A.10-2

ECONOMIC & FINANCIAL ASSUMPTIONS

	All Inputs: 1985 Energy Cost	All Inputs: Annual Escal. Rate 1985-1990	All Inputs: Energy Price 1990	All Inputs: Annual Escal. Rate 1990-2010
GFC Elect En Fr (cts/kwh)	4.90	5.00	6.25	5.00
Fuel Oil($/Mil Btu)	4.20	0.00	4.20	5.00
Coal Price($/Ton)	35.00	0.00	35.00	5.00
Coal Heat Content (Btu/lb)	6719	NA	6719	NA
Coal Price($/Mil.Btu)	2.60	NA	2.60	NA
Steam Price & Esc Rate	4.00	5.00	5.11	5.00
O & M Esc Rate(% per Yr)	N.A.	5.00	N.A.	5.00

	1985 Existing	1990-2010	Percent of Equip	
Depreciation Method	ACRS	SL		
Depreciation Term(Years)				
Equipment	5.00	5.00	100.00	Percent
Utilities & Other	15.00	15.00	0.00	Percent
Investment Tax Credit	10.00 %	10.00 %		
Nonconventional Gas Annual Income Tax Credit ($/Mil. Btu)	0.70	0.00 (thru 1999)	5.00 Percent Esc Rate	
Investor's Annual Income Tax Rate (Combined Fed. & State)	50.00 %	50.00 %		

OWNERSHIP AND FINANCING STRUCTURE

Parameter	Assumption		
Percent Government Funding	70.00		<Input
Percent Private Funding	30.00		
Percent equity		33.00	<Input
Percent debt		67.00	
Interest rate		13.00	<Input
Loan term(years)		15	<Input
Constr int rate		13.00	<Input
Constr loan amount($Mil)		0.00	<Input
1st yr portion		0.10	<Input
2nd yr portion		0.40	<Input
3rd yr portion		0.50	<Input

A.10-3

COAL GASIFICATION-FUEL CECONSTRUCTION COST BREAKDOWN ($Mil) — SITE: TX — GFC SIZE:11 MW

FINANCIAL ANALYSIS ($MIL)	Item		5.00 % Esc Rate 1985$	1989$	Period When Costs Will Occur 1987	1988	1989
Item							
Revenues	Coal Hndlg & Gasif.	8.08			20.00	40.00	40.00
Electric	Gas Processing & Systems	7.52					
Thermal	Fuel Cell/Pwr Cond.	15.40					
Other	Thermal Mgt Syst.	3.66					
	Balance of Plant	1.54					
Subtotal	Subtotal		36.20	42.35	7.98	16.76	17.60
Operating Costs							
Fuel	Prototype Investment(Incl above)		0.00	0.00	0.00	0.00	0.00
O & M	Unique Site Costs, Incl Civil		3.50	4.09	0.77	1.62	1.70
Other							
Subtotal							
	General Conditions(Incl above)		0.00	0.00	0.00	0.00	0.00
OPERATING CASH FLOW							
	Design & Engineering(Incl above)		0.00	0.00	0.00	0.00	0.00
Debt Service: Principal	Freproduction Costs(Incl above)		1.00	1.22	0.41	0.41	0.41
Interest	Contingency at a Percent of:	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	TOTAL CONSTRUCTION COST:		40.70	47.65	9.16	18.79	19.71
Coverage Ratio							
	Land		0.00	0.00	0.00	0.00	0.00
Debt Svc Reserve							
Fuel Reserve	Other Special		0.72	0.88	0.29	0.29	0.29
RESIDUAL CASH FLOW							
Management Fee	TOTAL CONSTRUCTION + SPECIAL:		41.42	48.53	9.45	19.08	20.00
Tax Adjustments	OTHER CAPITAL COSTS						
Depr 5 yr Equip(SL) at							
Depr 15 yr Equip(SL) at	Working Capital						
Amort Startup Cost	Accts Receivable at	45 days		0.70	0.00	0.00	0.70
Principal Payment	Fuel Inventory at	15 days		0.12	0.00	0.00	0.12
Debt Svc Reserve	Other Inventory/Supplies			0.10	0.00	0.00	0.10
Taxable Income(Loss)	Accnts Payable at	10 days		(0.16)	0.00	0.00	(0.16)
Tax Saving or Payment(-)	Subtotal Working Capital			0.76	0.00	0.00	0.76
10 % Inv Tax Credit at							
Syngas Tax Credit at	Priv Fin Fees at Percent of:	8.00 %		1.18	0.00	0.00	1.18
Priv Capital Requirement	3rd Pty Own Fee at Percent of:	2.00 %		0.30	0.00	0.00	0.30
Priv Form Debt Financing	Other Expenses at Percent of:	2.00 %		0.30	0.00	0.00	0.30
NET CASH FLOW	Subtotal			1.77	0.00	0.00	1.77
Cumulative Cash Flow	TOTAL OTHER CAPITAL COSTS:			2.54	0.00	0.00	2.54
	CONSTRUCTION INTEREST:			0.00	0.00	0.00	0.00

