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AN ASSESSMENT OF CENTRAL-STATION COGENERATION SYSTEMS FOR INDUSTRIAL COMPLEXES

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16 ABSTRACT

This report assesses the potential for cogeneration system development based on an analysis of the economic, environmental, energy efficiency and social aspects of such systems. The cogeneration system is an application of the principle of cogeneration in which utility-sized power plants supply both electrical and steam needs to one or more nearby industries. Such a system can result in increased energy efficiency reduced pollutants, and reduced overall cost. A number of methodological approaches, including environmental impact analysis, were used to investigate the broad scope of issues relevant to cogeneration system development As the study considered the subject from a general, comprehensive, planning-level perspective, the quantitative results cannot be applied to other sites However, trends associated with the impacts of cogeneration development are identified, and methodologies which are applicable to cogeneration systems in general are employed.

The conclusions and recommendations reveal that cogeneration systems are viable and attractive alternatives to conventional power systems. There are potentially important environmental benefits associated with these cogeneration systems but also environmental problems.

17 KEY WORDS AND DOCUMENT ANALYSIS

a DESCRIPTORS		b IDENTIFIERS/OPEN ENDED TERMS	c COSATI Field/Group
Pollution	Expenses	Pollution Control	
Boilers	Social Impacts	Stationary Sources	
Cogeneration		Energy Conservation	
Utilities			
Emission			
Fuel Consumption			

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DISCLAIMER

FOREWORD

When energy and material resources are extracted, processed, converted, and used, the related pollutional impacts on our environment and even on our health often require that new and increasingly more efficient pollution control methods be used. The Industrial Environmental Research Laboratory-Cincinnati (IERL-Ci) assists in developing and demonstrating new and improved methodologies that will meet these needs both efficiently and economically.

This document reports the methodology and results of an analysis of the environmental, economic, and energy conservation aspects of the applications of cogeneration principles to form a cogeneration system. The methodology concentrates on the comparison of systems that perform the same functions by using conventional energy conversion techniques and by using cogeneration techniques. Therefore, the methodology and conclusions in this report can be used by planners and policy makers in industry and government to evaluate specific projects or concepts involving the large scale application of cogeneration principles. This report will be of interest to those who are involved in environmental, economic, and energy related research. The Alternate Energy Sources Branch, Energy Polution Control Division should be contacted for further information on this subject.

David G. Stephan
Director
Industrial Environmental Research Laboratory

ABSTRACT

This report assesses the potential for cogeneration system development based on an analysis of the economic, environmental, energy efficiency and social aspects of such systems. The cogeneration system is an application of the principle of cogeneration in which utility-sized power plants supply both electrical and steam needs to one or more nearby industries. Such a system can result in increased energy efficiency, reduced pollutants, and reduced overall cost. A number of methodological approaches, including environmental impact analysis, were used to investigate the broad scope of issues relevant to cogeneration system development. As the study considered the subject from a general, comprehensive, planning-level perspective, the quantitative results cannot be applied to other sites. However, trends associated with the impacts of cogeneration development are identified, and methodologies which are applicable to cogeneration systems in general are employed.

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This report was submitted in fulfillment of Contract No. 68-03-2394 by the Georgia Institute of Technology under the sponsorship of the U S. Environmental Protection Agency. This report covers the period March 11, 1976, to March 31, 1978. Work was completed November, 1981.

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NOTES ON UNITS

The calculations performed in the course of this study were carried out using English units of measure. In particular, all computer programs cited in this report are in English units. After writing the report, the text and all tables and figures were converted to the International System of Units (SI), in order to conform with requirements for publications of the Office of Research and Development, U.S. Environmental Protection Agency. The only exceptions to this conversion are Appendix C which describes the contents of the MAIES computer program and Figure 6 which illustrates the mathematical equations and logic flow in the power plant model. These two parts of the report were not converted because they describe basic mathematical tools used in this study. All conversions made by the staff of the U.S. EPA.

APPLICATION OF SI PREFIXES

Multiplication Factor	Prefix	Symbol
10^{18}	exa	E
10^{15}	peta	P
10^{12}	tera	T
10^{9}	giga	G
10^{6}	mega	M
10^{3}	kilo	k
10^{2}	hecto	h
10^{1}	deka	da
10^{-1}	deci	d
10^{-2}	centi	c
10^{-3}	milli	m
10^{-6}	micro	μ
10^{-9}	nano	n
10^{-12}	pico	p
10^{-15}	femto	f
10^{-18}	atto	a

SI TO ENGLISH CONVERSIONS

TO CONVERT FROM	TO	MULTIPLY BY
kilograms (kg)	pounds (lb)	2.205
kilograms/sec (kg/s)	tons/day (TPD)	95.2
kilograms/sec (kg/s)	pounds/hour (lb/hr)	7.94×10^3
cubic meters (cu m)	gallons (gal)	2.64×10^2
hectares (ha)	acres (a)	2.47
meters (m)	feet (ft)	3.28
degrees celcius (°C)	degrees fahrenheit (°F)	$^{\circ}F = 1.8^{\circ}C + 32$
pascal (Pa)	pounds/sq. inch (psia) (absolute pressure)	1.45×10^{-4}
joules (J)	British Thermal Unit (Btu)	9.48×10^{-4}
joules/kilogram (J/kg)	Btu/pound (Btu/lb)	4.31×10^{-4}

ACKNOWLEDGMENTS

The significant contributions of the following people are gratefully acknowledged: Mr. Robert P. Zimmer, overall project management; Dr. Neil B. Hilsen, project director; Dr. George R. Fletcher, technical integration; Mr. Jeffrey S. Tiller, economic analysis; Mr. Stephen W. Day, environmental analysis; Ms. Patricia O. Mathiasmeier, editorial coordination. Significant contributions were also made by Dr. David L. Kelly, Mr. Roy D. Wilkins, Dr. Peter S. Sassone, Dr. Jack M. Spurlock, Ms. Anita Montelione, Mr. Armand A. Masse, and Mr. Joseph N. DiNunno. The staff at the Oak Ridge National Laboratory provided valuable assistance and data. Guidance and technical interaction was provided by Doctors C. C. Lee, Harry E. Bostian, and Benjamin L. Blaney from the Industrial Environmental Research Laboratory of the Environmental Protection Agency.

SECTION 1

INTRODUCTION

Approximately 26 percent of the national fuel consumption is associated with the production of electricity. Since electricity production is less than 35 percent efficient, approximately 17 percent of the national fuel consumption is waste heat that is associated with electricity production. Efforts are, therefore, being made to conserve fuel by better utilization of this wasted energy. One technique for utilizing the heat is to extract steam from power plant turbine while it still can perform useful work. The extracted steam can be used in a variety of ways, but a primary use is for heat in industrial processes, agricultural activities, and heating and cooling systems.

Europeans have taken the lead in waste heat utilization. Many countries, especially those in colder climates, have extensive district heating systems which utilize heat from electric power plants. Waste heat is also used in agricultural applications, such as greenhouses and soil heating.

The applications investigated during this project concentrate on the delivery of thermal energy to industrial processes. The general concept of co-siting industrial operations is considered in complexes that can provide mutually beneficial utilization of energy as well as other resources. A firm basis for co-siting has been established by Isard and others, (1) and has been discussed in the literature under various names, such as Industrial Complexes, Decoplexes, and Industrial Parks. Isard and co-workers, in the 1950's, pioneered the method of industrial complex analysis in investigating a petrochemical complex for Puerto Rico. Recently, this method has been extended to include environmental management activities, with specific reference to a proposed coal power-plant complex in New York State. A number of reports and papers have been published concerning investigations of industrial and agro-industrial complexes centered around nuclear reactors. These complexes are typically designated as "nuplexes," an acronym derived from <u>nu</u>clear com<u>plexes</u>. Attention has been given to Decoplexes, a term derived from <u>de</u>velopment/e<u>co</u>logy/com<u>plexes</u>, which emphasize the grouping of related industries around waste-treatment plants. Many petroleum and chemical companies now use a variation of industrial complex analysis in planning and developing their plant sites. In fact, at the present time there are many economically sound and well-integrated industrial complexes in operation or under construction in this country and abroad. Two examples relating specifically to energy utilization include the electrical utility/chemical facility at Midland, Michigan and the electric utility/refinery arrangement in Baton Rouge, Louisiana.

Several studies have reviewed the economic benefits from cogeneration systems. The term cogeneration is used here as a comprehensive term which describes a power plant that supplies both electrical and thermal energy. In the United States, industries have been somewhat reluctant to develop cogeneration systems in the past due to institutional problems and inexpensive petroleum. Although certain industries have used cogeneration systems successfully to satisfy their own needs, the full potential for the technique has not been realized. In-plant cogeneration systems and the large scale cogeneration systems utilize the same principles, the only difference is one of scale. In the following report the term cogeneration is used to refer to cogeneration systems.

In recent years, fuel oil prices have risen drastically to a current average wholesale price of about $2.20 per GJ. In response, many industries have resorted to alternative fuels such as coal. However, low sulfur content coal is in short supply in many parts of the country and the investment cost required to desulfurize coal makes the use of high sulfur coal generally prohibitive. An alternative to this apparent dilemma is to provide the energy needs of groups of co-sited industries by a large central power source that can take advantage of economics of scale.

Advantages of cogeneration include the ability to use cheaper fuels such as nuclear or coal, increases in energy efficiency due to operation at high temperatures and pressures, and decreases in pollutant emissions resulting from high energy efficiencies. Disadvantages include increased piping and steam extraction cost, increased energy losses from transporting process heat over large distances, and relatively concentrated pollutant emissions. In addition to the technical problems, negative social impacts may result from the construction of a large power plant and a number of industries in a small host community.

Past studies, which have investigated the technical and economic aspects of a cogeneration system, have treated environmental and social impacts only slightly. The present study addresses environmental and social impacts as an integral part of a broad-based investigation of the potential impacts of cogeneration.

PURPOSE

The purpose of the present study is to provide EPA with an up to date analysis of the environmental, economic, energy efficiency, and social impacts of integrating a number of industries into a complex and supplying their energy needs (thermal and electrical) from a large central source. The study encompasses a broad area of impacts and tends to be more general than specific. The results of the study are intended to provide guidelines about cogeneration, rather than action items related to specific details of cogeneration power plant design.

In order to fully evaluate the impacts of a new technology, an examination of its economics are needed since profitability is a primary requirement for any technology to develop commercially. The economic analysis performed in the study uses average estimates of the major components of the alternative energy systems (boilers, power plants, air pollution control equipment, fuel, etc.), rather than costing out specific components in detail. However, many impacts are treated separately from the economic analysis, including air pollution, water consumption, solid waste, and social impacts. These types of impacts are of sufficient importance that they are evaluated in detail in the study.

SCOPE LIMITING ASSUMPTIONS

The study is a comprehensive investigation of the planning level considerations associated with cogeneration. It therefore relies heavily on data that has been obtained from literature and from related studies. Since this study is not site specific, it concentrates on the potential environmental impacts and tangible costs associated with practical applications that could be developed using existing technology.

Power plants of the size 300-1300 Mw electric are considered. Both coal and nuclear fuel are considered because these fuels are anticipated to be abundant in the coming years, and the technology associated with electric power production using these fuels is well established. Fuel for industrial boilers is assumed to be coal, since shortages in fuel oil and natural gas would limit their application and the purpose of the study is to evaluate cogeneration, not fuel switching. A detailed engineering design of power plants or specific pieces of equipment is not performed here. Specific emphasis is placed on available technology and "off-the-shelf" equipment is considered to be utilized. Industrial processes are also considered to be unaltered. These assumptions are necessary in order to limit the scope of the study to a manageable size.

The extent to which nuclear power plants are considered in this study is more limited than the analysis of coal-fired power plants. The study bases the economic and energy efficiency analyses of cogeneration systems using nuclear power on the assumption that the costs associated with past nuclear power plants reflect adequate safety and environmental protection. A more extensive analysis was deemed beyond the scope of this study. For the same reason, no environmental impact analysis of nuclear power plants was performed. The social impact analysis described in Section 8 considers only the impacts of the demographic changes which are projected to arise from either coal or nuclear power plant construction and operation as a result of changes in the composition of the local workforce and related impacts on the local economy.

LEVEL OF DETAIL

The level of detail considered in this study is dictated by the need for a broad-scale, planning level analysis. Specific interrelationships between power system components are considered only in functional block fashion, while topics such as steam extraction and piping; thermodynamic energy balance of conventional and cogenerating power plants; and boiler, piping, turbine, and generation efficiency impacts on total cogeneration concept efficiencies are considered in greater detail. A power plant model is used as a computational aid for investigating impacts of thermodynamics, component efficiencies, and mass flows on cogeneration attractiveness.

The costs of the components of the alternative energy systems are grouped into initial investment costs, annual operation and maintenance costs, and annual fuel costs. Externalities, intangibles and nonquantifiable effects are not expressed in dollar terms, but are evaluated in the environmental and social impact analysis. A procedure for discounting future costs and benefits back to the present is used so that these items may be compared on a life cycle basis.

OVERVIEW

Section 2 of this report presents a summary of the major conclusions from this study. The basis for these conclusions are addressed separately for areas dealing with technical, economic, environmental, and energy conservation aspects of cogeneration systems. The recommendations in Section 3 are oriented toward cogeneration planning and design as well as for future policy research and development. Chapter 4 describes the analysis methodology and the remaining chapters describe the specific analyses. The energy related analysis is discussed in Chappter 5 and Chapter 6 discusses the environmental analysis. Chapter 7 presents the economic analysis while Chapter 8 closes with the results of the institutional and social impact analysis. There are four appendices which provide specific information to support the material presented in the body of the report. The appendices cover Cost-Benefit Analysis, and the multiplier model that was used in the social impact analysis.

SECTION 2

CONCLUSIONS

In this study, investigations of various aspects of cogeneration are made with emphasis on the concept of cogeneration as a total system. Thus, the analysis is designed to provide conclusions and recommendations about the concept rather than recommendations of specific technical aspects. Conclusions can be classified as technical, energy, economic, environmental, or social. A summary of the major conclusions follows.

TECHNICAL CONCLUSIONS

It is technically feasible to provide processed steam from the same facility that produces electricity.

A cogeneration system has fewer requirements for cooling than a conventional electrical utility system with a comparably sized boiler.

Less thermal energy would be ejected into the environment in the form of waste heat.

Better central transportation would result from a cogeneration system because the facilities would all be located in close proximity.

ENERGY AND ECONOMIC

Cogeneration systems can realistically achieve an energy efficiency that is almost twice that of a conventional steam electric power plant. Consequently, a cogeneration system may have environmental benefits because less fuel would be used.

Energy converted by a cogeneration system will cost less than energy from conventional separate facilities; however, a cogeneration system requires a higher construction cost.

In-plant cogeneration is an attractive option when an industrial complex is not large enough to warrent the use of a power plant for cogeneration system or the power plant is not located near the industries.

Numerous combinations of industries can be feasibly integrated. Most are economically attractive if the requirement for low temperature process heat is sufficiently large.

In general, as more steam is extracted, the economics of cogeneration improves. As steam transport distance increases, cogeneration system economics become less attractive.

ENVIRONMENTAL AND SOCIAL

The increased energy efficiency of a cogeneration system results in reductions in national air emissions, national water consumption, national solid waste generation, and land used for solid waste disposal compared to the use of conventional systems. However, a cogeneration system may contribute more pollution in the local area due to the increased concentration of industrial activity.

The integration of facilities in a cogeneration system can produce economic savings in air and thermal pollution control, and in wastewater treatment.

The main siting considerations are economic, resource, and environmentally dependent, as a cogeneration system can only locate where industries exist or are planned.

The key environmental issue is whether is is significant that local increases in air pollutant concentration, water consumption, land use, and social impact that result from cogeneration development are offset by national decreases in air emissions, water availability, and land usage resulting from scattered siting of industry and the use of conventional energy sources.

The social impacts of cogeneration, as measured by percentage change in economic and service requirement parameters, are inversely related to the size of the host community.

Larger host communities have greater capacity to accomodate the cogeneration system needs using existing resources than small host communities; in fact, a cogeneration system located in a sufficiently large community would induce a moderately positive rate of economic growth and produce generally positive changes in community patterns.

Changes in small host communities due to cogeneration system construction and operation are likely to be so large and so sudden that they will be detrimental.

SECTION 3

RECOMMENDATIONS

The recommendations arising from this study are divided into two categories: 1) cogeneration system planning and design recommendations and 2) identification of research areas which EPA may want to investigate further. Planning and design recommendations are in the form of general guidelines for use in investigating the potential for cogeneration development at a specific site. The research recommendations identify areas where information is needed to better elucidate the environmental problems and benefits associated with industrial cogeneration systems.

PLANNING AND DESIGN GUIDELINES

Based on the analyses performed in this study, the following recommendations are made for optimizing the energy and economic benefits of centralized cogeneration, while minimizing the environmental control costs and socioeconomic problems arising from development.

- Industries should locate as close to utility power plants as possible.
- Steam extracted for industrial use should not exceed 7 MPa (1000 psi) or 430°C (800°F). The minimum pressure of transported steam should be 0.7 MPa and should be at saturated conditions.
- Industries should require large quantities of low pressure steam to obtain maximum system efficiencies. The industries should condense the steam and return it to the power plant for reuse.
- The power plant should maximize the amount of low pressure steam extracted for industrial use. Industrial processes should be designed to interface with the cogeneration system.
- In-plant generation should be a better approach when distances between industries and utilities exceed several kilometers. The specific distance depends on technical and economic factors of the specific system.
- Centralization of other facilities (e.g. transportation, air pollution control and wastewater treatment) should be achieved when possible. Industrial co-siting should be sought to provide inter-industry resource needs, e.g., waste products from one industry may be used as raw materials for another.

- The host community of a large cogeneration system candidate should be greater than 20,000 in total employment and about 100,000 in total population to avoid significant negative social impacts. The construction schedule should be constrained when possible, rather than allowing the capacity of the public facilities to be exceeded. Manpower planning should be used to minimize the need for new workers. Housing regulations should be used to control short term housing problems.

FURTHER RESEARCH

The following areas should be considered for future environmental research.

- Site specific impact analyses of hypothesized cogeneration systems located in communities with different characteristics using ambient air quality modeling, social impact analysis, and institutional barrier identification and evaluation. The impacts are site specific, however many of the results can be generalized.

- Study of potential for technology transfer from European countries with cogeneration experience and from industries utilizing in-plant generation.

- Identification of the types of sites with potential for current or future cogeneration system development.

- Study of the impact of environmental quality regulations on cogeneration development, with emphasis on the impact of environmental standards on proper siting of cogeneration systems.

- Study of the land use impacts of alternative pollution control strategies, with emphasis on the impacts of disposing of flue gas desulfurization and fluidized bed combustion wastes.

- Further investigation of the use of cogeneration and process waste heat for pollution control, particularly wastewater treatment. A guidebook for use by industrial developers would be a useful product of such a study.

SECTION 4

OVERALL APPROACH

The cogeneration systems were evaluated from energy-efficiency, environmental, economic, and social impact points of view. Evaluation of a cogeneration system from a planning level requires a broad scale analysis. The overall methodology developed compared proposed cogeneration systems concepts with a status quo system and emphasized determination of cost differences.

The environmental impact comparisons were based on emission data, pollution-control-efficiency data, and relevant environmental quality regulations and standards. The economic analysis employed a cost benefit analysis approach where all future incurred costs and benefits were discounted back to the present so that they could appropriately be compared with initial investment costs. The energy efficiency analysis typically consisted of computing the fuel consumed by the two systems and determining whether the cogeneration systems were more energy efficient than the status quo systems. Construction, operation, maintenance, fuel costs and annual benefits of the two systems were covered in the economic analysis. The social impact analysis determined the population impacts of a large cogeneration system in large and small host communities, and included comparisons between coordinated and uncoordinated construction.

The evaluation of cogeneration systems and status quo systems involved a number of trade-offs between environmental, technical, and economic parameters. A cogeneration system may have higher construction and operation costs than a status quo system, but it has lower fuel costs. The cost of a cogeneration system increases as the steam transport distance increases; thus, large power plants that wish to supply steam to a number of industries may find the piping expensive. However, smaller plants designed to supply a relatively small steam load would not benefit from the economies of scale of larger facilities. The energy efficiency of a cogeneration system may decrease as additional pollution control systems are added and as steam transport piping increases in length. The centralization of industries and power plants in a cogeneration system may cause severe local environmental and social impacts even though national impacts are lower than in a status quo system. Cogeneration systems may be technically, economically and environmentally sound, but may be constrained by institutional problems, such as public opposition, or difficulties in negotiating industry-utility contracts. The resolution of these trade-offs is part of the evaluation area. Some trade-offs may require decision making and are included as recommendations to be considered during policy formulation.

The approach for comparing the cogeneration system and the status quo system stresses impact differences. Although it is not necessary or practical to assess absolute impacts of particular systems, relative impacts are important. For example, in the economic and energy efficiency analysis, although consideration was given to determining accurate estimates of capital, operation and maintenance costs of a cogeneration system, emphasis was given to costing those items which significantly differed between the cogeneration system and the status quo system (e.g., additional piping costs, piping thermal losses, cooling tower costs, pollutant collection efficiency, and costs of various air pollution control technologies). In the environmental analysis, consideration was given to cost savings achievable by combining effluents from co-located industries to speed the process of biochemical oxygen demand treatment with major emphasis on the reduction in treatment tank size.

COGENERATION SYSTEM DEFINITION

The cogeneration system, as described here, is a specific technical approach by which a large electrical utility supplies both electricity and steam to a group of centrally located industries. Figure 1 sketches the primary elements of a cogeneration system. Industries are physically grouped together, although the grouping may span a number of miles. Electricity is supplied from the cogeneration system to the industries in the conventional sense of a large utility (e.g., a turbine drives a generator whose output voltage is boosted to some appropriate level for transmission over high voltage transmission line to the industries). The distinction, however, between the cogeneration system and status quo system is that in addition to supplying electrical energy, the utility plant also supplies thermal energy to industries. The transport medium, once transported, either may be returned (closed cycle operation) or discarded (open cycle operation).

Power system backups may be either located at the industries or at the power plant. All excess steam beyond industry requirements is passed through a turbine for electricity generation and then condensed by cooling towers or by heat exchange between a local water supply such as a river. The types of fuel considered for the cogeneration system include uranium and coal of various levels of sulfur content.

A status quo system is defined for each cogeneration system concept considered so that relative cogeneration system impacts may be gauged. The status quo system consists of utility power plants which provide only electricity and industrial power plants which provide steam and sometimes electricity. Fuels used by the industries include coal, natural gas, and fuel oil; however, only coal is used for comparisons in order to separate the evaluation of cogeneration as a concept from the problem of fuel switching. Any additional electricity needs are supplied by a conventional power plant. This conventional power plant may use either coal or nuclear fuel.

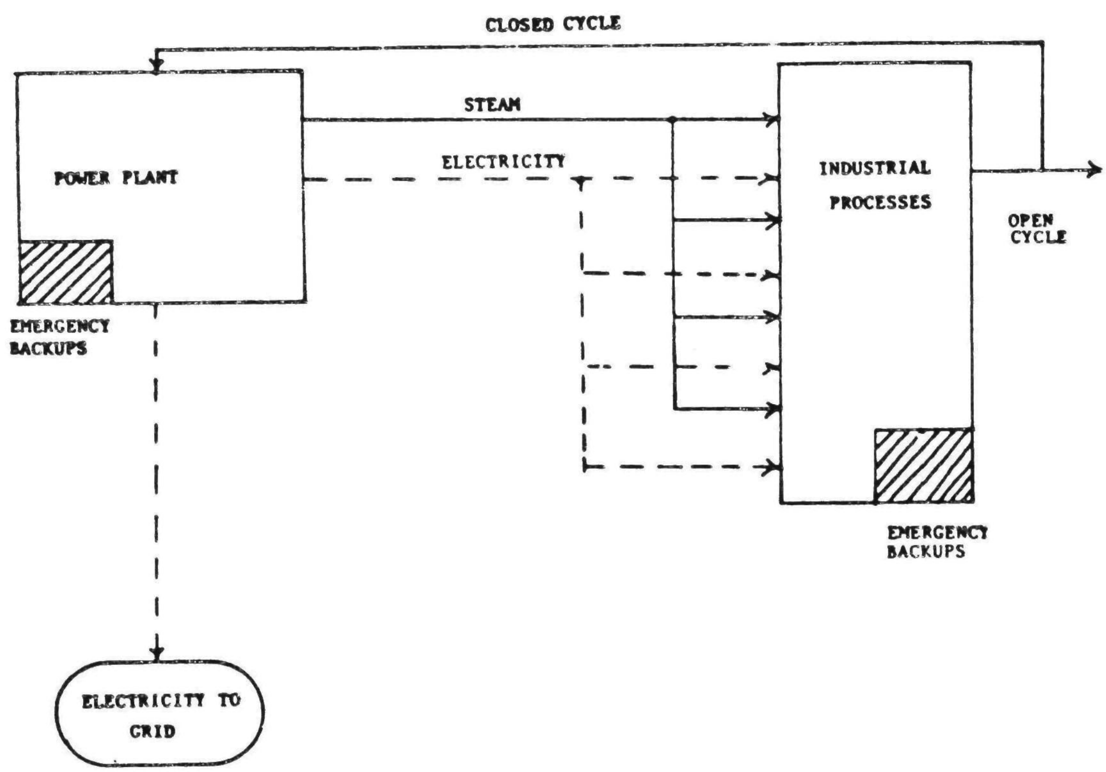

Figure 1. Cogeneration system.

BASIC METHODOLOGY

The basic methodology employed, as shown in Figure 2, was an interactive analysis. The first step in the methodology was to ascertain industry size (e.g., kg/day of output products). Based on combinations and sizes of industrial facilities, cogeneration system concepts were formulated to supply the total energy needs. The economic, energy efficiency, environmental, and social implications of the cogeneration system were then evaluated. Similarly, a status quo system was formulated whose impacts were then used to gauge the relative impacts of a particular cogeneration system.

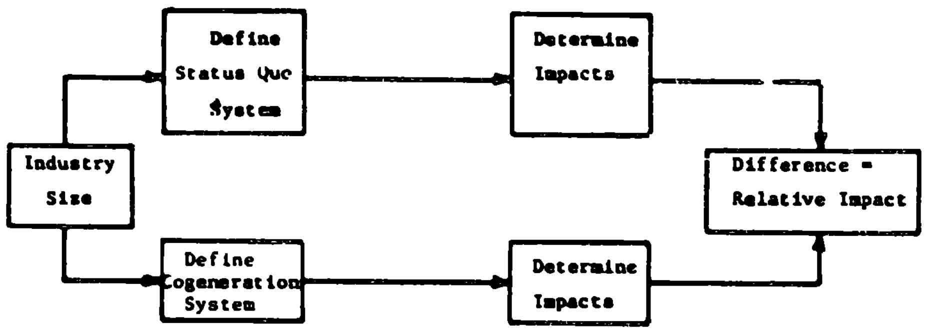

Figure 2. Basic methodology for evaluation of a cogeneration system.

The four types of analyses performed are shown schematically in Figure 3. For the economic and energy efficiency analysis, a computer simulation was developed for ease of changing scenario parameters and performing sensitivity analyses. (A description of the program is given in Appendix C). For the environmental analysis and the social impact analysis, a computer simulation was not necessary since the results were less quantitative.

Outputs of the four analyses were then utilized to arrive at a total impact assessment statement on cogeneration systems. Outputs of the analyses were in terms of dollar savings, weight of air emissions, overall energy efficiency, gallons of water saved, quantity of fuel saved, decrease in thermal emissions, savings in waste water treatment, and short-term population changes during and after cogeneration system construction.

For the applications of several of these analyses, an example case model was developed. This example case analysis provides a general indication of the relative merits of a cogeneration system and is a useful tool for making recommendations at a planning level.

The criteria for selecting an example case included applicability to a number of sites, high steam requirements, and high demand for electricity. A plant of typical size (909 Mg of Cl_2 produced per day)* would require 61.1 kg/sec. of steam at 210 kPa and 290°C. To simulate a large cogeneration system complex, it was necessary to assume that the equivalent of six 909 Mg per day chlorine plants were located in the same vicinity, with a nearby power plant providing the electrical and thermal requirements of the industrial complex. It was also assumed that the steam be transferred one-half mile to the industrial plants, condensed at the industries and returned as feedwater to the power plant.

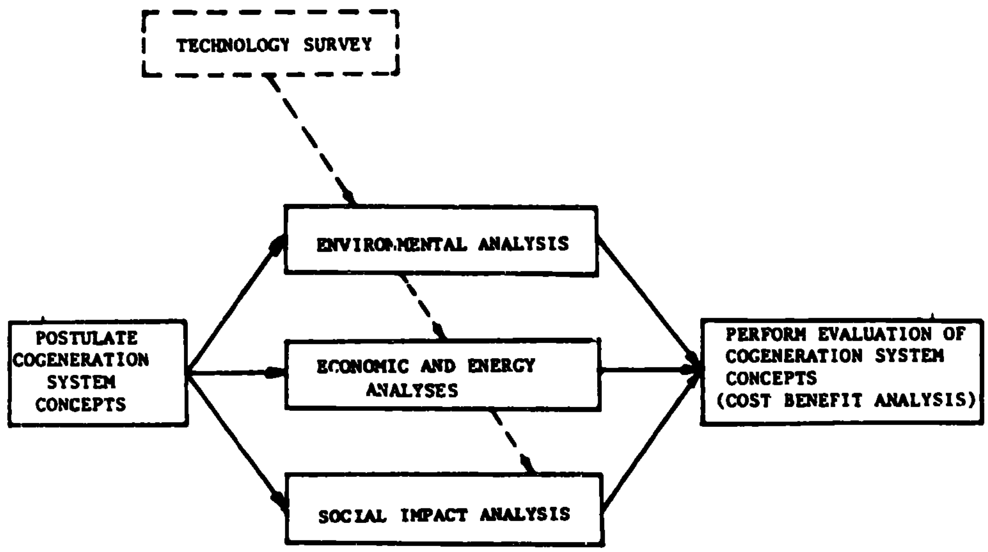

Figure 3. Cogeneration system analysis approach.

Figure 4 displays the example case cogeneration system with a coal-fired power plant. The specific values of the energy flows and the methods of evaulation will be discussed in detail in Section 5. A status quo system that would meet the same energy requirements is also shown. The low pressure steam required by the industry is extracted at the crossover point. The mass flow rate of steam piped is computed to account for piping loss.

In the example case, the mass flow rate of steam piped is 367 kg/sec. Extraction of this large quantity of steam at the crossover point reduces the steam flow through the low pressure turbine and causes a 194 Mw reduction in the electrical output of the power plant. To compare the two systems, supplementary utility capacity must be included in the cogeneration system

*1000 TPD Cl_2

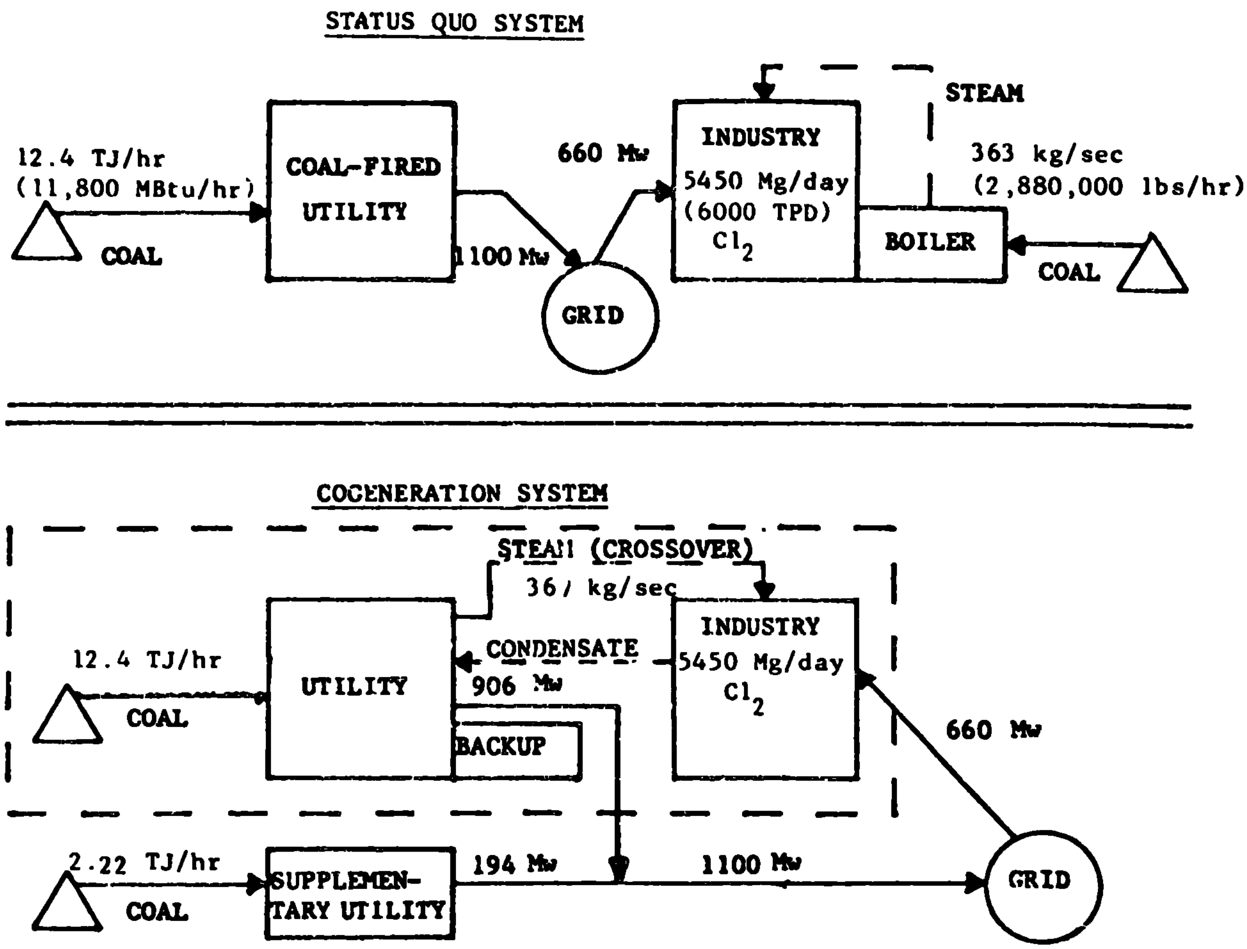

Figure 4 Example case

to make up the loss in electrical capacity. The supplementary capacity was assumed to be provided by a large power plant in the grid as a part of its load.

INDUSTRIAL APPLICATIONS

In order to evaluate the cogeneration concept from an energy efficiency, environmental impact, and cost standpoint, it is necessary to look at the energy requirements of specific industries. First, the energy requirements are used to establish the technical feasibility of supplying thermal energy to specific industries from a cogenerating power plant. The second step is to insure that the selected industries represent a significant potential market. Industrial process modifications are not addressed in this study because they are beyond the scope of this study and have been addressed in detail in another study. The energy requirements were also evaluated to determine the potential for load matching between the industry and the power plant.

Candidate Industries

Several energy intensive industries were selected to determine the compatability of the thermal energy requirements of those industries that could be supplied by a cogenerating power plant. The following energy intensive industries were selected for initial consideration:

Aluminum	Olefins
Ammonia	Petroleum
Cement	Phosphoric Acid
Chlorine and Caustic Soda	Pulp and Paper
Copper	Steel
Fertilizers	Sulfur
Glass	Textiles

Several of the industries were eliminated from consideration because of the forms of energy required. Steel, glass, and cement all require high temperatures that must be provided by the combustion of primary fuel or electrical energy. Copper and aluminum require electrical energy.

Ammonia production uses steam that must be at least 540°C which is several hundred degrees above the temperatures that can practically be supplied by a utility power plant.

Petroleum and olefin industries are very closely related, and rely on petroleum as feed stocks as well as a source of fuel. Much of the energy is derived from by-products of the chemical processes. In fact, some petroleum based industries presently use cogeneration systems for their own operation and still have excess by-product fuel. Therefore, these industries are not a good potential market for thermal energy from a large scale cogeneration system.

The fertilizer industry covers a broad range of processes which includes phosphoric acid, phosphate rock, sulfur, and sulfuric acid. Therefore, specific processes are considered rather than fertilizer production as a whole.

Thermal and Electrical Demands

The industries that were selected for preliminary analysis are shown in Table 1. The most important characteristics of these industries are the quantity and quality of steam required for the process applications. Each industry requires relatively large quantities of steam at temperatures and pressures that could be supplied by a cogeneration system. In general, these industries use electrical energy and steam at pressure of 3.45 MPa and below. The thermal and electrical demands of several industries are discussed in the following sub-sections.

TABLE 1. INDUSTRIAL ENERGY REQUIREMENTS

Industry	Electricity	Steam		
	Mw	Mass Flow kg/sec (1000 lb/hr)	Pressure MPa (psig)	Temperature °C (°F)
909 Mg/day chlorine (1000 T/day) and 1000 Mg/day caustic soda (1100 T/day)	110	6 .5 (480)	0.31 (30)	28.8 (550)
909 Mg/day phosphoric acid (1000 T/day)	7.56	0.370 (2.94)	0.790 (100)	232 (450)
1818 Mg/day Kraft pulp and pape. (2000 T/day)	94	152 (1205)	6.59 (705)	760 (1465)
1818 Mg/day Groundwood pulp and paper (2000 T/day)	185	94.5 (750)	0.55 (65)	168 (335)
66,900 m^2/day textiles (80,000 yd^2/day)	---	20.2 (160)	1.58 (215)	193 (380)

Chlorine and Caustic Soda--

Chlorine and caustic soda are produced almost entirely by electrolytic methods from fused chlorides or aqueous solutions of alkali metal chlorides. Therefore, there is a large demand for electrical energy. There is also a demand for steam used to control the temperature of the electrolytic solution, and to purify and concentrate the brine solutions.

Phosphoric Acid--

Phosphoric acid is an important compound in the production of fertilizers as well as several other chemical products. Phosphate rock is the basic raw material that is used in the production of phosphoric acid and it is found throughout the world.

The phosphate rock must be mined and separated from undesirable materials such as sand and clay. Energy requirements for the mining are primarily for mechanical energy that is supplied by electricity or oil powered engines. Phosphate rich ore is then mixed with water to separate the phosphate rock, and the slurry of phosphate rock and water is dried. This process requires large quantities of thermal energy that can be supplied as steam or by direct combustion of fuel.

The production of phosphoric acid from the phosphate rock is done by one of two major processes, the wet process or the furnace process. In the furnace process, temperatures of 1600°C to 2700°C are required which requires electric or direct combustion furnaces. The wet process requires some thermal energy that can be provided as a by-product of sulfuric acid production which is used in the wet process.

Pulp and Paper--

The paper industry is an energy intensive industry. Steam and electricity are the major forms of energy consumed; however, some fuel is required for direct combustion as part of chemical recovery processes.

Paper is made by separating wood fibers and reassembling them into a desired form. To process the wood fibers into the final form, the following general sequence is followed: 1) pulp wood acquisition, 2) debarking of roundwood, 3) chipping of roundwood, 4) pulping, 5) pulp bleaching, 6) papermaking, and 7) converting. The most energy intensive steps are chipping, pulping and papermaking.

Chipping is the cutting of logs into small chips that can be used in later processes. This requires mechanical energy that can be supplied by either electric motors or steam turbines. Electric motors are used most often.

Pulping is the process of separating individual fibers into a form that can be used to make paper. There are several different methods of making pulp. Some require mechanical while others require thermal energy. But all are energy intensive.

Paper is made by arranging fibers into an interlocking matrix by suspending the wood fibers in water and pouring the suspension onto a screen. Water is removed and a sheet is formed. This sheet is pressed between rollers and further dried by heating. The drying process is very energy intensive and normally uses large quantities of low pressure steam.

Textiles--

The textile industry is very diverse in its type of operations. There is a wide range of materials, and manufacturing techniques. Most of the energy required during the manufacturing stage is mechanical. The energy requirement of yarn production is very dependent on specific materials.

The one energy intensive process that most textile operations have in common is drying. At some point in most textile operations, water must be removed. For many years drying has been accomplished with hot gases that are the combustion by-products of a clean fuel such as natural gas. However, steam dryers are being used more and more often as natural gas becomes harder to obtain. The energy required for steam drying represents a significant energy requirement for low pressure steam.

The loss of energy due to transportation can be compensated by supplying steam at a higher pressure from the power plant. However, the energy loss results in a net loss of efficiency that is proportional to the distance the steam is transported.

Industry-Power Plant Compatibility

Industries and power plants require reliability and availability; however, the operating requirements associated with meeting these criteria may be different.

In general, industries that require large amounts of energy normally operate on a year-round basis, 24 hours a day. However, utilities usually must shut down for extended periods, a few weeks to several months, for major maintenance. The difference in the modes of operation between the utility and industrial operations could cause significant difficulties for an industrial energy consumer that must rely on a utility or large scale power plant for its source of energy. The difference in the operating schedules and maintenance procedures are primarily dictated by the objective of the utility and industries. For example, the maintenance of a utility power plant is based on maximizing the availability and reliability of the total system, which may consist of a large number of utility power plants. To maximize the reliability of the system, the utility will shut down power plants at regular intervals for major and preventive maintenance. In contrast, an industry that supplies its own energy is operating in a relatively isolated environment. Since the objective of the industry is to maximize the product output, the production of energy is only a means to that end. In this mode of operation, the power plant in an industry will be operated for maximum availability, 24 hours a day, all year. When it is necessary to shut down the power plant for major repairs, it is of great financial importance that all repairs and maintenance be performed as rapidly as possible, and the plant be put back into operation. To meet the operating requirements of the industry, it may be necessary to design the cogenerating power plant with sufficient redundant systems (i.e., multiple boilers with header systems) that the required availability can be satisfied. Although there will be additional cost in designing the cogenerating power plant to provide the reliability and availability required by the industries, the net result could still be a power system that is more reliable and has higher availability than individual power systems in each industry. Therefore, if the cogenerating system offers sufficient economic advantage over the status quo system, the availability and reliability requirements would be primarily an economic consideration.

SECTION 5

ENERGY

ENERGY ANALYSIS

The energy analysis included an investigation of the total energy utilization for both cogeneration systems and status quo systems. An analysis of energy production and consumption must include a detailed treatment of boiler-turbine-generator efficiencies, enthalpies of steam at extraction points, and thermal energy losses due to extraction control equipment. A computer model was employed to calculate the significant operating parameters of the total energy system. The energy system included the boiler, turbines, generators, and piping. Energy demands are based primarily on industries that produce their own steam. No attempt was made to optimize the grades of steam provided to satisfy particular industry needs. Instead, energy was assumed to be provided at the same grades in the cogeneration system as is presently provided in the status quo system. Industries in a particular grouping may have demands for steam that are slightly different in temperature and pressure. In practice, matching of steam conditions is accomplished by pressure regulation equipment at the point of use. The energy modeling approach taken here is to keep the energy supplied to a particular industry constant for a given grade, and then supply this energy demand from the most likely extraction point of the power plant turbine. Losses due to the mismatching of steam source with demand were not included in the energy analysis.

Power Plant Model

A power plant model was developed which includes an appropriate level of detail so that relationships between steam extracted for industries power plant fuel requirements, efficiencies, and ejected heat could be investigated. The same power plant model was used for computing mass flows, fuel requirements and electrical energy outputs for conventional power plants, cogeneration systems and industrial boilers. Discussion of the model essentially begins with the mass flows M_1, M_2, and M_4 of process steam extracted and piped to the industries at grades G_1, G_2, and G_4, respectively. The term steam grade refers to the specific characteristics of the steam that is defined by pressure and temperature. For conventional power plants, mass flows were set equal to zero.

Industries may have demands for steam that are slightly different temperatures and pressures. Since, in actuality, matching of steam conditions is accomplished by pressure regulation equipment at the point of use, mass flows from the cogeneration system at a particular grade are determined by keeping the energy supplied to the industry at a given grade constant and allowing temperature and pressure to vary. Table 2 presents the relationships between industry steam demands and power plant steam source.

TABLE 2. RELATIONSHIPS BETWEEN STEAM DEMANDS AND POWER PLANT STEAM SOURCE

Industry steam demand	Power plant steam source		
	Nuclear	Coal	Industrial
High (M_1)	None	Primary	None
Intermediate (M_2)	Primary	Cold reheat	Primary
Low (M_4)	Crossover	Crossover	Crossover

Figure 5 presents a block diagram of the power plant model. Definition of variables for efficiencies, mass flows, and enthalpies are given in Table 3. The general form of the model includes a three-stage turbine. A given power plant may effectively be either two or three stages. For example, a nuclear power plant or an industrial fossil-fuel power plant has only two stages, whereas a conventional coal-fired power plant is modeled as having a three-stage turbine.

It will be noted in Figure 5 that two mass flows are labeled M_9. This is due to the possibility of steam being extracted from either point (but not both) and used for feedwater heating. For a nuclear power plant, M_9 would be extracted from point B, whereas from a fossil-fuel power plant, M_9 would be extracted from point C.

Figure 6 illustrates the mathematical equations and logical flow of computation in the power plant model. The equations are based on mass flow and energy balance relationships for the Rankine cycle for backpressure turbines. The model is used for computing fuel requirements and electrical energy produced by cogeneration systems and conventional power plants using nuclear or coal fuel as well as industrial boilers using fuel oil, coal, or high Btu gas.

