ENERGY LABORATORY

MASSACHUSETTS INSTITUTE
OF TECHNOLOGY

INDUSTRIAL INTERFUEL SUBSTITUTION
PHASE I REPORT:
MODEL DEVELOPMENT AND CASE STUDY

Energy Systems Group*

MIT Energy Laboratory Report No. MIT-EL 82-036
June 1982

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PHASE I REPORT

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I. STUDY BACKGROUND AND METHODOLOGY

I.1 Introduction

In 1980, the industrial sector accounted for 20 percent of the U.S. oil consumption and 42 percent of the U.S. gas consumption. Focusing only on the industrial sector, more than 80 percent of the industrial sector energy demand was met by oil and gas, with coal and electricity providing the other 20 percent. This has meant that industrial firms are increasing facing the need to evaluate alternative sources of fuel since most of their energy demand is met with fuels that are increasingly subject to uncertainties in both price and availability.

The need to seek alternative energy sources comes both from the need to minimize costs, and the need to assure continuous energy supply to keep plants on line. The seriousness of the situation is evidenced by the fact that during the 1970s international oil prices increased in sharp steps by 2000 percent, with gas prices moving in the same direction at a slower rate. In addition in the winter of 1978 much of the industrial northeast was without gas at any price.

Large increases in natural gas prices occurred during the second half of the 1970s. Interstate prices of new gas at the wellhead increased from $0.56/mcf in 1976 to about $3.0/mcf in 1981. Gas deregulation in 1985 (if not earlier) is expected to lead to additional price increases during the 1980's and thereafter. Many industries experienced substantial gas curtailments during 1976-1978, which made gas an uncertain fuel for the industrial and utility sectors. While some industries have not yet felt the impact of the higher gas prices because of long-term contracts, these contracts will be ending during the 80s.

Even though during 1981-1982 the outlook for oil prices improved somewhat, oil prices are expected to increase in real terms over the next two decades. Uncertainty in supply may play a major role in fuel choice decisions in the decade ahead particularly given that the Middle East remains politically the most unstable region in the world.

For non-premium uses of oil and gas, especially in boilers, coal frequently is an attractive alternative under current economic conditions.* Today, the coal price is roughly 40 percent of the oil price on a per Btu-basis. However, oil and gas still provide nearly 70 percent of fuel used in industrial steam raising (40 percent of the total oil and gas consumption in the manufacturing sector). Given current economic conditions, much of this market could, in theory, be captured by coal. However, the use of coal is not free of problems. While coal is less expensive, the use of coal has a number of disadvantages. These disadvantages include its combustion and handling characteristics, the fact that use of coal does, in general, require more capital intensive equipment, and that it has the highest levels of pollutants of the three fuels. For each individual location where coal use is technically feasible, all these factors must be considered. In addition the regional implications of increased coal combustion must also be taken into consideration, specifically in transport system requirements, regional economic impacts and regional environmental impacts, (both air and water).

A major amount of effort has been invested over the past decade in evaluating the regional impacts of energy prices and of energy

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*An example of premium use of oil and gas is in special process heat applications which will not tolerate corrosive fuel elements and/or require well-regulated temperature. Use of oil and gas in feedstocks is another example. In 1976, approximately 20 percent of that total oil and gas consumption of the manufacturing sector was used as feedstock.

utilization and availability. The majority of this work has been directed from the top, or the federal level, down to the state and/or regional level. In retrospect this approach has not been successful in its ability to reflect actual behavior of regional energy economies. Macro or aggregate analyses and predictions of industrial energy behavior, for instance, have tended to overestimate the capital investments which industrial organizations would make and to underestimate the ability of industries to respond to prices through relatively non structural, behavioral changes.

The purpose of the methodological research and case study reported here has been the development and/or extension of a set of tools for use in evaluation of industrial interfuel substitution. A new approach to the evaluation of regional industrial fuels analysis has been developed which builds upon detailed plant specific energy economic analyses, these are then aggregated to the industry and finally to the regional level. The tools and the basic theoretical structure are not new. Existing tools are used in ways which allow decision makers both in industry and government to evaluate better specific strategic fuels options. The tools developed include plant analysis models of fuel use including steam turbine cogeneration, economic/financial models at the plant level and detailed data bases for combustion technologies. A framework for industry aggregation has been developed. Regional impacts are evaluated using an air quality model modified for this effort and regional economic and transport impacts can be evaluated given knowledge of fuel demands. Each of these components is discussed in greater detail in the sections which follow.

The remainder of this section of the report will present the overall framework developed for regional industrial fuels analyses. Section two will introduce each of the major tools and data bases developed. A full description of the individual components is included in the six appendices. The third section of the report presents the background for and results of a case study of a large industrial consumer such as a chemical or oil refinery. The final section presents a brief discussion of the model/framework extensions required for further implementation of the proposed methodology.

One caveat is required. The material discussed below offers a framework for regional fuel switching and cogeneration analyses. It builds upon work completed for individual industries by the MIT Energy Laboratory and upon engineering economic studies done of a set of commercially available or emerging energy technologies. The framework is presented here as a point of departure. During any actual regional study the framework will be modified and improved in light of the reality of the industries and region under study.

I.2 Framework for Regional Analysis

Figure I-1 presents the overall regional analysis framework. As can be seen the activities are divided into two major sections. The first is a preliminary analysis and the second the main analysis which includes detailed plant analyses, utility analyses and environmental impact and trade-off analyses.

Preliminary Analysis

Figure I-2 summarizes the components of the preliminary analysis. The first stage of which focuses on a general understanding of

FIGURE I-1.

THE REGIONAL ANALYSES

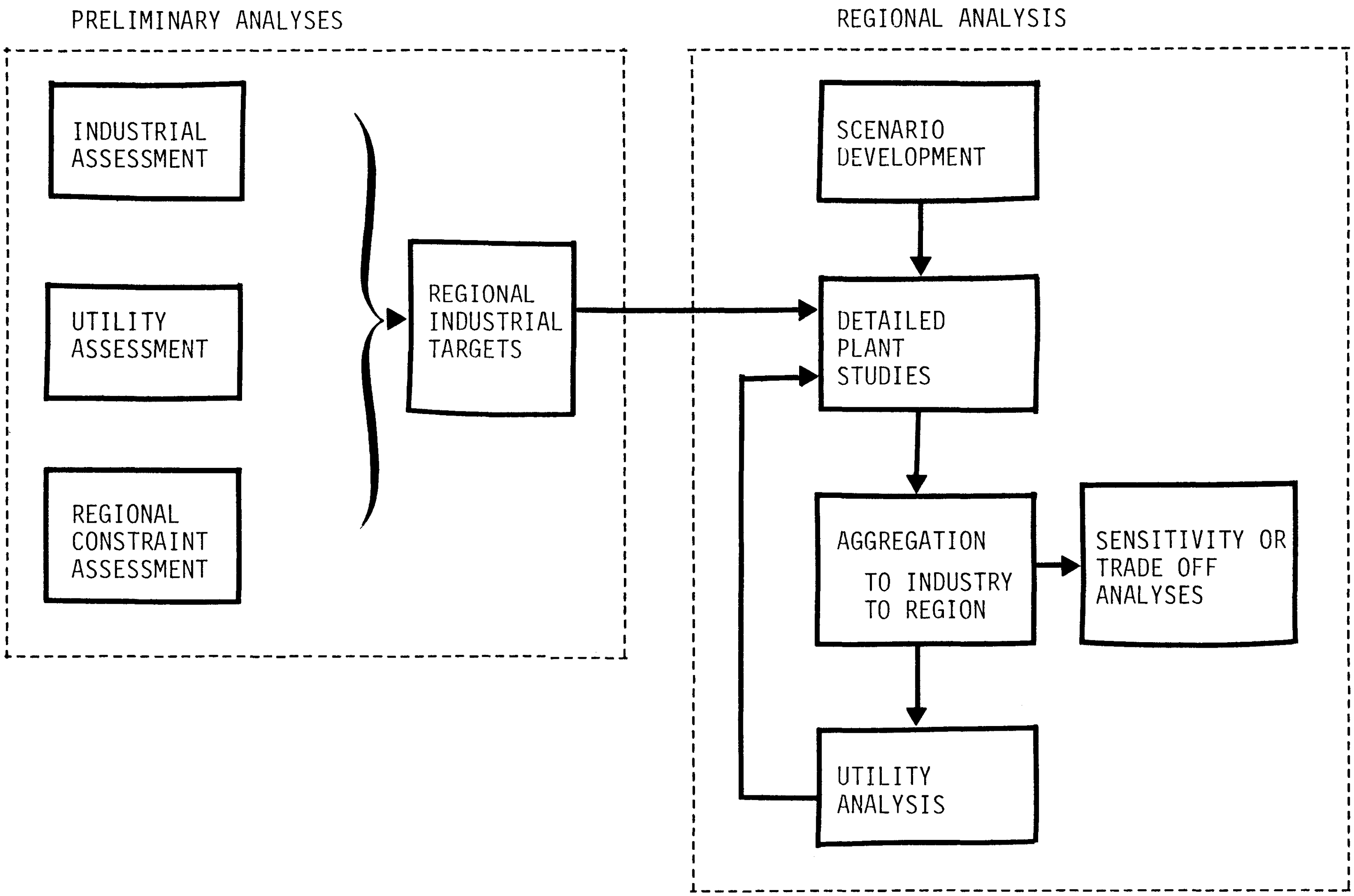
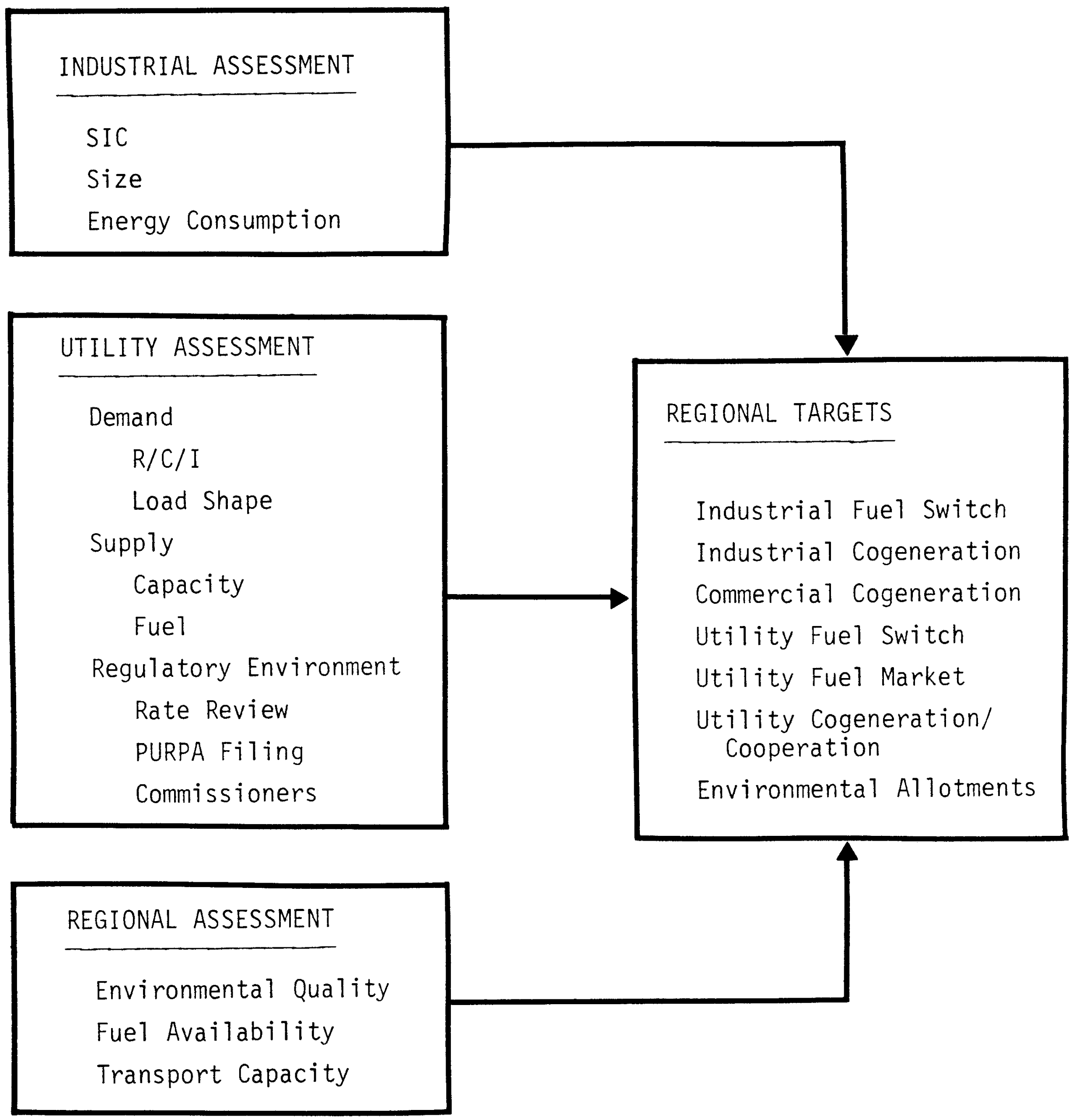


FIGURE I-2.

PRELIMINARY ANALYSES



the regional energy environment. The preliminary analysis will involve a relatively rapid paper/statistical study of the basic components of the regional energy structure. The first components are the industrial base of the region and the utility structure. In this component data will be collected on the distribution of industries by type, by size, by dominant fuel type and by level of energy consumed.

Other components of the preliminary analysis include the evaluation of regional environmental quality, regional fuel availability and regional transport capacity. Using published data it will be necessary to do a preliminary evaluation of both air and water quality constraints which are likely to influence the acceptability of the different fuels and technologies.

The output of these preliminary evaluations will be the structuring of the main study around a set of regional targets. These targets will be defined to reflect at least the following potential options:

- Industrial Fuel Switching: Traditional boiler systems
- Industrial Fuel Switching: Steam turbine cogeneration
- Utility Fuel Switching
- Utility Cogeneration and/or Cooperation with Industry
- Regional Business Opportunities in Alternative Fuels
    - Utility Involvement
    - Other Energy Company Involvement

These targets define the options that are then evaluated in detail using the modeling structures discussed in later portions of this report.

Study Structure

The main portion of the analysis shown in Figure I-3 is divided into

FIGURE I-3.

REGIONAL ANALYSIS

SCENARIO DEVELOPMENT

- Fuel Cost
- Fuel Availability (Transport)
- Environmental Requirements
- Return on Investment
- Technology Availability
- Utility Rates

↓

DETAILED PLANT STUDIES

- Technology
- Finance

To evaluate individual decision variables

↓

AGGREGATION TO DETERMINE
Amount/Capacity "Switched"
Under Scenario

↓

TRADE OFF ANALYSIS
On Individual
Criteria Variables

- Environment
- Coal Demand/Availability
- Regional/Capital Availability

the following modeling and analysis activities: scenario development, detailed plant analyses, aggregation to the industrial/regional levels, utility analysis, and trade-off analysis.

Scenario Development. Initially, the variables which are expected to have a major impact on the system (called here input variables) will be identified and divided into decision and exogenous variables and contingencies. Decision variables are those variables whose value depends on the decisions of the management of the firm; for example, the use of natural gas in a boiler is a decision variable. Exogenous variables are those variables whose value does not depend on the actions of the management of the firm; for example, the price of oil is an exogenous variable. Contingencies are events of low probability of occurrence but which could have an adverse impact on the firm; for example, a drastic decrease in a firm's oil supplies is a contingency.

Subsequently, scenarios will be generated from rationale combinations of input variables. For example, one scenario would be to introduce a medium level of coal capacity (50 percent of potential demand, with no cogeneration, and with high fuel prices). Scenarios will be developed in such a way that they span the whole space of values of input variables.

Detailed Plant Analyses. The area most fully developed in Phase I of the Interfuel Substitution Project has been that of industrial strategic planning models. This has involved work in engineering, environmental, and financial analysis. The engineering analyses evaluate alternative energy conversion systems available for use within specific plants for raising steam for process heat and cogeneration. The technology alternatives available for raising of steam are well known and understood yet not always well applied in evaluating potential fuel switches. MIT has adapted and expanded a pair of data bases for steam raising equipment which include both the physical characteristics of the equipment and the financial/cost data corresponding to each of the physical systems. The new data base and its application to a set of case studies in fuel switching is discussed in Section II.1 and Appendix A.

The second engineering area in which considerable effort has been expended in Phase I has been that of engineering analysis tools of cogeneration options. Prior work in evaluating cogeneration utilized oversimplified screening curves for the individual options. Section II.2 and Appendix B discuss the approach used in the case study to analyze the economic and environmental impacts of conceptually designed cogeneration system. In particular it looks more closely at the steam/electric trade-off and, for the case study example, at range of temperatures and pressures and alternatives for supplying both thermal and electrical energy.

The engineering analytic modeling efforts are complemented by a corporate strategic analysis model and an environmental model. The corporate strategic analysis model includes both debt and equity financing and advanced handling of shared capital. The financial model is described in Section II.3 and Appendix E. The environmental model used in the case study is a 50 square kilometers Gaussian plume model accepted by EPA and described in Section II.4 and Appendix F.

<u>Aggregation to the Industrial/Regional Levels</u>. The preliminary analyses in the regional study will have identified a set of potential industrial sector targets for fuel switching and introduction of alternative technologies such as cogeneration. In general it is expected that these targets will be defined in terms of both specific plants and

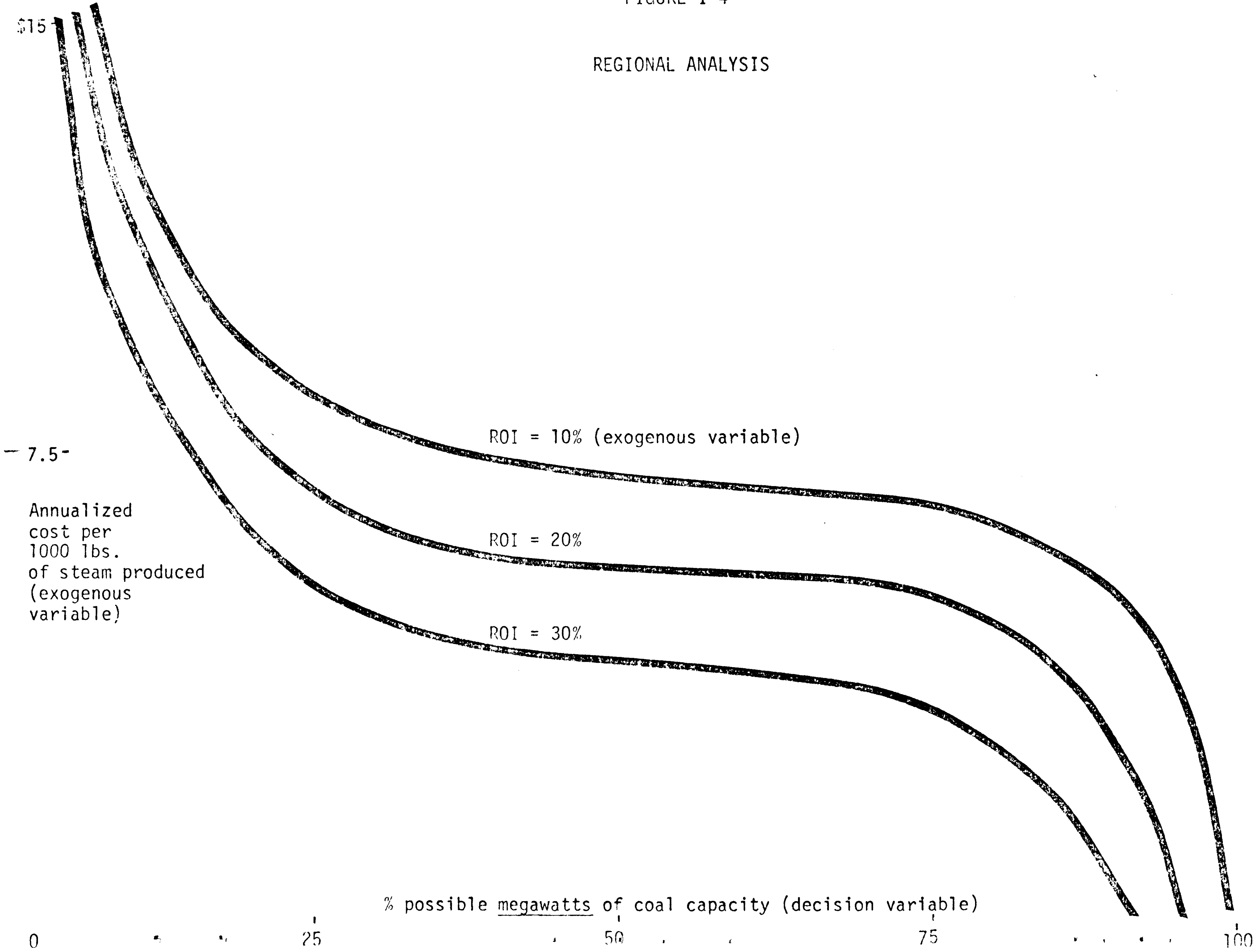
in some instances generic industries (SIC for instance). Detailed plant studies will be carried out at a limited number of representative sites to identify the economic, physical and environmental response which might be anticipated for these individual facilities given a set of scenarios.

The critical question at this point is "how will the individual plants be aggregated to the industrial level?" There is no obvious answer to this specific aggregate question. In general the aggregation process could be comprised of at least two steps. The first step is for the research group to satisfy itself that within reasonable bounds the disaggregation at the industry level is sufficiently fine to idendify the major energy consuming and financial characteristics of the individual facilities and yet sufficiently gross so as not to require as a sample the universe of plants in the region. This aggregation decision must be based in large part on judgment. The second step is to utilize individual plant data and the industrial groupings defined above to develop of a set of technology adoption curves which reflect the likely quantity of fuel switching as a function of the exogenous variables. Figure I-4 gives an example of the type of technology adoption curves to be developed. As can be seen these are hypothesized to be logistic curves which reflects the present state-of-the-art in analysis of new technology diffusion (Choffray and Lillien, MIT, 1980).

If we use the example of willingness, possibility or ability to switch to coal fired boilers it is possible by example to discuss one aggregation method. Assume that from the preliminary analysis it is apparent that a group of plants (such as kraft paper mills of x tons per day capacity) is sufficiently homogenous to be grouped together and that these facilities have characteristics which appear to make them

FIGURE I-4

REGIONAL ANALYSIS



attractive for fuel switching from oil to coal, i.e., they have been defined as regional targets. Detailed analysis of a single facility has demonstrated that the willingness to invest is highly dependent upon the required return on investment and that in turn is dependent on the price of the alternative fuel. In this example assume that a critical variable is, in fact, the relationship between the price per mmBtu of coal and oil. From the perspective of the regional study the question is how much coal capacity will be installed and under what conditions within the region and what will be the regional environmental and economical impact. With limited sampling of plants it will be possible to identify the range of required return on investment for individual firms to make the decision to invest. Given data on industrial fuel use capacity and data on required return on investment, a two dimensional curve can be used to estimate regional levels impacts of coal consumption. Figure I-4 shows one such a set of curves which relate MW of capacity to the relative price of coal and oil. In general one would expect it to have a logistic form with little response if the prices were the same or nearly the same, increased reponse (additional MW) with increased spread in the prices and finally less relative additions as the industry approached saturation. A curve such as this would then be used in conjunction with regional fuel price scenaria and regional utility and environmental models to identify levels of penetration anticipated as a function of collapsed or surrogate industrial decision parameters. Such a methodology could be extended to include three or possibly four dimensional decision surfaces constructed in the same manner.

While these heuristic approaches to aggreation of plant level to industrial level data are less than perfect they offer a logical two step process of detailed data analysis and then data reduction. The industrial groupings can then be handled additively if (and only if) the critical variables between industrial groupings in the analysis are either identical or nearly identical. Without this condition holding it is unlikely that the relative weighting of the industrial groups within the aggregation structure could be justified.

Utility Analysis. The utility may play a key role in regional energy studies, particularly those involved with cogeneration where the utility and industry must interact in pricing of energy and in long term planning. As a result, if required, the modeling structure will utilize a utility capacity planning and operating system model such as the EGEAS system developed at the MIT Enery Laboratory for EPRI and the utility industry (MIT Utility Systems Program, 1982). The objective of use of the EGEAS structure will be to evaluate two separate issues within the region. The first will be the short run operating cost impacts of significant penetration of cogeneration in the utility service territory. Utilizing the EGEAS structure it will be possible to calculate the avoided cost to the utility as a result of the power cogenerated by the industrial facilities. Given this avoided cost calculation it will be possible to iterate back to the detailed industrial models to evalute the impact in the initial assumptions concerning the value of energy sold to the utility by the firm and thereby to close the loop in the short time frame between the individual firm and the regional entity, the utility. In the longer time frame of capacity planning a similar type of analysis must be carried out to calculate the capital implications of alternative scenarios from the perspective of the utility, the plant and the region. Again the tool most readily available is EGEAS.

Trade-off-Analyses. Each scenario will be evaluated by using different criteria variables, such as costs, environmental impacts and security of supplies. Very often these criteria variables may be conflicting in the sense that all of them can not be optimized at the same time. For example the introduction of coal to substitute for natural gas in the industrial sector may lead to lower costs but also to higher environmental impact. For this reason, trade-off curves will need to be developed between the criteria variables in the case of conflict.

These trade-off curves will be useful for decision makers at the plant and regional level to know how far one moves from a particular objective by moving closer to another objective. For example, how much will the costs increase, if SO_2 emissions decrease by 10 percent. These trade-off curves can be developed at both the plant and regional levels.

I.3 Summary

The material presented in this section has defined a framework for evaluation of fuel switching and cogeneration decisions in the industrial sector of a regional energy economy. The methodology contains a set of suggested heuristics for aggregation of detailed plant data to the regional level. In addition, the framework suggests a structure which may be heavily dependent on the interaction between the utility and the industrial facility in terms of purchase and sale of energy and thereby of the economics of each party with respect to decision to cogenerate. The nature of the analytic system developed requires that the majority of the analyses be run "open loop", i.e., in order to evaluate the trade-off frontiers that scenarios be developed with which allow for the criteria variables to be evaluated in terms of alternative exogenous variables such as fuel prices and technology availability. This method has been seen to be functional for specific industrial analyses such as for the MIT Consolidated Edison study and for the case study covered in Phase I of this effort (MIT Energy Laboratory, 1981). A detailed regional case study will have to be completed to validate this approach.

I.4 Report Structure

The remainder of this report has been divided into four major sections. Section II presents in summary form the models and data structure developed in Phase 1; these are also described in detail in the appendices. Section III presents the background and the results of the case study used to test the tools developed during Phase 1. The case study was chosen because of our ability to evaluate a number of fuel and cogeneration options across a single facility. Because of data restriction and to test our work, a number of assumptions were made concerning both the availability and age of the capital stock used in steam raising. Section IV discusses the results of the case study in terms of strict interfuel substitution and in a detailed analysis of cogeneration. Section V presents the conclusions to Phase I. The final section of the main report discusses the types of extensions anticipated in a Phase 2 effort both in terms of the concrete examples required and further model development required.

Each of the data structures and modeling systems developed are described in greater detail in appendices to this report. These cover the steam rising data base, a detailed discussion of cogeneration and interfuel substitution, a discusison of technology, coal gasification evaluated during Phase 1, a discussion of both the economic and environmental models and finally a discussion of anticipated price paths for each of the major fuel types. This last Appendix draws heavily upon research work carried on outside of the present study but, as will be seen, expectations concerning fuel prices plays a major role in the relative economics of substitution of fuels in the industrial sector.

II. MODELS AND DATA STRUCTURES

The section which follows covers the four principal model/data structures developed under Phase 1 of the interfuel substitution project. As was stated in the introduction, the tools themselves are not unique though the data bases associated with them represent information collected from a variety of both public and corporate sources and as a result offers a relatively unique source. The development of the tools and their testing in the case study defined and discussed in Sections III and IV was done to prepare for an actual regional analysis requiring application of the models described here, the aggregation methodology discussed in Section I and the data reduction methodologies utilized earlier MIT Energy Laboratory activities such as the Consolidated Edison study. The data reduction methodologies are not applied in the case study because they require coordinated data, and specifically regional information such as transport, economic or environmental attributes.

II.1 Steam Raising: Equipment

The data base was developed from studies in the public domain, principally government-sponsored work, as well as confidential industrial data. Details of these data sources are discussed and references listed in Appendices A, B and C. In some steam generation cases, discrepancies between various sources were observed but the major ones were amenable to adjustments or explanation. On analyzing the reliability of these sources, as a rule more confidence was given to the industrial data than to the government-sponsored study information.

The engineering information for the detailed plant models was based on the following fuels:

Substituted fuels: oil, natural gas and coke

Substituting fuels: coal and synthetic gases

Fuel use for: steam generation and cogeneration of steam and electricity

For the following process units, capital and operating cost versus capacity correlations were developed taking also into account pollutant emission levels for various fuels. Fuel costs were excluded from operating costs.

(a) Steam generation: coal fired boilers
oil fired boilers

(b) Cogeneration: steam turbine (oil or coal fired boilers)
gas turbine (natural gas)

(c) Gasification: Koppers-Totzek (MBG)
Texaco (MBG)
Atmospheric fixed bed (LBG)

Process heaters were not included because they are too specific for particular technologies. Gas fired boilers were not considered a separate category because their costs do not substantially differ from their oil fired or dual oil/gas fired counterparts and can easily be handled by adjustment factors. Correlations were also not derived for the other fuels and other uses since these are too special cases to warrant the work required to obtain general correlations.

Figures II-1 through II-4 present capital and operating cost versus capacity for oil and coal-fired boilers, fuel oil desulfurization equipment and three types of gasification plants. An example of emission data are shown in Table II-1 which is based on the study "Industrial Fuel Choice Analysis Model" (Energy and Environmental Analysis, Inc., June

Figure II-1: Recommended Steam Raising Correlation (includes particulate control, 85% capacity factor)

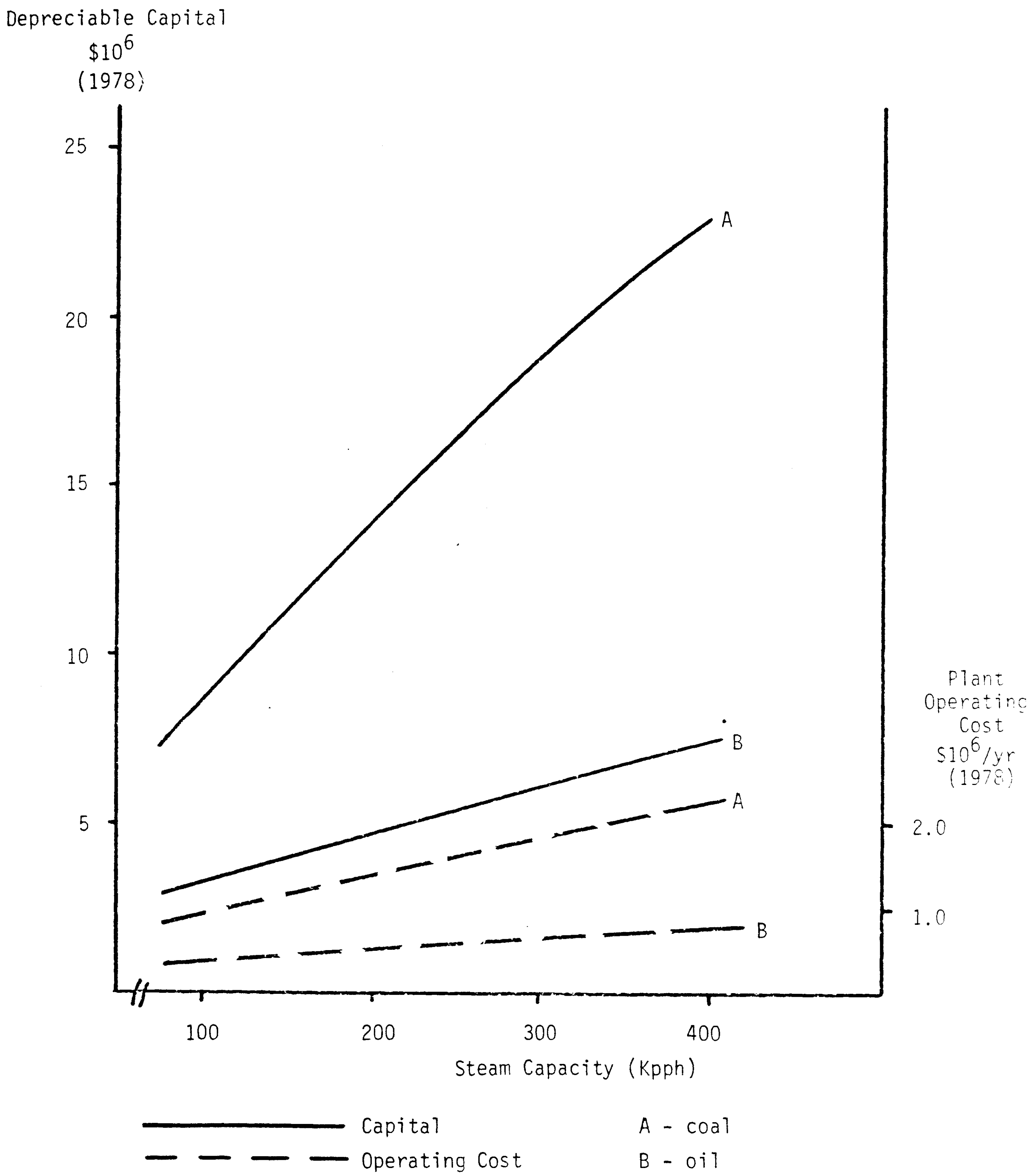


Figure II-2: Flue Gas Desulfurization Cost
(90% sulfur removal, 85% capacity factor)

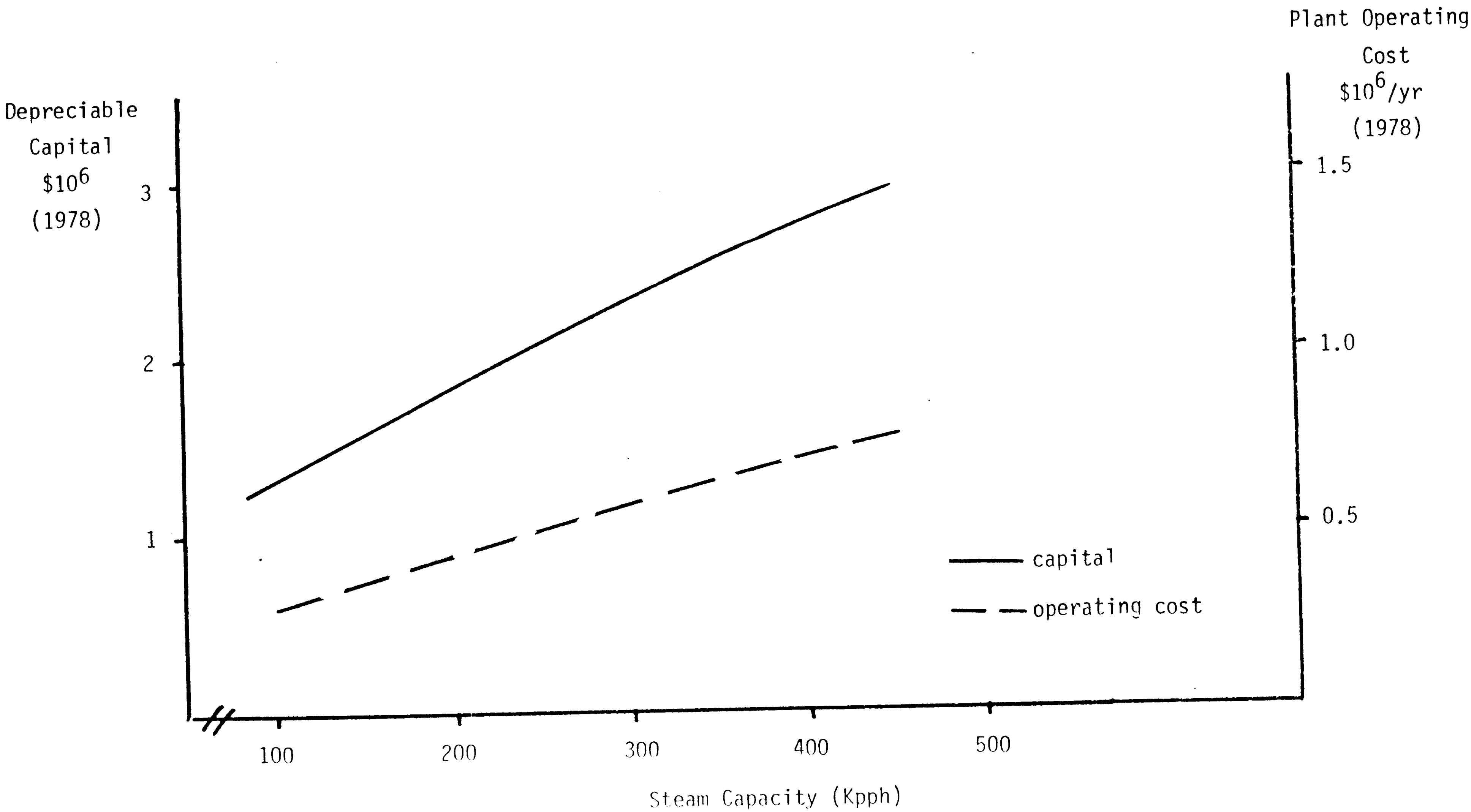


Figure II-3: Gasification Capital Cost

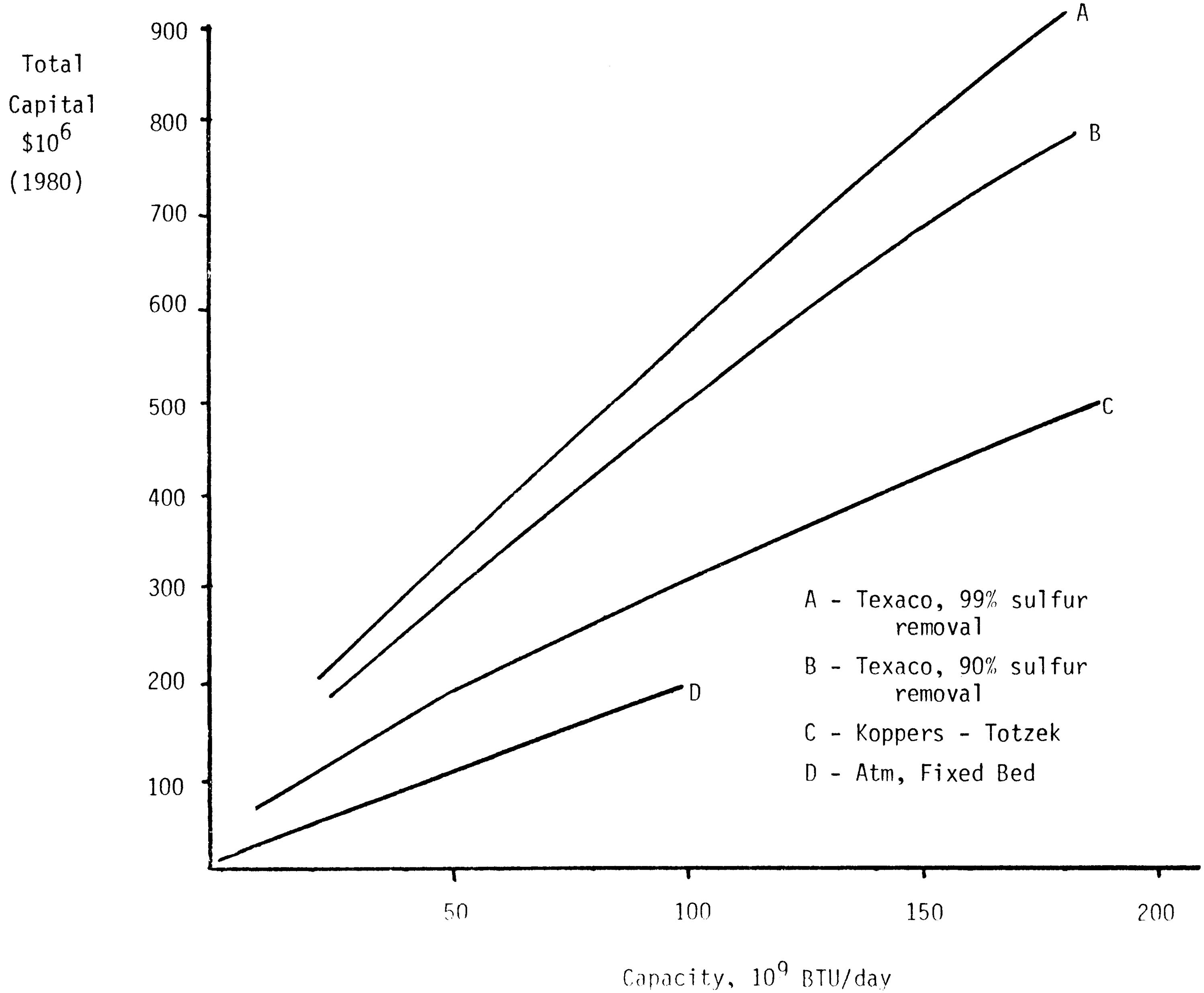


Figure II-4: Gasification Operating Cost at 90% Capacity Factor

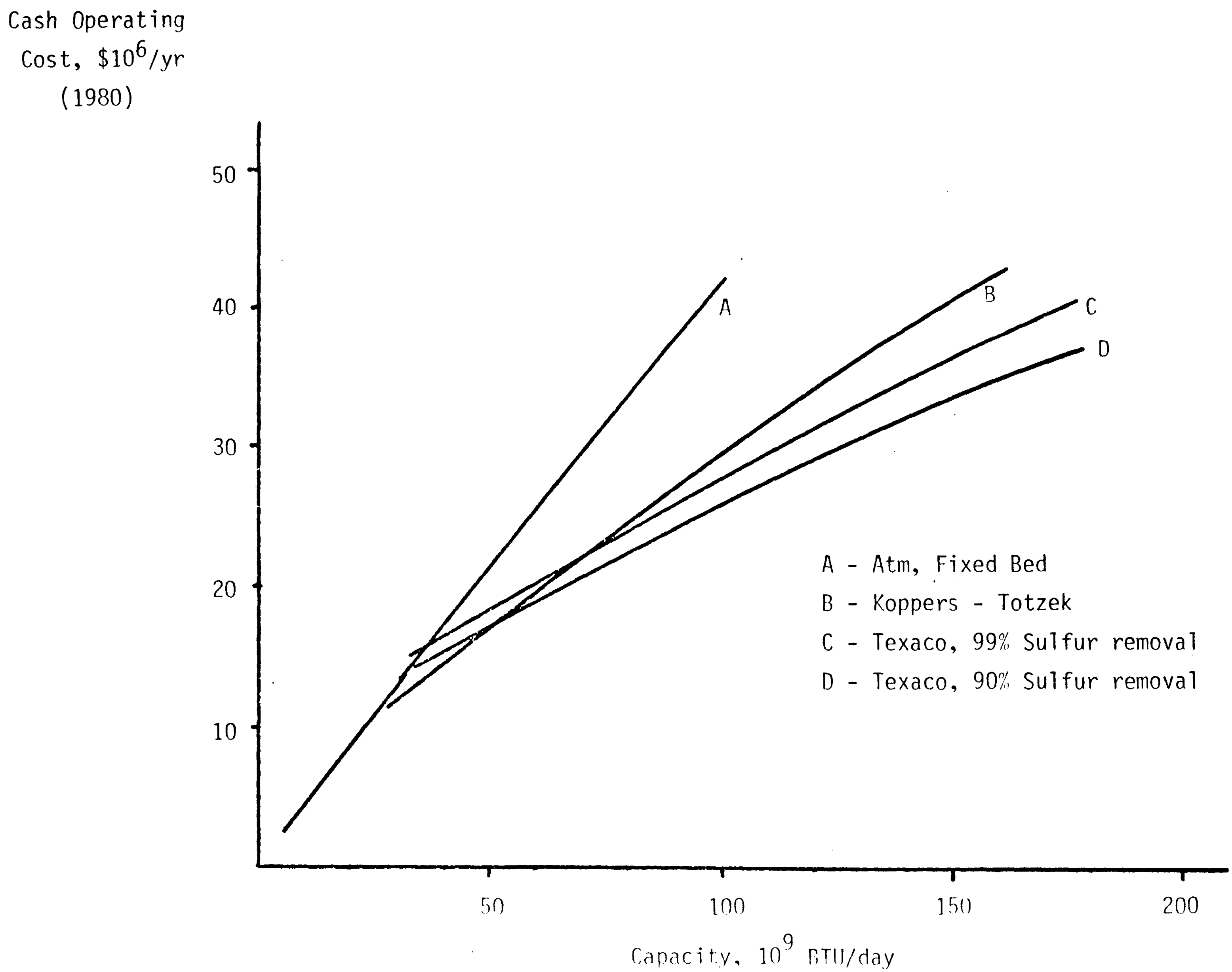


Table II-1. SPECIFIC EMISSION FACTORS

Uncontrolled boilers over 30 10^6 Btu/hr. (Ref. II-1)

