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COGENERATION TECHNOLOGY ALTERNATIVES STUDY (CTAS) UNITED TECHNOLOGIES CORPORATION FINAL REPORT

VOLUME I – SUMMARY REPORT

Power Systems Division
United Technologies Corporation

January 1980

Prepared for

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION
Lewis Research Center
Under Contract DEN3-30

for

U.S. DEPARTMENT OF ENERGY
Energy Technology
Fossil Fuel Utilization Division

NOTICE

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Lewis Research Center
21000 Brookpark Road
Cleveland, Ohio 44135

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Peter Bolan

UNITED TECHNOLOGIES.
POWER SYSTEMS DIVISION
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16. Abstract

The Cogeneration Technology Alternatives Study (CTAS) provides data and information in the area of advanced energy conversion systems for industrial cogeneration applications in the 1985-2000 time period. Six current and thirty-one advanced energy conversion systems were defined and combined with appropriate balance-of-plant equipment. Twenty-six industrial processes were selected from among the high energy consuming industries to serve as a frame work for the study. Each conversion system was analyzed as a cogenerator with each industrial plant. Fuel consumption, costs, and environmental intrusion were evaluated and compared to corresponding traditional values. Various cogeneration strategies were analyzed and both topping and bottoming (using industrial by-product heat) applications were included.

The advanced energy conversion technologies indicated reduced fuel consumption, costs, and emissions. Typically fuel energy savings of 10 to 25 percent were predicted compared to traditional on-site furnaces and utility electricity. With the variety of industrial requirements, each advanced technology had attractive applications. Overall, fuel cells indicated the greatest fuel energy savings and emission reductions. Gas turbines and combined cycles indicated high overall annual cost savings. Steam turbines and gas turbines produced high estimated returns. In some applications, diesels were most efficient. The advanced technologies used coal-derived fuels, or coal with advanced fluid bed combustion or on-site gasification systems.

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COGENERATION TECHNOLOGY ALTERNATIVES STUDY
VOLUME I

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VOLUME I

PREFACE

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/National Aeronautics and Space Administration-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 Power Systems Division of United Technologies Corporation under National Aeronautics and Space Administration contract DEN3-30. This United Technologies contractor report is one of a set of reports describing CTAS results. The other reports are the following: Cogeneration Technology Alternatives Study (CTAS) Volume I - Summary NASA TM 81400, Cogeneration Technology Alternatives Study (CTAS) General Electric Final Report NASA CR 159765-159770 and Cogeneration Technology Alternatives Studies (CTAS) Volume II - Comparison and Evaluation of Results, NASA TM 81401.

This United Technologies contractor report for the CTAS study is contained in six volumes:

Volume I	- Summary Report, DOE/NASA/0030-80/1 NASA CR 159759
Volume II	- Industrial Process Characteristics, DOE/NASA/0030-80/2 NASA CR 159760
Volume III	- Energy Conversion System Characteristics, DOE/NASA/0030-80/3 NASA CR 159761
Volume IV	- Heat Sources, Balance of Plant, and Auxiliary Systems, DOE/NASA/0030-80/4 159762
Volume V	- Analytic Approach and Results, DOE/NASA/0030-80/5 159763
Volume VI	- Computer Data, DOE/NASA/0030-80/6 NASA CR 159764

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

Aerojet Energy Conversion Company of Sacramento, California
Bechtel National, Incorporated of San Francisco, California
Cummins Cogeneration Company of New York, New York
DeLaval Turbine and Compressor Division of Trenton, New Jersey
Glassman, Dr. Irving, of Princeton, New Jersey
Gordian Associates, Incorporated of New York, New York
Mechanical Technology Incorporated of Latham, New York

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Myers, Dr. Philip S., of Madison, Wisconsin
New England Electric System of Westboro, Massachusetts
Power Systems Division of United Technologies of South Windsor, Connecticut
Rasor Associates, Incorporated of Sunnyvale, California
Rocket Research Company of Redmond, Washington
Southern California Edison Company of Rosemead, California
Sulzer Brothers, Limited of Winterthur, Switzerland
United Technologies Research Center of East Hartford, Connecticut
Westinghouse Electric Company of Pittsburgh, Pennsylvania

INTRODUCTION

On-site cogeneration of electrical and thermal energy is potentially an attractive means of energy conservation. However, only a small portion of industrial energy needs are currently being provided by cogeneration systems. In looking to the 1985-2000 time period, identification and evaluation of advanced candidate energy conversion system technologies which could serve as suitable cogeneration plants are appropriate.

Suitability is a complex criteria which must recognize national objectives and industrial needs. The following specific criteria were considered:

- The potential for overall conservation (on a BTU basis)
- The ability to use fuels which are expected to be more available and to move from light oil and natural gas towards heavy oil, coal, and coal-derived fuel.
- The possibility of attractive economics and reduced energy costs.
- The compatibility with environmental objectives and the possibility of improving the overall environment.
- The applicability to a wide range of industries and processes--both in new plants and retrofit situations -- with acceptable performance and reliability characteristics.

Many advanced energy conversion technologies are candidates for industrial cogeneration. To assist in establishing emphasis and priorities, a data base was required for evaluation of advanced energy conversion systems in the light of the above criteria. The objective of this study is to compare and evaluate advanced energy conversion systems and assess the advantage of using advanced technology in industrial cogenerations.

The approach to the study was to use experts and organizations directly involved in their appropriate areas with provision for consistency and objectivity. Gordian Associates defined the requirements and characteristics of twenty-six industrial processes selected from large energy consuming industries. These data and information, including projections to 2000, provided a framework for evaluation of the advanced energy conversion technology in cogeneration applications. The National Aeronautics and Space Administration provided groundrules, specifications and guidelines for consistency in the overall study. An experienced engineering firm, Bechtel National Incorporated, provided balance-of-plant data which was included on a consistent basis for all conversion systems. Bechtel National also provided both liquid fueled and coal-fired heat source designs. The following organizations and individuals with experience and self interest were selected to provide energy conversion data to a consistent format and to review and comment on other conversion system data:

TECHNOLOGY	ADVOCATE
Steam turbine	DeLaval Turbine & Compressor Division
High speed diesel engine	Cummins Cogeneration Company
Low speed diesel engines	Sulzer Brothers, Ltd.
Gas turbines Combined cycle Fuel cells	United Technologies Corporation Power Systems Division
Closed-cycle gas turbine	United Technologies Corporation United Technologies Research Center Power Systems Division
Stirling Engines	Mechanical Technology Incorporated
Thermionics	Rasor Associates
Organic Rankine cycles	Aerojet Energy Conversion Company

In addition, Dr. P. S. Meyers served as advocate for diesel engines. Some cogeneration applications incorporated heat pumps or thermal storage. Westinghouse Electric Company provided heat pump information and Rocket Research Company supplied thermal storage data.

United Technologies Research Corporation conducted the analysis of each conversion system applied as a cogeneration plant in each industrial process to determine fuel savings, pollutant reductions, and cost savings. These data were compiled and expanded to a national basis to indicate the potential value of each conversion system in cogeneration applications after 1985.

These parametric type analyses involved over 3300 combinations of energy conversion systems and industrial applications. More detailed design and analytical investigations were conducted in selected applications. Further economic analyses were conducted by United Technologies Research Center for 120 cases and the sensitivity of economic criteria to various parameters were examined. Bechtel National, Incorporated, prepared preliminary arrangement sketches and reviewed the parametric cost estimates for 20 cases to determine if there were any significant inconsistencies in the parametric approach to costs. The effects of time-of-day variations in energy requirements were evaluated for one conversion system-industrial plant case with and without thermal storage.

This Volume I summarizes the results developed in the course of the study while Volumes II thru VI provide detailed information and data in the various areas.

SUMMARY

The Cogeneration Technology Alternatives Study examined the prospects for advanced energy conversion systems in cogeneration applications. The selection of the conversion technologies emphasized systems which could be commercially available in 1985-2000, which had potential for energy savings, which moved from oil and gas towards coal or coal-derived fuel, and which were candidates for topping cogeneration applications. The technologies and fuels included in the study are listed in Table 1.

TABLE 1
ENERGY CONVERSION SYSTEMS AND FUELS

TECHNOLOGIES	FUELS
Steam Turbine	Petroleum
Gas Turbine	Distillate
Closed Cycle Gas Turbine	Boiler Fuel
Steam Injected Gas Turbine	
Combined Cycle	Coal
High Speed Diesel Engine	Coal Derived Fuels
Low Speed Diesel Engine	Gas
Low Temperature Fuel Cell	Distillate
High Temperature Fuel Cell	Boiler Fuel
Stirling Engine	
Thermionics	Process By-Product Heat
Compound Thermionics	(Bottoming)
Organic Rankine Cycle (Bottoming)	

The advanced steam turbine operates at higher pressure and temperature compared to current industrial turbine practice and uses both liquid and coal fuels. Advanced gas turbines are designed to use heavy coal-derived liquids and operate at higher temperatures. Gas turbines also operated with gasified coal and with pressurized fluidized bed or atmospheric fluidized bed coal combustion systems. The steam injected gas turbine and combined-cycle use the same fuels. The closed cycle gas turbine is a candidate for both liquid and coal fired heat sources. The high speed diesel uses distillate fuel while the low speed diesel can use coal-derived boiler fuel or pulverized coal. The fuel cells use distillate fuel or coal converted to gaseous fuel on-site. A special model Stirling engine which emphasizes the opportunity to recover heat was included with both liquid and coal-fired heat sources. Two thermionic conversion configurations were included; one where the thermionic converter operated by itself and the other where the converter was compounded with a bottoming steam turbine. Both of these systems were heated by a high temperature liquid-fired heat source. The organic Rankine cycle was compared with steam turbines for bottoming applications in the cement and glass industries using by-product heat.

Twenty-six industrial processes were selected from among the high energy consuming industries to serve as a framework for the study, Table 2. Of these, twenty-four are candidates for topping systems. All require electricity and thermal energy in the form of direct heat, steam, or hot water. Some produced by-product fuels which could be used by certain conversion technologies and others required direct use of specific fuels. A representative plant and associated energy requirements in the 1985-2000 time period were defined for each industry.

TABLE 2
SELECTED INDUSTRIAL PLANTS/PROCESSES

SIC	Process	SIC	Process
20 Food	Meat Packing Malt Beverages Bakery	29 Petroleum	Refinery
		30 Rubber	Tires
22 Textiles	Textile Mill	32 Stone and Glass	Bottles Portland Cement
24 Lumber	Saw Mill		
		33 Primary Metals	Steel Mill Iron Foundry Copper
26 Paper	Newsprint Writing Paper Corrugated Paper Boxboard	37 Transportation Equipment	Motor Vehicles
28 Chemicals	Chlorine Alumina Low Density Polyethylene High Density Polyethylene Polyvinyl Chloride Butadiene Rubber Nylon Styrene Ethylene		

Each of the energy conversion technologies was combined with the appropriate heat source and balance-of-plant equipment to define a complete conversion system. Then each conversion system was analyzed as a cogenerator with each representative industrial plant as illustrated in Figure 1. The fuel consumption, levelized annual cost, and environmental intrusion were evaluated for each cogeneration application and compared to values for the traditional system of providing the industrial process energy requirements. The assumptions were made that the electric utility consumed coal and that the traditional on-site furnaces raising steam consumed liquid boiler fuel. Both the utility and the in-plant furnaces were assumed to meet the appropriate emission requirements. Four cogeneration strategies were evaluated for each conversion system industrial plant combination: matching the electrical requirements; matching the thermal or steam requirements;

matching which resulted in minimum overall fuel use; and matching with a heat pump to upgrade low temperature conversion system heat.

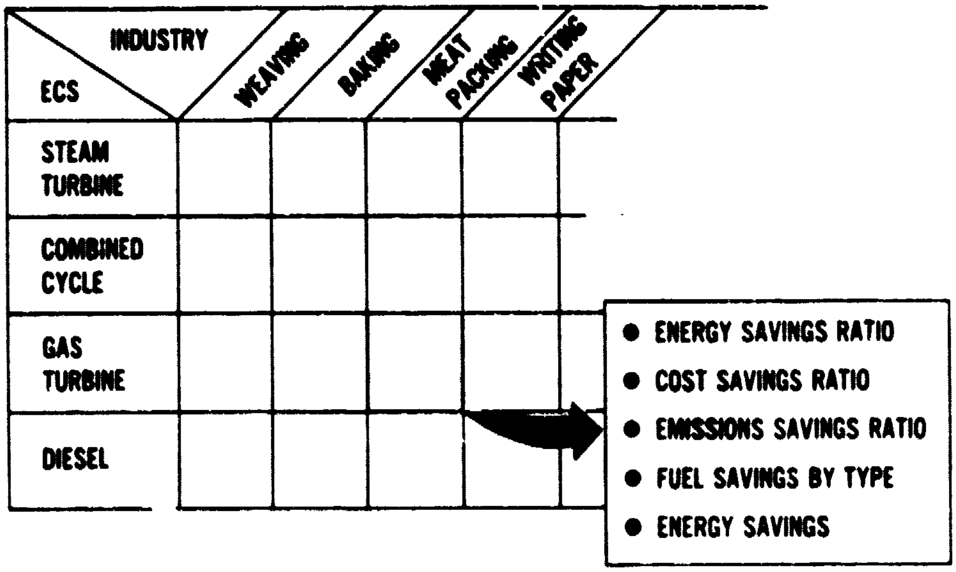

Figure 1. Technology Data Base for Each Cogeneration Strategy

With conservation, economic, and environmental data for over 3000 cases, a means to compile and summarize these data was required to permit evaluation and comparison of the various energy conversion systems. The data in each case were developed for one of 26 representative industrial plants. By assuming that the savings or advantages of a cogeneration energy conversion system in the representative plant could apply to all manufacturing plants producing the same commodity, the potential savings at the process level can be estimated. A further extension can be made if the savings at the process level are indicative of the savings for the four digit Standard Industrial Classification. These savings can be compiled and extended to other classifications by assuming that the estimated savings are representative of other industries not included in this study. In this way, the estimated savings for an energy conversion system applied in the 26 representative industrial plants can be compiled and scaled to indicate the potential savings if that energy conversion system were to be applied in all industrial plants across the nation. For consistency in making comparisons, the scale-up to the national level was applied to cogeneration systems which match the industrial electric requirements.

Figure 2 presents the relative savings of current conversion technologies scaled to the national level. In general, cogeneration with current conversion technologies would conserve energy resources. In the cases of the low speed diesel and steam turbine, if crude oil were used for fuel, the savings would be increased by approximately 10 percent. The advanced technology potential fuel energy savings are presented in Figures 3 and 4. The various technologies are identified at the bottom of each chart and the scale is proportional to potential savings on a national basis. Figure 3 presents data for liquid fuel systems, and coal-fired cases are included in Figure 4. The high temperature fuel cell, gas turbine, low speed diesel, and combined cycle systems appear most conserving. The advanced conversion technologies offer greater cogeneration conservation possibilities than the current conversion systems.

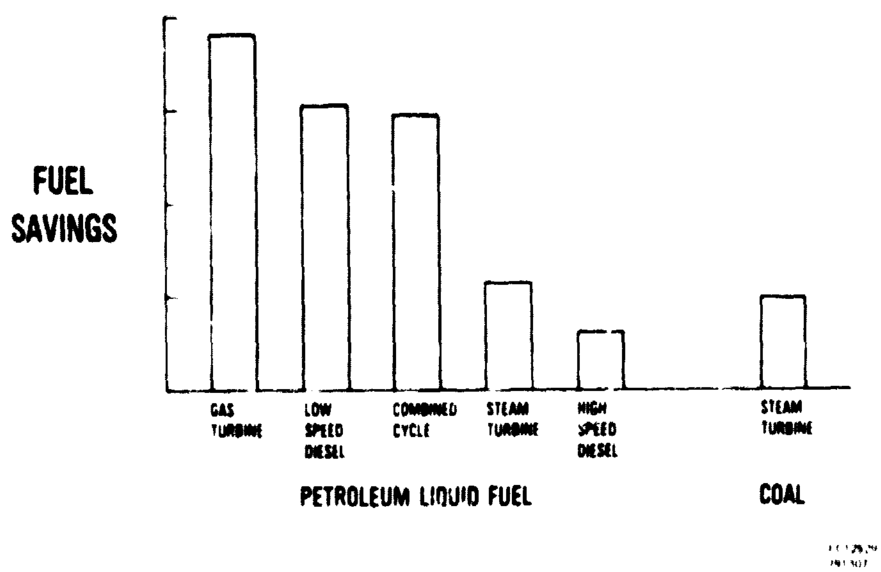

Figure 2. Relative Potential Fuel Savings with Current Technologies

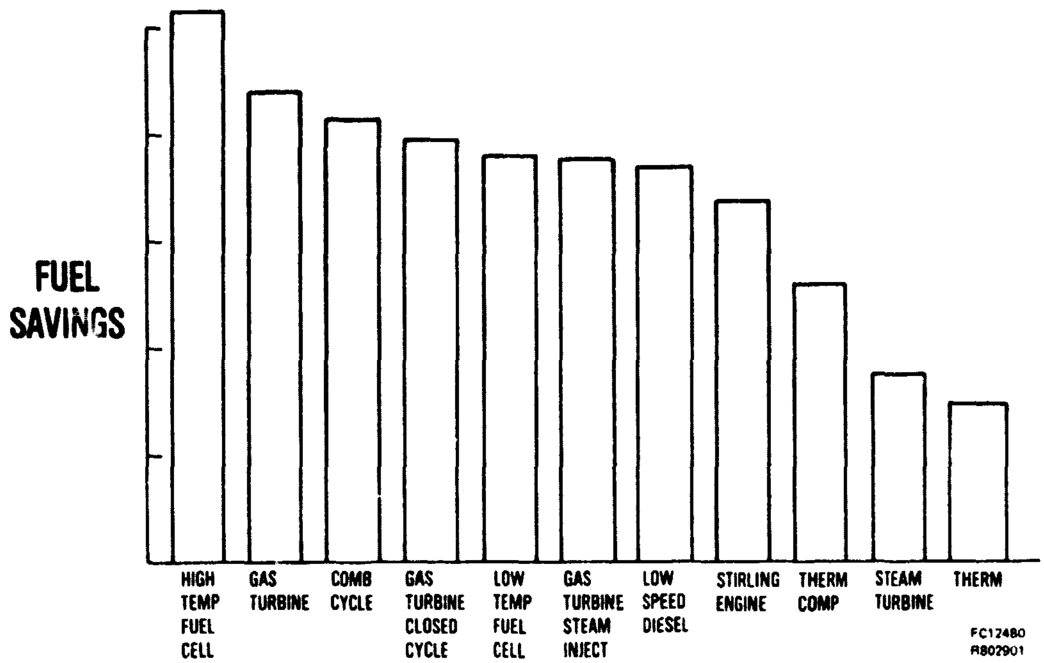

Figure 3. Relative Potential Fuel Savings with Advanced Technologies Using Liquid Fuel

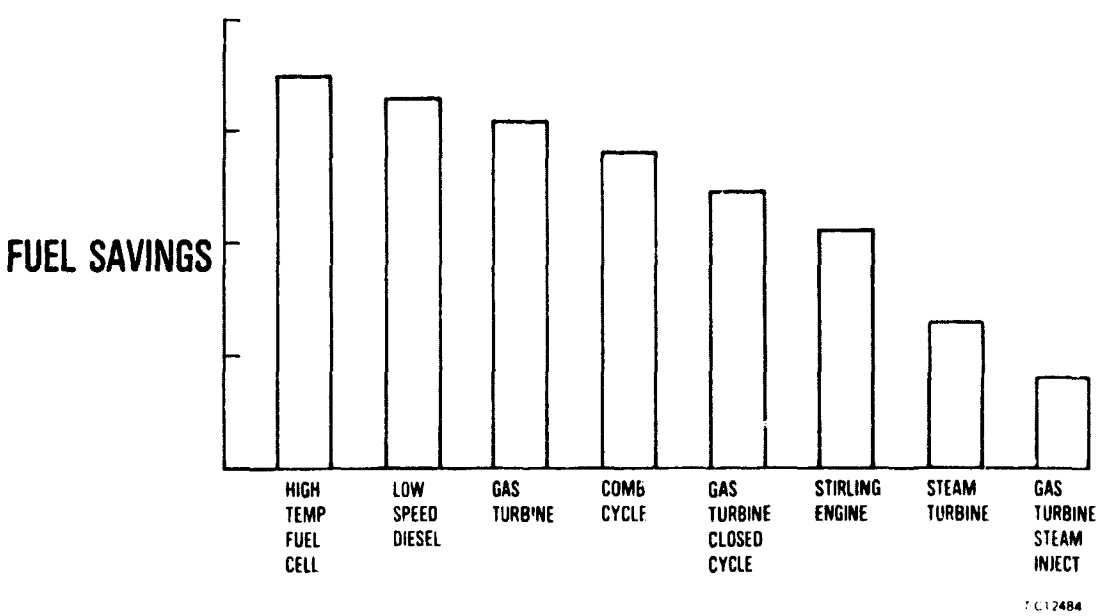

Figure 4. Relative Potential Fuel Savings with Advanced Technologies Using Coal

In addition to the potential energy savings indicated in Figures 3 and 4, economics, emissions, fuels availability, and technical characteristics are also important considerations in assessing the cogeneration potential of the various conversion technologies. To provide a measure of economic attractiveness, the levelized annual costs were determined for each conversion system - industrial process case based on economic groundrules summarized in Table 3. The relative fuel savings are presented in Figures 5, 6, and 7 for all cases which indicated annual cost savings. The advanced technologies have a higher proportion of cost saving cases than the current technologies.

TABLE 3

SUMMARY OF ECONOMIC GROUNDRULES

Cogeneration Plant Startup Date	1990
Base Year For Dollar	1978
Inflation Free Analysis	
Cost of Debt	3% above inflation
Cost of Equity	7% above inflation
Debt Capitalization	30%
Equity Capitalization	70%
Effective Tax Rate (Federal & State)	50%
Insurance and Other Taxes	3%
Economic Life	30 Years
Tax Life	15 Years
Depreciation	Sum-of-Years-Digits
Investment Tax Credit	10%
Fuel Escalation Rate (1985 base)	1%
Electricity Escalation Rate (1985 base)	1%
1985 Distillate Fuel Price	$3.80/million BTU
1985 Liquid Boiler Fuel Price	$3.10/million BTU
1985 Coal Price	$1.80/million BTU
1985 Electricity Price	3.3¢/KWH

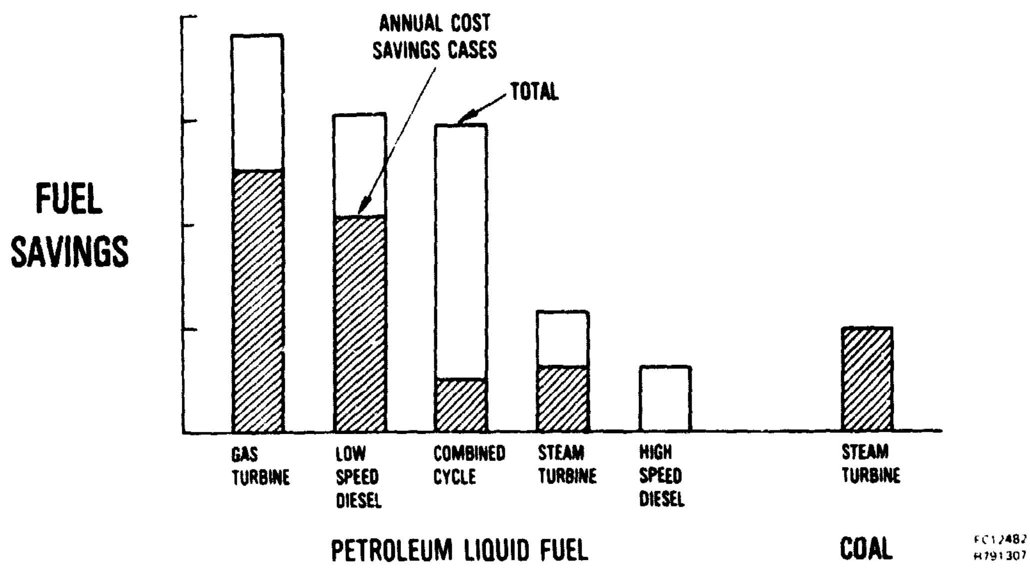

Figure 5. Relative Fuel Savings with Current Technologies

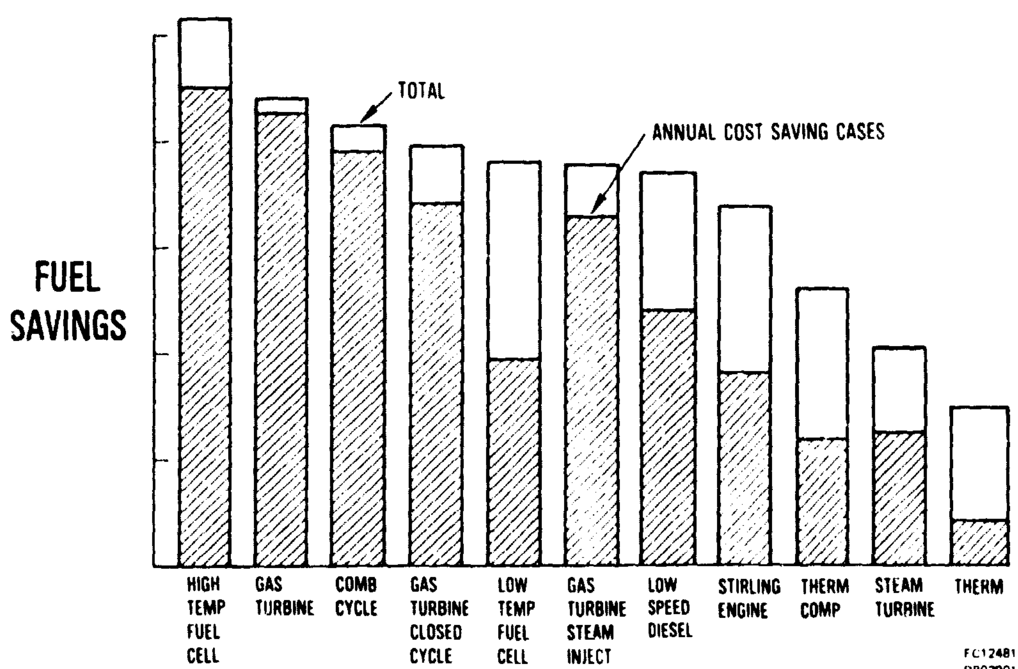

Figure 6. Relative Fuel Savings with Advanced Technologies Using Liquid Fuel

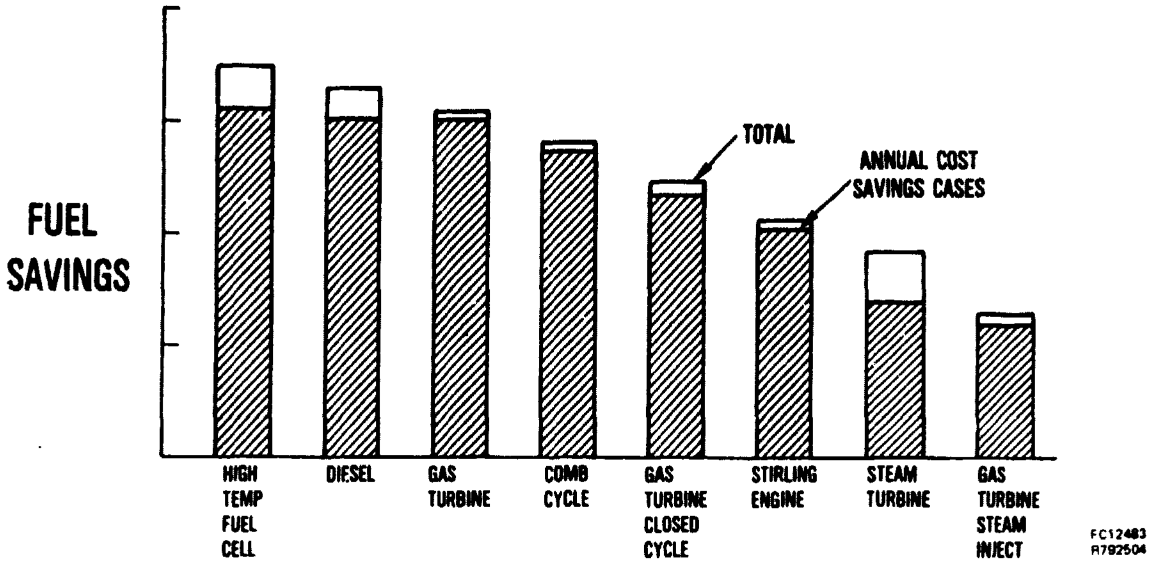

Figure 7. Relative Fuel Savings with Advanced Technologies Using Coal

The relative fuel savings for the bottoming cases are presented in Figure 8. The advanced organic Rankine systems appear to be an improvement over current technology steam turbines.

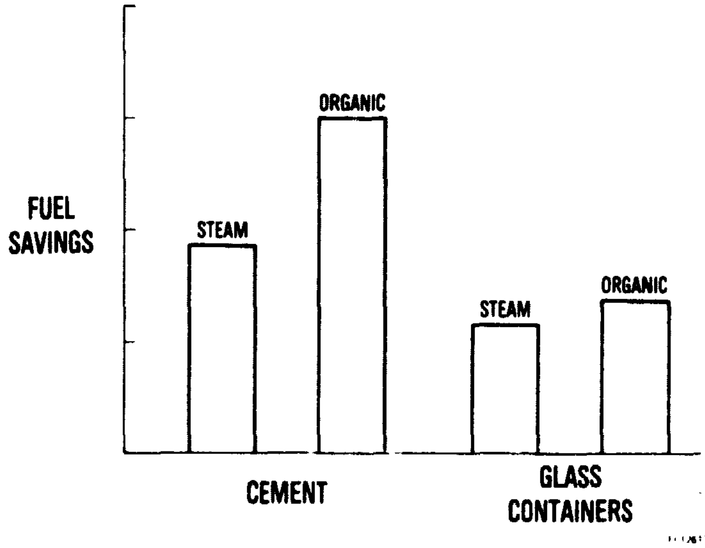

Figure 8. Relative Bottoming Application Fuel Savings

In addition to fuel and cost savings, environmental intrusion can be a significant factor in the acceptability of cogeneration systems. Total pollutant emissions for the advanced technologies are presented in Figure 9 for coal-derived liquid fuels and Figure 10 for coal.

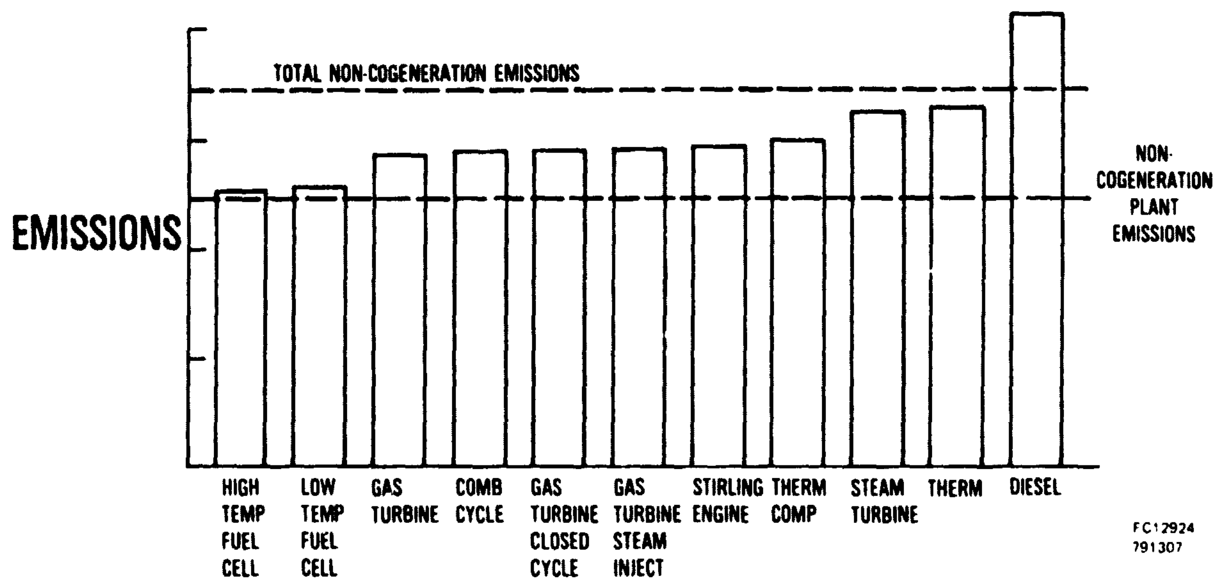

Figure 9. Emissions Impact of Advanced Technologies Using Liquid Fuels

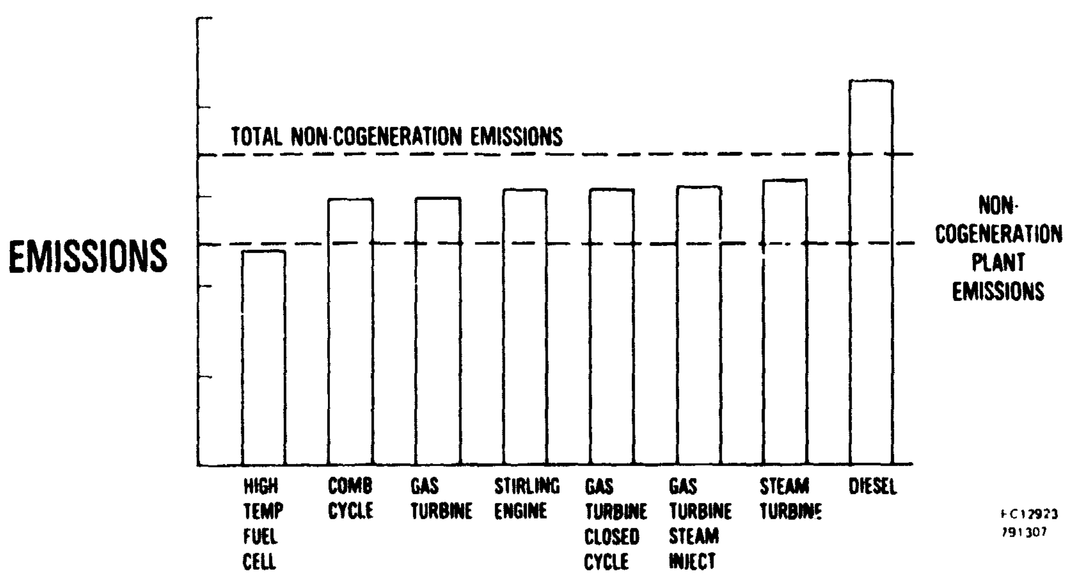

Figure 10. Emissions Impact of Advanced Technologies Using Coal

For reference, the estimated total emissions from the traditional configuration is shown in Figures 9 and 10. In the aggregate, all advanced technology conversion systems except the diesel engines would enhance the quality of the environment. The diesel engines are expected to exceed the nitrogen oxide specifications. A second important environmental criteria is on-site emissions since many cogeneration candidate industrial plants will be located in sensitive areas. The estimated level of pollutants emitted by traditional on-site furnaces is also indicated in Figures 9 and 10. The fuel cells appear to offer the greatest environmental advantage.

The advanced energy conversion technologies offer fuel conservation and reduced cost and emissions. Average fuel energy savings of 10 to 25 percent were predicted with individual cases of over 40 percent compared to traditional on-site furnaces and utility electric service. Each technology had applications offering significant conservation potential. Diesel engines provided some of the highest fuel energy ratios.

Assuming widespread use of each technology in cogeneration applications across the nation indicates potential energy savings levels of up to 5 quads in the most optimistic scenario. Restricting this estimate to cost saving and conserving situations produce comparable results of up to 4.5 quads. Fuel cells indicated the greatest fuel energy savings while the gas turbines and combined cycles indicated high overall annual cost savings. In terms of return-on-investment, the gas turbine was estimated to be most attractive with coal derived liquid fuels. For coal-fired systems the steam turbine and steam injected gas turbines produced high estimated returns.

Fuel cell powerplants provide minimum emissions of pollutants and in half of the cases would reduce emissions compared to traditional on-site steam boilers only.

Each of the advanced technologies offer some promise in cogeneration applications and most have limitations. To touch briefly on each:

Steam turbines have wide cogeneration applicability, evident by their use in industry today. Since the turbine can operate with steam generated from a variety of heat sources using a variety of fuels, it offers fuel flexibility and can use coal, coal derived fuel, or process by-product fuels. In this study the conservation potential at steam turbines is limited. The capital costs limit economic attractiveness in some cases. The advanced steam turbine in this study requires the development of the atmospheric fluidized bed coal combustion system.

High speed diesel-generators have been the principal prime movers in "total energy" systems which are cogeneration systems in commercial and residential buildings. They can also be used in industrial cogeneration applications although high speed diesel installations are limited to about 10 or 15 megawatts. The advanced high speed diesel engines operate at very high efficiency over a wide range of output levels.

High speed diesel-generators can be developed to operate on coal-derived distillate fuel. The high speed diesel engines emit relatively high levels of nitrogen oxides which may be a significant deterent. The high speed diesel advanced technology in this study is based on the development of the "adiabatic" engine which includes ceramic high temperature components and gas bearings.

The low speed diesel-generator offers operational flexibility and is able to operate very efficiently over a wide range of output levels while consuming coal derived boiler grade fuel or powdered coal. Principal drawbacks to low speed diesel cogeneration applications are the relatively high level of exhaust emissions and the low temperature of the recovered heat. Capital costs of diesel cogeneration systems are high.

The direct-fired gas turbine is very adaptable to industrial cogeneration and has been used in this way in process industries. The high temperature exhaust gases can raise high temperature steam, be used directly in the industrial process, or serve as preheated air for furnaces.

The advanced gas turbine can consume boiler-grade fuels, either coal-derived or petroleum based, with emission levels consistent with the guidelines specified for this study. Capital costs are low. This study assumed the development of advanced turbine and combustion systems to operate at 2500°F within the emission guidelines.

Both pressurized and atmospheric fluidized bed coal combustion were included with the advanced gas turbines. The atmospheric system provided some cases with high conservation and attractive economics while the pressurized systems were attractive in a wider range of applications.

The gasified coal direct-fired gas turbine is potentially adaptable to industrial cogeneration applications. In addition to the high temperature exhaust gases, there is an additional source of high temperature (2000-2400°F) heat from the fuel gas leaving the gasifier. Gasifiers under development are generally of large size and the gas turbine with coal gasification may be limited in smaller installations.

The closed cycle gas turbine results in small turbo-machinery with good performance at rated and part-power over a wide operating range. It uses a separate heat source which permits a variety of fuels. With coal atmospheric fluidized bed closed cycle systems, economics and conservation prospects were found to be reasonable. Advanced, high temperature liquid fueled systems are dependent upon the development of ceramic heat exchangers which are expected to be expensive.

Advanced combined cycles with either extraction or bypass steam turbines provide flexibility to meet a variety of industrial energy needs. The electrical and thermal energy provided can be varied as process needs vary and combined cycle systems can respond promptly to changes in demand. Generally, combined cycle conversion systems are applicable to the larger size applications (10 MW and above) with emphasis on high electrical to thermal energy ratio. Combined cycle power plants can operate with any fuels suitable for gas turbine operations.

Steam injected gas turbines are similar to the combined cycle in many respects. Since the steam passes through the gas turbine and no steam turbine is involved, the capital cost is reduced and the emissions are easier to control. In general, the steam injected gas turbine does not offer as large conservation benefits as the combined cycle, but the economics are more attractive.

The low temperature fuel cell power plant offers siting and operating flexibility. The low level of pollutants and the low noise may be particularly important in many industrial locations. The fuel cell powerplant is able to operate efficiently over a wide range of output levels and is capable of very rapid response to variations in demand. Applicability is limited by the low temperature of the recovered heat.

High temperature fuel cells embody many of the siting and operational characteristics of low temperature fuel cells which make them appropriate for cogeneration. In addition, high temperature fuel cells provide high temperature heat for industrial processes. The high temperature fuel cell power plants can also operate on a variety of fuels. Pipeline gas and coal-derived distillate fuel capabilities are being developed. On-site coal gasification represents an attractive option, particularly for the larger installations.

The Stirling engine can operate at high electrical efficiency over a wide range of output levels. Since it employs a separate heat source, it can operate with liquid fuels or coal. The Stirling engine has limited high temperature heat recovery capabilities, but it can be modified to provide larger amounts of process steam at some penalty in electrical efficiency. The advanced technology Stirling engine is based on the development of high temperature materials and heat exchangers.

Thermionic energy conversion systems are particularly applicable to cogeneration situations requiring large amounts of high temperature process heat. The compound configuration is appropriate for industrial processes requiring moderate amounts of electricity. Heavy oil or coal-derived oil serve as the basis for this study. The high temperature furnace can be modified to operate with a wide variety of light or distillate oils or gaseous fuels in addition to boiler grade oils. With a suitable flue gas desulfurizer, coal could be used directly. Thermionic conversion systems are dependent upon the development of high temperature furnaces and heat pipes as well as the development of the converters themselves.

INDUSTRIAL PROCESS REQUIREMENTS

INTRODUCTION

In order to provide a valid framework for selection of cogeneration systems and for the evaluation of advanced energy conversion system technology for industrial cogeneration applications, representative industrial processes were selected for the energy intensive industries. The processes considered are expected to be used in the 1985-2000 time period and could be candidates for cogeneration. Industries consuming significant quantities of oil and natural gas were considered.

INDUSTRIAL PROCESS SELECTION

The 26 industrial processes which were chosen as the basis for the study are presented in Table 2. The selected processes are arranged in accordance with the standard industrial classifications developed by the Federal government to categorize the entire field of economic endeavor according to type of activity. This study is limited to the activities under Division D, manufacturing, which includes the two digit classifications from 20 to 39. The system classifies manufacturing and industrial plants and establishments in accordance with their products rather than the processes employed or the fuels consumed. Therefore, there is wide variation in energy consumption from category to category because of the nature of the products and because of the structure of the classification system. Figure 11 indicates energy consumption of the 20-two-digit manufacturing industries and identifies the ten classifications included in this study.

