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COGENERATION TECHNOLOGY ALTERNATIVES STUDY (CTAS)

GENERAL ELECTRIC COMPANY
FINAL REPORT

VOLUME V - COGENERATION SYSTEM RESULTS

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
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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-159764

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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 eir poor economics due to the low effectiveness of the cycle igurations 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 [illegible]. 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

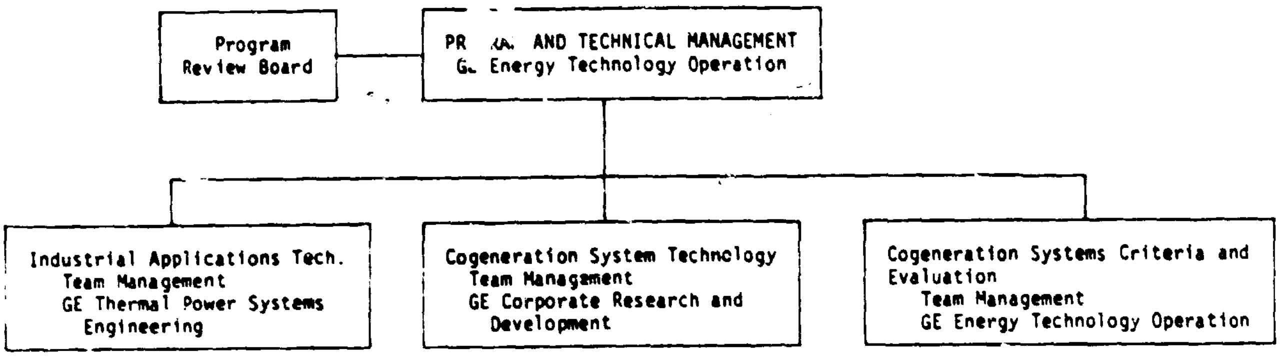


Figure 2-1. GE-CTAS Project Organization

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 8

PERFORMANCE OF ECS-INDUSTRIAL PROCESS MATCHES

8.1 METHODOLOGY

General

The heat and power needs of the industrial processes studied are described in Section 5, Volume III and the ability of various state-of-the-art and advanced energy conversion systems to provide heat and power is described in Section 6, Volume IV. The matching of energy conversion systems and industrial processes refers to the selection of size and type of energy conversion system to provide all of the heat and/or all of the power needed by a given industrial process.

Nocogeneration Case

One who plans to put in place and operate an industrial process must select the means by which heat and power are provided to the process. One way of providing the process needs is through an on-site process boiler supplying all of the process heat and power purchased from a utility to provide all of the process power. This case is called the nocogeneration case. There is no simultaneous production of power and useful heat occurring. The heat rejected at the utility generating site is not used.

Cogeneration Case

The operator of an industrial process may choose to provide for the process heat and power needs by installing an energy conversion system on-site that produces both power and useful heat. This case is referred to as the cogeneration case because power and useful heat are being produced simultaneously.

ECS-Process Matching

The possibilities for matching the ECS's with the processes are shown in Figures 8.1-1 and 8.1-2. Figure 8.1-1 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 of the power required line and heat required line represents the heat and power required by 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 and fixed configuration such that the ratio of available power to available heat is constant. The slope of the line is descriptive of the energy conversion system (power/heat ratio) characteristic and may be 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 in this case is not sufficient to meet the process needs and an auxiliary boiler must be used to make up the deficiency.

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 sold.

Figure 8.1-2 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 and less than the maximum available heat is recovered. Increasing the ECS size above that for matching heat in this case reduces all the advantages of cogeneration and was excluded from further study.

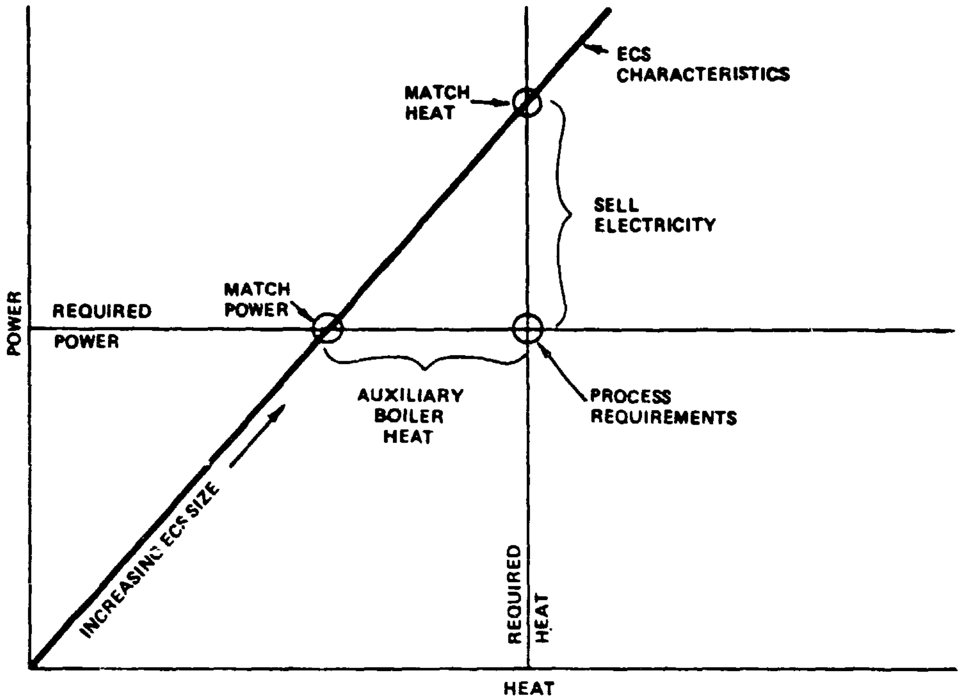


Figure 8.1-1. Matching of Energy Conversion System Output and Industrial Process Requirements (Power/Heat of ECS Greater Than Required)

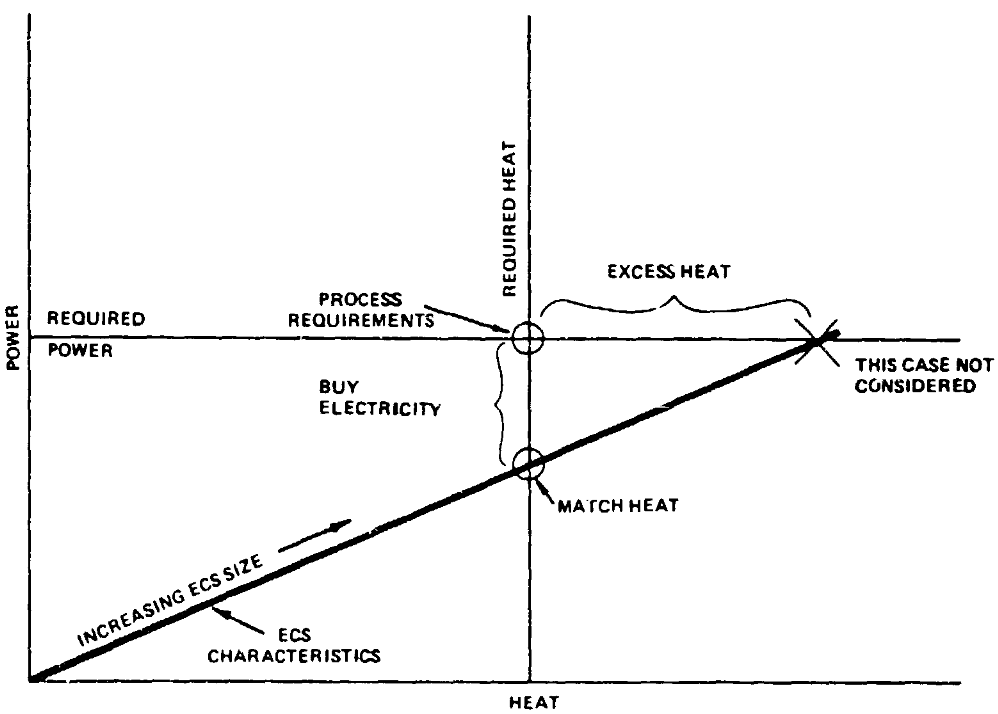


Figure 8.1-2. Matching of Energy Conversion System Output and Industrial Process Requirements (Power/Heat of ECS Less Than Required)

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

The energy conversion system characteristics and the costs described in Sections 6 and 7, Volume IV, and the process parameters described in Section 5, Volume III were entered into a computer data bank. A computer program was written to match up the heat and power needs of each process with the appropriate size of each type of energy conversion system. The computer data bank and computer program are described in Section 4, Volume II.

In summary, each match of energy conversion system and process (cogeneration case) yielded many calculated parameters of technical and economic interest. Each cogeneration case is compared to the nocogeneration case technically and economically and the results are reported in Sections 8 and 9, Volume V (complete computer printouts of the results are given in Volume VI).

8.2 ASSUMPTIONS/GROUNDRULES

The overall study assumptions and groundrules are given in Volume II. 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 by (GE). The groundrules and assumptions pertaining to the calculation of fuel energy savings and emissions savings for each plant are:

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 type and fuel sized as follows: (GE)

     <30 x 10^6 Btu/yr heat output, petroleum or coal residual

     30 x 10^6 to 100 x 10^6 Btu/hr heat output, coal AFB

     >100 x 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 waste 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 8.2-1.

- 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)

Table 8.2-1

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)

	Fuel Type		
Pollutant	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

8.3 FUEL ENERGY SAVINGS POTENTIAL OF COGENERATION

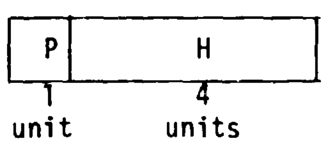
A derivation of the potential fuel energy savings possible through cogeneration is presented. The functional relationships of energy conversion system efficiency, fuel utilization effectiveness, utility system efficiency, process boiler efficiency and process heat and power demands are described as pertains to potential fuel energy savings. The possible constraint of not allowing export power is shown to have a significant effect on possible fuel energy savings. For some energy conversion systems the temperature at which heat is required has a significant effect on potential fuel energy savings.

Nocogeneration Fuel Energy

The bar shown in Figure 8.3-1 represents the total rate of energy required by an industrial process and is divided in proportion to the thermal power demand rate and electrical or mechanical power demand rate. Both energy demand rates are expressed in the same units (Btu/hr) where

P = Power (electric or shaft) required in Btu/hr (Btu/hr = kilowatts x 3413).

H = Heat (thermal power) required in Btu/hr



Total Process Power Requirements

Figure 8.3-1. Representation of Industrial Heat and Power Requirements

The length of the bar is representative of the total energy required by the process. For exemplary purposes assume that the process requires one unit of power and four units of heat. Given the CTAS groundrules and assumptions concerning the process boiler efficiency and the utility conversion efficiency of fuel energy to electric power, it is possible to calculate the fuel energy required to provide the process energy demands in this nocogeneration case. The process boiler converts fuel energy (based on higher heating value) to heat energy with an 85% efficiency. The electric utility converts fuel energy (based on higher heating value) to electric energy delivered to the process site with an efficiency of 32%. This is typical of coal-fired generating plants using flue gas desulfurization.

The bar shown in Figure 8.3-2 represents the fuel consumption rate required by a process boiler to provide the process with its thermal power where:

H is the heat required by the process, Btu/hr

L_b is the total losses (auxiliaries and unrecoverable heat) Btu/hr

F_b is the fuel energy required (based on higher heating value) to produce H, Btu/hr

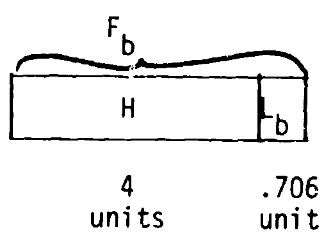


Figure 8.3-2. Representation of Process Boiler Fuel Input

The conversion efficiency of fuel energy to useful heat is

$$\eta_b = \frac{H}{F_b}$$

and for this study $\eta_b = 0.85$. To provide 4 units of heat energy requires 4.706 units of fuel energy.

The bar shown in Figure 8.3-3 represents the fuel consumption rate required by a utility to provide the electric power P required by the process where:

P is the electric power required by the process, Btu/hr

L_{UTIL} is the lost or unrecoverable energy, Btu/hr

F_{UTIL} is the fuel energy consumption rate (based on higher heating value) required by the utility to provide the electric power, P, required, Btu/hr

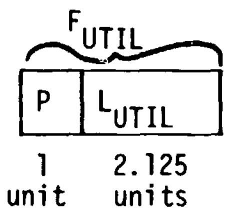


Figure 8.3-3. Representation of Utility Fuel Input

The electric utility conversion efficiency of fuel to electric power delivered is

$$\eta_{UTIL} = \frac{P}{F_{UTIL}}$$

and is assumed to be 0.32 for this study. Consequently, it requires 3.125 units of fuel energy to produce one unit of electric energy.

The total amount of fuel energy required to provide the industrial process with the required heat and power is represented by the bar in Figure 8.3-4.

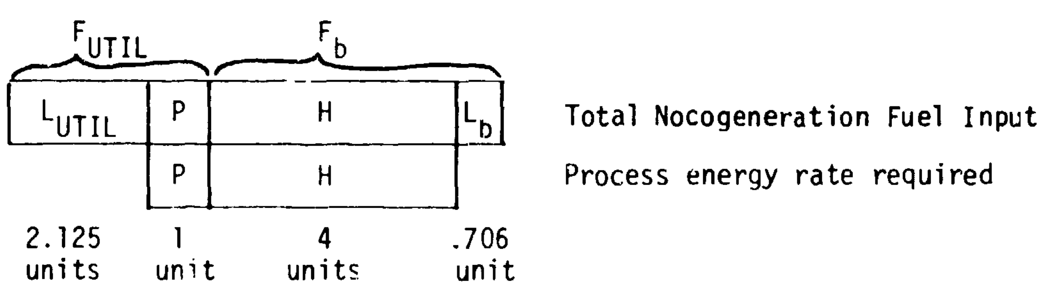


Figure 8.3-4. Representation of Total Fuel Input for Nocogeneration

The total consumption of fuel energy to provide the process with heat and power is:

$$F_{NOCOGEN} = F_b + F_{UTIL}$$
$$= 3.125 + 4.706$$
$$= 7.831 \text{ units fuel energy}$$

In terms of the Power, $\dot{P}$, and the heat, H, required by the process, the total fuel required is

$$F_{NOCOGEN} = \frac{P}{(P/F)_{UTIL}} + \frac{H}{(H/F)_b}$$
$$= \frac{P}{\eta_{UTIL}} + \frac{H}{\eta_b}$$

It is also observed that the maximum amount of fuel that could be saved is equal to the losses or $(L_{UTIL} + L_b) = 2.831$ units.

<u>Cogeneration Fuel Energy</u>

In cogeneration, fuel is converted to power and useful heat in an energy conversion system and supplied to an industrial process. The bar shown in Figure 8.3-5 represents the total fuel energy supplied to an energy conversion system and the proportions of fuel energy that are converted to power, useful heat, and unrecoverable losses

where:

P_{ECS} = ECS power output, Btu/hr

H_{ECS} = ECS useful heat output, Btu/hr

L_{ECS} = Unrecoverable losses

F_{ECS} = ECS fuel consumption (based on fuel higher heating value) to produce P_{ECS} and H_{ECS}, Btu/hr

$$\overbrace{\boxed{P_{ECS}} \quad \boxed{H_{ECS}} \quad \boxed{L_{ECS}}}^{F_{ECS}}$$

P_{ECS}	H_{ECS}	L_{ECS}	
1 unit	4 units	0.882 unit	F_{ECS} = 5.882 units

Figure 8.3-5. Representative of Cogeneration ECS Fuel Input

In this case where the cogeneration system is assumed to be ideally matched to the energy requirements of the industrial process

$$F_{COGEN} = 5.882$$

compared to the

$$F_{NOCOGEN} = F_{UTIL} + F_b = 7.831 \text{ units}$$

The fuel saved by cogeneration is

Fuel Saved = 1.949 units

The efficiency of the energy conversion system in converting fuel to electric power is

$$\eta_p = \frac{P_{ECS}}{F_{ECS}}$$

The electrical conversion efficiency has always been the primary measure of the performance of an energy conversion system because they have been primarily used for their ability to convert fuel to electricity. The heat rejected from an energy conversion system has always been of secondary concern. In cogeneration applications both power and heat (supplied at the desired temperature) are of interest. It is convenient to define another efficiency term for the energy conversion system - the heat conversion efficiency. The heat conversion efficiency of an energy conversion system is the ratio of useful thermal output to fuel input

$$\eta_h = \frac{H_{ECS}}{F_{ECS}}$$

Useful thermal output refers to the amount of heat that can be supplied at a specified (required) temperature. For instance, if an energy conversion system could supply 10 million Btu/hr at 200^{o}F and 0 Btu/hr at 400^{o}F, and the heat was actually required at 400^{o}F, then the useful heat supplied by the ECS would be 0 and η_h would be 0.

The electrical and thermal conversion efficiencies of the exemplary energy conversion system are

$$\eta_p = \frac{1}{5.882} = 0.170$$

$$\eta_h = \frac{4}{5.882} = 0.680$$

Another parameter of importance when considering energy conversion systems for cogeneration applications is the total fuel utilization or effectiveness of the energy conversion system. The effectiveness is simply the sum of the electrical and thermal conversion efficiencies and represents the ratio of total useful energy output of the ECS to fuel energy input (based on higher heating value). The effectiveness for a process boiler is 0.85 because the useful energy output is 0.85 of the fuel energy input. The effectiveness of the exemplary energy conversion system is 0.85 ($\eta_{ef} = \eta_p + \eta_h = 0.170 + 0.680 = 0.85$). A review of the energy conversion system characteristics given in Section 6 of Volume IV shows that the effectiveness of some energy conversion systems varies with the temperature at which it supplies the heat.

All further examples used in this section for illustrative purposes will assume an energy conversion system effectiveness of 0.85.

As an example, the power and heat outputs of the energy conversion system have been arbitrarily selected to ideally match the power and heat required of the exemplary process. If the energy conversion system described above is used to provide the heat and power needs of the process, then the fuel energy required would be 5.882 units as opposed to 7.831 units in the nocogeneration case (Figure 8.3-6) and the fuel energy saved relative to the nocogeneration fuel (called the Fuel Energy Saved Ratio) is

$$\text{Fuel Energy Saved Ratio} = \frac{7.831 - 5.882}{7.831} = 0.249$$

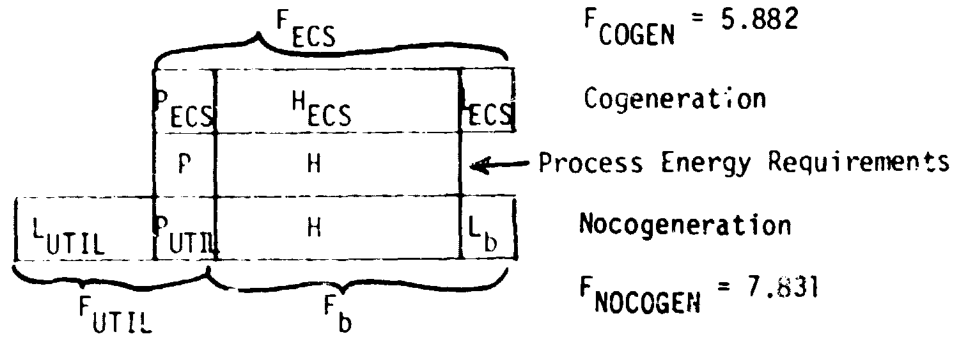


Figure 8.3-6. Cogeneration Vs. Nocogeneration Representation of Fuel Inputs

Power Match

The case where the power and heat needs of a process can be exactly matched by the output of an energy conversion system is not often found in practice. If the energy conversion system were more efficient (that is, if the electrical conversion efficiency were higher) and the power demands of the process were being matched by the ECS, then the heat output of the ECS would be less than that required by the process. In this case, an auxiliary boiler would be used to make up the deficiency. This situation is depicted in Figure 8.3-7.

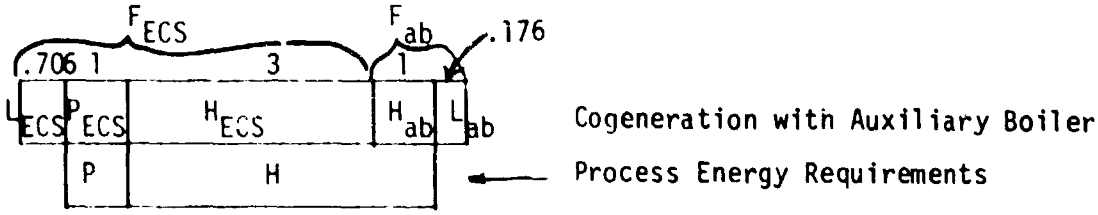


Figure 8.3-7. Representation of Fuel Inputs with Auxiliary Boiler (Power Match)

The efficiency of the auxiliary boiler is assumed the same as that of the process boiler (85%). The energy conversion system is assumed to be more efficient in this example, its electrical conversion efficiency is

$$\eta_p = \frac{1}{4.706} = 0.2125$$

as compared to 0.170 in the previous example.

In this case a larger portion of the fuel is converted to power and less to useful heat than previously. The thermal conversion efficiency of the energy conversion system in this case is then

$$\eta_h = \frac{3}{4.706} = 0.6375$$

or

$$\eta_h = \eta_{ef} - \eta_p = 0.85 - 0.2125 = 0.6375$$

The total fuel required in this cogeneration case is 5.882 units and the fuel energy saved ratio is 0.249 which is the same as the previous cogeneration case. It is interesting to note that even though a more efficient energy conversion system was used to cogenerate, the total fuel required to provide the process with heat and power is the same as would be required by the "less efficient" energy conversion system. It will be shown in this section that the potential fuel savings due to cogeneration may be limited when the power requirements of an industrial process are met by an energy conversion system (power match) as opposed to meeting the process heat requirements with reject heat from an energy conversion system (heat match).

Heat Match

If the heat needs of the process were matched with the more efficient energy conversion system, the power produced by the energy conversion system would exceed that required by the process and power would have to be exported. The fuel required in the nocogeneration case to produce the same amount of useful heat and power as in the cogeneration case is depicted in Figure 8.3-8.

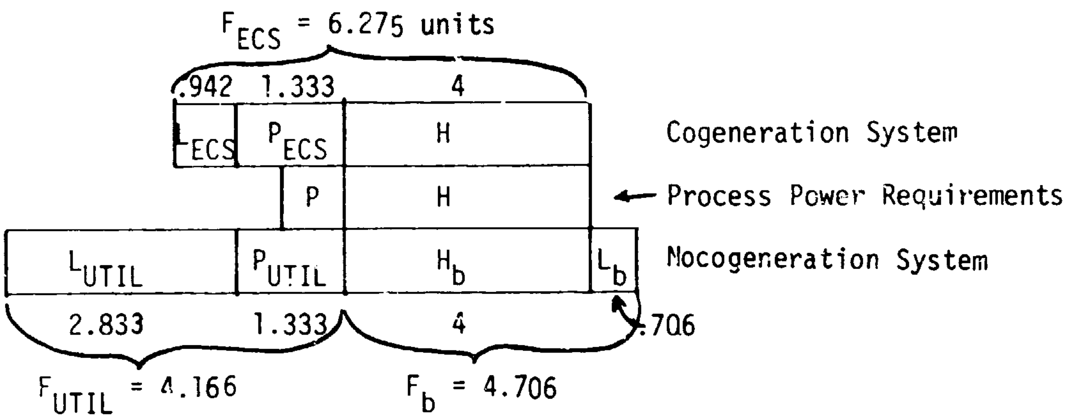


Figure 8.3-8. Representation of Fuel Inputs when Exporting Power (Heat Match)

The utility in this nocogeneration case is assumed to produce the same power as the ECS (which is more than that required by the industry) so that

$$F_{NOCOGEN} = F_{UTIL} + F_b = 8.872 \text{ units}$$

also,

$$F_{COGEN} = 6.275 \text{ units}$$

or the fuel saved by cogeneration is

Fuel Saved = 2.597 units

and Fuel Energy Saved Ratio $= \frac{8.872 - 6.275}{8.872} = 0.293$

If the case where the energy conversion system was sized to meet the power needs of the process is compared to the case where the energy conversion system is sized to match the heat needs of the process, it is seen that 0.333 units of additional power were produced for an additional fuel consumption of (6.275 - 5.882) or only 0.393 units of fuel. Thus an incremental fuel - electric power conversion efficiency of 85%. The incremental fuel-electric power conversion efficiency is equal to the effectiveness of the ECS in this instance.

When the ECS is less efficient than the one that can exactly meet the heat and power requirements of the process, the following example illustrates the situation when matching the power needs of the process (power match).

In this case assume the electrical conversion efficiency of the ECS is 15%, then

$$\eta_p = .15$$

and

$$\eta_h = \eta_{ef} - \eta_p = 0.85 - 0.15 = 0.70$$

The fuel energy requirements are represented by Figure 8.3-9.

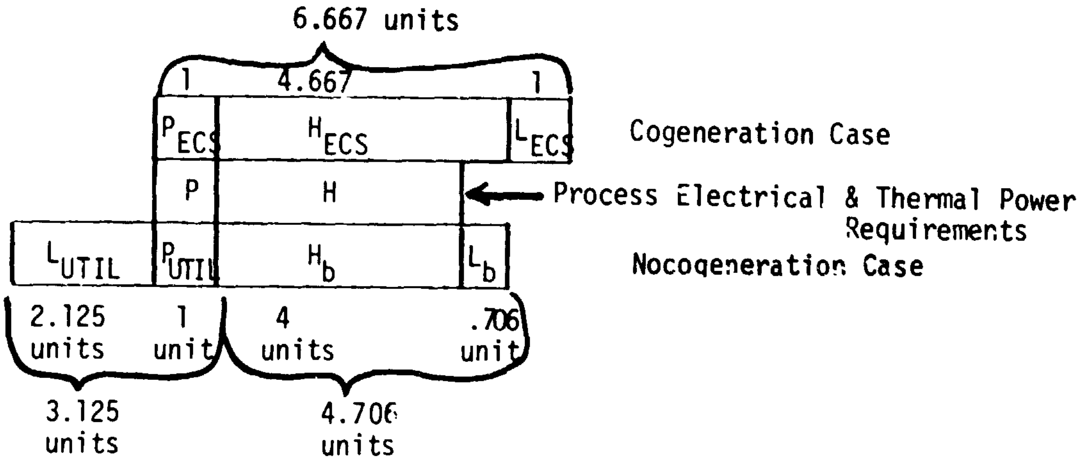


Figure 8.3-9. Representation of Fuel Inputs with Less Efficient ECS with Power Match

In this example, the cogeneration fuel is

$$F_{COGEN} = 6.667 \text{ units}$$

also,

$$F_{NO\,COGEN} = 7.831$$

$$\text{Fuel Energy Saved} = 1.164 \text{ units}$$

and

$$\text{Fuel Energy Saved Ratio} = \frac{7.831 - 6.667}{7.831} = 0.149$$

More heat is provided by the energy conversion system in the cogeneration case than is required by the process; however, fuel energy is saved in comparison to the nocogeneration case. Heat rejection equipment may have to be installed to dissipate the excess heat. This case was not considered in the CTAS study because heat was being wasted, although it is a possible and practical situation.

If this same "less efficient" ECS is sized to meet the process heat needs (heat match), the fuel savings displayed in Figure 8.3-10 result.

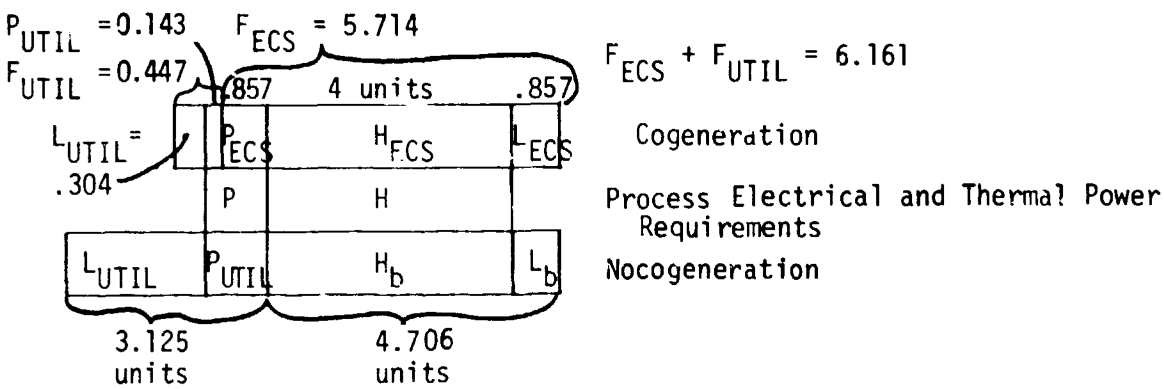


Figure 8.3-10. Representation of Fuel Inputs with Less Efficient ECS with Heat Match

In this example, the cogeneration fuel is

$$F_{COGEN} = 6.161$$

also,

$$F_{NOCOGEN} = 7.831$$

$$\text{Fuel Energy Saved} = 1.670$$

$$\text{Fuel Energy Saved Ratio} = \frac{7.831 - 6.161}{7.831} = 0.213$$

The fuel energy saved in this case is larger than in the previous case where excess heat from the ECS had to be dissipated.

From the previous example of fuel energy savings potential of various exemplary energy conversion systems used in cogeneration applications it is observed that the factors influencing the amount of fuel energy savings are the power and heat required by the process and the power and useful heat output of the ECS. Under some conditions a "more efficient" ECS cannot save any more fuel than a less efficient one. All of the previous examples assumed that the effectiveness of the ECS was 0.85. For the ECS's studied in CTAS the effectiveness varied from 0.49 to 0.85 at a process steam saturation temperature of 350°F. The system effectiveness and ECS power to heat ratio have a significant impact on the potential fuel energy savings.

Process-ECS Fuel Savings Functional Relationships

Using the definition of fuel energy saved ratio and the definition of ECS effectiveness, equations can be developed to describe the functional relationships between fuel energy saved ratio and process power/heat ratio, ECS power/heat ratio, ECS effectiveness and ECS electrical conversion efficiency.

The fuel energy saved ratio (FESR) is given by

$$\mathrm{FESR} = \frac{(\text{Fuel Used})_{\text{Nocogen}} - (\text{Fuel Used})_{\text{Cogen}}}{(\text{Fuel Used})_{\text{Nocogen}}} \qquad (8.3\text{-}1)$$

Nocogeneration Fuel Required

If power is not exported in the cogeneration case, then the fuel required in the nocogeneration case is

$$F_{\text{Nocogen}} = \frac{P}{\eta_{\text{UTIL}}} + \frac{H}{\eta_b} \qquad (8.3\text{-}2)$$

If power is exported in the cogeneration case, then the nocogeneration case must be re-defined as that to produce the same amount of electric power as was produced in the cogeneration case. Power export can only occur when the ECS is sized to meet the process thermal needs and the power to heat ratio of the ECS is greater than the power to heat ratio of the process. In this instance, the fuel required in the nocogeneration case would be

$$F_{Nocogen} = \frac{P_{ECS}}{\eta_{UTIL}} + \frac{H}{\eta_b} \tag{8.3-3}$$

Fuel Energy Saved Ratio For Power Match

The fuel energy required by an ECS sized to meet the power required by a process is

$$F_{ECS} = \frac{P}{(P/F)_{ECS}} = \frac{P}{\eta_p} \tag{8.3-4}$$

The total cogeneration fuel energy required is the sum of the ECS fuel energy requirement and that of an auxiliary boiler (if required) to meet the heat demand of the process. The auxiliary boiler would be required if the heat output of the ECS is less than that required by the process, or

$$(P/H)_{ECS} > (P/H)_{process}$$

The auxiliary boiler fuel is

$$F_{ab} = \left[H - \frac{P}{(P/F)_{ECS}} \cdot \left(\frac{H}{F}\right)_{ECS}\right] / \eta_{ab} \tag{8.3-5}$$

The total cogeneration fuel required is

$$F_{COGEN} = F_{ECS} + F_{ab} \tag{8.3-6}$$

for $(P/H)_{ECS} \geq (P/H)_{process}$

From equations 8.3-4, 8.3-5 and 8.3-6,

$$F_{COGEN} = \frac{P}{(P/F)_{ECS}} + \left[H - \frac{P}{(P/F)_{ECS}} \cdot \left(\frac{H}{F}\right)_{ECS} \right] / \eta_{ab} \qquad (8.3\text{-}7)$$

When the P/H of the ECS is less than that required by the process, $(P/H)_{ECS} \leq (P/H)_{process}$, the heat output of the ECS would be greater than that required by the process when the ECS is sized to meet the process power needs (power match) The total cogeneration fuel required is then

$$F_{COGEN} = F_{ECS} = P/(P/F)_{ECS} \qquad (8.3\text{-}8)$$

Combining the equations given previously and the definition of fuel energy saved ratio gives for $(P/H)_{ECS} \geq (P/H)_{process}$,

$$FESR = 1 - \left[\frac{\dfrac{(P/H)_{process}}{(P/F)_{ECS}} + \left(1 - \dfrac{(P/H)_{process}}{(F/H)_{ECS}}\right) / \eta_{ab}}{\dfrac{(P/H)_{process}}{\eta_{UTIL}} + \dfrac{1}{\eta_b}} \right] \qquad (8.3\text{-}9)$$

For the case where $(P/H)_{ECS} \leq (P/H)_{process}$,

$$FESR = 1 - \left[\frac{\dfrac{(P/H)_{process}}{(P/F)_{ECS}}}{\dfrac{(P/H)_{process}}{\eta_{UTIL}} + \dfrac{1}{\eta_b}} \right] \qquad (8.3\text{-}10)$$

Inspection of the fuel energy saved ratio Equations 8.3-9 and 8.3-10 reveals that maximum fuel energy savings are achieved when the ratio of power to heat of the energy conversion system is equal to the power to heat ratio of the process. The output of energy conversion system in that case would exactly match the process power and heat demands.

Reviewing the energy conversion system performance characteristics presented in Section 6, Volume IV, reveals that P/F, H/F and η_{ef} are functions of temperature at which heat is required by the process.

The equation relating these three terms is

$$\frac{P}{F} + \frac{H}{F} = \eta_{ef} \qquad (8.3\text{-}11)$$

The equation may be manipulated to give

$$P/F = \frac{\eta_{ef}}{(1 + 1/_{P/H})} \qquad (8.3\text{-}12)$$

Since in the case of a power match, the energy conversion system ratio of power to heat must equal or be greater than that of the process to achieve maximum fuel energy savings, Equation 8.3-12 represents the minimum energy conversion system efficiency required to give maximum fuel energy savings for a given process power to heat ratio and energy conversion system effectiveness.

Figure 8.3-11 graphically displays the relationsnip between the process power to heat ratio, the energy conversion system effectiveness and minimum energy conversion system efficiency to achieve maximum fuel savings for a power match. An upper bound on energy conversion system effectiveness of 0.85 was arbitrarily selected because it is the maximum achieved by any energy conversion system studied (with the given assumptions) and which also matches the process boiler efficiency. As expected, the effectiveness of the energy conversion system has a pronounced effect on the electrical power conversion efficiency required to achieve the maximum fuel savings.

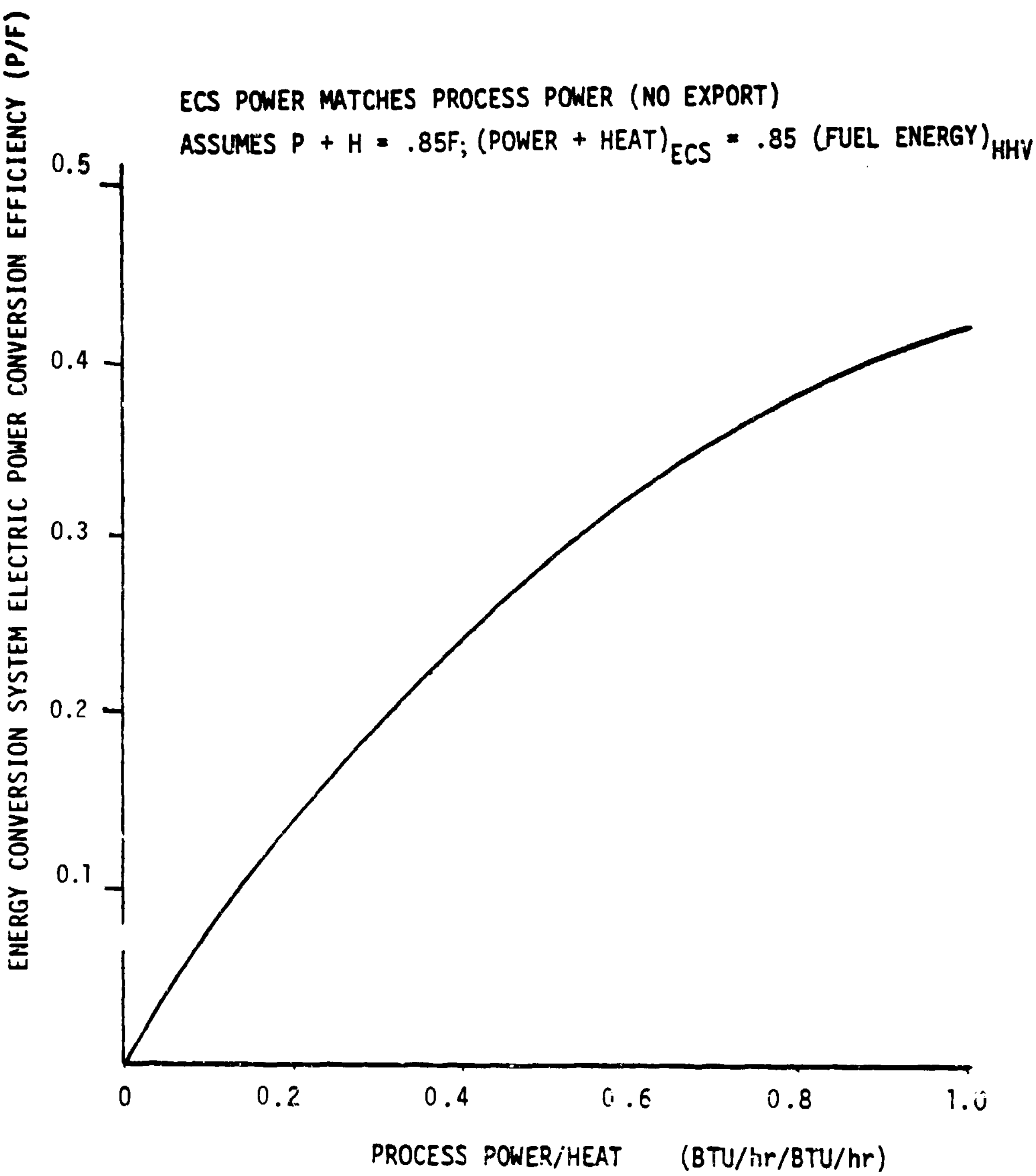


Figure 8.3-11. Energy Conversion System Minimum Electric Power Conversion Efficiency (P/F Required to Achieve Maximum Fuel Energy Saved Ratio Vs. Process Power to Heat Ratio)

Using Equations 8.3-10 and 8.3-12 for the case where the P/H of the ECS matches the P/H of the process and the implied assumption of an ECS effectiveness of 0.85 gives the results displayed in Figure 8.3-12 of maximum fuel energy savings possible vs. ECS electric power conversion efficiency for various process power to heat ratios.

$$FESR_{max} = 1 - \left[\frac{\left((P/H)_{process} + 1 \right) / \eta_{ef}}{\frac{(P/H)_{process}}{\eta_{UTIL}} + \frac{1}{\eta_b}} \right] \qquad (8.3\text{-}13)$$

It is also possible to achieve maximum fuel energy savings for the power match when the energy conversion system has the maximum effectiveness of 0.85 and a power to heat ratio greater than that of the process. In this case an auxiliary boiler with an efficiency (effectiveness) of 0.85 is used to supply the shortfall of heat giving a cogeneration system overall effectiveness of 0.85.