	lbs/10^6Btu Fuel		
Fuel	SO_2	PM	NO_x
Gas			
Natural gas	0.0006	0.01	0.279
MBG/LBG	20,000(S/B)(1-R)/E	0.01	0.279
Oil			
Residual (0.8%S)	0.8	0.08	0.37
Residual (3%S)	3.138	0.22	0.37
Distillate	0.2	0.014	0.209
Coal			
Underfeed stoker	19,000 S/B	2500 A/B	0.349
Chaingrate stoker	19,000 S/B	2500 A/B	0.325
Spreader stoker	19,000 S/B	6500 A/B	0.616
Pulverized coal	19,000 S/B	8000 A/B	0.663

Symbols

A = % ash in coal

B = Btu/lb. of coal

E = fractional gasifier efficiency (coal inlet to gas outlet)

R = fractional sulfur removal of gasifier

S = % sulfur in coal

1980).

Definition of Cost Items

To avoid misinterpretation of cost and economic data, definitions of capital and production cost scope and terminology are extremely important. The structure of these costs is shown in Tables II-2 and II-3. Other economic quantities such as revenue, cash flow and profitability will be discussed later (see Section II.3 and Appendix E).

Most of the capital items have a material and a labor component, such as purchased equipment cost versus setting labor cost. Another useful distinction is between battery limits and offsite costs. The former refers to equipment, commodities and buildings directly involved in the process but may also include some utility and site development subitems such as distribution and yard, respectively, adjacent to process equipment. Anything outside battery limits is offsite.

Production costs have been traditionally divided into a fixed and a variable component. The former is constant for a given plant while the latter varies with production rate and typically includes process materials and utilities. For plant scale-up, it is convenient to introduce a semivariable component, approximately proportional to depreciable capital cost, that includes operating supplies, maintenance, property insurance and taxes, and depreciation. Within a limited capacity range, operating labor, supervision and service costs may be considered fixed while G&A, being split between the semivariable and fixed components, is best estimated as proportional to operating and maintenance labor.

TABLE II-2

Capital Cost Structure

Process equipment

+ Commodities (foundations, supports, piping, electricals, instrumentation, insulation, painting, etc.)

+ Process buildings

+ Utilities (supply and distribution of electricity, water, etc.)

+ General facilities (maintenance shops, administrative buildings, etc.)

+ Site development (grading, roads, etc.)

+ Other direct (spare parts, etc.)

Subtotal - direct cost

+ Indirects (field and home office)

Subtotal - construction cost

+ Contractors's fee

Subtotal - depreciable capital excluding contingency

+ Contingency

Subtotal - depreciable capital

+ Non-depreciables (land, etc.)

Subtotal - fixed capital

+ Working capital

+ Start-up cost*

+ Investment expense (royalties, etc.)

Total Capital

*May be depreciated in certain industries

TABLE II-3

Operating and Production Cost Structure

Process materials (raw materials, chemicals, etc.)

+ Utilities (fuel, electricity, water, etc.)

+ Operating labor (wages and fringe benefits)

+ Operating supplies

+ Supervision (salaries and fringe benefits)

+ Services (indirect wages, salaries, fringe benefits and materials, as well as outside services)

+ Maintenance (labor, supervision and supplies)

+ Property insurance and taxes

Subtotal - Plant production cost

+ General and administrative (G&A)

Subtotal - Cash production cost

+ Depreciation -

Total production cost

(Operating Cost) = (Production Cost) - (Major raw material or fuel)

II.2 Steam Raising: Steam Turbine Cogeneration

The evaluation of industrial cogeneration is far more complex than that of steam raising because of three factors. The first is the joint production of electricity and thermal energy which requires consideration of the real time pattern of supply and demand for both electricity and heat as well as the distribution of the joint probabilities of each. The second factor is the partial dependence of the economic valuation of cogeneration on the price of available externally generated electricity. This price (exogenous to a given facility, endogenous to the region) will determine both the avoided cost to a facility of owner generated and consumed inhouse and of the market value of any excess generation sold back to the utility. Finally, the third factor parallels that associated only with steam raising, i.e., the choice of boiler fuel.

Section IV.2 and Appendix B present in far greater detail the approach taken to analysis of steam turbine cogeneration options. A steam turbine cogeneration system has been conceptually designed on a standard configuration. The same configuration has been considered for various inlet turbine steam conditions and various process pressure requirements, scaling costs with the usual economy of scale factors for oil or coal fired power plants of that size (10-100 MWe), starting from the 1800 psig, 900°F system. The thermodynamic analysis, extensively presented in Appendix B is used for technology assessment purposes and for overall fuel savings evaluation as a function of cogeneration systems design parameters as well as to gain insight on the real behavior of the steam turbine cogeneration systems, i.e. to individuate those significant performance parameters of a conceptually designed system that are characteristic of the technology and therefore useful to a regional assessment study. The behavior of those parameters has always been shown to be consistent with the economic performance of the technology.

The economic analysis has been performed on a before-tax and after-tax basis, both on the cogeneration power plant, i.e., as an incremental investment with respect to traditional boilers, charging all costs differential against cogenerated electricity in order to determine a cogenerated power busbar generation cost and on a steam cost basis, i.e. determining the process steam cost with and without cogenerated electricity revenue (or income if on an after-tax basis). Also, a first set of screening curves has been developed, using as a strategic economic parameter the minimum required difference in unit cost of coal (or coal-derived) and oil fuels needed in order to have oil-fired systems and coal-fired systems break even. Value of cogenerated electricity has always been considered either as a parameter or has been set as only electric utilities avoided costs, assuming in this case identical fuel costs for both the utility and the industrial facility.

The depth and consequent possibility of individuation of consistent economic parameters for the steam turbine cogeneration systems analysis will be particularly important to the further regional efforts in which the research team is involved as they will be used as prescreens for full-scale cogeneration analysis.

II.3 Financial/Economic

The Financial Model computes and evaluates the economic effects of alternative energy conversion processes such as cogeneration or gasification. These effects are measured by an investment analysis approach which is applicable to replacement and retrofitting as well as "green field" plants.

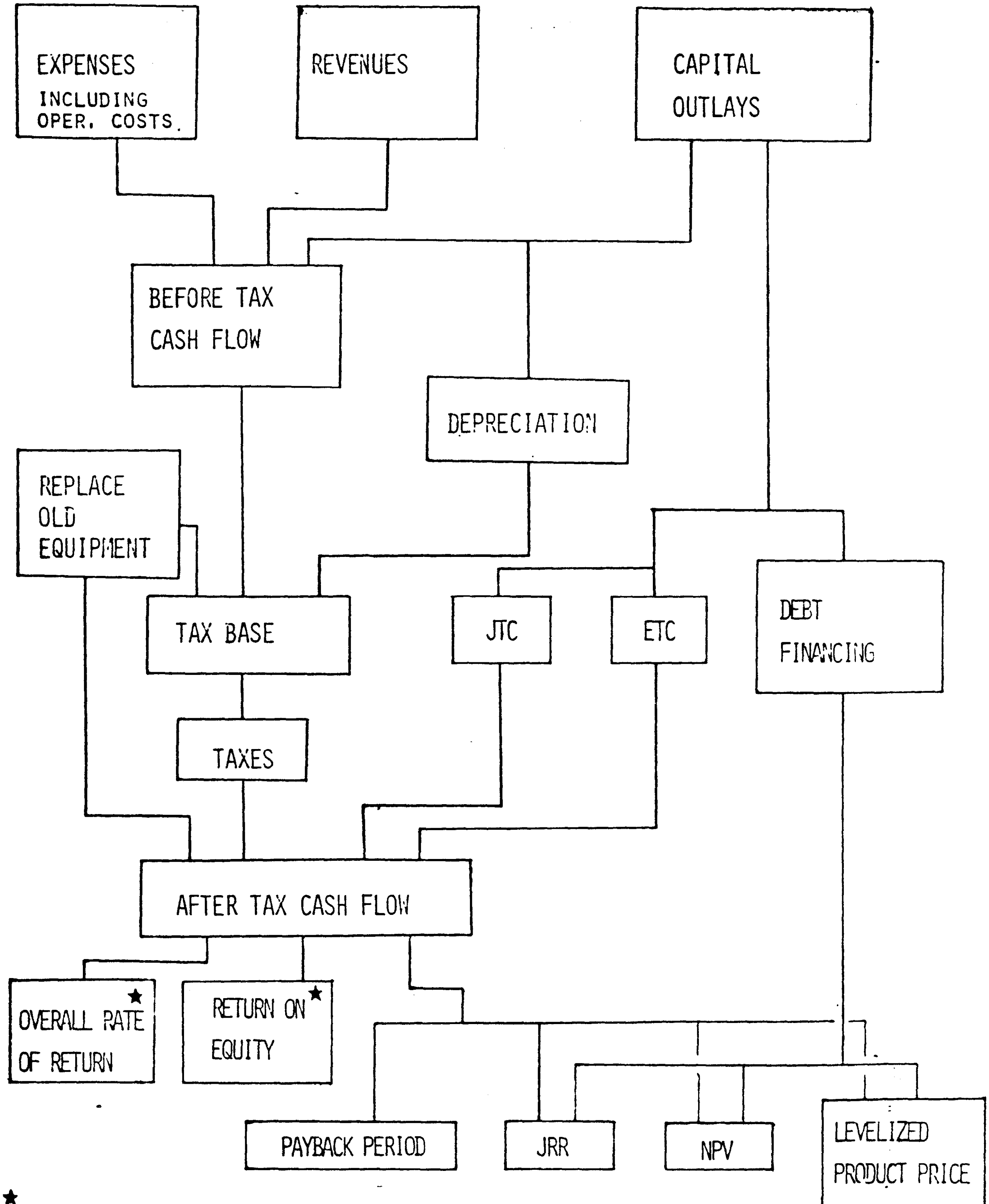
The basic structure of the Financial Model can be seen in Figure II-5. Operating costs, fuel costs, revenues, and capital outlays are the four main groups of financial data required for each option. These items are defined in Appendix E. Based on this data and the specific financial environment of the company (taxes, cost of capital, etc.) the After Tax Cash Flow (ATCF) is computed within the Model to evaluate profitability in terms of both Net Present Value (NPV) and Internal Rate of Return (IRR).

For debt financing, profitability is adjusted by adding the present value of the tax shields to the project's NPV. The payback period is also derived from the After Tax Cash Flow. Alternatively, Return on Equity and, based on that, Overall Rate of Return, are determined according to the Guidelines of the Engineering Societies' Committee on Energy (ESCOE) (see Appendix E). Levelized product prices are also computed using again the annual ATCF. Cost per unit output figures are generated by analyzing the capital cost and adding them to the sum of Revenues and Expenses.

Equipment replacement can be handled by considering the tax effects of selling the old equipment below or above cash value in addition to the differences in Operating Costs. All dollar variables within the model structure can be escalated independently. This allows the user to consider different escalation rates for various components such as material or labor. The escalation rates can also be varied from year to year.

The Financial Model uses the Interactive Financial Planning System (IFPS) (see Appendix E References) which allows for interactive and

FIGURE II-5
STRUCTURE OF THE FINANCIAL MODEL



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flexible programming of corporate financial models. The main features of this system are the possibility of asking "What if" questions, performing different kinds of sensitivity analyses and breakeven analyses as well as the option to run Monte Carlo simulations for various types of probabilistic distributions. These features are each applied in the case study discussed in Section IV.

II.4 Environmental

An important aspect of the interfuel substitution project methodology is the relationship between industrial fuel use and regional air quality. Each fuel/technology case considered in this report has an associated air quality dimension. Air quality simulation models are used to describe and analyze this dimension.

The air quality simulation model used in this project is the Climatological Dispersion Model (CDM). CDM is a computer supported algorithm which translates stack emission and local meteorology into a distribution of ground level concentrations across a specified area. The individual components of CDM are described in detail in Appendix F.

CDM is one of a set of air quality models designated by the Environmental Protection Agency as "Guideline Models." When used appropriately, the EPA will recognize the results of such models in determining compliance with federal air pollution laws and regulations.

CDM simulates the long-term (seasonal or annual) concentrations at ground level receptors of one or several air pollution sources in a region. As explained in Appendix F, CDM (as does all current guideline models), assumes constant meteorology across the study area. This assumption imposes a limitation on the size of the area which can be considered in any one CDM computer run. No area should be larger than 50 km^2. CDM uses average emission rates from sources and a joint frequency function of wind direction, wind speed and atmospheric stability, for the same averaging period, as inputs.

III. CASE STUDY: Background

The methodologies developed under Phase I in the fuel substitution project have been brought together for a demonstration of their usefulness in a case study which will be discussed in this and Section IV of the report. The objectives in developing the case study were to apply the models modified and developed under Phase I by individual team members to a specific and well-defined problem.

Because a considerable amount of the effort in Phase I had gone into looking at methods for evaluating the potential for interfuel substitution in meeting the energy demands of large energy consuming facilities such as refining and petro-chemicals, the case study chosen was a large facility with a large, flat, low to medium pressure process steam load, characteristic of both chemicals and refining. Thermal loads and system configurations are described in detail in Section IV (e.g., Tables VI-1, IV-2). The case study involved an evaluation of the potential for steam raising by alternative fuels and steam raising with cogeneration by alternative fuels. Our primary interest was in evaluating alternatives that included "dirty" fuels such as coal and the potential for coking. Though consideration was given to generation of medium Btu gas from both coal and coke, the case study does not include its use for direct fired process heat.

The following alternatives to generate the required process steam are considered:

- coke-fired boiler
- coal-fired boiler

COGENERATION (STEAM TURBINES, TOPPING PROCESS, NO EXTRACTIONS)

- o steam turbine coal-fired configuration 1 (coal 1)
- o steam turbine coal-fired configuration 2 (coal 2)
- o steam turbine coal-fired configuration 3 (coal 3)
- o steam turbine oil-fired configuration 1 (oil 1)
- o steam turbine oil-fired configuration 2 (oil 2)
- o steam turbine oil-fired configuration 3 (oil 3)
- o gas turbine natural gas-fired (gas turbine)
- o coal gasification (gasifier)

The case study elements can be characterized as follows (for detailed description see IV.1, IV.2).

- o Boiler systems: Three identically sized boilers of 1/3 capacity each. Backup is provided by the existing system.
- o Steam turbines: Topping cycle systems. Auxiliary power is mostly provided by the electricity generated. Different steam turbine inlet conditions lead to the generation of different amounts of electricity while providing the same process steam load.
- o Coal 1: small electricity generation per unit process steam
- o Coal 3: large electricity generation per unit process steam
- o Oil 1: same configuration as coal 1 but oil fired
- o Oil 3: same configuration as coal 3 but oil fired
- o Gasifier: One Texaco gasifier is providing MBG for the existing boiler.

Three caveats concerning the structuring of case study follow. First, three boilers were installed, each of which could handle roughly one-third of the load. Backup is assumed to be provided by the existing system.

The second major point is that one high-technology option, a coal gasifier, was kept in the analysis throughout the case study. As will be seen later, the gasifier is not an economically attractive investment under the scenarios presented here. This would be intuitive given that the case study did not allow for the use of a coal or coal-derived energy source in process heating. When gasifiers compete against unprocessed coal, the unprocessed coal, and even oil and natural gas are more economic investments.

The final point is that the comparative economic evaluation is incremental rather than an absolute, i.e. all investment and operating costs have been calculated compared to an existing system. The decision is whether or not to replace this existing system. It has been assumed that the capital value of the current boiler in the facility is fully depreciated on the books though maintains an operating life. For this reason the base case is one in which the capital cost is entirely paid off and the operating costs are for an existing oil-fired option. Any changes, therefore, are viewed as net savings or losses to the system when compared with this base case. For this reason, the addition of a new oil-fired boiler will add considerably to the capital costs and have only minimal savings in fuel. By the same token, addition of coal boilers will have a far more significant increase in capital cost but an associated decrease in fuel cost. Finally, as will be seen, it is not possible to pay off the capitalization of an investment such as a gasifier given the characteristics of this case study. From the perspective of the facility owner, then, the question is one of whether it is cost-effective to invest in new plants and facilities or whether it is more worthwhile to stay with the existing plant. A positive net present value indicates that, over the planning horizon, it is to the advantage of the manager to invest in the new plant. A negative net present value means that it is disadvantageous to invest in the new plant.

IV. CASE STUDY RESULTS

The section which follows presents the results of both a set of background analyses on the thermodynamics of boiler and cogeneration systems in general and the results when applied to the specific system chosen for a case study. At the outset it should be emphasized that the industrial load chosen for the case sudy was tightly defined and therefore not characteristic of all industrial loads. The load is large, relatively flat and has a high capacity factor. The experience of this effort as well as the experience of others would lead one to conclude a priori that such a system would favor any technology able to capture any economies of scale and would favor technologies with relatively higher capital costs and relatively lower operating costs. In fact these were the conclusions of the case study. It is important in this section to note, however, the additional conclusions which are reached concerning the relatively thermodynamic/economic properties of cogeneration systems relative to steam boilers and within cogeneration systems the relative importance of capital, operating and electrical buyback values to the overall economics of the decisions.

Because of the importance of the cogeneration analysis relative to the conclusions drawn from the case study, this section begins with a review of the main conclusions from Appendix B concerning cogeneration and steam raising. The subsequent portions of the chapter evaluate in detail the economic decisions surrounding cogeneration, the comparison of all of the interfuel substitution options evaluated including the gasifier, and a series of sensitivity studies on the results of the incremental analyses. The final portion of this section discusses the results of a trade-off between capital investment in emission controls and air qualiy which links together two of the modeling systems developed in the length of the research effort.

IV.1 Interfuel Substitution: Overview

The material which follows presents a set of conclusions concerning the thermodynamic/economic trade-offs between alternatives of the technologies under consideration in the case study. These focus first on the cogeneration technologies and then on the simple steam raising technologies. These conclusions follow directly from the detailed discussions presented in Appendix B.

In Appendix B it has been shown that any economic incremental analysis of steam turbine cogeneration systems

- supplying a flat thermal load of 1,000 10^6 BTU/hr as saturated steam at 200 psia with a load factor of 0.9
- on any typical industrial plant with any reasonable standard boiler system
- for any reasonable cogeneration system configuration
- on any realistic industrial financial environment
- with constant 1980 dollars typical fuel costs

will show that

1. Coal-fired systems are substantially more economical than oil-fired systems.
2. Coal-fired cogeneration is more economical than coal-fired boilers, if electricity is valued at current busbar generation costs of coal-fired central power plants
3. Oil-fired cogeneration is more economical than oil-fired boilers if electricity is valued at current busbar generation costs of

oil-fired central power plants.

4. Coal cogeneration is more economical compared to coal-fired boilers than is oil cogeneration is compared to oil-fired boilers.
5. Coal-fired cogenerated electric power has a busbar generation cost lower than oil-fired cogenerated electric power.
6. Oil-fired cogeneration economic advantages with respect to oil-fired boilers is not sufficient to lower steam generation cost to that of coal-fired boilers unless electricity is priced at an unreasonably high value.
7. In any fuel scenario in which the cost of oil increases, more rapidly than the cost of coal. All previous conclusions still hold.

IV.2 Interfuel Substitution: Steam Raising

The thermal load considered in the case study has a 200 psia saturated steam requirement of 23.2 lbm/CD with a constant load factor of 0.9. Low-pressure boiler data (boilers inlet/outlet, mass and heat flows) is presented in Table IV-1; steam and gas turbine systems are presented in Table IV-2.

Steam Turbine Cogeneration Systems

Three steam turbine systems are considered (system configuration 1, 2 and 3) each with a different turbine inlet condition, i.e., low, medium, and high (utility type) pressure. Each of the systems has been conceptually designed taking into consideration all standard requirements of systems of that size and with those characteristics. The main design

TABLE IV-1

LOW-PRESSURE BOILERS

(no cogeneration)

Boilers outlet: 200 psia, 500°F; enthalpy, 1,269 BTU/lbm

Boilers inlet: 200 psia, 250°F; enthalpy, 219 BTU/lbm

Mass Flow Rates:

Steam to process: $1.07 \cdot 10^6$ lbm/hr

Heat Flow Rates: Load Factor: 0.9

	[10^6 BTU/hr]	[10^{12} BTU/yr]
Heat to process water:	1,127	8.89
Net heat delivered to process:	981	7.74
Fuel requirement (Boiler efficiency: 0.85):	1,326	10.46

TABLE IV-2

HIGH-PRESSURE BOILERS

(steam turbines cogeneration)

Boilers outlet:	varies with system design
Boilers inlet:	same as low-pressure boiler
Steam turbine inlet:	varies with system design
Steam turbine outlet:	at process pressure, slightly superheated depending on system design

Mass Flow Rates:

Vary with system design

Heat Flow Rates:

Vary with system design except Net heat delivered to process:	$981 \cdot 10^6$ BTU/hr	$7.74 \cdot 10^{12}$ BTU/yr

GAS TURBINES

Net heat delivered to process:	$981 \cdot 10^6$ BTU/hr	7.74×10^{12} BTU/yr

difference between systems 1, 2 and 3 is the steam enthalpy at turbine inlet; thermodynamic differences are expressed through different efficiencies of conversion and electric power installed while economic differences are mainly due to larger boiler and steam turbine sizes and, consequently, larger capital cost. The description of each of the systems (on a per million BTU/hr saturated steam effectively delivered to process) is presented in Table IV-3.

As discussed in Appendix B, system capital costs have been computed for the medium-pressure steam turbine cogeneration system. They have been grouped into thermal and electric generation costs and scaled up and down to the high- and low-pressure systems using economy of scale factors (typical for those plants) of 0.35 for steam turbine/electric generation equipment, of 0.25 for coal-fired thermal generation equipment, and of 0.1 for oil-fired thermal generation equipment. An uncertainty factor of approximately 20 percent should probably be applied whenever those prespecified plant costs are used in a specific case without detailed knowledge of the industrial plant characteristics.

Operation and maintenance costs have been taken into account in the same way although with no economy of scale in O and M.

A breakdown of capital and O and M costs for the low-, medium- and high-pressure steam turbine cogeneration systems defined in the previous section is presented in Table IV-4.

System Economic Performance

Cogeneration may be considered a marginal investment compared with a traditional boiler system fired with the same fuel. This defines the 'electricity-as-a-byproduct' power plant capital, O and M and fuel costs

TABLE IV-3

COGENERATION CYCLE THERMODYNAMICS

Nomenclature:

Heat delivered to process, $\dot{Q}_p$:	$\dot{Q}_p = 10^6$ BTU/hr
Fuel requirement per $\dot{Q}_p$:	$\dot{F}$
Electric power installed:	$\dot{W}_e$
Electric power for in-house auxiliaries:	$\dot{W}_{aux}$
Net electric power:	$\dot{W}_{net}$
Mass flow rate:	$\dot{m}$
Turbine efficiency, η_t:	$\eta_t = 0.90$
Boilers efficiency, η_b:	$\eta_b = 0.85$
"Thermal" efficiency, η_{th}:	$\eta_{th} = \dot{Q}_p/\dot{F}$
"Electric" efficiency, η_e:	$\eta_e = \dot{W}_e/\dot{F}$
Cycle efficiency, η_c:	$\eta_c = \dfrac{\dot{W}_{net} + \dot{Q}_p}{\dot{F}}$

Turbine inlet	650 psia 800°F	1,200 psia 900°F	2,500 psia 1,000°F
$\dot{W}_e$ [KW_e]	35	54	76
$\dot{W}_{aux}$ [KW_e]	13	14	16
$\dot{W}_{net}$ [KW_e]	22	40	60
η_{th}	0.67	0.63	0.59
η_e	0.08	0.12	0.15
η_c	0.75	0.75	0.75
$\dot{m}$ [lbm/hr]	1,060	1,110	1,170

TABLE IV-3 (cont.)

CASE STUDY

$\dot{W}_e$ [MWe]	34.3	53.0	74.6
$\dot{W}_{net}$ [MWe]	21.6	39.2	58.9
Total electricity generated [10^6 KWhre/yr]	271	418	588
Net electricity available [10^6 KWhre/yr]	171	313	471
$\dot{F}$ [10^6 BTU/hr]	1,461	1,548	1,654
$\dot{F}$ [10^{12} BTU/yr]	11.60	12.22	13.05

TABLE IV-4

COGENERATION SYSTEMS CAPITAL AND O AND M COSTS

1980 $

Steam Turbine Inlet at		650 psia 800°F	1,200 psia 900°F	2,500 psia 1,000°F
steam turbine/ electric generation capital costs	[$/KWe]	319	274	243
	[10^6 $]	10.95	14.5	18.1
Coal-fired thermal generation capital costs	[$/$10^6$BTU/hr]	55,450	54,700	53,800
	[10^6 $]	81.5	84.8	89.1
Oil-fired thermal generation capital costs	[$/$10^6$BTU/hr]	21,300	21,200	21,100
	[10^6 $]	31.4	32.9	34.9
Electric generation O and M costs	[mills/KWhre]	4	4	4
	[10^6 $/yr]	1.1	1.7	2.35
Coal-fired thermal generation O and M costs	[$/$10^6$BTU steam]	1	1	1
	[10^6 $/yr]	9.9	10.4	11.0
Oil-fired thermal generation O and M costs	[$/$10^6$BTU steam]	.25	.25	.25
	[10^6 $/yr]	2.5	2.6	2.8
Coal-fired cogeneration system total capital cost	[10^6 $]	92.5	99	107
Oil-fired cogeneration system total capital cost	[10^6 $]	42	47	53
Coal-fired cogeneration system total O and M cost	[10^6 $/yr]	11	12	13
Oil-fired cogeneration system total O and M cost	[10^6 $/yr]	3.5	4.5	5

which allow for standard power plant economic evaluation. If it is worthwhile to install the cogeneration power plant, then cogeneration steam raising will be viable.

Two factors are considered to evaluate electricity generation costs: the busbar generation cost and the busbar generation cost structure. Both will be computed for the cogeneration power plant, initially by discounting cash flows at the real interest rate for equity (15 percent in this case).

Finally, the case of excess of revenues, i.e., profits from cogenerated electricity will be computed, under different fuel scenarios using the analytical, closed-form relationship between operating cash flow and return on debt and equity tax-sheltered capital described in Appendix B, Section B.4.

A breakdown of coal-fired cogeneration system and coal-fired standard boiler system costs as well as the busbar cogenerated electricity incremental cost and cost structure is presented on Table IV-5. Only net electricity available will be considered as a cogeneration system product; full installed power is considered for capital cost computation.

From Table IV-5 it may be seen that

1. The electricity as a byproduct, coal-fired cogeneration power plant is very similar to a coal-fired central power plant in terms of its fixed and variable incremental cost components of cogenerated electricity (See Appendix B).
2. The capital cost per KWe of installed capacity of the coal-fired cogeneration power plant as previously defined is close to one-half of the correspondent cost for coal central power plants.
3. The fuel cost of the coal-fired cogeneration power plant is

TABLE IV-5

HIGH PRESSURE STEAM TURBINE COAL-FIRED COGENERATION SYSTEM

1980 \$

Costs Breakdown

	Cogeneration System	Boiler System	Δ Costs
Capital [\$]	$107 \cdot 10^6$	$70 \cdot 10^6$	$37 \cdot 10^6$
[\$/yr]			$5.55 \cdot 10^6$
O and M [\$/yr]	$13.4 \cdot 10^6$	$8.6 \cdot 10^6$	$4.8 \cdot 10^6$
Fuel [BTU/yr]	$13.05 \cdot 10^{12}$	$10.5 \cdot 10^{12}$	$2.6 \cdot 10^{12}$
(2.50 \$/10^6 BTU) [\$/yr]			$5.5 \cdot 10^6$

BUSBAR COGENERATED ELECTRICITY INCREMENTAL COST AND COST STRUCTURE

Power installed	74.6 MWe	
Net electricity	$471 \cdot 10^6$ KWhre/yr	
Load factor	0.9	
Capital cost	11.5 mills/KWhre	33 percent
O and M cost	9.4 mills/KWhre	28 percent
Fuel cost	13.2 mills/KWhre	39 percent
Total cost, e_c^{HP}	34.1 mills/KWhre	100 percent

$$e_c^{HP} = \frac{10.3}{L} + 22.6 \text{ mills/KWhre}$$

Installed electric power incremental capital cost 500 \$/KWe approximately one half of the correspondent fuel cost on a coal-fired central power plant.

The analysis of the behavior of the coal cogeneration system economics with respect to the rate at which electricity is priced by the market (either utility buyback rate or effective cost of in-house generation by non-cogeneration technologies) follows.

The profits from cogenerated electricity, i.e., the net income (or after-tax revenue) coming from pricing (or selling) cogenerated electricity at a price greater than the busbar generation cost as previously defined, can be readily computed as indicated in Section IV.2.3.4. Tax credits are entirely taken the year of the capital expenditure; capital expenditure is 20 percent of total capital expenditure at the end of the first year of construction, 40 percent at the end of the second year; 40 percent at the end of the third year, the system is then put on line for the next seventeen years during which period it is totally linearly depreciated and at the end of which period it has a zero salvage value.

Fuel costs are assumed to be the same for the industry as for the utility. Fuel availability, major transportation costs, etc. discussion is performed in other sections of this study. The economic analysis of the coal-fired, high-pressure coal cogeneration plant, always as an incremental investment with respect to a similarly fired standard boiler system follows, first on a constant (in 1980 dollars) fuel cost scenario (Table IV-6) then on a fuel cost real increase scenario (Table IV-7), and for various values assigned to the cogenerated electricity.

TABLE IV-6

COAL-FIRED COGENERATION SYSTEM ECONOMIC PERFORMANCE

REAL CONSTANT FUEL COST AND ELECTRICITY VALUE SCENARIO

1980 $

		Electricity Value
fuel cost	2.5 $/$10^6$ BTU	
Δ capital, present worth	23.5 . 10^6 $	
Δ (Fuel + O and M), present worth	78 . 10^6 $	
Δ SL Depreciation, present worth	15 . 10^6 $	
	82 . 10^6 $	(25 mills/KWhre)
Electricity revenue, present worth	164 . 10^6 $	(50 mills/KWhre)
	246 . 10^6 $	(75 mills/KWhre)
	-14 . 10^6 $	(25 mills/KWhre)
NET PROFIT, PRESENT WORTH	27 . 10^6 $	(50 mills/KWhre)
	68 . 10^6 $	(75 mills/KWhre)

TABLE IV-7

COAL-FIRED COGENERATION SYSTEM ECONOMIC PERFORMANCE

REAL INCREASING FUEL COST AND ELECTRICITY VALUE SCENARIO

1980 \$

Coal initial cost	2.50 \$/10^6BTU	
Coal cost rate of increase	2 percent/yr	
Electricity initial value	25, 50, 75 mills/KWhre	
Electricity value rate of increase	3 percent/yr	
Coal levelized cost	3 \$/10^6 BTU	
Electricity levelized value	34, 67, 101 mills/KWhre	
		Initial Electricity Value
Δ capital, present worth	23.5 . 10^6 \$	
Δ (Fuel + O and M), present worth	85 . 10^6 \$	
Δ SL Depreciation, present worth	15 . 10^6 \$	
	113 . 10^6 \$	(25 mills/KWhre)
Electricity revenue, present worth	225 . 10^6 \$	(50 mills/KWhre)
	337 . 10^6 \$	(75 mills/KWhre)
	-2 . 10^6 \$	(25 mills/KWhre)
NET PROFIT, PRESENT WORTH	54 . 10^6 \$	(50 mills/KWhre)
	110 . 10^6 \$	(75 mills/KWhre)

TABLE IV-8

HIGH PRESSURE STEAM TURBINE OIL-FIRED COGENERATION SYSTEM

1980 $

Costs Breakdown

	Cogeneration System	Boiler System	Δ Costs
Capital [$]	$53 \cdot 10^6$	$25 \cdot 10^6$	$28 \cdot 10^6$
[$/yr]			$4.2 \cdot 10^6$
O and M [$/yr]	$5 \cdot 10^6$	$2.1 \cdot 10^6$	$2.9 \cdot 10^6$
Fuel [BTU/yr]	13.05×10^{12}	$10.5 \cdot 10^{12}$	$2.6 \cdot 10^{12}$
(at 6.17 $/$10^6$ BTU) [$/yr]			$16 \cdot 10^6$

BUSBAR COGENERATED ELECTRICITY INCREMENTAL COST AND COST STRUCTURE

Power Installed	74.6 MW_e	
Net Electricity	$471 \cdot 10^6$ $KWhr_e$/yr	
Load factor	0.9	
Capital Cost	9 mills/$KWhr_e$	19 percent
O and M Cost	5.6 mills/$KWhr_e$	12 percent
Fuel Cost	32.7 mills/$KWhr_e$	69 percent
Total cost e_o^{HP}	47.3 mills/$KWhr_e$	100 percent

$e_o^{HP} = 8.1/L + 38.3$ [mills/$KWhr_e$]

Installed electric power incremental capital cost 370 $/$KW_e$

Total Cost, with standard boiler system fully written off 55 mills/$KWhr_e$

Installed electric power incremental capital cost with standard boiler system fully written off 710 $/$KW_e$

Oil Fired Cogeneration

A breakdown of oil-fired cogeneration system and oil-fired standard boiler system costs as well as the busbar cogenerated electricity incremental cost and cost structure is presented in Table IV-8. Again, only net electricity available will be considered as a cogeneration system product; full installed electric power is taken into consideration for capital cost computation.

From Table IV-8 it may be seen that

1. The electricity as a by-product oil-fired cogeneration power plant is similar to some medium load oil-fired central power plants in terms of its fixed and variable incremental cost components relative weight in the total busbar generation cost.
2. The capital cost per KW_e of installed capacity of the cogeneration power plant as previously defined is close to one half of the correspondent cost for medium load central power plants.
3. The fuel cost of the oil-fired cogeneration power plant is approximately one half of the correspondent fuel cost on an oil-fired central power plant.

The analysis of the behavior of the oil cogeneration system economics with respect to the rate at which electricity is priced by the market (either utility buyback rate or effective cost of in-house generation by non-cogeneration technologies) follows. However, it may be immediately seen from equation 2 of Section IV.2.3.4 that the oil cogeneration system economics behavior with respect to electricity price is identical to the one obtained for coal cogeneration system, the present worth of the cogeneration system being, ceteris paribus, a linear function of the revenues from electricity.

