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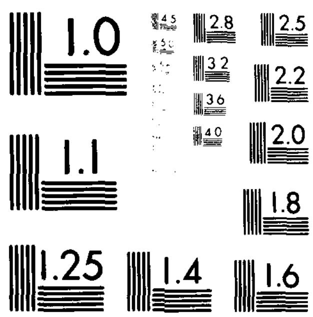

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TECHNICAL REPORT
CIVIL ENGINEERING LABORATORY

Naval Construction Battalion Center, Port Hueneme, California 93043

COGENERATION SYSTEMS

by

E. E. Cooper, Ph D

June 1980

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Discussions are included of the four broad interrelated categories of factors to consider when evaluating candidate approaches to cogeneration at a site. The categories are technical, economic/financial, legislative/regulatory, and institutional. The inability to resolve difficulties in any area may obviate implementation of cogeneration. Generalized performance curves are presented for cogeneration systems utilizing commercially available

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steam turbines, diesels, or combustion turbines with heat recovery. A summary is given of federal energy and environmental legislation and regulations currently in effect which impact cogeneration systems. The nature of institutional constraints on implementing cogeneration is also discussed. The potential for cooperative ownership/operation options with utility companies or third party investors is described. The economics of cogeneration is detailed. Finally, steps are listed for proceeding through the categories of factors toward implementation of cogeneration.

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CONTENTS

PRINCIPLE OF COGENERATION

Cogeneration can be an effective means of conserving energy where both thermal energy and electrical energy are needed. Figure 1 illustrates the benefit of cogeneration 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 a heater with an efficiency of 75%, an input energy of 267 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%, so that 300 units of energy are input at the central power plant. The conventional system has an overall, or "universal," efficiency of 53%. By comparison, the depicted cogeneration system is able to meet the same thermal and electrical loads at an overall efficiency of 75% by capturing exhaust heat from an on-site electrical generation process to provide the thermal energy. The relative thermal-to-electrical energy ratio of 2:1 in this ideal example is typical of cogeneration systems using combustion turbines. Other cogeneration systems have different characteristic thermal-to-electric ratios, as illustrated in Figure 2.

Retrofitting a facility for cogeneration usually involves the acquisition of a considerable amount of new equipment for generation of electrical power and capture or utilization of normally "wasted" heat. In fact, "retrofitting" generally requires the actual replacement of significant portions of the old systems that supply electrical and thermal energy, plus adding more capability. Therefore, cogeneration systems typically require carefully considered capital expenditures that will be recovered only if sufficient cost savings in fuel or purchase of electrical power is achieved.

FACTORS IMPACTING COGENERATION

The process of deciding whether to implement cogeneration and, if so, which system to select, can be a complex one. There are probably more nontechnical than technical factors which impact the outcome of an assessment of cogeneration for a particular site. Many technically sound cogeneration system projects have failed to reach the operational stage because the nontechnical constraints were not anticipated or could not be overcome when encountered. Because of this, it is important that there be an awareness from the outset of the need to identify both the technical and nontechnical issues and ensure that each be given the level of attention required by the decision process.

Factors impacting cogeneration may be put into the following categories:

1. Technical
2. Economic/Financial
3. Legislative/Regulatory
4. Institutional

In some cases, a particular issue or factor relevant to the evaluation of cogeneration may affect two or more categories (e.g., the type of fuel may be restricted by environmental and energy legislation, as well as affecting the technical design of the equipment, the capital costs, and the life cycle economics). Some examples of issues that might arise during the examination of cogeneration are:

1. Technical -

   Load patterns (profiles, magnitudes, driving functions)
   Choice of fuels
   Plant site location relative to loads and condition of
   distribution systems
   Performance of candidate systems

2. Economic/Financial -

Magnitude of capital costs
Impact of fuel choice and other parameters on capital costs, operating costs, ROI
Available tax incentives
Marketability of excess power
Sources of capital, outside versus self-generated
Utility company standby rates

3. Legislative/Regulatory -

Local air emissions standards and attainment status
Waste disposal restrictions
Jeopardy of any environmentally protected areas
National fuel use and energy legislation
State PUC facilities regulations regarding cogeneration
Status of PUC jurisdiction over regulation of cogeneration facilities
Zoning or siting restrictions

4. Institutional -

Utility company policies toward cogeneration
Availability of personnel and skills for operation and maintenance of system
Assessment of impact on facility mission
Assessment of impact on special requirements, (e.g., security)
Impact on community
Impression on community

Some of the more important factors are discussed below. Guidance is also provided for sources of information and data for a number of the questions which may arise.

The key requirement for a successful cogeneration application is to use the recovered "waste" heat beneficially. Heat recovery can be accomplished on engines driving electrical generating equipment or on engines producing mechanical shaft power, but the incorporation of heat recovery equipment is uneconomical unless a substantial portion of the heat is used.

A good energy survey of a facility provides the basic information needed to determine if load conditions are favorable for cogeneration. An energy survey should examine the thermal loads, the electrical loads, and the mechanical shaft loads. It is recommended that this energy survey include the following information about the various loads:

Thermal Energy	Electrical/Mechanical Shaft Energy
Present thermal energy usage profiles and demand levels; include extremes	Present electrical energy usage profiles and demand levels; include extremes
Existing thermal supply system characteristics/capacity, pressure, temperature; include purchases	Identification of any on-site electrical generating units and/or large motors or engines providing mechanical shaft power; include the output levels and profiles
Condition and coverage of thermal distribution system	Opportunities for conserving and reducing electrical energy usage
Major thermal loads and thermal state of energy required	
Opportunities for conserving and reducing thermal energy usage	

In addition, it is recommended that an energy audit include consideration of:

- Planned changes in operations or functions at the facility which would impact load profiles, demand levels, or capability to meet loads
- Opportunities to alter loads to benefit cogeneration potential

The data and information accumulated during the energy survey should be applied in the following way in preparation for the cogeneration assessment.

1. Estimate the loads after implementation of energy conservation measures.

2. Determine if the resulting thermal load is high enough to warrant cogeneration. Reference 1 recommends having a process heat load of at least 200 to 300 million Btu/hr, at which level diesels or combustion turbines with exhaust heat boilers would normally be used, or even higher for use of steam turbines.

3. Establish representative profiles which account for diurnal and seasonal effects, or other significant effects, such as process variations. In general, the potential for cogeneration is enhanced when electrical and thermal load patterns are similar and in phase.

COGENERATION SYSTEM OPTIONS

There are usually numerous cogeneration system alternatives for consideration at a site that stem from the basic questions:

1. What types of power plant should be used?
2. What capacity should the system have?

Commercial equipment (Figure 3) is readily available for four generic types of cogeneration systems: diesel engine systems, combustion turbine systems, steam turbine systems, and combined cycle systems. Other options, such as the organic Rankine bottoming cycle, are on the threshold of commercialization, but the sparse data base and experience level with them preclude their inclusion in this report. The selection of a system for a particular installation depends on many site specific factors that ultimately affect cost. One very important factor is how the system ratio of thermal/electrical output, which was addressed in Figure 2, matches that of the loads. Other important factors include types of fuel available, environmental restrictions, utility rate structures, etc. Further discussions of the performance of each type of system and other characteristics influencing selection are given in the sections below.

The size, or capacity, of a cogeneration system obviously depends upon the thermal and electrical loads to be served. As seen below, the electrical load may be considered "infinite" if the system is allowed to transfer power to the grid. This type of system can operate at its most efficient or economical point because it can sell power to the grid if the system electrical output exceeds the facility's electrical load. As a rule of thumb, the best overall efficiency for meeting the thermal and electrical loads will be obtained if the cogeneration system is sized to meet the typical or average thermal load. Fluctuations in loads cause the system to almost always operate at off-design points. The load swings and other factors result in compromises when deciding system capacity.

Figure 4 depicts cogeneration systems in a generalized sense and illustrates how backup capability or additional capacity to meet the thermal and electrical loads may be provided by fired auxiliary boilers and utility grid connections, respectively. The connection to the utility company grid is a very important and, in most cases, very beneficial feature for a cogeneration system. First, because the grid can carry part of the electrical load, the option exists to size the cogeneration system with respect to the thermal load if that appears to yield the best economy or fuel efficiency. Second, because the grid "backs up" the cogeneration system, standby and emergency electrical generating capacity do not have to be installed as part of the system, thus reducing capital costs. Third, the utility company or customers connected to the grid become potential markets for power generated in excess of that needed to meet the on-site electrical load. And fourth, a reliable cogeneration system adds to the total capacity of the utility company so that there becomes an incentive for the utility company to consider partial or total ownership and/or operation of the cogeneration system.

There are five basic types of cogeneration system arrangements that have progressive degrees of utility company or third party involvement. They are:

1. Navy ownership and operation of an under-capacity plant. The utility sells power to the facility to make up the difference between the electrical load and the capacity of the cogeneration plant.

2. Navy ownership and operation of an over-capacity plant. The utility purchases power from the facility in excess of that needed to meet the load.

3. Navy ownership with utility operation of the plant.

4. Utility/Navy joint venture in a cogeneration plant. This involves a mutually acceptable sharing of capital costs and operating responsibilities. A joint venture may also be arranged between the Navy and some third party other than the utility.

5. Utility or third party ownership and operation of a cogeneration plant. The utility or third party markets both thermal and electrical energy to the facility.

The degree to which a utility is willing to participate depends upon its needs and policies and varies from one utility to another. There is growing acceptance of cogeneration system connections to the grid and a trend toward cooperative participation by utilities as a result of demand growth, difficulties in providing new central plant capacity, and legislative or regulatory measures favoring cogeneration.

The degree to which the Navy is willing to participate in a cooperative venture or give up some responsibility for the utility system, particularly steam, likewise varies from one location to another. There may be growing acceptance of non-Navy involvement in the "steam side" of utility service at bases because of pressures to contract out more services, difficulties and delays in obtaining sufficient MILCON funding for cogeneration or coal conversion projects, and precedents set elsewhere.

If consideration is being given to a joint cogeneration venture at a particular Navy site, it is well to remember that each party has the fundamental responsibility to assess the economics and operational characteristics of alternatives from the perspective of its own needs and to determine conditions under which it would be willing to participate in a cooperative venture. The acceptability of these conditions to the other party is subject to the results of efforts to establish "Agreements in Principle" and subsequently to negotiation of a contract.

ECONOMIC/FINANCIAL CONSIDERATIONS

General Economic Concepts

An investor, whether it be the Navy, a utility company, or a third party, considering the financing of a cogeneration system is concerned with numerous factors and their impact on the economic projections for the system. The total annual cost of providing thermal plus electrical utility service to a facility is expressed as the summation of several basic contributing factors.

$$TC_j(y) = CC_j(y) + F_j(y) + OM_j(y) + P_j(y) - R_j(y)$$

where (y) = annual costs as a function of time (i.e., year)

j = costs occurring if alternative "j" is chosen to supply utility services

TC = total cost for thermal plus electrical services

CC = capital cost expenditure, including interest on funds during construction

F = fuel costs

OM = operation and maintenance costs

P = cost of payment for energy purchased from outside (electrical or thermal) or for service purchased from outside

R = any revenues resulting from operation and/or ownership of equipment at the facility

Cost estimates for future years necessitate estimating escalation rates for fuel, electricity, O&M, etc. Since the "crystal ball" is uncertain, escalation rates are sometimes varied parametrically, and the sensitivity of the economic projections to the variations is determined.

A cooperative, or joint, venture requires the mutual approval of the utility company or another outside party as well as the Navy in order to be implemented. Where there is the prospect for a cooperative venture, either in ownership or operation or both for a new system, it is perhaps more definitive to generalize the expression for total annual cost $TC_j(y)$ to reflect the economics of alternative approaches from the perspective of each participant.

$$TC_{nj}(y) = CC_{nj}(y) + F_{nj}(y) + OM_{nj}(y) + P_{nj}(y) - R_{nj}(y)$$

where n indicates that the cost term is from the perspective of a single participant. All other symbols are identified above.

Each participant would apply only the portion of capital costs, operation and maintenance costs, etc., incurred as its responsibility, and revenues it would realize.

Different alternatives for providing the necessary utility services would be compared by each party. One alternative may reduce fuel costs, but increase capital costs. Another may involve a larger plant which increases both fuel and capital costs, but results in revenues through sale of excess power to offset the increases. In the economic analyses of alternative options, the term "alternative" indicates not only different design options (such as steam turbines versus combustion turbines), but it also indicates different ownership/operation arrangements or even different means of financing the construction costs. For example, suppose that consideration of load patterns, fuel availability, and other items has resulted in the conclusion that a 20 MWe coal-fired extraction/ condensing steam turbine system is the best design to meet the utility needs of a given facility. Discussions with the local utility company, however, reveal that it would be open to cooperating in any of three ways: (1) owning and operating the entire cogeneration plant and selling both steam and electrical power to meet the facility needs; (2) owning and operating only the electrical generation portion of the cogeneration plant, with provisions for extracting steam needed for the facility, and continuing to provide electrical service; or (3) not owning or operating any part of the cogeneration plant, but selling power to the facility as needed or buying excess power from the cogeneration plant. Therefore, these are three distinct alternatives to be evaluated economically, based upon details to be negotiated and worked out with the utility company.

The cost components making up $TC_{nj}(y)$ provide the information needed by the Navy and potential outside investors to decide upon the economic viability of an option. Principally, each party is concerned with its own Return on Investment (ROI), with the magnitude and means of handling its portion of the capital expenditure, and with the total life cycle savings it will realize from each alternative.

Continuation of conventional service is usually the baseline against which cogeneration alternatives are compared. A typical scenario for continuing conventional service is that new boilers would be acquired by the Navy in some future year, steam would be supplied from on-base boilers, all electrical energy would be purchased from the utility company, and no electrical power would be generated on-base. Therefore, $CC_{n,conv}(y) = 0$ except for the year new boilers are purchased; then, $CC_{n,conv}(y)$ = cost of boilers. $F_{n,conv}(y)$ = annual boiler fuel cost; $OM_{n,conv}(y)$ = annual boiler operation and maintenance costs; $P_{n,conv}(y)$ = cost of electrical energy purchased from the utility; and $R_{n,conv}(y) = 0$. The annual savings for the Navy from operation of an alternative to the conventional system (i.e., exclusive of the handling of the capital outlay) is

$$S_{nj}(y) = \left[TC_{n,conv}(y) - TC_{nj}(y)\right] - \left[CC_{n,conv}(y) - CC_{nj}(y)\right]$$

A similar expression for savings could be written for each party in a cooperative venture.

