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COGENERATION TECHNOLOGY ALTERNATIVES STUDY (CTAS)

GENERAL ELECTRIC COMPANY

FINAL REPORT

VOLUME IV - ENERGY CONVERSION SYSTEMS

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D.H. Brown, H.E. Gerlaugh
and R.R. Priestley
April 1980

PREPARED FOR

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

FOR

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

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FOREWORD

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

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

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

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

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

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

General Electric Company

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

DeLaval

Dow Chemical

General Energy Associates

Institute of Gas Technology

J.E. Sirrine

Kaiser Engineers

N.A. Philips

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

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

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

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

Title	DOE Number	NASA Contract Report No.
UTC Vol. 1 - Summary	DOE/NASA/0030-80/1	CR-159759
Vol. 2 - Industrial Process Characteristics	DOE/NASA-0030-80/2	CR-159760
Vol. 3 - Energy Conversion System Characteristics	DOE/NASA-0030-80/3	CR-159761
Vol. 4 - Heat Sources, Balance of Plant and Auxiliary Systems	DOE/NASA-0030-80/4	CR-159762
Vol. 5 - Analytic Approach & Results	DOE/NASA-0030-80/5	CR-159763
Vol. 6 - Computer Data	DOE/NASA-0030-80/6	CR-159764

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Section 1

SUMMARY

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

OBJECTIVES

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

Specifically, the objectives of CTAS are:

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

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

SCOPE

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

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

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

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

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

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

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

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

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

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

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

RESULTS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Section 2

INTRODUCTION

BACKGROUND

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

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

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

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

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

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

OBJECTIVE, OVERALL SCOPE, AND METHODOLOGY

The objectives of the CTAS effort were to:

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

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

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

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

- Fuel Energy Saved
- Flexibility in Fuel Use

Table 2-1

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

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

* AFB - Atmospheric Fluidized Bed
FGD - Flue Gas Desulfurization

Table 2-2

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

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

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

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

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

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

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

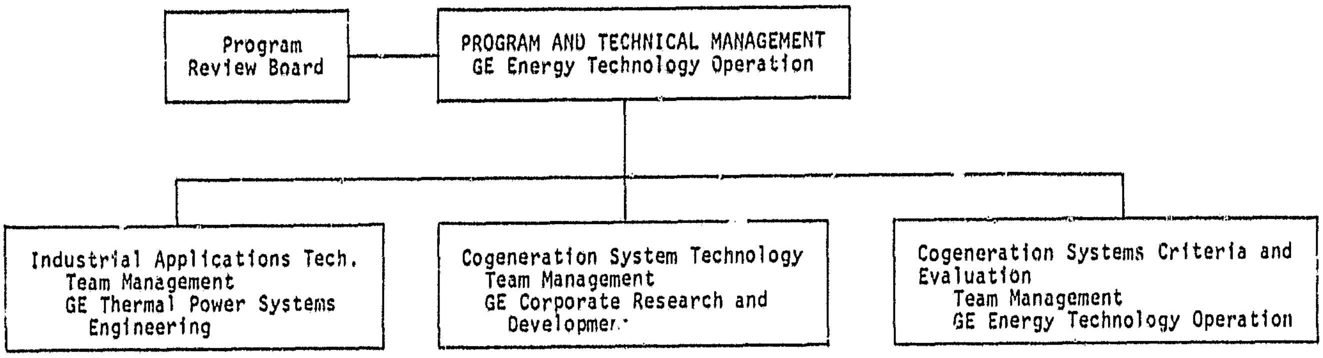


Figure 2-1. GE-CTAS Project Organization

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

Section 6

ENERGY CONVERSION SYSTEMS

6.1 INTRODUCTION

Cogeneration couples an energy conversion system (ECS) to both a power and a process heat requirement of a particular industrial plant or process. Most cogeneration evaluations focus on a particular industrial process, and then seek to find the maximum economic benefit that accrues to alternative energy conversion systems that are immediate candidates for that service. In such an economic selection process, use of a comparison to a base case results in the expression of an increment of difference in capital cost and a similar difference in on-site fuel consumption that can be expressed as the Fuel Charged to Power. Wilson (Ref. 6-1) and others have shown the utility of these means to determine the discounted rate of return on incremental investment as a determinant of the relative value of cogeneration energy conversion alternatives.

This convenient methodology, using fuel charged to power, was found to not suffice when the consideration was advanced energy conversion systems as a general class and not as candidates for a specific application. An alternative means of expressing the important performance attributes of energy conversion systems was developed. Based on fundamental thermodynamic relationships, the expressions that result are very simple, yet they can readily be transformed to more customary forms such as fuel charged to power.

The results are succinct expressions for power generated per unit of fuel energy and heat to process per unit of fuel energy related to the process temperature required by the industrial process. From these two characteristics all other expressions of performance may be derived for a particular application, such as fuel energy saved or fuel charged to power. The thermodynamic basis for the characterizing relations is so fundamental that quadratic expressions provide an excellent fit for the nearly linear results.

In conjunction with a disciplined expression of energy conversion system performance, it was an explicit objective of this evaluation to project performance at levels that could be commercialized by 1995. More speculative or optimistic performance levels with low probability of deployment by that time frame would have low probability of significant impact on national fuel savings and industrial cogeneration in the 1985 - 2000 time period which was of primary interest in this study. A common level of expectation for advanced performance was projected by consideration of the rates of technical advance from 1960 to 1978, a duration comparable to 1978 to 1995. As an additional discipline to assure uniformity, common components were always assigned the same parameters for their performance. For example, steam turbine inlet conditions were either 1450 psig, 1000 F or 850 psig, 825 F. No intermediate conditions were used. Thus steam turbines for use with all types of boilers, and as bottoming cycles with gas turbines, fuel cells, and thermionics all exhibit the same performance and the same schedule of costs wherever they appear in this study.

The final results of this work are performance characterizations that can be fitted to any industrial process requirement. In conjunction with a discipline for cost determination of a comparable nature, the differences between competing advanced energy conversion technologies may be evaluated with substantial fidelity.

6.2 ENERGY CONVERSION SYSTEM DATA SOURCES

The principal sources of data were General Electric specialists in particular fields and the General Electric Energy Conversion Alternatives Study (ECAS) performed for NASA. Additional expertise was secured in areas where General Electric experience was not specific to industrial applications or where a broadened overview was necessary. Table 6.2-1 presents a tabulation of the major contributing organizations associated with each major technical aspect of the study.

The General Electric ECAS study was used as a data source for specific advanced components such as atmospheric fluidized beds, pressurized fluidized beds, and closed cycle gas turbines. The Industrial Turbine Sales and Engineering Operation provided detailed performance and costs of state-of-the-art industrial cogeneration plant equipment that they routinely specify. All gas turbines were evaluated as heavy duty industrial units by the Gas Turbine Division. Aircraft derivative gas turbines were not evaluated due to limitations imposed by use of residual fuels.

The diesel engine evaluations were made by the Engine and Compressor Division of DeLaval Turbine, Inc. DeLaval has extensive experience and background in the type of medium speed diesels that serve the industrial sector. These engines tend to be more rugged and durable than the high speed lightweight diesels burning distillate that are favored for transportation service. In addition they have been successful in adapting residual oil firing to the medium speed diesel, a role more usual for the low speed marine diesel. DeLaval has made many cogeneration installations over the years, and thus was positioned to forecast both performance and costs with full knowledge of the application requirements.

The pressurized fluidized bed steam cycle evaluations combined two sources. The General Electric ECAS study results were a primary source. This work was updated by the Energy Systems Programs Department of General Electric. This group has had an early and a continuing activity in the coal-fired fluidized bed cycle, and in all areas of its technology. This awareness of critical problems in the technology was deemed to be essential to realism for this study.

The thermionic steam plant has the least progress toward commercial practice of all of the energy conversion systems. General Electric had evaluated a very advanced thermionic steam utility plant for the Electric Power Research Institute. The thermionic performance was projected by the Thermo Electron Corporation to two generations beyond current attainments in that study. The pulverized coal combustion and the heat pipes and steam

Table 6.2-1

ENERGY CONVERSION SYSTEM DATA SOURCES

System	Sources
Steam Turbine & Steam Sources	General Electric - ECAS Study - Industrial Turbine Sales & Engineering Operation
Gas Turbine Cycles	General Electric - Gas Turbine Division
Diesel Engines	DeLaval Corporation
Pressurized Fluidized Bed Steam Cycle	General Electric - ECAS Study - Energy Systems Programs Dept.
Thermionic Steam Plant	General Electric - EPRI Study - Corporate Research & Development
Stirling Cycle	General Electric - Space Division North American Philips
Closed Cycle Gas Turbine	General Electric - ECAS Study
Fuel Cells - Molten Carbonate - Phosphoric Acid	Institute of Gas Technology General Electric - Direct Energy Conversion Programs - Energy Systems Programs Department - Energy Tecnnology Operation
Integrated Gasifier Combined Cycle	General Electric - Corporate Research & Development - Gas Turbine Division - Energy Technology Operation
Heat Recovery Steam Generator	General Electric - Industrial Turbine Sales & Engineering Operation
Heat Pumps	General Electric - Corporate Research & Development

boiler were engineered by the Foster Wheeler Corporation. The power plant costs were the result of projections from these three companies. The resources for the CTAS program could not support a comparable in-depth design for a similar industrial design. The General Electric Corporate Research and Development team transformed the EPRI power plant performance and costs to accord with an industrial size power plant. Neither Foster Wheeler nor Thermo Electron participated in this effort. None of the technical inputs to the EPRI study from these companies were modified.

The General Electric Space Division has had a long term stirling cycle program. Developments include small units for solar space power and reverse cycles for heat pumping. North American Philips has been a consultant to the Division on stirling cycles. This group has carried projects from the conceptual stage through the complete development to hardware. However, the larger scale of an industrial-size stirling cycle and the impact on costs due to large volume manufacture were not part of their expertise. The General Electric Diesel Engine Department reviewed the full-scale stirling engine design to evaluate the estimated large-volume manufactured costs. General Electric Corporate Research and Development produced the cost and performance estimates for the modification of distillate and residual-fired stirling cycles for the combustion and heat exchange when burning pulverized coal.

The closed cycle gas turbine evaluations were based entirely on the General Electric ECAS study data. The working medium was helium. The heat input was from an atmospheric fluidized bed.

The molten carbonate fuel cell performance and costs were evaluated by the General Electric Energy Systems Programs Department. The Institute of Gas Technology provided technical data also. The Energy Technology Operation of General Electric integrated the gasifier and gas cleanup aspects of the evaluation for the coal-fueled units.

The phosphoric acid fuel cell was based on data from the General Electric Direct Energy Conversion Programs, from the Institute of Gas Technology, and from the General Electric Energy Technology Operation. The latter input concerned primarily operating and maintenance aspects of the technology to remove sulfur from the fuel gas produced by a reformer down to 20 ppm.

The integrated gasifier combined cycle required significant inputs from several groups. The earlier General Electric ECAS study results were out-of-date due to advances that had been made in the gasifiers and the gas cleanup systems. General Electric Corporate Research and Development integrated the system and provided data on the GEGAS gasifier. The General Electric Gas Turbine Division produced gas turbine and heat recovery steam generator performance data. The General Electric Energy Technology Operation modified all the cost and performance data so as to put it on the basis of the Texaco entrained gasifier on which the results of the study are based.

Heat recovery steam generators were based on current practice and current costs for General Electric units. These data were produced by the General Electric Industrial Turbine Sales and Engineering Operation.

Heat pumps were evaluated generically and performance estimates made by General Electric Corporate Research and Development. The CTAS team from the same organization detailed the performance and costs for the heat pumps that were integrated with the advanced diesel engines.

The selection of data sources and energy conversion system expertise depicted above was made to favor estimates of performance and costs that would realistically meet industrial requirements. A balance between optimism and conservatism was sought from all data sources.

6.3 FUEL CONSIDERATIONS

The specifications for fuels as used in this study have been presented in Vol. II, Section 3.1 Groundrules. Their application to energy conversion systems are presented in Table 6.3-1. Generally the most crude form of fuel was favored for the study. Coal and coal derived liquid fuels received the major emphasis. Residual liquid fuel, either from a petroleum base or coal derived, was of secondary importance. Distillate fuels, either petroleum based or coal-derived, were included only for the few ECS's that could not tolerate low grade fuels. As examples, the regenerative gas turbine, very small stirling cycles, fuel cells, and small diesels require distillate. In addition, state-of-the-art gas turbines and diesels burning both distillate and residual grade petroleum oils were included in the study. An indication (symbol OK) is given in Table 6.3-1 where a fuel can be used, but it was not evaluated in this study since a lower grade of fuel could be used and should produce a better economic result. Those indicators show fuel adaptability of the ECS.

The specific gas turbine systems that burn coal were detailed explicitly rather than cataloging them simply as coal burning gas turbines. The integrated gasifier system performs coal gasification at elevated pressure and temperature, and directly supplies the gas used in the gas turbine. A heat recovery steam generator (HRSG) and steam turbine are integral parts of that system. The second form of coal burning gas turbine utilizes a pressurized fluidized bed to burn coal directly with simultaneous sulfur capture by dolomite. Steam produced by heat exchange from the bed drives a steam turbine. The hot pressurized combustion products from the bed power a gas turbine. The third coal burning gas turbine is a closed cycle unit utilizing helium as its working fluid. Compressed helium would be heated in a coal-fired atmospheric fludized bed that simultaneously captures sulfur by use of limestone. Process heat would be derived from part of the necessary cooling before the expanded helium re-enters the closed cycle compressor.

Table 6.3-1

COGENERATION ENERGY CONVERSION SYSTEMS FUELS EVALUATED AND FUEL FLEXIBILITY

	Coal	Residual*	Distillate*
Steam Turbine	FGD	Yes	OK
	AFB	-	-
	PFB	-	-
Gas Turbine	-	Yes	Yes
Combined-Cycle	-	Yes	OK
Combined-Cycle - Integrated Gasifier	Yes	-	-
Helium Gas Turbine	AFB	OK	OK
Thermionic Steam	FGD	Yes	OK
Stirling Cycle	FGD	Yes	Yes
Diesel	-	Yes	Yes
Phosphoric Acid Fuel Cell	-	-	Yes
Molten Carbonate Fuel Cell	-	-	Yes
Molten Carbonate Fuel Cell - Integrated Gasifier	Yes	OK	-

FGD - Flue Gas Desulfurization
AFB - Atmospheric Fluidized Bed
PFB - Pressurized Fluidized Bed
OK - Fuel Flexibility Indicator
* - Both Petroleum Base and Coal Derived Liquids

The steam turbines selected for study cover the economic span for cogeneration. The boiler for state-of-the-art coal firing would require flue gas desulfurization (FGD) to meet emission standards. A residual-fired boiler also represents state-of-the-art. The use of an atmospheric fluidized bed (AFB) boiler or a pressurized fluidized bed (PFB) system is advanced art. Another advancement would be the incorporation of thermionic converters in the construction of a boiler.

The stirling cycle uses external combustion with heat transfer to its hot upper cylinder regions. Small demonstration units have run on distillate. Residual firing is an expected evolution. Coal firing would require use of a heat coupling medium such as a helium loop between the stirling cylinder heads and the heat source. The heat source temperature should exceed the limits for an atmospheric fluidized bed (AFB) that are generally set at 1550 F. The radiant heat transfer and heated gases from a pulverized coal-fired furnace using flue gas desulfurization of the cooled flue gas was deemed the more certain means to achieve a coal-fired stirling cycle that would be developed and deployed in the time frame of 1990 to 1995.

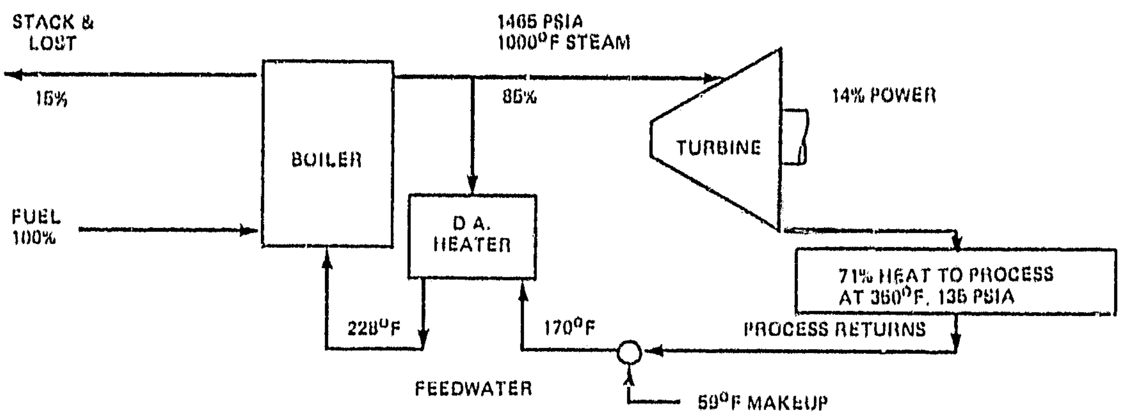
Two types of fuel cells were considered. The phosphoric acid fuel cell as considered applicable only for use with distillate fuels. The high temperature molten carbonate type was deemed applicable with distillate fuels; in large sizes a coal gasifier with intensive fuel gas cleanup would permit the use of coal.

The diesel engines considered were of medium speed and size that are typically applied in industry and in municipal power generation. Residual oil is their typical fuel. Distillate would become a required fuel only in small sizes. The burning of coal and of coal-in-oil slurries was considered but was rejected by us because the prolonged duration of combustion, the wear rate of injection equipment, and the mandatory exhaust gas scrubbing for sulfur (FGD), particulates, and NO_x were deemed to make both performance and cost of such units non-competitive.

Thermionic converters were considered as units added to the high temperature furnace section of a boiler. Either pulverized coal or residual grade liquid fuel would be fired. The steam would be produced at low pressure as heat to process, or it would be produced at high pressure to flow through a non-condensing steam turbine. In the latter case the thermionic units serve as topping units relative to the steam turbine.

6.4 ECS PARAMETERS AND CHARACTERIZATION

The convention for describing process heat requirements has been the expression of the steam flow requirement in pounds per hour and the gage pressure at which that steam condenses. A steam turbine cogeneration system is illustrated in Figure 6.4-1. The boiler feedwater is brought to 228 F by a combination of makeup water at 59 F, process return water and steam supply to the deaerator heater. For 100% fuel energy fired, of the order of 15% is accounted in stack loss and other system losses. The 85% of useful energy results in 14% electric power produced and 71% heat to process. The process temperature level is described by its condensing steam pressure, 135 psi absolute, or conventionally 120 psi gage. Figure 6.4-2 presents steam turbine cycle cogeneration performance characteristics wherein the abcissa is the gage pressure for the condensing steam that serves the process heat load. Gage pressure of steam has no thermodynamic significance, so it is not surprising that the characteristic reveals little of the underlying character of the energy conversion system.



VARIABLE: T PROCESS, EXHAUST PRESSURE

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

ADVANCED ART: TURBINE GENERATOR NONE
STEAM BOILER-ATMOSPHERIC FLUIDIZED BEDS

Figure 6.4-1. Steam Turbine Cogenerator

If the steam turbine inlet conditions (Figure 6.4-1) were held constant at the 1465 psia, 1000 F and the steam was expanded to atmospheric pressure, then a greater amount of turbine output would be achieved per pound of steam flow. Moreover, the preponderant temperature for the condensation of the exhaust steam would be 212 F. Now, if that same steam were expanded to 15 psi gage, less work would be produced, and the exhaust steam would have a predominant temperature of 250 F or thermodynamically 710 R. The predominant temperature for heat input to make steam would be 590 F, not the 228 F feedwater temperature nor the 1000 F superheat temperature. Figure 6.4-3 shows a Carnot cycle and an ideal Rankine cycle performing to these predominant temperatures. The area encompassed by the upper region of each diagram is the work or power produced by the cycle. The area encompassed in the lower region is the heat rejection of the cycle which is the heat to process in a cogeneration steam cycle. The band in the middle called "difference" is the change in both power and heat when the process temperature is raised from 212 F to 250 F. Power is reduced and heat to process is increased by the identical amount. Moreover, the magnitude of this difference varies directly with the difference in process temperature. This is an important finding; when cogeneration power and heat to process are related to the process steam condensation temperature, the relationships tend to be linear.

A test of this premise is shown in Figure 6.4-4 for a non-condensing steam turbine cogeneration system with an 80% efficient steam turbine, an 85% efficient boiler and boiler feed at 170 F. All parameters are expressed as fractions of the fuel fired higher heating value. The characteristics for power generated and for heat to process are indeed found to be close to linear as related to process temperature. The sum of power generated and heat to process was 0.85 at all process temperatures. In this case it accords exactly with the boiler efficiency.

Had the process heat been produced at 85% boiler efficiency by a "dedicated" process boiler, and the power produced in another energy conversion system at an assumed efficiency of 33%, then at each process temperature one could compute the fuel that would have been consumed if

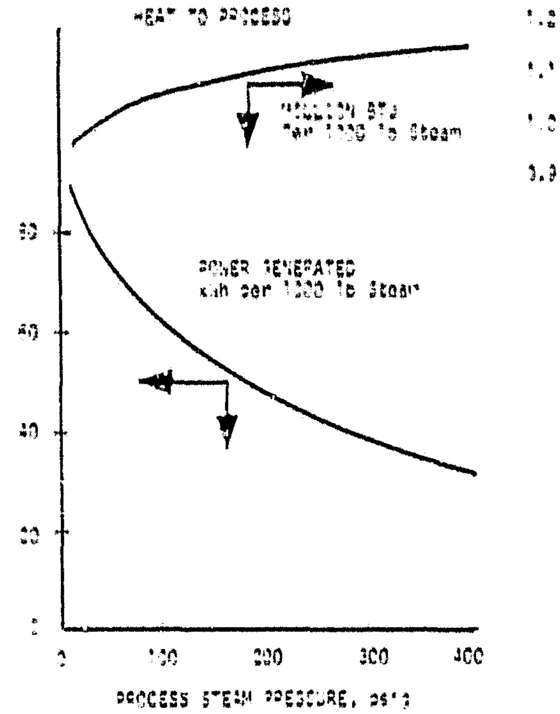


Figure 6.4-2. 1465 psia, 1000 F Steam Turbine Cogeneration Characteristic

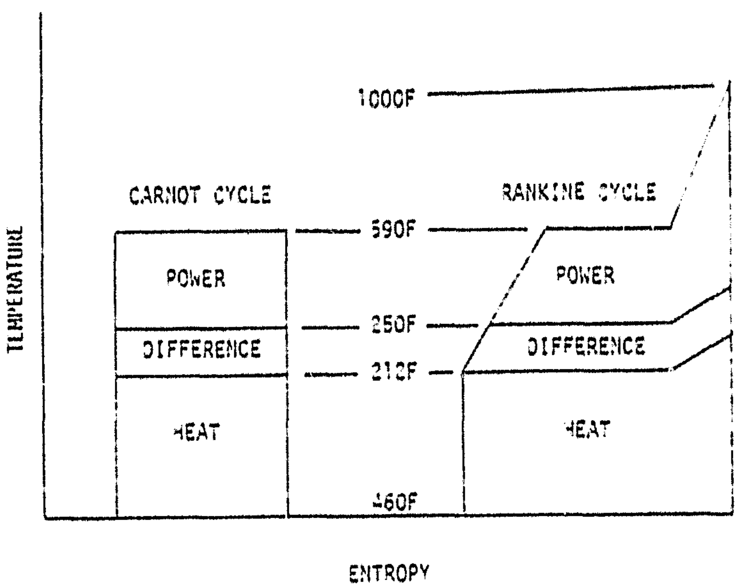


Figure 6.4-3. Ideal Cycle Cogenerators

cogeneration were not used. These values are all greater than 1.0 showing that more fuel would be required in each case. The difference then between nocogeneration and a cogeneration situation is found by subtracting 1.0 from the nocogeneration fuel requirement. These values are in reality the ratio of fuel saved to the fuel consumed by the cogenerating energy conversion system. Since all components of this evaluation tend to be linear, the result tends also to be linear with process steam condensing temperature. These results are readily transformed to the fuel energy saved ratio as defined for this study.

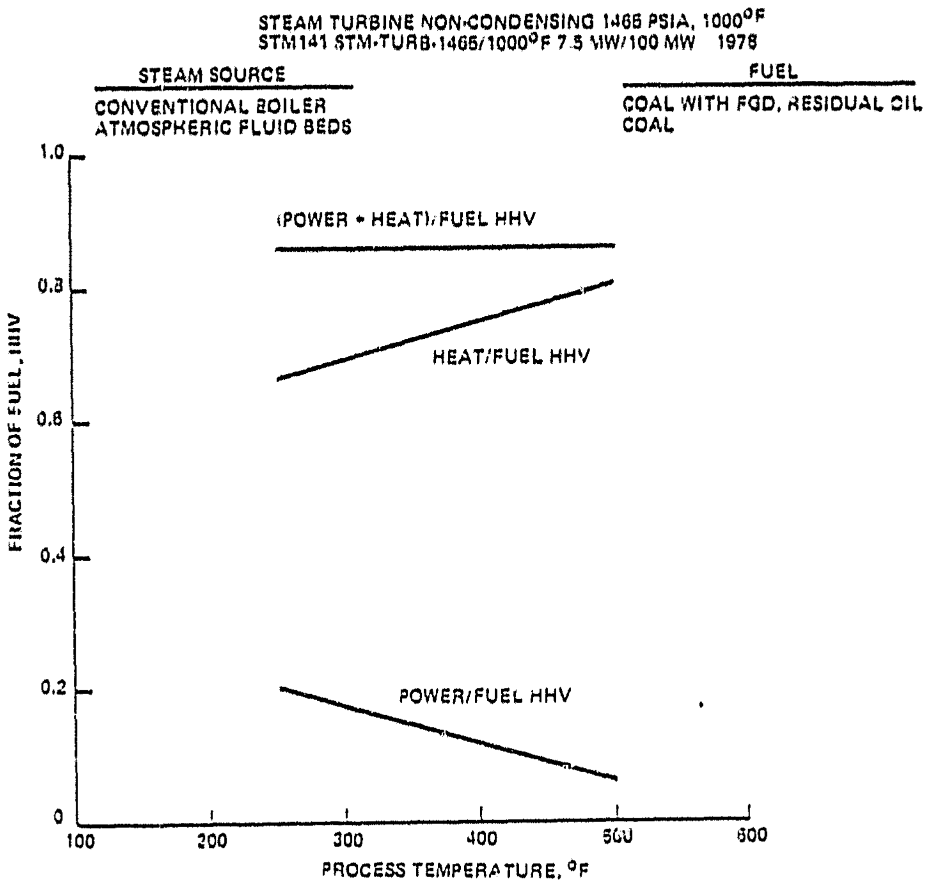
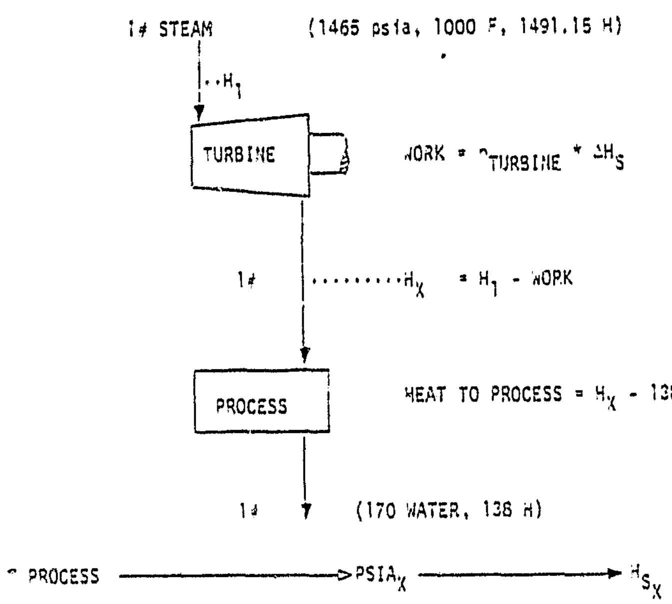


Figure 6.4-4. Energy Conversion System Characteristic

The mode of characterization using process temperature as the determinant provides the means to conveniently formulate the power to fuel energy ratio and the heat to process to fuel energy ratio for a cogeneration system; all other results such as energy effectively used and fuel energy saved can be derived from these two characteristics.

The synthesis of these cogeneration characteristics is most readily understood in the context of the steam turbine cogenerator illustrated in Figure 6.4-1. In Figure 6.4-5 the turbine and the process are shown in the context of the effect of one pound of steam upon them. Evaluations start with assignment of the process temperature, TPRO. The steam tables then provide the saturation pressure for the process; that is the back pressure on the steam turbine. The isentropic steam turbine expansion work can then be found; when multiplied by the steam turbine efficiency of 80%, the result is the turbine output expressed as Btu per pound of steam flow. The remainder of the steam energy span of



$$WORK = 531.85 - 0.856 * TPRO - 80 * \left(\frac{TPRO}{1000}\right)^2$$

Figure 6.4-5. Synthesis of Steam Turbine Cogeneration Characteristic

1353 Btu per pound (from inlet at 1491 to process return at 138) would be realized as process heat. The data for a range of process temperatures from 212 F to 500 F were calculated. These data were then correlated by a quadratic least squares fit to the process temperature:

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

Each calculated point was reevaluated as a check on the fidelity of the curve fit. The extreme deviations were +0.04% and -0.02%. This showed remarkably fine fidelity and corroborated the insight that process temperature is the fundamental determinant for cogeneration energy conversion system performance correlation.

The production of one pound of steam would require 1592 Btu of fuel energy for a boiler efficiency of 85%. Division of the work equation by this value produces the characterizing equation for power and then for heat.

$$\text{Power/Fuel Energy} = A_2 + B_2 * \left(\frac{\text{TPRO}}{1000}\right) + C_2 * \left(\frac{\text{TPRO}}{1000}\right)^2$$

$A_2 = 0.3341$, $B_2 = -0.5380$, $C_2 = -0.0500$

$$\text{Heat/Fuel Energy} = A_1 + B_1 * \left(\frac{\text{TPRO}}{1000}\right) + C_1 * \left(\frac{\text{TPRO}}{1000}\right)^2$$

$A_1 = 0.5159$, $B_1 = 0.5380$, $C_1 = 0.0500$

These are the six constants that describe the full range of characteristics for this particular energy conversion system throughout this study.

Each energy conversion system (e.g., Figure 6.4-4) has its own unique characterizing curves and constants. Each has been given a short name, STM 141 for example, and a longer more descriptive name, STM-TURB-1465/1000 F for example. Also the range of power generation for which the characterization was made would be given, 7.5 MW/100 MW for example. The date given is the estimated date of earliest commercial service. The fuels that are evaluated, and the applicable type boilers are also given. These characterizations and system parameters are presented in a series of charts for each ECS, and then in the computer input data sheet for all ECS's.

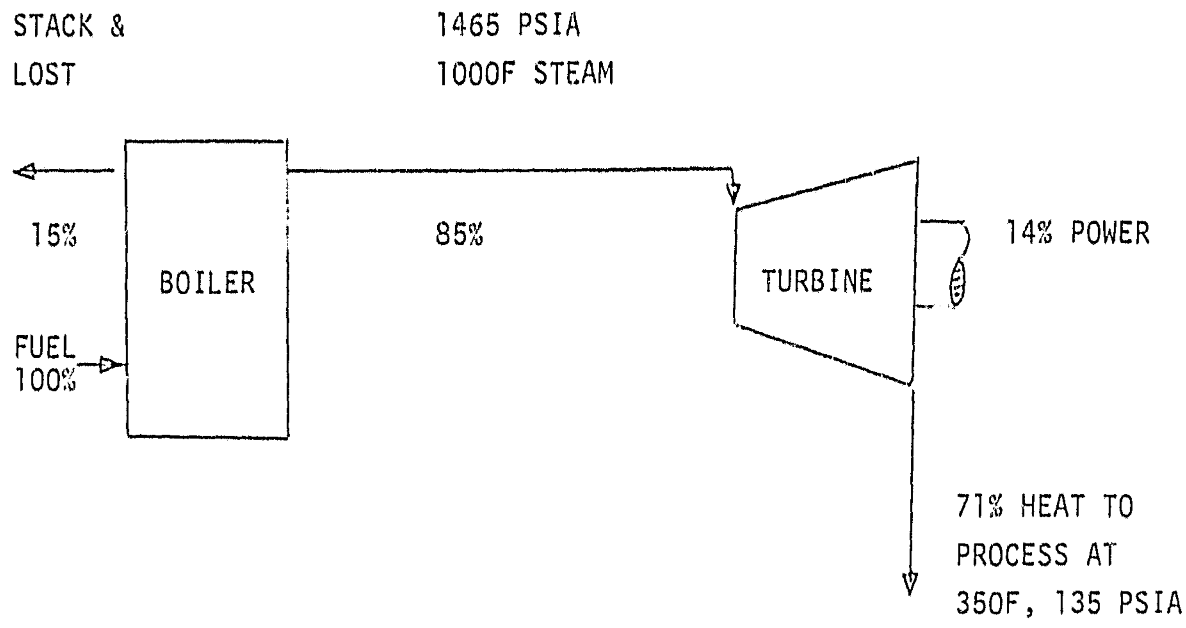
6.5 ECS PERFORMANCE AND DESCRIPTIONS

This section presents schematics, performance curves, and trends for all ECS's considered in this study. The figures of the characteristic performance curves for each ECS are grouped together at the end of the discussion of that ECS.

Steam Turbine Generator ECS

Figure 6.5-1 shows a schematic of the steam turbine applied to cogeneration. The turbine is non-condensing since the entire exhaust steam flow is utilized as process steam. The configuration of the process returns, makeup water, and feedwater system were detailed in Figure 6.4-1. The turbine costs were evaluated for a single automatic extraction non-condensing steam turbine. Two inlet throttle conditions were considered. The highest economic pressure level of 1465 psia was designated with the highest normal superheat of 1000 F. These conditions mandate full demineralization of the boiler feedwater. The lower throttle condition of 865 psia, 825 F was selected to avoid a large cost increment for high alloy steel superheaters and to use the least expensive feedwater treatment. The assigned steam turbine generator efficiencies are within two points of the range of efficiencies appropriate to the power range of the units. There is no advanced art in the steam turbine-generators. There is advanced art in one of the steam sources, the atmospheric fluid bed steam generator.

Figure 6.5-2 and Figure 6.5-3 present the cogeneration performance characteristic for the two steam turbine systems. The sum of the power plus heat to process divided by fuel higher heating value was 85%. The 15% lost energy derives from latent and sensible stack loss, and the excess auxiliary power required by coal burning boilers of either the atmospheric fluid bed type or the pulverized coal with flue gas scrubber type. Table 6.5-1 shows the steam sources and their basic boiler efficiency before adjustment for auxiliary power. The heat recovery steam



VARIABLE: T Process, Exhaust Pressure

Throttle	Efficiency	MW Range
1465 PSIA, 1000F	80%	7.5 - 100
865 PSIA, 825F	78%	5.0 - 50

ADVANCED ART: Turbine Generator None
Steam Boiler-Atmospheric Fluidized Beds

Figure 6.5-1. Steam Turbine Cogenerator

STM141 STM-TURB-1465/1000F 7.5 MW/100 MW 1978

Steam Source	Fuel
Conventional Boiler	Coal with FGD Residual Oil
Atmospheric Fluid Beds	Coal

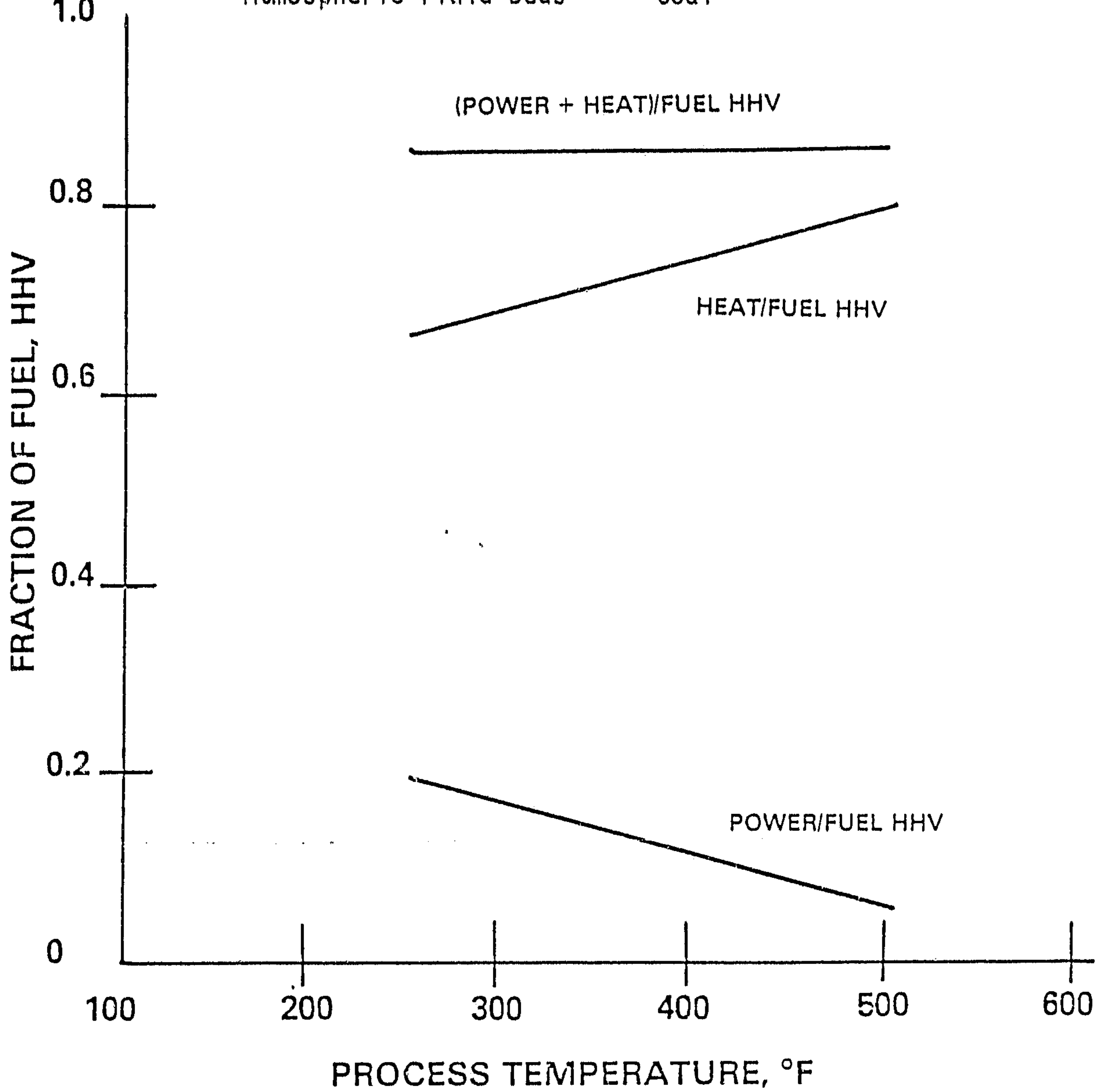


Figure 6.5-2. Energy Conversion System Characteristics. Steam Turbine Non-Condensing, 1465 psia, 1000^{O}F; Applicable Size, 7.5 to 100 MW; Available, 1978

STM088 STM-TURB-865/825F 5 MW/50 MW 1978

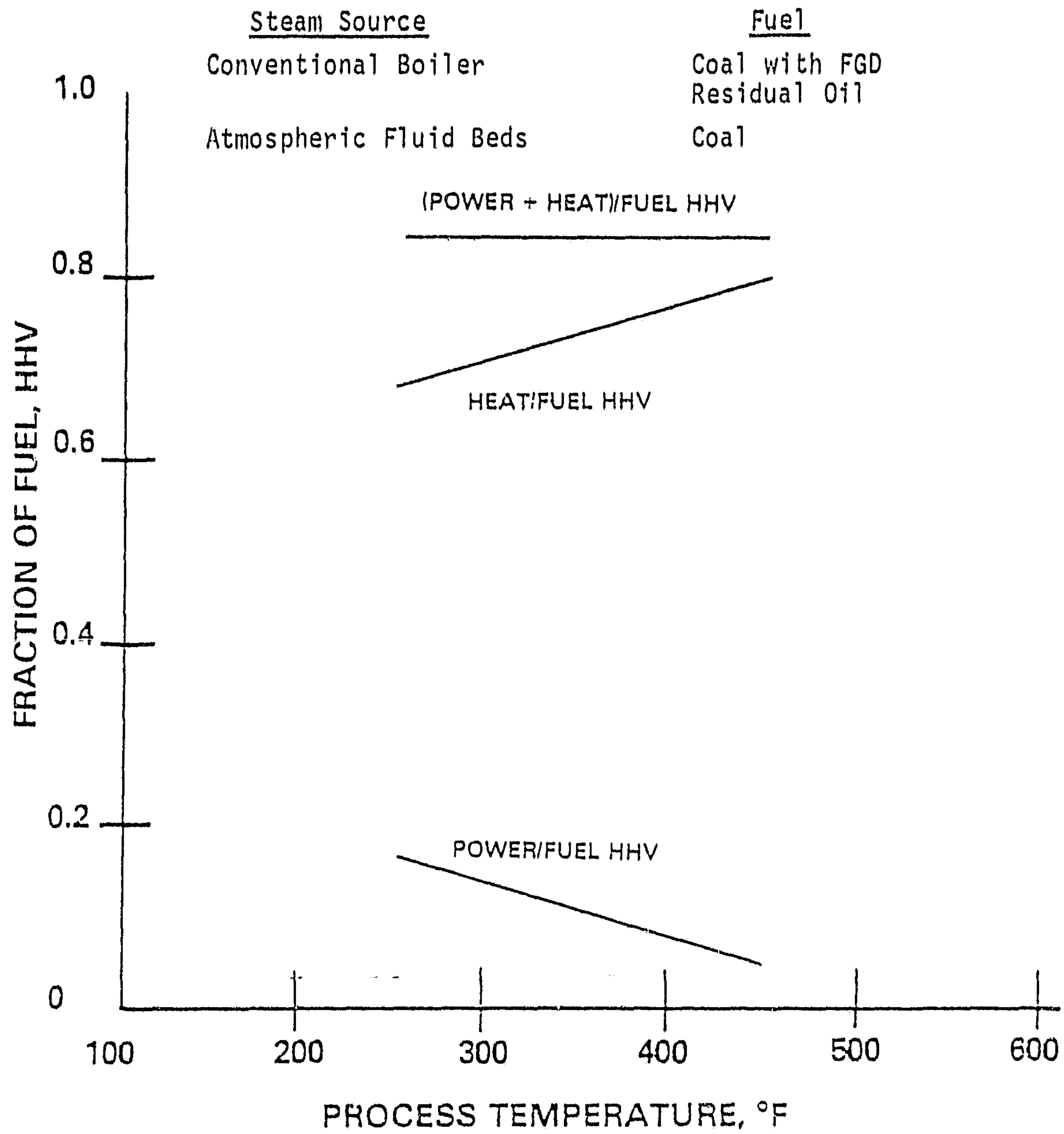


Figure 6.5-3. Energy Conversion System Characteristics. Steam Turbine, Non-Condensing; 865 psia; 825^{o}F. Applicable Size, 5 to 50 MW; Availability, 1978

Table 6.5-1

STEAM SOURCES FOR PROCESS OR STEAM TURBINE

Source	Heat to Steam/Energy Input
Coal-Fired Boiler Flue Gas Desulfurization	88%
Coal-atmospheric Fluidized Bed Boiler	88%
Residual Oil Boiler	85%
Distillate Oil Boiler	85%
Heat Recovery Steam Generators	Variable
Integrated Sources:	
Thermionic Boiler	-
PFB - Steam Plant	-
Gasifier - Gas Turbine Plant	-
Fuel Cells	-
Diesel Heat Pump	-

generator (HRSG) may have a ratio as high as 92% based on the variable sensible heat in the hot exhaust stream. Its steam production in each specific case is based on adherence to a minimum stack temperature of 300 F or a pinch temperature difference no lower than 40 F at the evaporator gas exit, whichever condition is most stringent. Similar restrictions apply to the steam generators and heat recovery equipment that are integrated portions of complex thermal systems.

Gas Turbine ECS's - Open Cycle

The variety of liquid-fired open cycle gas turbines are illustrated in Figure 6.5-4 along with selected heat balances. In each example the fuel higher heating value (HHV) is counted as 100 units. The latent heat loss of 6 units is deducted at the combustor. The heat recovery steam generator (HRSG) has the constraints enumerated in the preceeding section. The regenerative cycle would be constrained to burning distillate. Residual firing tends to accumulate sticky desposits that reduce the heat exchange effectiveness. The regeneration reduces the process heat availability as compared to the simple cycle. The steam injection gas turbine (STIG) increases its power and efficiency by the expansion of steam through the turbine. This use of steam reduces the process heat available. In the combined cycle the gas turbine HRSG produces steam at a high pressure appropriate for expansion through a steam turbine. The non-condensing steam turbine would increase power output by 10 units as compared to the simple cycle, but would reduce the heat to process.

Table 6.5-2 presents the range of gas turbine parameters. The liquid fuels are either petroleum or coal-based. Pressure ratios of 8, 12 and 16 were evaluated for advanced turbines. A value of 10 was assigned to state-of-the-art gas turbines. These values are appropriate for heavy duty industrial gas turbines. The total temperature at the first stage would be 2200 F for advanced air-cooled units and 2600 F for advanced water-cooled units. Although greater firing temperatures have been projected for each type of turbine, these are values that are considered to be most reasonably attainable considering the pace of advancement, the time to prove out and debug advancements, and the implications of low NO_x emission constraints. State-of-the-art gas turbines were assigned 1750 F firing residual oil and 2000 F firing distillate. Regenerators were considered at 60% and 85% effectiveness. STIG units were evaluated using 15% steam-to-air injection ratio which is at the exhaust visible plume limit, 10% with superheated steam and 10% with saturated steam. The latter gives a greater amount of process steam availability.

Table 6.5-2

GAS TURBINE COGENERATOR PARAMETERS

• Fuels:	Residual, Distillate	
• Variables:	Process Temperature	
	Pressure Ratio	8, (10), 12, 16
	Temperature ^{o}F	(1750), (2000), 2200, 2600
	Coolant	Air, Water
	Regeneration	0%, 60%, 85%
	Steam Injected	0%, 10%, 15%
	Bottoming Steam	1465 psia, 1000 F
		865 pisa, 825 F
• Range:	Air Flow, pounds per sec.	100 to 1000
	Output	10 MW to 200 MW
• Advanced Art:	2200 F	Air Cooled Turbine
	2600 F	Water Cooled Turbine
	SRC Fuel, Steam Injection	Water Cooled Turbine

Where combined cycles were evaluated the steam conditions were matched to one of the designated steam turbine cycles. The range of gas turbine compressor inlet airflow was a minimum of 100 pounds per second and a maximum of 1000 pounds per second. The lower limit was deemed to be marginal for residual firing due to the propensity for cooling passage plugging and for accelerated abrasive erosion of turbine buckets. The upper limit was deemed attainable by advances in technology for compressors and turbines. The turbine outputs relate to the extremes of airflow. All turbine costs were based on single shaft constant speed units including the 60 cycle generator.

