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Industrial Cogeneration Optimization Program

Volume I

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January 1980

Prepared for:

U.S. Department of Energy

Office of Industrial Programs

Conservation and Solar Energy

Washington D.C. 20585

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1.0 SUMMARY

1.1 BACKGROUND

For its energy needs the United States now relies largely on natural gas and petroleum-based fuels. Industry accounts for approximately 40% of the nation's energy consumption. Energy conservation involving both savings in terms of Btu's and also switching from gas or oil to coal is being studied and implemented in four major categories:

- Improved efficiency of energy use, through better maintenance, housekeeping, and insulation; and recovery of the potential energy value of waste heat now being discharged to the environment in the form of offgases and heated water.
- Improved efficiency in energy generation and conversion.
- Introduction and incorporation of new process technologies that are more energy-conserving.
- Introduction of new products that are less energy-intensive.

Major national efforts to improve the efficiency of energy conversion and use have resulted from increases in energy costs and concerns about availability. Part of the Department of Energy's (DOE) Industrial Energy Conservation Program involves reducing industrial (and agricultural) consumption of energy by industrial cogeneration of energy. Such a system involves the simultaneous production of:

- electricity or shaft power, and
- useful thermal energy.

Cogeneration is an efficient way of generating useful forms of energy. However, technological, institutional, and economic barriers currently hinder the market penetration of industrial cogeneration. Effectively applied, federal activity will lower those barriers and stimulate acceptance of industrial cogeneration systems. This program of work was conceived to better understand the economics of cogeneration and barriers to its more general applications.

1.2 SCOPE

The purpose and scope of this program was to:

- identify up to ten good near-term opportunities for cogeneration in five major energy consuming industrial sectors: Food and Kindred Products (SIC 20), Textile Mill Products (SIC 22), Paper and Allied Products (SIC 26), Chemical and Allied Products (SIC 28), and Petroleum Refining and Related Industries (SIC 29);

- select, characterize, and optimize cogeneration systems for these identified opportunities in order to achieve maximum energy savings for given minimum values of return on investment (ROI) or return on equity (ROE). Components of cogeneration systems chosen in this study are currently available. The optimization was done by considering pollution control standards and by using prices for energy forms likely to be used in the industrial sectors of interest in the time period of 1980 to 2000;
- help identify technical, institutional and regulatory obstacles hindering application of industrial cogeneration systems.

1.3 APPROACH

In undertaking this study, our overall approach involved:

- establishing a methodology for undertaking the analysis as outlined in Section 2 of this document;
- development of plant energy demand profiles, shown in Section 3, for plants selected by criteria established early in the study;
- review of energy price projection models and selecting one made by DOE's Energy Information Administration (EIA) which we used in determining the economics of cogeneration (details on energy models are presented in Section 4);
- establishing the state of the art in cogeneration component development and related costs as explained in Section 5;
- examination of various cogeneration systems for each plant (considering fuel availability/costs) and optimization of one system appearing to offer the best potential for achieving energy savings while meeting minimum (hurdle) rate return on investment criteria. State-of-the-art components considered for cogeneration systems included:
 - coal- and oil-fired power steam generators;
 - oil, natural gas, and coal-fired process steam boilers;
 - slow-speed, two-stroke cycle marine diesel engines;
 - high-speed, four-stroke cycle industrial diesel engines;
 - heat recovery steam generators (HRSG's);
 - waste heat boilers (generating saturated steam);
 - steam turbine/generators;
 - gas turbine/generators;
 - combined cycle subsystems with various steam turbine configurations;
 - coal-fired gas cycles;
 - particulate removal and flue gas desulfurization systems, including electrostatic precipitators, scrubbers, and baghouses;

- rankine bottoming cycles including fluorinol-85, methanol, and ammonia as working fluids;
- energy storage devices such as steam accumulators, packed beds, and moving beds in various configurations.

Further information on factors considered in system optimization are found in Section 6.

- development of capital and operating cost estimates in Sections 6 and 7 to calculate cash flow projections and determine return on investment for 3 potential ownership options of the cogeneration facility: a) industry ownership, b) utility ownership, and c) third party ownership. For industry and utility ownership, the return on investment calculations were based on the incremental cogeneration investment; for third party ownership, the cogeneration facility was treated as a new venture (see Section 6.1). For each ownership option, we used appropriate debt to equity ratios and took into account various tax credits allowed for the facility. Capital costs include all applicable equipment for pollution control, return on equity investment calculations include escalation and interest during construction; and
- determination of the average energy savings achieved for the 10 plants examined and extrapolating the results to other plants found in the industries considered in this study; a further elaboration on the national energy savings calculations is found in Section 8.

1.4 FINDINGS AND CONCLUSIONS

Table 1.4-1 shows that the ten plants selected for detailed analysis were drawn from DOE Regions I, III, IV, V, VI, and IX as illustrated in Section 3 (Figure 3.1-1). These six regions account for 84% of industrial energy use in the manufacturing sectors (SIC 20-39). In addition, Table 1.4-1 shows cogeneration systems considered ranged from small units needing under 100,000 Btu/hr to large units with fuel demands of just under 3 million Btu/hr. Our findings are presented from three viewpoints: 1) technical-economic, 2) financial/return-on-investment, and 3) energy conservation.

Technical-economic considerations: In general, we found that most of the plants operated 24 hours per day with some facilities closing down on weekends. Seasonal variations were noted in certain situations. Nevertheless, the energy demand profiles were found to be relatively constant, especially over the course of a 24-hour day. Because of this, heat storage devices were usually inappropriate except for the brewery where a steam accumulator proved to be economic to meet short-duration peak demands (for this batch process). We believe that the plants considered here are fairly typical ones in the industrial sectors covered in this study.

TABLE 1.4-1

SUMMARY OF COGENERATION SYSTEM INVESTMENTS AND ROE FOR PLANTS CONSIDERED

SIC Sector	Industry	Type of Plant	DOE Region	System Type*	Cogeneration System				Return on Equity ^f (ROE) %		
					Fuel Type*	Fuel Use (10 ⁹ Btu/hr)	$\frac{Kw^b}{Kw_e}$	Total Capital Costs ^c (\$ Millions)	Industry Ownership	Utility Ownership	Third Party Ownership
20	Food	Brewery	III	S.T.	Coal	0.12	13.0	15.6 ^d	12.2	18.2	< 0
		Soybean Oil	V	S.T.	Coal	0.082	14.9	12.9 ^d	12.2	13.7	< 0
22	Textiles	Finishing Mill	IV	S.T.	Coal	0.43	8.3	45.7	< 0	26.6	15.1
		Integrated Mill	IV	S.T.	Wood	0.30	10.6	26.7	< 0	30.1	< 0
26	Pulp and Paper	Writing Paper	III	S.T.	Coal	0.60	8.3	52.2 ^d	< 0	23.7	< 0
		Kraft	I	S.T.	Coal	0.27	7.9	31.4	< 0	34.8	26.7
28	Chemicals	Agricultural Chemicals	III	S.T.	Coal	0.23	8.3	25.9	15.2	39.2	44.5
		Air Separation ^a	VI	G.T.	Nat. Gas	0.34	1.4	24.8	18.0	>1000 ^g	28.4
29	Petroleum Refining	Large Sized Refinery	IX	C.C.	Naphtha/Resid.	2.9	2.3	100.3	< 0	>1000 ^g	< 0
		Medium Sized Refinery	VI	TE/OR	E	E	1.2	20.0 ^e	88.3	n.a.*	n.a.*

^aWith cluster chemical complex.^bThermal (kwh_t) to electric (kwh_e) energy ratio produced by cogeneration system.^cCapital cost estimates include necessary pollution control equipment; estimates exclude interest during construction and escalation.^dInitial capital costs shown here were used to calculate ROE; capital cost estimates based on final conceptual design were within $\pm 4\%$ of values shown here (see Subsection 7.2.10).^ePreliminary estimate (see Appendix C, Section 7).^fBased on incremental investment in cogeneration system; incremental investment is equal to total investment for third party ownership (see Section 6.1); interest during construction and escalation are considered for all ownership options.^gIncremental investments were found to be negative; thus ROE proved very large (∞) and was set equal to 1000.

*Abbreviations used:

C.C. = combined cycle

G.T. = gas turbine with waste heat boiler

S.T. = steam turbine

TE/OR = turbo-expander with steam and organic rankine

E = energy recovery from high temperature exhaust gases

n.a. = not applicable

However, the results and findings discussed here should not be extrapolated to facilities operating less than 24 hours a day, operating only part of the year, or exhibiting a large fluctuation in steam or electrical demand.

Table 1.4-1 shows that the most economic cogeneration system involved steam topping turbines (back pressure or extraction) in seven out of the ten cases. In these seven optimized cogeneration systems, coal was the most economic fuel choice in six cases; wood, in plentiful local supply, was the fuel choice for the seventh plant (a textile mill). The optimized steam topping cycles typically exhibited relatively high thermal to electric ratios (kw_t/kw_e) of 7.9 to 14.9, as shown in Table 1.4-1.

Cogeneration systems for the remaining three cases were selected largely as a response to local energy availability and fuel costs:

- A gas turbine and waste heat boiler were found to offer the optimal economics and energy savings for a plant in DOE Region VI (Gulf Coast) where natural gas is, and is projected to remain, competitive with coal.
- A combined cycle with a single automatic extraction/back pressure steam turbine was the optimum system for the large, complex petroleum refinery located on the West Coast. The gas turbine combustor was fired with naphtha and the heat recovery steam generator was fired with low sulfur residual oil.
- Inclusion of a rankine bottoming cycle has the potential of being the best choice for the medium size, medium complexity petroleum refinery in DOE Region VI. The cogeneration system for this plant recovers energy from the 55 psia gas discharge of a high temperature catalyst regenerator. Major system components include: 1) a turbo-expander, 2) heat exchangers, 3) a double automatic extraction/condensing generator drive steam turbine, and 4) a methanol rankine bottoming cycle for completing the recovery of waste heat from the turbo-expander exhaust.

The above three cogeneration systems exhibited relatively low thermal to electric ratios of 1.2 to 2.3.

With the exception of the petroleum refining industry, we generally found that the operation of an optimized cogeneration system would still result in net demand for electrical power largely because of the high thermal to electric ratios characterized by use of steam turbines. However, where economically priced natural gas or petroleum fuels were available, the optimized cogeneration facilities (typically involving gas turbines) exhibited low thermal to electric ratios resulting in electric energy generation that could more than

meet plant requirements. Consequently, a need is seen for development of an energy-efficient, coal-based cogeneration system capable of producing thermal to electric ratios (kw_t/kw_e) in the range of about 1 to 8. Above a thermal to electric ratio of 8, conventional coal-fired steam generators can be applied. An overview of the applicability of various cogeneration systems as a function of thermal to electric ratios and fuel use efficiency is found in Section 5 (Figure 5.1-13).

If certain other technical limitations could be overcome in a cost effective manner, further energy savings might be realized. Such technological factors include:

- development of higher throttle pressure for small efficient industrial steam turbines;
- development of gas turbines with a compressor ratio of about 8:1 using state-of-art expander inlet temperatures of about 2100°F;
- for coal-fired closed cycle or exhaust-heated gas turbines, development of heat exchangers which are capable of significantly increasing air preheat temperatures; and
- technological verification of new applications of near-term technology.

Financial and Return-on-Investment Considerations: Table 1.4-1 shows investments in cogeneration systems considered in this study ranged from \$12.9 million for the smallest cogeneration facility to slightly over \$100 million for the largest, and that all ten plants met return-on-investment criteria under at least one or more of the three ownership options evaluated.

When cogeneration offered an attractive return on investment, it did so for a variety of reasons. Broadly, we categorized these into situations that involved: a) low incremental investment costs achieved by the necessity of installing a new boiler to replace obsolete process steam boilers, b) low unit investment costs achieved by large-sized cogeneration units, c) high electric energy costs, and/or d) low cogeneration fuel costs. Moreover, the economics of cogeneration appear much more favorable when viewed against the investments required in supplying additional central electric utility capacity; with the utility owning and financing a cogeneration facility to supply a plant's utility needs (steam and electricity), return on investment and energy savings are simultaneously maximized.

However, it should be noted that, under the currently typical industrial ownership, only five of the ten plants showed a positive return on equity investment. Major impediments to

implementation of cogeneration under industrial ownership appear to include raising capital, long depreciation periods (28 years), and high charges by electric utilities in case the cogeneration facility has an outage resulting in short-term power purchases from the utility.

Thus, to make cogeneration more attractive to the industrial sector would require: 1) making other avenues available for financing cogeneration facilities, 2) covering utility demand or stand-by costs (wherever they are high) in such a way as to provide greater incentives for industrial cogeneration, and 3) addressing the issue of more rapid recovery of the relatively high capital investment required in a facility not directly related to its main line of business, such as by increasing investment tax credits or shortening depreciation periods.

Energy Conservation Considerations: In the plants considered in this study, we calculated average energy savings from cogeneration of 15 to 18% compared to separate generation of process steam and electric power. Extrapolation of these results to a national basis for the five industry sectors considered indicates potential energy savings equivalent to 630,000 to 750,000 barrels of oil per day or about 1.3 to 1.6 quads annually (10^{15} Btu/yr). Further details relating to the calculation of energy savings are presented in Section 8.

Properly applied, federal activity can do much to realize a substantial fraction of this potential by lowering the actual and perceived barriers to cogeneration and by stimulating wider implementation of this energy-conserving technology.

2.0 METHODOLOGY

In an initial meeting with DOE, we agreed on certain procedural issues and basic assumptions to be used in the course of this study. Recognizing that a parallel study was being undertaken by another contractor, DOE requested that the efforts be separately undertaken so that independent evaluations would be obtained about the economics of cogeneration. As a result, our approach in this study, made with DOE's concurrence, included:

- Establishing criteria for identification and for selection of reference cases that are good candidates for cogeneration: Because of the tremendous variety of products produced; plant types, sizes, and ages; processes, feedstocks and raw materials used; there are an enormous number of energy profiles that can be generated in plants included in SIC 20, 22, 26, 28, and 29. Criteria for plant selection included geographic diversity, inclusion of a range of cogeneration plant sizes and technologies, subsectors' energy use, etc. We elaborate further on the rationale for plant selection in Section 3.0. Plants selected were visited to determine the energy demand profiles.
- Establishing consistency in approach: In addition to assuring consistency in capital cost estimates, a key element in making comparative technology studies in the energy field is the relative price of energy in different industry sectors in various regions of the country. Recognizing the difficulties, discrepancies, and the enormous amount of past effort that has been devoted to developing economic models projecting energy costs, prices, and availability, our rationale for selection of the Mid-Range Energy Forecasting System (maintained by the Energy Information Administration) and how it was tailored to the specific plant site is discussed in Sections 4 and 6.
- Developing parametric cost data for components (e.g., a steam extraction turbine): Recognizing the large number of variables that have to be considered, a framework had to be devised which would consider all reasonable cogeneration options. Details on the approach and basic assumptions used are presented in Section 5.0.
- Optimizing the cogeneration system(s): Several assumptions had to be made regarding institutional/regulatory issues such as return-on-investment (ROI) hurdle rates, method of financing, debt-equity ratios, value of cogenerated power sold to electric utilities, while recognizing that it was beyond the scope of this study to enter into negotiations with utilities on equitable prices for electricity sold, stand-by or back-up charges if existing utility schedules did not contain such clauses, and so on. Many of these issues are presently being addressed in regulations to be promulgated by DOE regarding cogeneration. Key

assumptions made in this study included;

- Three ownership arrangements were considered: a) industry ownership which would consider a cogeneration venture as an incremental investment to a steam raising boiler and which would result in savings of purchased electricity; b) utility ownership which would look at incremental investments required over that of a central electric power generating boiler and as a result would generate increased revenues from steam sales; and c) third party ownership with fixed take or pay contracts for steam and electric power looking at the cogeneration system as a new venture.
- Costs (e.g., labor rates, electricity costs, fuel costs, capital equipment, etc.) reflect those at the plant site in mid to late 1978. For example, labor rates for plant construction were those found in a nearby urban area; electricity and fuel costs were those paid by the plant for which a cogeneration facility was conceptualized.
- ROE hurdle rates for industry or third party ownership were selected from a prior study done by Research Planning Associates (1977) who presented results parametrically as the fraction of industry investing in cogeneration versus return on equity (ROE). We chose to use an ROE hurdle rate based on selecting a midpoint where 50% of industry would potentially invest. This ROE hurdle rate ranged from about 16 to 25% depending on industry sector. In the utility sector, ROE's assumed typically ranged from 9 to 13%.
- Except in certain unusual situations cogeneration systems were sized to meet the steam requirements of the plant.*
- Calculations for optimizing the cogeneration system were done on the basis of debt-equity ratios reflecting the industry.
- Cogeneration systems were optimized to achieve maximum ROE until the hurdle rate was achieved. If the hurdle rate was achieved, ROE was then kept constant (at the hurdle rate) and energy savings were maximized. Where two or more systems achieve the hurdle rate, we normally select the one with greater energy savings as explained in this report.

The assumptions made, optimizing technique used, and specific cogeneration system proposed for each plant are discussed in Section 6.0.

- Capital Cost Estimating: Investments required and engineering details on the cogeneration system are presented in Section 7.0.

*One exception was a situation involving a cluster chemical complex described in Section 3.6.

- Estimating national energy savings: The methodology and rationale for estimating total energy savings by cogeneration in the five industrial sectors of interest are discussed in Section 8.0.

The work was accomplished by drawing upon the major strengths of each of the companies contributing to this report:

- Arthur D. Little, Inc. who acted as overall program coordinator and was mainly responsible for selection of plants and developing the energy use profile in Section 3.0; selection of the model for energy price projections as discussed in Section 4.0, and energy conservation potential by cogeneration covered in Section 8.0.
- Westinghouse Electric Corporation (Research Laboratories) who brought to this study their experience with in-plant power generation, development of energy systems components, design of cogeneration systems, systems analysis, and were primarily responsible for Sections 5.0 and 6.0 of this study.
- Gibbs & Hill, Inc. (a subsidiary of Dravo Corporation), who as architects and design engineers, bring to this study their experience and background in detailed design and implementation of cogeneration systems and were primarily responsible for equipment specifications and capital cost estimating shown in Section 7.0.

References

Research Planning Associates, Inc., "The Potential for Cogeneration Development in Six Major Industries in 1985," prepared for Department of Energy, December 1977.

3.0 INDUSTRIAL ENERGY USE

3.1 OVERVIEW

Industrial energy requirements in the manufacturing sector (SIC 20 through 39) included about 10.4 quads of purchased fuels and 635×10^9 billion kwh of purchased electric energy in 1976. Table 3.1-1 shows that sectors of interest to this study (SIC 20, 22, 26, 28 and 29) account for about 56% of purchased energy and 45% of purchased electric energy in the manufacturing sector. In addition, Table 3.1-1 shows that an estimated 2.66 quads of waste fuels were used in SIC 20, 22, 26, 28 and 29.

An overview of energy use in the industrial manufacturing sector by DOE region is provided in Figure 3.1-1 for the year 1976. More than 70% of industrial energy use can be found in Regions III, IV, V, and VI; each of which accounts for more than 1.4 quads annually of industrial manufacturing energy use.

Table 3.1-2 shows for each industry sector the DOE regions of most interest to this study from an energy consumption viewpoint. In some industry sectors, two or three DOE regions account for more than 80% of an industry's energy use (e.g., textiles in SIC 26 and petroleum refining in SIC 29). In other cases the industry is quite widely dispersed geographically, such as the food industry.

Census of Manufacturers data (1976) indicates that industry generation of electric power climbed steadily in the 1960's and peaked at 82.8 billion kwh in 1971 and has progressively declined since then to 65 billion kwh in 1976, roughly equaling the level achieved in 1958. However, the percent of self-generated industrial power has steadily declined from 21% in 1958 to 9% in 1976. In certain manufacturing sectors much of this self-generated electric energy is derived from by-product fuels or wastes (such as the use of slash, bark, and wood residues in the pulp and paper sector or the use of refinery off-gases in the petroleum sector). For the industries of interest to this study, Table 3.1-3 shows that self-generated power ranges from a low of about 2% of electricity in the textile sector (SIC 22) to 37% in the paper and allied products sector (SIC 26). However, such data do not illuminate the significant amount of shaft power used directly by some industries and generated by steam or gaseous fuels (rather than by electric power). An estimate of shaft power use is shown in Table 3.1-4 which gives an overview of the end use applications for energy in the industry sectors of interest. Illustrating the diversity of energy use applications, Table 3.1-4 shows: 1) electricity (and mechanical drives) accounted for 60% of the energy use in the textile sector but only 10% in the petroleum sector; and 2) process steam requirements ranged from 25% (petroleum) to 68% (pulp and paper); and 3) process heat requirements ranged from 5% (pulp and paper) to 65% (petroleum).

TABLE 3.1-1

ANNUAL INDUSTRIAL ENERGY USE IN SECTORS OF INTEREST

<u>SIC</u>	<u>Sector</u>	<u>Purchased Fuels^a (trillion Btu)</u>	<u>Waste Fuels^b (trillion Btu)</u>	<u>Purchased Electric Energy^a (billion kwh)</u>
20	Food and Kindred Products	804	20	39
22	Textile Mill Products	233	--	28
26	Paper and Allied Products	1,146	999	43
28	Chemicals and Allied Products	2,521	120	145
29	Petroleum and Coal Products	<u>1,197</u>	<u>1,530</u>	<u>28</u>
	Subtotal of 5 Sectors	5,901	2,660	283
	Other Manufacturing Sectors (in SIC 20-39)	<u>4,558</u>	n.a.	<u>352</u>
	Total Industrial Manufacturing*	<u><u>10,459</u></u>	n.a.	<u><u>635</u></u>

*Industrial Manufacturing accounts for about 60% of industry's energy use. The difference is accounted for by non-manufacturing sectors such as mining, agriculture, fishing, etc. found in SIC 1-19.

^aSource: U.S. Bureau of Census; Annual Survey of Manufacturers, 1976.

^bSource: Guidelines for Developing State Cogeneration Policies, by Resource Planning Associates, April 1979 (NTIS HCP/M8688-01; UC-95f).

n.a. Not available.

Industrial Manufacturing Energy
Use by DOE Region in 1976:

● Circles indicate DOE regions in which plants
were selected for conceptual analysis.

Source: Annual Survey of Manufacturers, 1976.

FIGURE 3.1-1 ENERGY USE IN INDUSTRIAL MANUFACTURING SECTOR BY DOE REGION

TABLE 3.1-2

LARGEST ENERGY CONSUMING DOE REGIONS

<u>SIC</u>	<u>Industry Sector</u>	<u>DOE Regions Accounting for 80% or More of Industry Sector Energy Use</u>
20	Food and Kindred Products	III*, IV, V*, VI, VII, IX
22	Textile Mill Products	III, IV** (2)
26	Paper and Allied Products	I*, III*, IV, V, VI
28	Chemicals, Allied Products	III*, IV, V, VI*
29	Petroleum and Coal Products	V, VI*, IX*

* Plant sites selected are found in these regions.

** Two textile plants were selected from Region IV which by itself accounts for 70% of U.S. energy use in the textile sector.

TABLE 3.1-3

PURCHASED AND SELF GENERATED ELECTRIC ENERGY

<u>SIC</u>	<u>Sector</u>	<u>Electric Energy</u>		
		<u>Purchased</u>	<u>Self Generated Less Sold</u>	<u>Self Generated As A Percent of Total*</u>
		(Billion kWh)	(Billion kWh)	
20	Food and Kindred Products	39	2.6	6.3
22	Textile Mill Products	28	0.5	1.8
26	Paper and Allied Products	43	25.5	37.2
28	Chemicals and Allied Products	145	15.0	9.4
29	Petroleum and Coal Products	28	4.5	13.8
	Subtotal	283	48.1	14.5
	Other Manufacturing Sectors (in SIC 20-39)	352	16.5	4.6
	Total Manufacturing	635	64.6	9.3

*Self generated ÷ (purchased + self generated)

Source: U.S. Bureau of the Census, Annual Survey of Manufacturers, 1976.

TABLE 3.1-4
ENERGY USE APPLICATIONS

<u>Industry</u>	<u>Total Energy Use*</u> (trillion Btu)	<u>Percent of Total Use</u>		
		<u>Process Steam</u>	<u>Process Heat</u>	<u>Electricity and Mechanical Drive</u>
Food Processing	1,200	37	27	36
Textiles	500	31	9	60
Pulp and Paper	2,600	68	5	27
Chemical	4,200	43	18	39
Petroleum	2,900	25	65	10

*Rounded values include electric energy converted to Btu at about 10,500 Btu/kWh.

Source: Guidelines for Developing State Cogeneration Policies, Resource Planning Associates, April 1979 (NTIS HCP/M 8688-01; UC-95f).

3.2 PLANT SELECTION

3.2.1 Criteria

In order to meet overall DOE objectives, we first developed criteria in conjunction with DOE for plant selection. It was agreed that we would consider, to the extent possible, selection of specific plant sites taking into consideration the following:

- Industry distribution: At least one plant was to be included in each of the industries of interest to this study (food, textiles, pulp and paper, chemicals, and petroleum refining.)
- Significant subsector energy use: To the extent possible, plants were selected in industry subsectors that in turn represented a significant amount of the industry's energy use.
- Geographical distribution: Plants were to be selected to incorporate as many DOE regions as possible. Regions included should have a reasonable concentration of the industry's plants.
- Company size distribution: Relatively small companies as well as large companies should be considered in each industry sector.
- Technical feasibility: Sites were not to be considered if a preliminary analysis indicated cogeneration to be technically unfeasible or unattractive (for example, lack of space for cogeneration facility, old plants likely to shut down in the near future, recent prior cogeneration studies done by plant management that indicated it to be unfeasible, and so on).
- Representative plant: It would be preferable to select plants practicing typical industry technology rather than selecting plants practicing a unique (one-of-a-kind) technology. Where a second plant was to be considered in an industry sector, it was thought to be preferable to consider a different technology, or DOE region in order to get as wide a range of examples for study as possible.
- Excluding candidate cogeneration facilities where an example could be cited of another similar plant already practicing cogeneration.

It was recognized early that the selection of 5 to 10 plants from the thousands of plants in the industries of interest to this study could not satisfy all of the above criteria and that any plants selected would be a sample illustrating the richness and diversity of industry as well as the multitude of problems that have to be considered in making a site-specific cogeneration analysis.

3.2.2 Overall Approach to Plant Selection

Industry specialists at Arthur D. Little, Inc. formed a core team that 1) first screened industry subsectors for potential applications of cogeneration, and 2) screened plants to identify potential candidate plants. We then reviewed the criteria for plant selection and made necessary changes or adjustments as necessary. Much of this effort represented the industry specialists' best judgment and necessary compromises (so as to include relatively large as well as small plants, to include as many DOE regions as possible, as well as meet other criteria discussed). The rationale for plant selection in each industry sector is discussed in the next subsections (see Sections 3.3 through 3.7).

3.2.3 Distribution of Candidate Plants

Figure 3.1-1 shows the regional distribution of the candidate plants for which cogeneration systems were optimized and indicates eight of the ten candidate plants examined in this study came from the four DOE regions representing 70% of industrial energy use. In addition, two plants were selected from other DOE regions, where certain industry sectors have clustered because of access to raw materials:

- a) a pulp and paper plant in DOE Region I (New England), and
- b) a petroleum refinery in DOE Region IX (California).

Thus, as shown in Figure 3.1-1, plants selected are found in six of the total ten DOE regions. These regions (Regions I, III, IV, V, VI and IX) account for about 84% of industrial energy use in the manufacturing sector (SIC 20-39).

The distribution in terms of size of net energy demands for the ten plants selected is shown in Table 3.2-1. It is seen that process steam demand ranges from 45,000 to 760,000 lb/hr. Both small companies and large companies are represented in the sample as is further discussed in the following sections:

- Section 3.3 - Food Industry (SIC 20)
- Section 3.4 - Textile Industry (SIC 22)
- Section 3.5 - Paper and Allied Products (SIC 26)
- Section 3.6 - Chemicals (SIC 28)
- Section 3.7 - Petroleum (SIC 29)

3.3 FOOD AND KINDRED PRODUCTS

3.3.1 Food Industry Characteristics

The U.S. food industry, with sales of more than 200 billion dollars, is a collection of many types of manufacturing operations that run the entire spectrum of producing highly processed specialty foods such as canned and frozen products to the seasonal processing of fresh vegetables and the

TABLE 3.2-1

ENERGY DEMAND SUMMARY FOR PLANTS

<u>Sector</u>	<u>Plant</u>	<u>Average Energy Demand</u>		
		<u>Electric</u> (MW)	<u>Process Steam</u> (000 lb/hr)	<u>Direct Process Heat</u> (million Btu/hr)
Food	Soybean Mill	1.6	45	5-11
Food	Brewery	4.5	80	--
Textiles	Integrated Mill	13.6-19.2	88-186	9.5-13
Textiles	Finishing Mill	8*	120-220	65-102
Pulp and Paper	Kraft Mill	28	520-760	--
Pulp and Paper	Writing Paper Mill	14-16	280-400	--
Chemicals	Air Separation/ Cluster Chemical Complex	61	500	--
Chemicals	Agricultural Chemical Plant	5	100-150	--
Petroleum Refining	Medium Sized	7.6	155-208 ^a	n.a. ^a
Petroleum Refining	Large Sized/Complex	120	1,600	n.a.

n.a. not available

*Ranges from an average monthly low of about 7.5 MW to a high of 9.6 MW.

^aPresently waste process heat is used to generate steam which is not included in steam use shown here.

continuous processing of bulk commodities, such as fats and oils, starches, and sweeteners. There are more than 35,000 manufacturing plants or establishments in the food processing industry representing 22,000 individual companies or firms (Census of Manufacturers, 1976^{*}). Of these, only 166 firms (fewer than 1%) are publicly owned, yet they account for 56% of all food industry sales. Of the other companies, most employ fewer than 100 people.

The energy consumption in the food industry is about one quad (10^{15} Btu) annually. Most of this energy is consumed in four major types of process operations:

- Water removal in evaporation and drying processes for the concentration and dehydration of foods and by-products.
- Refrigeration and freezing for cold storage and preservation of fresh and perishable foods.
- Thermal processes for commercial sterilization of canned foods, and other process heating requirements.
- Power for operating machinery.

Energy is purchased by the food industry in the following forms:

<u>Energy Source</u>	<u>%</u>
Natural Gas	48
Distillate Oils	5
Electricity	30
Coke, Coal and Others	17

Purchased Energy in the Food Industry, by type,
Census of Manufacturers, 1976.

Most of the purchased electricity is used for refrigeration and freezing. Only a small portion of the gas used is consumed in processes which require the "cleanliness" of gas, such as direct-fired driers; while most gas along with the oil and solid fuels is used to generate process steam in boilers.

Much of the food processing industry is relatively non-energy intensive (energy cost is less than 2% of shipments) when compared with other industry. Yet, because of the enormous size of this industry, it is a large energy consumer. The food processing industry, as an aggregate, consumes nearly one quadrillion Btu's per year. The highly fragmented nature of this industry with the diversity of product and processing technology that it encompasses makes it difficult to select certain processes or products which are "typical" but several subsectors can be identified as large energy users within the industry.

^{*}U.S. Department of Commerce, Census of Manufacturers, 1976.

3.3.2 Subsector Selection

Of the 47 4-digit SIC subsectors in the food industry, we have examined the top 10 energy consuming subsectors. These are:

Beet Sugar	Fluid Milk
Corn Milling	Bakery Products
Meat Processing	Soybean Mills
Malt Beverages	Cane Sugar
Canned Fruits & Vegetables	Frozen Fruits and Vegetables

Beet sugar processing, wet corn milling and cane sugar refining already use cogeneration to a large extent. Therefore, these subsectors were eliminated from our candidate list. Also, because of the seasonal nature of canned and frozen fruits and vegetables, these subsectors were eliminated as having less potential for the relatively capital intensive cogeneration system.

We looked for subsectors which were fairly homogeneous with respect to the type of plants and process operations involved, so that a given plant could indeed be representative. As a result, we selected the soybean oil mills industry and the malt beverages industry as sample subsectors for our industrial cogeneration optimization study in the Food and Kindred Products Industry sector.

3.3.3 Soybean Oil Mills Subsector

3.3.3.1 Industry Subsector Profile

The soybean oil mills industry is primarily engaged in the manufacture of crude soybean oil and defatted soybean meal for shipment to vegetable oil refineries and manufacturers of animal feed and soy protein-based food ingredients. The industry crushes approximately 800 million bushels of soybeans annually producing nearly 9 billion pounds of crude soybean oil and 35 billion pounds of soybean meal.

According to the Soybean Digest Blue Book*(1978), this industry is made up of approximately 50 firms operating a total of 100 plants or establishments. Nearly half of these plants (47) are owned by the 5 largest companies in the industry. Although plant size varies widely from less than 10,000 to more than 100,000 bushels per day, most plants fall into a median-size range of 20,000 to 50,000 bushels per day capacity. In general, soybean oil mills are located in soybean crop production areas in the North Central and South regions of the United States. The ten leading processing states are Illinois, Iowa, Tennessee, Arkansas, Indiana, Minnesota, Mississippi, Ohio, Missouri, and Kansas.

The soybean oil industry is relatively new (compared to beet sugar processing for example), and essentially came into being after World War II with the increased acceptance of soy protein in the human diet. We found that many

*Soybean Digest Blue Book, 1978, Publication for the American Soybean Association.

plants are considering the need to replace boilers (as well as other pieces of major equipment) that are now facing the end of their economic lives. Because of these planned boiler replacements and escalating fuel costs, the industry as a whole appears to be seriously interested in opportunities for cogeneration.

3.3.3.2 Energy Use in Soybean Oil Mills

Energy requirements for this industry in the form of direct heat, steam, and electricity amount to nearly 50 billion Btu's annually. This accounts for 5% of the total energy use by the Food and Kindred Products Industry, and ranks the soybean oil mill industry among the top ten energy using subsectors in this major industrial sector.

3.3.3.3 Process Plant Description

For this study we obtained data from a medium-sized plant in the DOE Region V of the United States. This plant has a crushing capacity of 40,000 bushels per day, and is typical of most plants in the industry. The buildings and most of the equipment have been in use for more than 20 years; other equipment is brand new. The flow of materials and energy through the plant under typical conditions is shown schematically in Figure 3.3-1.

Soybeans are received daily by truck and rail car and dried to a moisture content of 11 to 12% before being placed in storage elevators. The dried beans can then move directly to the preparation operations or to large long-term storage bins when receiving rates exceed crushing rates. Preparation consists of cleaning the beans through magnetic separators and screening operations, cracking through corrugated rolls to loosen the hulls and break the beans into smaller pieces, dehulling to remove the hulls for subsequent hull processing operations, conditioning of the cracked beans by heating to make them soft or plastic, and finally flaking in which the soft cracked beans are passed through smooth rolls to form thin flakes for subsequent extraction.

The flaked beans are conveyed from the preparation area to a separate solvent extraction building and subjected to a counterflow extraction with hexane. Three products emerge from the extractor: 1) mixture of meal and solvent, 2) oil and solvent (miscella), and 3) air and solvent vapors. Each of these requires further treatment for solvent separation. The solvent is separated from the meal by desolventizers, from the oil by distillation, and from the air by condensers and scrubbers.

The desolventized meal is then dried, cooled, and ground for storage and shipment. The desolventized crude soybean oil is stored in oil storage tanks for shipment to refineries, and the toasted ground hulls can be stored for shipment as a feed or fiber ingredient, or added back to some of the finished meal to produce a meal with lower protein concentration depending on market conditions for the various products. Each bushel of soybeans crushed yields approximately 44 lbs of meal, 11 lbs of oil, and 3 to 4 lbs of hulls.

FIGURE 3.3-1 PROCESS FLOW SCHEMATIC SOYBEAN OIL MILL

3.3.3.4 Energy Demand Profiles

Like most soybean oil crushing mills, the plant operates continuously around the clock. This provides an essentially constant demand for steam, heat, and electricity on an hourly and daily basis, with only slight seasonal or monthly fluctuations throughout the year as shown in the following energy profiles discussed below. The only interruption in these power demands occurs during two 4-day periods in April and August when the plant shuts down for planned routine maintenance. During these periods, the boiler is shut down completely and power is required for maintenance operations only. The energy demand profile is shown in Figure 3.3-2.