Under the same conditions stated on the previous section on coal cogeneration systems the economic analysis of the oil-fired, high-pressure oil cogeneration power plant, as an incremental investment with respect to a similarly fired standard boiler system (both for a newly installed and for a fully depreciated standard boiler system) follows, first on a constant (1980 dollars) fuel cost scenario (Table IV-9) then on a fuel cost real increase scenario (Table IV-10), and for various values assigned to the cogenerated electricity.

Standard Boiler Systems

In the previous sub-section the cogeneration power plants have been analyzed also by comparing them to similarly fired standard boiler systems. In order to have a complete picture of steam raising by cogeneration systems, all of the conclusions drawn on coal fired and oil fired systems (cogeneration or not) should be evaluated one set relative to another: this may be accomplished by perfoming an economic analysis of the standard boiler system, coal-fired with a standard boiler system, oil-fired. This economic analysis, whose results are presented in Table IV-11 in the form of an incremental analysis will determine the relative position of coal-fired and oil-fired systems and consequently will complete the picture of steam raising alternatives furnished in this work.

Conclusions on Steam Turbine Cogeneration

The system economic analysis performed substantially verifies all the conclusions reported in Section IV-1 and the more general findings of Appendix B given our case study load.

Table IV-9

OIL-FIRED COGENERATION SYSTEM ECONOMIC PERFORMANCE

REAL CONSTANT FUEL COST AND ELECTRICITY VALUE SCENARIO

1980 $

	New Standard Boiler	Fully Depreciated Standard Boiler	Electricity Value
Fuel cost: 6.17 $/$10^6$ BTU			
Δ capital, present worth [$]	$19 \cdot 10^6$	$36 \cdot 10^6$	
Δ (Fuel + O and M), present worth [$]	$131 \cdot 10^6$	$131 \cdot 10^6$	
Δ Sl Depreciation, present worth [$]	$12 \cdot 10^6$	$22 \cdot 10^6$	
	$82 \cdot 10^6$	$82 \cdot 10^6$	(25 mills/$KWhr_e$)
Electricity Revenue, present worth [$]	$164 \cdot 10^6$	$164 \cdot 10^6$	(50 mills/$KWhr_e$)
	$246 \cdot 10^6$	$246 \cdot 10^6$	(75 mills/$KWhr_e$)
	$-37 \cdot 10^6$	$-49.5 \cdot 10^6$	(25 mills/$KWhr_e$)
NET PROFIT, PRESENT WORTH	$3.5 \cdot 10^6$	$-8.5 \cdot 10^6$	(50 mills/$KWhr_e$)
	$44.5 \cdot 10^6$	$32.5 \cdot 10^6$	(75 mills/$KWhr_e$)

TABLE IV-10

OIL-FIRED COGENERATION SYSTEM ECONOMIC PERFORMANCE

REAL INCREASING FUEL COST AND ELECTRICITY VALUE SCENARIO

1980 $

Oil initial cost	6.17 $/$10^6$ BTU
Oil cost rate of increase	3 percent/yr
Electricity initial value	25, 50, 75 mills/$KWhr_e$
Electricity value rate of increase	3 percent/yr
Oil levelized cost	8.3 $/$10^6$ BTU
Electricity levelized value	34, 67, 101 mills/$KWhr_e$

	New Standard Boiler	Fully Depreciated Standard Boiler	Initial Electricity Value
Δ Capital, present worth [$]	$19 \cdot 10^6$	$36 \cdot 10^6$	
Δ (Fuel + O and M), present worth [$]	$157 \cdot 10^6$	$157 \cdot 10^6$	
Δ SL Depreciation, present worth [$]	$12 \cdot 10^6$	$22 \cdot 10^6$	
	$113 \cdot 10^6$	$113 \cdot 10^6$	(25 mills/$KWhr_e$)
Electricity revenue, present worth [$]	$225 \cdot 10^6$	$225 \cdot 10^6$	(50 mills/$KWhr_e$)
	$337 \cdot 10^6$	$337 \cdot 10^6$	(75 mills/$KWhr_e$)
	$-35 \cdot 10^6$	$-47 \cdot 10^6$	(25 mills/$kwhr_e$)
NET PROFIT, PRESENT WORTH [$]	$21 \cdot 10^6$	$9 \cdot 10^6$	(50 mills/$KWhr_e$)
	$77 \cdot 10^6$	$65 \cdot 10^6$	(75 mills/$KWhr_e$)

TABLE IV-11

OIL-FIRED AND COAL-FIRED STANDARD BOILER SYSTEMS ECONOMIC PERFORMANCE

REAL CONSTANT FUEL COST SCENARIO

1980 $

	Coal Boiler	Oil Boiler	Δ Costs
Capital [$]	$72 \cdot 10^6$	$25 \cdot 10^6$	$45 \cdot 10^6$
O and M [$]	8.6	2.1	$6.5 \cdot 10^6$
Fuel [Btu/yr]	$10.5 \cdot 10^{12}$	$10.5 \cdot 10^{12}$	zero
(2.50 $/$10^6$ BTU) [$/yr]	$26.15 \cdot 10^6$		$-38.4 \cdot 10^6$
(6.17 $/$10^6$ BTU) [$/yr]		$64.5 \cdot 10^6$	

Incremental Analysis: Coal With Respect To Oil

	New Oil Boiler System	Fully Depreciated Oil Boiler System
Δ Capital, present worth [$]	$31 \cdot 10^6$	47.10^6
Δ (Fuel + O and M), present worth [$]	$-224 \cdot 10^6$	$-224 \cdot 10^6$
Δ SL Depreciation, present worth [$]	$19 \cdot 10^6$	$29 \cdot 10^6$
Revenue, present worth [$]	zero	zero
NET PROFIT, PRESENT WORTH	$90.5 \cdot 10^6$	$79.5 \cdot 10^6$

The thermodynamic performance of the steam turbine cogeneration systems follows:

1. Cogeneration systems installed electric capacity may vary anwhere from 30 to 70 KWe for 10^6 BTU/hr to process as 200 psia saturated steam, by varying mainly the inlet conditions to the steam turbines.

2. The first law efficiency of the cycle is
   - 0.75
   - independent of system configuration
   - dependent on the cogeneration system components efficiency, except that of steam turbine efficiency

3. The (incremental) heat rate of cogenerated electricity is close to one-half of the heat rate achieved in central power plants.

The incremental heat rate as computed here is <u>not</u> a thermodynamic parameter of the cycle, in as much as it is dependent on the standard boiler system on which the incremental analysis is performed.

It should be emphasized that cogeneration systems generally are less efficient (due to higher steam outlet pressure imposed by process requirements and the correspondent decrease in thermodynamic cycle efficiency) and consequently more expensive means of electricity generation than central power plants. The only reason why they look so appealing under the thermodynamic analysis presented here is that in an "incremental" thermodynamic analysis it is assumed that the heat normally delivered by the cycle to the low-temperature reservoir is instead delivered as useful heat to process. Only incremental fuel consumption is charged against electricity cogeneration. This largely offsets the theoretical steam rate increase in cogeneration systems due to higher steam turbines outlet pressure and allows steam turbine cogeneration systems to transform into electricity up to 80 percent of the (incremental) fuel rate. This also explains why the thermodynamic first law efficiency as previously defined is independent of turbine efficiency (generally, a particularly important parameter) and dependent on all other components efficiency. Whatever steam energy is not converted into shaft work by the turbine is delivered as (useful) heat to process. As shown in Appendix B, using the second law of thermodynamics, this fact may be properly taken into account and different system configurations may be evaluated.

Thermodynamic performance influences therefore the system viability more than any other factor. The cost structure and cost figure fully characterize the economic behavior of the system and allow, for instance, a proper evaluation of system response to changes in fuel scenarios. Interestingly, most of the thermodynamic considerations here made do not generally appear on cogeneration studies and the only figure generally quoted as a technology characteristic of cogeneration systems, the electric power installed per 10^6 BTU/hr of heat delivered to process, is here shown to be a design parameter.

IV.3 Case Study Economic Evaluation

The economic evaution of this case study is also performed as an incremental investment analysis following Appendix E criteria. The existing steam generating equipment (oil boiler) is compared with a set of fuel substitution alternatives using coal, coke or natural gas or introducing cogeneration.

From the decision maker's viewpoint the question is, if it is worth investing money in one of the suggested options or if he should go ahead using the old system.

In a first step the profitability of all alternatives is computed in form of the NPV after 20 years. A sensitivity analysis and a market analysis for the key variables is performed for some of the most promising alternatives. Then different fuel price scenarios are assumed and the profitability of all options calculated for each of the scenarios.

The Financial Model calculates a set of evaluation criteria (see Appendix E). The comparison used in the case study is based on net present value (NPV) because the internal rate of return may be misleading. The input data--mainly capital, operating costs, fuel consumption and electricity generation--are listed in Table IV-11. It is assumed that the old steam raising equipment in this facility is already written off for tax purposes. The model otherwise would consider the differnce in depreciation between old and new equipment as well as tax effects which eventually result in the selling of old equipment.

The assumptions made for the analysis are the following:

- All dollar values are expressed in constant 1980 dollars
- Project life: 20 years -- 3 years construction, 17 years operation
- Tax life: 16 years
- Depreciation: straight line method
- Salvage value: book value
- Investment tax credit: 10 percent
- Energy Tax Credit: 10 percent
- Rate of debt financing: 60 percent
- Maturity: 20 years

Table IV-11

CASE STUDY, INPUT DATA IN $1980

	Capital	Operating	Fuel Req. 10^6 BTU	Fuel Cost	Elec. Gen.	Elec. Rev.
Coal boiler	70	8.6	9.7	-	-	-
Coke boiler	70	8.6	9.7	-	-	-
Cogeneration						
Coal 1	92.5	11.0	11.6	29.0	171	8.6
Coal 3	107	12.0	13.1	32.6	471	23.6
Oil 1	42	3.5	11.6	71.6	171	6.6
Oil 3	53	5	13.1	80.5	471	23.6
Gas turbine	67.8	10.0	20.1	373.7	1504	75.2
Gasifier	240.0	15.3	18.1	45.3	113.2	-
Old oil boiler	written off	2.1	9.7	79.5		

- Grace period: 3 years
- Interest on debt: 8 percent
- Discount rate: 15 percent
- Buyback rate/electricity value: 5 cents/$KWhr_e$
- Capital spread over the three years of construction: 20 percent, 40 percent, 40 percent.

The fuel price scenarios are:

- o Fuel Price Scenario 1: (For 1985 in 1980 dollars)

  Coal price: 2.50 $/MBTU

  Coke price: 2.67 $/MBTU

  Gas price: 5.60 $/MBTU

  Oil price: 6.17 $/MBTU

- o Fuel Price Scenario 2:

  Based on the prices in Scenario 1 starting in 1985 a real price increase with the following annual rate is assumed.

  Coal: 2 percent

  Coke: 2 percent

  Gas: 4 percent

  Oil: 3 percent

  Buyback rate: 3 percent.

Financial Model Results

The results of the economic analysis with the base set of assumptions are presented in Figure IV-1. In this incremental analysis the zero line represents the decision not to change from the use of the existing, oil burning equipment currently used to serve the load. Any value greater than the zero line represents an investment with a positive net present value (or an internal rate of return greater than 15 percent). Any value below the line shows a negative net present value. The x axis on Figure IV-1 represents the buyback rate for electrical power cogenerated by the 5 cogeneration options.

The results presented in Figure IV-1 need be seen in light of the discussions of IV.2 and in light of the description of the case study in Section III. As was stated the case will generally favor high capital low operating cost options . The one instance where this is not true is in terms of the gasifier system. The case study is not an ideal environment for the gasifier also because the systems called for boiler fuel not for direct firing. Under these circumstances a gasifier (a potential clean fuel supplier) is being competed against straight coal combustion (a dirty fuel). Under these circumstances the straight combustion will always appear more economic.

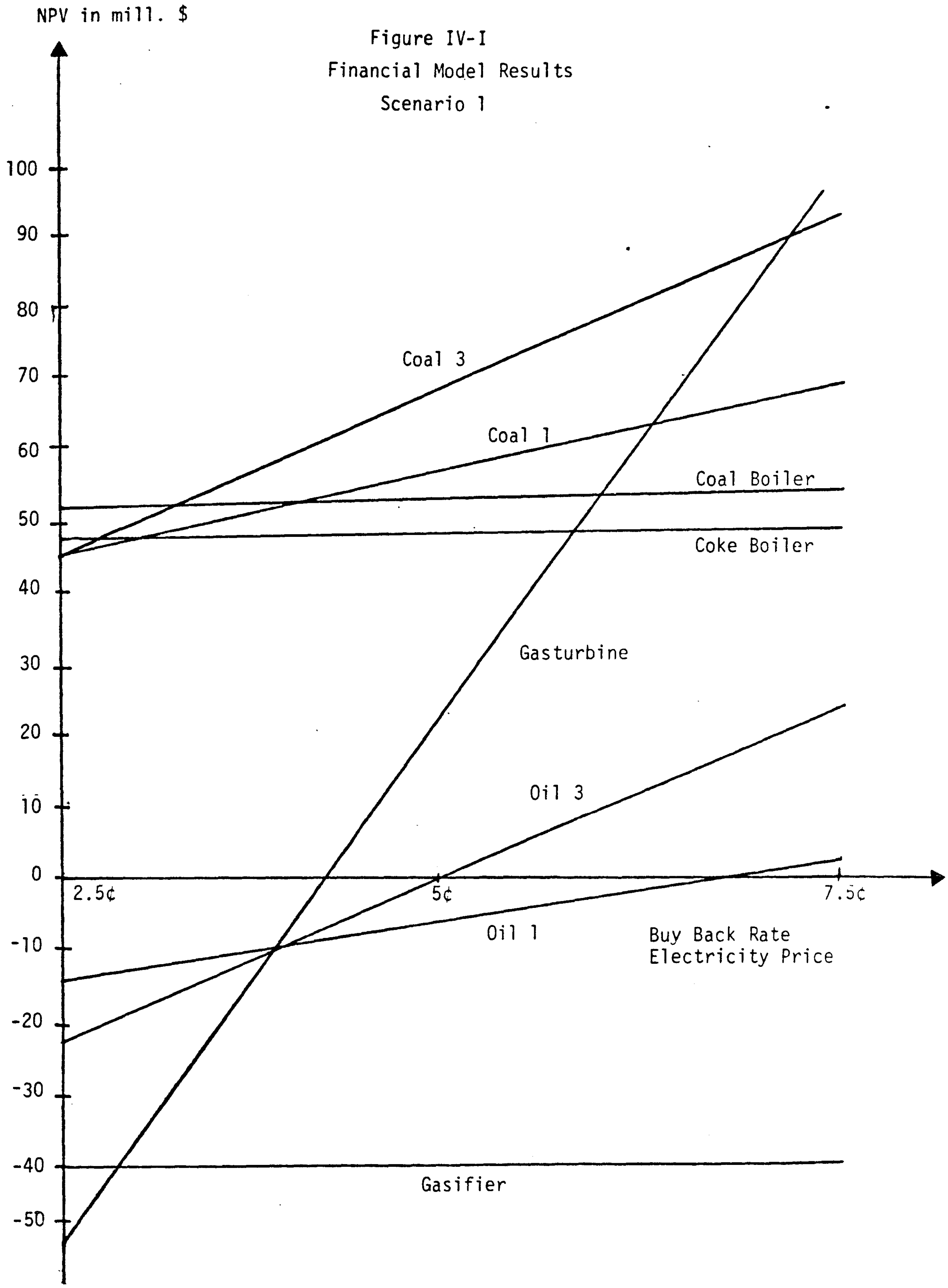
The other results from Figure IV-1 are also relatively intuitive. Given increasing buyback rates for electricity the systems with the greatest electrical to thermal output (e.g. steam turbine system 3) are those with the greater NPV at higher buyback rates (the NPV is linear to buyback rate in this incremental analysis--see section IV-1). This especially favors gasturbine systems at high buyback rates.

The final point to note may be the most significant from the perspective of the analysis and that is that for this case study the coal system is always superior to the oil system. With a decrease in capacity factor (or in size) this need no longer be the case.

Sensitivity Analyses

From the previous discussion it is possible to see, in terms of net

Figure IV-I
Financial Model Results
Scenario 1



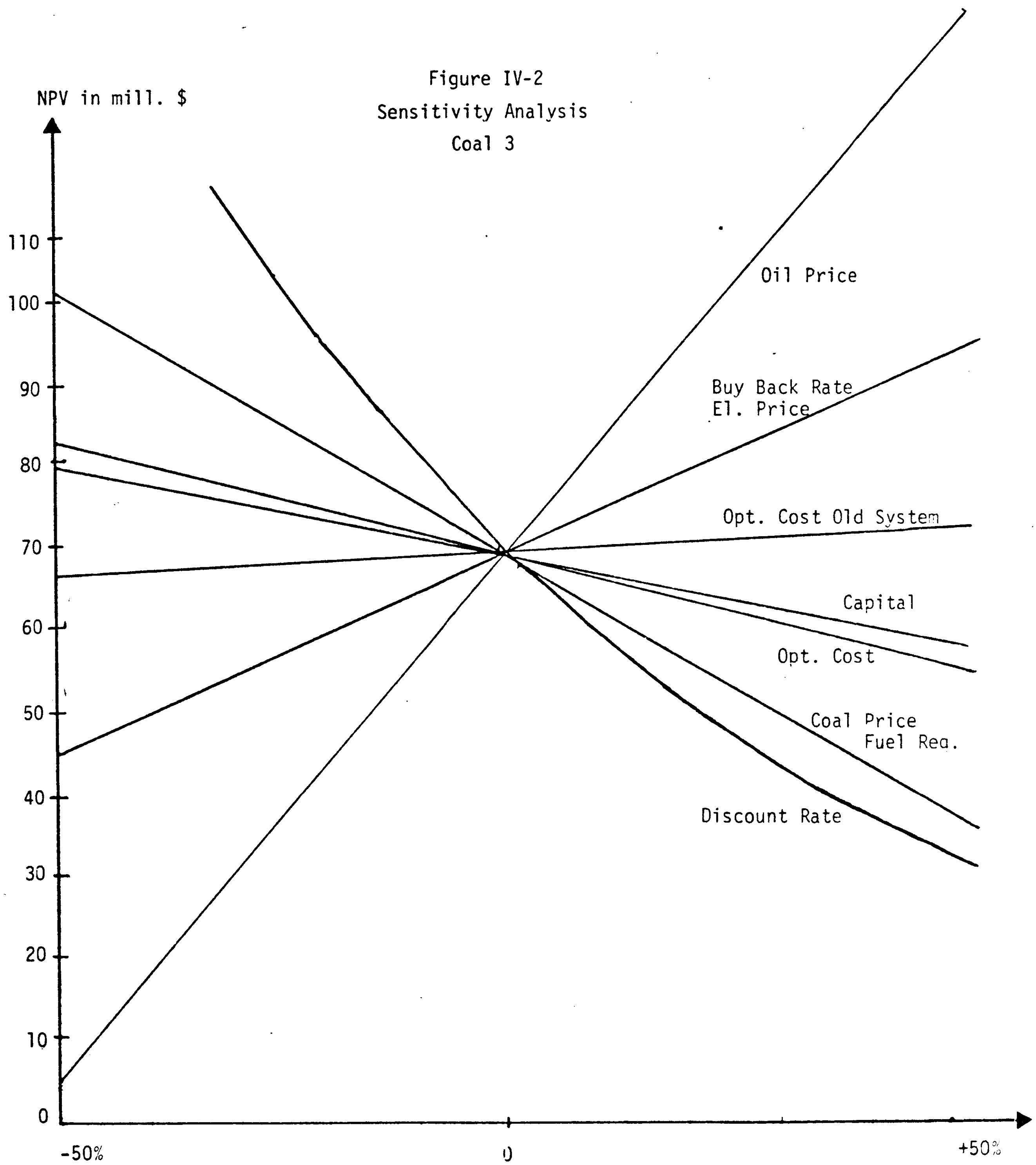
present value, that the "best case" is the coal-fired cogeneration system, option 3. To evaluate this option further and to test the flexibility of the modeling tools we utilized three types of sensitivity analysis. The first we have called parametric analysis. In this example we have evaluated the change in the NPV given a fixed percentage change in the independent or exogenous variables. This method offers a means of quickly evaluating the relative impacts of variable changes not taking into consideration the likelihood of the change, i.e., a change in fuel prices of 50 percent is likely but this is highly unlikely for capital costs.

The second type of sensitivity analysis used is referred to as scenario analysis. In this instance we examined through trade-off analyses the likely impact on the dependent variable of changes in a set of exogenous variables based on the research team's estimate of likely covariance. The third and final type of sensitivity analysis carried out utilized Monte Carlo Simulation to evaluate the probability distribution of likely outcomes as a function of the probability of specific variation in individual of the exogenous variables.

Parametric Analysis

We have carried out a set of sensitivity analyses in which the base case was systematically perturbed one variable at a time to measure its impact on the expected NPV. Figure IV-2 presents the results of that systematic analysis in a graphical form in which the variables have been subjected to range variation equal to + or - 50 percent of their value in the base case. The significance of this type of presentation is an ability to see the slope of the variation of path for the individual variables bearing in mind that the magnitude of the variation has been

Figure IV-2
Sensitivity Analysis
Coal 3



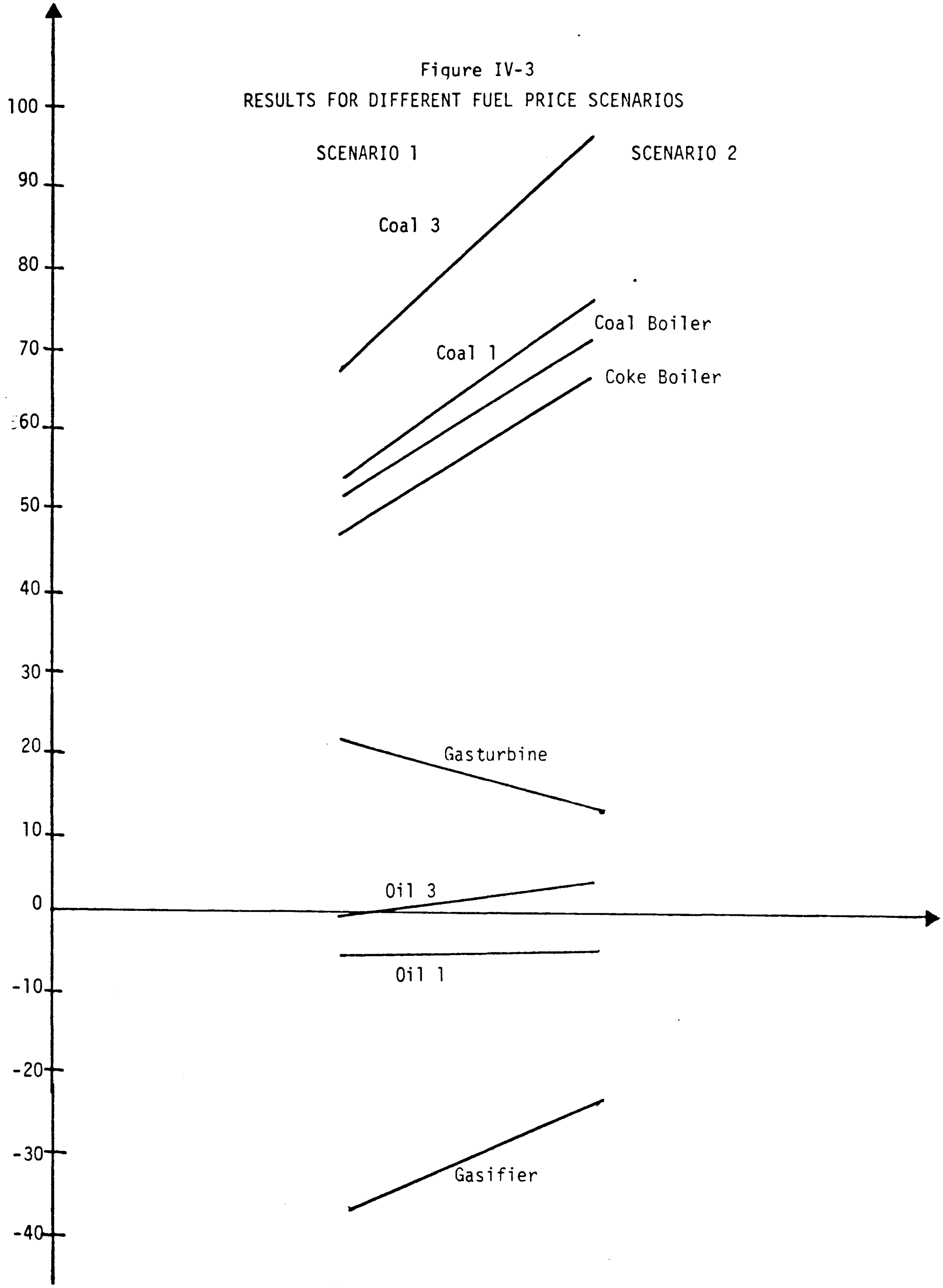
chosen arbitrarily (50 percent). For some of the variables investigated this is a reasonable range over which to evaluate the uncertainty. An example would be oil prices which could exceed the 50 percent increase on the postive side. Such variables as capital costs are unlikely to vary by 50 percent, certainly not to the minus side.

Given these caveats, Figure IV-2 presents a picture on the actual sensitivity of the decision variable, NPV to change in a set of exogenous variables. It is not surprising that it is to both the oil price and price paid for electrical energy that the NPV is the most sensitive. As with all such analyses, significant variation in the discount rate has a major influence on the profitability of the investment. This should, however, be seen for what it is, an internally consistent financial parmaeter which relates the importance of the trade-off between capital and operating expenditures. The case study facility requires heavy front end expenditures in capital with relatively lower operating costs. This when compared to the existing system which is dominated by operating costs, will assure you of increased NPV with decreasing discount rate.

Scenario Analysis

Figure IV-3 presents the results of evaluation of two of the fuel price scenarios compared across the eight technology options. The fuel scenarios were, in summary, first that prices will remain constant and the second that prices will increase (2 percent for coal, 3 percent for oil, 4 percent for gas and 3 percent overall for electricity). The sensitivity of the results is again a confirmation of the intuition of the research team. Those alternatives which move away from oil toward coal appear to be the most improved by the change in scenario. As one would expect, there is an increase in NPV for all of the options

Figure IV-3
RESULTS FOR DIFFERENT FUEL PRICE SCENARIOS



involving coal based on the relatively more rapid increase in the price of electricity over the cost of coal. In the same way there is a less dramatic increase in the NPV for oil fired cogeneration which reflects the identical rate of increase in price but starting from a different base. It is interesting that only the gas turbine technology shows a decline in NPV with change in scenario. This again would be expected given its relative fuel use characteristics.

The parametric and scenario sensitivity analyses carried out confirmed to a large extent the expectations of the research team given the case study chosen. The significance of the exercise was to test the modeling structures, in this case both the physical models and the financial stuctures and demonstrated that they were operating correctly.

Monte Carlo Analysis

The final type of sensitivity analysis run on the economic data was a Monte Carlo simulation of the electric utility buyback rate on NPV for the best case, coal cogeneration Case 3. In the Monte Carlo analysis one or more variables are described as a probability distribution rather than as either one deterministic value or set of scenario values. In the analysis discussed below the buyback rate of electricity was assumed to have a normal distribution with a mean of 5 cents and a variance of 1 cent per kWhre.

Figure IV-4 summarizes the results of the Monte Carlo analysis. The normal approximation table indicates the probability of the NPV being greater than any specific value using only the relationship of the normal distribution. The frequency table indicates the distribution of the results of 200 trials, i.e., 200 simulations in which the price of buyback electricity was randomly chosen from a normally distributed

Figure IV-4. Results of Monte Carlo Simulation of Buybackrate on Coal 3 System

NORMAL APPROXIMATION TABLE

PROBABILITY OF VALUE BEING GREATER THAN INDICATED

	90	80	70	60	50	40	30	20	10
PV1									
20	57.8	61.6	64.4	66.8	69.0	71.2	73.6	76.3	80.2

FREQUENCY TABLE

PROBABILITY OF VALUE BEING GREATER THAN INDICATED

	90	80	70	60	50	40	30	20	10
PV1									
20	57.7	60.9	63.7	67.0	69.1	71.6	74.7	76.5	79.9

SAMPLE STATISTICS

	MEAN	STD DEV	SKEWNESS	KURTOSIS	10PC CONF MEAN	90PC
PV1						
20	68.98	8.726	-.2	2.5	68.19	69.77

```
HISTOGRAM FOR COLUMN        20 OF PV1
27- 28                    *     *
25- 26                    *     *
23- 24                    *     *
21- 22              *     *     *  *
19- 20              *  *  *     *  *
17- 18              *  *  *  *  *  *  *
15- 16              *  *  *  *  *  *  *
13- 14              *  *  *  *  *  *  *
11- 12              *  *  *  *  *  *  *  *
 9- 10           *  *  *  *  *  *  *  *  *  *
 7-  8           *  *  *  *  *  *  *  *  *  *
 5-  6        *  *  *  *  *  *  *  *  *  *  *  *
 3-  4  *  *  *  *  *  *  *  *  *  *  *  *  *  *
 1-  2  *  *  *  *  *  *  *  *  *  *  *  *  *  *  *
        ---------------------------------------------
        4        5        6        7        8
        8        7        5        4        2
        .        .        .        .        .
        4        0        6        2        8
START      47.0   STOP      90.0 SIZE OF INTERVAL        2.87
```

Probability distribution of NPV Observations given 200 simulations.

selection of price quotes. Given that only one variable was analyzed in the Monte Carlo analysis the normal and the frequency tables are identical.

The results of the analysis in Figure IV-4 shows that there is a probability of .9 that, given the distribution of prices chosen, the NPV for the option chosen will exceed 61 million dollars. This value is roughly equivalent to the NPV of the second best option, Coal 1 at the expected value of the buyback rate, 5 cents. The conclusion to be drawn is that the choice of the best alternative has a high probability of exceeding all other alternatives across a wide range of values for buyback electricity and thus given this variable only would appear to be a sound investment strategy. To complete the evaluation it would be necessary to carry out the same type of analysis for each of the exogenous variables for which a reasonable and defendable probability distribution could be described. After the analysis had been handled independently the variables then would be grouped to evaluate the joint probabilities of individual sets of variables and the distribution of results, NPV, brought about by specific sets of variables. The same type of analysis can also be extended to the evaluation of sets of exogenous variables, the values of which are either interdependent or dependent upon the same external factors.

IV.4. Environmental Analyses

The purpose of the environmental research was to evaluate a set of canonical environmental models from which one could be chosen for incorporation into the interfuel substitution modeling structure under development at MIT. The model chosen, CDM, is described in Appendix F.

It is a Gaussian plume model which follows n detail the additive dispersion of multiple sources of particulates, sulfur and nitrogen compounds. The discussion which follows summarizes the application of the model to the case study technologies operating in a rectangular region. Because the analysis is incremental, i.e., is not concerned with absolute levels of specific pollutants, only resultant emissions from the case study facility are considered in the analysis of the results.

IV.4 Environmental Analyses

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Ten cases are considered in the case study energy use model of the refinery:

Case 1	9.66×10^6	MMBTU/YR	Coke Boiler
Case 2	9.66×10^6	MMBTU/YR	Coal Boiler
Case 3	9.66×10^6	MMBTU/YR	Oil Boiler
Case 4	11.60×10^6	MMBTU/YR	Coal Boiler Co-generation
Case 5	11.60×10^6	MMBTU/YR	Oil Boiler Co-generation
Case 6	13.05×10^6	MMBTU/YR	Coal Boiler Co-generation

Case 7 13.05×10^6 MMBTU/YR Oil Boiler Co-generation

Case 8 20.12×10^6 MMBTU/YR Natural Gas Turbine Co-generation

Case 9 Coal Gasifier and 12.88×10^6 MMBTU/YR MBG Boiler

The data input requirements for the Climatological Dispersion Model include:

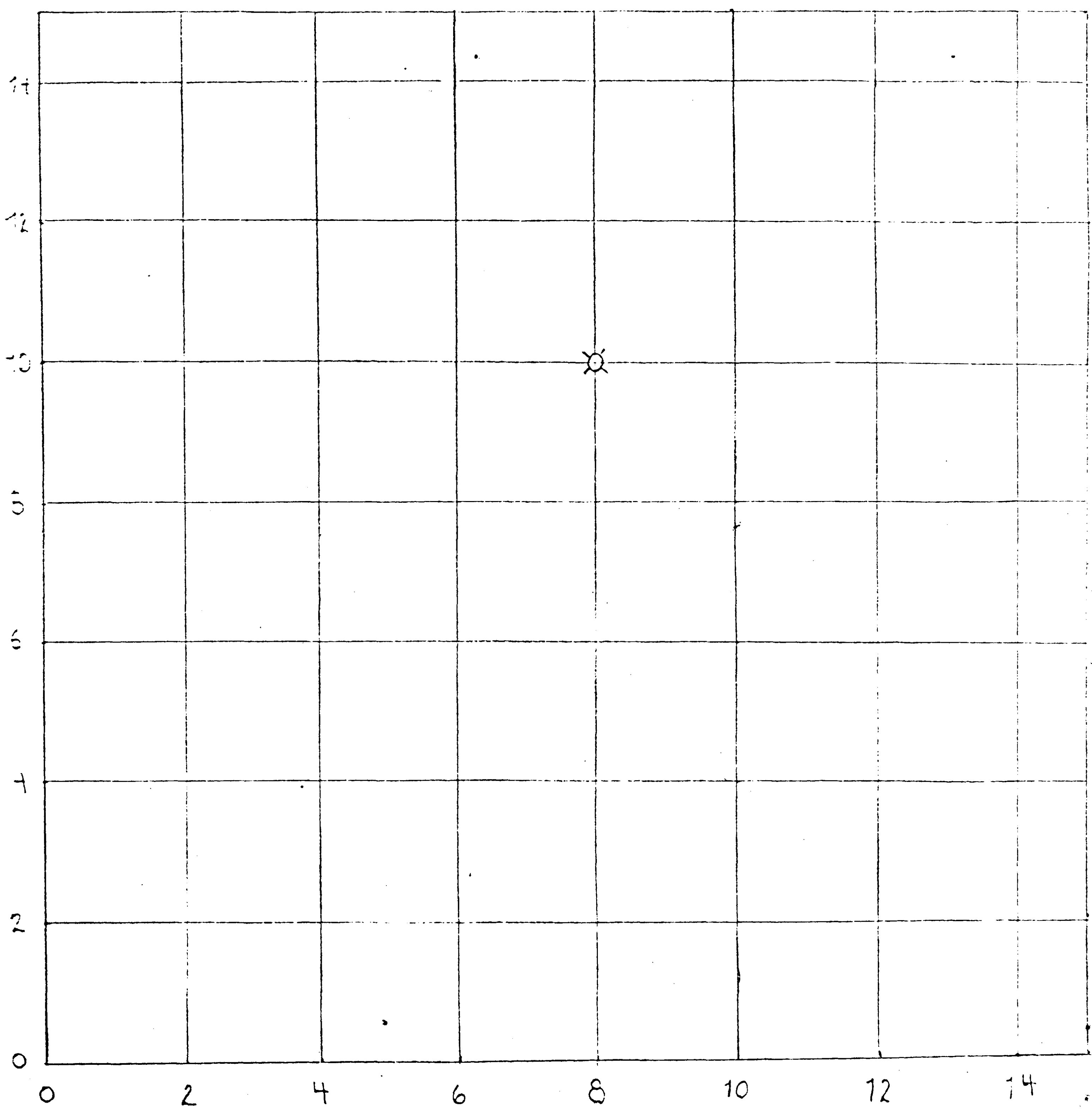
1. Emission Source
   a) Location
   b) emission rate (gm/sec)
   c) stack gas exit temperature
   d) stack height
   e) stack diameter
   f) stack gas exit velocity
2. Meteorology
   a) Values for Joint Frequency Function (i.e. wind speed, direction and atmospheric stability class)
   b) Average Nocturnal and Afternoon Mixing Heights
   c) Average Ambient Temperature
3. Receptor Grid Network

Figure IV-5 depicts a hypothetical 225 KM^2 region. The point source (refinery) is located at X=8.0 KM, Y=10.0 KM. There are 225 receptors, located at each unit kilometer node. The reason an area of 225 KM^2 was chosen for this example was because it was large enough to include for all cases the distance of maximum ground level concentration, as well as an additional margin to show concentrations tapering off.

It is assumed that the plant operates continuously at the same rate for 90 percent of the year. Emission rates and other emission source data for the ten cases are given in Table IV-12. Emission rates are a

FIGURE IV- 5

RECEPTOR GRID SHOWING LOCATION OF POINT SOURCE



KILOMETERS

function of fuel composition (e.g., sulfur and ash content), fuel consumption rate, combustion technology and emission control equipment. In all cases compliance with EPA's New Source Performance Standards (NSPS) is assumed.

Stack height is assumed to be 65 meters in all cases.* The inside stack diameter is assumed to be 4.0 meters. Stack gas exit velocity is then determined for each case directly from the process flow rate. Stack gas exit temperature is a function of combustion technology, emission control equipment and heat exchange equipment. The latter two data items were estimated for each case from published data.

Because this was a test run of the Interfuel Substitution Project methodology, a simplified joint frequency meteorology function was used. Throughout the test year it was assumed that class 4 stability (neutral) and class 4 wind speed (6.93 meters/sec) prevailed. The frequency occurrance of wind direction was spread uniformly across all 16 sectors. By virtue of its symmetry, this meteorological data base provides a built-in check as to whether the computer simulation model is performing properly; a symmetrical meteorology should generate a symmetrical distribution of concentrations for the case of a single point source (see Figures IV-6 and IV-7).

The average nocturnal and afternoon mixing heights were assumed to be 550 meters and 1000 meters respectively. Annual average ambient

---

*See proposed rule Federal Register October 1981. The new regulations set limitations of the stack height to be used in ambient air quality modeling. The new rule would allow a credit of 65 meters for all sources as a reasonable estimate of the height needed to insure that emissions will not be affected by common ground-level meteorological phenomena which may produce excessive pollutant concentrations (e.g. downwash).

