GAS-COOLED REACTOR ASSOCIATES

INDUSTRIAL PROCESS-HEAT MARKET ASSESSMENT

PREPARED UNDER CONTRACT DE-AC03-78SF02034
FOR THE SAN FRANCISCO OPERATIONS OFFICE
DEPARTMENT OF ENERGY

NOTICE

PORTIONS OF THIS REPORT ARE ILLEGIBLE.

**It has been reproduced from the best
available copy to permit the broadest
possible availability.**

OCTOBER 1981

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.

The following pages are an exact
representation of what is in the original
document folder.

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.

DOE/SF/02034--T45

DOE/SF/02034--T45

DE82 007227

INDUSTRIAL PROCESS-HEAT MARKET ASSESSMENT

Stuart Bresnick

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.

December 1981

Gas-Cooled Reactor Associates
3344 N. Torrey Pines Court, Suite 300
La Jolla, California 92037

CP
DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

TABLE OF CONTENTS

	<u>PAGE</u>
1.0 <u>INTRODUCTION</u>	1-1
1.1 Purpose	1-1
1.2 Structure of Report	1-2
1.3 Market Type and HTGR Designs	1-3
2.0 <u>CURRENT MARKET DATA</u>	2-1
2.1 Data Description	2-1
2.2 Sources of Data	2-7
2.2.1 Census of Manufactures	2-8
2.2.2 Energy Information Administration	2-8
2.2.3 Energy and Environmental Analysis	2-9
2.2.4 General Energy Associates	2-10
2.2.5 Oak Ridge Associated Universities	2-11
2.2.6 Dow Chemical Co.	2-12
2.2.7 Battelle Columbus Laboratory	2-12
2.2.8 Intertechnology Corporation	2-13
2.2.9 Mellon Institute - Energy Productivity Center	2-13
2.2.10 Data Resources, Inc.	2-14
2.3 Data Source Selection	2-14
2.4 Industrial Energy Use Data	2-15
2.4.1 Aggregate Data	2-15
2.4.2 Distribution by Fuel Type	2-17
2.4.3 Distribution by Service Demand	2-17
2.4.4 Distribution by Temperature and Heat Media	2-20
2.4.5 Distribution by Manufacturing Plant Size	2-20
2.5 Conclusions - Market Profile	2-27

Table of Contents
(Continued)

	<u>Page</u>
3.0 <u>PROJECTED MARKET DATA</u>	3-1
3.1 Sources of Forecasts	3-1
3.2 Forecast Source Selection	3-4
3.3 Forecast Data	3-4
3.3.1 EIA Forecasts	3-4
3.3.2 DRI Forecasts	3-10
3.3.3 Comparison of DRI & EIA	3-14
3.4 Forecast Summary	3-18
3.5 New Markets	3-19
4.0 <u>COGENERATION</u>	4-1
4.1 Nuclear Cogeneration Experience	4-3
4.1.1 Bruce Nuclear Power Development	4-3
4.1.2 Midland Nuclear Cogeneration Plant	4-14
4.2 Fossil Cogeneration Experience	4-24
4.2.1 Introduction	4-24
4.2.2 Experience/Case Studies	4-25
4.3 Projected Growth of Cogeneration	4-37
4.3.1 EIA Forecast	4-38
4.3.2 GEA Cogeneration Project	4-40
4.3.3 RPA Cogeneration Project	4-40
4.4 District Heating	4-50
4.4.1 Experience & Prognosis-U.S.	4-50
4.2.2 Experience & Prognosis-Europe	4-52

Table of Contents
(Continued)

	<u>Page</u>
5.0 <u>INSTITUTIONAL FRAMEWORK FOR COGENERATION AND PROCESS HEAT</u>	5-1
5.1 Federal Regulations	5-2
5.1.1 National Energy Act - 1978	5-2
5.1.2 Crude Oil Windfall Profit Tax Act - 1980	5-7
5.1.3 Powerplant & Industrial Fuel Use Act 1978	5-7
5.2 Current Activity - PURPA	5-7
5.3 Utility Perspective	5-13
5.3.1 General	5-13
5.3.2 Edison Electric Institute	5-16
5.3.3 Consolidated Edison	5-17
5.3.4 Southern California Edison	5-18
6.0 <u>FINANCIAL CONSIDERATION</u>	6-1
6.1 Cogeneration Economics	6-1
6.2 Financing Cogeneration Projects	6-4
6.2.1 Regulatory Impact	6-4
6.2.2 Financial Arrangements & Considerations	6-5
7.0 <u>HTGR SYSTEMS FOR PROCESS HEAT - HTGR-SC/C</u>	7-1
7.1 Design Description	7-1
7.2 Market Identification	7-7
7.3 Cost	7-9
8.0 <u>HTGR SYSTEMS FOR PROCESS HEAT - HTGR-SETS</u>	8-1
8.1 Design Description	8-1
8.2 Market Identification	8-9
8.3 Cost	8-10

Table of Contents
(Continued)

	<u>Page</u>
9.0 <u>HTGR SYSTEMS FOR PROCESS HEAT - HTGR-R</u>	9-1
9.1 Design Description	9-1
9.2 Market Identification	9-5
9.3 Cost	9-6

APPENDIXES

Appendix A - Industrial Process Energy Profile of 28 Utilities

Appendix B - GEA List of Plants Requiring More Than 500 MW Thermal Energy

TABLES

		<u>Page</u>
2.1-1	Fuel & Energy Consumption - 1980	2-3
2.1-2	Fuel & Energy Consumption - 1978	2-4
2.1-3	Energy Consumption Industrial Sector - 1974	2-5
2.1-4	Industrial Fuel Consumption by Fuel Type & Service Demand	2-6
2.4.1-1	Energy Consumption Historical Data	2-16
2.4.1-2	Industrial Fossil Energy Consumption - 1980	2-18
2.4.2-1	Industrial Fuel Consumption - Fuel Type as % of Total	2-19
2.4.4-1	Manufacturing Process Energy Requirements as Output of Boilers and Furnaces	2-21
2.4.4-2	Manufacturing Process Energy Use - 28 Utilities	2-22
2.4.5-1	Process Energy Use by Manufacturing Plant Thermal Demand	2-24
2.4.5-2	On-Site Electric Generation by Large Plants	2-25
2.4.5-3	Profile of Fuel Type For Process Energy & On-Site Generation	2-26
3.1-1	Forecast Comparisons for the Year 2000	3-2
3.3.1-1	End-Use Fuel Consumption - EIA Forecast	3-5
3.3.1-2	Energy Consumption - EIA Forecast	3-7
3.3.1-3	Industrial Fuel Use by Service Demand - EIA Forecast	3-8
3.3.1-4	Industrial End-Use Fuel Consumption by Fuel Type	3-11
3.3.2-1	U.S. Energy Demand - DRI Forecast	3-13
3.3.3-1	Energy Forecast for Year 2000 - DRI/EIA Comparison	3-17
3.5-1	Synthetic & Enhanced Recovery Fuel Forecasts	3-20

TABLES

		<u>Page</u>
4.1.1-1	Energy Requirements of Industries Interested in Locating at Bruce Station	4-5
4.2.2-1	Inventory of Known Cogenerators	4-26
4.2.2-2	EPRI Cogeneration Case Studies	4-31
4.2.2-3	Examples of Cogeneration Facilities	4-32
4.3.1-1	EIA Projections of Cogeneration	4-39
5.2-1	States' Cogeneration Rate-Setting Under PURPA	5-8
7.3.1	1170 MW(t) Cost Comparison	7-10
7.3.2	2240 MW(t) Cost Comparison	7-11

FIGURES

	<u>Page</u>
3.3.1-1 Industrial Fuel Use By Service Demand - EIA Forecast	3-9
3.3.1-2 Industrial Fuel Use by Fuel Type - EIA Forecast	3-12
3.3.2-1 U.S. Energy Demand-DRI Forecast	3-15
3.3.2-2 Industrial Energy Demand - DRI Forecast	3-16
4.0-1 Cogeneration - Typical Example	4-2
4.1.1.2-1 BNPD Bulk Steam System Energy Flow Diagram	4-8
4.1.1.2-2 Industrial Steam Supply from Bruce Station	4-9
4.1.2.2-1 General Plant Flow Sheet Arrangement for Twin-Unit Nuclear Cogeneration Plant at Midland, Michigan	4-18
4.1.2.3-1 Comparison of Midland Cogeneration (Dual-Purpose) Plant and Conventional Power Only Plant	4-22
4.1.2.3-2 Midland Unit 1 Electric Power Output and Net Core Heat Rate as a Function of Process Steam Flow to Dow	4-23
4.2.2-1 Lake Charles Project Annual Energy Purchases	4-35
4.2.2-2 Lake Charles Project Energy Conservation	4-36
4.3.3-1 Total Steam Demand & Technical Potential For Cogeneration	4-41
4.3.3-2 Expected 5 - Industry Cogeneration Development: 1981 - 1990	4-43
4.3.3-3 Cogenerated Steam Capacity by Industry: 1981 - 1990	4-44
4.3.3-4 Cogenerated Electric Power Development by Industry: 1981 - 1990	4-45
4.3.3-5 Expected Additional Cogeneration Capacity by Industry and Technology: 1981 - 1990	4-46
4.3.3-6 Net National Energy Savings By Fuel in 1990 from 5- Industry Cogeneration Installed From 1981 - 1990	4-47
4.3.3-7 Net Energy Savings By Time Period From 5- Industry Cogeneration Installed from 1981-1990	4-48
5.1.1.1-1 Requirements for Qualifying Facilities Under PURPA 201 & Order #70	5-4

FIGURES

Page

6.1-1	Cogeneration Joint Product Cost Curve	6-2
7.1.1-1	HTGR SC/C Plant	7-2
7.1.1-2	1170 - MW(t) HTGR SC/C Plant Heat Balance Diagram	7-3
7.1.1-3	Cutaway View of HTGR 1170 MW(t) NSSS System	7-5
7.1.4-1	Summary Schedule - HTGR SC/C Lead Plant	7-8
8.1-1	Indirect HTGR - Sensible Energy Transport & Storage Plant	8-3
8.1.5-1	Typical Molten Salt SETS System	8-7
8.1.6-1	Energy Balance for Multi-Purpose Cogeneration Application of the HTGR - SETS	8-8
9.1-1	HTGR-R Flow Diagram	9-2
9.1-2	TCP Concept	9-4

1.0 INTRODUCTION

The High-Temperature Gas-Cooled Reactor (HTGR) is unique among current reactor technologies in its ability to generate nuclear-derived energy in temperature regimes previously limited to fossil fuels. As a result, the HTGR can offer unique national and commercial benefits in the production of electricity and in expanding the role of nuclear energy to the production of process heat. Operating in the lower region of temperature capability ($<1300^{\circ}\text{F}/700^{\circ}\text{C}$), the HTGR can be used to generate high-quality steam at conditions equivalent to those produced by conventional fossil-fired steam boilers. This high-energy steam may be used with a conventional turbine generator power conversion system to realize the highest net Rankine cycle thermal efficiency of any current nuclear or fossil system. It may also be used in a topping cogeneration heat cycle to produce both electricity and process steam. Here again, the high quality steam is attractive since more electricity can be generated per unit of net process heat, and the resulting steam conditions are typical of those produced by modern industrial fossil-fired boilers. In the upper range of temperature capability ($>700^{\circ}\text{C}$) an added potential exists for advanced HTGR systems. High temperature direct heat can be provided via molten salt or helium and, at temperatures above about 850°C , the reforming process can be used to produce synthesis gas for long range energy transport or as input to various chemical processes. Definition of HTGR plant designs for the above applications has been pursued during the past three years, and preliminary evaluations have shown substantial promise for near-term HTGR deployment.

1.1 Purpose

This report is designed to be a reference resource, giving a broad perspective of the potential HTGR market for industrial process heat. It is intended to serve as a briefing document for those wishing to obtain background information and also to serve as a starting point from which more detailed and refined studies may be undertaken.

In doing so, the report presents a qualitative and quantitative description of the industrial process heat market in the U. S., provides a summary discussion of cogeneration experience to date, and outlines the existing institutional and financial framework for cogeneration. The intent is to give the reader an understanding of the current situation and experience in this area. The cogeneration area in particular is an evolving one because of regulations and tax laws, which are still in the process of being developed and interpreted. The report presents the latest developments in regulatory and legislative activities which are associated with that technology.

Finally, the report presents a brief description of the three HTGR systems under study during the current fiscal year and describes the specific market characteristics which each application is designed to serve.

Throughout the report, an attempt has been made to provide extensive reference to all sources of information. Much of the information presented herein was summarized or extracted from these references. For a complete description of any specific area, the reader should consult the referenced source(s).

1.2 Structure of the Report

Section 1 of the report provides a description of the purpose and structure, and also gives an overview of the types of industrial markets and types of HTGR designs under consideration.

Section 2 presents qualitative and quantitative information on characterization of the industrial process heat market. Several data sources are reviewed, and market data are presented in formats considered to be the most useful.

Section 3 presents forecasts of energy use. Since the HTGR applications are being considered for the late 1990's and beyond, the current market data is of interest only as an indication of the probable characteristics of the future market. Section 3 presents forecasts of industrial energy demands in the time period of interest. The latest available forecasts were used, but forecasts tend to change with time, and so the data presented should be updated as required.

Sections 4, 5 and 6 address various aspects of the cogeneration market. Section 4 reviews current experience with industrial cogeneration in the U. S. and also briefly mentions the use of district heating. Section 5 addresses the controversial and active area of institutional factors/government regulations which affect cogeneration projects. This is an area which will have a dramatic effect on the rate of growth of cogeneration, depending on the interpretation and implementation of existing and new regulations. Finally, Section 6 addresses financial issues surrounding cogeneration - costs and benefits, and current financing arrangements for cogeneration projects.

Sections 7-9 present descriptions of each of the three HTGR applications under current consideration, with information on the market characteristic best served by each design. A general design description and design status is given, to serve as an overview and introduction.

References are presented at the end of each section. This is considered to be a critical part of the report to be used as a starting point for detailed investigations of specific areas of interest. An attempt was made to be selective to list only sources which are still current and of special value to the topics herein.

1.3 Market Types and HTGR Designs

The industrial energy market is not easily characterized without a considerable volume of information. This is due to the diversity of the market in terms of plant size, plant location, plant demand cycle, process energy demand, etc. In addition, the market uses all types of fossil fuel as well as electricity and renewable fuels such as wood and biomass. Thus, within the total industrial energy market, there are many sub-markets broken down by concentration of demand, capacity factor, temperature, etc.

Industrial energy is required for two basic purposes, either as feedstock or for fuel and power. Industrial energy used for fuel and power is required to generate heat which is either used directly in a process or to raise steam which has multiple uses in manufacturing (mechanical drive, process heat, process input, etc.). It is this use of energy (fuel and power) which is of interest to HTGR Applications. The HTGR can generate heat which can replace the heat generated by the use of fossil fuels, and thereby reduce dependence on imported oil and on the limited supply of domestic fuels.

Thus, in order to intelligently assess the potential of the HTGR to supply industrial process heat, a profile of the industrial energy market is required in fine enough detail to determine if the HTGR output is compatible with industrial needs at a competitive price.

Three HTGR applications are under current consideration to serve the industrial process heat market, the steam cycle cogeneration plant (SC/C), the sensible energy transport and storage system (SETS), and the reformer thermochemical pipeline (R-TCP).

The SC/C couples the HTGR nuclear heat source to the Rankine steam cycle to offer an attractive system which conserves water and nuclear fuel resources due to the high thermal efficiency of the system (>38% in an all-electric mode and 95% in the maximum cogeneration mode) and the efficiency of the HTGR fuel cycle. The 2240 MW(t) design produces high-quality cogenerated steam (650 psia, 672°F) at a maximum flow of 5.2×10^6 lb/hr, when generating 285 MW(e) of electricity. Proportions of electricity and process steam can be varied, so that the HTGR-SC/C can serve a large potential market that ranges from baseload electricity production to industrial process heat. In particular, the system is suited for cogeneration with central baseloaded industrial applications such as petroleum refining, enhanced oil recovery, and metal refining and synfuels. SC/C system will deliver a substantial flow of high-quality cogenerated steam, which is usually greater than the need of any single industrial plant. Thus, the SC/C must be sited to serve on existing markets with a high, concentrated demand, or be designed as the focal point of an industrial energy park. The latter approach would attract industry to locate facilities near the reliable supply of high-quality, low-cost steam.

The SETS concept is one approach to solving the problems of distributing energy from an HTGR source when the HTGR cannot be sited close enough to all users. The SETS concept employs a molten nitrate salt as a heat transport media to supply the energy to industrial users. The molten nitrate salt is heated to about 1075°F at the HTGR and pumped to a salt-to-steam generator or other heat exchanger at the user site. A recent study (see "Investigation of Domain of Applicability of Molten Salt Energy Transport System Coupled to a HTGR", GCRA, April 1981) concluded that the SETS concept would be bounded by:

- Minimum size of 1000 MW(t)
- Minimum distance of 5-10 miles (below this distance, steam can be used)
- Maximum distance of 30-50 miles
- Demand fluctuations with periods no longer than daily (storage becomes a problem with longer periods)

The SETS concept appears to have a limited range of applications, bounded by economic constraints to a rather narrow market.

A second approach to solving the energy distribution problem is the R-TCP. A detailed description of this design is presented in a GCRA report, "HTGR-Reformer Application Study," December 1980. In the reformer version of the HTGR, the high temperature capability of the reactor is used to reform a mixture of steam and methane (H_2O and CH_4) in the presence of a catalyst to form hydrogen and carbon monoxide (H_2 and CO). The heat absorbed in this reaction, as well as the process steam, is supplied by the HTGR. The reformer gas is a stable energy form which can be transported via pipelines to user sites, where heat can be released by the highly endothermic methanation reaction ($CO + 3H_2 = CH_4 + H_2O$). This application has been called the thermo-chemical pipeline (TCP). The high grade heat released at the methanator typically delivers 480°C/900°F steam at the user site. The methane and water are sent back to the reformer, thus completing the cycle.

The HTGR-R-TCP provides a method for using high-grade heat from an HTGR at sites which are dispersed and not close to the HTGR site. Pipeline distances are not restricted by the need to control heat loss since the thermal energy is not being transported in a sensible form as in the molten salt system.

2.0 CURRENT MARKET DATA

An analysis and profile for current energy demands is useful in assessing the make-up and magnitude of the potential market for HTGR applications. However, it must be remembered that this is the current market and is likely to change both in profile and magnitude in the time period relevant to HTGR applications. The current picture is useful as a starting point from which to apply projections of demand/supply, technological changes and other factors which would change the energy demand situation.

The purpose of this section is to identify and evaluate sources of information on industrial energy consumption, which can serve as a reference for the HTGR program and thereby provide a consistent information base for the evaluation of HTGR applications.

2.1 Energy Data Description

An essential consideration in using energy consumption data is to have a clear understanding of the basis of the data, and the assumptions and considerations used in generating the data. Merely taking data from one source and comparing it with other sources, or using the data without understanding the precise definition or how it was developed, can lead to erroneous and misleading conclusions. Thus, an attempt is made in this report to describe the basis of each data source, to carefully define all units and to highlight those areas which have significant impact on the data and which may make direct comparison with other data misleading.

In this report we are primarily interested in the consumption of energy by industry for the generation of process heat and steam. A definition of "industry" is necessary before data can be evaluated. Energy consumption is broken down into four major end-use sectors by the U.S. Energy Information Administration (EIA):

- Residential
 - Commercial
 - Transportation
 - Industrial
- } These two are frequently presented jointly as "Residential/Commercial."

The industrial sector includes manufacturing, construction, mining, and agriculture, which is more "industry" than is of interest to HTGR applications. It is only the manufacturing segment which is of interest to the HTGR program, and this segment accounts for most of the energy consumption in the industrial sector.

Table 2.1-1 illustrates the relative consumption of each of the sectors in 1980. Table 2.1-2 presents similar energy consumption data for 1978. These data are presented for reference purposes, since 1978 is the most recent year in which certain detailed information is available from DOE (Ref. 2 and 3), and such information will be used later in the report. Comparing Tables 2.1-1 and 2.1-2, it can be noted that energy consumption dropped approximately 2 1/2 percent from 1978 to 1980, and consumption by the industrial sector increased from approximately 37 percent of total consumption to approximately 40 percent of total consumption. However, as just pointed out, it is only the manufacturing industries that are of interest in the HTGR program.

Manufacturing is defined as Standard Industrial Classification (SIC) categories SIC 20-39, as listed in Table 2.1-3. This table also lists the relative energy consumption in 1974 for agriculture, mining, construction, and each manufacturing SIC code.

These data indicate that manufacturing accounts for about 80 percent of total energy consumption in the industrial sector. For purposes of this report, it will be assumed that this percentage continues to be representative of manufacturing's share of industrial energy consumption. Table 2.1-3 also shows that the major energy users in manufacturing are:

- Chemicals (SIC-28)
- Primary Metals (SIC-33)
- Petroleum (SIC-29)
- Paper (SIC-26)
- Stone, glass, etc. (SIC-32)

Energy consumption by manufacturing industries includes several forms of energy. Some of these are potentially replaceable by HTGR-produced heat, while others have either limited potential or no potential for replacement. The EIA classifies industrial energy consumption by service demand and fuel type as listed in Table 2.1-4. The service demands which are of interest are those which contribute to what is generally termed "process heat." From the EIA service demand categories in Table 2.1-4, this would include direct heat, indirect heat (steam), metallurgical coal (most of which is used as heat), and refinery, gas plant and field use (use of process streams as fuel in a plant). Thus, the service demands which contribute to "process heat" accounted for approximately 72% of all industrial energy consumption.

Table 2.1-1Fuel and Energy Consumption - 1980

(Ref. 1)

	<u>Fuel</u> (1)	<u>ENERGY</u>		
		<u>Without Electricity Distributed</u> (2)	<u>With Electricity Distributed</u> (3)	
			<u>Quads</u>	<u>% of Total</u>
Residential & Commercial	16.6 quads	12.2 quads	27.3	36
Transportation	18.6	18.6	18.6	24
Industrial	<u>23.5</u>	<u>20.6</u>	<u>30.3</u>	<u>40</u>
Total	58.7	51.4	76.2	100

(1)"Fuel" includes fossil energy and electricity, but does not include losses in electrical conversion and transmission.

(2)Fossil fuel only.

(3)Includes all energy used to generate the electricity consumed (i.e., conversion and transmission losses included).

Table 2.1-2Fuel and Energy Consumption - 1978

	<u>Fuel</u> (1) (Ref. 2)	<u>Without Electricity Distributed</u> (2)	<u>ENERGY</u> <u>Quads</u>	<u>(Ref. 3) With Electricity Distributed</u> (3) <u>% of Total</u>
Residential	11.5 quads	14.8 quads	28.9	37
Commercial	7.6			
Transportation	20.7	20.6	20.6	26
Industrial	<u>23.3</u>	<u>19.3</u>	<u>28.7</u>	<u>37</u>
Total	63.1	54.7	78.2	100

(1)"Fuel" includes fossil fuel and electricity, but does not include losses in electrical conversion and transmission.

(2)Fossil fuel only.

(3)Includes all energy used to generate the electricity consumed (i.e., conversion and transmission losses included).

Table 2.1-3Energy Consumption - Industrial Sector - 1974

<u>Industry</u>	<u>SIC Code</u>	<u>Energy Consumption - 1974 (Ref. 4) % of Total Industry</u>
Agriculture, etc.	1-9	5.6
Mining	10-14	7.5
Construction	15-17	7.1
Manufacturing:		
Food and Kindred Products	20	3.7
Tobacco	21	<0.1
Textiles	22	1.3
Apparel	23	0.3
Lumber	24	1.0
Furniture	25	0.2
*Paper	26	8.8
Printing and Publishing	27	0.3
*Chemicals	28	20.7
*Petroleum Refining	29	12.2
Rubber and Misc. Plastics	30	1.0
Leather	31	<0.1
*Stone, Clay, Glass, and Concrete	32	5.2
*Primary Metals	33	19.1
Fabricated Metals	34	1.6
Machinery	35	1.4
Electrical and Electronic Machinery	36	1.0
Transportation Equipment	37	1.5
Measuring Equipment	38	0.2
Misc. Manufacturing Industries	39	<u>0.2</u>
Subtotal Manufacturing		79.8

*Major Energy Users

Table 2.1-4

Industrial Fuel Consumption - By Fuel Type and Service Demand
(Ref. 2)

		<u>1978 Consumption</u>	
		<u>Quads</u>	<u>% of Total</u>
A. <u>Fuel Type</u>			
Coal		3.4	14.6
Electricity - Utility		2.7	11.6
Natural Gas		8.5	36.5
Light Oil		3.6	15.5
Heavy Fuel Oil		3.2	13.7
Lubes, Waxes		0.5	2.1
Biomass		<u>1.3</u>	<u>5.6</u>
TOTAL(3)		23.3	100.0
B. <u>Service Demand</u>			
Direct Heat ¹		3.8	16.2
Indirect Heat (Steam) ¹		6.5	27.8
Metallurgical Coal ¹		2.0	8.6
Refinery, Gas Plant and Field Use ¹		4.6	19.6
Electric Services ²		3.6	15.4
Feedstock		2.4	10.3
Lubes, Waxes		<u>0.5</u>	<u>2.1</u>
TOTAL ³		23.5	100.0

(1)Contributes to "process heat."

(2)This includes fuel used to generate on-site electricity, making the total fuel used to satisfy the demand for electric services greater than that listed under electricity in "A".

(3)Totals may not add due to independent rounding.

Assuming that relative usage among SIC codes remains fairly constant from year to year, then the fraction of industrial energy consumption (C) which can be addressed by HTGR process heat applications is $0.80 (0.72)(C)$ or approximately $0.58C$. Further, not all of this (manufacturing process heat) represents fuel sources which are economically replaceable (i.e., waste heat and use of otherwise worthless or very cheap fuels do not represent replaceable energy). This point should be considered when specific numbers for market potential are evaluated. Actual data were presented here merely to provide an example so the reader can appreciate the subtleties in data interpretation. When information is presented on "industrial energy," it generally includes all industry and all energy, which means that less than 58% of the energy is relevant to the HTGR market.

Finally, when using energy data, attention should be given to definitions of terms as follows:

- Energy vs. Fuel Consumption: "Fuel" usually considers electricity as a fuel and does not assign losses associated with generation and transmission to the user. "Energy" is usually used to include all energy consumed directly or indirectly (via losses) by the sector. Also, feedstocks are usually included in energy consumption. Thus, feedstock use must be subtracted from energy consumption to get energy used for heat and power.
- Energy Input vs. Process Requirements: For industrial applications, fuels are used to generate heat or provide feedstock for process applications. Because of losses inherent in the energy conversion steps, the energy value of the fuel input will be greater than the energy required by the process. Thus, attention should be paid to whether energy demand is presented as fuel consumption (energy input) or process requirements.

2.2 Sources of Data

A variety of sources is available which describe U.S. industrial energy requirements by various classifications such as end use, fuel type, temperature, geography, industry. Most of these sources are not primary data; they are either compilations of other sources or data developed by models based on use of primary data. On casual reading, different sources may appear to present conflicting information. However, care must be taken to carefully read and understand the basis of the data. If the sources used different assumptions or included different scopes in developing the data, this may account for apparent conflicts. Also, information presented may not permit a direct comparison among the various sets of data. Following is a description of several major sources of industrial energy use data, with summary explanations of information available from each source, the background and basis of the information, and an assessment

of value of the source to the HTGR program. If the reader is interested in using one of these sources, he should obtain the source document(s) and carefully read the descriptive information on how the data were developed. This will help ensure that data are not misinterpreted or misapplied. Indiscriminate application of data will likely lead to erroneous conclusions.

2.2.1 Census of Manufactures (COM)

The Department of Commerce conducts the COM every five years (the last one was taken in 1977). It covers all manufacturing industries (SIC 20-39) with ten or more employees (approximately 300,000 establishments). The census provides basic industry statistics, including information on purchased fuels and electrical energy, and self-generated electricity minus the amount sold. Thus, it does not report fuels not purchased, which can be significant in industries such as steel, petroleum, chemicals, and paper. Between census years, the Annual Survey of Manufactures (ASM) is conducted. This includes all establishments with greater than 250 employees and a sampling of smaller establishments, for a total of about 70,000 establishments. There is a considerable lag between the census or survey year and the time of data publication. The last COM was conducted in 1977 and was published in 1980. The latest available ASM was conducted in 1978 and published in 1981.

The COM and ASM information is used as a source for many of the studies on industrial energy consumption, as it appears to be the most reliable and representative primary data available on actual consumption. However, it must be remembered that this data source covers only purchased fuels and electrical energy.

2.2.2 Energy Information Administration (EIA)

EIA, which is a part of the Department of Energy, is a significant and valuable source of data on energy use. Information from EIA is available through special publications, periodic reports, or direct contact with the appropriate office. The major reports of interest to the HTGR program are:

- Annual Report to Congress (ARC) - The ARC is a three-volume report published each year. Volume I discusses responsibilities and accomplishments of each EIA component and provides general information on data gathering and other reports. Volume II provides historical data on energy statistics. Volume III gives projections on energy supply, demand, and prices.
- Monthly Energy Review (MER) - The MER is a monthly periodical which reports latest statistical data and developments in energy.

The EIA information is very useful at the aggregate levels, but it does not provide detailed breakdowns required for HTGR applications studies. The EIA reports provide data on industrial energy use by fuel type and by service demand. Tables 2.1-2 and 2.1-4 have presented typical data from the 1980 ARC. EIA data come from a variety of federal surveys, plus models which use the survey data as input. Complete details on EIA data sources are available in Volume III of the ARC.

Another useful source from EIA is the Energy Consumption Data Base (ECDB), produced under contract to EIA by Energy & Environmental Analysis (EEA). The ECDB contains highly disaggregated energy consumption data as described in the next section under "EEA."

The ECDB is a secondary source, which relies on primary data from the Census of Manufacturers. Last year EIA planned to discontinue the ECDB after the latest update (in 1981), and replace it with primary data obtained from an extensive industrial energy survey program (Ref. 5). The survey, which was mailed to about 12,000 major energy users, required each user to report detailed information on fuel use and energy requirements. In 1981, authority for the survey was revoked, and EIA ceased to collect data. At that time EIA already had about an 80 percent response to the survey, and they now plan to analyze the data on a statistical basis, maintaining confidentiality of site and plant identification. EIA plans to issue reports on this effort around the end of 1981 (Ref. 6), and this may include data which is useful to the HTGR program.

Under the present budget, the ECDB and the survey effort will not be continued.

2.2.3 Energy and Environmental Analysis (EEA)

EEA is a consulting firm which developed and maintains the ECDB. The original ECDB was issued in 1977 and was based on 1967, 1971, and 1974 data. The recent update is based on 1975-76 census data and will improve on the earlier edition by adding more details. This update is currently under review by EIA and is expected to be available in late 1981.

The ECDB is a comprehensive source of detailed, disaggregated information on energy use. The main source of state and national data by industry and fuel type is the Annual Survey of Manufacturers. This is supplemented by trade association data to account for captive energy supplies and internally generated fuels. Functional use data is obtained from a variety of sources, including publications, surveys, and aggregated micro-data (energy output coefficients and production data used to determine energy consumption).

The ECDB provides output as detailed end-use data in a wide variety of functional categories. Detailed breakdowns of energy use are acknowledged to be subject to greater (and indeterminate) error than the aggregate data. However, the ECDB provides one of the few independent sources of detailed energy use information in the manufacturing sector. Therefore, it should be used as a primary source or at least to supplement or verify other sources. The most recent update will include 1975-76 data, and this time lag should be considered when evaluating current total usage; but the information on relative usage (distribution by fuel type, industry, function use, etc.) should be representative of current experience.

2.2.4 General Energy Associates (GEA)

GEA is a consulting firm which has developed a comprehensive data base on industrial (manufacturing) end use of energy. The data base is called IPEP (Industrial Plant Energy Profile). It is maintained in an active status and represents an ongoing effort by GEA. There is an ongoing validation program for IPEP based on actual plant surveys.

IPEP starts with the individual plant site as the basic data point. Thus, it is a powerful tool for aggregating data in a very wide variety of combinations. IPEP is based on detailed process analyses for 108 of the most energy-intensive industrial processes. These process estimates are matched to the approximately 400,000 plants in the Dun & Bradstreet file. IPEP also includes input from trade associations, the COM, and other government surveys. The result is a data base which includes energy use by industry regardless of source (i.e., it includes industrial energy generated by use of internal process streams and products). It represents true consumption of energy rather than the demand for purchased energy. It should be noted that IPEP, like most data bases or surveys, generally presents the plant internal use of heat by process temperature requirements. This is not necessarily representative of the temperature of heat a plant would purchase from an external source (i.e., the plant may purchase heat at some high temperature and then distribute it as needed in the plant over the required application temperatures).

In 1980, GEA produced reports on industrial energy consumption (Refs. 7 and 8) for GCRA and General Electric Company (GE) which are relevant to the HTGR program. The report for GCRA provided profiles of industrial energy use for process heat in 249 utility districts in the following categories:

- Total fossil fuel use as steam and as direct heat
- Total fossil fuel use by temperature (<500°F, 500-1000°F, 1000-1700°F, >1700°F)

- Total fossil fuel use by fuel type
- Plant profile by plant thermal rating (number of plants, number of plants operating <3000 hrs/year)

The report for GE provided similar profiles at the county level for 25 selected utilities. GEA has recently revised the GE report to account for correction and updating of utility district boundaries. In many cases, the energy distribution by utility changed dramatically. Recent conversations with Brown and Hamel of GEA confirmed that these boundary changes would also have a substantial impact on the GCRA report. GEA plans to revise the GCRA report to account for this update, with completion scheduled by the end of FY 1981.

In 1981 GEA produced a follow-on report on industrial energy consumption for GCRA (Ref. 9.) This report provided additional detail and refined and updated the earlier data presented in the 1980 report. The report provides profiles of industrial energy requirements as follows:

- Energy requirements as national aggregate and for 28 utilities, as steam and direct heat for 6 temperature ranges (<350°F, 350°-500°F, 500-750°F, 750°-1000°F, 1000°-1700°F, >1700°F)
- Plant profiles as national aggregate and for 28 utilities by plant thermal rating, number of shifts and integrated annual thermal energy use
- List and description of all plants with a thermal rating greater than 500 MW
- Profile of plants in the PSE&G service territory.

IPEP does represent a valuable resource for GCRA. It appears, at present, to be the most comprehensive data base which is maintained in an updated, active status. It also has great flexibility to provide data by any required combination of categories. Because it is based on the individual plant data, the disaggregated data are more credible than similar data generated from aggregate surveys.

2.2.5 Oak Ridge Associated Universities (ORAU)

In 1980, ORAU published the Industrial Energy Use Data Book (Ref. 10), which contains very detailed process and energy-use descriptions of the 10 most energy intensive manufacturing industries. It is not a primary source as it relies on data from other sources (Battelle, COM, IEA [below], and others). It also does not include internally generated fuels used for process heat. The latter is a significant factor in the steel, chemical, paper and petroleum industries.

The Data Book may represent a good resource for detailed specific industry analyses. It is planned to be a continuing effort, with revisions and updates issued regularly, as well as supplemental reports and validation efforts. This work should be monitored as a potentially valuable resource.

2.2.5.1 Institute for Energy Analysis (IEA)

IEA is a division of ORAU which focuses on broad energy policy questions. This group published a report (Ref. 11) in 1979 entitled Characterization of Industrial Process Energy Services. This is a derivative report which assembles and analyzes data provided by other sources. It draws heavily from the Battelle work described in Section 2.2.7 of this report. It presents process heat requirements in 1974 by industry and temperature from fuels purchased for heat and power. The process heat is reported as the process requirements, not what is actually used by industry. Also, preheat is not accounted for. It is a short report, and there is no continuing work by IEA in this area. Thus, it does not represent a good resource for the HTGR Program.

2.2.6 Dow Chemical Co.

Dow Chemical produced a report (Ref. 12) for Oak Ridge National Laboratory which studied five major industries (paper, chemical, petroleum, rubber, primary metals) and classified geographic locations where the steam requirements exceeded certain limits within specified distances. The study covered steam up to 450°F.

The Dow study is narrow in scope and, therefore, not useful as a broad process heat market survey. However, it is very useful in focusing on specific geographic sites suitable for nuclear-generated process steam.

The general approach used by Dow may be used to generate additional current data for industries located in specific utility service areas. These data would identify the promising existing process heat, steam and electric load concentrations and the geographical context for consideration of location of a nuclear plant.

Apparently there is no follow-on effort by Dow or ORNL.

2.2.7 Battelle Columbus Laboratories

Around 1976, Battelle developed a process heat data base for use in conjunction with a solar energy program (Ref. 13). The same data base was used in a later Battelle study on laser fusion systems for industrial process heat (Ref. 13). The data base has been inactive since its last use in 1977-1978.

The presentation of data in these two reports (Refs. 13 and 14) is selective, presenting only that segment of data relevant to the study.

The data base was developed under Elton Hall of Battelle (614-424-5186) as follows:

- (a) Process flow sheets were prepared for selected processes and industries.
- (b) Process heat inputs were calculated for (a), per unit of output.
- (c) Total heat requirement were obtained by multiplying (b) by the annual production in that industry.

The Battelle work is incomplete for a comprehensive survey as it does not include all industries and, therefore, cannot be correlated with SIC codes. Also, not all processes in each industry were analyzed, and so extrapolations were made to obtain totals.

The Battelle survey is not a good data source for GCRA because it is not comprehensive, it is based on 1974 data, and it has not been maintained in an active mode. However, the solar report (Ref. 13) has potential value in that it presents some very detailed analyses of industries or industry segments with regard to specific process descriptions and process heat requirements.