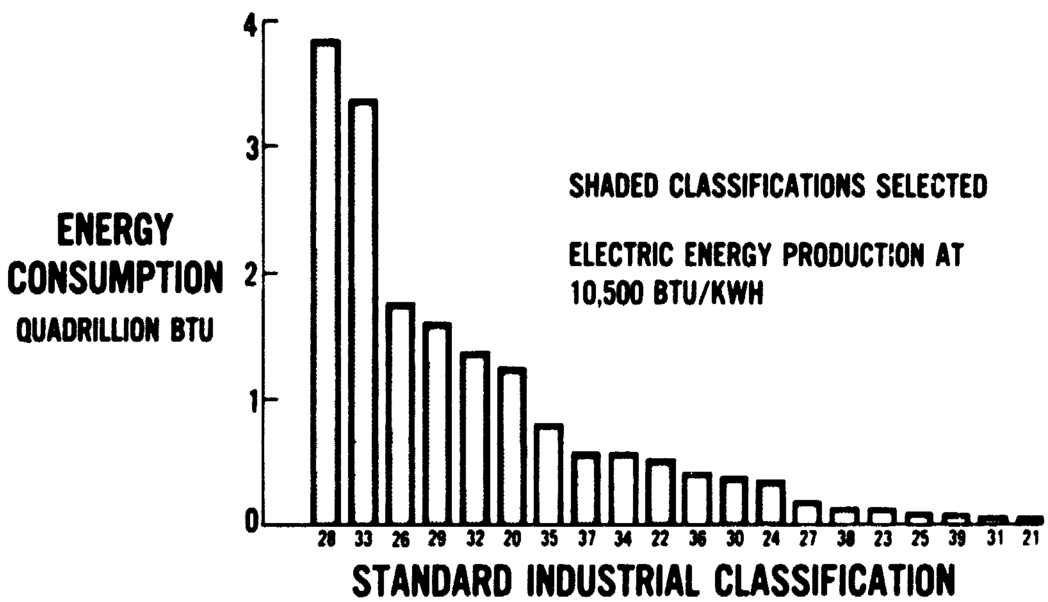

Figure 11. Industrial Energy Consumption by Two Digit Classification

The classification system extends to the 4 digit level and the selected processes are so identified in Table 4. Thirteen of the fifteen most energy consuming industries based on the 4 digit classifications are included in the 22 classifications chosen for this study. The 15 industries presently consume over half of the energy required by the manufacturing sector. The electrolytic reduction of aluminum oxide to aluminum metal is one industry of the fifteen not included in this study. Aluminum manufacture requires large quantities of electrical energy but little thermal energy is needed. Therefore, it was not considered a good candidate for cogeneration and was not included in the study.

TABLE 4. INDUSTRIAL PLANT/PROCESSES

No.	4-Digit SIC	Identification
		Food and Kindred Products
	2011	Meat Packing Plants
1		o Integrated packing plant engaged in the slaughter, cutting, deboning, curing, smoking, canning, and cooking of cattle and hogs.
	2051	Bread and Other Bakery Products, Except Cookies and Crackers
2		o Bakery producing bread and rolls
	2082	Malt Beverages
3		o Brewery
		Textile Mill Products
	2221	Weaving Mills, Synthetic
4		o An integrated mill for weaving man-made fibers and silk into fabrics over twelve inches in width -Operations integrated with weaving, can include texturizing, dyeing, and finishing.
		Lumber and Wood Products
		Sawmills and planing mills, general
5	2421	o Establishments primarily engaged in sawing rough lumber and lumber from logs and other unfinished forms of wood and in, combined or separately, producing surfaced lumber and standard patterns of lumber.

TABLE 4. INDUSTRIAL PLANT/PROCESSES (Cont'd)

No.	4-Digit SIC	Identification
		Paper and Allied Products
	2621	Paper Mills Except Building Paper Mills
6		o Integrated newsprint mill with ground wood pulping
7		o Integrated writing paper mill with Kraft pulping
	2361	Paperboard Mills
8		o Integrated corrugated paper mill
9		o Integrated box board mill including pulp wood acquisition, debarking and chipping, pulping, bleaching, boxboard production, and converting
		Chemical and Allied Products
	2812	Alkalies and Chlorine
10		o Chlorine and caustic soda plant
	2819	Industrial Inorganic Chemicals Not Elsewhere Classified
11		o Alumina plant
	2821	Plastics Materials, Synthetic Resins, and Nonvulcanizable Elastomers
12		o High density polyethylene resin
13		o Low density polyethylene resin
14		o Polyvinyl chloride resin
	2822	Synthetic Rubber (Vulcanizable Elastomers)
15		o Virgin styrene butadiene rubber plant engaged in the copolymerization of styrene and butadiene to produce a synthetic rubber of more than 50% butadiene content - The raw output of the plant is suitable for further processing into consumer goods.

TABLE 4. INDUSTRIAL PLANT/PROCESSES (Cont'd)

No.	4-Digit SIC	Identification
	2824	Synthetic Organic Fibers, Except Cellulosic
16		o Nylon production in a facility with two products: nylon 6,6, which is produced by polycondensation from adipic acid hexamethylenediamine, and nylon 6, which is produced by polycondensation from caprolactam - The output is in the form of fiber.
	2865	Cyclic (Coal Tar) Crudes, and Cyclic Intermediates, Dyes, and Organic Pigments (Lakes and Toners)
17		o Styrene plant producing ethylbenzene by alkylation of benzene with ethylene, followed by dehydrogenation of ethylbenzene to product styrene monomer
	2869	Industrial Organic Chemicals, Not Elsewhere Classified
18		o Ethylene
		<u>Petroleum Refining and Related Industries</u>
	2911	Petroleum Refining
19		o Integrated refinery
		<u>Rubber and Miscellaneous Plastics Products</u>
	3011	Tires and Inner Tubes
20		o Tire factory combining natural and synthetic rubbers with a variety of fibers, fillers, and other materials to manufacture pneumatic tires and inner tubes for all types of vehicles - Process steps include mixing, compounding, calendaring, extruding, and tire building.
		<u>Stone, Clay, Glass and Concrete Products</u>
	3221	Glass Containers
21		o Bottle and jar plant
	3241	Cement, Hydraulic
22		o Portlant Cement

TABLE 4. INDUSTRIAL PLANT/PROCESSES (Cont'd)

No.	4-Digit SIC	Identification
		Primary Metal Industries
	3312	Blast Furnaces (including Coke Ovens), Steel Works, and Rolling Mills
23		o Integrated steel mill producing raw and semi-finished steel from ore and scrap - Individual unit operations include coke ovens, blast furnaces, steel furnaces, soaking pits, rolling mills and various other finishing operations.
	3321	Grey Iron Foundries
24		o Foundry producing grey iron castings - Metal, coke and fluxes are combined and melted in a cupola or electric furnace, and then poured into molds for shaping prior to finishing.
	3331	Primary Smelting and Refining of Copper
25		o Hydrometallurgical copper refinement employing the relatively new Arbiter process for leaching copper from ores, rather than conventional pyrometallurgical techniques - The Arbiter process involves leaching, electro-winning and sulfur removal.
		Transportation Equipment
	3711	Motor Vehicles and Passenger Car Bodies
26		o Plant engaged in manufacturing or assembling complete motor vehicles from purchased raw materials, which may or may not be in semi-finished form -The main operations include production of motor vehicle bodies and chassies and the assembly of finished motor vehicles.

The product oriented classification system does not provide a simple energy situation (for example, classification 2869, industrial organic chemicals, not elsewhere classified, presently is the third largest energy consuming four-digit industry but it includes a large number of products produced by various methods). However, the standard industrial classification is the principle system generally used and, therefore, was used in this study. Using the Bureau of Census energy data at the four digit level for 1976, the national energy requirements for each industry are included in Table 5. This table presents data for the whole four-digit classification which in some cases contains more than one process and in other cases contains other products or processes not included in this study.

TABLE 5
1976 NATIONAL ENERGY REQUIREMENTS
4 DIGIT CLASSIFICATIONS

SIC	Industry	National Energy Requirements Trillion Btu
2011	Meatpacking	89.9
2051	Baking	56.1
2082	Malt Beverages	86.9
2221	Fabric Mill	102.2
2421	Saw Mill	115.6
2621	Newsprint Mill Writing Paper Mill	735.7
2631	Corrugated Paper Boxboard	537.1
2812	Chlorine	243.0
2819	Alumina	827.9
2821	LD Polyethylene HD Polyethylene Polyvinyl Chloride	226.3
2822	Butadiene Rubber	49.9
2824	Nylon	180.1
2865	Styrene	205.6
2869	Ethylene	1,255.7
2911	Petroleum Refining	1,404.1
3011	Tires	106.2
3221	Glass Container	178.3
3241	Cement	499.2
3312	Integrated Steel	1,741.2
3321	Gray Iron Foundry	153.9
3331	Copper	81.8
3711	Motor Vehicle	169.8
	TOTAL	9,046.5

In all, the industries in the 22 four-digit classifications are projected to require 55.8 percent of the industrial energy consumption in 1990.

Gordian Associates has developed detailed data for each of the selected industries which are presented in Volume II of this report. These data include national production and energy consumption data for the present and for projections to the year 2000. In addition, process data at the plant level defining energy requirements per unit of product output were developed. Gordian Associates projected a representative plant to the 1985-2000 period as the basis for the energy requirements. Assuming that the selected plant energy data is representative of the energy requirements of all plants producing the same commodity or product, the national fuel consumption for the 26 selected industrial processes is presented in Table 6.

TABLE 6

INDUSTRIAL PROCESS ENERGY REQUIREMENT - 1985

	Industry	Production Million Units	Electrical kWh/Unit	Thermal Million Btu/Unit	Total Industry Trillion Btu
1.	Meat Packing	20.9	200	0.68	58.8
2.	Baking	10.9	132	0.45	25.2
3.	Malt Beve ages	178.6	9	0.03	46.6
4.	Textile Mill	1.5	4,767	16.3	507.
5.	Saw Mill	43.7	174	0.59	51.8
6.	Newsprint	4.1	1,741	5.94	60.3
7.	Writing Paper	3.6	1,327	4.52	89.8
8.	Corrugated Paper	18.5	879	2.99	443.
9.	Boxboard	4.9	1,121	3.83	135.
10.	Chlorine	14.4	2,820	9.62	273.
11.	Alumina	9.7	270	9.22	890.
12.	LD Polyethylene	6.0	1,743	5.95	517.
13.	HD Polyethylene	3.3	1,210	4.13	28.5
14.	PVC	5.1	947	3.23	41.3
15.	Butadiene Rubber	1.9	185	0.63	13.0
16.	Nylon	1.2	1,263	4.31	10.7
17.	Styrene	5.2	68	0.23	122.
18.	Ethylene	20.	36	0.12	1,250.
19.	Petroleum	6,143.	4	0.14	1,118.
20.	Tires	5.5	931	3.18	63.5
21.	Glass	15.6	283	0.97	152.
22.	Cement	40.0	128	0.44	236
23.	Steel Mill	155.1	279	0.95	2,260.
24.	Gray Iron Foundry	9.8	665	2.27	85.5
25.	Copper	2.7	2,432	8.30	88.3
26.	Motor Vehicles	13.7	612	2.09	121.

The selected industries currently use large quantities of oil and natural gas and are logical candidates for cogeneration with energy conversion technologies which can improve efficiency and/or operate with coal or coal derived fuels. Table 7 presents the projected fuel usage in the chosen industrial processes in 1990. This table presents the energy value of the projected fuel purchased by the industry and the energy value of the fuel required to provide projected utility electricity (assuming coal is the utility fuel). The energy value of byproduct fuels used within the plant is not accounted for (e.g. hydrogen produced in the manufacture of chlorine).

TABLE 7
ESTIMATED NON-COGENERATION FUEL USE
PROCESS LEVEL - 1990
TRILLION BTU

Industry	Natl. Gas	Oil	Coal*	Other	Total
Meat Packing	35.60	7.63	59.67	2.05	104.95
Baking	14.93	2.77	15.69	6.58	39.97
Malt Beverage	30.74	15.32	20.03	5.06	71.15
Fabric Mills	12.02	9.09	84.49	2.12	107.71
Saw Mill	8.60	4.80	90.30	7.50	111.20
Newsprint Mill	11.82	11.82	96.40		120.04
Writing Paper	14.75	23.11	73.53		11.39
Corrg. Paper	143.37	96.92	265.49		505.78
Box Board	39.00	27.70	88.23		154.94
Chlorine	46.39	20.93	601.53		668.86
Alumina	40.85	38.21	32.01		111.07
LD Polyethylene	13.44	4.65	153.79	2.59	174.48
HD Polyethylene	11.80	4.08	58.27	2.27	76.42
PVC	21.56	7.46	81.96	4.15	115.12
Rubber	10.13	0.82	5.41	2.52	18.89
Nylon	1.57	3.43	23.52	0.37	28.89
Styrene	115.60	43.20	22.20	9.00	190.00
Ethylene	906.01	251.09	16.19		1,173.29
Petro Refining	1,973.32	936.06	495.70	683.07	4,082.15
Tires	23.55	17.50	67.34	0.91	109.30
Glass Container	131.95	31.56	49.87		213.38
Cement	48.92	15.88	235.81		300.61
Integrated Steel Mill	764.62	299.38	3,129.18	339.83	4,533.02
Gray Iron Foundry	36.96	2.01	75.24	40.62	154.83
Copper	77.49		82.65		160.14
Motor Vehicles	60.67	13.98	121.84	12.19	208.68
TOTAL	4,595.66	1,889.40	6,046.34	1,120.83	13,652.26

*Includes Utility Coal Consumption

The required temperature of the thermal energy needed by the process is a critical factor in designing cogeneration systems. Therefore, Gordian Associates determined the amounts of steam and hot water used for heating.

The process thermal requirements in terms of plant production for each selected industrial process are presented in Table 9. These data are catalogued according to a thermal bin system adopted in this study to provide a means of matching industrial requirements with the thermal output of the various energy conversion systems. The selected thermal bins are hot water, 50 psig steam at 300°F, and 600 psig steam at 500°F and at 700°F. In addition, direct fuel requirements are included as a thermal bin. The thermal bin system is described further on pages 27 and 28. The data in Table 9 are presented in terms of the selected bin system.

TABLE 9

SELECTED INDUSTRIAL PROCESS ELECTRICAL AND THERMAL REQUIREMENTS

Industry	Annual Plant Production	Plant Electrical Demand (MW_e)	E/T	HW	Thermal Requirements (Million Btu/Unit)			
					300°F	500°F	700°F	Direct
Meat Packing	200,000 tons	8.7	0.32	1.22	0.82	0	0	0.14
Baking	15,000 tons	0.32	0.24	0.03	0.66	0	0	1.18
Malt Beverages	2,000,000 barrels	2.4	0.13	0	0.21	0	0	0.01
Broad Woven Fabrics	6,000 tons	4.1	0.95	0	0	15.2	0	1.46
Saw Mills	12,000 M bd. ft	0.38	0.10	0	6.3	0	0	0
Newsprint	620,000 tons	130.0	0.68	0.64	2.5	5.7	0	0
Writing Paper	207,000 tons	33.0	0.22	0.9	7.0	12.6	0	0
Corrugated Paper	775,000 tons	82.0	0.14	1.5	9.4	10.2	0	0
Boxboard	517,000 tons	70.0	0.16	1.8	9.6	12.8	0	0
Chlorine/Caustic	220,000 tons	77.0	1.03	0	1.9	7.7	0	0
Alumina	900,000 tons	31.0	0.11	0	0	4.8	0	3.4
LD Polyethylene	190,000 tons	40.0	2.17	0	0.33	2.4	0	0
HD Polyethylene	140,000 tons	20.4	0.89	0	0	4.6	0	0
PVC	120,000 tons	13.7	0.67	0	0	4.9	0	0
Rubber	128,00 tons	2.9	0.10	0	1.3	3.4	0	1.6
Nylon	57,000 tons	8.2	0.94	0	0.43	2.7	1.4	0
Styrene	500,000 tons	4.3	0.01	0	23.8	0	0	4.5
Ethylene	652,000 tons	2.8	0.002	0	0	0	6.9	50
Petroleum	63.9×10^6 crude runs	34.6	0.03	0	0	0.1	0	0.41
Tires	100,000 tons	14.3	0.38	0	0	6.9	0	0
Glass	125,000 tons	4.7	0.11	0	0	0	0	8.6
Cement	725,000 tons	11.8	0.08	0	0	0	0	5.3
Steel	5,000,000 tons	200.0	0.07	0	0	1.2	0	13.2
Gray Iron Foundry	400,000 tons	35.7	0.35	0	0.06	0	0	6.5
Copper	36,000 tons	11.1	0.34	0	0	24.7	0	0
Motor Vehicles	210,000 autos	21.0	0.31	0	0	4.7	0	1.7

The fuel use by all of the manufacturing plants producing the same product (Table 7) can serve as the basis of estimated fuel use in the four-digit industries. These estimates are required to scale the analysis to national levels as discussed on page 80 of this report.

TABLE 8
ESTIMATED NON-COGENERATION FUEL USE
4-DIGIT LEVEL - 1990
TRILLION BTU

SIC	Industry	Natl Gas	Oil	Coal*	Other	Total
2011	Meat Packing	35.60	7.63	59.67	2.05	104.95
2051	Baking	14.93	2.77	15.69	6.58	39.97
2082	Malt Beverage	30.74	15.32	20.03	5.06	71.15
2221	Fabric Mills	12.02	9.09	84.49	2.12	107.71
2421	Saw Mills	8.60	4.8	90.30	7.50	111.20
2621	Newsprint Mill	91.63	91.63	747.29		930.54
	Writing Paper	114.34	179.15	570.00		863.49
2631	Corrugated Paper	305.69	206.65	566.08		1,078.42
	Box Board	83.16	59.06	188.12		330.26
2812	Chlorine	54.45	24.57	706.02		785.05
2819	Alumina	220.81	206.54	173.03		600.38
2821	LD Polyethylene	35.00	12.11	400.49	6.74	454.38
	HD Polyethylene	30.73	10.63	151.74	5.91	199.01
	PVC	56.15	19.43	213.44	10.81	299.79
2822	Rubber	27.78	2.09	13.77	6.41	48.07
2824	Nylon	2.24	4.90	33.60	0.53	41.27
2865	Styrene	214.07	80.00	41.11	16.67	351.85
2869	Ethylene	3,484.65	965.73	62.27		4,512.65
2911	Petro Refining	1,973.32	936.06	495.70	683.07	4,088.15
3011	Tires	29.07	21.60	83.14	1.12	134.94
3221	Glass Container	131.95	31.56	49.87		213.38
3241	Cement	112.98	36.67	544.60		694.25
3312	Integrated Steel Mill	764.62	299.38	3,129.18	339.83	4,533.02
3321	Gray Iron Foundry	36.96	2.01	75.24	40.62	154.83
3331	Copper	74.49		82.65		160.14
3711	Motor Vehicles	60.67	13.98	121.84	12.19	208.68
	TOTAL	8,007.65	3,243.36	8,719.36	1,147.21	21,117.53

* Includes Utility Coal Consumption

Since furnace losses are not accounted for in these data, a direct correspondence of energy requirements is not appropriate. Various studies have indicated current industrial heat supply efficiencies from 50 to 80 percent.

The steam and hot water requirements are presented by thermal category or bin in Figure 12. The most common thermal requirement is in the 500°F, 600 psig bin. Beyond the bin system no modifications to the industrial processes were considered ed whereby the process temperature requirements might be reduced. For example, situations where steam is used to heat hot water were carried in this study as steam requirements.

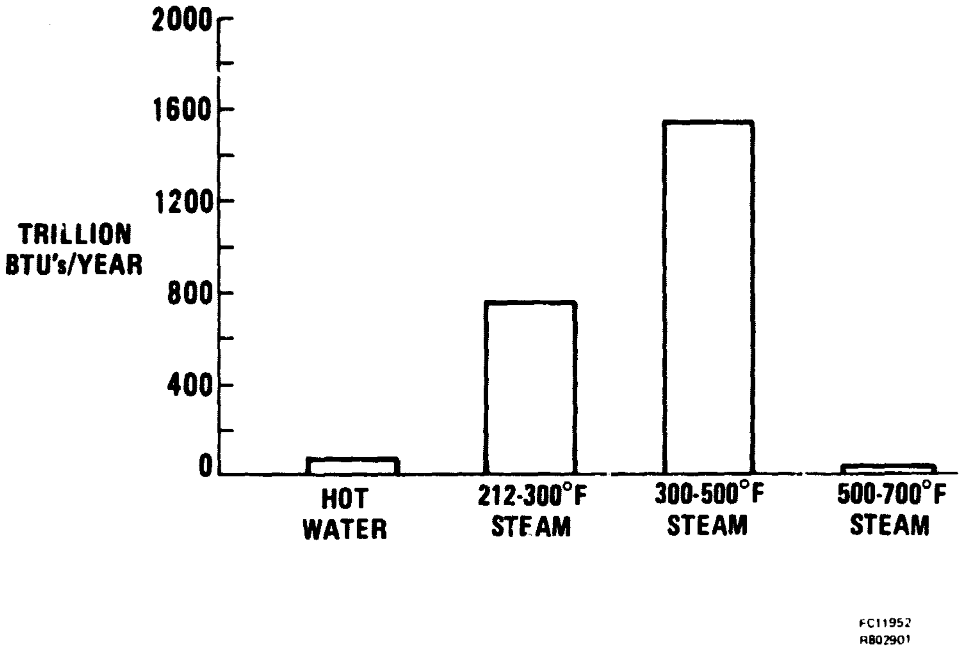

Figure 12. Process Thermal Requirements

Table 9 also lists the annual production of the plants selected to represent each process. The electrical demand is included. In terms of electrical requirements, the 26 selected industrial plants vary in size from 0.3 to 200 megawatts.

The ratio of electrical to thermal energy requirements, E/T, for the industrial process is a consideration in the evaluation of cogeneration possibilities. Generally close agreement between the equipment E/T and the process E/T suggests that all of the energy produced by the energy conversion equipment can be effectively utilized. If the equipment and process E/T ratios are not close, heat may have to be wasted or electricity exported. The general range of E/T for the selected industrial processes is included in Table 9 and fall in the range of 0.01 to 2. The selected industrial processes represent a reasonable cross-section of promising cogeneration opportunities in the energy intensive industries.

There are two types of cogeneration approaches to be considered in this study: topping systems where the heat rejected by the energy conversion system provides process heat; and bottoming systems where the heat from a high temperature exhaust stream from the process is used to generate electricity. The emphasis of this study is upon topping systems. Twenty-four of the 26 chosen processes are topping system candidates. Two are applicable to bottoming systems: glass containers (3221) and cement (3241). Opportunities for both topping and bottoming systems exist in the steel industry (3312) and in oil refineries (2911).

The selected industries provide basic materials and products which are expected to continue to be major factors in society in future years. One product , butadiene rubber, has been declining in market share somewhat but still represents two thirds of the synthetic rubber manufactured and also is a good cogeneration candidate. Conversely, the primary copper process chosen for this study is hydrometallurgical and is a good candidate for cogeneration. It has only reached the pilot plant stage. However, in response to high energy costs and environmental requirements, the copper industry is expected to move towards hydro-metallurgical plants in the 1985-2000 time period. Overall, the selected industries provide an effective base for the Cogeneration Technology Alternatives Study.

INDUSTRIAL PROCESSES

Industrial process energy requirements data has been developed by Gordian Associates and reported in Volume II. The information includes a description of the process and its energy consumption, detailed data concerning electrical and thermal energy requirements, anticipated future trends, and representative plant data.

PRINCIPAL ASSUMPTIONS AND GROUNDRULES

INTRODUCTION

In order to provide a manageable framework for the Cogeneration Technology Alternatives Study, a series of assumptions and groundrules were adopted. These assumptions concerned industrial requirements, fuel characteristics, traditional (non-cogeneration) equipment and utility performance, environmental considerations, cogeneration plant design, and economic factors. Some of the groundrules were specified by the National Aeronautics and Space Administration for consistency with or usefulness in other analyses, in particular, fuel characteristics and prices, emission standards, electric utility performance and rates, and economic parameters. Other assumptions were selected by the contractor or one of the principal participants. The energy conversion system technical projections to the 1985 - 2000 time period were made by the appropriate specialists. Among the more significant assumptions of this study was the selection of the thermal bin system for describing industrial thermal requirements and conversion system thermal capabilities.

INDUSTRIAL REQUIREMENTS

Conventionally, the industrialist provides process energy requirements by purchasing electricity from the local utility and purchasing fuels which are burned to meet thermal needs and, in some cases, provide steam for mechanical drive.

For this study all mechanical shaft power is assumed to be provided by electric motors and the industrial process electrical requirements were based on both utility electrical consumption and mechanical drive steam consumption.

The industrial thermal requirements are more complex. In many plants a central boiler provides steam to various elements of the process to meet thermal needs. Required temperatures (and associated steam pressures) vary from process to process and in many cases vary within the process. For purposes of this study, the industrial thermal requirements have been classified in five categories or bins:

(1) Hot Water: The hot water supply is at 140°F and a nominal 40 psig. The temperature of the return hot water is 110°F. In many industrial processes the hot water is consumed and makeup water is assumed to be provided at 60°F and 40 psig.

(2) Low Temperature Steam: Low temperature steam is required at 300°F and 50 psig. The hot water condensate is assumed to be returned at 130°F at atmospheric pressure.

(3) Medium Temperature Steam: This bin is for steam at 300-500°F with maximum pressure of 600 psig. The condensate is assumed to be returned at 130°F at atmospheric pressure.

(4) High Temperature Steam: This category consists of steam at 500-700°F and pressure of 600 psig. Again the condensate return is assumed to be 130°F at atmospheric pressure.

(5) Direct Heat or Hot Gas: The direct heat or hot gas category is heat currently provided by burning a specific fuel (such as natural gas in a bakery oven) or by consuming fuel in a furnace to provide hot gas to the process. The temperature, hot gas cleanliness, and specific fuel, if necessary, are defined in the industrial requirements.

Some industrial processes produce a byproduct fuel and the industrial process data specifies the quantity and characteristics of such byproduct fuels. In all cases the byproduct fuel could be burned to supplement hot gas needs or to raise steam. In those cases where the byproduct fuel could be consumed in the cogeneration energy conversion plant, it was used. For this study byproduct fuel was available at no cost. For simplicity, the assumption was made that byproduct fuel could be burned without emitting pollutants.

In some cases the industrial process produces byproduct heat which can be used in a cogeneration plant to raise steam or to produce electricity in a bottoming cycle. In this study, processed byproduct heat was first used to reduce the industrial process thermal requirements. When significant byproduct heat could not be used in the process it was used in the bottoming system. Figure 13 is a schematic diagram of the cogeneration system based on the assumed bin system for industrial requirements. The cogeneration plant produces conventional, regulated, 60 Hz electricity at an appropriate voltage and thermal energy in one of the five bins. The cogeneration plant uses process byproduct fuel and heat to the extent practical. Fuel is purchased to operate the cogeneration system. Electricity is purchased or sold to the electric utility according to need.

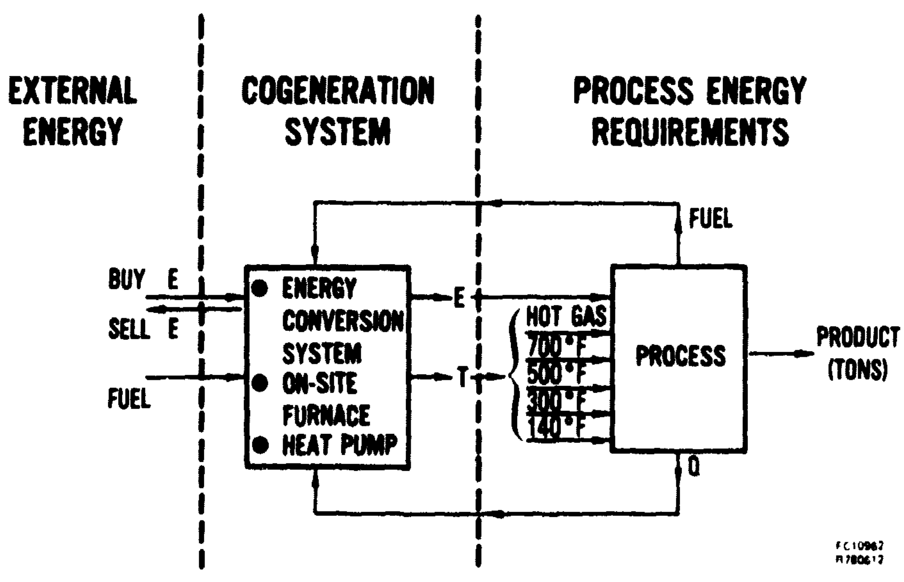

Figure 13. Cogeneration System Schematic Diagram

FUELS

One of the principal objectives of the cogeneration technology alternatives study was to emphasize systems with potential for energy saving and transition from the use of oil and natural gas to coal or coal derived fuels in the 1985-2000 time period. The fuels considered in the study included: high sulfur coal, petroleum distillate (No. 2), petroleum boiler fuel (No. 5), coal derived distillate, coal derived boiler fuel.

Gas derived from coal was produced on-site by low BTU gasification plants. Pipeline gas or synthetic natural gas was not considered in this study. Table 10 presents the specifications for liquid fuels and Table 11 provides the high sulfur coal specification used in the study.

TABLE 10. LIQUID FUEL SPECIFICATIONS

	Petroleum Distillate	Petroleum Boiler Fuel	Coal-Derived Distillate	Coal-Derived Boiler Fuel
Sulfur, % wt.	0.5	0.7	0.5	0.7
Nitrogen, % wt.	0.06	0.25	0.8 nominal	1.0 nominal
Hydrogen, % wt.	12.7	10.8	9.5 nominal	8.5 nominal
Ash, % wt.	--	0.03	0.06	0.26
Specific Gravity	0.85	0.96	0.95	1.05
Boiling Range, °F 90% pts.	430-675	500-800	430-675	500-800
Trace Elements, ppm wt. (order of magnitude)				
Vanadium	≤0.5	30	0.5	2
Sodium + Potassium	≤0.5	50	1	20
Calcium	≤1.0	5	2	5
Lead	≤0.5	5	1	5
Iron	--	--	30	30
Titanium	--	--	20	50
High (Gross) Heating Value, Btu/lb	19,350	18,500	17,700	17,000

TABLE 11. HIGH SULFUR COAL SPECIFICATION

Proximate Analysis (as received), %	
Moisture	13.
Volatile	36.7
Fixed Carbon	40.7
Ash	9.6
Ultimate Analysis (as received), %	
Ash	9.6
Sulfur	3.9
Hydrogen	5.9
Carbon	59.6
Nitrogen	1.0
Oxygen	20.0
Higher Heating Value (as received)	10788 Btu/lb
Gross Heating Value (dry)	12600 Btu/lb
Average Softening Temperature	1979°F
Initial Deformation Temperature	1990-2130°F
Fluid Temperature	2090-2440°F
Grindability (HGI)	55
Free-swelling Index	4.5
Selected Trace Elements, ppm in coal	
Fluorine	50-167
Lead	8-14
Vanadium	9-67
Selected Ash Constituents, %	
Fe_2O_3	20.8
TiO_2	0.8
CaO	7.7
MgO	0.9
N_2O	0.2
K_2O	1.7

Coal-derived fuel was assumed to be manufactured with minimum fuel processing. The overall plant efficiency was set at 70% and the assumption was made that no pollutants were emitted from the coal processing plant. The coal-derived liquid fuels may not be compatible with corresponding petroleum base fuels and separate storage, transportation, and utilization equipment could be required. For this study, the coal-derived fuels were assumed to be compatible with the petroleum base fuels.

ELECTRIC UTILITY

The electric utility was assumed to consume coal and generate and distribute electricity to the industrial plant at 32% efficiency (based on the higher heating value of the fuel). The pollutants emitted by the utility central station were assumed to meet the environmental standards for coal fired boilers defined in the following section.

INDUSTRIAL EQUIPMENT

The industrialist traditionally operates on-site furnaces to provide heat in various forms. The performance of these furnaces was established to permit comparison of cogeneration and non-cogeneration energy consumptions. For this study all non-cogeneration heat sources were fired by liquid boiler fuel and operated at 88% efficiency (ratio of thermal output to higher heating value of the fuel consumed). Furnaces required to provide supplementary heat in cogeneration systems were designed to provide the same efficiency. A groundrule efficiency of 85% was established for coal fired furnaces. While no non-cogeneration furnaces were designed to use coal, current technology heat sources to produce steam for cogeneration systems were designed to meet this efficiency groundrule.

EMISSIONS

The environmental guidelines for air pollutants adopted for this study are presented in Table 12. These values are based on the type and amount of fuel used by the power plant rather than the power plant electrical and thermal output.

TABLE 12 POLLUTANT EMISSION GUIDELINES

Fuel	Pollutant-Lbs. per Million BTU Heat Input			
	No_x	SO_x	Particulates	Smoke
High Sulfur Coal*	0.7	1.2	0.1	20 SAE Number
Petroleum Distillate	0.4	0.8	0.1	20 SAE Number
Petroleum Boiler Fuel	0.5	0.8	0.1	20 SAE Number
Coal-Derived Distillate	0.5	0.8	0.1	20 SAE Number
Coal-Derived Boiler Fuel	0.5	0.8	0.1	20 SAE Number
Gas*	0.2	0.2	0.1	20 SAE Number

* For systems on auxiliary furnaces using LBTU gas produced on-site from coal, the coal limitation shall apply.

COGENERATION SYSTEM DESIGN

The cogeneration plant consists of all of the on-site equipment necessary to provide the electrical and thermal energy requirements of the industrial process. For evaluation of the performance and economics of the cogeneration system, the "conventional" or "traditional" non-cogeneration system is also defined in terms of the on-site equipment required to supply the thermal energy for the industrial process. Common elements (for example, plant electrical distribution equipment) are not defined and are omitted from the study.

The cogeneration system comprises the energy conversion system which includes heat recovery equipment, the heat source, the balance of plant and any auxiliary furnaces required. In some cases it includes heat pumps and/or thermal storage. The balance of plant includes all of the items required for proper operation of the system not otherwise included such as fuel storage and handling, heat rejection, waste disposal, buildings, etc.

The guideline was established that the advanced energy conversion technologies be consistent with technology estimated to be commercially available in the 1985-2000 time period. In making this judgment, the existence of, or lack of, advanced technology programs or development programs supported by either government or industry were not considered.

The output of each energy conversion system was defined in terms of the bin system classifying thermal requirements in 5 categories: hot water, steam at 3 temperatures and hot gases, Figure 13. The industrial process energy requirements in this study vary over a wide range of electrical to thermal energy ratio and vary in the temperature of the thermal requirements. Since the energy conversion system design could emphasize electrical output or, alternately, heat recovery at one temperature or another, a number of designs were possible. In order to conduct the study with a manageable number of possibilities, up to 5 designs were defined for each energy conversion system-fuel combination. The cogeneration plant design life was set at 30 years.

The heat recovery equipment was included as part of the energy conversion system. In order to maintain consistency in the assumptions for the various advanced energy conversion systems, the approach or pinch temperature difference in the heat recovery heat exchanger was limited to a minimum of 30°F. Higher temperature differences were permitted. Since corrosion can be expected if the temperature of the exhaust gas from a furnace or conversion system is reduced to the dew point and if oxides of sulfur are present, an exhaust gas temperature limit of 300°F was adopted for acceptable corrosion characteristics with sulfur oxides in the exhaust stream. As indicated by the ASHRAE handbook, this minimum temperature varies with the amount of excess air employed. For this study, exhaust gas temperatures above those shown on Figure 14 were employed wherever there were sulfur oxides in the exhaust stream. If sulfur oxides were absent, lower exhaust temperatures were acceptable.

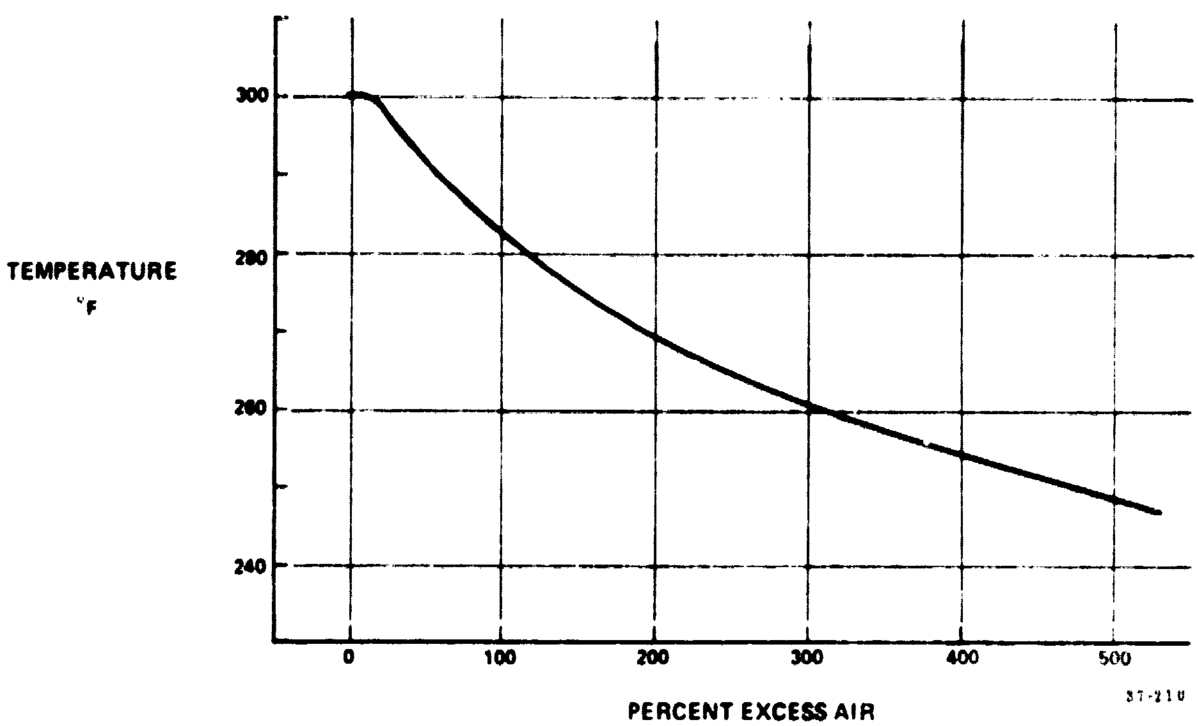

Figure 14. Heat Recovery Heat Exchanger Minimun. Exhaust Temperature with Sulfur Oxides Present

A number of groundrules were established for the design of the overall plant. Utility backup power was to be provided to the extent necessary to prevent damage to equipment or the production line in the event of shutdown caused by a cogeneration plant failure. Backup power sufficient to continue full production was not to be provided. Gordian Associates judged that half rated capacity would typically provide such damage-free shutdown characteristics. Therefore, the minimum number of energy conversior systems or heat sources used in this study is 2. With this minimum level of redundancy, no electric utility standby charge is necessary. The maximum number of units was set at 12.

A Middletown U.S.A. site was assumed to establish site environmental conditions. The site was located at sea level and the performance of energy conversion systems was based on an ambient temperature for average day conditions of 59°F. In sizing and estimating the cost of heat rejection systems (part of the balance of plant), the 5 percent summer environmental conditions included a wet bulb temperature of 77°F and a dry bulb temperature of 93°F.

Land costs were assumed to be zero for this study. Water was assumed to be available from the industrial plant water system for all uses. Additional water treatment was only required for boiler feedwater makeup. Waste water was assumed to be returned to the industrial plant waste water system except for coal stockpile runoff which was assumed to drain to an evaporator pond. The assumption was made that solid wastes were to be trucked from the site. The fuel storage system was designed for 30 days storage. The solid waste storage bins were designed for 7 days storage.

In order to estimate installation and site construction costs, a composite wage rate including fringe benefits of $14/manhour (1978 dollars) was set in this study. This groundrule was based upon a composite mix of 11 trades and skills and published wage rates for 30 or more cities. Distributable or indirect field costs include expenses that cannot be directly identified with any specific direct account item. Distributable field costs can be estimated as a percentage of direct field labor costs. For this study, distributable costs were set at 75% of direct field labor costs. Included in this distributable account are the following items:

- Temporary construction facilities including sheds, paving, temporary utility connections.
- Construction services including surveying, material handling, watchmen, etc.
- Construction equipment and tools.
- Consumables including fuel, oxygen, acetylene, etc.
- Field office costs.
- Preliminary operation and testing including alignment, balancing, and testing of all equipment.
- Payroll expenses including payroll taxes.
- Insurance.
- State and local taxes.

ECONOMIC ASSUMPTIONS

The 1985 fuel prices and rates of fuel price escalation relative to inflation adopted for this study are presented in Table 13. The escalation rates were assumed from 1985 through the time period of interest for all fuels except natural gas. The price on natural gas was assumed to be escalated at the two rates indicated. The prices for petroleum and coal-derived liquid fuels of similar grades were assumed to be the same.

TABLE 13 COGENERATION TECHNOLOGY ALTERNATIVES STUDY FUEL PRICES

Fuel	1985 Price 1978 Dollars/Million BTU	Escalation Above Inflation Percent Per Year
Coal	1.80	1.0
Petroleum Distillate	3.80	1.0
Coal-Derived Distillate	3.80	1.0
Petroleum Boiler Fuel	3.10	1.0
Coal-Derived Boiler Fuel	3.10	1.0
Natural Gas	2.40	4.6 (1985-2000) 1.0 (2000-)

The price of electricity purchased from the grid for all industries was set at 3.3 cents/kilowatt hour in 1985 in 1978 dollars and was escalated at a rate of 1% per year above inflation. In this study, for consistency and simplicity, the electric price was held constant throughout the country regardless of the amount used. The amount paid by the utility to the industrialist was assumed to be 60% of the normal utility rate. A utility standby charge of $2/kilowatt/month was established where it was deemed appropriate. However, with cogeneration power plant redundancy, no standby or demand charge was imposed and no credit for industrial generating capacity (which could feed the grid) was assumed.

