DOE/NASA/0031-80/2
NASA CR-159766
GE80ET0101

COGENERATION TECHNOLOGY ALTERNATIVES STUDY (CTAS)

GENERAL ELECTRIC COMPANY

FINAL REPORT

VOLUME II - ANALYTIC APPROACH

(NASA-CR-159766) COGENERATION TECHNOLOGY ALTERNATIVES STUDY (CTAS). VOLUME 2: ANALYTICAL APPROACH Final Report (NASA) 106 p HC A06/MF A01 CSCL 10B
N80-28859
Unclas
G3/44 23541

H.E. Gerlaugh, E.W. Hall, D.H. Brown,
R.R. Priestley, and W.F. Knightly

May, 1980

PREPARED FOR
National Aeronautics Space Administration
Lewis Research Center
Under Contract DEN3-31

FOR

U.S. Department of Energy
Office of Energy Technology
Division of Fossil Fuel Utilization

NOTICE

FOREWORD

The Cogeneration Technology Alternatives Study (CTAS) was performed by the National Aeronautics and Space Administration, Lewis Research Center, for the Department of Energy, Division of Fossil Fuel Utilization. CTAS was aimed at providing information which will assist the Department of Energy in establishing research and development funding priorities and emphasis in the area of advanced energy conversion system technology for advanced industrial cogeneration applications. CTAS included two Department of Energy-sponsored/NASA-contracted studies conducted in parallel by industrial teams along with analyses and evaluations by the National Aeronautics and Space Administration's Lewis Research Center.

This document describes the work conducted by the Energy Technology Operation of the General Electric Company under National Aeronautics and Space Administration contract DEN3-31.

The General Electric Company contractor report for the CTAS study is contained in six volumes:

Cogeneration Technology Alternatives Study (CTAS), General Electric Company Final Report

Title	DOE Number	NASA Contract Report No.
GE Vol. 1 - Summary Report	DOE/NASA/0031-80/1	CR-159765
Vol. 2 - Analytic Approach	DOE/NASA/0031-80/2	CR-159766
Vol. 3 - Industrial Process Characteristics	DOE/NASA-0031-80/3	CR-159767
Vol. 4 - Energy Conversion System Characteristics	DOE/NASA-0031-80/4	CR-159768
Vol. 5 - Cogeneration System Results	DOE/NASA-0031-80/5	CR-159769
Vol. 6 - Computer Data	DOE/NASA-0031-80/6	CR-159770

Members of the technical staffs of the following organizations have developed and provided information for the General Electric Company Cogeneration Technology Alternatives Study. The contributions of these people in time, effort, and knowledge are gratefully appreciated.

General Electric Company

- Corporate Research and Development
- Energy Systems Programs Department
- Energy Technology Operation
- Gas Turbine Division
- Industrial and Marine Steam Turbine Division
- Industrial Turbine Sales and Engineering Operation
- Installation and Service Engineering Business Division
- Space Division
- TEMPO
- Lamp Components Division

DeLaval

Dow Chemical

General Energy Associates

Institute of Gas Technology

J.E. Sirrine

Kaiser Engineers

N.A. Philips

This General Electric Company contractor report is one of a set of reports describing CTAS results. The other reports are the following:

Cogeneration Technology Alternatives Study (CTAS), Vol. I, Summary Report, NASA TM-81400.

Cogeneration Technology Alternatives Study (CTAS), Vol. II, Comparison and Evaluation of Results, NASA TM-81401

Cogeneration Technology Alternatives Study (CTAS) - United Technologies Corporation Final Report

Title	DOE Number	NASA Contract Report No.
UTC Vol. 1 - Summary	DOE/NASA/0030-80/1	CR-159759
Vol. 2 - Industrial Process Characteristics	DOE/NASA-0030-80/2	CR-159760
Vol. 3 - Energy Conversion System Characteristics	DOE/NASA-0030-80/3	CR-159761
Vol. 4 - Heat Sources, Balance of Plant and Auxiliary Systems	DOE/NASA-0030-80/4	CR-159762
Vol. 5 - Analytic Approach & Results	DOE/NASA-0030-80/5	CR-159763
Vol. 6 - Computer Data	DOE/NASA-0030-80/6	CR-1597[illegible]

TABLE OF CONTENTS

Volume I - Summary Report

TABLE OF CONTENTS (Cont'd)

Volume I - Summary Report (Cont'd)

TABLE OF CONTENTS (Cont'd)

Volume I - Summary Report (Cont'd)

TABLE OF CONTENTS

Volume II - Analytical Approach

Volume III - Industrial Process Characteristics

TABLE OF CONTENTS

Volume IV - Energy Conversion System Characteristics

Volume V - Cogeneration System Results

TABLE OF CONTENTS

Volume V - Cogeneration System Results (Cont'd)

Volume VI - Computer Data

LIST OF ILLUSTRATIONS

Volume II

LIST OF ILLUSTRATIONS (Cont'd)

Volume II

LIST OF TABLES

Volume II

LIST OF TABLES (Cont'd)

Volume II

Section 1

SUMMARY

Cogeneration systems in industry simultaneously generate electric power and thermal energy. Conventional nocogeneration installations use separate boilers or furnaces to produce the required thermal energy and purchase electric power from a utility which rejects heat to the outside environment. Cogeneration systems offer significant savings in fuel but their wide spread implementation by industry has been generally limited by economics and institutional and regulatory factors. Because of potential savings to the nation, the Department of Energy, Office of Energy Technology sponsored the Cogeneration Technology Alternatives Study (CTAS). The National Aeronautics & Space Administration, Lewis Research Center, conducted CTAS for the Department of Energy with the support of Jet Propulsion Laboratory and study contracts with the General Electric Company and the United Technologies Corporation.

OBJECTIVES

The objective of the CTAS is to determine if advanced technology cogeneration systems have significant payoff over current cogeneration systems which could result in more widespread implementation in industry and to determine which advanced cogeneration technologies warrant major research and development efforts.

Specifically, the objectives of CTAS are:

1. Identify and evaluate the most attractive advanced energy conversion systems for implementation in industrial cogeneration systems for the 1985-2000 time period which permit use of coal and coal-derived fuels.

2. Quantify and assess the advantages of using advanced technology systems in industrial cogeneration.

SCOPE

The following nine energy conversion system (ECS) types were evaluated in CTAS:

1. Steam turbine
2. Diesel engines
3. Open-cycle gas turbines
4. Combined gas turbine/steam turbine cycles
5. Stirling engines
6. Closed-cycle gas turbines
7. Phosphoric acid fuel cells
8. Molten carbonate fuel cells
9. Thermionics

In the advanced technology systems variations in temperature, pressure ratio, heat exchanger effectiveness and other changes to a basic cycle were made to determine desirable parameters for many of the advanced systems. Since coal and coal-derived fuels were emphasized, atmospheric and pressurized fluid bed and integrated gasifiers were evaluated.

For comparison, currently available non-condensing steam turbines with coal-fired boilers and flue gas desulfurization, gas turbines with heat recovery steam generators burning residual and distillate petroleum fuel and medium speed diesels burning petroleum distillate fuel were used as a basis of comparison with the advanced technologies.

In selecting the cogeneration energy conversion system configurations to be evaluated, primary emphasis was placed on system concepts fired by coal and coal-derived fuels. Economic evaluations were based on industrial ownership of the cogeneration system. Solutions to institutional and regulatory problems which impact the use of cogeneration were not addressed in this study.

Over fifty industrial processes and a similar number of state-of-the-art and advanced technology cogeneration systems were matched by

General Electric to evaluate their comparative performance. The industrial processes were selected as potentially suited to cogeneration primarily from the six largest energy consuming sectors in the nation. Advanced and current technology cogeneration energy conversion systems, which could be made commercially available in the 1985 to 2000 year time frame, were defined on a consistent basis. These processes and systems were matched to determine their effectiveness in reducing fuel requirements, saving petroleum, cutting the annual costs of supplying energy, reducing emissions, and improving the industry's return on investment.

Detailed data were gathered on 80 process plants with major emphasis on the following industry sectors:

1. SIC20 - Food and Kindred Products
2. SIC26 - Pulp and Paper Products
3. SIC28 - Chemicals
4. SIC29 - Petroleum Refineries
5. SIC32 - Stone, Clay and Glass
6. SIC33 - Primary Metals

In addition, four processes were selected from SIC22 - Textile Mill Products and SIC24 - Lumber and Wood Products. The industry data includes current fuel types, peak and average process temperature and heat requirements, plant operation in hours per year, waste fuel availability, electric power requirements, projected growth rates to the year 2000, and other factors needed in evaluating cogeneration systems. From this data approximately fifty plants were selected on the basis of: energy consumption, suitability for cogeneration, availability of data, diversity of types such as temperatures, load factors, etc., and range of ratio of process power over process heat requirements.

Based on the industrial process requirements and the ECS characteristics, the performance and capital cost of each cogeneration system and its annual cost, including fuel and operating costs, were compared with nocogeneration systems as currently used. The ECS was either sized to match the process heat requirements (heat match) and electricity either bought or sold or sized to match the electric power (power match) in which case an auxiliary boiler is usually required to supply the remaining heat needs. Cases where there was excess heat when matching the power were excluded from the study. With the fuel variations studied there are 51 ECS/fuel combinations and over 50 processes to be potentially matched in both heat and power resulting in a total of approximately 5000 matches calculated. Some matches were excluded for various reasons; e.g., the ECS out of temperature range or excess heat produced, resulting in approximately 3100 matches carried through the economic evaluation. Results from these matches were extrapolated to the national level to provide additional perspective on the comparison of advanced systems.

RESULTS

A comparison of the results for these specific matches lead to the following observations on the various conversion technologies:

1. The atmospheric and pressurized fluidized bed steam turbine systems give payoff compared to conventional boiler with flue gas desulfurization-steam turbine systems which already appear attractive in low and medium power over heat ratio industrial processes.

2. Open-cycle gas turbine and combined gas turbine/steam turbine systems are well suited to medium and high power over heat ratio industrial processes based on the fuel prices used in CTAS. Regenerative and steam injected gas turbines do not appear to have as much potential as the above systems, based on GE results. Solving low grade coal-derived fuel and NO_x emission problems should be emphasized. There is payoff in these advanced systems for increasing firing temperature.

3. The closed-cycle gas turbine systems studied by GE have higher capital cost and poorer performance than the more promising technologies.

4. Combined-cycle molten carbonate fuel cell and gas turbine/steam turbine cycles using integrated gasifier, and heat matched to medium and high power over heat ratio industrial processes and exporting surplus power to the utility give high fuel savings. Because of their high capital cost, these systems may be more suited to utility or joint utility-industry ownership.

5. Distillate-fired fuel cells did not appear attractive because of their poor economics due to the low effectiveness of the cycle configurations studied by GE and the higher price of distillate fuel.

6. The very high power over heat ratio and moderate fuel effectiveness characteristics of diesel engines limit their industrial cogeneration applications. Development of an open cycle heat pump to increase use of jacket water for additional process heat would increase their range of potential applications.

To determine the effect of the national fuel consumption and growth rates of the various industrial processes together with their distribution of power to heat ratios, process steam temperatures and load factors, each energy conversion system was assumed implemented without competition and its national fuel, emissions, and cost of energy estimated. In this calculation it was assumed that the total savings possible were due to implementing the cogeneration systems in new plants added because of needed growth in capacity or to replace old, unserviceable process boilers in the period from 1985 to 1990. Also, only those cogeneration systems giving an energy cost savings compared with nocogeneration were included in estimating the national savings. Observations on these results are:

1. There are significant fuel, emissions, and energy cost savings realized by pursuing development of some of the advanced technologies.

2. The greatest payoff when both fuel energy savings and economics are considered lies in the steam turbine systems using atmospheric and pressurized fluidized beds. In a comparison of the national fuel and energy cost savings for heat matched cases, the atmospheric fluidized bed showed an 11% increase in fuel saved and 60% additional savings in levelized annual energy cost savings over steam turbine systems using conventional boilers with flue gas desulfurization whose fuel savings would be, if implemented, 0.84 quads/year and cost savings \$1.9 billion/year. The same comparison for the pressurized fluidized bed showed a 73% increase in fuel savings and a 29% increase in energy cost savings.

3. Open-cycle gas turbines and combined-cycles have less wide application but offer significant savings. The advanced residual-fired open-cycle gas turbine with heat recovery steam generator and firing temperature of 2200 F were estimated to have a potential national saving of 39% fuel and 27% energy cost compared to currently available residual-fired gas turbines whose fuel savings would be, if implemented, 0.18 quads/year and cost savings \$0.33 billions/year.

4. Fuel and energy cost savings are several times higher when the cogeneration systems are heat matched and surplus power exported to the utility than when the systems are power matched.

Other important observations made during the course of performing CTAS were:

1. Comparison of the cogeneration systems which are heat matched and usually exporting power to the utility with the power matched systems shows the systems exporting power have a much higher energy savings, often reaching two to five times the power match cases. In the past, with few exceptions, cogeneration systems have been matched to the industrial process so as not to export power because of numerous load management, reliability, regulatory, economic and institutional reasons. A concerted effort is now underway by a number of government agencies, industries, and utilities to overcome these impediments and it should be encouraged if the nation is to receive the full potential of industrial cogeneration.

2. The economics of industrially owned cogeneration plants are very sensitive to fuel and electric power costs or revenues. Increased price differentials between liquid fuels and coal would make integrated gasifier fuel cell or combined-cycle systems attractive for high power over heat industrial processes.

3. Almost 75% of the fuel consumed by industrial processes studied in CTAS, which are representative of the national industrial distribution, have power over heat ratios less than 0.25. As a result energy conversion systems, such as the steam turbine using the atmospheric or pressurized fluidized bed, which exhibit good performance and economics when heat matched in the low power over heat ratio range, give the largest national savings.

Section 2

INTRODUCTION

BACKGROUND

Cogeneration is broadly defined as the simultaneous production of electricity or shaft power and useful thermal energy. Industrial cogeneration in the context of this study refers specifically to the simultaneous production of electricity and process steam or hot water at an individual industrial plant site. A number of studies addressing various aspects of cogeneration as applied to industry have been made in the last few years. Most of these focused on the potential benefits of the cogeneration concept. CTAS, however, was concerned exclusively with providing technical, cost, and economic comparisons of advanced technology systems with each other and with currently available technologies as applied to industrial processes rather than the merits of the concept of cogeneration.

While recognizing that institutional and regulatory factors strongly impact the feasibility of widespread implementation of cogeneration, the CTAS did not attempt to investigate, provide solutions, or limit the technologies evaluated because of these factors. For example, cogeneration systems which were matched to provide the required industrial process heat and export excess power to the utilities were evaluated (although this has usually not been the practice in the past) as well as systems matched to provide only the amount of power required by the process. Also, no attempt was made to modify the industrial processes to make them more suitable for cogeneration. The processes were defined to be representative of practices to be employed in the 1985 to 2000 time frame.

The cogeneration concept has been applied in a limited fashion to power plants since the turn of the century. Their principal advantage is that they offer a significant saving in fuel over the conventional method of supplying the energy requirements of an industrial plant by purchasing power from the utility and obtaining steam from an on-site process boiler.

The saving in fuel by a cogeneration system can be seen by taking a simple example of an industrial process requiring 20 units of power and 100 units of process steam energy. A steam turbine cogeneration system (assuming it is perfectly matched, which is rarely the case) can provide these energy needs with fuel effectiveness or power plus heat over input fuel ratio of 0.85 resulting in a fuel input of 141 units. In the conventional nocogeneration system the utility with an efficiency of 33% requires 60 units of fuel to produce the 20 units of power and the process boiler with an efficiency of 85% requires 118 units of fuel to produce the required steam making a total fuel required of 178 units. Thus the cogeneration system has a fuel saved ratio of 37 over 178 or 21%.

In spite of this advantage of saving significant amounts of fuel, the percentage of industrial power generated by cogeneration, rather than being purchased from a utility, has steadily dropped until it is now less than 5% of the total industrial power consumed. Why has this happened? The answer is primarily one of economics. The utilities with their mix in ages and capital cost of plants, relative low cost of fuel, steadily improving efficiency and increasing size of power plants all made it possible to offer industrial power at rates more attractive than industry could produce it themselves in new cogeneration plants.

Now with long term prospects of fuel prices increasing more rapidly than capital costs, the increased use of waste fuels by industry and the need to conserve scarce fuels, the fuel savings advantage of cogenerating will lead to its wider implementation. The CTAS was sponsored by the US Department of Energy to obtain the input needed to establish R&D funding priorities for advanced energy conversion systems which could be used in industrial cogeneration applications. Many issues, technical, institutional and regulatory, need to be addressed if industrial cogeneration is to realize its full potential benefits to the nation. However, the CTAS concentrated on one portion of these issues, namely, to determine from a technical and economic standpoint the payoff of advanced technologies compared to currently available equipments in increasing the implementation of cogeneration by industry.

OBJECTIVE, OVERALL SCOPE, AND METHODOLOGY

The objectives of the CTAS effort were to:

1. Identify and evaluate the most attractive advanced conversion systems for implementation in industrial cogeneration systems for the 1985-2000 time period which permit increased use of coal or coal-derived fuels.

2. Quantify and assess the advantages of using advanced technology systems in industrial cogeneration.

To select the most attractive advanced cogeneration energy conversion systems incorporating the nine technologies to be studied in the CTAS, a large number of configurations and cycle variations were identified and screened for detail study. The systems selected showed desirable cogeneration characteristics and the capability of being developed for commercialization in the 1985 to 2000 year time frame. The advanced energy conversion system-fuel combinations selected for study are shown in Table 2-1 and the currently available systems used as a basis of comparison are shown in Table 2-2. These energy conversion systems were then heat matched and power matched to over 50 specific industrial processes selected primarily from the six major energy consuming industrial sectors of food; paper and pulp; chemicals; petroleum refineries; stone, clay and glass; and primary metals. Several processes were also included from wood products and textiles.

On each of these matches analyses were performed to evaluate and compare the advanced technology systems on such factors as:

- Fuel Energy Saved
- Flexibility in Fuel Use

Table 2-1

GE-CTAS ADVANCED TECHNOLOGY COGENERATION ENERGY CONVERSION SYSTEMS MATCHED TO FUELS

	Coal	Coal Derived Liquids Residual	Coal Derived Liquids Distillate
Steam Turbine	AFB*	Yes	---
Pressurized Fluid Bed	Yes	---	---
Gas Turbine			
Open Cycle-HRSG	---	Yes	Yes
Regenerative	---	---	Yes
Steam Injected	---	Yes	---
Combined Gas Turbine/Steam Turbine Cycle			
Liquid Fired	---	Yes	---
Integrated Gasifier Combined Cycle	Yes	---	---
Closed Cycle-Helium Gas Turbine	AFB	---	---
Thermionic			
HRSG	FGD*	Yes	---
Steam Turbine Bottomed	FGD	Yes	---
Stirling	FGD	Yes	Yes
Diesels			
Medium Speed	---	Yes	Yes
Heat Pump	---	Yes	Yes
Phosphoric Acid Fuel Cell Reformer	---	---	Yes
Molten Carbonate Fuel Cell			
Reformer	---	---	Yes
Integrated Gasifier			
HRSG	Yes	---	---
Steam Turbine Bottoming	Yes	---	---

* AFB - Atmospheric Fluidized Bed
FGD - Flue Gas Desulfurization

Table 2-2

GE-CTAS STATE OF ART COGENERATION ENERGY CONVERSION MATCHED TO FUELS

	Coal	Petroleum Derived Residual	Petroleum Derived Distillate
Steam Turbine	FGD	Yes	---
Gas Turbine	---	Yes	Yes
Diesel	---	Yes	Yes

- Capital Costs
- Return on Investment and Annual Energy Cost Saved
- Emissions
- Applicability to a Number of Industries.

These matches were evaluated, both on a specific process site basis, and on a national level where it was assumed that each ECS is applied without competition nationwide to all new applicable industrial plants.

Because of the many different types of conversion systems studied and myriad of possible combinations of conversion system and process options, key features of the study were:

- The use of consistent and simplified but realistic characterizations of cogeneration systems
- Use of the computer to match the systems and evaluate the characteristics of the matches.

A major effort was made to strive for consistency in the performance, capital cost, emissions, and installation requirements of the many advanced cogeneration energy conversion systems. This was accomplished first by NASA-LeRC establishing a uniform set of study groundrules for selection and characterization of the ECS's and industrial processes, calculation of fuel and emissions saved and analysis of economic parameters such as levelized annual energy cost and return on investment. These groundrules and assumptions are described in Section 3. Second, in organizing the study, as shown in Figure 2-1, GE made a small group called Cogeneration Systems Technology responsible for establishing the configuration of all the ECS's and obtaining consistent performance, cost and emission characteristics for the advanced components from the GE organizations or subcontractors developing these components. This team, using a standard set of models for the remaining subsystems or components, then prepared the performance, capital costs, and other characteristics of the overall ECS's. As a result, any component or subsystem, such as fuel storage and handling, heat recovery steam generator or steam turbine, appearing in

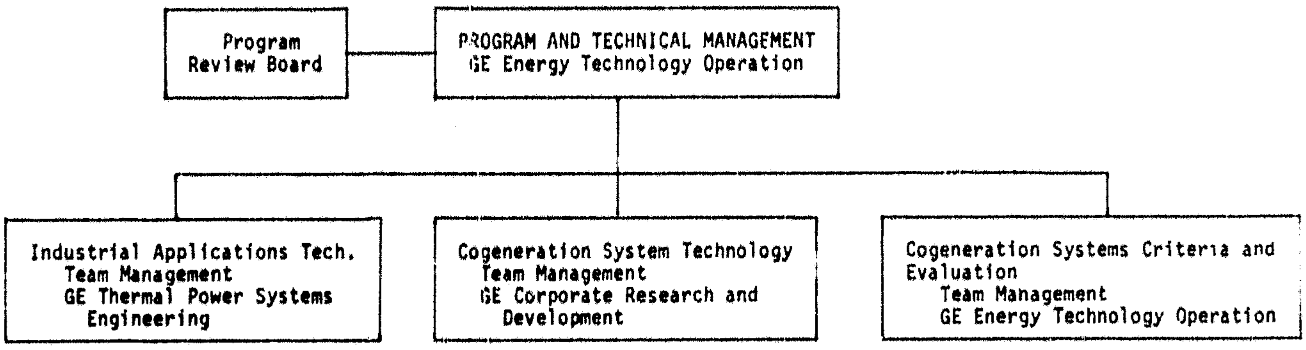


Figure 2-1. GE-CTAS Project Organization

more than one type ECS is based on the same model. This method reduces the area of possible inconsistency to the advanced component which, in many ECS's, is a small fraction of the total system. The characterization of the ECS's is described in Sections 5 and 6. The functions of obtaining consistent data on industrial processes from the industrial A&E subcontractors was the responsibility of the Industrial Applications Technology group and is described in Section 4. Matching of the ECS's and processes and making the overall performance and economic evaluations and comparisons was the responsibility of Cogeneration Systems Criteria and Evaluation. The methodology of matching the cogeneration systems is detailed in Section 8, the results of the performance analysis in Section 9, economic analysis in Section 10, the national savings in Section 11, and overall results and observations in Section 12.

Section 3

ASSUMPTIONS AND APPROACH

GROUNDRULES AND ASSUMPTIONS

Because of the scope and complexity of the CTAS and the need for a degree of consistency between the two parallel contractors, a number of groundrules were specified by NASA-LeRC. In the listing show below these groundrules are grouped as applying principally to definition of the industrial processes; energy conversion system (ECS) performance, capital cost or emissions; matching the ECS to the industrial processes; economic analysis of matches; and the national savings when cogeneration is implemented versus nocogeneration. In establishing many of these groundrules NASA-LeRC obtained recommendations from DOE and the contractors. In addition to the common groundrules specified by NASA-LeRC, assumptions were made by the GE contractor. These are identified as (GE).

Industrial Process Characteristics

In defining the more than 50 industrial processes to be studied in CTAS the following guidelines and groundrules were followed:

1. Processes be representative of the state-of-the-art which would be installed in new plants built during the 1985 to 2000 year time frame.

2. Represent a large national energy consumption and potential for cogeneration (a principal criterion).

3. Emphasize industrial processes requiring process steam and hot water. (GE)

4. Use average yearly capacity factors or operating hours and during the operating times use average electrical load and process heat requirements. (GE)

Definition of Energy Conversion Systems (ECS)

During the selection and definition of the performance, capital costs, and other characteristics of the energy conversion systems the following groundrules were used:

1. Advanced energy conversion systems were studied which could be commercially available in the 1985 to 2000 time frame after an intensive R&D program.

2. Emphasize energy conversion systems fueled by coal and coal derived liquids with the properties shown in Table 3-1.

3. Design and cost the ECS's to include cleanup equipment required to meet the emission requirements shown in Table 3-2. When uncertainty was encountered as to how the emission level specified could be met, the deficiency was included as a required development and a rough cost estimate included in the capital costs.

4. Assume boiler and heat recovery steam generators (HRSG) to have a boiler feedwater temperature of $170^{o}F$. (GE)

5. Set exhaust stack temperatures at $300^{o}F$ or higher if required by pinch point requirements, except for fuel cells. (GE)

6. Assume all process and auxiliary boiler efficiencies equal 85%. (GE)

7. All bottoming turbines; e.g., in the combined-cycle fuel cell and thermionic are 1465 psia/$1000^{o}F$ turbines. (GE)

8. Do not employ supplemental firing of heat recovery steam-generators. (GE)

9. Cost commercially available components, islands and balance of plant items common to more than one ECS using the same performance-cost model; e.g., steam turbines, boilers, heat recovery steam-generators, fuel storage and handling, structures, etc.

Table 3-1

LIQUID FUELS SPECIFICATIONS

	Petroleum #2 Distillate	Petroleum #5 Residual	Coal-Derived #2 Distillate	Coal-Derived #5 Residual
Sulfur, % wt.	.5	.7	.5	.7
Nitrogen, % wt.	.06	.25	.8 nominal	1.0 nominal
Hydrogen, % wt.	12.7	10.8	9.5 nominal	8.5 nominal
Ash, % wt.	--	.03	.06	.26
Specific Gravity	.85	.96	.95	1.05
Viscosity, Centistokes at 100° F	2.5	40	2.5	40
Boiling Range, °F 90% pts.	430-675	500-800	430-675	500-800
Cetane No.	45	40	45	40
Trace Elements, ppm wt. (order of magnitude)				
Vanadium	≤ .5	30	.5	2
Sodium & Potassium	≤ .5	50	1	20
Calcium	≤1.0	5	2	5
Lead	≤ .5	5	1	5
Iron	--	--	30	30
Titanium	--	--	20	50
High (Gross) Heating Value, Btu/lb	19,350	18,500	17,700	17,000

Table 3-2

EMISSION LIMITATION GUIDELINES

Emissions from energy conversion systems or auxiliary furnaces shall not exceed the values shown below.

(All units in lbs/10^6 Btu Heat Input)

Pollutant	Fuel Type: Solid	Liquid	Gaseous(a)
NO_x	0.7	(b)	0.2
SO_x	1.2	0.8	0.2
Particulates	0.1	0.1	0.1
Smoke	20 SAE number	20 SAE number	20 SAE number

(a) For systems or auxiliary furnaces using LBtu gas produced on-site from coal, the solid fuel limitation shall apply.

(b) The NO_x limitations for the various liquid fuels is keyed to the nitrogen content in the fuel as follows:

Liquid Fuel	NO_x
Petroleum Distillate	0.4 lbs/10^6 Btu heat input
Petroleum Residual Fuel	0.5
Coal-Derived Distillate	0.5
Coal-Derived Residual Fuel	0.5

Matching of Energy Conversion Systems (ECS) to Industrial Processes

When the ECS is matched to an industrial process the following groundrules were used:

1. Match the ECS in two ways, (1) match the power requirements of the process, and (2) match the process heat requirements of the process. In the power match, if additional heat is required, an auxiliary boiler is added or, if excess process heat is produced by the ECS, the match is dropped from further consideration (GE). In the ECS heat match, if the ECS cannot supply the process power requirements, the needed power is purchased from the utility. If excess power is generated by the ECS, it is exported to the utility for revenue.