2.2.8 Intertechnology Corporation

Intertechnology Corporation performed a study for the Energy Research and Development Administration in 1976 on the economic potential of solar thermal energy to provide industrial process heat. The final report (Ref. 15) from that study presents process heat data by application temperature for 14 four-digit SIC codes. Data were assembled from other sources (COM and SRI).

The data included only process heat derived from purchased energy. The Intertechnology work is not an ongoing effort. It is not a primary data source and does not appear to be of use to GCRA. Further, Intertechnology is no longer in business.

2.2.9 Mellon Institute - Energy Productivity Center

The Energy Productivity Center was awarded a two-year contract from DOE in 1979, to identify energy productivity opportunities in industry over the next 20 years. This work is currently

underway and is called the Industrial Energy Productivity Project. It looks at all industry but focuses on the major energy consumers (pulp and paper, petroleum refining, iron/steel, and chemical industries). The project will look at present and future requirements, technology changes and will characterize future energy use. The Energy Productivity Center is being assisted by several subcontractors, including EEA and GEA.

A final report is expected to be available by the end of 1981. A copy of this report should be obtained and evaluated for input to the HTGR Program.

2.2.10 Data Resources, Inc. (DRI)

DRI, Energy Service, has a considerable data base of disaggregated energy use information and projection from 1978 to 2000. The DRI forecasts are discussed in Section 3 of this report. While DRI's main use is in forecasts, they also present historical industrial energy use data by fuel type and by application (fuel and power vs. raw materials). The DRI historical data is taken from EIA reports and used directly or broken down into finer detail.

2.3 Data Source Selection

Based on the summary which is detailed in Section 2.2, the primary sources recommended as references for historical industrial energy use are:

- EIA Annual Report to Congress-Vol. 2 and 3, (ARC)
- EIA Monthly Energy Review (MER)
- General Energy Associates (GEA)
- Data Resources, Inc. (DRI)

These sources were selected because they represent continuing programs, are periodically updated and revised, have flexibility to manipulate data and extract specific information (GEA and DRI), and are well accepted as credible sources.

Other sources which may prove useful to verify or supplement the above are the ECDB and the Mellon Institute's Industrial Energy Productivity Project. When these documents become available, they should be reviewed and evaluated for possible use.

2.4 Industrial Energy Use Data

As discussed in the preceding sections, there are numerous sources of data addressing industrial energy use. The characteristics of these data sources were found to vary widely in terms of their scope, quality and maintenance programs, and only a few were found suitable for continued use within the HTGR Program. Of those endorsed for future use, the most reliable and most widely used source of primary data is the EIA, through their Annual Report to Congress and Monthly Energy Review. These documents remain the basic references used by most other analysts as a standard for comparison and as a starting point in developing more disaggregated data and finer breakdowns than are available from EIA.

This section presents selected energy use data which were derived from EIA publications and from energy distribution studies conducted within the scope of the HTGR Program, chosen to provide the reader with a basic insight to the industrial energy market. For more refined breakdowns of the data, the reader is directed to the sources referred to herein. Although HTGR applications are being considered for a future time frame, a knowledge of past trends and current energy use is important in understanding and assessing future energy requirements. Actual projections are presented in Section 3 of this report. Those projections, in conjunction with the data presented herein, should provide the necessary input to help evaluate future industrial energy requirements.

Energy data from EIA are subject to revision and are frequently revised in the latest Monthly Energy Review. These revisions are usually minor but are being pointed out here to alert the reader to the source of potential minor discrepancies between numbers herein and those in EIA reports issued after September, 1981.

2.4.1 Aggregate Data - Total and Industrial Energy

Table 2.4.1-1 presents aggregate historical data from 1973-1980. As described earlier, energy consumed by the industrial sector includes agricultural and mining use in addition to manufacturing process heat uses of interest to HTGR applications. Thus, the absolute values presented therein must be reduced as earlier described. The principal value of the table, however, is to illustrate trends and show the magnitude of the numbers involved.

The table illustrates the following facts:

- Total U. S. energy consumption has grown at an average rate of 0.3% per year from 1973 to 1980..
- Total U. S. energy consumption dropped significantly in 1980 (approximately 3.5% decrease).

Table 2.4.1-1

Energy Consumption - Historical Data
(Ref. 1)

<u>Year</u>	<u>TOTAL U. S.</u>	<u>INDUSTRIAL - WITHOUT</u>		<u>INDUSTRIAL - WITH</u>	
	<u>Quads/Annual</u> <u>% Change</u>	<u>Quads/Annual</u> <u>% Change</u>	<u>% of</u> <u>Total</u>	<u>Quads/Annual</u> <u>% Change</u>	<u>% of</u> <u>Total</u>
1973	74.61/4.2	21.45/4.9	29	29.47/5.6	39
1974	72.76/(-2.5)	20.69/(-3.6)	28	28.76/(2.4)	40
1975	70.71/(-2.8)	18.54/(-10.0)	26	26.51/(-7.2)	38
1976	74.51/5.4	19.55/5.4	26	28.23/6.5	38
1977	76.33/2.5	19.88/1.7	26	29.02/2.8	38
1978	78.15/2.3	20.00/0.6	26	29.37/1.2	38
1979	78.97/1.2	21.70/8.5	28	31.55/7.4	40
1980	76.20/(-3.5)	20.64/(-4.9)	27	30.29/(-4.0)	40

(1) Does not include wood-derived fuel used by paper industry, or biomass, solar, geothermal, wind, and waste energy.

(2) Includes all energy used to generate the electricity used.

- Industrial energy consumption, as a fraction of total energy consumption, has increased slightly in the last 2 years to about 27 percent without distributed electricity, and about 40 percent with distributed electricity included.

It should be noted that the data in Table 2.4.1-1 do not include wood-driven fuel consumed in the paper industry, solar energy, wind energy, biomass, and waste energy. However, these sources would not have a significant impact on the totals or distributions in Table 2.4.1-1.

Industrial fossil energy used for fuel and power purposes is the the energy category of special interest to HTGR process heat applications. Table 2.4.1-2 shows that in 1980 about 17 quads of energy were consumed in this category. The major fuel used was natural gas (46 percent), followed by petroleum (35 percent), and coal (19 percent). Thus, the fuels targeted for displacement are gas and petroleum, which is in line with national energy goals. The table shows that most of the energy for non-fuel (mainly feedstock) uses comes from petroleum.

2.4.2 Distribution by Fuel Type

Table 2.4.2-1 shows, on a relative basis, industrial energy consumption by fuel type from 1973 to 1980. This table includes non-fuel uses of energy, as well as electric consumption. It does not include the losses associated with the electricity consumed. Since 1973, relative consumption of coal and gas has declined, while consumption of petroleum and electricity have increased. Efforts to reduce reliance on petroleum are reflected in the drop from 1979-1980, but coal still decreased and gas still increased as a percent of total. However, the early part of 1981 does show increased use of coal and decreased use of gas.

2.4.3 Distribution by Service Demand

Industrial energy consumption is generally presented as total consumption for all industries and all purposes. Since only a portion of the consumption represents the potential HTGR market, it is useful to understand the elements of service demand and their relative contributions.

The EIA breakdowns, as presented in the Annual Report to Congress, were already described in Section 2.1 of this report. The EIA data is for 1978, and it shows that about 72 percent of total industrial energy consumption is attributed to process heat requirements.

TABLE 2.4.1-2
INDUSTRIAL FOSSIL ENERGY CONSUMPTION - 1980⁽¹⁾

	$\left(\frac{\text{TOTAL USE, QUADS}}{\quad} \right)$	-	$\left(\frac{\text{ESTIMATED NON-FUEL USE, QUADS}}{\quad} \right)$	=	$\left(\frac{\text{TOTAL USE FOR FUEL AND POWER, QUADS}}{\quad} \right)$	$\frac{\% \text{ OF TOTAL}}{\quad}$
GAS	8.46		0.59		7.87	46
PETROLEUM	8.86		2.97		5.89	35
COAL	<u>3.32</u>		<u>0.09</u>		<u>3.23</u>	<u>19</u>
	20.64		3.65		16.99	100

⁽¹⁾Data from Reference 1, except for estimated non-fuel use which was taken from Reference 3, Pg. 11.

TABLE 2.4.2-1
INDUSTRIAL FUEL CONSUMPTION
FUEL TYPE AS A % OF TOTAL
 (Reference 1)

<u>YEAR</u>	<u>COAL</u>	<u>GAS</u>	<u>PETROLEUM</u>	<u>ELECTRICITY (1)</u>
1973	18.3%	43.7%	28.1%	9.8%
1974	17.6	43.5	28.3	10.2
1975	18.2	40.9	29.6	11.1
1976	17.2	39.7	31.5	11.4
1977	15.5	38.4	34.2	11.7
1978	15.2	37.6	34.5	12.0
1979	14.8	34.8	38.3	11.5
1980	14.2	36.1	37.8	11.9
Jan- June 1981	16.2	34.5	36.3	13.0

(1) Purchased electricity only - does not include self-generated electricity or losses associated with purchased electricity.

2.4.4 Distribution by Temperature and Heat Media

In a report developed for GCRA in 1981, Reference 9, GEA presented a profile of process energy use of manufacturing industries. The data was presented as the energy profile of boiler and furnace outputs (vs. fuel inputs). The data can be converted (approximately) to energy input (fuel) consumed by applying the following estimates of furnace and boiler efficiencies:

Boilers:	75 - 80%
Furnaces:	60% (<500°F)
	55% (500-1000°F)
	50% (>1000°F)

Table 2.4.4-1 presents a summary of the GEA results. Major conclusions are as follows:

- The majority of energy is required as steam (57 percent), with about 43 percent as direct heat.
- Most of the steam is required at less than 500°F (90 percent), with about 50 percent at less than 350°F.
- Most direct heat is required above 1700°F (45 percent) with the next largest requirements at 1000-1700°F (25 percent) and 500-750 and 750-1000°F (12 percent each).

In addition to the national totals shown in Table 2.4.4-1, GEA generated the same data profile for each of the 28 utility service areas listed in Table 2.4.4-2. A summary of the data is also shown in Table 2.4.4-2, and the complete profile is presented in Appendix A.

2.4.5 Distribution by Manufacturing Plant Size

Table 2.4.5-1 presents a profile of energy use by manufacturing plant thermal rating (peak use). This data was also generated by GEA for GCRA, in 1981 (Ref. 9). The profile is based on 1977 data. More recent data would affect the totals, but are unlikely to affect the distribution. The following conclusions are drawn from this table:

- Three-shift plants account for 59 percent of all energy used but represent only 2 percent of all plants.
- About 47 percent of all energy use is consumed by three-shift plants with thermal demand greater than 100 MW each.

TABLE 2.4.4-1

MANUFACTURING PROCESS ENERGY REQUIREMENTS
AS OUTPUT OF BOILERS & FURNACES
 (1977 Data, Ref. 9)

<u>TEMPERATURE</u>	<u>STEAM</u>		<u>DIRECT HEAT</u>		<u>TOTAL</u>	
	<u>QUADS</u>	<u>%</u>	<u>QUADS</u>	<u>%</u>	<u>QUADS</u>	<u>%</u>
<350°F	3.1	49	0.15	3	3.25	29
350-500	2.6	41	0.16	3	2.76	25
500-750	0.5	8	0.57	12	1.07	10
750-1000	0.15	2	0.58	12	0.73	6
1000-1700	0	0	1.2	25	1.2	11
>1700	<u>0</u>	<u>0</u>	<u>2.1</u>	<u>45</u>	<u>2.1</u>	<u>19</u>
	6.35	100	4.76	100	11.1	100

STEAM, AS PERCENT OF TOTAL = 57 PERCENT

DIRECT HEAT, AS PERCENT OF TOTAL = 43 PERCENT

TABLE 2.4.4-2

MANUFACTURING PROCESS ENERGY USE, - 28 UTILITIES
 (1977 Data, Ref. 9)

	<u>QUADS/YEAR</u>		
	<u>STEAM</u>	<u>DIRECT HEAT</u>	<u>TOTAL</u>
Central Illinois Public Service Co.	.03	.03	.06
Commonwealth Edison Co.	.21	.21	.42
Consolidated Edison Co. of New York	.06	.04	.10
Consumers Power	.16	.05	.21
Detroit Edison Co.	.08	.09	.17
Duke Power Co.	.08	.03	.11
Florida Power and Light Co.	.05	.03	.08
Gulf States Utilities Co.	.26	.17	.43
Houston Lighting and Power Co.	.27	.34	.61
Idaho Power Co.	.01	.005	.015
Long Island Lighting Co.	.02	.008	.028
Los Angeles Dept. of Water and Power	.06	.04	.10
Louisiana Power and Light Co.	.15	.08	.23
Niagara Mohawk Power Corp.	.14	.13	.26
Northern Indiana Public Service Co.	.12	.09	.21
Ohio Edison Co.	.07	.06	.13
Ohio Power	.06	.08	.14
Orange and Rockland Utilities Inc.	.01	.006	.016
Pacific Gas and Electric Co.	.21	.16	.37
Pacific Power and Light	.09	.08	.17
Philadelphia Electric Co.	.12	.08	.20
Public Service Electric and Gas Co.	.20	.16	.36
Puget Sound Power and Light Co.	.03	.03	.06
Southwestern Public Service	.03	.04	.07
Tennessee Valley Authority	.28	.16	.44
Texas Electric Service Co.	.02	.02	.04
Union Electric Co.	.10	.09	.19
Virginia Electric Power	.09	.03	.12

In addition to the national summary shown in Table 2.4.5-1, the same plant profile was generated for each of the 28 utility districts listed in Table 2.4.4-2. These profiles are shown in Appendix A.

GEA also generated, for 4 utility districts, a listing and profile of all plants in those districts requiring greater than 2 MW(t) of process energy. The 4 districts are PSE&G, Houston Lighting and Power, Pacific Gas and Electric, and Northern Indiana Public Service. Because of the volume of data, that information is not included in this report.

When considering existing industrial sites, the most attractive potential for HTGR-supplied process heat would be a site with concentrated energy demand. In order to help identify such sites, all plants with peak thermal demands greater than 500 MW were identified and listed, along with profile of process energy use, electric demand and on-site generation. Table 2.4.5-2 presents a summary of the on-site generation data, which shows that about half of the total electric demand for these large plants is satisfied by on-site generation, except for the paper industry where the fraction about 3/4. The detailed list of these large plants is shown in Appendix B. For each of the SIC codes covered by these large plants, the process energy input was characterized with regard to purchased vs. non-purchased fuel used for process steam, direct heat and steam for on-site electric generation. Table 2.4.5-3 summarizes these results, which indicate that the petroleum and chemical industries represent the greatest potential for energy replacement by HTGR-produced process heat. These industries have the strongest reliance on oil and gas as fuels and also use internal fuel, which would otherwise be saleable.

TABLE 2.4.5-1

PROCESS ENERGY USE BY MANUFACTURING PLANT THERMAL DEMAND

(Ref. 9, 1977 Data)

PLANT THERMAL RATING (MWt)	TOTAL PLANTS			ONE-SHIFT PLANTS			THREE-SHIFT PLANTS		
	# OF PLANTS	TOTAL THERMAL ENERGY USE (Quads/Yr)	% OF ENERGY USE	# OF PLANTS	TOTAL THERMAL ENERGY USE (Quads/Yr)	% OF ENERGY USE	# OF PLANTS	TOTAL THERMAL ENERGY USE (Quads/Yr)	% OF ENERGY USE
<2	305,551	.75	6.6	287,684	.51	30.9	1,458	.04	.6
2-5	17,238	.62	5.5	8,935	.22	13.5	1,301	.10	1.6
5-10	6,223	.57	5.0	2,928	.17	10.5	675	.11	1.6
10-20	3,466	.69	6.2	1,362	.16	9.9	584	.21	3.3
20-25	1,389	.58	5.0	591	.13	8.0	310	.21	3.3
35-50	635	.39	3.5	247	.09	5.6	139	.14	2.2
50-100	1,114	1.2	10.9	341	.21	13.0	223	.41	6.4
100-500	1,056	3.8	34.5	89	.13	8.0	539	2.7	42.1
500-1000	78	1.4	12.7	0	0	0	78	1.4	21.8
>1000	23	1.1	10.0	0	0	0	23	1.1	17.1
TOTALS	336,773	11.1	100	302,177	1.62	100	5,330	6.42	100
ENERGY USE AS % OF TOTAL			100			15			59

TABLE 2.4.5-2

ON-SITE ELECTRIC GENERATION BY LARGE PLANTS*

<u>SIC Code (Industry)</u>	<u>Plants</u>	<u>% of Plants with On-Site Generation</u>	<u>% of Total Demand Generated On-Site</u>
26 (Paper)	22	100	77
28 (Chemical)	26	42	49
29 (Petroleum)	40	45	45
33 (Primary Metals)	13	95	47

*See Appendix B for breakdown by plant site.

TABLE 2.4.5-3

PROFILE OF FUEL TYPE FOR PROCESS ENERGY & ON-SITE GENERATION
(Reference 9)

INDUSTRY	APPLICATION	ESTIMATED PERCENTAGE (1)			
		COAL	OTHER PURCHASED FUEL	INTERNAL FUELS	
				WITH VALUE EXTERNAL TO PLANT	WITH NO EXTERNAL VALUE
SIC-26 (Paper)	Steam	6.3	39.1	0	31.9
	Direct Heat	3.9	1.2	0	0
	On-Site Electric	0.5	2.9	0	14.3
	Total	10.7	43.2	0	46.2(2)
SIC-28 (Chemical)	Steam	7.0	22.3	1.4	0
	Direct Heat	3.0	58.9	3.3	0
	On-Site Electric	1.8	2.3	0	0
	Total	11.8	83.5	4.7(3)	0
SIC-29 (Petroleum)	Steam	0.1	15.7	15.2	0
	Direct Heat	0	30.0	36.8	0
	On-Site Electric	0	2.1	0	0
	Total	0.1	47.8	52.0(4)	0
SIC-33 (Primary Metals)	Steam	1.3	3.3	2.2	4.4
	Direct Heat	44.6	31.4	6.6	2.2
	On-Site Electric	0.4	1.5	0	2.1
	Total	46.3	36.2	8.8	8.7(5)

- Notes: (1) All percentages are relative to total fuel used, including those internally generated, within the plant.
- (2) Major internal fuels (wood chips and spent pulping liquor) are considered to have no value outside plant limits because of nature of internal fuels to process and potential transportation costs except for very short distances.
- (3) Internal fuels were considered to have intermediate or higher Btu contents and therefore have value outside plant limits.
- (4) Major internal fuels such as refinery gas and petroleum coke are considered to have value outside the plant because of high Btu content.
- (5) Low Btu gas (<300 Btu/ft³) was considered to have little value outside plant limits.

2.5 CONCLUSIONS - MARKET PROFILE

The industrial energy market is not easily characterized. A meaningful characterization requires considerable data, with clear documentation regarding the source and basis of the data.

Several sources of data are available as described in this section. Specific profiles have been developed recently by General Energy-Associates for GCRA. These profiles are presented herein.

Some major characteristics of the industrial energy market are:

- Industrial energy consumption accounts for about 40% of total energy consumption and about 27% of total primary energy consumption.
- Within the industrial sector, about 2/3 of consumption is accounted for by 5 industries - Chemicals, Primary Metals, Petroleum refining, Paper, and Stone, Glass and Clay. The next largest consumer is the food industry.
- Major industrial fuels are oil and gas (~ 37% each), followed by coal and electricity (~ 13% each).
- About 90% of process steam requirements is supplied at less than 500 F.
- About 70% of process direct heat requirements is supplied above 1000 F.
- About 58% of total industrial energy consumption is required for manufacturing process steam and heat. This represents an upper bound for the market replaceable by HTGR produced heat.
- About 23% of manufacturing process energy is consumed by 101 large plants (requiring greater than 500 MWt).
- About 58% of manufacturing process energy is consumed by 1200 large plants (requiring greater than 100 MWt).

A significant fraction of national oil and gas consumption is burned to generate process steam and heat for manufacturing use (about 10 quads of oil and gas in 1980). The HTGR is technically capable of supplying this steam and a considerable part of the direct heat. Such an application would serve to reduce dependence on imported oil and release valuable fossil fuels from use as a heat source to uses in their unique application as chemical feedstocks.

SECTION 2 - REFERENCES

- (1) Monthly Energy Review, DOE/EIA-0035 (81/09), September 1981.
- (2) Annual Report to Congress, 1980, Volume 3, DOE/EIA-0173 (80)/3.
- (3) Annual Report to Congress, 1980, Volume 2, DOE/EIA-0173 (80)/2.
- (4) End-Use Energy Consumption Data Base: Series 1 Table, DOE/EIA-0014, June 1978.
- (5) Private communications on May 28, 1981 between S. Brésnick & Bruce Egan of Energy Information Administration.
- (6) Private communications on May 28, 1981 between S. Bresnick and John Preston of Energy Information Administration.
- (7) B. Hamel and H. Brown, Industrial Energy Profiles for HTGR Process Heat Market Assessment, General Energy Associates, Inc., June 28, 1980.
- (8) B. Hamel, H. Brown, and B. Hedman, HTR Multiplex Market Assessment, General Energy Associates, Inc., revised November 30, 1980.
- (9) B. Hedman, B. Hamel and H. Brown, Process Heat Market Study, General Energy Associates, Inc., 9/21/81.
- (10) R. S. Mack et al, Industrial Energy Use Data Book, ORAU-160, Oak Ridge Associated Universities, 1980.
- (11) S. W. Boercker, Characterization of Industrial Process Energy Service, ORAU/IEA-79-9(R), Institute for Energy Analysis, May 1979.
- (12) N. W. Barnes, The Potential Market for Process Heat from Nuclear Reactors, ORNL/TM-5516, July 1976.
- (13) Final Report on Survey of the Application of Solar Thermal Energy Systems for Industrial Process Heat, Volume 2: Industrial Process Heat Survey, TID-27348, Battelle Columbus, January 1977.
- (14) F. J. Bates et al, Final Report on Laser Fusion Systems in Industrial Process Heat, Battelle Columbus, June 1979.
- (15) Analysis of the Economic Potential of Solar Thermal Energy to Provide Industrial Process Heat, COO-2829-1, Intertechnology Corporation, February 7, 1977.

3.0 PROJECTED MARKET DATA

Energy forecasts are available from several sources, as described below. Forecasts vary depending on the source and may also change with the date the forecast was developed. Variations with time are due to the impact of recent trends and changed perceptions of future events based on changes in market conditions, politics, technology, etc. For example, almost all forecasts of energy consumption in the year 2000 have shown a growing conservatism from projections developed in the period from 1975 and 1980. These changes are largely due to lower energy consumptions emerging in the current years being reflected in the forecasts. Variations between different projection sources are also apparent and may be traced to different models and different assumptions regarding energy growth, economic growth, resource supplies, resource prices, technological changes, etc.

The most important caveat in using long-term energy forecasts is to remember that they are forecasts, not facts. That is, they represent the best educated guess of the forecaster regarding future events, based on a plausible set of assumptions. Considering this fact, plus the present volatility of political and economic conditions, all forecasts carry a considerable uncertainty. This point should be kept in mind when using forecasts, and the user should be ready to accept changes in the forecast with time.

This section of the report describes sources of energy forecasts and selects two sources to be used as a reference for HTGR program work. The sources were selected on the basis of being well-defined, having a history, being kept current, and having specific forecasts for breakdowns within the industrial sector. While the forecasts presented herein may be revised by the time this report is published, the reader will be able to refer to updated versions of the source(s).

3.1 Sources of Forecasts

Major sources of energy forecasts include: Pace Company Consultants & Engineers, Data Resources Inc. (DRI), Chase Econometrics, DOE Energy Information Administration (EIA), and major oil companies. Table 3.1-1 is a comparison of selected forecasts from recently published sources. EIA currently projects energy consumption to grow an average of 1.25 percent per year from 1978 to 2000 to a level of 103 quads per year. Both DRI and Exxon forecast lower average annual growth rates than EIA with consumption in 2000 of 96 quads and 92 quads, respectively. EIA and

Table 3.1-1
Forecast Comparisons for the Year 2000

	<u>EIA Mid-Oil Price</u>		<u>DRI</u> (Ref. 1)	<u>EXXON</u> (Ref. 2)	<u>Pace</u> (Ref. 5)
	<u>1979 ARC</u>	<u>1980 ARC</u>			
Real GNP Growth, % (1978 base year)	2.8	2.6	2.6	2.6	2.3
Domestic Energy Consumption, quads/yr	108	103	96	92	107
Industrial Energy Consumption, quads/yr	36	34	30	37	33
Industrial Energy Consumption as % of total	33	33	31	40	31

Exxon both forecast about 35 quads of industrial energy consumption in 2000. DRI's forecast is lower at 30 quads. Exxon forecasts industrial energy at the highest percent of total energy (38 percent), followed by EIA (33 percent) and DRI (31 percent). Pace projects the highest total consumption, but their industrial projections are in the range of other forecasters.

It is perhaps worth noting that current energy consumption has been decreasing significantly during the last 24 months, as indicated by the EIA Monthly Energy Reports. For example, the total domestic energy consumption decreased from about 79.0 quads/yr. in 1979 to 76.2 quads/yr. in 1980 and it appears it will decrease to less than 75.0 quads/yr. in 1981. Both because of the anticipated economic slowdown in the first half of 1982 and a continuing trend toward more efficient energy use, it is likely that the energy consumption in 1982 will be no larger than that in 1981 and, possibly, even somewhat lower. Incidentally, this will probably result in additional reductions in energy consumption projections for the year 2000 in future forecasts. It has been pointed out by at least one source (Transitional Energy Policy, published by Pergamon Press in 1981) that energy growth for the last 130 years has followed a cyclic behavior about a normal logistic growth curve. Consistent with that observation, the current decrease in energy growth continues the historical trend and, therefore, the energy growth stagnation would be expected to continue for another 10 to 15 years. However, on this basis another large energy growth period should begin toward the end of this century and continue for two to three decades into the next century. This observation is significant in that it emphasizes the importance of using the next 10 to 20 years to develop and introduce new energy technologies to prepare for the anticipated high-energy demands in later years.

It is also interesting to note that recent work done by Marchetti and co-workers at the International Institute for Applied Systems Analysis (IIASA) suggest that natural-gas utilization will grow during the next 20 years, replacing many of the uses of petroleum fuels. These observations are again based on historical trends of primary-energy growth using a substitution logistic methodology to describe the growth of alternative energy resources. Those studies also imply that nuclear energy will grow slowly during the next 20 years, but will become a much more important resource toward the middle of the 21st century.

3.2 Forecast Source Selection

The forecasts selected for this report, and recommended as a reference for HTGR work, are those by EIA and DRI. Both these sources are well documented, have been providing forecasts for several years, and involve an ongoing, continuing effort. They are also specific energy forecasts, while other sources offer energy forecasts as a part of an overall economic forecast.

The basis and description of the EIA forecast are documented in Volume III of the Annual Report to Congress (ARC - Reference No. 3). The latest ARC was released in May 1981 and should be used for reference. The current EIA forecasts are presented, along with comparisons with other forecasts, and comparisons between past EIA forecasts and actual historical data.

The EIA forecasts are broken down by mid-term (1985-1995) and long-term (2000-2020). They are based on different assumptions with regard to supply, price, and fuel types. Also EIA forecasts are given for three different world oil price assumptions (low, mid, high). Forecasts to be presented in this report will be from the long-term case and the mid-price oil case.

DRI provides forecasts of energy demand, supply, and prices to the year 2000. The forecasts are broken down by fuel type, sector, geographic area, and end use (fuel and power or raw material). The DRI forecasts are continually updated and available to DRI clients on-line and in the DRI quarterly Energy Review. DRI has two major advantages over EIA. First, it is updated monthly. The EIA forecast is updated and issued annually. Second, the DRI forecast provides a considerable level of detail with regard to breakdowns of energy use. The EIA forecasts do not provide as detailed a breakdown. The EIA forecast has a unique advantage in that it is carried out to the year 2020. DRI only goes to 2000. However, long-range forecasts are generally acknowledged to be short lived and therefore are subject to continual change.

These two sources will be used as references. They are each credible and widely used sources and can be used together to provide a cross-check.

3.3 Forecast Data

3.3.1 EIA Forecasts

Table 3.3.1-1 presents a summary of the latest EIA forecast for end-use fuel consumption using the mid-price world oil case. Note that "end-use" does not include the energy consumption which winds up as losses in electric generation and transmission, nor does it include synthetic fuels conversion losses. In the context of this analysis, electricity is considered as a "fuel." Highlights of the forecast shown in 3.3.1-1 are as follows:

Table 3.3.1-1

End-Use Fuel Consumption - EIA Forecast (Ref. 3)

	<u>Consumption (quads/year)</u>				<u>Annual % Change</u>			
	<u>1978</u>	<u>2000</u>	<u>2010</u>	<u>2020</u>	<u>1978- 2000</u>	<u>2000- 2010</u>	<u>2010- 2020</u>	<u>1978- 2020</u>
U. S., Total	63.1	72.5	77.1	83.2	0.6	0.6	0.8	0.7
U. S., Industrial	23.3	33.5	38.1	43.0	1.7	1.3	1.2	1.5
Industrial as % of Total	37	46	49	52	-	-	-	-

NOTE: End-use fuel consumption does not include electric generation and transmission losses.

- End-use fuel consumption is projected to grow at an average rate of about 0.7 percent per year to 2020.
- Industrial end-use fuel consumption is projected to grow more than twice as fast as total end-use consumption, or at about 1.5 percent per year.
- Industrial end-use fuel consumption is projected to increase from about 37 percent of the total in 1978 to about 52 percent of the total in 2020.

The EIA forecast of total energy consumption from 1978 to 2020 shows a growth rate of 1.3 percent per year, as indicated in Table 3.3.1-2. This rate is considerably higher than the 0.7 percent growth in end-use fuel consumption. The difference is due to the rapid growth in losses in synthetic fuels conversion. The synthetic fuels industry is projected by EIA to have considerable growth in the 2000-2020 period, as indicated by the six-fold increase in synthetic fuels conversion losses. Synthetic fuels conversion losses, which are insignificant in 1978, are projected to grow to 9 percent of total energy consumption in 2020.

EIA also breaks down industrial energy projections by basic service demands:

- Direct heat
- Indirect heat
- Electric services
- Feedstock
- Metallurgical coal
- Lubes and waxes

Direct heat is used in processes such as cement and brick kilns, glass melting, and metal heat treating, where the heat of combustion is used directly in the process. Indirect heat is primarily applied in the form of steam, which acts as a medium to carry the heat of combustion.

Table 3.3.1-3 and Figure 3.3.1-1 presents the EIA forecast of industrial energy use by service demand. A fundamental assumption of the long-term EIA forecast is that industry continues to improve overall energy efficiency while shifting to new fuel sources. This accounts for the fact that the EIA forecast shows the growth in industrial fuel consumption to be lower than the growth in value of goods produced.

Table 3.3.1-2
Energy Consumption - EIA Forecast
 (Ref. 3, P. 140)
 (Mid-Price Oil)

	<u>Consumption (Quads Per Year)</u>				<u>Average Annual % Change 1978- 2020</u>
	<u>1978</u>	<u>2000</u>	<u>2010</u>	<u>2020</u>	
<u>End-Use Consumption</u>					
Liquids	34.4	28.3	27.7	28.9	(.4)
Natural Gas	16.7	17.5	16.2	14.8	(.3)
Coal	3.7	9.8	12.3	14.1	3.2
Electricity	6.8	12.3	15.1	17.9	2.3
Other(1)	<u>1.5</u>	<u>4.5</u>	<u>5.8</u>	<u>7.5</u>	<u>3.9</u>
Total End-Use Consumption	63.1	72.4	77.1	83.2	0.7
<u>Conversion Losses</u>					
Electricity	15.1	28.0	34.1	39.8	2.3
Synthetic Fuels	0	2.1	6.4	12.5	9.3 (2000-2020)
<u>Total Consumption</u>	78.2	102.5	117.6	135.5	1.3

(1) Includes biomass, solar, and geothermal

Table 3.3.1-3

Industrial Fuel Use by Service Demand - EIA Forecast (Ref. 3)

	<u>Consumption (quads/year)</u>				<u>Annual % Change</u>			
	<u>1978</u>	<u>2000</u>	<u>2010</u>	<u>2020</u>	<u>1978- 2000</u>	<u>2000- 2010</u>	<u>2010- 2020</u>	<u>1978- 2020</u>
Industrial - Total	23.3	33.5	38.1	43.0	1.7	1.3	1.2	1.5
Total - Process Heat	16.9	20.4	21.6	22.3	0.9	0.6	0.3	0.7
Direct*	3.8	5.0	5.6	6.0	1.3	1.1	0.7	1.1
Indirect*	6.5	9.3	10.4	11.4	1.6	1.1	0.9	1.4
Metallurgical Coal*	2.0	2.0	2.0	2.0	0	0	0	0
Refinery, Gas Plant, and Field Use*	4.6	4.1	3.6	2.9	(.5)	(1.3)	(2.1)	(1.1)
Electric Services	3.6	7.0	8.9	11.2	3.1	2.4	2.3	2.7
Feedstock	2.4	5.1	6.4	8.0	3.5	2.3	2.3	2.9
Lubes, Waxes	0.5	1.0	1.2	1.4	3.2	1.8	1.6	2.5

*These components considered to be "process heat."

Figure 3.3.1-1

Industrial Fuel Use By Service Demand - EIA Forecast

(Ref. 3)

The demand for "process heat" is the primary area of interest to HTGR Applications. The following EIA categories of service demands are usually considered as "process heat": direct heat, indirect heat (steam), metallurgical coal (most of which gets used as heat), and refinery, gas plant, and field use. The latter category refers to the internal use of products generated at a manufacturing plant. The growth in direct and indirect heat is well below the GNP growth rate, indicative of the potential for increased industrial energy efficiency in these areas. Electricity requirements show a relatively larger growth rate and are projected to be supplied for the most part by utility generated electricity. The electric service category includes the fuel used to generate electricity on site, making the total fuel used to satisfy demand for electric services greater than the total electricity use shown in Table 3.3.1-4.

EIA forecasts of industrial energy use by fuel type are shown in Table 3.3.1-4 and Figure 3.3.1-2. Total industrial fuel use in 2000-2020 increases at about 1.3 percent per year, considerably less than the projected GNP growth of about 2 percent per year. EIA has assumed a continued increase in energy efficiency, despite the projected substitution of low- and medium-BTU gas from coal for natural gas, and the increase in industrial electricity generation. Both of these changes shift a portion of the projected energy losses associated with coal conversion and electricity generation to the industrial sector.

The major growth in industrial fuel use is forecasted to be centered in coal and electricity. Heavy oil use shows a major decline. The major demand for heavy oil is refinery use of petroleum coke and still gas (classified as heavy oil because they are crude oil byproducts). Heavy fuel oil for other industrial uses includes solid or liquid boiler fuel made from coal, and residual fuel oil. These fuel uses of heavy oil are projected to decline because fuel oil is not competitive with coal in this EIA forecast period. Industrial use of light oil shows as 1.9 percent annual growth, primarily because of growth in feedstock requirements.

Industrial use of natural gas and synthetic natural gas from coal (collectively termed high-BTU gas) is projected to decline after 2000. This is largely due to the use of low- and medium-BTU gas derived from coal in the direct heat category.

3.3.2 DRI Forecasts

Table 3.3.2-1 presents a summary of relevant data from a recent DRI forecast. The DRI forecast also has considerable detail on projections of demand, supply, and prices by geographic area. However, for purposes of this report, only the summary data will be presented.

Table 3.3.1-4

Industrial End-use Fuel Consumption by Fuel Type-EIA Forecast (Ref. 3)

	<u>Consumption (Quads/Year)</u>				<u>Annual % Change</u>			
	<u>1978</u>	<u>2000</u>	<u>2010</u>	<u>2020</u>	<u>1978- 2000</u>	<u>2000- 2010</u>	<u>2010- 2020</u>	<u>1978- 2020</u>
Industrial - Total	23.3	33.5	38.1	43.0	1.7	1.3	1.2	1.5
Coal	3.4	9.6	12.1	14.0	4.8	2.3	1.5	3.4
Utility Electricity	2.7	5.6	7.3	9.4	3.4	2.7	2.6	3.0
Natural Gas	8.5	8.8	8.1	7.4	0.2	(-0.8)	(-0.9)	(-0.3)
Light Oil	3.6	4.3	5.2	6.3	0.8	1.9	1.9	1.3
Heavy Fuel Oil	3.2	1.4	1.1	0.9	(-3.7)	(-2.4)	(-2.0)	(-3.0)
Geothermal	0	0.1	0.3	0.4	-	11.6	2.9	-
Lubes, Waxes	0.5	1.0	1.2	1.4	3.2	1.8	1.6	2.5
Biomass	1.3	2.7	2.9	3.1	3.4	0.7	0.7	2.1
Solar	0	0	<.05	<.05	-	-	-	-
Electricity - Autogeneration*	0.3	0.3	0.3	0.3				
Electricity - Cogeneration*	NA	0.3	0.4	0.6				

*Not included in totals; fuel used by these processes already included in fuel demands.

