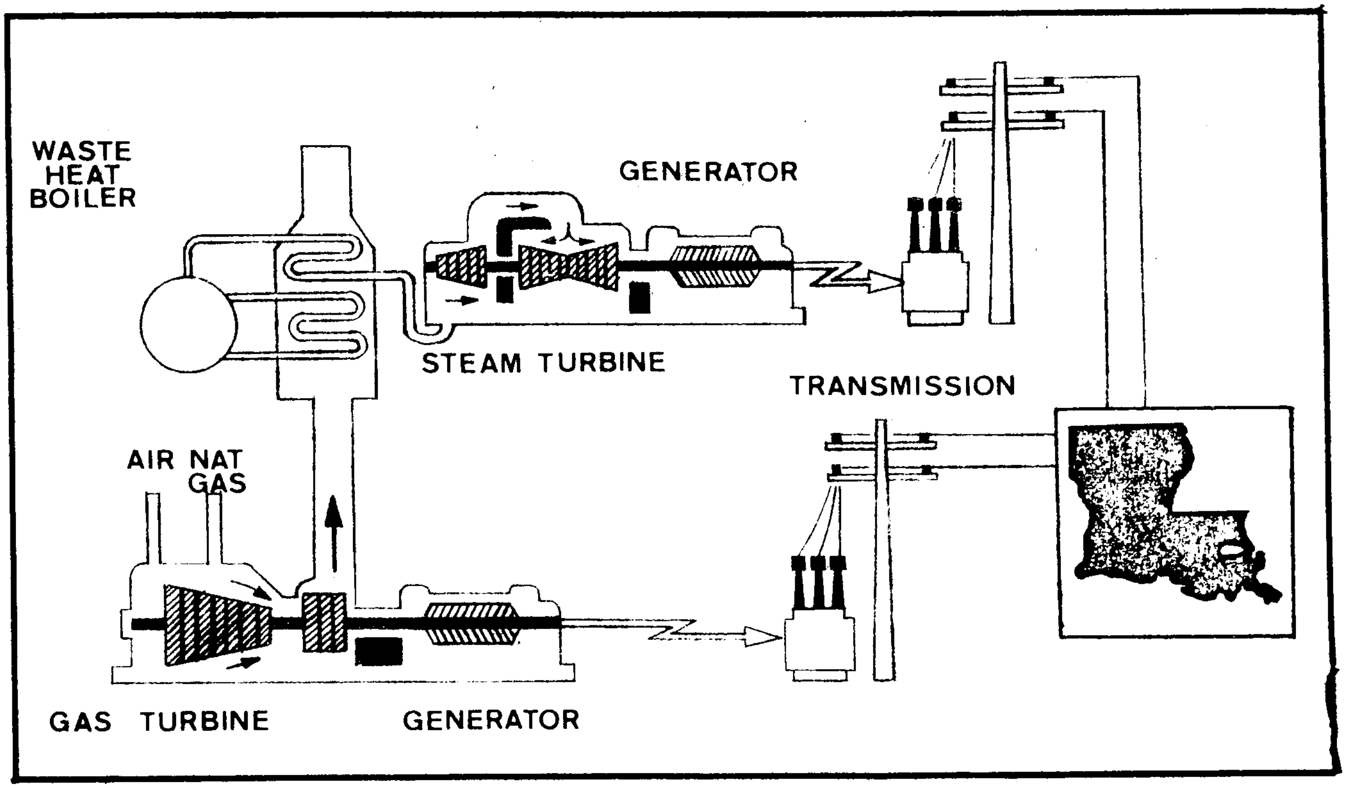
LOUISIANA PETROCHEMICAL INDUSTRY

COGENERATION ANALYSIS

July 1983



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Department of Natural Resources

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I. SUMMARY SECTION

A. Executive Summary

DNR engaged the consulting firm G.R. STUCKER AND ASSOCIATES, INC. to assess the cogeneration potential of the Louisiana petrochemical industry with respect to nine chemical complexes along the Mississippi River and Lake Charles.

Cogeneration is defined as 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. Cogeneration has been around since the early 1900's, reaching a peak in the 1940's, and declining to less than 10% of the total U.S. industry energy consumption in 1976. However, because of escalating fuel and electricity costs, cogeneration has received renewed attention, particularly in the heavily industrial regions of the Gulf Coast.

For this project chemical companies located within the nine complexes were evaluated for each of three basic cogeneration systems: steam turbine, gas turbine, and combined cycle. The systems were sized to provide the same amount of process steam being supplied by conventional fired boilers while providing the maximum amount of cogenerated electricity. The potential for cogenerating steam and electricity with waste heat or by-product fuel was also considered.

However, most of the chemical producers interviewed stated that they had already implemented energy conservation programs and indicated that if anything was available it would be low-level waste heat that was technically or economically unattractive for cogeneration.

Generally, it was found that a cogeneration system optimized for the heat requirements would still not produce all the electric power required for the plant operations largely because of the electricity intensiveness of most petrochemical producers. The gas-fired turbine and waste heat boiler system offer the most favorable economics and energy savings. Preliminary screenings indicated a simple payback for a gas turbine system of between three to five years with a corresponding internal rate-of-return (IRR) of 20 to 30 percent. The steam turbine system was least attractive because of higher capital costs of a new boiler required for the higher steam pressures. Generally, the existing plant boilers cannot be significantly uprated to provide the high pressure steam required to drive the steam turbine. Coal-fired steam turbine systems are more capital and labor intensive because of the costs associated with handling and storage of the coal. The associated payout periods are beyond what most companies are willing to project.

B. General Summary

In summary, this project calls for identifying the companies in Louisiana producing chemicals comprising the top 75% in volume/value; developing energy (heat and power) quantities consumed and produced; identifying potential cogeneration candidates from the group; assessing the impact of cogeneration and related efficiency improvements on ultimate product cost; reviewing and summarizing governmental regulations affecting cogeneration, fuel use, sale and purchase of electricity produced, and distribution of such power through the utility system grids; and summarizing incentives that encourage the use of cogeneration systems.

The regional importance of cogeneration is best illustrated by summarizing Louisiana's position with respect to the rest of the nation as presented in a recent DOE report. Based upon the remaining cogeneration capacity, the report ranked Louisiana third in the nation preceded only by California and Texas. It assessed the "best case" cogeneration potential for Louisiana at 3684 megawatts. Of this total, the chemical industries and refineries contributed 2728 megawatts and 793 megawatts, respectively. Louisiana was reported as the second largest existing cogenerator surpassed only by the state of Texas.

Our study calculated a "best case" cogeneration potential of 2174 megawatts for the nine major chemical complexes along the Mississippi River and Lake Charles (Taft, Geismar Part 1 and 2, Baton Rouge, Plaquemine, Donaldsonville, Convent, Norco, and Lake Charles). This document reports the cogeneration potential by complex but not by individual companies in order to honor the confidentiality agreements.

Block flow diagrams were developed for each of the nine complexes listed previously. Production capacities were assigned to the streams identified in the diagrams when information was available. In addition, the streams constituting 75 percent of the product volume/value were identified.

Performance and cost data were used to develop correlations defining each of the cogeneration systems. The resulting mathematical models provide a preliminary screening method for evaluating the performance characteristics and economic projections for various cogeneration systems. The economic model calculates the potential savings of a particular cogeneration system based upon system efficiency, capital costs, and operating and maintenance costs. The three basic cogeneration systems evaluated were the steam turbine system, the gas turbine system, and the combined cycle system.

Overall, the gas turbine systems had the best internal rate-of-return (IRR), typically between 20 and 30 percent. The corresponding simple payback periods ranged from three to five years. The sensitivity of the IRR/ Capital cost relationships developed from this data was reviewed based upon changes in the investment tax credit, tax rate, inflation, type of system (incremental heat rate), and fuel costs. The effect of utilizing waste heat or byproduct fuel was also reviewed. However, most of the chemical producers reportedly have already implemented energy conservation programs, leaving only low level waste heat sources that are either technically or economically unattractive for cogeneration. Generally, the operation of an optimized cogeneration system still resulted in a net demand for electricity because of the electricity intensiveness of most of the chemical producers.

Numerous federal statutes passed during recent years beginning in 1978 have provided a regulatory climate favorable to cogeneration. The most significant of these is the Public Utilities Regulatory Policies Act (PURPA). According to PURPA, utilities must buy power from, and supply backup power to, qualifying cogenerators at fair rates. The purchase rates are defined to be 100 percent of avoided cost, i.e. the cost which the purchasing utility can avoid as a result of the purchase, rather than generating an equivalent amount of energy itself or purchasing it from other suppliers. Utilities are required to provide interconnections with the cogenerator and to wheel (transmit) power from cogenerators to other utilities not on the local transmission system. Broad authority was given to the Federal Energy Regulatory Commission (FERC) to exempt qualifying facilities from regulation as a utility under certain federal and state laws. Multiparty projects are eligible for status as qualifying facilities, including utility company ownership if less than 50 percent.

Cogenerators are exempt from the stipulation in the Fuels Use Act of 1978 that prohibit industrial use of natural gas and oil fuels after 1990. They are exempt from the incremental pricing provisions of the

Natural Gas Policy Act of 1978. Also, cogeneration facilities qualify for the normal 10 percent investment tax credit.

Cogeneration facilities are eligible for accelerated depreciation, and this tax benefit can be transferred to others under certain circumstances. These tax benefits have stimulated a great deal of interest in "three-party" projects involving leveraged leasing, which enables the lessee to exclude certain types of leasing liabilities from the company balance sheet. By thus improving debt ratios, the company may gain more debt capacity. Therefore, instead of using equity or debt financing for cogeneration facilities, a company may lease those facilities from a third party owner at mutually beneficial terms and use its own scarce capital for production capacity or other process efficiency improvements.

Prospective cogenerators in Louisiana have an additional tax benefit in that energy conservation facilities are exempt from state sales tax.

Another boost for cogeneration could result from Act 642 of the 1983 Legislature - the Commerce and Industry Dept. venture capital bill, which proposes offering tax breaks to Louisiana residents who invest in venture funds that in turn put the majority of their equity capital in Louisiana businesses.

In general, cogeneration makes good economic sense, and the aggregate of tax benefits provide a powerful incentive for investment in this area.

II. BACKGROUND AND SCOPE

Louisiana's industrial base is dominated by such heavy industries as primary metals, inorganic chemicals, organic chemicals, and petroleum refining. Often, this group of industries is referred to as the "petrochemical industry." These industries all have one element in common — large energy requirements and/or a dependence on hydrocarbon based feedstocks and raw materials.

Louisiana's petrochemical industry faces several significant challenges today. Although the petrochemical industry faces such problems as reduced product demand and high capital costs, many of the most significant problems are tied to the cost and availability of energy and hydrocarbon feedstocks:

- Production of natural gas based bulk chemicals is shifting to world areas that have access to cheap natural gas that was previously just flared.

- The availability of cheap hydropower in various parts of the world is attractive to electricity intensive industries.

- Industries that originally located in Louisiana, in part due to the abundance of cheap intrastate natural gas and natural gas-fired electricity, are now often having to pay higher natural gas and electricity prices than industries in other states as a result of the disparity in the regulation of the price and availability of interstate gas versus intrastate gas.

Since industry dominates energy consumption in the state, industrial activity heavily influences the short-term and long-term energy supply and demand in the state.

Therefore, it is essential that action be initiated immediately "to get the ball rolling" on some of the more attractive alternatives. One of these alternatives is the concept of generating thermal energy and electricity, better known as cogeneration. (In the April 20, 1977 Energy Message, President Carter coined a new word, "Cogeneration". He further defined "Cogeneration" as "the production of electric power and other forms of useful energy - such as heat or process steam - from the same facility".) However, the concept of turbines supplying both electrical power and process heat in industrial plants has been around since the early 1900's. Cogeneration reached a peak in the 1940's and declined to less than 10% of the total U.S. industry energy consumption in 1976 as utility companies provided low cost, reliable, centrally produced power.

Recently, with escalating fuel and purchased electricity costs, the alternative of industrial cogeneration has become more attractive to the petrochemical industries. Some of the advantages are as follows:

- Conventional systems producing thermal energy for industrial processes convert approximately 75% of the fuel energy to useful work. Conventional electricity - generating systems, on the other hand, generally have an average efficiency of only 35%. Therefore, cogeneration significantly reduces the amount of fuel energy required to produce the same amount of useful energy.

- Because less fuel is needed, cogeneration results in less air, water, and thermal pollution overall versus fuel-fired utility companies.

- Capital and operating costs for grass roots systems are generally 10-30% less than the combined cost of separate systems.

- The availability of the power is generally more reliable because of decentralization.

In contrast, some of the disadvantages are as follows:

- Increased scarce-fuel consumption as for gas turbines that use natural gas, light fuel oil, etc. versus utility companies that use fuels such as coal or produce electricity via hydropower.

- Increased local pollution emissions which may not be outweighed by utility power plant emission reductions.

Louisiana has a 35 billion dollar petrochemical industry that with proper incentives could significantly benefit from cogeneration and related process improvements.

The scope of this project is to evaluate the viability of cogeneration and related efficiency improvements applied to nine major Louisiana chemical complexes along the Mississippi River and Lake Charles. The nine complexes were Taft, Lake Charles, Geismar (Part 1 and 2), Baton Rouge, Plaquemine, Donaldsonville, Norco and Convent.

Block flow diagrams were developed for each of the nine complexes which are presented as Figures 2 thru 10 (Figure 1 is a simplified overall flow diagram of the Louisiana Chemical Industry). Production capacities have been

FIGURE 1: LOUISIANA'S CHEMICAL INDUSTRY

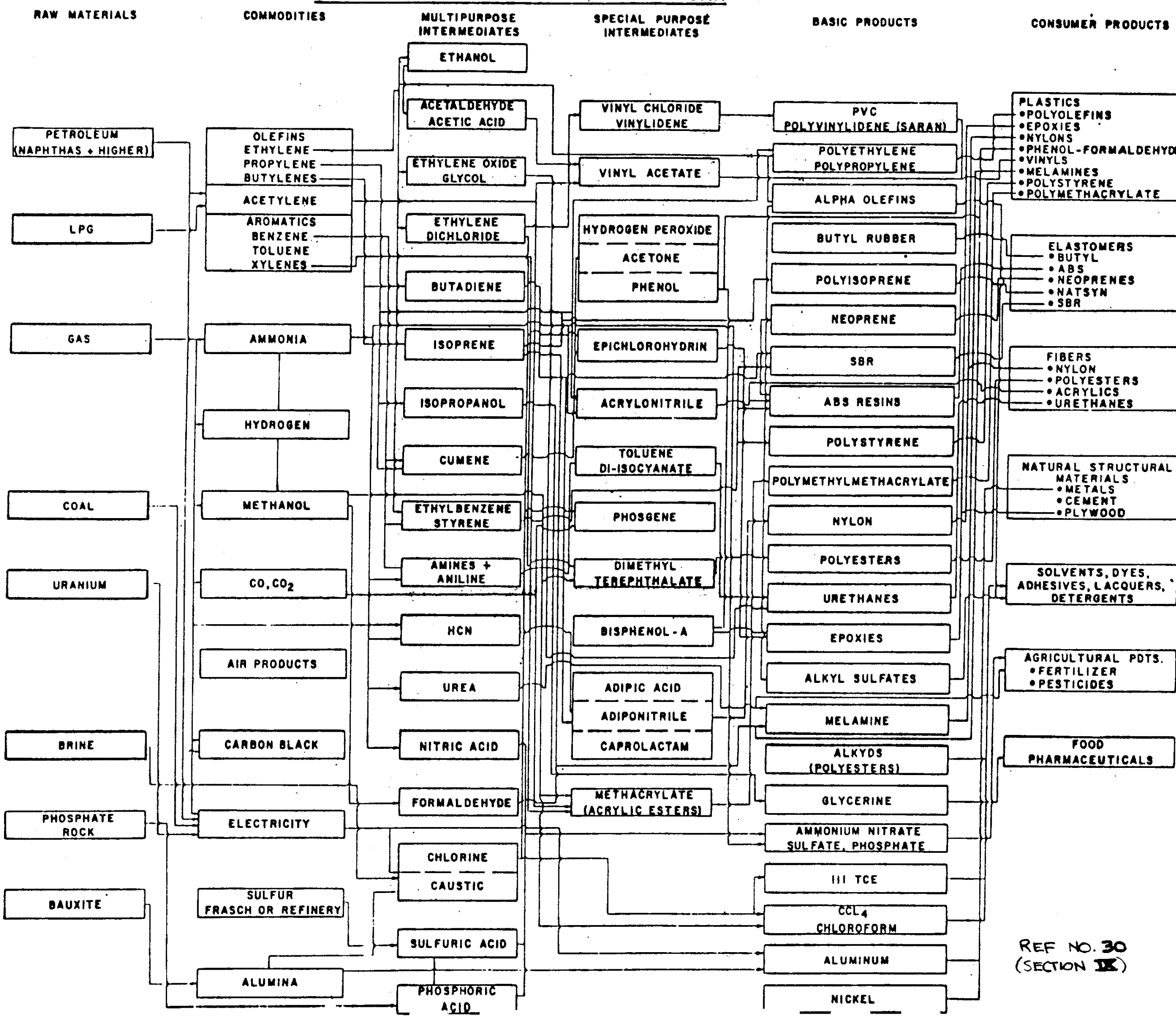

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FIGURE 2: TAFT PETROCHEMICAL FLOW DIAGRAM

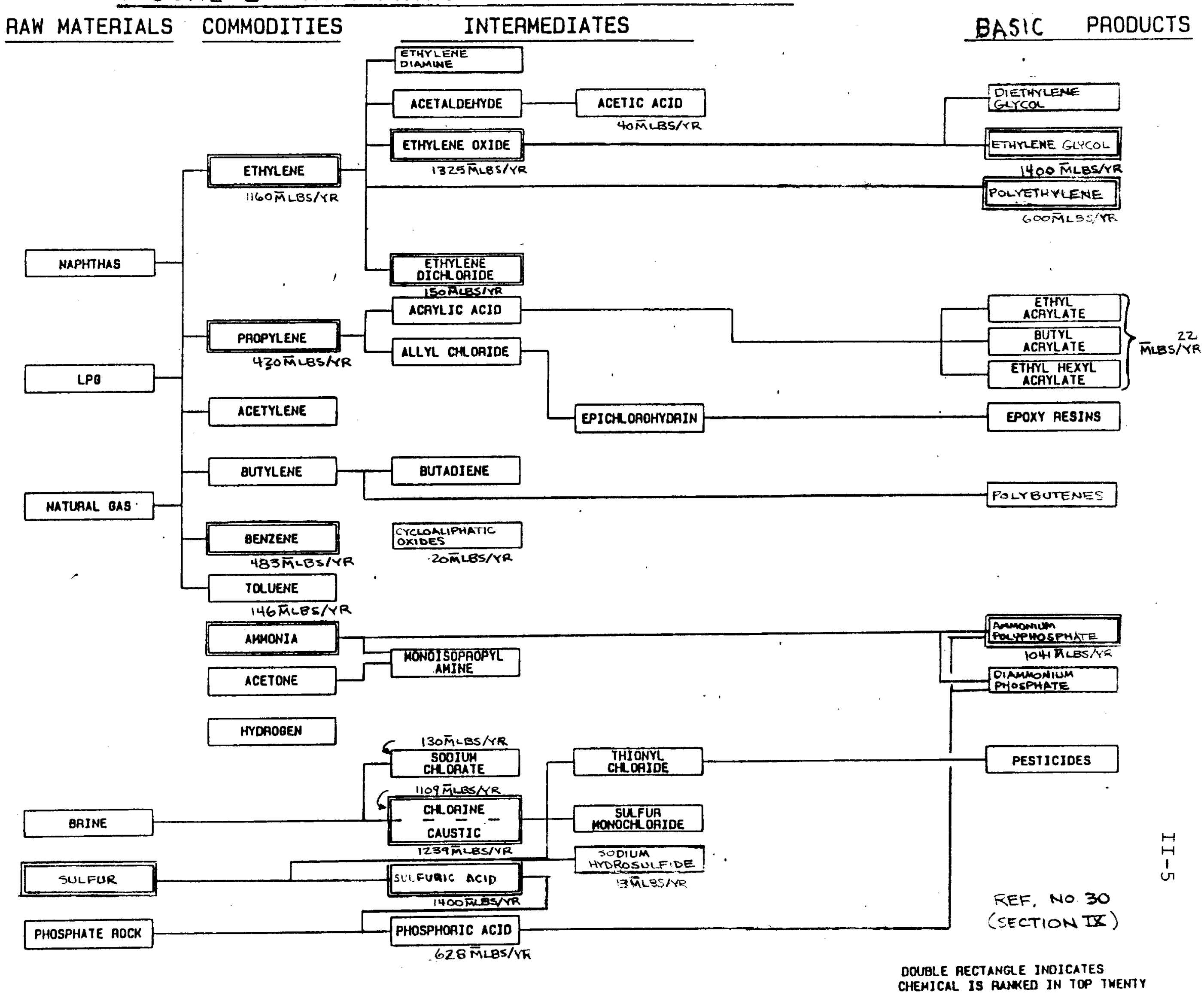
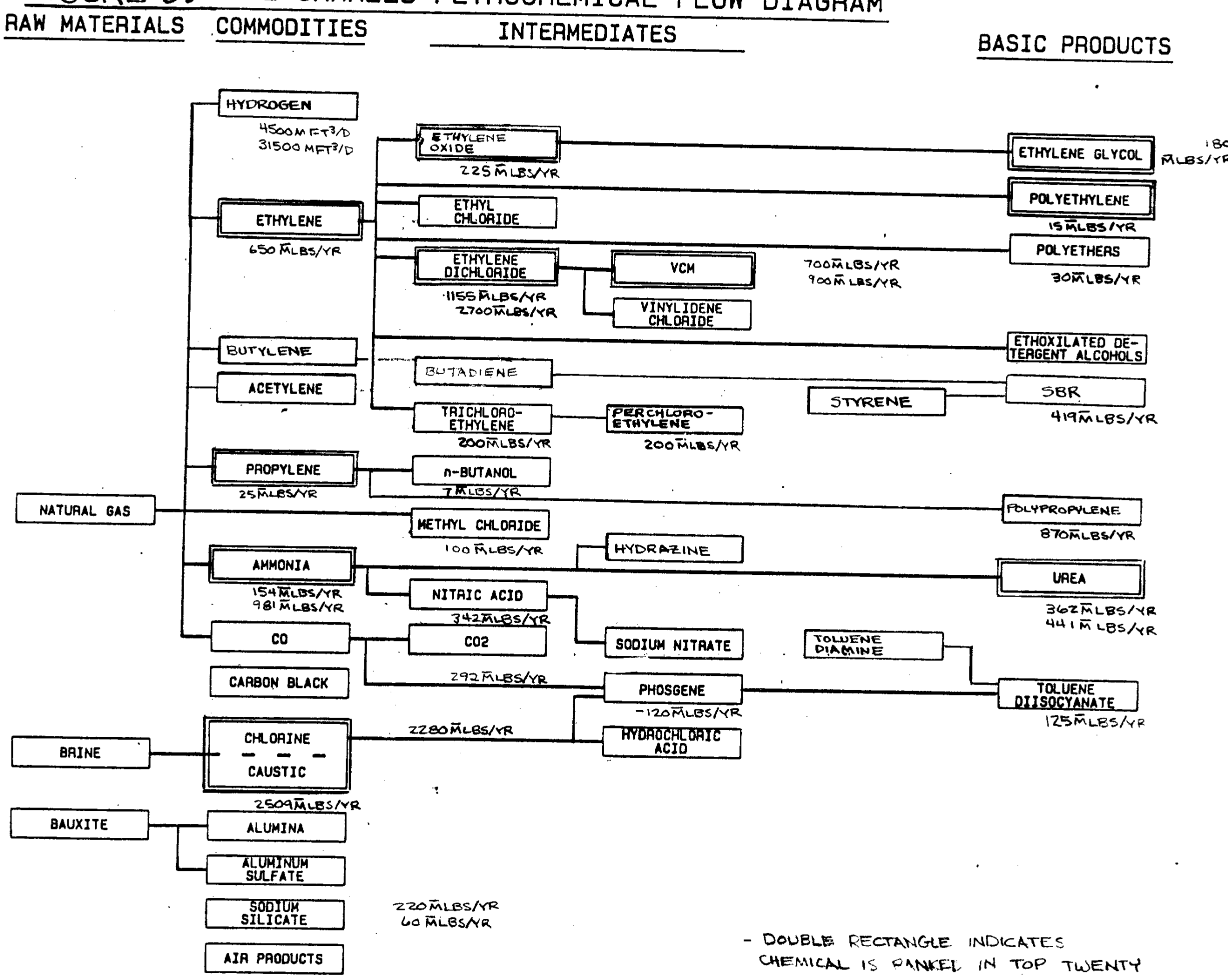


FIGURE 3: LAKE CHARLES PETROCHEMICAL FLOW DIAGRAM



- DOUBLE RECTANGLE INDICATES CHEMICAL IS RANKED IN TOP TWENTY
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FIGURE 4: GEISMAR PETROCHEMICAL FLOW DIAGRAM - SHEET 1

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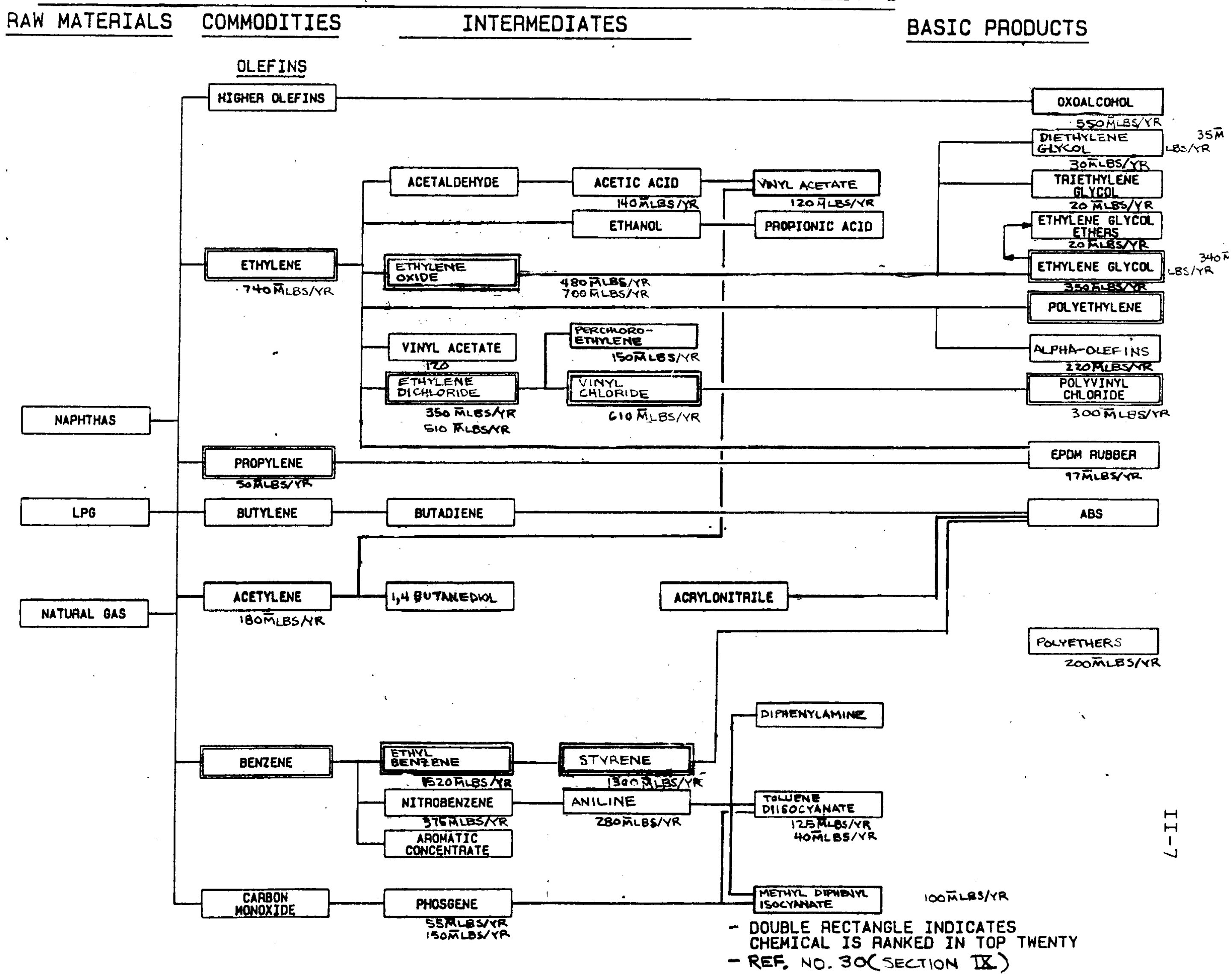