Return on Investment is a common measure of judging economic viability of candidate investments. A minimum ROI must be exceeded to gain approval for an investment. A minimum acceptable ROI is set by the investor himself, and depends on the type of investment being made. The acceptable ROI is a function of the economic life for the investment, which is also established by the investor. Substituting the minimum ROI into the expression below, the total savings to be realized must exceed the net capital expenditures. Otherwise the project is not viable.

$$\sum_{y=0}^{y=EL+N} \frac{\left[CC_{nj}(y) - CC_{n,conv}(y)\right]}{(1 + ROI_{nj})^{y}} \leq \sum_{y=N+1}^{y=EL+N} \frac{S_{nj}(y)}{(1 + ROI_{nj})^{y}}$$

where $CC_{nj}(y)$ = annual construction payments made for designated project by participant "n"

N = number of years from beginning of construction financing to startup of alternative system

EL = economic life of alternative system

S_{nj} = annual savings resulting from operation of the system by party "n"

It is quite often the case that $CC_{n,conv} = 0$ for all years through the economic life of the alternative system (i.e., if the conventional system was retained, no capital expenditure would be required). Removing the inequality and assuming $CC_{n,conv} = 0$, the commonly used expression for ROI is obtained

$$\sum_{y=0}^{N} \frac{CC_{nj}(y)}{(1 + ROI_{nj})^{y}} = \sum_{y=N+1}^{y=EL+N} \frac{S_{nj}(y)}{(1 + ROI_{nj})^{y}}$$

It is deduced from the definitions that ROI is analogous to the discount rate which the Navy prescribes to convert future savings or expenditures into present values. As used by the Navy, the discount rate is considered to be the rate of return over and above the inflation rate. Consequently, escalation rates of fuel costs, O&M costs, etc., are designated as price increases over and above those required to keep up with inflation. Utility companies or other firms often choose instead to include inflation in their return on investment, and appropriately account for inflation in the other terms also.

The discounted Savings-to-Investment Ratio (SIR), frequently used by the Navy to assess the viability of a project, is obtained by setting ROI = 0.10 and calculating the ratio of the right-hand side (savings) of the above equation to the left-hand side (investment). In general,

$$SIR = \frac{\displaystyle\sum_{y=N+1}^{y=EL+N} \frac{S_{nj}(y)}{(1 + ROI_{nj})^{y}}}{\displaystyle\sum_{y=0}^{y=EL+N} \frac{\left[CC_{nj}(y) - CC_{n,conv}(y)\right]}{(1 + ROI_{nj})^{y}}} \geq 1$$

Strictly speaking, return on investment applies only to projects which involve capital investment. Some alternatives may be based upon measures not involving capital expenditure. It is beneficial to account for the declining value of money by discounting the future expenditures in such cases also. The Navy chooses to discount at 10% over inflation in all cases, but some business might elect to use a different discount rate where capital expenditure is not involved. Drawing an analogy from the inequality defining ROI, and substituting for $S_{nj}(y)$, it is concluded that an alternative is viable when its discounted total life cycle cost is less than that of the conventional approach.

$$\sum_{y=0}^{y=EL+N} \frac{TC_{nj}(y)}{(1 + d_{nj})^y} \leq \sum_{y=0}^{y=EL+N} \frac{TC_{n,conv}(y)}{(1 + d_{nj})^y}$$

where d_{nj} = discount factor used by participant "n" for the particular type of expenditure involved

The Navy, or course, is able to perform economic assessments of cogeneration alternatives at a selected site from its own perspective most adequately. There is less likelihood, however, of the Navy being able to adequately perform an economic assessment from the perspective of a potential co-participant in a joint venture because some essential input might be unavailable.

Cost Estimates for Construction and O&M

Determination of ROI_j requires knowledge of construction costs, length of construction period, and the factors (F_j, OM_j, P_j, and R_j) contributing to the savings S_j. Data from References 1 and 2 are provided below which should be helpful in making rough planning estimates of construction costs, construction schedules, and O&M costs for various types of cogeneration plants. The information presented below is typical of mid-1978 costs, so projections of construction and O&M costs for future years should be made on the basis of an appropriate Construction Cost Escalation Factor and Labor Rate Escalation Factor.

Figures 5 through 8 provide cost estimating data for coal-fired steam turbine systems. A coal-fired plant is composed of the steam-generating section; the turbine/generator section, which may be either a backpressure unit or an extraction-condensing unit; the coal- and ash-handling facilities, which may involve open coal piles or storage of the coal in concrete silos; and the air pollution control equipment, which includes a baghouse and sulfur removal provisions, if necessary. The construction cost for a complete coal-fired plant is the sum of applicable costs.

Figures 5, 6, and 8 also provide cost estimating data for oil- and natural gas-fired steam turbine systems. Figure 5 shows the steam-generating station of an oil-fired plant to be less expensive than that of a coal-fired plant of equal capacity. On the other hand, the cost of the turbine section is independent of the type of fuel used. An oil-fired facility may need a sulfur stack removal unit if high sulfur oil is burned.

Figure 9 shows representative construction costs for combustion turbine and diesel cogeneration plants. These are made up of the engine/generator sets plus exhaust heat boilers, and include water treatment system, switchgear, foundations, and control panel costs. Costs for these systems are primarily just a function of engine rating.

Figure 10 indicates representative construction schedules for various types of cogenerating plants.

Estimating procedures for operating and maintenance costs are summarized in Table 1, which refers to Figures 11 through 15 for determining portions of the costs attributed to several components of steam turbine systems.

Fuel Costs and Fuel Flexibility

Over the operating life of a cogeneration system, fuel is often the largest contributor to the ownership and operation of the system. For systems burning oil or natural gas, fuel will typically constitute 65-90% of the total life cycle cost for the system, and will be a significant portion of the annual total utility cost, TC_j. For economic reasons, therefore, it is advisable to consider cogeneration plant designs that burn less expensive fuels and have the flexibility to handle various fuels where it appears two or more fuels may be competitive. The high cost of petroleum fuels and the likelihood of further rapid price escalations are making oil-fired systems difficult to economically justify in many installations. Natural gas may maintain some cost advantages over oil, but it also is a premium fuel, likely to become in short supply and undergo rapid price increases. Coal-fired systems require a larger capital expenditure to install, but the anticipated lower fuel costs will often more than offset the greater initial outlay. Flexibility to burn other fuels can usually be incorporated into the design of a coal-fired plant at relatively low cost. For example, solid waste might be substituted for a portion of the coal if the furnace volume is slightly increased and additional storage capacity is provided. Or oil- or natural gas-firing capability can be added to a coal-firing facility at minimum cost.

Since fuel cost is such an important contributor to the economic feasibility of cogeneration systems, it is beneficial to quickly determine the contribution which fuel makes to the cost of electrical power from a cogeneration system. Figure 16 shows how fuel cost impacts the cost of power generated on-site. In a cogeneration system, additional fuel is required over the amount needed to produce only the steam. The effective heat rate for power production from the cogeneration system is

$$HR_{EFF} = \frac{\dot{F}_{COGEN} - \dot{F}_{SO}}{\dot{E}}$$

where HR_{EFF} = effective heat rate, Btu/kW-hr

$\dot{F}_{COGEN}$ = fuel flow rate to the cogeneration system, Btu/hr

$\dot{F}_{SO}$ = fuel flow rate that would be used by boiler producing only steam, Btu/hr

$\dot{E}$ = power production from the cogeneration system, kW

Table 1. 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 11[a]
Hauling, Receiving Facility - Generating Plant (if not co-located)	Figure 12[a]
Steam Generating Facility	Figure 13[a]
Air Pollution Control System	Figure 14[a]
Electrical Generating Facility	(2.5% x capital)/yr[b], where Figure 7 shows capital investment
Hauling of Waste to Temporary Storage (if required)	Figure 15[a] plus Figure 12
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 7 shows capital investment
Air Pollution Control System (only if designed to use high sulfur fuel)	Figure 14[a]
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]

continued

Table 1. Continued

Potential Contributor to O&M Costs	Estimating Procedure or Figure
D. Diesel/Generator Sets With Exhaust Heat Boiler	
Diesel/Generator Set	13 mils/kW-hr[g]
Exhaust Heat Boiler	$1.00/$10^3$ lb of steam[f]

NOTE: For conventional steam generating facilities, use the appropriate parts of lists A and B above.

[a]Reference 2.

[b]Reference 1.

[c]Based on data from Long Beach Naval Shipyard and Sewell's Point Naval Complex compiled by CEL.

[d]Based on correspondence with Garrett Airesearch and Pacific Gas and Electric personnel. Includes costs for major overhauls.

[e]Based on data from San Diego Gas and Electric.

[f]CEL estimate.

[g]Based on Reference 3.

The fuel cost contribution to generated power is

$$FPC = (HR_{EFF})(CF)(1/10^3)$$

where FPC = fuel contribution to power costs, mils/kW-hr

CF = cost of fuel, \$/million Btu

For power from the cogeneration system to be economically attractive to the Navy, the fuel cost contribution must be sufficiently less than the cost of purchased power to allow for capital recovery and O&M. For the power to be economically attractive to a utility company, the fuel cost contribution must compare favorably with costs they experience or anticipate in their system.

PERFORMANCE CURVES AND CHARACTERISTICS OF COGENERATION PLANTS

Table 2 compares characteristics of diesel, combustion turbine, and steam turbine types of cogeneration systems for which components and equipment are readily available commercially. Because the combined cycle system is basically a combination of a combustion turbine and a steam turbine, its characteristics can be inferred from the information presented. The table indicates that steam turbine systems have a distinct advantage in fuel flexibility and potential for multifuel capability. The choice of fuels has a most significant impact on the economics of cogeneration and the compliance of the system with environmental and energy regulations. Diesel and combustion turbine systems are typically limited to the use of premium fuels, petroleum or natural gas. There are exceptions; for example, some engines (not necessarily operating in the cogeneration mode) have been set up to burn waste gases or synthetic fuels, such as sewer gas, where a nearby cost-effective source exists. A limited number of installations have burned residual petroleum, but special facilities to "wash" the fuel, heat it, and inject additives were usually required. But typically, the diesel and combustion turbines require premium fuels. Table 2 provides guidance, in the form of "Typical Applications," for the use of the various types of systems.

Figure 17, based upon data in Reference 4, generalizes the performance of diesel cycle engines and presents the data in normalized form. The figure shows that just under one-third of the fuel energy is converted into shaft energy to drive the electrical generator (the shaft energy curve is the engine efficiency, η); roughly one-third converts to heat, which is carried out in the exhaust gas; approximately 30% converts to heat, which is transferred to the jacket water and lubricating oil plus to airflow in the turbocharger (if the engine has a turbocharger); and about 5-10% is irretrievably lost from the engine structure. Practically all of the heat in the oil cooler, turbocharger aftercooler, and jacket water can be recovered as hot water or even low pressure (≦ 15 psig) steam. A temperature limit is set by the requirement to keep jacket water below 250°F on most engines. Figure 17 also shows the portion of the fuel energy recoverable from the exhaust gas stream at different temperatures. The normalized curves can be dimensionalized by assuming a full-load generator output, $\dot{E}_{100}$(kW). At any fraction of the full load output, the fuel energy input is

$$\dot{F}\left(\frac{\text{Btu}}{\text{hr}}\right) = \frac{\dot{E}}{\dot{E}_{100}}\left(\frac{\dot{E}_{100}}{\eta}\right)\left(\frac{3{,}413\ \text{Btu}}{\text{kW-hr}}\right)$$

Other quantities ratio according to the data from Figure 17.

Figure 18, also based upon data in Reference 4, is a similarly normalized performance curve for combustion turbines. Combustion turbines have no cooling jacket, and heat recovery potential from the lubricants is insignificant. Therefore, heat is only recoverable from the exhaust. It is seen that a significant portion of the fuel energy can be recovered to generate steam at 100 psig or higher, which is suitable for distribution over relatively long distances. The curves of Figure 18 are representative of many single-shaft, simple-cycle combustion turbines. Better part-load efficiencies are obtained with dual-shaft engines. Efficiency improvements may also be anticipated from future designs incorporating higher turbine inlet temperatures and recuperative heat exchangers.

Steam turbines do not lend themselves to a "universal" normalized curve of engine performance as the diesels and combustion turbines do. There are too many variables possible with steam turbine systems. Instead, a performance "map" of throttle steam flow rate versus electrical output, with extraction steam flow rate as a parameter, is illustrated in Figure 19. The specific generator design output throttle pressure, extraction pressure, and condenser pressure for which the curve is applicable are shown in Figure 19. The map is bounded by five essentially straight lines explained in the figure. It is noted that the "map" does not extend down to $\dot{E} = 0$. The curves become nonlinear at the low end of the scale, so it is better to design the equipment for operation at half-load or better in order to accurately map the performance. More detailed descriptions may be found in References 2 and 5.

An expression that relatively accurately relates the throttle flow rate to the electrical generation and the extraction flow rate is

$$M_{THR} = \left[\frac{\dot{E} - \frac{\dot{E}_B}{2}}{\frac{\dot{E}_B}{2}}\right](\dot{M}_{THR,B} - \dot{M}_{THR,\frac{1}{2}B}) + \dot{M}_{THR,\frac{1}{2}B}$$

$$+ \dot{M}_{EXT}\left[1 - \frac{C(H_{THR} - H'_{EXT})}{(H_{THR} - H'_{EXH})}\right]$$

where $\dot{M}_{THR}$ = throttle flow rate, lb/hr

$\dot{M}_{THR,B}$ = throttle flow rate at point B

$\dot{M}_{THR,\frac{1}{2}B}$ = throttle flow rate at $\dot{E} = \frac{1}{2}\dot{E}_B$

$\dot{E}$ = electrical generation, kW

$\dot{E}_B$ = electrical generation at point B

$\dot{M}_{EXT}$ = extraction flow rate, lb/hr

H_{THR} = enthalpy of steam at throttle valve, Btu/lb

H'_{EXT} = enthalpy of steam at extraction valve, isentropic

H'_{EXH} = enthalpy of steam leaving last turbine stage, isentropic

C = dimensionless empirical factor,
0.857 when exhaust pressure $\leq$ 1 atm
0.902 when exhaust pressure $\geq$ 1 atm

For the special case of a backpressure turbine with no extraction, $\dot{M}_{EXT} = 0$, and $\dot{M}_{THR}$ becomes a single-line function of $\dot{E}$.

