264
11-6-79

DR. 251

ORNL/TM-6626/V1

**OAK
RIDGE
NATIONAL
LABORATORY**

**UNION
CARBIDE**

**Assessment of an Atmospheric
Fluidized-Bed Coal-Combustion
Gas-Turbine Cogeneration System
for Industrial Application**

R. L. Graves
R. S. Holcomb
J. R. Tallackson

MASTER

**OPERATED BY
UNION CARBIDE CORPORATION
FOR THE UNITED STATES
DEPARTMENT OF ENERGY**

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

Printed in the United States of America. Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road, Springfield, Virginia 22161
NTIS price codes—Printed Copy: A09 Microfiche A01

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States nor any agency thereof, nor any of their employees, makes any warranty, expressed or implied, or assumes any legal liability or responsibility for any third party's use or the results of such use of any information, apparatus, product or process disclosed in this report, or represents that its use by such third party would not infringe privately owned rights.

Contract No. W-7405-eng-26

Engineering Technology Division

ASSESSMENT OF AN ATMOSPHERIC FLUIDIZED-BED COAL-
COMBUSTION GAS-TURBINE COGENERATION SYSTEM
FOR INDUSTRIAL APPLICATION

R. L. Graves
R. S. Holcomb
J. R. Tallackson

MASTER

Date Published: October 1979

DISCLAIMER

This book was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Prepared by the
OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37830
operated by
UNION CARBIDE CORPORATION
for the
DEPARTMENT OF ENERGY

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

CONTENTS

	<u>Page</u>
ABSTRACT	1
1. EXECUTIVE SUMMARY	2
1.1 Theoretical Potential Market	2
1.2 Impact on Oil and Natural Gas Consumption	2
1.3 Thermodynamic Feasibility	4
1.4 Other Findings	4
1.5 Recommendations	6
References	7
2. INTRODUCTION	8
2.1 Need for Coal-Combustion Cogeneration Systems	8
2.2 Proposed Cogeneration System	10
2.3 Objectives of the Study	12
2.4 Scope of Study	12
References	13
3. ENERGY CONSUMPTION IN THE UNITED STATES AND BY INDUSTRY	14
3.1 Energy Usage in the United States and by Industry	14
3.2 Ultimate Use of Energy Purchased by Industry	24
3.3 Energy Consumption for Process Heat	27
References	33
4. FEASIBILITY OF COGENERATION SYSTEMS FOR GENERATING INDUSTRIAL HEAT AND POWER	35
4.1 Cogeneration Prime Mover Characteristics	36
4.2 Temperature Requirements for Industrial Process Heat ...	43
4.3 Process Heat/Temperature and Power Consumption in the Six Major Industries	46
4.3.1 Primary metals	47
4.3.2 Chemical industry	65
4.3.3 Petroleum refining	81
4.3.4 Paper and pulp industry	89
4.3.5 Stone/clay/glass industries	91
4.3.6 Food industry	101
References	108
5. ANALYSIS OF GAS-TURBINE COGENERATION SYSTEMS FOR SELECTED INDUSTRIES AND PROCESSES	111
5.1 Analysis of Fluidized-Bed Furnace	111

	<u>Page</u>
5.2 Industries Selected for Application	115
5.2.1 Chemical industries	115
5.2.2 Paper/pulp — newsprint	122
5.2.3 Petroleum refining	125
5.2.4 Food industries	134
References	139
6. CONCEPTUAL DESIGN OF AFBC GAS-TURBINE COGENERATION SYSTEMS FOR INDUSTRIAL APPLICATIONS	140
6.1 Combustor Design	140
6.2 Gas-Turbine Selection	145
7. ECONOMIC COMPARISON OF COGENERATION SYSTEM WITH ALTERNATIVES	147
7.1 Assumptions Used for Cost Estimates	147
7.2 Coal-Combustion Cogeneration System	149
7.3 Pulverized Coal-Fired Boilers	149
7.4 AFBC Coal-Fired Boilers	149
7.5 Oil-Fired Package Boiler	152
7.6 Comparison of Annual Cost	153
8. CONCLUDING REMARKS AND RECOMMENDATIONS	157
8.1 Theoretical Potential Market	157
8.2 Impact on Oil and Natural Gas Consumption	157
8.3 Thermodynamic Feasibility	158
8.4 Other Findings	158
8.5 Recommendations	159
References	161
APPENDIX	163

ASSESSMENT OF AN ATMOSPHERIC FLUIDIZED-BED COAL-
COMBUSTION GAS-TURBINE COGENERATION SYSTEM
FOR INDUSTRIAL APPLICATION*

R. L. Graves
R. S. Holcomb
J. R. Tallackson

ABSTRACT

This study was initiated to provide information on the future potential industrial market for a cogeneration system consisting of a fluidized-bed coal combustor coupled to a gas-turbine (Brayton cycle) power system that uses air as the working fluid.

In assessing the potential applications for the system, the process heat energy consumption by industry is identified, with special detail included on the six most energy-intensive industries. The potential impact on the nation's oil and natural gas consumption that would result from widespread utilization of coal for process heat is also estimated.

The fraction of industrial process heat that the system could feasibly satisfy from a thermodynamic viewpoint is estimated, and the performance (potential fuel efficiency and heat/power ratio) of the atmospheric fluidized-bed gas-turbine system is calculated. Also treated are several specific case studies of industries in which the system could be incorporated. Major parameters are specified, and flow sheets are derived for systems that would satisfy the heat and power requirements of the process or industry. The overall fuel utilization efficiency, thermal power rating, and potential number of installations are specified for these case studies.

The findings of the study indicate that there is a sizable potential market for the system, with over 1000 possible installations disclosed after reviewing only 8 specific industries from 6 major Standard Industrial Classification (SIC) groups. The potential displacement of oil and gas by coal in process heating is shown to be about 1.60 m³/sec (870,000 bbl/day) of oil and 4590 m³/sec (14.0 billion ft³/day) of natural gas for all industries combined. Continued development of the fluidized-bed coal combustor and power system is recommended so that this potential may be at least partially realized.

*The following conversion factors may be useful in reviewing this report: 1 ft³ of natural gas = 1035 Btu (1087 kJ), 1 bbl of oil = 5.8 × 10⁶ Btu (6.1 × 10⁶ kJ), and 1 ton of coal = 2.6 × 10⁷ Btu (2.7 × 10⁷ kJ).

1. EXECUTIVE SUMMARY

This document reports the findings of a six-month study assessing the potential applications for a candidate industrial cogeneration system consisting of a fluidized-bed coal combustor driving a gas-turbine (Brayton cycle) power system. The system studied is shown in a flow diagram in Fig. 1.1. The study was carried out with three major objectives, each instrumental in reaching the overall objective cited above: (1) identify the potential industrial market for the system; (2) estimate the impact on the nation's oil and natural gas consumption; and (3) determine the thermodynamic feasibility and performance of the system. Significant findings with regard to these objectives are summarized in the following sections.

1.1 Theoretical Potential Market

The ability to satisfy industrial energy requirements primarily determines the applicability of the system, specifically, the use of process heat and electricity. Thus the potential market should be discussed in terms of energy as well as the number of installations. Based on extrapolation from the six largest users of industrial energy, the energy consumption for process heating was estimated as $15,750 \times 10^{12}$ kJ ($15,000 \times 10^{12}$ Btu) (in 1974), which is 50% of the total industrial burden on primary energy sources (fuels) and 19% of the total United States burden on primary fuels. Thus the "thermal market" for the coal-combustor cogeneration (CCC) system is substantial, especially in view of the recent thrust toward increased use of coal.

1.2 Impact on Oil and Natural Gas Consumption

The reduction in use of natural gas and oil is of paramount importance, and the ability to use more available fuels is a primary factor in determining the desirability of any cogeneration systems. Typically 90 to 92% of the oil and gas purchased by industry (excluding feedstocks) is used for heat. Thus the oil and gas presently consumed for process heat which theoretically could be displaced by coal can be identified.

Fig. 1.1. Atmospheric fluidized-bed coal-combustion gas-turbine cogeneration system.

The consumption values are listed in Table 1.1. A very large conservation potential exists for the nation's gas resources, as well as a substantial potential savings for oil.

Table 1.1. Estimated annual oil and gas consumption for industrial process heating

Fuel	Consumption
Oil, 10^6 m^3 (10^6 bbl) ^a	36-83 (225-523)
Oil, 10^{12} kJ (10^{12} Btu)	1452-3264 (1376-3094)
Natural gas, 10^9 m^3 (10^9 ft^3) ^b	170-250 (5937-8703)
Natural gas, 10^{12} kJ (10^{12} Btu)	6482-9466 (6145-8973)

^aAbout 53% of industrial oil consumption, 9% of U.S. oil consumption.

^bAbout 86% of industrial gas consumption, 40% of U.S. gas consumption.

1.3 Thermodynamic Feasibility

The capability of the CCC system to supply useful thermal process energy at temperatures up to 816°C (1500°F) while simultaneously producing electric power enhances the system's thermodynamic feasibility in satisfying process heat demands in industry. The high-temperature heating capacity of the gas-turbine system is unique among cogeneration systems, particularly those burning coal. From data on the temperature spectrum of process heating, the conclusion is reached that 61 to 64% of the energy is required at temperatures less than 816°C (1500°F). The thermodynamically feasible potential for CCC fuel conversion appears in Table 1.2.

1.4 Other Findings

Specific case studies were investigated on a preliminary basis to gain some insight into the actual fuel efficiency that is probable with

Table 1.2. Thermodynamically feasible savings of oil and gas with CCC^a

Fuel	Savings from process heat conversion to coal	Savings from electrical generation by coal cogeneration	Total
Oil, m ³ /sec (bbl/day)	1.60 (870,000)	1.17 (635,000)	2.77 (1,505,000)
Natural gas, m ³ /sec (10 ⁹ ft ³ /day)	4,590 (14.5)	1,228 (3.75)	5,818 (17.75)

^a1974 Bureau of Mines data base. Exhaust supplemental firing systems are not included. Estimates are for oil and gas, not energy equivalents.

the system. Practical problems were discussed where sufficient information existed. The market for about 1000 CCC units was identified on investigation of only 8 specific industries, including petroleum refining, food processing, and chemical manufacturing. Typical fuel efficiencies were on the order of 70%. However, the value of in-plant electric generation alone may prove to be an equally significant advantage for industry.

The advantages of in-house power generation with CCC systems will be increased if electrical energy becomes a more prominent and effective method of producing high-temperature energy for such processes as ferrous metal heating, metal reheating for hot forming (e.g., forging), and glass melting.

1.5 Recommendations

This survey was developed with the underlying premise that coal will become the preferred source of environmentally acceptable industrial energy. Fluidized-bed combustors, now in the development stage, conceptually satisfy this premise. The theoretical future market disclosed by this survey is a clear mandate to proceed with concentrated engineering and development programs designed to realize the full technological potential of CCC systems. Technological barriers to implementation of fluidized beds have recently been summarized in Ref. 1.

A recent study by Thermo Electron Corporation² estimated that a very high percentage of industry would invest in cogeneration systems provided a reasonable investment return over time would result. The most accurate economic data would be generated by several representative, detailed case studies of specific industrial facilities.

Cogeneration by industry is receiving much attention at this time and is highly recommended in the literature.²⁻⁴ The continued development of the equipment described in this report, resulting in a vendor-manufactured product, would be instrumental in accelerating the implementation of coal-burning cogeneration.

References

1. J. E. Jones, Jr., et al., *Systems Assessment of Atmospheric Fluidized Bed Combustion: Baseline Study*, ORNL/TM-6208 (December 1977).
2. Thermo Electron Corporation, *A Study of Inplant Electric Power Generation in the Chemical, Petroleum Refining and Paper and Pulp Industries*, TE5429-97-76, 1976.
3. National Consumer Research Institute, *Proceedings of the ERDA Conference on Cogeneration and Integrated Energy/Utility Systems*, CONF-770632, 1977.
4. E. V. Sherry, *Energy Conservation by Symbiosis*, Air Products and Chemical, Inc., Allentown, Pa., 1977.

2. INTRODUCTION

2.1 Need for Coal-Combustion Cogeneration Systems

The uncertainties concerning the extent of the supplies of natural gas and petroleum and further uncertainties pertaining to their cost have helped initiate the thrust to use more available fuels, primarily coal. The industrial sector is the largest consumer of natural gas and is also somewhat dependent on petroleum products. Industry, therefore, both by this fact and its general nature, is considered perhaps the most likely energy-consuming sector for conversion to the use of coal. Prerequisite to the conversion to coal is the demonstration of techniques to satisfy SO₂ emission requirements. Furthermore, because coal is a nonrenewable fuel, coal must be utilized in the most efficient manner possible. The fluidized-bed coal combustor in conjunction with a cogeneration power system appears to offer the potential for achieving both objectives cited.

The sulfur retention possible with fluidized-bed combustors appears to be sufficient for the anticipated Environmental Protection Agency (EPA) standards for SO₂ emissions. The sulfur retention capabilities and other characteristics of fluidized-bed coal combustion are summarized comprehensively in Ref. 1.

The broad conservation potential of cogeneration systems is best explained by referring to the thermodynamic concepts of efficiency and effectiveness. A corollary of the second law of thermodynamics is that a power system operating on a thermodynamic cycle must reject a portion of the thermal energy received from a high-temperature source to a lower-temperature reservoir. A conventional steam-electric utility plant rejects this thermal energy, usually to a body of water or to the atmosphere. The rejected heat for a conventional plant totals ~65% of the energy of the raw coal; thus the efficiency of such a plant is only 35% because the rejected heat is not utilized for a productive purpose. However, if a neighboring industry could utilize 80% of the utility's waste energy, the efficiency of the combined electricity production and heat utilization would be 87%, that is, 87% of the energy of the coal would

be used for productive purposes. A system of this type which produces electricity and utilizes "waste" energy (usually as process heat in industry) is, by definition, a cogeneration system. Its fuel conservation potential is evident in the previous example.

The concept of effectiveness is more abstract, but it is quantitative and subject to analysis and has received considerable attention in recent literature dealing with conservation.^{2,3} The effectiveness of a power system, for example, would be the degree to which that system is successful in converting the energy available from a process involving the release of thermal energy (combustion) into useful work (electricity). To maximize the effectiveness, two simplified requirements for the power system are (1) the peak temperature should be as close as possible to the temperature of the energy source, and (2) the waste heat should be rejected at a temperature as close as possible to the temperature of the environment.

The available energy that can be converted into electricity is somewhat more limited than energy in general. The availability of an energy source can be visualized as its potential for producing work (electricity) and is primarily a function of the temperature of the source. For instance, coal combustion produces a high-temperature, high-availability energy source. The ocean, in contrast, possesses tremendous amounts of energy but relatively little availability. The desirability of highly effective systems that utilize the availability of an energy source is summarized by the following statements.

1. Electricity is a versatile, highly refined, and valuable form of energy and can be generated only where there is energy of sufficient availability.

2. Availability is a nonrenewable resource just as a fuel.

The conservation of availability would be affected by reducing the quantity of refined fuels burned at high temperature for the sole purpose of providing process heat at a substantially lower temperature. Thus the conservation of availability is indeed an argument for cogeneration.

The potential for relieving the shortage of generating capacity currently being experienced by utilities is another advantage that should

be mentioned. Further cases in favor of cogeneration are well represented in the literature.^{4,5}

2.2 Proposed Cogeneration System

A recuperative gas-turbine cycle used in conjunction with the fluidized bed is capable of being both a high-effectiveness and a high-efficiency cogeneration system. Variable degrees of recuperation allow the system to satisfy a wide range of electricity and process heat needs for the various industries. Its potential for simultaneously producing electricity and high-temperature process heat is unique among cogeneration systems. The basic layout of the system is shown in Fig. 2.1. The system differs from that of a conventional oil-fired gas turbine in that air is heated in the fluidized-bed furnace and is used as the working fluid in the turbine in lieu of combustion gases. The recuperator may be up to 85% effective or nonexistent in cases of high-heat/power requirements. The compressor pressure ratio will typically range from 2 to a practical upper limit of about 7, where the power per pound of air flow is near maximum for a turbine inlet temperature of about 816°C (1500°F). Because of the need for high sulfur retention, the combustion temperature in the bed would be limited to about 871°C (1600°F), which can provide a turbine inlet temperature of about 816°C (1500°F).

The furnace operates at atmospheric pressure. An economizer heat exchanger in the upper part of the furnace extracts heat from the combustion gases before they leave the furnace. The flue gases are then used to dry the coal and limestone (if necessary) and to heat the incoming combustion air in a regenerative capacity. A flue-gas stack temperature of 149°C (300°F) was arbitrarily selected in establishing ground rules for the study. Heat recovery from the solids rejected from the bed is also practiced.

The effectiveness of the system is such that, with adequate recuperation, 30% of the coal energy can be converted to electricity while maintaining an overall efficiency of up to 85%. If an industry's electrical requirements involve significant load variations, the system can be made closed cycle, provided there is an ample heat sink to cool the

Fig. 2.1. Fluidized-bed gas-turbine cogeneration system.

compressor intake charge. The closed-cycle cogeneration system can maintain its effectiveness during shifts in electrical load.

2.3 Objectives of the Study

Having identified the CCC as a candidate system for industrial cogeneration, the specific objectives of this study can be outlined.

2.3.1 Identify potential market for system

The industrial energy requirements, particularly the temperature required, will primarily determine the applicability of the system. A number of typical installations are to be identified.

2.3.2 Estimate impact on oil and natural gas consumption

The reduction in use of natural gas and oil is a major concern, and the ability to accomplish such a reduction is a primary factor in determining the desirability of any cogeneration system. However, if coal-fired technology cannot be demonstrated as being economically competitive with current oil and gas prices, it can be argued that conservation of these fuels has not yet reached its ultimate degree of urgency.

2.3.3 Determine feasibility of system

The capability of the system to supply heat at specific temperatures and adequate electricity to specific plant processes will be determined. This system-process matching is the first test of feasibility, with economic and practical considerations to be examined in secondary roles at this time.

2.4 Scope of Study

The primary focus of the study in regard to the objectives cited will be on the six largest consumers of process heat in the industrial sector: (1) iron and steel manufacture, (2) petroleum refining, (3) chemical manufacture, (4) stone/clay/glass production, (5) food processing, and (6) paper/pulp production. Limited data on other industries are also included.

Economic questions and the practical problems of interfacing the CCC with industry are given minor attention. These questions are best answered in specific, detailed case studies involving specific manufacturing installations.

References

1. T. E. Dowdy et al., *Summary Evaluation of Atmospheric Pressure Fluidized Bed Combustion Applied to Electric Utility Large Steam Generators*, EPRI FP-308, Babcock & Wilcox Company (October 1976).
2. Federal Energy Administration, *The Data Base, The Potential for Energy Conservation in Nine Selected Industries, Vol. 2 - Petroleum Refining*, Office of Industrial Programs, 1975.
3. *Evaluation of the Theoretical Potential for Energy Conservation in Seven Basic Industries*, FEA/D-75/CE1, Battelle Columbus Laboratories (July 1975).
4. The Institute of Fuel, *Total Energy Conference Brighton 1971, Proceedings, Vol. 1*, London, 1971.
5. National Consumer Research Institute, *Proceedings of the ERDA Conference on Cogeneration and Integrated Energy/Utility Systems*, CONF-770632, 1977.

3. ENERGY CONSUMPTION IN THE UNITED STATES AND BY INDUSTRY

The general energy consumption pattern in the United States is valuable in placing the industrial consumption into perspective. This chapter presents a general discussion and generalized data, followed by data of increasing detail. Quantities of oil and gas used for industrial process heating are identified.

3.1 Energy Usage in the United States and by Industry

Assessments of fuel usage potential brought about by the development of new hardware or new schemes for using old hardware will take into account the overall energy involved and how and in what forms that energy is used and distributed among the different using sectors. In a preliminary evaluation such as this, gross and generalized consumption data will provide a qualitative indication of the possible benefits that will result if engineering developments enable desirable shifts in our existing pattern of primary energy consumption.

Figures 3.1 through 3.4 display the primary energy consumption in 1974 and distribution among the three user groups: (1) residential and commercial, (2) industrial, and (3) transportation. Table 3.1 (Ref. 1) consolidates these data; note that the energy used by the utilities (sector 4) is embedded in the end-use sectors, 1 through 3. Figure 3.5 (Ref. 2) shows relative consumptions by industrial groups. Because 80% of all process energy is consumed by the first six, this evaluation will tend to concentrate on (1) chemicals, (2) primary metals, (3) petroleum refining, (4) pulp and paper, (5) stone, clay, glass, and cement, and (6) food. The role played by fuels used for feedstock is quite significant in some industries. Thus the following clarification is quoted from the 1972 Census of Manufacturers² for the data in Fig. 3.5.

Data on fuels produced and consumed in the same establishment (such as coke-oven gas or blast-furnace gas); data on fuels used as raw materials (such as fuel oil and natural gas used to produce carbon black); and fuels converted to other fuel types (such as coal converted to coke) were not obtained in the 1971 survey...

Fig. 3.1. Total U.S. energy consumption and distribution in 1974.

Fig. 3.2. Amount and distribution of source energies in the process industries in 1974.

Fig. 3.3. Total U.S. consumption and distribution of natural gas by using sector in 1974.

Fig. 3.4. Total U.S. consumption and distribution of natural gas and petroleum by using sector in 1974.

Table 3.1. Distribution by fuel source and use sector of the energy consumed in the United States in 1974 [10^{15} kJ (10^{15} Btu)]

Sector	Primary energy source				Distributed electricity ^a	Total ^b	Percent of U.S. total
	Natural gas	Petroleum	Coal	Nuclear and hydro			
1. Residential and commercial	7.8 (7.4)	7.1 (6.7)	0.32 (0.30)		3.62 (3.43)	27.5 (26.1)	35.9
Percent	28.4	25.6	1.2		44.8		
2. Industrial	10.7 (10.1)	6.4 (6.1)	4.4 (4.2)	<0.1 (<0.1)	8.4 (8.0)	30.0 (28.4)	39.1
Percent	35.5	21.5	14.8		28.2		
3. Transportation	0.63 (0.60)	18.4 (17.4)	0.01 (0.01)		0.21 (0.20)	19.2 (18.2)	25.0
Percent	3.5	95.2			1.1		
					5.84 (19.9)		
4. Electric ^b utilities	3.6 (3.4)	3.4 (3.2)	9.4 (8.9)	4.6 (4.4)	21.0 (19.9)		
Percent	17.1	16.1	44.7	22.1			
5. Total by source	22.7 (21.5)	35.2 (33.4)	13.8 (13.1)	4.6 (4.4)			
U.S. total						72.7	
Percent of U.S. total	29.6	45.9	18.4	6.1		76.7	

^aThe primary energy required to generate electricity is estimated by assuming an efficiency of 32%, and the net distributed electrical energy in 1974 was 1.86×10^{12} kWh.

^bDifferences in totals obtained by vertical and horizontal summations are the result of rounding.

Source: Ref. 1.

Fig. 3.5. Fuels and electricity purchased by industry in 1971 (1 Btu = 1.055 kJ) (Ref. 2).

In other words, the fuel energy purchased was used only for heat or power.

Figure 3.6 shows the path of energy consumptions since 1960 based on data^{1,3} assembled for the years 1960, 1968, and 1973 through 1975. The dashed lines project the 1973 to 1985 usage based on annual growth rates of 2 and 3%. The most suitable basis for the projections was 1973

Fig. 3.6. Total U.S. energy consumption since 1960 and forecasts of usages through 1985.

because the lower usage levels reported for 1974 and 1975 reflect the recent recession — an abnormal disruption of the economy.

The assumption that industrial energy usage will increase at annual rates of 2 to 3% is arbitrary but not unsupported. To say that accurate energy forecasting is difficult is a gross understatement. Predicted consumptions from different sources vary by substantial amounts, and nearly all these include a large uncertainty band. Williams⁴ reported several forecasts of total U.S. consumption for 1980 and 1985,⁵⁻⁹ which are also shown in Fig. 3.6. By inspection, an annual growth rate of 3% is entirely reasonable. The gestation period for a new industrial methodology is usually several years; therefore, estimates of impacts and effects on our energy scenario should take into account escalations in consumption. Table 3.2 shows industrial consumption in 1973 and the projections of 1973 usages escalated under various assumptions to 1985.

Table 3.2. 1973 industrial energy consumptions [10^{15} kJ (10^{15} Btu)] with 1985 estimates of usage for average annual growth rates of 2 and 3%

Source of energy	1973	1985		
		2%, case 1 ^a	3%, case 1 ^a	3%, case 2 ^b
Natural gas	11.07 (10.49)	11.07 (10.49)	11.07 (10.49)	15.76 (14.94)
Petroleum	6.75 (6.40)	6.75 (6.40)	6.75 (6.40)	9.64 (9.14)
Coal	4.61 (4.37)	10.63 (10.08)	14.16 (13.42)	6.57 (6.23)
Distributed electricity	8.29 (7.86)	10.51 (9.96)	11.81 (11.19)	11.81 (11.19)
Total	30.71 (29.11)	38.95 (36.92)	43.8 (41.5)	43.8 (41.50)

^aCase 1: industrial consumption of natural gas and petroleum remain constant after 1973; electricity usage increases at 2 or 3%/year, and the remaining incremental growth requirements are met with coal.

^bCase 2: consumption rates of all source energy components escalate at 3%/year.

Growth rates, by industry, from the OBERS projection* are tabulated in Ref. 10. These rates are forecast for two scenarios: one with and one without energy conservation by the industrial users. The projected rates for the "big six" (chemicals; primary metals; petroleum; paper; stone, clay, and glass; and food) after weighting by the relative usages in Fig. 3.5 indicate total annual increases for the total consumption by these six users through 1985 of 2 and 3%, respectively, for the two scenarios.

A valuable benchmark for visualizing the potential impact of the CCC on energy consumption will be the total energy consumed by the industrial sector. Typical data found in the literature are provided in Table 3.3.

The task is to arrive at the fraction of the benchmark value that could be conserved by the implementation of cogeneration systems with

* Joint study for the Water Resources Council by the Office of Business Economics (OBE) of the U.S. Department of Commerce and the Economic Research Service (ERS) of the U.S. Department of Agriculture.

Table 3.3. Comparison of data for total industrial energy consumption^a

Total industrial energy consumption [10 ¹⁵ kJ (10 ¹⁵ Btu)]	Year	Reference	Remarks
20.95 (19.86)	1971	11 ^b	Purchased fuel plus purchased electricity at 10,500 Btu/kWhr
25.78 (24.44)	1971	8	Excludes feedstock
13.86 (13.14)	1971	2 ^b	Purchased fuel plus purchased electricity at 3,413 Btu/kWhr
20.87 (19.78)	1971	8 ^c	Excludes feedstock
12.00 (11.37)	1971	2	Purchased fuels only
18.41 (17.45)	1971	8 ^c	Excludes feedstock
23.86 (22.62)	1971	8	Purchased fuels plus feedstock plus electricity at 3,413 Btu/kWhr
29.96 (28.4)	1974	1	Purchased fuels plus feedstock plus electricity at 10,500 Btu/kWhr
31.23 (29.6)	1974	12	Total burden on primary fuel supplies

^a Assumes that internally derived fuel energy is not included.

^b Data from Bureau of Census.

^c Bureau of Mines data; includes coal used as coke in reducing operation in iron/steel industry, etc.

emphasis on oil and gas conservation. The CCC has the realistic potential of using coal to replace a very high percentage of the natural gas and petroleum currently used for process heating. Feedstock fuels and internally derived fuels would not be replaced. The coke utilized in reducing iron ore is, of course, also not displaceable. Therefore, the data compiled by the Bureau of Census for fuels consumed, supplemented by similar data from the Bureau of Mines, are the most satisfactory in determining a conservation impact target for the CCC. The data, broken down by fuel type, are shown in Table 3.4.