Figure 3.3.1-2

Industrial Fuel Use By Fuel Type-EIA Forecast

(Ref. 3)

TABLE 3.3.2-1
U.S. ENERGY DEMAND - DRI FORECAST
 (Ref. 1)

	Energy Consumption Quads/Year			Annual % Change		
	1980	1990	2000	1980- 1990	1990- 2000	1980- 2000
(1) Total	76.3	83.6	96.0	0.9	1.4	1.2
(2) Total, End Use*	58.5	60.7	66.4	0.4	0.9	0.6
(3) Total, Fuel and Power Uses	71.1	77.2	88.0	0.8	1.3	1.1
(4) Total Electricity*	7.1	9.5	12.2	2.9	2.6	2.8
(5) Industrial, Total*	23.3	26.3	29.7	1.2	1.2	1.2
(6) Industrial, Fuel and Power Uses*	19.2	21.1	23.1	1.0	0.9	1.0
(a) Fossil	16.6	17.5	18.5	0.5	0.6	0.5
(b) Electric*	2.8	3.6	4.6	2.5	2.5	2.5
(c) Solar	0	0.01	0.05	-	17.5	-
(d) Exotic	0	0.01	0.03	-	11.6	-
(e) Hydro Power	0.3	0.04	0.05	2.9	0.9	1.7

*Does not include electric conversion and transmission losses.

Figures 3.3.2-1 and 3.3.2-2 are plots of DRI forecasts showing anticipated changes in industrial demand for energy and fuel to the year 2000. Observations based on these forecasts from 1980 to 2000 are as follows:

- Industrial energy consumption will increase at an average rate of about 1.2 percent per year. This is about the same as the growth rate in total consumption.
- Industrial energy consumption for fuel and power uses will increase about 1 percent per year. This is substantially less than the 1.2 percent per year growth in total industrial energy consumption indicating a major growth in feedstock consumption.
- Most of the growth for fuel and power uses is accounted for by increased use of electricity with the fossil use growth about 1/5 of the electric use growth.
- Industrial demand for oil and gas will decrease, but demand for coal will increase substantially. The major increase in coal demand will be for steam coal.
- Industrial demand for solar and "exotic" fuel will increase significantly, but the total energy supplied by these sources will still be relatively minor in the year 2000.

3.3.3 Comparison of DRI and EIA

Table 3.3.3-1 presents a comparison of energy forecasts of DRI and EIA, along with key assumptions in the forecasts. An attempt was made to compare the same demand sectors, but care should be exercised in comparing actual forecast values since definitions of the sectors may be slightly different in some cases. Also, slightly different values may have been used for the base year, which would, of course, produce different values for 2000.

EIA generally is forecasting higher energy consumption than DRI, except for electricity which is about the same. The DRI forecast was developed more recently than the EIA forecast and is more representative of current projections.

Figure 3.3.2-1 - U.S. Energy Demand-DRI Forecast

(Ref. 1)

Figure 3.3.2-2
Industrial Energy Demand for Fuel &
Power Uses - DRI Forecast

(Ref. 1)

Table 3.3.3-1Energy Forecast for Year 2000 - DRI/EIA Comparison

	Consumption, Quads/Year	
	<u>EIA</u>	<u>DRI</u>
U. S., Total	102.5	96.0
U. S., End-Use*	72.4	66.4
U. S., Fuel and Power Uses	95.9	88.0
U. S., Electricity	12.3	12.2
Industrial, Total*	33.5	29.7
Industrial, Fuel and Power Uses	27.4	23.1

*Does not include losses associated with generation and transmission of electricity.

3.4 FORECAST SUMMARY

Several sources of energy forecasts are available. Forecasts tend to vary among forecasting sources, and with time. A reasonable assessment of future markets can be established by using the most recently developed forecasts from different (reliable) sources, and developing an understanding of future market potential based on the spectrum of forecasts and the associated assumptions. Forecasts tend to become obsolete very quickly and in order to maintain the most reasonable assessment of future market, it is necessary to keep abreast of the latest political and economic events as well as the latest forecast information.

Uncertainty regarding the precise size of the future industrial energy market is not of particular relevance in evaluating HTGR potential for supplying process heat and steam. It is clear that industrial process energy needs are substantial, and will continue into the future at least at this present level, and probably at a higher level. Thus, the market potential for HTGR-supplied heat will, in the aggregate, represent a very substantial market.

Relevant highlights of some current national energy forecasts to the year 2000 are:

- Growth in total energy consumption is projected to be moderate (~ 1.3%/year).
- Growth in total end-use fuel consumption is projected to be low (~ 0.8%/year), indicative of increased production of electricity and synthetic fuels which contribute to conversion losses.
- Growth in industrial end-use fuel consumption for fuel and power uses (excluding feedstock) is projected to be moderate (~1%/year).
- Growth in industrial fuel types for fuel and power uses is projected to be high for electricity (~ 3%/year), and negative for oil and gas (~ -1.4%/year each).

Thus, present forecasts project that coal will be replacing the industrial use of oil and gas for fuel and power uses. According to these forecasts, HTGR-produced steam and heat would be competing with coal as an industrial fuel to replace oil and gas.

3.5 New Markets

The term "new markets" is considered here to be industries which are likely to become large energy users within the next 20 years. These industries are all based on new techniques for producing fuels, including:

● Enhanced oil recovery	}	Liquids
● Shale oil		
● Synthetic liquids from coal		
● Alcohol from biomass		
● Enhanced gas recovery	}	Gas
● High BTU Gas from coal		
● Low BTU gas from coal		

"Synthetic fuels" is a term generally used to include shale oil, liquids and gases from coal, and alcohol from biomass. Thus, enhanced oil and gas recovery are usually not included as "synthetic fuels."

Forecasts of synthetic fuels and enhanced recovery fuels vary widely as they are highly dependent on forecasts of crude oil prices and government policy and support of synthetic fuels production, both of which vary dramatically with changes in political and economic events. Because of this, forecasts developed today are likely to be quite different from forecasts developed one year ago or one year from now.

Table 3.5.1 presents forecast data for synthetic and enhanced fuels production, gathered from recent reports of EIA, DRI, Exxon and PACE. The forecasts differ significantly probably because of different assumptions used in developing the forecasts and because of different times they were developed. The DRI forecast is from the most recently dated publication and may be more representative of current political and economic conditions.

The Exxon forecast shows over twice as much synthetic fuels production in 2000 as any of the other three sources. All forecasts except EIA are only projected to the year 2000, indicative of the great uncertainty associated with these forecasts. This high degree of uncertainty should be considered when using any of the long-range synthetic fuels forecasts.

The EIA forecast shows substantial synthetic fuels production in 2000-2020. EIA forecasts coal liquids to be major products followed enhanced gas and oil recovery. The EIA forecast of coal liquids may be unreasonably high, based on the current political environment.

EIA is forecasting that synthetic liquids production will be the major source of liquid fuel in 2020. After 2000, the EIA forecast shows that growth in synthetic production compensates

TABLE 3.5-1

SYNTHETIC AND ENHANCED RECOVERY FUELS FORECASTS
(QUADS)

	2000				2010	2020
	<u>EIA</u>	<u>EXXON</u>	<u>DRI</u>	<u>PACE</u>	<u>EIA</u>	
	(Ref 3)	(Ref 2)	(Ref 1)	(Ref 5)	(Ref 3)	
A) <u>LIQUIDS</u>						
ENHANCED OIL RECOVERY	3.6	--	--	--	4.1	2.5
SHALE OIL	1.2	--	2.0	2.4	2.3	3.0
SYNTHETIC LIQUIDS (Coal)	2.0	--	1.4	0.5	7.1	14.6
ALCOHOL (BIOMASS)	<u>0.4</u>	<u>--</u>	<u>--</u>	<u>--</u>	<u>0.6</u>	<u>0.9</u>
SUBTOTAL - LIQUIDS	7.2	--	--	--	14.1	21.0
B) <u>GAS</u>						
ENHANCED GAS RECOVERY	4.7	--	NA	NA	6.6	7.7
HIGH BTU (COAL)	0.3	--			0.7	1.2
LOW BTU (GAS)	<u>1.9</u>	<u>--</u>	<u>0.6</u>	<u>.08</u>	<u>2.9</u>	<u>3.5</u>
SUBTOTAL - GAS	6.9	--	--	--	10.2	12.4
<u>TOTAL</u>	14.1				24.3	33.4
TOTAL (WITHOUT ENHANCED RECOVERY)	5.8	12.2	4.0	3.0	13.6	23.2

for a projected decline in domestic crude production and displaces most of the higher cost oil imports. EIA projects shale oil to be less expensive than coal liquids in 2000, but the production of shale oil is shown to be less than coal liquids because shale oil is concentrated in a relatively small region, while coal is available in many areas.

EIA points out that although synthetic liquids could play a significant role in reducing oil imports, the magnitude of that role will depend strongly on the availability and cost of domestic crude and the cost of new synthetics technology.

Synthetic gas is forecasted to be more expensive than domestic natural gas but cheaper than imports. Thus, synthetic gas becomes a marginal source displacing imports and filling the gap between demand and domestic production.

Synthetic liquids are projected by EIA to play a greater role than synthetic gas because domestic natural gas can nearly satisfy the demand.

Because of the extreme sensitivity of synthetic fuels forecasts to changing political and economic conditions, the reader is urged to consult the most recent source material for the best available forecasts.

SECTION 3 - REFERENCES

- (1) DRI, Energy Review, Autumn 1981.
- (2) Exxon Co. USA, Energy Outlook, 1980-2000, December 1980.
- (3) Annual Report to Congress 1980, Vol. 3, DOE/EIA-0173 (80)/3
- (4) Synthetic Fuels Forecast to 2020, PACE Co., June 1980.
- (5) Pace Co., The Pace Energy & Petrochemical Outlook to 2000, April 1981.

4.0 COGENERATION

The term "cogeneration" has been defined in many different ways, a general definition being the coincident generation of process heat and electricity. For purposes of this discussion, however, the term cogeneration, unless otherwise noted, is intended to refer to the sequential use of energy to generate electricity, to operate mechanical drives and/or to produce process heat. For sequential cogeneration to be effective, one of the applications must have "waste energy" which can be used by the other application(s). Sequential cogeneration results in a higher percentage of energy in a fuel being put to useful work and less going to waste heat, as illustrated in Figure 4.0-1. Sequential cogeneration is therefore inherently thermodynamically efficient. A typical fossil-fueled electric generation plant has a fuel efficiency of 30-35 percent (65-70 percent of the fuel energy is rejected to the atmosphere and cooling water as waste heat). A cogeneration system, which utilizes that waste heat could raise fuel efficiency to over 80 percent. However, this example is based on a microscopic view of the total national energy situation and ignores institutional, regulatory, fuel choice and economic factors in the cogeneration evaluation. When all these other factors are considered, as well as taking a "macroscopic" energy perspective, then the benefits of cogeneration might be reduced. For example, if the cogeneration facility burns scarce oil or gas to displace coal or nuclear-fired electric cogeneration, then the cogeneration application may not be desirable. On the other hand, changes in the present institutional and regulatory structure would make realization of the cogeneration benefits more easily achieved. This subject is addressed in later sections of this report.

Cogeneration does not necessarily imply a utility/industry relationship. The "co" in cogeneration refers to the multiple use of heat energy rather than to the plant ownership or use. The cogeneration plant may be owned and operated solely by the utility or industry for their sole benefit, it may serve one or more industrial users and be isolated from the grid, or it may be connected to the grid.

The cogeneration concept is not new. It was in fact used extensively in the early part of this century, when industry met most of its electric requirements by through cogeneration (by necessity). In 1900, industry produced more than 50% of the nation's electricity. Then, as large central generating plants were developed, low-cost electricity became readily available and industrial use of cogenerated electricity declined substantially. In 1950 industry produced about 15% of the nation's electricity, and today that number is less than 5%.

In recent years (prior to approximately 1978), there was only limited interest in cogeneration outside of the paper, chemical, steel, and refining industries. Since 1978 however, there has been considerable renewed interest and activity in cogeneration.

FIGURE 4.0-1

CO-GENERATION - TYPICAL EXAMPLE

INDEPENDENT PROCESSES CO-GENERATION PROCESSES

● EXTRA FUEL

This has been brought on by Federal legislation introduced in 1978 as part of the National Energy Act (NEA) of 1978. This act was in turn brought on, in part, by the dramatic increase in the cost of fossil fuel, the heavy dependence on imported oil and the high cost of new electric generating facilities.

At present, only about 4% of electricity consumed in the U.S. is produced by cogeneration facilities. This number is expected to grow, as described elsewhere in this report.

The balance of this section (4.0) will discuss experience with cogeneration. The following two sections (5.0 and 6.0 will address the legislative, institutional and financial issues surrounding cogeneration.

4.1 Nuclear Cogeneration Experience

Following are brief overviews of the cogeneration facilities at the Bruce Nuclear Power Development in Canada and the Midland Nuclear Cogeneration Plant in Michigan. For detailed descriptions of these facilities, refer to GCRA report "Current Experience with Central Station Nuclear Cogeneration Plants", November 1981.

4.1.1 Bruce Nuclear Power Development

4.1.1.1 Background

The Ontario Hydro facilities designated as the Bruce Nuclear Power Development will, when completed in 1987, be one of the world's largest nuclear energy complexes. Bruce Station is located on the eastern shore of Lake Huron, approximately 100 miles northwest of Toronto, Canada. It will ultimately contain three nuclear generating complexes, three heavy water production plants, a steam distribution system, and associated support facilities. At the present time, five nuclear reactors of the Canadian CANDU type are in place, consisting of a single 200-MW(e) unit at Douglas Point and four 750-MW(e) units at Bruce A, for a combined rated electrical output of 3200 MW(e). Expansion to 6400 MW(e) is progressing on schedule with the construction of 4 800-MW(e) units at Bruce B which are substantially identical to those at Bruce A. All reactors at Bruce A and expectedly those at Bruce B are restricted to 88% of full power by the Atomic Energy Control Board.

In recent years, Canada, like the United States, realized that electrical growth was not going to progress as expected. Consideration was given, therefore, whether to continue with construction at Bruce B generating station and the additional heavy water production plants or to terminate or postpone those projects. As a result of these deliberations, one of the four planned heavy water plants was cancelled and operation of a second postponed for an indefinite period. The decision was made,

however, to continue the construction of the Bruce B generating station on schedule even though an excess of generating capacity and steam would result when the entire complex was completed. With all nine reactors in operation, and at 100% reactor licensing, excess steam in an amount approximating 872 MW(t) could be available for use. One consideration was the expectation that this steam could be used for supplying energy to an industrial park which could be developed around the southern perimeter of Bruce Station. In accordance with the evolving development plan, some 10,000 acres of land within a five-mile radius of the Bruce complex is available to industries who would be willing to locate new production facilities in the area. The principal incentive offered to potential users is the availability of process steam at less than half the cost of steam produced by gas-fired generators.

In 1980, an industrial survey was conducted. The objective of the survey was to identify possible energy-intensive industrial heat users who would consider participation in an energy park at the perimeter of Bruce Nuclear Power Development. The proposed energy park would be supplied with medium-pressure steam from the proven, reliable reactor complex at a cost less than half that from a comparable coal-fired station.

The survey was mailed to 103 selected industries who were involved in manufacturing products which required significant amounts of steam for their facilities. Forty-seven replies were received from those surveyed. Of those, 22 replies expressed varying degrees of interest, with the remainder showing no interest. A summary of the energy requirements represented by the interested industries is provided in Table 4.1.1.1-1. Among the interested parties were four industries with an integrated steam demand of approximately 1×10^6 lb/hr who were prepared to seriously consider relocation to the Bruce Station area to take advantage of the promised low-cost nuclear steam. The combined plants of the four interested parties would involve a capital investment of some \$200 million and provide direct job opportunities for 350-400 people.

In general, industries did consider that the Bruce location had the disadvantage of high transportation costs associated with the supply of raw materials and the delivery of finished products. Three of the four industries showing immediate interest specified that a port within a few miles of the Bruce facility was a definite requirement.

In response, Ontario Hydro has stated that, subject to the approval of the Atomic Energy Control Board, they would allow the use of the intake channel at Bruce B Nuclear Generating Station as a temporary docking facility. This facility could be used until a proposed site at Inverhuron could be developed (at a cost of \$22 million) into a facility capable of serving two full-sized vessels simultaneously.

Table 4.1.1.1-1
Energy Requirements of Industries Interested in
Locating at Bruce Station

<u>Industry</u>	<u>Steam Demand</u> <u>(X 10³ lb/hr)</u>
Salt Mining Solution Processing	200
Ethanol (Corn Feedstock)	400
Whiskey Distilleries (2)	50 (each)
Food Processing	100
Brewery/Fuel Alcohol	30-50
Chemical	500
Plastics	<u>50</u>
	1400

Further, to offset increased transportation costs and justify the necessary capital investment, industry response indicated that steam costs would necessarily need to be significantly less than achievable using natural gas as the primary fuel for producing steam. This incentive has been provided by Ontario Hydro's currently proposed energy pricing structure.

As part of the overall evaluation, the county of Bruce, in conjunction with Bruce Township and Ontario Hydro, is considering the availability of land at the Bruce perimeter suitable for industrial development.

In developing the Bruce Energy Park, two phases are contemplated. Phase one would involve approximately 700 acres of land owned by Ontario Hydro and located adjacent to the Bruce Nuclear Power Development site boundary. Immediate plans for the industrial steam supply system are to provide a 24-inch pipeline to the two-mile site boundary with a flow rate of 300,000 lb/hr. In addition to the initial industrial development, part of this phase would be to construct a small Agri-Park designed to use low-temperature (40-60°C) waste heat for greenhouses and a fish farm. A one-acre greenhouse is now in production and eventual plans call for 150 acres of greenhouses sustained year-round by low-grade heat, a replacement for the familiar cooling towers of U.S. facilities.

Phase two involves a long-term, comprehensive plan involving up to 10,000 acres of land located within a five-mile controlled development zone. This land would be purchased from local residents and then leased to the industrial users as they relocated to the area. As the industrial area expands, another larger pipeline would be constructed for greater flow rate and the 24-inch line would be used for condensate return.

4.1.1.2 Technical Overview

The facilities at Bruce Station date to 1967 when a single pressurized heavy water reactor [406 MW(e)] commenced operation at Douglas Point to supply electric power to the Ontario Hydro grid. Douglas Point was subsequently modified in 1973 to supply the steam necessary for operation of the first Bruce heavy water (deuterium oxide) production plant located nearby. Two thirds of the steam required for the heavy water plant was normally supplied by Douglas Point. The remaining one third of the needed steam was provided by a co-located oil-fired boiler which was designated so that it could provide all the required heavy water plant steam demand and thus operate as a backup system.

The CANDU reactors used by Ontario Hydro at Bruce Station are natural uranium-fueled, pressurized heavy water reactors with on-line refueling capability.

In 1969, Ontario Hydro began an aggressive expansion to the Bruce facility. The Bruce A complex of four reactors was next constructed with the four reactors at Bruce B following by several years. Bruce A was sited about one mile from the heavy water complex to avoid possible regulatory problems that might be associated with hydrogen sulfide gas, which is used in the production of heavy water. Unit one of Bruce A commenced operation in September of 1977 at about the same time as construction was completed on the first heavy water plant. This then allowed the oil-fired plant to be placed in a backup/emergency use role and to be used for steam tracing the lines to the heavy water plants as required. Energy for process uses is currently derived from main steam via reboilers and parallels the production of electricity. As such, no resource savings are achieved, however, the cogeneration of steam in this manner does allow the scale required for economic use of nuclear energy.

At present, the Bruce Nuclear Power Development includes two operating heavy water plants. Under normal circumstances, the heavy water production plants are given priority over electricity production as loss of steam input to these plants would result in extended down time (about one week) for restart. The reboiler system used at Bruce Station combines heat from the separate inputs of each reactor into a common secondary output to supply a pipeline to the heavy water plants. Each reactor steam supply to the reboiler is separate from the other reactor supply lines to prevent load fluctuations in one reactor from affecting the other reactors. The medium-pressure steam pipeline system includes two steam delivery pipes, each of which is 700 ft long and 66 in. in diameter. The pipeline system connects the reboiler system located near the reactors to the heavy water plants about one mile away (Fig. 4.1.1.2-1). When completed, the process steam output of the Bruce B generating station may be manifolded into the common supply system but more likely will be supplied separately to an off-site industrial complex.

In the immediate future, significant industrial steam loads could be supplied from the existing medium pressure Bruce Bulk Steam System (BBSS). Existing licensing restrictions to 88% of full power and provision of steam to the heavy water plants on a priority basis, however, would result in curtailment of electrical production at Bruce A. The curtailed electricity must be replaced using coal-fired facilities at appropriate cost.

Two schemes are available for supplying this curtailing steam to the industrial park from Bruce A. The first is a near-term scheme which consists of a small diameter designed for larger supply capacities (Figure 4.1.1.2-2). It is anticipated that for both, an above-ground supported and insulated steel pipeline would be utilized. For purposes of costing, it has been assumed the pipeline would tap into the existing BBSS 66 inch header and terminate at the site boundary.

*Current License Restriction

Figure 4.1.1.2-1
BNPD Bulk Steam System Energy Flow Diagram

Figure 4.1.1.2-2

The near-term scheme will accommodate current interest in having an early steam supply capability to a proposed industrial park adjacent to BNPD. This line will consist of a 24 inch supply pipeline and a 10 inch condensate return line. The lines will supply pipeline and a 10 inch condensate return line. The lines will run from the BBSS to the site boundary via the new BNPD Central Maintenance Facility (CMF). The purpose of the CMF is to supply heating steam to Bruce B during construction. The pipeline to the site boundary will have a total length of 2.8 miles including expansion loops. This line would be capable of handling 300,000 lb/hr of medium pressure (MP) steam for a maximum delivery pressure of approximately 145 psi at the BNPD site boundary. Of this, up to 50,000 lb/hr would be heating steam to the CMF and the remainder for off-site industrial use. Higher steam flow could be provided for lower pressure off-site steam requirements.

Detailed engineering of the first 5,900 feet of the pipeline from BBSS header to the CMF has begun with construction scheduled for completion in October 1982. Extension of the line to the boundary is committed for detailed design, and construction will commence following signing of the first off-site supply contract. It is anticipated that construction of the extension to the site boundary could be completed by 1983.

For longer term consideration, large scale delivery capacities of 1 million, 2 million, and 4 million lb/hr from Bruce A have been assumed for study purposes. Corresponding pipeline diameters are 34 inch, 46 inch, and 64 inch respectively. The existing MP steam headers from Bruce A have sufficient steam handling capacity to handle a total of 11.2×10^6 lb/hr. On-site peak demand is 5.8×10^6 lb/hr, and the remaining 5.4×10^6 lb/hr of MP steam handling capacity could be used to supply off-site steam demands. Reliability of supply would be lower for larger demands. It was assumed the BBSS would have sufficient handling capacity to reliably supply the largest assumed off-site delivery capacity (4×10^6 lb/hr). However, the reliability aspects of large-scale off-site supply would require detailed examination.

The future availability of non-curtailling steam from Bruce B will be dependent on reactor power licensing. For 100 percent reactor power level, 2708 MW(t) of high pressure steam per reactor could be generated at Bruce B. The maximum quantity of high pressure steam that the turbine-generator units will likely accept is 2496 MW(t). Therefore, at 100 percent licensing a total of 872 MW(t) (3,362,000 lb/hr) of excess or noncurtailling steam would likely be available from the four units.

Three alternative schemes for utilizing this potential non-curtailling steam for industrial supply have been assessed. These alternatives include:

- Scheme I Medium pressure steam supply using new MP steam reboilers
- Scheme II Higher pressure steam supply using new HP steam reboilers
- Scheme III Co-generation steam supply using back-pressure turbines.

For all three schemes a new reboiler building or back-pressure turbine building would need to be located adjacent to Bruce B.

Other alternatives such as the supply of Bruce B main steam to redundant reboiler equipment at Bruce A and the direct supply of nuclear main steam to the site boundary have not been included. The main reasons for these exclusions are; the need for extensive high pressure piping; increased problems associated with licensing; the potential for start up problems; and the potential negative effects on the reliability of the reactors.

It is estimated that the time required to undertake detailed engineering and construction of a new facility to utilize Bruce B non-curtailing steam is approximately four years.

4.1.1.3 Economics

In late 1980, Ontario Hydro advised potential industrial customers that they were prepared to offer steam in 1982 at a price not to exceed \$1.90/ MBTU (1982 U.S. dollars). This rate compares to a gas derived steam price in 1982 of about \$3.50-\$3.95. The estimate assumed that the process steam supplied would be at the expense of curtailing electric power production at the facility. On that basis, the cost cited is related to the cost of replacing curtailed electricity production using coal, taking into account fuel and O&M charges but not capital charges. If the Bruce reactors are eventually licensed to provide 100% power output, the necessary steam requirement for the industrial complex can be provided totally by non-curtailing steam.

The price quoted was also for an interruptible steam supply. However, a maximum of six interruptions per year lasting not more than four hours each was promised. Under this pricing structure, energy users would be responsible for returning condensate to the nuclear facility. Treatment would be in accordance with an Ontario Hydro water specification.

4.1.1.4 Utility Background

Ontario Hydro, the provincial utility of Ontario, Canada, is the owner and operator of Bruce Nuclear Power Development. Ontario Hydro is a financially self-sustaining provincial crown corporation mandated by provincial legislation. The organization has broad powers to produce, buy, and deliver electricity throughout the province and to exercise certain regulatory functions with respect to the large group of municipal electric utilities which it serves. Utility bulk power rates are regulated at the provincial level, thereby allocating equal unit energy costs to all municipal utilities regardless of the local area method of generating electric power. This arrangement permits all consumers to enjoy the advantages of cheaper nuclear-generated power.

Ontario Hydro serves approximately 2,878,000 retail customers through 24,535 transmission circuit miles. The total capacity of the system is 23,878 MW(e).

Ontario Hydro currently relies about equally on fossil (coal and oil), nuclear and hydraulic generating its electric power. By 1990, present construction will add 8000 MW(e) of nuclear generation to the current 5000 MW(e) nuclear now in service with the result that half of the annual electricity production will then be from nuclear power.

The utility's integrated power systems are interconnected with other producers located within the provinces of Ontario, Manitoba, and Quebec and in the United States within Michigan and New York.

At the present time, Ontario Hydro has nine nuclear reactors in operation, one at Douglas Point within the Bruce complex, four at Bruce Station A, and four at Pickering Station A. Four additional reactors are under construction at each of Bruce Station B and Pickering Station B, along with four units recently started at Darlington in Newcastle Township.

Similar to the United States in keeping with rising energy costs, conservation by customers, and predictions of a slowing economic growth rate, electric demand growth has decreased significantly and is predicted to be only slightly higher than 3% compounded until the turn of the century. Should this rate of growth again be overestimated, Ontario Hydro will simply restrict the use of higher-cost, fossil-fired plants in favor of less expensive nuclear energy.

4.1.1.5 Institutional and Regulatory Factors

The Canadian government's regulatory and licensing acts are largely in the hands of the individual provinces in Canada. Much less overall governmental control is felt than in the U. S., and a favorable environment exists for such innovative ideas as the energy park at Bruce Station. When a project such as this is undertaken, a mechanism available through the Canadian constitution is the Crown Corporation, a wholly or partly government-owned entity. A Crown Corporation is formed with a predetermined number of stock shares and can be a government-only venture or a joint venture between the government and private sector. At some appropriate time, the government-held shares may be offered to the private sector based upon their current market value. A notable example of the successful use of this concept is the SASOL project in South Africa.

At Bruce, the Ontario Energy Corporation (a Crown Corporation) has been established as the sole agent for the sale of thermal energy from the Bruce Nuclear Power Development. The Bruce Thermal Utility, composed of partners in the Bruce Agripark joint venture, has been incorporated to transport heat energy from the Ontario Hydro site boundary to future industrial users.

Key private sector organizations participating in the venture include Trans Canada Pipeline, Ltd., Consumers Gas Company, and Weston Energy Resources, Ltd.

4.1.1.6 Conclusions

Based upon the results of the industrial survey conducted by Atomic Energy of Canada Limited (AECL), definite interest in the development of an energy park in the vicinity of Bruce Station was evident. AECL's conclusion was that continuing and immediate efforts to implement the Bruce Industrial Energy Park are justified. The interest displayed by industry has obviously been produced by the promise of low cost energy coupled with Ontario Hydro's proven reliability in providing process steam for the heavy water plants.

Overall, the success evident in the continuing evolution of the Bruce Nuclear Power Development bodes well for the future of nuclear cogeneration. It is clearly evident that when operating in a favorable environment of government regulations and nuclear licensing, a concept such as an energy park supplied with nuclear steam can provide sufficient economic incentives to attract new industries. Such a favorable environment is generated by a realistic view of future energy needs and the vital necessity to reduce dependence upon foreign energy resources.

4.1.2 Midland Nuclear Cogeneration Plant

4.1.2.1 Background

The Consumers Power Company Midland Nuclear Cogeneration Plant was conceived in the late 1960s. At that time, nuclear energy was still in its ascendancy and utilities were in reasonable control of their own destinies. Further, Consumers Power Company was fast developing into an experienced nuclear utility as Big Rock Point had been in operation since 1962 and the construction at Palisades was well along toward completion. Also at that time, Dow Chemical Company was seeking fuel alternatives to coal since coal was proving to be expensive relative to the oil and natural gas that was being used by competitors in the southwest.

The prospects for inexpensive, reliable energy derived from nuclear fuel were of considerable interest to Dow. Reflecting this interest, a feasibility study was performed by Bechtel which ultimately led to an agreement between Dow and Consumers Power in 1967. Consumers Power in turn awarded an engineering, procurement, and construction contract to Bechtel Power Corporation, and the first nuclear cogeneration project in the U.S. went into initial engineering in February 1968. The location of the Midland Nuclear Cogeneration Plant is in the outskirts of Midland, Michigan and about 100 miles from Detroit.

The project was launched with great expectations from both Consumers Power and Dow Chemical. The large steam and electric load requirement at Dow allowed Consumers Power to plan for a much larger plant than would normally have been justified. This allowed Consumers to take advantage of economies of scale as well as the larger revenue base generated by cogenerated process steam and electric power. Dow would also benefit from the economies of scale and from the replacement of a number of small, older, high-maintenance, fossil-fired steam generating plants with a central off-site steam and electric power source. The projected process steam costs were substantially lower than fossil-fired steam production costs. This would help the Dow Midland plant compete with plants in other areas of the country where less expensive energy was available.

Since the project's inception, the Midland plant has endured the full impact of changing conditions in the U.S. institutional environment. Anti-nuclear intervention, inadequate rate relief, and escalating regulatory requirements have been key factors in delaying commercial operation of Midland from the originally scheduled dates of 1974-1975 to the current projected dates of 1983-1984. In addition, engineering has been suspended and restarted on two occasions in response to rapidly changing requirements.

Like other nuclear generating plants in the nation, the Midland plant was substantially affected by the aftermath of the Three Mile Island (TMI) accident. Since Midland, like TMI, has a Babcock & Wilcox steam supply system, Consumers Power, Bechtel, and Babcock & Wilcox have been reviewing design and operating procedures to determine what modifica-

tions may be necessary at Midland. In addition, a special company task force is currently implementing design changes based on information gained from the TMI accident. Construction progress at the plant has been complicated by the many additional requirements set forth by the Nuclear Regulatory Commission (NRC) as a result of TMI and by the fact that licensing requirements in general have changed considerably since the Midland project began. Additional regulatory delays following the TMI accident have been unrelated to the specific Midland plant design. Because the NRC directed its resources toward investigating TMI-related issues, consideration of licenses for all nuclear plants under construction in the U.S. was suspended for more than a year.

The regulatory "Catch 22" in which Dow found itself as a result of these delays would have elements of comedy were it not for the serious consequences. With the delay in the Midland nuclear facility, Dow was subjected to increasing pressure by the Environmental Protection Agency to upgrade or replace its existing coal-fired facilities which do not meet clean air requirements. The Federal Energy Regulatory Commission discouraged an interim change of these facilities to oil or gas due to shortages of these fuels in the northeast. Meanwhile, the much needed but elusive energy from the Midland nuclear plant receded further into the future as regulatory barriers and intervention became manifest.

The delays and changes at Midland have been very expensive. An original projected capital cost estimate of \$360 million has since increased nearly tenfold. The 1979 Bechtel estimate indicates that the total cost of the Midland plant will amount to \$3.1 billion if the project is completed in accordance with the licensing requirements and construction schedule now assumed by Bechtel. This estimate is based on fuel loading dates of July 1983 for Unit 2 and December 1983 for Unit 1 respectively. At the end of 1979, approximately \$1.26 billion had been invested in the Midland project. The company's applications for full-term, 40-year operating licenses for the Palisades and Midland plants are pending before the NRC.

The huge cost increase and major schedule delays encountered by Midland could have been substantially less had the Midland project been initiated only six months earlier, thereby avoiding some of the major regulatory impediments. A comparison has been drawn to the Oconee plant, which has a very similar nuclear steam supply system by the same supplier. Oconee Units 1, 2, and 3, committed only months earlier than Midland, entered into commercial operation during 1973-1974.

4.1.2.2 Plant Requirements

The operating performance and siting requirements for the Midland Nuclear Cogeneration Plant were specified jointly by Consumers Power Company and Dow Chemical Company since a major portion of the plant justification relates to the large electric and steam load for the Dow complex. The Dow complex will comprise a new load for Consumers Power since Dow has historically produced all of its internal steam and most of its electric power requirements with its own on-site industrial utility system. When the nuclear system comes on line, the Dow utility facilities will be phased out except to provide a backup capability complementing the nuclear system. Key requirements for the nuclear plant include the following:

- Process steam supply for Dow will take priority over electric power production for the Consumers Power grid.
- Process steam supply to Dow will be isolated (via reboiler/evaporators) from secondary steam produced in the reactor steam generators to avoid the possibility of radioactive contamination above normal background levels.
- Process steam supply to Dow at rated conditions of pressure, temperature, and flow should have an availability of 95%.
- The reactor will be sited close to the Dow complex to minimize steam transport piping costs and steam pressure and temperature losses in transmission.
- Process steam condensate and makeup water return will be provided by Dow at water quality specifications established by Consumers Power.
- Electric power supply to Dow will come from the Consumers Power grid.
- Flexibility will be provided to accommodate variations in process steam demand and associated variation in electric power output.

4.1.2.3 Nuclear Plant Description

The plant requirements as outlined above are met by utilizing two nuclear units.

Unit 1, the cogeneration unit of the twin plant, produces 4,050,000 lb/hr of process steam for Dow and 457 MW(e) net for the Consumers Power grid. Unit 2 is a conventional 2452-MW(t) condensing electric generation plant which produces 805 MW(e) net for the Consumers Power grid. Unit 2 also acts as backup for Unit 1 and is thus interconnected so that secondary steam can be diverted to supply process steam to the process steam evaporators of Unit 1. Under these conditions, a portion of the 805-MW(e) net output of the Unit 2 BOP is reduced. The nuclear steam supply system (NSSS) is identical for Units 1 and 2. The differences are in the BOP equipment, the disposition of plant electric and steam power products, the interface with Dow for Unit 1, and the control system to provide products per operating specifications. The essential differences are that the Unit 1 BOP is designed for optimizing both cogeneration and condensing electric power production while the Unit 2 BOP is designed only for optimizing condensing electric power production. In the following descriptions, primary attention will be given to the Unit 1 cogeneration plant since that unit has unique features for cogeneration, for backup provisions, and for the interface with Dow. Unit 2 is a standard baseload electric power plant except that a portion of its steam supply can be diverted to the Unit 1 high-pressure and low-pressure evaporators (reboilers) for backup when Unit 1 is out of service.

The primary function of the Unit 1 cogeneration unit is to provide process steam for Dow at the specified conditions and availability. Electric power is also cogenerated for use on the Consumers Power grid; however, any interference of this latter function with steam delivery results in action to maintain steam delivery to Dow at approximately 95% availability. Figure 4.1.2.2-1 shows the general concept of the Unit 1 plant (top portion of figure). A key unique system with Unit 1 is the process steam evaporator system (PSES). (Note that in some references the PSES is referred to as a "reboiler", "tertiary heat exchanger", or "steam transformer" system). The function of the PSES is to generate tertiary (process) steam and to provide complete physical separation between the secondary system steam and the tertiary steam delivered to Dow. This system will ensure that radioactivity will not be added to the process steam delivered to Dow. The PSES is designed to deliver tertiary steam to the Consumers Power/Dow site boundary at 3,650,000 lb/hr/175 psig (low-pressure tertiary steam) and at 400,000 lb/hr/600 psig (high-pressure tertiary steam). Note that the low-pressure evaporator heating steam is produced in series with electrical generation as a bottoming cycle with attendant cogeneration resource savings while the high-pressure evaporator heating steam is produced as a parallel product without use of a topping turbine for cogeneration of electric power.

As continuity of tertiary steam supply to Dow is given high priority, a backup secondary steam supply from the main steam system is provided via pressure reduction valves (in lieu of turbine extraction steam) for the low-pressure evaporators. In addition, main steam from the Unit 2 NSSS backs up the steam supplies from the Unit 1 NSSS.

The main differences in the Unit 1 BOP design and the Unit 2 BOP design are the extraction steam line on the high-pressure turbine and the use of only one low-pressure turbine unit (due to the reduced steam flows after steam extraction for low-pressure evaporator duty). Another difference is the high-pressure steam line from the steam generator directly to the high-pressure evaporator. This reduces the total prime steam flow to the high-pressure and low-pressure turbine in Unit 1 compared with Unit 2.

The Consumers Power Midland plant configuration shown in Fig. 4.1.2.2-1 includes as Unit 2 a conventional 2468-MW(t) Babcock & Wilcox pressurized water reactor system. This unit is designed to operate as a baseload electric power plant serving the Consumers Power grid system; however, the unit is configured within the Midland plant such that it can provide backup steam to the Unit 1 PSES during periods when Unit 1 is out of service or at reduced capacity. During these periods, Unit 2 electrical output will be reduced.