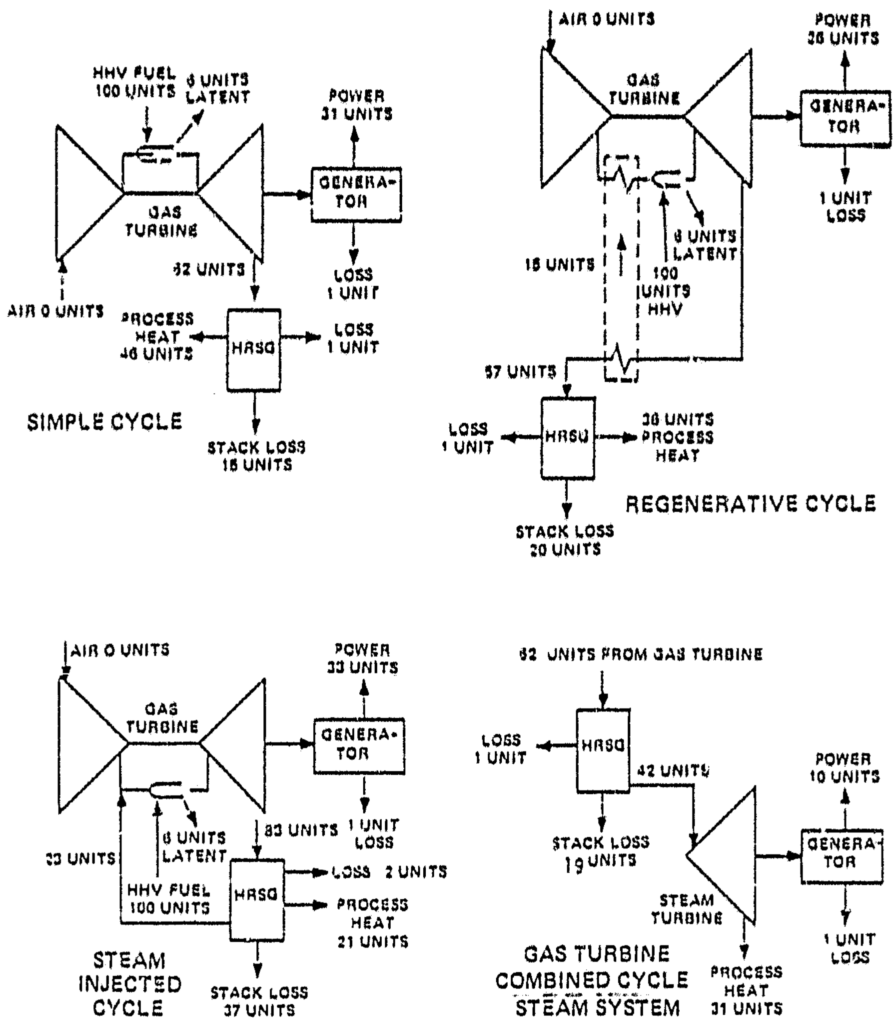


Figure 6.5-4. Gas Turbine Cogenerators

The advanced gas turbine art would include higher firing temperature, advanced air and water-cooling, the firing of coal-derived liquid fuels, and steam injection.

Gas turbine performance is presented in Figure 6.5-5. Starting at the least value of specific output, kilowatts per pound per second of air-flow, is the state-of-the-art simple cycle (SC) air-cooled (AC) unit firing residual oil at 1750 F, 10 pressure ratio (PR). The 10 PR characteristic continues to state-of-the-art distillate firing at 2000 F and then to the advanced case of 2200 F. At 2200 F the consequences of varied pressure ratio are shown with highest efficiency at 16 PR. Had the pressure drop imposed by the HRSG been omitted, then the advanced air-cooled simple cycle gas turbine at 2200 F would have shown greater specific output and efficiency as illustrated.

The effect of regeneration (regenerative cycle - RC) at 60% effectiveness (ε) is found to have a higher efficiency, but at reduced specific output. With 85% effectiveness even greater efficiency results with a 38% maximum at 10 PR. The performance for the 2600 F, 16 PR simple cycle water-cooled gas turbine is shown within the rectangular box; the specific output is significantly increased while the efficiency is less than the 16 PR air-cooled unit due to the heat removed by the water coolant. The regenerative water-cooled units reach efficiencies comparable to the air-cooled units at appreciably greater specific outputs.

The three STIG cases are located amongst the regenerative water-cooled characteristics. They exhibit extremely high specific output and efficiency when compared to any of the air-cooled or water-cooled alternatives.

The gas turbines for the integrated gasifier combined cycle appear at the lowest efficiency levels and are designated GCCAC for gasifier combined cycle air-cooled. Their high specific work as compared to the simple cycle air-cooled (SCAC) units is due to the addition of steam during the formation of the intermediate-Btu fuel gas that they burn. The lowered efficiency level is due to the reduction from coal fuel energy to the chemical and sensible energy available in the intermediate-Btu fuel gas.

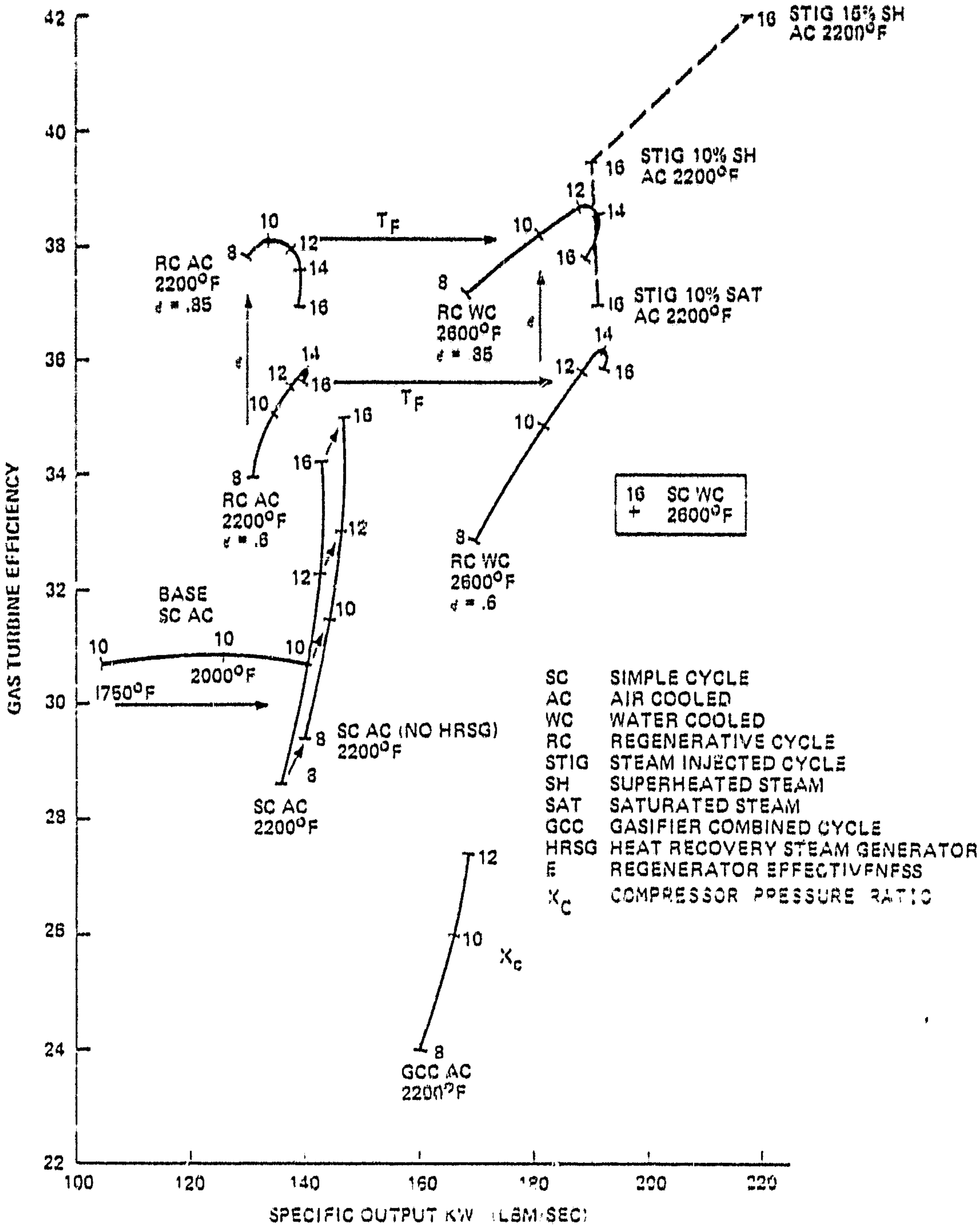


Figure 6.5-5. CTAS Gas Turbine Performance Map

The available thermal energy in the exhaust stream of these gas turbines is presented in Figure 6.5-6. The basis is a gas turbine compressor airflow of 1000 pounds per second, and heat exchange to cool the exhaust to 300 F. In general the units with greater efficiency have a reduced amount of energy in the exhaust stream.

The cogeneration systems synthesized from these gas turbine units are characterized in Figures 6.5-7 through 31. The sequence follows a purposeful pattern as follows:

Residual Liquid Fuel Fired Units:
- Gas Turbines with HRSG
- Combined Cycles
- Steam Injected Gas Turbines

Distillate Liquid Fuel Fired Units:
- Gas Turbine with HRSG
- Regenerative Gas Turbine with HRSG

Except for the combined cycles with steam turbines, the ratio of power to fuel HHV is independent of the temperature or heat to process and is constant for each system. Where the exhaust temperature is sufficiently hot the exhaust can be cooled to 300 F. For those cases the heat to process is also constant and independent of process temperature. Where exhaust temperatures are low the process temperature and HRSG pinch temperature difference fix the heat to process. As process temperature rises, the heat to process decreases, and the stack temperature would rise.

The great variety of gas turbine parametric cases permits a thorough search for the best fits to industry cogeneration requirements.

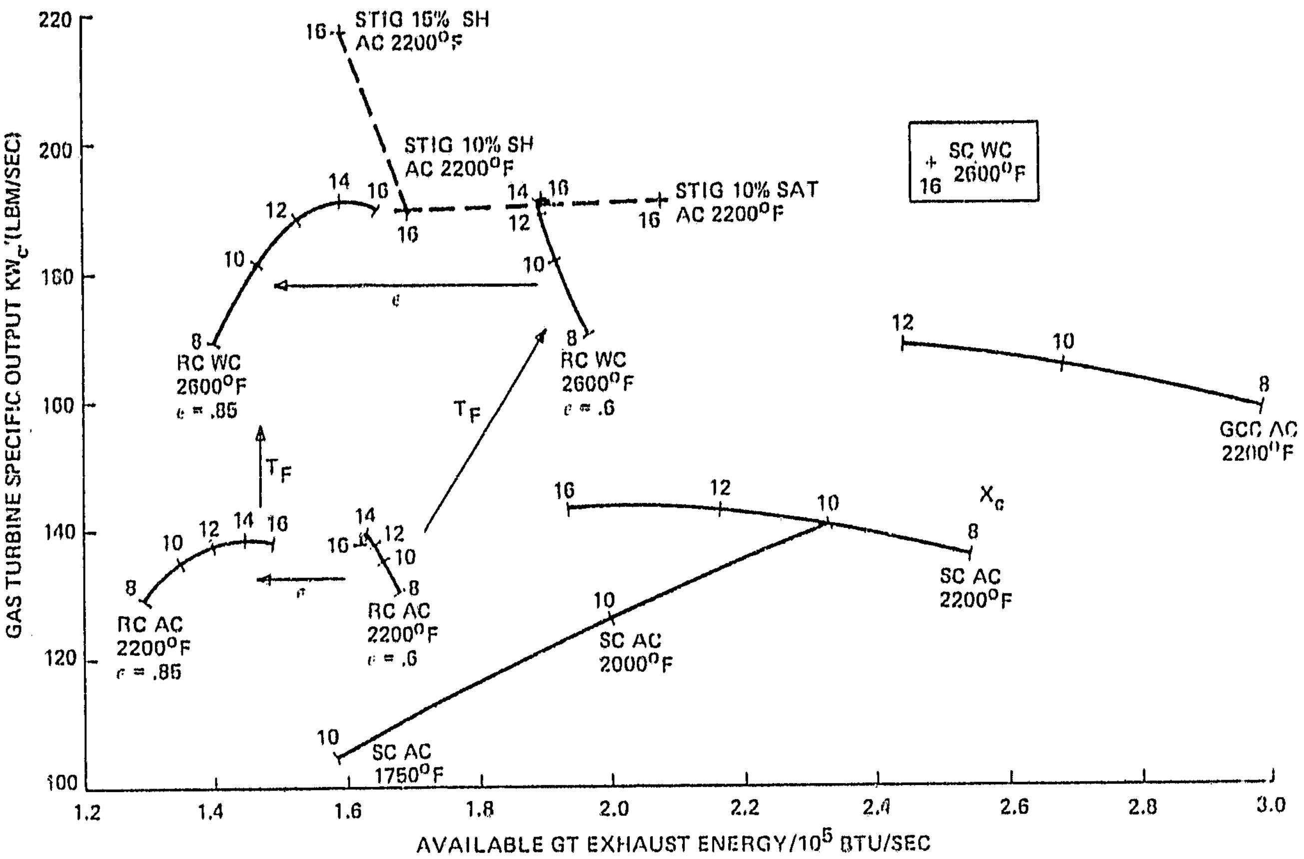


Figure 6.5-6. Gas Turbine Available Exhaust Energy, 1000 Pounds per Second Airflow

GTSOAR GT-HRSG-10/1750R-AC 10 MW/60 MW 1978

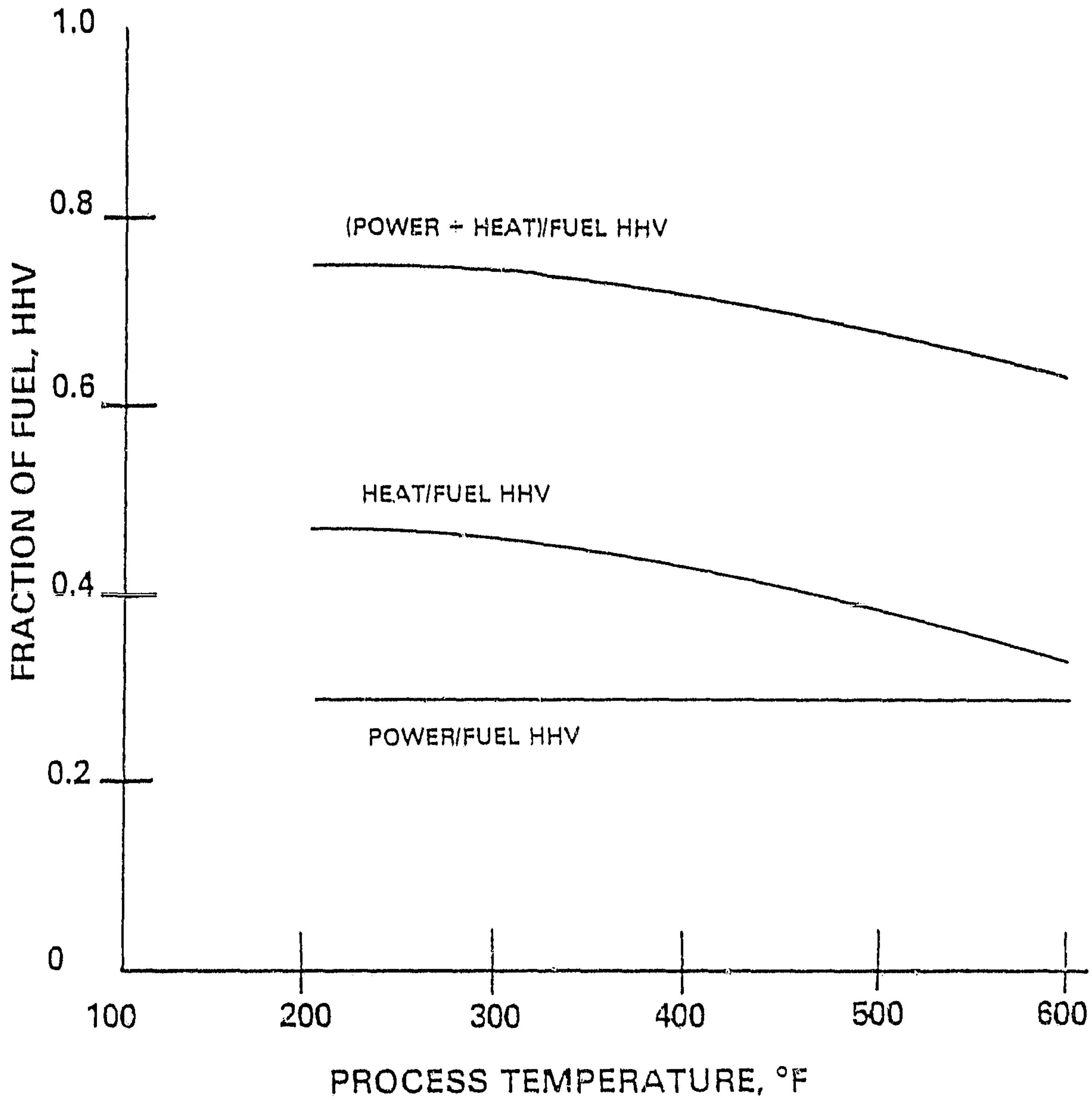


Figure 6.5-7. Energy Conversion System Characteristics. Gas Turbine, Air-Cooled, HRSG Steam to Process. Pressure Ratio, 10; Firing Temperature, 1750°F; Residual Fuel; Applicable Size, 10 to 60 MW; Available, 1978

GTAC08 GT-HRSG-08/2200R-AC 14 MW/136 MW 1985

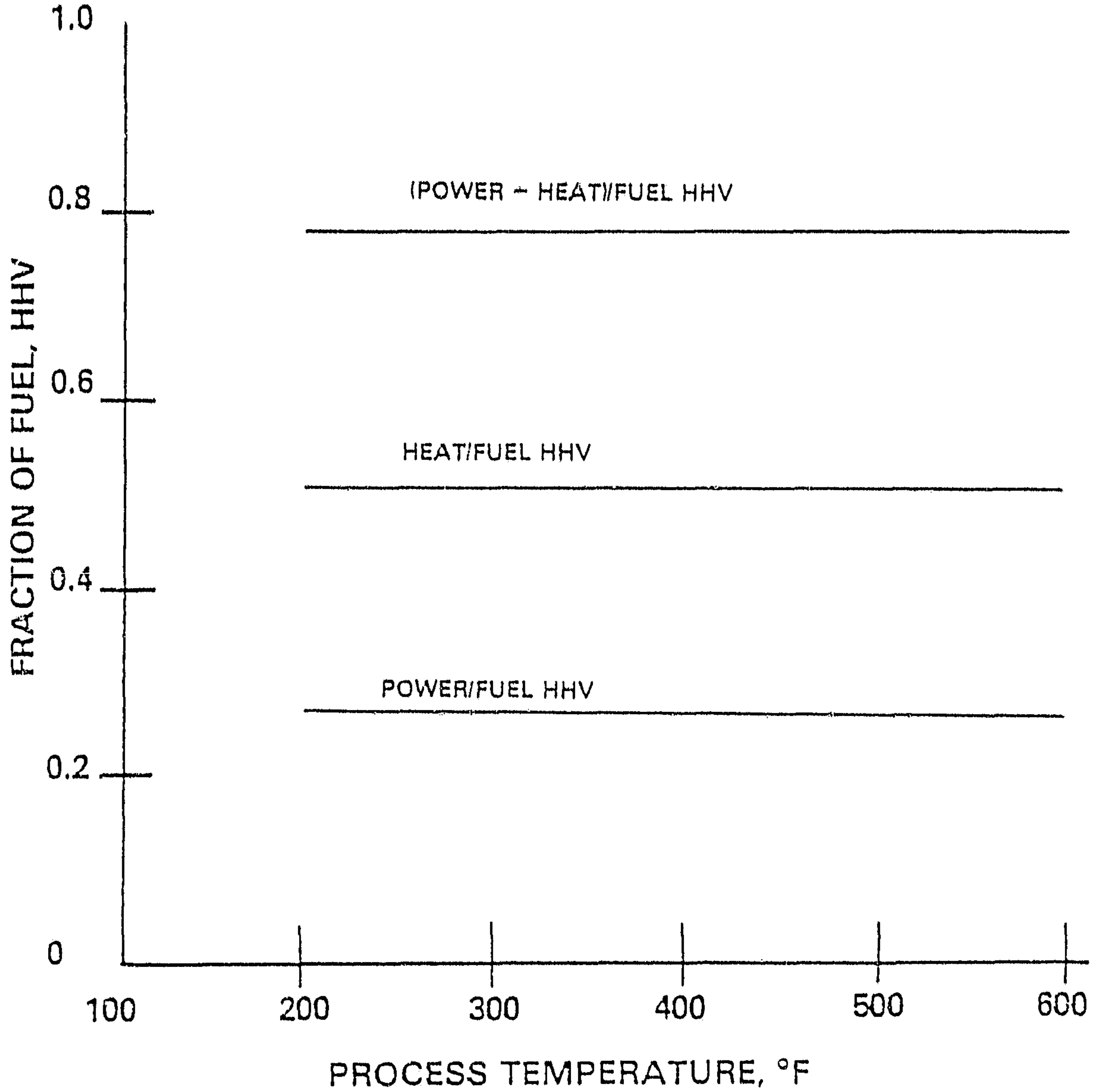


Figure 6.5-8. Energy Conversion System Characteristics. Gas Turbine, Air-Cooled, HRSG Steam to Process. Pressure Ratio, 8; Firing Temperature, 2200°F; Residual Fuel; Applicable Size, 14 to 136 MW; Available, 1985

GTAC12 GT-HRSG-12/2200R-AC 14 MW/143 MW 1985

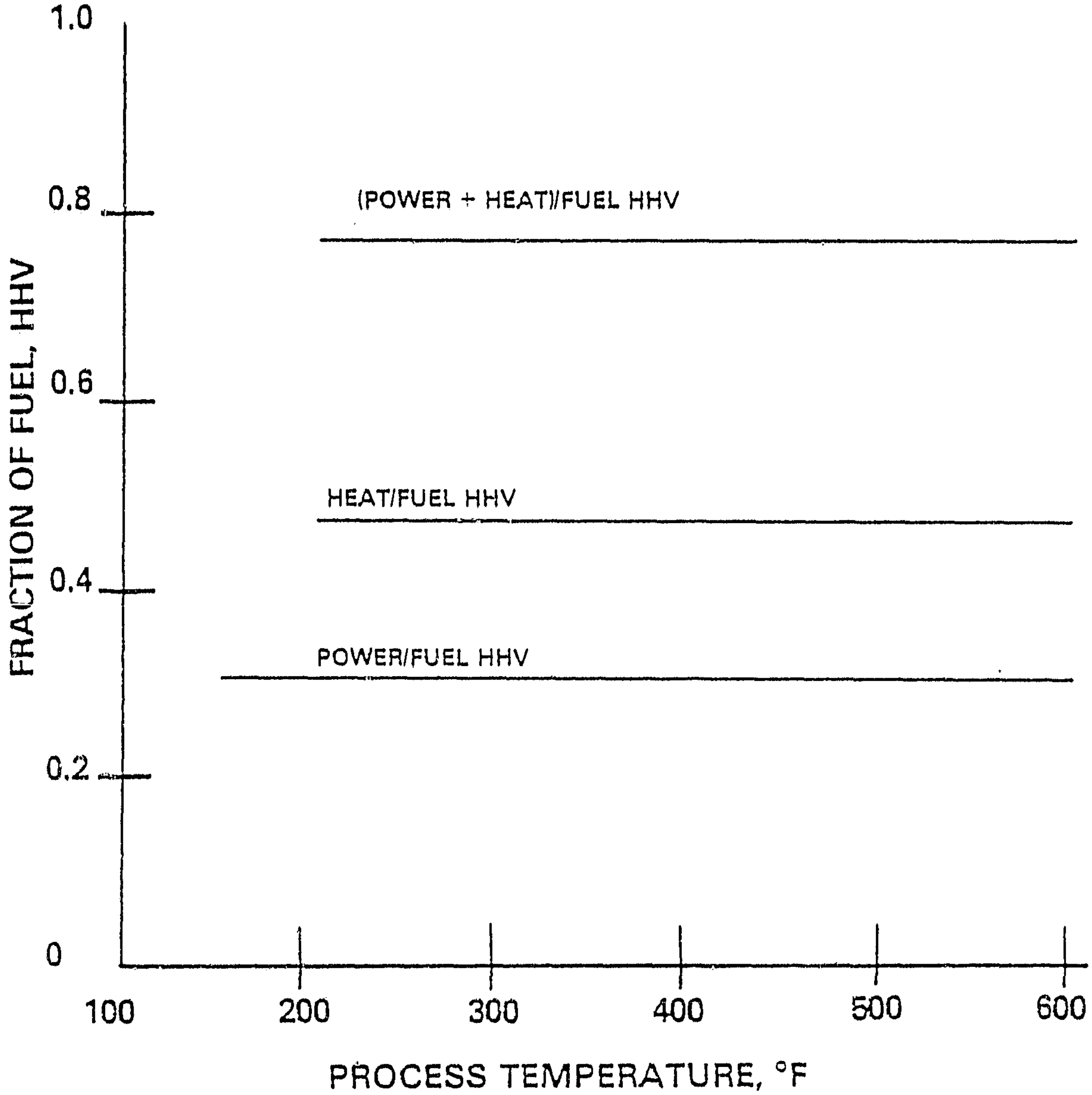


Figure 6.5-9. Energy Conversion System Characteristics. Gas Turbine, Air-Cooled, HRSG Steam to Process. Pressure Ratio, 12; Firing Temperature, 2200^{o}F; Residual Fuel; Applicable Size, 14 to 143 MW; Available, 1985

GTAC16 GT-HRSG-16/2200R-AC 14 MW/143 MW 1990

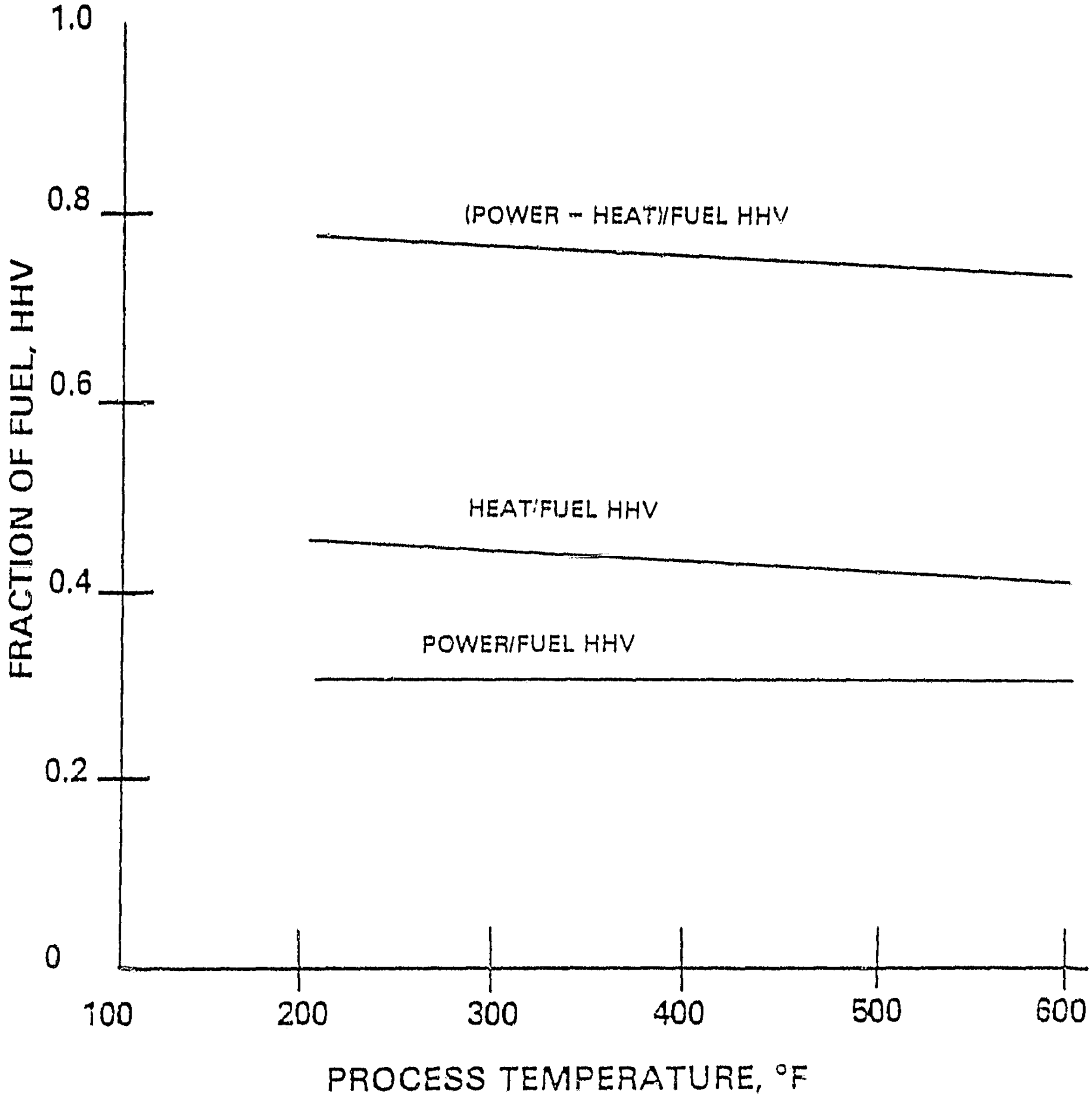


Figure 6.5-10. Energy Conversion System Characteristics. Gas Turbine, Air-Cooled, HRSG Steam to Process. Pressure Ratio, 16; Firing Temperature, 2200^{o}F; Residual Fuel; Applicable Size, 14 to 143 MW; Available, 1990

GTWC16 GT-HRSG-16/2600R-WC 20 MW/200 MW 1990

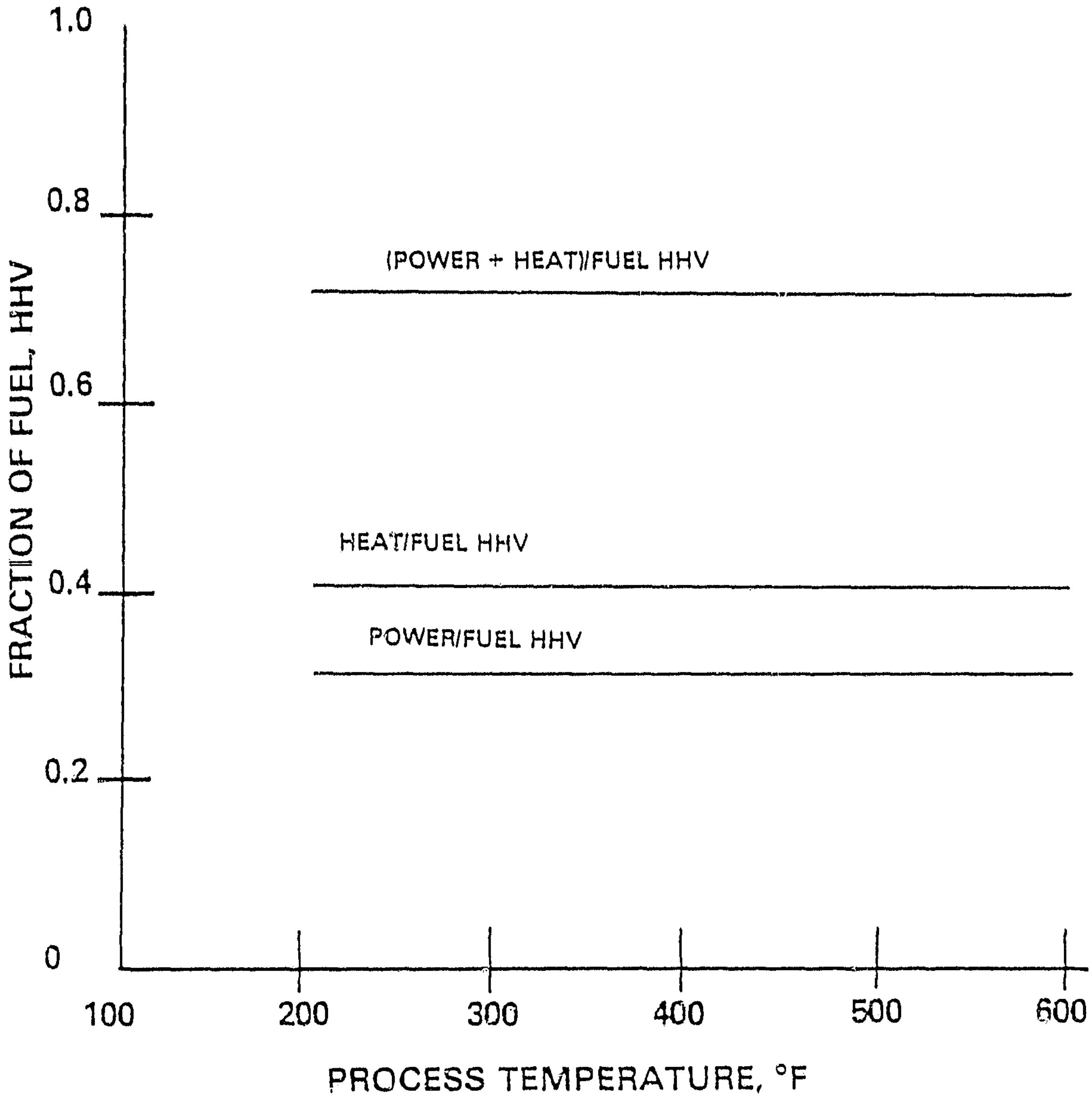


Figure 6.5-11. Energy Conversion System Characteristics. Gas Turbine, Water-Cooled, HRSG Steam to Process. Pressure Ratio, 16; Firing Temperature, 2600°F, Residual Fuel; Applicable Size, 20 to 200 MW; Available, 1990

CC1626 GTST-16/2600/1465-WC 20 MW/197 MW 1990

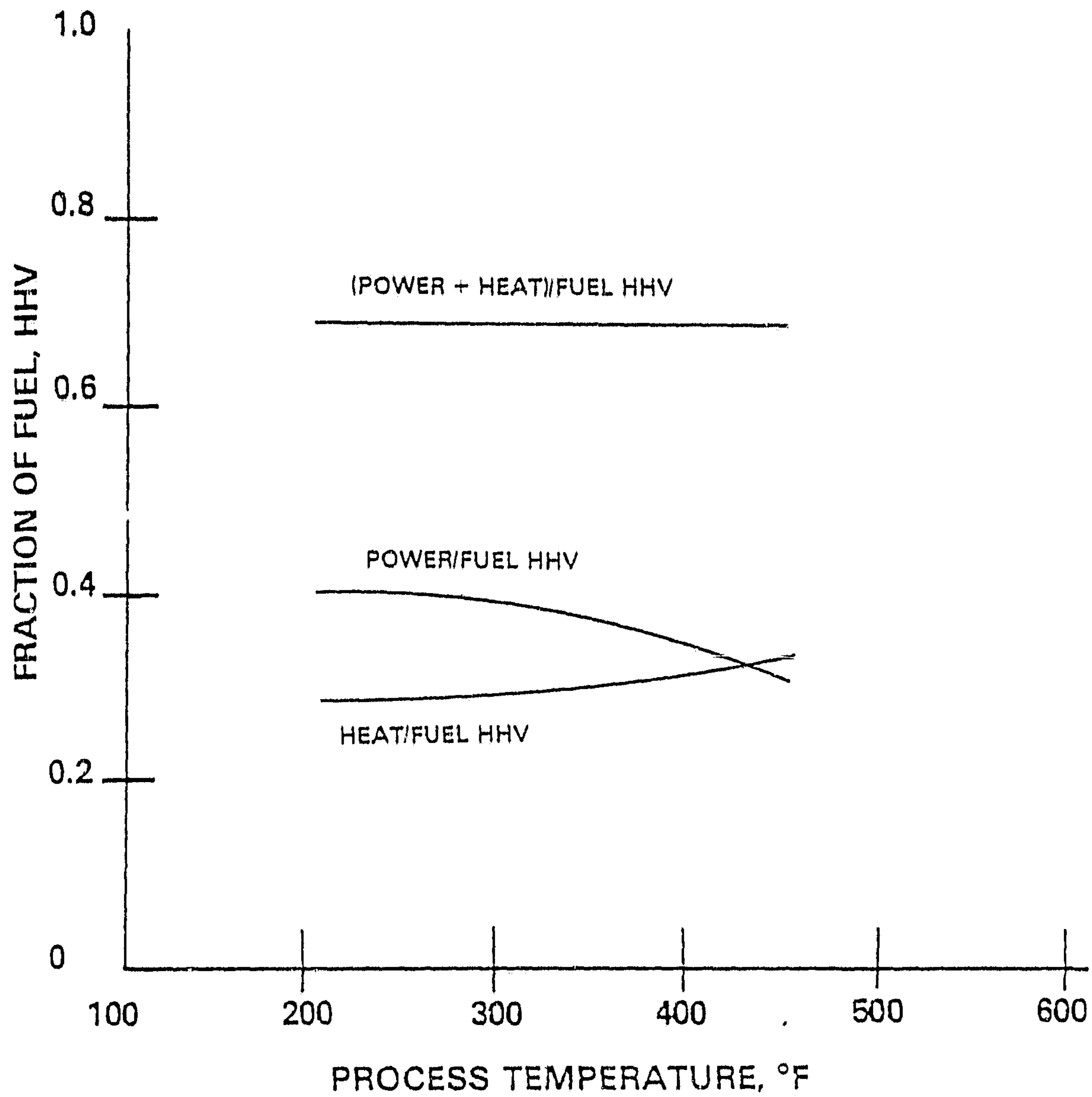


Figure 6.5-12. Energy Conversion System Characteristics. Combined Gas Turbine-Non-Condensing Steam Turbine. Pressure Ratio, 16; Firing Temperature, 2600°F; Water-Cooled Gas Turbine, Residual Fuel; 1465 psia, 1000°F Steam Turbine; Applicable Size, 20 to 197 MW; Available, 1990

CC1622 GTST-16/2200/865-AC 26 MW/165 MW 1990

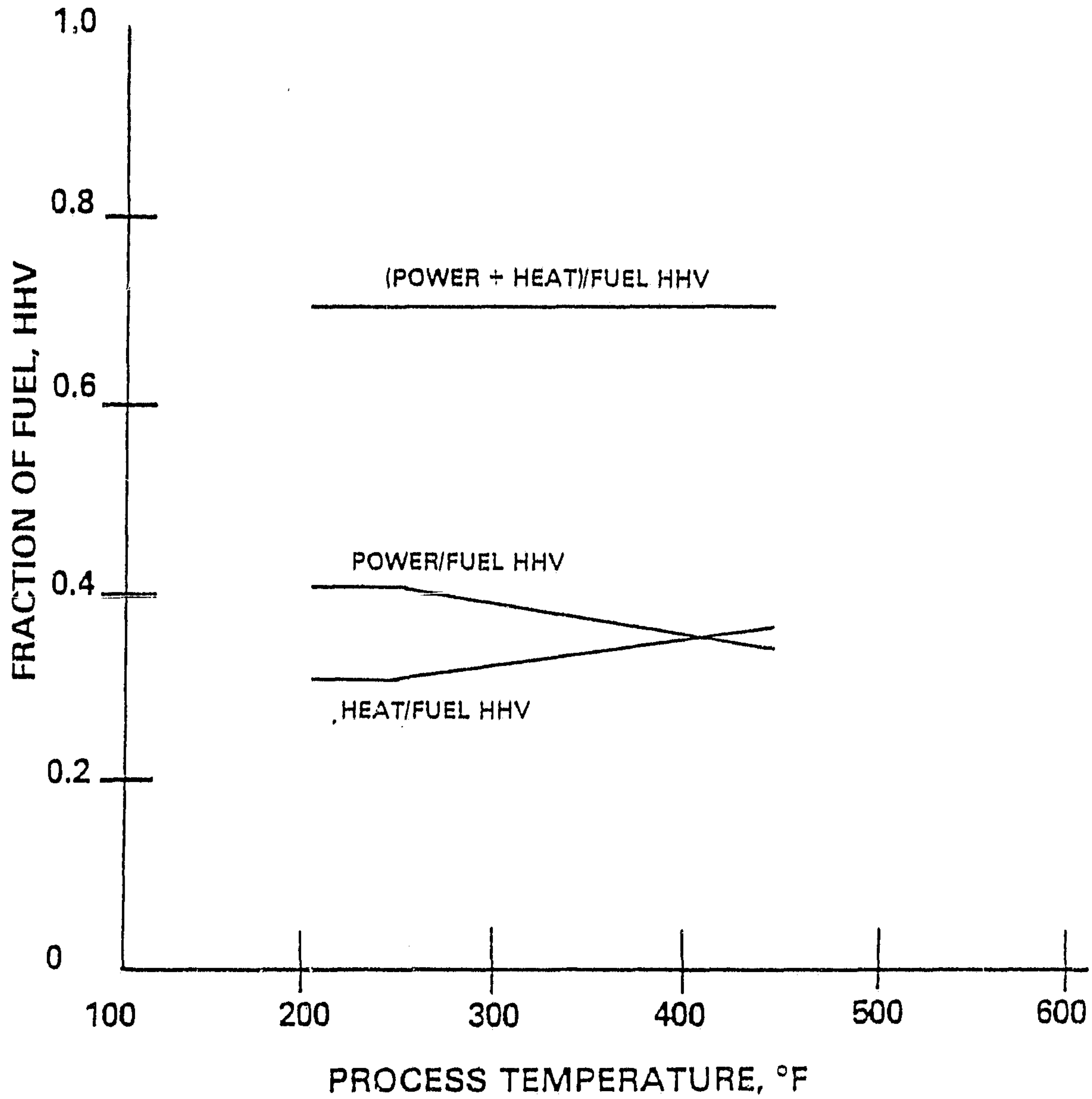


Figure 6.5-13. Energy Conversion System Characteristics. Combined Gas Turbine-Non-Condensing Steam Turbine; Pressure Ratio, 16; Firing Temperature, 2200°F; Air-Cooled Gas Turbine; Residual Fuel; 865 psia, 825°F Steam Turbine; Applicable Size, 26 to 165 MW; Available, 1990

CC1222 GTST-12/2200/1465-AC 14 MW/143 MW 1985

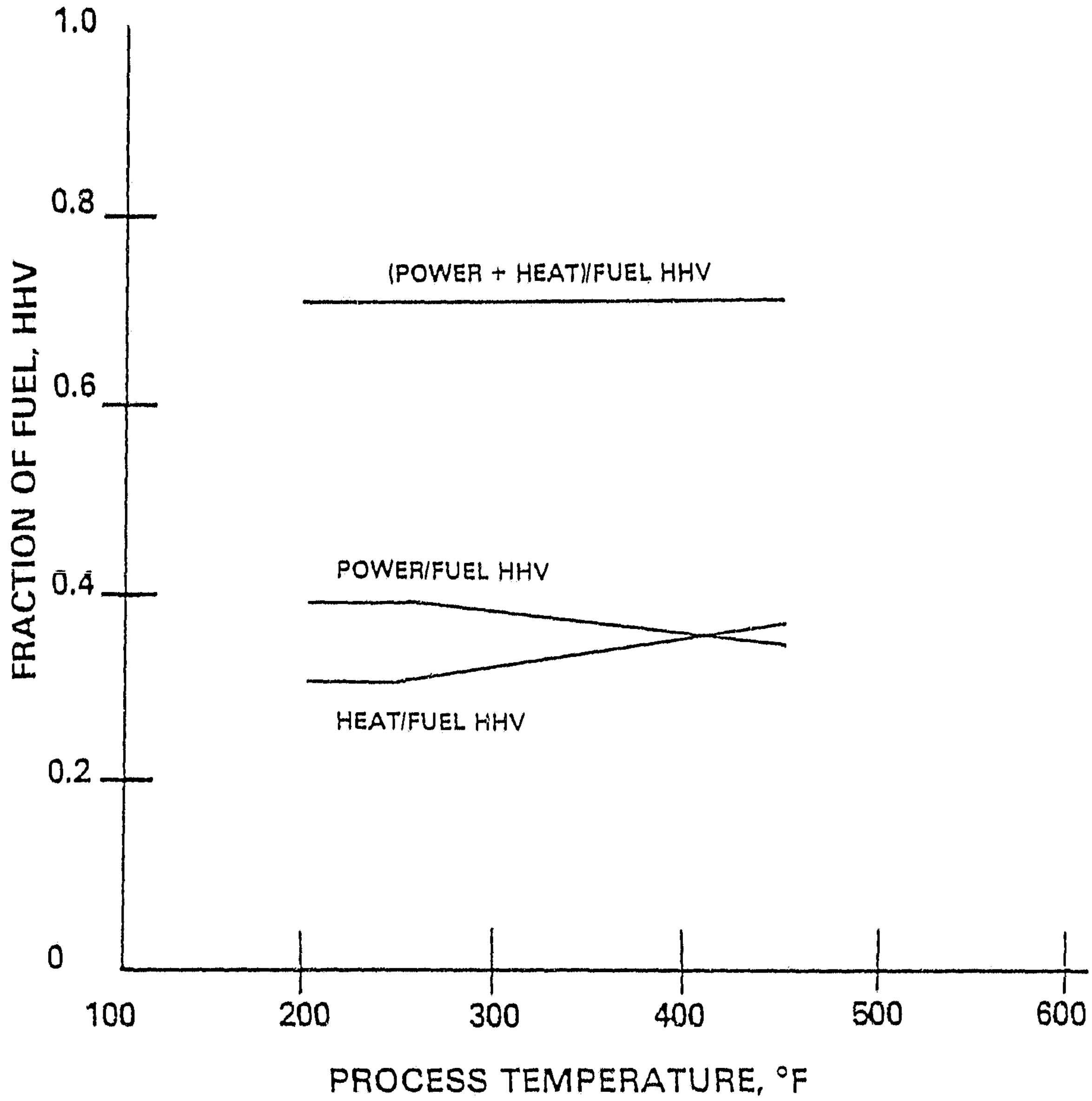


Figure 6.5-14. Energy Conversion System Characteristics. Combined Gas Turbine-Non-Condensing Steam Turbine; Pressure Ratio, 12; Firing Temperature, 2200°F; Air-Cooled Gas Turbine; Residual Fuel; 1465 psia, 1000°F Steam Turbine; Applicable Size, 14 to 143 MW; Available, 1985