The maximum impact of the CCC on natural gas and oil consumption can be bracketed by the data presented in Table 3.4: 39 to $90 \times 10^6 \text{ m}^3$ (245 to $569 \times 10^6 \text{ bbl}$) fuel oil per year and 183 to $268 \times 10^9 \text{ m}^3$ (6454 to $9460 \times 10^9 \text{ ft}^3$) of natural gas per year. An escalation factor of 2 to 3% should be applied to estimate the value in years after 1971. This conservation value does not include the natural gas and petroleum that would be saved by the reduction in generating load at gas- and oil-fired central power stations when the large-scale introduction of cogeneration systems occurs. The disagreement between the Bureau of Census data and the Bureau of Mines data has been noted throughout the related literature.¹¹ At least one investigation team concluded that the Bureau of Mines data are more complete.¹³ The 1974 Bureau of Mines data would indicate a target of $263 \times 10^9 \text{ m}^3$ ($9300 \times 10^9 \text{ ft}^3$) of gas and $101 \times 10^6 \text{ m}^3$ ($637 \times 10^6 \text{ bbl}$) of fuel oils per year.¹² Data for the six major industries to be studied in greater detail in this report are in Table 3.5.

All the industrial petroleum and natural gas could be replaced only hypothetically by the coal combustor. The amounts of energy, and subsequently the amounts of natural gas and petroleum, used for process heating that can actually be displaced by coal combustion cogeneration units must be determined.

3.2 Ultimate Use of Energy Purchased by Industry

The potential impact and applicability of the CCC are partially determined by (1) energy form(s) required by the process (electricity,

Table 3.4. Estimated fuel consumption for heat and power^a in 1971 by fuel type

Fuel type	Quantity ^b	Energy ^b [10 ¹² kJ (10 ¹² Btu)]	Quantity ^b	Energy ^c [10 ¹² kJ (10 ¹² Btu)]
Fuel oils, m ³ (bbl)	39.1 × 10 ⁶ (245.6 × 10 ⁶)	1578 (1496)	90.5 × 10 ⁶ (569 × 10 ⁶)	3,548 (3363)
Natural gas, m ³ (ft ³)	183 × 10 ⁹ (6454 × 10 ⁹)	7047 (6680)	268 × 10 ⁹ (9460 × 10 ⁹)	10,290 (9753)
Coal — coke, metric tons (tons)	68 × 10 ⁶ (75 × 10 ⁶)	2066 (1958)	144 × 10 ⁶ (159 × 10 ⁶)	4,570 (4332)

^aNonfuel uses excluded.

^bBureau of Census, 1971; Ref. 2.

^cBureau of Mines, 1971; Ref. 8.

Table 3.5. Purchased fuel consumption by the six major industries^a

Fuel type	Iron/steel SIC 331, 332	Petroleum SIC 29	Chemicals SIC 28	Stone/glass SIC 32	Paper/pulp SIC 26	Food SIC 20	Total
Distillate oil							
10 ⁶ m ³ (10 ³ bbl)	1.94 (12.2)	0.51 (3.2)	2.35 (14.8)	1.76 (11.1)	2.88 (18.1)	1.73 (10.9)	11.18 (70.3)
10 ¹² kJ (10 ¹² Btu)	75.0 (71.1)	19.6 (18.6)	90.5 (86.2)	68.3 (64.7)	111.2 (105.4)	67.0 (63.5)	432.1 (409.6)
Residual oil							
10 ⁶ m ³ (10 ⁶ bbl)	2.70 (17.0)	1.70 (10.7)	3.04 (19.1)	1.34 (8.4)	7.39 (46.5)	1.57 (9.9)	17.74 (111.6)
10 ¹² kJ (10 ¹² Btu)	112.8 (106.9)	71.0 (67.3)	126.7 (120.1)	55.7 (52.8)	308.4 (292.3)	65.6 (62.2)	740.2 (701.6)
Coal — coke							
10 ⁶ metric ton (10 ⁶ ton)	17.25 (19.0)	0.33 (0.36)	16.7 (18.4)	8.9 (9.8)	8.6 (9.5)	4.1 (4.5)	55.8 (61.5)
10 ¹² kJ (10 ¹² Btu)	523.4 (496.1)	9.9 (9.4)	506.8 (480.4)	270.0 (255.9)	261.6 (248.0)	124.0 (117.5)	1694.0 (1605.7)
Natural gas							
10 ⁹ m ³ (10 ⁹ ft ³)	20.4 (720)	37.4 (1322)	40.4 (1427)	19.9 (704)	13.5 (477)	13.6 (479)	145.15 (5129)
10 ¹² kJ (10 ¹² Btu)	786.3 (745.3)	1443.8 (1368.5)	1558.2 (1477.0)	768.8 (728.7)	520.9 (493.7)	523.1 (495.8)	5601.3 (5309.3)

^aData available from 1971, Bureau of Census, includes fuels used as fuel only.

direct heat, steam) and (2) process temperatures. This section deals primarily with item 1, with the ultimate purpose of developing an estimate for energy, oil, and natural gas used for industrial process heating.

A recent estimate of the fractional distribution by form of the energy consumed by industry is listed in Table 3.6. This tabulation is based on the more detailed breakdown in Table 3.7. The higher (48%) value for 1976 in Table 3.7 is assumed to include energy used for steam that is used in cogeneration systems and is not entirely available as process energy. However, these figures have come under recent criticism for a lack of real basis.¹³ Note that the fraction of electric power is markedly higher than that cited in other references.^{2,12} Furthermore, the aggregation of process heat data from individual industries has been expressed as the most accurate method for arriving at such percentages. This can hardly be argued, but the magnitude of the described task is frightening if applied to all manufacturers. Thus the six major consumers have received the greatest attention.

Table 3.6. Estimated fractional distribution
by energy form of the total industrial
energy consumed in the United States

Energy form	Distribution (%)
Process steam	40
Direct heat	30
Electricity	20
Other ^a	10

^aIncludes feedstocks and uncertainties.

3.3 Energy Consumption for Process Heat

Special attention is given here to the six major industries under close inspection. For determining the market and impact of the coal cogeneration system, the fraction of the total energy consumption delegated to process heating must be identified. An effort was made to exclude energy (fuel) consumption associated with raw materials because

Table 3.7. End-use energy distribution in industrial processes

End use	1960 ^a	1968 ^a	1976 ^b	Percent of industrial total		
	[10 ⁵ kJ (10 ¹⁵ Btu)]	[10 ⁵ kJ (10 ¹⁵ Btu)]	[10 ⁵ kJ (10 ¹⁵ Btu)]	1960 ^a	1968 ^a	1976 ^b
Process steam	8.07 (7.65)	10.69 (10.13)	13.82 (13.10)	41.7	40.5	48.0
Direct heat	5.36 (5.55)	7.31 (6.93)	9.50 (9.00)	30.2	27.8	33.0
Electrolytic processes	0.52 (0.49)	0.75 (0.71)		2.7	2.8	
Electric drive	3.34 (3.17)	5.05 (4.79)		17.3	19.2	
Feedstock	1.44 (1.37)	2.32 (2.20)		7.5	8.8	
Other	0.13 (0.12)	0.21 (0.20)	5.49 (5.20)	0.7	0.8	19.0
Total	19.36 (18.35)	26.33 (24.96)	28.81 (27.30)	100.0	100.0	100.0

^aReference 3.^bReference 14.

this is not actually used for process heating and also because it cannot be replaced by a new source without altering the industrial process. The data compiled from numerous sources are presented in Table 3.8. The potential for fuel conversion in process steam generators and heaters is somewhat lower than might be expected because of industrial efforts to make use of by-product fuels and waste heat recovery. For example, over 40% of the steel-making process heat is supplied by blast furnace gases and coke gases.¹⁵ By-product wood waste and pulping liquors provide about 50% of the process heating needs in the paper/pulp industry.¹⁵ Furthermore, heat recovery systems are prevalent in petroleum and other industries. Note that over 35% of the energy consumption in the chemicals group is as feedstock.¹⁹ The second data set in Table 3.8 is intended only to present comparative data from different sources.

Because of the influence of by-product fuels, the potential conservation of oil and gas is best derived by referring again to the Bureau of Census data on fuels consumed for heat and power. The necessary information is the quantity of oil and gas used specifically for process heating. The fractions of oil and gas used for heating are given in Table 3.9 (Ref. 20). The data can be partially confirmed by referring to the Bureau of Census information on internally generated electricity, which, after eliminating feedstocks, is the only other significant end use of oil and gas aside from process heat. Applying a typical value of 92% to the oil and gas consumption in Table 3.4, we arrive at estimates for the annual consumption of oil and gas for process heating. From data presented in Ref. 20, ~50% of the oil and gas is used for direct heat and the other 50% for generating steam. The estimates are listed in Table 3.10. In addition to potential savings of process heat fuel, coal-fired cogeneration systems would have substantial impact on the oil and gas consumption at central power stations. About 35% of the utility electricity in the United States is generated from fuel oil (18%) and natural gas (17%).¹² Furthermore, the industrial sector consumes ~42% of the utility electricity generated.¹² In terms of fuel value, industry accounts for $\sim 3003 \times 10^{12}$ kJ (2846×10^{12} Btu) of the oil and gas consumed by the utilities. If the entire industrial electrical load (781×10^9 kWh)¹² were generated by cogeneration systems operating at

Table 3.8. Process heat energy consumed in six major industries (from various references)

Industry	Total energy consumed ^a [10 ¹² kJ (10 ¹² Btu)]	Energy for process heat [10 ¹² kJ (10 ¹² Btu)]	Process heat total energy (%)	Date (reference)	Total energy consumed ^a [10 ¹² kJ (10 ¹² Btu)]	Energy for process heat [10 ¹² kJ (10 ¹² Btu)]	Date (reference)
Iron/steel	3,608 (3,420)	1875 (1777) ^b	52	1973 (15)	3629 (3440)		1973 (16)
Petroleum	3,346 (3,172)	3271 (3100) ^b	98	1976 (15)	2944 (2790)	2781 (2636)	1971 (11,13)
Paper/pulp	2,110 (2,000)	1101 (1044) ^b	52	1975 (15)	2110 (2000)	1152 (1092) ^b	1973 (17,13)
Chemical	4,389 (4,160)	1583 (1500)	36	1973 (18)	3931 (3726)	2125 (2014)	1971 (19,15)
Food	950 (900)	586 (555)	62	1971/1974 (17,15)	1088 (1031)	338 (320)	1971/1976 (2,13)
Stone/clay/glass	1,361 (1,290)	1234 (1170)	91	1972/1975 (17,15)	1377 (1305)	1045 (990)	1971/1976 (2,13)
Total	15,764 (14,942)	9550 (9146)	61				

^aIncludes feedstock and internally generated fuels; electricity conversion is 3413 Btu = 1 kWh.

^bIncludes large contribution of internally generated fuels.

Table 3.9. Ultimate use of oil and gas used as fuel in five major industries^a

Industry	Oil and gas, percent of total fuels ^b	Oil and gas used for heat (%)
Primary metals	38	89
Petroleum	52	93
Chemicals	75	93
Paper/pulp	46	92
Stone/clay/glass	74	98

^a1971 data primarily. Food industry data not available.

^bIncludes Bureau of Census fuels plus industry data on self-generated fuels.

Source: Ref. 20.

Table 3.10. Estimated annual oil and gas consumption for industrial process heating

Fuel	Consumption
Oils, 10^6 m^3 (10^6 bbl) ^a	36 to 83 (225 to 523)
Oils, 10^{12} kJ (10^{12} Btu)	1451 to 3264 (1376 to 3094)
Gas, 10^9 m^3 (10^9 ft^3) ^b	168 to 246 (5937 to 8703)
Gas, 10^{12} kJ (10^{12} Btu)	6482 to 9467 (6145 to 8973)

^aAbout 53% of industrial oil consumption, 9% of U.S. oil consumption.

^bAbout 86% of industrial gas consumption, 40% of U.S. gas consumption.

a modest 60% efficiency, the energy savings would be $4009 \times 10^{12} \text{ kJ}$ ($3800 \times 10^{12} \text{ Btu}$) per year.

The data presented in this section, although perhaps appearing to be rather incongruent, can logically be put into perspective as in Fig. 3.7. The target for industrial conversion to coal is evidently a

Fig. 3.7. Industrial energy consumption in perspective.

significant fraction (>15%) of the total U.S. fuel energy demand. The potential energy savings from cogeneration of electricity are also noteworthy at ~5% of the national energy consumption.

References

1. Federal Energy Administration, National Energy Information Center, *Monthly Energy Review*, Washington, D.C. (March 1976).
2. U.S. Bureau of the Census, Census of Manufacturers, 1972, *Special Report Series: Fuels and Electric Energy Consumed*, MC72 (SR)-6, U.S. Government Printing Office, Washington, D.C., 1973.
3. Office of Science and Technology, *Patterns of Energy Consumption in the United States*, Washington, D.C. (January 1972).
4. L. J. Williams, *A Preliminary Forecast of Energy Consumption Through 1985*, EPRI-SR-37, Electric Power Research Institute (March 1976).
5. Federal Energy Administration, *Project Independence Report* (November 1974).
6. National Petroleum Council, *U.S. Energy Outlook: A Summary Report of the National Petroleum Council* (December 1972).
7. Intertechnology Corporation, *The U.S. Energy Problem* (November 1971).
8. W. G. Dupree and J. A. West, *U.S. Energy Through the Year 2000*, U.S. Department of the Interior (December 1972).
9. *A Time to Choose*, Energy Policy Project of the Ford Foundation, 1974.
10. M. H. Farmer, E. M. Magee, and F. M. Spooner, *Application of Fluidized-Bed Technology to Industrial Boilers*, Exxon Research and Engineering Company, Linden, N.J. (January 1977).
11. J. G. Myers et al., Conference Board, *Energy Consumption in Manufacturing*, Ballinger Publishing Company, Cambridge, Mass., 1974.
12. W. G. Dupree and J. S. Corsentino, *U.S. Energy Through the Year 2000 (Revised)*, U.S. Department of the Interior (December 1975).
13. Intertechnology Corporation, *Analysis of the Economic Potential of Solar Thermal Energy to Provide Industrial Process Heat*, Vol. 1, Final Report, Report 00028-1 (NTIS-C002829/1) (February 1977).
14. Resource Planning Associates, Inc., *The Potential for Cogeneration Development in Six Major Industries by 1985*, Draft Final Report, Cambridge, Mass. (September 1977).
15. *Survey of the Applications of Solar Thermal Energy Systems to Industrial Process Heat*, Volume 2 - Industrial Process Heat Survey, TID 27348/2, Battelle Laboratories (January 1977).

16. Federal Energy Administration, *The Data Base — The Potential for Energy Conservation in Nine Selected Industries, Volume 6 — Steel*, Conservation Paper No. 14, Office of Industrial Programs, 1975.
17. Dow Chemical Company, *Energy Consumption: Paper, Stone/Clay/Glass/Concrete, and Food Industries*, EPA-650/2-75-032.c (April 1975).
18. J. T. Reding and B. P. Shepherd, *Energy Consumption: Fuel Utilization and Conservation in Industry*, EPA-650/2-75-032.d, Dow Chemical Company, Freeport, Tex. (August 1975).
19. International Research and Technology Corporation, *Industrial Energy Study of the Industrial Chemicals Group*, IRT-342-R (PB-236322) (August 1974).
20. Dow Chemical Company, *Evaluation of New Energy Sources for Process Heat*, NSF-OEP74-18055-1 (PB-245604), Midland, Mich. (September 1975).

4. FEASIBILITY OF COGENERATION SYSTEMS FOR GENERATING INDUSTRIAL HEAT AND POWER

The first test of the feasibility of a cogeneration system to efficiently generate a manufacturing plant's electricity, steam, and direct heat requirements is primarily a question of thermodynamics. Any cogeneration system that produces power through a thermodynamic cycle can be represented schematically, as in Fig. 4.1. The following oversimplified statements are useful in characterizing the system.

1. The electricity output is larger for large $T_2 - T_3$ (T representing temperature).
2. Electricity = $Q_1 - Q_2$ (Q representing heat transfer).
3. Useful thermal energy = $Q_2 - Q_3$,
 $= Q_1 - \text{electricity} - Q_3$.
4. Overall efficiency = $\frac{\text{electricity} + \text{useful thermal energy}}{Q_1}$.

The following conclusions may be drawn from these statements.

1. For high electricity output, the useful thermal energy available will be relatively small, and vice versa.

Fig. 4.1. Schematic of cogeneration system.

2. For high-temperature thermal energy plus electricity, T_2 must be high (peak temperature of power cycle).

3. For high overall efficiency, Q_3 must be small, that is, T_5 must be as close to T_6 as practical.

In relation to these concepts, the performance and capabilities of real systems can be adequately described by their respective heat/power ratios and useful heat delivery temperature. The potential conservation impact of a cogeneration system depends on whether the heat/power ratio and process heat temperature demand at an industrial site can be satisfied by the particular system.

4.1 Cogeneration Prime Mover Characteristics

The cogeneration capabilities of three types of power plants are compared in Fig. 4.2. Compression ignition (CI) and spark ignition (SI) internal combustion (IC) engines presently offer the highest electrical output per unit of fuel consumption. With reference to Fig. 4.1, one reason for this is that the peak temperature (T_2) permitted in the intermittently firing internal combustion engines is much higher than that allowable in the continuous operation of gas or steam turbines. A typical IC-engine cogeneration system is illustrated in Fig. 4.3.

The data for the IC engine in Fig. 4.2 is representative of typical CI and SI models.¹ The useful heat delivery temperature shown is that of the exhaust gases. However, about one-third of the heat value is in the cooling water at a temperature of $\sim 110^\circ\text{C}$ (230°F); thus the combined useful heat temperature would be less than that shown. The IC engine, with its high electrical output, also offers a relatively low capital cost and would have some important cogeneration applications. However, the IC engine unfortunately possesses the terminative characteristics of being unable to operate with coal as a fuel. Coal liquefaction or gasification would be prerequisite to its wide use in cogeneration.

Steam turbines are already used to some extent to provide either shaft power or electricity in industries where large quantities of process steam are generated. The data generated for Fig. 4.2 apply to a back-pressure turbine with varying feedwater and condensate return

Fig. 4.2. Comparison of cogeneration capabilities of different prime movers.

Fig. 4.3. A reciprocating IC-engine system (Ref. 1).

temperatures. Systems where most of the condensate is returned to the boiler feed offer high overall efficiency. A back-pressure turbine cogeneration schematic is shown in Fig. 4.4. This type of system is generally employed when the steam energy required is rather large in comparison to the electric demand.²

Other conventional steam cogeneration systems include the condensing-turbine system and the extraction steam-turbine system.

The condensing system is applicable only in cases where the temperature requirements for heat are very low. Steam extraction systems, on the other hand, are capable of supplying high-temperature steam in small amounts.

The significant advantages that have been identified for steam-turbine systems include (1) multifuel capability, (2) a wide range of available equipment, and (3) reliability.

As evident from Fig. 4.2, the major shortcoming of the steam systems is their inability to generate high-temperature useful heat in addition to significant electric power; for example, at a heat/power ratio of 4:1. Referring again to Fig. 4.1, the underlying reason is that T_2 is not high enough. The compatibility of conventional materials with high-temperature steam limits the peak cycle temperature to $\sim 538^\circ\text{C}$ (1000°F).

Fig. 4.4. Back-pressure turbine system for producing process steam and hot water.

The fluidized-bed gas turbine system shown in Fig. 4.5 is characterized by a combination of the better qualities of the IC engine and the steam turbine identified previously. The version of the system with a recuperator is capable of generating electricity sufficient for a heat/electric ratio of 3, while still delivering hot air to a direct heater or waste heat boiler at $\sim 360^{\circ}\text{C}$ (680°F). The turbine inlet temperature of 816°C (1500°F) is primarily responsible for the obvious advantage over steam system performance. This characteristic of gas turbines is not new, because they have been cited as potential cogeneration candidates elsewhere.^{3,4} However, the capacity for this particular system to burn coal is innovative and magnifies its attractiveness.

The overall fuel efficiencies for the systems of Fig. 4.2 are about 82 to 85% for the steam and CCC, with the IC engine being slightly lower. In generating the data (except for the case of the steam turbine condensing at high pressure), the assumption was made that the working fluid heat could be utilized down to 38°C (100°F), T_5 in Fig. 4.1. In some

Fig. 4.5. Atmospheric fluidized-bed coal-combustion gas-turbine cogeneration system.

applications, this may not be possible. In other cases, if the economics were favorable, a higher working fluid flow could be specified to increase the electric power, raising T_5 and sacrificing overall fuel utilization. The relations between the thermal rejection temperature (T_5 in Fig. 4.1), heat/power ratio, and useful heat temperature are depicted in Figs. 4.6 through 4.9. The importance of utilizing the waste heat to its fullest

Fig. 4.6. Cogeneration capability at 100°F rejection.

Fig. 4.7. Cogeneration capability at 200°F rejection.

extent is magnified at the higher electricity output if high fuel utilization is desired.

At least three scenarios may be followed in sizing a cogeneration system for a particular industrial plant or process.

1. Produce all the necessary process heat and electricity.
2. Produce the needed amount of process heat and whatever electricity results, regardless of the electricity requirements.

Fig. 4.8. Cogeneration capability at 300°F rejection.

3. Produce the needed electric power and whatever process heat follows, regardless of the process heat required at the plant.

Economics would undoubtedly play a major role in selecting a particular scheme. The price of utility electricity and the availability or lack of availability for the plant to sell its excess electricity also greatly influence the economic situation. Process heat is less

Fig. 4.9. Effect of thermal rejection temperature on overall fuel utilization.

expensive than electricity; thus, in some cases, producing additional electricity (at the expense of making the unit thermally over-sized and over-producing process heat) may be economically advantageous. In general, scenario 1 is followed in this preliminary study.

4.2 Temperature Requirements for Industrial Process Heat

In view of the power plant characteristics presented in the previous section, the following information is essential in selecting the proper cogeneration system, specifically, the major design parameters

of the gas-turbine system: (1) heat/electric ratio, (2) process heat temperatures, and (3) steam and direct heat required.

Because one of the objectives of this study is to ascertain the potential oil and gas savings due to implementation of the CCC, the amount of process heat required at temperatures which can be generated by the CCC must be estimated.

The CCC can produce useful thermal energy at up to $\sim 688^{\circ}\text{C}$ (1270°F) and still generate some power. Of course, the furnace is capable of producing hot air at up to 816°C (1500°F). Conversely, if the process heat required is less than $\sim 177^{\circ}\text{C}$ (350°F), it is possible that other means of heating may be more economical unless there is sufficient electrical demand. Because the applicability of the CCC appears to be best when the heat required is at temperatures of 177 to 593°C (350 to 1100°F), studying industrial process heat usage broken down into temperature bands will be useful.

Comprehensive data on process heat temperatures in industry have been collated in two recent solar energy studies. Intertechnology Corporation⁵ collected data for industries in 78 different SIC groups but did not necessarily identify all of the process heat energy consumed in all of the groups studied. The study, however, presents data for perhaps the broadest range of industrial representatives. A listing of their process heat temperature data is presented in the Appendix. Battelle Laboratories⁶ performed a similar study covering 22 industries representing at least 11 two-digit SIC groups. The most comprehensive table of data from the Battelle study is also included in the Appendix. Unfortunately, the formats for presentation of the data are not identical, but comparison is presented where possible.

Process heat consumption associated with the described temperature bands is presented in Table 4.1. A better comparison between data sets is obtained in regard to the six major industrial consumers. The process heat temperature spectrum on this basis is shown in Table 4.2.

These data indicate that the CCC is capable of supplying 61 to 64% of all industrial process heat requirements. Referring to the data in Table 3.10, converting 61% of the industrial process heating to coal-fired systems would displace $\sim 1.60 \text{ m}^3/\text{sec}$ (870,000 bbl/day) of oil and

Table 4.1. Temperature distribution of identified process heat consumption^a

Temperature [°C (°F)]	Process heat, percent of total	
	Ref. 5	Ref. 6
177 (<350)	25	20 ^b
177-593 (350-1100)	28	NA ^b
593-817 (1100-1500)	8	NA
817 (>1500)	39	NA

^a"Captive energy" from raw materials and self-generated fuels has been subtracted where necessary.

^bNA = not available.

Table 4.2. Temperature distribution of identified process heat consumption in six major industries combined

Temperature [°C (°F)]	Process heat, percent of total	
	Ref. 5	Ref. 6
177 (<350)	27 ^a	11 ^a
177-593 (350-1100)	29 ^b	46 ^b
593-817 (1100-1500)	8	4
817 (>1500)	36	39

^aReference 5 identified substantially more low-temperature process heat in primary metals and petroleum refining than Ref. 6.

^bReference 6 identified more process heat for petroleum refining in this temperature range.

4590 m³/sec (14 × 10⁹ ft³/day) of natural gas (Bureau of Mines data). The total potential savings of oil and gas thermodynamically feasible with the CCC are summarized in Table 4.3. The savings would be higher if exhaust gas supplemental firing were incorporated in the system. The CCC thermal energy in this capacity would act as a combustion air pre-heater for a high-temperature gas or oil flame. The 61% estimate is based on the assumption of uniform distribution of oil and gas consumption for process heat over the process heat temperature spectrum. However, a substantial fraction of the high-temperature heat is used in the steel industry and is generated from coal. The 61% and, therefore, the savings estimate are conservative.

Table 4.3. Thermodynamically feasible savings of oil and gas with CCC^a

	Source of savings		Total
	Process heat conversion to coal	Electrical generation by coal cogeneration	
Oil, m ³ /sec (bbl/day)	1.60 (870,000)	1.17 (635,000)	2.77 (1,505,000)
Natural gas, m ³ /sec (10 ⁹ ft ³ /day)	4590 (14 0)	1228 (3.75)	5818 (17.75)

^a1974 Bureau of Mines data base. Exhaust supplemental firing systems not included. Actual estimates for oil and gas, not energy equivalents.

Savings of the magnitude presented in Table 4.3 warrant further detailed assessment of the CCC and continued technological development of the system.

4.3 Process Heat/Temperature and Power Consumption in the Six Major Industries

Data for the six major industries are presented to assist in identifying specific manufacturers or processes that are suited to the application of the CCC cogeneration system. General characteristics of the industries needed in ascertaining practical barriers to the CCC implementation are discussed. Limited discussion is included on industrial

process changes that would enhance the applicability of the CCC. Comparative data for the six major industries are presented here, with individual attention following in subsequent sections.

Comprehensive data for the process heat temperature, heat consumption, and electricity consumption are presented in Table 4.4. The data are predominantly from the two previously mentioned solar energy studies^{5,6} and reflect only the process heat and electricity consumption that has been identified with reasonable certainty. Speculative or forecast data for total consumption are not presented. An effort was made to present the data from the most extensive aggregate study of industrial subgroups. The capabilities of the CCC system indicate applications in all industries listed, with the possible exception of the iron and steel manufacturers. The petroleum refining industry shows a large value of process heat in the temperature band most suited to the CCC. A more detailed discussion of the industries follows.

4.3.1 Primary metals

This evaluation subdivides primary metal production into three subsectors: (1) iron and steel, (2) aluminum, and (3) copper. From the work of Reding and Shepherd,⁸ the fuels used by these three groups in 1972 are listed in Table 4.5. Recall from Table 3.9 that ~89% of the oil and gas purchased as fuel is consumed in various process heaters or steam generators.

4.3.1.1 Iron/steel. If the coke energy for blast furnaces is included, the iron and steel manufacturers are the greatest consumers of energy in the industrial sector. In 1973, the steel plants in the United States consumed 4009×10^{12} kJ (3800×10^{12} Btu) of energy (electric - 3413 Btu/kWhr). Production was carried out in 43 integrated iron and steel plants and 118 electric furnace steel plants, with a total production of about 150 million tons.⁶ A flow diagram for steel-making industries is provided in Fig. 4.10 (Ref. 6).