The principal concern over interruption of process steam supply is the "freeze-up" of many of the Dow processes. This process freeze-up can occur at many temperature levels depending on the particular process involved. In general, process steam interruption can become critical in anywhere from five minutes to four hours depending on the particular process in question. Electric heat tracing of process equipment and piping would alleviate this freezing problem to some extent, but restoration of process steam supply is essential for most processes.

Figure 4.1.2.2-1 General Plant Flow Sheet Arrangement for Twin-Unit Nuclear Cogeneration Plant at Midland, Michigan

From the above, it is seen that reliability of process steam supply is very important for the Dow plant operations; thus, a major requirement for the Consumers Power Midland plant is that it provide process steam at high availability (approximately 95%). This is accomplished by providing various modes of operation for delivery of process steam under a wide range of operating conditions. From an operational/equipment point of view, this is handled by three modes of supplying the required evaporator heating steam.

Low-pressure and high-pressure evaporator secondary steam is used to generate low-pressure and high-pressure tertiary steam respectively, and steam supply to the evaporators can be accomplished by different operating modes.

Low-pressure secondary steam is normally extracted from the Unit 1 high-pressure turbine. When Unit 1 high-pressure turbine extraction cannot support the tertiary steam demand, backup secondary steam is furnished from main steam by reducing the pressure to about 300 psia via pressure reduction valves. This backup low-pressure heating steam can be supplied by either Unit 1 or Unit 2 main steam. High-pressure secondary steam to the high-pressure evaporators is normally supplied by Unit 1 main steam. In the event that the Unit 1 NSSS is shut down, main steam from Unit 2 can be supplied to the high-pressure evaporators. In the cross-connected mode, the Unit 1 NSSS is isolated from Unit 2 main steam. The condensate is returned to the condenser which is operating with the NSSS which supplied the secondary steam.

In terms of process steam unavailability, it has been predicted that there could be approximately 450 hrs/yr (approximately 5%) of total unavailability from both Units 1 and 2. This is predicated on normal refueling outages and planned outages plus the estimated unplanned or forced outages. Availability requirements for the Dow operations approach 95%. Thus, based on the above, the twin-unit nuclear plant configuration meets this criterion.

During the periods of nuclear plant unavailability, Dow would plan to light off their fossil-fueled backup supply and/or to reduce the total process steam load within their complex. This backup capability for electric and steam power will be provided for Dow facilities via a Dow operated coal fired facility and a gas/oil fired package boiler. Dow has committed to spending \$25 million for flue-gas cleanup systems (a bag-house system and tall stacks) for the existing coal-fired power house. This is intended to satisfy current Environmental Protection Agency requirements and to maintain the in-plant steam and electric supply until nuclear plant process steam becomes available. After that, the equipment would be used for backup as noted.

Licensing and safety issues revolve around potential impacts of the reactor on the surrounding area worker and resident populations and possible events at or near the Dow Chemical plant that could impact the reactor plant (in particular operating equipment and staff).

Although there are concerns regarding reactor impact on nearby facilities (radioactive release, etc.), these have been extensively researched and design provisions made to accommodate them. Another concern for a project like the Midland project is the possibility of chemical releases from Dow and the protection of the operating staff.

In terms of the potential hazard of toxic gases to the reactor plant facility, it should be noted that redundant (two per unit) mass spectrometers are being provided with the capability of monitoring for some 40 or 50 airborne gases. In the event that a toxic gas is detected, the control room isolation system dampers are closed.

This is similar to the 100% recirculation mode that every nuclear power plant control room must go into in the event of radiological releases in the vicinity of the control building location.

4.1.2.3 Economic Considerations and Project Benefits

In a dual-purpose facility such as the Midland Nuclear Cogeneration Plant, means must be found to allocate costs and benefits fairly. To simplify these aspects, arrangements have been made for Dow to purchase electric power from the Consumers Power grid under normal industrial rate arrangements. This leaves only the question of how to charge for process steam.

The basis for the agreement is that Dow steam costs will cover all costs which are associated with cogeneration of process steam. The cost of electricity provided to the Consumers Power grid will be commensurate with costs from a nuclear facility which only generates electric power.

The process steam power charges to Dow are made up of two parts: (1) a "capacity charge" and (2) a "commodity charge." The capacity charge recovers all costs except fuel directly or indirectly associated with process steam production and delivery to Dow. The commodity charge recovers the appropriate share of fuel costs allocable to the process steam actually delivered to Dow. (With a specified minimum and maximum reserve steam flow rate which can be adjusted annually.)

The large capital cost increases incurred at Midland have significantly impacted the projected costs for nuclear process steam. However, nuclear cogeneration energy from Midland is still expected to be competitive in the near future based on projections for the cost of fossil fuel and environmental pollution constraints.

The principal economic and efficiency benefits realized at the Midland Nuclear Cogeneration Plant are due to the cogeneration feature, namely the sequential use of steam first for "topping" down through the high-pressure turbine to produce electric power and then using the turbine extraction steam to produce process steam power via the evaporators.

These benefits are graphically shown in Fig. 4.1.2.3-1 where a conventional condensing electric power plant (Bar III) requires 309 MW(t) more thermal power output to produce 1262 MW(e) than the composite of Units 1 and 2 of the Midland dual-purpose (cogeneration) plant (Bar II). This is also reflected in the net core heat rates--10,386 BTU/KW-hr vs. 9,551 BTU/KW-hr. The advantage is even more dramatic when the heat rate for electric power production in the Unit 1 cogeneration unit alone is compared with the conventional plant (8,078 vs. 10,386 BTU/KW-hr). In essence, these data show that a cogeneration plant requires less capital investment per unit of electric power produced. Further, the plant serves the dual needs of industry for process steam and electric power.

The data in Fig. 4.1.2.3-2 show that the heat rate of the Unit 1 cogeneration plant at Midland varies over a wide range depending on the low-pressure process steam flow rate. The figure also graphically shows the significantly lower heat rate of the cogeneration Unit 1 plant compared to the condensing cycle Unit 2 plant.

As noted above, the Midland plant electric power production heat rate and total cost delivered to the grid are defined to be equivalent to a conventional 1262-MW(e) nuclear plant. There are benefits to the grid and ultimately to the utility electric customer due to the economy-of-scale associated with a larger plant than would have been constructed if the Dow/Consumers Power arrangement had not been consummated.

Other benefits of the cogeneration plant are the significantly reduced cooling water consumption per unit of power generated compared to a conventional plant. The major reduction in atmospheric pollutants in the Midland area is also important. Shutdown of the Dow fossil-fired boilers, even after state commission standards are met, will reduce sulphur dioxide pollutants by 35 tons per day and nitrogen oxides by 31 tons/day. Radioactivity releases (from the fossil fuels) would also be terminated (these exceed the normal nuclear plant emissions).

4.1.2.4 Conclusions

In summary, the Midland Nuclear Cogeneration Plant represents a pioneering effort which has been a victim of its timing as opposed to technical difficulties. Although the Midland Nuclear Cogeneration Plant has experienced long and difficult delays, retrofit requirements, and related major cost increases, the basic incentives for the project remain. In spite of the difficulties, it appears that the nuclear option continues to offer the potential for more economical process steam than fossil units over the life of the plant.

Figure 4.1.2.3-1 Comparison of Midland Cogeneration (Dual-Purpose) Plant and Conventional Power Only Plant

**UNIT 1 ELEC OUTPUT
MW (NET)** **UNIT 1 HEAT RATE
BTU/KWH**

F-423

Figure 4.1.2.3-2 Midland Unit 1 Electric Power Output and Net Core Heat Rate as a Function of Process Steam Flow to Dow

Construction is proceeding toward the currently scheduled commercial operation in 1984. The project should be a valuable source of information regarding process plant/nuclear plant interaction and other operational aspects.

4.2 Fossil Cogeneration Experience

4.2.1 Introduction

All currently operating cogeneration facilities in the U. S. are fueled by fossil, biomass, waste or renewable fuels. Only one nuclear facility is planned, as described in Section 4.1.2 of this report. Fossil Cogeneration systems are not new; they have been in use since the late 1800's. This section of the report does not review the early history but does present a review of the status and characteristics of some recently built or newly planned industrial cogeneration systems.

There are two basic types of cogeneration systems: topping electric cycles and bottoming electric cycles. The systems differ with regard to the order in which the heat is used to generate electricity and process heat or mechanical drive. In the bottoming electric cycle, heat from the fuel is first used in an industrial process. The "waste" heat from the process is then used (usually in conjunction with supplemental heat input) in a boiler to generate steam for electricity production. Supplemental heat is usually required because the waste heat is of too low a quality for electricity generation.

In the topping electric cycle, heat from the fuel is first used to generate electricity, and the waste heat is then used in an industrial process. A topping cycle can either use a steam turbine, a gas turbine or a diesel. When a steam turbine is used, fuel is burned in a boiler to generate steam. The steam then passes through a turbine to produce electricity, and the steam exiting the turbine is used in the process.

In the case of a gas turbine or diesel, the fuel is burned in the turbine or diesel which is connected directly to the generator, and waste heat from the diesel or turbine is passed through a waste heat exchanger which generates steam or heat for the process.

The major industrial users of cogeneration are the pulp and paper, chemical, petroleum refining, and steel industries. Some of these industries are well-suited for cogeneration since they generate as a "waste" product, material which is usable as an on-site fuel, but has little or no market value (e.g., wood waste, black liquor, sludge and bark in the paper industry, refinery waste in the petroleum industry). In the chemical industry, about 1/3 of the power requirement is cogenerated by gas and steam turbines (Ref. 1). Gas turbines are generally used for mechanically driven pumps and compressors, and steam turbines for electric generation.

Because of the renewed interest in cogeneration as an energy conservation measure, there has been considerable activity to gather information on existing cogeneration facilities and to project cogeneration growth potential. Information on experience is provided in the following section, and growth projections are presented in Section 4.4 of this report.

4.2.2 Experience/Case Studies

Current estimates of the total number of industrial cogeneration facilities in the U. S. range from about 350-400. A complete inventory is apparently not available at this time. An inventory of known cogeneration facilities with capacity greater than 10 MW was developed for EPRI and published in 1980 (Ref. 2). Table 4.2.2-1 provides the inventory list from that report. A total of 81 sites were identified, though it is not clear whether this represents all sites with capacity greater than 10 MW. However, it is clear that there are many sites with small capacities since over 350 sites are known to exist, and the 81 sites identified comprise about 7000 MW out of an estimated total capacity of about 9000 MW.

The inventory shown in Table 4.2.2-1 is part of a cogeneration data base being developed for EPRI by Synergic Resources Corp. (SRC). The final EPRI report on this data base is expected to be released in 1982.

Specific case studies of 17 of the larger cogenerators (> 10 MW) were also presented in the 1980 EPRI report (Ref. 2). Table 4.2.2-2 is a list of the 17 systems. For details on any of these, the reader is directed to Reference 2. Following is a summary description of characteristics of these 17 systems:

- Natural gas was the fuel most commonly used, either by itself or in combination with oil or internally-generated fuels.
- Steam topping turbines were the most widely used systems, followed by gas turbines and steam bottoming turbines.
- More than half of the systems were interconnected with a utility grid; a few were in parallel operation; and only one was isolated.

Several recently developed or newly expanded cogeneration facilities were described at the last two Energy Bureau Conferences on Cogeneration. Table 4.2.2-3 is a summary of the facilities described at these conferences. Highlights and significant points are described below.

Table 4.2.2-1

INVENTORY OF KNOWN COGENERATORS

(Ref. 2)

NAME OF FIRM	LOCATION	TYPE OF SYSTEM*	CAPACITY (MW)
NEW ENGLAND			
Atlantic Gelatin	Woburn, MA	S	7.5
General Electric	Lyon, MA	S	65.0
Greater Lawrence Industrial Assco.	Lawrence, MA	S	17.0
James River Mass., Inc.	Fitchburg, MA	S	13.5
Mass. Bay Transit Authority	South Boston, MA	S	120.0
United Shoe Machinery	Beverly, MA	S	10.0
TOTAL NEW ENGLAND			233.0
MIDDLE ATLANTIC			
AMSTAR	Brooklyn, NY	S	10.4
Bethlehem Steel	Lackawanna, NY	S	47.5
Eastman Kodak	Rochester, NY	S	113.7
International Paper	Hudson, NY	S	27.5
International Paper	Ticonderoga, NY	S	30.0
Procter & Gamble	Port Ivory, NY	S	10.5
American Cyanamid	Bound Brook, NJ	S	14.5
ARCO Polymers, Inc.	Monaca, PA	S	35.0
Avtex Fibers	Meadville, PA	S	17.0
Bethlehem Steel	Bethlehem, PA	S,I	44.0
Container Corp. of America	Philadelphia, PA	S	11.0
Crucible Steel	Midland, PA	S	24.0
Gulf Oil	Philadelphia, PA	S	36.0
Scott Paper	Chester, PA	S	10.4
Shenago, Inc.	Pittsburgh, PA	S	10.0
St. Joseph Zinc	Josephtown, PA	S	100.0
U.S. Government	Philadelphia, PA	S	22.5
U.S. Steel	Clairton, PA	S	35.0
U.S. Steel	Fairless, PA	S	60.0
U.S. Steel	Northampton, PA	S	10.0
U.S. Steel	Pittsburgh, PA	S	65.0
U.S. Steel	Pittsburgh, PA	S	62.0
Westvaco	Tyrone, PA	S	17.1
TOTAL MIDDLE ATLANTIC			813.1

Table 4.2.2-j cont'd

NAME OF FIRM	LOCATION	TYPE OF SYSTEM*	CAPACITY (MW)
EAST NORTH CENTRAL			
Goodyear Tire & Rubber	Akron, OH	S	64.5
Republic Steel	Cleveland, OH	S	42.5
Union Carbide	Cleveland, OH	S	160.0
U.S. Steel	Lorain, OH	S	28.0
Alton Box Board Company	Alton, IL	S	23.2
Caterpillar Tractor	, IL	S	10.0
CPC International	Pekin, IL	S	27.0
Deere & Company	East Moline, IL	S	10.0
Granite City Steel	Granite City, IL	S	21.0
Inland Steel	Chicago, IL	S	212.5
Libby-Owens-Ford Glass	Ottawa, IL	S	31.9
Marathon Oil	Robinson, IL	S	12.0
Monsanto Chemical	Sauget, IL	S	13.5
Shell Oil	Wood River, IL	S	20.0
U.S. Industrial Chemicals	Tuscola, IL	S	12.5
U.S. Steel	South, IL	S	105.5
Western Electric	Hawthorne, IL	S	52.5
Dow Chemical	Ludington, MI	S	17.5
Ford Motor Company	River Rouge, MI	S	345.0
Georgia Pacific	Kalamazoo, MI	S	20.0
White Pine Copper	White Pine, MI	S	52.0
Wyandotte	Detroit, MI	S	45.0
Allis Chalmers	, WI	S	13.5
TOTAL EAST NORTH CENTRAL			1,340.0
WEST NORTH CENTRAL			
Amoco Oil	Sugar Creek, MO	S	21.0
Anheuser-Busch	St. Louis, MO	S	23.5
Franklin Station	Franklin, MN	S	11.4
Hercules	Louisiana, MO	S	22.5
Monsanto	St. Louis, MO	S	100.0
TOTAL WEST NORTH CENTRAL			178.4

Table 4.2.2-1 cont'd

NAME OF FIRM	LOCATION	TYPE OF SYSTEM*	CAPACITY (MW)
SOUTH ATLANTIC			
DuPont	Wilmington, DE	S	22.5
Getty Oil	Delaware City, DE	S	100.0
Bethlehem Steel	Sparrow Point, MD	S	140.0
Cheasapeake Corp. of Virginia	West Point, MD	S	56.7
American Sugar	Baltimore, MD	S	10.0
U.S. Naval Gun Factory	Washington, DC	S	12.5
Dan River Mills	Danville, VA	S	19.4
Union Camp	Franklin, VA	S	81.5
Westvaco	Covington, VA	S	65.0
R. J. Reynolds	Winston-Salem, NC	S	32.5
Brunswick Pulp Paper	Brunswick, GA	S	26.0
Buckeye Cellulose	Jolley, FL	S	32.5
Monsanto Textiles	Pensacola, FL	S	16.3
Sugar Growers of Florida	Bella Glade, FL	S	15.0
TOTAL SOUTH ATLANTIC			629.9
EAST SOUTH CENTRAL			
American Enka	Lowland, TN	S	20.0
Bowater Southern	Calhoun, TN	S	24.0
North American Rayon	Elizabethtown, TN	S	24.0
W. R. Grace	Memphis, TN	S	35.0
Tennessee Eastman	Kingsport, TN	S	141.5
Alcoa	Mobile, AL	S	22.5
International Paper	Mobile, AL	S	98.5
Scott Paper	Birmingham, AL	S	10.0
U.S. Steel	Birmingham, AL	S	20.0
Union Camp	, AL	S	25.0
Alcoa	, AK	S	22.5
Reynolds Metals	, AK	S	18.0
TOTAL EAST SOUTH CENTRAL			461.0

Table 4.2.2-1 cont'd

NAME OF FIRM	LOCATION	TYPE OF SYSTEM*	CAPACITY (MW)
WEST SOUTH CENTRAL			
Allied Chemical	Baton Rouge, LA	S	20.5
Boise Southern	Derider, LA	S	52.5
Calcasieu Paper Company	Elizabeth, LA	S	12.5
Continental Oil Company	Lake Charles, LA	S	11.8
Copolymer Rubber	Baton Rouge, LA	S	14.0
Crown Zellerbach	Bogalusa, LA	S	42.0
Gulf States Utilities	Baton Rouge, LA	S	190.0
Hercules	Lake Charles, LA	S	13.0
Imperial Chemical	Baton Rouge, LA	S	80.0
International Paper	Bastrop, LA	S	56.0
Kaiser Aluminum & Chemical	Baton Rouge, LA	S	24.0
Kaiser Aluminum & Chemical	Chalmette, LA	S,I	501.2
Kaiser Aluminum & Chemical	Gramercy, LA	S,G	86.3
Olin	West Monroe, LA	S	53.0
Olin	Lake Charles, LA	S	14.0
PPG Industries	Lake Charles, LA	S,G	186.2
Alcoa	Point Comfort, TX	S,I	354.4
Amoco Oil	Texas City, TX	S,G	74.6
Celanese Chemical	Pampa, TX	S	30.0
Diamond Shamrock	Deer Park, TX	S	42.5
Dow Chemical	Freeport, TX	S	290.0
Eastex	Evadale, TX	S	42.0
E. I. DuPont de Nemours	Sabine River, TX	S	15.0
Gulf Oil	Port Arthur, TX	S,G	107.1
International Paper	Texarkana, TX	S	65.0
Lone Star Steel	Lone Star, TX	S	32.9
Mobil Oil	Beaumont, TX	S	135.0
Petro-Texas Chemical	Houston, TX	S	70.0
Phillips Butadiene	Borger, TX	G	33.0
PPG Industries	Corpus Christi, TX	S	37.5
Reynolds Metals	Corpus Christi, TX	I	235.1
Reynolds Metals	Ingleside, TX	S,G	39.0
Shell Oil	Houston, TX	S,G	60.0
St. Regis	Houston, TX	G,S	80.0
St. Regis	Lufkin, TX	S	78.5
Union Carbide	Texas City, TX	G,S	148.0
TOTAL WEST SOUTH CENTRAL			3,326.6

Table 4.2.2-1 cont'd

NAME OF FIRM	LOCATION	TYPE OF SYSTEM*	CAPACITY (MW)
MOUNTAIN			
FMC	Green River, WY	S	42.0
Amalgamated	Twin Falls, ID	S	10.9
Potlatch	Lewiston, ID	S	10.0
Stauffer Chemical	Henderson, NV	S,G	24.0
TOTAL MOUNTAIN			86.9
PACIFIC			
Crown Zellerbach	Omak, WA	S	12.0
ITT Rayonier	Gray Harbor, WA	S	10.8
Longview Fiber	Longview, WA	S	71.0
Simpson Timber	Simpson, WA	S	11.0
Weyerhaeuser	Longview, WA	S	81.0
Weyerhaeuser	Aberdeen, WA	S	15.0
Weyerhaeuser	Everett, WA	S	12.5
Brook Scanlon	Bend, OR	S	17.5
Roseburg Lumber	Dillard, OR	S	45.0
Weyerhaeuser	Springfield, OR	S	25.0
Applied Energy	San Diego, CA	S	14.0
Dow Chemical	Pittsburgh, CA	G	48.0
Kerr-McGee	Trona, CA	S	100.1
Holly Sugar	Brawley, CA	S	7.5
Louisiana-Pacific	Eureka, CA	S	27.5
Riverside Cement	Cro Grande, CA	S	15.0
Pacific Gas & Electric	Martinez, CA	S	46.0
Pacific Gas & Electric	Cleum, CA	S	87.0
Pacific Gas & Electric	Avon, CA	S	50.0
Stauffer Chemical	Pinnades, CA	G	15.5
Georgia Pacific	Fort Bragg, CA	S	14.0
TOTAL PACIFIC			725.4
TOTAL U.S.			7,794.3

*S = Steam Turbine; G = Gas Turbine; I = Internal Combustion.

Table 4.2.2-2
EPRI Cogeneration Case Studies
 (Ref. 2)

<u>NAME</u>	<u>Elect. Capacity</u>
1. AMERICAN ENKA COMPANY - LOWLAND, TENNESSEE	20 MW
2. ANHEUSER BUSCH, INC. - ST. LOUIS, MISSOURI	27
3. BOWATER SOUTHERN PAPER CORPORATION - CALHOUN, TENNESSEE	45
4. (NAME WITHHELD) - PENNSYLVANIA	11
5. GENERAL FOODS CORPORATION - WOBURN, MASSACHUSETTS	7.5
6. GULF STATES UTILITY COMPANY - BATON ROUGE, LOUISIANA	190
7. HOLLY SUGAR CORPORATION - BRAWLEY, CALIFORNIA	7.5
8. PACIFIC GAS AND ELECTRIC COMPANY - AVON, CALIFORNIA	50
9. POTLATCH CORPORATION - LEWISTON, IDAHO	20
10. RIVERSIDE CEMENT COMPANY - ORO GRANDE, CALIFORNIA	15
11. ST. REGIS PAPER - HOUSTON, TEXAS	95
12. SHELL OIL COMPANY - DEERPARK, TEXAS	50
13. CELANESE CHEMICAL COMPANY/SOUTHWESTERN PUBLIC SERVICE COMPANY - PAMPA, TEXAS	30
14. PHILLIPS PETROLEUM COMPANY/SOUTHWESTERN PUBLIC SERVICE COMPANY - BORGER, TEXAS	33
15. SOUTHERN CALIFORNIA EDISON - POMONA, CALIFORNIA	14.5
16. STAUFFER CHEMICAL COMPANY - HENDERSON, NEVADA	27
17. UNION CARBIDE CORPORATION - TEXAS CITY, TEXAS	70

TABLE 4.2.2-3
EXAMPLES OF NEW COGENERATION FACILITIES

<u>NAME/LOCATION</u>	<u>ON LINE</u>	<u>CAPACITY</u>	<u>SYSTEM</u>	<u>OWNERSHIP</u>	<u>COMMENTS</u>
1) Hoffman-LaRoche, Belvidere, NJ	1982	23 MW	Diesel	Industry	Provides all on-site electric
2) Phillips Petroleum, Borger, Texas (Southwestern Public Service Co.)	1966	33 MW	GT	Utility	Industry uses waste heat only
3) Celanese-Pampa, Texas (Southwestern Public Service Co.)	1979	30 MW	STT	Joint	Celanese owns boilers, SPS owns turbogenerators
4) Shell Oil, Deerpark, Texas	1979 (addition)	60 MW	STT, GT	Industry	Parallel operation- Shell buys power from HP&L
5) Hercules Chemical Lake Charles, LA	1977	12.4 MW	STT	Industry	No electric sales to utility
6) Kerr-McGee Searles Lake, CA					
a) Trona-Argus	--	100 MW	STT	Industry	Connecting with utility in 1981
b) West end	--	15 MW	GT	Industry	Connected to utility since 1979
7) Applied Energy, Inc. San Diego, CA					
a) Naval Training Ctr.	1971	17 MW		AEI	
b) Naval Center	1976	22-28 MW		AEI	
c) North Island	1977	19 MW		AEI	
d) Rohr		0.8 MW		AEI	

The system being installed by Hoffmann-LaRoche is unique in that it uses a slow speed, two-stroke diesel engine.. It is designed to completely eliminate the need for purchased electricity and will have a small excess of electricity available for sale to the utility (Ref. 1).

In the Phillips system, the utility (Southwestern Public Service) owns, operates and maintains the turbine. Gas is furnished by Phillips, and the waste heat is used by Phillips in existing boilers. Phillips benefitted by reduced steam production costs, and SPS benefitted by a favorable price for the fuel (gas) supplied by Phillips. The generated electricity is distributed over the SPS system, rather than being dedicated in any way to the Phillips' plant (Ref. 3).

The Celanese system also involves SPS but in an arrangement different from the Phillips system (Ref. 3 and 4). Celanese purchased and installed coal-fired boilers and is responsible for all aspects of the boiler plants. Celanese also operates the turbine generator unit for SPS. SPS purchased and installed the turbine generator, which is rated at 29,955 KW. When supplied with 1.3 million lbs/hr steam at 1450 psig and 950°F, the steam exhausts at 650 psig and 750°F. The estimated electrical load at the Celanese plant is 20-22MW with the excess generation to be "exported" to the grid.

Negotiations for this project were apparently difficult because each party had some difficulty understanding the values, problems and financing difficulties of the other party. However, there was a mutual benefit and the arrangement was worked out. Details of the financial arrangements and benefits to each party are described in Reference 3.

The Celanese project resulted in a significant conservation of coal and gas over that previously used to generate the steam. The electrical generation is highly efficient because of conservation of energy normally lost in the condenser and cooling tower. Generation of the 30MW conserves approximately 68,700 tons of coal per year compared to generation in one of the SPS coal-fired units.

The unit capital cost for this relatively small unit was considerably higher than with a larger conventional unit. The approximate capital cost for the cogeneration portion of the unit was \$500/KW (1980 dollars, Ref. 4). The high capital investment cost was offset by fuel savings, indicating the need to carefully evaluate the economics of a cogeneration project. Finally, SPS evaluated that a cogeneration project usually cannot be justified unless a new boiler plant is required for some reason other than solely for cogeneration.

The 1979 addition to the Shell oil refinery added 60 MW to an already existing large cogeneration system to bring the capacity to 140 MW. It is a complex system which supplies steam, electricity and mechanical drive to the Deer Park Refinery. Shell invested \$125 million in the 1975 expansion, indicating their satisfaction with cogeneration. The system is expected to stay economic until a utility shift to coal and nuclear make it obsolete, perhaps in 10-20 years.

Hercules Chemical uses cogeneration at six of its major chemical plants (Ref. 5). At one site, cogeneration has been in use over 60 years. Hercules produces electricity for on-site consumption and also buys electricity. They do not plan to sell electricity. Their latest installation at Lake Charles, LA. was developed when their outside steam supply contract was not renewed, and they were faced with installing their own boilers. An economic analysis showed an after-tax return on investment of greater than 15 percent for a cogeneration system, and Hercules decided to build their own boilers and generate electricity. The boilers replaced the lost steam supply, and the electrical power produced or saved by the cogeneration system was 12.4 MW or about 40 percent of the total plant requirement.

Although more fuel oil was used by Hercules with cogeneration than without, there was a net fuel savings because the utility would have had to use considerably more fuel to supply the electricity cogenerated by Hercules. The energy savings is shown schematically in Figures 4.2.2-1 and 4.2.2-2.

Kerr-McGee's cogeneration systems at Searles Lake, California, are among the oldest and largest systems in the U. S. today (Ref. 6). Three systems exist at the site. Two are tied together and known as the Trona/Argus system, and the third is at the Westend facility, about five miles away. The Westend facility has had a cogeneration agreement with SCE since June of 1979, but very little energy was sold because of an unfavorable price. Since that time a modified agreement was accepted which set a price more favorable for sales to SCE. In spite of a state climate favorable to industrial cogeneration, Kerr-McGee has experienced difficulty in economically connecting to the utility because of uncertainty on price for electricity sold, capacity payments, and interconnect equipment requirements (Ref. 6).

A unique third party approach to a cogeneration system has been established by SDG&E (Ref. 7). A wholly-owned subsidiary, Applied Energy, Inc. (AEI), was formed in 1968 to install a central steam plant for the Naval Training Center. As indicated in Table 4.2.2-3, there are now four systems owned by AEI. AEI owns the boiler and is the steam boiler interface with the customer. The customer buys the thermal energy in the steam and returns the condensate.

Figure 4.2.2-1

LAKE CHARLES PROJECT
ANNUAL ENERGY PURCHASES
(REF. 5)

WITHOUT CO-GENERATION

WITH CO-GENERATION

Figure 4.2.2-2LAKE CHARLES PROJECTENERGY CONSERVATION

(REF. 5)

FUEL REDUCTION AT THE UTILITY - 165,000 BBLs./Yr.

FUEL INCREASE AT LAKE CHARLES - 78,000 BBLs./Yr.

SAVINGS IN FUEL CONSUMPTION - 87,000 BBLs./Yr.

SAVINGS TO HERCULES - SUBSTANTIAL

The utility owns and operates the gas turbine and produces electricity which is sent to the grid. The steam customer contracts for a continuous supply of steam and is motivated in this arrangement by a desire to avoid making a capital investment in the steam plant, and a desire to avoid the internal problems associated with operating and guaranteeing that steam supply. There is a secondary motivation in that the electric supply reliability is increased because the turbine is "on-site" (Even though the electricity is sent out to the utility system, there is a possibility for direct or dedicated supply.)

4.3. Projected Growth of Cogeneration

Cogeneration currently accounts for a small percentage of national energy supply. It is estimated (Ref. 8) that about 4 percent of electricity in the U.S. (approximately 9400 MW in 1980) is supplied through cogeneration. However, estimates of cogenerated electricity seem to vary widely, and an accurate evaluation is often complicated by a failure to clearly define the stated value (i.e., as installed capacity, or consumption, as electric or steam generation), or to consistently define "cogenerated" electricity.

A recent article in Business Week (Ref. 9) reported that "... industry experts predict that there will be 1,000 cogenerators in the U. S. by 1990, triple the 350 in use today." Furthermore, the article goes on to state that the Mellon Institute estimates the 1990 market for cogeneration at \$18 billion and that General Electric expects that "...as much as 50,000 MW of power will be cogenerated in the U. S. by the end of this century." A report by Frost & Sullivan (Ref. 10) projects that, under the present PURPA laws, the cogeneration market could grow from \$5.8 billion in 1985 to \$28.4 billion in 2000 (in 1980 dollars). EPRI (Ref. 11) has projected that industrial cogeneration could account for up to 15% of total KW Hr by the year 2000, under conditions attractive to cogeneration development.

Cogeneration growth will depend on how the PURPA laws are implemented by the states, as well as on any future legislation/regulations which impact cogeneration projects. Thus, projections of cogeneration growth should be based on specific assumptions about the PURPA laws.

California is one of the states which has taken an aggressive stand in promoting and encouraging cogeneration. In California, in addition to conventional industrial and commercial applications, agricultural and forest waste products made important contributions to cogeneration capacity. California now has about 1,000 MW(e) of cogeneration capacity installed or under contract. It is expected this will grow to 6,000 MW by 1990 (Ref. 12).

A California state interagency task force on cogeneration has been set up by Governor Brown to promote development of cogeneration.

4.3.1 EIA Forecast

Forecasts of cogeneration growth to the year 2020 have been developed by the EIA. A summary of forecasts is presented in Table 4.3.1-1.

EIA projects that cogeneration output (steam and electricity) will increase to about 3.7 quads in 2020. This estimate is based on the use of fossil fuels and includes no contribution by a nuclear heat source. EIA projects that about 10 percent of the industrial demand for electricity in 2020 will be satisfied by cogeneration and autogeneration. The cogeneration contribution is twice that of autogeneration and amounts to about 0.6 quads (approximately 20,000 MW(e)) output per year, as shown in Table 4.3.1-1. This is considerably less than the forecast by GE of 50,000 MW mentioned earlier. In fact, the EIA forecast seems to be lower than all other forecasts. The forecast for 2000 of 0.3 quads (approximately 9900 MW(e)) appear to be unrealistically low, considering that over 9000 MW is estimated to exist today! Thus, the EIA values generally are unreasonably low, but their forecasts of growth rates may be reasonable and should be considered. EIA projects that industrial use of utility electricity will grow at an annual rate of 2.6 percent per year from 2000-2020, while the industrial use of cogeneration electricity grows at a rate of 3.5 percent per year. Autogeneration is projected to remain constant in this period. Autogeneration use is limited because it uses conventional techniques similar to a utility but on a smaller scale. Cogeneration grows because the energy efficiency is greater than with conventional generation and the cost of adding cogeneration equipment to a new installation is often less than that required for the same level of generating capacity by an electric utility.

Cogeneration is expected to be a major source of industrial indirect heat (steam) by 2020. However, there is uncertainty in the projections because of the wide range of energy requirements for individual plants. The fraction of fuel use for industrial indirect heat supplied by cogeneration is projected to grow dramatically from 0.3 percent in 1978 to about 35 percent in 2020. This amounts to an annual rate of growth of 13.5 percent. Total fuel use for industrial heat in this same period grows at a rate of about 1.4 percent per year.

In the period 2000-2020, the cogeneration contribution grows at at 4.1 percent per year, while the total usage grows at about 1 percent per year. By 2020, fuel use for cogeneration of industrial indirect heat is expected to amount to approximately 4 quads, as shown in Table 4.3.1-1.

TABLE 4.3.1-1

EIA PROJECTIONS OF COGENERATION (Ref. 13)
 (Middle World Oil Price Case)

	<u>1978</u>	<u>2000</u>	<u>2010</u>	<u>2020</u>
(A) <u>Cogeneration Output/ Quads Per Year¹</u>				
Gas	NA	0.25	0.39	0.56
Low BTU Gas	0	0.68	1.08	1.35
Fluidized Bed	<u>0</u>	<u>0.76</u>	<u>1.20</u>	<u>1.80</u>
TOTAL	NA	1.69	2.67	3.71
(B) <u>Industrial Cogeneration of Electricity, Output, Quads/Year</u>	NA	0.3	0.4	0.6
(C) <u>Industrial Cogeneration of Indirect Heat (Steam), Fuel Input</u>				
as % of total fuel use for indirect heat	0.3	19.7	27.7	35.2
as quads of fuel	0.02	1.8	2.9	4.0

¹Electricity and Steam Production

4.3.2 GEA Cogeneration Project

General Energy Associates (GEA) is currently engaged in a one-year project for the Department of Energy (Contract No. DE-AC01-80CS-40362) on cogeneration plant sites, present and projected. Output of the project, scheduled for December 1981, will include a "source book" of existing cogeneration plant sites and a profile and listing of the potential "best sites" for cogeneration facilities. The latter will be based on present technology and will be presented on a demographic basis (by geographic area, and SIC code).

4.3.3 RPA Cogeneration Project

Resource Planning Associates (RPA) carried out a study in 1977 on cogeneration potential in six major industries (Ref. 14). This work continued by RPA under a DOE project which was reported on at two recent conferences (Ref. 15 & 16). The papers presented at these conferences were in-process summaries of the work by RPA. The final report was recently published (Ref. 17). A summary of the work is presented below.

Five major energy-intensive industries were studied (pulp and paper, chemicals, petroleum refining, steel, and food processing). For each of these industries, the potential for cogeneration development was projected through 1990. Projections were made based on the demand growth in these industries, the fraction of that growth suitable for cogeneration, and for various assumptions regarding government action to stimulate cogeneration growth.

The RPA work projects that total steam demand in 1990 for the five industries will be 5 quads. Of these 5 quads, they estimate the potential for cogeneration development to be about 1/3 of the total demand, or about 1.6 quads/year. This is equivalent to 212 million lbs/hour of steam. Over 2/3 of this potential is in the chemicals and pulp and paper industries. Figure 4.3.3-1 shows the total steam demand for each of the 5 industries, and the steam demand technically available for cogeneration investment.

RPA has estimated cogeneration development as steam and electric output, under specific assumptions regarding utility buy-back rates. Cogeneration development is very sensitive to buy-back rates and the present uncertainty in this area results in high uncertainty associated with any cogeneration projection.

Figure 4.3.3-1 Total Steam Demand &

Technical Potential For Cogeneration

(Source: Ref. 17)

The following projections are all for the RPA case of "high" buy-back rates, unless specifically stated otherwise:

Cogeneration development in the 1981-1990 period is projected to be about 13,000 MW electric and 155 Million lb/hour of steam. This would require a capital investment of about \$29 billion in 1981-1990. About \$9.5 billion of this total is the increment associated with cogeneration (\$19.5 billion is projected to be spent on boilers without cogeneration).

Total cogeneration electric capacity is projected to increase from about 10,000 MW today to about 21,000 MW in 1990. Figure 4.3.3-2 shows the breakdown by industry.

Figure 4.3.3-3 shows projected cogenerated steam capacity by industry. Large users of steam are indicated to be a significant growth area. Plants using greater than 1/2 million lb/hour of steam make up about 1/2 of the growth.

Figure 4.3.3-4 shows cogenerated power development by industry and size range. Petroleum refining and pulp and paper are the industries which have the greatest projected growth in the upper size range (>50MW).

Figure 4.3.3-5 shows the RPA projection of cogeneration growth by technology and industry. Although combined cycle systems account for 60% of the total projected megawatt development, they account for only 15% of cogenerated steam.

Figure 4.3.3-6 shows the 1990 national net energy savings projected by RPA. About 185,000 boe/day are projected to be saved. However, since oil is replaced by gas, the net actual oil savings is about 280,000 bpd. Cogeneration systems are projected to be fueled by gas or black liquor.