CC0822 GTST-08/2200/1465-AC 14 MW/136 MW 1985

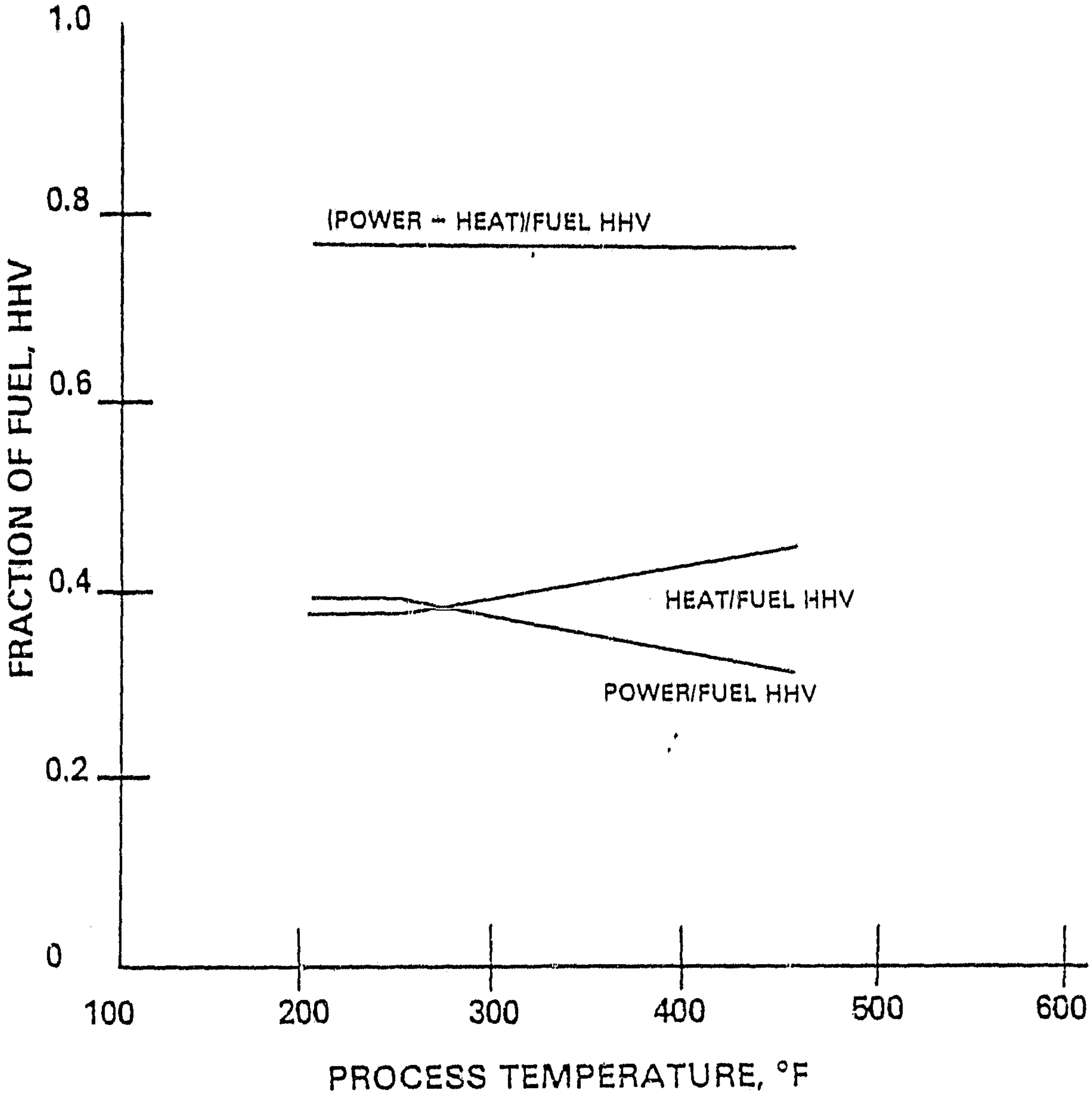


Figure 6.5-15. Energy Conversion System Characteristics. Combined Gas Turbine-Non-Condensing Steam Turbine; Pressure Ratio, 8; Firing Temperature, 2200°F; Air-Cooled Gas Turbine; Residual Fuel; 1465 psia, 1000°F Steam Turbine; Applicable Size, 14 to 136 MW; Available, 1985

STIG15 STIG-15-16/2200F-AC 22 MW/220 MW 1990

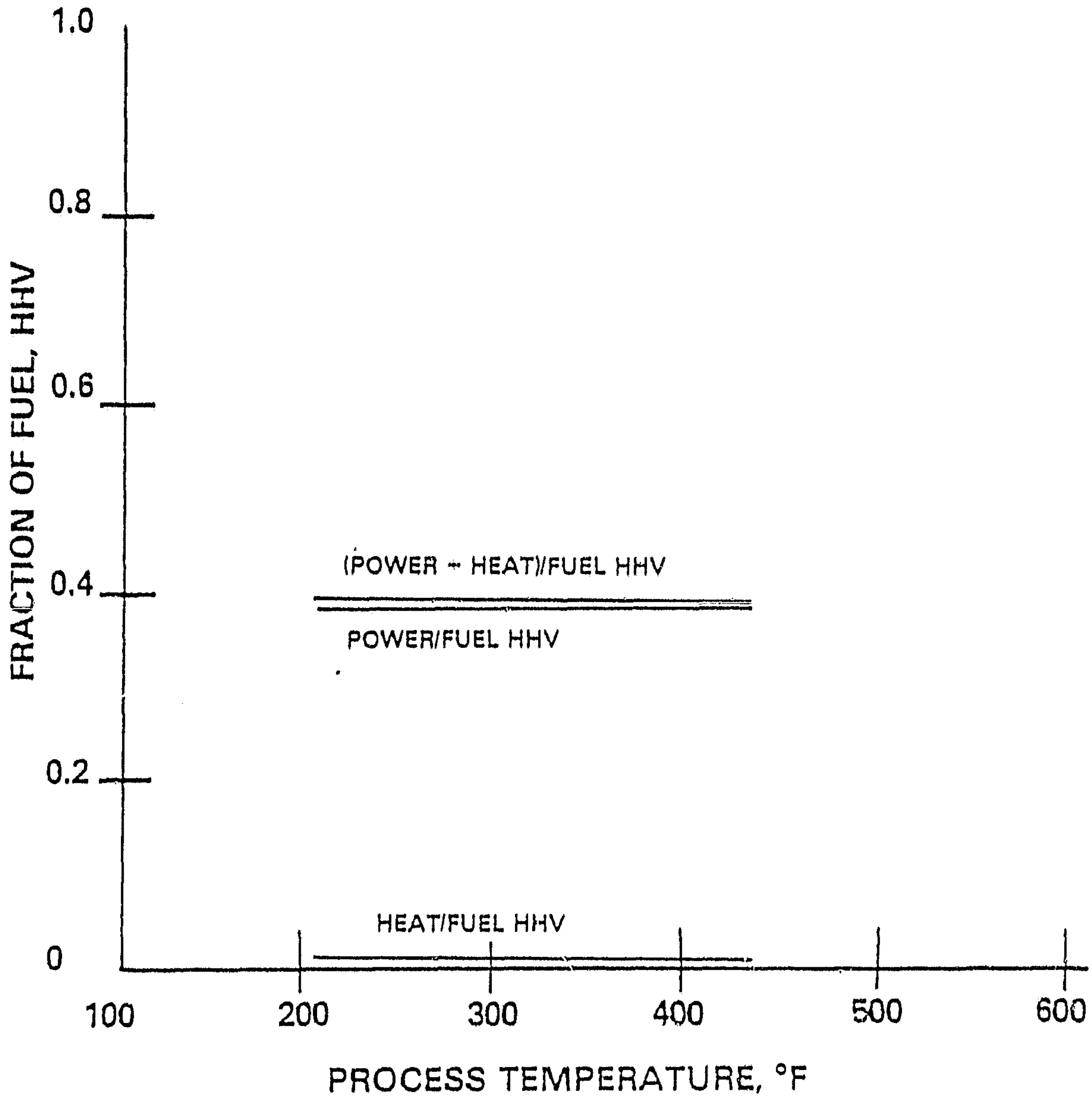


Figure 6.5-16. Energy Conversion System Characteristics. Gas Turbine Steam Injected, HRSG Steam to Process. Pressure Ratio, 16; Firing Temperature, 2200°F; Air-Cooled; Residual Fuel; Steam to Turbine is 15% of Airflow and Superheated; Applicable Size, 22 to 220 MW; Available, 1990

STIG10 STIG-10-16/2200F-AC 19 MW/190 MW 1990

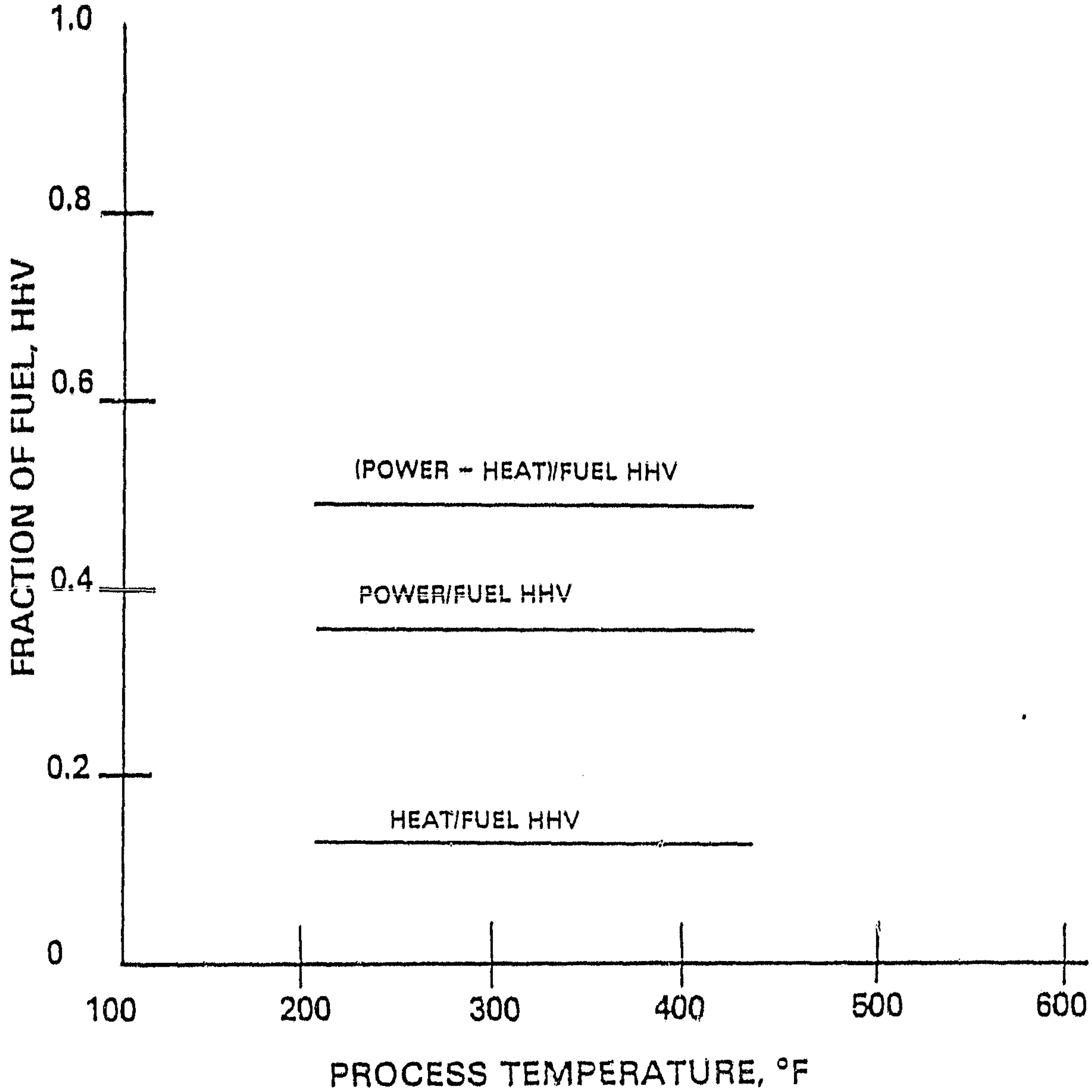


Figure 6.5-17. Energy Conversion System Characteristics. Gas Turbine Steam Injected, HRSG Steam to Process. Pressure Ratio, 16; Firing Temperature, 2200°F; Air-Cooled; Residual Fuel; Steam to Turbine is 10% of Airflow and Superheated. Applicable Size, 19 to 190 MW; Available, 1990

STIGIS STIG-IS-16/2200F-AC 19 MW/190 MW 1990

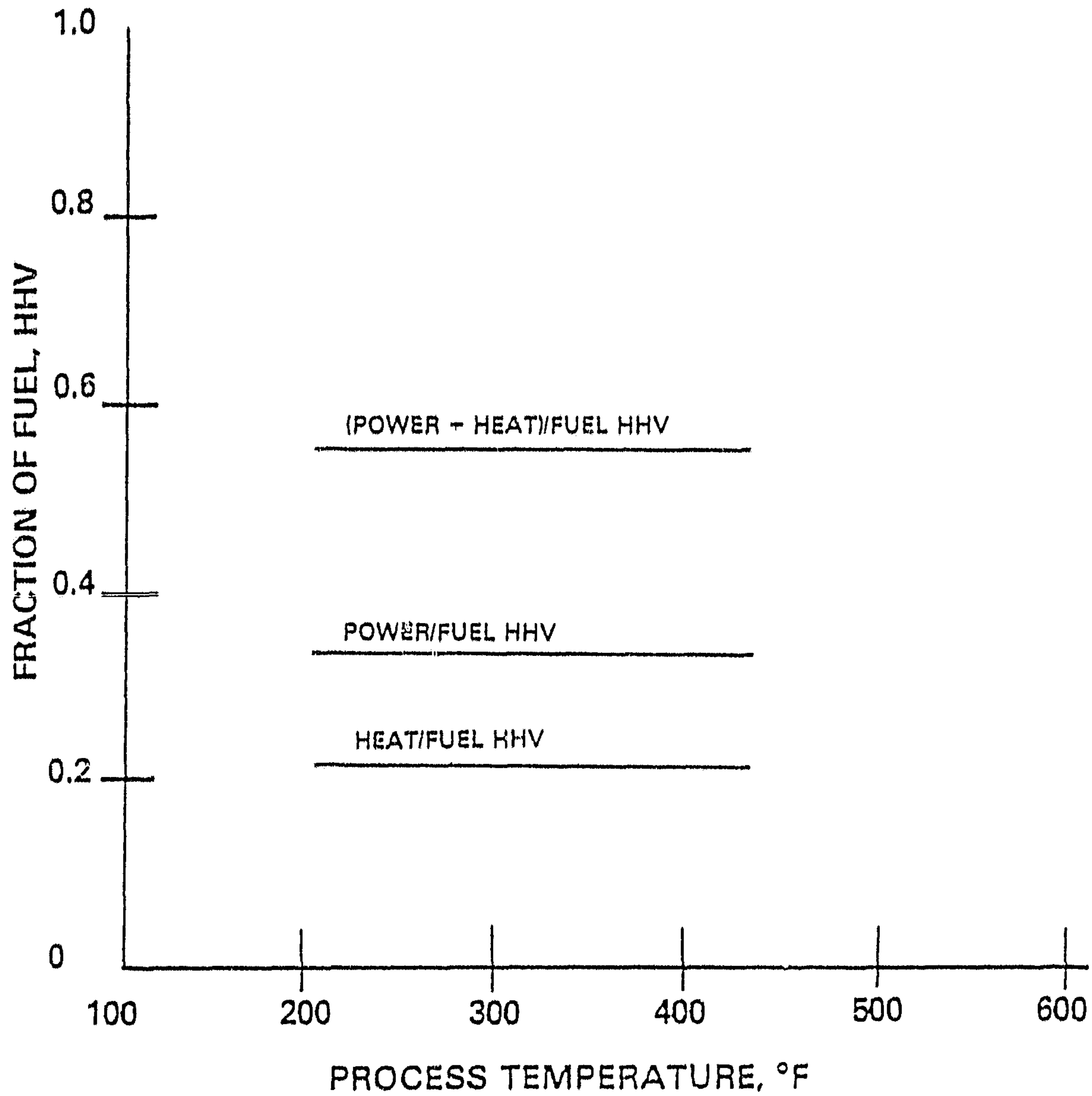


Figure 6.5-18. Energy Conversion System Characteristics. Gas Turbine Steam Injected, HRSG Steam to Process. Pressure Ratio, 16; Firing Temperature, 2200°F; Air-Cooled; Residual Fuel; Steam to Turbine is 10% of Airflow and Saturated. Applicable Size, 19 to 190 MW; Available, 1990

GTSOAD GT-HRSG-10/2000D-AC 13 MW/72 MW 1978

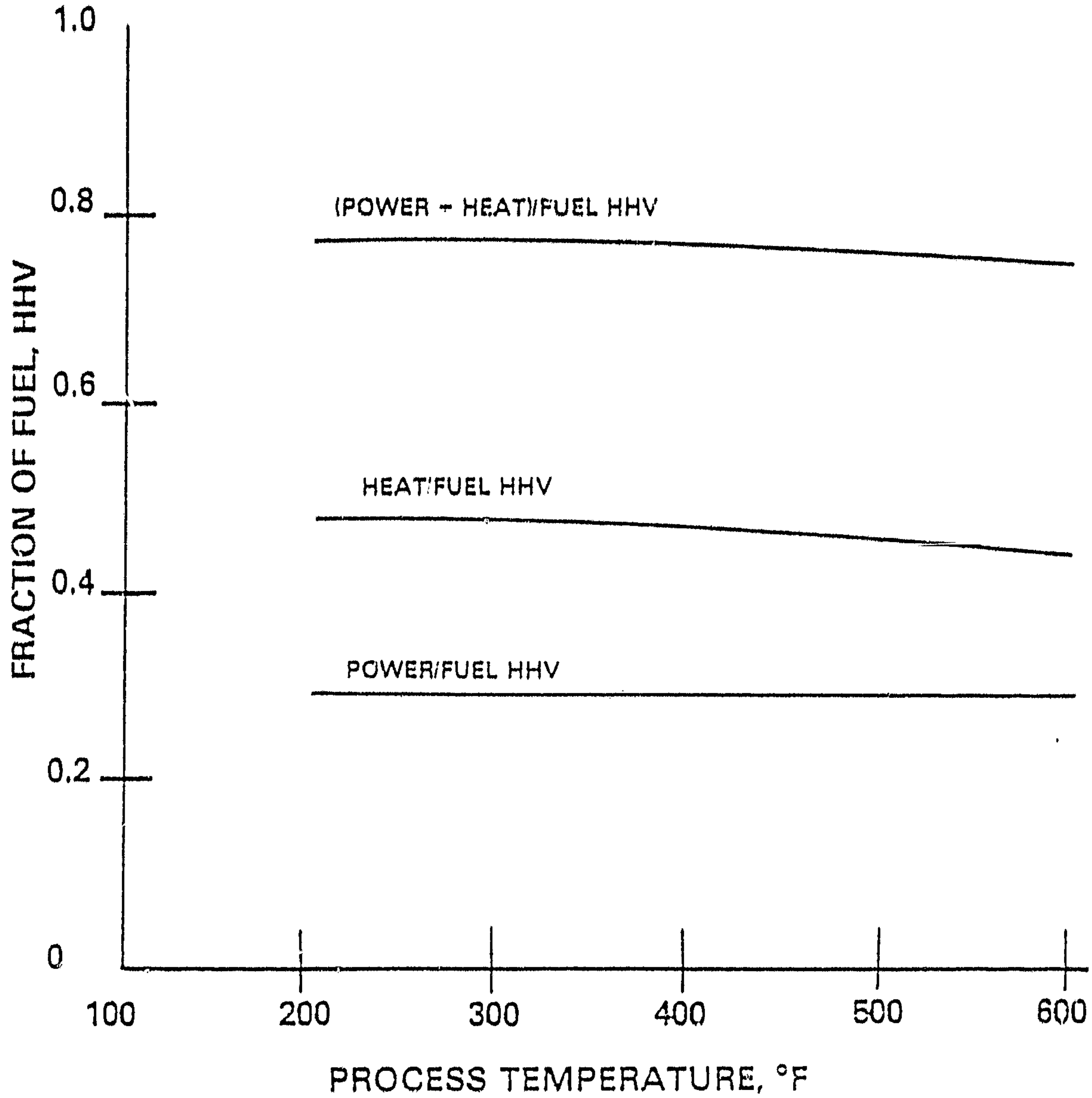


Figure 6.5-19. Energy Conversion System Characteristics. Gas Turbine, Air-Cooled, HRSG Steam to Process. Pressure Ratio, 10; Firing Temperature, 2000°F; Distillate Fuel; Applicable Size, 13 to 72 MW; Available, 1978

GTRA08 GT-85RE-08/2200D-AC 13 MW/130 MW 1985

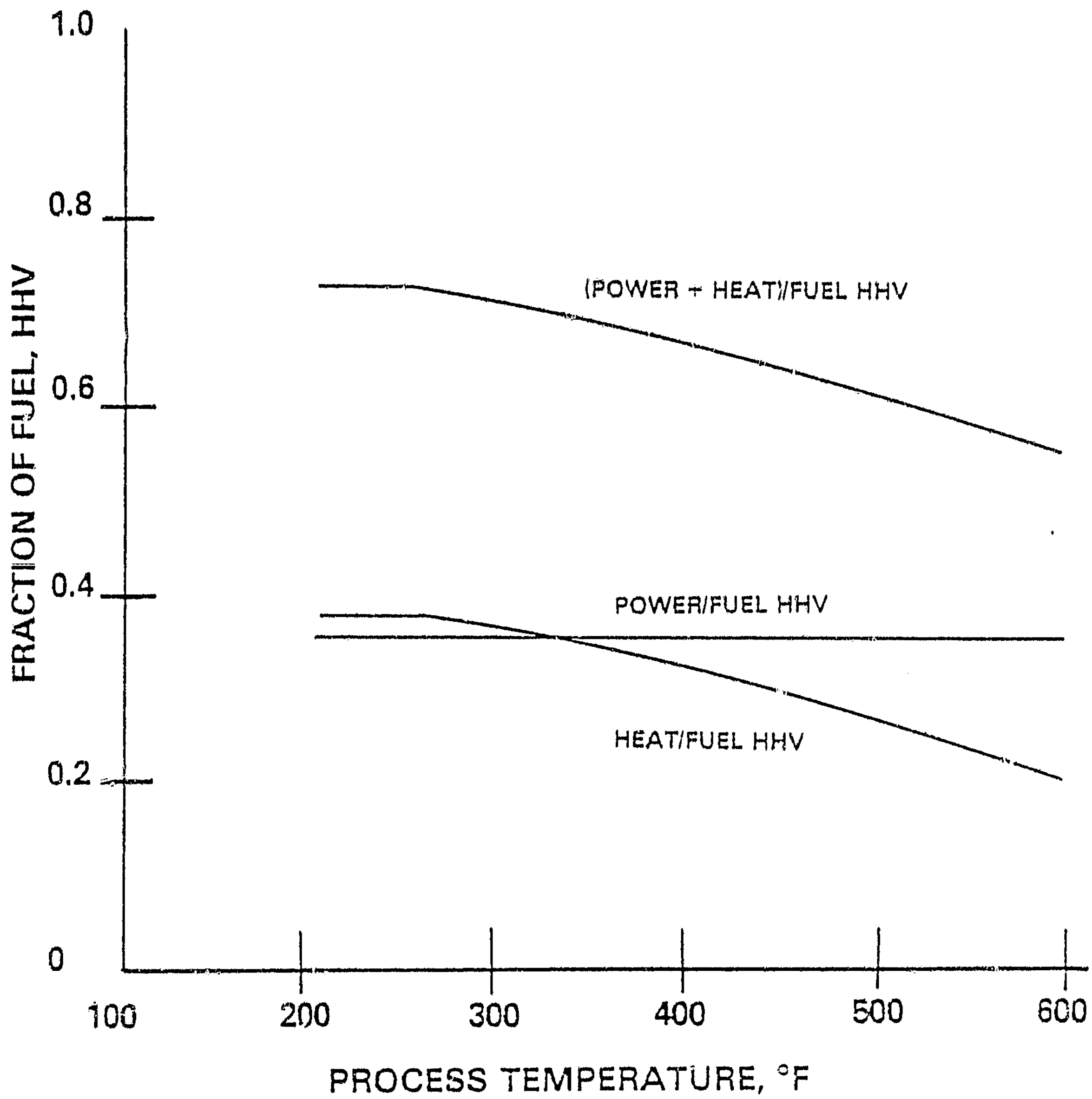


Figure 6.5-20. Energy Conversion System Characteristics. Gas Turbine, Air-Cooled; Regenerator Effectiveness, 85%; Pressure Ratio, 8; Applicable Size, 13 to 130 MW; Distillate Fuel; Available, 1985

GTRA12 GT-85RE-12/2200D-AC 14 MW/137 MW 1985

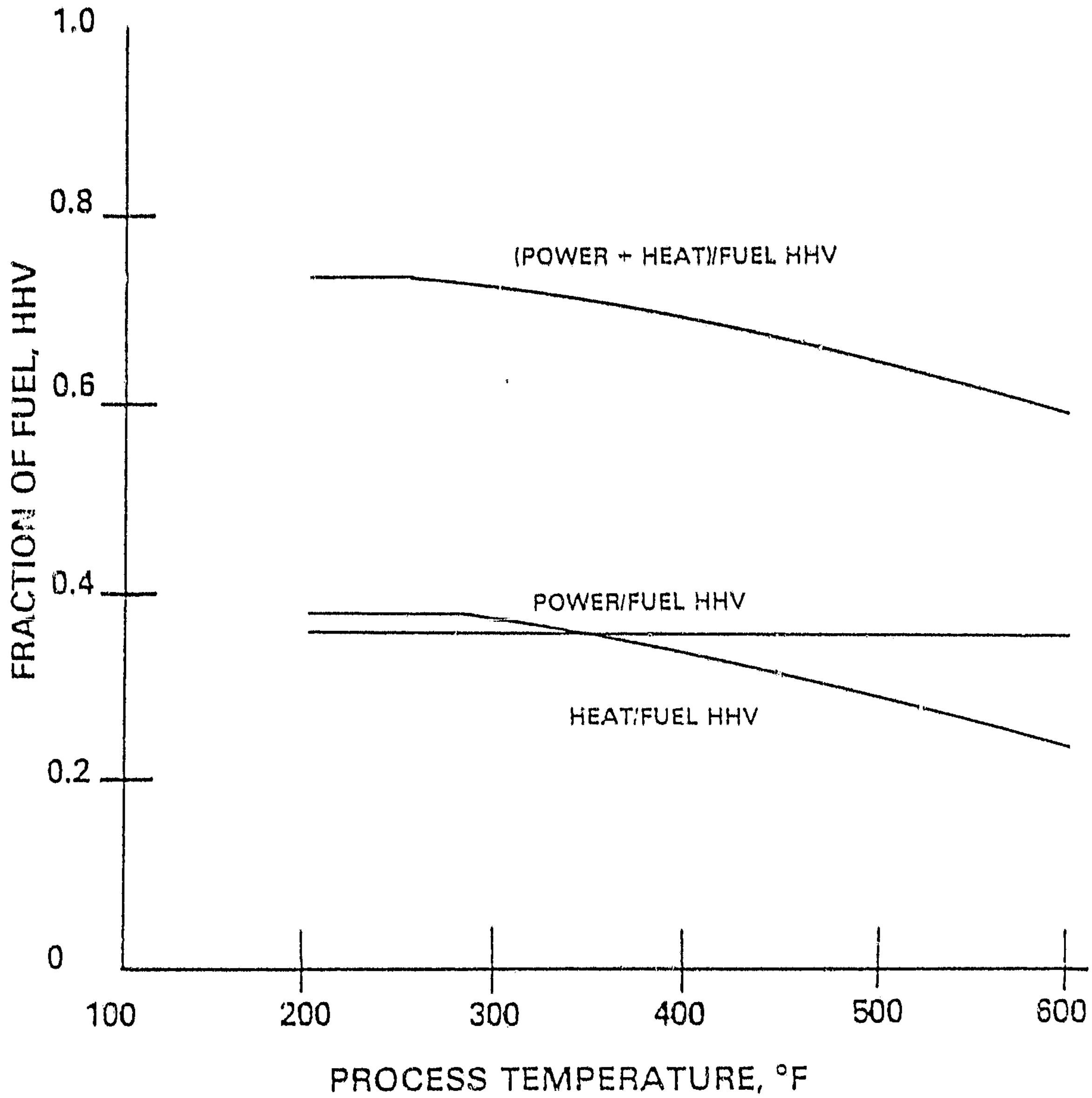


Figure 6.5-21. Energy Conversion System Characteristics. Gas Turbine, Air-Cooled. Regenerator Effectiveness, 85%; Pressure Ratio, 12; Firing Temperature, 2200°F; Distillate Fuel; Applicable Size, 14 to 137 MW; Available, 1985

GTRA16 GT-85RE-16/2200D-AC 14 MW/138 MW 1990

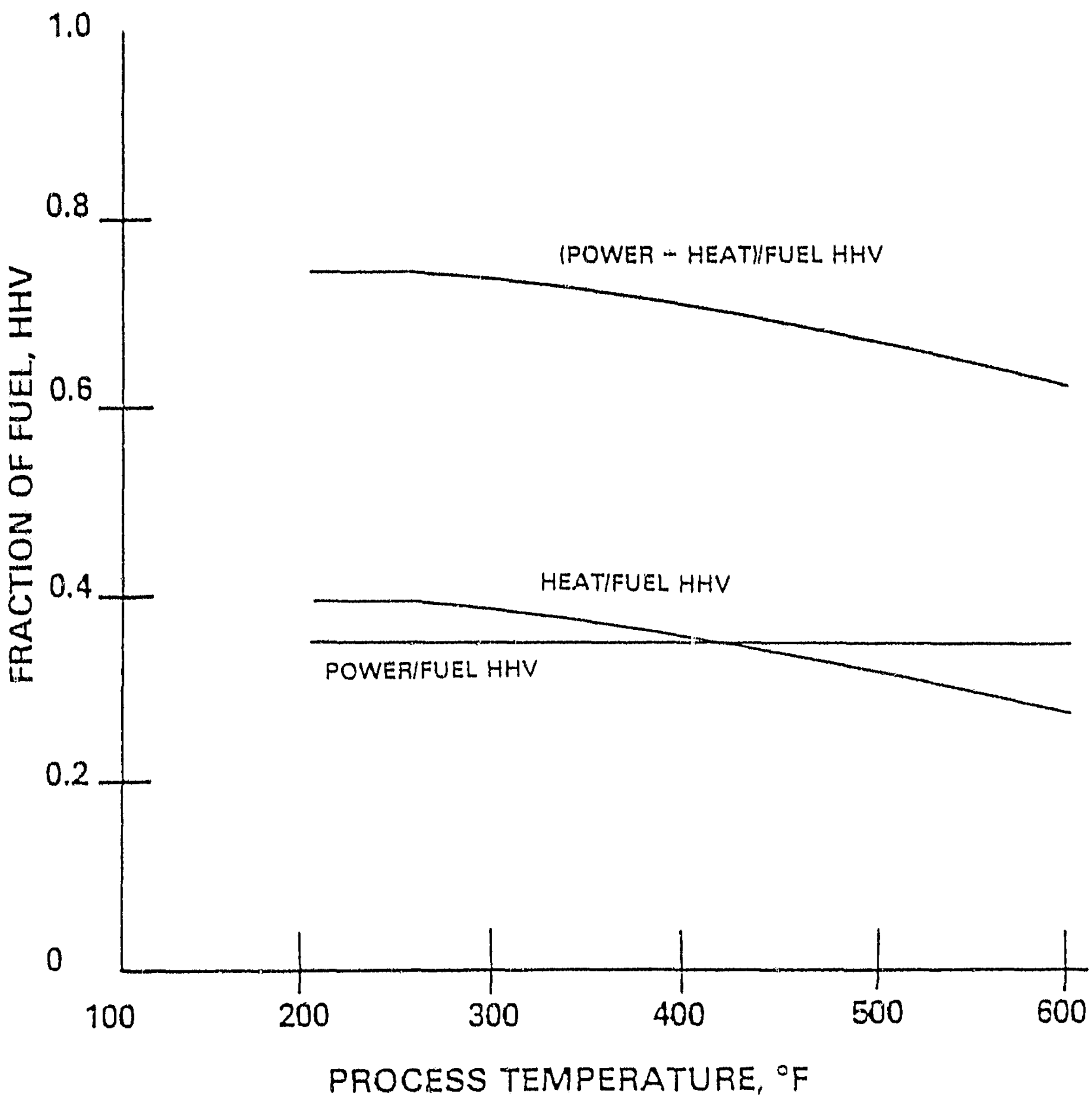


Figure 6.5-22. Energy Conversion System Characteristics. Gas Turbine, Air-Cooled. Regenerator Effectiveness, 85%; Pressure Ratio, 16; Firing Temperature, 2200°F; Distillate Fuel; Applicable Size, 14 to 138 MW; Available, 1990

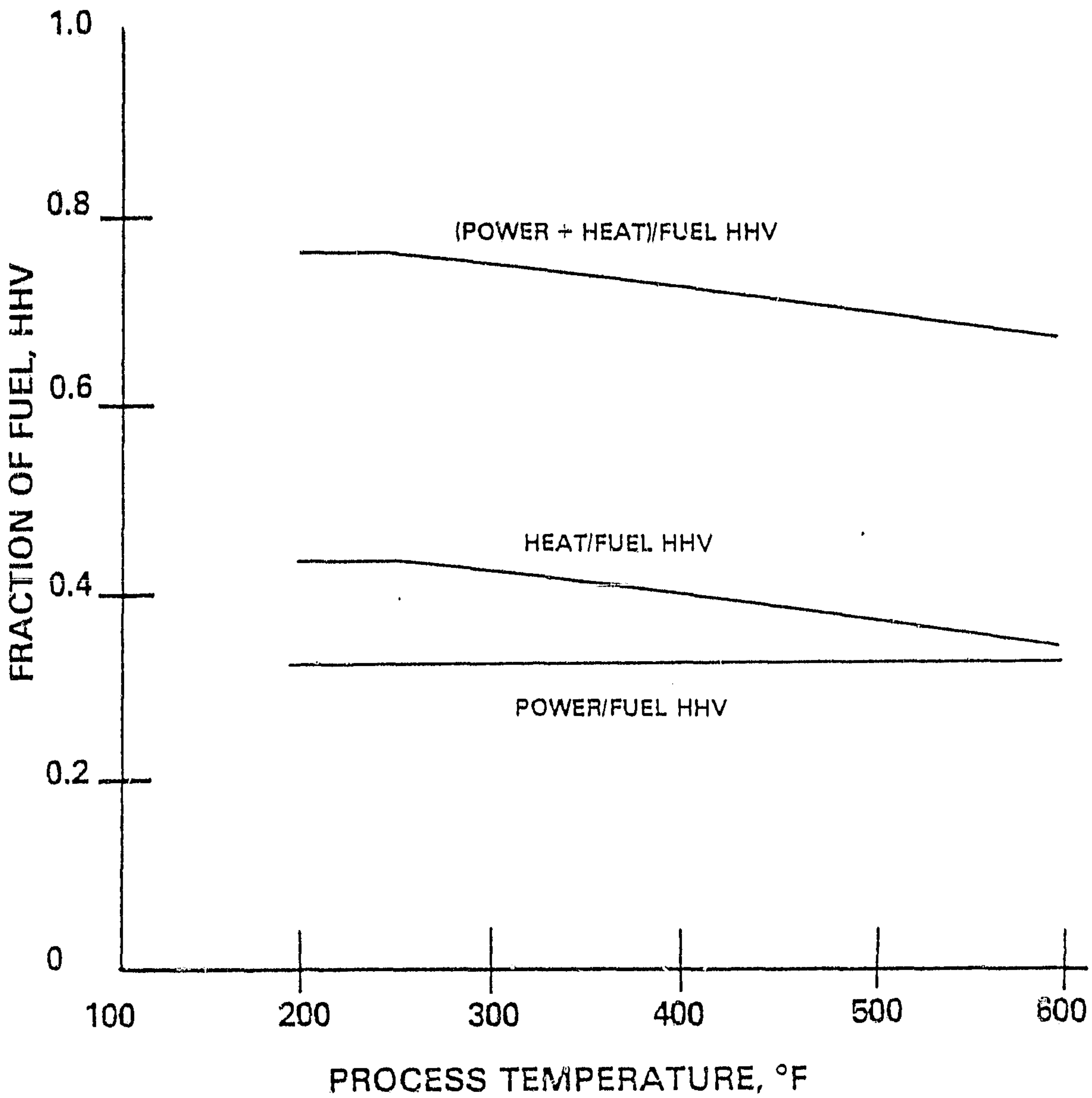


Figure 6.5-23. Energy Conversion System Characteristics. Gas Turbine, Air-Cooled. Regenerator Effectiveness, 60%; Pressure Ratio, 8; Firing Temperature, 2200^{0}F; Distillate Fuel; Applicable Size, 13 to 130 MW; Available, 1985

GTR212 GT-60RE-12/2200D-AC 14 MW/138 MW 1985

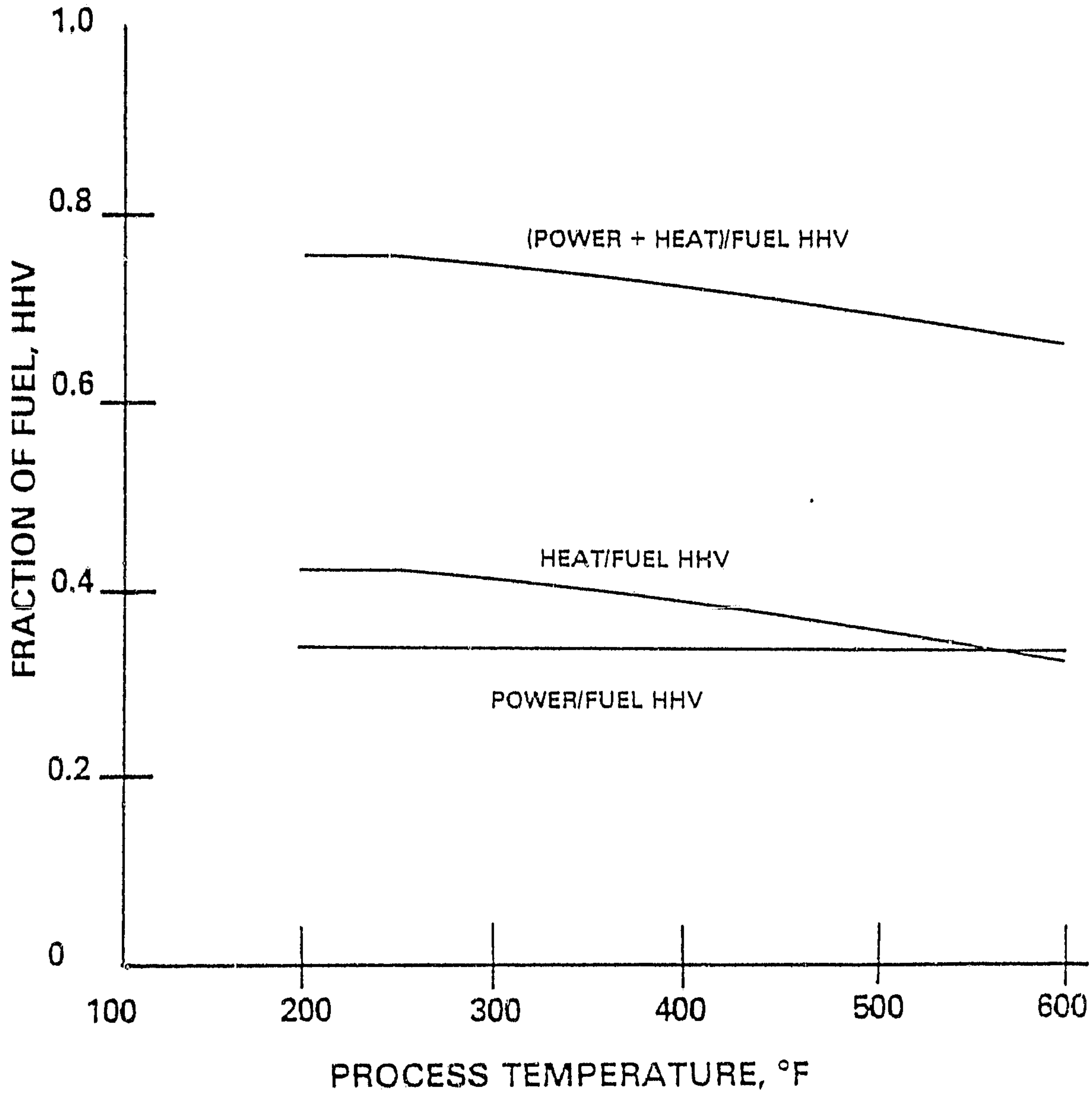


Figure 6.5-24. Energy Conversion System Characteristics. Gas Turbine, Air-Cooled. Regenerator Effectiveness, 60%; Pressure Ratio, 12; Firing Temperature, 2200°F; Distillate Fuel; Applicable Size, 14 to 138 MW; Available, 1985

GTR216 GT-60RE-16/2200D-AC 14 MW/139 MW 1990

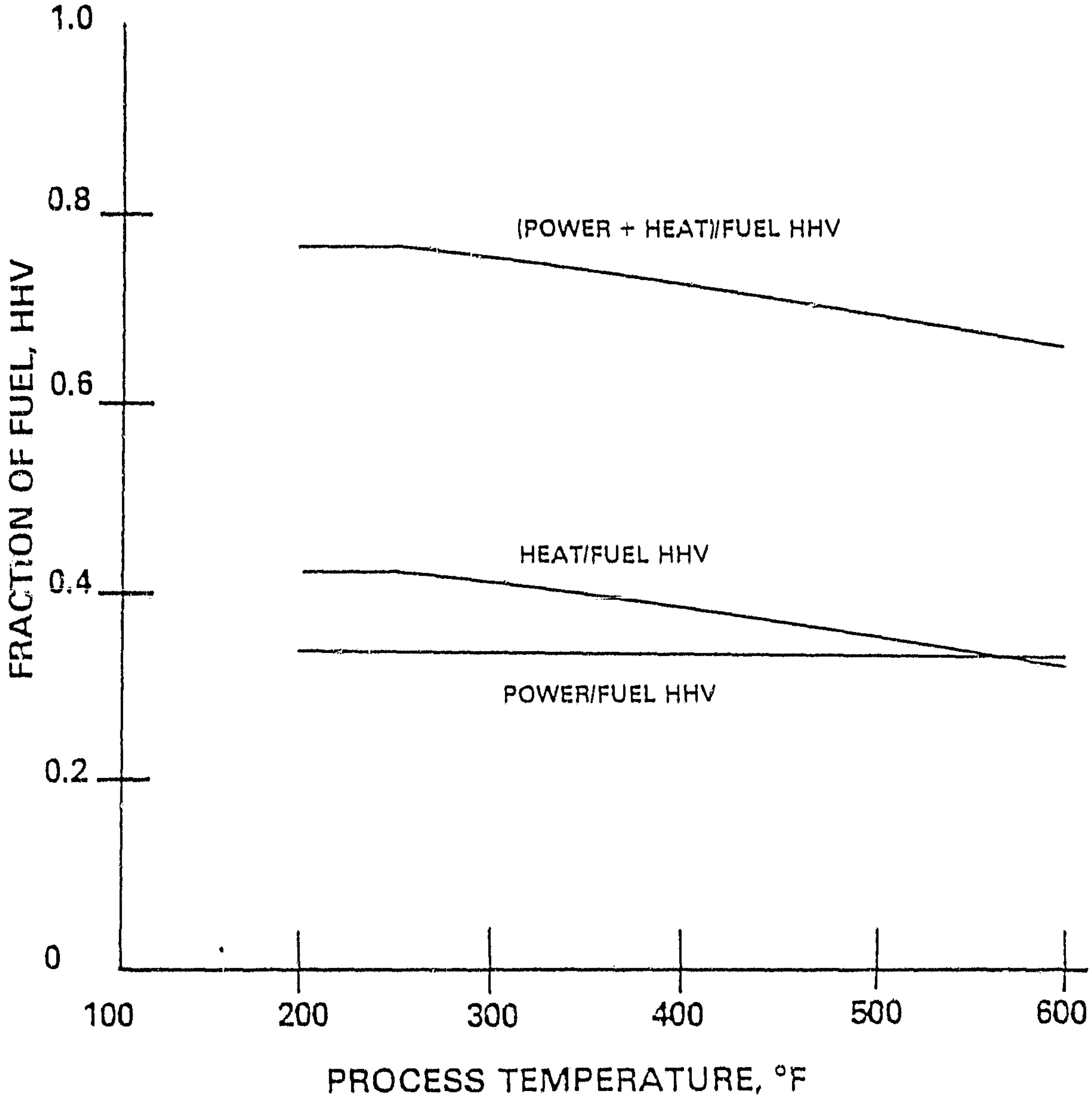


Figure 6.5-25. Energy Conversion System Characteristics. Gas Turbine, Air-Cooled. Regenerator Effectiveness, 60%; Pressure Ratio, 16; Firing Temperature, 2200°F; Distillate Fuel; Applicable Size, 14 to 139 MW; Available, 1990

GTRW08 GT-85RE-08/2600D-WC 27 MW/169 MW 1990

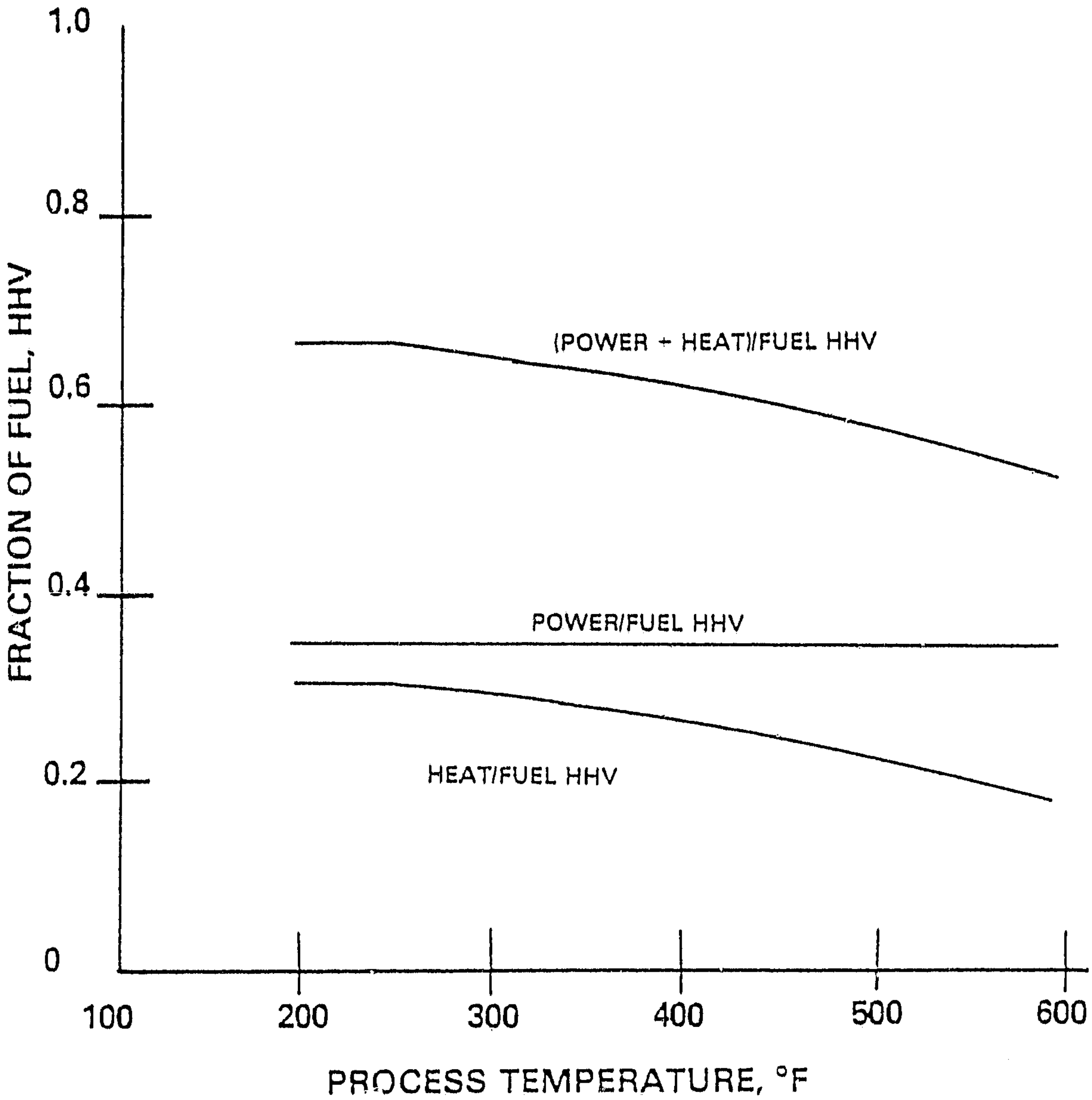


Figure 6.5-26. Energy Conversion System Characteristics. Gas Turbine, Water-Cooled. Regenerator Effectiveness, 85%; Pressure Ratio, 8; Firing Temperature, 2600°F; Distillate Fuel; Applicable Size, 17 to 169 MW; Available, 1990