In 1978 the plant purchased a total of 14,219,200 kwh of electricity to meet all of its electric power requirements. No electricity is generated on-site. Electric energy use is essentially uniform throughout the year, providing the plant with a constant 1.6 MW of power to drive the various electric motors throughout the plant representing a connected load of approximately 2,500 HP. This constant demand is consistent with the plant's continuous "around-the-clock" mode of operation. Although the plant shuts down for four days in mid-April and at the end of August for planned boiler maintenance, electric power is still required for maintenance operations.

With the exception of the two shutdown periods in April and August for boiler maintenance, the steam demand is essentially constant throughout the year at 45,000 pounds per hour. This steam is supplied by a single boiler fueled by either oil or natural gas to provide process steam at 150 psig for the various conditioning, desolventizing, roasting, and drying operations required throughout the plant. Again, because of the continuous around-the-clock schedule of operation, steam demand is essentially constant over an hourly or daily basis.

The boiler was installed in 1959 and is now 20 years old. While expecting to replace the boiler in the near future, the plant has made no specific implementation plans.

In addition to steam and electric power demand described above, the plant also requires direct heat for the bean drying operation. This heat is supplied directly by burning propane or natural gas to provide forced hot air through the large column dryers. The average winter heat demand for this operation is 11×10^6 Btu per hour, and fairly uniform on an hourly and daily basis. Since these dryers are located outdoors and operate with outside air, there is some seasonal variation with outside air temperature and moisture content of the beans, which reduces the heat demand to as little as 5×10^6 Btu per hour during the summer months.

FIGURE 3.3-2 ENERGY DEMAND PROFILES: SOYBEAN OIL MILL

3.3.4 Malt Beverages Subsector

3.3.4.1 Industry Subsector Profile

The malt beverages industry is primarily engaged in the production of lager beer. Other products include malt liquors, draught beer, ale, porter, and stout. Malt beverage is sold in a number of different packages including cans, bottles, and barrels (31 gallons) or kegs. The industry's by-products include brewer's yeast and spent grain, which is used primarily as animal feed. Industry output was an estimated 162 million barrels in 1978 showing a modest 2% annual growth rate from the 1973 output of 148 million barrels.

Both the number of brewers and breweries in the United States has declined steadily from over 600 operating breweries in 1940 to just 48 brewers operating 85 breweries today (Brewers Digest, 1979*). This trend is expected to continue as the leading brewers gain increasingly greater market share at the expense of smaller brewers who are forced to merge or consolidate. In 1978 the five largest brewers produced 120 million barrels out of the total industry output of 162 million barrels, indicating that 75% of the industry output is concentrated in 10% of the brewers (Maxwell, 1979**). As a result of this trend, many of the smaller outdated breweries are being replaced by a smaller number of larger and more efficient modern breweries.

Although plant size varies widely from less than one-half million barrels to more than 12 million barrels, most breweries fall into a median-size range of 1 to 5 million barrels. Because of the high transportation costs in shipping malt beverages, breweries tend to locate in major market centers throughout the United States with the exception of the high plains and mountain regions.

3.3.4.2 Energy Use in Breweries

Energy requirements for this industry subsector in the form of steam and electricity amount to 50 billion Btu's annually. This accounts for 5% of the total energy purchased by the Food and Kindred Products Industry (SIC 20), and from an energy viewpoint ranks the malt beverages industry among the top ten subsectors in the food industry.

3.3.4.3 Process Plant Description

For this study we obtained data from a medium-sized brewery in the DOE Region III. This brewery was newly constructed in the early 1970's with a capacity of 5 million barrels per year, and is typical of most modern breweries throughout the malt beverages industry. The flow of materials and energy through the plant under typical conditions is shown schematically in Figure 3.3-3.

*Brewer's Digest, 1979, "Buyer's Guide and Brewery Directory for 1979," Sieble Publishing Company, Chicago.

**Maxwell, J.C., 1979. "Special Report on 1978 Brewery Sales," Beverage Industry, January 5, 1979.

FIGURE 3.3-3 PROCESS FLOW SCHEMATIC MALT BEVERAGE BREWERY

In the mashing and brewing operation, ground barley malt and grain adjuncts (corn, rice or corn syrups) are mixed with hot brewing water and brought together in a mash tun to produce the wort under controlled conditions of time and temperature. The wort from the mash tun is then pumped into a lauter tun where it is filtered to remove the spent grains, and then sent to the brew kettles where it is brewed (boiled) and flavored with hops. The finished wort is then sent to the coolships for cooling prior to fermentation. The spent grain left after separation from the wort is sold wet for local use as animal feed.

In the fermentation and aging processes, the chilled wort flows into fermenting tanks where yeast is added to initiate fermentation. This process converts the fermentable sugars into alcohol and carbon dioxide. The evolved carbon dioxide is collected, compressed, and stored for subsequent use in carbonating the beer during filling. After seven to ten days of fermentation, the yeast is removed and the remaining wort, now called beer, is piped to large storage tanks for aging and mellowing (lagering) for three to six weeks at a temperature of 30 to 32°F.

When the lagered beer is ready for packaging, it is filtered, pasteurized, carbonated, and packaged in sterilized bottles or cans. Unpasteurized (draught) beer is packaged in kegs and kept under refrigeration.

3.3.4.4 Energy Demand Profiles

In 1978 the brewery purchased a total of 38,934,000 kwh of electricity. No electricity is generated on-site. The demand profiles shown in Figure 3.3-4 show that the use of this electricity is essentially constant throughout a 24-hour period providing the brewery with an average load of 4.5 MW of power to drive the various refrigeration compressors, gas compressors, and packaging and process machinery throughout the plant. Production is maintained "around-the-clock" for five or six days out of every week, and is essentially shut down on weekends where the demand is reduced to meet only the requirement for refrigeration and other non-production-related equipment. To meet seasonal variations in production requirements, the plant shifts from a five day per week production schedule during winter months to a six day per week schedule in the summer when production demand is greatest. This variation is reflected in the seasonal demand profile for electric power in the figure.

Average steam demand for the brewery is 80,000 lbs per hour at a maximum process steam pressure of 120 psig. Unlike the electric demand, space heating requirements during the winter months tend to compensate for the reduced production demand at that period, keeping total steam demand essentially constant throughout the year. During the course of a week, however, steam demand is reduced considerably when the brewery is shut down on weekends. With the exception of space heating requirements, there is little demand for steam when brewing and packaging operations are inoperative. During a 24-hour cycle, steam demand fluctuates cyclically every three hours between 60,000 and 90,000 lbs per hour. These fluctuations reflect the steam demand to the brew house in which the brewing cycles are repeated roughly every three hours.

The brewery maintains three oil-fired low pressure boilers. Two are rated at 60,000 lbs per hour each and the third is rated at 75,000 lbs per hour. Only two boilers are required to provide the total steam demand of the brewery at any one time, and the third boiler serves as backup to allow boiler shutdown and maintenance without disturbing production schedules. Although each of the boilers can be fired with natural gas, the brewery has elected to use No. 6 fuel oil exclusively. The process steam requirement throughout the brewery is no greater than 120 psig, and approximately 60 to 80% of the condensate returns to the boilers under pressure at 225 to 230°F.

3.4 TEXTILE INDUSTRY

3.4.1 Industry Characteristics

Containing more than 7,000 plants, the textile industry is extremely diversified, processing a variety of fibers, fabrics, and fabric blends into a multitude of end products. Polyester knit goods and polyester/cotton woven goods represent the most important types of fiber used in these operations. As a result, knitting mills now constitute the largest single SIC group, with 2,723 plants, followed by weaving mills of various types totaling 1,293 plants. These two categories together provide 56% of the total number of plants and a higher proportion of total production.

Textile facilities may be highly integrated manufacturing complexes that process fibers (natural and synthetic) into finished products, or small, nonintegrated contract plants (commission finishers) that process goods owned by other producers. Traditionally textile mills have been divided into greige mills where the fabric manufacture takes place and finishing mills where all the varied operations are completed such as fabric preparation, dyeing, and application of special finishes, etc. which contribute to the final fabric quality. Because of the requirements for a controlled temperature and humidity environment, the manufacture of either knitted or woven goods is found in buildings separated from the finishing operations which generally result in high humidity conditions from the use of extensive volumes of hot water and steam. A considerable number of integrated textile mills exist which combine greige manufacturing and finishing plants on the same site, but these operations are still found in separate buildings.

In recent decades, the industry has been concentrated in the Southeast, notably in North and South Carolina, Georgia and Alabama, and this trend is continuing. Today, nearly 40% of the textile plants are in the Southeast and more than 90% are on the Eastern Seaboard. The rest are scattered throughout the United States.

3.4.2 Energy Use

Energy use in greige mills (and knitting mills) is predominantly electrical for 1) powering equipment used in fabric manufacture, and 2) for air conditioning which constitutes a peak summer load in the southern southeast United States where much of the textile industry is concentrated. Only small amounts of steam are required in these operations, such as for space heating applications in the winter and for the "sizing" operations in the manufacture of woven fabric.

Finishing operations, by contrast, use large amounts of low pressure process steam either to heat water or in equipment such as dry cans to provide a drying operation for the fabric. A significant amount of electric power is also required to provide mechanical energy for the process equipment. Small amounts of steam may be required in the winter additionally, to fulfill space heating needs. An additional large energy demand in a finishing mill is accounted for by use of natural gas (or propane where natural gas is unavailable) for direct heating in drying and curing operations. Most of the operations use the hot combustion gas directly at a temperature of 380-420°F in order to dry the fabric and complete the chemical reactions arising from the application of special finishes. Use of a light oil (i.e., #2 fuel oil) in place of natural gas is feasible but can lead to process difficulties and we understand that textile mills will only use this fuel in the drying operations as a last resort. There are a few examples of indirectly heated tenterframes fueled by oil or steam to obtain the hot process gas, but these are not favored because of increased equipment complexity and higher cost operation.

Of the 53 million Btu of energy purchased by the textile industry in 1976, about 56% was for electrical energy and the remaining 44% was for distillate and residual fuel oil, natural gas, propane, and coal. Dyeing and finishing* operations consume about 60% of all the energy used in producing textiles; these operations rely heavily on steam for water heating and on propane and natural gas for drying and heat setting. The other processes, such as spinning, weaving, and knitting, consume the remaining energy, primarily in the form of electricity for motor power. Demand for energy in the textile industry is expected to increase along with population growth and consumer demands.

Bureau of Census data for 1976 show that four SIC categories account for 64% of the total energy used in the textile industry. These four are:

- Weaving Mills (man-made fiber)
- Weaving Mills (cotton)
- Textile Finishing Mills
- Knitting Mills

*Note that "finishing" is commonly used to indicate combined operations, including fabric preparation and dyeing as well as specialized "finishing" operations, which consist of end treatments to provide durable press characteristics, water repellency, etc.

3.4.3 Approach to Plant Selection

Many textile plants have practiced cogeneration; especially those constructed before the advent of widely distributed power supplies from centralized utility companies. However, with the decline in power costs in the 1940's and 1950's it became less economic to maintain and operate the relatively small generating units and it was uneconomic to replace them at the end of their useful life. With the increase in power costs which occurred in the 1970's, the picture changed again. Now the industry finds it economic to maintain and operate existing units and is considering the installation of new generating units at specific plants to take advantage of the efficiencies of combined steam/electric power generation.

The changing energy environment and the large number of textile plants (approximately 7,000 plants) precluded the selection of only two plants on any kind of a statistical basis. As a result, we conducted a 4-step screening process to identify potential cogeneration opportunities. First, taking into account the factors discussed above (Subsections 3.4.1 through 3.4.3) and using available in-house knowledge, we prepared a list of some 15 to 20 major companies which we believed would have plants meeting desirable characteristics for cogeneration, or were already known to be considering cogeneration. As a second step we approached 11 companies in order to ascertain whether any plants in the organization had a favorable energy profile and whether the company was interested in providing information to us and participating in this study. Thirdly, we selected 7 plants for further consideration. All of these plants expressed a keen interest in cooperating on this study. Finally, two plants were selected for detailed analysis: 1) an integrated finishing mill in Alabama, and 2) a finishing mill in South Carolina.

3.4.5 Plants Selected

3.4.5.1 Integrated Mill

This integrated mill, located in Alabama (DOE Region IV), has about 5,000 employees. The plant was started in 1900 and has since expanded considerably and there are now many buildings on the site. Average age of the equipment is 5-10 years. The plant covers all operations from manufacture of fabric through dyeing and finishing and including cutting and making of garments. The plant operates on a 24-hour per day, 6 days per week basis. It is generally shut down completely on Sunday. The boiler house provides process steam at 250 psi and space heating when required. Steam at the process interface is generally about 150 psi. Boiler capacity is indicated below:

- 2 x 100,000 lbs/hour (oil fired) 5-10 years old
- 2 x 60,000 lbs/hour (wood fired) > 5 years old

The plant also has 2 old coal fired boilers which are not presently being used. Wood is the most economic fuel in the area and the plant is planning to increase wood use to the extent possible.

The energy profile for this plant based on 1978 data is shown in Figure 3.4-1. Energy demands are steady throughout the work week except as influenced by production schedules. Energy demands on Sunday are minimal for electricity and practically zero for steam unless there is a need for winter space heating. In 1978, electricity demand varied from 13.6 MW to 19.2 MW with no particular seasonal pattern.

Steam use showed a more seasonable pattern falling from a peak of 180,000 lbs/hour in January to 88,000 lbs/hour in June. Natural gas used exclusively in process operations was more constant and averaged about 13 MCF/hour but did show a maximum of 16 MCF/hour and a minimum of about 10.5 MCF/hour in the monthly averages.

3.4.5.2 Finishing Plant

This finishing plant located in South Carolina (DOE Region IV) with 2,500 employees imports all its greige fabric from other company mills in the area. The operations include continuous and beck-dyeing, printing, and various types of special finishing. The plant was built in 1924 and the average age of its equipment is 8 to 10 years. Its products are sheeting, apparel fabrics, and home furnishings. In addition, the plant has some apparel operations, i.e., cutting and sewing, on the plant site.

Operations presently are 24-hour, up to 6 days per week, which is typical of textile industry operation, although 7 day operation is common at other plants in this company and is being considered at this site. The plant has a one week shutdown in July. Three boilers are on site, each rated at 150,000 lbs/hour; one is a coal fired stoker boiler, while the other two are dual fuel (oil/gas) boilers.

The plant has apparently excess boiler capacity, the oldest boiler being the stoker fired coal boiler which is not normally on-stream. The boilers all feed to a common header producing steam at 200 psi for delivery to the process units which operate at various pressure of about 150 psi. The process steam is used primarily to heat water and dry fabrics. The energy profile for this plant, using 1978 data, is shown in Figure 3.4-2.

Energy demands are minimal on Sundays, but fairly constant during the rest of the week. Electrical energy demand averages about 8 MW with a summer peak about 20% above the monthly average due to use of air conditioning in some parts of the plant. Steam use varies from 220,000 lbs/hour in winter down to a 120,000 lbs/hour in summer. A large part of the variation is attributed to a drop in production of about 35% during the summer. Natural gas use for drying and curing operations varied from a peak of 102 MCF/hour average in January to 65 MCF/hour average in June, also in line with changes in production.

FIGURE 3.4-1 ENERGY DEMAND PROFILES: INTEGRATED WOVEN TEXTILE MILL

FIGURE 3.4-2 ENERGY DEMAND PROFILES: TEXTILE FINISHING MILL

3.5 PULP, PAPER AND ALLIED PRODUCTS

3.5.1 Industry Characteristics

The pulp and paper industry ranks eleventh among U.S. manufacturing industries. With a 1977 output valued at \$47 billion, there are about 335 chemical and mechanical pulp mills and about 735 paper and board mills in the United States classified under SIC codes 2611, 2621, 2631 and 2661 (Lockwood's Directory*). The rest of the industry is classified under SIC 264 (converted paper products, including paper glazing, envelopes, bags, wallpaper, etc.) and SIC 265 (paperboard boxes and containers, including corrugated boxes and food containers) and is characterized by a diversity of operations and relatively low national energy use. The present annual pulping capacity of U.S. mills is about 53 million tons with a papermaking capacity of over 67 million tons. Most product sectors operated at 95% of capacity or higher in 1978, and over 1.5 million tons of new capacity is planned over the next three years.

Because of its energy intensive nature, the pulp and paper industry ranks fourth as a consumer of fuel and energy, and first as a consumer of fuel oil. The U.S. Bureau of Census data showed it consumed 2.2 quads (2.2×10^{15} Btu) and used 77 million barrels of fuel oil in 1976. Figure 3.5-1 shows schematically the uses of energy in a typical mill with steam required for the cooking of pulp, the evaporating of pulp liquor, and the drying of paper, and with electricity required for the chipping of logs, the refining of pulp, the driving of paper machines and the controlling of pollution. The typical kraft mills have the potential to cogenerate all of their electrical needs, and many mills cogenerate to varying degrees.

The industry is normally located near its raw material, trees, with major concentrations of the industry located in the forested areas of DOE Regions I, III, IV, V and X. In general, pulp mills are located adjacent to the paper-making facilities, the exceptions are a limited number of chemical pulp mills which produce pulp for sale.

The pulp is produced by either chemical treatment or mechanical breakdown. The important chemical pulping processes are kraft, sulfite and soda each of which dissolves the lignin from the cellulosic fibers in wood. The predominantly mechanical processes that break wood apart are stone and refiner groundwood, thermomechanical groundwood, and neutral sulfite semi-chemical process. From an energy viewpoint important distinctions between the processes are:

- waste pulping liquor from the kraft process is burned for energy and chemical recovery and
- mechanical groundwood requires electrical (or shaft) energy but little or no thermal energy.

*Lockwood's Directory of the Paper and Allied Trades, 101st Edition, Vance Publishing Corp., New York, N.Y., 1977.

PROCESS FLOW SCHEMATIC:
INTEGRATED KRAFT PULP AND PAPER MILL
FIGURE 3.5-1

3.5.2 Plant Selection

Even though there are about 3000 paper converting plants in the U.S. they account for only 14% of total energy use in the paper industry. Moreover, they are very diverse operations ranging from envelope-making to carton manufacture. Because of the relatively small energy use and diversity of operations, the paper converters found in SIC 264 and 265 were eliminated as candidates for possible reference plants.

The methodology for plant selection in the remaining pulp and paper sectors was to screen plant types to determine those accounting for the largest production and energy use. Recognizing that the kraft process accounts for over 60% of the pulp in the United States and has an energy balance favoring cogeneration, we focused on plants using kraft digesters. As a result from the initial list of 735 mills in SIC codes 2611, 2621, 2631 and 2661, we narrowed the list of mills further, by eliminating any kraft mills that purchased less than 8 megawatts of power since we believed that such mills would be unusually small mills or would be already extensively using cogeneration. These two restrictions reduced the list of candidate paper mills from 735 to 20 typical kraft mills that could at least theoretically install new or additional cogeneration capacity. We selected two reference kraft mills, one in DOE Region I that produces 1050 tons per day of paper products and a smaller mill in Region III that produces 350 tons per day of writing papers.

3.5.3 Kraft Pulp and Paper Mills

Both of the candidate mills for the cogeneration analysis are kraft pulp and paper mills*. These mills essentially convert wood into paper and paperboard products with expenditures of large amounts of energy. The process starts with logs from the wood yard being debarked, chipped, and the resulting wood chips contacted with white liquor in the digester. After the pulping is complete, the digester is blown, and the pulp fibers are separated from the spent black liquors. The black liquors are evaporated and burned in recovery boilers to recycle the pulping chemicals and generate part of the mill's process steam requirements. The pulp is refined, bleached if a brown color is not desired, and formed into paper products on a paper machine.

3.5.3.1 Characteristics

Kraft pulp and paper mills are the fastest growing and largest single segment of the industry. Over 80 mills account for 60 percent of the industry's total pulp and paper capacity. The newest and largest mills are located in the southeastern United States. Virtually all paper and paperboard products from fine writing papers and tissue to heavy-weight paperboard contain some kraft pulp. The kraft digester is found in all geographic regions of the paper industry with very little variation in the process in different parts of the country.

*The DOE Region I kraft mill also includes a small neutral sulfite semi-chemical pulping operation.

3.5.3.2 Energy Use

The energy use in kraft pulp and paper mills accounted for about 1.1 quad's in 1977. Energy consumption is high with one ton of paper requiring five tons of steam and 700 kwh of electrical energy (Westberg 1970)*. Energy used had the following approximate breakdown by source of fuel:

<u>Energy Source</u>	<u>Percent of Total</u>
Process wastes	45%
Oil	24%
Natural Gas	16%
Coal	10%
Purchased Electricity	5%

Source: American Paper Institute Data for 1976 as reported in Voluntary Industrial Energy Conservation Progress Report 5, July 1977. U.S. Department of Commerce and Federal Energy Administration.

As can be seen from the energy breakdown, relatively little electricity is purchased by the industry as a whole; this industry has historically co-generated a large part of its own power requirements. Also, since the residues from the wood yard and the black liquor are burned, not all of the requirements in this energy intensive process must be met by purchased fuels.

There are regional differences in energy use. The northeast and middle Atlantic areas in Regions I and III use oil for over 50% of their energy requirements. The north central area in Region V uses coal for over 40% of its energy.**

3.5.3.3 Region I Kraft Mill

The medium-sized pulp and paper plant selected for this study has a total capacity for 1050 tons per day of production. The kraft digesters have a capacity of 800 tons per day while a neutral-sulfite semi-chemical pulp process has a capacity of 250 tons per day. The plant produces a wide range of products including fine writing paper, corrugating medium tissue products and market pulp. Presently cogenerating 14.7 megawatts, this plant receives 5.6 megawatts from company-owned hydroelectric turbines. It has the steam available to potentially cogenerate the remaining 8 megawatts of electricity that it purchases. The energy demand profile for this mill is shown in Figure 3.5-2.

The complex operates on a 24-hour per day, 7-day per week schedule. This results in a very steady electrical demand of 28 megawatts at all times. The steam profile is also very steady over periods of a week, but it varies with the different heating loads of the changing seasons. The monthly averages of the steam consumption range from 520,000 pounds per hour in summer to 760,000 pounds per hour in winter. There are 8 oil-fired power boilers ranging in age from over 40 years old to approximately 20 years old. There are also two recovery boilers to burn the spent pulping liquor.

*Paper Trade Journal, January 12, 1970.

**American Paper Institute, Patterns of Fuel and Energy Consumption, March, 1974.

ENERGY DEMAND PROFILES: KRAFT PAPER MILL.

FIGURE 3.5-2

3.5.3.4 Region III Writing Paper Mill

This facility which started up 60 years ago is relatively small with about 350 tons/day production. The plant is old, but it is an economically viable operation today and for the foreseeable future. Presently it practices no cogeneration, and it has a potential for a maximum of 16 megawatts of co-generated power. The mill could be classed a semi-integrated operation that produces about 55 percent of its own pulp needs and purchases its remaining pulp needs as market pulp and recycle papers. The corporate size is relatively small in comparison to major corporations in the pulp and paper industry.

The energy profiles for both electric power and steam rates are shown in Figure 3.5-3. The electric power profile is fairly constant lying within a 14 to 16 megawatts band all year. The relative steady electric power consumption is the result of the steady operation on a 24-hour per day, 7-day per week schedule. The steam consumption profile in Figure 3.5-3 does not vary dramatically over periods up to a week, but increases from under 300,000 pounds per hour in the summer to 400,000 pounds per hour in winter because of heating loads. These fluctuations in the steam rates would change the potential for cogenerated electricity from about 11 megawatts in the summer to 16 megawatts in the winter. The four coal-fired power boilers are 60 years old and could be replaced in any upgrading of the system that might accompany any cogeneration plans. There is one recovery boiler (non-cogenerating) to burn the spent pulping liquor and one gas-fired package boiler to handle swing loads.

3.6 CHEMICALS

3.6.1 Chemical Industry Characteristics

The chemical industry (SIC 28) is a major consumer of energy and the producer of an unparalleled variety of materials. In 1976, the industry had sales of \$90 billion and included 11,000 establishments. These establishments ranged from very small, simple facilities producing small quantities of adhesives or toiletry ingredients, to old organic chemical synthesis complexes turning out hundreds of chemical intermediates and finished products, to enormous new plants yielding billions of pounds annually of a few basic chemicals.

Not including the use of internally generated waste heat and fuels, the chemical industry purchased 3 quads as fuel and electricity in 1976.* Using roughly 160×10^9 kwh in that year, it accounted for 23% of all electricity consumed by manufacturing industries. The industry uses energy in a wide variety of ways, but the major uses are for: firing steam boilers, direct heating of process furnaces, drying and concentrating, electrolysis, and the running of pumps, blowers, compressors, and mixers by prime movers (electric motors, gas and steam turbines, etc.).

* By form: 3% distillate, 8% residual fuel oil, 11% coal, 9% coke and breeze, 54% gas, 16% electricity (Bureau of Census, 1976).

ENERGY DEMAND PROFILE: WRITING PAPER MILL.

FIGURE 3.5-3

Because of both the professional training of their employees and the incentive of large energy bills paid by many of their processing plants, the larger companies in this industry are very sophisticated in their use of energy and innovative in adopting energy conserving technology (e.g., cogeneration).

3.6.2 Subsector Selection

Selecting subsectors of the chemical industry for a study of new opportunities in cogeneration is difficult for two reasons. First, the industry is so diverse that it is essentially impossible to extrapolate findings from one plant or subsector to a significant fraction of the industry. Second, cogeneration is already widespread in the industry. We have found that in large plants where cogeneration has been technically feasible and economically attractive, cogeneration has generally been installed. Moreover, chemical companies continue to actively investigate the potential for cogeneration in light of changing energy economics.

In 1976 the chemical industry generated 18.4×10^9 kwh of electricity,* largely by cogeneration. This quantity represented an average annual rate of growth in electricity generation of 2.9% over the preceding thirty years. However, since electricity use by the industry has been growing more rapidly, the percentage of electricity requirements self-generated by the chemical industry dropped from 39% in 1947 to 9.3% in 1976. This decline in the percentage contribution of self-generation has been blamed on a number of factors including: declining electricity prices charged by electric utilities, the penetration of low-pressure package boilers into the process industries, and the increasing reliability of utility-supplied power. (Contrary to some widespread utility industry attitudes toward industrial cogeneration, cogenerated power is frequently very reliable. Several chemical company representatives contacted during the course of this study pointed to their critical need for well controlled electric power and the impact of electrical outages on large continuous chemical processes; they described a number of large cogeneration facilities that were installed in the 1950's primarily because the reliability and the voltage and frequency control offered by electric utilities was not adequate for their requirements.)

Mechanical cogeneration is widespread in the chemical industry, and at least as much mechanical energy is supplied by steam driven equipment as by electrical cogeneration. Experience with such equipment shows that rising energy prices do not always work to the advantage of cogeneration. Several of the larger plants we contacted reported that new energy conservation measures have reduced their steam demand below that supplied by their cogenerating systems. Thus, to avoid wasting steam at times of low

* Bureau of the Census (electricity generated minus sold amounted to about 15×10^9 kwh, Table 3.1-3).

demand, they are converting a number of steam turbines (mechanical cogeneration) to electric motors. We believe that this phenomenon is widespread.

Because the chemical industry is so diverse, we have tried to identify examples of two generic opportunities for additional deployment of cogeneration. The first opportunity lies in inter-company transfers of energy through cogeneration projects; the second rests on the presumption that smaller companies and plants may have previously found cogeneration uneconomic and have recently lacked the technical and financial resources to aggressively change energy economics and, thus, might offer unrealized cogeneration potential. As an example of the first opportunity, we selected a large, new air separation plant which produces oxygen for some adjacent petrochemical plants. As the second example, we chose a modestly sized agricultural chemicals plant which we believe serves as a reasonable proxy for numerous smaller plants in many parts of the chemical industry.

3.6.3 Industrial Gases Subsector - An Example of Opportunity for Cogeneration by Inter-Company Energy Transfer (Cluster Chemical Complex)

3.6.3.1 Industry Subsector Profile

The industrial gas industry (SIC 2813) consists of establishments primarily engaged in manufacturing gases for sale in compressed, liquid, and solid forms. The products of this industry include argon, carbon dioxide, helium, hydrogen, neon, nitrogen, nitrous oxide, and oxygen. Oxygen and nitrogen are the highest volume products. In 1977, approximately 150 plants (many containing multiple units) produced oxygen in the United States. In that year, the industry produced roughly 15 million short tons of oxygen, of which approximately 85% was delivered to customers as gas. Over 80% of the gaseous oxygen production was intended for pipeline delivery. The steel industry accounted for 65% of domestic oxygen consumption; 12% was consumed by the chemical industry. Almost one-half of the oxygen consumed by the chemical industry was used in the production of propylene oxide, titanium dioxide, vinyl acetate, and acetylene. As one would expect from this pattern of oxygen use, air separation plants are largely concentrated around major steel and petrochemical centers in the Midwest, the Gulf Coast, California, Pennsylvania, West Virginia, etc. Major firms engaged in this industry include Airco, Air Products and Chemicals, Big Three Industries, Chemetron, Burdiox, Liquid Air Corporation of North America, the Linde Division of Union Carbide, and United States Steel.

The oxygen producing capacity of air separation plants varies greatly, from 10 short tons per day to 10,000 short tons per day. Modern plants are generally in the 500-1000 ton per day range. Consumption of oxygen grew very rapidly in the 1960's and, as a result, many of the domestic air separation plants are no more than 10 years old. The growth rate of the industry declined markedly in the 1970's, but is expected to be in the 4-5% per annum range through the 1980's.

3.6.3.2 Energy Use in Air Separation Plants

In 1976 the industrial gas industry consumed 92.7×10^{12} BTU's of purchased fuel and electricity. Purchased fuels accounted for 54.8×10^{12} BTU; while the total electricity purchased was 11.1×10^9 KWh. As a result, the data on self-generation was withheld in the 1976 census of manufacturers because few establishments in this industry subsector generated their own electricity. In addition, the energy used by this industry subsector was mostly consumed by air separation plants.

Individual air separation plants consume impressive quantities of electricity yet have negligible demands for process heat. As such, they are not good candidates for self-contained cogeneration systems. However, given the common proximity of air separation plants to major steam consuming industries, we believe that they might be good candidates for cooperative cogeneration projects. For example, an air separation plant, delivering gaseous oxygen and nitrogen over the fence to a major steel plant or petrochemical complex, might generate its electricity requirements in a steam topping cycle cogeneration system. The exhaust from the steam turbine would be delivered over the fence to the consumer of the industrial gases, or via a steam pipeline to some more remote steam customers. Alternatively, a merchant air separation plant, delivering liquid oxygen and nitrogen via truck or tank car to a number of relatively distant customers, might be sited adjacent to a large steam consuming industry which would accept exhaust steam from the cogenerating power plant.

We know of only one specific cogenerating system presently operating in the industrial gas industry. That plant is operated in Texas by Big Three Industries and supplies both steam and gaseous oxygen to surrounding industrial complexes.

3.6.3.3 Process Plant Description

The air separation plant we have used as a representative cogeneration site is located on the U.S. Gulf Coast and supplies oxygen and nitrogen via pipeline to several petrochemical complexes. The plant is modular in design, consisting of three air separation units (ASU) and one liquifier. The air separation units each have a capacity of approximately 1,050 tons per day of gaseous oxygen, part of which is used by a liquefier capable of producing 300 tons per day of liquid oxygen and nitrogen.

Within the air separation units, air is compressed, cooled by heat exchange with a counter-current flow of cold oxygen and nitrogen, and then fractionated in cryogenic distillation columns. The refrigeration necessary to liquefy the gases in the process is supplied by expansion of the product gases through turbines. Additional gas compression is required for liquid production.

Within 1-1/2 miles of this air separation plant are five petrochemical projects producing a variety of polymers and chemical intermediates and which might take steam from a cogeneration project at the air separation plant.

3.6.3.4 Electrical Demand

Because the air separation plant is modular in design, the owners have been considering four possible cogeneration systems ranging from 7,875 to 67,275 kw capacity. Power is presently supplied to the plant by a public utility at 138 kv; separate transformers reduce the transmission line voltage to 6900 volts and 4160 volts for use within the plant. The plant power factor is approximately 0.97-0.98. The total complex is on-stream 98% of the time, with half of the downtime for scheduled maintenance. An individual air separation unit may be down for two weeks per year when the petrochemical complex it supplies is down for annual maintenance. The average power load should approximate 90% of rated load with very little variation over a daily or weekly period. Provisions must be made, however, for the large instantaneous power requirements for starting the motors as large as 17,000 HP.

3.6.3.5 Steam Demand

The owners of the air separation plant have been considering two possible steam generation capacities. The most logical base case seems to be for the delivery of 500,000 lb/hr of 200 psig (saturated) steam starting in 1983. This steam would satisfy the incremental steam requirements incurred by various expansion projects being planned by petrochemical plants in the surrounding area. Additional steam could be sold at lower prices to displace existing steam generation capacity, perhaps up to a total of 1,000,000 lb/hr. The petrochemical plants planning expansion currently generate in excess of 700,000 lb/hr of steam in gas fired boilers; they require new boiler capacity to meet the needs of project expansions. Steam is used by these complexes for a variety of process heat needs. Steam header pressures within the plants vary from 150 psig to 200 psig.

Simultaneous demands for steam and electricity for one possible cogeneration configuration are shown in Figure 3.6-1. It is seen that the anticipated electric demand for air separation and steam demand by the petrochemical plants are constant, reflecting continuous (around-the-clock) operation. No seasonal variations are anticipated in energy demand.

3.6.4 An Example of Cogeneration Opportunities at Smaller Chemical Plants

3.6.4.1 Industry Subsector Profile

In canvassing the chemical industry for other potential cogeneration sites, we have found that most large plants with thermal/electric balances conducive to cogeneration are cogenerating to some degree. We believe that technically attractive opportunities for additional cogeneration are most numerous in smaller plants within the chemical industry at which cogeneration has heretofore been uneconomic, due to relatively low prevailing electricity prices and unfavorable economies of scale. As an example of

(Note The constant anticipated energy to be supplied)

FIGURE 3.6-1 ENERGY DEMAND PROFILES: AIR SEPARATION PLANT/CLUSTER CHEMICAL COMPLEX

such a small chemical plant, we have chosen an agricultural chemical operation located in DOE Region III. This plant produces a variety of herbicides, fungicides, and chemical intermediates. As such, it is a part of SIC 2879 (agricultural chemicals, nec*), a sector which accounted for purchased fuel and electrical energy consumption of 27×10^{12} Btu's in 1976 and electrical energy purchases of 10^9 kwh. So few establishments within this industry sector generated their own electricity that self-generation data was withheld in the 1976 Annual Survey of Manufactures. The pesticide industry is a diverse one with regard to products, processes, methods of operation, companies, and locations. Insecticides have historically been the largest volume products, whereas herbicides have accounted for the greatest sales value. Pesticide manufacturing plants are largely located in eastern, midwest and Gulf Coast states. As of 1976, 82 companies reported pesticide production within the United States; of these, we believe that ten accounted for 75% of pesticide sales. The plant we describe is owned by one of the ten dominant pesticide companies.

The plant is similar in size, thermal/electric balance, and modes of energy use to many other, modestly sized plants within the industry. We chose it as being representative of such plants, rather than of the product-defined agricultural chemicals subsector.

3.6.4.2 Process Plant Description

The agricultural chemical plant we have studied produces a number of materials at the same location. The plant is operated continuously, three shifts per day, 365 days per year. However, individual process units are shut down sequentially in the summer months to allow for employee vacations. Steam is widely used within the plant to supply process heat to reactors, to operate distillation columns and steam ejectors, and for steam tracing. Electrical energy is used to run numerous pumps, fans, and agitators and two large refrigerant compressors. These refrigeration units are the largest single electrical motors within the plant (each 400 HP).

3.6.4.3 Electrical Demand

Electricity is presently supplied to the plant by the local utility via two overhead feeders operating at 33 kv. As shown in Figure 3.6-2, the electricity demand of the plant averages about 5 mw, with short term demand seldom varying by more than 10%. Most motors are operated at 440 volts, except for the two 400 HP refrigeration compressors which operate at 2300 volts. The average power factor for the whole plant is estimated at 0.85.