In Figure 6, H_{TOTAL} is the total rate of thermal energy supplied by the power plants. For large nuclear utilities, H_{TOTAL} is set to 3750 Mw_{th}

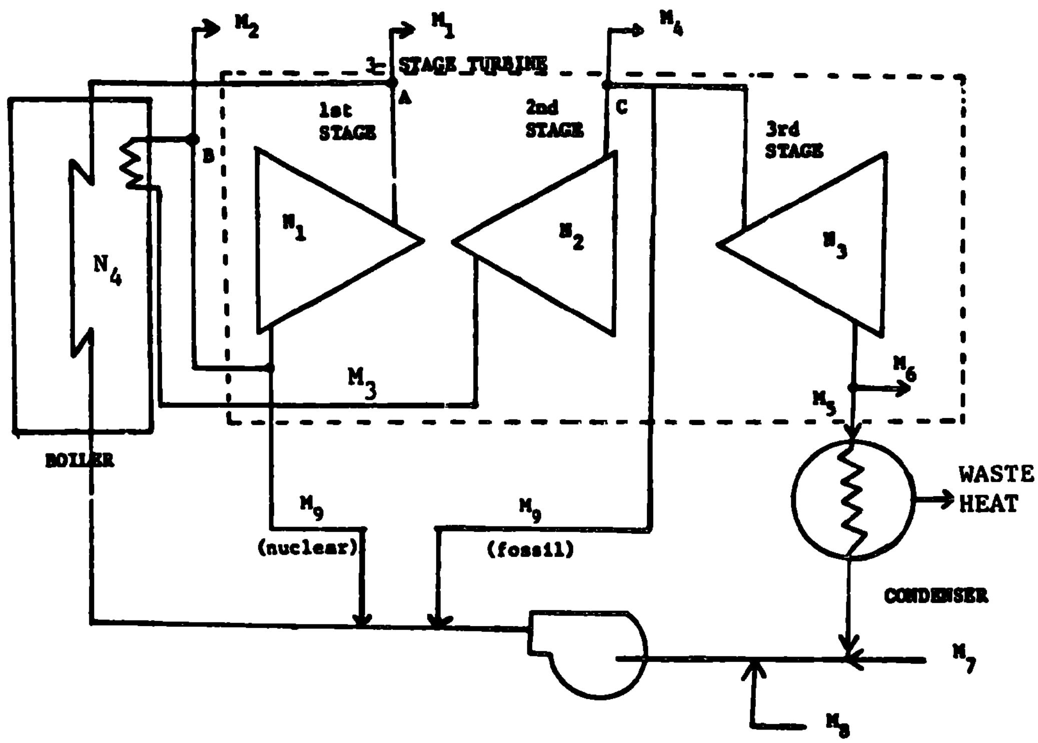

Figure 5. Block diagram of power plant model.

TABLE 3. DEFINITION OF EFFICIENCIES, MASS FLOW AND ENTHALPIES FOR POWER PLANT MODEL

Variable	Description
N_1	Efficiency of 1st stage of turbine
N_2	Efficiency of 2nd stage of turbine
N_3	Efficiency of 3rd stage of turbine
N_4	Efficiency of boiler
M_1	Mass flow to industries at high T & P
M_2	Mass flow to industries at intermediate T & P
M_3	Mass flow through boiler for reheat or moisture removal
M_4	Mass flow to industries at low T & P
M_5	Mass flow to condenser
M_7	Mass flow of make-up water
M_8	Mass flow of return water from industries
M_9	Mass flow for steam used for feedwater heating
h_1	Enthalpy of high pressure steam
h_2	Enthalpy of intermediate pressure steam
h_3	Enthalpy of reheat steam
h_4	Enthalpy of low pressure steam
h_5	Enthalpy of steam input to condenser
h_6	Enthalpy of steam output from condenser
h_7	Enthalpy of make-up water
h_8	Enthalpy of industrial condensate return

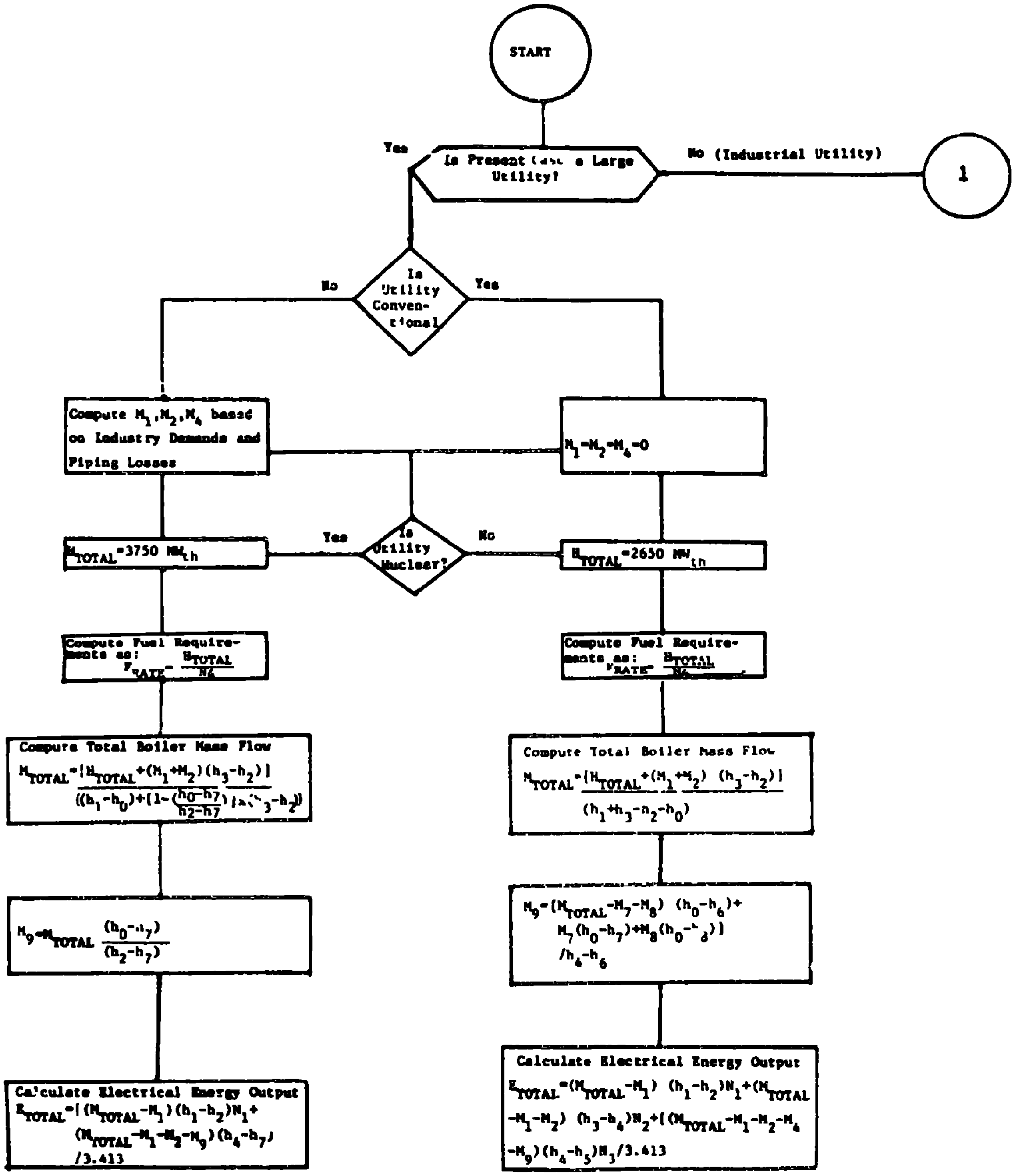

Figure 6. Flow diagram of power plant model.
(English units)

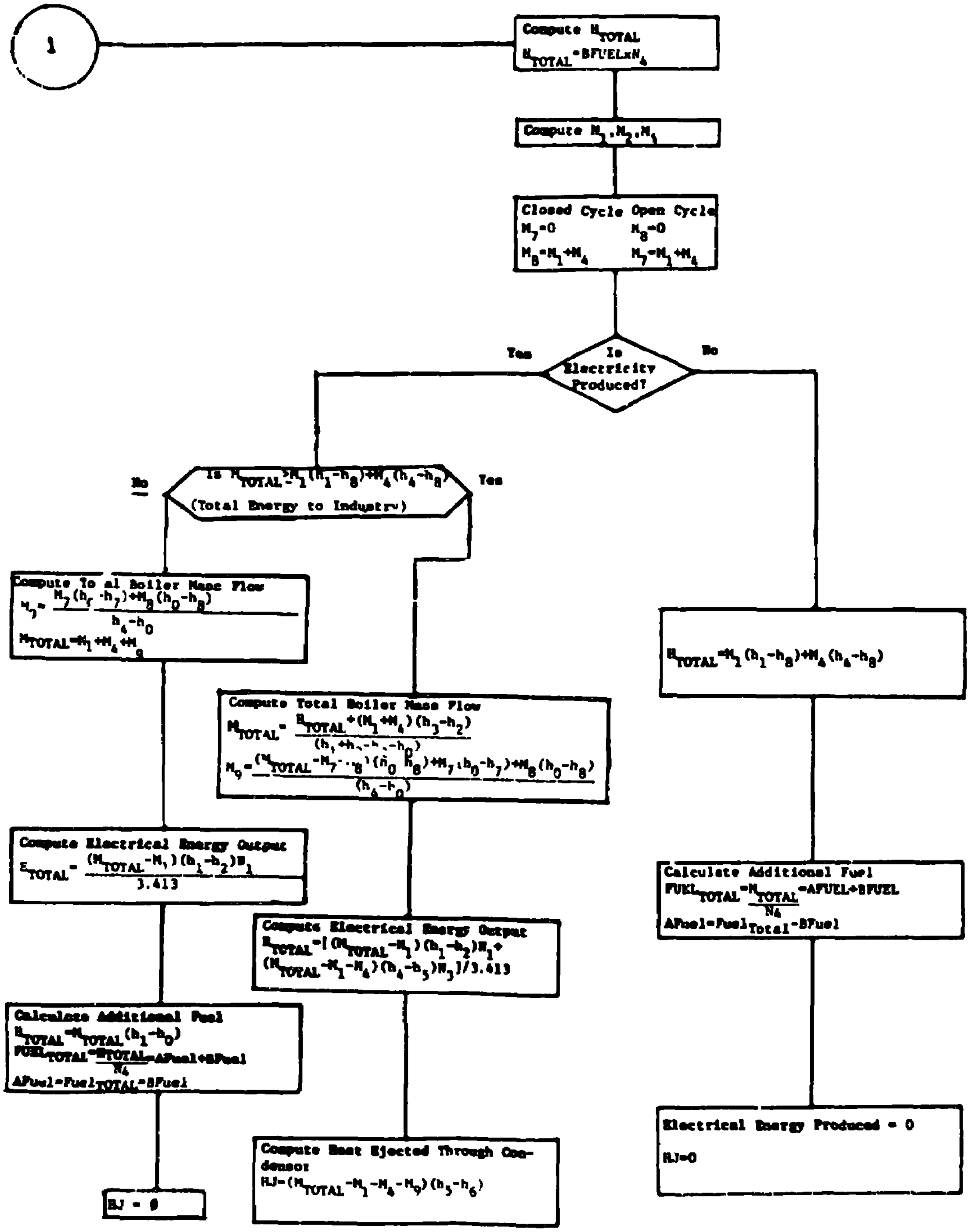

Figure 6. (continued)

and for large coal utilities, H_{TOTAL} is set to 2650 Mw_{th}. These sizes are typical of present utilities.

The mass flow rates to the industries M_1, M_2, and M_4 are computed based on industry energy demands and piping and extraction energy losses in transporting the steam to the industries. For conventional power plants these mass flows are set to zero.

Table 4 gives the steam enthalpies and boiler efficiencies assumed in the model for coal and nuclear utilities and industrial size boilers.

TABLE 4. ENTHALPIES* AND EFFICIENCIES USED IN POWER PLANT MODEL CALCULATIONS

Symbol	Coal-fired power plant	Nuclear power plant	Industrial power plant
N_1	0.85	0.85	0.8
N_2	0.92	0.92	0.8
N_3	0.90	0.90	0.8
N_4	0.87	0.87	0.8
h_0	550 (1280)	550 (1280)	550 (1280)
h_1	1422 (3299)	1191 (2763)	1505 (3492)
h_2	1281 (2972)	1089 (2526)	1359 (3153)
h_3	1514 (3512)	1278 (2965)	1359 (3153)
h_4	1359 (3153)	1278 (2965)	1359 (3153)
h_5	1106 (2566)	1003 (2327)	1106 (2566)
h_6	68 (158)	68 (158)	68 (158)
h_7	68 (158)	68 (158)	68 (158)
h_8	68 (158)	68 (158)	68 (158)

*Units: Btu/lb (kJ/kg)

By-product fuel may be burned in industrial boilers. For industrial power plants, a check is made to see whether industry demands can be met with by-product fuel alone. If not, industrial boiler mass flow is set equal to total mass flow demanded by the industrial process. Additional fuel requirements are then computed. If the particular industrial power plant also provides electricity, then the electricity generated is computed. Condensing in the industrial utility only occurs when H_{TOTAL} exceeds industrial energy needs.

Piping Energy Loss Model

Energy losses due to transporting steam occur due to friction in the pipes and losses through pipe insulation. Therefore, the energy loss will depend on the temperature and velocity of travel of the steam and the distance the steam is transported. In general, pipe size and insulation are selected based on economics in such a way that the losses can be assumed to be a function of the distance the steam is transported. As a result, the total mass of steam that must be supplied by the power plant can be approximated by (3).

$$M_S = M_D \Big/ (1 - L)^x$$

where

M_S = mass shipped in 10^6 lb/hr (= 7.94×10^3 M_S' (Kg/hr))

M_D = mass demanded in 10^6 lb/hr (= 7.94×10^3 M_D' (Kg/hr))

L = fraction lost per mile (= 1.61 L' (Km^{-1}))

x = number of miles (= 0.621 X' (Km))

Energy Efficiency Model

Energy efficiency is defined as the ratio of useful energy output to fuel energy input. For the case of conventional power plants, the only useful energy output is in the form of electrical energy produced. Inefficiencies in energy production occur due to 1) boiler heat losses, 2) extraction and piping thermal losses, 3) turbine thermal and frictional losses and 4) electrical generator losses. The primary source of energy loss, however, is the amount of heat ejected into the environment from condensation. Modern power plants have maximum total efficiencies on the order of 38 percent.

Industrial boilers are much more efficient due to the extraction of low grade steam for use in the industrial processes. Much of the heat wasted from the condensation is eliminated. Total energy efficiencies may be as high as 90 percent.

Cogeneration systems benefit from the same advantages as industrial sized boilers but on a much larger scale. By operating at higher temperatures and pressures, thermal energy may be produced even more efficiently.

However, much of the advantage of larger scale operation may be cancelled by the additional piping energy losses from piping extracted steam over larger distances.

The total energy efficiency, N_T, for each power plant is computed based on the useful electrical and thermal energy produced and the amount of fuel consumed as given in the following equation:

$$N_T = \frac{TH_S + EL}{TH_F}$$

where TH_S = total thermal energy supplied to the industries, $Mw_{thermal}$

EL = total electrical energy produced, $Mw_{electric}$

TH_F = total thermal energy in the fuel consumed, $Mw_{thermal}$

As noted earlier, all efficiencies of boilers and turbine stages are included in the power plant model and therefore are already included in the quantities TH_S and EL. For a conventional power plant, TH_S is zero.

Air Pollution Control Energy Loss Model

Table 5 presents the energy penalties, P_e, for air pollution control methods used on coal burning boilers. The energy penalty is defined to be the percent of plant output consumed. Pollution control systems consist of some combination of these control devices. The total control system energy efficiency, N_C, is computed as follows:

$$N_C = 100 \times \prod_{e=1}^{n} (0.01) \times (100-P_e)$$

where $\prod$ = indicates taking products

n = number of control devices

P_e = energy penalty for a given device, %

N_C = total energy efficiency, %

ENERGY ANALYSIS EXAMPLE CASE

Figure 7 displays the hourly fuel demands of the example case energy systems. All boilers use coal. In the status quo system, the industrial boilers burn 5.0 terajoules of coal hourly. In both the cogeneration system and status quo system, the power plant consumes 12.5 terajoules of coal per hour. To replace the electrical capacity lost, 2.2 terajoules of coal are combusted hourly in the supplementary utility. Thus, to produce the same amount of electricity and steam, the cogeneration system uses about 15 percent less fuel. If the industrial boiler in the status quo system burned natural gas or fuel oil, replacement of the example case

TABLE 5. ENERGY PENALTIES FOR POLLUTION CONTROL METHODS ON COAL BURNING BOILERS (PERCENT OF PLANT OUTPUT CONSUMER = PENALTY)

Control method	Penalty[1,2]
Electrostatic precipitator	0.2%
Flue gas desulfurization (non-regenerative limestone scrubbers)	5.0% (3.6 - 7.0% Range)
Combustion modification	Negligible
Flue gas treatment(dry)	3.0% (3.0 - 7.0)
Simultaneous flue gas treatment (wet and dry)	7.0%
Fluidized bed combustion, first generation(atmospheric and pressurized)	5.0%
Fluidized bed combustion, ultimate	0%

[1] These penalties represent a starting point for an analysis and not especially hard data. A sensitivity analysis with respect to the energy penalties would be in order to determine the true impact they may have on cogeneration system and status quo system economics. This is especially true in regards to flue gas treatment, flue gas treatment simultaneous, atmospheric fluidized bed combustion, and pressurized fluidized bed combustion values which are not well documented.

[2] The natural draft cooling tower energy penalty was built into the system baseline efficiency data. Data indicates the penalty can range significantly from 1 - 12 percent with an average of 2 - 4 percent. (Based on information in Development Document for Effluent Limitation Guidelines and New Source Performance Standards for Steam Electric Power Generation Point Source Category, U.S. EPA, Oct. 1974, p. 625.)

(References: 4, 5, 6, 7, 8, 9, 10, 11, 12, 13)

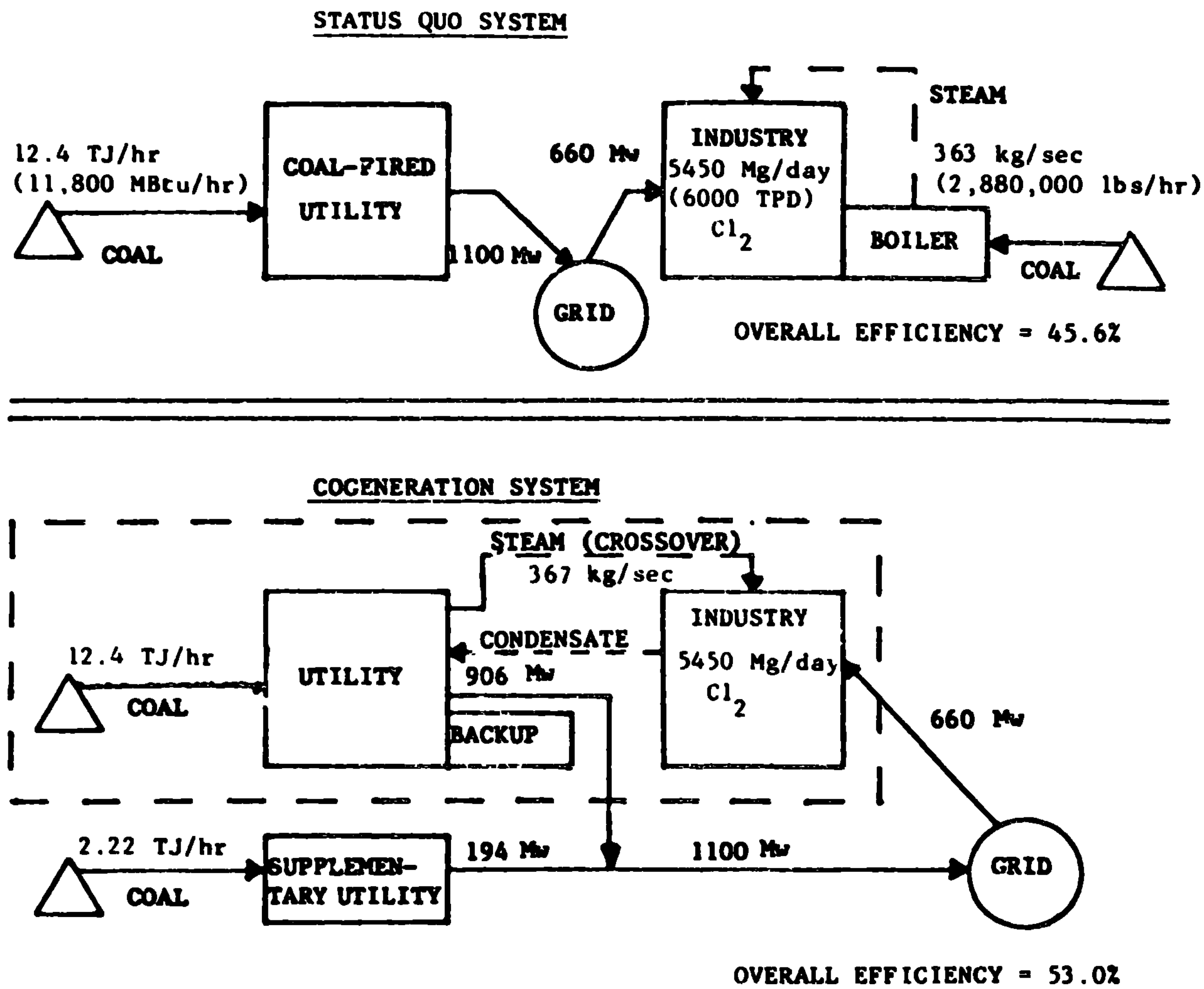

Figure 7. Coal-fueled example case.

industrial boilers with extracted steam would save about 35 trillion Btu's of these critical fuels annually, although an additional 15 trillion Btu's of coal would be combusted.

The example case cogeneration system consumed 20 trillion Btu's less fuel than the status quo system annually, or 15 percent of total combined utility and industrial consumption. The efficiencies of the cogeneration and status quo systems can be computed as discussed earlier. The efficiency of the status quo system power plant (N_{SQPP}) is computed as follows:

$$N_{SQPP} = \frac{\text{electrical output}}{\text{fuel consumed}} = \frac{1100 \text{ Mw} \times 3.601 \text{ GJ/Mwhr}}{12{,}416 \text{ GJ/hr}} = 0.319.$$

The efficiency of the status quo industrial boilers (N_{SQ}) is assumed to be 80 percent. The overall efficiency of the status quo system can then be determined by dividing total work output by total fuel input:

$$N_{SQ} = \frac{(1100 \times 3.601)\text{GJ/hr} + 3977 \text{ GJ/hr}}{12{,}416 \text{ GJ/hr} + 4971 \text{ GJ/hr}} = 0.456.$$

The efficiency of the cogeneration system power plant (N_{CSPP}) can be determined by dividing the total electrical output plus the industrial work output (equal to that in the status quo system) by total fuel consumption.

$$N_{CSPP} = \frac{(906 \times 3.601)\text{GJ/hr} + 3977 \text{ GJ/hr}}{12{,}416 \text{ GJ/hr}} = 0.567.$$

The power plant efficiency improvement is quite substantial, as the cogeneration system power plant is almost twice as efficient as the status quo power plant. However, to compute the overall efficiency of the cogeneration system (N_{CS}), the efficiency of the supplementary utility must be included. Thus,

$$N_{CS} = \frac{(906 \times 3.601 + 3977 + 194 \times 3.601)\text{GJ/hr}}{(12{,}416 + 2780)\text{GJ/hr}} = 0.530,$$

which represents a 17 percent improvement in overall efficiency.

The fuel savings and energy efficiency improvements found in the example case energy analysis are an important factor in favor of cogeneration systems. As current national goals are directed toward energy conservation, cogeneration systems are definitely in the national interest. To put things in perspective, annual fuel consumed by electric utilities totaled approximately 21 exajoules in 1977. If one third of all electric generation had occurred in cogeneration system-type configurations with efficiency improvements similar to the example case, total fuel consumption would have declined 2.8 exajoules, which is 3.2 percent of 1977 energy consumption.

SECTION 6

ENVIRONMENT

ENVIRONMENTAL ANALYSIS

One of the primary concerns of this study was to investigate how environmental considerations impact the viability of cogeneration systems. Four specific environmental aspects are considered in this study: 1) air emissions, 2) water consumption, 3) solid waste production, and 4) wastewater treatment. The following subsections contain the methodology, analysis, and regulations related to each aspect.

Air Emissions

The quantity of air pollutants produced by a power plant is determined basically by the concentration of the pollutant in the fuel and the quantity of fuel burned. The basic form of the equation used for computing air emissions is given below.

$$E_A = EF \times 8760 \times FUEL \times PF \times (1-N_c)\ (10^{-3})$$

where

E_A = annual emissions of pollutant in kilograms

EF = emission factor for pollutant in g/GJ of heat obtained from fuel burned

$FUEL$ = fuel consumption in GJ/hr at rated boiler capacity

PF = power plant factor

N_c = efficiency of pollution control

The five types of air pollutants considered in this study were: 1) particulates, 2) sulfur oxides, 3) nitrogen oxides, 4) carbon monoxide, and 5) hydrocarbons. An emission factor (EF) is associated with each pollutant for each fuel considered. Table 6 presents emission factors for each fuel considered. A number of pollution control technologies exist. Table 7 gives the types of air pollution control equipment considered along with efficiency of collection, N_c, for particulates, sulfur oxides and nitrogen oxides. Since electrostatic precipitators are considered to be present in all power plants using coal or high Btu natural gas, it is assumed for simplicity that all particulates collection is due to electrostatic precipitators with no collection due to any other control equipment.

Air pollution control equipment is grouped into six system types for

TABLE 6. LIST OF EMISSION FACTORS (g/GJ)

Fuel	Particulates	Sulfur oxides	Carbon monoxide	Hydro-carbon	Nitrogen oxides
Coal	2690	1560	18	6.0	335
Nuclear	----	----	----	----	----
Fuel Oil	22	6.0	.086	9.0	292

(Reference: 14)

TABLE 7. LEVEL OF EMISSION CONTROL FOR UTILITY AND INDUSTRIAL AIR POLLUTION CONTROL METHODS

	Percentage of emission eliminated by pollutant type		
Method of control	Particulates	Sulfur oxides	Nitrogen oxides
Electrostatic precipitators	98.5%	-	-
Flue gas desulfurization (Non-regenerative limestone scrubbers)	-	90%	-
Combustion modification	-	-	50%
Dry flue gas treatment	-	-	90%
Simultaneous dry flue gas treatment	-	90%	90%
Simultaneous wet flue gas treatment	-	90%	90%
Atmospheric fluidized bed combustion	-	90%	60%
Pressurized fluidized bed combustion	-	90%	80%

(References: 12, 13, 15, 16, 17, 18, 19, 20, 21) large utilities and three types for industrial boilers (14). The air pollution control systems are defined as in Table 8.

TABLE 8. AIR POLLUTION CONTROL SYSTEMS USED IN ANALYSIS

Utility Systems*	Industrial Systems
Electrostatic Precipitators + Flue Gas Desulfurization + Combustion Modification	Electrostatic Precipitators + Flue Gas Desulfurization + Combustion Modification
Electrostatic Precipitators + Flue Gas Desulfurization + Dry Flue Gas Treatment	Electrostatic Precipitators + Fluidized Bed Combustion
Electrostatic Precipitators + Dry Flue Gas Treatment, Simultaneous	Electrostatic Precipitators**
Electrostatic Precipitators + Wet Flue Gas Treatment, Simultaneous	
Electrostatic Precipitators + Atmospheric Fluidized Bed Combustion	
Electrostatic Precipitators + Pressurized Fluidized Bed Combustion	

* Assumed natural draft cooling tower used to control thermal emissions in all cases unless otherwise indicated.

**Assumed SO_x control not necessary.

Siting of cogeneration systems can be impacted by a number of environmental concerns and regulations. New source performance standards are air emission standards for seventeen types of new or substantially modified stationary sources that have been established by EPA. The only one of these source types relevant to this discussion is coal-burning steam-electric generators having a heat input greater than 264 GJ/hr. These standards described below limit the amount grams/GJ of particulates, SO_x and NO_x emitted by the emission source (22). It is not anticipated that these standards would have a constraining effect on the development of cogeneration systems, at least no more so than on a conventional utility. 1971 standards were used.

(a) Particulate Matter:

(1) 43 grams/GJ heat input (0.1 lbs per million Btu).

(2) No more than 20 percent capacity visible emissions, except for 2 minutes in any hour visible emissions may be as great as 40 percent capacity.

(b) Sulfur Dioxide:

(1) 340 g/GJ heat input (0.8 lb per million Btu) when oil is fired.
(2) 520 g/GJ heat input (1.2 lb per million Btu) when coal is fired.

(c) Nitrogen Oxides (as NO_2):

(1) 86 g/GJ heat input (0.20 lbs per million Btu) when gas is fired.
(2) 130 g/GJ heat input (0.30 lbs per million Btu) when oil is fired.
(3) 300 g/GJ heat input (0.70 lbs per million Btu) when coal is fired.

National ambient air quality standards were developed in 1971 for six pollutants to reflect thresholds of atmospheric concentrations above which the pollutants are thought to have significant deliterious effects on human health and/or on plant and animal life and property. These pollutants are particulate matter, sulfur oxides, nitrogen oxides, carbon monoxide, photochemical oxidants, and hydrocarbons. The national ambient air quality standards are expressed in terms of primary and secondary standards. The primary standards are specified to protect public health, and the more stringent secondary standards are set to protect against effects on soil, water, vegetation, materials, animals, weather, visibility, and personal comfort and well being. The primary standards are to be met nationwide in each air quality control region by 1982 and the secondary standards are to be met in a reasonable time thereafter, as determined by the EPA (22). Of the six pollutants, only three are of significant importance to the burning of coal from a stationary source. These are particulate matter, sulfur oxides (measured as sulfur dioxide) and nitrogen oxides (measured as nitrogen dioxide). The other three pollutants, carbon monoxide, photochemical oxidants and hydrocarbons are of more importance when analyzing emissions from mobile sources such as automobiles.

These standards can work to help or hinder development of cogeneration systems depending on conditions in the local air quality control regions. Because a cogeneration system is more efficient than a status quo system, it produces less emissions per unit of time. However, even though the total emissions are less than in a status quo system, and even though it can meet new source performance emission standards, there is the possibility it could cause national ambient air quality standards to be degraded locally. This is because a cogeneration system is a centralized complex. Industrial process emissions are not reduced in cogeneration systems because they are a result of the manufacturing process and not the fuel combustion process. Therefore, a cogenera tion system centralizes these emissions.

However in the status quo system, the industrial plants may be miles apart (often in different air quality control regions), thereby allowing better dispersion of the air pollutants and impacting national ambient air quality standards less severely. Also, if the supplementary utility capacity of the cogeneration system is located on site (rather than have the lost generating capacity made up at a different location, perhaps in another air quality control region), then the cogeneration system would have an increased negative impact on the national ambient air quality standards.

In the example case, if the cogeneration system is oversized by the supplementary utility capacity (194 Mw), then it is producing at least 20 percent more emissions at that point (ignoring cogeneration system industrial process emissions) than a status quo power plant at the site. The status quo industries could be scattered many miles away producing more pollution overall but having a much better chance for dillution. However, it is doubtful that these differences would significantly impact the cogenerating system siting in a particular air quality control region unless the region's pollutant concentrations are nearing the pollution limits or if the region has non-attainment status. Cogeneration systems would not normally be excluded from areas where large utilities locate and should always be acceptable in small locales where a conventional utility and industries could site with no problems. In an area where air quality limits are becoming critical but industrial development is being encouraged, cogeneration would be a more favorable approach than status quo development (assuming development is fairly concentrated).

A more recent regulatory development is the prevention of significant deterioration standards which has a greater potential to directly affect the placement of coal burning devices. These standards, promulgated under the Clean Air Act as amended in August 1977, state how much of an increase a single source can add to the ambient air quality of a particular region for particulate matter and sulfur dioxide. There are three classes of prevention of significant deterioration standards. All areas of the country will be designated as either Class I, Class II, or Class III for application of the these deterioration standards. Class I standards allow the smallest incremental increase in the ambient air quality. Congress has already designated areas of pristine air quality, such as certain national and international parks and national wilderness areas, as Class I regions. Areas designated for application of Class II standards are allowed a larger incremental increase in ambient air quality, though not as large as allowed in Class III areas. National ambient air quality standards will act as an overriding ceiling to any otherwise allowable increment. This includes all specified national ambient air quality standard pollutants--not just particulate matter and sulfur dioxide. The prevention of significant deterioration statutory scheme will not be fully effective until the states and/or EPA undertake further rule-making activity. The prevention of significant deterioration regulations state that all areas not classified as Class I will be designated Class II (23). A reclassification process is involved in changing any area to Class III. This reclassification involves, among other items, specific approval from the governor of the affected state after consultation with the state legislature and with local governments representing a majority of the residents in the area which is to be redesignated.

Major pollution-emitting facilities are required to have a prevention of significant deterioration permit before construction can begin. The permit acknowledges that all prevention of significant deterioration emission requirements will be met by the facility; that the proper procedures have been undertaken (hearings, review, analysis of air quality impact, etc.); that the best available control technology for each pollutant is obtained; and that proper air quality monitoring will be done. Twenty-eight specific emitting facilities are defined in the Clean Air Act (some of which are steam electric power plants with more than 264 GJ/hr (250 MBtu/hr) input, Kraft pulpmills, and Portland cement plants) as requiring permits if they emit one hundred tons or more of any air pollutant annually. Also the permit requirements include other facilities which are not specified but which have the potential to emit two hundred and fifty tons or more per year of any pollutant. These permit requirements also apply to major modifications to existing facilities. *

Prevention of significant deterioration standards could inhibit cogeneration system siting even though new source performance standards would be met and national ambient air quality standards would not be exceeded. "Prevention of significant deterioration requirements, however, can deny the use of a site for a power plant even though the best available control technology is used" (22). Studies have indicated that in many areas prevention of significant deterioration requirements would dictate emission controls significantly more stringent than new source performance standards or that overall facility size would be limited (25). It would be difficult for a cogeneration system to site in a Class I area. Most conceivable cogeneration systems should not have problems siting in a Class III area. The Class II areas, in which most of the country will be located, are where site specific conditions will determine cogeneration system acceptability. Local weather conditions can have significant impacts on prevention of significant deterioration evaluation. It is also in these Class II areas that innovative engineering approaches and systems designs may play a crucial role in the acceptability of cogeneration systems.

Local vs. National Concerns--

A paradox about cogeneration system is that because combustion is centralized it is more efficient and less emissions are produced. Yet combustion occurs at one facility in a centralized manner and therefore prevention of significant deterioration regulations would impact cogeneration systems more severely than a status quo configuration. This is because each of the decentralized industries and the utility component of a status quo system would be considered as individual point sources. Therefore, their incremental additions to ambient air concentrations are expected to be less than that made by the cogeneration system as an emission source, al-

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*For update on prevention of significant deterioration regulations, see "Prevention of Significant Deterioration: Workshop Manual," EPA 450/2-80-081 (October 1980).

though the total status quo additions could well exceed the cogeneration system additions. Thus, from a national viewpoint cogeneration systems can reduce air pollution when compared to status quo systems, but from a local viewpoint tney can have much more severe impacts. This dilemna raises the issue of whether cogeneration systems should receive special treatment in regard to prevention of significant deterioration.

Water Consumption

Steam power plants have two major requirements for water. The first is as a working fluid and the second is as a cooling medium.

Water that is used in the boiler is normally recycled many times. Therefore, the only water requirement is that used to replace water that is lost from leaks and control measures such as blowdown. For conventional power plants, the water requirement for replacement of boiler feedwater may range from 10 to 100 gallons per minute. The replacement of feedwater is minimized because it must be treated and conditioned to satisfy a very exacting set of conditions which is very expensive.

Water requirements for cooling are much larger than for that used in the boiler. For every kW hr of electrical energy produced, 5000 to 8000 kJ must be eliminated the form of waste energy. To dissipate this heat into cooling ponds, cooling towers, etc. between 2300 and 5230 cu cm water are required for each kW hr. This is a significant water requirement (i.e. 49 to 114 cu m/min). Therefore, it is the cooling water that causes the most severe problem.

A cogeneration system reduces water consumption because of its increased efficiency in comparison to a status quo system. From a national viewpoint, significant amounts of water can be saved. Water requirements depend on the industries within the complex. Therefore, there is the possibility of the combined cogeneration system and industrial complex water demands being high at a point source thereby causing perturbations on a local scale even though national water savings occur.

Solid Waste Production

Solid wastes are assumed to be proportional to volume of fuel burned. The major source of this solid waste arises from the control of sulfur oxides. T following equation relates area (A), in hectares, used for waste disposal to amount of fuel burned:

$$A = \beta E_s$$

where β = hectares/million tonnes
E_s = solid residuals in tonnes/year

and $E_s = (N_c) \times FUEL \times EF \times PF\ (10^{-3})$

where N_c = efficiency of control equipment
FUEL = fuel consumption rate in GJ/hr
EF = emission factor for pollutant in kg/GJ of heat
PF = power plant factor.

For a conventional boiler, β is assumed to be 275 hectares/(million tonnes·year) for ash and flue gas desulfurization sorbent solid waste and is based on ponding to 9.2 m depth for 30 years. β is assumed to be 178 hectares/(million tonnes·year) for ash and fluidized bed combustion sorbent solid waste. This is making a pessimistic assumption since ash has been used for many years as a filler in construction materials, in which case the waste can be disposed of as a useful product instead of requiring land for disposal. Experience with the ash and limestone sorbent from the fluidized bed combustion unit at Georgetown University indicates that both of these materials are suitable for use in construction materials (26).

In a cogeneration system, land devoted to the disposal of solid waste is reduced in comparison with a status quo system by the percentage increase in efficiency if industry has controls of comparable efficiency. If flue gas desulfurization is used for control of surfur oxides emissions, the reduction in land required is important because the land committed for disposal of flue gas desulfurization solid waste (sludge) usually cannot be used for any other purpose because of the thixotrophic nature of the sludge. Substantial amounts of land will be used by coal cogeneration for disposal of solid waste.

Wastewater Combined Treatment

Municipal and pulp and paper plants costs were assumed to include raw waste dumping, preliminary treatment, primary clarification, aeration tanks, diffused air system, secondary clarification, two-stage lime clarification, recalcination, ammonia stripping, multi-media filtration, carbon absorption, break point chlorination, sludge thickening, anerobic digestion, dewatering, truck hauling, sanitary landfill, administration and lab facilities, site working and piping, engineering, legal and other costs. The Economy Scale Equations are the following (1 MGD = 0.044 cu.m./sec).

1) New Facility Capital Cost

$$= \$17.31 \times (10^6) \times \left(\frac{\text{New Facility Capacity in MGD}}{\text{20 MGD}}\right)^{.8683}$$

2) Operation and Maintenance Cost in \$/MGD

$$= \left(\frac{20}{\text{New Facility Capacity in MGD}}\right) \times \$235.5 \times \left(\frac{\text{New Facility Capacity in MGD}}{\text{20 MGD}}\right)^{.5702}$$

These potential savings derived form several plants in close proximity are in addition to those which would result from the increased thermodynamic efficiency of cogeneration.

Water and Solid Waste Regulations--

Wastewater treatment of industrial processed wastes are not directly affected by a cogeneration system. However, combined wastewater treatment can lower costs (i.e. economy of scale benefits). Even though a cogeneration system could meet effluent guidelines and new source performance standards in the same manner as a status quo system, there is the possibility that water quality degradation can occur, because of the close proximity of the industries. The cogeneration system effluent discharge could be considered one point source even if the different wastewater streams are not treated together. The treated effluent streams in a cogeneration system enter a receptor (probably a river) at basically one point. This potentially causes a much higher concentration of water pollutants than would occur in the status quo system. The water discharge from the status quo plants would be released miles away from one another causing a lower concentration at any one point in the effluent receptor.

It is possible for treated wastewater to meet EPA effluent guidelines and new source performance standards and exceed state water quality standards which are subjective in nature. A water quality definition for the state of Georgia is based on acidity, bacteria levels, water temperature, and "freedoms," ("free from materials associated with municipal or domestic sewage, industrial waste or any other waste which will settle to form sludge deposits that become putrescent, unsightly, or otherwise objectionable") (22). It is easy to see the subjective nature of the definition and how similar types could possible impede cogeneration system siting.

In a cogeneration system that combines municipal and industrial waste treatment facilities, institutional constraints would have to be overcome. Many industries would rather pay a penalty fee for treatment of their effluent by a municipal waste treatment plant and write that fee off on their taxes than build their own plant and undertake the financial risks involved (27). The penalty fee could be applied to cogeneration system, as the municipality could own and operate the integrated wastewater treatment complex. Wastewater treatment plants constructed by industries are usually meant to have shorter lives than municipal facilities because of the risks surrounding process changes and changes in wastewater regulations. A joint venture in a wastewater treatment facility involves negotiations on who pays for what, and usually this is not a very straightforward process. A municipal system can be built using longer term, lower interest bonds. Municipal ownership can overcome some institutional barriers. Problems may represent somewhat of a barrier to cotreatment facilities in a cogeneration system. However, municipal and industrial facilities have engaged in joint ventures in constructing wastewater treatment facilities.

ENVIRONMENTAL ANALYSIS EXAMPLE CASE

The environmental example case analysis examines the major impacts of cogeneration systems on the surrounding physical environment. The analysis emphasizes air emissions, water consumption, solid waste production, and wastewater treatment. With the exception of wastewater treatment, the impacts are treated in comparative fashion; that is, the results are the net increase or decrease in the effect of the impact due to the cogeneration system. Combinations of wastewater treatment facilities are treated as additional options available in a cogeneration system.

Air Emissions

The major determinants of the amount of air pollutants emitted from combustion are amount of fuel consumed and types of pollution control devices installed. The combustion activities in the example case cogeneration system include the main power plant (972 Mw), back up power plant and the supplementary power plant (194 Mw). The cogeneration system substitutes for combustion in industrial boilers and in the conventional power plant. The example case cogeneration system consumes 17 percent less fuel than the comparable status quo system. Therefore, because air emissions are proportional to the amount of fuel burned, there are 17 percent less pollutants produced by the cogeneration system than the status quo system. Figure 8 shows the net reductions in emissions in a cogeneration system versus the amount of steam extracted from the utility and transferred to the industrial plants in a cogeneration system. The analysis assumes that the same pollution control systems are used by the cogeneration system and status quo system (ESP + FGD + CM). The figure indicates that as more steam is extracted from the utility, there is a greater reduction in net emissions. This is because the overall efficiency of the cogeneration system is increasing as more steam is extracted. The amount of pollution reduced in the example case is represented by the far right portion of the lines in Figure 8. The decrease in emissions in the example case is as follows:

particulates = 8.2×10^5 kg/yr

sulfur oxides (SO_x) = 3.6×10^6 kg/yr

nitrogen oxides (NO_x) = 3.2×10^6 kg/yr

carbon monoxide = 8.6×10^5 kg/yr

hydrocarbons = 4.1×10^5 kg/yr

The significance of the reduction in air emissions can be determined by computing the cost of controlling a kilogram of pollutant and multiplying by the amount of reduction. Table 9 displays the procedure by which the cost of control is quantified. The total reduction in air emission control costs is approximately $7.02 million. The regulatory and other related issues concerning this beneficial aspect are discussed in a previous subsection.

Water Consumption

Reductions in water consumption can be achieved in a cogeneration system because the increase in thermal efficiency results in less evaporative loss from cooling towers. In the cogeneration example case, 0.15 cu m of water per sec are saved from evaporation, enough water to meet

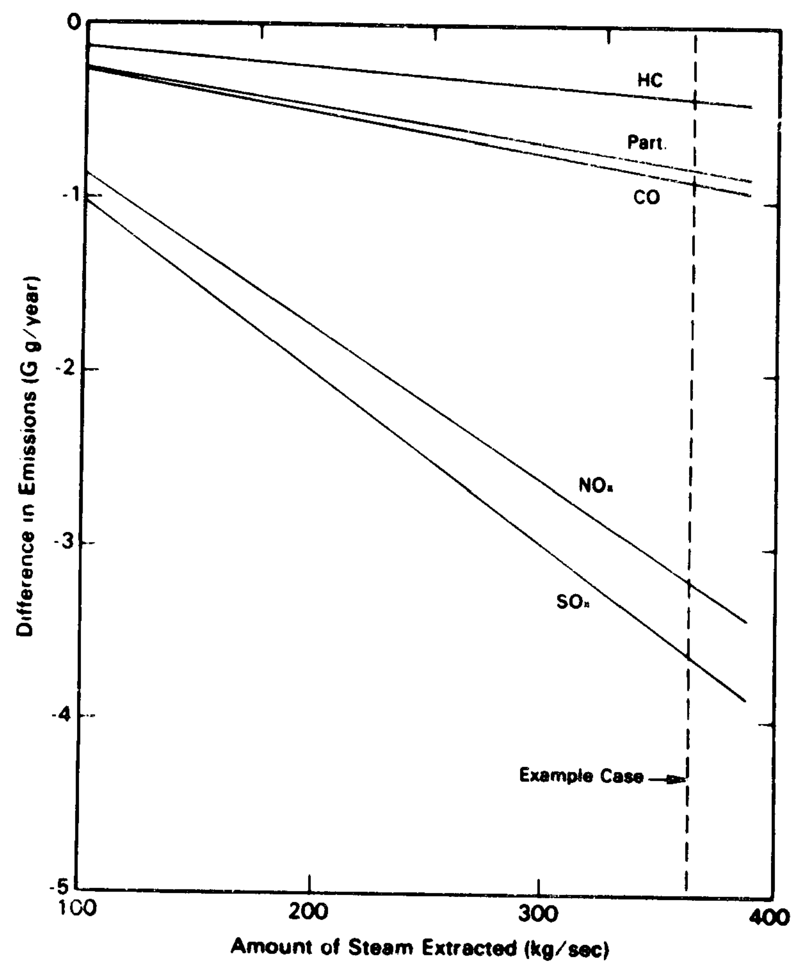


Figure 8. Reduction in emissions for a cogeneration system compared to a status quo system.

the daily needs of 28,000 people. The annual cost savings in demineralized make-up water (which are included in the computation of the net present value) are $919,800 for 3873 cu.m. (1,022,000 gallons).