FIGURE 5: GEISMAR PETROCHEMICAL FLOW DIAGRAM - SHEET 2 OF 2

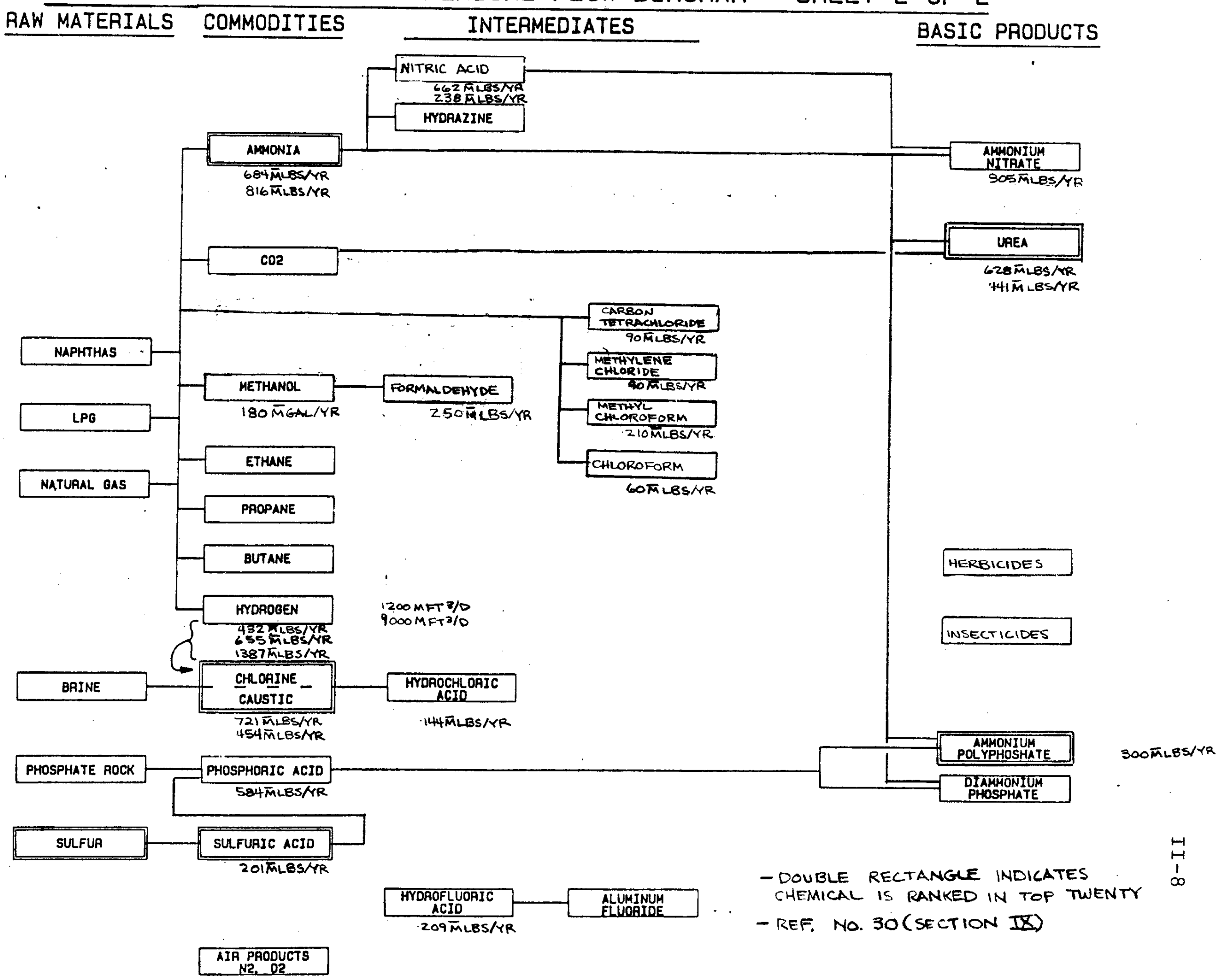


FIGURE 6: BATON ROUGE PETROCHEMICAL FLOW DIAGRAM

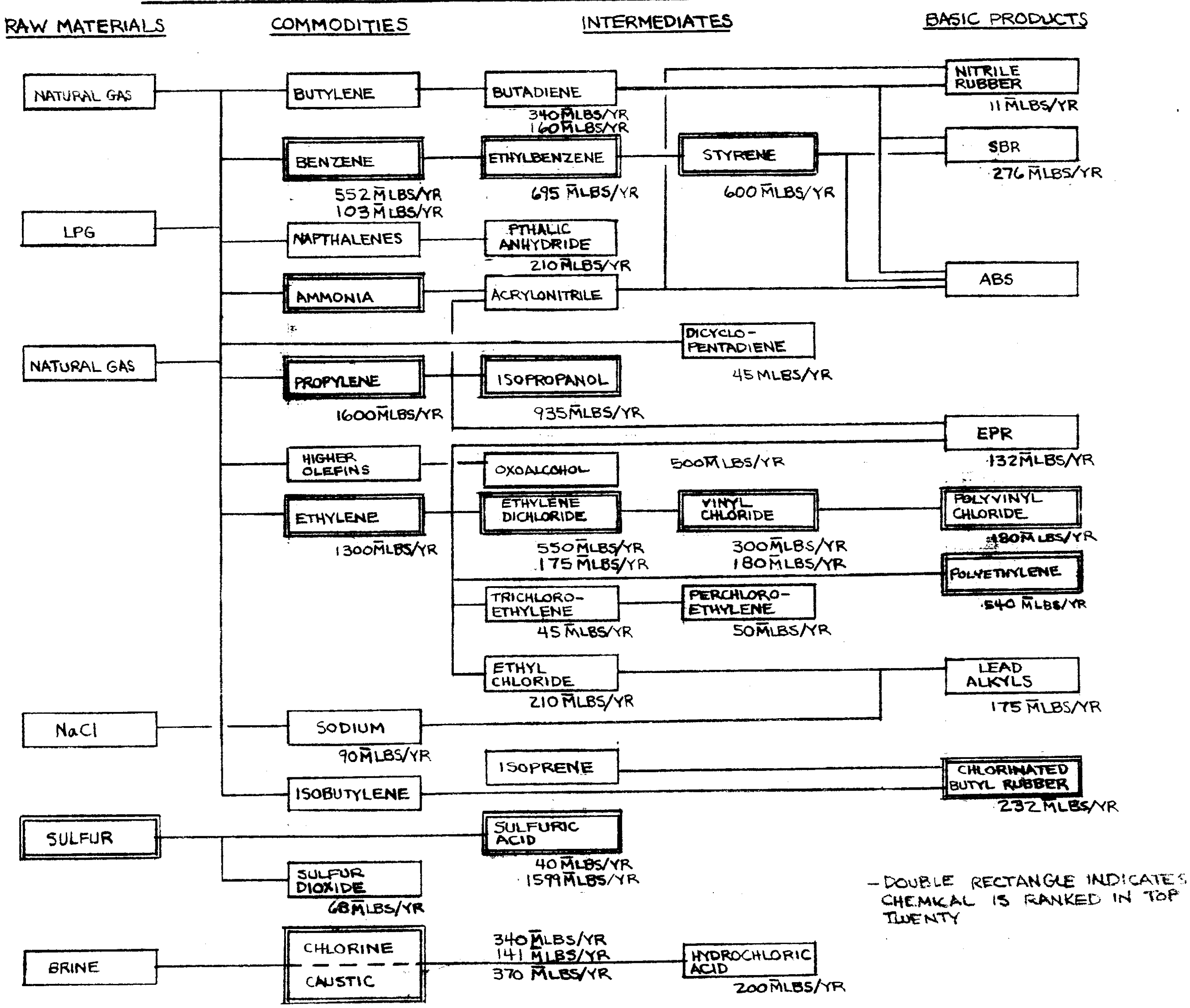


FIGURE 7: PLAQUEMINE PETROCHEMICAL FLOW DIAGRAM

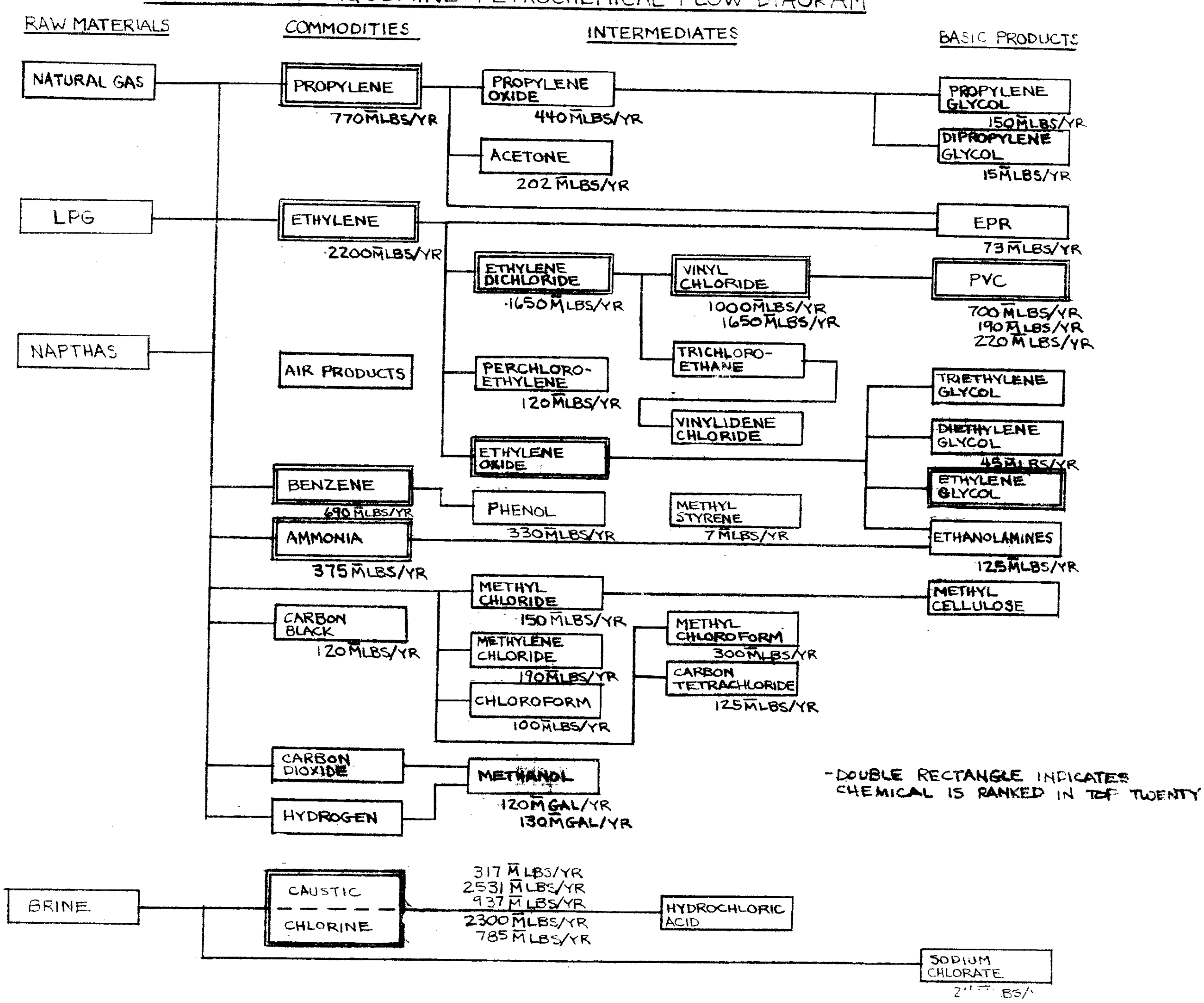
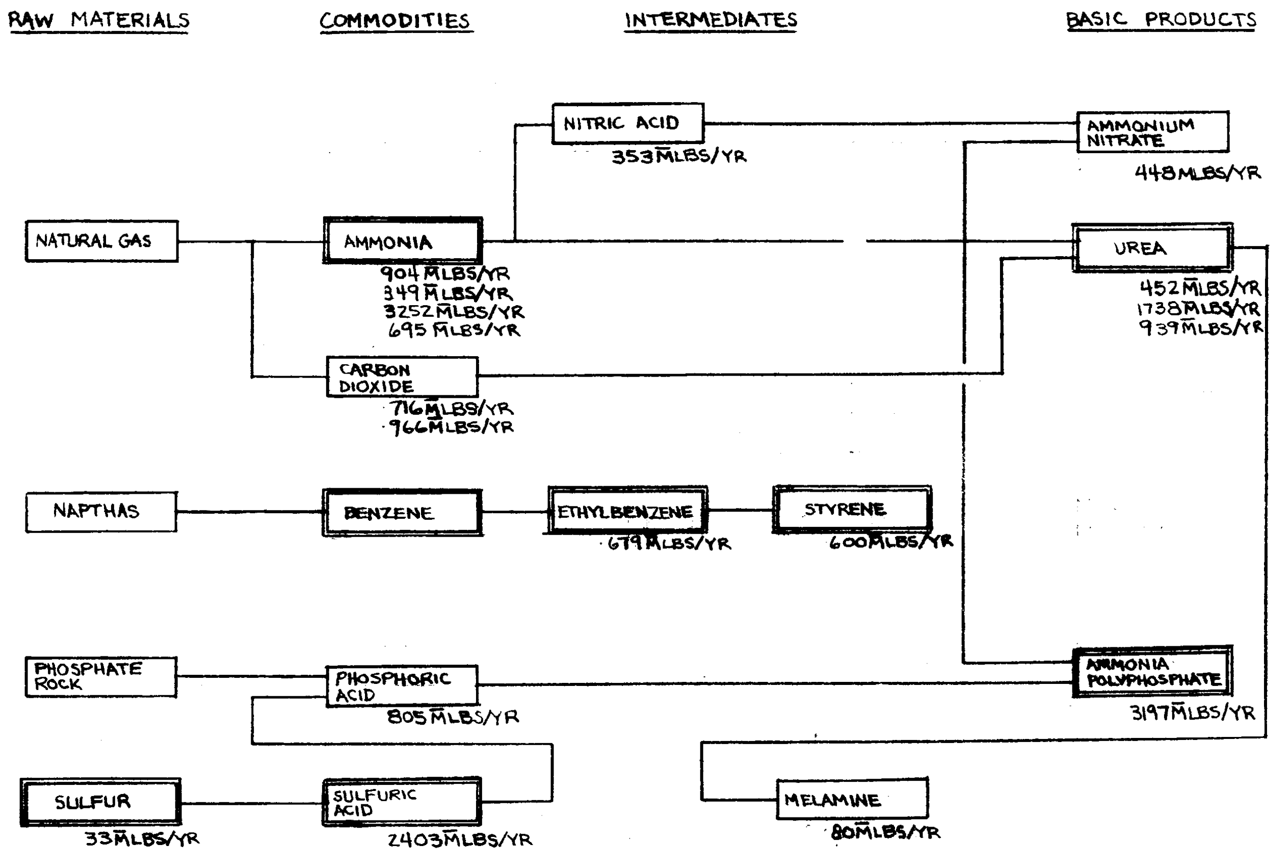


FIGURE 8: DONALDSONVILLE PETROCHEMICAL FLOW DIAGRAM



-DOUBLE RECTANGLE INDICATES CHEMICAL IS IN TOP TWENTY

FIGURE 9: NORCO PETROCHEMICAL FLOW DIAGRAM

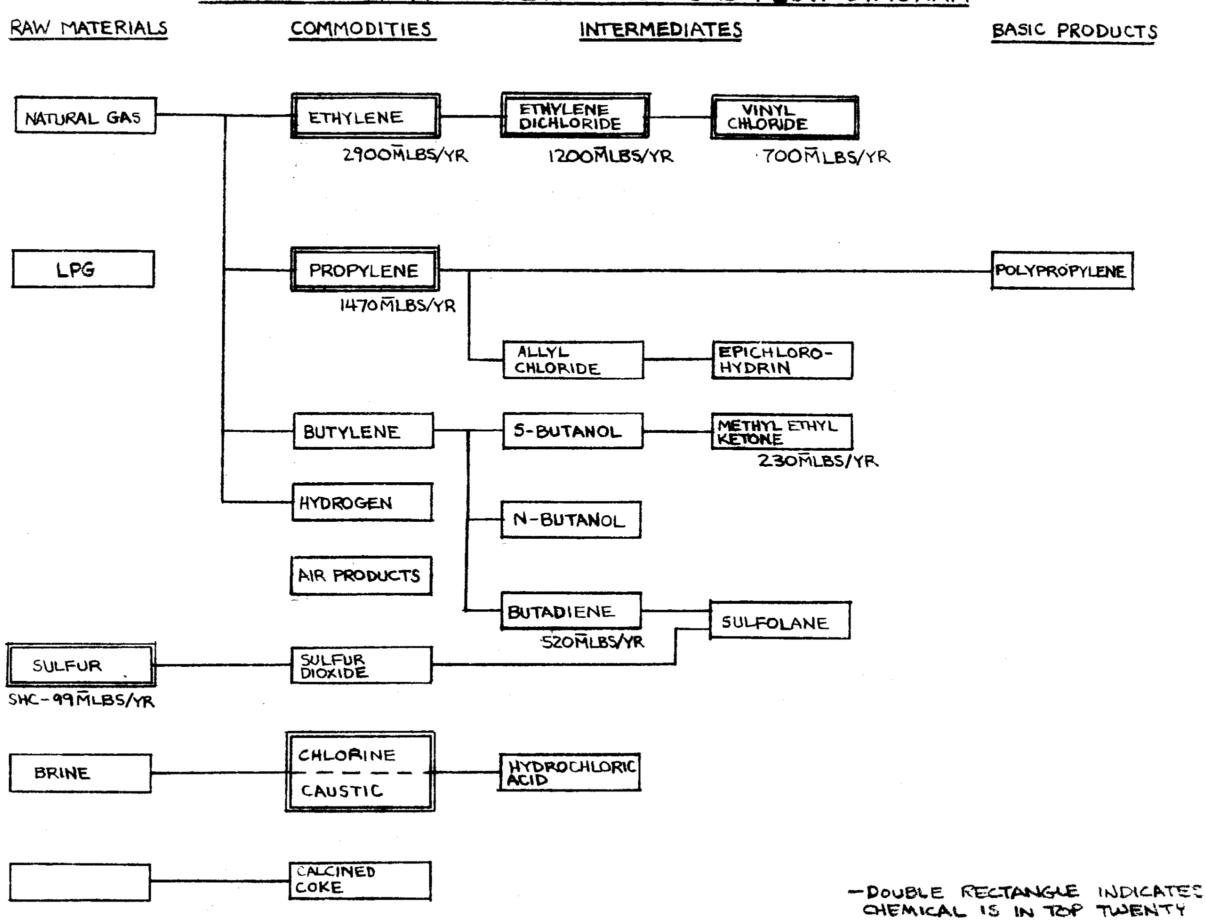
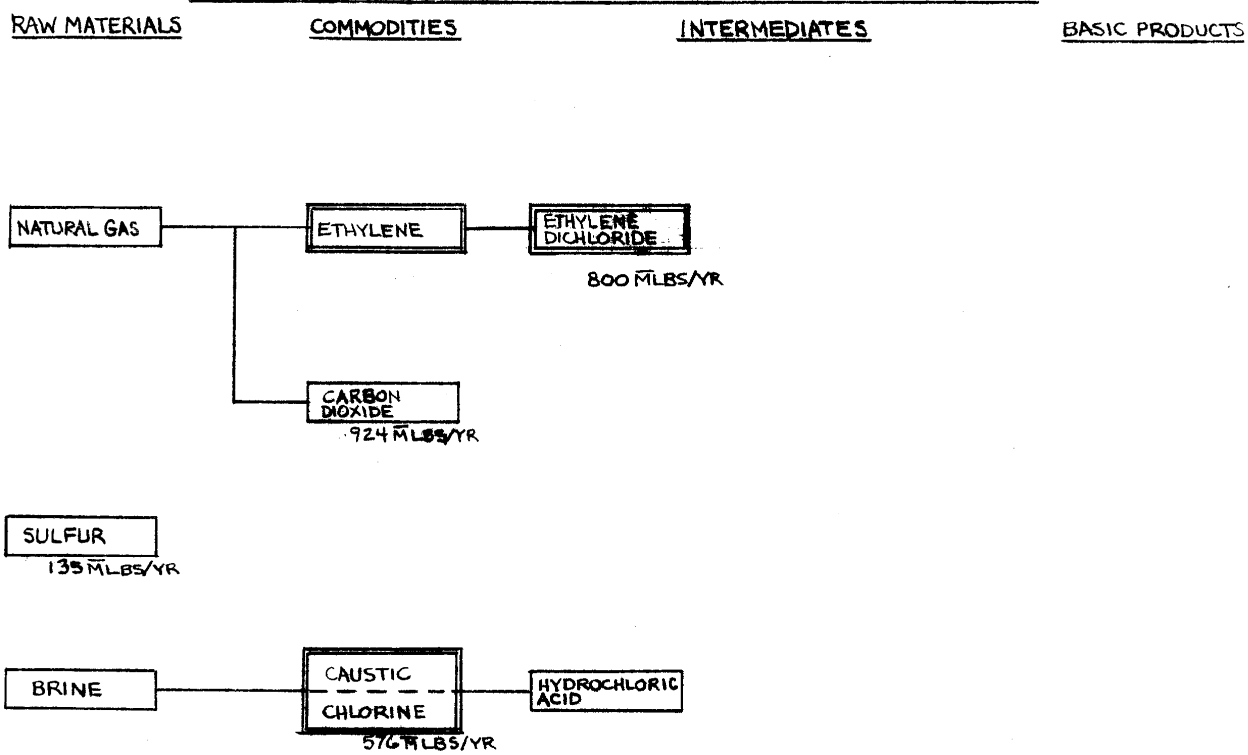


FIGURE 10: CONVENT PETROCHEMICAL FLOW DIAGRAM



- DOUBLE RECTANGLE INDICATES CHEMICAL IS IN TOP TWENTY assigned and product streams constituting 75% of the volume and value have been identified. As it turns out, 20 products from 34 different companies comprise the top 75%. In the nine complexes, there are a total of 62 companies (refer to Attachment A for a company and top 20 product summary).

Specific performance and efficiency correlations were developed for each type of cogeneration system. These correlations were used in conjunction with available plant data on fired boiler steam rates and conditions to calculate the cogeneration potential (refer to Section V and Table 8 for the results). The three basic types of cogeneration systems evaluated were the steam turbine system, the gas turbine system, and the combined cycle system.

An ecomomic model was developed to calculate the potential savings of these cogeneration systems based upon system efficiency (expressed as incremental heat rate), capital costs, and operating and maintenance costs. The viability of each of the three cogeneration systems was evaluated on the basis of the project's Internal Rate of Return (IRR) for several of the chemical companies located in the nine complexes. Because of the many variables and plant cases, a computer model was written to simplify this task. The results are summarized in Section V of this report.

Federal and state regulations affecting cogeneration, fuel use, sale and purchase of electricity by cogenerators, and distribution of such power through the utility system grid have been cited; and incentives for cogeneration have been listed and discussed.

III. COGENERATION SYSTEMS

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. Cogeneration thus offers significant overall energy-saving potential for the cogenerator.

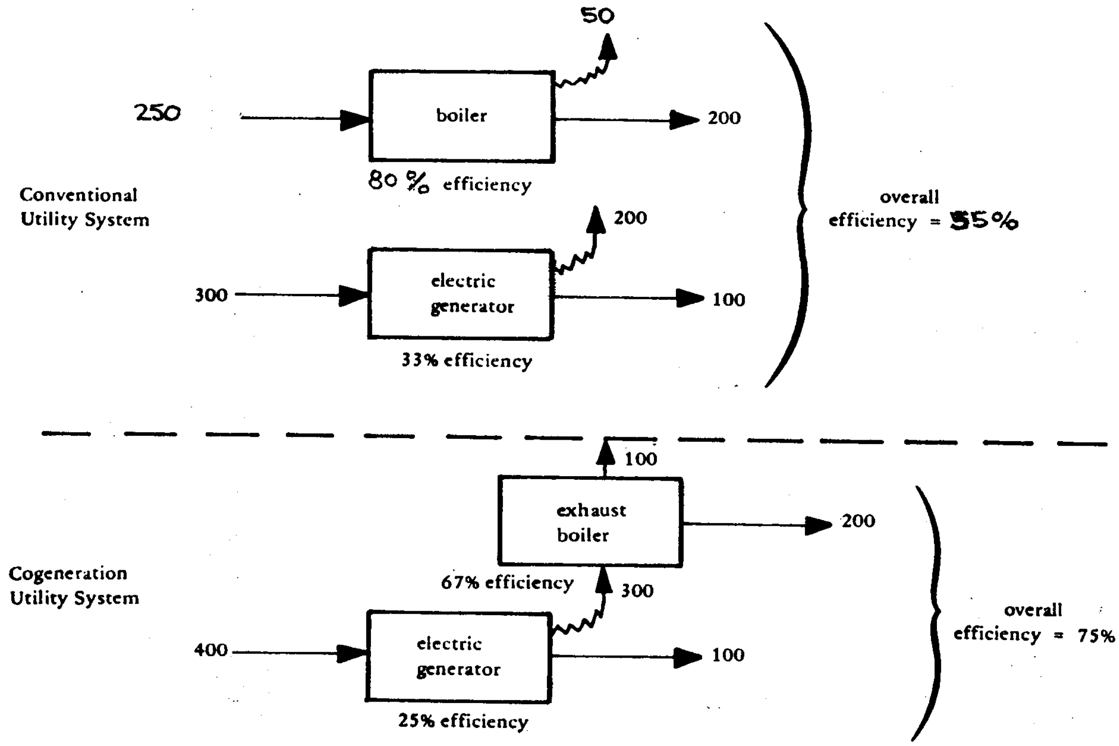
Figure 11 illustrates the benefit of cogenerating by comparing energy balances for a conventional system and for an ideal cogeneration system serving a load center that requires simultaneously 200 units of thermal energy and 100 units of electrical energy. In the conventional system, where the thermal energy is supplied by an on-site boiler or heater with an efficiency of 80%, an energy input of 250 units is required to meet the thermal load. The 100-unit electrical load is met by purchasing power from the utility company at a net efficiency of approximately 33% and a corresponding energy input of 300 units. The conventional system has an overall efficiency of 55%. By comparison, the cogeneration system can provide the same thermal and electrical loads at an overall efficiency of 75% by utilizing the exhaust heat from the turbine-generator.

There are two fundamental types of cogeneration systems: topping cycles and bottoming cycles. In a topping cycle, which is the most common type of cogeneration, electricity (or mechanical energy) is produced first and thermal energy from the exhaust is recovered for process use.

FIGURE 11

ENERGY BALANCE COMPARISON

Example: Need 200 units of energy as steam
100 units of energy as electricity



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In a bottoming cycle, thermal energy is produced for process use, and the waste heat is secondarily used for generating electrical and/or mechanical power. Topping/ Bottoming cycles can be used together in a combined cycle system.

A. Topping System Cogeneration

A prime mover is defined as the equipment that converts thermal energy to electrical and/or mechanical power. The prime mover determines the topping cycle classification. Three of the most common types of prime movers are steam turbines, gas turbines, and diesel engines.

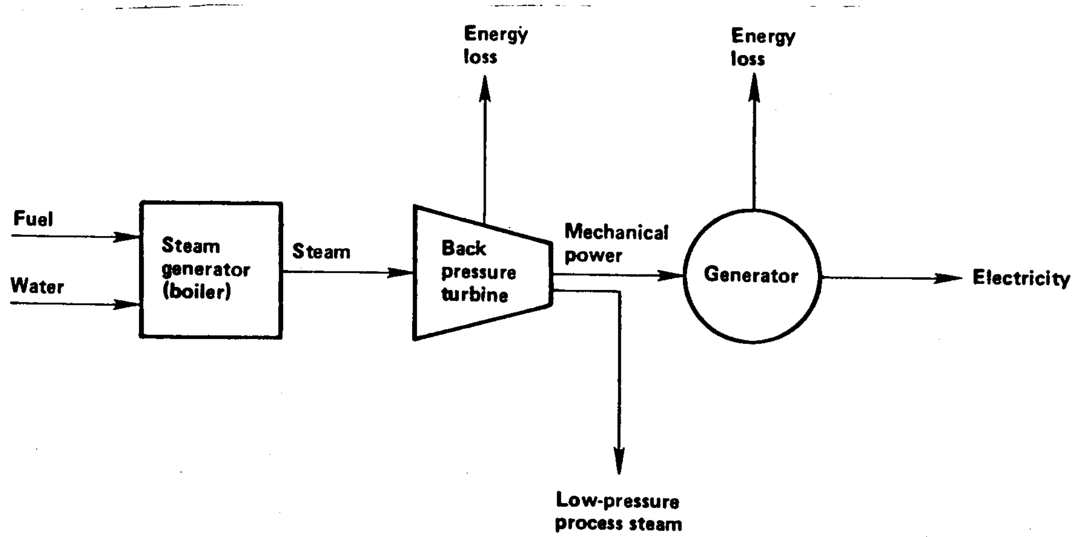
1. Steam Turbine

Steam turbine generators are the most common type of equipment used for the cogeneration of electricity and heat. The steam turbine has proven to be a dependable prime mover for cogeneration for over 70 years. While steam turbine systems can range from a few hundred kilowatts to over 200 MW most systems usually are in the range of 5 to 40 MW.

The steam turbine system consists of a steam boiler and a backpressure turbine (refer to Figure 12). The boiler can generate steam by firing fuels such as oil, natural gas, coal, wood, refuse, or industrial byproducts. Steam can also be generated by recovering waste heat from an industrial process. The mechanical

FIGURE 12

STEAM-TURBINE TOPPING SYSTEM



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energy generated by the expansion of the high pressure steam through the turbine is converted to electrical energy via a conventional generator. In a topping cycle, the turbine exhaust steam is utilized in some capacity by the industrial process (i.e. steam turbine drivers and/or process heating applications). In a bottoming cycle, the turbine exhaust steam may be utilized or it may be simply condensed and recovered as boiler feedwater (refer to Section III B).

Conventional process plant steam turbines are axial-flow turbomachines, in which steam moves parallel to the shaft axis. These turbines are available as either single-stage or multi-stage units. The system itself can be either condensing or non-condensing. Typically, single-stage turbines have a design range of 10 to 30 MW, medium size multi-stage turbines 7.5 to 50 MW, and large multi-stage turbines 50 to 200+ MW.

When the steam exhausts at a greater than or equal to atmospheric pressure, the turbine is called non-condensing. When the steam exhausts at a pressure lower than atmospheric, the turbine is referred to as a condensing turbine.

Single-stage turbines are usually not designed to operate condensing because it would result in inefficient power generation only. By definition this would not constitute a cogeneration scheme. However, a single-stage condensing turbine may be considered if the supply steam is generated by waste heat or by-product fuel that does not have a significant alternate use value.

Multi-stage extraction condensing turbines are capable of supplying the process steam at a controlled pressure and independently controlling the amount of electricity generated by the condensing section. Power generated by the steam which is extracted to the process is by-product power. However, the power generated by the steam expanding to the condenser is not considered by-product power (unless the supply steam is generated by waste heat or by-product fuel that does not have a significant alternate use value). A considerable amount of the energy used to generate the supply steam is rejected to the surroundings through the condenser cooling water. Therefore, the multi-stage condensing turbine is not as efficient as a noncondensing system. However, there may be overriding reasons for including a condenser section:

- The supply steam is generated by waste heat or by-product/waste fuel that does not have a significant alternate use value.

- The additional electricity available from the condensing section can be utilized to shave peak electrical demands and thereby reduce the demand charges paid to the utility company.

- Provide electricity when it is not available from a utility. This can also be extrapolated to providing reserve capacity during the shutdown of another turbine-generator (during normal operation the condenser load would be kept minimal).

- The industrial process or other user requires large quantities of low level heat. The fluid to be heated can be utilized as a cooling fluid in the turbine condenser.

