DOE/TIC-11604
(DE82005587)

Industrial Cogeneration Optimization Program: A Summary of Two Studies

August 1981

Pictured on the cover is the coal-fired industrial cogeneration system providing electric power and process steam for Kerr-McGee Chemical Corporation's new Argus facility, a soda-ash plant at Trona, California. The system went on-line in mid-1978. Power is generated by two 27.5 MW steam turbine generators (located in the building in the foreground). Two 600,000 lb/hr pulverized coal boilers (located in the red framework) are fed by six closed coal/coke silos (grey silos in the picture). Another view of the Argus facility, at the left, shows the 15,000-ton live coal pile maintained near the dust-control tower through which incoming coal passes on a conveyor belt. No stack emissions are visible in these pictures even though they were taken while the plant was operating.

This system is the first large coal-fired industrial power plant in California and burns low-sulfur New Mexico coal, displacing oil- and gas-fired central station power that would otherwise be purchased by Kerr-McGee from Southern California Edison. The ICOP studies concluded that cogeneration systems and applications of this type are most likely to be economically atractive to industry as well as being in the national interest in reducing dependence on imported oil. Photos compliments of Kerr-McGee Chemical Corporation.

Available from the National Technical Information Service, U. S. Department of Commerce, Springfield, Virginia 22161.

Price: Printed Copy A03
Microfiche A01

Codes are used for pricing all publications. The code is determined by the number of pages in the publication. Information pertaining to the pricing codes can be found in the current issues of the following publications, which are generally available in most libraries: *Energy Research Abstracts, (ERA); Government Reports Announcements* and Index (*GRA* and I); *Scientific and Technical Abstract Reports (STAR);* and publication, NTIS-PR-360 available from (NTIS) at the above address.

DOE/TIC-11604
(DE82005587)
Distribution Category UC-95f (Modified)

Industrial Cogeneration Optimization Program: A Summary of Two Studies

August 1981

Prepared for

Oak Ridge National Laboratory
Oak Ridge, Tennessee
Operated by
Union Carbide Corporation
Under Contract W-7405-eng-26 with
the U.S. Department of Energy

This document was prepared by
TRW Energy Engineering Division
8301 Greensboro Drive
McLean, Virginia 22102
Under P.O. 62B13817C-62X30

CONTENTS

INTRODUCTION

This booklet summarizes two studies performed under the Department of Energy's Industrial Cogeneration Optimization Program (ICOP). These studies resulted in significant findings concerning the types of cogeneration systems and applications that are most likely to be both economically attractive to industry and in the national interest through conservation of energy and reduction of dependence on imported oil. As industries, utilities, and institutions become increasingly aware of the cost-saving potential of cogeneration and the availability of the technology, free market forces could work to expand the role of cogeneration in industry.

The ICOP studies examined the economic and energy-saving impacts of adding cogeneration to site-specific plants in five major energy-intensive industries:

- Chemicals
- Food
- Pulp and paper
- Petroleum refining
- Textiles

These industries account for about 54 percent of total industrial energy consumption.

A central conclusion of the ICOP effort was that steam turbine cogeneration systems fired by coal or alternative fuels are generally the most attractive in terms of economic performance and oil/gas savings potential. Of the 15 cogeneration systems selected as optimum in the ICOP studies, 11 were coal- or wood-fired steam turbines. By contrast, gas turbines, combined cycles, and diesel engines, which are currently limited to oil- or gas-firing, are usually less economical. Although these systems save more total energy than steam turbine systems, they are counterproductive in saving oil or natural gas unless they are located in regions where electric utilities are dependent on oil or gas for central station generation.

This booklet first presents an overview of industrial cogeneration in Chapter 1. Chapter 2 provides a description of the two parallel ICOP studies, with Chapter 3 summarizing the major findings and conclusions. Chapter 4 then presents short descriptions of the five industrial sectors, followed by highlights of each of the site-specific case studies.

For more detailed information, the two ICOP final reports are available from:

National Technical Information
Service (NTIS)
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

These reports are:

Industrial Cogeneration
Optimization Program
Final Report, September 1979
U.S. Department of Energy
Prepared by TRW, Inc., with
assistance from Thermo
Electron Corporation
NTIS No: DOE/CS/4300-1

Industrial Cogeneration
Optimization Program
Final Report, January 1980
U.S. Department of Energy
Prepared by Arthur D. Little,
Inc., Westinghouse Electric
Corporation, and Gibbs &
Hill, Inc.
NTIS No: DOE/CS/05310-1

Chapter 1. OVERVIEW OF COGENERATION

Cogeneration - the name is new, the practice is nearly a century old. In the early 1900's, most industrial plants generated their own electricity, and many practiced cogeneration by using the exhaust steam for process heat. As centrally generated electricity became cheaper, widely available, and more reliable, on-site generation of industrial electricity declined. Other factors contributed to the decline, and by 1979, on-site generation of electricity accounted for less than four percent of U.S. power generation. Now that industrial plants in many regions of the nation face significantly increased purchased electricity costs, the cost-saving potential of cogeneration is becoming more valuable to industrial users.

To foster the adoption of cogeneration by industry, the U.S. Department of Energy (DOE) established the Industrial Cogeneration Optimization Program (ICOP). Two parallel ICOP studies sponsored by DOE assessed site-specific options for cogeneration systems in major energy-intensive industries. The capsulized results of these studies are presented so that industries, utilities, and institutions will become increasingly aware of the growing body of information on cogeneration.

WHAT IS COGENERATION?

Cogeneration is the sequential production of electrical or mechanical energy and useful thermal energy from the same fuel source. In contrast to a conventional system that produces either electricity or thermal energy, a cogeneration system produces both and requires 10 to 30 percent less fuel. Industrial cogeneration saves primary fuels that would otherwise be used by utilities to produce central station power for sale to the industrial plants. Cogeneration thus offers significant overall energy-saving potential for the nation, as well as significant dollar savings potential for the cogenerator. Figure 1 shows, for a hypothetical case, fuel savings for a utility and overall potential dollar savings for the industrial plant when cogeneration is adopted.

Technically, there are two fundamental types of cogeneration systems: topping cycles and bottoming cycles. In a topping cycle, which is by far the most common type of cogeneration, electricity (or mechanical energy) is produced first and thermal energy from the exhaust is captured for further use. The system shown in Figure 1 is a topping cycle. In a bottoming cycle, thermal energy is captured from a waste stream and then used to produce power, usually by driving a turbine to generate electricity. Topping and bottoming cycles can be used together in a combined cycle system.

A variety of concepts and technologies is available for both topping and bottoming cycles. For example, in a steam turbine topping cycle, high-pressure steam produced by burning any of a wide variety of fuels is used to drive a turbine. The turbine exhaust is used for industrial processes, and the mechanical energy is converted into electricity in a generator. Other topping cycle options include gas turbines, diesels, and fuel cells. Bottoming cycles can operate with steam or an organic compound as the working fluid. Heat pumps may also be used with cogeneration prime movers to upgrade low-temperature heat for process use.

INDUSTRIAL COGENERATION CAN HELP SOLVE THE NATION'S ENERGY PROBLEM

Process heat, process steam, and electricity account for a major portion of industrial energy use. Through cogeneration, the fuel needed to produce

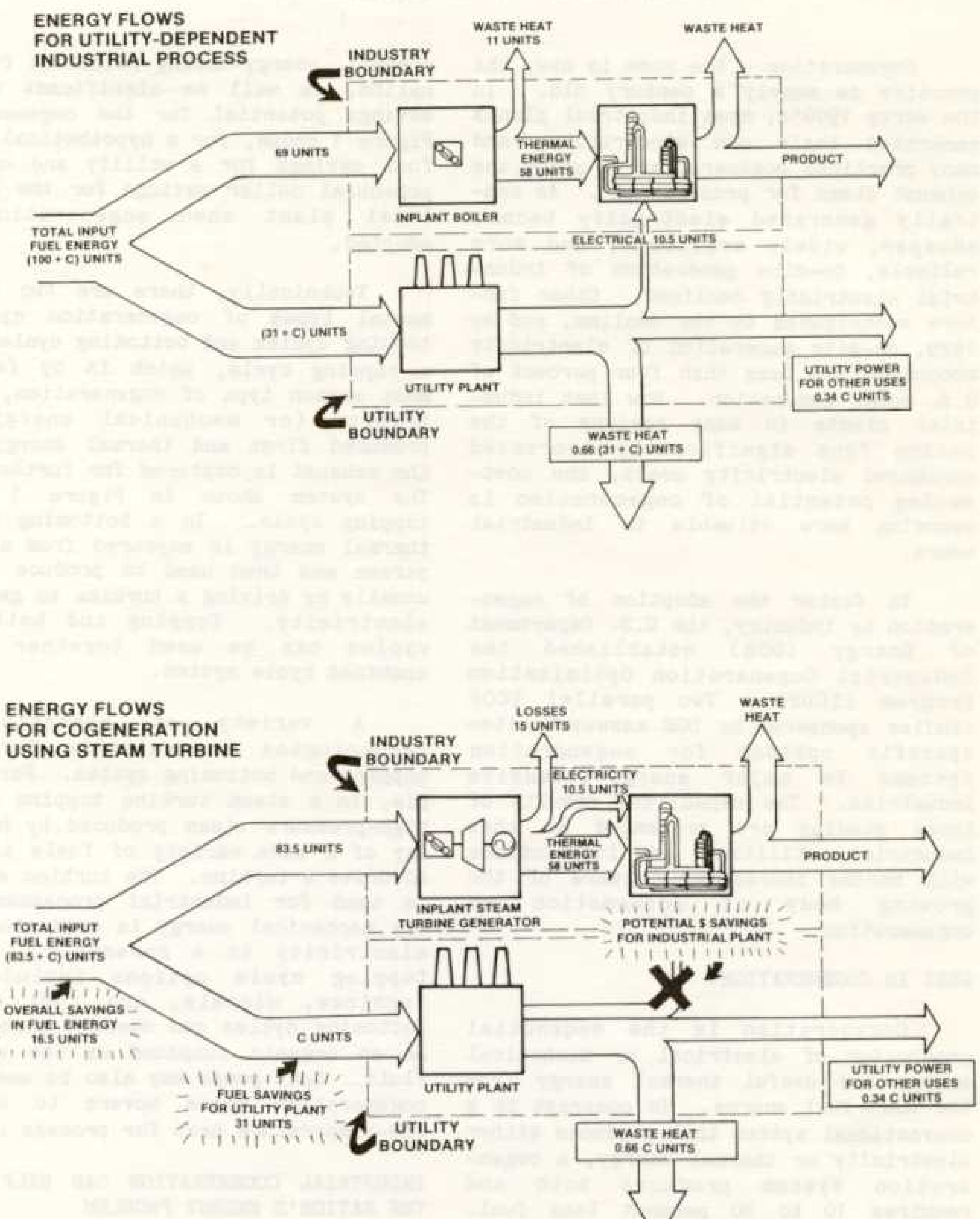


Figure 1. How Fuel and Dollars Can Be Saved When Cogeneration Is Adopted

this energy can be reduced. The greatest fuel-saving potential lies in those industries that are large energy consumers, such as the chemical, food, paper, petroleum refining, and textile industries.

If a cogeneration system is fueled with coal or alternative fuels (such as wood or process by-products) and either the industry or the utility had provided the services with oil or natural gas, then savings of these vital fuels (oil and natural gas) will result. Cogeneration thus has the potential to help lessen our nation's dependence on foreign oil and conserve our natural gas resources.

COGENERATION CAN HELP IN THE NEAR TERM

The technology for industrial cogeneration is available today. In addition, many cogeneration systems are currently economic, providing attractive returns on investment. As utility electricity prices increase, cogeneration systems will tend to become more economic. Furthermore, as oil and gas prices increase, cogeneration systems that conserve these fuels will become more economically attractive. The economics of replacing an oil-fired boiler with a coal-fired cogeneration system will improve as oil and electricity prices rise. Cogeneration has the potential to contribute energy savings in the near term (even within the next 5 years). If industries, utilities, and institutions become aware of the appropriate cogeneration systems and the availability of the technology, then free market forces could work to expand the role of cogeneration in industry.