Table 4.6 summarizes process heat requirements for 12 processes in iron and steel production. In the blast furnace, a portion of the coke input serves to reduce the iron oxide to iron and does not actually provide process heat. An estimate of the energy required to melt iron

Table 4.4. Annual process heat/temperature and electric requirements for six major industries

Industry	Process heat consumption [10 ¹² kJ (10 ¹² Btu)]				Electricity (10 ⁹ kWhr)	Date (reference)
	<177°C (<350°F)	177-593°C (350-1100°F)	593-816°C (1100-1500°F)	>816°C (>1500°F)		
Iron/steel	69 (65)	0 (0)	0 (0)	1806 (1712)	57.5 ^a	1973 (6)
Petroleum	63 (60)	2958 (2804)	241 (230)	0 (0)	23.1 ^b	1973 (6)
Chemicals	322 (305)	195 (185)	0 (0)	37 (35)	80.0 ^c	1977 (5) ^d
Paper/pulp	324 (307)	504 (478)	0 (0)	0 (0)	36.0 ^e	1973 (6) ^f
Stone/clay/glass	77 (73)	19 (18)	12 (11)	1080 (1024)	24.0 ^e	1974 (6)
Food processing	271 (256)	64 (61)	0 (0)	0 (0)	36.0 ^e	1977 (5)

^a20% generated in-plant.

^bElectricity value from Ref. 7.

^cElectricity value from Ref. 8; additional generated in-plant.

^dReference 8 shows about 1250×10^{12} total process heat consumption.

^eElectricity value from Ref. 8; additional generated in-plant.

^fApproximately 390×10^{12} Btu supplied by by-product fuels (Ref. 6).

Table 4.5. Energy consumption and distributions in the primary metals industries in 1972

Using subsector	Consumption		Oil and gas (10 ¹⁵ Btu)	Percent of subtotal
	10 ¹⁵ kJ/year	10 ¹⁵ Btu		
Steel				
Purchased electricity	0.418	0.397		12
Coal	2.32	2.202		64
Petroleum	0.193	0.183	= 0.842 =	24
Natural gas	0.695	0.659		
Subtotal ^a	3.626	3.441		
Percent of total		66		
Aluminum				
Purchased electricity	0.649	0.615		78
Coal				
Petroleum	0.063	0.060	= 0.175 =	22
Natural gas	0.121	0.115		
Subtotal ^a	0.833	0.790		
Percent of total		15		
Other metal processes				
Purchased electricity	0.272	0.258		27
Coal	0.293	0.278		29
Petroleum	0.017	0.016	= 0.433 =	44
Natural gas	0.440	0.417		
Subtotal ^a	1.022	0.969		
Percent of total		19		
Total ^a	5.481	5.200		

^a Accuracy of energy consumption figures estimated to be within $\pm 10\%$ (Ref. 8).

was obtained from data for electric furnace steel production in which the charge (steel scrap) is already reduced. This estimate is shown as the process heat consumption in the blast furnace.⁶ By-product fuels (coke oven gas and blast furnace gas) contribute about 777×10^{12} kJ (740×10^{12} Btu), which is 42% of the identified process heat. Most of the process heat is required at temperatures well above the capabilities

Fig. 4.10. Generalized flow diagram of the steel-making industry.

Table 4.6. Process heat requirements in the iron and steel industry, 1973

Process	Heat requirements [10 ⁶ kJ/metric ton (10 ⁶ Btu/ton)]	Annual production [10 ⁶ metric tons (10 ⁶ tons)]	Annual total [10 ¹² kJ (10 ¹² Btu)]	Distribution of annual total [10 ¹² kJ (10 ¹² Btu)]	
				Steam [100–177°C (212–350°F)]	Direct heat [>538°C (>1000°F)]
Blast furnace	3.29 (2.84)	83 (91)	271 (257)		271 (257)
Open hearth	3.76 (3.24)	36 (40)	137 (130)		137 (130)
Basic oxygen furnace	0.232 (0.20)	75 (83)	18 (17)		18 (17)
Electric furnace	0.116 (0.10)	25 (28)	3 (3)		3 (3)
Ingot casting	0.139 (0.12)	137 (151)	19 (18)		19 (18)
Slabbing/blooming mill	1.82 (1.57)	137 (151)	250 (237)		250 (237)
Slab and bloom casting	0.267 (0.23)	137 (151)	39 (37)		39 (37)
Slab and bloom reheat	3.22 (2.78)	137 (151)	442 (419)		442 (419)
Pickle line	0.15 (0.13)	137 (151)	21 (20)	21 (20)	
Cleaning line	0.35 (0.30)	137 (151)	47 (45)	47 (45)	
Annealing furnace	1.90 (1.64)	137 (151)	261 (247)		261 (247)
Billet reheat furnace	2.67 (2.30)	137 (151)	366 (347)		366 (347)
Total			1874 (1777)	68 (65)	1806 (1712)

of a fluidized bed. However, the electric demand of the steel industry has apparently made in-house generation attractive (refer to Table 4.4); thus the CCC may be economically desirable, even though operating at a rather low overall fuel efficiency. Although displacement of the oil- and gas-fired process heaters by fluidized beds does not appear thermodynamically feasible, some possibilities eventually may exist because of the nature of the industry. Some reasons for this conclusion are listed below.

1. Approximately 80% of the total production of raw steel takes place in Illinois, Indiana, Ohio, Pennsylvania, and in plants in or near Detroit, Michigan, Baltimore, Maryland, and Buffalo, New York. This region, in varying degrees, experiences shortages and curtailments of natural gas and has excellent access to very large supplies of high-sulfur noncompliance coal well suited for use in fluidized-bed combustors. Coal converted to coke is a necessity in integrated* steel plants. The larger steel producers own captive mines and are well equipped to store and handle coal.

2. The U.S. steelmakers are currently suffering from intense competition from the newer and more efficient postwar steel mills in Japan and Federal Republic of Germany; for example, Battelle⁹ reports these 1973 consumption rates:

<u>Country</u>	<u>10⁶ kJ per metric ton (10⁶ Btu per ton) of steel shipped</u>	<u>Relative energy consumption per ton of raw steel</u>
United States	39.2 (33.8)	100
United Kingdom	40.3 (34.7)	101
Federal Republic of Germany	34.1 (29.4)	87
Japan	30.5 (26.3)	76

3. The assumption is made that, in the future and referenced to the sum of heat and power, fluidized-bed energy systems used in steel production will show superior overall efficiency and lower net costs.

*"Integrated" plants, as opposed to "cold-metal" plants, conduct all phases of steel-making, starting with iron ore and ending with finished products. Cold-metal plants begin processing with scrap and pig iron.

If this is the case, there exists incentive to spend the capital for their adoption.

4. To operate efficiently, steel mills must operate continuously and at or near full capacity. Reliable in-house energy production with coal to achieve freedom from shutdowns caused by curtailments of natural gas and utility-produced electricity is a powerful incentive.

5. Related to item 4, the possibility that regulated electrical rates will not only rise but will no longer include discounts for large industrial users cannot be ignored. This becomes an additional incentive to achieve a lower-cost independent and unregulated supply of in-house-produced electricity using readily available noncompliance coal.

Further evidence indicating possible implementation of the CCC system in steel-making can be presented. There are wide variations in the energy forms and distributions required by different processing facilities with differing product lines. Figure 4.11 shows fractional distributions of energy sources for both integrated and cold-metal companies. The cold-metal companies not requiring coal as a reductant are heavily dependent on gas and petroleum, use little coal, and consume relatively large amounts of electricity. Cold-metal processing accounts for 10 to 15% of the total production.

Assessments that estimate the near-term usage of coal-fired gas-turbine energy systems in this industry do not envision replacement of the coal used for coke to reduce oxide ores. Directly or indirectly, on some time scale, energy produced in CCC systems is theoretically capable of replacing all but a very small fraction of the natural gas and petroleum used over a wide range of temperatures to process metallic steel and iron. The forming of finished steel products, sheets, bars, wire structural shapes, and pipe and tubing consumes large volumes of natural gas in soaking pits and reheating furnaces that produce the softening temperatures [1204 to 1315°C (2200 to 2400°F)] which enable plastic forming by rolling, drawing, forging, and similar procedures. These temperatures exceed by a wide margin the peak temperature of the direct heat available in the gas-turbine loop; however, they are readily attainable with turbine-produced electricity. Electrical energy is capable of producing the temperatures required to melt, form, and heat

- (a) "Integrated" companies are engaged in all phases of steel production, from ore to finished product.
- (b) "Cold-metal" companies do not have processing facilities (blast furnaces) for reducing ore to metallic iron.
- (c) The steel industry uses 6% of the total natural gas required by industry.

Fig. 4.11. Distribution of energy sources in the steel industry in 1975 (from American Iron and Steel Institute statistics).

treat steel and other metals. Electric melting of scrap and pig iron in steel mills and foundries has been steadily replacing fossil-fired open hearth furnaces. This trend began before fuel shortages became acute. Induction, resistance, and radiant heating with electricity has been reduced to well established practice. With ample and economical electrical power, the iron and steel industry is technologically capable of becoming virtually independent of continuing supplies of fuel oil and natural gas.* Lower-temperature energy for direct heat and steam as required in a particular facility is easily extracted from a CCC loop.

On a long-term basis, if blast furnaces are replaced by alternative direct reduction processes that use gaseous reducing agents (carbon monoxide and/or hydrogen), the opportunity to employ gas turbines that produce heat and electricity will expand. A large variety of alternative direct ore-reduction processes are described briefly in Ref. 10. Table 4.7 lists eight of these with typical maximum temperatures required within the process. The list is not complete.

A review of these and similar ore-processing methods leads to the following observations.

1. The iron and steel makers worldwide are actively pursuing developments intended to supplant and replace the blast furnace for ore reduction.
2. Some of these processes are in successful operation, notably in Scandinavia, where gas has been scarce and electricity relatively plentiful.
3. Processes based primarily on using hydrogen as a reducing agent are becoming practicable.
4. The temperatures, compared with blast furnaces, are low — in some cases $<816^{\circ}\text{C}$ (1500°F).
5. Melting, subsequent to ore reduction, is readily accomplished in electric furnaces.

The assumption is not unreasonable that, with hydrogen and after thorough and intensive engineering development, coal and coke used as

* Relatively small amounts of hydrocarbon gases will be required to obtain furnace atmospheres in a variety of processes.

Table 4.7. Temperatures and reducing agents in representative direct-reduction processes for iron production

Process identification	Reducing agents	Process temperatures	Remarks
1. Nu-iron	H ₂ , ~85%; CO, 15%	Maximum gas - 843°C (1550°F) Preheated ore - 926°C (1700°F)	Developed by U.S. Steel; a plant with a capacity of 1 million tons per year of 75% reduced briquettes under construction in Venezuela
2. H-iron	H ₂ , ~85%	Reduction - 538°C (1000°F) Product deactivation - 871°C (1600°F)	A low-temperature, high-pressure (~400-psi) process
3. Arthur D. Little (Esso research - Little process)	H ₂ , ~41%; CO, ~21%; N ₂ , ~38%	516-871°C (1500-1600°F)	See item 4
4. FLOR	H ₂ , ~41%; CO, ~21%; N ₂ , ~38%		A further development of the Arthur D. Little process; a 300-ton/day plant has been operating in Nova Scotia since 1965
5. Stelling	CO	593-704°C (1100-1300°F)	Developed in Sweden; CO is the principal reducing agent; hydrogen (an impurity), if used, prevents fluidized-bed operation
6. Norwegian H-iron	H ₂	899°C (1650°F)	Reduction to iron takes place in an electric furnace at 899°C (1650°F)
7. Wiberg-Soderfors	H ₂ , 20-30%; CO, 70-80%	Gas production, ~1038°C (1900°F) Ire reduction, 1019-871°C (1850-1600°F)	Several plants operating in Sweden; the largest, built in 1952, has a capacity of 20,000 tons/year
8. Novalfer - Onia	H CO	593-704°C (1100-1300°F)	Developed in France to process Algerian ores

a reducing agent can be eliminated as a processing step in steel production. The heat and electricity required to accomplish ore reduction and refining is obtained readily from abundant and inexpensive noncompliance coal in fluidized-bed systems. The assumption is also made that the hydrogen will be produced from coal, rather than by reforming natural gas. Alternatively, combining steam reforming of the coal to make carbon monoxide and hydrogen in the same fluidized beds used to develop power and process heat may be worth consideration.

If these developments take place, the long-term potential of fluidized-bed systems to produce heat and power for steel production systems would be greatly expanded. All energy forms and processing temperatures required to produce steel fall within the capability of fluidized-bed combustors coupled to gas turbines. Theoretically, if energy efficiencies per ton of steel remain unchanged by such a change in production methodology and if steel production remains at the 1973 level, then the market potential of efficient and reliable fluidized-bed energy production will approach 100% of the steel industry's requirements, resulting in the following theoretical market:

U.S. shipments, 1973	86.7×10^6 metric tons (95.5×10^6 tons)
Total annual energy rate	880×10^6 MW (3.0×10^{15} Btu/hr)
Total theoretical number of 100-MW CCC units at 100 MW each to maintain the 1973 production level	10,000

This 100% forecast and the assumptions on which it rests are extravagant and not for the near time. The forecast is included only to show that, neglecting cost considerations, the steel industry is potentially capable of large-scale reductions in its consumption of gas and petroleum by more extensive use of nonmetallurgical, noncompliance coal for heat and electricity and, further, that fluidized-bed systems are a very promising approach to achieving these reductions. Consider that possibly 25% of the previous theoretical market is realistic in the not too distant future. The opportunity to produce 2500 CCC modular systems of 100 MW each should attract the attention of equipment builders.

4.3.1.2 Primary aluminum production. After steel, aluminum production consumes more energy than that required to produce any other metal. Table 4.8 shows total fuel usages. That aluminum production is electrically intensive and, further, that coal usage is negligible is immediately apparent. Aluminum processing can be broadly subdivided into two general subprocesses: (1) raw material preparation and (2) electrolytic reduction to metallic aluminum. These processes are diagrammed in Fig. 4.12. The Hall process is almost standard throughout the industry, but Alcoa is developing an alternative (Fig. 4.13) that is reported to use 30% less electricity. Although new and better processes may be successfully developed and applied, the Hall process for electrolytic reduction will probably dominate the industry for an appreciable period. Heat requirements for some of the subprocesses are given in Table 4.9. The fuel used for the calcining operations and steam generation is predominantly natural gas.

The bauxite refining plants display heat/power requirements in the range of the CCC output. These refineries are generally separate facilities from the smelting operations. Displacement of the 40.3×10^{12} kJ (38.4×10^{12} Btu) of energy for steam generation would be equivalent to 1.05×10^9 m³ (37×10^9 ft³) of natural gas. Further oil and gas conservation, of course, would follow from the in-house coal-produced electricity. Bauxite is refined at nine plants in the United States that are owned by five different primary aluminum producers.

The total energy consumption by the aluminum industry has not changed appreciably in recent years. The Aluminum Association reports that energy efficiency increased 7.6% during the period 1972 through 1976. The almost constant total annual use rate is concluded to be the result of escalating production rates. Because of the great dependency on electricity, smelting plants have traditionally been located near sources of abundant and inexpensive power, particularly hydro sources. For this reason, aluminum smelters actually place little burden on the nation's rarer nonrenewable fuels; exceptions are some gas-fired power stations owned by aluminum companies in Texas, traditionally a location for inexpensive natural gas.

Table 4.8. Energy consumption and distribution^a by source
in the aluminum industry in 1972 and 1976

Source	Consumption and distribution			
	1972		1976	
	10 ¹⁵ kJ (10 ¹⁵ Btu)	Percent of total	10 ¹⁵ kJ (10 ¹⁵ Btu)	Percent of total
Natural gas and liquefied petroleum gas (LPG)	0.234 (0.222)	24.1	0.212 (0.201)	22.1
Liquid petroleum	0.026 (0.025)	2.7	0.034 (0.032)	3.5
Petroleum coke and pitch ^b	0.075 (0.071)	7.7	0.077 (0.073)	8.0
Coal	0.008 (0.008)	0.9	0.005 (0.005)	0.5
Electricity				
Hydro	0.109 (0.103)	11.2	0.124 (0.118)	12.9
Purchased	0.317 (0.300)	32.6	0.353 (0.335)	36.7
Subtotal	0.426 (0.403)	43.8	0.477 (0.453)	49.6
In-house	0.202 (0.191)	20.8	0.157 (0.149)	16.3
Total electricity	0.628 (0.594)	64.6	0.634 (0.602)	65.9
Total	0.971 (0.920)	100.0	0.964 (0.913)	100.0

^aThese data (Ref. 11) were provided by the Aluminum Association, Inc.

^bUsed as raw materials for electrode production.

Fig. 4.12. Major processes and heat requirements for production of aluminum metal (Ref. 6).

Table 4.9. Process heat/steam^a and electrical^b requirements in production of aluminum metal

Process	Steam-temperature		Direct heat-temperature		Electricity (10 ⁹ kWhr)
	10 ¹² kJ (10 ¹² Btu)	°C (°F)	10 ¹² kJ (10 ¹² Btu)	°C (°F)	
Bayer					
Calcining limestone	40.5 (38.4)	216 (420)	2.03 (1.92)	1204 (2200)	1.7
Digestion					
Calcining alumina			36.1 (34.2)	1149 (2100)	
Hall/Heroult					
Calcining coke			7.8 (7.4)	1299 (2370)	76.9
Anode baking			20.7 (19.6)	1093 (2000)	
Electrolytic cell (smelting plant)					

^aReference 6.

^bReference 12.

Fig. 4.13. Alcoa smelting process flow sheet.

4.3.1.3 Copper production. The production of metallic copper from sulfide ores can be divided into four steps: (1) mining, (2) beneficiation, (3) smelting, and (4) refining. Reference 13 analyzes four sets of energy consumption data reported in Refs. 14 through 21. Their results have been used in Table 4.10.

The copper industry is strongly dependent on electricity to mine and concentrate sulfide ores and to electrolytically refine the impure smelted metal. Often, the four subprocesses required to produce pure metallic copper are now performed at widely separated locations. For example, ore mined in Butte, Montana, has been smelted in Anaconda, 43 km (27 miles) away, and electrolytically refined in Great Falls, Montana. Assessments of potential retrofit applications of CCC systems to existing facilities consider these geographical separations and do not assume energy distributions based on the complete process. Figure 4.14

Table 4.10. Estimated^a energy consumption by primary copper production in 1973

	Electricity ^b (10 ⁹ kWhr)	Other		Subtotal
		10 ¹⁵ kJ (10 ¹⁵ Btu)	Percent gas and oil ^c	[10 ¹⁵ kJ (10 ¹⁵ Btu)]
Primary copper				
Mining and beneficiation	4.1	0.051 (0.048)	80	0.100 (0.095)
Smelting		0.040 (0.038)	88	0.040 (0.038)
Refining	0.044	0.006 (0.006)	100	0.012 (0.011)
	<u>4.14</u>	<u>0.097 (0.092)</u>		<u>0.152 (0.144)</u>
Total (primary)				
				0.019 (0.018)
Secondary copper				
				<u>0.171 (0.162)</u>
1973 total				

^aThese data were abstracted from Tables 1 and 4 in Ref. 13.

^bAverage of values reported by Chapman and Bravard and listed in Table 4 of Ref. 13.

^cApproximate values derived from Ref. 21.

Fig. 4.14. Basic processes in copper production.

is a flow sheet of the typical processes used to produce metallic copper from a sulfide ore. The reverberatory furnace and converter are the largest natural gas consumers. Required temperatures are outside the CCC capabilities. More detailed descriptions of the mechanics of the processes are provided in Refs. 11 and 20.

Electrically produced shaft power is used to produce compressed air and to drive crushers, ball mills, classifiers, flotation cells, pumps, and subsurface mining equipment. Obviously, all these requirements can be met with in-house CCC systems. Smelting can be accomplished in electric furnaces; economic considerations govern the methods used to provide the energy required by this process phase.

Final purification (refining) requires melting impure metallic copper produced by smelting to produce anodes for the electrolytic cells. Melting can be accomplished electrically; hypothetically, CCC systems are technologically capable of producing all the energy needed for refining.

4.3.2 Chemical industry

The chemical industry is very diverse, with over 11,000 plants of 1,300 companies which produce over 10,000 products.³ Ten major four-digit SIC groups have been identified as accounting for ~90% of the total energy use for SIC 28. Within these ten groups are approximately 1900 plants. These ten industries are listed:

1. SIC 2812 -- Alkalies and chlorine,
2. SIC 2816 -- Inorganic pigments,
3. SIC 2819 -- Industrial inorganic chemicals,
4. SIC 2821 -- Plastic materials and resins,
5. SIC 2822 -- Synthetic rubber,
6. SIC 2823 -- Cellulosic man-made fibers,
7. SIC 2824 -- Organic man-made fibers,
8. SIC 2865 -- Cyclic intermediates and crudes,
9. SIC 2869 -- Industrial organic chemicals,
10. SIC 2871 -- Fertilizers.

Energy consumption rates, forms, and sources have been reported by several authors. As expected, these are not identical. Considering the unavoidable uncertainties and the differences in interpretations associated with the data, collecting and assembling the various listings are well within reasonable tolerances. Table 4.11 shows total consumption rates abstracted from four references. Table 4.12, because it describes energy use as a function of temperature, is used as the basis for estimating the potential for CCC application in chemical processing. Excluding fuels used as feedstock, ~50% of the fuel is used to produce steam. Of the 1583×10^{12} kJ (1500×10^{12} Btu) of steam generation, ~13% is produced in waste heat boilers. Over 90% of the steam is generated at over 204°C (400°F), but much is used at under 149°C (300°F). This temperature distribution of generated and utilized steam is shown in Table 4.13.

Table 4.11. Estimates of annual energy consumption by the chemical process industries

Source	Year	Energy consumption [10^{15} kJ (10^{15} Btu)]	Remarks
Ref. 22	1971	2.93 (2.78)	Purchased energy; excludes feedstock
Ref. 8	1973	4.85 ($4.60 \pm 10\%$)	Includes feedstock energy
Ref. 8	1973	2.81 (2.66)	Excludes feedstock energy
Ref. 23	1971	2.28 (2.16)	Excludes feedstock energy and purchased electricity
Ref. 3	1971	3.20 (3.03)	This tabulation used as basis for CCC potential

In addition to the purchased electricity shown in Table 4.12, about 29.4×10^9 kWhr is generated yearly in-plant.³ About one-half this value is generated via steam drive. On the average, only 22% of the waste heat from the electricity generation is recovered, although a few plants are recovering up to 45%.²⁴ With 45% waste heat recovery, the overall fuel utilization for the in-house generation would approach 70%. Implementation of the CCC could make this the rule rather than the exception, with the added benefit of the ability to use coal.

Table 4.12. Fuel sources, temperature ranges, and energy forms used in the chemical industry in 1971

Energy form	Energy source and amount [10 ¹⁵ kJ (10 ¹⁵ Btu)]						Percent of total
	Electricity	Coal	Natural gas	Oil	Other	Total	
Steam		0.422 (0.400)	0.992 (0.940)	0.127 (0.120)	0.042 (0.040)	1.583 (1.500)	50
Nonsteam							
T < 538°C (1000°F)			0.100 (0.095)	0.021 (0.020)		0.121 (0.115)	4
T = 538-816°C (1000-1500°F)			0.164 (0.155)	0.016 (0.015)	0.190 (0.180)	0.369 (0.350)	11
T > 816°C (1500°F)			0.116 (0.110)	0.021 (0.020)		0.137 (0.130)	4
Subtotals		0.422 (0.400)	1.372 (1.30)	0.185 (0.175)	0.232 (0.220)	2.210 (2.095)	69
Purchased electricity at 10,000 Btu/kWhr	0.981 (0.930)					0.981 (0.930)	31
Total						3.191 (3.025)	100
Percent of total	31	13	43	6	7		

Source: Ref. 3.

Table 4.13. Steam generation and utilization temperatures in chemical industry

Generation temperature band [°C (°F)]	Annual steam generated ^a [10 ¹² kJ (10 ¹² Btu)]	Utilization temperature band [°C (°F)]	Annual steam utilized ^a [10 ¹² kJ (10 ¹² Btu)]
182 (<360)	53 (50)	163 (<325)	463 (439)
182-274 (360-525)	1277 (1210)	163-243 (325-470)	1037 (983)
274 (>525)	211 (200)	243 (>470)	40 (38)

^aNote that steam is usually generated at a higher temperature than is utilized for process.

Source: Ref. 3.

The CCC system (Tables 4.12 and 4.13) can displace all the gas and oil used for steam generation and probably one-half the oil and gas used for nonsteam heating. This would mean an annual displacement of $\sim 1171 \times 10^{12}$ kJ (1110×10^{12} Btu) of natural gas (1078×10^9 ft³) and 155×10^{12} kJ (147×10^{12} Btu) of oil (25×10^6 bbl) using the 1971 figures. CCC systems operating at heat power ratios of 3 to 4 could provide nearly all the electrical load.

The remaining subsections present data for specific subgroups, such as those listed at the beginning of the chemical industry discussion.

4.3.2.1 Alkalies and chlorine. The production of chlorine and caustic soda is examined specifically in this section. Electrolytic manufacture of chlorine and caustic soda requires large amounts of electric power, totaling $\sim 2\%$ of the total electricity generated in the nation. Nearly 50% of the electricity is generated at the plant because the large producer can utilize the waste heat (steam) for process energy, mostly in the caustic evaporator that concentrates the dilute NaOH liquor from the electrolytic cell.²⁴ Most of the chlorine is used in manufacturing chlorinated hydrocarbons for plastic, pesticides, and solvents; uses of caustic soda are numerous.

Electrolytic cells are either the diaphragm or mercury type. The diaphragm cells require less electricity but necessitate the use of evaporators. The basic manufacturing sequence for the diaphragm cell

is illustrated in Fig. 4.15. Usage of the mercury cell has been declining recently.²⁴

Process energy requirements for chlorine/caustic soda manufacture are given in Table 4.14.

Although cogeneration already exists to a large extent in industry, the fuel used for heat and power is predominantly natural gas (~80% of the purchased fuels in 1973).²⁴ This accounts for a potential displacement of $\sim 6.2 \times 10^9 \text{ m}^3$ ($220 \times 10^9 \text{ ft}^3$) of gas annually. Petroleum products are used to a lesser extent, $\sim 18 \times 10^{12} \text{ kJ}$ ($17 \times 10^{12} \text{ Btu}$) in 1973 ($2.8 \times 10^6 \text{ bbl}$).²⁴

4.3.2.2 Ammonia. Ammonia is produced by the iron-catalyzed reaction between hydrogen and nitrogen. In the United States, virtually all the hydrogen used for ammonia synthesis is obtained by steam-hydrocarbon reforming, using natural gas as the hydrocarbon feedstock. Nitrogen is obtained either from air liquefaction plants or by depleting the oxygen from air introduced into the reformer.⁶ About 80% of the ammonia produced is used in fertilizers.

Figure 4.16 shows the production procedure for manufacturing ammonia. Modern ammonia plants are engineered for precise temperature control and full reutilization of energy. Exiting gas streams from exothermic reactions are used to (1) heat inlet gas streams prior to reaction, (2) generate steam to run turbines for compression of gases and refrigeration, and (3) transport heat to other parts of the plant.⁶

Process energy loads for ammonia manufacture are listed in Table 4.15.

The steam generation could likely be accomplished by the CCC, but heating the reformer to 816°C (1500°F) may be a borderline application. The fuel presently used is almost exclusively natural gas. With the high waste-heat utilization already in practice, further efforts toward cogeneration may be nonproductive. Furthermore, ammonia plants have been given preference in obtaining natural gas, thus reducing their incentive for fuel conversion.²⁴

4.3.2.3 Synthetic rubber. Styrene butadiene rubber (SBR) accounts for nearly 60% of the synthetic rubber produced in the United States.²⁵ Most of the SBR goes into the manufacture of tires and tire products.

Fig. 4.15. Manufacture of chlorine and caustic soda in a diaphragm cell.

Table 4.14. Typical process energy consumption in manufacture of chlorine/caustic soda in diaphragm cell^a

Process	Temperature [°C (°F)]	1974 total ^b heat (steam) [10 ¹² kJ (10 ¹² Btu)]	Electricity (10 ⁹ kWh)
Brine heating during purification	66 (150)	10.6 (10.0)	
Brine heating	79–93 (175–200)	28.7 (27.2)	
Evaporation to 50% NaOH	143–149 (290–300)	175.1 (166.0)	
Cell			41.8–51.6

^aReference 6, with electricity from Ref. 24.