Using Equation 8.3-13 and varying the energy conversion system effectiveness and Equation 8.3-12 to define the minimum ECS electrical conversion efficiency $(P/F)_{ECS}$ yields the results shown in Figure 8.3-13. As expected, the effectiveness of the energy conversion system has a pronounced effect on the maximum fuel savings and the electrical power conversion efficiency required to achieve the maximum fuel savings.

Fuel Energy Saved Ratio for Heat Match

Equations for the fuel energy saved ratio of heat match cases are derived below.

The fuel energy required by an energy conversion system sized to satisfy the thermal power requirements of an industrial process is

$$F_{ECS} = H/(H/F)_{ECS} \qquad (8.3\text{-}14)$$

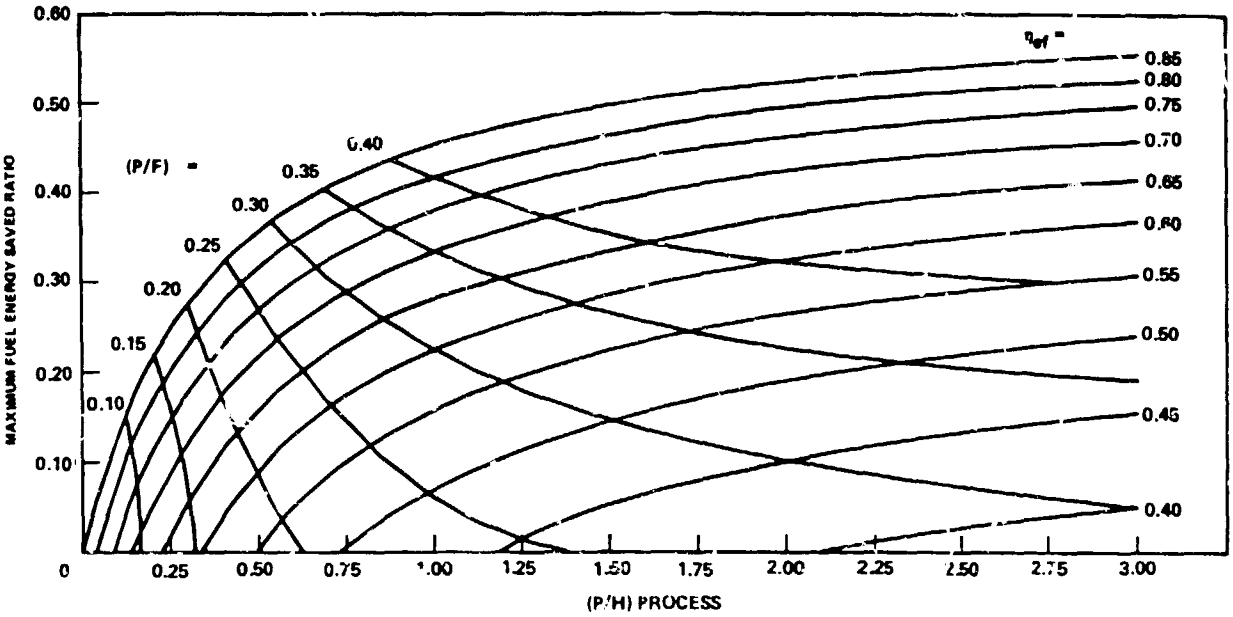


Figure 8.3-12. Maximum Fuel Energy Saved Ratio When Process Power Matched by ECS (ECS (P/H) Greater Than or Equal to Process (P/H))

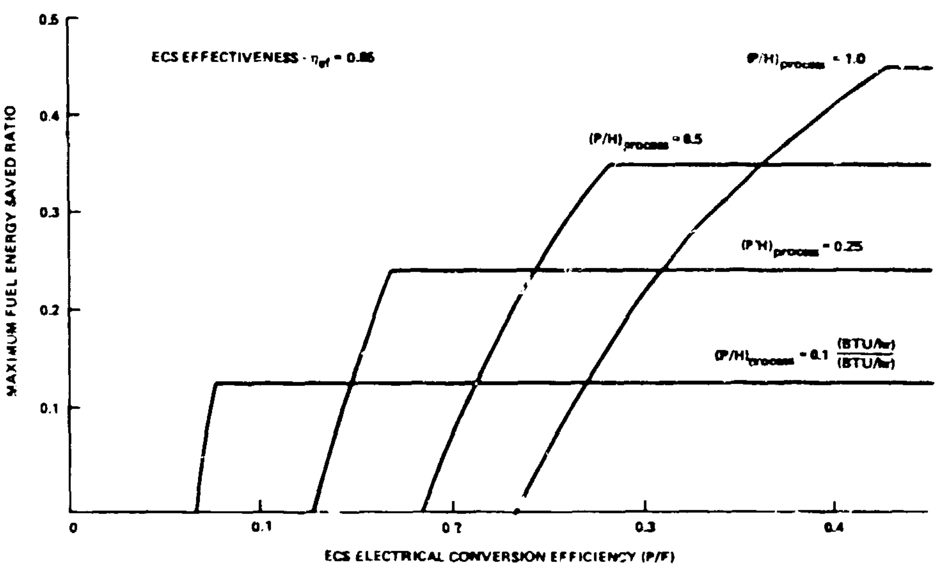


Figure 8.3-13. Maximum Fuel Energy Saved Ratio Vs ECS Electric Power Conversion Efficiency (ECS Power Output Equal to Process Power Needs (No Export Power))

If the electric power output of the ECS in this situation is not large enough to satisfy the process demands, then utility power must be purchased to make up the shortfall. The fuel energy required at the utility to provide the makeup power required is

$$F_{UTIL} = \frac{P - F_{ECS}\left(\frac{P}{F}\right)_{ECS}}{\eta_{UTIL}} = \frac{P - H(P/H)_{ECS}}{\eta_{UTIL}} \tag{8.3-16}$$

The total fuel required in the cogeneration case for $(P/H)_{ECS} \leq (P/H)_{process}$ is then

$$F_{COGEN} = F_{ECS} + F_{UTIL} \tag{8.3-17}$$

or

$$F_{COGEN} = H/(H/F)_{ECS} + \frac{P - H(P/H)_{ECS}}{\eta_{UTIL}} \tag{8.3-17}$$

The fuel energy saved ratio for $(P/H)_{ECS} \leq (P/H)_{process}$ is then

$$FESR = 1 - \left[\frac{\frac{1}{(H/F)_{ECS}} + \frac{(P/H)_{process} - (P/H)_{ECS}}{\eta_{UTIL}}}{\frac{(P/H)_{process}}{\eta_{UTIL}} + \frac{1}{\eta_b}} \right] \tag{8.3-18}$$

For the situation where the power output of the energy conversion system (when sized to match the heat needs of a process) is greater than the power required by the process and the excess power can be exported to the utility, then the nocogeneration case must be redefined such that the utility power produced is the same as that of the ECS in the cogeneration case.

$$F_{NOCOGEN} = \frac{P_{ECS}}{\eta_{UTIL}} + \frac{H}{\eta_b} \tag{8.3-19}$$

The fuel energy required by the energy conversion system in the cogeneration case is simply governed by the process heat requirement.

$$F_{COGEN} = H/(H/F)_{ECS} \tag{8.3-20}$$

The fuel energy savings ratio for $(P/H)_{ECS} \geq (P/H)_{process}$ is,

$$FESR = 1 - \left[\frac{1/(H/F)_{ECS}}{\frac{(P/H)_{ECS}}{\eta_{UTIL}} + \frac{1}{\eta_b}} \right] \tag{8.3-21}$$

Combining Equation 8.3-11 which relates the H/F of the ECS to the effectiveness (η_{ef}) and the (P/H) with Equation 8.3-18 for $(P/H)_{ECS} \leq (P/H)_{process}$ gives

$$FESR = 1 - \left[\frac{\frac{1 + (P/H)_{ECS}}{\eta_{ef}} + \frac{(P/H)_{process} - (P/H)_{ECS}}{\eta_{UTIL}}}{\frac{(P/H)_{process}}{\eta_{UTIL}} + \frac{1}{\eta_b}} \right] \tag{8.3-22}$$

or for $(P/H)_{ECS} \geq (P/H)_{process}$ gives,

$$FESR = 1 - \left[\frac{\frac{1 + (P/H)_{ECS}}{\eta_{ef}}}{\frac{(P/H)_{ECS}}{\eta_{UTIL}} + \frac{1}{\eta_b}} \right] \tag{8.3-23}$$

Incremental Efficiency of Generating Export Power

It is observed by comparing Figures 8.3-7 with 8.3-8 that the fuel energy savings possible for energy conversion systems having a (P/H) greater than the process (P/H) when matching the heat required by the process are potentially much greater than those savings possible when constrained to matching process power. The following compares the fuel required for both cogeneration cases and shows that the exported power is produced at a very attractive efficiency.

Rearranging Equation 8.3-11 gives

$$\frac{P}{\eta_{ef}} + \frac{H}{\eta_{ef}} = F \tag{8.3-24}$$

which simply states that the power output of the ECS divided by the effectivensss and the heat output of the ECS divided by the effectiveness is equal to the fuel energy input.

Using this relationship, we may simply express the difference in fuel energy requirements between the cogeneration case of matching process heat needs and exporting power and the cogeneration case of matching process power needs and using an auxiliary boiler to provide for the deficiency of process heat.

For the power match case,

$$F_{power} = \frac{P}{\eta_{ef}} + \frac{H_{ECS}}{\eta_{ef}} + \frac{(H - H_{ECS})}{\eta_{ab}} \tag{8.3-25}$$

where H_{ECS} is the useful heat output of the energy conversion system for the power match which is less than the process heat required (H).

For the heat match case,

$$F_{heat} = \frac{P_{ECS}}{\eta_{ef}} + \frac{H}{\eta_{ef}} \qquad (8.3\text{-}26)$$

where P_{ECS} is greater than the process power required (P) for the heat match case.

The incremental fuel energy required between the heat match case and the power match case is $\Delta F = F_{heat} - F_{power}$.

From equations 8.3-25 and 8.3-26

$$\Delta F = \frac{(P_{ECS} - P)}{\eta_{ef}} + (H - H_{ECS}) \left(\frac{1}{\eta_{ef}} - \frac{1}{\eta_{ab}}\right) \qquad (8.3\text{-}27)$$

The difference in power generated between the heat match and power match is

$$\Delta P = P_{ECS} - P \qquad (8.3\text{-}28)$$

The incremental efficiency of generating the power that is exported is

$$\eta_{P_{ex}} = \frac{\Delta P}{\Delta F} = \frac{P_{ECS} - P}{\frac{P_{ECS} - P}{\eta_{ef}} + (H - H_{ECS}) \left(\frac{1}{\eta_{ef}} - \frac{1}{\eta_{ab}} \right)} \qquad (8.3\text{-}29)$$

It is seen that when the ECS has the same effectiveness as the auxiliary boiler efficiency that the incremental efficiency of generating export power is equal to the ECS effectiveness. For this study the auxiliary boiler efficiency is 0.85 and several energy conversion systems have an effectiveness of 0.85; therefore, the efficiency of generating export power is as high as 0.85%.

$$\eta_{P_{ex}} = \eta_{ef} \quad \text{for} \quad \eta_{ef} = \eta_{ab}$$

This high efficiency underscores the importance of the need for freedom to export power in cogeneration applications.

8.4 PARAMETRIC FUEL ENERGY SAVINGS OF SELECTED ENERGY CONVERSION SYSTEMS

From the previous discussion it is observed that fuel energy savings depend upon whether export power is allowed or not, the ratio of power to heat required by the process, the ECS ratio of power to heat, and the effectiveness of the ECS. The ECS parameters are often functions of the temperature at which heat is supplied. Figures 8.4-1 through 8.4-6 display the range of fuel energy savings ratio with selected ECS's for heat matches and power matches for process power to heat ratios of 0.1, 0.25 and 1.0. For most ECS's the fuel energy savings vary from a minimum, shown as 0, corresponding to a low temperature at which heat is supplied to process to a maximum, shown as "●", corresponding to a high temperatue at which heat is supplied to process. The variations in fuel energy savings with temperature are due to the variation of energy conversion system power to heat ratio and effectiveness with the temperature at which heat must be supplied to process. There are three ECS's whose characteristics do not vary with temperature. These are the steam injected gas turbine burning residual fuel, and the distillate-fired fuel cells. These ECS's show up only as a point on the plots.

The line identified as the maximum theoretical fuel energy saving is the fuel energy savings possible only when utilizing a system with an 85% effectiveness and the appropriate power/heat ratio. For heat matches the maximum theoretical fuel energy savings line would be calculated from Equation 8.3-22 for an ECS P/H less than the process P/H or from Equation 8.3-23 for an ECS P/H greater than the process P/H. For power matches, Equation 8.3-13 gives the maximum fuel energy savings possible as a function of process P/H. The maximum fuel energy savings for power matches is given in Figure 8.3-12 for selected process P/H values.

The horizontal axis of the curves are actually the parameter $(P/H)_{ECS}/(P/H)_{process}$. For a heat match, the heat output of the ECS and the heat required by the process are the same and the term $(P/H)_{ECS}/(P/H)_{process}$ becomes $P_{ECS}/P_{process}$. Similarly, for the power match case, the ratio of ECS to process power to heat ratio becomes $H_{process}/H_{ECS}$.

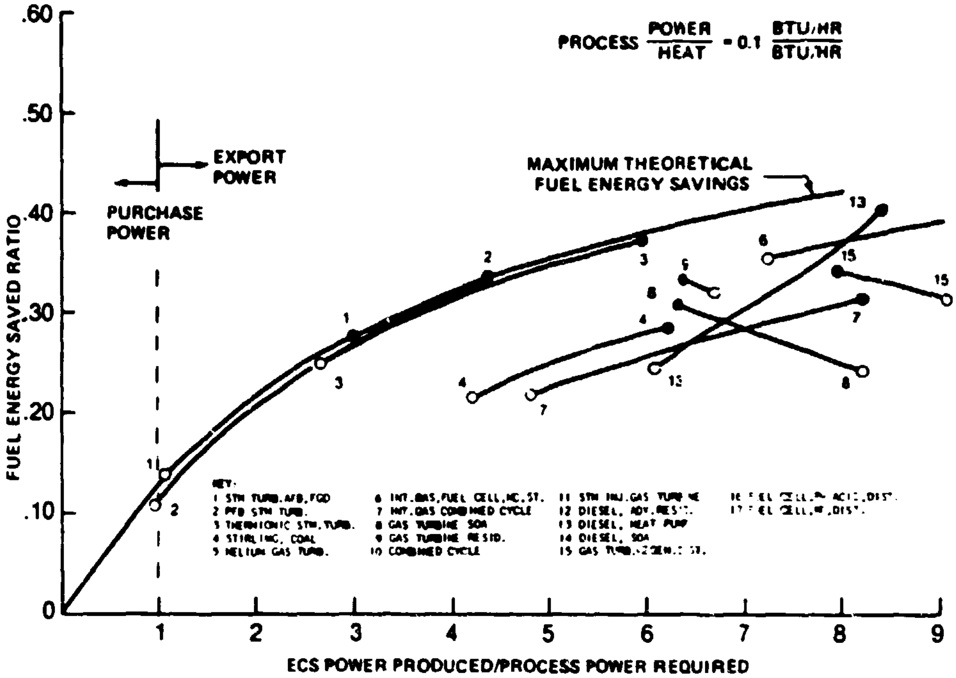


Figure 8.4-1. Fuel Energy Saving Potential of Energy Conversion Systems When Matched to Industrial Process Heat Needs (P/H = 0.1)

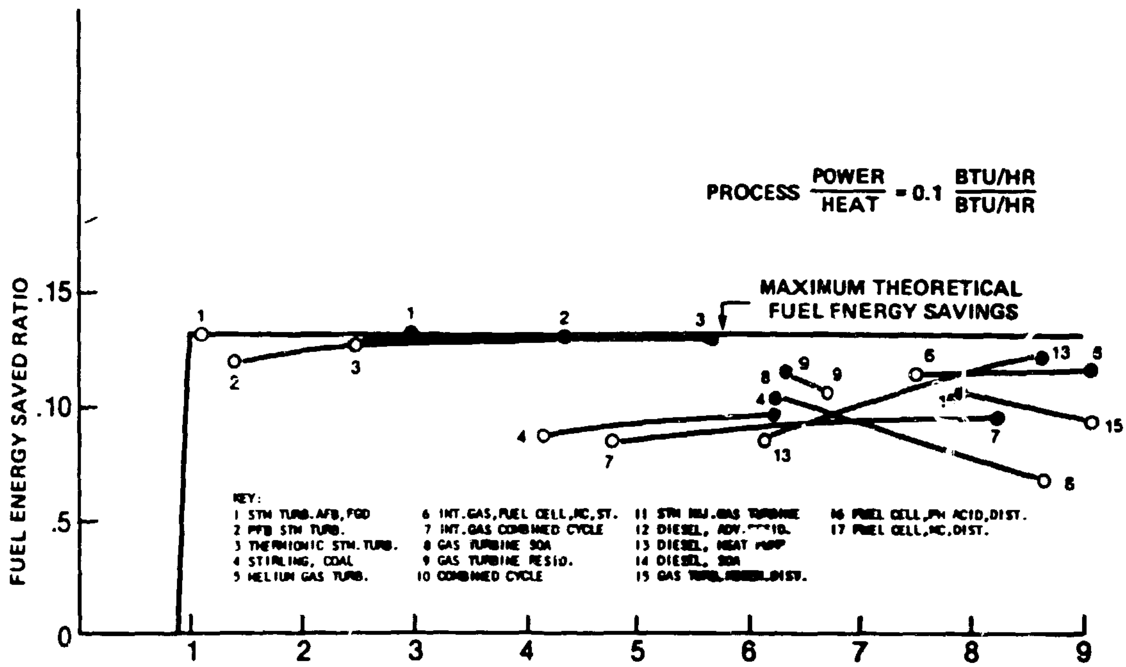


Figure 8.4-2 Fuel Energy Saving Potential of Energy Conversion Systems When Matched to Industrial Process Power Needs (P/H = 0.1)

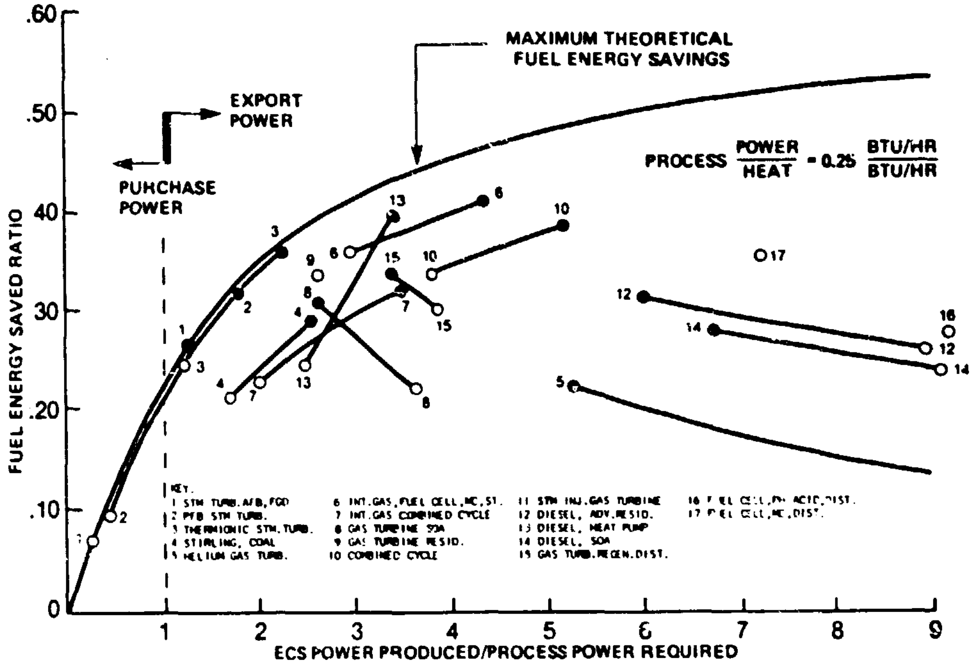


Figure 8.4-3. Fuel Energy Saving Potential of Energy Conversion Systems When Matched to Industrial Process Heat Needs (P/H = 0.25)

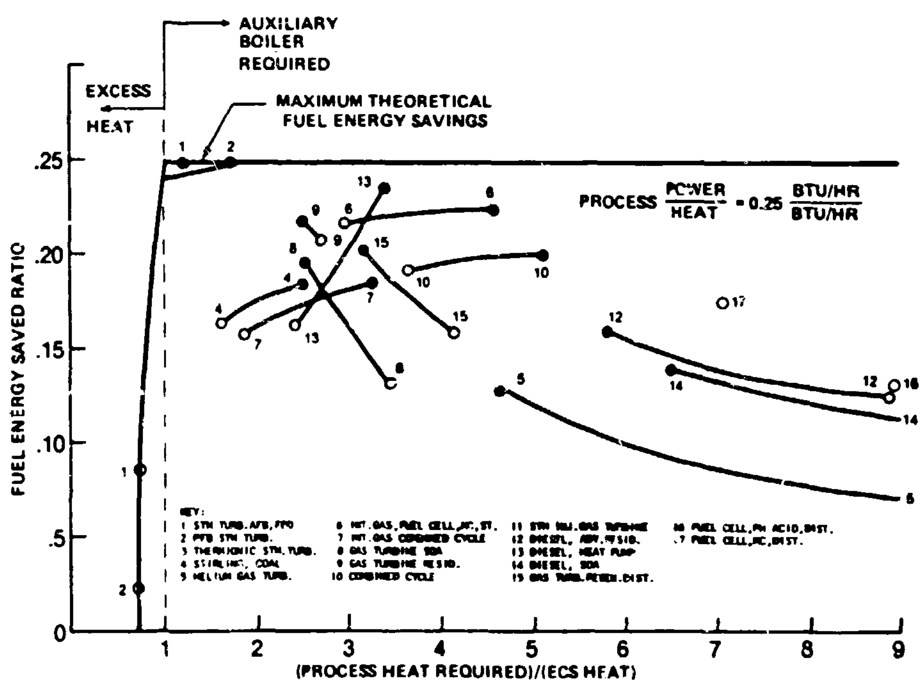


Figure 8.4-4. Fuel Energy Saving Potential of Energy Conversion Systems When Matched to Industrial Process Power Needs (P/H = 0.25)

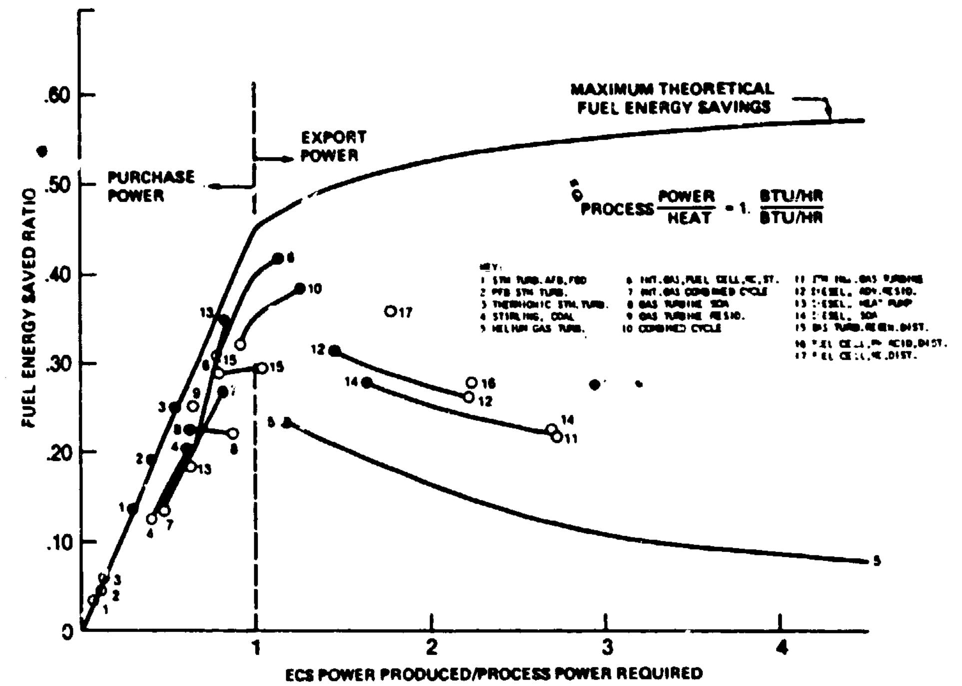


Figure 8.4-5. Fuel Energy Saving Potential of Energy Conversion Systems When Matched to Industrial Process Heat Needs (P/H = 1.0)

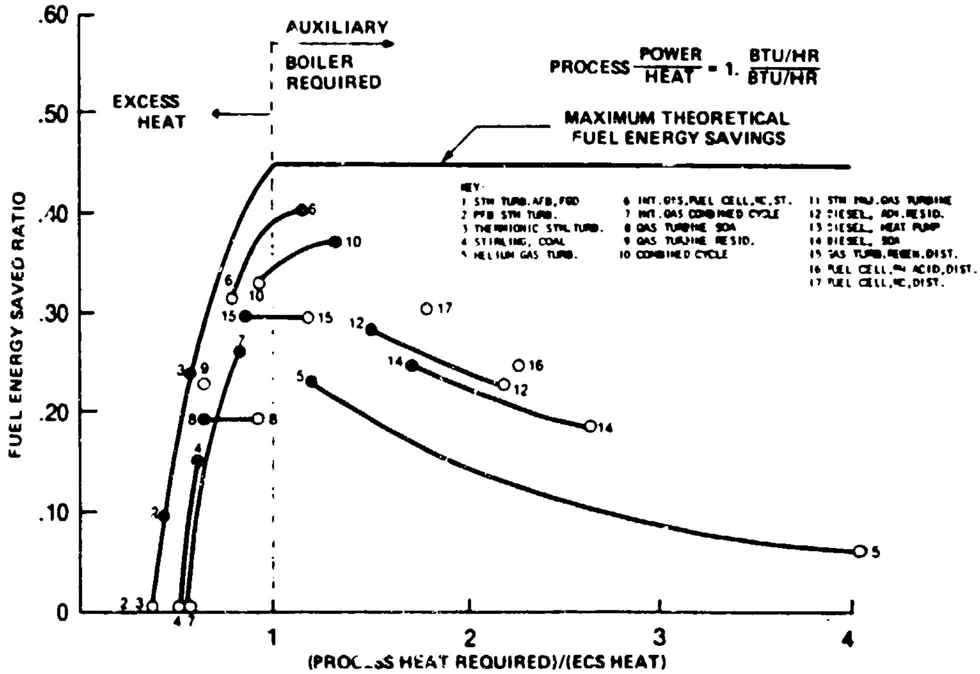


Figure 8.4-6. Fuel Energy Saving Potential of Energy Conversion Systems When Matched to Industrial Process Power Needs (P/H = 1.0)

The high power/heat ECS's are missing from the figures corresponding to the process power/heat of 0.1 (Figures 8.4-1 and 8.4-2) because they are off scale.

Low Process Power to Heat Ratio

Focusing on Figure 8.4-1, the heat match for a process power to heat ratio of 0.1 shows that power would have to be exported in all cases. The power produced by the ECS when sized to match the process heat requirements exceeds the process power needs for all cases. For example, if it were desired to use a stirling engine in a cogeneration application for a process having a power to heat ratio of 0.1 and the stirling engine was sized to meet the heat needs of the process, then the power produced will be from four to six times what is required by the process depending on the process temperature required.

It is unlikely that the industrial process owner would want to purchase a system that could cost as much as four times what he needs to pay (its output is 4 times the requirement) to satisfy his minimum needs. In this situation, if a stirling engine were desired, then he more likely would select an engine size to meet the process power requirement. This situation is displayed in Figure 8.4-2 for the power match for a process power to heat ratio of 0.1. Looking at the stirling engine reveals that when it is sized to meet the power needs of the process, that it can only meet from 16 to 25% of the process heat needs (the exact amount depends on the temperature that process heat is required). An auxiliary boiler would have to be purchased to provide the remaining 75 to 84% of the process heat needs.

Intermediate Power to Heat Ratio

Figure 8.4-3 represents the heat match case for a process power to heat ratio of 0.25. It is interesting that most of the energy conversion systems here would still be exporting power even at this higher process power to heat ratio.

Figure 8.4-4 is the power match case for a process power to heat ratio of 0.25. Note that the maximum fuel savings possible has increased from 13.8% for the 0.1 process power to heat ratio to 24.8%. Also, with the exception of the PFB and steam turbine at most temperatures, supplementary boiler capacity must be added to provide the shortfall between energy conversion system heat output and process requirements.

High Power to Heat Ratio

Figure 8.4-5 is the heat match case for a process power to heat ratio of 1. Only a few of the cogenerating systems in this case would be exporting power.

Figure 8.4-6 is the power match case for a process power to heat ratio of 1. It is observed here that most systems would provide more heat than was needed by the process (Process Heat Required/ECS Heat $<$ 1). The greatest fuel energy savings are obtainable with an integrated gasifier molten carbonate fuel cell with steam turbine bottoming followed closely by the combined cycle.

Comparison of Fuel Energy Saved Ratio at a Fixed Process Temperature

Figure 8.4- 7 provides a summary of the fuel energy savings ratio of the selected energy conversion systems when providing heat to an industrial process at 400°F for process power to heat ratios of 0.1, 0.25 and 1. The export power allowed case is the heat match case. If more power is produced than required by the process, it is assumed to be exported. Any shortfall in power required versus that produced is assumed to be purchased from the utility.

For each bar chart in the figure the results for state-of-the-art ECS's are shown on the left and fifteen selected advanced ECS's are shown on the right. These fifteen have been selected as representative of the various types of ECS's studied. A complete listing of the ECS's studied is given in Table 8.4-1 (taken from Volume II, Table 4-5). The four state-of-the-art systems and fifteen advanced systems selected for Figure 8.4-7

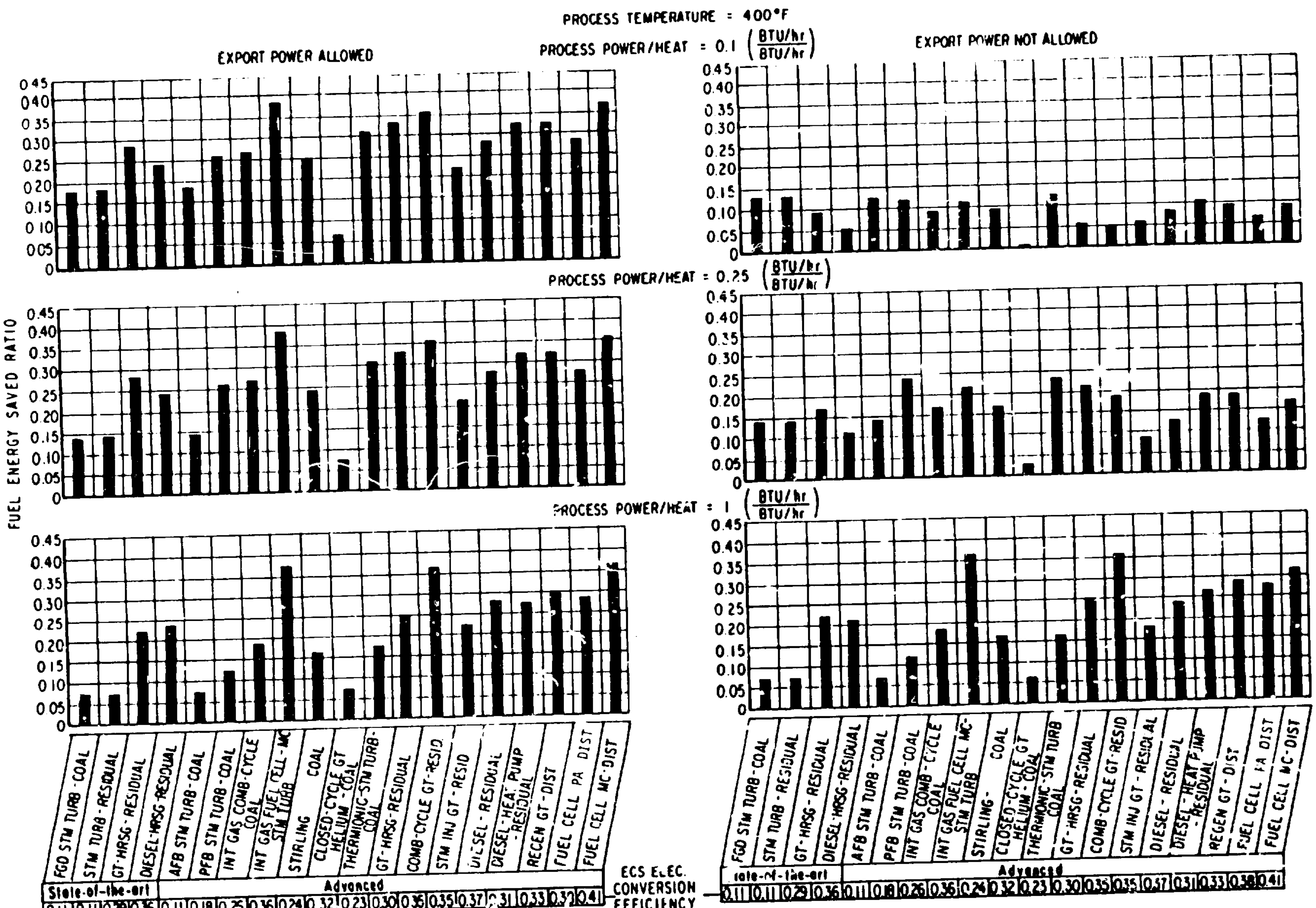


Figure 8.4-7. Summary of Fuel Energy Savings Ratio for Selected Energy Conversion Systems

Table 8.4-1

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
* PFB-TM	PFB Steam Turbine	Gas Turbine, T=1700°F, Steam Turbine P=1465 psia, T=1000°F	Coal-Pressurized Fluidized Bed	3	ADV
* TISTMI-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
HEGT0-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

* ECS's shown in Figure 8.4-7

(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

are identified by the asterisks (*). Several gas turbines with heat recovery steam generators of various pressure ratios and firing temperatures were considered but only one of these was selected for this comparison. For both the state-of-the-art and advanced systems, those utilizing coal are on the left; then those utilizing residual fuel are next followed by those that can only use distillate fuel.

Several conclusions can be drawn from this figure. The most obvious one is that the restriction of power export would significantly affect the potential fuel energy savings in the low to intermediate power to heat ratio process range. The reduction in fuel energy savings between the no export and export power cases diminishes with increasing process power to heat ratio.

The electrical conversion efficiency of each system is given at the bottom of the figure. Note that respectable values of fuel energy savings can be achieved at low process power to heat ratios even at low ECS electrical generating efficiencies (11 - 18%).

8.5 BY-PRODUCT OR WASTE FUEL

Several processes have by-product or waste fuel available. Assumptions on the utilization of waste fuel are reported in Section 3, Volume II. In performing fuel usage calculations where by-product fuel was available, the requirement for fuel energy was always first met with the by-product or waste fuel where technically feasible for both the nocogeneration and cogeneration cases. Waste or by-product fuel was utilized in the process boiler in the nocogeneration case to produce a part or all of the heat required by the process. All energy conversion systems capable of burning coal were assumed to be able to utilize waste or by-product fuel with the exception of the systems with coal gasifiers. Table 8.5-1 summarizes the possible utilization of waste or by-product fuels.

Table 8.5-1

PROCESS-ENERGY CONVERSION SYSTEM MATCH-UPS WHEN WASTE FUEL IS AVAILABLE

NO-COGEN CASE

FUEL ENERGY = ((Process Heat Required - Waste Fuel)$_{\geq 0}$ / Process Boiler Efficiency) + UTILITY FUEL

COGEN CASE

ENERGY CONVERSION SYSTEM Capable of Utilizing Waste Fuel		ENERGY CONVERSION SYSTEM Not capable of Utilizing Waste Fuel	
HEAT MATCH	POWER MATCH	HEAT MATCH	POWER MATCH
Size energy conversion system by process heat required.	Size energy conversion system to match power required.	Size energy conversion system to match the following: (Process heat required - heat available from waste fuel)$_{\geq 0}$.	Size energy conversion system to match process power required. Use waste fuel to maximum extent possible or mixture of waste fuel and primary fuel to supply any residual process heat demand.
Fuel Energy = (ECS Fuel Required - Waste Fuel)$_{\geq 0}$ + Utility Fuel	Fuel Energy = (ECS fuel required + Process Boiler Fuel required - waste fuel available)$_{\geq 0}$.	Fuel Energy = (ECS fuel) + Utility Fuel	Fuel Used = ECS fuel + primary fuel required to meet process heat after waste fuel is utilized.

NOTE: All cost estimates made for equipment where mixtures of primary fuel and waste fuel are burned or where waste fuel is burned by itself should be calculated as if the equipment is sized to provide the complete thermal energy requirement through combustion of the primary fuel. Waste fue[illegible] assumed to have no cost in regards to operating expenses.

8.6 ENERGY AND EMISSIONS SAVINGS RESULTS FOR REPRESENTATIVE MATCHES OF ECS's AND INDUSTRIAL PROCESSES

Fuel Energy Saved Ratio Results

Fuel energy saved ratios were computed for all energy conversion systems (described in Volume IV) matched up with all processes studied (described in Volume III). The computer-generated results are presented in Volume VI. A representative sampling of fuel energy saved ratio results for selected plants and selected energy conversion systems are presented in Table 8.6-1 for power matches and Table 8.6-2 for heat matches. Waste and by-product fuels were utilized where available and feasible, as specified in the assumptions (Volume II). By-product or waste fuel increases the fuel energy saved ratio when used and decreases the fuel energy saved ratio when not used.

For these selected results, the highest fuel energy saved ratio for state-of-the-art systems is achieved by both the gas turbine and diesel in both heat and power matches. The highest fuel energy saved ratio for advanced systems is achieved by the integrated coal gasifier molten carbonate fuel cell in the heat match case and by the distillate-fired molten carbonate fuel cell. Comparing advanced residual fueled systems, the air-cooled gas turbine and combined-cycle have the best fuel energy saved ratio. There is no single system that consistently has fuel energy savings higher than all others. Each system alone performs well in some specific application, but not necessarily better than all others in that application.