The costs of limestone and dolomite delivered to the site were established at $10 per ton and $12.50 per ton, respectively. These costs assumed a trucking distance of about 30 miles. The cost of these materials was assumed to have zero rate of escalation relative to inflation. Table 14 presents the requirements for the limestone and dolomite.

TABLE 14 FLUID BED COAL COMBUSTION SORBENT REQUIREMENTS

	AFB STEAM	AFB GAS	PFB GAS
Bed Temperature - °F	1500°F	1600°F	1650°F
Sorbent	Limestone	Limestone	Dolomite
Composition - Weight Percent			
- $CaCO_4$	97.0%	97.0%	54.0%
- $MgCO_3$	1.2	1.2	44.0
- SiO_2; $A1_2O_3$; Fe_2O_3	1.6	1.6	1.4
Size (screened)	1/8" - 1/16"	1/8" - 1/16"	1/8" x 1/16"
Use Rate - Atom Ratio Ca/S	3:1	4:1	1-1/2:1
Limestone Weight (Wet)/ Coal Weight (Wet)	0.38	0.51	0.345

All cogeneration and non-cogeneration plants considered in the study were assumed to start operation in 1990. Differences in construction time were accounted for by varying the date of the start of construction. The cost of capital for all industries was based on the following values: percentage of capitol raised through debt of 30%, percentage of capital raised through equity of 70%, cost of debt 3% above inflation rate, cost of common equity 7% above the inflation rate. These values result in a weighted after tax cost of capital of 5.4% above the inflation rate.

A total income tax rate of 50% (including federal, state and local income taxes) was used. An annual charge equal to 3% of the capital investment was assessed to cover other local taxes and insurance costs. An investment tax credit of 10% was applied to both non-cogeneration and cogeneration systems. The investment tax credit was assumed to reduce the tax liability in the first year of operation. The sum-of-the-years-digits depreciation method and a 15 year depreciation life were assumed for tax purposes for both non-cogeneration and cogeneration systems. The depreciation life applies to the total system. Zero salvage value was assumed for all equipment. For the base case economic analyses for the cogeneration technology alternatives study an inflation rate of zero was assumed. In order to provide consistent cost data, the definitions of the cost account categories presented in Table 15 were adopted.

TABLE 15 DEFINITIONS OF COST ELEMENTS

1.1 Fuel Storage and Retrieval

Storage tanks, pumps, conveyors, coal feed bins, crushers, heater, lock hoppers, surge hoppers, and other equipment associated with transfer of fuel intraplant.

1.2 Limestone Storage and Retrieval

Storage bins, conveyors, weigh feeders, dust collection equipment, and other equipment except unloading equipment. Unloading equipment used for coal will be used for limestone.

1.3 Waste Handling Systems

Storage bins, settling ponds, holding tanks, conveyors, elevators, pumps, filters, and other equipment for handling and disposing of solid and liquid waste.

2.1 Heat Source

Combustors, boilers, furnaces, process steam generators including fuel pulverizers, fuel feed systems, superheaters, heat pipes, flash boilers, emission control systems, exhaust stack, hot gas cleaning systems, boiler feed water treatment and supply and other major equipment associated with providing clean heat to the energy converter.

2.2 Special Emissions Controls

Gas clean-up systems including cyclone separators, filters, scrubbers, pumps, tanks, hoppers, and other appropriate equipment.

2.3 Feed Water Systems

Boiler feed water equipment including pumps, deaerator, tanks, demineralizer, etc.

2.4 Gasifier

Equipment to convert coal to gaseous fuel for use in energy conversion systems.

3.1 Primary Energy Converter

The primary cogeneration plant including all integrated components.

3.2 Primary Generator/Inverter

Equipment associated with converting mechanical energy or direct current electrical energy to conventional, regulated, 60 Hz alternating current electricity.

3.3 Secondary Energy Converter

Equipment such as a steam turbine used for steam bottoming as part of a combined cycle which produces energy in addition to but not in place of a primary energy converter.

3.4 Secondary Generator/Inverter

Equipment associated with converting, mechanical energy or direct current electrical energy to conventional, regulated 60 Hz alternating current electricity.

3.5 Bottoming Cycle Vapor Generator

Heat exchanger operating with a high temperature gas stream and a fluid boiler.

3.6 Heat Recovery Equipment

Heat exchangers used to provide process heat from energy converter heat streams. This does not include heat exchangers and condensers integral to the operation of the energy converter or external cooling systems.

3.7 Condensers

Water cooled heat exchangers condensing water or organic fluids.

3.8 Heat Pump

Equipment to increase steam temperature including evaporators, pumps, heat exchanger, and controls.

4.0 Thermal Storage

Equipment to store thermal energy including tanks, pumps, valves, etc.

5.0 Supplementary Heat

Furnaces, boilers, pumps, fans, heat exchangers, stacks, etc. required to provide hot water or steam.

6.0 Heat Rejection

Wet mechanical draft cooling tower, pumps, tanks, etc.

7.1 Site Preparation

Site preparation and improvements to existing facilities necessary to accommodate the cogeneration facility except for preparation normally required for conventional energy systems. Site preparation includes finish grading and landscaping, site drainage and sewage disposal, roads, walks, parking areas, railroad access track and track site, fencing, and dikes. Land is assumed to be available at no cost.

7.2 Structures

Permanent buildings and structures required for the cogeneration plant excluding these buildings and structures required for conventional energy supplies and including administration and maintenance structures, and auxiliary plant boiler housings.

7.3 Electrical Conditioning and Control

Transformers, switch gear, bus, conduit, and other equipment to provide the auxiliary power for the cogeneration plant.

8.1 Contingency

Estimates predict the cost of a project but predictions contain uncertainties. Contingency is the amount of money that construction experience has demonstrated must be added to an estimate to provide for uncertainties within the design detail in quantity, pricing, and productivity.

Contingency reduces the risk to these uncertainties and reflects a selected risk of overrun. The contingency is expected to be expended and is selected to yield the most probable total project cost. Contingency does not provide for changes in the defined scope of a project or foı unforseeable circumstances beyond the contractor's normal experience or control.

A. contingency of 20 percent applied to all costs has been reflected with consideration of the conceptual nature of the plants included in this study. The limited conceptual level of detail in these plant designs increases the risk of underestimating costs.

8.2 Engineering and Fees

Recent fossil fired power plant construction experience demonstrates that engineering and other home office cosfs and fees are equal to approximately 15 percent of total direct plus indirect field costs. Included in these costs are:

Engineering.

Estimating, schedule and cost control.

Purchasing, expediting, and inspection (procurement).

Construction management and administration.

Fees for engineering, procurement and construction management.

Fees typically amount to about 2 percent of the total field costs. About two-thirds of the remaining 13 percent are for engineering services and the remaining third is for other home office costs.

COGENERATION STRATEGIES

Each energy conversion cogeneration system may be applied such that its heat rejection is utilized in an industrial process (front end/or topping configuration) or such that it receives thermal input recovered from an industrial process (back-end or bottoming configuration), as appropriate. In this study emphasis was placed on front-end or topping configurations.

Four cogeneration strategies were examined. In one the electrical requirements of the industrial process were satisfied by the cogeneration plant and the heat recovered from the energy conversion system was utilized to satisfy the process requirements. If more heat needed to be supplied, it was provided by an auxiliary furnace.

In the second strategy, the selected cogeneration plant was of sufficient size to match the thermal requirements of the industrial process. Any surplus electricity generated by the cogeneration plant was exported to the electric utility. If there was a deficiency and the industrial process required more electricity, it was imported from the utility. No institutional barriers were assumed to exist that would impede import or export.

Since the industrial requirements involve thermal needs at various temperatures, a third strategy was introduced in which neither the electrical needs nor all of the thermal needs of the industrial process were satisfied; rather, the most energy-conserving cogeneration plant was selected.

In the fourth strategy, a heat pump was employed to raise the temperature of the conversion system rejected heat utilizing electricity from the cogeneration plant to drive the heat pump. The objective was to produce a better match such that both thermal and electrical needs of the industrial process would be satisfied with the cogeneration heat pump combination. This constitutes a limited approach to the industrial application of heat pumps. No low temperature industrial waste heat was identified or considered in the study. Westinghouse personnel indicated that the principal use of industrial heat pumps was expected to extract heat from low temperature waste streams to provide heat for higher temperature process streams.

ENERGY CONVERSION SYSTEMS

INTRODUCTION

The conversion technologies were selected for applicability in industrial processes. Front end, or topping, systems which produce electricity and recover heat for the process were emphasized. Backend, or bottoming, configurations which receive thermal energy from the industrial process and produce electricity for use at the plant site or for export to the electric utility were considered. The conversion systems were also chosen with emphasis on the potential for energy savings and transition from the use of oil and natural gas to coal or coal-derived or alternate fuels. The advanced technologies were selected to be consistent with technology estimated to be commercially available in the 1985-2000 period. In making this judgment, the existence of, or lack of, advanced technology programs or development programs supported by either industry or government was not considered.

The selected current technology energy conversion systems and associated fuels are presented in Table 16. Five cogeneration technologies, steam turbine, gas turbine, combined cycle and two classes of diesel engines are representative of current technology and use conventional fuels: oil and gas. In addition, a steam turbine with a coal-fired boiler and flue gas desulfurizor was classified as current technology. The advanced energy conversion systems and associated fuels are presented in Table 17 and include steam turbines; gas turbines, both direct and indirect fired; combined cycle; closed (or Brayton cycle) gas turbines; steam injected gas turbines; two classes of diesel engines; thermionic conversion, low and high temperature fuel cells; Stirling engines; and, for bottoming cogeneration applications only, organic rankine cycle. The fuels selected were generally the heaviest, least refined type appropriate for the technology in the 1985-2000 time period. Coal or coal-derived fuels were selected where possible.

TABLE 16 CURRENT ENERGY CONVERSION SYSTEMS AND FUEL COMBINATIONS

ENERGY CONVERSION SYSTEM \ FUEL	PETROLEUM		COAL	BY-PRODUCT HEAT
	DISTILLATE	BOILER FUEL		
STEAM TURBINE		●	●	
GAS TURBINE • DIRECT FIRED	●			
COMBINED CYCLE	●			
DIESEL • HIGH SPEED	●			
• LOW SPEED		●		
STEAM TURBINE (BOTTOMING)				●

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R780612

TABLE 17 ADVANCED ENERGY CONVERSION SYSTEMS AND FUEL COMBINATIONS

ENERGY CONVERSION SYSTEM \ FUEL	PETROLEUM		COAL DERIVED		COAL	BY-PROD HEAT
	DISTILLATE	BOILER FUEL	DISTILLATE	BOILER FUEL		
STEAM TURBINE				●	●	
GAS TURBINE						
● DIRECT FIRED		●		●	○ ●	
● INDIRECT FIRED					●	
● CLOSED CYCLE				●	●	
STEAM INJECTED GAS TURBINE						
● DIRECT FIRED		●		●	●	
● INDIRECT FIRED					●	
COMBINED CYCLE						
● DIRECT FIRED		●		●	●	
● INDIRECT FIRED					●	
DIESEL						
● HIGH SPEED			●			
● LOW SPEED				●	●	
FUEL CELL						
● LOW TEMPERATURE	●		●			
● HIGH TEMPERATURE	●		●		○	
STIRLING				●	●	
THERMIONICS						
● SIMPLE CYCLE				●		
● COMPOUND CYCLE				●		
ORGANIC RANKINE (BOTTOMING)						●

○ GASIFIED ON SITE

FC11376
R790702

The industrial process energy requirements in this study vary over a wide range. Some require a large amount of low temperature heat (usually hot water or low pressure steam) and others require substantial amounts of intermediate or high temperature heat. The choice of energy conversion system design conditions can emphasize heat recovery at one temperature or another. To provide the greatest applicability for each technology, a number of design configurations emphasizing performance in one or more of these categories were chosen by the technical specialists. In like manner, the ratio of electrical to thermal energy varies from industrial process to process. The technical advocate for each technology recognized this variability and provided data and information for designs calculated to produce the greatest congeneration benefits. Up to five design alternatives were considered for each of the energy conversion systems.

For each design option, the energy conversion system performance was defined in terms of electrical output and heat recovery in each of the thermal categories. These data were determined over an applicable size range. Off-design performance was also determined. Performance data were related to the higher heating value of the fuel to determine efficiency or fuel utilization. In addition, equipment and installation costs were estimated. Also, maintenance frequency and cost were predicted. The exhaust emissions were determined and the physical size and weight of the energy conversion systems were defined.

The following section summarizes the principal characteristics of each of the energy conversion systems. A detail report for each energy conversion system including a description of the system, performance, data, cost estimates, predicted emissions, physical data, cogeneration applicability, and potential technical developments is presented as Volume III of this report. In addition, printouts of the energy conversion system data used in the computer configurations are presented in Volume VI, Table VI-10, for the various design options evaluated in the study.

STEAM TURBINES

Historically, the steam turbine has been the principal cogeneration energy conversion technology. It is able to provide both shaft power for mechanical drive and electric generation and steam for industrial processes. Almost any thermal and electrical requirement can be satisfied with sufficient steam pressure drop, particularly if process steam and shaft power requirements coincide.

Single extraction steam turbines were selected for this study. These machines operate automatically to maintain the desired process steam pressure and the required turbine speed. Inlet steam pressure of 1200 psig and temperature of 950°F were selected for the current technology steam turbines. Extraction pressures of 600 and 50 psig are consistent with the thermal bin system selected for this study. In the 1985-2000 period, industrial steam turbine technology could be developed to operate with inlet steam conditions of 1800 psig and 1050°F.

The study encompasses four steam turbine-heat source combinations. Two configurations using liquid boiler fuel, either petroleum or coal-derived fuel, incorporate current and advanced turbine technology. The other two use coal. For the current technology, a coal furnace is employed with flue gas desulfurization. The advanced system uses an atmospheric fluid bed coal combustion system.

A total of 10 steam turbine design options were selected for each technology-thermal source combination. Half of the options extracted steam at 600 psig and half at 50 psig. Figure 15 presents representative electric output and extraction steam energy in terms of the higher heating value of the fuel consumed for a set of design options. Highest overall fuel utilization occurs at the highest extraction.

The estimated cost for the advanced technology steam turbine and its generator only is presented in Figure 16.

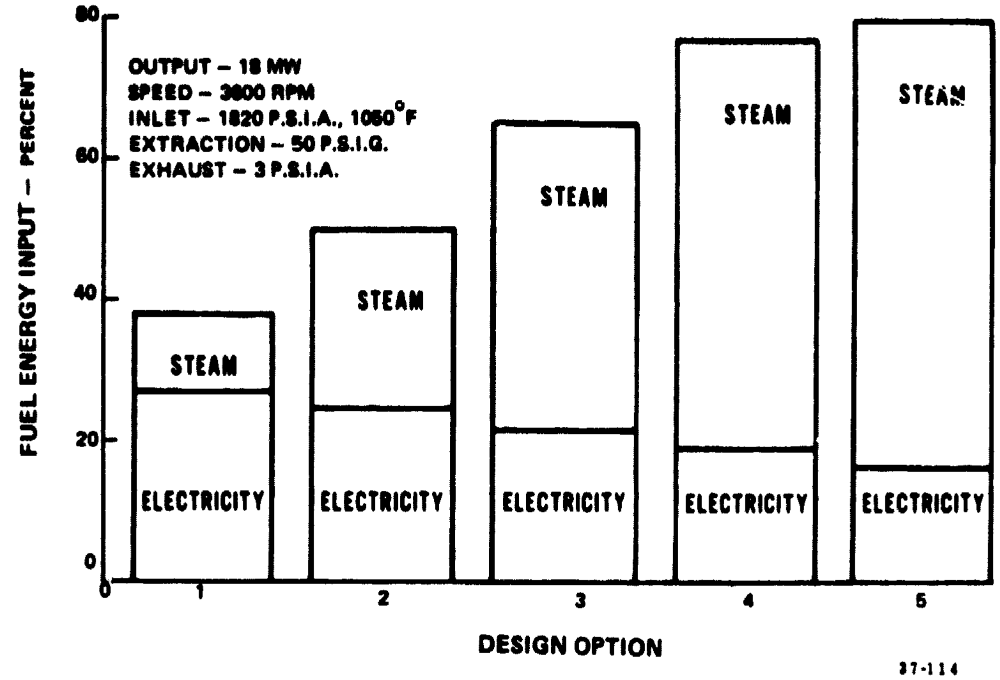

Figure 15. Advanced Technology Coal-Fired Steam Turbine Performance

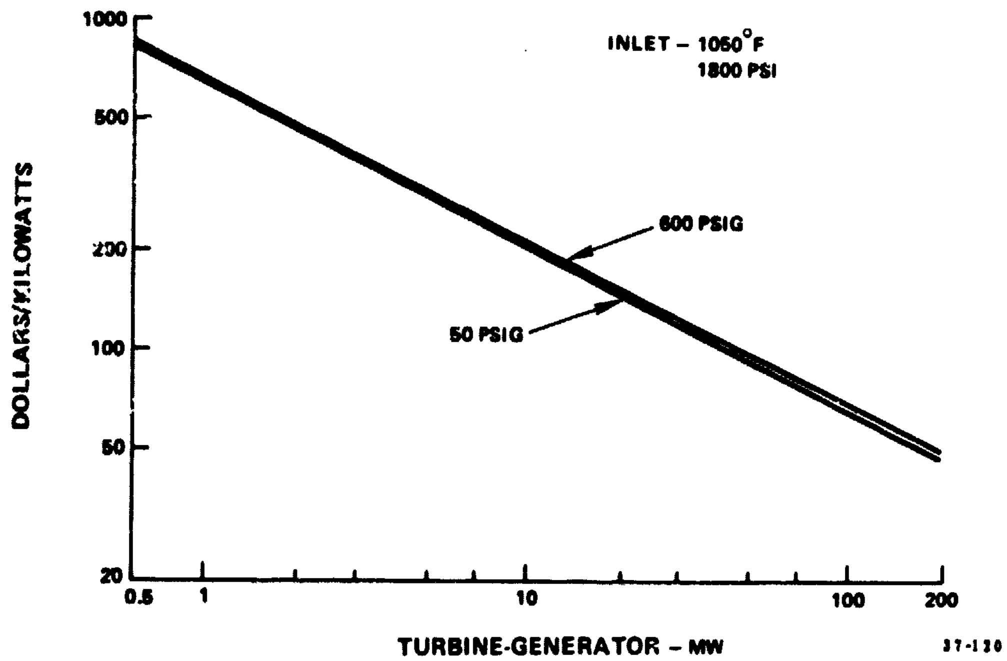

Figure 16. Steam Turbine – Generator Equipment Costs

DIESEL ENGINES

Diesel engine technology can be broadly classified by three types: high, medium and low speed. Current research efforts directed towards high temperature diesel engine operation, which could be most attractive for cogeneration application, appear to be most advanced for high speed engines. The low speed machines are most advanced in using heavy oils and coal. Therefore, both of these types of diesel engine-generators are included in the study.

The current low speed diesel engine-generator can provide thermal energy by recovering heat from the 540°F exhaust gases and the cooling water system which operates at about 160°F. In the advanced technology low speed diesel engine, the cooling water temperature is raised to 265°F. The heat recovery system provides 500°F steam as well as 300°F steam and hot water.

The low speed diesel-generator uses petroleum or coal-derived boiler fuel. The assumption was made that powdered coal systems could reach commercial application in the 1985-2000 period with performance and equipment cost similar to the diesel engine using boiler grade liquid fuel.

Figure 17 presents typical performance for current and advanced low speed diesel conversion systems. There is virtually no performance variation for various size designs from 8 to 28 megawatts. Low speed diesel generators provide high efficiency from 25 percent to rated electrical output. This is representative of both current and advanced diesel systems.

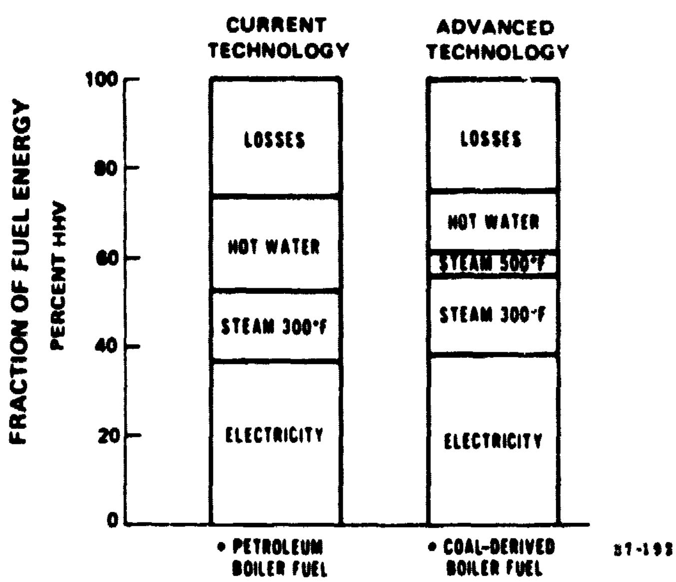

Figure 17. Low Speed Diesel-Generator Performance

The high speed diesel current technology engine is water cooled. A significant research effort for high speed diesel engines is aimed towards "adiabatic" powerplants which do not have water cooling systems. The use of gas bearings and the application of ceramic parts on the surfaces of the pistons, cylinder walls, and valves which are exposed to high temperature products of combustion are the basis of this design.

Current technology high speed diesel engines use petroleum distillate fuel. Advanced technology powerplants are expected to be able to operate on coal-derived distillate fuels.

Representative performance of the current and advanced high speed diesel systems is included in Figure 18.

Estimated costs of the diesel engine-generator equipment range from $250 to $600 per kilowatt. These cost estimates do not include the balance-of-plant, installation, and associated costs.

Both the low speed and high speed diesel engines produce nitrogen oxide emissions in excess of the guidelines, Table 12. The estimated emissions from the low speed diesel engine are presented in Figure 19. The high speed engine has similar values.

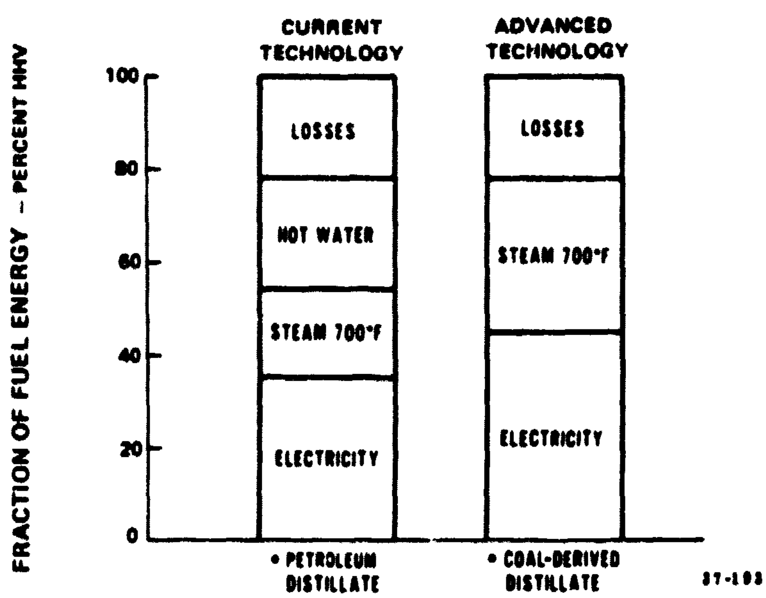

Figure 18. High Speed Diesel-Generator Performance

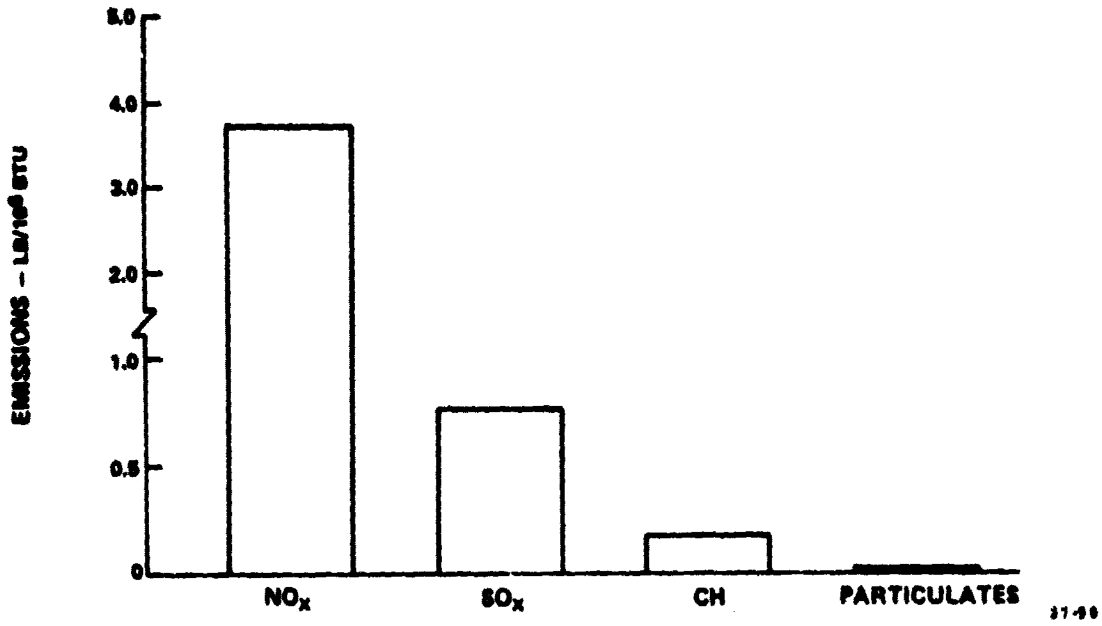

Figure 19. Low Speed Diesel Engine Emissions

GAS TURBINES

Introduction

The cogeneration gas turbine consists of five basic elements, a compressor, heater, turbine, generator, and heat recovery heat exchanger. Gas, usually air, is compressed and heated either indirectly through a heat exchanger or directly by burning fuel in the air stream. The hot gas expands through a turbine which drives the compressor and an electric generator. The turbine exhaust gas is typically about 1000°F and is the source of recovered heat for the industrial process.

A number of advanced gas turbine configurations are included in this study and are depicted in Figure 20. The simple system is shown in Figure 20A. The section labeled gas turbine includes the compressor, heater, and turbine. The generator and heat recovery heat exchanger are shown separately. The simple advanced gas turbine is heated by the combustion of coal-derived boiler fuel within the engine. Rich-lean combustion systems are expected to keep the level of emissions within the guidelines, Table 12.

Since only one-quarter of the oxygen in the air passing through the gas turbine is normally consumed in combustion, a supplemental combustor can raise additional steam for the industrial process. This arrangement, Figure 20B, is an attractive option if the industrial process requires a large amount of heat in relation to the electrical requirement. Both the current technology and advanced technology gas turbine energy conversion systems included design options with and without supplemental firing.

In the combined cycle, Figure 20C, the steam generated in heat recovery boiler is used to drive a steam turbine. Process steam can be extracted from the steam turbine or taken directly from the boiler, bypassing the turbine, as the needs of the industrial process dictate. A modification of the combined cycle is the steam injected gas turbine, Figure 20D. In this case, some of the steam from the heat recovery boiler is injected upstream of the turbine and the cost and complication of a separate steam turbine is avoided.

If an external heat source and heat exchanger are used to heat the compressor or discharge gas, the gas turbine exhaust is not contaminated by products of combustion and can be returned to the compressor inlet to complete the cycle. Since the heat recovery boiler removes most of the heat from the turbine exhaust, the cooling requirements after the boiler for the compressor return can be minimum. This closed cycle configuration, Figure 20E, is not limited to air as the working fluid and is not limited to atmospheric pressure at the compressor inlet. Therefore, the closed cycle offers a wide range of design possibilities.

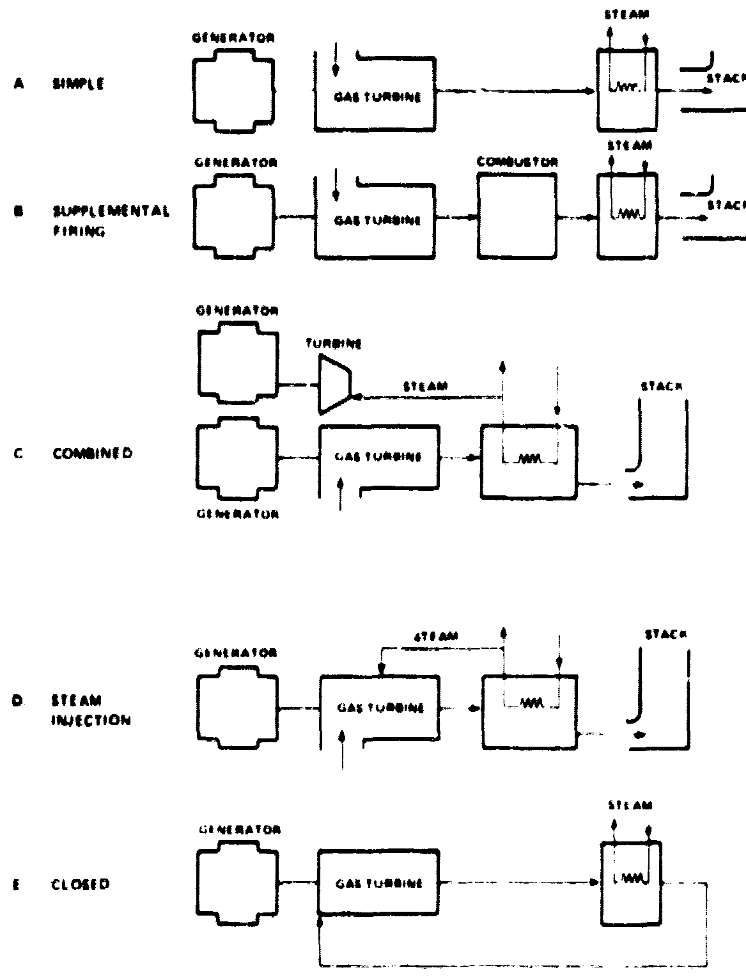

Figure 20. Gas Turbine Cogeneration Configurations

Advanced coal fired gas turbine systems could provide three or four alternatives, Figure 21. Atmospheric fluid bed coal combustion provides two possibilities. In the simplest case, the air from the compressor discharge is piped through the combustion chamber where it is heated before entering the turbine, Figure 21A. The air is provided for combustion by a separate blower. An alternate configuration, Figure 21B, uses a portion of the gas turbine exhaust air in the fluid bed combustion chamber. Typically, a quarter of the turbine exhaust would be used in the combustion chamber and the rest would pass through a boiler to raise steam for the industrial process. If larger amounts of steam are needed by the industrial process, a larger amount of air can be bled to the combustion chamber with additional coal and limestone. A boiler would be added in the combustion chamber to accept the increased heat release.

The compressor discharge air can be used at pressure in a fluid bed combustion system, Figure 21C. Again, about a quarter of the compressor discharge air would be used in the pressurized fluid bed combustion, and the rest would be piped through the combustion chamber to receive heat. The solid particles are removed from the products of combustion and this gas, along with the heated air, feed the turbine and subsequent heat recovery heat exhanger.

The last coal-fired system includes an on-site, integrated coal gasification plant, Figure 21D. Approximately 20 percent of the compressor discharge air is fed to the gasifier along with coal and water. The entrained flow gasifier produces a mixture with a heating value of about 350 Btu per cubic foot. The sulfur is removed and the fuel fed to the gas turbine combustion chamber where it is burned with the remaining 80 percent of the compressor discharge. Steam for the industrial process is raised in the turbine exhaust and also as part of the gasification process.

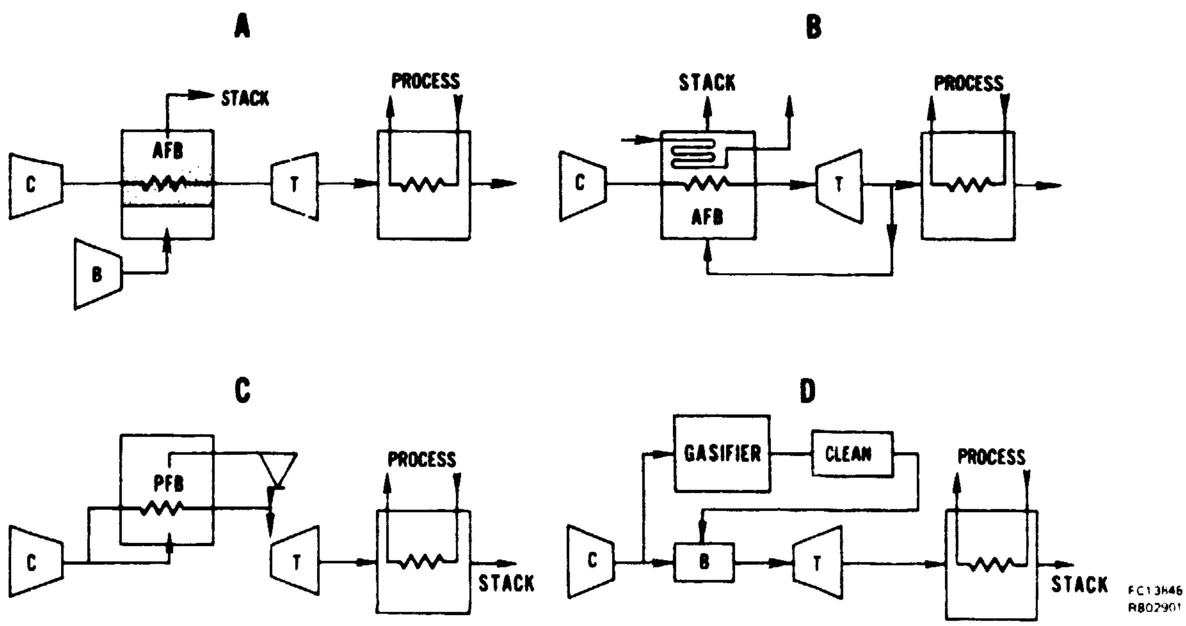

Figure 21. Coal-Fired Gas Turbine Cogeneration Configurations

Simple Gas Turbines

Current commercial gas turbines operate at pressure ratios from 6 to 14:1. Base levels of 10:1, 12:1 and 14:1 were selected as being representative of current engines in the 30 MW range. Turbine inlet temperatures for base load applications are about 2000°F. The turbine exhaust temperature varies between 900°F and 1100°F.

The advanced gas turbine chosen for this study has an air cooled turbine with 2500°F inlet temperature, and a pressure ratio between 14:1 and 18:1. By increasing the turbine inlet temperature and compression ratio relative to current gas turbines, the physical size of the advanced machines is reduced, the specific power is increased, and the conversion efficiency is improved.

The performance of the current and advanced technology simple gas turbines is presented in Figure 22. The advanced technology cases indicate improved electric generation efficiency and improved overall fuel utilization potential. The estimated costs of the simple gas turbine and generator are about $200 per kilowatt installed. The advanced technology represents about a 10 percent reduction in equipment costs. The estimated emission levels for advanced gas turbines with boiler-type fuels meet the emission guidelines assuming that effective measures of NOx control are developed by 1985-2000.

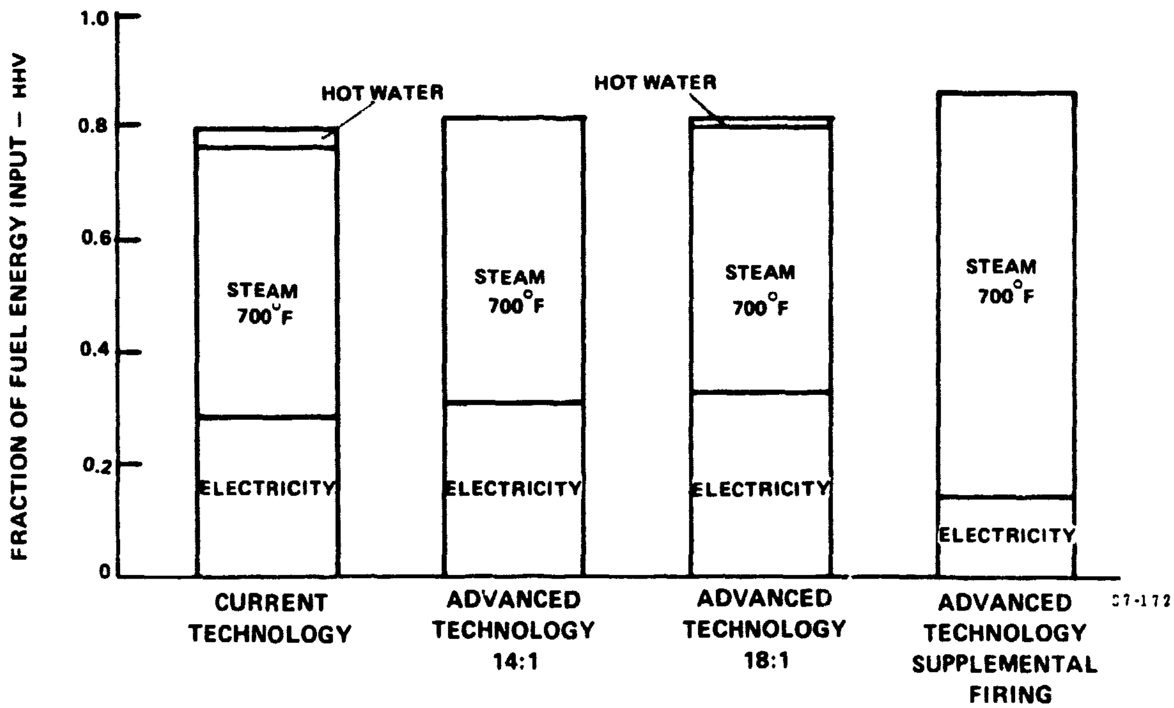

Figure 22. Gas Turbine Performance Liquid Fuels

Simple Gas Turbine With Coal Gasification

The combination of the gas turbine and an entrained flow, air-blown coal gasifier was included in the study. The advanced gas turbines with gasified coal used 2500°F turbine inlet temperature and the performance is shown in Figure 23.

The estimated cost of the coal gasifier-gas turbine combination is over $700 per kilowatt installed.

The estimated emissions from the coal gasifier-gas turbine system are within the study guidelines. The nitrogen oxide emissions are minimized by the low flame temperatures with the low BTU gas.

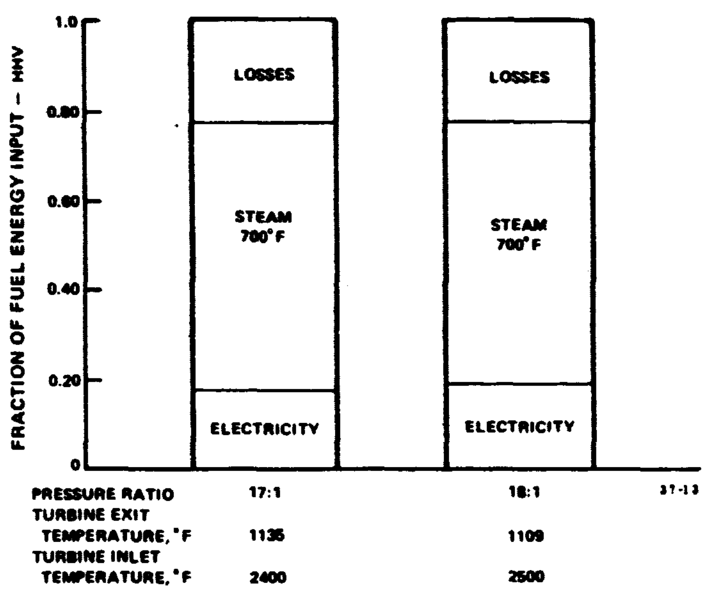

Figure 23. Performance of Advanced Gas Turbine with Coal Gasifier

Coal-Fired Gas Turbines

There are two coal-fired gas turbine systems included in the study. In one, the coal is consumed in a pressurized fluidized bed operating with compressor discharge air and, in the other, a coal-fired atmospheric fluid bed heats the gas turbine gas stream indirectly. Since both atmospheric and pressurized fluid beds operate between 1550 and 1650°F for most effective sulfur removal, the turbine inlet temperatures were set at 1600°F for the pressurized case and 1500°F for the atmospheric fluid bed. The gas turbine pressure ratio was 6:1 to 10:1 with this low turbine inlet temperature.

The performance of the advanced gas turbines with fluidized bed coal combustion systems are presented in Figure 24. The estimated gas turbine costs (without the fluidized bed heat source) are between $200 to $250 per kilowatt installed.

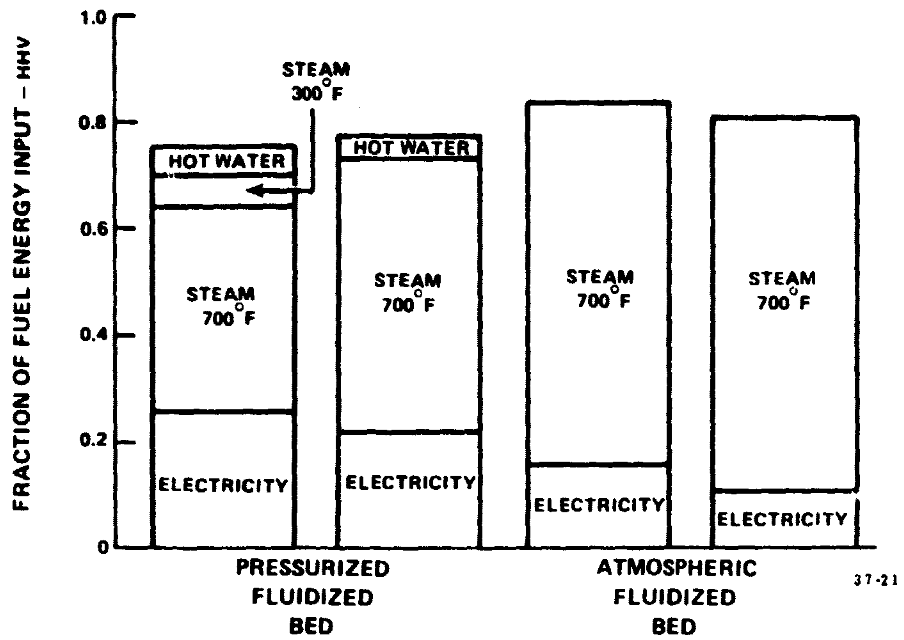

Figure 24. Coal-Fired Advanced Gas Turbine Performance

Closed Cycle Gas Turbines

Two closed cycle gas turbine heat sources were included in the study: (1) coal-fired atmospheric fluidized bed with a turbine inlet temperature of 1500°F and (2) liquid boiler fueled furnace with 2200°F turbine inlet temperature.