Table 2. Characteristics of Cogeneration Systems

Item	Diesel	Combustion Turbine	Steam Turbine
Heat recovery source	(1) Exhaust gas. (2) Jacket water, plus oil cooler and turbo-charger cooler (if equipped with turbo-charger).	Exhaust gas.	Steam extraction between intermediate turbine stages (extraction turbine) or after final stage) (backpressure turbine).
State of recovered heat	(1) Through heat ex-changers, exhaust provides hot water or saturated steam, usually ≦ 350°F. (2) Jacket water can provide hot water at < 250°F or saturated steam at ≦ 15 psig. (3) Exhaust can heat organic fluid through heat exchanger.	(1) Exhaust gas may be used directly for thermal content and O_2 content. (2) Through heat exchanger, exhaust provides hot water or steam. Steam is usually saturated at pressures 10-200 psig. Possible to produce limited superheated steam up to ≈600°F. (3) Exhaust can heat organic fluid through heat exchanger.	Extracted or back-pressure steam is usually at a slightly superheated state. Boiler/turbine combinations can be selected to provide steam at desired pressures from atmos-phere to 600+ psig, although pressures ≦ 200 psig are most common.
Fuels	(1) Distillate petroleum. (2) Natural gas.	(1) Distillate petroleum. (2) Natural gas.	(1) Coal. (2) Residual petroleum. (3) Distillate petroleum. (4) Natural gas. (5) Biomass. (6) Solid waste. (7) Liquid or gaseous waste.

continued

Table 2. Continued

Item	Diesel	Combustion Turbine	Steam Turbine
Capacity of units	Almost continuous sizes up to 2 MWe. Frequent sizes to 4 MWe. Discrete sizes even larger.	Limited choices available. Units available at nominal ratings of 0.5, 0.75 2.5, 4.75, 6.8, 7.5, 10.0, 19.4, 24.7, 28.3, and larger discrete sizes.	Standard NEMA ratings are 500, 700, 1,000, 1,500, 2,000, 2,500, 3,000, 4,000, 5,000, 6,000, and 7,500 kW. AIEE-ASME Preferred Standard Large 3,600-rpm, 3-phase, 60-cycle condensing unit ratings are 11.5, 15, 20, 30, 40, and 60 MWe.
Typical applications	Where the thermal load: (1) Only requires hot water or low pressure steam; (2) Is near the system; (3) Is roughly equal to the electrical load.	Where the thermal load: (1) Requires hot water or moderate (up to 200 psig) steam; (2) May be remotely located, requiring thermal distribution; (3) Is generally 1 to 3 times the electrical load.	Where the thermal load: (1) Is the essential load which would require reliable boilers anyway; (2) Is generally large.

The fuel energy required for a steam turbine system is

$$\dot{F}(\text{Btu/hr}) = \frac{\dot{M}_{THR}(H_{THR} - H_{FW})}{\eta_{BLR}}$$

where H_{FW} = enthalpy of feedwater (mixed makeup plus condensate return) entering water treatment, Btu/lb

η_{BLR} = overall boiler efficiency, dimensionless

ENERGY/ENVIRONMENTAL LEGISLATION AND REGULATIONS

Legislation and regulations are subject to changes and revisions. It will be necessary, therefore, to verify compliance of the cogeneration system design with appropriate legislation and regulations in effect at the time and in the specific location. The energy and environmental mandates in effect or recommended as of 1979, summarized from Reference 6, provide some insight into the types of legislative/regulatory matters which are likely to apply to cogeneration, now or in the future.

The Powerplant Industrial Fuel Use Act provides that new powerplants or fuel-burning installations of a single unit having a design fuel heat input of 100 x 10^6 Btu/hr or greater, or which result in two or more units at the same site having a combined design fuel heat input rate of 250 x 10^6 Btu/hr or greater, are prohibited from burning natural gas or petroleum, unless an exemption is provided by the Secretary of Energy. However, the Secretary of Energy is specifically authorized to exempt cogeneration facilities from the prohibition if the benefits of cogeneration are otherwise unobtainable. (Guidelines for exemption have been formulated.)

As points of reference, 100 x 10^6 Btu/hr corresponds roughly to a 7,500-kWe combustion turbine or a 4,500-kWe steam turbine system. It is seen that rather small installations, which would be more likely to involve natural gas- or petroleum-fired diesels or combustion turbines, are not restricted in choice of fuels under the Fuel Use Act.

The Public Utility Regulatory Policies Act of 1978 directs the Federal Energy Regulatory Commission (FERC) of the Department of Energy to develop regulations for encouraging cogeneration and small power production facilities using biomass, waste materials, renewable resources, or any combination of these as the primary energy source. The adjective "small" means that the power production capacity, together with any other facilities located at the same site, is not to be greater than 80 MWe. The regulations developed by FERC must include provisions to ensure that utilities buy or sell power from these types of facilities at equitable prices. Fossil fuels (coal, petroleum, and natural gas) are not considered renewable resources. As of March 1980, however, FERC has ruled that if cogeneration facilities under 30 MWe want to sell excess electricity to a utility, the utility must buy it at rates comparable to the utility's power-producing rates and provide warning to the cogenerator if the cogenerator would lose money at that rate. Utilities will be required to provide backup power and transmission equipment.

The Clean Air Act of 1977 requires that each state submit documentation to EPA of the attainment status of its air quality control regions for each of six pollutants for which national ambient air quality standards have been set. Areas with air quality better than the standards would be designated as an area of Prevention of Significant Deterioration (PSD), while an area where the air quality does not meet the standards would be termed a nonattainment area (NA). EPA has proposed new-source performance standards for new or modified steam-electric units capable of combusting more than 250 x 10^6 Btu/hr of fossil fuel. Performance standards for new sources would apply to modified or reconstructed facilities also, where the cost is 50% or more of the cost of replacing the existing powerplant. Another provision is that addition of pollutants to the atmosphere from new sources in NA regions must be more than offset by the further removal of pollutants from nearby existing sources by means of shutdowns, process changes, or additional pollution abatement equipment. All existing facilities owned by the company commissioning the new plant must be in compliance with applicable emission limits and standards.

Under the Resource Conservation and Recovery Act, EPA is empowered to identify and regulate hazardous wastes. Currently, powerplant wastes (flyash, bottom ash, scrubber sludge) are called "special wastes" and "problem wastes," and as such can be disposed of in sanitary landfills rather than in hazardous waste facilities. The characteristics of solid wastes from power plants are still being examined, however.

Discharges of heavy metals and toxic pollutants are controlled under the Clean Water Act. A powerplant must have a national pollutant discharge elimination system (NPDES) permit to discharge treated wastewater directly into a navigable waterway, and discharges to municipal sewers usually have to be in compliance with some wastewater quality guidelines established by the local sewage treatment agency. Potential impact of the Clean Water Act may be future regulations for: (a) a tank or cover over coal piles to prevent rainwater from picking up pollutants from the coal and flowing into streams, lakes, or sewers; (b) containment dikes to prevent coal-pile runoff; (c) ash pond linings to prevent seepage of pollutants into the ground water; and (d) prescribed or controlled cooling tower biocide-treatment practices to reduce toxic substances.

EPA has proposed emission standards for stationary engine/generator sets, including rather small units used in cogenerating facilities. Separate standards are proposed for combustion turbines and diesels. NO_x reduction is a primary goal of the standards. For combustion turbines, water injection during the combustion process appears to be the means of achieving the standards. It is basically the responsibility of new engine manufacturers to design their products to comply with new standards. Some future modifications of existing noncompliant engines may be required if they are used in a cogeneration system.

In addition to the federal legislation described above, each state maintains its jurisdiction over utility services through a Public Utilities Commission (PUC), or comparable body. A PUC may establish regulations or issue rulings affecting potential cogeneration applications. States may also have special tax incentives or other legislation favorable to cogeneration, of which the PUC would be aware. Since specifics differ from one state to another, the cognizant PUC would have to be contacted for relevant information regarding state legislation and products of its own authority regarding cogeneration in general, or for comments on a specific application of cogeneration.

INSTITUTIONAL CONSTRAINTS

Human preferences and opinions can have a strong influence on the consideration being given to cogeneration system alternatives. Those factors that are not solidly supported on technical or economic grounds, or mandated by legislation or regulations, are termed "institutional" factors. Some examples which often have to be dealt with in order to implement cogeneration are listed below.

- Corporate resistance due to concern that plant will become regulated by PUC
- Restrictive utility company policies on standby charges or ownership/operation options in order to obtain connection to the grid
- Corporate policy "not to get into the utility business"
- Unavailability of skilled personnel to operate new facility
- Reluctance by operating and maintenance personnel to assume new duties and responsibilities
- Concern over job losses if system is operated by utility company
- Community resistance to placement of the generating facility

Institutional factors are often very difficult to deal with. They are not generally quantifiable. Their root cause is often difficult or impossible to determine. They may even be contradictory. The best approach appears to be to express the nature of the institutional barriers in the clearest possible terms when they are encountered. Clear definition of a barrier is necessary for open examination, which is a big step toward solution.

IMPLEMENTING COGENERATION

The preceding discussions have pointed out that implementation of cogeneration can be a complex process involving technical, economic/financial, legislative/regulatory, and institutional factors. Guidance relevant to these factors has been outlined, and the need for a great deal of information has been discussed. This final section will describe a likely sequence of tasks leading from the seeds of thought regarding cogeneration to its implementation. Also in this final section, likely sources for much of the required information will be listed.

First, look at typical tasks involved in proceeding from concept to hardware. For a particular site, of course, circumstances may preclude some of the steps from occurring, or change the order, or even extend the process. However, these are basically the steps to be expected.

1. Question whether the existing thermal and electrical utility service is best for the facility, and whether cogeneration holds potential for achieving energy or cost savings. If changes such as an expansion or conversion to a different fuel are planned anyway, the consideration of incorporating cogeneration is often in order.

2. Conduct an energy audit or survey. Gather and analyze information on existing and anticipated loads, costs, and alternatives for conservation.

3. Formulate concepts of utility system alternatives. At this point, an approach somewhat like brainstorming is beneficial. Be open to various cogeneration options, including different types of equipment, capacities, and ownership/operation arrangements.

4. Determine constraints applicable to the various options and eliminate infeasible concepts from consideration. This is really a critical step. It is easy to eliminate a feasible approach by perceiving something as a constraint that really is not. For example, it is easy to rationalize that no utility company would be interested in participating in the cogeneration project under consideration. By exploratory discussions, however, it may be learned otherwise. Make sure that constraints used to eliminate various approaches are well founded, and be open to reconsidering the constraints and their impact later if conditions change.

5. Perform elementary performance estimates, environmental assessments, and cost estimates on promising alternatives, resulting in a preliminary ranking.

6. Discuss acceptance of alternatives with management, utility companies, permitting agencies, fuel suppliers, and other potentially involved parties. From discussions, define items requiring negotiation and further clarification.

7. Reassess the alternatives and rankings, as necessary.

8. For the preferred alternatives, identify any contractual arrangements that are critical to the success of the alternative. Conduct discussions with involved parties, arriving at "Agreements in Principle" on the critical items.

9. Select alternative for design. Proceed with design to an intermediate design review point. Formulate Environmental Impact Statement (EIS), if necessary.

10. Review intermediate design. Submit EIS and permit requests.

11. Complete contract negotiations with involved parties.

12. Complete plant design.

13. Proceed into construction of plant.

Potential involved parties and sources of information for various aspects of cogeneration are indicated in Table 3. In many cases there is more than one source for particular pieces of information or data.

Quite often the talents and insight of consultants/designers who are experienced or specialize in the cogeneration field are necessary in order to effectively address factors arising in deciding upon, designing, and successfully deploying a system. Assistance in recognizing and dealing with the tradeoffs between technical performance, economics, and obstacles to implementation can be most beneficial. The interest in cogeneration by numerous industrial firms, commercial concerns, and institutions as a means of achieving energy and cost savings, the encouragement offered by federal agencies and some states, and the growing acceptance by utility companies are all helpful in removing the obstacles to cogeneration.

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5. J. Kenneth Salisbury, editor. Kent's mechanical engineer's handbook, power volume, section 8, 12th ed. New York, N.Y., Wiley Handbook Series.

6. 1979 Generation Planbook, by the editors of POWER Magazine. New York, N.Y., McGraw-Hill, pp 165-183.

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Table 3. Sources of Information for Decision on Cogeneration

Required Information	Source of Information: Energy Audit	Utility Company	Fuel Suppliers[a]	Equipment Suppliers	Management	Public Utility Commission	Air Quality District	Sanitation and Water Quality Districts	Special Authorities[b]	Financial Institutions
Total Thermal Loads, Magnitude and Profile	X									
Total Electrical Loads, Magnitude and Profile	X									
Cooling Loads	X									
Major Load Centers and Energy Consumers	X									
Anticipated Load Changes; Mission or Function Changes	X									
Waste Heat Sources	X									
Waste Fuel Sources	X									
Complementary Off-Site Loads	X									
Present Electrical Energy Costs and Rate Formats	X	X								
Projected Electrical Energy Rate Structure		X								
Policies Toward Parallel Generation		X								
Ownership/Operation Policies and Preferences		X			X					
Cogenerator Rate Structure: Standby Charges, Reliability Requirements, Payment for Power to Grid		X								
Environmental and Siting Constraint Overview		X								
Tax and Investment Incentives		X				X				
Regulations Relative to Cogeneration		X				X				
Present Fuel Costs	X		X							
Projected Fuel Costs		X	X							
Projected Fuel Availability		X	X							
Fuel Characteristics and Properties			X							
Performance Data: Design and Off Design Conditions				X						
Fuel Consumption				X						
Fuel Flexibility				X						
Emissions Data and Specifications				X						
Air Emissions Regulations				X			X			
Other Emissions Regulations				X				X		
Fiscal Policies					X					
Funding Sources					X					X
Cost and Conditions of Financing										X
Siting Restrictions						X	X	X	X	

[a]Oil, natural gas, or coal.

[b]For example, zoning, airport, coastal.