For a perfect isentropic expansion, the energy available by the steam for conversion to output power is the change in enthalpy from the inlet conditions to the outlet pressure. The values of enthalpy can be read from steam tables, a Mollier diagram, or a table of Theoretical Steam Rates (TSR).

$$\text{TSR(lb/kWh)} = \frac{3413\,\text{(Btu/kWh)}}{\Delta H_{ISEN}\ \text{(Btu/lb)}}$$

However, because of frictional losses and other inefficiences in the turbine, the Actual Steam Rate (ASR) required is higher. Cogeneration type steam turbines generally have efficiency levels in the range of 65 to 85%.

$$\text{ASR(lb/kWh)} = N_{TURB} \times \text{TSR(lb/kWh)}$$

N_{TURB} = Turbine efficiency

Boiler efficiency is defined as the heat added to the steam divided by the fuel consumption. Radiation and unaccounted for losses generally represent only 1½% of input energy. Most of the losses occur in the exhaust stack. The following typical boiler efficiencies are based on $300^{\circ}F$ exhaust temperature.

- Natural gas 84%
- Oil 86-88%
- Coal 84-88%

Although the overall efficiency of steam turbine cogeneration systems is high, they cannot produce as much electricity per unit of process steam as other topping cycles. On the average, it takes from 4,000 to 6,000 Btu of fuel for each kilowatt-hour produced by steam turbine cogeneration systems (the dimensionless electricity/thermal ratio is less than 0.25).*

2. <u>Gas Turbine</u>

After the development of the aviation gas turbine, a significant effort was expended in developing a stationary gas turbine for utility and industrial use. As a result, gas turbines have successfully been established in the past 30 years as prime movers in oil refineries and petrochemical plants.

Gas turbine topping systems operate by firing compressed air and a gaseous fuel or light

* electricity/thermal ratio = the dimensionless ratio of the electricity produced to the gross process heat output.

petroleum products in a gas turbine. The combustion gases produce the mechanical shaft power that drives an electrical generator (refer to Figure 13).

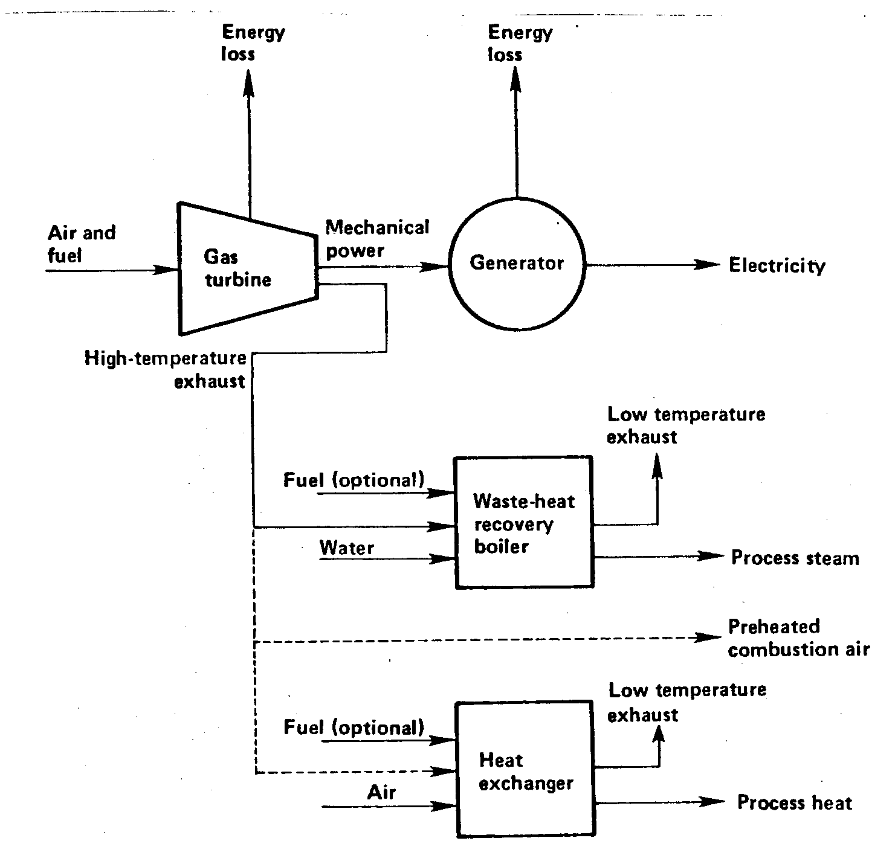
The exhaust of the gas turbine (at 900 to 1000°F) is recovered directly via a heat exchanger for process heating applications and/or indirectly via a boiler for process steam generation. The high pressure steam produced in the waste heat recovery boiler can be used to generate mechanical or electrical power via a steam turbine.

The electrical conversion efficiency of gas turbine topping cycle systems is lower than that of steam turbines. However, gas turbines produce about four times as much electricity while providing the same amount of process steam. The gas turbine cycles require about 5,500 to 6,500 Btu of fuel for each kilowatt-hour generated (the dimensionless electricity/thermal ratio is typically between 0.5 to 0.7).

Gas turbine systems cost less per kilowatt-hour than steam turbine systems and have less fuel flexibility. Although well established and highly reliable, gas turbines require more frequent maintenance than steam turbines. The combustion system must receive frequent minor inspections and mechanical parts must be inspected at intervals ranging from 5,000 to 10,000 hours, depending on the fuel used and the frequency of start-ups. Major modules can be replaced on-site without major

FIGURE 13

GAS TURBINE TOPPING SYSTEM



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disassembly. However, major overhauls are required at 20,000-75,000 hours.

The performance characteristics of a typical commercial gas turbine are given in Figures 14 thru 16. Because the amount of power is strongly influenced by the ambient temperature, the gas turbine should be sized for the highest prevailing ambient temperature.

For the associated waste heat boiler, the rate at which heat is transferred from the hot exhaust gases to produce steam is influenced by the "pinch point" temperature difference. The "pinch point" is defined as the minimum effective temperature difference existing between the exhaust gases and the generated steam. The surface area required to produce a given amount of steam will increase as the temperature difference decreases which correspondingly increases the cost of the boiler.

Another factor that influences the performance of the waste heat boiler is the gas turbine exhaust gas temperature (boiler inlet temperature). The amount of steam produced per unit of exhaust gas is greater at higher gas temperatures (refer to Figures 14 and 15).

The gas outlet temperature is usually not designed to fall below approximately 300°F. This temperature is safely above the temperature at which sulfuric acid condenses ("sulfur dewpoint") and

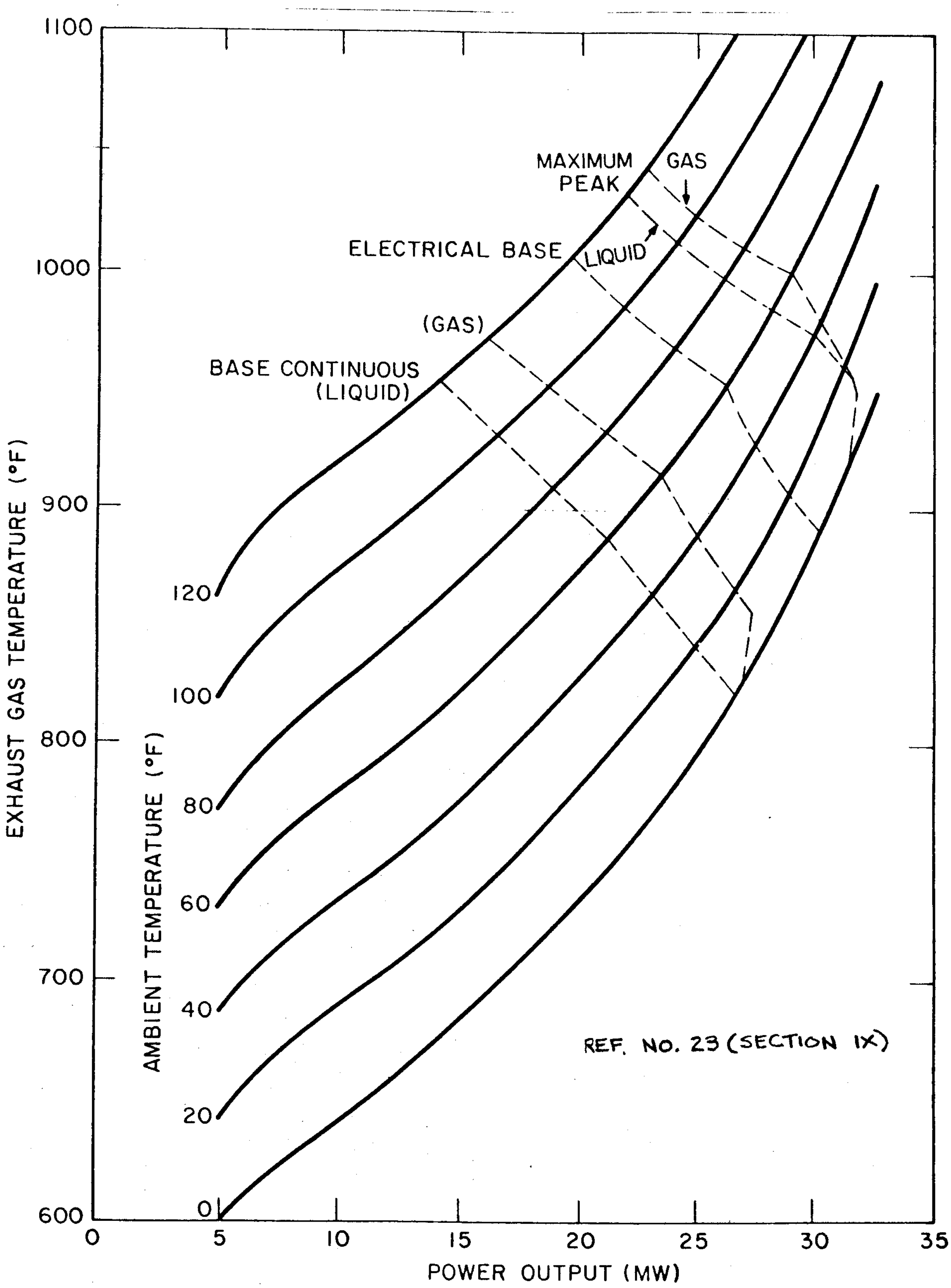


Figure 14: Exhaust Gas Temperature versus Power Output and Ambient Temperature - No Loss Conditions

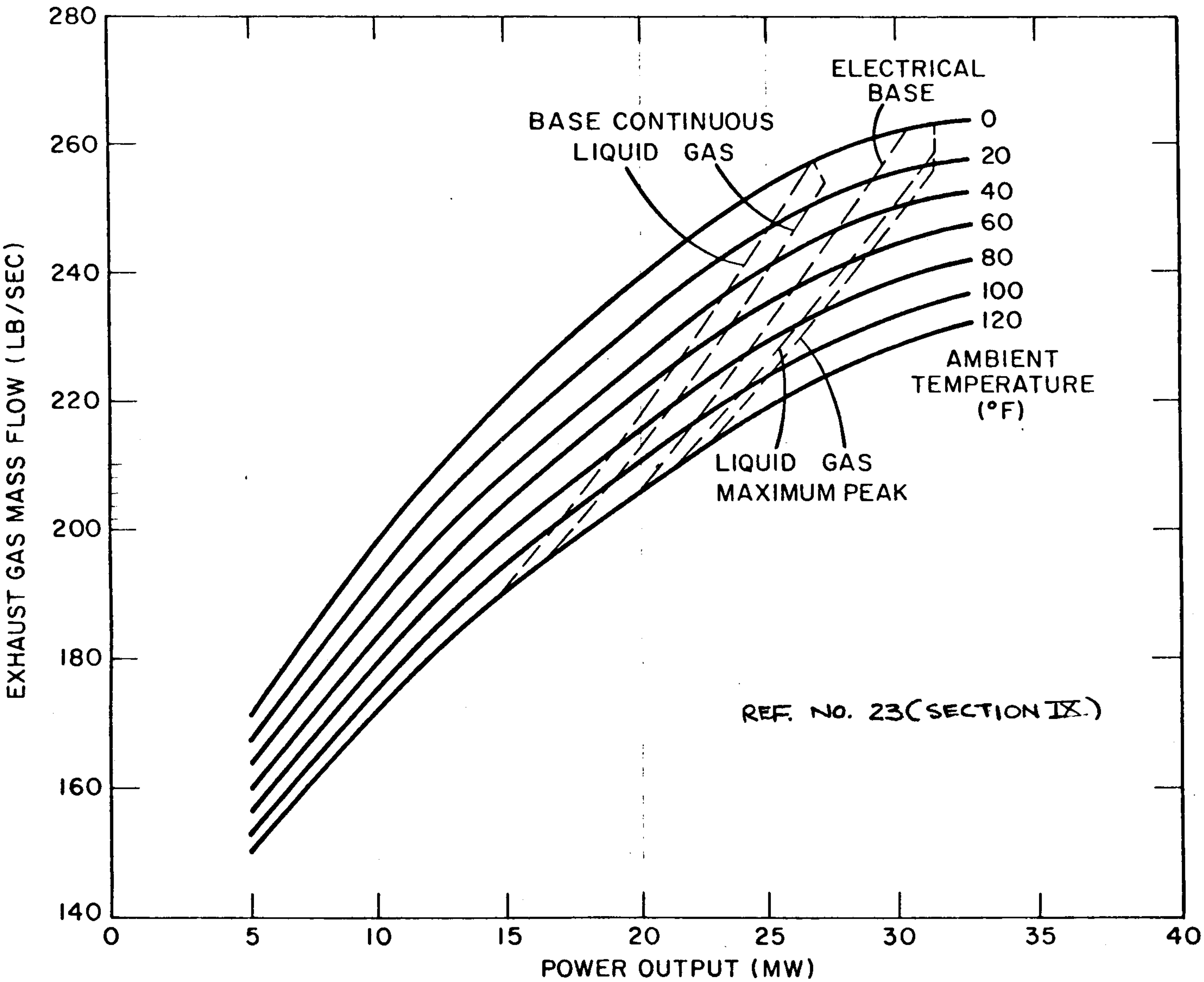


Figure 15 Exhaust Gas Mass Flow versus Power Output and Ambient Temperature - No Loss Conditions

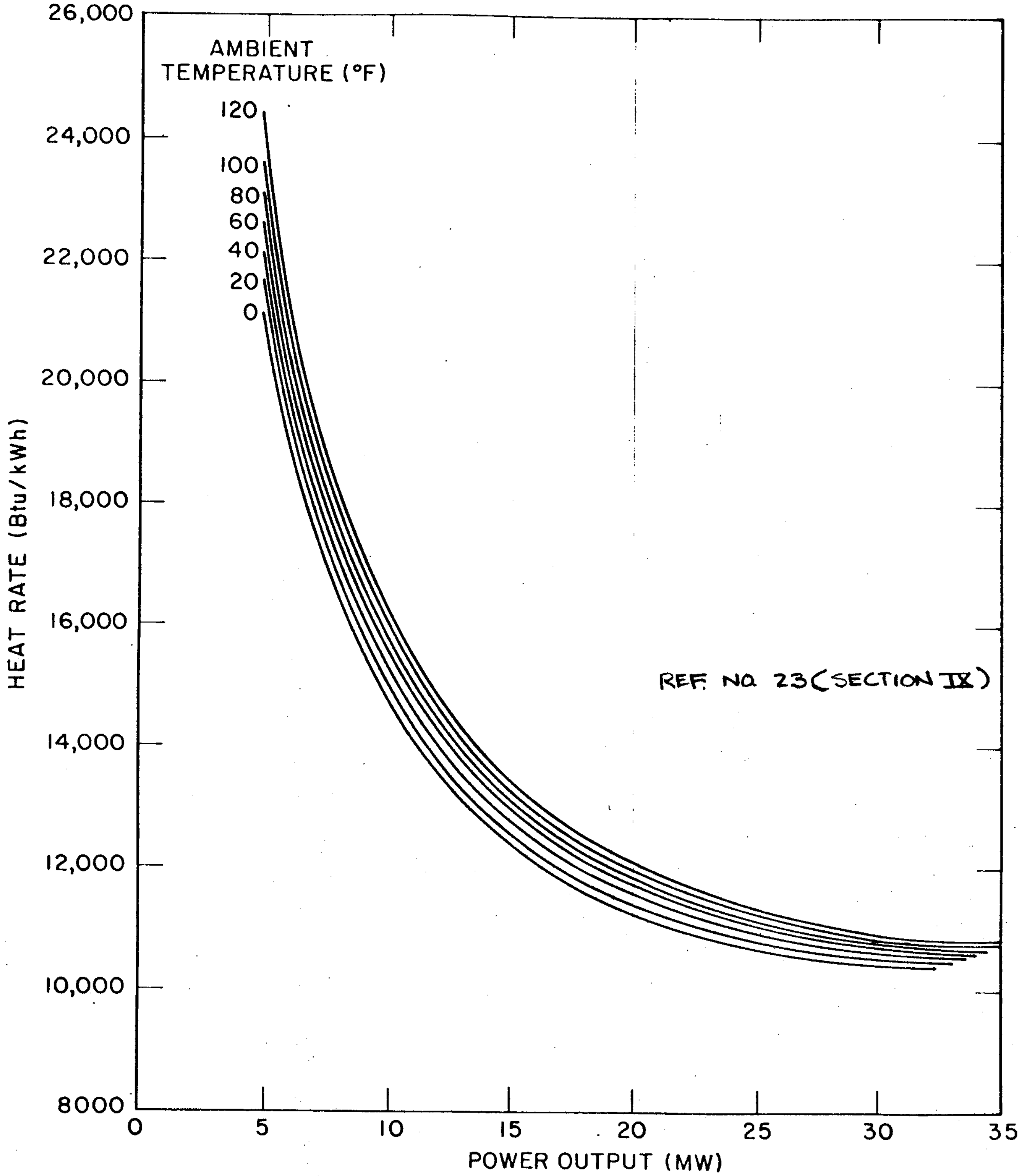


Figure 16: Heat Rate versus Power Output and Ambient Temperature
No Loss Conditions

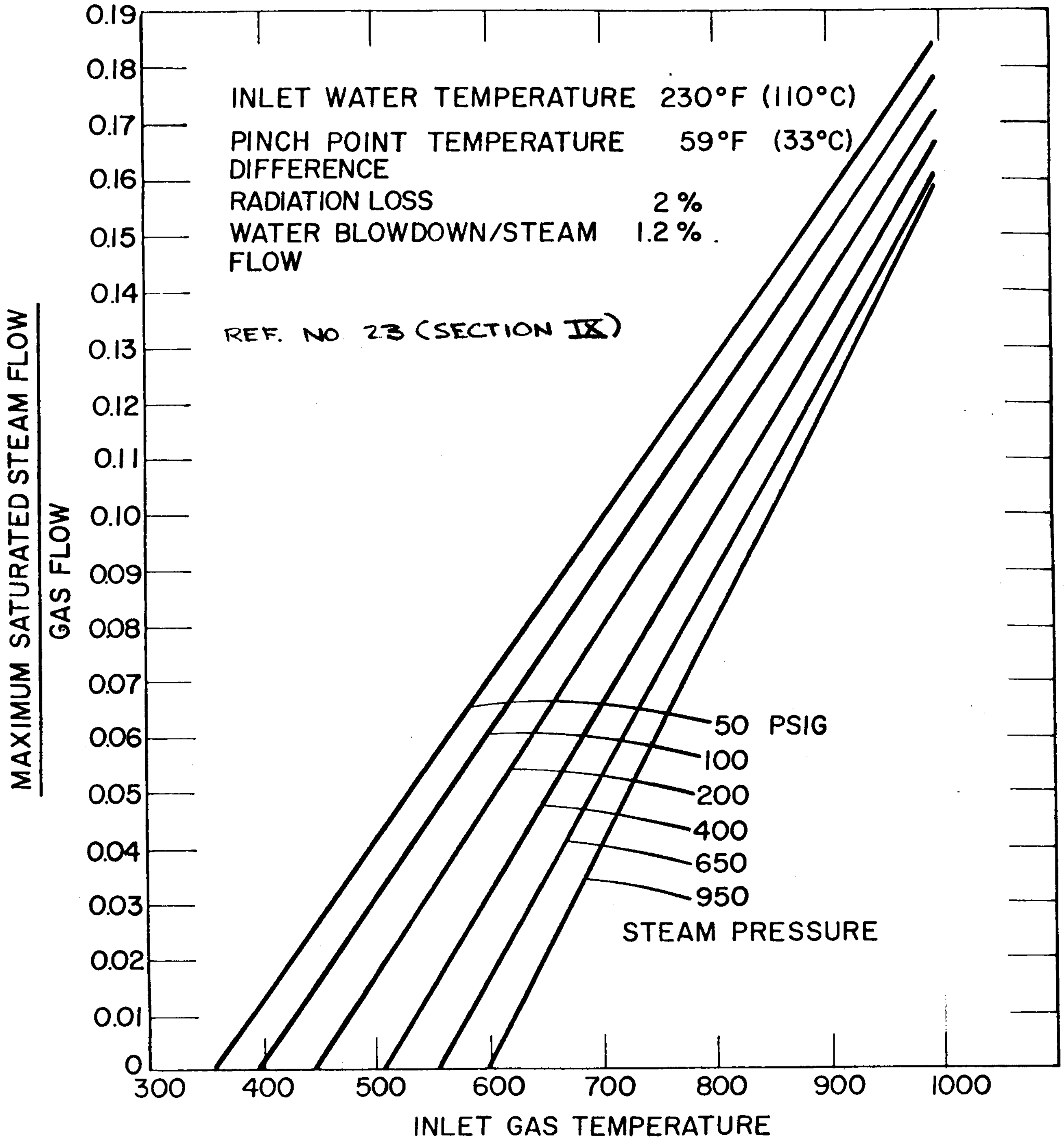


Figure 17: Steam Production from Recovery Boilers as a Function of Steam Pressure, Inlet Gas Temperature, and Gas Flow

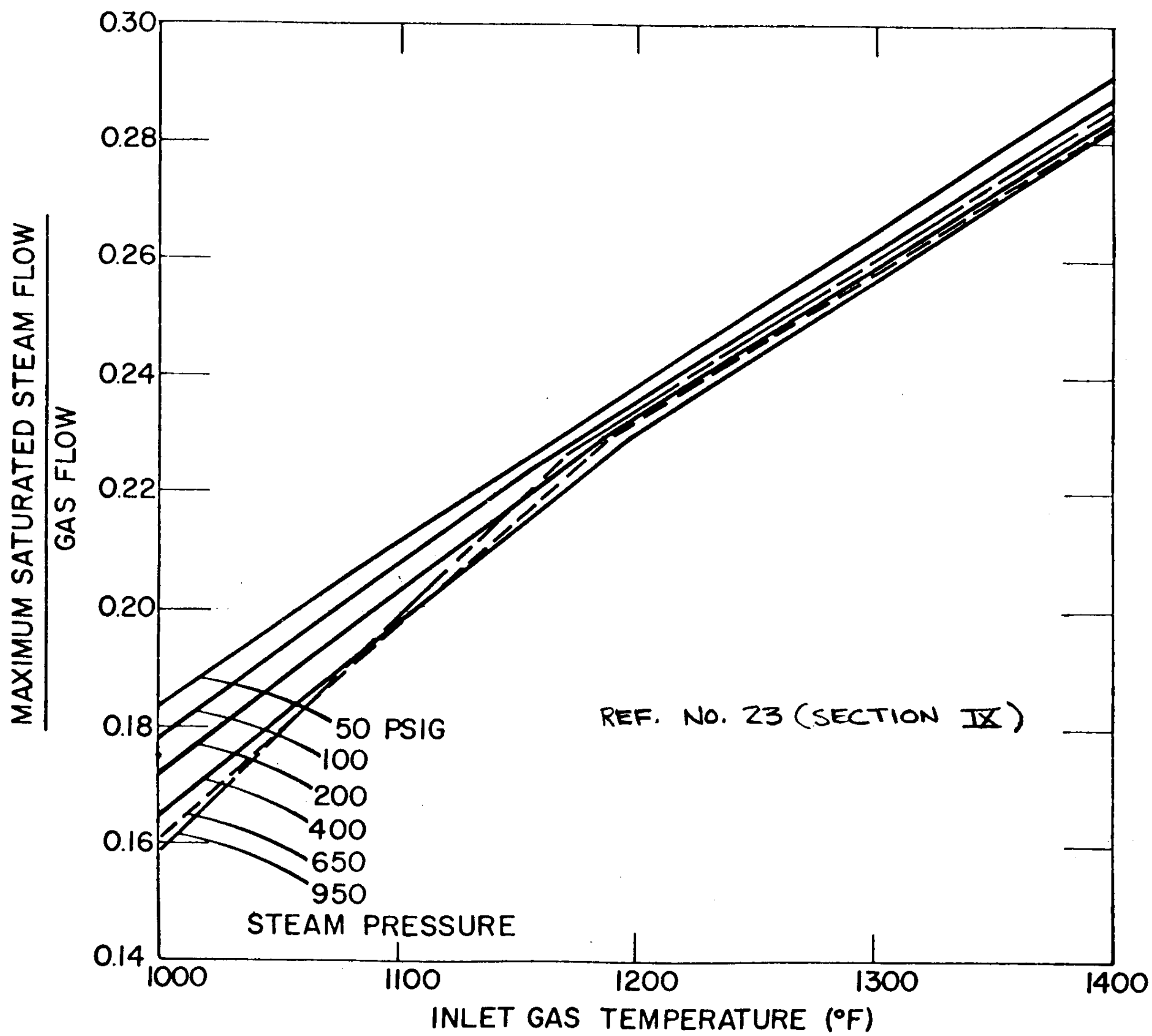


Figure 18: Steam Production from Recovery Boilers
as a Function of Steam Pressure, Inlet Gas Temperature, and Gas Flow

minimizes metal corrosion which eliminates the need for expensive alloys.

3. Combined Cycle

The combined cycle system is a variation on the gas turbine system, with the waste heat from the gas turbine used to generate steam which in turn is used to generate additional electricity via a steam turbine (refer to Figure 19).

Combined cycle systems produce more electricity per unit of process steam generated than any other system (the electricity to thermal ratio is between 0.6 to 0.8). Generally, the incremental heat rate for a combined cycle system is 5,000 to 5,500 Btu of fuel for each kilowatt-hour produced. Typically, the combined cycle system is less expensive per kilowatt than steam turbine systems. However, they are as limited in fuel flexibility as the gas turbine systems.

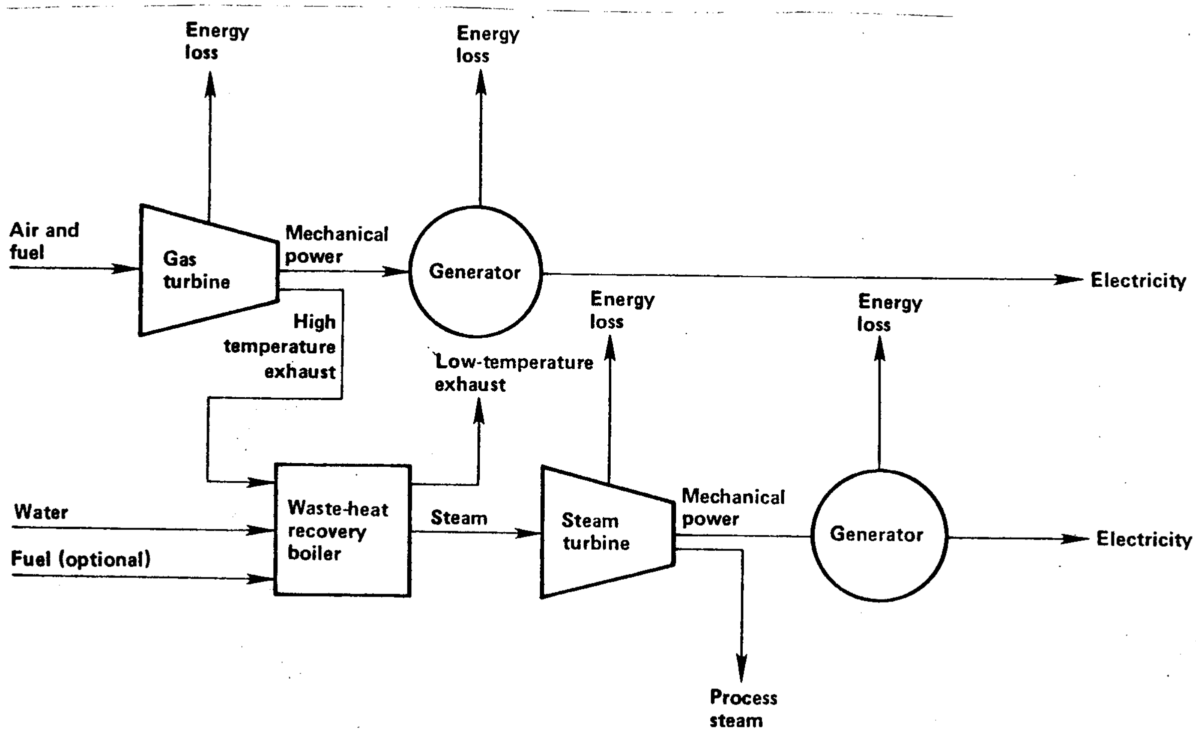
4. Diesel Engine

Diesel engines can be broadly classified into three categories based upon engine speed: high-speed diesels operating at 900 to 1500 rpm and producing up to 3.5 MW; medium-speed diesels operating at 500 to 600 rpm and producing between 5 to 20 MW; and low-speed diesels operating at 120 to 150 rpm and producing 8 to 28 MW.

The diesel engine cogeneration system is conceptually similar to a gas turbine cogeneration system consisting of a combustion section and a

FIGURE 19

COMBINED-CYCLE TOPPING SYSTEM



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waste heat recovery unit. The combustion of the fuel yields the mechanical power that drives the generator (refer to Figure 20). Thermal energy is recovered from the exhaust gases and from the engine water jacket.