GTRW12 GT-85RE-12/2600D-WC 19 MW/188 MW 1990

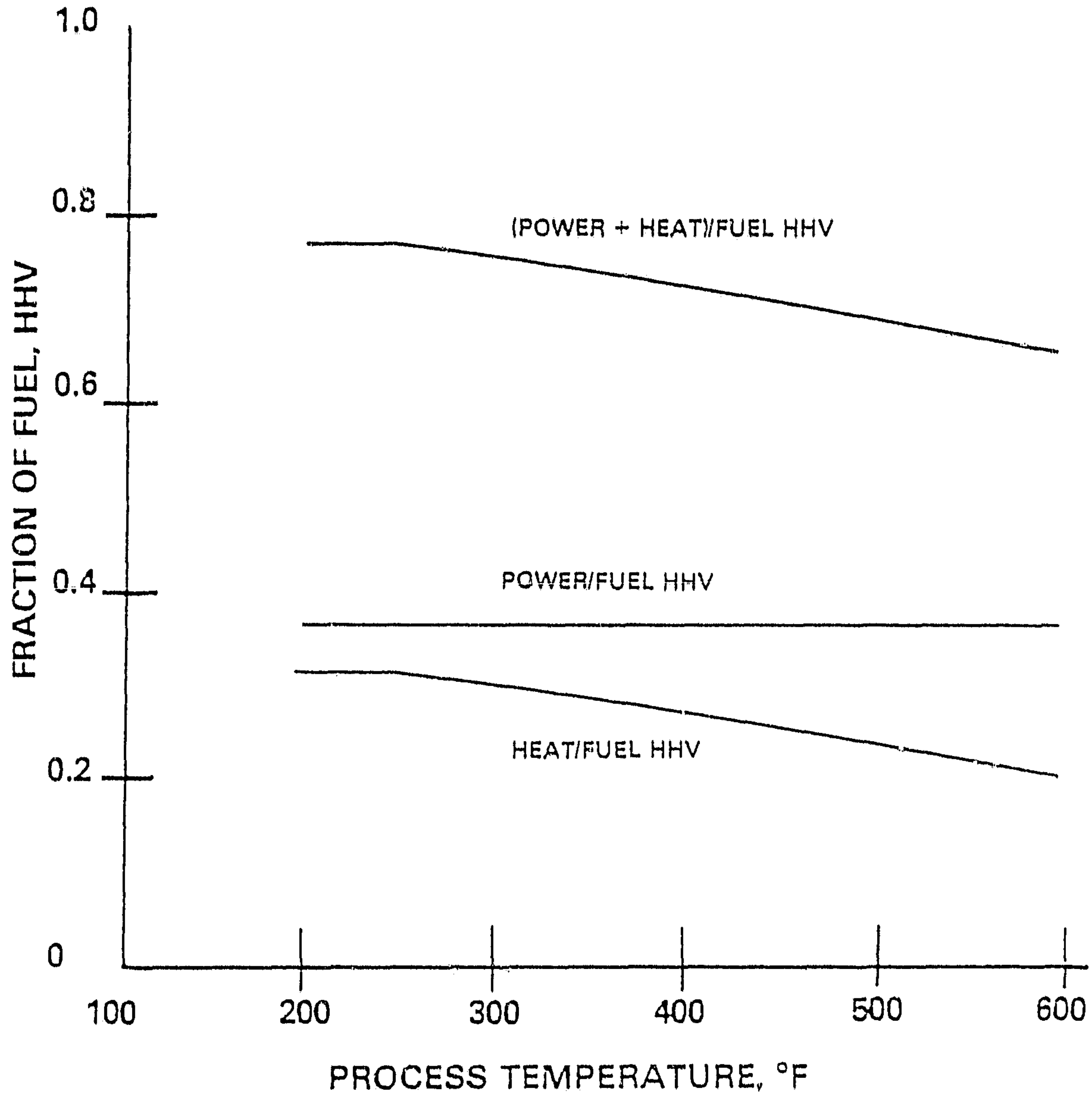


Figure 6.5-27. Energy Conversion System Characteristics. Gas Turbine, Water-Cooled. Regenerator Effectiveness, 85%; Pressure Ratio, 12; Firing Temperature, 2600°F; Distillate Fuel; Applicable Size, 19 to 188 MW; Available, 1990

GTRW16 GT-85RE-16/2600D-WC 19 MW/190 MW 1990

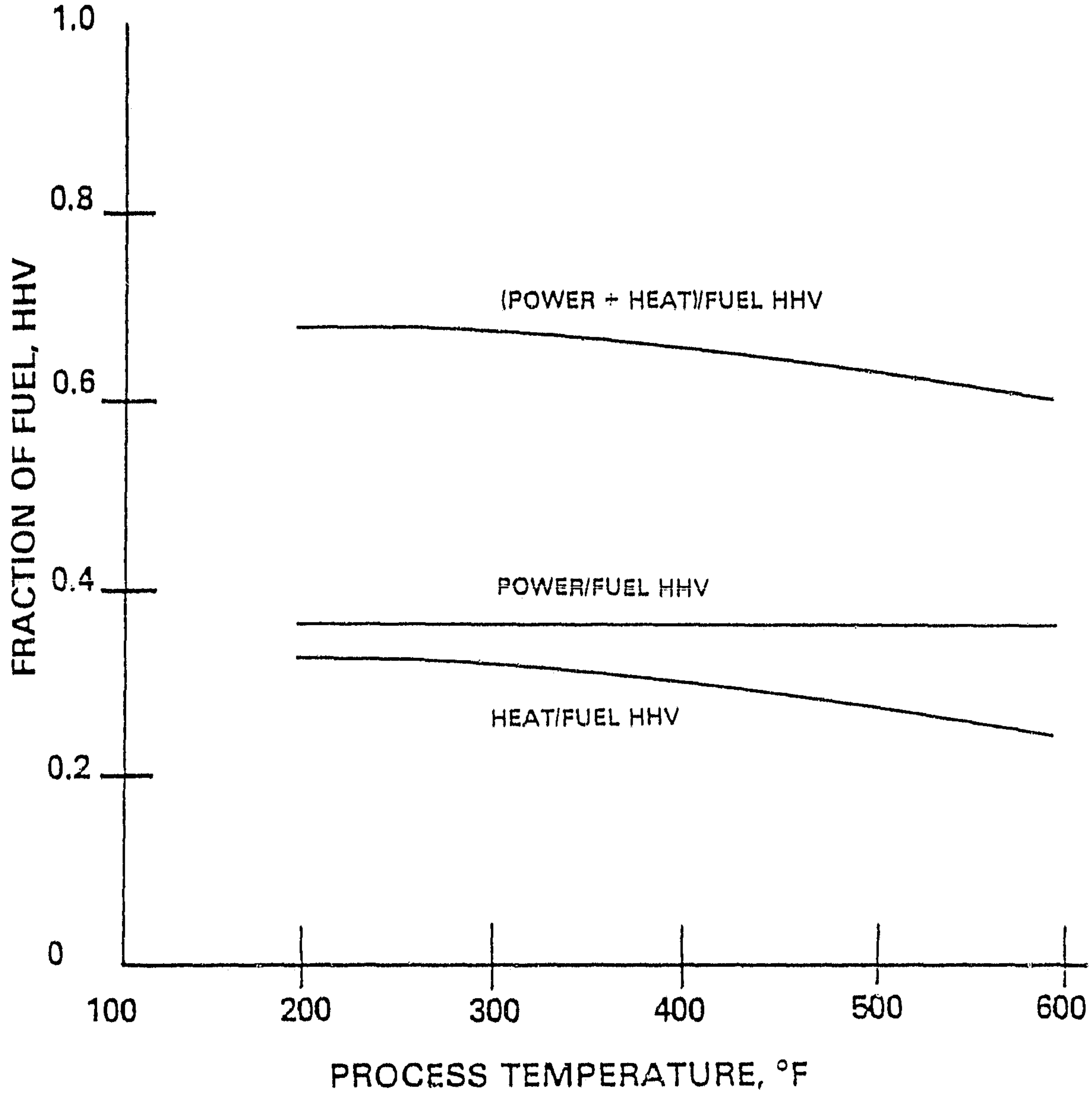


Figure 6.5-28. Energy Conversion System Characteristics. Gas Turbine, Water-Cooled. Regenerator Effectiveness, 85%; Pressure Ratio, 16; Firing Temperature, 2600°F; Distillate Fuel; Applicable Size, 19 to 190 MW; Available, 1990

GTR308 GT60RE-08/2600D-WC 17 MW/170 MW 1990

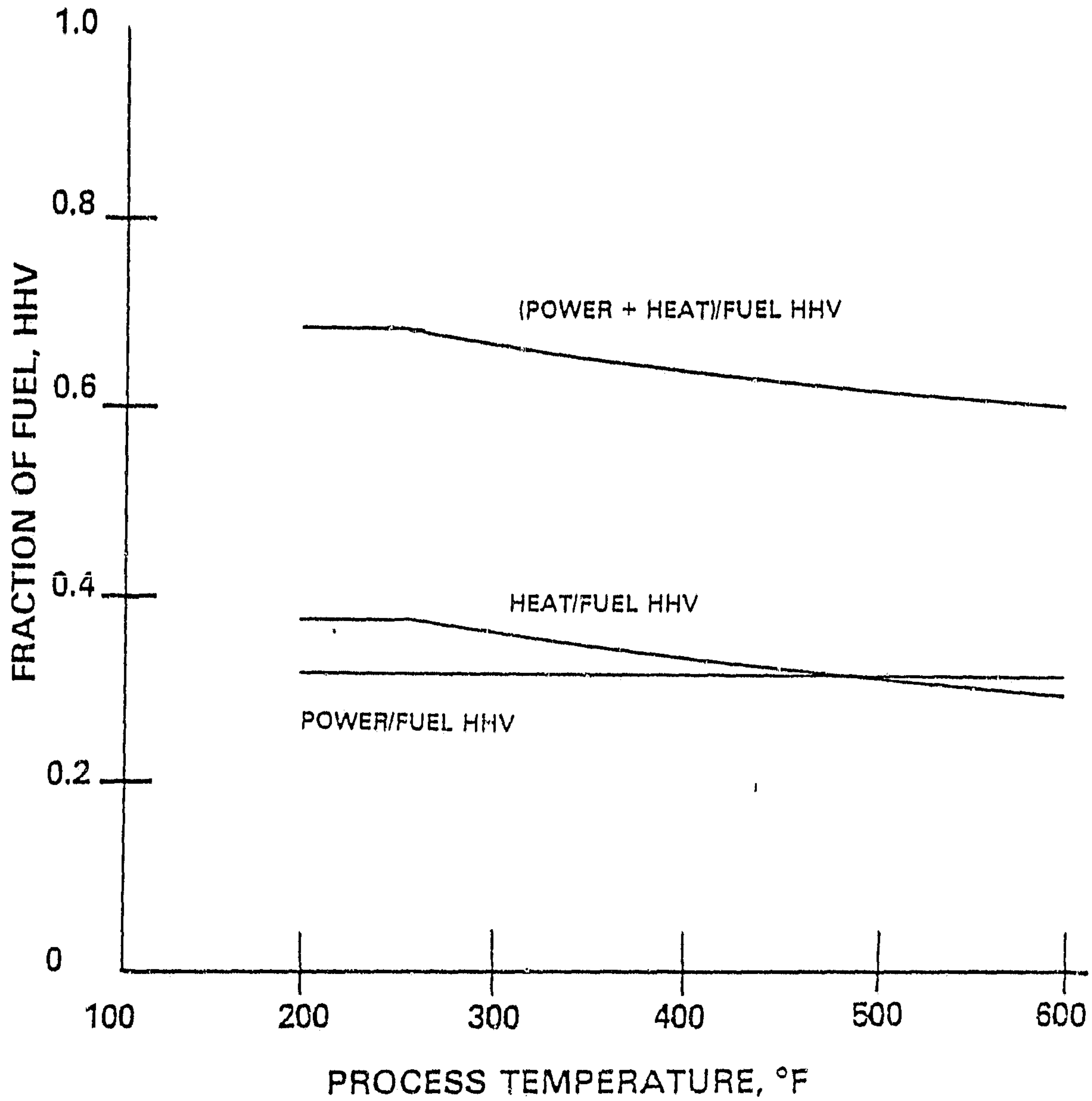


Figure 6.5-29. Energy Conversion System Characteristics. Gas Turbine, Water-Cooled. Regenerator Effectiveness, 60%; Pressure Ratio, 8; Firing Temperature, 2600°F; Distillate Fuel; Applicable Size, 17 to 170 MW; Available, 1990

GTR312 GT6ORE-12/2600D-WC 19 MW/190 MW 1990

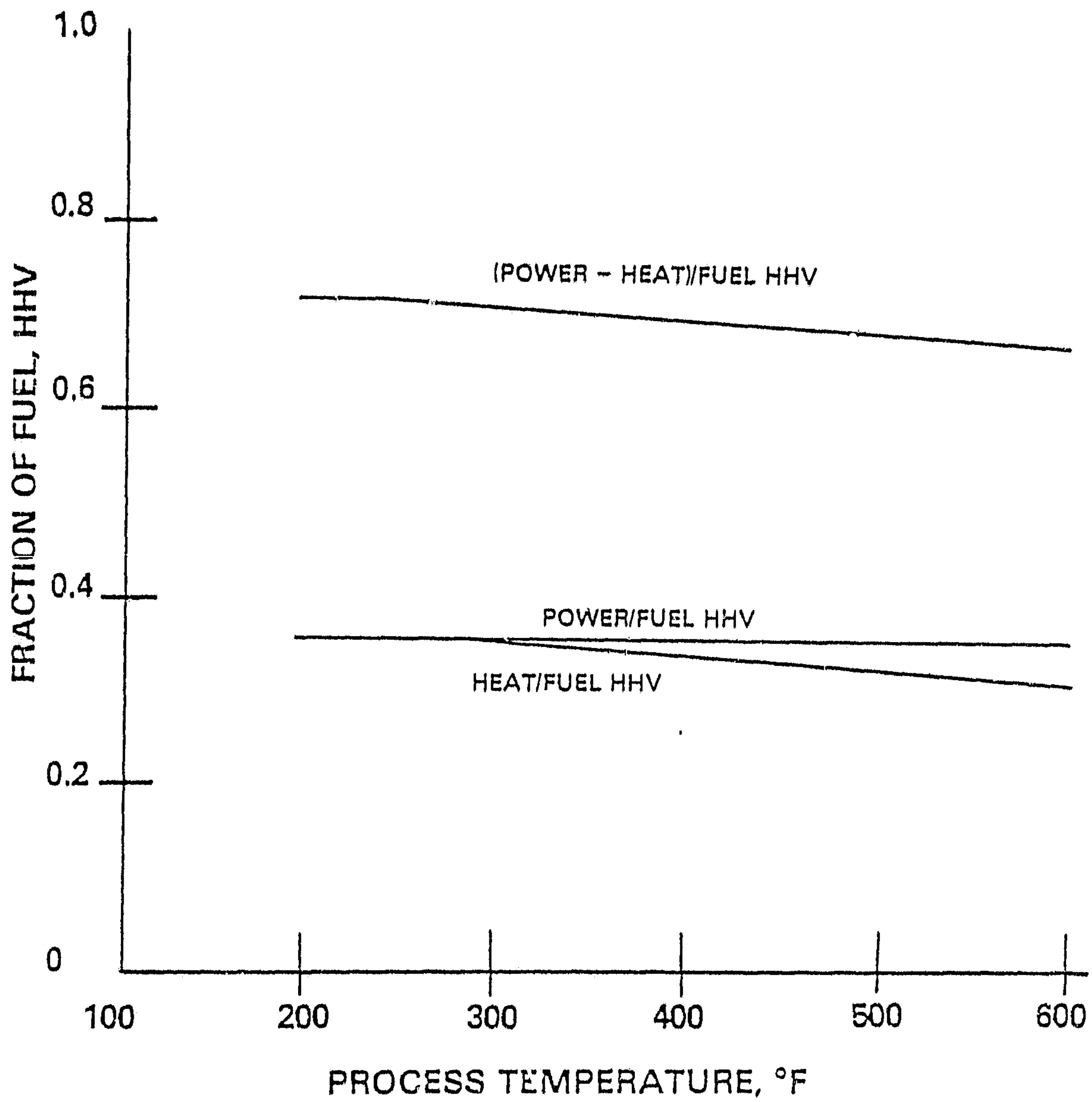


Figure 6.5-30. Energy Conversion System Characteristics. Gas Turbine, Water-Cooled. Regenerator Effectiveness, 60%; Pressure Ratio, 12; Firing Temperature, 2600°F; Distillate Fuel; Applicable Size, 19 to 190 MW; Available, 1990

GTR316 GT-60RE-16/2600D-WC 19 MW/190 MW 1990

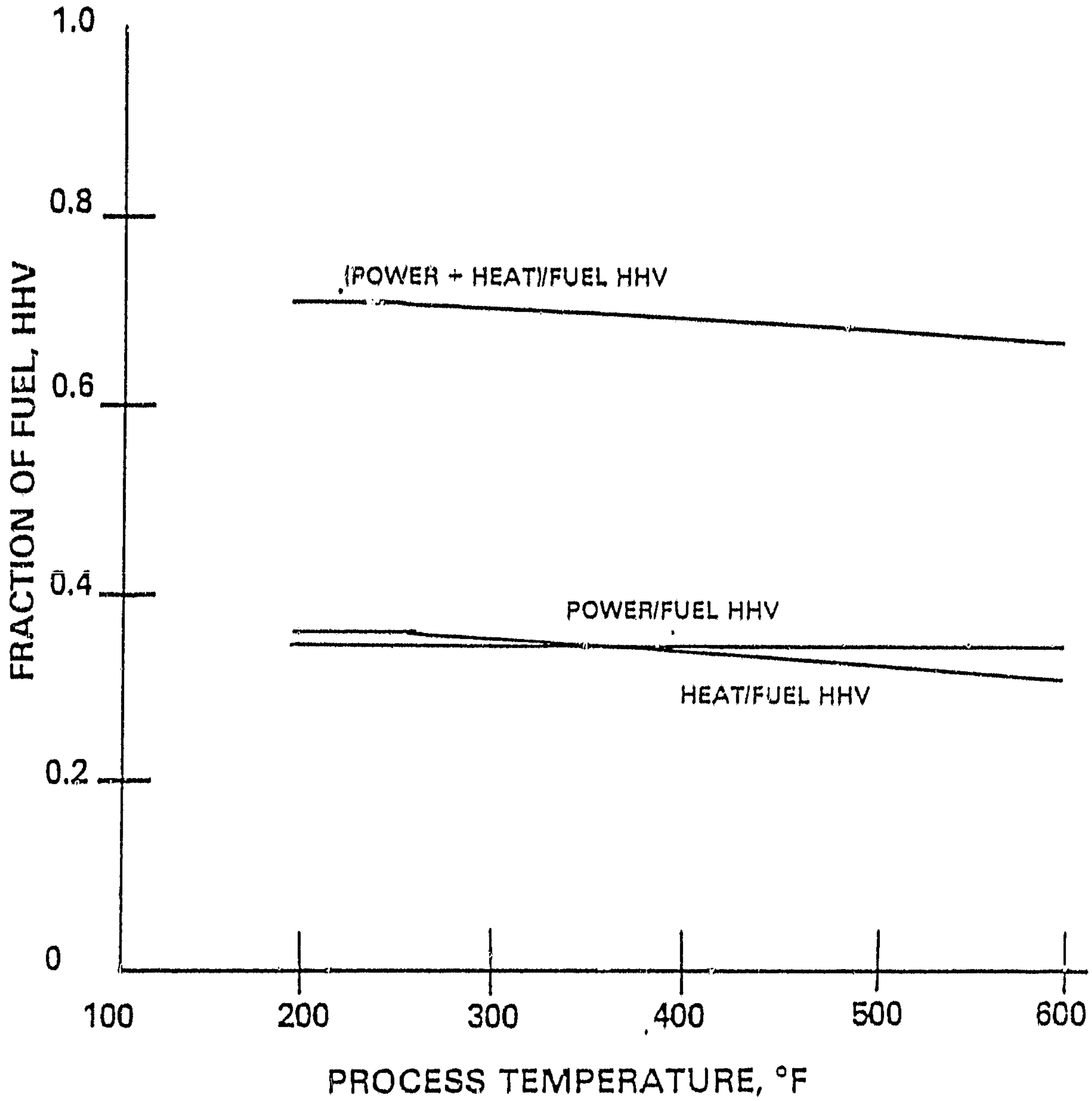


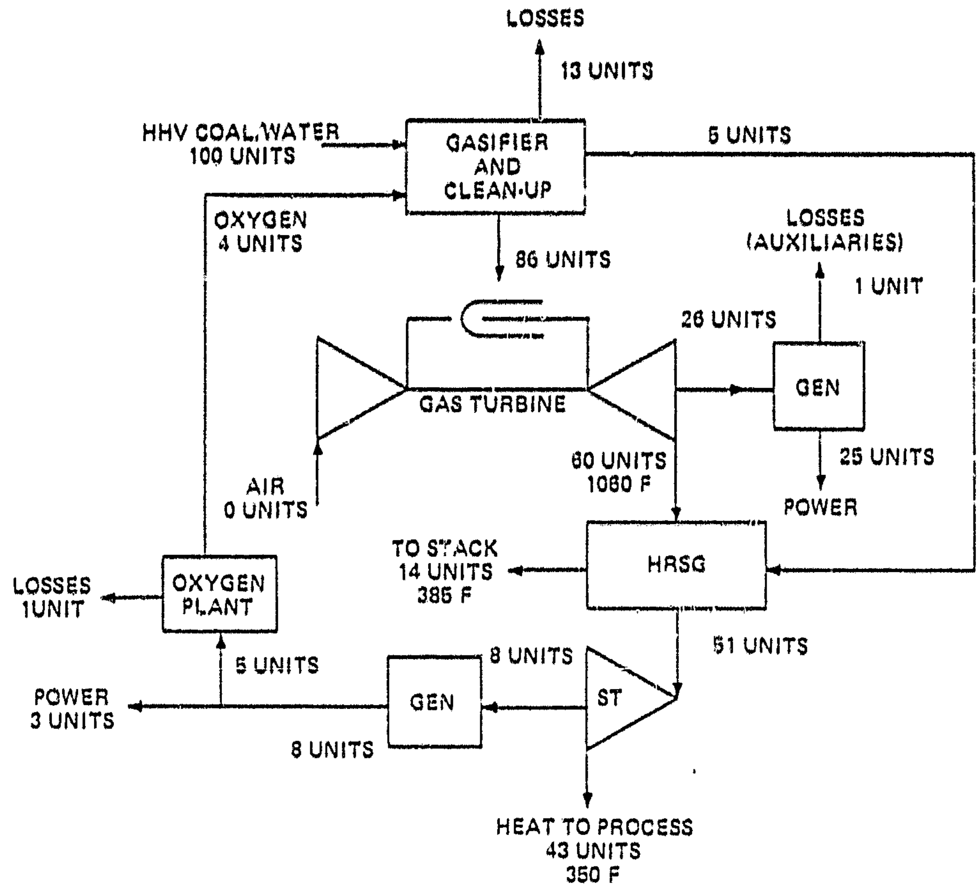
Figure 6.5-31. Energy Conversion System Characteristics. Gas Turbine, Water-Cooled. Regenerator Effectiveness, 60%; Pressure Ratio, 16; Firing Temperature, 2600°F; Distillate Fuel; Applicable Size, 19 to 190 MW; Available, 1990

Integrated Gasifier Combined Cycle ECS

Lurgi coal gasifiers produce a low-Btu fuel gas from the interaction of coal, steam, and air. An intermediate-Btu gas results when oxygen is used in place of air. The advanced entrained bed Texaco gasifier would operate at high pressure to produce a fuel gas adaptable to gas turbine firing after appropriate cleanup to remove particulates, sulfur and other deleterious components. Figure 6.5-32 presents a schematic and sample heat balance for such a gasifier used in conjunction with a gas turbine and non-condensing steam turbine combined cycle cogeneration power plant.

The gas turbine would be of advanced design and specially adapted to handle the high volume of combustion fuel gas. The firing temperature would be 2100 F, the compressor pressure ratio would be 12, and the first turbine stage nozzles would be water-cooled. The greater mass flow of combustion gases as compared to a conventional gas turbine produce greater generator output and more steam from the HRSG. The non-condensing steam turbine produces about one fifth of the total power output at 350 F process temperature. Steam conditions would be 1465 psia, 1000 F. As process temperature is varied the steam turbine power would vary, but the sum of steam turbine power and heat to process would remain constant at 51 units. The gas turbine generator output would be constant at 25 units and the oxygen plant power and auxiliaries constant at 6 units. The cogeneration characteristics are presented in Figure 6.5-33.

Advanced art for this coal-fueled gas turbine and steam turbine would be the gasifier, the gas cleanup system, the gas turbine, and the system integration and control.



FUEL: COAL

VARIABLES: PROCESS TEMPERATURE
STEAM TURBINE EXHAUST PRESSURE

RANGE: 30 MW - 500 MW

ADVANCED ART: GASIFIER, GAS CLEANUP, GAS TURBINE
SYSTEM INTEGRATION

Figure 6.5-32. Integrated Gasifier-Gas Turbine Cogenerator

IGGTST INT-GAS-GTST-12/2100

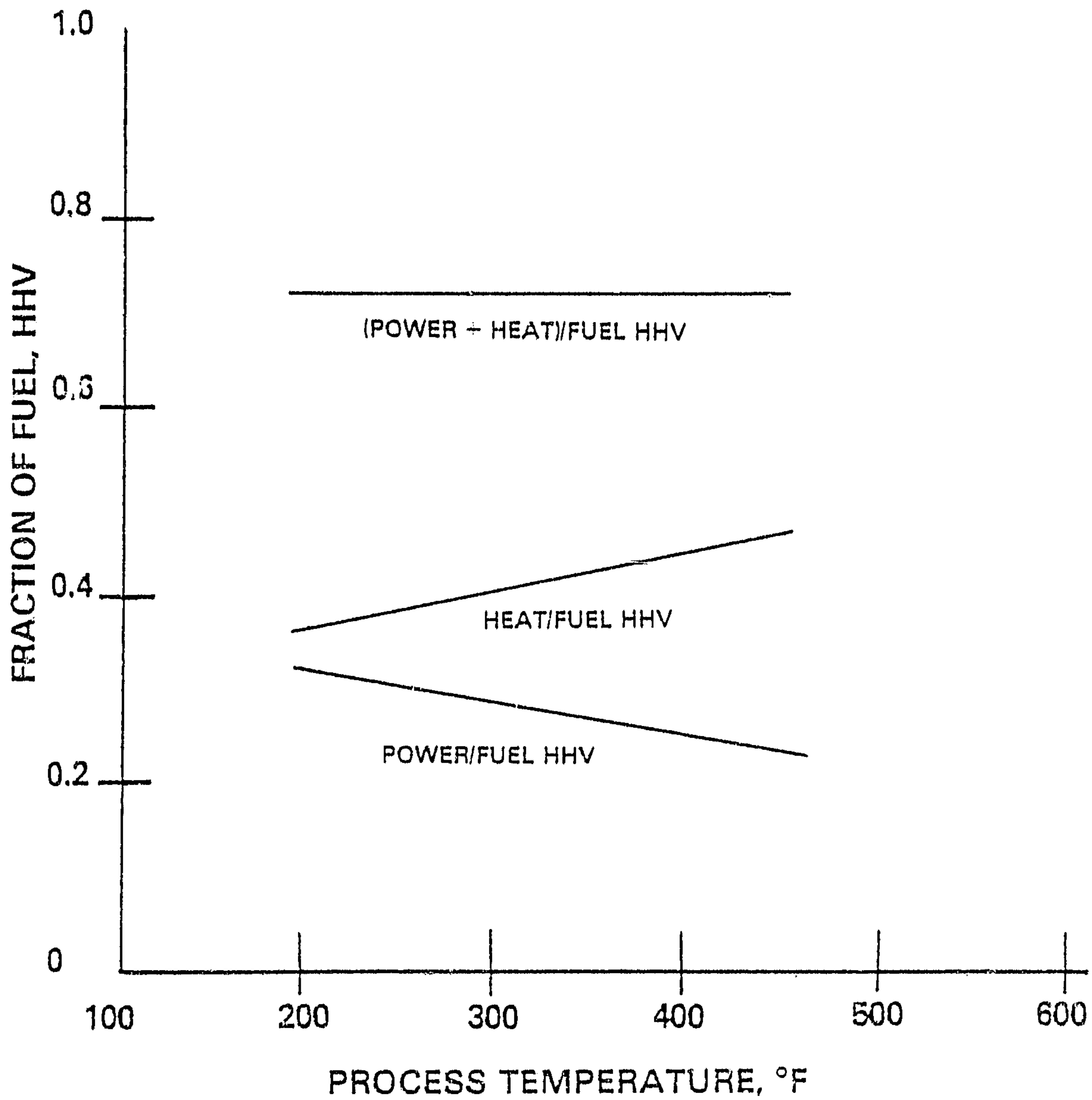
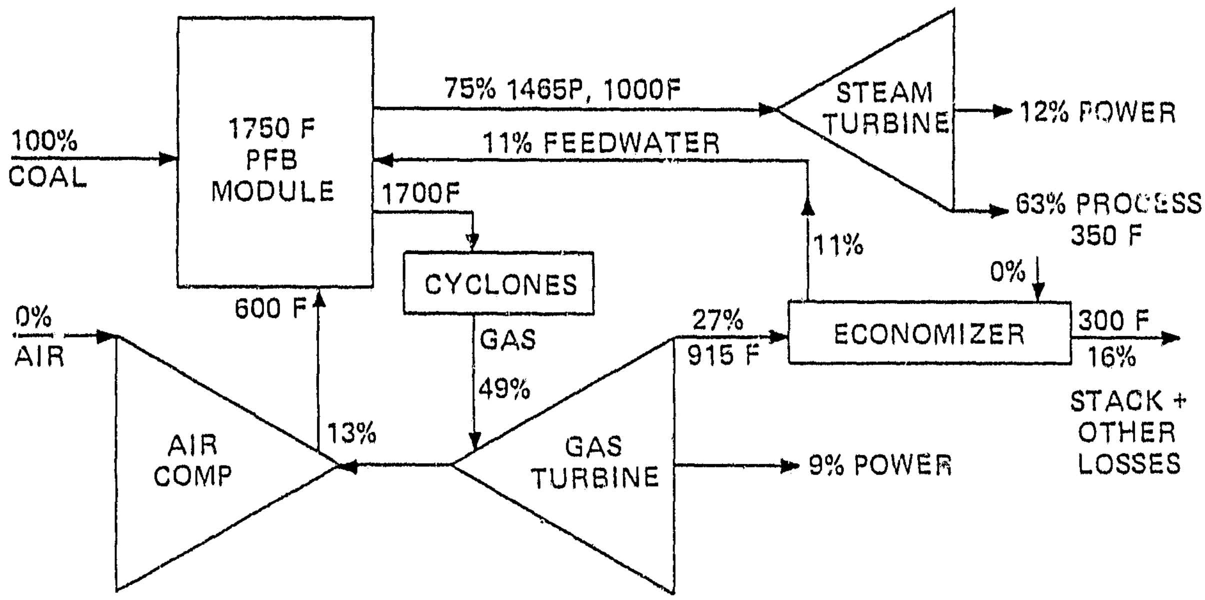


Figure 6.5-33. Energy Conversion System Characteristics. Integrated Coal Gasification with Water-Cooled Gas Turbine. Pressure Ratio, 12; Firing Temperature, 2100°F; Steam Turbine 1465 psia, 1000°F Non-Condensing; Coal Fuel

Pressurized Fluidized Bed Steam Cycle ECS

A second means of utilizing coal for a gas turbine system is the pressurized fluidized bed system illustrated in Figure 6.5-34. The schematic and example heat balance at 350 F process temperature are derivatives from the electric utility PFB steam system evaluated in detail in the General Electric ECAS study (Reference 4-2). The gas turbine functions as a supercharger pressurizing the PFB and supplying all of its air for coal combustion. The gas turbine expands the combustion gases from 1700 F to 915 F. The PFB bed temperature is held at 1750 F by the simultaneous combustion of coal and intensive heat transfer to the imbedded steam generating tubes. Dolomite fed into the bed captures the sulfur from the coal. Configurations of the PFB with air-cooled imbedded tubes were not considered since the poor heat transfer properties of gases mandate high alloy tube materials that would greatly increase the cost of the PFB per unit of coal burned as compared to steam generation.

The PFB feedwater would be preheated substantially by the economizer that brings the stack gas to the lowest permitted level in this study of 300 F. The steam conditions were the highest applicable to cogeneration of 1465 psia, 1000 F throttle conditions. The advanced art includes the PFB and the gas cleanup or gas turbine erosion protection means. System integration and control would also require development. The resulting cogeneration characteristics are shown in Figure 6.5-35. The power to fuel HHV ratio is appreciably greater than that for a steam turbine cogenerator alone. The sum of the power plus heat is at the maximum level permitted by restrictions on stack gas temperature.



FUEL:	COAL
VARIABLES:	PROCESS TEMPERATURE, STEAM TURBINE EXHAUST PRESSURE
RANGE:	13 MW - 600 MW
ADVANCED ART:	PFB, GAS CLEANUP
AVAILABILITY:	1990

Figure 6.5-34. Pressurized Fluidized Bed Cogenerator

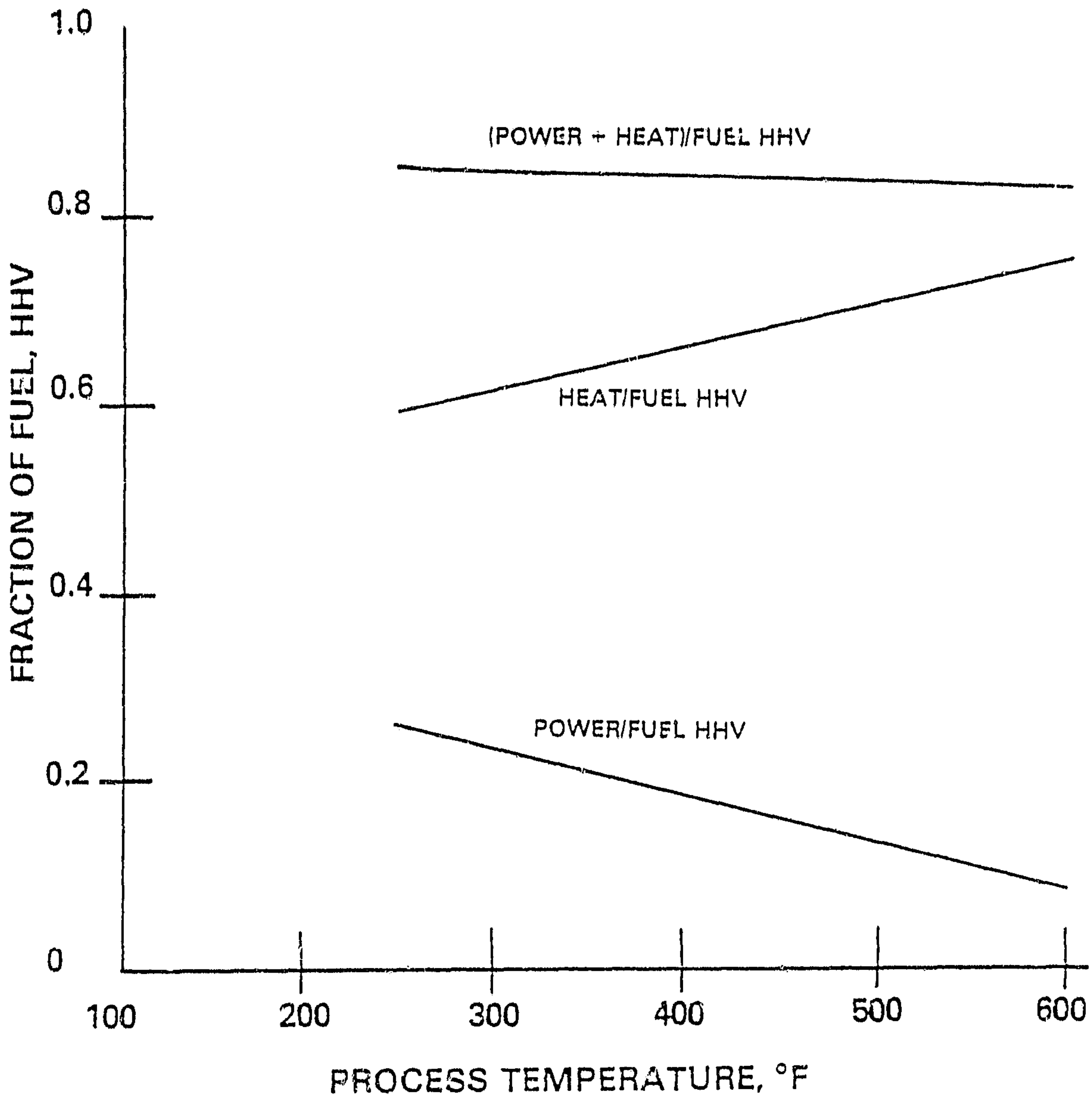


Figure 6.5-35. Energy Conversion System Characteristics. Pressurized Fluidized Bed with Gas Turbine and Non-Condensing Steam Turbine; 1465 psia, 1000°F; Coal Fuel; Dolomite Sulfur Capture Agent. Applicable Size, 13 to 600 MW; Available, 1990

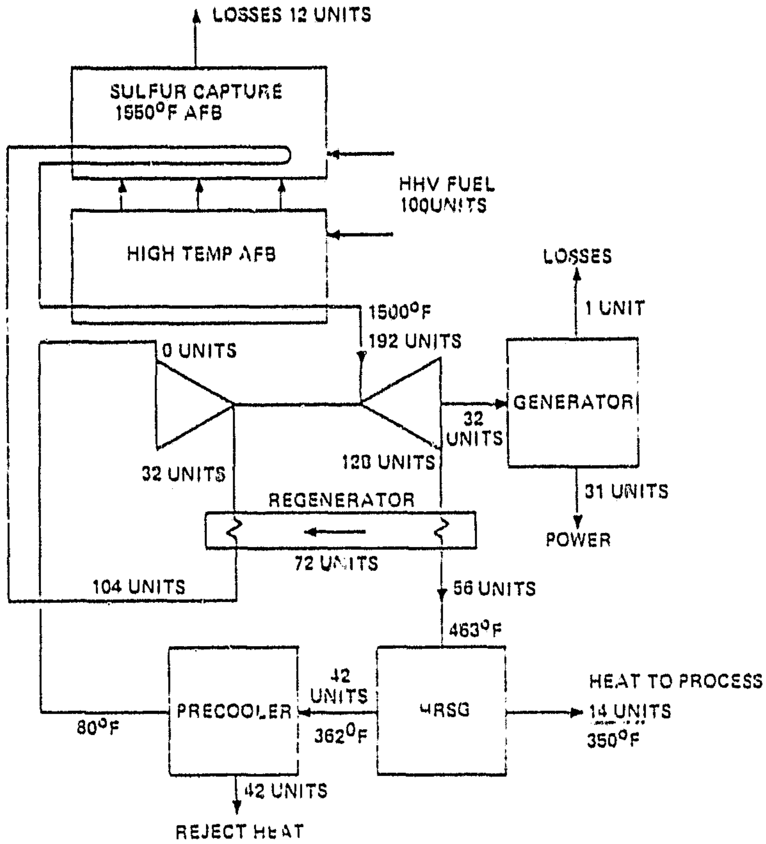
Closed Cycle Gas Turbine - AFB ECS

Figure 6.5-36 shows schematically another coal-fired gas turbine system. The externally-fired closed cycle gas turbine uses helium as its working fluid. The coal combustion products do not enter the gas turbine circuit. The atmospheric fluidized bed coal burner and helium heater differ significantly from the AFB steam generator. A high temperature bed permits heating the gas to 1500 F. All combustion products and excess air from that bed then flow into a low temperature bed at 1550 F. In the second bed all of the sulfur capture occurs using limestone sorbent. High temperature air preheat is required to bring the stack gas down to 300 F. All of these special features add to the cost of the AFB as compared to the AFB for steam. This added costliness must be the case wherever the heated meduim is hotter, 1000 F to 1500 F in this case, or has poorer heat transfer coefficients than steam. The closed cycle using air as its medium has lower heat transfer coefficients than helium and would require even greater cost in its AFB.

The closed cycle heat balance example achieves high efficiency in making power through the use of an 85% effective regenerator. As a result the helium flow to the HRSG is at 463 F, and relatively little process steam is produced. A heat rejection system is necessary to bring the helium to the 80 F compressor inlet condition. The heat rejection deprives the closed cycle of considerable energy. The closed cycle gas turbine is best adapted to cogeneration where there would be a considerable demand for heating at low temperature. Water heating service and space heating in a district heating service would provide the opportunity for greater fuel energy utilization than that provided by typical industrial processes.

Three regenerator effectivenesses were considered. The basis cycle performance and costs were determined by extension of the analysis and design presented in the General Electric ECAS study. The AFB helium heater represents the principal advanced art.

Figures 6.5-37, 6.5-38, and 6.5-39 present characteristics with regenerator effectiveness of 85%, 60%, and 0% respectively. The power to fuel HHV decreases appreciably with reduced regenerator effectiveness. At the same time the sum of power and heat to fuel HHV ratio increases greatly over the range of process temperature.