^bBased on 1974 production of 15.0×10^6 metric tons (16.6×10^6 tons) chlorine with 1.12 tons caustic soda per ton of chlorine.

Fig. 4.16. Production of ammonia.

Table 4.15. Process energy for ammonia production^a

Process energy ^b [10 ¹² kJ (10 ¹² Btu)]	Feedstock energy [10 ¹² kJ (10 ¹² Btu)]	Electricity (10 ⁹ kWhr)
273 (259)	382 (362)	0.93

^aFor centrifugal compressor plant, Ref. 24.

^bIncludes process heat for reformer and steam generator; based on 1975 production of 14.3 metric tons (15.8 × 10⁶ tons) (Ref. 6).

In general terms, SBR is produced by the emulsion polymerization, which involves mixing the two monomers, styrene and butadiene, in an emulsion reactor with water, catalyst, emulsifier, and other modifiers. Cold SBR is produced by polymerization at 5.0°C (41°F), and, because of its superior properties, it accounts for ~75% of all SBR production.

Production processes for SBR are shown in Fig. 4.17 (Ref. 6). Energy requirements are provided in Table 4.16. Process heat is required in the form of steam. The fuel for process heat is essentially all natural gas at the SBR plant.²⁵ This fact, coupled with a high kWhr/ton figure make SBR plants candidates for the CCC system. Potential displacement of natural gas would be $\sim 0.16 \times 10^9 \text{ m}^3$ ($5.6 \times 10^9 \text{ ft}^3$) annually.

4.3.2.4 Selected plastics. Four plastics materials account for over 60% of the total plastics production: (1) low-density polyethylene (LDPE), (2) high-density polyethylene (HDPE), (3) polystyrene, and (4) polyvinyl chloride (PVC).

Low-density polyethylene (LDPE) production accounts for ~20% of the total plastics production and uses ~30% of the U.S. ethylene production. Polymerization is carried out at pressures of 100 to 340 MPa (15,000 to 50,000 psig) and temperatures between 149 and 316°C (300 and 600°F). Generalized production processes are shown in Fig. 4.18; process energy is given in Table 4.17. The process steam is apparently generated by either oil or gas (~50% each).²⁶ The electricity demand is quite high, resulting in a heat/power ratio of 0.47, which is outside the performance

Fig. 4.17. Process for production of cold SBR (1 lb = 0.454 kg)
(Ref. 6).

Fig. 4.18. Low-density polyethylene - generalized process (1 lb = 0.454 kg) (Ref. 6).

Table 4.16. Process energy consumed in cold SBR production^a

Temperature [°C (°F)]	Heat quantity [10 ¹² kJ (10 ¹² Btu)] ^b	Electricity (10 ⁹ kWhr) ^b
121 (250)	4.67 (4.43)	
104 (220)	1.46 (1.38)	0.55

^aHeat and temperature from Ref. 6; electricity from Ref. 25.

^bBased on average 1970–1974 production of 1.19×10^6 metric tons (1.31×10^6 tons) annually.

capability of the CCC. Depending on the local cost of electricity, implementing the CCC for the electricity may be advantageous, even though the overall fuel utilization might be quite low. Union Carbide Corporation has introduced a low-pressure production method that requires less energy and may be a better candidate for the CCC.²⁷

The plastic exhibiting the fastest growth in production is HDPE. Production methods are numerous; the process presented here is the Hoechst slurry process. The process energy required is provided in Table 4.18; the general flow diagram is shown in Fig. 4.19 (Ref. 6). The heat/power ratio makes the process a likely application for the CCC. Presently, the industry uses natural gas (40%) and fuel oil (60%) for its process heat.²⁶ Implementation of the coal-fired CCC in this industry would displace $\sim 0.05 \times 10^9 \text{ m}^3$ ($1.9 \times 10^9 \text{ ft}^3$) of gas and $0.08 \times 10^6 \text{ m}^3$ ($0.5 \times 10^6 \text{ bbl}$) oil per year. The electricity in Table 4.18 does not include that required for extrusion and pelletization of the HDPE, which could bring the power demand to $\sim 600 \text{ kWhr/ton}$.

Polyvinyl chloride resins averaged 16% of the total production of all plastics and resin materials between 1969 and 1974.⁶ These resins are produced by suspension, emulsion, bulk, and solution processes, with a suspension polymerization process accounting for $\sim 85\%$ of the U.S. production. Figure 4.20 is a flow chart for the suspension process (Ref. 6). Temperatures and pressures shown are approximate averages of the ranges

Table 4.17. Process heat in LDPE manufacture

	Steam per short ton of LDPE			Process heat ^a [10 ³ kJ/metric ton (10 ³ Btu/ton)]	Electricity [kWhr/metric ton (kWhr/ton)]
	Used [kg (lb)]	Pressure [MPa (psi)]	Temperature [°C (°F)]		
Initiation	273 (600)	2.07 (300)	214 (417)	810 (699)	
Primary high-pressure separator	114 (250)	4.14 (600)	252 (486)	339 (292)	
Primary low-pressure separator	68 (150)	4.14 (600)	252 (486)	203 (175)	
Dryer 1	45 (100)	1.21 (175)	188 (370)	135 (116)	
Extruder	136 (300)	0.414 (60)	146 (295)	397 (342)	
Dryer 2	45 (100)	1.21 (175)	188 (370)	135 (116)	
Total				2018 (1740)	1201 (1090)

^aObtained by multiplying the pounds of steam by the difference between the enthalpy of steam at the indicated temperature and that of water at 21°C (70°F) (Ref. 6).

Table 4.18. Process energy in HDPE manufacture

	Steam per short ton of HDPE			Process heat ^a [10 ³ kJ/metric ton (10 ³ Btu/ton)]	Electricity [kWhr/metric ton (kWhr/ton)]
	Used [kg (lb)]	Pressure [MPa (psi)]	Temperature [°C (°F)]		
Hoechst slurry process					
Reactor preheat	250 (550)	0.414 (60)	146 (295)	727 (627)	
Steam distillation	318 (700)	0.414 (60)	146 (295)	925 (798)	
Hexane distillation	45 (100)	0.414 (60)	146 (295)	132 (114)	
Dryer 1	227 (500)	1.21 (175)	188 (370)	672 (579)	
Extruder	136 (300)	0.414 (60)	146 (295)	397 (342)	
Dryer 2	45 (100)	1.21 (175)	188 (370)	135 (116)	
Total				2988 (2576)	220 (200)

^aObtained by multiplying the pounds of steam by the difference between the enthalpy of steam at the indicated temperature and that of water at 21°C (70°F) (Ref. 6).

Fig. 4.19. High-density polyethylene — Hoechst slurry process (1 lb = 0.454 kg) (Ref. 6).

Fig. 4.20. Polyvinyl chloride - suspension process (1 lb = 0.545 kg) (Ref. 6).

normally expected. The average batch size may produce ~6 tons of PVC. Energy requirements for production are shown in Table 4.19.

Bulk and solvent processes account for ~75% of polystyrene production. Little detailed information has been published on styrene polymerization because it is generally proprietary.⁶ A schematic of a suspension polymerization process, based on an earlier Battelle report,¹¹ is shown in Fig. 4.21 (Ref. 6), and a summary of the process heat consumption is given in Table 4.20. Coal and natural gas account for ~40% each of the purchased fuels for manufacturing polystyrene.

4.3.3 Petroleum refining

The petroleum refining industry (SIC 2911) consumes about 12% of the total energy used by industry in the United States and consists of about 250 refineries belonging to approximately 130 companies.³ Total capacity of the refineries approached 27.5 m³/sec [15×10^6 bbl per calendar day (B/CD)] in 1975.⁶

A complex refinery could consist of about 29 major processes including gas- and oil-fired heaters and mechanical drivers. Except for fired heaters, each of the 28 processes utilizes heat energy supplied internally from fired heaters, indirect steam heaters, or both.⁶ However, in processes such as fluidized-bed catalytic crackers, heat is released during regeneration. Total process heat consumption is estimated to be about 3250×10^{12} kJ (3100×10^{12} Btu) annually, including direct heat and steam. Process temperatures and energy requirements are listed in Table 4.21. Similar information was compiled in Ref. 1. Note that virtually all the heating requirements fall in the range of the CCC useful thermal energy.

A typical refinery may generate up to 55% of its steam requirements in waste heat boilers in conjunction with the catalytic crackers.²⁸ Furthermore, ~20% of the plant's electrical or shaft power requirements are typically generated in-house, the majority in the form of shaft power and almost all from steam turbines.³ The electricity demand for a refinery is low relative to the heating requirements; thus the CCC should easily satisfy the entire electrical load. To satisfy the process heat and steam loads would require large units of low electrical

Table 4.19. Process heat in PVC manufacture

	Steam per short ton of PVC			Process heat ^a [10 ³ kJ/metric ton (10 ³ Btu/ton)]	Electricity [kWhr/metric ton (kWhr/ton)]
	Used [kg (lb)]	Pressure [MPa (psi)]	Temperature [°C (°F)]		
Suspension polymerization					
Initiation	205 (450)	0.207 (30)	121 (250)	588 (507)	
Vinyl chloride stripping					
Vinyl chloride distillation	3.2 (7)	0.207 (30)	121 (250)	9.3 (8)	
Rotary dryer	227 (500)	1.208 (175)	188 (370)	672 (579)	
Blending	45 (100)	0.207 (30)	121 (250)	131 (113)	
Melt compounding	114 (250)	0.414 (60)	145 (293)	342 (295)	
Drying pellets	45 (100)	1.208 (175)	188 (370)	135 (116)	
Total				1877 (1618)	485 (440)

^aObtained by multiplying the pounds of steam by the difference between the enthalpy of steam at the indicated temperature and that of water at 21°C (70°F) [Ref. 6]. Electricity from Ref. 26. Coal and natural gas account for ~80% of the fuels used.²⁶

Fig. 4.21. Polystyrene - suspension polymerization (1 lb = 0.454 kg)
(Ref. 6).

Table 4.20. Process heat in polystyrene manufacture

	Steam per short ton of polystyrene			Process heat ^a [10 ³ kJ/metric ton (10 ³ Btu/ton)]	Electricity [kWhr/metric ton (kWhr/ton)]
	Used [kg (lb)]	Pressure [MPa (psi)]	Temperature [°C (°F)]		
Suspension process					
Reactor (initiation)	45 (100)	0.207 (30)	121 (250)	131 (113)	
Dryer 1 (air at 138°F)	58 (150)	1.208 (175)	188 (370)	202 (174)	
Blending	45 (100)	0.207 (30)	121 (250)	131 (113)	
Melt compounding	136 (300)	1.725 (250)	204 (400)	405 (349)	
Dryer 2	45 (100)	1.208 (175)	188 (370)	135 (116)	
Total				1003 (865)	339 (308)

^aObtained by multiplying the pounds of steam by the difference between the enthalpy of steam at the indicated temperature and that of water at 21°C (70°F) (Ref. 6). Electricity from Ref. 26.

Table 4.21. Summary of energy consumed in refinery by process

Process	Processing temperature [°C (°F)]	Energy required ^a			Quantity processed ^b [10 ³ m ³ /year (10 ⁹ bbl/year)]	Process heat total [10 ¹² kJ/year (10 ¹² Btu/year)]	
		Electrical-mechanical [kWhr/m ³ (kWhr/bbl)]	Steam [kg/m ³ (lb/bbl)]	Fired heat [1000 kJ/m ³ (1000 Btu/bbl)]		Steam	Direct heat
Crude storage	Ambient	0 (0)	0 (0)	0 (0)			
Desalting		0.06 (0.01)	63 (22)	0 (0)	0.865 (5.44)	127 (120)	
Crude distillation	343 (650)	3.1 (0.5)	43 (15)	464 (70)	0.865 (5.44)	87 (82)	401 (380)
Vacuum distillation	416 (780)	1.3 (0.2)	51 (18)	199 (30)	0.313 (1.97)	3.7 (3.5)	62 (59)
Chemical sweetening		0.06 (0.01)	0 (0)	0 (0)			
Hydrogen generation	538 (1000)	3.1 (0.50)	0 (0)	663 (100)	NA		
Naphtha hydrogen treating	427 (800)	8.8 (1.4)	229 (80)	332 (50)			
Kerosene hydrogen treating	427 (800)	10.0 (1.6)	23 (8)	464 (70)			
Gas oil hydrogen treating	427 (800)	12.6 (2)	29 (10)	464 (70)	0.286 (1.80)	57 (54) ^c	133 (126) ^c
Lubricating oil hydrogen treating	427 (800)	37.7 (6)	71 (25)	663 (100)			
Residual oil hydrogen treating	454 (850)	18.8 (3)	71 (25)	531 (80)			
Catalytic hydrocracking	427 (800)	31.4 (5)	51 (18) ^d	1327 (200)	0.496 (3.12)	59 (56)	658 (624)
Gas processing		12.6 (2)	172 (60)	0 (0)	NA		
Amine stripping		3.1 (0.5)	3 (1)	0 (0)	NA		
Sulfur manufacture	176 (350)	0.63 (0.1)	11 (4)	3 (0.4)	NA		
Isomerization	260 (500)	7.5 (1.2)	57 (20)	199 (30)	0.03 (0.17)	3.6 (3.4)	3.7 (3.5)
Catalytic reforming	538 (1000)	31.4 (5)	0 (0)	1992 (300)	0.20 (1.25)		395 (374)

Table 4.21 (continued)

Process	Processing temperature [°C (°F)]	Energy required ^a			Quantity, processed ^b [10 ⁹ m ³ /year (10 ⁹ bbl/year)]	Process heat total [10 ¹² kJ/year (10 ¹² Btu/year)]	
		Electrical-mechanical [kWhr/m ³ (kWhr/bbl)]	Steam [kg/m ³ (lb/bbl)]	Fired heat [1000 kJ/m ³ (1000 Btu/bbl)]		Steam	Direct heat
Fluid-bed catalytic cracking	510 (950) 649 (1200) ^e	18.8 (3)	114 (40) ^d	465 (70)	0.67 (4.2)	177 (168)	309 (293)
Moving-bed catalytic cracking	493 (920)	6.3 (1.0)	286 (100) ^d	1992 (300)	0.09 (0.54)	57 (54)	171 (162)
Visbreaking	523 (975)	11.3 (1.8)	0 (0) ^d	1726 (260)	0.08 (0.51)		139 (132)
Coking	565 (1050)	94.2 (15)	0 (0) ^d	2324 (350)	0.17 (1.09)		402 (381)
Catalytic polymerization	188 (370)	7.5 (1.2)	57 (20)	0 (0)	NA		
Catalytic alkylation	149 (300)	50.2 (8)	572 (200)	0 (0)	0.05 (0.3)	53 (50)	
Lube oil processing	Low	37.7 (6)	858 (300)	0 (0)	0.13 (0.8)	24 (23)	
Asphalt processing	260 (500)	12.6 (2)	286 (100)	1328 (200)	0.04 (0.26)	27 (26)	56 (53)
Storage and blending		0.06 (0.01)	3 (1.0)	0 (0)			
Prime movers electric steam IC							
Steam generation							
Process heaters							
Total						675 (640)	2729 (2587)

^aThese are average values only. Actual values differ and depend on many factors, including the type of process employed.

^bBarrels per stream day times 365 days per year times 0.94 on-stream factor.

^cBased on total catalytic hydrotreated volume and mean of 13.6 kg (30 lb) steam and 73.5×10^3 kJ (70×10^3 Btu) fired heat per barrel.

^dIndicates processes that generate substantial amounts of high-pressure steam so that net steam consumption is negative.

^eRegenerator off-gas temperature of this process.

output, which might prove uneconomical compared to other heating means. However, not all the process heating and steam generation is accomplished by fuels purchased specifically for such. By-product and internally generated fuels are used to a great extent.

Three major fuel sources are evident in the petroleum refining industry. Petroleum products account for over one-half the energy requirements for the industry;³ this is generally called captive energy. Refinery gases are considered as residual products because they must be produced in the processes. However, they involve a mass loss from the crude oil which, along with the money spent on processing, makes these quite expensive.³ Because they have a market value, oil fuels and liquefied petroleum gas (LPG) are considered as purchased fuels. The valuable LPG is burned since there is no way to store it under pressure to meet the seasonal demand.³ Natural gas is the other major source of energy, accounting for 34% of total fuels on a national average.³ Coal use is very small at this time.

The fuels used to raise steam and those burned for direct heat are listed in Tables 4.22 and 4.23, respectively. A breakdown of the electrical and mechanical power consumption is presented in Table 4.24.

The potential for fuel displacement by coal may be ascertained from the data in Tables 4.22 and 4.23. The CCC useful thermal energy is capable

Table 4.22. Fuels utilized for steam generation
in petroleum refining - 1974

Fuel	10^{12} kJ (10^{12} Btu)	Percent of total
Coal		0
Oils	82.0 (77.7)	13.4
Natural gas and LPG	266.8 (252.9)	43.7
Refinery gas	262.0 (248.3)	42.9
Coke		0
Total	610.8 (578.9)	100

Source: Ref. 3.

Table 4.23. Fuels used for nonsteam heat in petroleum refining — 1974 [10^{12} kJ (10^{12} Btu)]

Fuel	Temperature band [°C (°F)]		
	149 (<300)	149–538 (300–1000)	538–816 (1000–1500)
Oils	23.2 (22.0)	187.3 (177.5)	
Natural gas and LPG	84.3 (79.9)	644.3 (610.7)	38.3 (36.3)
Refinery gas	80.1 (75.9)	610.4 (578.6)	36.5 (34.6)
Coke			257.3 (243.9)
Total	187.6 (177.8)	1442.0 (1366.8)	332.1 (314.8)

Source: Ref. 3.

Table 4.24. Electrical/mechanical power used in petroleum refining — 1974

Source	10^9 kWhr
Purchased electricity	19.63
In-plant	
Nonsteam	
Electric	0.097
Shaft	0.66
In-plant	
Steam	
Electric	1.34
Shaft	3.33
Total	25.06

Source: Ref. 3.

of generating all steam at the required temperature and can conservatively generate direct heat up to 538°C (1000°F) while producing some electric power. Although direct coal-fired heaters or steam generators (without a power system) may be more feasible in some cases, the potential for conversion to coal still exists. This potential amounts to $\sim 6.8 \times 10^9$ m³ (240×10^9 ft³) of natural gas and 2.1×10^6 m³ (13×10^6 bbl) of oil

for steam generation with an additional $18.7 \times 10^9 \text{ m}^3$ ($660 \times 10^9 \text{ ft}^3$) of gas and $5.4 \times 10^6 \text{ m}^3$ ($34 \times 10^6 \text{ bbl}$) oil used for nonsteam heating.

Individual process descriptions can be found in the literature^{7,28} and are not included in this section.

4.3.4 Paper and pulp industry

The paper and allied products industry (SIC 21) includes pulp, paper, and paperboard making, conversion of paper and board into finished products, and making building paper and board. Pulp, paper, and paperboard manufacturing (SIC 261, 262, 263) account for 86% of the fuel utilized by SIC 26.⁶ The pulp and paper industry (primary products) comprises some 350 companies operating over 700 mills.³ Over two-thirds of the U.S. production capacity consists of integrated mills that have both pulping and paper-making facilities on-site.³ Although smaller in size, the number of nonintegrated paper mills is about the same as the integrated plants.⁶

Four principal processes are used to produce most of the wood pulp: groundwood (mechanical), Kraft, sulfite, and semichemical. Use of the sulfite process has declined to ~5% of the production.⁶ Production of pulp and paper is summarized in Table 4.25, and Fig. 4.22 depicts the

Table 4.25. Pulp, paper, and paper board production

	10 ⁶ metric tons (10 ⁶ tons)			
	1972	1973	1974	1975
Pulp production	42.5 (46.8)	43.5 (47.9)	43.8 (48.2)	37.7 (41.5)
Pulp shipments	7.4 (8.1)	7.3 (8.0)	7.7 (8.5)	6.6 (7.3)
Paper and board production	54.0 (59.5)	56.0 (61.7)	55.0 (60.6)	45.4 (50.0)
Newsprint	3.2 (3.5)	3.2 (3.5)	2.9 (3.2)	
Other printing papers	11.2 (12.3)	12.1 (13.3)	12.3 (13.5)	
Packaging papers	5.2 (5.7)	5.2 (5.7)	5.4 (5.9)	
Tissue	3.6 (4.0)	3.6 (4.0)	3.5 (3.9)	
Paperboard — solid furnish	19.2 (21.1)	19.5 (21.5)	19.4 (21.4)	
Paperboard — combination furnish	6.7 (7.4)	7.2 (7.9)	6.6 (7.3)	
Wet machine board	0.09 (0.1)	0.09 (0.1)	0.09 (0.1)	
Construction paper and board	4.8 (5.3)	5.0 (5.5)	4.6 (5.1)	

Source: Ref. 6.

Fig. 4.22. Overall steam and materials flow for pulp and paper industry (1 lb = 0.454 kg, 1 Btu = 1.055 kJ) (Ref. 6).

processes in the industry. Descriptions of the various processes are available in Refs. 6 and 29.

The pulping and paper production require considerable amounts of steam, heat, and electricity. In estimating the potential for fuel conversion to coal, the contribution of by-product fuels, which is substantial, must be considered. Fuels used to generate steam are listed in Table 4.26, and steam requirements for the various processes are summarized in Table 4.27.

Table 4.26. Fuels consumed for steam generation
in pulp and paper industry — 1975

Fuel	10^{12} kJ (10^{12} Btu)	Percent of total
Coal	200 (190)	10.9
Fuel oils	459 (435)	25.0
Natural gas	295 (280)	16.0
Bark and wood	148 (140)	8.0
Pulping liquors	739 (700)	40.1

Source: Ref. 3.

The majority of the steam is generated at 4.1 to 8.2 MPa (600 to 1200 psig), which corresponds to about 254 to 299°C (490 to 570°F).³ The steam is generally used at a much lower temperature, usually not over 204°C (400°F). The high-pressure steam is often expanded through turbines to generate electricity or shaft power.

Fuels for direct heating are predominantly natural gas [85×10^{12} kJ (81×10^{12} Btu)] and fuel oil [74×10^{12} kJ (70×10^{12} Btu)].³ The only equipment needing high-temperature heat [$>816^\circ\text{C}$ (1500°F)] is the lime kiln.⁶ Heat to the lime kiln totals $\sim 99 \times 10^{12}$ kJ (94×10^{12} Btu) annually.⁶

Electrical consumption in 1975 was $\sim 59.0 \times 10^9$ kWhr, 54% of which was generated on-site. Potential for the CCC exists in generating the remaining electricity and the steam now being raised in gas-fired boilers. This latter natural gas usage (Table 4.26) amounts to 7.6×10^9 m³ (270×10^9 ft³) annually.

4.3.5 Stone/clay/glass industries

The stone/clay/glass and concrete industrial group (SIC 32) consumed $\sim 1424 \times 10^{12}$ kJ (1350×10^{12} Btu) of energy in 1971. Processes for making glass and cement accounted for $\sim 55\%$ of the total.³⁰ These two industries, along with the concrete block and gypsum industries, are discussed in this section.

Table 4.27. Summary of process heat requirements for major portion of pulp and paper industry^{a,b}

Process	Steam requirement			Temperature [°C (°F)]	
	Per ton of industry product [10 ⁶ kJ/metric ton (10 ⁶ Btu)]	Industry total 1975 ^c [10 ¹² kJ (10 ¹² Btu)]	Pressure [MPa (psig)]	100-177 (212-350)	>177 (>350)
Kraft pulping	3.17 (2.73)	109.1 (103.4)	0.83-1.04 (120-150)		181 (358)
Kraft black liquor recovery					
Evaporation	3.33 (2.87)	114.7 (108.7)	0.28 (40)	141 (287)	
Air preheating ^d	0.37 (0.32)	12.8 (12.1)	0.28 (40)	141 (287)	
Steam production ^d	11.76 (10.14)	-405.2 (-384.1)	3.14 (455)		371 (700)
Kraft pulp bleaching					
Caustic soda extraction	1.80 (1.55)	61.9 (58.7)	0.28 (40)	141 (287)	
Hypochlorite bleaching	0.66 (0.57)	22.8 (21.6)	0.28 (40)	141 (287)	
Chlorine dioxide bleaching ^e	2.46 (2.12)	84.7 (80.3)	0.28 (40)	141 (287)	
Hypochlorite bleaching	0.63 (0.52)	21.6 (20.5)	0.28 (40)	141 (287)	
NSSC ^f pulping	0.17 (0.15)	6.0 (5.7)	1.04 (150)		184 (364)
NSSC ^f black liquor recovery					
Evaporation	0.13 (0.11)	4.4 (4.2)	0.28 (40)	141 (287)	
Air preheating ^d	0.01 (0.01)	0.4 (0.4)	0.28 (40)	141 (287)	
Steam production ^d	0.44 (0.38)	-15.2 (-14.4)	3.14 (455)		371 (700)
Groundwood bleaching	0.05 (0.02)	1.6 (1.5)	0.28 (40)	141 (287)	
Pulp drying	0.34 (0.29)	11.6 (11.0)	0.28-1.04 (40-150)	177 (350)	
Papermaking	8.29 (7.15)	377.7 (358.0) ^g	0.28-1.04 (40-150)	177 (350)	
Total process heat		829.3 (786.1)			
Net after by-product credit		408.9 (387.6)			

^aAccounts for 91% of virgin pulp production, 70% of total paper production.^bOmits lime kilns.^cCalculated from 1973 production data (Table 4.25) for pulp processes studied, multiplied by 0.86, the ratio of pulp production 1973/1975.^dBy-product credit.^eIn five-step bleaching.^fNSSC = Neutral sulfite semichemical.^gCalculated from the 50 × 10⁶ tons paper and paper board production estimate for 1975.

Source: Ref. 6.

4.3.5.1 Portland cement. The Portland cement industry consists of 166 plants in 41 states and Puerto Rico.⁶ Two basic processes exist for cement production: wet and dry. The only difference is that the wet process utilizes a slurry to feed the raw materials into the kiln or preheater, whereas the dry process feeds dry materials. This process is generally more efficient and has recently been receiving greater attention.⁶ Energy consumption and costs are critical in cement manufacturing (about 40% of production cost); few wet processes have been installed in the recent past, and many wet processes have been converted to dry. A flowsheet for cement production is shown in Fig. 4.23 (Ref. 6).

ORNL-DWG 79-4913 ETD

Fig. 4.23. Flow sheet for cement manufacture.

The kiln is by far the largest energy consumer, accounting for almost 80% of the total. Essentially all fossil fuels used by the industry are consumed in the kiln. Process energy demands are supplied in Table 4.28.

Although the process temperatures are too high for direct use of the CCC thermal energy, electricity costs may make the internal generation attractive. Dry process plants generate ~20% of their own power.³¹ Furthermore, as reported in Ref. 6, the Portland Cement Association estimates that by 1980 more than 90% of the industry capacity will be able to utilize coal.³² Concentration of the industry in New York, Ohio, and Pennsylvania, where gas curtailments have been experienced, is certainly influential in this trend toward coal.

4.3.5.2 Concrete block and brick industry. Approximately 48×10^6 metric tons (53×10^6 tons) of block and brick are manufactured annually. The industry consumed about 16.2×10^{12} kJ (15.5×10^{12} Btu) in 1971, 92% of which was used for process heat.⁶ Two basic processes, high-pressure (autoclave) and low-pressure, are utilized in the production. Autoclave systems require twice the energy but have faster processing times; however, the recent trend is toward the low-pressure plants.

The flow sheet for concrete block manufacture is presented in Fig. 4.24, and a summary of the process heat requirements is given in Table 4.29. Electricity consumption is on the order of 10^9 kWhr annually. Interest has been expressed in the CCC by a local firm because of its potential for electric production only. However, the temperature requirements indicate that at least some of the process heat can be supplied. Fuels used for the process heat are split between gas and oil at 71 and 29%, respectively. The potential gas displacement by coal in the industry would be $\sim 0.28 \times 10^9$ m³ (10×10^9 ft³) annually, and oil displacement could be as high as 0.11×10^6 m³ (0.7×10^6 bbl). Present use of coal is very small.