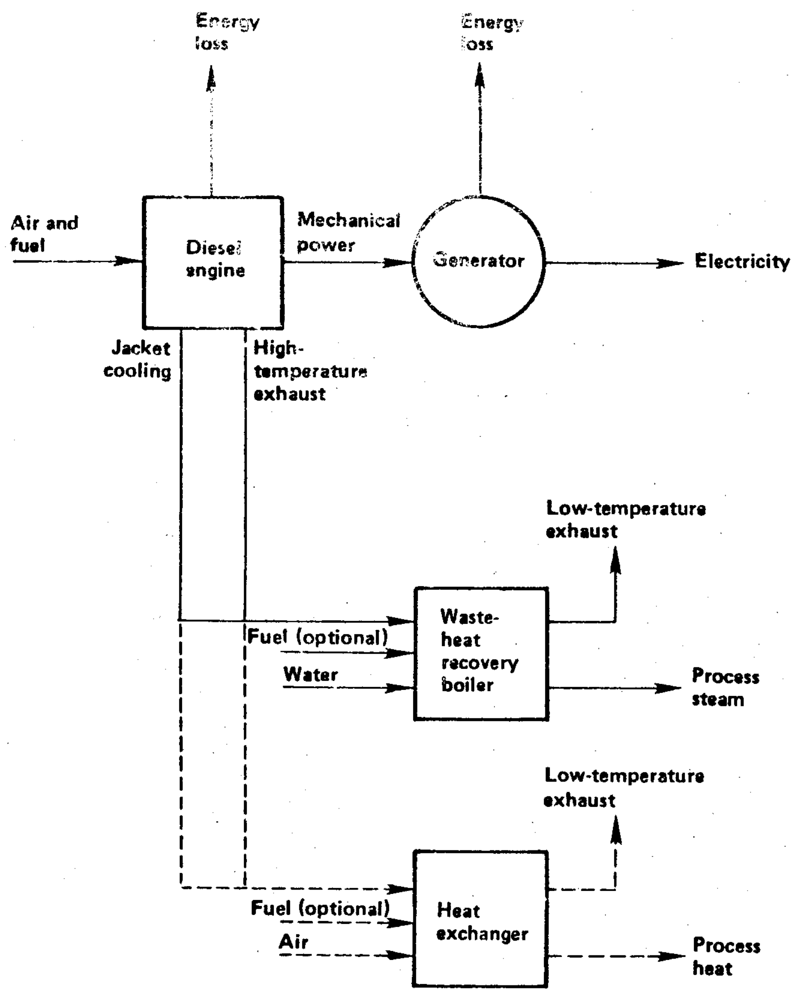
The temperature of the exhaust gases released by diesels is typically between 500°F to 950°F, generally lower than for gas turbines. Therefore, the pressure of the steam generated by a diesel is usually less than 400 psig. For low-speed diesels, the steam generated is usually less than 200 psig. Higher pressures can be obtained but at a significant penalty in mass flow and boiler efficiency. Therefore, higher pressures and mass flows are usually obtained by supplemental boiler firing.

In addition to the heat recovered from the exhaust gases, a substantial amount of low-level heat can be recovered from the cooling water jacket. This can be used to generate low pressure steam, to preheat boiler feedwater, or to provide general process heating.

The type of fuel used in diesel engines depends upon the engine speed and, to some extent, on the engine design. In general, as engine speeds are increased, higher grades of fuel oil are required. Engines operating on natural gas and dual-fuels (oil and gas) are available. In general, high-speed diesels use No. 2 distillate fuel; medium-speed use residual oil or distillate oil; and low-speed use residual oil.

FIGURE 20

DIESEL ENGINE TOPPING SYSTEM



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Of the three topping cycles, diesel engine cogeneration systems require the most maintenance. The engines typically require minor maintenance every 7,000 to 10,000 hours, with major overhauls every 20,000 to 30,000 hours. Capital costs per kilowatt are the highest of the three topping cycles (excluding coal-fired and oil-fired steam turbine systems).

The incremental heat rate for a diesel engine topping cycle is about 6,500 to 7,000 Btu of fuel for each kilowatt-hour produced. Of the three topping systems, this cycle is the least efficient. However, its electricity/thermal ratio is more than twice that of the gas turbine and more than eight times that of the steam turbine (e/t ratio of approximately 2.0).

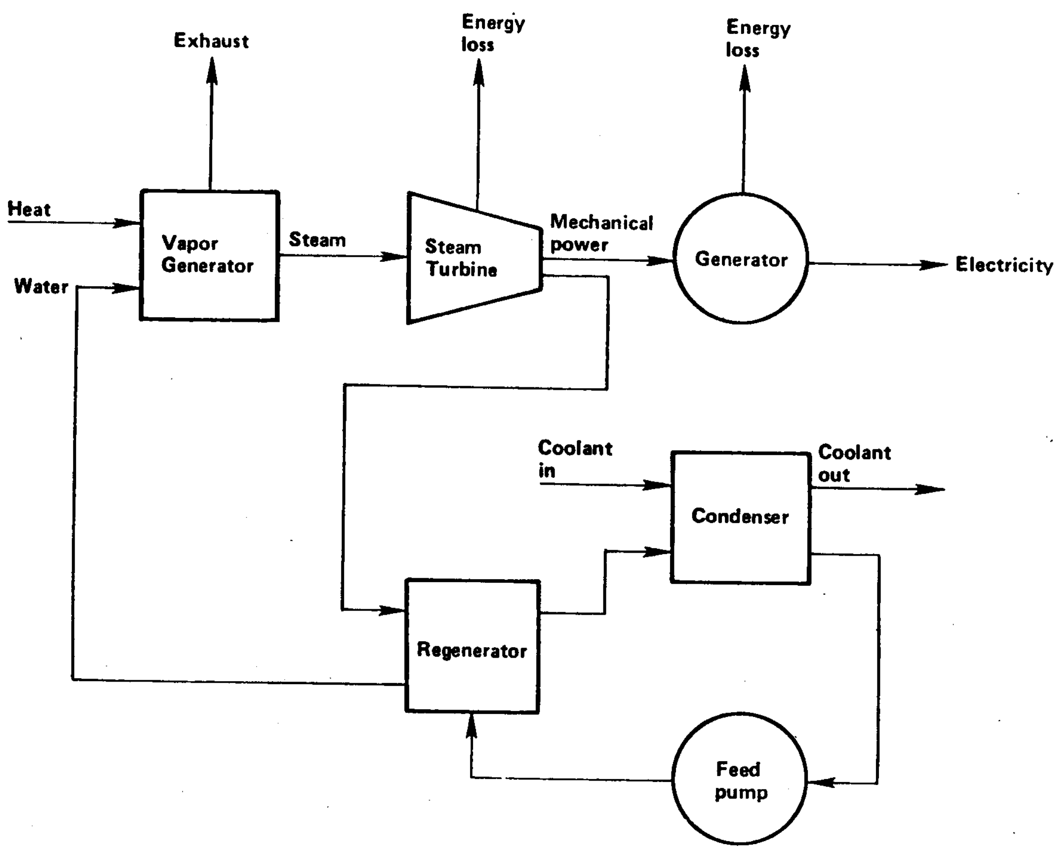
B. Bottoming System Cogeneration

Bottoming systems typically utilize the heat exhausted by gas turbines or industrial processes to generate power. Bottoming cycles are usually applied to plants that have extremely high-temperature equipment such as aluminum remelt furnaces, steel reheat furnaces, kilns, or hydrocarbon cracking furnaces. All bottoming cycles are based on the Rankine cycle utilizing either steam or an organic fluid.

In a steam bottoming system, recovered waste heat is used to produce steam in a recovery boiler (refer to Figure 21). The steam is expanded in a turbine to generate power. The exhaust steam can be further

FIGURE 21

STEAM RANKINE BOTTOMING SYSTEM



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utilized by the process for general heating applications or for driving a secondary turbine (provided the exhaust steam is at a high enough pressure). Figures 22 and 23 illustrate the amounts of power and steam for a given set of conditions that can be generated by a condensing and non-condensing system, respectively.

Another method of recovering more energy from rejected heat in bottoming systems is to use organic fluids with low boiling points and low latent heats of vaporization. A variety of such fluids are currently in use or being tested; toluene, butane, pentane, Fluorinol, Dowtherm-S, monochlorobenzene, and several fluorocarbons such as the Freons R11, R12, R113, R114, and C318 among others. These fluids are used in a closed condensing Rankine cycle similar to the condensing steam turbine systems. Depending upon the properties of the organic fluid utilized and the gas operating temperature, the system may produce more or less power than steam systems. The maximum amount of power that can be produced by some of the fluids listed is shown as a function of gas flow and temperature in Figures 24 and 25.

C. System Power and Thermal Characterization

The performance characteristics of each of the systems discussed are those that were defined in a 1980 General Electric Study, "Cogeneration Technology Alternatives Study (CTAS)". These characteristics were modeled into two equations with six constants for each major system.

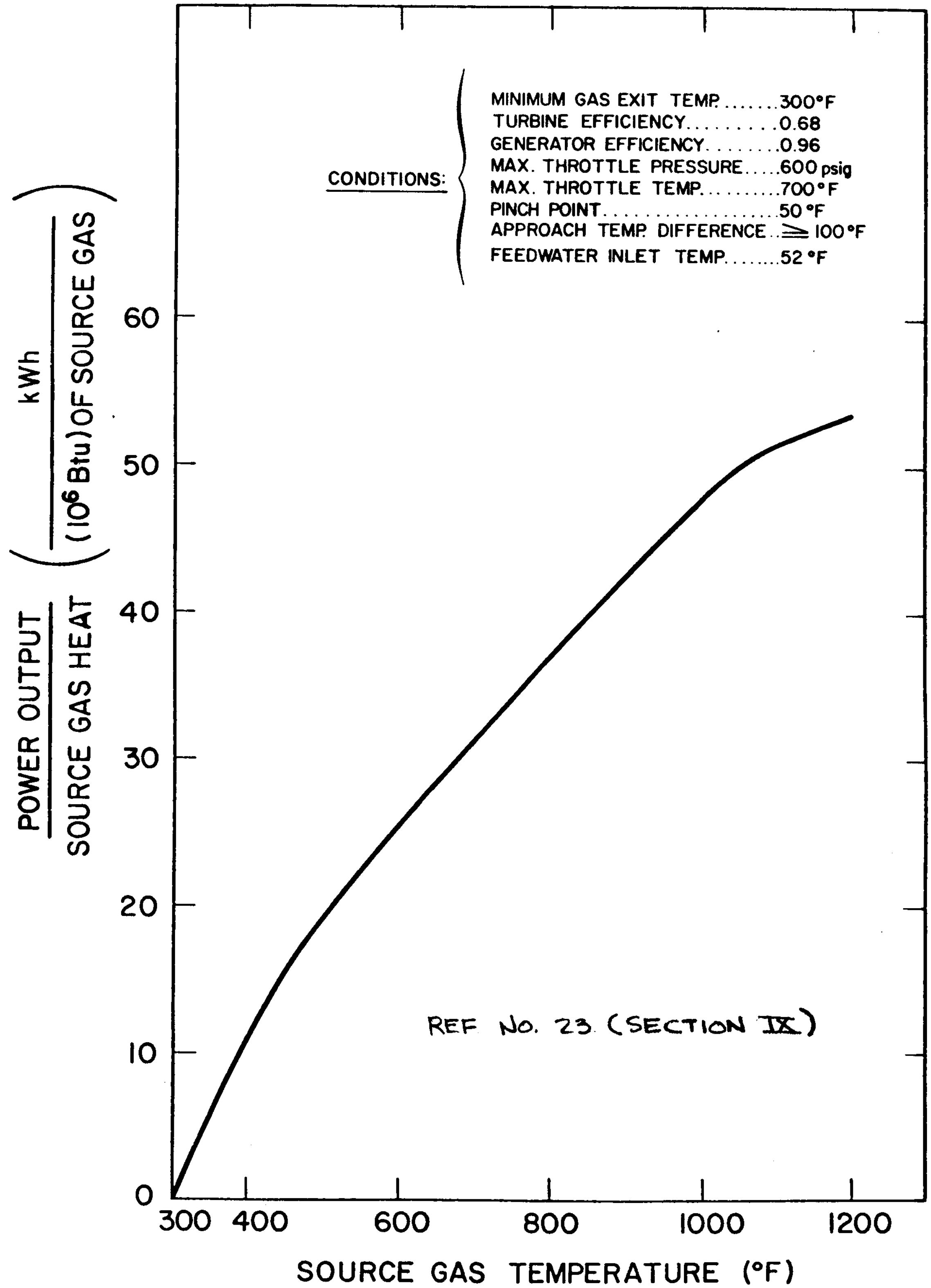

Figure 22: Power Generation by Condensing Steam Rankine Bottoming of Waste Heat

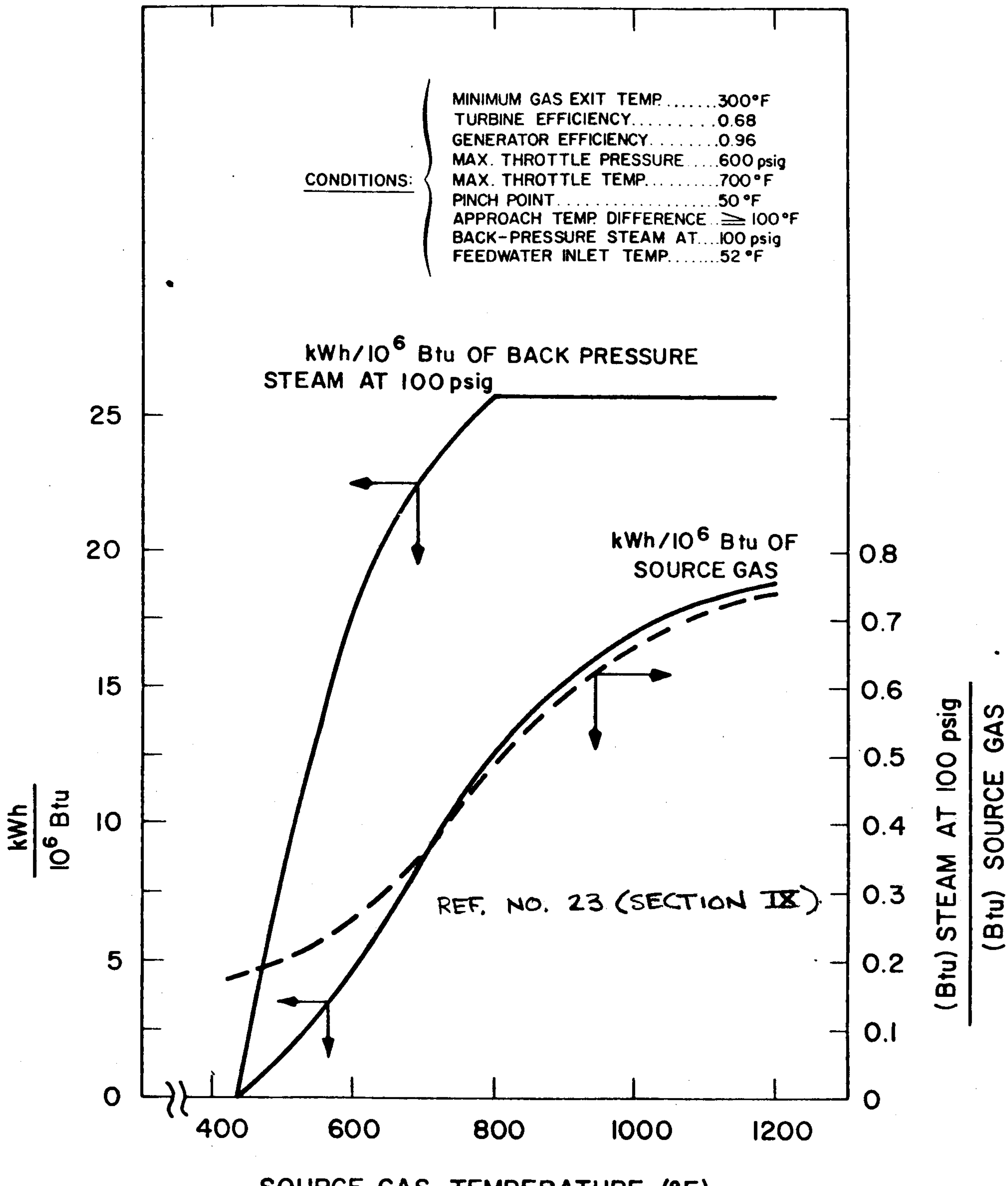

Figure 23: Power and Steam Generation by Noncondensing Steam Turbine Bottoming of Waste Heat

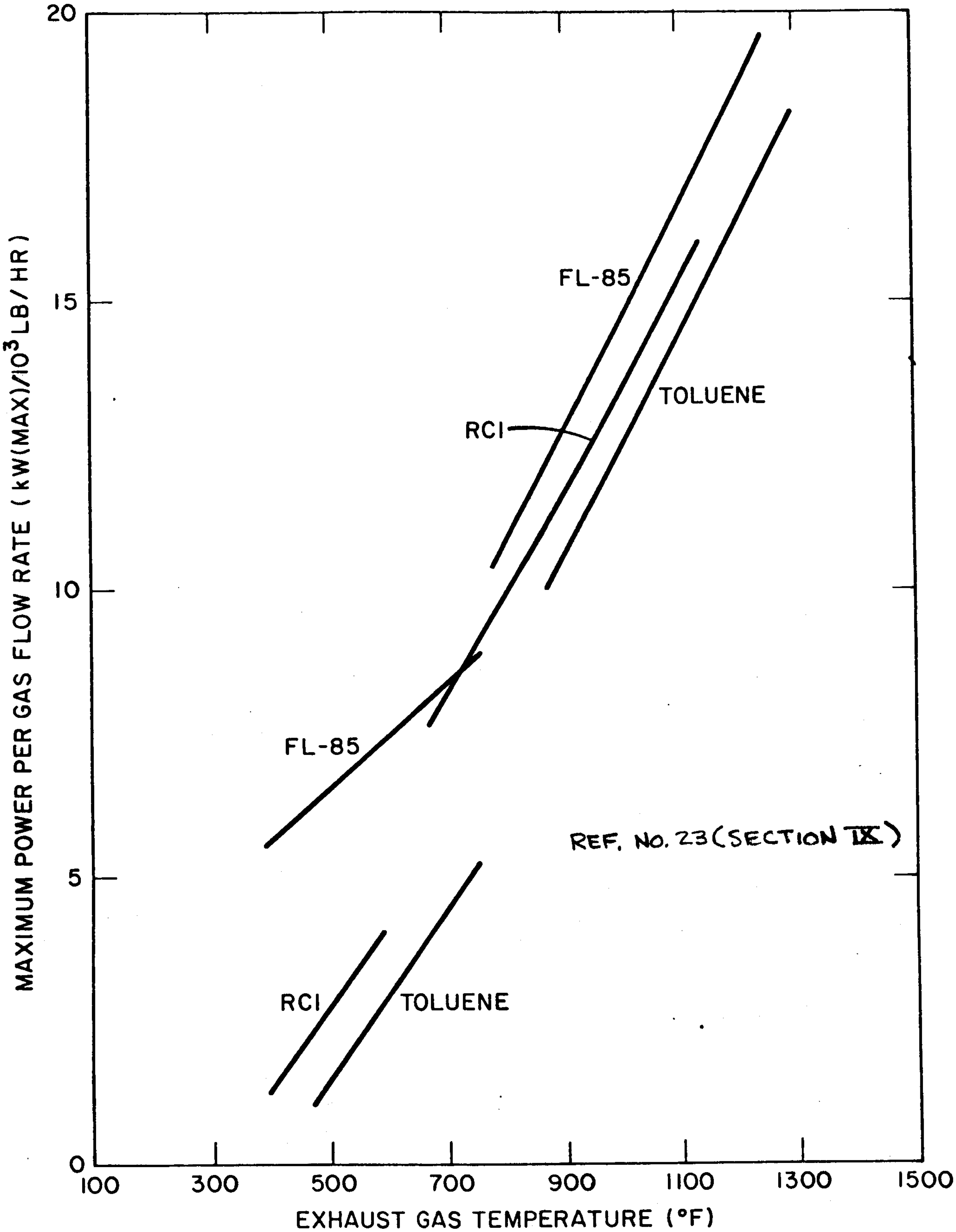

Figure 24: Power Generation Using Organic Fluids in Condensing Systems

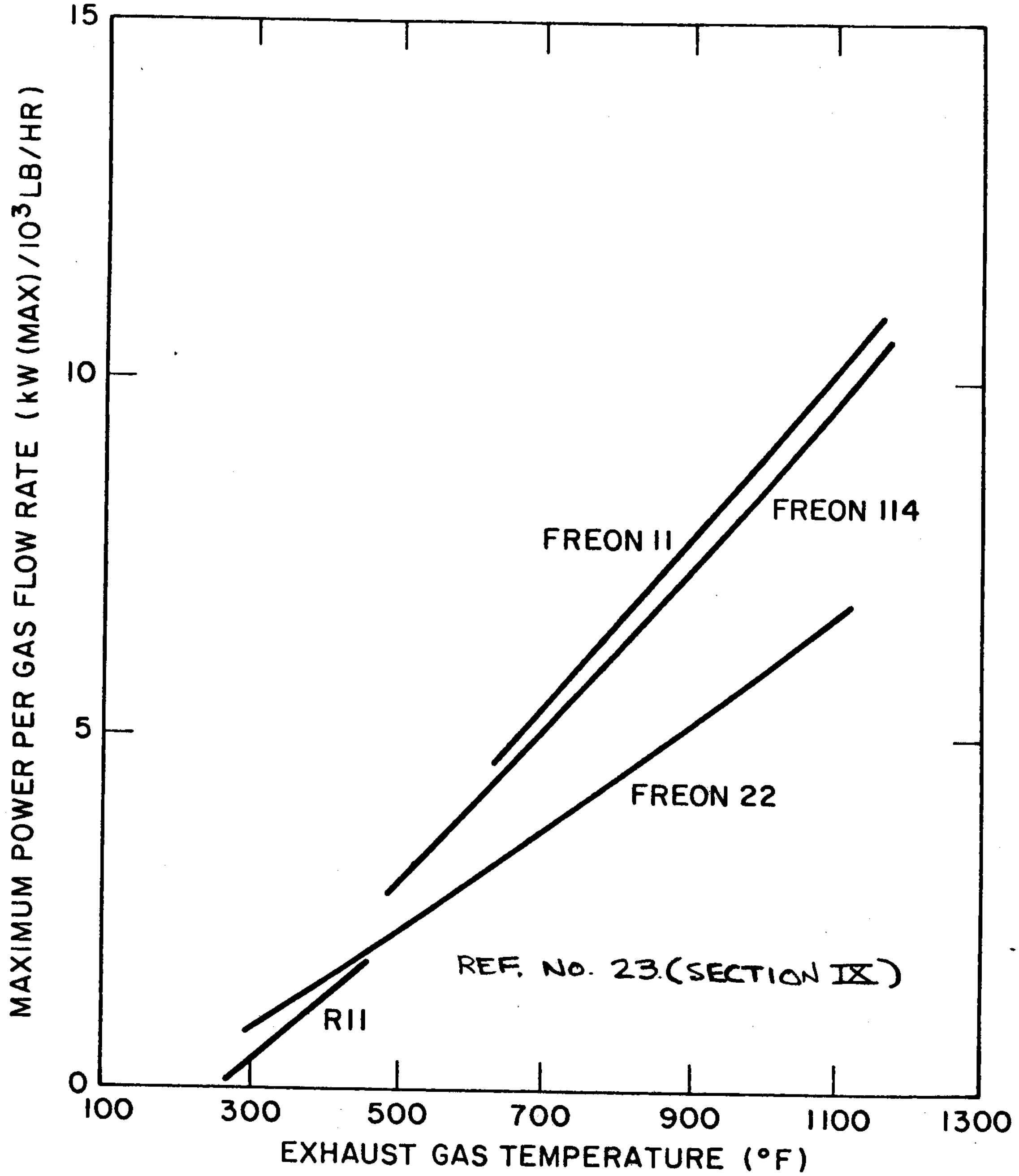

Figure 25: Power Generation Using Organic Fluids in Condensing Systems

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

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

TPRO is the temperature of the generated process steam in degrees Farenheit. The constants for each system are presented in Tables 1 and 2. With a knowledge of steam requirements (lbs/hr and temperature) these relationships can be used to match the plant thermal requirements to that of a particular cogeneration system.

TABLE I

CHARACTERIZING EQUATION (POWER)

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

(TPRO = Process Temperature)

Where Constants A_2, B_2, C_2 are as follows

ECS	A_2	B_2	C_2
Diesel	.3610	0	0
Steam Turbine	.3341	-0.538	-0.05
Gas Turbine/R and D	.2900	0	0
Advanced Gas Turbine	.323	0	0
Gas Turbine (Combined Cycle)	.4665	-0.2604	-0.0243
Gas Turbine (Closed Cycle)	0.176	0	0

REF NO. 27 (SECTION IX)

TABLE 2

CHARACTERIZING EQUATION (HEAT)

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

(TPRO = Process Temperature)

Where Constants A_1, B_1, C_1 are as follows

ECS	A_1	B_1	C_1
Diesel	0.3250	-0.423	0
Steam Turbine	0.5159	0.5380	0.05
Gas Turbine/R	0.4941	-0.082	-0.2989
Gas Turbine/D	0.5388	-0.3296	0.3167
Advanced Gas Turbine	0.5021	-0.2609	0.1929
CC Gas Turbine (Combined Cycle)	0.2499	0.2604	0.0243
Gas Turbine (Closed Cycle)	0.6044	-0.4000	0.2270

REF. NO. 27 (SECTION IX)

IV. INVESTMENT AND ENERGY SAVINGS ANALYSIS

A. System Capital Costs

Data on total installed costs for gas turbines, steam turbines, and diesel engines as a function of power output are given in Figure 26. For new boiler plants, or for existing boilers that are to be replaced, the economic analysis is generally based on the merit of installing a cogeneration system relative to that of installing a conventional steam boiler. The incremental economic analysis considers the increase in capital investment and evaluates the marginal return on investment based on the difference in capital costs. Figure 27 gives the incremental capital costs directly.

The capital cost curves are provided for quick estimating purposes and some caution should be exercised in the use of these figures.

- The capital costs presented in Figures 26 and 27 are expressed as 1981 dollars. To convert to current dollars, multiply the capital costs obtained from the figures by the ratio of the appropriate CE plant cost indices for 1981 and 1983 (refer to Table 3). Future capital cost projections can be estimated by prorating the present capital costs by an appropriate escalation factor.

- The capital cost curves are based upon historical data representing typical turnkey costs

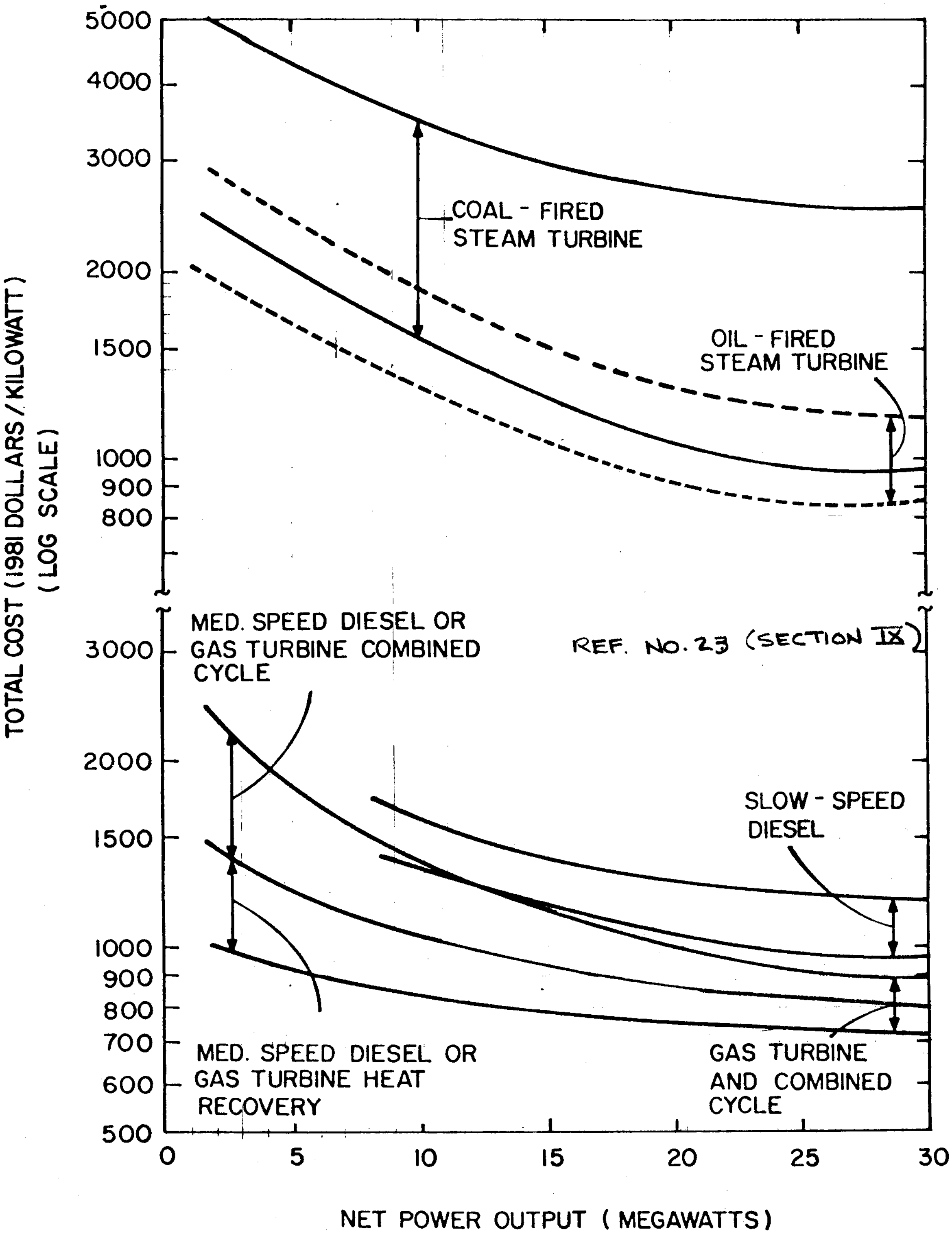

Figure 26: Typical Total (Turnkey) Costs of Industrial Cogeneration Systems, including Equipment, Installation, Engineering, and Construction

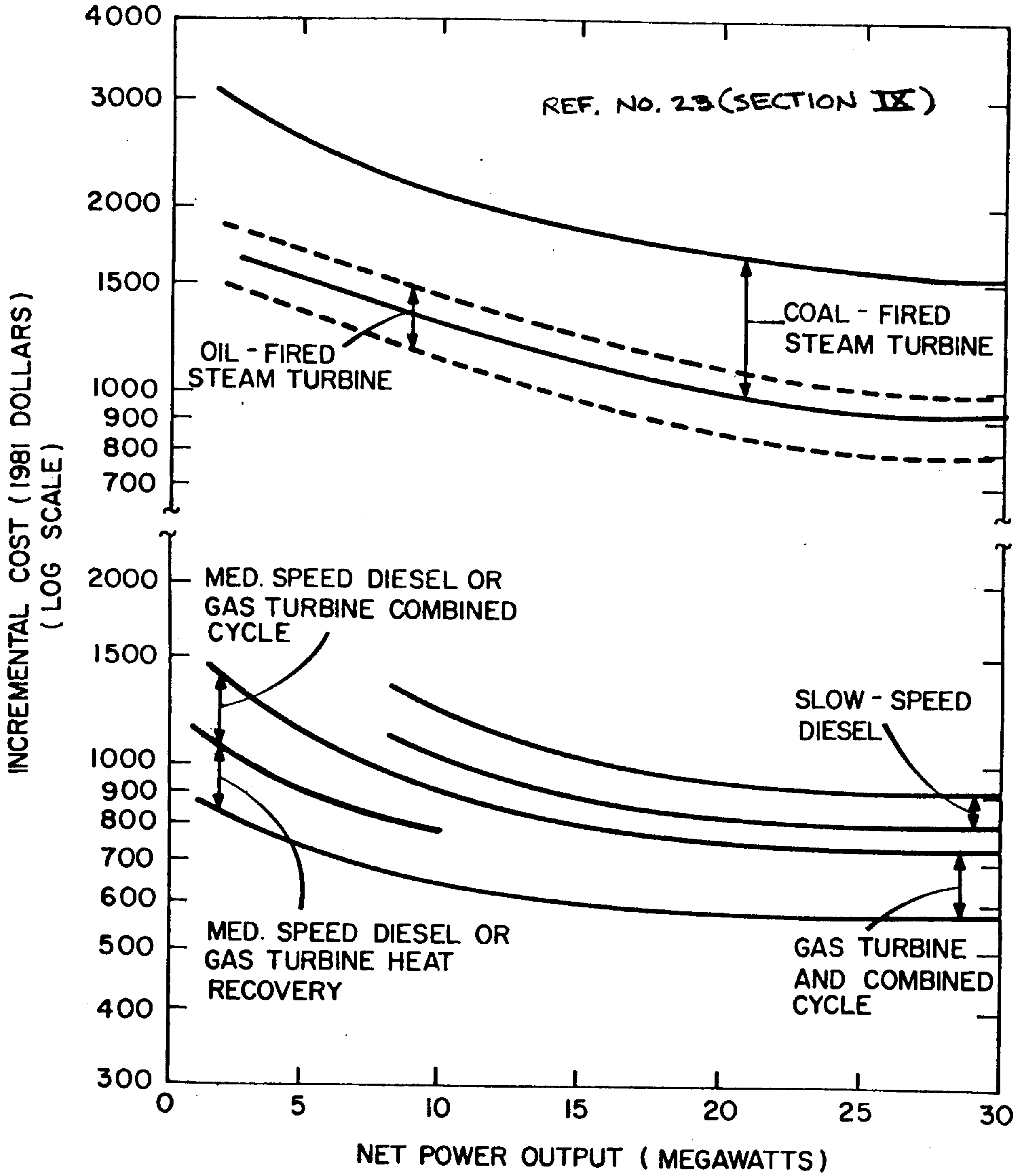

Figure 27: Typical Incremental (Turnkey) Costs of Industrial Cogeneration Systems, including Equipment, Installation, Engineering, and Construction

TABLE 3

CE PLANT COST INDEX(1)

YEAR	ANNUAL INDEX
1972	137.2
1973	144.1
1974	165.4
1975	182.4
1976	192.1
1977	204.1
1978	218.8
1979	238.7
1980	261.2
1981	297.0
1982	314.0

(1) Based upon economic indicators presented by "Chemical Engineering" a McGraw Hill Publication.

including all equipment, installation, engineering, and construction. Costs include some provision for escalation during project construction. The actual capital costs may be higher or lower because of site specific factors, governmental regulatory changes, unpredicted interest/inflation swings, among others.