How Fuel and Dollars Can Be Saved When Cogeneration is Adopted

In the hypothetical case, topping cycle cogeneration is assumed. The industrial process requires 58 units of thermal energy and 10.5 units of electrical energy. Without cogeneration, assuming an inplant boiler efficiency of 84%, 69 units of fuel energy are needed by the plant to provide thermal energy and 31 units of fuel energy are needed by the utility, operating at 34% efficiency, to provide 10.5 units of electrical energy. If the utility needs C units of fuel energy to provide electricity for its other customers, the total input to the industrial plant plus utility system would be 100+C units. If the industrial plant installs a steam turbine generator to provide the needed 58 units of thermal energy (unchanged from the first case) and 10.5 units of electrical energy independent of the utility, the fuel requirements of the utility are reduced by 31 units. The total fuel needs for the industrial plant are increased to 83.5 units; but the savings effected by not purchasing electrical power more than offset the cost of additional fuel and other system costs, thus providing a net dollar savings to the industry. Overall savings in fuel for both industrial plant and utility amount to 16.5 units in this example.

Chapter 2. THE ICOP STUDIES: WHAT AND WHY

ICOP is part of a DOE effort to reduce energy consumption by promoting industrial cogeneration. Two independent studies, both with the same objectives, were conducted simultaneously by teams headed by TRW, Inc. and by Arthur D. Little, Inc. (ADL).

OBJECTIVES

The primary objectives of ICOP as specified by DOE were to:

- o Characterize five major energy-intensive industries with respect to their energy use profiles. The industries were:
  - Chemicals and Allied Products (SIC 28)*
  - Food and Kindred Products (SIC 20)
  - Paper and Allied Products (SIC 26)
  - Petroleum Refining and Related Industries (SIC 29)
  - Textile Mill Products (SIC 22)
- o Select plants from each industry sector for site-specific analysis.
- o Select optimum cogeneration systems for site-specific plants, maximizing energy savings subject to industry-specific return on investment (ROI) or return on equity (ROE) hurdle rates.

(Private industry would normally optimize systems to maximize ROI rather than energy savings. The study results, however, are basically applicable to the real world because the primary ICOP optimization efforts were aimed at meeting the ROI hurdle rates.)

The ICOP studies also identified some of the technical, institutional, and regulatory obstacles hindering application of industrial cogeneration systems. The TRW team estimated the environmental effects of selected cogeneration systems, while the ADL study focused on satisfying all environmental regulations.

Using the results of the site-specific investigations, the ICOP study teams then estimated the potential national energy savings achievable through cogeneration in the five industries.

TWO PARALLEL STUDIES

DOE commissioned two private sector firms to perform ICOP studies in parallel. The contractors worked independently, choosing different industrial sites and different cogeneration schemes for optimization within the same five industries. The overall conclusions of the two studies were remarkably similar, thus enhancing the credibility of the results.

One of the study teams was headed by the Energy Engineering Division of TRW, Inc., with Thermo Electron Corporation as major subcontractor. The team also included New England Power Service Company, General Energy Associates (Drexel University), Charles T. Main, Inc., and industrial firms from the five industries: Exxon Research and Engineering Company; J. P. Stevens and Company; Scott Paper Company; E. I. DuPont de Nemours and Company; Union Carbide Corporation; and Greyhound Corporation (Armour and Company).

The other study team was headed by ADL, and included Westinghouse Electric Corporation and Gibbs and Hill, Inc.

---

* SIC = Standard Industrial Code

DESCRIPTION OF THE STUDIES

For each of the five industries, specific plants were selected as candidates for cogeneration systems. The TRW/Thermo Electron team selected eight plants for conceptual cogeneration system design and optimization. The ADL team selected 10 plants, two in each industry, and developed optimized cogeneration systems for each of these plants. The types of plants and their locations are shown in Table 1. The plants were selected to typify industrial practice, to represent a large fraction of energy use within the particular industrial sector, and to show good potential for cogeneration. Some geographical and plant size variation among the selected sites was also desired.

Conceptual cogeneration system alternatives were developed for the industrial plants. The TRW study developed site-specific design

Table 1. Industrial Plants Selected for Cogeneration Optimization

Industry	Type of Plant	Location	Study
Chemicals	Synthetic Textile Plant	Mid-Atlantic	TRW
	Synthetic Textile Plant	South Carolina	TRW
	Specialty Chemical Plant	West Virginia	TRW
	Agricultural Chemicals Plant	Maryland	ADL
	Air Separation Plant	Texas	ADL
Food	Meat Processing Plant	Missouri	TRW
	Hog Abattoir	Missouri	TRW
	Brewery	Pennsylvania	ADL
	Soybean Oil Mill	Indiana	ADL
Pulp & Paper	Integrated Paper Mill	Alabama	TRW
	Writing Paper Mill	Pennsylvania	ADL
	Kraft Paper Mill	New Hampshire	ADL
Petroleum Refining	Large Refinery	Louisiana	TRW
	Large Refinery	California	ADL
	Medium-Sized Refinery	Oklahoma	ADL
Textiles	Finishing Mill	South Carolina	TRW
	Finishing Mill	South Carolina	ADL
	Integrated Mill	Alabama	ADL

alternatives for each plant site based on the following options:

- Steam Turbine
  - Back-pressure
  - Extraction/condensing
- Gas Turbines
  - Open cycle with heat recovery
  - Combined cycle
- Diesels
  - Low-speed
  - Medium-speed
- Heat Pumps
  - Screw compressor
  - Westinghouse Templifier
- Fuel Cells
  - Phosphoric acid
- Bottoming Cycles
  - Steam
  - Organic Rankine

However, the conceptual designs selected for the specific plants were all steam turbines, gas turbines, or diesels. Fuel cells and bottoming cycles were incompatible with the plants selected, because reject heat from fuel cells was at too low a temperature to satisfy process needs, and plant reject heat was too cool or too corrosive to drive a bottoming cycle. The commercially available heat pumps were not economically attractive for upgrading cogenerated heat in the particular plants considered.

In the ADL study, conceptual designs were developed for the following cogeneration systems and these designs were then considered for each plant:

- Coal-fired conventional steam with particulate removal and flue-gas desulfurization
- Oil-fired gas turbine with waste heat boiler
- 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

Both studies included forecasted energy prices and availability through the year 2000. The forecasts were for delivered prices to industry by region for coal, residual oil, distillate oil, natural gas, and electricity.

The economic and energy savings for each conceptual cogeneration system were computed for each industrial plant, with the economic performance expressed as the ROI or ROE. The ADL study computed ROE for industrial ownership of the cogeneration system, utility ownership, and third-party ownership; various methods of financing the cogeneration systems were examined, depending on ownership. Optimum cogeneration systems were chosen for each industrial plant. The systems first had to have an ROI or ROE which exceeded an industry-specific hurdle rate. Then the optimum system was the one that realized the greatest energy savings. The fuel savings at the electric utility were computed based on fuels likely to be used at the utilities actually serving each plant.

The TRW study included an environmental assessment of each of the selected cogeneration systems. The assessment focused on air pollution emissions and considered the impact on overall emissions produced by adding the cogeneration systems. The ADL study designed cogeneration systems to meet current environmental regulations.

As a final step, the energy savings achieved by the optimum cogeneration system was projected to the national level. This projection was not the major thrust of the studies, but gives an indication of the potential of cogeneration in the five industries.

STUDY ASSUMPTIONS AND LIMITATIONS

The results and conclusions of the ICOP studies should be viewed in light of the following major assumptions and limitations under which the studies were conducted.

Technology Availability: The ICOP studies were limited to consideration of cogeneration components currently available or requiring only a modest advancement of available technology. Thus, the results are applicable to near-term systems.

Energy Prices: Both studies employed forecasts of energy prices through the year 2000. The national average energy prices used in each study are shown in Figures 2 and 3. (Regional or location-specific prices were used for the studies' analyses.) These prices include the assumed inflation*, and are in current dollars.) These forecasts were prepared in late 1978 and early 1979 and do not reflect dramatic increases in the price of oil occurring in late 1979 and early 1980. Taking into account these increases would reinforce the studies' conclusions that oil-fired cogeneration systems are less likely to be economically attractive than systems fired by coal or alternative fuels.

Cogeneration and Fuel Switching: In many of the cogeneration systems considered in ICOP, the installation of cogeneration was accompanied by a switch from oil or gas to lower-cost fuels. The purpose of ICOP was to evaluate cogeneration rather than fuel switching, and any oil and gas savings resulting from in-plant fuel switching were thus credited to cogeneration. In actual practice, however, industrial firms would evaluate fuel switching alone in addition to fuel switching plus cogeneration. Oil and gas savings through fuel switching would be attributed to cogeneration only if the fuel switch would not have occurred except for the added economic benefits of cogeneration. This limitation should be remembered when interpreting the ICOP results.

Rate Structures for Utility Electricity: The TRW study did not explicitly consider individual components of utility rate structures, which may include demand charges, ratchets, standby charges, and time-of-day pricing. The analyses used a composite rate or average charge per kilowatt-hour that includes all of these factors. The ADL study used an average kilowatt-hour price and a cost for standby power that was site-specific. This standby charge, plus higher escalation rates for coal, probably accounts for the generally lower investment returns found by the ADL study, as compared to the TRW study.

Optimization Criteria: The ICOP studies were directed to optimize the cogeneration system by maximizing energy savings, given a minimum ROI (or ROE) rate acceptable to industry. Normal industry practice would be to maximize ROI. However, most of the optimization effort in the studies was aimed at meeting the ROI hurdle rates. Therefore, the general conclusions of the study would not have been significantly different if ROI had been maximized in optimizing the cogeneration systems.

*For the TRW study, the average inflation rate for 1982-1990 was 5.8 percent. For the ADL study, an inflation rate of 7.5 percent per year was assumed. (These rates refer to the GNP price deflator.)

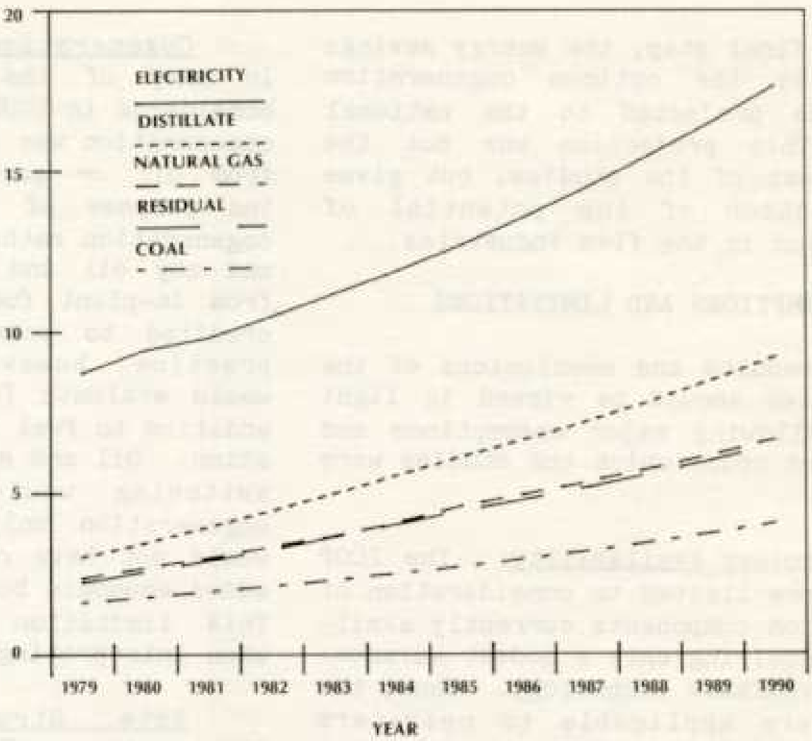


Figure 2. Industrial Energy Price Forecast for TRW Study, National Average in Current Dollars