Emissions Saved Ratio Results

The emissions saved ratio is calculated in a manner analogous to the fuel energy saved ratio. It is simply the rate of pollutant emissions (NO_x, SO_x, and particulates) for the nocogeneration case minus the emissions rate for the cogeneration case divided by the nocogeneration emissions rate. Pollutants resulting from combustion of by-product or waste fuels were ignored. The emissions saved ratio and emissions saved by type for each ECS-industrial process matchup are given in Volume V.

Table 8.6-1

FUEL ENERGY SAVED RATIO OF COGENERATION SYSTEMS FOR SELECTED INDUSTRIAL PROCESSES

POWER MATCH

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - PA - DIST	FUEL CELL MC - DIST
MEAT PACKING	.26	.26	.21	.19	.26	.26	.19	.24	.21	.12	.26	.23	.21	.10	.19	.24	.21	.19	.18
MALT BEVERAGES	.24	.24	.19	.20	.24	.24	.18	.22	.20	.11	.24	.21	.19	.10	.20	.22	.19	.20	.17
BLEACHED KRAFT PAPER	--	--	.22	.14	--	.30	.11	.05	.22	.11	.30	.25	.24	.12	.17	.25	.23	.16	.21
THERM-MECH PULPING	--	--	.27	.18	--	--	.26	.34	--	--	--	.32	.30	.15	.21	.31	.29	.20	.27
INTEGRATED CHEMICAL	--	--	.22	.14	--	--	.21	.27	.21	.11	.30	.25	.23	.12	.17	.25	.23	.16	.21
CHLORINE	--	--	--	.24	--	--	--	--	--	--	--	--	--	.20	.29	--	--	.26	.35
NYLON	--	--	--	.27	--	--	--	--	--	--	--	--	--	.20	--	--	--	.27	.35
PETRO-REFINING	.16	.16	.11	--	.16	.16	.11	.14	.11	.05	.16	.14	.13	--	--	.11	.12	.09	.11
INTEGRATED STEEL	--	--	--	.22	--	--	--	--	--	--	--	--	--	--	.26	--	--	.28	.34
COPPER	--	--	--	.20	--	--	--	.38	--	--	--	--	.34	.17	.24	--	--	.23	.30
ALUMINA	.14	.14	.09	--	.14	.13	.09	.12	.09	.04	.13	.11	.10	--	--	.09	.09	.07	.10

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by --.

Table 8.6-2

FUEL ENERGY SAVED RATIO OF COGENERATION SYSTEMS FOR SELECTED INDUSTRIAL PROCESSES

HEAT MATCH

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - PA - DIST	FUEL CELL MC - DIST
MEAT PACKING	.28	.28	.31	.33	.28	.33	.31	.42	.32	.14	.37	.34	.38	.22	.33	.40	.34	.35	.36
MALT BEVERAGES	.28	.28	.31	.37	.28	.33	.31	.42	.34	.14	.37	.34	.38	.22	.37	.40	.34	.33	.36
BLEACHED KRAFT PAPER	.29	.29	.29	.25	.21	.36	.17	.33	.31	.14	.40	.33	.36	.22	.29	.34	.33	.28	.36
THERM-MECH PULPING	.12	.12	.29	.25	.12	.2	.27	.39	.24	.09	.27	.33	.36	.22	.29	.34	.33	.28	.36
INTEGRATED CHEMICAL	.16	.16	.29	.25	.16	.26	.27	.39	.26	.11	.32	.33	.36	.22	.29	.34	.33	.28	.36
CHLORINE	.08	.08	.16	.26	.08	.12	.17	.30	.13	.04	.15	.18	.29	.22	.29	.22	.21	.28	.36
NYLON	.09	.09	.15	.27	.09	.13	.17	.30	.14	.05	.16	.17	.30	.22	.29	.23	.20	.28	.36
PETRO-REFINING	.18	.18	.27	--	.18	.26	.26	.39	.23	.09	.31	.33	.35	--	--	.28	.31	.28	.36
INTEGRATED STEEL	.06	.06	.12	.22	.06	.11	.03	.21	.16	.06	.16	.14	.18	--	.26	.13	.17	.28	.32
COPPER	.09	.09	.25	.25	.09	.15	.23	.39	.19	.07	.21	.28	.36	.22	.29	.32	.32	.28	.36
ALUMINA	.15	.15	.26	--	.15	.23	.25	.38	.22	.09	.29	.33	.34	--	--	.26	.31	.28	.36

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by --.

A representative sampling of emissions saved ratio results for selected ECS's and selected plants are presented in Tables 8.6-3 through 8.6-6. Tables 8.6-3 and 8.6-4 assume a coal-fired nocogeneration system. Tables 8.6-5 and 8.6-6 assume residual fuel is used as the nocogeneration fuel. The lower emissions saved ratio, when the residual fuel nocogeneration case is assumed, results from the fact that the nocogeneration emissions are reduced significantly in most cases. All systems with the exception of the diesel save emissions over the nocogeneration case. Of the advanced coal burning systems, the integrated coal gasifier molten carbonate fuel cell has the best emissions saved ratio of the advanced liquid fueled systems.

Table 8.6-3

EMISSIONS SAVED RATIO FOR COGENERATION SYSTEMS FOR SELECTED INDUSTRIAL PROCESSES
POWER MATCH
COAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED															
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - PA-DIST	FUEL CELL MC - DIST	
MEAT PACKING	.18	.28	.32	-1.8	.36	.41	.12	.51	.13	.19	.18	.11	.13	.03	-.03	.00	.46	.66	.43	
MALT BEVERAGES	.10	.21	.45	-1.1	.29	.35	.04	.43	.05	.13	.09	.04	.06	-.04	-.08	-.06	.42	.63	.39	
BLEACHED KRAFT PAPER	--	--	.57	.12	--	.47	-.12	.33	.19	.25	.27	.27	.28	.17	.18	.22	.55	.57	.55	
THERM-MECH PULPING	--	--	.53	-1.7	--	--	.26	.84	--	--	--	.19	.20	.09	-.07	-.02	.50	.74	.47	
CHLORINE	--	--	--	-2.4	--	--	--	--	--	--	--	--	--	.08	-.13	--	--	.83	.47	
NYLON	--	--	--	-2.8	--	--	--	--	--	--	--	--	--	.06	--	--	--	.83	.46	
PETRO-REFINING	.15	.25	.51	--	.33	.37	.11	.36	.09	--	.14	.15	.15	--	--	.02	.48	.58	.47	
INTEGRATED STEEL	--	--	--	-1.9	--	--	--	--	--	--	--	--	--	--	-.08	--	--	.79	.49	
COPPER	--	--	--	-2.2	--	--	--	.97	--	--	--	--	.16	.02	-.18	--	--	.76	.44	
ALUMINA	.12	.23	.51	--	.31	.35	.09	.31	.08	.21	.12	.15	.15	--	--	.02	.48	.56	.47	

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by --.

Table 8.6-4

EMISSIONS SAVED RATIO FOR COGENERATION SYSTEMS FOR SELECTED INDUSTRIAL PROCESSES
HEAT MATCH
COAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED															
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - PA-DIST	FUEL CELL MC - DIST	
MEAT PACKING	.20	.29	.43	-2.6	.37	.49	.28	1.0	.26	.20	.30	.16	.22	.06	-.06	.01	.49	.86	.46	
MALT BEVERAGES	.15	.25	.50	-2.2	.33	.46	.26	1.0	.25	.16	.27	.13	.21	.05	-.06	-.03	.48	.86	.45	
BLEACHED KRAFT PAPER	.26	.35	.56	-2.2	.41	.54	.16	1.0	.27	.25	.37	.26	.27	.09	-.07	.10	.54	.82	.50	
THERM-MECH PULPING	.11	.17	.53	-2.6	.21	.35	.27	1.0	.21	.18	.25	.19	.22	.07	-.14	-.04	.51	.85	.47	
CHLORINE	.07	.10	.29	-2.5	.13	.20	.17	.73	.11	.09	.14	.11	.13	.07	-.13	-.01	.32	.85	.47	
NYLON	.06	.09	.20	-2.8	.11	.18	.15	.72	.10	.07	.13	.08	.17	.06	-.13	-.01	.29	.85	.46	
PETRO-REFINING	.16	.27	.51	--	.34	.47	.26	1.0	.20	.21	.28	.19	.21	--	--	-.14	.49	.85	.47	
INTEGRATED STEEL	.05	.08	.26	-2.2	.07	.18	.03	.82	.14	.11	.15	.13	.15	--	-.08	.05	.29	.80	.46	
COPPER	.02	.07	.41	-2.7	.11	.22	.17	1.0	.11	.08	.13	.10	.17	.05	-.19	-.11	.46	.85	.45	
ALUMINA	.14	.24	.51	--	.32	.36	.25	1.0	.19	.21	.27	.19	.20	--	--	-.17	.49	.85	.47	

Note Matches producing excess heat, or match not possible because process temperature require exceeds ECS capability, are shown by --.

Table 8.6-5

EMISSIONS SAVED RATIO FOR COGENERATION SYSTEMS FOR SELECTED INDUSTRIAL PROCESSES

POWER MATCH

RESIDUAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB COAL	PFB STM TURE - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - PA - DIST	FUEL CELL MC - DIST
MEAT PACKING	.18	.28	.32	-1.77	.36	.41	.12	.51	.13	.19	.18	.11	.13	.03	-.03	0	.66	.46	.43
MALT BEVERAGES	.16	.26	.30	-1.65	.34	.39	.10	.46	.11	.19	.15	.10	.12	.03	-.02	0	.45	.65	.43
BLEACHED KRAFT PAPER	-	-	.41	-0.21	-	.43	-	-	.13	.20	.22	.22	.23	.12	.12	.16	.52	.54	.52
THERM-MECH PULPING	-	-	.40	-2.34	-	-	.22	.83	-	-	-	.15	.16	.04	-.13	-.07	.47	.72	.45
CHLORINE	-	-	-	-2.77	-	-	-	-	-	-	-	-	-	.06	-.15	-	-	.82	.46
NYLON	-	-	-	-2.7[illegible]	-	-	-	-	-	-	-	-	-	.06	-	-	-	.83	.46
PETRO-REFINING	.06	.18	.21	-	.26	.31	.02	.29	.0	.14	.06	.06	.07	-	-	-.08	.43	.54	.42
INTEGRATED STEEL	-	-	-	-2.19	-	-	-	-	-	-	-	-	-	-	-.10	-	-	.79	.48
COPPER	-	-	-	-2.55	-	-	-	.97	-	-	-	-	.18	.35	-.14	-	-	.77	.45
ALUMINA	.03	.15	.18	-	.24	.28	-.01	.23	-.02	.13	.03	.05	.05	-	-	-.08	.42	.52	.42

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by - .

Table 8.6-6

EMISSIONS SAVED RATIO FOR COGENERATION SYSTEMS FOR SELECTED INDUSTRIAL PROCESSES

HEAT MATCH

RESIDUAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - PA - DIST	FUEL CELL MC - DIST
MEAT PACKING	.20	.29	.43	-2.6	.37	.49	.28	1.00	.26	.20	.30	.16	.22	.06	-.06	.01	.49	.86	.46
MALT BEVERAGES	.20	.29	.43	-2.52	.37	.49	.28	1.00	.28	.20	.30	.16	.22	.06	-.03	.01	.49	.87	.46
BLEACHED KRAFT PAPER	.21	.30	.46	-2.44	.37	.51	.13	1.00	.24	.21	.35	.22	.25	.03	-.09	.06	.52	.81	.49
THERM-MECH PULPING	.06	.13	.42	-2.85	.17	.32	.24	1.00	.17	.14	.21	.15	.19	.06	-.17	-.08	.48	.85	.46
CHLORINE	.05	.03	.21	-2.85	.10	.18	.15	.72	.09	.07	.12	.08	.16	.06	-.16	-.03	.31	.85	.46
NYLON	.06	.09	.20	-2.79	.11	.18	.15	.72	.10	.07	.13	.08	.17	.06	-.12	-.01	.29	.85	.46
PETRO-REFINING	.03	.19	.41	-	.28	.43	.23	1.00	.15	.16	.24	.15	.18	-	-	-.19	.47	.85	.46
INTEGRATED STEEL	.03	.06	.19	-2.39	.08	.16	.01	.81	.12	.0[illegible]	.14	.11	.13	-	-.10	.03	.27	.80	.44
COPPER	.05	.10	.35	-2.87	.13	.24	.20	1.00	.13	.11	.16	.13	.19	.06	-.17	-.07	.48	.85	.46
ALUMINA	.05	.16	.40	-	.25	.41	.21	1.00	.14	.16	.21	.15	.17	-	-	-.23	.47	.95	.46

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by - .

Section 9

ECONOMIC EVALUATION OF COGENERATION SYSTEMS

9.1 INTRODUCTION

One of the most important considerations effecting an industry's decision as to which type of cogeneration system to install, or whether to put in a cogeneration system at all, is the relative economics of the alternatives. Since World War II there has been a steady decline in the amount of power that industry has generated in-plant. In 1978 it was approximately 10%. One of the primary reasons for the decline is that the utilities offer power at a lower price than what it would cost industry to generate it. For instance, the national average price for purchased power to industry in 1978 was 25.9 mills per kWh even though the cost of power from a new utility base loaded plant is approximately 40 mills per kWh. This lower price results from the fact that the utility costs are based on its entire system consisting of a mixture of plants, many of which were built at much lower capital cost than new plants. Industry, on the other hand, considering a new cogeneration plant at high capital cost, has often found that they could not save enough in energy costs to justify the additional capital cost over installing a process boiler and purchasing power from the utility. As a result cogeneration plants were installed only in those industries which had several characteristics favoring their economics such as large quantities of waste fuel (as in the case in many pulp paper plants), steam requirements of over 100,000 pounds per hour and continuous operation (so the utilization of the power plant equipment was high).

In the future with the prospects of fuel costs rising more rapidly than capital costs, the significantly better fuel efficiency and resulting lower fuel cost of the cogeneration type power plants will make their relative economics more attractive than in the past. This rapidly rising energy cost is increasing the energy portion of the costs of production so that capital expenditures to reduce the cost of energy will receive much higher industrial management priority than in the past. The economic criteria typically used by industrial management in deciding between alternate methods of satisfying their power and process heat requirements are:

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.

Until recently industrial management tended to weigh criteria 1 and 2 most heavily in their choice which emphasizes the short term effects. Now more consideration is being given to the longer term trends in fuel and power availability and the resulting increasing energy costs.

Since industrial ownership is primarily emphasized in this study, these selection criteria establish the type of economic parameters that are used in comparing the relative merits of the state-of-the-art and advanced technology cogeneration systems for a particular industrial process application. The first economic parameter is total capital cost including interest during construction of the power plant. Second is the discounted cash flow return on investment called ROI. ROI is the discount rate which makes the difference, in discounted after tax cash flows, of two alternate power plants over their economic life equal to their difference in capital costs. It is also analogous to the interest rate which would be obtained if the capital were loaned as an investment. So ROI is a measure of the profitability of the investment and takes into account the time value of money, taxes, depreciation and the escalation of operating expenses such as fuel and revenue from the export of surplus power. A good indicator of criteria 3 is the levelized annual energy cost (LAEC) of the power plant. LAEC is the constant total cost of energy each year over the economic life of the power plant and includes the cost of capital and the recovery of the initial investment including all expenses, operation and maintenance, taxes and insurance, fuel and purchased power or revenue from export power. It is analogous to the utility method of calculating the cost of electricity in dollars per kWh except here it is in total cost per year for the power plant. The term "levelized" means that the escalation of expenses like fuel is taken into account by finding the total "present worth"(1) of the expense over the economic life of the plant and then finding the annual payment required to pay off this total expense at cost of money (interest rate) for the project.

A more detailed explanation of the concepts behind ROI and LAEC is given in the following sections. The detailed equations and basic economic groundrules; e.g., cost of money, years of economic life, fuel and power costs, etc. were established by NASA-LeRC after consultation with the CTAS contractors. One important groundrule laid down was that the ROI and LAEC are calculated in constant 1978 dollars with zero inflation. This means that the cost of money (interest) rates, discount factors and expenses do not include the effect of inflation; e.g., the cost of debt used in the calculations is 3% and not the 9% interest rate prevalent when the inflation rate was about 6%. The following equation converts the ROI calculated in this study to the ROI_i normally used that includes the effect of inflation:

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

---

(1) The "present worth" or sometimes called "discounted" 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

$$\text{Present Worth of \$1} = \frac{1}{(1.124)^{10}} = \$.31$$

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.

where

ROI_i includes inflation

ROI is calculated with inflation set to zero as in this study

and

i = rate of inflation per year over the economic life

Escalation of expenses above inflation such as fuel and power is included in the calculations.

During the study a simple method of plotting the LAEC, capital cost and ROI of the atlernate power plants for a specified industrial process was developed which gives an excellent graphic understanding of the relation between these parameters and how they would affect the selection of the best alternative energy conversion system based on the above economic criteria.

In the following subsections the groundrules and fuel and power costs, analytical methodology and economic results of the power and heat matches of the various power plant/fuel types with approximately 50 different industrial processes will be discussed. Also, the sensitivities of capital cost, fuel and purchased power cost on ROI and LAEC will be described.

9.2 METHODOLOGY AND GROUNDRULES

The work flow diagram shown in Figure 9.2-1 shows input data required and the economic groundrule factors used for each particular cogeneration ECS-industrial process match in the analyses of the economic evaluation. Because of the very large number of matches to be evaluated, nearly all the analyses were performed by computer using the CTAS Cogeneration Evaluation Data System.

The economic analysis of a given cogeneration system matched to an industrial process in this study is always made by comparing the matched cogeneration system to the nocogeneration system base case. Two types of nocogeneration base cases were studied; namely,

1. Coal-fired nocogeneration boiler base case used for comparison with all heat and power matches larger than 30×10^6 Btu/hr process heat requirements. For less than 30×10^6 Btu/hr, a residual oil-fired boiler is used.

2. Residual oil-fired nocogeneration boiler base case used for comparison in all heat and power matches.

Primary emphasis is placed on the matches using a coal-fired nocogeneration process boiler because we believe the majority of medium and large industrial plants putting in new power plants in the 1985 to 2000 year time frame would be required to consider only coal-fired boilers. As will be seen, the use of coal or residual-fired boilers as the nocogeneration base case has a significant effect on the ROI and levelized annual energy cost savings (LAECS) of the various cogeneration systems.

After consultation with the CTAS contractors and DOE, NASA-LeRC established the detailed methodology to be utilized in calculating the ROI and LAEC[1] and the specific values of parameters such as cost of capital, tax depreciation life and fuel costs which were held constant in the calculation of all of the matches. These parameters and the values used are shown in Table 9.2-1.

---

(1) "Groundrules for CTAS Economic Analysis"; August 1978; NASA-LeRC

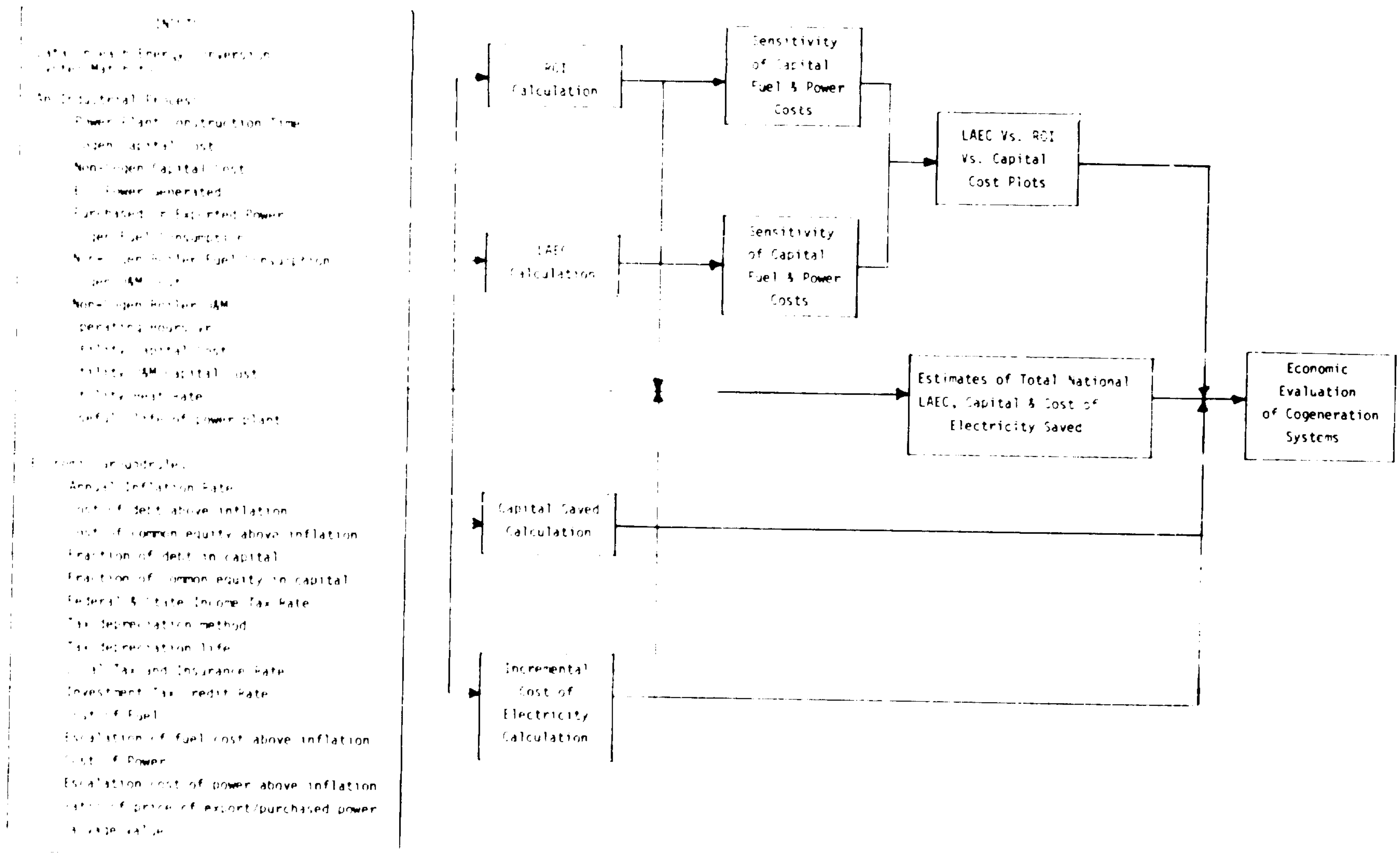


Figure 9.2-1. Work Flow Diagram of Economic Evaluation of Cogeneration Systems

Notice that the first item in the table, the annual inflation rate is set equal to zero. This is very important to remember in comparing the results of CTAS with other economic studies. For instance, a value of 9% ROI calculated in CTAS is equivalent to an ROI_i of 15.5% [(1+.09) (1+.06) - 1 = .155 or 15.5%] because the cash flow included 6% inflation (sometimes call current dollars). Also, an expense item in CTAS such as cost of coal, is given as its cost in 1985 in 1978 dollars of $1.80 (sometimes called constant dollars) with an escalation above inflation of 1%. In a study where inflation at 6% is included, the cost of coal in 1985 (sometimes called current dollars) is $1.80 (1+.06)^7 = \$2.71$ where the exponent 7 = 1985 - 1978. In our opinion, economic analysis is more realistic when the inflation rate is set equal to zero because when inflation is included, the calculated ROI_i is misleadingly high since future inflated savings or cash flows have less purchasing power than constant non-inflated dollars. Finally, inflation rates are changing rapidly so that comparison of the results of studies done at different inflation rates are difficult to compare and "rules of thumb" cannot be deduced. This whole problem is eliminated if the analysis is performed in constant dollars with zero inflation and, if desired, the results converted to current dollars with inflation.

Referring to the values of cost of debt equal to 3% and equity capital of 7% in Table 9.2-1, they seem very low. Again, this is because these do not include inflation and are the values commonly used by investment analysts. The 30 to 70% split in debt to equity for capital investments is typical of many industries. A change from current IRS regulations is the use of a 15-year tax depreciation life. Currently industrial power plants generating over 500 kW or 12,500 pounds per hour steam are classed as "Industrial Steam and Electric Generation Systems" with a "guideline" depreciation life of 28 years. Prior to several years ago, industrial power plants were classed the same as process equipment with a representative tax depreciation life of 15 years and in our opinion the IRS will reduce power plant depreciation in the future to its former level.

Table 9.2-1

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- [illegible])
Purchased & Exported Power	1%
Limestone	0
Dolomite	0

All power plants for the purpose of the economic comparison were assumed to begin their first year of operation January 1, 1990. Actually, some types of advanced cogeneration systems; e.g., thermionics, could not be developed to a commercial state by 1990 but the same date was assumed for this system for ease of economic comparison.

Of the groundrules specified, the fuel and power costs are probably the most controversial. The fuel and power costs in Table 9.2-1 are the base values used in the study but sensitivities of ROI and LAEC to wide variations in nocogeneration and cogeneration fuel and power costs were calculated to study the effect of various differentials between coal, oil and coal-derived liquids. The results of this sensitivity analysis are presented later in this section.

9.3 RETURN ON INVESTMENT (ROI) ANALYSIS

ROI is the discount rate which makes the difference in discounted, after tax cash flows for two alternative power plants over their economic life equal their difference in capital cost. The term "discounted" refers to the fact that \$1 received ten years from now has a discounted value of \$.31 today if during these 10 years the inflation rate is 7% and the cost of capital (interest) above inflation is 5%. The reason is, it only requires that $\frac{1.00}{(1+.05)^{10}}$ = \$.61 be invested today to be paid \$1 ten years from now at 5% interest, but the \$1 received is only worth $\frac{1}{(1+.07)^{10}}$ = \$.51 in purchasing power. So the combined effect of interest and inflation is $\frac{1}{[(1+.07)\times(1+.05)]^{10}}$ = \$.31 and the quantity $(1+.07)\ (1+.05) -1 = .124$ is called the discount factor and the \$.31 is called the "discounted" value or "present worth".

Cash Flow Calculations

In this study cash flow, S_i, is calculated for each year of operation over the economic life, n, of the plant and is defined as:

$$S_i = \text{Cash Flow} = \text{Revenues} - \text{Cash Operating Expenses} - \text{Income Tax} \quad (9\text{-}1)$$

where the income tax, T, is:

$$\text{Income Tax} = \text{Income Tax Rate (Revenues} - \text{Cash Operating Expenses} - \text{Tax Depreciation)} - \text{Investment Tax Credit} \quad (9\text{-}2)$$

A simplified example of the calculation of the ROI of a base case no-cogeneration and a cogeneration alternate investments whose parameters are shown in Table 9.3-1 will assist in understanding the ROI concept.

Table 9.3-1

SIMPLIFIED ROI CALCULATION

	Nocogeneration Case	Cogeneration Case
Capital Cost, C, \$	1000	2000
Revenue, $Q_{j,EE}$, \$/yr	0	50
Cost of Purchased Power, $Q_{j;EP}$, \$/yr	500	0
Cash Operating Expense, $Q_{j,F}$, \$/yr	100	200
Depreciation, $Q_{j,DEP}$, \$/yr	100	200
Income Tax Rate, t, fraction	0.5	0.5
Investment Tax Credit, c, fraction	0	0.1
Economic Life, n, years	5.0	5.0
Escalation of Expenses, e, %	0	0

Income tax and cash flow for base case using equation (9-1) and (9-2) are:

Cogeneration Case

Income Tax_{BASE} = 0.5 (50 - 200 - 200) - 0.1x2000 = -\$375 (1st year)
= 0.5 (50 - 200 - 200) - 0x2000 = -\$175 (2,3,4&5th year)

Cash Flow $= (S_j)_{COGEN}$ = 50 - 200 - (-375) = \$225 (for 1st year)
= 50 - 200 - (-175) = \$25 (for 2,3,4&5th year)

Nocogeneration Case

Income $\text{Tax}_{NOCOGEN}$ = 0.5 (-500 - 100 - 100) - 0x1000 = -\$350 (1,2,3,4&5th yr)

Cash Flow $= (S_j)_{NOCOGEN}$ = -500 - 100 - (-350) = -\$250 (1,2,3,4&5th years)

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

$$C_{COGEN} - C_{NOCOGEN} = \sum_{j=1}^{n} \frac{(S_j)_{COGEN} - (S_j)_{NOCOGEN}}{(1 + ROI)^j} \qquad (9\text{-}3)$$

Table 9.3-2 shows the difference in cash flows and present worth of the cash flows when the final calculated ROI is used as the discount factor so that the sum of the present worth equals the difference in capital costs of the cogeneration alternative and nocogeneration base case. The actual calculation of the value of the ROI is iterative until the value of ROI is found which satisfies equation (9-3) as shown at the bottom of Table 9.3-2.

Table 9.3-2

EXAMPLE ROI SOLUTION

Year	Δ Cash Flow	Present Worth Factor	Present Worth of Δ Cash Flow
j	$(S_j)_{COGEN} - (S_j)_{NOCOGEN}$	$\frac{1}{(1+ROI)^j}$ ROI = 0.1944	$\frac{(S_j)_{COGEN} - (S_j)_{NOCOGEN}}{(1+ROI)^j}$
1	225 - (-250) = 475	.837	397.67
2	25 - (-250) = 275	.701	192.75
3	25 - (-250) = 275	.587	161.37
4	25 - (-250) = 275	.491	135.10
5	25 - (-250) = 275	.411	113.11
	$1575		$1000.00

$$C_{COGEN} - C_{NOCOGEN} = 2000 - 1000 = \sum_{j=1}^{5} \frac{(S_j)_{COGEN} - (S_j)_{NOCOGEN}}{(1+ROI)^j} = 1000.00$$

For ROI = 0.194 or 19.4%

In this simplified example the economic life was taken as 5 years and as a result the ROI is 19.4% since the sum of the five years' cash flow is only $1575 or $575 more than the difference in capital cost. Had the economic life been 10 years with a continuing cash flow of $275 per year the ROI = 30.2%; for 15 years 31.9% and 20 years 32.3%. In the actual ROI calculations in CTAS the economic life is 30 years and in all matches but those having a low ROI, the ROI does not increase much beyond 15 years.

The detailed calculations used to compare the ROI of the various cogeneration system-industrial process matches will be discussed in the following paragraphs, each of the parameters used will be defined and the values of the economic groundrule factors shown to aid in understanding their impact.

Capital Investment

The capital cost, K, <u>without</u> interest and escalation above inflation during construction was described in Section 7. In the ROI and LAEC calculations a total capital investment, C, is used which includes these additional costs and it is calculated by using the groundrule parameters shown in Table 9.2-1 and the equation:

$$C = k_m k_e K(1+e_k)^{(N^*-1978-0.5)-L} \qquad (9\text{-}4)$$

where

C = Capital investment including cost of capital and escalation during construction

k_m = Cost of capital factor = $e^{0.418mL}$

k_e = Escalation factor = $e^{0.562e_kL}$ = 1.0

K = Capital cost in 1978 $'s without construction cost

e_k = Capital cost escalation plus inflation rate = 0 + 0 = 0

N^* = First full year of operation = 1990

L = Design and construction time in years = 3

e = Base of natural logarithms

m = Cost of capital before taxes and without inflation = $f_D i_D + f_p i_p + f_C j_C$

= (0.3 x 0.03) + 0 x - + 0.7 x 0.07 = 0.058

For example for a construction time L = 3 years, the ratio of capital investment to capital cost is:

$$k_m = e^{0.418 \times 0.058 \times 3} = 1.075$$

$$k_e = e^{0.562 \times 0 \times 3} = 1.000$$

$$(1 + e_k)^{(N^*-1978-0.5)-L} = (1 + 0)^{(1990-1978-0.5)-3} = 1.000$$

$$\frac{C}{K} = 1.075 \times 1.000 \times 1.000 = 1.075$$

Revenue From Sale of Power to Utility

If a heat match of the cogeneration system to the industrial process produces more power than required by the process, the surplus is assumed to be exported to the utility grid and a revenue received at a rate of 0.6 times the rate paid for purchased power. Actually the setting of this export power rate is a complicated function of the particular utility system involved, load profile, reliability, etc., but for the purpose of comparing the economics of the various cogeneration systems the 0.6 purchase power rate is used. The yearly revenue is given by the expression:

$$Q_{j,EE} = MW_{EE} x 10^3 x h x p_{EE} (1+e_{pE})^{(N^*-1985-0.5)+J}, \ \$/yr \qquad (9-5)$$

where

$Q_{j,EE}$ = Revenue from sale of power to utility, \$/yr

MW_{EE} = Average power exported, MW

h = Plant operating time, hr/yr

p_{EE} = Price received for export power in 1985 in 1978 \$/kWh = 0.0198

e_{pE} = Rate of inflation plus escalation of power price above inflation = 0 + 0.01 = 0.01

N* = First year of full operation = 1990

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

Purchased Power Expense

When the nocogeneration system is supplying the industrial process or the cogeneration system is heat matched and has a lower power over heat ratio than the process, power must be purchased from the utility. The equation for the expense of purchased power in year J is:

$$Q_{j,EP} = MW_{EP} x 10^3 x h x p_{EP} (1+e_{pE})^{(N^*-1985-0.5)+j}, \ \$/yr \tag{9-6}$$

where

MW_{EP} = Average power purchased, MW

p_{EP} = Cost of purchased power in 1985 in 1978 \$/kWh = \$0.033/kWh

e_{pE} = Rate of inflation plus escalation of price of power above inflation = 0+0.01 = 0.01

Purchased Fuel Expense

The expense per year of fuel is calculated using the expression:

$$Q_{J,F} = F x h x p_C (1+e_{pC})^{(N^*-1985-0.5)+J}, \ \$/yr \tag{9-7}$$

where

F = Total average power plant fuel, 10^6 Btu/hr

p_C = Cost of fuel in 1985 in 1978 \$/10^6 Btu (\$1.80 for coal, \$3.10 for residual or \$3.80 for distillate)

e_{pC} = Rate of inflation plus escalation of fuel price above inflation = 0 + 0.01 = 0.01 for coal and oil

As mentioned above, the relative costs and escalation rates assumed for coal and oil are always subjects for heated debate; e.g., the approximately 50% increase in OPEC crude this year has brought the price of oil to the value assumed in the study for 1985. In addition there is no differentiation in this study between the cost of petroleum derived oils (P[illegible] and coal derived liquids (CDL). While today the cost of CDL is projected as being higher than PDL, in the time frame of 1990 to 2020 when the plants in this study are assumed to operate, this may be an accurate assumption. As we will see below in the sensitivity studies, the fuel price differentials are very important in determining the relative economics of the various cogeneration systems.

Operating and Maintenance (O&M) Expenses

The O&M expense per year, Q_{OM}, for the various power plant systems for 1985 in 1978 dollars is calculated from the following equation:

$$Q_{OM} = L(F)^{M} + N(C) + P(Fxh) \times 10^{-6}, \ \$/yr$$

where

L, M, N, and P are given in Table 9.3-3 and ECS's in Table 8.4-1

F is the fuel flow in Btu/hr and h is operating hours/yr

and C is the total capital cost in dollars

Escalation of O&M costs are added by using the equation:

$$Q_{j,OM} = Q_{OM}(1-e_{OM})^{(N^{*}-1985-0.5)+J}, \ \$/yr \qquad (9\text{-}8)$$

where

Q_{OM} = Operating and maintenance cost in 1985 in 1978 \$/yr

e_{OM} = Rate of inflation plus escalation of O&M above inflation = 0 + 0 = 0

Local Taxes and Insurance Expense

The following equation is used in calculating this expense:

$$Q_{j,T} = pC, \ \$/yr \qquad (9\text{-}9)$$

where

p = Fraction of capital investment for local real estate tax and insurance = 0.03

C = Capital investment including cost of capital and escalation during construction.

Table 9.3-3

CTAS OPERATING AND MAINTENANCE FACTORS TABLE FOR COSTS IN $/YR

	ECS	DISTILLATE & RESIDE					COAL: FGD, PFB, PULVERIZED & GASIFIED					COAL: AFB				
			OPN Labor					OPN Labor					OPN Labor			
		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	STM098	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	TISTMI	2.5	1174.	0.300	0.025	0.006	3.0	1751.	0.300	0.025	0.075	0.	0.	0	0.	0.
5	TIH2SG	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.	0.350	0.025	0.	2.0	482.	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	HEGT90	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	1491.	0.300	0.025	0.306	0.	0.	0.	0.	0.
12	ICGTST	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.	0.350	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
15	GTAC12	1.5	270.	0.350	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	GTMC16	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	CC0822	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	STIG05	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.	0.350	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.	0.350	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.	0.350	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.
43	GTR312	1.5	270.	0.360	0.025	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	FCPAQS	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	[illegible]	1.5	622.	0.320	0.025	0.	3.0	1002.	0.320	0.025	0.075	3.0	1463.	0.300	0.025	0.119

With inflation it is more accurate to include the term $(1+e_T)^{(N^*-1985-0.5)+j}$ to account for the probable increase in real estate taxes and insurance with inflation. Since the study was done with zero inflation this term has a value of one.

Depreciation

Depreciation is calculated for each year of tax life using Sum of Years Digits method from the following equation:

$$Q_{j,DEP} = \frac{2(n_T - j)\ C}{n_T(n_T + 1)}\ , \ \$/yr \qquad (9\text{-}10)$$

where

$Q_{j,DEP}$ = Depreciation deduction in year, j, of operation, \$/yr

$= \frac{2(15 - j)C}{15(15 + 1)} = \frac{(15 - j)C}{120}$

n_T = Tax life of power plant = 15 years

C = Total capital investment, \$

Cash Flow Calculations

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 using Equations (5), (6), (7), (8), (9) & (10) and substituting these values into Equation (2) to obtain the income tax and Equation (1) for the cash flow. In these cash flow equations:

Cash flow = S_j =

Revenue = Revenue from sale of power to utility $Q_{j,EE}$ in equation (9-5).

+ Cash Operating Expenses

= Purchased Power, $Q_{j,EP}$, in equation (9-6)

+ Purchased Fuel, $Q_{j,F}$, in equation (9-7)

+ Operating & Maintenance, $Q_{j,OM}$, in equation (9-8)

+ Local Taxes & Insurance, $Q_{j,T}$, in equation (9-9)

- Income Tax =

Tax rate (Revenue - Cash Operating Expenses - Depreciation)

- Investment Tax Credit

ere

Depreciation = $Q_{j,DEP}$ in equation (9-10)

Investment Tax Credit = cC for year j = 1 only.

The above cash flows are then substituted in equation (9-3) in the manner shown in the simplified example of Table 9.3-2 and the ROI calculated.

This calculation methodology was programmed into the computerized CTAS Cogeneration Evaluation and Data System. An example of a computer printout of the cash flows for a PFB Steam Turbine - 1465/1000 cogeneration system power matched to the hypothetical industrial process plant is shown in Table 9.3-4 and the cash flows for the corresponding coal-fired nocogeneration system are shown in Table 9.3-5.