TABLE 9. ESTIMATED COST SAVINGS DUE TO POLLUTION CONTROL REDUCTION

	Cost of control ($/GJ burned)	Cost savings in cogeneration system due to decreased fuel consumption (millions of 1977 dollars)
Particles	0.05	0.88
Sulfur oxides	0.30	5.61
Nitrogen oxides	0.03	0.53
Total		7.02

Solid Waste Production

Table 10 displays the amount of solid waste produced and the amount of land necessary for the disposal of the solid wastes from flue gas desulfurization, fluidized bed combustion, and electrostatic precipitation in the example case. Even though less solid waste is produced by the flue gas desulfurization method, the fluidized bed combustion waste requires less land area for disposal because of the inability to compact flue gas desulfurization waste. Because the amount of solid waste produced is directly proportional to the amount of fuel burned, there is a 17 percent decrease in the amount of solid waste produced and the amount of land used for waste disposal. The reduced solid waste load is especially important in the flue gas desulfurization case because of the inability to reclaim the land used for disposal. The amount of land saved over a 30 year life span from usage as a receptor is 60.0 ha for flue gas desulfurization waste and 47.4 ha for fluidized bed combustion waste. Despite these savings, the total amount of land required for disposal for the cogeneration system solid waste is 241 ha in the flue gas desulfurization case and 224 ha in the fludized bed combustion case.

Wastewater Combined Treatment

In a cogeneration system, there are many possibilities for combining

TABLE 10. SOLID WASTE ANALYSIS OF EXAMPLE CASE

	Ash and flue gas desulfurization sorbent		Ash and fluidized bed combustion sorbent	
	Solid waste (10^9 kg/ year)	*Ponding Acreage required (hectares)	Solid waste (10^9 kg/ year)	**Landfill acreage required (hectares)
Status quo system	1.06	292	1.52	271
Cogeneration system	.88	241	1.25	224
Amount reduced	.18	51.0	.27	47.3

BASIS

- Status quo system = 16.8 GJ/hr, 80 percent annual load factor.
- Cogeneration system = 82.4 percent of status quo system fuel consumption, 80 percent annual load factor.
- Atmospheric fluidized bed combustion and pressurized fluidized bed combustion waste output assumed equal at 13 kg/GJ which includes ash and sorbent. Different estimates for atmospheric fluidized bed combustion (1.22 kg/GJ), and pressurized fluidized bed combustion (13.4 kg/GJ) were calculated but were combined into one value because of the uncertainties involved in the estimates.
- Flue gas desulfurization waste output is 9.0 kg/GJ which includes ash and sorbent.
- Ash waste composes approximately 4.3 kg/GJ of the waste output coefficients used, the rest being composed of sorbent.

* Ponded to 9.2 m depth for 30 years.

** Filled to 9.2 m depth for 30 years.

facilities other than energy production and supply, including transportation, pollution control, and utilization of waste products. Wastewater treatment presents intriguing possibilities in a cogeneration system. Waste products from an ammonia plant and a phosphoric acid plant can be used to treat the effluent from a pulp and paper plant. Effluent from a textile mill and pulp and paper plant can be combined with municipal wastewater to create a large wastewater treatment plant (2). The following combinations are analyzed.

I) 10.5 kg/s (1000 TPD) Kraft pulp and paper plant with an effluent of 1.5 cu m/s (35 MGD), 0.66 cu m/s (15 MGD) of municipal wastewater from a municipality of 120,000 people, and 2.19 kg/s (208 TPD) textile (carpet) mill with a 0.15 cu m/s (3.5 MGD) effluent flow.

II) the 10.5 kg/s pulp and paper plant and the 0.66 cu m/s municipal treatment facility.

III) the 10.5 kg/s pulp and paper mill and the 2.19 kg/s textile mill.

IV the 2.19 kg/s textile mill and 0.66 cu m/s of municipal wastewater.

V) a 10.5 kg/s phosphoric acid plant, a 10.5 kg/s pulp and paper mill, and an ammonia plant. (The chemical plant's waste streams supply phosphorous and nitrogen as nutrients to aid in the biological treatment of pulp and paper effluent.)

A summary of the benefits arising from the different wastewater treatment combinations analyzed in the study are presented below.

I) Pulp and paper (Kraft), municipal wastewater, textile (carpet) mill
Economy of scale derived capital and O&M cost savings
Municipal wastewater supply N and P nutrients for biological treatment of pulp and paper and textile wastewater

II) Pulp and paper (Kraft) and municipal wastewater
Economy of scale derived capital and O&M cost savings
Municipal wastewater supply N and P nutrients for biological treatment of pulp and paper wastewater.

III) Pulp and paper (Kraft) and textile (carpet) mill
Economy of scale derived capital and O&M cost savings

IV) Textile (carpet) mill and municipal wastewater
Economy of scale derived capital and O&M cost savings

V) Pulp and paper (Kraft), ammonia, phosphoric acid
Ammonia and phosphoric acid supply N and P as nutrients for biological treatment of pulp and paper wastewater

Table 11 displays the capital and annual operating and maintenance cost savings for the various cogeneration system wastewater treatment combinations considered. The cost savings achievable in Cases I-IV reflect the advantages of economy of scale when centralizing treatment processes. The savings are computed as the difference in costs between the sum of separate waste treatment facilities, as in the status quo system, and the cost of the centralized cogeneration system facility. Case V includes the cost saving due to utilization of effluent from the ammonia and phosphoric acid plants as a chemical in the treatment of biological waste from

TABLE 11 . COST SAVINGS FROM COMBINED TREATMENT OF WASTEWATER FROM VARIOUS COGENERATION SYSTEM INDUSTRIES

Cogeneration system wastewater treatment combinations		Total flow (cu m/s)	Capital cost savings (1977 dollars)	Annual operating and maintenance cost savings (1977 dollars)
I.	Pulp and paper, municipal and textile	2.34	4,350,000	1,380,600*
II.	Pulp and paper, and municipal	2.2	3,260,000	727,900*
III.	Pulp and paper, and textile	1.69	980,000	495,200
IV.	Textile and municipal	0.810	710,000	372,800
V.	Pulp and paper, ammonia, and phosphoric acid	1.5+	Not applicable	72,800*†

Basis: A 10.5 kg/s Kraft pulp and paper plant (1.5 cu m/s); municipality of 120,000 people (0.66 cu m/s); 2.19 kg/s textile (carpet) mill (0.15 cu m/s); 10.5 kg/s ammonia plant; and a 10.5 kg/s phosphoric acid plant with waste flow of roughly 8.5 (-5) cu m/s. See Appendix 1 for calculation of economy of scale benefits.

* \$72,800/year in N and P chemical cost savings are included based on values of \$14.6/kg for anhydrous ammonia, 6.6¢/kg for 35% phosphoric acid; BOD_5:N:P = 100:5:1; 0.035 kg/kg of pulp and paper plant wastewaters; 60% deficiency in N and P; and 340 operating days/year for all plants.

+ Spill rates of phosphoric acid of 0 - 2.5 (-3) kg/kg (0.1 (-3) kg/kg average) and 1.2 (-3) - 1.8 (-3) kg stripped ammonia/kg condensate supply enough P and N to supply the nutrient needs unless phosphoric acid waste flow drops below its average level.

Note: In the footnotes to this table powers of ten are shown in parenthesis. For example, 8.5 (-5) is 8.5×10^{-5}.

the other plants. The largest cost savings occur when the pulp and paper, textile, and municpal waste treatment functions are combined in a 2.34 cubic meters per sec facility, which is the largest of the four centralized cases. Savings on the order of $4.3 million in capital costs and $1.4 million in annual operation and maintenance costs are achieved. Savings in the other cases are directly related to the amount of centralization achieved, which is reflected in the size of the facility as measured in cubic meters per sec. The smallest savings occur when phosphoric acid and ammonia waste streams are used to supply nitrogen and phosphorous in the pulp and paper waste treatment facility. Their savings, approximately $72,800 per year, may be reduced substantially by the added costs of channeling the ammonia and phosphoric acid waste streams in the proper amounts to the pulp and paper treatment facility. The economy of scale cost savings are significant, especially when large volumes of wastewater are involved. The net present value of the 2.34 cubic meters per sec treatment facility is $21.5 million, assuming a 7 percent discount rate over a 30 year life. If the net present value of the cogeneration system in Case I is in the range of $200 million before including the wastewater treatment benefits, the net present value could increase by 10 percent to over $221 million if wastewater treatment is centralized.

Another aspect of wastewater treatment that a cogeneration system can impact is in decreasing the cost of the waste treatment process through heat addition. Increases in wastewater temperature within specific limits can increase the efficiencies of the physical, biological, and chemical techniques of wastewater treatment. Data indicates that the greatest cost savings occur from heat addition to biological (secondary treatment) components of wastewater treatment systems. The concept of operating the wastewater treatment component of a cogeneration system at elevated temperatures provides two opportunities for economic benefits. First, cost savings are possible through a reduction in size of the more efficient wastewater treatment facilty, and second, heat from the cogeneration system power plant which otherwise would be wasted can be utilized with a potential savings through the reduction in size of heat rejection equipment. A study by the New York State Atomic & Space Development Authority that examined the costing of nuclear power plants, wastewater treatment plant, and water distillation plant looked at the potential of the usage of heat in the wastewater treatment process (27). Because the addition of heat increases biological activity and settling rates, smaller size equipment can be used to achieve the same level of performance that existed without heat addition. That study estimated that an increase in temperature from approximately 20 °C to 30 °C could allow reductions in the size of the following equipment:

grit chambers (27 percent smaller)
primary settling tanks (22 percent smaller)
aeration basins (18 percent smaller)
final clarifier (22 percent smaller)
gravity thickener (23 percent smaller)
vacuum filter facilities (14 percent smaller)

In the case of the 2.34 cubic meters per sec centralized treatment facility (Case I) an average 18 percent reduction in the size of the treatment facility would save $6.45 million in capital cost and $295,000 in annual operation and maintenance costs when compared to the non-heated centralized facility. However, the cost of heat exchangers (which can be expensive) needs to be subtracted from the cost savings. It is not clear that the necessary heat exchanger technology exists at a low enough price to make heat addition economically sound. Heat exchanger fouling is also a problem in configurations where the heat exchanger is in contact with the wastewater. The heating of the air that is pumped through the secondary treatment unit, which supplied oxygen for stimulating the growth of the biological mass, may be an easier mode of transferring heat to the wastewater than direct heating of the wastewater through the heat exchanger. The concept of heat addition to wastewater has had little study in the past. Heat exchanger heat transfer coefficients, heat exchanger fouling, heat exchanger costs, and alternative modes of heating wastewater need to be investigated in greater detail to determine if wastewater heating is a technically and economically viable means of reducing wastewater treatment costs.

The advantages of centralizing wastewater treatment facilities can be significant. However, the cost savings achievable will probably not be a primary impetus for the development of a cogeneration system as they are dwarfed by the cost savings due to energy efficiency improvements. The advantages of centralization just serve to increase the overall attractiveness of cogeneration systems.

SECTION 7

ECONOMIC

ECONOMIC ANALYSIS

The economic analysis methodology evaluates the economic viability of cogeneration systems. The cost-benefit analysis, described in Appendix A, is the basic economic analysis technique used. To facilitate the comparison of cogeneration systems with non-cogenerating alternatives, the MAIES computer model was utilized. A complete description of the computer model is given in Appendix C. However, the basic purpose of the model was to insure that comparisons were made in a concise manner. In addition, the computer model made it possible to make a large number of comparisons that could be used to generalize results. The computer model contains capital cost data, operating cost data and performance data for a wide range of components.

The cost curves used in the study are based on private industry and public sector documents, literature and interviews. The major cost components investigated are shown in Figure 9. The figure indicates which components are common to both status quo and cogeneration systems. The major substitution achieved by cogeneration is the replacement of industrial boilers with supplementary utility capacity. The steam conventionally derived from the industrial boilers is supplanted by steam extracted from a modified utility power plant. Supplementary capacity is needed because steam that is extracted from the modified power plant can no longer produce electricity. The total electrical output of the power plant is therefore reduced, and electricity from another power plant must replace the capacity lost to keep total energy supplied the same. This allows a comparison to be made between the cogeneration and status quo systems based on a tabulation of costs, which does not require an assessent of the value of difference in energy produced. The cost of conventional utility power plants are well documented, however, there are very few instances of cogenerating systems that utilize utility size power plants. Therefore, the approach used to calculate the cost of a cogeneration system was to define a conventional or status quo power plant and then calculate the differences in cost of specific components to determine the cost of the cogeneration system. For example, some equipment, such as cooling towers and turbines, are smaller in the cogenerating power plant due to decreased steam flow after the extraction point. The sub-sections discuss the cost models used for the specific components of the two systems, define the specific values and assumptions inherent in the calculations, and present specific examples of comparisons

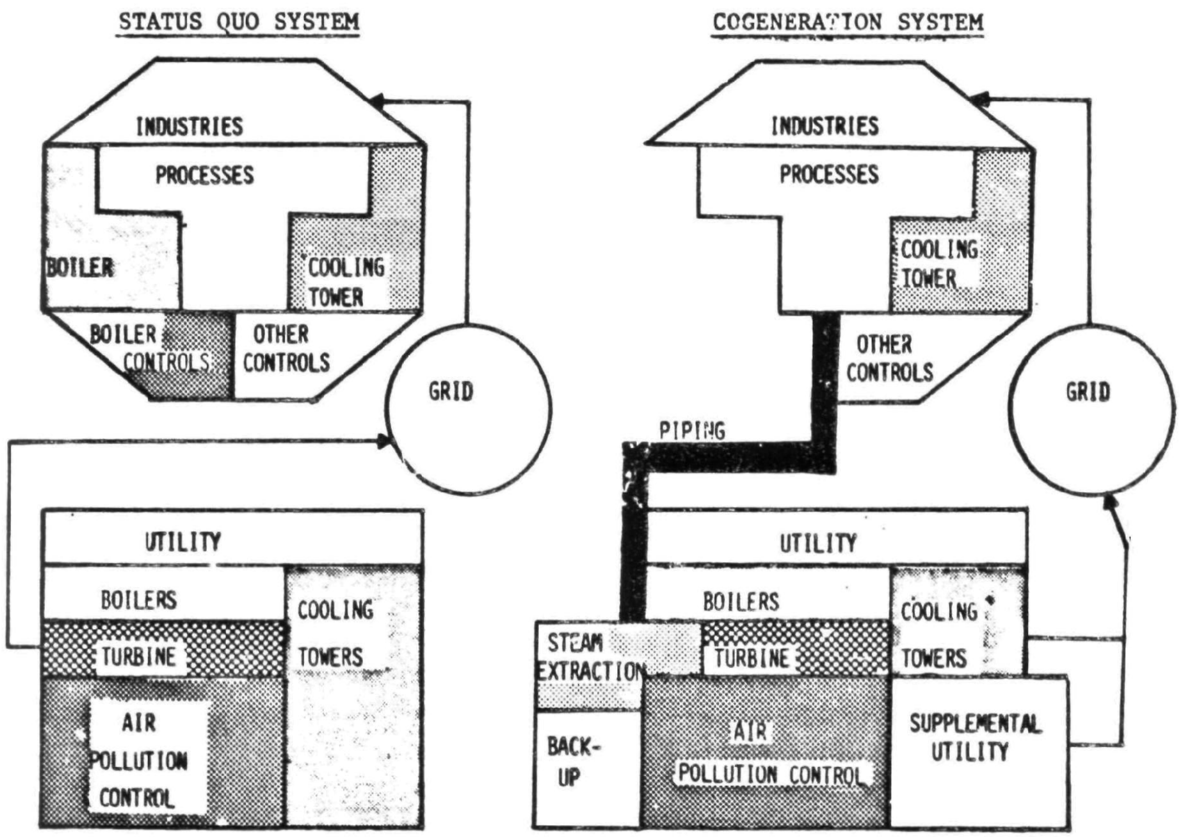


Figure 9. Schematic diagram of system components.

between cogenerating and non-cogenerating energy supply systems.

The cost models compute capital, operation and maintenance and fuel costs. The net present value model compares the two systems in an economic context. Costs which are incurred at different point in the 30 year time stream are discounted back to the present. Costs have been projected in real dollars; that is, only costs which will escalate faster or slower than the average inflation rate have been projected. Costs are projected using escalation rates, which do not include the average inflation rate. Thus, a cost that increases annually at 5 percent in current dollars when the average inflation rate is 5 percent, would have an escalation rate equal to zero. A cost increasing 8 percent annually would have an escalation rate of 2.85 percent. A real dollar discount rate must also be used in the analysis. The following are categories of costs which may be assigned different escalation rates.

- Capital costs
  - Utility power plants
  - Industrial boilers
- Operation and maintenance costs
  - Utility power plants
  - Industrial boilers
- Steam Piping
- Fuel Costs

The present worth factor when considering both escalation and discount rates is as follows:

$$PWF(d, e) = \frac{(1+x)^n - 1}{x(1+x)^n} = \frac{x^n - 1}{(x-1)x^n}$$

where

d = discount rate
e = escalation rate
$x = \frac{1 + d}{1 + e}$
n = lifetime of facility, (years)

The net present value (NPV) can then be computed as follows:

$$NPV = (C_{SQ} - C) + (O\&M_{SQ} - O\&M)\ PWF(d,e_{O\&M}) + (O\&M_{IND})\ PWF(d,e_{IND}) - (O\&M_{PIPE})\ PWF\ (d,e_{PIPE}) + (F_{SQ} + F_{IND})\ PWF(D,e_F)$$

where

C = Capital costs
O&M = Operation and maintenance costs
F = Fuel Costs
IND = Industrial systems

Status Quo System Costs

Figures 10 and 11 display cost estimates for conventional coal and nuclear power plants, respectively. Causes of such wide variance in estimates of coal fired power plant costs include: (28)

1. Failure to consider the same cost components (e.g. air pollution control devices, contingency fees, interest during construction).
2. Use of region specific variables.
3. Variation in the year in which the estimate was made.
4. Different assumptions for economic variables (e.g. capital recovery factor and the wholesale price index).
5. Use of estimtes obtained from different companies.

The cost curves used in the model are the lines plotted in the figures. These curves are based on Oak Ridge National Laboratory's ORCOST II model (29). All of the costs are adjusted to the same time frame in order to insure that the relative results indicate trends that are correct even if the magnitude is not exact. The curve for the coal-fired power plants are adjusted upwards (making these plants more expensive) to reflect differences between the ORCOST model estimates and other estimates. Both curves show an economy of scale factor which results in lower unit costs of power plants with increasing size. The dotted line displays this relationship. The model for cost of a power plant with no pollution controls is as follows:

$$\text{Coal power plant cost} = 1.915 \ (\text{Mw capacity})^{.763}$$

$$\text{Nuclear power plant cost} = .50 \ (\text{Mw capacity})^{.657}$$

Operation and maintenance cost estimtes also show significant variance. The operation and maintenance costs for similar plants differ markedly in any one year. Thus, any estimates reflect average annual values. The ORCOST II model was used to approximate these costs and can be represented in equation form as follows:

$$\text{Nuclear power plants} = 1.532 \ (\text{Mw capacity})^{.328}$$

$$\text{Coal power plants} = 0.924 \ (\text{Mw capacity})^{.388}$$

Estimates of the cost of cooling towers for coal-fired plants are as follows:

$$\text{Natural draft cooling towers} = .523 \ (\text{Mw capacity})^{.6}$$

$$\text{Forced draft cooling towers} = .372 \ (\text{Mw capacity})^{.6}$$

Operating and maintenance costs of cooling towers are assumed to be equal to 5 percent of the construction costs. The construction cost of cooling towers in nuclear plants is estimated by calculating the capacity of a coal fired plant that would eject the same amount of heat and using this capacity in the above equations. Therefore, the cooling tower model reflects the dependence of cooling tower costs on the amount of steam to be condensed,

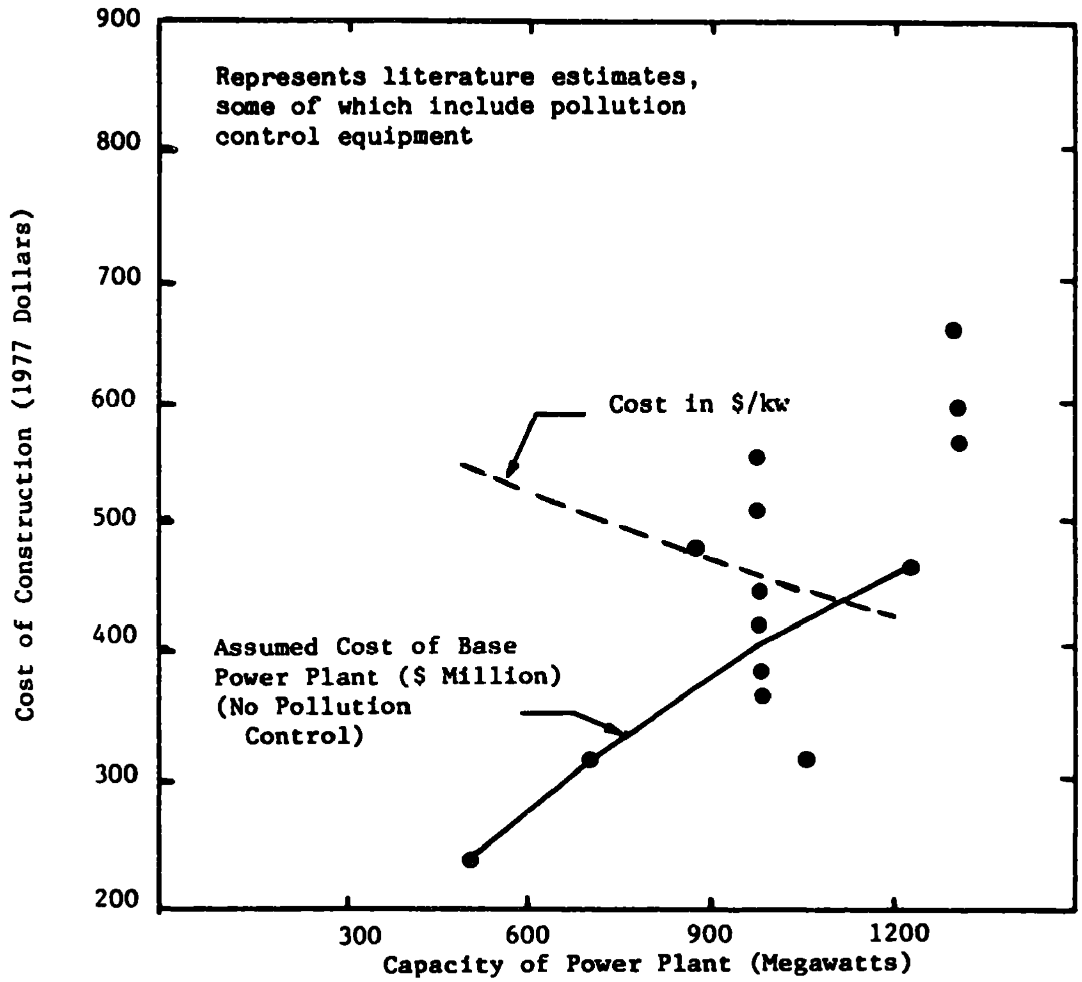


Figure 10. Cost of constructing coal-fired power plants.

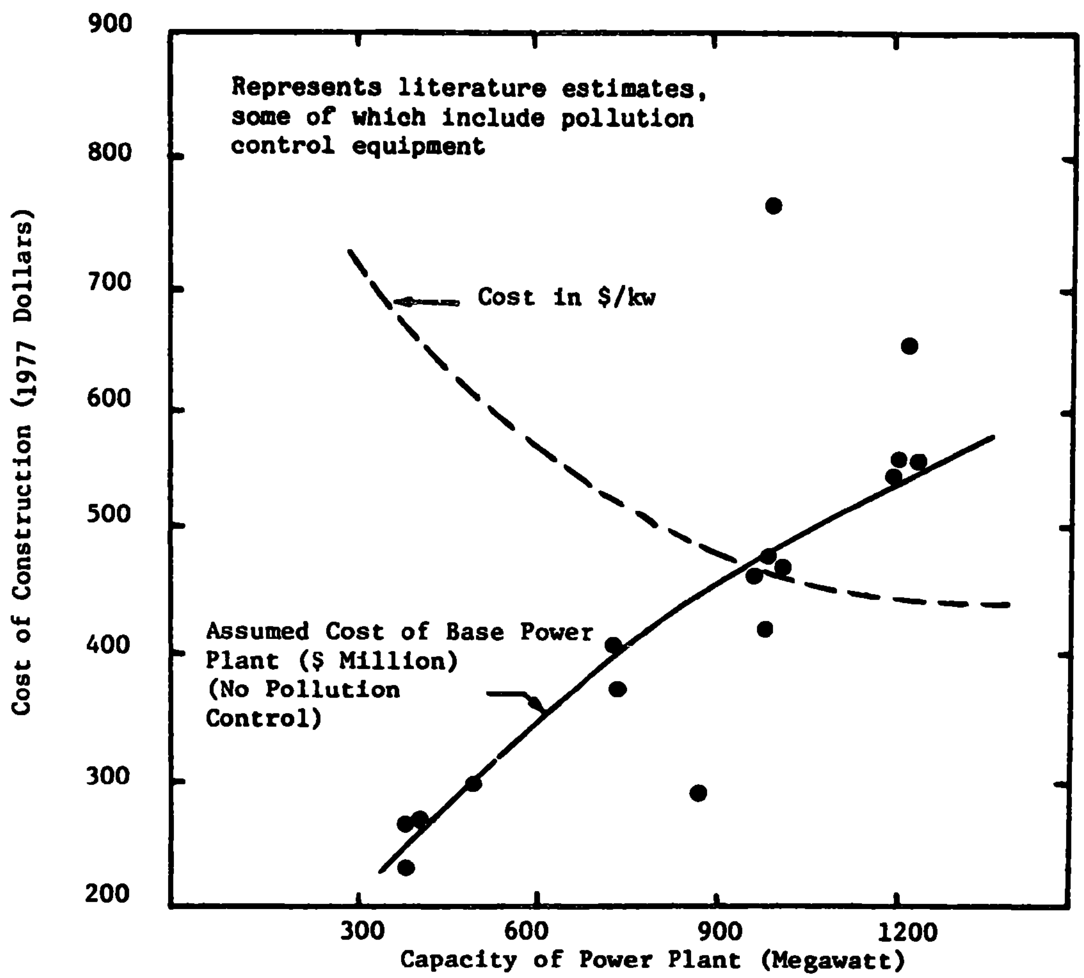


Figure 11. Cost of constructing nuclear power plants.

not the amount of electricity generated. Operation and maintenance costs of cooling towers for nuclear power plants are assumed to be equal to 5 percent of the construction cost.

Industrial boilers must be designed to deliver steam at the pressure and temperature needed for industrial processes. The cost of industrial boilers can vary widely depending on alternatives and special features required by the specific application. For purposes of comparison, the industrial boilers will be assumed to supply only thermal energy in the form of steam. The cost relationships were extracted from reports prepared for Oak Ridge National Laboratory (31). The relationship between capital cost and unit capacity is illustrated in Figure 12 for industrial size power plants.

In addition to presently utilized technologies, the atmospheric fluidized bed combustion boiler has the potential of providing cost effective alternative to the high expense of air pollution control equipment (31). This technology would replace present technology for both boilers and pollution control equipment. Discussion of the technological aspects of boilers is contained in Appendix B, and the projected costs of this type of boiler are illustrated in Figure 13.

Cogeneration System Costs

The construction cost of the cogenerating power plant is based on the cost of a conventional plant. The following modifications must be taken into account to estimate cogenerating power plant costs.

1) The cost of piping, steam extraction, and back-up equipment must be added to those of the conventional power plant.
2) Since steam is being extracted from the power plant, the intermediate and low pressure turbines can be smaller.
3) Also, due to steam extraction, less condensing and cooling requirements exist; thus, savings in the cost of this equipment can be achieved.
4) Because the status quo utility generates more electricity than the cogenerating plant, additional capacity must be added elsewhere in the system.

The cost estimates for piping include facilities for transporting process heat to and returning condensate from the industries. There are two components of this piping, the cost of extraction and the cost of piping itself. The cost of extraction is a function of the total amount of steam extracted, while the cost of piping is a function of the amount of steam shipped to each individual industry over a specified distance. Table 12 gives the estimates to be used for piping costs. Maintenance costs are assumed to be 5 percent of construction costs.

To calculate the savings in turbine costs, the following procedure was used:

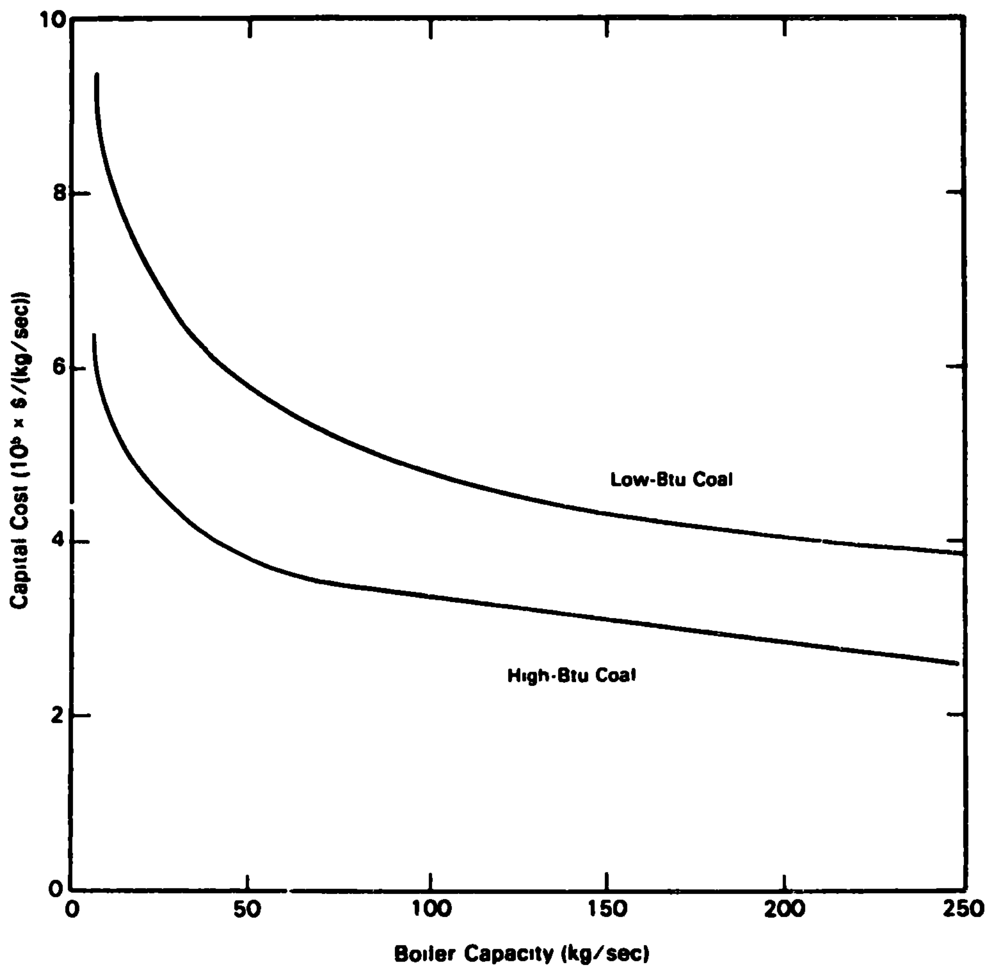


Figure 12. Unit capital costs of pulverized-coal steam plants. (Covers single-unit plants delivering 6.3 to 63 kg/sec, two-unit plants delivering 12.6 to 126 kg/sec, and four-unit plants delivering 23.2 to 232 kg/sec of steam.)

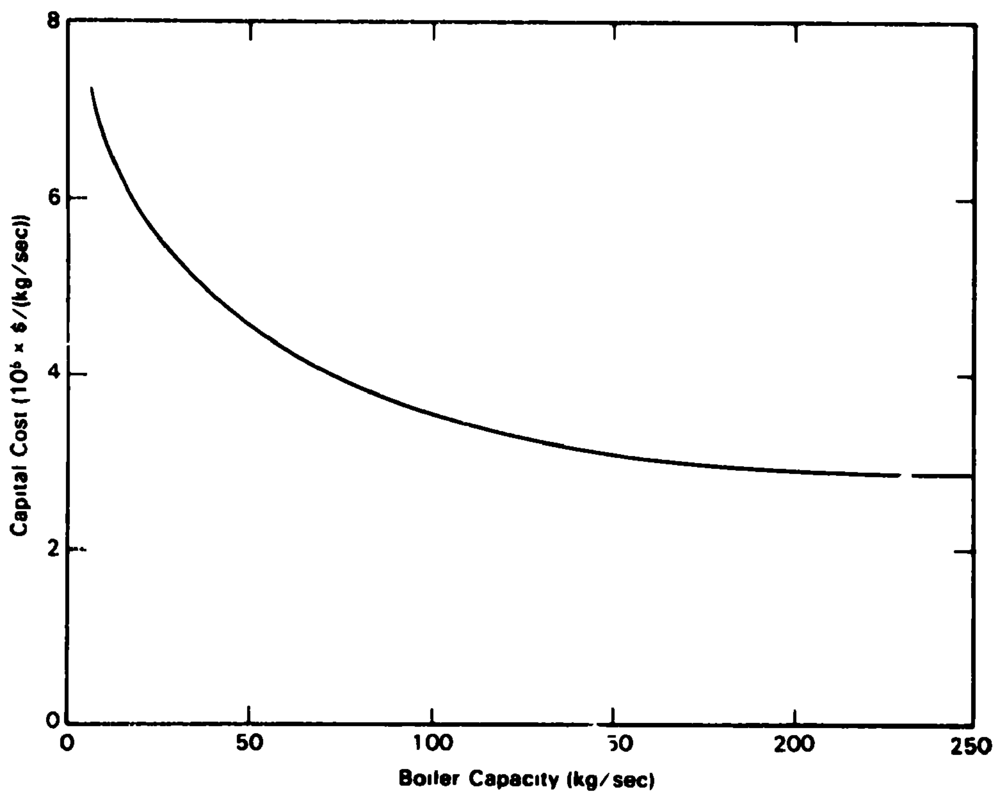


Figure 13. Unit capital costs of AFBC steam plant. (Covers single-unit plants delivering 6.3 to 63 kg/sec, two-unit plants delivering 12.6 to 126 kg/sec, and four-unit plants delivering 23.2 to 232 kg/sec of steam.)

1) The cost of turbine/generators in the status quo utility was computed based on the ORCOST II cost breakdown.
2) The cost of turbine/generators in the cogenerating power plant was estimated, based on the actual electrical output of the plant, using ORCOST II cost breakdown.
3) The cost savings are estimated as 1) minus 2).

TABLE 12. CAPITAL COST OF PIPING (1977 DOLLARS)

Technology	Cold reheat/ primary steam	Crossover steam
Coal extraction	$ 2.33 [MFR]	$ 2.21 [MFR] + $380,833
Piping cost/km	$469.80 $[MFR]^{.6053}$	$ 90.54 $[MFR]^{.7658}$
Nuclear extraction	$502.50 $[MFR]^{.679}$	$ 9.33 [MFR]
Piping cost/km	$ 33.14 $[MFR]^{.7059}$	$ 17.14 $[MFR]^{.9034}$

MFR = Mass Flow Rate in pounds/hour = 2.20 (Mass Flow Rate in kg/hr)

The formula for calculating turbine cost savings is shown in Table 13. This costing procedure is admittedly an approximation, but is well within the margin of error that exists in available sources of data.

TABLE 13. TURBINE COST SAVINGS

Type of power plant	Cost (1977 dollars)
Coal-fired plant	\$466,751 $(\text{Status quo system capacity in MW}_e)^{.71738} - \left(\begin{array}{l}\text{Cogeneration system electrical}\\ \text{generation in MW}_e\end{array}\right)^{.71738}$
Nuclear pressurized water reactor	\$505,707 $(\text{Status quo system capacity in MW}_e)^{.71738} - \left(\begin{array}{l}\text{Cogeneration system electrical}\\ \text{generation in MW}_e\end{array}\right)^{.71738}$

The cost savings achievable due to reduced condensing and cooling requirements can be related directly to total mass flow through this section of the power plant. Since the amount of steam extracted is known, reduced cooling costs can be computed based on the extracted steam. In general,

$$\text{Savings} = \left(\text{Cost of Conventional Cooling Facility}\right) \times \left[1 - \frac{MF_e}{MF_t}\right]^{\alpha}$$

where

MF_t = total steam condensed in cooling system

MF_e = amount of steam extracted

α = economy of scale factor

Table 14 shows the cost savings for different types of power plants. Operation and maintenance costs are reduced proportionately.

TABLE 14. COST SAVINGS DUE TO REDUCED COOLING REQUIREMENTS IN A COGENERATION SYSTEM WITH NATURAL DRAFT COOLING

Type of power plant	Cost (1977 dollars)
Coal-fired plant	$\left[1 - \left(\frac{\text{Mass Extracted}}{\text{Total Mass Cooled}}\right)\right]^{.6} \times \left(\text{status quo system cooling tower cost}\right)$
Nuclear pressurized water reactor	$\left[1 - \left(\frac{\text{Mass Extracted}}{\text{Total Mass Cooled}}\right)\right]^{.6} \times \left(\text{status quo system cooling tower cost}\right)$

Capital cost of additional capacity is computed based on the assumption it is provided by a conventional power plant located elsewhere on the utility network. The cost of additional generation is estimated to be a fractional component of the total cost of the power plant. Table 15 shows how to compute this cost. Operation and maintenance costs are computed similarly and added to the cost of the cogeneration system.

Fuel Costs

Fuel costs are the most critical variable in the analysis, and yet they are the least predictable. Eastern bituminous coal is presumed to be the primary fuel in the analysis, although alternative industrial fuels, such as Western coal and gasified coal, are also considered. Nuclear fuel is considered as an alternative for coal in utility size power plants.

The current and projected costs for fuels are shown in Figure 14.

The fuel costs model is straightforward. The power plant model computes annual fuel consumption which is multiplied by the cost of fuel to determine the annual cost of fuel. Fuel for providing industrial back-up steam requirements (Y) are computed as follows:

$$Y = \frac{(D)\ (8760\ \text{Hours/yr})\ BPF}{h_B \times N_p}$$

D = Hourly energy demand for steam at industry

BPF = Back-up Plant Factor

h_B = Enthalpy of back-up steam

N_p = Efficiency of back-up facility.

TABLE 15. COST OF ADDITIONAL GENERATION

Type of power plant	Cost (1977 dollars)
Coal-fired plant	Frac X 2,056,175$(\text{status quo system}_{\text{capacity}})^{.763}$
Nuclear pressurized water reactor	Frac X 4,434,861$(\text{status quo system}_{\text{capacity}})^{.6573}$
Nuclear boiling water reactor	Frac X 5,141,750$(\text{status quo system}_{\text{capacity}})^{.6573}$

$$\text{where Frac} = \frac{(\text{status quo system}_{\text{capacity}})-(\text{cogeneration system}_{\text{capacity}})}{(\text{status quo system}_{\text{capacity}})}$$

Air Pollution Control Costs

The costs of individual pollution control devices are listed in Tables 16 and 17. Table 16 displays the costs of the air and thermal pollution control devices for a 1000 Mw power plant and Table 17 displays the costs

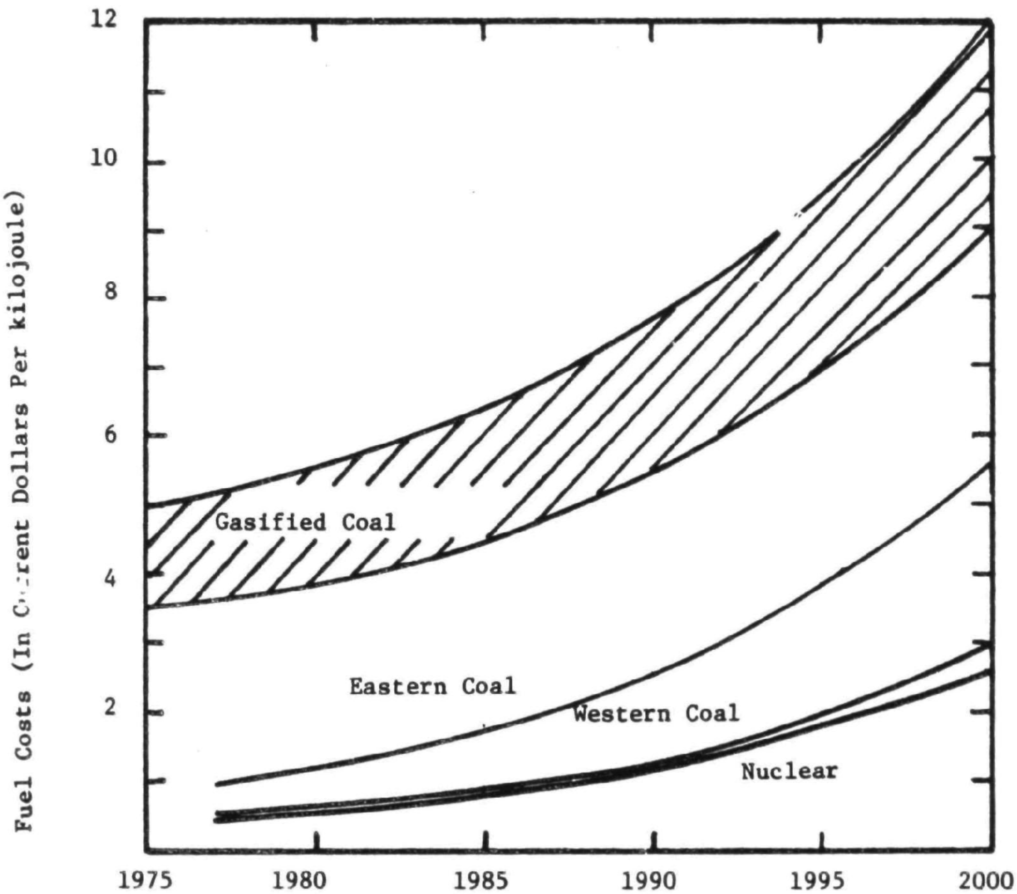


Figure 14. Cost of fuels.

TABLE 16. RANGE OF AIR AND THERMAL POLLUTION CONTROL EQUIPMENT COSTS FOR A 1000 MW UTILITY POWER PLANT

	CAPITAL ($/kw) ($/kg)			O&M ($/kwhr) ($/GJ)		
	High	Chosen	Low	High	Chosen	Low
Particulate						
Electrostatic precipitator	30 7.0	25 5.9	10.8 2.4	.0003 .030	.0002 .020	.00004 .004
SO_x						
Flue gas desulfurization	120 27.9	87 20	48 11	.0053 .530	.0014 .140	.0008 .080
NO_x						
Combustion modification	10 2.4	8 1.8	6 1.3	.00033 .033	.0002 .020	.0001 .010
Dry flue gas treatment	30 7.0	28 6.6	28 6.6	.0017 .170	.0011 .110	.0011 .116
SO_x and NO_x						
Simultaneous treatment						
Dry flue gas treatment	131 30.3	122 28.3	65 1.5	.0044 .440	.0033 .330	.0033 .330
Wet flue gas treatment	110 25.3	96 22.2	96 22.2	.0049 .490	.0045 .450	.0041 .409
Fluidized bed combustion atmospheric	182 42.2	107 24.9	32 7.5	.013 1.30	.001 .995	.000 0
Fluidized bed combustion pressurized	273 63.4	198 50.0	120 27.9	.021 2.10	.0065 .650	.000 .000
Natural draft Cooling tower	64.1 15	33.0 7.7	12.2 2.9	.0048 .480	.0048 .480	.0001 .010

(References: 7, 13, 33, 34, 35, 36)

of the air and thermal pollution control devices for a 12.6 kilogram/sec industrial boiler. Both capital costs and operating and maintenance costs are given. Operating and maintenance costs include all on-site non-capital costs such as maintenance and energy costs plus off-site waste disposal costs (such as for flue gas desulfurization of fluidized bed combustion systems). They do not account for capacity additions necessary for make-up of power consumed by the control devices. Table 16 displays utility pollution control capital costs in both \$/kw and \$/kg. Steam and operation maintenance costs in \$/kwh and \$/GJ for easy comparison with the industrial pollution control costs are given in Table 17. Most costs for the pollution control devices vary over a wide range. This is usually due to the uncertainty surrounding new control technologies or site specific considerations. High, low, and chosen values are specified in each table with the high and low values representing the extremes of the ranges and the chosen value being the value used in the economic analysis. Fluidized bed combustion costs presented are only the additional costs of a fluidized bed combustion boiler when compared to a conventional boiler. These additional costs are assumed to be the costs for pollution control.