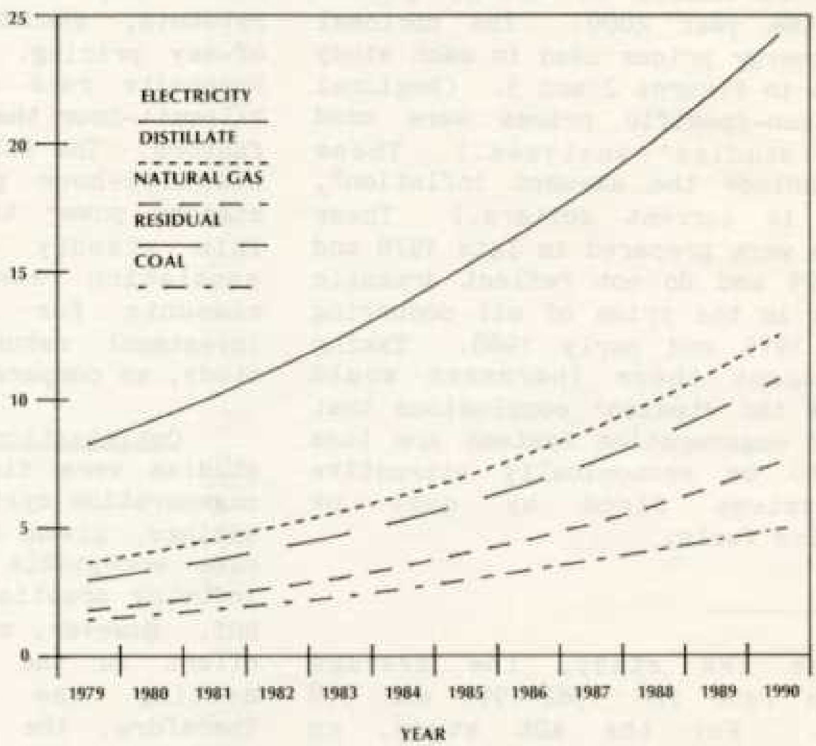


Figure 3. Industrial Energy Price Forecast for ADL Study, National Average in Current Dollars

Chapter 3. ICOP FINDINGS AND CONCLUSIONS

Cogeneration can be an economically viable means of saving energy and reducing dependence on imported oil, according to the results of the ICOP studies. The most economic cogeneration systems involved steam turbines fired by coal or alternative fuels, such as wood. Such systems were found to be optimum for most of the industrial plants considered. These systems generally produced the highest oil and gas savings.

The optimum cogeneration systems generally did not produce more electrical power than could be used in the plant, primarily because of the high thermal-to-electric ratios characteristic of steam turbines.

THE TRW/THERMO ELECTRON STUDY

Economics and Energy Savings

Based on the economic and energy savings analysis of cogeneration alternatives for each of the eight reference case plants, an optimum cogeneration system was selected for one plant in each of the five industries. Table 2 summarizes the results, based on the conceptual designs.

Four of the five systems selected were coal-fired steam turbine systems; the fifth system (for the food industry) was a small natural-gas-fired gas turbine. None of the systems produced electrical power for export.

ROI proved to be very sensitive to fuel and electricity prices; the use of low-cost coal and wood fuels made the steam turbine systems economic. Even using oil prices based on the 1978 OPEC price, the oil-fired systems considered could not produce an ROI that would meet the industrial investment criteria. Gas turbines and diesels, though they had the greatest net energy savings, could not, in general, meet the ROI hurdle rates.

Coal-fired cogeneration systems that displace coal and nuclear energy within the utility can still be a good economic investment by industrial standards.

The coal-fired steam turbine systems showed the greatest net oil and gas savings while meeting the ROI hurdle rates. The major mechanism for oil and gas savings, however, was industrial

Table 2. Summary of Selected Cogeneration Systems (TRW)

INDUSTRY	PLANT	SYSTEM	ROI (%)	HURDLE RATE RANGE (%)	NET ENERGY SAVINGS (10^{12} BTU/YR)	OIL & GAS SAVINGS (10^{12} BTU/YR)
Chemical	Union Carbide Institute, WV	7.9-MW Coal-Fired Steam Turbine	33.5	20-25	0.38	0
Food	Greyhound Kansas City, MO	0.88-MW Gas-Fired Gas Turbine	26.8	20-30	0.05	-0.03
Paper	Scott Paper Mobile, AL	52.9-MW Coal-/Wood-Fired Steam Turbine	17.7	16-19	0.86	0
Petroleum	Exxon Norco, LA	11.1-MW Coal-Fired Steam Turbine	14.7	10-30	0.37	5.95
Textiles	Stevens Cheraw, SC	5.25-MW Coal-Fired Steam Turbine	17.6	15-30	0.34	0.91

fuel switching rather than displacement of utility electricity. Oil- and gas-fired cogeneration systems are counterproductive in saving oil and gas unless they are located in regions where utilities are dependent on oil and gas for generation.

Environmental Effects

The environmental impacts of cogeneration are highly site-specific and depend on (1) the fuels used and displaced, (2) environmental controls employed, and (3) complex interactions between the cogeneration system and the electric utility. Net changes in air emissions are also dependent on the geographic locations of the utility plants affected. The coal-fired steam turbine systems predominant in the system selection resulted in an increase in local air emissions, which may or may not be offset by a reduction in utility emissions. Of the five selected cogeneration systems, two systems could result in net decreases in emissions, one would produce a net increase, and two would probably produce no significant change. Because of uncertainties in the types of utility fuels displaced and the locations where these displacements occur, however, it is not clear that net decreases in emissions would actually take place within the Air Quality Control Regions containing the industrial plants.

Regulatory Effects

The Public Utilities Regulatory Policies Act (PURPA) and the Powerplant and Industrial Fuel Use Act (FUA) can significantly affect cogeneration. PURPA contains a number of provisions designed to encourage industrial cogeneration by preventing electric utility discrimination and reducing utility-related state and Federal regulation. The FUA may prohibit oil and gas firing of a cogeneration facility unless an exemption is granted on the basis that cogeneration reduces oil or gas consumption. There are also other grounds for exemption. The evolving Federal Energy Regulatory Commission (FERC) and Economic Regulatory Administration (ERA) rules for implementing these two laws have acted as a disincentive to new cogeneration by creating uncertainty and thereby delaying investment decisions on the part of industry. The future of the FUA is uncertain under the current climate of reducing Federal regulation.

The existing legislation, however, would have a favorable impact on the cogeneration systems selected in the TRW ICOP study. Four of the five cogeneration systems selected in ICOP burn coal and do not increase oil or gas consumption. As a result, these systems would avoid the regulatory problems associated with the FUA and would be eligible to receive the benefits of PURPA. The gas-fired gas turbine for the Greyhound Food plant results in a small net increase in oil and gas consumption, but the unit is too small to fall under FUA jurisdiction.

National Level Energy Savings

National net energy savings due to cogeneration could reach 0.3 quads* annually by 1985 for the five industries studied, according to the ICOP estimate. Net oil and natural gas savings, however, were estimated at 0.75 quads, as a result of a switch from oil or gas to coal or alternative fuels that frequently accompanies the installation of economic cogeneration systems.

Although 78 percent of the potential energy savings are in the pulp and paper industry, chemicals and petroleum refining account for 85 percent of the potential oil and gas

---

*One quad = One quadrillion Btu (or approximately one quintillion joules), which is equivalent to about 170 million barrels of oil.

savings. The industries have differing potentials for switching from oil and gas to coal and alternative fuels when implementing cogeneration. The food industry, with small plants and intermittent operations, has little potential for cogeneration.

The greatest oil and gas savings potential is in the Southwest Power Pool region, where there is a significant concentration of plants in the petroleum and chemical industries and utilities depend on natural gas and oil for electric generation.

THE ADL STUDY

Technical-Economic Considerations

For each of the five industrial sectors, two plants were identified as favorable near-term opportunities for industrial cogeneration. Most of the industrial plants studied operated 24 hours per day with some facilities closing on weekends. The energy demand profiles were fairly constant, and heat storage devices were usually considered inappropriate. The results presented here are only applicable to plants operating 24 hours a day without large fluctuations in steam or electrical demand.

The optimum cogeneration systems (Table 3) involved steam-topping turbines (back-pressure or extraction) in seven of the ten cases. In six of these cases, coal was the most economic fuel; wood, in plentiful local supply, was the fuel choice for the seventh plant, a textile mill. The cogeneration systems for the remaining three cases were selected largely as a response to local energy availability and fuel costs.

With the exception of the petroleum refining industry, the operation of the ten optimized cogeneration systems resulted in a net demand for electrical power, largely because of the high thermal-to-electric ratios characteristic of steam turbines. However, when economically priced natural gas or petroleum fuels were available, the optimized cogeneration facilities (generally gas turbines) exhibited low thermal-to-electric ratios, resulting in electric energy generation in excess of plant needs.

Financial Considerations

Investments in coal cogeneration systems for the ten plants ranged from $12.9 million to just over $100 million. All ten plants met ROE criteria under at least one of the three ownership options (industry, utility, or third party).

A variety of reasons led to attractive ROE for cogeneration systems:

- Low incremental investment costs when an obsolete process boiler needed replacement
- Low unit investment costs achieved by large-sized cogeneration units
- High electric energy costs
- Low-cost cogeneration fuel

With utility ownership, the cogeneration system is compared with new central utility capacity, and the economics become more favorable; ROE and energy savings tend to be simultaneously maximized. If investment in cogeneration is less costly than new central generation, then the incremental investment is negative and the ROE is infinite (reported as greater than 1000 in the tables).

However, under the currently typical industrial ownership, only five of the ten plants showed a positive ROE. Financial disincentives include the cost and difficulty in raising capital, long depreciation periods (28 years), and high charges by electric utilities if the cogeneration system has an outage resulting in short-term power purchases from the utility.

National Level Energy Savings

Compared to separate generation of process steam and electric power, the optimized cogeneration systems in this study yielded an average energy savings of 15 to 18 percent. 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. This represents, in essence, a savings close to the technical limit of energy savings and thus is a higher estimate than that made by the TRW study.

Table 3. Summary of Plant Optimization Results (ADL)

Industry	Type of Plant & Location	Fuel and Cogeneration System	Return on Equity (%) Industry Ownership	Utility Ownership	Third Party Ownership	Net Energy Savings (10^{12} BTU/YR)	Oil & Gas Savings (10^{12} BTU/YR)
Chemicals	Agricultural Chemicals Maryland	10.5-MW Coal-Fired Conventional Steam with Back-Pressure Turbine	15.2	39.2	44.5	0.24	0.58
	Air Separation Texas	64-MW Gas-Fired Gas Turbine with Waste Heat Boiler	18.0	>1000*	28.4	2.49	-3.11
Food	Brewery Pennsylvania	4-MW Coal-Fired Conventional Steam with Back-Pressure Turbine and Steam Accumulator	12.2	18.2	<0	0.09	0.65
	Soybean Oil Mill Indiana	2.1-MW Coal-Fired Conventional Steam with Back-Pressure Turbine	12.2	13.7	<0	0.05	0.54
Paper	Writing Paper Mill Pennsylvania	22-MW Coal-Fired Conventional Steam with Back-Pressure Turbine	0	23.7	<0	0.46	0.50
	Kraft Paper Mill New Hampshire	10-MW Coal-Fired Conventional Steam with Double Extraction/Back-Pressure Turbine	0	34.8	26.7	0.33	1.73
Petroleum	Large Refinery California	235-MW Naphtha Low Sulfur Residual Combined Cycle with Single Extraction/Back-Pressure Turbine	0	>1000*	<0	7.90	7.90
	Medium-Sized Refinery Oklahoma	31.1-34.9-MW Bottoming Cycle Turbo Expander/Steam Rankine/Organic Rankine	88.3	—	—	3.15	3.15
Textiles	Finishing Mill S. Carolina	20-MW Coal-Fired Conventional Steam with Single Extraction/Back-Pressure Turbine	0	26.6	15.1	0.50	2.23
	Integrated Mill Alabama	9-MW Wood-Fired Conventional Steam with Back-Pressure Turbine	0	30.1	<0	0.30	1.13

*ROE proved to be very large and was taken to be greater than 1000.

For each of the five major industrial sectors, cogeneration systems were designed, analyzed, and optimized for site-specific plants. Some of the details about these systems and the resulting implications are presented for each industry sector.

The TRW study assumed a 1982 startup to compute the economics of the cogeneration systems. The capital costs include escalation and interest during construction and are in current dollars (valid at construction start, January 1979 or later). The ADL team assumed a 1978 startup for their cogeneration systems, and the capital costs are given in December 1978 dollars.

CHEMICAL INDUSTRY

The chemical and allied products industry (SIC 28) is a major consumer of energy and the producer of a wide 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 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 percent 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).