FUEL.	COAL
VARIABLES:	PROCESS TEMPERATURE 250°F TO 550°F REGENERATOR 0%, 60%, 85% EFFECTIVENESS
RANGE:	50 MW - 300 MW
ADVANCED ART:	TWO STAGE AFB - HELIUM HEATER REGENERATOR
AVAILABILITY:	1990

Figure 6.5-36. Helium Closed Cycle Cogenerator - AFB

HEGT85 HELIUM-GT-85-REGEN 50 MW/300 MW 1990

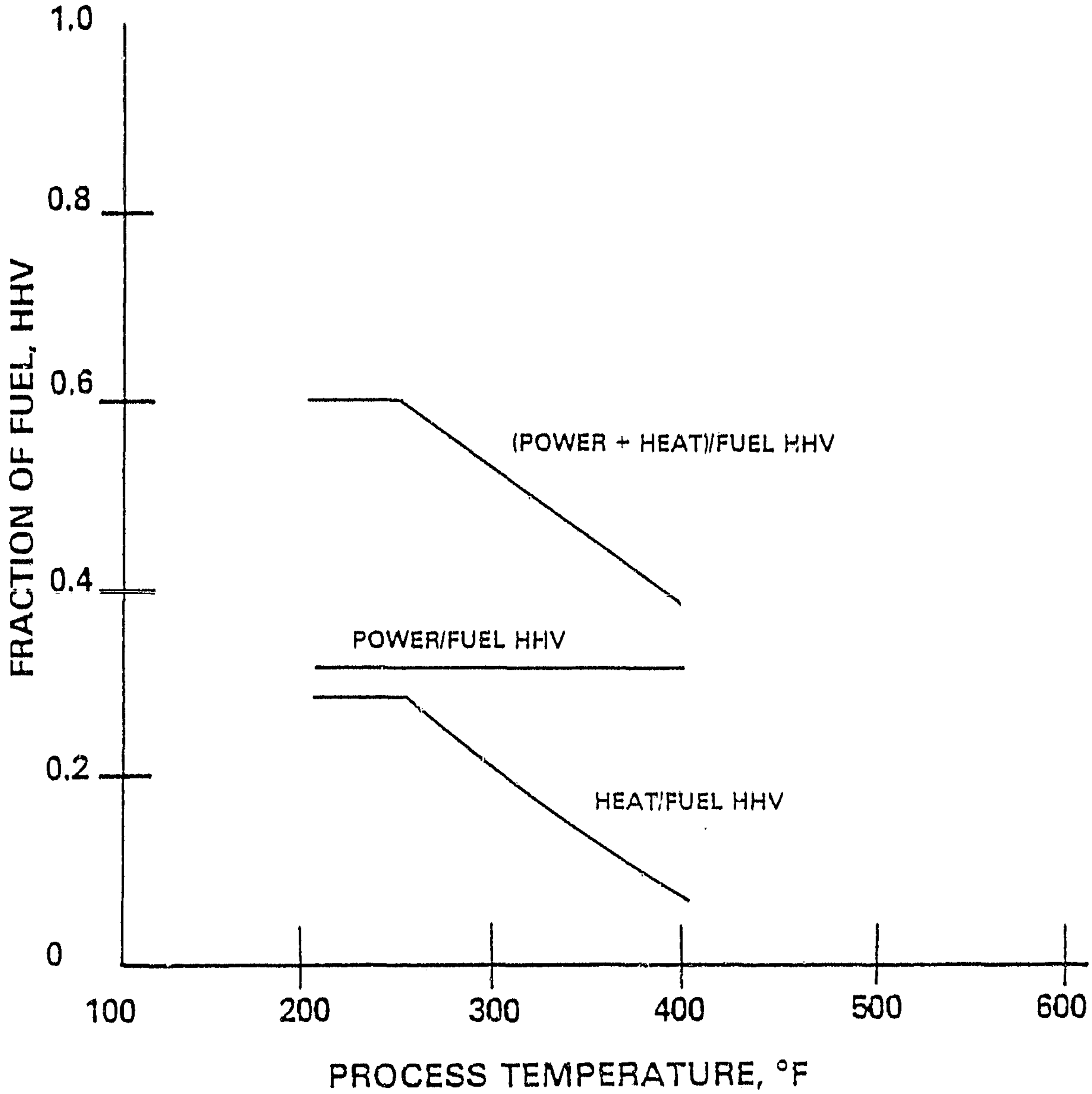


Figure 6.5-37. Energy Conversion System Characteristics. Helium Closed Cycle Gas Turbine; AFB Coal Fuel; Regenerator Effectiveness, 85%; Applicable Size, 50 to 300 MW; Available, 1990

HEGT60 HELIUM-GT-60-REGEN 50 MW/300 MW 1990

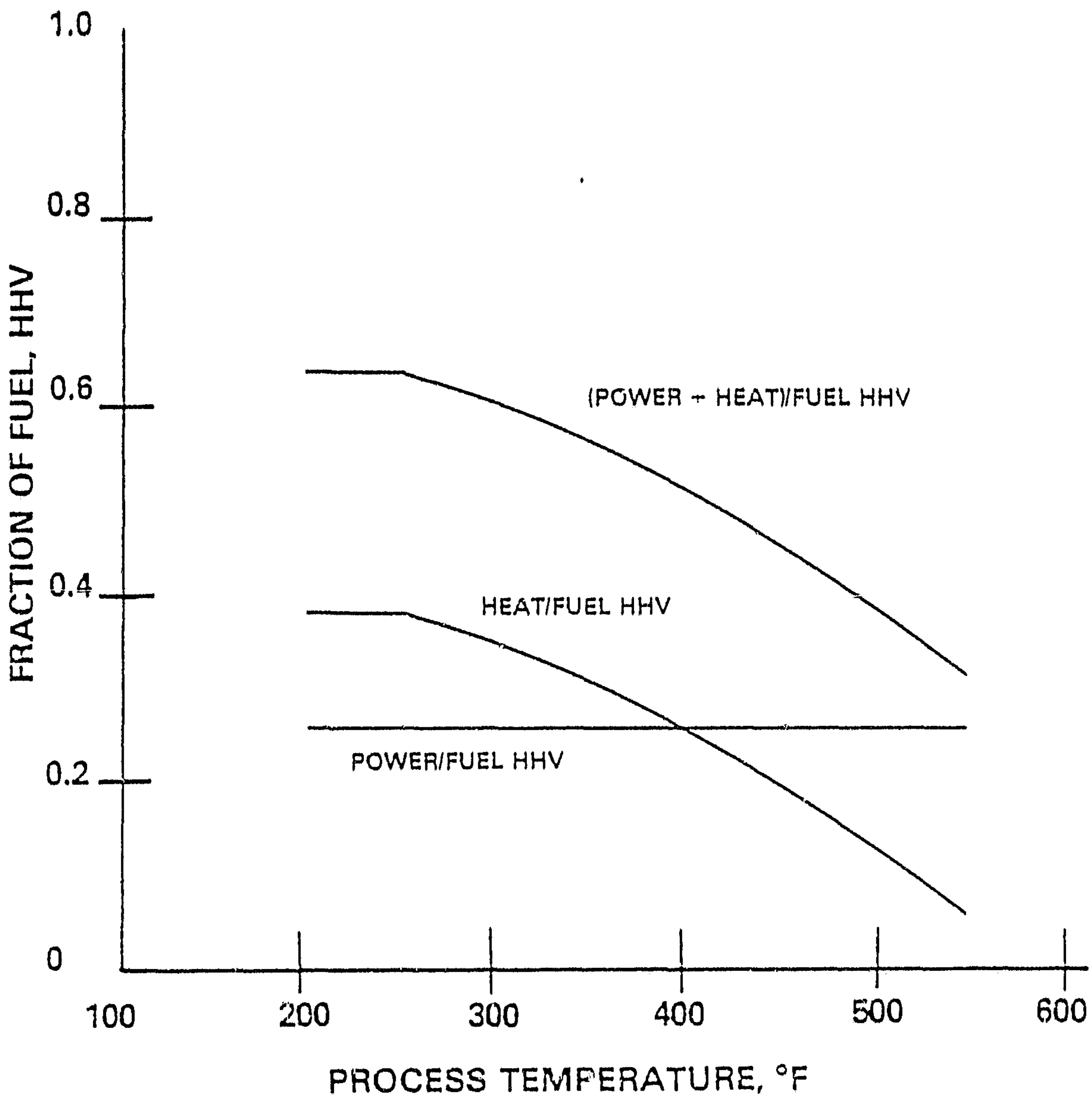


Figure 6.5-38. Energy Conversion System Characteristics. Helium Closed Cycle Gas Turbine; AFB Coal Fuel; Regenerator Effectiveness, 60%; Applicable Size, 50 to 300 MW; Available, 1990

HEGTOO HELIUM-GT-00-REGEN 50 MW/300 MW 1990

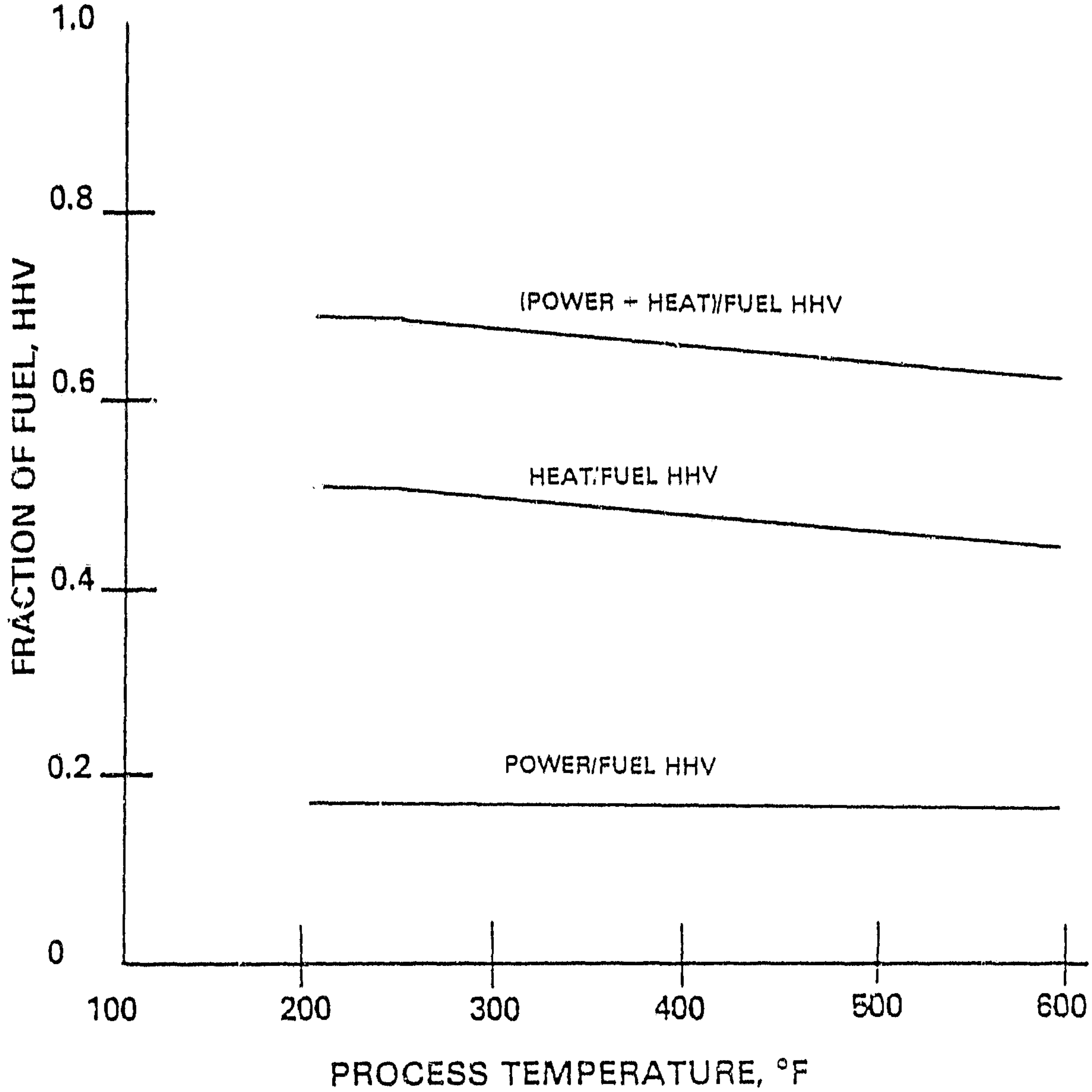


Figure 6.5-39. Energy Conversion System Characteristics. Helium Closed Cycle Gas Turbine; AFB Coal Fuel; Regenerator Effectiveness, 00%; Applicable Size, 50 to 300 MW; Available, 1990

Stirling Cycle ECS

The stirling cycle uses helium as an enclosed working medium in a totally different manner than the helium closed cycle gas turbine. Nonetheless the thermodynamic functions are nearly identical. Figure 6.5-40 shows the North American Philips concept of such an oil-fired unit. Atop each cylinder are burners supplied with highly preheated air. These deliver 80 percent of the fuel HHV to the helium heaters. Within the cylinder the lower piston is the power piston. It drives the crankshaft as in any reciprocating engine. The upper piston is a displacer of helium and is moved by the rhombic drive in the crankcase. The power piston provides the functions of helium compressor and helium expander. The displacer piston surges the captive helium through an external regenerator of high effectiveness and through the helium heater and through the helium heat rejection heat exchanger. The pressure of the captive helium may be changed with engine load so that temperatures throughout the cycle are nearly unchanged with load.

A schematic of the stirling cycle system and a heat balance for 228 F process temperature are shown in Figure 6.5-41. The stirling engine at 1800 rpm converts 35 percent of the heat delivered to it into electric power. The heat to process from cylinder heat rejection would be 39% of the fuel energy. The other engine losses represent lubricating oil cooling at a temperature below the process level. Only 80% of the fuel HHV would be delivered to the stirling cycle at the 1472 F hot temperature. The resulting electric power would be 28% of the fuel HHV. The combustor heat balance shows gas leaving at 1500 F and preheated air entering at 1200 F. Without a high temperature air preheater less of the fuel energy would be conveyed into the stirling cycle. The hot gas leaving the air preheater is cooled in the economizer to 300 F while heating process feedwater.

The industrial-size stirling engine for cogeneration is a significant development beyond current developments. Unit sizes would be in the range of 500 kW to 2 MW. Combustion of coal would represent a further development

- 1 MEGAWATT
- 8 CYLINDER, IN-LINE CONFIGURATION
- SINGLE ACTING

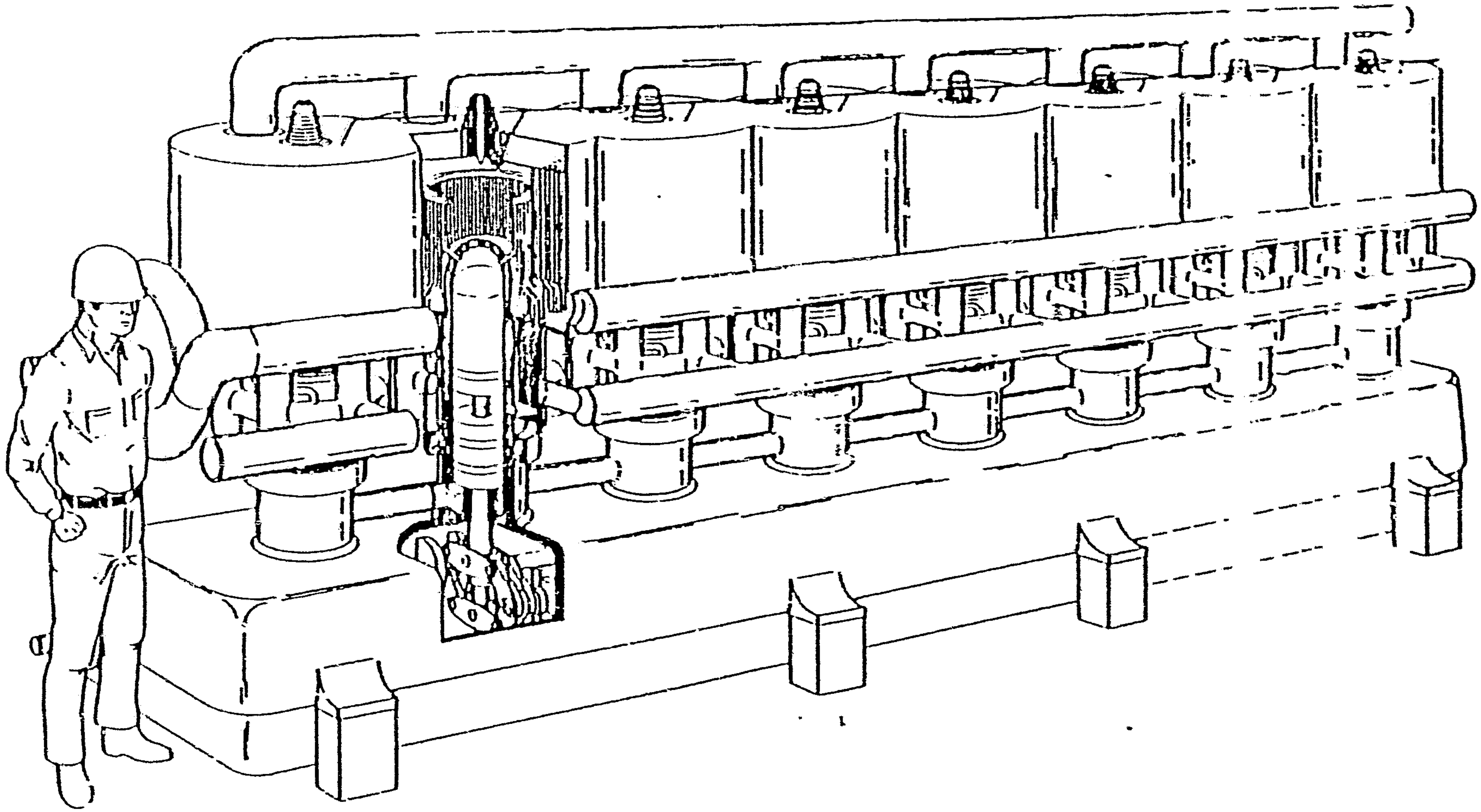
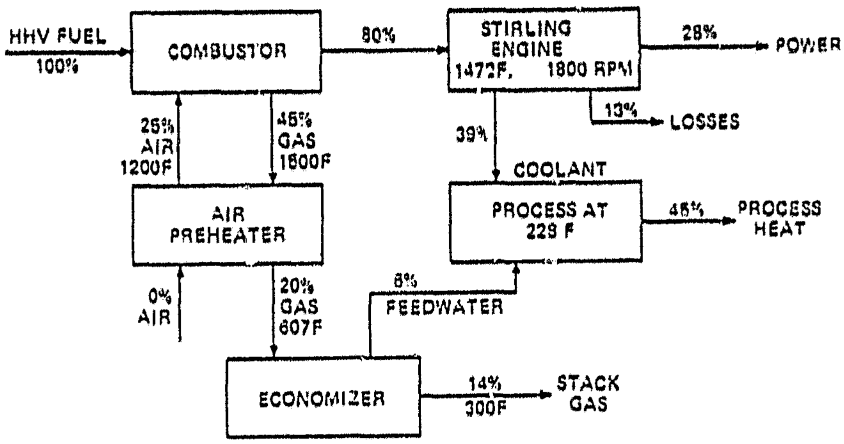


Figure 6.5-40. North American Philips Stirling Cogeneration Engine



FUEL : COAL, RESIDUAL, DISTILLATE
VARIABLES : PROCESS TEMPERATURE 229F TO 500F
RANGE : 500 kW TO 2 MW
ADVANCED ART. INDUSTRIAL STIRLING CYCLE
AIR PREHEATER TO 1200F
COAL BURNER HEAT EXCHANGER
AVAILABILITY: 1990

Figure 6.5-41. Stirling Cycle Cogenerator

that is considered to be of a similar order of magnitude. The earliest such system was evaluated as a pulverized coal burner with flue gas desulfurization of the flue gas. Heat conveyance to the stirling engine would be by a secondary enclosed and pressurized helium circuit. Several stirling engines could be serviced by a single large off-board coal combustor. The AFB for the helium closed cycle gas turbine was determined to not be applicable to the stirling cycle because all of the heat must be conveyed to the stirling engine at temperatures above the highest temperature of the helium closed cycle gas turbine. There is no efficient recipient for lower temperature heat below 1500 F.

The cogeneration characteristics of the stirling cycle ECS are presented in Figure 6.5-42. As compared to other alternatives the decline of power with increased process temperature is modest. The sum of power plus heat represents the fuel energy minus the minimum stack loss at 300 F and minus the low temperature lube oil and miscellaneous losses.

Consideration was given to the use of hydrogen as a working fluid. Improved performance of the order of 3% improvement in efficiency would be realized. The hazards due to the presence of hydrogen at high pressure and high temperature were considered to present a total barrier to the commercialization of such units for industrial use.

Higher hot wall temperature than 1472 F (800 C) would produce higher stirling cycle efficiency. Present superalloy technology places this upper limit on units to be developed and commercialized in the time span of 1985 to 2000. Above 1472 the superalloy creep rupture properties degrade. Substitution of ceramics for engine hot side components is envisioned as an avenue to hotter temperatures. Ceramic technology for stirling engines is in its earliest development stage. There is no assurance of success, and these potential advantages were not considered appropriate for this study.

The advantages of slower speed engines, of the order of 900 rpm, were considered. Since both hydraulic parasitic pressure drops and mechanical friction decrease with speed, the efficiency would improve by approximately 2%. The increased size and weight would appreciably increase the cost at no increase in power output. As a result the cost disadvantage of the stirling engine would be further aggravated to achieve a marginal performance improvement.

STIRL STIRLING-1472F 0.5/2 MW 1990

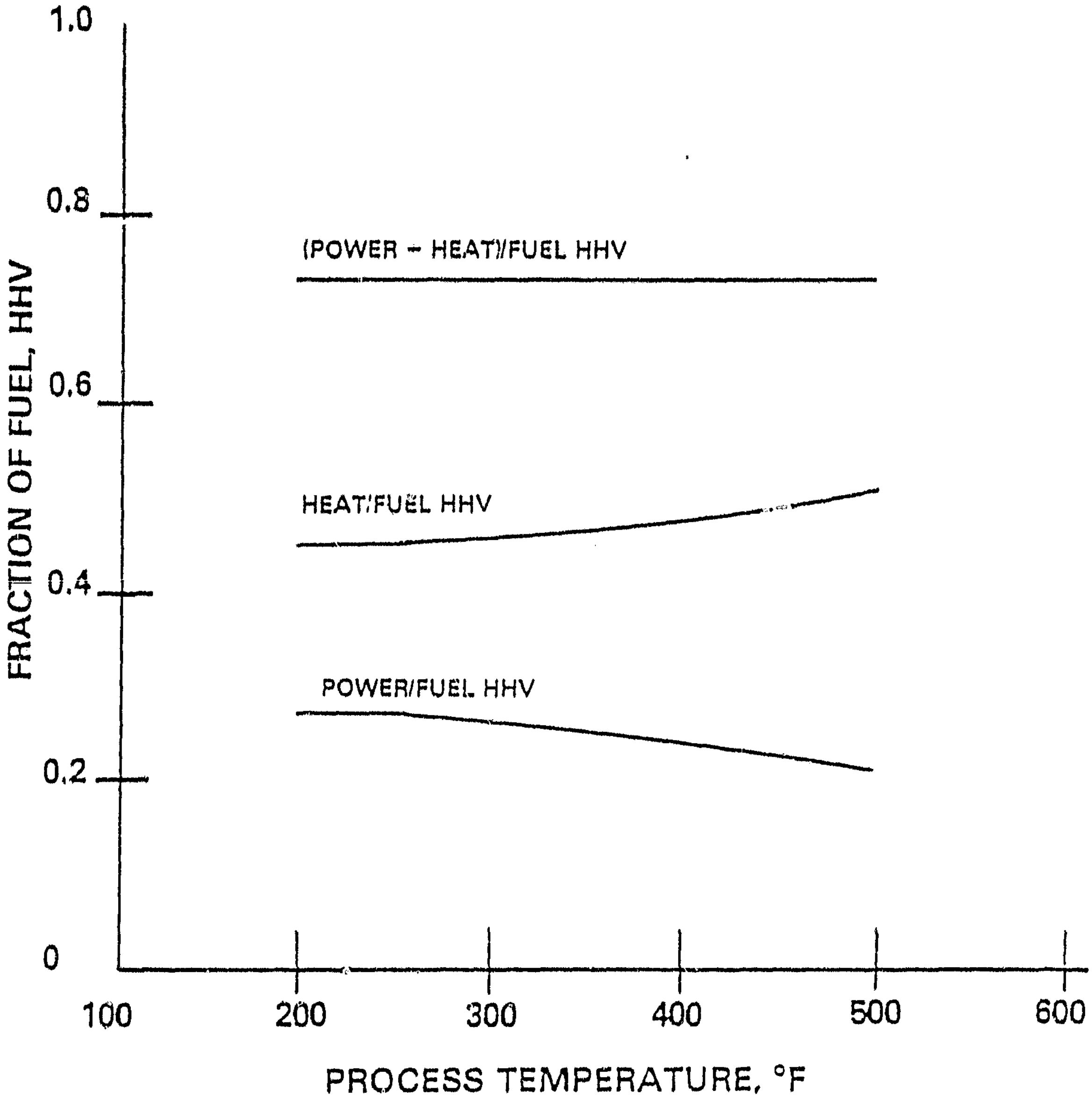


Figure 6.5-42. Energy Conversion System Characteristics. Stirling Engine Cycle, 1472°F Hot Side; Helium Working Fluid; Fuel Energy into Engine, 80%; Fuels: Distillate, Residual, Coal with FGD; Applicable Size, 0.5 to 2 MW; Available, 1990

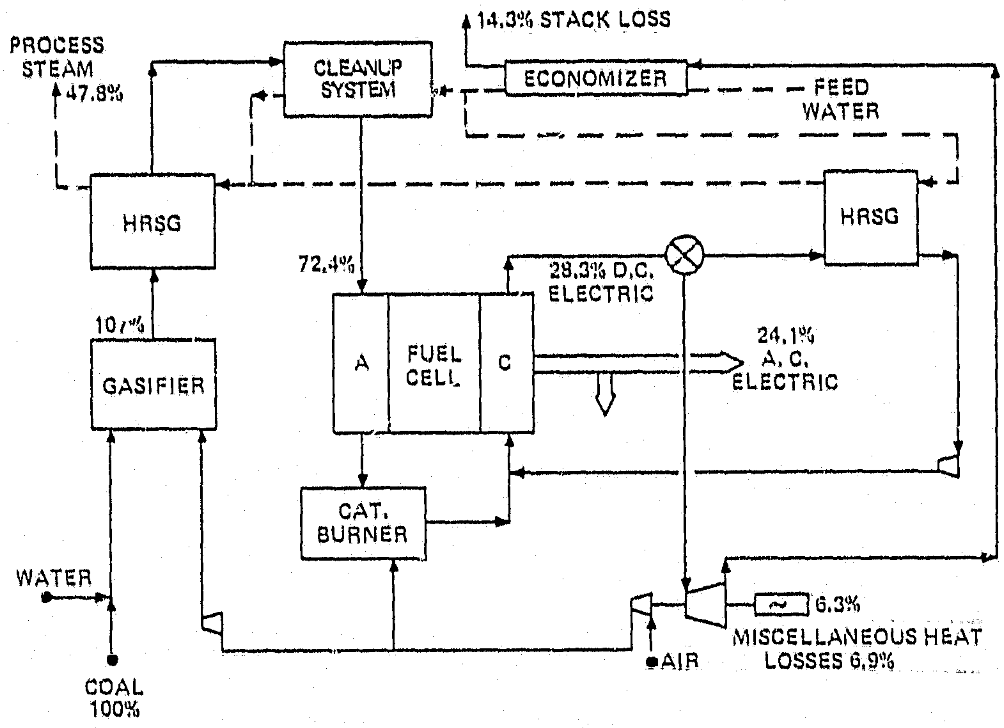
Fuel Cell ECS's

The molten carbonate fuel cell operates at a temperature of 1300 F. Figure 6.5-43 presents a schematic and heat balance for a coal-fueled molten carbonate fuel cell energy conversion system. The pressurized coal gasifier would be the entrained bed type where the effluent gases are at 2475 F. These gases are cooled by an HRSG en route to the gas cleanup system. The fuel gas that is not consumed in the anode (A) side of the fuel cell at 1300 F is burned with supplementary air in the catalytic burner. These combustion gases with excess air provide the necessary oxygen on the cathode (C) side of the fuel cell. The recirculation loop has an HRSG, a blower, and a hot gas bleed-off to the expansion gas turbine. The gas turbine exhaust passes through an economizer to be cooled to the minimum stack temperature of 300 F. The aggregate net ac power produced is 30.4% of the fuel energy of which 6.3% is produced by the gas turbine generator. The aggregate steam production from all HRSG's sends 47.8% heat to process. Figure 6.5-44 presents the resulting cogeneration characteristic.

The ability to produce high pressure steam can be exploited to increase power production by the addition of a non-condensing steam turbine with 1465 psia, 1000 F throttle conditions. Figure 6.5-45 presents the resulting characteristics. The sensitivity to process temperature derives entirely from the steam turbine characteristic.

A greatly simplified system would be used for a small distillate-fired molten carbonate fuel cell. The basic fuel cell would be unchanged. The distillate would be processed in an autothermal reformer with air and steam to form the fuel gas. That gas stream would be cooled in an HRSG and then passed through a zinc oxide reactor to reduce sulfur to below 1 ppm. The resulting cogeneration characteristic, Figure 6.5-46 is similar to that for the larger coal-fueled system. The reduced power and heat result from the system simplifications.

c-2



MOLTEN CARBONATE FUEL CELL

FUELS:	COAL, DISTILLATE
VARIABLES:	PROCESS TEMPERATURE 200°F TO 500°F
ADVANCED ART:	MOLTEN CARBONATE FUEL CELL GASIFIERS, SYSTEM INTEGRATION
AVAILABILITY:	1990

Figure 6.5-43. Molten Carbonate Fuel Cell Cogenerator

FCMCCL FUEL-CL-MOLTCARB-CL 100 MW/1000 MW 1990

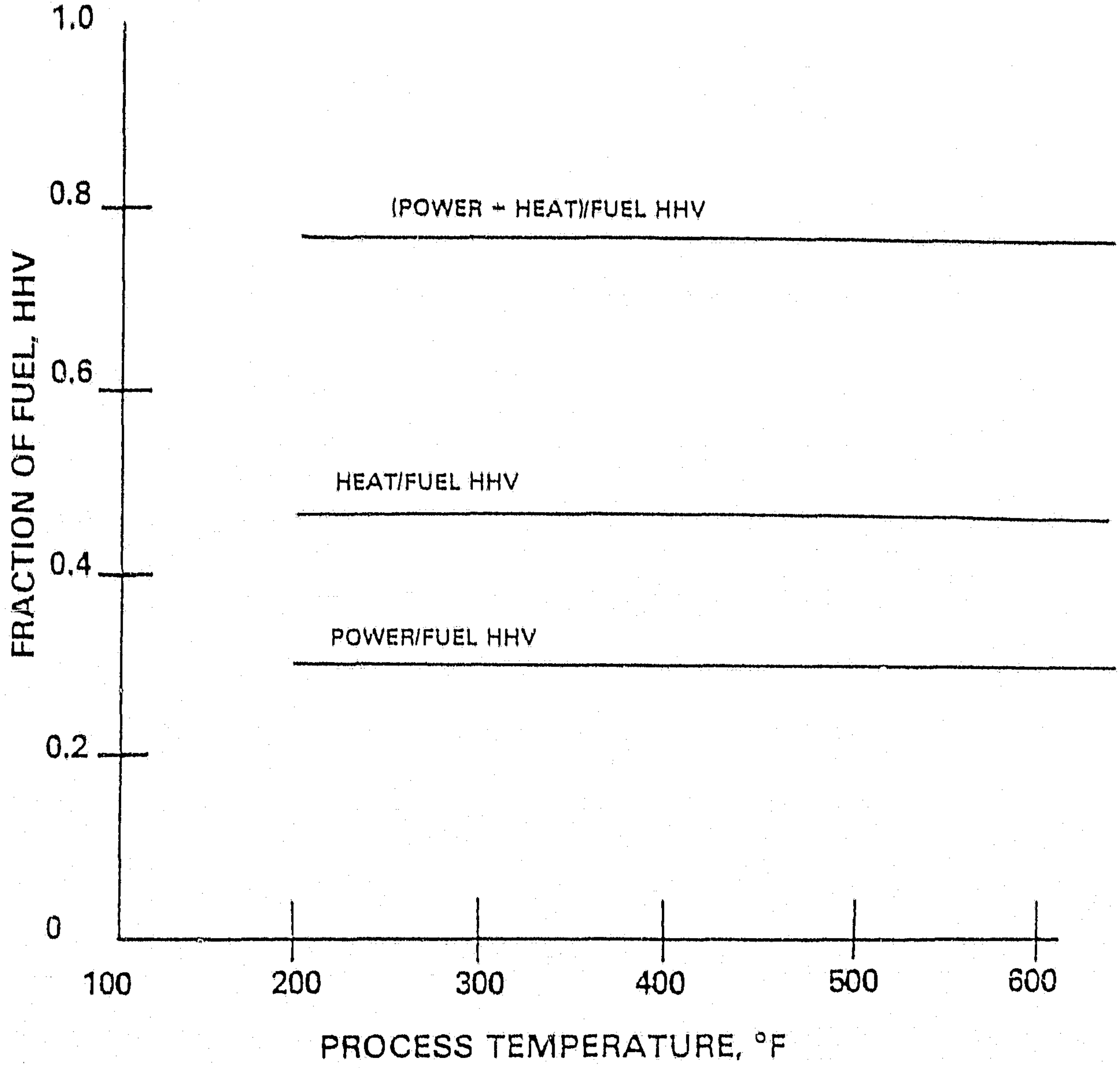


Figure 6.5-44. Energy Conversion System Characteristics. Fuel Cell, Molten Carbonate; Coal Fuel; Applicable Size, 100 to 1000 MW; Available, 1990

FCSTCL FUEL-CL-STMTB-COAL 125 MW/1250 MW 1990

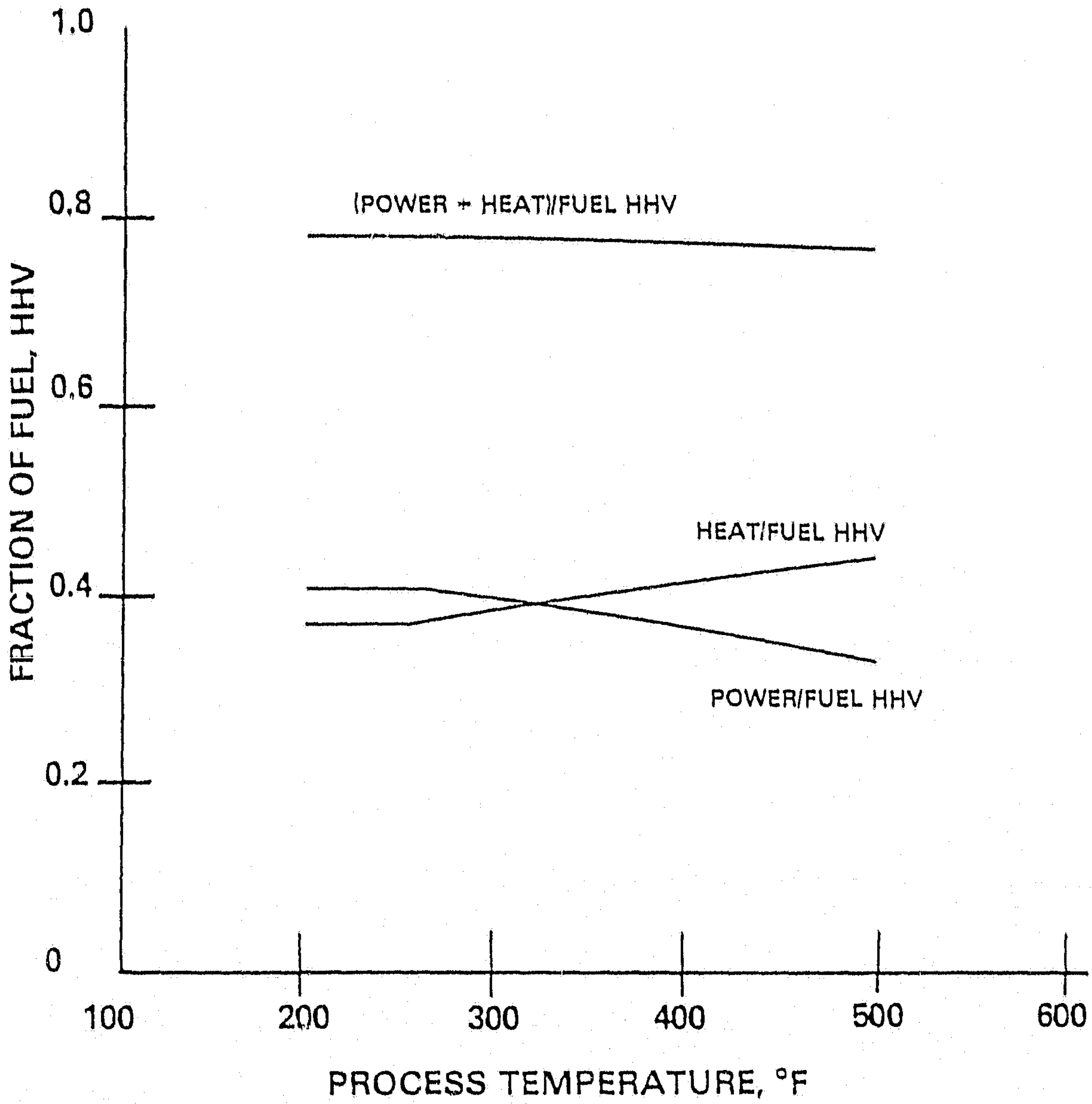


Figure 6.5-45. Energy Conversion System Characteristics. Fuel Cell, Molten Carbonate with 1465 psia, 1000°F Steam Turbine, Non-Condensing, Coal Fuel. Applicable Size, 125 to 1250 MW; Available, 1990

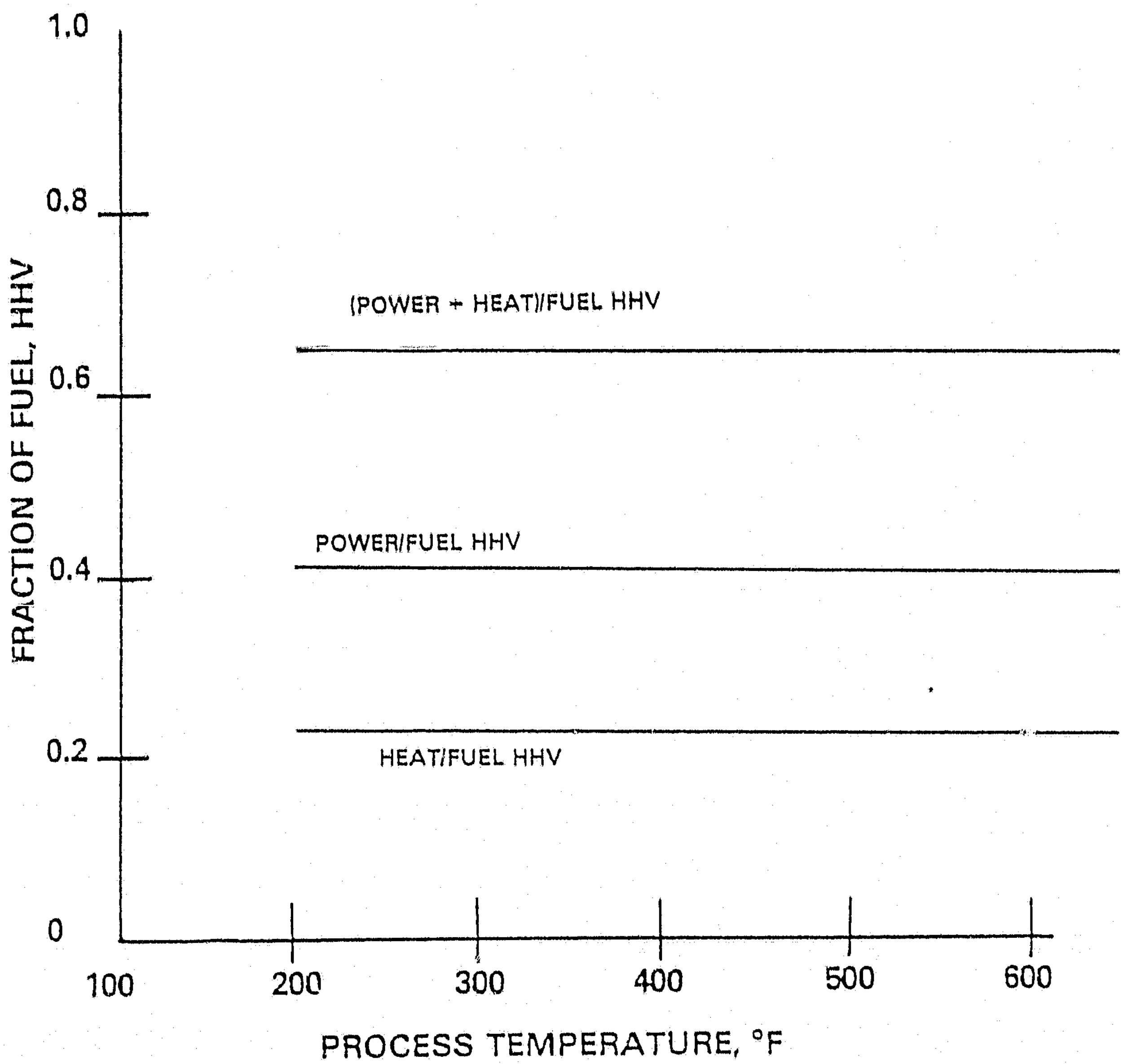
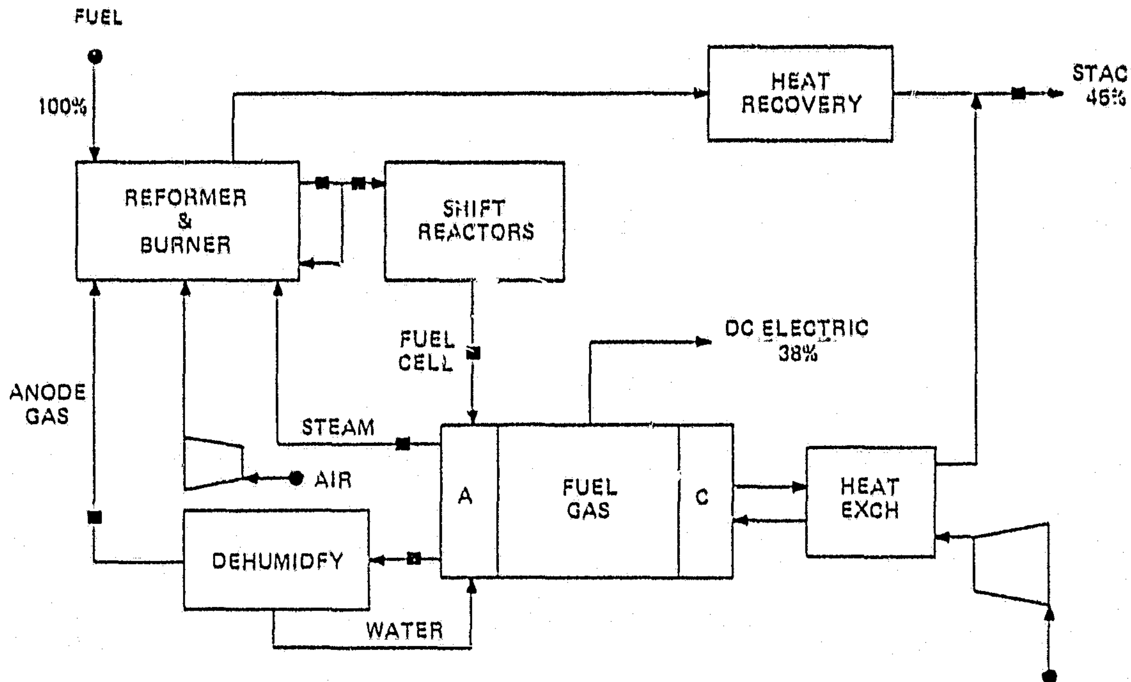


Figure 6.5-46. Energy Conversion System Characteristics. Fuel Cell, Molten Carbonate, Distillate Fuel; Applicable Size, 4.4 to 25 MW; Available, 1990

The phosphoric acid fuel cell operating at 375 F is shown schematically in Figure 6.5-47 with a rudimentary heat balance. The fuel gas at the anode is hydrogen. The distillate fuel oil must be processed through a zinc oxide reactor to remove any trace of sulfur. The zinc oxide consumption results in a high operating expense. The reformer burns spent anode fuel gas and some distillate oil as its heat source and uses the bulk of the distillate fuel as a chemical feedstock. There is extensive heat exchange at the reformer that heats the incoming fluid streams and cools the effluent gas streams. The shift reactors produce a high concentration of hydrogen in the fuel gas stream. A great loss of water would occur if a 300 F stack temperature were used. The stack gases are cooled to 100 F in order to recover and recycle water in the system. The cleanliness of the exhaust products permits this unusual practice.

The cogeneration characteristics are shown on Figure 6.5-48. Although the fuel cell operates at a nominal 325 F to 375 F level, other heat exchangers operate at temperatures up to 750 F. Process steam can be produced at temperature levels from 160 F to 600 F to the extent of 0.17 of the fuel energy. If a water heating load were available in the range of 50 F to 200 F, then an additional 0.309 of fuel energy would be available for that service. The low temperature level of this additional heat source precludes its economic use with an open cycle heat pump such as that to be described for use with the advanced diesel engine.



PROCESS HEAT SOURCES, 17%
160°F - 600°F PROCESS TEMPERATURE

PHOSPHORIC ACID FUEL CELL

FUEL:	DISTILLATE - DESULFURIZED
VARIABLES:	PROCESS TEMPERATURE 160°F to 600°F
RANGE:	1 MW - 10 MW
ADVANCED ART:	PHOSPHORIC ACID FUEL CELL SHIFT REACTORS SYSTEM INTEGRATION
AVAILABILITY:	1985

Figure 6.5-47. Phosphoric Acid Fuel Cell Cogenerator

FCPADS FUEL-CL-PHOSACID-DS 1 MW/10 MW 1985

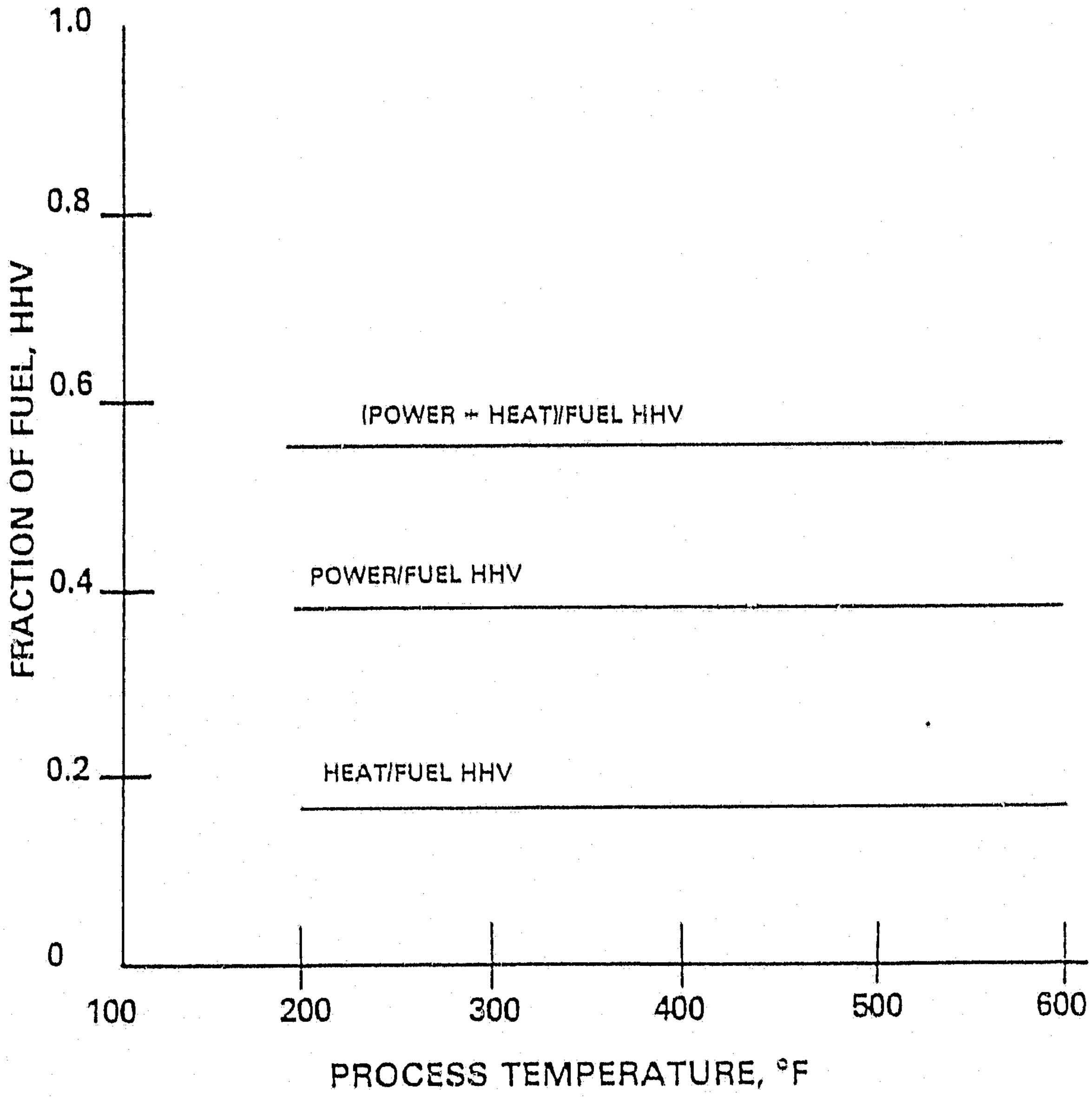
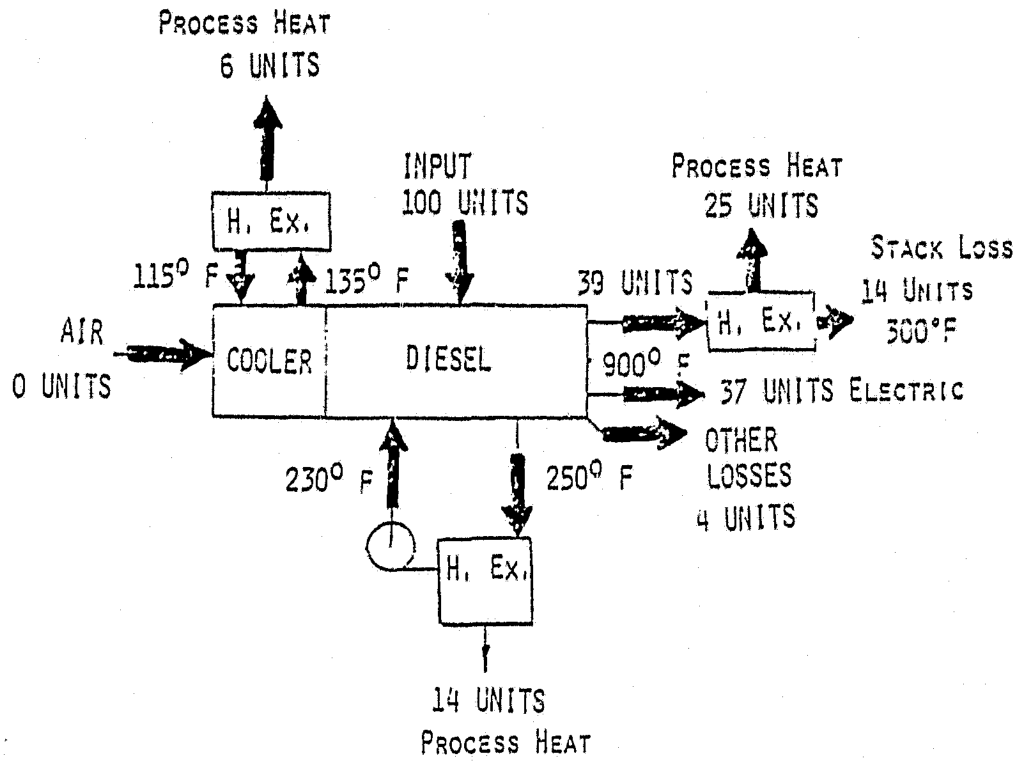


Figure 6.5-48. Energy Conversion System Characteristics. Fuel Cell Phosphoric Acid, Distillate Fuel; Applicable Size, 1 to 10 MW; Available, 1985

Diesel Engine ECS

Small high speed diesels burning distillate are typical of installations for hospitals, shopping centers, apartment complexes, and light industry. Such units are not typical of industrial diesel cogeneration installations. The DeLaval 17 inch diameter bore by 21 inch stroke 450 rpm sixteen cylinder engine burning residual typifies the later installations. The four cycle diesel has had a growth of 80% in power output by increased supercharging over the last twenty-five years. Most current diesels use the latest techniques in combustion chamber shape and fuel injection, and metallurgy, lubricatiion, and air treatment. Engine ratings are achieved with identical cylinders aggregated in four to twenty cylinder configurations. Diesel advancement has been evolutionary. It is expected to continue that way. Cylinder coolant temperature level may climb from the 150 F level to 250 F for advanced diesels. Higher supercharge with intercooling and charge air cooling will permit a 50 percent increase in BMEP and power output per cylinder. Truly revolutionary steps, such as the adiabatic diesel with ceramic parts or the slow speed coal-burning diesel, will require prolonged development to meet the standards of diesel reliability and low maintenance expense. These latter are considered by GE and DeLaval to be a generation beyond the advanced diesels that will be ready for cogeneration application over the period 1985 to 2000.