Since the cycle is closed, any gas could serve as working fluid. For this study air and helium were considered. A maximum pressure of 600 psi was selected. The closed cycle permits a choice of compressor inlet temperature and pressure (or pressure ratio). Pressure ratios of 3:1 and 6:1 were considered. High compressor inlet temperatures improve the production of recovered heat at a modest penalty in electric generation efficiency. Compressor inlet temperatures of 190 and 300°F were included.

Five closed Brayton cycle designs were selected with each heat source to cover a range of possible industrial applications. Two design options used helium as the working fluid and one of these employed a regenerator. Three options used air as the working fluid and one of these also used a regenerator. The compressor inlet temperature was 190°F except for one case at 300°F.

The performance of the various closed cycle design options are included in Table 18. The overall fuel utilization is relatively independent of design parameter selection except for turbine inlet temperature and heat source. Helium offers no performance advantage. All of the high turbine inlet temperature cases provide high temperature steam but the regenerator reduces the quality of the recovered heat with low turbine inlet temperatures.

TABLE 18 CLOSED CYCLE GAS TURBINE PERFORMANCE

Turbine Inlet Temperature - °F	1500	1500	1500	1500	1500	2200	2200	2200	2200	2200
Fluid	Air	Air	Air	He	He	Air	Air	Air	He	He
Regenerator (Effectiveness = 0.35)			Yes		Yes		Yes			Yes
Compressor Inlet Temperature °F	190	300	190	190	190	190	190	190	190	190
Pressure Ratio	6:1	6:1	6:1	3:1	3:1	6:1	6:1	14:1	6:1	4:1
Electric Efficiency	0.19	0.15	0.24	0.18	0.25	0.23	0.32	0.28	0.21	0.27
Heat Recovery										
700°F	0.48	0.60		0.50		0.63	0.39	0.44	0.57	0.43
500°F			0.32		0.23					
300°F			0.13		0.20					
Hot Water	0.17	0.08	0.14	0.16	0.15	0.02	0.17	0.15	0.11	0.17
Total Fuel Utilization	0.83	0.84	0.83	0.83	[illegible]	0.88	0.87	0.87	0.88	0.87

Since the turbomachinery is basically a volume flow device, the operating pressure has a direct effect on turbomachinery size for a given output. With 600 psi turbine inlet pressure in the closed cycle compared with 200 to 270 psi in the conventional case, the closed cycle turbomachinery is 1/2 to 1/3 the size of the simple gas turbine. The estimated costs for the turbomachinery are about $190 per kilowatt.

Steam Injected Gas Turbines

In a steam injection cycle, steam produced by the exhaust heat of the gas turbine is injected at high pressure into the gas turbine to produce additional power.

Air to steam ratios of 20:1 and 10:1 were selected as representative for cogeneration systems.

With the direct coal-fired gas turbine, a split flow pressurized fluidized bed design was used.

In the indirect coal-fired system with an atmospneric fluidized bed, the steam injection system is similar to the system with the pressurized fluidized bed.

The performance of the steam injected gas turbine energy conversion systems with liquid and both direct and indirect coal-fired configurations is presented in Figure 25. As the amount of steam injected increases, the electrical output increases and the overall fuel utilization decreases.

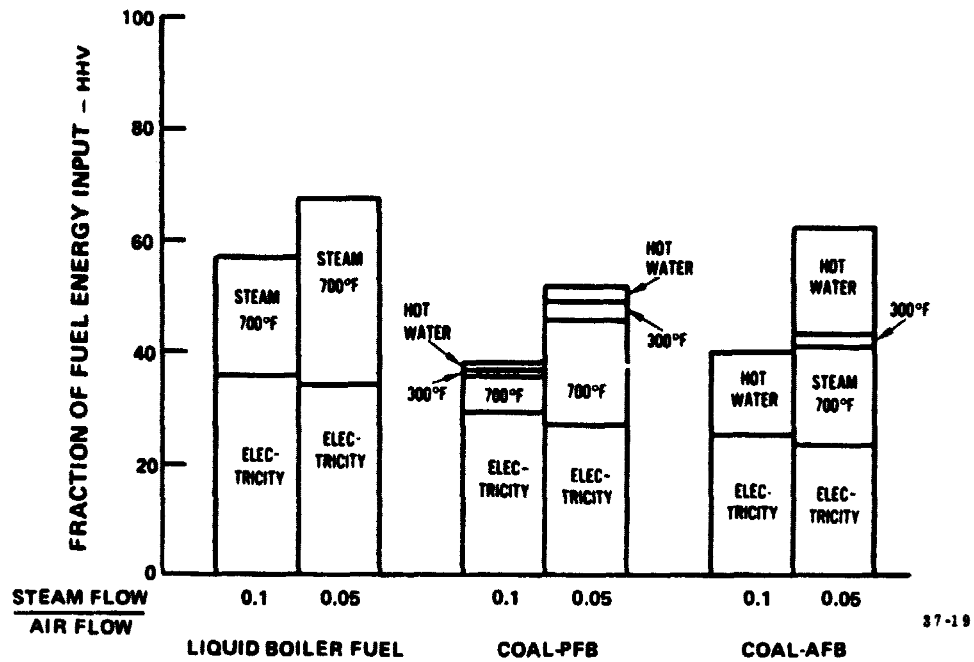

Figure 25. Steam Injected Gas Turbine Performance

The cost of the steam injection cycle is potentially lower than a combined cycle because the steam turbine is eliminated. The gas turbine, of course, must be modified to accept the steam and certain components enlarged to produce the increased power. The engine-generator costs per unit electrical output are the lowest in the gas turbine family: \$140 to \$190 per kilowatt installed.

Although steam injection is one method of reducing NOx emissions, the conservative assumption was made that the emissions for steam injected engines are the same as the emissions for other advanced gas turbines.

Combined Cycle

In cogeneration applications emphasizing electrical needs in relation to thermal, the combined cycle is a logical candidate. The gas turbines in the combined cycle configurations operate with the same fuels as the simple gas turbine. In this study. the steam was split between the steam turbine and the industrial process. The turbine inlet steam is at 800°F and 800 psia. This simple approach is representative of other methods (back pressure, extraction, etc., turbines).

A summary of the performance of the various combined cycle, fuel combinations is presented in Figure 26. if thermal output were minimized, the electrical efficiency would be 0.45.

The estimated costs of the combined cycle systems range from \$180 to \$220 per kilowatt.

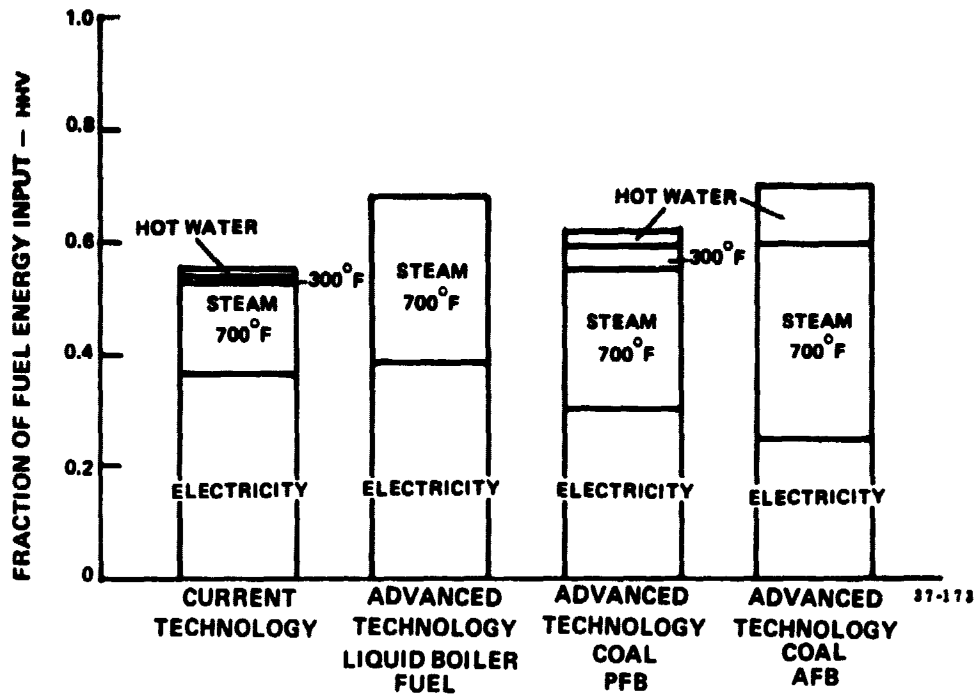

Figure 26. Combined Cycle Performance

Fuel Cell Power Plants

Two fuel cell types were included in this study: the low temperature phosphoric acid cell and the molten carbonate electrolyte cell which operates at high temperature. Both types of powerplants embody the same basic elements, shown schematically in Figure 27. Hydrocarbon fuel is reformed to produce a hydrogen rich gas which is fed to the fuel cells. Air is also supplied to the cells at moderate pressure and the electro-chemical reaction produces direct current electricity and water. Some water is used in the fuel processing section. The direct current is converted to conventional alternating current electricity in the inverter.

Two low temperature fuel cell-fuel combinations were evaluated. One is based on current power plant developments and utilizes a light petroleum distillate fuel, such as naphtha, which is converted to a hydrogen-rich process gas utilizing the steam reforming process. The other configuration operates on heavier distillate fuel and utilizes an adiabatic reformer for fuel processing.

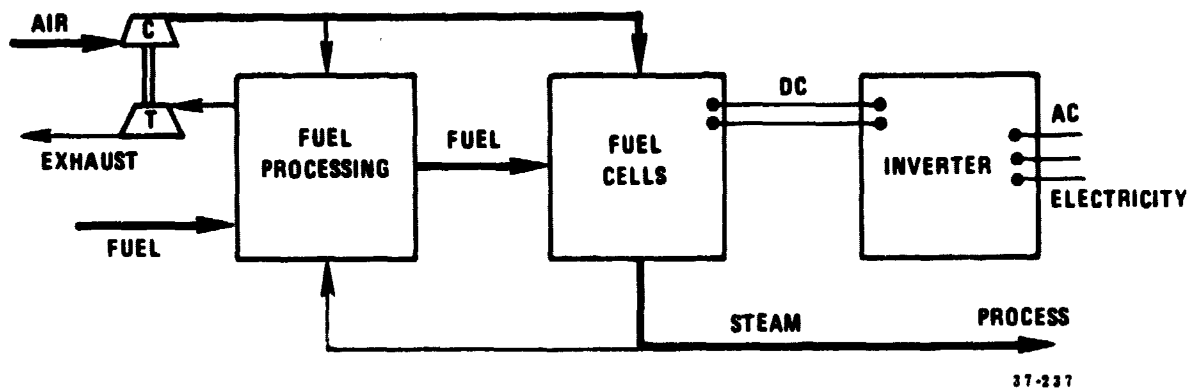

Figure 27. Schematic Diagram of Fuel Cell Power Plant

The fuel cell conversion system provides high overall efficiency. The low operating temperature of the cells (400°F) limits the ability to provide high temperature steam. However, significant quantities of 300°F steam are available with some designs. Figure 28 presents performance data for the low temperature fuel cell operating on coal-derived distillate fuel.

Equipment cost estimates installed were $300 to $400 per kilowatt. The powerplants which emphasized steam over hot water were the most expensive.

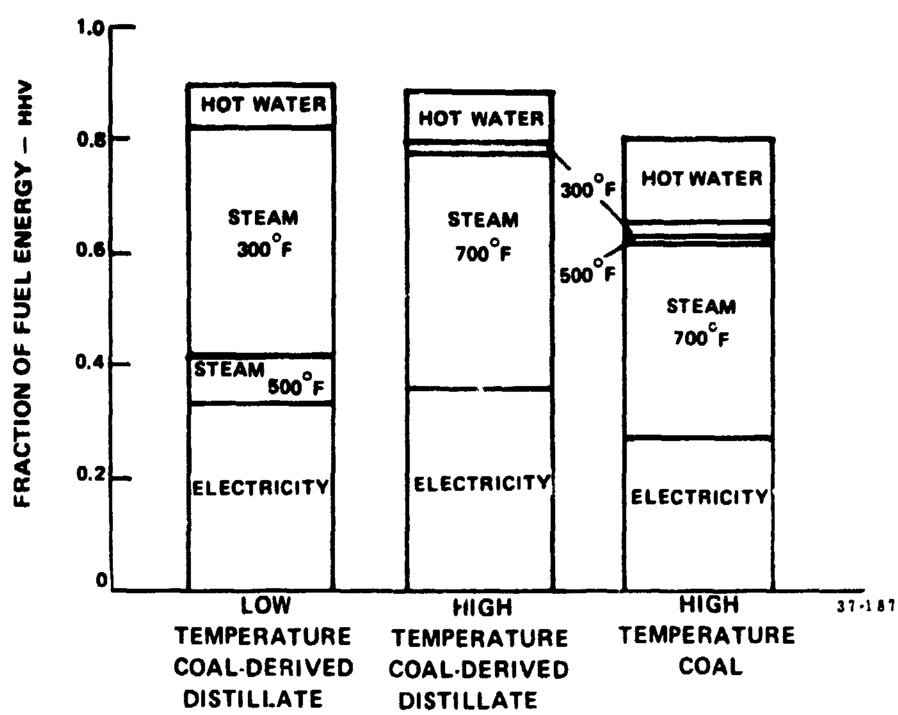

Figure 28. Representative Performance of Fuel Cell Power Plants

The estimated emissions from the low temperature fuel cell powerplants, based on the measured emissions from powerplants, fall well below the emission guidelines. The nitrogen oxide emissions are essentially an order of magnitude lower than the guidelines.

Fuel cells operating at elevated temperature and employing molten carbonate electrolyte have attractive features in terms of both improved performance and the elimination of expensive materials. Three high temperature fuel cell-fuel combinations were included in the study. Two use distillate fuels and one uses coal. The fuel cell system consuming coal employs an entrained flow, air-blown gasification plant operating at 600 psig which converts coal into a stream containing essentially hydrogen, carbon oxides and nitrogen. The gasifier effluent is cooled by generating steam for cogeneration.

The high temperature fuel cell designs can emphasize thermal or electrical output. The electrical efficiency can exceed 45 percent but the recovered heat is predominantly in the form of hot water. The performance of a design emphasizing steam generation is included in Figure 28. The performance of the high temperature fuel cell with coal fuel is also included in Figure 28.

The cost estimates for the liquid fueled high temperature fuel cells were $300 to $350 per kilowatt installed. The coal-fired system including the coal gasifier is estimated to cost over $700 per kilowatt installed. This estimate is based on a power plant designed to produce 100 megawatts electric output.

The emission of pollutants by the high temperature fuel cell is estimated to be very low in relation to the study guidelines. The nitrogen oxides are 1/5 to 1/6 of the nitrogen oxides specified by the guidelines with liquid fuels. The nitrogen oxide level for the coal case is higher than for the liquid fueled cases but still falls below the guidelines by a factor of 3.

Stirling Engines

The Stirling engine is a closed cycle, regenerative piston engine with cyclic compression at low temperature and expansion at high temperature of the working gas. In this study the Stirling engine energy conversion system was considered with two heat sources: a coal derived boiler fueled and a coal-fired system. Figure 29 is a schematic diagram of the coal-fired configuration. The use of an intermediate heat exchanger to add heat to the working fluid at an intermediate temperature and the generation of work from this heat input adds to the versatility of the Stirling engine for cogeneration. A mean cyclic pressure of 1000 psia was chosen.

Present machines typically run at about 1290°F; however, advanced designs will raise this temperature. The Stirling engine was limited in this study to an upper temperature of 1600°F with the liquid fueled heat source. With the coal-fired system, the highest temperature in the Stirling engine was limited to 1450°F to provide proper operation of the atmospheric fluidized bed. A mean cyclic pressure of 100 psia was chosen.

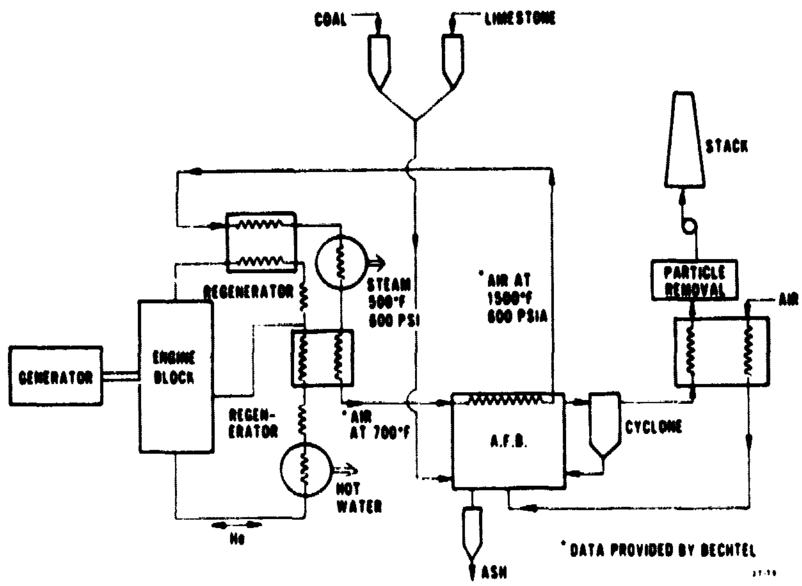

Figure 29. Coal-Fired Stirling Engine System Schematic Diagram

Figure 30 presents the performance of various designs of the Stirling energy conversion system including the heat source. Two design options, one emphasizing electrical output and the other emphasizing thermal output, were included for each heat source.

Estimated installed costs for the Stirling engine were $200 to $250 per kilowatt.

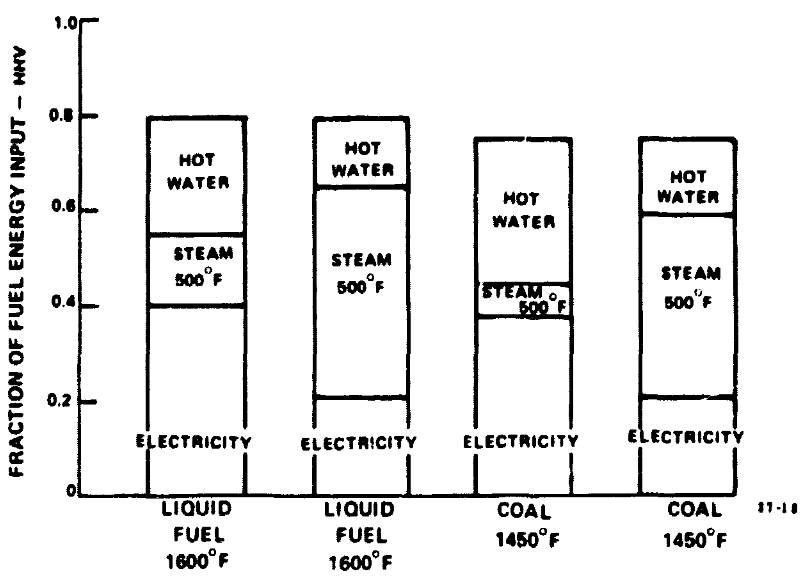

Figure 30. Stirling Engine Performance

Thermionic Conversion

The thermionic energy converter is an electronic device for converting heat directly to electric power. For large scale industrial applications a power module design, called a Thermionic Heat Exchanger (THX), was established. Heat is transferred from the heat source, shown schematically in Figure 31, to the thermionic converters using 30 vertical lithium-filled heat pipes. The emitters of the converters operate at 2400°F, with a current density of 20 A/cm².

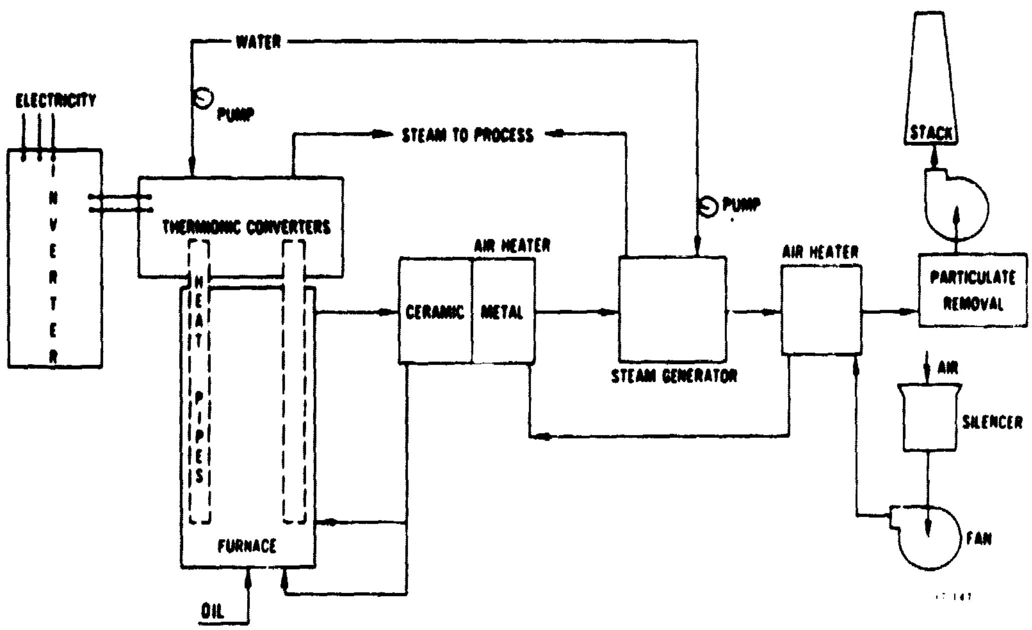

Figure 31. Thermionic Energy Conversion System Schematic Design

In the design for this study, thermionic heat exchangers were installed vertically in a liquid fueled furnace, and the heat pipe portions served as the inner walls of the furnace. Thermionic heat pipes were also installed in the combustion chamber in a curtain arrangement.

The heat source includes a ceramic and metal air preheater with a design exhaust temperature of 2200°F. Ceramic heat exchangers are in the research and development stage and are projected to be capable of operation to 2200°F although the cost of a commercial ceramic heat exchanger in 1985-2000 is expected to be high. After preheating the combustion air, there is sufficient energy in the furnace exhaust gas to generate additional steam at 600 psig and 700°F for use in the industrial process.

The performance of the thermionic converter energy conversion system is presented in Figure 32.

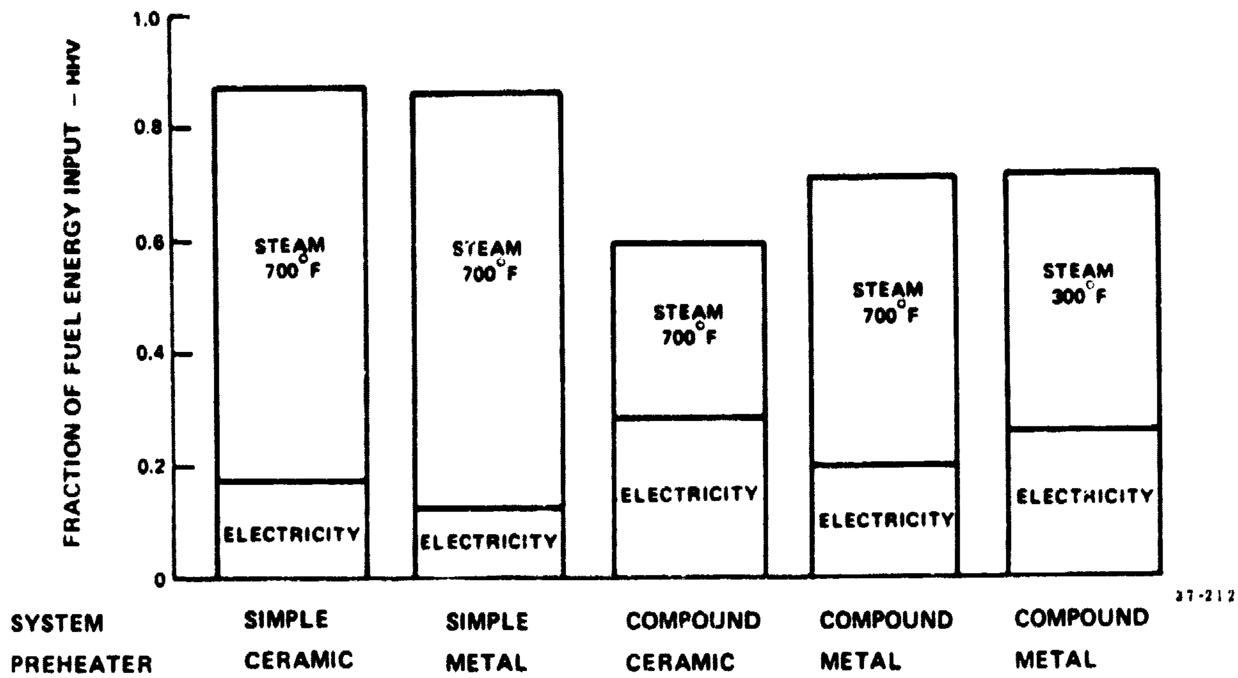

Figure 32. Performance of Thermionic Converter Systems

Since the ceramic heat exchanger typically represents over one third of the cost of the heat source, an alternate heat source without the ceramic heat exchanger was designed. In this modification the furnace exhaust gases first generate steam and then preheat the combustion air to 1400°F in a metallic heat exchanger. The performance of this conversion system is also included in Figure 32.

The characteristics of the thermionic heat pipes and the furnace lead to a maximum electrical to thermal energy ratio of 0.25 with the ceramic heat exchanger. To provide higher electric output, the collector temperature was raised to 1110°F, and the steam pressure and temperature were raised to 1800 psi and 1050°F. Passing this steam through an extraction turbine is an effective way to increase the electrical output. The performance of a compound steam turbine-thermionic converter energy conversion system is presented in Figure 32.

Another design option was developed using the metallic heat exchanger and the compound steam turbine-thermionic converter system. The performance of this system is included in Figure 32.

The estimated costs of the thermionic heat pipes and inverter (without the heat source) range between $400 and $520 per kilowatt. With the steam turbine, generator, and condenser added in the compound thermionic system, the corresponding equipment cost is also in the range of $400 to $500 per kilowatt.

HEAT SOURCFS

Thermal energy sources are required to serve three purposes in this study:

1. Provide steam or hot gas for a cogeneration energy conversion system;
2. Provide steam for industrial processes; and,
3. Recover heat from an industrial waste heat stream and provide steam for bottoming cogenerations systems.

A total of 14 heat source designs were developed by Bechtel National, Incorporated to meet the requirements of this study and the detailed data for each of these systems is presented in Volume IV of this report.

The industrial thermal energy requirements for this study were established in five categories including hot water and steam at three temperatures. Three steam generators and a water heater were designed based on current technology, the emission guidelines, and petroleum-based or coal-derived liquid boiler fuel. These designs were provided to evaluate performance and costs for equipment required for the non-cogeneration or traditional configuration. Also, these designs served in cogeneration systems where recovered heat was less than the requirement and a separately-fired supplemental furnace or boiler was used.

The four designs were similar and Figure 33 is a schematic diagram of the 700°F steam generator. Each was a shop-assembled, water-tube, natural circulation boiler with water-cooled furnace walls. The furnace used staged firing for NOx emission control. Each incorporated an economizer. Data for designs from 50,000 - 250,000 BTU/hr were developed. The efficiencies were 88% and the estimated equipment and installation costs ranged from $3,000 - $5,000/million BTU/hr. The four furnaces were designed to use petroleum boiler fuel, but they could be modified readily to fire a wide variety of petroleum-based or coal-derived distillate or heavy fuels as well as gaseous fuels of various compositions. In this study, the assumption was made that these furnaces could burn pulping liquors produced in papermills without appreciable effect on performance and cost. A more accurate assessment would increase the cost and reduce efficiency of such furnaces. However, the assumed characteristics tend to produce conservative comparisons between cogeneration and non-cogeneration systems in papermills.

Four steam generators were designed for steam turbine cogeneration topping systems. In this study, current technology steam turbines operate with 1200 psi and 950°F steam. A petroleum fueled boiler and a coal-fired boiler were designed based on current technology. A flue gas desulphurizer was provided (under balance-of-plant) to limit the sulphur emissions from the coal-fired boiler to levels consistent with the study guidelines. The advanced technology turbine with 1800 psi and 1050°F steam was the basis for a coal-derived liquid fueled boiler and an atmospheric fluidized bed coal-fired boiler design.

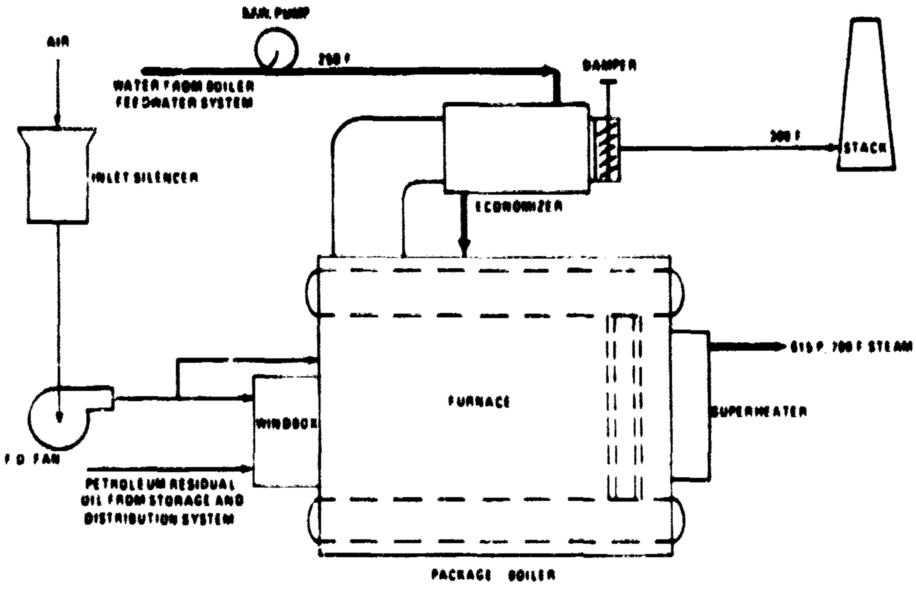

Figure 33. Diagram of 700°F Steam Generator

A schematic diagram of the coal-fired, atmospheric fluidized bed, steam generator is presented in Figure 34. In this advanced technology heat source, coal is fired in the presence of limestone at or near atmospheric pressure. Sulphur released from the coal is absorbed by the limestone reducing sulphur dioxide emissions. Heat is transferred to the water by heat transfer surfaces within the bed, in the water-cooled walls, and in the convection space of the bed. Fly ash collected in the cyclone separator is reinjected to enhance combustion efficiency. The system includes an economizer and air preheater. The spent bed material is cooled for heat recovery. The thermal efficiency of the boiler is normally 84%. The variation in thermal efficiency with size is shown in Figure 35. The estimated costs for the boiler are included in Figure 36. Designs of less than 150 million BTU/hr are shop fabricated. Larger units are assembled in the field. Further details on these four sources are presented in Volume IV of this report.

In bottoming cogeneration systems, industrial waste heat is used in an energy conversion system to produce electricity for the industrial process or for export to the electric utility. A waste heat boiler was designed to provide 1200 psi, 950°F steam for a bottoming steam turbine system based on current technology.

Stirling engines, indirectly heated gas turbines, and the closed cycle gas turbine energy conversion systems require high temperature furnaces which produce hot gas streams. Three furnaces were included which provide air or helium at high temperature. One is a coal-fired atmospheric fluidized bed system which provides hot air or helium at 1500°F. The other two are fired by coal-derived boiler fuel and provide either hot gas at 1800 and at 2200°F. All three heat sources can operate at pressures up to 600 psi.

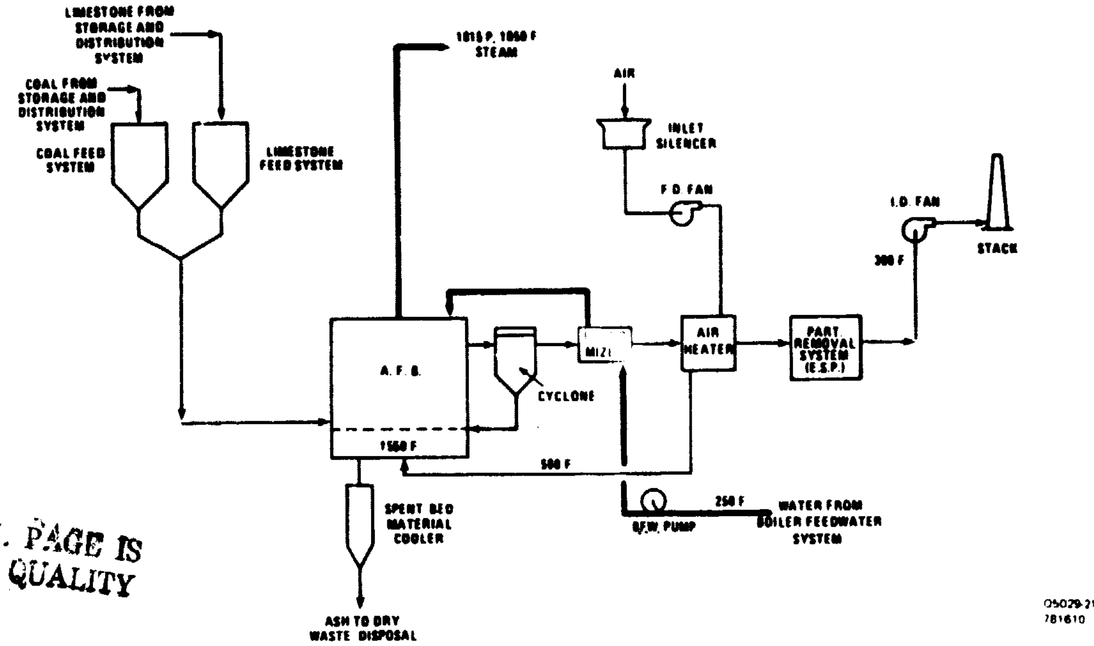

Figure 34. Schematic Diagram of Coal-Fired 1050°F Steam Generator

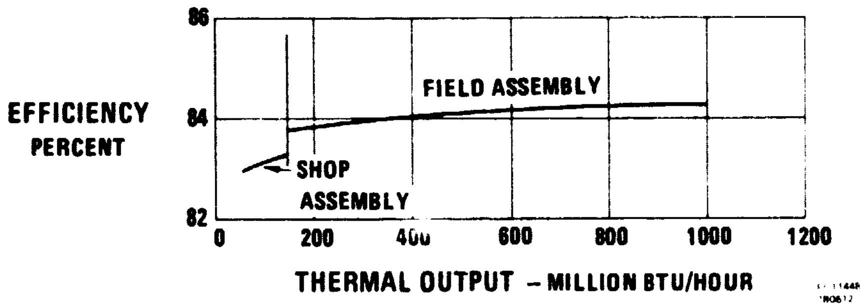

Figure 35.
Predicted Efficiency of Coal-Fired 1050°F Steam Generator

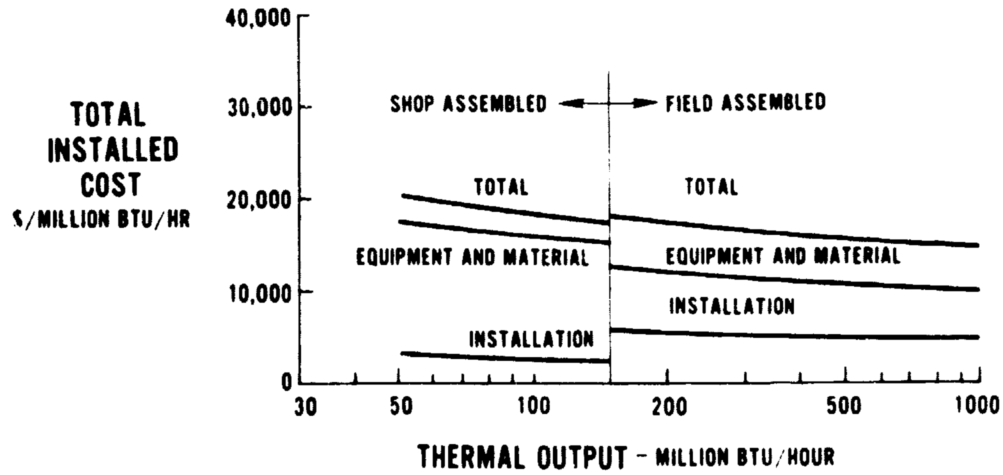

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Figure 36.
Coal-Fired 1050°F Steam Generator Estimated Installed Costs

A schematic diagram of the coal-derived oil-fired 2200°F gas generator is included as Figure 37. It is an advanced technology heat source incorporating a coal-derived boiler fue! fired furnace and a ceramic U-tube heat exchanger to heat high pressure air or helium to 2200°F. The system recirculates exhaust gas from the heat exchanger to the furnace to moderate its combustion gas temperature and includes an air preheater for heat recovery. The 1800°F hot gas generator incorporates substantially the same elements and features as the higher temperature heat source. The principal difference is in the size and cost of the ceramic heat exchanger. The higher temperature heat exchanger costs approximately $10,000/million BTU/hr more than the lower temperature heat exchanger. These furnaces are 88% efficient.

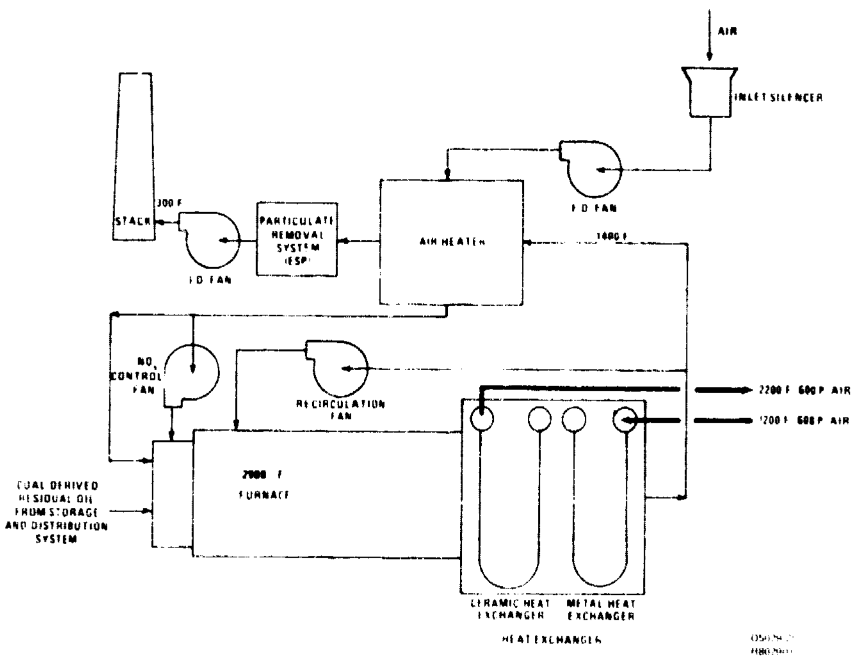


Figure 37. Hot Gas Generator

The third hot gas generator is a coal-fired, atmospheric fluidized bed system which is similar to the coal-fired atmospheric fluidized bed steam generator. It uses a super alloy heat exchanger to provide hot air or helium at 1500°F. Its thermal efficiency is 84%. The cost of the equipment and installation is in the range of $23,000 to $29,000 per 100 million Btu/hour output.

Certain advanced technology gas turbine systems burn coal and use the products of combustion in the turbine with high pressure fluidized bed coal-fired combustion and gas cleanup incorporated in the system. A pressurized fluidized bed hot gas generator system, shown schematically in Figure 38, was designed for this study. It is an advanced technology heat source in which coal is fired in the presence of dolomite at high pressure. Sulphur released from the coal is absorbed by the dolomite reducing sulphur dioxide emissions. Heat is transferred to high pressure air in tubes within the fluidized bed combustion zone. This air is combined with the pressurized fluidized bed combustion products which have passed through a two stage multi-clone and granular bed hot gas clean-up system to form a hot gas stream which is supplied to the gas turbine. The fly ash collected in the cyclone is reinjected to achieve good combustion efficiency.