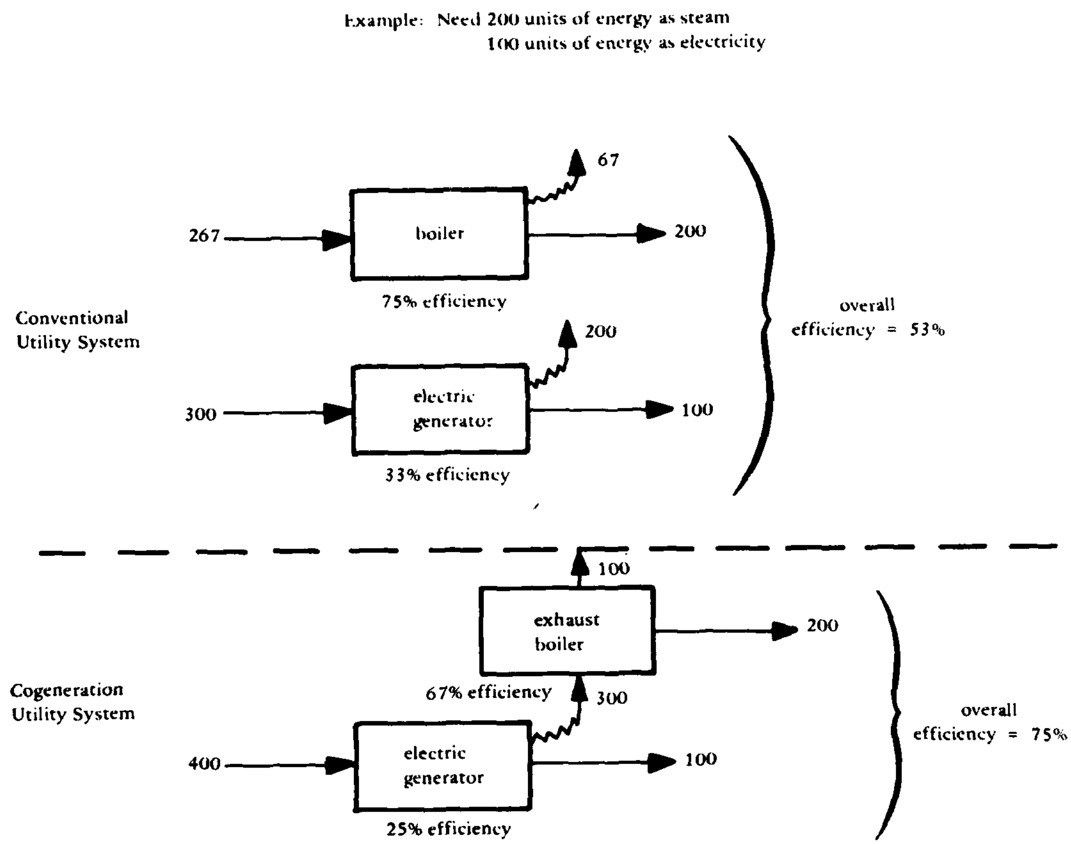


Figure 1. Energy balance comparison.

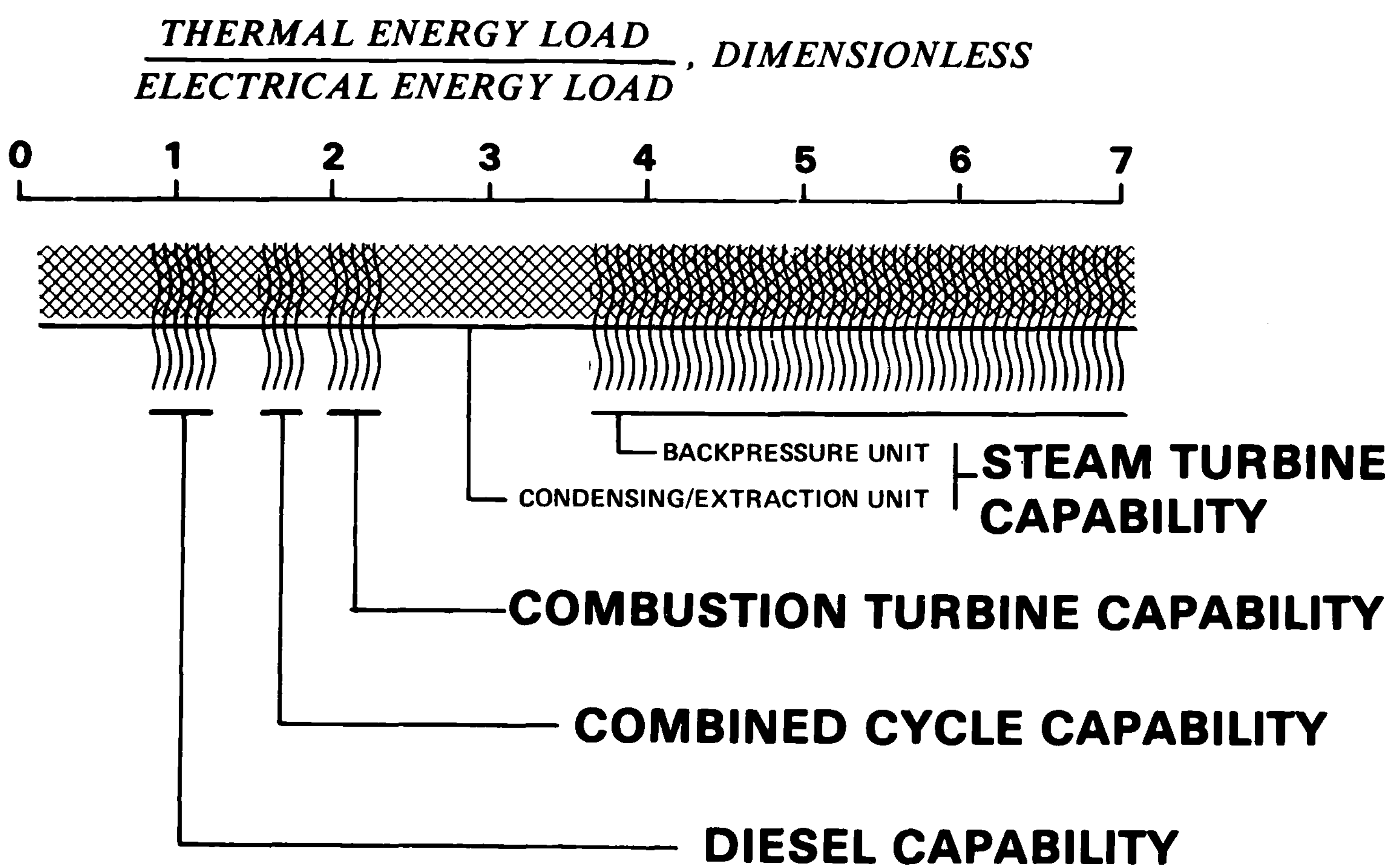


Figure 2. Thermal/electrical capabilities of cogeneration systems.

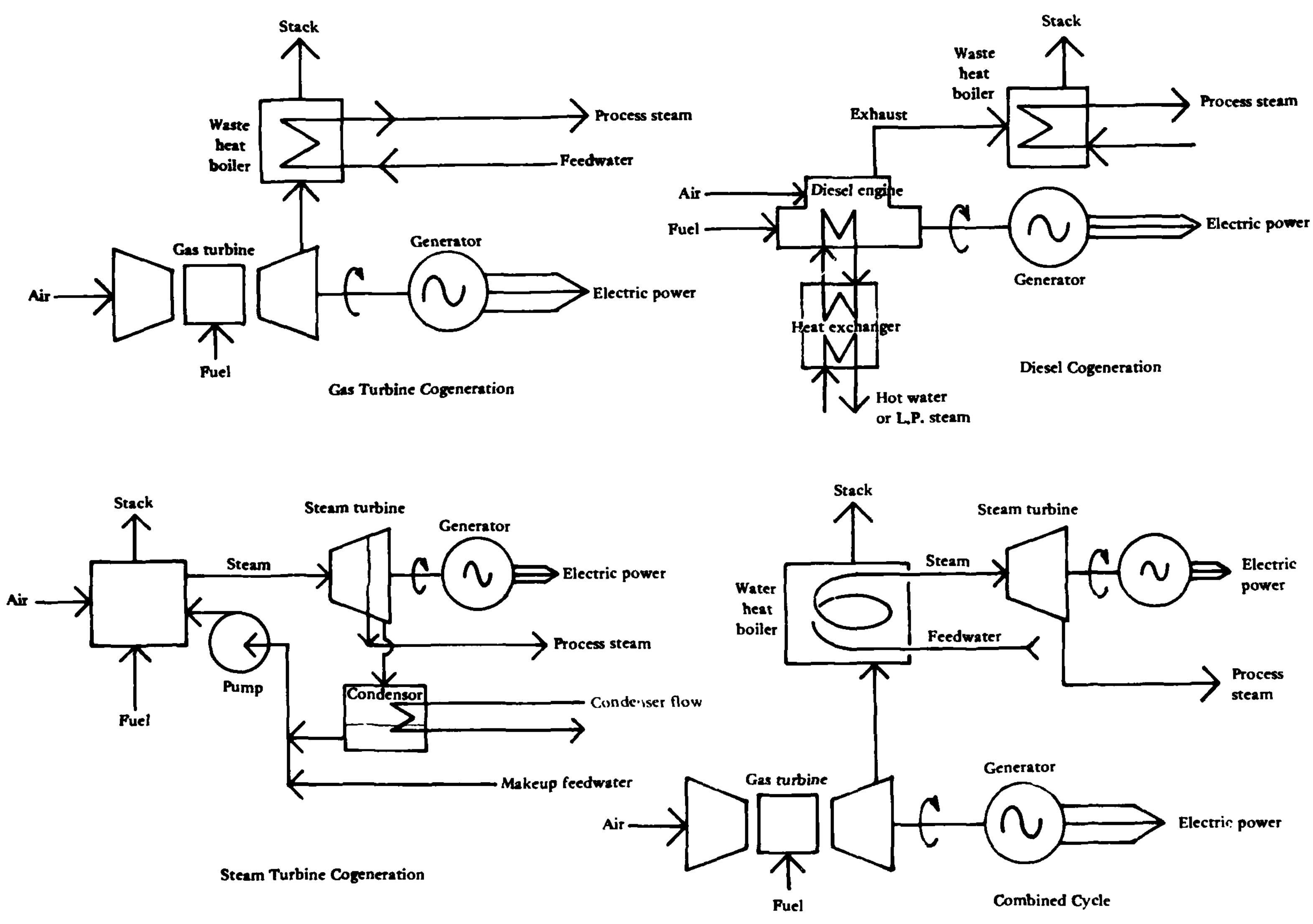


Figure 3. Examples of cogeneration concept.

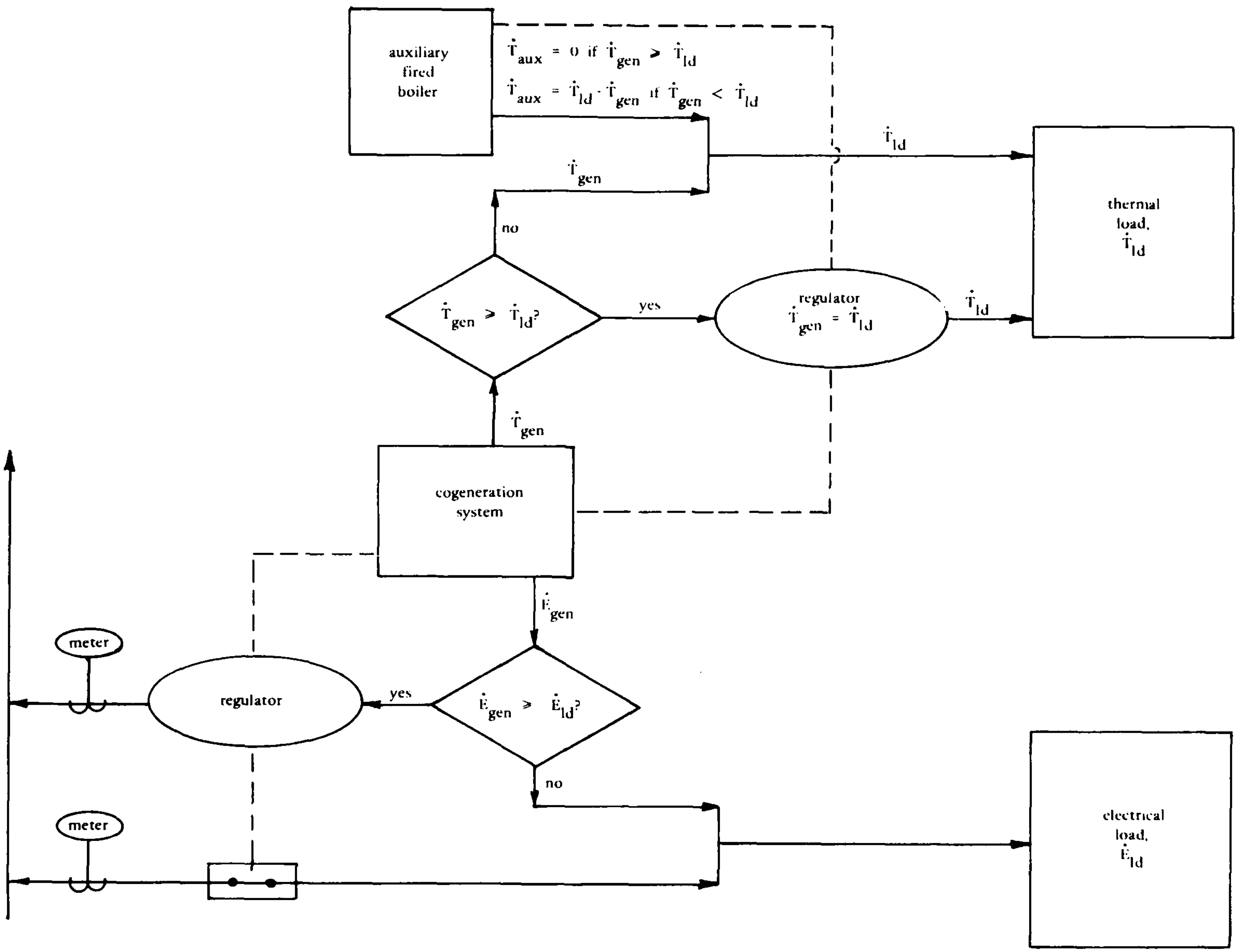


Figure 4. Integrated utility company service and cogeneration plant.