The results of the ROI analysis for all of the cogeneration/fuel systems heat and power matched to all of the industrial processes are shown in Computer Report 5.2, Section 12.1 for the base case of a coal-fired nocogeneration process boiler and in Section 12.2 for the base case of an oil-fired nocogeneration process boiler. A sample of a computer

Table 9.3-4

EXAMPLE OF COMPUTER PRINTOUT OF LEVELIZED ANNUAL COSTS AND ROI CASH FLOWS FOR PFB STEAM TURBINE POWER MATCHED TO HYPOTHETICAL PROCESS 10101

```
PROCESS # 10101
ECS PFBSTM   3 COGEN MEGAWATTS    10.00        COST NOCOGEN $   12.284       COST COGENERATION   20.820 x .75 = 15615 = x_C
PFB-STMTB-1465/1000F           SITE FUEL= COAL-PFB
```

YEAR	REVENUE	FUEL	POWER	OANDM	LCLTX	OPCOST	DEPREC	TAX-CRE	GROSS	US-TAX	CASHFLOW	NET-FLOW
						CAPITAL INVESTMENT=			16.793		S_{COGEN}	$S_{COGEN} - S_{NO-COGEN}$
												3.582
1990	0.	1.281	0.	1.457	0.504	3.242	2.099	1.679	3.242	4.350	-1.108	-1.282
1991	0.	1.294	0.	1.457	0.504	3.255	1.959	0.	3.255	2.607	0.648	-0.919
1992	0.	1.307	0.	1.457	0.504	3.267	1.819	0.	3.267	2.543	0.724	-0.915
1993	0.	1.320	0.	1.457	0.504	3.281	1.679	0.	3.281	2.480	0.801	-0.911
1994	0.	1.333	0.	1.457	0.504	3.294	1.539	0.	3.294	2.417	0.877	-0.907
1995	0.	1.346	0.	1.457	0.504	3.307	1.399	0.	3.307	2.353	0.954	-0.903
1996	0.	1.360	0.	1.457	0.504	3.321	1.259	0.	3.321	2.290	1.031	-0.899
1997	0.	1.373	0.	1.457	0.504	3.334	1.120	0.	3.334	2.227	1.107	-0.895
1998	0.	1.387	0.	1.457	0.504	3.348	0.980	0.	3.348	2.164	1.184	-0.892
1999	0.	1.401	0.	1.457	0.504	3.362	0.840	0.	3.362	2.101	1.261	-0.888
2000	0.	1.415	0.	1.457	0.504	3.376	0.700	0.	3.376	2.038	1.338	-0.884
2001	0.	1.429	0.	1.457	0.504	3.390	0.560	0.	3.390	1.975	1.415	-0.883
2002	0.	1.443	0.	1.457	0.504	3.404	0.420	0.	3.404	1.912	1.492	-0.880
2003	0.	1.458	0.	1.457	0.504	3.419	0.280	0.	3.419	1.849	1.569	-0.877
2004	0.	1.472	0.	1.457	0.504	3.433	0.140	0.	3.433	1.787	1.647	-0.874
2005	0.	1.487	0.	1.457	0.504	3.448	0.	0.	3.448	1.724	1.724	-0.871
2006	0.	1.502	0.	1.457	0.504	3.463	0.	0.	3.463	1.731	1.731	-0.884
2007	0.	1.517	0.	1.457	0.504	3.478	0.	0.	3.478	1.739	1.739	-0.896
2008	0.	1.532	0.	1.457	0.504	3.493	0.	0.	3.493	1.747	1.747	-0.909
2009	0.	1.548	0.	1.457	0.504	3.508	0.	0.	3.508	1.754	1.754	-0.922
2010	0.	1.563	0.	1.457	0.504	3.524	0.	0.	3.524	1.762	1.762	-0.935
2011	0.	1.579	0.	1.457	0.504	3.539	0.	0.	3.539	1.770	1.770	-0.948
2012	0.	1.594	0.	1.457	0.504	3.555	0.	0.	3.555	1.778	1.778	-0.961
2013	0.	1.610	0.	1.457	0.504	3.571	0.	0.	3.571	1.786	1.786	-0.974
2014	0.	1.626	0.	1.457	0.504	3.587	0.	0.	3.587	1.794	1.794	-0.987
2015	0.	1.643	0.	1.457	0.504	3.604	0.	0.	3.604	1.802	1.802	-1.001
2016	0.	1.659	0.	1.457	0.504	3.620	0.	0.	3.620	1.810	1.810	-1.015
2017	0.	1.676	0.	1.457	0.504	3.637	0.	0.	3.637	1.818	1.818	-1.029
2018	0.	1.692	0.	1.457	0.504	3.653	0.	0.	3.653	1.827	1.827	-1.043
2019	0.	1.709	0.	1.457	0.504	3.670	0.	0.	3.670	1.835	1.835	-1.057

Table 9.3-5

EXAMPLE OF COMPUTER PRINTOUT OF LEVELIZED ANNUAL COSTS AND ROI COAL FLOWS FOR COAL-FIRED NOCOGENERATION SYSTEM MATCHED TO HYPOTHETICAL PROCESS 10101

PROCESS # 10101
ECS GNOCGN 47 COGEN MEGAWATTS 0. COST NOCOGEN $ 12.284 $_NC COST COGENERATION 0
N O C O G E N E R A T I SITE FUEL= COAL-FGD

YEAR	REVENUE	FUEL	POWER	OANDM	LCLTX	OPCOST	DEPREC	TAX-CHD	GROSS	US-TAX	CASHFLOW	NET-FLOW
						******************COSTS - MILLIONS 1978$						
						CAPITAL INVESTMENT=$			13.211 = $_NC		NO-COGEN	
												0.
1990	0.	0.659	2.758	0.828	0.396	4.641	1.651	1.321	4.641	4.467	0.174	0.
1991	0.	0.665	2.785	0.828	0.396	4.675	1.541	0.	4.675	3.108	1.567	0.
1992	0.	0.672	2.813	0.828	0.396	4.709	1.431	0.	4.709	3.070	1.639	0.
1993	0.	0.679	2.841	0.828	0.396	4.744	1.321	0.	4.744	3.033	1.712	0.
1994	0.	0.686	2.870	0.828	0.396	4.779	1.211	0.	4.779	2.995	1.784	0.
1995	0.	0.692	2.899	0.828	0.396	4.815	1.101	0.	4.815	2.958	1.857	0.
1996	0.	0.699	2.928	0.828	0.396	4.851	0.991	0.	4.851	2.921	1.930	0.
1997	0.	0.706	2.957	0.828	0.396	4.887	0.881	0.	4.887	2.884	2.003	0.
1998	0.	0.713	2.986	0.828	0.396	4.924	0.771	0.	4.924	2.847	2.077	0.
1999	0.	0.721	3.016	0.828	0.396	4.961	0.661	0.	4.961	2.811	2.150	0.
2000	0.	0.728	3.046	0.828	0.396	4.998	0.550	0.	4.998	2.774	2.224	0.
2001	0.	0.735	3.077	0.828	0.396	5.036	0.440	0.	5.036	2.739	2.298	0.
2002	0.	0.742	3.108	0.828	0.396	5.074	0.330	0.	5.074	2.702	2.372	0.
2003	0.	0.750	3.139	0.828	0.396	5.112	0.220	0.	5.112	2.666	2.446	0.
2004	0.	0.757	3.170	0.828	0.396	5.151	0.110	0.	5.151	2.631	2.521	0.
2005	0.	0.765	3.202	0.828	0.396	5.191	0.	0.	5.191	2.595	2.595	0.
2006	0.	0.772	3.234	0.828	0.396	5.230	0.	0.	5.230	2.615	2.615	0.
2007	0.	0.780	3.266	0.828	0.396	5.270	0.	0.	5.270	2.635	2.635	0.
2008	0.	0.788	3.299	0.828	0.396	5.311	0.	0.	5.311	2.655	2.655	0.
2009	0.	0.796	3.332	0.828	0.396	5.352	0.	0.	5.352	2.676	2.676	0.
2010	0.	0.804	3.365	0.828	0.396	5.393	0.	0.	5.393	2.696	2.696	0.
2011	0.	0.812	3.399	0.828	0.396	5.435	0.	0.	5.435	2.717	2.717	0.
2012	0.	0.820	3.433	0.828	0.396	5.477	0.	0.	5.477	2.738	2.738	0.
2013	0.	0.828	3.467	0.828	0.396	5.519	0.	0.	5.519	2.760	2.760	0.
2014	0.	0.836	3.502	0.828	0.396	5.562	0.	0.	5.562	2.781	2.781	0.
2015	0.	0.845	3.537	0.828	0.396	5.606	0.	0.	5.606	2.803	2.803	0.
2016	0.	0.853	3.572	0.828	0.396	5.649	0.	0.	5.649	2.825	2.825	0.
2017	0.	0.862	3.608	0.828	0.396	5.694	0.	0.	5.694	2.847	2.847	0.
2018	0.	0.870	3.644	0.828	0.396	5.738	0.	0.	5.738	2.869	2.869	0.
2019	0.	0.879	3.680	0.828	0.396	5.783	0.	0.	5.783	2.892	2.892	0.

printout from these reports is shown in Table 9.3-6 for about one half of the cogeneration fuel systems (ECS's) matched to hypothetical industrial process #10102 requiring 30 MW of electric power and a power/heat ratio of 0.25. The first ECS is the nocogeneration base case using a <u>residual</u> fired process heat boiler. The cogeneration fuels by type shown are for the on-site power plant plus the utility fuel consumed if power is purchased or minus if the cogeneration fuel or fuel saved includes the saving of utility fuel. The nocogeneration minus cogeneration fuel or fuel saved includes the saving of utility fuel. For each cogeneration system/fuel combination the data is shown for the ECS sized for matching process power requirements if the cogeneration system does not produce a surplus of process heat and the next line shows the data for the ECS sized to deliver the process heat required; e.g., both matches are shown for the PFB STM. If the ECS only appears <u>once</u> in the tabulation, the power match case produces excess heat and is not shown; e.g., the residual fired, coal-FGD (F) and coal-AFB (A) STM141. Usually comparison of the data in the column on power required by process and the column on cogeneration power produced indicates which type of match is shown. An exception to this last rule is the above three STM141 matches which are actually heat matches but also almost match the power required within the roundoff of the data. "O&M" is in 10^6 dollars/year and includes only the on-site power plant. "FESR" is the fuel energy saved ratio. Capital cost is the on-site power plant capital cost, K, without interest and escalation during construction and "norm cost" is the ratio of the cogeneration over the nocogeneration on-site capital cost. The column labelled $/kW equivalent is the ECS capital cost divided by the ECS fuel input and should be ignored as it did not prove to be a helpful indicator. Finally, the ROI's are shown for each cogeneration system-fuel ECS match where the nocogeneration base case is shown as the first system in the listing for a particular industrial process. A ROI of 0 indicates that the sum of even the undiscounted cash flows over the 30-year life was less than the difference in capital cost between the cogen and nocogen cases and thus the ROI = 0. An example is not shown here on this sample computer printout, but often the ROI is shown equal to 999. This usually means that the capital cost of the cogen ECS is less than the nocogen case and is most often found in the case where coal-fired nocogen case is compared with an

C-2

Table 9.3-6

SAMPLE OF COMPUTER OUTPUT OF ROI & LAEC

DATE 06/08/79
I&SE-PEO-ADV-DES-ENGR

GENERAL ELECTRIC COMPANY
COGENERATION TECHNOLOGY ALTERNATIVES STUDY
REPORT 5.2
SUMMARY OF FUEL SAVED BY TYPE & ECONOMICS

		------------FUEL USE IN BTU*10**6------------																		
		COGENERATION CASE			**NOCOGEN - COGEN**															
ECS	PROCS	DISTIL	RESIDL	COAL	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	10102	0.	566.	246.	0.	0.	0.		30.	0.	0.74	0.25	0.	14.6	1.00	103.1	0	25.6	1.00	60
STM141	10102	0.	602.	3.	0.	-48.	243.		30.	30.	0.98	0.25	0.28	19.0	1.30	107.7	65	20.6	0.81	139
STM141	10102	0.	1.	604.	0.	555.	-358.	F	30.	30	2.01	0.25	0.25	34.5	2.37	195.9	30	16.0	0.83	122
STM141	10102	0.	1.	604.	0.	556.	-358.	A	30.	30.	1.95	0.25	0.25	29.8	2.04	169.1	36	16.4	0.80	124
STM088	10102	0.	591.	61.	0.	-35.	185.		30.	23.	0.93	0.25	0.19	17.2	1.18	102.2	67	21.8	0.85	134
STM088	10102	0.	18.	634.	0.	536.	-368.	F	30.	23.	1.89	0.25	0.19	32.1	2.21	191.5	29	17.3	0.88	116
STM088	10102	0.	18.	634.	0.	536.	-388.	A	30.	23.	1.75	0.25	0.19	23.4	1.60	139.2	54	16.3	0.84	122
PFBSTM	10102	0.	0.	606.	0.	556.	-359.		30.	30.	3.12	0.25	0.25	42.4	2.91	239.1	20	17.9	0.70	131
PFBSTM	10102	0.	0.	665.	0.	594.	-296.		30.	45.	3.13	0.25	0.31	41.0	2.81	209.0	25	18.0	0.63	125
TISTMT	10102	0.	606.	0.	0.	-50.	246.		30.	30	2.40	0.25	0.24	65.9	4.52	371.3	2	27.2	1.06	134
TISTMT	10102	0.	728.	0.	0.	-99.	490.		30.	60.	3.11	0.25	0.35	101.7	6.98	477.0	0	29.8	1.17	130
TISTMT	10102	0.	0.	606.	0.	556.	-359.		30.	30.	3.78	0.25	0.24	91.4	6.28	515.1	6	23.9	0.94	128
TISTMT	10102	0.	0.	728.	0	629.	-238.		30.	60.	4.45	0.25	0.35	128.5	8.82	602.4	5	25.2	0.98	123
TIHRSG	10102	0.	627.	38.	0.	-71.	208.		30.	25.	2.52	0.25	0.17	84.9	5.83	470.5	0	30.8	1.21	115
TIHRSG	10102	0.	11.	654.	0	545.	-407.		30.	25.	3.72	0.25	0.17	108.6	7.45	601.6	3	27.3	1.07	110
STIRL	10102	657.	0.	0.	-657.	556.	246.		30.	30.	1.43	0.25	0.18	28.9	1.98	149.8	0	27.9	1.09	140
STIRL	10102	887.	0.	0.	-887.	652.	569		30.	69.	1.71	0.25	0.27	46.9	3.22	180.6	0	31.0	1.21	127
STIRL	10102	0.	657.	0.	0.	-102.	246.		30.	30.	1.43	0.25	0.18	28.9	1.98	149.9	14	23.6	0.92	135
STIRL	10102	0.	887.	0.	0.	-235.	569.		30.	69.	1.71	0.25	0.27	47.0	3.23	180.8	6	25.2	0.99	121
STIRL	10102	0.	0.	657.	0.	556.	-411.		30.	30.	2.85	0.25	0.18	54.2	3.72	281.6	14	19.7	0.77	121
STIRL	10102	0.	0.	887.	0.	652.	-318.		30.	69.	3.40	0.25	0.27	82.1	5.64	315.9	11	19.8	0.77	109
HEGT85	10102	0.	0.	722.	0.	556.	-476.	A	30.	30.	3.34	0.25	0.10	75.4	5.18	356.6	7	23.7	0.93	111
HEGT85	10102	0.	0.	1941.	0.	930.	-442	A	30.	183.	7.47	0.25	0.20	199.4	13.69	350.7	0	33.6	1.32	85
HEGT60	10102	0.	0.	716.	0.	556.	-470.	A	30.	30.	3.27	0.25	0.11	72.4	4.97	344.8	8	23.2	0.91	112
HEGT60	10102	0.	0.	1183.	0.	703.	-448.	A	30.	90.	4.65	0.25	0.18	119.5	8.20	344.8	4	26.5	1.04	95
HEGT00	10102	0.	0.	719.	0.	556.	-472.	A	30	30.	3.13	0.25	0.10	67.1	4.61	318.9	9	22.6	0.88	112
HEGT00	10102	0.	0.	812.	0.	565.	-468.	A	30	42.	3.05	0.25	0.13	72.5	4.98	304.6	9	22.4	0.86	102
FCMCCL	10102	0.	0.	631.	0.	556.	-385.		30.	30.	3.52	0.25	0.21	64.3	4.42	348.0	10	21.3	0.83	125
FCMCCL	10102	0.	0.	864.	0.	671.	-232.		30.	77.	4.87	0.25	0.34	88.8	6.10	351.1	9	20.6	0.81	115
FCSTCL	10102	0.	0.	824.	0.	556.	-378.		30.	30.	3.43	0.25	0.22	62.3	4.28	340.6	11	20.9	0.82	126
FCSTCL	10102	0.	0.	1074.	0.	769.	-47.		30.	125.	6.12	0.25	0.41	111.0	7.62	362.8	9	19.0	0.74	109
IGGTST	10102	0.	0.	659.	0.	556.	-413.		30.	30.	2.85	0.25	0.18	60.0	4.12	310.6	12	20.6	0.81	121
IGGTST	10102	0.	0.	1001.	0.	699.	-277.		30.	68.	3.06	0.25	0.30	87.3	5.99	287.6	11	18.9	0.74	106
GTSOAR	10102	0.	852.	0.	0.	-96.	246.		30.	30.	1.21	0.25	0.19	22.9	1.57	119.9	28	22.6	0.88	140
GTSOAR	10102	0.	926.	0.	0.	-251.	646.		30.	79.	1.30	0.25	0.30	33.8	[illegible].32	124.6	14	22.8	0.89	125
GTAC08	10102	0.	833.	0.	0.	-77.	246.		30.	30.	1.16	0.25	0.21	21.0	1.44	113.2	36	21.8	0.85	144
GTAC08	10102	0.	901.	0.	0.	-183.	520.		30.	63.	1.07	0.25	0.31	25.3	1.74	107.9	29	20.9	0.82	134
GTAC12	10102	0.	833.	0.	0.	-77.	246.		30.	30.	1.18	0.25	0.21	21.7	1.49	116.8	33	21.8	0.86	143
GTAC12	10102	0.	878.	0.	0.	-202.	643.		30.	78.	1.20	0.25	0.33	30.1	2.07	117.4	22	21.0	0.82	130
GTAC16	10102	0.	835.	0.	0.	-79.	246		30.	30	1.23	0.25	0.21	23.8	1.63	128.0	25	22.2	0.87	141
GTAC16	10102	0.	929.	0.	0.	-231.	722.		30.	88.	1.31	0.25	0.38	34.2	2.35	126.8	18	21.3	0.83	126
GTWC16	10102	0.	653.	0.	0.	-97.	246.		30.	30.	1.23	0.25	0.19	23.7	1.62	123.6	23	22.7	0.88	139
GTWC16	10102	0.	1018.	0.	0.	-303.	768.		30.	94.	1.30	0.25	0.31	33.0	2.27	111.1	15	22.8	0.88	123

Note: 1) See Table 8.4-1 for glossary of ECS codes
2) Process 10102 is a hypothetical process.

Table 9.3-7

RETURN ON INVESTMENT OF COGENERATION ENERGY CONVERSION SYSTEMS COMPARED TO NOCOGENERATION IN SELECTED INDUSTRIAL PROCESSES

POWER MATCH

COAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - PA-DIST	FUEL CELL MC - DIST
MEAT PACKING	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MALT BEVERAGES	5	-19	0	0	10	2	0	0	5	0	0	17	0	0	0	0	0	0	0
BLEACHED KRAFT PAPER	--	--	999	0	--	34	1	0	12	6	4	999	999	-24	0	5	-30	0	0
THERM-MECH PULPING	--	--	40	0	--	--	9	8	--	--	--	131	39	0	0	10	0	0	0
INTEGRATED CHEMICAL	--	--	999	0	--	--	15	12	12	10	6	999	51	999	0	0	0	0	0
CHLORINE	--	--	--	1	--	--	--	--	--	--	--	--	--	10	7	--	--	0	0
NYLON	--	--	--	4	--	--	--	--	--	--	--	--	--	4	--	--	--	0	0
PETRO-REFINING	48	-14	-31	--	999	38	12	10	10	6	4	-25	-28	--	--	0	-61	999	0
INTEGRATED STEEL	--	--	--	0	--	--	--	--	--	--	--	--	--	--	4	--	--	0	0
COPPER	--	--	--	0	--	--	--	4	--	--	--	--	19	0	0	--	--	0	0
ALUMINA	22	-19	-35	--	999	28	6	5	6	1	0	-29	-32	--	--	0	-64	999	999

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by --.

Table 9.3-8

RETURN ON INVESTMENT OF COGENERATION ENERGY CONVERSION SYSTEMS COMPARED TO NOCOGENERATION IN SELECTED INDUSTRIAL PROCESSES

HEAT MATCH

COAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - PA-DIST	FUEL CELL MC - DIST
MEAT PACKING	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MALT BEVERAGES	12	999	0	0	24	8	0	0	8	0	0	-22	0	0	0	0	0	0	0
BLEACHED KRAFT PAPER	42	999	999	0	999	49	6	7	7	5	4	999	17	0	0	0	0	0	0
THERM-MECH PULPING	30	-2	39	0	999	22	10	9	15	4	2	136	20	0	0	8	0	0	0
INTEGRATED CHEMICAL	44	-9	2	0	999	66	14	13	10	10	6	26	9	0	0	0	0	0	0
CHLORINE	35	999	52	0	999	27	14	14	14	5	4	110	42	0	6	13	11	0	0
NYLON	9	12	15	4	12	8	4	5	14	1	0	22	17	0	8	11	7	0	0
PETRO-REFINING	43	-12	0	--	999	103	11	11	5	3	3	0	0	--	--	0	0	0	0
INTEGRATED STEEL	31	999	999	0	999	54	9	11	9	7	3	999	73	--	2	5	14	0	0
COPPER	10	999	24	0	23	8	3	4	16	0	0	72	20	0	0	11	6	0	0
ALUMINA	36	-17	0	--	999	44	8	8	3	0	0	0	0	--	--	0	0	0	0

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by --.

oil-fired cogen ECS and is a "winner" investment wise even though the ROI value cannot be calculated. "LEVL CHRG" is the levelized annual energy cost (LAEC) in 10^6 dollars per year and "NORM ENRG" is the ratio of the cogen LAEC over the nocogen LAEC. The levelized annual energy cost savings ratio (LAECSR) is not shown but is one minus the "NORM ENRG".

A selected sample of the ROI's calculated for a sample of cogeneration systems and industrial processes using a coal-fired nocogen process boiler are shown in Table 9.3-7 for matching the cogen ECS to the process power requirements. The large number of blanks indicate matches where excess process heat is generated and the ROI was not calculated. The negative values of ROI indicate that the nocogen capital cost was higher than the cogen but the cash flows were less for the nocogen case or the positive value would be the ROI realized if the nocogen system were installed instead of the cogen ECS. Table 9.3-8 shows the ROI's when these cogen ECS's are heat matched to the process.

The effect on ROI of using a residual-fired nocogen process boiler as the base case against which the power and heat matched ECS's are compared is shown in Tables 9.3-9 and -10. Since none of the cogeneration ECS's have a lower capital cost than the nocogen residual-fired process boilers, all of the ROI's equal to or are greater than zero. As with the coal-fired nocogen base, the steam turbine, gas turbine, and combined ECS's tend to have the highest ROI's.

An application of these ROI results is best seen from the plots of capital cost versus LAEC versus ROI which will be discussed in a later section. Inspection of these tables shows that coal-fired steam turbine systems, particularly the AFB, show up very well in those industrial processes with low power to heat ratios. Those cogen systems burning high priced distillate fuel; e.g., the regenerative gas turbine and fuel cells, are very poor when compared to a coal-fired nocogen ECS. Also, those cogen systems with high capital cost show up with poor ROI's; e.g., thermionics. As an economic index, ROI is very sensitive to capital costs and if ECS's are screened on ROI the selections will be different than if screened on LAEC or fuel energy saved ratio.

Table 9.3-9

RETURN ON INVESTMENT OF COGENERATION ENERGY CONVERSION SYSTEMS COMPARED TO NOCOGENERATION IN SELECTED INDUSTRIAL PROCESSES

POWER MATCH

RESIDUAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING-AFB - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - PA-DIST	FUEL CELL MC - DIST
MEAT PACKING	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MALT BEVERAGES	7	10	6	3	10	5	0	1	7	0	0	10	5	0	2	4	0	0	0
BLEACHED KRAFT PAPER	-	-	23	1	-	22	7	5	13	9	7	30	21	9	6	11	0	0	0
THERM-MECH PULPING	-	-	19	2	-	-	10	9	-	-	-	25	20	8	6	11	6	0	0
INTEGRATED CHEMICAL	-	-	30	4	-	-	19	16	16	15	10	37	30	15	8	13	4	0	0
CHLORINE	-	-	-	4	-	-	-	-	-	-	-	-	-	13	9	-	-	0	0
NYLON	-	-	-	4	-	-	-	-	-	-	-	-	-	4	-	-	-	0	0
PETRO-REFINING	32	100	20	-	48	30	19	17	18	15	12	29	24	-	-	7	0	0	0
INTEGRATED STEEL	-	-	-	0	-	-	-	-	-	-	-	-	-	-	5	-	-	0	0
COPPER	-	-	-	0	-	-	-	4	-	-	-	-	13	1	2	-	-	0	0
ALUMINA	25	65	15	-	45	27	15	14	16	13	9	24	20	-	-	4	0	0	0

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by -.

Table 9.3-10

RETURN ON INVESTMENT OF COGENERATION ENERGY CONVERSION SYSTEMS COMPARED TO NOCOGENERATION IN SELECTED INDUSTRIAL PROCESSES

HEAT MATCH

RESIDUAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING-AFB - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - PA-DIST	FUEL CELL MC - DIST
MEAT PACKING	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MALT BEVERAGES	11	15	6	0	17	9	2	2	9	1	0	10	3	0	0	4	0	0	0
BLEACHED KRAFT PAPER	24	54	16	0	46	27	8	8	9	8	5	24	15	0	0	6	0	0	0
THERM-MECH PULPING	19	26	19	0	29	18	11	9	14	7	4	26	16	0	0	10	3	0	0
INTEGRATED CHEMICAL	34	84	19	0	55	42	17	15	14	15	10	28	17	0	0	7	0	0	0
CHLORINE	24	43	27	1	39	23	15	15	15	9	6	34	31	0	8	14	15	0	0
NYLON	9	12	15	4	12	8	4	5	14	1	0	22	17	0	8	11	7	0	0
PETRO-REFINING	31	131	1	-	54	39	14	14	10	11	8	17	10	-	-	0	0	0	0
INTEGRATED STEEL	16	102	21	0	39	23	9	11	9	7	4	28	25	-	4	7	11	0	0
COPPER	8	10	14	0	12	7	4	5	13	1	0	20	14	0	0	10	6	0	0
ALUMINA	30	93	0	-	49	32	12	11	9	8	6	14	8	-	-	0	0	0	0

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by -.

9.4 LEVELIZED ANNUAL ENERGY COST (LAEC) ANALYSIS

The levelized annual energy cost is defined as the minimum constant cost each year over the life of the project to include all expenses, the cost of money and recovery of the initial investment. This calculation of LAEC is often referred to as the "utility method"(1) 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

$$\begin{aligned} \text{LAEC} = {} & \text{levelized fixed charges} \\ & + \text{levelized operating costs} \\ & - \text{levelized revenues} \end{aligned} \tag{9-11}$$

Levelized Fixed Charges

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 and depreciation. In fact, the quantity called the "capital recovery factor", CRF_{m',n_B}, in equation (9-15) below is the constant annual installment payment on a loan of $1 to be repaid in n_B years at an interest rate of m' and is calculated by the equation:

$$CRF_{m',n_B} = \frac{m'(1+m')^{n_B}}{(1+m')^{n_B} - 1} \tag{9-12}$$

where for the CTAS groundrules shown in Table 9.2-1:

(1) The method of calculating LAEC is the same as described in the "Technical Assessment Guide", by EPRI, June 1978 except that the values of cost of money, escalation, etc. are different and inflation is zero (constant dollars) and local taxes and insurance are not included in the fixed charge rate (FCR)

m' = after tax cost of capital assuming zero inflation

$$= (1-t)i_d f_d + i_p f_p + i_c f_c \qquad (9\text{-}13)$$

$$= (1-0.5)0.03\times0.3+0\times0+0.07\times0.7 = 0.0535$$

n_B = book life which in CTAS groundrules was equal to useful life of investment, n = 30 years.

$CRF_{m';n_B}$ = capital recovery factor

$$= \frac{0.0535\ (1+0.0535)^{30}}{(1+0.0535)^{30} - 1} = 0.0677$$

The levelized fixed charges (LFC) are calculated by the equation:

$$LFC = C \times FCR \qquad (9\text{-}14)$$

where

FCR = fixed charge rate

C = capital investment as defined in equation (9-4).

The fixed charge rate is equal to:

$$FCR = \frac{CRF_{m';n_B}}{(1-t)} \left[1-t(DEP)-c \right] \qquad (9\text{-}15)$$

where

t = Federal and State Income Tax Rate = 0.50

c = Investment Tax Credit Rate = 0.10

DEP = levelized depreciation factor as defined below.

The term DEP for "sum of the years digits" (SYD) depreciation is equal to:

$$DEP = \frac{2\left[n_T - \frac{1}{CRF_{m';n_T}}\right]}{n_T\ (n_T + 1)m'} \qquad (9\text{-}16)$$

where

n_T = tax depreciation life = 15 years

CRF_{m',n_T} = capital recovery factor for after tax cost of capital, m', and tax life, n_T

$$= \frac{0.0535\ (1+0.0535)^{15}}{(1+.0535)^{15}-1} = 0.0986$$

so that

$$DEP = \frac{2\left[15 - \frac{1}{0.0986}\right]}{15\ (15+1)\ 0.0535} = 0.757$$

Substituting these values into equation (9-15), the value of FCR used in CTAS without local tax and insurance is:

$$FCR = \frac{CRF_{m',n_B}}{(1-t)} \left[1-t(DEP)-c\right]$$

$$= \frac{0.0677}{(1-0.5)} \left[1-\ (0.5 \times 0.757) - 0.10\right] = 0.0706 \qquad (9\text{-}17)$$

Those readers who include an inflation of, say 6.5%, in their economic calculations will be accustomed to values of fixed charge rates in industry of over 0.20 and view the CTAS value of 0.0706 as very low. This is due to cost of money <u>not</u> including inflation, the FCR not including local taxes and insurance of 0.03 and using a book life, n_B, of 30 years. If an inflation rate of 6.5% is used the FCR is 0.137 or 0.167 including local taxes and insurance. If the book life is reduced to more representative value of 15 years the FCR is 0.167 or with the 0.03 local tax and insurance, 0.197. This is approximately the value many of us are accustomed to seeing with inflation.

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

To account for the escalation of the operating expenses or revenue over the operating life of the power plant, they are levelized by first finding the sum of the present worths of each expense over the life, n, of the plant and using the discount rate of the after tax cost of money, m', or:

$$\text{Present Worth} = \sum_{j=1}^{j=n} \frac{Q_J}{(1+m')^j} \tag{9-18}$$

where

Q_J = operating expense in year j, \$/year

n = life of plant, years = 30

m' = after tax cost of money = 0.0535

The present worth of the expense in equation (9-18) is then multiplied by the capital recovery factor, $CRF_{m',n}$, to give the "levelized" annual cost or revenue, LC, or:

$$LC = CRF_{m',n} \sum_{j=1}^{j=n} \frac{Q_J}{(1+m')^j} \tag{9-19}$$

This levelized cost is the average annual constant payment required to meet these escalating expenses. This calculation can be simplified if the expense, Q_j, increases at a constant annual escalation rate, e_p. Thus, if

$$Q_j = Q_o\ (1+e_p)^j \tag{9-20}$$

where Q_o is the operating cost in year j = 0 and e_p is the escalation rate, equation (9-19) for the levelized cost becomes:

$$LC = CRF_{m',n} \times Q_o \left[\sum_{j=1}^{j=n} \left(\frac{1+e_p}{1+m'} \right)^j \right] \tag{9-21}$$

If the substitution

$$1 + k_p = \frac{1+m'}{1+e_p}$$

is made in equation (9-21), it simplifies to:

$$LC = Q_o \quad \frac{CRF_{m',n}}{CRF_{k_p,n}} = Q_o(LF) \tag{9-22}$$

where the quantity $\frac{CRF_{m',n}}{CRF_{k_p,n}}$ is often referred to as the "levelization factor", LF. If the escalation of the expense or revenue $e_p = 0$, equation (9-22) reduces to

$$LC = Q_o \tag{9-23}$$

A typical value of the levelization factor, LF, used in CTAS to calculate the levelized expense of coal, oil or purchased or export power with zero inflation is from equation (9-22)

$$LF = \frac{LC}{Q_o} = \frac{CRF_{m',n}}{CRF_{k_p,n}} = \frac{0.0677}{0.0600} = 1.1277 \tag{9-24}$$

where

$m' = 0.0535$

$n = 30$ years

$e_p = 0.01$ above inflation

$k_p = \frac{1+m'}{1+e_p} - 1 = \frac{1 + 0.0535}{1 + 0.01} - 1 = 1.0431 - 1 = 0.0431$

Figure 9.4-1 shows the values of levelization factor for escalation rates varying from 1 to 15% per year and costs of capital (or discount rates) from 5 to 15%. Because these levelization factors can be very large for even 10% total escalation rates, it is very important in comparing 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 are used.

The levelized operating costs and revenue portion of the LAEC of equation (9-11) is

Levelized Expenses

= Local Taxes and Insurance, $Q_{o,T} \times (LF_T)$

+ Operating and Maintenance, $Q_{o,om} \times (LF_{om})$

+ Purchased Fuel, $Q_{o,F} \times (LF_F)$

+ Purchased Electricity, $Q_{o,EP} \times (LF_{EP})$

+ Levelized Revenue

= Revenue from export power, $Q_{o,EE} \times (LF_{EE})$ (9-25)

where

Q_o = the expense or revenue in first year of plant operation, \$/year

LF = levelization factor as defined in equation (9-22).

Throughout the CTAS reports, revenue is considered to have a negative value when power is sold to produce income to the industrial. The unit cost of fuel or power, p, given in Table 9.2-1 is for 1985 in 1978 dollars and must be escalated to 1990, the first year of operation for all power plants studied in CTAS. This is done by multiplying the cost in 1985 by $(1+e_p')^5$

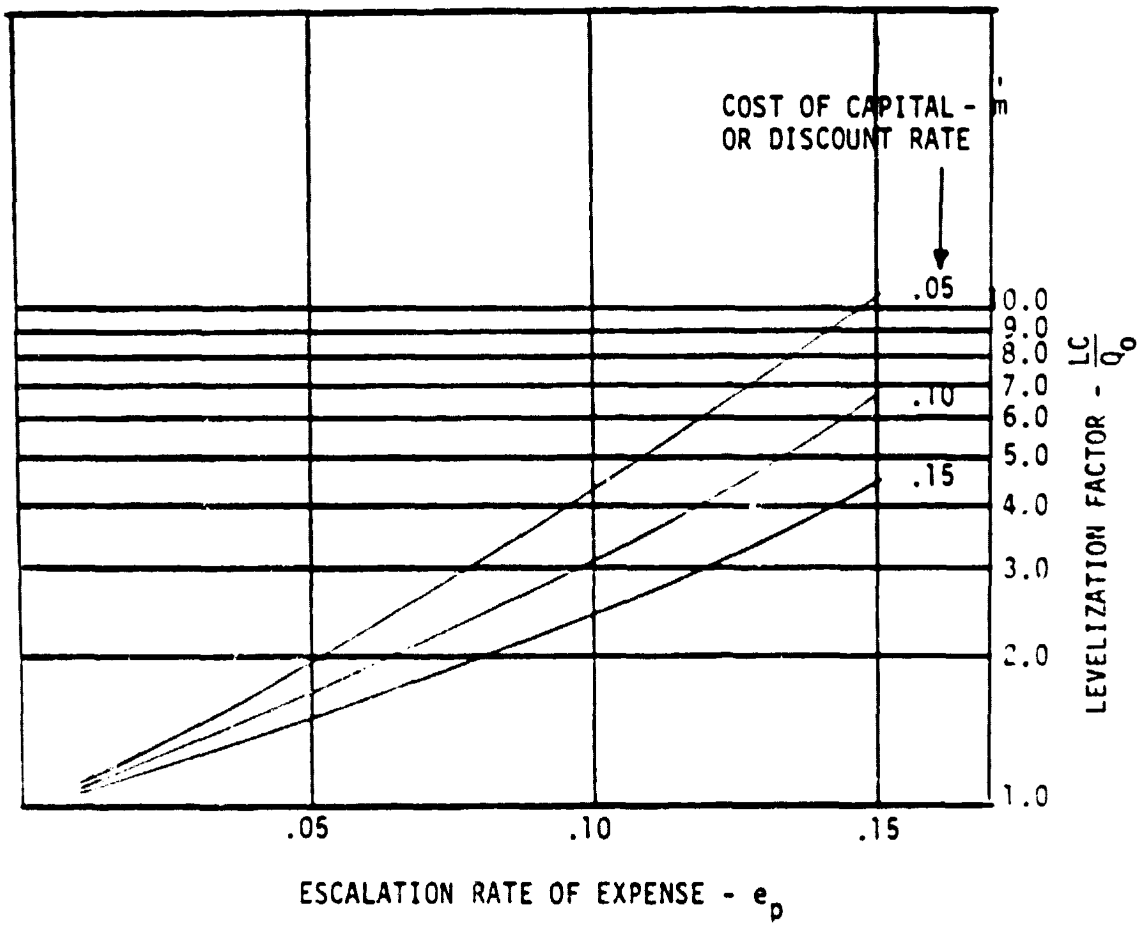


Figure 9.4-1. Levelization Factors for Range of Expense Escalation Rates and Costs of Capital (Economic Life = 30 Years)

where 5 is the number of years between 1985 and 1990 and e_p' is the escalation rate above inflation for the particular item shown in Table 9.2-1. For instance, the cost of coal in 1990 in 1978 dollars is $1.80(1+0.01)^5 = \$1.892/10^6$ Btu and its levelized cost over the period from 1990 to 2020, using the levelization factor of equation (9-24), is $1.892 \times 1.1277 = \$2.133/10^6$ Btu.

Levelized Annual Energy Cost Calculations

This LAEC calculation methodology was programmed into the computerized CTAS Cogeneration Evaluation and Data System and LAEC's calculated for all of the cogeneration/fuel systems heat and power matched as shown in Computer Report 5.2, Section 12.1 for the base case of a coal-fired nocogeneration system. These same values of LAEC are repeated for the oil-fired nocogeneration case in Section 12.2 as only the LAEC of the nocogeneration system change because of their different fuel. A sample of Computer Report 5.2 for the oil- or liquid-fired nocogeneration base case is shown in Table 9.3-6, the same sample as used to illustrate the values of ROI. In this tabulation the third column from the right labeled "LEVL CHRG" is the LAEC in millions of dollars per year for the energy conversion system indicated in the column labeled "ECS" matched to hypothetical industrial process #10102. The column labeled "NORM ENRG" is the ratio of the cogeneration over the nocogeneration LAEC and if this ratio is less than 1.0, the cogeneration $LAEC_{CG}$ is less than the nocogeneration $LAEC_{NC}$.