2. Nocogeneration case assumptions:

   - Place principal emphasis on a coal-fired nocogeneration process boiler. (GE)

   - Process boiler efficiency - 85%. (GE)

   - Process boiler type and fuel sized as follows: (GE)

     $<30 \times 10^6$ Btu/yr heat output, petroleum or coal residual

     $30 \times 10^6 - 100 \times 10^6$ Btu/hr heat output, coal AFB

     $>100 \times 10^6$ Btu/hr heat output, coal, flue gas desulfurization

   - Waste or by-product fuels converted to heat at various efficiencies depending on type of waste fuel. Fossil fuel and by-product fuel assumed to be fired in same boiler. (GE)

   - Utility fuel-electric efficiency - 32% including transmission and distribution losses.

   - Process boiler emissions are:

	$lb/10^6$ Btu Fired		
	NO_x	SO_2	Part.
petroleum residual-fired boiler	0.22	0.75	0.016
coal-derived residual-fired boiler	0.5	0.8	0.1
AFB coal	0.27	1.2	0.1

   - Emissions due to burning ste or by-product fuels are not included. (GE)

3. Cogeneration case assumptions:

- Approximate the process steam saturation temperature used to determine the performance parameters of a cogeneration system by using the peak temperature in systems consisting of a heat recovery steam-generator to supply process steam. When the process steam is extracted from a steam turbine, the weighted average temperature of multiple process steam conditions is used.

- In the fuel saved by type calculations assume that the mix of utility fuel displaced by cogenerated power is 23% gas and oil and 77% coal. Utility emissions are set equal to specifications shown in Table 3-2.

- Auxiliary boiler efficiency - 85%. (GE)

- Waste or by-product fuels combustible in all systems that use coal except for systems with coal gasifier.

- Emissions due to burning waste or by-product fuels are not included. (GE)

- Minimum size of energy conversion system not observed when calculating fuel energy or emissions savings. (GE)

Economic Evaluation of Energy Conversion System-Industrial Process Matches

In the economic analysis the following groundrules and values of parameters were used:

1. In the calculation of return on investment (ROI) and levelized annual energy cost (LAEC) use the detailed methodology prescribed in NASA "Groundrules for CTAS Economic Analysis".

2. All economic calculations are made on an inflation-free basis. (Sometimes this is called using constant dollar analysis and in this report all results are in 1978 dollars. Escalation of particular expense or revenue above the inflation rate is included).

3. Assume all ECS plants are 100% industrially-owned.

4. Use values of specific parameters in the economic analysis as shown in Table 3-3.

5. When the maximum practical size of a component is exceeded by the ECS plant size requirement, use the minimum number of equal size units which will not exceed the maximum size allowed for the component. (GE)

Table 3-3

ECONOMIC ANALYSIS GROUNDRULES
(All Costs are in 1978 Constant Dollars)

Factor	Value
Annual Inflation Rate	0
Cost of Debt (before taxes) Above Inflation	3%
Fraction of Debt in Capital	30%
Cost of Preferred Equity Above Inflation	-
Fraction of Preferred Equity in Capital	0
Cost of Common Equity Above Inflation	7%
Federal & State Income Tax Rate	50%
Tax Depreciation Method	Sum of Years Digits
Tax Depreciation Life	15 Years
Salvage Value	0
Investment Tax Credit	10%
Local Real Estate Taxes and Insurance	3%
Useful Life of Investment	30 Years
First Full Year of Operation	1990
Capital Cost Escalation Rate Above Inflation	0
Cost of Fuels, Power & Expendables for 1985 in 1978 $'s	
Coal	$ 1.80/10^6 Btu
Distillate Oil (Petroleum or Coal-Derived)	$ 3.80/10^6 Btu
Residual Oil (Petroleum or Coal-Derived)	$ 3.10/10^6 Btu
Natural Gas	$ 2.40/10^6 Btu
Purchased Power	$ 0.033/kWh
Exported Power	0.6 x purchase power rate
Limestone	$10.00/Ton
Dolomite	$12.50/Ton
Escalation of Fuels & Power Above Inflation	
Coal	1%
Distillate Oil (Petroleum or Coal-Derived)	1%
Residual Oil (Petroleum or Coal-Derived)	1%
Natural Gas	4.6% (1985-2000) 1.0% (2000-)
Purchased & Exported Power	1%
Limestone	0
Dolomite	0

National Savings Analysis

In estimating indicators of the nationwide fuel and emissions savings to permit comparison of the various types of ECS's, the following groundrules were followed:

1. Potential cogeneration applications consist of new industrial process plants built from 1985 to 2000 because of the need for additional capacity or to replace old or obsolete plants. (GE)

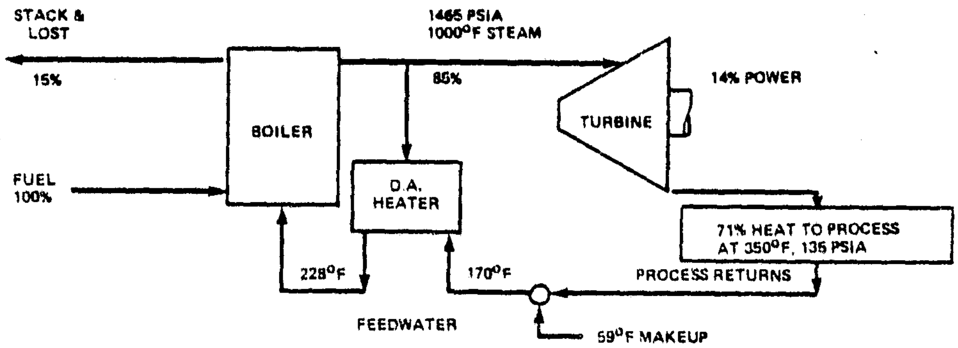
2. In comparing ECS's on a national level, assume each ECS is implemented independently of all other ECS's.

APPROACH USED AND FACTORS CONSIDERED

In the following sections the analysis used to characterize the energy conversion systems performance and capital cost, their matching to the industrial process and the evaluation of their matched performance and economics will be described.

Energy Conversion System Characterization

The convention for describing process heat requirements has been the expression of the steam flow requirement in pounds per hour and the gage pressure at which that steam condenses. A steam turbine cogeneration system is illustrated in Figure 3-1 to serve as an example of the methodology used in this study. The boiler feedwater is brought to 228 F by a combination of makeup water at 59 F, process return water, and steam supply to the deaerator heater. For 100% fuel energy fired, of the order of 15% is accounted in stack loss and other system losses. The 85% of useful energy results in 14% electric power produced and 71% heat to process. The process temperature level is described by its condensing steam pressure, 135 psi absolute, or conventionally 120 psi gage.



VARIABLE: T PROCESS, EXHAUST PRESSURE

THROTTLE	EFFICIENCY	MW RANGE
1465 PSIA, 1000°F	80%	7.5 – 100
865 PSIA, 825°F	78%	5 – 50

ADVANCED ART: TURBINE GENERATOR NONE
STEAM BOILER ATMOSPHERIC FLUIDIZED BEDS

Figure 3-1. Steam Turbine Cogenerator

If the steam turbine inlet conditions (Figure 3-1) were held constant at 1465 psia, 1000 F and the steam was expanded to atmospheric pressure, then a greater amount of turbine output would be achieved per pound of steam flow. Moreover, the preponderant temperature for the condensation of the exhaust steam would be 212 F. Now, if that same steam were expanded to 15 psi gage, less work would be produced, and the exhaust steam would have a predominant temperature of 250 F.

The characteristic of this steam turbine system is shown in Figure 3-2 for a non-condensing steam turbine cogeneration system with an 80% efficient steam turbine, an 85% efficient boiler and boiler feed at 170 F. Steam or process heat temperature, power, and heat to process all vary as steam turbine outlet pressure is varied. All parameters are expressed as fractions of the fuel-fired higher heating value. For the steam turbine

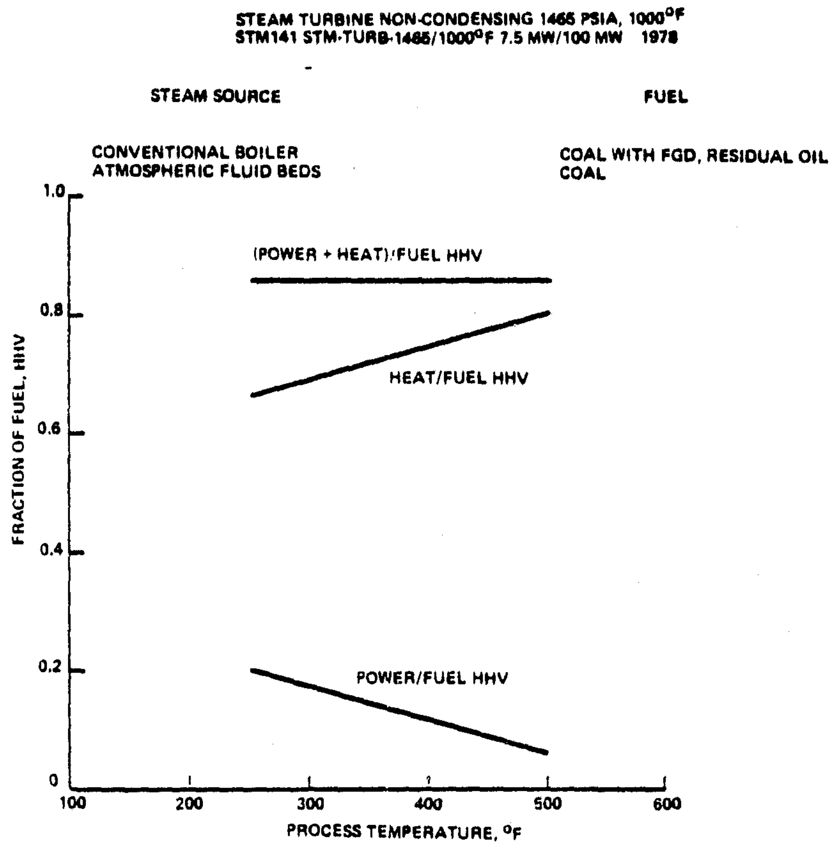


Figure 3-2. Energy Conversion System Characteristic

the characteristics for power generated and for heat to process are found to be close to linear as related to process temperature. The sum of power generated and heat to process was 0.85 at all process temperatures, and equals one minus the energy that was not made useful.

The synthesis of these cogeneration characteristics is readily understood in the context of the steam turbine cogenerator illustrated in Figure 3-1. In Figure 3-3 the turbine and the process are shown in the context of the effect of one pound of steam upon them. Evaluations start with assignment of the process temperature, TPRO. The steam tables then provide the saturation pressure for the process - that is the back pressure on the steam turbine. The isentropic steam turbine expansion work can then be found; when multiplied by the steam turbine efficiency of 80% the result is the turbine output expressed as Btu per pound of steam flow. The remainder of the steam energy span of 1353 Btu per pound (from inlet at 1491 to process return at 138) would be realized as process heat. The data for a range of process temperatures from 212 F to 500 F were calculated. These data were then correlated by a quadratic least squares fit to the process temperature:

$$\text{Btu/lb Turbine Output} = 531.85 - 0.856 * \text{TPRO} - 80 * \left(\frac{\text{TPRO}}{1000}\right)^2$$

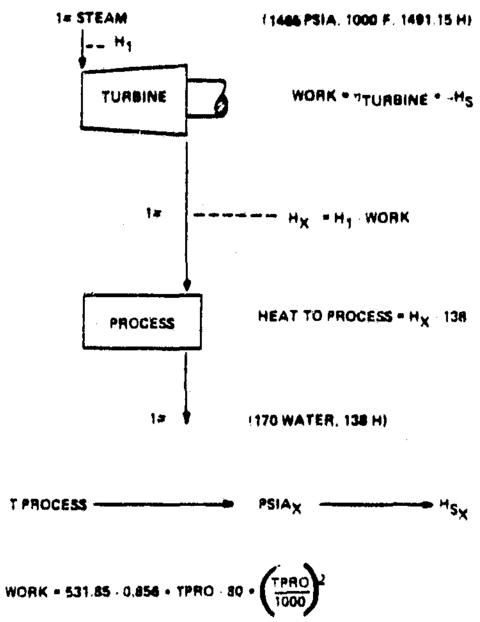


Figure 3-3. Synthesis of Steam Turbine Cogeneration Characteristic

Each energy conversion system has its own characterizing curves and constants and a range of power generation over which it can be applied. These characterizations and system parameters are presented in a series of charts for each ECS in Volume IV of the General Electric final report.

Steam Turbine ECS

Figure 3-1 shows a schematic of the steam turbine applied to cogeneration. The turbine is non-condensing since the entire exhaust steam flow is utilized as process steam. A condensing section on a cogeneration turbine would produce power at a lower efficiency than a utility steam turbine and would appreciably reduce the fraction of fuel energy realized in power and heat to process. The configuration of the process returns, makeup water, and feedwater system are detailed in Figure 3-1. The turbine costs were evaluated for a single automatic extraction non-condensing steam turbine. This selection provides for process steam at two levels where required, or alternatively for a feedwater heater and auxiliary steam main for the powerhouse. Two inlet throttle conditions were considered. The highest economic pressure level of 1465 psia was designated with the highest normal superheat of 1000 F. These conditions mandate full demineralization of the boiler feedwater. The lower throttle condition of 865 psia, 825 F was selected to avoid a large cost increment for high alloy steel superheaters and to use the least expensive feedwater treatment. The assigned steam turbine-generator efficiencies are within two points of the range of efficiencies appropriate to the power range of the units.

The span of steam turbine ratings selected and the chosen steam conditions represent the envelope of economic choices as evidenced by the industrial turbine application experience of General Electric. More advanced conditions have been available but the cost increments could not be justified.

Figures 3-2 and 3-3 show the cogeneration characteristics for the steam turbine system.

Capital Cost Methodology

It is essential that there is consistency among the capital cost estimates if economic distinctions are to be made. Three distince data sources were used for the basis of costs in this study. Considerable effort was made to assure that the final cost assemblage for each energy conversion system represented a complete power plant, including all of the required elements of an industrial power house, and was consistent with all the others regardless of the source of data.

A major part of the cost of most systems is in components that are parts of many other systems. The cost of each component; e.g., a steam turbine, was based on the same methodology regardless of which ECS it was a part of. This method of costing helped to assure consistency between ECS's. The cost of a diesel engine or a small gas turbine, for example, to be installed in a purchaser's building on purchaser provided foundations and connected at purchaser's expense is just a small part of a new "green field" industrial power house with all prerequisite services and amenitites. For example, a diesel-generator adapted for cogeneration costs 210 dollars per kilowatt; however, completely installed the cost is 540 dollars per kilowatt, and the entire power house installation would cost 1000 dollars per kilowatt. The complete power house installed costs are reported in this study.

To corroborate the level and order of these complete plant costs, comparisons were made to more detailed evaluations of large installations such as utility power plants. Corroboration was found in every instance.

Explicit cost evaluation requires detailed build-up to provide confidence in the final estimates. Where only cost estimates are required, there are techniques that permit extrapolation from data sources of high confidence with good assurance that the new data is of a high level of fidelity. These techniques are used for individual equipment and for complete power plant systems. The concept is that the cost of an entity does not increase linearly as its size increases. Instead the cost varies as the size to an exponent. For example, the appropriate exponent has been found to be 0.6 for heat exchangers and 0.8 for steam turbine generators. At some unit size it may become necessary to add multiple units rather than continue increased unit sizes. Some elements like fuel cell modules and dc to ac inverters and thermionic converters are small in unit capacity and are always aggregates of numerous modules with little cost advantage in the conversion system itself as their numbers increase. Economics of scale, however, still apply to other components of the power plant costs.

For the purpose of this study data were secured at two unit ratings for equipment cost, direct field material to install the equipment, and direct field labor to install the equipment. These data were input to the computer. The computer thereafter compares the equipment size required to the input data and interpolates costs along a power law fit of the input data. When the equipment size exceeds the limit of the input data, additional units are added to reduce the required unit size and the same search made. This procedure continues until sizes within the span allowed are found.

The elements that comprise a major sector or island of the energy conversion system are presented in Table 3-4. The costs developed from Table 3-4 only include direct costs. Cost adders above these levels are 1% for start-up, 2% for spare parts, 90% for indirect field costs, and an additional 26% made up of 6% engineering, 15% contingency, and 5% fee. The resulting multipliers to get total installed costs are presented in Table 3-5 along with a set of multipliers to derive only the indirect portion of costs. An example of the capital cost by island report is shown in Table 3-6. Notice in the footnote of this example that the gas turbine island equipment cost is \$167/kW, its cost including installation materials and labor is \$196/kW and the complete power plant capital cost is \$445/kW.

Table 3-4

GE-CTAS CAPITAL COSTS

COST ISLANDS MASTER LIST

Major Islands Accounts:	Major Component Accounts:	
1.0 Fuel Handling	1	Gas Metering/Scrubber
	2	Gas Storage
	3	Gas Pressure Regulation
	4	Fuel Oil Unloading
	5	Fuel Oil Storage
	6	Fuel Oil Transfer
	7	Fuel Oil Pump and Heater Set
	8	Coal Unloading
	9	Coal Storage
	10	Coal Preparation
	11	Coal Transfer
	12	Limestone/Dolomite Unloading
	13	Limestone/Dolomite Storage
	14	Limestone/Dolomite Preparation
	15	Limestone/Dolomite Transfer
2.0 Fuel Utilization and Cleanup	20	Gas-fired Boiler
	21	Oil-fired Boiler
	22	Coal-fired Boiler
	23	Coal-fired AFB Boiler
	24	Coal-fired PFB Boiler
	25	Coal Gasifier
	26	Liquid Waste Boiler
	27	Solid Waste Boiler
	28	Reformer, Shifter, and Cleanup for Fuel Cells
	29	Stirling Engine Combustion and Cleanup
3.0 Energy Conversion	30	Steam Turbine-Generators, Non-condensing
	31	Gas Turbine-Generators
	32	Diesel Engine-Generators
	33	Thermionic Boiler/Generator and Cleanup
	34	Stirling Engine-Generators
	35	Fuel Cells-Molten Carbonate
	36	Fuel Cells-Phosphoric Acid
	37	Prime Conversion Bottoming HRSG and Steam Turbine-Generator
4.0 Bottoming Cycle	40	Heat Recovery Steam Generators
	41	Steam Turbine-Generator, Condensing
	42	Organic Vapor Boiler
	43	Expansion Turbine-Generators
	44	Regenerators, Vapor
5.0 Heat Sink	50	Cooling Towers, Wet, Induced-Draft
	51	Circulating Pumps
	52	Steam Condensers
	53	Vapor Condensers
6.0 Heat/Energy Storage	60	Media
	61	Containment
	62	Heat Exchangers
7.0 Process Interface	70	Heat Exchangers
	71	Heat Recovery/Process Steam Generators
8.0 Balance of Plant	80	Master Control
	81	Electric Switchgear and Transformer
	82	Interconnecting Piping, Ducting, Wiring
	83	Structures and Miscellaneous
	84	Service Facilities

Table 3-5

CTAS CAPITAL COST STRUCTURE

Total Installed Cost		
Equipment	*	(1 + 0.01 + 0.02) * (1.26)
Material	*	(1 + 0.01) * (1.26)
Direct Labor	*	(1 + 0.01 + 0.90) * (1.26)
Indirect Cost		
Equipment	*	0.2978
Material	*	0.2726
Direct Labor	*	1.4066

Another aspect of the methodology was the derivation of some costs where detailed evaluations had not been done. An example would be the residual oil-fired thermionic plant. It was determined that the difference in cost from oil-fired to coal-fired steam boilers at the same firing rate should be appropriate for the thermionic units. These differences were derived and were applied to the coal-fired data to derive the costs for the oil-fired thermionic unit. The coal-fired stirling cycle represented the reverse transition. Cost of the oil-fired unit was known. The oil to coal cost difference was added to the oil-base case to determine the coal-fired case.

Data Sources

Two of the energy conversion system costs were derived from the General Electric study for ECAS (Reference 1.) These were the pressurized fluidized bed steam cycle plant and the helium closed cycle gas turbine plant. As indicated in the previous section, costs for the thermionic energy conversion systems were derived on a similar basis from the General Electric EPRI study (Ref. 2).

Table 3-6

SAMPLE OF CAPITAL COST BY ISLAND CALCULATION

DATE 03/31/79 — GENERAL ELECTRIC COMPANY — PAGE 102
I SE-PEO ADV. ES. ENGRG. — COGENERATION TECHNOLOGY ALTERNATIVES STUDY
REPORT 5.3
CAPITAL COSTS BY ISLAND FOR SELECTED PROCESS-ECS MATCHES

PROCESS 28121

ECS GTSOAR PROCESS MEGAWATTS 52.11 PROCESS TEMP. 338. PROCESS HEAT BTU*10**6) 265.
GT-HRSG-10/1750R-AC SITE FUEL= RESIDUAL COGEN FUEL BTU*10**6= 613. FUEL= 179662.

ISLAND DESCRIPTION	COMPONENT DESCRIPTION	MAJOR EQUIPMNT	INSTALL MAT'L	INSTALL LABOR	INDRCT FLD CST	TOTAL INSTALLD	TOTAL	$PER-KW FUEL
		COSTS - MILLIONS 1978$						
1. FUEL-HANDLING	1. FUEL-OIL-UNLOADING-S	0.171	0.034	0.205	0.185	0.425	0.596	3.317
	ISLAND TOTAL	0.171	0.034	0.205	0.185	0.425	0.596	3.317
3. ENERGY-CONVERSION	31. GAS-TURBINE-GENERATO	8.695	0.956	0.566	0.509	2.032	10.726	59.703
	ISLAND TOTAL	8.695*	0.956	0.566	0.509	2.032	10.726	59.703
4. BOTTOMING-CYCLE	40. HEAT-RECOVERY-STEAM-	0.749	0.639	1.152	1.037	2.829	3.578	19.913
	ISLAND TOTAL	0.749	0.639	1.152	1.037	2.829	3.578	19.913
8. BALANCE OF-PLANT	84. POWER-PLANT-STRUCTUR	0.	0.210	0.190	0.171	0.579	0.579	3.225
	80. MASTER-CONTROL	0.117	0.018	0.029	0.026	0.073	0.191	1.062
	81. ELECTRIC-SWITCHGEAR-	0.	0.094	0.084	0.076	0.243	0.243	1.356
	82. INTERCONNECTING-PIPI	0.	0.162	0.162	0.146	0.471	0.471	2.622
	83. STRUCTURES-MISCELLAN	0.	0.599	0.558	0.502	1.659	1.659	9.232
	ISLAND TOTAL	0.117	1.060	1.024	0.922	3.026	3.143	17.493
TOTAL THIS CASE		9.732	2.711	2.948	2.653	8.311	18.043	14.766
INDIRECT COSTS	SPARES						0.195	
	START UP						0.154	
	SPARES+STARTUP						0.349	
	CONTINGENCY						2.759	
	ENGINEERING SERVICES						1.105	
	A-E FEE						0.920	
**** GRAND TOTAL ****							23.173*	

* The major equipment cost of the gas turbine generator island is $\frac{8.695\times10^6}{52.11\times10^3}$ = \$167/kW. Including the installation materials and labor the cost is $\frac{(8.695+.956+.566)10^6}{52.11\times10^3}$ = \$196/kW. The total installed plant cost is $\frac{23.173\times10^6}{52.11\times10^3}$ = \$445/kW.

A number of energy conversion systems costs were synthesized from the data bank used by General Electric in application engineering for industrial power generation including cogeneration. These included all nocogeneration boilers firing all types of fuels, both of the package and of the field erected type, and conventional power boilers providing steam for turbines. Also, cost of heat recovery steam generators for gas turbines were from the same source as were industrial steam turbine costs.

The bulk of the advanced energy conversion systems costs were synthesized from data on basic equipment costs. The following were added to each system to complete the power house assemblage:

Component	Component Description
80	Master Control
81	Electric-Switchgear
82	Interconnecting Piping
83	Structures-Miscellaneous
84	Service Facilities

The stirling cycle costs were produced by General Electric in collaboration with North American Philips. The costs were then reviewed with the General Electric Locomotive Diesel Engine Department. The molten carbonate and phosphoric acid fuel cell costs were developed by General Electric in collaboration with the Institute of Gas Technology. The integrated gasifier combined-cycle costs and performance were developed from EPRI reports (Ref. 3, 4) on Coal Gasification Combined-Cycle Systems and internal GE studies. All gas turbine cost estimates were new evaluations in 1978 dollars for cogeneration applications. The diesel cost estimates were derived by the DeLaval Corporation to represent growth versions of current cogeneration diesel systems. The heat pump for the diesel used cost estimates based on one of the more expensive air compressors that would satisfy the performance requirements so that the cost estimates would cover modifications necessary to handle steam.

Cost Comparisons

Since cost differences are a dominant factor in economic appraisals, it is essential that costs developed for cogeneration systems have a high level of consistency. The smallest plant sizes are subject to the greatest uncertainty for relative costs. For a comparison of relative costs an industrial plant having 10 megawatts power demand and 137 million Btu per hour process heat at 300 F was selected. The capital cost was evaluated as dollars per kilowatt of electrical power produced after deletion of the direct and indirect costs of an auxiliary boiler if one was necessary. Table 3-7 presents the results. The order of listing generally follows increasing cost. As expected distillate-fired units tend to be least expensive followed by residual-fired and then coal-fired units.

Table 3-7

CAPITAL COSTS FOR 10 MW POWER DEMAND AND 137 MILLION BTU PER HOUR AT 300 F
(Auxiliary Boiler Cost Deleted)

	CAPITAL COST, $/kW		
Energy Conversion System	Coal Fired	Residual	Distillate
Phosphoric Acid Fuel Cell			580
Gas Turbine-State-of-the-Art		775	655
-Steam Injected		665	
-Combined Cycle		680	
-Advanced		695	
-Regenerative			745
Steam Turbine-Adv. Boiler	1260-AFB		
	1540-PFB		
-State-of-the-Art	1635-FGD	840	
Stirling Cycle	1445-FGD	845	845
Diesel -Advanced		980	
-Heat Pumped		995	
-State-of-the-Art		1040	1040
Integrated Gasifier Comb. Cycle	1555-G		
Molten Carbonate Fuel Cell	2200-G		510
-Steam Turbine	2205-G		
Helium Closed-Cycle G.T.	2645-AFB		
Thermionic	5660-FGD	4410	
-Steam Turbine	3450-FGD	2700	

FGD - Flue Gas Desulfurization
AFB - Atmospheric Fluidized Bed
PFB - Pressurized Fluidized Bed
G - Gasifier

Among distillate-fueled units the phosphoric acid fuel cell and state-of-the-art gas turbine are the least expensive alternatives at 10 MW rating. For residual fired units several gas turbine alternatives are least costly. The state-of-the-art residual fired gas turbine is less costly than the steam turbine, stirling cycle or diesel. For coal fired units the steam turbine with atmospheric fluidized bed is least costly followed by the stirling cycle, then the PFB steam cycle, the integrated gasifier combined-cycle, and finally the state-of-the-art steam turbine plant with flue gas desulfurization. The greatly advanced cycles are most costly. The source of these costs are apparent. The molten carbonate system is complex because of the gas cleanup required by the fuel cell. The helium closed-cycle features a two-stage AFB furnace that heats gas over a high temperature span. The thermionic units are inherently costly notwithstanding the assignment that they would be manufactured into large panels in the factory in order to reduce field erection costs.