4.3.5.3 Gypsum. The gypsum industry is characterized by a highly competitive market and simple processing, with primary products of gypsum board and plaster materials.

Process heat requirements totalled $\sim 48.4 \times 10^{12}$ kJ (45.9×10^{12} Btu) in 1973. About 70% of the heat is in the form of steam at 177 to 343°C

Table 4.28. Energy in cement production via long rotary kiln - 1973^a

Process	Energy [10 ¹⁵ kJ (10 ¹⁵ Btu)]			Electricity (10 ⁶ kWhr)	Temperature [°C (°F)]
	Natural gas and LPG	Fuel oil	Coal		
Drying limestone	0.028 (0.027)				399 (750)
Crushing and milling				3.6	37.8 (exit 100)
Pyroprocessing	0.232 (0.22)	0.084 (0.080)	0.20 (0.19)	1.1	37.8-1343-1149 (100-2450-2100)
Air pollution				0.45	
Cooler fan				0.62	
Clinker milling				4.4	
Total	0.260 (0.247)	0.084 (0.080)	0.20 (0.19)	10.17	

^a1973 U.S. production - 76×10^6 metric tons (84.1×10^6 tons). Use of this type kiln was not exclusive in practice. Actual 1973 process heat was about 515×10^{12} kJ (490×10^{12} Btu).

Source: Ref. 6.

Table 4.29. Summary of 1971 process heat requirements in the concrete block and brick industry by process

	Estimated production by process [10 ⁶ metric tons (10 ⁶ tons)]	Calculated process heat required per unit [10 ⁶ kJ/metric ton (10 ⁶ Btu/ton)]	Calculated process heat requirement [10 ¹² kJ (10 ¹² Btu)]	Maximum temperature required [°C (°F)]
Low-pressure systems	40.9 (45.0)	0.251 (0.216)	10.2 (9.7)	74 (165)
Autoclave systems	7.3 (8.0)	0.660 (0.569)	4.9 (4.6)	177 (350)
Total	48.2 (53.0)		15.1 (14.3)	

Source: Ref. 6.

Fig. 4.24. Flow sheet for concrete block and brick manufacture (Ref. 6).

(350 to 650°F), with the remaining being direct heat at 177°C (350°F) or less. The basic production sequence is illustrated in Fig. 4.25 (Ref. 6). Process heat and electrical requirements are provided in Tables 4.30 and 4.31. The heavy dependence on natural gas and process temperature involved indicates that the industry is a potential target for the CCC. Possible product contamination is apparently preventing to some extent the conversion to coal. There is, however, some incentive in the $\sim 0.85 \times 10^9 \text{ m}^3$ ($30 \times 10^9 \text{ ft}^3$) of natural gas to be displaced annually.

4.3.5.4 Glass industry. The glass industry is characterized by demands for very high-temperature heat. From 60 to 85% of the energy is needed at over 1093°C (2000°F).

A typical flow sheet for production of glass containers is shown in Fig. 4.26, where the temperatures are noted. The production sequence for flat glass is similar. Glass container production involves the largest tonnage of glass in the industry. Figures for annual production vary from 8.0 to $8.4 \times 10^9 \text{ kg}$ (17.7 to $18.5 \times 10^9 \text{ lb}$) in 1967.³³

Table 4.30. Energy use in gypsum manufacture, 10^6 kJ per metric ton (10^6 Btu per ton) processed (1973)

	Natural gas	LPG	Other petroleum products	Coal	Electricity ^a	Total	Percent	Maximum temperature [°C (°F)]
Mining or quarrying			0.29 (0.25)		0.02 (0.02)	0.31 (0.27)	7.3	Ambient
Crushing					0.01 (0.01)	0.01 (0.01)	0.3	Ambient
Grinding and drying	0.12 (0.13)	0 (>0.0)	0.01 (0.01)	0.01 (0.01)	0.04 (0.03)	0.17 (0.15)	4.1	Nominal
Calcining	0.78 (0.67)	0 (>0.0)	0.08 (0.07)	0.04 (0.03)	0.04 (0.03)	0.93 (0.80)	21.7	160 (320)
Finish processing	2.34 (2.02)	0.01 (0.01)	0.23 (0.20)	0.09 (0.08)	0.17 (0.15)	2.85 (2.46)	66.6	299 (570)
Total	3.24 (2.73)	0.02 (0.02)	0.61 (0.53)	0.14 (0.12)	0.28 (0.24)	4.28 (3.69)	100.0	

^a3413 Btu/kWhr.

Source: Ref. 6.

Fig. 4.25. Flow sheet for gypsum production (Ref. 6).

Table 4.31. Process heat required for U.S. 1973 gypsum production

Process/operation	Gypsum ^a [10 ⁶ kJ/metric ton (10 ⁶ Btu/ton)]	Gypsum produced [10 ⁶ metric tons (10 ⁶ tons)]	Total process heat [10 ¹² kJ (10 ¹² Btu)]
Drying	0.14 (0.12)	18.73 (20.635) ^b	2.6 (2.5)
Calcining	0.89 (0.77)	13.54 (14.916) ^c	12.1 (11.5)
Finish processing	2.68 (2.31)	12.52 (13.793) ^d	33.7 (31.9)
Total			48.4 (45.9)

^aProcess heat components from Table 4.30.^bAssumes drying is required for all material shipped.^cIncludes plasters and prefabricated products.^dExcludes plasters.

Source: Ref. 6.

Fig. 4.26. Process flow diagram: SIC 3221, glass containers (Ref. 6).

Process heat and temperature data are provided in Table 4.32, and the fuels and electricity used in glass container production are listed in Table 4.33.

Table 4.32. Process heat in glass industry (1975)

Temperature band [°C (°F)]	Quantity [10 ¹² kJ (10 ¹² Btu)]
<177 (<350)	22 (21)
177-593 (350-1100)	19 (18)
593-816 (1100-1500)	11.4 (10.8)
>816 (>1500)	304 (288)

Source: Ref. 6.

The widespread implementation of the CCC would probably occur only if the trend continues toward electric glass melting, which is an established procedure. Possible product contamination concerning the use of coal is also a factor in the glass industry. Economical in-house electric generation is always a possible incentive, along with preheating, which would reduce the demand on natural gas. The present annual displacement potential, based on the process heat required at less than 816°C (1500°F), is about $1.6 \times 10^9 \text{ m}^3$ ($57 \times 10^9 \text{ ft}^3$) of natural gas, which is not negligible by any standard.

4.3.6 Food industry

Energy consumption in the food industry is rather difficult to quantify because of (1) the diversity of the industry and (2) incomplete information (probably resulting from the minor importance of energy costs in many food processes). In 1971, the approximate total energy consumption for the food category (SIC 20) was about $945 \times 10^{12} \text{ kJ}$ ($900 \times 10^{12} \text{ Btu}$)³⁰ (3413 Btu/kWhr electricity).

The generation of process steam is by far the most important use of fossil fuels. Electricity is required for mechanical drives and

Table 4.33. Energy sources for glass container production

Energy source	1967 consumption	Consumption per ton of container	10^6 kJ per metric ton (10^6 Btu per ton)
Coal			
Refined oils	241 m ³ (1515 bbl)	0.03 m ³ (7.18 gal)	1.230 (1.060)
Natural gas	2.7×10^9 m ³ (94.6×10^9 ft ³)	0.3×10^3 m ³ (10.67×10^3 ft ³)	12.81 (11.046)
Electric energy (purchased)	2.33×10^3 kWhr	263 kWhr	1.041 (0.897) ^a

^a3413 Btu/kWhr.

Source: Ref. 33.

refrigeration. The heat energy and electricity consumptions for 13 food industries are listed in Table 4.34. Natural gas accounted for ~68% of the fuels consumed for heat or internal power generation, with fuel oils and coal constituting ~18 and 14%, respectively.

Table 4.34. Heat and electricity consumption by 13 food processing industries during 1971^a

Process	Heat ^b [10 ¹⁵ kJ (10 ¹⁵ Btu)]		Electricity ^d [10 ¹⁵ kJ (10 ¹⁵ Btu)]	
	Census ^c	Ref. 34	Census	Ref. 34
Meat packing	0.083 (0.079)	0.081 (0.077)	0.032 (0.030)	0.036 (0.034)
Beet sugar	0.088 (0.083)	0.078 (0.074)	0.0004 (0.0004)	0.001 (0.001)
Cane sugar	0.036 (0.034)	0.046 (0.044)	0.0002 (0.0002)	0.0003 (0.0003)
Wet corn milling	0.064 (0.061)	0.065 (0.062)	0.009 (0.009)	0.011 (0.010)
Fluid milk	0.046 (0.044)	0.046 (0.044)	0.039 (0.037)	0.039 (0.037)
Prepared animal feeds	0.049 (0.046)	0.056 (0.053)	0.028 (0.027)	0.033 (0.031)
Frozen fruits and vegetables	0.027 (0.026)	0.028 (0.027)	0.027 (0.026)	0.028 (0.027)
Canned fruits and vegetables	0.052 (0.049)	0.044 (0.042)	0.011 (0.010)	0.008 (0.008)
Sausage and meat processing	0.018 (0.017)	0.018 (0.017)	0.009 (0.009)	0.012 (0.011)
Malt beverages	0.045 (0.043)	0.045 (0.043)	0.020 (0.021)	0.027 (0.026)
Animal and marine fats and oils	0.036 (0.034)	0.023 (0.022)	0.005 (0.005)	0.004 (0.004)
Bread, cake, and related products	0.046 (0.044)	0.052 (0.049)	0.026 (0.025)	0.021 (0.020)
Soybean oil	0.040 (0.038)	0.041 (0.039)	0.017 (0.016)	0.017 (0.016)

^aThese data compiled in Ref. 34.

^bA small amount (<10%) of the heat is used for space heating.

^cReference 22.

^d10,600 Btu/kWhr.

In general, the process steam is required at low temperatures, <204°C (400°F). A few operations presently utilize a direct gas flame, but this is not absolutely necessary.

Data on temperature and heat requirements for several of the industries presented in Ref. 6 are included in this report.

4.3.6.1 Pork processing. The flow sheet for pork processing is shown in Fig. 4.27. Process energy required is shown in Table 4.35.

The gas flame can be replaced by hot air for polishing and singeing. According to Ref. 5, $\sim 260^{\circ}\text{C}$ (500°F) is sufficient. Thus the CCC is capable of supplying all heat and electricity. The heat values shown are generated entirely by gas; therefore, the displacement potential for pork processing could be as high as $0.82 \times 10^9 \text{ m}^3$ ($29 \times 10^9 \text{ ft}^3$) of natural gas annually.

4.3.6.2 Meat processing. Conversion of raw pork into final meat products is often done in an integrated plant with the slaughtering and basic processing. The general production sequence is shown in Fig. 4.28. Process energy data are given in Table 4.36.

Fig. 4.27. Process flow sheet for hog slaughtering and processing (SIC 2011) (Ref. 6).

Table 4.35. Process energy (fuel used) in pork processing

Operation	Steam [kJ/kg (Btu/lb) ^a]	Temperature [°C (°F)]	Electricity [kJ/kg (Btu/lb) ^b]
Livestock			12.6 (5.4)
Sticking			
Blood processing	56.1 (24.1)	188 (370)	6.0 (2.6)
Scalding/dehair	149.6 (64.3)	146 (295)	26.1 (11.2)
Hair processing	24.4 (10.5)	146 (295)	0.2 (0.1)
Polishing/singeing	140.5 (60.4) ^c	Flame	10.7 (4.6)
Killing			17.9 (7.7)
Cooling (refrigeration)	993.4 (427.1) ^d		4.7 (2.0)
Edible rendering	60.2 (25.9)	143 (290)	25.1 (10.8)
Inedible rendering	516.4 (222.0)	188 (370)	94.0 (40.4)
Motive power			31.2 (13.4)
Lighting			68.4 (29.4)
Sterilization	1195.6 (514.0)	60 (140)	
Total	3136.2 (1348.0)		296.9 (128.0)

^aPer kg or lb of live hog slaughtered, 1975 total was 10×10^9 kg (22.3×10^9 lb).

^b3413 Btu/kWhr.

^cNonsteam.

^dNonsteam; natural gas and propane used.

Source: Ref. 6.

Table 4.36. Process energy (fuels used) in meat processing

Operation	Steam [kJ/kg (Btu/lb) ^a]	Temperature [°C (°F)]	Electricity [kJ/kg (Btu/lb) ^b]
Loading dock			1.6 (0.7)
Curing			35.8 (15.4)
Formulating			27.9 (12.0)
Blending	349.6 (150.3)	121 (250)	45.1 (19.4)
Cooking, smoking	2673.3 (1149.3) ^c	121 (250)	264.2 (113.6)
Refrigeration			1425.6 (612.9)
Packaging			26.5 (11.4)
Storage			133.7 (57.5)
Food services			41.9 (18.0)
Compressors			194.2 (83.5)
Waste disposal			10.9 (4.7)
Motive			62.1 (26.7)
Lighting			682.4 (293.4)
Space heating	141.7 (60.9) ^d		
Sterilization	1748.0 (751.5)	60 (140)	
Total	4912.6 (2112)		2951.9 (1269)

^aPer kg or lb of meat processed in 1975; total 2.3×10^9 kg (5×10^9 lb) raw meat input.

^b3413 Btu/kWhr.

^c548 Btu/lb is nonsteam direct heat at 38–76°C (100–200°F).

^dNonsteam.

Source: Ref. 6.

Fig. 4.28. Process flow sheet for meat processing (SIC 2013) (Ref. 6).

The fuels used were 19% fuel oil and 81% natural gas. The electrical power consumption is substantial, giving a heat/power ratio of about 1.7. This nonintegrated plant is, therefore, a borderline case for the CCC if total electricity demand is to be satisfied. However, the integrated plant could be an ideal application. Substitution of coal for natural gas for process heat in this industry would annually displace $\sim 0.23 \times 10^9 \text{ m}^3$ ($8 \times 10^9 \text{ ft}^3$) of gas.

4.3.6.3 Soybean meal processing. Production of soybean meal, flour, and oil are grouped into SIC 2075. The flow diagram for a typical plant is illustrated in Fig. 4.29 (Ref. 6). Process energy requirements are summarized in Table 4.37.

The energy source is essentially 100% natural gas for the in-house direct heat, which is $\sim 0.17 \times 10^9 \text{ m}^3$ ($6 \times 10^9 \text{ ft}^3$) in 1975.

Table 4.37. Process energy (fuels) used in soybean processing

Operation	Steam [kJ/kg (Btu/lb) ^a]	Temperature [°C (°F)]	Electricity [kJ/kg (Btu/lb) ^b]
Storage and cleaning			39.3 (16.9)
Dryer	246.3 (105.9) ^c	121 (250)	8.6 (3.7)
Storage			2.6 (1.1)
Cleaning, weighing, cracking			30.2 (13.0)
Dehuller	148.9 (64) ^d	232 (450)	32.1 (13.8)
Conditioner	79.8 (34.3) ^d	232 (450)	3.3 (1.4)
Flaker			47.9 (20.6)
Extractor			8.8 (3.8)
Desolventizer	444.7 (191.2) ^d	232 (450)	14.2 (6.1)
Toaster	45.8 (19.7) ^d	232 (450)	77.7 (33.4)
Flash desolventizer	48.8 (21.0) ^d	232 (450)	15.6 (6.7)
Flash chamber	441.9 (190) ^d	121-127 (250-260)	10.0 (4.3)
Total	1456.2 (626.1)		290.3 (124.8)

^aPer kg or lb soybeans input to process in 1975; 27×10^9 kg (60×10^9 lb).

^b3413 Btu/kWhr.

^cNonsteam.

^dPurchased steam from utility.

Source: Ref. 6.

Fig. 4.29. Process flow sheet for the production of soybean oil and meal (SIC 2075) (Ref. 6).

References

1. The Institute of Fuel, *Total Energy Conference Brighton 1971, Proceedings, Vol. 1*, London, 1971.
2. A. J. Miller et al., *Use of Steam Electric Power Plants to Provide Thermal Energy to Urban Areas*, ORNL/HUD-14, Oak Ridge National Laboratory, 1971.
3. Thermo Electron Corporation, *A Study of Inplant Electric Power Generation in the Chemical, Petroleum Refining and Paper and Pulp Industries*, TE5429-97-76, 1976.

4. National Consumer Research Institute, *Proceedings of the ERDA Conference on Cogeneration and Integrated Energy/Utility Systems*, CONF-770632, 1977.
5. Intertechnology Corporation, *Analysis of the Economic Potential of Solar Thermal Energy to Provide Industrial Process Heat, Vol. 1, Final Report*, Report 00028-1 (NTIS C002829/1) (February 1977).
6. *Survey of the Applications of Solar Thermal Energy Systems to Industrial Process Heating, Vol. 2, Industrial Process Heat Survey*, TID 27348/2, Battelle Laboratories (January 1977).
7. V. O. Haynes, *Energy Use in Petroleum Refineries*, ORNL/TM-5433, Oak Ridge National Laboratory, 1976.
8. J. T. Reding and B. P. Shepherd, *Energy Consumption: Fuel Utilization and Conservation in Industry*, EPA-650/2-75-032d, Dow Chemical Company, Freeport, Tex. (August 1975).
9. *Potential for Energy Conservation in the Steel Industry*, FEA/D-75/402, Battelle Columbus Laboratories, 1975.
10. H. E. McGannon, ed., *The Making, Shaping and Treating of Steel*, Ninth Ed., United States Steel Corporation, Pittsburgh, Pa., 1971.
11. *Voluntary Industrial Energy Conservation - Progress Report No. 5*, U.S. Department of Commerce, Office of Energy Programs, and Federal Energy Administration, Office of National Energy Conservation Program (July 1977).
12. Federal Energy Administration, *The Data Base - The Potential Energy Conservation in Nine Selected Industries, Vol. 5, Aluminum*, Conservation Paper No. 13, Office of Industrial Programs, 1975.
13. E. H. Hall et al., *Evaluation of the Theoretical Potential for Energy Conservation in Seven Basic Industries*, FEA/D-75/CE1, Battelle Columbus Laboratories, 1975.
14. P. F. Chapman, "The Energy Costs of Producing Copper and Aluminum from Primary Sources," *Met. Mater.* (February 1974).
15. P. F. Chapman, *The Energy Costs of Producing Copper and Aluminum from Primary Sources*, Open University, Energy Research Group, Report No. ERG 001 (December 1973).
16. P. F. Chapman, "Energy Conservation and Recycling of Copper and Aluminum," *Met. Mater.* (June 1974).
17. P. F. Chapman, *The Energy Costs of Producing Copper and Aluminum from Secondary Sources*, Open University, Energy Research Group, Report No. ERG 002 (October 1973).
18. J. C. Bravard, H. B. Flora II, and C. Portal, *Energy Expenditures Associated with the Production and Recycle of Metals*, Oak Ridge National Laboratory, ORNL/NSF/EP-24 (November 1972).
19. H. H. Kellogg, "Energy Efficiency in the Age of Scarcity," *J. Met.* (June 1974).

20. H. H. Kellogg and J. Tien, "Energy Considerations in Metal Production, Selection, and Utilization," paper presented at the AIME Meeting, Chicago, Ill. (Oct. 2, 1973).
21. Federal Energy Administration, *The Data Base — The Potential for Energy Conservation in Nine Selected Industries, Vol. 4, Copper*, Conservation Paper No. 12, Office of Industrial Programs, 1975.
22. U.S. Bureau of Census, Census of Manufacturers, 1972, *Special Report Series: Fuels and Electric Energy Consumed*, MC72(SR)-6, U.S. Government Printing Office, Washington, D.C., 1973.
23. Dow Chemical Company, *Evaluation of New Energy Sources for Process Heat*, NSF-OEP74-18055-1 (PB-245604), Midland, Mich. (September 1975).
24. International Research and Technology Corporation, *Industrial Energy Study of the Industrial Chemicals Group*, IRT-342-R (PB-236322) (August 1974).
25. Federal Energy Administration, *The Data Base — The Potential for Energy Conservation in Nine Selected Industries, Vol. 9, Styrene Butadiene Rubber*, Conservation Paper No. 17, Office of Industrial Programs, 1975.
26. Federal Energy Administration, *The Data Base — The Potential for Energy Conservation in Nine Selected Industries, Vol. 1, Selected Plastics*, Conservation Paper No. 9, Office of Industrial Programs, 1975.
27. "News from Union Carbide," *The Wall Street Journal* (Nov. 28, 1977).
28. Federal Energy Administration, *The Data Base — The Potential for Energy Conservation in Nine Selected Industries, Vol. 2, Petroleum Refining*, Conservation Paper No. 10, Office of Industrial Programs, 1975.
29. Federal Energy Administration, *The Data Base — The Potential for Energy Conservation in Nine Selected Industries, Vol. 8, Selected Paper Products*, Conservation Paper No. 16, Office of Industrial Programs, 1975.
30. Dow Chemical Company, *Energy Consumption: Paper, Stone/Clay/Glass/Concrete and Food Industries*, EPA-650/2-75-032-c, 1975.
31. Federal Energy Administration, *The Data Base — The Potential for Energy Conservation in Nine Selected Industries, Vol. 3, Cement*, Conservation Paper No. 11, Office of Industrial Programs, 1975.
32. *Min. Congr. J.* (December 1975).
33. Federal Energy Administration, *The Data Base — The Potential for Energy Conservation in Nine Selected Industries, Vol. 7, Glass*, Conservation Paper No. 15, Office of Industrial Programs, 1975.
34. *Industrial Energy Study of Selected Food Industries*, FEA-EI-1652 (PB-237316), Development Planning and Research Associates (July 1974).

5. ANALYSIS OF GAS-TURBINE COGENERATION SYSTEMS FOR SELECTED INDUSTRIES AND PROCESSES

An essential test of feasibility for the CCC is its application to specific case studies from which realistic estimates of fuel utilization can be procured. Insight into the equipment requirements can also be gained. Such case studies, if carried out in sufficient detail, would reveal the economic viability of the system; however, the studies in this report are preliminary and primarily demonstrate the thermodynamic feasibility of the CCC. Where information is sufficient, the practicability of the system is discussed. The conceptual systems that are evolved in this section were not necessarily optimized for fuel utilization, and cases where improvement is possible are noted.

5.1 Analysis of Fluidized-Bed Furnace

Mass and energy balances must be performed on the furnace in some detail in order to arrive at a furnace efficiency, that is, the degree to which the energy in the coal can be transferred to the power system. The basic ground rules for the furnace are listed in Table 5.1, and the basic furnace system layout is shown in Fig. 5.1.

Data available in the literature indicated that at 871°C (1600°F), a calcium/sulfur ratio of 4 would be satisfactory for the 90% sulfur retention warranted by the SO₂ emission regulations of the EPA.¹ The furnace analysis included losses from the coal and limestone dryers, carbon loss caused by incomplete combustion, and calcination and sulfation reactions. A loss of 0.2% was assumed for radiation. Thermal input from the induced- or forced-draft fans required with the furnace system was not considered in this analysis. The calculated energy losses are summarized in Table 5.2. The 86% efficiency, as indicated in Table 5.2, results in 24,832 kJ per kg (10,676 Btu per lb) of dry coal available to the power system. An analysis in another study using a similar system resulted in a comparable value for furnace efficiency.²

Combustion air is heated regeneratively to 449°C (840°F) with heat from the flue gases. Higher degrees of regeneration are perhaps possible, but the following reasons dictated the selected values.

Table 5.1. Basis for furnace calculations

Fluidized-bed temperature, °C (°F)	871 (1600)
Excess air, %	15
Calcium/sulfur ratio	4
Sulfur retention, %	90
Sulfur content of dry coal (Illinois No. 6), %	4.5
Moisture in coal, %	13.0
Combustion efficiency, %	99
Combustion air relative humidity at 16°C (60°F), %	60
Limestone moisture, %	5
Coal higher heating value, kJ/kg (Btu/lb) dry coal	28,842 (12,400)

Table 5.2. Summary of energy losses in fluidized-bed furnaces

Loss mechanism	Percent of coal LHV ^a [27,709 kJ/kg (11,913 Btu/lb) dry coal] ^b
Calcination/sulfation	1.32
Radiation	0.21
Unburned carbon	0.35
Drained solids	0.91
Coke and limestone dryers	1.73
Stack loss	5.86
Total, based on LHV	10.38

^a LHV = lower heating value; HHV = higher heating value.

^b In the United States, efficiency is customarily based on the fuel HHV. Thus the HHV efficiency = LHV efficiency × (LHV/HHV) = 86%.

Fig. 5.1. Atmospheric fluidized-bed gas-turbine cogeneration system.

1. The recuperator effectiveness is $\sim 83\%$; higher effectiveness would greatly increase cost.
2. Higher incoming combustion air temperatures lead to materials problems in the air tuyere plate.
3. Stack gas temperature of $\sim 149^\circ\text{C}$ (300°F) was desired.

The flue-gas temperature leaving the economizer depends on the amount of heat transferred to the power system air while in the economizer. A trade-off exists between the surface area required in the economizer and the undesirable aspects of piping extremely hot flue gases. A compromise value of 538°C (1000°F) was chosen arbitrarily. The flue gases are cooled to $\sim 132^\circ\text{C}$ (270°F) in the air preheater (Fig. 5.1). Part of these gases cool the drained solids to $\sim 204^\circ\text{C}$ (400°F) and then reenter the stack-gas stream, resulting in a final exit temperature of $\sim 149^\circ\text{C}$ (300°F).

Several power system parameters were also fixed for the analysis. These are enumerated in Table 5.3, where the given compressor and turbine efficiencies are noted as conservative.

Table 5.3. Power system fixed parameters

Turbine inlet temperature, $^\circ\text{C}$ ($^\circ\text{F}$)	816 (1500)
Turbine efficiency, %	82
Compressor efficiency, %	80
System pressure drop, $\Delta P/P$, %	10
Generator electrical efficiency, %	97
Working fluid	Dry air

Potential locations for extracting process heat from the flow streams are indicated in Fig. 5.1. Note that utilizing the flue gases for indirect process heat in lieu of regenerative heating is possible. This practice, instead of extracting all process heat from the power system, would tend to reduce the heat-exchanger surface area in the furnace. In general, however, the available heat in the flue gases which can be extracted is rather small.

The merits of closing the power cycle are evident in cases of variable electrical load because a closed-cycle system can maintain its electrical output effectiveness at reduced loads, that is, the heat/power ratio would remain constant. The open-cycle system at reduced electrical load would tend to increase in heat/power ratio. Industrial loads considered in this study are assumed to be rather constant, allowing the use of the more simple open cycle. An excellent discussion of the relative merits of the open and closed systems is available in Ref. 2.

5.2 Industries Selected for Application

Several factors influenced the choice of industries or processes to be analyzed: (1) completeness of available data on process energy, (2) apparent practicality of application, (3) thermodynamic interface with the CCC, and (4) energy intensiveness of industry. For these studies, the CCC needed to be capable of supplying 100% of the industrial process energy requirements. Electrical power is generally overproduced to allow for the furnace auxiliary power consumption.

5.2.1 Chemical industries

Investigated from the chemicals group were high-density polyethylene (HDPE), styrene butadiene rubber (SBR), and chlorine/caustic soda.

5.2.1.1 HDPE production system. Energy requirements for HDPE production were summarized in Table 4.18. The heat/power ratio is seen to be about 3.3, and, by referring to Fig. 4.6, a proper system may be ascertained. The use of a recuperator is mandatory for adequate electrical output if the overall fuel utilization is to be high. The plant was assumed to produce a primary product, excluding extrusion and pelletization. A summary of the performance of the contrived system (Fig. 5.2) is provided in Table 5.4. The heat and power requirements appear to place this application out of capabilities of a conventional back-pressure steam system. Note also that a portion of the process heat ultimately appears as hot air (see Figs. 4.18 through 4.21). Although the system derived

Fig. 5.2. CCC cogeneration system for the HDPE industry.