Table IV-12

Emission Source Input Data

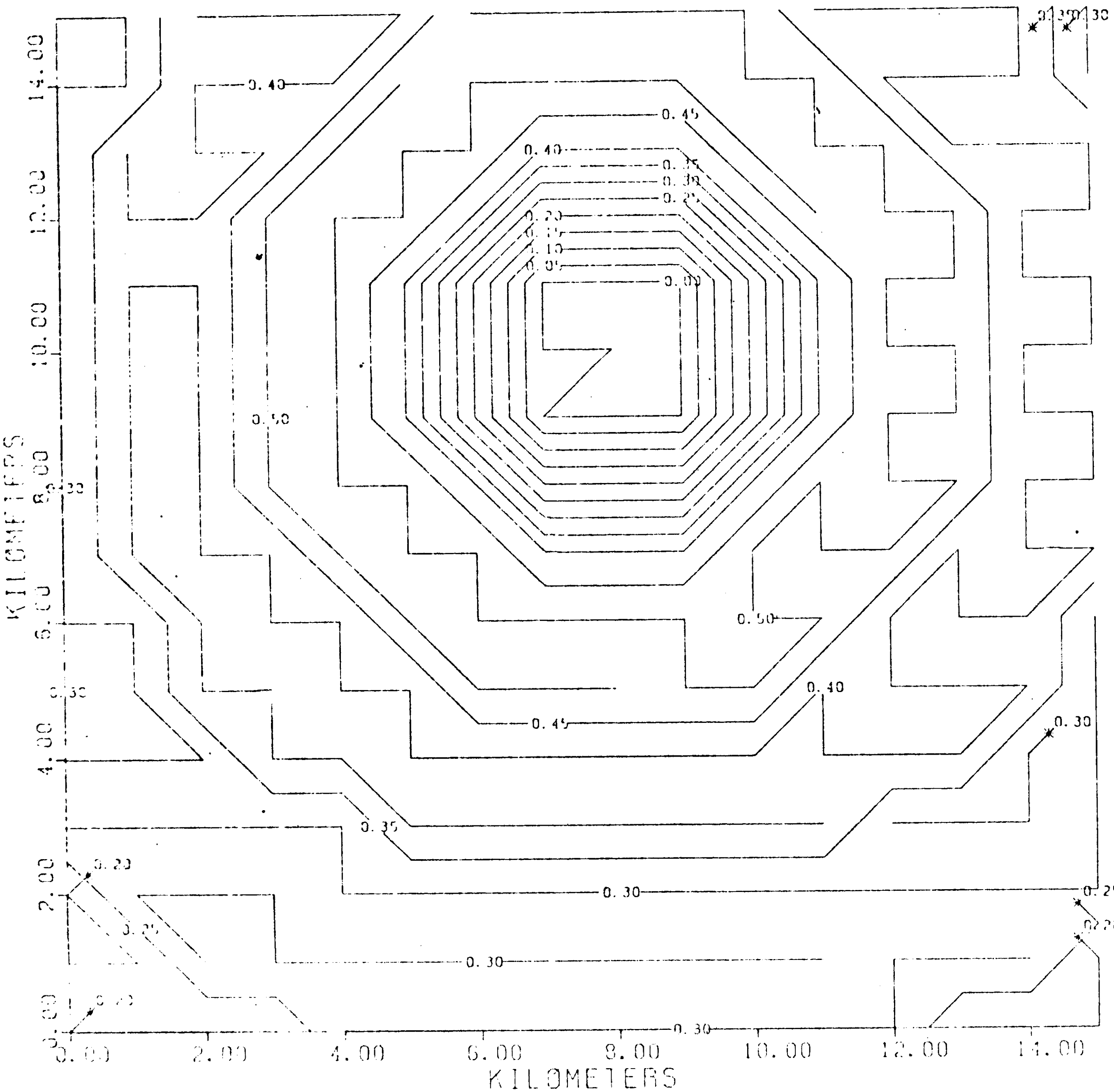
	emission rates (gm/sec) SO_2	PM	NO_x	flow rate (m^3/sec)	exit Temp. C
Case 1	30.87	1.54	101.89	163.83	79
Case 2	41.68	12.35	101.89	163.83	79
Case 3	15.44	2.16	30.88	166.63	149
Case 4	50.05	14.83	122.35	201.56	79
Case 5	18.54	2.59	37.08	226.70	149
Case 6	56.31	16.68	137.65	200.06	79
Case 7	20.85	2.92	41.71	225.06	149
Case 8	--	--	96.44	865.57	232
Case 9(*)					
i)	98.56	0.29	4.64	20.99	154
ii)	59.68	2.06	47.33	221.29	149

*Item i) is due to the coal gasifier. Item ii) is due to the medium BTU gas (MBG) boiler.

CDM CONTOUR PLOT -- CONCENTRATIONS IN MICROGRAMS PER CUBIC METER

FIGURE IV-6

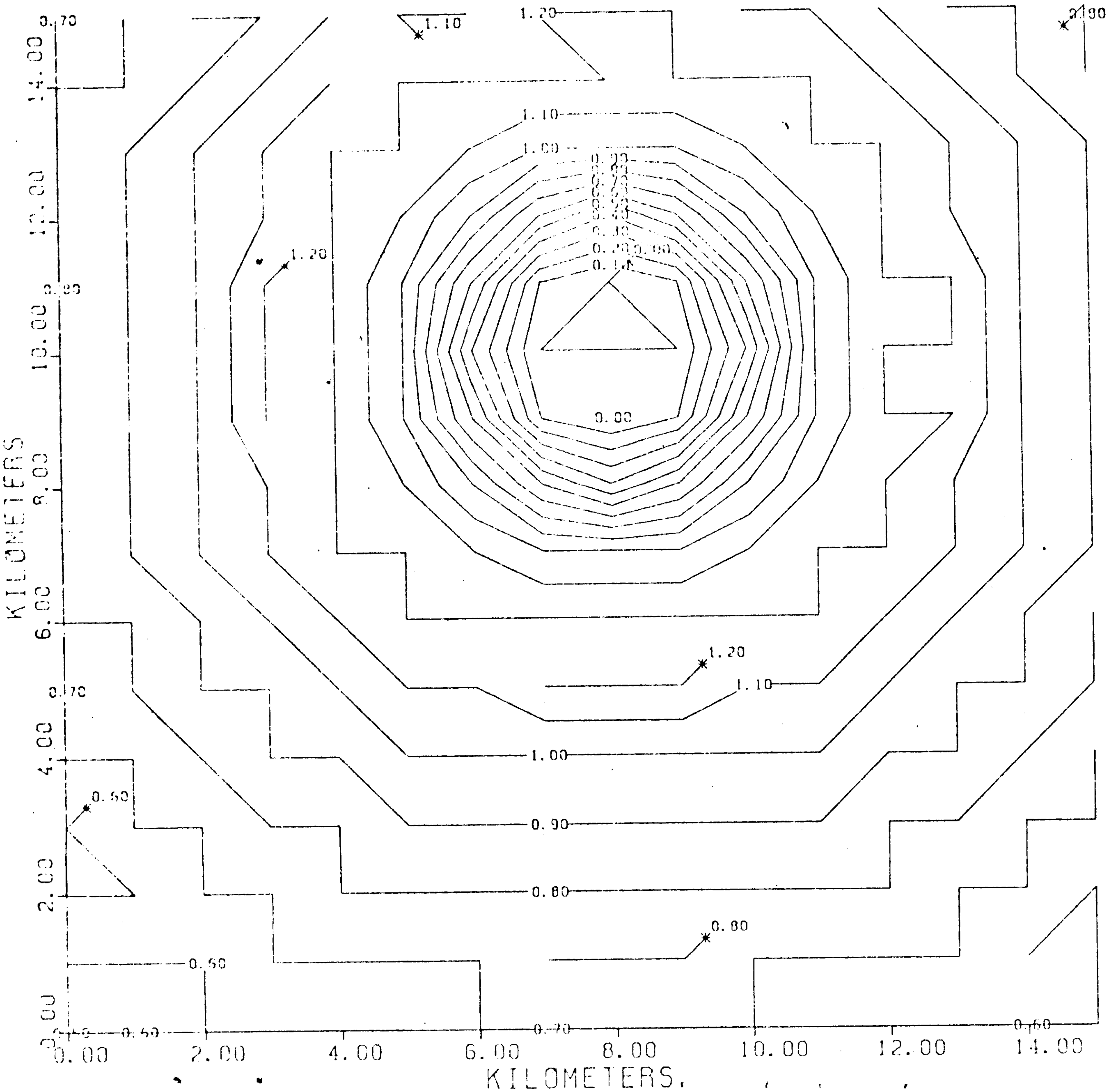
SO_2



CDM CONTOUR PLOT -- CONCENTRATIONS IN MICROGRAMS PER CUBIC METER

FIGURE IV-7

NO_x



temperature was assumed to be 10 degrees Centigrade.

The output of the CDM simulation is in effect a distribution of pollutants across the receptor grid. There are three forms in which this output can be presented: 1) predicted concentration frequencies i.e. the number of times that a given concentration level was "measured" among the receptors--see Tables IV-13 through IV-16; 2) contour plots or isopleths as shown in Figures IV-6 and IV-7; or 3) the predicted concentrations by individual receptor--see Table IV-17. Note that for the latter two forms of presentation only a single case, Case 6, was considered. In all nine cases total suspended particulates (TSP) did not exceed 0.1 $\mu g/m^3$.

The relationship between stack emission rates and ground level concentrations is influenced by plume rise. As was explained in the background section, plume rise is determined by the diameter of the stack and the stack gas exit velocity and temperature (flow rate). These three factors combined with ambient temperature give rise to the bouyancy and momentum effect that sets the plume center-line above the top of the stack. Case 8 is a graphic example of how plume rise can influence ground level concentrations. Note in Table F.4 that case 8 has a relatively high NO_x emission rate. However, the high emission flow rate and stack gas exit temperature associated with this case set the plume so high that simulated values fall below 0.25 $\mu g/m^3$ throughout the receptor grid.

Thus one can see that simply reducing emissions will not alone guarantee an improvement (i.e. reduction) in ground level concentrations. In fact as is discussed in reference [6], in some cases reduced emission rates could result in greater ground level concentrations. The reason for this is precisely that plume rise could

Table IV-13

Predicted Annual Average Concentration

Frequencies at 256 Receptor Grid Points within

225 KM^2 Area

($\mu g/m^3$)

--- SO_2 ---

	0.0*	0.1	0.2	0.3	0.4	0.5
Case 1	9	22	128	97	0	0
Case 2	9	0	65	98	128	0
Case 3	21	235	0	0	0	0
Case 4	9	0	46	88	113	0
Case 5	29	227	0	0	0	0
Case 6	9	0	22	70	94	61
Case 7	25	231	0	0	0	0
Case 8	256	0	0	0	0	0

	0.0-1.0	1.1-1.5	1.6-2.0	2.1	2.2	2.3	2.4
Case 9	70	93	53	4	12	20	4

*Predicted concentrations of 0.0 will be the result of either: 1) actual zero levels of pollutant such as those that would occur in close proximity to the stack; or 2) negligable levels (less than 0.05 ug/m^3) which would occur at receptors furthest away from the stack.

Table IV-14

Predicted Annual Average Concentration

Frequencies at 256 Receptor Grid Points within

225 KM^2 Area

($\mu g/m^3$)

--- NO_x ---

	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2
Case 1	5	4	0	0	10	28	43	49	33	52	32	0	0
Case 2	5	4	0	0	10	28	43	49	33	52	32	0	0
Case 3	13	73	178	0	0	0	0	0	0	0	0	0	0
Case 4	5	4	0	0	4	19	29	41	41	41	72	0	0
Case 5	21	60	175	0	0	0	0	0	0	0	0	0	0
Case 6	5	4	0	0	4	1	27	26	35	41	41	28	44
Case 7	21	35	200	0	0	0	0	0	0	0	0	0	0
Case 8	234	22	0	0	0	0	0	0	0	0	0	0	0
Case 9	5	8	89	154	0	0	0	0	0	0	0	0	0

Table IV-15

Percentage

Predicted Annual Average Concentration

Frequencies at 256 Receptor Grid Points within

225 KM^2 Area

($\mu g/m^3$)

--- SO_2 ---

	0.0	0.1	0.2	0.3	0.4	0.5
	Percent:					
Case 1	4	9	50	38	0	0
Case 2	4	0	11	34	50	0
Case 3	8	92	0	0	0	0
Case 4	4	18	34	44	0	0
Case 5	11	89	0	0	0	0
Case 6	3	0	9	27	37	24
Case 7	10	90	0	0	0	0
Case 8	100	0	0	0	0	0

	0.0-1.0	1.1-1.5	1.6-2.0	2.1	2.2	2.3	2.4
Case 9	26	36	21	2	5	8	2

Table IV-16

<u>Percentage</u>

Predicted Annual Average Concentration

Frequencies at 256 Receptor Grid Points within

225 KM^2 Area

($\mu g/m^3$)

--- NO_x ---

0.0 :0.1:0.2:0.3:0.4:0.5:0.6:0.7:0.8:0.9:1.0:1.1:1.2:

Percent:

Case 1	18	82
Case 2	18	82
Case 3	100	0
Case 4	11	89
Case 5	100	0
Case 6	6	94
Case 7	100	0
Case 8	100	0
Case 9	100	0

TABLE IV-17

DISTRIBUTION OF POLLUTANTS FOR CASE 6

COORDINATES		POINT SOX	POINT TSP	POINT NOX
0.0	0.0	0.2	0.1	0.5
0.0	1.00	0.2	0.1	0.6
0.0	2.00	0.2	0.1	0.6
0.0	3.00	0.3	0.1	0.6
0.0	4.00	0.3	0.1	0.7
0.0	5.00	0.3	0.1	0.7
0.0	6.00	0.3	0.1	0.8
0.0	7.00	0.3	0.1	0.8
0.0	8.00	0.3	0.1	0.8
0.0	9.00	0.3	0.1	0.8
0.0	10.00	0.3	0.1	0.8
0.0	11.00	0.3	0.1	0.8
0.0	12.00	0.3	0.1	0.8
0.0	13.00	0.3	0.1	0.8
0.0	14.00	0.3	0.1	0.8
0.0	15.00	0.3	0.1	0.7
1.00	0.0	0.2	0.1	0.6
1.00	1.00	0.2	0.1	0.6
1.00	2.00	0.3	0.1	0.6
1.00	3.00	0.3	0.1	0.7
1.00	4.00	0.3	0.1	0.7
1.00	5.00	0.3	0.1	0.8
1.00	6.00	0.3	0.1	0.8
1.00	7.00	0.4	0.1	0.9
1.00	8.00	0.4	0.1	0.9
1.00	9.00	0.4	0.1	0.9
1.00	10.00	0.4	0.1	0.9
1.00	11.00	0.4	0.1	0.9
1.00	12.00	0.4	0.1	0.9
1.00	13.00	0.4	0.1	0.9
1.00	14.00	0.3	0.1	0.8
1.00	15.00	0.3	0.1	0.8
2.00	0.0	0.2	0.1	0.6
2.00	1.00	0.3	0.1	0.6
2.00	2.00	0.3	0.1	0.7
2.00	3.00	0.3	0.1	0.7
2.00	4.00	0.3	0.1	0.8
2.00	5.00	0.4	0.1	0.9
2.00	6.00	0.4	0.1	0.9
2.00	7.00	0.4	0.1	1.0
2.00	8.00	0.4	0.1	1.0
2.00	9.00	0.4	0.1	1.0
2.00	10.00	0.4	0.1	1.0
2.00	11.00	0.4	0.1	1.0
2.00	12.00	0.4	0.1	1.0
2.00	13.00	0.4	0.1	1.0
2.00	14.00	0.4	0.1	0.9
2.00	15.00	0.4	0.1	0.9
3.00	0.0	0.2	0.1	0.6
3.00	1.00	0.3	0.1	0.7

COORDINATES		POINT SOX	POINT TSP	POINT NOX
3.00	2.00	0.3	0.1	0.7
3.00	3.00	0.3	0.1	0.8
3.00	4.00	0.4	0.1	0.9
3.00	5.00	0.4	0.1	0.9
3.00	6.00	0.4	0.1	1.0
3.00	7.00	0.4	0.1	1.1
3.00	8.00	0.5	0.1	1.1
3.00	9.00	0.5	0.1	1.2
3.00	10.00	0.5	0.1	1.2
3.00	11.00	0.5	0.1	1.2
3.00	12.00	0.5	0.1	1.1
3.00	13.00	0.4	0.1	1.1
3.00	14.00	0.4	0.1	1.0
3.00	15.00	0.4	0.1	0.9
4.00	0.0	0.3	0.1	0.6
4.00	1.00	0.3	0.1	0.7
4.00	2.00	0.3	0.1	0.8
4.00	3.00	0.3	0.1	0.8
4.00	4.00	0.4	0.1	0.9
4.00	5.00	0.4	0.1	1.0
4.00	6.00	0.4	0.1	1.1
4.00	7.00	0.5	0.1	1.2
4.00	8.00	0.5	0.1	1.2
4.00	9.00	0.5	0.1	1.2
4.00	10.00	0.5	0.1	1.2
4.00	11.00	0.5	0.1	1.2
4.00	12.00	0.5	0.1	1.2
4.00	13.00	0.5	0.1	1.2
4.00	14.00	0.4	0.1	1.1
4.00	15.00	0.4	0.1	1.0
5.00	0.0	0.3	0.1	0.6
5.00	1.00	0.3	0.1	0.7
5.00	2.00	0.3	0.1	0.8
5.00	3.00	0.4	0.1	0.9
5.00	4.00	0.4	0.1	1.0
5.00	5.00	0.4	0.1	1.1
5.00	6.00	0.5	0.1	1.2
5.00	7.00	0.5	0.1	1.2
5.00	8.00	0.5	0.1	1.1
5.00	9.00	0.4	0.1	1.0
5.00	10.00	0.4	0.1	1.0
5.00	11.00	0.4	0.1	1.0
5.00	12.00	0.5	0.1	1.1
5.00	13.00	0.5	0.1	1.2
5.00	14.00	0.5	0.1	1.2
5.00	15.00	0.4	0.1	1.1
6.00	0.0	0.3	0.1	0.7
6.00	1.00	0.3	0.1	0.7
6.00	2.00	0.3	0.1	0.8
6.00	3.00	0.4	0.1	0.9
6.00	4.00	0.4	0.1	1.0

TABLE IV-17 (cont.)

DISTRIBUTION OF POLLUTANTS FOR CASE 6

COORDINATES		POINT SOX	POINT TSP	POINT NOX
12.00	11.00	0.5	0.1	1.2
12.00	12.00	0.5	0.1	1.2
12.00	13.00	0.5	0.1	1.2
12.00	14.00	0.4	0.1	1.1
12.00	15.00	0.4	0.1	1.0
13.00	0.0	0.2	0.1	0.6
13.00	1.00	0.3	0.1	0.7
13.00	2.00	0.3	0.1	0.7
13.00	3.00	0.3	0.1	0.8
13.00	4.00	0.4	0.1	0.9
13.00	5.00	0.4	0.1	0.9
13.00	6.00	0.4	0.1	1.0
13.00	7.00	0.4	0.1	1.1
13.00	8.00	0.5	0.1	1.1
13.00	9.00	0.5	0.1	1.2
13.00	10.00	0.5	0.1	1.2
13.00	11.00	0.5	0.1	1.2
13.00	12.00	0.5	0.1	1.1
13.00	13.00	0.4	0.1	1.1
13.00	14.00	0.4	0.1	1.0
13.00	15.00	0.4	0.1	0.9
14.00	0.0	0.2	0.1	0.6
14.00	1.00	0.3	0.1	0.6
14.00	2.00	0.3	0.1	0.7
14.00	3.00	0.3	0.1	0.7
14.00	4.00	0.3	0.1	0.8
14.00	5.00	0.4	0.1	0.9
14.00	6.00	0.4	0.1	0.9
14.00	7.00	0.4	0.1	1.0
14.00	8.00	0.4	0.1	1.0
14.00	9.00	0.4	0.1	1.0
14.00	10.00	0.4	0.1	1.0
14.00	11.00	0.4	0.1	1.0
14.00	12.00	0.4	0.1	1.0
14.00	13.00	0.4	0.1	1.0
14.00	14.00	0.4	0.1	0.9
14.00	15.00	0.4	0.1	0.9
15.00	0.0	0.2	0.1	0.6
15.00	1.00	0.2	0.1	0.6
15.00	2.00	0.3	0.1	0.6
15.00	3.00	0.3	0.1	0.7
15.00	4.00	0.3	0.1	0.7
15.00	5.00	0.3	0.1	0.8
15.00	6.00	0.3	0.1	0.8
15.00	7.00	0.4	0.1	0.9
15.00	8.00	0.4	0.1	0.9
15.00	9.00	0.4	0.1	0.9
15.00	10.00	0.4	0.1	0.9
15.00	11.00	0.4	0.1	0.9
15.00	12.00	0.4	0.1	0.9
15.00	13.00	0.4	0.1	0.9
15.00	14.00	0.3	0.1	0.8
15.00	15.00	0.3	0.1	0.8

TABLE IV-17 (cont.)

DISTRIBUTION OF POLLUTANTS FOR CASE 6

COORDINATES		POINT SOX	POINT TSP	POINT NOX
6.00	5.00	0.5	0.1	1.1
6.00	6.00	0.5	0.1	1.2
6.00	7.00	0.5	0.1	1.1
6.00	8.00	0.4	0.1	0.9
6.00	9.00	0.2	0.1	0.6
6.00	10.00	0.2	0.1	0.4
6.00	11.00	0.2	0.1	0.6
6.00	12.00	0.4	0.1	0.9
6.00	13.00	0.5	0.1	1.1
6.00	14.00	0.5	0.1	1.2
6.00	15.00	0.5	0.1	1.1
7.00	0.0	0.3	0.1	0.7
7.00	1.00	0.3	0.1	0.8
7.00	2.00	0.3	0.1	0.8
7.00	3.00	0.4	0.1	0.9
7.00	4.00	0.4	0.1	1.0
7.00	5.00	0.5	0.1	1.2
7.00	6.00	0.5	0.1	1.2
7.00	7.00	0.4	0.1	1.0
7.00	8.00	0.2	0.1	0.6
7.00	9.00	0.0	0.0	0.1
7.00	10.00	0.0	0.0	0.0
7.00	11.00	0.0	0.0	0.1
7.00	12.00	0.2	0.1	0.6
7.00	13.00	0.4	0.1	1.0
7.00	14.00	0.5	0.1	1.2
7.00	15.00	0.5	0.1	1.2
8.00	0.0	0.3	0.1	0.7
8.00	1.00	0.3	0.1	0.8
8.00	2.00	0.3	0.1	0.8
8.00	3.00	0.4	0.1	0.9
8.00	4.00	0.4	0.1	1.0
8.00	5.00	0.5	0.1	1.2
8.00	6.00	0.5	0.1	1.2
8.00	7.00	0.4	0.1	1.0
8.00	8.00	0.2	0.1	0.4
8.00	9.00	0.0	0.0	0.0
8.00	10.00	0.0	0.0	0.0
8.00	11.00	0.0	0.0	0.0
8.00	12.00	0.2	0.1	0.4
8.00	13.00	0.4	0.1	1.0
8.00	14.00	0.5	0.1	1.2
8.00	15.00	0.5	0.1	1.2
9.00	0.0	0.3	0.1	0.7
9.00	1.00	0.3	0.1	0.8
9.00	2.00	0.3	0.1	0.8
9.00	3.00	0.4	0.1	0.9
9.00	4.00	0.4	0.1	1.0
9.00	5.00	0.5	0.1	1.2
9.00	6.00	0.5	0.1	1.2
9.00	7.00	0.4	0.1	1.0
9.00	8.00	0.2	0.1	0.6
9.00	9.00	0.0	0.0	0.1
9.00	10.00	0.0	0.0	0.0
9.00	11.00	0.0	0.0	0.1
9.00	12.00	0.2	0.1	0.6
9.00	13.00	0.4	0.1	1.0
9.00	14.00	0.5	0.1	1.2
9.00	15.00	0.5	0.1	1.2
10.00	0.0	0.3	0.1	0.7
10.00	1.00	0.3	0.1	0.7
10.00	2.00	0.3	0.1	0.8
10.00	3.00	0.4	0.1	0.9
10.00	4.00	0.4	0.1	1.0
10.00	5.00	0.5	0.1	1.1
10.00	6.00	0.5	0.1	1.2
10.00	7.00	0.5	0.1	1.1
10.00	8.00	0.4	0.1	0.9
10.00	9.00	0.2	0.1	0.6
10.00	10.00	0.2	0.1	0.4
10.00	11.00	0.2	0.1	0.6
10.00	12.00	0.4	0.1	0.9
10.00	13.00	0.5	0.1	1.1
10.00	14.00	0.5	0.1	1.2
10.00	15.00	0.5	0.1	1.1
11.00	0.0	0.3	0.1	0.6
11.00	1.00	0.3	0.1	0.7
11.00	2.00	0.3	0.1	0.8
11.00	3.00	0.4	0.1	0.9
11.00	4.00	0.4	0.1	1.0
11.00	5.00	0.4	0.1	1.1
11.00	6.00	0.5	0.1	1.2
11.00	7.00	0.5	0.1	1.2
11.00	8.00	0.5	0.1	1.1
11.00	9.00	0.4	0.1	1.0
11.00	10.00	0.4	0.1	1.0
11.00	11.00	0.4	0.1	1.0
11.00	12.00	0.5	0.1	1.1
11.00	13.00	0.5	0.1	1.2
11.00	14.00	0.5	0.1	1.2
11.00	15.00	0.4	0.1	1.1
12.00	0.0	0.3	0.1	0.6
12.00	1.00	0.3	0.1	0.7
12.00	2.00	0.3	0.1	0.8
12.00	3.00	0.3	0.1	0.8
12.00	4.00	0.4	0.1	0.9
12.00	5.00	0.4	0.1	1.0
12.00	6.00	0.4	0.1	1.1
12.00	7.00	0.5	0.1	1.2
12.00	8.00	0.5	0.1	1.2
12.00	9.00	0.5	0.1	1.2
12.00	10.00	0.5	0.1	1.2

be reduced through the application of emission control technology. In terms of simulated concentrations, the lower plume center-line could more than offset the reduction in emissions in certain situations.*

Case 9, the coal gasifier, also stands out as an exceptional example. The high simulated SO_2 ground level concentrations are the result of high SO_2 emission rates and low flow rate coming from the gasifier unit. By its very nature coal gasification is more inefficient than the coal boiler technologies considered. Hence more primary fuel input is required to produce a unit of steam. Consequently there is more sulfur flowing through the system. As described in Appendix C, the gasifier technology used in this study is the Texaco entrained flow process.

The Texaco process produces MBG that retains ten percent of the total sulfur that was originally contained in the primary coal input. The sulfur removed in the gasifier unit is received either as a solid (elemental sulfur) or emitted from the plant in the form of SO_2 in the tail gas stream. The total flow rate for the tail gas stream is the sum of the flue gas from the gasifier process boiler and the aforementioned SO_2 stream. As is peculiar to the Texaco process, this is a relatively low value.

Compliance with Federal Environmental Standards

It has been mentioned that the technologies considered in the ten cases all meet the New Source Performance Standards (NSPS) for emission

*It would not be fair to say with complete confidence that in these cases the reduction in emissions would have a negative net environmental impact. Indeed, one cannot deny the old adage "what goes up must come down." Emissions which do not come down within the receptor grid will come down further away, at another time, quite possibly in another form such as acid rain.

rates set be EPA. The basic federal standards concerned with the more "downstream" aspects of air pollution will now be discussed. Of course in an actual application of the Interfuel Substitution Project, all relevent local, state and federal laws and regulations would be taken into account.

Stated simply, there are two situations under which a new or modified emission source falls: attainment or nonattainment. These terms are defined by the National Ambient Air Quality Standards (NAAQS), see table F.10 (Appendix F). If in an area any of the primary standards are exceeded, the area is designated a nonattainment area. Consequently no new or modified source may be constructed without applying "Lowest Achievable Emissions Rate" (LAER) control technology and providing an emission offset of at least as much as the new or modified source will emit (pertaining to the offending pollutant).

If the area is an attainment area then a set of standards known as Prevention of Significant Deterioration (PSD) applies, see Table F.11 (Appendix F). PSD standards are based on concentration increments. Most of the 48 contiguous United States is designated Class II. Whether any of the cases considered in this report would be in PSD compliance in a Class II area would depend on how much of the increment had not already been consumed.

Capital Environmental Trade-Off

A major issue in any evaluation of new fuel use technologies is the trade-off between increased profitability and environmental quality. In the case analysis a set of evaluations of individual of the case analyses were made comparing the NPV for specific technological options with their level of emissions. Figures IV-6 and IV-7 indicate the level of emissions in SO_2 and NO_x at ground level with the use of 1.7 percent sulfur oil and 1.7 percent sulfur coal. The differences are based largely on fuel combustion rates and on fuel quality. Figure IV-8 shows the results of a limited analysis of the impact of alternative coal qualities on both environmental quality (SO_2) and on system NPU. The results are interesting in that moving from 1.7 to 3 percent sulfur coal increases the ground level pollutants by over 60 percent while the increase in NPU is only 33 percent over this range. Further the shape of the curve indicates diminishing returns to increasing sulfur content in the coal.

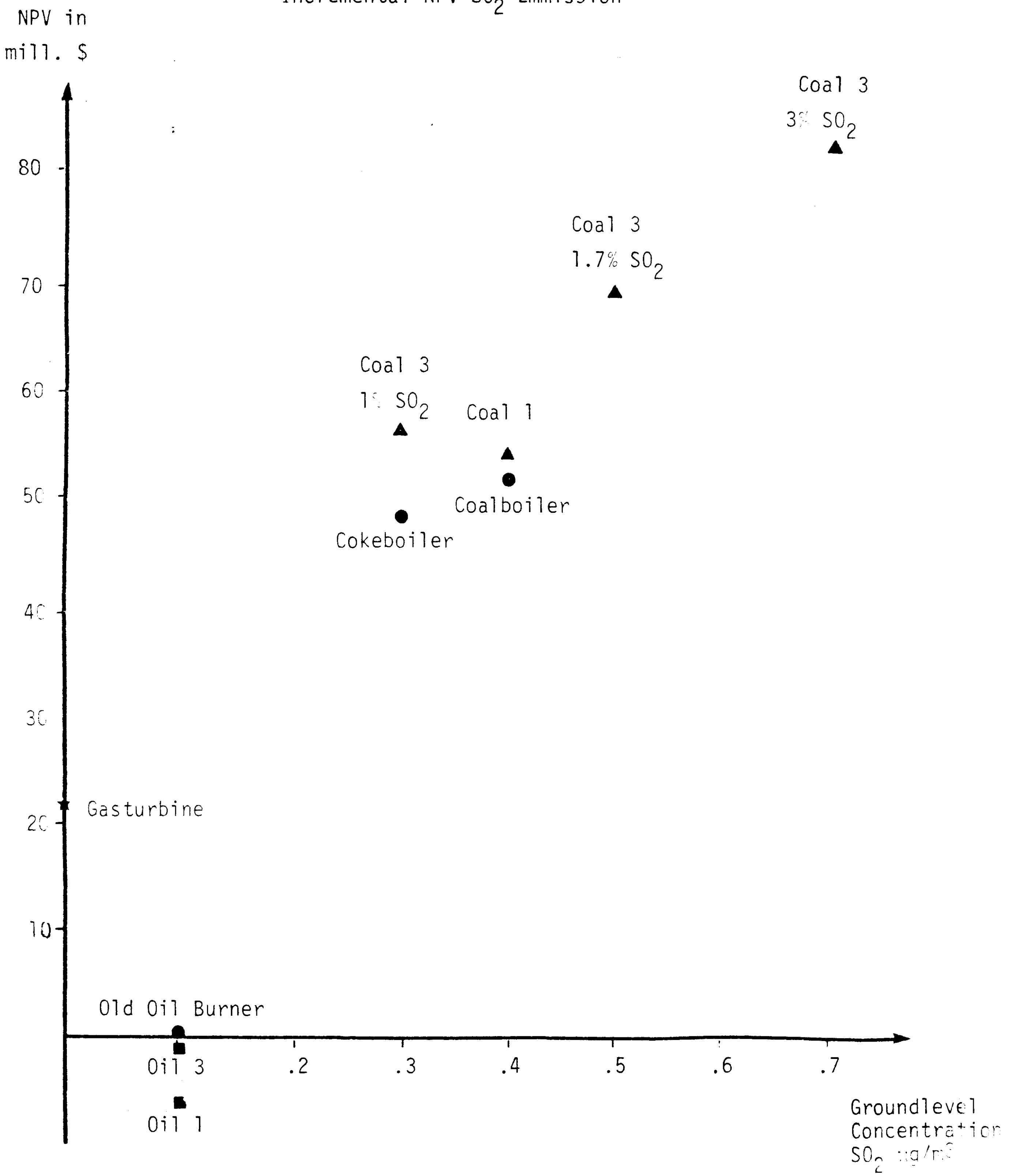
The conclusions that can be reached from this type of analysis is the trade-off between capital and operating costs and environmental quality. It is clear that the relation is non-linear and as a result regions of high sensitivity can be identified in which it is possible to gain the most in environmental quality and in NPU. The next step in this type of analysis would be to incorporate capital expenditures in abatement technologies such as scrubbers into the trade-off costs.

IV.5 Conclusions

The objective of the case study was to test the tools and combinations of tools developed in this effort for evaluation of interfuel substitution potential in industry. The broader objective of the research effort was to develop a set of regional aggregation methods (described in Part I) and to test the regional integration tools, in this case regional air quality modeling capability (presented in this chapter and in Appendix F).

FIGURE IV-8

Economic Environmental Trade-Offs
Incremental NPV-SO_2 Emmission



The initial sections of the chapter presented the results of our evaluation of cogeneration and boiler fuel switching for the case study and presented the general conclusions which can now be used as a screening tool for our further interfuel substitution analyses. This effort identified the key parameters for both cogeneration and traditional boiler analyses: size, fuels cost, discount rate, load factor.

This chapter also tested the economic/financial model and, using this model, tested a set of sensitivity analysis methods or techniques. These were parametric analysis, scenario analysis and Monte Carlo analysis. In each instance the methods performed successfully and the results were of interest. These are presented in Figures IV-2, IV-3 and IV-4. Having carried out this set of analyses it is clear that they have relatively divergent purposes in the analyses. The parametric analysis provided a summary review of the direction and slope of impact of a large set of exogenous variables whose values were modified by fixed percentage steps. This analysis looked at one variable at a time. The choice of step size was arbitrary, and therefore offers only a screen on the actual impact of individual variables and offers little information on the impact of sets of variables which move together.

The second type of sensitivity analysis carried out was called scenario analysis and involved definition of a set of variables and the manner in which they would covary in a "snapshot" format. Here the objective was to paint a set of likely futures--in our case associated with future fuel prices--and evaluate as point solutions the relative impact on the measured dependent variable, in this case net present value.

The final method tested, Monte Carlo analysis, fulfills yet another function in describing the dependent variable as a probability distribution in terms of one or more input variables whose values can be described probabilistically. This analysis is particularly useful in evaluating the robustness of an investment decision, i.e., the range of variable values over which the decision still dominates or the range over which the NPV will continue to meet some type of hurdle condition.

The final analysis carried out was a trade-off analysis of capital vapue (NPV) against environmental air quality. Once again the modeling structure performed as required and the results showed the relative steepness of the trade-off curve and thereby the improvements in NPV with increases in sulfur emissions. For a more interesting analysis of this type of trade-off, it is necessary to work within an actual region and to look at a set of capital investments in scrubbing technologies along with alternatives in fuel consumption.

In summary, the case study demonstrated the modeling and analytic facility developed during the project. While there were no major surprises in this effort the development of the screening criteria for cogeneration and fuel burning has offered a major advantage in extension of this work to a full-scale regional evaluation.

V. CONCLUSIONS TO PHASE I

The case study results reported in Section 4 of the report have produced two major sets of conclusions. The first set of conclusions is that the modeling structures developed and tested in the case study were shown to work effectively for the case study analysis both individually and when used in pairs. Thus the objectives of Phase I to develop a set of planning models for use in regional interfuel substitution analysis was completed successfully and the models are ready for testing in a specific area. This is discussed in greater detail in Section 6 which follows.

There is a second set of conclusions which can be drawn from the results of the case studies. These are both specific to the analyses done and discussed in Chapter 4 as well as going beyond those conclusions from Chapter 4 and building on the combined experience of the research team in carrying out the case study analysis and in doing, as will be seen, a set of side analyses that can be used to summarize our efforts. The results are reported here in two groups. The first group contains two results that lead directly from the economic and engineering analyses carried out in the study. Figures 5-1 and 5-2 show the cost trade-offs between oil and coal systems (both traditional boilers and cogeneration systems). Primary issues associated with Figures 5-1 and 5-2: These are that the coal versus oil decision, i.e., the screening curve decision presented herein, shows high sensitivity to size, economic parameters, end load factor, as it may be seen from the larger oil-coal fuel costs differential needed to obtain an economically feasible fuel switching.

Those figures summarize a major set of conclusions concerning the relative significance of the size of an installation and the difference

FIGURE 5.1
OIL/COAL FUEL COST DIFFERENTIAL

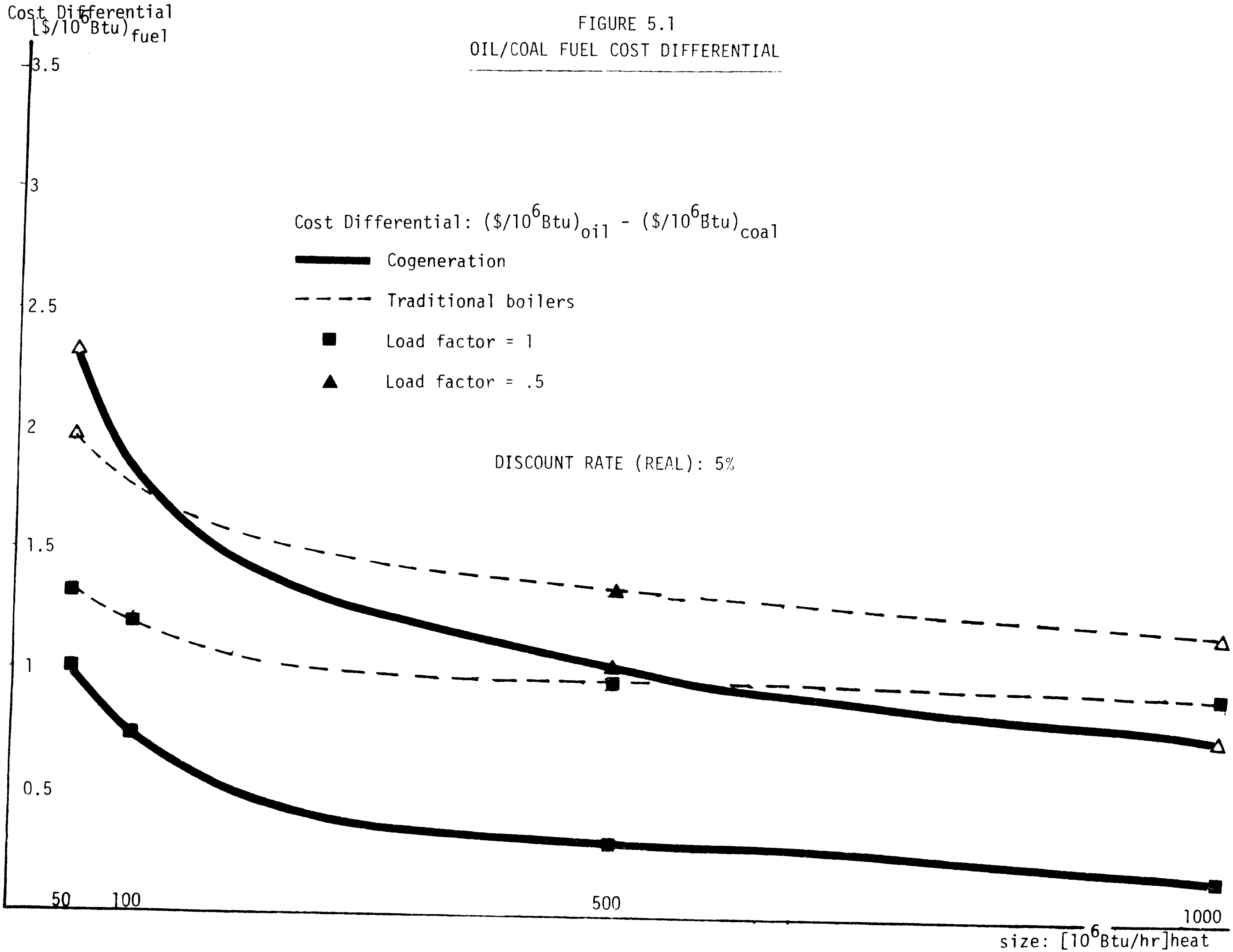
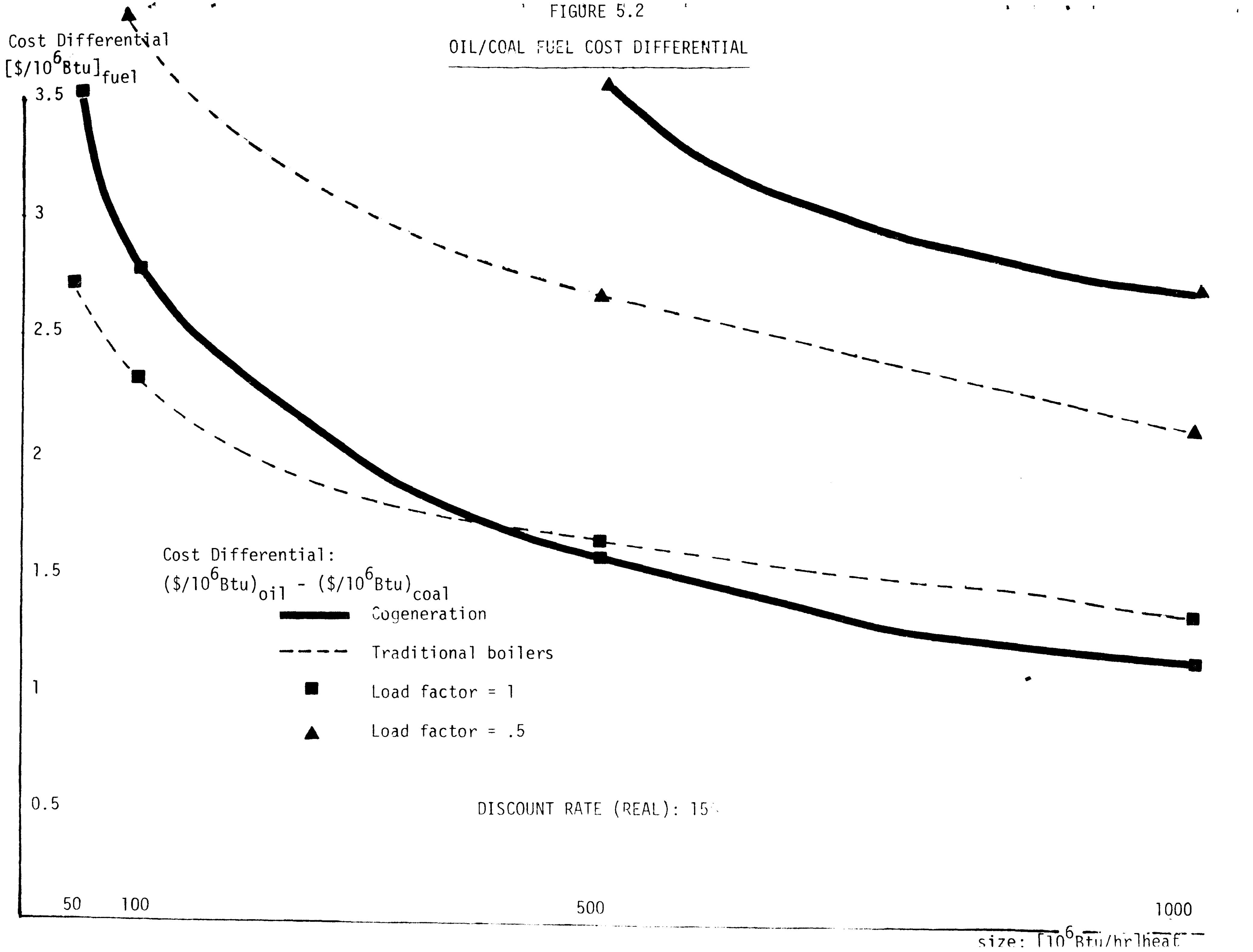


FIGURE 5.2

OIL/COAL FUEL COST DIFFERENTIAL



in absolute dollar terms between the cost of coal per million Btu delivered and the cost of oil per million Btu delivered. It also shows the impact of a change in the discount rate. The plot indicates the breakeven point between an oil system and a coal system, i.e., economic indifference between investment in one technology versus another. The numbers presented in Figures 5-1and 5-2 are derived from the boiler data information discussed in Chapter 4 and Appendices A and B. What is significant about the figures is that the absolute size of the dollar difference between the two fuels affects dramatically the size at which coal becomes an economically attractive investment. As one would expect, also, as the discount rate decreases, the size of unit at which coal becomes cost-effective relative to oil decreases. Those figures offer an extremely facile screening tool for evaluation of the cost-effectiveness of decision between coal and oil capital stocks. As such, it will offer one of the preliminary screening tools to be used in Phase II of this effort.