These data at a low power level represent the highest levels of costs that are expected. The cost data are of a nature that unit costs decrease as size and ratings increase. The best sources of comparative data are at power levels between 400 MW and 1000 MW for complete electric utility plants. Such plants would tend to be more complex than cogeneration power plants. They would incur costs for heat rejection systems and for low temperature-low pressure elements of their energy conversion machinery. At the same time they tend to be more efficient. Nonetheless, one would expect their order of costliness to be similar to that for cogeneration plants. Hence the major issue is one of order and relative costs, not of absolute cost level.

Several data sources were available as discussed previously. These include the General Electric in-depth studies for ECAS and for EPRI. Values were taken from those studies and adapted to the same basis as the CTAS costs. The ascending order of costs and their ratios were corroborated for the gas turbine, steam turbine with residual boiler and AFB, PFB and FGD, for the helium gas turbine with AFB and the thermionic-steam turbine cycle with FGD. These data are presented in the detailed General Electric report, Volume IV. The corroboration that has been found indicates that a consistency exists among the costs that are synthesized for each type cogeneration energy conversion system in this study. The discipline of using common components as elements for all systems, of applying a consistent basis for indirect costs, and bringing each system to a common level of completeness assures that no system has been either favored or penalized by arbitrary assignment of costs.

Energy Conversion System - Industrial Process Matching Methodology

The evaluation and comparison of various types of cogeneration (ECS's) is difficult because of the tremendous variations in the energy requirements of industrial processes as shown by Figure 3-4. Table 3-8, which summarizes the performance characteristics of the ECS's shows they have a very wide range of power over heat ratios, ranging from 0.2 to 2.7. Power over input fuel (efficiency) range from 0.14 to 0.41, process heat over input fuel from 0.13 to 0.71, and power plus heat over input fuel (fuel effectiveness) from 0.49 to 0.85. For these reasons comparisons of the ECS's must be made based upon their performance and costs when matched to specific industrial processes.

The possibilities considered for matching the ECS's with the processes are shown in Figures 3-5 and 3-6. Figure 3-5 represents the case where the ratio of power to heat of the ECS is greater than that required by the process. The ordinate of the figure represents power and the abscissa represents heat. The circled point at the intersection is the power required by the process. Any point along the sloped line beginning at the origin and moving upward and to the right represents an energy conversion system of increasing size. The slope of the line is descriptive of the energy conversion system (power/heat ratio) characteristic and is often dependent upon the temperature at which heat is required by the process. As is readily observed, when the size of energy conversion system is selected to match the power required by the process, the heat output of the ECS is not sufficient to meet the process needs and an auxiliary boiler must be used to make up the deficiency.

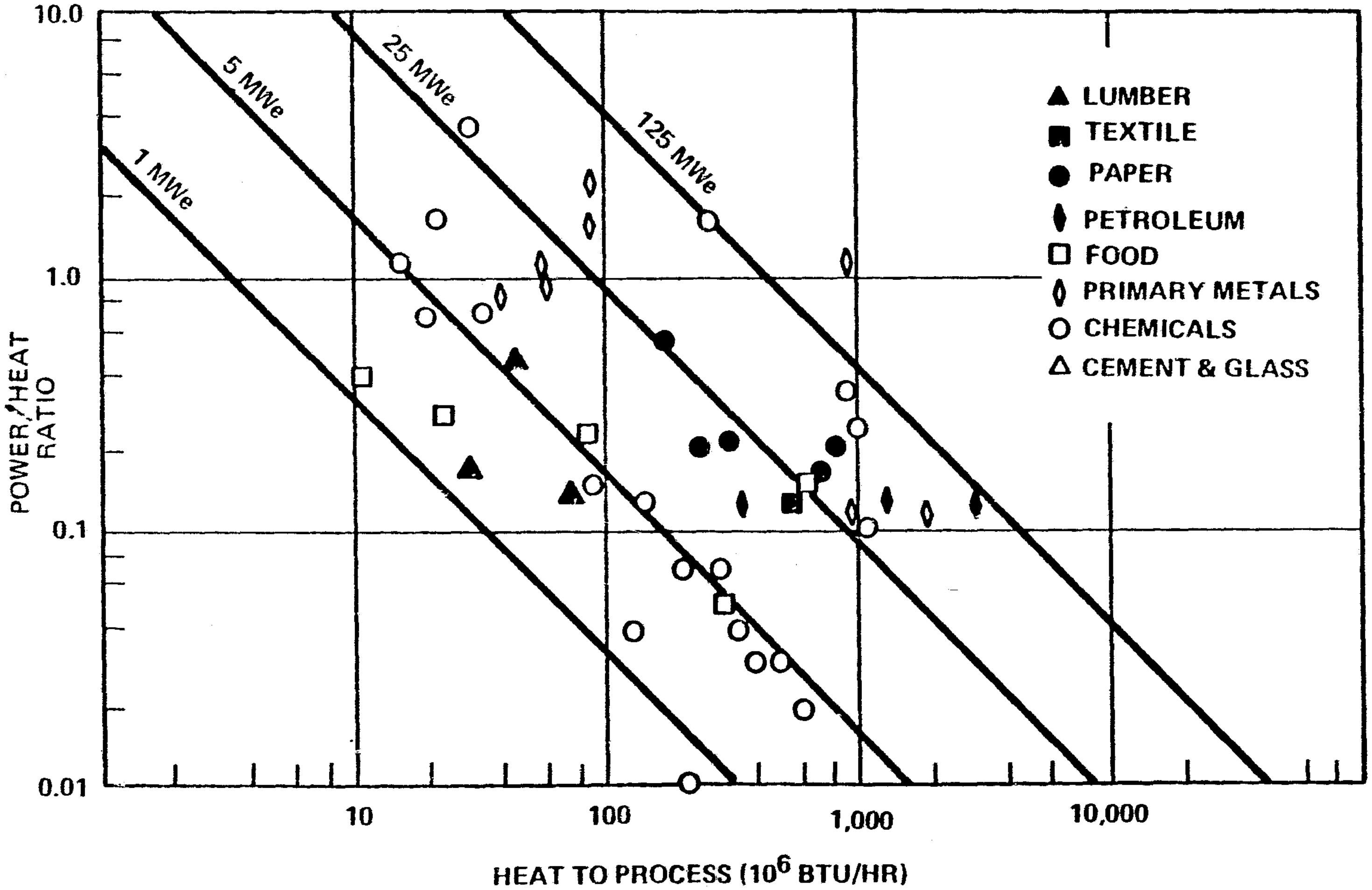


Figure 3-4. Industrial Process Characteristics Graphic Summaries (Power/Heat Ratio Versus Heat to Process)

Table 3-8

COGENERATION ENERGY CONVERSION SYSTEM (ECS) PERFORMANCE CHARACTERISTICS

ECS	Performance Characteristics at Process Sat. Steam = 350°F*			
Current State-of-Art	Power / Heat	Power / Fuel	Process Heat / Fuel	Power + Process Heat / Fuel
FGD STM TURB - COAL	.20	.14	.71	.85
GT-HRSG - RESIDUAL	.68	.29	.43	.72
DIESEL-HRSG - RESIDUAL	2.03	.36	.18	.54
Advanced				
AFB STM TURB - COAL	.20	.14	.71	.85
PFB STM TURB - COAL	.32	.21	.64	.84
INT GAS COMB CYCLE - COAL	.66	.28	.43	.71
INT GAS FUEL CELL MC - STM TURB	.96	.38	.40	.78
STIRLING - COAL	.54	.26	.47	.73
CLOSED CYCLE GT HELIUM - COAL	.36	.18	.49	.67
THERMIONIC-STM TURB - COAL	.44	.26	.59	.84
GT-HRSG - RESIDUAL	.66	.31	.46	.77
COMB CYCLE GT - RESID	1.08	.37	.34	.72
STM INJ GT - RESIDUAL	2.70	.36	.13	.49
DIESEL - RESIDUAL	1.75	.37	.21	.58
DIESEL-HEAT PUMP - RESIDUAL	.78	.33	.43	.76
REGEN GT - DISTILLATE	.85	.33	.39	.72
FUEL CELL - DISTILLATE	2.24	.38	.17	.55
FUEL CELL MC - DIST.	1.77	.41	.23	.65

* Performance characteristics of most ECS's varies with process steam temperature.

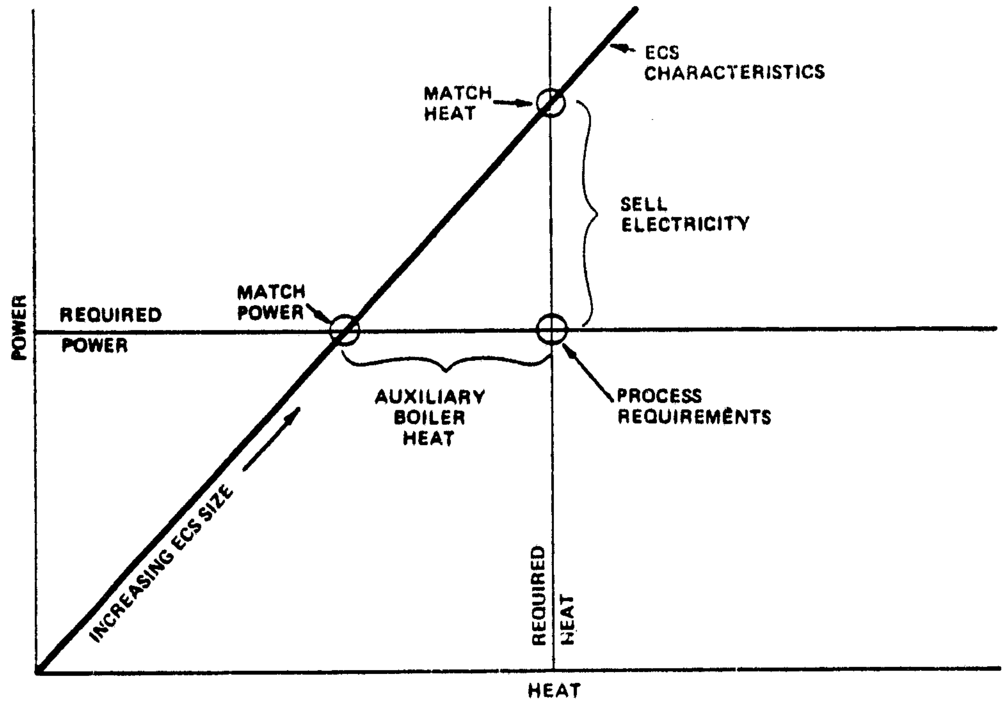


Figure 3-5. Matching of Energy Conversion System Output and Industrial Process Requirements (Power/Heat of ECS Greater Than Required)

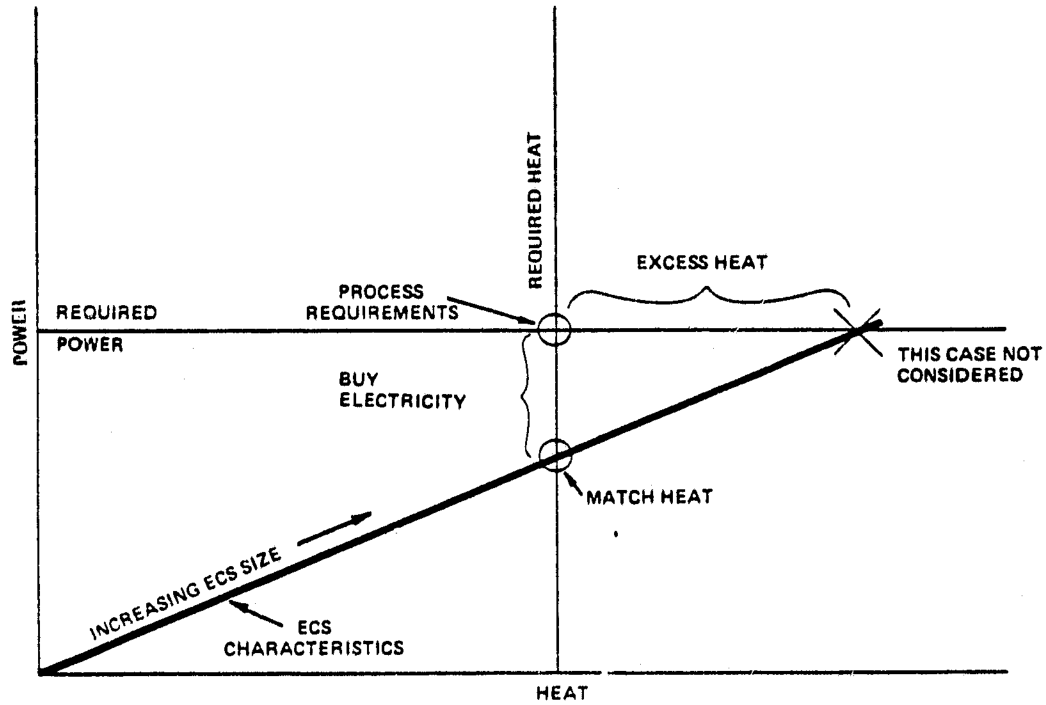


Figure 3-6. Matching of Energy Conversion System Output and Industrial Process Requirements (Power/Heat of ECS Less Than Required)

When the size of energy conversion system is selected to meet the heat needs of the process (no auxiliary boiler), more electric power is produced than required by the process and the excess power must be exported to the utility.

Figure 3-6 represents the case where the ratio of power to heat of the ECS is less than that required by the process. When the ECS is sized to produce the heat required by the process, the power output is less than the process needs and the deficiency must be purchased from the utility. In the case where the ECS is sized to produce the power required by the process, more heat is produced than can be used by the process. Increasing the ECS size above that for matching heat in this case decreases the advantages of cogeneration and this was excluded from further investigation in this study.

The case where the energy conversion system is sized to meet the power needs of a process is referred to as a <u>power match</u>. Similarly the case where the energy conversion system is sized to meet the heat needs of a process is referred to as a <u>heat match</u>.

<u>Fuel Energy Use and Indices of Performance</u>

A knowledge of the methodology used in accounting for the nocogeneration and cogeneration fuel energy in the various ECS-process matches shown in Figure 3-5 and 3-6 is essential to understanding the fuel saved by cogeneration when compared to a nocogeneration system. This methodology is best shown by going through some example calculations for a steam turbine and gas turbine with a heat recovery steam generator both matched to a specific industrial process. A medium integrated chemical plant with the following energy requirements is used in this example:

H = process steam requirements = 1054×10^6 Btu/hr

T_p = process steam saturation temperature = 366^oF

P = process power requirements = 77.2 MW or 264×10^6 Btu/hr

P/H = process power over heat ratio $= \frac{264}{1054} = 0.25$

The performance of a back pressured steam turbine-generator with a coal-fired boiler and flue gas desulfurization (STM-FGD) and of the residual-fired gas turbine with heat recovery steam generator (GT-HRSG) can be characterized by specifying their ratios of delivered power over input fuel, process heat over fuel and power plus heat over fuel. The values of these ratios for these ECS's at the process heat steam temperature, 366°F, are:

Cogeneration ECS Type	STM-FGD	GT-HRSG
$\left(\frac{P_E}{F_E}\right) = \frac{\text{ECS power}}{\text{ECS fuel}}$	0.13	0.29
$\left(\frac{H_E}{F_E}\right) = \frac{\text{ECS heat}}{\text{ECS fuel}}$	0.72	0.42
$\left(\frac{P_E + H_E}{F_E}\right) = \frac{\text{ECS power + ECS heat}}{\text{ECS fuel}}$	0.85	0.71
$\left(\frac{P_E}{H_E}\right) = \frac{\text{ECS power}}{\text{ECS fuel}}$	0.18	0.71

Heat Match Performance

When the cogeneration ECS's are heat matched to this process, the ECS fuel is:

	STM-FGD	GT-HRSG
$F_E = \text{ECS fuel} = H \times \left(\frac{F_E}{H_E}\right)$	$= 1054 \times \frac{1}{.720} = 1465\times10^6$ Btu/hr;	$1054 \times \frac{1}{.424} = 2486\times10^6$ Btu/hr

and the power produced by the ECS is:

	STM-FGD	GT-HRSG
$P_E = \text{ECS power} = F_E \times \left(\frac{P_E}{F_E}\right)$	$= 1465\times0.13 = 191\times10^6$ Btu/hr;	$2486\times0.29 = 721\times10^6$ Btu/hr
or	$= \frac{191\times10^6}{3.413\times10^6} = 55.8$ MW;	$\frac{721\times10^6}{3.413\times10^6} = 211$ MW

Notice that the steam turbine ECS with its power over heat ratio of 0.18 supplying a process requiring a power over heat ratio of 0.25 corresponds to the case shown in Figure 3-6 and when heat matched the ECS produces less power than required by the process and must buy power from the utility. The gas turbine ECS with its power over heat ratio of 0.68 is greater than that of the process and corresponds to the type match shown in Figure 3-5 and in a heat match produces more power than required by the process, so the surplus is sold to the utility. Purchased or exported (sold) power to the utility for the two systems is:

	STM-FGD	GT-HRSG
$P_{UTIL} = P - P_E$	$= 264 - 191 = 73\times10^6$ Btu/hr;	$264 - 721 = -458\times10^6$ Btu/hr
or	$= \frac{73\times10^6}{3.413\times10^6} = 21.4$ MW;	$\frac{-458\times10^6}{3.413\times10^6} = -135$ MW

and assuming a utility efficiency of 0.32, the utility fuel consumed in the case of the steam turbine cogeneration system or displaced by the gas turbine system is:

	STM-FGD	GT-HRSG
$F_{UTIL} = \frac{P_{UTIL}}{\eta_{UTIL}}$	$= \frac{73}{.32} = 228\times10^6$ Btu/hr;	$\frac{-458}{.32} = -1430\times10^6$ Btu/hr

The total cogeneration system fuel is the total fuel required to supply the power and heat requirements of the process plus the ECS fuel to generate exported power. In the case of the steam turbine cogeneration system, its total fuel consumption is that of the ECS plus the utility fuel for purchased power and that of the gas turbine system is the gas turbine ECS fuel or:

F_{CG} = cogeneration system fuel = F_E+F_{UTIL}

	STM-FGD		GT-HRSG	
(F_{UTIL} = 0 if $P-P_E<0$)	= 1465+228	= 1693×10^6 Btu/hr;	2486+0	= 2486×10^6 Btu/hr

A graphic presentation of the fuel consumptions, heat and power produced and losses by these two heat matched cogeneration systems is shown by the upper bars in Figure 3-7. The required process power and heat are shown by the middle bar in these energy-fuel diagrams.

In these fuel calculations the nocogeneration system, consisting of an on-site process boiler and purchased power from the utility, is sized to furnish the required process heat and power plus the export power to the utility. Assuming a process boiler efficiency of 0.85, its fuel consumption is:

	STM-FGD	GT-HRSG
F_b = nocogeneration boiler fuel $= \frac{H}{\eta_b} = \frac{1054}{.85}$	= 1240×10^6 Btu/hr;	1240×10^6 Btu/hr

and the utility power and fuel consumption is:

	STM-FGD	GT-HRSG
P_{NUTIL} = nocogeneration utility power =	$P(\text{if } P-P_E>0)$ = 264×10^6 Btu/hr;	$P_E(\text{if } P-P_E<0)$ = 721×10^6 Btu/hr

and the utility fuel is:

	STM-FGD	GT-HRSG
F_{NUTIL} = nocogeneration utility fuel $= \frac{P_{NUTIL}}{\eta_{NUTIL}}$	$= \frac{264}{.32}$ = 823×10^6 Btu/hr;	$\frac{721}{.32}$ = 2253×10^6 Btu/hr

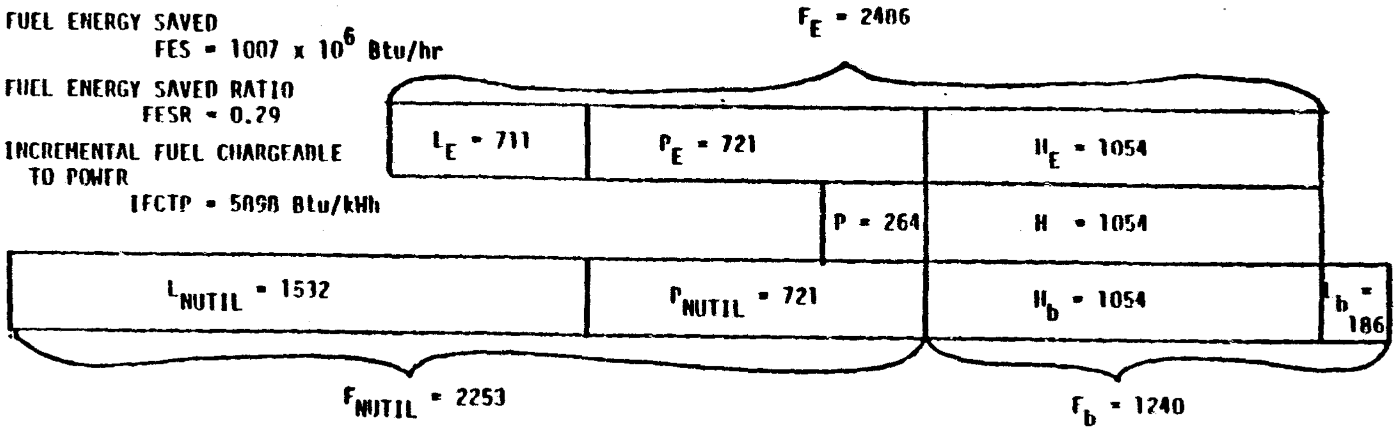
a) Heat Matched - 10^6 Btu/hr

GAS TURBINE WITH HEAT RECOVERY STEAM GENERATOR

FUEL ENERGY SAVED
FES = 1007 x 10^6 Btu/hr

FUEL ENERGY SAVED RATIO
FESR = 0.29

INCREMENTAL FUEL CHARGEABLE TO POWER
IFCTP = 5898 Btu/kWh



COGENERATION SYSTEM FUEL
F_{CG} = 2486

PROCESS POWER & HEAT REQ'D
P+H = 1318

NOCOGENERATION FUEL
F_{NC} = 3493

$\frac{\text{Fuel Energy Saved}}{\text{Process Heat}} = \left(\frac{FES}{H}\right) = 0.955$

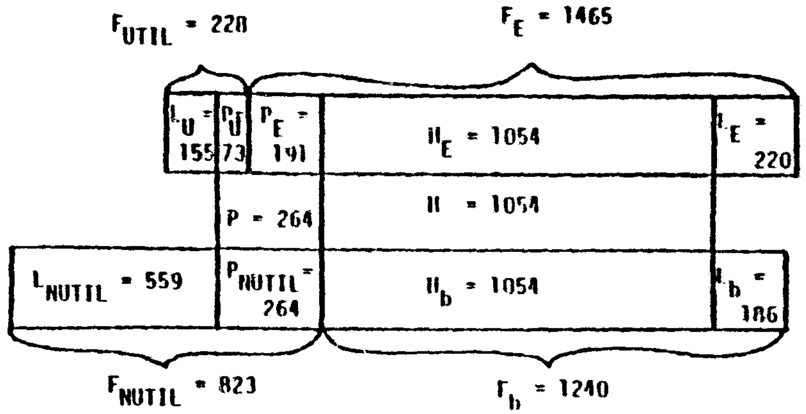
STEAM TURBINE

FUEL ENERGY SAVED
FES = 370 x 10^6 Btu/hr

FUEL ENERGY SAVED RATIO
FESR = 0.18

INCREMENTAL FUEL CHARGEABLE TO POWER
IFCTP = 4013 Btu/kWh

$\frac{\text{Fuel Energy Saved}}{\text{Process Heat}} = \left(\frac{FES}{H}\right) = 0.351$



COGENERATION SYSTEM FUEL
F_{CG} = 1693

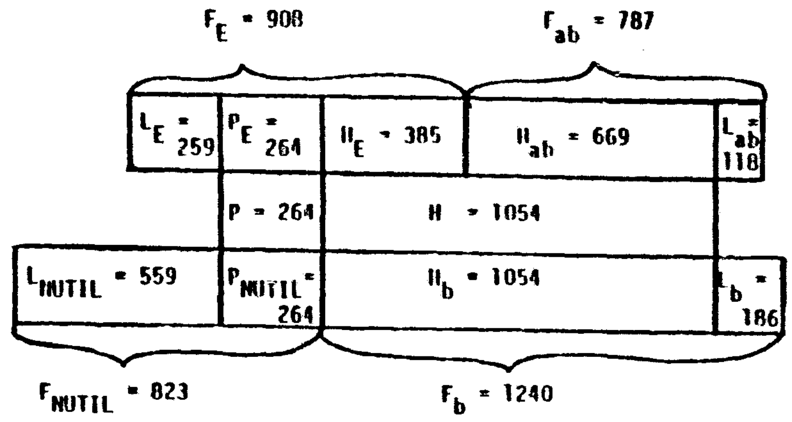
PROCESS POWER & HEAT REQ'D
P+H = 1318

NOCOGENERATION FUEL
F_{NC} = 2063

Figure 3-7a. Cogeneration Systems Energy-Fuel Diagrams for Gas Turbine and Steam Turbine Energy Conversion Systems Matched to a Medium Integrated Chemical Plant (SIC 2800-2)

b) Power Matched - 10^6 Btu/hr

GAS TURBINE WITH HEAT RECOVERY STEAM GENERATOR



FUEL ENERGY SAVED
FES = 368 x 10^6 Btu/hr

FUEL ENERGY SAVED RATIO
FESR = 0.18

INCREMENTAL FUEL CHARGEABLE TO POWER
IFCTP = 5893 Btu/kWh

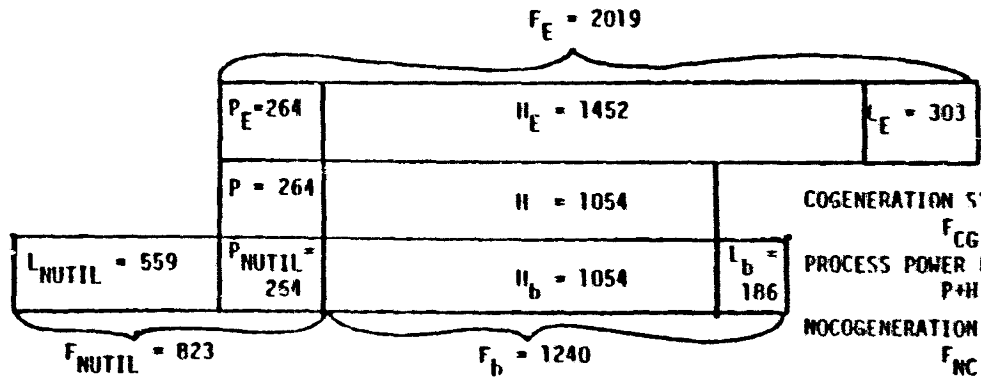
$\frac{\text{Fuel Energy Saved}}{\text{Process Heat}} = \left(\frac{FES}{H}\right) = 0.349$

COGENERATION SYSTEM FUEL
F_{CG} = 1695

PROCESS POWER & HEAT REQ'D
P+H = 1318

NOCOGENERATION FUEL
F_{NC} = 2063

STEAM TURBINE



FUEL ENERGY SAVED
FES = 44 x 10^6 Btu/hr

FUEL ENERGY SAVED RATIO
FESR = 0.02

INCREMENTAL FUEL CHARGEABLE TO POWER
IFCTP = 10090 Btu/kWh

$\frac{\text{Fuel Energy Saved}}{\text{Process Heat}} = \left(\frac{FES}{H}\right) = 0.042$

COGENERATION SYSTEM FUEL
F_{CG} = 2019

PROCESS POWER & HEAT REQ'D
P+H = 1318

NOCOGENERATION FUEL
F_{NC} = 2063

Figure 3-7b. Cogeneration Systems Energy-Fuel Diagrams for Gas Turbine and Steam Turbine Energy Conversion Systems Matched to a Medium Integrated Chemical Plant (SIC 2800-2)

Total nocogeneration fuel is the sum of the process boiler and utility fuel or:

	STM-FGD	GT-HRSG
F_{NC} = nocogeneration fuel = $F_b + F_{NUTIL}$ =	$1240+823 = 2063\times10^6$ Btu/hr;	$1240+2253 = 3493\times10^6$ Btu/hr

The lower bars on the energy-fuel diagrams of Figure 3-7 show these nocogeneration fuels. <u>In making these calculations care must be taken to be sure both the cogeneration and nocogeneration systems are sized to produce the same power and process heat and include the utility as part of the systems</u>.