TABLE 17. RANGE OF AIR AND THERMAL POLLUTION CONTROL EQUIPMENT COSTS FOR A 12.6 KG/SEC (100,000 LB/HR) INDUSTRIAL BOILER

	Capital (\$/kg)			O&M (\$/GJ)		
	High	Chosen	Low	High	Chosen	Low
Particulate						
Electrostatic precipitator	33	11	9.9	.079	.054	.0095
SO_x						
Flue gas desulfurization	55	40	23.1	.385	.236	.110
NO_x						
Combustion modification	6.6	5.50	2.4	.079	.054	.006
SO_x and NO_x Simultaneous treatment						
Atmospheric fluidized bed combustion	11	6.6	0	3.08	.246	.000
Natural draft cooling tower	-	47.3	-	-	.141	-

(References: 18, 33, 37)

The data in Table 16 and 17 were derived independently (except for cooling towers) and then economy of scale equations were determined from the two sets of values to aid in calculating cost values for plant sizes other than those given in the tables. The scaling factor for both capital, and operation and maintenance costs for the industrial air pollution control equipment used is 0.85. This is a conservative value as opposed to other estimates that tend to use scaling factors on the order of 0.65 to 0.75. This tends to give the analysis a conservative bias (i.e. less favorable to cogeneration since economies of scale due to cost savings from air-thermal pollution centralization in cogeneration are reduced). The calculated economy of scale factors that could be calculated from the costs in Tables 16 and 17 are given in Table 18.

TABLE 18. ECONOMY OF SCALE FACTORS FOR AIR POLLUTION CONTROL TECHNOLOGIES

Technology	Capital cost	O&M cost
Electrostatic precipitator	.86	.78
Flue gas desulfurization	.85	.89
Combustion modification	.75	.78
Atmosphere fluidized bed combustion	1.29	.81
Average	.82 (excluding atmosphere fluidized bed combustion)	.82

ECONOMIC ANALYSIS EXAMPLE CASE

The cost and energy models discussed in previous sections and discussed in detail in Appendix C were used to evaluate the principle of cogeneration for a number of industry/power plant combinations. The specific example that was introduced and used in Sections 5 and 6 will also be used for the illustration of the economic analysis. The Results of additional cases will be presented in later sections. All costs in this example have been converted to 1977 constant dollars.

Capital Costs

Initial construction costs are shown in Table 19. The costs of the cogenerating utility power plant includes the cost savings in turbines and cooling towers, and the additional costs of the supplementary utility. It may be noted by the reader that there are several assumptions inherent in this example case that are not consistant with the real world. For example, flue gas desulfurization is not included in the calculation of the cost for this example. This was omitted because this study is interested specifically in the impact of cogeneration and not various other pollution technologies. If pollution control technologies such as flue gas desulfurization are included on both industry and utility size boilers, the cogeneration system is given a significant cost advantage due to economies of scale, and it would then become necessary to address other issues that are addressed in Section 6 relative to the environmental analysis. For this specific example, the bottom line is that the capital cost of the cogeneration system is 22.6 million dollars more than the equivalent conventional or status quo system. However, it should be noted that this is only a 4.2 percent increase in the total cost.

TABLE 19. CAPITAL COSTS OF EXAMPLE SYSTEMS

(Millions of 1977 dollars)

	A Status quo	B Cogeneration	NET B - A
Utility power plants			
Base power plant	436.1	492.0	
Electro-static precipitators	27.0	31.8	
Natural draft cooling	34.9	29.2	
Subtotal	498.0	553.0	55.0
Piping		7.8	7.8
Industrial boilers			
Base boilers	21.0		
Natural draft cooling	19.2		
Subtotal	40.2	0	-40.2
TOTAL	538.2	560.8	22.6

Operation and Maintenance Costs

Table 20 is a tabulation of the operation and maintenance costs of the example energy systems. Industrial boilers cost proportionately more to operate than utility power plants and, thus, the costs of operation and maintenance in the additional cogeneration facilities are balanced by the costs of industrial boilers. The costs shown are for the first year and are expected to increase at a higher rate than the wholesale price index due to increasing problems of maintenance over time. However, the difference in the first year cost is less than 0.05 percent of the total operation and maintenance cost. From a realistic point of view this difference is insignificant and would have almost no impact on an investment decision. The cost of operation and maintenance is included as part of the life-cycle cost.

TABLE 20. OPERATION AND MAINTENANCE COSTS* OF EXAMPLE SYSTEMS (MILLIONS OF 1977 DOLLARS)

First year operation and maintenance costs	A Status quo	B Cogeneration	NET B - A
Utility power plants			
Base power plant	15.9	18.1	
Electro-static precipitators	1.7	2.0	
Natural draft cooling	1.7	1.5	
Subtotal	19.3	21.6	2.3
Piping	0	.4	.4
Industrial boilers			
Base boilers	1.6	0	
Natural draft cooling	1.0	0	
Subtotal	2.6	0	-2.6
Total first year costs	21.9	22.0	0.1

*First-year costs

Fuel Costs

The first year costs of fuel for the example analysis are shown in Table 21. The cost differences reflect the significant reduction in fuel consumption in the cogeneration system. These fuel costs in the cogeneration system include fuel consumed in the cogenerating power plant, and in the supplementary power plant. The plant factor (fraction of time during the year that the system is operating) is assumed to be 0.9. This is high for utility power plants that are operated for the prime purpose of producing electricity. The net cogeneration fuel savings are $20.8 million annually, a 16 percent decline in the cost of fuel. This saving is a direct result of the reduction in the total fuel requirement that was discussed in detail in Section 5. For purposes of analysis, it was assumed that the cost of fuel escalated at a rate of 1 percent. This is a very conservative assumption. A 30 year projection of the fuel costs of this example is included in the print-out of the MAIES computer model in Appendix C.

TABLE 21. FUEL COSTS OF EXAMPLE SYSTEMS
(MILLIONS OF 1977 DOLLARS)

First year fuel cost	A Status quo	B Cogeneration	NET B - A
Utility			
Base power plant	92.7	92.7	
Supplementary power plant	0	16.4	
Subtotal	92.7	109.1	16.4
Industrial boilers	37.1	0	-37.1
Total first year costs	129.8	109.1	-20.7
Present worth(escalated at 1% annually)	1781.1	1496.3	284.8

Life-Cycle Cost

To this point, the discussion of costs has centered around capital cost and the first year operating, maintenance, and fuel cost. Table 22 lists the capital cost and the first year cost for fuel, operation and maintenance. It is noted that after only the first year of operation the net savings in fuel for the cogeneration system is approximately 90 percent of the additional capital investment. The 20.8 million dollar saving will occur annually and increase as the cost of fuel increases. This means that in this example, the incremental costs of the cogeneration is recovered within less than 2 years. However, facilities of the type included in this example have an economic life on the order of 30 years. Therefore, the net present value over the project life will give a better indication of the true value of applying the principle of cogeneration. In terms of 1977 dollars, the life cycle net present value is 234.5 million dollars, or approximately 10 times the additional capital cost.

TABLE 22. NET PRESENT VALUE COMPUTATION*

COST COMPONENT	COST (Millions of 1977 dollars) Status quo	Cogeneration
Capital	538.2	560.8
First year O&M	21.9	22.0
First year fuel	129.8	109.1

*Assumptions: (1) Fuel cost escallation rate is 1%; (2) Discount rate is 7%; and (3) Plant life is 30 years.

Sensitivity of Cost Variables

The economic analysis example showed cogeneration to be economically viable; however, the analysis was based on general estimates. Sensitivity analysis can provide a significant amount of information on the reliability of the results in response to changes in the cost estimates.

As the cost models used in the analysis are only estimates which represent average values, the uncertainity of the net present value computed may be high. Sensitivity analysis serves as a check to determine which variables are most critical in the economics of cogeneration systems. The equation for sensitivity of the independent variable x is:

$$\text{Sensitivity }(x) = \frac{\dfrac{NPV_1 - NPV_0}{NPV_0}}{\dfrac{x_1 - x_0}{x_0}}$$

where

x_0 = base value for independent variable

x_1 = new value for independent variable

Sensitivity is a measure of the fraction by which net present value changes in response to a change in the variable under investigation. The sensitivity was used to rank the variables, and identify those that are most critical to the economics of the cogeneration system. Table 23 displays the sensitivity of cogeneration system economics to changes in key parameters. Fuel costs, as expected, show the highest sensitivity. The discount rate is also a critical parameter. Construction, operation and maintenance costs of power plants, and industrial boilers possess moderate sensitivity, because their magnitude is small related to the cost of power plant. Although the variables listed in Table 23 are separate, it should be recognized that they are not independent variables. For example, the capital cost of power plants both utility and industrial are closely related, as are the operating and maintenance cost. As is shown in Table 23, the sign of the sensitivity of these linked variables are opposite so that the net result would be much less than that indicated in this table. The following sections will investigate the relationship between the net present value and some of the most sensitive variables.

Sensitivity of Fuel Costs

The high energy efficiency of cogeneration provides significant fuel savings. The fuel source in the example is coal, at a price of \$.92/GJ. MBtu. Although this price may vary significantly for different regions in the country, an associated important variable is the rate by which fuel prices will change in the future. The example case assumption for this is a one percent escalation rate. Figure 15 is a plot of the net present value as a function of the first year price of fuel. The example fuel price is \$.92 per GJ. As this figure illustrates, increases in the price of fuel significantly increase the value of cogeneration. This is because the same output product is produced with less energy. Figure 16 illustrates how the net present value of cogeneration systems change as the coal escalation rate is changed. The cogeneration system economics are attractive at all realistic rates.

Sensitivity of Discount Rate

The discount rate is a critical variable in all economic analyses. Many reports have been criticized due to their treatment of discount rate. Lovins (38), in a critique of cost-risk-benefit analysis, claims that many

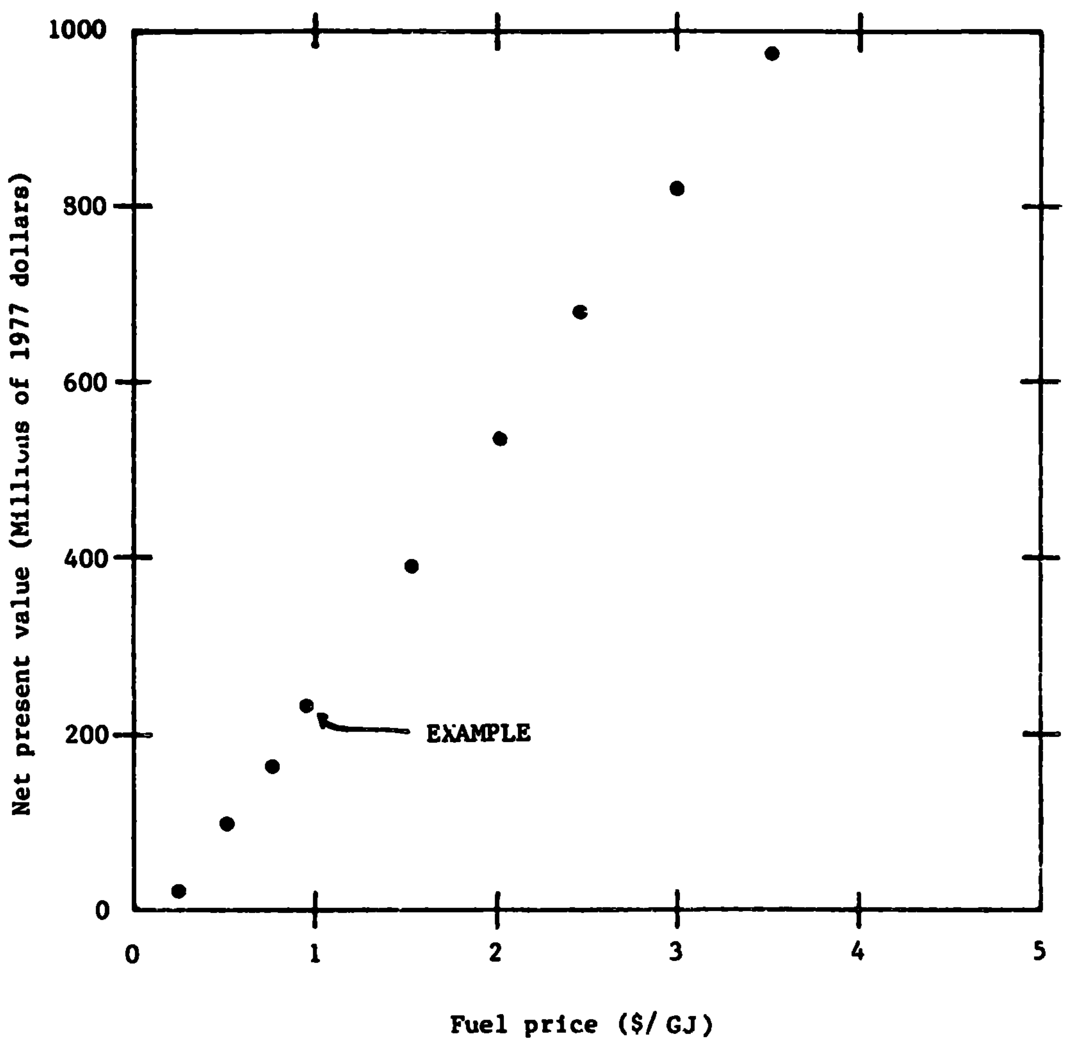


Figure 15. Impact of first year coal price on net present value.

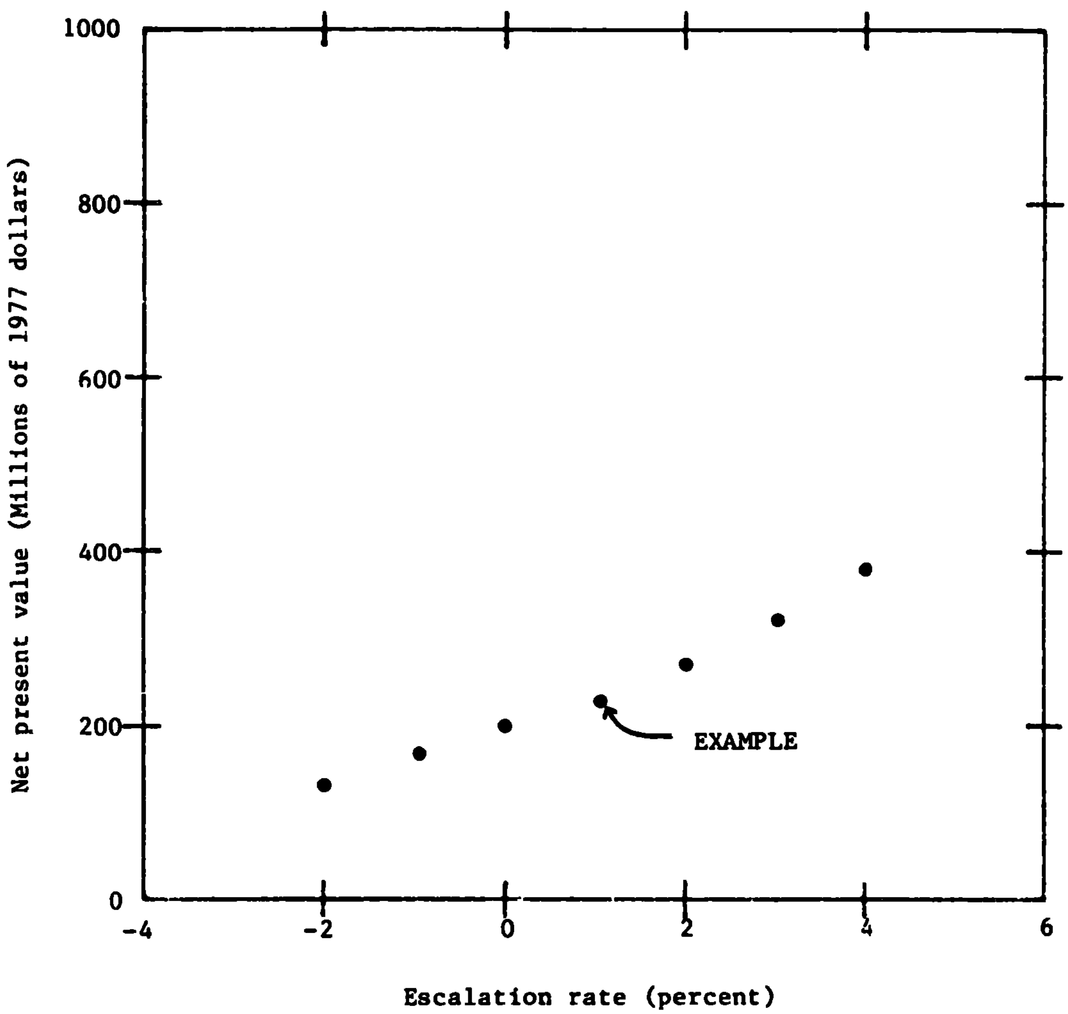


Figure 16. Impact of coal price escalation on net present value.

analysts adjust the discount rate to justify their own preferences. We attempt to avoid the pitfalls of other studies by showing the sensitivity of cogeneration economics to different discount rates. Figure 17 illustrates that the net present value does not become negative at discount rates within the range of this figure. This occurs because the discount rate is an indicator of the time value of money. The general trend is for higher discount rates to favor investments with a quick return on the investment. Therefore, since the example returned the original investment in less than two years, the net present value will be positive even for large discount rates.

TABLE 23. RANKING OF COST PARAMETERS BY SENSITIVITY

Parameter	Sensitivity
Fuel costs	+1.25
Discount rate	- .85
Operating and maintenance cost of industrial boilers	+ .39
Capital cost of utility power plants	- .46
Operating and maintenance cost of utility power plants	- .38
Capital cost of industrial boilers	+ .33
Capital cost of cooling towers	+ .07
Operating and maintenance cost of cooling towers	+ .05
Capital cost of piping	- .07
Operating and maintenance cost of piping	- .06
Operating and maintenance cost of flue gas desulfurization equipment	- .015
Capital cost of flue gas desulfurization equipment	- .005
Operating and maintenance cost of particle control	+ .015
Operating and maintenance cost of nitrogen oxide control	[illegible] .015

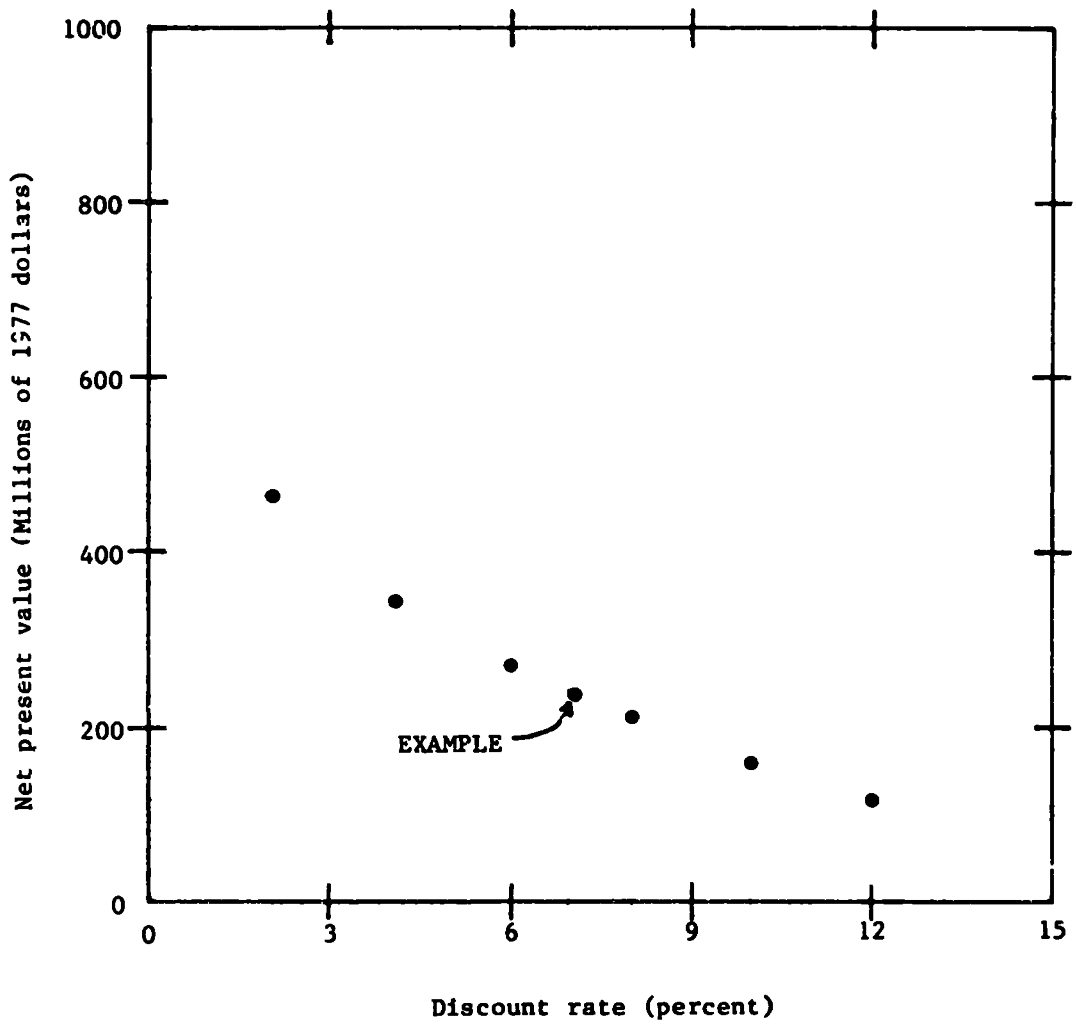


Figure 17. Impact of discount rate on net present value.

Sensitivity of the Capital Costs of Power Plants

Table 23 indicated that cogeneration economics showed moderate sensitivity to the costs of power plants. The basic reason for this sensitivity is that the cogeneration must include a supplementary power plant to replace electrical capacity lost due to steam extraction. Thus, the cogeneration system has some additional utility capacity. Figure 18 is the sensitivity of net present value to changes in utility power plant costs. The sensitivity curve shows only a moderate amount of change in cogeneration system economics. Even when power plant costs increase by 50 percent, the net present value is reduced by only 34 million dollars out of the original 234 million. It should be pointed out that the sensitivity of the net present value to the capital cost of the power plant as indicated in this figure is higher than would be anticipated in the real world. This is because the assumption is made that capital cost of the utility power plant is an independant variable, which is not true. In reality, all capital costs, specifically for utility and industrial power plants, are closely related. Therefore, the economic impact for variations in capital cost are significantly less than would be indicated in Figure 18.

Sensitivity of Energy Transport Distance

Another important consideration that has not been previously addressed is the relationship of the distance between the power plant and the industry to the economics. In general, the closer the better, however, Figure 19 illustrates the relationship. There are two factors that cause the benefits to reduce as distance increases. The first is the increased cost of the piping and the second is the loss of thermal energy associated with increasing distances.

The data used in this application was for systems that use saturated steam as a transport media. However, there are several other transport media that could be employed, including pressurized water and heat transfer oil. The selection of the specific heat transfer medium will depend on the specific factors such as application, distance, temperature, and quantity. In general, all of the options will exhibit the same basic relationship between cost and distance. However, the general trend is that direct utilization of steam is most economical for short distances while pressurized water is most economical for greater distances. For applications such as space heating, where the required temperature is low (38°C), it may be economical to transport thermal energy as far as 80 km with pressurized water. At the present time the use of hydrocarbon heat transfer oils is prohibitively expensive in all but very specialized cases that require high temperatures because of the high cost of these oils.

In-Plant Cogeneration

An alternative technical approach to cogeneration is in-plant cogeneration. In-plant cogeneration is the application of the principal of cogeneration within the industrial plant. Basically, the industry buys a boiler

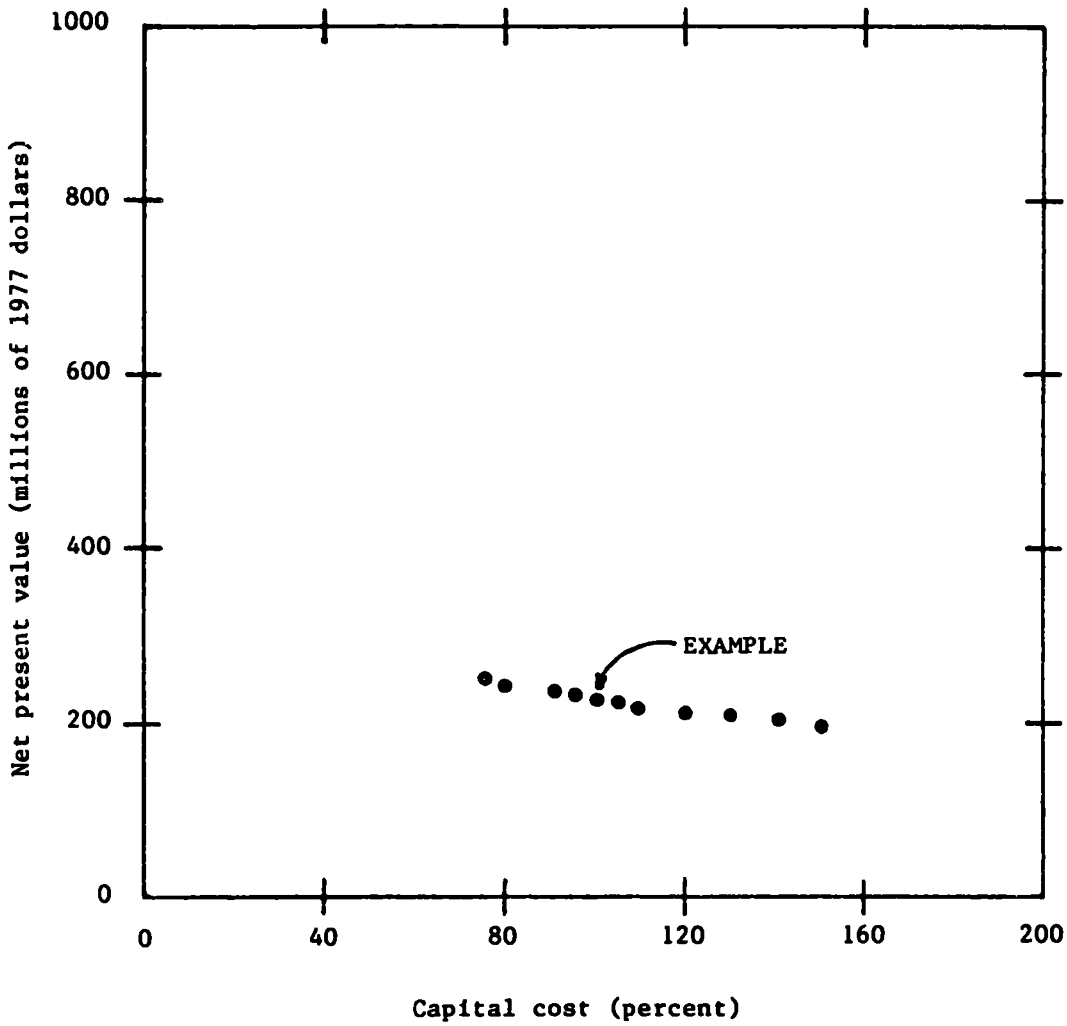


Figure 18. Impact of capital cost on net present value.

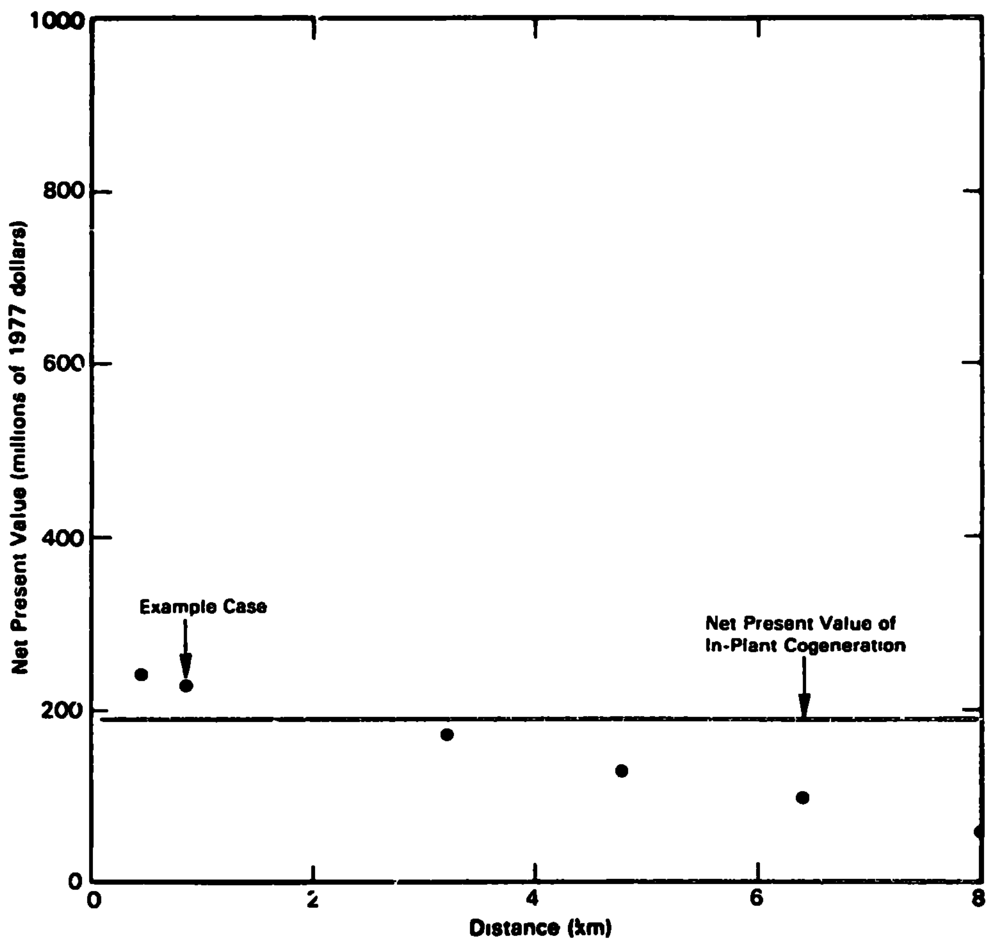


Figure 19. Impact of steam transport distance on net present value.

that can provide the required quantity of steam but operates at a higher temperature and pressure than is required by the process. By adding steam turbines and electrical generators, the industry can produce electricity with the high pressure steam and then use the exhaust from the turbines to provide the process heat. This technique is often employed in paper, chemical, and petrolium plants. The present value of using inplant cogeneration that provides the same thermal energy as the example case is 196 million dollars. The solid line at 196 million dollars in Figure 19 illustrates the relative value of inplant cogeneration as compared with transporting steam over a distance. As is noted, large scale cogeneration is more cost effective for distances of less than 2 kilometers, while in-plant generation is more cost effective for separation distances greater than 2 kilometers. The 2 kilometer value is not to be considered as a general result. However, the economics of in-plant cogeneration are well documented and will be increasingly important in the future. In general, the planners of an industrial complex of the size used for this example case would probably have elected to employ in-plant cogeneration if large scale cogeneration was not a practical option.

SECTION 8

INSTITUTIONAL AND SOCIAL IMPACT

In developing a large industrial complex, there are many institutional barriers to overcome. These institutional barriers include regulatory, licensing, political, and social. Although many of these barriers can be overcome by satisfying simple formal requirements, some barriers are difficult to specify, let alone satisfy. Most of the institutional barriers are manifestations of real concerns of the society. In this section, the institutional constraints are identified, and a simple method of evaluating the impact of a cogeneration system on the local community is given.

INSTITUTIONAL CONSTRAINTS

Institutions are the structures within society. They include government organizations, industries, banks, research organizations, consumer groups and environmental lobbyists. Although cogeneration systems may be technically, economically, and environmentally favorable, institutional constraints may inhibit development. Problems of obtaining licensing, right of ways, contracts, etc., reflect poor interfacing between institutions. Several institutional constraints are discussed in this section.

Institutional Inertia Constraints

Society possesses an inertia to resist change. Institutions that have been operating in a similar manner for several years tend to resist acceptance of other modes of operation. To overcome this inertia, energetic support for the change is required, particularly in management.

Capital Formation Constraints

Many utilities face a severe problem in obtaining sufficient funds to finance new power plants. They may find it even more difficult to find adequate funding to pay the additional costs of a cogeneration system power plant. A case in point is Union Electric's proposed construction of a solid waste resource recovery system for the city of St. Louis. The plans fell through in large part because funds originally allocated for the resource recovery system were needed to build new conventional electric power plants. Capital financing of cogeneration systems must involve utilities, industries, banks, long term debt markets, and possibly government. Typically, utility projects have been financed in the short term by bank loans and in the long term by bonds. The utilities' inability to increase revenue as operating costs increase has made banks uncertain of the utilities earning capabilities. For this reason, higher capital amounts are being required. The same may be true for cogeneration systems. The large capital requirements force a multi-ownership situation between industries, and possibly utilities. Multi-ownership arrangements present a host of contractural problems. Cost and benefit sharing must be explicitly specified, and much interface between the owners is required.

Contractual Constraints

Difficulties may arise in negotiating a contract for the industry to purchase utility-generated steam. Variables include price, price escalaters, steam supply reliability and ownership questions. The local Public Service Commission may elect to become involved in the contracting procedure or may oppose the project totally. The reliability question is crucial because it will determine the extent of the utility back-up system. The industry may have to purchase part of the system, in particular the piping on industry-owned land.

Environmental Regulatory Constraints

A number of environmental issues are discussed in Section 6. Decisions will have to be made regarding the acceptability of cogeneration systems in areas of marginal air or water quality. An important problem occurs when local, state and federal agencies have jurisdiction over the environment of the same area. In such cases, the utility or industry project planners feel frustrated by the uncertainty of what the actual regulations pertaining to the project are.

FPC Regulatory Constraints

The Federal Power Commission and state public service authorities will be involved in setting the rate structure for energy (electrical and thermal) produced by cogeneration systems which is used in the power grid. This involves the accounting of the cost, or marginal cost of producing the power which goes to the grid. Rates for energy used by the utilities must be specified in the contractual agreements between utilities and industry, depending on the ownership.

Licensing, Permits, and Right-of-Way Constraints

One of the most strategic points at which a project can be forestalled is during the approval process. Persons or institutions opposed to a project can apply pressure for the rejection, and sometimes even, revocation of approvals. If steam lines have to cross private property, there could be substantial problems obtaining the right-of-way due to the space and safety problems. Another problem may be with civil court actions brought by irate local citizens. Large cogeneration systems would provide a likely target for law actions involving anything from aesthetics to zoning, because they will have the same characteristics of large utility power plants.

Public Approval Constraints

One of the most neglected parties in utility and industry projects is the public, particularly those citizens who live near a proposed development. Failure to include the public can eventually backfire and produce united public opposition. An example of the consequences of such action is the cogeneration system planned for Midland, Michigan. A nuclear power plant is being constructed to supply steam to the nearby Dow Chemical complex. However, public opposition has plagued the project. Construction has been delayed for several years. More active solicitation of public involvement during the planning stages might have prevented many of the problems.

SOCIAL IMPACT ANALYSIS

In any comprehensive analysis, the impact of a cogeneration system on a local community must be considered. A concentrated and rather abrupt increase in the level of industrial activity results in demographic changes in a locale which have implications in terms of housing, the demand for public services, and the size of the local private commercial sector. Changes, resulting from a cogeneration system, affecting the general public can be both positive and negative. To some extent, these community effects can be anticipated, thereby allowing the opportunity to plan for timely adjustments. The value of any such analysis lies in the fact that it is a systematic, though generally imprecise, process of trying to alert society to what logically might be expected. A social impact analysis itself is not a plan for action; its real function is to raise the level of awareness about potential consequences which would warrant attention. Its function will have been served if the major problems which are actually experienced in the implementation of a cogeneration system are identified in the analysis.

The overall approach was to determine the magnitude of the absolute impacts of constructing and operating a large cogeneration system, given that it is technically, economically and environmentally feasible.

There are two general objectives in this social impact analysis. First the major changes that would be caused by a cogeneration system in the host community are to be identified. The second objective is to identify general policies and location parameters which might mitigate possibly undesirable impacts.

The social impacts of interest depend on two factors: the particular cogeneration concept and the pre-existing demographic make-up of the host community. Rather than treating a number of different concepts, just the extreme case, a large cogeneration system, was examined. The impacts of such a case constitutes an approximate upper limit on the impact expected from other possible cogeneration system concepts. Basically, the analysis determines the extent of change to population distributions when a cogeneration system brings additional construction and industrial workers into a community.

The methodology was developed considering potential impacts from a large cogeneration concept, in a "typical small" and in a "typical large" host community. Interpolation of quantitative results gives a fair representation of the impacts from this large cogeneration system in any host community of interest. Further, in generalizing results along another dimension, some subjective scaling is used to extend the quantitative results to smaller or larger cogeneration system concepts. This approach is deemed to be an acceptable compromise between a completely general analysis which precludes any quantitative treatment, and the assessment of a specific cogeneration system concept in some actual community which allows little, if any, generalization of results.

To approximate how changes in a host community occur over time, the analysis was carried out for 3 time periods. Separate computations were made for the large cogenerations system during its construction phase, during the start-up of operation phase, and during its long-term operation phase.

Multiplier Models

The methodology for determining population effects from a cogeneration system installation is developed around the multiplier notion from economics. This multiplier notion is presented here and used to estimate a host community's population distribution. A certain fraction of a dollar received by an individual, individual 1, is spent on the consumption of goods and services needed to sustain his standard of living. Also, individual 2, the recipient of that fraction of a dollar spent by individual 1, on the average spends the same fractional part of his revenue for his consumption of goods and services. The same fraction of individual 2's expenditures, receipts to other individuals, continues to be spent on their consumption of goods and services. Theoretically this continues indefinitely. However, taking a practical limit and combining the fractions yields a multiplier which is used to estimate total expenditures.

Expressing this same serial dependency notion in terms of man-days of work per day, instead of dollars, yields the multiplier model used in the present analysis. A simplified example should help to explain the multiplier logic. Suppose we define a standard unit of output as one man-day of work, and assume individual 1 is a producer of non-consumption goods. Other workers are producers of consumer goods. Individual 1 and his family consume fraction p of individual 2's output in man-days/day. Individual 2 and his dependents, spending some of the receipts received from individual 1, consume p of individual 3's output, and so on. The community's total consumption per day resulting from individual 1's presence, expressed in man-days/day, is C.

$$C = p + p^2 + p^3 + \ldots$$

or

$$C = p\sum_{j=1}^{\infty} p^j = \frac{p}{1-p}$$

Where p is the fraction individual output consumed by a worker and family.

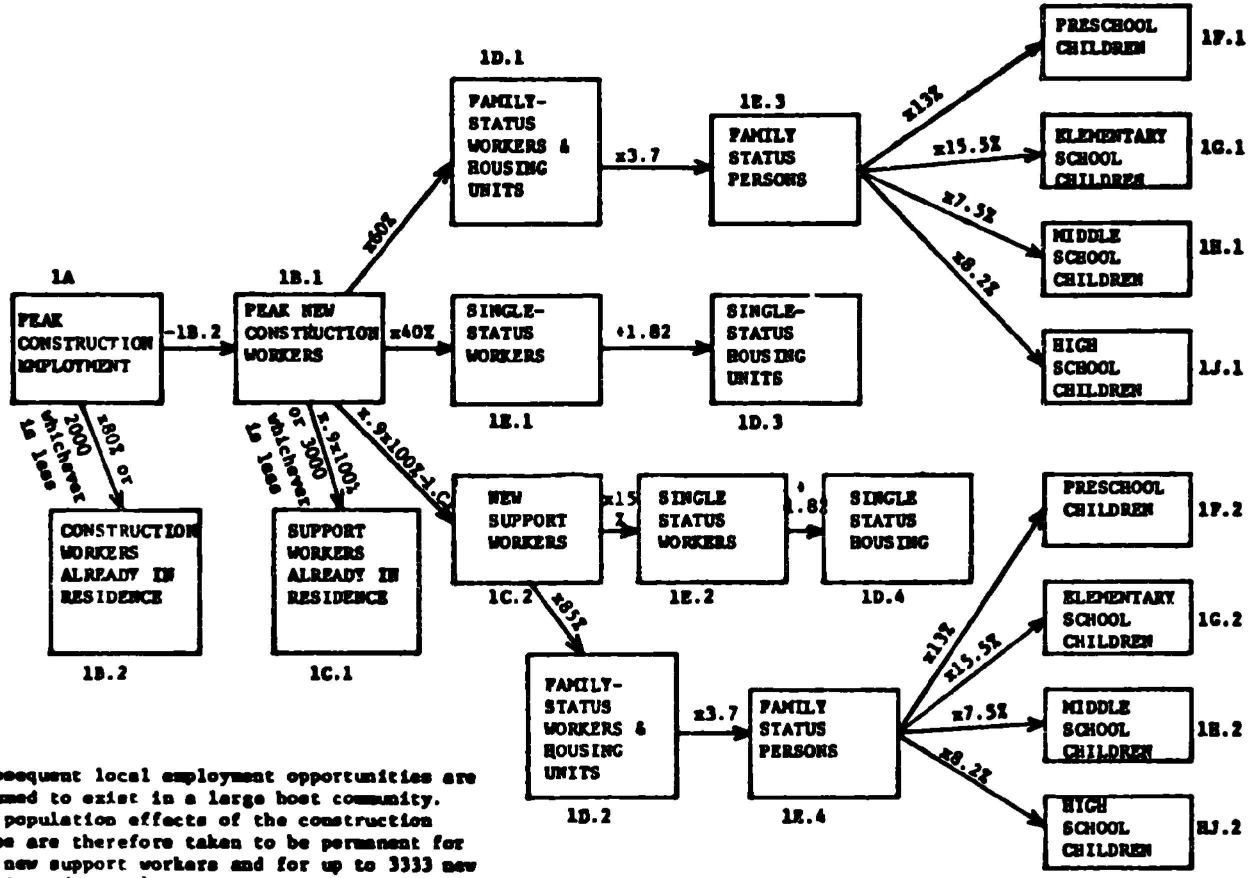
To produce $\frac{p}{1-p}$ man-days of consumption goods requires $\frac{p}{1-p}$ workers employed in the production of consumption goods, ($\frac{p}{1-p}$ is called the multiplier). For every individual like individual 1, a producer of other than consumption goods, there must be $\frac{p}{1-p}$ other individuals to produce the necessary consumption goods. In the cogeneration context, for a group of N industrial or construction workers there must be a group of $\frac{p}{1-p}$ local commercial workers to provide the necessary goods to sustain the entire work force, i.e. $N\ (1 + \frac{p}{1-p})$, plus their dependents.

The multiplier notion can be generalized beyond the area of consumption. Similar reasoning can be applied to model other aspects of human behavior and yield simple multiplier relationships to describe a community. Such models presume that there is an identifiable steady state social structure in a community. When a fairly large number of people are considered, this static model of a community is quite reasonable. Excepting the influence of the possibility of large numbers of people migrating into or out of a community, social change is in fact observed to be a very gradual phenomenon. The problems will be much more severe for a small host community. Essentially what is done in the present methodology is to superimpose the structure of a new cogeneration system population on that of the host community.

Social Impact Models

Four multiplier models were developed to evaluate effects of a large cogeneration system on small and large host communities. Appendix D contains block diagrams of each model along with an explanation of parameter assumptions. The models estimate short term population effects of construction as well as long term population effects of industrial activity. Three sources of information (39,40,41) provided the composition of different sized communities, employment statistics by type of occupation, the multiplier factors, and the construction and operating parameters for various industrial activities.

Figure 20 shows the model used for determining the population effects from constructing a large cogeneration system in a large host community. This is one of four models used to compute population effects of constructing and operating cogeneration systems in a host community. To apply these models, one must specify the total work force needed to construct and operate a cogeneration system, and the number and type of workers currently available in the host community. Distribution effects are easily computed using the indicated multiplier factors in Figure 20.



*Subsequent local employment opportunities are assumed to exist in a large host community. The population effects of the construction phase are therefore taken to be permanent for all new support workers and for up to 3333 new construction workers.

Figure 20. Population effects* for the construction phase: large cogeneration system concept in a large host community.

These average factors were developed using population distributions from small and large communities in the Atlanta metropolitan area. The assumption is made that the factors represent reasonable values for this type of social impact analysis of a hypothetical host community.