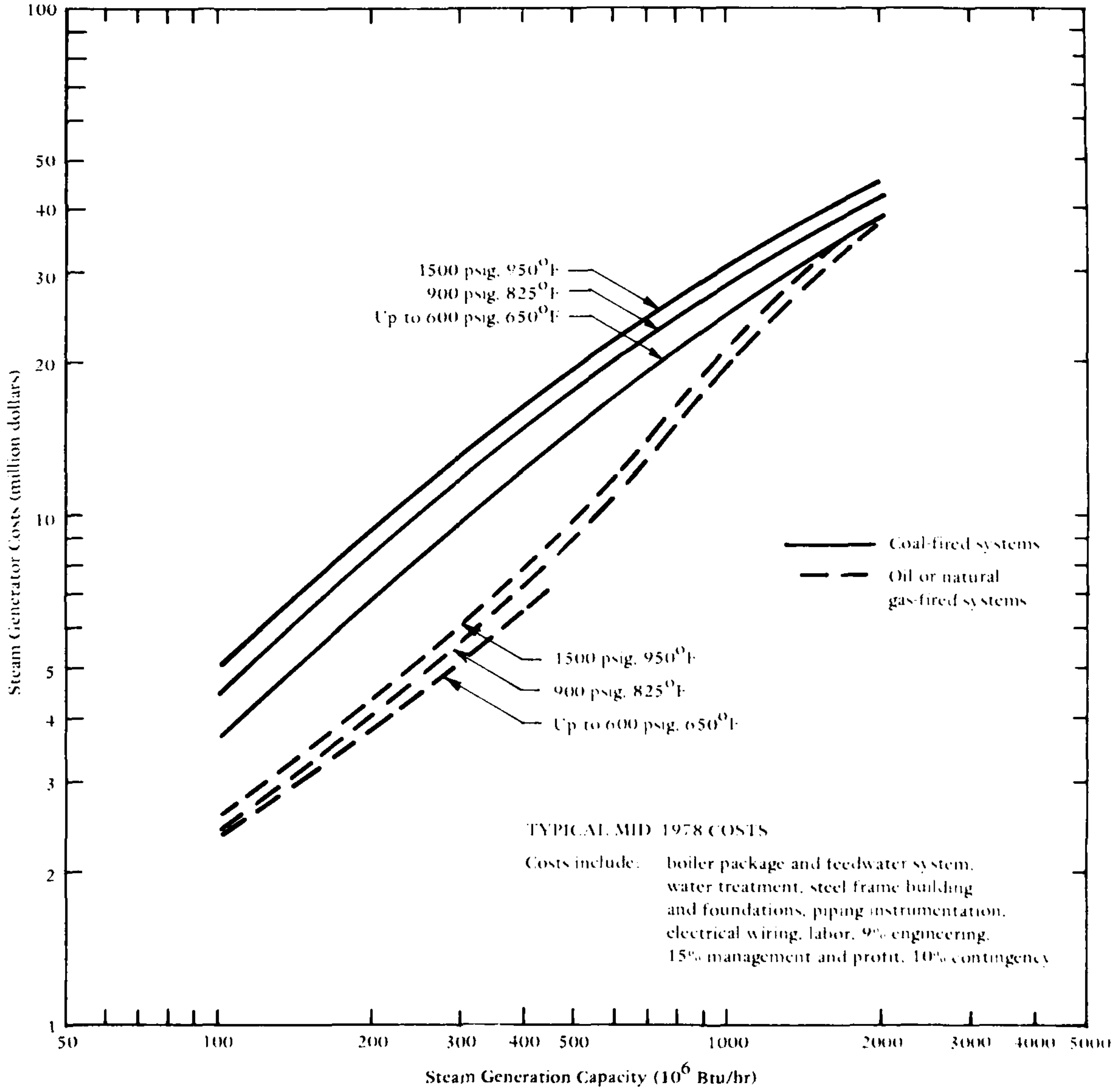


Figure 5. Steam generator costs.

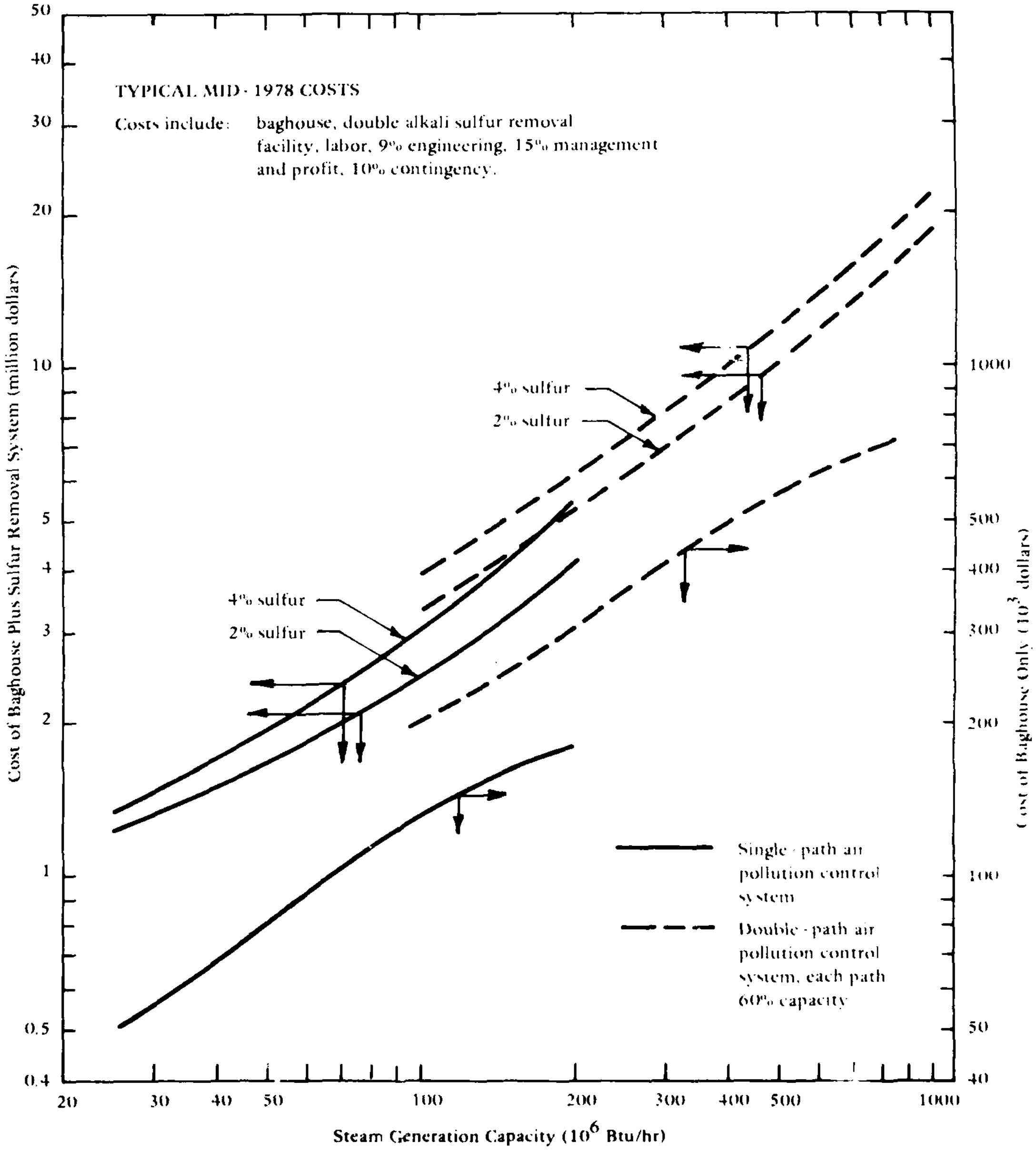


Figure 6. Air emission control system costs.

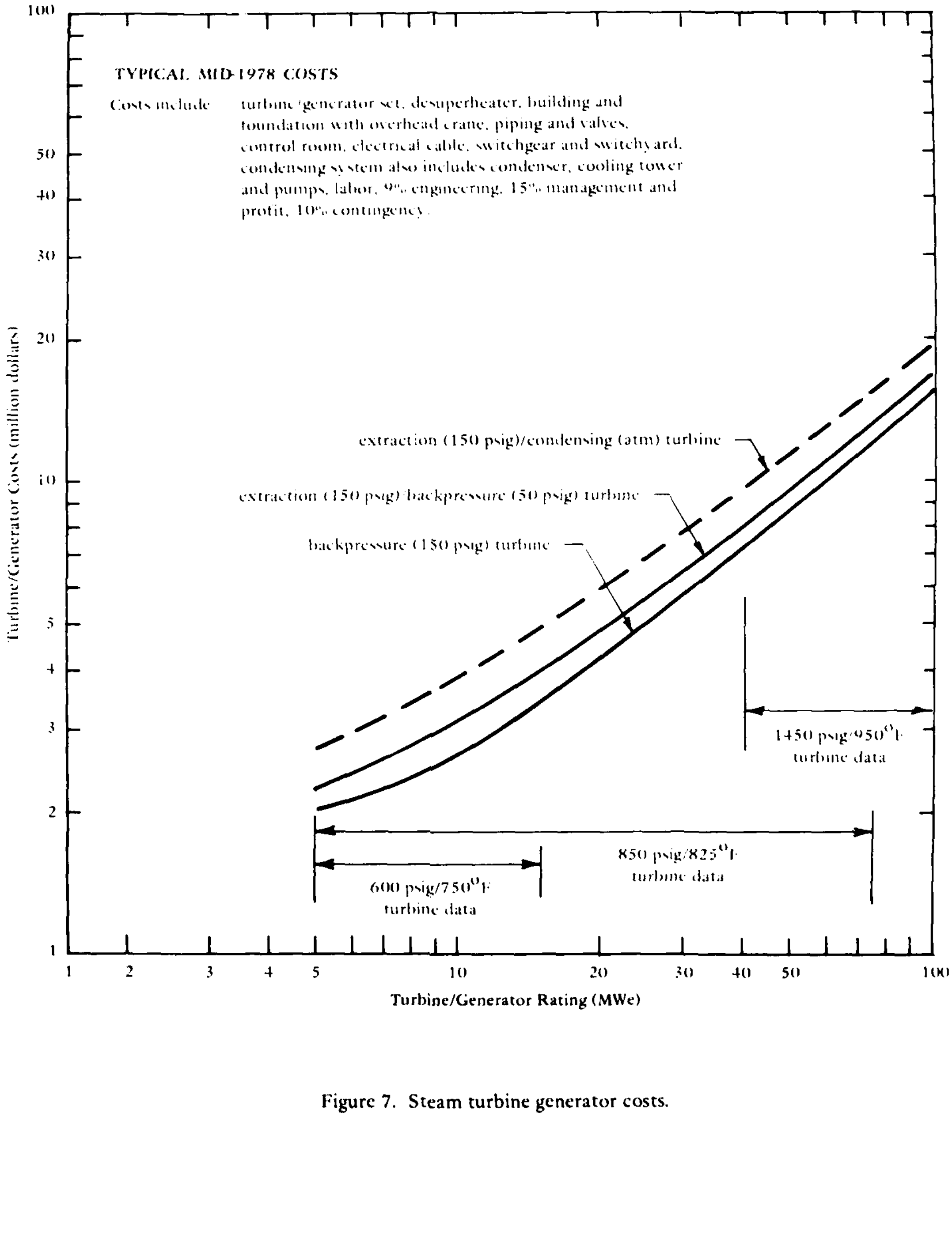


Figure 7. Steam turbine generator costs.

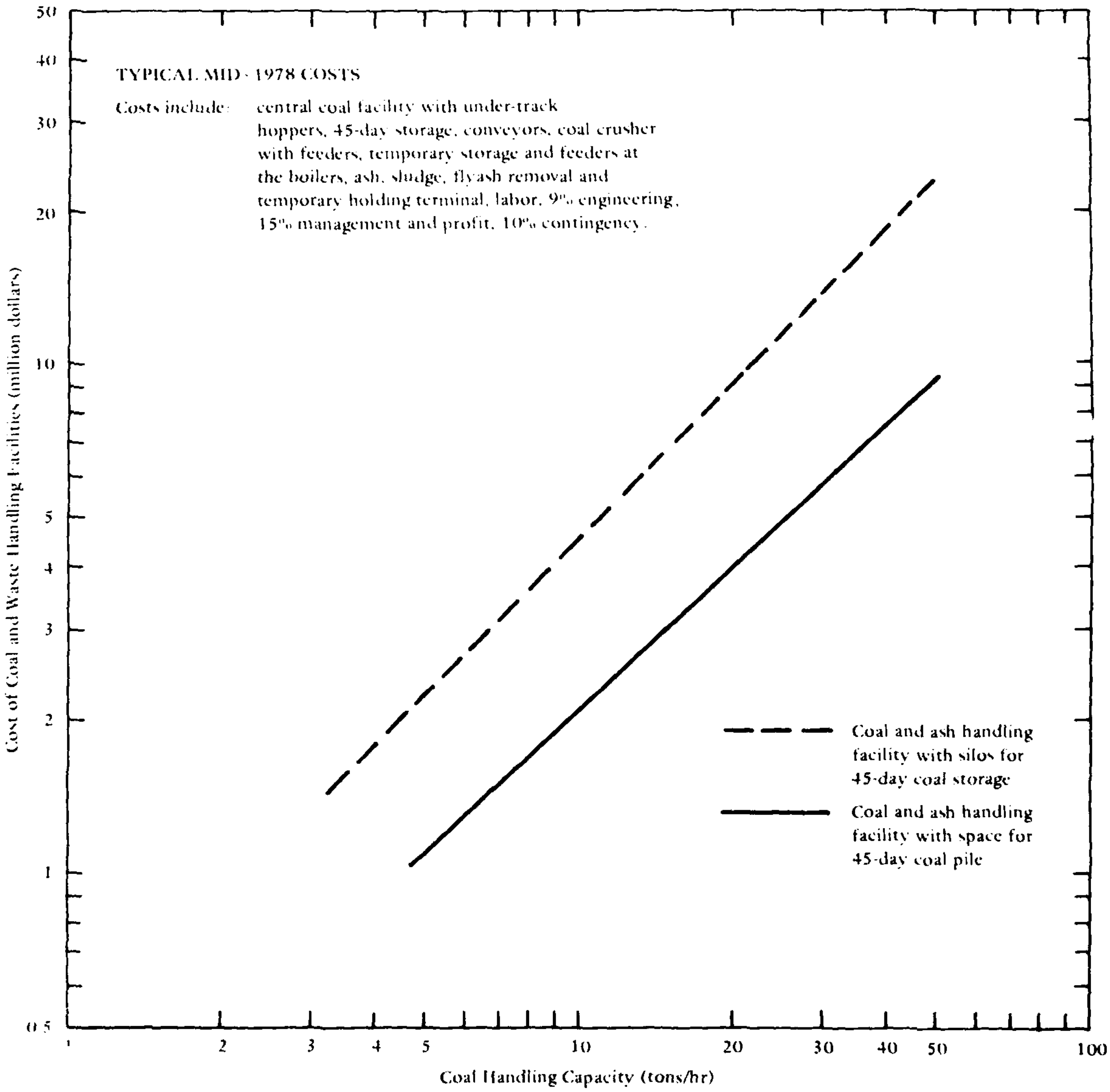


Figure 8. Coal- and waste-handling facility costs.