A parameter indicating the fraction of the nocogeneration fuel which would be saved if the cogeneration system were implemented is called fuel energy saved ratio (FESR) and for these two systems is:

	STM-FGD	GT-HRSG
$\text{FESR} = \dfrac{\text{Nocogen fuel - Cogen fuel}}{\text{Nocogen fuel}} = \dfrac{F_{NC}-F_{CG}}{F_{NC}} =$	$\dfrac{2063-1693}{2063} = 0.18;$	$\dfrac{3493-2486}{3493} = 0.29$

An important aspect of the FESR is that it represents a saving in both the generation of power and process steam but that the fuel consumption of the on-site cogeneration plant is higher than either the fuel for the nocogeneration process boiler or the fuel required by the utility to generate the power.

Another index of the fuel savings of cogeneration systems is called the incremental fuel chargeable to power (IFCTP) or sometimes just fuel chargeable to power. The IFCTP is the cogeneration ECS fuel plus auxiliary boiler fuel, F_{ab}, (required in some power matches) minus the nocogeneration process boiler fuel divided by the power produced by the ECS, or:

	STM-FGD	GT-HRSG
$\text{IFCTP} = \dfrac{F_E+F_{ab}-F_b}{P_E} =$	$\dfrac{(1465+0-1240)3413}{191} = 4013$ Btu/kWh;	$\dfrac{(2486+0-1240)3413}{721} = 5898$ Btu/kWh

This incremental heat rate for the cogeneration ECS credits all of the thermodynamic cycle benefits of cogenerating to the generation of power and usually results in astoundingly low heat rates. Of course a similar parameter could be calculated where all of the cycle benefits of cogeneration were credited to producing the process heat but the parameter s seldom if ever used. As we will see later in the economic analysis of these systems, the IFCTP is of little interest to the industrial owner of a cogeneration plant but is of importance to utility manager who is looking at cogeneration as a means of generating low cost power. Since the fuel energy saved ratio (FESR) is a measure of the total fuel saved by the cogeneration system compared to the nocogeneration system when matched to an industrial process, the FESR was used in CTAS.

Another parameter, the fuel energy saved per unit process heat, $\frac{FES}{H}$, is of interest from a national point of view because the <u>amount</u> of cogeneration which can be installed is limited by the amount of process heat that is required. Values of $\frac{FES}{H}$ for these two systems when heat matched are:

		STM-FGD	GT-HRSG
$\left(\frac{FES}{H}\right) = \frac{\text{fuel energy saved}}{\text{process heat}}$	$\frac{Btu}{Btu}$	$\frac{370}{1054} = 0.351;$	$\frac{1007}{1054} = 0.995$

and for the power matches:

$\left(\frac{FES}{H}\right) =$		$\frac{44}{1054} = 0.042;$	$\frac{368}{1054} = 0.394$

<u>Power Matched Cases</u>

Using a similar calculation procedure to that shown above for heat matches except that the ECS fuel is calculated by process power, P, and ECS power over fuel ratio, $\frac{P_E}{F_E}$, the energy and fuels of the power matched cogeneration ECS and auxiliary boiler and nocogeneration process boiler and purchased utility power can be determined. These are shown for the steam turbine and gas turbine ECS's by the fuel-energy diagrams in Figure 3-7b. Notice that when the steam turbine is matched to supply the required process power it produces more heat than the process requires, and assuming there was no other need for process steam nearby, it would be rejected to the surroundings. As a result, its FESR = 0.02 and IFCTP = 10090 Btu/kWh are poor. These power matches which produced excess process heat were excluded from economic evaluations in the study.

Study of the energy-fuel diagram in Figure 3-7b for the gas turbine ECS shows that it does not produce the required process heat because of its high power over heat ratio of 0.68 and an auxiliary boiler must be added to the cogeneration system. This gas turbine cogeneration system has an FESR = 0.18 and a IFCTP = 5893 Btu/kWh.

A comparison of the power and heat matched FESR's for a single ECS shows that they are signficantly higher for the heat matched case and power is exported to the utility. On the other hand, the IFCTP are equal in the heat and power match if power matches producing excess heat are excluded.

The above calculations illustrate the false conclusions which can be made if just the uninstalled efficiency of the ECS's or a single performance index like IFCTP are used as criteria to judge the desirability of a type of power plant for cogeneration applications. Determining the relative advantages of the various ECS's is further complicated because the strong effect of the relative match of ECS and process power over heat ratio and the tremendous diversity of industrial processes.

Capital Costs and Cost Parameters

The total installed cost of the above steam turbine and gas turbine cogeneration and corresponding nocogeneration systems was calculated using General Electric capital cost models for all subsystems except their advanced components whose costs were estimated by organizations engaged in their development. The capital cost of the utility plant to furnish purchased power was assumed to be that of a new base loaded plant at $800 per kW. The nocogeneration process boiler is coal-fired in these comparisons. These capital costs are graphically depicted in Figure 3-8 in a similar format of the energy-fuel diagrams of Figure 3-7 with the gas turbine and steam turbine heat matched to a medium integrated chemical plant in Figure 3-8a and the power matched in Figure 3-8b.

A comparison of the capital costs of the heat matched gas turbine and steam turbine systems shows some startling differences. Since the

a) Heat Matched - 10^6 \$

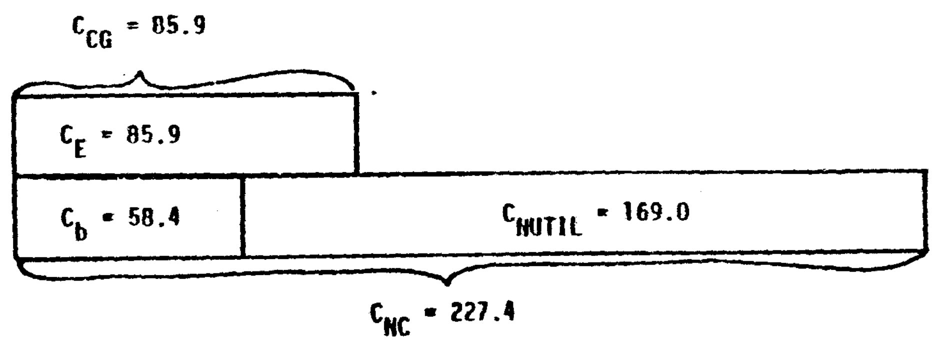
GAS TURBINE WITH HEAT RECOVERY STEAM GENERATOR

CAPITAL COST SAVED CCS = 141.5

ONSITE CAPITAL COST RATIO OSCCR = 1.47

CAPITAL COST SAVED RATIO CCSR = 0.62

INCREMENTAL CAPITAL CHARGEABLE TO POWER - ICCTP = \$130/kW



COGENERATION SYSTEM CAPITAL COST = C_{CG} = 85.9

NOCOGENERATION SYSTEM CAPITAL COST = C_{NC} = 227.4

$\frac{\text{Capital Cost Saved}}{\text{Process Heat}} = \left(\frac{CCS}{H}\right) = \$134{,}300/10^6$ Btu/hr

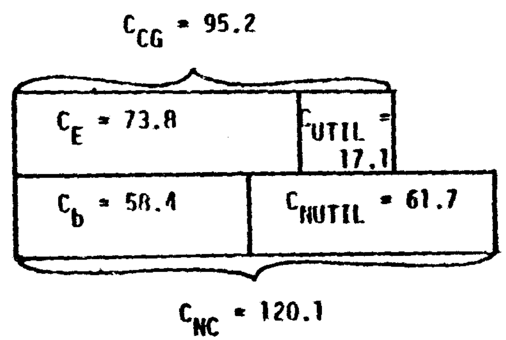
STEAM TURBINE

CAPITAL COST SAVED CCS = 24.9

ONSITE CAPITAL COST RATIO OSCCR = 1.26

CAPITAL COST SAVED RATIO CCSR = 0.21

INCREMENTAL CAPITAL CHARGEABLE TO POWER - ICCTP = \$276/kW



COGENERATION SYSTEM CAPITAL COST = C_{CG} = 95.2

NOCOGENERATION SYSTEM CAPITAL COST = C_{NC} = 120.1

$\frac{\text{Capital Cost Saved}}{\text{Process Heat}} = \left(\frac{CCS}{H}\right) = \$23{,}600/10^6$ Btu/hr

Figure 3-8a. Cogeneration Systems Capital Cost Diagrams for Gas Turbine and Steam Turbine Energy Conversion Systems Matched to a Medium Integrated Chemical Plant (SIC 2800-2)

b) Power Matched - 10^6 \$

GAS TURBINE WITH HEAT RECOVERY STEAM GENERATOR

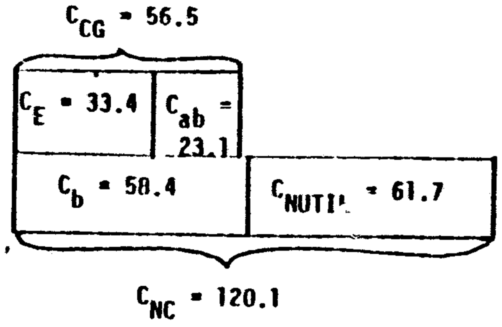
CAPITAL COST SAVED CCS = 63.6

ONSITE CAPITAL COST RATIO
OSCCR = 0.97

CAPITAL COST SAVED RATIO
CCSR = 0.53

INCREMENTAL CAPITAL CHARGEABLE TO POWER - ICCTP = -\$25/kWh

$$\frac{\text{Capital Cost Saved}}{\text{Process Heat}} = \left(\frac{CCS}{H}\right) = \$60{,}300/10^6 \text{ Btu/hr}$$



COGENERATION SYSTEM CAPITAL COST = C_{CG} = 56.5 ,

NOCOGENERATION SYSTEM CAPITAL COST = C_{NC} = 120.1

STEAM TURBINE

(Produces excess process heat and costs not calculated)

Legend: Units in 10^6 Dollars

Nocogeneration System

C_b = Process Boiler Capital Cost

C_{NUTIL} = Utility New Plant Capital Cost @ \$800/kW

C_{NC} = Nocogeneration System Capital Cost

Cogeneration System

C_E = Cogeneration ECS Capital Cost

C_{ab} = Auxiliary Boiler Capital Cost

C_{UTIL} = Utility New Plant Capital Cost @ \$800/kW

C_{CG} = Cogeneration System Capital Cost

Figure 3-8b. Cogeneration Systems Capital Cost Diagrams for Gas Turbine and Steam Turbine Energy Conversion Systems Matched to a Medium Integrated Chemical Plant (SIC 2800-2) gas turbine cogeneration system produces 2.7 times as much power as required, it not only displaces a $\$58.4\text{x}10^6$ process boiler, but $\$169\text{x}10^6$ of new utility plant. The steam turbine ECS, on the other hand, produces only 0.7 of the power required and must buy the remaining power from the utility for an added cost to the cogeneration system of $\$17.1\text{x}10^6$ but still saving costs over the nocogeneration system. So the first conclusion is that the cogeneration systems save capital costs over the nocogeneration systems.

Let's look at the cost savings and some of the other capital cost parameters for these two systems. First, the capital cost savings (CCS) are:

	STM-FGD	GT-HRSG
CCS = Nocogeneration - Cogeneration =	120.1-95.2 = $24.9\text{x}10^6\$$;	227.4-85.9 = $141.5\text{x}10^6\$$

The capital cost saved ratio (CCSR) is defined analogous to the fuel energy saved ratio and is:

	STM-FGD	GT-HRSG
$\text{CCSR} = \frac{\text{Nocogeneration - Cogeneration}}{\text{Cogeneration}} =$	$\frac{120.1-95.2}{120.1} = 0.21$;	$\frac{227.4-85.9}{227.4} = 0.62$

both of which are significant savings to the nation. But most cogeneration plants are owned by industry and their management is only interested in their on-site capital costs which were expressed as the on-site capital cost ratio (CCR) of the cogeneration plant which included the ECS C_E, and auxiliary boiler C_{ab}, if required, over the nocogeneration system on-site cost which is only the process boiler, C_b, and for these matches are:

	STM-FGD	GT-HRSG
$\text{CCR} = \frac{C_E+C_{ab}}{C_b} =$	$\frac{73.8+0}{58.4} = 1.26$	$\frac{85.9+0}{58.4} = 1.47$

Another parameter related to capital costs is the incremental capital chargeable to power (CCTP) which, analogous to the increment of fuel chargeable to power, is equal to the capital cost of the on-site ECS, C_E, and auxiliary boiler, C_{ab}, minus the nocogeneration process boiler, C_b, over the power, P_E, produced by the ECS or:

$$\text{ICCTP} = \frac{C_E + C_{ab} - C_b}{P_E} = \overbrace{\frac{3.413(73.8+0-58.4)10^6}{190.5 \times 10^3}}^{\text{STM-FGD}} = \$276/\text{kW}; \quad \overbrace{\frac{3.413(85.9+0-58.4)10^6}{721 \times 10^3}}^{\text{GT-HRSG}} = \$130/\text{kW}$$

A similar analysis was carried out for the gas turbine ECS power matched to the process and the results are shown in Figure 3-8b. Note that in this match the ICCTP is:

$$\text{ICCTP} = \frac{C_E + C_{ab} - C_b}{P_E} = \frac{3.413(33.4+23.1-58.4)10^6}{264 \times 10^3} = -\$25/\text{kW}$$

The negative ICCTP results from the low cost of the gas turbine ECS and its oil-fired auxiliary boiler compared to the nocogeneration coal-fired process boiler. As in the case of incremental fuel chargeable to power, these incremental capital chargeable to power are astoundingly low and are of interest primarily to the utility who is looking at cogeneration versus other new power plant options as an alternate method of generating power.

Table 3-9

FUEL ENERGY AND CAPITAL COST SAVED RATIOS, INCREMENTAL FUEL AND CAPITAL COST CHARGEABLE TO POWER AND FUEL AND CAPITAL SAVED PER UNIT PROCESS HEAT OF A STEAM TURBINE AND GAS TURBINE WITH HEAT RECOVERY STEAM GENERATOR, HEAT AND POWER MATCHED TO A MEDIUM INTEGRATED CHEMICAL PLANT

	Steam Turbine		Gas Turbine w/HRSG	
Fuel Energy and Capital Cost Saved Ratios	FESR	CCSR	FESR	CCSR
Heat Match	0.18	0.21	0.29	0.62
Power Match	0.02	---(1)	0.18	0.53
Fuel & Capital Chargeable to Power	IFCTP Btu/kWh	ICCTP $/kW	IFCTP Btu/kWh	ICCTP $/kW
Heat Match	4013	276	5898	130
Power Match	10090	---(1)	5893	-25
Fuel & Capital Saved per Unit Process Heat	$\left(\frac{FES}{H}\right)$ $\frac{Btu}{Btu}$	$\left(\frac{CCS}{H}\right)$ $\frac{\$}{10^6\ Btu/hr}$	$\left(\frac{FES}{H}\right)$ $\frac{Btu}{Btu}$	$\left(\frac{CCS}{H}\right)$ $\frac{\$}{10^6\ Btu/hr}$
Heat Match	0.351	23600	0.955	134,300
Power Match	0.042	---(1)	0.349	60,300
On-Site Fuel & Capital Cost Ratios	OSFR	OSCCR	OSFR	OSCCR
Heat Match	1.18	1.26	2.01	1.47
Power Match	1.63	---(1)	1.37	0.97

Note:
(1) Match dropped because produces excess unusable process heat.

Economic Evaluation

In the above discussion we saw that while cogeneration saves fuel and capital cost, from a national standpoint compared to nocogeneration, the onsite cogeneration plant has a higher capital cost and fuel consumption than the onsite nocogeneration process boiler. When the cogeneration plant is to be entirely owned by industry, the economic criteria used by industrial management in deciding between alternate methods of satisfying their power and heat requirements include:

1. Minimum Capital Cost

2. Rate of return on investment (ROI). The rate of return (decrease in energy cost) on the investment (increase in capital cost) must exceed a "hurdle rate" for that industry

3. Minimum cost of energy (levelized annual energe cost - LAEC).

Until recently, industrial management tended to weigh criteria 1 and 2 most heavily in their choice which emphasizes the short term effects. More consideration is now being given to the longer term trends in fuel and power availability and the resulting increasing energy costs because the cost of energy is becoming a significant portion of industries contributed value in producing a product.

In the remainder of this section economic parameters will be defined which measure the extent the cogeneration systems meet the above criteria for implementation by industrial owners. As in the discussion of performance and costs, the method of analysis will be illustrated for a back pressure steam turbine with a coal-fired boiler and FGD and a residual-fired open cycle gas turbine cogeneration system compared with a nocogeneration system consisting of a coal-fired process boiler with FGD and purchased power from a utility.

The complete groundrules used in the economic analysis of industrially owned cogeneration plants are given in Table 3-3. Some of the key groundrules are shown in Table 3-10.

Table 3-10

ECONOMIC GROUNDRULES FOR INDUSTRIALLY OWNED COGENERATION
(All Costs are 1985 Costs in 1978 Dollars)

Annual Inflation Rate	0
Cost of Coal	$\$1.80/10^6$ Btu
Cost of Residual	$\$3.10/10^6$ Btu
Cost of Power	\$0.0330/kWh
Revenue from Power	\$0.0198/kWh
Escalation Rate of Fuel & Power (above inflation)	1%/yr
Income Tax Rate	50%
Depreciation Method	Sum of Year Digits
Depreciation Tax Life	15 Years
Investment Tax Credit	10%
First Year of Operation	1990
Local Taxes and Insurance	3%
Economic Life	30 Years

The detailed economic analysis is shown in Volume 5, Section 9 of the CTAS Final Report. Because of the use of 0% inflation (or sometimes called constant dollars) in this economic analysis the values of interest during construction, fixed charge rate and levelization factor on fuel and power have the following low values:

Interest During Construction	= 0.075
Fixed Charge Rate	= 0.0706
Levelization Factor on Power and Fuel	= 1.1277

Return on Investment (ROI) Analysis

ROI is the discount rate which makes the summation of the difference in discounted[1], after tax cash flows for two alternative power plants

(1) The "discounted value" or sometimes called "present worth" value of \$1 received 10 years from now in 1978 dollars at an inflation rate of 7% and a cost of capital (interest rate) above inflation of 5% for a total discount rate of (1+.07) (1+.05) - 1 = 0.124 is

$$\text{Discounted Value of } \$1 = \frac{1}{(1.124)^{10}} = 0.31$$

in 1978 dollars. In this study all calculations are done in 1978 dollars, which is another way of saying that the inflation rate is set equal to zero in all calculations unless specifically noted.

over their economic life equal their difference in capital cost. In this study, cash flow, S_j, is calculated for each year of operation over the ecnonomic life, n, of the plant and is defined as:

$$S_j = \text{Cash Flow} = \text{Revenues} - \text{Cash Operating Expenses} - \text{Income Tax} \quad (1)$$

where the income tax is

$$\text{Income Tax} = \text{Income Tax Rate (Revenues - Cash Operating Expenses - Tax Depreciation)} - \text{Investment Tax Credit} \quad (2)$$

The definition of ROI defined above can be expressed algebraically as the value of ROI which satisfies the equation:

$$C_{COGEN} - C_{NOCOGEN} = \sum_{j=1}^{n} \frac{(S_j)_{COGEN} - (S_j)_{NOCOGEN}}{(1 + ROI)^j} \quad (3)$$

where

C_{COGEN} = Capital cost of cogeneration system

$C_{NOCOGEN}$ = Capital cost of nocogeneration system

j = Years of plant operation = 1, 2, 3, etc. to 30

n = Economic Life = 30 years

Cash flows for the nocogeneration base case, $S_{j\ NOCOGEN}$, and alternate cogeneration system, $S_{j\ COGEN}$, are calculated for each of the 30 years of operation by substituting these values into Equation (2) to obtain the income tax and Equation 1 for the cash flow. Revenue is from the sale of excess power (if any) to the utility and cash operating expenses include fuel, purchased power, operating and maintenance and local taxes and insurance. Cost of capital is not included as an operating expense and is included as part of the ROI[(2)]. Different values of trial ROI's are used to calculate the sum of the "discounted" differential cash flows until,

---

(2) The ROI calculated in this report is based on zero inflation and may be converted to an ROI_i with inflation at any rate, i per year, by the expression

$$ROI_i = (1+ROI)(1+i)-1$$

by iteration, the value of ROI is found which makes the total discounted differential cash flows equal the difference in capital cost. This iterative calculation for ROI is best done by a computer although we'll see below a graphical approximation which is very helpful in understanding some of the interaction of the various cost components on ROI.

The ROI's for the heat and power matched gas turbine with heat recovery steam generator (GT-HRSG) and coal-fired steam turbine with flue gas desulfurization (STM-FGD) compared with a nocogen coal-fired and residual-fired process boiler are shown in Table 3-11.

Table 3-11

RETURN ON INVESTMENT (ROI) FOR INDUSTRIALLY OWNED COGENERATION STEAM TURBINE - COAL-FIRED BOILER OR RESIDUAL-FIRED GAS TURBINE WITH HRSG APPLIED TO MEDIUM INTEGRATED CHEMICAL PLANT

Nocogeneration Base Case	Type Match	Steam Turbine Coal - FGD	Gas Turbine-HRSG Residual
Coal-Fired Process Boiler	Heat	45%	0%
	Power	--	-62
Residual-Fired Process Boiler	Heat	35	13
	Power	--	24

As we will see in later discussion the primary reason that the gas turbine-HRSG does not have a good ROI when the nocogen boiler is coal-fired is the much higher cost of the gas turbine residual fuel compared to that of the coal for the nocogen process boiler. When the gas turbine-HRSG is compared to the residual-fired nocogen boiler and both systems are using the same high priced residual, the gas turbine gives good ROI's.

Levelized Annual Energy Cost (LAEC) Analysis

The levelized annual energy cost is defined as the minimum constant revenue required each year over the life of the power plant to cover all expenses, the cost of money and recovery of the initial investment. This calculation of LAEC is often referred to as the "utility method" cost calculation and includes the cost of capital, recovery of investment, income tax, depreciation, local real estate taxes, fuel and operating and maintenance costs and the cost of purchased power or revenue from exported power in the units of total energy system costs in 1978 dollars per year. The LAEC is equal to:

$$\begin{aligned} \text{LAEC} = {} & \text{levelized fixed charges} \\ & + \text{levelized operating costs} \\ & - \text{levelized revenues} \end{aligned} \tag{4}$$

The levelized fixed charges (LFC) are analogous to the annual mortgage payments an individual makes on his loan to purchase his house except that factors are included to take into account the tax deductions for interest, depreciation and investment tax credit. The levelized fixed charges (LFC) are calculated by the equation:

$$\text{LFC} = \text{C} \times \text{FCR} \tag{5}$$

where

FCR = fixed charge rate

C = capital investment.

For the economic groundrules used in CTAS including zero inflation, the fixed charge rate is 0.0706. If an inflation of 6.5% is included as well as local taxes and inflation, the FCR is 0.167. A detailed discussion of this low value of FCR and details of the LAEC calculation are given in the Final CTAS Report, Volume V, Section 9.4.

<u>Levelized Operating Expenses and Revenues</u>

The operating expenses or revenue over the operating life of the power plant are levelized to account for their escalation. This levelized cost is the average annual constant payment during the life of the plant required to meet these escalating expenses. Levelization factor is the ratio of the levelized expense divided by the expense in the first year of operation and is calculated for a particular expense item by summing the present worth, using the cost of capital, of each years' expense over the economic life of the power plant and then multiplying by the capital recovery factor for the cost of capital and years of economic life. The equation for the levelization factor is:

$$LF = \frac{LC}{Q_o} = \frac{CRF_{m',n}}{CRF_{k,n}} \qquad (6)$$

where

LF = levelization factor

LC = levelized expense

Q_o = expense during first year of operation

m' = after tax cost of capital = 0.0535

n = economic life of plant = 30 years

$k = \frac{1+m'}{1+e} - 1 = 0.0437$

e = escalation rate of expense = 0.01

$CRF_{m',n}$ = capital recovery factor at m' interest for n years(3)

$$= \frac{m'(1+m')^n}{(1+m')^n - 1} = \frac{0.0535(1.0535)^{30}}{(1.0535)^{30} - 1} = 0.0677$$

$$CRF_{k,n} = \frac{k(1+k)^n}{(1+k)^n - 1} = \frac{0.0437(1.0437)^{30}}{(1.0437)^{30} - 1} = 0.0600$$

$$LF = \frac{0.0677}{0.0600} = \underline{\underline{1.1277}}$$

Because these levelization factors can be very large for even 10% total escalation rates as shown in Figure 3-9, it is very important in comparing

---

(3) The capital recovery factor is the yearly equal installment payment to repay a $1 loan at m' interest over n years.

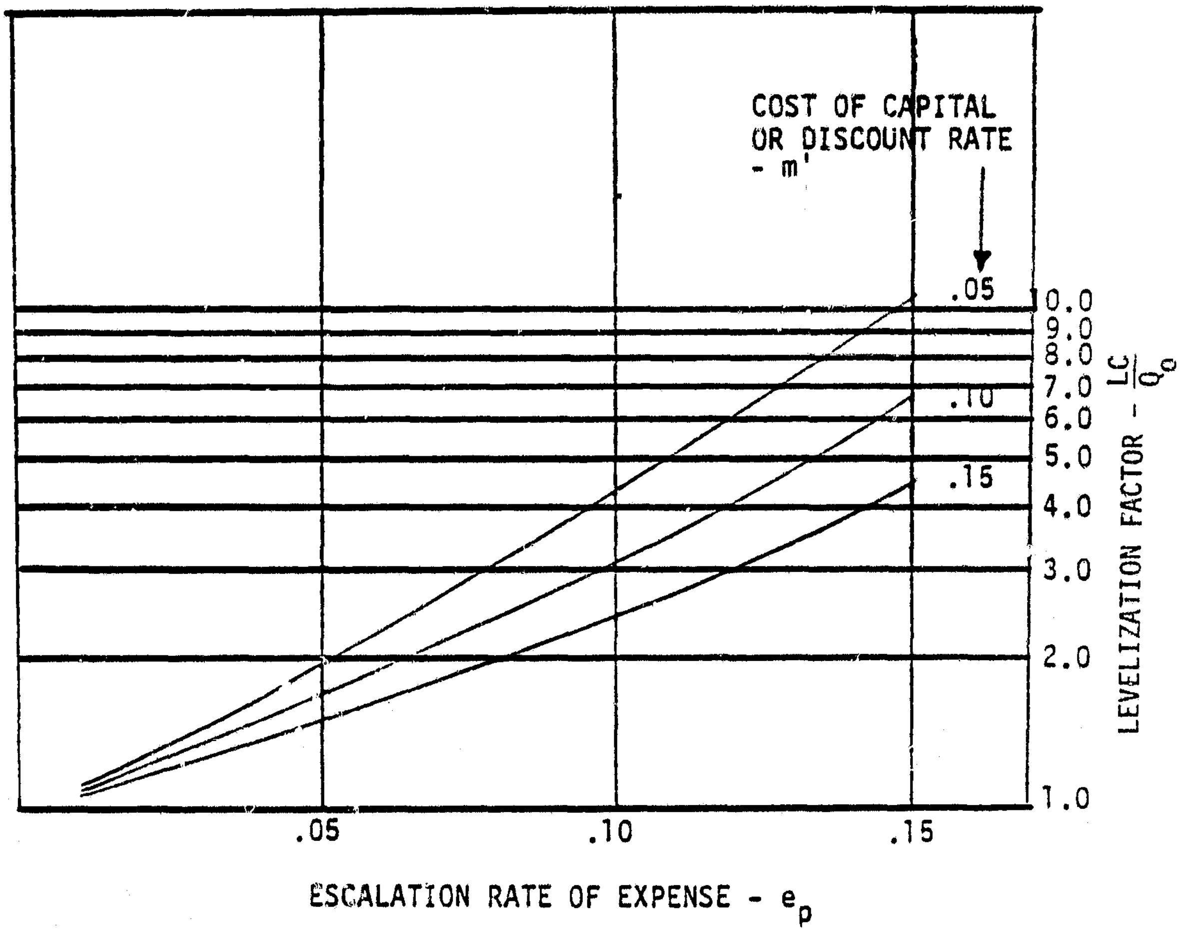


Figure 3.9. Levelization Factors for Range of Expense Escalation Rates and Costs of Capital (Economic Life = 30 Years).

levelized costs to understand the groundrules on inflation and the escalation above inflation of the expense or revenue. In CTAS the inflation rate was set at zero and only the escalation of the expense or revenue above the inflation rate is used to give a levelization factor of 1.128 on oil, coal, and electric power prices.