3.6.4.4 Steam Demand

The plant steam demand profile is also shown in Figure 3.6-2. Demand is typically for 120,000 lb/hr of steam at 160 psig (saturated) with average monthly variations noted in Figure 3.6-2 reflecting changes in ambient temperatures and production schedules. Over short periods of time, demand seldom varies by more than 10%.

*nec = not elsewhere classified.

FIGURE 3.6-2 ENERGY DEMAND PROFILES: AGRICULTURAL CHEMICAL PLANT

3.6.4.3 Electrical Demand

The electricity demand of the plant is typically 5 MW, seldom varying by more than 10%. Electricity is presently supplied to the plant by the local utility via two overhead feeders operating at 33 kv.

Most motors are operated at 440 volts, except for the two 400 HP refrigeration compressors which operate at 2300 volts. The average power factor for the whole plant is estimated at 0.85.

The electrical demand profile of the plant is summarized in Figure 3.6-2.

3.6.4.4 Steam Demand

The plant steam demand profile is summarized in Figure 3.6.2. Demand is typically for 120,000 lb/hr of steam at 160 psig (saturated), although it may vary as much as 40% from this figure as ambient temperatures and production schedules change. Over short periods of time, demand seldom varies by more than 10%.

Steam is presently supplied by four package boilers, which burn low-sulfur No. 6 fuel oil. Economizers were retrofitted to two of these boilers and they typically operate at 85-86% thermal efficiency.

There are five steam turbines installed in the powerhouse which drive fans and boiler feedwater pumps and supply deaerator steam. One of these turbines is being replaced by an electric motor to eliminate wastage of exhaust steam in the summer. A single 275 HP turbine is used outside the powerhouse as a reducing valve.

3.7 PETROLEUM REFINING

3.7.1 Industry Profile

3.7.1.1 General Description

Petroleum refining (SIC 2911) is by far the largest segment of the Petroleum and Coal Products industry group (SIC 29), in terms of production capacity and energy use. The U.S. petroleum refining industry is composed of nearly 300 individual refineries scattered throughout the country, with major concentrations in the Gulf Coast, California and Midwest Regions. Each refinery is characterized by a unique capacity, processing configuration, and product distribution. Some broad industry statistics are listed below:

Capacity Profile:

(K = 1000)

Refinery Size	No. Plants	Total Capacity	
		KBbl/d	%
>100 KBbl/day (Large)	42	8,813	50
35-99 KBbl/day (Medium)	56	3,184	18
<35 KBbl/day (Small)	187	5,622	32
Total	285	17,629	100

Geographical Orientation:

	DOE REGION									
	I	II	III	IV	V	VI	VII	VIII	IX	X
No. Plants	1	6	17	42	33	100	13	35	47	13
Capacity, KBbl/d	14	750	1105	2479	2678	7740	588	657	2650	515

Energy Profile (1976):

	Quantity 10 ¹⁵ Btu	%
Total Electricity	0.09	3
Total Fuel*	2.88	97
Total Energy	2.97	100

Sales (1978):

Gross Sales**, \$, Billion 300

*10% of crude runs including catalyst coke.

**Including foreign operations and income from non-energy investments.

Refineries in the United States range in size from about 600,000 BPD to only a few hundred BPD. These refineries vary from fully integrated, high-complexity plants capable of producing a complete range of petroleum products and some petrochemicals to very simple plants capable of producing only a very small number of products. Also some refineries are modern and of recent construction, while others contain at least some operating process units constructed 40 or more years ago.

The crude slates for refineries vary widely as do the product mixes and, to some extent, product properties also vary from refinery to refinery. Because of this, each refinery is characterized by a unique capacity, processing configuration, and product distribution.

For the purpose of collecting statistics on the refining industry, the United States has been divided into several refining regions called Petroleum Administration for Defence (PAD) districts. Capacity in PAD III (Texas, New Mexico, Arkansas, Louisiana, Mississippi, and Alabama) is the largest, representing 40% of total U.S. refining capacity, while PAD IV (Rocky Mountains) represents less than 5% of the total.

It is apparent that the refining industry is characterized by a diversity of operations; however, within a given PAD district, there are similarities in crude supply patterns, processing configurations, and product outputs. For example, in PAD V, which happens to correspond with DOE region IX, the nature of California crudes and some of the strictest product specifications in the country has resulted in a predominance of high conversion refineries with extensive hydroprocessing.

3.7.1.2 Energy Use

Petroleum refining (SIC 2911) consumes approximately 94% of the purchased energy used by industry group SIC 29. In addition, it ranks among the top industry segments in regard to total purchased energy used which amounted to 1.22 quads in 1976 or about 3% of crude runs. About 7% of the purchased energy was in the form of electricity and 90% of the purchased fuel was natural gas. On the average, refinery energy consumption amounts to about 10% of crude runs.

However, purchased energy represents less than half the energy consumed in the refining of petroleum (Table 3.7-1). The remainder is supplied from by-product fuels produced in the refining processes. These include refinery gas, residual fuel oil, and assorted distillate fuels. Therefore, in terms of total energy consumption, this industry segment ranks near the top in the nation. Consequently, a small percentage decrease in energy consumption by this industry is a relatively large quantity of energy saved.

The major fuel end-users include direct fired heaters (crude heater, catalytic reformers) and boilers. A major portion of the electricity is used for pumping liquid and gaseous fluids.

TABLE 3.7-1

PETROLEUM REFINING INDUSTRY ENERGY PROFILE (1976)

	<u>Quantity</u>	<u>%</u>
<u>Electricity, 10⁶ kWh</u>		
● Purchased	26,277	95
● Self-Generated	<u>1,500</u>	<u>5</u>
TOTAL ELECTRICITY	27,777 (0.29 quad) [†]	100
<u>Fuels, 10¹⁵ Btu</u>		
● Purchased Fuel		
- Natural Gas	1.011	35
- Other	0.117	4
● Internal Fuel	<u>1.842</u>	<u>61</u>
TOTAL FUEL	2.882*	100
TOTAL ENERGY, 10 ¹⁵ BTU	3.17	--

[†]@ 10,500 Btu/kwh

* 10% of crude runs including catalyst coke

Source: "A Study of Inplant Electric Power Generation in the Chemical, Petroleum Refining, and Paper and Pulp Industries," Thermo Electron Corp., prepared for Federal Energy Administration, June 1976, NTIS PB-255 658.

Self-generation and cogeneration are both practiced by the refining industry, although there is limited statistical data on the amount. One study showed that self-generated electricity equals 6% of total electricity use. However, in-plant generation of shaft power is twice the amount of electricity generation.* In some cases, cogeneration of electricity is used as a means of balancing the process steam demands via pressure reduction from the high pressure steam system.

In general, the refining industry is very sophisticated in regard to balancing process energy requirements and credits. Many examples of cogeneration (mostly shaft power) can be found in the larger, complex refineries.

Petroleum refineries convert crude oil to finished products by employing two fundamental operations; namely, physical separation (distillation, extraction) and chemical conversion (changing molecular structure). Chemical conversion includes processes which make smaller molecules from large ones (catalytic cracking) and processes which build bigger molecules from small ones (alkylation). A good description of basic refinery processes can be found in a prior report.*

The petroleum refining industry is the first supplier of liquid fuels to the rest of industry. Consequently, it has access to some fuels not available elsewhere, such as vacuum bottoms, petroleum coke, refinery gas, and naphtha. Depending on individual refinery product demands, some of these fuels may have depressed values which would make them attractive for cogeneration projects.

3.7.1.3 Selection of Sample Refineries

In the selection of sample refineries, the following factors were considered:

- Geographic location
- Refinery capacity (size; see Section 3.7.1.1 for definition)
- Complexity (process configuration)
- Future trends in product demands and process requirements

The sample refineries selected have the following descriptors:

REFINERY IDENTIFICATION:	<u>A</u>	<u>B</u>
DOE Region:	VI	IX
Size	Medium	Large
Complexity	Medium	High
Product Trends	Excess Residuals	Excess Residuals, Light Naphtha

*"A Study of Inplant Electric Power Generation in the Chemical, Petroleum Refining, and Paper and Pulp Industries," Thermo Electron Corp. prepared for Federal Energy Administration, June 1976, NTIS PB-255 658.

These refineries are representative of refineries that make up the bulk of the industry capacity.

In addition to the typical refineries, there are a large number of small, non-integrated, essentially unique refineries in the United States. These small refineries represent well over one-half of the total number of those in the United States. However, their combined process capacity is less than 10% of the total U.S. throughput. The plants range from those whose "primary" product is asphalt to those that are essentially topping refineries producing a very small number of products. Often these refining configurations are designed to enable them to produce products for marketing in the immediate geographic area. These can be viewed as specialty refineries. These refineries were not considered in the selection process.

3.7.2 Sample Refinery "A"

3.7.2.1 Process Plant Description

Sample refinery "A" is a medium-size conversion refinery located in DOE Region VI. The refinery is classified as medium in regard to both size and complexity. A simplified block flow diagram illustrating the refinery process configuration is shown in Figure 3.7-1. The capacity of the individual units is noted on the diagram. The major refined products include 30,000 BPD of motor gasolines and 17,000 BPD of distillate fuels. Residual fuel oil and asphalt constitute 12,000 BPD of output.

The refinery crude runs consist of 20,000 BPD of domestic mid-continent crude and the balance made up of Iranian and Arabian (medium) crudes. Because two-thirds of the feedstock slate is comprised of heavy, sour crudes, the refinery produces a large amount of high sulfur vacuum bottoms, which is increasingly difficult to market. This problem is not unique to this refinery, but represents a trend caused by a general increase in the processing of lower quality crudes and the regulation of sulfur content in fuels.

One of the alternatives being considered is to upgrade the vacuum bottoms to higher quality products by installing heavy oil conversion facilities in the form of a heavy oil fluid catalytic cracking unit (HOC) with feed desulfurization. A simplified block diagram of the HOC unit is shown in Figure 3.7-2. The HOC unit converts crude residuals to gasoline and No. 2 fuel oil through contact with heated catalyst in a fluidized reactor system. Coke formed in the process adheres to the catalyst and reduces its effectiveness. The catalyst is reactivated (regenerated) by burning the coke off the catalyst, which also reheats the catalyst. The flue gas produced in the catalyst regenerator represents a source of energy that can be utilized in a cogeneration system.* The flow rate and process conditions for the regenerator flue gas are summarized on the following page.

* While heat recovery is practiced here, mechanical or electrical energy is not generated.

FIGURE 3.7-1 REFINERY "A" PROCESS CONFIGURATION

FIGURE 3.7-2 PROCESS FLOW SCHEMATIC: HEAVY OIL CRACKER ALTERNATIVE FOR REFINERY "A"

Flow, klb/hr	845.4
Pressure, psig	40
Temperature, °F	1300 max

<u>Composition</u>	<u>Mol %</u>	<u>Wt %</u>
N ₂	78.95	71.07
CO ₂	20.06	28.39
O ₂	0.93	0.48
H ₂ S	<u>0.06</u>	<u>0.06</u>
	100.00	100.00

Particulates*

Dust Loading, gr/scf	0.31
Size, micron	0.5-60
Distribution	85% > 10μ

The options for recovering this energy are discussed in section 6. The energy demands for the sample refinery are presented next.

3.7.2.2 Energy Demand Profiles

This sample refinery presently does not have the HOC unit installed. Since by-product energy from the HOC unit will be utilized for cogeneration, the refinery thermal and electric energy demand profiles after installing the HOC must be defined. This was done by adding the incremental demands for the HOC unit to the existing refinery demands.

3.7.2.3 Electrical Demand

The electrical demand for the refinery after installing the HOC unit is estimated at 9415 kw. Except during refinery turn-around, this demand is very steady with only a ±1% variation. During turn-around periods, which last about 1 month every 2-3 years, the demand will drop to 5185 kw. During the turn-around period, the HOC unit and consequently the proposed cogeneration system would be shut down. This refinery does not currently generate any electricity.

Associated with the HOC unit is an air compressor which represents an additional 30,000 HP load that can be driven by an electric motor or steam

*J.P. Balfoort, Hydrocarbon Processing, March 1976, p. 142.

turbine. Other pumping requirements include a 4500 HP wet gas compressor and large pumps which amount to 3200 HP. These loads are not included in the electrical demand presented above.

The main distribution voltage in the refinery is 12,500 V and the power factor is 0.94 to 0.96. The rate schedule of the local utility provides an incentive to maintain a high power factor by offering a bonus for values over 0.90.

3.7.2.4 Steam Demand

Refinery "A" generates a substantial amount of steam from process waste heat. Consequently, the net steam supplied from boilers is a rather small amount. The net steam demand by steam level, excluding HOC steam demand and production is summarized below:

<u>Steam Level</u>	<u>Demand, Klb/hr</u>		
	<u>Maximum</u>	<u>Average</u>	<u>Minimum</u>
150 psig, saturated	163	128	110
50 psig, saturated	50	--	45
15 psig, saturated	0	0	0

The maximum steam demand occurs during the winter months, and the minimum during summer. The monthly variation in steam demand is shown in Figure 3.7-3. About 45% of the average steam demand is returned as pressurized condensate at 210°F.

Gross steam production from the HOC amounts to:

600 psig saturated	606 klb/hr
250 psig saturated	47 klb/hr

This steam could be superheated by exchange with regenerator flue gas.

The existing boiler facilities consist of 3 units with a total capacity of 150 klb/hr. Two of the units are less than 5 years old. The third unit is over 25 years old and earmarked for replacement. The boilers are fired with gas, which is a mixture of process and natural gas.

3.7.3 Sample Refinery "B"

3.7.3.1 Refinery Description

Sample refinery "B" is a large (>100,000 Bbl/d), complex refinery located in DOE Region IX. Like many refineries in this region, the crude slate is comprised of a mixture of domestic California and Alaskan crudes, with imported Mid-East and other foreign crudes as the balancing crude.

**FIGURE 3.7-3 ENERGY DEMAND PROFILES: OIL REFINERY "A"
(MEDIUM-SIZED)-MONTHLY VARIATIONS**

EXISTING FIRED BOILERS AT REFINERY "B"

<u>Boiler Location</u>	<u>Boiler Numbers</u>	<u>Age (years)</u>	<u>Pressure (psig)</u>	<u>Capacity (#/hr ea)</u>
Number One Power Plant	1,2,3	38	800	140,000
	4,5	33	800	140,000
	6	28	790	185,000
	7	27	800	185,000
Number Two Steam Plant	1,2,3	31	135	70,000
	4	20	500	175,000
	5	12	500	240,000
	6	9	500	100,000
Catalytic Steam Plant (TCC Boilers)	1,2,3,4	31	460	60,000
	Subtotal:	800 psig		1,070,000
		460/500 psig		755,000
		135 psig		210,000
TOTAL CAPACITY (1b/HR)				2,035,000

The boilers are fired by refinery gas and low sulfur fuel oil. A major portion of the refinery gas is used in direct fired process heaters, however, the split between boiler and process heater demand is not known. The energy demand profile for Refinery "B" is shown in Figure 3.7-4.

3.7.3.2 Available Fuels

Available fuels, available at this refinery, that could be used for cogeneration are summarized below:

<u>Available Fuel</u>	<u>Sulfur Level Wt. %</u>	<u>Heating Value 10⁶ Btu/Bbl</u>
Lt. Naphtha	<100 ppm	5.0/Bbl
L.S. Fuel Oil	0.5-0.25	6.0/Bbl
H.S. Fuel Oil	2-3	6.3/Bbl
Petroleum Coke	3-4 (2% N ₂)	29.5/ton

The petroleum coke contains 3-5% ash.

FIGURE 3.7-4 ENERGY DEMAND PROFILES: OIL REFINERY "B" (LARGE-SIZED)–MONTHLY VARIATIONS

4.0 ENERGY PROJECTIONS

Among the factors affecting the economic attractiveness of energy systems are projections on the future prices for fuels and electricity. In general, the higher the electricity prices, the greater are the returns from cogeneration in terms of savings in electricity bills. On the other hand, increasing prices for the fuel used in cogeneration will act to lower the rate of return from this investment.

In this section we present the rationale for selection of consistent, regionalized energy price forecasts that can be used as input to optimizing cogeneration systems discussed in this study.

4.1 GENERAL APPROACH

Figure 4J-1 contains a schematic depiction of the four stages we went through in developing the price forecasts. In the first stage, we located models that forecast energy prices. In the second stage, we reviewed these models and selected the one we felt was most appropriate. The model we picked generated alternative forecasts, with each alternative corresponding to a different scenario, so in the third stage we selected a scenario. In the fourth stage, we tabulated the regional forecasts corresponding to that scenario.

4.1.1 Stage 1: Locating Models

In response to concerns about rising energy prices and availability since the OPEC Embargo in 1973, a large number of energy models have been developed by the federal government, universities, and consulting companies. The great majority of these models are concerned with either energy demand or supply, but there are some models that forecast price. In the first stage, we surveyed the different sources to identify models concerned with energy price predictions.

We undertook a search of computerized literature bases. Retrieval of information from these bases is on a code word basis. Since each publication referenced in these bases is accompanied by a string of code words describing its subject matter, we undertook the search to identify publications coded under "energy" or "price." Among the bases searched was National Technical Information Service (NTIS) and ENERGYLINE. The NTIS base contains citations to U.S. government sponsored research and dates back to January 1970. ENERGYLINE contains a coverage of over 200 journals.

In addition to literature searches, research groups were contacted by phone. Among those contacted were the Energy Information Administration (EIA), the Oakridge National Laboratory, MIT Energy Lab, and Stanford Research Institute. These phone calls identified models that had not yet been indexed.

FRAMEWORK FOR SELECTING ENERGY PRICE FORECASTS

FIGURE 4.1-1

4.1.2 Selecting a Model

Having identified the energy price forecasting models, we next had to select the most appropriate one for this study. Our criteria for selection were: (1) coverage and (2) performance. The model we selected should cover (i.e. forecast) the variables whose values we required. It's performance in generating these forecasts should be the best among models with similar coverage.

Since we need a model that simultaneously forecasts residual, distillate, natural gas, coal, and electricity prices by region, multi-fuel coverage is important because if we take, say, electricity price forecasts from one model and coal prices from another, the ratio of coal to electricity price could be inconsistent. Regional detail is needed because energy prices vary substantially by region. To take an example, national electricity price forecasts are unlikely to represent what will happen in the Pacific Northwest, historically an area of relatively very low electricity prices.

There turned out to be very few models which forecasted residual, distillate, natural gas, coal, and electricity prices on a regionalized basis. We selected the Mid-Range Energy Forecasting System (MEFS)--up to 1979 known as Project Independence Evaluation System (PIES)--maintained by the EIA, from among them. This model was selected because: (1) its logic appeared sound, (2) its forecasts were plausible, (3) it represented the culmination of a vast amount of research effort, (4) it is well documented (5) its forecasts are annually disseminated, (6) it is the oldest of the regionalized energy price forecasting models and, (7) EIA personnel are available to clarify issues concerning it.

4.1.3 Stage 3: Selecting a Scenario

The MEFS forecasts are reported annually to Congress. The 1978 forecasts--the latest available at the time of our study--presented projections to 1990 corresponding to six alternative scenarios. Each scenario contains assumptions about three different parameters: (1) macroeconomic growth, (2) geological resources and (3) world oil price. For reasons that will be explained later, we selected the so-called F scenario, corresponding to the highest energy prices in this model.

4.1.4 Stage 4: Tabulating Forecasts

The MEFS model forecasts for each of ten DOE regions delivered industrial energy prices for residual, distillate, electricity, coal and natural gas. To optimize a specific cogeneration system, we required price forecasts specific to the plant being analyzed. Therefore, the regional forecasts from MEFS had to be localized to a plant level, which was done by using 1) available energy prices at the specific plant site and 2) applying escalation rates (%/yr in constant 1978 dollars) derived from the MEFS forecasts (Energy Information Administration, 1978b) to obtain energy prices in any future year. Table 6.1-5 shows the energy prices and escalation rates used in the optimization of cogeneration systems discussed in Section 6 of this report. In the following Subsections 4.2 and 4.3, we provide further information on the MEFS model and the related forecasts.

4.2 MEFS MODEL: DESCRIPTION AND EVALUATION

4.2.1 Introduction

The Mid-Range Energy Forecasting Systems (MEFS) is a very large model that uses econometrics, process analysis, and optimization methods in generating regional energy demand, production, import, and price forecasts for the years 1985 and 1990. The model currently resides at the Energy Information Administration (EIA), a somewhat autonomous group within the Department of Energy, created by the Department of Energy Organization Act of 1977 (P.L. 95-91).

The MEFS model's antecedents date back to the oil embargo of 1973. In the wake of that embargo, President Nixon proposed the launching of a project to make the U.S. independent of oil imports. Concurrently, a model, the Project Independence Evaluation System (PIES), was assembled by the Federal Energy Administration to help in the formulation of appropriate policies. The ill-conceived notion of energy independence was soon discarded but the PIES model survived. The model was used to generate forecasts reported annually to Congress, as well as to analyze national energy policies.

Both the PIES logic and forecasts have undergone considerable scrutiny and criticism. Academicians such as Waverman (1977) have focussed on logical flaws in the model's structure, while industry experts, like Perry (1977) have criticized the implausibility of the forecasts. The model has been modified to respond to some of these criticisms and the current version is in many ways an improvement over the original. Because of the model changes, and also possibly to avoid some of the opprobrium attached to the original model, PIES was renamed MEFS in 1979.

This section describes the model's logic and the next section selects a scenario and presents the forecasts corresponding to that scenario. Our information on the model's logic comes from documentation issued by the EIA (1978) and the FEA (1977, 1976a, 1976b, 1976c) and from discussions with EIA personnel. The forecasts are those presented in the 1978 Administrators Annual Report to Congress (AAR) issued by EIA (1978).

4.2.2 Model Overview

MEFS is not a single model, rather it is a system of integrated energy supply and demand models. On the supply side, there are models for the primary extraction of coal, crude oil and natural gas and for their conversion in refineries and/or utilities into secondary energy forms. In the refinery model, crude oil is converted to residual, distillate, gasoline, and other petroleum products. Part of the refinery output and some of the coal and natural gas is converted in an electric utility model into electricity. The electricity and the remaining refinery, coal, and gas production are consumed in the residential, commercial, industrial, and transportation demand sectors. Demand not satisfied by domestic production is assumed to be imported.

Figure 4.2-1 contains a schematic overview of the MEFS logic. As the figure shows, the disparate supply and demand models are linked together by an Integration Model. The demand and supply models are used to generate curves for each fuel type showing the quantities that would be demanded or supplied at different prices. The oil supply curve is modified to be perfectly horizontal at the point corresponding to an exogenous world oil price, on the assumption, that the U.S. can import as much as it wants at the world price. The curves are entered into an Integration Model, which solves for equilibrium demand, domestic production, imports and prices.

MEFS MODEL OVERVIEW

FIGURE 4.2-1

The MEFS demand and supply curves incorporate various assumptions about policy development, and exogenous forces. Changing these assumptions will shift the curves, thereby, changing the equilibrium price forecasts. In the AAR, the curves incorporate only the most likely set of policies. Therefore, the user cannot select forecasts corresponding to alternative policies. The AAR does report forecasts corresponding to alternative exogenous scenarios, with a scenario a combination of assumption on GNP, geological resources, and world oil price. Varying the GNP causes shifts in the energy demand curves, while the other two scenario components affect the energy supply curves.

4.2.3 Integrating Model

Because of its central importance, it is useful to start our description with the Integrating Model. This model is regarded as a major innovation in terms of techniques for equilibrating demand and supply. It is the one component of MEFS that has remained largely intact over the years.

The premise on which the model is based is that the domestic energy market is workably competitive. Demand and supply curves are input to the model, and it locates the equilibrium by identifying the point at which demand and supply intersect. This equilibration is performed by the iterative use of a large-scale optimization program. The starting iteration involves:

- Assuming initial demand prices and reading off the demand curves, the quantities demanded at those prices
- Using an optimization program, in which the supply curves are imbedded, to compute the least-cost method of supplying the quantity demanded
- Reading off the supply prices associated with the least-cost method
- Adding mark-ups and taxes to the supply prices to give demand prices

The demand prices of step 4 will, in general, not be the same as those assumed in step 1. As a consequence, a second iteration will be required. The assumed price in step 1 of the second iteration will be the average of the prices in step 1 and step 4 of the first iteration. The iterative process will be stopped, and equilibrium declared, when the difference between the price in step 1 and step 4 is below a specified tolerance level.

Equilibration is performed separately for each year, and the inputs, that is curves, must also be provided for each year of analysis. Currently, the model is run for the years 1985 and 1990. The solution of 1985 has no effect on 1990 and so the equilibration is, in effect, an exercise in comparative static situations.

4.2.4 Coal Supply Model

Coal has been assigned a central role in U.S. energy policy and of all the fuels, by far the greatest increase in production is expected to come from coal. The higher costs associated with extracting this additional production will mean a substantial rise in prices.

The curves generated by the Coal Supply Model trace out the price that must be paid to bring out various supply levels. The curves are of a long-run equilibrium nature and ignore the effect on production of such temporary phenomenon as strikes or excess inventories. These curves, which are derived for the years 1985 and 1995, are input to the Integration Model.

There is a curve derived for each class of coal in each region. Coal is classified by sulfur content and Btu, and so we have, for example, a supply curve for low-sulfur, high-Btu coal in the Northern Appalachia region. The reasons for the sulfur disaggregation is the Environmental Protection Agency regulations on the use of high-sulfur coal. The Btu disaggregation is prompted by the wide variation in heat content that exists among coals.

The supply curves show the production that will become available at different prices from existing mines or from as yet undeveloped mines. It should be pointed out that a mine is assumed to either produce at rated capacity or shut down. Thus, supply is determined by the number of mines in operation and their capacity rather than at the rate at which they operate. For an existing mine to operate, the price must exceed its (unit) variable cost. For a new mine to come on stream, the price must exceed the sum of variable cost, fixed cost, and normal profit.

The basis for developing mine costs is technological categorization framework developed by the modelers. There are one-hundred and two mine categories, with deep mines, for example, disaggregated by scale of operation, seam thickness, and seam depth. Associated with each mine category is a set of costs developed by deterministic accounting methods. All mines falling within a category are assumed to have the same set of costs.

4.2.5 Oil and Gas Supply Model

Under any scenario, the U.S. production of crude oil and natural gas is expected to change only marginally over the next decade. That is not to say, the industry is expected to be stagnant, new sources must be developed to replace wells that will run dry. In predicting the new finds of oil and gas, the probabilistic element is much greater than was the case for coal. In the case of coal, the reserves are known, the question is whether the price is high enough to develop them. With respect to oil and gas, there is uncertainty about the level of drilling activity, as well as the reserves that are likely to be located by such drilling.

While the situations are very different, the end product of the Oil and Gas Supply Model must--because of the requirements of the Integration Model--be the same as the Coal Supply Model. The Oil and Gas Supply Model generates long-run equilibrium curves for the years 1985 and 1990, showing the quantities that would be available at different prices.

In MEFS, oil and gas supply from traditional sources is modeled using similar methodologies. Traditional sources are defined to consist of on-shore and off-shore production from the Alaskan and lower 48 states outer continental shelf area. Supply from non-traditional sources are judgemental approximations made by technical experts. Non-traditional sources include oil from tar sands and shale, as well as production from the Alaskan North slope.

The oil (and gas) supply curve for traditional sources is derived point by point. A point on the oil and gas supply curves is derived by estimating the production from new and old wells corresponding to an assumed oil price trajectory. By varying the price trajectories, a set of production estimates are traced out to give a production-price (that is, supply) curve. Estimating the production corresponding to a given price trajectory involves the following sequence of operations:

- A level of drilling activity is selected, with the selection based on the assumption that drilling will continue up to the point at which the expected present value from drilling equals the costs. The expected present value is determined by the assumed oil price trajectory and the size of the undiscovered oil reserve base.
- Finding rates are used to project the amount of oil located by the drilling activity.
- Recovery factors are used to estimate how much of the located oil will eventually be produced by each of three methods (primary, secondary, and tertiary). This cumulative production figure is added to existing reserves.
- Decline rates are used to project the rate at which production will occur out of reserves.

It should be pointed out that the concept of a supply curve assumes deregulation of oil prices. With controls, the curve is a single point--namely, the quantity that will be supplied at the control price. Also, the reader should note that the supply curve will become perfectly elastic at the world oil price, on the assumption that the U.S. can import as much as it wants at this price.

4.2.6 Refinery Model

The refinery occupies a central position in the energy economy. It produces from domestic and imported crude oil, a variety of petroleum products, chief of which are gasoline, residual, and distillate. While refineries have some freedom in changing their input-output relationships, a particular refinery operates most economically when the attributes of its crude oil input and the mix of its petroleum output reflect design mode conditions.

The MEFS Refinery Model is based on the Refineries Petrochemical Modeling System (RPMS) developed by Bonner and Moore for use in the oil industry. Given demands for gasoline, distillate, residual, and other petroleum products, the Refinery Model selects the crude oil supplies and mix of refinery modes that would satisfy these demands at minimum cost. Some of the identified modes reflect those at which existing refineries can operate, others reflect modes that could result from building new refineries or modifying existing ones. Each mode is itself an optimal state of a refinery's operation and so not only do we have optimality between refineries but also within a refinery.

In the model, any given crude oil is described by a set of chemical characteristics. Each refinery mode, of which there are twenty-six, requires the set of chemical characteristics for the crude to produce fixed proportions of the final product.

Each crude type available to a refinery is assumed to have a chemical composition that can be represented by ten characteristics, including: (1) gravity measured in lbs./cu.in, (2) distillate measured as volume fraction, (3) reformer feedstock measured as volume fraction, (4) sulfur measured as lbs. in the cut, and so on. There are a variety of crude types in the model. The list includes domestic crude types such as Oklahoma Mix, Pacific Offshore, and West Texas Mix and imported crudes like Arabian Light, Algerian, and Venezuelan Mix. It should be noted that the list of domestic crudes includes oil extracted from shale and tar sands.

4.2.7 Electric Utilities Model

The MEFS Electric Utilities Model estimates the optimal generating capacity required to meet electricity demand. The complicating factor in the analysis is that utilities must provide service on demand. This demand, which is subject to diurnal, weekly, and seasonal periodicities can be represented by a load duration curve showing the demand for electricity in each of the 8760 hours of the year. The high point on the curve is the peak, and the utilities must have sufficient capacity to meet this demand. The area under the curve is equal to the total utility send-out, that is, total electricity demand.

In the MEFS Electric Utilities Model, the total electricity demand is partitioned into three segments: base (65%), intermediate (33%), and peak (2%). The model determines for each segment, the plants, existing and new, that will be required to satisfy demand. In making this determination, the objective function is to minimize the cost of meeting demand.

In identifying the required capacity mix, the model selects from a wide variety of generating plants. These plants are distinguished by type and include coal-fired steam turbines, residual-fired steam turbines, distillate-fired simple cycle gas turbines, hydro, nuclear, fuel gas, and geothermal.

Base load facilities operate almost continuously, shutting down only for maintenance or repairs. They account for about half-system capacity but supply about 65% of demand. Because of their high rate of utilization, the MEFS Electric Utilities Model selects for base units those plant types (e.g. nuclear) with low operating costs even if they have high capital costs.

Intermediate and peak-load facilities often start-up and shut down on a daily basis. These units have low utilization rates and so the model selects for intermediate and peak load, those plant types with low capital costs even if their operating costs are relatively high. In the model, gas turbines may be operated only as peak load units while nuclear, fuel gas, and geothermal plants may be operated only as base units.

4.2.8 Transportation Network

An important characteristic of the U.S. energy system is that the regions of production are not always located near the regions of consumption. A large transportation network is required to move resources from extraction through conversion, and to consumption. Much of the network is in place but more will have to be built, for example, to transport the additional coal expected to be mined in the western states.

In MEFS, transportation costs, like other supply costs, are incorporated into the cost minimizing objective function of the Integration Module. These costs can be a significant percentage of price, especially in the case of coal. In the transportation analysis, costs are developed for each link in the network, where a link is the distance between two shipment points, and there is a separate network for each mode of transport. In MEFS, the transport modes for crude oil are pipeline and barge, for coal, the modes are rail and barge; for natural gas, pipelines are the only mode and refined petroleum products are moved through pipelines, barge, or truck.

4.2.9 Demand Model

In the MEFS Demand Model, demand curves are derived for eight major fuel types--distillate, residual, gasoline, other petroleum products, steam coal, metallurgical coal, natural gas, and electricity. These demand curves, depict for the years 1985 and 1990, the quantities of these fuels that could be purchased at various prices. In developing the curves, economic, price, and technical factors are taken into account, as is the possibility of substitution between fuels.

The unusual characteristic of the MEFS Demand Model is that it must generate demand curves not point estimates of demand. The reason, of course, is that this is what the Integration Model requires. The derivation of a demand curve starts with the estimation of forecasting equations for each fuel. Next, assumed values for the exogenous variables, and a specific energy price are entered into the equation to give a predicted demand value--i.e., one point on the demand curve. This step is repeated continuously, each time with the same exogenous values, but in combination with a different energy price to give various points on the demand curve.

The MEFS analysis is disaggregated by sector as well as fuel. The methodology used to predict energy demand in the residential, commercial, and industrial sectors involves two stages. In the first stage, total energy consumption is predicted and in the second stage, it is distributed between the different fuel types. Total energy consumption is predicted using an econometric equation, in which an energy price index, sectoral activity, and a lagged dependent variable are the explanatory variables. The share of a particular fuel is an econometric function of the ratio of its price to the energy price index and its own value lagged a year.

The second stage of fuel share allocation in MEFS has been criticized by Waverman (12), among others, for ignoring the symmetry and adding-up constraints. This means that the fuel shares predicted by MEFS are not "theoretically pure," though purity, of course, is not synonymous with accuracy. In response to these criticisms, the residential and commercial sector method described here is being dropped by EIA to be replaced by the Hirst (1976, 1978) model developed at the Oakridge National Laboratory. This model uses a "multi-national" approach to predicting fuel shares and has the added advantage that it incorporates, at various points in the analysis, engineering information on appliance efficiency improvements, insulation retrofits, and so on.

In the transportation sector, simple technical methods are used to project the fuel consumed by the different transport modes. Fuel substitution is not generally possible in this sector which considerably simplifies the problem. Auto-

mobile gasoline consumption, for example, is predicted by dividing vehicle miles travelled (VMT) by the miles per gallon (MPG). The VMT is predicted as a function of disposable income, unemployment, and the cost of automobile travel. MPG is calculated from a vintaged automobile fleet, vintaging is necessary because of continuing improvements in vehicle fuel efficiency.

4.3 MEFS FORECASTS

In the 1978 Annual Administration Report (AAR) to Congress, there are a number of alternative MEFS forecasts reported, with each set corresponding to a different scenario. In the AAR, a scenario is a combination of assumptions on GNP, oil and gas reserves, and world oil price. These assumptions affect the model's energy demand and supply curves, and thus its price solution. There are three GNP alternatives, three oil and gas reserve choices, and two possible world oil prices. Table 4.3-1 shows the values corresponding to each of these which we discuss below.

The GNP forecasts are all from the Data Resources Inc. (DRI) macroeconomic model. According to the low case, GNP which in 1978 was \$2,108 billion will rise in constant (1978) dollar terms to \$2,669 billion in 1985 and \$3,005 in 1990. The low case is referred to by DRI as CYCLELONG and it depicts a future characterized by marked cyclicalities caused by destabilizing monetary and fiscal policies. In the medium case, GNP in constant dollars is \$2,758 billion in 1985 and \$3,208 billion in 1990. This case called TRENDLONG presents a situation of stable growth, where the economy approaches full employment in the early 1980's and remains on this trajectory thereafter. This stability is achieved through balanced monetary and fiscal policies and an absence of any major negative external shocks to the economy. In the high case, GNP rises to \$2,803 billion in 1985 and \$3,241 billion in 1990. This case called CEASPIRIT was developed by DRI in conjunction with the staff at Council of Economic Advisors (CEA). It reflects the economic targets of CEA and is somewhat more optimistic than TRENDLONG, particularly in the early 1980's.