Figure 4.3.3-7 shows that over the lifetime of all cogeneration systems projected to be installed in 1981-1990, almost 8 quads of energy will be saved. (Coal and oil are saved, gas and black liquor are used.)

All the above figures assumed a high utility buy-back rate. RPA also made projections based on low buy-back rates. Under this assumption, there was a relatively small drop (12%) in projected cogeneration steam growth (155 MM lb/hr to 138 MM lb/hr). However, the projected cogenerated electric growth dropped about 50% (12,800 MW to 6,200 MW). This difference is explained as being reflective of the more attractive economics of technologies with low electric/steam ratios.

RPA concludes that 6,200-12,000 MW(e) is the most likely range for industrial cogenerated electric development in the 1980's. The range is due to different assumptions regarding utility buy-back rates.

Figure 4.3.3-2

Expected 5-Industry Cogeneration Development: 1981-1990*

(MW)

(Source: Ref. 17)

* Figures represent upper end of range considered likely.

Figure 4.3.3-3**Cogenerated Steam Capacity by Industry: 1981-1990***
(000 lbs steam/hr)

(Ref. 17)

Size Range	Food Processing	Pulp & Paper	Chemicals	Petroleum Refining	Steel	Total
Under 50	3,400	200	1,400	1,500	0	6,500
50-100	2,500	4,500	38,100	0	400	45,500
100-500	2,750	9,400	13,800	2,050	0	28,000
500-1,000	0	41,000	9,900	11,100	8,000	70,000
Over 1,000	0	0	0	5,000	0	5,000
Total	8,650	55,100	63,200	19,650	8,400	155,000

* Figures represent the upper end of the range of cogeneration investment considered likely.

Figure 4.3.3-4**Cogenerated Electric Power Development by Industry: 1981-1990***
(MW)

(Ref. 17)

Size Range	Food Processing	Pulp & Paper	Chemicals	Petroleum Refining	Steel	Total
Under 5	380	200	1,090	70	0	1,740
5-25	150	860	1,070	250	0	2,330
25-50	90	1,800	1,150	380	400	3,820
Over 50	60	2,500	650	1,500	200	4,910
Total	680	5,360	3,960	2,200	600	12,800

* Figures represent the upper end of the range of cogeneration investment considered likely.

Figure 4.3.3-5**Expected Additional Cogeneration Capacity by Industry and Technology: 1981-1990***
(MW)

(Ref. 17)

	Food Processing	Pulp & Paper	Chemicals	Petroleum Refining	Steel	Total
Coal boiler with steam turbine	170	110	1,720	680	400	3,080
Coal AFB with steam turbine	0	0	120	50	0	170
Black liquor boiler and steam turbine	0	2,100	0	0	0	2,100
Oil/gas combustion turbine/HRB	420	0	570	180	0	1,170
Combined cycle	90	3,150	1,550	1,290	200	6,280
Total	680	5,360	3,960	2,200	600	12,800

* Figures represent the upper end of the range of cogeneration investment considered likely.

Figure 4.3.3-6

(Ref. 17)

**Net National Energy Savings by Fuel in 1990 from 5-Industry Cogeneration
Installed from 1981-1990**
(000 boe/day)

Figure 4.3.3-7

(Ref. 17)

**Net Energy Savings by Time Period from 5-Industry Cogeneration
Installed from 1981-1990**
(quadrillion Btu)

The effect of government action in providing financial incentives and regulatory relief was also examined. Three actions which showed significant energy-saving benefits and which were cost effective were:

- Shortening depreciation life for cogeneration equipment
- Broadening the scope of Investment Tax Credits (ITC)
- Removing utility ownership limitations on cogeneration plants qualified under PURPA.

Shortening depreciation life from an average of 15 years to 5 years, including cogeneration and conventional boiler systems, is projected to increase cogeneration capacity in 1990 from 12,800 MW to 14,100 MW (10% increase). The percentage increase in oil savings is even greater, because the additional investment would be in oil-dependent areas.

Making the additional 10% ITC for cogeneration systems applicable to oil and gas-fired systems, and extending it to 1990 would have about the same impact as shortening depreciation life to 5 years. The incentive to use oil or gas favors cogeneration technologies with high electric to thermal outputs, thus displacing more utility power and increasing oil savings.

RPA evaluated the present PURPA law restricting utility ownership to 50% in unregulated plants. They conclude that lifting this restriction could have a significant impact in cogeneration development in three areas:

- a) Some cogeneration investment that industry would have made will be made by utilities causing shift to technologies with higher electric to thermal outputs. The increase could be about 2000 MW(e).
- b) Stimulation of additional utility-owned cogeneration, about 1000 MW.
- c) Establishment of additional and higher avoided cost tariffs by utilities, adding about 1000 MW of industry-owned systems.

Together, these add up to about 4000 MW of additional cogeneration capacity in 5 industries by 1990.

RPA concludes that full deregulation of utility ownership has the greatest potential impact on cogeneration development.

4.4 District Heating

District heating is a system where thermal energy is generated in a central source, and distributed to industrial, commercial and residential users for space heating and cooling, hot water, and other purposes. The distribution is usually by underground or understreet pipes. The heat transport medium is steam or hot water. In the U. S. almost all district heating systems use steam, while in Europe, hot water is used.

A focal point of information on this subject is the International District Heating Association (IDHA), located in Washington, D.C. The IDHA is a non-profit, technical organization dedicated to the advancement of district heating and cooling. It provides statistical data on district heating and holds an annual convention and other conferences to provide for information exchange and dissemination.

Timely information is also published in the District Heating Cogeneration Bulletin prepared for DOE by ANL. This report presents up-to-date information on recent projects and legislation in district heating.

4.4.1 Experience and Prognosis - U. S.

Almost all district heating systems in the U. S. use steam as the heat transport medium. Steam is a less desirable medium than hot water because of higher heat losses, higher water use and costlier installation. Most of the steam systems existing in the U. S. were built in the early 1900's when steam heat systems achieved their greatest growth. During this period, waste heat from electric power plants was plentiful and sold for distribution costs only. Also, plants were relatively small and located close to the users. As these plants were replaced with large, remotely located plants, the old existing steam systems were preserved, but there has been no incentive to expand or upgrade them.

District heating is not used extensively in the U. S., and there is only minor activity in developing new systems. A district heating survey was carried out in 1979 for EPRI by EUS, Inc. (Ref. 18). That report presents information on experience in the U. S. and Europe and presents ten case studies of existing systems in the U. S. It also discusses economic and institutional barriers to district heating growth.

Significant conclusions of this report are as follows:

- U. S. systems use steam technology which has higher costs than the European type of hot water systems.
- Although hot water systems are technologically superior, the European experience is not directly applicable in the U. S. because of differences in environmental regulations, subsidies, requirements for customer hookups, and greater oil dependence in Europe for heating.
- District heating, as practiced in the U. S., is not generally a viable method of large-scale energy distribution.
- District heating in the U. S. represents a small and generally unprofitable portion of the utility's business.
- Most of district heating systems in the U. S. are more than 40 years old and have not undergone major upgrading since they were built.

In spite of the low level of interest, there are a few projects currently being developed. Two of these are described below.

In Trenton, New Jersey, a \$22 million heating and electricity plant is in the final design stage. The plant will provide circulating hot water heat to 25 buildings, heated by waste heat from generation of 12 MW of electricity.

In St. Paul, Minnesota, a 165 MW district heating system is in the final design stage, and construction is expected to start in 1982. The St. Paul District Heating Development Co. (DHDC) plans to tap waste heat from a local power plant to heat circulating water for 100 downtown buildings.

The largest district heating system in the U.S., and one of the oldest in existence, is the Consolidated Edison system. Con Ed supplies more steam than the next 8 largest domestic steam companies combined, and is responsible for 37% of all district heating steam sold in the U.S.

While the Con Ed system, started in New York in 1879, grew to be one of the world's largest, the Chicago system has been totally discontinued since 1979.

After Con Ed, the next largest systems in the U. S. are owned by Philadelphia Electric, Detroit Edison and Boston Edison. The vast majority of steam customers are commercial, with a small fraction of customers as industrial, residential and other.

Because of the low level of interest in district heating in the U. S., no further information will be presented here. If the reader is interested in pursuing the subject further, it is suggested he consult the IDHA, EPRI (Research Project 1276-3) or sources of European experience.

4.4.2 Experience and Prognosis - Europe

Unlike the U. S., in Northern Europe, district heating is used extensively. For example, in Denmark about one-third of all houses have a district heating connection, much like any other utility connection (Ref. 19). Furthermore, the present thrust in Denmark is for more decentralized heat and power production. Other European countries are also very active in developing modern, efficient and economical district heating systems. The majority of district heating development occurred in Denmark, Finland, Sweden, West Germany and the Soviet Union.

There are several major differences between European countries and the U. S. which are responsible for the difference in district heating use:

- Fuel cost and availability
- Building design
- Winter vs. summer peaking
- Concentration of population
- Environmental regulations
- Government support and subsidy

European systems generally supply hot water via generation and transmission systems which can be expanded as the load grows. Distribution of hot water, rather than steam as in U. S. systems, results in lower installation costs and thermal losses.

District heating systems are generally fossil-fueled. The use of a nuclear heat source has been evaluated (Refs. 20 and 21), but apparently there are no such systems in operation today in Europe or North America.

SECTION 4 - REFERENCES

- (1) J. Davis & S. Nydick, Industry/DOE Diesel Cogeneration Technology Demonstration Program - An Update, Energy Bureau Conference on Cogeneration, March 1981.
- (2) EPRI EM-1531, Industrial Cogeneration Case Studies, September 1980.
- (3) C. Milnar, Utility/Industrial Cogeneration: Making it Happen, Energy Bureau Conference on Cogeneration, March 1980.
- (4) C. Lignon, Cogeneration Project--Southwestern Public Service Co. and Celanese Chemical Company, Tampa Plant, presentation at EEI Prime Movers Committee, January 29, 1980.
- (5) P. Graybeal, In-Plant Cogeneration, Energy Bureau Conference on Cogeneration, March 1980.
- (6) D. Higgins, Industrial Cogeneration: An Update, Energy Bureau Conference on Cogeneration, March 1981.
- (7) P. Hodiak, Industrial/Utility Cogeneration: Third Party Ownership, Energy Bureau Conference on Cogeneration, March 1980.
- (8) "Cogeneration - Will It Slow or Will It Grow?," Electrical World, April 1981, P.24.
- (9) Business Week, April 6, 1981, Pp. 56-60.
- (10) Cogeneration Systems & Associated Products & Service Markets, Frost & Sullivan, Inc. 1980.

- (11) Plugging Cogeneration into the Grid, EPRI Journal, July/August 1981 P. 7.
- (12) Progress & Prognosis of Cogeneration in California, C. Dedrick, Energy Bureau Conference on Cogeneration, March 1981.
- (13) EIA 1980 Annual Report to Congress, DOE/EIA-0173(80)/3, Pp. 128, 142, 146.
- (14) The Potential for Cogeneration in Six Major Industries by 1985, Resource Planning Associates, December 1977.
- (15) Expected Industrial Cogeneration Investment in the 1980's, P. Bos, Energy Bureau Conference on Cogeneration, March 1981.
- (16) Expected Industrial Cogeneration Investment in the 1980's, P. Bos, The Sixteenth Intersociety Energy Conversion Engineering Conference, 8/12/81.
- (17) The Potential for Industrial Cogeneration Development by 1990, Final Report, Resource planning Associates, July 31, 1981.
- (18) EPRI EM-1435, Dual Energy Use Systems District Heating Survey, 7/80.
- (19) W. Mikkelsey & Fl. Hammer-Sorensen, National or Localized Plans for Combined Heat and Power Developments, Second International Total Energy Congress, October 8-12, 1979.
- (20) G. Tedestal, Heat Extraction From the Barsebeck Nuclear Power Station, ibid.
- (21) Y. El Mahgary et al, Economic Analysis and Probabilistic Site Evaluation of Nuclear Plants Producing District Heat and Electricity, ibid.

5.0 INSTITUTIONAL FRAMEWORK FOR COGENERATION AND PROCESS HEAT

As discussed earlier, the use of industrial cogeneration has declined dramatically since the early part of this century. Prior to the National Energy Act (NEA) of 1978, there was, in fact, very little industrial interest in cogeneration. Industry was reluctant to enter into this area because of some major uncertainties:

- The possibility of being regulated as an electric utility if cogeneration was installed.
- The marketability and price for exported electricity.
- The cost of backup or supplementary power.
- The availability of tax credits or other benefits to make the project financially sound.

On the other hand, some utilities perceived industrial cogeneration as government-sponsored and partially subsidized competition which could pose problems for economic utility system operation and possibly also threaten system safety and reliability. Utilities had no financial incentive to participate in a cogeneration project, especially if they had excess capacity. Utilities with excess capacity found that new capacity connected to their system could introduce costly cutbacks in their efficient generators.

Passage of the National Energy Act of 1978 and other energy-related legislation has relieved much of the uncertainty surrounding cogeneration from the perspective of industry. The legislation was aimed at promoting and encouraging industrial cogeneration, but has done little to relieve the utility concerns. The legislation has created considerable activity and confusion regarding its interpretation and implementation. This section of the report will discuss each of the major legislative actions, their implementation and impact on cogeneration development. However, this is an area of active review and reader should check the latest legislative and regulatory actions to get the most recent information.

5.1 Federal Regulations

5.1.1 National Energy Act (NEA) - 1978

The NEA (PL 95) was signed by President Carter on November 8, 1978. Three parts of this act contain provisions relating to cogeneration and small power production:

- Public Utilities Regulatory Policy Act (PURPA)-PL-95-617
- Natural Gas Policy Act (NGPA) of 1978-PL 95-621
- Energy Tax Act of 1978-PL 95-618.

All of these acts, as well as others discussed later, tend to give incentives to industry for cogeneration, while giving no incentives or, in some cases, disincentives to utilities for cogeneration. The legislation puts utilities at unfair disadvantage. As a result, efforts are underway by utilities and utility groups to revise these regulations such that utilities may have the same incentives afforded to industry. (Refs. 1 and 2).

5.1.1.1 PURPA

Numerous articles, papers, studies, testimonies and analyses have been presented on PURPA (e.g. Refs. 3-7). This section will present a brief discussion on what PURPA is and what its effect is on cogeneration projects. For legal interpretations or the full text of the law, the reader is directed to the cited references.

Public Law 95-617 is called the "Public Utility Regulatory Policies Act of 1978," or "PURPA." One part of PURPA, "Title II-Certain Federal Energy Regulatory Commission and Department of Energy Authorities," contains two sections which affect cogeneration and small power production. Those sections are 201, "Definitions," and 210, "Cogeneration and Small Power Production."

Section 201 amends the Federal Power Act by adding definitions for "cogeneration facility" and "qualifying facility." The latter refers to facilities qualifying for benefits as set forth in Section 210. Section 210 also requires the Federal Energy Regulatory Commission (FERC) to develop rules implementing 201 and 210 and encouraging cogeneration. The FERC published

proposed rules in June of 1979. This was followed by numerous hearings, revised proposed rules, and more hearings. The final rules were published in two parts as numbers 69 and 70. Order No. 69 was issued on February 19, 1980. This order implemented Section 210, and it is entitled "Small Power Production and Cogeneration Facilities--Rates and Exemptions". Essentially, it covers rights of a "qualifying facility" (QF). Order No. 70 is entitled "Small Power Production and Cogeneration Facilities--Qualifying Status." Orders 69 and 70 comprise most of Part 292 of Chapter I, Title 18, of the Code of Federal Regulations. Additions, revisions and corrections to Part 292 have been published, and for the latest revision, the reader is directed to 18 CFR, Part 292.

A brief description of the content of Orders 69 and 70 follows. The actual orders are each about 100 pages long

a) Order No. 70, Section 201-Qualifying Facility (QF)

Order No. 70 sets forth standards which a QF must meet and describes procedures for obtaining qualifying status. A small power production facility is defined as one no larger than 80 MW. A cogeneration facility is defined as: "... equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial, heating or cooling purposes, through the sequential use of energy." Critical terms in this definition are equipment (which defines limits of the "facility"), useful, and sequential. Complete discussion of these terms is available in Order No. 70.

Figure 5.1.1.1-1 lists the basic requirements for these facilities to be classified as a QF.

Two of the qualifying requirements for cogenerators merit some further comment. The sequential use of energy was imposed in order to ensure ~~that the~~ energy-conserving characteristic of cogeneration is retained. By imposing the sequential use, this ensures that otherwise wasted heat is employed, and excludes the case of a boiler with two steam line outputs in parallel.

FIGURE 5.1.1.1-1

REQUIREMENTS FOR QUALIFYING FACILITIES
UNDER PURPA 201 AND ORDER NO. 70

(A) SMALL POWER PRODUCTION FACILITY

- Size less than 80 MW.
- 3/4 of fuel must be other than oil, natural gas and coal, AND,
- Utility ownership is not over 50 percent.

(B) COGENERATION FACILITY

- Utility ownership is not over 50 percent
- Diesel facilities built before March 13, 1980
- Energy used sequentially
- Efficiency tests (depends on process and fuel)

a) Order No. 70, Section 201 -
Qualifying Facility (QF) - Continued

The lengthiest requirement to explain is the efficiency standard. Essentially, the efficiency tests attempt to define conditions which result in savings in oil or gas usage. In fact, the rules allow for a waiver of the specific test formula if it can be shown that the facility will produce "significant energy savings" of oil and gas. The efficiency tests are different for topping-cycles (heat used first to produce power) or bottoming cycles (heat used first for process).

For topping-cycles, the efficiency requirement is:

- 1) 5 percent of total energy output must be useful thermal output ("bonafide" test).
- 2) For facilities where installation began on or after March 13, 1980, power output plus 1/2 thermal output must be at least 42 1/2 percent of the oil and gas energy input on an annual basis. If, however, the thermal energy output is less than 15 percent of the total energy output, then the 42 1/2% is raised to 45 percent.
- 3) For facilities where installation began prior to March 13, 1980, no efficiency standards apply.

Thus, facilities initiated prior to the ruling can become qualified without meeting any efficiency standard.

After a facility becomes a QF, it can then benefit from incentives under Section 210, as described in the next section.

b) Order No. 69, Section 210 - Rates
and Exemptions

Order No. 69 finalizing FERC's rulemaking pursuant to Section 210, Order No. 69 required the rules to be implemented by March 20, 1981 by each state regulatory commission and by each non-regulated utility. In some cases this was done, but for most states the commissions are only in the initial phase of implementation.

Order No. 69 provides advantages for Qualifying Facilities. These advantages are designed to remove uncertainties (referred to earlier) which have kept industry away from cogeneration projects. Specifically, these advantages are:

- Exemption from regulation as a utility.
- Assured market for exported power, at an attractive price.
- Assured interconnection with utility, and ability to purchase power at the going industrial rate.

These advantages are stated very simply here, but the implementation by states, with regard to the cogenerator's price for buying and selling power and the cost and method of interconnection, are areas of considerable complication. A wide variation in interpretation is developing as each state implements the rules.

Basically, the price to be paid by utilities to cogenerators for electric power is the "avoided" cost to the utility. That is, "the sole determinant for the price for the power will be what the utility would pay based on the avoidance of generating cost on its system by reason of purchase of power from the cogenerator" (Ref. 6). This includes fuel costs as well as cost of avoided capacity additions. On the other hand, utilities are required to sell power to a OF at the going industrial rate. Each state is required to post its "avoided cost" tariff, but the avoided cost concept has been interpreted differently, resulting in widely different avoided cost rates.

5.1.1.2 Natural Gas Policy Act (NGPA) - 1978

The NGPA provides for the deregulation of natural gas prices and establishes a pricing system which places a higher gas price on industrial users of gas. Section 206(c)(3) of the NGPA exempts qualified cogenerators from the higher gas prices and assigns them a higher allocation priority for gas requirements. The treatment is different for topping and bottoming cycles, but both types can benefit from the exemption.

5.1.1.3 Energy Tax Act - 1978

The Energy Tax Act makes certain "energy property" eligible for an extra 10 percent investment tax credit (ITC). This is in addition to the normal 10 percent ITC and is termed an "energy tax credit." The eligible property includes certain cogeneration equipment, as defined in the act but excludes any utility property. It also provides for accelerated depreciation of gas or oil-fired boilers that are being replaced by a more energy-efficient cogenerator.

5.1.2 Crude Oil Windfall Profits Tax Act - 1980

This is primarily developed to reduce oil-derived profits, but also includes incentives for production of fuel from non-conventional sources. This act, combined with the Energy Tax Act of 1978, provided the 10 percent energy tax credit to certain cogenerators.

5.1.3 Power Plant and Industrial Fuel Use Act (FUA) - 1978

This act placed restrictions on the use of natural gas or petroleum in power plants or major fuel burning installations (min. energy input of 100 million BTU's per hour). It prohibits the use of these fuels in new installations and requires a phasing out of the use in older installations. However, the act provides a permanent exemption for a cogeneration facility that offers economic and other benefits not obtainable without oil and gas use. To qualify for the exemption, the cogeneration facility must produce electric power and any other form of useful energy, e.g., steam, gas or heat, which is or will be used for industrial, commercial or space heating purposes.

The final rules implementing the FUA were published in the Federal Register of June 6, 1980, starting on Page 38276.

5.2 Current Activity - PURPA

FERC Order No. 69 required state regulatory commissions to have cogeneration rate-setting mechanisms in place by March 20, 1981, but less than half of the states actually met that deadline. A state-by-state status report as of 4/81 is presented in Table 5.2-1. Apparently, FERC does not plan to enforce the deadline unless there are specific complaints (Ref. 8).

Table 5.2-1
(Taken From Fuel & Power)

STATES' COGENERATION RATE-SETTING UNDER PURPA

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), state regulatory agencies were required to have in place by March 20, 1981, mechanisms to assure that industrial cogenerators receive just, reasonable and non-discriminatory prices for sales of electricity to utilities. As an

incentive to cogenerate, the rates are to be based on the utility's "avoided costs," not on the cost-of-service. The status of state cogeneration proceedings under PURPA and the approved rates for the sale of cogenerated electric power to utilities (in cents per kilowatt-hour) are shown below. In

some states, rates are divided into reliable and non-reliable categories to accommodate different cogeneration procedures. Also, in some states, rates for each power company were too numerous to list.

STATE	STATUS	RATES	COMMENT
ALABAMA Public Service Commission.	Final rates for production of 100 kw or less. Others pending. PSC is developing rates for larger producers, but has deferred at request of Alabama Industrial Group because industrial users have not yet agreed to terms with utilities.	For producers of 100 kw or less: Option A (standard rate) is 1.88 cents June through Oct. and 1.77 cents Nov. through May; Option B (time-of-day rate) is 2.61 cents on-peak and 1.88 cents off-peak June through Oct. and 2.2 cents on-peak and 1.77 cents off-peak Nov. through May.	Call Wallace Tidmore, Alabama PSC, (205) 832-3421.
ALASKA Public Utilities Commission.	Not approved.	Not available.	Call Robert Barber, Alaska PUC, (907) 276-6222.
ARIZONA Arizona Corporation Commission.	Pending. Has not held hearings.	Not available.	Call Jim Apperson, ACC, (602) 255-4251.
ARKANSAS Public Service Commission.	Pending. Proposed order being considered.	Not available.	Call Betty Wood, Arkansas PSC, (501) 370-5480.
CALIFORNIA Public Utilities Commission.	Temporary rates. In Dec. 1979 PUC ordered utilities to buy cogenerated power at avoided costs. These interim utility-set rates are subject to PUC rulemaking in May. Also, staff has recommended summer hearings on accuracy of utility-avoided cost figures.	Temporary rates set by each utility.	Call John Quinley, California PUC, (415) 557-2904.
COLORADO Public Utilities Commission.	Pending.	Not available.	Call Mike Homyakl, Colorado PUC, (303) 866-4300.
CONNECTICUT Department of Public Utility Control.	Temporary rates. Department-set rates in effect until utility-proposed rates are approved.	Temporary. For non-reliable power sources: 6.6 cents on-peak and 5.2 cents off-peak. For reliable power sources: 4.7 cents on-peak and 5.4 cents off-peak.	Call Mark Jeske, Connecticut DPUC, (203) 566-7882.
DELAWARE Public Service Commission.	Pending. Hearings May 20-21 on Delmarva Power Co. tariff. Hearing May 6 for Lincoln-Ellendale Electric Co.	Not available.	Call Robert Kennedy, Delaware PSC, (302) 736-4247.
FLORIDA Public Service Commission.	Final rules. Commission encourages negotiated rates. In lieu of contract, rates are based on computer-monitored utility fuel costs.	Utilities are filing tariff schedules.	Call Florida PSC, (904) 488-8501.
GEORGIA Public Service Commission.	Proceedings suspended. Awaiting outcome of Supreme Court decision on constitutionality of PURPA.	Not available.	Call Sam Weaver, Georgia PSC, (404) 658-4541.

GEORGIA Public Service Commission.	Proceedings suspended. Awaiting outcome of Supreme Court decision on constitutionality of PURPA.	Not available.	Call Sam Weaver, Georgia PSC, (404) 656-4541.
HAWAII Public Utilities Commission.	Not approved.	Not available.	Call Leroy Yuen, Hawaii PUC, (808) 548-3990.
IDAHO Public Utilities Commission.	Pending. Rates filed by CP National, but they have not yet been approved.	Not available.	Call Idaho PUC, (702) 885-5134.
ILLINOIS Commerce Commission.	Final rules. Rules subject to approval of Illinois legislature's Joint Committee on Administrative Rules. Rates not yet filed.	Not available.	Call Charles Teclaw, ICC, (217) 785-0326.
INDIANA Public Service Commission.	Pending. Cogeneration rate formula developed by PSC sent to state attorney general's office for approval. Then must go to governor.	Not available.	Call William D. Boyd, Indiana PSC, (317) 232-2711.
IOWA State Commerce Commission.	Final rules. Commission has developed rate and avoided-cost formula.	Not available.	Call Bob Latham, Iowa SCC, (517) 373-6430.
KANSAS Kansas Corporation Commission.	Pending. Staff is developing avoided-cost methodology. Hearing April 27-28.	Not available.	Call Carol Lawson, KCC, (913) 296-3326.
KENTUCKY Utility Regulatory Commission.	Pending. Commission now deciding rates on case-by-case basis. Hearings begin April 27. Rate schedule expected by July.	Not available.	Call Richard Heman, Kentucky URC, (502) 564-3940.
LOUISIANA Public Service Commission.	Pending. Hearing held in Feb. No action expected soon.	Not available.	Call Arnold Chauviere, Louisiana PSC, (504) 342-4404.
MAINE Public Utilities Commission.	Pending. PUC asking utilities to file cogeneration rate requests. Hearings not yet scheduled.	Not available.	Call Maine PSC, (207) 289-3831.
MARYLAND Public Service Commission.	Pending. April 6 proposed order requires utilities to file tariffs for facilities producing 100 kw or less. Each tariff to be considered separately.	Not available.	Call Paul Daniels, Maryland PSC, (301) 659-6021.
MASSACHUSETTS Department of Public Utilities.	Pending. All hearings held. DPU to adopt cogeneration rules by end of April.	Not available.	Call Massachusetts DPU, (617) 727-6900.
MICHIGAN Public Service Commission.	Pending. PSC ordered utilities to remove cogeneration barriers, and sent out questionnaires on cogeneration rates. Hearings to be held.	Not available.	Call Margaret Cooney, Michigan PSC, (517) 373-8171.
MINNESOTA Public Service Commission.	Pending. Avoided-cost formula being debated by PSC and state legislature.	Not available.	Call Stuart Mitchell, Minnesota PSC, (612) 296-8662.
MISSISSIPPI Public Service Commission.	Pending. Power companies asked to submit avoided-cost rate design for power producers under 100 mw. Larger projects likely to be decided case by case. Hearings expected in late April.	Not available.	Call C. Keith Howle, Mississippi PSC, (601) 353-7265.

STATES' COGENERATION RATE-SETTING UNDER PURPA

STATE	STATUS	RATES	COMMENT
MISSOURI Public Utilities Commission.	Final PSC order issued April 7, effective May 15.	To be negotiated between utility and cogenerator. Commission will hold hearings if trouble arises in negotiations.	Not applicable.
MONTANA Public Service Commission.	Final rules. Rates to be approved in October.	Not available.	Call Ted Otis, Montana PSC, (406) 449-2649.
NEBRASKA (No utility regulatory agency)	Public power districts deal directly with Department of Energy to set rates. Some public power districts have set rates for power producers under 100 kw and will set rates for larger producers on case-by-case basis.	Not available.	Not available.
NEVADA Public Service Commission.	Final rules. Idaho Power and CP National have filed rates, but rates have not yet been approved. Sierra Pacific Power has not established a rate. Nevada Power has approved rate.	Nevada Power: beginning April 1981, 4.423 cents on-peak and 2.452 cents off-peak; beginning May 1981, 5.348 cents on-peak and 2.257 off-peak; beginning June 1981, 4.577 cents on-peak and 1.947 cents off-peak. Capacity credits also set.	Call Nevada PSC, (702) 805-5134.
NEW HAMPSHIRE Public Utilities Commission.	Final rates.	For non-reliable power sources, 7.7 cents, and for reliable power sources, 8.2 cents.	Call Judy Elliott, New Hampshire PUC, (603) 271-2437.
NEW JERSEY Board of Public Utilities.	Hearings concluded. Final rates expected by end of April. Jersey Power & Light already has tariff.	Not available.	Call Steve Gable, New Jersey BPU, (201) 648-2045.
NEW MEXICO Public Service Commission.	Pending. Task force formed to submit recommendations. Electric utilities to present recommendations by April 27.	Not available.	Call New Mexico PSC, (505) 827-2827.
NEW YORK Public Service Commission.	Temporary rates. Utility-proposed rates can now be used in contracts, but are subject to change by PSC rate-setting.	Interim rates determined by individual utilities.	Call Craig Indyke, New York PSC, (518) 474-6515.
NORTH CAROLINA Public Utilities Commission.	Approved.	Separate rate schedules filed by each of state's four major suppliers: Duke Power Co., Carolina Power and Light Co., Virginia Electric and Power Co., and the Nantahala Power and Light Co.	Call North Carolina PUC, (910) 733-2267.
NORTH DAKOTA Public Service Commission.	Final rules. Cogeneration rules approved. Utilities in process of filing rate schedules.	Not available.	Call Wally Owen, North Dakota PSC, (701) 224-4078.
OHIO Public Utilities Commission.	Pending. Hearings held. Suggested tariffs due by May 4.	Not available.	Call Ohio PUC, (614) 468-7750.
OKLAHOMA Oklahoma Corporation Commission.	Final order issued March 20 by OCC.	Firms with plans for cogeneration projects will negotiate contract terms with utilities, subject to review by commission. Either party can appeal to OCC. Tariffs to be experimental for next 30 months.	Not applicable.
OREGON Public Utility Commission.	Pending. Proposed rules issued.	Not available.	Call Leon Hagen, Oregon PUC, (503) 378-6687.
PENNSYLVANIA Public Utility Commission.	Pending. Staff has proposed regulations that basically follow FERC draft. Hearings expected.	Not available.	Call Rick Sand, Pennsylvania PUC, (717) 78
RHODE ISLAND	Pending. Two major electric utilities were ordered	Not available.	Call Laura Dawd, Rhode Island

PENNSYLVANIA Public Utilities Commission.	Pending. Staff has proposed regulations that basically follow FERC draft. Hearings expected.	Not available.	Call Rick Sandusky, Pennsylvania PUC, (717) 746-146.
RHODE ISLAND Public Utilities Commission.	Pending. Two major electric utilities were ordered to submit proposed cogeneration rates. No hearing dates set.	Not available.	Call Laura Dowd, Rhode Island PUC, (401) 277-3500.
SOUTH CAROLINA Public Service Commission.	Final rules. Commission encourages negotiated rates and will review agreements at request of user or utility. In lieu of contract, rates are based on rate schedules set by utilities.	Carolina Power and Light Co. has filed rate schedule for producers up to 5 mw, Duke Power Co. has set rates for producers up to 80 mw, and South Carolina Electric and Gas Co. has set rates for producers up to 100 kw.	Call South Carolina PSC, (803) 758-5362.
SOUTH DAKOTA Public Utilities Commission.	Pending	Not available.	Call Walter Washington, South Dakota PUC, (605) 773-3201.
TENNESSEE Tennessee Valley Authority Board of Directors.	Final rates.	TVA pays 135 percent of its wholesale rate of power produced on peak and 85 percent of its wholesale rate for power produced off-peak. (Current wholesale rates are 4.12 cents on-peak and 2.594 cents off-peak.)	Call Robert Hemphill, TVA, (615) 755-2061.
TEXAS Public Utility Commission.	PUC staff preparing proposed order based primarily on report of industry-utility task force completed late 1980.	Detailed methodologies for estimating avoided costs developed by task force and expected to be incorporated into commission's order.	Call Tom Halicki, Texas PUC, (512) 458-02707.
UTAH Public Service Commission.	Temporary rates. Interim utility-set rates have been approved but are subject to PSC rate-setting.	Utah Power and Light and CP National: 2.2 cents for units up to 1 mw (or 100 kw for hydro) for delivering energy; 2.6 cents for units the same size delivering energy and capacity. For larger units, rates are negotiable on case-by-case basis up to 3.5 cents.	Call Douglas Kirk, Utah PSC, (801) 533-6416.
VERMONT Public Service Board.	Pending. Expects to adopt rules within next two months.	Not available.	Call Deborah DeGraff, Vermont PSB, (802) 828-2880.
VIRGINIA State Corporation Commission.	Final rates.	During July, Aug, Sept., Dec., Jan. and Feb., rates are 4.31 cents on-peak and 2.274 cents off-peak. During March, April, May, June, Oct. and Nov., rates are 3.9 cents on-peak and 2.274 cents off-peak.	Call Virginia SCC, (804) 788-4932.
WASHINGTON Utilities and Transportation Commission.	Final rules. Rates will be determined later for units 100 kw and less. Rates for larger systems will be negotiable.	Not available.	Call David Rees, Washington UTC, (206) 753-8420.
WEST VIRGINIA Public Service Commission.	Pending. For facilities below 100 kw, proposed order likely this month and becomes final if PSC does not act in 15 days. For larger facilities, hearings expected on draft proposal.	Not available.	Call Rick Hitt, West Virginia PSC, (304) 348-2174.
WISCONSIN Public Service Commission.	Temporary rates. Six largest utilities have own rates. Hearings on PSC rates are continuing.	Temporary. For production of 200 kw or below: from 1.5 cents off-peak to 2.5-4.8 cents on-peak. For larger producers, rates are negotiable.	Call Terrence Nicolla, Wisconsin PSC, (608) 266-5620.
WYOMING Public Service Commission.	Final rates.	Rates established for 28 different utilities.	Call Dave Walker, Wyoming PSC, (405) 777-7427.

An uncertainty which has probably contributed to the slowness of PURPA implementation is the Mississippi Federal court ruling earlier this year that major portions of PURPA were unconstitutional. The basis for this ruling was that the Act unduly displaces and usurps the right of a state to make its own policies on intrastate matters. The ruling is currently in appeal by FERC at the U. S. Supreme Court and is not expected to be heard before January of 1982. The State of Georgia is the only state which has "officially" delayed cogeneration rule-making activities until after the government's appeal to the Supreme Court is settled. While most observers believe the lower court ruling will be reversed, this court action has probably contributed to the slowness of state activity.

Varied approaches have been adopted by state agencies regarding implementation of PURPA. Some have set generic rates, while others have provided minimum rates (performing a case-by-case review of cogeneration systems). Also, many state commissions tend to set rates for small power producers (less than 100KW), and encourage individual contract negotiations for the larger industrial cogenerators.

Most commissions focus on the issue of "avoided cost," and have yet to face the issues of back-up power and interconnection requirements. Both these issues are vitally important in assessing the economics of an industrial cogeneration project. Thus, even though rates may be set, these factors are enough of an uncertainty to hold up a project.

FERC left implementation of the interconnection guidelines up to the state commissions. The guidelines prevent utilities from charging cogenerators twice for system hook-up or charging for "unnecessary safety equipment", and stipulate that utility connection charges cannot be any more than the expense of connecting minus the avoided cost of connecting to other power plants.

Acceptance and perspective of PURPA varies with different users and utilities. Some potential industrial cogenerators are considering cogeneration systems which would not be considered without PURPA incentives. Skeptics of PURPA, however, consider the guidelines to be a financial burden to utilities that will ultimately be passed on to consumers, and also that the practice of utilities purchasing power at avoided cost and

selling power at normal retail prices is inherently unstable. Industries with this view are reluctant to start cogeneration projects counting on these conditions, and then facing regulatory changes which would reduce or eliminate benefits needed to make the project financially sound. As one industry energy conservation manager put it: "You can't just go to a utility and shove PURPA down their throat, because eventually, if they're hurting enough, they'll find a way around it. You don't want to spend 20 or 30 million dollars on cogeneration equipment and then have the utility find a way out a couple of years later when you're still paying off capital costs... I could see the entire program being thrown out in six months,.... And based on that possibility, I couldn't recommend going ahead with a new cogeneration project" (Ref. 8). Obviously, this opinion is not shared universally since there are many industrial cogeneration projects. As discussed elsewhere in this report, the attractiveness of any project will depend on matching utility/industry needs to the mutual benefit of each party, and this can often be done with the proper financial, ownership, operation and contractual arrangements.

5.3 Utility Perspective

5.3.1 General

Utilities have varied perspectives on industrial cogeneration, depending on such factors as amount of excess capacity, state regulatory climate, customer makeup and projected demand growth.