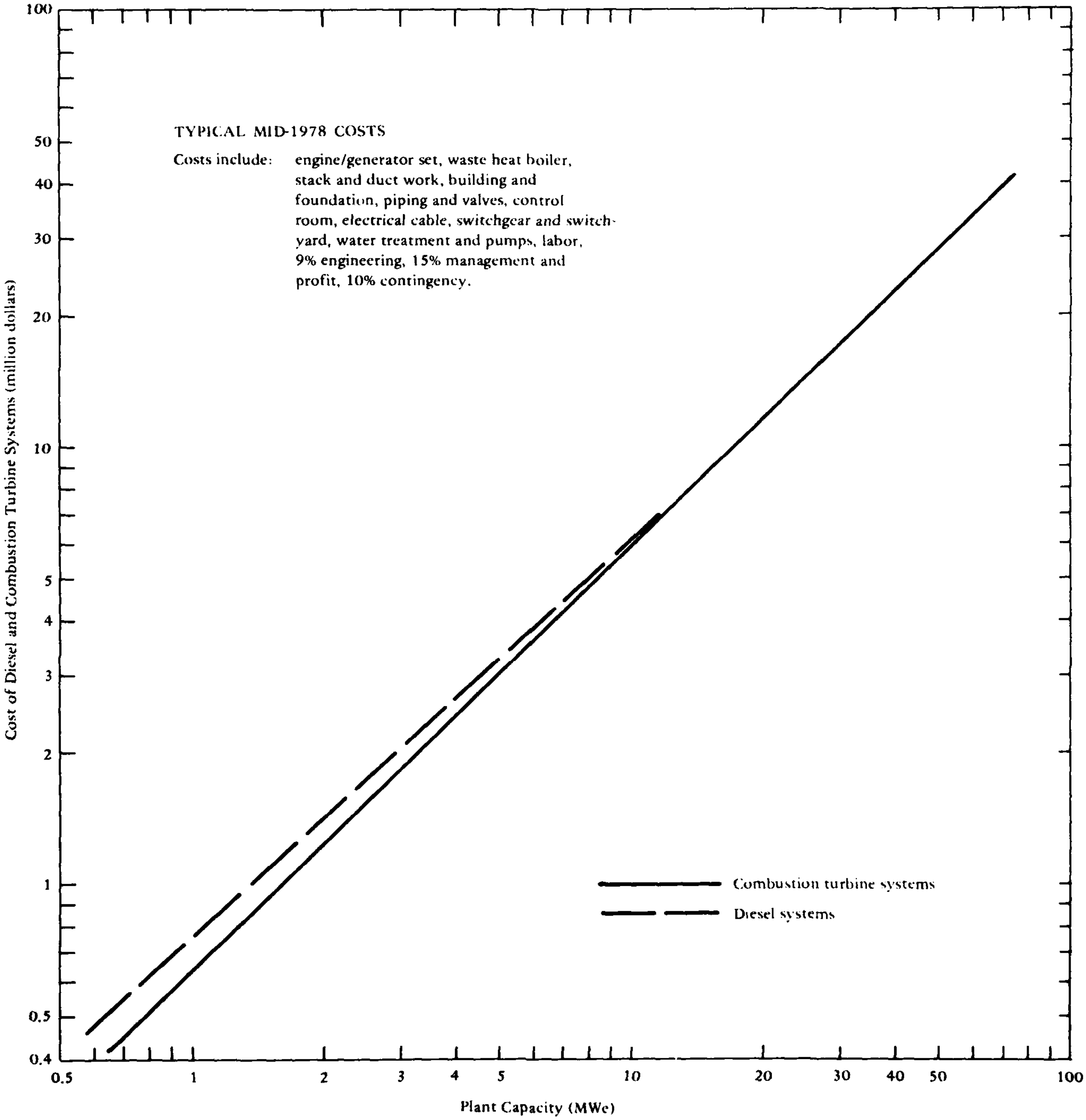
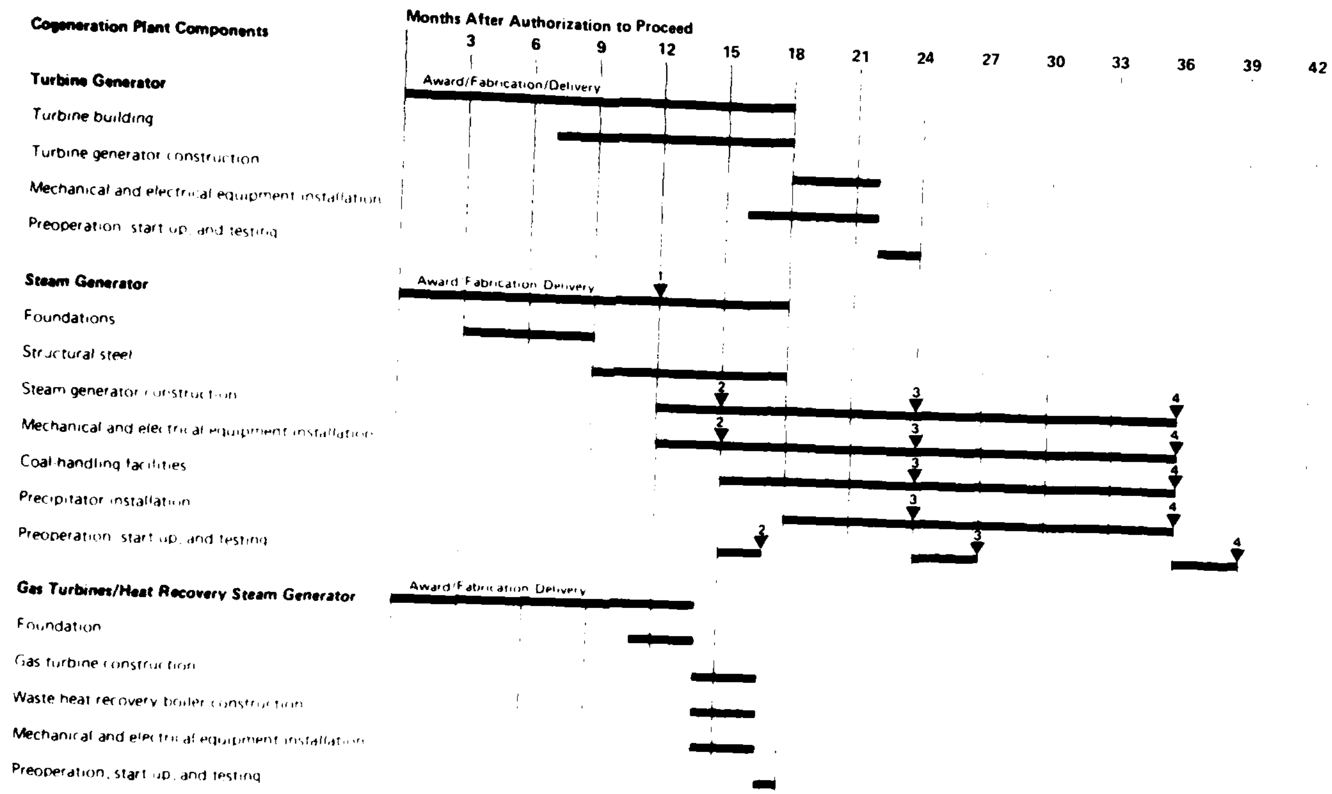


Figure 9. Diesel and combustion turbine system costs.



1 Twelve month delivery schedule for steam generators rated at 1 million pounds per hour and under
2 Work phase completed for steam generators rated at 400 000 pounds per hour and under oil fired only
3 Work phase completed for steam generators rated at 1 million pounds per hour and under coal fired only. Work phase completed for oil fired steam generators rated greater than 400 000 pounds per hour but under 1 million pounds per hour
4 Work phase completed for all steam generators rated over 1 million pounds per hour

Figure 10. Estimated implementation schedules for cogeneration plants and process steam boilers (Ref 7).

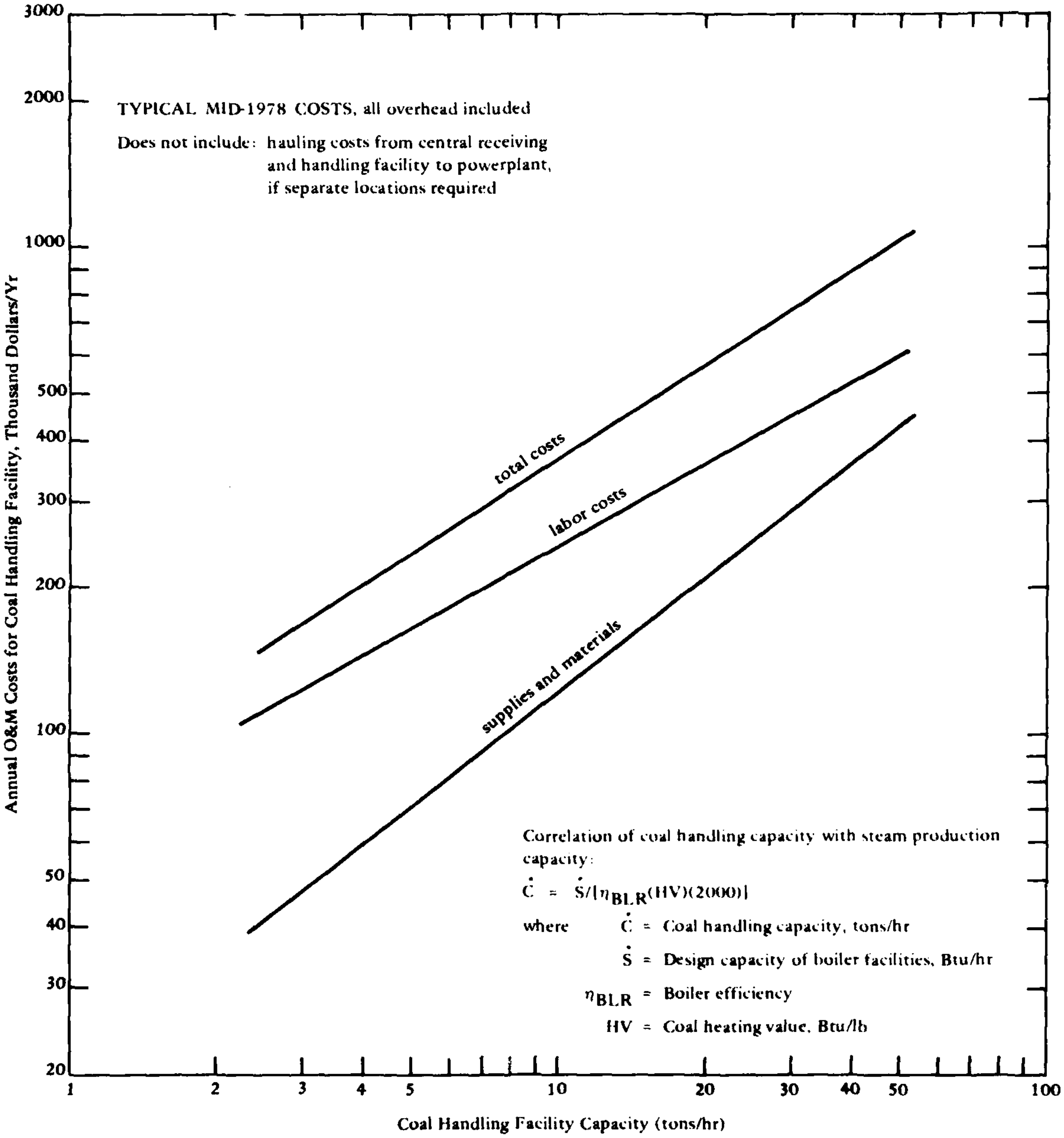


Figure 11. Operating and maintenance costs for central receiving and coal-handling facilities with stockpile.