This levelized operating cost and revenue portion of the LAEC of equation (4) is:

$$\begin{aligned} \text{Levelized Expenses} = {} & \text{local taxes and insurance} \\ & + \text{operating and maintenance} \\ & + \text{purchased fuel} \\ & + \text{purchased electricity} \\ & - \text{revenue from export power} \end{aligned} \tag{7}$$

The levelized annual energy costs for the steam turbine and gas turbine heat and power matched to the medium integrated chemical plant are shown in Table 3-12 along with a nocogeneration coal-fired boiler as well as a residual-fired boiler. Notice the very large effect fuel and power costs have on the total LAEC. The table also shows the levelized annual energy cost savings ratio (LAECSR) which is defined as:

$$\text{LAECSR} = \frac{\text{LAEC}_{\text{NOCOGEN}} - \text{LAEC}_{\text{COGEN}}}{\text{LAEC}_{\text{NOCOGEN}}} \tag{8}$$

and values are shown for both the coal-fired and residual-fired nocogen boilers.

Selection of Cogeneration Systems Based on Economic Criteria

In the introduction of this section the economic criteria used by industrial management in deciding between alternate methods of satisfying their process heat and power requirements were low capital cost, a return on investment which exceeded the industry's "hurdle rate" and minimum cost of energy.

A graphic method of portraying these economic parameters, their relationships and the application of the above selection criteria is shown

Table 3-12

LEVELIZED ANNUAL ENERGY COST (LAEC) ELEMENTS, SAVINGS RATIO (LAECSR) AND RETURN ON INVESTMENT (ROI) OF STEAM TURBINE-COAL FGD AND GAS TURBINE-HRSG-RESIDUAL COGENERATION COMPARED TO COAL OR OIL FIRED PROCESS BOILER NOCOGENERATION OWNED BY MEDIUM INTEGRATED CHEMICAL PROCESS-SIC 2800-2

ECS	MATCH	CAPITAL COST	← Levelized Costs - 10^6 \$/yr						→		
			CAPI-TAL	TAXES & INSURANCE	O&M	FUEL	PURCHASED POWER	REVENUE	TOTAL LAEC	LAECSR	ROI
Nocogen Process Coal Boiler		58.4	4.43	1.88	3.09	22.95	26.03	0	58.38	----	----
Steam Turbine Coal-FGD	Heat	73.8	5.60	2.38	3.88	27.11	7.14	0	46.11	0.21	45
Gas Turbine-HRSG Residual	-Heat	85.9	6.36	2.70	2.80	79.21	0	-27.12	63.96	-0.10	0
	-Power	56.5	4.19	1.78	2.30	54.02	0	0	62.29	-0.07	-62
Nocogen Process Residual Boiler		32.9	2.43	1.04	1.33	39.52	26.03	0	70.35	----	----
Steam Turbine	-Power	73.8	5.60	2.38	3.88	27.11	7.14	0	46.11	0.34	35
Gas Turbine-HRSG	-Heat	85.9	6.36	2.70	2.80	79.21	0	-27.12	63.96	0.09	13
	-Power	56.5	4.19	1.78	2.30	54.02	0	0	62.29	0.11	24

in Figure 3-10. Coal and oil-fired nocogeneration and coal-fired steam turbine and residual-fired gas turbine cogeneration systems all matched to a medium integrated chemical process are plotted at the intersection of their LAEC and capital cost of this graph. A very important characteristic of this graph is that the ROI is a function of the slope of the line connecting any two power plant alternatives plotted on this graph. This correlation was used to derive the "ROI Protractor" shown on Figure 3-10.

The first criterion in selecting a power plant to meet the energy requirements of the industrial process is minimum capital cost and, in this example, is represented by power plant A, a liquid-fired nocogeneration boiler and purchasing the required power from the utility. The next higher capital cost alternative with a lower LAEC is cogeneration oil-fired system B having a modest savings in LAEC at a considerable increase in capital cost and giving a ROI of 24% on the increase in incremental investment over system A, and other factors being equal, would almost always be selected over system A. The next higher capital cost system with lower LAEC is system C, the coal-fired nocogeneration boiler and has an ROI = 100% on the incremental investment between C and B. System D gives a significant reduction in LAEC over C at considerable increase in capital cost but yields a ROI = 45% on the incremental increase in capital cost. System E would not be considered because its LAEC and capital cost are higher than D's. Therefore, if other factors were equal and the high capital cost could be obtained, system D would be selected. If there were additional alternatives to be considered, they would be added to the plot and the process continued until the ROI of the next alternative is less than the "hurdle rate" established by management.

This plot is also very convenient in seeing the effect of changes in capital, fuel or power costs. Using the data in Table 3-12, the effect of increasing the fuel cost 50% for system A is shown by point M, system B by point N and system E by O. The slope of the line connecting M and N shows this fuel price increase reduces the ROI from 24% to 7%. The effect of a 50% increase in the price of power on the relative economics of systems

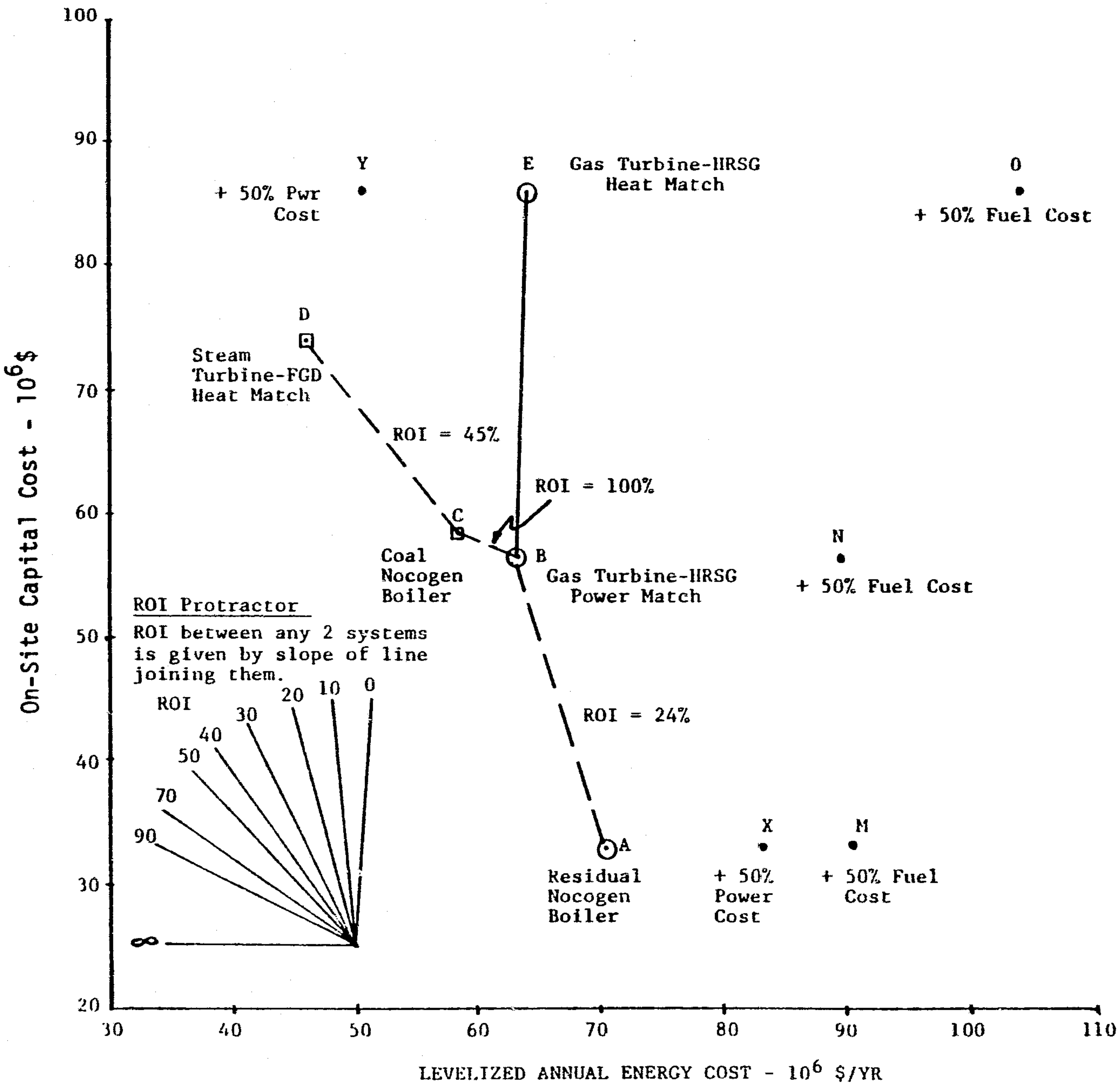


Figure 3-10. Economics of Medium Integrated Chemical Industrial Owned Coal-Fired Steam Turbine-FGD and Residual-Fired Gas Turbine with Heat Recovery Steam Generator Cogeneration Compared Nocogen Coal or Residual Process Boiler and Purchase Power from Utility

A and B can be seen finding the ROI = 47% of the line X-B (system B is a power match and purchases no power). The effect on system A and E may be seen by connecting X-Y to give an increase in ROI from 13% to 36%. Note in the latter case system E exports surplus power to the utility and, since the revenue received for export power is assumed to be 0.6 times the cost of power, system E's LAEC is reduced because of the 50% increase in power cost.

These examples show the care which must be taken in making economic analyses involving the use of ROI because it is based on taking the difference in capital and operating costs and as a result is very sensitive. The graphical presentation shown here is very helpful in analyzing sensitivities and selecting, based on their economics, the cogeneration system which best meets the above industrial management criteria.

REFERENCES

1. NASA Report CR-134949, Vol. II, Part 2 "ECAS General Electric Phase II Final Report, Volume II Advanced Energy Conversion Systems - Conceptual Designs Part 2, Closed Turbine Cycles", December 1976, General Electric, Brown DH, Pomeroy BD, Shah RP.

2. EPRI Report AF-664, Volume 1, "Comparative Study and Evaluation of Advanced Cycle Systems", February 1978, General Electric, Pomeroy BD, Fleck JJ, Marsh WD, Brown DH, Shah RP.

3. EPRI Report AF-642, "Economic Studies of Coal Gasification Combined-Cycle Systems for Electric Power Generation", January 1978, Fluor Engineers and Constructors, Irvine, CA.

4. EPRI Report AF-753, "Economics of Texaco Gasification-Combined-Cycle Systems", April 1978, Fluor Engineers and Constructors, Irvine, CA.

Section 4

COMPUTER SYSTEMS ANALYSIS

INTRODUCTION

The computer system designed for CTAS was used extensively in Task II through Task VI for the analysis of all cogeneration options addressed in the study. The objective of this section is to describe how the computer system was used in this study. In the discussion that follows the process and economic data bases are described, the computer program logic and system flow charts are described where necessary, and typical reports are shown.

PROCESS DATA BASE

An extremely large volume of data was gathered during the process characterization of Task II. The computer system flow chart for handling the Task II process data is shown in Figure 4-1. Specific items (Table 4-1) needed for the systems analysis were extracted from this data and entered into the process data base using the form shown in Table 4-2.

Creating and Updating

The computer program NEWPROC creates the data base by using questions and answers at a timesharing terminal. Updates to the data base utilize the same input form (Table 4-2) and are processed through program CHGPROC. This results in specific changes to specific processes. The output of this program contains only those process descriptions updated so that the updated processes may be verified before merging with the entire data base. Program PROCMAS updates each process with a general change.

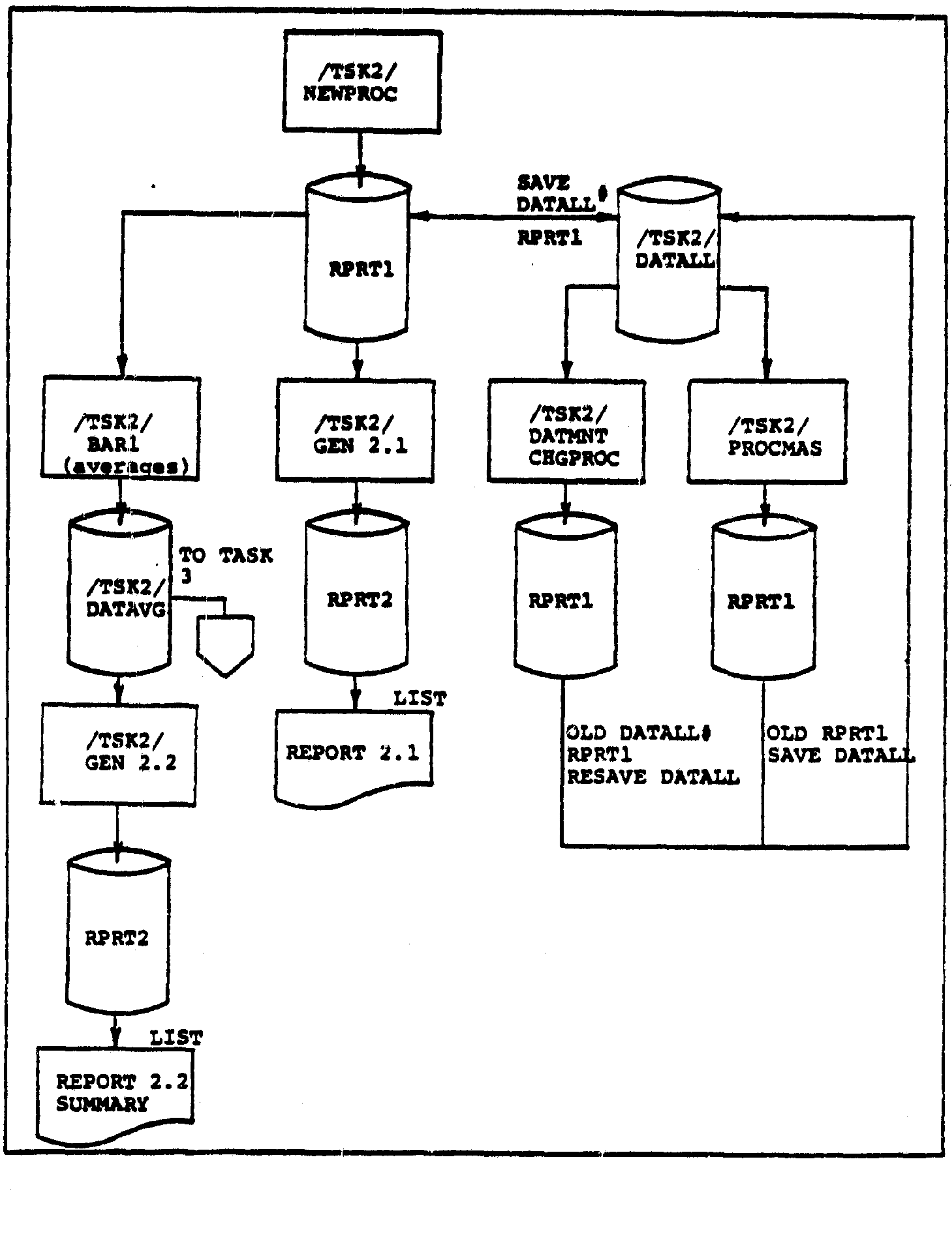


Figure 4-1. Industrial Process Data Handling - Data Base Creating, Updating and Reporting

Table 4-1

CONTENTS OF CTAS PROCESS DATA BASE

SIC Code.

Process Description.

Product.

Plant Size.

Steam Requirements (maximum of 3): flow, psig, % return, temperature of return.

Other Heat to Process: Description, Btu/hr, temperature.

Operational Time: Hr/yr.

Large Horsepower Loads: Number, horsepower, type drive.

Waste Heat Streams (maximum of 3): Type, flow, temperature, service.

Fuel: Type and quantity (maximum of 2).

By-Product Fuel: Type and quantity.

Number of New Plants.

Process Status.

Anticipated Changes.

Plant Size in 1978 and 2000.

Economic Criteria for Investment and Hurdle Rate.

Industrial Investment Level in 1985 to 2000.

National Capacity in 1978 and 2000.

National Energy Consumed in 1978, 1985 and 2000.

Cost of Energy as Percent of Operating Cost.

Table 4-2

CTAS DATA INPUT FORM

SIC Code _ _ _ _

Process # _ _ _

Change Code

1 Description ____________________

2 Plant size ____________

3 Plant UM __________

4 KWAVG, KWPEAK ________, ________

5 Steam Loads
Flow,PSIG,%,Temp.
1. ______, ______, ______, ______
2. ______, ______, ______, ______
3. ______, ______, ______, ______

6 Other:Type,BTU,Temp. ______, ______, ______

7 Operating Hours/Yr ______

8 Large HP:#,Total,Type ______, ______, ______

9 Waste Heat:Type,Flow,T,Serv
1. ______, ______, ______, ______
2. ______, ______, ______, ______
3. ______, ______, ______, ______

10 Fuels:Type,Qty
1. ______, ______
2. ______, ______
3. ______, ______

11 Number New Plants ______

12 Economic Criteria ______
ROI ______

13 Capital Invest:$,X10** ______, ______

14 Old or New ______

15 National Capacity:78,2K,UM ______, ______, ______

16 Process Changes ______

20 Growth (%) ______

17 National Energy:78,85,2K ______, ______, ______ (BTU/HR*10**12)

18 Plant Size:78,2K,UM ______, ______, ______

19 Cost of Electricity ______

0 Ends this process & writes

Reports From Process Data

Two reports are generated from the process data base. Program GEN2.1 generates a detailed report of all data stored for this process. Figure 4-2 shows a typical page from this report. This program (GEN2.1) operates on the entire data base or on a portion of the data base containing only those processes recently updated.

Program GEN2.2 generates a summary report of the process data to be used in matching the ECS performance curves in Task III. Figure 4-3 shows one page of this summary report. The contents of this report are described in Table 4-3. This program reads a file created by a program (BAR1) that reads the process data base, accesses the steam tables and generates the reduced process data file for ECS matching.

ECONOMICS DATA BASE

The Economics Data Base is developed in three steps:

1. Fuel savings evaluation
2. Capital cost estimating
3. Return on Investment (ROI) and Levelized Annual Energy Costs (LAEC) analysis

The computer system flow chart for steps 1 and 2 is shown in Figure 4-4.

Fuel Savings Analysis

The first step in establishing the economics data base is matching each process against each potential ECS-fuel combination (computer program MAPANL). (Each match of a process and ECS-fuel combination is called a case.)

ECS Characteristics Table

The data for each ECS is described in Table 4-4 and reported in Figure 4-5. A glossary of the ECS abbreviations used in Figure 4-5 and

```
DATE 11/16/78 TIME 17.08                G E N E R A L   E L E C T R I C   C O.                       SIC CODE 2011
16SE ADV DESIGN ENGR
                                CTAS INDUSTRIAL PROCESS DATA BANK INFORMATION                          PROCESS   1

      PROCESS DESCRIPTION MEAT-PACKING    PRODUCTS MEAT-LARD        SIZE     100   TPD

           SYSTEM LOADS                              FUELS-PROCESS-PLANT-STATUS                 ECONOMIC-NATIONAL FACTO

KILOWATTS AVG  1940   KILOWATTS PEAK  2330

 STEAM REQUIREMENTS=PROCESS+HEATING=
      FLOW               PERCENT     TEMP                                  FUEL    MILLIONS BTU/HR
      LB/HR     PSIG     RETURN      RETURN                                TYPE    QUANTITY
      10**3
  1.   24.       15.       25.        180.                 PRIMARY         GAS       27.0         ECONOMIC CRITERIA   DRR
  2.   0.        0.        0.         0.                   SECONDARY       OTHER     15.0         EXPECTED ROI           0.
  3.   0.        0.        0.         0.                   BY-PRODUCT      0         0.           INVESTMENT LEVEL
                                                                                                  1985-2000=
                                                                                                  $ BILLIONS=          2 BOR

 OTHER HEAT TO PROCESS                                                                            NATIONAL CAPACITY
  DIRECT
   MILLIONS OF BTU/HR       2.                        NUMBER OF NEW PLANTS       30               MILLIONS OF TPY
   TEMPERATURE            800.
 OPERATIONAL HOURS PER YEAR  2100                     PROCESS STATUS-    OLD                       1978          18 000
 LARGE HORSEPOWER LOADS                               ANTICIPATED PROCESS CHANGES                  2000          23 000
                                                        NONE
   NUMBER                   1

   TOTAL HP               320                         PLANT SIZE   TPD

   TYPE DRIVE          MOTOR                          1978         100

 WASTE HEAT STREAMS                                   2000         180

             FLOW    TEMP    SERVICE                                                          NATIONAL ENERGY CONSUMED
     TYPE    LB/HR                                                                            TRILLIONS BTU PER YEAR
             10**3
  1.AIR      120.    450.    BOILER-S                                                         1978          117.000
  2.VAPOR     34.    200.    COOK                                                             1985          132 000
  3.AIR       25.    475.    COOK-STA                                                         2000          151.000

                                                                                              COST OF ENERGY AS %
                                                                                              OF OPERATING COST    8
```

4-2. Typical Data Base Report

DATE 11/18/78 TIME 8.75
I&SE-ADV. DESIGN ENGR.

GENERAL ELECTRIC CO.
COGENERATION TECHNOLOGY
ALTERNATIVES STUDY(CTAS)

PAGE 3

SUMMARY OF DATA USED FOR
ENERGY CONVERSION SYSTEM MATCHING
IN THE
LUMBER AND WOOD PRODUCTS
INDUSTRY

SIC. CODE	PROC. NO.	PROCESS DESCRIPTION	PROCESS POWER MWE	PROCESS POWER MBTU /HR	PROCESS HEAT TEMP MBTU /HR	PROCESS HEAT TEMP F PEAK	PROCESS HEAT TEMP F AVG	POWER /HEAT RATIO	LOAD FACTOR HRS/YR	PRIMARY FUEL
2421	1	SOFTWOOD-LUM	1.500	5.123	30.	353.	353.	0.17	4000	0
2436	1	SOFT-PLYWOOD	3.000	10.245	75.	406.	406.	0.14	6000	0
2492	1	PARTICLE-BOA	5.000	17.075	37.	406.	406.	0.46	8000	NAT-GAS

Figure 4-3. Typical Summary Data by SIC Code

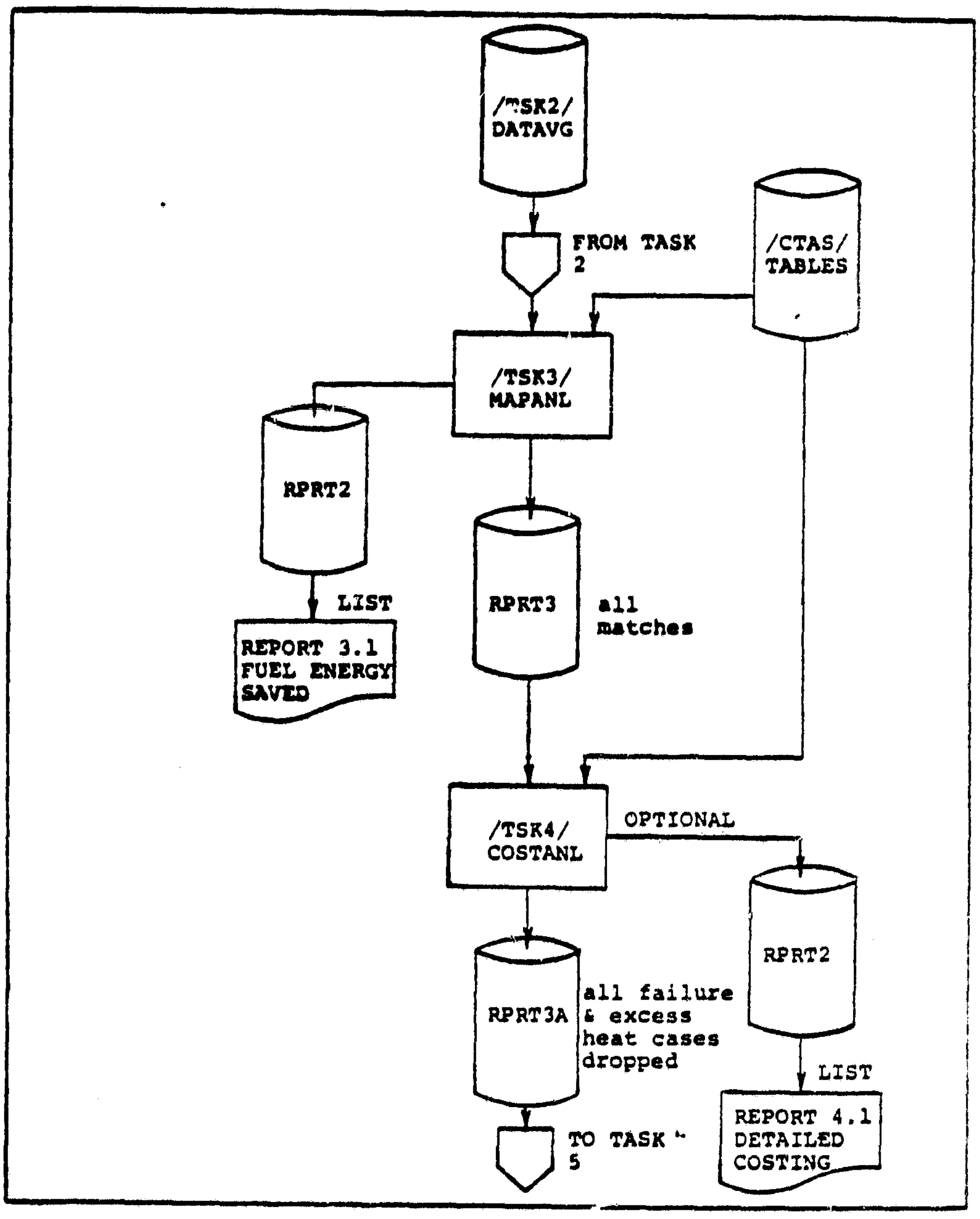


Figure 4-4. ECS Performance and Capital Cost Data Handling - Process and Performance Matching and Capital Costing