Cogeneration is widespread in the industry. In 1976 the chemical industry generated 18.5×10^9 kWh of electricity (Bureau of Census), largely by cogeneration. The percentage of self-generated electricity has been dropping over the years; there is much untapped potential for cogeneration.

Mechanical cogeneration, in which mechanical energy and steam are produced, is also widespread in the chemical industry. Experience with such equipment shows that rising energy prices do not always work to the advantage of mechanical cogeneration. Several larger plants reported that new energy conservation measures have reduced their steam demand below that supplied by their cogeneration systems. Thus, to avoid wasting steam at times of low demand, a number of steam turbines (providing mechanical cogeneration) are being converted to electric motors. This phenomenon may be widespread.

Investments in process-related projects have priority over energy projects in the industry. The hurdle rate for investment is generally a ROI of about 20 to 25 percent. Utility ownership of cogeneration facilities, however, may be attractive with an ROE of about 11 to 14 percent.

The ICOP studies examined potential cogeneration systems for a variety of chemical plants in this diverse industry: an air separation facility, a small agricultural chemical plant, two synthetic textile fiber plants, and a specialty chemicals plant.

The DuPont synthetic textile fiber plant located in the mid-Atlantic region proved not to be a good candidate for cogeneration. Gas-fired gas turbines could possibly be economic, but the future availability of gas for industrial use is too uncertain for DuPont to invest in such a system.

Air Separation Plant (ADL)

This Texas plant, selected for the ADL study, is a large, new air separation plant that produces oxygen for some adjacent petrochemical plants. Although air separation plants have negligible demand for process heat, their large demand for electricity combined with proximity to major steam-consuming industries makes them candidates for cooperative cogeneration projects. This plant was selected as an example of intercompany transfer of energy through cogeneration.

The potential market for process steam to satisfy incremental steam requirements due to expansion of the petrochemical plants is estimated to be 500,000 pounds per hour at 215 psia. There may also be a market for an additional 500,000 pounds per hour of steam to replace part of the steam being produced by existing boilers.

The optimum cogeneration system for this plant is a gas-fired gas turbine with a waste heat boiler, sized to match the power requirements. This system proved optimal since, for this case, natural gas was less expensive than coal and the gas turbine system had a relatively low capital cost. About 280,000 pounds per hour of steam at 215 psia would be available for sale to the neighboring industries. Details on the optimized cogeneration system are given in Table 4.

The gas turbine cogeneration system would result in additional natural gas being burned at the plant and savings of coal at the utility, as shown in Figure 4.

Table 4

Data on Air Separation Plant

Location		Texas
Cogeneration Components		Gas Turbine Waste Heat Boiler
Fuel Type		Natural Gas
Electrical Output (Net)		64 MW
Steam Output (Net): @ 215 psia, 388°F		362,556 lb/hr
Steam for Export		280,000 lb/hr
Ratio of Thermal to Electrical Energy		1.4
Capital Cost		$24,800,000
ROE:	Industry Ownership	18%
	Utility Ownership	>1000%*
	Third-Party Ownership	0

*Negative Incremental Investment

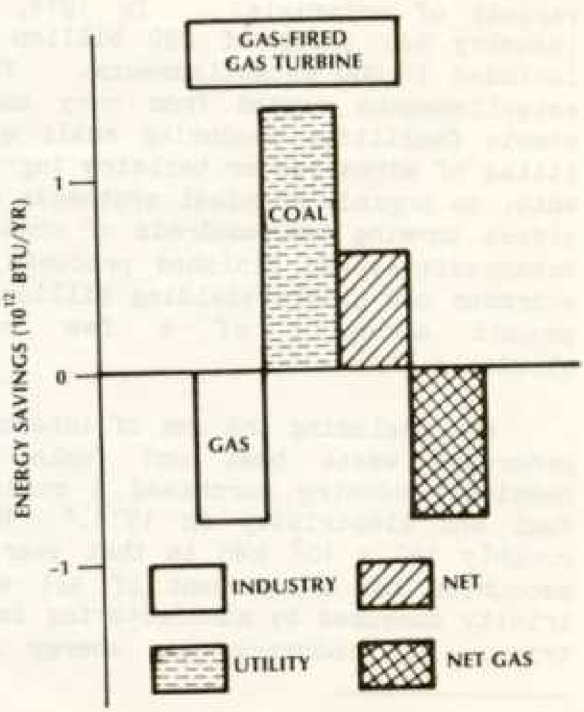


Figure 4. Energy Savings for Air Separation Plant

Agricultural Chemicals Plant (ADL)

The plant chosen is a pesticide plant in Maryland that is similar in size to many other modestly sized plants in the industry. This plant was selected by the ADL study team as an example of cogeneration opportunities in a smaller chemical plant. Most large chemical plants are already cogenerating to some degree, but the cogeneration potential is largely untapped in smaller plants.

The optimum cogeneration system for this plant was a coal-fired steam turbine with flue gas desulfurization. Both the low cost of the fuel and the match to the plant's heat-to-electricity ratio made this system more attractive than the other option considered, a low-sulfur residual-oil-fired gas turbine with a waste heat boiler. The throttle pressure of the back-pressure steam turbine was optimized at 1215 psia, the highest pressure possible at the power rating of the plant. Data on the optimum system are given in Table 5.

A new coal-fired cogeneration system would replace low-sulfur residual oil presently burned at the plant and displace coal burned at the utility. Figure 5 shows the resulting energy savings with the net oil savings shown by the last bar.

Table 5
Data on Agricultural Chemicals Plant

Location		Maryland
Cogeneration Components		Coal Boiler Steam Turbine Generator
Fuel Type		Coal
Electrical Output (Net)		10.5 MW
Steam Output (Net): @ 175 psia, 546°F		191,000 lb/hr
Steam for Export		None
Ratio of Thermal to Electrical Energy		8.3
Capital Cost		$25,900,000
ROE:	Industry Ownership	15.2%
	Utility Ownership	39.2%
	Third-Party Ownership	44.5%

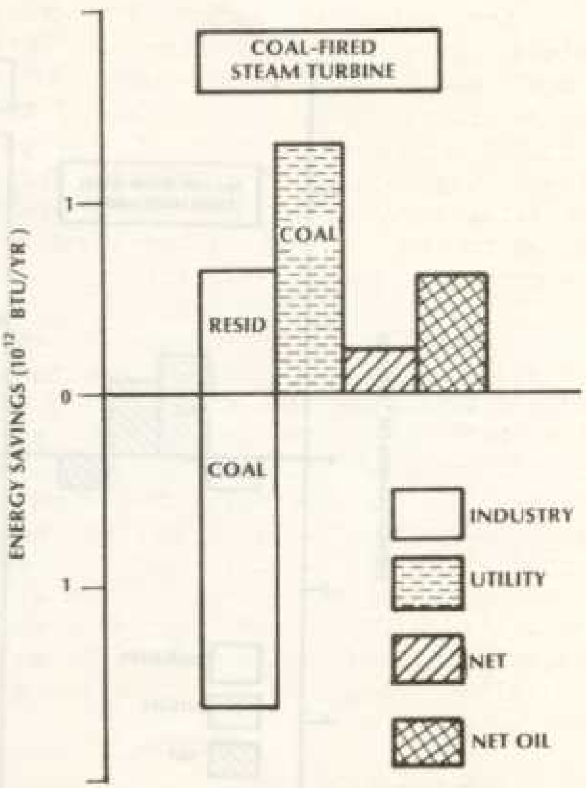


Figure 5. Energy Savings for Agricultural Chemicals Plant

Synthetic Textile Fiber Plant (TRW)

The TRW ICOP team considered a DuPont synthetic textile plant, located in South Carolina. The site consists of two adjacent processing plants; one plant produces intermediates that are used in the second plant for synthetic textile fiber production. Each plant has steam boiler facilities that are fired by residual oil, with no current cogeneration.

Three of the alternative cogeneration systems considered for the DuPont plants were (1) a 16.1-MW slow-speed residual oil-fired diesel engine topping existing boilers, (2) double-extraction 11.1-MW steam turbine generators powered by new coal-fired boilers, and (3) a 34.4-MW distillate-fired gas turbine topping existing process heaters. None of the three systems results in power export.

Only the coal-fired steam turbine system is likely to meet DuPont's ROI hurdle rate, because of fuel costs. The gas turbines, in particular, replace residual oil with higher cost distillate oil. However, this system was not one of the final systems chosen for optimization and so no data table is provided here.

Figure 6 illustrates the energy savings. Coal and possibly nuclear fuel are displaced at the utility. Although the steam turbine system is the smallest energy saver, it is the only system that produces positive oil savings, due entirely to the substitution of coal for residual oil in the plant.

An ROI of 21 percent was calculated for the steam turbine system. Using DuPont's local energy price forecasts, which predict higher escalation of residual oil price, the ROI is increased to 28 percent, illustrating the sensitivity of the ROI to fuel prices.

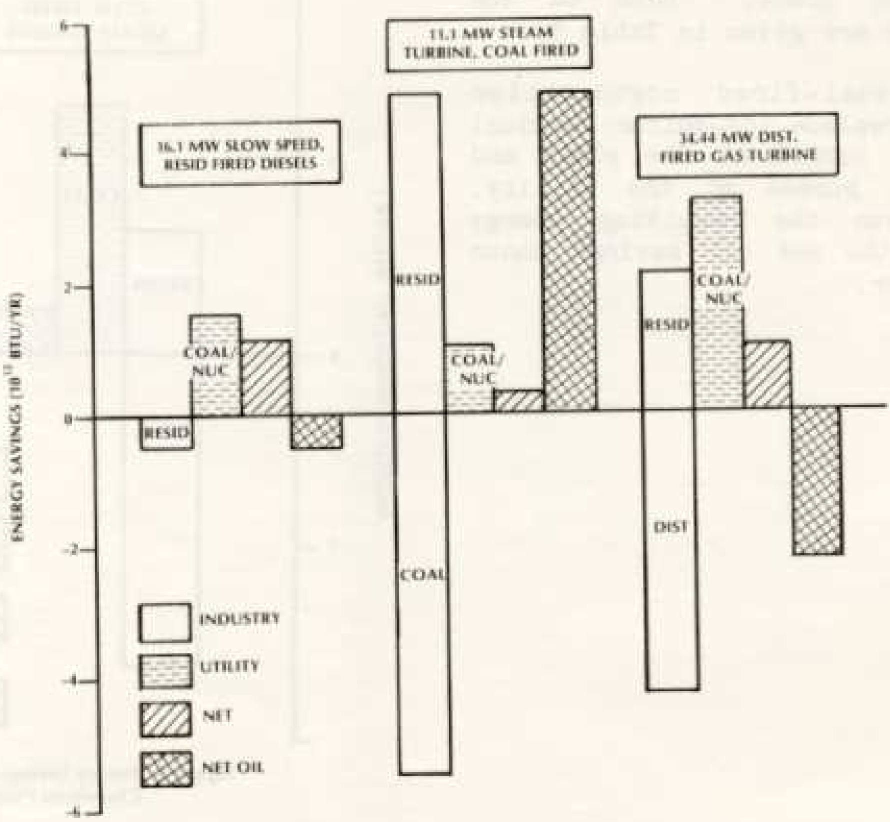


Figure 6. Energy Savings for Synthetic Textiles Plant

Specialty Chemicals Plant (TRW)

The Union Carbide specialty chemicals plant in Institute, West Virginia presents a very attractive opportunity for cogeneration. The facility is currently being converted to coal. Although the plant now cogenerates shaft power using back-pressure and extraction steam turbines, throttling valves are also used in the steam distribution system to reduce 415-psia steam to 90 psia for process use. By the interposition of a steam turbine between these two headers in place of throttling valves, electricity can be generated as the steam pressure is reduced. There are no new boilers required for this system but merely a requirement for additional coal firing in the existing boilers.

This coal-fired steam turbine system has a low capital cost and low fuel costs which result in an attractive ROI of 33.5 percent. A sensitivity analysis showed the ROI for this system exceeds 20 percent for a wide range of energy prices.

Data for this 7.9 MW cogeneration system are given in Table 6, with the energy savings shown in Figure 7. Coal burned at the utility is displaced by this cogeneration system, resulting in a net coal savings - equivalent to 380 billion Btu per year. This also results in a net decrease in air emissions, though not a decrease at the plant site.