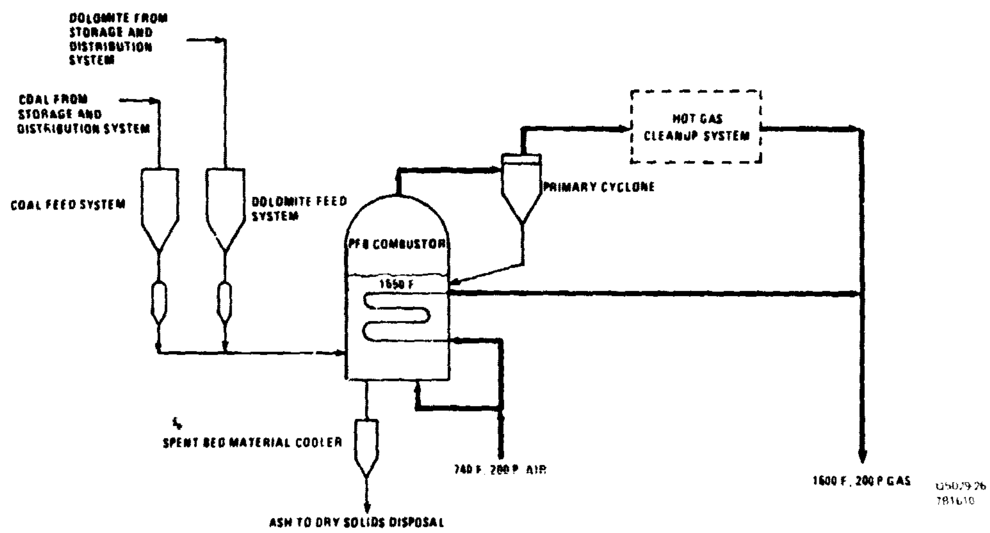


Figure 38. Coal-Fired Pressurized Fluidized Bed Hot Gas Generator

The thermionic conversion system requires a special furnace to heat lithium filled heat pipes. The heat pipes are installed vertically in the wall and as curtains and are connected to the thermionic converter units which are installed on top of the furnace. In order to heat the heat pipes to 2400°F, a high temperature air pre-heater is incorporated using the ceramic and super alloy heat exchanger technology used in the hot gas generators. A schematic diagram of this system is included in the Figure 31. Consistent with the high temperature hot gas generator in this study, the air is preheated to 2200°F. The products of combustion leave the preheater at 1100°F and provide heat for a steam generator in a low temperature air heater. The furnace is fired with coal-derived boiler fuel with secondary air for emission control.

The ceramic heat exchanger is expensive so an alternate thermionic furnace was designed. In this case, the furnace exhaust first raised steam and then preheated the combustion air to 1400°F in a metallic heat exchanger. The efficiency of both furnaces is 88%. For the same thermal energy input, the furnace with the lower temperature preheat cost 17% less than the furnace with the ceramic heat exchanger.

The performance of the heat sources is summarized in Figure 39.

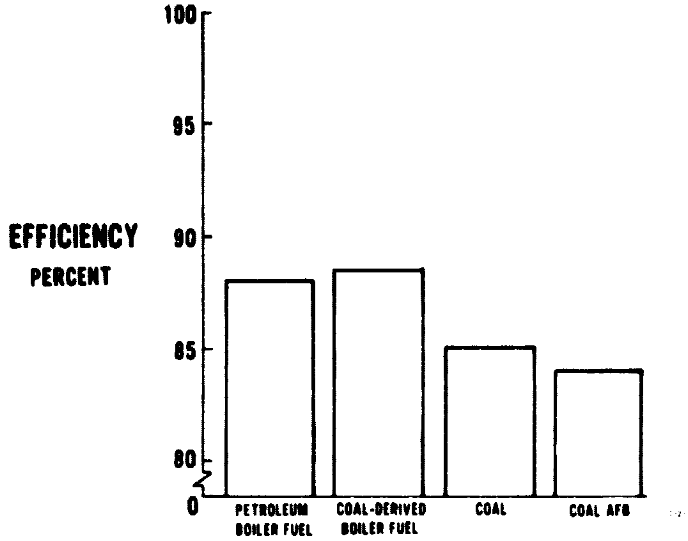


Figure 39. Heat Source Performance

Figure 40 presents a summary of the installed costs of the heat sources. These costs do not include balance-of-plant elements such as fuel storage facilities. The high pressure steam generator costs vary with fuel and provision for environmental protection. The estimated cost of the liquid-fuel fired hot gas generators appear to be strongly influenced by the design temperature and the associated cost of the ceramic heat exchanger. The pressurized fluidized bed is to be integrated in a gas turbine. The higher estimated thermionic furnace cost is based on the ceramic preheater while the lower value is for the metallic preheater.

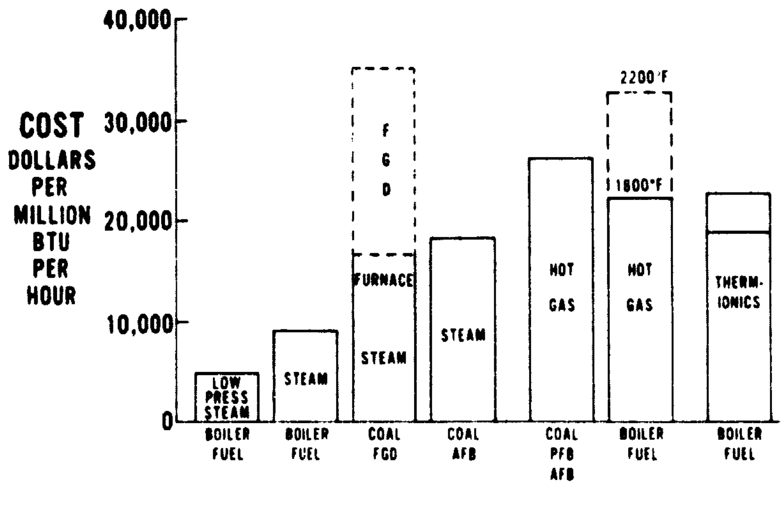


Figure 40. Heat Source Estimated Installed Cost

HEAT PUMP

Under ideal conditions the output available from an energy conversion system will exactly match the thermal and electric requirements of an industrial process, but this situation is rarely achieved. In some cases conversion system heat is available at temperatures higher than that required by the industrial process and is thermodynamically useful. Conversely, there are other conversion system-industrial process configurations where some, if not all, of the recovered heat is not usable because its temperature or quality is below that required. In these situations an industrial heat pump may provide an opportunity to effectively use available low quality heat.

One of the cogeneration strategies in this study involved sizing the energy conversion system such that the power produced meets the process electric requirements and also provides electricity to operate a heat pump. The process thermal needs would be met by the heat pump.

The use of heat pumps to economically promote energy conservation in industrial applications is not new. Typical applications involve the use of manufacturing process low temperature waste heat and provide energy at temperatures up to 220°F. The application of heat pumps in this study is unusual and not being pursued by industry. The requirements are above the present 220°F output capability of commercial industrial heat pumps. Temperature lift requirements range from 160°F to 200°F. Since these conditions are beyond current practice, a number of cycles were analyzed using methanol or steam as working fluids to raise 300°F and 500°F steam. These data and correlations of the performance of current equipment provided a basis for the advanced technology heat pump characteristics.

Heat pump capital cost estimates are shown in Figure 41. The estimated installation cost is equal to the heat pump equipment cost for applications in existing plants. Further heat pump information is contained in Volume IV of this report.

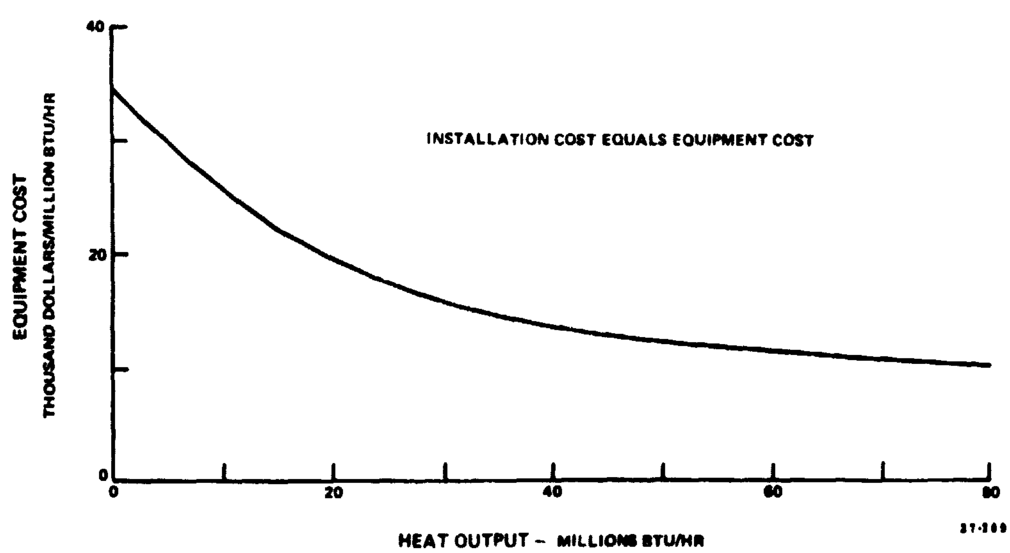


Figure 41. Estimated Industrial Heat Pump Equipment Cost

HEAT STORAGE

The thermal and electrical energy requirements of an industrial plant may vary in the course of day or season. To accommodate such variations, two approaches are apparent. In one, the energy conversion system would be sized and operated to meet the electrical needs. If at any time the recovered heat were insufficient, auxiliary furnaces would provide the thermal deficiencies. In the other approach, the size of the energy conversion system would be chosen so that the average heat recovered meets the average process thermal requirement. At any time when the heat recovered exceeds the process requirements, the excess heat would be stored. If the heat recovered is less than process requirements, stored heat would be used. In such an approach, excess electricity produced would be exported or a shortfall in electrical production would be supplemented by purchased electricity.

For purposes of this study, the industrial thermal requirements have been classified in five categories or bins: hot water, steam at three temperatures, and hot gases. For each of the five categories an advanced thermal energy storage system was selected for suitability, efficiency, and applicability in the 1985-2000 time period. Each can be applied in existing industrial plants as well as newly constructed facilities.

The estimated parasitic electrical power requirements, overall ("round trip") thermal efficiencies, and specific costs of the selected systems are presented in Table 19. A detailed description of each system design and basis for the performance and cost estimates are presented in Volume IV of this report.

TABLE 19. ESTIMATED THERMAL STORAGE SYSTEM PERFORMANCE AND COST

Temperature °F	Storage Medium	Parasitic Power Percent of Energy Stored	Round-Trip Efficiency Percent	Specific Cost $/Million BTU
140	Water	0.03	98	650
300	Water (Saturated)	0	95	2,800
500	Water (Saturated)	0	85	4,400
700	Water (Saturated) plus solid-molten salt	0	70	12,500
1,000	Solid sensible Medium 1) High MgO brick 2) Taconite pellets 3) Native rock	2	80	3,000

BALANCE-OF-PLANT

To provide a comparable, consistent, and complete basis for estimating the performance and costs of the various cogeneration and non-cogeneration systems, Bechtel National, Incorporated, developed data for balance-of-plant systems which were not included in the energy conversion system, heat source, thermal storage, or heat pump. The following balance-of-plant systems were considered:

- o Fuel storage and distribution for three fuels:

  1. Petroleum-based or coal-derived distillate liquid fuel.
  2. Petroleum-based or coal-derived boiler fuel.
  3. Coal.

- o Limestone storage and distribution system.
- o Waste solids disposal systems for dry wastes and wet wastes.
- o Combustion gas clean-up systems including a sulphur dioxide scrubber system and a hot gas clean-up system.
- o Boiler feed-water system.
- o Heat rejection system.
- o Electrical conditioning and control system.
- o Buildings.
- o Site preparation and development.
- o Energy conversion equipment installation.

In developing the cost estimates for the balance-of-plant, an island system was adopted. Normally in the construction and installation of an industrial or utility powerplant, there are significant expenses associated with material and installation labor that are not attributed to one of the principal elements and are not normally included in the indirect field costs; for example, piping and installation of that piping. For this study the estimated cost of such items was assigned to the balance-of-plant elements by Bechtel National, Incorporated, based on their knowledge and experience. The definitions of cost elements, Table 15, reflect this island approach in the balance-of-plant cost estimates.

Each cogeneration system requires one or more of the balance-of-plant elements. Since pipeline gas is not used in this study, all systems used one of the fuel storage and distribution systems. The fluidized bed coal-fired heat sources require limestone or dolomite storage and distribution and dry waste solids disposal. The conventional coal-fired boiler requires wet waste solids disposal and the sulphur dioxide scrubber. Pressurized fluid bed heat sources require the hot gas clean-up system before utilizing the combustion products in the gas turbine.

All steam and hot water systems require a feed-water system. Some cogeneration systems need heat rejection to dispose of excess thermal energy. In the conduct of the analysis, the required balance-of-plant elements were established for each energy conversion system-fuel combination and the appropriate parasitic losses and estimated costs were included in each complete system.

Detailed descriptions of each balance-of-plant element and associated parasitic requirements and estimated costs are included in Volume IV of this report.

The annual operating and maintenance costs for the cogeneration facility balance of plant can best be related to the type and size of heat source used in the plant. The annual costs in dollars per million Btu/hr of design thermal output capacity of the heat source are included in Table 20.

TABLE 20
ESTIMATED ANNUAL BALANCE-OF-PLANT OPERATING AND MAINTENANCE COSTS

Type of Plant	Dollars/Million Btu/Hr
Oil-fired heat source	117
Coal-fired heat source	204
Coal-fired heat source with sulfur dioxide scrubber	554
Coal-fired heat source with hot gas cleanup system	258

A descriptive section follows for several balance-of-plant systems.

Boiler Oil Storage and Distribution System

The boiler oil storage and distribution system shown schematically in Figure 42, includes provisions for unloading, storage, and distribution to the energy conversion system of petroleum or coal-derived boiler fuel. Design and operating characteristics for system providing fuel flows equivalent to 50 to 1200 million Btu/hr are as follows:

o	Fuel	100°F unloading temperature 150°F circulating temperature
o	Tanks	30 day storage tank capacity 24 hour day tank capacity Carbon steel construction 4 in fiberglass insulation
o	Unloading Pumps	Capacity to unload 48 hours of burner fuel in four hours or less

- o Circulation Pump — 10:1 for <100 million Btu/hr of delivered fuel energy; 5:1 for 100 million to 500 million Btu/hr of delivered fuel energy; 2:1 for >500 million Btu/hr of delivered fuel energy
- o Booster Pumps — Capacity designed for maximum burner consumption
- o Heaters — Steam heating provided to maintain specified operating temperatures

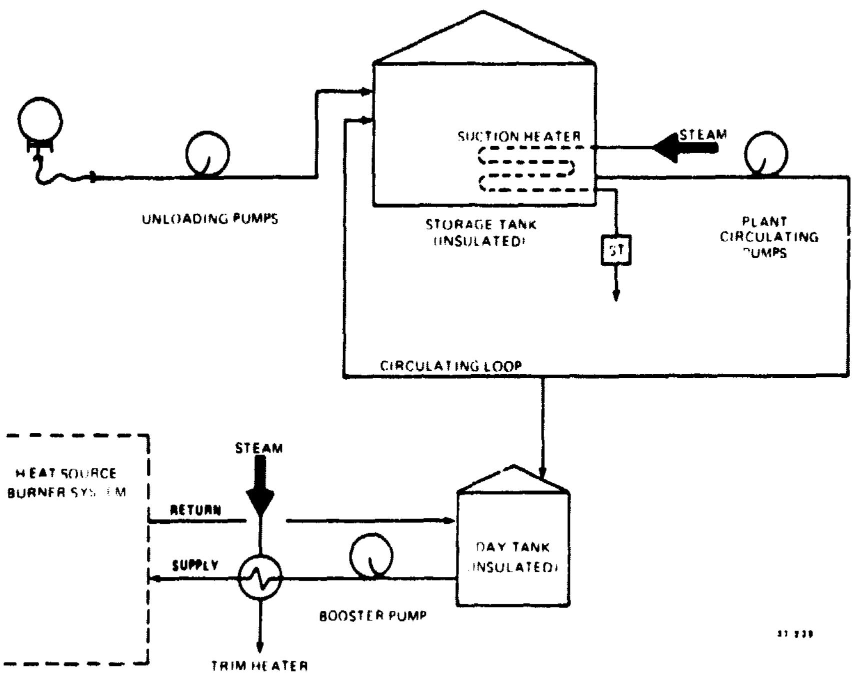


Figure 42. Boiler Oil Storage and Distribution System

Electric power required for the system pumps is 0.2 kWe per million Btu/hr of delivered fuel energy. Low pressure, 300°F steam is required for the system heaters. The system energy required is 7000 Btu/hr per million Btu/hr of delivered fuel energy.

Figure 43 indicates the estimated field construction cost as a function of the heat content of the fuel flow.

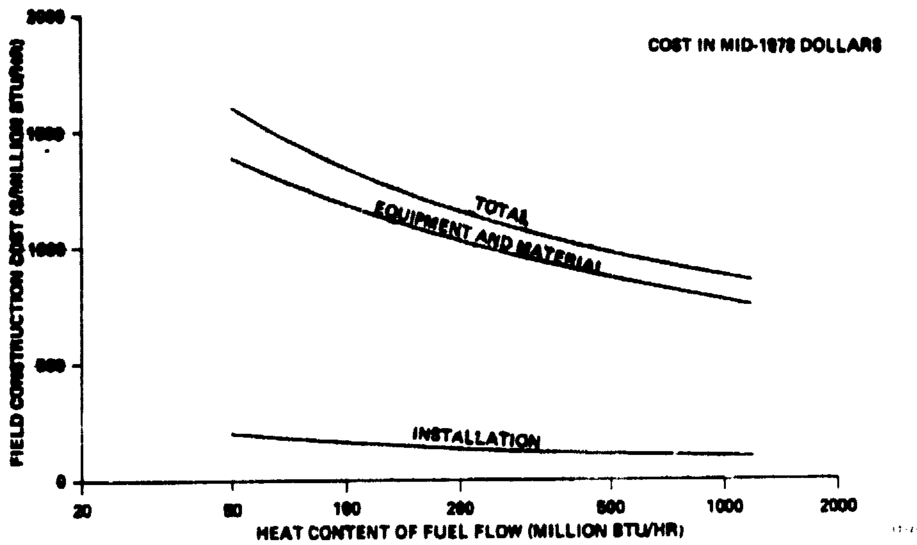


Figure 43. Estimated Field Construction Cost for Boiler Oil Storage and Distribution System

Limestone Storage and Distribution System

The limestone storage and distribution system, illustrated in Figure 44, includes provisions for stockpiling, transfer to day bins, and conveying to the heat source. It is assumed that unloading equipment used for coal handling will be used for unloading the limestone. Design and operating characteristics of limestone systems providing 2000 to 60,000 lb/hr of stone are based on 30 day live storage. The system required for handling dolomite is similar to the limestone handling system.

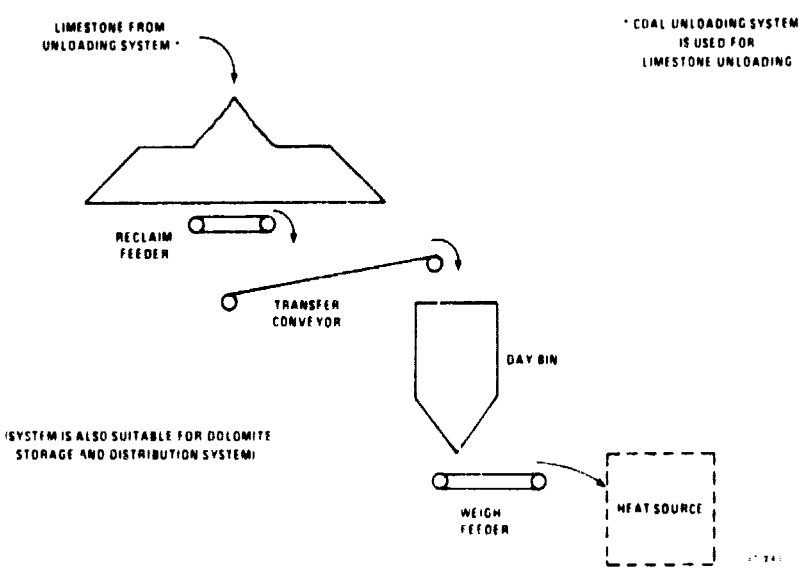


Figure 44. Limestone Storage and Distribution System

The electric power requirement for all drives in the system is 0.45 kWe per thousand lb/hr of limestone supplied by the system.

Figure 45 shows the estimated field construction cost as a function of system capacity.

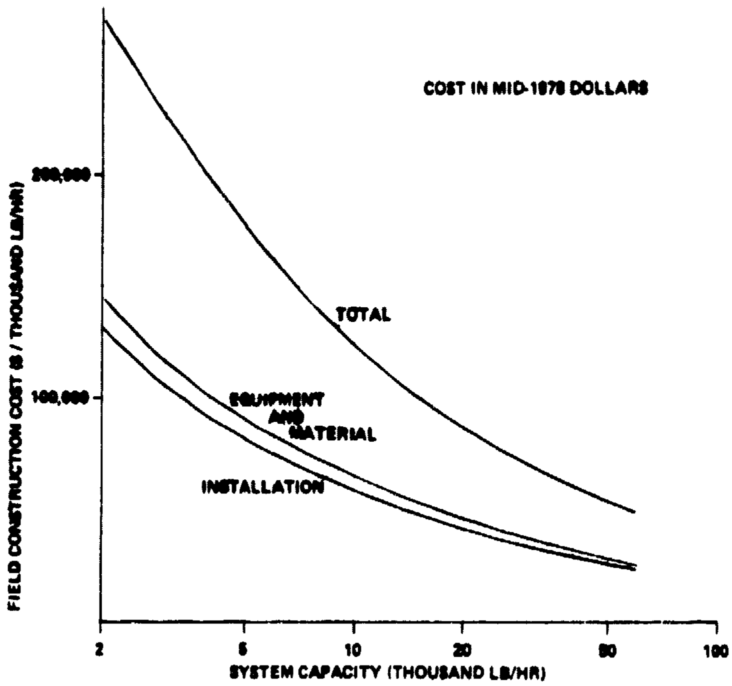


Figure 45. Estimated Field Construction Cost for Limestone Storage and Distribution System

Wet Waste Solids Disposal System

The wet waste solids disposal system is illustrated schematically in Figure 46. The system includes provisions for forming a solids waste slurry, slurry clarification, sludge filtration, water reclamation, and sludge disposal. The system is suitable for solid wastes above 350°F from coal fired boiler bottom ash or hot gas cleanup system.

The pump power requirement is 0.005 kWe per lb/hr of solid waste handled. Makeup water required is 0.5 lb per lb/hr of solid waste handled. The cost breakdown for the design point flow of 1,000 lb/hr is presented in Table 21.

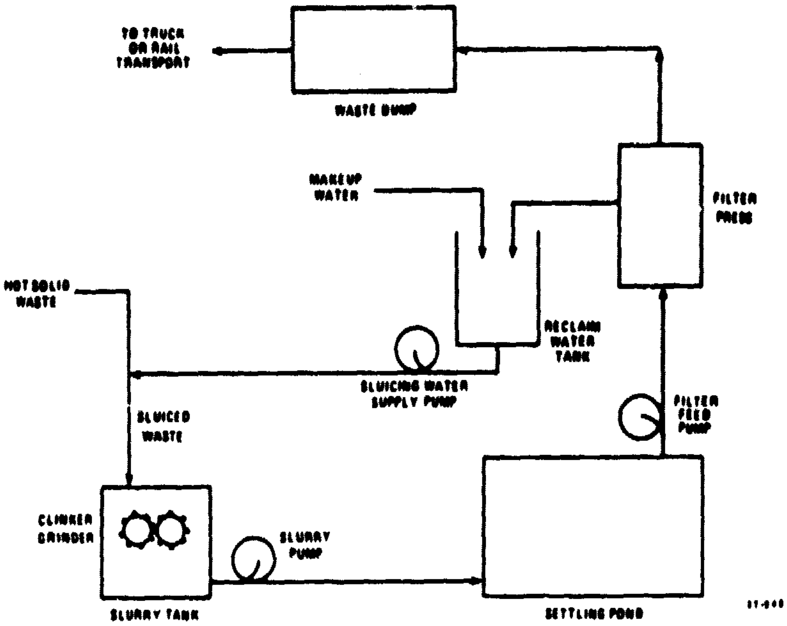


Figure 46. Wet Waste Solids Disposal System

TABLE 21

WET WASTE SOLIDS DISPOSAL SYSTEMS
ESTIMATED FIELD CONSTRUCTION COST
(1,000 LB/HR FLOW)

Item	Dollars
Equipment	
Tanks	13,000
Pumps	8,000
Other	2,000
Civil/Structural	10,000
Piping/Instrumentation	5,000
Total Equipment and Materials	38,000
Direct Installation Labor (@ $14/MH)	9,000
Indirects (@ 75% of Direct Labor)	7,000
Total Field Construction Cost (Mid-1978 Dollars)	54,000

Sulfur Dioxide Scrubber System

The sulfur dioxide scrubber system, illustrated schematically in Figure 47, includes provisions for removing the sulfur from the flue gas, heating the clean flue gas, and disposing of the waste solids. The sulfur dioxide concentration in the heat source flue gas is assumed to be 3000 ppm. With a scrubber efficiency of 85 percent, the concentration in the clean flue gas to the stack is 450 ppm. The system also removes 20 to 25 percent of the total particulate matter. The sulfur dioxide emission in the cleaned flue gas is 1.2 pounds of sulfur per million input Btu/hr. The flue gas reheat system furnishes 225°F clean air for mixing with 125°F scrubbed flue gas to achieve 175°F mixture temperature at the stack entrance. A 250 cfm per million input Btu/hr dilution air fan capacity and 42 square feet per million input Btu/hr air heat exchanger area are required. The solid waste disposal rate of 11 lb. (dry) per million input Btu/hr.

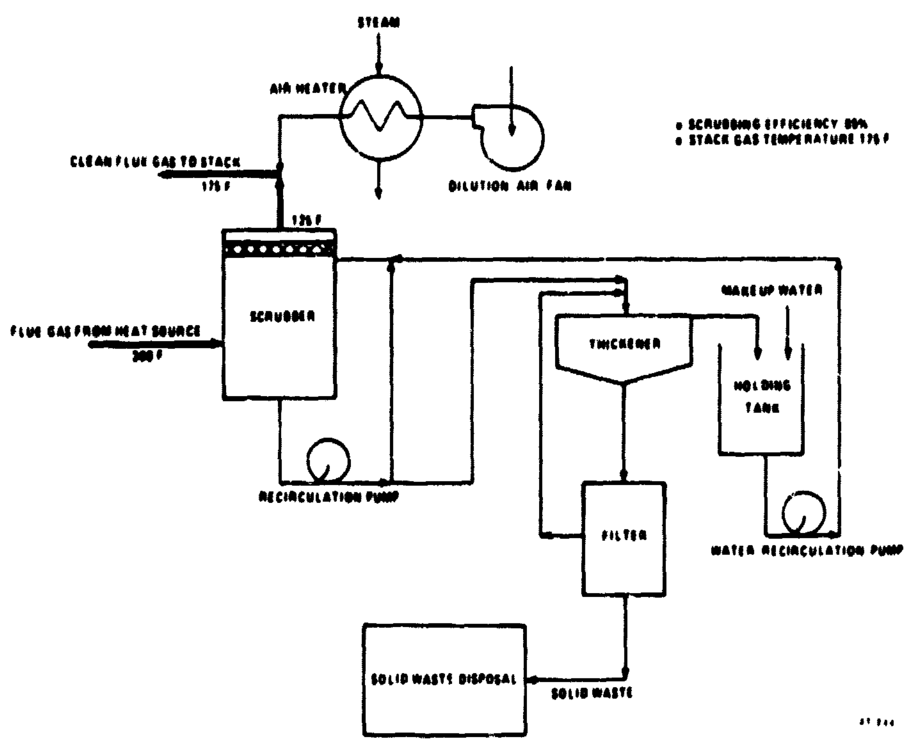


Figure 47. Sulfur Dioxide Scrubber System

The following utilities and operating materials, per million input Btu/hr of fuel fired, are required for the scrubber system:

- 0.2 kWe of auxiliary electric power
- 50,000 Btu of steam for air heating
- 0.2 gal/min of makeup water
- 6 lb. of lime as CaO
- 0.5 lb. of soda ash as Na_2CO_3.

Figure 48 presents shows the estimated equipment and installation cost as a function of heat content of the fuel consumed.

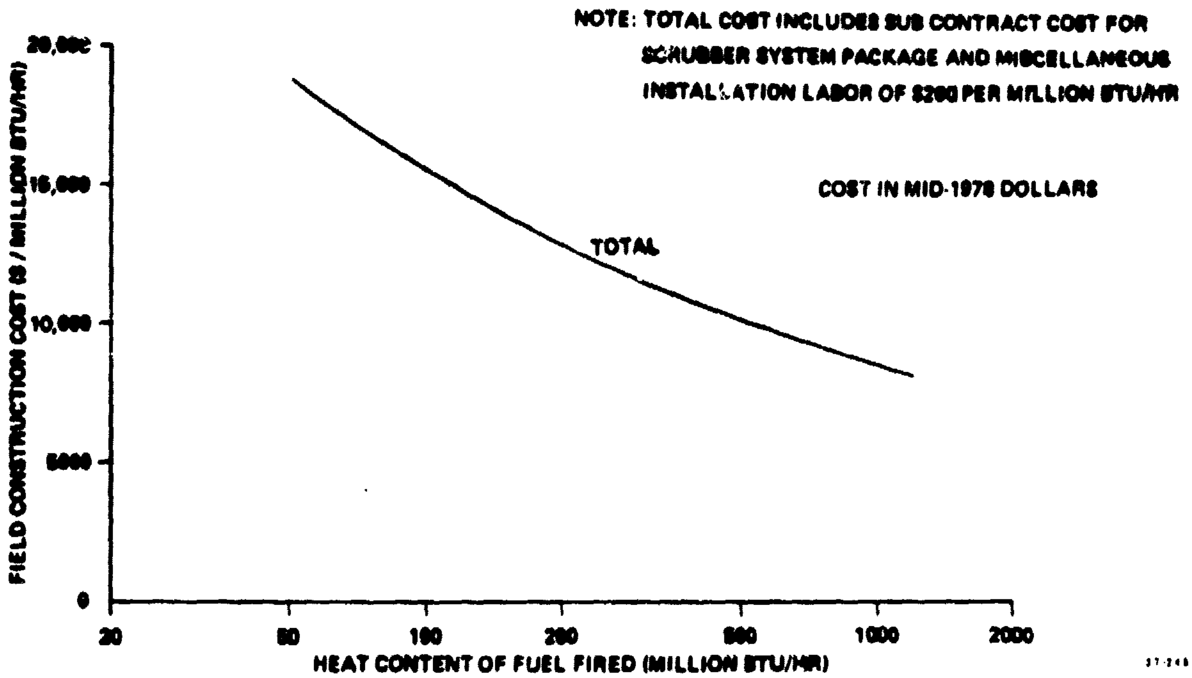


Figure 48. Estimated Field Construction Cost for Sulfur Dioxide Scrubber System

Boiler Feedwater System

The feedwater system shown in Figure 49 supplies oxygen free, saturated water at 250°F for cogeneration and noncogeneration steam generators. The system includes a tray type deaerating feedwater heater operating with 10 minute storage capacity; 15 psig operating pressure, a mixed bed demineralizer makeup water treatment system sized for 10 percent makeup and an epoxy lined, carbon steel storage tank sized for 10 hour capacity.

Electric power requirement for the system equipment is 5.4 kWe per 100,000 lb/hr of feedwater output capacity. Steam requirement for feedwater heating is 0.11 pound of 300°F steam per pound of feedwater when operating at 15 psig and 0.1 pound of 300°F steam when operating at 10 psig. Makeup water required is 10 percent of the feedwater output capacity.

Figure 50 shows the field construction cost as a function fo system capacity.

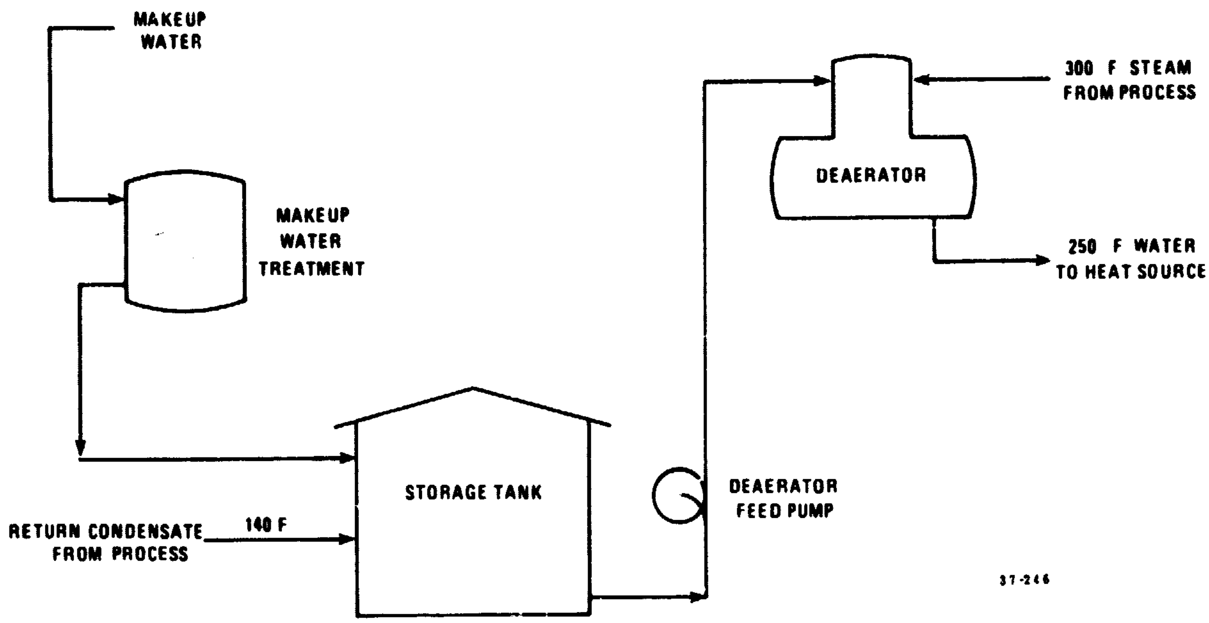


Figure 49. Boiler Feedwater System

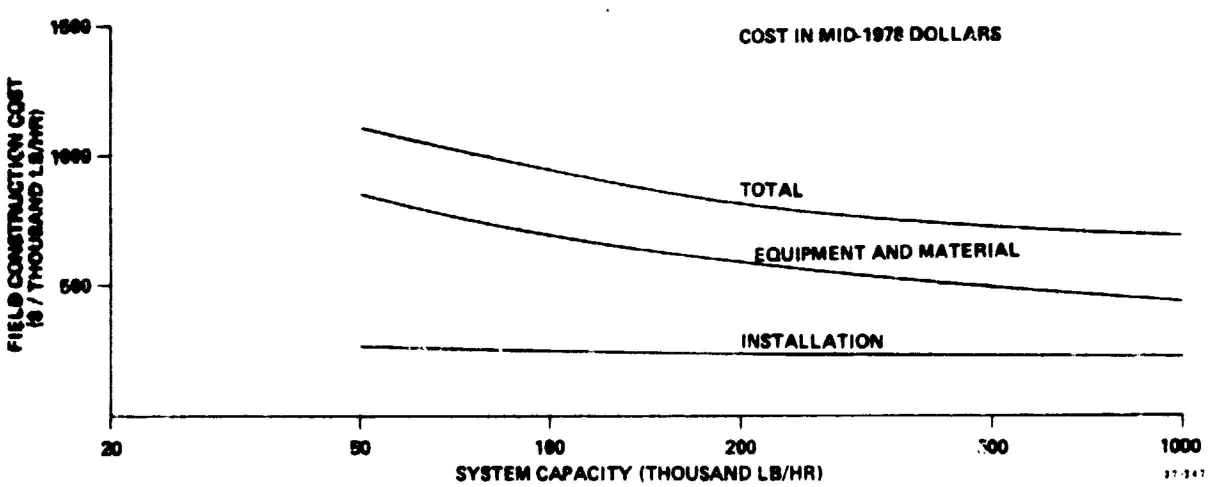


Figure 50. Estimated Field Construction Cost for Boiler Feedwater System

COGENERATION ANALYSIS

The objective of the cogeneration technology alternatives study is to evaluate advanced energy conversion systems in industrial cogeneration applications. Parameters of interest are fuel use and conservation potential, economics and potential savings, and emissions and environmental benefits. Data were gathered to define the energy requirements of representative industrial processes. The estimated performance and cost in the 1985-2000 period were defined for the advanced energy conversion systems. The conventional energy equipment and balance-of-plant characteristics were established. A set of study groundrules and guidelines was adopted. These data and information provided the basis for the analysis.

For purposes of comparison, fuel consumption by type, capital and operating costs, and emissions were established for conventional or non-cogeneration systems meeting the requirements of each industrial process. In a non-cogeneration case, the electrical requirements were met by the electric utility. For purposes of this study, the assumption was made that the utility consumed coal and met the study emission guidelines. On-site furnaces and associated balance-of-plant equipment were selected to meet the thermal requirements. If processed byproduct fuels were available, they were used to the extent that they were projected to be used by Gordian Associates. The representative industrial plant consumed petroleum-based or coal-derived boiler fuels in the furnaces and the fuel consumption was established at the plant level. In practice a variety of fuels would be used by the many plants producing the product. In looking towards potential national fuel savings by type, projections of the national fuel mix to 1990 were the basis of certain comparisons.

Based on the estimated capital costs for the on-site equipment, the levelized annual costs were determined for use in comparisons. In addition to the annual cost of fuel, electricity, and maintenance, an annual charge was established which would recover the on-site equipment capital investment in accordance with the groundrules, Table 3. The pollutants emitted by the furnaces on-site were calculated and the total pollutants (including the electric utility pollutants) produced to provide the process energy requirements were determined.

In the cogeneration case, for each industrial process, the first step was to define the cogeneration strategy. Then the cogeneration system could be defined. For simplicity, the match electrical requirements strategy was addressed first. The energy conversion system was sized to meet the peak electric requirement with 2 - 12 power plants. Actually this is an iterative process to properly account for the parasitic electric loads imposed by the balance-of-plant or other equipment.

With the electrical need met, the available heat from the conversion system was applied to the industrial process and parasitic thermal requirements. If there was energy available in a high temperature bin but no industrial thermal need at that temperature, the conversion system recovered heat was moved down to the next highest temperature bin until all the available recovered heat was used in the industrial process or discarded. In many cases, the recovered heat would not be adequate to meet the thermal requirements. In these cases an auxiliary furnace was added to the system to meet the thermal needs.

In some cases the temperature of the recovered heat is lower than the process requirement. In these situations the recovered heat was used to preheat the boiler feedwater to minimize auxiliary furnace fuel consumption. The objective in each case was to define the system which would have minimum fuel consumption.

Since there were as many as five design options for each energy conversion system - fuel combination, the option with the minimum fuel consumption was selected and retained for each industrial process. For any strategy, a set of data was established for each industry-conversion system combination and a corresponding set was determined for the non-cogeneration cases. In addition to the fuel consumption data the levelized annual cost and emission data were retained.

Comparative parameters were calculated for each industry - conversion system in which the difference between the non-cogeneration and co-generation value was divided by the non-cogeneration value. The resulting savings ratios were retained. The energy savings ratio, cost savings ratio, emission savings ratio, as well as fuel, energy, and cost savings were determined for each industrial process-energy conversion system as depicted in Figure 1.

A second cogeneration application strategy is to choose a powerplant size such that the industrial thermal need is satisfied and electricity is imported or exported as necessary. Specifically, the powerplant size was selected such that no auxiliary furnaces were required except for thermal requirements which could not be satisfied by the energy conversion system. The fuel energy savings ratio levelized cost savings, and emission savings were evaluated for the strategy which matched thermal requirements for each industry-conversion system combination. Since matching thermal requirements can result in substantial electricity exports, the reference non-cogeneration fuel consumption used in the analysis included the fuel saved by the utility as a result of the electricity supplied to the grid. Otherwise the design option which produced maximum export would appear to have the greatest fuel energy savings ratio.

With some conversion systems supplying heat in several bins and some industrial processes requiring heat in several bins, neither matching the electrical nor matching the thermal requirements may provide the best fuel energy savings ratio. Therefore, a third strategy was included where the size of the conversion system was selected to provide the maximum fuel energy savings ratio. Again, the fuel energy savings, levelized annual cost savings, and emission savings were determined for each industrial process-conversion system combination.

The last strategy involved adding a heat pump to raise the temperature of some or all of the rejected heat while consuming some electric power to run the heat pump. In this strategy the objective was to meet both the thermal and electrical industrial requirements.

The capital cost and levelized annual costs and cost savings ratio were calculated for all cases. For selected cases, the cogeneration system discounted cash flow rate-of-return, the payback period, and the net present value were evaluated.

A detailed description of the analyses performed in the study is presented in Volume V of this report.

RESULTS AND CONCLUSIONS

The energy conversion system characteristics, heat source data, and balance-of-plant information were combined to define cogeneration systems which were applied, consistent with the assumptions and groundrules, to satisfy the requirements of the various industrial processes. For each strategy-conversion technology-fuel-industry combination, fuel consumption, cost, and emission data were compiled for the most energy conserving conversion system design option. Summary data including fuel savings, fuel energy savings ratio, cost savings, cost savings ratio, capital costs, emissions savings ratio, and emission savings (on-site and total) for each of these 3,364 cases are presented in Volume VI of this report.

In the following sections the results for these cases are summarized in three ways:

First, a series of matrix charts are presented indicating the results for each energy conversion system - fuel- industry combination. Second, the energy and cost savings ratio for each energy conversion system are summarized statistically for the various industrial applications. Third, an extrapolation to national consumption levels is introduced to aid in evaluating and comparing energy conversion systems. Extending the results to the national level is not intended as a prediction of future events; rather it is a simplified means examining the relative merits and advantages of the various advanced energy conversion technologies.

DETAIL RESULTS

Figure 1 indicates that the energy costs and emission savings were computed for each intersection of the matrix of industrial applications and energy conversion systems. One method of presenting the results of the analysis is to indicate the savings in each industry - conversion system box in the matrix. A series of charts have been prepared for that purpose. Figure 51 is one such matrix chart. In this figure each of the 26 industrial processes occupies a vertical column. The energy conversion systems both current and advanced are included as horizontal rows.