Table 9.4-1 shows a sample of Computer Report 5.4, entitled "Economic Sensitivity Report" which shows the levelized cost elements making up the LAEC in millions of dollars/year for some of the energy conversion system/fuel combinations matched to the industrial process. In this sample a power match is indicated when the tabulated value of "POWER GEN/REQD" is 1.00 and both the "PURCHD ELEC" and "REVNUE" are 0. All other matches are heat matches and as mentioned previously when power is exported to the utility a negative revenue is shown. The ratio of the cogeneration $LAEC_{CG}$ over the nocogeneration $LAEC_{NC}$ is tabulated in the column labeled "NOPML".

Table 9.4-1

SAMPLE ECONOMIC SENSITIVITY REPORT

DATE 06/07/79
I&SE-PEO-ADV-ENERGY-SYS

GENERAL ELECTRIC COMPANY
COGENERATION TECHNOLOGY ALTERNATIVES STUDY
REPORT 5.4

PAGE 3

ECONOMIC SENSITIVITY REPORT FOR SELECTED PROCESS-FCS MATCHES

SENSITIVITY OF CAPITAL COST — PERCENT OF ORIGINAL COST 100

ENERGY CONV SYSTEM	SITE-FUEL	POWER REQD MW	POWER GEN/REQD	FESR	POWER /HEAT RATIO	CAPITAL COST *10**6	************LEVELIZED ANNUAL ENERGY COSTS($ MILLIONS)*********** CAPITAL	TAXES + INSNC	OANDM	FUEL	PURCHD ELEC	REVNUE	TOTAL	NORML	PRESNT WORTH 15%.	ROI %	GROSS PAY BACK
10102 ONOCGN	RESIDUA	30.	0.	0.	0.25	14.6	1.08	0.46	0.74	14.04	9.24	0.	25.55	1.000	0.	0	0
10102 STM141	RESIDUA	30.	0.99	0.246	0.25	19.0	1.44	0.61	0.98	17.50	0.11	0.	20.64	0.808	13.	55	2
10102 STM141	COAL-FG	30.	0.99	0.246	0.25	34.5	2.62	1.11	2.01	10.16	0.11	0.	16.02	0.627	20.	30	4
10102 STM141	COAL-AF	30.	0.99	0.246	0.25	29.8	2.26	0.96	1.95	10.16	0.11	0.	15.44	0.604	24.	38	3
10102 STM088	RESIDUA	30.	0.75	0.187	0.25	17.2	1.30	0.55	0.93	16.67	2.30	0.	21.75	0.851	10.	67	2
10102 STM088	COAL-FG	30.	0.75	0.187	0.25	32.1	2.44	1.04	1.89	9.68	2.30	0.	17.35	0.679	17.	29	4
10102 STM088	COAL-AF	30.	0.75	0.187	0.25	23.4	1.77	0.75	1.75	9.66	2.30	0.	16.26	0.636	25.	54	2
10102 PFBSTM	COAL-PF	30.	1.00	0.245	0.25	42.4	3.22	1.37	3.12	10.24	0.	0.	17.94	0.702	10.	20	5
10102 PFBSTM	COAL-PF	30.	1.52	0.308	0.25	41.0	3.11	1.32	3.13	11.31	0.	-2.86	16.02	0.627	17.	25	4
10102 TISTMT	RESIDUA	30.	1.00	0.245	0.25	65.9	5.00	2.13	2.40	17.63	0.	0.	27.16	1.063	-30.	2	20
10102 TISTMT	RESIDUA	30.	1.99	0.349	0.25	101.7	7.72	3.28	3.11	21.10	0.	-5.48	29.82	1.167	-55.	0	29
10102 TISTMT	COAL	30.	1.00	0.245	0.25	91.4	6.94	2.95	3.78	10.24	0.	0.	23.91	0.936	-32.	6	11
10102 TISTMT	COAL	30.	1.99	0.349	0.25	128.5	9.75	4.14	4.45	12.30	0.	-5.48	25.16	0.985	-54.	5	13
10102 TIHRSG	RESIDUA	30.	0.85	0.171	0.25	84.9	6.29	2.67	2.52	17.92	1.42	0.	30.82	1.206	-49.	0	939
10102 TIHRSG	COAL	30.	0.85	0.171	0.25	108.6	8.24	3.50	3.72	10.41	1.42	0.	27.29	1.068	-51.	3	17
10102 STIRL	DISTILL	30.	1.00	0.180	0.25	28.9	2.14	0.91	1.43	23.45	0.	0.	27.93	1.093	-14.	0	68
10102 STIRL	DISTILL	30.	2.31	0.274	0.25	46.9	3.48	1.48	1.71	31.64	0.	-7.27	31.04	1.215	-32.	0	66
10102 STIRL	RESIDUA	30.	1.00	0.180	0.25	28.9	2.14	0.91	1.43	19.13	0.	0.	23.62	0.924	-1.	14	7
10102 STIRL	RESIDUA	30.	2.31	0.274	0.25	47.0	3.48	1.48	1.71	25.81	0.	-7.27	25.22	0.987	-14.	6	12
10102 STIRL	COAL	30.	1.00	0.180	0.25	54.2	4.02	1.71	2.85	11.11	0.	0.	19.63	0.771	-0.	14	7
10102 STIRL	COAL	30.	2.31	0.274	0.25	82.1	6.08	2.59	3.40	14.99	0.	-7.27	19.79	0.774	-14.	11	8
10102 HEGT85	COAL-AF	30.	1.00	0.100	0.25	75.4	5.72	2.43	3.34	12.20	0.	0.	23.70	0.927	-24.	7	11
10102 HEGT85	COAL-AF	30.	6.09	0.201	0.25	199.4	15.14	6.43	7.47	32.80	0.	-28.19	33.61	1.317	-114.	0	26
10102 HEGT60	COAL-AF	30.	1.00	0.107	0.25	72.4	5.49	2.34	3.27	12.11	0.	0.	23.20	0.908	-21.	8	10
10102 HEGT60	COAL-AF	30.	2.99	0.178	0.25	119.5	9.07	3.86	4.65	19.99	0.	-11.05	26.51	1.038	-54.	4	15
10102 HEGT00	COAL-AF	30.	1.00	0.104	0.25	67.1	5.09	2.17	3.13	12.14	0.	0.	22.53	0.882	-16.	9	9
10102 HEGT00	COAL-AF	30.	1.40	0.126	0.25	72.5	5.50	2.34	3.05	13.72	0.	-2.20	22.42	0.877	-18.	9	10
10102 FCMCCL	COAL	30.	1.00	0.213	0.25	64.3	5.00	2.13	3.52	10.66	0.	0.	21.31	0.834	-12.	10	8
10102 FCMCCL	COAL	30.	2.56	0.337	0.25	88.8	6.91	2.94	4.87	14.59	0.	-8.67	20.63	0.808	-22.	9	9
10102 FCSTCL	COAL	30.	1.00	0.222	0.25	62.3	4.84	2.06	3.43	10.55	0.	0.	20.88	0.817	-9.	11	8
10102 FCSTCL	COAL	30.	4.17	0.409	0.25	111.0	8.63	3.67	6.12	18.15	0.	-17.56	19.01	0.744	-28.	9	9
10102 IGGTST	COAL	30.	1.00	0.179	0.25	60.0	4.66	1.98	2.05	11.13	0.	0.	20.63	0.807	-7.	12	8
10102 IGGTST	COAL	30.	2.94	0.296	0.25	87.3	6.79	2.89	3.06	16.92	0.	-10.75	18.90	0.740	-15.	11	8
10102 GTSOAR	RESIDUA	30.	1.00	0.188	0.25	22.9	1.69	0.72	1.21	18.96	0.	0.	22.59	0.884	5.	25	4
10102 GTSOAR	RESIDUA	30.	2.62	0.299	0.25	33.8	2.51	1.07	1.30	26.96	0.	-9.00	22.83	0.893	-0.	14	7
10102 GTACO8	RESIDUA	30.	1.00	0.211	0.25	21.0	1.56	0.66	1.16	18.43	0.	0.	21.81	0.853	3.	36	3

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A sample of levelized annual energy cost savings ratios (LAECSR) calculated for selected cogeneration systems and industrial processes are shown in Table 9.4-2 for heat matches and Table 9.4-3 for power matches using a coal-fired process boiler as the nocogeneration base case. Tables 9.4-4 and 9.4-5 show the LAECSR's when a residual-fired boiler is used as the nocogeneration base case.

The LAECSR is defined as

$$LAECSR = 1 - \frac{LAEC_{CG}}{LAEC_{NC}} \tag{9-26}$$

so that positive values indicate a LAEC savings when a cogeneration is installed compared to the nocogeneration base case. A negative value of LAECSR indicates the $LAEC_{CG}$ is more for the cogeneration case than the nocogeneration system.

A study of Table 9.4-2 for the heat matches shows a pattern of results similar to those shown for ROI in Table 9.3-8. The LAECSR's for the small 1.9 MW_e meat packing plant with only 2100 hours per year operation are negative. The coal-fired-FGD steam turbine performs well with the AFB-steam turbine showing slightly better LAECSR's. The same is true for the state-of-the-art gas turbine compared with the advanced gas turbine. Also, there is a correlation with the cost of cogeneration fuel cost with higher LAEC savings with coal-fired units compared with residual- and distillate-fired units showing up poorly.

Table 9.4-2

LEVELIZED ANNUAL ENERGY COST SAVINGS RATIO OF COGENERATION OVER NOCOGENERATION
IN SELECTED INDUSTRIAL PROCESSES

POWER MATCH

COAL NOCOGENERATION BASE

	STATE OF THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - PA - [illegible]	FUEL CELL MC - DIST
MEAT PACKING	-.84	-.34	-.35	-.38	-.68	-1.1	-1.7	-1.5	-.85	-1.4	-2.1	-.26	-.4	-.41	-.38	-.56	-.44	-.38	-.41
MALT BEVERAGES	.01	-.01	-.06	-.11	.08	-.06	-.26	-.24	.00	-.29	-.45	-.12	-.07	-.15	-.11	-.09	-.22	-.30	-.34
BLEACHED KRAFT PAPER	--	--	+.05	-.14	--	.25	-.05	-.10	.13	.03	-.02	.09	.05	-.07	-.08	0	-.12	-.4	-.33
THERM-MECH PULPING	--	--	.09	-.12	--	--	.13	.10	--	--	--	.15	.11	-.05	-.05	.05	.06	-.40	-.31
INTEGRATED CHEMICAL	--	--	.01	-.19	--	--	.19	.16	.15	.09	.05	.05	.02	-.11	-.13	-.04	-.18	-.48	-.41
CHLORINE	--	--	--	-.06	--	--	--	--	--	--	--	--	--	.04	.04	--	--	-.37	-.25
NYLON	--	--	--	-.01	--	--	--	--	--	--	--	--	--	-.01	--	--	--	-.31	-.19
PETRO-REFINING	.19	-.08	-.17	--	.23	.16	.08	.07	.07	.02	-.01	-.23	-.15	--	--	-.23	-.39	-.56	-.52
INTEGRATED STEEL	--	--	--	-.14	--	--	--	--	--	--	--	--	--	--	-.03	--	--	-.37	-.29
COPPER	--	--	--	-.11	--	--	--	-.05	--	--	--	--	.11	-.05	-.06	--	--	-.35	-.25
ALUMINA	.12	-.13	-.21	--	.18	.11	.01	.00	.02	-.04	-.09	-.17	-.19	--	--	-.27	-.44	-.58	-.54

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by --.

Table 9.4-3

LEVELIZED ANNUAL ENERGY COST SAVINGS RATIO OF COGENERATION OVER NOCOGENERATION
IN SELECTED INDUSTRIAL PROCESSES

HEAT MATCH

COAL NOCOGENERATION BASE

	STATE OF THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - PA - [illegible]	FUEL CELL MC - DIST
MEAT PACKING	-.61	-.23	-.33	-.98	-.44	-.84	-2.1	-2.3	-.61	-1.3	-2.7	-.2	-.7	-1.8	-.98	-.7	-.55	-1.1	-1.7
MALT BEVERAGES	.13	.05	-.05	-.21	.21	.08	-.29	-.35	.11	-.26	-.65	.02	-.12	-1.3	-.21	-.11	-.33	-.89	-1.8
BLEACHED KRAFT PAPER	.29	.15	.03	-1.1	.27	.34	.05	.09	.10	.01	-.06	.11	.07	-.91	-.65	.07	-.21	-2.2	-1.4
THERM-MECH PULPING	.11	.01	.10	-.79	.15	.15	.16	.14	.19	-.02	-.10	.17	.12	-.65	-.42	.04	.09	-1.7	-1.0
INTEGRATED CHEMICAL	.18	-.02	-.01	-1.2	.21	.28	.25	.29	.15	.10	.06	.08	.03	-1.0	-.73	-.11	-.28	-2.5	-1.6
CHLORINE	.08	.02	.07	-.15	.09	.10	.13	.19	.10	00	-.01	.10	.18	-.12	.02	.07	.01	-.63	-.31
NYLON	.04	.03	.08	-.01	.06	.04	-.04	.02	.12	-.06	-.17	.11	.15	-.13	.07	.08	.02	-.49	-.21
PETRO-REFINING	.21	-.06	-.29	--	.25	.27	.19	.27	.01	-.03	-.06	-.07	-.14	--	--	-.50	-.70	-3.9	-2.6
INTEGRATED STEEL	.05	.03	.06	-.26	.08	.10	.06	.15	.07	.02	-.04	.08	.11	--	-.04	00	.01	-.42	-.23
COPPER	.03	.01	.10	-.50	.07	.04	-.07	-.02	.15	-.12	-.28	.15	.14	-.44	-.22	.07	.00	-1.1	-.61
ALUMINA	.16	-.11	-.39	--	.21	.21	.11	.14	-.07	-.13	-.20	-.12	-.20	--	--	-.62	.83	-4.2	-2.8

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by --.

Table 9.4-4

LEVELIZED ANNUAL ENERGY COST SAVINGS RATIO OF COGENERATION OVER NOCOGENERATION IN SELECTED INDUSTRIAL PROCESSES

POWER MATCH

RESIDUAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING-AFB - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - PA-DIST	FUEL CELL MC - DIST
MEAT PACKING	-.84	-.34	-.35	-.38	-.68	-1.11	-1.69	-1.52	-.85	-1.43	-2.12	-.26	-.41	-.41	-.57	-.56	-.44	-.38	-.41
MALT BEVERAGES	.08	.06	.01	-.03	.14	.01	-.18	-.15	.06	-.20	-.35	.05	.01	-.07	-.03	-.02	-.14	-.21	-.25
BLEACHED KRAFT PAPER	-	-	.13	-.04	-	.32	.04	0	.21	.11	.07	.17	.13	.03	.01	.09	-.02	-.28	-.21
THERM-MECH PULPING	-	-	.16	-.05	-	-	.19	.16	-	-	-	.21	.17	.02	.02	.11	.01	-.30	-.22
INTEGRATED CHEMICAL	-	-	.15	-.02	-	-	.31	.29	.28	.23	.19	.19	.16	.05	.04	.11	-.01	-.27	-.20
CHLORINE	-	-	-	-.02	-	-	-	-	-	-	-	-	-	.08	.08	-	-	-.31	-.20
NYLON	-	-	-	-.01	-	-	-	-	-	-	-	-	-	-.01	-	-	-	-.31	-.19
PETRO-REFINING	.35	.13	.06	-	.38	.33	.27	.26	.25	.21	.19	.09	.08	-	-	.02	-.12	-.25	-.22
INTEGRATED STEEL	-	-	-	-.12	-	-	-	-	-	-	-	-	-	-	-.01	-	-	-.35	-.26
COPPER	-	-	-	-.10	-	-	-	-.04	-	-	-	-	.13	-.04	-.04	-	-	-.33	-.23
ALUMINA	.31	.10	.04	-	.35	.30	.22	.21	.22	.18	.13	.07	.06	-	-	0	-.14	-.25	-.22

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by -.

Table 9.4-5

LEVELIZED ANNUAL ENERGY COST SAVINGS RATIO OF COGENERATION OVER NOCOGENERATION IN SELECTED INDUSTRIAL PROCESSES

HEAT MATCH

RESIDUAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING-AFB - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - PA-DIST	FUEL CELL MC - DIST
MEAT PACKING	-.61	-.23	-.33	-.98	-.44	-.84	-2.11	-2.32	-.61	-1.26	-2.65	-.20	-.70	-1.75	-.93	-.70	-.55	-1.06	-1.71
MALT BEVERAGES	.19	.11	.02	-.27	.27	.14	-.20	-.26	.17	-.18	-.54	.09	-.04	-1.10	-.13	-.02	-.24	-.76	-1.58
BLEACHED KRAFT PAPER	.35	.22	.12	-.93	.41	.40	.13	.17	.17	.10	.03	.19	.15	-.75	-.50	.02	-.10	-1.94	-1.21
THERM-MECH PULPING	.17	.08	.16	-.66	.21	.21	.22	.20	.25	.05	-.02	.23	.18	-.54	-.32	.10	-.01	-1.47	-.88
INTEGRATED CHEMICAL	.30	.13	.14	-.88	.32	.39	.36	.39	.28	.23	.20	.21	.18	-.73	-.47	.05	-.09	-1.96	-1.23
CHLORINE	.12	.06	.11	-.10	.13	.14	.17	.23	.14	.05	.03	.14	.22	-.07	.06	.11	.06	-.56	-.26
NYLON	.04	.03	.08	-.01	.06	.04	-.04	.02	.12	-.06	-.17	.11	.15	-.13	.07	.08	.02	-.49	-.21
PETRO-REFINING	.36	.15	-.03	-	.40	.41	.35	.41	.20	.17	.15	.14	.08	-	-	-.20	-.38	-2.89	-1.84
INTEGRATED STEEL	.07	.05	.08	-.24	.10	.12	.08	.16	.08	.04	-.02	.10	.12	-	-.02	.02	.03	-.40	-.21
COPPER	.05	.03	.11	-.48	.08	.05	-.05	0	.16	-.11	-.26	.16	.15	-.42	-.20	.09	.02	-1.04	-.59
ALUMINA	.34	.12	.10	-	.37	.37	.29	.32	.15	.10	.05	.12	.05	-	-	-.28	-.45	-3.08	-2.01

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by -.

9.5 EFFECT OF ECONOMIC RESULTS ON IMPLEMENTATION OF COGENERATION BY INDUSTRY

In Section 9.1 the economic criteria used by industrial management in deciding between alternate methods of satisfying their process heat and power requirements were listed as:

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.

A graphic method of portrahing these economic parameters, their relationships and the application of the above selection criteria is shown in Figure 9.5-1. A number of alternate nocogeneration and cogeneration systems all matched to a single industrial process are plotted at the intersection of their LAEC and capital cost on this graph. A very important characteristic of this graph is that the slope of the line connecting any two power plant alternatives plotted on this graph is a function of the ROI of implementing the alternative with the higher capital cost and lower LAEC compared with the other. A correlation of the ROI of cogeneration versus coal- and liquid-fired nocogeneration systems for two different processes is shown in Figure 9.5-2. This correlation was used to derive the "ROI Protractor" shown on Figure 9.5-1.

The first criteria 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 considerable savings in LAEC at a modest increase in capital cost and gives a ROI of 131% on the increase in incremental

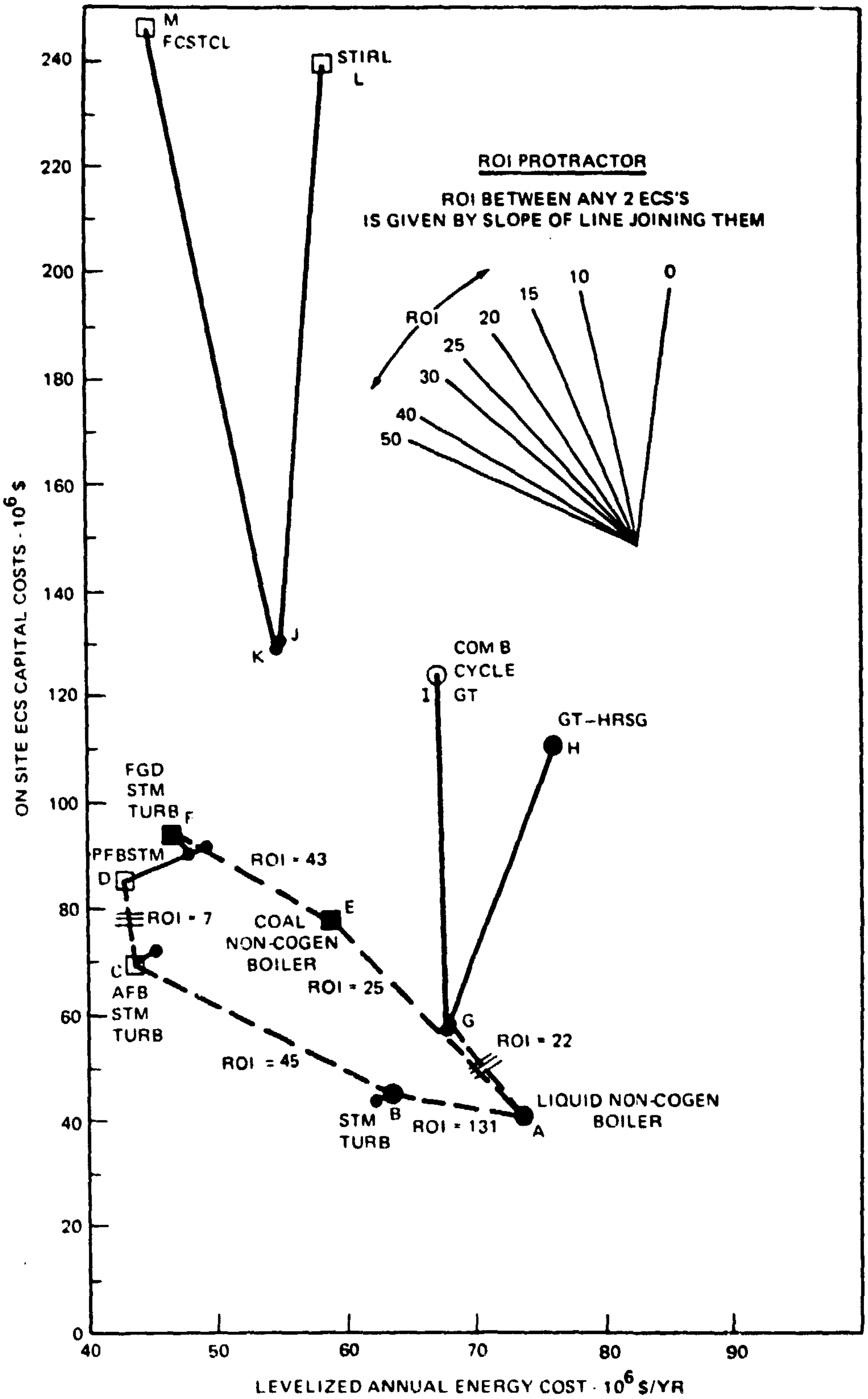

Figure 9.5-1. Industrial Economics of a Small Sample of Cogeneration and Nocogeneration ECS's Heat and Power Matched to a Medium Petroleum Refinery - SIC 2911-2
(A more complete selection of ECS's matched to this process is shown in Figure 9.5-2.)

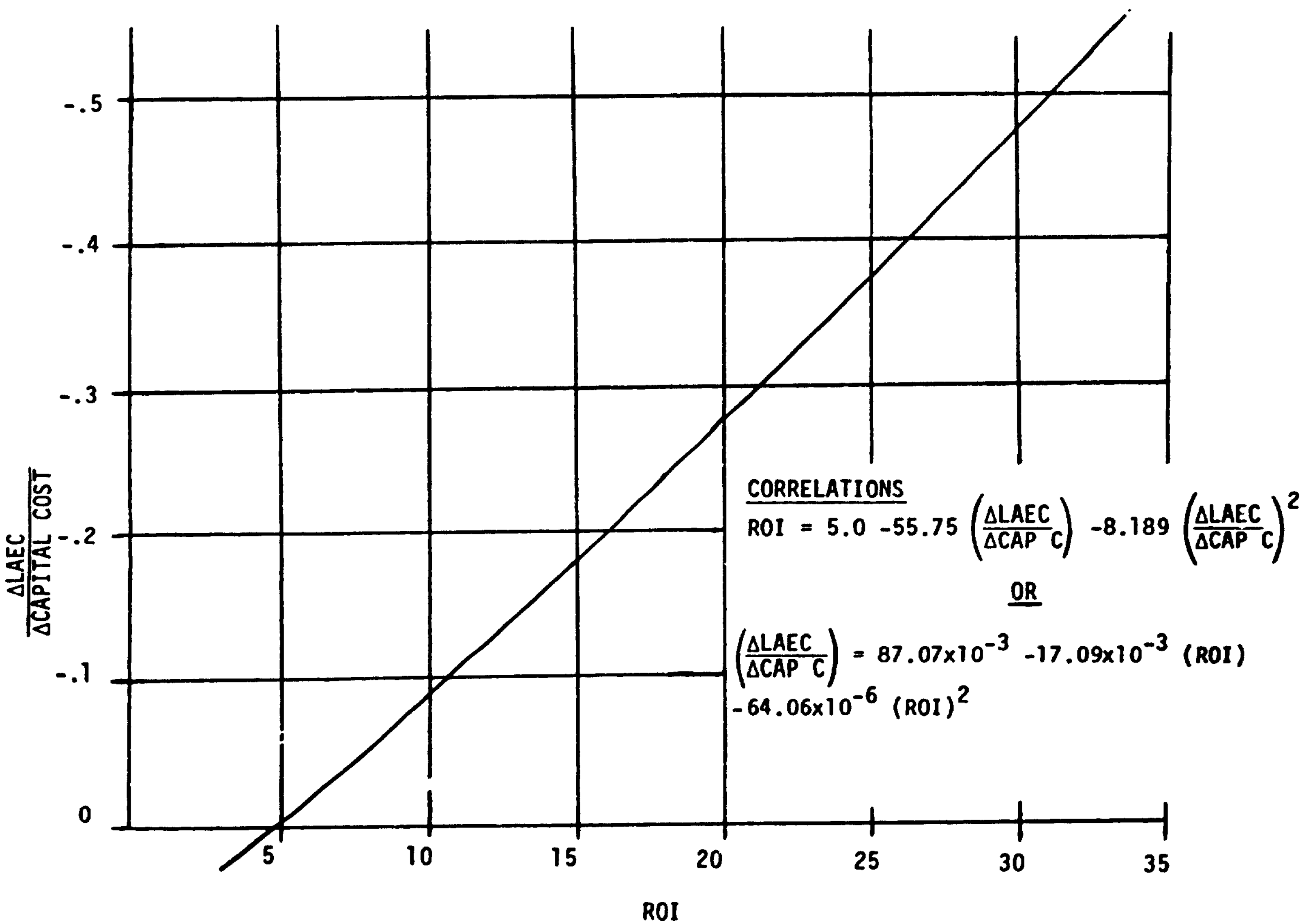

Figure 9.5-2. Correlation of $\frac{\Delta LAEC}{\Delta CAPITAL\ COST}$ versus Return on Investment (ROI) from Computer Data on Matches to Copper Smelter #3331-4 & Medium Refinery #2911-2

investment over system A, and other factors being equal, would almost always be selected over system A. The next higher capital cost systems are two systems very close together labelled G but these systems would not be selected over B because, in addition to the higher capital cost, they have a higher LAEC than B. System C, a coal-fired cogeneration system is the next higher capital cost system and gives a significant decrease in LAEC over system B and has a ROI of 45% on the incremental investment over B. The only remaining alternative system which gives a reduction in LAEC compared with C, is system D but the reduction in LAEC is small compared with the incremental increase in capital cost so its ROI is only 7% which is not high enough to be considered.

If the choice of power plants were restricted to those burning coal (shown as □ or ■ on the plot), the base coal-fired nocogeneration case is system E. Advanced Cogeneration System C gives a significant reduction in LAEC compared with E at a reduction in incremental capital cost so it is a winner. Theoretically the ROI of C compared to E can not be calculated because there is a savings with a reduction in capital cost. As before there is a low ROI = 7% when system D is compared to C so D would not be chosen. If the selection were limited to present state-of-the-art coal-fired systems (shown by ■) system F with a ROI of 43% compared with E would be the system selected.

On Figure 9.5-1, when both a power match and heat match can be made with a single cogeneration ECS-fuel combination, the power match is indicated by a dot, ., and the heat match is indicated by a □, ■, ○ or ● and is connected to the power match by a straight solid line; e.g. line GH, JL, or KM. These latter systems have a much higher power to heat ratio than the process so that when heat matched to the process they generate from 3 to 6 times the power required by the process, are advanced systems and, at the price assumed received for export power of 0.6 times the purchase power, do not give a favorable ROI.

Application of the various energy conversion systems and the fuels to supply a given industry with heat and power result in a wide spectrum of economics. These plots provide a vehicle for displaying results and comparing the economics of state-of-the-art systems versus advanced systems using either coal or liquid fuels. When the fuel energy saved ratio, shown as a decimal number, and power generated by the various heat matched cogeneration systems, shown as MW_e, are also noted on these plots, the key data for comparison can be presented on one sheet for each industrial process. Coupling the data presented by these plots for several processes with representative power to heat ratios and the energy requirement characteristics of the national population of industrial processes allows the process results to be used to infer probably preferred systems from a national perspective.

Figure 9.5-3 is a plot of selected CTAS ECS cogeneration economics for a medium-sized petroleum refinery. The refinery requires 52 megawatts of electricpower and 1333 million Btu per hour of steam at 470^{0}F and operates 8760 hr/yr. The power to heat ratio of the petroleum refinery is 0.13. As shown in Section 10, about 60% of industrial process energy required in the U.S. for steam and electric power is consumed by processes with power to heat ratios less than or equal to 0.20 so that ECS's which have bood performance and economics application probably will have high national impact. A direct conclusion is clouded by the effect of the national distribution of process temperature variations.

In comparison to the liquid-fueled nocogeneration case, the liquid-fueled cogeneration systems that have a ROI greater than 15% are the power matched state-of-the-art and advanced gas turbine (GE-HRSG ·), the advanced diesel with a heat pump (DIESEL-HEAT PUMP ·), the advanced combined-cycle (COMB CYCLE ·), the state-of-the-art steam turbine (STM TURB ·, ●). These systems are all sized to match process power required with the exception of the state-of-the-art steam turbine where both the heat match and power match cases are economic. The heat match cases of all other systems have poorer economics than the power match cases. The fuel energy savings of these power matched cases are all about 11% to 14%. The steam

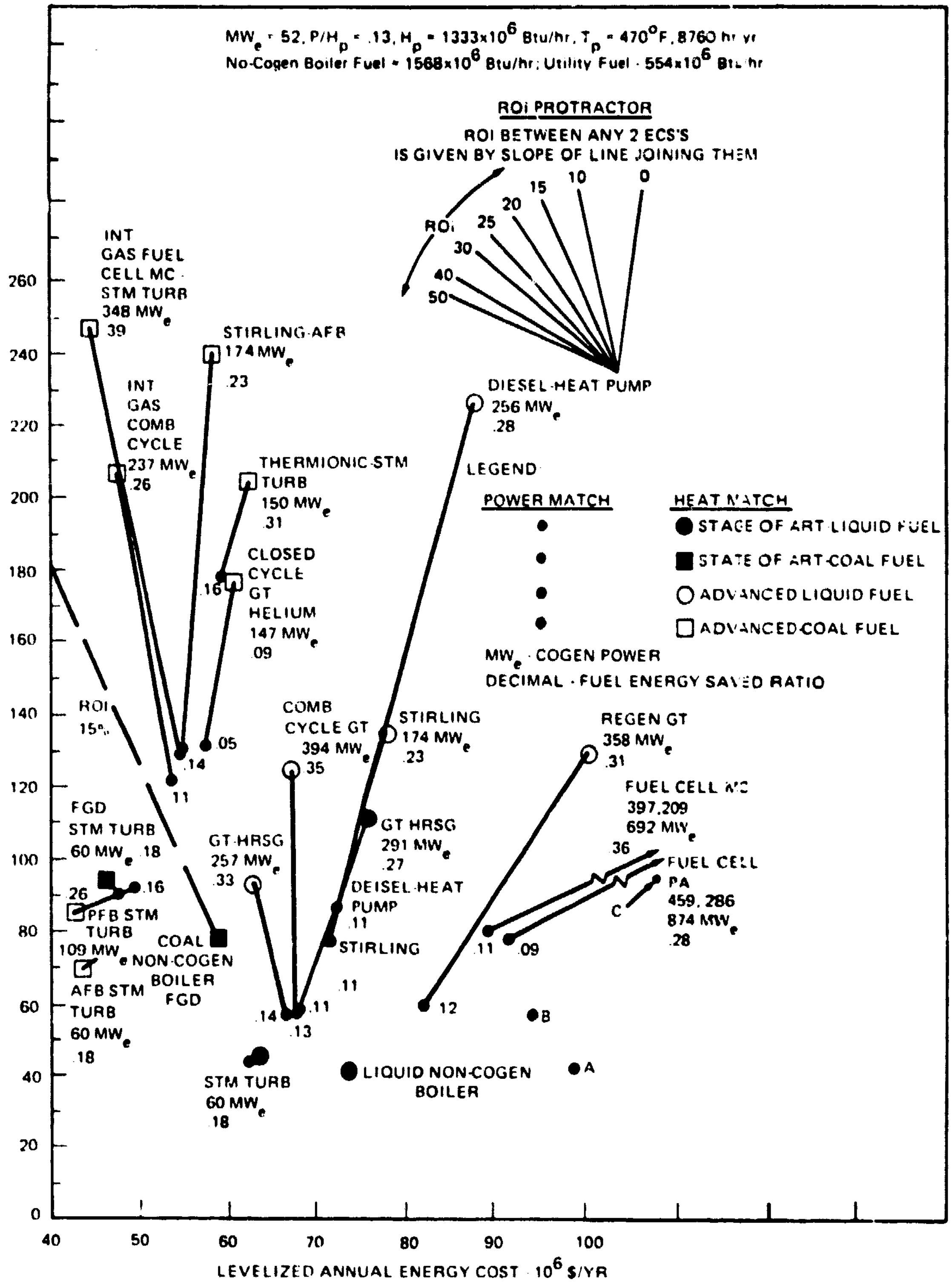

Figure 9.5-3. Industrial Economics of Cogeneration and Nocogeneration ECS's Heat and Power Matched to Medium Petroleum Refinery - SIC 2911-2

turbine saves about 18% fuel energy and it has the best return on investment (> 50%) of any system.

An area of concern on the liquid-fired systems is the possibility of an increasing price differential between liquid fuel and coal. The ground rule base price of coal used is $\$1.80/10^6$ Btu and residual liquids is \$3.10 in 1985 (in 1978 dollars). The effect of increasing the liqu
price by 50% to $\$4.65/10^6$ Btu is to significantly increase the LAEC of the liquid-fired systems as shown by point A for the nocogen liquid boiler, point B for the gas turbine, (GT-HRSG ·), power matched and point C for the same gas turbine (GT-HRSG ⊙) heat matched. The slopes of the lines A-B and A-C compared to those connecting the same ground rule base costs show a significant reduction in ROI and <u>make the liquid cogeneration ECS's uneconomical compared to the coal-fired systems</u>.

Concentrating on coal burning systems only, the coal-fired nocogeneration case with flue gas desulfurization (COAL NON COGEN BOILER FGD ☐) costs \$78 million with a levelized annual nocogeneration case is about double that of the liquid-fired nocogeneration case. Even though the coal-fired nocogeneration equipment is very expensive, if the industrial can raise the capital, it appears to be a good investment with an ROI of about 25% (using the ROI protractor) compared to the liquid nocogeneration case

The coal-fired cogeneration systems that fall to the left of the 15% ROI hurdle line are the state-of-the-art steam turbine with flue gas desulfurization (FGD STM TURB ■), the PFB steam turbine (PFB STM TURB ☐), and the AFB steam turbine (AFB STM TURB ☐) matched to process heat or power. Of the economically feasible systems, the AFB steam turbine matched to process heat gives the best economics. The capital cost is less than the nocogeneration boiler with flue gas desulfurization and the levelized annual cost of energy is also less. A ROI cannot be calculated in this situation with the nocogeneration case as the base because there would be a negative incremental investment. The heat matched PFB gives a higher FESR of 0.26 vs. 0.18 for the AFB.

Figure 9.5-4 shows the economics for a thermomechanical pulp mill which has a power to heat ratio of 0.58. The economics shown here may be considered representative of those for processes with power to heat ratios of from 0.20 - 0.6. About 22% of industrial energy for steam and electric power is consumed by industries that require power to heat ratios over this range. Liquid-fired cogeneration ECS's which have favorable economics compared to the liquid nocogeneration boiler are the state-of-the-art steam turbine (STM TURB ●), the state-of-the-art gas turbine (GT-HRSG ●), the advanced combined-cycle (COMB CYCLE ⊙), and the advanced air-cooled gas turbine (GT-HRSG ⊙). The state-of-the-art steam turbine, while it only generates 10 MW out of the 31.3 MW required and saves 12% in fuel, still gives a good ROI (≈26%) for the lowest increment of capital cost. The other systems when compared to the state-of-the-art steam turbine are less attractive investments (ROI's less than 15%) with the exception of the advanced air-cooled gas turbine (GT-HRSG ⊙). It has a ROI of about 25% compared to the state-of-the-art steam turbine and has a fuel energy saved ratio of 0.33.

Next, the coal-fueled systems are compared to the coal-fueled nocogeneration case. Systems that have good ecnomic potential (fall to the left of the 15% ROI hurdle line) are the state-of-the-art steam turbine with flue gas desulfurization (FGD STM TURB ■), the advanced PFB steam turbine (PFB STM TURB ⊡) and the advanced steam turbine with AFB (AFB STM TURB ⊡). The only state-of-the-art system in consideration here is the state-of-the-art steam turbine-boiler with flue gas desulfurization. It gives an attractive ROI of ≈27% while saving 12% in fuel energy. Of the advanced systems, the AFB steam turbine is the ultimate economic winner because its initial capital cost is less than that of the nocogeneration boiler with flue gas desulfurization.

Figure 9.5-5 shows the economics for a copper smelter which has a power to heat ratio of 0.86. The economics shown here may be considered somewhat typical for those processes with power to heat ratios from 0.6 to 1.5. About 12% of industrial energy for steam and electric power is consumed by industries that require power to heat ratios over this range.