DATE 05/10/79 GENERAL ELECTRIC COMPANY
I&SE PEO ENERGY CONVERSION SYSTEM CHARACTERISTICS

ECS		ECS	SIZE MIN MW	SIZE MAX MW	DATE	FUEL PTR D	FUEL PTR R	FUEL COAL D	FUEL COAL R	FUEL COAL F	FUEL COAL A	FUEL COAL P	FUEL COAL X	HEAT A1	HEAT B1 *10**-3	HEAT C1 *10**-6	POWER A2	POWER B2 *10**-3	POWER C2 *10**-6	TEMP MIN	TEMP MAX	DATE REVISED
1	STM141	STM-TURB-1465/10	7.5	100.0	1978	N	Y	N	Y	Y	Y	N	N	0.5159	0.5380	0.0500	0.3341	-0.5380	-0.0500	250	500	11-16-78
2	STM0S8	STM-TURB-865/825	5.0	50.0	1978	N	Y	N	Y	Y	Y	N	N	0.5469	0.5452	0.0600	0.3031	-0.5452	-0.0600	250	450	11-20-78
3	PFBSTM	PFB-STMTB-1465/1	13.0	600.0	1990	N	N	N	N	N	N	Y	N	0.4733	0.4645	0.	0.3833	-0.5051	0.	250	600	11-20-78
4	TISTMT	TI-STMTB-1465/10	12.0	300.0	1995	N	Y	N	Y	N	N	N	Y	0.4281	0.4310	0.0664	0.4149	-0.4310	-0.0664	250	500	11-20-78
5	TIHRSG	THERMIONIC-HRSG	3.0	100.0	1995	N	Y	N	Y	N	N	N	Y	0.7071	-0.0004	-0.4567	0.1407	0.	0.	250	650	11-20-78
6	STIRL	STIRLING-1472F	0.5	2.0	1990	Y	Y	Y	Y	N	N	N	Y	0.4172	0.0891	0.2037	0.3077	-0.0660	-0.2358	220	500	11-16-78
7	HEGT85	HELIUM-GT-85-REG	50.0	300.0	1990	N	N	N	N	N	Y	N	N	0.4460	-0.2737	-1.7050	0.3210	0.	0.	250	400	01-04-79
8	HEGT60	HELIUM-GT-60-REG	50.0	300.0	1990	N	N	N	N	N	Y	N	N	0.4297	0.1910	-1.5600	0.2590	0.	0.	250	550	01-04-79
9	HEGT00	HELIUM-GT-00-REG	50.0	300.0	1990	N	N	N	N	N	Y	N	N	0.6044	-0.4000	0.2270	0.1760	0.	0.	250	600	01-04-79
10	FCMCCL	FUEL-CL-MOLTCARB	100.0	1000.0	1990	N	N	N	N	N	N	N	Y	0.4783	-0.0046	-0.0245	0.3040	0.	0.	250	650	11-16-78
11	FCSTCL	FUEL-CL-STMTB-CO	125.0	1250.0	1990	N	N	N	N	N	N	N	Y	0.2373	0.3150	0.	0.4918	-0.3150	0.	250	500	11-16-78
12	IGGTST	INT-GAS-GTST-12/	80.0	500.0	1990	N	N	N	N	N	N	N	Y	0.3100	0.3225	0.0300	0.4000	-0.3225	-0.0300	250	500	01-22-79
13	GTSOAR	GT-HRSG-10/1750R	10.0	60.0	1978	N	Y	N	Y	N	N	N	N	0.4941	-0.0820	-0.2989	0.2906	0.	0.	250	600	11-16-78
14	GTAC08	GT-HRSG-08/2200R	14.0	136.0	1985	N	Y	N	Y	N	N	N	N	0.4303	0.1564	-0.1715	0.2700	0.	0.	250	600	11-16-78
15	GTAC12	GT-HRSG-12/2200R	14.0	143.0	1985	N	Y	N	Y	N	N	N	N	0.5161	-0.2437	0.2783	0.3050	0.	0.	250	600	11-16-78
16	GTAC16	GT-HRSG-16/2200R	14.0	143.0	1990	N	Y	N	Y	N	N	N	N	0.5021	-0.2609	0.1929	0.3230	0.	0.	250	600	11-16-78
17	GTWC16	GT-HRSG-16/2600R	20.0	200.0	1990	N	Y	N	Y	N	N	N	N	0.3991	0.0209	-0.0155	0.3150	0.	0.	250	600	11-16-78
18	CC1626	GTST-16/2600/146	20.0	197.0	1990	N	Y	N	Y	N	N	N	N	0.2260	0.2355	0.0220	0.4516	-0.2355	-0.0220	250	450	11-16-78
19	CC1622	GTST-16/2200/865	26.0	165.0	1990	N	Y	N	Y	N	N	N	N	0.2504	0.2496	0.0275	0.4619	-0.2496	-0.0275	250	450	11-16-78
20	CC1222	GTST-12/2200/146	14.0	143.0	1985	N	Y	N	Y	N	N	N	N	0.2497	0.2604	0.0243	0.4665	-0.2604	-0.0243	250	450	11-16-78
21	CC0822	GTST-08/2200/146	14.0	136.0	1985	N	Y	N	Y	N	N	N	N	0.2957	0.3082	0.0288	0.4613	-0.3082	-0.0288	250	450	11-16-78
22	STIG15	STIG-15-16/2200F	22.0	220.0	1990	N	Y	N	Y	N	N	N	N	0.0130	0.	0.	0.3810	0.	0.	250	430	11-16-78
23	STIG10	STIG-10-16/2200F	19.0	190.0	1990	N	Y	N	Y	N	N	N	N	0.1325	0.	0.	0.3591	0.	0.	250	430	11-16-78
24	STIG1S	STIG-1S-16/2200F	19.0	190.0	1990	N	Y	N	Y	N	N	N	N	0.2108	0.	0.	0.3352	0.	0.	250	430	11-16-78
25	DEADV3	DIESEL-ADVANCED-	2.0	15.0	1990	N	Y	N	Y	N	N	N	N	0.3598	-0.4230	0.	0.3710	0.	0.	250	450	11-20-78
26	DEADV2	DIESEL-ADVANCED-	2.0	15.0	1990	N	Y	N	Y	N	N	N	N	0.2540	0.	0.	0.3710	0.	0.	220	149	11-16-78
27	DEADV1	DIESEL-ADVANCED-	2.0	15.0	1990	N	Y	N	Y	N	N	N	N	0.3910	0.	0.	0.3710	0.	0.	150	227	11-16-78
28	DEHTPM	ADV-DIESEL-HEAT-	2.0	15.0	1990	N	Y	N	Y	N	N	N	N	0.5092	-0.4036	0.5000	0.4012	-0.0197	-0.5000	220	500	11-16-78
29	DESOA3	DIESEL-SOA-3	0.3	10.0	1978	Y	Y	Y	Y	N	N	N	N	0.3258	-0.4230	0.	0.3610	0.	0.	250	450	11-16-78
30	DESOA2	DIESEL-SOA-2	0.3	10.0	1978	Y	Y	Y	Y	N	N	N	N	0.2200	0.	0.	0.3610	0.	0.	155	249	11-16-78
31	DESOA1	DIESEL-SOA-1	0.3	10.0	1978	Y	Y	Y	Y	N	N	N	N	0.4010	0.	0.	0.3610	0.	0.	100	154	11-16-78
32	GTSOAD	GT-HRSG-10/2000D	13.0	72.0	1978	Y	N	Y	N	N	N	N	N	0.5383	-0.3296	0.3167	0.2920	0.	0.	250	600	11-16-78
33	GTRA08	GT-85RE-08/2200D	13.0	130.0	1985	Y	N	Y	N	N	N	N	N	0.4038	0.0554	-0.6556	0.3570	0.	0.	250	600	11-16-78
34	GTRA12	GT-85RE-12/2200D	14.0	137.0	1985	Y	N	Y	N	N	N	N	N	0.4097	0.0097	-0.5019	0.3580	0.	0.	250	600	11-16-78
35	GTRA16	GT-85RE-16/2200D	14.0	138.0	1990	Y	N	Y	N	N	N	N	N	0.4251	-0.0315	-0.3923	0.3490	0.	0.	250	600	11-16-78
36	GTR208	GT-60RE-08/2200D	13.0	130.0	1985	Y	N	Y	N	N	N	N	N	0.4722	-0.1399	-0.1411	0.3200	0.	0.	250	600	11-16-78
37	GTR212	GT-60RE-12/2200D	14.0	138.0	1985	Y	N	Y	N	N	N	N	N	0.4475	-0.0998	-0.1818	0.3300	0.	0.	250	600	11-16-78
38	GTR216	GT-60RE-16/2200D	14.0	139.0	1990	Y	N	Y	N	N	N	N	N	0.4465	-0.0703	-0.2119	0.3376	0.	0.	250	600	11-16-78
39	GTRW08	GT-85RE-08/2600D	17.0	169.0	1990	Y	N	Y	N	N	N	N	N	0.3302	0.0246	-0.4617	0.3510	0.	0.	250	600	11-16-78
40	GTRW12	GT-85RE-12/2600D	19.0	188.0	1990	Y	N	Y	N	N	N	N	N	0.3330	-0.0106	-0.3406	0.3640	0.	0.	250	600	11-16-78
41	GTRW16	GT-85RE-16/2600D	19.0	190.0	1990	Y	N	Y	N	N	N	N	N	0.3503	-0.0560	-0.2192	0.3570	0.	0.	250	600	11-16-78
42	GTR308	GT-60RE-08/2600D	17.0	170.0	1990	Y	N	Y	N	N	N	N	N	0.4497	-0.3540	0.0124	0.3100	0.	0.	250	700	11-16-78
43	GTR312	GT-60RE-12/2600D	19.0	190.0	1990	Y	N	Y	N	N	N	N	N	0.3916	-0.1419	0.0133	0.3420	0.	0.	250	600	11-16-78
44	GTR316	GT-60RE-16/2600D	19.0	190.0	1990	Y	N	Y	N	N	N	N	N	0.3944	-0.1486	0.0273	0.3390	0.	0.	250	600	11-16-78
45	FCPADS	FUEL-CL-PHOSACID	1.0	10.0	1995	Y	N	Y	N	N	N	N	N	0.1700	0.	0.	0.3800	0.	0.	160	600	04-22-79
46	FCMCDS	FUEL-CL-MOLTCARB	4.4	25.0	1990	Y	N	Y	N	N	N	N	N	0.2330	0.	0.	0.4120	0.	0.	300	650	11-16-78

EOF ON TABLES

Figure 4-5. Energy Conversion System Characteristics

Table 4-3

CONTENTS OF EXTRACT OF PROCESS DATA BASE FOR ECS MATCHING

SIC Code
Process Number
Process Description
Process Power Requirements
Process Heat Requirements
Operational Hours Per Year
Primary Fuel
By-Product Fuel Type and Quantity*
Hot Water Requirements*

* Added directly to programs later as needed.

computer reports is shown in Table 4-5. Process temperatures that exceeded the highest allowable temperature for the ECS were deleted from the economic data base during capital costing. All cases where the power generated on site was lower than the minimim size for the ECS were flagged but not deleted.

Fuel Savings Evaluation Program MAPANL. For every process a nocogeneration base case consisting of an on-site process boiler supplying all process heat and a utility supplying all process power is established. For each cogeneration case the ECS is matched to the process in two ways: a power match and a heat match. In the power match case, the ECS is required to generate all process power, completely replacing the utility. The heat generated by this match is then used to satisfy process heat requirements. If insufficient heat is generated, an auxiliary boiler is added to the system. If excess heat is generated the match is flagged and deleted during capital costing.

In the heat match case, the ECS is required to supply all process heat. Power generated in this match replaces utility power. If excess

Table 4-4

CONTENTS OF ECS CHARACTERISTICS TABLE

ECS number

Short ECS Description

Long ECS Description

Minimum Size - MW (for information only)

Maximum Size - MW (for information only)

Expected Date of Commercialization (for information only)

Fuel Options

PTR	=	Petroleum based
Coal	=	Coal based
D	=	Distillate
R	=	Residual
F	=	Coal with flue gas desulfurization (FGD)
A	=	Coal with atmospheric fluidized bed (AFB)
P	=	Coal with pressurized fluidized bed (PFB)
X	=	Plain Coal

If a "Y" appears under these options it means that fuel can be used in that ECS. An "N" means it cannot be used.

Heat Equation

The factors A_1, B_1, and C_1 in the table are used in the following equation to determine the fraction of fuel that is converted to heat:

$$A_1 + B_1 * (\text{Temperature}) + C_1 * (\text{Temperature})^2$$

Power Equation

The factors A_2, B_2, and C_2 are used in the following equation to determine the fraction of fuel that is converted to electric power:

$$A_2 + B_2 * (\text{Temperature}) + C_2 * (\text{Temperature})^2$$

Maximum and Minimum Temperatures for Application of this ECS

Date Revised.

Table 4-5.- GLOSSARY OF ABBREVIATIONS ENERGY CONVERSION SYSTEMS (ECS) AND FUELS

ECS - Fuel Abbreviation	ECS TYPE &	DESCRIPTION	FUEL & UTILIZATION SYSTEM	ECS Performance Characteristics Number	STATUS (State of Art or Advanced)
STM141-Coal F	Steam Turbine	Throttle P=1465 psia; T=1000°F	Coal-Flue Gas Desulfurization	1	SOA
STM141-Coal A	" "	" " " "	Coal-Atmospheric Fluidized Bed	1	ADV
STM141-Residual	" "	" " " "	Residual-Petroleum or Coal Derived	1	SOA
STM088-Coal F	" "	" P=865 psia; T=825°F	Coal-Flue Gas Desulfurization	2	SOA
STM088-Coal A	" "	" " " "	Coal-Atmospheric Fluidized Bed	2	ADV
STM088-Residual	" "	" " " "	Residual-Petroleum or Coal Derived	2	SOA
PFBSTM	PFB Steam Turbine	Gas Turbine T=1000°F Steam Turbine P=1465 psia, T=1000°F	Coal-Pressurized Fluidized Bed	3	ADV
TISTMT-Coal F	Thermionic-Steam Turbine	" " " " "	Coal-Flue Gas Desulfurization	4	ADV
TISTMT-Residual	" " "	" " " " "	Residual-Petroleum or Coal Derived	4	ADV
TIHRSG-Coal F	Thermionic and HRSG(1)		Coal-Flue Gas Desulfurization	5	ADV
TIHRSG-Residual	" " "		Residual-Petroleum or Coal Derived	5	ADV
STIRL-Coal	Stirling Engine	Helium @ T=1472°F	Coal-Flue Gas Desulfurization	6	ADV
STIRL-Residual	" "	" "	Residual-Petroleum or Coal Derived	6	ADV
STIRL-Distillate	" "	" "	Distillate- " " "	6	ADV
HEGT85-Coal A	Closed Cycle Gas Turbine	Helium @ T=1500°F; Regen. Eff.=85%	Coal-Atmospheric Fluidized Bed	7	ADV
HEGT60-Coal A	" " " "	" " " " =60%	" " " "	8	ADV
HEGTO-Coal A	" " " "	" " " " = 0%	" " " "	9	ADV
FCMCCL-Coal	Fuel Cell, Molten Carbonate,	HRSG	Coal-Integrated Gasifier	10	ADV
FCSTCL-Coal	" " " "	, Steam Turbine P=1465 psia; T-1000°F	" " "	11	ADV
FCMCDS-Distillate	" " " "	, HRSG	Distillate-Petroleum & Coal Derived	46	ADV
FCPADS-Distillate	" " , Phosphoric Acid,	HRSG	" " " "	45	ADV
GTSOAR-Residual	Gas Turbine AC(2) with	HRSG, P/P=10, T=1750°F	Residual - " " "	13	SOA
GTSOAD-Distillate	" " " "	" " =2000°F	Distillate- " " "	32	SOA
GTAC08-Residual(4)	" " " "	" , P/P=8, T=2200°F	Residual - " " "	14	ADV
GTAC12-Residual	" " " "	" , P/P=12, T=2200°F	" " " "	15	ADV
GTAC16-Residual	" " " "	" , P/P=16, T=2200°F	" " " "	16	ADV
GTWC16-Residual	" " WC(3)	" " T=2600°F	" " " "	17	ADV
CC1622-Residual	Combined Cycle, AC, P/P=16,	T=2200; STM TURB P=865, T=825°F	" " " "	19	ADV
CC1222-Residual	" " " P/P=12,	" " " P=1465, T=1000°F	" " " "	20	ADV
CC0822-Residual	" " " P/P=8,	" " " " "	" " " "	21	ADV
CC1626-Residual	" " , WC, P/P=16,	T=2600; " " " "	" " " "	18	ADV
IG GT ST-Coal	" " , AC, P/P=12,	T=2100; " " " "	Coal, Integrated Gasifier	12	ADV
STIG15-Residual	Steam Injected Gas Turbine,	AC, HRSG, P/P=16, T=2200, 15% Super. Steam	Residual-Petroleum or Coal Derived	22	ADV
STIG10-Residual	" " " "	" " " " " , 10% " "	" " " "	23	ADV
STIGIS-Residual	" " " "	" " " " " , 10% Sat.	" " " "	24	ADV
GTRA08-Distillate	Gas Turbine, AC, w/HRSG,	Reg. Eff.=85%, P/P=8, T=2200°F	Distillate, " " "	33	ADV
GTRA12-Distillate	" " " "	" " " , P/P=12, "	" " " "	34	ADV
GTRA16-Distillate	" " " "	" " " , P/P=16, "	" " " "	35	ADV
GTR208-Distillate	" " " "	" " =60%, P/P=8, "	" " " "	36	ADV
GTR212-Distillate	" " " "	" " " , P/P=12, "	" " " "	37	ADV
GTR216-Distillate	" " " "	" " " , P/P=16, "	" " " "	38	ADV
GTRW08-Distillate	" " , WC, "	" " =85%, P/P=8 ,T=2600°F	" " " "	39	ADV
GTRW12-Distillate	" " " "	" " " , P/P=12, "	" " " "	40	ADV
GTRW16-Distillate	" " " "	" " " , P/P=16, "	" " " "	41	ADV
GTR308-Distillate	" " " "	" " =60%, P/P=8 , "	" " " "	42	ADV
GTR312-3-Distillate	" " " "	" " " , P/P=12, "	" " " "	43	ADV
GTR316-3-Distillate	" " " "	" " " , P/P=16, "	" " " "	44	ADV
DESOA1-3-Distillate	Medium Speed Diesel with	175°F Jacket Water	" " " "	29-31	SOA
DESOA 1-3-Residual	" " " "	" "	Residual, " " "	29-31	SOA
DESADV1-3-Residual	" " " "	250°F " "	" " " "	25-27	ADV
DEHTPM-Residual	" " " "	" " " w/Vapor Compression Heat Pump	" " " "	28	ADV

(1) HRSG - Heat Recovery Steam Generator
(2) AC - Air Cooled
(3) WC - Water Cooled
(4) Detailed analysis of the effect of cycle variations on simple, steam injected and regenerative gas turbines and combined cycles are shown in Volume VI - Computer Data.

power is generated, it is exported to the grid. (In this case a new equivalent nocogeneration case requires that the utility be evaluated as if it were generating as much power as the ECS in this heat match case (all process power plus all power exported).) If insufficient power is generated, the shortfall is purchased from the utility. The methodology for this matching is shown in Figure 4-6.

Almost 7200 cases were evaluated and for each case detailed fuel usage reports, Figure 4-7, were generated. Output includes fuel used and power and heat generated by the ECS, process boiler fuel used, utility fuel used or saved, net fuel savings, and fuel energy savings ratio (FESR). FESR is the ratio of fuel energy saved by cogeneration divided by the fuel energy used without cogeneration (all exclusive of waste fuel). Each line represents a case consisting of an industrial process identified at the top of the figure, an ECS shown on the left, either a power or heat match, and the ECS fuel type. A 1 in the fail column indicates that the ECS cannot supply heat at the required temperature and a 10 indicates that the ECS is outside the size range for which the cost data is considered accurate.

Capital Cost Estimating

The second step in establishing the economic data base is capital cost estimating for each case that was not previously flagged for having exceeded the temperature limits of the ECS or for having excess heat generated.

Component Cost Table. The Component Cost Table, Figure 4-8, contains all major components used in each ECS. A component may be part of many different ECS's, but it occurs only once on this table. This provides a consistent estimate for that component independent of ECS application. The component cost table is described in Table 4-6.

Component Logic Table. The Component Logic Table, Table 4-7, contains the specific components to be costed for each ECS and special logic

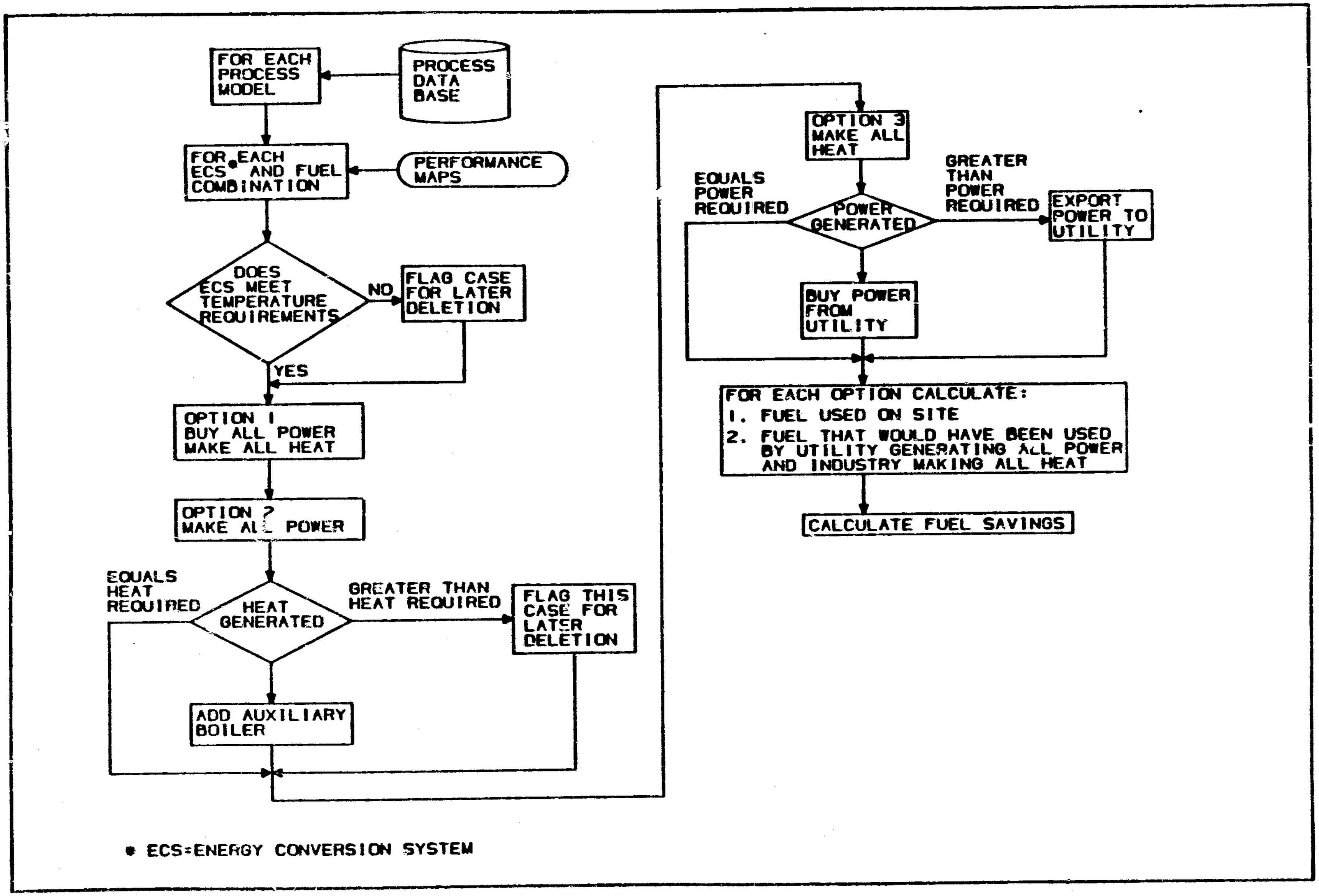


Figure 4-6. CTAS Matching of Process Model to Energy Conversion Systems Performance Maps

DATE 04/28/78 GENERAL ELECTRIC COMPANY PAGE 1

COGENERATION TECHNOLOGY ALTERNATIVES STUDY

REPORT 8.1

FUEL ENERGY SAVED BY PROCESS AND ECS

1 SE PEG ADV DESIGN ENGR

INDUSTRY 10101 MW 10.00 PROCESS MILLIONS BTU/HR 137.0 PROCESS TEMP(F) 300. PRODUCT NASA-CLBR01 HOURS PER YEAR 8000.

POWER TO HEAT RATIO 0.248

UTILITY FUEL COAL WASTE FUEL EQV BTU*10**6= 118. HOT WATER BTU*10**6= 0.

	WASTE FUEL USED 10**6 BTU/HR	FUEL SAVED= NO-NET 10**6 BTU/HR	COGEN FUEL USED 10**6 BTU/HR	COGEN PROCES HEAT 10**6 BTU/HR	COGEN PROCES POWER 10**6 BTU/HR	COGEN MW ELECT	AUX PROCES BOILR 10**6 BTU/HR	UTILIT FUEL USED 10**6 BTU/HR	TOTAL FUEL SITE 10**6 BTU/HR	SITE FUEL USED	NET= TOTAL+ UTILIT 10**6 BTU/HR	FAIL	FESR	POWER FACTR	HEAT FACTR
0 ONOCON N O C O G E N	118.	0.	0.	0.	0.	0.	181.	107.	181.	COAL-FGD	288.	0	0.	0.13	0.81
1 STM141 STM-TURB-1 POWR	118.	65.	203.	138.	34.	10.	-2.	0.	203.	RESIDUAL	203.	0	0.43	0.17	0.68
1 STM141 STM-TURB-1 HEAT	118.	66.	201.	137.	34.	10.	0.	1.	201.	RESIDUAL	202.	0	0.44	0.17	0.68
1 STM141 STM-TURB-1 POWR	118.	65.	203.	138.	34.	10.	-2.	0.	203.	COAL-FGD	203.	0	0.43	0.17	0.68
1 STM141 STM-TURB-1 HEAT	118.	66.	201.	137.	34.	10.	0.	1.	201.	COAL-FGD	202.	0	0.44	0.17	0.68
1 STM141 STM-TURB-1 POWR	118.	65.	203.	138.	34.	10.	-2.	0.	203.	COAL-AFB	203.	0	0.43	0.17	0.68
1 STM141 STM-TURB-1 HEAT	118.	66.	201.	137.	34.	10.	0.	1.	201.	COAL-AFB	202.	0	0.44	0.17	0.68
2 STM088 STM-TURB-8 POWR	118.	13.	284.	182.	34.	10.	-83.	0.	284.	RESIDUAL	284.	0	[illegible]	0.13	0.84
2 STM088 STM-TURB-8 HEAT	118.	80.	181.	137.	26.	8.	0.	28.	181.	RESIDUAL	215.	0	0.33	0.12	0.63
2 STM088 STM-TURB-8 POWR	118.	13.	284.	182.	34.	10.	-83.	0.	284.	COAL-FGD	284.	0	0.08	0.13	0.84
2 STM088 STM-TURB-8 HEAT	118.	80.	181.	137.	26.	8.	0.	28.	181.	COAL-FGD	216.	0	0.33	0.12	0.63
2 STM088 STM-TURB-8 POWR	118.	13.	284.	182.	34.	10.	-83.	0.	284.	COAL-AFB	284.	0	0.08	0.13	0.84
2 STM088 STM-TURB-8 HEAT	118.	80.	181.	137.	28.	8.	0.	28.	181.	COAL-AFB	216.	0	0.33	0.12	0.63
3 PFBSTM PFB-STMTB- POWR	118.	66.	147.	90.	34.	10.	55.	0.	202.	COAL-PFB	202.	10	0.44	0.17	0.65
3 PFBSTM PFB-STMTB- HEAT	118.	100.	224.	137.	52.	18.	0.	-85.	224.	COAL-PFB	188.	0	0.48	0.23	0.61
4 TISTMT TI-STMTB-1 POWR	80.	65.	122.	68.	34.	10.	80.	0.	202.	RESIDUAL	202.	10	0.18	0.17	0.68
4 TISTMT TI-STMTB-1 HEAT	118.	35.	66.	37.	18.	5.	118.	48.	183.	RESIDUAL	233.	10	0.23	0.08	0.50
4 TISTMT TI-STMTB-1 POWR	118.	65.	122.	68.	34.	10.	80.	0.	202.	COAL	202.	10	0.44	0.17	0.66
4 TISTMT TI-STMTB-1 HEAT	118.	130.	243.	137.	68.	20.	0.	-106.	243.	COAL	137.	0	0.61	0.28	0.56
5 TIHRSG THERMIONIC POWR	0.	25.	243.	161.	34.	10.	-28.	0.	243.	RESIDUAL	243.	0	-0.62	0.14	0.86
5 TIHRSG THERMIONIC HEAT	118.	12.	58.	37.	6.	2.	118.	82.	173.	RESIDUAL	255.	10	0.06	0.03	0.54
5 TIHRSG THERMIONIC POWR	118.	25.	243.	161.	34.	10.	-28.	0.	243.	COAL	243.	0	0.17	0.14	0.36
5 TIHRSG THERMIONIC HEAT	118.	46.	206.	137.	29.	8.	0.	18.	206.	COAL	222.	0	0.31	0.13	0.62
6 STIRL STIRLING-1 POWR	82.	48.	128.	59.	34.	10.	82.	0.	220.	DISTILLA	220.	0	0.16	0.16	0.62
6 STIRL STIRLING-1 HEAT	118.	30.	80.	37.	21.	6.	118.	40.	198.	DISTILLA	238.	0	0.20	0.08	0.56
6 STIRL STIRLING-1 POWR	82.	48.	128.	59.	34.	10.	82.	0.	220.	RESIDUAL	220.	0	0.16	0.16	0.62
6 STIRL STIRLING-1 HEAT	118.	30.	80.	37.	21.	6.	118.	40.	198.	RESIDUAL	238.	0	0.20	0.08	0.56
6 STIRL STIRLING-1 POWR	118.	48.	128.	59.	34.	10.	92.	0.	220.	COAL	220.	0	0.32	0.16	0.62
6 STIRL STIRLING-1 HEAT	118.	118.	288.	137.	78.	28.	0.	-140.	288.	COAL	188.	0	0.36	0.27	0.46

Figure 4-7. Fuel Energy Saved Report

TYPICAL COST ESTIMATING CONSTANT

Island	Comp.	Component Name	Units of Meas.	Size Min.	Size Max.	Component $x10^6 Min.	Component $x10^6 Max.	% Material Min.	% Material Max.	% Labor Min.	% Labor Max.
3	78	THERMIONIC-LARGE	1	1228.	2456.	40.0	80.0	1.0	1.0	0.90	0.90

OTHER COMPONENTS REQUIRED BY THERMIONICS-STEAM TURBINE 1465/1000 F

COAL FIRED ECS

	LIMESTONE HANDLING
	FGD SCRUBBER
	DC-AC INVERTERS
10	COAL HANDLING
32	STEAM TURBINE-GEN-1450
80	BOP MASTER CONTROL SYSTEM
81	BOP ELECTRIC PLANT
82	BOP PIPING DUCTING & WIRING
83	BOP STRUCTURES & MISC.