In our view, CYCLELONG is clearly the most realistic of the three alternatives. Even this so-called low case depicts GNP growing at a compound rate of 3.4% between 1978 and 1985 and 2.4% between 1985 and 1990. Our selection of CYCLELONG was based on discussions with macroeconomists at Arthur D. Little, Inc.

The three alternative oil and gas reserve estimates reported in Table 4.3.1 come from the U.S. Geological Survey (USGS) Circular 725. In presenting its estimates of the amount of undiscovered oil and gas reserves, USGS indicates the probability of occurrence. The low estimates supposedly have a 95% chance of being attained or exceeded, the medium estimates have a 50% chance, while there is only a 5% chance of the high estimates being attained or exceeded. The low estimate for undiscovered oil is 46 billion barrels (bb) of which 35 bb is offshore and 11 bb is onshore; alternatively, classified 37 bb occurs in the lower 48 states and 9 bb is in Alaska. The low estimate for gas is 312 trillion cubic feet (Tcf), with 262 Tcf onshore and 50 Tcf offshore; of the reserves 24 Tcf occur in Alaska. Under the medium case, oil reserves go from 46 bb to 89 bb and gas reserves from 312 Tcf to 522 Tcf. Much of the increase

TABLE 4.3-1

MEFS SCENARIO CASE VALUES

CASE	GNP (BILLIONS 1978 DOLLARS)		RESERVES (UNDISCOVERED)		REAL WORLD OIL PRICE (1978 DOLLARS)	
	1985	1990	Oil (bb)	Gas (Tcf)	1985	1990
LOW	2669	3005	46	312	NA	NA
MEDIUM	2758	3208	89	522	\$15.32	\$15.32
HIGH	2803	3241	143	768	\$19.61	\$24.97

bb = billion barrels
tcf = trillion cubic feet

SOURCE: Energy Information Administration, Annual Report to Congress,
Volume II, 1978. pp 7, 9, and 12-13.

in the estimates comes from upward revisions in the Alaskan and offshore reserves. In the high case, the oil estimates are 149 bb and the gas estimates are 768 Tcf. It could be noted that in the high case, Alaskan oil reserves are put at 50 bb (versus 9 bb for the low case) and its gas reserves at 137 Tcf (versus 24 Tcf in the low case).

We selected the medium estimate as the most likely of the cases. There is some controversy surrounding USGS estimates but, in any event, their medium alternative is preferable to the two extreme cases.

As Table 4.3-1 shows, there are two alternative world (that is, imported) crude oil price cases. In the medium case, crude oil prices in 1978 dollars remain constant and are \$15.32 a barrel in both 1985 and 1990. In the high case, real prices increase to \$19.61 in 1985 and to \$24.97 in 1990. We selected the high world oil price case. Our decision is based, in part, on analyses conducted by EIA's international group (1978b) with their Oil Market Simulator (OMS).

The OMS model is run under various scenarios with crude oil production varied between scenarios. In OMS Scenario D, OPEC production is 40.2 million barrels a day (mmbd), non-OPEC production is 27.5 mmbd and the world oil price in 1985 is \$15.30 a barrel (1978 dollars). In OMS Scenario C, OPEC production is 34.2 mmbd and non-OPEC production is 22.8 mmbd. This cutback of approximately 10 mmbd results in a 1985 price of \$20.41. Our feeling is that Scenario C production is more likely than that of Scenario D. During 1978, OPEC production averaged 29.9 mmbd. The OPEC nations have not shown any enthusiasm for raising production levels and an OPEC output of 40 mmbd, assumed by Scenario C, seems most improbable.

To summarize our selection of scenario components, we would pick 1) the low GNP case; 2) the medium oil and gas reserve case; and 3) the high world oil price case. As it turns out, we cannot have all three of our choices. There are three GNP cases, three reserve cases, and two world oil price cases, which would give 18 possible scenarios. However, the model is run for only six of the 18 alternatives. The cases associated with the six alternatives are reported in Table 4.3-2.

The scenario closest to our desired combination is Scenario F. In this scenario we have medium GNP, medium reserves, and high world oil price. Fortunately, the model's solutions are fairly insensitive to GNP and so the fact that Scenario F has a medium GNP case, instead of a low case, is not a major concern.

Table 4.3-3 presents the 1985 Scenario F forecasts and Table 4.3-4 the 1990 forecasts. These forecasts are taken directly from the Appendix to Volume II of the 1978 Administrators Annual Report (Issued September 1978) and are shown here to illustrate the relative magnitude of energy price increases for the various fuel forms. Table

TABLE 4.3-2

MEFS SCENARIO COMBINATIONS

SCENARIO	GNP	RESERVES	REAL WORLD OIL PRICE
A	HIGH	HIGH	MEDIUM
B	HIGH	LOW	MEDIUM
C	MEDIUM	MEDIUM	MEDIUM
D	LOW	HIGH	MEDIUM
E	LOW	LOW	MEDIUM
F	MEDIUM	MEDIUM	HIGH

SOURCE: Energy Information Administration, Annual Report to Congress, Volume II, (1978). pp XVL.

TABLE 4.3.3

INDUSTRIAL PRICE FORECASTS
FOR 1985

(1978 \$/Million Btus)

	New- Engl (1)	NY/ NJ (2)	Mid- Atl. (3)	S.- Atl. (4)	Mid- West (5)	S.- West (6)	Cntrl (7)	N.- Cntrl (8)	West (9)	N.- West (10)	U. S. (11)
Electricity	11.46	8.82	10.73	9.41	9.21	9.32	10.35	6.94	10.24	3.67	9.15
Distillate	4.21	4.26	4.41	4.40	4.16	4.18	4.05	4.20	4.10	4.10	4.22
Residual	3.56	3.70	3.83	3.49	3.64	3.53	3.62	3.47	3.42	3.48	3.57
Coal	2.08	1.96	1.85	1.98	1.77	1.64	1.70	1.39	1.77	1.82	1.77
Natural Gas	3.74	3.09	2.92	2.47	2.70	2.16	3.34	2.43	2.67	2.86	2.41

SOURCE: Energy Information Administration, Annual Report to Congress, Volume, II: Appendix, (1978), p. A284.

TABLE 4.3-4

INDUSTRIAL PRICE FORECASTS
FOR 1990

(1978 \$/Million Btus)

	New- Engl (1)	NY/ NJ (2)	Mid- Atl. (3)	S.- Atl. (4)	Mid- West (5)	S.- West (6)	Cntrl (7)	N.- Cntrl (8)	West (9)	N.- West (10)	U. S.: (11)
Electricity	12.44	9.51	11.53	10.58	10.71	12.03	11.90	11.51	10.90	5.49	10.71
Distillate	5.20	5.25	5.42	5.40	5.16	5.18	5.06	5.24	5.18	5.18	5.24
Residual	4.45	4.59	4.72	4.39	4.59	4.49	4.57	4.47	4.46	4.52	4.51
Coal	2.21	2.09	1.98	2.11	1.88	1.72	1.80	1.47	1.85	1.88	1.88
Natural Gas	5.36	4.25	3.88	3.81	4.58	2.71	3.55	2.74	3.12		3.16

SOURCE: Energy Information Administration, Annual Report to Congress, Volume II: Appendix, (1978), p. A310.

4.3-3 and Table 4.3-4 report the forecasts in 1978 dollars, and thus, are adjusted to exclude the effect of inflation (To put these forecasts in actual dollars, they must be multiplied by an inflation index.)

The forecasts are presented for each of ten DOE regions. The states in each region are listed below.

Region 1, New-Engl.:	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont
Region 2, N.Y./N.J.:	New Jersey and New York
Region 3, Mid-Atl.	Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia
Region 4, S-Atl.:	Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee
Region 5, Midwest:	Illionis, Indiana, Michigan, Minnesota, Ohio, Wisconsin
Region 6, S-West:	Arkansas, Louisiana, New Mexico, Oklahoma Texas
Region 7, Cntrl.:	Iowa, Kansas, Missouri, Nebraska
Region 8, N-Cntrl.:	Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming
Region 9, West:	Arizona, California, Hawaii, Nevada
Region 10, N-West:	Alaska, Idaho, Oregon, Washington

Energy prices and escalation rates used in this study for each particular plant site examined are summarized in Table 6.1-5.

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5.0 CHARACTERIZATION OF NEAR-TERM TECHNOLOGY COGENERATION SYSTEMS FOR APPLICATION TO INDUSTRIAL PROCESSES

In order to select cogeneration system candidates for each of the process applications, we have established the thermodynamic characteristics of each of the near-term energy conversion technologies. This section of the ICOP study report describes the approach that has been used in these characterizations and summarizes the results for each of the energy conversion systems. The detailed characterizations can be found in the Appendixes.

There are two generic types of thermodynamic cycles for cogeneration applications—topping and bottoming. In the topping cycle a system designed primarily for the generation of electricity supplies heat to an industrial process as a by-product. In the bottoming cycle, waste heat from an industrial process is recovered for the purpose of generating electricity.

Figure 5.1-1 is a generalized diagram of a topping cogeneration system for application to industrial processes in which provision is made for the following matching options:

- Match both heat and power
- Match heat with excess electricity exported to utility grid
- Match heat with supplemental electricity purchased from utility grid
- Match power with supplemental process steam produced by an auxiliary process steam boiler
- Match power with excess process steam exported to industrial customer

Figure 5.1-2 is a generalized diagram of a bottoming cogeneration system for application to industrial processes in which provision is made for the same matching options. The waste heat from the industrial process is assumed to be a high temperature gas stream. This waste heat would be utilized in the energy conversion subsystem primarily for the generation of electricity. When the bottoming cycle uses steam, process steam can be obtained from it for use in the process from which the waste heat came or for use in another industrial process.

This section of the report is concerned with the characterization of near-term technology cogeneration systems for application to processes in five energy-intensive industries. Parameters used for characterizing candidate energy conversion systems were:

- Ideal energy utilization factor
- Ratio of gross process heat* to electrical energy

*Gross process heat is the thermal energy supplied to the energy utilization subsystem by the energy conversion subsystem. It includes the losses from the process steam going to the point of use and the losses from the condensate returning from the point of use. The net process heat is the thermal energy actually used in the process.

Fig. 5. 1-1 – Generalized diagram of topping cogeneration system for application to industrial processes

Fig. 5. 1-2 — Generalized diagram of bottoming cogeneration system for application to industrial processes

- Electricity generation efficiency
- Ratio of energy savings to gross process heat

The concept of the ideal energy utilization factor can be explained using Figure 5.1-3, which is a generalized model of energy conversion subsystems for cogeneration application. There are three constituents of the system: fuel, combustion air, and sorbents for pollution control (when required). The useful products of this system are process steam less the requirements for the energy conversion subsystem (feedwater heating and flue gas desulfurization) and electrical power less the requirements for the energy conversion subsystem (fans, pumps, coal pulverizers, and solids handling).

There are five categories of energy loss from this system: incomplete combustion of the fuel (unburned hydrocarbons, carbon monoxide, and unburned carbon), sensible and latent heat losses from the combustion products and boiler blowdown, sensible heat losses from the ash and spent sorbent, heat rejected to the condenser cooling water and dump coolers, and electrical and mechanical loss.

In most candidate systems the loss of energy due to unburned hydrocarbons and carbon monoxide is negligible. In most candidate systems the energy loss associated with unburned carbon also is negligible, except in coal-fired systems, where the unburned carbon in the ash is often a significant loss. Where these losses are not negligible, they tend to be fuel specific.

Appendix B1 is an analysis of the sensible heat loss associated with the products of combustion from energy conversion systems: gaseous (carbon dioxide, nitrogen, and excess air), vapor (water from the moisture and hydrogen in the fuel and moisture in the air), and solids (ash from fuel and spent sorbent for pollution control). This is the predominant loss in an energy conversion subsystem for cogeneration application where process heat requirements are matched, in other words, where there is no heat rejection to the condensing cooling water. The minimum losses are a strong function of the amount of excess air used and a weak function of the fuel used.

Appendix B2 is an analysis of the thermodynamic loss associated with boiler blowdown for both process and power steam boilers. Parameters considered are the concentration of dissolved solids in makeup water, the ratio of condensate returned from the industrial process to the process steam supplied, steam temperature, steam pressure, boiler feedwater temperature, and recuperator effectiveness. The use of high-effectiveness recuperators for both process and moderate-pressure power steam boilers will reduce the thermodynamic loss due to boiler blowdown to near negligible levels.

Latent heat loss in the water vapor derived from the moisture in the fuel and combustion air and the hydrogen in the fuel does not represent a loss in available energy but is included as part of the fuel higher-heating-value which is the convention used here.

S-5

Fig. 5. 1-3— Model of energy conversion subsystem for industrial cogeneration applications

When process heat requirements are matched in a cogeneration system, the heat rejection to the condenser cooling water is zero. Other forms of heat rejection to the cooling water may occur, however, among the various candidate energy conversion subsystems—for example, in the gas turbine expander cooling air coolers and gas turbine compressor intercoolers. The quantities of heat rejected in these cases are typically small and are a function of the specific configuration of the system.

The last category of energy loss is electrical and mechanical loss from the turbogenerator, mechanical drives, and motors. Together, these losses constitute a small percentage of the energy from the fuel and also tend to be a function of configuration choice.

The ideal energy utilization factor* is, therefore, as follows:

$$\begin{aligned} \text{I.E.U.F.} &= \frac{\text{Energy in fuel} - \text{losses} - \text{auxiliary energy requirements}}{\text{Energy in fuel}} \\ &= \frac{\text{Energy to process steam} + \text{energy in electricity}}{\text{Energy in fuel}} \end{aligned}$$

The second parameter for characterizing energy conversion subsystems is also based on the gross process heat supplied. The use of these two parameters, therefore, characterizes the energy conversion subsystem independently of the energy utilization subsystem.

Figure 5.1-4 is a correlation of the four parameters used in characterizing the candidate energy conversion subsystem for cogeneration applications. This correlation is described in Appendix B-3.

Characterizations were made for the following near-term technology energy conversion subsystem/fuel combinations with the indicated environmental controls.

- Coal-fired conventional steam with particulate removal and flue gas desulfurization (FGD)
- Oil-fired gas turbine with waste heat boiler
- Oil-fired combined cycle
- Oil-fired diesel engines with waste heat boilers
- Coal-fired, indirectly-heated open cycle gas turbine with waste heat boiler, particulate removal, and flue gas desulfurization.
- Coal-fired, closed-cycle gas turbine with waste heat boiler, particulate removal, and flue gas desulfurization.

*This energy utilization factor is designated as ideal because it is based on gross energy to the process steam (losses associated with the utilization of the process steam are not included).

Fig. 5.1-4 — Energy utilization characteristics of cogeneration technology

Appendix B-4 characterizes coal-fired conventional steam energy conversion subsystem with particulate removal and FGD. Figure 5.1-5 (Figure B.4-3 of Appendix B-4) shows the ideal energy utilization factor and the ratio of gross process heat to electrical energy correlated with variables of steam turbine throttle conditions (600, 900, 1200, and 1500 psig) and process steam supply pressure (14.7, 29.8, 67.0, 134.6, 247.3, and 422.6 psia) from a back-pressure steam turbine.

Appendix B-5 characterizes oil-fired gas turbine energy conversion subsystem with waste heat boiler. The ideal energy utilization factor and the ratio of gross process heat to electrical energy are correlated with variables of gas turbine expander inlet temperature (1900, 2000, and 2100°F), gas turbine compressor pressure ratio (4, 8, 12, and 16), and process steam supply pressure (29.8, 67.0, 134.6, and 247.3 psia) from the waste heat boiler. Figure 5.1-6 (Figure B.5-6 of Appendix 5) shows the effects of the dominant parameters - compressor pressure ratio and process steam supply pressure.

Appendix B-6 is the characterization of the oil-fired combined-cycle energy conversion subsystem. The ideal energy utilization factor and the ratio of gross process heat to electrical energy are correlated with variables of gas turbine expander inlet temperature (1900, 2000, and 2100°F), gas turbine compressor pressure ratio (4, 8, 12, and 16), and heat recovery steam generator inlet temperature (1300, 1400, and 1500°F). Steam turbine throttle conditions were 1250 psia/950°F unless constrained by limits of 40°F on pinch point temperature difference and 15°F on approach. Figures 5.1-7 and 5.1-8 (Figures B.6-6 and B.6-7 of Appendix B-6) show the effects of the dominant parameters - compressor pressure ratio, process steam supply pressure, and heat recovery steam generator inlet temperature.

Appendix B-7 characterizes oil-fired diesel engine with waste heat boiler energy conversion subsystems. Two diesel engine types were characterized - the slow-speed two-stroke cycle marine diesel and the high-speed four-stroke cycle industrial diesel. The ideal energy utilization factor and the ratio of gross process heat to electrical energy are correlated with variables of process steam supply pressure from the waste heat boiler (29.8, 67.0, 134.6, and 247.3 psia) and boiler feedwater subcooling to the waste heat boiler (0, 50, 100, 150, and 200°F). Figures 5.1-9 and 5.1-10 (Figures B.7-2 and B.7-3 of Appendix B-7) show the effects of these parameters for the two types of diesel engines.

Appendix B-8 characterizes the coal-fired closed-cycle gas turbine energy conversion subsystem with waste heat boiler, particulate removal, and flue gas desulfurization. The ideal energy utilization factor and the ratio of gross process heat to electrical energy are correlated with variables of gas turbine recuperator effectiveness (0, 0.2, 0.4, 0.6 and 0.8) and process steam supply pressure from the waste heat boiler (29.8, 67.0, 134.6, and 247.3 psia). The expander inlet temperature used (1325°F) is that used commercially in Europe for coal-fired closed-cycle gas turbines. Figure 5.1-11 (Figure B.8-2 of Appendix B-8) shows the effects of these parameters.

Fig. 5.1-5 — Characterization of conventional coal-fired energy conversion subsystem with FGD and particulate removal

Fig. 5.1-6— Characterization of oil-fired gas turbine energy conversion subsystem with waste heat boiler

Fig. 5.1-7- Characterization of oil-fired combined-cycle energy conversion subsystem with modified/unfired HRSG

Fig. 5.1-8 – Characterization of oil-fired combined-cycle energy conversion subsystem with modified/fired HRSG

Fig. 5.1-9 — Characterization of four-stroke cycle diesel with a waste heat boiler energy conversion subsystem

Fig. 5.1-10 - Characterization of low speed two-cycle diesel plus waste heat boiler energy conversion subsystem

Fig. 5.1-11-Characterization of coal-fired closed cycle gas turbine energy conversion subsystem with waste heat boiler, particulate removal, and FGD

Appendix B-9 characterizes the coal-fired indirectly heated gas turbine energy conversion subsystem with a waste heat boiler, particulate removal, and flue gas desulfurization. The ideal energy utilization factor and the ratio of gross process heat to electrical energy are correlated as a function only of process steam supply pressure from the waste heat boiler (14.7, 29.8, 67.0, 134.6, and 247.3 psia). Here, again, the expander inlet temperature (1325°F) is that used commercially in Europe for coal-fired closed-cycle gas turbines. Figure 5.1-12 (Figure B.9-2 of Appendix B-9) shows the effect of this parameter.

Figure 5.1-13 is a composite of the characteristics of the candidate near-term technology energy conversion subsystem/fuel combinations superimposed on the correlation of Figure 5.1-4. This shows the energy conversion subsystems that give the highest ratio of energy savings to gross process heat over the range of gross process heat-to-electrical energy ratio. For high ratios of process heat to electrical energy, the coal-fired steam energy conversion subsystem is best.

Figure 5.1-13 also shows that, for low ratios of gross process heat to electrical energy, the diesel engine with waste heat boiler is superior. Even though the ideal energy utilization factor of the two-stroke-cycle diesel is only 0.5 to 0.6, the ratio of energy savings to gross process heat ranges from 2 to 4, the highest values for any of the energy conversion subsystems.

For intermediate ratios of gross process heat to electrical energy, the combined cycle and the gas turbine with waste heat boiler show the highest Ideal Energy Utilization Factor (IEUF). With state-of-the-art technology using a conservative expander inlet temperature (EIT)*, the coal-fired, closed cycle gas turbine with waste heat boiler shows a considerably better IEUF than separate generation when the process steam temperature is below about 275°F. Above such steam temperatures, this coal-fired, gas cycle shows about the same IEUF as separate generation. The coal-fired, indirectly heated open cycle gas turbine with waste heat boiler is slightly better than the closed-cycle steam with the same expander inlet temperature. It should be noted that these gas cycle systems provide the capability of using coal and other alternative fuels (industrial solid waste, municipal refuse) over the gross process heat to electrical energy ratio range of 0.5 to 4.0.

The energy conversion subsystems characterized herein are for those cases in which process steam is supplied at only one pressure level. In many industrial processes process steam is required at multiple pressure levels. Approximate characterizations of subsystems with process steam at more than one pressure can be obtained by weighting the values for each of the several process steam supply pressures.

We have investigated the possibility of using thermal energy storage to efficiently reconcile time-varying energy supplier and process heat requirements. Storage systems examined in Appendix B10 include:

- packed beds
- fluid bed heat exchanger with packed bed storage
- moving bed exchanger/storage
- combined fluid and rock thermal storage
- steam accumulator

*EIT = 1325°F.

Fig. 5.1-12 — Characterization of coal-fired indirectly-heated gas turbine energy conversion subsystem with waste heat boiler, particulate removal, and FGD

Fig. 5. 1-13 — Energy utilization characteristics of candidate cogeneration systems

For the energy demand profiles considered in this study, only the steam accumulator was found to be appropriate in one plant (see discussion relating to the brewery found in Appendix C4).

Appendix B11 characterized bottoming cycles for top working fluid temperatures ranging from 100°C (212°F) to 300°C (572°F) and for capacities in the range from 3 to 30 MW. The ratio of plant power to the thermal input to the working fluid is correlated as a function of the throttle inlet conditions. Bottoming cycles considered in Appendix B11 were found to be cost effective in the medium-sized petroleum refinery (see Appendix C7).

Costing algorithms were developed for the energy conversion equipment to be used in the various cogeneration configurations under consideration. The algorithms covered the following types of equipment:

- Fired power steam generators (coal & oil)
- Heat recovery steam generators (HRSG's)
- Waste heat boilers (generating saturated steam)
- Steam turbine/generators
- Gas turbine/generators
- Particulate removal and flue gas desulfurization systems
- Organic cycles
- Oil and coal-fired process steam boilers

Details on these algorithms are given in Appendix B-12.

6.0 OPTIMIZATION OF COGENERATION SYSTEMS

6.1 INTRODUCTION

The objective of this task was to determine the optimum near-term technology cogeneration system for each of the ten industrial plants characterized in Section 3.0. Three different ownership options were considered for each plant except where the peculiarities of a given plant precluded one or more of them. The ownership options used are as follows:

- Industry
- Utility
- Third party (completely independent company - not a joint venture between industry and utility)

The industrial ownership case consigns responsibility for the financing, construction, and operation of the cogeneration facility to the company which owns the industrial plant which uses the electricity and process steam generated by the cogeneration facility. In the cases in which process heat requirements are matched, the only possible revenues are those from the sale of excess electricity to the local utility. For those cases in which electricity requirements are matched, the only possible revenues are those from the sale of process steam to neighboring industries. Cash flow is computed on the basis of the above revenues and the incremental costs of owning and operating the cogeneration facility versus the costs of owning and operating the process steam boiler required under separate generation.

For utility ownership, revenues are derived from the sale of both electricity and process steam, whether process heat or electricity requirements are matched. Cash flow is computed on the basis of these revenues and incremental costs of owning and operating the cogeneration facility as compared to those of owning and operating the equivalent amount of electric generation capacity in a central station.

For third-party ownership, revenues are obtained from the sale of both process steam and electricity and the cash flow is based on these revenues and the total cost of owning and operating the cogeneration facility. The procedures for calculating discounted cash flow return on equity for the three different ownership categories are developed in Section 6.5. The procedures for calculating the energy savings from the use of cogeneration rather than separate generation are developed in Section 6.6.

By definition, the optimum cogeneration system for a given industrial plant is the one which meets the return-on-investment hurdle rate for the particular owner and gives the maximum energy savings. Because three different ownership categories were considered, there could be different optimum systems for each ownership category. In such an event, preference would be given to the optimum cogeneration system for the industry ownership category since it is the category which would have the fewest institutional and regulatory problems.

6.1.1 Optimization Techniques

Two approaches to optimization were considered: the use of sophisticated optimization techniques such as geometric programming, and the development of a cogeneration system design parameter matrix on coordinates of return-on-equity and energy savings. It was decided that the matrix approach should be used since it provides the additional information required to select near-optimum commercially available equipment when the optimum design point cannot be matched by commercially available equipment.

6.1.2 General Information On Plants

6.1.2.1 Ranking of Plants

The ten industrial plants in five energy intensive process industries which were characterized in Section 3.0 are summarized in Table 6.1-1 from the standpoint of average electric power requirements, annual electrical energy consumption, annual process steam consumption, annual fuel consumption for direct process heat, and total annual equivalent fuel consumption. Average annual power consumption ranged from 1600 to 120,000 kW, annual process steam consumption ranged from 128.2 to 4720×10^6 kWh/yr, and annual total equivalent fuel consumption ranged from 211.9 to 8306×10^6 kWh eq/yr. Table 6-1.1a is a compilation of the capacity factors for the energy utilization subsystem in the ten industrial plants. The brewery was the only plant which had a diurnal process heat demand profile which indicated that energy storage should be considered.

6.1.2.2 Financial Data

The financial data for the ten industrial plants treated in this study are summarized in Table 6.1-2. These data include:

- Industry specific return-on-equity hurdle rates
- Company specific return-on-equity hurdle rates
- Company specific debt-to-equity ratios
- Median debt-to-equity ratios for the industry
- Utility specific debt-to-equity ratios for the utility servicing each plant
- Median debt-to-equity ratios for the utilities in the region in which the plant is located
- Utility specific return-on-equity for 1978 for the utility servicing each plant
- Median return-on-equity for 1978 for the utilities in the region in which the plant is located.

TABLE 6.1-1
SUMMARY OF PLANT ENERGY USE CHARACTERISTICS

Industry	Plant	Average Electric Power Requirements (kW)	Annual Electric Energy Consumption (kWh/yr)	Annual Process Steam Consumption (kWh/yr)	Annual Direct Process Heat Fuel Consumption (kWh/yr)	Total Annual Energy Consumption (1) (kWh/yr)	Rankings (2)
Food	Soybean Oil Mill	1600	14.2×10^6	128.2×10^6	20.5×10^6	211.9×10^6	(1) (1) <1>
	Brewery	4500	38.9×10^6	172.1×10^6	—	313.6×10^6	(2) (2) <2>
Textiles	Finishing Mill	9000	65.0×10^6	412.6×10^6	184×10^6	855.1×10^6	(4) (5) <7>
	Integrated Mill	16000	116.7×10^6	279.7×10^6	25.4×10^6	687.9×10^6	(8) (3) <4>
Pulp and Paper	Writing Paper Mill	14000	120.9×10^6	782.4×10^6 (4)	—	1265.9×10^6	(7) (8) <8>
	Kraft Paper Mill	10000	88.0×10^6	498.0×10^6 (4)	—	837.2×10^6	(6) (6) <6>
Chemicals	Agricultural Chemicals	5100 (5800) (3)	44.5×10^6 (50.5×10^6) (3)	310.2×10^6 (361.9×10^6) (3)	—	492×10^6 (570×10^6) (3)	(3) (4) <3>
	Air Separation	67000	530.4×10^6	$(1308 - 2615) \times 10^6$	—	$(3054 - 4593) \times 10^6$	(9) (9) <9>
Petroleum Refining	Medium Size and Complexity	9415	82.5×10^6	498.1×10^6	—	821.7×10^6	(5) (7) <5>
	Large/Complex	120000	963.6×10^6	4720×10^6	—	8306×10^6	(10) (10) <10>

(1) Electricity generation efficiency assumed to be 35% and process steam boiler efficiency assumed to be 85%

(2) (Power), (process heat), and <total energy consumption> in ascending order

(3) Projected to 1982

(4) Net after credit for black liquor recovery boiler

TABLE 6.1-1a

SUMMARY OF ENERGY UTILIZATION SUBSYSTEM CAPACITY FACTORS FOR TEN INDUSTRIAL PLANTS

Industry	Type of Plant	Workday Capacity Factor	Overall Capacity Factor	
Chemical	Agricultural Chemicals	0.62	0.62	(1)
	Air Separation	0.76	0.76	(2)
Food	Brewery	0.70	0.55	(1)
	Soybean Oil Mill	0.86	0.86	(1) (4)
Petroleum Refining	Large/Complex	0.90	0.90	(1)
	Medium/Less Complex	1.0	1.0	(3)
		0.82	0.82	(1)
Pulp and Paper	Writing Paper Mill	0.53	0.53	(1)
	Kraft Paper Mill	0.86	0.86	(1)
Textile	Finishing Mill	0.56	0.47	(1) (4)
	Integrated Mill	0.56	0.48	(1) (4)

(1) Based on Net Process Steam Requirements

(2) Based on Elective Power Requirements

(3) Based on Process Characteristics

(4) Does Not Include Direct-Fired Driers

TABLE 6.1-2

SUMMARY OF FINANCIAL DATA FOR TEN INDUSTRIAL PLANTS

Industry	Type of Plant	Location State/Region	Industry Specific ROE at 50% Participation (1)	Company Specific ROE (2)	Utility Specific ROE for 1978 (2)	Median ROE for Utility Region for 1978 (2)	Company Specific DER	Median DER for Industry (2)	Utility Specific DER (2)	Median DER for Utility Region (2)
Chemical	Agricultural Chemicals	Maryland/III	21%	17-22%	12.0	13.2	0.5 ⁽²⁾	0.5	1.0	1.0
	Air Separation	Texas/VI		-	11.5	13.7	0.6		-	1.0
Food	Brewery	Penna./III	16%	-	11.9	11.5	4.5 ⁽³⁾	0.4	0.9	1.0
	Soybean Oil Mill	Indiana/V		-	0 ⁽⁶⁾	11.3	0.5 ⁽²⁾		∞ ⁽⁶⁾	1.0
Petroleum Refining	Large/Complex	Calif./IX	25%	15%	10.3	10.8	0.2 ⁽²⁾	0.4	0.9	1.0
	Medium/Less Complex	Okla./VI		10-15%	13.3	13.7	3 ⁽⁵⁾		1.1	1.0
Pulp and Paper	Writing Paper Mill	Penna./III	16.5%	-	10.6	11.3	0.5 ⁽²⁾	0.5	1.0	1.0
	Kraft Paper Mill	N. Hamp./I		-	-	11.5	-		-	1.0
Textile	Finishing Mill	S. Carol./IV	24%	-	12.4	13.2	0.7 ⁽²⁾	0.3	0.9	1.0
	Integrated Mill	Alabama/IV		-	8.8	13.2	3.7 ⁽⁴⁾		1.1	1.0

(1) The Potential for Cogeneration Development in Six Major Industries by 1985, prepared by Resource Planning Associates Inc. (RPA) Cambridge, Massachusetts, for the Department of Energy, Office of Conservation and Solar Applications; Project Director, Peter Bos (RPA); Project Manager (RPA), James Williams; Project Manager, Burns & Roe, Jerome Morton; December 1977.

RPA Reference
No.: RA-77-1018

(2) 31st Annual Report on American Industry Finances, Forbes, Jan. 9, 1979

(3) 29th Annual Report on American Industry Finances, Forbes, Jan. 1, 1977

(4) Stockbroker

(5) A.D. Little

(6) Municipal Utility

Nomenclature:

ROE - return on equity

DER - debt/equity ratio

This summary shows that the ROE and DER values vary significantly among the ten plants and among the five industries whereas the values for the utilities have narrow ranges which is to be expected for a regulated industry. For third-party ownership, it was assumed that the third party would be an independent company with minimum equity capital so a debt/equity ratio of 5 was used. The interest rate on the debt fraction of the capital investment was assumed to be 10% for all plants and all categories of ownership.

6.1.2.3 Tax Data

Table 6.1-3 summarizes part of the tax data used in determining cash flows for the ten industrial plants. Data included are:

- Federal income tax rate
- Depreciation life
- State income tax rates
- Local property taxes.

The IRS guideline depreciation period for industrial steam and electric generation systems (28 years) is substantially greater than the industry specific values which range from 9 to 18 years (Table 6.1-3). The variation in state income tax rates is considerable (from 0 to 10-1/2%). Annual local property taxes were assumed to be 1-1/2 percent of the capital investment for all plants.

The Energy Tax Act of 1978 imposed constraints on the method of depreciation of capital equipment. New gas and oil-fired facilities are required to use straight line depreciation rather than accelerated depreciation, e.g., sum-of-years-digits. The sum-of-years-digit method of depreciation was used for all coal-fired systems.

The Energy Tax Act of 1978 also imposed constraints on application of investment tax credits. New gas and oil-fired facilities were denied the standard 10% investment tax credit for industrial equipment. New coal-fired industrial facilities were granted an additional 10% investment tax credit under the alternate fuels provision. Public utilities are, however, excluded from the alternate fuel investment tax credit. The investment tax credit for cogeneration facilities is, therefore, a function of fuel and ownership category as shown in Table 6.1-4.

TABLE 6.1-3
SUMMARY OF TAX DATA FOR TEN INDUSTRIAL PLANTS

Industry	Type of Plant	Location State/DOE Region	Federal Income Tax Rate	Depreciation Life For Industrial Steam and Electric Systems	Industry Specific Depreciated Life - Years (2)	State Corporate Income Tax (3)		Local Property Taxes - (4)
						Rate - %	Federal Income Tax Deductible	
Chemical	Agricultural Chemicals	Maryland/ III	46% (1) ↓	28 Years (2) ↓	11	7	No	1 1/2% ↓
	Air Separation	Texas/ VI				0	-	
Food	Brewery	Penna./ III			12	10.5	No	
	Soybean Oil Mill	Indiana/ V			18	3	No	
Petroleum Refining	Large/ Complex	Calif./ IX			16	9	No	
	Medium/ Less Complex	Okla./ VI				4	No	
Pulp and Paper	Writing Paper Mill	Penna./ III			16	10.5	No	
	Kraft Paper Mill	N. Hamp./ I				5	No	
Textile	Finishing Mill	S. Carol./ IV			9	6	No	
	Integrated Mill	Alabama/ IV			10	5	Yes	

(1) 1978 Tax Reform Act

(2) Tax Information on Depreciation, Publication 534, Internal Revenue Service, Dept. of Treasury, 1979 Edition

(3) Winton, John M. "Plant Sites - 1979." Chemical Week, Nov. 1, 1978, pp. 41-54

(4) Tentative Standard for Cost Estimating of Investor-Owned Plants for Producing Pipeline Gas From Coal,
Office of Coal Research, June 4, 1965

TABLE 6.1-4

INVESTMENT TAX CREDITS FOR COGENERATION FACILITIES

Ownership Category	<u>Topping Fuel</u>			<u>Bottoming</u>
	Oil	Natural Gas	Coal	
Industry	0	0	20	10
Utility	0	0	10	10
Third Party	0	0	20	10

6.1.2.4 Energy Cost Data

Energy cost data for each of the DOE regions was compiled by A. D. Little. Where available, actual energy costs were used. The fuel and electrical energy costs and escalation rates used for the ten plants are summarized in Table 6.1-5.

The stand-by charge for electrical energy was assumed to be \$50/kW (Williams, 1978, RPA, 1977) for all plants except the large petroleum refinery where a value of \$15.60 was given in the utility rate schedule.

The price* of excess electrical energy sold to the utility was assumed to be 0.6 of the cost of electrical energy purchased from the utility for all plants except the large petroleum refinery where a ratio of 0.475 was given for the specific utility.