The second set of conclusions that can be drawn from this project are directly related to the coal-to-oil fuel switching decision. These may be summarized under three specific headings, General Constraints, the Coal Decision, the Cogeneration Decision, and the possibility of a physically cleaned coal-derived fuel that can substitute for residual oil in boilers designed for oil.

The three general conclusions about the economic feasibility and physical feasibility of coal combustion in industry: These are environmental feasibility, availability of supply, and availability of storage capacity within the facility.

Environmental Feasibility

There are regions defined by the EPA in which coal combustion at the industrial level, is highly constrained based on air quality constraints in the region as a whole. This is a case for a significant number of the major urban areas in the Northeast and North Central regions of the United States. In these areas, coal combustion at even a large industrial scale, will be heavily constrained and thereby from a regional perspective, not be a viable option for industrial fuels.

Availability of Supply

The supply lines for provision of coal were traditionally the railroads. Within some regions, again notably the Northeast and North Central portions of the United States, the rail lines which once supplied coal to industrial customers are no longer available. Provision of both reliable and adequate supplies for industrial customers therefore becomes a major consideration in the fuel switching decision. Without guaranteed adequate supplies, there is little if any possibility of an industry switching to coal even if the economics look favorable on other grounds.

Storage Capacity

It is significant to note that many of the possible industrial sites for coal combustion do not have sufficient storage space for coal piles. This either eliminates the possibility of coal as an option or forces that option to be structured around the highly reliable centralized storage facility from which a large number of industrial firms would be able to receive coal on a nearly daily basis.

The above three criteria represent significant pre-screens to the coal conversion decision at a specific industrial location. They are important because they may determine that coal is not a viable option for an entire region, given the environmental characteristics of the region, the supply availability characteristics of that region and the general physical layout of a large number of industries within the region.

The discussion which follows characterizes the coal substitution process for existing facilities, making a decision to switch from oil to coal. These are broad conclusions. For every conclusion there is the exception. Despite this, however, these conclusions will, we feel, offer a structure within which to consider the screening of the interfuel substituion decision at the industrial level.

The first concern is the initial decision of the economic viability of coal. Given the currently commercially available technologies for fossil fuel combustion one can make the following two broad statements.

For any thermal load greater than 500 x 10^6 Btu/hr coal steam raising will dominate oil steam raising from an economic perspective. This is the case for several reasons. A significant one is that any industry in the 500,000,000 Btu/hr category has a reasonably high load factor. The industries themselves are large, have a flat load, and can take advantage of the scale economies associated with coal combustion. Classical sectors in which such plant installations occur, would be refining, chemicals, very large food processing, paper, and, again very large, textiles, cement.

In the range between 100 and 500 million Btu/hr the following factors will lead to a decision to switch to coal over oil. These are:

Size--The larger the system, as was discussed above, the higher the probability that coal will be an attractive option;

Coal cost relative to oil cost--The greater the absolute difference between the per million Btu delivered cost of coal and that of oil, the more likely is the economics to favor coal.

Lower discount rate--The discount rate or interest rate used in the analysis will always influence positively a large investment decision as the interest rate becomes lower.

Load factor--The greater the load factor, i.e., the relative evenness of thermal demand throughout the year, the higher the probability of a decision to invest in coal over oil.

In this range between 100 and 500 million Btu/hr there is a wide variety of options for coal conversion. It is in this range that most of the decisions to move to coal will have to be made. It is in this range that much of the interest in screening and evaluation of potential for coal conversion arises.

The next sequential decision and thereby conclusions drawn from this project are in the area of cogeneration. Here, two major general conclusions have emerged from this study. They will not be discussed in detail in the set of conclusions, but rather the reader is encouraged to return to Section 4.2 and to refer to Appendix B.

The first conclusion is that for industries with a large, flat thermal load coal is a viable option for a boiler fuel within the industry, and it will be cost-effective for that industry to cogenerate and when it does so, its net present value to the investment in capital stock will increase relative to only coal combustion. This is a significant conclusion, obtained pricing ccogenerated electricity at coal fired electric utilities fuel costs. Given PURPA regulations, i.e., buyback rate set equal to avoided cost, it will be possible for an industry either to save or to sell back to the utility at a favorable price. In addition, the combined first and second law of thermodynamic thermodynamic efficiencies when compared with the separate raising of steam and generation of electricity favor cogeneration.

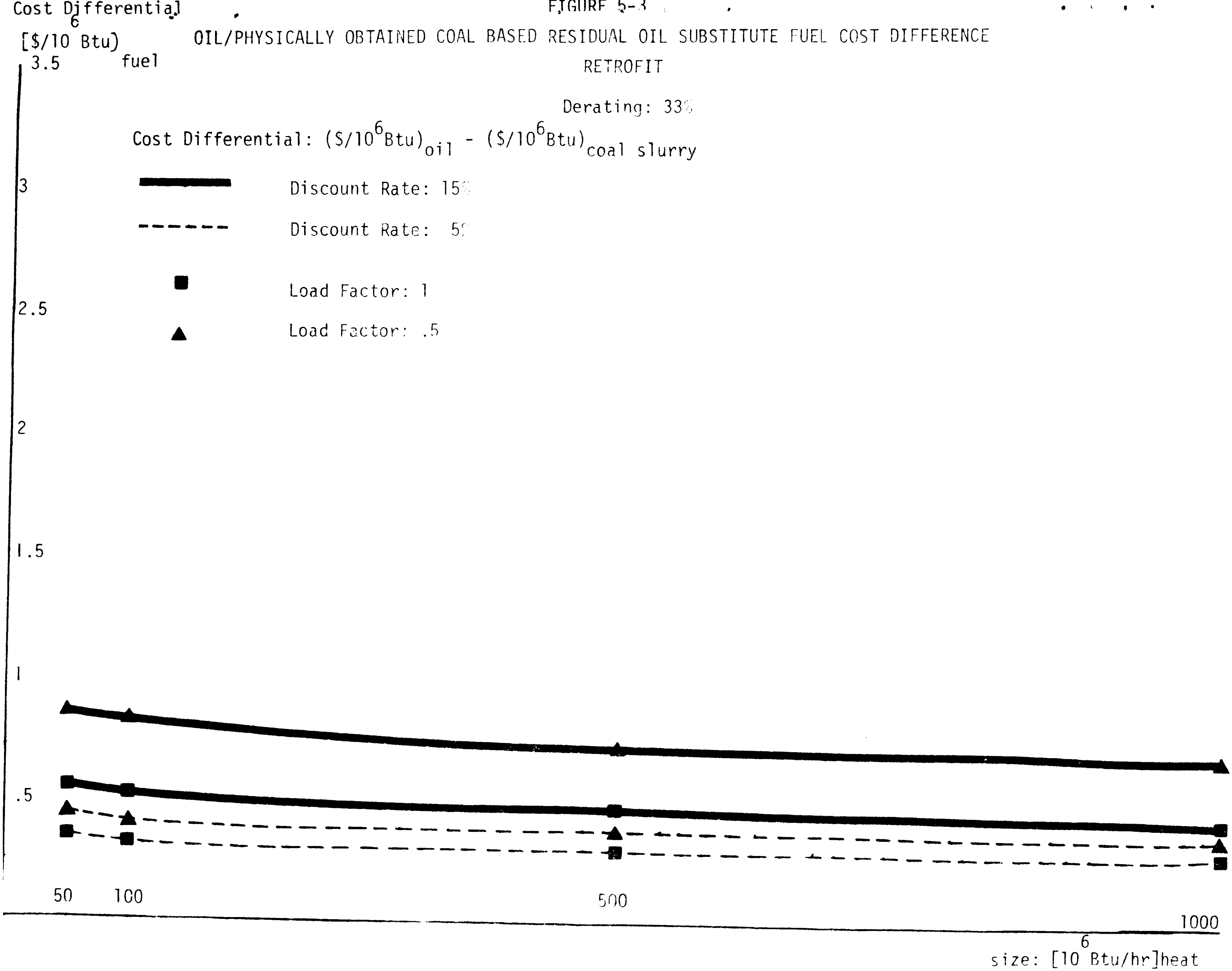
The second major conclusion which emerges from the steam turbine cogeneration analysis is that if the decision has been made to cogenerate, the dominant system configuration from an economic perspective will be the one that, within the constraints of technology availability for a specific-sized installation, raises steam at high pressure and temperature. This again is discussed in greater detail both earlier in this chapter and in Appendix B. It is sufficient to say that the higher electrical output achievable from higher pressure and temperature relative to the incremental cost and capital to achieve those temperatures guarantees that from an economic perspective the decision will be to generate steam at high temperature and pressure in order to generate as much electricity as possible prior to using steam in process. Other cogeneration technologies might be analyzed in the same way. Most of these will generally have higher cogenerated electricity incremental cost of cogeneration but also larger installed electric power per unit heat rate delivered to process.

The final areas of conclusions for this study are summarized in Figure 5-3. These relate to the possibility of a coal-based physically derived liquid substitute for residual oil. The question is often asked whether a fuel such as coal-water mixture can be a substitute for residual oil. If it were, it would be usable in existing boilers probably with acceptable retrofitting capital cost and with some decrease in the boiler heat rate. The economic viability of such a technology

FIGURE 5-3

OIL/PHYSICALLY OBTAINED COAL BASED RESIDUAL OIL SUBSTITUTE FUEL COST DIFFERENCE

RETROFIT



comes from its ability to furnish process energy at a cost lower than oil. Thus, the absolute difference in price between oil and coal slurry determines the amount of money that can be spent on a combination of capital (including boiler derating) and physical beneficiation of fuel such that the total system cost does not exceed the one allowed by the differential between coal slurry and oil costs. Figure 5-3 indicates the region of acceptability for the price of beneficiated fuel.

In conclusion, then, the results of the case study and those specific conclusions that can be drawn from it as well as the more general conclusions in the paragraphs immediately above have indicated that the evaluation, in particular the regional evaluation, of interfuel substitution possibilities in the industrial sector depends significantly on the relative prices of oil and coal, upon the availability of those fuels upon the industry loads, and upon such other constraints as environment and financing. The first project identified a set of tools, modified and developed those tools and tested them in an effort to be prepared to carry out a Phase II effort in a specific region. That Phase II effort is presented in Section 6 which follows.

VI EXTENSIONS OF WORK: Phase II

The efforts reported in this report represented the first phase in a two-phase effort to evaluate industrial interfuel substitution possibilities on a regional basis. The work was motivated by a desire to develop a systematic method of evaluation which held the potential for "bottom up" aggregation of individual decisions but in which the actual nature of the individual investment decision was not lost. Phase II is structured to take the methodology described in this document and apply it to a specific region of interest to a set of sponsors, several of whom participated in this phase of the work.

Several points have been learned in the length of this effort which will influence dramatically the shape of Phase II. The first is positive and that, as was discussed in the previous section, is that there may be a relatively simple screening methodology for evaluation of cogeneration and fuel switching potential, i.e., the technologies for combustion allow for a series of functional relations to hold for specific size ranges that make the decision relatively independent of many of the economic parameters to date believed to be of major importance in the evaluation of such decisions.

The efforts of Phase I emphasized what had been suspected concerning regional analysis and that was that the method of aggregation of information would be the most critical issue. Section I of this report discusses a methodology for aggregation which, though heuristic in some ways, appears to lead to correct conclusions concerning the potential for interfuel substitution. This method will need to be modified as it is applied in the first of the regional studies. Several issues are clear, however. The first is that there is no simple functional means of aggregation that has been used successfully in applications such as this. The second is that the method finally used will require research judgment and will result in a distribution of outcomes that are a function both of traditional variable uncertainty in such areas as fuel prices and capital costs as well as a function of the business environment in which such decisions are made. Finally, the potential will be a function of the availability of a critical mass for significant savings in interfuel substitution, i.e., the availability of fuels at the significantly lower costs that occur with economy of scale in transport and/or processing.

The second phase of the work is beginning at this time for Georgia and the Southeast. It is being jointly undertaken by MIT and Georgia Tech using the methodology and tools described in this report combined with the experience and data developed through five years plus of energy conservation efforts by Georgia Tech in the industrial sector of the state. Using Georgia as the data base, the potential for interfuel substitution within the region will follow. It is clear already that some of our conclusions from Phase I will be modified as we implement Phase II but the tools developed and the experience gained and data bases developed form the required building blocks for much of the further work in this area by MIT and other research groups.

APPENDICES

Appendix A: STEAM RAISING: TRADITIONAL BOILER SYSTEMS

This appendix presents the cost and environmental data needed to model fuel choice decisions for industrial steam raising facilities. A great number of factors affect the cost to produce steam including the amount of steam required, the steam load duration curve, the fuels that are being considered, the required system reliability, and the environmental regulations. The approach taken in this analysis is to present cost data described in terms of the key variables that determine cost. Expressed in this manner, a comparison of steam raising costs for alternative fuels can be easily obtained for the diverse range of industrial conditions. The analysis is divided into two parts: Section 1 presents the necessary cost data for the economic analysis while Section 2 describes the environmental factors that must be considered.

A.1 Boiler System Cost Analysis

1.1. Steam cost variables

In order to model fuel choice decisions for industrial steam raising, it is necessary to capture the factors which most strongly determine steam generation costs. In general, these factors can be divided into three categories: general system specifications, economic evaluation variables, and "site-specific" variables. In modeling fuel choice decisions, the effects of system specifications and economic variables are easily accounted for. The "site-specific" factors, those which account for a firm's particular operating practices, design philosophy, and site-related conditions, are not.

The general system specifications and the economic variables include the following factors:

- o fuel type
- o steam quality (pressure and temperature)
- o peak and annual steam demand
- o pollution control requirements
- o system reliability and backup requirements
- o fuel price
- o discount rate
- o life of facility
- o expected escalation rates

Once these factors are specified, a screening level estimate can be made of the system's capital, operating, and fuel cost components.

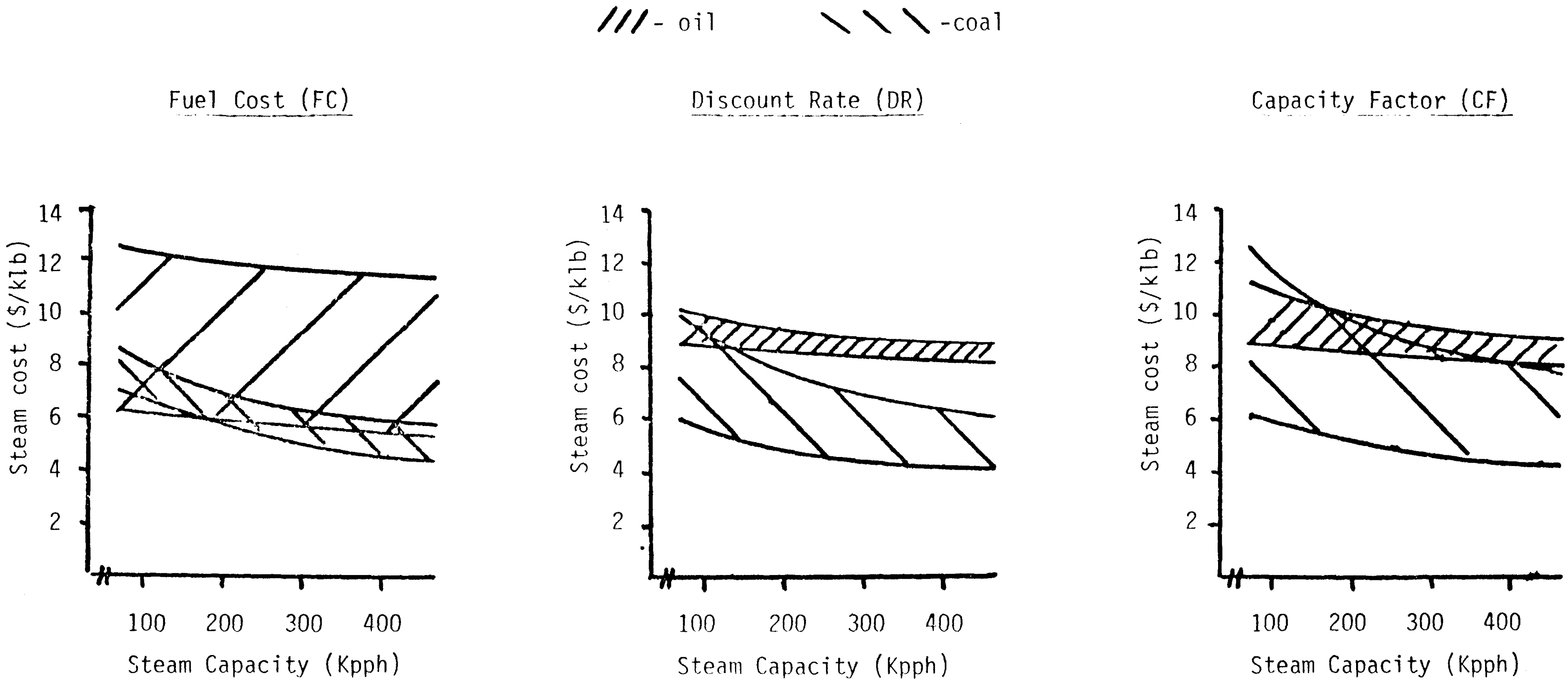
Each of these factors has a strong impact on the cost of raising steam. For example, a coal-fired boiler can require between 2 to 4 times the capital of an oil- or gas-fired boiler for the same steam production capacity. On top of this, pollution control can add up to 25 percent to the capital cost. Similarly, system reliability requirements can add to capital cost by requiring that several boilers be used to meet peak demand. This, however, entails a higher capital cost since the economies of scale are not captured. Related to this is the question of how to provide "backup" capacity for the system. For a coal-fired system, capital costs would be significantly lower if an oil-fired unit was used for backup. Since the backup would only be used for limited times, the penalty for using high price fuel oil might be offset by the savings in capital cost.

An illustration of the relation between several of these variables and steam cost is presented in Figure A.1 using a simplified analysis methodology (1). Shown here is the steam cost variation due to: type and cost of fuel, size of boiler, discount rate, and load factor (2). As shown in this figure, steam raising costs vary greatly, depending on the specifications. In addition to the absolute cost, it is also important to understand the sensitivities to each of the key variables.

The cost of steam produced in a coal-fired boiler is more sensitive to discount rate, size, and capacity factor than for an oil-fired boiler. This occurs since the coal-fired system is more capital intensive and uses a low-cost fuel. Steam cost for an oil-fired boiler is, however, much more sensitive to fuel price variations since fuel makes up the largest portion of the annualized cost. One can conclude that it is much more important to optimize an oil-fired boiler's efficiency than minimize its capital cost. In addition, the accuracy of the capital cost estimate for the oil-fired system is relatively unimportant. This can be seen by the very small change in steam cost, roughly 10 percent, when the discount rate was increased by a factor of 5.

The third set of factors, those that are "site-specific", are more difficult to take into account. These factors include the variations that occur between firms in their operating and maintenance practices, design philosophy, and the specific site constraints unique to each facility. While these factors might, in some cases, ultimately determine the decision, they are almost impossible to capture without a detailed knowledge of the case.

Figure A-1: Steam Cost Variations (1978)



coal $1 to $2/MMBTU
oil $3 to $7/MMBTU
15% DR
60% CF

low 5%
high 25%
60% CF
$1.50 coal FC
$5.00 oil FC

low 30%
high 90%
15% DR
$1.50 coal FC
$5.00 oil FC

Each firm has its own operating and maintenance practices which will affect the estimate of annual operating costs. For example, the number of operating and maintenance personnel varies widely from plant to plant depending on state regulation, company policy, and plant management. Variations in operating and maintenance practices affect the life of the system, system availability, and the efficiency of the boiler. To some degree, these variations are reflected in different assumptions used by firms to estimate their operating and maintenance costs.

Variations in boiler system capital costs can occur due to design philosophy differences. One factor is the degree of reliability designed into the system, for example, through redundancy of auxiliary equipment. Another factor to consider is the quality of the material used in areas operating under extreme conditions. While low quality materials might significantly reduce the up-front capital cost, they might well result in costly repair later. In addition, the sophistication and automation of subsystems varies considerably. For coal-fired systems, this is especially true for the fuel system including the coal receiving, storage, internal distribution, and preparation subsystems (3). These factors need to be considered when comparing capital cost estimates, but requires a knowledge of detailed assumptions behind the estimates.

The last "site-specific" factor to consider is cost variations due to site constraints. In general, natural gas and oil-fired boilers are the least sensitive to site constraints due to the relatively small size of the system, the lack of fuel handling problems, and the easily controlled combustion characteristics of the fuel. Coal, and other solid fuels, are subject to numerous problems that can result in additional capital expenditures beyond the requirements of the basic system.

Coal delivery and internal plant distribution can pose a problem. For example, if no rail spur to the site exists, then one would have to be built. In addition, land for coal unloading, storage, and preparation must be available near the boiler site. Space limitations may also exist for the actual boiler, especially if the new boiler is to replace an existing oil or gas unit, or if an existing plant is to be expanded. Small package oil- or gas-fired boilers might be able to fit in where a coal-fired unit might not. For small steam plants, this is especially true since a coal-fired boiler requires three times more space than a package oil-fired unit (4). Total space requirements for the coal-fired system are even greater when all the auxiliary equipment space requirements are considered. The only way to assess the cost impact of site constraints for a particular case is to prepare an engineering assessment.

Boiler Data Sources

Three boiler system data sets were compared over the range of boiler sizes typically found in industrial plants. The sources of the data sets are: a major industrial firm; Cameron Engineers, a private sector engineering/marketing consulting firm (4); and a series of studies funded by the Environmental Protection Agency including PEDCo's report on boilers, Radian's report of sulfur control, and GCA's report on particulate control (5). The primary details of each of the data sources are presented in Tables A-1 and A-2.

The Industrial Data base was developed for use as a screening tool for choosing between oil and coal. It was developed from engineering designs for a number of different steam capacities with intermediate

TABLE A-1: DESIGN PARAMETERS FOR BOILER DATA BASES

	Industrial	Cameron	EPA
Fuels (See 2.2-2)	Coal, Oil	Coal, Oil	Coal, Oil, Gas, Dual-fired
Size Range	25 to 1,000 kpph	100 to 1,000,000 kpph	5 to 700 MMBtu/hr.
Steam (press./temp.)	150 psig/500°F	250 psig sat. to 1500 psig/950°F	150 psig sat. to 900 psig/750°F
Boiler Type[1]			
Coal:	S.S < 50 kpph P.C > 150 kpph	S.S/P < 100 kpph S.S/FE < 200 kpph PC/FE > 200 kpph	U.F.S./P < 75 MMBtu/hr S.S/FE < 200 " PC/FE > 200 "
Oil:	P < 150 kpph FE > 300 kpph	P < 100 kpph FE > 100 kpph	F.T/P < 30 " W.T/P < 150 " W.T/FE > 150 "
No. of Trains	3 at 50% capacity	1	1
Drive	steam	electric	electric
Pollution Control[2]	ESP FGD (dual alkali)	FF < 100 kpph ESP > 100 kpph FGD (dual alkali) with reheat	ESP FGD (dual alkali)
Pollution Control Design Level	Utility NSPS	Utility NSPS	varies

1. S.S. - Spreader Stoker
   P.C. - Pulverized Coal
   U.F.S. - Underfeed Stoker
   P - Package
   F.E. - Field Erected
   F.T. - Fire Tube
   W.T. - Water Tube

2. ESP - Electrostatic precipitator
   FF - Fabric Filter
   FGD - Flue Gas Desulfurization

TABLE A-2: BOILER FUEL SPECIFICATION

Fuel Type	Sulfur (%)	Ash (%)	Btu/lb.
Industrial Data Source			
Residual Oil (15° API)	0.7		18,600
Coal			
Wyoming	0.4	6	8,050
S. West Virginia	0.7	7.9	12,650
N. West Virginia	1.7	11.8	12,100
Illinois	3.3	8.0	10,800
Cameron			
Residual Oil (#6)	0.3		18,215
Coal			
Powder River Basin	0.6	6	8,224
Illinois Bituminous	3.2	8.2	12,000
Texas Lignite	0.7	8.1	6,500
EPA			
Natural Gas	Trace	0	21,800
Distillate Oil	0.5	Trace	19,500
Residual Oil	3.0	0.10	18,500
Coal			
Eastern, high sulfur	3.54	10.6	11,800
Eastern, medium sulfur	2.28	13.2	13,200
Eastern, low sulfur	0.9	6.9	13,800
Western, low sulfur	0.6	5.4	9,600

sizes scaled from the original designs. Costs for residual oil-fired boilers were developed by the internal engineering department while an outside engineering/construction firm developed those for coal-fired boilers.

The system is designed to include three 50 percent capacity trains of equipment where each train includes a boiler, electrostatic precipitator (ESP), and a flue gas desulfurization (FGD) unit. All drive power, such as for the feedwater pumps, is obtained from auxiliary steam turbines. This is an important design feature since roughly 15 percent of the steam produced by the boilers is internally consumed for auxiliary power. Possible advantages of steam drive are improvement in system reliability and reduction of operating costs by making the system independent of outside utility services. Two capital cost components were excluded from the estimates: site grading and boiler feedwater system. These cost items, however, make up only 1 percent of the total capital cost in comparable estimates.

Detailed cost breakdowns are reported for each fuel type and size. Capital costs are divided into material and installation labor components. Operating costs are reported broken down by maintenance, labor, taxes, feedwater, ash disposal, scrubber cost, and ESP electricity demand. They do not seem to include overhead beyond the boiler system level.

The Cameron Engineers data set was developed from estimates made by Combustion Engineering for the boiler system and FMC for the FGD system. Cameron estimated the balance of plant costs such as feedwater, foundations, electrical, earthwork, site development, water treatment, and fuel handling. The capital costs are divided into boiler and auxiliary equipment cost, boiler installation cost, and a detailed listing of balance of plant costs. Operating costs are broken down into raw materials, salaries and wages, utilities, maintenance, and taxes.

The EPA's study of boiler systems was performed by several different consulting firms using a common set of assumptions. Estimates were developed from vendor quotes that were obtained for detailed equipment lists for eight different boiler sizes. Pollution control costs for SO_2 and PM were developed for each fuel type, boiler type and size, and as a function of pollution control level. Capital and operating cost estimates are broken down by equipment unit and operating cost component.

Boiler Cost Comparison

The three data sources were compared for similar fuel types as a function of size and capacity factor. All costs were normalized to mid-1978 dollars and to the same definition of indirect costs for contingency and engineering fee (6). The capital cost comparisons are presented in Figures A-2 and A-3 while operating costs are shown in Figures A-4 and A-5. In general, there is good agreement between the three sources for capital costs of coal-fired boilers, but there is some discrepancy in the capital cost estimates for oil-fired boilers and in all operating costs.

The Industrial Data designed in three trains of 50 percent capacity, was adjusted to correspond to a single boiler. Since a detailed equipment cost list was not available, the Industrial Data was adjusted by taking one-third of the system cost for a steam rate that was one-half of the system's full load production rate. This methodology tends to underestimate the boiler cost since not all of the system components were

Figure A-2: Coal-Fired Boiler Capital Cost

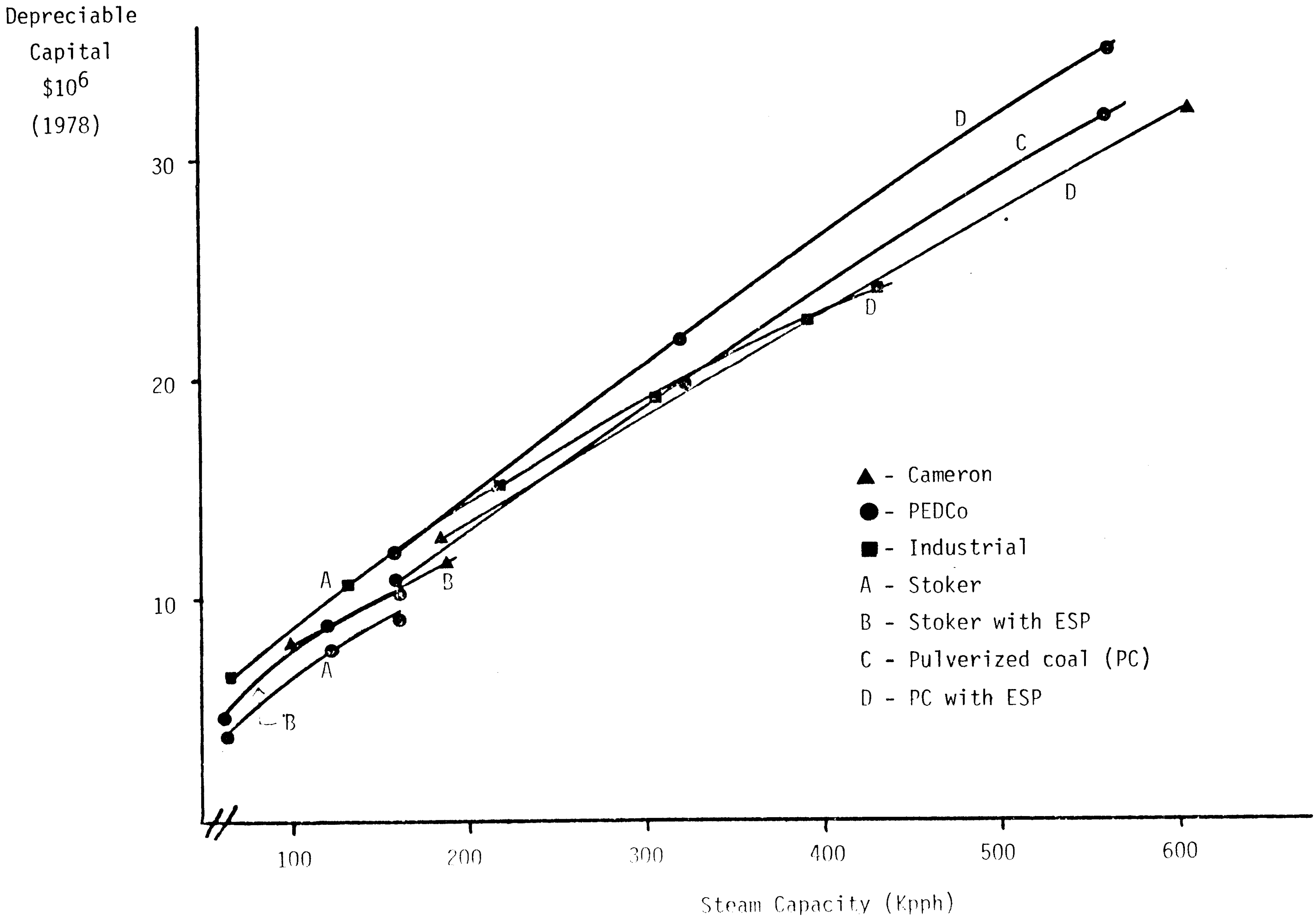


Figure A-3: Oil-Fired Boiler Capital Cost

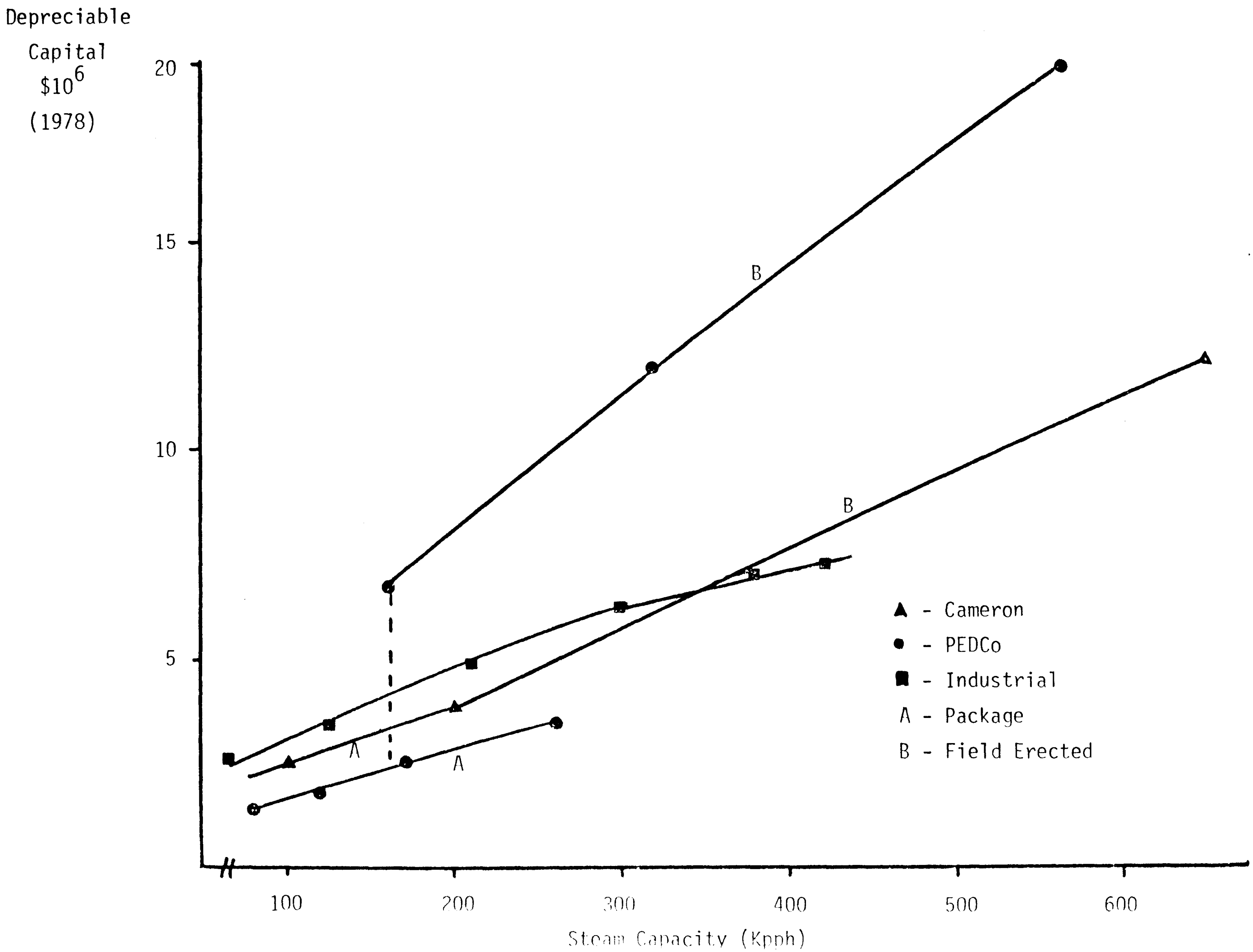


Figure A-4: Coal-Fired Boiler Operating Cost (at 85% capacity factor)