In 1980 EPRI published a report (Ref. 9) which presented results of a survey of eleven utilities on the issue of cogeneration. Of the eleven utilities surveyed, four were actively promoting cogeneration; six did not promote but were receptive to proposals; and one was uninterested in cogeneration.

The four utilities promoting cogeneration do so because of state PUC directives and lack of capacity (So. Calif. Edison and Pacific Gas & Electric), or to defer new plant construction (Pennsylvania Power & Light), or because of directive by charter to minimize power cost to customers (Tennessee Valley Authority).

In the past, if cogenerators used expensive fuels, such as oil or gas, the utility was likely to find cheaper sources of power and would be unwilling to buy power from the cogenerator. However, if the cogenerators used cheaper fuel (coal, wood, by-products) or if the utility's source was expensive, then the utility was willing to buy power from the cogenerator. With the passage of PURPA, this has changed, and utilities are now required to buy the power at nondiscriminatory rates. Those rates, however, depend on the utility's alternatives regarding generating or purchasing power, and so the fuel mix of the utility is important in determining its policy on cogeneration.

Thus, the policy of a utility toward industrial cogeneration will depend on its circumstances at any given time and may change with time. Even if a utility favors cogeneration, the mechanism of implementing the system and the connection to the utility raise some concerns as expressed below.

Utilities have expressed the following concerns regarding industrial cogeneration facilities (which are connected to the utility for power sales):

- Reliability and maintenance and its affect on utility and its customers
- Safety of interconnection equipment and utility personnel
- Loss of customers and erosion of base load
- Availability of buy-back power
- Requirement for back-up capacity
- Development of equitable rates

Basically, most of these concerns stem from the utility's loss of control over generating capacity upon which it will rely to service its customers. Also resulting from this loss of control is uncertainty regarding the reliability and availability of the capacity at times when the utility needs it or can economically use it. In addition, there is also the possibility that the industry may go out of business, leaving the utility with a loss of capacity it had depended on. Utilities strive for a long-term dependable supply of electricity over which they can exercise control to suit their needs. This has led some utilities to favor utility ownership of the cogeneration system.

Because of concern with safety of equipment and personnel, most utilities prefer to install the interconnection equipment themselves, and some actually bear the cost as well.

The loss of industrial customers from the utility load base would result from cogeneration growth, and this could hurt the economic viability of a utility.

With regard to rates, the utilities tend to believe that both parties should see a benefit. Industry should receive a price higher than its cost, and the utility should pay a price less than its cost to generate or buy replacement power.

All utilities in the EPRI survey saw a need for standby power as a back-up. Standby charges are assessed on the basis of \$ per KW of standby capacity per month. Utilities favoring cogeneration usually have lower rates and special arrangements (interruptability or power requirement changes on demand), while those who do not favor cogeneration tend to have higher standby rates. Typical standby charges are in the range of about \$3 to \$6 per KW per month.

In spite of the utility concerns, some still have a favorable attitude toward cogeneration. Also, all utilities in the EPRI survey would strongly favor cogeneration under the following conditions:

- No reliability or safety problems
- Cogenerator is a firm supplier of power at a rate which saves the utility money
- Utilities get exemptions from NEA to burn oil or gas or get exceptions from emission standards to burn coal
- No significant erosion of utility base load

Obviously, these are "ideal" conditions and unlikely to be fully achieved in practice. However, they do represent the direction in which conditions must change to motivate utilities to encourage and participate in cogeneration projects.

Two bills have been introduced to the House Energy and Commerce committee regarding modifications to PURPA and other cogeneration-related legislation. The bills, HR 2876 and HR 2992, would allow utilities the benefits presently denied them for cogeneration projects. Hearings on these bills were held 4/27/81 and 6/23/81 before the House Subcommittee on Energy Conservation and Power.

5.3.2 Edison Electric Institute (EEI)

In a statement presented to the U. S. House Subcommittee on Energy Conservation and Power (Ref 1), the EEI presented its views on legislation and regulatory changes to promote cogeneration. The statement focuses on the issue of equal treatment for electric utility ownership of cogeneration facilities. Following is a summary of some of the major points in that statement:

- a. EEI supports cogeneration as a means of energy conservation wherever it will reduce the nation's dependence on oil and natural gas.
- b. The current legislation and regulatory environment is not conducive to the most effective and efficient deployment of cogeneration technology. It tends to prohibit or discourage participation by utilities and should be revised to provide equal competitive business opportunities for electric utilities.
- c. Major cogeneration investment by industry is unlikely because of finite capital resources (cogeneration investment competes with higher priority or more profitable investments), lack of required skills in industrial firms and a finite amount of air and water quality and land available (these resources may be dedicated to higher priority, mainstream business projects).
- d. In order to contribute to national energy goals and promote development of cogeneration, the following legislative and regulatory changes were recommended:
 - Amend Section 201 of PURPA to allow utilities to own more than 50 percent of a cogeneration facility and be eligible for rate and exemption privileges of a QF.
 - Provide utilities with equal treatment with respect to cogeneration tax incentives under the Energy Tax Act of 1978 and the Crude Oil Windfall Profits Tax Act of 1980.

- Amend regulations to recognize full range of purchase rates allowed under Section 210 of PURPA. Purchase rates should be based on negotiations between utility and OF but should not exceed 90 percent of true full avoided costs.
- Grant exceptions from Fuel Use Act for new cogeneration facilities only where there is a net oil/gas savings.

5.3.3 Consolidated Edison

The Con Ed position (Ref. 10) was presented at the same hearing as the EEI position, (Ref. 1) as well as at the 1981 Energy Bureau Conference on Cogeneration (Ref. 11). The case was made that no encouragement of any type can be justified for cogeneration facilities that cause greater dependence on imported oil, dirtier air and inequitable taxation and that cogeneration has limited application in terms of reducing the nation's dependence on imported oil. Namely, this application would be for oil or gas-fired units in a low-growth region heavily dependent on oil, and when virtually all of the waste heat is used. Con Ed's position is that this is a very, very infrequent occurrence. If oil and gas-fired cogeneration facilities displace or delay coal and nuclear plants by reducing capacity needs, then the nation's long-term oil dependence is compounded.

Following are recommendations of Con Ed to the House Subcommittee:

- a. Provide encouragement only to developments that help to reduce oil imports
- b. Preserve fuel use restrictions for cogeneration in the Fuel Use Act
- c. Amend PURPA to add requirement for qualification for benefits by a cogeneration facility that they show a net lifetime savings of oil for all parties affected
- d. Amend PURPA to remove limit on utility ownership
- e. Amend PURPA to replace full avoided cost rule with rule allowing utility rate payers to share benefits
- f. Amend Internal Revenue Code to make utilities eligible for energy credit with respect to investment in cogeneration and other energy facilities

- g. Consider the environmental and socio-economic problems caused by cogeneration facilities powered by internal combustion engines when evaluating a cogeneration project

5.3.4 Southern California Edison (SCE)

As mentioned earlier, utilities have varied perspectives on cogeneration. This is illustrated by comparing the SCE position with that of Con Ed.

SCE is committed to accelerated development of cogeneration and small power production (Ref. 12). They have already arranged for 200 MW of cogeneration on their system and have over 1000 MW more under negotiation. SCE believes that it makes sense for a capacity short utility to support cogeneration as a practical means of meeting the expanding needs of their customers, and one of the few ways available to produce new power in a relatively short time.

Cogeneration facilities in California are using biomass, wind, solar and other renewable sources as well as waste heat.

SCE sees are the benefits to a utility as follows:

- Reduction of large fossil fuel inventories
- Third party investors may be willing to invest in new cogeneration technologies (wind, solar, biomass) and may share the risk of developing those technologies
- Overall system reliability could be improved by using several diverse small plants instead of fewer large central plants

The factors tending to block cogeneration, as perceived by SCE, are similar to those stated earlier:

- Initial cost of cogeneration plant
- Regulatory uncertainty, particularly the Fuel Use Act re oil or gas as cogeneration fuel
- Air quality requirement
- Interconnection, operation, maintenance and standby power provision

SECTION 5 - REFERENCES

- (1) Statement by Edison Electric Institute, Recommended Legislative and Regulatory Changes to Promote Cogeneration Development, presented by R.C. Mitchell before the House Subcommittee on Energy Conservation and power, April 27, 1981.
- (2) Statement by B. Schwartz of Consolidated Edison to the House Subcommittee on Energy Conservation and Power, April 27, 1981.
- (3) T. Barry and Associates, Guidelines to Assist Rural Electric Cooperatives Fulfill the Requirements of Sections 201 and 210 of PURPA for Cogeneration and Small Power Production, February 1981.
- (4) J. Liles, Technical Aspects of the FERC Rules Under Section 201 of PURPA, Energy Bureau Cogeneration Conference, March 30-31, 1981.
- (5) R. Feldman, Federal Legislation Implications for Utilities and Cogenerators, Energy Bureau Cogeneration Conference, March 12-18, 1980.
- (6) R. Ain, Emerging Issues in Cogeneration Legislation, Energy Cogeneration Conference, March 30-31, 1981.
- (7) K. Seplow, Summary of Ground Rule Affecting Cogeneration Financing, *ibid* (Ref. 4)
- (8) Energy User News, 4/20/81.
- (9) EPRI-EM1531, Industrial Cogeneration Case Studies, September 1980.
- (10) B. Schwartz, Statement on Behalf of Consolidated Edison Co. of New York, Inc., *ibid* (Ref. 1)
- (11) B. Schwartz, Urban Cogeneration: Myths and Realities, Energy Bureau Conference on Cogeneration, March 31, 1981.
- (12) E. A. Meyers, Jr., Cogeneration--A Utility Perspective, Southern California Edison, Energy Bureau Conference on Cogeneration, March 31, 1981.

6.0 FINANCIAL CONSIDERATIONS

6.1 Cogeneration Economics

The cogeneration of energy in the form of electricity, steam, and/or heat offers several advantages over separate generation including improvements in resource utilization and energy costs. As the value of the energy resources increase, energy economics dictate that these resources be consumed more effectively and more efficiently. Of the 76.3 quads of energy consumed in 1980, 32.5% was devoted to the generation of electric power. Due to low energy conversion efficiencies and transmission/distribution losses, less than one-third of the energy consumed in electric power generation is delivered to the ultimate user. The conversion losses associated with electric power generation amounts to over 17 quads in 1980 or 22% of the total national energy consumption. If this wasted energy can be recovered and effectively utilized, it would support an annual growth rate in energy use of about 5% for five years without the need for new capacity additions. Of equal importance is the potential reduction in cooling water requirements to dissipate this energy to the atmosphere.

While the potential and incentives for cogeneration are real, the extent to which wasted or lost energy can be utilized is many times limited by geographic considerations or mismatches between the quality of the excess energy and the user energy requirements. Whenever industry and electric generation facilities are or can be co-sited, improvements in energy utilization can be attained. The HTGR is especially well-suited for cogeneration because of its characteristic high temperature capability. This permits efficient generation of electric power and the supply of steam and/or heat to industry at useful temperature and pressure levels. The economic incentives for deploying such a system relative to separate generation result from the improved utilization of the fuel consumed and the economics of scale achieved through combining the steam and electrical power outputs. This can easily be illustrated through the use of joint-product cost curves.

Figure 6.1-1 presents the prices of electricity and process energy as generated from a single source. The diagonal lines represent cogeneration plant with dual products. The two end points of this line are determined by dividing the annual plant revenue requirement (fixed charges, fuel, and O&M expenses), first by the annual electric output (KWe-hr) and second by the annual process energy output (MBTU).

Figure 6.1-1 Cogeneration-Joint Product Cost Curve

These points are shown as points X and Y respectively on Figure 6.1-1. The horizontal line reflects the price of electricity supplied by an electric power plant generating the same quantity of electricity. Similarly, the vertical line represents the price of process energy when generated from a separate steam power plant with the same process energy output. The joint product cost curve illustrates the economic incentives of cogenerated energy and is denoted by the shaded area of Figure 6.1-1. This figure is particularly useful in evaluating cogeneration plant product pricing strategies or incentives. For example, between points A and B, there are several different ways of allocating joint costs:

- Point A: This method charges the electrical users the same as separately produced electricity, and the heat users receive all the cost benefits. In other words, this method provides a heat user incentive for installing the joint-product system that does not penalize the electric user.
- Point B: This method is the reverse of method A. It does not penalize the heat user, and all the cost benefits are received by the electric user.
- Point C: This method has been called the equal discount method. It divides the cost benefits of the joint system between electrical and heat users in an "equal" (approximately the same fraction) manner.

Any of the above points might be selected, depending on whether the heat users, electric users, or both users require incentives to participate in the cogeneration project. There are many different methods to allocate costs between two product streams. The method presented here and on Figure 6.1-1 shares all plant costs between the two product streams; that is, there are no portions of the plant complex which are solely allocated to the electric or steam generation cost streams.

Figure 6.1-1 may also be utilized to better understand the incentives for converting to cogeneration. As noted previously, an electric generating station can improve energy utilization substantially by cogenerating steam or heat. However, while the total energy output of the plant increases, there then must be a trade-off between the added thermal output and the lost electric output of the plant. As most electric power plants are operated by utilities, this reduction in output must be evaluated against

electric generating capacity requirements. In static electric growth scenarios, there may be incentives to increase utilization of an otherwise idle power plant through conversion to cogeneration. These plants can typically be characterized as high operating cost (premium fuel) plants. The improved energy utilization helps defray the cost of operation as the costs are spread over a larger product output. For dynamic electric growth scenarios, decisions are not so easy in the requirement for electric power generating capacity may limit a utility's ability to deploy cogeneration capacity. An often neglected question is this: What cogeneration incentives are offered to the utility? Figure 6.1-1 illustrates that in theory both the electric consumer and the process energy consumer can share the advantages of lower energy costs from a cogeneration plant. However, to date the utility has typically not shared in the benefits. Nor has the utility been given any incentive to cogenerate relative to producing strictly electric power. The second diagonal line $X'-Y'$ on Figure 6.1-1 represents a case where the cogeneration plant offers the utility higher revenues and hence a higher rate of return. Similarly, points A' , B' and C' reflect the three cost benefit allocation methods discussed above for the higher revenue stream. This is one way in which the energy producer can share cogeneration benefits with the energy consumers. Since many utilities associate more risk with a cogeneration plant relative to an electric generating station, the higher return may be required to stimulate more widespread deployment of utility owned control cogeneration. The current government incentives for cogeneration are targeted primarily at industry.

When considering the deployment of a new central cogeneration station, many of these same incentives may be required to bring the utility, the electric consumers, and the process energy consumers together in such a venture. A new cogeneration facility has an additional advantage in that the added electric capacity may be attained with little or no cooling water requirements and less heat rejection to the atmosphere. As long as there is a shaded area on Figure 6.1-1 to work with, incentives for the participants may be negotiated such that all benefit from the cogeneration plant.

6.2 Financing Cogeneration Projects

6.2.1 Regulatory Impact

Government regulations have, of course, a significant impact on the financing and financial viability of a cogeneration project. Regulations affecting cogeneration, as discussed in Section 5 of this report, are still in an evolutionary stage. Thus, any assessment of cogeneration project financing is subject to change, based on changing regulations.

Four key areas impacting financing have been identified (Ref. 1) as being affected by regulations:

- (a) Firmness and clarity of the terms of contractual arrangements, particularly with respect to purchase and sale of power.
- (b) Clear availability of the investment tax credit.
- (c) Absence of restrictive regulation under the Public Utility Holding Co. Act (and Federal Power Act) and state utility regulation.
- (d) Stability in the regulatory environment such as fuel choice (extent to which natural gas and oil may be used by Cogenerators under an exemption to the Powerplant & Industrial-Fuel Use Act).

Detailed discussion of each of these areas is presented in Reference 1. In most cases, the regulatory environment is still in a state of flux. Reference 1 discusses the status as of early 1981 and highlights areas where further activity may be necessary.

A discussion of the regulatory ground rules affecting cogeneration financing is presented in Reference 2. The effect of PURPA, the Fuel Use Act, The National Gas Policy Act, environmental legislation, and tax considerations (credits, depreciation, etc.), are all discussed.

6.2.2 Financial Arrangements and Considerations

Most cogeneration projects involving single users are based on financing decisions similar to those for any other wholly-owned asset. However, an HTGR Cogeneration facility (or any other large facility) would almost certainly be a multi-party project. This type of project results in unique and special financing difficulties, which arise from the multi-party nature of the project and the problems of coordinating the needs and restrictions of each party to obtain an arrangement with adequate benefits to all participants.

The financial considerations of large multi-party cogeneration projects are discussed in considerable detail in References 2 and 3. Following are some highlights from those references. A major

constraint of multi-party projects (aside from the complexity of Federal legislation) is the difficulty in balancing energy requirements of various users. Another constraint which has served to limit the move to cogeneration is the lack of certainty with regard to fuel use policies. The recent high cost of money has also meant that fewer projects will prove to be financially attractive. On the other hand, actions of some state regulators (such as in California) are forcing cogeneration by state policy and regulation which make cogeneration projects an attractive (or necessary) option.

In spite of the constraints described above, it is believed (Ref. 3) that "significant" cogeneration projects will be developed.

The Kidder, Peabody study (Ref. 4) developed a preferred analytical approach to structuring ownership and arrangements, after studies show a significant advantage of scale in co-mingling energy requirements of different parties. First, three specific ownership issues are resolved:

- (a) Identification of potential participants.
- (b) Selection of role(s) of each participant (purchaser of output, investor, provider of other commitments to support financing).
- (c) Deciding on format of ownership role, i.e., undivided interest in project assets vs. owning an interest in new entity which, in turn, owns the assets. The latter makes funding the common responsibility of all participants while the former makes each participant responsible for providing its proportionate share of the funding.

The project is developed by having each participant attempt to maximize six specific objectives:

- (a) Economic benefit.
- (b) Risk limitation (developmental and operational stages)
- (c) Control.
- (d) Funding arrangements to give leverage without impairing debt-raising ability.
- (e) Tax benefits.
- (f) Avoiding burdensome governmental regulations.

Many of these objectives will interact (e.g., risk/benefit, etc.), and often attainment of one party's objectives will be contrary to the interests of others. Thus, considerable effort is required to develop an arrangement which results in the maximum possible benefit to each party.

In the case of participants who are both purchasers of output and investors, Seplow (ref. 3) discusses two methods of analyzing advantages to participants:

- (a) Cost of Service - Comparing to costs of alternate sources.
- (b) Return on Investment - Comparing to returns on alternate investments.

Seplow goes into considerable detail on these approaches, and the methods of borrowing and financing. For further details, the reader is referred to references 3 and 4.

Seplow (Ref. 3) presents an example of the balancing of participant's needs, in the context of a joint development of a cogeneration facility by a utility and one or more industrial uses. His approach is designed to reconcile the problem which the utility may have in construction financing, with the problem industry may have in financing utility-type assets with an industrial-type capital structure. He suggests that industry bear the burden of construction financing, with the utility assuming responsibility for permanent financing after completion of the project. Possible industry objection to this arrangement could be resolved by compensation in the facility purchase price and by lower charges for output, which would result in a long-term savings over the operating period.

Seplow also discusses other approaches, such as third-party arrangements, and points out that any arrangement must be carefully evaluated in terms of current and pending tax laws.

Techniques do exist to develop favorable financing structures for cogeneration projects. Although there are limitations and restrictions involving legal, regulatory and accounting practices, the most significant limitation has been suggested to be the willingness and patience of the participants to work their way through the complexities of financing a multi-party cogeneration project. If the benefits to each party are substantial and this can be demonstrated, then financing activities can be developed, albeit with some difficulty.

SECTION 6 - REFERENCES

- (1) R. Feldman, Project Financing of Cogeneration: Impacts of the Regulatory Environment, Energy Bureau Conference on Cogeneration, 3/30/81.
- (2) K. Seplow, Financing Coeneration Projects, ibid
- (3) K. Seplow, Financing An industrial Cogeneration Project, Third National Conference and Workshop on Cogeneration, 3/18/80.
- (4) ORNL/SUB-79/13521/1 - Financial Considerations Affecting Implementation of a Large Multi-party Cogeneration Project, April 1979.

7.0 HTGR SYSTEMS FOR PROCESS HEAT - HTGR-SC/C

7.1 Design Description

7.1.1 Plant Description

The HTGR Steam Cycle/Cogeneration (HTGR-SC/C) concept is an adaptation of the standard reference HTGR Nuclear Steam Supply System (NSSS) design which produces high quality steam at 2500 psi/1000°F. A two loop 1170 MW(t) plant, a four loop 2240 MW(t) plant and a six loop 3360 MW(t) plant are configurations which are available for process steam/cogeneration purposes.

For the cogeneration plant, the turbine plant is modified for a heat cycle that can supply process steam at various conditions. The configuration of the overall steam cycle/cogeneration plant is shown by Figure 7.1.1-1. A typical heat balance for cogeneration with the steam production matched for chemical/petroleum refinery requirements at a single pressure and temperature level of 650 psi/670°F is shown by Figure 7.1.1-2. The mix of electricity to steam may be varied, and other single or multiple extraction steam pressure levels, may be specified to fit a wide range of conditions. Specific plant arrangements are adaptable to individual site conditions, including the use of dry cooling where necessary.

7.1.1.1 Nuclear Steam Supply System (NSSS)

The NSSS for the HTGR-SC/C plants include the nuclear, control, and heat transfer systems and components used to generate steam. For design purposes, the HTGR NSSS is divided into about 15 major system categories, i.e., prestressed concrete reactor vessel (PCRVR), reactor core, reactor internals components, primary coolant, core auxiliary cooling (CACS), neutron and region flow and storage wells, main and auxiliary circulator service, helium services, plant protection (PPS), plant control (PCS), plant data acquisition, processing, and display (DAP), and gas waste systems.

(To be filled in at a later date.)

Figure 7.1.1-1 HTGR-Steam Cycle/Cogeneration Plant

POWER ALLOCATIONS	MW	%
PROCESS USES		
ELECTRIC	151	13
STEAM	1001	85
LOSSES	18	2
TOTAL	1170	100

LEGEND

W = FLOW (106 LB/HR)
P = PRESSURE (PSIA)
T = TEMPERATURE (°F)

Figure 7.1.1-2 1170-MW(t) HTGR-PS/C Plant Heat Balance Diagram

MW(t) and 3360 MW(t) reactors. In addition to the primary coolant loops, three core auxiliary cooling system loops are provided. Each consists of a gas/water heat exchanger with auxiliary electric-motor-driven circulators located in cavities in the PCRV wall. Should the main loops not be available, coolant gas is circulated from the reactor core through the core auxiliary cooling water system for rejection from cooling towers to the atmosphere. The arrangement of the reactor core and cooling loops in the PCRV is shown in Figure 7.1.1-3.

7.1.1.2 Balance of Plant (BOP)

The BOP for the HTGR-SC/C plants are those structures, equipment and systems not supplied as part of the NSSS. Again, for design and accounting purposes, the BOP can be broken down into about six major categories, i.e., structures and improvements, turbine plant equipment, electric plant equipment, miscellaneous plant equipment, waste heat rejection system, and reactor plant BOP systems.

For electric generation with the HTGR-SC/C, superheated steam from the NSSS is expanded through a tandem compound turbine-generator requiring no moisture separation or reheat. The exhaust heat is condensed in a water-cooled condenser, then the waste heat is rejected to the atmosphere in a wet cooling tower. For cogeneration applications, superheated steam is first partially expanded in a back-pressure turbine to conditions required for the process steam (topping cogeneration heat cycle). The flow is then divided and the bulk of the steam directed to the process users. The remaining steam is further cascaded through a second back-pressure turbine-generator with extraction and exhaust steam used to heat the boiler feed water. For the arrangement shown on Figure 7.1.1-3 a single extraction pressure of 650 psia is assumed in the first turbine in order to supply high energy steam for power and/or process heat by the industrial users. With the high throttle conditions provided by the HTGR-SC/C, multiple pressure levels can also be supplied ranging approximately from 200 to 1000 psia. On-site capability is provided to treat the condensate returned as well as make-up water from rivers, wells, etc.

The PCRV and auxiliary systems are housed inside a conventional secondary reactor containment building. The BOP systems and equipment are arranged and housed in separate structures considering function and service. The reactor containment building (RCB) is a steel-lined, reinforced concrete cylinder with a hemispherical dome and circular base mat. The design pressure of

Figure 7.1.1-3 Cutaway view of HTGR NSS system (1170-MW(t) size shown)

the containment is approximately 60 psig. The reactor service, fuel storage, and control auxiliary and diesel generator buildings are major structures adjacent to the reactor containment building for functional arrangement of operation and service to the NSSS. Fuel storage for 1.3 cores is provided on site, and the facility is capable of handling either truck or rail shipping of fresh or spent fuel.

7.1.2 Plant Output

As discussed in Section 7.1.1, the steam cycle/cogeneration plant can be configured for different quantities of process steam by varying the number of basic helium loop modules and by modifying the turbine plant and turbine extraction steam conditions. Past design studies have shown that the two, four and six loop plants are the preferred plant layouts.

The importance of this modularity feature lies in the potential flexibility to achieve various plant sizes using essentially the same primary system components, i.e., steam generators, isolation valves, circulator, core auxiliary cooling heat transfer equipment, core blocks, etc.

The plant output for the 1170 MW(t) size plant depicted in Figure 7.1.1-2 is 2.74 million pounds of steam per hour at 650 psi and 670°F. For the similar 2240 MW(t) plant, 4.85 million pounds per hour of steam are produced at the same conditions. Electric output for the two plants is 151 MW and 350 MW respectively.

7.1.3 Plant Availability

Availability is defined as the percent of time, averaged over the life of the plant, that the plant is operating, or capable of operating. Capacity factor is the ratio of the actual annual plant output to the theoretical plant output. Availability of the mature HTGR-SC/C plant is expected to be 90% and the capacity factor 80%. In the case of the SC/C plant, availability and capacity factor apply to the cogenerated steam output.

By combining the HTGR with other HTGR units, coal fired units and possibly oil or gas fired peaking units, the availability and capacity factors can be enhanced to meet almost any user requirement. Studies are presently underway to optimize the mix of units for economy and availability/capacity factors.

7.1.4 Design Status

The HTGR-SC/C applies near-state-of-the-art technology allowing early Lead Project Deployment. Application of HTGR technology to steam cycle systems and the temperature regime identified for the

HTGR-SC/C Lead Project have been demonstrated in the operation of the Peach Bottom and Fort St. Vrain generating stations. The HTGR-SC/C Lead Project, however, must include time for the completion of design and licensing to current requirements as well as verification and demonstration in some key areas such as the main helium circulators, steam generators, fuels, etc.

The schedule presented in Figure 7.1.4-1 is viewed as a "reasonable target" to design, license and build an HTGR-SC/C plant. Developmental and regulatory issues will be dealt with in the interval from project inception to receipt of a construction permit. The preapplication licensing review will provide for early NRC involvement in the process of evolving criteria for the resolution of safety issues and give guidance to the formulation of testing programs required to verify design adequacy of key components.

7.1.5 Inherent HTGR Safety Features

The safety of the HTGR-SC/C is well defined and major issues concerning licensing have been identified. The system has inherent characteristics that make the thermal response of the core to transients very slow and limit the potential for release during low-probability accidents. In addition, engineered safeguard systems are provided that further protect the public and facilitate siting and plant licensing. Using the latest methods of safety analysis, a wide spectrum of accident conditions has been postulated and the significance of each essential design feature as it contributes to safety has been determined. For those low probability events that can be postulated involving overheating of the core or leakage of primary coolant, the releases are limited to a small fraction of the core inventory on a time scale of days, allowing time for mitigating actions and evacuation of the nearby population. This should be a very positive factor in public acceptance of this nuclear power option. Further, it is planned to conduct a preapplication review with the NRC to reduce licensing/regulatory risks to the utility by establishing specific criteria for licensing an HTGR and resolving safety issues prior to filing a preliminary safety analysis report (PSAR).

7.2 Market Identification

The HTGR-SC/C has the potential for many commercial applications in the utility and industrial process industries. It can be used as an efficient means for generating baseload electricity and as a new industrial energy source of high quality steam. The high quality steam output can be varied in quantity and conditions.

SUMMARY SCHEDULE HTGR-SC/C LEAD PLANT

Availability and capacity factor requirements can be met by configuring HTGR plant(s) with alternate steam and electric producing units.

In addition, a study is presently underway to configure a cogeneration plant that will also have the capability to utilize the full output of the nuclear heat source to produce electricity with a heat rate comparable to that of a conventional HTGR electric generation plant. This configuration will allow an HTGR cogenerating plant to be located in an area where the full steam output exceeds industrial demand and allows the plant to phase-in steam users.

7.3 Costs

A cost comparison between the HTGR-SC/C and a comparably sized, coal-fired cogeneration plant for both 1170 MW(t) and 2240 MW(t) size plants is presented in Tables 7.3-1 and 7.3-2. Joint product cost curves for these systems depicted in Figure 7.3-1. The PWR was not included in this comparison because fossil-fired superheaters are required to produce steam conditions comparable to those produced by the HTGR.

The comparison indicates that the HTGR-SC/C has a significant steam cost advantage over the reference coal plant. It is noted that in addition to the sensitivities of coal cost, the added dimensions of plant size, credit for electricity, and steam transmission distances also impact the comparison between the HTGR-SC/C and coal.

TABLE 7.3-1

1170 MW(t) COST COMPARISON
(Constant 1980 \$)

	<u>HTGR-SC/C</u>	<u>COAL</u>
<u>Plant Parameters</u>		
Power Rating (MWt)	1170	1230
Net Electrical Output (MWe)	150	157
Process Flow (lb/hr)	2.7×10^6	2.7×10^6
Distance from Process Steam User (miles)	2	2
<u>Plant Costs (x 10⁶)</u>		
Total Base Construction Costs	589	434
Real Escalation	73	59
Interest During Construction	78	38
Total Investment Cost	740	531
<u>Annual Energy Production (10⁶)</u>		
Process Steam Delivered (Btu/yr)	20.8	20.8
Net Electricity (KWe-hr)	920	963
<u>Annual Revenue Requirements (x 10⁶)</u>		
Fixed Charges	61	44
O&M	25	30
Fuel (20% Enriched - Once Through)	30	95
Total	116	169
<u>Product Costs</u>		
All Revenue Requirements Allocated to Electricity (mills/KWe-hr)	126	175
All Revenue Requirements Allocated to Process Steam (\$/MBTU)	5.58	8.12
Steam Price Corresponding to Electric Price of 32 mills/KWe-hr (\$/MBTU)	4.16	6.64

TABLE 7.3-2
2240 MW(t) COST COMPARISON
 (Constant 1980 \$)

	(A) <u>HTGR-SC/C</u>	(B) <u>HTGR-SC/C</u>	<u>COAL</u>
<u>Plant Parameters</u>			
Power Rating (MWt)	2240	2240	2360
Net Electrical Output (MWe)	549	265	274
Process Flow (lb/hr)	2.59×10^6	5.18×10^6	5.24×10^6
Distance from Process Steam User (miles)	2	2	2
<u>Plant Costs (x 10⁶)</u>			
Total Base Construction Costs	764	769	723
Real Escalation	95	96	99
Interest During Construction	<u>101</u>	<u>102</u>	<u>63</u>
Total Investment Cost	960	967	885
<u>Annual Energy Production (10⁶)</u>			
Process Steam Delivered (Btu/yr)	20.8	40.3	40.7
Net Electricity (KWe-hr)	3366	1625	1680
<u>Annual Revenue Requirements (x 10⁶)</u>			
Fixed Charges	80	80	73
O&M	33	33	48
Fuel (20% Enriched - Once Through)	<u>57</u>	<u>57</u>	<u>184</u>
Total	170	170	305
<u>Product Costs</u>			
All Revenue Requirements Allocated to Electricity (mills/KWe-hr)	51	105	182
All Revenue Requirements Allocated to Process Steam (\$/MBTU)	8.17	4.22	7.49
Steam Price Corresponding to Electric Price of 32 mills/KWe-hr (\$/MBTU)	3.00	2.93	6.17

SECTION 7 - REFERENCES

- (1) High Temperature Gas-Cooled Reactor: Steam Cycle/Cogeneration Application Study, Gas-Cooled Reactor Associates, December 1980.
- (2) 1170 MW(t) HTGR Process Steam/Cogeneration Design and Cost Report, United Engineers & Constructors, May 1, 1980.
- (3) The HTGR for Electric Power Generation Design and Cost Evaluation, United Engineers & Constructors, September 1980.

8.0 HTGR SYSTEMS FOR PROCESS HEAT-HTGR-SETS

Increased flexibility in serving process heat users would result from the ability to transport and store energy. In that regard, the direct transport of steam is probably limited by economics to an upper range of between 10 and 20 miles. For intermediate distances, a concept is under evaluation in which reactor thermal energy is transported using molten salt. This configuration is identified as the Sensible Energy Transport and Storage (HTGR-SETS) concept.

The primary advantages for using molten salt as an energy carrier are:

- Load flexibility - The HTGR-SETS system can be tailored to specific user demands through adjustments in its electricity production to process heat load split and thermal storage facilities.
- Site flexibility - The molten salt thermal transport system makes it possible to site a reactor a considerable distance from an industrial complex and still be able to deliver heat to this complex for electricity and/or process steam generation purposes without unacceptable transmission loss.
- Resource conservation/utilization - The HTGR-SETS concept permits continuous operation of the NHS at full power, taking full advantage of lower fuel cost.

A description of the HTGR SETS system and its technical and economic aspects are presented in the following sections.

8.1 Design Description

The HTGR-SETS concept contains three basic systems: (1) the nuclear island, including the nuclear heat source, primary and secondary helium circuits, attendant heat exchangers, and site buildings necessary for system containment; (2) the energy transport system consisting of a hot salt delivery line and warm salt return line plus necessary pumping stations; and (3) the heat utilization system at the user end configured for the required application. Nuclear heat not used for plant operation is delivered via the hot salt supply line to high-temperature thermal storage tanks located at the nuclear island and/or the end user site. During periods of peak or fluctuating power demand, this

thermal storage capacity is discharged to provide the heat input necessary to satisfy the fluctuating demand. Hot molten salt is supplied to the heat utilization system (user end) at 1050°F and is returned to the nuclear heat source at about 550°F, well above the freezing temperature of the salt.

System Schematic

A schematic flow diagram of the HTGR-SETS concept showing the major components and key system design parameters is shown in Figure 8.1-1. Heat generated in the reactor is transported by the primary coolant helium to the intermediate heat exchanger (IHx) which transfers the heat to the externally located secondary helium system. Four primary/secondary helium loop combinations are required for the plant. Parallel circuitry is employed to route the hot secondary helium simultaneously to eight helium-to-salt heat exchangers that provide the thermal input to the molten salt supply line.

Hot salt leaving the helium/salt heat exchanger is used to charge the hot storage tanks and supply heat input to the end user heat recovery system. During peak demand periods, the salt is circulated from hot storage to cold storage through steam generators or various process heat direct heat exchangers that power electric cogeneration processes or supply direct heat to certain manufacturing processes. The heat utilization system at the end user site is separated from the nuclear heat source site by hot and cold molten salt piping with pumping stations located approximately every ten miles. Electric power necessary for pipeline pumps is supplied primarily from an external electric utility grid. Power to supply this amount to the grid can be provided from cogeneration facilities at the user site or from another nuclear, fossil or hydro facility. Diesel, gas-fired or coal-fired sources can be used on site and along the pipeline to supply back-up power should it be required upon loss of the primary source.

A set of hot and warm storage tanks can be provided at both the heat source and end user sites to permit the piping to be maintained at operating temperature, thereby reducing thermal shock problems during short duration outages of the nuclear heat source. Heat supplied to the molten salt by operating the pipeline pumps is sufficient to keep the salt in a molten salt state for extended shutdowns of the heat source. A gas or diesel-fired, small capacity, steam generating and pipeline heat tracing system will be supplied to allow initial system heat up at start of initial operation and as a back-up system for pump-supplied heat.

Figure 8.1-1

INDIRECT HTGR – SENSIBLE ENERGY TRANSPORT AND STORAGE PLANT

For the reference plant studied, all the reactor energy was shipped off site and any necessary electric power required for operation of equipment at the nuclear heat source site and along the pipeline would be purchased from the local electric grid. The reference heat user was selected to be the multipurpose application described in Reference 1 which requires process steam at 650 and 700°F. The reference heat utilization system (steam generators and ancillary equipment and buildings) was configured to meet this requirement.

The following system description will consider the reference SETS plant utilizing a 20 mile pipeline with 3000 MW(t) hours of storage at the user site to improve reliability. The heat utilization system will be adapted to a multipurpose application to supply an average steam temperature and pressure requirement of 700°F and 650 psia which could represent a multitude of processes. Inlet steam conditions are 950°F and 1800 psi. These conditions are reduced to those required for the process by extracting the proper temperature and pressure from a topping turbine generator.

8.1.1 Nuclear Heat Source (NHS)

The HTGR-SETS nuclear heat source is the standard 1170 MW(t) design with four secondary helium loops supplied by an intermediate heat exchanger inside the PCRV and terminated with four helium to salt heat exchangers, as described in Section 8.1.3.

8.1.2 Balance of Plant (BOP)

The BOP for the HTGR SETS plants are those structures, equipment and systems not supplied as part of the NHS. For design and accounting purposes, these can be broken down into about six major categories, i.e., structures and improvements, turbine plant equipment, electric plant equipment, miscellaneous plant equipment, waste heat rejection system, and reactor plant BOP systems.