SOCIAL IMPACT ANALYSIS EXAMPLE CASE

The basic purpose of the example case analysis is to assess the observable effects on a community of constructing a cogeneration system. It is therefore necessary to identify those factors which could substantially influence the effect either directly or indirectly. The parameters dealing with the development of the methodology for the social impact analysis included size of host community, type of power source of the cogenerating utility, and construction scenario. These are the factors which are considered to have the most potential for altering the effects upon a community.

The analysis consisted of the steps shown in Figure 21. The particular cogeneration system to be considered must be specified in terms of the type of utility (nuclear or coal), its size, the term and man-hour requirements for the construction of the utility and the various industrial plants, and the industrial work force to be employed in the cogeneration system.

The host community in which the cogeneration system is to operate must be defined in terms of its pre-existing employment levels by type (industrial, construction, other support), its demographic parameters (family units, school age children, etc.) and idle resources (unemployment levels, housing vacancy rate, etc.)

The third step is to specify a construction scenario. This is expressed in terms of the extent to which there is centralized planning for all the elements in a cogeneration system. The importance of this will be seen in a later discussion. The construction scenario affects peak construction requirements and the change in total labor requirements over the term of the cogeneration system construction phase.

Applying the multiplier models as described previously is a straightforward procedure which yields population distributions used to measure the changes in the host community.

Cogeneration System

To quantify the social impacts, it is necessary to define a typical large cogeneration concept. A large utility power plant is taken to be 1000 MW, either fossil fuel (coal) or nuclear. The construction period for the utility is taken as six years. For a coal-fired power utility, a peak construction force of 1000 workers is expected to be needed; for a nuclear power utility, 2000 construction workers. The operating work force for the utility is taken to be 125 workers and 100 workers for coal and nuclear, respectively. The specific composition of the accompanying new industrial community is not critical for present purposes. A few large

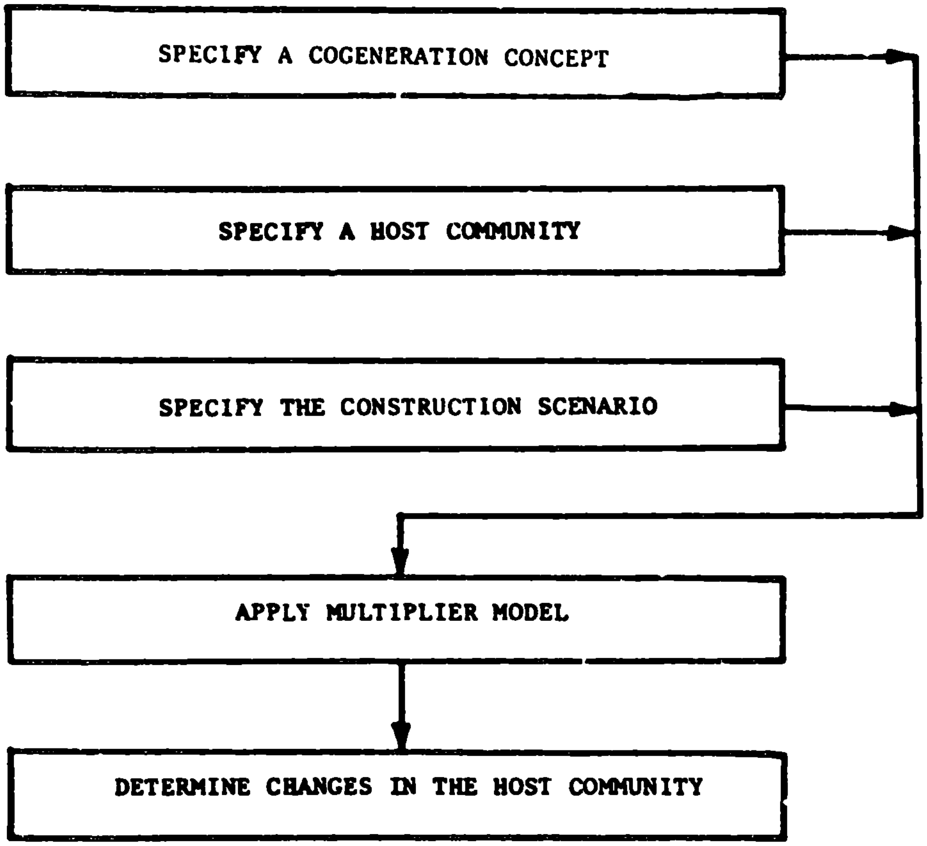


Figure 21. Steps in the social impact analysis.

plants or many small plants may be assumed. The assumption used is that the total construction effort will be 15,000 man-years and the total industrial employment will be 5000 workers. Individual industrial plants are expected to take, on the average, three years to build. These input figures are representative of the list of corresponding ranges of values cited in Reference 10.

The methodology presented in the beginning of this section produced the community multiplier models shown in Appendix D. Beyond their use in specifying the host communities, these constitute the basic models employed in quantifying the cogeneration system social impacts. To apply them, all that is needed is an estimate of the appropriate work force (construction or industrial workers) and estimates of the numbers and types of workers currently available in an cogeneration system host community.

It would be expected that in building a cogeneration system, individual construction projects would gradually require more and more workers, reach a peak, and gradually require fewer and fewer workers until each is completed. For this analysis, a reasonable approximation to the cogeneration system construction profiles are shown in Figure 22.

The difference in the length of the construction period between the utility and the industrial plants gives rise to different construction scheduling possibilities. Two extreme cases are considered. First, individual industries might schedule their own construction so that it will take three years and be completed concurrently with the construction of the utility. This schedule, called "not coordinated construction," eliminates unnecessary periods of idle (non-income earning) capital investment prior to industrial operation. From the industry standpoint, this is the most desirable. Figure 22a is a model of "not coordinated construction." The other extreme, a "coordinated construction" effort, is a schedule wherein the industrial construction is staggered over time to span the entire six years required to build the utility. A model of coordinated construction is given in Figure 22b. During the first and last 1½ years of cogeneration system construction, there are gradual changes in the number of construction workers. In the interim three years, the aggregate non-utility construction work requires a fairly constant number of workers. The total man-hours required for construction is assumed to be the same for either coordinated or not coordinated construction.

Superimposing the construction manpower requirements given earlier for the utility, on those shown in Figures 22a and 22b for the industrial plants gives the profiles shown in Figures 22c and 22d for a nuclear and fossil fuel power utility. In each of these figures, the peak work force for both coordinated and not coordinated construction are shown along with the long term cogeneration system employment.

Large Cogeneration System in a Large Host Community

Table 24 shows the summary results for a large cogeneration system

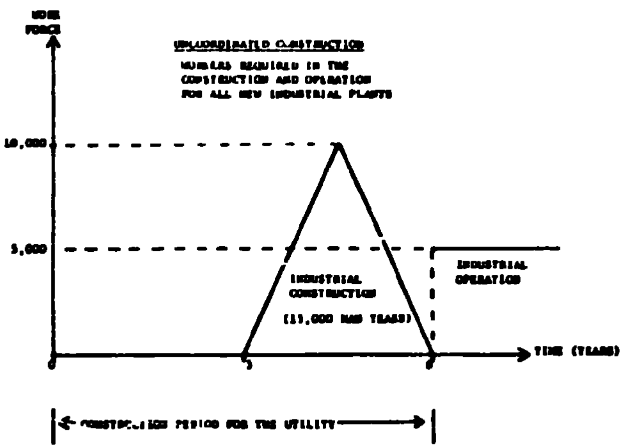


Figure. 22a.

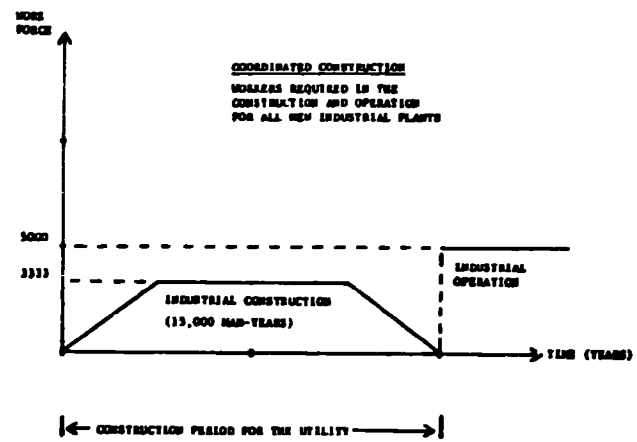


Figure 22b.

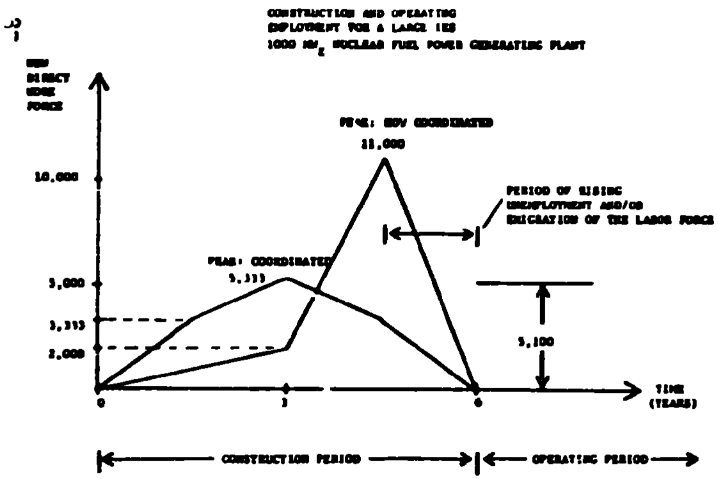


Figure 22c.

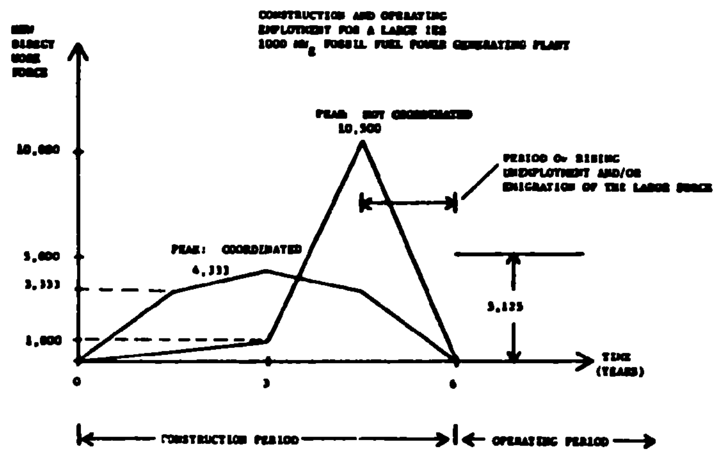


Figure 22d.

Figure 22. Cogeneration system construction profiles.

TABLE 24.
LARGE COGENERATION SYSTEM IN A LARGE HOST COMMUNITY– THE FIRST EIGHT TO TEN YEARS (1000 MW_e POWER PLANT)

Community parameter	Host community preexisting value	Type[a] of utility	Phase in cogeneration system development	Graphical representation of the percentage increase[b] (0–80)
Total population	164,750	N	Peak construction	5.3- 24.5
		C		3.7- 22.8
		N	Just prior to operation	5.3- 16.9
		C		3.7- 16.0
		N	at full operation	32.3- 33.7
		C		32.9- 33.8
Family-status Persons	137,250	N	Peak construction	4.7- 22.9
		C		3.3- 21.3
		N	Just prior to operation	4.7- 16.9
		C		3.3- 16.0
		N	at full operation	31.7- 33.7
		C		32.5- 33.8
Children preschool / elementary / middle / high school	20,442 / 24,374 / 11,794 / 12,894	N	Peak construction	4.7- 22.9
		C		3.3- 21.3
		N	Just prior to operation	4.7- 16.9
		C		3.3- 16.0
		N	at full operation	31.7- 33.7
		C		32.5 33.8
Occupied dwellings	46,620	N	Peak construction	5.8- 26.0
		C		4.1- 24.2
		N	Just prior to operation	5.8- 16.9
		C		4.1- 16.0
		N	at full operation	32.9- 33.7
		C		33.3- 33.8
Vacancy rate (as % original housing)	assumed to be zero	N	Peak construction	0.0- 0.0
		C		0.0- 0.0
		N	Just prior to operation	0.0- 9.2
		C		0.0- 8.3
		N	at full operation	0.0- 0.0
		C		0.0- 0.0
Residential land (acres)	8,763	N	Peak construction	5.8- 26.0
		C		4.1- 24.2
		N	Just prior to operation	5.8- 26.0
		C		4.1- 24.2
		N	at full operation	32.9- 33.7
		C		33.3- 33.8

a. N = Nuclear C = Coal --Both are 1000 MWe
b. Coordinated construction of cogeneration system
Construction of cogeneration system not coordinated
Denotes coordinated construction of cogeneration system
Denotes construction of cogeneration system not coordinated

TABLE 24. (CONTINUED)

Community parameter	Host community preexisting value	Type[a] of utility	Phase in cogeneration system development	Graphical representation of percentage increase[b]	
Construction workers	2,569	N	Peak construction	18.8-	50.8
		C		13.2-	48.0
		N	Just prior to operation	18.8-	22.6
		C		13.2-	22.6
		N	at full operation	33.7-	33.7
		C		33.8-	33.8
Industrial workers	15,152	N	Peak construction	0.0-	0.0
		C		0.0-	0.0
		N	Just prior to operation	0.0-	0.0
		C		0.0-	0.0
		N	at full operation	33.7-	33.7
		C		33.8-	33.8
Support workers (other than construction)	32,279	N	Peak construction	0.0-	15.8
		C		0.0-	14.6
		N	Just prior to operation	0.0-	15.8
		C		0.0-	14.4
		N	at full operation	33.7-	33.7
		C		33.8-	33.8
Total work force	50,000	N	Peak construction	6.7-	28.2
		C		4.7-	26.3
		N	Just prior to operation	6.7-	16.9
		C		4.7-	16.0
		N	at full operation	33.7-	33.7
		C		33.7-	33.8
Family-status workers	42,500	N	Peak construction	4.7-	22.9
		C		3.3-	21.3
		N	Just prior to operation	4.7-	16.8
		C		3.3-	16.0
		N	at full operation	31.7-	33.7
		C		32.5-	33.8
Single-status workers	7,500	N	Peak construction	17.8-	58.2
		C		12.4-	54.6
		N	Just prior to operation	17.8-	16.9
		C		12.4-	16.0
		N	at full operation	44.8-	33.7
		C		41.6-	33.8
Unemployment increase	BASE LEVEL 6% TO 8%	N	Peak construction	0.0-	0.0
		C		0.0-	0.0
		N	Just prior to operation	6.3-	14.4
		C		4.5-	13.8
		N	at full operation	0.0-	0.0
		C		0.0-	0.0

a. N = Nuclear C = Coal --Both are 1000 MWe

b. Coordinated construction of cogeneration system

Construction of cogeneration system not coordinated

Denotes coordinated construction of cogeneration system

Denotes construction of cogeneration system not coordinated

in a large community obtained using the multiplier models in Appendix D, and input data for the large host community shown in Table 24. For each of the community parameters, Table 24 shows the value that existed prior to the advent of the cogeneration system. For each phase in the cogeneration system development, the percentage increase in the pre-existing value of the community parameter is shown for both a nuclear and a coal power utility. The percentage increases shown graphically in the bar chart were computed for both a coordinated (cross hatched) and not-coordinated (solid white) construction scenario. The figures in the far right opposite each of the bars in the figure are the numerical values of the percentage increases. Expressed as percentage change, the results shown in the figure allow comparisons to be made across community parameters to determine what aspects of the host community will be most affected by the cogeneration system. The percentage change format further allows results to be extrapolated to other host communities.

General observations about the quantitative results in Table 24 can be made by considering each phase in the cogeneration system development separately. The major features of the impact of a large cogeneration system in a large host community are discussed below.

Peak Construction Phase--

If the construction work is coordinated, peak employment will be reached roughly three years after the beginning of the cogeneration system construction. If industries are left to schedule construction projects independently (not coordinated construction), peak employment will be reached after roughly 4½ years. The host community is expected to supply some of peak labor requirements. Only the new labor immigrating to the cogeneration system will require increased support from the community in terms of housing, public services, and consumer goods and services. The four to six percent increase in housing requirements with coordinated construction over three years, should be easily met. The 24 to 26 percent increase in housing requirements with not coordinated construction would, in most cases, overtax the local housing industry since most of the increased demand is expected to occur during only a 1½ year period beginning in the third year. A surge in the demand for moderate cost housing may result in overcrowding, artifically high rents and a general decline in the quality of new housing. Though overcrowding would be remedied as the housing supply expands, the sudden interim worsening of living standards tends to cause irreversible and general declines in affected neighborhoods. Inferences may be drawn about the long term changes in the local tax base, crime rates, and other social problems based on similar observations of general decline seen in large urban areas.

The larger peak work force required if cogenerations system construction is not coordinated is likely to far exceed the immediately available work force, causing wage rates to become artifically high. Wage increases would be expected to occur in both construction and non-construction jobs since these necessarily compete for workers in the general labor market. The institutional forces that historically have prevented wages from decreasing once they have risen, (i.e., labor unions and employment contracts), might foster high levels of long run employment.

Without a coordinated cogeneration system construction effort in which labor requirements are distributed over an extended period, excessive demand for labor is very likely to occur. Because this situation is remedied by an influx of workers, over-crowding and neighborhood decline are probable consequences of inadequacies in housing and public services. To the extent that the excess demand for labor is reduced by wage increases, inflationary pressures will mount affecting both the local community and the construction costs and completion date of the cogeneration system. Some disruption in the local economy may be expected to result if construction wages become high enough to divert local labor from other employment. Though generally expansionary in character, the local economic changes occur over a short period of time. They are likely to foster uncertainty and thereby will not stimulate needed community capital investment. The only recourse will be to over-utilize existing public resources to provide the additional services needed to accommodate the new cogeneration system construction population.

In general, the cogeneration system impact during construction phases is two to five times greater if the construction projects are not coordinated. The impacts of a cogeneration system having a nuclear utility are only one to two percent greater than if the cogeneration system were to have a coal-fired utility. The most dramatic changes in the community, besides the obvious increase in the number of construction workers, are in the number of single-status workers and new housing. If the cogeneration system construction had not been coordinated, the temporary increase in the local work force would have far exceeded the community's capacity to absorb them into a permanent work force.

Phase Just Prior to Operation--

As construction employment opportunities diminish toward the end of the cogeneration system construction phase, many of these workers will find it in their best interest to leave the community seeking employment elsewhere. If construction isn't coordinated, a housing surplus of 8 to 10 percent and employment in the commercial sector of the community will be induced. A portion of these former cogeneration system construction workers will remain, however, causing a higher than normal unemployment. The total local unemployment will reach a level 13 to 15 percent above normal. Had the cogeneration system construction been coordinated, its completion would have left a smaller labor surplus. In this case, long run employment expectations and the depressed but non-critical conditions in immediate labor market would result in relatively little worker emigration. Unemployment would temporarily increase to a level four to seven percent above normal. No significant surplus of housing would arise nor would employment in the commercial sector noticeably increase.

The period of high inflationary pressure (the construction phase) followed by a period of rapidly increasing unemployment together result in the host community's economy being temporarily in a poorer state than it had been prior to the beginning of the cogeneration system. The detrimental impacts of the construction phase can be greatly reduced by the coordinated construction approach, by reducing the total number of workers required as well as by reducing the fluctuations of the work force. To the extent that the local populace perceives this cause and effect relationship and fails to see the condition as temporary, resistance to its further industrialization may be created. Such opposition may result in the passage of local ordinances and other political action aimed at restricting or discouraging future industrial expansion.

It should be noted that the impact differences between a coordinated construction cogeneration system and one in which construction had not been coordinated persist well beyond the construction phase. This is mainly due to the fact that differences in the changes in housing construction and the expansion of the local commercial section, dictated by differences in previous peak employment levels, are not easily reversed.

Full Operation Phase--

As might be expected, the long run changes in the community caused by the cogeneration system appear to be almost completely independent of whether the construction had been coordinated or not. The slight differences (typically on the order of one percent that will persist derive from the disproporionately high outflow of single-status workers that would have followed an uncoordinated construction phase.

Excepting the clearly undesirable impacts of temporary unemployment and housing vacancies, the community parameters will have all increased by roughly 33 percent. This demonstrates the multiplier effect: the creation of roughly 10 percent more jobs in the local community (the long run new industrial employment of the cogeneration system) causes a 33 percent increase in the size and level of economic activity of the community.

The analysis shows little difference in impact between cogeneration system with a coal-fired utility and one with a nuclear utility. This is probably a valid conclusion in terms of measures used here to characterize a host community. A real difference betwen the two may still exist in terms of less tangible measures, (e.g. community attitudes on safety and pollution).

Large Cogeneration System in a Small Host Community

Beyond its size, the main feature which distinguishes a small host community from a large host community is the fact that it will be able to provide little, if any, of the labor required to construct and operate a cogeneration system. The small community's existing public services would generally be inadequate to support a cogeneration system. In particular, water treatment plants, schools, and health and safety facilities are likely to require immediate expansion. Even in the short term, more intensive use of existing facilities is not likely to be a practical way of meeting the needs created by a large cogeneration system, as had been the case in the large host community. The major features of the impact of cogeneration system in a small host community are discussed below.

Peak Construction Phase--

If in a small host community, there is coodinated cogeneration system construction, the 45 to 56 percent increase in housing requirements (occupied dwellings) over a three year period (roughly 4500 new units) is likely to be more than the local residential construction industry could provide. If housing units were built in groups of four or five so that each required as little as six total man-months of labor, less than 3100 units could be built in the three year period. Allowing for weather conditions and more realistic scheduling conditions, probably less than half the needed units could actually be completed. If the construction is not coordinated, about 10,000 new housing units would be needed with a 4½ year period. Less than a third of these could reasonably be expected to be completed by the resident construction industry. Given the generally rural conditions assumed to exist around the small host community and the extreme pressure on housing, it is likely that a large number of mobile homes would appear. In this case, much of the investment in housing would have been diverted outside the local economy and the potential increase in the property tax base substantially reduced.

The 100 to 200 percent increase in construction workers and corresponding 25 to 66 percent increase in the supporting commercial workers should significantly change the character of the community. A predominance of construction trades in the rapidly growing work force and the expectation that a majority of these will be short term residents and not be living locally in family units might actually reduce the amount of non-cogeneration system capital investments and interrupt any previous growth that had been underway. A large portion of the local population will feel no real vested interest, long term or even short term, in the community.

Any wage and price stability that had existed in the community is likely to be lost. The expected surge in the demand for labor and consumables is likely to create correspondingly high pressure to increase supplies and prices. Expanded supply levels will probably be frustrated by local reluctance to make the necessary capital investment in economic capacity. The local increase in demand would then result in significant and rapid wage and price increases and, to a much lesser extent, in increases in the quantitites of goods and services provided in the community.

Phase Just Prior to Operation--

Anticipating that there will be little opportunity for suitable long term employment, most of the cogeneration system construction work force will leave the host community toward the end of the construction phase. Appreciable induced unemployment is to be expected in the commercial sector, roughly 10 and 24 percent above normal for the coordinated and uncoordinated cases, respectively. Despite the higher emigration from a small host community, the cogeneration system would tend to cause higher employment in a small community than in a large one.

The actual housing surplus and newly developed residential land just prior to operation may be somewhat less than the figures indicated in Appendix D. Those figures are based on the assumption of no house trailers being used to alleviate the earlier peak construction housing shortage. The figures in the table should be reduced accordingly if a significant number of house trailers are observed during the construction phase.

It should be noted that there are only small differences between the impacts of cogeneration system with a nuclear power plant and one with a coal-fired power plant. As is the case for the cogeneration in a large host community, attention should be directed to the differences in cogeneration system impacts which derive coordinated versus uncoordinated construction.

Full Operation Phase--

In the long term, all the community pressures associated with high rates of change in demand will have to be alleviated by expanded public, commercial, and industrial capacity. A demographic and economic equilibrium will be reestablished and the community will have roughly doubled in size and doubled in the level of economic activity. Such appreciable growth in an originally small community would generally be accompanied by some economies of increased scale and some increase in the variety of locally available goods and services. Both of these are usually precursors to or are directly associated with a general improvement in the recreational-cultural facilities and a greater number of local economic opportunities.

GENERALIZATION OF RESULTS

More complete comparisons of changes in small and large host communities for a conventional and nuclear power utility, respectively, are given in Appendix D. The impacts as measured in percentage change are seen to be inversely related to the size of the host community. The cogeneration system induced rates of change of the demographic and economic parameters of a community are also inversely related to the size of the community. For a large cogeneration system, changes in a small host community are likely to be so large and so sudden that they will be detrimental. However, a larger host community, having relatively greater capacity to accommodate the cogeneration system using existing resources, should fare much better. A sufficiently large community would be expected to experience a more moderate rate of induced economic growth and show generally positive, desirable changes in its community parameters.

Acceptability criteria for social impacts have not been established in this study. Nevertheless, it seems clear from the contrasting impacts of a large cogeneration system in the small and large host communities that there exists some larger host community which can adequately accommodate large cogeneration systems. Interpolation of the quantitative results should yield the minimum community size apropriate. This analysis might be repeated for one or more small cogeneration systems to yield the curve shown schematically in Figure 23. If a cogeneration system and host community gave a point below the curve, the ensuing social impacts would be undesirable unless some appropriate counteractive measures were undertaken.

Generalizing from the tabulated results in this section, the cogeneration system impacts are four to five times greater in a small community than in a large one. Although it depends partly on the migration assumptions made in the analysis, it is nonetheless clear that the larger the host community, the more social-economical benefits the original residents will receive. Conversely, the social-economic impact will constitute a burden to the original residents in a small host community. Most cogeneration system social-economic benefits will accrue to the transient and new permanent residents in a small host community.

The coordinated construction scenario will produce far less traumatic impacts on all community parameters than the non-coordinated construction. This typically two to five time larger adverse impact, for non coordinated construction, appears for both small and large host communities, in both nuclear and coal utilities.

Based on results of the multiplier model analyses and references drawn above, steps which could be taken to minimize the impacts of cogeneration development were identified. These are not exhaustive or unique of cogeneration systems; they are illustrative of the options which might be desirable or practical.

a. Restrictions on the minimum size community which can be selected as a site for cogeneration development.

b. Approval of over all development plans by the host community.

c. Having the cogeneration system firms bear the initial cost of expanded public services. This cost might eventually be transferred to the new industrial community by imposing some focused tax scheme, e.g. temporary excise taxes on payrolls or property of new industry, and rebates to the construction firms.

d. Development of provisions to control the rate of wage and price increases.

e. Development of provisions to provide adequate assistance in the expected period of high-level, short-duration unemployment.

f. Establishment of comprehensive zoning ordinances to preclude residential profiteering by permitting an undesirably high proportion of low cost housing. (Care should be taken to insure the proper distribution of growth across the host community.)

Implementation of a cogeneration system, like any other major development which causes change in a community, should be carefully planned. Rates and percentage changes in community parameters must be considered if appropriate expansion of community resources is to be possible. Uncontrolled social impacts can alternately produce over investment and over utilization of public and private facilities. Such excesses, even if short lived, generally have very adverse social and economic effects on specific segments of a community. The social costs and benefits, though less easily estimated than are the technological costs and benefits, still require careful and thorough consideration.

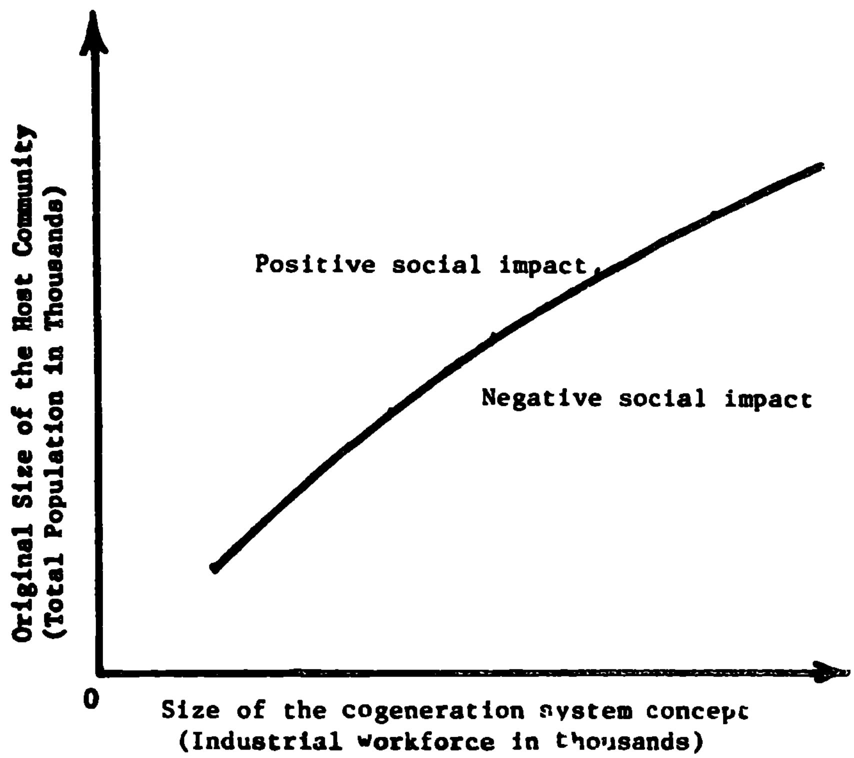


Figure 23. Relative sizes of the cogeneration system concept and the host community.

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APPENDIX A

COST-BENEFIT ANALYSIS

A cost-benefit analysis is an estimation and evaluation of net benefits associated with alternatives for achieving defined goals. Techniques used in identifying and comparing cost and benefits are almost as numerous as existing analyses. Nevertheless, some principles and guidelines can be stated.

Cost-benefit analysis is based on Depuit's concept of consumer's surplus (42). The tool has been developed extensively in planning for water-related projects, especially since the Congressional mandate in 1936. Cost benefit analysis has been applied to many other problems as well, e.g., defense systems, aerospace activities and agricultural projects.

As applied welfare economics, cost-benefit analysis uses a decision criterion identified as the potential Pareto superiority criterion which labels a project as superior if those who gain from the project would compensate those who ose so that none would be worse off with the project. This criterion identifies net benefits and forms the basis for a more detailed review of decision criteria.

Many criteria have been suggested as appropriate for evaluating alternative projects. Some, such as net present value and benefit-cost ratios have a long history of use in cost-benefit analysis and some, such as cut-off and pay-back criteria, have been employed only occasionally in public expenditure evaluations. The net present value criterion was used in this analysis.

NET PRESENT VALUE

The net present value (NPV) method reduces a stream of costs and benefits to a single number in which costs or benefits which are projected to occur in the future are discounted. For example, if a project is expected to yield a benefit worth \$100 next year, we might value that \$100 next year, as \$95 today. The formula is

$$NPV = -C_o + \frac{B_1 - C_1}{(1 + d)} + \ldots + \frac{B_t - C_t}{(1 + d)^t} + \frac{B_n - C_n}{(1 + d)^n}$$

where C_t is the dollar value of costs incurred at time t,

B_t is the dollar value of benefits incurred at time t,
d is the discount rate, and
n is the life of the project, in years.

The principal problem associated with using the net present value method is the determination of the appropriate discount rate. However, the consideration of a range of reasonable values is often sufficient in a cost benefit analysis. If the net present value is greater than zero, the project is determined to be economical and should be undertaken. Of course, the higher the net present value, the more favorable is the project. Another advantage of net present value is that it can be related to units of production. The net present value can be spread into a series of equal annual values using the following formula:

$$\text{Annual Equivalent (AE)} = \text{NPV} \; \frac{(1 + d) \times d^n}{(1 + d)^n - 1}$$

Then the annual equivalent can be divided by annual production (e.g., kilowatt hours generated by a power plant to determine the cost per kilowatt hour).

BENEFIT COST RATIO

The benefit-cost ratio (B/C) is normally defined in terms of discounted values. The formula for computing the benefit-cost ratio is

$$B/C = \frac{\sum_{t=0}^{n} \frac{B_t}{(1 + d)^t}}{\sum_{t=0}^{n} \frac{C_t}{(1 + d)^t}}$$

While this has been traditionally a popular criterion, it is sensitive to the definition of benefits and costs. While, it would seem that a positive benefit should be identical to a negative cost (of the same magnitude), it clearly makes a difference in the calculation of a ratio whether a sum is added to the numerator or subtracted from the denominator. An appliciton where this difficulty is likely to surface is in the assessment of external effects, e.g., pollution. Is a reduction of pollution a positive benefit to society or a reduction in cost? It is clear from its definition that the net present value criterion suffers from no such ambiguity.

IDENTIFICATION AND QUANTIFICATION OF COSTS AND BENEFITS

The most important aspect of a cost-benefit analysis is the identification of all relevant costs and benefits. Second only to this in importance is the quantification of such costs and benefits. The justification for quantification is to facilitate the analysis of trade-offs.

Once relevant cost and benefits have been identified, a scenario for analysis must be developed; that is, a determination of the goals of the project. If, for example, a cogeneration system is to be built, is the real objective to concentrate industria. activity in a single location for aesthetic reasons, to decrease energy costs, to increase local employment or to minimize profits? When this quesiton is settled, a set of accounts must be devised through which to organize the analysis. This process is based on experience and observation and, to some extent, public law. Federal projects, for example, require both national economic development and environmental accounts, with distributional accounts (using regional development or income-class categories) displayed for information. After the summary accounts are established, the analyst must identify the benefits and cost appearing under each account and carefully check for double-counting problems.

In the economic and energy efficiency analysis, a number of costs and benefit categories were identified. In addition to fuel costs, capital cost, and operation and maintenance costs for a large power plant, a number of additional costs are separated and identified. Among these are capital and operation and maintenance costs for specific pollution control equipment such as SO_x scrubbers, electrostatic precipitators and cooling towers.

APPENDIX B

TECHNOLOGY SURVEY

The following sections will address the technical aspects associated with supplying industrial energy needs with multipurpose power plants. The specific topics addressed will be power systems, industry applications, pollution control and cogeneration.

CONVENTIONAL POWER SYSTEM

Most electric power is produced by steam which is used as the working medium in coal, oil and nuclear power systems. Although the specific hardware may vary depending on the source of heat energy, the basic principles of steam electric generation are the same (43, 44).

Basic Steam Cycle

Because of its unique properties and natural availability, water has been used for many centuries as a working fluid to convert thermal energy to mechanical energy. As a result, the physical and thermodynamic properties of water and steam have been studied in more detail than any other fluid. Figure B-1 shows a simple representation of a steam-electric generation system. Water is pumped into the boiler under high pressure, and the boiler adds heat until the water undergoes a phase change to a high pressure steam. This high pressure steam expands in the turbine until it reaches atmospheric pressure.

The operation of a power plant approaches that of the Rankine cycle, which was independently proposed by Rankine and Clausius. Figure B-2 is the temperature-entropy (T-S) diagram of the basic Rankine cycle. All steps are assumed to be reversible. Liquid is compressed isentropically from points A to B. From B to C, heat is added reversibly to heat the compressed liquid and convert it to superheated steam. Isentropic expansion with shaft work output takes place from C to D and unavailable heat is rejected to the atmosphere from D to A. The area enclosed by the path is the usable thermal energy, and the shaded area is the energy that is unavailable for useful work.

Improvements in Basic Rankine Cycle--

If the Rankine cycle is closed in the sense that the same fluid repeatedly executes the various processes, it is termed a condensing cycle. Higher efficiency of the condensing steam cycle is a result of the particular

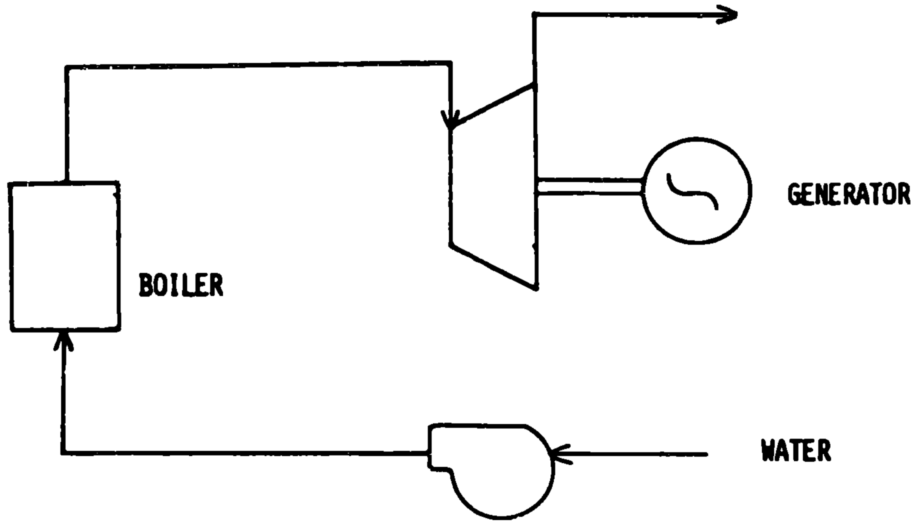


Figure B-1. Steam-electric power generation.

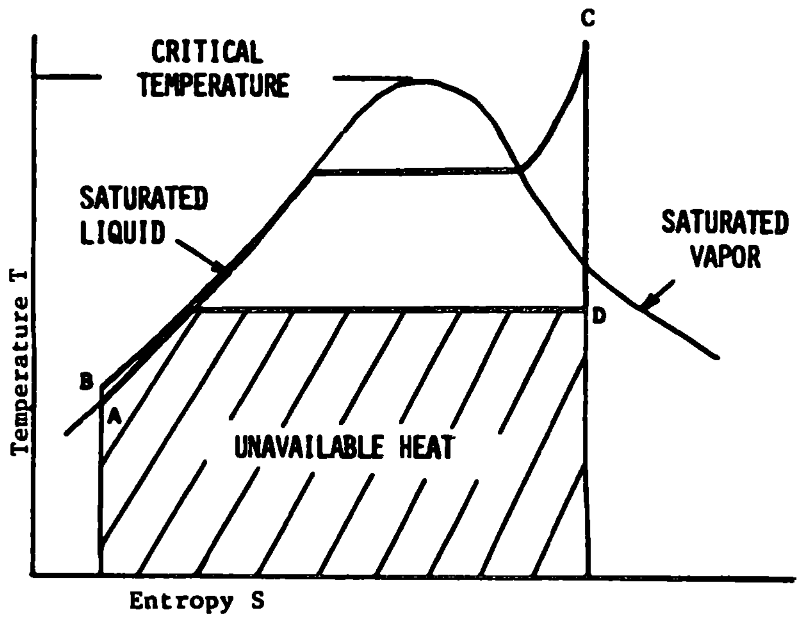


Figure B-2. Temperature-entropy (T-S) diagram of the basic Rankine cycle for steam power plant using superheated steam.

pressure-temperature relationship between water and its vapor state, steam. The lowest temperature at which an open or noncondensing steam cycle may reject heat is approximately the saturation temperature of 100 °C. This corresponds to normal atmospheric pressure of approximately 101 kPa. The condensing cycle takes advantage of the much lower sink temperature for heat rejection available in natural bodies of water and the atmosphere, and the discharge pressure is the saturation presure corresponding to a condensing temperature which may be 38 °C or lower. The decrease in the exhaust pressure results in an increase in the heat available to do the work.

Figure B-3 shows the T-S diagrams for several modifications of the Rankine cycle and the relationships between energy that is avialable to produce electrical energy and the unavailable energy. Figure B-3a is typical of a simple, open cycle steam turbine system such as the one previously depicted in Figure B-1. For open cycle operation, the exhaust is at atmospheric pressure, therefore the temperature is 100 °C or the temperature of boiling water. By condensing the steam and reusing the condensate, the exhaust temperature can be reduced to approximately 38 °C. The associated improvement in efficiency is reflected in Figure B-3b, by an increase in the usable energy and a corresponding decrease in the unavailable energy.

Another successful technique to improve the efficiency of the steam cycle is to reheat the steam after it has partially expanded so that condensation will not occur at high pressures. The diagram of such a reheat steam cycle is shown in Figure B-3c. In this cycle, the water may be heated to approximately 550 °C at a pressure in excess of 20 MPa As the steam expands, the temperature decreases quickly and the steam begins to condense at pressures that are still high enough to drive turbines. The steam is reheated in the boiler to approximately 550 °C without increasing the pressure. Now the steam contains sufficient energy to drive one or more additional stages of the turbine to produce usable mechanical energy.

Figure B-3d is for a modern steam power cycle condensing system with single reheat and regenerative feedwater heating. Regenerative feedwater heating is done by extracting steam at various stages in the turbine to heat the feedwater as it is pumped to the economizer and boiler.

Figure B-4 is a diagram of a widely used supercritical steam cycle showing schematically the arrangement of various components including the feedwater heaters. This cycle also employs one stage of steam reheat which is still another method of increasing the mean high temperature. Regenerative heating is used in all modern condensing steam power plants. It not only improves cycle efficiency but has other advantages, such as lower volume flow in the final turbine stages and a convenient means of deaerating the feedwater. The steam power-cycle diagram of Figure B-4 uses fossil fuel which is burned with air. A large portion of the resulting heat is

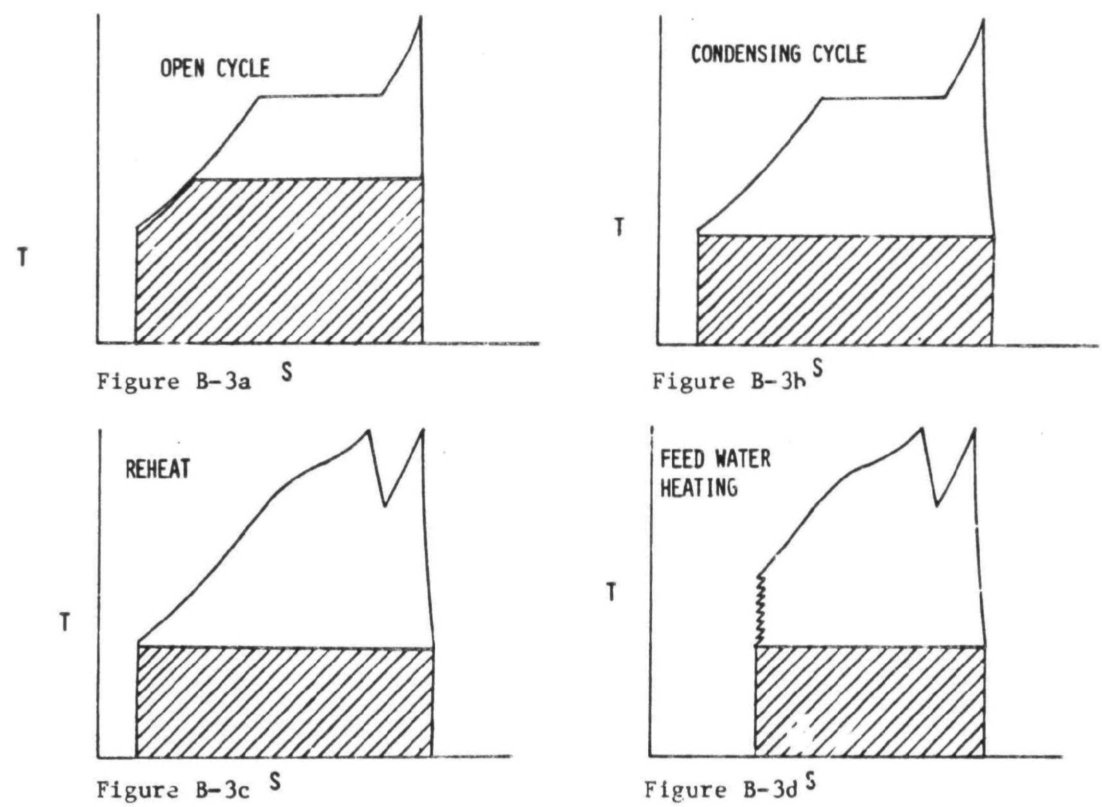
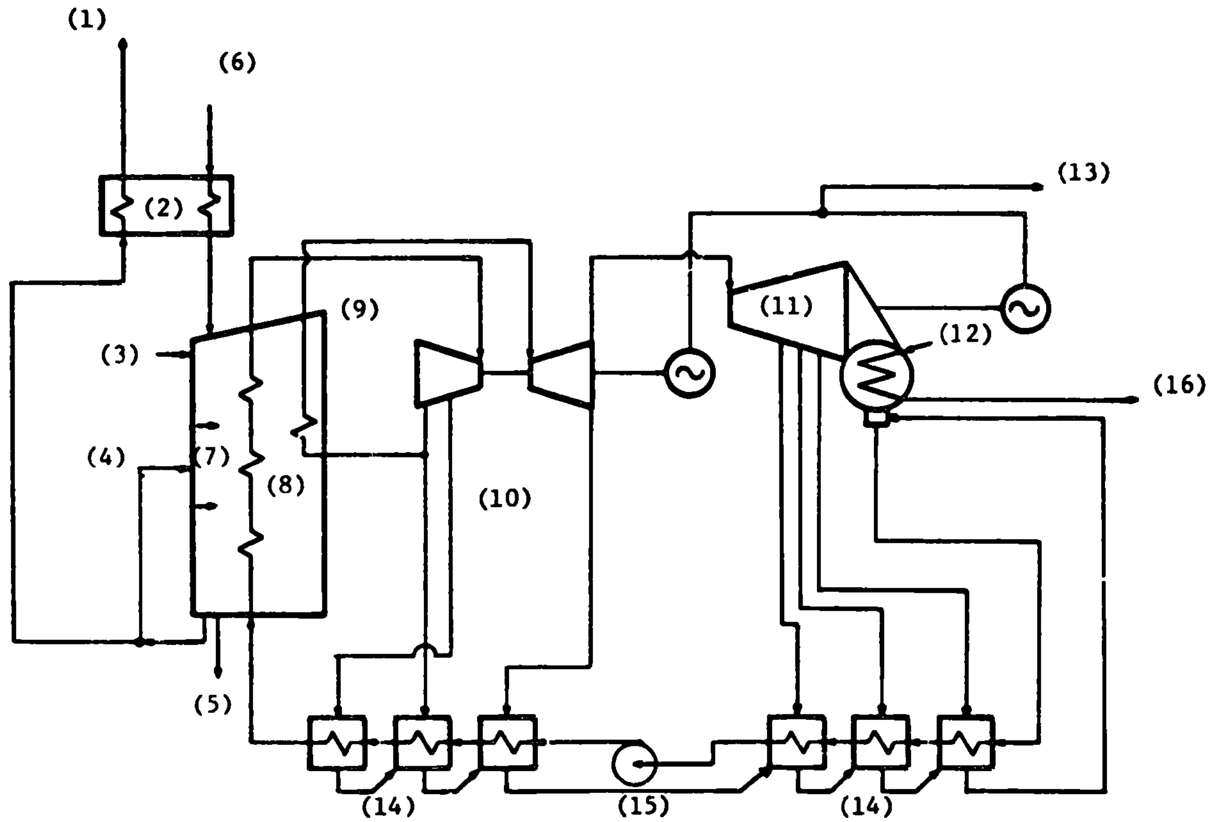


Figure B-3. Improvements in basic Rankine cycle.