Table 6
Data on Specialty Chemicals Plant

Location	Institute, West Virginia
Cogeneration Components	Coal Boiler Steam Turbine Generator
Fuel Type	Coal
Electrical Output (Net)	7.9 MW
Steam Output (Net): @ 75 psig, 320°F @ 200 psig, 388°F	200,000 lb/hr 125,000 lb/hr
Steam for Export	None
Ratio of Thermal to Electrical Energy	14.7
Capital Cost	$2,800,000
ROI	33.5%

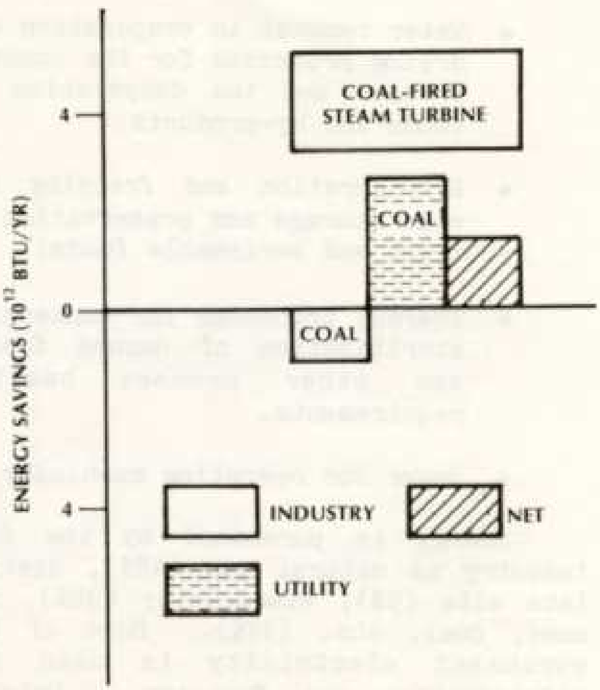


Figure 7. Energy Savings for Specialty Chemicals Plant

FOOD AND KINDRED PRODUCTS

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 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.* The food industry is a large consumer of energy because of its size, rather than because of energy-intensive processes.

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 the 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 as natural gas (48%), distillate oils (5%), electricity (30%), and coke, coal, etc. (17%). Most of the purchased electricity is used for refrigeration and freezing. Only a small portion of the gas used is consumed in processes that require the "cleanliness" of gas, such as direct-fired driers; most gas, along with the oil and solid fuels, is used to generate process steam in boilers.

The outlook for the continuing use of natural gas and oil in the food industry appears good if the industry can maintain its priority status. Coal is not excluded for health reasons but is viewed as uneconomical in small installations.

In general, there is a strong incentive to save on energy costs, particularly in the meat packing industry. Serious efforts are made to account for energy uses and to initiate conservation measures where feasible. However, the industry is generally marked by small base-load power demands, mainly for refrigeration, and large fluctuating thermal demands. Under these circumstances, only a very limited amount of cogeneration can be practiced, particularly without economical energy storage devices. Power export might be considered but only if free from litigation, liability, or regulatory constraints. Utility ownership is the more attractive alternative. Industry ROE/ROI hurdle rate was estimated at 16 percent by the ADL team and 20 to 30 percent by the TRW team. Utilities, however, could accept an ROE of 11 to 12 percent.

The highly fragmented nature of the industry makes it difficult to choose a typical plant for a cogeneration analysis. Four plants from this diverse industry were chosen for the ICOP studies: a meat processing facility, a hog abattoir, a soybean mill, and a brewery. However, none of the three gas-fired cogeneration systems considered for the hog abattoir produced an attractive ROI; the systems were small, did not operate continuously, and replaced utility steam (currently cogenerated).

---

*Census of Manufacturers, 1976.

Meat Processing Facility (TRW)

The TRW ICOP study analyzed cogeneration possibilities for a Greyhound Corporation (Armour and Company) meat processing plant in Kansas City, Missouri. This plant is representative of SIC 2013 within the food industry (SIC 20).

The optimum cogeneration system selected for this facility was a natural-gas-fired gas turbine with a waste heat boiler. Low capital cost combined with relatively inexpensive, locally abundant natural gas gave this system an acceptable ROI.

Data on the optimized system are given in Table 7. This system displaces coal burned at the utility and replaces services previously supplied by distillate oil and natural gas at the industry; this results in increased use of natural gas but a net energy savings (shown in Figure 8). The system results in a slight reduction in net air emissions.

Four other cogeneration options were considered for the plant, which requires 2 MW of electricity, 30-psia steam, 140°F water, and direct heat: (1) a medium-speed natural-gas-fired engine generating 3.88 MW with a heat recovery boiler, (2) a coal-fired steam turbine generating 239 kW, (3) a natural-gas-fired steam turbine generating 252 kW, and (4) a natural-gas-fired, back-pressure steam turbine also supplying cooking heat and generating 283 kW. None of these systems, which generally had high capital costs, produced acceptable ROI's.

Table 7
Data on Meat Processing Facility

Location	Kansas City, Missouri
Cogeneration Components	Gas Turbine Waste Heat Boiler Open Heat Exchanger
Fuel Type	Gas
Electrical Output (Net)	0.88 MW
Steam Output (Net): @ 30 psia	7,720 lb/hr
Steam for Export	None
Ratio of Thermal to Electrical Energy	2.8
Capital Cost	\$360,000
ROI	26.8%

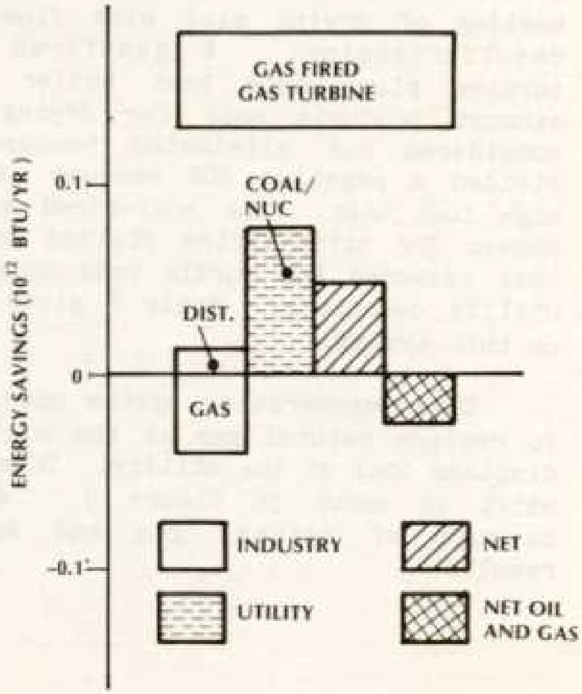


Figure 8. Energy Savings for Meat Processing Facility

Soybean Oil Mill (ADL)

Soybean oil mills account for five percent of the total energy used in the food and kindred products industry. The plant chosen by the ADL team is a medium-sized mill with a crushing capacity of 40,000 bushels per day, and is typical of most plants in the industry. The plant, located in Indiana, produces desolventized crude soybean oil, desolventized ground meal, and toasted ground hulls.

The soybean oil mill operates continuously with essentially constant energy demands. Electricity demand is 1.6 MW; steam use is 45,000 pounds per hour at 165 psia supplied by a single boiler burning oil or natural gas. Direct heat for bean drying is supplied by propane or natural gas.

The optimum cogeneration configuration for this plant was a coal-fired back-pressure steam turbine (indirect heating of drying air) with flue gas desulfurization. A gas-fired gas turbine plus waste heat boiler with exhaust products used for drying was considered but eliminated because it yielded a negative ROE because of the high fuel cost. The coal-fired system chosen for optimization yielded an ROE that exceeded the hurdle rate only for utility ownership. Table 8 gives data on this system.

This cogeneration system uses coal to replace natural gas at the mill and displace coal at the utility. This fuel shift is shown in Figure 9. A net savings of natural gas and energy results.

Table 8
Data on Soybean Oil Mill

Location		Indiana
Cogeneration Components		Coal Boiler Steam Turbine Generator
Fuel Type		Coal
Electrical Output (Net)		2.1 MW
Steam Output (Net): @ 165 psia, 505°F		57,100 lb/hr
Steam for Export		None
Ratio of Thermal to Electrical Energy		14.9
Capital Cost		$12,900,000
ROE:	Industry Ownership	12.2%
	Utility Ownership	13.7%
	Third-Party Ownership	0%

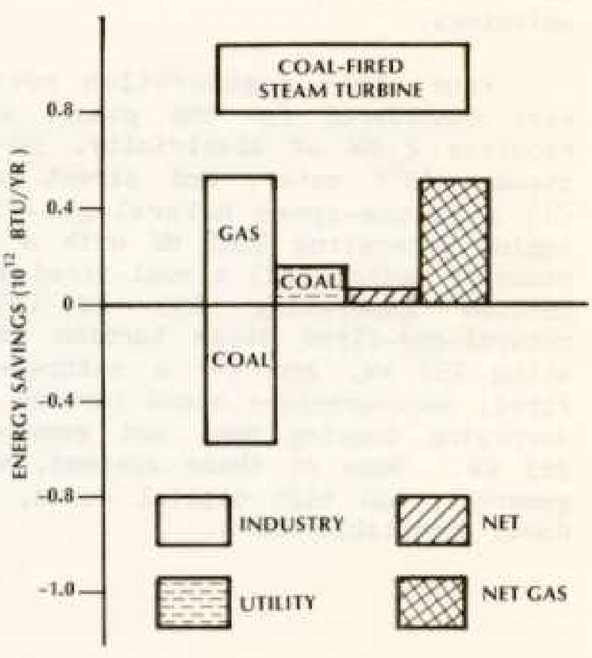


Figure 9. Energy Savings for Soybean Oil Mill

Brewery (ADL)

The malt beverages industry consumes five percent of the energy purchased by the food and kindred products industry. A medium-sized brewery in Pennsylvania with a capacity of 5 million barrels per year was studied by the ADL team. Most breweries are medium-sized.

Electrical demand is essentially constant throughout the day at 4.5 MW. Production is maintained for 5 or 6 days per week. The average steam demand is 80,000 pounds per hour at a maximum pressure of 135 psia, fluctuating between 60,000 and 70,000 pounds per hour as the brewing cycles are repeated every 3 hours. The steam is provided by oil-fired boilers using No. 6 fuel oil (residual oil).

The optimized cogeneration system includes a coal-fired boiler designed to generate the base-load steam demand as well as a small quantity of steam which is stored as hot water during the periods between peak steam demands. Steam is generated at 915 psia, the highest pressure practical in the appropriate capacity range, and expanded to 135 psia through a back-pressure turbine. Replacing oil with low-cost coal gives this system near acceptable ROE for the industry and utility ownership options. The net power output is 2.3 MW. Table 9 gives data on this system.

As shown in Figure 10, this cogeneration system replaces residual oil with coal at the plant and displaces coal used to generate electricity at the utility, resulting in oil savings and net energy savings.

An oil-fired combined-cycle system was also considered for this brewery. This system proved to be economically infeasible, primarily because coal at the utility was displaced by high-cost oil at the plant.

Table 9
Data on Brewery

Location		Pennsylvania
Cogeneration Components		Coal Boiler Steam Turbine Generator Steam Accumulator
Fuel Type		Coal
Electrical Output (Net)		4.0 MW
Steam Output (Net): @ 135 psia, 552°F		82,100 lb/hr
Steam for Export		None
Ratio of Thermal to Electrical Energy		13
Capital Cost		$15,600,000
ROE:	Industry Ownership	12.2%
	Utility Ownership	18.2%
	Third-Party Ownership	<0

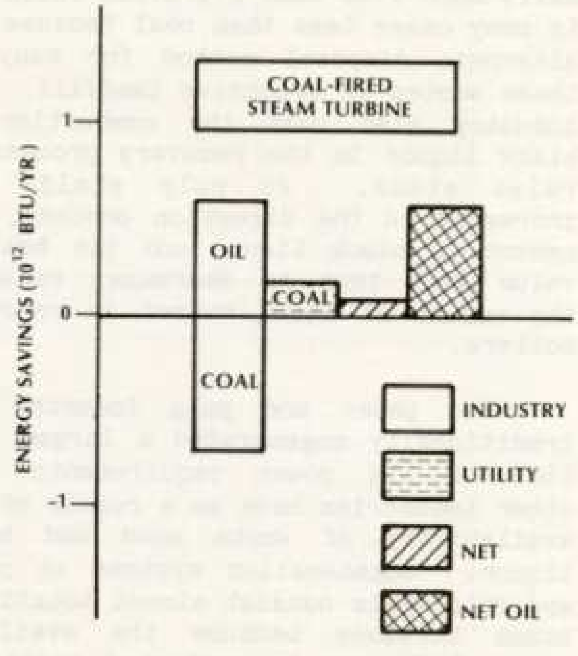


Figure 10. Energy Savings for Brewery

PULP, PAPER, AND ALLIED PRODUCTS

The pulp, paper and allied products industry ranks first among U.S. manufacturing industries as a fuel oil consumer and fourth as an energy consumer, with most of the energy use in pulp, paper, and board mills. The U.S. Bureau of Census data show a 1976 energy use of 2.2 quads with 77 million barrels of fuel oil consumed.