The PCRV and auxiliary systems are housed inside a conventional secondary containment building, and typically BOP systems and equipment are arranged and housed in separate structures considering function and service. The reactor containment building (RCB) is a steel-lined, reinforced concrete cylinder with a hemispherical dome and circular base mat. The design pressure is approximately 60 psig. The reactor service, fuel storage, and control auxiliary and diesel generator buildings are major structures adjacent to the RCB for functional arrangement of operation and service to the NHS. fuel storage for 1.3 cores is provided on site, and the facility is capable of handling either truck or rail shipping of fresh or spent fuel.

8.1.3 Secondary Helium-To-Salt Energy Conversion System

This system includes all of the piping, compressors, valves, and reactor containment building piping penetrations required to circulate the secondary helium coolant between the intermediate heat exchangers located in the PCRV and the helium to salt heat exchangers as well as facilities for helium storage and purification. Piping and associated equipment to transport the salt from the helium-to-salt exchangers to the salt transfer station is also included. There are four secondary loops.

One secondary helium circulator is provided in each secondary loop. Secondary supply helium piping is carbon steel with an internal thermal barrier to keep the carbon steel piping below about 600°F. The internal thermal barrier consists of a fibrous insulating material such as Saffil encased in Inconel 713 LC and is designed to be fabricated in cast modular cylinders which could be installed in and removed from the carbon steel pipe with relative ease.

The helium-to-salt exchangers supplied by General Atomic are designed for a salt inlet temperature of 500° and an outlet temperature of 1050°F. The hot molten salt is transported to the transfer station in 316 stainless pipe and returned to the helium-to-salt exchangers in carbon steel pipe.

8.1.4 Main Loop Cooldown System

Since no on-site turbine plant or condenser is provided in the HTGR-SETS design, a system is needed to remove reactor heat during startup or when a complete loss of heat load occurs (e.g. salt pipeline shutdown) to avoid unnecessary challenges to safety systems. The system provided to accomplish this function is similar to the core auxiliary cooling system except that it is not safety related and includes a helium-to-water heat exchanger located outside of reactor containment which can be supplied with hot helium from either one of two secondary helium loops. This system is designed to accommodate a peak heat load of 30 (MW(t)).

8.1.5 Sensible energy Transmission and Storage (SETS System)

The SETS system is designed to transport heat from the 1170 MW(t) NHS site described in Section 8.1.2, to a user site 20 miles away using molten draw salt as the heat transfer medium. The heat input to the pipeline from the NHS is actually 1210 MW(t) due to the net effect of helium circulator energy gains and primary and secondary loop heat losses. After being heated at the NHS to a temperature of 1050°F, molten draw salt is pumped to the user site at a flow rate of 20.12×10^6 lb/hr by in-line can-type pumps situated in pump stations along both the hot and cold legs of the pipeline. Salt is delivered to the user site at about 1042°F and is supplied to the return pipeline at 500°F. The net effect of heat losses through the pipeline walls and transfer pump energy inputs results in delivery of 1187 MW(t) to the user site.

A typical SETS system flow diagram is illustrated schematically in Figure 8.1.5-1. For the reference SETS system, hot and cold salt storage facilities are provided at the user site only.

The SETS pipeline is encased in a concrete conduit to minimize potential environmental problems. A steam heat tracing system provides both the pipeline and storage facilities with start-up preheating and salt freeze protection capabilities. Decomposition of salt in the SETS system is impeded by a purified air cover gas system which maintains a dry, CO₂ free air atmosphere in all vapor spaces interfacing with the molten salt.

Molten draw salt is used by the SETS system to store and transport heat. Draw salt is a binary eutectic compound whose composition is 60 wt% sodium nitrate (NaNO₃), and 40 wt% potassium nitrate (KNO₃). Molten draw salt has a relatively wide range of operating temperatures (500°F) and has good heat transfer characteristics.

The SETS pipeline requires pump stations about every 2 1/2 miles for the hot leg, and about every 7 miles for the cold leg. Each pump station is provided with 3 - 50% capacity, in-line, can-type pumps for each pipeline leg. (These pumps are similar in design to the molten sodium pumps used in conjunction with the liquid metal fast breeder reactor (LMFBR) program).

Steam heat tracing provides the SETS system with startup preheating and freeze protection. Steam, which is generated at 600°F and 1500 psia by an auxiliary boiler located at the salt transfer stations at both the NHS and user sites, is transported through 4-inch schedule 80 pipe welded to the pipeline. Tracers are constructed of the same material as the pipeline to avoid problems caused by differential thermal expansion between the pipeline and tracers. One 30,000 lb/hr capacity boiler is required to trace a 10-mile segment of sendout and return pipeline. Storage tanks are heated with internal steam coils. Each pair of hot and cold storage tanks requires an additional 3,000 lb/hr of boiler capacity. Backup steam tracing pipe and auxiliary boilers are provided.

8.1.6 Salt-To-Steam Energy Conversion System

This system provides the interface between the salt transmission system and the user site. It consists of salt/steam heat exchangers and salt storage.

Salt/Steam Heat Exchangers- The salt/steam energy conversion system was designed to generate steam at the remote end of the energy transmission system. The nuclear heat source supplies 1210 MW(t) energy to the pipeline. Allowing for pumping power gains and heat losses, the net energy delivered to the user site is approximately 1187 MW(t), as shown on Figure 8.1.6-1. The salt/steam heat exchangers produced 3.5×10^6 lb/hr of 950°F, 1800 psia steam. A preheater, two boilers and a superheater in series are required.

Figure 8.1.5-1

Typical Molten Salt SETS System

ENERGY BALANCE FOR
MULTI-PURPOSE COGENERATION APPLICATION
OF THE HTGR - SETS

Salt storage tanks are located in the salt storage and transfer station. The tanks are designed to API specifications and special design features have been incorporated to contain the molten salt in a reliable manner. One hot tank and one cold tank provide about 3000 MW(t)-Hrs of storage. In the event of loss of pipeline salt flow, stored energy is provided to the process by pumping salt from hot storage through the salt/steam heat exchangers to cold storage. The hot tank is refilled when pipeline flow is restored. Earthen berm type dikes are provided to contain 100% of the storage tank's contents in the event of a tank failure.

8.1.7 Turbine Plant Equipment

The turbine plant provides 2,832,948 lbs/hr of process steam at 650 psia and 700°F while producing 145 MW of electricity. The turbine-generator unit is composed of two completely independent turbine-generator sets. The high pressure turbine is designed to deliver 100,192 KW(e) with throttle steam conditions at 1,800 psia 950°F and exhausts 700 psia steam at 707°F to both the process and the low-pressure turbine. The low-pressure turbine is designed to deliver 44,877KW(e) with throttle steam conditions of 675 psia at 673°F, while supplying extraction steam to three stages of feedwater heating and exhausting to the fourth stage feedwater heater. The turbine-generator unit functions to produce electricity as a by-product of the process steam. The demands of the process system and feedwater heating determine the actual electrical output of the facility. The plant is designed to function whether or not the turbine generator units are on the line.

8.2 Market Identification

The reference heat user, described in Reference 1, requires process steam at 650 and 700°F. The reference heat utilization system (steam generators and ancillary equipment and buildings) was configured to meet this requirement.

Several specific applications are readily adaptable to the capabilities of the SETS system. Some of these applications are:

- Direct heat from the molten salt pipeline to a specific process such as the Exxon Catalytic coal Gasification Process or SRC-II Coal Liquifaction Process.

- High temperature, high pressure steam production (1000°F, 2500 psi) for coupling to various oil refinery processes.
- A hybrid heat utilization system that uses both direct heat and high temperature steam to adapt to a variety of processes.
- By utilizing the advantage of hot salt storage, an on-site combined base load and peaking electric power plant can be configured.

8.3 Costs

The work completed in FY 1981 on the pipeline and storage system by United Engineers and Constructors and on the nuclear heat source by General Atomic Company provided capital costs for their respective portions of the HTGR-SETS system. These preconceptual designs and cost estimates are reported in Reference 2. Work in the remainder of CY 1981 and early in CY 1982 will concentrate on areas within the preconceptual design which have the potential for cost reductions. These revised costs will be integrated into selected applications for the SETS system and total plant capital and product costs will be developed. An HTGR-SETS Screening Report will be developed which will contain the information developed during the SETS screening phase and will present capital and product estimates for the SETS nuclear heat source, balance of plant, pipeline and storage system, and the selected application. This report will be available in early CY 1982.

SECTION 8 - REFERENCES

- (1) Multipurpose Cogeneration Application of the HTGR-SETS, United Engineers and Constructors, August 28, 1981.
- (2) Sensible Energy Transport and Storage Design and Cost Topical Report, United Engineers and Constructors, September 1981.

9.0 HTGR SYSTEMS FOR PROCESS HEAT-HTGR-R

At core outlet temperatures above approximately 850°C (1560°F) the HTGR offers a further potential for nuclear process heat. In the Reforming (HTGR-R) concept, a portion of the reactor thermal energy is converted to a storable/transportable energy form through the use of a highly endothermic, reversible chemical reaction. (The balance of the reactor thermal energy is used for process steam or for baseload electricity through the conventional steam cycle). It is this distinguishing feature--the capability of storing and transporting reactor energy--which offers the potential for wide spread displacement of fossil fuels (notably gas and oil) by nuclear energy in utility and industrial applications. Since peak reforming temperatures in excess of about 705°C (1300°F) are required for suitable conversion efficiencies, the HTGR is uniquely capable of supplying these requirements with nuclear energy. The HTGR-R may ultimately provide the nuclear heat source alternative to fossil energy systems in synthetic fuel production, steelmaking, and hydrogen production.

9.1 Design Description

Configurations evaluated to date include an 1170-MW(t) indirect cycle plant with a core outlet temperature of 850°C. (Figure 9.1-1) and a similar design with a core outlet temperature of 950°C and containing the reformers directly inside the PCRV.

The 850°C IDC HTGR-R has its entire primary coolant system contained in a multicavity PCRV which provides the necessary biological shielding in addition to fulfilling the pressure containment function. The multicavity design allows each component (e.g., helium circulators and intermediate heat exchangers) to be located in a separate cavity which facilitates its removal and replacement. The reactor core is cooled by helium, has ceramic coated fuel particles containing uranium and thorium, and employs graphite as the moderator. Thermal energy is removed from the reactor core by independent primary/secondary helium systems and is supplied to separate process loops. Three independent shutdown loops have been provided, each with the capability of full-core decay heat removal. The primary helium is heated by the reactor core and transfers its heat to the process plant via the secondary helium loops. Each primary loop includes one intermediate heat exchanger (IHX), an electric motor driven

Figure 9.1-1 HTGR-R Flow Diagram

primary helium circulator, and related instrumentation and controls. The primary coolant flows downward through the reactor core, where it is heated from 427°C (800 F) to 850°C (1562°F). The primary helium flows upward through the shell side of the IHX, counter currently transferring heat to the secondary helium. The secondary helium system transports thermal energy from the IHX to the reformers and steam generators. The secondary helium loops each consist of a reformer, a steam generator, an electric motor driven secondary helium circulator, and related piping, valves, and instrumentation. The helium thermal energy is split between the reformer and steam generator at a ratio of 42% and 58%, respectively. The HTGR-R utilizes its high temperature capability to reform a mixture of steam and methane (H_2O and CH_4) in the presence of a catalyst to form hydrogen and carbon monoxide (H_2 and CO). The heat absorbed in this endothermic chemical reaction is supplied by the HTGR. For practical conversion efficiencies, peak reforming temperatures above approximately 705°C/1300°F are required. The steam generator provides steam for electrical power generation, for process plant needs, and for export.

In the reformer system studied, emphasis was placed upon energy storage/transmission and subsequent recovery of reactor heat via methanation. This application of the HTGR-R has been referred to as the Thermochemical Pipeline (TCP) and is illustrated in Figure 9.1-2. The reformer effluent gases are cooled by counter-current heat exchange with the reformer inlet gases. Any excess steam is condensed and the effluent gases are compressed for transmission through a pipeline to a user site. At the user site, the hydrogen and carbon monoxide combine in the presence of a catalyst in an exothermic reaction. The high-grade heat released in the methanator delivers 480°C/900°F steam at the user site. The methanator effluent is cooled in a recuperative heat exchanger again preheating the inlet gases. The methane and water are then transmitted back to the reformer via two pipelines, completing the cycle. The pipeline itself may serve as a gas storage mechanism for short time periods and additional storage may be provided using underground caverns. On-site methanation may be utilized for utility load-following applications or remote methanation may be used for remote industrial process heat and cogeneration or for repowering of existing oil and gas fired electrical power plants. In the above applications, the nuclear heat source is base loaded while the thermochemical transmission/storage system is load following.

*PRINCIPAL REACTION

Figure 9.1-2 Thermochemical Pipeline (TCP) Concept

Although the status of 850°C IDC HTGR-R plant design is the least advanced of the commercial HTGR concepts under consideration, many conclusions, observations, and recommendations can be made which form a basis for future HTGR Program tasks on the Reformer option. It is obvious that additional work is required to properly assess the HTGR-R concept as well as related high-temperature concepts (950°C) providing direct nuclear-generated heat instead of using the secondary helium system. This future work will be accomplished as part of the continuation of the High Temperature Process Heat studies through FY 1983.

The following activities will be included in the future scope of the HTGR Program:

- Consideration of potential HTGR-R plant performance and cost improvements emphasizing improvements in the reformer, TCP, and methanation plants (energy delivery system).
- Examination of alternative configurations (direct cycle), ranges of core outlet temperatures, and basic performance and cost improvements in the nuclear heat source/balance of reactor plant.
- Evaluation of alternative applications to include the production of synfuels or other direct coupled process heat applications.
- Examination of modular reactors with a power rating of 200 to 300 MW(t) which could be linked together to provide the same total power as the full scale reactor.
- Additional characterization of the potential market for the HTGR-R. The market and the technical/institutional barriers to HTGR-R penetration must be better defined to firmly establish the commercial/national incentives for the HTGR-R system.

9.2 Market Identification

Based upon market assessments conducted through FY 1980, a very large market is projected for industrial process heat, synthetic fuel, and chemical feedstock applications which could be served by the HTGR-R if appropriate economic incentives exist. At present, a large portion of U.S. energy requirements is beyond the scope of applications served by current nuclear technologies. The capability of the HTGR-R is expected to have substantial benefits relative to coal, its anticipated competitor in these energy sectors, in terms of impact on air quality (including acid rain and the greenhouse effect), mining and transportation requirements, and solid waste disposal.

9.3 Costs

In initial estimates, the HTGR-R exhibited disappointing economic performance relative to competing power generation alternatives in the time frame (1995 startup) studied. However, the potential for improved economic performance remains. The full commercial potential must be investigated further through the conduct of design trade-off studies, plant optimization studies, and examination of alternative applications such as hydrogen production for synthetic fuel plants. Improvements in the nuclear plant capital cost and performance are expected. There also is the prospect for large improvements in the capital cost and performance of the thermochemical pipeline concept. These studies and the investigation of designs for alternative applications will be initiated to determine the commercial potential for the HTGR-R and to formulate the basis for the HTGR-R Design and Development Program.

An optimized HTGR-R commercial plant design and cost estimate has not yet been developed. Major findings of studies to date indicate that:

- There is a large potential market for the HTGR-R if institutional and technical barriers can be overcome in a timely manner.
- The significant environmental benefits which are attained through offset of fossil fuels are a key market factor in the projected deployment of HTGR-R systems.
- The 950°C direct cycle requires solving significant materials issues and addressing unique safety and licensing issues.
- The 850°C HTGR-R plant as presently configured and applied has limited economic potential.

Design trade-off studies and alternative applications must be investigated to determine if a commercial potential exists for the HTGR-R at 850°C or 950°C. If commercial incentives are only identified for the HTGR-R with core outlet temperatures greater than 850°C, the design and development program duration and cost and the demonstration path for the HTGR-R must be assessed.

The projected economic performance, schedule, and deployment cost for the HTGR-R have eliminated the HTGR-R from consideration as a lead project. However, the large potential market, fossil resource conservation, and environmental advantages of the HTGR-R system provide incentives for continued examination of the HTGR-R. The nature of the technical issues confronting this plant and its large deployment cost have dictated that the HTGR-R would be better considered as a follow-on plant to the HTGR-SC/C. This approach would delay the entry of the commercial HTGR-R somewhat but would provide a more conservative and cost-effective path for the HTGR Program.

SECTION 9 - REFERENCES

- (1) High Temperature Gas-Cooled Reactor - Reformer Application Study,
Gas-Cooled Reactor Associates, December 1980.
- (2) HTGR High Temperature Process Heat Design and Cost Status Report,
Gas-Cooled Reactor Associates, GCRA 82-002, December 1981.

tr

APPENDIX A

INDUSTRIAL PROCESS ENERGY PROFILE OF 28 UTILITIES

APPENDIX AINDUSTRIAL PROCESS ENERGY PROFILE OF 28 UTILITIES

Each utility is represented by two tables, A and B. In Table A, the totals for process energy use in Btu/yr as a function of temperature ($^{\circ}\text{F}$) are presented. In Table B, the industrial plant totals and thermal process energy (MWH-thermal) profiles as a function of plant thermal process power (MW-thermal) rating and hours of operation are developed.

In Table A, the estimated steam energy represents that generated by the boiler and used directly or eventually in industrial processes (exclusive of steam solely used for generation of electricity or mechanical energy). The estimated temperature is that at the output of the boiler.

The direct heat represents the furnace output or energy used or required in the process to perform the process heating operations. Efficiencies were estimated to obtain these values. The temperatures are those estimated for the furnace unit operation. Thus the energies shown do not include the estimated stack losses, convective losses or radiation losses in the boilers or furnaces of these operations.

In Table B, the number of plants represents industrial plant sites ranging from the smallest (one employee) to the largest. Most of these plants are coded or listed under industrial categories by utilities, but many of the smaller plants may be categorized under small commercial-industrial or other classifications because of size or lack of information on plant operations. The plants presented in Tables B of this report represent only manufacturing sites in SIC's 20-39. In utility classification in many instances, the industrial category may include large commercial users. This is variable and is dependent upon the particular utility and its method of accounting.

The thermal rating as presented in Table B is determined by dividing the total thermal process energy as defined in Table A for an individual plant by 3,412 BTU/kwhr and converting to Megawatts thermal. Each plant in a given thermal rating range is multiplied by its estimated hours of operation per year to obtain MWH/yr of thermal process energy; then all plants in that range are summed to provide the total.

The 28 utilities were geographically bounded by the electric region which they serve as defined by the towns and municipalities presented in the Electrical World Directory of Electric Utilities.

<u>Utility</u>	<u>Tables A & B Number*</u>
Central Illinois Public Service	2
Commonwealth Edison Co.	3
Consolidated Edison Co. of New York	4
Consumers Power	5
Detroit Edison Co.	6
Duke Power Co.	7
Florida Power and Light Co.	8
Gulf States Utilities Co.	9
Houston Lighting and Power Co.	10
Idaho Power Co.	11
Long Island Lighting Co.	12
Los Angeles Dept. of Water & Power	13
Louisiana Power and Light Co.	14
Niagara Mohawk Power Corp.	15
Northern Indiana Public Service Co.	16
Ohio Edison Co.	17
Ohio Power	18
Orange and Rockland Utilities Inc.	19
Pacific Gas and Electric Co.	20
Pacific Power and Light Co.	21
Philadelphia Electric Co.	22
Public Service Electric and Gas Co.	23
Puget Sound Power and Light Co.	24
Southwestern Public Service	25
Tennessee Valley Authority	26
Texas Electric Service Co.	27
Union Electric Co.	28
Virginia Electric Power	29

*Table #1 was not used.

TABLE 2A

CENTRAL ILLINOIS PUBLIC SERVICE CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.16E+14	0.62E+12	0.17E+14
350-500	0.14E+14	0.45E+12	0.15E+14
500-750	0.11E+13	0.11E+14	0.12E+14
750-1000	0.15E+12	0.11E+14	0.11E+14
1000-1700	0.00E+00	0.16E+13	0.16E+13
>1700	0.00E+00	0.28E+13	0.28E+13
TOTALS	0.32E+14	0.27E+14	0.59E+14

TABLE 2B

CENTRAL ILLINOIS PUBLIC SERVICE CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
PLANT THERMAL RATING (MW)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	732	0.62E+06	672	0.39E+06	2	0.13E+05
2-5	59	0.63E+06	34	0.26E+06	6	0.13E+06
5-10	22	0.62E+06	7	0.12E+06	4	0.16E+06
10-20	9	0.46E+06	3	0.10E+06	1	0.73E+05
20-35	5	0.41E+06	3	0.23E+06	0	0.00E+00
35-50	1	0.15E+06	0	0.00E+00	0	0.00E+00
50-100	10	0.27E+07	3	0.46E+06	2	0.89E+06
100-500	5	0.66E+07	0	0.00E+00	2	0.43E+07
500-1000	1	0.54E+07	0	0.00E+00	1	0.54E+07
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	844	0.17E+08	722	0.16E+07	18	0.11E+08

TABLE 3A

COMMONWEALTH EDISON CO

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.10E+15	0.35E+13	0.11E+15
350-500	0.82E+14	0.58E+13	0.88E+14
500-750	0.20E+14	0.24E+14	0.43E+14
750-1000	0.91E+13	0.23E+14	0.32E+14
1000-1700	0.00E+00	0.63E+14	0.63E+14
>1700	0.00E+00	0.92E+14	0.92E+14
TOTALS	0.21E+15	0.21E+15	0.42E+15

TABLE 3B

COMMONWEALTH EDISON CO

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	15732	0.11E+08	14764	0.71E+07	83	0.63E+06
2-5	838	0.93E+07	346	0.26E+07	65	0.15E+07
5-10	260	0.70E+07	109	0.18E+07	30	0.15E+07
10-20	107	0.61E+07	31	0.11E+07	17	0.16E+07
20-35	64	0.73E+07	21	0.13E+07	12	0.23E+07
35-50	20	0.38E+07	5	0.47E+06	5	0.16E+07
50-100	26	0.77E+07	11	0.18E+07	4	0.24E+07
100-500	46	0.61E+08	9	0.35E+07	22	0.46E+08
500-1000	2	0.11E+08	0	0.00E+00	2	0.11E+08
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	17095	0.12E+09	15296	0.20E+08	240	0.69E+08

TABLE 4A

CONSOLIDATED EDISON CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.35E+14	0.17E+13	0.37E+14
350-500	0.25E+14	0.28E+13	0.28E+14
500-750	0.36E+13	0.22E+13	0.58E+13
750-1000	0.20E+12	0.31E+13	0.33E+13
1000-1700	0.00E+00	0.20E+14	0.20E+14
>1700	0.00E+00	0.78E+13	0.78E+13
TOTALS	0.64E+14	0.38E+14	0.10E+15

TABLE 4B

CONSOLIDATED EDISON CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	17542	0.74E+07	17020	0.57E+07	21	0.14E+06
2-5	326	0.32E+07	197	0.14E+07	17	0.36E+06
5-10	100	0.21E+07	57	0.91E+06	5	0.25E+06
10-20	45	0.22E+07	25	0.80E+06	5	0.52E+06
20-35	16	0.17E+07	10	0.63E+06	2	0.40E+06
35-50	12	0.19E+07	6	0.66E+06	1	0.32E+06
50-100	12	0.28E+07	9	0.17E+07	1	0.56E+06
100-500	8	0.86E+07	3	0.84E+06	1	0.40E+07
500-1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	18061	0.30E+08	17327	0.13E+08	53	0.66E+07

TABLE 5A

CONSUMERS POWER CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.80E+14	0.90E+12	0.81E+14
350-500	0.63E+14	0.10E+13	0.64E+14
500-750	0.13E+14	0.45E+13	0.18E+14
750-1000	0.19E+12	0.39E+13	0.41E+13
1000-1700	0.00E+00	0.30E+14	0.30E+14
>1700	0.00E+00	0.10E+14	0.10E+14
TOTALS	0.16E+15	0.51E+14	0.21E+15

TABLE 5B

CONSUMERS POWER CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	4640	0.36E+07	4360	0.25E+07	28	0.20E+06
2-5	289	0.34E+07	119	0.84E+06	19	0.47E+06
5-10	92	0.27E+07	29	0.50E+06	11	0.54E+06
10-20	37	0.26E+07	5	0.14E+06	9	0.10E+07
20-35	23	0.32E+07	2	0.12E+06	4	0.81E+06
35-50	8	0.16E+07	2	0.24E+06	2	0.57E+06
50-100	23	0.66E+07	6	0.95E+06	4	0.20E+07
100-500	21	0.41E+08	1	0.49E+06	9	0.34E+08
500-1000	1	0.59E+07	0	0.00E+00	1	0.59E+07
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	5134	0.71E+08	4524	0.58E+07	87	0.45E+08

TABLE 6A

DETROIT EDISON

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.38E+14	0.97E+12	0.39E+14
350-500	0.28E+14	0.18E+13	0.30E+14
500-750	0.83E+13	0.64E+13	0.15E+14
750-1000	0.62E+13	0.64E+13	0.13E+14
1000-1700	0.00E+00	0.24E+14	0.24E+14
>1700	0.00E+00	0.55E+14	0.55E+14
TOTALS	0.80E+14	0.94E+14	0.17E+15

TABLE 6B

DETROIT EDISON

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	8704	0.51E+07	8343	0.39E+07	29	0.18E+06
2-5	374	0.39E+07	182	0.13E+07	15	0.35E+06
5-10	106	0.33E+07	33	0.56E+06	16	0.82E+06
10-20	49	0.32E+07	17	0.61E+06	7	0.77E+06
20-35	22	0.30E+07	6	0.44E+06	2	0.39E+06
35-50	10	0.14E+07	6	0.68E+06	0	0.00E+00
50-100	25	0.92E+07	3	0.46E+06	7	0.39E+07
100-500	16	0.12E+08	4	0.17E+07	7	0.73E+07
500-1000	2	0.98E+07	0	0.00E+00	2	0.98E+07
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	9308	0.51E+08	8594	0.97E+07	85	0.23E+08

TABLE 7A

DUKE POWER CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.44E+14	0.14E+13	0.45E+14
350-500	0.32E+14	0.37E+13	0.36E+14
500-750	0.36E+13	0.69E+13	0.10E+14
750-1000	0.19E+12	0.14E+13	0.16E+13
1000-1700	0.00E+00	0.83E+13	0.83E+13
>1700	0.00E+00	0.85E+13	0.85E+13
TOTALS	0.79E+14	0.30E+14	0.11E+15

TABLE 7B

DUKE POWER CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	426E	0.42E+07	3844	0.23E+07	58	0.47E+06
2-5	361	0.43E+07	151	0.11E+07	77	0.16E+07
5-10	119	0.32E+07	59	0.97E+06	29	0.13E+07
10-20	80	0.47E+07	17	0.57E+06	23	0.19E+07
20-35	22	0.26E+07	7	0.44E+06	6	0.11E+07
35-50	9	0.18E+07	4	0.46E+06	4	0.12E+07
50-100	12	0.39E+07	2	0.29E+06	4	0.20E+07
100-500	7	0.75E+07	0	0.00E+00	2	0.40E+07
500-1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	4873	0.32E+08	4084	0.61E+07	203	0.14E+08

TABLE 8A

FLORIDA POWER AND LIGHT CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F) -----	STEAM (BOILER OUTPUT) -----	DIRECT HEAT (FURNACE OUTPUT) -----	TOTAL -----
<350	0.25E+14	0.89E+12	0.26E+14
350-500	0.20E+14	0.12E+13	0.21E+14
500-750	0.36E+13	0.12E+13	0.48E+13
750-1000	0.19E+12	0.12E+13	0.14E+13
1000-1700	0.00E+00	0.18E+14	0.18E+14
>1700	0.00E+00	0.49E+13	0.49E+13
-----	-----	-----	-----
TOTALS	0.49E+14	0.27E+14	0.76E+14

TABLE 8B

FLORIDA POWER AND LIGHT CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	5834	0.28E+07	5640	0.21E+07	13	0.83E+05
2-5	125	0.12E+07	71	0.51E+06	2	0.39E+05
5-10	38	0.79E+06	26	0.44E+06	2	0.93E+05
10-20	24	0.13E+07	11	0.36E+06	3	0.35E+06
20-35	8	0.11E+07	3	0.23E+06	1	0.26E+06
35-50	4	0.64E+06	2	0.20E+06	1	0.28E+06
50-100	6	0.16E+07	3	0.54E+06	0	0.00E+00
100-500	5	0.13E+08	1	0.24E+06	3	0.12E+08
500-1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	6044	0.22E+08	5757	0.46E+07	25	0.13E+08

TABLE 9A

GULF STATES UTILITIES CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.13E+15	0.18E+13	0.13E+15
350-500	0.12E+15	0.12E+13	0.12E+15
500-750	0.15E+14	0.41E+14	0.55E+14
750-1000	0.32E+11	0.43E+14	0.43E+14
1000-1700	0.00E+00	0.65E+14	0.65E+14
>1700	0.00E+00	0.19E+14	0.19E+14
TOTALS	0.26E+15	0.17E+15	0.43E+15

TABLE 9B

GULF STATES UTILITIES CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	999	0.68E+06	961	0.49E+06	3	0.29E+05
2-5	69	0.62E+06	47	0.31E+06	1	0.29E+05
5-10	43	0.96E+06	26	0.44E+06	2	0.83E+05
10-20	30	0.18E+07	15	0.47E+06	8	0.91E+06
20-35	23	0.35E+07	7	0.48E+06	14	0.28E+07
35-50	11	0.19E+07	5	0.51E+06	4	0.11E+07
50-100	22	0.56E+07	9	0.14E+07	5	0.21E+07
100-500	14	0.16E+08	0	0.00E+00	5	0.88E+07
500-1000	3	0.15E+08	0	0.00E+00	3	0.15E+08
>1000	7	0.80E+08	0	0.00E+00	7	0.80E+08
TOTALS	1221	0.12E+09	1070	0.42E+07	52	0.11E+09

TABLE 10A

HOUSTON LIGHTING AND POWER CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.14E+15	0.11E+13	0.14E+15
350-500	0.11E+15	0.12E+13	0.11E+15
500-750	0.23E+14	0.14E+15	0.16E+15
750-1000	0.20E+13	0.14E+15	0.14E+15
1000-1700	0.00E+00	0.24E+14	0.24E+14
>1700	0.00E+00	0.36E+14	0.36E+14
TOTALS	0.27E+15	0.34E+15	0.61E+15

TABLE 10B

HOUSTON LIGHTING AND POWER CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	4001	0.24E+07	3807	0.16E+07	15	0.13E+06
2-5	189	0.21E+07	93	0.73E+06	22	0.42E+06
5-10	67	0.14E+07	49	0.81E+06	3	0.13E+06
10-20	55	0.34E+07	21	0.64E+06	10	0.11E+07
20-35	30	0.32E+07	17	0.11E+07	9	0.17E+07
35-50	10	0.23E+07	3	0.31E+06	6	0.17E+07
50-100	23	0.71E+07	8	0.14E+07	2	0.12E+07
100-500	15	0.19E+08	5	0.23E+07	3	0.45E+07
500-1000	8	0.41E+08	0	0.00E+00	8	0.41E+08
>1000	4	0.94E+08	0	0.00E+00	4	0.94E+08
TOTALS	4402	0.18E+09	4003	0.89E+07	82	0.15E+09

TABLE 11A

IDAHO POWER CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.55E+13	0.66E+12	0.62E+13
350-500	0.49E+13	0.18E+12	0.51E+13
500-750	0.19E+11	0.66E+11	0.85E+11
750-1000	0.00E+00	0.20E+13	0.20E+13
1000-1700	0.00E+00	0.23E+13	0.23E+13
>1700	0.00E+00	0.32E+12	0.32E+12
TOTALS	0.10E+14	0.54E+13	0.16E+14

TABLE 11B

IDAHO POWER CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
PLANT THERMAL RATING (MW)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	615	0.32E+06	607	0.29E+06	2	0.11E+05
2-5	49	0.47E+06	34	0.26E+06	3	0.70E+05
5-10	14	0.34E+06	8	0.13E+06	1	0.61E+05
10-20	7	0.35E+06	4	0.11E+06	0	0.00E+00
20-35	2	0.30E+06	0	0.00E+00	0	0.00E+00
35-50	1	0.13E+06	0	0.00E+00	0	0.00E+00
50-100	0	0.00E+00	0	0.00E+00	0	0.00E+00
100-500	5	0.27E+07	0	0.00E+00	1	0.78E+06
500-1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	693	0.47E+07	653	0.78E+06	7	0.92E+06

TABLE 12A

LONG ISLAND LIGHTING CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
-----	-----	-----	-----
<350	0.10E+14	0.30E+12	0.10E+14
350-500	0.76E+13	0.69E+12	0.83E+13
500-750	0.12E+13	0.58E+12	0.17E+13
750-1000	0.15E+11	0.46E+12	0.48E+12
1000-1700	0.00E+00	0.44E+13	0.44E+13
>1700	0.00E+00	0.14E+13	0.14E+13
-----	-----	-----	-----
TOTALS	0.19E+14	0.79E+13	0.27E+14

TABLE 12B

LONG ISLAND LIGHTING CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
PLANT THERMAL RATING (MW)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	4376	0.21E+07	4183	0.16E+07	10	0.59E+05
2-5	105	0.95E+06	62	0.45E+06	4	0.74E+05
5-10	33	0.70E+06	22	0.36E+06	1	0.33E+05
10-20	10	0.51E+06	3	0.11E+06	0	0.00E+00
20-35	10	0.61E+06	9	0.52E+06	0	0.00E+00
35-50	3	0.53E+06	1	0.86E+05	0	0.00E+00
50-100	2	0.55E+06	1	0.15E+06	0	0.00E+00
100-500	3	0.18E+07	2	0.11E+07	0	0.00E+00
500-1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	4542	0.78E+07	4283	0.43E+07	15	0.17E+06

TABLE 13A

LOS ANGELES POWER AND LIGHT
PROCESS ENERGY USE(BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.32E+14	0.16E+13	0.34E+14
350-500	0.24E+14	0.30E+13	0.27E+14
500-750	0.46E+13	0.32E+13	0.78E+13
750-1000	0.11E+13	0.31E+13	0.42E+13
1000-1700	0.00E+00	0.93E+13	0.93E+13
>1700	0.00E+00	0.22E+14	0.22E+14
TOTALS	0.62E+14	0.42E+14	0.10E+15

TABLE 13B
LOS ANGELES POWER AND LIGHT
INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	5497	0.31E+07	5277	0.23E+07	14	0.10E+06
2-5	191	0.21E+07	81	0.59E+06	11	0.23E+06
5-10	58	0.14E+07	27	0.47E+06	5	0.26E+06
10-20	34	0.18E+07	18	0.63E+06	3	0.35E+06
20-35	9	0.83E+06	5	0.32E+06	0	0.00E+00
35-50	10	0.19E+07	2	0.20E+06	3	0.85E+06
50-100	8	0.26E+07	2	0.32E+06	2	0.95E+06
100-500	7	0.69E+07	3	0.12E+07	2	0.42E+07
500-1000	2	0.10E+08	0	0.00E+00	2	0.10E+08
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	5814	0.31E+08	5415	0.40E+07	42	0.47E+06

TABLE 14A

LOUISIANA POWER AND LIGHT CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.72E+14	0.21E+13	0.74E+14
350-500	0.67E+14	0.14E+13	0.68E+14
500-750	0.89E+13	0.24E+14	0.33E+14
750-1000	0.19E+12	0.25E+14	0.25E+14
1000-1700	0.00E+00	0.15E+14	0.15E+14
>1700	0.00E+00	0.13E+14	0.13E+14
TOTALS	0.15E+15	0.82E+14	0.23E+15

TABLE 14B

LOUISIANA POWER AND LIGHT CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	1544	0.12E+07	1460	0.79E+06	8	0.65E+05
2-5	88	0.84E+06	60	0.40E+06	3	0.77E+05
5-10	43	0.92E+06	29	0.47E+06	2	0.99E+05
10-20	30	0.15E+07	17	0.54E+06	3	0.34E+06
20-35	14	0.17E+07	5	0.35E+06	2	0.44E+06
35-50	4	0.96E+06	0	0.00E+00	1	0.37E+06
50-100	16	0.49E+07	6	0.12E+07	2	0.86E+06
100-500	10	0.96E+07	1	0.61E+06	2	0.36E+07
500-1000	6	0.30E+08	0	0.00E+00	6	0.30E+08
>1000	1	0.15E+08	0	0.00E+00	1	0.15E+08
TOTALS	1756	0.67E+08	1578	0.44E+07	30	0.51E+08

TABLE 15A

NIAGRA MOHAWK POWER CORP.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.64E+14	0.22E+13	0.66E+14
350-500	0.53E+14	0.27E+13	0.55E+14
500-750	0.15E+14	0.85E+13	0.23E+14
750-1000	0.54E+13	0.85E+13	0.14E+14
1000-1700	0.00E+00	0.34E+14	0.34E+14
>1700	0.00E+00	0.71E+14	0.71E+14
TOTALS	0.14E+15	0.13E+15	0.26E+15

TABLE 15B

NIAGRA MOHAWK POWER CORP.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
PLANT THERMAL RATING (MW)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	3683	0.29E+07	3446	0.19E+07	17	0.13E+06
2-5	264	0.31E+07	125	0.91E+06	27	0.65E+06
5-10	87	0.28E+07	28	0.47E+06	19	0.95E+06
10-20	46	0.30E+07	8	0.27E+06	9	0.92E+06
20-35	23	0.32E+07	6	0.36E+06	9	0.19E+07
35-50	16	0.29E+07	5	0.47E+06	5	0.14E+07
50-100	32	0.12E+08	6	0.11E+07	12	0.65E+07
100-500	27	0.47E+08	0	0.00E+00	19	0.40E+08
500-1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	4178	0.77E+08	3624	0.55E+07	117	0.52E+08

TABLE 16A

NORTHERN INDIANA PUBLIC SERVICE CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.34E+14	0.15E+13	0.35E+14
350-500	0.24E+14	0.30E+13	0.27E+14
500-750	0.32E+14	0.98E+13	0.42E+14
750-1000	0.29E+14	0.84E+13	0.38E+14
1000-1700	0.00E+00	0.15E+14	0.15E+14
>1700	0.00E+00	0.58E+14	0.58E+14
TOTALS	0.12E+15	0.95E+14	0.21E+15

TABLE 16B

NORTHERN INDIANA PUBLIC SERVICE CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	1202	0.11E+07	1112	0.71E+06	4	0.22E+05
2-5	126	0.13E+07	64	0.46E+06	5	0.11E+06
5-10	45	0.12E+07	16	0.27E+06	6	0.31E+06
10-20	20	0.14E+07	5	0.18E+06	6	0.69E+06
20-35	9	0.98E+06	5	0.35E+06	1	0.20E+06
35-50	3	0.42E+06	0	0.00E+00	0	0.00E+00
50-100	9	0.24E+07	3	0.50E+06	2	0.10E+07
100-500	10	0.12E+08	3	0.13E+07	5	0.85E+07
500-1000	1	0.72E+07	0	0.00E+00	1	0.72E+07
>1000	3	0.35E+08	0	0.00E+00	3	0.35E+08

TABLE 17A

OHIO EDISON CO.