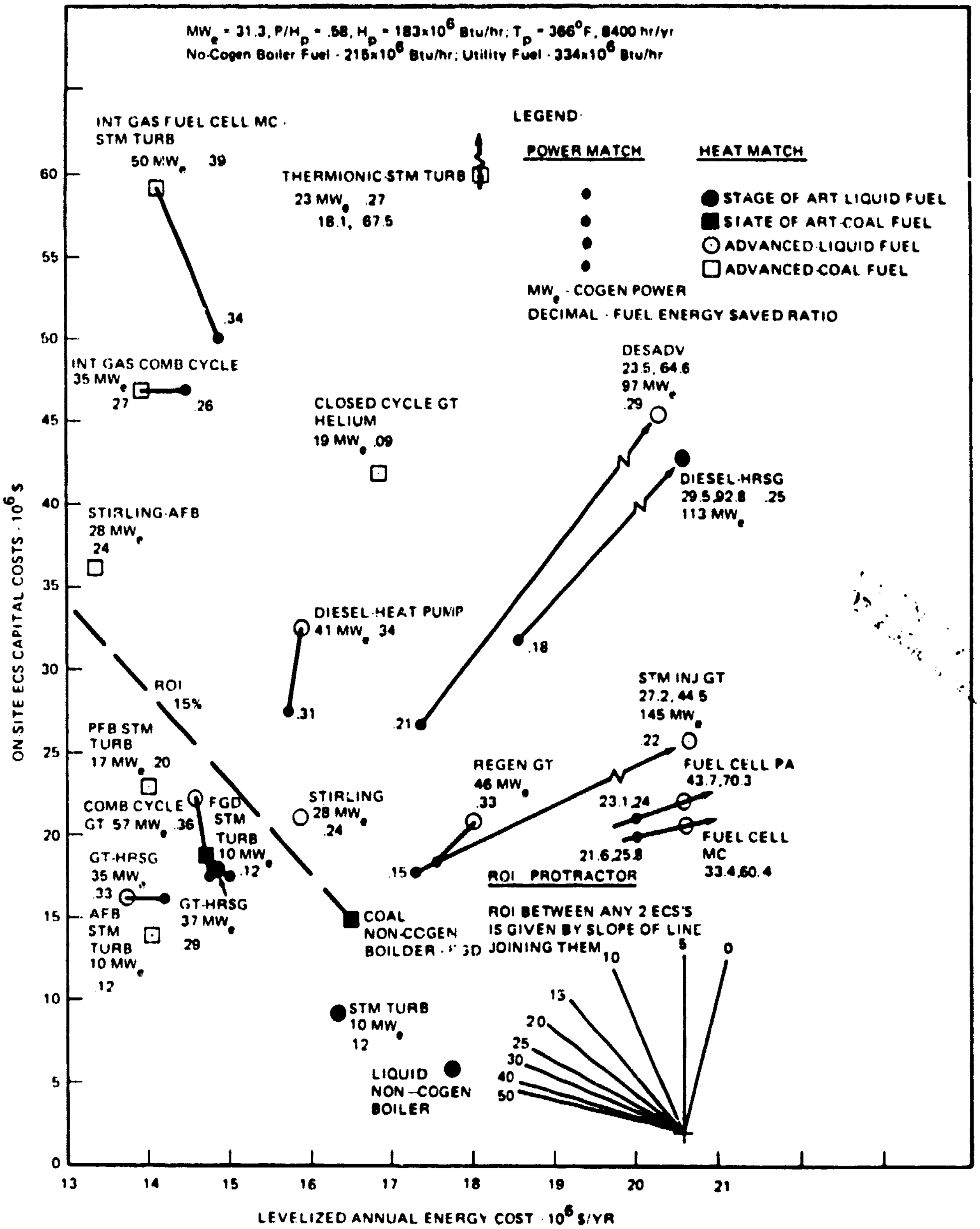

Figure 9.5-4. Industrial Economics of Cogeneration and Nocogeneration ECS's Heat and Power Matched to Thermo-Mechanical Pulp, SIC 2621-7

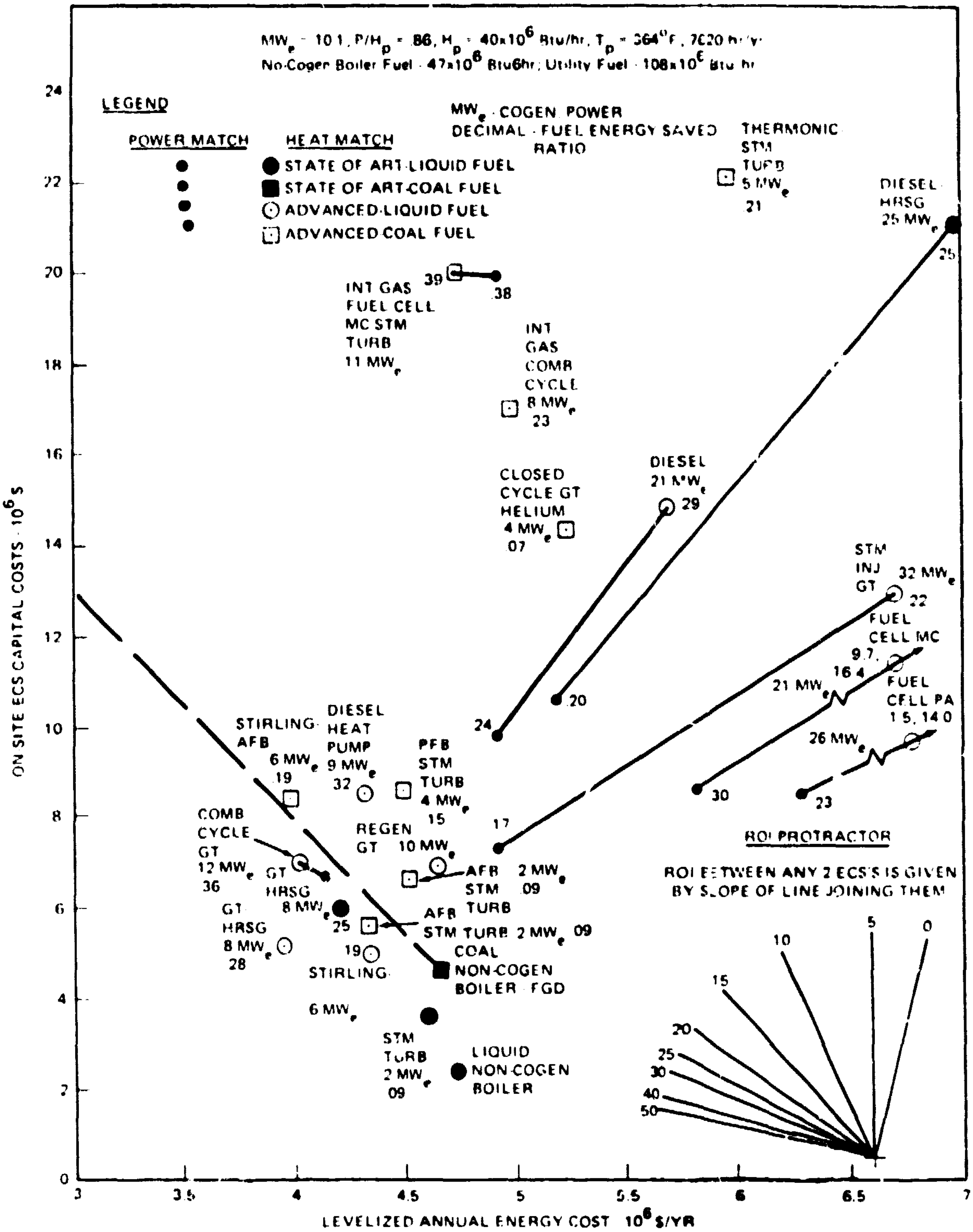

Figure 9.5-5. Industrial Economics of Cogeneration and Nocogeneration ECS's Heat and Power Matched to Copper Smelter, SIC 3331-4

Of the liquid-fueled systems compared to the liquid nocogeneration case, the state-of-the-art steam turbine (STM TURB ●) and state-of-the-art gas turbine (GT-HRSG ●) both have ROI's less than 15%. Of the advanced systems, the advanced air-cooled gas turbine (GT-HRSG ⊙)is clearly the economic winner with a ROI of ≈19%. Comparing coal-fired systems, the only system with favorable economics is the AFB steam turbine (AFB STM TURB ⊡) with a ROI of ≈22%.

Tables 9.5-1, -2 and -3 show the levelized cost components for fuel and power (variable operating and maintenance component is not shown) corresponding to the systems shown in Figures 9.5-3, -4 and -5. One very convenient feature of these capital cost versus LAEC and ROI plots is that it is very easy to visualize the effect of changing the price of fuel or purchased or exported power when the original magnitude of the levelized cost of the item is known. For instance on Figure 9.5-5 for the Copper Smelter, the best choice of cogeneration system is the advanced Gas Turbine-HRSG-Residual (GT-HRSG ⊙) using the base groundrules with a 1985 residual fuel cost of $\$3.10/10^6$ Btu in 1978 dollars. Table 9.5-3 shows a breakdown of the levelized costs for the power systems shown on the plot of Figure 9.5-5 and for the GT HRSG RESIDUAL the fuel cost is 2.39×10^6 \$/yr. If the fuel cost were increased by 50% or 1.2×10^6, an inspection of the plot with the gas turbine moved 1.2×10^6 \$/yr to right indicates that it has a ROI compared to the coal nocogeneration base case <u>poorer than zero</u>. In fact, a 50% increase in liquid fuel prices would eliminate all of the liquid-fired systems and the steam turbine AFB would again be the most economic choice!

These type plots are a very convenient method for comparing not only alternate power plant economics and their sensitivities to changes in the various cost components but in comparing any investment alternative. Of course, the general groundrules used in calculating economic characteristics of all the alternative investments entered on a single plot must be the same.

Table 9.5-1

CAPITAL COST, LEVELIZED ENERGY COSTS AND RETURN ON INVESTMENT OF COGENERATION ECS's AND NON COGENERATION PROCESS BOILERS MATCHED TO A THERMAL MECH. PULP - SIC 2621-7

	POWER MATCH							HEAT MATCH						
	LEVELIZED COSTS - 10^6 \$/YEAR							LEVELIZED COSTS - 10^6 \$/YEAR						
ECS	CAP. COST	CAP. MAIN. TAXES INS.	FUEL	POWER	TOTAL	(C) ROI	(R) ROI	CAP. COST	CAP. MAIN. TAXES INS.	FUEL	POWER	TOTAL	(C) ROI	(R) ROI
NON COGEN RESIDUAL	5.8	.77	6.58	10.12	17.7	---	--	5.8	.77	6.58	10.12	17.7	---	--
NON COGEN COAL FGD	14.8	1.97	3.82	10.12	16.5	---	--	14.8	.77	3.82	10.12	16.52	---	--
STM TURB RESIDUAL	-	-	-	-	-	---	--	9.2	1.23	7.78	6.94	16.35	---	--
STM TURB COAL FGD	-	-	-	-	-	---	--	18.6	2.48	4.52	6.94	14.7	30	19
GT HRSG SOA RESIDUAL	17.5	2.33	12.22	0	14.99	40	19	17.8	2.37	13.19	-1.04	14.82	39	19
DIESEL SOA HRSG RESID	31.8	4.24	13.80	0	18.58	0	2	92.8	12.36	32.71	-15.90	29.51	0	0
AFB STM TURB COAL	-	-	-	-	-	--	--	13.9	1.85	4.52	6.94	14.06	0	29
PFB STM TURB COAL	-	-	-	-	-	--	--	22.9	3.95	5.05	4.74	14.00	22	18
INT GAS COMB CYC COAL	46.9	6.25	7.17	0	14.42	9	10	46.9	6.25	7.53	-.65	13.92	10	11
INT GAS FUEL CELL MCST COAL	50.0	6.66	6.47	0	14.86	8	9	59.0	7.86	8.08	-3.69	14.13	9	9
CLOSED CYCLE GT HELIUM COAL	-	-	-	-	-	--	--	41.9	5.58	6.65	3.87	16.83	4	7
THERMIONIC STM COAL	-	-	-	-	-	--	--	67.5	8.99	5.47	2.84	18.11	2	4
STIRLING COAL	-	-	-	-	-	--	--	36.2	4.82	6.81	.96	13.34	15	14
STIRLING RESIDUAL	-	-	-	-	-	--	--	21.0	2.80	11.72	.96	15.82	13	13
GT HRSG RESIDUAL	16.1	2.14	11.44	0	14.01	131	25	16.2	2.16	12.05	-.76	13.73	136	26
COMB CYCLE GT RESIDUAL	17.4	2.32	11.81	0	14.77	39	20	22.2	2.96	16.07	-4.95	14.58	20	16
STM INJ GT RESIDUAL	17.7	2.36	14.25	0	17.3	0	8	44.5	5.93	42.21	-22.13	27.24	0	0
DIESEL HRSG RESIDUAL	26.7	3.56	13.25	0	17.35	0	6	64.6	8.60	27.28	-12.76	23.50	0	0
DIESEL HEAT PUMP RESID	27.4	3.65	11.53	0	15.73	10	11	32.4	4.32	13.05	-1.87	14.90	8	10
REGEN GT DIST	18.3	2.44	14.67	0	17.58	0	6	20.8	2.77	17.73	-2.81	17.99	0	3
FUEL CELL PA DIST	24.9	3.32	16.49	0	23.07	0	0	70.3	9.36	40.32	-17.19	43.74	0	0
FUEL CELL MC DIST	25.8	3.44	15.11	0	21.58	0	0	60.4	8.04	29.42	-12.33	33.35	0	0

Table 9.5-2

CAPITAL COSTS, LEVELIZED ENERGY COSTS AND RETURN ON INVESTMENT OF COGENERAION ECS's AND NON COGENERATION PROCESS BOILERS MATCHED TO A MEDIUM SIZED REFINERY - SIC 2911-2

	POWER MATCH LEVELIZED COSTS - 10^6 \$/YEAR							HEAT MATCH LEVELIZED COSTS - 10^6 \$/YEAR						
ECS	CAP. COST	CAP. MAIN. TAXES INS.	FUEL	POWER	TOTAL	(C) ROI	(R) ROI	CAP. COST	CAP. MAIN. TAXES INS.	FUEL	POWER	TOTAL	(C) ROI	(R) ROI
NON COGEN RESIDUAL	41.1	5.5	50.0	17.5	73.4	---	---	41.1	5.5	50.0	17.5	73.4	---	---
NON COGEN COAL FGD	77.5	10.3	29.0	17.5	58.8	---	---	77.5	10.3	29.0	17.5	58.8	---	---
STM TURB RESIDUAL	44.9	6.0	56.6	0	63.6	-14	100	44.0	5.9	57.7		62.6	-12	131
STM TURB COAL FGD	90.4	12.0	32.9	0	47.7	48	32	93.8	12.5	33.5	-1.7	46.6	43	31
GT HRSG SOA RESIDUAL	58.3	7.8	60.5	0	69.1	-31	20	110.6	14.7	109.1	-48.3	75.9	0	1
DIESEL SOA HRSG RESID	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AFB STM TURB COAL	72.0	9.6	32.9	0	45.6	0	48	69.6	9.3	33.5	-1.7	43.8	[illegible]	54
PFB STM TURB COAL	91.5	12.2	33.1	0	49.6	38	30	84.8	11.3	37.6	-11.6	43.0	103	39
INT GAS COMB CYC COAL	121.7	16.2	34.9	0	53.8	12	19	206.4	27.5	55.8	-37.4	47.7	1	14
INT GAS FUEL CELL MCST COAL	128.9	17.2	33.6	0	54.7	10	17	245.9	32.8	59.9	-60.0	42.9	11	14
CLOSED CYCLE GT HELIUM COAL	130.7	17.4	37.4	0	57.8	6	15	176.8	23.5	42.9	-19.3	60.8	3	11
THERMIONIC STM COAL	177.6	15.7	33.0	0	59.4	4	12	294.5	39.2	40.5	-19.9	62.4	3	8
STIRLING COAL	130.0	17.3	35.0	0	54.8	10	18	239.3	31.9	48.9	-24.7	58.4	5	10
STIRLING RESIDUAL	76.8	10.2	60.2	0	71.3		9	134.0	17.8	84.3	-24.7	77.9	0	0
GT HRSG RESIDUAL	56.6	7.5	58.4	0	66.7	-25	29	92.2	12.3	91.7	-41.5	62.9	0	17
COMB CYCLE GT RESID	56.8	7.6	59.1	0	67.7	-28	24	123.2	16.4	119.1	-69.2	67.3	0	10
STM INJ GT RESIDUAL	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL HRSG RESIDUAL	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL HEAT PUMP RESID	86.0	11.4	59.9	0	72.2	0	7	225.6	30.0	98.8	-41.2	88.0	0	0
REGEN GT DIST	59.0	7.9	73.4	0	82.0	-61	0	128.7	17.1	144.5	-61.8	100.2	0	0
FUEL CELL PA DIST	77.8	10.4	75.9	0	91.8		0	459.1	61.1	306.3	-166.2	285.5	0	0
FUEL CELL MC DIST	79.6	10.6	73.5	0	89.2	0	0	397.3	52.9	223.5	-129.2	208.5	0	0

Table 9.5-3

CAPITAL COSTS, LEVELIZED ENERGY COSTS AND RETURN ON INVESTMENT OF COGENERATION ECS's AND NON COGENERATION PROCESS BOILERS MATCHED TO A COPPER SMELTER - SIC 3331-4

ECS	POWER MATCH LEVELIZED COSTS - 10^6 $/YEAR							HEAT MATCH LEVELIZED COSTS - 10^6 $/YEAR						
	CAP. COST	CAP. MAIN. TAXES INS.	FUEL	POWER	TOTAL	(C) ROI	(R) ROI	CAP. COST	CAP. MAIN. TAXES INS.	FUEL	POWER	TOTAL	(C) ROI	(R) ROI
NON COGEN RESIDUAL	2.2	.29	1.30	2.96	4.73	---	---	2.2	.29	1.30	2.96	4.73	---	---
NON COGEN COAL FGD	4.6	.62	.76	2.96	4.66	---	---	4.6	.62	.76	2.96	4.66	---	---
STM TURB RESIDUAL	-	-	-	-	-	---	---	-	.48	1.54	2.33	4.60		0
STM TURB COAL FGD	-	-	-	-	-	---	---	6.6	.88	.90	2.33	4.51	10	8
GT HRSG SOA RESIDUAL	-	-	-	-	-	---	---	6.0	.80	2.61	.61	4.21	24	14
DIESEL SOA HRSG RESID	10.6	1.42	3.42	0	5.19	0	0	21.1	2.82	6.45	-2.56	6.98	0	0
AFB STM TURB COAL	-	-	-	-	-	---	---	5.6	.75	.90	2.33	4.33	23	12
PFB STM TURB COAL	-	-	-	-	-	---	---	8.6	1.15	1.00	1.89	4.49	8	7
INT GAS COMB CYC COAL	-	-	-	-	-	---	---	17.0	2.27	1.49	.74	4.98	3	4
INT GAS FUEL CELL								20.0	2.67	1.60	-.16	4.74	4	5
MCST COAL	19.9	2.66	1.53	0	4.92	4	0	20.0	2.67	1.60	-.16	4.74	4	5
CLOSED CYCLE GT HELIUM COAL	-	-	-	-	-	---	---	14.3	1.91	1.32	1.72	5.23	0	1
THERMIONIC STM COAL	-	-	-	-	-	---	---	22.1	2.96	1.08	1.52	5.98	0	0
STIRLING COAL	-	-	-	-	-	---	---	8.4	1.12	1.35	1.14	3.99	16	13
STIRLING RESIDUAL	-	-	-	-	-	---	---	5.0	.67	2.33	1.14	4.35	61	14
GT HRSG RESIDUAL	-	-	-	-	-	---	---	5.2	.70	2.39	.70	3.96	72	20
COMB CYCLE GT RESID	6.7	.90	2.84	0	4.13	19	13	7.0	.94	3.19	-.41	4.03	20	14
STM INJ GT RESIDUAL	7.3	.98	3.55	0	4.92	0	1	12.9	1.73	8.37	-3.81	6.71	0	0
DIESEL HRSG RESIDUAL	9.8	1.31	3.26	0	4.92	0	2	14.8	1.98	5.39	-1.94	5.69	0	0
DIESEL HEAT PUMP RESID	-	-	-	-	-	---	---	8.5	1.14	2.59	.33	4.31	11	0
REGEN GT DIST	-	-	-	-	-	---	---	6.9	.92	3.51	.03	4.64	6	6
FUEL CELL PA DIST	8.5	1.14	4.06	0	6.28	0	0	16.4	2.19	8.00	-2.83	9.66	0	0
FUEL CELL MC DIST	8.6	1.15	3.66	0	5.81	0	0	14.0	1.87	5.83	-1.87	7.53	0	0

9.6 SENSITIVITY OF ROI TO CHANGES IN COSTS

Return on Investment (ROI) is a very important index of the economic performance of cogeneration ECS's and the question arises as to its sensitivity to changes in fuel, power, and capital costs. A conventional method of presenting these sensitivities is shown in Figure 9.6-1 for a steam turbine coal-fired AFB boiler cogeneration system heat matched to a medium petroleum refinery and compared to a nocogeneration residual-fired boiler with power from the utility. Four costs were varied from -10% to +50% of their base value; namely the cost of residual fuel for the nocogeneration boiler, coal fuel for the steam turbine AFB boiler and its capital cost and the price received for the power exported to the utility. None of these sensitivities are startling and since the system has a high base ROI of 54%, it would appear to take a very major change to make this AFB ECS look poorly.

The greatest uncertainty is felt to be in the fuel costs. Figure 9.6-2 shows the sensitivity to cogen fuel cost of several cogeneration ECS's heat or power matched to the same medium refinery with a residual-fired nocogeneration boiler as the base. Probably the greatest uncertainty exists in the future price of oil since the OPEC price has risen about 50% in 1979 bringing it over the \$3.10 per 10^6 Btu assumed in the groundrules in 1985. For the residual-fired combined cycle ECS shown, heat and power matched in Figure 9.6-2, an additional 20% increase would bring the heat matched combined cycle ECS to zero ROI. Therefore, the probable continued steep increase in oil prices needs to be considered in deciding on the possible implementation of an oil-fired cogeneration system.

A more complete understanding of these cost sensitivities can be seen by preparing the capital cost versus levelized annual energy cost plot shown in Figure 9.6-3. This is the same plot for ECS's matched to a medium petroleum refinery as shown in Figure 9.5-3 except only a few ECS's are shown and for these the effect of increasing the fuel, power, and capital cost by 25% over the base is indicated. Now it becomes clear what the effect of these cost increases have on these cogeneration ECS's relative to both the coal- and oil-fired nocogeneration base cases; e.g., a 25%

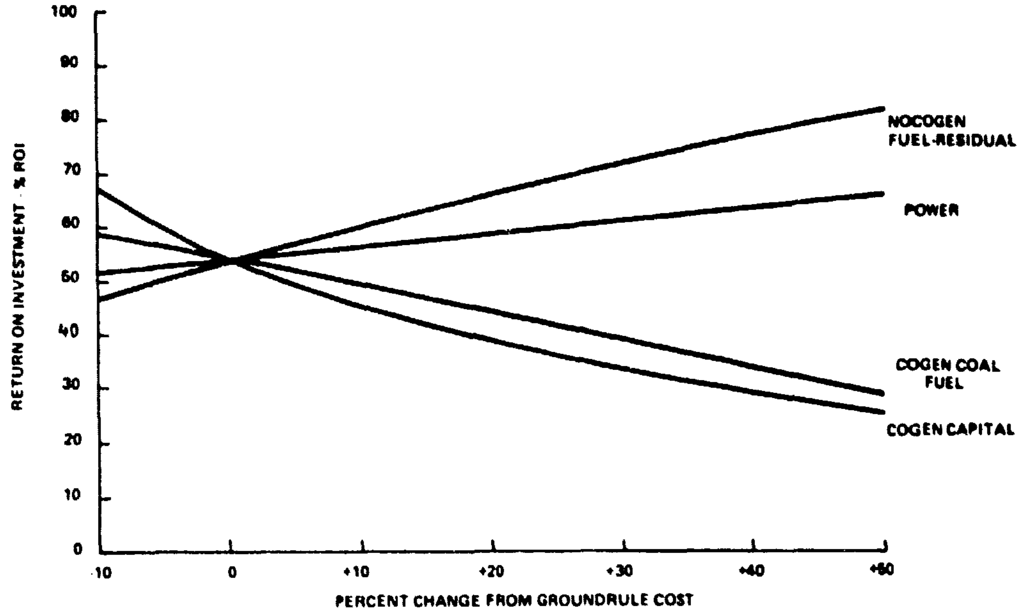

Figure 9.6-1. Sensitivity of ROI to Changes in Costs of Steam Turbine AFB Heat Matched to Medium Petroleum Refinery - SIC 2911-2
Base: Residual Fired Nocogeneration Boiler & Utility Power

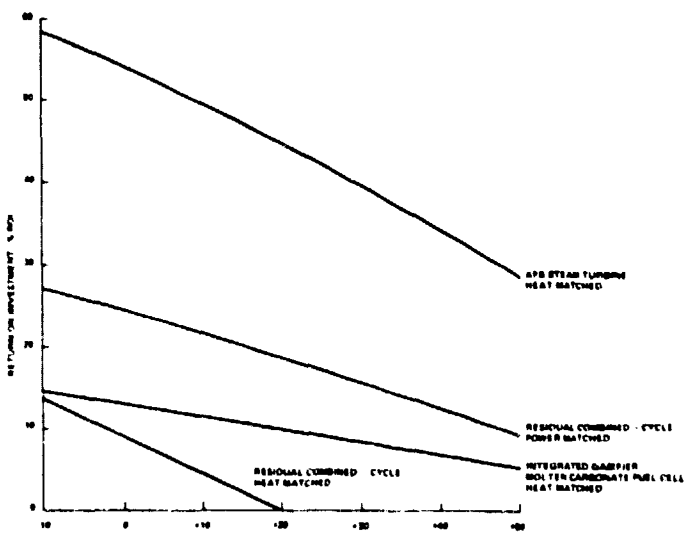

Figure 9.6-2. Sensitivity of ROI to Cogeneration Fuel Costs for Selected ECS's Matched to Medium Petroleum Refinery - SIC 2911-2
Base: Residual Fired Nocogeneration Boiler & Utility Power

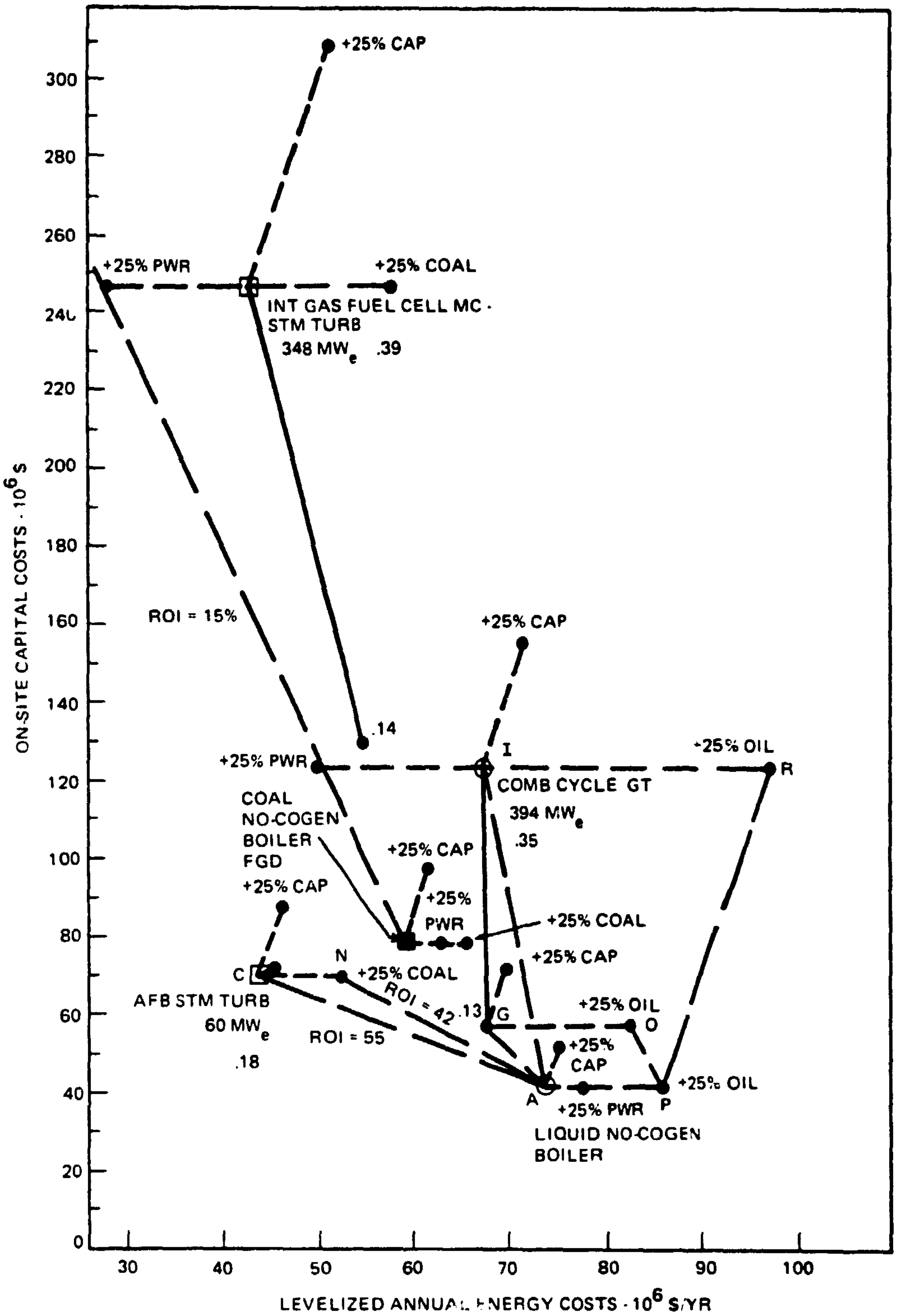

Figure 9.6-3. Economic Sensitivities to Fuel, Power and Capital Costs of Selected Nocogeneration and Cogeneration ECS's Heat and Power Matched to Medium Petroleum Refinery - SIC 2911-2

increase in price of power received by the heat matched combined cycle, just gives an ROI of 15% compared with a coal-fired nocogen base and any increase in oil price would rapidly decrease its ROI. Note also as the price of oil increases, the ROI of the power matched combined cycle compared to the oil-fired nocogen base decreases. Using these plots, a pair of dividers and the ROI protractor, a wide range of contingencies can be easily investigated. Such an analysis should be made as a part of the detailed economic analysis of any cogeneration system seriously considered for implementation.

Section 10

NATIONAL CONSIDERATIONS

Fuel energy saved, emissions saved, and capital saved were calculated on a national basis to provide a measure of comparison between energy conversion systems. The savings were calculated for each energy conversion system employed in all suitable CTAS processes without competition from other ECS's. The results were scaled to a national level. The yearly rate of national savings of fuel, emissions, and capital costs were computed for the year 1990 assuming that each of the energy conversion systems were available and implemented beginning in 1985. These national savings were calculated for both heat and power matches.

METHODOLOGY

A basic assumption affecting the amount of total savings possible was that cogeneration could only be employed in new plants by capacity addition to existing plants or where replacement of old unserviceable industrial boilers was assumed necessary. Figure 10-1 displays the relationship between the yearly amount of fuel energy that cogeneration can be applied to and the total yearly amount of energy used by industry. The top line in the figure represents the total yearly rate of energy consumption by industry. In this figure, the industrial energy consumption includes fuel for direct heat and steam and the fuel used in utilities to generate the purchased electric power at an assumed efficiency of 32%. The portion of energy consumption rate between the top line and the horizontal dashed line represents the increase in the rate of energy consumption from the 1985 base year due to increased industrial capacity. The portion of energy consumption rate between the horizontal dashed line and the lower solid line represents the difference from the 1985 base year attributed to the replacement of old unserviceable boilers. The amount of fuel energy

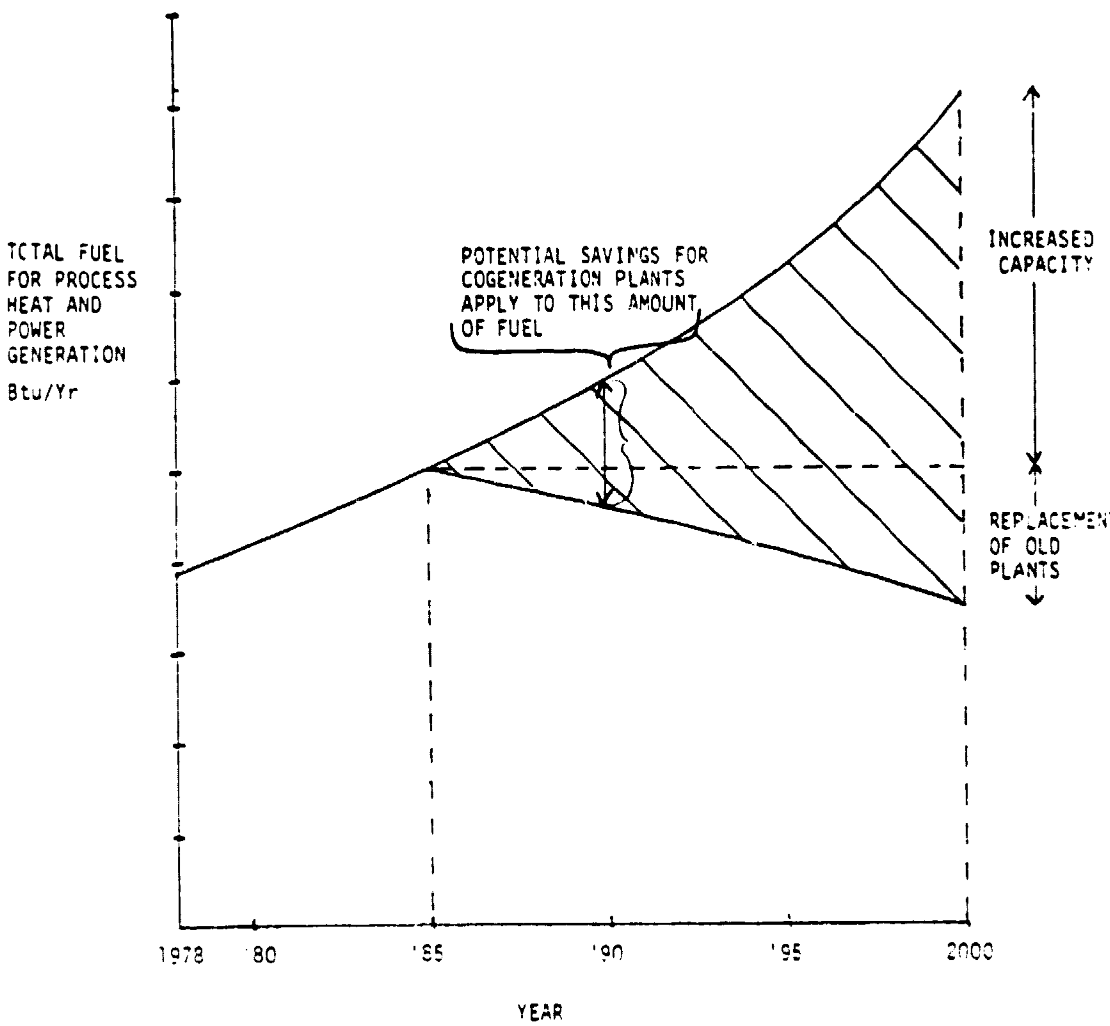

Figure 10-1. Potential Industrial Fuel Use for Process Heat and Power Generation Applicable to Cogeneration

considered here is all of that consumed by industry and utilities in producing the heat and power required by industrial processes. The total yearly rate of fuel energy that cogeneration could be applied to beginning from 1985 is represented by the difference between the two solid curved lines. The solid vertical line shows the amount for the year 1990.

The rate of replacement of old unserviceable industrial boilers was assumed to occur in a compound manner such that the total industrial capacity in 1985 was replaced in thirty years. This results in a compound annual replacement rate of 2.338%. The rate of increase in energy consumption varied by industry. The average annual rate of increase in energy consumption for all CTAS processes was 2.7%. A summary of the total energy consumption (also including the fuel used in generating power at a utility) is given in Table 10-1. Total fuel use is given for the year 1985 and for 2000. That part of the increase which occurs between 1985 and 1990 is also given. Values are given for each of the 4-digit SIC codes that were considered in the CTAS study and the total use for each of the 2-digit SIC codes considered. The fuel use shown for the 2-digit industries includes the 4-digit industries shown and all other 4-digit industries in that category.

The scale factors, M, listed in Table 10-1 were developed in order to convert the savings determined for each of the ECS's when matched to a particular process into a national savings potential for that ECS. They were developed so they could be applied directly to the savings calculated for each CTAS process. The scale factors take into account the processes not covered by CTAS data, the power to heat ratio of these processes and the amount of fuel used in direct heating applications.

SAMPLE CALCULATION

A sample calculation of using this scaling method for determining the national fuel energy saved from the process level is given using the food and kindred products industry, SIC 20 as an example.

Table 10-1

NATIONAL FUEL ENERGY SAVINGS DATA BASE

Process/Sector SIC Code	Scale Factors, M		* Total Direct + Indirect Nocogeneration Fuel Energy, 10^{12} Btu		
	Power	Heat	1985	2000	New Capacity + Replacement, 1985 - 1990
2011	.101	.084	96	168	31.44
2026	.082	.101	80	101	16.20
2046	.153	.119	141	159	23.0
2063	.372	1.052	118	162	27.38
2082	.111	.079	120	190	34.49
20	.099	.046	1688	2372	403.02
2260	.721	.608	75	75	9.19
22	.069	.081	435	435	53.28
2421	.316	.252	300	400	67.0
2436	.361	.529	150	275	51.93
2492	.178	.380	100	172	32.05
24	.079	.046	1093	1684	300.0
2621-2	.118	.107	454	784	146.05
2621-4	.148	.127	441	950	182.6
2621-6	.118	.107	69	128	24.21
2621-7	.078	.152	110	205	38.6
2621-8	.123	.105	191	419	80.61
26	.113	.064	1457	2864	543.7
2812	.041	.055	240	300	47.95
2813	.041	.041	33	66	12.61
2819-1	.046	.061	76	135	25.33
2819-2	.036	.022	229	405	75.93
2821-2	.063	.139	110	160	27.93
2821-3	2.012	2.68	38	60	10.92
2822	.022	.030	9	13	2.28
2824-1	.082	.109	55	75	15.19
2824-2	.041	.054	20	25	4.0
2865-1	.140	.419	65	90	15.4
2865-2	.004	.004	10	15	2.67
2865-3	.066	.139	45	60	10.05
2865-4	.403	1.422	45	65	11.38
2869-1	.108	.299	0	0	0
2869-2	.0403	.040	750	1100	194.16
2869-3	.108	.299	6	11	2.07
2869-4	.140	.419	24	30	4.79
2873	.207	.674	250	305	47.7
2874	.036	.025	48	60	9.59
2895	.021	.029	20	24	3.7
28	.096	.183	2321	3357	586.3
2911-1	.179	.206	580	630	87.18
2911-2	.173	.184	870	950	128.5
2911-3	.166	.154	1250	1280	163.0
29	.186	.155	2887	3058	404.9
32	0	0	1945	2115	
3312-1	.028	.028	643	835	137.0
3325-1	.016	.016	3539	4596	756.0
3325-4	.020	.020	414	538	88.0
3331-1	.002	.002	5.8	9.3	1.7
3331-2	.002	.002	7.8	12.4	2.26
3331-3	.002	.002	5.8	9.3	1.70
3331-4	.013	.013	15.5	24.8	4.53
3331-5	.016	.016	38.8	62.0	11.31
3331-6	.014	.014	23.3	37.2	6.79
3334-1	.015	.015	49.2	86.4	16.18
3334-2	.059	.059	197	346	64.86
3334-3	.074	.074	246	432	80.56
33	.369	.495	6960	9381	1557.0
TOTAL NATIONAL			19901	29858	4548.0

* NOTE: Direct + Indirect Nocogeneration fuel energy refers to industrial fuel consumption for direct process heat (sensible), steam, hot water, and the fuel consumed at a utility to provide for the process electric power needs. Utility conversion efficiency was assumed to be 33% for this data.