Figure 6.5-49 presents a schematic and heat balance for the advanced diesel engine. The amount of available heat for process is related to the temperature at which it is available. For example, the air cooler system heat at 115 F to 135 F would only be useful if there were a cold water heating load. The jacket water heat would not be useful for processes above 250 F. The 25 units of process heat from the exhaust gas cooler would be reduced as the process temperature rose above 250 F. The advanced diesel efficiency is one percent greater than state-of-the-art diesels. Higher values are projected for diesels, but those projections do not debit the engine and electric drive parasitic loads essential to diesel operation. The residual fuel could be displaced by distillate. However, the smallest



FUELS:	RESIDUAL (DISTILLATE)
VARIABLES:	T PROCESS 2 MW TO 15 MW
ADVANCED ART:	HIGHER SUPERCHARGE 250 F JACKET COOLANT GREATER EFFICIENCY

Figure 6.5-49. Diesel Cogenerator

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OF POOR QUALITY

size engine to burn residual fuel would be 2 MW, whereas industrial distillate burning diesels could be as small as 300 kW.

The cogeneration characteristic for state-of-the-art and the advanced diesel are presented in Figures 6.5-50 and 6.5-51. The power to fuel energy ratio is indifferent to process temperature and the degree of exploitation of the diesel heat resources. Three regimes are identified for process heat recovery. In Figure 6.5-51 for the advanced diesel below 228 F process temperature in region 1, all heat except the air cooler is available. In region 2 from 228 F to 250 F the jacket water heat is unavailable with a step decrease in the usable heat. In region 3 (above 250 F) the exhaust gas heat becomes progressively less usable.

Table 6.5-3 presents the distinctions in diesel cogenerator heat balances between the state-of-the-art and the advanced diesel.

Table 6.5-3

DIESEL HEAT BALANCE

Energy Source	State-of-the-Art Energy/Fuel Energy		Advanced Energy/Fuel Energy	
Air Cooler	0.0576	115 F to 135 F	0.0576	115 F to 135 F
Lube Oil	0.0481	156 F to 170 F	0.050	228 F to 250 F
Jacket Water	0.1332	160 F to 175 F	0.0874	228 F to 250 F
Exhaust Gas	0.2201	300 F to 820 F	0.254	300 F to 900 F
Subtotal	0.459		0.449	
Power Net	0.361		0.371	
Total	0.820		0.820	

DESOA(123) DIESEL-SOA-(123) 0.3 MW/10 MW 1978
(Keyed to temperature regimes on characteristic)

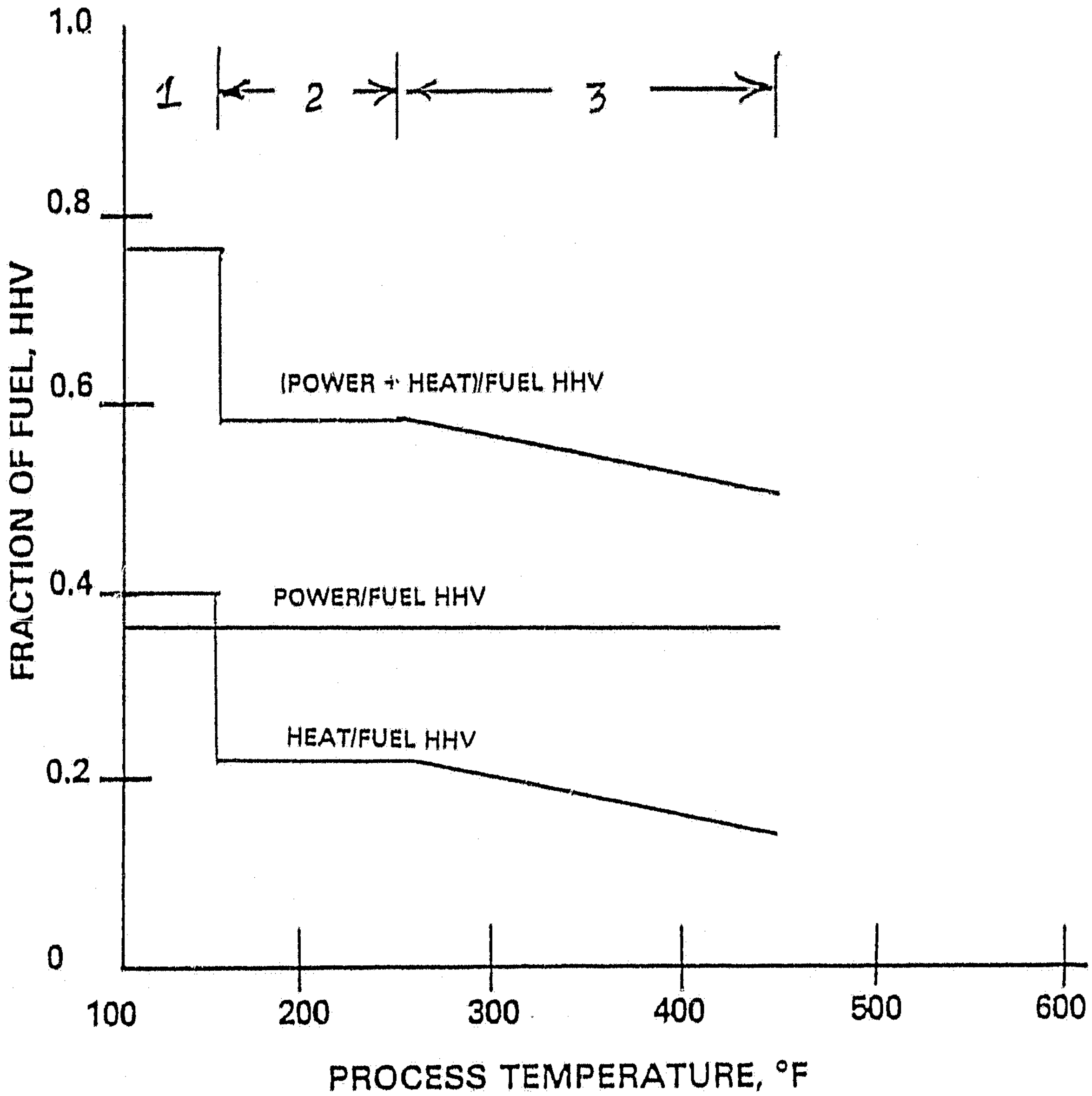


Figure 6.5-50. Energy Conversion System Characteristics. Diesel, State-of-The-Art, Residual Fuel above 1 MW; Distillate Fuel over Full Range; Jacket Water, 175°F; Minimum Exhaust From Stack Cooler, 300°F; Applicable Size, 0.3 to 10 MW; Available, 1978

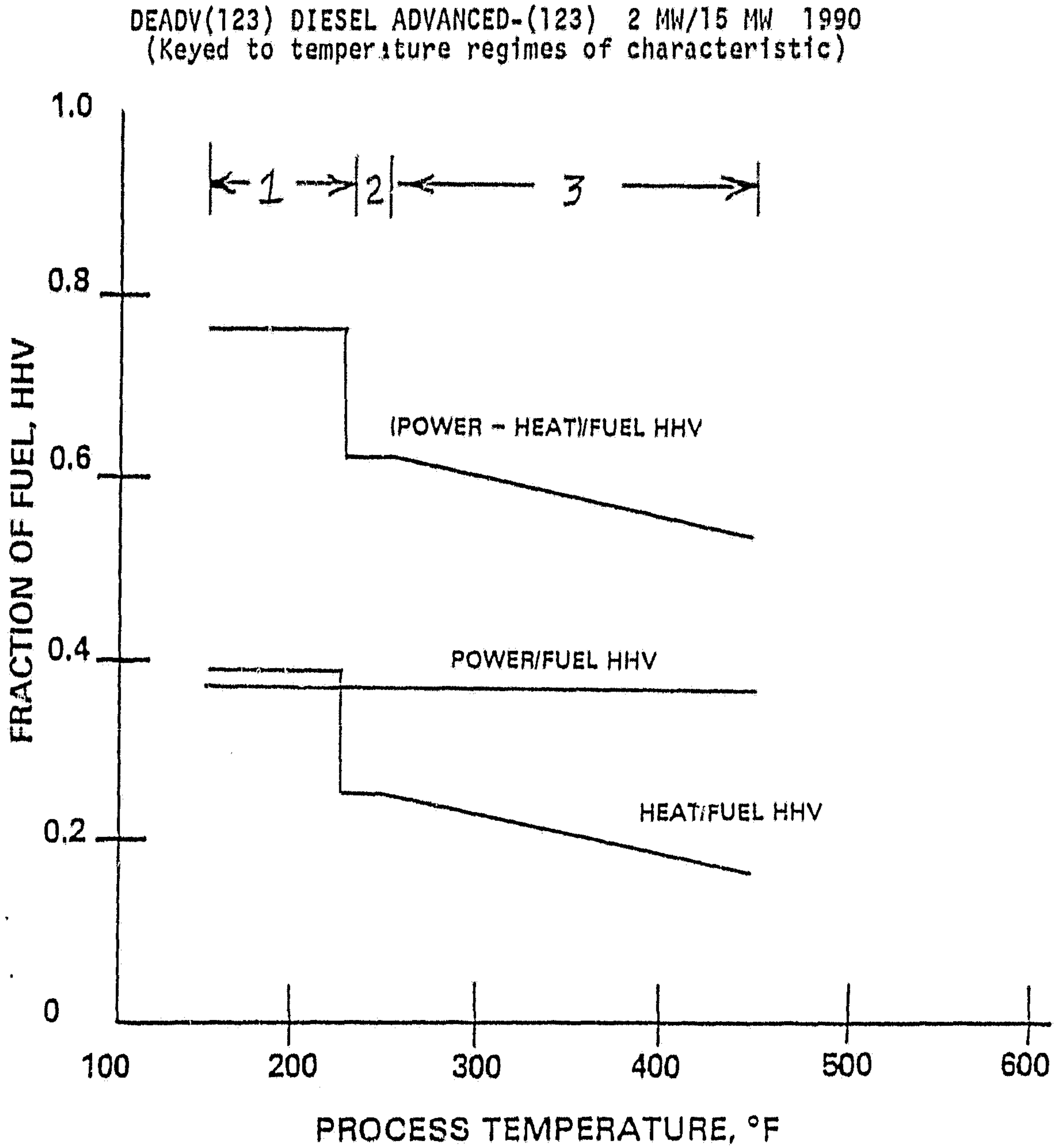


Figure 6.5-51. Energy Conversion System Characteristics. Diesel-Advanced, Residual Fuel; Jacket Water, 250°F; Minimin Exhaust From Stack Gas Cooler; Applicable Size 2 to 15 MW; Availability, 1990

Diesel Heat Pumped ECS

The drastic reduction in available heat to process at temperatures above 228 F in the advanced diesel is a severe detriment to the diesel cogenerator. Higher coolant temperatures such as 300 F or 350 F for the jacket water would require severe reductions in power output to maintain cylinder wall temperatures that assure lubrication of the upper piston rings. Also the gross distortion of the cylinders from cold tc operating temperatures would introduce great design integrity uncertainties.

The open cycle heat pump is a means to provide high process steam temperatures from the 250 F jacket water heat. Such a heat pump system is illustrated in Figure 6.5-52. The diesel jacket coolant water at 250 F is throttled to 20 psia. It subdivides into water af 228 F and saturated steam at 228 F. A similar flashing of process condensate produces the same flow of 228 F water as that of 250 F water. The pump beneath the flash chamber pressurizes the jacket water by 10 psi and circulates it through the jacket. The power to drive this pump is assessed against the heat pump system. The steam is compressed from 20 psia to the pressure of the process. The compressor is motor driven to provide flexibility. The motor power as well as the added pump power are debited from the diesel generator output.

The heat balance for the diesel-heat pump cogenerator serving a 350 F process is presented in Figure 6.5-53. The heat pump is added to the basic advanced diesel which is unchanged. The air cooler reject heat is not usable. The stack gas cooler produces 21 units of heat with a stack temperature of 400 F. The heat pump delivers 18 units of heat from 14 units of jacket water heat and 4 units of mechanical drive input. The aggregate is 39 units of heat to process per 100 units of fuel energy, and a reduction to 33 units of power. Without the heat pump these values would be 20.5 and 37 respectively. The heat to process is nearly doubled by application of the heat pump.

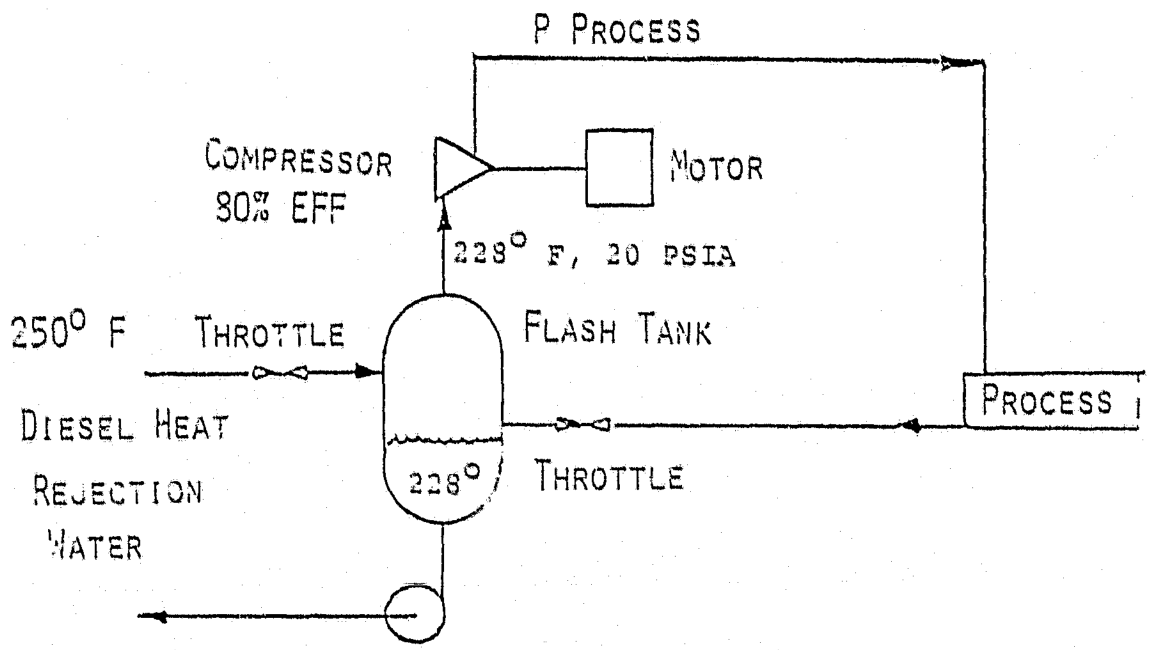
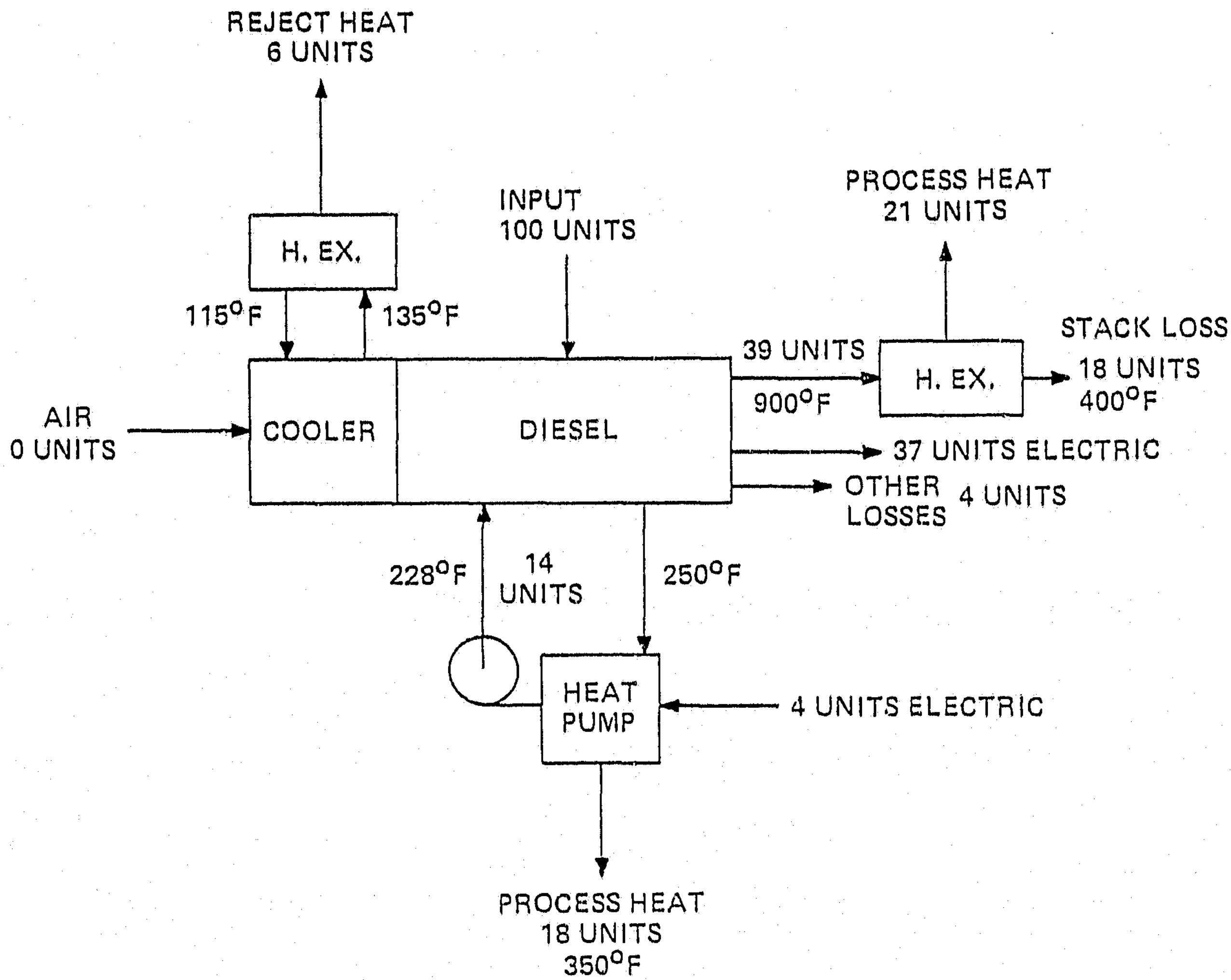


Figure 6.5-52. Diesel Heat Pump



- VARIABLE: PROCESS TEMPERATURE
- ADVANCED ART: VAPOR COMPRESSION HEAT PUMP DIESEL JACKET WATER 250°F
- AVAILABILITY: 1990

Figure 6.5-53. Diesel - Heat Pump Cogenerator

The resulting cogeneration characteristic over the range of process temperatures is shown in Figure 6.5-54. The heat to fuel energy ratio is nearly constant. The power to fuel energy ratio drops as the heat pump uses an increasing amount of power. The sum of net power and heat is high, indicative of a high cogeneration fuel energy utilization.

The heat pump system would require modest development effort. The compressor inlet steam density is comparable to atmospheric air. Conventional compressor technology is applicable. Primary concerns would be the influence of the temperature level on the compressor and its seals. As compared to the advanced diesel alone, the diesel heat pump cogenerator has a greatly enhanced characteristics.

Diesel NO_x Emissions

State-of-the-art diesels operating on distillate fuel produce approximately four pounds of NO_x per million Btu of fuel, and units burning residual fuel produce twice as much NO_x. There are no evident means to reduce diesel NO_x production an order of magnitude to the emission guideline values of 0.4 and 0.5, respectively. Exhaust gas treatment by addition of ammonia and catalytic NO_x conversion at a regulated temperature level is the only currently viable means to reach emission guideline levels for NO_x. Such exhaust gas treatment does not change projected cogeneration performance. Nor would it add appreciably to the fabrication and erection costs if the exhaust gas treatment functions were incorporated in the heat recovery steam generator design. The diesel engine representative for this evaluation advised that the cost margins already applied to the fully erected diesel installations would cover the cost increment for exhaust gas NO_x reduction.

DEHTPM ADV-DIESEL-HEAT-PUMP 2 MW/15 MW 1990

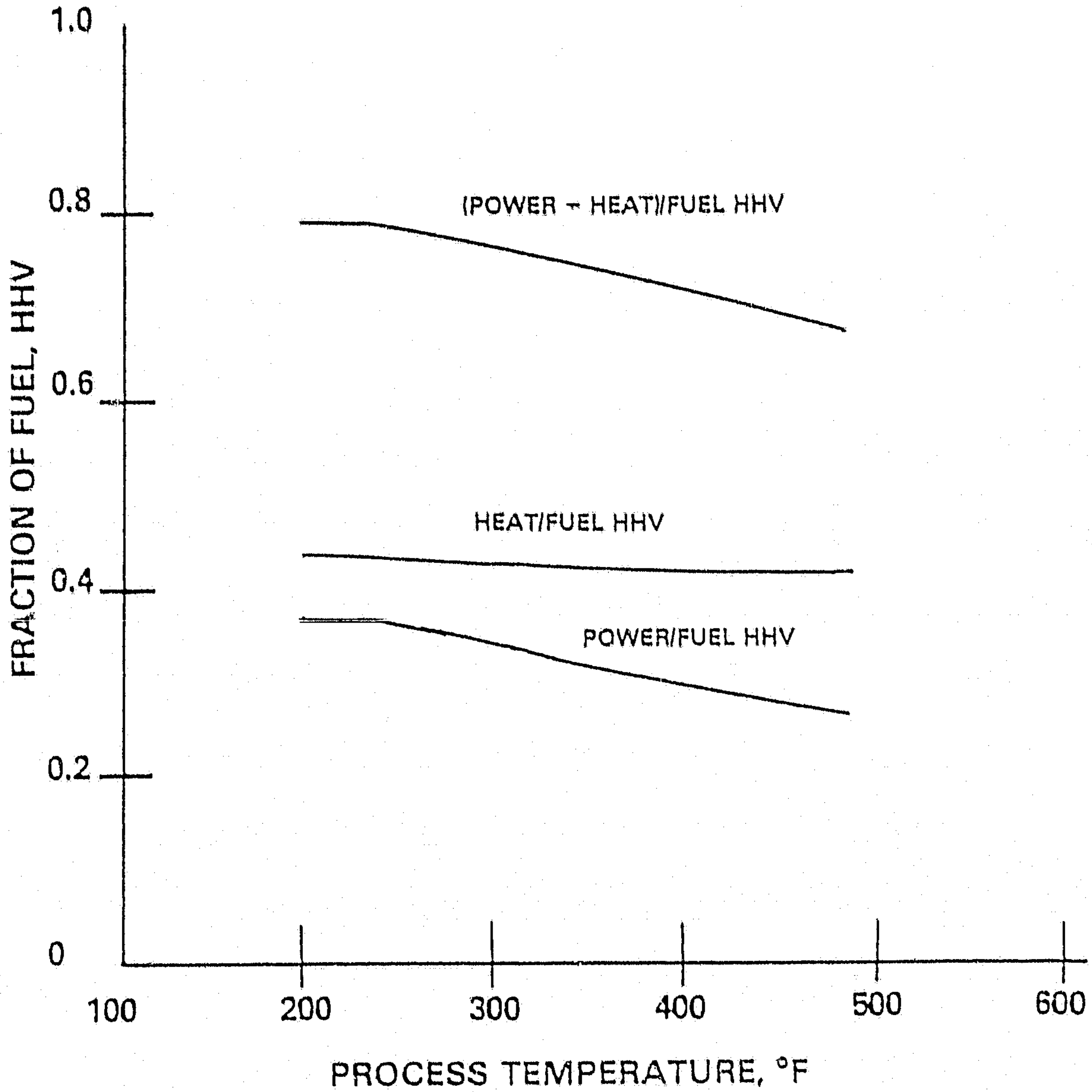


Figure 6.5-54. Energy Conversion System Characteristics. Advanced Diesel Heat Pump Providing Process Steam From Jacket Water Heat by Vapor Compression; Jacket Water Temperature, 250^{o}F; Residual Fuel; Applicable Size, 2 to 15 MW; Available, 1990

Thermionic ECS

The thermionic steam generator is illustrated in Figure 6.5-55. Pulverized coal is burned in primary air and 1000 F secondary air. Radiant and convective heat exchange to the high temperature thermionic emitters at 1600K drive direct current electricity and heat energy to the thermionic collectors. The thermionic collectors use heat pipes to discharge heat to the combustion air flow. The combustion gases flow upward out of the radiant furnace zone toward the steam superheater zone. En route they heat by convection the low temperature thermionic elements with 1300 K emitter temperature. At 2310 F the combustion gases begin their heat exchange with the steam superheater and steam generator surfaces. This furnace concept has been adapted to cogeneration from the General Electric study for EPRI by modifications to the thermionic element cooling concepts. Figure 6.5-56 shows a schematic of the thermionic steam cogenerator. The air coolant of the high temperature elements heats primary air and also produces steam. The low temperature elements are unchanged. The 1000 F secondary air is used for staged combustion of the pulverized coal. NO_x limitation is achieved by this means. The secondary steam generator brings the stack gas to 300 F. Flue gas desulfurization is applied to limit sulfur emissions. Residual oil could be substituted for coal as fuel. This would be particularly suitable for small ratings. Steam conditions of 1465 psia, 1000 F are producible in this system. Non-condensing steam turbine bottoming may be used to increase the power output.

Figure 6.5-57 presents the thermionic unit performance as a function of collector average temperature. In the EPRI study for electric utility applications the high temperature collector average temperature was 900 F. The rearrangement for this study permits the lowest operable collector temperature of 710 F. As a result the efficiency increases from 33% to 38%.

A heat balance, Figure 6.5-58, is shown based on input of 1000 units of coal higher heating value. The energy flow of 381.9 units to the high temperature thermionic elements produces 145.1 units of DC electricity, 120.1 units of net heat to combustion air, and 116.7 units of heat to steam.

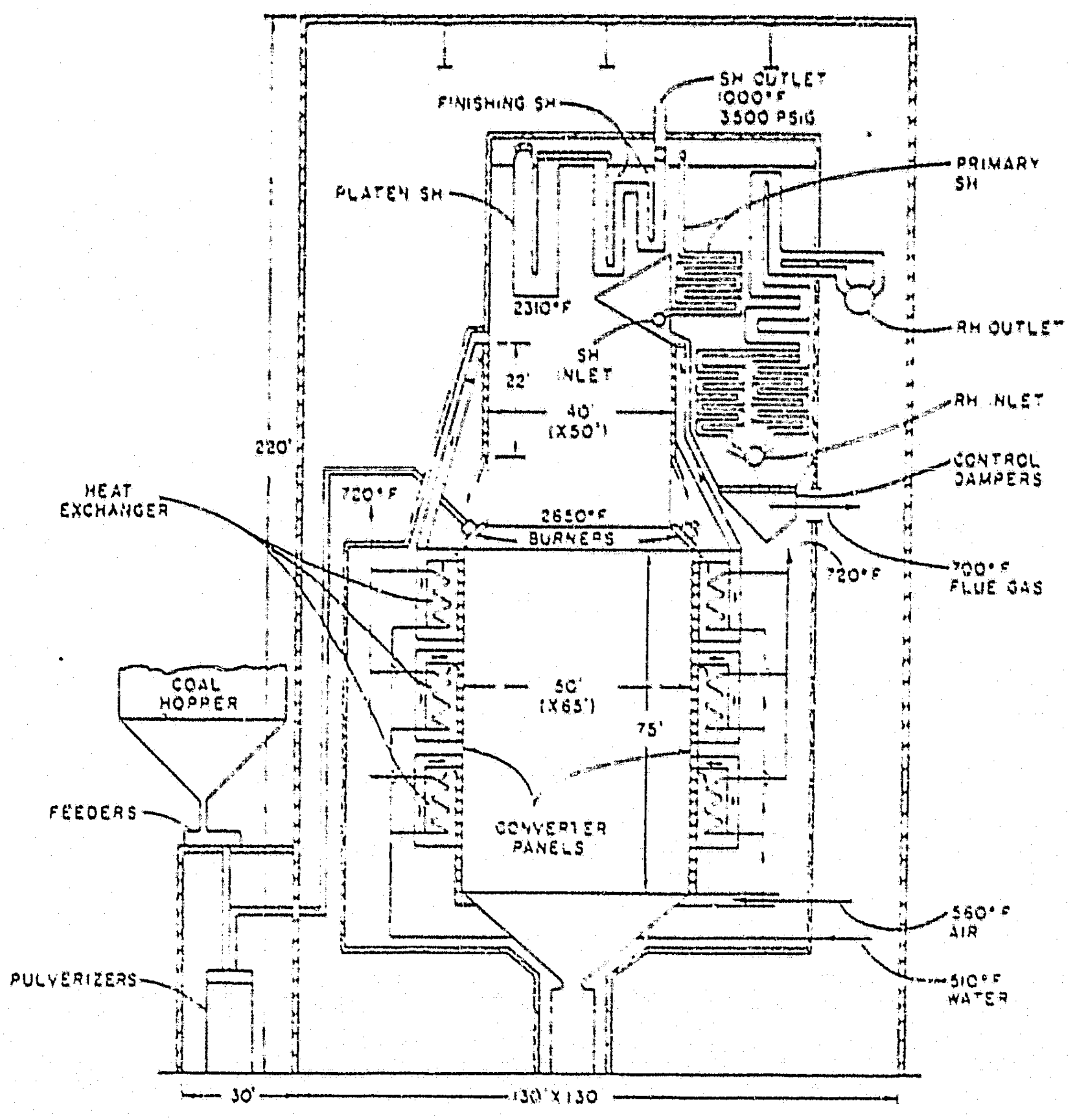
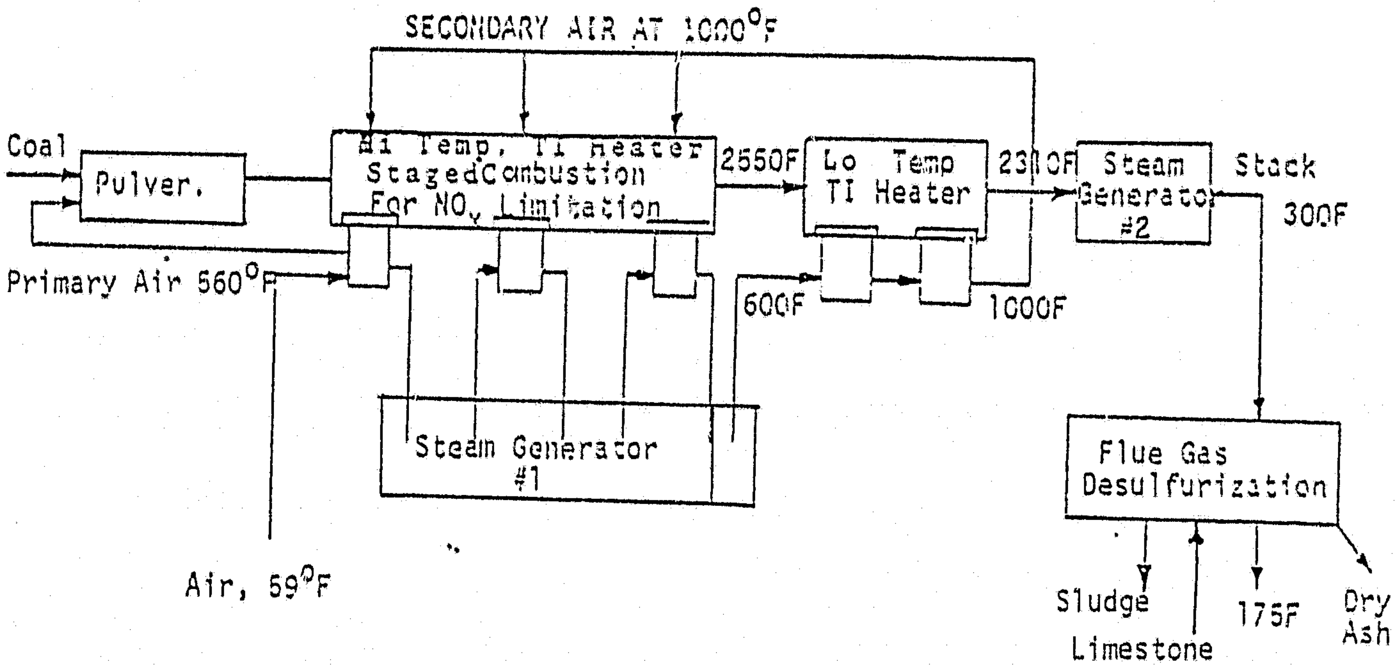


Figure 6.5-55. Thermionic-Steam Generator



FUEL: COAL, RESIDUAL OIL

VARIABLES: PROCESS TEMPERATURE

RANGE 3MW - 100 MW or 12 MW to 300 MW WITH STEAM TURBINE

ADVANCED ART: THERMIONIC POWER UNITS

Figure 6.5-56. Thermionic-Steam Cogenerator

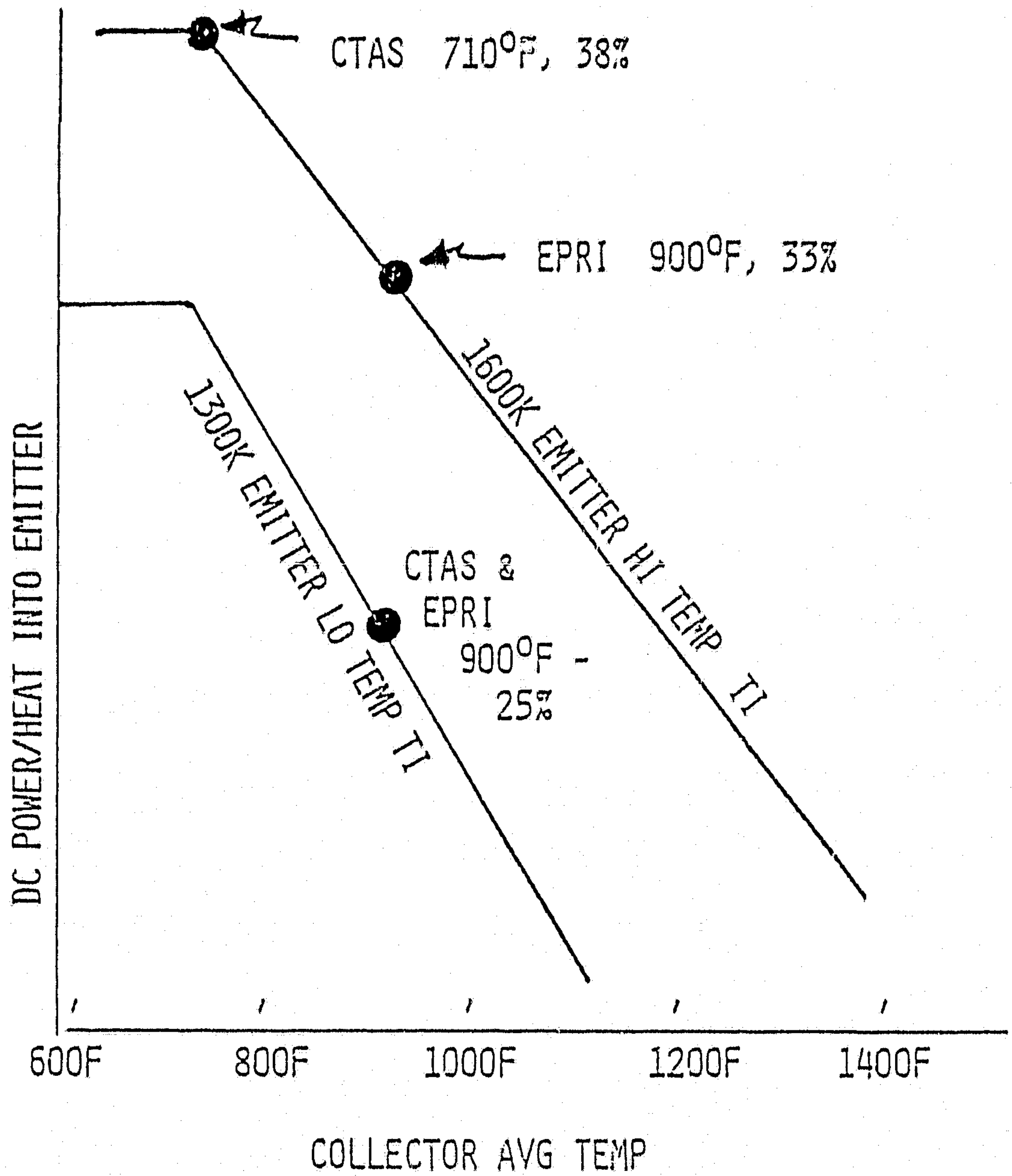


Figure 6.5-57. Thermionic Unit Performance

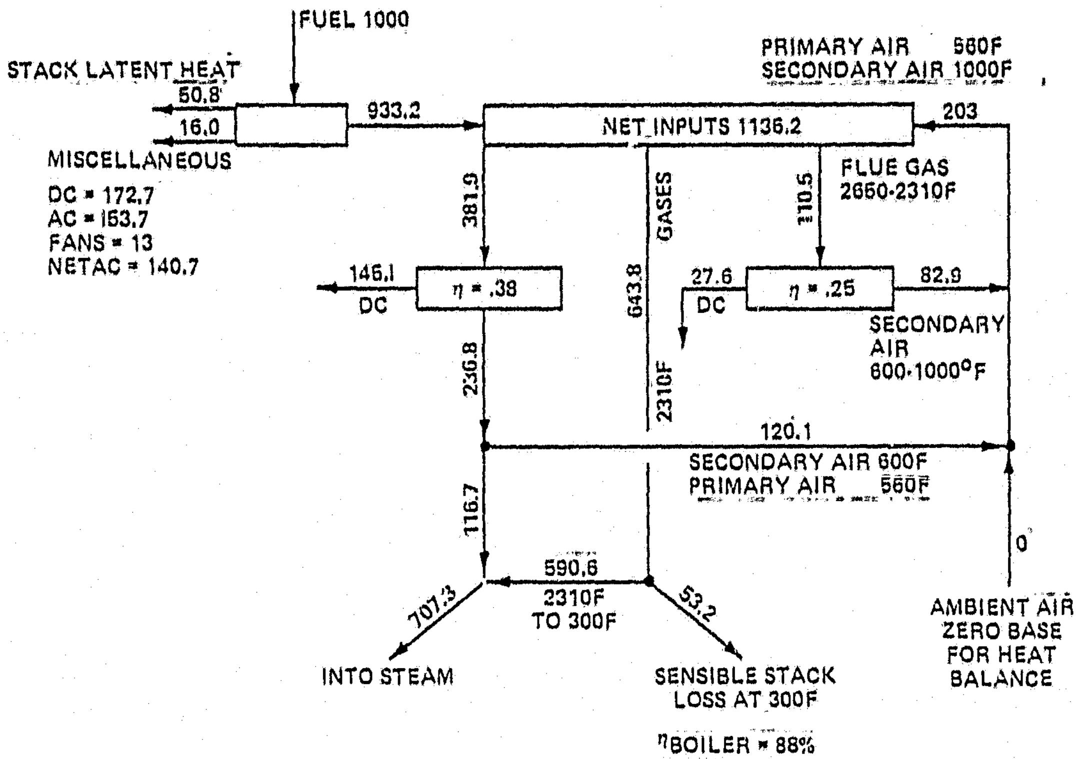


Figure 6.5-58. Thermionic-Steam Cogenerator Heat Balance Based on 1000 Btu Coal HHV

The 110.5 units of input to the low temperature thermionic elements create 27.6 units of dc electricity and 82.9 units of net heat to combustion air. The flue gas stream delivers 590.6 units of heat to steam. The conversion of dc to ac incurs losses that result in 153.7 units of ac output. The restricted airflow path through the thermionic collectors requires additional fan power of 13 units. The bottom line result is that 1000 units of fuel energy produce 140.7 units of net electric output from the thermionic elements and 707.3 units of heat in steam.

Figure 6.5-59 presents the cogeneration characteristic for the thermionic topped process boiler. The gradual drop in heat to process is due to the small effect of blowdown of drum water from the process boiler.

Figure 6.5-60 extends the heat balance of Figure 6.5-58 for the production of steam at 1465 psia, 1000 F throttle condition for expansion through a non-condensing steam turbine with turbine exhaust steam providing heat to process. For a 350 F process the heat to process would be 0.587 of fuel energy, the steam turbine power would be 0.115 of fuel energy, and the thermionic net ac output would remain at 0.141 of fuel energy. The resulting relations for power (PWR) and heat to process (HTP) as ratios of fuel HHV are expressed in terms of process temperature in degrees F (TPRO) in Figure 6.5-60. The cogeneration characteristics for this arrangement are shown in Figure 6.5-61.