PROCESS ENERGY USE(BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
-----	-----	-----	-----
<350	0.30E+14	0.23E+13	0.32E+14
350-500	0.20E+14	0.28E+13	0.23E+14
500-750	0.11E+14	0.88E+12	0.12E+14
750-1000	0.82E+13	0.16E+13	0.98E+13
1000-1700	0.00E+00	0.12E+14	0.12E+14
>1700	0.00E+00	0.42E+14	0.42E+14
-----	-----	-----	-----
TOTALS	0.69E+14	0.62E+14	0.13E+15

TABLE 17B

OHIO EDISON CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	2446	0.21E+07	2275	0.14E+07	25	0.17E+06
2-5	168	0.21E+07	62	0.44E+06	24	0.60E+06
5-10	67	0.20E+07	22	0.38E+06	13	0.58E+06
10-20	28	0.19E+07	3	0.93E+05	6	0.57E+06
20-35	16	0.17E+07	9	0.63E+06	2	0.41E+06
35-50	6	0.93E+06	2	0.22E+06	1	0.27E+06
50-100	13	0.36E+07	6	0.11E+07	0	0.00E+00
100-500	17	0.20E+08	1	0.31E+06	9	0.15E+08
500-1000	1	0.45E+07	0	0.00E+00	1	0.45E+07
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	2762	0.38E+08	2380	0.45E+07	81	0.22E+08

TABLE 18A

OHIO POWER CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.31E+14	0.60E+12	0.31E+14
350-500	0.23E+14	0.93E+12	0.24E+14
500-750	0.59E+13	0.95E+13	0.15E+14
750-1000	0.33E+13	0.95E+13	0.13E+14
1000-1700	0.00E+00	0.15E+14	0.15E+14
>1700	0.00E+00	0.43E+14	0.43E+14
TOTALS	0.63E+14	0.79E+14	0.14E+15

TABLE 18B

OHIO POWER CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	1522	0.15E+07	1382	0.90E+06	11	0.90E+05
2-5	159	0.18E+07	67	0.47E+06	16	0.37E+06
5-10	65	0.19E+07	19	0.30E+06	13	0.66E+06
10-20	36	0.24E+07	8	0.19E+06	9	0.92E+06
20-35	17	0.17E+07	5	0.29E+06	4	0.61E+06
35-50	8	0.16E+07	2	0.19E+06	3	0.89E+06
50-100	13	0.59E+07	1	0.22E+06	6	0.34E+07
100-500	15	0.16E+08	0	0.00E+00	9	0.13E+08
500-1000	2	0.89E+07	0	0.00E+00	2	0.89E+07
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	1837	0.42E+08	1482	0.25E+07	73	0.28E+08

TABLE 19A

ORANGE AND ROCKLAND UTILITIES INC.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
-----	-----	-----	-----
<350	0.68E+13	0.48E+12	0.73E+13
350-500	0.51E+13	0.62E+12	0.57E+13
500-750	0.11E+13	0.17E+12	0.12E+13
750-1000	0.26E+10	0.10E+13	0.11E+13
1000-1700	0.00E+00	0.24E+13	0.24E+13
>1700	0.00E+00	0.12E+13	0.12E+13
-----	-----	-----	-----
TOTALS	0.13E+14	0.60E+13	0.19E+14

TABLE 19B

ORANGE AND ROCKLAND UTILITIES 'INC.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
PLANT THERMAL RATING (MW)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	670	0.51E+06	620	0.30E+06	5	0.52E+05
2-5	26	0.27E+06	12	0.84E+05	2	0.36E+05
5-10	11	0.34E+06	4	0.64E+05	2	0.10E+06
10-20	9	0.68E+06	2	0.77E+05	2	0.27E+06
20-35	3	0.44E+06	1	0.74E+05	1	0.18E+06
35-50	1	0.22E+06	0	0.00E+00	0	0.00E+00
50-100	1	0.21E+06	1	0.21E+06	0	0.00E+00
100-500	3	0.29E+07	0	0.00E+00	1	0.93E+06
500-1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	724	0.55E+07	640	0.81E+06	13	0.16E+07

TABLE 20A

PACIFIC GAS AND ELECTRIC CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F) -----	STEAM (BOILER OUTPUT) -----	DIRECT HEAT (FURNACE OUTPUT) -----	TOTAL -----
<350	0.11E+15	0.77E+13	0.11E+15
350-500	0.98E+14	0.50E+13	0.10E+15
500-750	0.99E+13	0.33E+14	0.43E+14
750-1000	0.17E+13	0.37E+14	0.39E+14
1000-1700	0.00E+00	0.37E+14	0.37E+14
>1700	0.00E+00	0.39E+14	0.39E+14
-----	-----	-----	-----
TOTALS	0.21E+15	0.16E+15	0.37E+15

TABLE 20B

PACIFIC GAS AND ELECTRIC CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
PLANT THERMAL RATING (MW)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	10781	0.55E+07	10410	0.42E+07	30	0.18E+06
2-5	459	0.46E+07	276	0.20E+07	13	0.28E+06
5-10	172	0.43E+07	91	0.15E+07	9	0.45E+06
10-20	127	0.71E+07	64	0.22E+07	18	0.19E+07
20-35	53	0.49E+07	36	0.23E+07	7	0.14E+07
35-50	21	0.32E+07	10	0.11E+07	0	0.00E+00
50-100	21	0.61E+07	7	0.12E+07	2	0.11E+07
100-500	36	0.34E+08	6	0.25E+07	13	0.20E+08
500-1000	4	0.23E+08	0	0.00E+00	4	0.23E+08
>1000	1	0.14E+08	0	0.00E+00	1	0.14E+08
TOTALS	11675	0.11E+09	10900	0.17E+08	97	0.12E+08

TABLE 21A

PACIFIC POWER AND LIGHT CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F) -----	STEAM (BOILER OUTPUT) -----	DIRECT HEAT (FURNACE OUTPUT) -----	TOTAL -----
<350	0.41E+14	0.14E+14	0.54E+14
350-500	0.42E+14	0.83E+13	0.50E+14
500-750	0.66E+13	0.78E+13	0.14E+14
750-1000	0.19E+13	0.91E+13	0.11E+14
1000-1700	0.00E+00	0.49E+13	0.49E+13
>1700	0.00E+00	0.41E+14	0.41E+14
-----	-----	-----	-----
TOTALS	0.91E+14	0.84E+14	0.18E+15

TABLE 21B

PACIFIC POWER AND LIGHT CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	2925	0.20E+07	2841	0.16E+07	4	0.41E+05
2-5	175	0.14E+07	144	0.10E+07	3	0.65E+05
5-10	103	0.22E+07	74	0.12E+07	4	0.22E+06
10-20	62	0.25E+07	50	0.17E+07	2	0.23E+06
20-35	18	0.13E+07	13	0.83E+06	1	0.17E+06
35-50	11	0.15E+07	4	0.47E+06	0	0.00E+00
50-100	29	0.72E+07	10	0.16E+07	3	0.18E+07
100-500	16	0.15E+08	0	0.00E+00	6	0.11E+08
500-1000	3	0.18E+08	0	0.00E+00	3	0.18E+08
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	3342	0.51E+08	3136	0.85E+07	26	0.32E+08

TABLE 22A

PHILADELPHIA ELECTRIC CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.58E+14	0.15E+13	0.60E+14
350-500	0.48E+14	0.27E+13	0.51E+14
500-750	0.74E+13	0.15E+14	0.23E+14
750-1000	0.25E+13	0.15E+14	0.17E+14
1000-1700	0.00E+00	0.10E+14	0.10E+14
>1700	0.00E+00	0.36E+14	0.36E+14
TOTALS	0.12E+15	0.81E+14	0.20E+15

TABLE 22B

PHILADELPHIA ELECTRIC CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	5358	0.33E+07	4965	0.25E+07	31	0.21E+06
2-5	278	0.31E+07	131	0.10E+07	17	0.36E+06
5-10	99	0.27E+07	31	0.53E+06	9	0.41E+06
10-20	48	0.29E+07	13	0.43E+06	11	0.11E+07
20-35	25	0.29E+07	11	0.72E+06	5	0.12E+07
35-50	10	0.15E+07	5	0.49E+06	1	0.26E+06
50-100	21	0.78E+07	4	0.81E+06	5	0.27E+07
100-500	17	0.13E+08	3	0.13E+07	7	0.74E+07
500-1000	4	0.20E+08	0	0.00E+00	4	0.20E+08
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	5860	0.58E+08	5163	0.77E+07	90	0.34E+08

TABLE 23B

PUBLIC SERVICE ELECTRIC AND GAS

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.41E+14	0.16E+13	0.43E+14
350-500	0.35E+14	0.44E+13	0.39E+14
500-750	0.94E+13	0.44E+13	0.14E+14
750-1000	0.67E+12	0.23E+14	0.24E+14
1000-1700	0.00E+00	0.21E+14	0.21E+14
>1700	0.00E+00	0.11E+14	0.11E+14
TOTALS	0.87E+14	0.66E+14	0.15E+15

TABLE 23B

PUBLIC SERVICE ELECTRIC AND GAS

INDUSTRIAL PLANT AND THERMAL ENERGY PROFILE

	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
PLANT THERMAL RATING (MW)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	8088	0.47E+07	7544	0.28E+07	72	0.58E+06
2-5	177	0.26E+07	38	0.30E+06	46	0.11E+07
5-10	94	0.34E+07	9	0.16E+06	37	0.18E+07
10-20	56	0.42E+07	11	0.38E+06	25	0.26E+07
20-35	19	0.31E+07	3	0.22E+06	9	0.20E+07
35-50	5	0.15E+07	1	0.15E+06	3	0.12E+07
50-100	22	0.87E+07	1	0.20E+06	11	0.57E+07
100-500	9	0.86E+07	0	0.00E+00	4	0.58E+07
500-1000	1	0.77E+07	0	0.00E+00	1	0.77E+07
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	8474	0.45E+08	7610	0.42E+07	212	0.28E+08

TABLE 24A

PUGET SOUND POWER AND LIGHT CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.13E+14	0.93E+12	0.14E+14
350-500	0.12E+14	0.42E+12	0.13E+14
500-750	0.96E+12	0.81E+13	0.90E+13
750-1000	0.48E+11	0.80E+13	0.81E+13
1000-1700	0.00E+00	0.32E+13	0.32E+13
>1700	0.00E+00	0.13E+14	0.13E+14
TOTALS	0.27E+14	0.34E+14	0.61E+14

TABLE 24B

PUGET SOUND POWER AND LIGHT CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	1194	0.69E+06	1163	0.58E+06	1	0.26E+04
2-5	57	0.51E+06	37	0.27E+06	0	0.00E+00
5-10	17	0.33E+06	13	0.21E+06	0	0.00E+00
10-20	15	0.70E+06	5	0.13E+06	0	0.00E+00
20-35	3	0.28E+06	2	0.11E+06	0	0.00E+00
35-50	4	0.49E+06	3	0.34E+06	0	0.00E+00
50-100	4	0.14E+07	0	0.00E+00	1	0.50E+06
100-500	5	0.37E+07	0	0.00E+00	4	0.27E+07
500-1000	2	0.93E+07	0	0.00E+00	0	0.93E+07
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	1301	0.18E+08	1223	0.16E+07	8	0.13E+08

TABLE 25A

SOUTHWEST PUBLIC SERVICE CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.16E+14	0.24E+12	0.17E+14
350-500	0.16E+14	0.39E+12	0.17E+14
500-750	0.86E+12	0.14E+14	0.15E+14
750-1000	0.00E+00	0.15E+14	0.15E+14
1000-1700	0.00E+00	0.47E+13	0.47E+13
>1700	0.00E+00	0.11E+13	0.11E+13
TOTALS	0.34E+14	0.36E+14	0.69E+14

TABLE 25B

SOUTHWEST PUBLIC SERVICE CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	866	0.46E+06	835	0.36E+06	0	0.00E+00
2-5	47	0.49E+06	25	0.18E+06	5	0.87E+05
5-10	11	0.27E+06	5	0.82E+05	0	0.00E+00
10-20	6	0.43E+06	2	0.79E+05	1	0.13E+06
20-35	8	0.77E+06	3	0.20E+06	2	0.32E+06
35-50	3	0.39E+06	3	0.39E+06	0	0.00E+00
50-100	6	0.15E+07	1	0.12E+06	0	0.00E+00
100-500	10	0.92E+07	1	0.31E+06	5	0.72E+07
500-1000	1	0.63E+07	0	0.00E+00	1	0.63E+07
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	958	0.20E+08	875	0.17E+07	14	0.14E+08

TABLE 26A

TENNESSEE VALLEY AUTHORITY

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.14E+15	0.41E+13	0.15E+15
350-500	0.12E+15	0.50E+13	0.12E+15
500-750	0.20E+14	0.92E+13	0.29E+14
750-1000	0.55E+12	0.65E+13	0.71E+13
1000-1700	0.00E+00	0.61E+14	0.61E+14
>1700	0.00E+00	0.77E+14	0.77E+14
TOTALS	0.28E+15	0.16E+15	0.44E+15

TABLE 26B

TENNESSEE VALLEY AUTHORITY

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (NWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (NWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (NWH/YR)
<2	7314	0.71E+07	6597	0.43E+07	49	0.37E+06
2-5	666	0.73E+07	331	0.24E+07	51	0.12E+07
5-10	274	0.70E+07	133	0.21E+07	29	0.14E+07
10-20	121	0.72E+07	42	0.15E+07	18	0.19E+07
20-35	44	0.64E+07	10	0.63E+06	19	0.38E+07
35-50	27	0.48E+07	8	0.80E+06	7	0.21E+07
50-100	43	0.15E+08	7	0.11E+07	13	0.68E+07
100-500	26	0.59E+08	2	0.62E+06	13	0.48E+08
500-1000	2	0.13E+08	0	0.00E+00	2	0.13E+08
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	8517	0.13E+09	7130	0.13E+08	201	0.78E+08

TABLE 27A

TEXAS ELECTRIC SERVICE CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F) -----	STEAM (BOILER OUTPUT) -----	DIRECT HEAT (FURNACE OUTPUT) -----	TOTAL -----
<350	0.12E+14	0.91E+12	0.13E+14
350-500	0.93E+13	0.12E+13	0.11E+14
500-750	0.48E+12	0.54E+13	0.59E+13
750-1000	0.35E+11	0.54E+13	0.54E+13
1000-1700	0.00E+00	0.29E+13	0.29E+13
>1700	0.00E+00	0.76E+13	0.76E+13
-----	-----	-----	-----
TOTALS	0.22E+14	0.23E+14	0.45E+14

TABLE 27B

TEXAS ELECTRIC SERVICE CO.
INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	2256	0.16E+07	2127	0.11E+07	8	0.62E+05
2-5	122	0.13E+07	61	0.45E+06	7	0.16E+06
5-10	40	0.93E+06	20	0.33E+06	4	0.15E+06
10-20	30	0.17E+07	13	0.44E+06	2	0.26E+06
20-35	12	0.14E+07	4	0.22E+06	2	0.43E+06
35-50	4	0.41E+06	4	0.41E+06	0	0.00E+00
50-100	7	0.21E+07	2	0.32E+06	0	0.00E+00
100-500	3	0.39E+07	0	0.00E+00	1	0.31E+07
500-1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	2474	0.13E+08	2231	0.33E+07	24	0.41E+07

TABLE 28A

UNION ELECTRIC CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
<350	0.50E+14	0.76E+12	0.51E+14
350-500	0.42E+14	0.13E+13	0.44E+14
500-750	0.86E+13	0.87E+13	0.17E+14
750-1000	0.10E+13	0.93E+13	0.10E+14
1000-1700	0.00E+00	0.48E+14	0.48E+14
>1700	0.00E+00	0.23E+14	0.23E+14
TOTALS	0.10E+15	0.92E+14	0.19E+15

TABLE 28B

UNION ELECTRIC CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	2828	0.20E+07	2669	0.14E+07	11	0.85E+05
2-5	159	0.18E+07	67	0.50E+06	14	0.31E+06
5-10	62	0.19E+07	15	0.22E+06	7	0.40E+06
10-20	28	0.18E+07	6	0.24E+06	8	0.77E+06
20-35	15	0.16E+07	8	0.47E+06	2	0.41E+06
35-50	6	0.14E+07	2	0.22E+06	3	0.96E+06
50-100	10	0.33E+07	4	0.65E+06	2	0.11E+07
100-500	20	0.43E+08	1	0.24E+06	9	0.35E+08
500-1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	3128	0.57E+08	2772	0.39E+07	56	0.39E+08

TABLE 29A

VIRGINIA ELECTRIC POWER CO.

PROCESS ENERGY USE (BTU/YR)

TEMPERATURE (DEGREES F)	STEAM (BOILER OUTPUT)	DIRECT HEAT (FURNACE OUTPUT)	TOTAL
-----	-----	-----	-----
<350	0.47E+14	0.14E+13	0.48E+14
350-500	0.37E+14	0.17E+13	0.39E+14
500-750	0.53E+13	0.79E+13	0.13E+14
750-1000	0.13E+12	0.22E+13	0.24E+13
1000-1700	0.00E+00	0.55E+13	0.55E+13
>1700	0.00E+00	0.10E+14	0.10E+14
-----	-----	-----	-----
TOTALS	0.89E+14	0.29E+14	0.12E+15

TABLE 29B

VIRGINIA ELECTRIC POWER CO.

INDUSTRIAL PLANTS AND THERMAL ENERGY PROFILE

PLANT THERMAL RATING (MW)	ALL PLANTS		PLANTS <3000 HRS/YR		PLANTS >6000 HRS/YR	
	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)	NUMBER OF PLANTS	TOTAL THERMAL ENERGY USE (MWH/YR)
<2	2357	0.20E+07	2178	0.13E+07	13	0.70E+05
2-5	213	0.20E+07	146	0.10E+07	13	0.27E+06
5-10	97	0.21E+07	61	0.95E+06	5	0.26E+06
10-20	60	0.34E+07	28	0.10E+07	7	0.69E+06
20-35	14	0.19E+07	5	0.36E+06	7	0.13E+07
35-50	10	0.23E+07	2	0.24E+06	4	0.12E+07
50-100	9	0.42E+07	1	0.18E+06	6	0.32E+07
100-500	11	0.12E+08	0	0.00E+00	8	0.10E+08
500-1000	1	0.46E+07	0	0.00E+00	1	0.46E+07
>1000	0	0.00E+00	0	0.00E+00	0	0.00E+00
TOTALS	2772	0.35E+08	2421	0.51E+07	64	0.22E+08

APPENDIX B

GEA LIST OF PLANTS REQUIRING MORE THAN 500

MW THERMAL ENERGY

APPENDIX BPROFILE OF INDIVIDUAL PLANTS GREATER THAN 500 MW_t
OF THERMAL PROCESS ENERGY

Profiles of individual plants with an estimated greater than 500 MW_t thermal process energy use are presented in Tables B1, B2, B3, and B4 for SIC's 26, 28, 29 and 33 respectively. In addition, profiles of additional plants that have been estimated to approach 500 MW_t are presented in Table B5.

In each of these tables, the name of the plant, city and state location, process steam (lb/yr and lb/hr), process direct heat (Btu/hr), on-site electric generation (MW), total plant electric demand (MW), and the utility which supplies the plant electricity are included. The process heat (steam and direct heat) definition are those established in Appendix A. The steam temperatures and plant hours of operation are footnoted in each table.

TABLE B1

PROFILE OF PLANTS WITH PROCESS
THERMAL DEMAND GREATER THAN 500 MW

SIC 26

PLANT	CITY	STATE	STEAM GENERATION ¹		DIRECT HEAT (10 ⁹ Btu/hr)	ON-SITE ELECTRIC GENERATION (MW)	ELECTRIC DEMAND (MW)	UTILITY
			(10 ⁹ lb/yr)	(10 ⁶ lb/hr) ²				
SCOTT PAPER	Mobile	AL	21	2.6	.13	44	84	Alabama Power Co.
GEORGIA PACIFIC	Crownet	AR	13	1.6	.12	40	52	AR Power & Light Co.
CONTAINER CORP. OF AMERICA	Fernandino Beach	FL	15	1.8	.07	50	50	FL Public Utilities Co.
ST. JOE PAPER	Port St. Joe	FL	18	2.2	.14	53	67	FL Power Corp.
ST. REGIS PAPER	Jacksonville	FL	15	1.8	.07	42	50	Jacksonville Electric Auth.
BRUNSWICK PULP	Brunswick	GA	14	1.7	.07	26	54	Georgia Power Co.
GEORGIA KRAFT	Rome	GA	16	1.9	.12	40	55	Georgia Power Co.
GREAT NORTHERN NEKOOSA	Cedarspring	GA	25	3.0	.19	68	82	Georgia Power Co.
UNION CAMP	Savannah	GA	28	3.4	.21	90	115	Savannah Electric & Power Co.
CONTINENTAL FOREST	Hodge	LA	15	1.8	.07	44	50	Louisiana Power & Light
OLIN KRAFT	West Monroe	LA	17	2.0	.11	50	58	Louisiana Power & Light
ST. REGIS PAPER	Monticello	MS	17	2.0	.11	50	57	Mississippi Power & Light
CHAMPION PAPER	Canton	NC	17	2.0	.05	40	64	Carolina Power & Light
FEDERAL PAPERBOARD	Reigelwood	NC	15	1.8	.05	50	54	Carolina Power & Light
WEYERHAEUSER CORP.	Valliant	OK	19	2.3	.14	21	62	Public Service Co. of OK
INTERNATIONAL PAPER CO.	Georgetown	SC	16	1.9	.13	53	57	Georgetown Light & Water Dep.
WESTVACO	Charleston	SC	19	2.3	.15	60	67	S. Carolina Electric & Gas Co.
EASTEX CORP.	Evadale	TX	15	1.8	.06	32	56	Houston Lighting & Power Co.
UNION CAMP	Franklin	VA	20	2.4	.11	55	72	Franklin Municipal Light Dep.
WESTVACO	Covington	VA	16	1.9	.05	45	54	Virginia Electric & Power Co.
CROWN ZELLERBACH	Camas	WA	15	1.8	.11	45	50	Puget Sound Power & Light Co.
LONGVIEW FIBRE	Longview	WA	17	2.1	.08	70	90	Public Utility District No. 1 of Cowlitz County

1. Average process steam conditions: 25% less than 350°F; 65% between 350°-500°F; 10% greater than 500°F.

2. Average yearly hours of operation for large plants range from 8000 to 8500 hours.

TABLE B2

PROFILE OF PLANTS WITH PROCESS
THERMAL DEMAND GREATER THAN 500 MW
SIC 28

PLANT	CITY	STATE	STEAM GENERATION ¹		DIRECT HEAT (10 ⁹ Btu/Hr)	ON-SITE ELECTRIC GENERATION (MW)	ELECTRIC DEMAND MW	UTILITY
			(10 ⁹ lb/yr)	(10 ⁶ lb/hr) ²				
STANDARD OIL OF INDIANA	Decatur	AL	2.7	.32	2.8	-	100	Decatur Electric Dept.
ALCOA	Mobile	AL	13	1.5	.32	15	17	Alabama Power Co.
AMERICAN ROECHIST CORP.	Baton Rouge	LA	19	2.3	.51	-	120	Gulf State Utilities Co.
CF INDUSTRIES	Donaldsonville	LA	10	1.2	.72	-	125	Louisiana Power & Light Co.
COS-MAR INC.	Carville	LA	25	3.0	.69	-	160	Gulf State Utilities Co.
DOW CHEMICAL	Plaquemine	LA	30	3.6	2.0	250	500	Plaquemine City Lgt. & Water
GEORGIA-PACIFIC CORP.	Plaquemine	LA	12	1.4	.85	-	230	Plaquemine City Lgt. & Water
KAISER ALUMINUM & CHEMS.	Baton Rouge	LA	13	1.6	.29	15	17	Gulf State Utilities Co.
KAISER ALUMINUM & CHEMS.	Gramercy	LA	13	1.5	.42	80	81	Louisiana Power & Light Co.
PPG INDUSTRIES	Lake Charles	LA	21	2.5	.99	400	400	Gulf State Utilities Co.
DOW CHEMICAL	Midland	MI	17	2.0	.46	150	150	Consumers Power Co.
EASTMAN KODAK	Kingsport	TN	11	1.3	.80	100	96	Kingsport Power Co.
AMERICAN ROECHIST CORP.	Bayport	TX	18	2.1	.45	-	130	Houston Lighting & Power Co.
ATLANTIC RICHFIELD CHEM.	Channelview	TX	4.5	.53	1.6	-	98	Houston Lighting & Power Co.
CELANESE CORP.	Clear Lake	TX	11	1.3	.77	-	240	Houston Lighting & Power Co.
DIAMOND SHAHROCK CORP.	La Porte	TX	10	1.2	.76	-	190	Houston Lighting & Power Co.
DOW CHEMICAL	Oyster Creek	TX	10	1.2	.51	-	150	Houston Lighting & Power Co.
DOW CHEMICAL	Freeport	TX	84	9.9	3.5	1200	1300	Houston Lighting & Power Co.
MONSANTO	Texas City	TX	31	3.7	1.2	-	220	Community Public Service Co.
MONSANTO	Chocolate Bayou	TX	7.6	.90	1.1	-	110	Houston Lighting & Power Co.
OXIRANE INTERNATIONAL	Channelview	TX	23	2.8	.51	-	140	Houston Lighting & Power Co.
REYNOLDS METALS	Corpus Christi	TX	18	2.1	.46	-	24	Central Power & Light Co.
UNION CARBIDE	Texas City	TX	11	1.3	.53	40	55	Community Public Service Co.
ALLIED CHEMICAL	Green River	WY	13	1.6	.81	16	30	Pacific Power & Light Co.
FMC	Green River	WY	17	2.0	1.2	43	44	Pacific Power & Light Co.
STAUFFER CHEMICAL	Green River	WY	11	1.3	.68	-	25	Pacific Power & Light Co.

1. Average process steam conditions: 17% less than 350°F; 68% between 350-500°F; 15% greater than 500°F.

2. Average yearly hours of operation for large plants range from 8200 to 8700 hours.

TABLE B3

PROFILE OF PLANTS WITH PROCESS
THERMAL DEMAND GREATER THAN 500 MW
SIC 29

PLANT	CITY	STATE	STEAM GENERATION ¹		DIRECT HEAT (10 ⁹ Btu/Hr)	ON-SITE ELECTRIC GENERATION (MW)	ELECTRIC DEMAND MW	UTILITY
			(10 ⁹ lb/yr)	(10 ⁵ lb/hr) ²				
ATLANTIC RICHFIELD CO.	Carson	CA	7.9	.93	2.0	-	51	Southern California Edison
CHEVRON USA INC.	El Segundo	CA	12	1.4	3.9	-	92	Southern California Edison
CHEVRON USA INC.	Richmond	CA	16	1.9	3.8	20	99	Pacific Gas and Electric
EXXON CORP.	Benicia	CA	7.7	.91	1.9	-	43	Pacific Gas and Electric
MOBIL CORP.	Torrance	CA	6.7	.79	1.9	40	42	Southern California Edison
SHELL OIL CO.	Martinez	CA	8.4	.99	1.5	-	37	Pacific Gas and Electric
TEXACO INC.	Wilmington	CA	9.7	.44	1.3	-	29	Los Angeles Dept of Water & Power
TOSCO CORP.	Martinez	CA	5.6	.78	1.6	-	36	Pacific Gas and Electric
UNION OIL CO.	Rodeo	CA	5.0	.59	1.6	-	33	Pacific Gas and Electric
UNION OIL CO.	Wilmington	CA	7.4	.87	1.5	-	34	Los Angeles Dept of Water & Power
GETTY OIL	Delaware City	DE	15	1.8	3.1	100	140	Delmarva Power and Light
MARATHON OIL CO.	Robinson	IL	5.7	.68	1.5	12	37	Central Illinois Public Service
MOBIL CORP.	Joliet	IL	10	1.2	1.5	-	47	Commonwealth Edison Co.
SHELL OIL CO.	Wood River	IL	16	1.9	2.6	20	76	Illinois Power Co.
UNION OIL	Lemont	IL	6.9	.82	.93	-	32	Commonwealth Edison Co.
AMOCO	Whiting	IN	17	2.0	2.3	64	73	N. Indiana Public Service Co.
ASHLAND OIL	Catlettsburg	KY	12	1.4	1.6	5	56	Kentucky Power Co.
CITIES SERVICE	Lake Charles	LA	18	2.1	2.1	75	100	Gulf States Utilities Co.
CONOCO	Lake Charles	LA	5.7	.67	1.0	12	46	Gulf States Utilities Co.
EXXON CORP.	Baton Rouge	LA	27	3.2	3.3	-	100	Gulf States Utilities Co.

1. Average process steam conditions: 48% less than 350°F; 42% between 350-500°F, 10% greater than 500°F.

2. Average yearly hours of operation for large plants range from 8200 to 8700 hours.

TABLE B3 (Cont'd)

PROFILE OF PLANTS WITH PROCESS
THERMAL DEMAND GREATER THAN 500 MW
SIC 29 CONT'D.

<u>PLANT</u>	<u>CITY</u>	<u>STATE</u>	<u>STEAM GENERATION¹</u> <u>(10⁹ lb/yr) (10⁶ lb/hr)²</u>		<u>DIRECT HEAT</u> <u>(10⁹ Btu/hr)</u>	<u>ON-SITE</u> <u>ELECTRIC</u> <u>GENERATION (MW)</u>	<u>ELECTRIC</u> <u>DEMAND</u> <u>MW</u>	<u>UTILITY</u>
GULF OIL CO.	Belle Chasse	LA	10	1.2	1.1	-	37	Louisiana Power & Light Co.
MARATHON OIL CO.	Garyville	LA	10	1.2	1.3	5	44	Louisiana Power & Light Co.
SHELL OIL CO.	Norco	LA	18	2.2	3.9	-	190	Louisiana Power & Light Co.
CHEVRON USA INC.	Pascagoula	MS	12	1.4	2.9	-	78	Mississippi Power Co.
EXXON CORP.	Linden	NJ	12	1.4	1.7	-	56	Public Service Electric & Gas
STANDARD OIL OF OHIO	Lima	OH	5.1	.60	1.1	-	32	Ohio Power Co.
STANDARD OIL OF OHIO	Toledo	OH	6.4	.76	1.2	-	34	Toledo Edison Co.
ATLANTIC RICHFIELD CO.	Philadelphia	PA	4.0	.48	1.7	-	40	Philadelphia Electric Co.
BP OIL CORP.	Marcus Hook	PA	6.4	.75	1.2	-	38	Philadelphia Electric Co.
GULF OIL CO.	Philadelphia	PA	9.3	1.1	1.3	36	53	Philadelphia Electric Co.
SUN OIL CO.	Marcus Hook	PA	15	1.8	1.3	-	41	Philadelphia Electric Co.
ATLANTIC RICHFIELD CO.	Houston	TX	15	1.8	2.6	-	89	Houston Lighting & Power Co.
AMOCO	Texas City	TX	22	2.6	2.8	75	110	Community Public Service Co.
EXXON CORP.	Baytown	TX	43	5.1	5.6	175	240	Houston Lighting & Power Co.
GULF OIL CO.	Port Arthur	TX	23	2.7	2.8	105	130	Gulf States Utilities Co.
Mobil CORP.	Beaumont	TX	18	2.2	3.3	110	110	Gulf States Utilities Co.
PHILLIPS PETROLEUM	Sweeny	TX	7.6	.90	1.7	5	120	Southwestern Public Service Co.
SHELL OIL CO.	Deer Park	TX	32	3.8	5.1	150	300	Houston Lighting & Power Co.
TEXACO INC.	Port Arthur	TX	23	2.7	2.6	110	110	Gulf States Utilities Co.
ATLANTIC RICHFIELD	Ferndale	WA	3.2	.38	1.5	-	33	Puget Sound Power & Light Co.

1. Average process steam conditions: 48% less than 350°F; 42% between 350-500°F; 10% greater than 500°F.

2. Average yearly hours of operation for large plants range from 8200 to 8700 hours.

TABLE B4

PROFILE OF PLANTS WITH PROCESS
THERMAL DEMAND GREATER THAN 500 MW

SIC 33

PLANT	CITY	STATE	STEAM GENERATION ¹		DIRECT HEAT ³ (10 ⁹ Btu/Hr)	ON-SITE ELECTRIC GENERATION (MW)	ELECTRIC DEMAND (MW)	UTILITY
			(10 ⁹ lb/yr)	(10 ⁶ lb/hr) ²				
U.S. STEEL	Fairfield	AL	5.2	.59	1.2	20	100	Alabama Power Co.
BETHLEHEM STEEL	Chesterton	IN	8.1	.92	2.0	150	170	North. IN Public Service
INLAND STEEL	E. Chicago	IN	11.	1.3	3.4	210	410	North. IN Public Service
U.S. STEEL	Gary	IN	17.	1.9	4.1	60	260	North. IN Public Service
BETHLEHEM STEEL	Sparrows Point	MD	6.7	.77	1.7	140	170	Baltimore G&E Co.
FORD MOTOR CO.	Dearborn	MI	5.4	.62	1.4	130	130	Detroit Edison Co.
NATIONAL STEEL	Detroit	MI	5.5	.63	1.4	-	180	Detroit Edison Co.
REPUBLIC STEEL	Cleveland	OH	5.7	.65	1.4	45	120	Cleveland Electric Illuminating Co.
U.S. STEEL	Lorain	OH	4.9	.56	1.2	30	110	Ohio Edison Co.
WHEELING-PITTSBURGH STEEL	Steubenville	OH	5.4	.62	1.3	15	100	Ohio Power Co.
BETHLEHEM STEEL	Bethlehem	PA	7.9	.90	1.9	45	210	Penn. Power & Light
U.S. STEEL	Clairton	PA	7.4	.84	1.3	40	36	Duquesne Light Co.
NATIONAL STEEL	Wairton	WV	6.0	.68	1.5	110	140	Monongahela Power Co.

1. Average process steam conditions: 22% less than 350°F; 58% between 350-500°F; 20% greater than 500°F.
2. Average yearly hours of operation for large plants range from 8200 to 8700 hours.
3. Direct heat does not include end uses that can not be replaced such as blast furnace coke.

TABLE B5

PROFILE OF ADDITIONAL PLANTSTHAT MAY APPROACH 500 MW PROCESS THERMAL DEMAND

<u>PLANT</u>	<u>CITY</u>	<u>STATE</u>	<u>SIC</u>	<u>STEAM GENERATION (10⁶ lb/hr)</u>	<u>DIRECT HEAT (10⁹ Btu/hr)</u>	<u>ON SITE ELECTRIC GENERATION (MW)</u>	<u>ELECTRIC DEMAND (MW)</u>	<u>UTILITY</u>
INTERNATIONAL PAPER	Mobile	AL	26	1.3 - 2.5	.06-.13	98	40 - 110	Alabama Power Co.
MONSANTO CHEMICAL	Decatur	AL	28	< 1.7	.80-2.4	5	50 - 80	Decatur Electric Dept.
MONSANTO CHEMICAL	Pensacola	FL	28	< 2.0	1.8	16	< 60	Gulf Power Co.
INTERNATIONAL PAPER	Panama City	FL	26	1.5 - 1.8	.05-.10	49	40 - 50	Gulf Power Co.
AMOCO	Wood River	IL	29	< 2.5	.5-1.5	12	5 - 20	Illinois Power Co.
INTERNATIONAL PAPER	Bastrop	LA	26	< 1.8	.06-.11	56	20 - 80	Louisiana Power & Light
INTERNATIONAL PAPER	Springhill	LA	26	1.2 - 1.8	.04-.11	33	40 - 50	Louisiana Power & Light
EASTMAN KODAK	Rochester	NY	28	< 2.5	.25-.75	114	< 125	Rochester Gas & Electric
SOUTHLAND PAPER	Lufkin	TX	26	1.0 - 2.2	.03-.15	78	75 - 100	Texas Power & Light Co.
NECHES-BUTANE	Port Arthur	TX	28	< 2.0	.60-1.8	-	< 40	Gulf States Utilities
CELANESE CORP.	Bishop	TX	28	< 2.0	.60-1.8	-	20 - 80	Central Power & Light
EASTMAN KODAK	Longview	TX	28	< 2.0	.70-1.6	-	20 - 60	Southwestern Electric Power
UNION CARBIDE	S. Charlestown	WV	28	< 2.0	.10-.50	7	10 - 60	Appalachian Power co.