Description:

(1)	Stack	(9)	High Pressure Turbine
(2)	Air Heater	(10)	Reheat Turbine
(3)	Fuel In	(11)	Low Pressure Turbine
(4)	Flue Gas Recirculation	(12)	Condenser
(5)	Ash Pit	(13)	Net Power
(6)	Air In	(14)	Regenerative Feedwater Heaters
(7)	Economizer/Boiler/Superheater	(15)	Boiler Feed Pump
(8)	Reheater	(16)	Waste Heat

Figure B-4. Power cycle diagram of a modern fossil fuel power plant.

then transferred in the boiler for generating and superheating steam. The remaining heat is discharged to the environment. The principle of regeneration is employed in an air heater to recycle low level (low temperature) heat from the combustion gases which would otherwise be rejected to the atmosphere through the stack. Feedwater heaters, on the other hand, utilize heat from steam which could have been partially converted to work by further expansion thorugh the turbine. Both types of regeneration will increase cycle efficiency and reduce waste heat if used properly.

Limits to Efficiency--

In steam power plants operated solely for the generation of electric power, thermal efficiencies are limited to a maximum of about 39 percent in fossil-fuel plants and 34 percent in nuclear plants (44, 45). More than half of the energy released from the fuel is wasted and must be transferred to the environment in some way. This is usually done through a condenser, resulting in the heating of some body of water or the air.

Coal Power Plants

Coal-fired fossil-fuel power plants will be addressed specifically at this point. Coal is emphasized because it is the most abundant fossil fuel available in the United States and it will become more important as other fuels become more scarce.

A modern coal-fired power plant is a complex set of processes that burn coal to produce high pressure steam that can be used to drive turbines and produce electricity (43, 46, 47). The major functional components of a coal-fired power plant are: coal supply system, water treatment system, boiler, turbine-generator system, flue gas treatment system, and cooling system. Figure B-5 is a simplified representation of the flow of the three major materials (air, coal, and water) used in a coal fired power plant.

Coal Supply System--

The coal supply system involves the transportation of coal to the power plant, storage, and pulverization. Coal is normally transported by rail or barge and stored in large piles until it is needed by the power plant. The transportation and storage sytems and the associated material handling equipment must be capable of handling large quantities of coal, since a large coal fired power plant (2500 MW thermal) uses about 7700 tonnes of coal per day. The cost associated with transporting and handling coal can be prohibitive for small power plants.

Coal burned in modern power plants is usually pulverized to increase efficiency and enable the production of a high temperature flame that can be controlled. The advantages of coal pulverization are partially offset by high capital and operating costs of the pulverization and dust control equipment, and increases in the production of fly ash.

Water Treatment System--

The water that is converted to steam in the boiler must be highly purified to prevent corrosion or buildup of deposits in the boiler. The primary

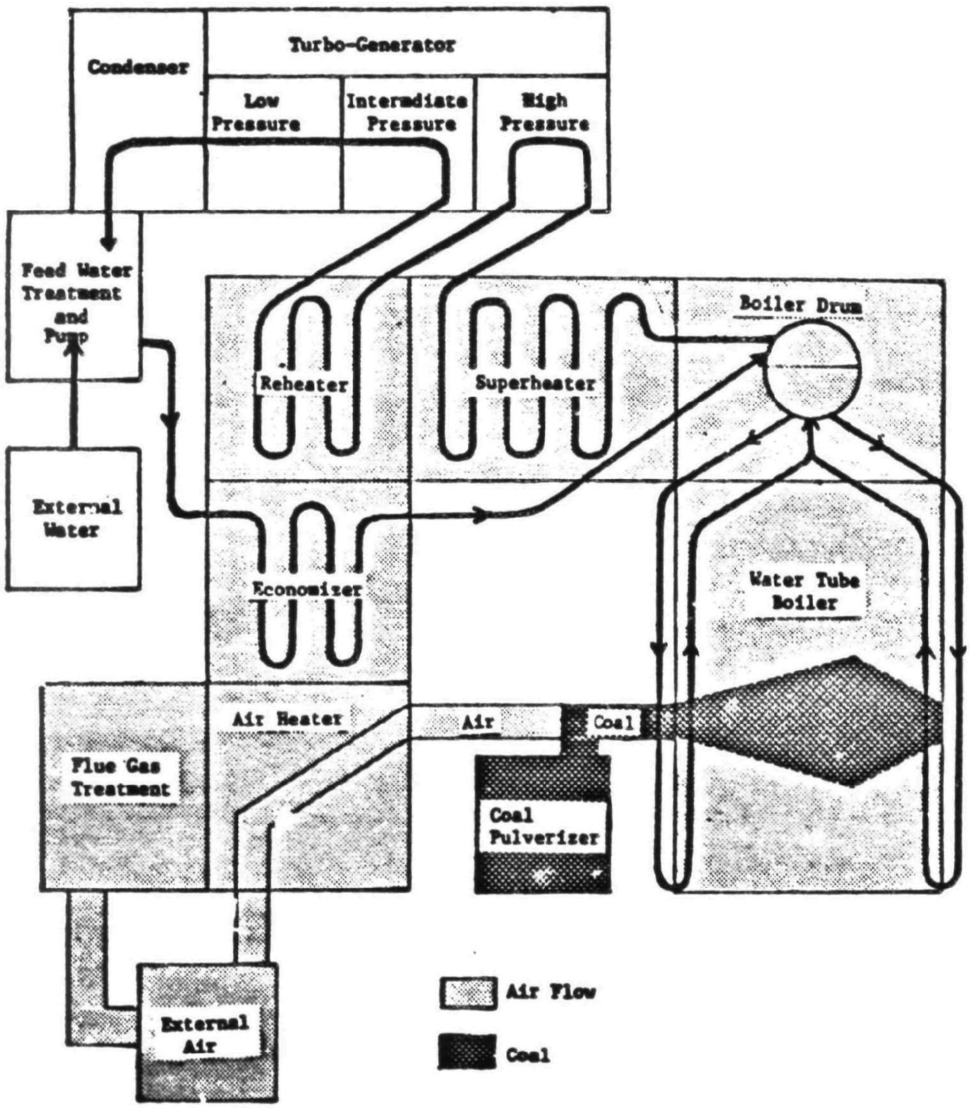


Figure B-5. Material flows through coal fired boiler.

purpose of the water treatment system is to provide water that is sufficiently free of minerals and gases for safe operation of the power plant. The requirement for water treatment is common to all steam boiler systems whether coal fired, oil fired, industrial, or nuclear. A large power plant commonly uses between 22 to 37 thousand cu m of water per hour. However, the principal source of water is condensate that is recycled from the turbines, and only 2 to 5 percent raw water must be treated to replace lost condensate.

Boiler--

Boilers are essentially furnaces having walls lined with water-filled tubes that burn fuel at high temperatures, and convert water to steam. Boiler operation is a delicate balance between water flow and combustion temperature. Water is pumped into the boiler until it reaches the desired temperature. High pressure water is heated in the economizer and in effect recovers heat that would normally be ejected into the environment in the form of hot flue gas. From the economizer, the water flows into the boiler where it is converted to steam. After the water is converted to steam, additional heat is added in the superheater before it is used in the turbines. In some cases, steam is returned to the reheater after going through the first stage of the turbine to prevent condensation in later turbine stages. Present constraints on material design limit the maximum steam temperature and pressure to approximately 540°C and 24 kPa.

Turbine-Generator System--

The steam turbine converts thermal energy in the steam into mechanical energy. The operating principle of the steam turbine is relatively simple (48). The only major moving part is the rotor, which contains sets of blades. There are two methods of using steam in a turbine. The first method allows the steam to expand through a nozzle which produces a stream of high velocity steam. When this high velocity steam strikes the blades on the rotor, the energy is transferred to the rotor in the form of an impulse. A second method allows the steam to expand as it flows through a series of fixed and moving blades. Mechanical rotation results from a reaction to the forces produced by pressure differences, turbines are classified either impulse or reaction type, depending on which method of energy conversion is used.

To extract the maximum energy from the steam, turbines may have many stages or sets of blades. The diameter of each successive set of blades must be increased, because as the steam expands, its volume increases. For applications that employ high pressures, it is not unusual to employ several low pressure turbines in parallel to limit the diameter of the blades. It is desirable to limit the blade size to limit the centrifugal forces that are encountered during the high speed operation.

Turbines are selected based on anticipated operating conditions. Flexibility in the operating conditions allows two important applications of the steam turbine. Back pressure turbines are specially selected turbines that accept high pressure steam and exhaust steam from the turbine at pressures well above atmospheric pressure. For example, a back pressure turbine may have an inlet steam pressure of 7 MPa and an outlet pressure of 720 kPa. In a large utility power plant there may in effect be several back pressure turbines that are operated in series followed by a condensing turbine. The term condensing turbine refers to the conditions of the exhaust steam in the condenser which is at the pressure of condensing steam (i.e., 1.5 inches or 38 mm of mercury). The extraction turbine is specially designed so that steam can be extracted at pressures sufficiently high for uses other than driving a turbine.

From a practical standpoint, there is a wide range of possible turbine combinations that are available during the design phase of a power plant. However, once the turbines are installed, much of the versatility is gone. Manufacturers market turbines in a range of sizes, and esentially every large turbine is custom designed by selecting standard size blades that satisfy the steam inlet and outlet conditions. By applying this modular design approach, the manufacturer can provide turbines that operate at near maximum efficiency for a wide range of applications.

The rotation shaft of the turbine can be used to power any number of mechanical systems. However, the most common application of large turbines is to power electric generators.

Flue Gas Treatment System--

The flue gas treatment system removes particles and gases from the flue gas that would be harmful to the environment. The cost of pollution control is significant in terms of capital, labor, and energy. It is important to note that flue gas treatment is primarily a direct response to government regulation.

Cooling System--

From a functional standpoint, the cooling system consists of a heat exchanger or condenser that actually condenses the steam, and a heat sink that can absorb the heat from the condenser steam. The heat sink is always the environment. In some cases the heat is ejected from the condenser into a river or large body of water or it may be ejected into the air by cooling towers. Regardless of the method used, the heat ejected through the condenser heats the environment in some way. The size and cost of the cooling system is therefore a function of the quantity of steam that must be condensed. All of the heat from the condenser must be absorbed by the environment.

By condensing the turbine exhaust steam, the outlet pressure can be reduced, resulting in an increase in the efficiency of the steam cycle. However, to condense the steam, approximately 60 percent of the thermal energy that is used to produce the high pressure steam must be removed by the condenser. Condensation temperature is around 38 °C which is too low in temperature to have economic value for the large quantities of heat available.

Nuclear Power Plants

Although there are several promising techniques that utilize nuclear energy to produce electric power, only two basic types of systems are in widespread use. These are the pressurized water reactor and the boiling water reactor (46). Since these systems rely on the basic steam cycle for the production of electricity, there are many similarities to fossil steam plants. The major functional components of the nuclear power plant are: reactor, water treatment system, turbine generator system, and cooling system. However, the water treatment, turbine generator, and cooling system perform the identical functions that were previously discussed relative to the coal-fired power plant. The reactor replaces the boiler.

The reactor is a vessel containing the nuclear fuel where nuclear fission takes place. Once the fuel elements are installed in the nuclear reactor, a controlled nuclear chain reaction can be produced. There is no requirement for a continuous fuel handling system because the reactor can operate for approximately 1.5 years on one set of fuel elements. Large quantities of heat are released as a result of the nuclear reaction. The heat is transferred from the fuel elements directly to a working fluid (usually water).

Since heat is generated inside the fuel elements of the nuclear reactor, all of the heat is transferred to the working fluid. However, this causes some operational problems. Water that is circulated, not only serves as a working fluid for the steam cycle, but also serves as a coolant for the fuel elements. If the fuel elements cannot be cooled sufficiently, the fuel elements will overheat, rupture, and contaminate the system. To protect against fuel cell rupture, nuclear reactors that use water as a working fluid must not allow departure from nucleate boiling. In effect, this limits the temperature and pressure of steam that can be produced by nuclear reactors.

The two types of nuclear steam systems (pressurized and boiling) are similar, but were developed by making different tradeoffs between safety and economics (3, 46, 49). Schematic diagrams of both systems are shown in Figure B-6. Steam is generated directly in the reactor of the boiling water reactor. However, to prevent departure from nucleate boiling and protect the fuel elements from rupture, the maximum pressure is limited to approximately 7 MPa and saturated steam is produced at a maximum temperature of approximately 290 ^{o}C. This low pressure and temperature limits the efficiency of the steam cycle to a maximum of approximately 33 percent. The pressurized water reactor system uses water under high pressure, but does not produce steam in the reactor. The water is circulated through a special heat exchanger called a steam generator which transfers heat to water at a lower pressure and produces steam that is used to drive the turbines. The advantage of the pressurized system is that the steam generator provides isolation between the reactor and the turbines. Therefore, the probability of contaminating the turbines with radioactive material is significantly reduced, while the efficiency is essentially unaltered.

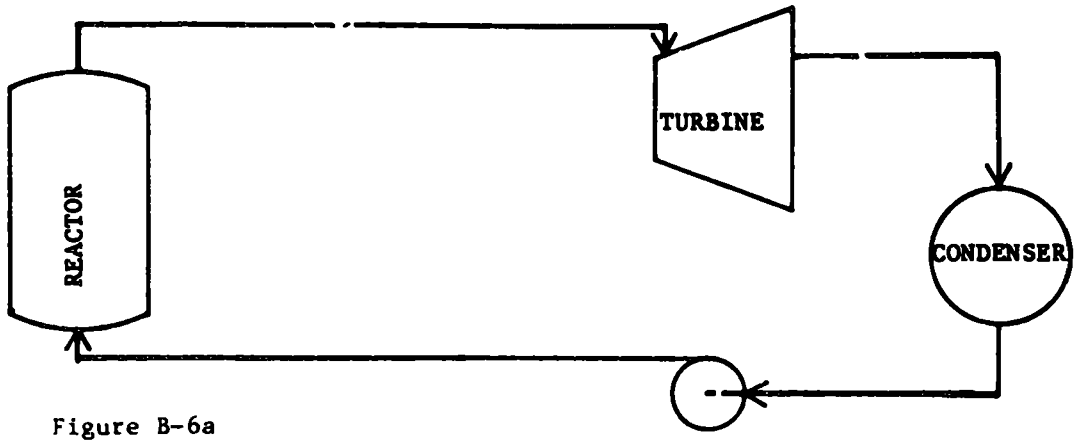


Figure B-6a
Boiling water reactor nuclear steam power system.

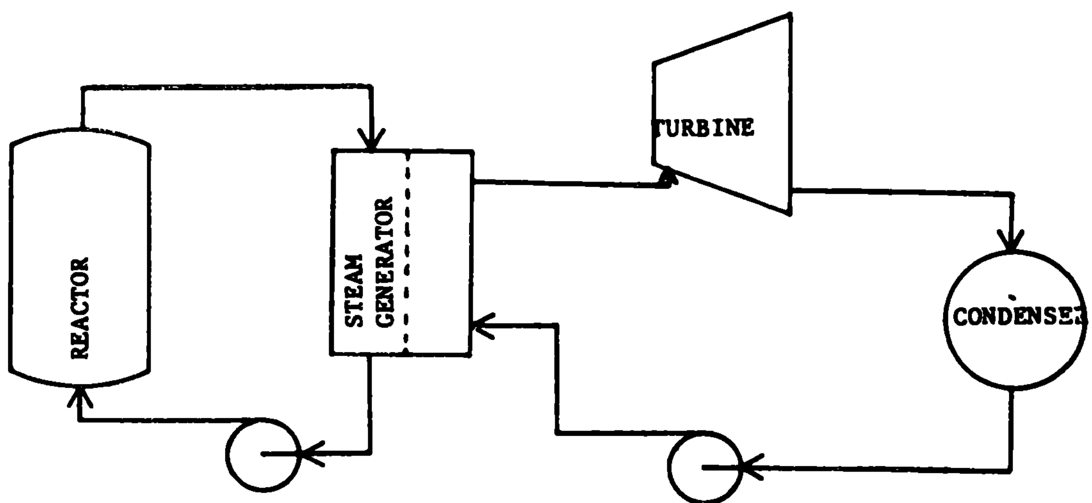


Figure B-6b
Pressurized water reactor nuclear steam power system.

Figure B-6. Pressurized and boiling nuclear power cycles.

MULTIPURPOSE POWER PLANTS

One practical means available for improving the use of energy in steam plants is the use of multipurpose steam plants, where steam is exhausted or extracted from the turbines at a proper pressure level for use in an industrial process. With such arrangements, it is possible to obtain an overall thermal utiization between 65 percent and 70 percent (3, 50, 51, 52). Combination power-and-process installations have been used successfully in industry for many years. By trading electricity production for available thermal energy, the net efficiency of the input fuel can be increased.

Steam can be used as a controlled temperature source of heat. At a given pressure, the transformation of steam to water is associated with the release of large amounts of heat. For pressures below 100 psi, the latent heat of transformation is approximately 900 Btu per pound, but the temperature of the steam/water remains constant during the transformation. Therefore, the steam pressure can be used to control the temperature for applications that require heat at a specific temperature.

Thermal Energy

The heat wasted in the condenser of an electric power plant can be used by a multipurpose power plant. By extracting steam at high pressure, the heat associated with the phase transformation can be used. Figure B-7 illustrates how it is possible to increase efficiency of the system by trading electricity production for thermal energy availability. Diagram A shows the T-S diagram for a typical steam condensing power cyle. The enclosed area represents the electrical energy produced, while the shaded area represents the heat that is ejected through the condenser. In the condensing cycle, the condensing temperature is approximately 38 °C which corresponds to an absolute pressure of 7 kPa. However, the condensation of steam produces approximately 2.2 kJ/kg of condensed steam that must be ejected through the condenser. For example, by extracting the steam at 345 kPa, the condensation temperature is 138 °C, and the heat that is available from the condensation process is 21.5 kJ/kg of steam condensed. Because of its higher temperature, this heat can be used for many more applications, such as drying. Diagram B in Figure B-7 shows the relationship between the electricity production and the unavailable thermal energy. As compared with Diagram A, the electricity production is reduced due to the extraction of steam, but the area that represents the unavailable energy is reduced significantly. The overall efficiency of the energy system represented by Diagram B has a potential efficiency of as high as 80 percent, while the energy system represented by Diagram A has an efficiency that is limited to a maximum value of less than 40 percent.

Reduction of Electric Generation Capacity--

As an example of the impact of steam extraction on electricity production, Figure B-8 shows the electricity production in megawatts electric

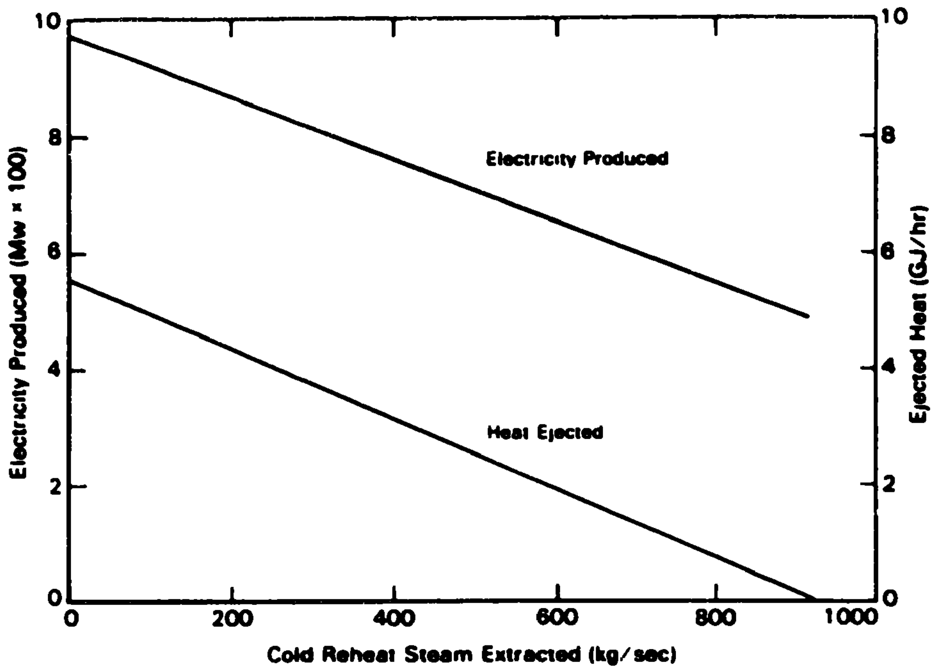


Figure B-8. Effect of steam extraction on electric power production.

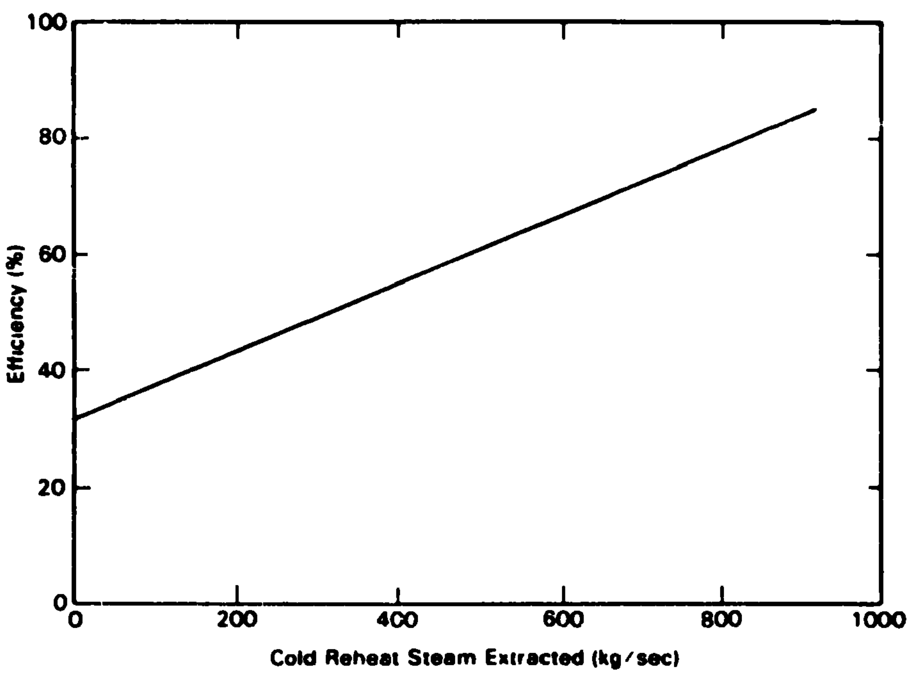


Figure B-9. Effect of steam extraction on system efficiency.

and the heat ejected through the condenser as a function of extracted steam. The maximum electricity production occurs when no steam is extracted for use as thermal energy; however, the maximum production also corresponds to maximum heat ejected through the condenser. Heat ejected through the condenser is waste energy, because it is of such low temperature that it has no economical uses. As steam is extracted from the system, and used to supply thermal energy, the electricity production decreases, but simultaneously the ejected heat also decreases. If sufficient steam is extracted, no heat is ejected through the condenser; however, electricity can still be produced. Electrical production is primarily a result of the steam flow through the high pressure turbine.

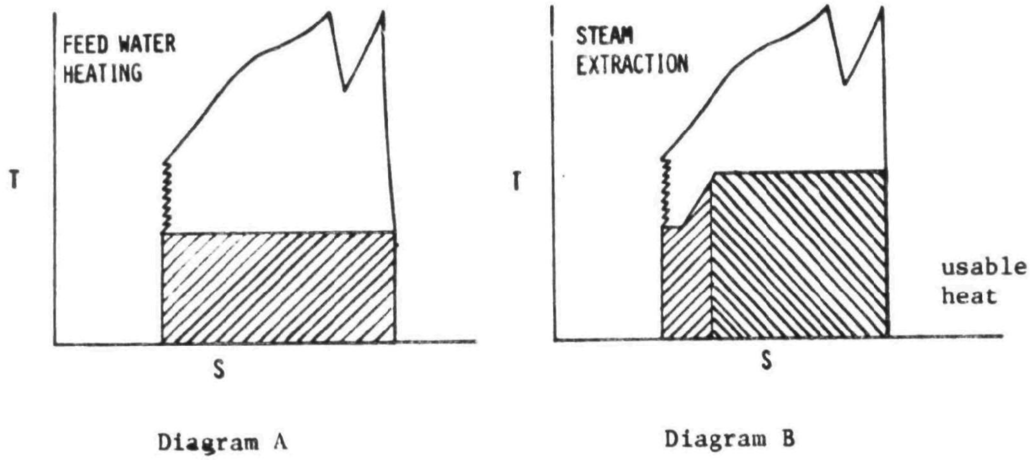


Figure B-7. Potential increase in available energy from steam extraction.

Improved Efficiency--

The increase in efficiency is directly related to the ability to use the heat that is normally ejected through the condenser. By making the assumption that all of the extracted steam is used at 100 percent efficiency, it is posible to calculate an effective system efficiency. Figure B-9 shows that the system efficiency with no steam extraction is approximately 35 percent. As the extracted steam increases, so does the efficiency. The potential efficiency of this system with maximum extraction is slightly over 80 percent.

Proven Technology--

Experience in industry where both processed steam and electricity have been produced have shown that the concept of multipurpose power plants is technically feasible, and in many cases economically desirable. One significant advantage of the multipurpose power plant is that the size of cooling towers and heat exchangers can be reduced or eliminated. Although the principle of multipurpose power plants is philosophically desirable, there are many engineering, economic, institutional, and environmental factors that can limit actual use.

Industrial In-Plant Cogeneration

Many industries that require process heat have found it practical and economical to use steam as a transfer medium. The production of processed steam for industries is very similar to the production of steam for utility applications. Some type of fuel is consumed in a boiler and steam is generated. The general term that is used for industrial power plants which are capable of producing both electrical energy and processed steam is in-plant cogeneration. In-plant cogeneration employs the same principles as a utility power plant, except that the industry has a need for the thernal energy contained in the steam that the utility industry normally ejects through the condenser.

Even though in-plant cogeneration has the potential to save significant amounts of energy, it is not always practical for an industry to operate an in-plant cogeneration facility (50, 51). The following are some of the barriers to in-plant cogeneration that may be incountered by an industry (53).

a. The variations in the operating requirements for electricity and process steam are incompatible.

b. The industries may fear possible action by regulatory agencies, (such as the Public Seavice Commission that regulates the utility industry).

c. The industry may be reluctant to produce its own electrical energy regardless of the economic feasibility, because the unit cost of installing and operating a small in-plant cogeneration facility is much higher than that of a large facility.

In spite of the barriers which may discourage in-plant cogeneration, there are many examples of industrial facilities which have demonstrated the economic and technical feasibility of the principles.

Coal-Fired Multi-Purpose Power Plant

The use of large coal-fired power plants to supply both thermal and electrical energy is essentially an extension of in-plant generation technology on a larger scale. However, applying this principle on such a large scale presents a number of other problems.

Boiler pressure of a utility size power plant is often in excess of 20 MPa. Theoretically, steam can be extracted at any pressure below boiler pressure; however, as a practical matter the maximum extraction steam pressure is limited. In general, 20 MPa steam cannot be shipped economically because very expensive piping systems would have to be used to prevent small losses ot thermal energy which would siginificantly reduce the pressure. For most applications, steam would be extracted between the turbine stages. Typical steam conditions that might exist at potential extraction points in a coal fired power plant are:

Primary boiler steam - 24 MPa, 540 ^{o}C
Cold reheat steam - 5.0 MPa, 310 ^{o}C
Crossover steam - 1.1 MPa, 350 ^{o}C

The specific location of these points in the steam cycle is identified in Figure 5 as points A, B, and C respectively. The steam extraction temperature and pressure can be selected by utilizing specific turbines.

Nuclear Multi-Purpose Power Plant

Using process heat from a nuclear reactor requires the additional consideration of radiation contamination (3). Steps must be taken to insure that radioactive steam does not contaminate consumer products. In a boiling water reactor system, protection can be provided by a level of isolation in the form of steam regenerators. In the case of a pressurized water reactor system, this level of isolation is provided by the steam generator. The principal impacts of this isolation requirement are an increase in capital cost and a reduction in the available temperature and efficiency.

The maximum pressure of the steam that can be extracted from the nuclear power cycle is approximately 7 MPa for a pressurized water reactor system and 4.8 MPa for a boiler water reactor system. In both cases, the steam will be saturated.

POLLUTION CONTROL

There are two types of pollution that must be given specific consideration, air pollution and thermal pollution. Air pollution is only a consideration for fossil fuel boilers, but thermal pollution is a problem with both fossil and nuclear power plants.

The pollution control systems considered in this report are for control of steam-power boilers emissions, not industrial process emissions. The cogeneration system replaces the need for steam production in an industry by supplying steam and electricity directly to the industry. This eliminates the need for pollution control devices in the industry that would have been used to control power boiler emissions. However, this has no impact on the need for pollution control of emissions that occur as a result of the specific manufacturing process.

Air Pollution Control

There are three major categories of air pollutants that must be controlled: particules, sulfur oxides (SO_x), and nigrogen oxides (NO_x). Each of these pollutants can cause environmental damage if emitted in large quantities. Coal fired power plants emit large quantities of all three types of pollutants and are subject to pollution control regulations. Although the required level of control is specified, the actual control is a technical problem. There are several technologies that may be used to control each type of emission.

Particulate Emissions--

When pulverized coal is burned, one of the by-products is fly-ash. Some of the small particles of fly-ash are suspended in the flue gas and carried out the stack to the environment. Since these particles are visible in the atmosphere, particulate control is desirable not only from an environmental standpoint, but also from a social and institutional standpoint.

There are several technical approaches to the control of particulates from coal combustion. These technologies fall into three categories: wet scrubbing, mechanical, and electrostatic. Wet scrubbing collection systems primarily mix the fuel gas with water. The water traps the particles and forms a slurry from which the solids can be removed. Collection efficiencies as high as 99.9 percent are possible with this type of system. Mechanical collectors such as cyclones spin the gas stream, and the centrifugal action forces the particles out of suspension. Other mechanical collectors such as the bag house are just like large fabric filter systems. The electrostatic precipitator uses sets of electrically charged electrodes to first charge the particles and then attract them to an electrode. After a predetermined amount has been collected on an electrode, the electrodes are rapped with a mechanical hammer, and the particles fall to the floor of the precipitator for collection. Mechanical and electrostatic collector systems are only effective for particulate control.

SO_x Emissions--

Oxides of sulfur and particularly SO_x are considered to be a serious health hazard as well as having a very unpleasant odor. Sulfur oxides result when fuels that contain sulfur are burned. The most common sulfur bearing fuels are eastern coal and residual oil.

The easiest way to reduce the output of SO_x is fuel substitution. Fuel substitution with low sulfur fuels such as natural gas, distilled oil, or low sulfur coal is not always an acceptable solution. These fuels are limited in availability and the cost may be unacceptable.

Another option is stack gas clean up. There are several processes that are capable of reducing SO_x emissions by at least 85 percent. All of these technologies involves similar principles. The stack gases are mixed with a material that absorbs the sulfur compounds. Some of these processes produce large quantities of quick-sand-like sludge that must be thrown away. This throwaway sludge creates a major disposal problem. Other processes are regenerative, and can produce elemental sulfur or sulfuric acid and the absorbing medium can be reused.

A third option for the reduction of SO_x emissions is the physical cleaning of the coal. This technique requires the precombustion treatment of the fuel which may be costly and energy consuming.

NO_x Emissions--

Oxides of nitrogen are formed primarily as a result of high temperature combustion of fuel in air. The resulting NO_x is important in the formation of smog and has other detrimental effects on the environment.

Control options for NO_x are primarily in the categories of combustion modification and flue gas treatment. Combustion modification includes several methods that are designed to reduce NO_x production. Specific examples of combustion modification are low excess air on firing, staged combustion, flue gas recirculation, and water injection. Some of the combustion modification techniques are very cost effective because little or no capital cost is associated with the modifications. Flue gas treatment is accomplished with techniques that are very similar to those discussed previously relative to SO_x control.

Fludized Bed Combustion--

There is one technology currently under development that has the potential of simultaneous control of all three major pollutants. This technology is fluidized bed combustion. In this process, fuel is injected into a bed of limestone powder where combustion takes place. Since the combustion takes place in intimate contact with the limestone, the particules and SO_x are absorbed directly. Also, the combustion temperature is relatively low, so less NO_x is formed relative to a conventional power plant. As a result, fluidized bed combustion requires little or no stack gas clean up.

Thermal Pollution Control

Approximately 50 percent of the thermal energy from the fuel is ejected through the condenser of a steam electric power plant. This heat must be disposed of in some way, specifically transferred to the environment.

For many years it was standard practice to use natural bodies of water or rivers to cool the condensers. However, as the demand for electric power has increased, and the size of power plants has increased, the heating of streams and other natural bodies of water has reached unacceptable levels.

Alternative methods of disposing of the huge quantities of heat have been developed. These methods are cooling ponds and cooling towers. Cooling ponds are large man-made lakes that can transfer the heat to the air by convection or evaporation. Cooling towers perform the same function, but they are tall structures that don't need large areas of land. Although both methods transfer heat to the environment, they don't directly heat natural water resources.

Technologies Selected

Various options for air and thermal pollution control were selected for use in the analysis. These options included technologies that control emissions before, during, and after combustion. All of these technologies have been proven by actual use or are considered sufficiently promising that enough research experience and literature are available to estimate costs and operating characteristics.

Several technologies are considered.

Solvent refined coal, which controls SO_x emissions.

Electrostatic precipitator which controls particulate emissions.

Flue gas desulfurization which controls SO_x emissions.

Combustion modification in the boiler which controls NO_x emissions.

Dry flue gas treatment which controls NO_x emissions.

Dry flue gas treatment with simultaneous treatment control of SO_x and NO_x emissions.

Wet flue gas treatment with simultaneous treatment control of SO_x and NO_x emissions.

Atmosphere fluidized bed combustion boiler which controls SO_x emissions.

Pressurized fluidized bed combustion which takes place under pressure and controls SO_x and NO_x emissions.

Forced draft cooling tower which controls thermal emissions.

Natural draft cooling tower which controls thermal emissions.

In general, these technologies appear to be the most economical methods of satisfying present and future standards for industrial and utlity power boilers. Electrostatic precipitation and flue gas desulfurization are proven technologies and are in widespread use. Wet and dry flue gas treatment are presently being examined as alternatives to satisfy the more stringent NO_x standards that may be imposed in the future.

Wet and dry methods of simultaneous flue gas treatment control of SO_x and NO_x emissions are presently considered within economically feasible ranges though high in cost. However, only dry blue gas treatment methods can be considered economically feasible for selective control of NO_x emissions. Combustion modification is considered a cheaper method of controlling NO_x than flue gas treatment, but combustion modification may not decrease NO_x emissions enough to meet more stringent NO_x standards if they are promulgated.

Although fludized bed combustion is not a fully developed technology, it has a good probability of acceptance by industries and utilities. It also seems to be the only other method aside from flue gas desulfurization that can economically and in an energy efficient manner meet EPA SO_x standards. Atmospheric fluidized bed combustion with SO_x emission control boiler technology will not be commercially available on a significant scale until the early 1980's, while pressurized fluidized bed boiler technology will not be commercially available until the mid 1980's. Pressurized fluidized bed combustion boilers are more applicable to utility applications because they can make use of the high pressure flue gases to turn a gas turbine to generate electricity. As much as one-fifth of the electric power derived from the boiler could come from this use of the pressurized fluidized bed combustion boiler's flue gases. This gives the boiler a higher thermal efficiency than conventional boiler. However, much of this efficiency advantage would be lost if the pressurized fluidized bed combustion boiler is used in an industrial setting where the purpose of the boiler would be to generate steam and not electricity.

Transportation of Thermal Energy

The transportation of steam from the power plant to the industries impact a cogeneration system both economically and operationally. A utility size power plant could supply thermal energy to several large industries. In such a case, the facilities required by the power plant and the industries would require a physical separation between them that could easily be several miles. Regardless of the separation distance, steam must be available at the industries. Therefore, the power plant and the industries must be connected by a piping system through which some heat-transfer medium will flow. There are three generic heat transfer media that are suitable for transporting thermal energy at temperatures below 340 °C. These are high-temperature water, organic fluids, and steam (32). The selection of the heat transfer medium depends on the spcific application, but steam and high-temperature water are most often used.

Organic fluids that are used for thermal energy transfer and storage are usually by-products of the petrolium process. Several manufacturers offer these organic fluids under various tradenames. The basic characteristic of these fluids is a very high boiling point, which allows these fluids to be heated to several hundred degrees without having to pressurize the working fluid. By operating near atmospheric pressure, the piping system is simpler than for steam and pressurized water systems even though a system of heat exchangers must be used (32). However, precautions must be taken to contain the organic fluids because they can be very detrimental to the environment if a leak does occur. The major reason organic fluids are not extensively used is the cost of the fluid and the cost of the precautions that must be taken to protect the fluids from atmospheric contamination.

Steam has been used as a heat transfer medium for many years. Operationally, steam has several advantages, e.g., water is readily available to make steam, steam can be extracted directly from power cycle, and steam is often the desired end use energy form. However, there are several disadvantages also such as, steam can only be shipped a few miles, and the cost of piping is higher for steam than for pressurized water systems. In general, steam is the cheapest method of transporting high temperature thermal energy for distances of less than a few miles.

High-temperature water is becoming more popular as a heat transfer medium for transfering low and medium temperature thermal energy for distinct heating applications (2). Water has the advantages that it is abundant and that the thermal capacity is very high. However, when water is used, heat exchangers must be employed. The heat exchangers are an additional cost as well as an efficiency loss to the system. Pressurized water is most economical in systems that have high system capacity and long distances to transfer the thermal energy.

APPENDIX C*

DESCRIPTION OF MAIES COMPUTER PROGRAM

PURPOSE

A FORTRAN computer program has been written to help in the comparison of costs and benefits associated with a cogeneration system and a status quo system. The program called Model for Assessment of Integrated Energy System (MAIES) is used to compute costs and benefits as well as energy balance, energy efficiency, electrical energy output and fuel requirements for both the cogeneration system and the status quo system for the energy and economic analysis. In addition, the program computes the volume of air pollutants (particles, sulfur oxides, carbon monoxide, hydrocarbons and nitrogen oxides) produced and emitted as well as thermal heat ejected into the environment by conventional, cogeneration, and industrial power plants.

APPROACH

The cost elements included in the program logic make it possible to compare the costs of providing both thermal and electrical energy to a group of co-located industries from a large central source, to providing these energy requirements from a status quo system consisting of a large utility which provides electricity only and industrial boilers which provide steam and by-product electricity to individual industries.

The program is arranged to automatically evaluate an equivalent status quo system following the evaluation of a cogeneration system. Any number of industries may be co-located at varying distances from the centralized power plant. The program contains all data related to industry thermal and electrical energy requirements, pollution control equipment efficiencies and costs, and all costs associated with particular utility power plant types (nuclear or coal) and industrial boiler types (coal, fuel oil or natural gas). To facilitate the evaluation of a variety of cost and technical parameters as well as industries types and locations, the program reads all concepts from files, or inputs are typed in at a teletype in response to programmed questions. In addition, practically any parameter may be varied and the run repeated without re-entering original data.

As an example, a cogeneration concept may be read in that consists of a number of industries located at some distance from the centralized cogeneration power plant. A file may be set up to run this concept and repeat the evaluation of the concept for succeeding sets of relative industry locations. Many other parameters may also be changed and runs repeated. Examples of these parameters are discount rate, all capital and operation

*The MAIES Computer Program is written in English units and therefore this appendix has been written in those units, too.

and maintenance costs, fuel type, fuel costs, industry size, industry electrical and thermal demands, pollution control system type, pollution control system costs, pollution control equipment pollutant collection efficiency, power plant size (Mw $_{thermal}$), and industrial boiler type.

PROGRAM OUTPUTS

Program outputs include efficiency and fuel use analysis of the status quo system, industrial utilizer, and the cogeneration system. Cost comparisons between the status quo system and the cogeneration system are made on the level of capital and operation and maintenance costs as well as fuel costs. The net present value of the overall system is an integral part of program output. An environmental inpact analysis is also part of available program output.

DEFINITION OF PARAMETERS

This section lists the parameters used in the MAIES computer program so that the level of detail considered by the program is understood.