Pulp can be produced either by chemical processes such as kraft or by predominately mechanical processes. In the kraft process, wood chips are converted to brown pulp using a digestor liquor containing sodium sulfate. Black liquor, which can be used as a fuel, is a by-product of the kraft process.

The paper and pulp industry is unique because there are large amounts of combustible forest materials available for use in boilers to raise steam. The cost of the waste material is normally much less than petroleum fuels and in many cases less than coal because the alternate disposal method for many of these wastes is expensive landfill. The industry also uses the combustion of black liquor in the recovery process to raise steam. As pulp yields are increased in the digestion process, the amount of black liquor and its heating value will tend to decrease, reducing the amount of steam raised in recovery boilers.

The paper and pulp industry has traditionally cogenerated a larger portion of its power requirements than other industries have as a result of the availability of waste wood and black liquor. Cogeneration systems in paper and pulp mills consist almost totally of steam turbines because the available waste fuels can be combusted easily in boilers and supplemented with conventional fuels. These cogeneration systems are usually in the 10- to 50-MW range and tend to supply 75 to 100 percent of the power requirements for large mills. Many of the mills, especially in New England and the Pacific Northwest, also use hydroelectric power extensively. Agreements with utilities for interchange of power are more prevalent in the paper and pulp industry than in other industries, as a result of the large amount of power cogenerated.

The hurdle rates for investment in the pulp and paper industry are returns in the 16- to 19-percent range. Utility ROE investment hurdle rates should be in the 10- to 12-percent range.

Recognizing that the kraft process accounts for 60 percent of the pulp in the United States, that it is the largest and fastest growing segment of the industry, and that it has an energy balance favoring cogeneration, three kraft process plants were considered for cogeneration by the ICOP study: a kraft pulp and paper mill, a writing paper mill, and an integrated pulp and paper mill.

Kraft Pulp and Paper Mill (ADL)

A medium-sized pulp and paper complex in New Hampshire was selected for the ADL ICOP study. The complex consists of two plants with a capacity for production of 1050 tons per day, 800 tons of which is in kraft digesters and 250 tons is in a neutral-sulfite semi-chemical pulp process. The plants produce a wide range of products including fine writing paper, corrugated medium tissue products, and market pulp. These plants presently cogenerate 14.7 MW, receive 5.6 MW from company-owned hydro-electric turbines, and have the steam available to potentially cogenerate the remaining 8 MW of electricity (currently purchased).

The complex operates on a continuous schedule with a very steady electrical demand and a steam demand that only varies seasonally. Eight oil-fired boilers and two recovery boilers that burn spent pulping liquor provide the steam. The company plans to install a bark-burning boiler to reduce oil use.

Added cogeneration for one of the plants, a paper mill, was considered for this study. That plant currently cogenerates 2.1 MW and has an average steam demand of 179,000 pounds per hour. The current steam generator will be eliminated in the optimized cogeneration system, leaving a total power demand (for both plants) of 10.1 MW. The optimum system proved to be a coal-fired steam with extraction/back-pressure turbine. This coal-fired system was selected over a residual-fired steam turbine because of lower fuel cost. Data for the optimized cogeneration system are given in Table 10.

This system replaces oil-fired steam with coal-fired cogeneration and displaces coal at the electric utility. These energy savings are shown in Figure 11.

Table 10
Data on Kraft Paper Mill

Location	New Hampshire
Cogeneration Components	Coal Boiler Steam Turbine Generator
Fuel Type	Coal
Electrical Output (Net)	10 MW
Steam Output (Net): @ 55 psia, 368°F	68,900 lb/hr
@ 155 psia, 530°F	90,800 lb/hr
@ 265 psia, 620°F	27,000 lb/hr
Steam for Export	None
Ratio of Thermal to Electrical Energy	7.9
Capital Cost	$31,400,000
ROE: Industry Ownership	0
Utility Ownership	34.8%
Third-Party Ownership	26.7%

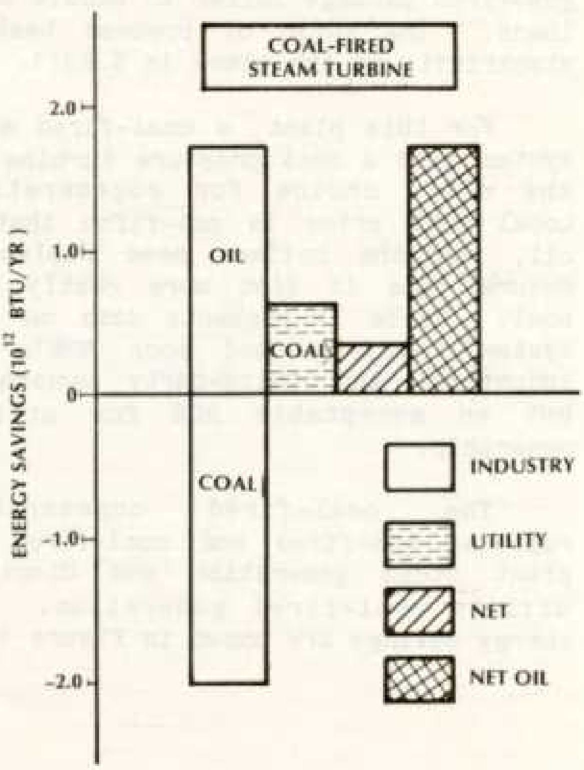


Figure 11. Energy Savings for Kraft Paper Mill

Writing Paper Mill (ADL)

This Pennsylvania facility, also selected by the ADL study team, is 60 years old and has a relatively small output of 350 tons per day. It is expected to remain economically viable for the foreseeable future. The mill, representative of smaller mills, could be classed as 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 plant presently practices no cogeneration. Plant electric demand stays between 14 and 16 MW all year, as the plant operates continuously. Four coal-fired power boilers are 60 years old and could be replaced in any upgrading of the system that might accompany cogeneration plans. There is one recovery boiler (noncogenerating) to burn the spent pulping liquor and one gas-fired package boiler to handle swing loads. The ratio of process heat to electricity in the plant is 5.23:1.

For this plant, a coal-fired steam system with a back-pressure turbine was the clear choice for cogeneration. Local coal price is one-fifth that of oil, and the boilers need replacing. Natural gas is also more costly than coal. Table 11 presents data on this system, which showed poor ROE's for industrial and third-party ownership, but an acceptable ROE for utility ownership.

The coal-fired cogeneration replaces gas-fired and coal-fired in-plant steam generation and displaces utility coal-fired generation. The energy savings are shown in Figure 12.

Table 11
Data on Writing Paper Mill

Location		Pennsylvania
Cogeneration Components		Coal Boiler Steam Turbine Generator
Fuel Type		Coal
Electrical Output (Net)		22 MW
Steam Output (Net): @ 180 psia, 541°F		385,000 lb/hr
Steam for Export		None
Ratio of Thermal to Electrical Energy		8.3
Capital Cost		$52,200,000
ROE:	Industry Ownership	0
	Utility Ownership	23.7%
	Third-Party Ownership	0

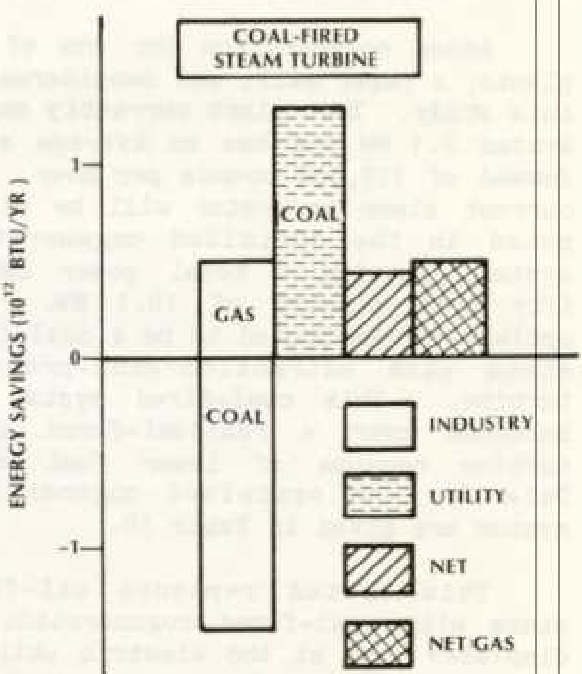


Figure 12. Energy Savings for Writing Paper Mill

Integrated Pulp and Paper Mill (TRW)

The Scott Paper Mill in Mobile, Alabama, is an integrated, bleached kraft paper and pulp mill producing 800 tons per day of tissue paper and 600 tons per day of writing paper. Integrated mills, which combine pulping and paper-making operations, account for about 70 percent of the pulp and paper industry. This mill is representative of large, integrated mills.

The optimum cogeneration system selected by the TRW team was a back-pressure/extraction steam turbine powered by coal/wood boilers with a throttle pressure of 1265 psia (Table 12). This system adds to existing cogeneration currently supplying about 43 percent of required energy. Existing recovery boilers are used with the new system to keep the cost low. Scott Paper plans to become independent of petroleum fuels by the mid-1980's. The ROI for this system was computed relative to a wood- and coal-fueled plant, and as such, was marginally acceptable.

Cogeneration at the Scott plant displaces coal at the electric utility while burning more wood and coal at the plant. The energy savings are shown in Figure 13. No oil or gas savings are involved. Net air emissions at the plant increase slightly compared with wood and coal firing and no new cogeneration, while air emissions at the utility decrease, resulting in net decreases in some emissions (SO_2, NO_x, particulates) and slight increases in CO and hydrocarbons.

Four other cogeneration options were considered, all wood and coal fueled. Two produced power for export, a third was similar to the option selected but with a higher throttle pressure, and a fourth simply topped the existing system with a back-pressure turbine. None produced acceptable ROI's.

Table 12

Data on Integrated Pulp and Paper Mill

Location		Mobile, Alabama
Cogeneration Components		Wood/Coal Boilers Wood Boiler Steam Turbine Generator
Fuel Type		Wood - 85% Coal - 15%
Electrical Output (Net)		52.9 MW
Steam Output (Net):	@ 65 psia*	712,000 lb/hr
	@ 145 psia**	279,000 lb/hr
	@ 315 psia**	125,000 lb/hr
Steam for Export		None
Ratio of Thermal to Electrical Energy		7.3
Capital Cost		$43,600,000
ROI		17.7%

*From New Steam Turbines
**From Existing Turbines

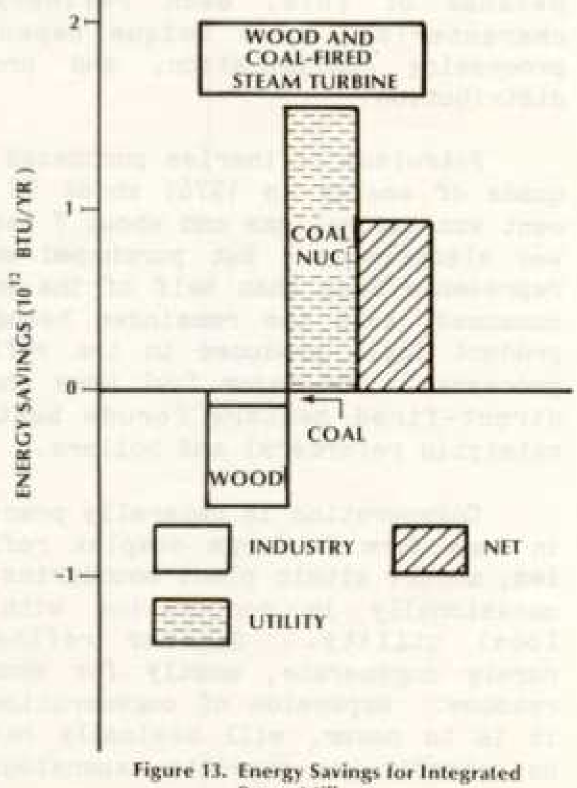


Figure 13. Energy Savings for Integrated Paper Mill

PETROLEUM REFINING

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.