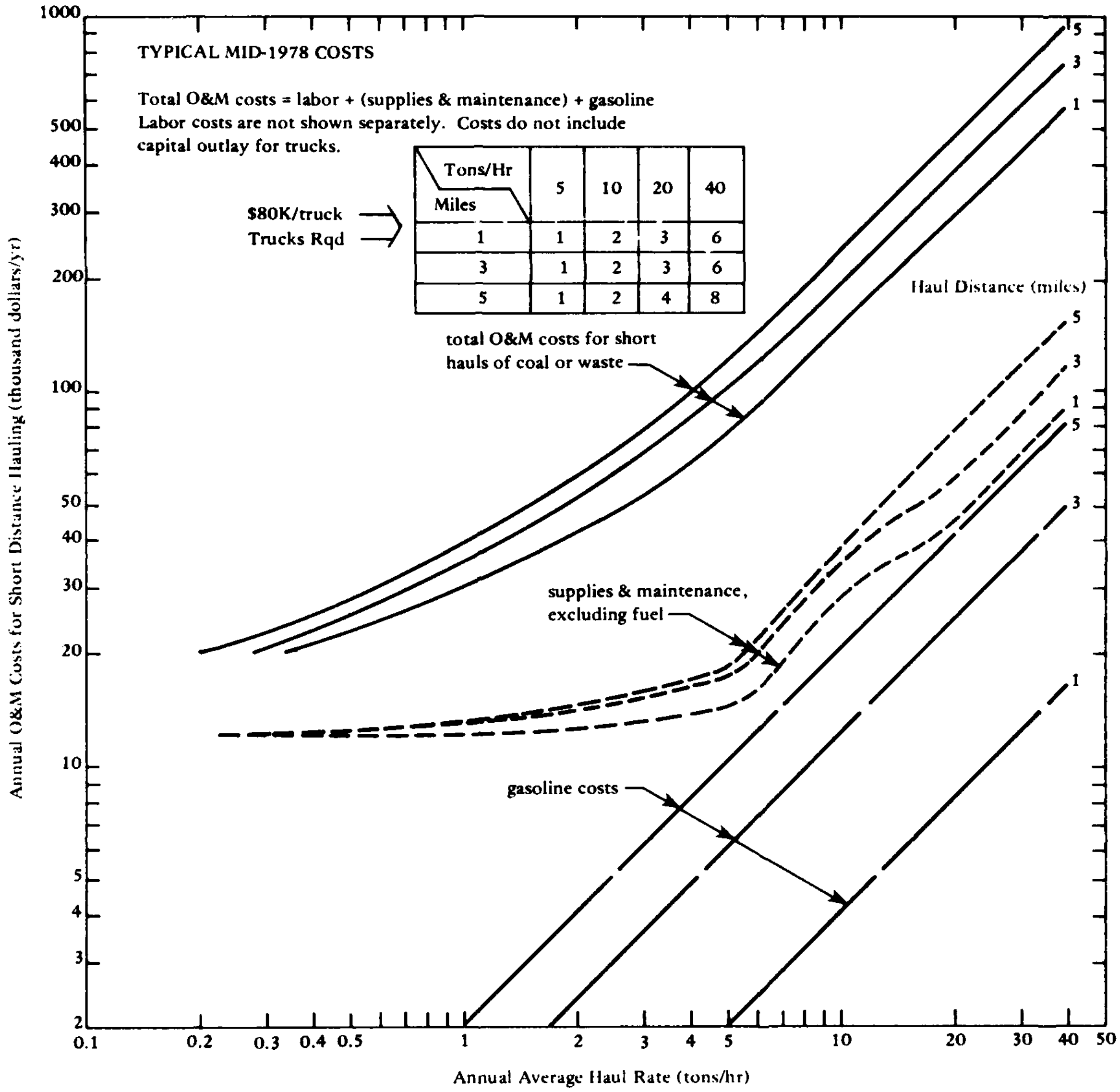


Figure 12. Operating and maintenance costs for short distance hauling of coal or solid waste.

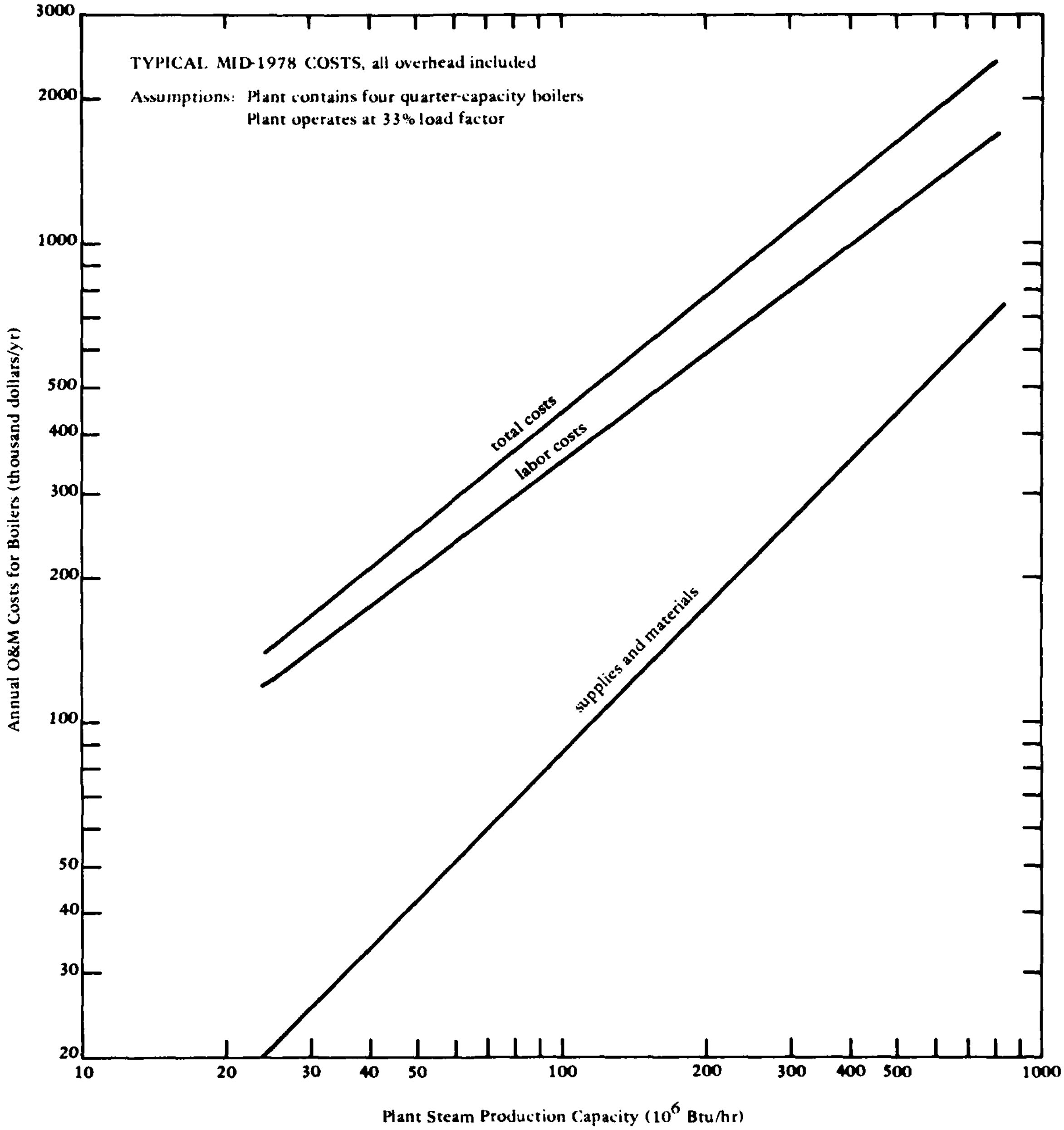


Figure 13. Operating and maintenance costs for coal-fired steam boilers.

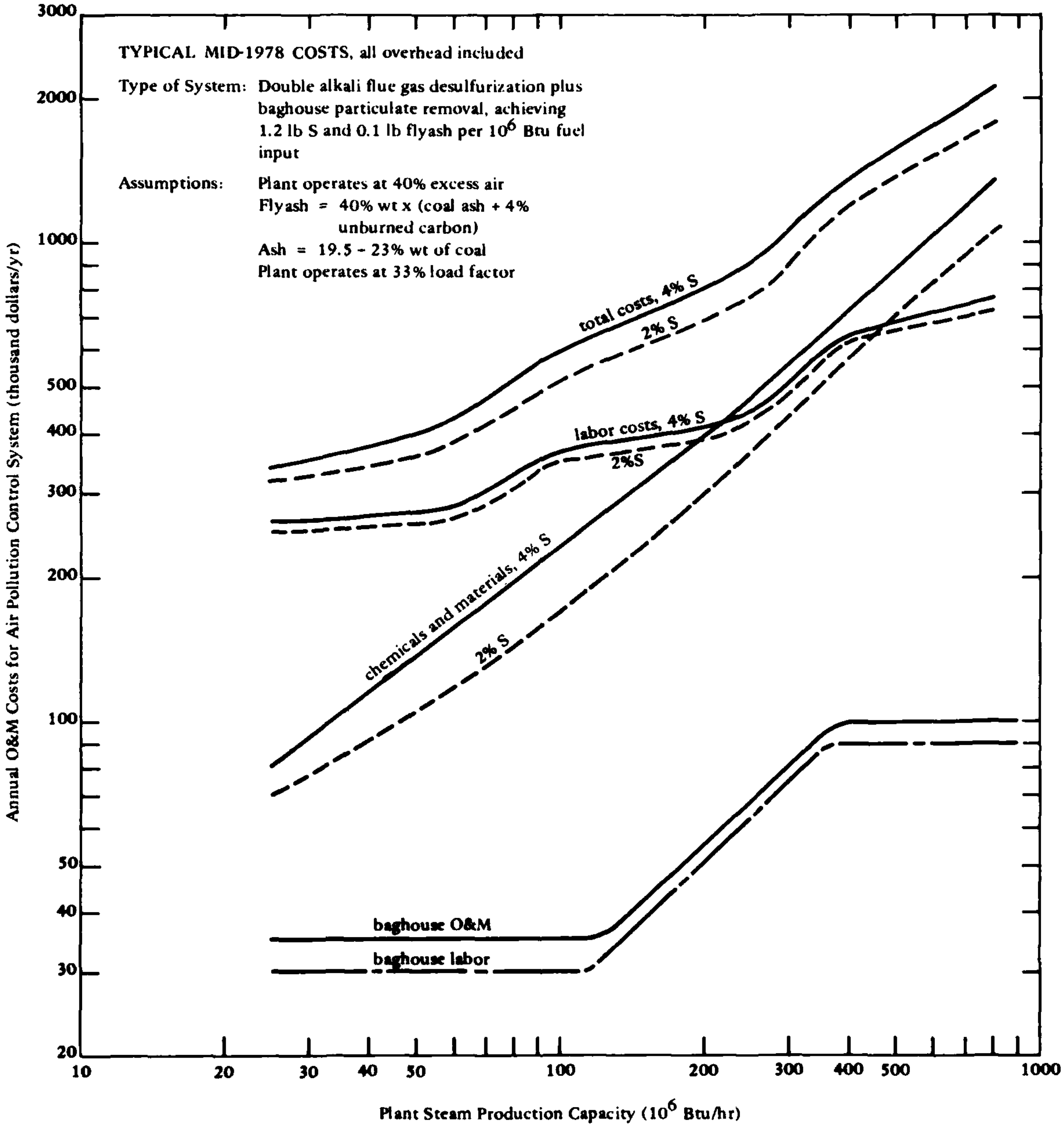


Figure 14. Operating and maintenance costs for air pollution control of coal-fired generating plants.

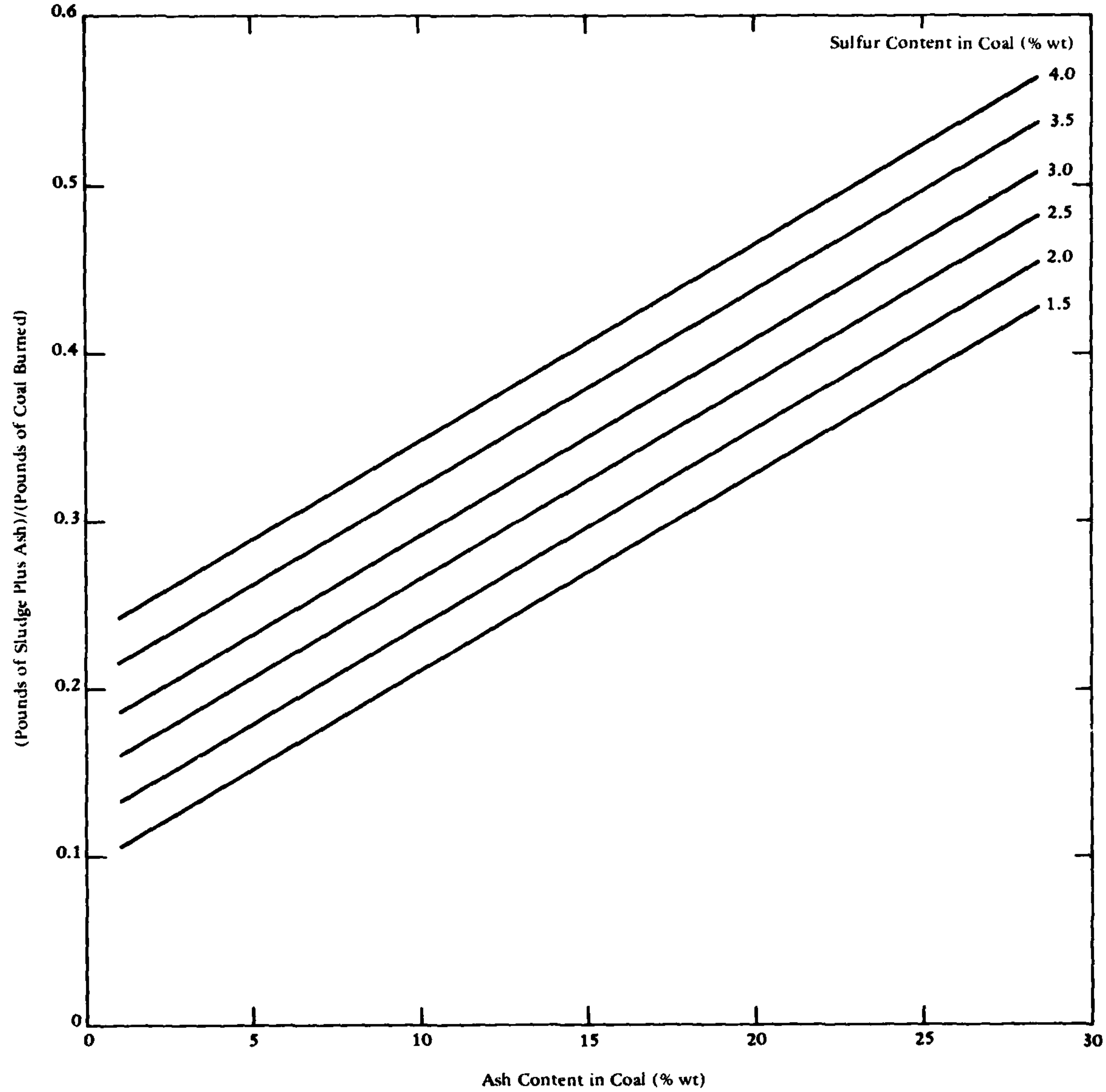


Figure 15. Solid waste production as a function of ash and sulfur content in coal.