The price of process steam for utility and third-party ownership was assumed to be equal to what it would cost the industry to generate it on-site. For one of the plants, this cost was given. One of the plants required a bottoming cycle and only industry ownership was considered so the price of process steam was not required. For the other eight plants, the cost of producing process steam on-site was estimated based on the following assumptions:

Process steam boiler design

- New 100% capacity unit
- Fuel is that being currently used

Cost Data

- Boiler - based on information given in Coffin (1979) for process steam boilers with construction completed in 1978
- Fuel - based on data compiled by A. D. Little in Section 4.0
- Boiler efficiency (higher heating value basis)
 - Coal - 85%
 - Oil - 84%
 - Natural gas - 82%
- Annual capital charge - 15%
- Maintenance - 3% of capital investment per year
- Operating supplies - 0.6% of capital investment per year
- Operating labor requirements (50% overhead on operating labor) -
 - 2 men per shift for oil and natural gas
 - 3 men per shift for coal

* Only a few plants were found to have excess electric energy to sell. At the time cogeneration systems were being optimized in this study, FERC was still deliberating on methods by which to set appropriate prices for sales of cogenerated electric energy to utilities considering such factors as capacity payments, reliability, etc.; see DOE/FERC Dock No. RM79-54 and 55 (18CFR, Part 292).

TABLE 6.1-5
SUMMARY OF FUEL AND ELECTRICAL ENERGY COST AND ESCALATION RATES USED FOR TEN PLANTS
 (Time base - Dec. 1978)

Industry	Type of Plant	Location State/DOE Region	Fuel Cost (\$/10 ⁶ Btu (HHV))/Escalation Rate (%/Year)			Electrical Energy	
			Coal	Natural Gas	Fuel Oil	Cost (\$/kWh)	Escalation Rate (%/year)
Chemical	Agricultural Chemicals	Maryland/III	1.13/5.6	-	3.42 ⁽⁸⁾ /4.5	3.15 ⁽⁷⁾	2.1
	Air Separation	Texas/VI	1.95/-1.0	1.61/4.4	2.28/5.8	2.03	6.0
Food	Brewery	Penna./III	1.03/5.6	1.63/7.7	2.77/4.5	2.45 ⁽⁷⁾	2.1
	Soybean Oil Mill	Indiana/V	1.20/5.0	1.61/8.5	2.76/4.2	2.67 ⁽⁷⁾	2.9
Petroleum Refining	Large/Complex	Calif./IX	1.92/-0.3	2.40 ⁽⁷⁾ /6.8	2.06/7.6 ⁽³⁾	4.0 ⁽⁷⁾	2.6
	Medium/Less Complex	Okla./VI	-	-	-	2.1	6.0
Pulp and Paper	Writing Paper Mill	Penna./III	0.97 ⁽⁷⁾ /5.6	2.63 ⁽⁵⁾⁽⁷⁾ /7.7	5.25 ⁽⁵⁾⁽⁷⁾ /4.5	2.4 ⁽⁷⁾	2.1
	Kraft Paper Mill	N. Hamp./I	1.51/3.3	-	3.26 ⁽⁸⁾ /3.6	3.5 ⁽⁷⁾	0.8
Textile	Finishing Mill	S. Carol./IV	1.20/4.8	2.08 ⁽⁷⁾ /9.5	2.03 ⁽⁷⁾ /4.6	2.36	3.6
	Integrated Mill	Alabama/IV	1.20/4.8	1.29/9.5	2.55/4.6	2.36	3.6

(1) Includes 10% local tax on energy purchased

(2) Wood was the preferred fuel for this plant. The cost of wood was assumed to be \$1.84 /10⁶ Btu (HHV) and the escalation rate for wood was assumed to be 4.8%.

(3) Compliance low sulfur residual

(4) By-product light naphtha was an alternate fuel for this plant. The value of light naphtha was estimated to be \$2.58/10⁶ Btu (HHV) and the escalation rate was estimated to be 7.3%.

(5) Updated to mid-1979 after oil price increases occurred

(6) Bottoming cycle

(7) Plant specific values - not DOE region

(8) Includes 12 1/2 % Premium for Low-Sulfur Residual

- Labor costs - obtained from Winton (1978).

The process steam prices for the ten plants are summarized in Table 6.1-6.

6.1.2.5 Operating Labor Costs

The operating labor requirements for process steam boilers and cogeneration systems were assumed to be as shown Table 6.1-7.

TABLE 6.1-7
OPERATING LABOR REQUIREMENTS

Process steam boiler	Workers per shift
Oil or gas-fired	2
Coal-fired	3
Cogeneration systems	
Oil or gas-fired	3
Coal-fired	4

Average hourly earnings for the states wherein the ten plants are located were obtained from Winton (1978). Overhead on operating labor was assumed to be 50%. These values were used to compute the incremental operating labor costs for industry ownership given in Table 6.1-8 and the operating labor costs for third-party ownership given in Table 6.1-9. In Table 6.1-8 incremental labor costs are given for converting from a clean-fuel fired process steam boiler to a coal-fired cogeneration system and for converting from a process steam boiler to a cogeneration system using the same type of fuel. In Table 6.1-9 operating labor costs are given for clean fuels and for coal.

The incremental labor requirements for utility ownership were assumed to be as follows:

Total energy consumption kWh eq/yr	Incremental labor requirements (fraction of third-party ownership)
< 500 x 10 ⁶	100%
> 500 x 10 ⁶ <2500 x 10 ⁶	33%
>2500 x 10 ⁶	25%

The operating labor costs for utility ownership which were calculated on this basis are shown in Table 6.1-10.

TABLE 6.1-6
SUMMARY OF PROCESS STEAM PRICES FOR TEN PLANTS FOR UTILITY AND THIRD PARTY OWNERSHIP
(December 1978 Base)

Industry	Type of Plant	Location State/Region	Boiler Capacity -lb/hr	Process Steam Supply Pressure psia	Process Boiler Fuel	Capacity Factor %	Process Steam Price - \$/1000 lb	Process Steam Escalation Rate (b)
Chemical	Agricultural Chemicals	Maryland / III	210,000	175	Low Sulfur Residual Oil	62	4.50 ^(a)	0.03
	Air Separation	Texas / VI	-	-	Natural Gas	-	2.56 ^(c)	0.022
Food	Brewery	Penna. / III	100,000	135	Natural Gas	55	3.00 ^(a)	0.03
	Soybean Oil Mill	Indiana / V	52,500	165	Natural Gas	86	2.85 ^(a)	0.03
Petroleum Refining	Large/ Complex	Calif. / IX	720,000 580,000 300,000	165 565 895	Compliance Fuel Oil	90	3.65 ^{(d) (a)}	0.037
	Medium/ Less Complex	Okla. / VI	-	-	-	-	(e)	-
Pulp and Paper	Writing Paper Mill	Penna. / III	418,000	180	Coal	53	2.83 ^(a)	0.028
	Kraft Paper Mill	N. Hamp. / I	195,000	280	Residual Oil	86	3.89 ^(a)	0.0175
Textile	Finishing	S. Carol. / IV	275,000	165	Residual Oil	47	3.43 ^(a)	0.024
	Integrated Mill	Alabama / IV	200,000	265	Residual/ Wood	48	4.00 ^(a)	0.03

(a) Estimated by procedure described in text

(b) Nominally one-half of the escalation rate of the fuel used by the process boiler

(c) Value given is for new steam (500,000 lb/hr) and is equal to fuel value plus 60 cents. Backout steam (> 500,000 lb/hr) would be priced at fuel value. (supplied by A. D. Little)

(d) Weighted average price for process and power steam

(e) Bottoming plant (only industry ownership considered so there would be no steam sales)

TABLE 6.1-8
OPERATING LABOR COST INCREMENT, INDUSTRY OWNERSHIP

Industry	Type of Plant	Location	July 1978		Incremental Operating Labor Costs - \$/Year	
			Average Hourly Earnings (\$)	Operating Hours/Year	Clean → Coal ⁽²⁾	Clean → Clean ⁽²⁾ Coal → Coal
Chemical	Agricultural Chemicals	Maryland / III	6.70	8760	177,000	88,500
	Air Separation	Texas / VI	8.74	8760	344,500	459,500
Food	Brewery	Penna. / III	6.44	6880	133,000	66,500
	Soybean Oil Mill	Indiana / V	6.96	8760	184,000	92,000
Petroleum Refining	Large/Complex	Calif. / IX	7.29	8760	191,600	95,800
	Medium/Less Complex	Okla. / VI	8.56	8760	(1)	(1)
Pulp and Paper	Writing Paper Mill	Penna. / III	6.44	8760	169,000	84,700
	Kraft Paper Mill	New Hampshire / I	5.00	8760	131,400	65,700
Textile	Finishing Mill	S. Carolina / IV	6.40	7344	141,000	70,500
	Integrated Mill	Ala. / IV	6.99	7490	157,500	79,000

(1) It is assumed that the operating labor requirements for the maximum cogeneration cases will not exceed those for the reference case (minimum cogeneration).

(2) See text for explanation

TABLE 6.1-9
OPERATING LABOR COSTS, THIRD-PARTY OWNERSHIP

July 1978					Operating Labor Costs \$/Year	
Industry	Type of Plant	Location	Average Hourly Earnings (\$)	Operating Hours/Year	Oil & Gas	Coal
Chemical	Agricultural Chemicals	Maryland / III	6.70	8760	264,000	352,000
	Air Separation	Texas / VI	8.74	8760	344,500	459,500
Food	Brewery	Penna. / III	6.44	6880	199,000	266,000
	Soybean Oil Mill	Indiana / V	6.96	8760	274,000	366,000
Petroleum Refining	Large/Complex	Calif. / IX	7.29	8760	287,400	383,200
	Medium/Less Complex	Okla. / VI	8.56	8760	(1)	(1)
Pulp and Paper	Writing Paper Mill	Penna. / III	6.44	8760	253,400	338,700
	Kraft Paper Mill	New Hampshire / I	5.00	8760	197,100	262,800
Textile	Finishing Mill	S. Carolina / IV	6.40	7344	211,500	282,000
	Integrated Mill	Ala. / IV	6.99	7490	236,000	314,000

(1) Third-party ownership is not practical for this plant.

TABLE 6.1 - 10
OPERATING LABOR COST INCREMENT, UTILITY OWNERSHIP

July 1978					Incremental Operating Labor Costs - \$/Year	
Industry	Type of Plant	Location	Average Hourly Earnings (\$)	Operating Hours/Year	Oil & Gas	Coal
Chemical	Agricultural Chemicals	Maryland / III	6.70	8760	132,000	176,000
	Air Separation	Texas / VI	8.74	8760	86,000	115,000
Food	Brewery	Penna. / III	6.44	6880	199,000	266,000
	Soybean Oil Mill	Indiana / V	6.96	8760	274,000	366,000
Petroleum Refining	Large/Complex	Calif. / IX	7.29	8760	71,900	95,800
	Medium/Less Complex	Okla. / VI	8.56	8760	(1)	(1)
Pulp and Paper	Writing Paper Mill	Penna. / III	6.44	8760	253,400	338,700
	Kraft Paper Mill	New Hampshire / I	5.00	8760	98,500	131,400
Textile	Finishing Mill	S. Carolina / IV	6.40	7344	105,800	141,000
	Integrated Mill	Ala. / IV	6.99	7490	118,000	157,000

(1) Utility ownership in not practical for this plant.

6.1.3 Inflation

It was assumed that there would be an inflation rate of 7-1/2 % per year over the life of the cogeneration facilities. This factor was applied to construction costs, operating labor, operating supplies, maintenance costs, property taxes, and insurance. Constant dollar energy escalation rates shown in Table 6.1-5 are added to the 7-1/2% general inflation rate.

6.1.4 Maintenance Requirements

The annual maintenance factor for new cogeneration and separate generation facilities was assumed to be 3% over the 28 year life of the equipment. Existing process steam boilers used to backup the cogeneration system were assumed to require negligible maintenance.

For existing process boilers less than 21 years old, levelized maintenance factors required to provide 28 years of additional service were estimated (see Figure 6.1-1). These estimates were based on the assumption that maintenance costs after the first 28 years of boiler life would be 10% greater than the sum of the normal maintenance factor and the sum-of-years-digits depreciation for a new boiler of the same configuration.

6.1.5 Stand-By Requirements

It was assumed that, for industry and third-party ownership, a contract would be made with the local utility for stand-by power equal to the generating capacity of the cogeneration facility.*

A scenario for process steam backup was developed as follows. For plants where existing process steam boilers are considered to be adequate for stand-by service for the 28-year cogeneration project life, it was assumed that this equipment would provide stand-by for process steam for utility and third-party ownership as well as for industry ownership. Where existing process steam boilers are not adequate for 28 years of stand-by service, the cogeneration system would consist of a 100% capacity cogeneration facility plus a new 100% capacity stand-by process steam boiler or three 50% capacity cogeneration modules for all three ownership categories.

*Recognizing that there are differences in opinion on the amount of standby power, we assumed that the standby power was equal to the design capacity.

Fig. 6. 1-1 — Levelized maintenance factor for 28 years additional service as function of process boiler age

6.1.6 Candidate Energy Conversion Subsystems

The candidate energy conversion subsystems which were considered are as follows:

Topping systems

- Conventional steam with extraction/back-pressure or extraction/condensing turbine
- Gas turbine with waste heat boiler
- Combined-cycle with extraction/back-pressure turbine
- Two-and four-stroke cycle diesel engines with waste heat boiler and possibly heat pump.

Bottoming systems

- Turbo-expanders
- Steam Rankine cycles
- Organic Rankine cycles
- Ammonia Rankine cycles.

These topping and bottoming cycles are characterized in Appendix C. The component performance numbers used in the optimization calculations for these candidate subsystems are values which approximate the composite of commercially available equipment.

6.1.7 Utility Central Station Model

The models of the utility central station used in calculating incremental cost of a cogeneration system for utility ownership and energy saved for all ownership categories are as follows:

Coal-fired

- Coal - high-sulfur bituminous
- Capacity - 1000 MW
- Capacity factor - 70%
- Particulate removal - ESP
- FGD process - limestone slurry
- Flue gas reheat technique - steam
- Heat rate - 9930 Btu (HHV)/kWh (TVA, 1976; and Bechtel, 1977)
[9500 Btu (LHV)/kWh]
- Specific cost (Dec. 1978 base) - 1000 \$/kW (Fluor, 1978; and TVA, 1976)

Oil fired

- Oil - low-sulfur residual
- Capacity - 1000 MW
- Heat rate - 8200 Btu (LHV)/kWh (TVA, 1975)
- Specific cost (Dec. 1978 base) - \$785/kW (UE&C, 1972).

It was assumed that the cogeneration system installation would be in lieu of new central station capacity. The transmission losses from the utility central station to the industrial plant were assumed to be 10%. The overall transmission losses for excess power generated by the cogeneration system then sold to the utility, and resold to industrial customers were also assumed to be 10%.

6.1.8 Process Steam Boiler Model for Separate Generation

Existing process steam boilers that are 21 years old or older are 92% depreciated assuming 28 years for depreciation life and using sum-of-years-digits depreciation rate. It was assumed, therefore, that any such process steam boiler would be scrapped and replaced with new equipment for the separate generation alternative.

For process steam boilers less than 21 years old, it was assumed that their operating lives could be extended for an additional 28 years (the depreciation life for the cogeneration facility) by increasing the level of maintenance appropriately.* It was also assumed that the fuel currently being used in these existing boilers would continue to be used during the extended life period.** Depreciation of the undepriciated capital investment for the existing boilers under 21 years old would be applicable to both separate and cogeneration (standby service) alternatives and so would cancel out in calculation of incremental costs for the industry ownership cases. It would not be included in cost analyses for utility and third-party ownership.

Replacement process steam boilers would be coal-fired when fuel energy input exceeds 100×10^6 Btu/hr. Oil and natural gas could be used in installations with energy inputs less than 100×10^6 Btu/hr.† Therefore, for the purposes of this study, it was assumed that oil or natural gas will be used in new process steam boilers with energy inputs less than 100×10^6 if these fuels are currently being used for process steam generation.

Table 6.1-11 describes the process steam boilers for future separate generation for each of the ten plants.

* The writing paper mill treated in this study is operating coal-fired process steam boilers which are approximately 60 years old.

** FUA gives DOE the authority to prohibit the use of gas or oil in individual existing industrial boilers with a fuel heat input rate of 100×10^6 Btu/hr or greater or aggregations of units of total input greater than 250×10^6 Btu/hr.

† FUA prohibits the use of oil or natural gas in new industrial boilers for individual units with a capacity of 100×10^6 Btu/hr or greater and an aggregation of units with a total input of 250×10^6 Btu/hr or greater. (FUA = fuel use act.)

TABLE 6.1-11

**DESCRIPTION OF PROCESS STEAM BOILERS FOR FUTURE SEPARATE GENERATION
(REFERENCE CASES FOR COGENERATION SYSTEMS)**

Industry	Type of Plant	Location State/ DOE Region	Age of Existing Process Steam Boilers - Years	Process Steam Boilers for Separate Generation	Fuel for Process Steam Boilers for Separate Generation	
Chemical	Agricultural Chemicals	Maryland / III	7 to 27	One Existing 43% Cap.	Low S Resid.	(4)
				One New 57% Cap.	Coal	
	Air Separation	Texas / IV	-	-	-	
Food	Brewery	Penna. / III	8	Three Existing 50% Capacity	Gas	(3)
	Soybean Oil Mill	Indiana / V	21	One New 100% Capacity	Gas	
Petroleum Refining	Large/ Complex	Calif. / IX	~ 25	New 100% Capacity (2)	Coal	(3)
	Medium/ Less Complex	Okla. / VI	-	-	-	
Pulp and Paper	Writing Paper Mill	Penna. / III	~ 60	Two New 50% Capacity	Coal	(5)
	Kraft Paper Mill	N. Hamp. / I	~ 40	One New 100% Capacity	Coal	(3)
Textile	Finishing Mill	S. Carol. / IV	~ 25	New 100% Capacity (1)	Coal	(3)
	Integrated Mill	Alabama / IV	~ 8	Two Existing 50% Cap.	Residual Oil	
				Two Existing 25% Cap.	Wood	

(1) One Boiler for 165 psia Steam and One for 325 psia Steam.

(2) One Boiler for Each of 880, 550, & 150 psig Pressures.

(3) Existing Boilers Which are Adequate for 28 Years Stand-by Service Provide 100% Back-up for These New Boilers.

(4) Other Existing Boilers Which Are Adequate for 28 Years Stand-by Service Provide Back-up for More Than 57% Of Required Capacity.

(5) Existing Boiler Will Provide 50% Back-up for 50% Capacity Module.

6.1.9 Fuels for Cogeneration

The Fuel Use Act of the 1978 National Energy Act prohibits the use of natural gas in new electric utility generating facilities or in new industrial boilers with a fuel heat input rate of 100×10^6 Btu/hr or greater. The law allows for a permanent exemption for cogenerating power-plants to burn oil or natural gas when less than half of the electric power generated is sold or exchanged for resale if the potential cogenerator can prove that he is unable to comply with the prohibitions of FUA and that there are specific economic benefits of cogeneration associated with the use of petroleum or natural gas which are not obtainable with an alternate fuel.

6.1.10 References to Section 6.1

Coffin, B. Dwight, "Estimating Capital and Operating Costs for Industrial Steam Plants", Power, April 1979, p. 106.

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TVA, "Cost Comparison of Commercial Atmospheric and Pressurized Fluidized Bed Power Plants to Conventional Power Plants with Flue Gas Desulfurization", Prepared for EPA by TVA, March 1976. †

UE&C, "1000-MWE Central Station Power Plants Investment Cost Study," WASH-1230, Vol. III and IV, Prepared for U.S. Atomic Energy Commission by United Engineers and Constructor, June 1972.

Williams, Robert H., "Industrial Cogeneration", Report #66, Center for Environmental Studies, Princeton University, May 1978.

Resource Planning Associates Inc. (RPA), "The Potential for Cogeneration Development in Six Major Industries by 1985," RPA Reference No. RA-77-1018, RPA, Cambridge, Massachusetts, for the Department of Energy, Office of Conservation and Solar Applications; Project Director, Peter Bos (RPA); Project Manager (RPA), James Williams; Project Manager, Burns & Roe, Jerome Morton; December 1977.

Winton, John M., "Plant Sites - 1979", Chemical Week, Nov. 1, 1978, p. 41-54.

Bechtel Power Corporation, "Coal-fired Power Plant Capital Cost Estimates." EPRI Report AF-342, prepared by Bechtel Power Corporation, January 1977.

6.2 OPTIMIZING A COGENERATION SYSTEM - AGRICULTURAL CHEMICAL PLANT EXAMPLE

An example of the procedure followed for selecting and optimizing a cogeneration system is given here for the commonly found system involving a steam turbine/generator. The agricultural chemicals plant is located in Maryland (DOE Region III). The peak electrical energy requirement is 7200 kW. The annual energy requirements for the entire plant are as follows:

- Process heat (sat'd steam) 361.9×10^6 kWh/yr
- Electricity 50.5×10^6 kWh/yr

The candidate energy conversion subsystems under consideration were the coal-fired steam plant with FGD and a low-sulfur residual-oil fired gas turbine with WHB.

The residual oil-fired gas turbine was rejected on the basis of poor ROE for all three ownership options, a result of the poor match between the required ratio of process heat to electricity (7.17) and the actual ratio produced by a GT/WHB System (1.0 to 2.0). The conventional coal-fired steam boiler using a BPT was selected for consideration because it produced good ROE's for all ownership options and had a process heat to electricity ratio of 8.3.

Figure 6.2-1 shows the energy utilization system model. Table 6.2-1 shows conditions at each of the indicated state points. Figure 6.2-2 shows the cogeneration system configuration for the agricultural chemicals plant cogeneration facility. The throttle pressure of the back-pressure steam turbine is the only significant design parameter having an effect on energy savings and equipment costs. Figures 6.2-3a, 6.2-3b, and 6.2-3c contain the optimization curves for the two successful ownership options, utility and third-party. The industrial ownership case failed to provide an acceptable ROE since only 57% of the existing steam generating capacity need be replaced by coal-burning units under separate generation. The incremental capital costs are thereby made significantly higher, preventing the increase in cycle efficiency from yielding positive results. In both cases, higher operating pressures result in a slight decrease in the return on equity as overall energy efficiency and savings are improved. The optimum plant was chosen to be that using a throttle pressure of 1215 psia, the highest pressure possible at the power rating of the plant (10,880 kW). Table 6.2-2 contains the state point conditions for the configuration in Figure 6.2-2. The boiler is a pulverized coal-fired unit burning Ohio Pittsburgh No. 8 seam coal. The combustion air is preheated to 540°F by an air heater at the stack. The properties of the feedstock coal are given in Table 6.2-3.

After partial expansion through the steam turbine, steam exhausts at 175 psia to the process in Figure 6.2-1, and provides as well the heat required by the flue gas reheater downstream of the FGD system and for deaeration of the condensate return.

Fig. 6 .2-1 – Model of process heat utilization subsystem for agricultural chemicals plant with coal-fired steam energy conversion subsystem

Fig. 6.2-2 - Model of energy conversion subsystem for agricultural chemicals plant

Fig. 6.2-3a - Annual energy savings vs return on equity, industry ownership

Fig. 6.2-3b - Annual energy savings vs return on equity, utility ownership

Fig. 6.2-3c - Annual energy savings vs return on equity, third party ownership

TABLE 6.2-1

STATEPOINTS FOR ENERGY UTILIZATION SUBSYSTEM IN AGRICULTURAL CHEMICALS PLANT

STATION	PRESSURE (psia)	TEMPERATURE (F°)	ENTHALPY (Btu/lb)	FLOW RATE (lb/s)
1	175	535.4	1290.6	53.40
2	>15	330	301.0	9.35
3	15	100	68.0	44.05
4	>15	140	108.8	53.40
5	39.8	140	108.8	53.40

TABLE 6.2-2

STATEPOINTS FOR CONVERSION SUBSYSTEM IN AGRICULTURAL CHEMICALS PLANT

STATION	PRESSURE (psia)	TEMPERATURE (F°)	ENTHALPY (Btu/lb)	FLOW RATE (lb/s)
1	14.7	77	0.8	89.65
2	16.1	85	2.0	89.65
3	15.9	510	112.7	89.65
4	15.7	3212.9	928.9	98.60
5	15.5	2006.5	540.9	96.60
6	15.2	1423.0	364.0	96.60
7	15.2	1423.0	364.0	96.60
8	14.9	682.0	155.1	96.60
9	14.7	279.0	50.3	96.60
20	39.8	139.8	107.8	53.40
21	29.8	250.0	218.6	60.01
22	1340.0	253.5	224.8	60.01
23	1315.0	558.9	560.5	60.01
24	-----	-----	-----	-----
25	-----	-----	-----	-----
26	1265.0	573.9	580.8	314.44
27	1265.0	573.9	700.0	314.44
28	1265.0	573.9	1195.6	60.01
29	1215.0	945.5	1467.9	60.01
30	175.0	535.4	1290.6	60.01
31	175.0	535.4	1290.6	0.99
32	175.0	535.4	1290.6	59.02
33	175.0	535.4	1290.6	5.62
34	175.0	535.4	1290.6	53.40

TABLE 6.2-3
FUEL SPECIFICATIONS
OHIO PITTSBURGH NO. 8 SEAM COAL

(Source of data: USBM, Pittsburgh, PA)

SAMPLE: Run of mine		As received ⁽¹⁾	As fired ⁽²⁾	
PROXIMATE ANALYSIS (wt %):	Volatile matter	42.8	46.8	
	Fixed carbon	48.7	45.3	
	Ash	8.5	7.9	
		<u>100.0</u>	<u>100.0</u>	
ULTIMATE ANALYSIS (wt %): (includes moisture)	C	71.2	66.3	
	H	5.4	5.8	
	O	9.3	14.6	
	N	1.3	1.2	
	S(3)	4.3	4.0	
	Ash	8.5	7.9	
		<u>100.0</u>	<u>100.0</u>	
GROSS HEATING VALUE:	(Btu/lb)	13000	12099	
NET HEATING VALUE:	(Btu/lb)	12500	11634	
ASH ANALYSIS (wt %):	SiO ₂	45.3		
	Al ₂ O ₃	21.2		
	Fe ₂ O ₃	27.3		
	TiO ₂	1.0		
	P ₂ O ₅	0.11		
	CaO	1.9		
	MgO	0.6		
	Na ₂ O	0.2		
	K ₂ O	1.8		
	SO ₃	0.7		
		<u>100.1</u>		
	FUSIBILITY OF ASH:	Initial deformation temperature	--	2080°F
		Softening temperature	--	2230°F
Fluid temperature		--	2420°F	
PARTICLE DENSITY:	Coal	--	~1.4 gm/cc	
	Ash	--	~2.8 gm/cc	
GRINDABILITY (Hardgrove):	50-60			
FREE SWELLING INDEX:	5-5.5			
(1) 3.3% moisture				
(2) 10% moisture assumed				
(3) ~60% organic & 40 pyritic				

The energy distribution summary is shown in Table 6.2-4. The ideal energy utilization factor (IEUF) was 0.8739, and the ratio of process heat to electricity was 8.30, meaning that a small amount of supplemental power must be purchased. The preliminary capital costs of the cogeneration system are shown in Table 6.2-5.

These costs and the economic and financial data appropriate to the company and the region involved are used to analyze the cash flow over the specified project life. The DCFROE was computed for the optimum case. These assumptions are presented in Table 6.2-6. The detailed results of the DCFROE calculation, as well as the specific contributions of the cash flow vector, are given in Tables 6.2-7a, 6.2-7b and 6.2-7c, for the industrial, utility, and third-party ownership options, respectively. The system configurations were identical for all three ownership options.

TABLE 6.2-4

POWER SUMMARY - AGRICULTURAL CHEMICALS PLANT

HP STEAM PWR=	7015.7991 KW
LP STEAM PWR=	3868.5752 KW
ST POWER=	10884.3741 KW
GROSS POWER	= 10884.3741 KW
FGD AUXILIARIES	= 1680.9429 KW
AUXILIARY POWER	= 640.0930 KW
BOILER FEED PUMP POWER	= 372.9561 KW
NET POWER GENERATED	= 8190.3822 KW
TOTAL FUEL=	6.9548 LB/SEC
THERMAL RATING -	291285008.0000 BTU/HR
HEAT RATE	35564.2749 BTU/KWHR
TOTAL PROCESS HEAT =	.2274+009 BTU/HR
PROCESS HEAT AT 175.0 PSIA =	.2274000+009 BTU/HR
RPHEE =	8.2975 KWT/KWE
IEUF =	.8739

TABLE 6.2-5

AGRICULTURAL CHEMICALS

SUMMARY OF CAPITAL COSTS: DEC. 1978 \$

STEAM GENERATOR COST (INSTALLED)	= \$ 5731856.4
STEAM GENERATOR BOP COSTS	= \$ 7164820.5
TURBINE GENERATOR COST (INSTALLED)	= \$ 1936693.0
TURB-GEN BOP COSTS	= \$ 1936693.0
FLUE GAS DESULF COSTS (INST+BOP)	= \$ 2261916.6
TOTAL DIRECT COSTS	= \$19031979.2
INDIRECT COSTS	= \$ 2854796.9
ENGINEERING	= \$ 1903197.9
CONTINGENCY (20%)	= \$ 3806395.8
SUBTOTAL	= \$27596369.8
INTEREST DURING CONSTRUCTION (36 mo.)	= \$ 4567199.0
ESCALATION DURING CONSTRUCTION	= \$ 3343257.0
TOTAL CAPITAL COST	= \$35506825.8
SPECIFIC CAPITAL COST (\$/kWt)	= 416.03

TABLE 6.2-6

RATE OF RETURN ON EQUITY SUMMARY
FOR INDUSTRIAL COGENERATION

ENERGY UTILIZATION SYSTEM CHARACTERIZATION
 AGRICULTURAL CHEMICALS PLANT

REQUIRED RATIO OF PROCESS HEAT/ELECTRICITY	=	7.1700
REQUIRED PROCESS HEAT	=	361867820.0 (KWH/YR)
REQUIRED ELECTRIC POWER	=	50469709.5 (KWH/YR)
SUPPLEMENTAL ELECTRIC POWER PURCHASED	=	6858041.5 (KWH/YR)
ASSUMED CAPACITY FACTOR	=	.6200
ASSUMED STANDBY POWER FRACTION	=	1.0000

ENERGY CONVERSION SYSTEM CHARACTERIZATION
 COAL-FIRED STEAM WITH BPT

ACTUAL RATIO OF PROCESS HEAT/ELECTRICITY	=	8.2975
IDEAL ENERGY UTILIZATION FACTOR	=	.8739
SPECIFIC CAPITAL COST OF CONVERSION SYSTEM	=	416.0350 (\$/KWT)
INCR. LABOR COST (INDUSTRY) (1ST YEAR)	=	219886.5371 (\$)
INCR. LABOR COST (UTILITY) (1ST YEAR)	=	218644.2402 (\$)
INCR. LABOR COST (3RD PARTY) (1ST YEAR)	=	437288.4805 (\$)

TABLE 6.2-6 (CONT'D)

AGRICULTURAL CHEMICALS
ECONOMIC AND FINANCIAL ASSUMPTIONS

DEBT / EQUITY RATIO (INDUSTRY)	=	.5000
DEBT / EQUITY RATIO (UTILITY)	=	1.1000
DEBT / EQUITY RATIO (3RD PARTY)	=	5.0000
LIFE OF PROJECT	=	28 (YEARS)
LIFE OF INVESTMENT FOR TAX PURPOSES	=	28 (YEARS)
INCOME TAX RATES (FEDERAL + STATE)	=	.5300 (%/100)
INTEREST RATE ON DEBT	=	.1000 (%/YR/100)
INVESTMENT TAX CREDIT RATE	=	.2000 (%/100)
ITCR UNDER SEPARATE GENERATION (INDUSTRIAL)	=	.2000 (%/100)
ITCR UNDER SEPARATE GENERATION (UTILITY)	=	.1000 (%/100)
PROPERTY TAX RATE (1ST YEAR)	=	.0150 (%/100)
INSURANCE RATE (1ST YEAR)	=	.0150 (%/100)
CHARGE FOR STANDBY POWER	=	66.1108 (\$/KW)
MAINTENANCE & SUPPLIES COST FACTOR (1ST YR)	=	.0375 (%/100)
BOILER HEAT RATE (SEPARATE GENERATION)	=	3750.0000 (BTU/KWH)
CENTRAL STATION BUS BAR HEAT RATE	=	9500.0000 (BTU/KWH)
TRANSMISSION LOSSES OF PURCHASED POWER	=	.1000 (%/100)
SPECIFIC CAPITAL COST OF NEW UTILITY STATION	=	1000.0000 (\$/KW)
PRICE OF PROCESS STEAM (1ST YR)	=	6.0816 (\$/10^6 BTU)
PRICE OF POWER AT CENTRAL STATION BUS BAR	=	.0272 (\$/KWH)
PRICE OF POWER BOUGHT FROM UTILITY (1ST YR)	=	.0454 (\$/KWH)
PRICE OF POWER SOLD TO UTILITY (1ST YR)	=	.0272 (\$/KWH)
PRICE OF FUEL (COGENERATION)	=	1.7262 (\$/10^6 BTU)
PRICE OF FUEL, (SEP.GEN.: INDUSTRY)	=	3.2162 (\$/10^6 BTU)
PRICE OF FUEL (SEP.GEN.: UTILITY)	=	1.7262 (\$/10^6 BTU)
GENERAL INFLATION RATE	=	.0750 (%/100/YR)
FUEL PRICE RELATIVE ESC.(COGENERATION FUEL)	=	.0560 (%/100/YR)
FUEL PRICE REL. ESC.(SEP.GEN.: INDUSTRY)	=	.0510 (%/100/YR)
FUEL PRICE REL. ESC.(SEP.GEN.: UTILITY)	=	.0560 (%/100/YR)
RELATIVE ESC. OF ELECTRICAL ENERGY COSTS	=	.0210 (%/100/YR)
RELATIVE ESC. OF PROCESS STEAM COSTS	=	.0300 (%/100/YR)

TABLE 6.2-7a

AGRICULTURAL CHEMICALS
FOR INDUSTRIAL OWNERSHIP

INCREMENTAL CAPITAL INVESTMENT = 26390130 (\$)
NET INCREMENTAL EQUITY CAPITAL INVESTMENT = 14074736 (\$)

YEAR	NET SAVINGS IN ELECT	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	INCOME TAXES ON SAVINGS
1	1447018.	-1629101.	1551392.	791704.	-1042328.
2	1588211.	-1825897.	1667746.	851082.	-921882.
3	1743181.	-2046254.	1792827.	914913.	-788632.
4	1913271.	-2292963.	1927289.	983531.	-640911.
5	2099959.	-2569139.	2071836.	1057296.	-476848.
6	2304862.	-2878262.	2227224.	1136593.	-294347.
7	2529759.	-3224216.	2394266.	1221838.	-91057.
8	2776600.	-3611336.	2573835.	1313476.	135652.
9	3047527.	-4044460.	2766873.	1411986.	388729.
10	3344890.	-4528986.	2974388.	1517885.	671470.
11	3671267.	-5070933.	3197468.	1631727.	987564.
12	4029491.	-5677015.	3437278.	1754106.	1341136.
13	4422669.	-6354717.	3695073.	1885664.	1736796.
14	4854210.	-7112383.	3972204.	2027089.	2179691.
15	5327860.	-7959309.	4270119.	2179120.	2675575.
16	5847726.	-8905853.	4590378.	2342554.	3230865.
17	6418318.	-9963549.	4934656.	2518246.	3852724.
18	7044585.	-11145243.	5304755.	2707114.	4549141.
19	7731960.	-12465232.	5702612.	2910148.	5329022.
20	8486406.	-13939426.	6130308.	3128409.	6202294.
21	9314467.	-15585524.	6590081.	3363040.	7180015.
22	10223326.	-17423211.	7084337.	3615267.	8274498.
23	11220867.	-19474367.	7615662.	3886413.	9499448.
24	12315743.	-21763313.	8186837.	4177893.	10870116.
25	13517451.	-24317067.	8800849.	4491235.	12403463.
26	14836416.	-27165631.	9460913.	4828078.	14118344.
27	16284079.	-30342313.	10170481.	5190184.	16035710.
28	17872998.	-33884077.	10933267.	5579447.	18178835.