- The capital costs are projected for systems in the range of 2 to 30 megawatts. Because the curves flatten out at the upper power range, larger system capital costs can be extrapolated (i.e. the dollar per kilowatt capital cost of a 100 megawatt system would be equivalent to the dollar per kilowatt capital cost of a 30 megawatt system). In actuality, there would be a perceptable difference in the capital costs (dollars/kilowatt) attributable to the "economies of scale".

The time required to construct new or retrofit cogeneration facilities depends upon the type of system and site specific factors. In general, small diesel and gas turbine systems require less than a year to install. Larger systems may take 2 to 3 years to get to operational status. Coal-fired systems usually take even longer. The construction period and corresponding rate of expenditure should be taken into account when developing the economic basis (refer to Figure 28). The objective is to develop a construction strategy that minimizes the total capital expenditure (taking into account variables such as interest rate on borrowed funds, inflation, construction delays, etc.).

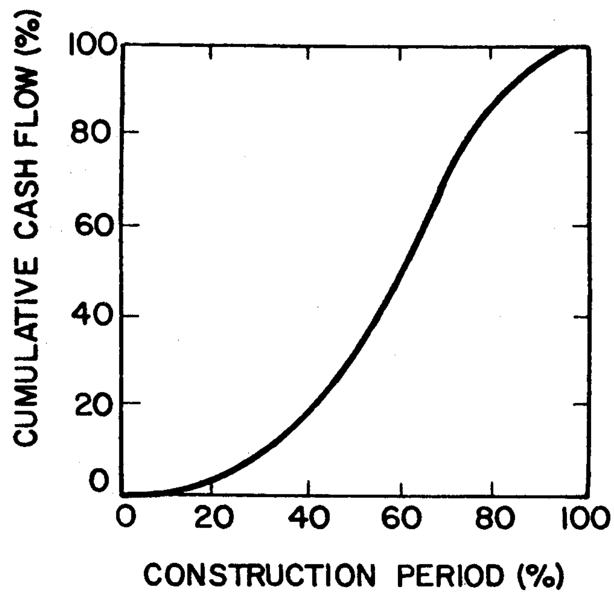

Figure 28: Construction Cash Flow Profile

REF. NO. 23 (SECTION IX)

B. Operating and Maintenance Costs

Operating and maintenance costs include all annual expenses incurred by operating and maintaining the cogeneration facilities (i.e. insurance, property tax, parts, labor, etc.). These costs vary with the type and age of the system employed. The costs are also dependent upon site-specific factors such as the plant process, feedstock availability, environmental regulations, etc. These factors usually necessitate evaluating the operating and maintenance costs on an individual basis.

However, for an initial estimate the procedures outlined in Table 4 can be used to develop operating and maintenance costs. Although the O & M costs developed from the table are mid-1978 projections, the relationships are still reasonable and can be used to project the present O & M costs for the various cogeneration systems. For future O & M costs, an appropriate escalation factor should be included (typically 5 to 10%).

Another more simplified approach is to calculate the total incremental O & M costs as a percentage of the capital costs of the cogeneration system.

- The O & M costs for a coal-fired steam turbine system is approximately 4% of the capital costs for the turbine/generator.

- The O & M costs for a gas or oil-fired steam turbine system is approximately 2.6% of the capital costs for the turbine/generator.

Table 4. Estimating Procedures for Operating and Maintenance Costs for Cogeneration Systems

Potential Contributor to O&M Costs	Estimating Procedure or Figure
A. Steam Turbine Cogeneration Plants, Coal-Fired	
Central Receiving and Handling Facility	Figure 29
Hauling, Receiving Facility - Generating Plant (if not co-located)	Figure 30
Steam Generating Facility	Figure 31
Air Pollution Control System	Figure 32
Electrical Generating Facility	(2.5% x capital)/yr[b], where Figure 26 shows capital investment
Hauling of Waste to Temporary Storage (if required)	Figure 33 plus Figure 30
Waste Disposal (annual cost, knowing average tons per hour throughout year)	10 miles from base[a]: $\$135{,}000\ (TPH/2.8)^{0.6}$ if TPH > 2.8; \$135,000 if TPH ≦ 2.8 50 miles from base[a]: $\$140{,}000\ (TPH/2.2)^{0.75}$ if TPH > 2.2; \$140,000 if TPH ≦ 2.2
B. Steam Turbine Cogeneration Plants, Oil- or Natural Gas-Fired	
Steam Generating Facility	$\$1.10/10^3$ lb of steam[c] (for natural gas or distillate oil) $\$1.50/10^3$ lb of steam[c] (for residual oil)
Electrical Generating Facility	(2.5% x capital)/yr[b], where Figure 26 shows capital investment
Air Pollution Control System (only if designed to use high sulfur fuel)	Figure 32
C. Combustion Turbine/Generator Sets With Exhaust Heat Boilers	
Turbine/Generator Set	4.0 mils/kW-hr[d] for units operating on "continuous" duty, and for units ≦ 2 MWe on peaking duty 7.0 mils/kW-hr[e] for units > 2 MWe on peaking duty
Exhaust Heat Boiler	$\$1.00/10^3$ lb of steam[f]
D. Diesel/Generator Sets With Exhaust Heat Boilers	
Diesel/Generator Set	13.0 mils/kW-hr
Exhaust Heat Boiler	$\$1.00/10^3$ lb of steam

REF. NO. 15 (SECTION IX)

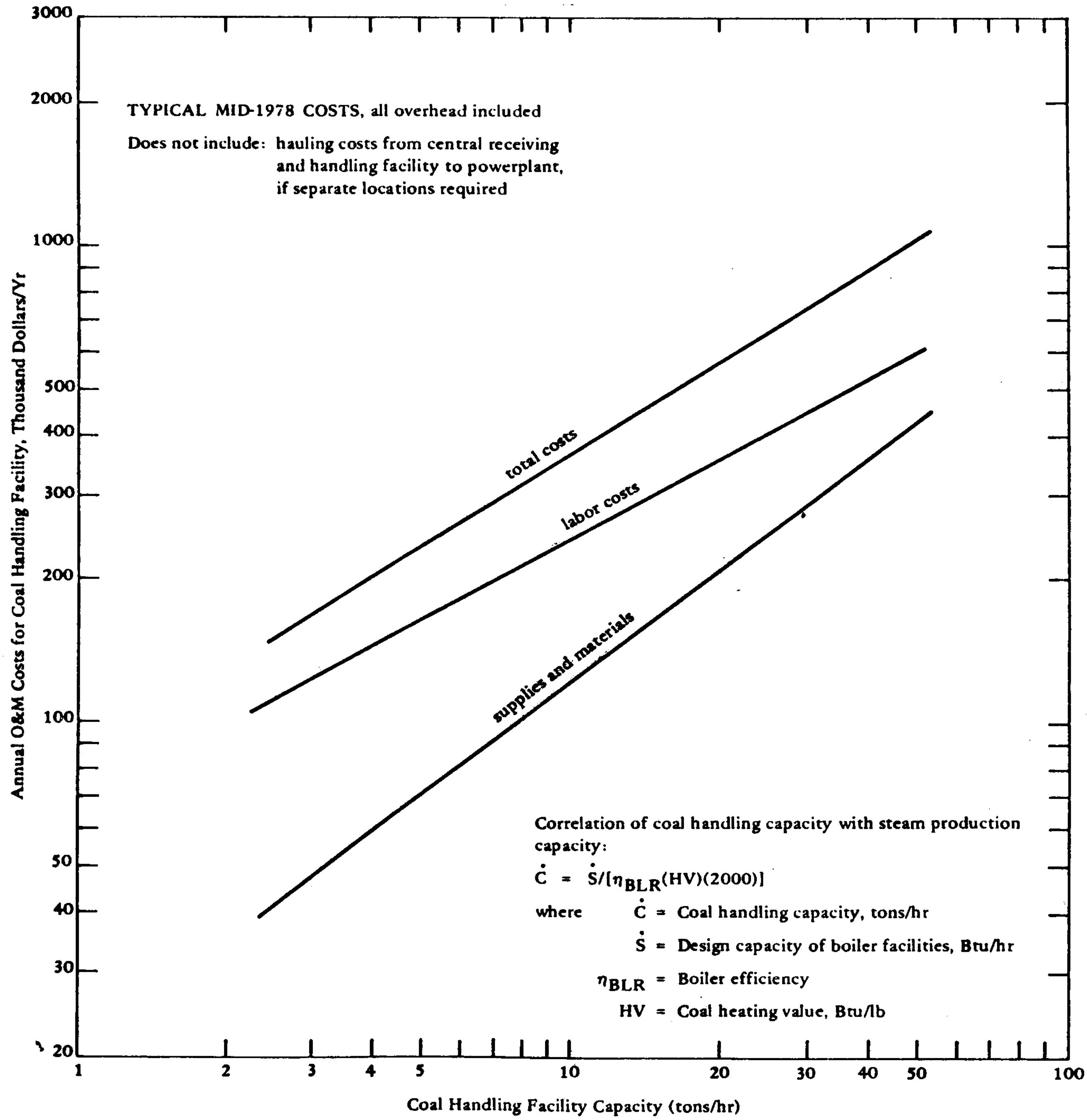

Figure 29: Operating and maintenance costs for central receiving and coal-handling facilities with stockpile.

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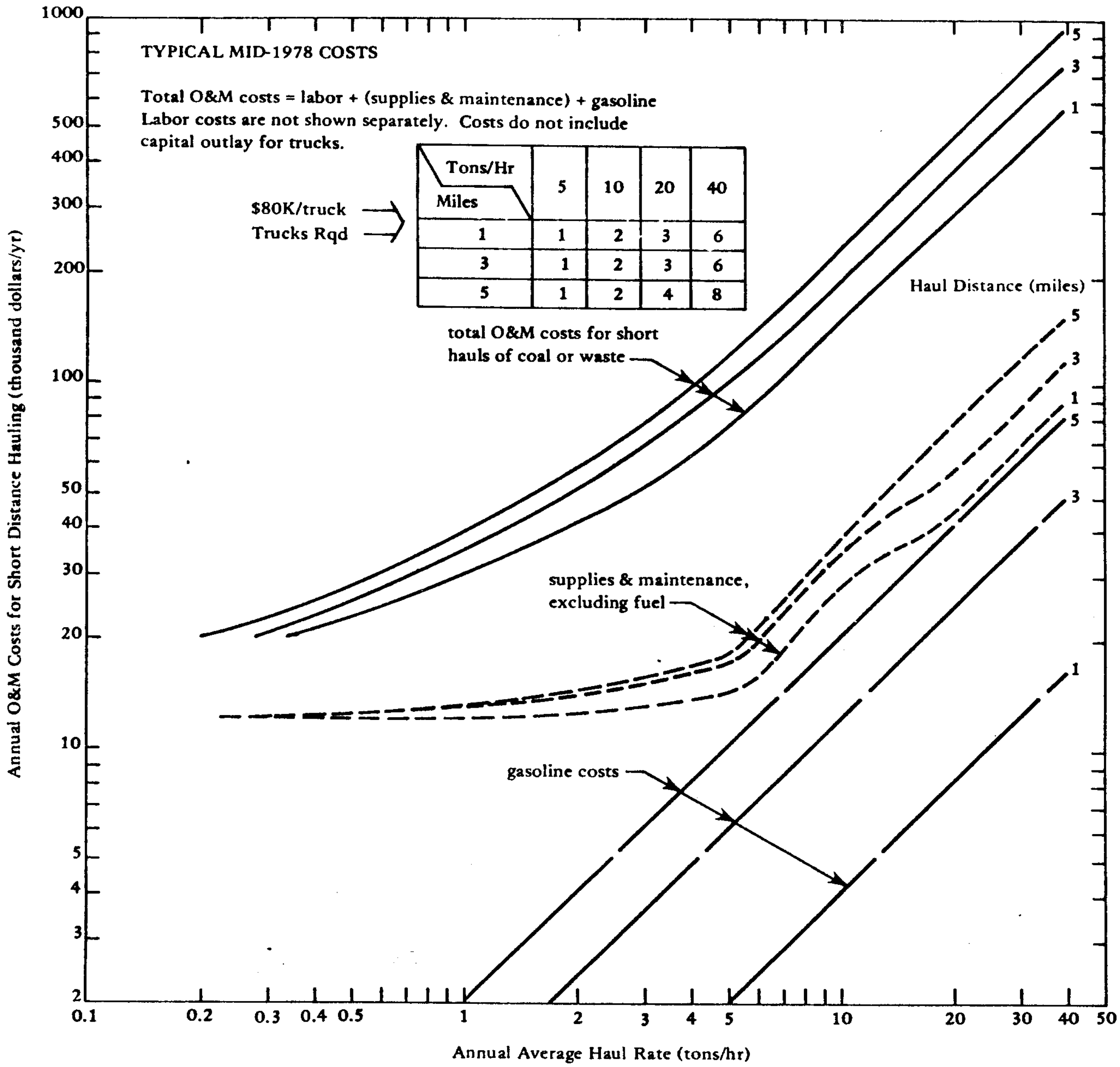

Figure 30: Operating and maintenance costs for short distance hauling of coal or solid waste.

REF. NO. 15 (SECTION IX)

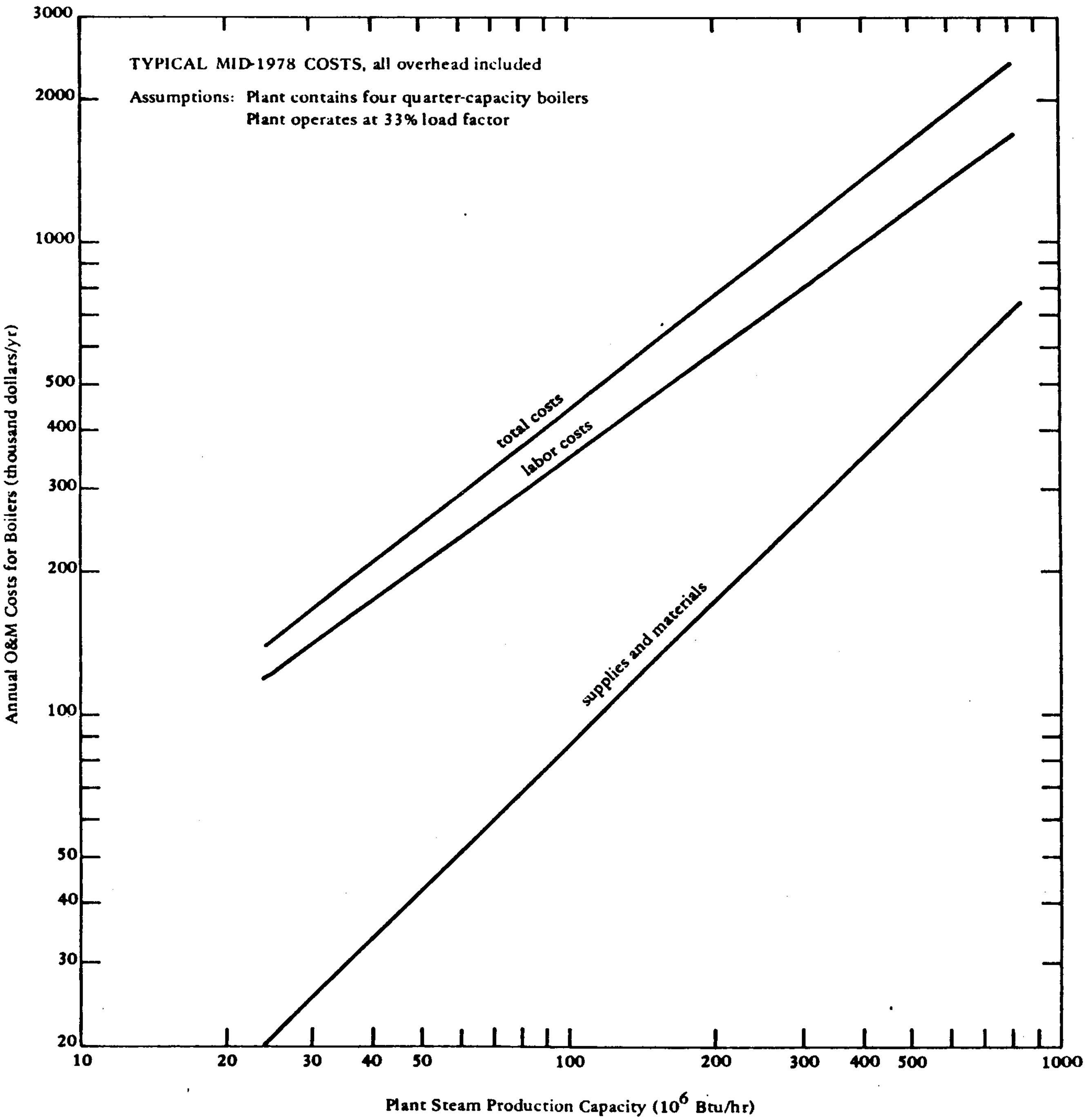

Figure 31: Operating and maintenance costs for coal-fired steam boilers.

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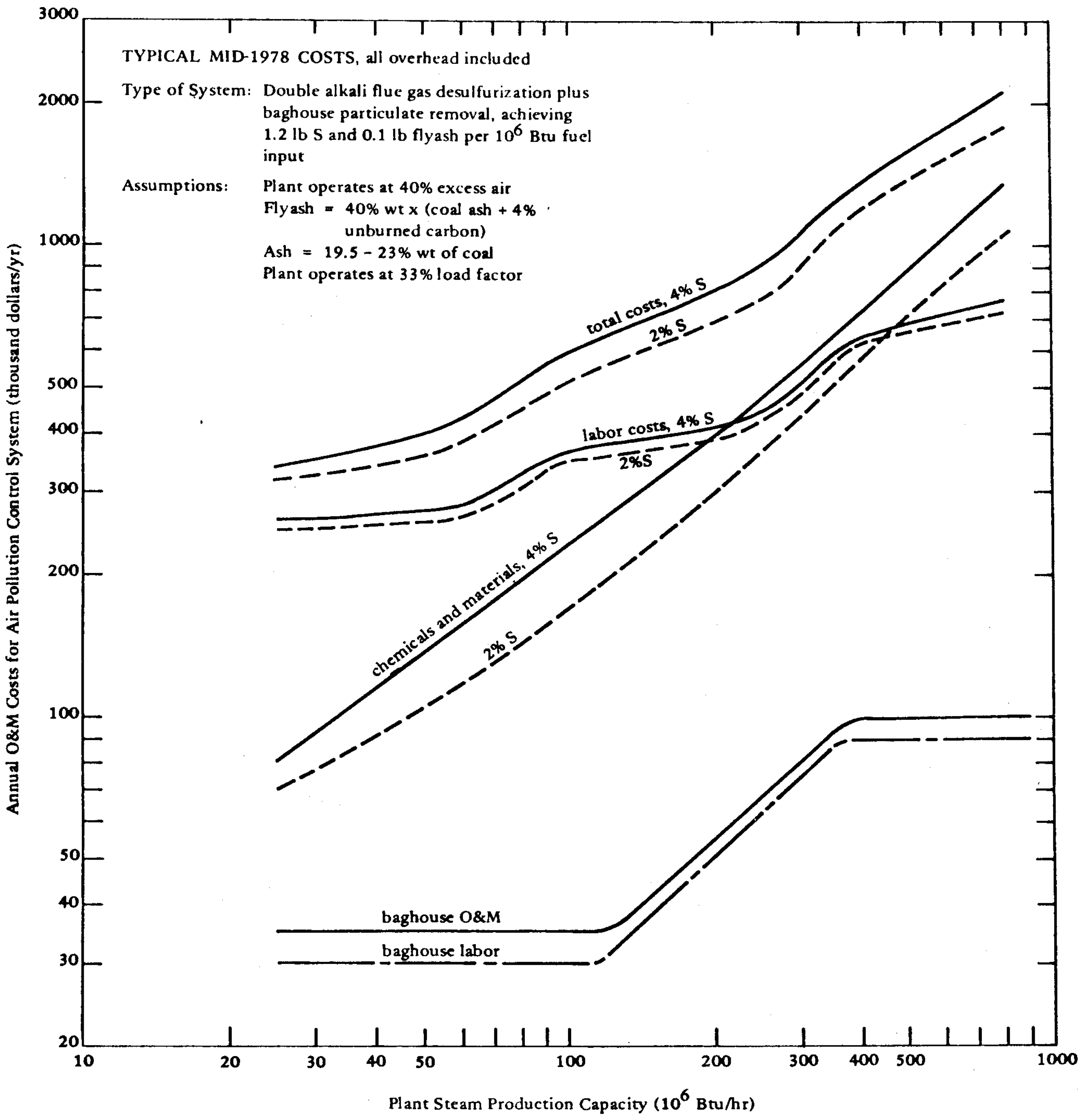

Figure 32: Operating and maintenance costs for air pollution control of coal-fired generating plants.

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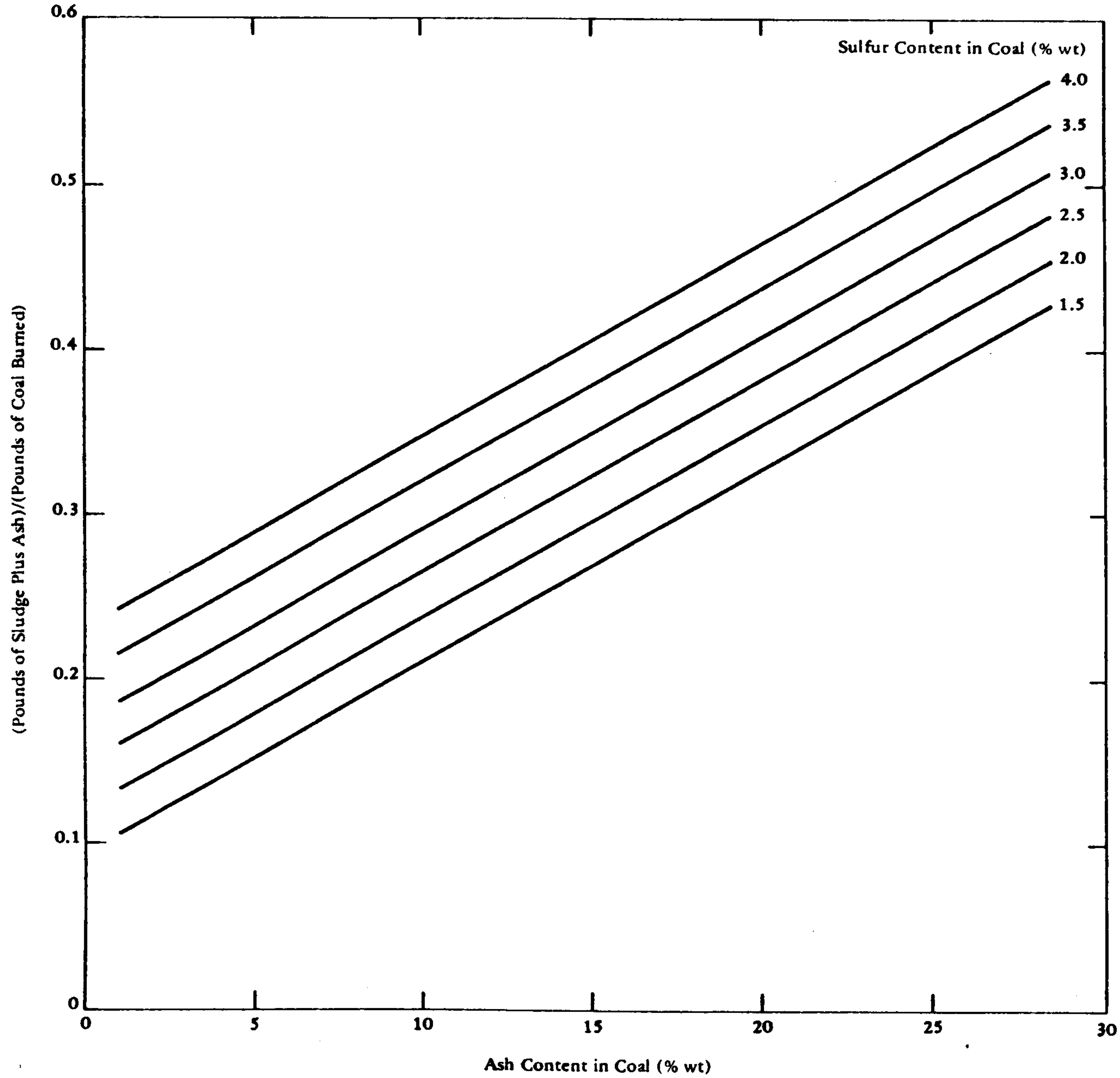

Figure 33: Solid waste production as a function of ash and sulfur content in coal.

REF. NO. 15 (SECTION IX)

- The O & M costs for a gas turbine or diesel engine system is approximately 4.5 and 6.0% of the system capital costs, respectively, less 2.0% of the capital cost for an equivalent sized boiler.

- The O & M costs for a combined cycle system is 2.6% of the capital cost for the turbine/generator, plus 4.5% of the capital costs for a gas turbine, less 2.0% of the capital cost for an equivalent sized boiler.

  Boiler, turbine/generator, gas turbine, and diesel system capital costs can be developed from Figures 34 thru 36.

C. Fuel and Electricity Costs

The price of fuel is usually the most significant factor in determining cogeneration operating costs while the cost of purchased electricity is the predominant factor in determining cogenerated power savings. Therefore, forecasting the fuel and electricity costs are essential for analyzing the economic feasibility of a cogeneration system. The forecast should project over the initial period of decision-making, design, construction, and start-up. Obviously, the forecast will need to project over the economic life of the system (or the desired payout period).