Refineries vary from large, highly complex 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. Most of the production is from large refineries--those with capacities over 100,000 barrels per day.

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

Petroleum refineries purchased 1.22 quads of energy in 1976; about 90 percent was natural gas and about 7 percent was electricity. But purchased energy represents less than half of the energy consumed, with the remainder being by-product fuels produced in the refinery processes. The major fuel uses include direct-fired heaters (crude heaters, catalytic reformers) and boilers.

Cogeneration is generally practiced in some form in large complex refineries, mostly within plant boundaries, but occasionally in cooperation with the local utility. Smaller refineries rarely cogenerate, mostly for economic reasons. Expansion of cogeneration, if it is to occur, will basically have to be retrofit, as capacity expansions are not likely. ROI's needed for the petroleum industry to invest in cogeneration are generally 20 to 25 percent, though in certain circumstances they can be as low as 10 percent or as high as 30 percent. Utility ownership should be feasible with an ROE of 10 to 11 percent.

Cogeneration options were examined for two large refineries and one medium-sized refinery.

Large Refinery--Louisiana (TRW)

The refinery in Norco, Louisiana, is typical of large refineries. Production is 203,800 barrels per day. Currently, the boilers are fueled solely by oil. Existing cogeneration produces 35.9 MW of shaft power.

Selection of an optimum cogeneration system was not straightforward. The economic performance of the three cogeneration options considered by the TRW ICOP team is marginal or poor with the exception of a gas-fired gas turbine, which is dependent on the continued availability of low-cost natural gas. However, conversions to coal for steam production in petroleum refining are being considered, and Exxon representatives expect some conversions to occur by 1985. A coal-fired boiler with a steam turbine would improve the economics of a fuel switch to coal, and so it was chosen as the system for this analysis.

Table 13 gives data on the optimized coal-fired cogeneration system. The ROI is marginal but will meet the investment criteria for some refineries.

Since the utility in Louisiana burns oil and natural gas, cogeneration displaces these fuels. Also, residual oil previously burned in the refinery is replaced by coal. These energy savings, along with net energy savings and total oil and gas savings are shown in Figure 14.

This cogeneration system would increase refinery air emissions due to the burning of coal in place of residual oil. There would be no significant offset at the utility, since the fuels displaced are natural gas and oil.

Table 13
Data on Large Refinery — Louisiana

Location	Norco, Louisiana
Cogeneration Components	Coal Boiler Steam Turbine Generator
Fuel Type	Coal
Electrical Output (Net)	11.1 MW
Steam Output (Net): @ 640 psia, 740°F	450,000 lb/hr
Steam for Export	None
Ratio of Thermal to Electrical Energy	16
Capital Cost (Incremental vs. Coal-Fired Boiler)	$10,220,000
ROI	14.7%

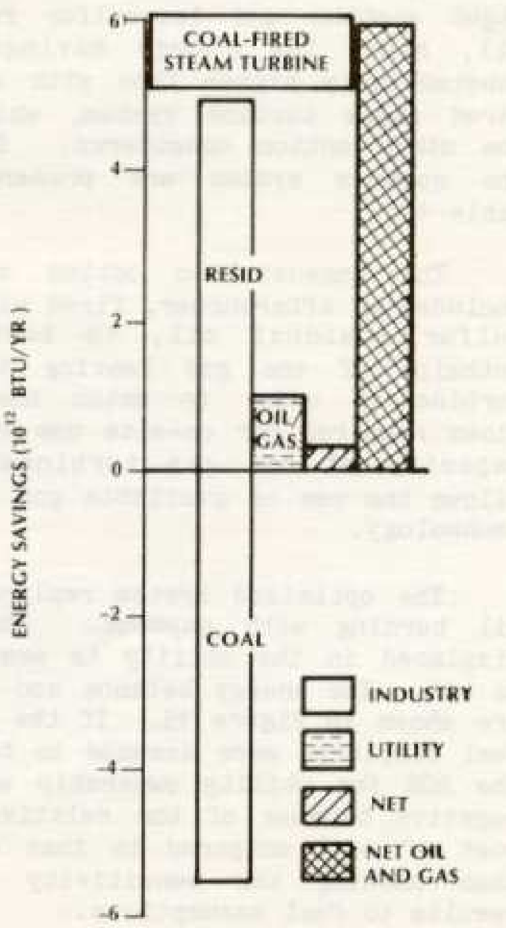


Figure 14. Energy Savings for Large Refinery in Louisiana

Large Refinery--California (ADL)

The ADL ICOP team also considered cogeneration options for a large refinery, one with output capacity exceeding 100,000 barrels per day. The refinery handles domestic (California and Alaska) and foreign crudes. This refinery is representative of large, complex refineries that comprise about half of domestic refining capacity.

The boilers are currently fired by refinery gas and low-sulfur fuel oil. Steam is required for mechanical drives. Peak electrical demand is 120 MW.

Only cogeneration options using fuels available at the refinery were considered. The system selected was a combined cycle configuration fired by light naphtha and low-sulfur residual oil, since the energy savings were substantially higher than with a coke-fired steam turbine system, which was the other option considered. Data on the optimum system are presented in Table 14.

The cogeneration option selected includes an afterburner, fired with low-sulfur residual oil, to boost the enthalpy of the gas leaving the gas turbine in order to match the steam flows required for on-site use with the capacity of the gas turbines; this allows the use of available gas turbine technology.

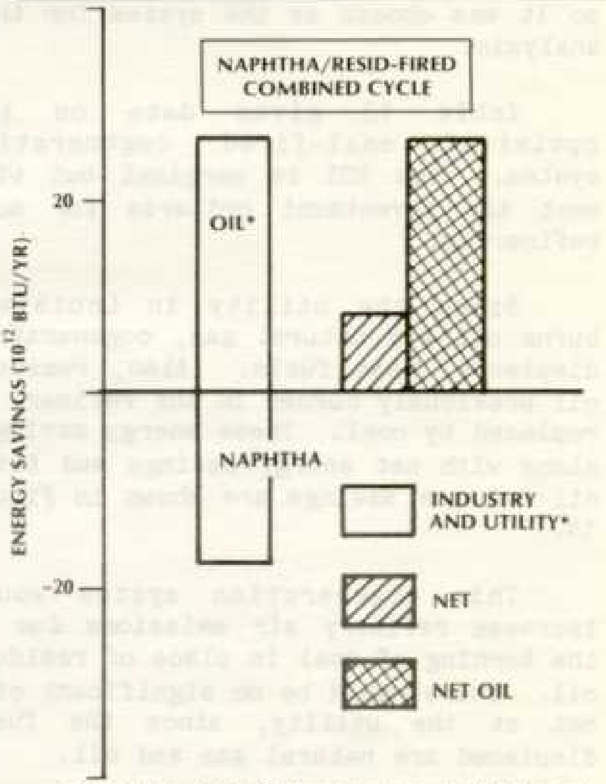
The optimized system replaces some oil burning with naphtha. The fuel displaced in the utility is assumed to be oil. The energy balance and savings are shown in Figure 15. If the utility fuel displaced were assumed to be coal, the ROE for utility ownership would be negative because of the relatively low cost of coal compared to that of oil, thus showing the sensitivity of the results to fuel assumptions.

Table 14

Data on Large Refinery — California

Location		California
Cogeneration Components		Gas Turbines (2) Waste Heat Boilers with Aux. Firing Steam Turbine Generator
Fuel Type		Naphtha/ Residual Oil
Electrical Output (Net)		235 MW
Steam Output (Net):	@ 895 psia, 740°F	300,000 lb/hr
	@ 565 psia, 635°F	580,000 lb/hr
	@ 165 psia, 403°F	720,000 lb/hr
Steam for Export		None
Electricity for Export		1,130 GWh/year
Ratio of Thermal to Electrical Energy		2.3
Capital Cost		$100,300,000
ROE:	Industry Ownership	0
	Utility Ownership	>1000%*
	Third-Party Ownership	< 0

*Negative Incremental Investment



*Data Not Available in Report to Separate Industry and Utility Oil Savings

Figure 15. Energy Savings for Large Refinery in California

Medium-Sized Refinery (ADL)

A medium-capacity refinery located in Oklahoma was considered by the ADL ICOP team. The major refined products include 30,000 barrels per day of motor gasolines and 17,000 barrels per day of distillate fuels, with residual fuel oil and asphalt constituting an additional 12,000 barrels per day of output. This plant represents smaller and simpler refineries than the other two cases.

Because two-thirds of the feedstock for this refinery is heavy, sour crude, a large amount of high-sulfur vacuum bottoms are produced, which are increasingly difficult to market. The vacuum bottoms can be converted to gasoline and distillate oil by installing a heavy oil fluid catalytic cracking unit (HOC) with feed desulfurization. The catalyst in the HOC must be regenerated to remove the coke that adheres to it. Cogeneration can recover energy from the regenerating process via bottoming cycles. Options for increasing cogeneration were considered and compared with a reference case involving minimal cogeneration (with 10 MW generated).

The optimum cogeneration option involves a turboexpander, a double-extraction steam turbine, and a methanol Rankine bottoming cycle in the exhaust gas path. This option was preferred both because it yielded a higher ROE (only industry ownership was considered) and because it yielded greater energy savings than an option without the turboexpander. Table 15 presents data for the optimized system.

The energy savings (Figure 16) are accomplished simply by displacing the utility-produced power, assumed to be generated by coal.

Table 15

Data on Medium Sized Refinery

Location	Oklahoma
Cogeneration Components	Turbo-Expander Heat Exchangers Catalyst Regenerator Condensing Mechanical Steam Turbine Steam Turbine Generator Methanol Rankine Bottoming Cycle
Fuel Type	Exhaust Gases
Electrical Output (Net)	31.1-34.9 MW
Steam Output (Net): @ 65 psia, 298°F @ 165 psia, 420°F	45,000-50,000 lb/hr 107,000-158,000 lb/hr
Steam for Export	None
Ratio of Thermal to Electrical Energy	1.2
Capital Cost (Incremental Over Minimal Cogeneration)	\$20,000,000
ROE (Industry Ownership)	88.3%

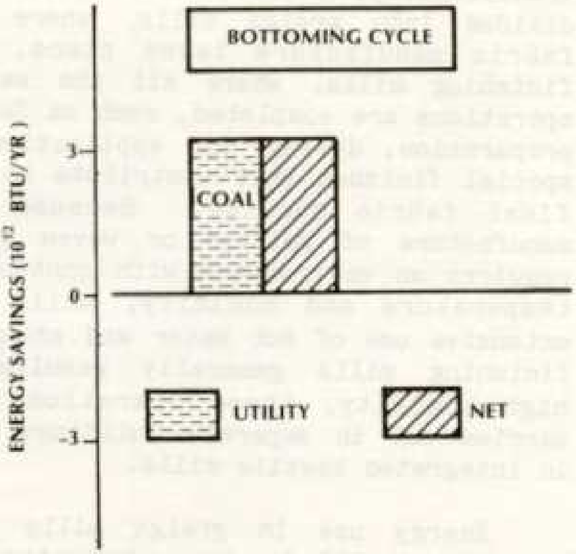


Figure 16. Energy Savings for Medium-Sized Refinery

TEXTILE INDUSTRY

With more than 7000 plants, the textile industry is quite diversified, processing a variety of fibers, fabrics, and fabric blends into a multitude of end products. The largest volume is in polyester knit goods and polyester/cotton woven goods.

In recent decades, the industry has been concentrated in the Southeast, notably in North and South Carolina, Georgia, and Alabama. This trend is continuing. Accordingly, the plants considered in the ICOP studies are located in these states. Today nearly 40 percent of the textile plants are in the Southeast and more than 90 percent are on the Eastern Seaboard.