There were five processes selected for CTAS in the food and kindred product sector. The 4-digit SIC codes for these processes were:

2011	Meat Packing
2026	Fluid Milk
2046	Wet Corn Milling
2063	Beet Sugar
2082	Malt Beverages

The fuel energy saved ratio, when a given energy conversion system is utilized to provide heat and power, for example, is denoted by

$$FESR_{2011}$$

The scaling factor for the Meat Packing process that scales the contribution of that process to the 2-digit SIC level is M_{2011}, so the Meat Packing process scales to $M_{2011}FESR_{2011}$.

For a given energy conversion system the fuel energy saved ratio for the 2-digit SIC code 20 is calculated from:

$$FESR_{20} = M_{2011}FESR_{2011} + M_{2026}FESR_{2026} + M_{2046}FESR_{2046} + M_{2063}FESR_{2063} + M_{2082}FESR_{2082}$$

The 2-digit SIC fuel energy saved ratios were in turn scaled to give a national fuel energy saved ratio. The national fuel energy saved ratio for a given energy conversion system is

$$FESR_{NATIONAL} = M_{20}FESR_{20} + M_{22}FESR_{22} + M_{24}FESR_{24} + M_{26}FESR_{26} + M_{28}FESR_{28} + M_{29}FESR_{29} + M_{33}FESR_{33}$$

These seven sectors account for over 75% of the total national industrial energy use. The eighth sector considered, SIC 32 (Stone, Clay and Glass), accounts for another 7% but uses no steam from bottoming cycles and so is not included here. The remaining fuel use is assumed to scale in the same ratio as these so that the national fuel energy saved ratio and the national industrial fuel use rate attributable to new capacity and replacement capacity for the period beginning in 1985 to 1990 combine to give:

$$FES_{NATIONAL} = FESR_{NATIONAL}(\text{National Industrial Fuel Energy Use})$$

The type of fuel used for these calculations was assumed to be coal or coal derived wherever possible. The state-of-the-art gas turbine and state-of-the-art diesel were assumed to burn petroleum derived fuel. Utility fuel displaced here was assumed to be coal.

The methodology and derivation of the scaling factors was developed by General Energy Associates, Inc. Additional detail is given in the Appendix of this section.

NATIONAL FUEL ENERGY SAVED

National fuel energy saved by fuel type for selected energy conversion systems is summarized in Figures 10-2 and 10-3. Heat match cases are presented in Figure 10-2 and power match cases are presented in Figure 10-3. The fuel energy saved for the year 1990 is given in units of quads/year, where a quad is defined as 10^{15} Btu. Negative savings for oil and gas, of course, means increased use of these fuels. The savings for each ECS type assumes that each ECS is used exclusively wherever applicable in cogeneration systems. Nineteen ECS's were selected as representative of all the various ECS's considered. The four on the left are currently available state-of-the-art systems. The fifteen advanced systems represent various levels of development. In both the current and advanced systems those

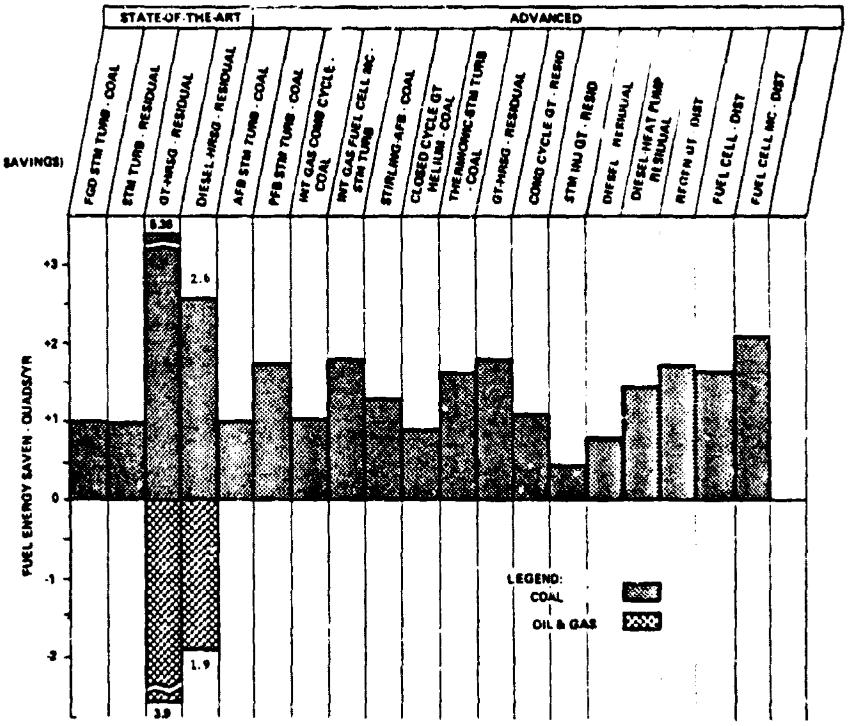

Figure 10-2. Potential for National Fuel Energy Saved by Fuel and ECS Type in 1990 (Heat Match)

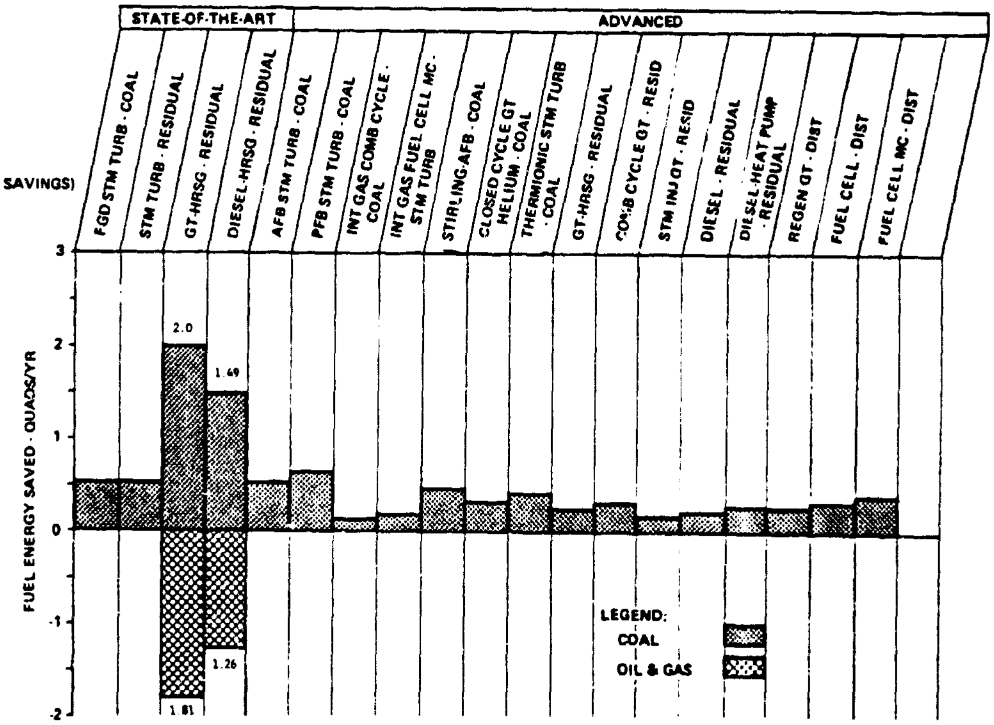

Figure 10-3. Potential for National Fuel Energy Saved by Fuel and ECS Type in 1990 (Power Match)

utilizing coal are shown on the left, then residual fuel, with advanced systems utilizing distillate on the right. The advanced systems utilizing residual and distillate fuels were assumed to utilize fuels derived from coal in 1990. It was assumed that the current gas turbine and diesel systems using residual fuel would continue to require petroleum derived residual in 1990.

A more complete set of data for all ECS's is given in Table 10-2 which is taken from Computer Report 6.1 in Volume VI.

In comparing Figure 10-2 with 10-3, it is apparent that more fuel energy can be saved in all cases for heat matches than for power matches. In the heat match cases much more power is generated than used in the industry and the excess is exported and sold to the utility. Therefore, even with current state-of-the-art systems if maximum benefits are to be obtained from cogeneration, it will be necessary to make provisions for exporting and selling power to the utilities. An alternative to this could be utility ownership of the cogeneration plant. The effect of this export power on utilities was not examined but some of the factors to be considered are the effects on the utility load factor, peaking, intermediate and baseload power requirements, standby power, growth rates, and above all the economics of the remaining electric power generation.

NATIONAL EMISSIONS SAVED

The national emissions saved were calculated in a somewhat similar manner. The emission savings were calculated on a per plant basis and ratioed to a 2-digit SIC level and to a national level based on appropriate conversions from the fuel energy saved ratios and scale factors.

The national emissions saved per year in 1990 for the same selected ECS's are given in Figure 10-4 for the heat matches and in Figure 10-5 for the power matches. The emissions saved for the year 1990 are given in units of million tons/year. A more complete set of data is given in Table 10-2.

Table 10-2

NATIONAL FUEL ENERGY SAVED REPORT WITH ECONOMIC CONSTRAINTS

DATE 04/24/79
ISE PEU AES
FUEL UNITS = Quads/yr
EMISSION UNITS= 10^3 Tons/yr
COST =$*10**9

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

(SAVINGS ARE POSITIVE)

TYPE MATCH=HEAT

PROCS	ECS	ECS FUEL	*****F U E L ****DIRECT***** OIL+GAS	COAL	S A V I N G S**** ----TOTAL---- OIL+GAS	COAL	FESR	- - - E M I S S I O N S ------DIRECT------- NOX	SOX	PART	S A V I N G S - - - ********TOTAL******** NOX	SOX	PART	EMSR	CAPITL SAVING $\$10^9$	--ELECTRIC POWER--- TOTAL EXPORT $MWH\times10^6$	SVNG $\$10^6$	LAEC SAVED $\$10^6$
ALL	SIMI41	COAL-A	0.031	-0.479	0.347	0.578	0.17	358.	-275.	-22.	800.	477.	60.	0.34	14.	38.	193.	3062.
ALL	SIMI41	COAL-F	0.035	-0.421	0.318	0.527	0.16	-162.	-239.	-19.	235.	435.	55.	0.18	4.	28.	175.	1906.
ALL	SIMI41	RESIDU	-0.583	0.437	-0.464	0.836	0.07	-75.	29.	-7.	87.	295.	0.	0.28	9.	12.	110.	991.
ALL	SIMO88	COAL-A	0.020	-0.282	0.209	0.350	0.11	274.	-161.	-13.	538.	288.	36.	0.30	10.	15.	138.	2011.
ALL	SIMO88	COAL-F	0.020	-0.281	0.208	0.349	0.10	-135.	-161.	-13.	128.	287.	36.	0.14	3.	15.	137.	1153.
ALL	SIMO88	RESIDU	-0.490	0.390	-0.394	0.710	0.06	-61.	38.	-5.	69.	251.	0.	0.26	8.	7.	211.	623.
ALL	PFBSIM	COAL-P	0.042	-1.058	0.610	0.843	0.27	1094.	-618.	137.	1889.	733.	285.	0.46	11.	97.	204.	2472.
ALL	TIHRSG	RESIDU	-0.011	0.008	-0.009	0.013	0.00	-3.	0.	-0.	-1.	4.	-0.	0.02	0.	0.	1.	74.
ALL	STIRL	COAL	0.018	-0.379	0.165	0.119	0.05	-137.	-220.	-18.	71.	133.	21.	0.20	0.	22.	42.	413.
ALL	STIRL	DISTIL	-0.018	0.006	-0.013	0.023	0.00	-2.	-0.	0.	4.	11.	2.	0.26	1.	0.	3.	97.
ALL	STIRL	RESIDU	-0.339	0.180	-0.273	0.399	0.02	-61.	-28.	-16.	27.	118.	-13.	0.15	2.	0.	14.	196.
ALL	HECT60	COAL-A	0.	-0.018	0.005	-0.000	0.00	-1.	-11.	-1.	6.	2.	0.	0.16	-0.	0.	0.	3.
ALL	HECT00	COAL-A	0.	-0.034	0.010	-0.000	0.00	-1.	-21.	-2.	13.	4.	1.	0.17	-0.	1.	1.	3.
ALL	FCMCCL	COAL	0.	-0.155	0.074	0.091	0.03	63.	109.	8.	166.	284.	27.	0.97	0.	16.	5.	161.
ALL	FCSTCL	COAL	0.001	-0.427	0.188	0.201	0.07	92.	162.	12.	354.	607.	60.	0.98	2.	50.	7.	301.
ALL	IGGTST	COAL	0.	-0.388	0.137	0.070	0.04	-136.	-233.	11.	56.	92.	46.	0.25	1.	39.	7.	171.
ALL	GTSOAR	RESIDU	-0.428	0.198	-0.333	0.516	0.03	-36.	-42.	6.	97.	184.	31.	0.39	4.	5.	17.	332.
ALL	GTAC08	RESIDU	-0.453	0.265	-0.361	0.574	0.04	-168.	-22.	-19.	-43.	184.	-14.	0.15	4.	9.	16.	366.
ALL	GTAC12	RESIDU	-0.483	0.254	-0.372	0.625	0.05	-191.	-41.	-22.	-40.	208.	-13.	0.18	5.	13.	18.	416.
ALL	GTAC16	RESIDU	-0.457	0.221	-0.345	0.595	0.05	-189.	-50.	-22.	-36.	202.	-12.	0.18	5.	11.	19.	447.
ALL	GTWC16	RESIDU	-0.473	0.212	-0.360	0.589	0.04	-198.	-62.	-24.	-44.	192.	-14.	0.16	5.	10.	17.	397.
ALL	CC1626	RESIDU	-0.485	0.169	-0.350	0.619	0.05	-222.	-93.	-27.	-38.	213.	-12.	0.19	5.	10.	15.	493.
ALL	CC1622	RESIDU	-0.464	0.175	-0.335	0.606	0.05	-209.	-81.	-25.	-32.	211.	-11.	0.19	5.	10.	17.	490.
ALL	CC1222	RESIDU	-0.487	0.186	-0.352	0.639	0.05	-216.	-83.	-26.	-31.	224.	-11.	0.21	5.	14.	17.	480.
ALL	CC0822	RESIDU	-0.476	0.219	-0.352	0.635	0.05	-197.	-59.	-24.	-26.	222.	-11.	0.21	5.	16.	16.	434.
ALL	STIG10	RESIDU	-0.081	0.006	-0.058	0.083	0.00	-40.	-29.	-3.	-8.	23.	-0.	0.05	1.	0.	13.	89.
ALL	STIG15	RESIDU	-0.132	0.029	-0.099	0.140	0.01	-65.	-35.	-3.	-19.	39.	0.	0.08	1.	0.	9.	140.
ALL	DEADV3	RESIDU	-0.131	0.028	-0.095	0.150	0.01	-99.	-35.	-8.	-50.	47.	-4.	-0.13	1.	1.	11.	60.
ALL	DEHTPM	RESIDU	-0.196	0.094	-0.147	0.257	0.02	-158.	-22.	-10.	-92.	88.	-6.	-0.04	1.	2.	13.	176.
ALL	GTSOAD	DISTIL	-0.345	0.144	-0.262	0.421	0.03	-12.	22.	7.	102.	210.	16.	0.36	4.	0.	36.	303.
ALL	GTRA08	DISTIL	-0.130	0.047	-0.095	0.162	0.01	-31.	-8.	0.	17.	74.	9.	0.36	2.	0.	7.	116.
ALL	GTRA12	DISTIL	-0.125	0.047	-0.092	0.159	0.01	-30.	-7.	0.	17.	73.	9.	0.36	2.	0.	7.	129.
ALL	GTRA16	DISTIL	-0.071	0.029	-0.053	0.090	0.01	-16.	-2.	0.	10.	41.	5.	0.34	1.	0.	5.	110.
ALL	GTR208	DISTIL	-0.105	0.046	-0.079	0.131	0.01	-22.	-1.	1.	13.	59.	7.	0.29	1.	0.	5.	121.
ALL	GTR212	DISTIL	-0.109	0.046	-0.082	0.137	0.01	-24.	-2.	1.	14.	62.	8.	0.30	1.	0.	6.	122.
ALL	GTR216	DISTIL	-0.160	0.068	-0.120	0.201	0.02	-34.	-4.	1.	22.	91.	11.	0.33	2.	0.	7.	134.
ALL	GTRW08	DISTIL	-0.044	0.014	-0.033	0.052	0.00	-11.	-4.	-0.	5.	23.	3.	0.40	1.	0.	6.	76.
ALL	GTRW12	DISTIL	-0.091	0.029	-0.067	0.111	0.01	-23.	-8.	-0.	11.	50.	6.	0.40	1.	0.	7.	98.
ALL	GTRW16	DISTIL	-0.060	0.021	-0.045	0.073	0.01	-14.	-4.	0.	9.	32.	4.	0.38	1.	0.	6.	89.
ALL	GTR312	DISTIL	-0.091	0.034	-0.069	0.108	0.01	-20.	-5.	0.	11.	48.	6.	0.34	2.	0.	9.	187.

Table 10-2 (Cont'd)

NATIONAL FUEL ENERGY SAVED REPORT WITH ECONOMIC CONSTRAINTS (Cont'd)

DATE 04/24/79
ISE PEO AES
FUEL UNITS = Quads/yr
EMISSION UNITS = 10^3 Tons/yr
COST = $*10**9

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

(SAVINGS ARE POSITIVE)

TYPE MATCH=HEAT

			*****F U E L	S A V I N G S****				- - - E M I S S I O N S	S A V I N G S - - -						CAPITL	—ELECTRIC POWER—		
			****DIRECT*****		——TOTAL——		FESR	———DIRECT———			********TOTAL********			EMSR	SAVING	TOTAL	SVNG	LAEC
PROGS	ECS	ECS FUEL	OIL+GAS	COAL	OIL+GAS	COAL		NOX	SOX	PART	NOX	SOX	PART		$10^9	EXPORT MWHx10^6	$10^6	SAVED $10^6
ALL	GTR316	DISTIL	-0.054	0.021	-0.041	0.065	0.00	-12.	-3.	0.	7.	29.	4.	0.33	1.	0.	5.	94.
ALL	FCMCDS	DISTIL	-0.034	0.008	-0.024	0.040	0.00	-7.	-5.	-0.	7.	18.	2.	0.16	1.	0.	10.	82.
ALL	STM141	COAL-A	0.	-0.106	0.104	0.244	0.07	127.	-63.	-5.	273.	185.	22.	0.34	2.	0.	117.	806.
ALL	STM141	COAL-F	0.	-0.087	0.053	0.090	0.03	-44.	-52.	-4.	30.	74.	9.	0.15	1.	0.	16.	403.
ALL	STM141	RESIDU	-0.266	0.237	-0.215	0.407	0.04	-10.	36.	-1.	59.	48.	1.	0.38	6.	0.	101.	792.
ALL	STM088	COAL-A	0.	-0.035	0.021	0.036	0.01	76.	-21.	-2.	106.	30.	4.	0.28	0.	0.	24.	85.
ALL	STM088	COAL-F	0.	-0.028	0.017	0.029	0.01	-10.	-17.	-1.	14.	24.	3.	0.11	-0.	0.	17.	34.
ALL	TISTMT	COAL	0.	-0.132	0.078	0.128	0.04	142.	-79.	7.	251.	106.	27.	0.33	1.	0.	12.	550.
ALL	STIRL	COAL	0.	-0.202	0.082	0.074	0.03	-71.	-121.	-10.	44.	75.	11.	0.11	-C.	0.	28.	308.
ALL	HEGT60	COAL-A	-0.171	0.115	-0.154	0.172	0.00	1.	0.	-3.	23.	36.	-5.	0.25	2.	0.	21.	4.
ALL	HEGT00	COAL-A	0.	-0.099	0.028	-0.004	0.00	33.	-59.	-5.	72.	8.	2.	0.22	-0.	0.	2.	42.
ALL	FCMCCL	COAL	0.	-0.057	0.028	0.037	0.01	25.	43.	3.	64.	100.	10.	0.46	-0.	0.	3.	93.
ALL	FCSTCL	COAL	0.	-0.085	0.044	0.062	0.02	24.	45.	3.	86.	149.	15.	0.44	-1.	0.	7.	105.
ALL	IGGTST	COAL	0.	-0.099	0.040	0.036	0.01	-35.	-60.	4.	22.	37.	15.	0.12	-0.	0.	6.	133.
ALL	GTS0AR	RESIDU	-0.465	0.262	-0.408	0.452	0.01	34.	-18.	9.	114.	117.	24.	0.56	5.	0.	85.	101.
ALL	GTAC08	RESIDU	-0.398	0.220	-0.351	0.378	0.00	-70.	-27.	-10.	-7.	73.	-13.	0.26	5.	0.	79.	130.
ALL	GTAC12	RESIDU	-0.456	0.266	-0.398	0.460	0.01	-77.	-23.	-11.	1.	101.	-14.	0.24	5.	0.	87.	222.
ALL	GTAC16	RESIDU	-0.500	0.270	-0.429	0.500	0.02	-106.	-38.	-14.	-10.	117.	-16.	0.24	6.	0.	95.	225.
ALL	GTMC16	RESIDU	-0.459	0.262	-0.399	0.463	0.01	-83.	-26.	-11.	-2.	102.	-14.	0.21	5.	0.	88.	170.
ALL	CC1626	RESIDU	-0.647	0.315	-0.541	0.669	0.02	-161.	-70.	-21.	-18.	162.	-20.	0.14	7.	0.	106.	207.
ALL	CC1622	RESIDU	-0.582	0.308	-0.491	0.615	0.02	-132.	-48.	-17.	-9.	152.	-17.	0.22	6.	0.	111.	218.
ALL	CC1222	RESIDU	-0.581	0.308	-0.489	0.615	0.02	-132.	-47.	-17.	-8.	153.	-16.	0.22	7.	0.	111.	248.
ALL	CC0822	RESIDU	-0.454	0.267	-0.393	0.473	0.02	-77.	-21.	-10.	6.	111.	-13.	0.25	5.	0.	91.	170.
ALL	STIG15	RESIDU	-0.189	0.004	-0.138	0.175	0.01	-67.	-74.	-9.	3.	42.	-4.	0.19	3.	0.	92.	197.
ALL	STIG10	RESIDU	-0.394	0.175	-0.335	0.374	0.01	-87.	-53.	-10.	-7.	77.	-11.	0.08	5.	0.	106.	207.
ALL	STIG15	RESIDU	-0.345	0.168	-0.298	0.325	0.01	-75.	-37.	-8.	-12.	64.	-10.	0.09	5.	0.	90.	181.
ALL	DEADV3	RESIDU	-0.136	0.006	-0.100	0.127	0.01	-58.	-51.	-7.	-8.	31.	-3.	-0.12	1.	0.	70.	23.
ALL	DEHTPM	RESIDU	-0.098	0.061	-0.080	0.120	0.01	-40.	-3.	-3.	-16.	37.	-2.	0.10	C.	0.	6.	8.
ALL	GTS0AD	DISTIL	-0.302	0.	-0.223	0.262	0.01	-20.	-81.	-1.	88.	100.	13.	0.62	4.	0.	177.	135.
ALL	GTRA08	DISTIL	-0.117	0.	-0.087	0.101	0.00	-27.	-33.	-2.	15.	39.	6.	0.49	2.	0.	68.	50.
ALL	GTRA12	DISTIL	-0.117	0.	-0.087	0.101	0.00	-27.	-33.	-2.	15.	39.	6.	0.49	2.	0.	68.	58.
ALL	GTRA16	DISTIL	-0.120	0.	-0.090	0.101	0.00	-28.	-34.	-2.	15.	38.	6.	0.48	2.	0.	68.	30.
ALL	GTR208	DISTIL	*******	0.	**************		-0.00	-0.E 36	-0.E 36	-0.E 35	0.E 36	0.E 36	0.E 35	0.43	0.E 35	0.	0.E 36	0.E 36
ALL	GTR212	DISTIL	-0.127	0.	-0.097	0.101	0.00	-29.	-36.	-2.	13.	36.	6.	0.45	2.	0.	68.	20.
ALL	GTR216	DISTIL	-0.124	0.	-0.094	0.101	0.00	-29.	-35.	-2.	14.	37.	6.	0.46	2.	0.	68.	27.
ALL	GTRM08	DISTIL	-0.113	0.	-0.089	0.101	0.00	-27.	-34.	-2.	15.	39.	6.	0.48	2.	0.	68.	32.
ALL	GTRM12	DISTIL	-0.115	0.	-0.085	0.101	0.00	-26.	-32.	-2.	16.	39.	6.	0.50	2.	0.	68.	52.
ALL	GTR308	DISTIL	-0.121	0.	-0.090	0.104	0.00	-28.	-34.	-2.	16.	40.	6.	0.50	2.	0.	70.	31.
ALL	GTR312	DISTIL	-0.122	0.	-0.092	0.101	0.00	-28.	-34.	-2.	14.	37.	6.	0.47	2.	0.	68.	35.
ALL	GTR316	DISTIL	-0.124	0.	-0.093	0.101	0.00	-28.	-35.	-2.	14.	37.	6.	0.46	2.	0.	68.	17.
ALL	FCPADS	DISTIL	-0.110	0.	-0.080	0.101	0.01	-25.	-31.	-2.	17.	41.	5.	0.52	2.	0.	68.	8.
ALL	FCMCDS	DISTIL	-0.102	0.	-0.072	0.101	0.01	-23.	-29.	-2.	19.	43.	6.	0.56	2.	0.	68.	49.

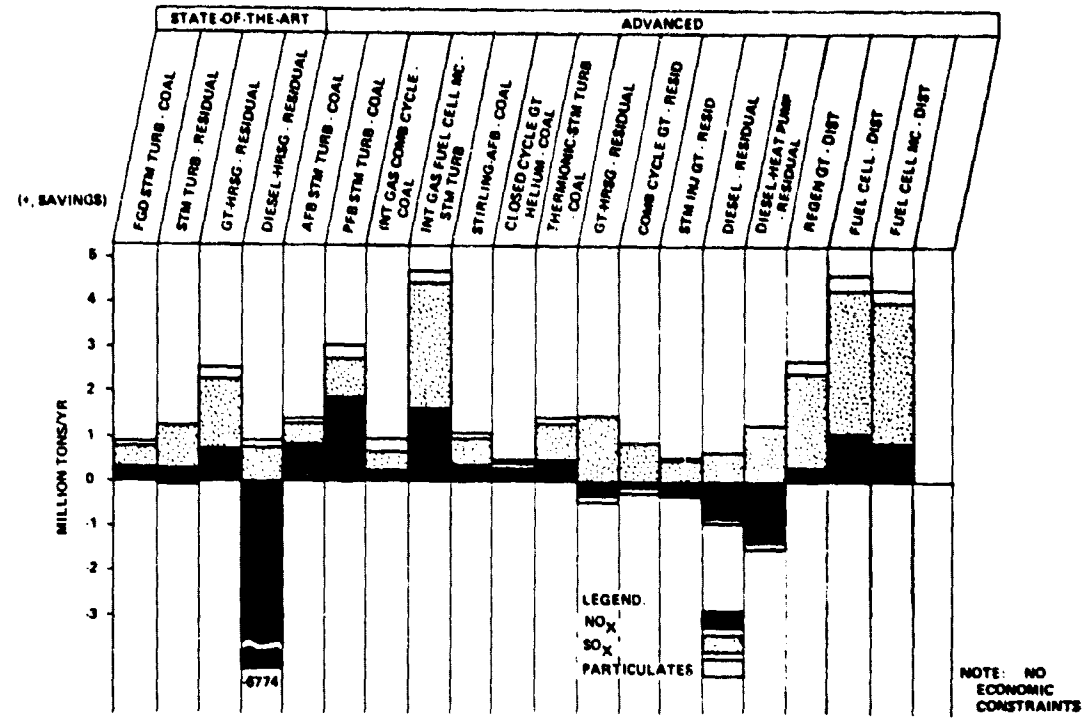

Figure 10-4. Potential for National Emissions Saved by Fuel and ECS Type in 1990 (Heat Match), Coal Nocogeneration Case

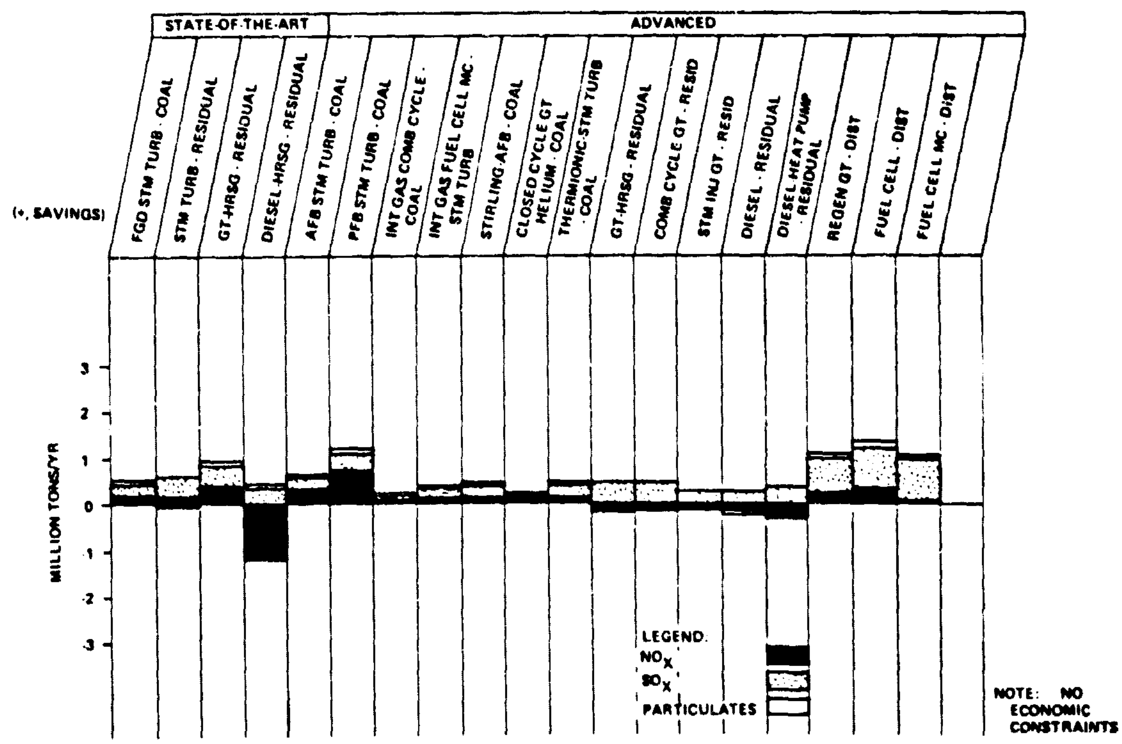

Figure 10-5. Potential for National Emissions Saved by Fuel and ECS Type in 1990 (Power Match), Coal Nocogeneration Case

As with fuel energy saved, more emissions are saved with heat matches than with power matches. Diesel engines as currently used without emission scrubbing equipment were assumed in this study in order to determine the effect of these diesel engines on the environment. As expected, the emissions of NO_x would increase significantly unless NO_x scrubbers are used to bring their level of NO_x emissions down to the required specifications. Several systems would increase the level of particulate emissions, somewhat, but all systems as assumed in this study would decrease the level of SO_2 emissions.

LEVELIZED ANNUAL ENERGY COST SAVINGS

Up to this point the fuel energy and emission savings have been shown for all systems without regard for economics. One of the economic factors discussed in Section 9 is the levelized annual energy cost (LAEC). This is an annual charge, levelized for equal amounts every year for a 30-year period, that would pay for supplying the total amount of energy used by the industry for that period. Levelized annual energy cost saving (LAECS) is the difference between that cost with cogeneration and the cost without cogeneration. A positive saving occurs when the cost with cogeneration is less than without.

Many of the matches between particular industries and ECS's result in large savings in fuel use. The totals of all these fuel savings for each ECS was given in Figures 10-2 and 10-3. Of those matches, however, many of them had a higher annual energy cost than without cogeneration because of the cost of equipment or the cost of operation. While those matches saved fuel it is not reasonable to include them because no industry would be willing to pay the added costs. The potential national fuel energy savings shown in Figures 10-6 and 10-7, for heat and power matches, are based on only matches that result in a levelized annual charge for energy that is no greater than that for the no-cogeneration case (LAECS ≥ 0). The levelized annual energy cost savings that result from these matches are given in Figures 10-8 and 10-9 for the heat and power matches, respectively.

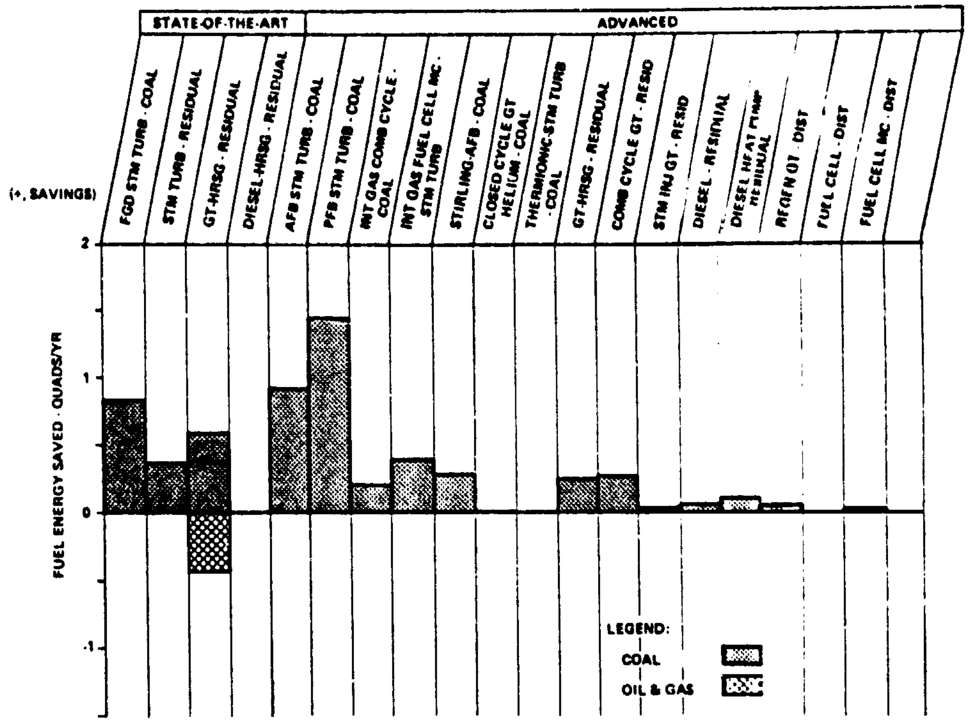

Figure 10-6. Potential for National Fuel Energy Saved by Fuel and ECS Type in 1990 (Heat Match and LAECS ≥ 0)

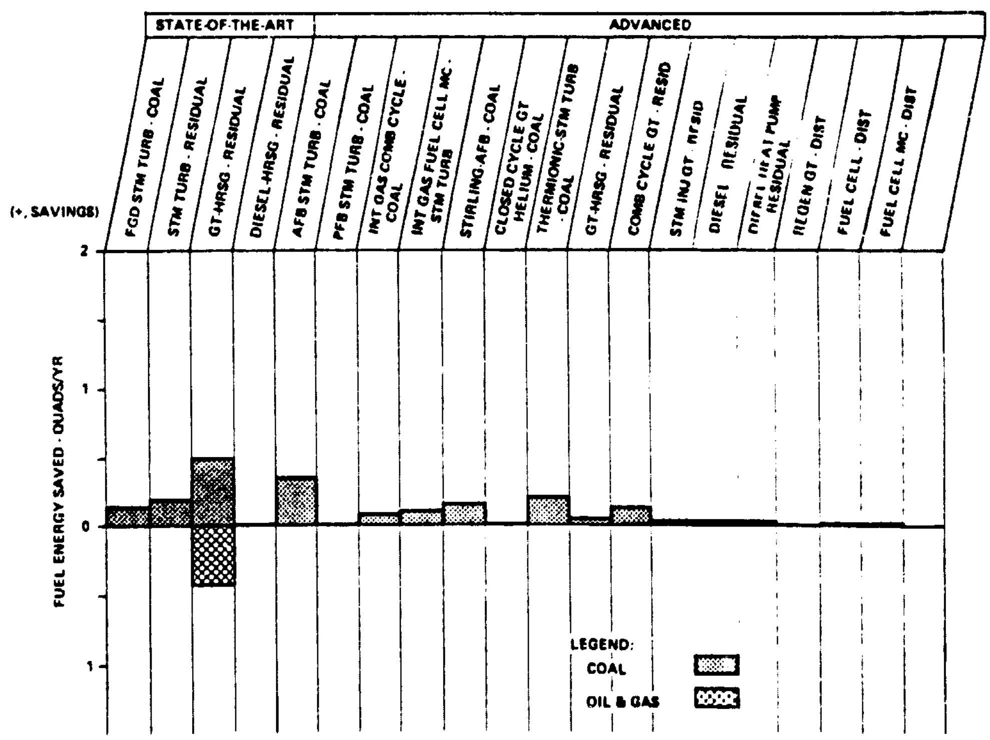

Figure 10-7. Potential for National Fuel Energy Saved by Fuel and ECS Type in 1990 (Power Match and LAECS ≥ 0)

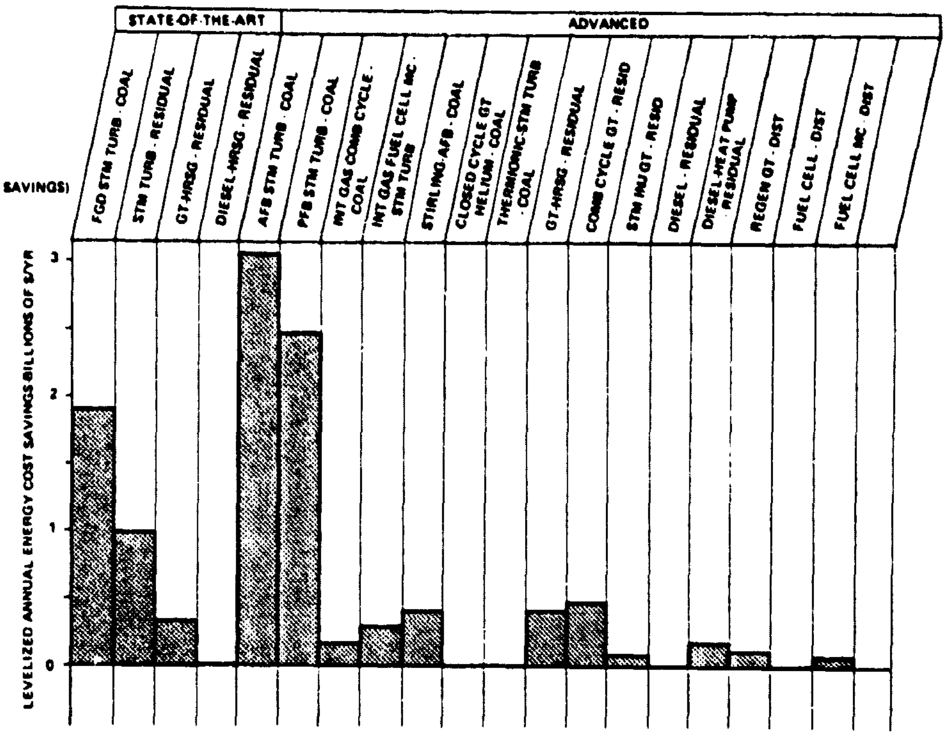

Figure 10-8. Potential for National Levelized Annual Energy Cost Savings in 1990 (Heat Match and LAECS $\geq$ 0)

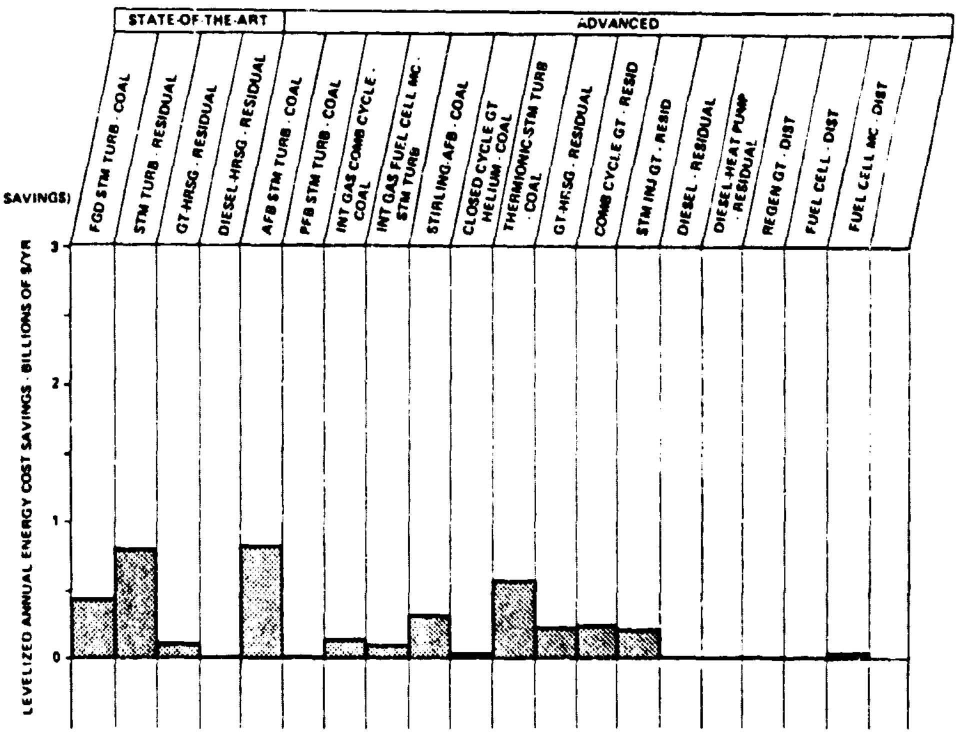

Figure 10-9. Potential for National Levelized Annual Energy Cost Savings in 1990 (Power Match and LAECS $\geq$ 0)

For many of the ECS's, particularly the advanced systems that are also expensive, the national fuel saving decreases substantially. Three systems, all using steam turbines and burning coal, show the best savings in LAECS and have the least decrease in fuel energy saved when restricted to positive savings in annual energy costs. These three systems are the current coal fired boiler and steam turbine with flue gas desulfurization, the atmospheric fluidized bed boiler, steam turbine and gas turbine. As before, the heat matches with export of power show much larger savings in both fuel energy and annual energy costs.