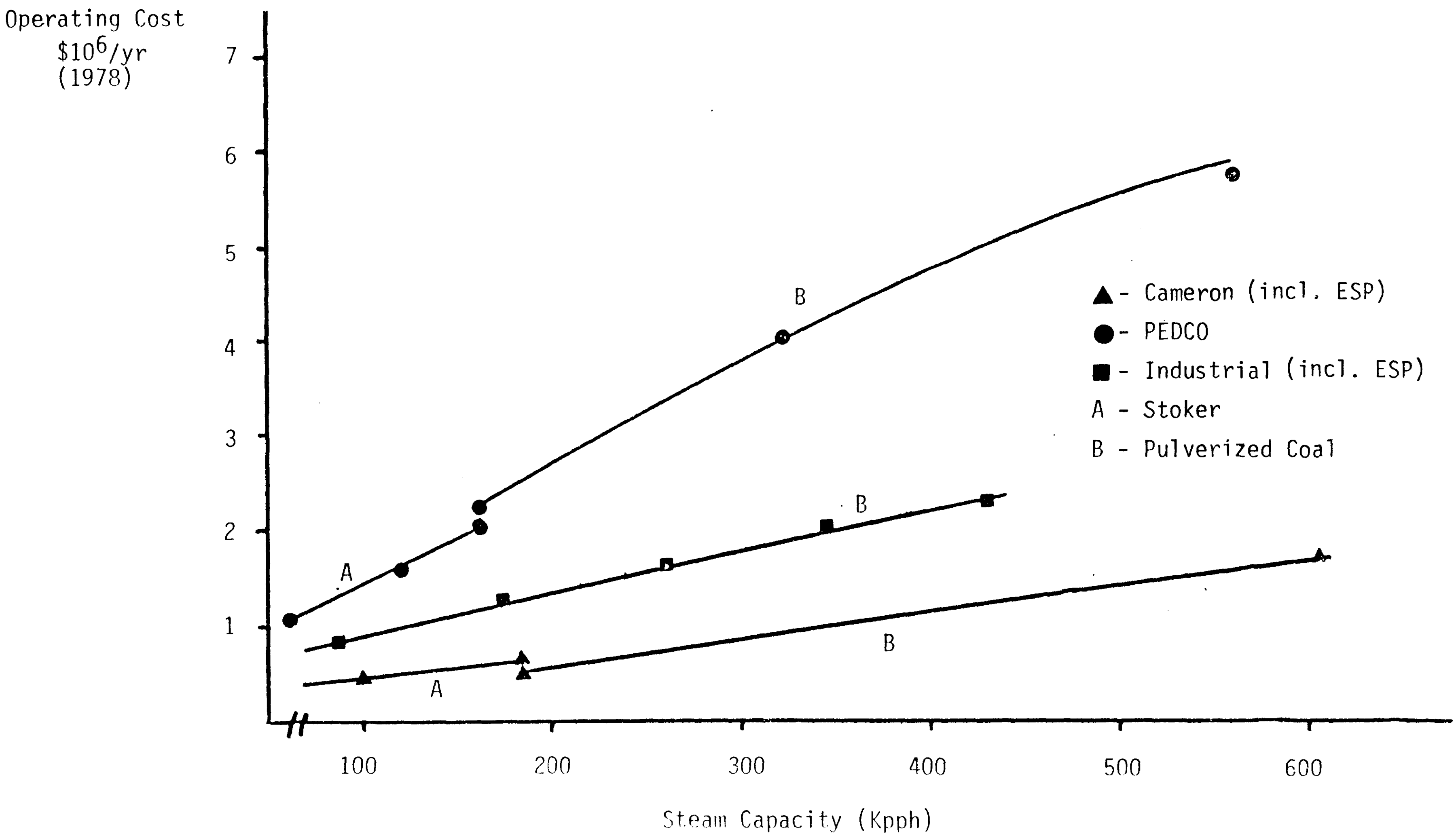
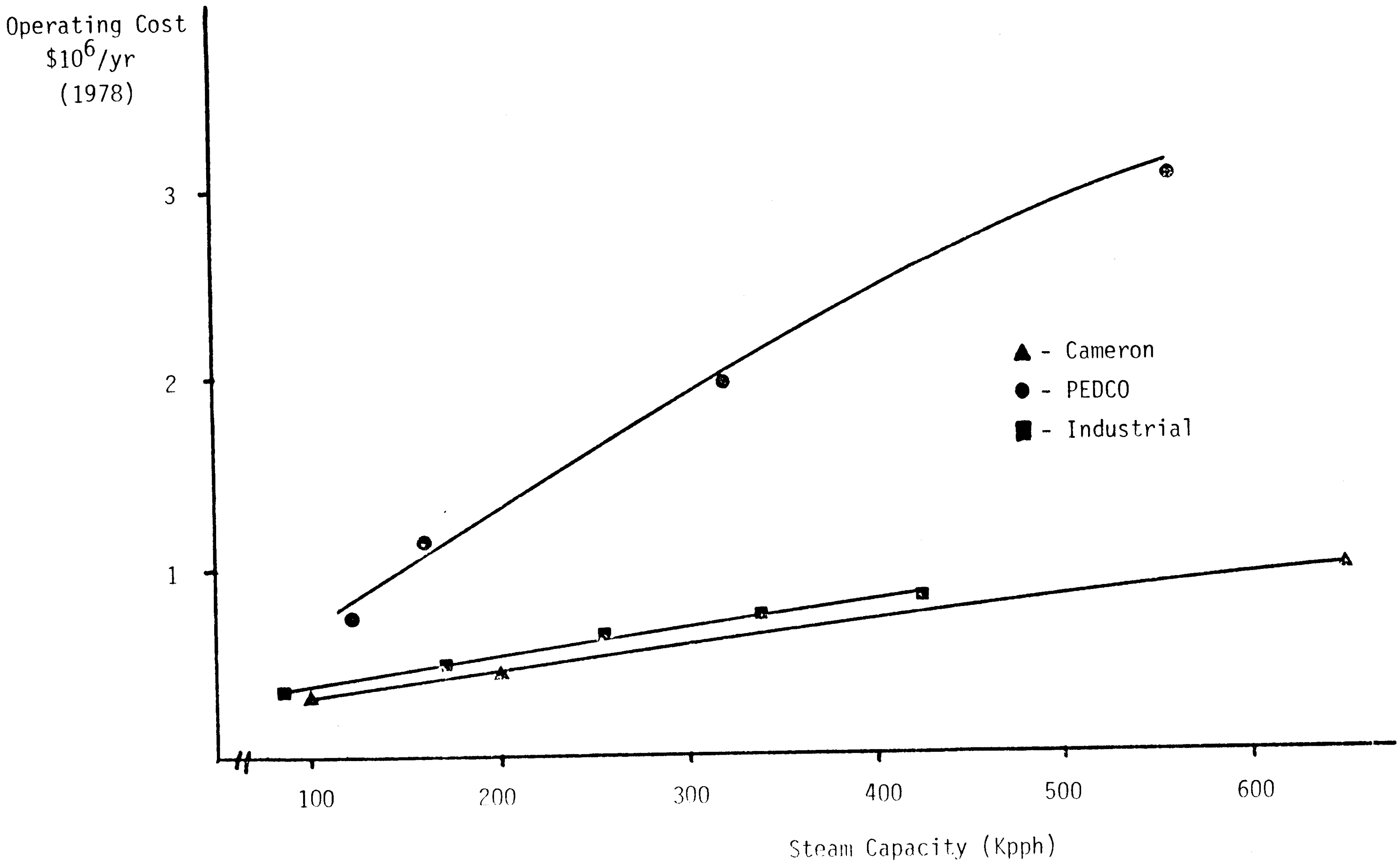


Figure A-5: Oil-Fired Boiler Operating Cost
(at 85% capacity factor)



installed as three at 50 percent capacity.

Capital cost estimates for boilers firing medium to high sulfur bituminous (Figure A-2) are well correlated. Note that the Industrial and Cameron estimates include an ESP for particulate control while the PEDCo data does not. When adjusted by including the GCA ESP estimate, the PEDCo estimate is slightly higher than the others.

The capital cost estimates for boilers firing residual oil (Figure A-3) show good agreement between the Industrial and Cameron estimates, while the PEDCo package boiler estimates are roughly 30 to 50 percent less and the field erected units are 70 percent greater than the other estimates. Several factors account for this discrepancy including differences in installation costs and the design criteria of the estimates.

PEDCo and Cameron installation cost estimates are quite different for package vs. field erected systems. In comparing the package boiler estimates, equipment costs for the Cameron and PEDCo are similar, but the installation costs for the boiler portion of the system are quite different. Specifically, PEDCo's installation cost for the boiler is only 3 percent of the equipment cost while Cameron's is 25 percent. For field erected units, PEDCo's equipment cost estimates are much larger than Cameron's, although the installation to equipment cost ratios are similar.

Several design differences also exist which account for the cost differences. First, the design for the Industrial Data includes steam drive which consumes 15 percent of the nominal output, thus increasing the relative capital cost. Secondly, differences in the amount of oil storage capacity result in Cameron's fuel oil system (accounting for 7 percent of total capital cost) costing twice as much as the PEDCo estimate. Similarly, the Industrial system had a 30 day oil storage capacity while PEDCo had only 7. The third major design difference is in the water treatment system. Cameron's treatment system cost over 20 times PEDCo's and accounts for 20 percent of Cameron's total capital cost. Unfortunately, the difference in cost cannot be explained due to insufficient specification of the equipment design parameters.

The comparison of non-fuel operating costs, presented in Figures A-4 and A-5, shows general agreement between the Industrial and Cameron estimates, while the PEDCo estimates are significantly higher. All estimates were normalized to an 85 percent capacity factor. (For this capacity factor, only utility services, such as electricity and water are variable. The major operating cost component, labor, is held constant since labor is employed in 8-hour shifts (7).)

The major factors accounting for the high PEDCo estimates are the inclusion of overhead costs beyond the boiler system, and higher staffing levels for operating and maintenance labor. The PEDCo estimate includes 30 percent of direct labor cost to cover payroll burden, and 25 percent of labor and materials cost for overhead which apparently corresponds to the fraction of the entire plant overhead allocated to the boiler system. The other estimates do not and so are not total operating costs. In addition, PEDCo's operating manpower levels are much higher than the other estimates. For oil-fired boilers, PEDCo labor levels range from one to five times as much as the Industrial source but are comparable to the Cameron level. For coal-fired installations, the manpower requirements are close for the small sizes, but PEDCo is over twice as large for boilers over 200 kpph. This is a significant difference since operating labor costs account for 10 percent of the

Industrial, and up to 40 percent of the PEDCo operating cost estimates.

A comparison of the Industrial and Cameron operating costs show that they are close for oil-fired systems, but differ for coal-fired systems. The main difference for both fuels is that Cameron underestimates maintenance costs by a factor of 10 compared to the Industrial and PEDCo estimates. For coal, this difference becomes apparent since all other operating cost components are the same as the Industrial Data. For oil, however, the difference is covered by the fact that the Cameron labor cost is twice that of the Industrial estimates.

The last cost component to consider is the annual fuel cost (AFC). Fuel cost can be expressed as a function of the size, capacity factor, and efficiency of the boiler system. Specifically:

$$AFC = \frac{\text{Size} \times \text{C.F.} \times \Delta H \times \text{F.C.} \times 8760\ \text{hrs/yr}}{\eta} \times 10^{-3}$$

where

AFC = Annual fuel cost

Size = Steam capacity of boiler in kpph

C.F. = Capacity factor expressed as decimal (2)

ΔH = Difference in enthalpy between feedwater and steam in BTU/lb steam

F.C. = Fuel cost in \$/MMBTU

η = System conversion efficiency

The system conversion efficiency relates the BTU's of steam produced per BTU of fuel consumed (not including the electricity used by the system). The efficiency depends on the boiler design, typically varying with type and size of boiler, how internal power requirements are met (i.e., steam vs. electric drive), whether stack re-heating is required, and whether the system is operating near full load or under partial load conditions (efficiencies are generally lower at partial load). The conversion efficiencies operating near full load for the systems reviewed are presented in Table A-3.

Pollution Control Costs

To meet the requirements of local and federal air pollution regulations, boiler systems will require some form of pollution control. In most cases, boilers are controlled for SO_2 and PM emissions. Nitrogen oxides (NO_x) emission limitations, when required, are generally met by combustion modification, which is not capital intensive (but does alter fuel economy somewhat).

SO_2 is controlled with Flue Gas Desulfurization (FGD) equipment. There are many different process types and system configurations that are used. For the purpose of this review, only costs for the dual alkali systems are compared since this is the system used in the Industrial and Cameron studies. (Costs for other systems, such as the sodium throwaway, dry scrubbing, and regenerable processes can be found in the Radian reports (5)).

Capital and operating costs for the FGD system are shown in Figures A-6 and A-7. Operating costs have been normalized to an 85 percent capacity factor by scaling costs for the raw materials, electricity, and water used in the scrubber. The base case chosen to compare the data is for a medium sulfur eastern coal with a 90 percent SO_2 removal level. Radian capital and operating cost data is also presented for 30, 50 and 70 percent SO_2 removal levels.

TABLE A-3: BOILER SYSTEM CONVERSION EFFICIENCIES (Btu steam/Btu fuel)

Cameron (electric drive)			
Nominal Size (Kpph)	100	200	650
Oil	.87	.87	.87
Coal with FGD*			
without reheat	.85S	.86S/.87PC	.87PC
with reheat	.81S	.81S/.81PC	.81PC
Industrial (steam drive)			
Nominal Size (Kpph)	50	250	500
Oil	.69	.69	.69
Coal			
without FGD	.70	.72	.73
with FGD (no reheat)	.69	.71	.71

*S - Stoker

PC - Pulverized Coal

Figure A-6: FGD Capital Cost

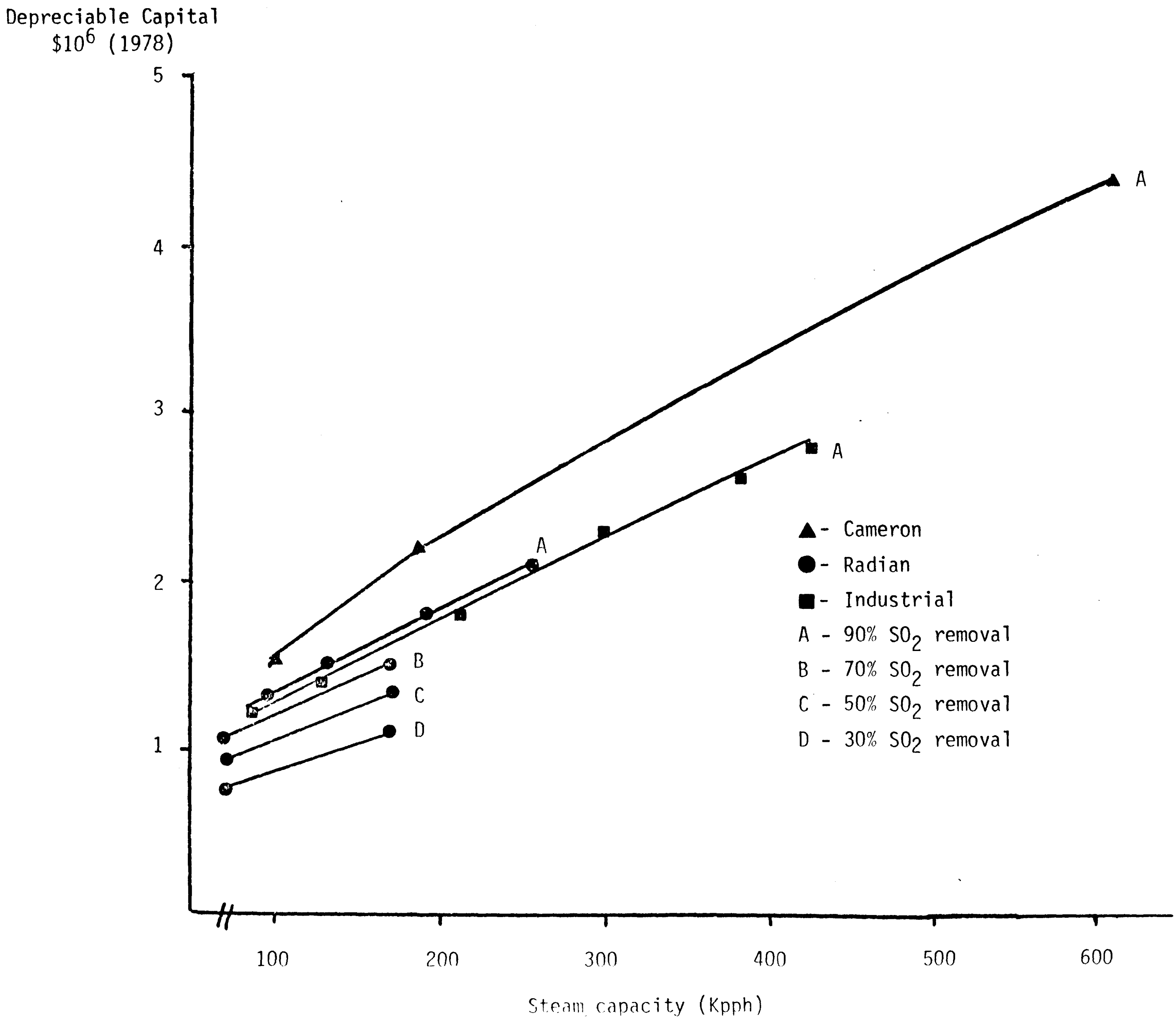
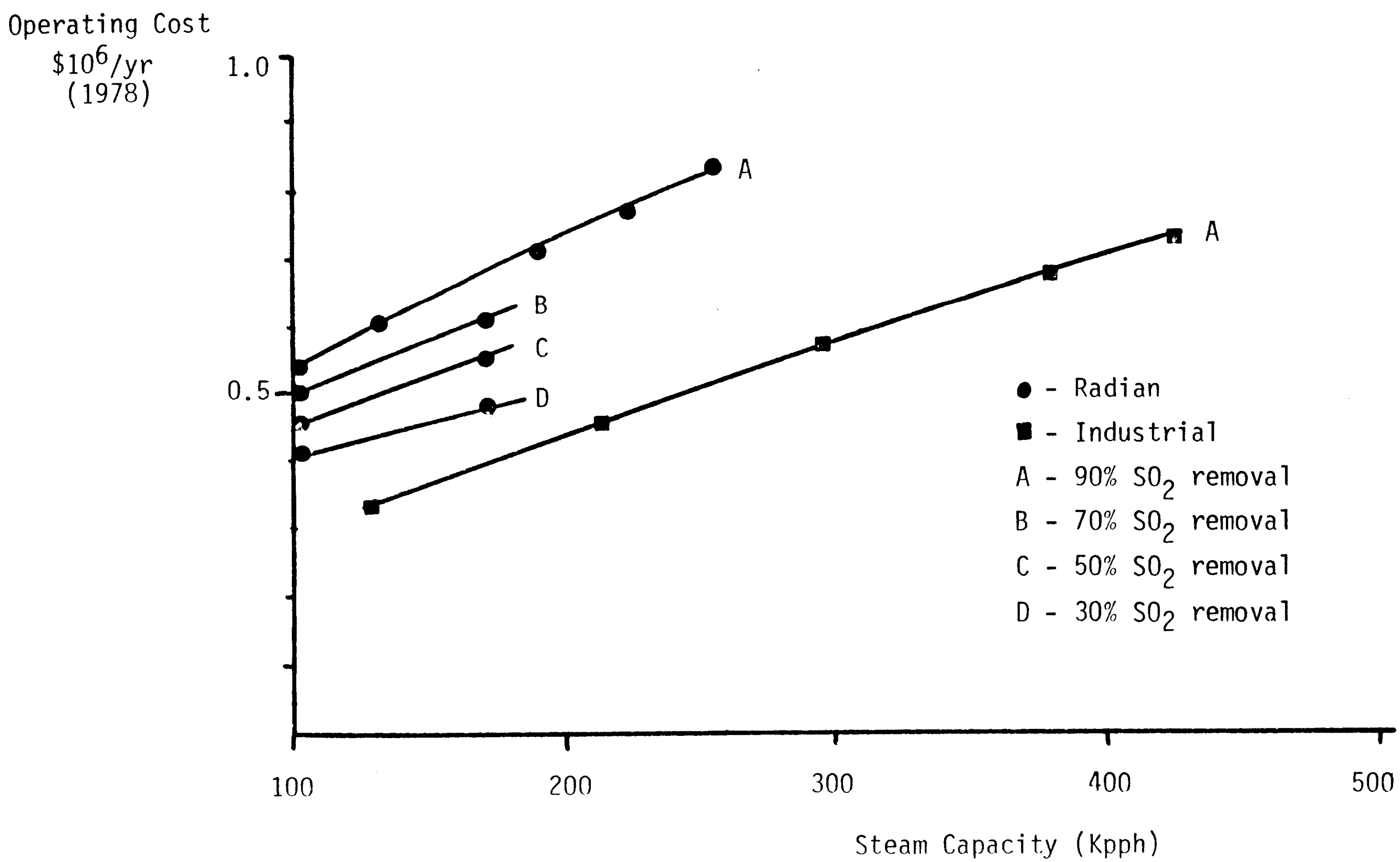


Figure A-7: FGD operating cost (at 85% capacity factor)



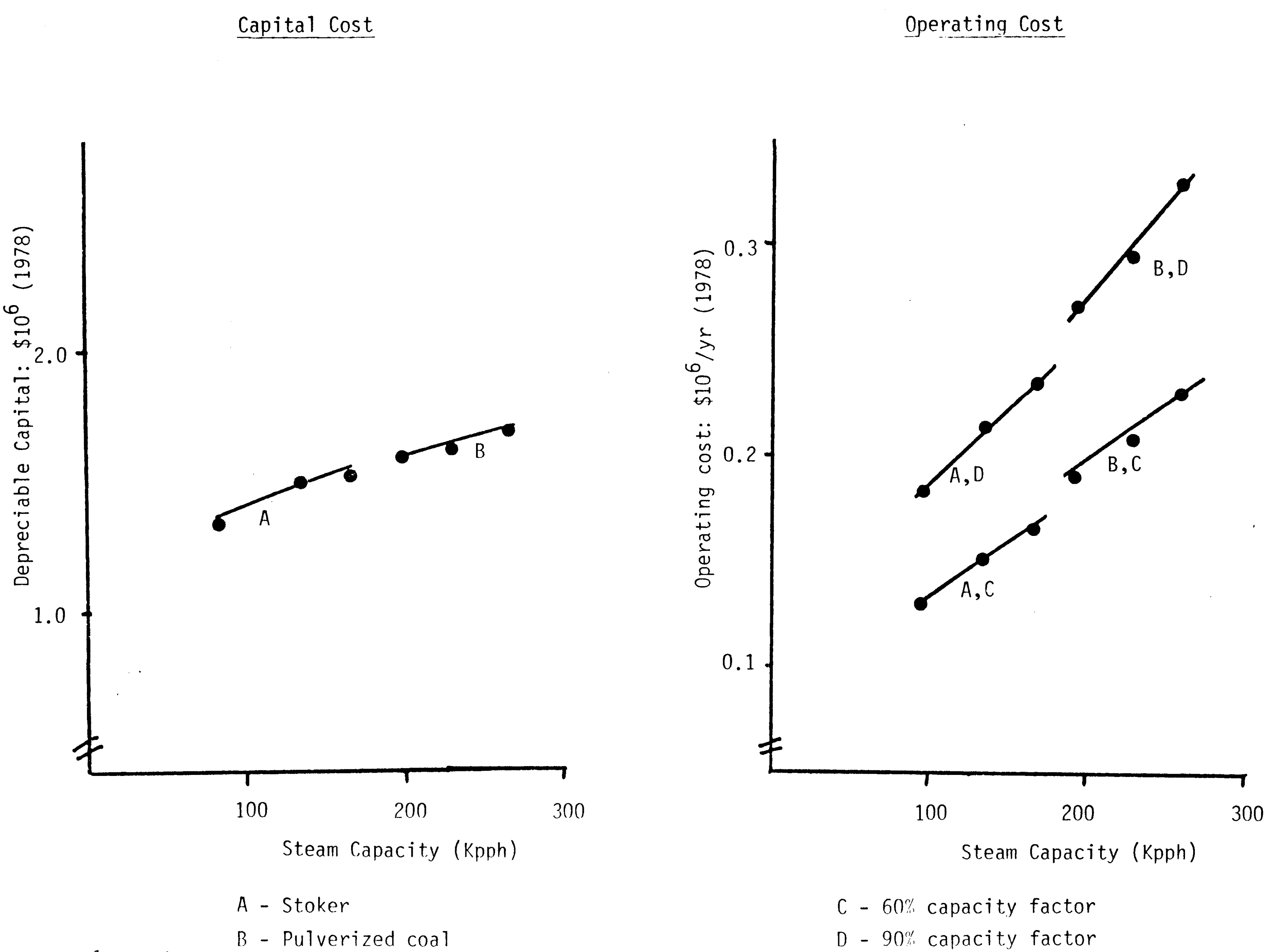
The comparison shows that the Radian and the Industrial capital cost estimates are well correlated, while the Cameron estimate is roughly 30 percent higher. The higher estimate is explained by design differences in terms of reliability and performance. The Cameron system is designed to achieve high reliability levels by including spare equipment for critical components. Items that are 100 percent spared include recirculation, soda ash transfer, regeneration return, and thickener underflow pumps. In addition, gas handling components were sized for 110 percent of expected flue gas flows in order to make sure removal requirements are always achieved. Lastly, the Cameron estimate includes flue gas reheat, which is not always included in industrial systems, while the Radian and Industrial estimates do not (8).

The FGD operating cost comparison, Figure A-7, was made only between Radian and the Industrial data since Cameron's costs were on an inconsistent basis. The difference between the two estimates is that Radian includes overhead cost components that are excluded in the Industrial estimate.

Particulate control can be achieved through a number of different processes including fabric filters, electrostatic precipitators, venturi scrubbers, and mechanical collectors. To achieve removal rates greater than 90 percent, the most effective systems are the ESP and fabric filters. In general, fabric filters are more cost effective for small boilers while ESP are suited for large systems. The actual decision must be made by comparing the capital and operating costs for both systems under the required operating conditions.

To provide an idea of PM control costs, Figure A-8 presents the cost for an ESP as a function of size for midwestern coal with 7.6 percent

Figure A-8: Particulate Control Cost (ESP)



ash. (Only the GCA estimates are shown since the Cameron and Industrial estimates for PM control are included in the boiler cost.) The capital cost of the system is determined by the control process, the amount of flue gas needed to be treated, the amount of ash entrained into the flue gas, and the level of control required. Different control costs are shown for stoker and pulverized coal boilers since they have difference ash entrainment levels (see Section A.2).

A.2 Environmental Factors

Local and federal air pollution standards impose limitations on boiler emissions. Industrial boilers that have a firing rate greater than 250 MMBtu/hr. are required to meet the Federal New Source Performance Standard (NSPS) of 1971. In contrast, utility boilers must meet a more stringent NSPS as revised in 1979 (9). The NSPS specifies the allowable emission rate for SO_2, NO_x, and PM per unit fuel combusted for oil, natural gas, and coal (see Table A-4). The industrial boiler NSPS is currently being reviewed and a new standard might soon be promulgated.

Additional requirements are prescribed by the Prevention of Significant Deterioration (PSD) and Nonattainment (NA) provisions of the Clean Air Act for major emission sources (10). Boilers must also meet the provisions of local standards specified in the State Implementation Plan (SIP) which vary from location to location.

PSD, NA and sometimes SIP regulations require air quality modeling of the emissions from the proposed source. In order to model the impact on air quality, the boiler system's annual emissions must be known. Annual emissons can be estimated from the specific emission factor for each

TABLE A-4: NEW SOURCE PERFORMANCE STANDARDS, (lb. pollutant/ MMBtu fuel)

Current Industrial Boiler Standard

	SO_2	PM	NO_x
Coal	1.2	0.1	0.7
Oil	0.8	0.1	0.3
Natural Gas	---	---	0.2

Revised Utility Standard (1979)

	SO_2*	PM	NO_x
Coal	90%	0.03	0.6
Oil	90%	0.03	0.3
Natural Gas	90%	0.03	0.2

*Percentage reduction of potential emissions. 1.2 lb./MMBtu ceiling, 0.6 lb./MMBtu floor with 70% scrubbing required below that.

pollutant (pound pollutant emitted per million Btu of fuel consumed) and the boiler systems's size and capacity factor. Typical emission factors for uncontrolled boilers are presented in Table A-5, while emissions from controlled boilers can be factored from the uncontrolled rate by applying the percentage reduction achieved.

Specific emission factors vary for each fuel type and for the particular combustion system's characteristics. For example, particulate emissions from uncontrolled coal-fired boilers will vary with the amount of ash in the coal and with the type of boiler. Thus, even for the same coal, the three types of stoker boilers and the pulverized coal boiler each have a different level of particulate emissions. This occurs since the manner of fuel injection into the combustion chamber critically affects the distribution of ash between that carried out with the flue gas and that dropped out as bottom ash. Similarly, NO_x emissions from gas, oil, and coal-fired boilers vary with the combustion air level, flame temperature, residence time within the particular combustion chamber and with fuel characteristics.

To provide an idea of the range of annual emissions, Figure A-9 presents an example for three boiler sizes used at two different capacity factors as a function of the specific emission factor. It is important to note that any boiler emitting over 100 tons per year qualifies as a major emission source, and thus must meet PSD and NA.

TABLE A-5: Specific emission factors for uncontrolled boilers (lbs./MMBtu fuel)[a]

	SO_2	PM	NO_x
Natural gas	0.0006	0.01	0.279
MBG/LBG	$20{,}000\frac{S}{B}\,\frac{(1-SR)}{\eta}$	0.01	0.279
Resid (0.8%S)	0.8	0.08	0.37
Resid (3%S)	3.138	0.22	0.37
Distillate	0.2	0.014	0.209
Coal			
Underfeed stoker	$19{,}000\frac{S}{B}$	$2500\frac{A}{B}$	0.349
Chaingrate stoker	$19{,}000\frac{S}{B}$	$2500\frac{A}{B}$	0.325
Spreader stoker	$19{,}000\frac{S}{B}$	$6500\frac{A}{B}$	0.616
Pulverized coal	$19{,}000\frac{S}{B}$	$8000\frac{A}{B}$	0.663

a) For boilers over 30 MMBtu/hr., Reference, see note 11.

S = % sulfur in coal

A = % ash in coal

B = Btu/lb. of coal

SR = % sulfur removal of gasifier (decimal)

η = gasifier efficiency (Btu gas out/Btu coal in)

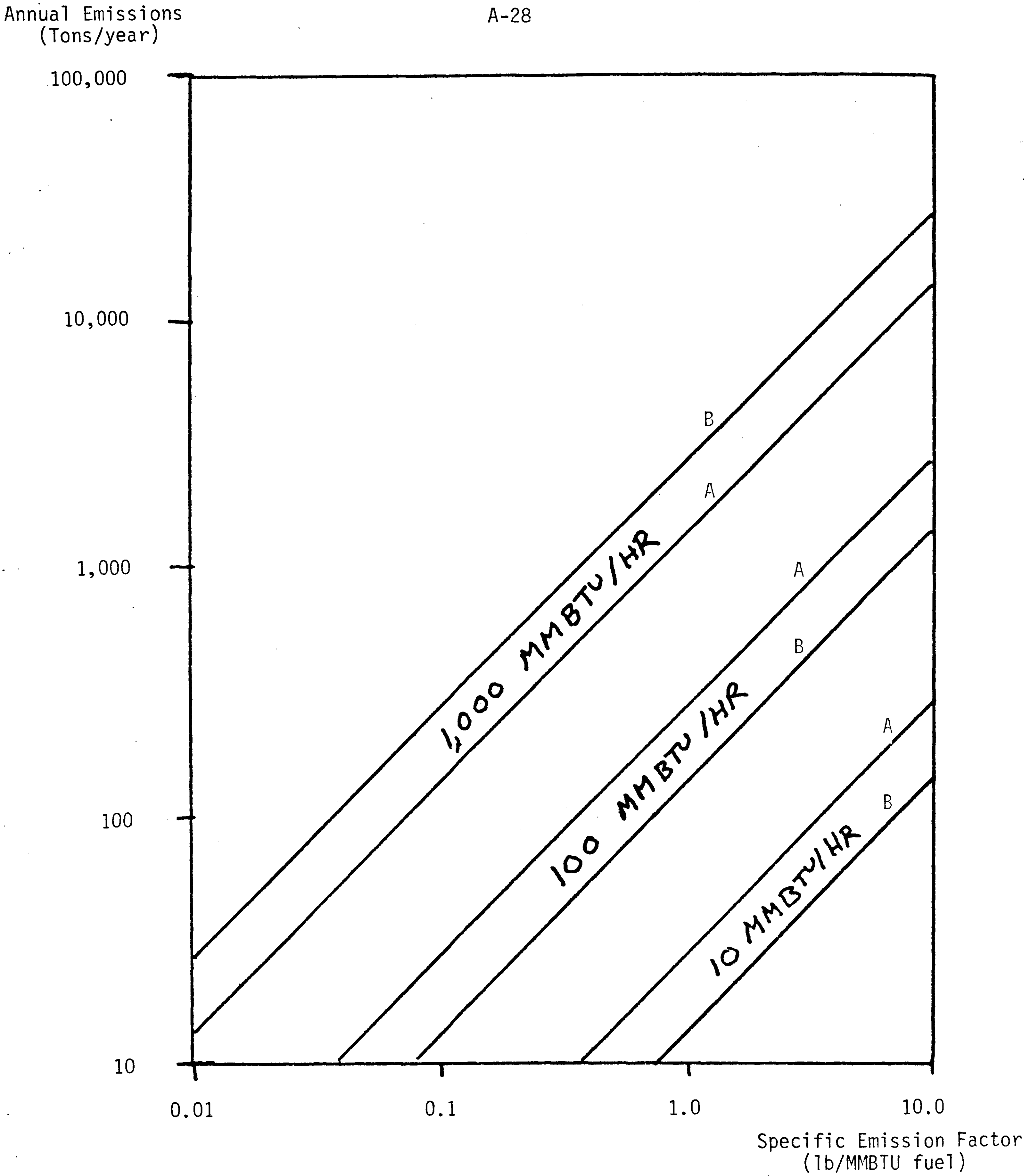


Fig. A-9: Annual Boiler Emissions

A - 60% capacity factor

B - 30% capacity factor

Notes

1. A simplified cost analysis methodology is used to calculate steam costs presented in Figure 1.1-1 based on the Industrial Data base. The methodology is adopted from the Electric Power Resaerch Institute's "Technical Assessment Guide", July 1979, not including the inflation and tax considerations. (In EPRI's method, inclusion of taxes increase the annual fixed charge rate. By considering a range of discount rates, the analysis presented here includes the values that would be obtained if taxes were considered.) Annualized steam costs were calculated by:

$$\text{Steam Cost} = \frac{\text{AFCR x Capital + Annual Operating and Fuel Costs}}{\text{Annual Steam Production}}$$

where AFCR is the annual fixed charge rate. In this case AFCR = Capital Recovery Factor (CRF) and is calculated by:

$$\text{CRF} = \frac{i(1+i)^n}{(1+i)^n - 1}$$

where i = interest rate
n = lifetime of boiler in years

The base case assumptions are: 60 percent capacity factor, 15 percent real interest rate, 30 year lifetime of boiler, $1.50/MMBtu coal price, $5/MMBtu oil price.

2. Capacity factor is defined as the ratio of the actual annual amount of steam produced to the maximum annual steam produced if full capacity for 8760 hours per year could be maintained.

3. For an idea of the variations in coal handling systems, see: Babcock and Wilcox Co., Steam: Its Generation and Use, 1975; and Midkiff, L.A., "Designing for Coal-Handling Flexibility," Power, November 1979.

4. Cameron Engineers, "Solid Fuels for U.S. Industry, Volume III, Economics of Coal Utilization," March 1979.

5. The EPA series of reports include:

Energy and Environmental Analysis, "Industrial Fuel Choice Model," June 1980.

GCA, "Technology Assessment Report for Industrial Boiler Applications: Particulate Collection," December 1979.

PEDCo Environmental, "Capital and Operating Costs for Industrial Boilers," June 1979.

PEDCo Environmental, "Cost Equations for Industrial Boilers," January 1980.

PEDCo Environental, "The Population and Characteristics of Industrial/ Commercial Boilers," August 1979.

Radian, "Costs of Sulfur Dioxide and Particulate Matter Emission Control for Coal- and Oil-Fired Industrial Boilers," August 1981.

Radian, "Technology Assessment Report for Industrial Applications: Flue Gas Desulfurization," November 1979.

6. Capital costs were normalized using the Chemical Engineering Plant Cost Index, operating costs using the GNP price deflator. A description of the breakdown of capital and operating costs is presented in Chapter III, Section 2, "Definition of Cost Items." Boiler estimates do not include working or startup capital.

7. For boilers operated with less than 3 shifts/day, 7 days/week, the labor component of operating cost should be adjusted by:

Capacity Factor Range	Labor Cost Adjustment
75-100 percent	1
50-75 percent	.75
30-50 percent	.50
0-30 percent	.30

8. Stack gas reheat requirements are determined by regulations that are based on local air quality, in particular PSD, NA, SIP. Reheat is employed to decrease pollution concentrations to the required ambient air quality levels by increasing plume rise which results in greater pollutant dispersion. Very few SIP standards specify flue gas dispersion requirements for industrial boilers and, to date, not many industrial boilers have needed to use reheat to meet PSD requirements.

9. Environmental Protection Agency, "New Source Performance Standards: Electric Utility Steam Generating Units," Federal Register, June 11, 1979.

10. Major emission sources are now interpreted as any source that emits over 100 tons per year of SO_2, NO_x, or PM after pollution control is applied. See United States Court of Appeals for the District of Columbia Circuit, "Alabama Power Company vs. Costle EPA," December 1979.

11. Energy and Environmental Analysis, "Industrial Fuel Choice Analysis Model," June 1980, page 5-10.

APPENDIX B

STEAM RAISING: STEAM TURBINE COGENERATION

B.1 INTRODUCTION

Any industrial plant may be seen as a complex energy conversion system in which raw materials, fuels, and other inlet streams constitute the front end and finished products and other outlet streams constitute the back end of the system. If all inlet and outlet streams are identified and properly quantified, at equilibrium the system behaves as a steady-state system, and energy is "conserved," i.e., the sum of the energy content of all inlet streams will equal the sum of the energy content of all outlet streams. Consequently an energy balance of the system as a whole will not give any clear idea of how energy flows within the system. When back end streams are divided (always somehow arbitrarily) into "useful products" and waste streams, the amount of input energy not found into useful products may be quantified and a first energy efficiency of the system may be defined as the ratio between the energy content of the useful products and the total energy content of inlet streams: this efficiency is generally known as first law efficiency. Once every waste stream is associated to a source (i.e., a system's component or components) proper action may be taken to minimize the energy loss of that set of components, either by altering the components characteristics (therefore at a component level, e.g., adding insulation) or using the waste stream (generally) internally to the system to perform some task that otherwise would be performed through an amount of inlet stream energy (therefore at a system level, e.g., pre-heating combustion air). This practice, often known as first law optimization, is generally well established in the industry; its purpose is to minimize primary energy requirements by minimizing the amounts of energy in the waste streams.

However neither thermodynamics nor economics value a fixed amount of energy based only on the quantity of energy considered, e.g.,

- a certain amount of energy, say a million BTU furnished at constant temperature as low-pressure saturated steam is economically valued on the range of ten dollars. Its thermodynamic value may be defined through the efficiency of a Carnot cycle and equals the maximum amount of work that may be obtained from the steam (as previously defined) through a heat interaction with the atmosphere; in this case, assuming a 200 psia saturated steam condition (heat source at 380 degrees F) and a 50 degrees F atmospheric temperature, approximately 390,000 BTU of work (or 115 kWh).
- the same amount of energy, i.e., one million BTU (or 293 kWh) if furnished as electric energy is economically valued at least 15 dollars and its thermodynamic value again may be set equal to the maximum work that may be generated with that amount of energy, in this case, one million BTU (or 293 kWh) since electric energy may be considered as pure work.

It is clear that this distinction between identical amounts of energy is not perceived by the previously defined first law optimization, while it is clearly perceived by any economic or thermodynamic analysis of the system, as it has been shown using the previous intuitive examples and a semi-rigorous thermodynamic approach.