Textile facilities may be highly integrated manufacturing complexes that process natural and synthetic fibers 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 that contribute to the final fabric quality. Because the manufacture of knitted or woven goods requires an environment with controlled temperature and humidity, while the extensive use of hot water and steam in finishing mills generally results in high humidity, these operations are carried out in separate buildings even in integrated textile mills.

Energy use in greige mills (and knitting mills) is predominantly electrical for powering equipment used in fabric manufacture and for air conditioning. 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, used to dry fabric. A significant amount of electric power is also required to provide mechanical energy for the process equipment. Another large energy demand in a finishing mill is for natural gas (or propane where natural gas is unavailable) for direct heating in drying and curing operation. Small amounts of steam may be required in the winter for space heating needs.

Of the 53 million Btu of energy purchased by the textile industry in 1976, about 56 percent was for electrical energy and the remaining 44 percent was for distillate and residual fuel oil, natural gas, propane, and coal. Dyeing and finishing operations consume about 60 percent of all the energy used in producing textiles. The other processes, such as spinning, weaving, and knitting, consume the remaining energy, primarily in the form of electricity for motor power.

Many textile plants, especially plants constructed before the wide distribution of centralized utility power and consequent decline in power costs, have practiced cogeneration. With the increase in power costs in the 1970's, the industry finds it economically attractive to operate existing cogenerating units and to install new ones. Returns of 15 to 30 percent are required by the industry for investment in cogeneration. Utility ROE's of 9 to 13 percent could attract investment. The ICOP studies looked at the optimum cogeneration systems for an integrated mill and two finishing plants.

Integrated Mill (ADL)

An integrated mill in Alabama was selected by the ADL study group as having desirable characteristics for cogeneration. Started in 1900, the plant has expanded considerably to a medium-sized multibuilding facility. Average age of the equipment is 5-10 years. All operations from fabric manufacturing through dyeing, finishing, and cutting and making garments are conducted on a 24-hour-per-day, 6-days-per-week basis. The plant requires energy in the form of process steam, direct process heat, electricity, and direct power steam for mechanical drives. Using oil and wood, the boiler house produces process steam at 265 psia. Natural gas is used in process operations.

The cogeneration system selected as optimum was a wood-fired boiler generating steam for a back-pressure steam turbine. Wood was the company's preferred fuel since it is in plentiful supply locally. Also, the economics of the wood-fired system were much better than for a gas-fired combustion turbine with waste heat boiler. Data on the optimized system are shown in Table 16.

This system replaces natural gas with wood cogeneration at the mill and displaces coal-fired generation at the electric utility. Figure 17 shows the energy savings.

Table 16

Data on Integrated Textile Mill

Location		Alabama
Cogeneration Components		Wood Boiler Steam Turbine Generator
Fuel Type		Wood
Electrical Output (Net)		9 MW
Steam Output (Net): @ 265 psia, 617°F		191,000 lb/hr
Steam for Export		None
Ratio of Thermal to Electrical Energy		10.6
Capital Cost		$26,700,000
ROE:	Industry Ownership	0
	Utility Ownership	30.1%
	Third-Party Ownership	0

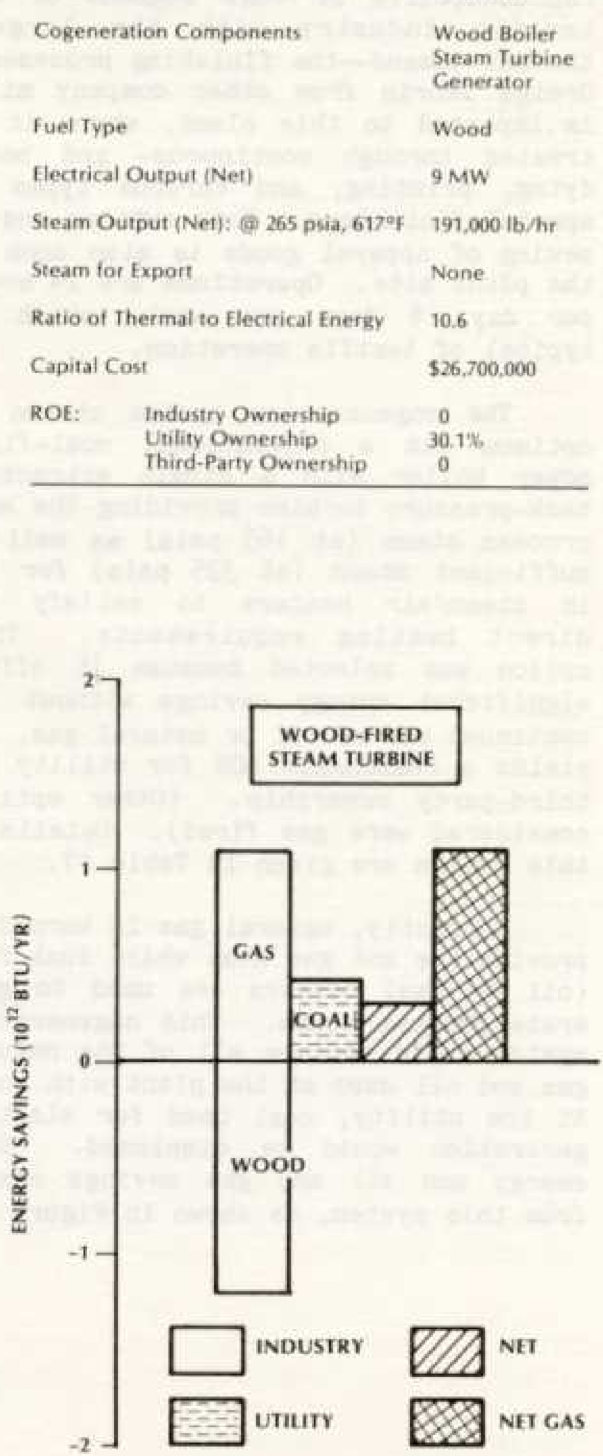


Figure 17. Energy Savings for Integrated Textile Mill

Finishing Plant (ADL)

A finishing plant located in South Carolina was chosen by the ADL team as representative of that segment of the textile industry with the largest thermal demand--the finishing processes. Greige fabric from other company mills is imported to this plant, where it is treated through continuous- and beck-dying, printing, and various types of special finishings. Some cutting and sewing of apparel goods is also done on the plant site. Operations are 24 hours per day, 6 days per week, which is typical of textile operation.

The cogeneration system chosen as optimum was a conventional coal-fired power boiler with a single extraction back-pressure turbine providing the main process steam (at 165 psia) as well as sufficient steam (at 335 psia) for use in steam/air heaters to satisfy the direct heating requirements. This option was selected because it offers significant energy savings without the continued use of oil or natural gas, and yields a reasonable ROE for utility and third-party ownership. (Other options considered were gas fired). Details on this system are given in Table 17.

Currently, natural gas is burned to provide the hot gas heat while dual fuel (oil or gas) boilers are used to generate process steam. This cogeneration system would replace all of the natural gas and oil used at the plant with coal. At the utility, coal used for electric generation would be displaced. Both energy and oil and gas savings result from this system, as shown in Figure 18.

Table 17
Data on Textile Finishing Mill

Location		South Carolina
Cogeneration Components		Coal Boiler Steam Turbine Generator
Fuel Type		Coal
Electrical Output (Net)		20 MW
Steam Output (Net):	@ 165 psia, 515°F @ 335 psia, 662°F	278,000 lb/hr 102,000 lb/hr
Steam for Export		None
Ratio of Thermal to Electrical Energy		8.3
Capital Cost		$45,700,000
ROE:	Industry Ownership Utility Ownership Third-Party Ownership	0 26.6% 15.1%

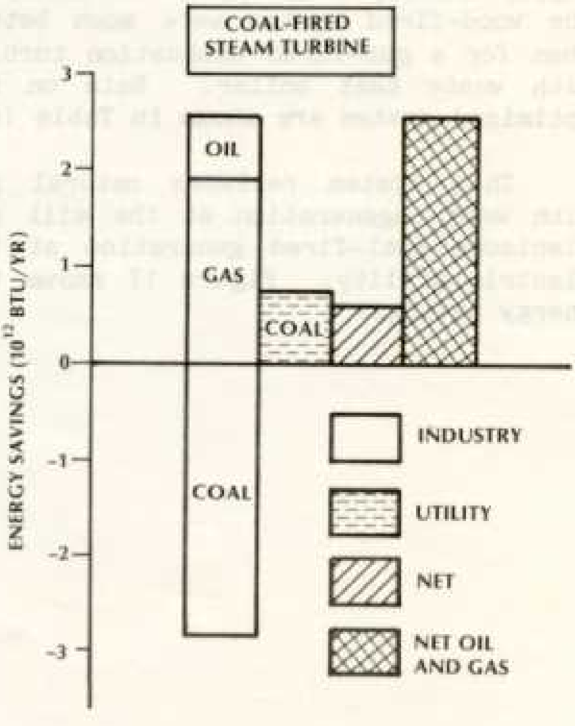


Figure 18. Energy Savings for Textile Finishing Mill

Finishing Plant (TRW)

The TRW ICOP team examined cogeneration options for the J.P. Stevens' Delta 2 and 3 finishing plants in Cheraw, South Carolina, where raw greige cloth from different mills is treated, dyed, and/or printed. Delta 2 is a batch process operation while Delta 3 runs continuous processes, giving this plant complex characteristics common to a large number of finishing plants. The finishing process, using more thermal energy than other textile processes, is a good candidate for cogeneration.

The cogeneration system selected for the Cheraw complex was a coal-fired steam turbine sized to meet the thermal requirements of the plant. New coal-fired boilers replace the oil, gas, and coal boilers currently used, thus conserving oil and gas through use of less expensive coal. This cogeneration system provided the best ROI of the systems considered and is in line with J.P. Stevens' belief that coal is the only viable fuel for cogeneration. Technical data on the optimized system are presented in Table 18.

The fuels that would be displaced at the electric utility are coal and possibly nuclear fuel. The changes in fuel use in the plants, the utility, and the net energy savings are shown in Figure 19. The system results in a net savings of oil and gas. Since the plant's consumption of coal is increased, this results in increased air emissions which could be substantially offset by reduced emissions at the utility. The net effect would be a small increase in air emissions.

The other cogeneration systems considered for the plants were medium- and slow-speed diesels fired with distillate or residual oil and a coal-fired steam turbine operating at a higher pressure than the selected system. High-cost fuel and higher capital cost (for the steam turbine) made these systems uneconomic.

Table 18
Data on Textile Finishing Plant

Location	Cheraw, South Carolina
Cogeneration Components	Coal Boilers Steam Turbine Generator
Fuel Type	Coal
Electrical Output (Net)	5.25 MW
Steam Output (Net): @ 140 psia	126,000 lb/hr
Steam for Export	None
Ratio of Thermal to Electrical Energy	8.9
Capital Cost	$9,450,000
ROI	17.6%

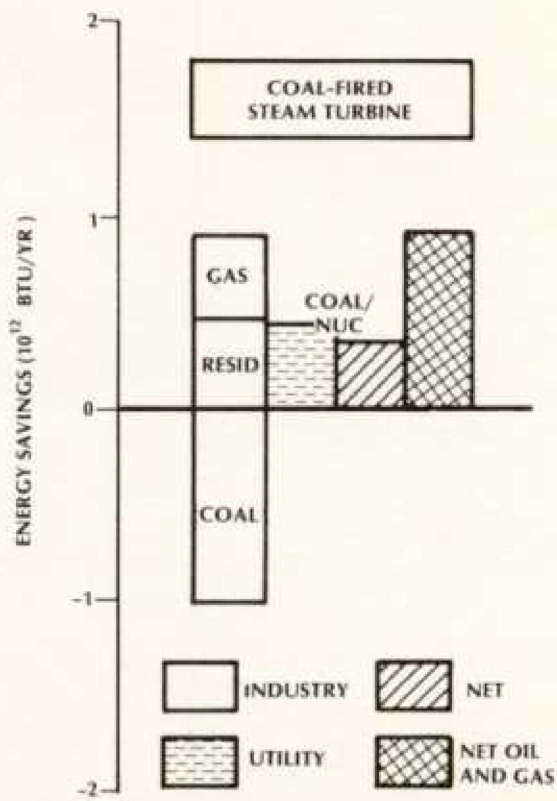


Figure 19. Energy Savings for Textile Finishing Mill