However, the problem with making forecasts is that there are too many variables to permit a rigorous

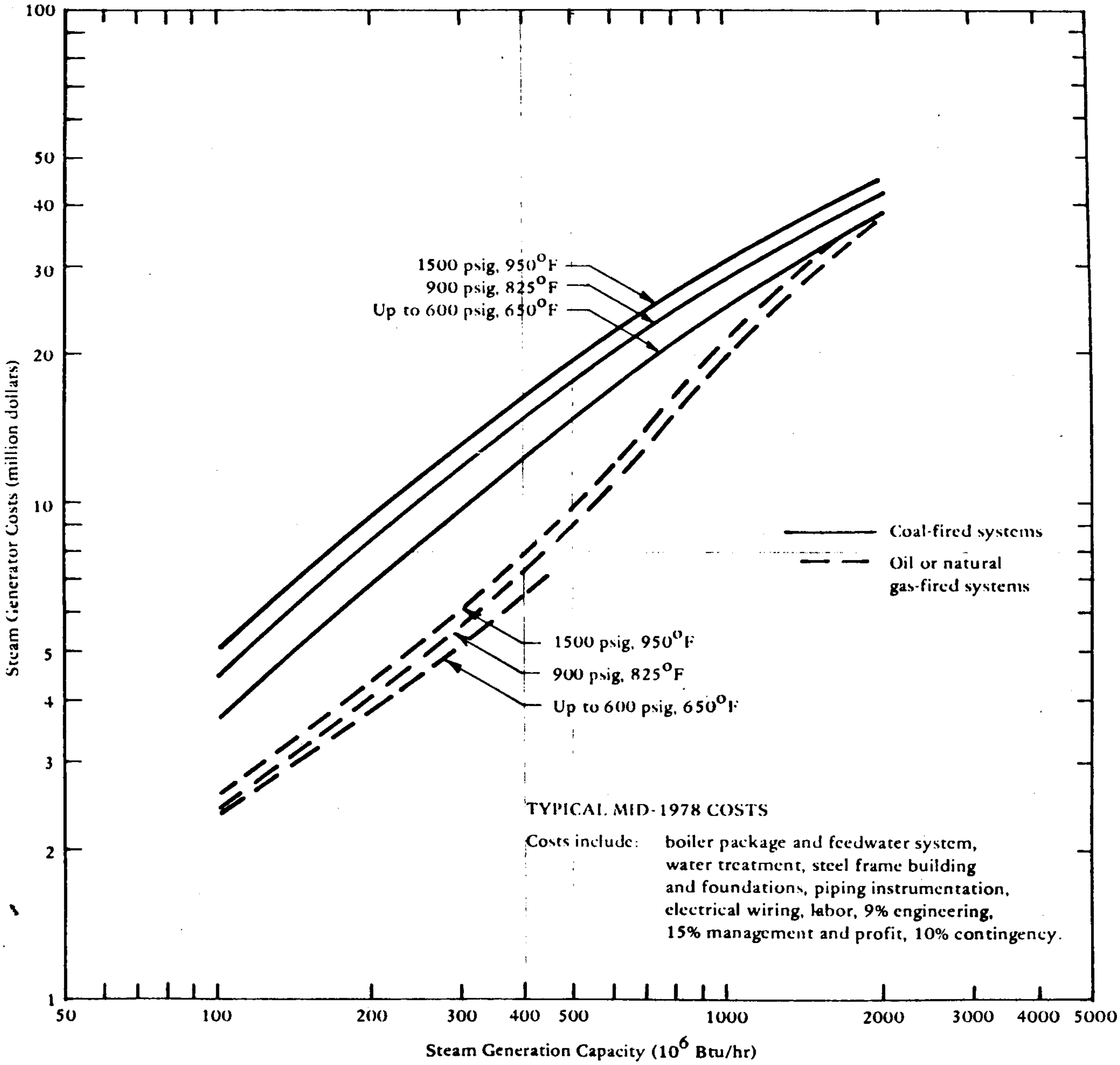

Figure 34: Steam generator costs.

REF. NO. 13 (SECTION IX)

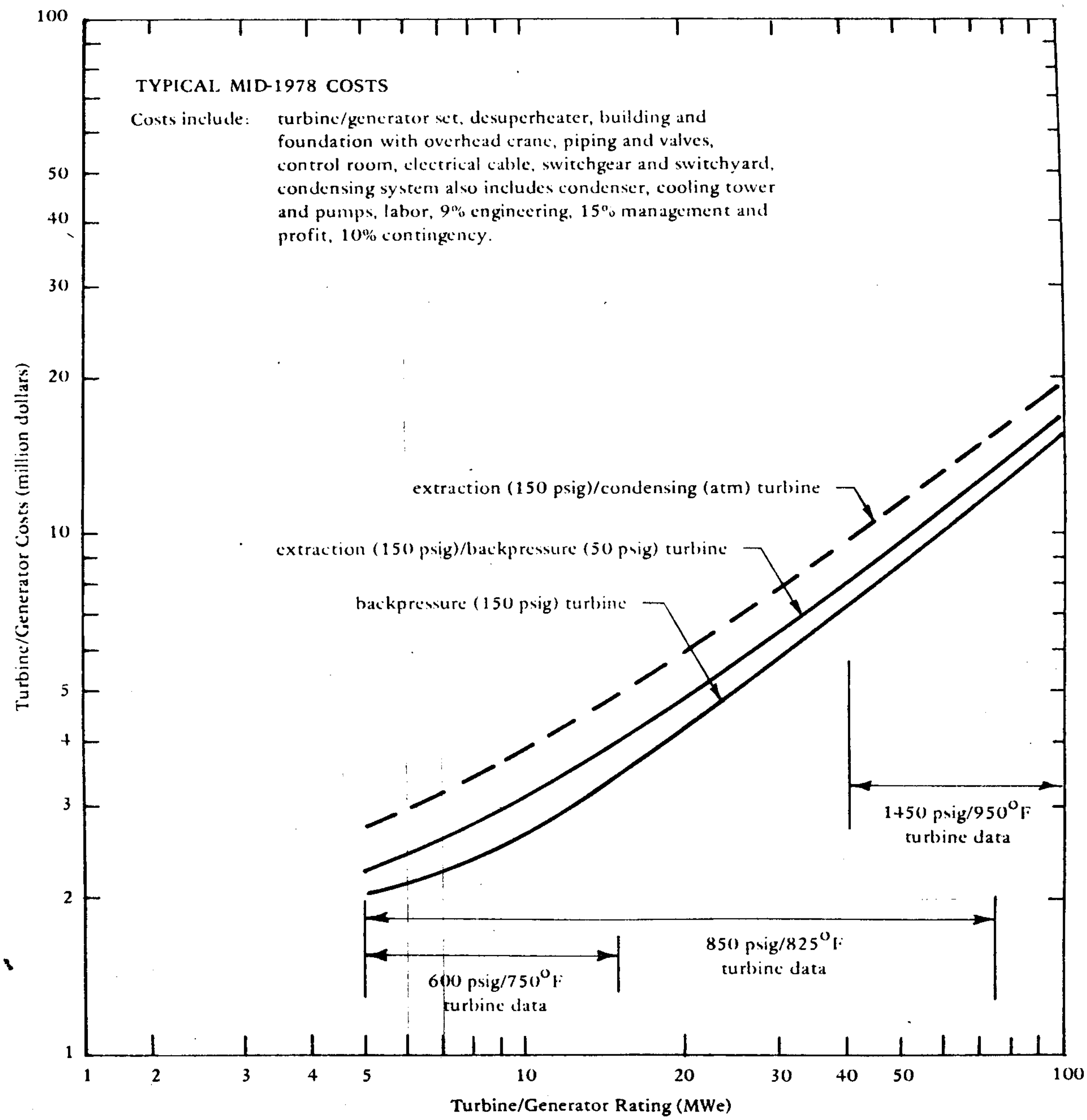

Figure 35: Steam turbine generator costs.

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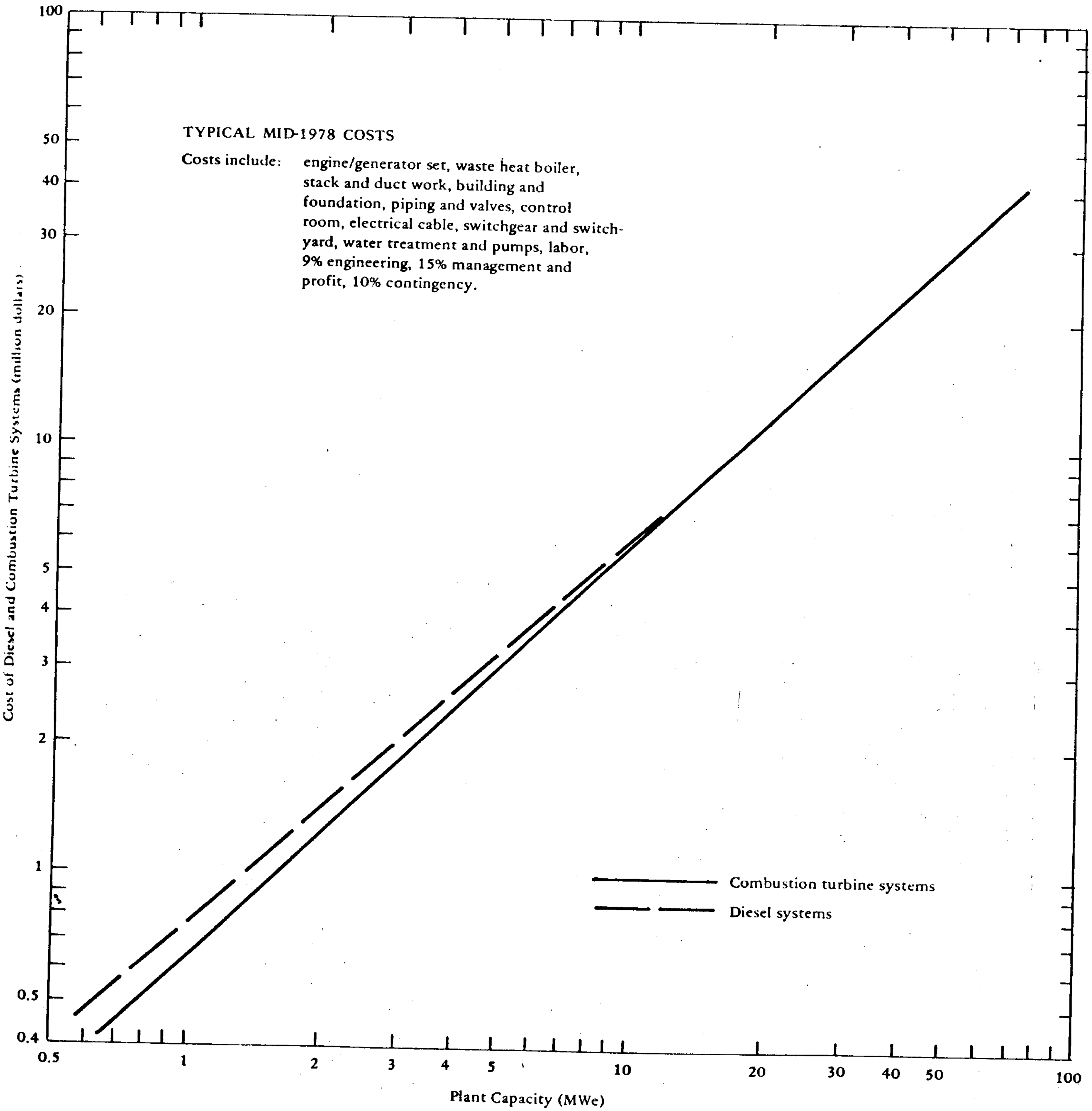


Figure 36: Diesel and combustion turbine system costs.

REF. NO. 15 (SECTION IX)

projection several years into the future. For example, in the fall of 1981 the Department of Energy projected that the world oil prices would be $44/bbl in 1985. Approximately one year later DOE revised their projection to $32.50/bbl. The present oil price has dropped to $28.60/bbl and is expected to remain relatively flat through 1985.

1. Fuel Costs

The cost of fuel is generally the largest factor contributing to the cost of operating a cogeneration system. For cogeneration systems firing oil or natural gas, the fuel cost typically represent 65 to 90% of the total life cycle costs. Figure 37 shows the relative impact of fuel costs upon the cost of various cogeneration systems.

a. Oil Prices

A previous study, "Handbook of Industrial Cogeneration - October 1981", projected oil prices based upon low, best, and high cost scenarios (refer to Figure 38). Although the events that have transpired since then have resulted in significantly lower oil prices than were projected, these curves are still useful in illustrating the spread and and the rate of change between the three scenarios.

The reason for the much higher rate of increase projected for the price of oil in the

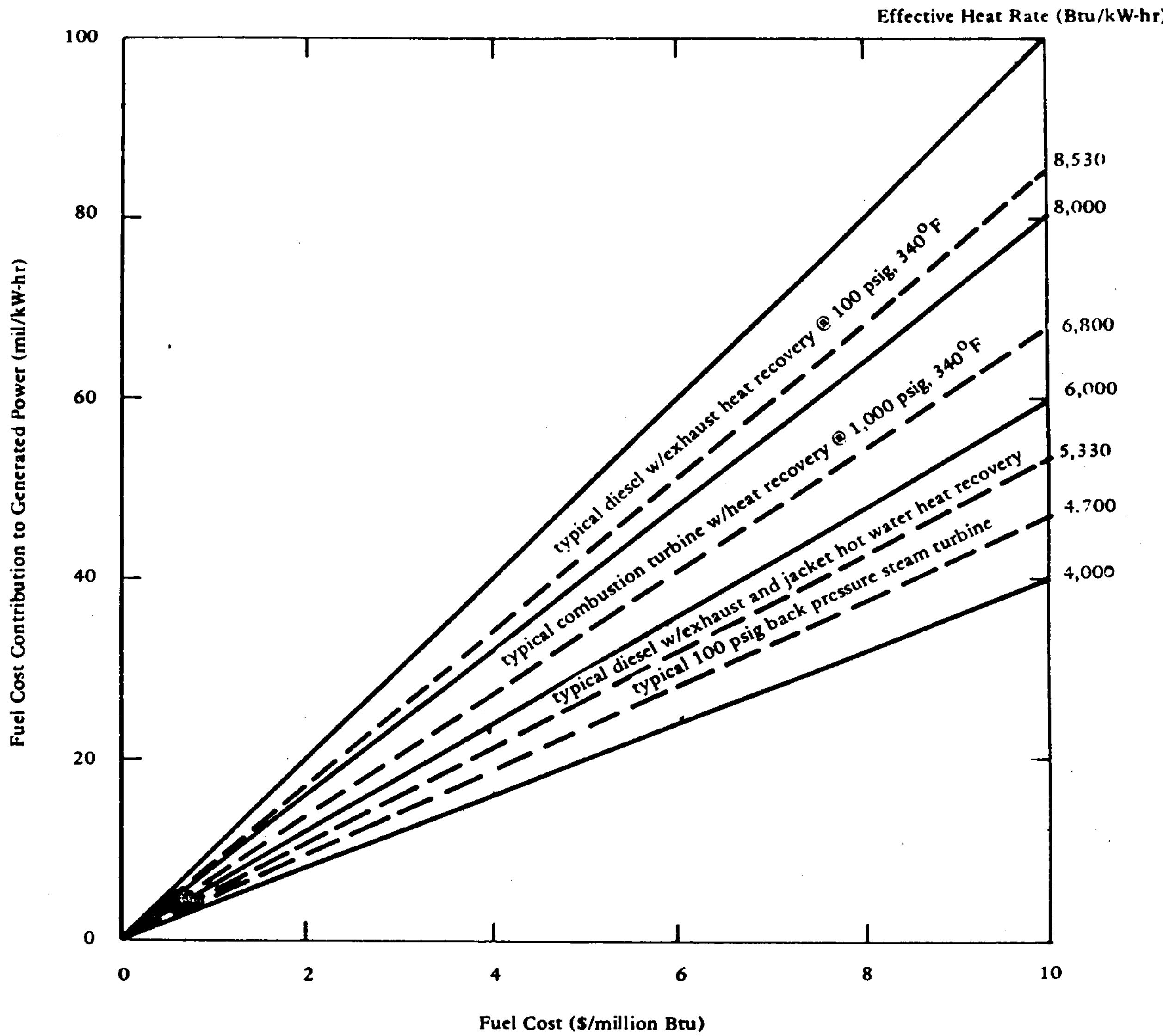
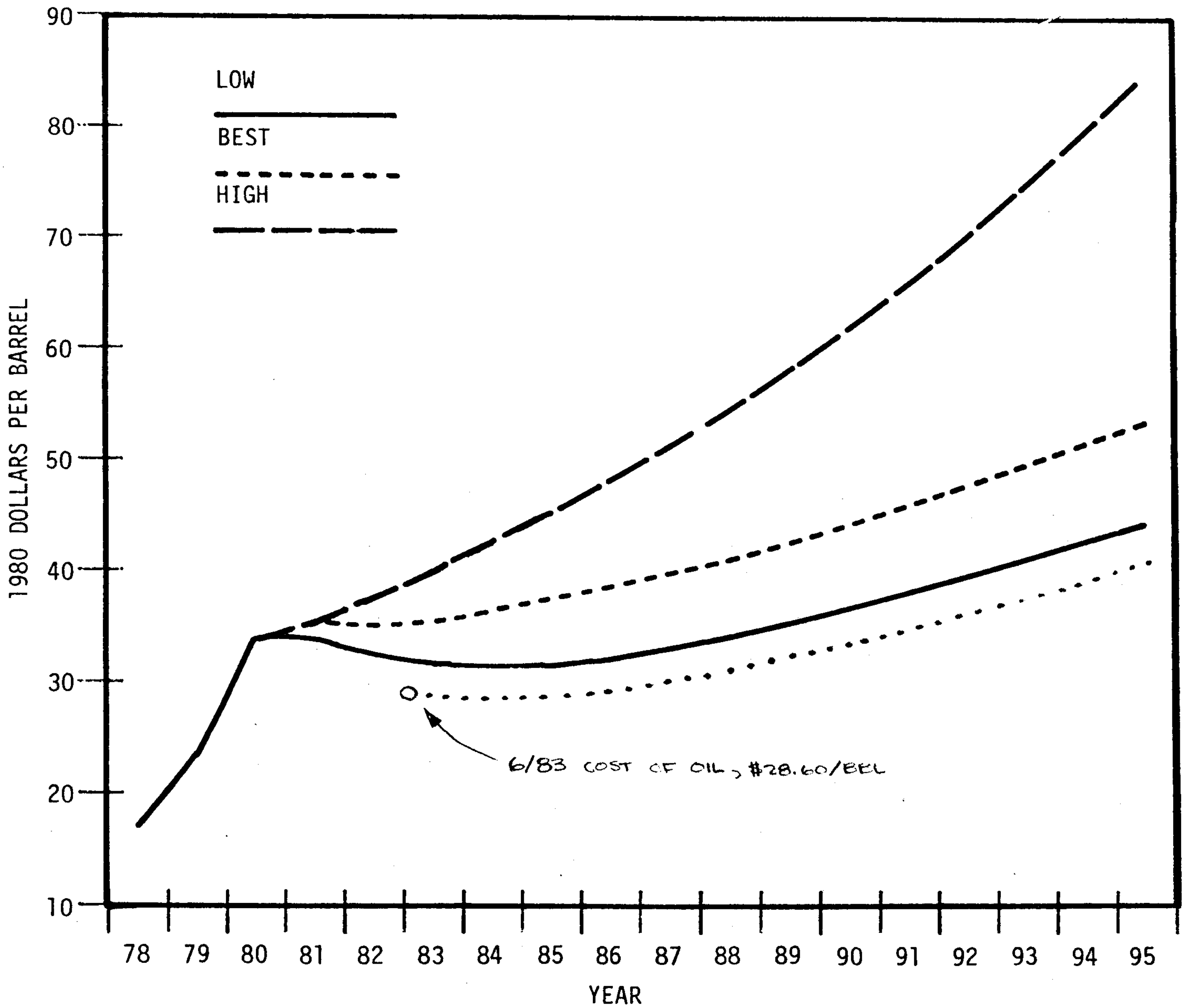


Figure 37: Fuel cost contribution to power costs for cogeneration systems.

REF. NO. 15 (SECTION IX)

FIGURE 38

PROJECTED PRICE OF IMPORTED CRUDE OIL (LOW, BEST, AND HIGH SCENARIO)



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high case is based upon the assumption that a major oil disruption was probable in the next 15 years. The timing and magnitude of such a disruption and ensuing price increase are not predictable. However, to provide an upper boundary for future oil prices, it was represented by assuming a continual steep rise over a broad interval.

Based upon the recent decline in oil prices and discussions with various chemical producers, the projections for low, best, and high cost scenarios obtained from Figure 38 are probably 15 to 25 percent high. Distillate and residual fuel oil follow crude oil prices. However, distillate generally follows crude oil prices more closely than residual oil. Residual fuel oil is usually dependent upon the demand and price of substitute fuels.

b. Natural Gas

Historically, Louisiana's petrochemical firms were assured of plentiful supplies of natural gas at low prices. This gave most of them a competitive advantage over companies located in other states and countries. However, when the Natural Gas Policy Act (NGPA) of 1978 took effect, the price advantage of Louisiana's natural gas reversed. By 1982 Louisiana petrochemical companies serviced by intrastate pipelines were paying more for natural gas than out-of-state competitors. The natural gas price differential is even greater in comparison to many third world oil producing countries.

The following natural gas price projections are based upon DOE's "Annual Report to Congress - Energy Projections" dated February, 1982.

	Dollars per Thousand Cubic Feet		
		Inflation Rates	
Year	1983 Dollars	6%	10%
1985	4.58	5.15	5.54
1990	6.40	9.62	12.47
1995	7.23	14.55	22.69

A more recent price projection released by Gulf States Utilities at the beginning of 1983, reflects a more moderate increase (refer to Table 5).

As a comparison, the current natural gas "glut" has resulted in some short-term contracts ranging from $2.75 to $3.25 per MCF. Many experts predict that gas prices will be flat for a few years followed by new shortages and thus higher prices. This understandably makes current cogeneration economic planning difficult and allowance must be made in sensitivity studies.

TABLE 5

PROJECTED

GULF COAST GAS PRICES

(Mid - Year)

YEAR	Constant 1982 Dollars	Current Dollars Assuming Inflation	Assumed Inflation
1983	$3.85	$4.12	7%
1984	4.16	4.76	7%
1985	4.50	5.51	8%
1986	4.55	5.96	8%
1987	4.59	6.44	8%
1988	4.68	7.02	9%
1989	4.76	7.65	9%
1990	4.85	8.34	9%
1991	4.94	9.09	9%
1992	5.04	9.91	9%
1993	5.13	10.80	9%

REF. NO. 31 (SECTION IX)

c. Coal Prices

Coal costs and availability are based upon six coal suppliers at seven different mine locations (refer to Table 6). The primary coals surveyed are Eastern high-sulfur coals from Kentucky, West Virginia, and Southern Illinois. All of these coals have a higher heating value greater than 10,000 BTu/lb with a corresponding sulfur content of 2 to 3 percent. The costs presented in Table 6 are based upon 1983 dollars and give a breakdown of transportation costs.

2. Electricity Costs

The low cost and availability of electricity in Louisiana has historically been taken for granted. Relatively inexpensive steam boiler/electric generators could be built to operate on inexpensive native natural gas. However, many of the old gas contracts have expired or are about to expire. The new contracts will reflect a gas price increase of ten or more times the old gas price, sometimes as low as 25 cents per MCF. Although coal has been proposed as a cheaper fuel source, it is also fraught with cost uncertainties such as transportation costs and capital costs required for conversions or totally new plants.

In addition, most of the present high voltage transmission systems and interties to other

Table 6

COAL SUPPLY AND COST SUMMARY

Supplier	Heating Value Btu/Lb	Ash %	S %	1983 Mine Mouth Cost $/Ton	1983 Transport Cost $/Ton (3) Barge	Rail	1983 Delivered Cost (3) $ Ton	$ MMBtu
ARCO Coal (West Virginia)	11,500	NA	2 +	28.00 (1)	6.25	-	34.25	1.49
Zeigler (Illinois)	11,068	9.60	3.14	-	-	-	39.88	1.80
Peabody (Illinois)	10,800	8.53	3.08	31.15 (1)	7.50	-	38.65	1.79
AMAX (Illinois)	11,600	11.00	2.80	31.00	12.00 (2)	-	43.00	1.85
Consol (Illinois Burning Star)	11,100	9.80	2.90	28.00	8.15	-	36.15	1.63
Consol (Illinois Burning Star)	11,100	9.80	2.90	28.00	-	16.75	44.75	2.02
Consol (Illinois Hamilton)	11,841	8.00	2.30	36.00	9.00	-	45.00	1.88
Consol (Illinois Hamilton)	11,841	8.00	2.30	36.00	-	24.70	60.70	2.56
Diamond Shamrock (West Virginia)	12,500	9.00	NA	NA	NA	-	42.50	1.70

NA Information Not Available
(1) Loaded on Barge
(2) Increased above current costs to reflect "normal" market conditions.

(3) DELIVERED TO ST. GABRIEL, LA.

REF NO. 21 (SECTION IX)

systems were in service in the mid-1960's. Consequently most of this system was conceived prior to concerns about moving power from one region to another. Louisiana's electrical import capacity in 1980/1981 was only about 10 to 15 percent of the total state demand. As a result, Louisiana is presently unable to fully take advantage of potentially cheaper hydro or nuclear generated electricity produced in other parts of our nation.

Gulf States Utilities (GSU) and Louisiana Power and Light (LP&L) are two of the largest utility companies in Louisiana. The cost of the electricity produced by GSU and LP&L is expected to double by 1985 and 1986, respectively (refer to Figure 39). If this occurs, it will obviously place a heavier burden on an already strained petrochemical industry.

D. Calculation of System Economic Performance and Energy Savings

The various types of cogeneration systems have been presented along with basic information necessary to calculate each systems' cost and performance characteristics. In addition, fuel and electricity costs have been given for the present and projected future. This information provides the basis for a preliminary investment analysis of various cogeneration systems and fuel sources.

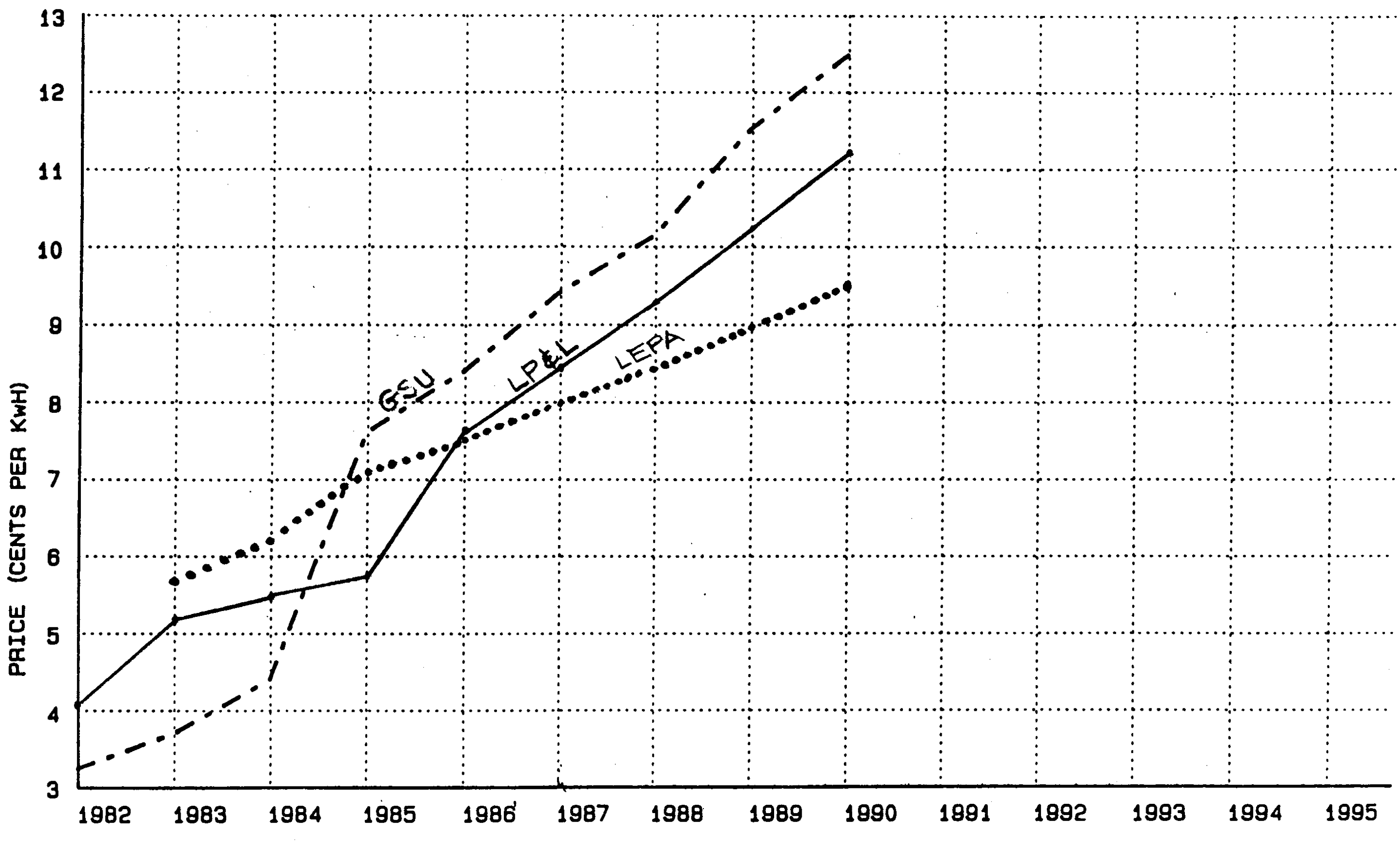


FIGURE 39

PROJECTED INDRUSTRIAL ELECTRICAL RATES (KWH)

REF. NO. 21 & 30 (SECTION IX)

There are several options available for evaluating the viability of an investment plan. Some of the more familiar methods are listed below.

- Simple Payback: Involves the determination of the number of years required for the sum of the net cash flows (annual net profits plus depreciation) to equal the total capital investment.

- Net Present Value: Determines the net present value of all the cash flows (annual net profits plus depreciation) over the economic life of the project using a predetermined discount rate.

- Internal Rate of Return: Involves determination of the discount rate that forces the present value of all cash flows over the project life to equal the present value of the capital investment.

- First Year Return on Investment: Defined as the net cash flow in the first year of operation divided by the total capital investment.

This study employed the Internal Rate of Return (IRR) Method because it is probably the most accepted and readily applicable procedure.

1. Total Annual Savings

The total annual cost of a cogeneration system is simply the summation of the costs previously discussed.

$$TC_i = CC_i + FC_i + OM_i - EC_i - R_i - D_i$$

where TC_i = total annual cost
CC_i = capital investment cost
FC_i = overall fuel costs
OM_i = operating and maintenance costs
EC_i = purchased electricity cost
R_i = revenues resulting from the operation such as export sales of steam or electricity
D_i = allowances for depreciation and investment tax credits.