Table 5.4. System parameters per metric ton (ton) of HDPE

Steam, kg (lb)		
Required, 188°C (370°F)	300	(600)
146°C (295°F)	825	(1,650)
Produced	All	
Electricity, kWhr		
Required	220	(200)
Produced	303	(275)
Compressor pressure ratio	4.0	
Power air flow, kg (lb)	10,800	(21,600)
Coal feed rate (dry), kg (lb)	207.8	(415.5)
Recuperator effectiveness, %	49	
Overall thermal utilization, %	69.1	
Used heat/power ratio	2.67	

here generates steam as is presently used, the system's hot air supply could be used directly.

The overall power air exit temperature is $\sim 110^{\circ}\text{C}$ (230°F), higher than desired. The generation of steam using hot gas requires consideration of the "pinch point" in the waste-heat boiler. This characteristic of waste-heat boilers tends to increase the required air flow in order to maintain a pinch-point temperature difference of ~ 14 to 17°C (20 to 30°F). In this case, however, a little less recuperation would appear to increase the overall utilization.

With this system, the specific energy of HDPE production is ~ 6001 kJ/kg (2580 Btu/lb) of HDPE based on the coal feed rate. This would be lowered if part of the steam condensate were returned to the boiler feed line. The amount of condensate that is reused was unavailable in this industry, as well as in most others. For this reason, the boiler feeds are always assumed to be fresh cold water.

About 93% of the HDPE production capacity is located in Texas and Louisiana, with the average plant producing ~ 11.8 metric tons (13 tons)/hr (300 days/year, 24 hr/day).³ There are about 15 facilities in the

United States for production of HDPE. The average furnace size for a cogeneration system would be ~20 MW(t).

5.2.1.2 Styrene butadiene rubber. The steam energy requirements were converted to flow values for use in this analysis. Information for the system shown in Fig. 5.3 is presented in Table 5.5. The specific energy of the SBR production is ~10,583 kJ/kg (4,550 Btu/lb) of SBR. If the electricity had been produced at a central station with an efficiency of 35% and the steam generated in boilers at 86%, the specific energy would be ~10,932 kJ/kg (4,700 Btu/lb).

Table 5.5. System parameters per metric ton (ton) of SBR

Steam, kg (lb)	
Required, 121°C (250°F)	1,787 (3,574)
104°C (220°F)	544 (1,088)
Produced	All
Electricity, kWhr	
Required	464 (421)
Produced	526 (477)
Compressor pressure ratio	4.0
Power air flow, kg (lb)	19,420 (38,840)
Coal feed rate (dry), kg (lb)	366.8 (733.6)
Recuperator effectiveness, %	52
Overall thermal utilization, %	76.0
Used heat/power ratio	3.24

Texas and Louisiana dominate production of SBR with ~87% of U.S. production capacity.³ Operating 300 days/year and 24 hr/day, the average Gulf Coast plant produces 21.3 metric tons (23.5 tons)/hr. SBR is produced at 14 plants that would require average cogeneration systems of 63 MW(t) each.

Obviously, the rubber and plastics production is located near the source of abundant gas and oil fuels and petrochemical feedstocks. The economics of importing coal into these areas is certainly a valid concern.

Fig. 5.3. CCC cogeneration system for the SBR industry.

5.2.1.3. Chlorine and caustic soda. In the recent past, there have been market shortages of both chlorine and caustic soda. These are caused by a lack of production capacity and also, to a lesser extent, the periodic unavailability of sufficient electric power.⁴ The electric demand of the industry is so high that thermal utilization in the CCC was less than 60%. The present state-of-the-art systems in the industry are reported to operate with considerably lower utilizations, with perhaps one large plant approaching 55% utilization.⁴ The plant chosen is a diaphragm cell production facility. Mercury cells require no steam and thus are not likely to implement total energy systems.

The flow sheet for the derived system, shown in Fig. 5.4, is described in Table 5.6. In cases of high power demand such as this, the option of a combined cycle (gas-turbine topping, steam bottoming) cannot be ignored.

Table 5.6. System parameters per metric ton (ton) chlorine and 1.12 metric ton (ton) caustic soda

<hr/>	
Steam, kg (lb)	
Required, 149°C (300°F)	4,310 (8,620)
100°C (212°F)	707 (1,413)
66°C (150°F) (hot water)	259 (517)
Produced	All
Electricity, kWhr	
Required	2,777 (2,520)
Produced	3,031 (2,750)
Compressor pressure ratio	3.5
Compressor efficiency, % ^a	82
Turbine efficiency, % ^a	85
Recuperator effectiveness, %	80
Power system air flow, kg (lb)	100,000 (200,000)
Coal feed rate (dry), kg (lb)	1,430 (2,859)
Used heat/power ratio	1.21
Overall thermal utilization, %	58.5
<hr/>	

^aImproved machinery included to enhance power output.

Fig. 5.4. CCC cogeneration system for the caustic soda-chlorine industry.

The specific energy for one electrochemical unit (ecu)* is 18,612 kJ (17,726 Btu). A value typical of the industry today is ~20,836 kJ/ecu (19,750 Btu/ecu) with purchased electricity.⁴

There are ~64 chlorine/caustic plants in the United States which produced $\sim 15.1 \times 10^6$ metric tons (16.6×10^6 tons) (ecu) in 1974.³ For a 300 day year and 24 hr/day, the average production is 32.7 metric tons (36 ecu tons)/hr. The average CCC installation size would be ~374 MW(t), requiring four 90-MW(t) units per plant, totaling 256 90-MW units in the United States. The production of chlorine/caustic is carried out in all parts of the United States, with Louisiana possessing the greatest concentration of capacity at 17% of the total. Expenditures for new equipment totalled \$28.5 million in 1970, which indicates an interest in new concepts that might pay for themselves over time.⁴

5.2.2 Paper/pulp — newsprint

Newsprint is, of course, only one of several qualities of paper that can be manufactured from pulp. Newsprint production was ~5.3% of the total paper and paper-board production for 1974.⁵ The variety of integrated pulp and paper mills results in high uncertainty as to the application or need for new cogeneration systems. Much of the fuel requirements are satisfied by the burning of bark, wood scrap, and various liquors arising from the pulping process. For this reason, a nonintegrated paper mill in which dry pulp is a raw material was chosen for the application. There are about equal numbers of integrated and nonintegrated paper mills in the United States.³ A process flow diagram for converting dry pulp into finished paper is shown in Fig. 5.5.

The process energy requirements for this particular plant operation were derived from data in Refs. 3 and 5. A diagram of the cogeneration system is presented in Fig. 5.6, and the pertinent data are given in Table 5.7.

The specific energy for newsprint production is about 4701 kJ/kg (4053 Btu/lb) of newsprint. The 1975 newsprint production was expected

* One ecu here means one ton of chlorine plus 1.12 tons of caustic soda (1 ton = 0.9078 metric ton).

Fig. 5.5. Refining, stock preparation, and papermaking (1 lb = 0.454 kg) (Ref. 3).

Fig. 5.6. CCC cogeneration system for the newsprint industry.

Table 5.7. System parameters per metric ton (ton) of newsprint

Steam, kg (lb)	
Required, 177°C (350°F)	2,250 (4,500)
Produced	All
Electricity, kWhr	
Required	330.6 (300)
Produced	366 (332)
Compressor pressure ratio	4.0
Recuperator effectiveness, %	10
Power system air flow, kg (lb)	12,650 (25,300)
Coal feed rate (dry), kg (lb)	362.9 (653.7)
Used heat/power ratio	4.62
Overall thermal utilization, %	78.6

to be about 3.8×10^6 tons,³ or 479 metric tons (528 tons)/hr (300 days/year, 24 hr/day), which would require 14 CCC units rated at 90 MW(t). About 197 nonintegrated paper mills exist in the country,³ but the number involved in making newsprint instead of writing paper is uncertain. The manufacture of writing paper is very similar to making newsprint, involving the same basic production sequence. The production of writing paper is more energy intensive, however, requiring about 350 kWhr and 4800 kg steam/metric ton (9600 lb steam/ton) of finished paper.⁵ Another interesting statistic is that, including all types of paper/pulp facilities, there are 538 plants with no in-house electricity generation.³ Furthermore, at least 36% of these plants are located in regions where coal is a major power source. A potentially sizable market for the CCC exists in these plants that have no total energy package at present.

5.2.3 Petroleum refining

Petroleum refining involves many diverse processes, as indicated in Section 4.3.3. Two processes were selected for analysis because these were considered to be exceptionally practicable applications.

Furthermore, they are quite energy intensive among the various processes, with the equipment handling some of the largest flows of oil in a refinery.

5.2.3.1. Atmospheric-pressure distilling column crude-oil preheater.

The first step in the manufacture of petroleum products is the separation of the crude oil into the main conventional streams, as indicated in Fig. 5.7. Each stream contains many compounds and boils within a limited range. The crude oil passes through a heat-exchanger train to recover heat from product streams being run down to storage. Often, the crude is piped into a flash drum where light fractions will vaporize and pass directly into the fractionating tower. The balance of the crude is ultimately raised to $\sim 343^{\circ}\text{C}$ (650°F) in a fired heater and enters the tower, where separation of the crude oil into the required product boiling ranges takes place, controlled by temperature levels and reflux rates throughout the system.

Typical product streams are light gasoline, naphtha, kerosene, diesel or light gas oil, and a bottom product used as a fuel oil blending component.

The crude units generally handle the entire input to the refinery, typically $0.09 \text{ m}^3/\text{sec}$ ($50,000 \text{ bbl/day}$). The terminal temperature required for the crude oil entering the column varies in the literature,^{3,7} but 343°C (650°F) was chosen. Heat recovery from the stripping steam usually raises the crude temperature to $\sim 135^{\circ}\text{C}$ (275°F) before entering the crude heater. The remaining heat is supplied in a pipe still heater, which is usually gas-fired.⁷ The values for electrical requirements of this unit vary in the literature also, with 3.77 kWhr/m^3 (0.6 kWhr/bbl) selected as typical. Using thermodynamic data for oil from Refs. 8 and 9 to perform the heating from 135 to 343°C (275 to 650°F), it was determined that $501,240 \text{ kJ/m}^3$ ($75,448 \text{ Btu/bbl}$) would be required. The heat/power ratio for the unit then becomes ~ 37 . To meet the heat demand, the CCC must produce a surplus of electricity, which is assumed to be utilized elsewhere in the refinery. There will be waste heat exiting from the heater at $\sim 149^{\circ}\text{C}$ (300°F), which may or may not be employed for low-temperature process heating. The crude-oil heater was

Fig. 5.7. Atmospheric-pressure crude-oil distillation unit (Ref. 6).

assumed to be a rather conventional counterflow heat exchanger. The CCC system flow sheet is provided in Fig. 5.8, and data for the system are given in Table 5.8.

Table 5.8. System parameters per cubic meter (barrel) of crude-oil input

Thermal energy		
Required, ^a kJ (Btu)	501,240	(75,448)
Produced	501,240	(75,448)
Electricity, kWhr		
Required	3.8	(0.6)
Produced	26.2	(4.16)
Compressor pressure ratio	3.0	
Recuperator effectiveness, %	None	
Oil heater LMTD, °C (°F)	123	(222)
Power system air flow, kg (lb)	1,065	(372.5)
Coal feed rate (dry), kg (lb)	31.2	(10.9)
Used heat/output power ratio	5.31	
Overall thermal utilization, %	66.5	

^aBased on sensible heat in crude oil, 135 to 343°C (275 to 650°F), 34.5 API (Ref. 9).

Pipestill heaters reportedly operate at 60 to 70% fuel efficiency.⁷ A pipestill heater operating at 70% efficiency and a central power station operating at 36% efficiency produce the electricity and heat at a fuel cost of 973,000 kJ/m³ (147,340 Btu/bbl). The CCC performs the identical duty at 890,000 kJ/m³ (134,910 Btu/bbl) (8.5% reduction). If the CCC were to replace the pipestill heater in even one 0.09-m³/sec (50,000-bbl/day) refinery, the displacement of natural gas could be 0.15×10^6 m³ (5.2×10^6 ft³) per day. The thermal rating of such a unit would be about 82 MW and would likely generate over one-half the refinery's entire electrical demand. Out of approximately 259 refineries in the

Fig. 5.8. CCC cogeneration system for crude-oil heating prior to distilling at atmospheric pressure.

United States, about 71 have capacities averaging $0.09 \text{ m}^3/\text{sec}$ (50,000 bbl/day).³ Refineries having flows of $0.04 \text{ m}^3/\text{sec}$ (20,000 bbl/day) or less numbered 124, with the remaining 64 averaging $0.27 \text{ m}^3/\text{sec}$ (150,000 bbl/day).³

There is an obvious question of capital investment in an air/oil heater. Using a typical pipestill example from Ref. 9, the CCC heat exchanger was found to possibly involve only 40% more heat transfer surface area. Gas-fired stills depend heavily on radiation heat transfer and, because of the low gas velocities, the convection zone in the still is rather inefficient and requires a relatively large surface area. The CCC heat exchanger allows high gas velocities, $>15 \text{ m/sec}$ ($>50 \text{ ft/sec}$), which lower the surface area requirements. Because the system electrical output is not critical in this case, the increase in pressure drop can be tolerated. In fact, the higher system $\Delta P/P$ would increase the gas temperature available to the oil heater, further reducing the surface area requirements. The heat exchanger surface in the fluidized-bed furnace itself is not included in this comparison, but the electrical production would likely justify its cost.

5.2.3.2 Vacuum-distilling unit oil heater. A second stage of processing, carried out under vacuum to keep temperatures as low as possible and to avoid undue cracking of products, is used where the crude oil is to be reduced to a low percentage of bottoms (see Fig. 5.9). Overhead products include heavy lubricating fractions, or heavy cracking stock, in addition to the products taken overhead from a single-stage distillation unit. The residuum is a viscous pitch used for fuel oil blending; occasionally, it is a very high melting point asphalt.

Increasingly, vacuum distillation of crude oil is utilized as a means to produce a low-sulfur fuel oil pool in a refinery. Processes to desulfurize vacuum gas oils are available and proven commercially. Processes to desulfurize residues are much more complex and more expensive to install and operate, as well as being somewhat limited in application because of metal contamination of catalysts, for example. The vacuum gas oils are therefore desulfurized and back blended with the vacuum bottoms to achieve a low-sulfur heavy fuel oil pool. In a typical refinery, the flow through the vacuum column is typically 35 to 50%

Fig. 5.9. Vacuum distilling unit in relation to atmospheric column
 (Ref. 6).

of the charge to the atmospheric column.^{7,10} Reduced crude residual from the atmospheric unit makes up most of the vacuum distiller charge. The charge to the vacuum column heater enters at 316 to 343°C (600 to 650°F), with a terminal temperature of 399 to 427°C (750 to 800°F). Steam, ~34.3 to 48.6 kg/m³ (12 to 17 lb/bbl),^{3,7} is also required at 232 to 260°C (450 to 500°F). Because the gas temperature leaving the reduced crude heater will be quite hot, this steam will probably be generated in a waste-heat boiler. Electrical loads for the unit vary from 1.26 to 3.15 kWhr/m³ (0.2 to 0.5 kWhr/bbl) in the literature.^{3,6,7} Again, this power demand is small enough that surplus power will be produced. The high-temperature heat requirements suggest that a low-pressure ratio system be employed. The system that was formulated is depicted in Fig. 5.10, and data are listed in Table 5.9. For a 0.09-m³/sec (50,000-bbl/day) refinery in which half the volume flow went to the vacuum unit,

Table 5.9. System parameters per cubic meter (barrel) of reduced crude oil input

Thermal energy	
Required, ^a kJ (Btu)	239,923 (36,133)
Produced, kJ (Btu)	239,923 (36,133)
Steam, kg (lb)	
Required, 260°C (500°F)	45.8 (16)
Produced, 260°C (500°F)	45.8 (16)
Electricity, kWhr	
Required	1.89 (0.3)
Produced	11.5 (1.83)
Compressor pressure ratio	2.0
Recuperator effectiveness, %	None
Oil heater LMTD, °C (°F)	153 (276)
Power system air flow, kg (lb)	701.3 (245.2)
Coal feed rate (dry), kg (lb)	22.0 (7.70)
Used heat/output power ratio	8.75
Overall thermal utilization, %	63.9

^aBased on sensible heat in crude oil, 316 to 399°C (600 to 750°F), 26 API (Ref. 9).

Fig. 5.10. CCC cogeneration system for crude-oil heating prior to vacuum distilling.

a 29-MW(t) CCC unit would be sufficient. The refining industry has been experimenting with the concept of replacing pipestills with fluidized-bed direct oil heaters, indicating a real interest in converting to coal.

5.2.4 Food industries

No one food processing industry is representative of the entire SIC 20 category. Two industries, meat packing and soybean processing, were chosen primarily because they exhibit a definite dependence on electricity and require some heat at over 177°C (350°F).

5.2.4.1 Soybean meal, flour, oil. The specific energy required per pound of soybeans is less than many other food industries, but the total energy consumption per year is among the highest. The plant from which the data in Section 4.3.6.3 were presented apparently lacked the capability to generate either steam or electricity. According to Ref. 11, at least some plants do generate steam, but none generate electricity in-house. The system devised to meet the needs of a soybean plant is illustrated in Fig. 5.11, and the descriptive data are given in Table 5.10. The specific energy requirement of the soybean plant would be 2400 kJ/kg (1035 Btu/lb). About 119 soybean processing plants were reported to exist in 1973,¹¹ ranging in capacity from 45 to 3268 metric tons (50 to 3600 tons) per day. The plants generally use their capacity consistently. A 908-metric ton (1000-ton) per day plant would require a CCC unit rated at 25 MW(t). Coal is reported to represent ~25% of the purchased fuels in Ref. 11, indicating that there is no interface problem with coal utilization.

5.2.4.2. Meat packing/processing. An integrated meat packing and meat processing plant displays a rather high electrical demand. The best data available were for hog slaughtering and pork processing. Reportedly, there is no "typical" plant in the meat packing business, but there exists at least one integrated plant locally. Approximately 0.51 kg of pork is available per kg of live hog.³ This pork may be used in its raw state or may be converted to other products. This analysis assumes that all of the 0.51 kg/kg undergoes further processing.

Fig. 5.11. CCC cogeneration system for a soybean meal, flour, and oil plant.

Table 5.10. System parameters per metric ton (ton) of soybeans cleaned

Steam, kg (lb)	
Required, 232°C (450°F)	300 (600.4)
127°C (260°F)	123 (245.5)
Produced	All
Direct heat	
Required, 177°C (350°F), kJ (Btu)	245,920 (212,000)
Produced, 16 to 204°C	2,993 (2,580)
(60 to 400°F) air, kJ (lb)	
(sensible heat)	
Electricity, kWhr	
Required	80.7 (73.2)
Produced	90.4 (82.0)
Compressor pressure ratio	4.5
Recuperator effectiveness	None
Power system air flow, kg (lb)	3,126 (6,252)
Coal feed ratio (dry), kg (lb)	84 (167.0)
Used heat/power ratio	4.69
Overall thermal utilization, %	76.9

The pertinent data for the formulated system, Fig. 5.12, are listed in Table 5.11. The polishing and singeing is conventionally accomplished with a gas flame, but the substitution of hot air at 568°C (1055°F) should be more than adequate. The energy required to convert 1 lb of hog on-the-hoof to hot dogs is ~8700 kJ/kg (3745 Btu). There are ~991 hog slaughtering facilities in the United States, many of which are involved in meat processing.³ A typical plant can handle 1400 hogs per day, which would be equivalent to 153 metric tons (168 tons) per day. The required CCC unit size would be about 16 MW(t). Coal was reportedly once an important fuel in the industry;¹¹ thus, there should be little problem with its use.

The plants presented in Section 5 were generally of average size in the industry. A more complete listing of size distribution is provided in Table 5.12, with the data primarily from Ref. 3.

Fig. 5.12. CCC cogeneration system for hog slaughtering and pork processing.

Table 5.11. System parameters per metric ton (ton) of hog slaughtered^a

Steam, kg (lb) ^a	
Required, 188°C (370°F)	185 (370)
146°C (295°F)	76 (152)
121°C (250°F)	288 (576)
60°C (140°F) (hot water)	11,230 (22,460)
Produced	All
Direct heat	
Required, flame, kJ (Btu/ton)	140,128 (120,800)
Produced, 568 to 427°C	910 (1,820)
(1055 to 800°F) gas, kg (lb)	
(sensible heat)	
Electricity, kWhr	
Required	500 (454)
Produced	517 (469)
Compressor pressure ratio	4.0
Recuperator effectiveness, %	73
Power system air flow, kg (lb)	18,408 (36,816)
Coal feed rate (dry), kg (lb)	302 (604)
Used heat/power ratio	2.19
Overall thermal utilization, %	68.1

^aDerived from data in Ref. 3. See Sect. 4.3.6.1.Table 5.12. Size distribution of plants given preliminary analysis^a

Industry	Number of plants in unit size range [MW(t)]		
	<20	20-100	>100
HDPE	8	7	0
SDR	4	8	2
Chlorine/caustic	2	19	47
Soybean	26 _b	83	0
Meat packing	936 ^b	55	0
Atmospheric distiller	163	96	64
Vacuum distiller	174	85	0
Total	1313	353	113

^aBased on 300 days/year, 24 hr/day.^bAbout 830 are <1.5 MW(t).

References

1. Babcock and Wilcox Company, *Summary Evaluation of Atmospheric Pressure Fluidized Bed Combustion Applied to Electric Utility Large Steam Generators: Appendices*, EPRI FP-308 (October 1976).
2. A. P. Fraas et al., *Use of Coal and Coal-Derived Fuels in Total Energy Systems for MIUS Applications, Vol. II*, ORNL/HUD/MIUS-28, Oak Ridge National Laboratory, 1976.
3. *Survey of the Applications of Solar Thermal Energy Systems to Industrial Process Heating, Vol. II - Industrial Process Heat Survey*, TID 27348/2, Battelle Laboratories (January 1977).
4. International Research and Technology Corporation, *Industrial Energy Study of the Industrial Chemicals Group*, IRT-342-R (PB-236322) (August 1974).
5. Federal Energy Administration, *The Data Base - The Potential for Energy Conservation in Nine Selected Industries, Vol. 8, Selected Paper Products*, Conservation Paper No. 16, Office of Industrial Programs, 1975.
6. Federal Energy Administration, *The Data Base - The Potential for Energy Conservation in Nine Selected Industries, Vol. 2, Petroleum Refining*, Conservation Paper No. 10, Office of Industrial Programs, 1975.
7. V. O. Haynes, *Energy Use in Petroleum Refineries*, ORNL/TM-5433, Oak Ridge National Laboratory, 1976.
8. R. H. Perry et al., *Perry's Chemical Engineers Handbook*, 4th ed., McGraw-Hill Book Company, 1963.
9. W. L. Nelson, *Petroleum Refinery Engineering*, 3rd ed., McGraw-Hill Book Company, 1949.
10. G. D. Hobson and W. Pohl, eds., *Modern Petroleum Technology*, 4th ed., Holsted Press, John Wiley and Sons, 1973.
11. Development Planning and Research Associates, *Industrial Energy Study of Selected Food Industries*, FEA-EI-1652 (PB-237316) (July 1974).

6. CONCEPTUAL DESIGN OF AFBC GAS-TURBINE COGENERATION SYSTEMS FOR INDUSTRIAL APPLICATIONS

6.1 Combustor Design

The primary consideration in the design of atmospheric fluidized-bed combustor (AFBC) gas-turbine cogeneration systems is the design of the fluidized-bed combustor in unit sizes up to 20 MW(e). The thermal rating corresponding to this power output is about 90 MW(t), or 0.09×10^6 kW (307×10^6 Btu/hr). This is a rather high heat rating for a single unit and will require a fairly large area for the fluidized bed. The bed area can be minimized by increasing the bed depth. The economical limit for the bed depth for an atmospheric fluidized bed is probably about 1.5 to 1.8 m (5 to 6 ft) deep because of the fan power requirements.

The layout drawing for one concept of the combustor is shown in Fig. 6.1. In this design, the bed tube bundle is composed of U-tubes that extend across the full width of the bed, with the turbine air inlet and outlet manifolds on the same side of the bed. The combustion plenum, air distributor plate, and tube bundle are designed to be removed as a unit from the side of the combustor by disconnecting the turbine air inlet and outlet pipes and removing bolts from the air plenum flange. In this layout, the economizer tube bundle is located above the freeboard. The plenum width is decreased in the economizer region to increase the flue-gas velocity through the economizer for improved heat transfer. The combustor is lined with refractory and does not make use of cooling tubes in the combustor walls.

An alternate layout for the combustor design is shown in Fig. 6.2. Here the economizer is located beside the freeboard to reduce the overall height of the unit. A solids removal point is located below the economizer for particulates that settle out of the flue gas after they pass downward through the economizer.

The principal parameters for a conceptual design of a 90-MW(t) combustor are given in Table 6.1. The design is for a closed-cycle gas turbine with a compressor outlet pressure of 1.2 MPa (175 psia). The

Fig. 6.1. Conceptual layout of a coal-fired fluidized-bed combustor (elevation view).

Fig. 6.2. Alternate layout of a coal-fired fluidized-bed combustor (elevation view).

Table 6.1. System parameters for conceptual design
of a 90-MW(t) fluidized-bed combustor for
a gas-turbine cogeneration plant

Turbine air flow, kg/sec (lb/sec)	237 (522)
Turbine inlet temperature, °C (°F)	816 (1500)
Compressor outlet pressure, MPa (psia)	1.2 (175)
Compressor pressure ratio	4.3
Number of tubes in bed	8640
Tube OD, cm (in.)	2.54 (1)
Tube length in bed, m (ft)	3.7 (12)
Horizontal tube pitch, cm (in.)	6.1 (2.4)
Vertical tube pitch, cm (in.)	5.1 (2)
Number of tube layers in bundle	24
Tube bundle depth, cm (in.)	124 (49)
Expanded bed depth, cm (in.)	147 (58)
Freeboard height, m (ft)	3.7 (12)
Bed width, m (ft)	3.7 (12)
Bed module length, m (ft)	3.7 (12)
Number of bed modules	6
Total bed area, m ² (ft ²)	80 (864)
Superficial velocity, m/sec (ft/sec)	1.7 (5.5)
Bed temperature, °C (°F)	900 (1650)
Number of coal-feed points per bed module	16

diameter of the tubes in the bed tube bundle was chosen to be 2.5 cm (1 in.). A bed tube bundle depth of 124 cm (49 in.) was used to reduce the bed area to a value of 80 m² (864 ft²). The tube bundle is divided into 12 modules to reduce the air flow in the manifolds and thus reduce their diameter. The bed is divided into six modules, with two tube bundles in each bed module. The optimum length diameter ratio for 2.5-cm (1-in.) tubes is given with U-tubes extending 1.82 m (6 ft) into the bed; for this design, the bed was made 3.66 m (12 ft) wide with a tube bundle installed in each of the two sides of each bed module. Each bed module has a separate combustion air plenum and air distributor to allow each module to be started individually to reduce the heating requirements during startup. This design is illustrated in Fig. 6.3.

Coal and limestone are fed to the fluidized bed through feed nozzles located underneath the bed which are supplied by feed lines brought through the distributor plate. There are 16 coal-feed points per bed

Fig. 6.3. Layout of fluidized-bed combustor with deeper bed and alternate tube configuration.

module with each point serving 0.84 m^2 (9 ft^2). Each bed module is served by its own coal-feed system. The coal-feed system chosen for the conceptual design consists of a rotary feeder to meter the coal feed. This is followed by a two-stage riffle flow divider to split the coal into four equal streams. Each of these streams is transported pneumatically by compressed air, and at a point near the combustor, each is divided again into four by means of an in-line flow splitter that divides the two-phase flow. Each of the 16 feed lines enters the air plenum and passes through the distributor plate. The coal enters the bed through a feed nozzle on each of the feed lines.