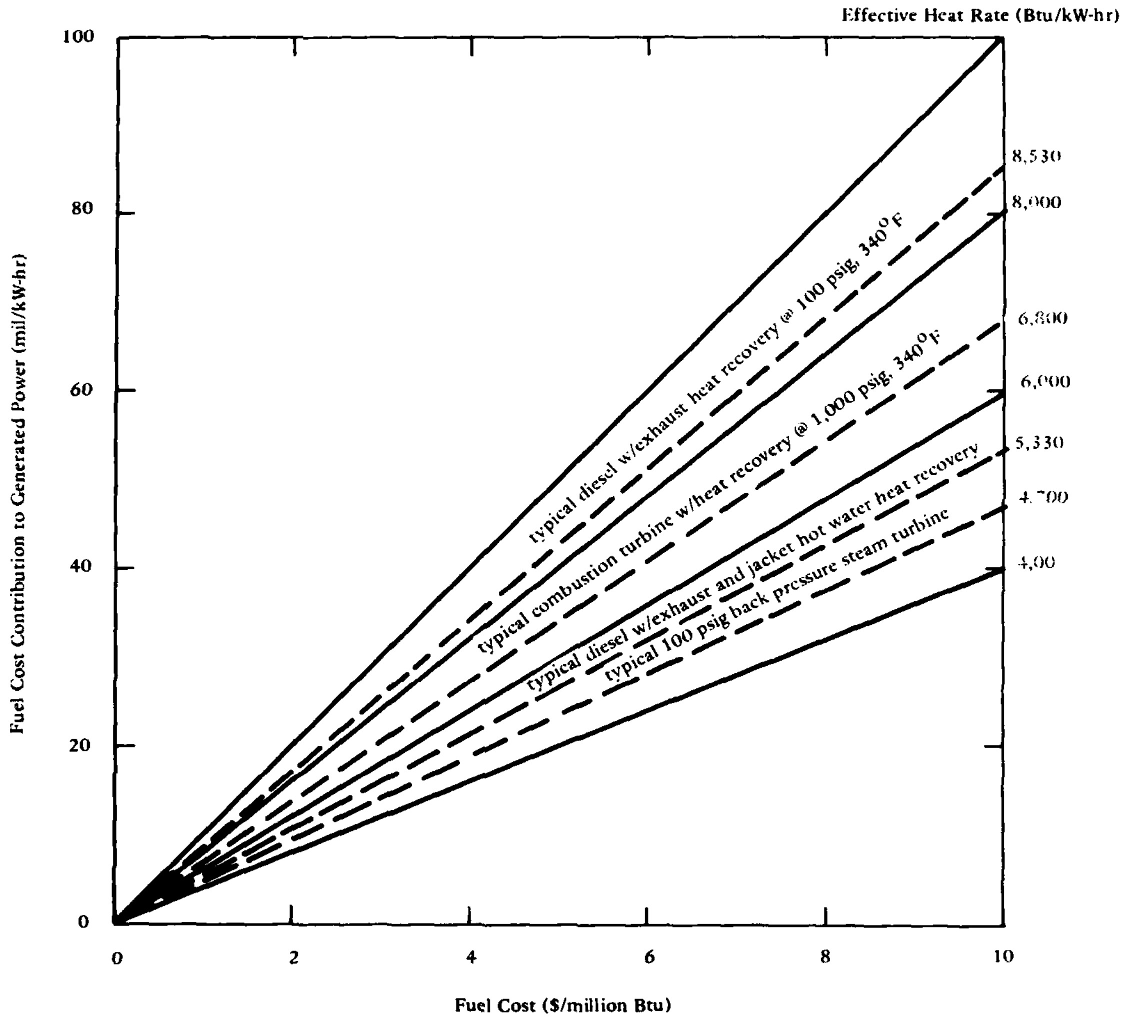


Figure 16. Fuel cost contribution to power costs for cogeneration systems.

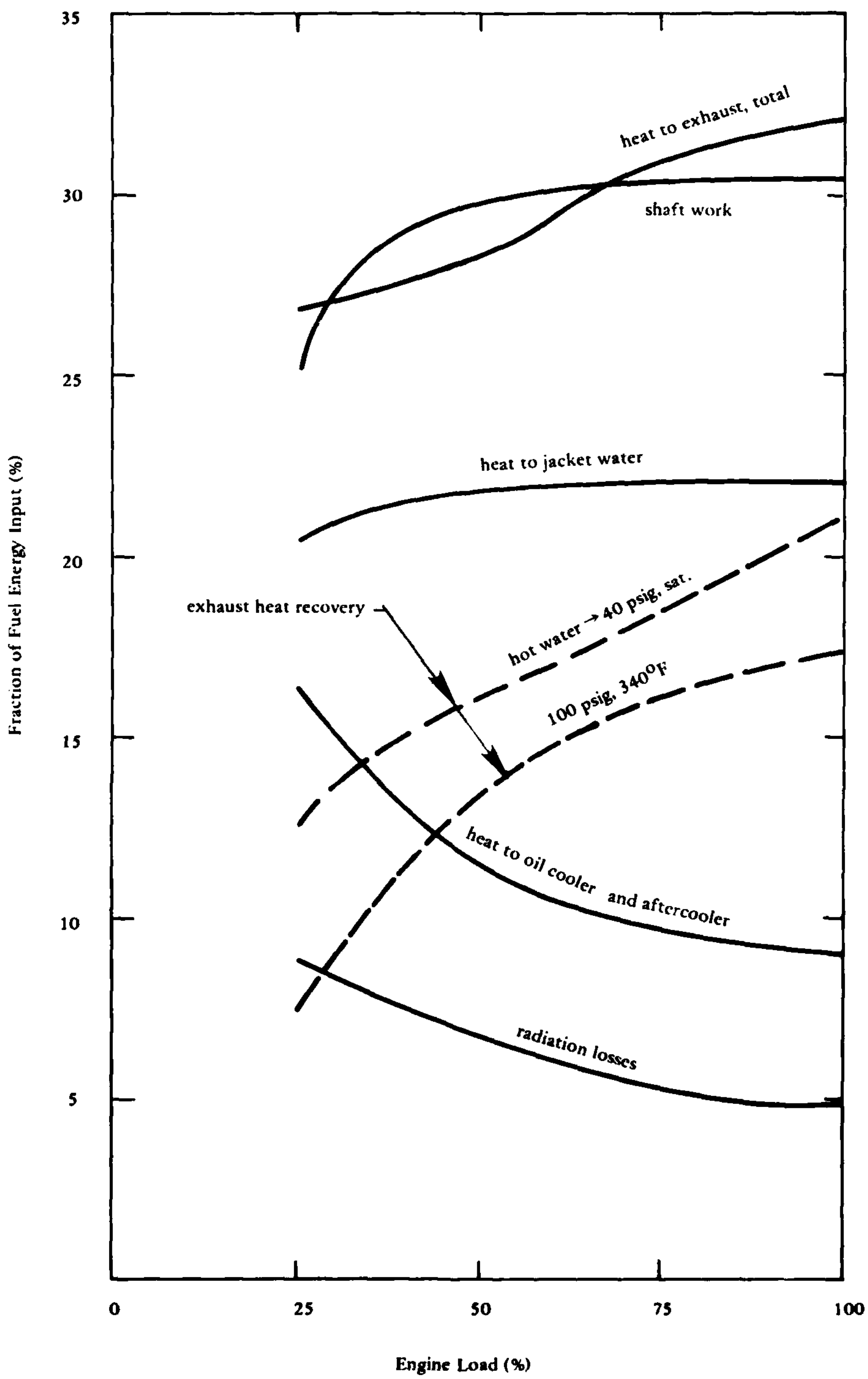


Figure 17. Heat balance for diesel engine in heat recovery application, relative output.

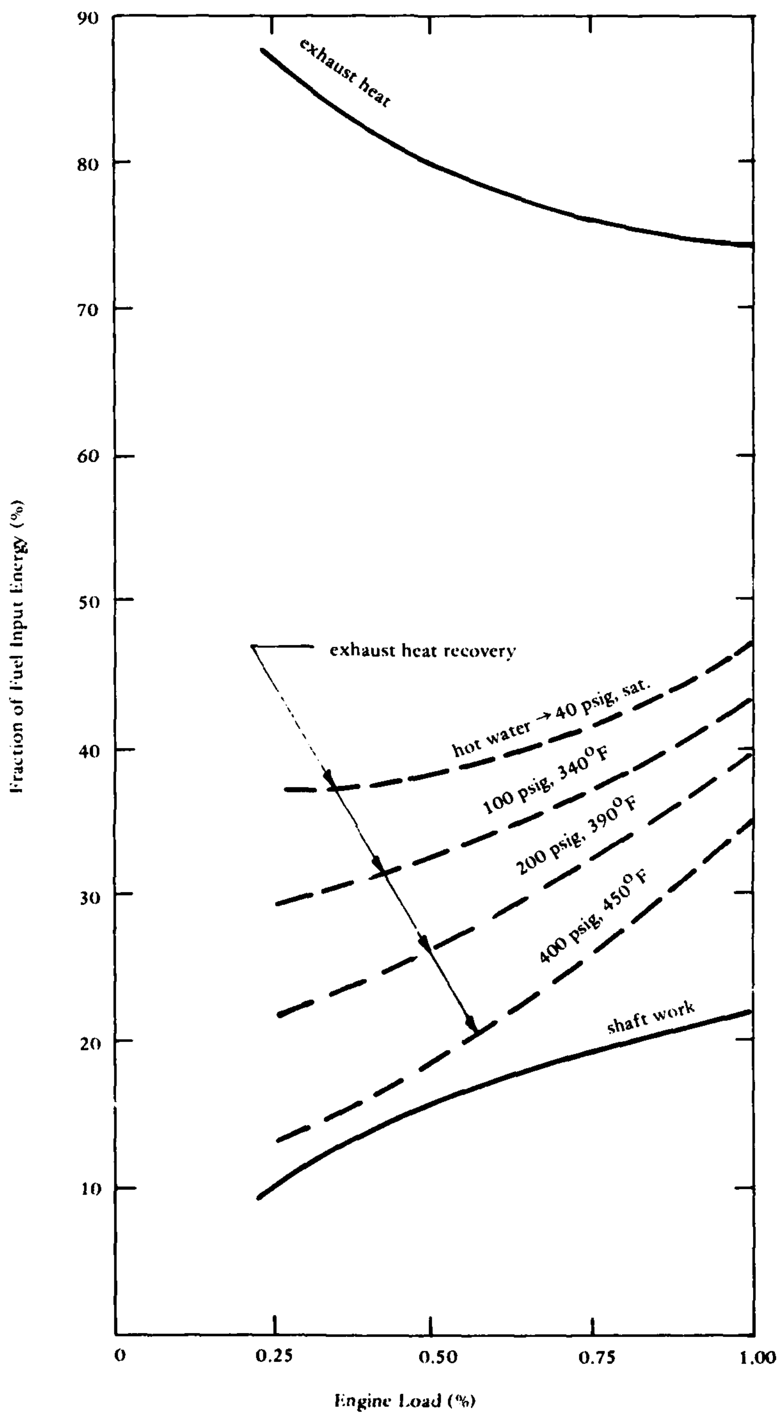


Figure 18. Heat balance for combustion turbine in heat recovery application, relative output.

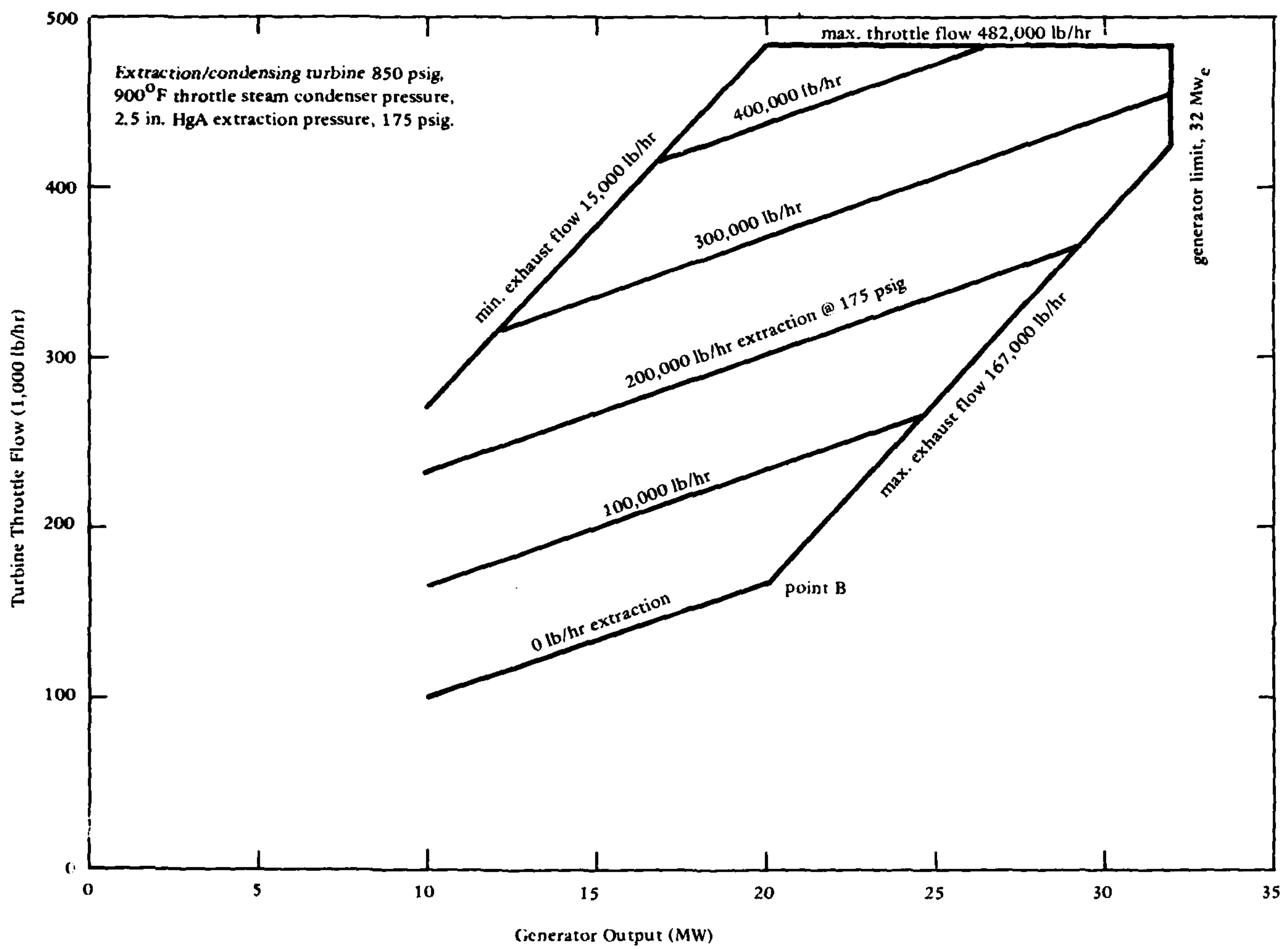


Figure 19. Performance map for an extraction/condensing steam turbine-generator set.

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