YEAR	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	895680	785891
2	937490	721748
3	990655	669192
4	1056653	626282
5	1137142	591374
6	1233983	563075
7	1349258	540208
8	1485302	521784
9	1644728	506966
10	1830460	495056
11	2045770	485468
12	2294315	477712
13	2580182	471382
14	2907938	466141
15	3282683	461711
16	3710110	457866
17	4196570	454418
18	4749147	451217
19	5375739	448144
20	6085150	445103
21	6887185	442018
22	7792764	438833
23	8814040	435504
24	9964538	432000
25	11259299	428300
26	12715041	424388
27	14350347	420259
28	16185854	415911

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY (ROE) = 13.97 %
ANNUAL ENERGY SAVED UNDER COGENERATION = 240068.2812 MBTU/YR

TABLE 6.2-7b

AGRICULTURAL CHEMICALS
FOR UTILITY OWNERSHIP

INCREMENTAL CAPITAL INVESTMENT = 26444468 (\$)
NET INCREMENTAL EQUITY CAPITAL INVESTMENT = 11333343 (\$)

YEAR	STEAM REVENUE	DELTA ELECT. REVENUE	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	TAXES
1	7515462.	914227.	1940587.	1210312.	793334.	676552.
2	8321496.	1003432.	2202954.	1301085.	852834.	966850.
3	9213976.	1101342.	2500793.	1398667.	916797.	1282805.
4	10202174.	1208806.	2838901.	1503566.	985556.	1626791.
5	11296357.	1326755.	3222720.	1616334.	1059473.	2001375.
6	12507891.	1456213.	3658432.	1737559.	1138934.	2409331.
7	13849362.	1598303.	4153052.	1867876.	1224354.	2853651.
8	15334706.	1754258.	4714544.	2007967.	1316180.	3337553.
9	16979353.	1925429.	5351950.	2158564.	1414894.	3864498.
10	18800388.	2113303.	6075534.	2320456.	1521011.	4438196.
11	20816729.	2319508.	6896946.	2494491.	1635086.	5062620.
12	23049323.	2545834.	7829413.	2681577.	1757718.	5742011.
13	25521362.	2794244.	8887949.	2882696.	1889547.	6480883.
14	28258527.	3066893.	10089600.	3098898.	2031263.	7284034.
15	31289253.	3366145.	11453714.	3331315.	2183607.	8156540.
16	34645025.	3694596.	13002255.	3581164.	2347378.	9103754.
17	38360703.	4055096.	14760160.	3849751.	2523431.	10131300.
18	42474887.	4450772.	16755734.	4138482.	2712688.	11245059.
19	47030318.	4885056.	19021109.	4448868.	2916140.	12451147.
20	52074318.	5361716.	21592762.	4782533.	3134850.	13755882.
21	57659288.	5884885.	24512104.	5141223.	3369964.	15165750.
22	63843244.	6459102.	27826139.	5526815.	3622711.	16687345.
23	70690431.	7089349.	31588233.	5941326.	3894415.	18327303.
24	78271977.	7781092.	35858961.	6386925.	4186496.	20092210.
25	86666646.	8540332.	40707092.	6865944.	4500483.	21988500.
26	95961642.	9373655.	46210691.	7380890.	4838019.	24022308.
27	106253525.	10288289.	52458375.	7934457.	5200870.	26199309.
28	117649212.	11292169.	59550747.	8529541.	5590936.	28524514.

YEAR	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	3217052	2353194
2	3468852	1856031
3	3747866	1466842
4	4056536	1161326
5	4397497	920882
6	4773596	731213
7	5187900	581286
8	5643714	462554
9	6144584	368375
10	6694318	293564
11	7296994	234067
12	7956970	186700
13	8678891	148957
14	9467701	118861
15	10328643	94850
16	11267261	75686
17	12289401	60385
18	13401197	48166
19	14609064	38408
20	15919670	30615
21	17339909	24392
22	18876861	19423
23	20537732	15458
24	22329786	12294
25	24260255	9770
26	26336222	7758
27	28564487	6155
28	30951393	4878

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY (ROE) = 36.71 %

ANNUAL ENERGY SAVED UNDER COGENERATION = 240068.2812 MBTU/YR

TABLE 6.2-7c

AGRICULTURAL CHEMICALS
FOR THIRD PARTY OWNERSHIP

INCREMENTAL CAPITAL INVESTMENT = 35506814 (\$)
NET EQUITY CAPITAL INVESTMENT = 4734241 (\$)

YEAR	STEAM REVENUE	DELTA ELECT. REVENUE	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	TAXES
1	7515462.	1447018.	2735250.	1768794.	1065204.	-1067640.
2	8321496.	1588211.	3105055.	1901453.	1145095.	-827907.
3	9213976.	1743181.	3524859.	2044062.	1230977.	-570003.
4	10202174.	1913271.	4001420.	2197367.	1323300.	-292519.
5	11296357.	2099959.	4542411.	2362170.	1422548.	6022.
6	12507891.	2304862.	5156545.	2539332.	1529239.	327151.
7	13849362.	2529759.	5853710.	2729782.	1643931.	672455.
8	15334706.	2776600.	6645132.	2934516.	1767226.	1043555.
9	16979353.	3047527.	7543553.	3154605.	1899768.	1442103.
10	18800388.	3344890.	8563442.	3391200.	2042251.	1869753.
11	20816729.	3671267.	9721219.	3645540.	2195420.	2328144.
12	23049323.	4029491.	11035527.	3918955.	2360076.	2818866.
13	25521362.	4422669.	12527530.	4212877.	2537082.	3343429.
14	28258527.	4854210.	14221252.	4528843.	2727363.	3903212.
15	31289253.	5327860.	16143965.	4868506.	2931915.	4499410.
16	34645025.	5847726.	18326629.	5233644.	3151809.	5132971.
17	38360703.	6418318.	20804389.	5626167.	3388194.	5804511.
18	42474887.	7044585.	23617142.	6048129.	3642309.	6514221.
19	47030318.	7731960.	26810180.	6501739.	3915482.	7261755.
20	52074318.	8486406.	30434915.	6989369.	4209143.	8046089.
21	57659288.	9314467.	34549715.	7513572.	4524829.	8865361.
22	63843244.	10223326.	39220836.	8077090.	4864191.	9716684.
23	70690431.	11220867.	44523492.	8682871.	5229005.	10595917.
24	78271977.	12315743.	50543068.	9334086.	5621180.	11497400.
25	86666646.	13517451.	57376489.	10034143.	6042769.	12413647.
26	95961642.	14836416.	65133790.	10786703.	6495976.	13334971.
27	106253525.	16284079.	73939876.	11595706.	6983174.	14249069.
28	117649212.	17872998.	83936547.	12465384.	7506913.	15140516.

YEAR	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	1501971.	1067727.
2	1627108.	822268.
3	1768360.	635281.
4	1926976.	492119.
5	2104264.	382026.
6	2301585.	297042.
7	2520342.	231233.
8	2761976.	180139.
9	3027950.	140390.
10	3319731.	109418.
11	3638773.	85259.
12	3986487.	66401.
13	4364211.	51676.
14	4773166.	40178.
15	5214415.	31202.
16	5688797.	24199.
17	6196859.	18739.
18	6738769.	14486.
19	7314222.	11177.
20	7922307.	8606.
21	8561377.	6612.
22	9228868.	5067.
23	9921110.	3872.
24	10633083.	2950.
25	11358149.	2240.
26	12087717.	1695.
27	12810877.	1277.
28	13513950.	958.

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY (ROE) = 40.67 %

ANNUAL ENERGY SAVED UNDER COGENERATION = 240068.2812 MBTU/YR

The final table, Table 6.2-8 presents the fuel energy savings to be expected as a result of the installation of a cogeneration system rather than a conventional single-purpose boiler. The net results are a reduction in the consumption of low-sulfur residual and an increase in the consumption of coal with a 12% overall savings.

TABLE 6.2-8

FUEL REQUIREMENTS-AGRICULTURAL CHEMICALS PLANT

	Separate Generation (MBtu/yr)*	Cogeneration (MBtu/yr)	Savings (MBtu/yr)
Gas	-	-	-
Oil (Low Sulfur Residual)	583512	-	583512
Coal	1306227	1649671	-343444
Overall	1889739	1649671	240068

Percent Energy Saved = 12.2%

*Throughout Section 6 and Appendix C, MBtu is to be interpreted as million Btu in accord with power generation practice.

6.3 SUMMARY OF OPTIMIZED COGENERATION SYSTEMS

A similar analysis was performed for each of the other plants considered in this study. The results of the cogeneration system optimization for the ten industrial plants are summarized in Table 6.3-1. Details are presented in Appendix C.

The optimum cogeneration systems for four of the plants (agricultural chemicals, brewery, soybean oil mill, and writing paper mill) were coal-fired steam cycles with back pressure turbines. The brewery employed a steam accumulator for short-duration peak demands. The optimum system for the integrated textile mill was a wood-fired steam cycle with a back pressure turbine.

A coal-fired steam cycle with a single automatic extraction/back pressure turbine was the optimum system for the textile finishing mill. A coal-fired steam cycle with a double automatic extraction/back pressure turbine was the optimum system for kraft paper mill.

The optimum cogeneration system for the air separation plant was a natural gas-fired gas turbine with a waste heat boiler. A combined cycle with a single automatic extraction/back pressure steam turbine was the optimum system for the large, complex petroleum refinery. The gas turbine combustor was fired with naphtha and the heat recovery steam generator was fired with low sulfur residual oil.

The only plant where a bottoming cycle was feasible is the medium size, medium complexity petroleum refiner. The optimum bottoming system for this plant consists of a turbo-expander for recovering energy from the 55 psia effluent from a heavy oil catalytic cracker catalyst regenerator, heat exchangers for partially recovering the waste heat from the exhaust of the turbo-expander by superheating by-product steam from the catalytic cracker, and the catalyst regenerator for use in condensing mechanical drive steam turbines and a double automatic extraction/condensing generator drive steam turbine, and a methanol Rankine bottoming cycle for completing the recovery of waste heat from the turbo-expander exhaust.

For all sites except one (the large petroleum refinery), it was assumed that new central station generating capacity for the local utility would be coal-fired steam. It was assumed that new central station generating capacity for the utility which serves the large petroleum refinery would be residual oil-fired steam since all existing steam plants in that utility burn residual oil. Subsequent to this decision, the federal government proposed that all new steam plants be prohibited from burning oil so a coal-fired steam plant should have been assumed for the utilities serving all ten of the plants.

In all cases the optimum cogeneration systems for all ownership categories had the same design parameters.

TABLE 6.3-1
SUMMARY OF PLANT OPTIMIZATION RESULTS

Industry	Type of Plant	Location State/DOE Region	Energy Conversion System Configuration	Cogeneration Fuel	Return on Equity - %			Energy Savings - 10 ⁶ Btu/yr				
					Industry Ownership	Utility Ownership	Third Party Ownership	Total	Nat. Gas	Fuel Oil	Coal	Other
Chemical	Agricultural Chemicals	Maryland / III	Conventional Steam With Back Pressure Turbine	Coal	(3) 17-22 14.0 21	(5) 12 36.7 13.2	40.7	(12.2%) 240,068	-	583,512	-343,444	-
	Air Separation	Texas / VI	Gas Turbine With Waste Heat Boiler	Natural Gas	(2) 13.9 21	(5) 11.5 > 1000 13.7	20.0	(29.9%) 2,488,484	-3,113,435	-	5,601,919	-
Food	Brewery	Penna. / III	Conventional Steam With Back Pressure Turbine and Steam Accumulator	Coal	(4) 12.2 16	(5) 11.9 18.2 11.5	< 0	(10.6%) 85,997	-	645,290	-559,293	-
	Soybean Oil Mill	Indiana / V	Conventional Steam With Back Pressure Turbine	Coal	(4) 12.2 16	(6) 0 13.7 11.3	< 0	(6.7%) 46,300	544,270	-	-497,970	-
Petroleum Refining	Large/Complex	Calif. / IX	Combined Cycle With Single Extraction/Back Pressure Turbine	Naphtha/Low Sulfur Residual	15 < 0 25	(5) 10.3 > 1000 10.8	< 0	(23.1%) 7,903,218	-	26,067,430	-	-18,080,739 (Naphtha)
	Medium/Less Complex	Oklahoma / VI	Turbo Expander/Steam Rankine/Organic Rankine	None (Bottoming Cycle)	(1) 10-15 88.3 25	-	-	(100%) 3,150,760	-	-	3,150,760	-
Pulp and Paper	Writing Paper Mill	Penna. / III	Conventional Steam With Back Pressure Turbine	Coal	< 0 16.5	(5) 10.6 23.7 11.3	< 0	(14.1%) 456,322	501,485	-	-45,163	-
	Kraft Paper Mill	N. Hamp. / I	Conventional Steam With Double Extraction/Back Pressure Turbine	Coal	< 0 16.5	(7) 42.2 11.5	37.0	(13.7%) 325,891	-	1,728,068	-1,402,177	-
Textile	Finishing Mill	S. Carol. / IV	Conventional Steam With Single Extraction/Back Pressure Turbine	Coal	< 0 24	(5) 12.4 29.8 13.2	20.4	(16.7%) 497,536	1,585,158	640,412	-1,728,033	-
	Integrated Mill	Alabama / IV	Conventional Steam With Back Pressure Turbine	Wood	< 0 24	(5) 8.8 34.0 13.2	< 0	(11.4%) 297,192	1,134,559	-	408,031	-1,245,397 Wood

- (1) Meets Both Company Specific and Industry ROE Hurdle Rates
 (2) Meets Only Company Specific ROE Hurdle Rate
 (3) Does Not Meet Either Company Specific or Industry ROE Hurdle Rate
 (4) Does Not Meet Industry ROE Hurdle Rate. Company Specific ROE Hurdle Rate Not Known
 (5) Exceeds Both Utility Specific ROE for 1978 and Utility Region ROE for 1978
 (6) Municipal Utility Supplies This Plant. ROE Exceeds 1978 ROE for Privately Owned Utilities in This Region
 (7) Exceeds 1978 ROE for Utility Region. Utility Specific ROE Not Known

Key to Return on Equity Format

	b
a	
	c

- a. Discounted Cash Flow Return on Equity
 b. Company Specific ROE Hurdle Rate
 c. Industry Specific ROE Hurdle Rate

Only one plant (medium petroleum refinery) has an ROE for industry ownership which meets both the company-specific and industry ROE hurdle ratio (see Table 6.1-2). One plant (air separation) has an ROE for industry ownership which meets the company specific ROE hurdle rate but does not meet the industry hurdle rate. One plant (agricultural chemicals) has an ROE which does not meet either the company specific or the industry ROE hurdle rate. The company specific ROE hurdle rates are not known for the brewery and the soybean oil mill. The ROE values for these two plants do not, however, meet the industry hurdle rates. The other five plants have ROE values for industry ownership that are less than zero which means that the discounted cash flow over the project life is negative (incremental expenses exceed incremental revenues).

The one plant which shows outstanding economic potential for industry ownership is the medium-sized petroleum refinery, wherein a maximum recovery bottoming cycle gives a 88% ROE compared to a bottoming cycle configuration which just meets the on-site process steam and electric power requirements.

All of the topping cycle plants have ROE values which exceed both the utility specific and the utility regional average return-on-equity for 1978 (see Table 6.1-2). Two of the plants have ROE values greater than 1000% which means that the net incremental equity capital investment (cost of cogeneration facility minus cost of equivalent amount of central station capacity) is negative. There is no utility specific ROE for the utility which serves the soybean oil mill since it is a municipal utility.

The ROE hurdle rate for third-party ownership is assumed to be 20%. Four of the topping cycle plants (agricultural chemicals, air separation, kraft paper mill, and textile finishing mill) have ROE values for third-party ownership which equal or exceed 20%. The other five plants have ROE values for third-party ownership that are less than zero. Here again, this means that the discounted cash flow over the project life is negative (expenses exceed revenues).

Those cases where the ROE is less than the hurdle rates can be improved in a variety of ways such as a) effectively decreasing the net equity capital investment via increased investment tax credits; b) by increasing the present worth of depreciation allowances; and/or c) increasing revenues by reducing standby power charges.

A preliminary sensitivity analysis indicated that an investment tax credit rate of 35% is required to meet the 17% company-specific ROE hurdle rate for the agriculture chemical plant and a value of 49% is required to meet the industry-specific ROE hurdle rate of 21%.

A depreciation life of about 9 years is required to attain the 17% company-specific ROE hurdle rate for the agricultural chemicals plant while a depreciation life of only about 3 years would be required to attain the industry-specific ROE hurdle rate of 21%.

ROE is a rather weak function of stand-by power charges for conventional steam energy conversion systems where the ratio of process heat to electrical energy generated is high. Decreasing the stand-by power charge for the agricultural chemicals plant to zero increased the ROE from 14 to 16.25% which still does not meet either the company-specific or industry ROE hurdle rates.

For the air separation plant where the ratio of process heat to electrical energy for the energy conversion system is low and the electrical demand is matched, ROE is a strong function of stand-by power charges. Decreasing the stand-by charge to zero for this plant increased the ROE for industrial ownership from 13.9 to 36.7% which exceeds both the company-specific and the industry ROE hurdle rates. The ROE for third-party ownership increased from 20 to 26.7%.

Reducing the stand-by charges to zero increases the ROE's for industrial ownership for the brewery and the soybean oil mill from 12.2 to 12.8%. In both cases, the ROE is still below the industry hurdle rate. The ROE's for third-party ownership stayed below zero.

Those cases where the ROE is less than 0% cannot be helped by increasing the investment tax credit since it does not affect the expense or revenue (savings) components. Here again, shortening the depreciation/project life would help in that the present value of the depreciation credits would be increased, and the only way to increase revenues (savings) would be to reduce the stand-by power charges.

For the large-capacity petroleum refinery where the cogeneration system has a low process-heat-to-electrical-energy ratio and about 50% of the electricity generated is exported, the ROE is a weak function of the stand-by power charges. The ROE's for both industrial and third-party ownership are still less than zero when the stand-by power charge is reduced to zero.

The large petroleum refinery ROE's for both industrial and third-party ownership would be improved by increasing the price for the excess power sold to the local utility. This utility specifies a price for power purchases which is only 47.5% of the price charged the industry, whereas a ratio of 0.6 was assumed for all of the other plants.

The incremental central station capacity for the utility serving the large petroleum refinery was assumed to be fired with a low-sulfur residual oil fired steam plant. If coal is assumed rather than oil, the discounted cash flow rate of return on equity becomes negative for the utility ownership case as well as for the industry and third-party ownership cases because of the relatively low price of coal in that area over the lifetime of the installation.

The design, operating, and economic factors associated with the ten industrial plants optimized in this study are so diverse that it is extremely difficult to reach general conclusions regarding the factors which favor cogeneration and those that discourage it. Prior to the start of the cogeneration system optimization for the various plants, a sensitivity analysis was made to identify those factors which have the greatest effect on return-on-investment. The industry model was the soybean oil plant x 10. The cogeneration system model was a coal-fired steam system with back pressure turbine. Those factors which were found to have the highest sensitivity were:

- Cost of cogeneration system
- Debt to equity ratio
- Cost of central station generating capacity
- Price of process steam under utility and third-party ownership
- Investment tax credit rate

Those factors which had moderate sensitivity were:

- Price of power sold to utility for industry and third-party ownership
- Central station heat rate for utility ownership
- Power transmission losses under utility ownership
- Process steam boiler efficiency under separate generation for industry ownership
- Maintenance cost factor
- General inflation rate
- Property taxes and insurance rates
- Depreciation/project life
- Incremental labor costs

Those factors which were found to have low sensitivity were:

- Incremental cost of supplies and chemicals
- Stand-by power fraction
- Charge for stand-by power .

The above results will not necessarily hold for cogeneration systems with substantially different characteristic ratios of process heat to electrical energy.

6.4 TECHNOLOGICAL ASPECTS

In selecting and optimizing cogeneration systems, one often encounters technological limitations. Technology developments in cogeneration which have the potential for increasing the energy saved or return on investment include:

1. Development of higher throttle pressure for small industrial steam turbines.
2. Development of gas turbines with compressor pressure ratios of about 8 and using state-of-the-art expander inlet temperatures ($\sim 2100^{\circ}\text{F}$).
3. Development of heat exchangers for coal-fired closed cycle or exhaust heated gas turbines which are capable of heating air significantly higher than the temperature levels currently used in European closed cycle installation. (Fluidized bed combustion is considered to have the highest potential for fired heat exchangers of this type).
4. Technological verification for new applications of near-term technology.

In addition, there appears to be a need for instruments and controls for cogeneration systems and for energy management in order to ensure that potential savings are realized in implementing a cogeneration system.

6.5 RETURN ON EQUITY INVESTMENT EQUATIONS

Discounted cash flow rates of return on equity investment for cogeneration systems are derived here for three ownership arrangements: industrial, utility, and third party.

Case I: Industrial Ownership (See Figures 6.5-1 and 6.5-4: see pages 6-66, 69).

The gross savings (before taxes) for year i are:

$$GS_i = S_i - \Delta FC_i - \Delta OM_i - \Delta DEP_i - \Delta INT_i - \Delta PTI_i \quad (6.5-1)$$

The net savings on purchase of electricity for year i are:

$$S_i = EP \times PEP_i + EX \times PEX_i - PSB \times CSB_i^* \quad (6.5-2)$$

The incremental fuel costs for the year i are:

$$\Delta FC_i = FUC \times PFC_i - FUP \times PFP_i - FUD \times PFD_i \quad (6.5-3)$$

The amount of fuel used annually under cogeneration is:

$$FUC = (QS + (EP + EX) \times 3413) / IEUF$$

$$RPHEE = QS / ((EP + EX) \times 3413)$$

$$\begin{aligned} FUC &= (QS + QS / RPHEE) / IEUF \\ &= (QS / IEUF) \times (1 + 1 / RPHEE) \end{aligned}$$

The amount of fuel used annually by industry for process steam generation is:

$$FUP = QS \times HRS \quad (6.5-4)$$

The amount of fuel used annually by industry for direct heating is:

$$FUD = QD \times (LHV / HHV) D \quad (6.5-5)$$

The incremental operating and maintenance costs for year i are:

$$\Delta OM_i = \Delta LC_i + \Delta SC_i + \Delta MC_i \quad (6.5-6)$$

The incremental cost of maintenance labor and material for year i can be expressed as a function of the incremental capital investment, i.e.

$$\Delta MC_i = MCF_i \times \Delta C_o \quad (6.5-7)$$

* If EX is < 0 , $PEX_i = PEP_i$.

Combining Equations 6.5-6 and 6.5-7 gives:

$$\Delta OM_i = \Delta LC_i + \Delta SC_i + MCF_i \times \Delta C_o \quad (6.5-8)$$

The incremental capital investment for a new plant or for an old plant with an existing process boiler which must be replaced is:

$$\Delta C_o = CC_o - IC_o$$

$$CC_o = (EP + EX) / (8760 \times CFAC) \times SCC$$

$$IC_o = (QS) / (8760 \times CFAC) \times SCI \quad (6.5-9)$$

When retrofitting an old plant with an existing process steam boiler which is capable of being operated for an additional period equal to the cogeneration system project life with accelerated maintenance, IC_o is zero and $\Delta C_o = CC_o$.

The incremental depreciation for year i is:

$$\Delta DEP_i = \Delta C_o / L$$

$$(\text{straight line depreciation is assumed}) \quad (6.5-10)$$

The incremental interest on debt for year i is:

$$\Delta INT_i = DER / (1 + DER) \times \Delta C_o \times IR_i \quad (6.5-11)$$

The incremental property taxes and insurance are:

$$\Delta PTI_i = (PTR_i + INR_i) \times \Delta C_o \quad (6.5-12)$$

The net savings (after taxes) for year i are:

$$NS_i = GS_i - \Delta TAX_i \quad (6.5-13)$$

The net cash flow for year i is:

$$NCF_i = NS_i + \Delta DEP_i \quad (6.5-14)$$

Substituting Equation 6.5-12 into Equation 6.5-13 gives:

$$NCF_i = GS_i - \Delta TAX_i + \Delta DEP_i \quad (6.5-15)$$

Incremental taxes for year i are:

$$\Delta \text{TAX}_i = \text{TR} \times \text{GS}_i = \text{TR} \times (\text{NS}_i + \Delta \text{TAX}_i) \quad (6.5-16)$$

Discounted Cash Flow Rate of Return or Equity

The discounted cash flow rate of return on equity (r) is defined as that rate of return which equates the present worth of the net yearly cash flows to the incremental equity capital investment minus any investment tax credit. The criterion for evaluating cogeneration projects is the return on equity (ROE) hurdle rate. Industry specific hurdle rate correlations will be used which give the fraction of an industry which will invest in cogeneration as a function of rate of return on equity.

The general expression for net incremental equity capital investment for industrial ownership is as follows when a new process steam boiler is required:

$$\text{NAECI} = (\Delta \text{C}_0 - (\text{ITCR} \times \text{CC}_0 - \text{ITCRI} \times \text{IC}_0)) / (1 + \text{DER}) \quad (6.5-17a)$$

If the investment tax credit rate for the process steam boiler is the same as that for the cogeneration system, Equation 17a becomes:

$$\text{NAECI} = \Delta \text{C}_0 \times (1 - \text{ITCR}) / (1 + \text{DER}) \quad (6.5-17b)$$

When retrofitting a plant with an existing process steam boiler which is capable of being operated for an additional period equal to the cogeneration system project life with accelerated maintenance, Equation 17b becomes:

$$\text{NAECI} = \text{CC}_0 \times (1 - \text{ITCR}) / (1 + \text{DER}) \quad (6.5-17c)$$

The present worth of the net yearly cash flows over the life of the project is:

$$\sum_{i=1}^N \frac{1}{(1+r)^i} \times \text{NCF}_i = \sum_{i=1}^N \frac{1}{(1+r)^i} \times (\text{GS}_i - \text{TAX}_i + \Delta \text{DEP}_i) \quad (6.5-18)$$

Substituting Equation 6.5-1 into Equation 6.5-18 gives:

$$\sum_{i=1}^N \frac{1}{(1+r)^i} \times \text{NCF}_i = \sum_{i=1}^N \frac{1}{(1+r)^i} \times (\text{S}_i - \Delta \text{FC}_i - \Delta \text{OM}_i - \Delta \text{INT}_i - \Delta \text{PTI}_i - \text{TAX}_i)$$

Equating Equations 6.5-16 and 6.5-18 gives:

$$\frac{(1-ITCR)}{(1+DER)} \times \Delta C_0 = \sum_{i=1}^N \frac{1}{(1+r)^i} \times (S_i - \Delta FC_i - \Delta OM_i - \Delta INT_i - \Delta PTI_i - TAX_i) \quad (6.5-20)$$

The interest on debt is a function of the interest rate, the debt/equity ratio, and the initial capital investment. The debt/equity ratio and the initial capital investment are fixed. It is assumed that the debt is long term bonds and that the interest rate is fixed. The incremental annual interest on debt is, therefore, constant. Inflation will cause S_i , ΔFC_i , ΔPTI_i , and ΔOM_i to increase with time. S_i and ΔFC_i are expected to increase significantly relative to general inflation. Relative escalation rates for electric energy and fuel are obtained from energy price projections made in section 4.0. It is assumed that ΔOM_i and ΔPTI_i will keep pace with general inflation rates. The right hand side of Equation 6.5-19 will, therefore, have three different escalation rates.

The annual interest on incremental debt is:

$$\Delta INT = DER / (1+DER) \times \Delta C_0 \times IR \quad (6.5-21)$$

The incremental operating and maintenance costs and property taxes and insurance for year i as a function of inflation rate are:

$$\begin{aligned} \Delta OM_i &= \Delta OM_1 \times (1+E_1)^{i-1} \\ \Delta OM_1 &= \Delta LC_1 + \Delta SC_1 + MCF_1 \times \Delta C_0 \\ \Delta OM_i &= (\Delta LC_1 + \Delta SC_1 + MCF_1 \times \Delta C_0) \times (1+INF)^{i-1} \end{aligned} \quad (6.5-22)$$

$$\begin{aligned} \Delta PTI_i &= \Delta PTI_1 \times (1+INF)^{i-1} \\ \Delta PTI_1 &= (PTR_1 + INR_1) \times \Delta C_0 \\ \Delta PTI_i &= (PTR_1 + INR_1) \times \Delta C_0 \times (1+INF)^{i-1} \end{aligned} \quad (6.5-23)$$

The incremental fuel cost for year i as a function of inflation rate and relative fuel cost escalation is:

$$\begin{aligned}\Delta FC_i &= FUC/10^6 \times PFC_i - FUS/10^6 \times PFS_i \\ PFC_i &= PFC_1 \times (1+INF)^{i-1} \times (1+EFC)^{i-1} \\ PFS_i &= PFS_1 \times (1+INF)^{i-1} \times (1+EFS)^{i-1} \\ \Delta FC_i &= FUC/10^6 \times PFC_1 \times (1+INF)^{i-1} \times (1+EFC)^{i-1} - FUS/10^6 \times PFS_1 \times (1+INF)^{i-1} \\ &\quad \times (1+EFS)^{i-1} \quad (6.5-24)\end{aligned}$$

The net savings on purchase of electricity for year i as a function of inflation rate and relative electric energy cost escalation are:

$$\begin{aligned}S_i &= S_1 \times (1+INF)^{i-1} \times (1+EE)^{i-1} \\ S_1 &= EP \times PE_1 + EX \times PEX_1 - PSB \times CSB_1 \quad (*) \\ S_i &= (EP \times PE_1 + EX \times PEX_1 - PSB \times CSB_1) \times (1+INF)^{i-1} \times (1+EE)^{i-1} \quad (6.5-25)\end{aligned}$$

Substituting Equation 6.5-21 into Equation 6.5-20 gives:

$$\begin{aligned}\frac{(1-ITCR)}{(1+DER)} \times \Delta C_o &= \sum_{i=1}^N \frac{1}{(1+r)^i} \times (S_i - \Delta FC_i - \Delta OM_i - \Delta PTI_i - TAX_i \\ &\quad - DER/(1+DER) \times \Delta C_o \times IR) \quad (6.5-26)\end{aligned}$$

Equation 6.5-26 is solved for r using iterative techniques.

(*) If EX is < 0 , $PEX_1 = PE_1$.

Case II, Utility Ownership (see Figures 6.5-2 and 6.5-4: see pages 6-67, 69).

The gross revenue increment (before taxes) for year i is:

$$\Delta \text{GREV}_i = \text{SREV}_i + \Delta \text{EREV}_i - \Delta \text{FC}_i - \Delta \text{OM}_i - \Delta \text{DEP}_i - \Delta \text{INT}_i - \Delta \text{PTI}_i \quad (6.5-27)$$

The revenue from the sale of process steam for year i is:

$$\text{SREV}_i = \text{QS} \times \text{PS}_i \quad (6.5-28)$$

The incremental revenue from the sale of electricity for year i is:

$$\Delta \text{EREV}_i = \text{EP} \times (\text{PEP}_i - \text{PEB}_i) \quad (6.5-29)$$

The incremental fuel costs for year i are:

$$\Delta \text{FC}_i = \text{FUC} / 10^6 \times \text{PFC}_i - \text{FUS} / 10^6 \times \text{PFS}_i \quad (6.5-30)$$

The amount of fuel used annually under separate generation is:

$$\text{FUS} = \left(\text{EP} / (1 - \text{TL}) + \text{EX} / (1 - \text{TLX}) \right) \times \text{HRE}^* \quad (6.5-31)$$

The amount of fuel used annually under cogeneration is:

$$\begin{aligned} \text{FUC} &= (\text{QS} + (\text{EP} + \text{EX}) \times 3413) / \text{IEUF} \\ (\text{EP} + \text{EX}) \times 3413 &= \text{QS} / \text{RPHEE} \\ \text{FUC} &= (\text{QS} + \text{QS} / \text{RPHEE}) / \text{IEUF} \\ &= (\text{QS} / \text{IEUF}) \times (1 + 1 / \text{RPHEE}) \end{aligned} \quad (6.5-32)$$

The incremental operating and maintenance costs for year i are:

$$\Delta \text{OM}_i = \Delta \text{LC}_i + \Delta \text{SC}_i + \Delta \text{MC}_i \quad (6.5-33)$$

The incremental cost of maintenance labor and materials for year i can be expressed as a function of the incremental capital investment i.e.

$$\Delta \text{MC}_i = \text{MCF}_i \times \Delta \text{C}_o \quad (6.5-34)$$

The incremental capital investment is:

$$\Delta \text{C}_o = \text{CCo} - \text{UCo} \quad (6.5-35)$$

* If $\text{EX} > 0$, $\text{TLX} = 0$. If $\text{EX} < 0$,
 $\text{TLX} = \text{TL}$.

$$CCo = (EP+EX)/(8760 \times CFAC) \times SCC$$

$$UCo = (EP/(1.0-TL)+EX)/(8760 \times CFAC) \times SCU$$

The incremental depreciation for year i is:

$$\Delta DEP_i = \Delta C_o / L$$

(straight line depreciation is assumed)

The incremental interest on debt for year i is:

$$\Delta INT_i = DER/(1+DER) \times \Delta C_o \times IR_i \quad (6.5-36)$$

The incremental property taxes and insurance for year i are:

$$\Delta PTI_i = (PTR_i + INR_i) \times \Delta C_o \quad (6.5-37)$$

The net revenue increment (after taxes) for year i are:

$$\Delta NREV_i = \Delta GREV_i - \Delta TAX_i \quad (6.5-38)$$

The incremental net cash flow for year i is:

$$\Delta NCF_i = \Delta NREV_i + \Delta DEP_i \quad (6.5-39)$$

Substituting Equation 6.5-38 into Equation 6.5-39 gives:

$$\Delta NCF_i = \Delta GREV_i - \Delta TAX_i + \Delta DEP_i \quad (6.5-40)$$

Incremental income taxes for year i are:

$$\Delta TAX_i = TR \times \Delta GREV_i = TR \times (\Delta NREV_i + \Delta TAX_i) \quad (6.5-41)$$

Discounted Cash Flow Rate of Return on Equity

The discounted cash flow rate of return on equity (r) is defined as that rate of return which equates the present worth of the incremental net yearly cash flows to the incremental equity capital investment minus any investment tax credit. The criterion for evaluating cogeneration projects is the return on equity (ROE) hurdle rate. Industry specific hurdle rate correlations will be used which give the fraction of an industry which will invest in cogeneration as a function of rate of return on equity.

The general expression for net incremental equity capital investment is equal to:

$$N\Delta ECI = (\Delta C_0 - (ITCR \times CC_0 - ITCRU \times UC_0)) / (1 + DER) \quad (6.5-42a)$$

If the investment tax credit rates for the utility central station is equal to that for the cogeneration system, Equation 16a becomes:

$$N\Delta ECI = \Delta C_0 \times (1 - ITCR) / (1 + DER) \quad (6.5-42b)$$

The present worth of the net yearly cash flows over the life of the project is:

$$\sum_{i=1}^N \frac{1}{(1+r)^i} \times \Delta NCF_i = \sum_{i=1}^N \frac{1}{(1+r)^i} \times (\Delta GREV_i - \Delta TAX_i + \Delta DEP_i) \quad (6.5-43)$$

Substituting Equation 1 into Equation 17 gives:

$$\sum_{i=1}^N \frac{1}{(1+r)^i} \times \Delta NCF_i = \sum_{i=1}^N \frac{1}{(1+r)^i} \times (SREV_i + \Delta EREV_i - \Delta FC_i - \Delta OM_i - \Delta TAX_i - \Delta PTI_i - \Delta INT_i) \quad (6.5-44)$$

Equating Equations 6.5-42 and 6.5-44 gives:

$$\frac{(1 - ITCR)}{(1 + DER)} \times \Delta C_0 = \sum_{i=1}^N \frac{1}{(1+r)^i} \times (SREV_i + \Delta EREV_i - \Delta FC_i - \Delta OM_i - \Delta TAX_i - \Delta PTI_i - \Delta INT_i) \quad (6.5-45)$$

The interest on debt is a function of the interest rate, the debt/equity ratio, and the incremental capital investment. The debt/equity ratio and the incremental capital investment are fixed. It is assumed that the debt is long term bonds and that, therefore, the interest rate is fixed. The annual interest on debt is, therefore, constant. Inflation will cause $SREV_i$, $\Delta EREV_i$, ΔFC_i , ΔPTI_i and ΔOM_i to increase with time. $SREV_i$, $\Delta EREV_i$, and ΔFC_i are expected to increase at a rate significantly greater than general inflation. Relative escalation rates for electric energy and fuel will be obtained from energy price projections generated and shown in Table 6.1-5. A relative escalation rate for process steam will be assumed. It is assumed that ΔOM_i and ΔPTI_i will keep pace with the general inflation rate.