6.2 Gas-Turbine Selection

The gas turbine for the fluidized-bed coal-combustion system requires a flow path for the turbine drive air that differs from the majority of the conventional oil-fired gas turbines being built for current use. Because the heat is to be supplied in the fluidized-bed tube bundle, the air must be brought out of the compressor, sent through the combustor tubes, and then routed into the turbine. Most of the gas turbines being built have the oil-fired combustion chamber located inside the turbine casing between the compressor outlet and turbine inlet; the air then flows directly from the compressor through the combustion chamber to the turbine and never exits from the casing until it is exhausted from the turbine. Gas turbines of this design would require modification to provide air ports from the compressor and to the turbine for use with the fluidized-bed combustor.

There are at least two turbine manufacturers offering gas turbines for sale that are designed with external combustion chambers where the air is ducted out of the compressor, through the burner, and then back into the turbine. The AiResearch Manufacturing Company of Phoenix, Arizona, builds a line of gas turbines with external combustors with power output ratings from 500 kW(e) to 6 MW(e). The Sulzer Company of Switzerland offers gas turbines with external combustion chambers in two power ratings, 4 MW(e) and 20 MW(e). The Sulzer turbines are designed for a pressure ratio of 4.5:1, which makes them well suited for use with a recuperator in the system.

Virtually all the gas turbines being produced are designed for open-cycle operation. The turbine cycle is open in the sense that the air to the compressor is drawn from the atmosphere. The compressed air is heated inside the tubes in the fluidized-bed combustor; passed through the turbine, recuperator, and process waste-heat exchanger; and then discharged to the atmosphere. Open-cycle machines designed for an external combustor can be used in open-cycle systems with the fluidized-bed combustor.

For closed-cycle operation, modifying open-cycle turbines by providing seals designed for a pressure difference of about 0.17 MPa (25 psig) at the compressor inlet and turbine exhaust will be necessary. In some designs, higher strength casings or higher capacity thrust bearings may have to be provided.

The use of a closed-gas cycle turbine offers two advantages.

1. The turbine can follow a varying electrical load on the generator by changing the pressure in the turbine loop and still maintain a constant turbine inlet temperature and full-load cycle efficiency at part load.

2. For a given pressure ratio, the pressure can be higher for the closed cycle, thus resulting in a higher heat transfer capability in the combustor tubes and in the recuperator. This leads to a reduction in the heat transfer surface area for these components. The increased pressure can also increase the power output of a turbine of a given size. These effects will result in a lower cost for closed-cycle systems.

In applications where the turbine generator is required to follow a widely varying electrical load, two turbines could be controlled by bleeding part of the compressor air to the atmosphere. When the load drops below 50%, one of the turbines would be shut down. For applications where the electrical load varies only slightly, a single turbine generator could be used with each combustor and bypass controls used to follow load changes. In all applications, installing two to four combustor units to provide increased reliability for supplying both heat and electrical power will be most desirable.

7. ECONOMIC COMPARISON OF COGENERATION SYSTEM WITH ALTERNATIVES

The cost of supplying process heat and electricity with a coal combustion cogeneration (CCC) system has been compared with the cost of supplying heat with each of four alternative systems and buying electricity from the utility system. Heat supply systems of four types were included in the comparison: pulverized coal-fired boiler burning low-sulfur coal; pulverized coal-fired boiler burning high-sulfur coal with stack-gas scrubber; AFBC coal-fired boiler; and oil-fired boiler.

A CCC installation with a total thermal rating of 360 MW(t) composed of four units of 90 MW(t) each was used as a basis for the cost comparison. Two comparisons are presented: one in which the CCC is assumed to produce hot process air of the same energy content as the steam produced by the boilers, and a second where the CCC is assumed to be used with a waste-heat boiler. Details of the process heat condition and cycle configuration are presented in Table 7.1. In both cases, the total fuel input to the CCC is 360 MW(t).

7.1 Assumptions Used for Cost Estimates

The major assumptions used for making the cost estimates are given in Table 7.2. The capital costs for the systems were based on the cost for buying the equipment in 1978. The plant life was assumed to be 20 years, and the capital or fixed charges for the investment were assumed to be 21%/year, which is considered in the range of satisfactory capital returns for industrial investments.

The fuel prices assumed for the cost estimate are average values reported for early 1978 for eastern Pennsylvania. Fuel prices vary depending on locality but are reported to be similar to those for a number of areas in the midwestern and northeastern states. The price for purchased electricity was assumed to be 3.5¢/kWhr. The prices reported for these same states varied from about 3.2 to 3.8¢/kWhr. The amount of electricity used was based on an assumed plant load factor of 85% for each case. The cost of fuel and purchased electricity was assumed to increase at a

Table 7.1. CCC system parameters for economic comparison (four modules)

Parameters	Case I	Case II
Steam temperature, °C (°F)	371 (700) ^a	186 (367)
Steam pressure, MPa (psig)	4.48 (650)	1.03 (150)
Gas-turbine cycle configuration	Open	Closed
Compressor pressure ratio	4.3	6.11
Turbine inlet temperature, °C (°F)	816 (1,500)	816 (1,500)
Steam flow rate, kg/sec (lb/hr)	75.6 (600,000)	72.7 (578,000)
Gas-turbine air flow, kg/sec (lb/sec)	162 (358)	132 (291)
Recuperator effectiveness, %	54	13
Turbine adiabatic efficiency, %	85	85
Compressor adiabatic efficiency, %	85	85
System $\Delta P/P$, %	10	10
Bed temperature, °C (°F)	900 (1,650)	900 (1,650)
Bed tube heat transfer coefficient, $W/m^2-^{\circ}C$ (Btu/hr-ft ² -°F)	284 (50)	284 (50)
Power output, MW(e)	76	66

^aIn case I, the CCC produces hot air at 371°C (700°F), that is, the turbine exhaust.

Table 7.2. Assumptions used for cost estimate

1978 dollars for capital investment
9% construction interest rate
Three-year construction time
15% contingency for coal-fired plants
10% contingency for oil-fired plant
20% indirect cost for engineering and construction
21% annual capitalization rate for 20-year life
\$25/ton cost for high-sulfur coal
\$33/ton cost for low-sulfur coal
\$6/ton cost for limestone
\$2.20/10 ⁶ Btu cost for fuel oil
3.5¢/kWhr cost for purchased electricity
7% annual escalation rate for fuel and electricity
85% plant load factor

rate of 7%/year over the 20-year plant life as a result of general cost escalation.

7.2 Coal-Combustion Cogeneration System

The estimated capital costs for the CCC system installation are shown in Table 7.3. Because a combustor of this type has not yet been built or developed, a cost range was used for the combustor to allow for a greater uncertainty in its estimated cost than for other equipment of a more conventional nature in the system. The combustor cost estimate was based on a conceptual design sized for a nominal rating of 90 MW(t) and the design conditions given in Table 7.1. About two-thirds of the system cost is for the heat supply equipment, and about one-third is for the electric power generating equipment.

7.3 Pulverized Coal-Fired Boilers

The cost was estimated for conventional pulverized coal-fired boilers with and without stack-gas scrubbers. The cost estimate without scrubbers is given in Table 7.4 and with scrubbers in Table 7.5. The addition of scrubbers is estimated to add about \$10 million to the overall cost.

The cost estimates for these systems were derived from estimates made in 1977 for Oak Ridge National Laboratory (ORNL) by United Engineers for installations composed of four boilers of a 31.5 kg/sec (250,000 lb/hr) steam capacity each. The costs were adjusted for escalation and for the rated steam capacity of the installation.

7.4 AFBC Coal-Fired Boilers

The cost estimate for this system is also derived from estimates made in 1977 for ORNL by United Engineers for a four-boiler installation of 31.5 kg/sec (250,000 lb/hr) each. The cost for four AFBC units of 18.9 kg/sec (150,000 lb/hr) steam at 4.5 MPa (650 psig) and 371°C (700°F) is given in Table 7.6. Because the AFBC boiler is not fully developed, United Engineers did not give a detailed breakdown of the cost of the

Table 7.3. Capital costs for CCC system [four 90-MW(t) units]

	Case I (hot air)	Case II (steam)
Construction permits	\$ 300,000	\$ 300,000
Yard work	1,000,000	1,000,000
Building	4,800,000	4,800,000
Combustor plant equipment		
Four 90-MW(t) combustors	14,400,000 to 23,000,000	16,400,000
Coal-feed system	2,000,000	2,000,000
Air heaters	1,200,000	1,200,000
Air and gas ducts	320,000	320,000
Bag filter	2,300,000	2,300,000
Forced- and induced-draft fans	780,000	780,000
Ash handling	1,400,000	1,400,000
Stack and breaching	1,200,000	1,200,000
Instruments and controls	1,000,000	1,000,000
Combustor equipment subtotal	\$24,600,000 to 33,200,000	\$26,600,000
Coal handling	4,300,000	4,300,000
Electrical	1,200,000	1,200,000
Heat subtotal capital	\$36,200,000 to 44,800,000	\$38,200,000
Power generation system		
Four 20-MW gas-turbine generators	12,000,000	9,840,000
Recuperators	1,600,000	1,000,000
Piping	5,600,000	5,600,000
Precooler		2,000,000
Waste-heat boiler		4,000,000
Power subtotal capital	\$19,200,000	\$22,440,000
Total installed capital	55,400,000 to 64,000,000	60,640,000
Contingency, 15%	8,300,000	9,100,000
	\$63,700,000	\$69,700,000
Indirect (engineering, construction facilities), 20%	12,740,000	14,000,000
Interest during construction	10,550,000	11,550,000
Total capital cost	\$86,990,000 to 100,500,000	\$95,250,000

Table 7.4. Capital costs for pulverized coal-fired industrial boiler without scrubbers, 75.6 kg/sec (600,000 lb/hr), 4.48 MPa (650 psig), 371°C (700°F)

Construction permits	\$ 300,000
Yard work	780,000
Boiler house	2,400,000
Boiler plant equipment	
Four 19-kg/sec (150,000-lb/hr) boilers including pulverizer and controls	16,600,000
Forced- and induced-draft fans	660,000
Precipitator	2,000,000
Ash handling	980,000
Feed water treatment, 50%	550,000
Stack and breaching	840,000
Subtotal	\$21,630,000
Coal handling	4,300,000
Electrical	1,000,000
Total capital	\$30,410,000
Contingency, 15%	4,560,000
Total installed cost	\$34,970,000
Indirect (engineering, construction facilities), 20%	6,994,000
Interest during construction	5,791,000
Total capital cost	\$47,755,000

Table 7.5. Capital costs for pulverized coal-fired industrial boilers with scrubbers, 75.6 kg/sec (600,000 lb/hr), 4.48 MPa (650 psig), 371°C (700°F)

Construction permits	\$ 300,000
Yard work	780,000
Boiler house	2,400,000
Boiler plant equipment	
Four 19-kg/sec (150,000-lb/hr) boilers	16,600,000
Forced- and induced-draft fans	660,000
Ash handling	980,000
Feed water treatment	550,000
Stack and breaching	840,000
Total boiler equipment	\$19,630,000
Coal handling	4,300,000
Electrical	1,000,000
Scrubber system (fans, scrubber, and particulate collection reaction tanks)	8,300,000
Total	\$36,710,000
Contingency, 15%	5,500,000
Total installed cost	\$42,210,000
Indirect (engineering, construction facilities), 20%	8,440,000
Interest during construction	6,990,000
Total capital cost	\$57,640,000

Table 7.6. Capital cost for atmospheric fluidized-bed industrial boiler, four units, 75.6 kg/sec (600,000 lb/hr) steam, 4.48 MPa (650 psig), 371°C (700°F)

Construction permits	\$ 300,000
Yard work	780,000
Boiler house	2,200,000
Boiler plant equipment	20,770,000
Coal handling	4,300,000
Electrical	840,000
Subtotal	\$29,190,000
Contingency, 15%	4,400,000
Total installed cost	\$33,590,000
Indirect (engineering, construction facilities), 20%	6,790,000
Interest during construction	5,572,000
Total capital cost	\$45,952,000

boiler plant equipment. Their estimate was based on information from boiler firms engaged in AFBC boiler development, but, because of the uncertainty in the costs, they preferred to give an overall boiler cost estimate only. The total estimated capital cost is about \$2 million less than pulverized-coal boilers without scrubbers and about \$12 million less than the pulverized-coal system with scrubbers.

7.5 Oil-Fired Package Boiler

The comparison included the cost of an oil-fired package boiler to supply steam for process heat, and this cost estimate is given in Table 7.7. The boiler cost was based on a unit cost of \$44/kg-hr (\$20/lb-hr) of steam capacity for the total direct cost for this system. A 10% contingency was included, as well as indirect charges and interest during construction. The capital cost is about one-third of that for the coal-fired boilers, but this difference is more than offset by the

Table 7.7. Capital costs for oil-fired package boiler

	Case I (high pressure)	Case II (low pressure)
Capital cost	\$12,000,000	\$11,000,000
Contingency, 10%	1,200,000	1,100,000
Total installed capital	\$13,200,000	\$12,100,000
Indirect, 20%	2,640,000	2,400,000
Interest during construction	1,580,000	1,500,000
Total capital cost	\$17,420,000	\$16,000,000

higher fuel costs for the oil-fired boiler. This is the only option chosen for comparison with the CCC coupled to a waste-heat boiler.

7.6 Comparison of Annual Cost

The annual cost for each of the systems is given in Table 7.8. The annual cost includes the fixed capital charges of 21% of the capital cost, the cost of fuel and limestone, and the cost of purchased electricity. The cost of fuel, limestone, and electricity includes a multiplying factor of 1.63 to account for 7% cost escalation per year for 20 years discounted to the present worth. The cost for the CCC system includes a range of uncertainty for the capital cost and a range in the purchased electricity in the amount of 10% of the system electrical output to allow for the effect of a 10% decrease in power output for the case where the turbine inlet temperature is assumed to be reduced from 816 to 788°C (1500 to 1450°F) to ease the materials requirements for the tubes in the fluidized bed.

The greatest factor in the cost comparison is the influence of the cost of purchased electricity. For the electricity cost and load factor used here, the annual costs show that the cost savings realized by in-plant electrical generation results in a substantial annual cost savings with the CCC system, despite its considerably larger capital costs. The

Table 7.8. Annual cost comparisons

Pulverized coal-fired boiler without scrubber			
Capital cost		\$	47,755,000
Annual capital, 21%			10,028,000
Annual coal cost, $8,877,000 \times 1.63$			14,470,000
Purchased electricity, $19,800,000 \times 1.63$			32,274,000
Total		\$	56,772,000
Pulverized coal-fired boiler with scrubber			
Capital cost			57,640,000
Annual capital, 21%			12,100,000
Annual coal cost, $6,725,000 \times 1.63$			10,962,000
Annual limestone, $538,000 \times 1.63$			877,000
Purchased electricity			32,274,000
Total		\$	56,213,000
Atmospheric fluidized-bed boiler			
Capital cost			45,952,000
Annual capital, 21%			9,450,000
Annual coal cost, $6,725,000 \times 1.63$			10,962,000
Annual limestone, $1,072,000 \times 1.63$			1,747,000
Purchased electricity			32,274,000
Total		\$	54,433,000
CCC system			
	<u>Hot air</u>	<u>Steam</u>	
Capital cost	\$86,990,000 to 100,500,000	\$95,250,000	
Annual capital, 21%	18,270,000 to 21,105,000	20,000,000	
Annual coal cost, $10,595 \times 1.63$	17,270,000	17,270,000	
Annual limestone, $1,310 \times 1.63$	2,135,000	2,135,000	
Purchased electricity ^a	3,200,000	2,800,000	
Total	\$37,675,000 to 43,710,000	\$42,210,000	
Oil-fired package boiler			
Capital cost	17,420,000	16,000,000	
Annual capital, 21%	3,660,000	3,400,000	
Annual oil cost, $13,450,000 \times 1.63$	21,920,000		
Purchased electricity	32,274,000	27,860,000	
Total	\$57,854,000	\$53,160,000	

^a A contingency of 10% purchased power is assumed and added.

other significant effect is the fact that the higher estimated fuel costs for oil results in a slightly higher annual cost for the oil-fired boiler than for any of the alternative coal-fired boilers.

Comparisons of the annual costs for the systems are illustrated in Figs. 7.1 and 7.2. The estimated annual cost savings with the CCC system

Fig. 7.1. Comparison of the annual cost of the CCC hot air system with alternative systems purchasing electricity.

ranges from 20 to 30% as compared with the AFBC boiler and 25 to 35% as compared with the oil-fired package boiler system. Where the oil-fired boiler is already installed and fully capitalized, the annual savings would still amount to 20 to 30%.

Furthermore, as indicated by the results of the second case utilizing a waste boiler with the CCC, the addition of the boilers does not detract significantly from the annual cost advantage of the CCC. The cost of the precooler is also relatively low, which means that closing the gas-turbine cycle may result in a net economic advantage due to the reduction in heat-exchanger surface requirements in the furnace and recuperator that would result.

Fig. 7.2. Comparison of the annual cost of the CCC system coupled to waste-heat boiler with alternate system and purchased electricity.

8. CONCLUDING REMARKS AND RECOMMENDATIONS

This report was intended to include enough detailed data to support the conclusions, allow readers to draw their own conclusions, and avoid the over-generalizing so prevalent in energy surveys. Significant findings in regard to the objectives of the study (see "Introduction," Chapter 2) are summarized in the following sections.

8.1 Theoretical Potential Market

The industrial energy requirements primarily determine the applicability of the system, specifically the process heat and electricity. Thus the potential market should be discussed in terms of energy and not just the number of installations. Based on extrapolation from the six greatest energy-consuming industries (from Table 3.8), the industrial process heat energy consumption was estimated as $15,750 \times 10^{12}$ kJ ($15,000 \times 10^{12}$ Btu) (1974), ~50% of the total industrial burden on primarily energy sources (fuels) and ~19% of the total United States burden on primary fuels. This "thermal market" for the fluidized-bed gas-turbine is substantial, especially in view of the recent thrust toward increasing the use of coal.

8.2 Impact on Oil and Natural Gas Consumption

The reduction in use of natural gas and oil is of paramount importance, and the ability to use more available fuels is a primary factor that will determine the desirability of any cogeneration system. Typically 90 to 92% of the oil and gas purchased by industry (excluding feedstocks) is used for heat. Therefore, the oil and gas presently consumed for process heat which could theoretically be displaced by coal can be identified.

The values are listed in Table 8.1. A tremendous conservation potential for the nation's gas resources exists here and a substantial potential savings for oil.

Table 8.1. Estimated annual oil and gas consumption for industrial process heating

Fuel	Consumption
Oil, 10^6 m^3 (10^6 bbl) ^a	36-83 (225-523)
Oil, 10^{12} kJ (10^{12} Btu)	1452-3264 (1376-3094)
Natural gas, 10^9 m^3 (10^9 ft^3) ^b	170-250 (5937-8703)
Natural gas, 10^{12} kJ (10^{12} Btu)	6482-9466 (6145-8973)

^aAbout 53% of industrial oil consumption, 9% of U.S. oil consumption.

^bAbout 86% of industrial gas consumption, 40% of U.S. gas consumption.

8.3 Thermodynamic Feasibility

The capability of the CCC to supply useful thermal process energy at temperatures up to 816°C (1500°F) while producing electricity enhances its thermodynamic feasibility in satisfying process heat demands in industry. The high-temperature heating capacity of the CCC is somewhat unique among cogeneration systems. From data on the temperature spectrum of process heating, 61 to 64% of the energy is required at temperatures less than 816°C (1500°F). Thus the thermodynamically feasible potential for fuel conversion appears as the values in Table 8.2.

8.4 Other Findings

Specific case studies were investigated on a preliminary basis to gain some insight as to the actual fuel efficiency likely with the system. Practical problems were discussed where sufficient information existed. The market for about 1000 CCC units was identified on investigation of only eight specific industries, including representatives from petroleum refining, food processing, and chemicals. Typical fuel efficiencies were on the order of 70%. However, the value of in-house electric generation alone may prove to be an equally significant advantage for industry.

The advantages of in-house power generation with fluidized-bed gas-turbine systems will be increased if electrical energy becomes a more prominent and effective method of producing high-temperature energy for such processes as ferrous metal heating, metal reheating for hot forming (e.g., forging), and glass melting. Furthermore, in a preliminary analysis, the economics appeared favorable for the CCC over noncogeneration systems.

8.5 Recommendations

This survey has been developed with the premise that coal will become the preferential source of environmentally acceptable industrial energy. Fluidized-bed combustors, now in the development stage, conceptually satisfy this premise. The theoretical future market disclosed by this survey is a clear mandate to proceed with concentrated engineering and development programs designed to realize the full technological potential of CCC systems. Technological barriers to implementation of fluidized beds have recently been summarized in Ref. 1.

A recent study by the Thermo Electron Corporation² estimated that a very high percentage of industry would invest in cogeneration systems, provided a reasonable investment return results. Another recommendation is a detailed economic study of the system proposed here. The most accurate economic data would be generated by several representative, detailed case studies of specific industrial facilities. Such studies should consider the smaller industries because, even though their energy consumption may be a small part of the national consumption, they likely represent a large number of installations. Note that this report is not of the same nature as a design study, and the information generated within is not sufficient for a detailed economic assessment of any of the case studies.

A nontechnical barrier that may exist in industrial utilization of the CCC is the interface problem between utility and in-house generated power. Shortages of generating capacity in some utilities in the nation should enhance the acceptance of cogeneration.

Table 8.2. Thermodynamically feasible savings of oil and gas with CCC^a

	Savings from process heat conversion to coal	Savings from electrical generation by coal cogeneration	Total
Oil, m ³ /sec (bbl/day)	1.60 (370,000)	1.17 (635,000)	2.77 (1,505,000)
Natural gas, m ³ /sec (10 ⁹ ft ³ /day)	4,590 (14.0)	1,228 (3.75)	5,818 (17.75)

^a1974 Bureau of Mines data base. Exhaust supplemental firing systems not included. Actual estimates are for oil and gas, not energy equivalents.

Cogeneration by industry is receiving much attention at this time and is highly recommended in the literature.²⁻⁴ The continued development of the equipment described in this report resulting in a vendor-manufactured product would be instrumental in accelerating the implementation of coal-combustion cogeneration.

References

1. J. E. Jones, Jr., et al., *Systems Assessment of Atmospheric Fluidized Bed Combustion: Baseline Study - Draft*, ORNL/TM-6208 (December 1977).
2. Thermo Electron Corporation, *A Study of Inplant Electric Power Generation in the Chemical, Petroleum Refining and Paper and Pulp Industries*, TE5429-97-76, 1976.
3. National Consumer Research Institute, *Proceedings of the ERDA Conference on Cogeneration and Integrated Energy/Utility Systems*, CONF-770632, 1977.
4. E. V. Sherry, *Energy Conservation by Symbiosis*, Air Products and Chemical, Inc., Allentown, Pa., 1977.

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

APPENDIX

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

Table 1. List of industrial process-heat applications and annual requirements (1974) found from survey

Industry - SIC group	Application temperature requirement [°C (°F)]	Process heat used for application [10 ¹² kJ/year (10 ¹² Btu/year)]
Iron ore - 1011		
Pelletizing of concentrates	1288-1371 (2350-2500)	39.2 (37.2)
Copper concentrate - 1021		
Drying	121 (250) ^a	1.8 (1.7)
Bituminous coal - 1211		
Drying (including lignite)	66-104 (150-220) ^a	19 (18)
Sand and gravel - 1442		None
Potash - 1474		
Drying filter cake	121 (250) ^a	1.09 (1.03)
Phosphate rock - 1475		
Calcining	760-871 (1400-1600)	0.75 (0.71)
Drying	232 (450) ^a	11.1 (10.5)
Sulfur - 1477		
Frasch mining	163-171 (325-340)	63 (60)
Meat packing - 2011		
Sausages and prepared meats - 2013		
Scalding, carcass wash, and cleanup	60 (140)	46.1 (43.7)
Singeing flame	260 (500)	1.12 (1.06)
Edible rendering	93 (200)	0.55 (0.52)
Smoking/cooking	68 (155)	1.22 (1.16)
Poultry dressing - 2016		
Scalding	60 (140)	3.33 (3.16)
Natural cheese - 2022		
Pasteurization	77 (170)	1.35 (1.28)
Starter vat	57 (135)	0.02 (0.02)
Make vat	41 (105)	0.50 (0.47)
Finish vat	38 (100)	0.02 (0.02)
Whey condensing	71-93 (160-200)	10.8 (10.2)
Whey drying	49 (120) ^a	3.10 (2.94)
Process cheese blending	74 (165) ^a	0.07 (0.07)
Condensed and evaporated milk - 2023		
Stabilization	93-100 (200-212)	3.09 (2.93)
Evaporation	71 (160)	5.48 (5.20)
Spray drying	177-204 (350-400)	3.78 (3.58)
Sterilization	121 (250)	0.57 (0.54)
Fluid milk - 2026		
Pasteurization	72-77 (162-170)	1.52 (1.44)
Canned specialties - 2032		
Beans		
Precook (blanch)	82-100 (180-212)	0.42 (0.40)
Simmer blend	77-100 (170-212)	0.25 (0.24)
Sauce heating	88 (190)	0.21 (0.20)
Processing	121 (250)	0.40 (0.38)
Canned fruits and vegetables - 2033		
Blanching/peeling	82-100 (180-212)	1.98 (1.88)
Pasteurization	93 (200)	0.16 (0.15)
Brine syrup heating	93 (200)	1.08 (1.02)
Commercial sterilization	100-121 (212-250)	1.76 (1.67)
Sauce concentration	100 (212)	0.46 (0.44)

Table 1 (continued)

Industry - SIC group	Application temperature requirement [°C (°F)]	Process heat used for application [10 ¹² kJ/year (10 ¹² Btu/year)]
Dehydrated fruits and vegetables - 2034		
Fruit and vegetable drying	74-85 (165-185)	6.16 (5.84)
Potatoes		
Peeling	100 (212)	0.35 (0.33)
Precook	71 (160)	0.50 (0.47)
Cook	100 (212)	0.50 (0.47)
Flake dryer	177 (350)	1.15 (1.09)
Granule flash dryer	288 (550)	1.15 (1.09)
Frozen fruits and vegetables - 2037		
Citrus juice concentration	88 (190)	1.40 (1.33)
Juice pasteurization	93 (200)	0.28 (0.27)
Blanching	82-100 (180-212)	2.38 (2.26)
Cooking	77-100 (170-212)	1.49 (1.41)
Wet corn milling - 2046		
Steep water evaporator	177 (350)	3.86 (3.66)
Starch dryer	49 (120) ^a	3.20 (3.03)
Germ dryer	177 (350)	2.03 (1.92)
Fiber dryer	538 (1000)	3.09 (2.93)
Gluten dryer	177 (350)	1.39 (1.32)
Steepwater heater	49 (120)	0.81 (0.77)
Sugar hydrolysis	132 (270)	1.99 (1.89)
Sugar evaporator	121 (250)	2.89 (2.74)
Sugar dryer	49 (120) ^a	0.17 (0.16)
Prepared feeds - 2048		
Pellet conditioning	82-88 (180-190)	2.40 (2.28)
Alfalfa drying	204 (400) ^a	17.7 (16.8)
Bread and baked goods - 2051		
Proofing	38 (100)	0.89 (0.84)
Baking	216-238 (420-460)	6.75 (6.40)
Cane sugar refining - 2062		
Mingler	52-74 (125-165)	0.62 (0.59)
Melter	85-91 (185-195)	3.48 (3.30)
Defecation	71-85 (160-185)	0.46 (0.44)
Revivification	399-599 (750-1110)	4.18 (3.96)
Granulator	43-54 (110-130)	0.46 (0.44)
Evaporator	129 (265)	27.84 (26.39)
Beet sugar - 2063		
Extraction	60-85 (140-185)	4.88 (4.63)
Thin juice heating	85 (185)	3.25 (3.08)
Lime calcining	538 (1000)	3.14 (2.98)
Thin syrup heating	100 (212)	7.05 (6.68)
Evaporation	132-138 (270-280) ^a	32.5 (30.8)
Granulator	66-93 (150-200)	0.16 (0.15)
Pulp dryer	110-138 (230-280) ^a	17.4 (16.5)
Soybean oil mills - 2075		
Bean drying	71 (160)	4.27 (4.05)
Toaster desolventizer	102 (215)	6.41 (6.08)
Meal dryer	177 (350) ^a	4.60 (4.36)
Evaporator	107 (225)	1.71 (1.62)
Stripper	100 (212)	0.32 (0.30)
Animal and marine fats - 2077		
Continuous rendering of inedible fat	166-177 (330-350)	17.4 (16.5)