The fuel energy savings ratios for a match electric strategy are presented in Figure 51. Fuel energy saving ratios greater than 30 percent are represented by the darker shading while savings less than 10 percent are not shaded. A review of the chart will indicate some of the more conserving energy conversion systems: the gas turbine with coal derived boiler fuel; the combined cycle with coal derived boiler fuel, and the high temperature fuel cell with coal derived distillate fuel. In certain cases, the results include energy conversion systems designs which were outside the range considered practical. For example, the results shown for the advanced technology high speed diesel engine are not limited by powerplant size considerations. As a result, this conversion technology appears attractive in certain large industries where a sizeable number of units would be required. In practice, the high speed diesel engine is limited to about 1½ megawatts electric output. Its application in a paper mill requiring 90 megawatts might be considered too complex. However, the results are included here for completeness but were not carried forward to the detail economic analysis. The matrix chart, Figure 51, also indicates industrial processes which are good cogeneration candidates with the advanced energy conversion systems.

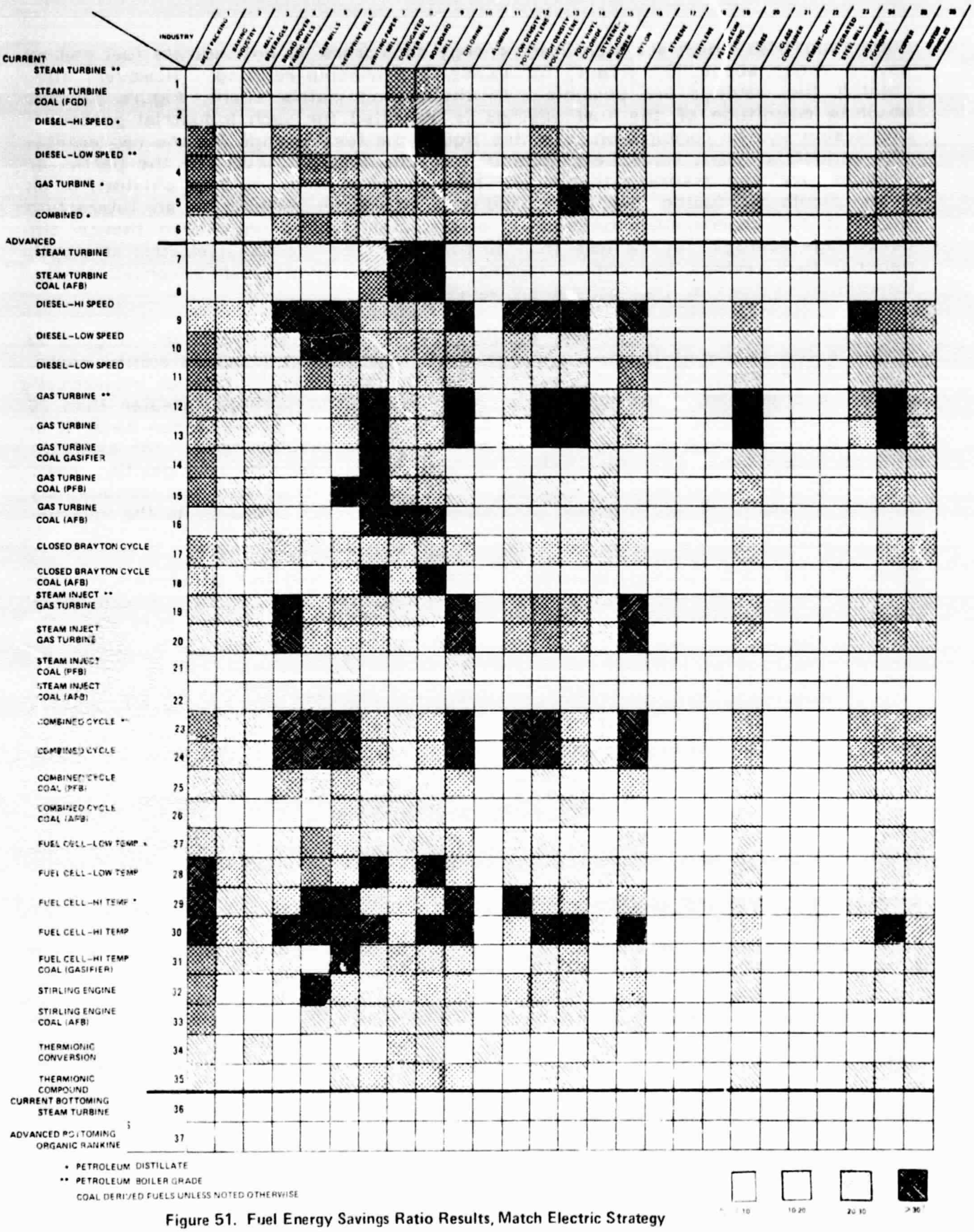


Figure 51. Fuel Energy Savings Ratio Results, Match Electric Strategy

Some industries which are significant energy consumers do not indicate fuel energy saving ratios above 10 percent; for example, petroleum refining. However, substantial fuel savings are possible. In the second matrix chart, Figure 52, the absolute magnitude of the fuel savings is indicated for each industrial process - conversion system combination. In this figure the fuel savings for the representative industrial plant have been extended to the national level for the particular product produced assuming that similar percentage savings could be obtained in all other plants producing the same product. Petroleum refining is an interesting prospect for cogeneration because it offers high fuel savings even though the percentage savings may be less than 10 percent. For the match electric strategy, national fuel savings are not as strong a discriminator between advanced energy conversion systems as the fuel energy savings ratio.

Economics is an important element in the acceptability of cogeneration. Figure 53 presents the matrix of the cost savings ratios based upon levelized annual costs. Conversion systems which exhibited high fuel savings generally provide economically attractive situations. Again, in this chart the highest savings (greater than 20 percent) are achieved with the darker shading. A second influence can be seen in Figure 53: The type of fuel is a factor in the cost savings ratio. For example, the gas turbine energy conversion systems using coal: on-site gasified coal, atmospheric fluid bed coal combustion, or pressurized fluid bed coal combustion; present a number of economically attractive circumstances compared to the conventional gas turbine.

While the high temperature fuel cell with coal derived liquid fuel presents a number of attractive fuel energy savings ratio cases, the high temperature fuel cell operating with an on-site coal gasification plant appears to provide the more dramatic cost savings.

The pollutants emitted by cogeneration plants can be an important factor in their acceptability. Figure 54 presents the emission savings ratios for the match electric strategy. Again, the darkest squares are the most attractive. The most significant conclusion of this chart is that the diesel powerplants offer the least attractive emission characteristics. The emissions savings ratios presented in Figure 54 represent the total emissions including the emissions from electric utilities.

These matrix charts, taken simply, do not indicate strong discriminating factors which would recommend one energy conversion system over another. Two factors are combined in Figure 55. This chart presents the energy savings ratio for only those cases which are economically attractive, that is, have positive cost savings ratios. The gas turbine is most commonly represented in Figure 55. The high speed diesel, gas turbine combined cycle and high temperature fuel cell also appear to have many attractive cases for the match electric strategy.

The cogeneration strategy can affect the results and conclusions. A second set of matrix charts are included for the strategy which maximizes the energy savings ratio. In some cases this strategy will match the electrical requirements. In others the thermal requirements will be satisfied without an auxiliary furnace. In most cases the maximum fuel energy savings ratio occurs at a power level between the match electric and the match thermal situation.

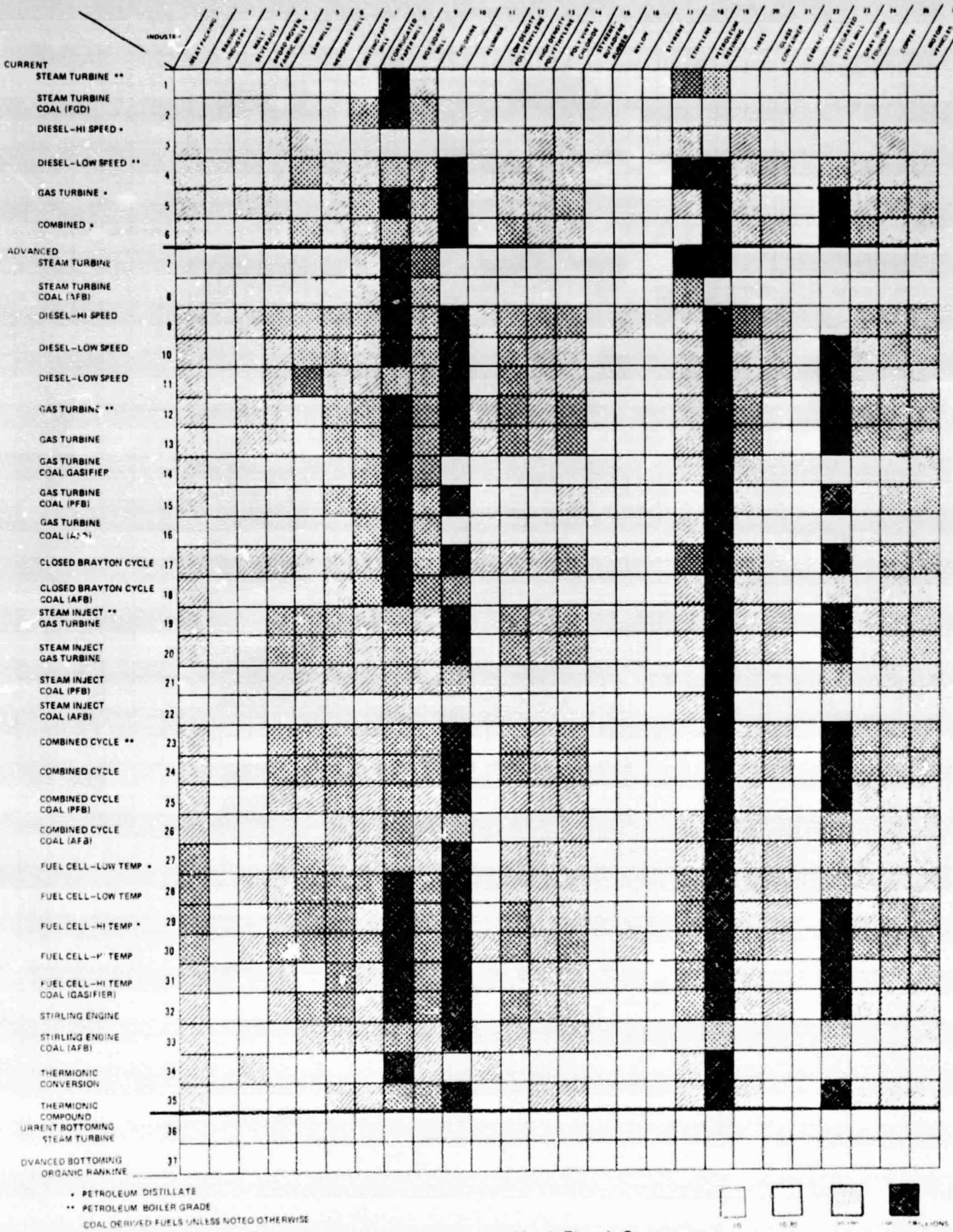


Figure 52. Fuel Energy Savings, Match Electric Strategy

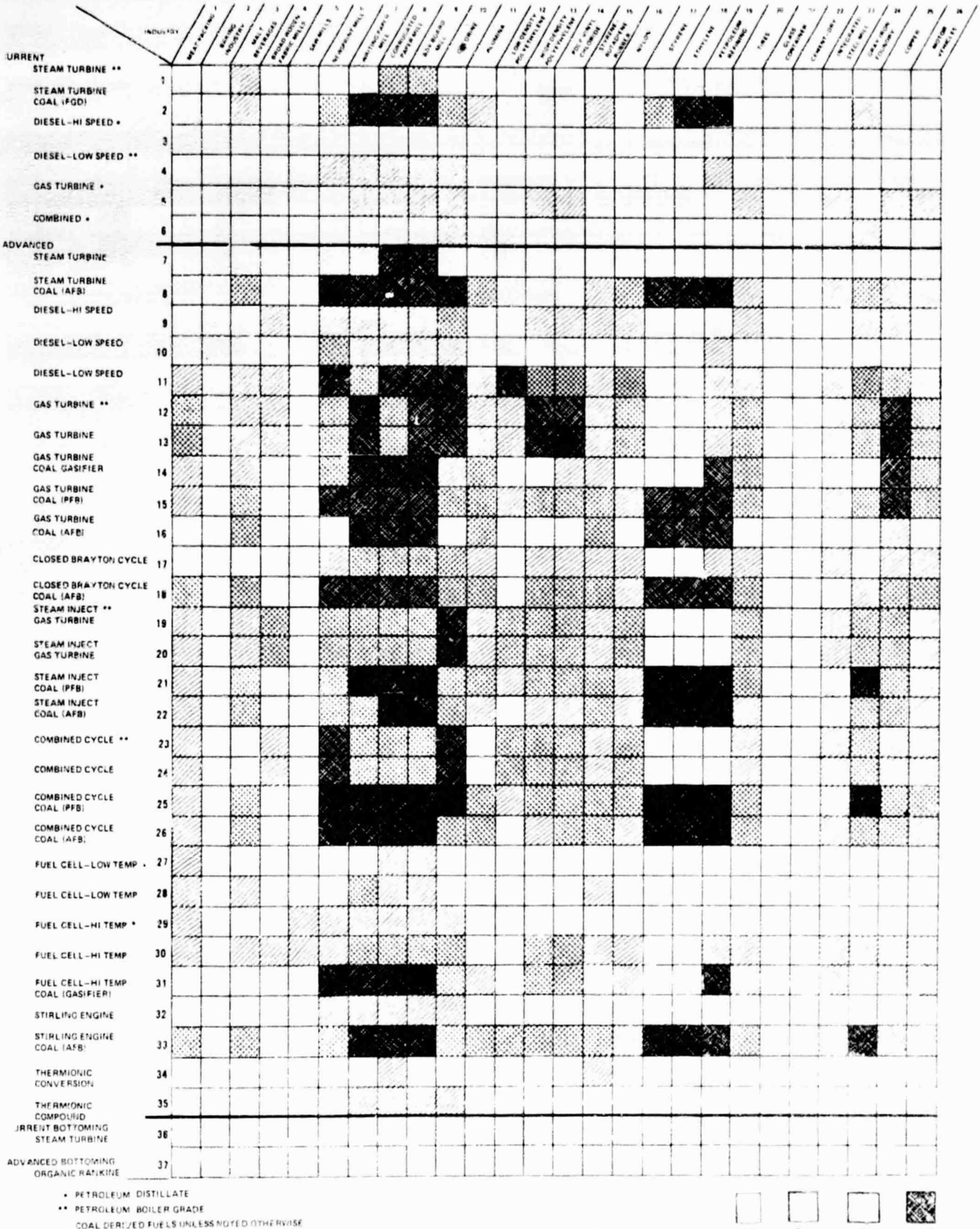


Figure 53. Cost Savings Ratio Results, Match Electric Strategy

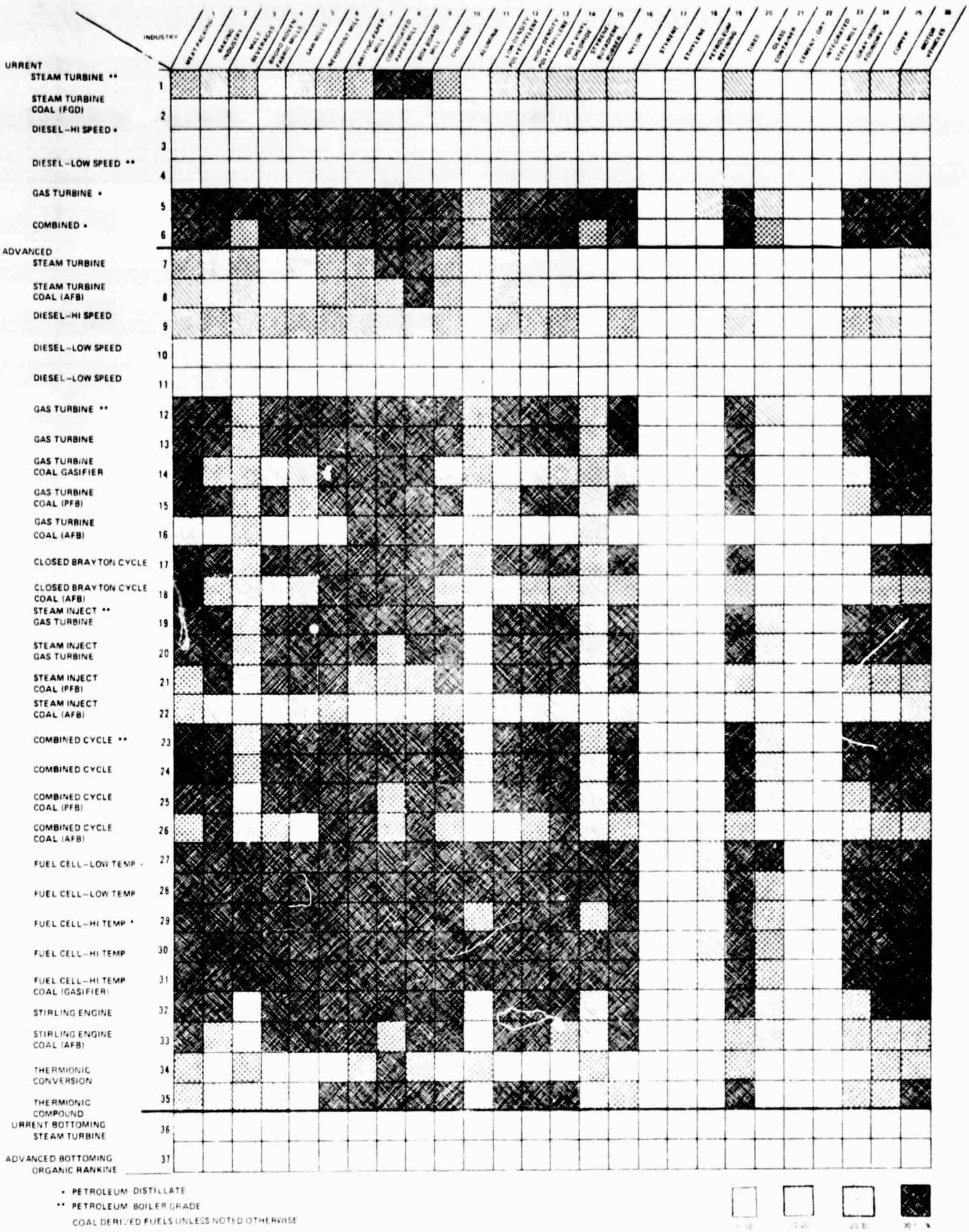


Figure 54. Emission Savings Ratio Results, Match Electric Strategy

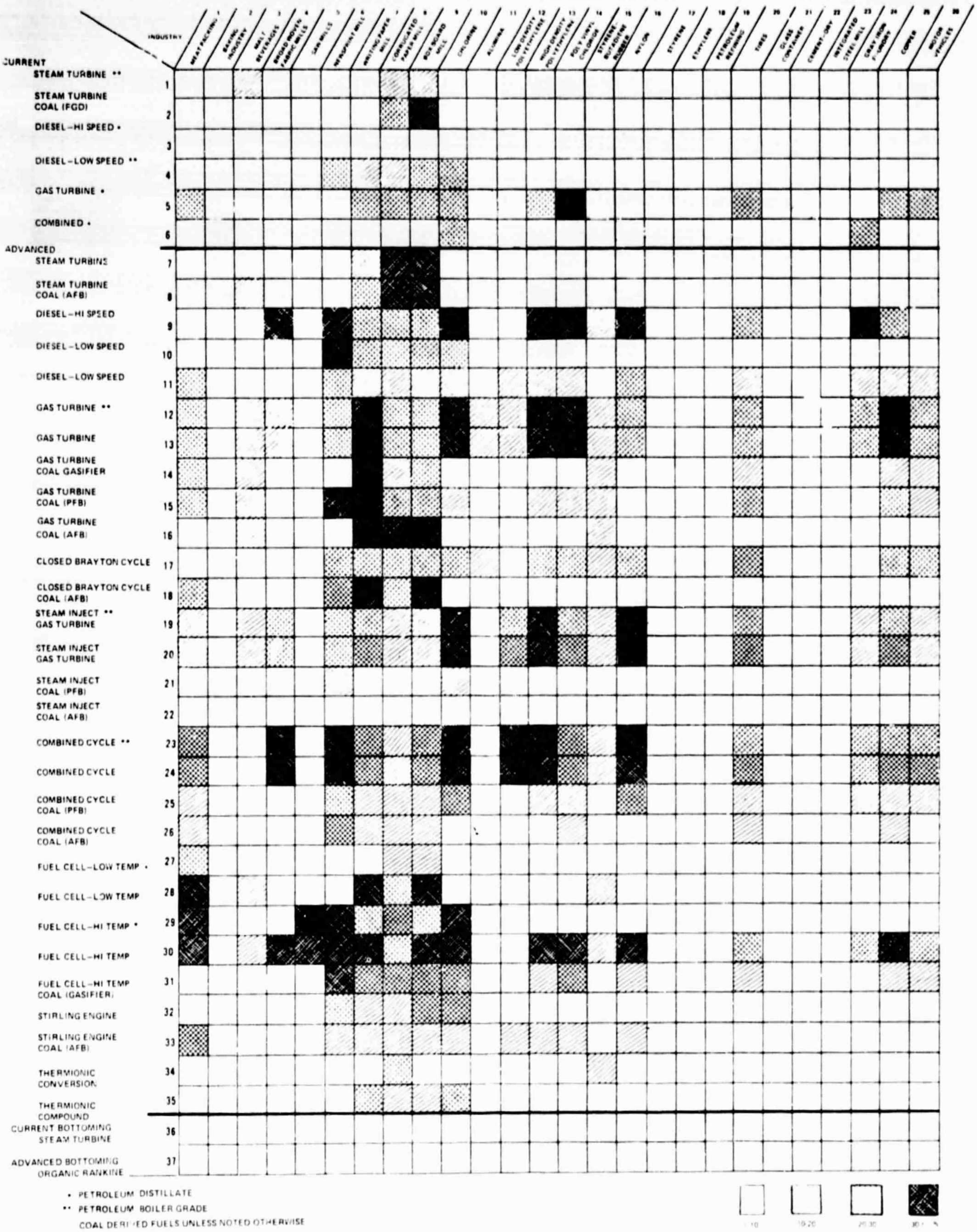
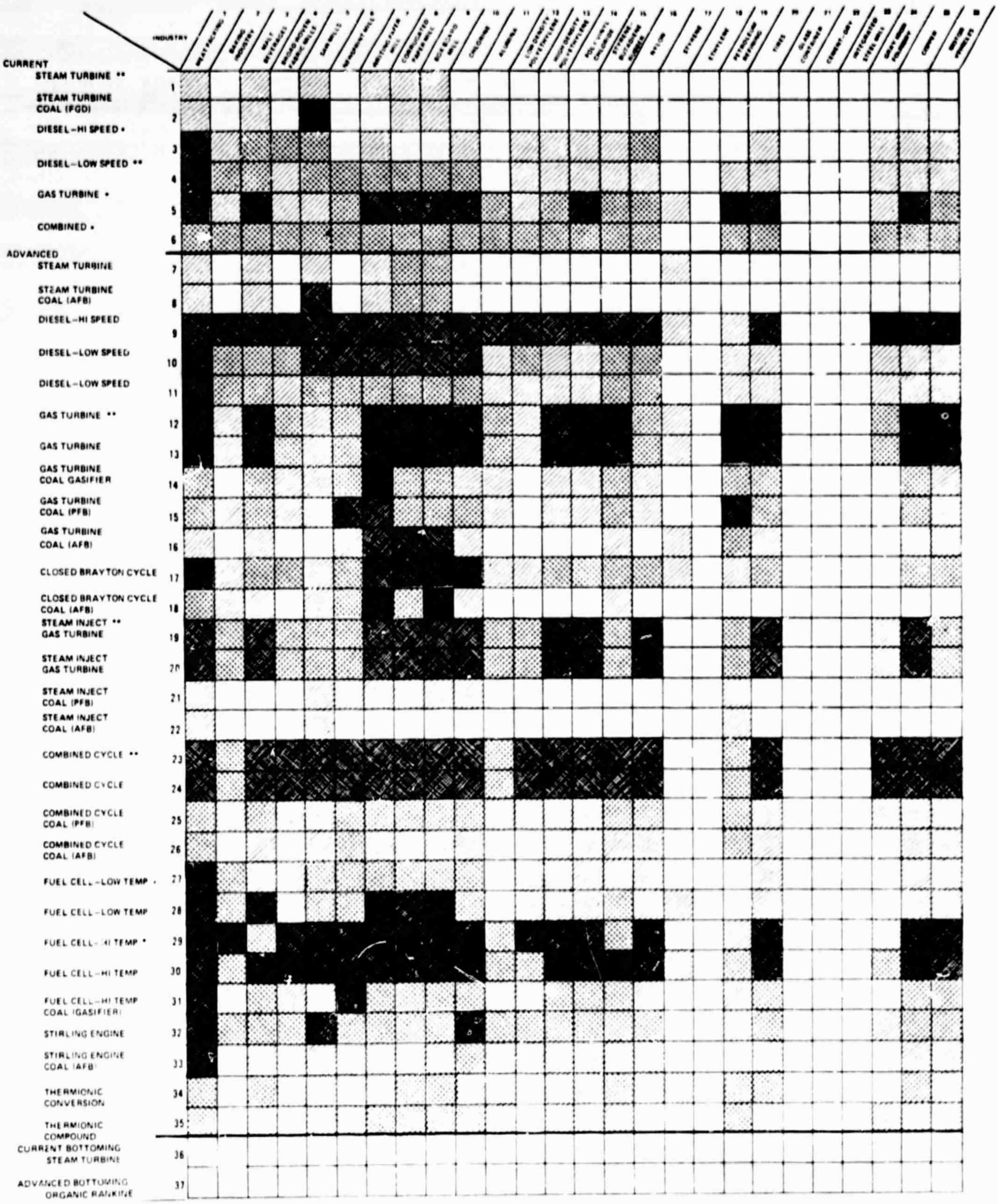


Figure 55. Fuel Energy Savings Ratio Results for Cases with Positive Cost Savings Ratios, Match Electric Strategy

Figure 56 presents the energy saving ratio for the maximum savings strategy. The darkest cases are the most conserving. With this strategy there are more attractive energy conversion systems than appeared with the match electric situation. In addition to the high speed diesel, gas turbine, combined cycle, and high temperature fuel cell; the low speed diesel, closed cycle gas turbine and steam injected gas turbine also appear promising for this strategy. In addition, some industries, which produced low percentage savings with the match electric situation, produce significantly higher fuel energy savings ratios with this most conserving strategy.

The fuel savings scaled to a national level are presented in Figure 57. The patterns are similar to those with the match electric strategy. The cost savings ratio is presented in Figure 58 and the emission savings are indicated in Figure 59. The last chart with this maximum energy savings ratio strategy Figure 60 indicates the energy savings ratio for only those cases which have positive cost savings ratios. Again, the gas turbine, combined cycle, and high temperature fuel cell are the dominant technologies.



* PETROLEUM DISTILLATE
** PETROLEUM BOILER GRADE
COAL DERIVED FUELS UNLESS NOTED OTHERWISE

Figure 56. Fuel Energy Savings Ratio Results, Maximum Fuel Savings Strategy

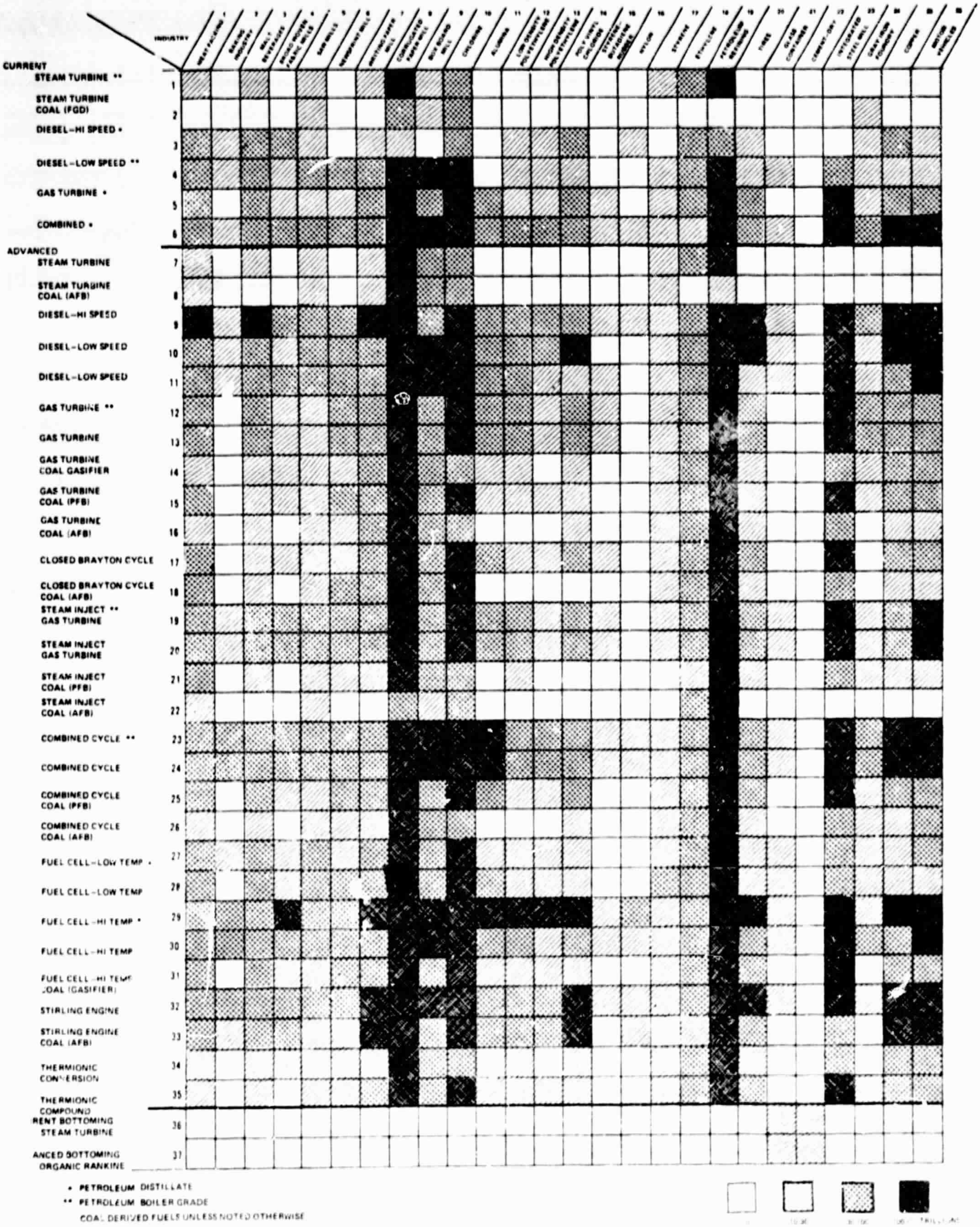


Figure 57. Fuel Energy Savings, Maximum Fuel Savings Strategy

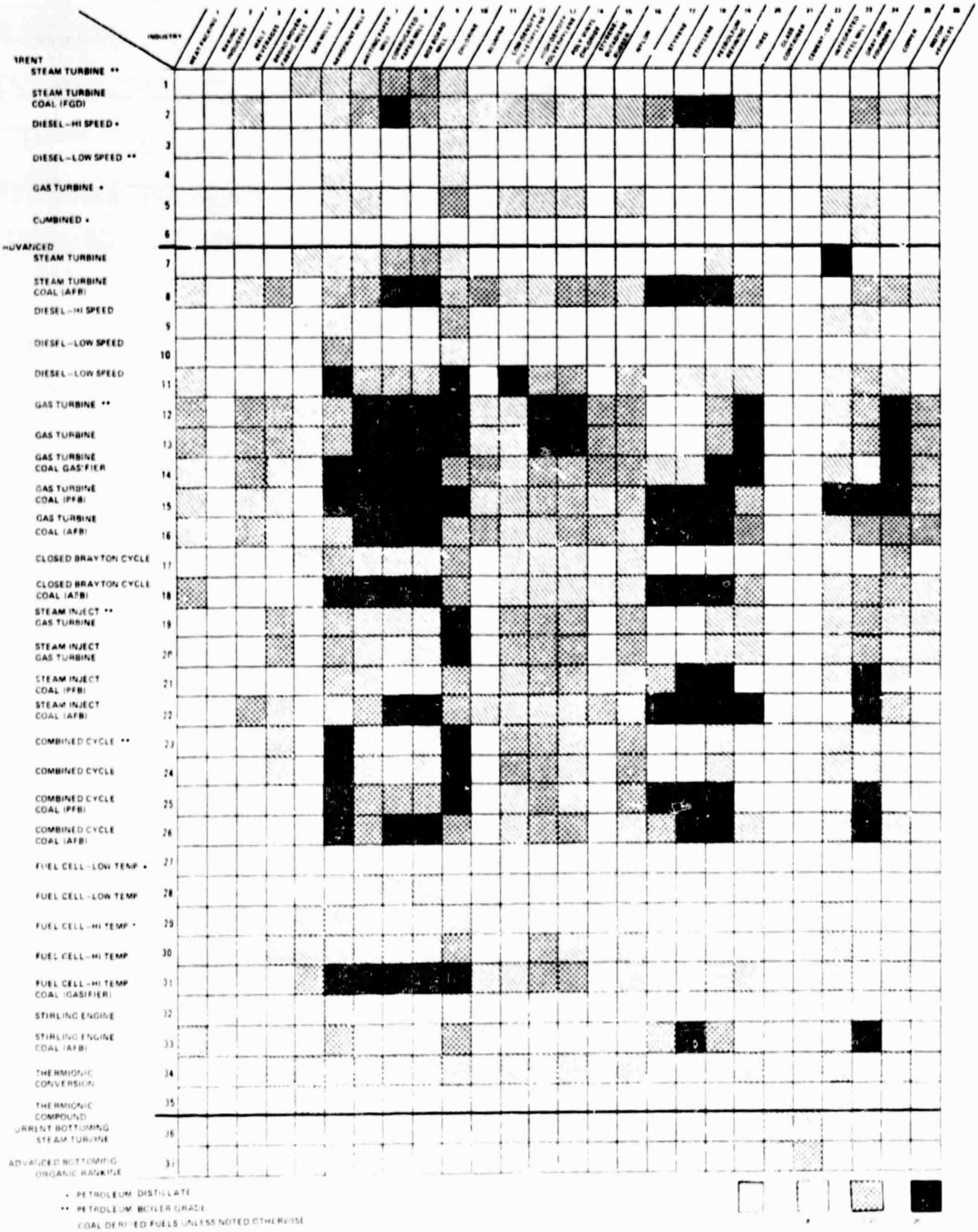


Figure 58. Cost Savings Ratio Results, Maximum Energy Savings Strategy

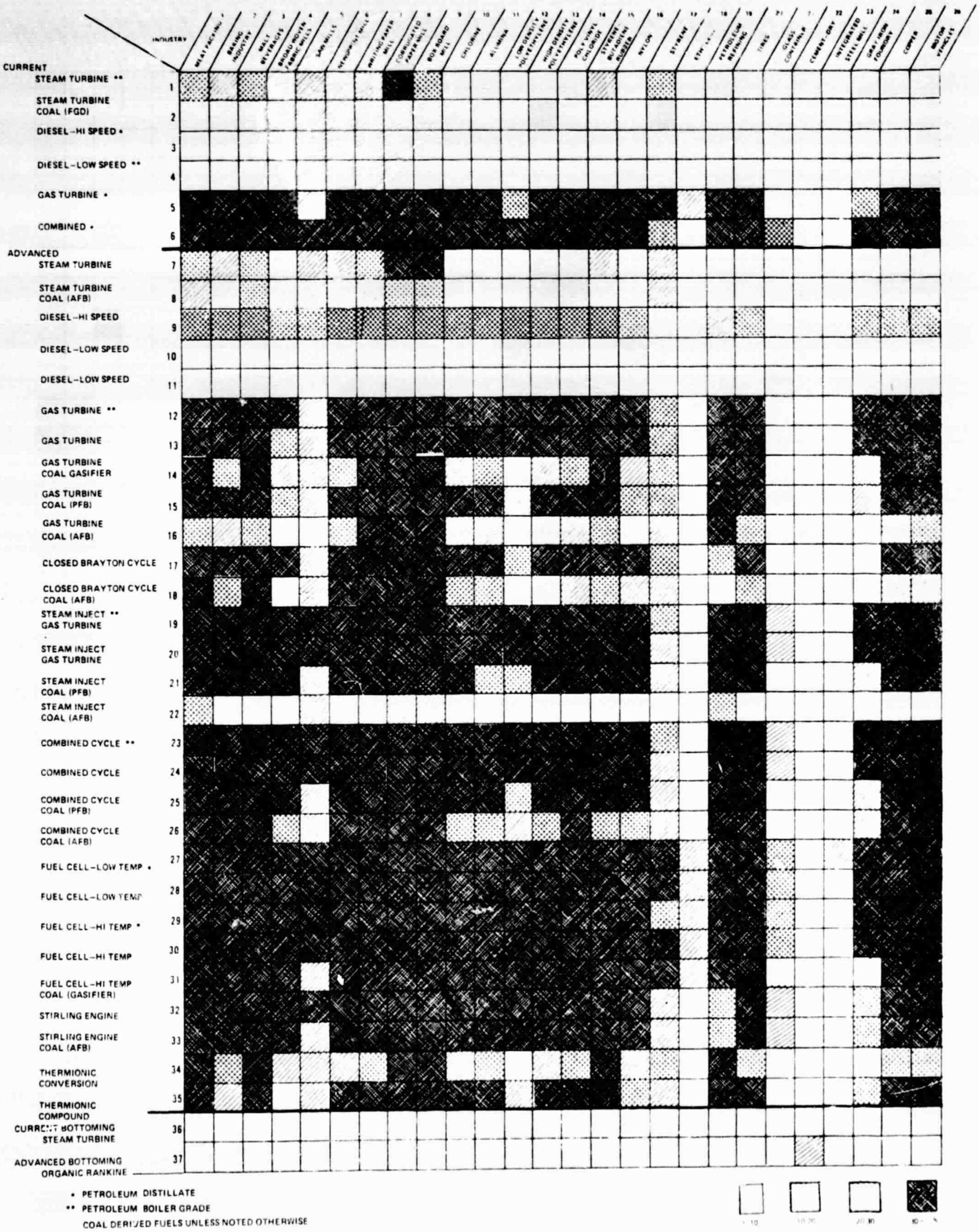


Figure 59. Emissions Savings Ratio Results, Maximum Energy Savings Strategy

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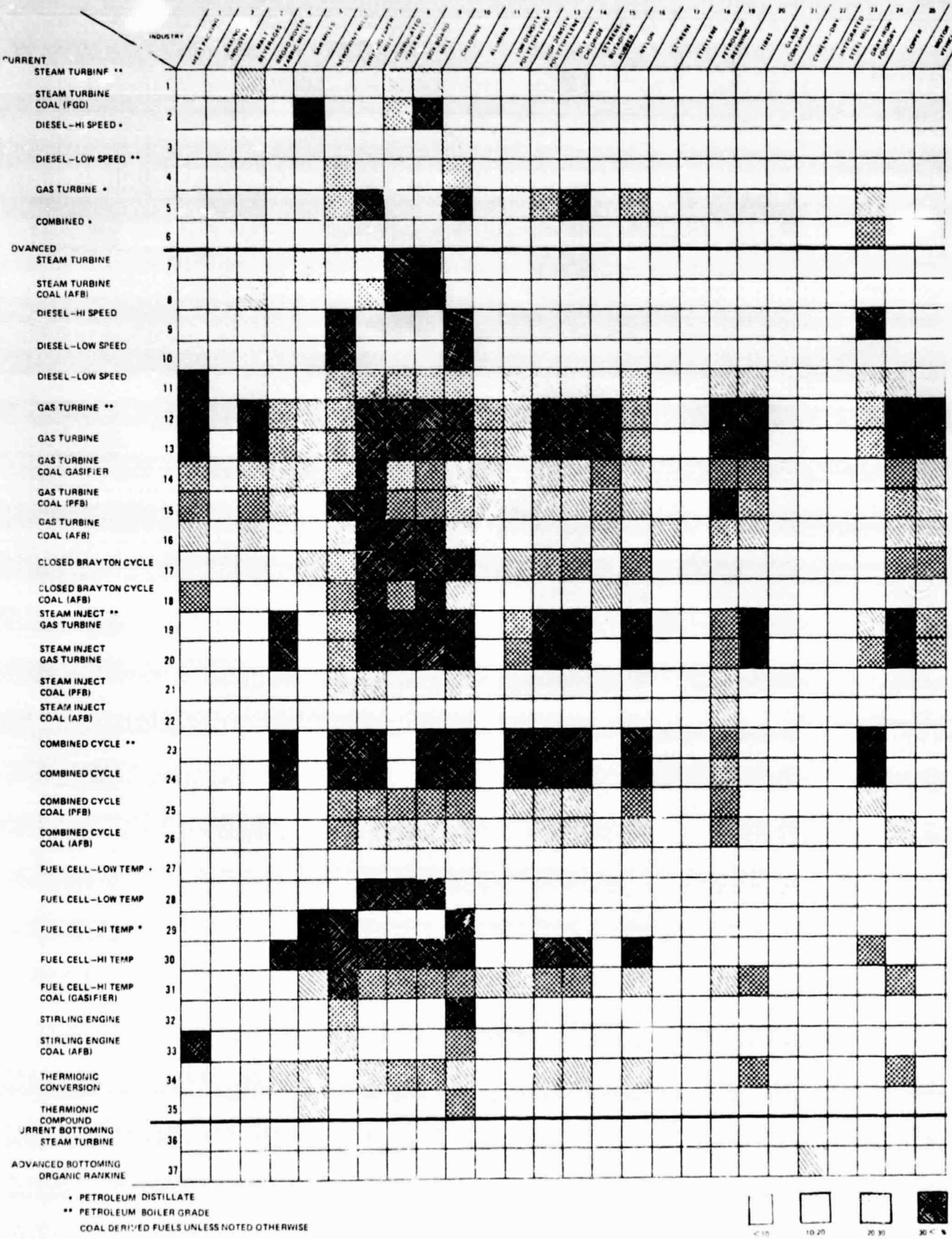

Figure 60. Fuel Energy Savings Ratio Results for Cases With Positive Cost Savings Ratios, Maximum Energy Savings Ratio Strategy

STATISTICAL RESULTS

There is a significant variability from one cogeneration application to another. Figure 61 indicates the statistical distribution of the fuel energy savings ratio for the advanced gas turbine with coal-derived boiler fuel in the various industrial applications. These data can be represented by a normal distribution shown as a straight line in Figure 61. The average value of the fuel energy savings ratio is a general figure-of-merit for each energy conversion system.