These will be, therefore, four different inflation rates applied to the right hand side of Equation 6.5-45.

The annual interest on incremental debt is:

$$\Delta INT_1 = DER / (1 + DER) \times \Delta C_0 \times IR \quad (6.5-46)$$

The incremental operating and maintenance costs and property taxes and insurance for year i as a function of general inflation rate are:

$$\begin{aligned} \Delta OM_1 &= \Delta OM_1 \times (1 + INF)^{i-1} \\ \Delta OM_1 &= \Delta LC_1 + SC_1 + MCF_1 \times \Delta C_0 \\ \Delta OM_1 &= (\Delta LC_1 + \Delta SC_1 + MCF_1) \times \Delta C_0 \times (1 + INF)^{i-1} \end{aligned} \quad (6.5-47)$$

$$\begin{aligned} \Delta PTI_1 &= \Delta PTI_1 \times (1 + INF)^{i-1} \\ \Delta PTI_1 &= (PTR_1 + INR_1) \times \Delta C_0 \\ \Delta PTI_1 &= (PTR_1 + INR_1) \times \Delta C_0 \times (1 + INF)^{i-1} \end{aligned} \quad (6.5-48)$$

The incremental fuel costs for year i as a function of general inflation rate and relative fuel cost escalation are:

$$\begin{aligned} \Delta FC_1 &= FUC / 10^6 \times PFC_1 - FUS / 10^6 \times PFS_1 \\ PFC_1 &= PFC_1 \times (1 + INF)^{i-1} \times (1 + EFC)^{i-1} \\ PFS_1 &= PFS_1 \times (1 + INF)^{i-1} \times (1 + EFS)^{i-1} \\ \Delta FC_1 &= FUC / 10^6 \times PFC_1 \times (1 + INF)^{i-1} \times (1 + EFC)^{i-1} - FUS / 10^6 \times PFS_1 \times (1 + INF)^{i-1} \times (1 + EFS)^{i-1} \end{aligned} \quad (6.5-49)$$

The revenue from sale of process steam and incremental revenue from sale of electric energy for year i as a function of general inflation rate and relative fuel cost escalation are:

$$\begin{aligned} SREV_1 &= SREV_1 \times (1 + INF)^{i-1} \times (1 + EES)^{i-1} \\ SREV_1 &= QS \times PS_1 \\ SREV_1 &= QS \times PS_1 \times (1 + INF)^{i-1} \times (1 + EES)^{i-1} \end{aligned} \quad (6.5-50)$$

$$\Delta \text{EREV}_i = \Delta \text{EREV}_1 \times (1 + \text{INF})^{i-1} \times (1 + \text{EEE})^{i-1}$$

$$\Delta \text{EREV}_i = \text{EP} \times (\text{PEB}_1 - \text{PEP}_1)$$

$$\Delta \text{EREV}_i = \text{EP} \times (\text{PEB}_1 - \text{PEP}_1) \times (1 + \text{INF})^{i-1} \times (1 + \text{EEE})^{i-1} \quad (6.5-51)$$

Substituting Equation 6.5-46 into Equation 6.5-45 gives:

$$\frac{(1 - \text{ITCR})}{(1 + \text{DER})} \times \Delta C_0 = \sum_{i=1}^N \frac{1}{(1+r)^i} \times (\text{SREV}_i + \Delta \text{EREV}_i - \Delta \text{FC}_i - \Delta \text{OM}_i - \Delta \text{TAX}_i - \Delta \text{PT}_i - \text{SER} / (1 + \text{DER}) \times \Delta C_0 \times \text{IR}) \quad (6.5-52)$$

Equation 6.5-52 is solved for r using iterative techniques.

Case III: Third Party Ownership (see Figures 6.5-3 and 6.5-4: see pages 6-68, 69).

The gross profit (before taxes) for year i are:

$$GP_i = SREV_i + EREV_i - FC_i - OM_i - DEP_i - INT_i - PTI_i \quad (6.5-53)$$

The revenue from the sale of process steam for year i is:

$$SREV_i = QS \times PS_i \quad (6.5-54)$$

The revenue from the sale of electrical energy for year i is:

$$EREV_i = EP \times PEP_i + EX \times PEB_i \quad (6.5-55)$$

The fuel costs for the year i are:

$$FC_i = FU \times PFC_i \quad (6.5-56)$$

The amount of fuel used annually is:

$$\begin{aligned} FU &= (QS + (EP + EX) \times 3413) / IEUF \\ RPHEE &= QS / (EP + EX) \times 3413 \\ FU &= (QS + QS / RPHEE) / IEUF \\ &= (QS / IEUF) \times (1 + 1 / RPHEE) \end{aligned} \quad (6.5-57)$$

The operating and maintenance costs for year i are:

$$OM_i = LC_i + SC_i + MC_i \quad (6.5-58)$$

The cost of maintenance labor and materials for year i can be expressed as a function of the capital investment, i.e.

$$MC_i = MCF_i \times C_o \quad (6.5-59)$$

The capital investment in the energy conversion subsystem is:

$$C_o = ((EP + EX) \times SCC) / (CFAC \times 8760) \quad (6.5-60)$$

The depreciation for year i is:

$$DEP_i = C_o / L$$

(straight line depreciation is assumed) (6.5-61)

The interest on debt for year i is:

$$INT_i = DER / (1 + DER) \times C_o \times IR_i$$

(6.5-62)

The property taxes and insurance costs for year i are:

$$PTI_i = (PTR_i + INR_i) \times C_o$$

(6.5-63)

The net profit (after taxes) for year i are:

$$NP_i = GP_i - TAX_i$$

(6.5-64)

The net cash flow for year i is:

$$NCF_i = NP_i + DEP_i$$

(6.5-65)

Substituting Equation 6.5-64 into Equation 6.5-65 gives:

$$NCF_i = GP_i - TAX_i + DEP_i$$

(6.5-66)

Income taxes for year i are:

$$TAX_i = TR \times GP_i = TR \times (NP_i + TAX_i)$$

(6.5-67)

Discounted Cash Flow Rate of Return on Equity

The discounted cash flow rate of return on equity (r) is defined as that rate of return which equates the present worth of the net yearly cash flows to the equity portion of the capital investment minus any investment tax credit. The criterion for evaluating cogeneration projects is the return on equity (ROE) hurdle rate. Industry specific hurdle rate correlations will be used which give the fraction of an industry which will invest in cogeneration as a function of the rate of return on equity.

The net equity portion of the capital investment is:

$$NECI = C_o \times (1 - ITCR) / (1 + DER)$$

(6.5-68)

The present worth of the net yearly cash flows is:

$$\sum_{i=1}^N \frac{1}{(1+r)^i} \times NCF_i = \sum_{i=1}^N \frac{1}{(1+r)^i} \times (GP_i - TAX_i + DEP_i) \quad (6.5-69)$$

Substituting Equation 6.5-53 into Equation 6.5-69 gives:

$$\sum_{i=1}^N \frac{1}{(1+r)^i} \times NCF_i = \sum_{i=1}^N \frac{1}{(1+r)^i} \times (SREV_i + EREV_i - FC_i - OM_i - TAX_i - INT_i - PTI_i) \quad (6.5-70)$$

Equating Equations 6.5-68 and 6.5-70 gives:

$$\frac{(1-ITCR)}{(1+DER)} \times CC_o = \sum_{i=1}^N \frac{1}{(1+r)^i} \times (SREV_i + EREV_i - FC_i - OM_i - TAX_i - INT_i - PTI_i) \quad (6.5-71)$$

The interest on debt is a function of the interest rate, the debt/equity ratio, and the capital investment. The debt/equity ratio and the capital investment are fixed. It is assumed that the debt is long term bonds and that, therefore, the interest rate is fixed. The annual interest on debt is, therefore, constant. Inflation will cause all of the other terms to increase with time. $SREV_i$, $EREV_i$, and FC_i are expected to increase at a rate significantly greater than general inflation. Relative escalation rates for electric energy and fuel will be obtained from energy price projections shown in Section 4.0. A relative escalation rate for process steam will be assumed. It is assumed that OM_i and PTI_i will keep pace with general inflation.

The annual interest on debt is:

$$INT_i = DER / (1+DER) \times CC_o \times IR \quad (6.5-72)$$

The operating and maintenance costs and property taxes and insurance for year i as a function of general inflation rate are:

$$\begin{aligned}
 OM_i &= OM_1 \times (1+INF)^{i-1} \\
 OM_1 &= LC_1 + SC_1 + MCF_1 \times C_0 \\
 OM_i &= (LC_1 + SC_1 + MCF_1 \times C_0) \times (1+INF)^{i-1} \quad (6.5-73) \\
 PTI_i &= PTI_1 \times (1+INF)^{i-1} \\
 PTI_1 &= (PTR_1 + INR_1) \times C_0 \\
 PTI_i &= (PTR_1 + INR_1) \times C_0 \times (1+INF)^{i-1} \quad (6.5-74)
 \end{aligned}$$

The fuel costs for year i as a function of general inflation rate and relative fuel cost escalation are:

$$\begin{aligned}
 FC_i &= FC_1 \times (1+INF)^{i-1} \times (1+EFC)^{i-1} \\
 FC_1 &= FU \times PF_1 \\
 FC_i &= FU \times PF_1 \times (1+INF)^{i-1} \times (1+EFC)^{i-1} \quad (6.5-75)
 \end{aligned}$$

The revenue from sale of process steam and electric energy for year i as a function of general inflation rate and relative electric energy and process steam cost escalation are:

$$\begin{aligned}
 SREV_i &= SREV_1 \times (1+INF)^{i-1} \times (1+ES)^{i-1} \\
 SREV_1 &= QS \times PS_1 \\
 SREV_i &= QS \times PS_1 \times (1+INF)^{i-1} \times (1+ES)^{i-1} \quad (6.5-76) \\
 EREV_i &= EREV_1 \times (1+INF)^{i-1} \times (1+EE)^{i-1} \\
 EREV_1 &= EP \times PEP_1 + EX \times PEB_1 \\
 EREV_i &= (EP \times PEP_1 + EX \times PEB_1) \times (1+INF)^{i-1} \times (1+EE)^{i-1} \quad (6.5-77)
 \end{aligned}$$

Substituting Equation 6.5-72 into Equation 6.5-71 gives:

$$\frac{(1-ITCR)}{(1+DER)} \times C_o = \sum_{i=1}^N \frac{1}{(1+r)^i} \times (SREV_i + EREV_i - FC_i - OM_i - TAX_i) - PTI_i - DER / (1+DER) \times C_o \times IR \quad (6.5-78)$$

Equation 6.5-78 is solved for r using iterative techniques.

Assumptions for Case I

1. The energy conversion plant is sized to meet the process steam needs of the industrial plant.
2. Any excess electric power is sold to utility for resale to its customers.
3. Any electric power deficiency is made up by purchase of power from local utility.
4. Existing process steam boiler is retained for standby.
5. Arrangement is made with local utility for standby power.

Assumptions for Case II

1. The energy conversion plant is located in close proximity to the industrial plant.
2. The energy conversion plant is sized to meet the process steam needs of the primary customer.
3. Pressure loss in steam supply line is 1% per 100 ft of pipe.
4. There are no transmission losses for the electric energy supplied to the primary customer(s). (close proximity)
5. Any excess power generated by the energy conversion plant is fed into the utility grid for sale to its other customers.
6. Transmission losses for excess electric energy sold to secondary customer(s) are equal to the typical value for the pertinent utility.
7. Supplemental power is generated at a higher heating value heat rate typical of the pertinent utility.
8. Transmission losses for the supplemental power are equal to the value typical of the pertinent utility.
9. Existing process steam boiler is retained for standby.

Assumptions for Case III

1. The energy conversion plant is located in close proximity to the industrial plant.
2. The energy conversion plant is sized to meet the process steam requirements of the industrial plant.
3. The pressure loss in the steam supply line is 1% per 100 ft of pipe.
4. The transmission losses for the electric energy supplied to the industrial plant are nil because of close proximity.
5. Any excess power generated by the energy conversion plant is sold to the local utility for resale to its customers.
6. Transmission losses for the excess power are equal to the value typical of the pertinent utility.
7. Supplemental power is generated at a higher heating value heat rate typical for the pertinent utility.
8. Transmission losses for the supplemental power are equal to the value typical of the pertinent utility.
9. Existing process steam boiler is retained for standby.
10. Arrangement is made with local utility for standby power.

Fig. 6.5-1—Case I, cogeneration model (industry ownership)

Fig. 6.5-2 - Case II, cogeneration model (utility ownership)

Fig. 6.5-3 – Case III, cogeneration model (third party ownership)

Fig. 6.5-4 - Reference case, separate generation model

NOMENCLATURE

- CC_0 - cogeneration capital investment (\$)
- CFAC - capacity factor
- CSB_i - annual charge for standby power in year i (\$/kW)
- DEP_i - depreciation for year i (\$)
- DER - debt equity ratio
- EE - relative price escalation of electrical energy (%/100/year)
- EFC - relative escalation of cogeneration fuel prices (%/100/year)
- EFS - relative price escalation of fuel used under separate generation (%/100/year)
- EP - amount of electrical energy used annually by industrial plant (kWh/yr)
- $EREV_i$ - revenue from the sale of electrical energy for year i (\$)
- ES - relative price escalation of process steam (%/100/year)
- EX - amount of electrical energy generated by energy conversion subsystem in excess of amount used by industrial plant (kWh/yr)
- FC_i - fuel costs for year i (\$)
- FUC - amount of fuel used annually under cogeneration, Btu(LHV)/yr
- FUD - amount of fuel used annually for direct heating, Btu(LHV)/yr
- FUP - amount of fuel used annually for process steam generation, Btu(LHV)/yr
- FUS - amount of fuel used annually under separate generation, Btu(LHV)/yr

NOMENCLATURE (CONT.)

- GREV₁ - gross revenue from sale of process steam and electrical energy for year 1 (\$)
- GS₁ - gross savings for year 1 (\$)
- HRE - bus bar heat rate for generation of electrical energy at utility central station (Btu(LHV)/kWh)
- HRS - heat rate for process steam under separate generation (dimensionless) LHV fuel
- IC₀ - capital investment for industrial process boiler (\$)
- IEUF - ideal energy utilization factor for energy conversion subsystem (dimensionless)
- INF - general inflation rate (%/100/year)
- INR₁ - insurance rate for year 1 (%/100)
- INT₁ - interest on debt for year 1 (\$)
- IR₁ - interest rate on debt for year 1 (percent per annum/100)
- ITCR - cogeneration system investment tax credit rate (%/100)
- ITCRI - process steam boiler investment tax credit rate (%/100)
- ITCRU - utility central station investment tax credit rate (%/100)
- L - life of facility for tax purposes (years)
- LC₁ - operating labor costs for year 1 (\$)
- (LHV/HHV)D - ratio of lower to higher heating value for fuel used in direct heating (dimensionless)
- MC₁ - cost of maintenance labor and material for year 1 (\$)
- MCF₁ - maintenance cost factor for year 1 (percent of incremental capital investment/100)
- N - life of project (years)
- NCF₁ - net cash flow for year 1 (\$)
- NECI - net equity capital investment (\$)

NOMENCLATURE (CONT.)

- NS_i - net savings for year i (\$)
- OM_i - operating and maintenance costs for year i (\$)
- PEB_i - price of electrical energy at central station bus bar (\$/kWh)
- PEP_i - price of electrical energy purchased from utility in year i (\$/kWh)
- PEX_i - price of electrical energy sold to utility in year i (\$/kWh)
- PFC_i - price of cogeneration fuel for year i , ($\$/10^6$ Btu)(LHV))
- PFD_i - price of fuel used for direct heating for year i , $\$/10^6$ Btu(LHV)
- PFP_i - price of fuel used for process steam generation for year i $\$/10^6$ Btu(LHV)
- PFS_i - price of fuel used by utility central station under separate generation for year i ($\$/10^6$ Btu(LHV))
- PS_i - price of process steam for year i (\$/Btu)
- PSB - amount of standby power provided to industrial plant by utility (kW)
- PTI_i - property taxes and insurance for year i (\$)
- PTR_i - property tax rate for year i (%/100)
- QD - higher heating value of fuel used annually for direct heating, Btu(HHV)/yr
- QS - gross process heat used by industrial plant annually (Btu/yr)
- $RPHEE$ - ratio of gross process heat to electrical energy (dimensionless)
- S_i - net savings on purchase of electricity for year i (\$)
- SC_i - costs of supplies and chemicals for year i (\$)

NOMENCLATURE (CONT.)

- SCC - specific cost of energy conversion subsystem under cogeneration (\$/kW)
- SCI - specific cost of industrial process steam boiler (\$/Btu/hr)
- SCU - specific cost of new utility generation plant (\$/kW)
- $SREV_i$ - revenue from the sale of process steam for year i (\$)
- TAX_i - sum of federal and state corporate income taxes on gross savings for year i (\$)
- TL - transmission losses for power from central station to industrial customer (%/100)
- TR - sum of federal and state corporate income tax rates (%/100)
- UIC_0 - undepreciated capital investment for an existing, operable industrial process steam boiler (\$)
- Y - age of existing process steam boilers (years)

6.6 ENERGY SAVING FORMULAE

Different energy savings formulae are required for the following two cases:

- $EE > EP$
- $EE < EP$

For the $EE > EP$ case, the fuel used under separate generation is

$$FUS = QS \times HRS / 10^6 + (EP / (1 - TL) + EX) \times HRE / 10^6 + QD \quad (6.6-1)$$

and the fuel used under cogeneration is

$$FUC = (QS + (EP + EX) \times 3413) / IEUF / 10^6 + QD^* \quad (6.6-2)$$

The fuel saved by cogeneration is, of course, equal to FUS minus FUC or

$$\begin{aligned} ESC &= (QS / 10^6) \times (HRS - 1 / IEUF) + (EP / 10^6) \\ &\times (HRS / (1 - TL) - 3413 / IEUF) + (EX / 10^6) \\ &\times (HRS - 3413 / IEUF) \end{aligned} \quad (6.6-3)$$

For the $EE < EP$ case the fuel used under separate generation is

$$FUS = QS \times HRS / 10^6 + EP / (1 - TL) \times HRE / 10^6 + QD \quad (6.6-4)$$

and the fuel used under cogeneration is:

$$FUC = ((QS + EE \times 3413) / IEUF + EI / (1 - TL) \times HRE) / 10^6 + QD^* \quad (6.6-5)$$

Substituting $EE = EP - EI$ into Eq. 6.6-5 gives:

$$FUC = ((QS + EP \times 3413) / IEUF - EI \times (3413 / IEUF - HRE / (1 - TL))) / 10^6 \quad (6.6-6)$$

The energy savings are:

$$\begin{aligned} ESC &= (QS / 10^6) \times (HRS - 1 / IEUF) \\ &+ (EP / 10^6) \times (HRE / (1 - TL) - 3413 / IEUF) \\ &- (EI / 10^6) \times (HRE / (1 - TL) - 3413 / IEUF) \\ &= (QS / 10^6) \times (HRS - 1 / IEUF) \\ &+ (EE / 10^6) \times (HRE / (1 - TL) - 3413 / IEUF) \end{aligned} \quad (6.6-7)$$

* When the same quantity of fuel is used for direct heating under both separate and cogeneration, the QD terms cancel out. When process steam is used to completely replace QD under cogeneration, the QD term will be zero in the cogeneration case.

NOMENCLATURE

EE	=	electrical energy generated by cogeneration system - kWh/year
EP	=	electrical energy required by industrial plant - kWh/year
FUS	=	fuel used under separate generation - 10^6 Btu/year
QS	=	gross thermal energy requirements of industrial plant - Btu/year
HRS	=	heat rate for separate generation of process steam - Btu/Btu
TL	=	transmission losses for electric power
EX	=	electrical energy exported from cogeneration system - kWh/year
HRE	=	heat rate for utility central station - Btu/kWh
FUC	=	fuel used under cogeneration - 10^6 Btu/year
IEUF	=	ideal energy utilization factor for cogeneration system
ESC	=	energy savings by cogeneration - 10^6 Btu/year
EI	=	electrical energy imported to industrial plant under cogeneration - kWh/year
QD	=	fuel used for direct heating - Btu/year

7.0 CAPITAL COST ESTIMATES

7.1 OVERVIEW

7.1.1 Approach

Conceptual designs and capital cost estimates have been developed for each plant using the data generated in Sections 3.0, 5.0 and 6.0. The designs contain all the major components necessary for a cogeneration facility with the exception of mechanical and electrical distribution systems. Site preparations for these facilities were assumed to be minimal requiring only clearing and grubbing. Soils in each facility were assumed to have sufficient bearing capacity so that spread footings could be used for the foundations of all equipment and structures. Capacities and sizes of systems and components such as cranes, pumps, drivers, deaerators, ductwork, breeching, stacks, piping, electrical switchgear and wiring, insulation, alarms and controls were determined by using the principles and engineering guidelines common to accepted industrial and utility practice. Each component specified is of standard design and is available from at least two manufacturers. Raw water at each facility was assumed to be clarified and filtered before being treated for boiler makeup. Typically for coal fired plants, coal was assumed to be delivered by truck and dumped into a hopper from which an elevator or belt conveyor system would move the coal to the bunkers. All bunkers were sized to have a capacity to operate the facility for 3 days at 100% load. Steam generators are of the field erected type for fossil firing and the waste heat type used with gas turbines. Depending on size and feedwater temperatures, fossil fired steam generators are provided with economizers and in some cases, air heaters. Standard steam generator accessories are included such as burners, soot blowers, platforms, ladders, fans, ducts, breeching, burner and combustion controls, flame safety controls, feedwater regulators and control valves, and standard steam generator trim. The ash handling systems are of the pneumatic type which transport ash to storage silos with capacities of up to 3 days of full load operation. Trucks (by others) haul the ash to an off-site disposal area. Makeup water is treated either by a sodium zeolite softener or demineralizer, depending on the pressure of the steam generator, then stored in tanks, and mixed with the returned condensate (also stored in tanks) usually in the deaerator. Boiler feed pumps are motor driven. Blow down flash tanks are used to keep solids in the steam generator water within prescribed limits. Products of the blow down tanks are used to maximize heat recovery. Basic turbine accessories include stop, intercept, dump, and pressure control valves, speed governing and lubrication systems, and turbine supervisory controls. Generators include excitation systems. Gas turbine-generators with waste heat boiler units include a generator, excitation equipment, starting system, fuel system, shipped assumbled on skids with piping and wiring, ready for placement on foundations. Accessories to gas turbine generator sets include deaerators, motor driven feed pumps, by-pass stacks, relief valves, regulators, alarms, controls, switchgear, and transformers. Depending on regulatory requirements, particulate control was achieved either by electrostatic

precipitators, baghouses, or scrubbers. Desulfurization of flue gas was obtained through the use of venturi scrubbers or tray towers.

Waste water disposal facilities include sludge ponds lined, and bounded by retaining dikes. Waste water would be pumped to existing water treatment facilities assumed to be elsewhere on the site. Buildings for boilers and steam turbine generator sets are enclosed and of braced steel construction with corrugated siding, insulated or uninsulated, depending on the function of the building. Ground floors are concrete slabs on grade. Upper floors are assumed to be concrete or metal grating based on the building use. Spread footings are used for foundations. Roads are asphalt with a gravel base. A 10 ft. battery limit about the buildings and exterior equipment was assumed for the purpose of estimating piping and electrical runs. Standard estimating techniques were used in developing the capital cost of each facility. Installed equipment costs were derived starting with major component cost acquired through direct solicitation of manufacturers, published book prices, and in-house data. Engineering, design, and construction management was estimated to be 10 percent of direct and indirect costs. A contingency allowance of approximately 20 percent was used which is in accordance with the experience and practice applied on similar assignments for conceptual designs. The Project Milestone Schedules are based on in-house data and equipment deliveries obtained from vendors.

7.1.2 Conceptual Designs and Cost Estimates

Information consisting of a site plan, plot plan, flow diagram, one-line diagram, brief preliminary specifications of major components, cost estimate, and schedule has been made up for cogeneration facilities for plants in each of the five industrial sectors. An example of this information for a cogeneration facility for the industrial sector SIC 20 (Food Processing) is included in Subsection 7.2.1. For the cogeneration facilities of the plants of the other industrial sectors, only descriptions and cost estimates are presented in the sections following Subsection 7.2.1. The balance of the information for these cogeneration facilities, numbered to coincide with the subsections covering these facilities, are included in Appendix A.

7.2 CONCEPTUAL DESIGNS FOR PLANTS

7.2.1 Soybean Oil Plant (SIC 20, DOE Region V, Indiana)

The site plan of this plant is shown on Figure 7.2.1-1. The plot plan of the cogeneration facility is shown on Figure 7.2.1-2.

The basic cogeneration system selected is a coal-fired spreader stoker boiler with an appropriate backpressure steam turbine generator set. Exhaust steam from the turbine is piped to the process. The primary cycle for this unit is shown in Figure 7.2.1-3, Block Flow Diagram and Heat Balance. Brief specifications of the major components are given in Table 7.2.1-1.

For this size cogeneration plant, sized coal from Chinook Mine-Indiana No. 3 seam would be delivered by truck and unloaded into a reclaim pit

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INFORMATION

ISSUED FOR

INDUSTRIAL COGENERATION OPTIMIZATION
PROGRAM

SIC 20 DOE REGION V INDIANA

PLOT PLAN
COGENERATION FACILITY
SOYBEAN OIL PLANT

Gillette & Hill, Inc.
51 LEXINGTON AVENUE, 17TH FLOOR
NEW YORK

SCALE: 1" = 60'

Figure 7.2.1-2

JOB NO. 11-2775-U01

INDUSTRIAL COGENERATION
OPTIMIZATION PROGRAM
SIC 20 DOE REGION V INDIANA
BLOCK FLOW DIAGRAM AND
HEAT BALANCE
COGENERATION FACILITY
SOYBEAN PLANT

Scale & Hill Inc.
ENGINEERS, DESIGNERS, CONSTRUCTORS
NEW YORK

SCALE: NONE

INFORMATION

NO.	ISSUE NO.	DATE	OWN.	CHG.	APPROVALS	REVISION	DATE	BY	REASON	DATE	BY	REASON	DATE	BY	REASON	DATE	BY	REASON	DATE	BY	REASON

ISSUE FOR

JOB NO. 11-2775-003

Figure 7.2.1-3

TABLE 7.2.1-1

SOYBEAN PLANT COGENERATION FACILITY
PRELIMINARY SPECIFICATIONS OF MAJOR COMPONENTS

Boiler

Type	Non-reheat, balanced draft
Firing	Crushed coal, stoker fired
Steam flow	63,000 lb/hr
Steam conditions	915 psia at 876 F
Flue gas flow	27,900 cfm

Steam Turbine

Type	Single shaft, noncondensing
Steam throttle conditions	915 psia/876 F
Steam exhaust conditions	165 psia/505 F
Speed	5500 rpm
Reduction gear	Mechanical 5500/1800 rpm

Generator

Rating	2100 kW
Voltage	13.8 kV
Power factor	0.9
Short circuit ratio	0.64
Cooling	Forced air

Fly Ash Removal

Type	Baghouse
Construction	Fiberglass cloth
Net surface	6200 ft ²

Flue Gas Desulfurization

Type	Tray tower, caustic feed
Capacity	27,900 cfm for coal with 4.3 percent sulfur

Deaerator

Type	Tray
Design pressure	50 psig
Steam flow	4932 lb/hr
Feedwater flow	63,000 lb/hr
Effluent oxygen	Less than 0.5 ppm
Storage capacity	10 minutes

from which a conveyor would transport the coal into coal bunkers located within the boiler building. Flue gas treatment, involving desulfurization and a baghouse, has been included for environmental reasons. Ash handling is accomplished by means of a pneumatic conveyor system which transports both bottom and fly ash to a storage silo for truck loading and transport to an offsite disposal area. The sludge pond, which receives effluent from the desulfurization system, is periodically emptied into trucks for transport to the offsite disposal area. The one-line electrical diagram is shown on Figure 7.2.1-4.

The Conceptual Cost Estimate, Table 7.2.1-2, is based on labor rates, including fringe benefits, taken from a local urban area. A Project Milestone Schedule is shown on Figure 7.2.1-5.

7.2.2 Agri-Chem Plant (SIC 28, DOE Region III, Maryland)

The Conceptual Cost Estimate, Table 7.2.2-1, is based on labor rates including fringe benefits, taken from a local urban area.

The site plan of this plant and plot plan of the cogeneration facility are shown respectively on Figure A2-M-1 and Figure A2-M-2 found in Appendix A.

The basic cogeneration system selected is a coal-fired spreader stoker boiler with an appropriate backpressure steam turbine generator set. Exhaust steam from the turbine is piped to the process. The primary cycle for this unit is shown on Figure A2-M-3, Block Flow Diagram and Heat Balance (Appendix A). Brief specifications of the major components are given in Table A2-1.

For this size cogeneration plant, sized Ohio Pittsburgh No. 8 seam coal would be delivered by truck and unloaded into a reclaim pit from which a conveyor would transport the coal into coal bunkers located within the boiler building. Flue gas treatment, involving desulfurization and an electrostatic precipitator, has been included for environmental reasons. Ash handling is accomplished by means of a pneumatic conveyor system which transports both bottom and fly ash to a storage silo for truck loading and transport to an offsite disposal area. The sludge pond which receives effluent from the desulfurization system is periodically emptied into trucks for transport to the offsite disposal area. The one-line electrical diagram is shown on Figure A2-E-1 (Appendix A). A Project Milestone Schedule is shown on Figure A2-M-4 (Appendix A).

7.2.3 Brewery (SIC 20, DOE Region III, Pennsylvania)

The Conceptual Cost Estimate shown in Table 7.2.3-1, is based on labor rates including fringe benefits, taken from a local urban area.

In addition, the site plan of this plant and the plot plan of the cogeneration facility are shown respectively in Figure A3-M-1 and Figure A3-M-2 of Appendix A.

ENGINEERS, DESIGNERS, CONSTRUCTORS

JOS #0. (1-2775-00)

Figure 7.2.1-4

TABLE 7.2.1-2

CONCEPTUAL COST ESTIMATE
SOYBEAN PLANT COGENERATION FACILITY
(SIC 20, DOE REGION V, INDIANA)

<u>Acct.</u> <u>No.</u>	<u>Description</u>	<u>Total,</u> <u>\$1000</u>
321	Structures and Improvements ¹	1,360
322	Boiler Plant Equipment ²	5,310
323	Turbine Gen. Plant Equipment ²	564
324	Accessory Electrical Equipment	880
325	Miscellaneous Power Plant Equipment	<u>240</u>
Total Direct Cost, Including Freight ³		8,354
	Indirect Construction Cost ⁴	<u>1,346</u>
Total Direct and Indirect Costs		9,700
	Engineering Design and Construction Management	<u>970</u>
Subtotal		10,670
	Contingency Allowance	<u>2,130</u>
TOTAL COST ⁵		12,800

1. Site conditions assumed to be level, clear, and of good soil bearing for spread footings.
2. Boiler and turbine building are enclosed.
3. Based on a 5-day week, 8 hours per day, with no provision for premium time. Connections to existing plant utility and process networks will be made by others within 10 ft of the respective cogeneration building(s) for all systems, including process steam and electric power.
4. Includes supervision, insurance, payroll taxes, temporary facilities, construction equipment, small tools, consumables, miscellaneous job expenses, overhead, and profit for contractors.
5. Does not include escalation, interest during construction, owner costs, and land costs which are not considered in a conceptual design.

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TABLE 7.2.2-1

CONCEPTUAL COST ESTIMATE
 AGRI-CHEM PLANT COGENERATION FACILITY
 (SIC 28 DOE REGION III, MARYLAND)

<u>Acct.</u> <u>No.</u>	<u>Description</u>	<u>Total</u> <u>\$1,000</u>
321	Structures and Improvements ¹	2,911
322	Boiler Plant Equipment ²	9,753
323	Turbine Gen. Plant Equipment ²	1,714
324	Accessory Electrical Equipment	1,966
325	Miscellaneous Power Plant Equipment	<u>476</u>
Total Direct Cost ³		16,850
Indirect Construction Cost ⁴		<u>2,790</u>
Total Direct and Indirect Costs		19,640
Engineering Design and Construction Management		<u>1,960</u>
Subtotal		21,600
Contingency Allowance		<u>4,300</u>
TOTAL COST ⁵		25,900

1. Site conditions assumed to be level, clear, and of good soil bearing for spread footings.
2. Boiler and turbine building are enclosed.
3. Based on 5-day week, 8 hours per day with no provision for premium time. Connections to existing plant utility and process networks will be made by others within 10 ft of the respective cogeneration building(s) for all systems, including process, steam and electric power.
4. Includes supervision, insurance, taxes, temporary facilities, construction equipment, small tools, consumables, miscellaneous job expenses, overhead and profit for contractors.
5. Does not include escalation, interest during construction, sales tax, owner costs, and land costs which are not considered in a conceptual design.

TABLE 7.2.3-1

CONCEPTUAL COST ESTIMATE
BREWERY PLANT COGENERATION FACILITY
(SIC 20, DOE REGION III, PENNSYLVANIA)

<u>Acct.</u> <u>No.</u>	<u>Description</u>	<u>Total</u> <u>\$1,000</u>
321	Structures and Improvements ¹	1,568
322	Boiler Plant Equipment ²	6,151
323	Turbine Gen. Plant Equipment ²	1,264
324	Accessory Electrical Equipment ²	1,239
325	Miscellaneous Power Plant Equipment	<u>303</u>
Total Direct Cost ³		10,525
Indirect Construction Cost ⁴		<u>1,745</u>
Total Direct and Indirect Costs		12,270
Engineering Design and Construction Management		<u>1,230</u>
Subtotal		13,500
Contingency Allowance		<u>2,700</u>
TOTAL COST ⁵		16,200

1. Site conditions assumed to be level, clear, and of good soil bearing for spread footings.
2. Boiler and turbine building are enclosed.
3. Based on 5-day week, 8 hours per day with no provision for premium time. Connections to existing plant utility and process networks will be made by others within 10 ft of the respective cogeneration building(s) for all systems, including process steam and electric power.
4. Includes supervision, insurance, taxes, temporary facilities, construction equipment, small tools, consumables, miscellaneous job expenses, overhead and profit for contractors.
5. Does not include escalation, interest during construction, sales tax, owner costs, and land costs which are not considered in a conceptual design.

The basic cogeneration system selected is a coal-fired spreader stoker boiler with an appropriate backpressure steam turbine generator set. Exhaust steam from the turbine is piped to the process. The primary cycle for this unit is shown in Figure A3-M-3, Block Flow Diagram and Heat Balance. Brief specifications of the major components are given in Table A3-1. For this size cogeneration plant, sized Ohio Pittsburgh No. 8 seam coal would be delivered by truck and unloaded into a reclaim pit from which a conveyor would transport the coal into coal bunkers located within the boiler building. Flue gas treatment, involving desulfurization and an electrostatic precipitator, has been included for environmental reasons. Ash handling is accomplished by means of a pneumatic conveyor system which transports both bottom and fly ash to a storage silo for truck loading and transport to an offsite disposal area. The sludge pond which receives effluent from the desulfurization system is periodically emptied into trucks for transport to the offsite disposal area. The one-line electrical diagram is shown on Figure A3-E-1 and a Project Milestone Schedule is shown on Figure A3-M-4 (Appendix A).

7.2.4 Air Separation Plant/Cluster Chemical Complex (SIC 28, DOE Region IV, Texas)

The Conceptual Cost Estimate shown in Table 7.2.4-1, is based on labor rates, including fringe benefits,, taken from a local urban area.