AFIEF	-	Annual fuel use in cogeneration system
AFIND (8)	-	Annual fuel use in industries
AFSQ	-	Annual fuel use in status quo systems
AFUEL (8)	-	Additional industrial fuel requirements
ANCOST (50)	-	Annual cogeneration system fuel costs
ANFUEL (4)	-	Industrial by-product fuel
BASE	-	Area of power plant in square feet
BFUEL (8)	-	Industrial by-product fuel
BLCIEFC	-	Base linear coefficient for capital cost of coal total cogeneration system
BLCIEFN	-	Base linear coefficient for capital cost of nuclear total generation system
BLCSQC	-	Base linear coefficient for capital cost of coal status quo system
BLCSQN	-	Base linear coefficient for capital cost of nuclear status quo system
CAPCIEF	-	Capital cost of total cogeneration system utility
CAPCIND (8)	-	Capital cost of each industrial utility
CAPCSQ	-	Capital cost of status quo utility
CCCTIEF	-	Capital cost of cooling towers for total cogeneration systems
CCCTIND (8)	-	Capital cost of cooling towers for industries
CCCTSQ	-	Capital cost of cooling towers for status quo systems
CCEPIEF	-	Capital cost of electrostatic precipitators for total cogeneration systems
CCEPSQ	-	Capital cost of electrostatic precipitators for status quo systems
CCNOIEF	-	Capital cost of NO_2 control equipment for total cogeneration systems
CCNOSQ	-	Capital cost of NO_2 control equipment for status quo

		systems
CCSOIEF	-	Capital cost of SO_2 scrubbers for total cogeneration systems
CCSOSQ	-	Capital cost of SO_2 scrubbers for status quo systems
CLCIEFC	-	Linear coefficient for capital cost of coal total cogeneration system
CLCIEF	-	Linear coefficient for capital cost of nuclear total cogeneration system
CLCSQC	-	Linear coefficient for capital cost of coal status quo sys-tems
CLCSQN	-	Linear coefficient for capital cost of nuclear status quo systems
COOLSAV	-	Cost savings of total cogeneration system Cooling towers over status quo systems towers
COSTIND(50, 8)	-	Annual industry costs
D	-	Discount rate
DIST (8)	-	Distance from power plant to each industry
EETIND (8)	-	Electrical energy requirements for industries
EESUP	-	Electrical energy provided by supplemental utility
EFFIES	-	Efficiency of cogeneration system
EFFLDSS	-	Fuel use efficiency of power plant
EFFO	-	Efficiency of status quo systems
EFFPOL(5,3)	-	Efficiency of pollution control devices
EFFS	-	Efficiency of total cogeneration system power plant
EFIND (8)	-	Efficiency of industrial power plants
EINLOSS	-	Fuel use efficiency of industrial boilers
ELECT (8)	-	Industrial electrical requirements
ELECTP (8)	-	Electrical energy purchased by industrial power plants
EMIEF(S)	-	Emissions from cogeneration system
EMIND (5,8)	-	Emissions from industries
EMINDX (4,5)	-	Emissions index file
EMSQ (5)	-	Emissions from status quo systems
EMSSQ (5)	-	Solid waste produced from status quo systems
EMSIEF (5)	-	Solid waste produced from cogeneration system
EMSIND (5,8)	-	Solid waste produced from industries
ENPEN	-	Total energy penalty
ENTLPC (9)	-	Enthalpy for coal plants
ENTLPI (9)	-	Enthalpy for industrial boilers
ENTLPN (9)	-	Enthalpy for nuclear plants
ENTLS (9)	-	Enthalpy for small industrial boilers
ETA (4)	-	Turbine efficiencies
ETAI (4)	-	Industrial boiler efficiencies
ETAS (4)	-	Small industrial boiler efficiencies
ETIEF	-	Electrical energy required for cogeneration system
ETSQ	-	Electrical energy required for status quo systems
EXCESS	-	Total cogeneration system electrical energy produced but not used
EXCIEFC	-	Exponential coefficient capital cost of coal total cogeneration system

EXCIEFN	-	Exponential coefficient capital cost of nuclear total cogeneration system
EXCSQC	-	Exponential coefficient capital cost of coal status quo systems
EXCSQN	-	Exponential coefficient capital cost of nuclear status quo systems
FACTOR (8)	-	Factor for electrical requirements
FM (8, 8)	-	Steam mass flow rate
FMI (8,8)	-	Effective steam mass flow rate
FOMPIP	-	O&M factor for piping
FRATE	-	Adjusted fuel rate for total cogeneration system
FRATIEF	-	Fuel rate for total cogeneration system
FRATIND (8)	-	Fuel rate for industries
FRATESQ	-	Fuel rate for status quo systems
FUELIND (SO)	-	Annual industry fuel costs
FUELCSQ (SO)	-	Annual status quo systems fuel costs
FWORD 1	-	Alphanumeric for total cogeneration system fuel type
FWORD 2	-	Alphanumeric for industrial fuel type
GRF (u)	-	Fuel price growth rate
GTLIEF	-	Total cogeneration system fuel costs over life of facility
GTFLSQ	-	Total status quo systems fuel costs over life of facility
GTFUEL	-	Total fuel costs
GTOMIEF	-	Total O&M costs for total cogeneration system
GTOMSQ	-	Total O&M costs for status quo system
H (8,8)	-	Industry enthalpiers
HJIEF	-	Heat ejected from cogeneration system
HJIND (8)	-	Heat ejected from industrial boilers
HJSQ	-	Heat ejected from status quo systems
HTOT1 (8)	-	Heat produced by industries
HTOTIEF	-	Heat produced by cogeneration system
HTOTSQ	-	Heat produced by status quo systems
ICNTCC	-	Pollution control system used
IEFUPT	-	Mass calculation option for power plant
IEFF	-	Total cogeneration system fuel type
INDCAP (P)	-	Industry power capacity
INDCNTL	-	Industry pollution control system used
INDELEC (8)	-	Industry electrical requirements
INDFUEL (8)	-	Industry fuel requirements
INBLOP	-	Industrial boiler option
INDOPT	-	Industrial power plant option
1PLANT (8,2)	-	Alphanumeric of industrial plant type
ISMALL	-	Small industrial boiler option
ITITL (3)	-	Title for output
IWORD (5)	-	Input read and write work options
ISQF	-	Status quo systems fuel type
IOP1	-	Status quo systems energy print option
IOP2	-	Total cogeneration system energy print option
IOP4	-	Scenario print option
IOP5	-	Economic analysis print option
IOP6	-	Fuel use and cost analysis print option

IOP7	-	Environmental impact print option
LIFE	-	Facility life
N	-	Number of years of operation
NAME (4)	-	Status quo systems fuel titler
NCDM	-	Number of pollution control systems
NIEFF	-	Alphanumeric of total cogeneration system fuel type
NGRADES (8)	-	Industrial steam grade
NO	-	Years beyond 1975 of initial operation
NP	-	Plant number
NPLANTS	-	Number of industries
OMCIEF	-	O&M costs of cogeneration system
OMCIND (8)	-	O&M costs of industries
OMCOE (5)	-	O&M cost coefficients
OMCSQ	-	O&M costs of status quo systems
OMCTIEF	-	O&M costs of total cogeneration system cooling towers
OMCTIND (8)	-	O&M costs of industrial cooling towers
OMCTSQ	-	O&M costs of status quo system cooling towers
OMEPIEF	-	O&M costs of total cogeneration system electrostatic precipitators
OMEPSQ	-	O&M costs of status quo systems electrostatic precipitatos
OMEXP (5)	-	O&M costs exponents
OMNOIEF	-	O&M Costs of total cogeneration system NO_2 control equipment
OMNOSQ	-	O&M costs of status quo systems NO_2 control equipment
OMPIP	-	O&M costs of piping
OMSOIEF	-	O&M costs of total cogeneration system SO_2 scrubbers
OMSOSQ	-	O&M costs of status quo systems SO_2 scrubbers
PEXTCOE (2,2)	-	Steam extraction cost coefficients
PEXTEXP (2,2)	-	Steam extraction cost exponents
PEN (8)	-	Industrial energy penalty
PF	-	Plant Factor for total cogeneration system
PFIND (8)	-	Plant factor for industries
PFSQ	-	Plant factor for status quo systems
PIPCOE (2,2)	-	Piping cost coefficient
PIPCON	-	Piping distance effectiveness constant
PIPEXP (2,2)	-	Piping cost coefficients
PIPEXT (2)	-	Steam extraction costs
PIPXOL	-	Additional extraction costs for nuclear plants
PIPCOST (8,8)	-	Piping costs for each industry
PEICEFC (4)	-	Initial price of fuel
PRF (4,50)	-	Annual price of fuel
RATIO	-	Ratio of supplementary electrical energy to status quo systems electrical energy
R1	-	Inflation rate for capital costs of piping
R2	-	Inflation rate for capital cost of total cogeneration system
R3	-	Inflation rate for capital cost of cooling towers
R4	-	Inflation rate for capital cost of turbines
R5	-	Inflation rate for capital cost of industrial boilers
R6	-	Inflation rate for capital cost of status quo system

R7	-	Inflation rate for O&M cost of piping
R8	-	Inflation rate for O&M cost of total cogeneration system
R9	-	Inflation rate for O&M cost of status quo systems
R10	-	Inflation rate for O&M cost of industrial boilers
SCCCT	-	Sensitivity for capital cost of cooling towers
SCCEP	-	Sensitivity for capital cost of electrostatic precipitators
SCCIND	-	Sensitivity for capital cost of industrial boilers
SCCNOX	-	Sensitivity for capital cost of NO_2 control equipment
SCCSOX	-	Sensitivity for capital cost of SO_2 scrubbers
SFUELPR	-	Sensitivity for fuel price
SOMCT	-	Sensitivity for O&M cost of cooling towers
SOMIND	-	Sensitivity for O&M cost of industrial boilers
SOMEP	-	Sensitivity for O&M cost of electrostatic preciptators
SOMNOX	-	Sensitivity for O&M cost of NO_2 control equipment
SOMSOX	-	Sensitivity for O&M cost of SO_2 scrubber
SQXCESS	-	Excess electrical power in status quo systems
SWORD (8,8)	-	Alphanumeric steam pressure grade for industries
SM1	-	High mass flow rate for steam
SM2	-	Intermediate mass flow rate for steam
SM4	-	Low mass flow rate for steam
TCCIEF	-	Total capital costs of total cogeneration system
TCCIND	-	Total capital costs of industries
TCCSQ	-	Total capital costs of status quo system
TCOST(50)	-	Annual total status quo systems fuel costs
TEETIND	-	Total industry electrical energy
TEFFSQ	-	Overall status quo systems efficiency
TFUEL	-	Total industrial fuel requirement
THERMG (8,8)	-	Thermal energy for industries
TNRIND (8)	-	Turbine energy for industries
TOMCIEF	-	Total O&M costs for total cogeneration system
TOTALM	-	Total mass of system
TOMCIND	-	Total O&M costs for industrial utilities
TOMC5Q	-	Total O&M costs as status quo systems
TPIPCST	-	Total piping costs
TTHIND	-	Total thermal energy for industries
TURBCOE (5)	-	Turbine energy coefficients
TURBEXP (5)	-	Turbine energy exponents
TURBTAV	-	Savings in turbine costs of cogeneration system over status quo systems
WORD1(12)	-	First command for input
WORD2(12)	-	Second command for input
XPV (50)	-	Net present value

MAIES COMPUTER PROGRAM SUBROUTINE DESCRIPTION

Figure C-1 presents a flow chart of the sequence of subroutine calls for the Model for Assessment of Integrated Energy Systems (MAIES). The following paragraphs describe the computations performed in each sub-routine.

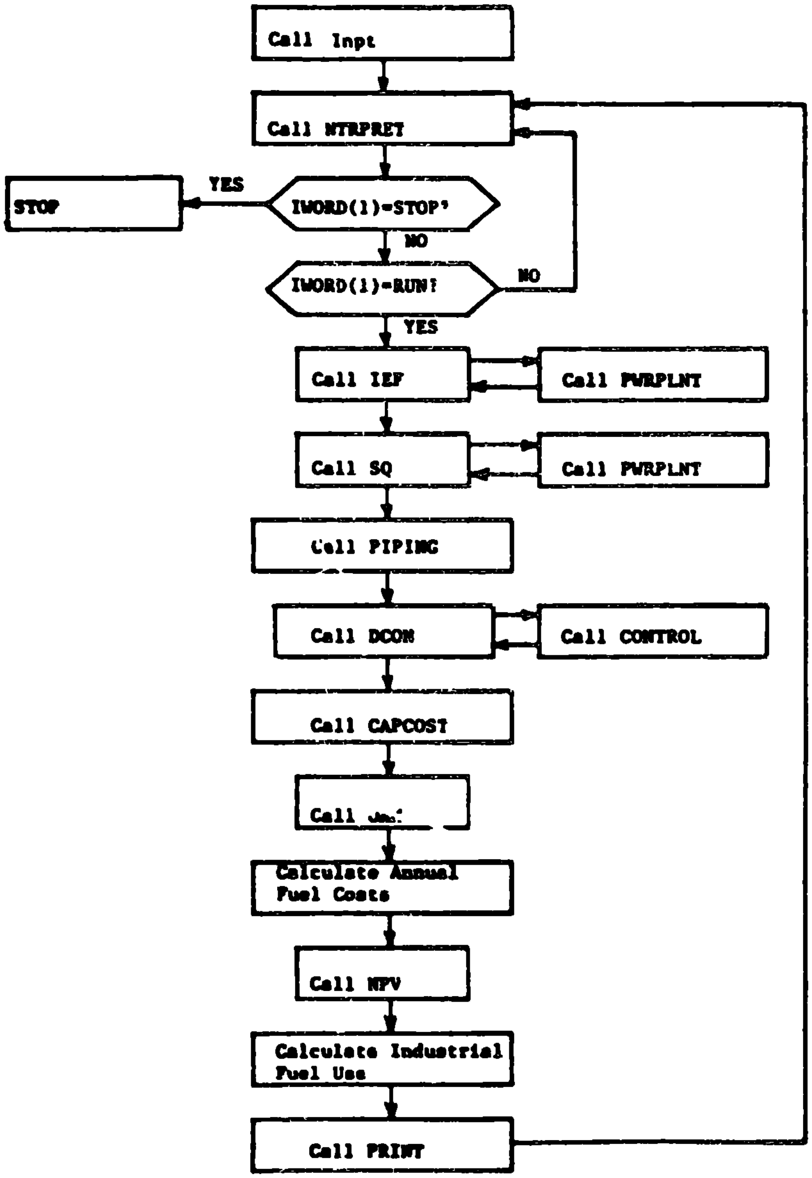


Figure C-1. Flowchart of the MAIES computer program.

Subroutine INPT

Subroutine INPT contains data statements which initialize the coefficients used in many subroutines of MAIES. INPT also contains initial or base values for all variable parameters in MAIES. INPT initializes all print options to zero, which suppresses all optional printouts.

Subroutine NTRPRET

Subroutine NTRPRET reads an alphanumeric command, then calls the apropriate subroutine--PTABLE, RTABLE, or RESET--based on the command. NTEPRET also allows the user to enter an alphanumeric heading to label the program's output.

Subroutine PTABLE, RESET

Subroutines PTABLE and RESET set and reset flags which determine the outputs listed by subroutine PRINT. For example, the user may enter:

"PRINT SCENARIO".

NTRPRET reads this command, then calls PTABLE which sets a flag. PRINT set the "SCENARIO" flag and lists the industries and their associated parameters.

Subroutine RTABLE

Subroutine RTABLE allows the user to change many of the values initialized by subroutine INPT. Based on the command received from NTRPRET, RTABLE solicits the required input from the user. In this way, the following parameters can be updated or varied: open or closed cycle cogeneration system utility, industrial boiler size and type, plant factors for the cogeneration system, status quo, and industrial utilities, the capital costs and O&M costs of status quo, cogeneration system, and industrial utilities and pollution controls, the type of pollution control system used, fuel prices and escalation or deflation rates, discount rate, base size of status quo utility, distances for steam shipping, emission indices, type of fuel used, initial year of operation, and the life of the facility. RTABLE also reads in factors for sensitivity analysis of costs.

Subroutine CONCEPT

RTABLE calls subroutine CONCEPT when a "READ CONCEPT" command is received. CONCEPT reads the industry names, their distances from the cogeneration system utility (over which the steam is piped), whether the industrial utilities are open or closed cycle, the type of fuel used, the amount of electrical energy provided by the industrial utilities, and a sizing factor used to increase/decrease the industries' electrical demand, mass flow rates, capital costs of the utililties, amount of by-product fuel, and the industries capacities (tons/day, etc.) Parameters scaled by the sizing factor are unique to a given industry.

Subroutine PWRPLNT

Subroutine PWRPLNT calculates the amount of fuel required by the cogeneration system utility, status quo utility, and the industrial utilities. PWRPLNT also calculates the total electrical energy provided by the status quo and cogeneration system utilities. These calculations are based on the mass flow rates and grades of steam required (high, intermediate, or low pressure), the steam piping distances, and the type of fuel used.

Subroutine SQ

Subroutine SQ calls PWRPLNT to calculate the fuel requirements and the electrical energy provided by the status quo utility. SQ also calls PWRLNT for each of the industrial utilities. Based on the fuel requirements calculated by PWRPLNT, SQ computes the total emissions of particles, sulfur oxides, nitrous oxides, carbon monoxide, and hydrocarbons produced annually by the utilities. SQ also sums the total thermal and electrical demand of the industries and calculates an overall efficiency for the industrial utilities.

Subroutine IEF

Subroutine IEF calls PWRPLNT to calculate the fuel requirements and the electrical energy provided by the cogenerating utility. IEF then calculates overall efficiencies for the cogeneration system and status quo utilities. The efficiency for the cogeneration system utility is based on its own fuel requirements and energy (thermal and electric) output. The efficiency for the status quo system is based on fuel requirements of the status quo utility and that of the industrial utilities as well as energy output. The fuel requirements of the cogeneration system are also used to calculate annual emissions.

Subroutine PIPING

Subroutine PIPING calculates the capital cost of piping steam to each of the industries. Parameters in this calculation include distance from the cogenerating utility, mass flow rates and grades of steam required, and whether the industries operate open or closed cycle.

Subroutine CONTROL

Subrouting CONTROL calculates capital costs and operation and maintenance costs for pollution control equipment used by the cogeneration system, status quo utility, and industrial utilities. For the status quo utility, costs are based on the total electrical energy provided. Costs for the industrial utilities are based on a percentage of the total electrical energy supplied by the status quo utility. Costs for the cogeneration system utility are based on electrical energy sold to the power grid as well as the total electrical energy supplied by the status quo utility. All operation and maintenance costs are also a function of plant factor (percentage of time plant remains in operation each year).

Subroutine CAPCOST

Subroutine CAPCOST calculates capital costs of the cogenerating and status quo utilities. Capital cost of the status quo utility is a function of total electrical energy supplied; capital cost of the cogenerating utility is based on a percentage of the electrical energy provided by the status quo and the electrical energy sold to the power grid by the cogeneration system. CAPCOST also sums the capital costs of the industrial utilities.

Subroutine O&M

Subroutine O&M calculates operation and maintenance costs of the cogenerating and status quo utilities. Costs for the status quo utility are based on total heat energy; costs for the cogenerating utility are functions of total heat energy and electrical energy sold to the power grid. O&M also calculates an operation and maintenance cost for the industrial utilities which is a percentage of their total capital cost.

Subroutine NPV

Subroutine NPV calculates net resent value of the cogeneration system for each year of operation based on capital costs, annual fuel costs, operation and maintenance costs, and discount rate.

Subroutine PRINT

Subroutine PRINT is the last subroutine called. PRINT inspects output flags set by INPT and PTABLE and prints the outputs desired by the user.

Outputs include:

- Heading
- Fuel used by cogeneration and status quo utilities
- Cogeneration and status quo utility sizes
- Industry name and capacity
- Open or closed system
- Electrical energy & fuel requirements for cogeneration systems, status quo system, and industries
- Heat ejected through condensors
- Efficiency of status quo, cogeneration, and industries
- Summary of capital and operation and maintenance costs
- Annual fuel costs
- Fuel use analysis
- System efficiency analysis
- Summary of pollutants produced and emitted

Before the PRINT subroutine is called, MAIES calculates annual fuel costs based on fuel requirements and plant factors for the status quo and industrial utilities and the cogeneration system utility.

Input Options

The read options provide a method of changing various values of the input variables.

Command	Input Request
READ IEFOPT	Yes
READ SMALL	None
READ SCCCT	Yes
READ SUMCT	Yes
READ SCCIN	Yes
READ SUMIN	Yes
READ SCCEP	Yes
READ SCCSO	Yes
READ SCCNO	Yes
READ SOMEP	Yes
READ SOMSO	Yes
READ SOMNO	Yes
READ PF	Yes
READ PFSQ	Yes
READ PFIND	Yes
READ CNTRL	Yes
READ INDCN	Yes
READ FUIEF	***Enter Type of Fuel***
READ FUIND	Enter Fuel Used by each Industry
READ FUSQ	***Enter Type of Fuel
READ NYES	Yes
READ CNCPT	Yes
READ PRICE	Write Fuel I.D., Base Fuel Price and Annual of Increase
READ NEWSQ	Yes
RED DIST	Yes
READ SDR	Yes
READ EMISS	Yes
READ DEFLA	Yes
READ ESCAL	Yes (#, Rate)
READ CAPCO	Yes
READ SFLPR	Yes
READ COOLS	None
READ COOL 1	None
READ COOLN	None
READ LCIN	Yes
READ LCLC	Yes
READ LCSM	Yes
READ LCSC	Yes
READ EXCIN	Yes
READ EXCIC	Yes
READ EXCSN	Yes
READ EXCSC	Yes
READ NYIO	Yes

Output Options

Command	Output
---	Net present value

---	Efficiency analysis
PRINT SQ	Status quo parameters
---	Industrial parameters
PRINT IEF	Total cogeneration system parameters
PRINT SCEN	Industrial power plant parameters
PRINT COST	Capital costs
---	Operation and maintenance costs
PRINT FUEL	Annual fuel costs
---	Fuel use analysis
PRINT POLL	Environmental impact analysis
RESET	Suppeerset output

*RESET may be used for any PRINT option

User's Guide for MAIES

This section presents the approacn to executing the MAIES computer program on the Georgia Tech CDC 7400 general purpose computer. The executable version of the program is XMAIES. The program may be executed demand or batch and provides a number of input and output options that may be chosen by the user during program execution. These options are described in detail in the following sections.

To execute, enter:

"XMAIES".

The program then responds with a question mark. Any of the input and output options listed may be entered using "READ" or "PRINT". After appropriate options have been set, and the "concept" has been read-in, the user may enter "RUN" to begin program computations or "END" to terminate program execution. All output options may be reset using the "RESET" command. The following is the range of values that may be used for the input and output variables.

Input Variables

All commands are followed by a carriage return and each command initiates an input request.

"READ" Options:

IEFOPT	-	Cogeneration system open or closed system "0" is entered for closed cycle (default) "1" is entered for open cycle
INBLOP	-	Industrial boiler type "1" Low Btu Boiler (default) "2" AFBC Boiler
SMALL	-	Size of Industrial Utility Sets size to small
SCCCT	-	Sensitivity factor for capital cost of cooling towers, Default = 1.0
SOMCT	-	Sensitivity factor for O&M cost of cooling towers,

Default = 1.0

SCCIND - Sensitivity factor for capital cost of industries
Default = 1.0

SOMIND - Sensitivity factor for O&M cost of industries,
Default = 1.0

SCCEP - Sensitivity factor for capital cost of electrostatic precipitator
Default = 1.0

SOMEP - Sensitivity factor for O&M costs of electrostatic precipitator
Default = 1.0

SCCSOX - Sensitivity factor for capital cost of SO_2 scrubbers
Default = 1.0

SOMSOX - Sensitivity factor for O&M cost of SO_2 scrubbers
Default = 1.0

SCCNOX - Sensitivity factor for capital cost of NO_2 control equipment
Default = 1.0

SOMNOX - Sensitivity factor for O&M cost of NO_2 control equipment
Default = 1.0

PF - Plant factor for cogeneration system
Default = .9

PFSQ - Plant factor for status quo system
Default = .9

PFIND - Plant factor for industries
Default = .9 for one industry

CNTCC - Sets system pollution control efficiencies, depends on system used
"0" ESP
"1" ESP, FGD, combustion modification
"2" ESP, FGD, dry flue gas treatment
"3" ESP simultaneous dry flue gas treatment
"4" ESP, simultaneous wet flue gas treatment
"5" ESP, AFBC
"6" ESP, PFBC

INDCNTL - Sets industrial pollution control system
"0" ESP
"1" ESP, FGD, combustion modification
"2" ESP, FBL

FUIEF - Initiates input request for fuel type used by total cogeneration system:
"NU" is entered for nuclear
"CO" is entered for coal

FUSQ - Initiates input request for fuel type used by status quo systems:
"NU is entered for nuclear
"CO" is entered for coal

FUIND - Initiates input request for fuel type used by industries
"1" = coal

"2" = nuclear
"3" = natural gas
"4" = fuel oils

NYRS	-	Initiates a request for life at facility Input is an interger greater than or equal to 50 Default = 30
CNCPT	-	Initiates c l to subroutine CONCEPT inputs are of the form TITLE 1D1, 1D2
TITLE	-	Alphanumeric lable displayed on output (3Alo FORMAT)
1D1, 1D2	-	Alphanumeric lable displayed on output (2A10 FORMAT) the user must enter at least the first 10 characters of the following: Chlorine Sulphur (or Sulfur) Phosphoric Steel Pulp and Paper Ammonia Textures if input is one of these type of plants. The program solicits further information DIST - distance (in miles) from industry to cogeneration system INDOPT - open or closed cycle "0" closed cycle "1" open cycle INDELC - industrial electrical requirements INDFUEL - industrial fuel requirements Other possible responses are READ FACTOR END READ FACTOR - initiates a request for a scaling factor that adjusts the "size" of the industry; input is a real number. The electrical demand, mass flow rates and by-product fuel are all multiplied by this factor END - suoroutine returns to RTABLE
PRICE	-	Initiates a request for fuel ID, base fuel price, and annual rate of increase of fuel prices.
NEWSQ	-	Changes base status quo power plant size Default = 3,000 sq ft
DIST	-	Changes distance from industrial plants to cogeneracion system Default = 0.5
SPR	-	Changes discount rate Default = 0.07
EMISS	-	Changes emission control induicer
DEFLA	-	Solicits new deflation rates
ESCAL	-	Solicits number of rate, and new escalation rate.
CAPCO	-	Reads in sensitivity analysis factor for capital costs Default = 1.0

SFLPR	-	Reads in sensitivity analysis factor for fuel costs Default = 1.0
COOLS	-	Changes status quo system cooling to forced draft Default = Natural draft
COOLI	-	Changes total cogeneration system cooling to forced draft Default = Natural draft
COOLN	-	Changes industrial cooling to forced draft Default = Natural draft
LCIN	-	Changes linear coefficient for capital costs of nuclear total cogeneration system Default = 4.434861
LCLC	-	Changes linear coefficient for capital costs of coal total cogeneration system Default = 1.9154
LCSN	-	Changes linear coefficient for capital costs of nuclear status quo system Default = 4.434861
LCSC	-	Changes linear coefficient for capital cost of coal status quo system Default = 1.154
EXCIN	-	Changes exponent for capital cost of nuclear status quo system Default = 0.6573
EXCIC	-	Changes exponent for capital costs of coal total cogeneration system Default = 0.7632
EXCIN	-	Changes exponent for capital cost of nuclear status quo system Default = 0.6573
EXCSC	-	Changes exponent for capital cost of coal status quo system Default = 0.7632
NY10	-	Changes year of initial operation (difference from 1975) Default = 2 1977

Output Options

All commands are followed by a carriage return. Net present value, system efficiency, and open or closed cycle are always part of initial printout.

"PRINT" Option:

SQ	-	Lists for status quo utility and each industry, total electrical energy, fuel requirements, heat ejected through the condenser, and power plant efficienty
IEF	-	Lists for cogeneration system, open or closed cycle, total electrical energy, fuel requirements, heat ejected through the condenser, power plant efficiency, and overall cogeneration system efficiency.

SCEN - Lists for industries; name, distance, electrical demand, electricity applied, mass flow rate, enthalpy, thermal energy, and open or closed cycle.

COST - Lists the capital and operation and maintenance costs of the cogeneration system and status quo system for the following: utility power plants, additional feedwater systems, extraction and piping, industrial utilities, and pollution control devices. Also lists fuel costs for status quo systems and cogeneration system.

FUEL - Lists annual fuel costs for the status quo systems and cogeneration system for N years as well as fuel use analyses of status quo systems and cogeneration system

POLL - Lists pollution control system and summarizes pollutants produced and emitted as well as solid waste produced.

"RESET" Option:

"RESET" may be used to suppress output initially set by the "PRINT" command.
Enter:
RESET OPNAME
where OPNAME is any of the above PRINT options.

Example Program Output

The following pages present an example output from the MAIES computer program. The particular concept consists of a large chlorine plant co-located in a complex and supplied thermal and electrical energy by a coal-fired cogenerating power plant. Electrostatic precipitators and natural draft cooling towers are used.

....

CONCEPT : BASE CASE: 6000 TON/DAY CL2

COAL-FIRED UTILITY — SQ - 1100. MWE; IEF - 906. MWE; SUPP - 194. MWE

CHLORINE — 6000 TONS/DAY

INITIAL YEAR OF OPERATION- 1977

CLOSED CYCLE

NET PRESENT VALUE (M$) = 234.553

OVERALL ENERGY EFFICIENCY

STATUS QUO			INTEGRATED ENERGY	
UTILITY	INDUSTRIES	OVERALL	FACILITY	SYSTEM
.3190	.8000	.4565	.5670	.5298

ENERGY EFFICIENCY FACTOR FOR POLLUTION CONTROLS: .9881

....

....

CONCEPT : BASE CASE: 6000 TON/DAY CL2

SCENARIO DEFINITION

PLANT NAME	DIST.(MILES)	ELECT. DEMAND (MW)	ELECT. SUPPLY (MW)
CHLORINE	.50	660.000	0.000

TAP NO.	MASS FLOW (100,000 LB/HR)	ENTHALPY (BTU/LB)	THERMAL ENERGY (MW)
1	28.800	1309.00	1104.577
TOTAL			1104.577

CLOSED CYCLE

....

....

** STATUS QUO FACILITY **

STATUS QUO UTILITY

ELECTRICAL ENERGY (MWE)= 1099.920

FUEL REQUIREMENTS (MBTU/HR)= 11769.

HEAT EJECTED THROUGH CONDENSER (MBTU/HR) = 6027.

POWER PLANT EFFICIENCY= .3190

INDUSTRIAL POWER PLANTS

---CHLORINE

ELECTRICAL ENERGY (MWE)= 0.000

FUEL REQUIREMENTS (MBTU/HR)= 4712.4

HEAT EJECTED THROUGH CONDENSER (MBTU/HR) = 0.

POWER PLANT EFFICIENCY= .8000

....

....

** INTEGRATED ENERGY FACILITY **

CLOSED CYCLE

ELECTRICAL ENERGY (MWE)= 905.816

FUEL REQUIREMENTS (MBTU/HR)= 13846.

HEAT EJECTED THROUGH CONDENSER (MBTU/HR) = 3007.

POWER PLANT EFFICIENCY= .5670

EFFICIENCY OF IES = .5298

....

CONCEPT : BASE CASE: 6000 TON/DAY CL2

ECONOMIC ANALYSIS

	CAPITAL COST (M$)		OPERATION AND MAINTENANCE COST (M$)	
	STATUS QUO	IES	STATUS QUO	IES
UTILITY POWER PLANT (COAL)	436.117	492.021	15.892	18.101
ADDITIONAL FEEDWATER SYSTEMS	0.000	0.000	0.000	0.000
EXTRACTION AND PIPING	0.000	7.786	0.000	.389
INDUSTRIAL UTILITIES (COAL)	21.031	0.000	1.612	0.000
TOTALS	457.148	499.807	17.505	18.490

FUEL COSTS (M$)	STATUS QUO	INTEGRATED ENERGY SYSTEM
UTILITY POWER PLANT	92.730	109.094
INDUSTRIAL UTILITIES CHLORINE	37.130	0.000
TOTAL (FIRST YEAR)	129.860	109.094
TOTAL OVER LIFE	1781.111	1496.296

POLLUTION CONTROL

CAPITAL COSTS (M$)

	STATUS QUO			INTEGRATED	!	
	UTILITY	INDUSTRIES	TOTAL SQ	ENERGY SYSTEM	!	NET VALUE
PARTICLES	27.000	0.000	27.000	31.765	!	-4.765
SULF OXIDE	0.000	0.000	0.000	0.000	!	0.000
NITR OXIDE	0.000	0.000	0.000	0.000	!	0.000
COOLING	34.740	19.185	54.126	29.189	!	24.937
TOTALS	61.741	19.185	81.126	60.954	!	20.172

OPERATION & MAINTENANCE COSTS (M$)

	STATUS QUO			INTEGRATED	!	
	UTILITY	INDUSTRIES	TOTAL SQ	ENERGY SYSTEM	!	NET VALUE
PARTICLES	1.695	0.000	1.695	1.994	!	-.299
SULF OXIDE	0.000	0.000	0.000	0.000	!	0.000
NITR OXIDE	0.000	0.000	0.000	0.000	!	0.000
COOLING	1.747	.959	2.706	1.459	!	1.247
TOTALS	3.442	.959	4.401	3.454	!	.948

CONCEPT : BASE CASE: 6000 TON/DAY CL2

** ANNUAL FUEL COSTS ($MILLIONS) **

YEAR	UTILITY	IND. UTILITIES	TOTAL STATUS QUO	IEF
1	92.730	37.130	129.860	109.094
2	93.657	37.501	131.159	110.185
3	94.594	37.876	132.470	111.287
4	95.540	38.255	133.795	112.400
5	96.495	38.638	135.133	113.524
6	97.460	39.024	136.484	114.659
7	98.435	39.414	137.849	115.806
8	99.419	39.808	139.228	116.964
9	100.413	40.206	140.620	118.134
10	101.418	40.609	142.026	119.315
11	102.432	41.015	143.446	120.508
12	103.456	41.425	144.881	121.713
13	104.491	41.839	146.330	122.930
14	105.536	42.257	147.793	124.160
15	106.591	42.680	149.271	125.401
16	107.657	43.107	150.764	126.655
17	108.733	43.538	152.271	127.922
18	109.821	43.973	153.794	129.201
19	110.919	44.413	155.332	130.493
20	112.028	44.857	156.885	131.798
21	113.148	45.306	158.454	133.116
22	114.280	45.759	160.039	134.447
23	115.423	46.216	161.639	135.791
24	116.577	46.678	163.255	137.149
25	117.743	47.145	164.888	138.521
26	118.920	47.617	166.537	139.906
27	120.109	48.093	168.202	141.305
28	121.310	48.574	169.884	142.718
29	122.523	49.059	171.583	144.145
30	123.749	49.550	173.299	145.587

FUEL USE ANALYSIS

FUEL USE	STATUS QUO		INTEGRATED ENERGY SYSTEM	
COAL	(MBTU/HR)	(TBTU/YR)	(MBTU/HR)	(TBTU/YR)
UTILITY	11769.0	92.787	13845.9	109.161
CHLORINE	4712.4	37.153		
TOTAL FUEL CONSUMED	16481.4	129.939	13845.9	109.161
HEAT THROUGH CONDENSER	6027.2		3007.2	

CONCEPT I BASE CASE: 6000 TON/DAY CL2

ENVIRONMENTAL IMPACT ANALYSIS

CONTROL SUMMARY

STATUS QUO UTILITY & IEF : SYSTEM 0, NAT. DRAFT COOLING
PARTICLES - ELECTROSTATIC PRECIPITATOR

INDUSTRIAL UTILITIES : SYSTEM 0, NAT. DRAFT COOLING

SUMMARY OF POLLUTANTS PRODUCED ANNUALLY (MILLION LBS)

AIR EMISSION SUMMARY

TOTAL PRODUCED

FACILITY	PARTICLES	SOX	CO	HC	NOX
CHLORINE	232.58	134.86	3.20	1.60	24.15
STATUS QUO UTILITY	580.84	336.82	7.98	3.99	60.31
TOTAL	813.42	471.68	11.17	5.59	84.46
IEF	683.35	396.25	9.39	4.69	70.95
DIFFERENCE	130.07	75.43	1.79	.89	13.51

TOTAL EMITTED

FACILITY	PARTICLES	SOX	CO	HC	NOX
CHLORINE	3.02	13.49	3.20	1.60	24.15
STATUS QUO UTILITY	7.55	336.82	7.98	3.99	60.31
TOTAL	10.57	350.30	11.17	5.59	84.46
IEF	8.88	396.25	9.39	4.69	70.95
DIFFERENCE	1.69	-45.95	1.79	.89	13.51

SOLID WASTE PRODUCED

FACILITY	PARTICLES	SOX	CO	HC	NOX
CHLORINE	229.55	121.38	0.00	0.00	0.00
STATUS QUO UTILITY	573.29	0.00	0.00	0.00	0.00
TOTAL	802.84	121.38	0.00	0.00	0.00
IEF	674.46	0.00	0.00	0.00	0.00
DIFFERENCE	128.38	121.38	0.00	0.00	0.00

APPENDIX D

SOCIAL IMPACT ANALYSIS MULTIPLIER MODELS

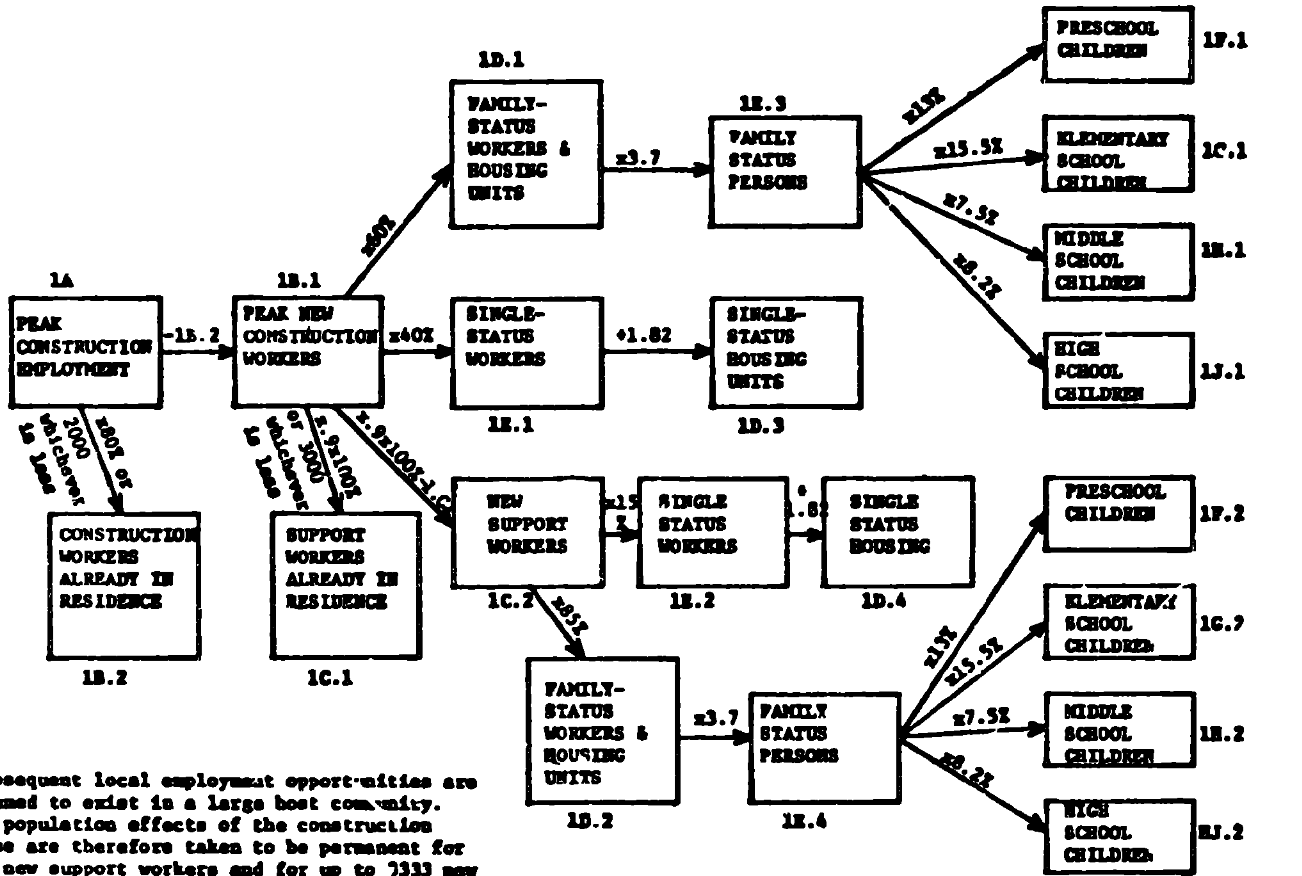
Figures D-1, D-2, D-3, and D-4 are the multiplier models used to determine population distribution effects from cogeneration system construction. Each figure is accompanied by a table of explanatory comments supporting the particular values of the parameters shown in the figures. Figures D-1 and D-2 describe the effects of a large cogeneration system in a large host community. The basic differences reflected in Figure D-1 for the construction phase and Figure D-2 for the long term effects are the family status composition of the construction work force and its lesser consumption of general goods and services available in the community. The lower than average proportion of family status workers during cogeneration system construction (60% vs 85%) is based on experience with other large construction projects. This and the more modest support requirement of construction workers, are undoubtedly related and both are probably influenced by the short term nature of construction projects.

Figures D-3 and D-4 describe the population effects of a large cogeneration system in a small host community. The differences are similar to those noted between Figures D-1 and D-2. The main differences between the pairs of Figures D-1 and D-2 for the large host community and D-3 and D-4 for the small, lie in the lesser diversity of goods and services generally available in a small community and its typically larger amount of available land.

The long run community statistics shown in Figures D-2 and D-4 were used to develop the specific data describing the hypothetical large and small host communities. A large host community was assumed to be a contiguous area containing 50,000 employed persons (datum for block 2D-1 in Figure D-2). A small host community was assumed to be a small contiguous area separated by sparsely populated areas from neighboring population centers. This small host community was assumed to be large enough to provide its own essential public services and contain 10,000 employed persons (datum for block 4A in Figure D-4).

Tables D-1 through D-8 provide a graphical representation of the results of the application of the multiplier models. Table D-1 addresses the situation of a large cogeneration system in a large host community. In general, the large host community has little difficulty accomodating the demands of the increased industrial activity. Table D-2 addresses the construction and operation of a large cogeneration system in a small host community. The small host community would have to provide a significant increase in facilities and services. This increase would be approximately 100 percent over a period of four to five years. Table D-3 is a comparison of the changes that would occur in a large host community and a small host community. While the changes are minimal for the large community, they are large for the small community. Table D-4 compares the changes that occur in host communities just prior to operation as the cogeneration related population is changing from transient to permanent. The impacts of full scale operation are compared in Table D-5.

Tables D-6 through D-8 compare the effects of a large nuclear powered cogeneration facility on the host communities for the various phases of construction and operation. The basic impacts are the same, since the impacts are predominantly related to the increased need for housing and services.



*Subsequent local employment opportunities are assumed to exist in a large host community. The population effects of the construction phase are therefore taken to be permanent for all new support workers and for up to 3333 new construction workers.

Figure D-1. Population effects* for the construction phase: large cogeneration system concept in a large host community.

Explanation of the Parameters in Figure D-1

Comment No.	Diagram from Node	Arc from Node	Comment
1	1A	1B.1	It is assumed that a large construction capability will exist in the host community. As many as 2000 of the required labor force will already in in residence. The minimum 20 percent influx of new workers is felt to be indicative of what might be expected in a typical large host community. This is assumed to be an indication of a general unemployment rate of 6 percent to 8 percent. (See Comment 3.)
2	1A	1B.2	See Comment 1
3	1B.1	1C.1	The .9 multiplier from (18) reflects the high consumption rates being associated with urban living. The 100 percent figure up to a maximum of 3000 implies that the commercial sector in the host community is expected to adequately support most if not all of the new construction (see Comment 1).
4	1B.1	1C.2	See Comment 3
5	1B.1	1D.1	The family status of the new work force is that cited in (18) for construction workers.
6	1B.1	1E.1	See Comment 5
7	1C.2	1D.2	The family status for new commercial sector workers is assumed to be the same as that cited in (18) for permanent workers in the industrial sector.
8	1C.2	1E.2	See Comment 7
9	1D.1 and 1D.2	1E.3 and 1E.4	The 3.7 factor from (18) is the estimated number of persons per family.

Explanation of the Parameters in Figure D-1 (Cont'd.)

Comment No.	Diagram from Node	Arc from Node	Comment
10	1E.1 and 1E.2	1D.3 and 1D.4	The 1.82 divisor, computed for the urban living patterns in (19) is the average number of single-status persons per non-family dwelling unit.
11	1E.3 and 1E.4	1F.1 and 1F.2	The percentage is the average number of children in this age group as a percentage of the total family-status population. The figure is computed from data in (19) after first adjusting the basic family size to 3.7 persons. Underlying this average is an assumption that the age distribution of in-residence children per family is unaffected by family relocation.
12	1E.3 and 1E.4	1G.1 and 1G.2	See Comment 11
13	1E.3 and 1E.4	1H.1 and 1H.2	See Comment 11
14	1E.3 and 1E.4	1J.1 and 1J.2	See Comment 11
15	New dwelling units		The new dwelling units in the host community are given by the sum: NDU1 = 1D.1 + 1D.2 + 1D.3 + 1D.4
16	New residential land developed		In an urban setting, (19) gives a typical figure of 5.32 dwelling units per acre. New acreage required for housing: NAH1 = NDU1/5.32
17	Density of new population		The average density of the new local population is: AD1 = (1E.1 + 1E.2 + 1E.3 + 1E.4)/NAH1

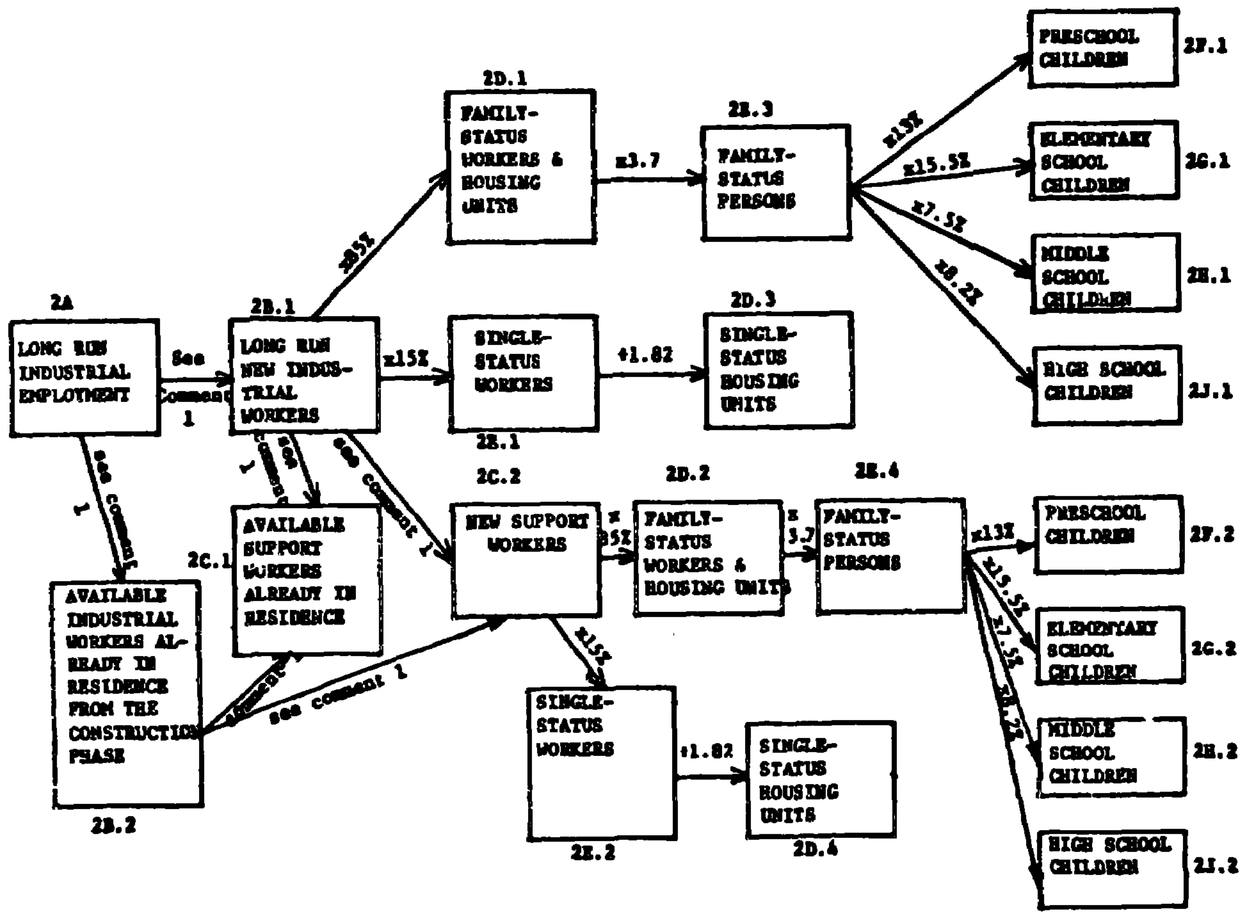


Figure D-2. Long run population effects of the industrial activity: large cogeneration system concept in a large host community.