Very often energy flows within a system degrade their thermodynamic (and economic) value without performing any useful task (and many times losing little if any energy): for instance this happens in any combustion process (in which close to 30 percent of the capacity of performing work is lost by the system while changing state from fuel and combustion air to combustion gases) and in any heat exchanger (among other things, the higher the difference in temperature between the hot and the cold stream). In the latter case, and for most industrial processes, the difference in temperature may be many hundreds of degrees Rankine (corresponding to the difference in temperature between the combustion gases--approximately 4,000 degrees Rankine and the working fluid heated by the combustion gases at maximum temperatures set by technology, materials or economic limitations (approximately 1,500 degrees Rankine) and the temperature at which the heat is delivered to process (700-800 degrees Rankine in the majority of industrial processes). This is where cogeneration plays its role (the better the higher the working fluid temperature and the lower the process temperature requirement) by making use of the change of state in which the working fluid incurs while degrading its thermodynamic (and economic) value from high to low temperatures; while that change of state occurs electric energy (pure work) is generated, and only then, low-temperature heat is delivered to process. The fuel requirement to supply only a certain amount of heat to process may be (and generally is) higher in cogeneration systems than in standard boilers; the fuel requirement to generate only a certain amount of electricity is always higher in cogeneration systems than in central power plants; but the fuel requirement to supply a combined thermal and electric load with cogeneration systems is less than the combined fuel requirement of a standard boiler system supplying the thermal load and a central power plant supplying the electric load. In other terms the incremental fuel consumption of cogeneration system with respect to traditional boilers is less than the amount of fuel needed by a central power plant in order to generate the same amount of electricity. Therefore cogeneration will always be a primary energy saving technology; its economic viability will be determined by whether or not the value of the cogenerated electricity may offset the larger capital cost of the facility, the incremental fuel consumption and the incremental O and M expenditure.

The purpose of this appendix is to analyze under what conditions cogeneration systems will be viable, through a well-defined thermodynamic analysis of conceptually designed systems in order to obtain a generally valid methodology for the economic assessment of cogeneration systems at a regional level aimed at interfuel switching analysis.

B.2 METHOD OF ANALYSIS

B.2.1 Thermodynamic Analysis

The cogeneration system is conceptually designed to supply a thermal load at various temperatures. The thermodynamic cycle characteristics are computed and the system characteristics are furnished on a per million BTU/hr of heat delivered to process base for various process temperatures. The thermodynamic definition of the cycle is obviously independent of the size of the system and of the thermal load duration curves and would be valid for any system, cogenerating or not, whose working fluid changes state following that cycle. Some of the usual cycle parameters have also been redefined and re-computed in order to gain further insight on the thermodynamic performance of cogeneration systems.

It will be shown in the next subsection that a particularly useful way of assessing cogeneration systems economics is obtained by comparing the cogeneration systems' economics to the economics of their existing alternatives, performing an incremental analysis (this approach follows also from the analysis presented in the Introduction). Consequently, an incremental thermodynamic analysis is also performed in which only the incremental fraction of the working fluid changes of state (as described by the thermodynamic cycle) with respect to the same working fluid operating within an existing, standard boiler thermodynamic cycle are assessed against the cogeneration system. If the working fluids and/or cycles are different in the standard and cogeneration systems, a thermodynamic comparative analysis may not be directly performed; then merely incremental fuel consumption is assessed against the cogeneration system. Since cogeneration is seen in this study as an alternative technology for steam raising, electricity is here considered a by-product and all increments will be charged against it.

Although the same nomenclature is used in this incremental thermodynamic analysis as in a classical thermodynamic analysis, none of the cycle characteristics obtained through this approach has any physical meaning; furthermore, all of the cycle characteristics will be dependent upon the standard system taken into consideration and with respect to which the incremental analysis is performed. In spite of those caveats, the incremental thermodynamic analysis, when coupled to an incremental economic analysis consistently performed allows making use of the usual relationships between thermodynamic performance and economic evaluation of central power plants.

B.2.2 Economic Analysis

The cogeneration system is conceptually designed and its costs assessed. Then, the economic analysis of the cogeneration plant is performed, also as an incremental investment with respect to a traditional system, assessing all incremental capital, fuel and O and M costs against the cogenerated electric power, here seen as a by-product. This, and the incremental thermodynamic analysis mentioned in the previous section are sufficient to characterize the cost and cost structure of the cogenerated power. This cost is compared then to the cost of electricity available to the industry in order to assess the economic viability of the cogeneration plant. The thermodynamic and economic incremental analysis allow therefore the performance of the usual analysis of power plants for what concerns sensitivity to load factors and cost of fuels and altogether perfectly defines and explains the economic behavior of the plant.

It will be shown how the cost structure of the busbar generation cost of cogenerated electricity is a particularly useful tool to assess cogeneration systems viability and characteristics under a wide range of economic scenarios.

B.3 STEAM TURBINE COGENERATION SYSTEMS

B.3.1 System Thermodynamic Analysis

The system's thermodynamic performance for different turbine inlet conditions and process pressure and temperature requirements for an ideal system in which heat is furnished at process as de-superheated saturated steam, 100 percent return available as saturated water at process pressure, no in-house auxiliaries power, no extractions, no re-heating, and with boiler, steam turbine system and electric generator efficiencies of 0.9 is presented in Tables B.1, B.2 and B.3 for low, medium and high process pressure steam requirements; the electric power installed is furnished on a per million BTU/hr of heat delivered to process.

From the above mentioned tables it may be seen that:

- the installed electric power increases as the process pressure decreases and/or as the steam at turbine inlet increases
- the thermal efficiency (as previously defined) decreases as the installed electric power increases (and for the same reasons)
- the electric efficiency (as previously defined) increases as the installed electric power increases (and for the same reasons)
- the cycle efficiency is:
  - substantially constant (i.e., independent of process pressure or steam turbine inlet conditions)
  - set by the boiler and electric generator efficiency and by all other components efficiency but
  - independent from steam turbine efficiency (the latter will influence, however, electric <u>and</u> thermal efficiencies) and
  - higher the lower is the electric power installed (due to electric generator losses)
- The incremental heat rate (as previously defined) is independent of process pressure and depends on cogeneration system efficiency and on the standard boiler system used for comparison.

Quite evidently, the main energy losses of this ideal cogeneration system are at the boiler and at the generator; both components have now

Table B.1

THERMODYNAMIC PERFORMANCE OF AN IDEAL COGENERATION SYSTEM

PROCESS PRESSURE: 50 psia

Steam turbines inlet conditions	650 psia 800°F	1200 psia 900°F	1500 psia 900°F	2500 psia 1000°F
Electric Power, $\dot{W}_e$ [kWe]	66	83	87	102
Thermal Efficiency, η_{th}	.72	.68	.68	.65
Electric Efficiency, η_e	.16	.19	.20	.23
Cycle efficiency,* $\eta_{th}+\eta_e$	.89	.88	.88	.88
Incremental heat rate [(BTU/hr)/kWe]	4,200	4,200	4,200	4,200

*Eventual differences in values are due to reduced number of significative figures η_{th} and η_e.

Table B.2

THERMODYNAMIC PERFORMANCE OF AN IDEAL COGENERATION SYSTEM

PROCESS PRESSURE: 200 psia

Steam turbines inlet conditions	650 psia 800°F	1200 psia 900°F	1500 psia 900°F	2500 psia 1000°F
Electric Power, $\dot{W}_e$ [kWe]	34	53	58	76
Thermal Efficiency, η_{th}	.80	.75	.74	.71
Electric Efficiency, η_e	.09	.14	.15	.18
Cycle efficiency,* $\eta_{th}+\eta_e$	.89	.89	.89	.89
Incremental heat rate [(BTU/hr)/kWe]	4,200	4,200	4,200	4,200

*Differences in values are due to reduced number of significative figures.

Table B.3

THERMODYNAMIC PERFORMANCE OF AN IDEAL COGENERATION SYSTEM

PROCESS PRESSURE: 400 psia

Steam turbines inlet conditions	650 psia 800°F	1200 psia 900°F	1500 psia 900°F	2500 psia 1000°F
Electric Power, $\dot{W}_e$ [kWe]	15	35	38	59
Thermal Efficiency, η_{th}	.85	.79	.79	.74
Electric Efficiency, η_e	.04	.09	.10	.15
Cycle efficiency,* $\eta_{th}+\eta_e$	.89	.89	.89	.89
Incremental heat rate [(BTU/hr)/kWe]	4,200	4,200	4,200	4,200

*Differences in values are due to reduced number of significative figures.

reached a quite high efficiency (close to .9). The steam turbine efficiency (also on the range of .9) acts mainly as a switch between thermal and electric power output and has no major effect on the overall energy conversion efficiency of the system, here defined as cycle efficiency. Pumping power is practically totally recovered as enthalpy of the working fluid at the pump outlet, pumps efficiency being also on the range of .9. Various steam losses may be substantially recovered by re-injection of steam at lower pressure stages and may be kept well below 2 percent. Pressure drops, highly dependent on system geometry are not taken into account. The steam turbine cogeneration system appears therefore to be a well established technology, with little space for improvements both at a system and components level. The efficiency with which the fuel energy is usefully employed is very high. Furthermore, due to the use made of the heat that otherwise would be delivered to the low temperature reservoir, the incremental heat rate of the cogenerated electricity is on the range of one half of the heat rate of central power plants.

All this, taking into consideration amounts of energy usefully employed (thermal and electric), compared to amount of energy in fuel. A further insight into cogeneration systems' thermodynamic performance is given by the second approach presented in the introduction, concerning the different economic and thermodynamic value of identical amounts of energy.

The behavior of the system under this approach will depend upon both steam turbine inlet conditions and process pressure as well as upon all component efficiencies, including turbine efficiency (and reservoir temperature). More specifically it will be a function of thermal and electric efficiencies (as previously defined), those two parameters taking into consideration all functional dependencies with respect to components efficiencies, steam turbine inlet conditions and process pressure, and of process and atmospheric temperature.

The computation of the efficiency of conversion under this approach, for each process pressure, shows how the systems thermodynamic performance (say, at 200 psia process pressure) decreases ceteris paribus, from 0.46 for steam turbine inlet at 2500 psia, 1,000° F to 0.40 for steam turbine inlet at 650 psia, 800° F (while it would increase increasing the process pressure).

Approximately two thirds of this work generation comes from the ideal heat engine: if we were to take into account that less than half of that amount of work may be really generated, the efficiency here considered would be, for most systems' configurations and process pressures, below .3. It should be stressed, however, that the second law efficiency computed strictly as indicated in the introduction is higher than the correspondent efficiency of a traditional boiler and central power plant (.30-.35) supplying the same thermal and electric load. Many other ways of computing "significative" adimensional performance ratios (often called "efficiencies") of the cogeneration system exist, but the one presented here should be sufficient to make the point that cogeneration systems are, under any condition, a substantially inefficient way of generating electricity only, certainly less efficient than standard power plants. The fact that cogeneration plants are also a less efficient way of heat only supply is merely academic and may be seen immediately from the previous tables simply comparing the thermal efficiency of the cycle with the efficiency of a standard boiler, in this case assumed to be .9

for both systems.

The point here made is that no miracle may be expected from cogeneration systems. They are substantially a power plant in which the steam expansion is interrupted at process pressure (and consequently are a less efficient way of generating electricity only) and heat is then delivered to process. It has been shown how even if that heat source was to be used to generate work, the total electricity generated would still be less (for a fixed amount of fuel) than the electricity that might have been generated, with the same amount of fuel, by a central power plant, i.e. Rankine cycle is a more practical and efficient way to generate work than heat engines. Or they are substantially a traditional boiler system in which a better use of fuel availability is made, reducing the irreversibilities generation by letting the working fluid cool down at process temperature through an expansion on a turbine. However, it is very important to notice that energy-wise (say, first law efficiency-wise) cogeneration systems are less efficient than traditional boilers; availability (or maximum work, say second law efficiency-wise) cogeneration systems are less efficient than central power plants. A better thermodynamic performance may be stated only if the cogeneration system is compared simultaneously to both a central power plant (in which heat at low temperature is delivered to reservoir) and to a boiler system (in which the only use made of the high temperature heat available is at low temperature). The surprising cycle efficiency presented in the Tables B.1, B.2 and B.3 should be interpreted only in these terms, i.e. effectively most of the energy of the fuel is usefully employed (but only because a useful use of what could otherwise be a waste stream is found, and even then with a lesser efficiency than a traditional boiler); also, a proper use of the fuel availability is achieved (and even then to a lesser extent than in central power plants if the real work that might have been extracted from the low-temperature heat source is taken into consideration).

However, in order to furnish a fixed amount of process heat and generate the correspondent amount of electricity cogeneration fuel consumption will be inferior to the fuel consumption of a traditional boiler system and a power plant furnishing respectively the same amount of heat and electricity. This sort of "duality", clearly seen into any economic evaluation of cogeneration systems derives therefore from the thermodynamic analysis of the systems. The delta in fuel consumption (or cogeneration system fuel savings) per unit of heat delivered to process may be immediately shown to be:

$$\Delta = 1/\eta_b + (\eta_e - \eta_{cpp})/(\eta_{cpp}(\eta_c - \eta_e)) \quad (1)$$

$$= 1/\eta_b + (\eta_c - \eta_{th} - \eta_{cpp})/(\eta_{cpp}\ \eta_{th})$$

$$\dot{\Delta} = (\eta_c - \eta_{cpp})/(\eta_c - \eta_e)^2 \quad (2)$$

$$= (\eta_c - \eta_{cpp})/\eta_{th}^2$$

$$\Delta\text{percent} = \Delta/(1/\eta_b + \eta_e/((\eta_c - \eta_e)\ \eta_{cpp})) \quad (3)$$

$$= \Delta/(1/\eta_b + (\eta_c - \eta_{th})/(\eta_{th}\eta_{cpp}))$$

where:

η_b = traditional boiler system overall efficiency

η_{cpp} = central power plant efficiency

η_c, η_{th}, η_e as previously defined.

The delta in fuel consumption is therefore a monotonic increasing (or decreasing) function of η_e (or η_{th}); the first derivative increases (or decreases) approximately as η_e^2 (or precisely as η_{th}^2), with an asymptote at $\eta_e = 0.89$ (or $\eta_{th} = 0$).

For values of η_{th} on the range of 0.885 (cogeneration cycle efficiency including loss at electric generator) the fuel savings are zero and the cogeneration system behave practically as a traditional boiler system with an additional loss at electric generator. For a realistic value of η_e, say .2 (and a cycle efficiency of .89), fuel savings are approximately 27 percent (ideal cogeneration system with respect to traditional boiler systems and central power plant).

Overall fuel savings depend therefore upon electric and thermal efficiencies of conversion of cogeneration systems (and consequently upon cogeneration system characteristics and process pressure) as well as on the efficiency of conversion of traditional boiler systems and power plants. It should be stressed that the incremental heat rate is, under all realistic conditions, independent of process pressure and turbine inlet conditions, and depends only on boiler and electric generator efficiency as well as on the traditional boiler system with respect to which the incremental analysis is performed.

B.3.2 System Economic Analysis

In order to gain some insight on how the thermodynamic performance of the cogeneration system varies upon variation of some systems' characteristics and components' efficiency, cogeneration systems identical to the ones discussed in section 3.3.1, but with a boiler efficiency of .85 (instead of .9) and some excess steam requirements will be defined for the economic analysis.

The decrease in boiler efficiency is here assumed to be the same for the traditional boiler system than for the cogeneration system. The excess steam requirement may be viewed in different ways, in as much as it is equivalent to an incremental fuel consumption with respect to the one considered in the previous section. For traditional boiler systems, the increment in fuel consumption may provide some extra steam for auxiliary power (low pressure steam turbine and/or jet pumps, etc.) or it may be assessed against make up water heating up to condensate temperature if electric drives are taken into consideration (in this case, 50 percent recovery at condensate temperature is assumed), besides accounting for some of the steam lines losses (headers, pressure drops, etc.)

Same options for the cogeneration system, for what concerns make up water requirements and/or auxiliary power low pressure turbines feed (the latter will also supply low pressure steam for deaeration). Steam losses in cogeneration system might be higher due to different steam conditions and systems' complexity; however also recovery possibilities are more important and therefore differences between the two systems may be neglected. Any consistent set of options for incremental fuel usage for both systems may be chosen, e.g. make up water heating requirements, or drives, or drives and losses for the traditional boiler system and steam for deaeration (with correspondent power generation and power from previous expansion on high pressure turbine stages) for cogeneration.

In this analysis a fraction of 13 percent of the generated steam is diverted from process (or 13 percent of fuel usage is for make up water heating up to process condensate temperature, etc.). For 200 psia process steam, the low, medium and higher pressure cogeneration system thermodynamic performance table, under the previous assumptions, is presented in Table B.4. Unless previously specified, all underlying assumptions and definitions are the same used for Tables B.1, B.2, B.3. Finally, it should be noticed that none of the conclusions drawn on the previous section have been inferred.

Capital, O and M and fuel costs for the medium pressure cogeneration system (oil or coal fired) and a traditional boiler system (oil or coal fired) for 200 psia process steam requirement have been computed. Discount rate is assumed to be 15 percent/yr, real; system life 20 years; zero salvage; all costs are therefore in year zero dollars, i.e. 1980$. Differences in efficiency of combustion and conversion between oil and coal boilers are neglected. Cogeneration systems are as previously defined. Three 1/3 size boilers, no back-up have been considered. Fuel costs are 2.50 $/$10^6$BTU for coal and 6.17 $/$10^6$ BTU for oil (1980$) i.e. high fuel cost scenario. The results for flat process steam loads of 1,000, 250 and 125 10^6 BTU/hr, 100 percent of the time with costs scaled up to the high pressure system are presented in Tables B.5, B.6 and B.7. Economy of scale for O and M costs has been neglected as well as O+M dependency on load factor (O+M costs correspond to a load factor of approximately .85). The capital costs presented, if scaled down to usual size references with usual scale factors correspond to approximately 1,100 $/$KW_e$ for $1MW_e$; 85,000 and 25,000 $/$10^6$ BTU/hr for 100 10^6 BTU (coal and oil boiler respectively). O and M costs have been assumed to be 1$ and .25$ per 10^6 BTU/hr of steam (coal and oil boiler respectively) and 4 mills/$KWhr_e$.

The total cost per million BTU delivered to process may be immediately derived (as a function of load factor) with simple algebraic

Table B.4

THERMODYNAMIC PERFORMANCE OF COGENERATION SYSTEM

PROCESS PRESSURE: 200 psia

Steam turbines inlet conditions	650 psia 800°F	1200 psia 900°F	2500 psia 1000°F
Electric Power, $\dot{W}_e$ [kWe]	35	54	76
Thermal Efficiency, η_{th}	.67	.63	.59
Electric Efficiency, η_e	.08	.12	.16
Cycle efficiency, $\eta_{th}+\eta_e$	.75	.75	.75
Incremental heat rate [(BTU/hr)/kWe]	4,400	4,400	4,400

TABLE B.5

HIGH PRESURE COGENERATION SYSTEM AND TRADITIONAL BOILER SYSTEM
CAPITAL, O AND M AND FUEL COSTS (1980$)

200 psia process steam: 1000 10^6BTU/hr, 100 percent of time

Oil Boiler System	capital	29 10^6 $	4.3 10^6 $/yr
	O and M		2.5 10^6 $/yr
	fuel		71.7 10^6 $/yr
Coal Boiler System	capital	76 10^6 $	11.4 10^6 $/yr
	O and M		9.9 10^6 $/yr
	fuel		29.1 10^6 $/yr
Cogeneration Oil Fired System (thermal gen.)	capital	35 10^6 $	5.3 10^6 $/yr
	O and M		3.1 10^6 $/yr
	fuel		89.5 10^6 $/yr
Cogeneration Coal Fired System (thermal gen.)	capital	89 10^6 $	13.4 10^6 $/yr
	O and M		12.3 10^6 $/yr
	fuel		36.2 10^6 $/yr
Steam Turbine System	capital	18 10^6 $	2.7 10^6 $/yr
	O and M		2.6 10^6 $/yr

TABLE B.6

HIGH PRESURE COGENERATION SYSTEM AND TRADITIONAL BOILER SYSTEM
CAPITAL, O AND M AND FUEL COSTS (1980$)

200 psia process steam: 250 10^6BTU/hr, 100 percent of time

Oil Boiler System	capital	8 10^6 $	1.2 10^6 $/yr
	O and M		.6 10^6 $/yr
	fuel		17.9 10^6 $/yr
Coal Boiler System	capital	27 10^6 $	4.1 10^6 $/yr
	O and M		2.5 10^6 $/yr
	fuel		7.3 10^6 $/yr
Cogeneration Oil Fired	capital	10 10^6 $	1.5 10^6 $/yr
System	O and M		.8 10^6 $/yr
	fuel		22.4 10^6 $/yr
Cogeneration Coal Fired	capital	32 10^6 $	4.8 10^6 $/yr
System (thermal gen.)	O and M		3.1 10^6 $/yr
	fuel		9.1 10^6 $/yr
Steam Turbine System	capital	7 10^6 $	1.1 10^6 $/yr
System (thermal gen.)	O and M		.7 10^6 $/yr

TABLE B.7

HIGH PRESSURE COGENERATION SYSTEM TRADITIONAL BOILER SYSTEM

CAPITAL, O AND M AND FUEL COSTS (1980$)

200 psia process pressure: 125 10^6BTU/hr, 100 percent of time

Oil Boiler System	capital	4 10^6 $	.7 10^6 $/yr
	O and M		.3 10^6 $/yr
	fuel		9.0 10^6 $/yr
Coal Boiler System	capital	16 10^6 $	2.4 10^6 $/yr
	O and M		1.2 10^6 $/yr
	fuel		3.6 10^6 $/yr
Cogeneration Oil Fired System (thermal gen.)	capital	5 10^6 $	.8 10^6 $/yr
	O and M		.4 10^6 $/yr
	fuel		11.2 10^6 $/yr
Cogeneration Coal Fired System (thermal gen.)	capital	19 10^6 $	2.9 10^6 $/yr
	O and M		1.5 10^6 $/yr
	fuel		4.5 10^6 $/yr
Steam Turbine System	capital	5 10^6 $	.7 10^6 $/yr
	O and M		.3 10^6 $/yr

manipulation of the data presented in Tables B.4, B.5, B.6 and B.7. The results are presented in Table B.8.

The minimum required revenue from cogenerated electricity has now to be computed in order to be able to obtain the busbar generation cost of cogenerated electricity. This will be done assessing against cogenerated electricity all deltas in capital, O and M and fuel of the cogeneration system with respect to the alternative system used for comparison (in this case a traditional boiler system). This conceptually simple operation goes far beyond the implementation of a thorough and complete financial analysis. Main issues are not only discount rates or further tax sheltering due to debt financing, but the approach to and the traditional system of comparison. If electricity is already in-house generated through non-cogeneration power systems, the cash flow will be different from the case in which electricity is orginally bought from electric utilities. In the former case capital delta will be positive, O and M delta need not necessarily to be positive, fuel costs delta will generally be positive; in the later case capital, O and M and fuel costs delta will practically always be positive. Furthermore traditional in-house electricity generation may bring to a more or lesser expensive cost per $KWhr_e$ than the electric utilities cost, depending on utilities mix, age and type of in-house generation, etc. In this analysis, no in-house traditional power generation option will be considered. Deltas in capital O and M and fuel costs will therefore correspond only to differences between cogeneration systems cost and traditional boilers costs. A 20 percent investment credit and a straight line depreciation correspondent to the delta capital cost will also be taken into consideration and assessed in favour of cogenerated power, as well as tax

TABLE B.8

COST* OF 10^6 BTU OF SATURATED STEAM AT 200 PSIA (1980$)

FOR DIFFERENT STEAM PEAK LOADS, AS A FUNCTION OF LOAD FACTOR

	Steam Peak Load [10^6BTU/hr]	Cost	Capital Ther.	Capital Elec.	O and M Ther.	O and M Elec.	Fuel	[$/$10^6$BTU]
Oil Boiler System	1,000	c=	.5/L		+.29		+8.34	= .5/L +8.63
	250	c=	.57/L		+.29		+8.34	= .57/L+8.63
	125	c=	.61/L		+.29		+8.34	= .61/L+8.63
Coal Boiler System	1,000	c=	1.32/L		+1.15		+3.38	=1.32/L+4.53
	250	c=	1.86/L		+1.15		+3.38	=1.86/L+4.53
	125	c=	2.21/L		+1.15		+3.38	=2.21/L+4.53
Cogeneration Oil Fired System	1,000	c=	.61/L	+.32/L	+.36	+.30	+10.40	= .92/L+11.06
	250	c=	.70/L	+.51/L	+.36	+.30	+10.40	=1.21/L+11.06
	125	c=	.75/L	+.65/L	+.36	+.30	+10.40	=1.4 /L+11.06
Cogeneration Coal Fired System	1,000	c=	1.55/L	+.32/L	+1.43	+.30	+4.22	=1.87/L+5.95
	250	c=	2.20/L	+.51/L	+1.43	+.30	+4.22	=2.71/L+5.95
	125	c=	2.61/L	+.65/L	+1.43	+.30	+4.22	=3.26/L+5.95

*COGENERATION SYSTEMS STEAM COST DOES NOT INCLUDE VALUE OF COGENERATED ELECTRICITY.

sheltering of deltas in fuel and O and M expenditures assuming a combined effective corporate tax rate of 50 percent. The final after-taxes steam costs equations for cogeneration systems are presented in Table B.9, for different steam peak loads, always as a function of load factor.

From Table B.9 it may be seen how the investment credit and depreciation allowance tax sheltering effects are a minimal portion of the steam cost, i.e., approximately 1 percent. By neglecting them in the steam cost computation other than the incremental analysis performed on Table B.9 in order to take properly into account the revenues from cogenerated electricity, no major approximation is introduced and, anyhow, the only effect would be to slightly shift down the steam cost with no perceivable effect on the relative values of the cogeneration schemes against the traditional boiler systems. The economy of scale impact may also be seen, larger for coal than for oil, for cogeneration than for traditional boiler system, as expected. Fuel and O and M costs are assumed independent of system size and load factor (the latter, however, have been computed for a .85 load factor).

The minimum reuired revenue from cogeneration electricity that would allow steam cogeneration and generation at some costs may be immediately derived from the cost equations in Tables B.8 and B.9, as a function of steam peak load and load factor, for similarly fired alternatives, traditional and cogenerative. This minimum required revenue is presented in Table B.10. Coal fired sytems are more capital intensive than oil fired systems (see Table B.9) and coal systems have larger scale factors, i.e. the effect of the load factor will increase following the second diagonal of Table B.10.

Those values should be compared to electricity value for the firm.

TABLE B.9

COST OF 10^6 BTU OF SATURATED STEAM AT 200 PSIA (1980$)
FOR DIFFERENT STEAM PEAK LOADS, AS A FUNCTION OF LOAD FACTOR

e = value of electricity [$/$KWhr_e$]
c = 200 psia saturated steam cost [$($10^6$BTU)]

	From Table B.8	After tax income from electricity	Δ investment tax credit (discounted)	Δ fuel expend. (tax shelter)	Δ O+M expend. (tax shelter)	Δ depr. allow. (tax shelter)
COGENERATION OIL FIRED SYSTEM VS. OIL BOILER SYSTEM						
Steam peak load:						
1,000x10^6 BTU/hr						
c = .92/L	+11.06	- [.5 76 e	+0.09/L	+.99	+0.17	+0.07/L]
c = .76/L	+ 9.90	- [.5 76 e]				
250x10^6 BTU/hr						
c = 1.21/L	+11.06	- [.5 76 e	+0.13/L	+.99	+0.17	+0.11/L]
c = .97/L	+ 9.90	- [.5 76 e]				
125x10^6 BTU/hr						
c = 1.48L	+11.06	- [.5 76 e	+0.16/L	+.99	+0.17	+0.14/L]
c =1.11/L	+ 9.90	- [.5 76 e]				
COGENERATION COAL FIRED SYSTEM VS. COAL BOILER SYSTEM						
1,000x10^6 BTU/hr						
c =1.87/L	+ 5.95	- [.5 76 e	+0.11/L	+0.40	+0.30	+0.09/L]
c =1.67/L	+ 5.25	- [.5 76 e]				
250x10^6 BTU/hr						
c =2.71/L	+ 5.95	- [.5 76 e	+0.17/L	+0.40	+0.30	+0.14/L]
c =2.40/L	+ 5.25	- [.5 76 e]				
125x10^6 BTU/hr						
c =3.26/L	+ 5.95	- [.5 76 e	+0.21/L	+0.40	+0.30	+0.18/L]
c =2.87/L	+ 5.25	- [.5 76 e]				

TABLE B.10

MINIMUM REQUIRED REVENUE FROM COGENERATED ELECTRICITY
COAL FIRED COGENERATION AGAINST COAL FIRED BOILER
OIL FIRED COGENERATION AGAINST OIL FIRED BOILER

Steam Peak Load*	Load Factor**	Oil Fired Systems [mills/$KWhr_e$]	Coal Fired Systems [mills/$KWhr_e$]
1,000 10^6BTU/hr	1	40	28
1,000 10^6BTU/hr	.5	47	37
125 10^6BTU/hr	1	47	36
125 10^6BTU/hr	.5	60	54

*Minimum reqired revenue is a non-linear function of steam peak load.

**Minimum required revenue is a linear function of load factor.

CORRESPONDENT COAL AND OIL FIRED TRADITIONAL BOILER SYSTEMS
STEAM COSTS*
10^6BTU of Steam (200 psia)

1,000 10^6BTU/hr	1	9.13	5.85
1,000 10^6BTU/hr	.5	9.63	7.17
125 10^6BTU/hr	1	9.24	6.24
125 10^6BTU/hr	.5	9.85	8.85

*Whenever electricity is valued as indicated on the upper portion of the table, those are also the steam generation costs of cogeneration systems.

This value need not be necessarily the so-called electric utility buy-back rate. Many large industrial plants have straight in-house power generation. In any event it is not the purpose of this paper to analyze, at this stage, the various possible interactions with the electric utility, highly dependent on many factors here not specified, and obviously also on the different electric utilities.

Only a couple of observations: a fully depreciated standard oil boiler, with an overall efficieny in the range of .7 (certainly not below US average) would furnish low temperature thermal energy at an operation cost not inferior to 8 $\$/10^6$ BTU steam, i.e. aproximately 3 cents per $KWhr_{th}$. Similarly, an oil-fired fully depreciated industrial power generation station could not furnish electric energy at less than 6 cents per $KWhr_e$.

B.4 CONCLUSIONS

An effort will be made to draw general conclusions from the previous analysis for what concerns steam turbine cogeneration systems assessment their interfuel switching potential and economic viability.

B.4.1 Thermodynamic Performance of Steam Turbines Cogeneration Systems

The system considered for the thermodynamic analysis is a steam turbine system topping process (50, 200 or 400 psia process pressure), no extractions, no reheating, de-superheated process steam delivered at constant pressure, 100 percent return available as saturated water at process pressure, no auxiliary power, steam losses fully recovered, no deaeration steam requirements, main components efficiencies: .9; for the economic analysis the constraints of no auxiliary power and no deaeration steam have been released and boiler efficiency set to .85.

Whenever applicable same assumptions have been made for the traditional boiler system here assumed to furnish slightly super-heated steam at process pressure.

Whenever needed, the U.S. average efficiency of conversion for central power plants of .33 has been assumed; whenever ideal cogeneration systems cycles have been compared against electric utilities cycles, the fact that the former were ideal cycles and the latter were real-life cycles has been taken into account.

1. Cogeneration systems make a less efficient use of fuel energy than traditional boilers (e.g., losses at electric generator) and a more efficient use of fuel energy than central power plants (e.g., heat delivered to low temperature reservoir in the latter is instead usefully employed in the former).
2. Cogeneration systems make a more efficient use of fuel availability than traditional boiler systems (e.g., working fluid at high temperature is used for electricity generation and only afterwards low-temperature heat is delivered to process) and a less efficient use of fuel availability than central power plants (e.g., steam expansion is interrupted at process pressure requirement). This, computing the actual work extracted from energy conversion system and comparing it to the fuel input availability, i.e. actual work that might be obtained from saturated steam at process pressure for standard boilers, electric output for central power plants and both the actual work that might be obtained from saturated process steam (via heat interaction) and electric output for cogeneration systems.

Should the maximum work that a system in a certain state might generate while interacting with the atmosphere, i.e., the availability be taken into consideration, then the second-law efficiency would generally be higher for cogeneration than for central power plants systems (see text).

3. Cogeneration systems make more efficient use of fuel energy and availability, whily supplying a thermal and electric load, than a traditional boiler system and a central power plant supplying separately and simultaneously the same loads.

4. Corollary: First law wise or second law wise (if actual and not maximum work is taken into consideration), cogeneration thermodynamic performance is not the best, inasmuch as another cycle with higher efficiency would exist in both cases (a boiler system and a central power plant, respectively). It is only by comparing the cogeneration system's thermodynamic performance to both a traditional boiler and a central power plant simultaneously that the cogeneration system appears to have a superior thermodynamic performance. This characteristic of the cogeneration system (closely reflected also in any economic analysis) should convince the reader that no thermodynamic breakthrough could be expected from cogeneration cycles per se (see text).

5. The first law efficiency of the cogeneration system equals the traditional boiler system efficiency minus the electric generation losses and depends only upon the components efficiency, all but the steam turbine efficiency. Thermal and electric efficiency of conversion (defined respectively as the

ratio of thermal or electric energy to the fuel energy) do depend upon the steam turbine efficiency also, although, as previously stated, their sum (the cycle or first law efficiency) does not.

6. The (incremental) heat rate of cogenerated electricity equals approximately 5,000 BTU/hr per KWe, is substantially independent of process pressure, steam turbine inlet conditions and steam turbine efficiency; consequently it substantially depends upon boilers and electric generator efficiencies only.
7. The electric power installed per million BTU/hr delivered to process is clearly a design parameter.
8. The electric efficiency of conversion increases with low process steam pressure requirement, high pressure steam turbine inlet conditions, and higher efficiencies of conversion of all components.
9. The thermal efficiency of conversion increases with high process steam pressure requirement, low pressure steam turbine inlet conditions, higher efficiency of conversion of components but with lower steam turbine efficiency.
10. Fuel savings of the cogeneration system with respect to traditional boiler system <u>and</u> central power plant:
    - are a function of thermal and electric efficiencies of conversion of the cogeneration system, traditional boiler efficiency and central power plant efficiency.
    - obviously increase while traditional boiler system and/or central power plant efficiencies decrease and
    - increase with the electric efficiency of conversion of the

cogenerator system (or decreases with the thermal efficiency of conversion); also, the first derivative of the fuel savings function increases as η_e^2.

B.4.2 Steam Turbine Cogeneration Systems Economic Viability

The economic viability of a specific steam cogeneration system will depend upon:

- whether or not the incremental fuel consumption, and the increment in capital and O and M expenditures may be offset by the value of cogenerated electricity and
- the cogeneration system having a life of at least 20 years, on the sensitivity of the previous conclusion to fuel cost and electricity value (if electricity is sold to electric utilities, also on electric utilities pricing and therefore on electric utilities units mix, etc.)
- whatever value is given to total capital, strategic impact, reliability and system versaility considerations.
- reliability and underlying assumptions of cogeneration systems design and economic evaluation.

For the ideal plant here considered, 1,000 10^6 BTU/hr process heat requirement furnished as 200 psia saturated steam, relatively high fuel costs scenario, a standard financial scenario (15 percent discount rate), and comparing similarly fired alterntives:

1. The (incremental) installed power capital cost is approximately 500-600 $/KWe for coal cogeneration and 400-500 $/kWe for oil cogeneration. The former corresponds to approximately 50 percent of the correspondent cost for coal fired central power

plants; the latter equals, for the less expensive or is 60 percent for the more expensive, oil fired central power plants. For smaller plants, coal fired cogeneration capital cost will increase more rapidly than oil fired cogeneration capital costs (see text).

2. The thermodynamic analysis has shown that fuel cost per KWhre cogeneration plants is approximately 50 percent of central power plant fuel cost (obviously assuming identical fuel costs for both systems).

3. O and M costs of cogeneration power plants are also in the range of 50 percent of correspondent central power plants.

The previous three conclusions imply that the cogeneration power plant analysis, to be performed in order to define the economic viability of the system and the system configuration design (units mix, load factors, etc.) will show similar dependencies and behavior than the ones of central power plants. Coal fired cogeneration may be comparable to base load central power plant and oil fired cogeneration to medium load central power plants. This behavior will strongly attenuate diminishing the size of the system, all cogeneration power plants becoming then more and more capital intensive, coal more rapidly than oil.

4. The minimum required revenue from the cogenerated electricity, on a tax-sheltered environment, is in the range of 35 mills/kWhre for coal fired and of 45 mills/kWhre for oil fired cogeneration systems. Again, the minimum required revenue will increase more rapidly for coal fired than oil fired generation power plants if the size of the system or the load factor are reduced (see text).

5. The extra capital expenditure for a cogeneration system with respect to a similarly fired traditional boiler system will be in the range of 40 percent or 80 percent of the cost of a traditional coal fired boiler system or the cost of a traditional oil fired boiler system respectively. Also those percentages strongly increase decreasing the size of the systems.

6. For large systems, increasing fuel cost scenario will not substantially change the previous conclusions (if any change, probably for the better, due to slightly lower weight of fuel costs into busbar generation cost of cogeneration power).

   For smaller systems (even far smaller than the ones here considered), increasing fuel cost sometimes will be highly beneficial to the (relative) economic viability analysis of cogeneration systems, due to increased weight, in smaller systems, of capital cost into busbar generation cost of cogenerated power. This is about the only advantage of smaller systems, cogeneration wise.

Finally a general statement:

Large systems (range of 1,000 10^6 BTU/hr) generally loaded for most of the time, gas, coal, and, better, coal-cogeneration. Advantages: stability to fuel prices, good chances of selling electricity to electric utilities (although avoided fuel costs only would probably not be enough; will need some capital avoided cost or particular arrangements on demand charges); extra capital cost approximately 40 percent of traditional systems.

Small systems (mainly less than 150 10^6 BTU/hr), a probably less constant thermal load duration curve, adverse economies of scale, higher incremental capital cost per installed unit power, will make coal traditional, coal cogeneration, and, at the end, oil cogeneration less and less attractive. Adverse fuel scenario (high fuel cost increase scenario) will be beneficial to the economics of those systems. Interaction with electric utilities more problematic than for large systems, due to large variable cost component of busbar generation cost of cogenerated power.

Once the analysis performed on this paper has been extended to other system sizes and process pressures, a family of curves of all the parameters that define cogeneration system performance under different constraints and at various levels of aggregation, may be constructed.

B.5 COST SCREENING OF COGENERATION SYSTEMS

A relationship between Operating Rvenues and Return on Tax-Sheltered Debt and Equity Capital is formulated by stating that the investment remaining at the end of year n equals the investment remaining at the beginning of year n minus the repayment amount for year n. The general expression obtained for year n will be a function of Operating Revenues, Cash Operating Costs, Depreciation Aloowance, Interest on Debt and on Equity, Debt Ratio, Composite Tax Rate and Life of System (assuming a zero salvage value. After straightforward algebraic manipulation and upon definition of an interest rate on tax-sheltered composite capital, i_a, (the latter function of interest on debt and on equity, debt ratio and composite tax rate) the following is obtained:

$$AEX = (AER - AEF)(1 - t) - AEC + t\ AED \qquad (1)$$

where:

AEX = Annual equivalent net income

AER	=	Annual equivalent revenue
AEF	=	Annual equivalent cash operating costs
AEC	=	Annual equivalent of capital expenditures
AED	=	Annual equivalent of depreciation
t	=	Combined effective income tax rate = 0.50
r_d	=	debt ratio = 0.6
i_d	=	rate of return on debt capital = 0.08
i_e	=	rate of return on equity capital = 0.15
i_c	=	$r_d i_d + (1 - r_d) i_e$ = rate of return on composite capital = 0.1080
i_a	=	$i_c - t r_d i_d$ = rate of return required (or discount rate) on tax-sheltered composite capital = 0.0840.

The present equivalent net income, PEX, or present worth, is immediately obtained from the previous equation (PE being present equivalent):

$$PEX = (PER - PEF)(1 - t) - PEC + t\,PED \qquad (2)$$

On both equations 1 and 2, all terms are discounted at the discount rate on tax-sheltered composite capital, i_a.