Figure 4-8. Example of Capital Cost of Advanced Cogeneration ECS Components

Table 4-6

CONTENTS OF COMPONENT COST TABLE

Island Number:	Groups components into specific costing areas.
Component Number:	Unique number assigned to this component.
Component Name:	For information only.
Unit of Measure:	Determines basis for cost function. 1 = millions Btu/hr. 2 = Megawatts. (This code is an indicator and for special components may be overridden in COSTANL.)
Minimum and Maximum Size:	In the same units as the unit of measure. When the maximum size is exceeded, multiple units are used. When unit is below minimum, no special actions are taken.
Component Cost:	Cost of major component (a function of size).
Material Cost:	Cost of installation material as a percentage of component cost (a function of size).
Labor Cost:	Cost of installed labor as a percentage of component cost (a function of size).

Table 4-7

CTAS COMPONENT LOGIC TABLE

Line No.	Table No.	ECS No.	ECS ID	Limestone Dolomite	Conventional Boiler	AFB or PFB	Gasifier	Reformer	Prime Mover Logic	ST Non-Cond	Gas Turbine	Diesel Engine Generator	Thermionic Generator	Stirling Engine	Fuel Cell	ST	HRSG	HRSG Logic	Condensing ST	Bottom Cycle	Cooling Tower	Heat Exchanger	Water Conditioner
				COMPONENT																			
				Number on Cost Table																			
2020	100	22	ST1615	0	0	0	0	0	1	0	26	0	0	0	0	0	47	3	0	0	0	0	39
2030	100	23	ST1610	0	0	0	0	0	1	0	26	0	0	0	0	0	47	2	0	0	0	0	39
2040	100	24	ST1615	0	0	0	0	0	1	0	26	0	0	0	0	0	47	2	0	0	0	0	39
2050	100	18	CC1626	0	0	0	0	0	2	0	106	0	0	0	0	32	56	7	0	0	0	0	0
2060	100	21	CC0822	0	0	0	0	0	3	0	103	0	0	0	0	32	55	4	0	0	0	0	0
2070	100	20	CC1222	0	0	0	0	0	4	0	104	0	0	0	0	32	50	5	0	0	0	0	0
2080	100	19	CC1622	0	0	0	0	0	5	0	105	0	0	0	0	31	49	6	0	0	0	0	0
2090	100	12	IGGTST	0	0	0	16	0	6	0	66	0	0	0	0	32	56	8	0	0	0	0	0
2100	100	3	PFBSTM	37	0	33	0	0	7	0	35	0	0	0	0	32	0	0	0	0	0	0	0
2110	100	7	HEGT85	0	0	12	0	0	1	0	60	0	0	0	0	0	0	0	0	0	89	0	0
2120	100	8	HEGT60	0	0	14	0	0	1	0	62	0	0	0	0	0	0	0	0	0	89	0	0
2130	100	9	HEGT00	0	0	13	0	0	1	0	61	0	0	0	0	0	0	0	0	0	89	0	0
2140	100	10	FCMCCL	0	0	0	15	0	8	0	0	0	0	0	98	0	0	0	0	0	0	0	0
2150	100	46	FCMCDS	0	0	0	0	16	8	0	0	0	0	0	99	0	0	0	0	0	0	0	0
2160	100	45	FCPADS	0	0	0	0	18	8	0	0	0	0	0	99	0	0	0	0	0	0	0	0
2170	100	11	FCSTCL	0	0	0	15	0	9	0	0	0	0	0	98	32	0	0	0	0	0	0	0
2180	100	6	STIRL	0	90	0	0	0	13	0	0	0	0	96	0	0	0	0	0	0	0	0	0
2190	100	5	TIHRSG	0	0	0	0	0	14	0	0	0	77	0	0	0	0	0	0	0	0	0	0
2200	100	4	TISTM	0	0	0	0	0	10	0	0	0	77	0	0	32	0	0	0	0	0	0	0
2210	100	47	NOCOGN	37	1	76	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2220	100	1	STM141	37	1	74	0	0	1	32	0	0	0	0	0	0	0	0	0	0	0	0	0
2230	100	2	STM068	37	1	75	0	0	1	31	0	0	0	0	0	0	0	0	0	0	0	0	0
2240	100	13	GTSOAR	0	0	0	0	0	1	0	101	0	0	0	0	0	42	1	0	0	0	0	0
2250	100	32	GTSOAD	0	0	0	0	0	1	0	102	0	0	0	0	0	46	1	0	0	0	0	0
2260	100	14	GTAC08	0	0	0	0	0	1	0	103	0	0	0	0	0	46	1	0	0	0	0	0
2270	100	15	GTAC12	0	0	0	0	0	1	0	104	0	0	0	0	0	46	1	0	0	0	0	0
2280	100	16	GTAC16	0	0	0	0	0	1	0	105	0	0	0	0	0	46	1	0	0	0	0	0
2290	100	17	GTWC16	0	0	0	0	0	1	0	106	0	0	0	0	0	46	1	0	0	0	0	0
2300	100	28	DEHPTM	0	0	0	0	0	11	0	0	68	0	0	0	0	0	0	0	0	0	0	0
2310	100	27	DEADV1	0	0	0	0	0	12	0	0	68	0	0	0	0	0	0	0	0	0	0	0
2320	100	26	DEADV2	0	0	0	0	0	12	0	0	68	0	0	0	0	0	0	0	0	0	0	0
2330	100	25	DEADV3	0	0	0	0	0	12	0	0	68	0	0	0	0	0	0	0	0	0	0	0
2340	100	31	DESOA1	0	0	0	0	0	1	0	0	68	0	0	0	0	0	0	0	0	0	0	0
2350	100	30	DESOA2	0	0	0	0	0	1	0	0	68	0	0	0	0	0	0	0	0	0	0	0
2360	100	29	DESOA3	0	0	0	0	0	1	0	0	68	0	0	0	0	0	0	0	0	0	0	0
2370	100	33	GTRA08	0	0	0	0	0	1	0	107	0	0	0	0	0	40	1	0	0	0	0	0
2380	100	34	GTRA12	0	0	0	0	0	1	0	108	0	0	0	0	0	42	1	0	0	0	0	0
2390	100	35	GTRA16	0	0	0	0	0	1	0	109	0	0	0	0	0	42	1	0	0	0	0	0
2400	100	39	GTRW08	0	0	0	0	0	1	0	110	0	0	0	0	0	42	1	0	0	0	0	0
2410	100	40	GTRW12	0	0	0	0	0	1	0	111	0	0	0	0	0	42	1	0	0	0	0	0
2420	100	41	GTRW16	0	0	0	0	0	1	0	112	0	0	0	0	0	42	1	0	0	0	0	0
2430	100	36	GTR208	0	0	0	0	0	1	0	113	0	0	0	0	0	42	1	0	0	0	0	0
2440	100	37	GTR212	0	0	0	0	0	1	0	114	0	0	0	0	0	42	1	0	0	0	0	0
2450	100	38	GTR216	0	0	0	0	0	1	0	115	0	0	0	0	0	42	1	0	0	0	0	0
2460	100	44	GTR316	0	0	0	0	0	1	0	118	0	0	0	0	0	42	1	0	0	0	0	0
2[illegible]0	100	43	GTR312	0	0	0	0	0	1	0	117	0	0	0	0	0	42	1	0	0	0	0	0
2[illegible]	[illegible]	42	GTR308	0	0	0	0	0	1	0	116	0	0	0	0	0	36	1	0	0	0	0	0
#OF ON TABLES																							
TABLE 100=				47					Special Logic Indicator									Special Logic Indicator					
TABLE 110=				0																			
TABLE 120=				0																			
TABLE 130=				0																			
RECORDS READ=				244																			

indicators to size the prime mover and heat recovery steam generators. The contents of the component logic table are described in Table 4-8. Some components specified for an ECS such as limestone handling are dependent upon the fuel used in a particular application of the ECS and logic for including them in the cost estimate is contained in program COSTANL. Fuel handling is not listed as a component option since all systems require it.

Cost Analysis Program - COSTANL. The Component Cost Table and the Component Logic Tables are used in program COSTANL to update the economic data base with the total installed capital cost. A cost report generated in this program is shown in Figure 4-9.

For each case the Component Logic Table is interrogated and each component specified is sized and costed. Requirements that exceed the component maximum size result in multiple units of that component. The special logic indicators direct the program to specific equations for sizing components, such as heat recovery steam generators and prime movers. Fuel handling systems and boilers are dependent on the fuel type as well as flow. Auxiliary boilers are selected, as required, to be compatible with the fuel used on site. Indirect costs are added to the total direct costs to give the total installed cost.

Return on Investment (ROI) and Levelized Annual Energy Costs (LAEC) Analysis

The third and last step in developing the economic data base is the calculation of the percentage Return On Investment (ROI) and Levelized Annual Energy Costs (LAEC). The computer system flow chart for step 3 is shown in Figure 4-10. These calculations use data already in the economics data base, such as the capital costs and the on-site fuel use, power generation, power requirements and auxiliary boiler requirements.

Factors for the following items were established in groundrules.

- Cost of fuel and purchased power
- Escalation rate of fuel and purchased power

Table 4-8

CONTENTS OF THE COMPONENT LOGIC TABLE

ECS Number: Matches number on ECS characterization table

ECS Short Description: For information only

Components to be Costed: A zero indicates component is not used in ECS. Number given is for smallest unit on component table - larger units are selected based on logic in COSTANL

- Limestone & Dolomite Handling
- Conventional Boiler
- AFB or PFB
- Gasifier
- Reformer
- Prime Mover (plus prime mover logic code)
- Steam Turbine-non condensing
- Gas Turbine
- Diesel Engine Generator
- Thermionic Generator
- Stirling Engine
- Fuel Cell
- Steam Turbine for combined cycles
- Heat Recovery Steam Generators (plus HRSG logic code)
- Condensing Steam Turbine
- Cooling Tower
- Heat Exchanger
- Water Conditioner

DATE 03/31/78
I SE-PEO ADV. DES. ENGRG.

GENERAL ELECTRIC COMPANY
COGENERATION TECHNOLOGY ALTERNATIVEE STUDY
REPORT 6.3
CAPITAL COSTS BY ISLAND FOR SELECTED PROCESS-ECS MATCHES

PROCESS 20111

ECS DEADV3 PROCESS MEGAWATTS 1.04 PROCESS TEMP. 260. PROCESS HEAT(BTU*10**6) 24.
DIESEL-ADVANCED-3 SITE FUEL= RESIDUAL COGEN FUEL BTU*10**8= 19. KW FUEL= $228.

ISLAND DESCRIPTION	COMPONENT DESCRIPTION	MAJOR EQUIPMNT	INSTALL MAT'L	INSTALL LABOR	INDRCT FLD CST	TOTAL INSTALLD	TOTAL	$PER-KW FUEL
		******************	COSTS - MILLIONS 1978$	************				
1. FUEL-HANDLING	1. FUEL-OIL-UNLOADING-S	0.035	0.007	0.042	0.037	0.086	0.121	23.081
	ISLAND TOTAL	0.035	0.007	0.042	0.037	0.086	0.121	23.081
3. ENERGY-CONVERSION	32. DIESEL-ENGINE-GENERA	1.453	0.163	0.163	0.146	0.471	1.925	368.094
	ISLAND TOTAL	1.453	0.163	0.163	0.146	0.471	1.923	368.094
2. FUEL-UTILIZATION-CLE	21. OIL-FIRED-BOILER	0.095	0.196	0.299	0.269	0.764	0.859	164.319
	ISLAND TOTAL	0.095	0.196	0.299	0.269	0.764	0.859	164.319
8. BALANCE-OF-PLANT	84. POWER-PLANT-STRUCTUR	0.	0.064	0.056	0.050	0.169	0.169	32.400
	80. MASTER-CONTROL	0.070	0.010	0.017	0.016	0.043	0.113	21.626
	81. ELECTRIC-SWITCHGEAR-	0.	0.013	0.013	0.011	0.037	0.037	7.018
	82. INTERCONNECTING-PIPI	0.	0.025	0.025	0.022	0.071	0.071	13.666
	83. STRUCTURES-MISCELLAN	0.	0.056	0.047	0.042	0.145	0.145	27.721
	ISLAND TOTAL	0.070	0.167	0.157	0.142	0.466	0.536	102.431
TOTAL THIS CASE		1.652	0.532	0.661	0.595	1.788	3.440	113.746
INDIRECT COSTS	SPARES						0.033	
	START UP						0.028	
	SPARES+STARTUP						0.061	
	CONTINGENCY						0.526	
	ENGINEERING SERVICES						0.210	
	A-E FEE						0.176	
GRAND TOTAL							4.412	

Figure 4-9. Sample Capital Cost Report

ORIGINAL PAGE IS
OF POOR QUALITY

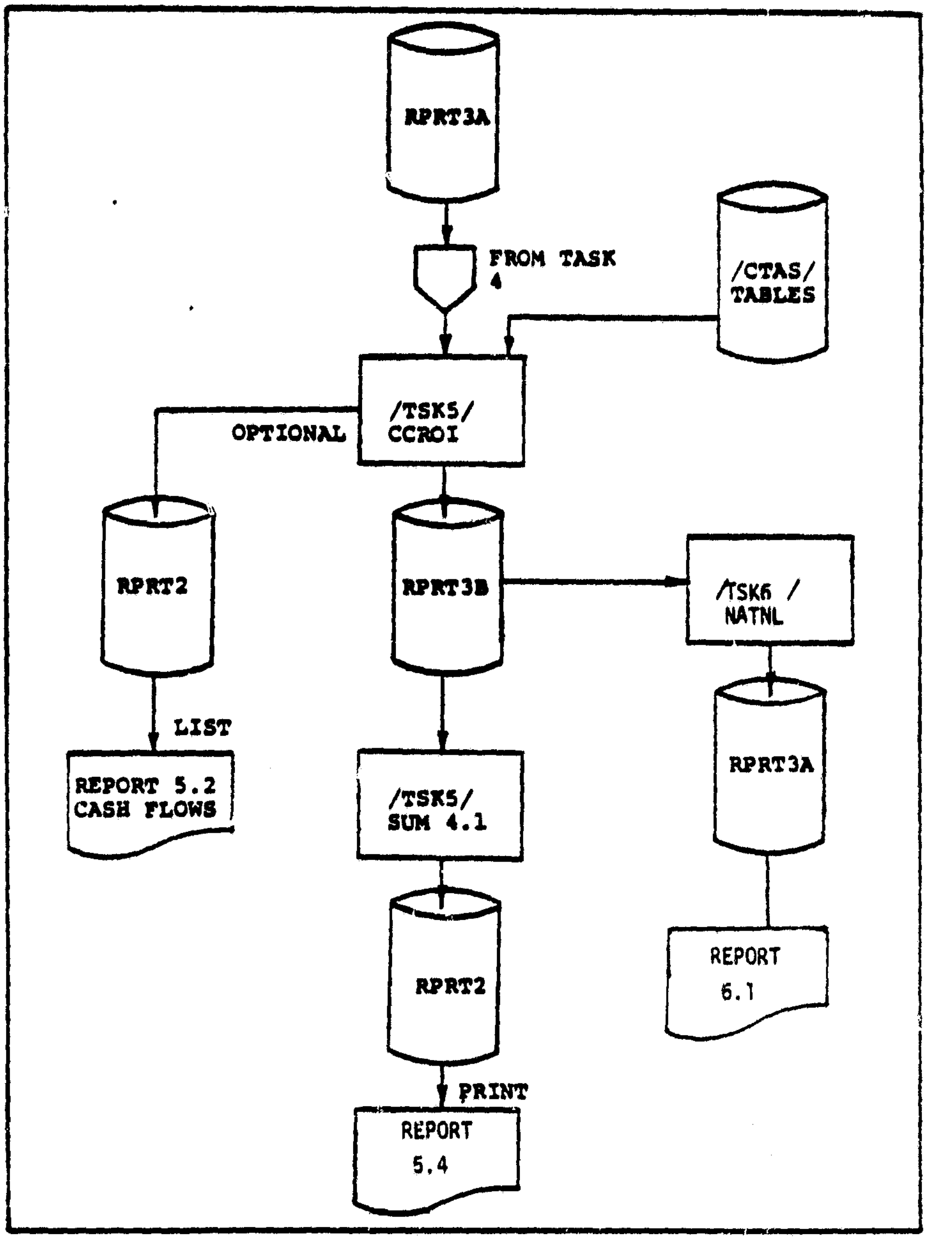


Figure 4-10. Economics and Potential National Savings Data Handling

- Selling price for exported power
- Depreciation method and equipment life
- Tax, rates, tax credits
- Industrial cost of capital

Operating and Maintenance Costs. The operating and maintenance costs were calculated as shown in Table 4-9. The values of L, M, N, and P are a function of ECS and type of fuel used and are stored in the table shown in Figure 4-11 along with the time for construction. In matches requiring an auxiliary boiler, its O&M must be calculated separately and added to the O&M of the cogeneration ECS.

Table 4-9

CONTENTS OF OPERATING AND MAINTENANCE TABLE

O&M Costs = L*(fuel flow)M+N*(Capital Cost)+P*(fuel flow*operating hrs/yr)

L*(fuel flow)M	is cost of operating labor in 10^6 \$/yr with fuel flow in Btu/hr.
N*(Capital Cost)	is cost of parts for maintenance and major replacements in 10^6 \$/yr with capital cost in 10^6\$.
P*(fuel flow*operating hrs/yr)	is cost of limestone, dolomite, ZnO, and water in 10^6 \$/yr with fuel flow in 10^6 Btu/hr.

ROI Analysis Program (CCROI). This program evaluates the year by year cash flow of each case. The cash flow of the no-cogeneration case is compared to the cash flow of the cogeneration case, and the discount rate (ROI) that makes these two cases have equal present worth is determined. Due to the groundrules (coal is no-cogeneration fuel) established in this study, some cases yield infinite ROI's because both the cogeneration capital cost and annual costs are less than the no-cogeneration capital cost and annual costs. Other cases resulted in negative ROI's. These negative values were

		DISTILLATE & RESIDE					COAL: FGD, PFB, PULVERIZED & GASIFIED					COAL: AFD				
			O/M Labor					O/M Labor					O/M Labor			
	ECS	Const. Yrs.	Factor L	Expon. M	Maint. N	Mat'l P	Const. Yrs.	Factor L	Expon. M	Maint. N	Mat'l P	Const. Yrs.	Factor L	Expon. M	Maint. N	Mat'l P
1	STM141	2.5	1174.	0.300	0.025	0.	3.0	1751.	0.300	0.025	0.082	3.0	1463.	0.300	0.025	0.119
2	STM088	2.5	1174.	0.300	0.025	0.	3.0	1751.	0.300	0.025	0.075	3.0	1463.	0.300	0.025	0.119
3	PFBSTM	0.	0.	0.	0.	0.	2.5	1463.	0.300	0.025	0.272	0.	0.	0.	0.	0.
4	TISTMT	2.5	1174.	0.300	0.025	0.006	3.0	1751.	0.300	0.025	0.075	0.	0.	0.	0.	0.
5	THRSG	2.0	270.	0.360	0.025	0.	2.5	536.	0.350	0.025	0.075	0.	0.	0.	0.	0.
6	STIRL	1.5	324.	0.360	0.025	0.	2.0	489.	0.360	0.025	0.075	0.	0.	0.	0.	0.
7	HEGT85	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2.5	355.	0.350	0.025	0.119
8	HEGT60	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2.5	355.	0.350	0.025	0.119
9	HEGT00	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2.5	355.	0.350	0.025	0.119
10	FCMCCL	0.	0.	0.	0.	0.	3.5	508.	0.340	0.025	0.303	0.	0.	0.	0.	0.
11	FCSTCL	0.	0.	0.	0.	0.	4.0	1401.	0.300	0.025	0.306	0.	0.	0.	0.	0.
12	IOGTST	0.	0.	0.	0.	0.	4.0	1751.	0.300	0.025	0.	0.	0.	0.	0.	0.
13	GTSOAR	1.5	270.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
14	GTAC08	1.5	270.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
15	GTAC12	1.5	270.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
16	GTAC16	1.5	270.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17	GTWC16	1.5	270.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18	CC1626	2.5	1174.	0.300	0.025	0.003	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19	CC1622	2.5	1174.	0.300	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
20	CC1222	2.5	1174.	0.300	0.025	0.003	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
21	CC0322	2.5	1174.	0.300	0.025	0.003	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
22	STIG15	1.5	270.	0.360	0.025	0.112	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
23	STIG10	1.5	270.	0.360	0.025	0.071	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
24	STIG15	1.5	270.	0.360	0.025	0.071	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
25	DEADV3	1.5	324.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
26	DEADV2	1.5	324.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
27	DEADV1	1.5	324.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
28	DEHTPM	1.5	378.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
29	DESOA3	1.5	324.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
30	DESOA2	1.5	324.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
31	DESOA1	1.5	324.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
32	GTSOAD	1.5	270.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
33	GTRA08	1.5	270.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
34	GTRA12	1.5	270.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
35	GTRA16	1.5	270.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
36	GTR208	1.5	270.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
37	GTR212	1.5	270.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
38	GTR216	1.5	270.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
39	GTRW08	1.5	270.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
40	GTRW12	1.5	270.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
41	GTRW16	1.5	270.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
42	GTR308	1.5	270.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
43	GTR312	1.5	270.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
44	GTR316	1.5	270.	0.360	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
45	FCPADS	1.5	137.	0.360	0.025	1.236	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
46	FCMCDS	1.5	137.	0.360	0.025	1.236	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
47	OJOCGB	1.5	622.	0.320	0.025	0.	3.0	1002.	0.320	0.025	0.075	3.0	1163.	0.300	0.025	0.119

Figure 4-11. CTAS Operating and Maintenance Factor Table for $/yr

caused by capital costs favoring cogeneration, but with the cogeneration annual costs exceeding the nocogeneration annual costs. Levelized Annual Energy Costs (LAEC) are not based on incremental costs or cash flows and thus are more continuous than ROI. Levelized capital, taxes and insurance, operating and maintenance, fuel, purchased electricity, and revenue are the components of the total LAEC. Besides LAEC and ROI, the present worth of the investment at a 15% interest rate, and the net payback are calculated. Figure 4-12 shows the format of the output with capital costs at the base values. Other calculations show the sensitivity to changes in the various factors. Figure 4-13, for example, shows the sensitivities of economic factors to capital cost, fuel cost, and power cost in graphical form.

Reports From Economic Analyses

Fuel Saved By Type. A summary report (5.2) shows the fuel saved by type and the economics of the process and ECS matches. A sample page is shown in Figure 4-14. This report accounts for fuel differences in both type and quantity used between the nocogeneration case, and the cogeneration case including the displacement of utility fuel that occurs due to on-site power generation. In the cogeneration case any fuel burned on-site is added to any utility fuel burned due to a shortfall of on-site power. The fuel savings (nocogen-cogen heading on the report) shows what fuel was saved (positive quantity in the column under the appropriate fuel) and how much. The single letters F and A appearing after the cogen coal column in Figure 4-14 indicates FGD or AFB coal systems. On other pages of the report P indicates a PFB coal system.

National Fuel and Emissions Savings. Report 6.1, Fuel and Emissions Savings, Figure 4-15, describes the fuel and emissions savings by type, calculates emissions saved ratio (EMSR), capital saving, total export megawatt hours, cost of electricity and LAEC savings on a national basis.

Input requirements for this program include the Emissions by ECS and Fuel (Table 4-10) and a table on National Energy Use by SIC (Table 4-11).