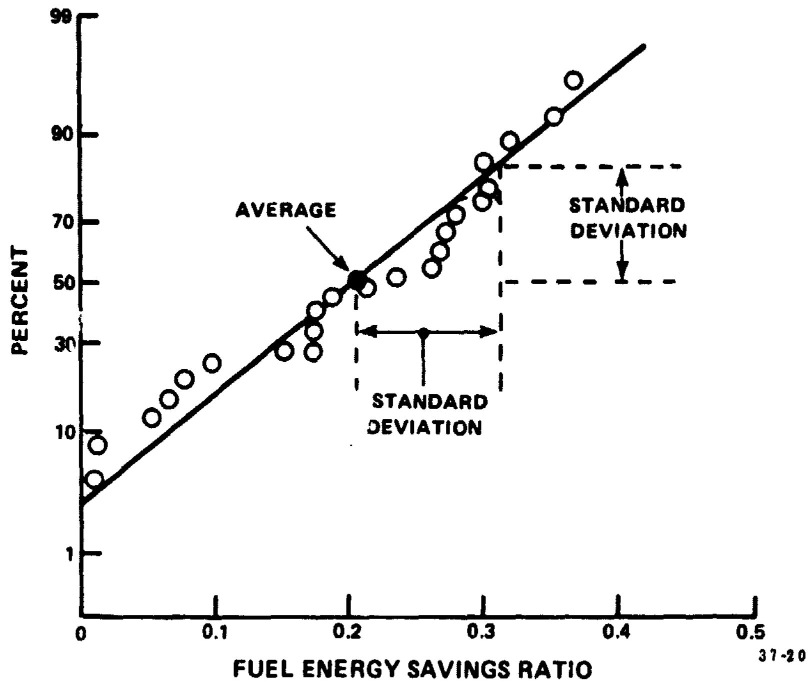

Figure 61. Distribution of Fuel Energy Savings Ratio for Advanced Gas Turbine - Match Electric Strategy

Figure 62 presents the average fuel energy savings ratio for the liquid fueled advanced technologies. In developing the data for Figure 62, applications with negative fuel energy savings ratios were eliminated. While some technologies provide higher average savings ratios than others, all technologies had some applications of high potential savings. The best application is shown for each technology and marked "highest" in Figure 62. The spread of one standard deviation above and below the average is included as an indication of the variability for each technology (16 percent of the data would fall above and 16 percent would be expected to fall below this range). The large standard deviation for the high-speed diesel systems is in part due to the fact that these systems are limited in applicability to about half the industrial processes because of size restrictions.

Figure 62 represents the data for liquid fueled cases. All of these advanced technology conversion systems used coal-derived boiler fuels except the fuel cells and the high speed diesel which used coal-derived distillate.

Since comparisons of liquid fueled and coal-fired systems lead to difficulties, the fuel energy savings ratio data for coal-fired systems are included in Figure 63. For summary purposes, not all of the coal-fired cases are included. For those technologies where there was more than one type of coal-fired technology, the system with the largest overall fuel savings potential has been presented. For example, the gas turbine with a pressurized fluidized bed is presented in Figure 63 and the other two coal-fired gas turbines (atmospheric fluidized bed and coal gasifier) are not plotted. The gas turbine with the coal gasifier produced practically the same average fuel energy savings ratio and standard deviation as the pressurized fluidized bed gas turbine, although the number of industrial applications was smaller with the gasifier. The atmospheric fluidized bed gas turbine applied in a papermill provided the highest fuel energy savings ratio of any coal-fired system sized to match the electric requirements. However, this conversion system was fuel energy conserving in only nine industrial applications compared to 22 process possibilities with the pressurized fluidized bed system. For the atmospheric fluidized bed the spread in the data is very large; the standard deviation is about three times the standard deviation of the other systems. If a line indicating the range of data was presented for the atmospheric fluidized bed gas turbine, it would extend beyond the scale in both directions in Figure 63.

With steam-injected gas turbines and combined cycles, the pressurized bed configurations had higher fuel energy savings ratios and greater overall savings potential than the corresponding atmospheric fluidized bed cases.

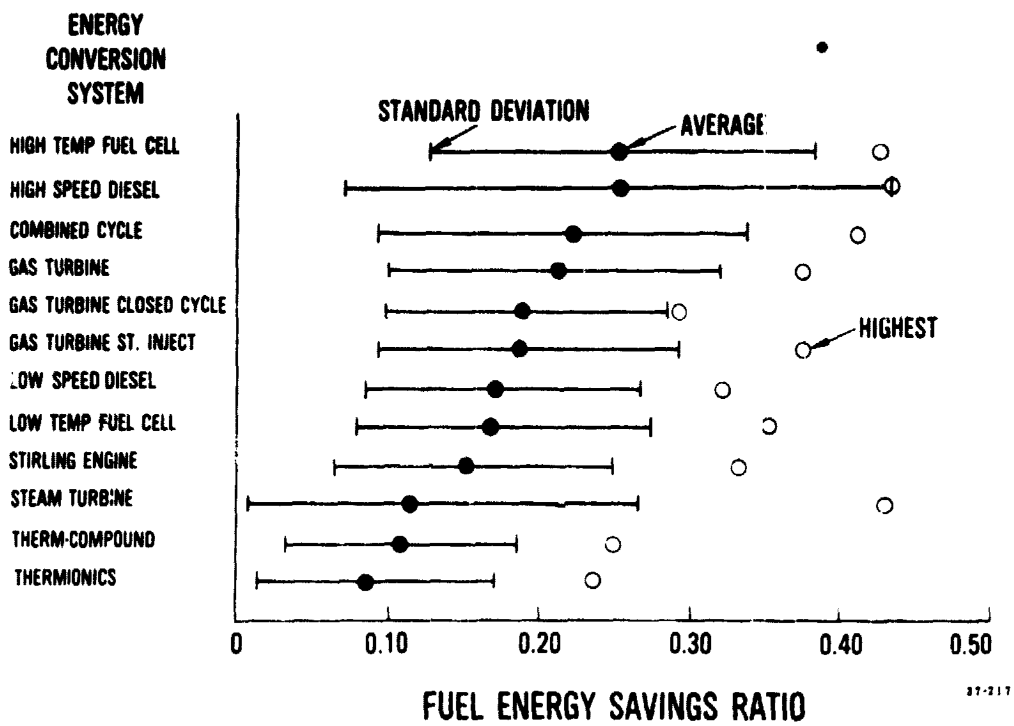

Figure 62. Summary of Advanced Technology Conservation Potential - Liquid Fuels

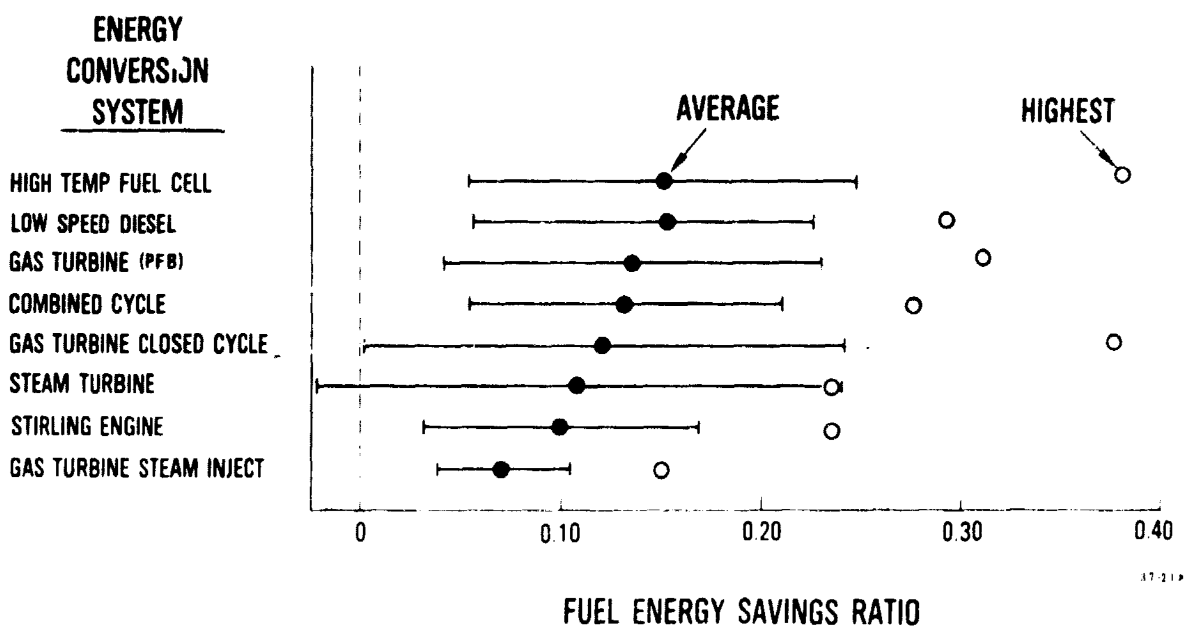

Figure 63. Summary of Advanced Technology Conservation Potential - Coal

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The results presented in Figures 62 and 63 were developed for conversion systems sized to match the electrical energy requirements with auxiliary furnaces for any additional thermal needs. If a thermal matching strategy were adopted, the data are summarized in Figures 64 and 65. The liquid fuel high speed diesel engine applied to only three industrial processes of the 24 topping possibilities because of size limitations. Those three applications are all very favorable so the average fuel energy savings ratio is high. The indicated range of data for the steam turbine is very wide due to two industrial applications: corrugated paper and boxboard, which had very high fuel energy savings ratios. In all of the steam turbine cases with positive fuel energy savings ratios, 76 percent fell below 0.1 fuel energy savings ratio.

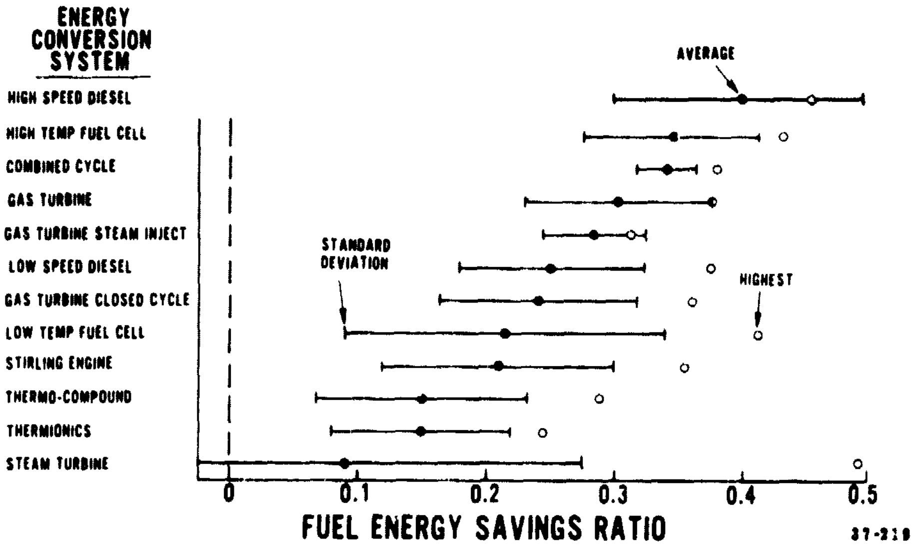

Figure 64. Advanced Technology Conservation Potential - Match Thermal Strategy - Liquid Fuels

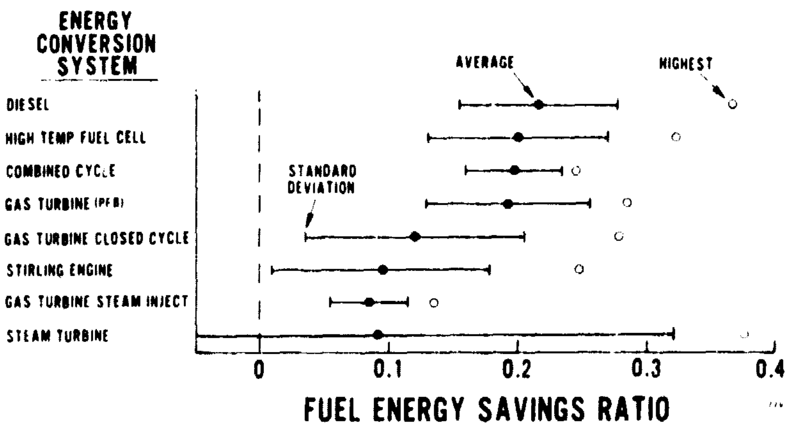

Figure 65. Advanced Technology Potential - Match Thermal Strategy - Coal

In the coal-fired cases, Figure 65, the gas turbine and combined cycle cases include the pressurized fluidized bed coal combustion system. In each case the average and maximum fuel energy savings ratio is superior with the pressurized fluidized bed compared to the atmospheric fluidized bed.

To summarize the emissions savings possibilities, similar simple averages were developed and presented in Figures 66 and 67 for the match electric strategy. Fuel cells offer the greatest environmental benefits. In fact, in some cases the on-site emissions are reduced compared to the on-site emissions from the conventional furnaces.

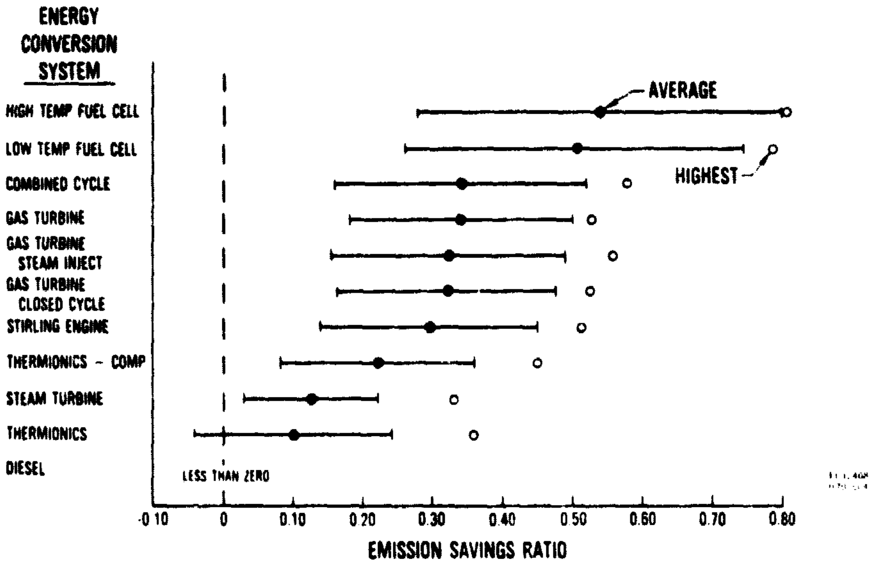

Figure 66. Advanced Technology Emissions Savings - Liquid Fuel

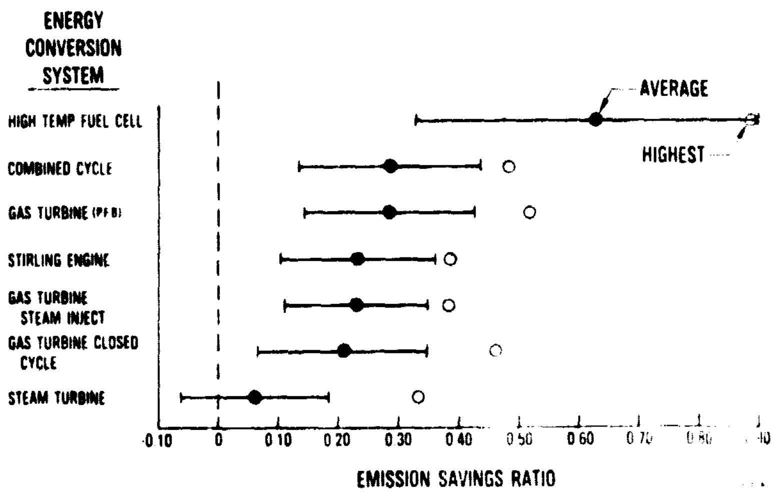

Figure 67. Advanced Technology Emissions Savings - Coal

The diesel engines produce nitrogen oxides in excess of the guidelines and, on the average, do not reduce pollutants compared to the non-cogeneration configuration.

The potential cost savings based on levelized annual costs to the industrialist are presented in Figures 68 and 69. In summarizing the fuel energy savings ratios, only the positive savings were considered. The emissions savings summary in Figures 66 and 67 included those applications with positive fuel energy savings ratios. This same approach was used in summarizing the data in Figures 68 and 69, which indicate the cost savings ratio data for those situations which conserve fuel.

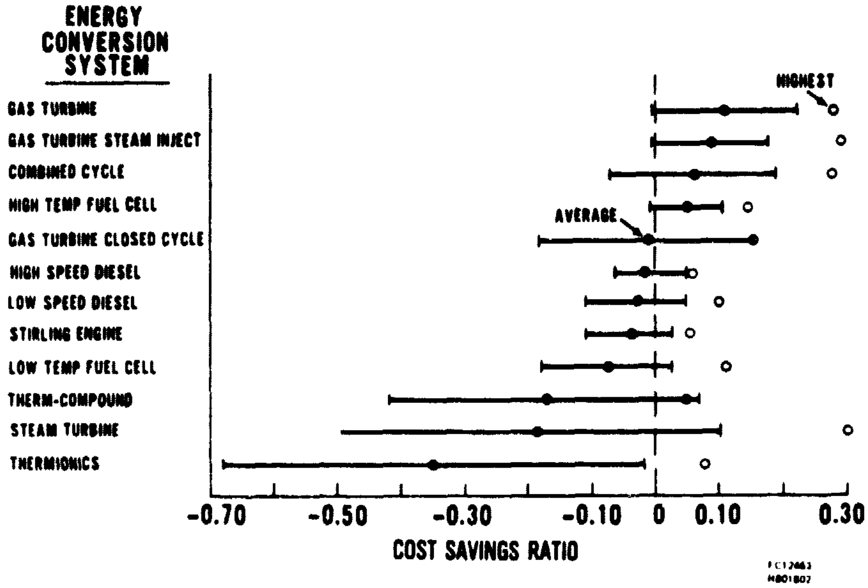

Figure 68. Advanced Technology Cost Savings Ratio - Liquid Fuels

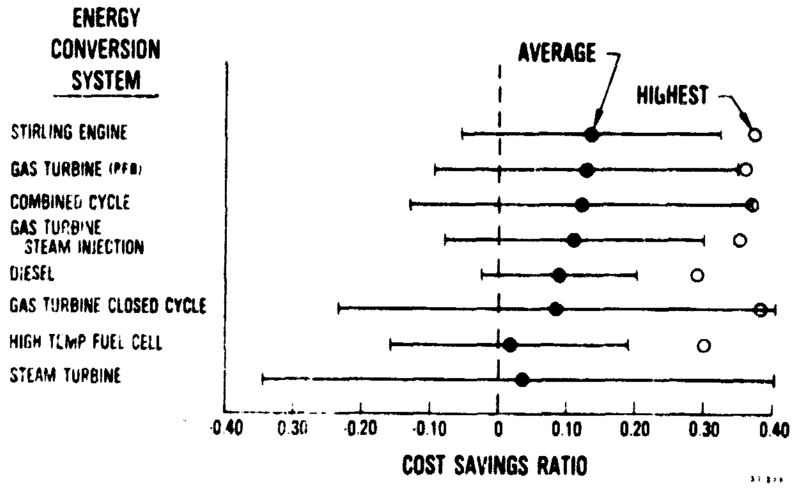

Figure 69. Advanced Technology Cost Savings Ratio - Coal

With the economic assumptions adopted for this study, coal-fired systems generally offer higher average savings. In fact, in many cases the liquid fuel systems do not provide economic savings. Of particular interest are those cases which conserve fuel and indicate levelized annual cost savings to a potential industrial plant owner. Therefore, the data were analyzed to determine the relative number of cases with indicated annual cost savings and the results are presented in Figure 70 for the liquid fueled conversion systems. The various gas turbines and the high temperature fuel cells have the highest proportion of cost saving cases.

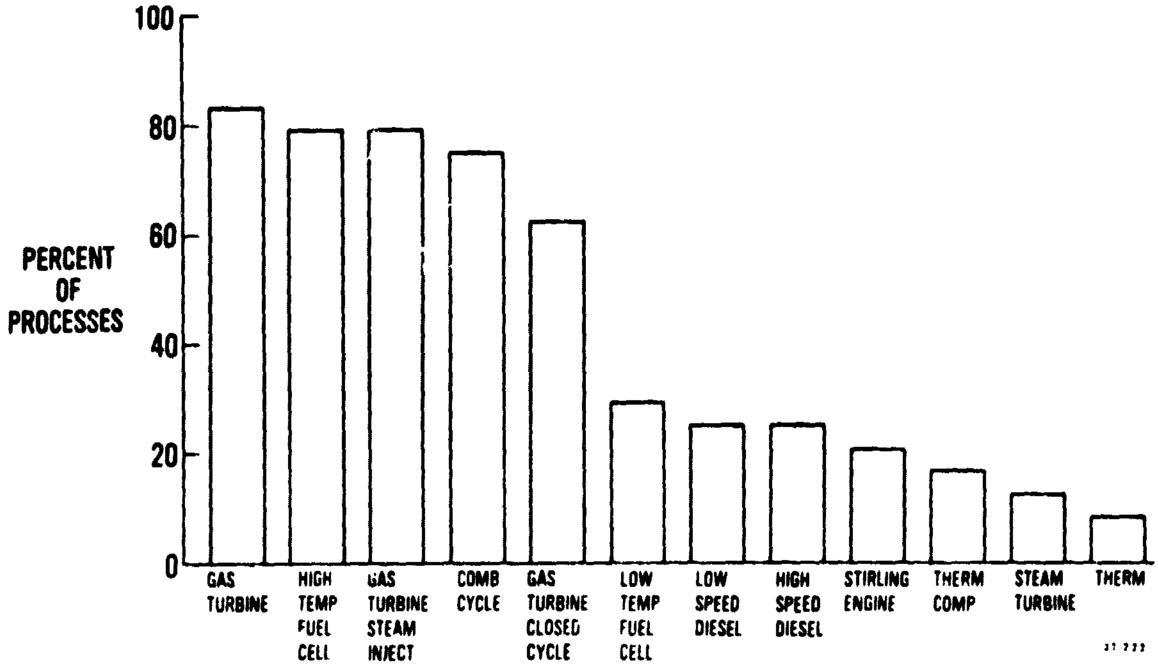

Figure 70. Fraction of Industrial Processes with Positive Annual Cost Savings - Liquid Fuels

If only the cost savings and fuel savings cases are considered for an energy conversion system, the average cost savings ratio is positive. The average cost savings ratio data for the liquid-fueled cases for the match electric strategy limited to the conserving and cost savings cases are presented in Figure 71. This result can be compared with Figure 68 where the cost savings ratio for all cases is presented. A similar improvement in the average cost savings ratio situation occurs with the coal fired conversion systems.

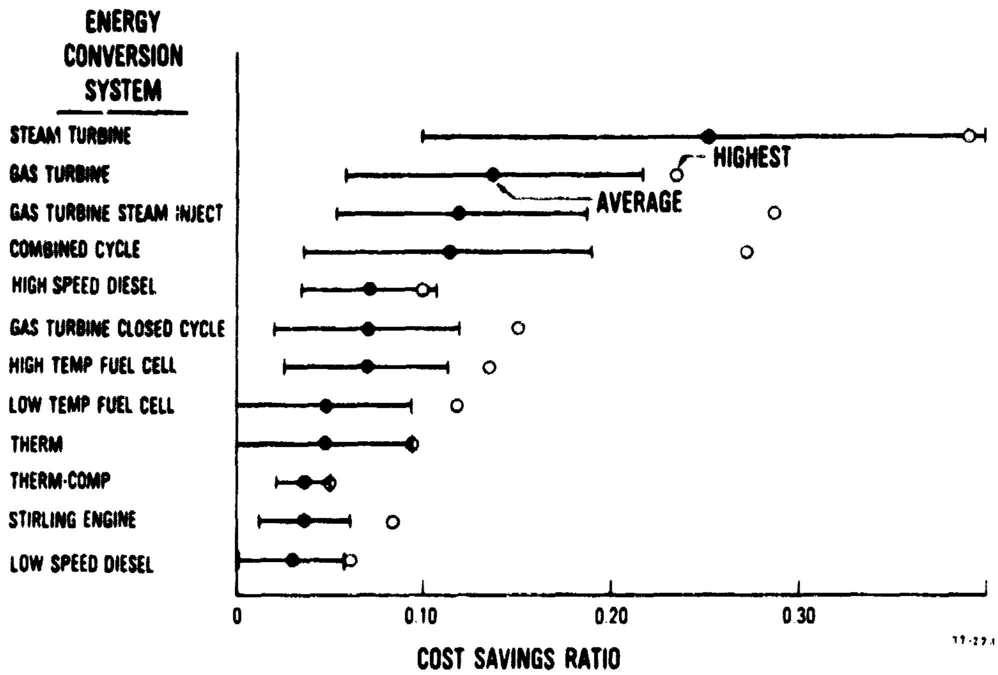

Figure 71. Advanced Technology Cost Savings Ratio - Cost Savings Cases Only - Liquid Fuels

INTEGRATED RESULTS

The data discussed thus far have been simple arithmetic averages of fuel, emission, and cost ratios. The variation in the data is substantial indicating that there are good cogeneration prospects for each of the conversion technologies in certain specific industrial process applications. In calculating the averages, the savings ratios for industrial processes with small fuel savings were given the same weight as the ratios for processes with large overall savings.

A system is needed to summarize the fuel, cost, and emissions savings whereby the size of the potential savings as well as the savings ratios are considered. For example, the fuel energy savings ratios for the petroleum refining industry are typically less than 10 percent, Figure 51. However, cogeneration with most of the advanced energy conversion systems could produce significant savings in absolute terms, Figure 52. In order to develop a relative comparison and evaluation of the advanced energy conversion systems, a projection of the potential savings to the national level is needed.

The basic analyses were conducted for typical industrial plants. In order to develop projections to the national level, major assumptions are required. The first is that all industrial plants are candidates for cogeneration, both new and old. Second, the assumption is made that all plants fitting the appropriate criteria install cogeneration equipment. For example, if positive fuel energy savings were the criteria, all plants with predicted fuel energy savings would be included.

Assuming that the typical plants are representative of the manufacture of the product in the 1985-2000 period, the fuel consumption can be scaled based on the production level expected in 1985-2000 and the energy consumption per unit of product produced, as indicated in Figure 72. In order to assess the potential of each conversion technology for savings at the national level, the assumption was made that the data for the process or product are representative of the potential savings in the four-digit industrial classification. Some four-digit classifications contain more than one of the study processes. Double accounting was avoided by summing the savings and then scaling to the four-digit level using the projected industry data presented in Volume II of this report. Bureau of Census data were used to scale from the four-digit level to the national level again assuming that the savings estimated in the study industries are representative of the possible savings in other industries not studied. The whole analysis is depicted in Figure 72. The data presented in Volume VI includes the total fuel savings, the utility fuel savings, and the fuel use by type--oil, gas or coal for each technology based on the assumptions outlined.

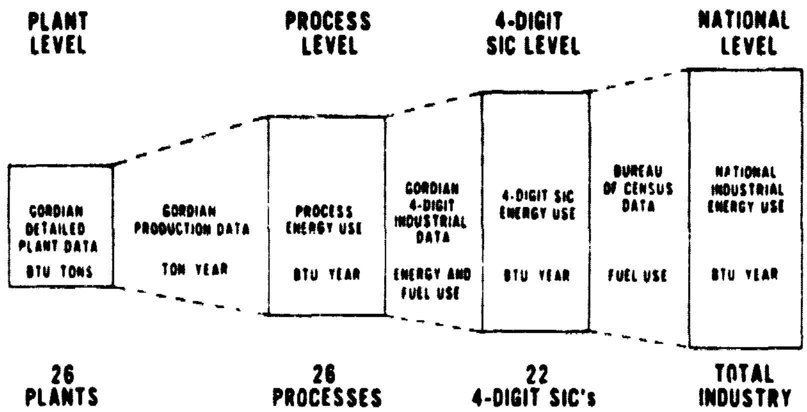

Figure 72. National Impact Evaluation

The same assumptions for extention of the data to the national level were applied to all of the technologies to provide a basis for comparison. The fuel savings were summarized for all cases with positive fuel savings, for cases with economic savings, cases with emissions savings, the combination of cost and fuel savings cases and the combination of fuel, cost, and emissions savings. These data are presented in tabular form in Volume VI. A summary is presented here in graphic form. Figure 73 presents the potential fuel energy savings, including the effect of utility fuel consumption, scaled to the national level assuming cogeneration with each current energy conversion technology.

Also included are the fuel savings for those situations where both fuel and levelized cost savings estimates are positive.

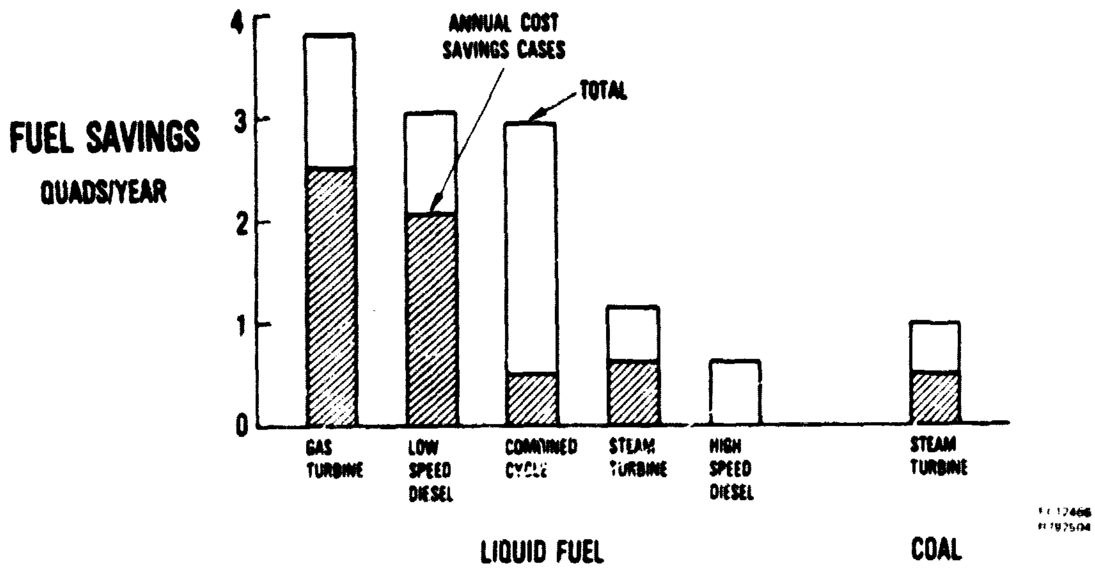

Figure 73. Current Technology Potential Fuel Savings

Figure 74 presents the advanced liquid fueled conversion systems and Figure 75 presents the estimated national data for coal-fired systems. This analysis indicates that cogeneration offers the possibility of substantial fuel energy savings and that the advanced technologies are estimated to provide greater fuel savings and superior economics.

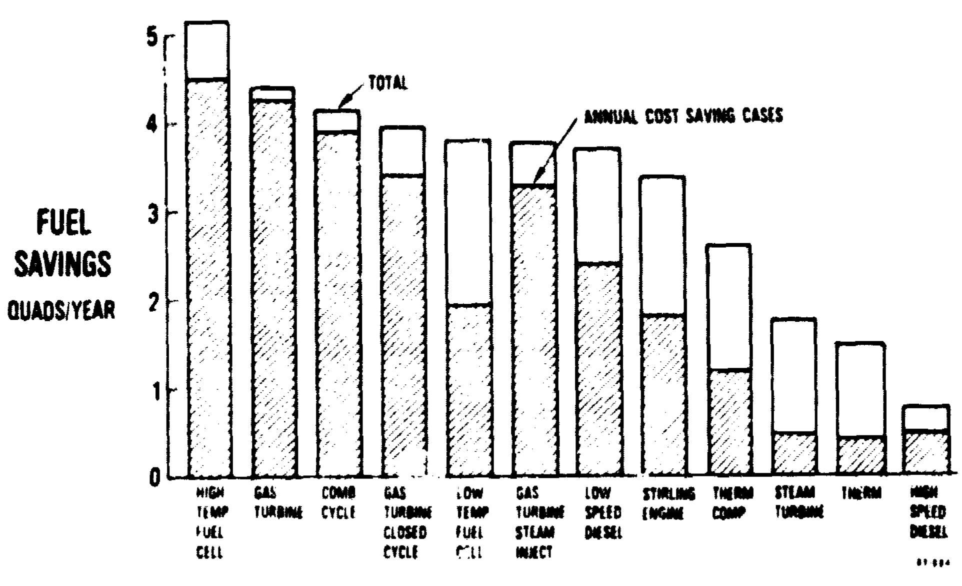

Figure 74. Liquid Fueled Advanced Technology Potential Fuel Savings

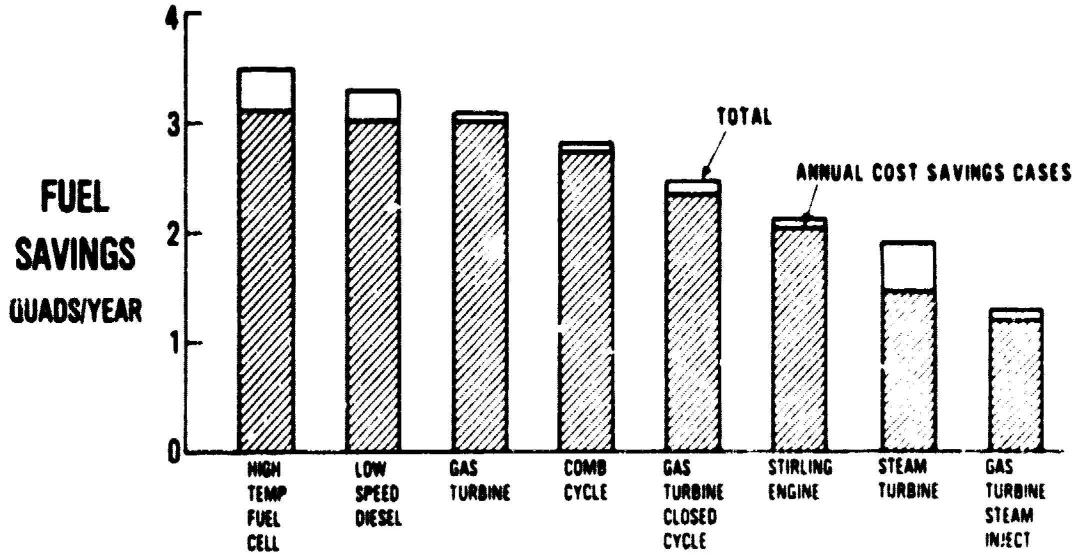

Figure 75. Coal Fired Advanced Technology Potential Fuel Savings

The potential emissions at the national level are presented in Figures 76 and 77. These data include the emissions from the conversion system and any auxiliary furnaces required. These data were developed for a match electric strategy and, as a result, there were no utility emissions.

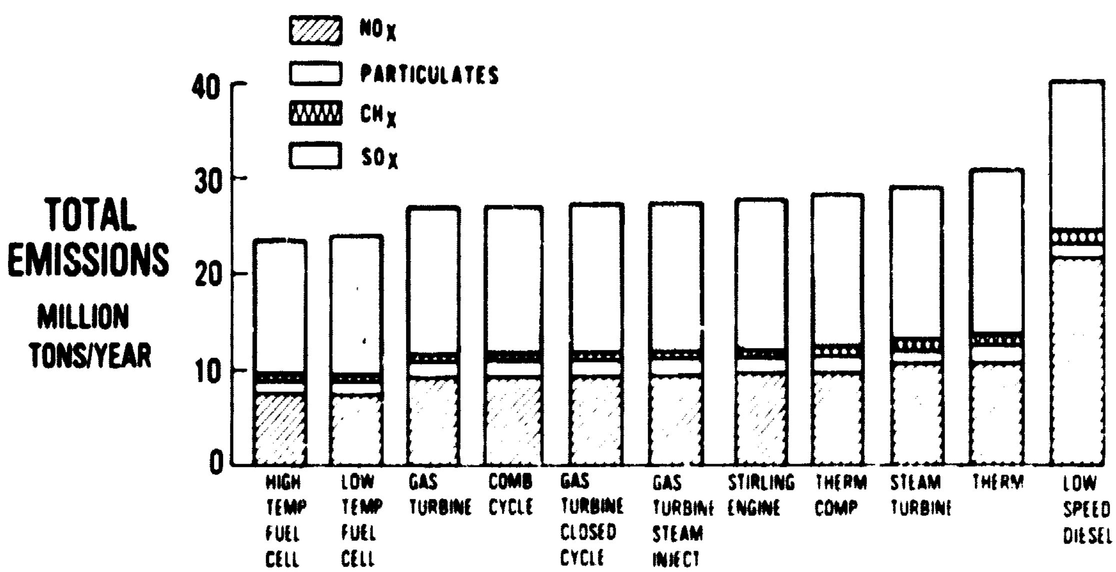

Figure 76. Advanced Technology Emissions - Liquid Fuels

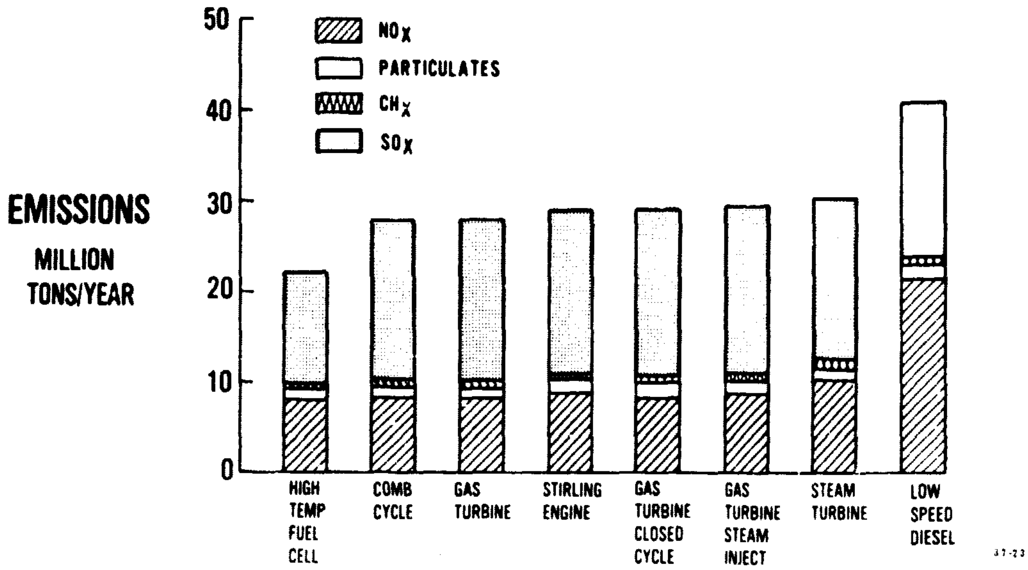

Figure 77. Advanced Technologies Emissions - Coal

The estimated nitrogen oxide emissions by the diesel engines exceeded the guidelines. Methods of reducing NOx emissions from diesel engines need to be developed.

The fuel cell is an electro-chemical conversion device and the pollutants associated with combustion are minimized. The sulphur in the fuel is removed in fuel cell powerplants. Various methods of sulphur removal are employed and some are regenerative. In these cases, the sulphur is absorbed on a material and then discharged as sulphur dioxide or elemental sulphur when the material is restored to its original condition. The data presented in Figures 60 and 61 are based on the assumption that regenerative type absorbtion is used and sulphur is discharged in the oxide form at the plant site.

In order to evaluate the environmental impact of cogeneration systems nationally, the emissions data are presented in Figures 78 and 79 in relation to the emissions from conventional furnaces traditionally located at the industrial plant and the total emissions including the electric utility. The assumptions were made that the conventional furnaces met the pollution guidelines for liquid fueled systems and that the utilities consumed coal and met the pollution guidelines for coal-fired systems. All cogeneration systems with the exception of diesels are estimated to reduce the total pollutants emitted nationally.

A potential constraint on the application of cogeneration at industrial locations is the environmental rules which could be applied locally. In comparing to the non-cogeneration emissions at the industrial plant, the fuel cell systems offer the most promising situation.