GFC O & M COST BREAKDOWN($Mil)

	Escal.Rate:	5.00 % 1985$	1990$	1995$
Direct Labor	0.80			
Fringes @ 20%	0.16			
Contract Oper Fee	0.10			
Contract Maint.	0.22			
Chem & Supplies	0.18			
Spare Pts/Maint Sup	0.30			
Water & Site Utils	0.10			
Ash/Sludge Disp.	0.08			
Miscel	0.07			
Subtotal		2.01	2.56	3.27
Wheeling Charge		0.00	0.00	0.00
Fuel Cell Reloading Costs in 1985$ of	32 $/kw/yr	NA	NA	0.60
TOTAL O & M		2.01	2.56	3.87

OTHER ANNUAL EXPENSES

	1985$	1990$	1995$
Legal/Account.	0.00	0.00	0.00
Insurance	0.20	0.26	0.33
Prop. Taxes	0.00	0.00	0.00
TOTAL OTHER	0.20	0.26	0.33

COAL GASIFICATION-FUEL CE

FINANCIAL ANALYSIS ($MIL)

Item
Revenues
Electric
Thermal
Other
Subtotal
Operating Costs
Fuel
O & M
Other
Subtotal
OPERATING CASH FLOW
Debt Service: Principal
Interest
Subtotal
Coverage Ratio
Debt Svc Reserve
Fuel Reserve
RESIDUAL CASH FLOW
Management Fee
Tax Adjustments
Depr 5 yr Equip(SL) at
Depr 15 yr Equip(SL) at
Amort Startup Cost
Principal Payment
Debt Svc Reserve
Taxable Income Loss(-)
Tax Saving or Payment(-)
10 % Inv Tax Credit at
Syngas Tax Credit at
Priv Capital Requirement
Priv Perm Debt Financing
NET CASH FLOW
Cumulative Cash Flow

A.10-4

ENERGY PRODUCTION	In 1985 $	In 1990 $	In 1995 $
Net Amount of Electric Power Sold			
KWh(Mil)	78.77	78.77	84.32
Avg Monthly Max. MW	11.10	11.10	11.10
Avg Monthly Min. MW	11.10	11.10	11.10
Price(cts/kwh)	4.90	6.25	7.98
Price/KW/Mo	0.00	0.00	0.00
Annual Energy Revenues ($ Mil)	3.86	4.93	6.73
Annual Capacity Revenues ($ Mil)	0.00	0.00	0.00
Subtotal Elect Revs	3.86	4.93	6.73
Steam/Hot Water Sold			
Amount(Mil lbs)	144.05	144.05	154.20
Energy Content(Bil Btus)	151.83	151.83	162.53
Price per Unit ($/000 lb)	4.00	5.11	6.52
Thermal Revenues	0.58	0.74	1.00
Other Revenues: Esc Rate:	(Tars Based on	of retail fuel oil price)	NA percent
Tars/Oils	0.00	0.00	0.00
Sulfur	0.00	0.00	0.00
Ammonium Sulfate	0.00	0.00	0.00
Other Revs:	0.00	0.00	0.00
GFC Total Revs ($Mil)	4.44	5.66	7.73
Fuel Use			
Energy Content(Bil Btus)	1,137.49	1,137.49	1,137.49
Amount(Mil Tons)	84,647.18	84,647.18	84,647.18
Cost			
Fuel Cost($/ton)	35.00	35.00	44.67
Total Fuel Cost($ Mil)	2.96	2.96	3.78
O & M Costs	2.01	2.56	3.87
Other Annual Costs	0.20	0.26	0.33
GFC OPER COSTS ($Mil)	5.17	5.78	7.98