TIHRSG THERMIONIC HRSG 3 MW/100 MW 1995

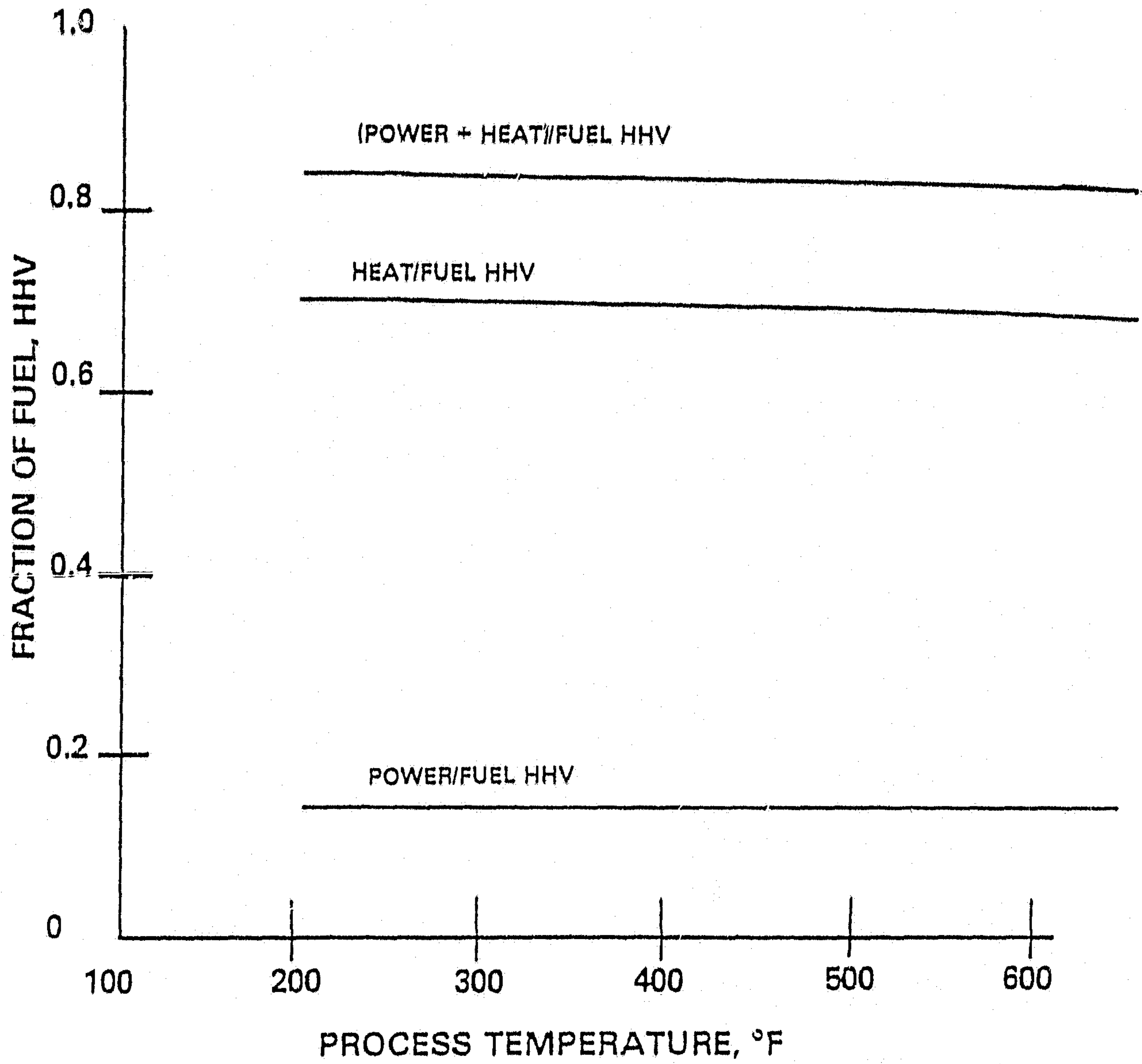
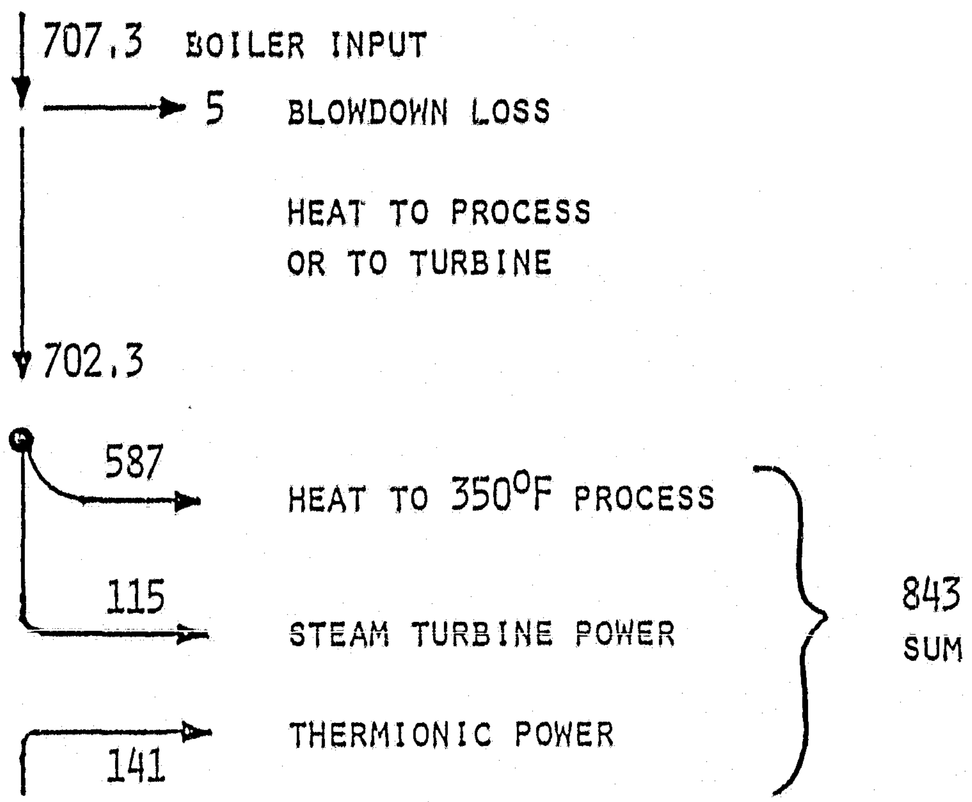


Figure 6.5-59. Energy Conversion System Characteristics. Thermionic Topped Boiler, Coal Fired, Flue Gas Desulfurization, DC inverted to AC. Applicable Size, 3 to 100 MW; Available, 1995



$$PWR = 0.415 - 0.431^* \left(\frac{TPRO}{1000}\right) - 0.0664^* \left(\frac{TPRO}{1000}\right)^2$$

TI PART IS 0.141

$$HTP = 0.428 + 0.431^* \left(\frac{TPRO}{1000}\right) + 0.0664^* \left(\frac{TPRO}{1000}\right)^2$$

Figure 6.5-60. Thermionic-Steam Turbine Bottoming Heat Balance 350°F (1000 Units Fuel HHV Basis)

TISTMT TI-STMTB-1465/1000F 12 MW/300 MW 1995

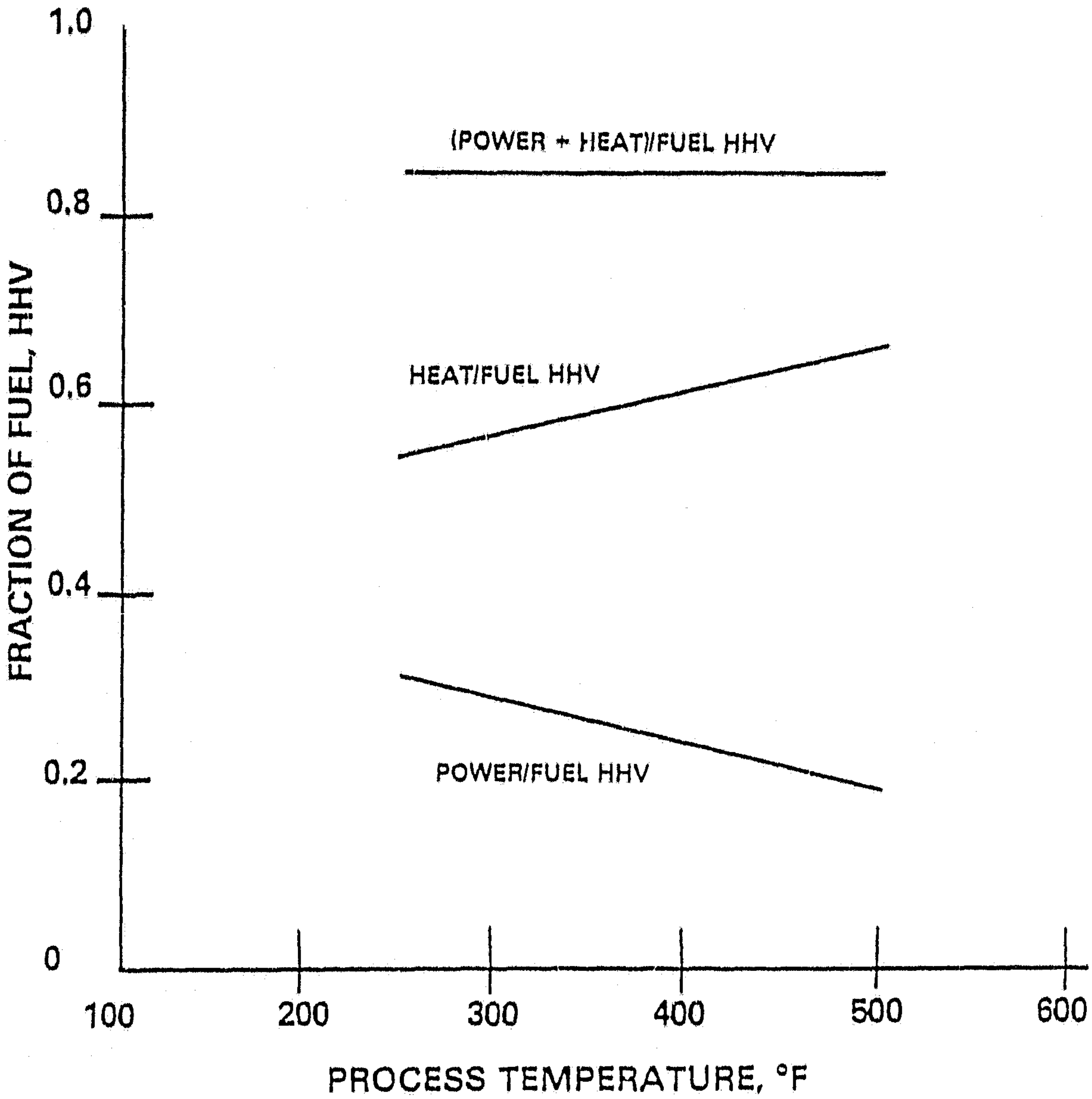


Figure 6.5-61. Energy Conversion System Characteristics. Thermionic Topping at 1465 psia, 1000°F Steam Turbine, Non-Condensing, Coal-Fired with FGD. Applicable Size, 12 to 300 MW; Available, 1995

Overview

The endeavor of this work was to project each energy conversion system at a level of performance that could be commercially available to industry in the time span of 1985 to 1995 in order to produce fuel savings of significance before 2000. There is a significant time span between laboratory demonstration of a concept and a readiness to offer commercial performance guarantees to a purchaser. The selections made do not deny any additional technical potential; only the timing of realization of the greatly advanced technology.

6.6 PERFORMANCE AND DATA SUMMARY

The performance input data file for each energy conversion system was comprised of the elements shown in Table 6.6-1. That table illustrates, for example, the line items of the Thermionic Steam Turbine energy conversion system. A six character ECS name is followed by a more extensive name. In this case the name indicates that the steam turbine has 1465 psia, 1000 F throttle conditions. The size indicates the applicable range of one unit. Multiple units could, of course, be combined. The date indicates the earliest commercial service expectation. The fuel options in this example are petroleum residual, coal-derived residual, and coal with flue gas desulfurization. The constants for the characterizing equations (see Section 6.4) are given and the temperatures for which they were derived. Finally the date of last revision of the input data.

The summary of all these data are presented in Table 6.6-2. The characteristic for the diesel engines had three discrete line segments dependent on the process temperature. These have been given as a line for each line segment over the temperature ranges of 150 to 227 F, 228 F to 249 F and at 250 F to 450 F for the Diesel-Advanced. The general order of conversion systems in the table proceeds from coal burners to residual burners to distillate burners.

In the fuel option field the Y indicates options evaluated and N the options not evaluated. The sequence of eight options are presented in the following order: petroleum distillate (D), and residual (R); coal-derived liquid distillate (D) and residual (R); coal-fired with flue gas desulfurization (F), with atmospheric fludized bed (A), with pressurized fluidized bed (P), and exceptions (X). All coal gasifiers were treated as exceptions as were the special atmospheric fludized beds for helium heating, the stirling coal-fired configuration, and the thermionic coal-fired configuration.

Table 6.6-1

ENERGY CONVERSION SYSTEM (ECS) INPUT DATA FILE

ECS	TISTMT
ECS	TI-STMTB-1465/1000F
Size	12 to 300 MW
Date	1995
Fuel	Residual, Coal Residual, Coal-FGD
Heat	0.4281
	$+0.4310 * (TPRO/1000)$
	$+0.0664 * (TPRO/1000)^2$
Power	0.4149
	$-0.4310 * (TPRO/1000)$
	$-0.0664 * (TPRO/1000)^2$
Temperature	250 to 500 F T Process
Date Revised	11-20-78

Table 6.6-2

DATE 05/10/79
I&SE PE0

GENERAL ELECTRIC COMPANY
ENERGY CONVERSION SYSTEM CHARACTERISTICS

ECS	ECS	SIZE MIN MW	SIZE MAX MW	DATE	FUEL PTR D	FUEL PTR R	COAL D	COAL R	COAL F	COAL A	COAL P	COAL X	HEAT A1	HEAT B1 *10**-3	HEAT C1 *10**-6	POWER A2	POWER B2 *10**-3	POWER C2 *10**-6	TEMP MIN	TEMP MAX	DATE REVISED
1 SIM141	SIM-TURB-1465/10	7.5	100.0	1978	N	Y	N	Y	Y	Y	N	N	0.5159	0.5380	0.0500	0.3341	-0.5300	-0.0500	250	500	11-16-78
2 SIM050	SIM-TURB-865/825	5.0	50.0	1978	N	Y	N	Y	Y	Y	N	N	0.5469	0.5452	0.0600	0.3031	-0.5452	-0.0600	250	450	11-20-78
3 PFBSIN	PFB-SIMTB-1465/1	13.0	600.0	1990	N	N	N	N	N	N	Y	N	0.4733	0.4645	0.	0.3933	-0.5051	0.	250	600	11-20-78
4 TISIN1	TI-SIMTB-1465/10	12.0	300.0	1995	N	Y	N	Y	N	N	N	Y	0.4281	0.4310	0.0664	0.4149	-0.4310	-0.0664	250	500	11-20-78
5 THRSC	THERMIONIC-HRSG	3.0	100.0	1995	N	Y	N	Y	N	N	N	Y	0.7071	0.0004	-0.0456	0.1407	0.	0.	250	650	11-20-78
6 STIR	STIRLING-1472F	0.5	2.0	1990	Y	Y	Y	Y	N	N	N	Y	0.4172	0.0891	0.2037	0.3077	-0.0660	-0.2350	228	500	11-16-78
7 HEGT85	HELIUM-GT-85-REG	50.0	300.0	1990	N	N	N	N	N	Y	N	N	0.4460	-0.2737	-1.7050	0.3210	0.	0.	250	400	01-04-79
8 HEGT60	HELIUM-GT-60-REG	50.0	300.0	1990	N	N	N	N	N	Y	N	N	0.4297	-0.1910	-1.5600	0.2590	0.	0.	250	550	01-04-79
9 HEGT00	HELIUM-GT-00-REG	50.0	300.0	1990	N	N	N	N	N	Y	N	N	0.6044	-0.4000	0.2270	0.1760	0.	0.	250	600	01-04-79
10 FCMCCL	FUEL-CL-MOLTCARB	100.0	1000.0	1990	N	N	N	N	N	N	N	Y	0.4783	-0.0046	-0.0245	0.3040	0.	0.	250	650	11-16-78
11 FCSTCL	FUEL-CL-SIMTB-CO	125.0	1250.0	1990	N	N	N	N	N	N	N	Y	0.2873	0.3150	0.	0.4918	-0.3150	0.	250	500	11-16-78
12 ICGTST	INT-GAS-GTST-12/	80.0	500.0	1990	N	N	N	N	N	N	N	Y	0.3100	0.3225	0.0300	0.4000	-0.3225	-0.0300	250	500	04-22-79
13 GTS0HR	GT-HRSG-10/1750R	10.0	60.0	1978	N	Y	N	Y	N	N	N	N	0.4941	-0.0820	-0.2909	0.2900	0.	0.	250	600	11-16-78
14 GTAC08	GT-HRSG-08/2200R	14.0	136.0	1985	N	Y	N	Y	N	N	N	N	0.4803	0.1564	-0.1715	0.2700	0.	0.	250	600	11-16-78
15 GTAC12	GT-HRSG-12/2200R	14.0	143.0	1985	N	Y	N	Y	N	N	N	N	0.5161	-0.2437	0.2703	0.3050	0.	0.	250	600	11-16-78
16 GTAC16	GT-HRSG-16/2200R	14.0	143.0	1990	N	Y	N	Y	N	N	N	N	0.5921	-0.2609	0.1929	0.3230	0.	0.	250	600	11-16-78
17 GTUC16	GT-HRSG-16/2600R	20.0	200.0	1990	N	Y	N	Y	N	N	N	N	0.3991	0.0209	-0.0155	0.3150	0.	0.	250	600	11-16-78
18 CC1626	GTST-16/2600/146	20.0	197.0	1990	N	Y	N	Y	N	N	N	N	0.2260	0.2355	0.0220	0.4616	-0.2355	-0.0220	250	450	11-16-78
19 CC1622	GTST-16/2200/865	26.0	165.0	1990	N	Y	N	Y	N	N	N	N	0.2504	0.2496	0.0275	0.4619	-0.2496	-0.0275	250	450	11-16-78
20 CC1222	GTST-12/2200/146	14.0	143.0	1995	N	Y	N	Y	N	N	N	N	0.2497	0.2604	0.0243	0.4665	-0.2604	-0.0243	250	450	11-16-78
21 CC0822	GTST-08/2200/146	14.0	136.0	1985	N	Y	N	Y	N	N	N	N	0.2957	0.3082	0.0208	0.4613	-0.3082	-0.0208	250	450	11-16-78
22 STIG15	STIG-15-16/2200F	22.0	220.0	1990	N	Y	N	Y	N	N	N	N	0.0130	0.	0.	0.3810	0.	0.	250	430	11-16-78
23 STIG10	STIG-10-16/2200F	19.0	190.0	1990	N	Y	N	Y	N	N	N	N	0.1325	0.	0.	0.3591	0.	0.	250	430	11-16-78
24 STIG1	STIG-15-16/2200F	19.0	190.0	1990	N	Y	N	Y	N	N	N	N	0.2100	0.	0.	0.3352	0.	0.	250	430	11-16-78
25 DEADV3	DIESEL-ADVANCED-	2.0	15.0	1990	N	Y	N	Y	N	N	N	N	0.3598	-0.4230	0.	0.3710	0.	0.	250	450	11-20-78
26 DEADV2	DIESEL-ADVANCED-	2.0	15.0	1990	N	Y	N	Y	N	N	N	N	0.2540	0.	0.	0.3710	0.	0.	228	249	11-16-78
27 DEADV1	DIESEL-ADVANCED-	2.0	15.0	1990	N	Y	N	Y	N	N	N	N	0.3910	0.	0.	0.3710	0.	0.	150	227	11-16-78
28 DEHTH	ADV-DIESEL-HEAT-	2.0	15.0	1990	N	Y	N	Y	N	N	N	N	0.5092	-0.4036	0.5000	0.4012	-0.0197	-0.5000	220	500	11-16-78
29 DESOA3	DIESEL-SOA-3	0.3	10.0	1978	Y	Y	Y	Y	N	N	N	N	0.3250	-0.4230	0.	0.3610	0.	0.	250	450	11-16-78
30 DESOA2	DIESEL-SOA-2	0.3	10.0	1978	Y	Y	Y	Y	N	N	N	N	0.2200	0.	0.	0.3610	0.	0.	155	249	11-16-78
31 DESOA1	DIESEL-SOA-1	0.3	10.0	1978	Y	Y	Y	Y	N	N	N	N	0.4010	0.	0.	0.3610	0.	0.	100	154	11-16-78
32 GTSOAH	GT-HRSG-10/2000D	13.0	72.0	1978	Y	N	Y	N	N	N	N	N	0.5303	-0.3296	0.3167	0.2920	0.	0.	250	600	11-16-78
33 GTRA08	GT-85RE-08/2200D	13.0	130.0	1985	Y	N	Y	N	N	N	N	N	0.4039	0.0554	-0.6556	0.3570	0.	0.	250	600	11-16-78
34 GTRA1	GT-85RE-12/2200D	14.0	137.0	1985	Y	N	Y	N	N	N	N	N	0.4077	0.0097	-0.5019	0.3500	0.	0.	250	600	11-16-78
35 GTRA16	GT-85RE-16/2200D	14.0	130.0	1990	Y	N	Y	N	N	N	N	N	0.4251	-0.0315	-0.3023	0.3490	0.	0.	250	600	11-16-78
36 GTR20	GT-60RE-08/2200D	13.0	130.0	1985	Y	N	Y	N	N	N	N	N	0.4722	-0.1399	-0.1411	0.3200	0.	0.	250	600	11-16-78
37 GTR21	GT-60RE-12/2200D	14.0	130.0	1985	Y	N	Y	N	N	N	N	N	0.4475	-0.0990	-0.1818	0.3300	0.	0.	250	600	11-16-78
38 GTR21	GT-60RE-16/2200D	14.0	139.0	1990	Y	N	Y	N	N	N	N	N	0.4465	-0.0903	-0.2117	0.3370	0.	0.	250	600	11-16-78
39 GTR00	GT-85RE-08/2600D	17.0	169.0	1990	Y	N	Y	N	N	N	N	N	0.3302	0.0246	-0.4617	0.3510	0.	0.	250	600	11-16-78
40 GTRN1	GT-85RE-12/2600D	19.0	180.0	1990	Y	N	Y	N	N	N	N	N	0.3330	-0.0106	-0.3406	0.3640	0.	0.	250	600	11-16-78
41 GTRN1	GT-85RE-16/2600D	19.0	190.0	1990	Y	N	Y	N	N	N	N	N	0.3503	-0.0560	-0.2182	0.3570	0.	0.	250	600	11-16-78
42 GTR30	GT-60RE-08/2600D	17.0	170.0	1990	Y	N	Y	N	N	N	N	N	0.4437	-0.3540	0.0124	0.3100	0.	0.	250	600	11-16-78
43 GTR31	GT-60RE-12/2600D	19.0	190.0	1990	Y	N	Y	N	N	N	N	N	0.3816	-0.1419	0.0133	0.3420	0.	0.	250	600	11-16-78
44 GTR31	GT-60RE-16/2600D	19.0	190.0	1990	Y	N	Y	N	N	N	N	N	0.3844	-0.1486	0.0278	0.3390	0.	0.	250	600	11-16-78
45 FCPAD	FUEL-CL-PHOSACID	1.0	10.0	1985	Y	N	Y	N	N	N	N	N	0.1700	0.	0.	0.3800	0.	0.	160	600	04-22-79
46 FCMCD	FUEL-CL-MOLTCARB	4.4	25.0	1990	Y	N	Y	N	N	N	N	N	0.2330	0.	0.	0.4120	0.	0.	200	650	11-16-78

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Table 6.6-3 presents evaluations at 250 F and at 350 F process temperatures for the ratio of power to heat (P/H) of the ECS, the ratio of power to fuel energy (PWR), the ratio of heat to process to fuel energy (HT), and the fuel energy effectively used (EFEC). These data show the great variation in ECS power to heat ratio and the great variation in the amount of fuel energy effectively used. The star values were exceedingly large. The zero values for the diesels are in inappropriate temperature ranges.

Table 6.6-3

Energy Conversion System Characteristics

ECS	ECS	SIZE MIN MW	SIZE MAX MW	DATE	PTR D	PTR R	COAL D	COAL R	COAL F	COAL A	COAL P	COAL X	T= 250. P/H	T= 250. PWR	T= 250. HT	T= 250. EFEC	T= 350. P/H	T= 350. PWR	T= 350. HT	T= 350. EFEC
					*****	FUEL	******						POWER/HEAT RATIO FOR PROCESS TEMPERATURE				POWER/HEAT RATIO FOR PROCESS TEMPERATURE			
STM141	STM-TURB-1465/1000F	7.5	100.0	1978	N	Y	N	Y	Y	Y	N	N	0.3006	0.1965	0.6535	0.8500	0.1966	0.1397	0.7103	0.8500
STM088	STM-TURB-865/825F	5.0	50.0	1978	N	Y	N	Y	Y	Y	N	N	0.2374	0.1631	0.6870	0.8500	0.1408	0.1049	0.7451	0.8500
PFBSTM	PFB-STMTB-1465/1000F	13.0	600.0	1990	N	N	N	N	N	N	Y	N	0.4361	0.2570	0.5894	0.8465	0.3248	0.2065	0.6359	0.8424
TISTMT	TI-STMTB-1465/1000F	12.0	300.0	1995	N	Y	N	Y	N	N	N	Y	0.5611	0.3030	0.5400	0.8430	0.4359	0.2559	0.5871	0.8430
TIHRSG	THERMIONIC-HRSG	3.0	100.0	1995	N	Y	N	Y	N	N	N	Y	0.2074	0.1407	0.6765	0.8192	0.2361	0.1407	0.6510	0.7917
STIRL	STIRLING-1472F	0.5	2.0	1990	Y	Y	Y	Y	N	N	N	Y	0.6114	0.2765	0.4522	0.7287	0.5402	0.2557	0.4733	0.7291
HEGT85	HELIUM-GT-85-REGEN	50.0	300.0	1990	N	N	N	N	N	Y	N	N	1.1810	0.3210	0.2718	0.5928	2.2583	0.3210	0.1421	0.4631
HEGT60	HELIUM-GT-60-REGEN	50.0	300.0	1990	N	N	N	N	N	Y	N	N	0.6817	0.2590	0.3799	0.6390	0.8479	0.2590	0.3054	0.5644
HEGT00	HELIUM-GT-00-REGEN	50.0	300.0	1990	N	N	N	N	N	Y	N	N	0.3394	0.1760	0.5186	0.6946	0.3576	0.1760	0.4922	0.6682
FCMCCL	FUEL-CL-MOLTCARB-CL	100.0	1000.0	1990	N	N	N	N	N	N	N	Y	0.6392	0.3040	0.4756	0.7796	0.6418	0.3040	0.4737	0.7777
FCSTCL	FUEL-CL-STMTB-COAL	125.0	1250.0	1990	N	N	N	N	N	N	N	Y	1.1284	0.4131	0.3661	0.7791	0.9598	0.3816	0.3976	0.7791
IGGTST	INT-GAS-GTST-10/2200	80.0	500.0	1990	N	N	N	N	N	N	N	Y	0.8089	0.3175	0.3925	0.7100	0.6645	0.2835	0.4265	0.7100
GTSOAR	GT-HRSG-10/1750R-AC	10.0	60.0	1978	N	Y	N	Y	N	N	N	N	0.6375	0.2900	0.4549	0.7449	0.6763	0.2960	0.4288	0.7188
GTAC08	GT-HRSG-08/2200R-AC	14.0	136.0	1985	N	Y	N	Y	N	N	N	N	0.5308	0.2700	0.5087	0.7787	0.5253	0.2700	0.5140	0.7840
GTAC12	GT-HRSG-12/2200R-AC	14.0	143.0	1985	N	Y	N	Y	N	N	N	N	0.6454	0.3050	0.4726	0.7776	0.6561	0.3050	0.4649	0.7699
GTAC16	GT-HRSG-16/2200R-AC	14.0	143.0	1990	N	Y	N	Y	N	N	N	N	0.7195	0.3230	0.4489	0.7719	0.7435	0.3230	0.4344	0.7574
GTWC16	GT-HRSG-16/2600R-WC	20.0	200.0	1990	N	Y	N	Y	N	N	N	N	0.7810	0.3150	0.4033	0.7183	0.7787	0.3150	0.4045	0.7195
CC1626	GTST-16/2600/1465-WC	20.0	197.0	1990	N	Y	N	Y	N	N	N	N	1.4021	0.4013	0.2863	0.6876	1.2100	0.3765	0.3111	0.6876
CC1622	GTST-16/2200/865-AC	26.0	165.0	1990	N	Y	N	Y	N	N	N	N	1.2647	0.3978	0.3145	0.7123	1.0881	0.3712	0.3411	0.7123
CC1222	GTST-12/2200/1465-AC	14.0	143.0	1985	N	Y	N	Y	N	N	N	N	1.2633	0.3999	0.3165	0.7164	1.0824	0.3724	0.3440	0.7164
CC0822	GTST-08/2200/1465-AC	14.0	136.0	1985	N	Y	N	Y	N	N	N	N	1.0211	0.3824	0.3746	0.7570	0.8595	0.3499	0.4071	0.7570
STIG15	STIG-15-16/2200F-AC	22.0	230.0	1990	N	Y	N	Y	N	N	N	N	******	0.3810	0.0130	0.3940	******	0.3810	0.0130	0.3940
STIG10	STIG-10-16/2200F-AC	19.0	190.0	1990	N	Y	N	Y	N	N	N	N	2.7102	0.3591	0.1325	0.4916	2.7102	0.3591	0.1325	0.4916
STIG15	STIG-15-16/2200F-AC	19.0	190.0	1990	N	Y	N	Y	N	N	N	N	1.5901	0.3352	0.2108	0.5460	1.5901	0.3352	0.2108	0.5460
DEADV3	DIESEL-ADVANCED-3	2.0	15.0	1990	N	Y	N	Y	N	N	N	N	1.4603	0.3710	0.2540	0.6251	1.7521	0.3710	0.2117	0.5828
DEADV2	DIESEL-ADVANCED-2	2.0	15.0	1990	N	Y	N	Y	N	N	N	N	0.	0.	0.	0.	0.	0.	0.	0.
DEADV1	DIESEL-ADVANCED-1	2.0	15.0	1990	N	Y	N	Y	N	N	N	N	0.	0.	0.	0.	0.	0.	0.	0.
DEHTPM	ADV-DIESEL-HEAT-PUMP	2.0	15.0	1990	N	Y	N	Y	N	N	N	N	0.8305	0.3650	0.4396	0.8046	0.7760	0.3331	0.4292	0.7622
DESOA3	DIESEL-50A-3	0.3	10.0	1978	Y	Y	Y	Y	N	N	N	N	1.6405	0.3610	0.2201	0.5811	2.0309	0.3610	0.1778	0.5388
DESOA2	DIESEL-50A-2	0.3	10.0	1978	Y	Y	Y	Y	N	N	N	N	0.	0.	0.	0.	0.	0.	0.	0.
DESOA1	DIESEL-50A-1	0.3	10.0	1978	Y	Y	Y	Y	N	N	N	N	0.	0.	0.	0.	0.	0.	0.	0.
GTSOAD	GT-HRSG-10/2000D-AC	13.0	72.0	1978	Y	N	Y	N	N	N	N	N	0.6132	0.2920	0.4762	0.7682	0.6317	0.2920	0.4622	0.7542
GTRA08	GT-85RE-08/2200D-AC	13.0	130.0	1985	Y	N	Y	N	N	N	N	N	0.9478	0.3570	0.3767	0.7337	1.0412	0.3570	0.3429	0.6999
GTRA12	GT-85RE-12/2200D-AC	14.0	137.0	1985	Y	N	Y	N	N	N	N	N	0.9398	0.3580	0.3809	0.7389	1.0176	0.3580	0.3518	0.7098
GTRA16	GT-85RE-16/2200D-AC	14.0	138.0	1990	Y	N	Y	N	N	N	N	N	0.8873	0.3490	0.3933	0.7423	0.9503	0.3490	0.3673	0.7163
GTR208	GT-60RE-08/2200D-AC	13.0	130.0	1985	Y	N	Y	N	N	N	N	N	0.7470	0.3200	0.4284	0.7484	0.7683	0.3200	0.4060	0.7260
GTR212	GT-60RE-12/2200D-AC	14.0	138.0	1985	Y	N	Y	N	N	N	N	N	0.8025	0.3300	0.4112	0.7412	0.8455	0.3300	0.3903	0.7203
GTR216	GT-60RE-16/2200D-AC	14.0	139.0	1990	Y	N	Y	N	N	N	N	N	0.8206	0.3370	0.4107	0.7477	0.8665	0.3370	0.3889	0.7259
GTRW08	GT-85RE-08/2600D-WC	17.0	169.0	1990	Y	N	Y	N	N	N	N	N	1.1415	0.3510	0.3075	0.6585	1.2435	0.3510	0.2823	0.6333
GTRW12	GT-85RE-12/2600D-WC	19.0	188.0	1990	Y	N	Y	N	N	N	N	N	1.1778	0.3640	0.3091	0.6731	1.2658	0.3640	0.2876	0.6516
GTRW16	GT-85RE-16/2600D-WC	19.0	190.0	1990	Y	N	Y	N	N	N	N	N	1.1064	0.3570	0.3227	0.6797	1.1744	0.3570	0.3040	0.6610
GTR308	GT-60RE-08/2600D-WC	17.0	170.0	1990	Y	N	Y	N	N	N	N	N	0.8588	0.3100	0.3610	0.6710	0.9500	0.3100	0.3263	0.6363
GTR312	GT-60RE-12/2600D-WC	19.0	190.0	1990	Y	N	Y	N	N	N	N	N	0.9857	0.3420	0.3470	0.6890	1.0253	0.3420	0.3336	0.6756
GTR316	GT-60RE-16/2600D-WC	19.0	190.0	1990	Y	N	Y	N	N	N	N	N	0.9714	0.3390	0.3490	0.6880	1.0096	0.3390	0.3358	0.6748
FCPADS	FUEL-CL-PHOSACID-DS	1.0	10.0	1985	Y	N	Y	N	N	N	N	N	2.2353	0.3800	0.1700	0.5500	2.2353	0.3800	0.1700	0.5500
FCMCDS	FUEL-CL-MOLTCARB-DS	4.4	25.0	1990	Y	N	Y	N	N	N	N	N	1.7682	0.4120	0.2330	0.6450	1.7682	0.4120	0.2330	0.6450

6.7 COGENERATION FUEL SAVED WINDOWS

The fuel-saving capability of cogeneration systems is of prime national significance. Although this aspect will be explored in depth using the ECS characteristics coupled to explicit industrial plants, it is worthwhile to secure a graphic insight of the prospect for fuel saving. These relationships have been derived and verified mathematically. Only the logic for a few specific situations will be reviewed here. The end result of this graphical approach is that for any selected process temperature a figure can quickly be constructed so that one can see the order of fuel savings that can be anticipated and one can see how the process demand for power and heat effect the fuel energy saved ratio.

Figure 6.7-1 crossplots the data from Table 6.6-2 for coal fueled energy conversion systems with 350 F process temperature. Lines of constant fuel energy saved ratio (FESR) are downslanting parallel lines. The "NO HEAT" point on the left ordinate stands for the purchase of electricity from the utility which is no cogeneration. Similarly the "NO POWER" point at 0.85 on the heat axis is the condition for a no cogeneration process boiler or for any auxiliary process boiler. The line connecting the "NO HEAT" and "NO POWER" points represents all ratios of power to heat for non-cogeneration cases. It is obvious that there would be no fuel saved along that characteristic line. The succession of increasing FESR characteristics lie above the non-cogeneration line. The selected definition of FESR produces the unequal spread in those lines. When the fuel saved is expressed as a ratio to only the cogeneration fuel energy the spread is constant. The cogeneration fuel energy appears to be a fundamental entity.

An industrial plant or process has an exact power to process heat ratio that must be satisfied. Such a requirement would show up as a ray or line emanating from the axis origins of Figure 6.7-1. Such a line going through the upper steam turbine point would lie close to the Thermionic-HRSG (TI) point. It would be remote from the molten carbonate fuel cell with steam turbine (Fuel Cell STM) point. The fuel cell system would satisfy the power requirement, but it would produce insufficient heat.

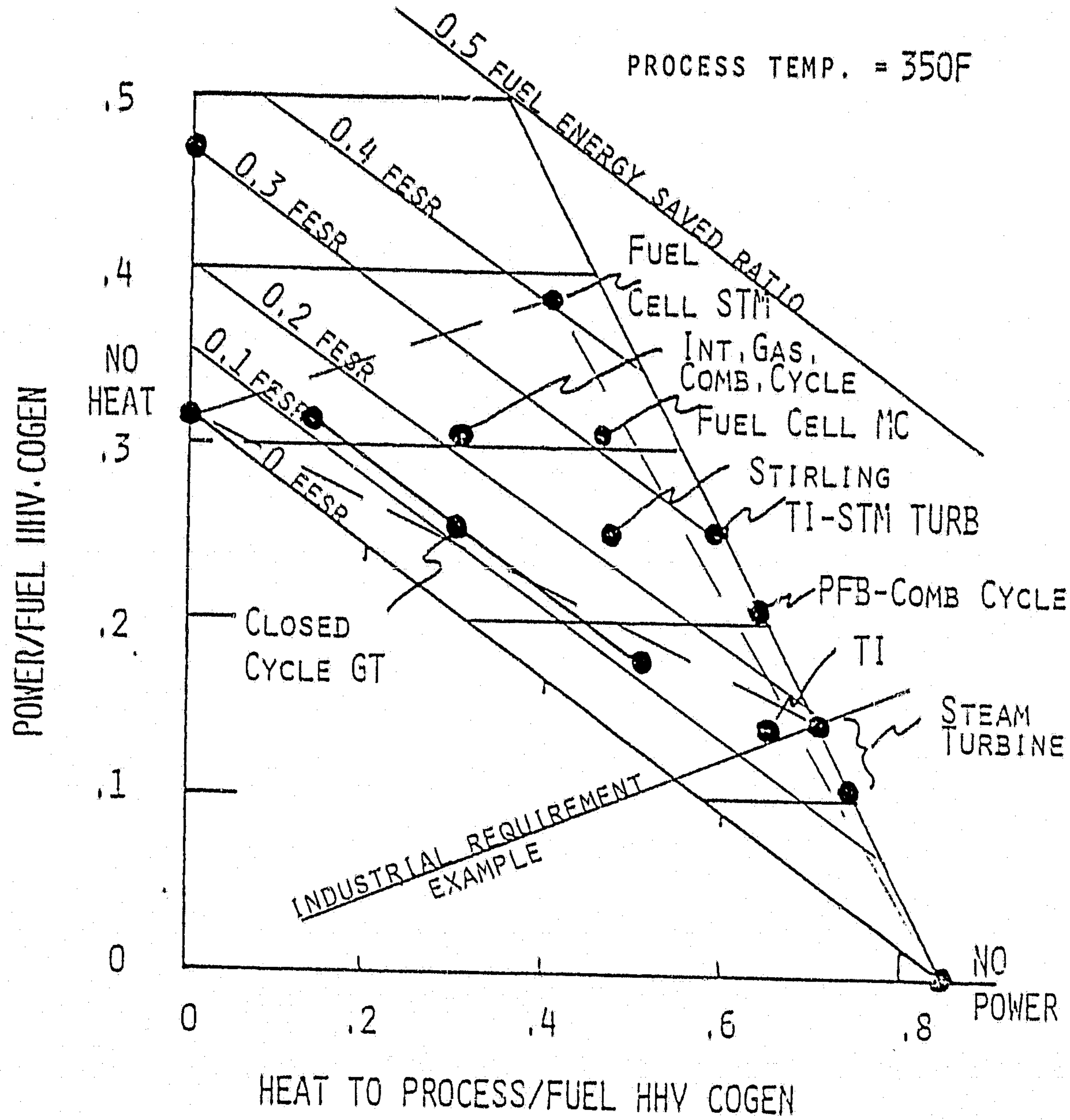

Figure 6.7-1. Cogeneration Window for Energy Conversion Systems Using Coal

An auxiliary boiler would produce the remainder of the heat. The dashed line from the fuel cell point shows all proportions of added auxiliary boiler. The FESR drops rapidly along that dashed line. At the industrial requirement example ratio the FESR for the fuel cell is poorer than the steam turbine, but superior to the thermionic unit (TI). By similar dashed line connections to both the "NO HEAT" point and the "NO POWER" point, one can see the range and order of FESR for any specified industrial power to heat requirement.

The entire characteristic for the Fuel Cell STM as shown by the dashed lines gives insight as to the industrial process and energy conversion matches that will produce the greatest fuel energy saved ratio (FESR). Any deviation from the power to heat ratio of the ECS degrades the FESR. Hence the optimum is exactly at the ECS power to heat ratio for each individual ECS. The computer program that evaluates all combinations produces two matches. One exactly matches the heat required by process. The other exactly matches the power required on-site. Of these two matches, one will generally require either heat makeup with an auxiliary boiler, or power makeup from the utility. That combination will be the typical on-site cogeneration system with no power export and no excess heat. The second combination would export power, and would exactly match the power to heat ratio of the ECS. On that basis the hierarchy of FESR for the power export cases can be seen from Figure 6.7-1 and are tabulated in Table 6.7-1.

The characteristics for oil-fired energy conversion systems are shown in Figure 6.7-2. The parametric variations for gas turbines are shown as crosshatched ranges. There is an obvious progression from state-of-the-art (SOA) to advanced gas turbine to regenerative gas turbine to combined cycles. The steam injected gas turbine (STIG) has a very high power to heat ratio. The state-of-the-art (SOA) diesel and the advanced diesel are very close to one another and to the phosphoric acid (PA) fuel cell and the molten carbonate (MC) fuel cell. The heat pumped diesel has a significantly changed characteristic from the other diesels.

Table 6.7-1

HIERARCHY OF FESR FOR COAL-FUELED ENERGY CONVERSION SYSTEMS AT 350 F PROCESS AT OPTIMUM POWER/HEAT RATIO FOR EACH ECS

Energy Conversion System	Fuel Energy Saved Ratio
Molten Carbonate Fuel Cell - Steam Turbine	0.4
Molten Carbonate Fuel Cell - HRSG	0.3
Thermionic - Steam Turbine	0.3
PFB Combined Cycle	0.25
Stirling Cycle	0.24
Integrated Gasifier Combined Cycle	0.22
Steam Turbine	0.2
Thermionic HRSG	0.15
Closed Cycle Gas Turbine	0.12

The thermionic (TI) and steam turbine units have the same location as was the case for coal-fired units. At low power to heat process requirements the steam turbine and even the state-of-the-art gas turbine show very good fuel energy saved ratio. At high power to heat ratio a variety of energy conversion systems may show to best advantage.

Figures of the form of Figure 6.7-1 and Figure 6.7-2 at the process temperature required can give vivid insight of the fuel savings potential of energy conversion system candidates. Placing the process power to heat line on the chart along with line connectors from each ECS point to the "NO" points then shows the range of FESR for on-site cogeneration and the hierarchy amongst the energy conversion systems.

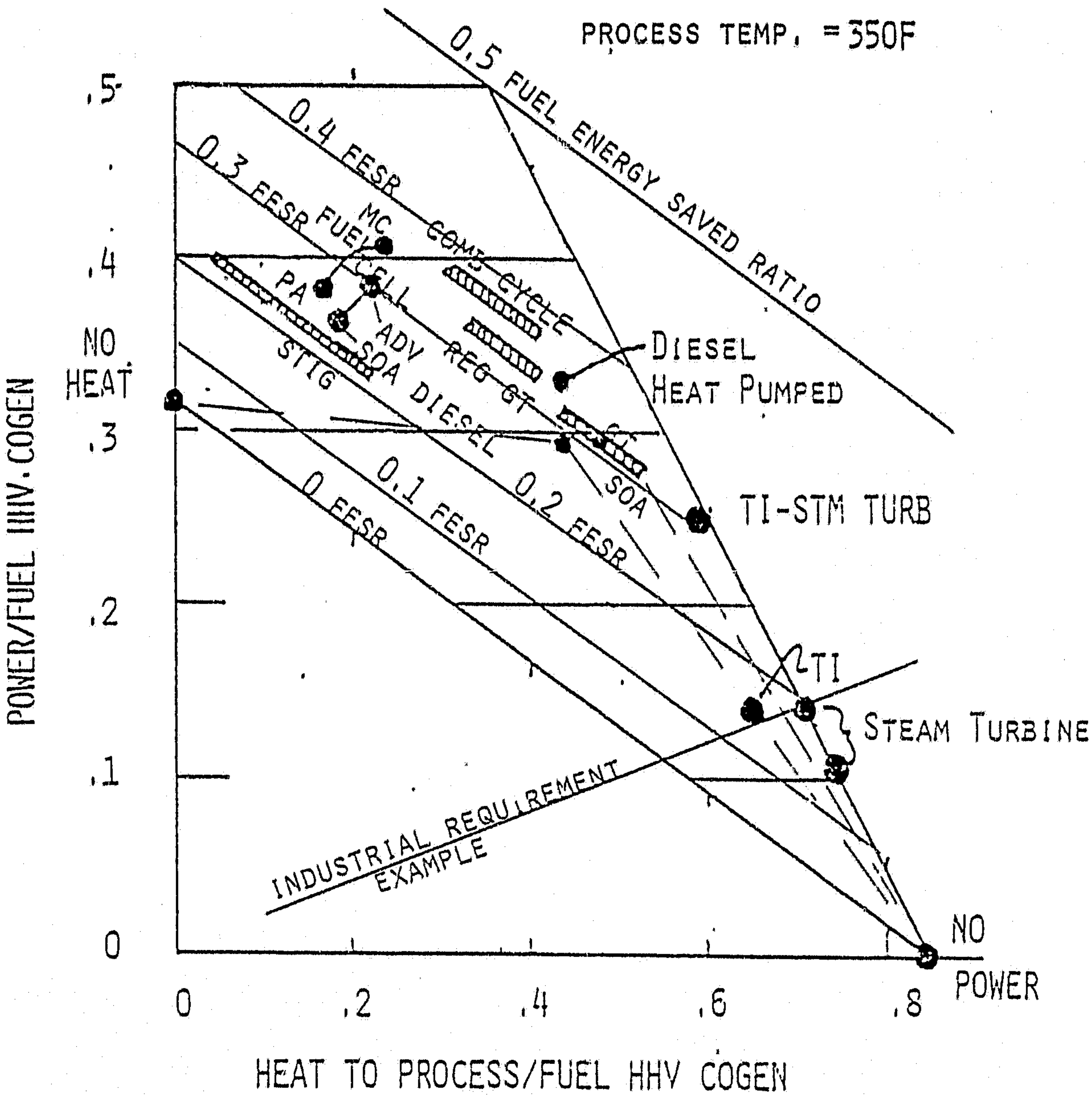

Figure 6.7-2. Cogeneration Window for Energy Conversion Systems Using Oil

6.8 ENVIRONMENTAL, NATURAL RESOURCE, AND OPERATIONAL FACTORS

Introduction

A qualitative review of the emission characteristics, resource requirements, and system flexibility of the cogeneration energy conversion technologies was conducted. The purpose of this assessment was to estimate the range of these factors for the respective technologies, and to identify areas of potential noncompliance and concern, and hence potential development requirements.

The results of this review are enumerated below. The review emphasized major differences between the respective potential cogeneration energy conversion technologies, both advanced and state-of-art, and the nocogeneration case. Although this screening identified some areas requiring improvement, none of the candidate energy conversion technologies were found to present insurmountable obstacles to implementation.

Emissions

Emission guidelines for the study were specified by NASA. The limits for solid and liquid fuels are summarized in Table 6.8-1. Five different fuels, coal and four liquid fuels, were considered in this study. The coal specification, the same as that used in the ECAS studies (Reference 6-2), is given in Table 6.8-2, and the specifications for the liquid fuels are tabulated in Table 6.8-3. Table 6.8-4 presents the estimated emissions of particulates, SO_2 and NO_x for each energy conversion technology and fuel combination. These data were used to estimate the reduction in emissions over the nocogeneration case.

Table 6.8-1

EMISSION GUIDELINES

Pollutant	Units	Solid Fuel	Liquid Fuel
Particulates	(lb/MBtu)	0.1	0.1
SO_2	(lb/MBtu)	1.2	0.8
NO_x	(lb/MBtu)	0.7	0.4-0.5*

* 0.4 for petroleum distillate
  0.5 for petroleum residual and coal derived liquids

Particulates. All coal fired and coal-derived residual fired systems would exceed the guideline limit without particulate removal. In general, the assumption was made that electrostatic precipitators or baghouses would be used to meet the specified limit of 0.1 lb/MBtu.

If a system designed for use with petroleum residual fuel were to be fired on coal-derived residual, the resulting exhaust gas particulate emission would be 0.153 lb/MBtu, 53% above the specified limit. Consequently, fuel washing or particulate removal from the exhaust gas would be required to meet the 0.1 lb/MBtu limit when burning coal-derived residual.

SO_2 Emission. All liquid fuel fired systems will meet the SO_2 limit even if all the sulfur in the fuel were converted to SO_2. The coal fired systems, however, would require some form of sulfur removal, either flue gas desulfurization or fluidized bed combustion. Regardless of the sulfur capture mechanism, the SO_2 emission requirement was set at the maximum allowable limit. This represents the most economical operating condition for these systems.

Table 6.8-2

COAL SPECIFICATION

Proximate Analysis (as received), %		
Moisture	13.0	
Volatile	36.7	
Fixed Carbon	40.7	
Ash	9.6	
Ultimate Analysis (as received), %		
Ash	9.6	
Sulfur	3.9	
Hydrogen	5.9	
Carbon	59.6	
Nitrogen	1.0	
Oxygen	20.0	
Higher Heating Value (as received)		10788 Btu/lb
Gross Heating Value (dry)		12600 Btu/lb
Average Softening Temperature		1979^{o}F
Initial Deformation Temperature		1990-2130^{o}F
Fluid Temperature		2090-2440^{o}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	

Table 6.8-3

LIQUID FUELS SPECIFICATIONS

	Petroleum #2 Distillate	Petroleum #5 Residual	Coal-Derived #2 Distillate	Coal-Derived #5 Residual
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
Viscosity, Centistokes at 100°F	2.5	40.0	2.5	40.0
Boiling Range, °F 90% pts.	430-675	500-800	430-675	500-800
Cetane No.	45	40	45	40
Trace Elements, ppm wt. (order of magnitude)				
Vanadium	0.5	30	0.5	2
Sodium + Potassium	0.5	50	1.0	20
Calcium	1.0	5	2.0	5
Lead	0.5	5	1.0	5
Iron	-	-	30.0	30
Titanium	-	-	20.0	50
Higher (Gross) Heating Value, Btu/lb	19,350	18,500	17,700	17,000

Table 6.8-4

SUMMARY OF ENERGY CONVERSION SYSTEM EMISSION CHARACTERISTICS

Energy Conversion System	Fuel Fired	Pounds/Million Btu Fired		
		NO_x	SO_2	PART.
No-Cogeneration Cases	Coal FGD	0.7	1.2	0.1
	Coal AFB	0.27	1.2	0.1
	Pet Resid	0.22	0.75	0.016
	Pet Dist	0.05	0.52	0.0
	Coal Resid	0.5	0.8	0.1
	Coal Dist	0.46	0.56	0.034
Steam Turbine & Thermionics	Same as No-Cogeneration Cases			
PFB	Coal	0.15	1.2	0.03
Stirling	Coal FGD	0.7	1.2	0.1
	Pet Resid	0.22	0.75	0.016
	Pet Dist	0.05	0.52	0.0
	Coal Resid	0.5	0.8	0.1
	Coal Dist	0.46	0.56	0.034
Helium Closed Cycle Turbine	Coal AFB	0.36	1.2	0.1
Integrated Gasifier Combined Cycle	Coal	0.7	1.2	0.1
Air Cooled Gas Turbines &	Pet Dist	0.4	0.52	0.0
Steam-Injected Gas Turbines	Pet Resid	0.5	0.75	0.016
	Coal Dist	0.8	0.56	0.034
Water Cooled Gas Turbines	Pet Dist	0.4	0.52	0.0
	Pet Resid	0.5	0.75	0.016
	Coal Dist	0.8	0.56	0.034
	Coal Resid	1.2	0.8	0.153
Diesels				
- State-of-the-Art	Pet Dist	3.8	0.52	0.0
	Pet Resid	8.1	0.75	0.016
	Coal Dist	22.0	0.56	0.034
	Coal Resid	28.0	0.8	0.153
- Advanced	Pet Resid	1.9	0.75	0.016
	Coal Resid	1.9	0.8	0.153
Molten Carbonate Fuel Cells	Pet Dist	0.11	0.003	0.0
	Coal Dist	1.51	0.003	0.03
	Coal	0.001	0.001	0.005
Phosphoric Acid Fuel Cells	Pet Dist	0.027	0.0	0.0
	Coal Dist	0.39	0.0	0.0

An exception to this approach was made for the molten carbonate fuel cell which is irreversibly deactivated by sulfur compounds. The low sulfur emissions in these systems are a consequence of the need to limit the concentration of sulfur passing through the cells to a level acceptable for cell performance.