To determine the potential savings of a cogeneration system it is necessary to compare the annual expenditures of a cogeneration system with that of the conventional plant (i.e. steam supplied by an on-site boiler and electricity purchased from a local utility). Expressed in the terms previously defined, the annual savings, excluding capital outlay costs, is as follows:

$$S_i = (FC_{CONV} - FC_{COGEN})_i + (OM_{CONV} - OM_{COGEN})_i + (EC_{CONV} - EC_{COGEN})_i - (R_{CONV} - R_{COGEN})_i - (D_{CONV} - D_{COGEN})_i$$

A more specific equation derived from the above relation can be used for a preliminary economic evaluation of a potential cogeneration system.

$$S_i=\left[EC_i-\left[(IHRxFC_i)+\frac{OM_i}{(E_T xHRS)}+\frac{SC}{(8760-HRS)}+\frac{(D_i+I_i)C_T}{HRS}\right]\right]x\ HRS\ x\ (1-Tx)$$

where S_i = Annual dollar savings per kilowatt-hour generated by the cogeneration system.

EC_i = The average cost of electricity projected for the specified year, \$/kWh.

IHR = Incremental heat rate representing the additional fuel required to produce one kilowatt of electricity, Btu/kW. This is directly dependent upon the type of system employed.

FC_i = The average cost of fuel projected for the specified year, \$/Btu.

OM_i = Annual operating and maintenance costs in dollars for the specified year (may be considered as base year x assumed escalation factor).

E_T = Generator capacity of the cogeneration system being considered, kW.

HRS = Annual hours of operation (service factor x 8760).

SC = Standby charges for backup power are usually a higher payment charged by the utility company for the incremental electricity purchased during an outage of the cogeneration system, \$/kW.

D_i = The depreciation factor for a specified year expressed as a fraction of the total capital investment. The depreciation factor is dependent upon the depreciation schedule selected (i.e. straight-line, sum-of-the-years, etc.).

I_i = The investment tax credit for a specified year expressed as a fraction of the total capital investment.

C_T = Total capital investment cost in dollars per kilowatt cogenerated.

TX = Tax rate

The only variable in the above equation that probably requires further discussion is the Incremental Heat Rate term, IHR. This term assumes that the conventional system utilizes the same fuel as the cogeneration system. If waste fuel or waste heat are used, it is assumed to have the same value when utilized by either the conventional system or the cogeneration system.

If the cogeneration system utilizes a fuel that is more or less costly than the fuel being used by the conventional system, the terms, IHR x FC_i, will need to be replaced by the original terms, $(FC_{COGEN} - FC_{CONV})_i$.

2. Internal Rate of Return

The Internal Rate of Return (IRR) is a common method for evaluating the viability of an investment. A minimum acceptable IRR is set by the investor based upon the type of investment, risk factors, interest rates charged for borrowed capital, etc. If the calculated IRR equals or exceeds the minimum specified IRR, the project is considered viable.

The IRR calculation determines the discount rate at which the present value of all the annual savings over the project life equals the present value of the capital investment discounted during the construction period. However, for a preliminary evaluation the calculation can be simplified by assuming the capital outlay during the construction phase is instantaneous and/or the construction period is short in comparison to the overall project life.

$$C_{COGEN} - C_{CONV} = \sum_{i=0}^{n} \frac{S_i}{(1+IRR)^n}$$

n = total life of the project, years.

In addition, if the conventional plant would not require a new boiler at any point during the economic life of the cogeneration system, $C_{CONV} = 0$.

$$C_{COGEN} = \sum_{i=0}^{n} \frac{S_i}{(1+IRR)^n}$$

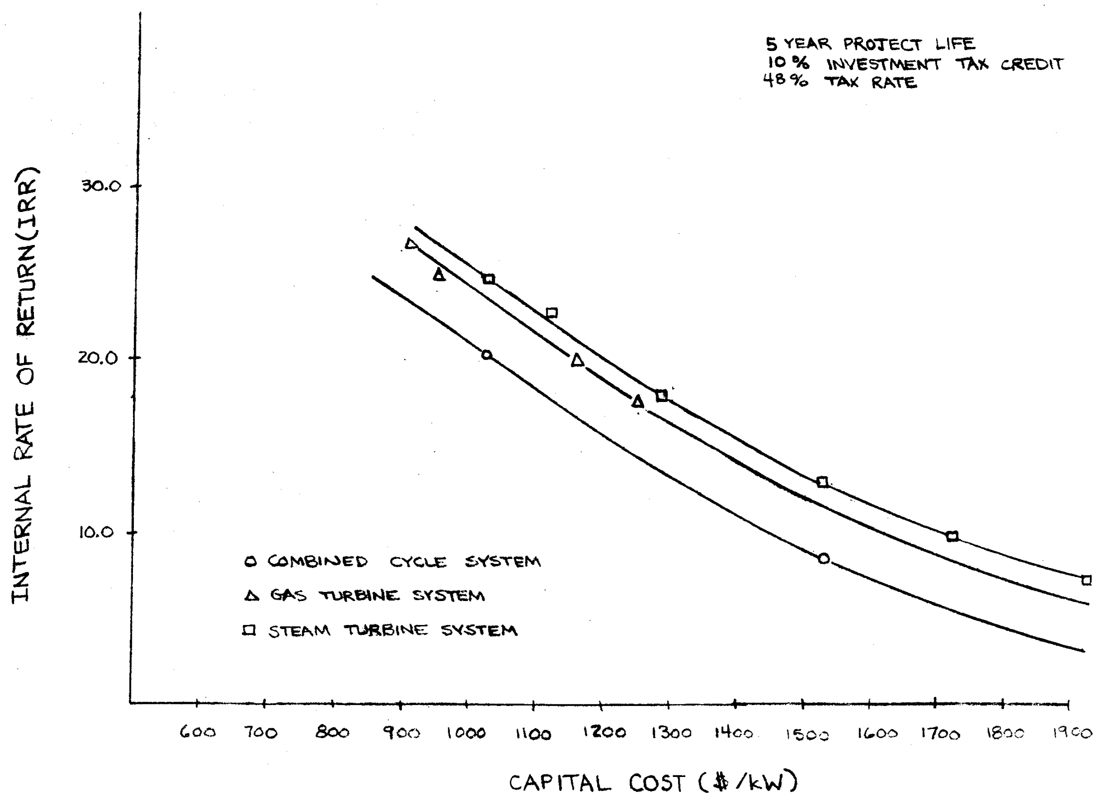
3. Sensitivity Analysis

To calculate the IRR it was necessary to make several assumptions and projections. Because of the many variables that can affect this calculation, a sensitivity analysis is useful in ascertaining the "degree of risk" pertaining to a capital investment.

- Figure 40 shows the relation between system capital cost and the IRR for the project basis (Attachment B summarizes the project assumptions). The difference between the curves projected for each system is attributable to the characteristic differences in the Incremental Heat Rate (IHR). As the IHR increases (i.e. a combined cycle system versus a gas turbine), the IRR curve shifts downward and parallel to the original relationship.

- Changes in income tax regulations and financing can significantly alter the IRR/Capital Cost relationships for a prospective

FIGURE 40


5 YEAR PROJECT LIFE
10 % INVESTMENT TAX CREDIT
48 % TAX RATE
INTERNAL RATE OF RETURN (IRR)
30.0
20.0
10.0
O COMBINED CYCLE SYSTEM
Δ GAS TURBINE SYSTEM
□ STEAM TURBINE SYSTEM
600
700
800
900
1000
1100
1200
1300
1400
1500
1600
1700
1800
1900
CAPITAL COST ($/kW)

project. Figure 41 compares the effect of altering the investment tax credit. Roughly a 10% change in the first year investment tax credit corresponds to a 2% change in the IRR (for the overall defined project basis). Figure 42 compares the effect of different tax rates upon the IRR/Capital Cost relationships. As an approximation, a 10% change in the tax rate corresponds to an 8% change in the IRR.

- For the last two years the inflation rate has increased very moderately. However, in the recent past our economy was experiencing double-digit inflation. After calculating the uninflated IRR, Table 7 can be used to estimate the inflated IRR for different projected inflation rates.

- The effect of changes in fuel cost on the projected savings is indirectly represented by Figure 37. The effect of fuel cost changes is more pronounced for a gas turbine system than for a steam turbine system because of its correspondingly higher incremental heat rate. Similiarly, combined cycle systems are more sensitive to fuel cost changes than either the gas turbine or steam turbine systems.

FIGURE 41
EFFECT OF INVESTMENT TAX CREDIT UPON THE IRR/CAPITAL COST RELATIONSHIP

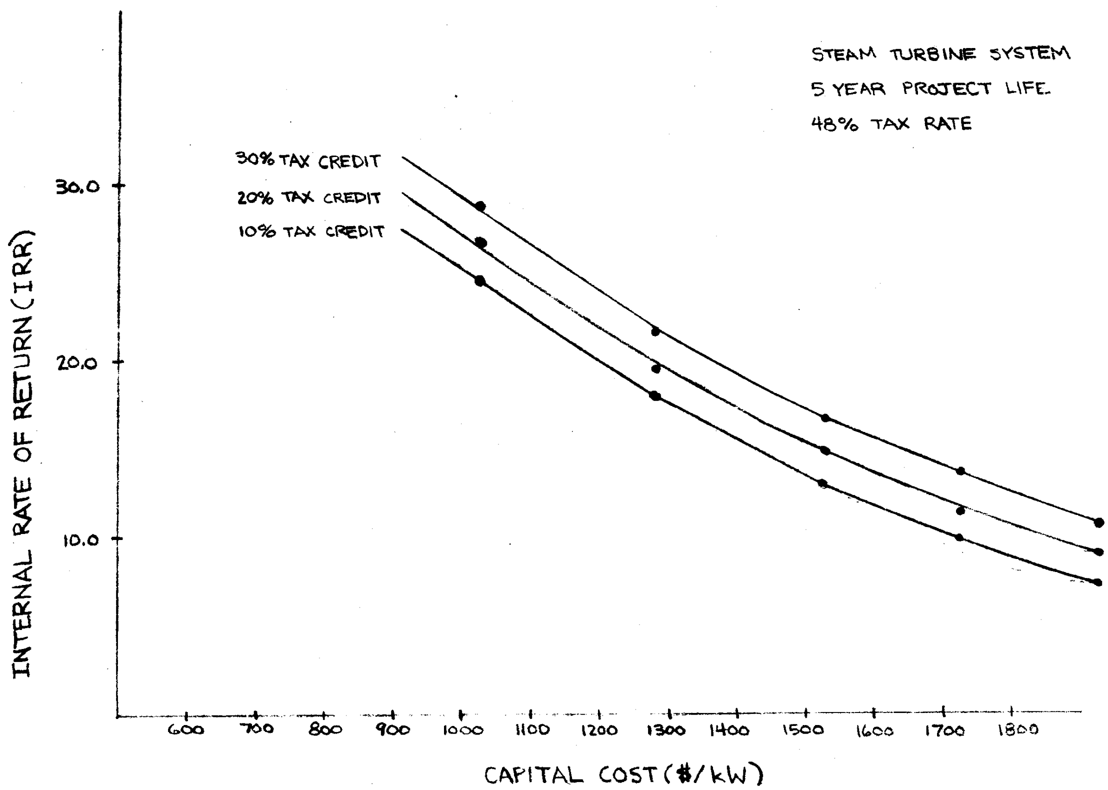


FIGURE 42

EFFECT OF TAX RATE UPON THE IRR/CAPITAL COST

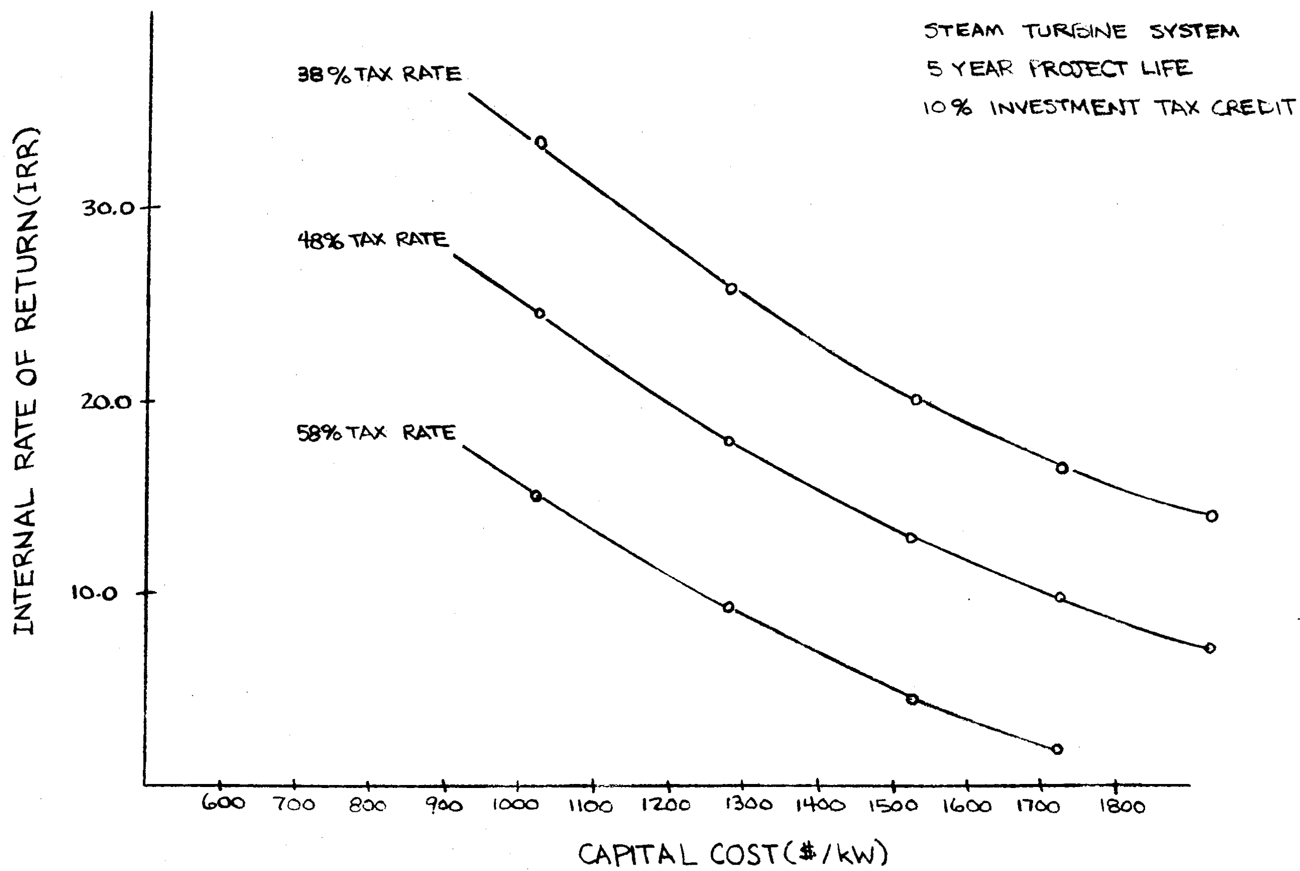


TABLE 7

INFLATED ROI (%) AS A FUNCTION OF INFLATION

UNINFLATED ROI (%/YR)	INFLATION IN %/YR 6 %	8 %	10%	12%	14%	16%
1.0	7.1	9.1	11.1	13.1	15.1	17.2
2.0	8.1	10.2	12.2	14.2	16.3	18.3
3.0	9.2	11.2	13.3	15.4	17.4	19.5
4.0	10.2	12.3	14.4	16.5	18.6	20.6
5.0	11.3	13.4	15.5	17.6	19.7	21.8
6.0	12.4	14.5	16.6	18.7	20.8	23.0
7.0	13.4	15.6	17.7	19.8	22.0	24.1
8.0	14.5	16.6	18.8	21.0	23.1	25.3
9.0	15.5	17.7	19.9	22.1	24.3	26.4
10.0	16.6	18.8	21.0	23.2	25.4	27.6
11.0	17.7	19.9	22.1	24.3	26.5	28.8
12.0	18.7	21.0	23.2	25.4	27.7	29.9
13.0	19.8	22.0	24.3	26.6	28.8	31.1
14.0	20.8	23.1	25.4	27.7	30.0	32.2
15.0	21.9	24.2	26.5	28.8	31.1	33.4
16.0	23.0	25.3	27.6	29.9	32.2	34.6
17.0	24.0	26.4	28.7	31.0	33.4	35.7
18.0	25.1	27.4	29.8	32.2	34.5	36.9
19.0	26.1	28.5	30.9	33.3	35.7	38.0
20.0	27.2	29.6	32.0	34.4	36.8	39.2
21.0	28.3	30.7	33.1	35.5	37.9	40.4
22.0	29.3	31.8	34.2	36.6	39.1	41.5
23.0	30.4	32.8	35.3	37.8	40.2	42.7
24.0	31.4	33.9	36.4	38.9	41.4	43.8
25.0	32.5	35.0	37.5	40.0	42.5	45.0

REF. NO. 27 (SECTION IX)

V. LOUISIANA PETROCHEMICAL COGENERATION POTENTIAL

Utilizing the cost information and economic equations previously presented, a computer program was developed to calculate the cogeneration potential for the petrochemical companies located within the nine major complexes identified earlier (refer to Figures 2 thru 10). These companies were evaluated for each of three basic cogeneration systems; steam turbine, gas turbine, and combined cycle.

The systems were sized to provide the same amount of process steam being supplied by conventional fired boilers while providing the maximum amount of cogenerated electricity. The potential for cogenerating steam and electricity with waste heat or by-product fuel was also considered. However, most of the chemical producers interviewed had already implemented energy conservation programs, leaving only low-level waste heat sources that are either technically or economically unattractive for cogeneration. Because of the present economic uncertainties that are rippling through Louisiana's petrochemical industry, most companies are not willing to consider projects that are based upon economic projections beyond 1990. Therefore, an economic project life of five years was assumed for our models with an anticipated startup in 1985.

The majority of the steam and electrical data was obtained from returned questionnaires (refer to Attachment C , Sample Questionnaire) and direct company contacts. The results of the calculations are summarized (Table 8) for the three basic cogeneration systems by

TABLE 8

LOUISIANA PETROCHEMICAL
NEW COGENERATION POTENTIAL

	COGENERATION CAPACITY (MEGAWATTS)		
COMPLEX	STEAM TURBINE	GAS TURBINE	COMBINED CYCLE
Taft	42	223	307
Lake Charles	-	-	-
Geismar (Part 1)			
Geismar (Part 2)	56	469	584
Baton Rouge	220 (1)	660 (2)	860 (2)
Plaquemine	7	125	142
Donaldsonville	25	147	194
Norco	-	-	-
Convent	13	62	87
TOTAL (3)	363	1686	2174

(1) Estimated info from DNR

(2) Prorated from basic data provided by DNR for steam turbine cogeneration

(3) Totals are not additive

complex. Although there are some "gaps" where information was not made available, the overall results are considered to be a reasonable representation of Louisiana's petrochemical cogeneration potential.

The total calculated cogeneration potential for the nine complexes was 363 megawatts for steam turbine systems, or 1686 megawatts for gas turbine systems, or 2174 megawatts for combined cycle systems. Table 8 summarizes the cogeneration potential for each complex by the system type.

A May 1983 DOE Report, "Industrial Cogeneration Potential (1980-2000) Targeting of Opportunities at the Plant Site (TOPS)", reported that Louisiana had a "best case" cogeneration potential of 3684 megawatts. Of this, 2728 megawatts was attributed to the chemical industry and 793 megawatts was attributed to refineries (refer to Table 9). In addition, the number of potential cogenerators, potential annual electricity cogeneration, potential annual steam cogeneration, and potential cogeneration energy savings for Louisiana are summarized in Tables 10 thru 13

The DOE Report indicated that the total existing cogenerated power for Louisiana was 1634 megawatts. The chemical industry is reported to contribute 648 megawatts and the refineries 87 megawatts (refer to Table 14). Tables 15 thru 17 present a breakdown of existing Louisiana cogeneration by number, annual electricity generation, and annual steam generation.

TABLE 9

TOTAL POTENTIAL POWER GENERATION(MW)

SIC	0.0<MW<1.0	1.0<MW<2.0	2.0<MW<5.0	5.0<MW<10.	10.<MW<20.	20.<MW<50.	50.<MW<100	100<MW<200	MW>200	TOTAL
	COGENERATION UNIT SIZE									
20	2.	5.	23.	0.	0.	0.	0.	0.	0.	30.
21	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
22	0.	0.	3.	0.	0.	0.	0.	0.	0.	3.
23	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
24	3.	0.	8.	0.	0.	0.	0.	0.	0.	11.
25	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
26	0.	0.	9.	0.	11.	41.	60.	0.	0.	120.
27	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
CHEMICALS	1.	0.	12.	33.	112.	344.	463.	662.	1100.	2728.
REFINERIES	0.	3.	8.	0.	0.	0.	62.	464.	255.	793.
30	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
31	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
32	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
33	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
34	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
35	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
36	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
37	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
38	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
39	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL	6.	8.	64.	33.	123.	385.	585.	1126.	1355.	3685.

REF. NO. 28 (SECTION IX)

TABLE 10

NUMBER OF POTENTIAL COGENERATION PLANTS

SIC	COGENERATION UNIT SIZE									
	0.0<MW<1.0	1.0<MW<2.0	2.0<MW<5.0	5.0<MW<10.	10.<MW<20.	20.<MW<50.	50.<MW<100	100<MW<200	MW>200	TOTAL
20	3	3	8	0	0	0	0	0	0	14
21	0	0	0	0	0	0	0	0	0	0
22	0	0	1	0	0	0	0	0	0	1
23	0	0	0	0	0	0	0	0	0	0
24	5	0	3	0	0	0	0	0	0	8
25	0	0	0	0	0	0	0	0	0	0
26	0	0	2	0	1	1	1	0	0	5
27	0	0	0	0	0	0	0	0	0	0
28: CHEM.	1	0	4	5	8	10	7	5	2	42
29: REF.	0	2	2	0	0	0	1	3	1	9
30	0	0	0	0	0	0	0	0	0	0
31	0	0	0	0	0	0	0	0	0	0
32	0	0	0	0	0	0	0	0	0	0
33	0	0	0	0	0	0	0	0	0	0
34	0	0	0	0	0	0	0	0	0	0
35	0	0	0	0	0	0	0	0	0	0
36	0	0	0	0	0	0	0	0	0	0
37	0	0	0	0	0	0	0	0	0	0
38	0	0	0	0	0	0	0	0	0	0
39	0	0	0	0	0	0	0	0	0	0
TOTAL	9	5	20	5	9	11	9	8	3	79

REF. NO 28 (SECTION IX)

TABLE II

POTENTIAL ELECTRIC COGENERATION(10*6 KWH/YR)

SIC	COGENERATION UNIT SIZE 0.0<MW<1.0	1.0<MW<2.0	2.0<MW<5.0	5.0<MW<10.	10.<MW<20.	20.<MW<50.	50.<MW<100	100<MW<200	MW>200	TOTAL
20	8.	24.	72.	0.	0.	0.	0.	0.	0.	103.
21	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
22	0.	0.	12.	0.	0.	0.	0.	0.	0.	12.
23	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
24	10.	0.	27.	0.	0.	0.	0.	0.	0.	37.
25	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
26	0.	0.	47.	0.	76.	295.	431.	0.	0.	850.
27	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
28 : CHEM.	3.	0.	86.	253.	960.	2924.	3952.	5627.	9350.	23156.
29: REF.	0.	26.	69.	0.	0.	0.	537.	3930.	2203.	6765.
30	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
31	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
32	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
33	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
34	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
35	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
36	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
37	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
38	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
39	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL	21.	50.	313.	253.	1036.	3219.	4920.	9557.	11553.	30923.

REF. NO. 28 (SECTION IX)

TABLE 12

POTENTIAL STEAM COGENERATION(10**6 LB/YR)

	COGENERATION UNIT SIZE								
SIC	0.0<MW<1.0	1.0<MW<2.0	2.0<MW<5.0	5.0<MW<10.	10.<MW<20.	20.<MW<50.	50.<MW<100	100<MW<200	MW>200	TOTAL
20	132.	416.	1241.	0.	0.	0.	0.	0.	0.	1789.
21	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
22	0.	0.	209.	0.	0.	0.	0.	0.	0.	209.
23	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
24	204.	0.	528.	0.	0.	0.	0.	0.	0.	733.
25	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
26	0.	0.	702.	0.	1051.	5119.	7488.	0.	0.	14360.
27	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
28: CHEM.	48.	0.	1715.	2457.	16823.	48696.	40327.	77486.	42330.	229882.
29: REF.	0.	1343.	2279.	0.	0.	0.	27734.	15678.	19699.	66734.
30	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
31	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
32	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
33	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
34	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
35	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
36	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
37	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
38	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
39	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL	384.	1759.	6675.	2457.	17874.	53816.	75549.	93164.	62029.	313707.

REF. NO. 28 (SECTION IX)

TABLE 13

POTENTIAL ENERGY SAVINGS (109 BTU/YR)**

	COGENERATION UNIT SIZE									
SIC	0.0<MW<1.0	1.0<MW<2.0	2.0<MW<5.0	5.0<MW<10.	10.<MW<20.	20.<MW<50.	50.<MW<100	100<MW<200	MW>200	TOTAL
20	65.	207.	618.	0.	0.	0.	0.	0.	0.	891.
21	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
22	0.	0.	104.	0.	0.	0.	0.	0.	0.	104.
23	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
24	91.	0.	235.	0.	0.	0.	0.	0.	0.	327.
25	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
26	0.	0.	398.	0.	637.	2550.	3730.	0.	0.	7315.
27	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
28: CHEM.	29.	0.	762.	1896.	8059.	24340.	29140.	44160.	60500.	168885.
29: REF.	0.	289.	676.	0.	0.	0.	5990.	23680.	6970.	37605.
30	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
31	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
32	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
33	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
34	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
35	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
36	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
37	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
38	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
39	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL	186.	496.	2793.	1896.	8696.	26890.	38860.	67840.	67470.	215127.

REF. NO. 28 (SECTION IX)

TABLE 14

TOTAL EXISTING POWER GENERATION(MW)

					COGENERATION UNIT CAPACITY					
SIC	0.0<MW<1.0	1.0<MW<2.0	2.0<MW<5.0	5.0<MW<10.	10.<MW<20.	20.<MW<50.	50.<MW<100	100<MW<200	MW>200	TOTAL
20	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
21	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
22	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
23	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
24	0.	0.	0.	0.	0.	0.	53.	0.	0.	53.
25	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
26	0.	2.	0.	0.	25.	106.	109.	0.	0.	242.
27	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
28 CHEM.	1.	0.	0.	0.	27.	45.	166.	0.	410.	648.
29 REF.	0.	0.	0.	0.	12.	0.	75.	0.	0.	87.
30	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
31	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
32	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
33	0.	0.	0.	0.	0.	0.	0.	0.	604.	604.
34	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
35	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
36	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
37	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
38	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
39	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL	1.	2.	0.	0.	64.	151.	403.	0.	1014.	1634.

REF. NO. 28 (SECTION IX)

TABLE 15

NUMBER OF EXISTING COGENERATION PLANTS

	COGENERATION UNIT CAPACITY								
SIC	0.0<MW<1.0	1.0<MW<2.0	2.0<MW<5.0	5.0<MW<10.	10.<MW<20.	20.<MW<50.	50.<MW<100	100<MW<200	MW>200	TOTAL
20	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	1	0	0	1
25	0	0	0	0	0	0	0	0	0	0
26	0	1	0	0	2	3	2	0	0	8
27	0	0	0	0	0	0	0	0	0	0
28: CHEM.	1	0	0	0	2	2	2	0	1	8
29: REF.	0	0	0	0	1	0	1	0	0	2
30	0	0	0	0	0	0	0	0	0	0
31	0	0	0	0	0	0	0	0	0	0
32	0	0	0	0	0	0	0	0	0	0
33	0	0	0	0	0	0	0	0	1	1
34	0	0	0	0	0	0	0	0	0	0
35	0	0	0	0	0	0	0	0	0	0
36	0	0	0	0	0	0	0	0	0	0
37	0	0	0	0	0	0	0	0	0	0
38	0	0	0	0	0	0	0	0	0	0
39	0	0	0	0	0	0	0	0	0	0
TOTAL	1	1	0	0	5	5	6	0	2	20

REF. NO. 28 (SECTION IX)

TABLE 16

EXISTING ELECTRIC COGENERATION(106 KWH/YR)**

	COGENERATION UNIT CAPACITY									
SIC	0.0<MW<1.0	1.0<MW<2.0	2.0<MW<5.0	5.0<MW<10.	10.<MW<20.	20.<MW<50.	50.<MW<100	100<MW<200	MW>200	TOTAL
20	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
21	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
22	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
23	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
24	0.	0.	0.	0.	0.	0.	387.	0.	0.	387.
25	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
26	0.	11.	0.	0.	110.	724.	549.	0.	0.	1394.
27	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
28 ;CHEM	4.	0.	0.	0.	108.	189.	1097.	0.	1952.	3351.
29;REF.	0.	0.	0.	0.	64.	0.	217.	0.	0.	281.
30	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
31	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
32	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
33	0.	0.	0.	0.	0.	0.	0.	0.	1600.	1600.
34	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
35	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
36	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
37	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
38	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
39	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL	4.	11.	0.	0.	283.	913.	2250.	0.	3553.	7014.

REF. NO. 28 (SECTION IX)

TABLE 17

EXISTING STEAM COGENERATION(106 LB/YR)**

SIC	COGENERATION UNIT CAPACITY									
	0.0<MW<1.0	1.0<MW<2.0	2.0<MW<5.0	5.0<MW<10.	10.<MW<20.	20.<MW<50.	50.<MW<100	100<MW<200	MW>200	TOTAL
20	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
21	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
22	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
23	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
24	0.	0.	0.	0.	0.	0.	6609.	0.	0.	6609.
25	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
26	0.	190.	0.	0.	1881.	12350.	9364.	0.	0.	23785.
27	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
28: CHEM	63.	0.	0.	0.	1846.	3228.	18718.	0.	33308.	57163.
29: REF	0.	0.	0.	0.	1097.	0.	3699.	0.	0.	4796.
30	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
31	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
32	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
33	0.	0.	0.	0.	0.	0.	0.	0.	27299.	27299.
34	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
35	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
36	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
37	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
38	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
39	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL	63.	190.	0.	0.	4824.	15577.	38390.	0.	60607.	119652.

REF. NO. 28 (SECTION IX)

Based upon the remaining potential cogeneration capacity, Louisiana is ranked third in the nation preceded only by California and Texas. However, Louisiana is the second largest existing cogenerator with Texas ranked first.