A.10-5

					GFC CF ANALYSIS		II SITE	Priv Eqty: 5.06	Priv Debt: 10.26	Tot Cap Costs of 51.07 times	= 30.00	33.00 Percent	67.00 Percent			
	[illegible]	[illegible]	[illegible]		Operating Period 1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Subtotal Yrs 1-10		2000
[illegible]	[illegible]	[illegible]	[illegible]		4.93	5.17	5.43	5.70	5.99	6.73	7.07	7.42	7.79	8.18	64.40		8.59
[illegible]	[illegible]	[illegible]	[illegible]		0.74	0.77	0.81	0.85	0.89	1.00	1.05	1.11	1.16	1.22	9.62		1.28
[illegible]	[illegible]	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00
[illegible]	[illegible]	0.00	0.00		5.66	5.94	6.24	6.55	6.88	7.73	8.12	8.53	8.95	9.40	74.02		9.87
Operating Costs																	
Fuel	0.00	0.00	0.00		2.96	3.11	3.27	3.43	3.60	3.78	3.97	4.17	4.38	4.60	37.26		4.83
O & M	0.00	0.00	0.00		2.56	2.69	2.82	2.96	3.11	3.87	4.07	4.27	4.48	4.71	35.54		4.94
Other	0.00	0.00	0.00		0.26	0.27	0.28	0.30	0.31	0.33	0.34	0.36	0.38	0.40	3.21		0.42
Subtotal	0.00	0.00	0.00		5.78	6.07	6.37	6.69	7.02	7.98	8.38	8.80	9.24	9.70	76.02		10.18
OPERATING CASH FLOW	0.00	0.00	0.00		(0.12)	(0.12)	(0.13)	(0.14)	(0.14)	(0.24)	(0.26)	(0.27)	(0.28)	(0.30)	(2.00)		(0.31)
Debt Service: Principal				15	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	6.84		0.68
Interest	0.00	0.00	0.00	Yrs	1.33	1.25	1.16	1.07	0.98	0.89	0.80	0.71	0.62	0.53	9.34		0.44
	(Constr	Loan	Interest)														
Subtotal	0.00	0.00	0.00		2.02	1.93	1.84	1.75	1.66	1.57	1.48	1.40	1.31	1.22	16.18		1.13
Coverage Ratio					(0.06)	(0.06)	(0.07)	(0.08)	(0.09)	(0.16)	(0.17)	(0.19)	(0.22)	(0.24)	(0.12)		(0.28)
Debt Svc Reserve					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00
Cumul Reserve					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N.A.		0.00
RESIDUAL CASH FLOW	0.00	0.00	0.00		(2.14)	(2.05)	(1.97)	(1.89)	(1.80)	(1.82)	(1.74)	(1.67)	(1.59)	(1.52)	(18.18)		(1.44)
Management Fee					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00
Tax Adjustments	(Private share | of equipment)															
Depr 5-yr Equip(SL) at	0.95	30.00	Percent)		2.72	2.72	2.72	2.72	2.72						13.58		
Depr 15-yr Equip(SL) at	1.00	30.00	Percent)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00
Amort Startup Cost	0.00	0.00	0.00														
Principal Payment					0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	6.84		0.68
Debt Svc Reserve					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00
Taxable Income/Loss(-)	0.00	0.00	0.00		(4.17)	(4.08)	(4.00)	(3.92)	(3.84)	(1.13)	(1.06)	(0.98)	(0.91)	(0.83)	(24.92)		(0.76)
Tax Saving or Payment(-)	0.00	0.00	0.00		2.08	2.04	2.00	1.96	1.92	0.57	0.53	0.49	0.45	0.42	12.46		0.38
10 % Inv Tax Credit at	30.00	Percent)	1.46														
Syngas Tax Credit at	0.00	$/Mil Btu	to 1999)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Priv Capital Requirement			(15.32)														
Priv Fern Debt Financing			10.26														
NET CASH FLOW	0.00	0.00	[illegible]	(3.60)	(0.05)	(0.01)	0.03	0.07	0.11	(1.25)	(1.21)	(1.18)	(1.14)	(1.10)	(1.06)	(1.03)	(0.99)
Cumulative Cash Flow	0.00	0.00	(3.60)		(3.65)	(3.66)	(3.63)	(3.56)	(3.44)	(4.70)	(5.91)	(7.08)	(8.22)	(9.32)	(10.38)	(11.41)	(12.40)

ROE= EPR Percent; NPV= EPR at a EPR Percent Disc Rate.
(Using a 10 Year Cash Stream)

END

2-81

DTIC