NO_x Emission. Estimating NO_x emissions is difficult because of the two sources of NO_x, fuel bound nitrogen and thermally generated NO_x. The thermally generated NO_x can be limited by reduction of combustion temperature through staged combustion or water injection or a dwell period to equilibrate temperature. These approaches work well in boilers, but have limited applicability in gas turbines and diesel engines where the combustion is rapid and is immediately followed by a gasious expansion that quenches the composition of species as it was at high temperature. Combustion process modification is one approach to limiting NO_x formation in gas turbines and diesels. Another approach is to flow the exhaust gases through a catalytic converter, also with the possible addition of ammonia, to reduce the NO_x concentration. This would be the only means for the diesel to reach the NO_x emission standards. The high level of fuel bound nitrogen in the coal-derived liquid fuels would require special measures to limit or reduce NO_x in applications where the petroleum based liquid fuels could meet the standards.

Land Requirements

A comparison of land requirements for the candidate energy conversion technologies was made using as a basis a plant firing fuel at a continuous rate equal to 100 MW of fuel energy release and including facilities to store on-site a thirty day fuel supply. Table 6.8-5 summarizes the estimated land requirements. The land requirements ranged from 50,000 to 130,000 square feet exclusive of sludge disposal ponds. Most of the plants were in the 60,000 to 100,000 square feet range. The land area required for the fuel supply is not significantly different for storage of either coal or liquid fuels. This is primarily due to the requirement for a diked area surrounding each fuel oil storage tank, which must be capable of containing the fuel in the event of a tank rupture.

Table 6.8-5

ESTIMATES OF LAND USAGE

BASIS: 100 MW_t Plant
30 day fuel storage
Sludge disposal area not included in coal fired systems.

Energy Conversion System	Land Area Required (10^3 ft^2) Coal	Liquid Fuel
Stirling Engine	70	50
Gas Turbine	NA	60
Diesel Engine	NA	80
Steam Turbine	100	60
Integrated Gasification Combined Cycle	90	NA
Phosphoric Acid Fuel Cell	NA	80
Molten Carbonate Fuel Cell	100	90
Helium Closed Cycle Gas Turbine/AFB	130	NA

NA - Not Applicable

The land requirement for sludge disposal for the coal-fired boiler with flue gas desulfurization was on the order of ten times the plant area. The large land requirement could be a significant hurdle for the use of boilers with FGD at industrial sites.

Water Requirements

Estimates of the water required by each energy conversion system were made on a gallons per million Btu fuel input basis. The requirements for each system and fuel combination are summarized in Table 6.8-6. The results indicated that most systems required between essentially zero and 8 gallons per MBtu. Two major exceptions were the steam injected gas turbine at 25 to 40 gallons per MBtu and the distillate-fired molten carbonate fuel cell at 17 gallons per MBtu. The fuel cell system contains a steam reformer which consumes water and leads to the higher than average requirement. In the steam injected gas turbine cycle water leaves the system in the turbine exhaust.

Table 6.8-6

ESTIMATES OF WATER REQUIREMENTS
(gal/MBtu)

Energy Conversion System	Coal	Petroleum Distillate	Petroleum Residual	Coal-derived Distillate	Coal-derived Residual
Gasification Combined Cycle	8	NA	NA	NA	NA
Steam Boiler	8	NA	2	NA	2
	1	NA	1	NA	1
	1	NA	1	NA	1
Air Cooled Gas Turbine	NA	0	1	0	NA
Water Cooled Gas Turbine	NA	4	5	4	5
Steam Injected Gas Turbine	NA	NA	25-40	NA	NA
Diesel Engine	NA	1	1	2	2
Stirling Engine	8	0	0	0	0
Molten Carbonate Fuel Cell	1	17	NA	17	NA
Phosphoric Acid Fuel Cell	NA	0	NA	0	NA
Thermionics	8	NA	2	NA	2

NA - Not Applicable

Waste Disposal

The amount of liquid and solid waste produced by each energy conversion system was estimated on the basis of pounds per MBtu of fuel fired; the results are given in Tables 6.8-7 and 6.8-8. The total amount of waste ranged from several pounds per MBtu for diesels and the phosphoric acid fuel cell to as much as 80 pounds per MBtu for coal fired boilers with scrubbers. The liquid fuel fired systems produce less than 2 lb/MBtu of solid wastes, the coal fired systems produced solid wastes in the range of 10 to 30 lb/MBtu. Most of the solids from the scrubber are sludge which can leach into soil and cause significant environmental problems. The liquid wastes are mainly system blowdown which should present little hazard.

Table 6.8-7

SOLID WASTES

Energy Conversion System (all coal fired)	Solid Waste (lb/MBtu)
Steam/Scrubber	24
AFB	30
PFB	30
Molten Carbonate Fuel Cell	13
Gasification Combined Cycle	12
Thermionics	24
Stirling	24

-Liquid fuel fired systems all produce less than 2 lbs/MBtu of solid waste.

Table 6.8-8

LIQUID WASTES

Energy Conversion System	Coal	Petroleum Distillate	Petroleum Residual	Coal-derived Distillate	Coal-derived Residual
Steam/Scrubber	60	NA	10	NA	10
AFB	10	NA	10	NA	10
PFB	10	NA	10	NA	10
Gas Turbine	NA	0	7	0	7
Gasification Combined Cycle	0	NA	NA	NA	NA
Diesel Engine	NA	5	10	10	20
Stirling Engine	60	0	0	0	0
Molten Carbonate Fuel Cell	4	40	NA	40	NA
Phosphoric Acid Fuel Cell	NA	0	NA	0	NA

NA - Not Applicable

Fuel Flexibility

The assessment of fuel flexibility required an evaluation of the number of different fuels a given energy conversion system could potentially utilize. The results of this assessment are summarized in Table 6.8-9. The stirling engine has the greatest potential flexibility of the advanced systems. It can use coal directly or any of the liquid fuels as a heat source since it is an externally fired device. The phosphoric acid fuel cell which requires distillate fuel and the integrated gasifier systems which are designed to utilize coal only are the most inflexible systems.

Table 6.8-9

FUEL FLEXIBILITY

Steam/Boiler	- Coal and residual
Diesel Engines	
• State of the Art	- Petroleum distillate and residual
• Advanced	- Coal derived liquids
Gas Turbines - Air Cooled	- Present - petroleum distillate (2000 F) and petroleum residual (1750 F)
	- Next generation - petroleum distillate and residual (2200 F)
	- Third generation - coal derived distillate
Gas Turbines - Water Cooled	- First generation - petroleum distillate
	- Next generation - petroleum residual and coal derived distillate
	- Third generation - coal derived residual
Stirling Engine	- Petroleum residual and distillate, coal-derived distillate and residual, coal
AFB and PFB	- Coal and heavy liquids
Phosphoric Acid Fuel Cells	- Petroleum and coal-derived distillate
Molten Carbonate Fuel Cell	- Petroleum and coal-derived distillate, coal
Integrated Gasifier Combined Cycle	- Coal
Thermionics	- Coal and residual

Operational Flexibility

The ability of an energy conversion system to respond rapidly to changes in demand for power and process heat is a measure of operational flexibility. This capability will be qualitatively reviewed for each type ECS.

The non-condensing steam turbine output can be varied promptly by throttle control. The heat to process may be maintained by use of bypass desuperheaters in parallel with the steam turbine to make up any deficiency of steam. The steam generator would be fired at a rate to produce the required steam. This response is adequate for oil-fired and pulverized coal fired units. The AFB steam generator has a limited turndown ratio. Two approaches are being pursued to expand the flexibility of AFB's. The first is subdivision into numerous AFB cells that may be fired independently. The second is segmentation of the cell into four sectors where as little as one sector at half design firing rate may be used. Where HRSG's provide steam, their gas flow or their primary heat input may be varied to match steam demand.

Gas turbines realize prompt response to power demand from no load to full load. The availability of steam from the gas turbine HRSG drops as the gas turbine load is reduced. Excess steam generation can be reduced by partial bypass of the gas turbine exhaust gas around the HRSG. The integrated gasifier gas turbine system response is dependent on the manner in which it would be structured. A constant speed gas turbine compressor would maintain a constant level of pressurization. Variation of numbers of gasifiers in operation as well as modulation of their coal, air, and steam inputs would match variations in power demand. The holdup of fuel gas in the gas cleanup system would provide a limited store of gas for abrupt load increases. Transient firing of start-up fuel might also satisfy a temporary inadequacy of fuel gas. This system is conceptually flexible, but the rate of acceptable load changes may be less than that for less complex systems.

The pressurized fluidized bed steam cycle operational flexibility is difficult to assess until the manner of control has been specified. The fuel input may be varied to match demand. The bed airflow may either remain fixed, or be varied to match the demand. The need to hold bed temperature in a narrow band best suited to sulfur capture indicates that a close match of fuel energy release to heat transfer to the steam coolant is essential.

Until the orchestration of these numerous control restraints have been simulated a cautious viewpoint that the PFB will have limited rates of response to load demands is appropriate. The flexibility of the range of power and process heat at steady demand should be excellent.

The helium closed cycle gas turbine and the stirling cycle both have excellent adaptability and flexibility for changing load demands. For both of these ECS's the helium charge would be varied to match the partial load. Temperatures would be held constant as would rotational speed. The principal limitation would be the rate of maneuver for the heat source. The response of the coal fired AFB would correspond to that discussed for AFB steam generators. One special transient response must be addressed for these highly regenerative thermal cycles. That is the limitation of overspeed when generator load is abruptly lost. The thermal energy accumulated in the regenerator is a powerful driving force that must be either discharged or instantly contained in order to avoid overspeed. The adaptability of these units to steady loads should be excellent. The rate of load increase may be slower than other ECS's due to the need to thermally charge up the cycle regenerators and the high temperature air preheaters of the furnace.

The thermionic topping unit with a process steam HRSG may have a rapid reduction in electrical output resulting from a small decrease in firing rate. The thermionic heat input is primarily due to radiation which varies as the fourth power of the absolute flame temperature. Some control over this sensitivity has been achieved in pulverized coal furnaces by tilting the burners as firing rate was changed. This sensitivity would have less overall influence when the thermionic units are coupled to an HRSG powering a steam turbine. The great flexibility of the steam turbine could compensate for the power variability of the thermionic units. Aside from this expressed reservation, the judgment as to flexibility of thermionic units for cogeneration service should be held in abeyance until their concepts are further developed.

Diesel engines in cogeneration service operate with flexibility in meeting power and heat requirements. All installations include full heat rejection systems in order to make power production independent of heat demand. No changes for the advanced diesels are expected.

In each fuel cell system the temperature of the fuel cell must be kept nearly constant. As the power demand varies the heat rejected from the fuel cell and hence the heat available to process must vary in synchronism. This degree of inflexibility in the natural power to heat ratio of the fuel cell must be overcome to provide a flexible cogeneration power and heat supply. As a means to permit power to rise higher than heat to process would permit, a heat rejection to atmosphere system is added. To overcome any insufficiency of heat to process, a fuel combustion and low pressure steam boiler may be added. These additions do not add substantially to the cost of the fuel cell systems, but they do enhance the overall system flexibility in meeting cogeneration demands.

For state-of-the-art cogeneration installations it has been customary to provide for wide variations in power and heat demand. Steam boilers are specified oversize. Steam reducing stations are provided. Steam condensers and small steam turbine condensing stages are added to extend the power range and to provide heat rejection capability. Gas turbine HRSG's are provided with supplementary firing. The simplified system descriptions and performance of this study do not include such detail. However, the cost of these adders as measured by the extended flexibility they secure is small. This flexibility will certainly be required for advanced ECS's when applied to specific industrial cogeneration applications.

6.9 SIGNIFICANT DEVELOPMENT REQUIREMENTS

The level of performance estimated for each advanced energy conversion system was premised on the achievement of specific advanced developments. These developments are deemed to be necessary to achieve the advanced performance levels shown. Wherever the developments are severe, or wherever the organization to undertake the developments is not yet substantial, a late date of deployment has been assigned. The degree of advancement in technology has been purposely limited to technical achievemencs that can be commercialized in ten to fifteen years, and to technology that does not require large cost increases due to dependence on expensive materials. The developments required by each advanced energy conversion system have been defined to assure a consistent basis for comparing the future attainment of performance targets.

Steam Turbine - AFB ECS

Advanced steam conditions for the cogeneration steam turbine are known to be uneconomic and have been excluded from this study. The significant advancement that has been assumed is the development of an atmospheric fluidized bed (AFB) boiler that meets all environmental and reliability criteria. Current development programs have been in place over many years and the expectation of success is high.

PFB Steam Cycle ECS

The pressurized fluidized bed coal-burning steam cycle would be a second and more advanced step in exploitation of the fluidized bed concept. As compared to heating gases in the tubes immersed in the fluidized bed, the heating of water to generate steam and the superheating of steam impose temperatures and heat duty that do not require unproven materials or technology. In addition, raising steam requires less heat exchange surface since greater temperature difference for heat exchange exists as compared to heating gas. Consideration of relative costs and of technology readiness resulted in the exclusion of gas-cooled PFB cycles from this study. Critical technology requiring significant development for the PFB steam cycle would be hot gas cleanup of particulates and alkali metals, protective cladding of gas turbine hot path surfaces, and the overall system integration and control.

Thermionic ECS

The thermionic topping system has been studied conceptually, but its evolution into developed hardware has not started. The thermionic element performance used in this study was based on significant improvement over current achievements. In addition the assumed costs are deemed to be difficult to meet. A long and persistent development program would be necessary. The concept of the integration of the boiler combustor with heat pipes in panels is an element of the thermionic system that is capable of development and proof of concept separate from the thermionic development. This development should be proven at an early date since it is crucial to the economics of the thermionic topping concept. The system integration and control represents another critical development.

Stirling Cycle ECS

The stirling cycle has been the subject of intensive development for use in the automobile and as a means of heat pumping. Commercial units have not been marketed to date. Nonetheless the intensiveness of development effort to date would indicate that critical problems are being discovered and addressed. The industrial unit would differ as to its physical size, and perhaps the seals and drive mechanisms selected for that size. The development of the industrial size unit would be a significant development. That effort must entail the use of higher than normal heat rejection temperatures that would match cogeneration process needs.

The use of coal for the stirling cycle was deemed to represent a development as great as that for the industrial size stirling cycle alone. The heat input temperature of 1472 F is a significant challenge. An atmospheric fluidized bed at 1550 F bed temperature would be exceedingly costly as a heat source. The heat exchange temperature differences would be small, and the tube wall temperatures would mandate use of expensive high alloy metals. Only use of a pulverized coal-fired furnace can assure adequate heat exchange. A high air preheat of 1200 F would be required. Such a pulverized coal-fired unit with flue gas desulfurization and high air preheat would differ considerably from steam boilers, and would require significant development effort. The heat conveyance to the stirling cycle would be by a pressurized helium loop. The additional cost attributed to using coal was evaluated as the full differential between oil- and coal-fired boilers. This cost goal may be difficult to meet in view of the expensive high alloy materials that are required for high temperature heat exchange.

Helium Closed Cycle Gas Turbine ECS

The helium closed cycle gas turbine unit was not considered to be a significant development. A 50 MW unit is already operational in Germany. It and other closed cycle gas turbine units utilize oil, coke oven gas, and pulverized coal as fuels. The significant advanced art considered was development of an atmospheric fluidized bed to burn coal and capture sulfur while heating helium from 1000 F to 1500 F. As detailed in the ECAS study of advanced coal-fired utility plants, the fluidized bed would differ significantly from AFB's for steam production. A high temperature bed would be required and it would have insufficient sulfur capture ability. Its effluent gases would pass through a low temperature fluidized bed at 1550 F where sulfur capture would be consummated. Developments over and above those for the steam producing AFB are needed for the closed cycle concepts. The projected costs are expected to exceed those of steam producing AFB's due to the use of more expensive high alloy tube materials.

Fuel Cell - Molten Carbonate ECS

The coal-fueled fuel cell has numerous areas of significant development. Paramount is development of the molten carbonate fuel cell to a state of commercial readiness with regard to performance, reliability and cost. The coal gasifier requires development, with the Texaco entrained bed gasifier being the prototype used for this study. The fuel gas cleanup system is another significant development. The system integration and control will require significant development in order to achieve simultaneously the requirements of all of the major system elements during the variety of transients experienced by an industrial cogeneration system.

Integrated Gasifier Combined Cycle ECS

There has been sufficient detailed examination of the integrated gasifier, gas turbine, steam turbine to identify the major development elements. Pressurized gasification is essential to economic success. Significant development of advanced gasifiers is necessary. Two types were considered. The General Electric fixed bed GEGAS gasifier, and the Texaco entrained bed gasifier. The fuel gas cleanup systems are a separate but related development. Of critical importance is retention of both chemical and thermal energy after cleanup. The system integration and control are significant due to the system complexity and the sensitive interdependence of its elements.

Advanced Gas Turbine ECS's

Advances in the gas turbine that require significant development are the achievement of 2200 F in an air-cooled gas turbine and the achievement of 2600 F in a water-cooled gas turbine. The steam injected gas turbine would require significant additional development of its combustor and steam injection control. A separate development that must be successful is the achievement of a NO_x limiting combustion system. This requirement appears to be especially severe for burning the coal-derived liquid fuels. They have a high fuel-bound nitrogen content. The means to meet emission standards when burning those fuels in gas turbines must be developed.

Advanced Diesel ECS

Both current and advanced diesel engines will have NO_x concentrations in their exhaust that exceed emission standards. Exhaust gas treatment will be mandatory. An exhaust gas de-NO_x system must be added to the diesel. The costs attributed to the diesel systems were estimated to fully cover this expense by the diesel energy conversion representative for this study. The tabulated diesel emissions for this study were at the diesel exhaust level since authoritative performance of de-NO_x systems were not available. Demonstration of de-NO_x systems that meet emission standards are crucial to the continued and future use of diesels in cogeneration.

The jacket water temperature of the medium speed diesel would be brought to 250 F. This is deemed to be a significant development for an industrial size diesel. Small diesels experience only small thermal distortion due to temperature. The means to accommodate higher temperatures are more severely limited as diesel size increases. Higher temperatures such as 300 F or 350 F jacket water would be excellent for coupling to industrial processes. Rational extrapolation from the evolutionary history of diesel development show that these temperatures are not to be expected in the time span of 1985 to 2000. The open cycle heat pump using 250 F jacket water as its heat source was considered as an alternative to reach high process temperatures. Although the evaluation and costing were based on conventional components, such a unit would be a significant development. Its system integration and control would also be significant.

The development of the diesel to the performance levels projected was deemed to be evolutionary and not subject to expedition. Diesel manufacturers have probed all avenues of diesel exploitation and are well aware of the critical technical developments that balk revolutionary breakthroughs. Higher supercharge pressures, intercooling and aftercooling charge air, and evolution into compound engines are recognized development routes. The use of micronized coal in a slurry of oil was considered as a means to burn coal in the diesel. For industrial size diesels the wear due to ash content, the slowness of burning, and the abrasion of injection equipment were found to preclude coal burning in diesels as an economic approach to cogeneration.

Fuel Cells - Distillate Fueled ECS's

A molten carbonate fuel cell can operate on reformed gases produced from distillate and steam. The fuel cell itself would be the significant development.

The low temperature phosphoric acid fuel cell is already developed. It is especially vulnerable to poisoning by the cumulative effects of sulfur in the fuel gas fed to it. The fuel gas cleanup system would be the significant development for this type fuel cell.

Overview of Significant Developments

A number of significant developments have impact on more than one ECS system. Some of these might be undertaken generically rather than solely as an element of a particular ECS.

NO_x limitations when burning coal derived liquid fuels could take the form of combustion system modification, exhaust gas treatment, or a revision of the emission standard.

The atmospheric fluidized bed combustor shows a sequence of evolutionary development steps. First for production of process steam, then next for power steam boilers. Beyond that level are helium heaters for the closed cycle gas turbine and for the stirling cycle and for any high temperature gas heating service.

Very high temperature air preheaters are required whenever the final heat recipient is unusally hot. In this category are the thermionic units, the stirling cycle, and the closed cycle gas turbine.

Coal gasifiers and fuel gas cleanup are developments significant to the molten carbonate fuel cell, the integrated gasifier combined cycle, and the pressurized fluidized bed gas turbine.

The dc to ac inverters for thermionics and fuel cells merit strenuous development effort to achieve cost reductions.

REFERENCES FOR SECTION 6

1. Wilson, W.B., "The Role of Turbines in the Paper Industry: How to Conserve Energy and Increase Profits," Technical Association Pulp & Paper Industrial, Volume 59, No. 6, June 1976.

2. Corman, J.C., Fox, G.R., et al., "Energy Conversion Alternatives Study (ECAS), Phase II Final Report," NASA Contract NAS 3-19406, Corporate Research and Development, General Electric Company, Schenectady, New York, December 1976.

Section 7

CAPITAL COSTS

7.1 CAPITAL COST METHODOLOGY

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

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

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

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

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

Some of the cogeneration plant data were derived from recent detailed evaluations of advanced concept utility power plants. An example is the thermionic energy conversion system. Table 7.1-1 presents data for the pulverized coal-fired thermionic boiler and steam generator derived from the General Electric EPRI study (Ref. 1). The data were converted to 1978 dollar basis, the air heater was deleted to accord with the cogeneration configuration, and the flue gas scrubber costs were replaced with values used for this cogeneration study. Since the largest thermionic-boiler module would be one sixth of the 7366 million Btu per hour firing rate designated in Table 7.1-1, that critical size along with the firing rate determine the scaling of costs.

Table 7.1-1

THERMIONIC COST BASIS EXAMPLE
(1978 dollars)

	Major Components	(10^6 dollars) Direct Material	Direct Labor
Converters	102.3		
Panels	20.5		
Inverters	21.9		1.1
Furnace, Fans, Mills Minus Air Preheater	55.8	25.09	51.4
Scrubber		30.5	11.4
Other Mechanical		19.7	11.7
Electrical		22.5	18.3
Civil & Structural		25.3	18.5
Pipe and Instrumentation		12.9	10.8
Yardwork		2.2	2.1
	200.5	138.3	125.3

Plant fired 7366 million Btu/hr coal

TI boiler was 6 modules

From Table 7.1-1 a number of relationships have been drawn that scale the costs to smaller firing rates as follows:

F = Firing rate in million Btu per hour/7366

PWR = Power to Fuel Energy Ratio for Thermionic-steam cogeneration plant

X = 1.0 if F $>1/6$

X = 0.7 if F $<1/6$

$$\text{Major Component Cost} = 144.7*F+55.8F^{X}$$
$$\text{Direct Material Cost} = 138.3*F^{0.7}$$
$$\text{Direct Labor} = 125.3*F^{0.7}$$
$$\text{Steam Turbine MW} = F*7366*(PWR-0.141)/3412$$

The major components in converters, panels, and inverters are made up of numerous modules and thus scale linearly. The furnace and heat recovery part scale as do boilers with a 0.7 power when they are less than maximum size, but linearly for multiple units. Other direct field costs scale as the 0.7 power. For computer input the size parameter was the coal firing rate in million Btu per hour. The fuel handling costs would be an additional cost related to firing rate. When a steam turbine was added its power rating determines its cost. For the 1465 psia, 1000 F steam turbine the MW rating for this combination was determined from the calculation of power to fuel energy (PWR) for the thermionic plant with steam turbine bottoming.

Table 7.1-2 presents the elements of computer input data for the thermionic-steam turbine (TISTMT) energy conversion system. Islands are identified, 1 being fuel handling and 3 being energy conversion equipment. The components are explicitly numbered. The size range would be million Btu per hour for the first two items, but MW for the steam turbine. The equipment costs are in 1978 million dollar units and apply to the extremes of the size range stated. The direct material cost is expressed as a ratio (DM/E) to equipment cost for each extreme of the size range. The direct labor is expressed as a similar ratio (DL/E). These latter two columns are zeros for the steam turbine system installation. The cost distributions for steam turbine systems were proprietary. All costs for proprietary data items were entered as an adjusted equipment cost so that subsequent application of indirect charges would produce the total installation costs that are appropriate.

The costs developed from Table 7.1-2 only include direct costs. Cost adders above these levels are 1% for start-up, 2% for spare parts, 90% for indirect field costs, and an additional 26% made up of 6% engineering, 15% contingency, and 5% fee. The resulting multipliers to get total installed cost are presented in Table 7.1-3 along with a set of multipliers to derive only the indirect portion of costs.

Table 7.1-2

CTAS CAPITAL COST OF ECS COMPONENTS EXAMPLE
3/29/79

Island	Comp.	Name	Size	Equipment	$\frac{DM}{E}$	$\frac{DL}{E}$
3	77	Thermionic-Coal-Small	200/1228	6.54/33.42	1.69/1.18	1.53/1.07
INCLUDED ARE: FGD scrubber, limestone handling, DC-AC inverters, electrical controls, structure and enclosure.						
1	10	Coal Handling	200/8000	0.16/3.88	0.20/0.20	0.65/0.65
2	32	Steam Turbine	7.5/100	1.67/9.47	0/0	0/0

Table 7.1-3

CTAS CAPITAL COST STRUCTURE

Total Installed Cost

Equipment	*	(1 + 0.01 + 0.02)	*	(1.26)
Material	*	(1 + 0.01)	*	(1.26)
Direct Labor	*	(1 + 0.01 + 0.90)	*	(1.26)

Indirect Costs

Equipment	*	0.2978
Material	*	0.2726
Direct Labor	*	1.4066

An example of the computer printout of costs is presented in Table 7.1-4. All direct and indirect costs are detailed arriving at the grand total of 212.9 million dollars for this cogeneration power plant complete with all structures, facilities and amenities.

Other data sources did not provide for a complete plant facility as in this example. In those cases the missing elements were identified, and additional items were added to realize a common level of completeness.

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

The master list for cost islands used in the entire cost evaluations is presented as Table 7.1-5.

Table 7.1-4

CTAS CAPITAL COST BY ISLAND COMPUTER OUTPUT EXAMPLE

GENERAL ELECTRIC COMPANY

DATE 03/31/79
I SE-PEO ADV. DES. ENGRG.

COGENERATION TECHNOLOGY ALTERNATIVES STUDY
REPORT 5.3
CAPITAL COSTS BY ISLAND FOR SELECTED PROCESS-ECS MATCHES

PROCESS 28003

ECS TISTMT PROCESS MEGAWATTS 97.20 PROCESS TEMP. 366. PROCESS HEAT(BTU*10**6) 947.
TI-STMTB-1465/1000F SITE FUEL= COAL COGEN FUEL BTU*10**6= 1336. KW FUEL= 391469.

ISLAND DESCRIPTION	COMPONENT DESCRIPTION	************************COSTS - MILLIONS 1978$************ MAJOR EQUIPMNT	INSTALL MAT'L	INSTALL LABOR	INDRCT FLD CST	TOTAL INSTALLD	TOTAL	$PER-KW FUEL
1. FUEL-HANDLING	2. COAL-UNLOAD-STORE-HA	0.921	0.184	0.599	0.539	1.322	2.243	5.729
	ISLAND TOTAL	0.921	0.184	0.599	0.539	1.322	2.243	5.729
3. ENERGY-CONVERSION	33. THERMIONIC-BOILER/GE	36.356	41.838	37.935	34.142	113.915	150.272	383.866
	30. STEAM-TURBINE-GENERA	5.305	0.	0.	0.	0.	5.305	13.553
	ISLAND TOTAL	41.662	41.838	37.935	34.142	113.915	155.577	397.419
2. FUEL-UTILIZATION-CLE	22. COAL-FIRED-BOILER	2.014	2.254	2.488	2.239	6.982	8.996	22.979
	ISLAND TOTAL	2.014	2.254	2.488	2.239	6.982	8.996	22.979
TOTAL THIS CASE		44.596	44.277	41.022	36.920	122.219	166.815	94.312
INDIRECT COSTS	SPARES						0.892	
	START UP						1.299	
	SPARES+STARTUP						2.191	
	CONTINGENCY						25.351	
	ENGINEERING SERVICES						10.140	
	A-E FEE						8.450	
GRAND TOTAL							212.948	

Table 7.1-5

GE-CTAS CAPITAL COSTS
COST ISLAND MASTER LIST

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

7.2 DATA SOURCES

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

A number of energy conversion systems costs were synthesized from the data bank used by General Electric in application engineering for industrial power generation including cogeneration. These included all noncogeneration boilers firing all types of fuels, both of the package and of the field erected type. Also conventional power boilers providing steam for turbines. New data on atmospheric fludized bed steam boilers of industrial size were developed to supplement the data base. Cost of heat recovery steam generators for gas turbines were from the same source as were steam turbine costs. An additional item, 83 structures miscellaneous, was added to costs synthesized entirely from this data base.

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

Component	Component Description
80	Master control
81	Electric-Switchgear
82	Interconnecting Piping
83	Structures - Miscellaneous
84	Power Plant structure

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

7.3 CAPITAL COST SUMMARIES

Examples of the three distinct island cost compositions have been selected from Report 4.1, January 25, 1979 for exposition. The process requirement was 137 million Btu per hour of process heat at 300 F and 10 megawatts of electric power. The selected cases each produce the process heat exactly; one produces a surplus of electrical power, one requires a partial purchase of electricity to meet the full industry demand, and two require auxiliary process heat boilers.

Table 7.3-1 presents the cost data for steam turbine cogeneration plant with an atmospheric fluidized bed boiler (AFB) with steam throttle conditions of 865 psia, 825 F. Most of the normal balance of plant items were incorporated in the cost structure for islands, 1, 2, and 3. Only the cost of auxiliary structures, item 83, was required to complete the plant. The island subtotals for direct and indirect costs are presented along with the grand total for the entire plant. The last column served as a means to check certain items and has no inherent significance. All other steam turbine cases and nocogeneration cases have a composition of costs similar to Table 7.3-1.

A second type cost composition is presented in Table 7.3-2 for the thermionic boiler with steam turbine cogeneration plant. In this instance the energy conversion island encompasses everything except the fuel handling. Even the limestone handling and flue gas scrubber have been included. As described earlier, this completeness results from deriving the cost correlation from utility-type installations that were inherently complete stand-alone power plants. Similar cost compositions are found for the pressurized fluidized bed combined cycle plant and the helium closed cycle coal-fired AFB plants. The item for island 2 was an auxiliary boiler sized to produce the process heat that was not produced by the cogeneration ECS. Wherever such an auxiliary boiler was required to fulfill the process heat requirement, its fuel was the same as that of the cogeneration ECS. The fuel handling item was sized to supply the total fuel consumption.

Table 7.3-1

GENERAL ELECTRIC COMPANY
COGENERATION TECHNOLOGY ASSESSMENT STUDY
REPORT 4.1
CASE CAPITAL COST ESTIMATE

DATE 01/25/79
I SE-PEO ADV. DES. ENGRG.

ECS STM008 PROCESS MEGAWATTS 7.52 PROCESS TEMP. 300. PROCESS HEAT(BTU*10**6) 137.
STM-TURB-865/825F SITE FUEL= COAL-AFB COGEN FUEL BTU*10**6= 191. KW FUEL= 56082.

ISLAND DESCRIPTION	COMPONENT DESCRIPTION	MAJOR EQUIPMNT	INSTALL MAT'L	INSTALL LABOR	TOTAL DIRECT	TOTAL INDIRECT	TOTAL	$PER-KW FUEL
		COSTS - MILLIONS 1978$						
1. FUEL-HANDLING	2. COAL-UNLOAD-STORE-HA	0.154	0.031	0.100	0.285			5.081
	3. LIMESTONE/DOLOMITE-U	0.121	0.117	0.105	0.343			6.115
	ISLAND TOTAL	0.275	0.148	0.205	0.628	0.411		11.196
2. FUEL-UTILIZATION-CLE	23. COAL-FIRED-AFB-BOILE	3.670	0.917	0.857	5.444			97.065
	ISLAND TOTAL	3.670	0.917	0.857	5.444	2.548		97.065
3. ENERGY-CONVERSION	30. STEAM-TURBINE-GENERA	1.531	0.	0.	1.531			27.305
	ISLAND TOTAL	1.531	0.	0.	1.531	0.456		27.305
8. BALANCE-OF-PLANT	83. STRUCTURES-MISCELLAN	0.	0.219	0.196	0.415			7.399
	ISLAND TOTAL	0.	0.219	0.196	0.415	0.335		7.399
TOTAL THIS CASE		5.476	1.284	1.258	8.018	3.750	11.768	142.965

Table 7.3-2

GENERAL ELECTRIC COMPANY
COGENERATION TECHNOLOGY ASSESSMENT STUDY
REPORT 4.1
CASE CAPITAL COST ESTIMATE

DATE 01/25/79
I SE-PEO ADV. DES. ENGRG.

ECS TISTMT PROCESS MEGAWATTS 10.00 PROCESS TEMP. 300. PROCESS HEAT(BTU*10**6) 137.
TI-STMTB-1465/1000F SITE FUEL= COAL COGEN FUEL BTU*10**6= 122. KW FUEL= 35757.

ISLAND DESCRIPTION	COMPONENT DESCRIPTION	MAJOR EQUIPMNT	INSTALL MAT'L	INSTALL LABOR	TOTAL DIRECT	TOTAL INDIRECT	TOTAL	$PER-KW FUEL
		******************COSTS - MILLIONS 1978$******************						
1. FUEL-HANDLING	2. COAL-UNLOAD-STORE-HA	0.162	0.032	0.105	0.299			8.361
	ISLAND TOTAL	0.162	0.032	0.105	0.299	0.205		8.361
3. ENERGY-CONVERSION	33. THERMIONIC-BOILER/GE	5.768	7.849	7.141	20.757			580.507
	30. STEAM-TURBINE-GENERA	1.268	0.	0.	1.268			35.469
	ISLAND TOTAL	7.036	7.849	7.141	22.026	14.279		615.976
2. FUEL-UTILIZATION-CLE	22. COAL-FIRED-BOILER	1.223	1.327	1.494	4.043			113.078
	ISLAND TOTAL	1.223	1.327	1.494	4.043	2.827		113.078
TOTAL THIS CASE		8.429	9.208	8.739	26.368	17.310	43.678	737.415

The third cost compositon applies to all the remaining energy conversion systems. The stirling energy conversion system has been chosen as representative in Table 7.3-3. Only the basic equipment costs were provided as inputs along with the direct costs for their installation. The two items that appear as component descriptions 29 are the stirling engine cogenerator and its combustion system. The necessary balance of plant to provide a complete power house is seen to be significant. None of these items can be omitted or neglected. Treated on a comparable basis were the diesel, fuel cells, gas turbine systems, and combined cycles including integrated gasifier plant.

The stirling cogenerator in Table 7.3-3 exactly produces the process heat required; the power produced is in excess of the 10 megawatts the process requires. Another example of cost composition is presented in Table 7.3-4 where the 10 megawatt power requirement of the process is exactly met, but an auxiliary boiler must be added as island 2, component 22 to produce the process heat not supplied by the cogenerator. In each case the auxiliary boiler fires the same fuel as that supplied for the cogenerator. The fuel handling is sized for the total fuel requirement.

Similar cost details were produced for every combination of ECS and process plant in both heat match and power match combinatins required in this study.

Table 7.3-3

GENERAL ELECTRIC COMPANY
COGENERATION TECHNOLOGY ASSESSMENT STUDY
REPORT 4.1
CASE CAPITAL COST ESTIMATE

DATE 01/25/79
I SE-PEO ADV. DES. ENGRG.

ECS STIRL PROCESS MEGAWATTS 23.16 PROCESS TEMP. 300. PROCESS HEAT(BTU*10**6) 137.
STIRLING-1472F SITE FUEL= COAL COGEN FUEL BTU*10**6= 296. KW FUEL= 86848.

ISLAND DESCRIPTION	COMPONENT DESCRIPTION	MAJOR EQUIPMNT	INSTALL MAT'L	INSTALL LABOR	TOTAL DIRECT	TOTAL INDIRECT	TOTAL	$PER-KW FUEL
		********************COSTS - MILLIONS 1978$********************						
1. FUEL-HANDLING	2. COAL-UNLOAD-STORE-HA	0.225	0.045	0.146	0.416			4.788
	ISLAND TOTAL	0.225	0.045	0.146	0.416	0.285		4.788
2. FUEL-UTILIZATION-CLE	29. STIRLING-ENGINE-COMB	6.694	0.604	1.073	8.372			96.394
	29. STIRLING-ENGINE-COMB	6.725	0.807	0.807	8.339			96.015
	ISLAND TOTAL	13.419	1.411	1.880	16.710	7.025		192.408
8. BALANCE-OF-PLANT	84. POWER-PLANT-STRUCTUR	0.	0.356	0.311	0.667			7.677
	80. MASTER-CONTROL	0.212	0.032	0.053	0.297			3.422
	81. ELECTRIC-SWITCHGEAR-	0.	0.121	0.121	0.243			2.796
	82. INTERCONNECTING-PIPI	0.	0.119	0.119	0.238			2.737
	83. STRUCTURES-MISCELLAN	0.	0.319	0.290	0.610			7.022
	ISLAND TOTAL	0.212	0.947	0.895	2.054	1.580		23.655
TOTAL THIS CASE		13.856	2.403	2.921	19.180	8.890	28.071	220.851

Table 7.3-4

DATE 01/25/79
I SE-PEO ADV. DES. ENGRG.

GENERAL ELECTRIC COMPANY
COGENERATION TECHNOLOGY ASSESSMENT STUDY
REPORT 4.1
CASE CAPITAL COST ESTIMATE

ECS STIRL — STIRLING-1472F
PROCESS MEGAWATTS 10.00 — SITE FUEL= COAL
PROCESS TEMP. 300. — COGEN FUEL BTU*10**6= 128.
PROCESS HEAT(BTU*10**6) 137. — KW FUEL= 37493.

ISLAND DESCRIPTION	COMPONENT DESCRIPTION	MAJOR EQUIPMNT	INSTALL MAT'L	INSTALL LABOR	TOTAL DIRECT	TOTAL INDIRECT	TOTAL	$PER-KW FUEL
		********************COSTS - MILLIONS 1978$********************						
1. FUEL-HANDLING	2. COAL-UNLOAD-STORE-HA	0.173	0.035	0.113	0.321			8.557
	ISLAND TOTAL	0.173	0.035	0.113	0.321	0.220		8.557
2. FUEL-UTILIZATION-CLE	29. STIRLING-ENGINE-COMB	3.322	0.328	0.571	4.221			112.584
	29. STIRLING-ENGINE-COMB	2.903	0.348	0.348	3.600			96.015
	22. COAL-FIRED-BOILER	1.327	1.447	1.624	4.398			117.296
	ISLAND TOTAL	7.553	2.123	2.543	12.219	6.405		325.895
8. BALANCE-OF-PLANT	84. POWER-PLANT-STRUCTUR	0.	0.276	0.241	0.517			13.782
	80. MASTER-CONTROL	0.187	0.028	0.047	0.262			6.975
	81. ELECTRIC-SWITCHGEAR-	0.	0.056	0.056	0.113			3.011
	82. INTERCONNECTING-PIPI	0.	0.099	0.099	0.198			5.293
	83. STRUCTURES-MISCELLAN	0.	0.246	0.222	0.468			12.489
	ISLAND TOTAL	0.187	0.706	0.665	1.558	1.184		41.550
TOTAL THIS CASE		7.913	2.863	3.321	14.097	7.809	21.906	376.003

7.4 COST CORROBORATION

Since cost differences are a dominant factor in economic appraisals, it is essential that costs developed for cogeneration systems have a high order of fidelity. The smallest plant sizes are subject to the greatest diversity for relative costs. For an overview of relative costs a plant size of 10 megawatts power demand and 137 million Btu per hour process heat at 300 F was selected. The capital cost was evaluated as dollars per kilowatt of electrical power produced after deletion of the direct and indirect costs of an auxiliary boiler if one was necessary. Table 7.4-1 presents the results. The order of listing generally follows increasing cost. As expected distillate-fired units tend to be least expensive followed by residual-fired and then coal-fired units.

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

These data at a low power level represent the highest levels of costs that are expected. The cost data are of a nature that unit costs decrease as size and ratings increase. The best sources of data for comparison are at power levels between 400 MW and 1000 MW for complete electric utility plants. Such plants would tend to be more complex than cogeneration power plants.

Table 7.4-1

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

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

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

They would incur costs for heat rejection systems and for low temperature-low pressure elements of their energy conversion machinery. At the same time they tend to be more efficient. Nonetheless, one would expect their order of costliness to be similar to that for cogeneration plants. Hence the issue is one of order and relative costs, not of absolute cost level.

Several data sources were available as discussed in Section 7.2 These included the General Electric in-depth studies for ECAS and for EPRI. Values were taken from those studies and adapted to the same basis as the CTAS costs. First, assumed interest and escalation during construction were deleted, and then the base cost was indexed to be in mid-1978 dollars. Data for state-of-the-art gas turbines in complete cogeneration power houses in mid-1978 dollars were developed by the Industrial Turbine Sales and Engineering Operation of General Electric for comparison to the costs synthesized by the CTAS computer program.

These data are presented in Figure 7.4-1. The dashed connecting lines are simply visual identifiers. In general, the spread in data at 10 MW exceeds that at 400 to 1000 MW. That indicates somewhat higher cost ratios at 10 MW. The order is exactly the same, which is an excellent and unexpected corroboration of the relative costs at 10 MW. Furthermore, the slopes of the interconnecting lines, except for the gas turbine case, have slopes giving cost to size exponents ranging from 0.7 to 0.85. This is the range that would be chosen for extrapolating the data at 400 to 1000 MW down to 10 MW. The state-of-the-art gas turbine characteristic is very different. Smaller units cannot be appreciably cost reduced and in some particulars give up cost advantages that accrue to larger sizes. As a result gas turbines show a high sensitivity to size. The line shown for the distillate-fired gas turbine has an exponent of about 0.5.

The corroboration that has been found indicates that a consistency exists among the costs that are synthesized for each type cogeneration energy conversion system in this study. The discipline of using common components as elements for all systems, of applying a consistent basis for indirect costs, and bringing each system to a common level of completeness assures that no system has been either favored or penalized by arbitrary assignment of costs.

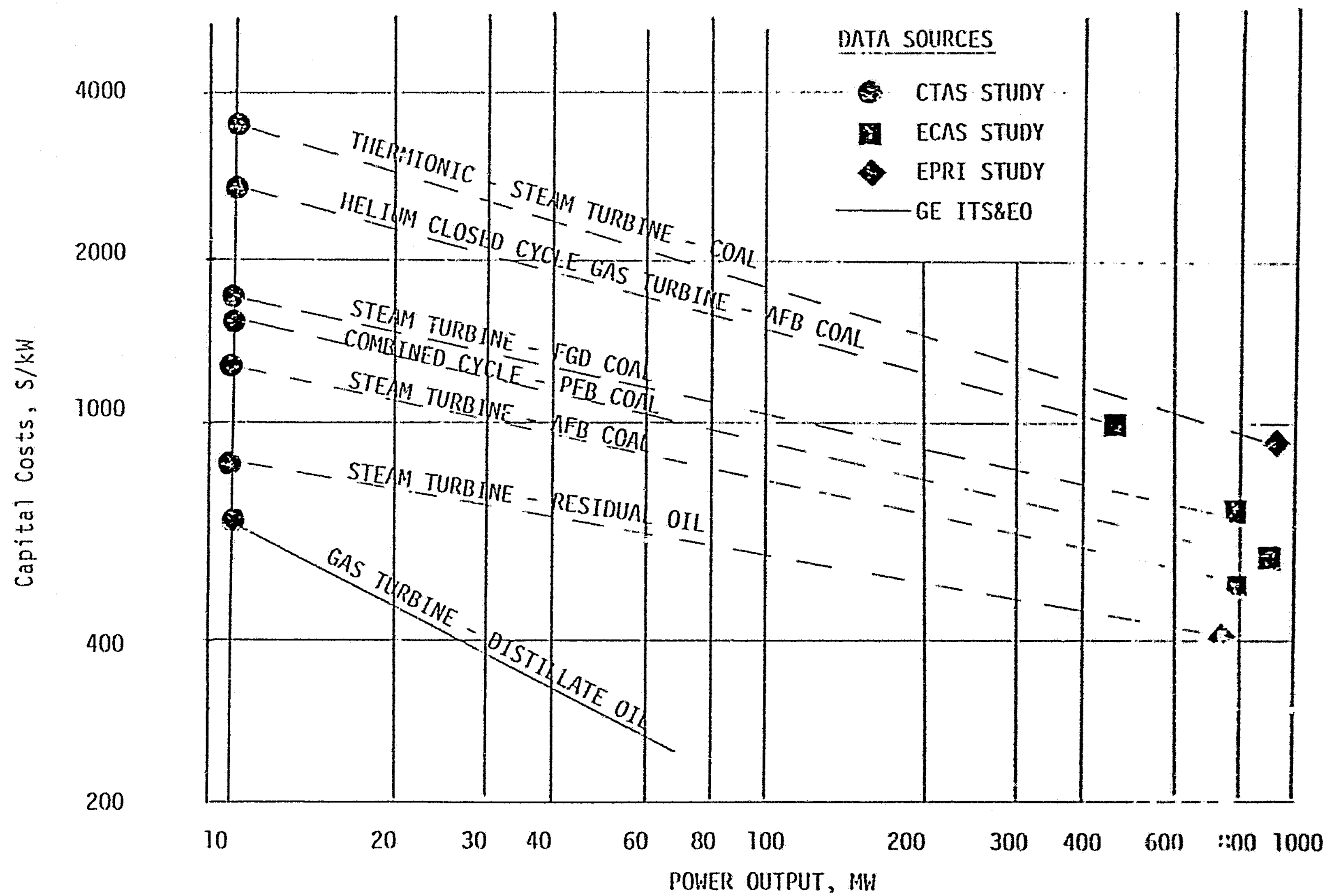

Figure 7.4-1. Capital Cost Corroboration

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