Other pertinent information for this cogeneration facility is summarized in Appendix A:

- The site plan of this plant is shown on Figure A4-M-1. The plot plan of the cogeneration facility is shown on Figure A4-M-2.
- The basic cogeneration system selected is a natural gas-fired turbine generator set with a waste-heat boiler. Steam from the waste-heat boiler is piped to the process. The primary cycle for this unit is shown on Figure A4-M-3, Block Flow Diagram and Heat Balance. Brief specifications of the major components are given in Table A4-1. The one-line electrical diagram is shown on Figure A4-E-1.
- A Project Milestone Schedule is shown on Figure A4-M-4.

7.2.5 Large Petroleum Refinery "B" (SIC 29 DOE Region IX, California)

The Conceptual Cost Estimate, Table 7.2.5-1, is based on labor rates, including fringe benefits, taken from a local urban area.

The basic cogeneration system selected consists of a combined-cycle configuration consisting of a naphtha-fired gas turbine generator set with a waste-heat boiler supplementary fired with low-sulfur residuals. An appropriate backpressure steam turbine generator set completes the cycle. Exhaust steam from the turbine is piped to the process.

Other relevant information is found in Appendix A:

TABLE 7.2.4-1

CONCEPTUAL COST ESTIMATE
AIR SEPARATION PLANT COGENERATION FACILITY
(SIC 28, DOE REGION VI, TEXAS)

<u>Acct.</u> <u>No.</u>	<u>Description</u>	<u>Total</u> <u>\$1,000</u>
321	Structures & Improvements ¹	633
322	Boiler Plant Equipment ²	4,471
324	Accessory Electrical Equipment	2,841
325	Miscellaneous Plant Equipment	456
344	Gas Turbine Plant	<u>8,355</u>
Total Direct Cost ³		16,756
	Indirect Construction Cost ⁴	<u>1,994</u>
Total Direct and Indirect Costs		18,750
	Engineering Design and Construction Management	<u>1,880</u>
Subtotal		20,630
	Contingency Allowance	<u>4,170</u>
TOTAL COST ⁵		24,800

1. Site conditions assumed to be level, clear, and of good soil bearing for spread footings.
2. Waste heat boiler and gas turbine buildings are open structures.
3. Based on 5-day week, 8 hours per day with no provision for premium time. Connections to existing plant utility and process networks will be made by others within 10 ft of the respective cogeneration building(s) for all systems, including process steam and electric power.
4. Includes supervision, insurance, taxes, temporary facilities, construction equipment, small tools, consumables, miscellaneous job expenses, overhead and profit for contractors.
5. Does not include escalation, interest during construction, sales tax owner costs, and land costs which are not considered in a conceptual design.

TABLE 7.2.5-1

CONCEPTUAL COST ESTIMATE
 LARGE REFINERY "B" COGENERATION FACILITY
 (SIC 29, DOE REGION IX, CALIFORNIA)

<u>Acct. No.</u>	<u>Description</u>	<u>Total \$1,000</u>
321	Structures & Improvements ¹	3,670
322	Boiler Plant Equipment ²	24,688
323	Turbine Generator Plant Equipment ²	4,462
324	Accessory Electrical Equipment	7,310
325	Miscellaneous Plant Equipment	1,554
344	Gas Turbine Plant	<u>23,584</u>
Total Direct Cost ³		65,268
Indirect Construction Cost ⁴		<u>10,732</u>
Total Direct and Indirect Costs		76,000
Engineering Design and Construction Management		<u>7,600</u>
Subtotal		83,600
Contingency Allowance		<u>16,700</u>
TOTAL COST ⁵		100,300

1. Site conditions assumed to be level, clear, and of good soil bearing for spread footings.
2. Waste heat boilers and gas turbine buildings are open structures; closed structure for steam turbine generators.
3. Based on 5-day week, 8 hours per day with no provision for premium time. Connections to existing plant utility and process networks will be made by others within 10 ft of the respective cogeneration building(s) for all systems including process steam and electric power.
4. Includes supervision, insurance, taxes, temporary facilities, construction equipment, small tools, consumables, miscellaneous job expenses, overhead and profit for contractors.
5. Does not include escalation, interest during construction, sales tax, owner costs, and land costs which are not considered in a conceptual design.

- The site plan of this plant is shown on Figure A5-M-1. The plot plan of the cogeneration facility is shown on Figure A5-M-2.
- The primary cycle for this unit is shown on Figure A5-M-3 Block Flow Diagram and Heat Balance. Brief specifications of the major components are given in Table A5-1. The fuels are naptha and low-sulfur residuals from the petroleum refinery. The one-line electrical diagram is shown on Figure A5-E-1.
- A Project Milestone Schedule is shown on Figure A5-M-4 (Appendix A).

7.2.6 Writing Paper Mill (SIC 26, DOE Region III, Pennsylvania)

The Conceptual Cost Estimate, Table 7.2.6-1, is based on labor rates, including fringe benefits, taken from a local urban area.

In addition, the site plan of this plant is shown on Figure A6-M-1 while the plot plan of the cogeneration facility is shown on Figure A6-M-2, both found in Appendix A.

The basic cogeneration system selected is a coal-fired spreader stoker boiler with an appropriate backpressure steam turbine generator set. Exhaust steam from the turbine is piped to the process. The primary cycle for this unit is shown on Figure A6-M-3, Block Flow Diagram and Heat Balance (Appendix A). Brief specifications of the major components are given in Table A6-1 (Appendix A). For this size cogeneration plant, sized coal from Pittsburgh No. 8 seam would be delivered by truck and unloaded into a reclaim pit from which a conveyor would transport the coal into coal bunkers located within the boiler building. Flue gas treatment, involving desulfurization and a baghouse, has been included for environmental reasons. Ash handling is accomplished by means of a pneumatic conveyor system which transports both bottom and fly ash to a storage silo for truck loading and transport to an offsite disposal area. The sludge pond, which receives effluent from the desulfurization system, is periodically emptied into trucks for transport to the offsite disposal area. The one-line electrical diagram is shown on Figure A6-E-1 and a Project Milestone Schedule is shown on Figure A6-M-4 (Appendix A).

7.2.7 Integrated Textile Mill (SIC 22, DOE Region IV, Alabama)

The Conceptual Cost Estimate, Table 7.2.7-1, is based on labor rates including fringe benefits taken from a local urban area.

In addition, the site plan of this plant is shown on Figure A7-M-1 while the plot plan of the cogeneration facility is shown on Figure A7-M-2 (Appendix A).

The basic cogeneration system selected consists of a wood chip-fired spreader stoker boiler with an appropriate backpressure steam turbine generator set. Exhaust steam from the turbine is piped to the process.

TABLE 7.2.6-1

CONCEPTUAL COST ESTIMATE
WRITING PAPER PLANT COGENERATION FACILITY
(SIC 26, DOE REGION III, PENNSYLVANIA)

<u>Acct. No.</u>	<u>Description</u>	<u>Total \$1,000</u>
321	Structures & Improvements ¹	3,272
322	Boiler Plant Equipment ²	22,435
323	Turbine Generator Plant Equipment ²	3,809
324	Accessory Electrical Equipment	3,212
325	Miscellaneous Power Plant Equipment	<u>817</u>
Total Direct Cost ³		33,545
Indirect Construction Cost ⁴		<u>4,605</u>
Total Direct and Indirect Costs		38,150
Engineering Design and Construction Management		<u>3,820</u>
Subtotal		41,970
Contingency Allowance		<u>8,330</u>
TOTAL COST ⁵		50,300

1. Site conditions assumed to be level, clear, and of good soil bearing for spread footings.
2. Boiler and turbine buildings are closed structures.
3. Based on 5-day week, 8 hours per day with no provision for premium time. Connections to existing plant utility and process networks will be made by others within 10 ft of the respective cogeneration building(s) for all systems, including process steam and electric power.
4. Includes supervision, insurance, taxes, temporary facilities, construction equipment, small tools, consumables, miscellaneous job expenses, overhead and profit for contractors.
5. Does not include escalation, interest during construction, sales tax, owner costs, and land costs which are not considered in a conceptual design.

TABLE 7.2.7-1

CONCEPTUAL COST ESTIMATE
INTEGRATED TEXTILE MILL COGENERATION FACILITY
 (SIC 22, DOE REGION IV, ALABAMA)

<u>Acct.</u> <u>No.</u>	<u>Description</u>	<u>Total</u> <u>\$1,000</u>
321	Structures & Improvements ¹	2,725
322	Boiler Plant Equipment ²	9,133
323	Turbine Generator Plant Equipment ²	1,904
324	Accessory Electrical Equipment	2,725
325	Miscellaneous Power Plant Equipment	<u>570</u>
Total Direct Cost ³		17,057
Indirect Construction Cost ⁴		<u>3,203</u>
Total Direct and Indirect Costs		20,260
Engineering Design and Construction Management		<u>2,040</u>
Subtotal		22,300
Contingency Allowance		<u>4,400</u>
TOTAL COST ⁵		26,700

1. Site conditions assumed to be level, clear, and of good soil bearing for spread footings.
2. Boiler and turbine buildings are closed structures.
3. Based on 5-day week, 8 hours per day with no provision for premium time. Labor rates, including fringe benefits, taken from a local urban area. Connections to existing plant utility and process networks made by others within 10 ft of the respective cogeneration building(s) for all systems, including process steam and electric power.
4. Includes supervision, insurance, taxes, temporary facilities, construction equipment, small tools, consumables, miscellaneous job expenses, overhead and profit for contractors.
5. Does not include escalation, interest during construction, sales tax, owner costs, and land costs which are not considered in a conceptual design.

The primary cycle for this unit is shown on Figure A7-M-3, Block Flow Diagram and Heat Balance (Appendix A). Brief specifications of the major components are given in Table A7-1 (Appendix A). For this size cogeneration facility, wood chips from storage are transferred onto a conveyor which transports the chips into bunkers located within the boiler building. For environmental reasons, particulate control is obtained by a venturi scrubber. Ash handling is accomplished by means of a pneumatic conveyor system which transports both bottom and fly ash to a storage silo for truck loading and transport to an offsite disposal area. The one-line electrical diagram is shown on Figure A7-E-1 and a Project Milestone Schedule is shown in Figure A7-M-4 (Appendix A).

7.2.8 Kraft Paper Mill (SIC 26, DOE Region I, New Hampshire)

The Conceptual Cost Estimate shown in Table 7.2.8-1, is based on labor rates, including fringe benefits, taken from a local urban area.

In addition, the site plan of this plant is shown on Figure A8-M-1 while the plot plan of the cogeneration facility is shown on Figure A8-M-2 (Appendix A).

The basic cogeneration system selected, consists of a coal-fired spreader stoker boiler with an appropriate backpressure and extraction steam turbine generator set. Extraction and exhaust steam from the turbine are piped to the process. The primary cycle for this unit is shown in Figure A8-M-3, Block Flow Diagram and Heat Balance (Appendix A). Brief Specifications of the major components are given in Table A8-1 (Appendix A). For this size cogeneration facility, sized coal from Ohio Pittsburgh No. 8 seam coal would be delivered by truck and unloaded into a reclaim pit from which a conveyor would transport the coal into coal bunkers located within the boiler building. Flue gas treatment, involving desulfurization and an electrostatic precipitator, has been included for environmental reasons. Ash handling is accomplished by means of a pneumatic conveyor system which transports both bottom and fly ash to a storage silo for truck loading and transport to an off-site disposal area. The sludge pond which receives effluent from the desulfurization system is periodically emptied into trucks for transport to the off-site disposal area. The one-line electrical diagram is shown on Figure A8-E-1 and a Project Milestone Schedule is shown on Figure A8-M-4 (Appendix A).

7.2.9 Textile Finishing Mill (SIC 22, DOE Region III, S. Carolina)

The Conceptual Cost Estimate shown in Table 7.2.9-1 is based on labor rates, including fringe benefits, taken from a local urban area.

In addition, the site plan of this plant is shown on Figure A9-M-1 (Appendix A). The plot plan of the cogeneration facility is shown on Figure A9-M-2 (Appendix A).

The basic cogeneration system selected is a coal-fired spreader stoker

TABLE 7.2.8-1

CONCEPTUAL COST ESTIMATE
KRAFT PAPER MILL COGENERATION FACILITY
(SIC 26, DOE REGION I, NEW HAMPSHIRE)

<u>Acct. No.</u>	<u>Description</u>	<u>Total \$1,000</u>
321	Structures & Improvements ¹	2,800
322	Boiler Plant Equipment ²	11,244
323	Turbine Generator Plant Equipment ²	3,048
324	Accessory Electrical Equipment	2,763
325	Miscellaneous Power Plant Equipment	<u>570</u>
Total Direct Cost ³		20,525
Indirect Construction Cost ⁴		<u>3,345</u>
Total Direct and Indirect Costs		23,870
Engineering Design and Construction Management		<u>3,330</u>
Subtotal		26,200
Contingency Allowance		<u>5,200</u>
TOTAL COST ⁵		31,400

1. Site conditions assumed to be level, clear, and of good soil bearing for spread footings.
2. Boiler and turbine buildings are closed structures.
3. Based on 5-day week, 8 hours per day with no provision for premium time, Labor rates, including fringe benefits, taken from a local urban area. Connections to existing plant utility and process networks made by others within 10 ft of the respective cogeneration building(s) for all systems, including process steam and electric power.
4. Includes supervision, insurance, taxes, temporary facilities, construction equipment, small tools, consumables, miscellaneous job expenses, overhead and profit for contractors.
5. Does not include escalation, interest during construction, sales tax, owner costs, and land costs which are not considered in a conceptual design.

TABLE 7.2.9-1

CONCEPTUAL COST ESTIMATE
TEXTILE FINISHING MILL COGENERATION FACILITY
(SIC 22, DOE REGION IV, S. CAROLINA)

<u>Acct.</u> <u>No.</u>	<u>Description</u>	<u>Total</u> <u>\$1,000</u>
321	Structures & Improvements ¹	2,663
322	Boiler Plant Equipment ²	20,996
323	Turbine Generator Plant Equipment ²	3,846
324	Accessory Electrical Equipment	2,850
325	Miscellaneous Power Plant Equipment	<u>802</u>
Total Direct Cost ³		31,157
Indirect Construction Cost ⁴		<u>3,453</u>
Total Direct and Indirect Costs		34,610
Engineering Design and Construction Management		<u>3,490</u>
Subtotal		38,100
Contingency Allowance		<u>7,600</u>
TOTAL COST ⁵		45,700

1. Site conditions assumed to be level, clear, and of good soil bearing for spread footings.
2. Boiler and turbine buildings are closed structures.
3. Based on 5-day week, 8 hours per day with no provision for premium time. Labor rates, including fringe benefits, taken from a local urban area. Connections to existing plant utility and process networks made by others within 10 ft of the respective cogeneration building(s) for all systems, including process steam and electric power.
4. Includes supervision, insurance, taxes, temporary facilities, construction equipment, small tools, consumables, miscellaneous job expenses, overhead and profit for contractors.
5. Does not include escalation, interest during construction, sales tax, owner costs, and land costs which are not considered in a conceptual design.

boiler with an appropriate extraction and backpressure steam turbine generator set. Extraction and exhaust steam from the turbine is piped to the process. The primary cycle for this unit is shown in Figure A9-M-3, Block Flow Diagram and Heat Balance (Appendix A). Brief specifications of the major components are given in Table A9-1 (Appendix A). For this size cogeneration plant, sized coal from Clift, Alabama seam would be delivered by truck and unloaded into a reclaim pit from which a conveyor would transport the coal into coal bunkers located within the boiler building. Flue gas treatment, involving desulfurization and an electrostatic precipitator, has been included for environmental reasons. Ash handling is accomplished by means of a pneumatic conveyor system which transports both bottom and fly ash to a storage silo for truck loading and transport to an offsite disposal area. The sludge pond, which receives effluent from the desulfurization system, is periodically emptied into trucks for transport to the offsite disposal area. The one-line electrical diagram is shown on Figure A9-E-1 and a Project Milestone Schedule is shown in Figure A9-M-4.

7.2.10 Summary of Investment Costs and Returns on Equity Envestment

Capital cost estimates developed in this section for the conceptual designs of cogeneration plants are summarized in Table 7.2.10-1. A comparison is also offered in this table with the preliminary investment costs shown in Section 6 which were developed from parametric equations and used in optimizing cogeneration systems. The cost variances ranged from -28% for the air separation plant to +19% for the kraft paper plant. Seven of the ten plants had variances which exceeded 5%.

The economic analyses of the optimum configuration of the seven plants with variances greater than 5% were rerun using the conceptual design cost estimates. Following the methodology of Section 6, interest during construction and escalation during construction were added. Where the variances were less than 5%, investments and ROE's found in Section 6 were used. The results are shown in Table 1.0-1. Only one of the plant/ownership options (textile finishing mill/third party ownership) showed a significant change relative to the ROE hurdle rates shown in Table 6.3-1. The ROE for the textile finishing mill with third party ownership fell below the assumed ROE hurdle rate for third party ownership (20%). As a result, the optimizations appear to reflect realistically ROE's and potential energy savings.

TABLE 7.2.10-1

COMPARISON OF PLANT CAPITAL COST ESTIMATES¹

<u>Plant</u>	<u>Estimate</u> <u>(\$ million)</u>		<u>Difference⁴</u> <u>(%)</u>
	<u>Parametric</u> <u>Equation²</u>	<u>Conceptual</u> <u>Design³</u>	
Brewery	15.6	16.2	+0.0385
Soybean Oil	12.9	12.8	-0.0078
Finishing Mill	41.0	45.7	+0.1150
Integrated Textile Mill	23.8	26.7	+0.1220
Writing Paper	52.2	50.3	-0.0364
Kraft Paper	26.3	31.4	+0.1940
Agricultural Chemical	27.6	25.9	-0.0616
Air Separation/Cluster Chemical Complex	34.6	24.8	-0.2830
Large Refinery	93.8	100.3	+0.0693
Medium Refinery	20.0	--	--

¹ Before escalation and interest during construction.

² From Section 6 and Appendix C.

³ From Section 7.

⁴ (Column 3 - Column 2) ÷ Column 2

8.0 POTENTIAL FOR ENERGY SAVINGS IN INDUSTRY

8.1 ENERGY SAVINGS

Table 8.1-1 summarizes industry energy use and savings resulting from application of cogeneration systems in the plants examined. Total energy savings (gas, oil, coal) are seen to range from a low of about 7% for the small (1.6 MW) cogeneration system in the soybean plant to over 20% for the large cogeneration plants found in the petroleum and chemical sectors.

We found the thermal to electric energy ratio relating to plant energy use to be an important consideration in selecting cogeneration systems for particular plants. Although energy use estimates have been made on an industry wide basis as discussed in Section 3 (see Table 3.1-1), we found that energy use by 4 digit Standard Industrial Classification (SIC) sector was not readily available. However, purchased fuels and electric energy by 4 digit SIC sector are reported by the U.S. Bureau of Census. In-plant waste and by-product fuels (if not derived from purchased energy forms) have to be added to purchased fuels to obtain total fuel use. Table 3.1-1 indicates that waste and by-product fuels are especially significant in the petroleum refining sector (SIC 29) and the pulp and paper sector (SIC 26).

These purchased and waste fuels are used not only for generating thermal energy requirements in a plant (e.g., steam, process heat requirements) but also in some facilities for generating electric energy and shaft power (such as a steam-driven, turbo compressor); in-plant, self-generated electric power (including hydroelectric power) is especially significant in the pulp and paper sector (SIC 26) as shown in Table 3.1-3. We have not found any readily available data on shaft power use in the industrial sector except 1) an estimate in petroleum refining that shaft power generation is equal to twice the electricity generation (see Subsection 3.7.1.2 dealing with petroleum refinery energy use), and 2) an estimate based on discussions with industry personnel that at least as much mechanical energy is supplied by steam driven equipment as by electrical cogeneration in the chemical sector (see Subsection 3.6.2).

Because of the lack of detailed energy use data by 4 digit SIC sector, census figures on purchased fuels and electric energy are used here in further discussions relating to the determination of thermal to electric energy ratios. This data, by 4 digit SIC sector, is shown in:

- Table 8.1-2 and Figure 8.1-1 for the Food Industry Sector,
- Table 8.1-3 and Figure 8.1-2 for the Textile Sector,
- Table 8.1-4 and Figure 8.1-3 for the Pulp and Paper Sector,
- Table 8.1-5 and Figure 8.1-4 for the Chemical Sector, and
- Table 8.1-6 and Figure 8.1-5 for the Petroleum Sector.

TABLE 8.1-1

SUMMARY OF ENERGY SAVINGS IF COGENERATION WERE IMPLEMENTED
IN SPECIFIC PLANTS CONSIDERED IN THIS STUDY

Sector	Plant Considered in this Study	Energy Use, Separate Generation ^c (Billion Btu/Yr)	Savings if Cogeneration Were Implemented (Billion Btu/yr)				Energy Savings As % of "Energy Use, Separate Generation"	
			Coal	Oil	Natural Gas	Total ^{a,e}	Oil and/or Natural Gas Saved	Total Energy Savings ^a
Food	Soybean	688	-498	--	544	46	79	6.7
	Brewery	811	-559	645	--	86	80	10.6
Textiles	Finishing Mill	3,549	-2,062	763	1,890	591	75	16.7
	Integrated Mill	2,606	-837	--	1,134	297	44	11.4
Pulp and Paper	Writing Paper	3,237	-45	--	501	456	15	14.1
	Kraft Paper	2,377	-1,402	1,728	--	326	73	13.7
Chemicals	Ag Chemical	1,890	-343	584	--	240 ^e	31	12.2
	Air Separation	8,315	5,602	--	-3,113	2,489	-37	29.9
Petroleum Refining	Medium	3,511	--	--	--	4,814	--	Footnote d
	Large/Complex	33,971	--	7,903 ^b	--	7,903	23	23.3
AVERAGE								15

^a Savings in coal, oil, gas and other fuels (e.g., wood) (rounded values).

^b Includes naphtha.

^c Based on electric energy converted at about 10,500 Btu/kWh and thermal energy at 3,413 Btu/kWh (e.g., see Table 6.2-8).

^d Excluded from average savings calculation since it represents using part of feedstock for generating fuels.

^e For example, savings of 240 billion Btu/yr out of 1,890 billion Btu/yr are achieved by implementing cogeneration in the Agricultural Chemical plant. Table 6.2-8 shows that 583.5 billion Btu/yr of oil are saved by increasing coal consumption by 343.4 billion Btu/yr which results in a net saving of 240 billion Btu/yr (i.e., 583.5-343.4).

TABLE 8.1-2

FOOD AND KINDRED PRODUCTS: PURCHASED FUELS AND ELECTRICITY

<u>SIC</u>	<u>Purchased Fuels</u> <u>(Trillion Btu/yr)</u>	<u>Electric Energy</u> <u>(Million kWh/yr)</u>
2011	52.8	3533.5
2013	12.5	1456.1
2016	12.5	1522.3
2017	2.9	251.7
2021	4.1	161.8
2022	19.4	858.2
2023	18.6	477.5
2024	3.3	848.9
2026	28.9	2963.8
2032	18.4	490.4
2033	40.8	1275.0
2034	11.3	425.8
2035	5.9	248.4
2037	24.2	1725.7
2038	7.5	1034.1
2041	5.5	1538.4
2043	7.6	509.6
2044	2.6	272.6
2045	1.2	202.2
2046	78.5	2133.6
2047	11.4	743.1
2048	21.7	1451.3
2051	33.2	2185.5
2052	9.0	523.5
2061	12.0	142.5
2062	33.3	498.0
2063	91.6	835.7
2065	10.1	1087.5
2066	3.4	320.7
2067	0.9	98.9
2074	4.9	512.7
2075	41.8	1427.4
2076	2.2	87.9
2077	21.7	560.0
2079	23.7	606.4
2082	39.8	2206.7
2083	8.3	323.8
2084	3.3	271.7
2085	14.0	280.3
2086	16.3	1350.2
2087	3.6	228.4

TABLE 8.1-2 (Cont.)

FOOD AND KINDRED PRODUCTS: PURCHASED FUELS AND ELECTRICITY

<u>SIC</u>	<u>Purchased Fuels</u> <u>(Trillion Btu/yr)</u>	<u>Electric Energy</u> <u>(Million kWh/yr)</u>
2091	2.6	134.0
2092	2.6	352.5
2095	8.8	481.0
2097	0.3	617.3
2098	1.6	251.1
2099	<u>24.4</u>	<u>1394.5</u>
TOTAL (SIC 20)	804.3	39061.7

Source: Annual Survey of Manufacturers, Bureau of the Census, 1976.

Source: Bureau of Census, 1976.

FIGURE 8.1-1 FOOD AND KINDRED PRODUCTS (SIC-20): PURCHASED ELECTRICITY VS. FUELS BY 4-DIGIT SIC SECTORS

TABLE 8.1-3

TEXTILE MILL PRODUCTS: PURCHASED FUELS AND ELECTRICITY

<u>SIC</u>	<u>Purchased Fuels</u> <u>(Trillion Btu./yr)</u>	<u>Electric Energy</u> <u>(Million kWh/yr)</u>
2211	18.8	4372.6
2221	28.7	7082.0
2231	5.5	341.7
2241	2.4	456.4
2251	2.6	486.2
2252	3.0	306.8
2253	6.0	697.3
2254	3.0	214.0
2257	18.4	1472.0
2258	8.1	730.1
2259	0.2	20.3
2261	24.2	490.3
2262	38.7	1132.4
2269	7.0	419.0
2271	1.7	104.8
2272	22.9	855.2
2279	0.5	41.9
2281	9.1	4476.2
2282	8.5	2112.9
2283	1.0	140.9
2284	2.5	368.0
2291	0.5	67.3
2292	0.3	17.8
2293	1.1	81.2
2294	0.7	96.3
2295	8.3	406.8
2296	2.2	752.3
2297	4.5	325.4
2298	0.8	168.0
2299	2.0	166.8
TOTAL (SIC 22)	233.0	28025.6

Source: Annual Survey of Manufacturers, Bureau of the Census, 1976.

Source: Bureau of Census, 1976.

FIGURE 8.1-2 TEXTILE MILL PRODUCTS (SIC-22): PURCHASED ELECTRICITY VS. FUELS BY 4-DIGIT SECTORS

TABLE 8.1-4

PAPER AND ALLIED PRODUCTS: PURCHASED FUELS AND ELECTRICITY

<u>SIC</u>	<u>Purchased Fuels</u> <u>(Trillion Btu/yr)</u>	<u>Electric Energy</u> <u>(Million kWh/yr)</u>
2611	87.2	5418.8
2621	516.2	33544.8
2631	430.5	20275.7
2641	14.1	954.8
2642	1.0	338.7
2643	5.2	1316.9
2645	2.9	192.8
2646	5.7	580.7
2647	6.6	887.3
2648	0.7	134.6
2649	5.0	403.8
2651	4.7	612.0
2652	1.2	108.1
2653	27.8	1638.5
2654	4.1	731.5
2655	2.2	236.7
2661	<u>31.3</u>	<u>1497.4</u>
TOTAL (SIC 26)	1146.3	43458.8

Source: Annual Survey of Manufactures, Bureau of the Census, 1976.

Source: Bureau of Census, 1976.

FIGURE 8.1-3 PAPER AND ALLIED PRODUCTS (SIC-26): PURCHASED ELECTRICITY VS. FUELS BY 4-DIGIT SIC SUB-SECTORS

TABLE 8.1-5

CHEMICALS, ALLIED PRODUCTS: PURCHASED FUELS AND ELECTRICITY

<u>SIC</u>	<u>Purchased Fuels (Trillion Btu/yr)</u>	<u>Electric Energy (Million kWh/yr)</u>
2812	109.8	15300.3
2813	54.8	11117.1
2816	41.2	1422.2
2819	225.1	59595.7
2821	140.1	8336.3
2822	36.2	1307.0
2823	54.9	522.8
2824	109.3	7399.4
2831	1.6	232.7
2833	21.9	744.3
2834	27.9	2522.8
2841	22.3	778.0
2842	6.5	427.7
2843	9.1	321.3
2844	4.3	553.8
2851	12.0	984.5
2861	7.9	250.6
2865	154.0	5091.5
2869	1021.8	29362.4
2873	282.8	5407.9
2874	55.7	3279.5
2875	2.6	189.2
2879	23.6	1018.4
2891	7.2	333.7
2892	17.3	486.0
2893	2.2	210.1
2895	26.3	538.0
2899	42.4	1182.0
TOTAL (SIC 28)	2520.9	145423.4

Source: Annual Survey of Manufacturers, Bureau of the Census, 1976.

FIGURE 8.1-4 CHEMICALS, ALLIED PRODUCTS (SIC-28): PURCHASED ELECTRICITY VS. FUELS BY 4-DIGIT SIC SECTORS

TABLE 8.1-6

PETROLEUM AND COAL PRODUCTS: PURCHASED
FUELS AND ELECTRICITY

<u>SIC</u>	<u>Purchased Fuels</u> <u>(Trillion Btu/yr)</u>	<u>Electric Energy</u> <u>(Million kWh/yr.)</u>
2911	1128.2	26277.4
2951	29.7	595.2
2952	26.7	592.0
2992	5.9	175.0
2999	<u>6.5</u>	<u>76.5</u>
TOTAL (SIC 29)	1197.1	27713.1

Source: Annual Survey of Manufacturers, Bureau of the Census, 1976.

Source: Bureau of Census, 1976.

FIGURE 8.1-5 PETROLEUM AND COAL PRODUCTS (SIC-29): PURCHASED ELECTRICITY VS. FUELS BY 4-DIGIT SIC SUB-SECTORS

In addition, we show in Figure 8.1-1 a dashed line representing the thermal to electric energy demand ratio for the brewery and soybean plant examined in the food sector of this report (see Section 6). Similarly, thermal to electric demand ratios for the other specific plants examined are shown by dashed lines on the appropriate industry plots (see Figures 8.1-2 through 8.1-6).

We focused on designing a cogeneration system to meet both a plant's thermal energy requirements and purchased electricity needs in an optimized cogeneration system as discussed in Section 6. In some cases, such as in textiles, we found that an optimized cogeneration system could satisfy the steam and electric needs but not the process heat requirements which would continue to be met by combusting fuels, typically natural gas. In other cases we found it necessary to be able to sell electric power, while in yet others we found we could meet plant energy requirements fairly closely by a cogeneration system. Moreover, cogeneration was already being practiced in several plants considered in this study such as the Kraft paper mill and for such cases we considered only additional cogeneration opportunities. Most of the optimized cogeneration plants proved to be economically viable under one or more types of ownership options. For comparative purposes, we developed the range in cogenerated energy supply systems examined in this study. For example, the lowest ratio of cogenerated process heat to electricity (RPHEE) was found in the petroleum sector for the medium-sized refinery where $RPHEE = 1.17 \text{ (kW}_t\text{/kW}_e\text{)}$; thus, the ratio of delivered process heat (steam) to electricity is about 4,000 Btu/kwhe. Similarly, the highest heat rate was found in the soybean plant where RPHEE was 14.9 yielding 51,000 Btu of thermal energy (steam) supplied per kilowatt of electricity. The range in thermal to electric energy ratios that could be supplied by the ten optimized cogeneration systems considered in this document is summarized by the two dotted lines appearing in each of the plots shown in Figures 8.1-1 through 8.1-5.

Examination of these figures shows that most of the 4 digit SIC sectors are included in the thermal to electric energy use range of the optimized cogeneration systems. Thus, one is led to suspect that for plants found in other subsectors of industries analyzed, there appears to be a reasonable technical chance of supplying a plant's purchased energy needs by cogeneration. As a result we anticipate that optimized cogeneration systems, developed for other plants not examined in this study, would exhibit a similar range in energy savings as found in Table 8.1-1.

For the actual plants examined, we found average energy savings of 15% as shown in Table 8.1-1. If the average percent savings found in each industry sector of Table 8.1-1 are weighted by energy use in that sector, we calculate average energy savings of 18%. Thus, depending on the method of calculating an average value, average energy savings can be either 15 or 18% of the five industry purchased energy requirements. These potential energy savings are derived from situations that are technically and economically suitable for cogeneration*.

*All cogeneration facilities examined in this study were calculated to achieve ROE hurdle rates (and thus deemed to be economically suitable for cogeneration) under one or more ownership options (see Table 6.3-1).

Total energy requirements in the 5 SIC sectors of interest to this study are calculated in Table 8.1-7 and are shown to be about 8.9 quads. Applying the 15-18% energy savings found above to the total five-industry energy use (in 1976) found in Table 8.1-7 yields potential energy savings of 1.34 to 1.6 quads or roughly 630,000 to 750,000 barrels of oil per day (based on 1 million bbl/day equalling 2.12 quads). This energy savings is calculated on the basis of 1976 purchased energy requirements and as such represents retrofit situations in the five industries considered. Potential savings of oil and natural gas can be significantly greater, but often a large fraction of such savings is achieved by greater use of coal. For example, Table 8.1-1 shows that the agricultural chemical plant can achieve total energy savings of about 12% by implementation of a cogeneration system, while fuel oil savings amount to 31% of total energy input (before cogeneration). To achieve this oil saving, more coal had to be used. As discussed in Section 6 (see Table 6.2-8), 583.5 billion Btu/yr of oil is saved by using an additional 343.4 billion Btu/yr of coal. Net savings are thus 240 billion Btu/yr (= 583.5 - 343.4) as shown in Table 8.1-1. An idea of the amount of coal substituted for natural gas or oil can be obtained by scanning the coal, oil, and gas savings columns in Table 8.1-1 (a negative value indicates increased use of that fuel).

8.2 DISCUSSION

Obviously, not all of these potential savings calculated can be realized under present economic, financial, and regulatory practices. One of the most comprehensive recent studies on the potential of cogeneration was completed by Research Planning Associates (1977).^{*} In addition to the five industry sectors studied here, RPA included an analysis of the steel industry. In Exhibit 1 of their study, RPA indicated about 6.6×10^{15} Btu of process energy was technically suitable for additional cogeneration in 1976. By 1985 a total of 7.3×10^{15} Btu would be technically suitable to be derived from cogeneration facilities simultaneously producing 380-740 billion kwh (or an average of 560 billion kwh). Using RPA's numbers, we calculate energy savings of 15-23% of the energy required under separate generation of process steam and electric power as follows:

- 7.3×10^{15} Btu process steam generated in steam raising boilers at 80% efficiency would require about 9.1 quads of fuels.
- 560 billion kwh of electricity generated in condensing turbines would require 5.9 quads of fuels.
- Total fuel energy requirements under separate generation are thus 15 quads (9.1 for steam and 5.9 for electricity).
- RPA calculated energy savings resulting from cogeneration of 2.2-3.5 quads or 15-23% of the 15 quads used under separate generation.

^{*}"The Potential for Cogeneration in Six Major Industries in 1985," Exhibit 1, December 1977.

TABLE 8.1-7

TOTAL ENERGY REQUIREMENTS

<u>SIC</u>	<u>Industry</u>	<u>Purchased Fuels</u> [†] (Trillion Btu/yr)	<u>Electricity</u>		<u>Total Energy Requirements</u> (Trillion Btu/yr)
			<u>Purchased</u> [†] (Billion kWh)	<u>Fuel Requirements</u> * (Trillion Btu/yr)	
20	Food	804	39	410	1,214
22	Textiles	233	28	294	527
26	Paper and Allied Products	1,146	43	452	1,598
28	Chemicals	2,521	145	1,523	4,044
29	Petroleum	1,197	28	294	1,491
TOTAL					8,874

[†]Source: Purchased fuels and purchased electricity are rounded values from Annual Survey of Manufacturers, Bureau of the Census, 1976.

*Fuel requirements to generate electricity are based on 10,500 Btu/kWh.

Such energy savings fall into the 7-30% range of values found for the plants studied in this report. However, one should recognize that we selected only plants that had a realistically good potential for cogeneration to begin with. In other words, we eliminated from consideration unrealistically small facilities, plants with lack of space, etc. and furthermore made no attempt to extrapolate to new facilities as RPA did. Thus, the above calculations based on RPA's data are not strictly comparable with this study, but it is interesting that the savings are of the same order of magnitude: 15-18% average energy savings by cogeneration found in this study versus 15-23% calculated from RPA's results. Thus, potential energy savings of 630,000 to 750,000 bbl/day (1.34-1.6 quads) that are calculated as being technically and economically achievable in this study for the five industry sectors considered does not appear to be an unrealistic potential.

*U.S. GOVERNMENT PRINTING OFFICE : 1980 O-311-703/24