Table 1 (continued)

Industry — SIC group	Application temperature requirement [°C (°F)]	Process heat used for application [10 ¹² kJ/year (10 ¹² Btu/year)]
Shortening and cooking oil — 2079		
Oil heater	71–82 (160–180)	0.76 (0.72)
Wash water	71–82 (160–180)	0.13 (0.12)
Dryer preheat	93–132 (200–270)	0.63 (0.60)
Cooking oil reheat	93 (200)	0.34 (0.32)
Hydrogenation preheat	149 (300)	0.39 (0.37)
Vacuum deodorizer	149–204 (300–400)	0.37 (0.35)
Malt beverages — 2082		
Cooker	100 (212)	1.61 (1.53)
Water heater	82 (180)	0.56 (0.53)
Mash tub	77 (170)	0.63 (0.60)
Grain dryer	204 (400) ^a	9.68 (9.18)
Brew kettle	100 (212)	4.20 (3.98)
Distilled liquor — 2085		
Cooking (whiskey)	100 (212)	3.33 (3.16)
Cooking (spirits)	160 (320)	6.61 (6.27)
Evaporation	121–143 (250–290) ^a	2.45 (2.32)
Dryer (grain)	149–204 (300–400)	2.05 (1.94)
Distillation	110–121 (230–250)	8.11 (7.69)
Soft drinks — 2086		
Bulk container washing	77 (170)	0.22 (0.21)
Returnable bottle washing	77 (170)	1.34 (1.27)
Nonreturnable bottle washing	24–29 (75–85)	0.45 (0.43)
Can warming	24–29 (75–85)	0.55 (0.52)
Cigarettes — 2111		
Drying	104 (220) ^a	0.45 (0.43)
Rehumidification	104 (220) ^a	0.45 (0.43)
Tobacco stemming and redrying — 2141		
Drying	104 (220) ^a	0.26 (0.50)
Finishing plants, cotton — 2261		
Washing	100 (200)	16.2 (15.4)
Dyeing	100 (200)	4.7 (4.5)
Drying	135 (275)	23.4 (22.2)
Finishing plants, synthetic — 2262		
Washing	93 (200)	37.9 (35.9)
Dyeing	100 (212)	16.0 (15.2)
Drying and heat setting	135 (275)	24.5 (23.2)
Logging camps — 2411		None
Sawmills and planing mills — 2421		
Kiln drying of lumber	149 (300)	66.9 (63.4)
Plywood — 2435		
Plywood drying	121 (250)	53.4 (50.6)
Veneer — 2436		
Veneer drying	100 (212)	61.0 (57.8)
Wooden furniture — 2511		
Makeup air and ventilation	21 (70)	6.0 (5.7)
Kiln dryer and drying oven	66 (150)	4.0 (3.8)
Upholstered furniture — 2512		
Makeup air and ventilation	21 (70)	1.5 (1.4)
Kiln dryer and drying oven	66 (150)	0.9 (0.9)

Table 1 (continued)

Industry - SIC group	Application temperature requirement [°C (°F)]	Process heat used for application [10 ¹² kJ/year (10 ¹² Btu/year)]
Pulp mills - 2611		
Paper mills - 2621		
Paperboard mills - 2631		
Building paper - 2661		
Pulp digestion	188 (370)	267 (253)
Pulp refining	66 (150)	185 (175)
Black liquor treatment	138 (280)	173 (164)
Chemicals recovery - calcining	1038 (1900)	101 (96)
Pulp and paper drying	143 (290)	404 (383)
Solid and corrugated fiber boxes - 2653		
Corrugating and glue setting	149-177 (300-350)	22.8 (21.6)
Alkalies and chlorine - 2812		
Mercury cell (phased out by 1983)		6.8 (6.4)
Diaphragm cell	177 (350)	86.6 (82.1)
Cyclic intermediates - 2865		
Ethylbenzene	177 (350)	3 (3)
Styrene	121-177 (250-350)	37 (35)
Phenol	121 (250)	0.47 (0.45)
Alumina - 28195		
Digesting, drying, heating	138 (280)	119.4 (113.2)
Calcining	1204 (2200)	37.2 (35.3)
Plastic materials and resins - 2821		
Polystyrene, suspension process		
Polymerizer preheat	93-102 (200-215)	0.107 (0.102)
Heating wash water	88-93 (190-200)	0.068 (0.064)
Drying	93 (200)	0.036 (0.034)
Synthetic rubber - 2822		
Cold SBR latex crumb		
Bulk storage	27-38 (80-100)	0.189 (0.179)
Emulsification	27-38 (80-100)	0.091 (0.086)
Blowdown vessel	54-63 (130-145)	0.912 (0.865)
Monomer recovery by flashing and stripping	49-60 (120-140)	4.319 (4.095)
Dryer air temperature	66-93 (150-200)	3.864 (3.663)
Cold SBR, oil-carbon black masterbatch		
Dryer air temperature	66-93 (150-200)	0.534 (0.506)
Oil Emulsion holding tank	27-38 (80-100)	0.030 (0.028)
Cold SBR, oil masterbatch		
Dryer air temperature	66-93 (150-200)	1.15 (1.09)
Oil emulsion holding tank	27-38 (80-100)	0.095 (0.090)
Cellulosic man-made fibers - 2823		
Polyester	<288 (<550)	51.6 (48.9)
Nylon	<279 (<535)	44.0 (41.7)
Acrylic	<121 (<250)	24.8 (23.5)
Polypropylene	<282 (<540)	4.1 (3.9)
Noncellulosic fibers - 2824		
Rayon	<100 (<212)	39.9 (37.8)
Acetate	<100 (<212)	39.7 (37.6)
Pharmaceutical preparations - 2834		
Autoclaving and cleanup	121 (250)	19.88 (18.85)
Tablet and dry-capsule drying	121 (250)	1.05 (1.00)
Wet capsule formation	66 (150)	0.05 (0.05)

Table 1 (continued)

Industry — SIC group	Application temperature requirement [°C (°F)]	Process heat used for application [10 ¹² kJ/year (10 ¹² Btu/year)]
Soaps and detergents — 2841		
Soaps		
Various processes in soap manufacture	82 (180)	0.53 (0.50)
High-temperature processes	254 (490) ^a	0.002 (0.002)
Spray drying	260 (500) ^a	0.001 (0.001)
Detergents		
Various low-temperature processes	82 (180)	0.38 (0.36)
High-temperature processes	260 (500) ^a	0.001 (0.001)
Drum-dried detergents	177 (350) ^a	0.33 (0.31)
Spray-dried detergents	260 (500) ^a	0.020 (0.019)
Organic chemicals, N.E.C. — 2869		
Ethanol	93-121 (200-250)	6 (6)
Isopropanol	93-177 (200-350)	12 (11)
Cumene	121 (250)	1 (1)
Vinyl chloride monomer	121-177 (250-350)	9 (9)
Urea — 2873215		
High-pressure steam-heated stripper	191 (375)	5.35 (5.07)
Low-pressure steam-heated stripper	143 (290)	0.94 (0.89)
Explosives — 2892		
Dope (inert ingredients)		
Drying	149 (300)	0.006 (0.006)
Wax melting	93 (200)	0.124 (0.118)
Nitric acid concentrator	121 (250)	0.074 (0.070)
Sulfuric acid concentrator	93 (200)	0.028 (0.027)
Nitric acid plant	93 (200)	0.235 (0.223)
Blasting cap manufacture	93 (200)	0.017 (0.016)
Petroleum refining — 2911		
Crude distillation		
Atmospheric topping	343 (650)	290 (275)
Vacuum distillation	227-427 (440-800)	193 (183)
Thermal operations	291-543 (555-1010)	162 (154)
Catalytic cracking	607 (1125)	471 (447)
Delayed coking	482 (900)	237 (225)
Hydrocracking	268-432 (515-810)	96 (91)
Catalytic reforming	496 (925)	525 (498)
Catalytic hydrotreating	371 (700)	55 (52)
Hydrotreating	371 (700)	131 (124)
Alkylation	7-171 (45-340)	62 (59)
Hydrogen plant	871 (1600)	131 (124)
Olefins and aromatics	649 (1200)	131 (124)
Lubricants	Unavailable	26 (25)
Asphalt	Unavailable	101 (96)
Butadiene	121-177 (250-350)	63 (60)
Paving mixtures — 2951		
Aggregate drying	153-163 (275-325) ^a	92.9 (88.1)
Heating asphalt	163 (325)	5.20 (4.93)
Asphalt felts and coatings — 2952		
Saturator	204-260 (400-500)	1.60 (1.52)
Asphalt coating	149-204 (300-400)	1.30 (1.23)
Drying (steam)	177 (350)	3.50 (3.32)
Sealant	149-204 (300-400)	0.60 (0.57)
Tires and inner tubes — 3011		
Vulcanization	121-171 (250-340)	6.52 (6.18)

Table 1 (continued)

Industry - SIC group	Application temperature requirement [°C (°F)]	Process heat used for application [10 ¹² kJ/year (10 ¹² Btu/year)]
Plastics products - 3079		
Blow-molded bottles		
High-density polyethylene	218 (425)	3.71 (3.52)
Leather tanning and finishing - 3111		
Bating	32 (90)	0.099 (0.094)
Chrome tanning	29-54 (85-130)	0.063 (0.060)
Retan, dyeing, fat liquor	49-60 (120-140)	0.16 (0.15)
Wash	49 (120)	0.036 (0.034)
Drying	43 (110) ^a	2.16 (2.05)
Finishing drying	43 (110) ^a	0.14 (0.13)
Flat glass - 3211		
Melting	1260-1482 (2300-2700)	52.8 (50.1)
Fabrication (including temper- ing and laminating)	799-1093 (1470-2000)	3.7 (3.5)
Annealing	499 (930)	6.2 (5.9)
Glass containers - 3221		
Melting-firing	1482-1593 (2700-2900)	104.0 (98.60)
Conditioning	816-1093 (1500-2000)	44.56 (42.25)
Annealing	649 (1200)	13.51 (12.81)
Post forming	649 (1200)	1.50 (1.42)
Hydraulic cement - 3241		
Drying	135-163 (275-325) ^a	8 (8.0)
Calcining	1260-1482 (2300-2700)	494 (468.0)
Brick and structural tile - 3251		
Brick kiln	1371 (2500)	74.2 (70.4)
Clay refractories - 3255		
Refractories firing	1816 (3300)	9.5 (9.0)
Concrete block - 3271		
Low-pressure curing	74 (165) ^a	12.96 (12.29)
Autoclaving	182 (360)	5.72 (5.42)
Ready-mix concrete - 3273		
Hot water for mixing concrete	49-88 (120-190)	0.36 (0.34)
Lime - 3274		
Calcining	982 (1800)	137.0 (129.9)
Gypsum - 3275		
Kettle calcining	166 (330)	10.5 (10.0)
Wallboard drying	149 (300)	11.79 (11.18)
Treated minerals - 3295		
Expanded clay and shale		
Bloating process	982 (1800)	30.7 (29.1)
Fuller's earth		
Drying and calcining	593 (1100)	6.72 (6.37)
Kaolin		
Calcining	1040 (1900)	1.5 (1.4)
Drying	110 (230) ^a	13.4 (12.7)
Expanded perlite		
Drying	71 (160) ^a	0.23 (0.22)
Expansion process	871 (1600)	1.8 (1.7)
Barium		
Drying	110 (230) ^a	0.36 (0.34)
Blast furnaces and steel mills - 3312		
High-temperature uses	1482 (2700)	3480 (3300)

Table 1 (continued)

Industry — SIC group	Application temperature requirement [°C (°F)]	Process heat used for application [10 ¹² kJ/year (10 ¹² Btu/year)]
Ferrous castings		
Gray iron foundries — 3321 (73% of heat)		
Malleable iron foundries — 3322 (10% of heat)		
Steel foundries — 3323 (17% of heat)		
Melting in cupola furnaces	1482 (2700)	154 (146)
Mold and core preparation	149–246 (300–475)	124.1 (117.7)
Heat treatment and finishing	482–982 (900–1800)	17 (16)
Pickling	38–100 (100–212)	160 (151)
Primary copper — 3331		
Smelting and fire-refining	1095–1371 (2000–2500)	34.37 (32.58)
Primary zinc — 3333		
Pyrolytic reduction	1300 (2400)	1.1 (1.0)
Primary aluminum — 3334		
Prebaking anodes	1093 (2000)	8.59 (8.14)
Galvanizing — 3479		
Cleaning, pickling	54–88 (130–190)	0.012 (0.011)
Galvanizing (melting zinc)	454 (850)	0.015 (0.014)
Motors and generators — 3621		
Drying and preheat	66 (150)	0.045 (0.043)
Baking	177 (350)	0.140 (0.133)
Oxide coat laminations	816–927 (1500–1700)	0.76 (0.72)
Annealing	816 (1500)	0.71 (0.67)
Motor vehicles — 3711		
Baking — prime and paint ovens	121–149 (250–300)	0.31 (0.29)
Casting foundry	1454 (2650)	24 (23)
Inorganic pigments — 2816		
Drying chrome yellow	93 (200)	0.079 (0.075)

^aNo special temperature required; requirement is simply to evaporate water or to dry the material.

Source: Intertechnology Corporation, *Analysis of the Economic Potential of Solar Thermal Energy to Provide Industrial Process Heat, Vol. 1, Final Report*, C0028-1 (NTIS C002829/1) (February 1977).

Table 2. Summary of process heat requirements, 10¹² kJ (10¹² Btu/year), 1974

SIC code	Description	Hot water [<100°C (<212°F)]	Steam		Direct heat/hot air			Rounded total
			[100-177°C (212-350°F)]	[>177°C (>350°F)]	[<100°C (<212°F)]	[100-177°C (212-350°F)]	[>177°C (>350°F)]	
1211	Bituminous coal and lignite						11.6 (11)	11.6 (11)
1477	Sulfur mining		46.4 (44)					46.4 (44)
20	Food and kindred products	53 (60)	290 (275)	105.5 (100)	10.6 (10)	100.2 (95)	15.8 (15)	586 (555)
22	Textile mill products	20 (19)	202 (191)	4.2 (4)		72.8 (69)	13.7 (13)	312 (296)
24	Lumber and wood products	5.3 (5)	22.2 (21)	4.2 (4)	111.8 (106)	4.2 (4)	73.9 (70)	222 (210)
26	Paper and allied products		491 (465)				99.2 (94)	590 (559)
28	Chemicals		1477 (1400)			475 (450)	264 (250)	2216 (2100)
2911	Petroleum refining		126.6 (120)	401 (308)			2743 (2600)	3271 (3100)
32	Stone, clay, and glass	8.4 (8)	21.1 (20)	39.0 (37)		25.3 (24)	1140 (1081)	1234 (1170)
3312	Blast furnaces and steel mills		68.6 (65)				1806 (1712)	1875 (1777)
3331	Primary copper	15.0 (14.2)			2.5 (2.4)		58.5 (55.4)	76.0 (72)
3334	Primary aluminum			40.5 (38.4)			66.6 (63.1)	108 (102)
3711 } 3712 } 3713 }	Automobile and truck manufacturing	13.7 (13)	1.5 (1.4)		22.5 (21.3)	10.6 (10)	1.0 (0.9)	49.6 (47)
	Rounded total	126.6 (120)	2743 (2600)	594 (563)	148 (140)	688 (652)	6293 (5965)	10,592 (10,040)
	Percent of total	1.2	25.9	5.6	1.4	6.5	59.4	

Source: *Survey of the Applications of Solar Thermal Energy Systems to Industrial Process Heating, Vol. 2, Industrial Process Heat Survey*, TID 27348/2, Battelle Laboratories (January 1977).

Internal Distribution

1. T. D. Anderson	51. J. O. Kolb
2. S. J. Ball	52. R. E. Kuhlmann
3. Seymour Baron	53. M. E. Lackey
4. M. Bender	54. Milton Levenson
5. W. J. Boegly, Jr.	55. R. E. MacPherson
6. J. R. Buchanan	56-60. L. E. McNeese
7. R. S. Carlsmith	61. J. T. Meador
8. D. A. Casada	62. W. R. Mixon
9. J. E. Christian	63. F. R. Mynatt
10. R. G. Chenoweth, Jr.	64. L. F. Parsly
11. J. A. Conlin	65. S. A. Reed
12. F. L. Culler	66. J. L. Rich
13. J. H. DeVan	67. M. W. Rosenthal
14. H. L. Falkenberry	68. G. Samuels
15. M. H. Fontana	69. M. J. Skinner
16. E. C. Fox	70. C. B. Smith
17. A. P. Fraas (Consultant)	71. I. Spiewak
18. W. Fulkerson	72-76. J. R. Tallackson
19. L. C. Fuller	77. J. F. Thomas
20. R. E. Gant	78. H. E. Trammell
21-30. R. L. Graves	79. D. B. Trauger
31. W. L. Greenstreet	80. J. J. Tudor
32. M. P. Guthrie	81. M. E. Whatley
33. R. H. Guymon	82. J. S. White
34. J. F. Harvey	83. G. P. Zimmerman
35. E. C. Hise	84. Biology Library
36. R. S. Holcomb	85. Emergency Technology Library
37. J. M. Holmes	86. MIT Practice School
38. H. Inouye	87-88. Central Research Library
39-48. J. E. Jones	89. Y-12 Document Reference Section
49. M. A. Karnitz	90-93. Laboratory Records Department
50. O. H. Klepper	94. Laboratory Records, RC

External Distribution

95. R. N. Abrams, VP, Gilbert Associates, Inc., P.O. Box 1498, Reading, PA 19603
96. Seymour Alpert, Manager, Process Development Fossil Fuel Department, Electric Power Research Institute, 3412 Hillview Avenue, P.O. Box 10412, Palo Alto, CA 94304
97. James W. Babcock, United Technologies Corporation, Power Systems Division, P.O. Box 109, South Windsor, CT 06074
98. R. C. Balfour, Balfour Lumber Company, Thomasville, GA 31792

- 99-101. J. V. Basilico, Office of Research and Development, Environmental Protection Agency, Air, Land and Water Use, Waste Management Division, Room 3817-A, Washington, DC 20460
- 102-104. Harold Benson, Mail Code EZ, Urban Systems Project Office, Johnson Space Center, National Aeronautics & Space Administration, Houston, TX 77058
- 105. S. D. Berwager, FEA/DOE, Office of Program Development, Room 206, Old Office Building, Washington, DC 20461
- 106. W. C. Best, U.S. Army Facilities Engineering Support Group, Attention: FEFA-RTD, Fort Belvoir, VA 22060
- 107. Harold Beuther, Manager, Catalyst and Chemicals Research, Gulf Research and Development Company, P.O. Box 2038, Pittsburgh, PA 15230
- 108. S. B. Bram, Consolidated Edison Company of N.Y., 4 Irving Place, New York, NY 10003
- 109. T. T. Bramlette, Sandia Laboratories 8451, Livermore, CA 94550
- 110. R. D. Brooks, General Electric Company, K-1 Combustion Building, P.O. Box 8, Schenectady, NY 12301
- 111. Wilson Cadman, Kansas Gas & Electric Company, 201 N. Market St., Wichita, KS 76201
- 112. T. R. Casberg, Staff Mechanical Engineer, Directorate of Construction Standards and Design, Office of the Deputy Assistant, Secretary of Defense (Installation and Housing), The Pentagon, Washington, DC 20301
- 113. Steve Cavros, Office of Conservation, Department of Energy, Washington, DC 20545
- 114. A. T. Christensen, Manager - Program Development, General Electric, 777 14th St., NW, Washington, DC 20005
- 115. R. A. Chronowski, Aqua-Chem Inc., Cleaver Brooks Division, P.O. Box 421, Milwaukee, WI 53200
- 116. E. L. Daman, VP, Foster Wheeler Corp., 110 South Orange Avenue, Livingston, NJ 07039
- 117. F. R. DeSanti, General Manager - Marketing, Public Service Electric and Gas Company, 80 Park Place, Newark, NJ 07101
- 118. J. F. Dinwiddie, Office of Fossil Energy, Department of Energy, 20 Massachusetts Avenue, N.W., Washington, D.C. 20545
- 119. L. J. Dugas, Division VP, Commonwealth Edison Company, 7601 S. Lawndale Ave., Chicago, IL 60652
- 120. P. A. Duker, VP, Customer and Marketing Policy, Detroit Edison Company, 2000 Second Avenue, Detroit, MI 48226
- 121. John Eilering, VP, Commonwealth Edison Company, P.O. Box 767, Chicago, IL 60690
- 122. Engineering Library, University of Tennessee, Knoxville, TN 37916
- 123. S. I. Freedman, Fossil Fuel Utilization, Department of Energy, Germantown Mail Stop E178, Washington, DC 20545
- 124. D. A. Furlong, VP, Combustion Power Company, Inc., 1346 Willow Road, Menlo Park, CA 94025
- 125-127. R. J. Gallina, Supervisor Consumer Services, Baltimore Gas and Electric Company, 1508 Woodlawn Drive, Baltimore, MD 21207
- 128. R. L. Gamble, Foster-Wheeler Energy Corporation, 110 South Orange Avenue, Livingston, NJ 07039

129. C. D. Glass, VP, Gulf States Utility Company, P.O. Box 2951, Beaumont, TX 77704
130. Martin Gutstein, Special Projects Branch, Lewis Research Center, National Aeronautics and Space Administration, Cleveland, OH 44135
131. John Hamrick, VP, Marketing, San Diego Gas and Electric Company, P.O. Box 1831, San Diego, CA 92112
132. J. R. Hoffmann, HQDA (DAEN-FEP), Washington, DC 20314
133. J. S. Holdhusen, Fluidyne Engineering Corporation, 5900 Olson Memorial Highway, Minneapolis, MN 55422
134. H. L. Jaeger, Westinghouse Electric Corporation, Long Range Development, Combustion Turbine Systems Division, Lester Branch, Box 9175, Philadelphia, PA 19113
135. A. A. Jonke, Chemical Engineering Division, Argonne National Laboratory, 9700 South Cass Avenue, Argonne, IL 60439
136. J. R. Kaye, Union Electric Company, 1901 Gratiot Street, P.O. Box 149, St. Louis, MO 63166
137. J. H. Kleinau, VP, Copeland Systems, Inc., 708 Enterprise Drive, Oak Brook, IL 60521
138. H. Landsberg, Co-Director, Energy & Materials Division, Resources for the Future, 1755 Massachusetts Avenue, NW, Washington, DC 20036
139. R. I. LaRock, NASA Headquarters, Mail Code NT, 600 Independence Avenue, Washington, DC 20546
140. G. S. Leighton, Office of Conservation, Department of Energy, 1016 16th Street, NW, Washington, DC 20545
141. Albert M. Leon, Dorr-Oliver, Inc., 77 Haremeyer Lane, Stamford, CT 06904
142. G. L. Linsteadt, Head, Technology Utilization Office, Department of the Navy, Naval Weapons Center, China Lake, CA 93555
143. Eric Lister, Railway Labor Building, 400 1st Street, Mail Stop 4128, Washington, DC 20545
144. Valmore Loisell, Jr., Combustion Engineering, Inc., C-E Power Systems, 1000 Prospect Hill Road, Windsor, CT 06095
- 145-147. G. H. Lovin, Edison Electric Institute, 1140 Connecticut Avenue, NW, Washington, DC 20036
148. Rene H. Males, Director, Energy Analysis and Environment Division, Electric Power Research Institute, 3412 Hillview Avenue, P.O. Box 10412, Palo Alto, CA 94303
- 149-151. H. H. Maschke, Department of Defense, HQDA (DAEN-MCE-U), Washington, DC 20314
152. J. L. Mason, VP - Engineering, The Garrett Corp., 9851-9951 Sepulveda Blvd., Los Angeles, CA 90009
- 153-177. Mathematica, Inc., c/o N. R. Friedman, Suite 2970, 475 L'Enfant Plaza West, SW, Washington, DC 20024
178. S. Moskowitz, Curtiss-Wright Corporation, One Passaic Street, Woodridge, NJ 07075
179. E. A. Myers, c/o Southern California Edison Company, 224 Walnut Grove Ave., Rosemead, CA 91770
180. Leon Nonemaker, Pennsylvania Power & Light Company, Two North Ninth Street, Allentown, PA 18101

- 181-183. M. H. Novinsky, Office of Planning and Development, Department of HEW — OFEPM — Room 504, 330 Independence Ave., SW, Washington, DC 20201
- 184. Ruth Perks, Department of Energy, Washington, DC 20545
- 185-194. C. W. Phillips, National Bureau of Standards, Room A146, Bldg. 225, Washington, DC 20234
- 195. David Pilati, Brookhaven National Laboratory, Bldg. 475, Upton, NY 11973
- 196. Mike Prior, IAEA Coal Research, 14/15 Lower Grosvenor Place, London SW1W OEX, England
- 197. R. H. Roberts, Pullman Kellogg, Division of Kellogg Inc., Research and Development Center, 16200 Park Row, Industrial Park Ten, Houston, TX 77084
- 198-207. J. H. Rothenberg, HUD-MIUS Program Manager, Department of Housing and Urban Development, 451 7th St., SW, Rm 8158, Washington, DC 20410
- 208-232. W. N. Saunders, Fossil Fuel Utilization, Department of Energy, Germantown Mail Stop E178, Washington, DC 20545
- 233. L. A. Schmidt, CEA Combustion, Inc., 61 Taylor Reed Place, Stamford, CT 06906
- 234. Marion Semchyshen, Director of Research, Materials Research for Molybdenum Development, Climax Molybdenum Research Laboratory, P.O. Box 1568, Ann Arbor, MI 48106
- 235. E. G. Sharp, Mitre Corp., 1820 Dolly Madison Blvd., McLean, VA 22101
- 236. J. Sherman, Department of Housing and Urban Development, 451 7th Street, SW, Room 8158, Washington, DC 20410
- 237. A. R. Siegel, Director, Division on Community Development Research, Department of Housing and Urban Development, 451 7th Street, SW, Room 8162, Washington, DC 20410
- 238. R. D. Smith, Combustion Power Company, 1346 Willow Park, Menlo Park, CA 94025
- 239. H. W. Sternberg, Consultant, 1100 Ptarmigan Drive, No. 6, Walnut Creek, CA 94595
- 240. Carl Streed, Process Research and Development Division, Mobil Research and Development Corporation, Billingsport Road, Paulsboro, NJ 08066
- 241. Don Sykora, Gen. Manager, Marketing, Houston Lighting and Power Company, P.O. Box 1700, Houston, TX 77001
- 242. L. D. Taylor, Professor of Economics, University of Arizona, Tucson, AZ 85721
- 243. Norman Taylor, Supervisor, Gas & Steam Meter Engineering Unit, Baltimore Gas and Electric Company, 300 Front Street Building, P.O. Box 1475, Baltimore, MD 21203
- 244. U.S. Army Engineer Research and Development Laboratories, Library, Fort Belvoir, VA 22060
- 245. U.S. Naval Civil Engineering Laboratories, Library, Port Hueneme, CA 93041
- 246. F. R. White, AiResearch Manufacturing Company of California, Garrett Corporation, P.O. Box 3413, Oak Ridge, TN 37830

- 247. McCauly Whiting, Consultant, Dow Chemical Company, 2020 Dow Center, Midland, MI 48640
- 248. B. A. Wolfe, Babcock & Wilcox Company, Contract Research Division, P.O. Box 835, Alliance, OH 44601
- 249. L. L. Radcliffe, DOE, ORO
- 250. Office of Assistant Manager, Energy Research and Development, Department of Energy, ORO
- 251-503. Given distribution as shown in TID-4500 under category UC-90e, Coal Conversion and Utilization - Direct Combustion of Coal (25 copies - NTIS)