DATE 04/22/78 GENERAL ELECTRIC COMPANY PAGE 1
188E-PKG-ADV-ENERGY-SYS COGENERATION TECHNOLOGY ALTERNATIVES STUDY
REPORT 8.4

ECONOMIC SENSITIVITY REPORT FOR SELECTED PROCESS-ECS MATCHES

SENSITIVITY OF CAPITAL COST PERCENT OF ORIGINAL COST 100

ENERGY CONV SYSTEM		SITE-FUEL	POWER RECD MW	POWER GEN/REQD	FESR	POWER /HEAT RATIO	CAPITAL COST $10**6	CAPITAL	TAXES + INSNC	OANDM	FUEL	PURCHD ELEC	REVNUE	TOTAL	NORML	PRESNT WORTH 18%	ROI %	GROSS PAY BACK
								********LEVELIZED ANNUAL ENERGY COSTS($ MILLIONS)**********										
10101	ONOCON	COAL-FG	10.	0.	0.	0.25	12.9	0.83	0.40	0.83	0.74	3.08	0.	5.87	1.000	0.	0	0
10101	STM141	RESIDUA	10.	0.99	0.439	0.25	9.9	0.63	0.27	0.57	2.42	0.03	0.	3.93	0.658	8.	999	0
10101	STM141	COAL-FG	10.	0.99	0.439	0.25	18.2	1.23	0.52	1.08	1.41	0.03	0.	4.27	0.718	3.	26	4
10101	STM141	COAL-AF	10.	0.99	0.439	0.25	12.8	0.95	0.40	0.90	1.41	0.03	0.	3.74	0.628	7.	999	1
10101	STM088	RESIDUA	10.	0.75	0.333	0.25	7.4	0.58	0.24	0.64	2.15	0.76	0.	4.26	0.713	8.	999	0
10101	STM088	COAL-FG	10.	0.75	0.333	0.25	14.8	1.13	0.48	1.02	1.28	0.76	0.	4.66	0.778	3.	31	4
10101	STM088	COAL-AF	10.	0.75	0.333	0.25	11.8	0.89	0.39	0.92	1.25	0.76	0.	4.20	0.704	6.	999	0
10101	PFBSTM	COAL-PF	10.	1.00	0.436	0.25	20.8	1.58	0.67	1.59	1.43	0.	0.	5.27	0.882	-2.	10	9
10101	PFBSTM	COAL-PF	10.	1.52	0.484	0.25	19.9	1.51	0.64	1.48	1.79	0.	-0.95	4.44	0.744	1.	17	6
10101	TISTMT	RESIDUA	10.	1.00	0.187	0.25	26.8	2.25	0.96	1.27	3.56	0.	0.	8.02	1.344	-15.	0	63
10101	TISTMT	RESIDUA	10.	0.64	0.235	0.25	20.5	1.55	0.66	1.01	1.91	1.42	0.	6.56	1.099	-8.	0	999
10101	TISTMT	COAL	10.	1.00	0.436	0.25	41.4	3.14	1.34	1.98	1.43	0.	0.	7.88	1.319	-20.	0	999
10101	TISTMT	COAL	10.	1.99	0.510	0.25	57.1	4.33	1.84	2.15	2.12	0.	-1.83	8.61	1.441	-30.	0	999
10101	TIHRSG	RESIDUA	10.	0.23	0.083	0.25	17.5	1.30	0.55	0.84	1.62	2.37	0.	6.68	1.118	-8.	0	68
10101	TIHRSG	COAL	10.	0.85	0.308	0.25	49.1	3.65	1.55	1.79	1.49	0.47	0.	8.92	1.494	-26.	0	992
10101	STIRL	DISTILL	10.	1.00	0.146	0.25	11.1	0.82	0.35	0.77	4.56	0.	0.	6.51	1.090	-1.	-26	0
10101	STIRL	DISTILL	10.	0.63	0.201	0.25	8.8	0.69	0.29	0.70	2.86	1.18	0.	5.69	0.953	2.	999	0
10101	STIRL	RESIDUA	10.	1.00	0.146	0.25	11.?	0.83	0.35	0.77	3.72	0.	0.	5.67	0.948	2.	999	0
10101	STIRL	RESIDUA	10.	0.63	0.201	0.25	9.3	0.69	0.29	0.70	2.33	1.18	0.	5.18	0.865	4.	999	0
10101	STIRL	COAL	10.	1.00	0.321	0.25	21.8	1.62	0.69	1.44	1.72	0.	0.	5.47	0.917	-3.	6	10
10101	STIRL	COAL	10.	2.32	0.365	0.25	28.1	2.08	0.88	1.43	3.02	0.	-2.43	4.98	0.834	-4.	6	9
10101	HEGT85	COAL-AF	10.	1.00	0.178	0.25	36.4	2.69	1.14	1.69	2.08	0.	0.	7.60	1.273	-16.	0	999
10101	HEGT85	COAL-AF	10.	6.10	0.235	0.25	91.7	6.98	2.96	3.34	8.97	0.	-9.43	12.80	2.144	-60.	0	999
10101	HEGT60	COAL-AF	10.	1.00	0.191	0.25	34.0	2.58	1.10	1.66	2.06	0.	0.	7.38	1.237	-18.	0	999
10101	HEGT60	COAL-AF	10.	3.00	0.236	0.25	55.1	4.18	1.78	2.12	4.69	0.	-3.70	9.08	1.520	-30.	0	999
10101	HEGT00	COAL-AF	10.	1.00	0.166	0.25	31.2	2.37	1.01	1.58	2.07	0.	0.	7.01	1.173	-12.	0	999
10101	HEGT00	COAL-AF	10.	1.40	0.203	0.25	33.4	2.53	1.08	1.41	2.60	0.	-0.74	6.88	1.152	-13.	0	26
10101	FCMCCL	COAL	10.	1.00	-0.403	0.25	29.8	2.32	0.99	1.72	3.56	0.	0.	8.58	1.437	-17.	0	74
10101	FCMCCL	COAL	10.	2.57	0.092	0.25	40.3	3.13	1.33	2.09	4.88	0.	-2.80	8.53	1.428	-22.	0	999
10101	FCSTCL	COAL	10.	1.00	-0.388	0.25	29.0	2.25	0.96	1.73	3.52	0.	0.	8.47	1.418	-18.	0	74
10101	FCSTCL	COAL	10.	4.18	0.266	0.25	50.3	3.91	1.66	2.68	8.06	0.	-8.07	8.41	1.409	-27.	0	999
10101	IGGTST	COAL	10.	1.00	-0.466	0.25	28.8	2.28	0.96	1.81	3.72	0.	0.	8.63	1.429	-16.	0	72
10101	IGGTST	COAL	10.	2.95	0.065	0.25	40.4	3.14	1.34	1.84	5.65	0.	-3.60	8.18	1.370	-21.	0	999
10101	GTSOAR	RESIDUA	10.	1.00	0.216	0.25	10.6	0.78	0.33	0.71	3.42	0.	0.	5.25	0.879	3.	999	0
10101	GTSOAR	RESIDUA	10.	0.71	0.238	0.25	9.6	0.71	0.30	0.67	2.43	0.89	0.	5.00	0.838	4.	999	0
10101	GTAC08	RESIDUA	10.	1.00	0.168	0.25	9.6	0.71	0.30	0.68	3.68	0.	0.	5.37	0.899	3.	999	0
10101	GTAC08	RESIDUA	10.	0.67	0.215	0.25	8.3	0.62	0.26	0.63	2.10	1.32	0.	4.93	0.826	6.	999	0
10101	GTAC12	RESIDUA	10.	1.00	0.255	0.25	9.6	0.72	0.31	0.68	3.26	0.	0.	4.97	0.832	4.	999	0
10101	GTAC12	RESIDUA	10.	0.71	0.265	0.25	8.8	0.65	0.28	0.65	2.30	0.90	0.	4.78	0.801	6.	999	0
10101	GTAC16	RESIDUA	10.	1.00	0.298	0.25	10.1	0.75	0.32	0.69	3.07	0.	0.	4.83	0.810	5.	999	0
10101	GTAC16	RESIDUA	10.	0.79	0.295	0.25	9.4	0.70	0.30	0.66	2.44	0.63	0.	4.73	0.792	5.	999	0
10101	GTWC16	RESIDUA	10.	1.00	0.278	0.25	10.4	0.77	0.32	0.70	3.18	0.	0.	4.98	0.830	4.	999	0
10101	GTWC16	RESIDUA	10.	0.85	0.260	0.25	9.8	0.73	0.31	0.68	2.87	0.48	0.	4.87	0.815	5.	999	0

Figure 4-12. Sample Economic Sensitivity Report

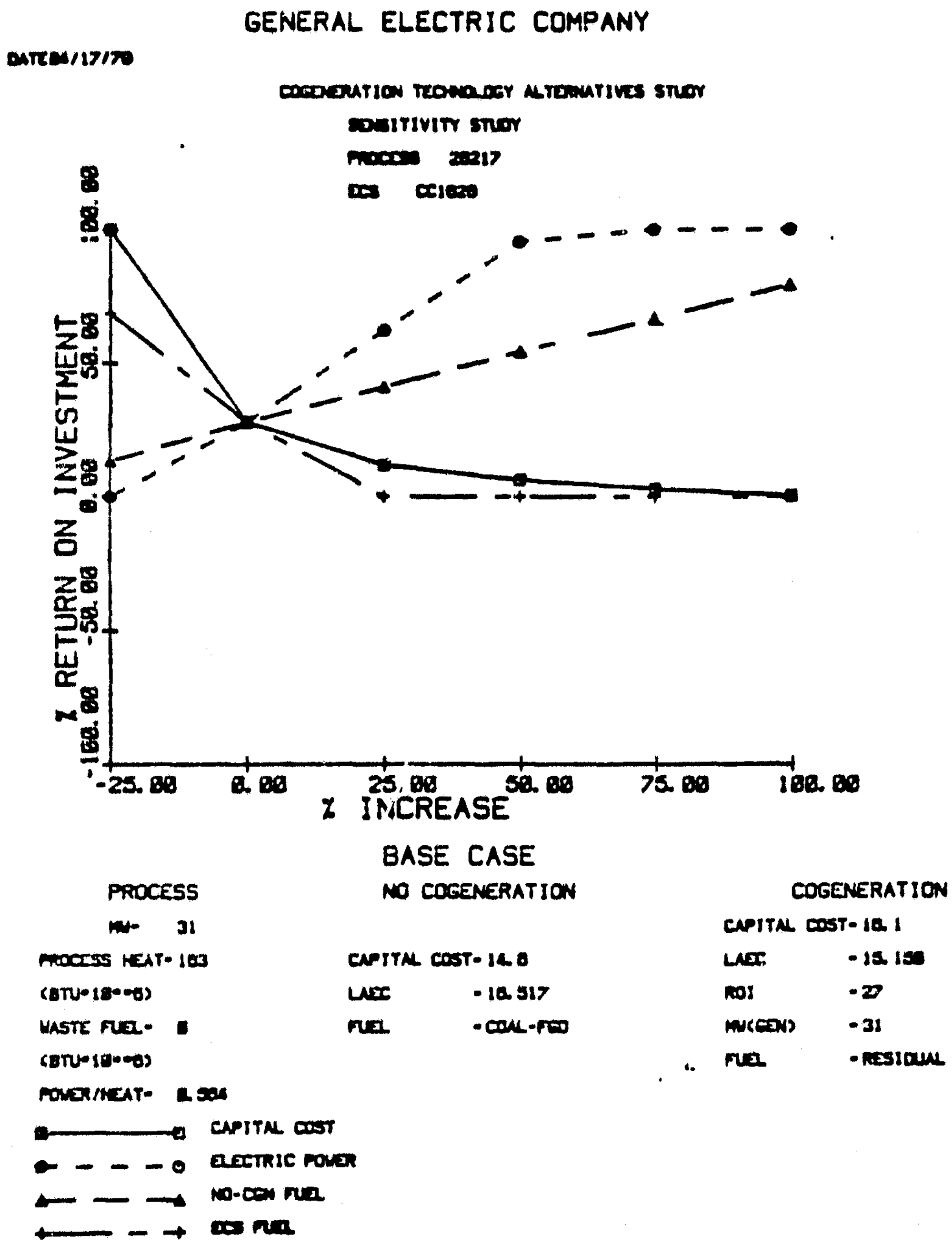


Figure 4-13. Sample Economic Sensitivity

DATE 04/22/78
1 GE-PED-ADV-DES-ENGR

GENERAL ELECTRIC COMPANY
COGENERATION TECHNOLOGY ALTERNATIVES STUDY
REPORT 6.2
SUMMARY OF FUEL SAVED BY TYPE ECONOMICS

PAGE 1

ECS	PROCS	----FUEL USE IN BTU*10**6---- **COGENERATION CASE** DISTIL	RESIDL	COAL	**NOCOGEN - COGEN** DISTIL	RESIDL	COAL	POWER REQD MW	COGEN POWER MW	O M	POWER /HEAT RATIO	FESR	CAPITAL COST *10**6	NORM COST	$/KW EQVL	ROI (%)	LEVL CHRG	NORM ENRG	WRTH
ONOCGN	10101	0.	25.	128.	0.	0.	0. F	10.	0.	0.88	0.25	0.	12.3	1.00	260.1	0	8.8	1.00	80
STM141	10101	0.	84.	1.	0.	-59.	126.	10.	10.	0.57	0.25	0.44	6.3	0.58	141.8	999	3.9	0.68	178
STM141	10101	0.	0.	84.	0.	24.	42. F	10.	10.	1.09	0.25	0.44	16.2	1.32	278.2	25	4.3	0.71	160
STM141	10101	0.	0.	84.	0.	24.	42. A	10.	10.	0.88	0.25	0.44	12.8	1.01	211.6	999	3.7	0.63	164
STM088	10101	0.	80.	20.	0.	-58.	106.	10.	8.	0.54	0.25	0.33	7.4	0.60	132.5	999	4.3	0.71	166
STM088	10101	0.	6.	94.	0.	18.	32. F	10.	8.	1.02	0.25	0.33	14.9	1.22	266.6	31	4.6	0.78	160
STM088	10101	0.	6.	94.	0.	18.	32. A	10.	8.	0.82	0.25	0.33	11.9	0.98	209.6	999	4.2	0.70	154
PFBSTM	10101	0.	0.	85.	0.	26.	41.	10.	10.	1.89	0.25	0.44	20.8	1.69	381.2	10	6.3	0.88	169
PFBSTM	10101	0.	0.	108.	0.	37.	62.	10.	16.	1.48	0.25	0.46	19.8	1.62	304.3	17	4.4	0.74	160
TISTMT	10101	0.	122.	0.	0.	-87.	128.	10.	10.	1.27	0.25	0.19	28.5	2.41	489.8	0	6.0	1.34	143
TISTMT	10101	0.	77.	38.	0.	-52.	86.	10.	8.	1.01	0.25	0.23	20.5	1.67	391.1	0	6.9	1.10	136
TISTMT	10101	0.	0.	85.	0.	26.	41.	10.	10.	1.96	0.25	0.44	41.4	3.37	696.8	0	7.8	1.32	166
TISTMT	10101	0.	0.	126.	0.	49.	62.	10.	20.	2.18	0.25	0.61	67.1	4.86	600.8	0	6.8	1.44	160
TIHRSG	10101	0.	74.	63.	0.	-60.	62.	10.	8.	0.84	0.25	0.08	17.8	1.43	346.8	0	6.7	1.12	112
TIHRSG	10101	0.	4.	101.	0.	21.	25.	10.	8.	1.79	0.25	0.31	40.1	3.92	798.3	0	6.9	1.49	143
STIRL	10101	128.	0.	0.	-128.	28.	126.	10.	10.	0.77	0.25	0.19	11.1	0.81	173.1	-26	6.8	1.09	153
STIRL	10101	80.	9.	91.	-80.	16.	66.	10.	6.	0.70	0.25	0.20	9.3	0.76	160.7	999	6.7	0.95	149
STIRL	10101	0.	126.	0.	0.	-103.	128.	10.	10.	0.77	0.25	0.18	11.1	0.81	173.3	999	5.7	0.95	150
STIRL	10101	0.	89.	31.	0.	-65.	95.	10.	6.	0.70	0.25	0.20	9.3	0.79	160.8	999	6.2	0.86	147
STIRL	10101	0.	0.	102.	0.	26.	24.	10.	10.	1.44	0.25	0.32	21.8	1.78	340.6	0	5.6	0.92	155
STIRL	10101	0.	0.	179.	0.	67.	56.	10.	23.	1.43	0.25	0.36	26.1	2.26	323.2	0	6.0	0.83	137
HEGT85	10101	0.	0.	123.	0.	26.	2. A	10.	10.	1.68	0.25	0.18	36.4	2.88	500.5	0	7.6	1.27	137
HEGT85	10101	0.	0.	831.	0.	180.	14. A	10.	81.	9.34	0.25	0.24	91.7	7.46	482.4	0	12.8	2.14	113
HEGT60	10101	0.	0.	122.	0.	26.	4. A	10.	10.	1.66	0.25	0.19	34.0	2.76	484.4	0	7.4	1.24	139
HEGT60	10101	0.	0.	278.	0.	74.	12. A	10.	30.	2.12	0.25	0.24	66.1	4.49	478.1	0	9.1	1.62	120
HEGT00	10101	0.	0.	122.	0.	25.	9. A	10.	10.	1.88	0.25	0.18	31.2	2.54	444.6	0	7.0	1.17	138
HEGT00	10101	0.	0.	164.	0.	34.	8. A	10.	14.	1.41	0.25	0.20	33.4	2.72	419.8	0	6.9	1.16	128
FCMCCL	10101	0.	0.	211.	0.	26.	-85.	10.	10.	1.72	0.25	-0.40	26.8	2.43	483.1	0	4.6	1.44	71
FCMCCL	10101	0.	0.	289.	0.	83.	-34.	10.	28.	2.08	0.25	0.08	40.3	3.28	478.4	0	6.8	1.43	107
FCSTCL	10101	0.	0.	208.	0.	25.	-83.	10.	10.	1.73	0.25	-0.39	29.0	2.36	474.6	0	6.6	1.42	73
FCSTCL	10101	0.	0.	359.	0.	102.	28.	10.	42.	2.65	0.25	0.27	50.3	4.09	478.2	0	6.4	1.41	113
IGGTST	10101	0.	0.	220.	0.	26.	-84.	10.	10.	1.81	0.25	-0.47	28.9	2.35	446.2	0	6.8	1.43	64
IGGTST	10101	0.	0.	335.	0.	72.	-49.	10.	28.	1.64	0.25	0.06	40.4	3.29	412.3	0	6.2	1.37	99
GTSOAR	10101	0.	116.	0.	0.	-93.	126.	10.	10.	0.71	0.25	0.22	10.6	0.86	186.2	999	6.3	0.86	159
GTSOAR	10101	0.	91.	24.	0.	-66.	102.	10.	7.	0.67	0.25	0.24	9.6	0.78	182.0	999	6.0	0.84	151
GTAC08	10101	0.	125.	0.	0.	-102.	126.	10.	10.	0.88	0.25	0.14	9.6	0.78	165.0	999	6.4	0.90	154
GTAC08	10101	0.	83.	36.	0.	-58.	90.	10.	6.	0.63	0.25	0.21	8.3	0.68	148.7	999	4.9	0.83	160
GTAC12	10101	0.	112.	0.	0.	-87.	126.	10.	10.	0.88	0.25	0.25	8.8	0.80	167.8	999	6.0	0.83	164
GTAC12	10101	0.	68.	24.	0.	-62.	102.	10.	7.	0.68	0.25	0.27	8.8	0.72	163.2	999	4.8	0.80	155
GTAC16	10101	0.	106.	0.	0.	-81.	126.	10.	10.	0.66	0.25	0.30	10.1	0.82	162.6	999	4.8	0.81	167
GTAC16	10101	0.	89.	17.	0.	-64.	108.	10.	8.	0.66	0.25	0.30	9.4	0.76	169.0	999	4.7	0.79	158
GTWC16	10101	0.	108.	0.	6.	-84.	128.	10.	10.	0.70	0.25	0.28	10.4	0.88	182.6	999	6.0	0.83	165
GTWC16	10101	0.	95.	18.	0.	-71.	113.	10.	8.	0.68	0.25	0.28	9.9	0.80	181.1	999	4.9	0.82	165

Figure 4-14. Sample Fuel Saved by Type + Economics Report

DATE 04/24/78
ISE PEO AES
FUEL UNITS =
EMISSION UNITS=
COST =$*10**9

GENERAL ELECTRIC COMPANY
COGENERATION TECHNOLOGY ALTERNATIVES STUDY
REPORT 6.1 FUEL AND EMISSIONS SAVINGS
TIME 1990 LEVEL ALL

PAGE 1

(SAVINGS ARE POSITIVE)

TYPE MATCH=HEAT

PROCS	ECS	ECS FUEL	FUEL SAVINGS DIRECT OIL+GAS	FUEL SAVINGS DIRECT COAL	FUEL SAVINGS TOTAL OIL+GAS	FUEL SAVINGS TOTAL COAL	FESR	EMISSIONS SAVINGS DIRECT NOX	EMISSIONS SAVINGS DIRECT SOX	EMISSIONS SAVINGS DIRECT PART	EMISSIONS SAVINGS TOTAL NOX	EMISSIONS SAVINGS TOTAL SOX	EMISSIONS SAVINGS TOTAL PART	EMSR	CAPITL SAVING	ELECTRIC POWER TOTAL EXPORT MWH	SVNG	LAEC SAVED
20	STM141	COAL-A	0.121	-0.226	0.186	-0.009	0.43	39.	-88.	-8.	131.	71.	16.	0.41	-1.	8.	284.	-497.
22	STM141	COAL-A	0.	-0.004	0.003	0.005	0.14	4.	-3.	-0.	6.	4.	0.	0.38	0.	0.	2.	28.
24	STM141	COAL-A	0.	-0.018	0.062	0.188	0.82	-2.	-11.	-1.	84.	136.	15.	0.78	-2.	2.	249.	-265.
26	STM141	COAL-A	0.	-0.043	0.026	0.046	0.13	26.	-26.	-2.	63.	37.	6.	0.39	1.	1.	4.	304.
28	STM141	COAL-A	0.029	-0.211	0.140	0.161	0.61	214.	-115.	-8.	370.	150.	21.	0.32	6.	18.	31.	1091.
29	STM141	COAL-A	0.	-0.025	0.015	0.026	0.10	30.	-16.	-1.	82.	21.	3.	0.36	1.	1.	2.	176.
33	STM141	COAL-A	0.	-0.006	0.004	0.006	0.01	4.	-3.	-0.	8.	6.	1.	0.09	0.	0.	0.	47.
ALL	STM141	COAL-A	0.176	-0.629	0.512	0.497	0.18	370.	-307.	-23.	842.	488.	71.	0.34	4.	36.	649.	1037.
20	STM141	COAL-F	0.121	-0.226	0.186	-0.009	0.43	-57.	-88.	-8.	36.	71.	16.	0.26	-1.	8.	283.	-926.
22	STM141	COAL-F	0.	-0.004	0.003	0.005	0.14	-2.	-3.	-0.	2.	4.	0.	0.21	0.	0.	2.	18.
24	STM141	COAL-F	0.	-0.018	0.062	0.188	0.82	-7.	-11.	-1.	78.	136.	15.	0.77	-6.	2.	248.	-718.
26	STM141	COAL-F	0.	-0.043	0.026	0.045	0.13	-16.	-26.	-2.	22.	37.	6.	0.23	1.	1.	4.	238.
28	STM141	COAL-F	0.029	-0.211	0.140	0.161	0.61	-76.	-115.	-8.	61.	160.	21.	0.16	2.	16.	31.	766.
29	STM141	COAL-F	0.	-0.025	0.015	0.026	0.10	-8.	-16.	-1.	13.	21.	3.	0.17	0.	1.	2.	139.
33	STM141	COAL-F	0.	-0.006	0.004	0.006	0.01	-4.	-3.	-0.	1.	6.	1.	0.04	0.	0.	0.	28.
ALL	STM141	COAL-F	0.176	-0.629	0.512	0.497	0.18	-196.	-307.	-23.	274.	498.	71.	0.18	-8.	36.	647.	-838.
20	STM141	RESIDU	-0.326	0.216	-0.259	0.437	0.43	-57.	1.	-8.	32.	147.	-2.	0.34	4.	8.	265.	-343.
22	STM141	RESIDU	-0.026	0.021	-0.022	0.030	0.14	-2.	2.	-0.	2.	8.	-1.	0.30	0.	0.	2.	2.
24	STM141	RESIDU	-0.021	0.003	0.041	0.209	0.82	-7.	-7.	-1.	79.	138.	14.	0.76	3.	2.	260.	813.
26	STM141	RESIDU	-0.191	0.148	-0.164	0.235	0.13	-16.	12.	-2.	20.	69.	-3.	0.32	2.	1.	4.	101.
28	STM141	RESIDU	-1.317	1.136	-1.206	1.607	0.61	-76.	194.	-8.	71.	379.	-33.	0.25	7.	16.	32.	-401.
29	STM141	RESIDU	-0.181	0.156	-0.166	0.207	0.10	-9.	21.	-1.	11.	62.	-6.	0.27	1.	1.	2.	-43.
33	STM141	RESIDU	r0.038	0.030	-0.032	0.042	0.01	-4.	4.	-0.	1.	11.	-1.	0.07	0.	0.	0.	14.
ALL	STM141	RESIDU	-2.466	2.012	-2.129	3.136	0.18	-198.	221.	-23.	264.	847.	-36.	0.27	20.	38.	683.	-66.
20	STM088	COAL-A	0.127	-0.220	0.184	-0.029	0.88	45.	-81.	-8.	126.	68.	18.	0.38	-1.	8.	236.	-489.
22	STM088	COAL-A	0.	-0.004	0.002	0.004	0.11	4.	-2.	-0.	8.	3.	0.	0.35	0.	0.	2.	26.
24	STM088	COAL-A	0.	-0.005	0.043	0.141	0.81	-1.	-3.	-0.	60.	101.	11.	0.58	-3.	0.	205.	-427.
26	STM088	COAL-A	0.	-0.032	0.020	0.034	0.10	28.	-18.	-2.	66.	28.	3.	0.33	1.	0.	4.	262.
28	STM088	COAL-A	0.020	-0.108	0.073	0.069	0.24	148.	-65.	-4.	221.	70.	10.	0.28	2.	6.	18.	966.
29	STM088	COAL-A	0.	-0.017	0.011	0.018	0.07	33.	-10.	-1.	48.	16.	2.	0.30	1.	0.	1.	144.
33	STM088	COAL-A	0.	-0.004	0.002	0.004	0.00	6.	-2.	-0.	8.	3.	0.	0.06	0.	0.	0.	38.
ALL	STM088	COAL-A	0.160	-0.422	0.364	0.262	0.12	266.	-188.	-13.	673.	301.	46.	0.30	0.	13.	607.	141.
20	STM088	COAL-F	0.127	-0.220	0.184	-0.029	0.88	-88.	-81.	-8.	28.	88.	18.	0.21	-8.	8.	235.	-854.

Figure 4-15. Sample Fuel and Emissions Savings Report

ORIGINAL PAGE IS
OF POOR QUALITY

Table 4-10

CONTENTS OF EMISSIONS BY ECS AND FUEL

ECS Number:	For matching to appropriate ECS
ECS Description:	For information only
Same as Number:	Refers ECS back to other ECS with identical emissions.
NO_x:	Pounds emitted per million Btu
SO_2:	Pounds emitted per million Btu
Particulate:	Pounds emitted per million Btu

(NO_x, SO_2 and Particulate data for each possible fuel type for each ECS)

Table 4-11

CONTENTS OF NATIONAL ENERGY USE

SIC Code	
CTAS Process Number	
Power Match	FESR multiplier to next highest level
Heat Match	FESR multiplier to next highest level
Energy Consumption 1985	
Energy Consumption 2000	

Levels: At CTAS process level next highest level is 2-digit SIC
: At 2-digit SIC next highest level is national.

The FESR is scaled by multipliers discussed in Section 10 (Volume V) so that

$$\underset{(2\text{-digit})}{\text{FESR}} = \underset{(\text{CTAS})}{\text{FESR}} * \underset{(\text{Process to 2-digit})}{\text{Multiplier}}$$

$$\underset{\text{(National)}}{\text{FESR}} = \underset{\text{(2-digit)}}{\text{FESR}} * \underset{\text{(2-digit to National)}}{\text{Multiplier}}$$

All other factors are scaled by market size

$$\text{Scalar - 2-digit} = \frac{\text{FESR(2-digit)* Market(2-digit)}}{\text{FESR(CTAS) * Market(CTAS}}$$

$$\text{Scalar-National} = \frac{\text{FESR(National) * Market(National)}}{\text{FESR(2-digit) * Market(2-digit)}}$$

These scaling factors account for the fact that

1. All process in a 4-digit SIC code are not represented in CTAS.
2. All 4-digit SIC codes in a 2-digit SIC code are not represented in CTAS.
3. All 2-digit SIC codes in the nation are not represented in CTAS.