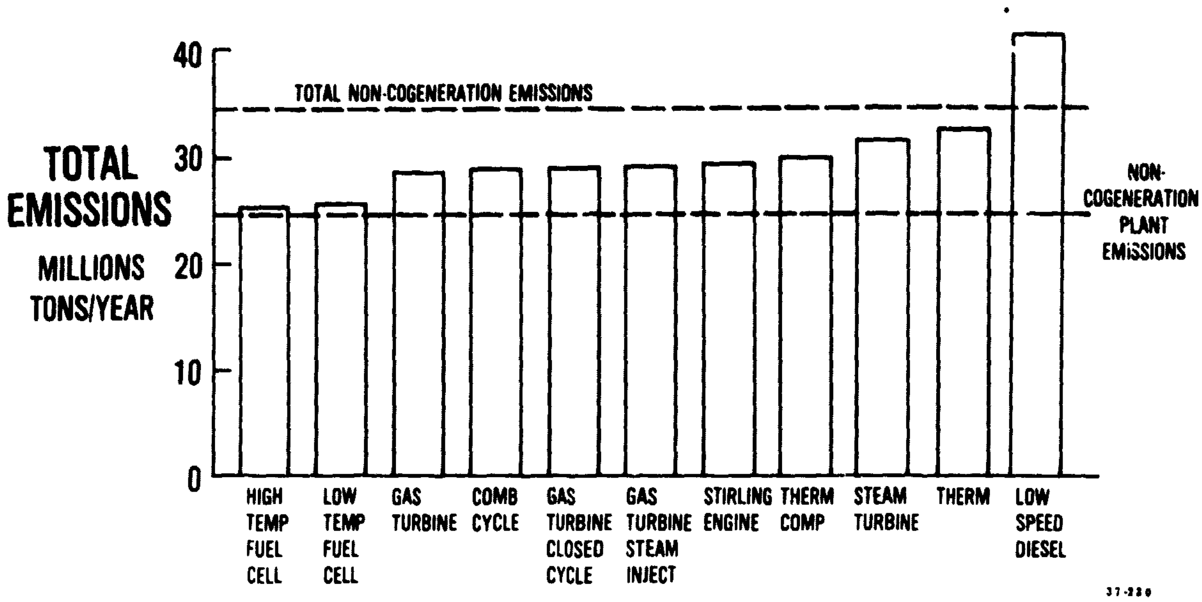

Figure 78. Emissions Impact - Liquid Fuels

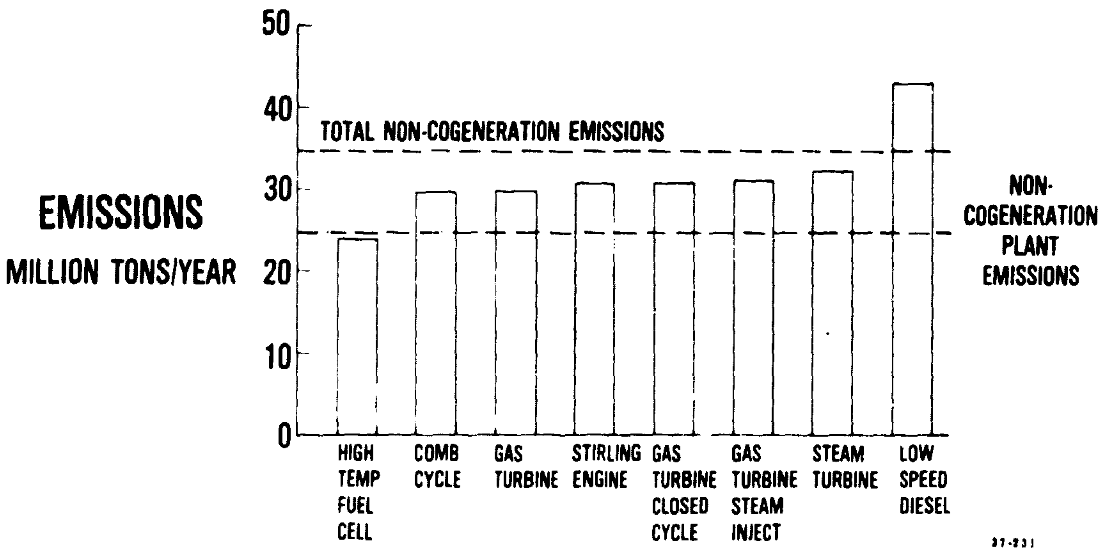

Figure 79. Emissions Impact - Coal

The summation and scale-up of the data to a potential national level has been based on fuel energy saving cases. An alternate economic criteria could be applied. In Figure 80, the potential annual cost savings (levelized) are presented regardless of fuel energy savings for liquid fueled conversion systems. The corresponding data for coal-fired systems is included in Figure 81.

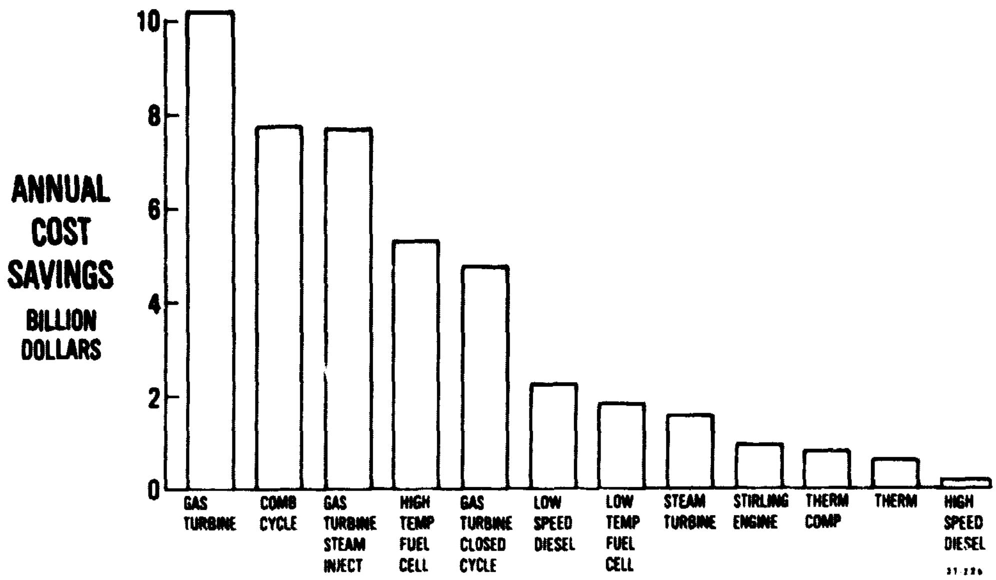

Figure 80. Estimated Potential Annual Cost Savings - Liquid Fuels

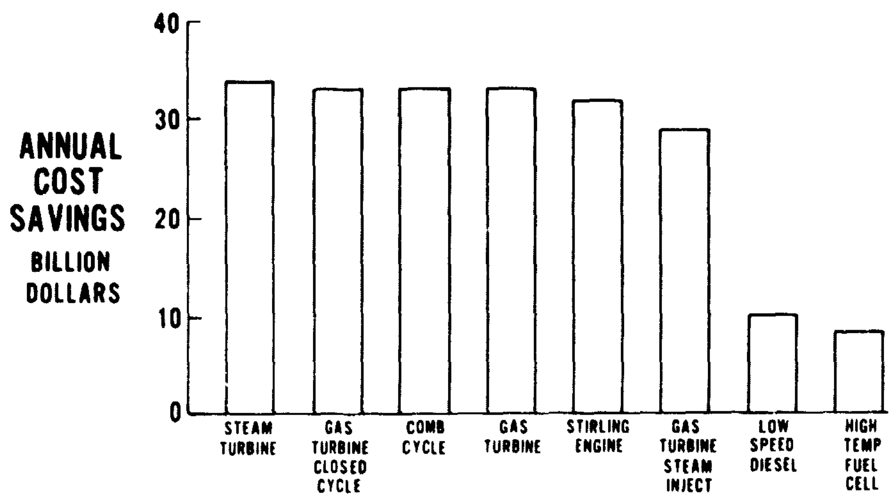

Figure 81. Estimated Potential Annual Cost Savings - Coal

Of particular interest are situations which indicate both economic and fuel energy savings. For the cases with liquid fuel, the data presented in Figure 80 are also all fuel savings cases. With coal-fired systems there are conversion system-industrial process combinations where there are levelized annual cost savings, but fuel energy is not conserved. Figure 82 presents the estimated potential national annual cost savings for the coal-fired conversion technologies which have both fuel energy conservation and levelized annual cost savings.

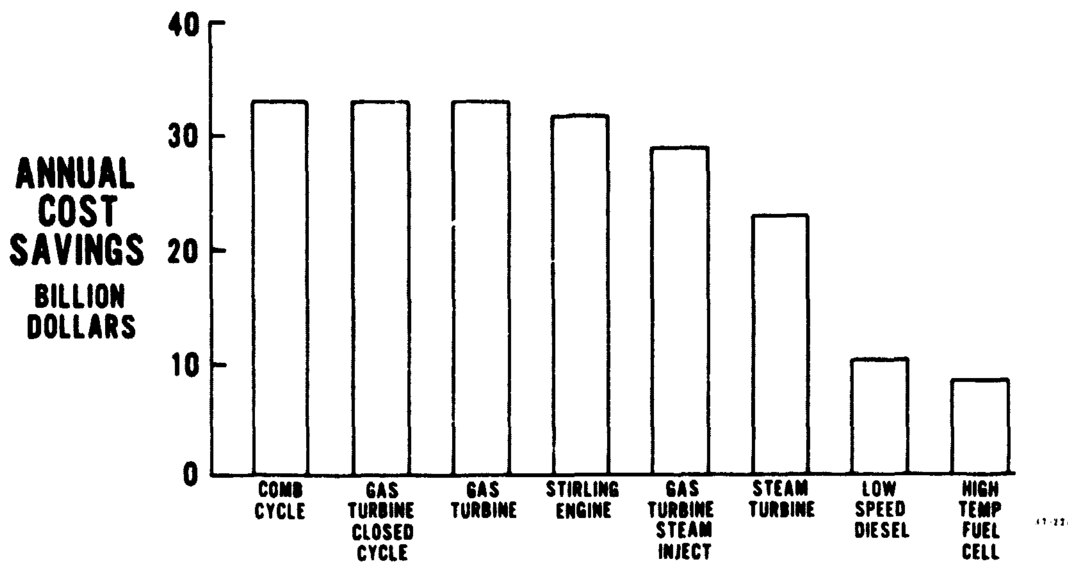

Figure 82. Estimated Potential Annual Cost Savings with Fuel Energy Savings - Coal

The only cases with industrial plant site emission savings, annual cost savings, and fuel energy savings involved fuel cells. At the estimated national level for these cases fuel energy savings were in the range of 2 - 3 quadrillion BTU. Levelized annual cost savings had a potential of over $2 billion with liquid fuel and a potential of over $7 billion with coal fuel.

The national scale-up has been summarized for cogeneration systems meeting the industrial electrical requirements. The data in Volume VI include national summaries using the same scale-up techniques and coefficients for the other strategies. However, the scale-up systems which imported or exported electricity with the utility present difficulties in expanding the possibilities to the national level. Situations in which significant quantities of electricity are exported to the electric utility may be questionable when expanded nationally. Exported electrical energy in some conversion system-industrial process combinations would amount to eight times the electricity traditionally provided to the industrial plant. For the advanced gas turbine technology with a matched thermal requirements strategy, 19 industries produced positive conservation results. Of these, 12 would export electricity to the utilities. Scaling to the national level by the techniques used in the study, without cogeneration the utilities would have supplied 820 billion kilowatt-hours of electricity to industry in 1990. If the advanced gas turbine were used throughout industry and the assumptions, techniques and coefficients for scale-up were applied overall, industry would export 470 billion kilowatt-hours. Since the utilities would not be required to provide industry and would accept this exported energy, the net effect would be a reduction of 1290 billion kilowatt-hours generated by the utilities. For individual applications, the matched thermal strategy can provide conservation benefits to society and economic benefits to the industrialist. Therefore, such applications are an important element of the study, and the data are included in Volume VI. However, the national benefits with the matched thermal or optimum strategies printed in Volume VI can only be considered broad indications of the possibilities.

The fourth strategy addressed in the study involved a limited analysis utilizing a heat pump to improve the quality of the heat recovered to provide better matching between the conversion system and the industrial process. The results are included in Volume VI. In general, this strategy is of interest with conversion systems with low temperature recovered heat (some diesels, fuel cells and Stirling engines) and with industries with high electrical useage in relation to the thermal requirements (textiles, newsprint, chlorine, low density polyethylene, nylon). As an example, the low-speed diesel engine applied in the chlorine plant would improve fuel energy savings with the heat pump compared to the matched electric strategy. However, the economic comparison would not be quite as favorable.

In addition to the topping cogeneration applications, steam and advanced organic Rankine cycle bottoming systems were evaluated in cement plants and glass making. The fuel savings results are summarized in Figure 83 and the estimated levelized annual cost savings are included in Figure 84. These results are scaled from the representative plants to the four digit industrial classification levels to indicate potential national benefits.

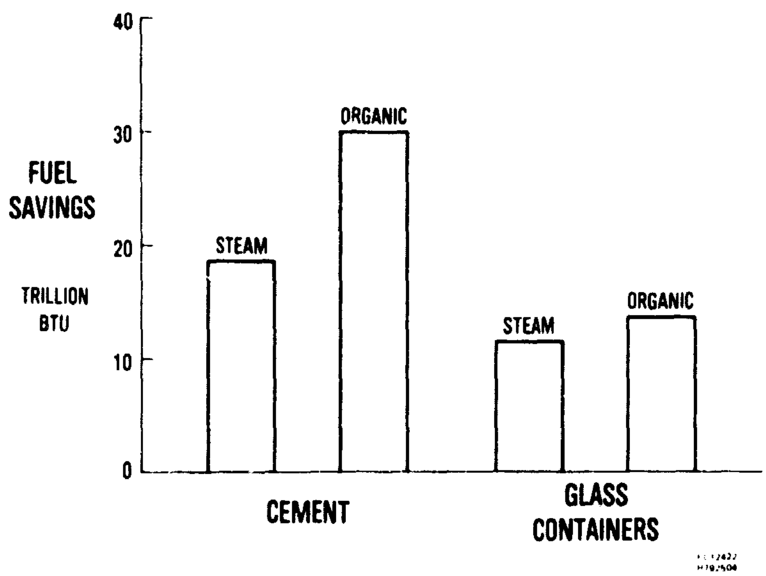

Figure 83. Bottoming Applications Fuel Savings

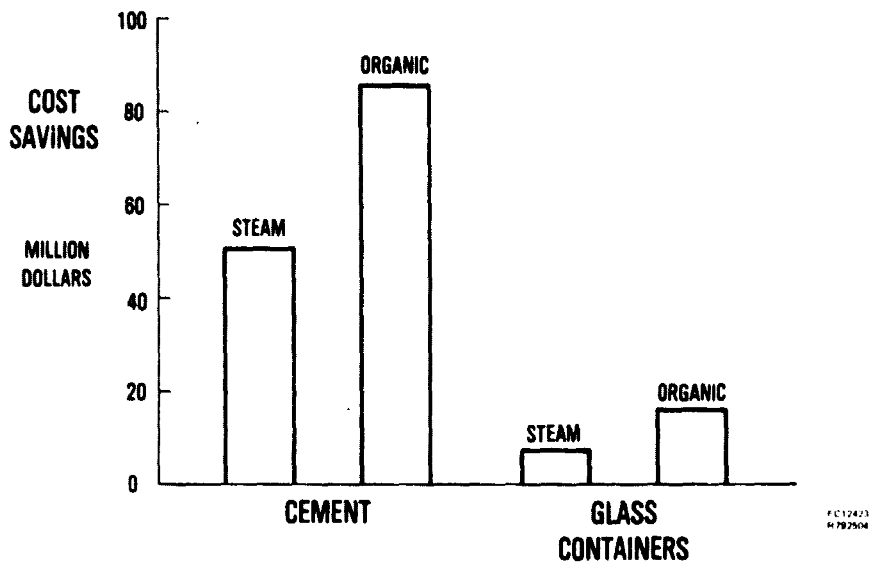

Figure 84. Bottoming Applications Estimated Annual Cost Savings

The evaluation of advanced energy conversion techniques to determine the potential for transition from the use of oil and natural gas to coal or coal-derived or alternate fuels in the 1985-2000 time period is complicated. Qualitatively all of the advanced energy technologies are able to use coal or coal-derived liquid fuels. The diesel engines exceed the NOx emissions guidelines primarily due to the nature of the combustion process. The additional nitrogen in the coal-derived fuel is a secondary factor in this case.

Quantitatively, the fuel consumption for the non-cogeneration situation was projected by Gordian Associates to the time period of interest. While a representative plant would normally consume only one or two fuels, the consumption of all fuels was determined at the process level and scaled up to the national level. The advanced conversion technology used one fuel and the auxiliary furnace used the same fuel or another. The consumption of fuels by type was determined for the conversion system and scaled-up to the national level. The resulting fuel savings are tabulated in Volume VI.

If coal-derived fuels are available for cogeneration, then a reasonable assumption would be to expect such fuels to be available for non-cogeneration industrial furnaces. For the purposes of this study, if coal-derived fuels are available, the assumption is made that all systems, cogeneration and non-cogeneration, use the coal-derived fuels. Assuming a conversion efficiency from coal to coal-derived fuel of 70%, and assuming the coal conversion plant did not introduce pollutants, the relative merits of the various conversion system cogeneration applications can be estimated based on a single fuel--coal. Figure 85 indicates the estimated coal consumption on a national basis, assuming either coal or a coal-derived liquid is used in cogeneration energy conversion systems installed in all appropriate industrial plants. This extention to the national level is based on the same set of assumptions outlined on pages 100 and 101 and Figure 72.

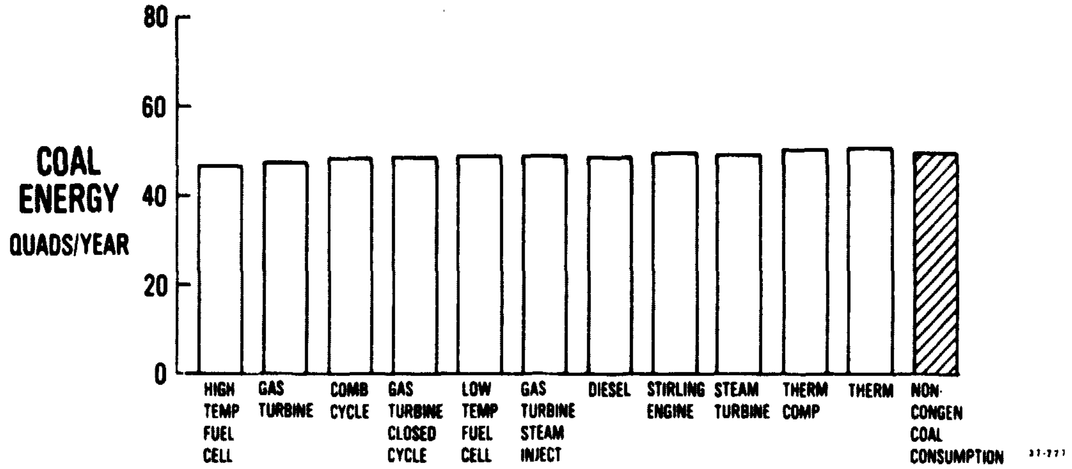

Figure 85. Coal Requirements Including Coal for Conversion to Coal-Derived Fuels

SPECIAL COMPARISONS

In addition to the representative industrial plants which served as the basis for the study, two additional fictitious plants were defined to permit comparison of capital costs of the energy conversion cogeneration plants. The electrical demands were 10 and 30 megawatts for these industries. The thermal requirements were four times the electrical requirements and the plânts operated continuously. The results of these calculations are presented in Figures 86, 87, and 88. The installed costs include the balance-of-plant and the auxiliary furnaces as well as the energy conversion systems. Generally the coal-fired systems are significantly more capital intensive than the liquid fueled technologies.

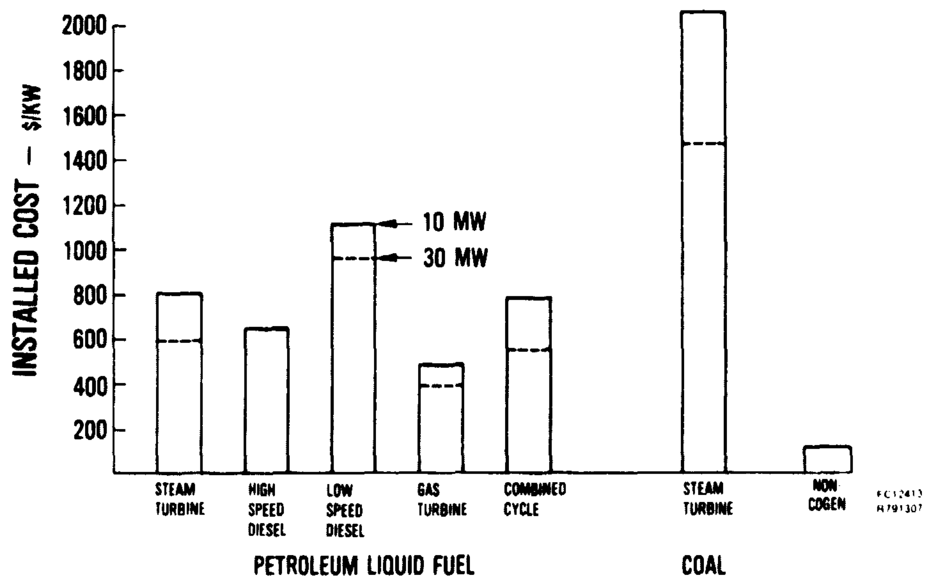

Figure 86. Current Technology Estimated System Installed Cost for Special Industries

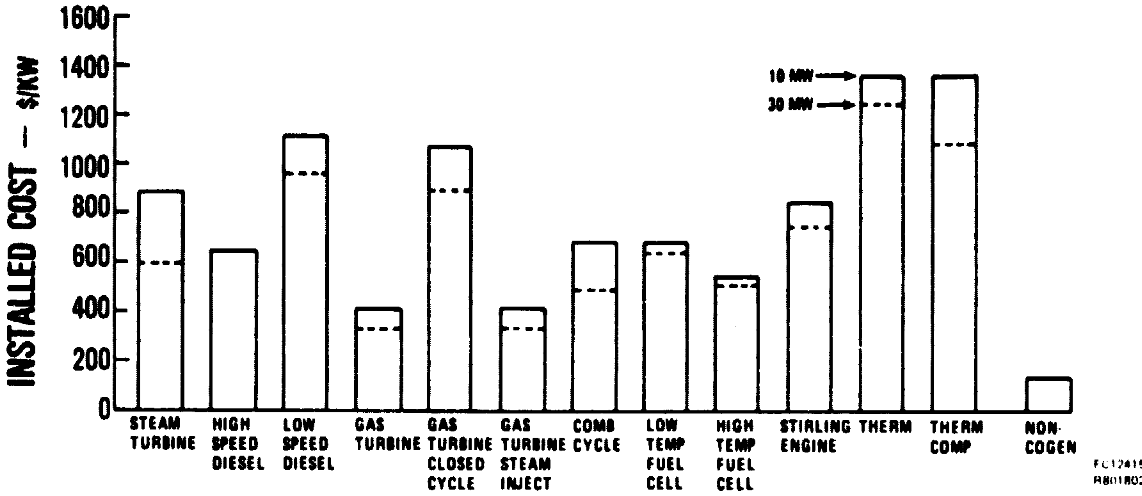

Figure 87. Advanced Technology Estimated System Installed Cost for Special Industries - Liquid Fuels

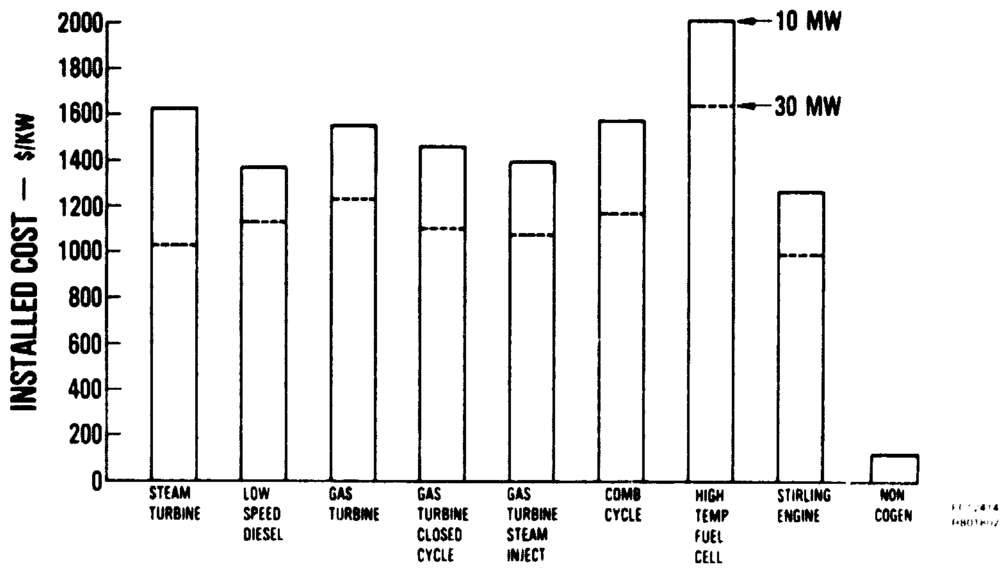

Figure 88. Advanced Technology Estimated System Installed Cost for Special Industries - Coal

ECONOMICS

Based on the results of the analysis of the 3,364 strategy-conversion system - fuel-industry cases, 120 were selected for more detailed economic analysis. In order to conduct this evaluation both internal and external factors which could influence an industrialist's decision concerning cogeneration were identified.

Internal factors are defined as those industry-related criteria involving policies, practices, and constraints specific to a particular industry or individual firm which influence capital investment decisions. In this study, significant internal factors were selected for evaluation including: discounted cash flow rate-of-return, payback period, net present value, levelized annual cost, and life cycle cost. One or more of these factors could be the critical measure of a capital investment attractiveness to the industrialist. The estimated rate-of-return in relation to the perceived risk may be the most important or most commonly used criteria in industry. Of course, the magnitude of the investment, the exposure and competing investment opportunities are also significant factors. Utilities often use levelized annual cost or life cycle cost as an investment criteria. If generalization were possible, the levelized annual cost factor tends to be affected more by operating costs and the rate-of-return factor tends to be influenced more by the capital requirements.

External factors are those conditions prevalent throughout the business community which are imposed on all industrial firms which influence the capital investment decisions of the industrialist. External factors which are generally beyond the control of any firm or group of industrial firms include political, environmental, regulatory and economic areas some of which are under partial or direct control of the government. Examples of external factors are the general Federal income tax rate, investment tax credit, cost of purchased fuels and electricity and relevant institutional and environmental regulations. These factors have been addressed and included in the Principal Assumptions and Ground Rules section of this report. To summarize, the economic evaluations are based on the ground rules presented in Table 3.

A summary of the inflation-free return on investment results for the liquid fueled conversion systems of the 120 cases evaluated are presented in Figure 89. While there is significant variability for a conversion system from one application to another, on the average, the systems with the relatively low capital investment offer the highest rate-of-return prospects.

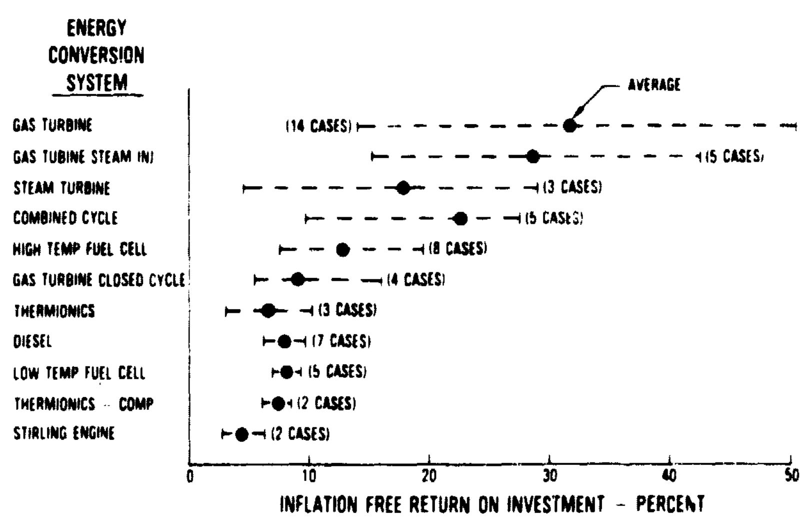

Figure 89. Advanced Technology Return-on-Investment - Liquid Fuels

The corresponding coal-fired cases are included in Figure 90. The coal-fired systems with large capital requirements and lower operating (fuel) costs generally do not provide as high returns as the liquid fueled systems. For example, on the average, the simple gas turbine provides the highest rate of return and the lowest installed equipment costs. The closed cycle gas turbine, with expensive heat exchangers, has about three times the equipment cost of the gas turbine and the rate-of-return is depressed accordingly. The data presented in Figure 89 are developed without inflation and should be examined in that light. With the groundrules used in this study, the inflation free-cost of capital is 5.4 percent so an inflation-free rate-of-return above 8 percent might be considered favorably.

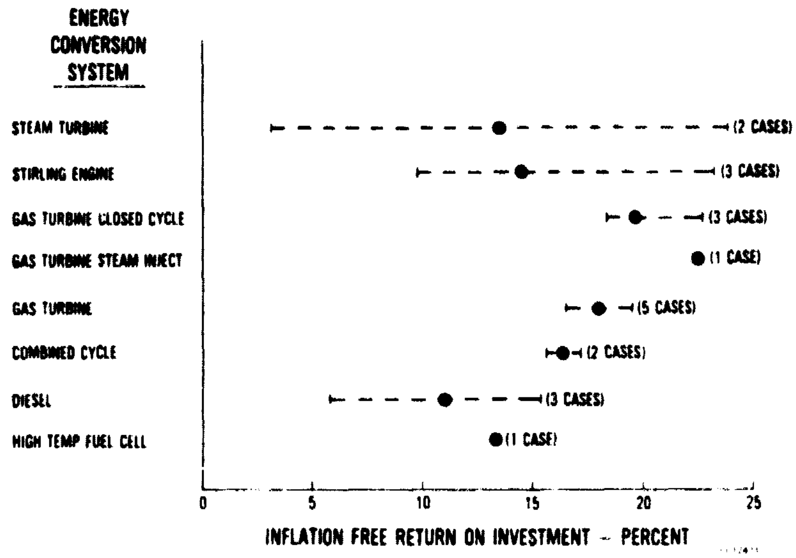

Figure 90. Advanced Technology Return-on-Investment - Coal

ECONOMIC SENSITIVITY

In order to investigate the effect of changes in the values of several of the major economic variables affecting the results of the study, sensitivity analysis were conducted where selected variables are varied individually within prescribed ranges. The objective of this activity was to determine the trend relationships between the rate-of-return and the variable selected and identify those variables which have the greatest effect on the overall results. Sixty different cases were selected for detailed sensitivity studies. These cases covered a representative set of industries, including firms producing newsprint, corrugated paper, chlorine, and textiles; and examinations were made of the effect created by variations in capital costs, investment tax credit, tax life, electric utility rates, fuel (coal and oil) prices, fuel escalation rates, and general inflation rate. The results are summarized in Table 22 which indicates the consequences of a 1 percent variation in the factor on the rate of return. For example, a 1 percent increase in the electric rate (from 3.30 to 3.33 cents per kilowatt hour in 1985) would increase the rate-of-return by 0.53

percent. Also a one percent increase in capital cost would cause th rate of return to be reduced by 0.21 percent. The results of this analysis indicate that projected escalation rates for fuels and utility electricity have the strongest influence on the overall results of the study. Assumed fuel prices and electric rates in 1990 have important bearing on these results. Capital equipment cost and investment tax credits appear to have modest influence.

TABLE 22. ECONOMIC SENSITIVITY

Factor	Average Rate of Return Slope Negative	Positive
Fuel Escalation	1.25	
Fuel and Electric Rate Escalation		1.09
Inflation		0.90
Coal Escalation	0.85	
Electric Rate		0.53
Fuel Price	0.30	
Non-Cogeneration Fuel Price		0.25
Capital Cost	0.21	
Investment Tax Credit		0.20
Coal Price	0.15	
Tax Life	0.04	

TIME-OF-DAY VARIATIONS

A broad analysis of the type conducted for this study of necessity involves assumptions or approximations. To better evaluate the degree of approximation the consequences of energy variations in the course of the day were evaluated for one conversion system-industry combination. The industrial process selected to illustrate these variations was meat packing. The representative plant, defined by Gordian Associates and described in detail in Volume II of this report, is an integrated plant engaged in slaughter for meat as a product and the production of meat products. The principal uses of energy in the meat packing plant include electricity for refrigeration, lighting and cutting; hot water for clean up and processing; and steam for processing, cleaning, and cooking.

The energy consumption of the meat packing plant was analyzed accounting for the hourly and seasonal variations. An alternate cogeneration configuration, including a hot water thermal storage system, was introduced based upon the data developed by Rocket Research Company and presented in Volume IV of this report. The results are presented in Table 23. Using the time-of-day variation analysis, the fuel energy savings ratio was reduced by 0.02 compared with the steady-state analysis. The levelized annual cost savings were reduced by 0.05 and the estimated economic advantage with the steady-state analysis became negative with the time-of-day analysis.

With thermal storage the detailed analysis indicated improvements over the results of the steady-state analysis from a conservation, cost, and environmental standpoint. The steady-state analysis appeared to be a reasonable initial evaluation for general purposes.

TABLE 23. ESTIMATED COGENERATION RESULTS IN MEAT PACKING PLANT WITH FUEL CELL

	Steady-State Analysis	Time-of-Day Analysis Storage	No Storage
Fuel Energy Savings Ratio	0.3130	0.3234	0.2934
Cost Savings Ratio	0.0180	0.0271	-0.0307
Emissions Savings Ratio	0.6510	0.6726	0.6102

CONCLUSIONS

Advanced energy conversion system technology which could be developed and brought to commercial use in the 1985-2000 period have been postulated and evaluated in twenty-six cogeneration applications representing the energy intensive industries. A substantial body of data has been developed for these systems. The analyses and evaluations in this study have emphasized the following criteria:

- o The potential for overall fuel conservation
- o The ability to move from light oil and natural gas fuels towards heavy oil, coal and coal-derived fuels.
- o The possibility of reduced energy costs and attractive economics.
- o The possibility of improving the environment both from an overall standpoint and at the industrial plant location.
- o The applicability to a wide range of industrial processes both in existing and new plants.

Each of the advanced energy conversion technologies included in this study could be attractive in a number of industrial cogeneration applications. However, each energy conversion system has limitations. Table 24 is a summary of both the favorable and unfavorable aspects for each of the advances energy conversion systems used in topping-type cogeneration applications. In the following, each system is discussed in turn.

TABLE 24. ADVANCED TECHNOLOGY EVALUATIONS

TECHNOLOGY	PLUS	MINUS
Steam Turbine	Fuel Flexibility Reliability Thermal Quality	Capital Cost
High Speed Diesel	High Fuel Utilization	Limited Size Excessive Emissions
Low Speed Diesel	Fuel Flexibility Fuel Utilization	Capital Cost Thermal Quality Excessive Emissions
Gas Turbine	High Conservation Low Capital Cost Thermal Quality	
Combined Cycle And Steam Injection	Fuel Utilization Thermal Quality Range of Applications	Limited Size
Closed Cycle	Fuel Flexibility Thermal Quality Range of Applications	Capital Cost
Low Temperature Fuel Cell	Low Site Emissions Fuel Utilization	Distillate Fuel Cost Thermal Quality
High Temperature Fuel Cell	Low Site Emissions High Conservation	Distillate Fuel
Stirling Engine	Fuel Flexibility	Capital Cost Thermal Quality
Thermionic Conversion	Thermal Quality	Capital Cost Fuel Utilization

Advanced combined gas turbine-steam turbine cycles provide flexibility to meet a variety of industrial energy needs. The electrical and thermal energy provided can be varied as process needd vary and combined cycle systems can respond promptly to changes in demand. Generally combined cycle conversion systems are applicable to larger sized applications with emphasis on high electrical requirements in relation to thermal energy needs. Combined cycle powerplants can operate with any fuels suitable for gas turbine operations including coal-derived boiler fuel and coal - atmospheric or pressurized fluidized bed combustion systems or integrated coal gasification systems. Steam injected gas turbines are similar to the combined gas turbine - steam turbine. Since the steam passes through the gas turbine, and no steam turbine is involved, the capital cost is reduced. Steam injection helps reduce exhaust emissions. In general, steam injected gas turbines did not offer as large conservation benefits as the combined cycle, but the economics were more attractive.

The closed cycle gas turbine offers design flexibility to meet a variety of requirements since the cycle is not limited by ambient conditions. Heat is provided by an external source which permits the use of a variety of fuels including coal and coal-derived fuels. With coal atmospheric fluid bed combustion systems, conservation and economics were found to be reasonable in a wide variety of applications. A second design approach used coal-derived liquid fuels. The systems were dependent upon the development of ceramic heat exchangers which were predicted to be expensive.

Low temperature fuel cell powerplants offer high operating efficiency over a wide range of output levels and are capable of very rapid response to variations in demand. They offer unusual siting and operating flexibility. The low level of pollutants and the low noise may be particularly important in many industrial locations. Applicability is limited by the low temperature of the recovered heat. For the advanced technology postulated in this study, distillate fuels including coal derived distillate fuels would be used by the low temperature fuel cell powerplant.

Many of the attractive siting and operational characteristics of low temperature fuel cells are also characteristics of high temperature fuel cell powerplants. In addition, high temperature fuel cells can produce high temperature heat for industrial processes. The high temperature fuel cell powerplants operated with gaseous and distillate fuels. On-site coal gasification presents an attractive option particularly for the larger installations. The high temperature fuel cell offered the greatest conservation potential of the various technologies studied.

The Stirling engine is independently heated by a separate source and, therefore, can operate with almost any fuel: coal-derived liquids or coal. The Stirling engine can operate at high electrical efficiency over a wide range of output levels. It normally has limited high temperature heat recovery capabilities, but was modified to provide larger amounts of process steam at some penalty in electrical efficiency. The advanced technology Stirling engine in this study is based upon the development of high temperature materials and heat exchangers.

Industrial cogeneration practiced today typically uses steam turbines to provide mechancial shaft power or electrical energy. Steam extracted or discharged from the turbine also provides industrial thermal requirements. The reliability and applicability of the steam turbine are well established. Steam turbines can operate with steam generated from practically any boiler and therefore, can use a variety of fuels. The advanced steam turbines in this study represent a moderate advance in steam pressure and temperature. The advanced coal fired boiler is based on the development of the atmospheric fluidized bed combustion system. Based on results of this study the principal drawbacks of steam turbines were the capital costs which limited economic attractiveness in many cases and limited conservation potential.

High speed diesel generators have been the principal prime-movers in cogeneration systems in commercial and multi-family residential buildings. They can also be used in industrial cogeneration applications of small and moderate size. High speed diesel engines are typically rated below 1½ megawatts and might be limited to installations of 10-15 megawatts. The high speed diesel advanced technology in this study is based upon the development of the "adiabatic" engine which includes ceramic high temperature components. As a result, high speed diesel engines are expected to operate at very high electrical efficiency over a wide range of output levels. These powerplants can be developed to operate on coal-derived distillate-type fuels. Diesel engines attained some of the highest fuel energy savings ratios in this study. However, the diesel engines are expected to exceed the nitrogen emission limitations.

The low speed diesel generator is based upon current marine powerplant technology and is expected to operate very efficienctly over a wide range of output levels while consuming coal-derived boiler grade fuel or powdered coal. The advanced technology in this study, postulates higher cooling jacket temperatures. However, the relatively low temperature of the recovered heat is a drawback for widespread industrial cogeneration applicability. The estimated capital costs of low speed diesel cogeneration systems were high. The powerplant has a relatively high level of exhaust emissions which exceeds the study guidelines.

The direct fired gas turbine is adaptable to industrial cogeneration and has been used in this way in process industries. The high temperature exhaust gases can be used directly in some industrial processes or can raise high temperature steam. The advanced gas turbines consumed coal-derived or petroleum-based boiler grade fuels with emission levels consistent with the guidelines specified for this study. Turbine inlet temperatures of 2500°F were postulated for the 1985-2000 period. Estimated capital costs were low.

In addition to the liquid fuels, the study included coal fired advanced gas turbines. Both pressurized and atmospheric fluid bed combustion systems were included. Atmospheric fluid bed coal combustion systems provided some cases with high conservation and attractive economics while the pressurized systems were attractive in a wider range of applications. These turbines operated with inlet temperatures of 1500 to 1600°F. A gas turbine with an integrated coal gasification plant was included with a turbine inlet temperature of 2500°F. Coal gasification systems under the development are generally of large size and the use of the gas turbine with coal gasification may be limited in smaller applications.

Thermionic energy conversion systems are particularly applicable to cogeneration situations requiring large amounts of high temperature process heat. In this study a liquid fueled heat source was employed. Thermionic conversion systems are dependent upon the development of high temperature furnaces and heat pipes as well as the development of the converters themselves. Their applicability is limited by the cost of the high temperature materials and the relatively low electrical efficiency. A thermionic heat source could be designed to operate with coal if a suitable flue gas desulfurizer were employed.

This study indicates that the current energy conversion technology in industrial cogeneration applications could save fuels. However, such cogeneration plants are not widely used. This situation is due to a number of factors including fuel availability, economics, and in some locations, on-site emissions. The advanced technologies projected for the 1985-2000 time period provided improved fuel conservation in cogeneration applications. These technologies reduce petroleum consumption and increase use of coal or coal-based fuels. The advanced energy conversion technologies improved the economics of providing industrial energy requirements.

The advanced technologies generally reduced total emissions to the atmosphere. Each of the advanced technologies had applications offering significant conservation potential.

In the most optimistic scenerio, potential energy saving levels of up to five quadrillion BTU could be envisioned. High temperature fuel cell powerplants showed the greatest national fuel energy savings while gas turbines and combined cycles indicated high levelized annual cost savings. Diesel engines provided some of the highest fuel energy savings ratios. In terms of return-on-investment, the gas turbine burning coal-derived liquid fuels was estimated to be the most attractive. For coal-fired systems, the steam turbine and steam injected gas turbines produced high estimated returns. Fuel cell powerplants provided minimum pollutants and half of the cases would reduce on-site emissions when compared to traditional on-site steam boilers.

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