Explanation of the Parameters in Figure D-2

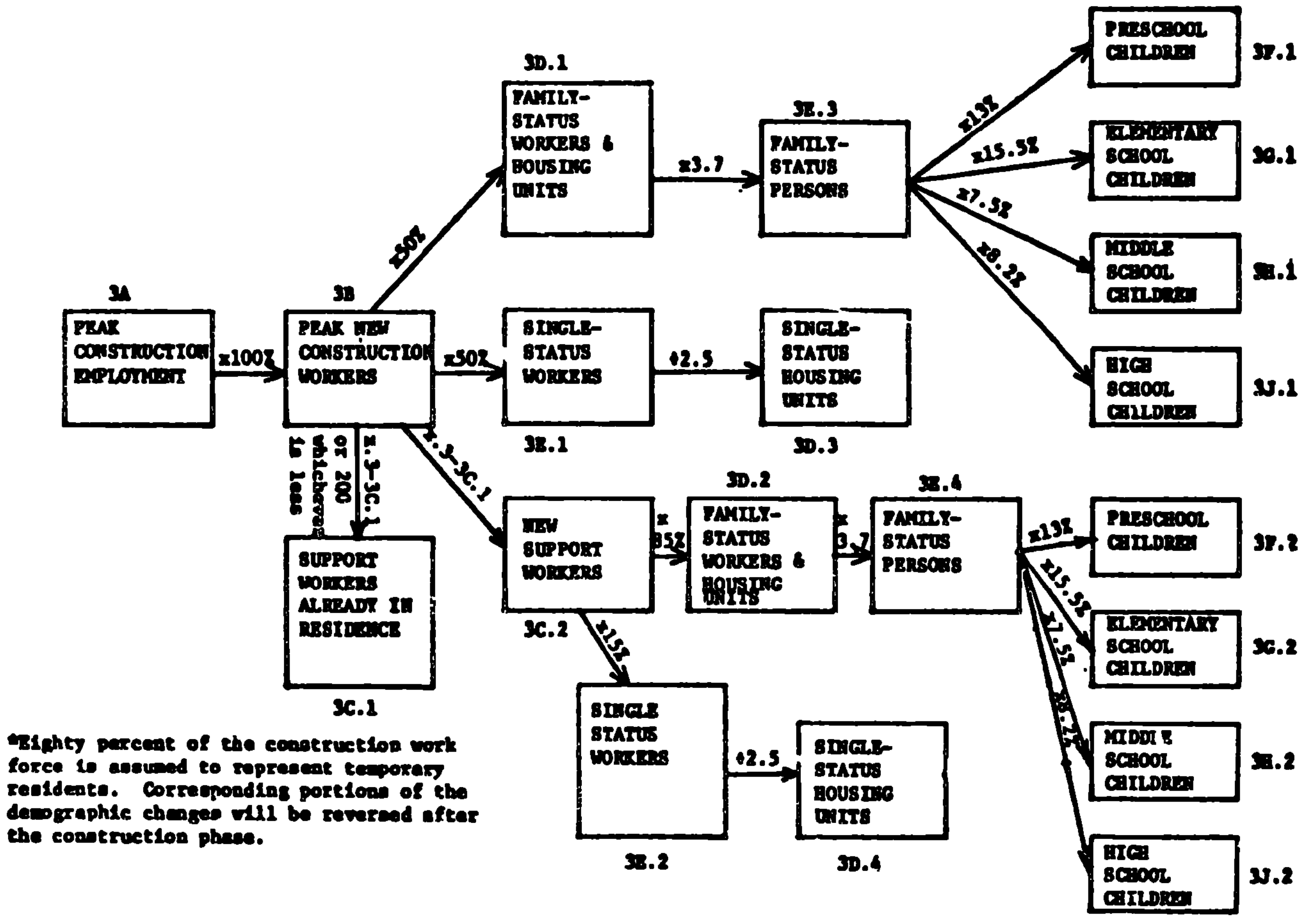
Comment No.	Diagram from Node	Arc from Node	Comment
1	2A 2A 2B.1 2B.1	2B.1 2B.2 2C.1 2C.2	Of the construction workers still in residence beyond the construction phase, only a portion will find future work in local construction. The remaining are assumed to take industrial jobs, since the alternate employment opportunities are likely to arise only gradually over time. Therefore, the long run increase in construction jobs in subtracted from the locally available work force. Similarly, other employed workers from the commercial sector are assumed first to fill any long run opportunities in this sector while the remaining will seek industrial employment. Cogeneration system related Long Run Construction Employment: LRCE = (Long Run Industrial Employment)(1+2.3) x 5.14 percent Cogeneration system related Long Run Other Commercial Employment: LROCE = (Long Run Industrial Employment)(2.3) - LRCE The total locally available work force is computed from Figure B.1.
2	2A	2B.1	See Comment 1
3	2B.1	2C.1	The 2.3 multiplier from (18) is the estimated ratio of support workers to industrial workers. This reflects the high consumption rates being associated with urban living.
4	2B.1	2C.2	See Comment 3
5	2B.1	2D.1	The 85 percent figure from (18) is the percentage of new industrial workers estimated to family status residents.
6	2B.1	2E.1	The complement of new workers are single-status residents. See Comment 5.

Explanation of the Parameters in Figure D-2 (Cont'd.)

Comment No.	Diagram from Node	Arc from Node	Comment
7	2D.1 and 2D.2	2E.3 and 2E.4	The 3.7 factor from (18) is the estimated number of persons per family.
8	2E.1 and 2D.2	2D.3 and 2E.4	The 1.82 divisor, computed for the urban living pattern in (19) is the average number of single-status persons per non-family dwelling unit.
9	2C.2 and 2C.2	2D.2 and 2E.2	The family status for new commercial sector workers is assumed to be the same as that cited in (18) for permanent workers in the industrial sector.
10	2E.3 and 2E.4	2F.1 and 2F.2	The percentage is the average number of children in this age group as a percentage of the total family-status population. The figure is computed from data in (19) after first adjusting the basic family size to 3.7 persons. Underlying this average is an assumption that the age distribution of in-residence children per family is unaffected by family relocation.
11	2E.3 and 2E.4	2G.1 and 2G.2	See Comment 10
12	2E.3 and 2E.4	2H.1 and 2H.2	See Comment 10
13	2E.3 and 2E.4	2J.1 and 2J.2	See Comment 10
14	New dwelling units		The new dwelling units in the host community is given by the sum: NDU2 = 2D.1 + 2D.2 + 2D.3 + 2D.4
15	New residential land developed		In an urban setting, (19) gives a typical figure of 5.32 dwelling units per acre. New acreage required for housing:

Explanation of the Parameters in Figure D-2 (Cont'd.)

Comment No.	Diagram from Node	Arc from Node	Comment
			NAH2 = NDU2/5.32
16	Density of new population		The average density of the new local population is: AD2 = (2E.1 + 2E.2 + 2E.3 + 2E.4)/NAH2



*Eighty percent of the construction work force is assumed to represent temporary residents. Corresponding portions of the demographic changes will be reversed after the construction phase.

Figure D-3. Population effects* for the construction phase: large cogeneration system concept in a small community.

Explanation of the Parameters in Figure D-3

Comment No.	Diagram from Node	Arc from Node	Comment
1	3A	3B	Host community will supply few if any of the construction work force.
2	3B	3C.1	The .3 is the estimated ratio of support workers to construction workers. This reflects low consumption rates being associated with rural living. The 10 percent constitutes an adjustment to the 20 percent figure cited in (18) to reflect the assumed low level of commercial activity previously existing in the host community. Up to 200 support workers are assumed available in the host community.
3	3B	3C.2	See Comment 2.
4	3B	3D.1	The 50 percent figure differes from the 60 percent in (18) to reflect a lower number of workers who are expected to remain beyond the construction period.
5	3B	3E.1	See Comment 4.
6	3D.1 and 3D.2	3E.3 and 3E.4	The 3.7 factor from (18) is the estimated number of persons per family.
7	3E.1 and 3E.2	3D.3 and 3D.4	The divisor 2.5, computed for rural living patterns in (19), is the average number of single-status persons per non-family dwelling unit.
8	3C.2	3D.2	The family status for new commercial sector workers is assumed to be the same as that cited in (18) for permanent workers in the industrial sector.
9	3C.2	3E.2	See Comment 8.

Explanation of the Parameters in Figure D-3 (Cont'd.)

Comment No.	Diagram from Node	Arc from Node	Comment
10	3E.3 and 3E.4	3F.1 and 3F.2	The percentage is the average number of children in this age group as a percentage of the total family-status population. The figure is computed from data in (19) after first adjusting the basic family size to 3.7 persons. Underlying this average is an assumption that the age distribution of in-residence children per family is unaffected by family relocation.
11	3E.3 and 3E.4	3G.1 and 3G.2	See Comment 10.
12	3E.3 and 3E.4	3H.1 and 3H.2	See Comment 10.
13	3E.3 and 3E.4	3J.1 and 3J.2	See Comment 10.
14	New dwelling units		The new dwelling units in the host community are given by the sum: NDU3 = 3D.1 + 3D.2 + 3D.3 + 3D.4
15	New residential land developed		In a rural setting, (19) gives a typical figure of 2.08 dwelling units per acre. New acreage required for housing: NAH3 = NDU3/2.03
16	Density of new population		The average density of the new local population is: AD3 = (3E.1 + 3E.2 + 3E.3 + 3E.4)/NAH3

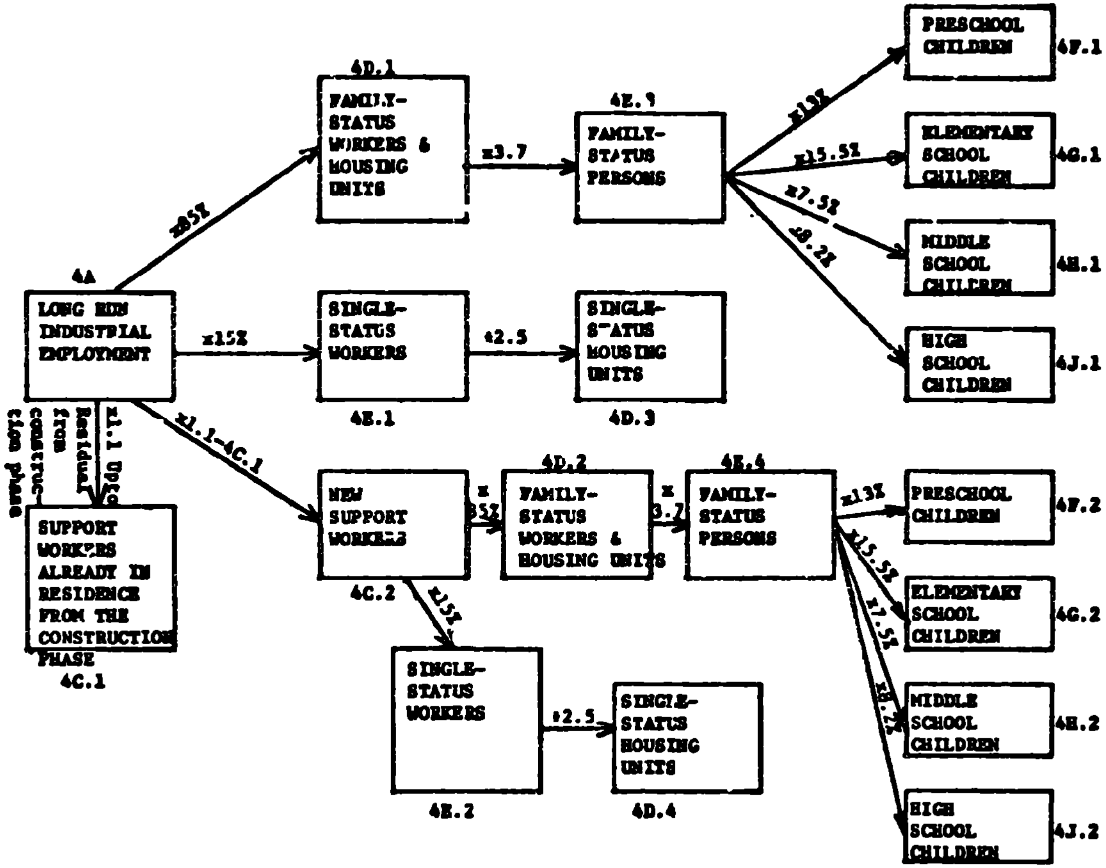


Figure D-4. Long run population effects of the industrial activity: large cogeneration system concept in a small community.

Explanation of the Parameters in Figure D-4

Comment No.	Diagram from Node	Arc from Node	Comment
1	4A	4B	Host community will supply few if any of the new industrial work force. The construction work force is assumed to subsequently emigrate.
2	4B	4C1	The 1.1 is the estimated ratio of support workers to industrial workers from (18). This reflects low consumption rates being associated with rural living. The idle commercial work force from the construction phase is the most the local community can provide to support the immigraiton industrial work force.
3	4B	4C.2	The 1.1 and 80 percent come from (18) (see Comment 2).
4	4B	4D.1	The 85 percent figure from (18) is the percentage of new industrial workers estimated to be family status residents.
5	4B	4E.1	The 15 percent comes from (18) (see Comment 4).
6	4D.1 and 4D.2	4E.3 and 4E.4	The 3.7 factor from (18) is the estimated number of persons per family.
7	4E.1 and 4E.2	4D.3 and 4D.4	The divisor 2.5, computed for rural living patterns in (19), is the average number of single-status persons per non-family dwelling unit.
8	4C.2	4D.2	The family status of a new worker is assumed to be the same for the commercial and industrial sectors (see Comment 4).
9	4C.2	4E.2	See Comment 8.

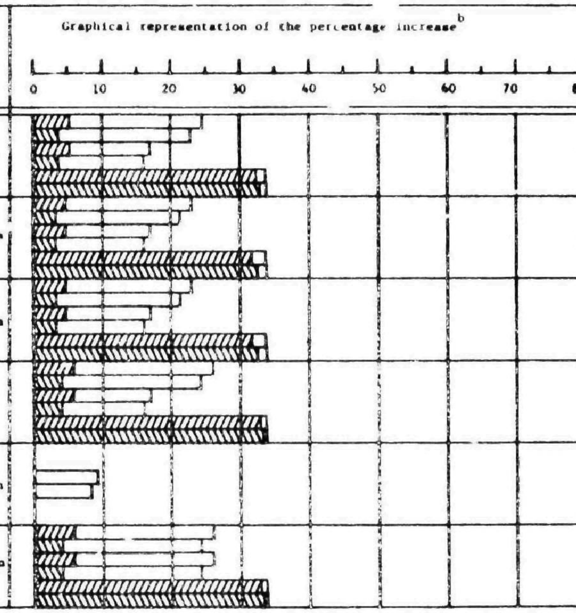
Explanation of the Parameters in Figure D-4 (Cont'd.)

Comment No.	Diagram from Node	Arc from Node	Comment
10	4E.3 and 4E.4	4F.1 and 4F.2	The percentage is the average number of children in this age group as a percentage of the total family-status group. The figure is computed from data in (19) after first adjusting the basic family size to 3.7 persons. Underlying this average is an assumption that the age distribution of in-residence children per family is unaffected by family relocation.
11	4E.3 and 4E.4	4G.1 and 4G.2	See Comment 10.
12	4E.3 and 4E.4	4H.1 and 4H.2	See Comment 10.
13	4E.3 and 4E.4	4J.1 and 4J.2	See Comment 10.
14	New dwelling units		The new dwelling units in the host community is given by the sum: 4D.1 + 4D.2 + 4D.3 + 4D.4 minus those vacated by the construction work force: 0.8 (3D.1 + 3D.3). NDU4 = 4D.1 + 4D.2 + 4D.3 + 4D.4 - 0.8 (3D.1 + 3D.3)
15	New residential land developed		In a rural setting (19), gives a typical figure of 2.08 dwelling units per acre. New acreage required for housing: NAH4 = NDU4/2.08
16	Density of new population		The average density of the new local population is: AD4 = (4E.1 + 4E.2 + 4E.3 + 4E.4)/NAH4

TABLE D-1.

LARGE COGENERATION SYSTEM IN A LARGE HOST COMMUNITY- THE FIRST EIGHT TO TEN YEARS (1000 MW_e POWER PLANT)

Community parameter	Host community preexisting value	Type[a] of utility	Phase in cogeneration system development	Graphical representation of the percentage increase[b]	
Total population	164,750	N	Peak construction	5.3-	24.5
		C		3.7-	22.8
		N	Just prior to operation	5.3-	16.9
		C		3.7-	16.0
		N	at full operation	32.3-	33.7
		C		32.9-	33.8
Family-status Persons	137,250	N	Peak construction	4.7-	22.9
		C		3.3-	21.3
		N	Just prior to operation	4.7-	16.9
		C		3.3-	16.0
		N	at full operation	31.7-	33.7
		C		32.5-	33.8
Children preschool	20,442	N	Peak construction	4.7-	22.9
elementary	24,374	C		3.3-	21.3
middle	11,796	N	Just prior to operation	4.7-	16.9
high school	12,894	C		3.3-	16.0
		N	at full operation	31.7-	33.7
		C		32.5	33.8
Occupied dwellings	46,620	N	Peak construction	5.8-	26.0
		C		4.1-	24.2
		N	Just prior to operation	5.8-	16.9
		C		4.1-	16.0
		N	at full operation	32.9-	33.7
		C		33.3-	33.8
Vacancy rate (as % original housing)	assumed to be zero	N	Peak construction	0.0-	0.0
		C		0.0-	0.0
		N	Just prior to operation	0.0-	9.2
		C		0.0-	8.3
		N	at full operation	0.0-	0.0
		C		0.0-	0.0
Residential land (acres)	8,763	N	Peak construction	5.8-	26.0
		C		4.1-	24.2
		N	Just prior to operation	5.8-	26.0
		C		4.1-	24.2
		N	at full operation	32.9-	33.7
		C		33.3-	33.8



a. N = Nuclear C = Coal --Both are 1000 MWe

b. Coordinated construction of cogeneration system

Construction of cogeneration system not coordinated

Denotes coordinated construction of cogeneration system

Denotes construction of cogeneration system not coordinated

TABLE D-1.(continued)

Community parameter	Host community preexisting value	Type[a] of utility	Phase in cogeneration system development	Graphical representation of percentage increase[b]
Construction workers	2,569	N	Peak construction	15.8- 50.8
		C		13.2- 48.0
		N	Just prior to operation	18.8- 22.6
		C		13.2- 22.6
		N	At full operation	33.7- 33.7
		C		33.8- 3.8
Industrial workers	15,152	N	Peak construction	0.0- 0.0
		C		0.0- 0.0
		N	Just prior to operation	0.0- 0.0
		C		0.0- 0.0
		N	At full operation	33.7- 33.7
		C		33.8- 33.8
Support workers (other than construction)	32,279	N	Peak construction	0.0- 15.8
		C		0.0- 14.4
		N	Just prior to operation	0.0- 15.8
		C		0.0- 14.4
		N	At full operation	33.7- 33.7
		C		33.8- 33.8
Total work force	50,000	N	Peak construction	6.7- 28.2
		C		4.7- 26.3
		N	Just prior to operation	6.7- 16.9
		C		4.7- 16.0
		N	At full operation	33.7- 33.7
		C		33.7- 33.8
Family-status workers	42,500	N	Peak construction	[illegible]- 22.[illegible]
		C		3.3- 21.3
		N	Just prior to operation	4.7- 16.0
		C		3.3- 16.0
		N	At full operation	31.7- 33.7
		C		32.5- 33.8
Single-status workers	7,500	N	Peak construction	17.8- 58.2
		C		12.4- 54.6
		N	Just prior to operation	17.8- 16.9
		C		12.4- 16.0
		N	At full operation	44.8- 33.7
		C		41.6- 33.8
Unemployment increase	BASE LEVEL 6% TO 8%	N	Peak construction	0.0- 0.0
		C		0.0- 0.0
		N	Just prior to operation	6.3- 15.4
		C		4.5- 13.8
		N	At full operation	0.6- 0.0
		C		0.0- 0.0

a. N = Nuclear C = Coal --Both are 1000 MWe

b. Coordinated construction of cogeneration system
Construction of cogeneration system not coordinated

▨ Denotes coordinated construction of cogeneration system

▭ Denotes construction of cogeneration system not coordinated

TABLE D-2.
LARGE COGENERATION SYSTEM IN A SMALL HOST COMMUNITY-
THE FIRST EIGHT TO TEN YEARS
(1000 MW_e POWER PLANT)

Community parameter	Host community preexisting value	Type[a] of utility	Phase in cogeneration system development	Graphical representation of the percentage increase[b] (0–400)
Total population	32,950	N	Peak construction	52.4-109.5
		C		47.7-104.4
		N	Just prior to operation	14.4-31.0
		C		11.7-29.5
		N	At full operation	107.1-107.1
		C		107.6-107.6
Family-status persons	31,450	N	Peak construction	45.8-95.7
		C		37.2-91.3
		N	Just prior to operation	14.4-31.0
		C		11.7-24.5
		N	At full operation	107.1-107.1
		C		107.6-107.6
Children: preschool	4,089	N	Peak construction	45.8-95.7
elementary	4,875	C		37.2-91.3
middle	2,359	N	Just prior to operation	14.4-31.0
high	2,579	C		11.7-29.5
		N	At full operation	107.1-107.1
		C		107.6-107.6
Occupied dwellings	9,100	N	Peak construction	55.4-115.6
		C		45.0-110.3
		N	Just prior to operation	14.4-31.0
		C		11.7-29.5
		N	At full operation	107.1-107.1
		C		107.6-107.6
Vacancy rate (as % original housing)	Assumed to be zero	N	Peak construction	0.0-0.0
		C		0.0-0.0
		N	Just prior to operation	41.0-84.6
		C		33.4-80.8
		N	At full operation	0-8.5
		C		0-2.6
Residential (acres)	4,375	N	Peak construction	55.4-115.6
		C		45.0-110.3
		N	Just prior to operation	55.4-115.6
		C		45.0-110.3
		N	At full operation	107.1-115.6
		C		107.6-110.3

[a] N = Nuclear; C = Coal. Both are 1000 MWe.
[b] [illegible] construction of cogeneration system [illegible]
[illegible] system not [illegible]
[illegible]
[illegible]

TABLE D-2. (continued)

Community parameter	Host community preexisting value	Type[a] of utility	Phase in cogeneration system development	Graphical representation of the percentage increase[b]
Construction workers	514	N	Peak construction	101.0-208.5
		C		82.1-199.0
		N	Just prior to operation	0.0-0.0
		C		0.0-0.0
		N	At full operation	107.1-107.1
		C		107.6-107.6
Industrial workers	4,762	N	Peak construction	0.0-0.0
		C		0.0-0.0
		N	Just prior to operation	0.0-0.0
		C		0.0-0.0
		N	At full operation	107.1-107.1
		C		107.6-107.6
Support workers (other than construction)	4,724	N	Peak construction	30.5-65.6
		C		24.7-62.4
		N	Just prior to operation	30.5-65.6
		C		24.7-62.4
		N	At full operation	107.1-107.1
		C		107.6-107.6
Total work force	10,000	N	Peak construction	67.7-141.0
		C		55.0-134.5
		N	Just prior to operation	14.4-31.0
		C		11.7-29.5
		N	At full operation	107.1-107.1
		C		107.6-107.6
Family-status workers	8,500	N	Peak construction	45.8-95.7
		C		37.2-91.3
		N	Just prior to operation	14.4-31.0
		C		11.7-29.5
		N	At full operation	107.1-107.1
		C		107.6-107.6
Single status workers	1,500	N	Peak construction	197.1-397.7
		C		156.1-379.5
		N	Just prior to operation	14.4-31.0
		C		11.7-29.5
		N	At full operation	107.1-107.1
		C		107.6-107.6
Unemployment increase	Base level 6% to 8%	N	Peak construction	0.0-0.0
		C		0.0-0.0
		N	Just prior to operation	12.6-23.7
		C		10.5-22.8
		N	At full operation	0.0-0.0
		C		0.0-0.0

a N = nuclear C = coal Both are 1000MWe
b Coordinated construction of cogeneration system
Construction of cogeneration system not coordinated
Denotes coordinated construction of cogeneration system
Denotes construction of cogeneration system not coordinated

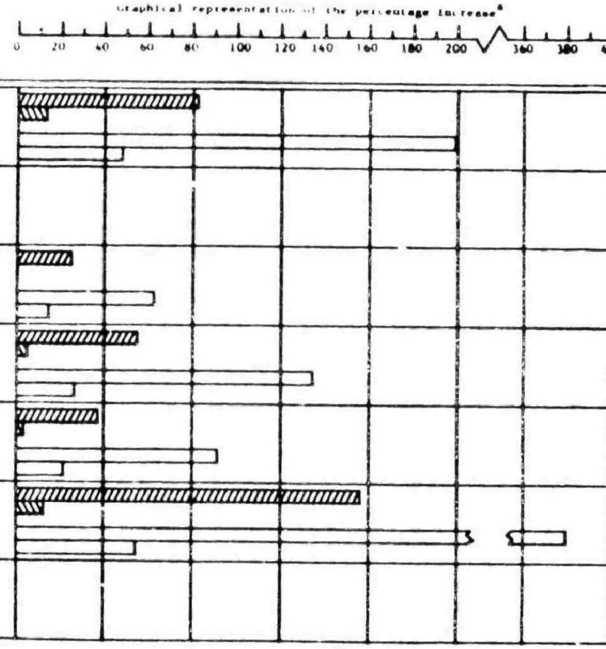
TABLE D-3.
PEAK CONSTRUCTION PHASE-
COMPARISON OF CHANGES IN A SMALL AND A LARGE HOST COMMUNITY
(COAL-FIRED POWER PLANT - 1000 MW_e)

Community parameter	Preexisting value: Small host community	Preexisting value: Large host community	Management of cogeneration system construction	Size of host community	Graphical representation of the percentage increase[a]
Total population	32,950	164,750	Coordinated	Small	42.7
				large	3.7
			not coordinated	small	104.4
				large	22.8
Family status persons	31,650	157,250	Coordinated	Small	37.2
				Large	3.3
			not coordinated	small	91.3
				large	21.3
Children: preschool	4,089	20,442	Coordinated	Small	37.2
elementary	4,175	24,374		large	3.3
middle	2,359	11,796	not coordinated	small	91.3
high	2,579	12,894		large	21.3
Occupied dwellings	9,100	46,620	Coordinated	Small	45.0
				large	4.3
			not coordinated	small	110.3
				large	24.2
Vacancy rate (as % original housing)	Assumed to be zero	Assumed to be zero	Coordinated	Small	0.0
				large	0.0
			not coordinated	small	0.0
				large	0.0
Residential land (acres)	6,375	8,763	Coordinated	Small	45.0
				large	4.3
			not coordinated	small	110.3
				large	24.2

[a] Increases are expressed as a percentage of the base value in the appropriate host community.

TABLE E-3. (continued)

Community parameter	Prevailing value: Small host community	Prevailing value: Large host community	Management of cogeneration system construction	Size of host community	Graphical representation of the percentage increase[a]
Construction workers	514	2,569	Coordinated	Small	82.1
				large	13.2
			not coordinated	small	199.0
				large	48.0
Industrial workers	4,762	15,152	Coordinated	Small	0.0
				large	0.0
			not coordinated	small	0.0
				large	0.0
Support workers (other than construction)	4,724	32,279	Coordinated	Small	24.7
				large	0.0
			not coordinated	small	62.4
				large	14.4
Total work force	10,000	50,000	Coordinated	Small	55.0
				large	4.7
			not coordinated	small	134.5
				large	26.3
Family-status workers	8,500	42,5000	Coordinated	Small	37.2
				large	3.3
			not coordinated	small	91.3
				large	21.3
Single-status workers	1,500	7,500	Coordinated	Small	156.1
				large	12.4
			not coordinated	small	379.5
				large	54.6
Unemployment increase	Base level 6% to 8%	Base level 6% to 8%	Coordinated	Small	0.0
				large	0.0
			not coordinated	small	0.0
				large	0.0



[a] Increases are expressed as a percentage of the base value in the appropriate host community.

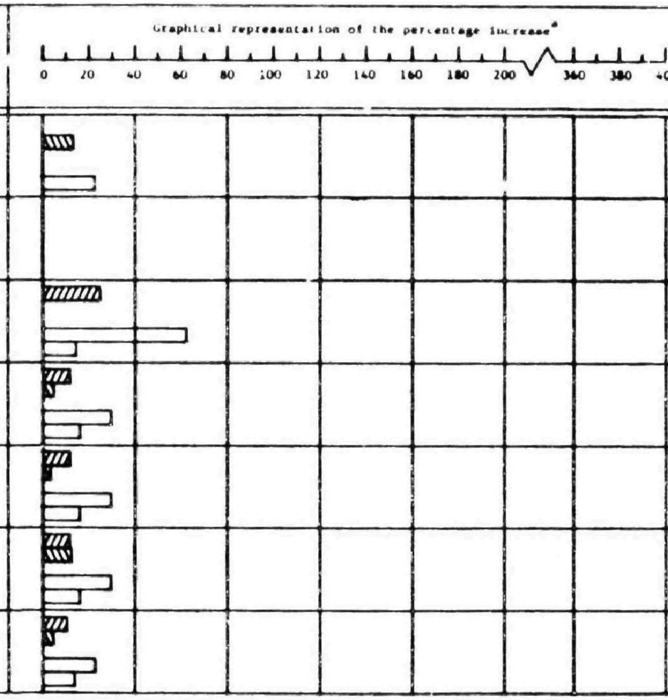
TABLE D-4.
PHASE JUST PRIOR TO OPERATION–
COMPARISON OF CHANGES IN A SMALL AND A LARGE HOST COMMUNITY
(COAL-FIRED POWER PLANT – 1000 MW_e)

Community parameter	Preexisting value: Small host community	Preexisting value: Large host community	Management of cogeneration system construction	Size of host community	Graphical representation of the percentage increase* (0–400)
Total population	32,950	164,750	Coordinated	Small	11.7
				large	3.7
			not coordinated	small	29.5
				large	16.0
Family-status persons	31,450	157,250	Coordinated	Small	11.7
				large	3.3
			not coordinated	small	29.5
				large	16.0
Children: preschool / elementary / middle / high	4,089 / 6,875 / 2,359 / 2,579	20,442 / 24,374 / 11,794 / 12,894	Coordinated	Small	11.7
				large	3.3
			not coordinated	small	29.5
				large	16.0
Occupied dwellings	9,100	46,620	Coordinated	Small	11.7
				large	4.3
			not coordinated	small	29.5
				large	16.0
Vacancy rate (as % original housing)	Assumed to be zero	Assumed to be zero	Coordinated	Small	33.4
				large	8.0
			not coordinated	small	80.0
				large	8.3
Residential land (acres)	6,375	8,761	Coordinated	Small	45.9
				large	6.1
			not coordinated	small	110.3
				large	24.2

*Increases are expressed as a percentage of the base value in the appropriate host community.

TABLE D-4. (continued)

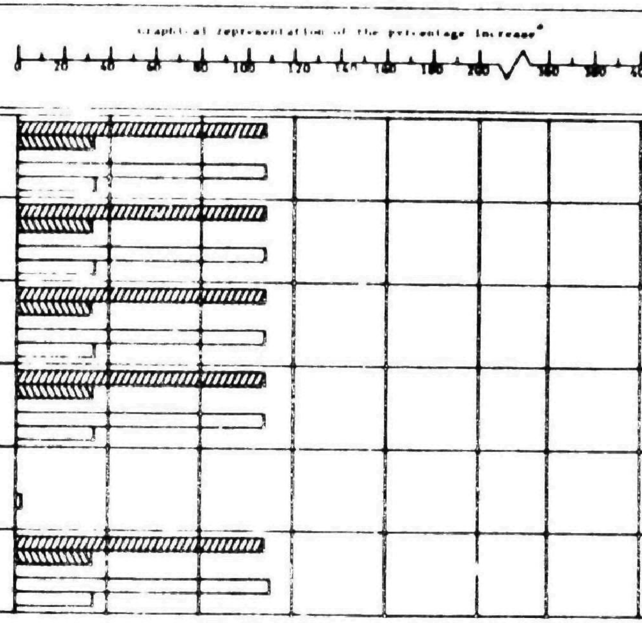
Community parameter	Preexisting value: Small host community	Preexisting value: Large host community	Management of cogeneration system construction	Size of host community	Graphical representation of the percentage increase[a]
Construction workers	514	2,569	Coordinated	Small	0.0
				large	13.2
			not coordinated	small	0.0
				large	22.6
Industrial workers	4,762	15,152	Coordinated	Small	0.0
				large	0.0
			not coordinated	small	0.0
				large	0.0
Support workers (other than construction)	4,724	32,279	Coordinated	Small	24.7
				large	0.0
			not coordinated	small	62.4
				large	14.4
Total work force	10,000	50,000	Coordinated	Small	11.7
				large	4.7
			not coordinated	small	29.5
				large	16.0
Family-status workers	8,500	42,500	Coordinated	Small	11.7
				large	13.3
			not coordinated	small	29.5
				large	16.0
Single-status workers	1,500	7,500	Coordinated	Small	11.7
				large	12.4
			not coordinated	small	29.5
				large	16.0
Unemployment increase	Base level 6% to 8%	Base level 6% to 8%	Coordinated	Small	10.5
				large	4.5
			not coordinated	small	22.8
				large	13.8



[a]Increases are expressed as a percentage of the base value in the appropriate host community.

TABLE D-5.
FULL OPERATION PHASE-
COMPARISON OF CHANGES IN A SMALL AND A LARGE HOST COMMUNITY
(COAL-FIRED POWER PLANT - 1000 MW_e)

Community parameters	Preexisting value: Small host community	Preexisting value: Large host community	Management of cogeneration system construction	Size of host community	Graphical representation of the percentage increase[a]
Total population	32,950	164,750	Coordinated	Small	107.6
				large	32.9
			not coordinated	small	107.6
				large	33.8
Family status persons	31,450	157,250	Coordinated	Small	107.6
				large	32.5
			not coordinated	small	107.6
				large	33.8
Children preschool / elementary / middle / high	4,089 / 6,375 / 2,359 / 2,579	20,442 / 24,374 / 11,794 / 12,894	Coordinated	Small	107.5
				large	32.5
			not coordinated	small	107.6
				large	33.8
Occupied dwellings	9,100	46,620	Coordinated	Small	107.6
				large	33.3
			not coordinated	small	107.6
				large	33.8
Vacancy rate (as % original housing)	Assumed to be zero	Assumed to be zero	Coordinated	Small	0.0
				large	0.0
			not coordinated	small	2.6
				large	0.0
Residential land (acres)	4,375	8,763	Coordinated	Small	107.6
				large	33.3
			not coordinated	small	110.3
				large	33.8



[a] Increases are expressed as a percentage of the base value in the appropriate host community.

TABLE D-5. (continued)

Community parameter	Preexisting value: Small host community	Preexisting value: Large host community	Management of cogeneration system construction	Size of host community	Graphical representation of the percentage increase[a] (0 20 40 60 80 100 120 140 160 180 200 360 380 400)
Construction workers	534	2,569	Coordinated	Small	[illegible]7.6
				large	33.8
			not coordinated	small	107.6
				large	33.8
Industrial workers	4,762	15,152	Coordinated	Small	107.6
				large	33.8
			not coordinated	small	107.6
				large	33.8
Support workers (other than construction)	4,724	32,279	Coordinated	Small	107.6
				large	33.8
			not coordinated	small	107.6
				large	33.8
Total work force	10,000	50,000	Coordinated	Small	107.6
				large	33.8
			not coordinated	small	107.6
				large	33.8
Family-status workers	8,500	42,500	Coordinated	Small	107.6
				large	32.5
			not coordinated	small	107.6
				large	33.8
Single-status workers	1,500	7,500	Coordinated	Small	107.6
				large	41.6
			not coordinated	small	107.6
				large	33.8
Unemployment increase	Base level 6% to 8%	Base level 6% to 8%	Coordinated	Small	0.0
				large	0.0
			not coordinated	small	0.0
				large	0.0

[a] Increases are expressed as a percentage of the base value in the appropriate host community.

TABLE D-6.
PEAK CONSTRUCTION PHASE-
COMPARISON OF CHANGES IN A SMALL AND LARGE HOST COMMUNITY
(NUCLEAR POWER PLANT - 1000 MW_e)

Community parameters	Preexisting value: Small host community	Preexisting value: Large host community	Management of cogeneration system construction	Size of host community	Graphical representation of the percentage increase*
Total population	32,930	164,750	Coordinated	Small	52.60
				large	3.30
			not coordinated	small	109.50
				large	24.50
Family-status persons	31,450	157,250	Coordinated	Small	45.80
				Large	4.70
			not coordinated	small	95.70
				large	22.90
Children: preschool	4,089	20,442	Coordinated	Small	45.80
elementary	4,875	24,376		Large	4.70
middle	2,359	11,794	not coordinated	small	95.70
high	2,579	12,894		large	22.90
Occupied dwellings	9,100	46,620	Coordinated	Small	55.40
				large	5.80
			not coordinated	small	115.60
				large	26.00
Vacancy rate (as % original housing)	Assumed to be zero	Assumed to be zero	Coordinated	Small	0.00
				large	0.00
			not coordinated	small	0.00
				large	0.00
Residential land (acres)	4,375	8,763	Coordinated	Small	55.40
				large	5.80
			not coordinated	small	115.60
				large	26.00

Scale of graphical representation: 0 20 40 60 80 100 120 140 160 180 200 ... 360 380 400

*Increases are expressed as a percentage of the base value in the appropriate host community.

TABLE D-6. (continued)

Community parameter	Preexisting value: Small host community	Preexisting value: Large host community	Management of cogeneration system construction	Size of host community	Graphical representation of the percentage increase[a]
Construction workers	516	2,569	Coordinated	Small	101.00
				large	18.80
			not coordinated	small	208.50
				large	50.80
Industrial workers	4,762	15,152	Coordinated	Small	0.00
				large	0.00
			not coordinated	small	0.00
				large	0.00
Support workers (other than construction)	4,724	32,279	Coordinated	Small	30.50
				large	0.00
			not coordinated	small	65.60
				large	15.80
Total work force	10,000	50,000	Coordinated	Small	67.70
				large	6.70
			not coordinated	small	141.00
				large	28.20
Family-status workers	8,500	42,500	Coordinated	Small	45.80
				large	4.70
			not coordinated	small	95.70
				large	22.90
Single-status workers	1,500	7,500	Coordinated	Small	192.10
				large	17.80
			not coordinated	small	397.70
				large	58.20
Unemployment increase	Base level 6% to 8%	Base level 6% to 8%	Coordinated	Small	0.00
				large	0.00
			not coordinated	small	0.00
				large	0.00

[a]Increases are expressed as a percentage of the base value in the appropriate host community.

TABLE D-7.
PHASE JUST PRIOR TO OPERATION–
COMPARISON OF CHANGES IN A SMALL AND A LARGE HOST COMMUNITY
(NUCLEAR POWER PLANT - 1000 MW_e)

Community parameter	Preexisting value: Small host community	Preexisting value: Large host community	Management of cogeneration system construction	Size of host community	Graphical representation of the percentage increase[a]
Total population	32,950	164,750	Coordinated	Small	14.60
				large	5.30
			not coordinated	small	31.00
				large	16.90
Family-status persons	31,450	157,250	Coordinated	Small	14.40
				large	4.70
			not coordinated	small	31.00
				large	16.90
Children: pre-school	4,089	20,442	Coordinated	Small	14.40
elementary	4,875	24,374		large	4.70
middle	2,359	11,794	not coordinated	small	31.00
high	2,579	12,894		large	16.90
Occupied dwellings	9,100	46,620	Coordinated	Small	14.40
				large	5.80
			not coordinated	small	31.00
				large	16.90
Vacancy rate (as % original housing)	Assumed to be zero	Assumed to be zero	Coordinated	Small	41.00
				large	0.00
			not coordinated	small	84.60
				large	9.20
Residential land (acres)	4,375	8,763	Coordinated	Small	55.40
				large	5.80
			not coordinated	small	115.60
				large	26.00

[a]Increases are expected as a percentage of the base value in the ppropriate host community.

TABLE D-7. (continued)

Community parameter	Preexisting value: Small host community	Preexisting value: Large host community	Management of cogeneration system construction	Size of host community	Graphical representation of the percentage increase[a] (0–400)
Construction workers	514	2,569	Coordinated	Small	0.00
				large	18.00
			not coordinated	small	0.00
				large	22.60
Industrial workers	4,762	15,152	Coordinated	Small	0.00
				large	0.00
			not coordinated	small	0.00
				large	0.00
Support workers (other than construction)	4,726	32,279	Coordinated	Small	30.50
				large	0.00
			not coordinated	small	65.60
				large	15.80
Total work force	10,000	50,000	Coordinated	Small	14.60
				large	6.70
			not coordinated	small	31.00
				large	16.90
Family-status workers	8,500	42,500	Coordinated	Small	14.60
				large	4.70
			not coordinated	small	31.00
				large	16.90
Single-status workers	1,500	7,500	Coordinated	Small	14.60
				large	17.80
			not coordinated	small	31.00
				large	16.90
Unemployment increase	Base level 6% to 8%	Base level 6% to 8%	Coordinated	Small	12.60
				large	6.30
			not coordinated	small	23.70
				large	14.40

[a] Increases are expressed as a percentage of the base value in the appropriate host community.

TABLE D-8.
FULL OPERATION PHASE-
COMPARISON OF CHANGES IN A SMALL AND A LARGE HOST COMMUNITY
(NUCLEAR POWER PLANT - 1000 MW_e)

Community parameter	Preexisting value: Small host community	Preexisting value: Large host community	Management of cogeneration system construction	Size of host community	Graphical representation of the percentage increase[a]
Total Population	32,950	164,750	Coordinated	Small	107.10
				large	32.30
			not coordinated	small	107.10
				large	33.70
Family-status persons	31,450	157,250	Coordinated	Small	107.10
				large	31.70
			not coordinated	small	107.10
				large	33.70
Children: preschool	4,089	20,442	Coordinated	Small	107.10
elementary	4,875	24,376		large	31.70
middle	2,359	11,794	not coordinated	small	107.10
high	2,579	12,894		large	33.70
Occupied dwellings	9,100	46,620	Coordinated	Small	107.10
				large	32.90
			not coordinated	small	107.10
				large	33.70
Vacancy rate (as % original housing)	Assumed to be zero	Assumed to be zero	Coordinated	Small	0.00
				large	0.00
			not coordinated	small	3.50
				large	0.00
Residential land (acres)	4,375	8,763	Coordinated	Small	107.10
				large	32.90
			not coordinated	small	115.60
				large	33.70

[a]Increases are expressed as a percentage of the base value in the appropriate host community.

TABLE D-8. (continued)

Community parameter	Preexisting value: Small host community	Preexisting value: Large host community	Management of cogeneration system construction	Size of host community	Graphical representation of the percentage increase[a]
Construction workers	514	2,569	Coordinated	Small	107.10
				large	33.70
			not coordinated	small	107.10
				large	33.70
Industrial workers	4,762	15,152	Coordinated	Small	107.10
				large	33.70
			not coordinated	small	107.10
				large	33.70
Support workers (other than construction)	4,724	32,279	Coordinated	Small	107.10
				large	33.70
			not coordinated	small	107.10
				large	33.70
Total work force	10,000	50,000	Coordinated	Small	107.10
				large	33.70
			not coordinated	small	107.10
				large	33.70
Family-status workers	8,500	42,500	Coordinated	Small	107.10
				large	31.70
			not coordinated	small	107.10
				large	33.70
Single-status workers	1,500	7,500	Coordinated	Small	107.10
				large	44.80
			not coordinated	small	107.10
				large	33.70
Unemployment increase	Base level 6% to 8%	Base level 6% to 8%	Coordinated	Small	0.00
				large	0.00
			not coordinated	small	0.00
				large	0.00

[a] Increases are expressed as a percentage of the base value in the appropriate host community