Generally, it was found that the operation of an optimized cogeneration system would still result in a net demand for electrical power largely because of the electricity intensiveness of most of the petrochemical producers. The natural gas-fired gas turbine and waste heat boiler system was found to offer the most favorable economics and energy savings of the three types of cogeneration systems evaluated. Many of the preliminary screenings indicated a simple payback for a gas turbine system between three to five years. The internal rate-of-return (IRR) was typically 20 to 30 percent.

The steam turbine system was the least attractive because of higher capital costs of a new boiler required for the higher steam pressures. Generally, the existing plant boilers cannot be significantly uprated to provide the high pressure steam required to drive the steam turbine. Coal-fired steam turbine systems are more capital and labor intensive because of the costs associated with handling and storage of the coal. The associated payout periods are beyond what most companies are willing to project.

When a cogeneration system offers an attractive IRR it is usually because of one or more of the following: low incremental investment costs achieved by the necessity of installing a new boiler to replace obsolete boilers; low system capital investment costs because of large system economies of scale; a high differential between the cost of electrical energy and the cogeneration fuel cost (particularly if waste heat is utilized that does not have a significant alternate use value.

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VI. REGULATION OF COGENERATION

Recognizing the significance of cogeneration as a means of energy conservation with concomitant economic improvement, the U.S. Congress provided for special treatment of cogeneration facilities under several statutes. Important among these statutes are the Public Utility Regulatory Policies Act of 1978 (PURPA), the Natural Gas Policy Act of 1978 (NGPA), the Energy Tax Act of 1978 (ETA) as later amended by the Crude Oil Windfall Profit Tax Act of 1980 (COWPTA), and the Powerplant and Industrial Fuel Act of 1978 (FUA).

Later, the Economic Recovery Tax Act of 1981 provided greater incentive through the accelerated cost-recovery system (ACRS). Some of the tax benefits from this act were reduced by the Tax Equity and Fiscal Responsibility Act of 1982, but legislation has recently been introduced to restore those benefits allowed cogenerators.

PURPA

Prior to the passage of PURPA, Congress determined that certain regulatory and institutional barriers and a lack of economic incentives had limited development of technologies for conservation of electric energy and improvement of efficiency in the use of facilities and resources for generation of electricity. PURPA authorized the Federal Energy Regulatory Commission (FERC) to provide appropriate incentives and to remove those barriers. The act provides for the encouragement of production of electric power by qualifying cogeneration facilities and small power producers.

In the past, a developer of cogeneration or small power production facilities faced three major regulatory and economic obstacles: (1) Utilities were generally not required to purchase electric power generated by these facilities, and were not required to pay appropriate rates for this power; (2) some Utilities charged discriminatorily high rates for backup power required by cogenerators and small power producers; and (3) a cogenerator or small power producer providing electricity to a utility grid might be subjected to the same Federal and State regulations as an electric utility. Sections 201 and 210 of PURPA are designed to remove these obstacles and encourage cogeneration and small power production.

The FERC rules under Section 201 of PURPA:

- Establish sequential use of energy (i.e., energy input must produce electric energy and forms of useful thermal energy - 5 percent of the total energy output is required to be useful thermal energy) and efficiency standards that must be met by a cogeneration facility to be a qualifying facility.

- Establish the ownership criteria for a qualifying facility - must be owned by a concern not primarily engaged in the generation or sale of electric power; however, an electric utility may own up to 50 percent of a qualifying facility.

- Establish the procedures for obtaining qualifying status.

The FERC rules under Section 210 of PURPA provide that:

- Electric utilities must purchase electric energy and capacity made available by qualifying cogenerators and small power producers.

- The rates for utility purchase of energy and capacity must reflect the cost that the utility can "avoid" as a result of that purchase rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers. (Thus, the rate would be 100 percent of avoided cost).

- That rates under private contracts with terms not conforming to the rules are not precluded.

- Electric utilities are required to furnish data concerning present and future costs of energy and capacity on their systems.

- Electric utilities are required to supply energy to qualifying facilities on a nondiscriminatory basis at a rate that is just and reasonable and in the public interest.

- Electric utilities must provide certain types of services which may be requested by qualifying facilities to supplement or backup those facilities' own generation.

In recent court cases where FERC's rules have been challenged, the courts have upheld that utilities must buy surplus electricity from qualifying facilities at a price equal to 100 percent of avoided costs. Also upheld were the provisions which require utilities to interconnect with qualified cogenerators, to wheel (transmit) power from cogenerators to utilities not on the local grid, and to accept "buy-all, sell-all" arrangements whereby a cogenerator can sell its entire output to the utility and buy back all its power requirements.

PURPA established a procedure for implementing Sections 201 and 210 rules, directing FERC to prescribe such rules. Further, PURPA required the States to implement FERC rules.

Louisiana has complied by the adoption of the prescribed rules and regulations through Louisiana Public Service Commission Order No. U-14964 dated November 24, 1982. A copy of this order is included herein as Attachment D.

The Louisiana PSC philosophy in the administration of the regulations is to take a passive role, whenever possible, preferring cogenerators and the utilities to make their own deal, with the PSC intervening as arbitrator only when the contracting parties cannot agree.

As of this date, there are only a very few active negotiations in progress with no contracts finalized. Therefore, a trend has not been established.

Before concluding this section a brief survey will be made of those other Federal Acts mentioned in the first paragraph which have impact on cogeneration.

The Natural Gas Policy Act of 1978 (NGPA)

The rules under this act provide FERC authority to exempt qualifying cogenerator facilities from incremental pricing of natural gas. Incremental pricing has reference to the provisions that natural gas pipelines must pass through certain acquisition costs for natural gas to customers burning the gas as industrial boiler fuel. These surcharges would load future price increases more heavily on industry than on residences.

How lasting this relative benefit is to cogenerators will depend upon the final resolution of natural gas policy which is currently under much debate in Washington.

The Energy Tax Act of 1978 (ETA) and The Crude Oil Windfall Profit Tax of 1980 (COWPTA)

The major advantage to cogenerators provided by ETA as amended by COWPTA was the 10 percent energy tax credit, above and beyond the 10 percent investment tax credit. Unfortunately, this tax credit expired at the end of 1982. However, legislation has been introduced to restore this tax benefit, of which more will be written later.

Power Plant and Industrial Fuel Use Act of 1978 (FUA)

This act provides permanent exemptions from prohibitions on oil and gas use for eligible cogeneration facilities.

The Economic Recovery Tax Act of 1981 and The Tax Equity and Fiscal Responsibility Act of 1982

The 1981 economic recovery law provided a five-year depreciation for long-lived cogeneration facilities put in service before 1985. It also allows companies whose income is not sufficiently high to absorb the new faster depreciation rates to transfer the tax benefits to others seeking a tax shelter. (These incentives are discussed further in the next section).

Under the Tax Equity and Fiscal Responsibility Act of 1982, the five-year depreciation schedule was increased to eight-years and the additional 10 percent energy tax credit was removed.

Subsequently, legislation was introduced by Senator Bob Packwood (R., Ore.) that would restore reductions in the tax benefits allowed cogenerators.

While the foregoing summaries of regulations offer highlights of pertinent sections, prospective cogenerators should refer to the Federal Register and consult with the appropriate Federal agency to obtain the latest information on implementing rules.

VII. INCENTIVES TO ENCOURAGE COGENERATION

While PURPA opened the door for a new era of industrial cogeneration, cogenerators also have several other incentives. Cogenerators are exempt from stipulations in the Fuel Use Act of 1978 that prohibit industrial use of natural gas and oil fuels after 1990. They are exempt from the incremental pricing provisions of the Natural Gas Policy Act of 1978 which shift future price increases more heavily toward industry than residences. Also, cogeneration facilities qualify for the normal 10% investment tax credit.

The Economic Recovery Tax Act of 1981 (ERTA) provided the accelerated tax recovery system (ACRS) allowing cogeneration facilities put in service prior to 1985 to be depreciated in five years. The law also permits companies which do not have enough income to absorb faster depreciation to transfer the tax benefits to other companies which can fully utilize the tax shelter. These tax advantages have stimulated a great deal of interest in so called "three-party projects" for cogeneration. These projects involving leveraged leasing, offer incentives in those cases where companies which previously may have been able to absorb tax benefits under the old tax rules may not be able to do so under the faster tax write-offs provided by ERTA. In a typical arrangement for a cogenerator facility, a third party owner puts up 20-40% of the project cost, a lender 60-80% of the project cost, and a chemical company lessee operates the cogeneration facility selling surplus power to an electric utility and excess steam to another plant. Because of the tax benefits available, the third party owner-lessor is able to pass part of these benefits over to the lessee in the form of lower rental payments.

Leveraged leasing also offers an advantage to the lessee in that he may exclude certain types of leasing liabilities from the company balance sheet, a so called "off-balance sheet" accounting which improves debt ratios and may give the company more debt capacity. By thus leasing cogeneration facilities and using their scarce capital for production capacity or other process efficiency improvements, chemical companies "can have their cake and eat it too".

Some of the tax incentives that cogenerators had earlier have been taken away or reduced. The provision for an extra 10% tax credit (over and above the normal 10% investment tax credit) available to certain kinds of energy property including cogeneration facilities expired at the end of 1982. Also the Tax Equity and Fiscal Responsibility Act of 1982 increased the depreciation schedule from five to eight years. But, legislation has been introduced by Senator Bob Parkwood (R., Ore.) to restore those reductions in tax benefits formerly allowed cogenerators.

Prospective cogenerators in Louisiana have an added tax benefit in that energy conservation facilities (including cogeneration) are exempt from state sales tax.

Another boost for cogeneration could result from Act 642 of the 1983 Louisiana Legislature - the Commerce and Industry

Department venture capital bill, which offers tax breaks to Louisiana residents who invest in venture funds that in turn put the majority of their equity capital in Louisiana businesses.

Inherently, cogeneration makes good economic sense, and the aggregate of all the tax benefits provides a powerful incentive for virtually every industry to at least investigate this vehicle for efficiency improvement.

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VIII. ATTACHMENTS

ATTACHMENT A

LOUISIANA CHEMICAL INDUSTRY COMPANIES
LISTED BY COMPLEX AND CHEMICALS PRODUCED

Below are listed 62 companies in 9 complexes and the top 20 ranking chemicals produced. The top 20 ranking chemicals are these which comprise 75% by volume and value of the total Louisiana production. The top 20 ranking chemicals are produced by 34 companies.

	CHEMICALS PRODUCED THAT ARE IN TOP 20 RANKING
NORCO	
Big Three Industries	- None -
Kaiser Aluminum & Chem. Corp.	- None -
Shell Oil & Chemical Co.	Ethylene, Ethylene Dichloride, Propylene, Sulfur, Vinyl Chloride.
PLAQUEMINE	
Allemania Chemical Co.	- None -
Big Three Industries	- None -
Dow Chemical USA	Benzene, Caustic, Chlorine, Ethylene, Ethylene Glycol, Ethylene Oxide, Polyethylene, Propylene, Vinyl Chloride.
Georgia Pacific	Ammonia, Caustic, Chlorine, Ethylene Dichloride, Polyvinyl Chloride, Vinyl Chloride.
B.F. Goodrich	Caustic, Polyvinyl Chloride
Copolymer Rubber & Chemical Co.	- None -
Hooker Chemical Co.	Polyvinyl Chloride
Sid Richardson Carbon	- None -
CONVENT	
Convent Chemical Corp.	Caustic, Chlorine, Ethylene Dichloride.
Texaco, Inc.	Sulfur

BATON ROUGE	CHEMICALS PRODUCED THAT ARE IN TOP 20 RANKING
Allied Chemical Co.	Sulfuric Acid
American Hoechst	Benzene, Ethylbenzene, Styrene.
Copolymer Rubber & Chemical Co.	- None -
Exxon Chemical Co. USA	Benzene, Chlorinated Butyl Rubber, Ethylene, Isopropanol, Oxoalcohol, Propylene.
Ethyl Corp.	Chlorine, Ethylene Dichloride, Polyvinyl Chloride, Vinyl Chloride.
Formosa Plastics	Caustic, Chlorine, Ethylene Dichloride, Vinyl Chloride.
Grant Chemical	- None -
Kaiser Aluminum & Chemical	- Plant Shutdown -
Reynolds Metal	- None -
Stauffer Chemical Co.	Sulfuric Acid
USS Chemicals	- Plant Shutdown -
DONALDSONVILLE	
Agrico	Ammonia, Ammonia Polyphosphate, Sulfuric Acid, Urea.
Ammonia Prod.	Ammonia
CF Industries	Ammonia, Urea.
CS Industries	- None -
Freeport Uranium Co.	- None -
Melamine Chemical Co.	- None -
Triad Chemical Co.	Ammonia, Urea.
Gulf Oil Chemical Co.	Benzene, Sulfur

TAFT	CHEMICALS PRODUCED THAT ARE IN TOP 20 RANKING
Beker Industries	Ammonia Polyphosphate, Sulfuric Acid.
Hooker Chemical Co.	Caustic, Chlorine
Shell Chemical Co.	- None -
Union Carbode Corp.	Benzene, Ethylene, Ethylene Dichloride, Ethylene Glycol, Ethylene Oxide, Polyethylene, Propylene.
Witco Chemical Co.	- None -

LAKE CHARLES	
Big Three Industries	- None -
Calcasieu Chemical Corp.	Ethylene Glycol, Ethylene Oxide
Cities Service Co.	- Plant Shutdown -
Columbian Chemical	- None -
Conoco Chemicals	Ethylene, Ethylene Dichloride, Propylene, Vinyl Chloride.
Firestone Synthetic Rubber & Latex Co.	- None -
W. R. Grace	- None -
Hercules, Inc.	Polyethylene, Propylene.
Jupiter Chemical	Ammonia
Liquid Air Corp.	- None -
Liquid Carbonics	- None -
Olin	Ammonia, Urea.
PPG Industries	Caustic, Chlorine, Ethylene Dichloride, Vinyl Chloride.

GEISMAR [1]	CHEMICALS PRODUCED THAT ARE IN TOP 20 RANKING
Allied Chemical Co.	Ammonia, Ammonia Polyphosphate, Chlorine, Propylene, Sulfuric Acid, Urea.
Allied Corp/BASF Wyandotte/ Borg-Warner	Ethylene, Propylene.
BASF Wyandotte	Caustic, Chlorine, Ethylene Glycol, Ethylene Oxide.
Liquid Carbonics	- None -
Shell Chemical Co.	Ethylene Glycol, Ethylene Oxide, Oxoalcohol.
Rubicon Chemicals, Inc.	- None -
Vulcan Materials Co.	Caustic, Chlorine, Ethylene Dichloride.
Uniroyal	- None -
Borden	Ammonia, Ethylene Dichloride, Polyvinyl Chloride, Urea, Vinyl Chloride.
Air Products	- None -
Union Oil Co.	- None -
Brewster Phosphates	Ammonia Polyphosphates

(1) Shown as Geismar Sheet-1 and Sheet-2 on Block Flow Diagrams.

ATTACHMENT B

COMPUTER MODEL ASSUMPTIONS

1. 5 year project life
2. Project start-up in 1985
3. 1985 natural gas rate ~ \$4.58/MCF with an escalation rate of 8.0 percent/year
4. Service factor overall ~ 0.95
5. Standby charge 100 mills/kWh based upon electricity purchased during outage
6. No cogen base case capital costs = 0
7. 100 percent equity - 0 financed capital
8. Investment tax credit = 10% for 1st year
9. Straight line depreciation
10. Incremental O & M costs ~ 4.0 percent of capital cost
11. Capital cost calculated from Figures 26 (adjusted to IQ83\$) and prorated to startup year @ 10 percent/year
12. 48 percent tax rate
13. Electricity cost projection per Figure 39
14. System heat and power characterization per Tables 1 & 2
15. Assumed existing boilers could not be significantly uprated or modified for use with either the steam turbine or gas turbine systems
16. Minimum exhaust gas temperature = 300°F

ATTACHMENT C

The Department of Natural Resources is doing a detailed analysis of the prospects for cogeneration across the state. We would appreciate your cooperation in answering as best you can the following brief questions. You may either mail it to:

Department of Natural Resources
P. O. Box 44156
Baton Rouge, LA 70804

or hand it in at the 26 April meeting.

DNR Cogeneration Questionnaire 4/83

Name/Position ______________________

Company ______________________

1. Has Cogeneration been considered before? ☐ Yes ☐ No

2. If so, please explain to what extent, when, and general findings:

3. Are you currently considering Cogeneration? ☐ Yes ☐ No

4. If so, are you working with other companies?

   ☐ Consultants ☐ Manufacturers ☐ Utilities ☐ Industrial ☐ Other

5. Are you cogenerating now? ☐ Yes ☐ No

6. If so, to what extent? () ☐ 5MW, () ☐ 10MW, () ☐ 25MW, () ☐ 50MW, () ☐ 100MW, () ☐ ______

*7. List your total steam consumption/production at each level (i.e. 100psig, 600psig, etc.) and identify contributions by major steam generators.

*8. List your major drivers,—200HP, and horsepower (electrical, steam, gas turbine, diesel, other). Also, list potential waste heat sources in a congeneration scheme.

*9. What is your total power consumption? ________MW ________MWH/YR
(M=Million)

*At operating capacity.

ATTACHMENT D

LOUISIANA PUBLIC SERVICE COMMISSION

ORDER NO. U-14964

LOUISIANA PUBLIC SERVICE COMMISSION DOCKET NO. U-14964

ex parte

In re: Adoption of rules and regulations for the sale of electric energy by electric utility companies to qualifying cogeneration facilities and qualifying small power production facilities and the purchase of electric energy from such facilities as prescribed by Sec. 210 of the Public Utility Regulatory Policies Act of 1978 and the rules promulgated thereunder.

Adoption of Rules and Regulations for the purchase of electric energy and capacity by electric utility companies from qualifying cogeneration facilities and qualifying small power production facilities and the sale of electric energy and capacity to such facilities.

Section 101 Definitions.

(a) General rule. Terms defined in the Public Utility Regulatory Policies Act of 1978 (PURPA) shall have the same meaning for purposes of this rule as they have under PURPA, unless further defined in this rule.

(b) Definitions. The following definitions apply for purposes of this rule.

(1) "Qualifying facility" means a cogeneration facility or a small power production facility which is a qualifying facility under Subpart B of the Federal Energy Regulatory Commission's Regulations under Section-201 of the Public Utility Regulatory Policies Act of 1978 as in effect on the date of the adoption of these rules except that:

(i) A cogeneration facility which utilizes reject heat from a useful thermal energy process for the production of electrical energy and otherwise qualifies under these Rules shall be considered to be a qualifying facility regardless of the source of the energy input to the thermal process and the efficiency standard of Section 201 shall only apply to any such facility utilizing oil or natural gas for supplemental firing.

(2) "Purchase" means the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

(3) "Sale" means the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

(4) "System emergency" means a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

(5) "Rate" means any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.

(6) "Avoided costs" means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

(7) "Interconnection costs" means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility.

(8) "Supplementary power" means electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.

(9) "Long term contract" means a contract which is for a term of at least one year and can be for a term of up to twenty years.

(10) "Back-up power" means electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

(11) "Interruptible power" means electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

(12) "Maintenance power" means electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

(13) "Firm power" from a qualifying facility is power or power producing capacity that is available to the electric utility pursuant to a legally enforceable obligation for scheduled availability over a specified term.

(14) "Non-firm power" from a qualifying facility is power provided under an arrangement that does not guarantee scheduled availability, but instead provides for delivery as available.

(15) "Commission" means the Louisiana Public Service Commission.

Section 201 Scope.

(a) Applicability. This subpart applies to the regulation of sales and purchases between qualifying facilities and electric utilities.

(b) Negotiated rates or terms.

(1) Any electric utility and qualifying facility may agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this subpart; and

(2) Any contract entered into between a qualifying facility and an electric utility for any purchase shall comply with applicable rules, regulations, practices and procedures of the Commission in effect at the date of execution of the contract.

(3) No utility may unreasonably refuse to negotiate and enter into a long-term contract for the purchase of energy and/or capacity.

(c) Review and Approval of Contracts. All contracts between utilities and qualifying facilities shall be filed with the Commission. Upon filing, the Commission may, within 60 days, approve the contract with a finding that it is just and reasonable, or order further review of the contract prior to approval. If the Commission has not ordered further review of the contract within 60 days from the date of filing, the contract shall be automatically approved.

(d) Confidentiality of Qualifying Facility Data. Any data or information furnished by a qualifying facility to a utility during negotiations which is specified as confidential and privileged shall be regarded by the utility as confidential and privileged.

Section 202 Availability of electric utility system cost data.

(a) Applicability. This section applies to all electric utilities regulated by the Commission.

(b) Each electric utility shall make available data from which avoided costs may be derived, not later than six months from the date these rules become effective and not less often than every two years thereafter, and shall maintain for public inspection the following data:

(1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;

(2) The electric utility's system plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and

(3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt-hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

(4) Additional data may be made available as mutually agreed upon by the electric utility and qualifying facility. In the event of a dispute, the Commission will determine the reasonableness of the request, and issue an appropriate Order, pursuant to the provision of Section 301 of these Rules.

(c) Review.

(1) Any data submitted by an electric utility under this section shall be subject to review for accuracy, adequacy, content and timeliness, by the Commission which has ratemaking authority over such electric utility.

(2) In any such review, the electric utility has the burden of coming forward with justification for its data.

Section 203 Electric utility obligations under this subpart.

(a) Obligation to purchase from qualifying facilities. Each electric utility shall purchase, in accordance with Section 204, any energy and capacity which is made available from a qualifying facility:

(1) Directly to the electric utility; or

(2) Indirectly to the electric utility in accordance with paragraph (d) of this section.

(b) Obligation to sell to qualifying facilities. Each electric utility shall sell to any qualifying facility, in accordance with Section 205, any energy and capacity requested by the qualifying facility.

(c) Obligation to interconnect.

(1) Subject to paragraph (c) (2) of this section, any electric utility shall make such interconnections with any qualifying facility that normally would or could be served, under the Commission's Rules, by that utility as may be necessary to accomplish purchases or sales under this subpart. The obligation to pay for any interconnection costs shall be determined in accordance with Section 206.

(2) No electric utility is required to interconnect with any qualifying facility if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under Part II of the Federal Power Act.

(3) The Commission shall be informed of any request for an interconnection made by a qualifying facility to an electric utility company solely to permit the sale of energy by such qualifying facility to an electric utility other than the one requested to provide the interconnection before an agreement is consummated.

(d) Transmission to other electric utilities. If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to Section 204 (e) (4). The rate paid by a purchasing utility shall not include any charges for transmission; however, the wheeling utility shall be paid a reasonable transmission charge, including consideration of line losses, by the selling qualifying facility. Rates for wheeling within the meaning of this rule shall apply only to transmission from the qualifying facility to the purchasing utility. The Commission shall be informed of any proposed agreement between a qualifying facility and an electric utility company other than the electric utility company whose service area includes the location of the qualifying facility before such agreement is consummated.

(e) Parallel operation. Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with any applicable standards established in accordance with Section 208.

Section 204 Rates for purchases.

(a) Rates for purchases.

(1) Rates for purchases shall:

(i) Be just and reasonable to the electric consumers of the electric utility and in the public interest; and

(ii) Not discriminate against qualifying cogeneration and small power production facilities.

(iii) Rates for purchases shall be negotiated and, if the parties cannot agree, the parties shall submit the issue to the Commission which will resolve the matter on a case by case basis.

(2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

(b) Relationship to avoided costs.

(1) For purposes of this paragraph, "new capacity" means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

(2) Subject to paragraph (b) (3) of this section, a rate for purchases satisfies the requirements of paragraph (a) of this section if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e) of this section.

(3) A rate for purchases (other than from new capacity) may be less than the avoided cost if the Commission finds that with respect to a particular qualifying facility, avoided cost rates would be unjust or unreasonable to the electric consumers of the electric utility.

(4) Rates for purchases shall be in accordance with paragraphs (b) (2) and (b) (3) of this section, regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.

(5) In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery.

(c) Standard rates for purchases.

(1) There shall be put into effect, not later than six months from the date the rules become effective, standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.

(2) The standard rates for purchases under this paragraph:

(i) Shall be consistent with paragraphs (a) and (e) of this section; and

(ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(iii) Shall specify terms and conditions of service such as metering, safety, liability and access to equipment, etc.

(d) Purchases "as available" or pursuant to a legally enforceable obligation. Each qualifying facility shall have the option either:

(1) To provide non-firm energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(2) To provide firm energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates shall as agreed upon prior to the beginning of the specified term, be based on either

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

(3) Nothing in these rules shall restrict the right of a qualifying facility to provide some portions of its energy or capacity upon terms and conditions for purchase by a utility which may differ from the terms and conditions upon which it provides other portions of its energy or capacity for purchase by the utility.

(e) Factors affecting rates for purchases. In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(1) The data provided pursuant to Section 202(b);

(2) The availability of capacity and energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system;

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities;

(3) The relationship of the availability of energy and capacity from the qualifying facility as derived in paragraph (e) (2) of this section, to the ability of the electric utility to avoid costs, including the avoidance or deferral of capacity additions or portions thereof, the avoidance or deferral of demand charges associated with power purchases from other utilities or pools, and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

(f) Periods during which purchases not required.

(1) Any electric utility which gives notice pursuant to paragraph (f) (2) of this section will not be required to purchase electric energy during any period during which, due to operational circumstances such as light loading problems, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.

(2) Any electric utility seeking to invoke paragraph (f) (1) of this section must notify each affected qualifying facility in time for the qualifying facility to cease the delivery of energy to the electric utility.

(3) Any electric utility which fails to comply with the provisions of paragraph (f) (2) of this section will be required to pay the same rate for such purchase of energy as would be required had the period described in paragraph (f) (1) of this section not occurred.

(4) A claim by an electric utility that such a period has occurred or will occur is subject to such verification by the Commission as it determines necessary or appropriate either before or after the occurrence.

Section 205 Rates for sales.

(a) General rules.

(1) Rates for sales:

(i) Shall be just and reasonable and in the public interest; and

(ii) Shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.

(2) Rates for sales to any qualifying facility shall be determined in the same manner as any other sales and shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load, cost or other characteristics as deemed appropriate by the Commission.

(i) Rates for sales of power as described in paragraphs (b) and (c) of this section shall be negotiated by the parties and shall be filed with the Commission to become effective not later than 12 months after the date these rules become effective.

(b) Additional Services to be Provided to Qualifying Facilities.

(1) Upon request of a qualifying facility, each electric utility shall provide:

(i) Supplementary power;

(ii) Back-up power;

(iii) Maintenance power; and

(iv) Interruptible power.

On peak and off peak rates for Back-Up and Maintenance Power shall be required. The peak period is defined as the summer season from June 1 through September 15 during the hours of 6 a.m. and 12 midnight on weekdays and the off-peak period is defined as all other hours of the year unless otherwise defined by the Commission.

(2) The Commission may waive any requirement of paragraph (b) (1) of this section if, after notice in the area served by the electric utility and after opportunity for public comment, the electric utility demonstrates and the Commission finds that compliance with such requirement will:

(i) Impair the electric utility's ability to render adequate service to its customers; or

(ii) Place an undue burden on the electric utility; or

(iii) Unreasonably interfere with the operation of existing contracts under which the utility is providing power to its customers.

(c) Rates for sales of back-up and maintenance power. The rate for sales of back-up power or maintenance power:

(1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and

(2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with outages of the utility's facilities.

Section 206 Interconnection costs.

(a) Obligation to pay. Each qualifying facility shall be obligated to pay any interconnection costs which electric utility may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.

(b) Reimbursement of interconnection costs. The Commission shall determine the options available to the qualifying facility for payments of interconnection costs.

Section 207 System emergencies.

(a) Qualifying facility obligation to provide power during system emergencies. A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent:
 (1) Provided by agreement between such qualifying facility and electric utility; or
 (2) Ordered under section 202(c) of the Federal Power Act.

(b) Discontinuance of purchases and sales during system emergencies. During any system emergency, an electric utility may discontinue:
 (1) Purchases from a qualifying facility if such purchases would contribute to such emergency. For billing purposes, purchases shall continue to the extent that a qualifying facility itself is able to use the power it produces; and
 (2) Sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

Section 208 Standards for operating reliability.

The Commission may establish reasonable standards to ensure system safety and reliability of interconnected operations.

Section 301 Resolution of disputes.

(a) A proceeding to resolve a dispute between an electric utility and a qualifying facility arising under this rule may be instituted by the filing of a petition with the Commission in accordance with the Rules of Practice and Procedure of the Commission.

(b) Commission Resolution of Disputes Related to Contracts. If a contract has not been successfully negotiated within 90 days after submission of a written proposal by the qualifying facility, or of a written request to the utility for a proposal; or, if there is an alleged breach of an existing contract or a dispute between the parties as to interpretation of an existing contract, the Commission may, in its discretion on a case-by-case basis, provide a resolution of the specific matters at issue according to the following procedures:
 (1) The qualifying facility or the electric utility may petition the Commission for informal arbitration of the specific matters in dispute, naming the other party as respondent.
 (2) Upon receipt of a petition from either party, and of a certificate of service of the petition upon the other party, the Commission shall assign the case to one or more members of its staff, who will conduct informal arbitration on an expedited basis and issue a written decision within 30 days, except that:
 (3) Within 30 days of the issuance of the staff decision either party may bring a formal appeal to the Commission from any part of the decision. If no appeal has been filed within 30 days, the staff decision will become final and binding upon the parties as an order of the Commission.

(4) An appeal and Commission proceedings upon the appeal will be conducted according to the Commission's existing rules for the formal adjudication of cases, except that to the extent possible, an expedited schedule will be maintained which will permit issuance of the Commission's final decision within 90 days of the staff decision appealed from. The Commission's decision will be in the form of an Order and will be final and binding upon the parties subject to appeal.

Section 401 Exemptions from regulation.

(a) Exemption. All qualifying facilities are exempted from Louisiana State laws and regulations, other than those promulgated herein, respecting:

(1) The rates of electric utilities; and

(2) The financial and organizational regulation of electric utilities.

BY ORDER OF THE COMMISSION:
BATON ROUGE, LOUISIANA
NOVEMBER 24, 1982

Thomas E. Powell
CHAIRMAN

Ed Kennon
COMMISSIONER

Louis J. Lambert Jr.
COMMISSIONER

John F. Schwegmann
COMMISSIONER

Louis S. Quinn
SECRETARY

George J. Hebert
VICE CHAIRMAN

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