CHARACTERISTICS OF NATIONAL AND INDUSTRIAL STEAM AND ELECTRIC POWER DEMAND

The methodology described and used here on National Considerations is complex and obscures the reasons why the national fuel savings, emissions, and economics of the various cogeneration technologies give the national results presented. Each ECS was employed separately (without competition from others) in all CTAS processes. An understanding of the characteristics of the steam and electric power requirements of the national population of industrial processes is needed to generalize the results from a process basis to a national basis. It was established extensively in Section 8 that the process power to heat ratio is very influential on fuel energy savings realizable with the various cogeneration technologies. The process power to heat ratio also influences the economic choice of cogeneration technology for a given fuel type and process temperature. All of the cogeneration technologies studied were employed in the production of steam and electric power. Therefore, a distribution of national industrial fuel energy consumption for steam and electric power versus power to heat ratio will give insight as to the national impact of various cogeneration technologies. The potential application of cogeneration systems to industry can be more closely focused on by considering situations where industry will have to make a choice between cogeneration or nocogeneration in the 1985 - 1990 time period. This will probably occur in the following situations:

- New plant construction or capacity additions
- Replacement of old unserviceable process boilers
- Changeout of existing serviceable boilers due to future non-availability of current fuel type (such as gas-coal conversions due to legal requirements)

CTAS processes are representative of the eight industrial sectors that consume 85% of industrial energy and therefore are representatives of most of U.S. industry where cogeneration of steam and electric power has potential.

Table 10-3 presents the distribution and cumulative percent of energy consumption rate for CTAS processes for steam and electric power. The energy consumption rate is only that attributable to new capacity projected to be installed between 1985 and 1990 and replacement of capacity in existence in 1985 at a 2.3% rate. The table shows that 74.68% of the energy is consumed by industrial processes with a power to heat ratio of 0.25 or less. Also, note that 65.87% of the energy is consumed by industrial processes with power to heat ratios between 0.1 and 0.25. Energy conversion systems that have good performance, fuel flexibility, and economics when applied to industrial processes with power to heat ratios from 0.1 to 0.25, will have the largest impact on fuel energy and emission savings from a national implementation standpoint.

Table 10-3

DISTRIBUTION OF CTAS PROCESS ENERGY CONSUMPTION RATE FOR STEAM AND ELECTRIC POWER IN 1990

Process Ratio of Power To Heat		% of CTAS Process Energy for Steam & Electric Power	Cumulative %
$\frac{Btu/hr}{Btu/hr}$	$\frac{KW}{10^6\ Btu/hr}$		
0 - 0.05	0 - 14.7	6.18	6.18
0.05 - 0.1	14.7 - 29.3	2.63	8.81
0.1 - 0.15	29.3 - 44.0	39.97	48.78
0.15 - 0.20	44.0 - 58.6	11.5	60.28
0.20 - 0.25	58.6 - 73.3	14.4	74.68
0.25 - 0.30	73.3 - 87.9	2.09	76.77
0.30 - 0.60	87.9 - 175.8	5.28	82.05
0.60 - 1.0	175.8 - 293.0	.92	82.97
1.0 - 1.5	293.0 - 439.5	11.12	94.09
>1.5	>439.5	5.91	100.00

Note: Energy consumption rate data used to compile this table is for that attributable to the production of process steam and electric power for CTAS processes due to new capacity and replacement capacity (at 2.338% (a 30-year replacement rate) of that in place in 1985) for the period 1985 - 199C.

Section 11

RESULTS AND OBSERVATIONS

BACKGROUND

The objective of the Cogeneration Technology Alternatives Study (CTAS) is to determine the advantages of advanced relative to current industrial cogeneration systems and to evaluate and compare the advanced technologies in order to identify those justifying major research and development effort.

In CTAS the performance, emission, and cost characteristics of advanced technology cogeneration steam turbine-fluidized bed boiler, open and closed-cycle gas turbines, combined-cycle, thermionic, stirling, diesel, phosphoric acid fuel cell, and molten carbonate fuel cell energy conversion systems (ECS's) judged to be available in the 1985 to 2000 year time frame were consistently defined for comparison with currently available steam turbine-boilers, open-cycle gas turbines, and diesels. These ECS's were matched to the electric power or steam requirements of over 50 specific industrial processes selected from the food; paper and pulp; chemical; petroleum refining; stone, clay and glass; and primary metals groups. The resulting cogeneration systems were evaluated for their fuel, emissions, and cost of energy saved compared to both a coal-fired or residual-fired boiler nocogeneration system defined for each industrial process. In addition, the return on investment to the industrial owner was calculated using the nocogeneration system as a base case. These data permitted a comparison of advanced technology and currently available ECS's in a wide range of specific industrial process and their relative advantages with and without the export of power to the utility grid.

To determine the effect on comparison of systems 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 ECS was assumed implemented without competition and its national fuel savings, emissions reduction, and energy cost savings estimated. In this calculation it was assumed that the total savings possible were due to implementing the cogeneration ECS in new plants added because of needed growth in capacity, or to replace old unserviceable process boilers in the period from 1985 to 1990. National fuel savings, emissions reduction, and energy cost savings were compared for advanced and currently available cogeneration systems to determine those advanced systems which indicated the greatest potential benefit.

To achieve the level of performance estimated for these attractive advanced technology systems, the significant advanced developments required were identified.

RESULTS AND OBSERVATIONS

The comparison of the various cogeneration systems required that an economic criteria for implementation by industry be established since those systems providing the highest fuel savings often had high capital costs and low returns on investment. Attractive cogeneration systems for industrial ownership were identified using the following criteria: the system would have a return on investment greater than 10% before inflation, a capital cost which is less than two and one half times the capital cost of the nocogeneration coal-fired process boiler and a fuel energy saved ratio of 0.15 or greater.

In Tables 11-1 and 11-2 the intersection of an energy conversion system with an industrial process represents a power or heat matched cogeneration system. Those matches meeting the above criteria are shown cross hatched and those shown as solid black exceed the criteria by having a fuel energy saved ratio equal to or greater than 0.25. The reason for a cogeneration system not meeting these criteria is shown by noting which

Table 11-1

SUMMARY OF DESIRABLE CHARACTERISTICS OF COGENERATION SYSTEMS FOR SELECTED INDUSTRIAL PROCESS

POWER MATCH

Legend:

- Return on Investment ≥ 10% — o (upper corner)
- $\frac{\text{Cogeneration Capital Cost}}{\text{Nocogeneration Capital Cost}} \le 2.5$ — o (lower corner)
- Fuel Energy Saved Ratio ≥ .15 — o
- Fuel Energy Saved Ratio ≤ .25 — x
- Meets Minimum Criteria — ▨
- Meets Minimum Criteria Plus Fuel Energy Saved Ratio ≥ .25 — ■
- Match not practical because excess heat produced or process requires higher temperature process steam than can be supplied. — ---
- Does not meet any of the criteria — (blank)

	STATE-OF-THE ART				ADVANCED															
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - DIST	FUEL CELL MC - DIST	
MEAT PACKING	x	o x	o o o	o o o	x	x	o	o	o		x	o o	o o	o	o o	o	o o	o o	o o	
MALT BEVERAGES	o o	o o	o o	o o	▨	o o	o	o	o o		o	▨	o o	o	o o	o o	o o	o o	o o	
BLEACHED KRAFT PAPER	---	---	▨	o	---	■	o	o	▨	o	x	■	▨	o	o o	o x	o o	o o	o o	
THERM-MECH PULPING	---	---	■	o o	---	---	x	x	---	---	---	■	■	o o	o o	■	o x	o o	o x	
INTEGRATED CHEMICAL	---	---	▨	o	---	---	▨	■	o o	o o	x	■	▨	o o	o o	o x	o o	o o	o o	
CHLORINE	---	---	---	o	---	---	---	---	---	---	---	---	---	▨	x	---	---	x	x	
NYLON	---	---	---	x	---	---	---	---	---	---	---	---	---	o	---	---	---	x	x	
PETRO-REFINING	▨	o o	o	---	▨	▨	o o	o o	o o	o	o o	o	o	---	---	o	o	o o	o	
INTEGRATED STEEL	---	---	---	o	---	---	---	---	---	---	---	---	---	---	x	---	---	o	x	
COPPER	---	---	---	o o	---	---	---	x	---	---	---	---	■	o o	o o	---	---	o o	o x	
ALUMINA	o o	o	o	---	o o	o o	o	o	o	o	o	o	o	---	---	o	o	o o	o o	

Table 11-2

SUMMARY OF DESIRABLE CHARACTERISTICS OF COGENERATION SYSTEMS FOR SELECTED INDUSTRIAL PROCESS HEAT MATCH

Legend

- Return on Investment ≥ 1[illegible]% → o (upper left corner of box)
- $\frac{\text{Cogeneration Capital Cost}}{\text{Noncogeneration Capital Cost}}$ ≤ 2.5 → o (upper right corner of box)
- Fuel Energy Saved Ratio ≥ .15 → o (lower left corner of box)
- Fuel Energy Saved Ratio ≥ .25 → x
- Meets Minimum Criteria → hatched box
- Meets Minimum Criteria Plus Fuel Energy Saved Ratio ≥ .25 → black box
- Match not practical because excess heat produced or process requires higher temperature process steam than can be supplied. → ---
- Does not meet any of the criteria → empty box

	STATE-OF-THE ART				ADVANCED															
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - DIST	FUEL CELL MC - DIST	
MEAT PACKING	x	o x	x	x	x	x	x	x	x		x	o x	x	o	x	x	x	x	x	
MALT BEVERAGES			o x	o x		o x	x	x	x		x	o x	o x	o	o x	o x	o x	o x	x	
BLEACHED KRAFT PAPER				x			o	x	x	o	x			o o	x	x	x	x	x	
THERM-MECH PULPING	o o	o		x	o o		o x	x			x			o	x	x	x	x	x	
INTEGRATED CHEMICAL		o o	o x	x			o x	o x	o x	o o	x		o x	o	x	x	x	x	x	
CHLORINE	o o	o o		x	o o	o o	o o	o x	o		o			o	x			x	x	
NYLON		o o	o o	x	o		o	x	o		o		o x	o	x	o	o	x	x	
PETRO-REFINING		o o	o x	---			o x	o x	o	o	x	o x	o x	---	---	x	o x	x	x	
INTEGRATED STEEL	o o	o o	o o	o	o o	o o		o o	o	o	o	o o		---	x	o		x	x	
COPPER	o o	o o		x	o o	o o	o	x			o			o	x		o x	x	x	
ALUMINA		o o	o x	---			x	x	o		x	o x	o x	---	---	x	o x	x	x	

"O's" or "X's" are missing from the rectangle representing the cogeneration system match. Based on study results including Tables 11-1 and -2, the following observations on the various types of cogeneration systems were made:

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 temperatures.

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.

The national savings calculated by implementing each type cogeneration energy conversion system without competition in the new plants built from 1985 to 1990 gives an index which can be used to compare the relative potential of the various types of cogeneration energy conversion systems. The absolute magnitude of these savings should not be used because each energy conversion system was assumed to be 100% implemented but using these results to compare the various systems, the following observations are made:

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 were 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 was 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 were 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.

SIGNIFICANT DEVELOPMENT REQUIREMENTS

The level of performance estimated for each advanced energy conversion system studied in CTAS was premised on the achievement of certain advanced developments. The developments required for the most attractive conversion systems by fuel type are shown in Table 11-3 for coal-fired ECS's and in Table 11-4 for coal-derived liquid-fired.

Table 11-3

SIGNIFICANT DEVELOPMENTS OF MOST ATTRACTIVE ECS's
(Coal Fired)

ECS	SIGNIFICANT DEVELOPMENTS
Steam Turbine AFB	Atmospheric Fluidized Bed Boiler
Pressurized Fluidized Bed	System and Control
	Particulate Removal or Gas Turbine Erosion Protection
	Pressurized Fluidized Bed

Table 11-4

SIGNIFICANT DEVELOPMENTS OF MOST ATTRACTIVE ECS's
(Coal-Derived Liquid Fuel)

ECS	SIGNIFICANT DEVELOPMENTS
GT-HRSG, and Combined-Cycle	2200 F air-cooled gas turbine
	NO_x reduction systems

Certain developments have broad generic impact on advanced energy conversion systems and thus merit aggressive development effort regardless of the particular advanced systems that are most attractive. Table 11-5 lists the most important of these developments along with the energy conversion systems requiring their development.

Table 11-5

CRITICAL DEVELOPMENTS REQUIRED FOR COGENERATION ENERGY CONVERSION SYSTEMS

1. Fluidized Bed Combustion

   Nocogeneration AFB process steam boilers
   AFB power steam boilers
   Gas turbine for PFB system
   Helium heaters - Closed-cycle gas turbine
   \- Stirling cycle

2. NO_x Reduction Systems

   Advanced diesels
   Coal-derived liquid-fired units

3. Fuel Gas Clean-up Systems and Coal Gasifiers

   Molten carbonate fuel cell
   Integrated gasifier gas and steam turbine
   Gas turbine for PFB system

4. Very High Temperature Air Preheaters

   Thermionic boiler
   Stirling cycle
   Closed-cycle gas turbine - AFB

5. DC-AC Inverters - Cost Reductions

   Thermionics
   Fuel cells

APPENDIX-SCALING METHODOLOGY

The total industry savings were obtained by using the 4-digit SIC industry data generated in CTAS to scale to the 2-digit SIC industry level and then scaling the 2-digit data to a national level.

Scaling to 2-Digit SIC Industry

It was assumed that the fuel savings for each cogeneration system, producing both steam and electric power, is a strong function of the ratio of steam to power. This relationship was not determined for each energy conversion system (ECS) but for purposes of estimating the total national savings some simplifying models were developed.

The relationships were developed for both heat and power matches and for regimes of the ratio of heat to power required by the industrial process.

Power Match. For the power match case the fuel energy saved is approximated for two regimes. Regime I is for process heat to power ratios (H/P) less than 2 and regime II is for H/P ratios greater than 2. The resulting equations for the savings ratio are:

$$SR = \frac{(1/0.85)(H/P)}{F/P + 3} \qquad \text{(I-P)}$$

for regime I, where,

H is the industrial process heat requirement

P is the industrial power requirement

and F is the nocogeneration total fuel requirement for both the utility and the industry, including the fuel used for direct heat,

and

$$SR = \frac{(2/0.85)}{F/P + 3} \qquad \text{(II-P)}$$

for regime II. The savings ratio, SR, is defined as the savings in fuel energy between nocogeneration and cogeneration diveded by the nocogeneration fuel energy used including the fuel energy for direct heat in addition to the process heat and fuel for electric power.

Heat Match. For the heat match case the fuel energy saved is approximated for three regimes. Regime I is for an H/P less than 2, regime II for H/P between 2 and 6, and regime III for H/P greater than 6. In the heat match case it was assumed that the amount of export power was limited to twice that required by the process, or $P_{ECS} = 3\,P$ where P_{ECS} is the power generated by the ECS. The heat match equations are:

$$SR = \frac{(1/0.85)(H/P)}{F/P + 3} \qquad \text{(I and II-H)}$$

and

$$SR = \frac{(1/0.85)(H/P) + 3}{F/P + 3} \times \frac{(\frac{1}{3})\,(\frac{1}{0.85})\,6}{(\frac{1}{3})\,(\frac{1}{0.85})\,6 + 1} \times \frac{1}{H/P - 5} \qquad \text{(III-H)}$$

Savings Ratio. The savings ratio (SR) for the total 2-digit industry may be obtained by integrating over each of the 4-digit SIC's within the 2-digit sector and weighting it by fossil fuel used in that 4-digit sector. It is assumed that the values of H/P are known for each industry and that the SR function is defined as above.

Thus,

$$SR_{r2} = \sum_{i=1}^{N} f_i SR_{r4_i}$$

where,

$$\sum f_i = 1.0$$

f_i = fraction of fossil fuel used in each 4-digit SIC within 2-digit group

SR_{r4_i} = relative savings ratio for the ith 4-digit SIC

i = 1 to N where N is the total number of 4-digit groups in 2-digit groups

and

SR_{r2} = relative savings ratio for 2-digit SIC industry.

Case of single 4-digit SIC industry. In the case of only one 4-digit SIC industry in a 2-digit SIC sector, i equals some number j in the above analysis and we let

$$SR_{r4} = SR_{r4_j} \quad \text{(only one 4-digit SIC designated by j).}$$

We also now define

$$SR_2 = \left(\frac{SR_{r2}}{SR_{r4}}\right) \times SR_4$$

Where

SR_4 = the FESR calculated in Section 8 for the 4-digit industry and a particular ECS,

SR_{r2} and SR_{r4} are defined above

SR_2 = estimated FESR for the 2-digit SIC industry scaled from the single 4-digit SIC industry, SR_4.

For the single 4-digit SIC within the 2-digit sector, the equation becomes,

$$SR_2 = M\ SR_4$$

where M = multiplier for the single 4-digit industry and is given by

$$M = \frac{\sum_{i=1}^{N} f_i SR_{r4_i} \times (H/P)}{SR_{r4} \times (H/P)}$$

The ratio H/P is ratio of the process heat to power. Thus, by using this multiplier, M, times the calculated SR for the 4-digit group, the SR for the 2-digit group is estimated.

<u>Case of multi 4-digit SIC industries</u>. In the case of several 4-digit SIC industries in a 2-digit SIC sector, as previously,

$$SR_{r2} = \sum_{i=1}^{N} f_i SR_{r4_i}$$

where

$\Sigma\ f_i = 1.0$

f_i = fraction of fossil fuel used by ith 4-digit group within the 2-digit sector

SR_{r4_i} = relative savings ratio for ith 4-digit SIC

i = 1 to N where N = total number of 4-digit groups in 2-digit groups

and SR_{r2} = relative savings ratio for 2-digit SIC industry.

In this case of multi 4-digit SIC groups or plants in this 2-digit SIC sector,

$$SR_2 = \frac{1}{K}\sum_{j=1}^{k}\left(\frac{SR_{r2}}{SR_{r4_j}}\right)SR_{4j}$$

$$= \sum_{j=1}^{k}\left(\frac{1}{K}\frac{SR_{r2}}{SR_{r4_j}}\right)SR_{4j}$$

$$= \sum_{j=1}^{K} M_j SR_{4j}$$

where

$$M_j = \frac{1}{K}\ \frac{SR_{r2}}{SR_{r4_j}}$$

and

j = 1 to K, where K = total number of 4-digit groups (plants) specified and analyzed by GE

SR_{r4_j} = relative savings ratio for the jth 4-digit SIC group (plant) specified by GE

and

M_j = multiplier for the jth 4-digit SIC group (plant)

Thus, each multiplier (M_j) is used for each 4-digit SIC group or plant to scale up to the 2-digit savings ratio, SR:

$$SR_2 = M_1SR_{41} + M_2SR_{42} + \cdots\ M_jSR_{4j} + \cdots\ M_kSR_{4k}$$

If there were five industries considered within a 2-digit group, then $K = 5$ and SR_2 represents the estimated savings ratio (not relative) for the 2-digit SIC group and the values SR_{41}, etc. are those calculated by GE for specific technology. For each technology, different values are used for SR_{4j} but the same values are used for M_j since it is assumed that the same relative savings function is reasonable.

$$SR = SR\ (H/P)$$

<u>Scaling To Total Industry From 2-Digit Savings Ratio</u>

The same procedure developed in the multi 4-digit SIC group is used in this analysis. In this case there are multi 2-digit SIC sectors from which to scale to the total industry savings ratios. Thus,

$$SR_T = \frac{1}{L} \sum_{k=1}^{L} \frac{SR_{rT}}{SR_{r2_k}} SR_{2k} = \sum_{k=1}^{L} M_k SR_{2k}$$

and

$$M_k = \frac{SR_{rT}}{LSR_{r2_k}}$$

$$SR_{rT} = \sum_{i=1}^{20} F_i SR_{r2_j}$$

where F_i = fraction of total industry fossil fuel used by ith 2-digit SIC group. There are 20 groups.

K = 1 to L, where L = total number of 2-digit SIC sectors covered by the GE analysis. (In this study L = 8).

SR_{r2_k} = relative savings ratio for the kth 2-digit SIC group specified by GE.

M_k = multiplier for the kth 2-digit SIC group specified by GE.

SR_{2k} = estimated savings ratio for the 2-digit SIC industry sector scaled from the 4-digit plant-cogen technology calculations performed by GE.

and

SR_T = savings ratio estimated for the total industry and scaled from the 2-digit groups selected by GE.

Thus,

$$SR_T = M_1 SR_{21} + M_2 SR_{21} + \cdots M_k SR_{2k} + \cdots M_8 SR_{28}$$

where the M_k are the 2-digit multipliers and there are eight 2-digit groups considered in the GE study.

Since GE calculated savings ratios based on fossil fuel used to produce steam plus 3 times the electric use, (but did not include the direct heat) the multiplier must correct for the fossil fuel used for direct heat also. Thus the multipliers are corrected for the proper fuel basis as follows:

$$M = \frac{\text{Estimated savings ratio for 2-digit sector based on National Energy}}{\text{Estimated savings ratio for 4-digit (or sub 4-digit sector based on GE energy (boiler fuel + 3P).}}$$

Analysis Modification For H/P Ratio of Zero

In many 4-digit industries within 2-digit sectors (particularly SIC-32) the H/P is essentially zero. For those industries with H/P equal to zero, the multiplier is essentially, F_i, the fraction of fuel used in that process.

If the savings are very low for a cogeneration system producing steam, then the overall savings for the 2-digit sector is very low if most industries have an H/P near zero. For those 2-digit groups having a mix (H/P greater than or equal to 0) of industries (e.g. SIC 28 or 33), then the multipliers that have been developed from the previous analysis are modified by the fraction of fuel in those industries with H/P = 0.

Plant Scaling to 4-Digit Groups

Each plant or industrial process was considered to be a sub 4-digit group and therefore represented a specified fraction of the energy used within that 4-digit group. Using these fractions, a fraction (f_i) of the 2-digit group used by the sub 4-digit group was developed. These fractions (f_i) were estimated as well as the heat/power ratio (H/P) for each industrial process (sub 4-digit group) and for each 4-digit group within a 2-digit sector. For those eight 2-digit groups analyzed in detail, a weighted (H/P) was determined and an (H/P) was estimated for the remaining 12 2-digit SIC groups. Thus the following information was required for selected 4-digit (and sub 4-digit groups) and 2-digit industrial groups.

f_i = 4-digit (sub 4-digit) fossil fuel fraction

F_i = 2-digit fossil fuel fraction

H/P = heat/power ratio

Data for Industrial Processes Specified by GE

The data for those processes specified by GE are contained in Table A-1.

Data for Plant Size Distribution

Each of the 4-digit groups (not sub 4-digit processes) has been profiled to size of plant by employees and the percent of energy within each size category. These data are presented in Table A-2.

Table A-1

INDUSTRIAL PROCESS DATA
(4-Digit or Sub 4-Digit SIC Group)

	SIC Group	f_i	H/P Ratio
SIC-20 (Food Industry)	2011	.0656	3.6
	2026	.0359	2.4
	2046	.0975	6.7
	2063	.1139	20.0
	2082	.0495	4.2
SIC-22[(a)] (Textiles)	2260	.2997	7.7
SIC-24 (Lumber and Wood)	2421	.2510	5.9
	2436	.1315	7.1
	2492	.0279	2.2
SIC-26[(b)] (Paper and Pulp)	2621-2	.3607	4.5
	2621-4	.3246	6.3
	2621-6	.0090	4.5
	2621-7	.0721	2.1
	2621-8	.1353	4.8
SIC-28[(c)] (Chemicals)	2812	.0420	0.6
	2813	.0224	.0
	2819-1	.0101	9.1
	2819-2	.0303	9.1
	2921-2	.0395	14.3
	2821-3	.0139	0.01
	2822	.0134	1.37
	2824-1	.0269	0.27
	2824-2	.0127	0.61
	2865-1	.0231	33.0
	2865-2	.0049	0
	2865-3	.0158	14.3
	2865-4	.0170	100.0

(Cont'd)

(a) This represents 2261, 2262 and 2269 combined into one 4-digit 2260 within SIC 22 since only one analysis was performed by GE.

(b) These 5 industrial processes represent the three 4-digit SIC's - 2611, 2621 and 2631. The combined fossils of these 3 were considered and then disaggregated into the above 5 industrial processes. The designation numbers used above are similar to those given by GE.

Table A-1 (Cont'd)

INDUSTRIAL PROCESS DATA
(4-Digit or Sub 4-Digit SIC Group)

	SIC Group	f_i	H/P Ratio
SIC-28[c] (Cont'd) (Chemicals)	2869-1	.0041	25.0
	2869-2	.3828	7.7
	2869-3	.0041	25.0
	2869-4	.0206	33.0
	2873	.1160	50.0
	2874	.0223	6.7
	2895	.0095	1.47
SIC-29[d] (Petroleum)	2911-1	.1958	7.8
	2911-2	.2984	7.5
	2911-3	.4382	7.1
SIC-32 (Stone, Clay & Glass)	3211	.0446	0
	3221	.1198	0
	3229	.0548	0
	3241-1	.1096	0
	3241-2	.0365	0
	3241-3	.1827	0
	3241-4	.0365	0
SIC-33[e] (Primary Metals)	3312-1	.0947	0.45
	3312-2	.5207	0.95
	3312-3	.0609	0.67
	3331-1	.0022	0
	3331-2	.0029	0
	3331-3	.0022	0
	3331-4	.0058	1.16
	3331-5	.0146	0.95
	3331-6	.0087	1.10
	3334-1	.0047	0
	3334-2	.0187	0
	3334-3	.0234	0

(c) The sub 4-digit processes were assumed to represent some fraction of the 4-digit total. This was estimated and used to calculate the f_i for that process. 2819-Alumina was built back into SIC 28 since it is a part of the chemical sector and is required in the weighting process. GE had included it in primary metals SIC-33, but that would be improper in the analysis to estimate total savings ratio for the 2-digit sectors. 2819-1, 2 came from 3334-4, 5, 6.

(d) These refineries are small, medium and large as defined by GE.

(e) The GE designated 3312 and two 3325's were combined into three processes in 3312. After reading process description and comparing products, it appeared that they should be primarily in 3312. Also alumina plants (GE designated 3334-4,5,6) were removed and put in 2819 (chemical industry).

Table A-2

PLANT DISTRIBUTION DATA
(Energy Distribution, %/Number of Plants)

	Employee Size Range: 1 to 5	6 to 10	11 to 25	26 to 50	51 to 100	101 to 250	251 to 500	501 to 1000	1001 to 2500	Over 2500
(a) Food Industry, SIC-20										
2011	1/1224	1/314	3/315	7/407	9/248	14/175	20/98	15/38	18/22	11/6
2026	1/756	1/279	4/368	14/574	26/477	38/360	12/61	3/7	1/0	0/1
2046	0/10	0/1	0/5	4/6	1/6	7/7	2/1	39/8	47/3	0/0
2063	0/5	0/1	0/2	0/0	1/1	57/46	29/13	13/2	0/0	0/0
2082	0/25	0/3	0/14	1/20	2/21	12/37	28/45	20/17	20/7	16/3
(b) Textiles, SIC-22										
2261	0/37	0/29	1/28	4/39	7/30	19/37	13/11	38/16	6/1	10/1
2262	0/26	0/20	1/33	4/56	9/55	25/64	25/26	24/14	5/1	7/1
2269	1/37	1/24	1/23	9/52	12/34	28/37	28/17	22/7	0/0	0/0
(c) Lumber & Wood, SIC-24										
2421	4/5251	5/1233	6/823	17/1036	20/544	24/306	11/61	6/16	7/11	0/0
2436	0/2	0/1	0/5	3/34	6/44	36/103	42/67	13/10	0/0	0/0
2492	0/0	0/1	0/3	4/10	19/22	63/39	13/3	0/0	0/0	0/0
(d) Paper & Pulp, SIC-26										
2611	0/24	0/1	0/3	2/8	4/7	8/6	33/11	37/7	16/1	0/0
2621	0/31	0/15	0/16	1/36	2/38	10/92	16/64	37/78	32/30	2/1
2621	0/16	0/6	0/7	1/28	8/76	19/92	22/49	21/23	30/17	0/0

Table A-2, Plant Distribution Data (Cont'd)

	1 to 5	6 to 10	11 to 25	26 to 50	51 to 100	101 to 250	251 to 500	501 to 1000	1001 to 2500	Over 2500
(e) Chemicals, SIC-28										
2812	0/7	0/1	0/2	2/8	4/9	15/13	12/6	31/6	37/3	0/0
2813	4/176	9/121	18/123	27/103	20/40	16/14	5/1	0/0	0/0	0/0
2819	0/36	1/46	1/55	5/105	7/69	15/67	16/31	19/20	28/10	9/2
2821	0/17	0/17	1/34	5/106	7/63	19/76	18/30	16/16	22/9	11/2
2822	0/11	0/7	1/10	3/9	1/5	10/7	15/7	38/9	33/2	0/0
2824	0/3	0/2	0/1	0/8	1/5	2/8	2/5	7/9	20/10	68/17
2865	0/26	1/18	1/20	3/31	7/33	16/33	22/20	20/10	30/7	0/0
2869	0/137	0/57	1/57	3/94	4/64	12/89	11/36	17/28	30/22	23/7
2873	0/3	0/2	0/2	7/21	16/25	28/18	33/13	16/2	0/0	0/0
2874	0/10	0/7	2/17	8/45	16/39	24/29	32/15	11/3	7/1	0/0
2895	0/3	0/0	0/1	13/13	22/13	48/11	17/1	0/0	0/0	0/0
(f) Petroleum, SIC-29										
2911	0/8	0/16	0/29	2/61	3/54	14/85	16/55	19/38	29/20	17/6
(g) Stone, Clay & Glass, SIC-32										
3211	1/0	0/0	0/1	15/2	2/2	35/2	25/9	23/11	0/5	0/2
3221	0/1	0/1	0/0	2/0	24/2	39/9	24/56	11/47	0/15	0/2
3229	1/117	1/29	1/17	1/15	2/18	11/36	14/20	36/26	28/10	6/1
3241	0/20	0/2	0/9	0/3	7/33	60/129	26/30	5/2	0/0	0/0
(h) Primary Metals, SIC-33										
3312	0/64	0/33	0/32	0/26	0/22	1/41	3/47	6/44	12/40	77/68
3331	0/0	0/0	0/0	0/0	1/1	8/9	19/9	35/10	38/6	0/0
3334	0/0	0/0	0/0	1/1	0/0	0/1	10/8	41/16	48/9	0/0

Data and Multipliers for 4-Digit SIC Groups

Data for the fraction of the 2-digit total fuel represented by each 4-digit selected industry is given in Table A-3 . The fraction f_i' is based on the total industry fuel including direct heat plus the utility fuel to supply the electric power (based on an efficiency of 1/3). The totals for each 2-digit sector indicates what fraction of the total 2-digit sector is represented by the selected 4-digit industries. The multipliers as defined earlier are also given for both the power match and the heat match cases.

Data and Multipliers for Total Industry

Data for the total industry fraction of fuel represented by each 2-digit selected industry is given in Table A-4 . The fraction F_i' is again based on the total fuel including direct heat plus the utility fuel to supply the electric power. The total of the selected 2-digit groups represents about 85% of the total industrial fuel for all sectors. The heat to power ratio (H/P) representative of each 2-digit sector is also shown. The multipliers given in this table are used to determine the total national savings.

Table A-3

DATA AND MULTIPLIERS FOR 4-DIGIT SIC GROUPS

4-Digit SIC Group	f'_i	Multiplier, M: Power Match	Multiplier, M: Heat Match	Fraction of Energy for Steam and Electric Power: $\frac{\text{Boiler Fuel + 3E}}{\text{Boiler Fuel + 3E + Direct Heat}}$
(a) Food Industry, SIC-20				
2011	.0738	.101	.084	.96
2026	.0492	.082	.101	.99
2046	.0767	.153	.119	.55
2063	.0787	.372	1.052	.29
2082	.0504	.111	.079	.91
	.3288			
(b) Textiles, SIC-22				
2260	.1723	.721	.608	.8
(c) Lumber & Wood, SIC-24				
2421	.3254	.316	.252	1
2436	.1386	.361	.529	1
2492	.0390	.178	.380	.9
	.503			
(d) Paper, Pulp, SIC-26				
2621-2	.3472	.118	.107	.7
2621-4	.3125	.148	.127	.87
2621-6	.0087	.118	.107	.7
2621-7	.0694	.078	.152	.46
2621-8	.1302	.123	.105	.72
	.868			
(e) Chemicals, SIC-28				
2812	.0576	.041	.055	.64
2813	.041	.041	.041	.65
2819-1	.0877	.046	.061	1
2819-2	.1071	.036	.022	1
2819-2	.0403	.063	.139	1
2821-3	.0142	2.012	2.68	.36
2822	.0119	.022	.030	.4
2824-1	.0285	.082	.109	.42
2824-2	.0134	.041	.054	.47
2865-1	.0196	.140	.419	1
2865-2	.0041	.004	.004	.23
2865-3	.0134	.066	.139	1
2865-4	.0144	.403	1.422	1

(Cont'd)

Table A-3 (Cont'd)

DATA AND MULTIPLIERS FOR 4-DIGIT SIC GROUPS

4-Digit SIC Group	f'_i	Multiplier, M: Power Match	Multiplier, M: Heat Match	Fraction of Energy for Steam and Electric Power: (Boiler Fuel + 3E) / (Boiler Fuel + 3E + Direct Heat)
(e) Chemicals, SIC-28 (Cont'd)				
2869-1	.0032	.108	.299	1
2869-2	.2999	.0403	.040	.66
2869-3	.0032	.108	.299	1
2869-4	.0161	.140	.419	1
2873	.0878	.207	.674	1
2874	.0224	.036	.025	1
2895	.0075	.021	.029	.27
	.8933			
(f) Petroleum, SIC-29				
2911-1	.1964	.179	.206	.63
2911-2	.2993	.173	.184	.61
2911-3	.4395	.166	.154	.59
	.9352			
(g) Stone, Clay & Glass, SIC-32				
3211	.0446	.076	.076	.21
3221	.1276	.217	.217	.25
3229	.0591	.100	.100	.26
3241-1	.1073	.182	.182	.19
3241-2	.0358	.061	.061	.19
3241-3	.1789	.304	.304	.19
3241-4	.0358	.061	.061	.19
	.5891			
(h) Primary Metals, SIC-33				
3312-1	.0796	.028	.028	.18
3312-2	.4378	.016	.016	.21
3312-3	.0512	.020	.020	.19
3331-1	.0018	.002	.002	.11
3331-2	.0023	.002	.002	.11
3331-3	.0018	.002	.002	.11
3331-4	.0047	.013	.013	.17
3331-5	.0117	.016	.016	.16
3331-6	.0070	.014	.014	.16
3334-1	.0147	.015	.015	.77
3334-2	.0589	.059	.059	.77
3334-3	.0736	.074	.074	.77
	.7451			

Table A-4

DATA AND MULTIPLIERS FOR TOTAL INDUSTRY

SIC Group	F_i	H/P	Multiplier, M Power Match	Heat Match
20	.0612	5.8	.099	.046
22	.0264	2.3	.069	.081
24	.0178	4.6	.079	.046
26	.0809	4.7	.113	.064
28	.2195	12.5	.096	.183
29	.0996	7.1	.186	.155
32	.0721	0.1	.072	.072
33	.2687	0.6	.369	.495
	.8462			