B.6 LEVELIZED COST OF FUEL

In order to be able to use the previous equations on varying fuel costs and electricity values scenario, a levelized cost of fuel and a levelized value of electricity have to be computed. Continuous rates of increase both for fuel cost and electricity worth are assumed for levelized costs computation purposes. The present worth is then computed at a continuously compounded discount rate on composite tax-sheltered capital, i_a, and continuously discounted at the same discount rate as a continuous uniform series of payments for the seventeen years of effective operation under consideration; the levelized cost expression obtained after straightforward integration is:

$$\text{Levelized cost, } G = G_o \, \frac{e^{(t-i_a)} - 1}{t - i_a} \, \frac{e^{i_a N} \, i_a}{e^{i_a N} - 1}$$

where t is the rate of increase, N are the years of operation of the plant and G_o is the fuel cost (or electricity value) at the first year of plant operation, i.e., the 1980 dollar cost increased at the discretely compounded increase rate until the end of the construction period of three years.

APPENDIX C

COAL GASIFICATION

Coal derived low and medium Btu gases are two important options that energy intensive industries are evaluating as alterntives to their use of oil and natural gas in steam-raising, process heat and feedstock applications. In order to compare coal-derived gases to other alternatives, it is necessary to understand the system economics. This covers the production of these fuels consistent with the environmental and particular end-use requirements unique to each user. This Appendix provides the necessary information to estimate capital and operating cost to produce low and medium Btu gas for a range of typical industrial plant sizes.

Gasification Data

Capital and operating costs as a function of capacity were developed from published data for the following three gasification processes:

Process	Product	Reference
1. Koppers-Totzek	Medium Btu gas	1, 2, 3
2. Texaco	Medium Btu gas	6 through 12
3. Atmospheric Fixed Bed	Low Btu gas	1, 4, 3, 5

For the Koppers-Totzek and Atmospheric Fixed Bed processes, consistent cost data in a sufficient wide range of capacities can be found in the literature. For the Texaco process, however, while good preliminary engineering information are reported, only a few realistic cost estimates are available. The best source is Bechtel's study for

NIPSCO (6) that is based on a detailed engineering design for a plant actually being built for Tennessee Eastman (13). The design has revealed that the earlier capital costs were grossly underestimated. Another feature of the Bechtel study is that it includes shift conversion and methanation, and provides for a more efficient sulfur removal of 99% while most of the other designs remove around 90% sulfur.

To determine the effect on the Texaco process capital cost of plant capacity and sulfur removal efficiency, a pair of sectionalized cost estimates were first developed for a 99% or 90% sulfur removal alternatives based on Bechtel's 115 billion Btu/day designs.(6,7) The sections of each alternative plant were then scaled up and down to 170 and 30 billion Btus/day which are the approximate sizes of the Fluor study (8) and Tennessee Eastman project (13), respectively.

Both alternative plants of our study assume the standard MBG design without shift conversion and methanation. In eliminating these sections, a change in equipment configuration and size was required in the acid gas removal and sulfur recovery sections. Another configuration and size change in these sections was called for by the adjustment to the 90% sulfur recovery alternative. As only flowsheets but no individual equipment specifications and cost were available, the functional unit concept (14,15) was used to determine the effect of the changes on the sectional estimates.

In scaling the individual plant sections of the two alternatives up and down to the 170 and 30 billion Btu/day level, the standard exponential relationship was used:

$$\text{Cost} = \text{const. } (\text{Capacity})^{e}$$

For each section, a specific exponent was selected from literature data (16,17) based on the mix of equipment types in that section. For some sections, the number of trains was also changed and the exponent applied to train capacity. Results are shown in Table C-1.

The sources of cost estimates for the Koppers-Totzek and Atmospheric Fixed Bed processes are presented in Table C-2. Slight adjustments were made in the quoted construction costs to match the definitions of Table II-1 in the main body of the report. Once construction costs were normalized, the following factors were applied consistently to compute total capital which was then escalated to 1980 dollars:

Item	Factor	Base
Contractor's fee	10%	Construction cost
Contingency	15%	Construction cost
Non-depreciables	0	--
Working capital	1%	Depreciable capital
	30 days	Daily fuel cost
Start-up	20%	Cash production cost
Other cost	1%	Construction cost

Bechtel's Texaco process battery limits and offsite cost were available at the level of depreciable capital excluding contingency. The above percentages were used to calculate total capital, see last two lines in Table C-1.

In the area of operating cost, the Bechtel study provides a cost breakdown and a rough manning table. As pointed out in Section II of the main body of this report, operating costs may be estimated based on

TABLE C-I. TEXACO PROCESS CAPITAL COSTS[1]

Section	35 Billion Btu/Day			115 Billion Btu/Day			170 Billion Btu/Day		
	No. of trains[2]	10^6 for Alternative[3]: 87%S	99%S	No. of trains[2]	10^6 for Alternative[3]: 87%S	99%S	No. of trains[2]	10^6 for Alternative[3]: 87%S	99%S
Coal Handling	1+0	8	8	1+0	22	22	1+0	31	31
Oxygen Plant	2+0	42	42	4+0	119	119	5+0	166	166
Gasification	2+1	92	92	4+1	215	215	5+1	293	293
Acid Gas Removal	1+0	7	23	2+0	20	63	3+0	27	95
Sulfur Recovery	1+1	4	16	2+1	8	34	2+1	10	45
Battery Limits		153	181		389	453		527	630
Offsites		30	33		61	66		78	86
Depreciable capital excl. contingency		183	214		450	519		605	716
Contingency, working capital, start-up		38	44		96	111		131	155
TOTAL CAPITAL		221	258		546	630		736	871

1. Cost in 1980 dollars.
2. Operating and standby.
3. Sulfur removal alternative.

TABLE C-II. SIZES AND COST SOURCES OF GASIFICATION PLANTS

Capacity, 10^9 Btu/day	Costs Based on Year	Reference
(a) Koppers-Totzek Process		
12	1975	2
20	1980	3
36	1975	2
72	1975	2
100	1977	1
150	1977	1
180	1975	2
(b) Atmospheric Fixed Bed Process		
0.7	1978	4
1.8	1978	4
2.5	1977	1
3.6	1978	4
4.8	1978	4
9.6	1978	4
10	1977	5
20	1980	3
50	1977	5
100	1977	5

the variable, fixed and semivariable component as follows:

Component	Items Included	Proportional To
Variable	Process materials, utilities	Production
Fixed	Operating labor, supervision, services, part of G&A	No. of operators
Semivariable	Operating supplies, maintenance labor and supplies, property insurance and taxes, rest of G&A	Depreciable Capital

G&A (general and administrative) costs are computed as proportional to operating and maintenance labor.

The Bechtel study operators and maintenance people were distributed among the plant sections based on the numbers of functional units (14,15). The total number of men was then decreased in accordance with the elimination of shift conversion and methanation, and the changes in acid gas removal and sulfur recovery sections. The resulting manning provided a basis for the fixed component and a check for maintenance cost.

Next, the scale-up and scale-down of sectional manning was computed using the following rules:

o Operators:

Coal handling: No. of men = const. $(\text{Capacity})^{0.6}$

Gasification: 6 men/shift for 4 to 5 trains

5 men/shift for 2 to 3 trains

4 men/shift for 1 train

Other sections: No. of men independent of capacity o Maintenance people

No. of men is proportional to depreciable capital

The estimate of the variable and remaining semivariable costs was straightforward. The resulting operating costs of the Texaco process are reported in Table C-3 for the three selected capacities.

Operating costs of the Koppers-Totzek and Atmospheric Fixed Bed processes, published for various capacities, required only slight adjustment and escalation to 1980 dollars. The references are also covered in Table C-2.

The capital and operating cost of all processes investigated are presented in Figures II-3 and II-4 in the main body of the report. No attempt was made at this point to establish the effect on cost of the level of sulfur removal for the Koppers-Totzek and Atmospheric Fixed Bed processes. However, it is planned to do so in the next phase of the project along the same lines as it has been done for the Texaco process.

TABLE C-III. TEXACO PROCESS OPERATING COSTS[1]

	35 Billion Btu/Day $\$10^6$ for Alternative[2]:		115 Billion Btu/Day $\$10^6$ for Alternative[2]:		170 Billion Btu/Day $\$10^6$ for Alternative[2]:	
	90S	99%S	90S	99%S	90S	99%S
Catalyst	.1	.1	.3	.3	.4	.4
Water	.2	.2	.6	.6	.9	.9
Electricity	.6	.6	2.1	2.1	3.2	3.2
Ash Disposal	.3	.3	1.1	1.1	1.7	1.7
Wages	8.2	8.6	11.6	12.4	13.5	14.5
Contract Maintenance Labor	2.0	2.3	4.9	5.6	6.7	7.8
Maintenance Materials	2.5	2.9	6.1	7.0	8.4	9.8
Operating Supplies	0.5	0.6	1.2	1.4	1.7	2.0
	14.4	15.6	27.9	30.5	36.5	40.3

1. Cost in 1980 dollars.
2. Sulfur removal alternative.

<u>References</u>

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APPENDIX D: FUEL PRICES

The purpose of this appendix is to discuss future fuel price developments. Initially oil price developments are discussed because oil is considered a benchmark fuel, subsequently natural gas price developments are discussed because of the importance of natural gas for the industrial sector, and finally coal price developments are discussed since coal is considered the major alternative to oil and natural gas in the industrial sector. The major conclusions of this appendix follow below.

Despite the recent softness in the international oil market, oil prices are expected to remain relatively constant in real terms over the next ten to fifteen years. More specifically, oil prices are expected to increase at an annual real rate of -1 to +5 percent over the next ten to fifteen years. The following scenarios for oil prices were used in this study: first, oil prices were assumed to remain constant in real terms; and second, oil prices were assumed to increase at an annual real rate of 3 percent after 1985 (see Table D-1).

The fate of future natural gas prices will largely depend on the fate of the Natural Gas Policy Act. As mentioned later in this appendix, several amendments are being proposed for this act. The following scenarios for natural gas prices were used in this study: first, natural gas prices are decontrolled in 1985 according to the provisions of the Act and they remain constant in real terms thereafter; second, natural gas prices are not decontrolled in 1985, they increase in an annual rate of 4 percent in real terms during 1985/95, and they remain constant in real terms thereafter; and third, natural gas prices are decontrolled in 1985 according to the provisions of the Act and they increase in real

Table D-1

Scenarios of Fuel Prices

	Scenario 1		Scenario 2			Scenario 3	
				Annual Real Growth Rate			
	1985* ($/ MMBtu)	Post 1985 Real Growth Rate	1985* ($/ MMBtu)	1985/95	post 1995	1985* ($/ MMBtu)	Post 1985 Annual Real Growth Rate
Oil							
-Low Sulfur (0.3%)	6.17	0	6.17	0	0	6.17	3
-High Sulfur (2.0%)	5.10	0	5.10	0	0	5.10	3
Gas	5.60	0	3.77	4	0	5.60	4
Coal							
-Low Sulfur (1%)	2.50	0	2.50	0	0	2.50	2
-High Sulfur (3%)	2.00	0	2.00	0	0	2.00	2

*All prices in 1980 dollars.

terms at 4 percent annually thereafter (see Table D-1).

Finally, coal prices are expected to remain relatively constant in real terms. More specifically, coal prices are expected to increase at annual real rate of 0 to 3 percent, depending on the transportation cost involved, in other words on how far is the coal use located from the mine mouth. The following scenarios for coal prices were used in this study: first coal prices were assumed to remain constant in real terms; and second, coal prices were assumed to increase at an annual rate of 2 percent in real terms after 1985 (see Table D-1).

D.1 Oil

Delivered oil prices to the U.S. industrial sector will mainly depend on international oil prices, which in turn will depend on the oil prices of the Organization of Petroleum Exporting Countries (OPEC). During the last decade, OPEC was able to increase the price of its oil by 2000 percent in nominal terms.

The Libyan breakthrough in 1970/71, the quadrupling of oil prices following the 1973 oil embargo, and the tripling of oil prices following the 1979 Iranian revolution were the three major events that led to the 2000 percent increase in OPEC oil prices during the last decade. In all three cases, a sequence of political events took place beforehand which created the economic environment for these oil price increases. Since political events are difficult to predict several years in advance, the aforementioned oil price increases surprised oil analysts. In the future, political and economic considerations are expected to continue being the two major factors determining the oil policy of the major OPEC oil producers. Keeping in mind the pitfalls involved in making oil price predictions, an attempt will be made below to sketch the possible developments in the oil market over the next two decades. Initially, a range of the demand for OPEC oil is developed for the next two decades.

Demand for OPEC Oil

During 1979/81, demand for OPEC oil decreased from 30.8 million barrels a day (mmbd) in 1979 to 26.8 in 1980 and to 22.5 in 1981. Although it was not the first time demand for OPEC oil registered a decline, it was the first time it did so for two consecutive years and, more importantly, the size of the recent decline has been much greater than that of any previous ones. For example, the second largest decline in demand for OPEC oil occurred during 1974/75, when demand for OPEC oil declined from 30.7 mmbd in 1974 to 27.3 mmbd in 1975. These developments have revived speculation about OPEC's ability to control the oil market in the future. More specifially, some oil analysts have argued that OPEC countries may price their oil out of the market, if they insist on the currently prevailing prices.

Predicting the future demand for OPEC oil involves guessing the future world energy demand. The latter will depend on future economic growth and energy utilization efficiency, both of which have become very difficult to predict after the 1973 energy price increases, as explained below.

Since 1973, the world economy has been growing at a substantially slower rate than before. For example, the Organization for Economic Cooperation and Development (OECD) economies grew at an annual rate of 5.2 percent during 1963/68, at a 4.6 percent rate during 1968/73, but at only a 2.2 percent rate during 1974/81. Similarly, the world energy income elasticity after 1973 has been substantially lower than before. This decrease in energy income elasticity was more pronounced in the OECD countries. For the OECD as a whole, during 1960/72 it took on the average a 1.02 percent increase in energy consumption to increase the level of economic activity by 1 percent. However, during 1973/81, it took only a 0.4 percent increase in energy consumption to increase the level of economic activity by 1 percent. What do these data imply for the future?

Analysts disagree on the values of future economic growth rates and energy income elasticities will prevail in the future, they disagree on the magnitude of these variables. The problem becomes even more complicated by the fact that an accurate enough prediction of the economic growth rate and energy income elasticity is beyond the present or prospective capability of the profession of econometrics. Indeed, the annual economic growth rate over next ten to fifteen years cannot be predicted within 0.5 percent. However, a difference of 0.5 percent in the annual economic growth rate may result in a difference in the demand for OPEC oil of up to 10 mmbd by 1990, which is equivalent to the production capacity of Saudi Arabia. Similarly, the annual energy income elasticity cannot be predicted within an accuracy of 0.1, but a change in this income elasticity from 1.0 to 0.9 may result in a decrease of up to 10 mmbd in the demand for OPEC oil by 1990. With this caveat in mind, a range of the demand for OPEC oil over the next two decades is developed below.

In case the OECD economies grow at an annual rate of about 3 percent and the OECD energy income ratio continues to decline at about the same rate as during the 1970's, the demand for OPEC oil is not expected to increase over the next two decades. In other words, the demand for OPEC oil will remain at about 23 mmbd which is close to the level it reached in 1981. However, if the industrial economies grow at an annual rate of 3.3 percent or if their energy income ratio delines at half the rate it declined during the 1970s, then demand for OPEC oil will grow and could reach a level of up to 34 mmbd over the next two decades. Let us now examine how OPEC will react to different levels of demand within this range.

OPEC Oil Prices during the 1980's and 1990's

The oil policies of the various OPEC countries will differ, depending on the economic development needs of each OPEC country, on its domestic socio-political situation, and on its stake in preserving a healthy oil market in the long-term, which in turn will depend upon its existing and potential oil reserves. Based upon their respective social, economic, and political conditions, OPEC countries can be divided into the following groups according to the oil policy they are expected to follow in the future.*

The first group consists of Algeria, Ecuador, Gabon, Indonesia, Nigeria, and Venezuela. These countries have strong incentives to produce close to their productive capacities and to seek large oil price increases. This behavior is dictated by their large oil revenue needs for economic development and the fact that their oil exports are expected to decline over the next two decades due to an anticipated decline in oil

*For a more detailed discussion, see Aperjis, D., "The Oil Market in the 1980's: OPEC Oil Policy and Economic Development," Ballinger, Cambridge, Massachusetts, February 1982.

production and an increase in domestic oil consumption. The radical leaderships in Iran and Libya can be expected to support this group of countries by advocating large oil price increases and producing only as much oil as they need for their own economic development.

On the other hand, Saudi Arabia and United Arab Emirates (UAE) have an incentive to block large oil price increases for both economic and political reasons. The economic reasons include their interest in preserving a healthy market for their oil exports in the long-term and their interest in preserving the value of their vast financial surpluses in the West. The political reasons include their desire to solicit support from the West (especially the U.S.) with regard to the Arab/Israeli conflict and for the defense and survival of their own conservative monarchies. Lastly, Iraq, Kuwait, and Qatar can be expected to float between these two positions.

OPEC's oil policy will emerge as a compromise among the oil policies of these three groups. The oil supply curve of OPEC will lie within the shaded region of Figure D-1. The position of the left boundary of this region, DS, depends on the economic development needs of individual OPEC countries. More rapid economic growth in Saudi Arabia, UAE, Kuwait, Iraq, Iran, or Libya would shift curve DS to the right, while slower economic growth in these countries would shift DS to the left. The position of the right boundary of this region, DC, depends on the productive capacities of Saudi Arabia and UAE and any production ceilings introduced by the governments of Kuwait and Iraq.

In other words, to satisfy a medium level of economic development, OPEC's production behavior will have to follow curve AD for oil prices below \$25 per barrel, and a curve between DS and DC for oil prices above

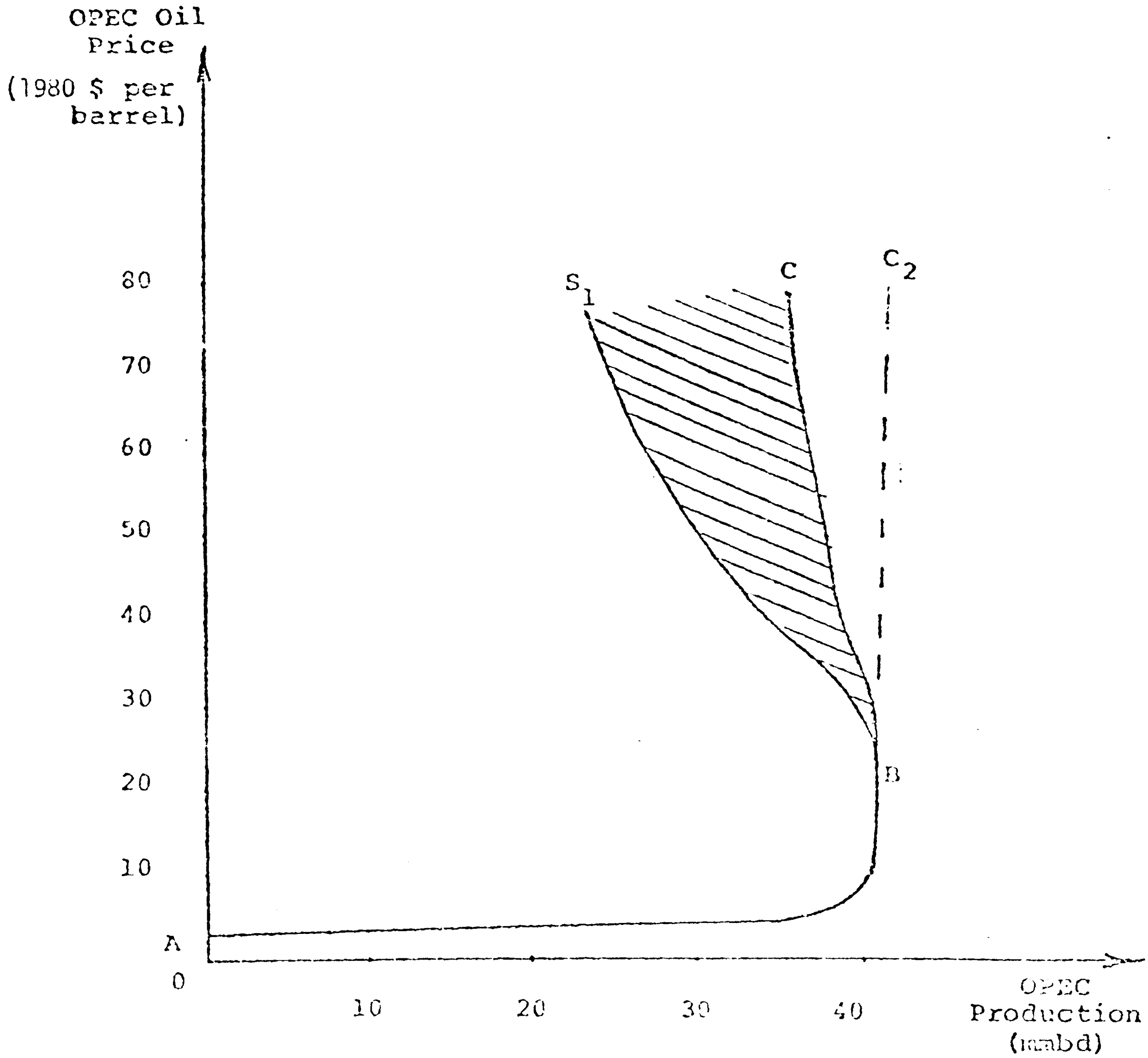

Figure D-1: Probable Region of OPEC Oil Supply.

Source: Aperjis, D., "The Oil Market in the 1980's: OPEC Oil Policy and Economic Development," Ballinger, Cambridge, Mass., February 1982.

$25 per barrel. The exact position of OPEC's supply curve will depend on the willingness of Saudi Arabia, UAE, Kuwait, Qatar, and Iraq to produce at levels above that which is required for their short-term economic development needs.

If a high level of demand for OPEC oil were to occur over the next two decades (about 34 mmbd), Saudi Arabia, UAE, Kuwait, Iraq, and Qatar would have to produce close to their productive capacities in an effort to prevent any sharp price increases by the rest of OPEC. In this case, oil prices can be expected to increase in real terms at a rate of about 3-5 percent annually. For a medium level of demand during the 1980's (about 28 mmbd) the so-called price moderates, because of their surplus productive capacities, will have sufficient bargaining power to impose their pricing policies on the rest of OPEC. However, oil prices would not necessarily decrease from current levels, since it would be politically very difficult for the price moderates to actually decrease oil prices. Rather, the moderates would use their large bargaining power to keep prices relatively constant in real terms by cutting their own production. The ability of the price moderates to absorb production cuts without any major impact on their economic development plans makes OPEC oil prices sticky downwards.

But there is a limit to the production cuts OPEC's moderates could afford without affecting their economic development plans. This limit is represented by curve DS in Figure D-1. If the demand for OPEC oil shifts to the left of curve DS, then OPEC countries would be forced to scale down their economic development plans to avoid a collapse in oil prices. Note that in this case prices would not simply decrease by a few percentage points. Indeed they would collapse because the demand curve for OPEC oil and curve DS are negative sloping and almost parallel. In the case of a price collapse, AD would become the new OPEC oil supply curve. The further to the left the demand curve shifts, the more the OPEC countries will have to decrease their economic development plans to avoid a drastic price deterioration. It is questionable whether OPEC would be able to keep its members together and avoid a price collapse if a low demand for OPEC oil (about 23 mmbd) prevailed over the next two decades.

To summarize, oil prices over the next two decades will most probably not be lower than today's levels because OPEC oil prices appear to be sticky downwards. More specifically, OPEc prices are expected to remain realtively constatn in real terms during the 1980s. Jacoby and Paddock* reached a similar conclusion for future oil prices, using a combinion of gualitative argumets ad a large oil model at MIT Energy Laboratory. For example, they predicted that oil prices will increast at a rate of -1 to +5 during the 1980s.

D.2 Natural Gas

In 1978 the Natural Gas Policy Act (NGPA) became a law and it was thought that Federal policy on natural gas prices had been settled for good. However, changes in the international oil prices during 1979/80 have raised a lot of questions about the appropriateness of NGPA. Several alternatives and amendments to NGPA have been proposed recently. The NGPA, extending controls on natural gas prices beyond 1985, and

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*Jacoby H.D. and Paddock J.1., "World Oil Prices and Economic Growth in the 1980s," MIT Energy Lab, December 1981 (MIT-EL 81-060WP).

ending controls of natural gas prices before 1985 are the regulatory schemes discussed in this section, together with the impact of such schemes on natural gas prices..

The NGPA

The NGPA extended price controls to the intrastate gas markets creating more than 20 categories for natural gas, which, however, could be grouped into the following general groupings:

> "New" gas, in general, gas that came into production after April 21, 1977. The prices of most of this gas will increase at an annual rate of 3-4 percent in real terms until 1985, when most "new" gas may be decontrolled.

> "Old" gas, in general, gas that came into production before April 21, 1977. The prices of interstate "old" gas will remain controlled at 1978 real prices until exhausted. The prices of part of the "old" intrastate gas will be deregulated in 1985, with the remainder receiving higher prices than "old" interstate gas.

> High cost gas, in general, gas from wells below 15000 feet and unconventional gas other than tight sands. This gas represented about 2 percent of 1981 gas supplies. The prices of this gas are not regulated under the NGPA and they are set at the free market.

Thus, pursuant to NGPA, about 40 percent of domestic gas supplies will not be decontrolled in 1985 and approximately 20 percent will remain controlled in 1990 (See also Table D-2). Actually, the NGPA provides for standby controls which would allow the Congress and the President to extend price controls for another two years, if necessary. In this case, the prices of most gas would be controlled until 1987.

The intention of the price structure of the NGPA was to adjust wellhead prices to coincide with market clearing levels by 1985 in order to produce a smooth transition toward decontrol. This intention can be seen very clearly in Figure D-2. Intrastate gas prices were set at a price equivalent to the price of No. 6 oil (low sulfur), and are to be increased until 1985 at the rate the drafters of the Act expected oil prices to escalate. Average interstate gas prices were also expected to move toward parity with No. 6 oil (low sulfur) as supplies of old gas were phased out.

However, during 1979/80 oil prices increased at a much faster rate than the NGPA drafters had expected. Assuming that oil prices do not decrease drastically by 1985, there will be a gap between the price of oil and the price of gas that is expected to be deregulated in 1985. If gas competes with oil, the price of that portion of gas that is deregulated in 1985 (i.e., new gas and a part of intrastate gas) will have to increase drastically as well for the market to clear. This potential "fly-up" of the prices of deregulated gas in 1985 is illustrated in Figure 3. In other words, the hope that the NGPA will smooth the transition to decontrolled natural gas prices may have been eliminated by the oil price increases during 1979/80.

This potential "fly-up" of natural gas prices has initiated a lively debate about the usefulness of the NGPA. Several alternatives to the

Table D-2: NGPA Natural Gas Categorization

Section	Description	1980 Production Estimate (TCF)*	Avg. Price 3/81 ($ Per MCF)	Date of NGPA Deregulation	Comments
102	New Natural Gas	2.2	$2.73	1/1/85	Includes OCS
103	New Onshore Production Wells	2.5	$2.41	1/1/85, 1/1/87	1/1/85 For Wells Deeper Than 5000 Ft.
104	Old Interstate Gas	7.8	$.25 - $1.99 (Avg. ≈ $1.25)	Not Deregulated	Price Escalates at Monthly Inflation Adjustment
105	Old Intrastate Gas	5.3	$.50 - ? (Avg. ≈ $2.00)	1/1/85	
106	Sales Under "Roll-Over" Contracts	0.9			
	• Interstate		$ .75	Not Deregulated	
	• Intrastate		$1.37	1/1/85	
107	High Cost Gas	0.4	Market (≈ $ 7.00)	11/1/79	107(c), "Tight Sands" Gas Is Not Deregulated
108	Stripper Well Gas	0.4	$2.92	Not Deregulated	< 60 mcf Per Day
109	Prudhoe Bay and Other Gas	Negligible	$1.99	Not Deregulated	
		Total ≈ 18 TCF			

*Estimates

Source: Jacoby, H.D. and Wright, A.W., "Obvious and Not-so-Obvious Issues in Natural Gas Deregulation," M.I.T. Energy Laboratory Working Paper. March 1982 (MIT-EL 82-081WP)

Figure D-2

Natural Gas Policy Act As Passed

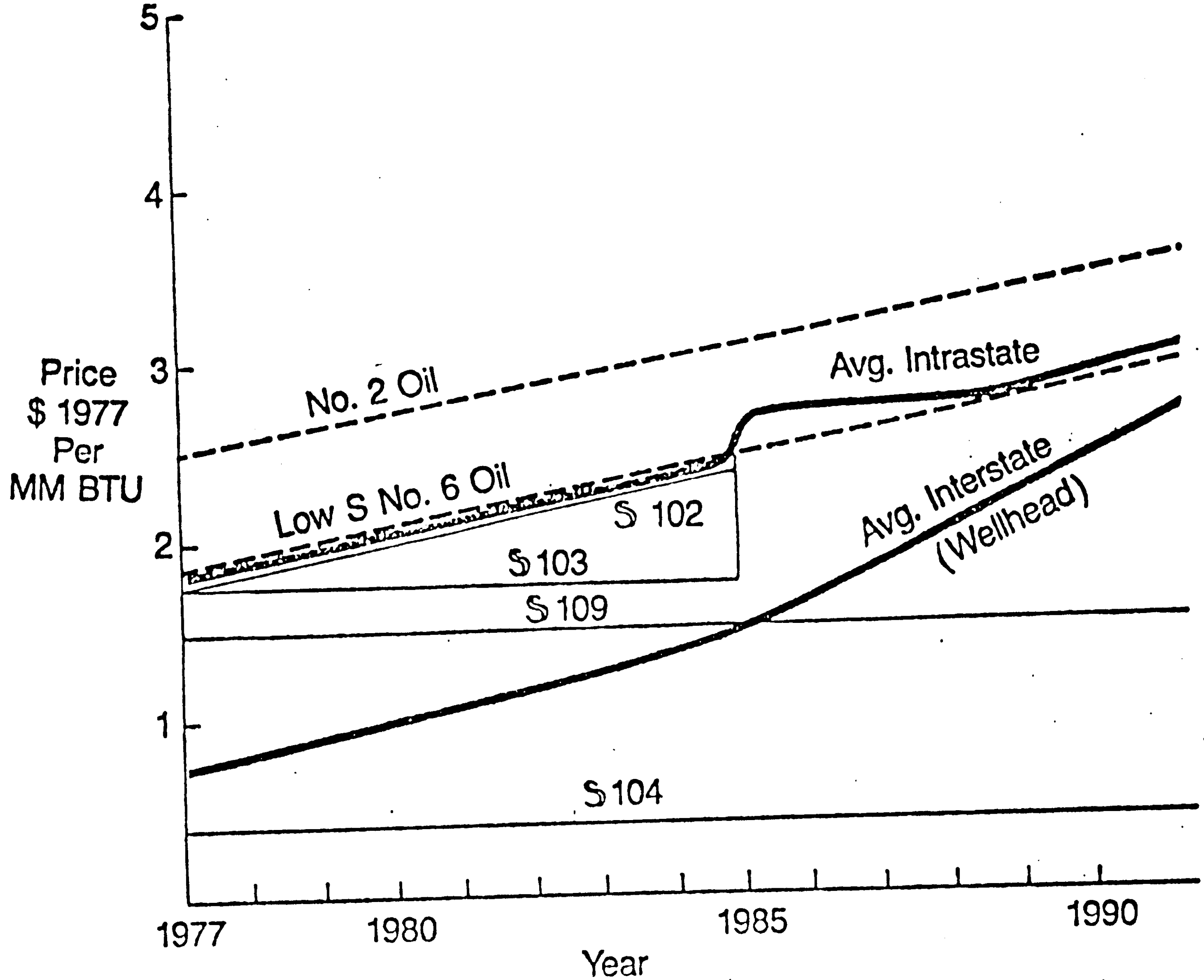
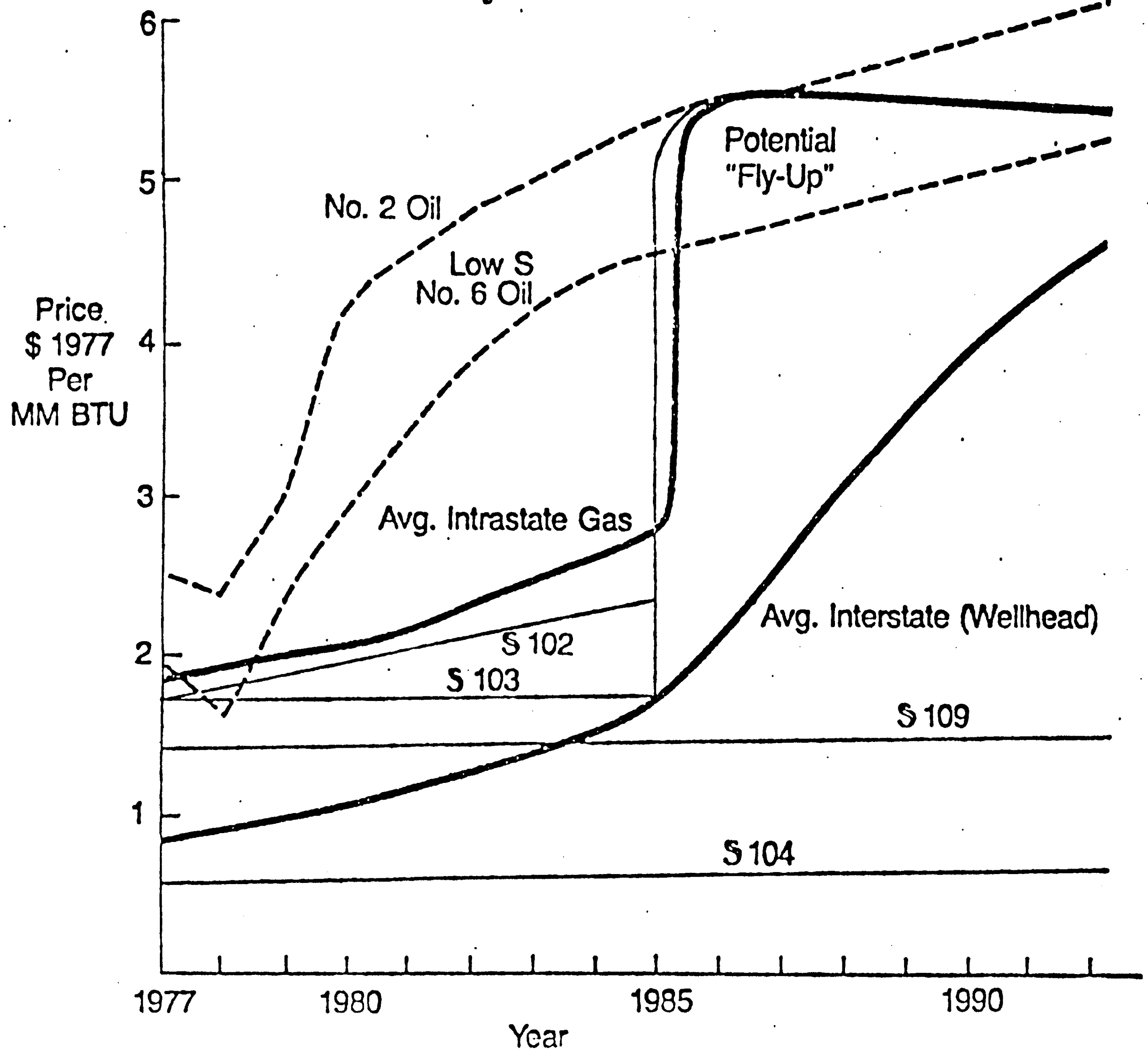


Figure D-3

Natural Gas Policy Act Current Situation



NGPA have been proposed ranging from immediate decontrol of all gas prices to extending price controls to 1995. In addition to the "fly-up" problem, proponents of a policy change on natural gas see the following instability problems created by the NGPA.

If gas competes with oil in the industrial and electric utility markets, the market may clear when the average price of gas reaches the price of oil. Pipelines companies will be tempted to bid up the price of deregulated gas until the average gas price at retail reaches the price of oil or clears the market. Thus, prices of deregulated gas may go well above the price of oil or the market clearing price of gas. The rolled-in pricing of natural gas facilitates this whole process. Supporters of this argument cite as an example the fact that prices of deep gas (from wells below 1500 feet) reached a level of about $10 per mcf in 1981, which was twice the price of oil in 1981.

The aforementioned instability is also enhanced by the unequal treatment of "old" gas in the interstate and intrastate markets by NGPA. More specifically, "old" gas will not be deregulated in the interstate market while part of "old" gas will be deregulated in the intrastate market. Consequently, more price-controlled gas is expected to exist after 1985 in the interstate market than in the intrastate market. Thus, interstate pipelines will be in a position to bid higher prices for deregulated gas, which may result in a shift of deregulated gas supplies from the intrastate to the interstate market. Needless to say, the uneven endowment of price-controlled gas among interstate pipelines may result in unequal access to deregulated gas supplies among interstate pipelines and their respective service regions. The U.S. Department of Energy estimates that 0.9 (Tcf) will shift from the intrastate to the interstate market between 1984 and 1985.*

The U.S. Department of Energy estimates of natural gas prices under NGPA are depicted in Table D-3. Note the "fly-up" of the new gas price from $3.28 per million cubic feet (mcf) in 1984 to $6.76 per mcf in 1985. In other words, at the time of decontrol, wellhead prices of new gas will reach a level of about 110 percent of crude oil prices, because of rolled-in pricing by pipelines and gas distributors. However, as the controlled supplies of "old" gas decrease, the marginal wellhead price of gas will decrease from $6.76 in 1985 to $6.21 in 1990, the latter being equal to 85 percent of crude oil price.

Extension of Price Controls

Price controls could be extended for a certain period of time. Actually, as mentioned earlier, the NGPA has a provision that authorizes the extension of price controls until 1987. Table D-4 depicts DOE's estimated impact on natural gas prices if price controls similar to the ones dictated by NGPA are extended to 1990. Note that in this case natural gas prices for the industrial sector remain well below the oil price. At the same time, uncontrolled gas prices are almost double the average price of gas at the wellhead. This results from the ability of pipelines to bid up the prices of uncontrolled gas, because the pipelines have larger quantities of controlled gas than in the case in which gas prices are decontrolled in 1985.

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*"A Study of Alternatives to the Natural Gas Policy Act of 1978," U.S. Department of Energy, November 1981.

TABLE D-3: IMPACT OF NGPA ON NATURAL GAS PRICES

GAS PRICES (1980$/mcf)	1982	1984	1985	1990
Wellhead[1]				
Average Domestic	2.27	2.61	4.45	5.35
New Gas[2]	3.03	3.28	---	----
Marginal[3]	6.56	6.93	6.76	6.21
Delivered				
Residential	4.31	4.83	6.59	7.36
Industrial	3.15	3.50	5.60	6.37
OIL PRICES[4]				
Crude Oil (1980$/mcf)	5.74	6.08	6.27	7.27
" " (1980$/bbl.)	32.73	34.72	35.76	41.46
Residual Fuel Oil				
Low Sulfur (.3%)	5.68	6.00	6.17	7.08
High Sulfur (2.0%)	4.65	4.95	5.10	5.95

1. Includes 7% severance and other taxes.

2. The new gas price equals the Section 102 price, plus severance and other taxes.

3. The marginal wellhead price equals the Section 107 deregulated price to 1985 and the deregulated gas price after 1985.

4. Crude oil prices are average refiner acquisition costs.

Source: "A Study of Alternatives to the Natural Gas Policy Act", U.S. Department of Energy, November 1981.

TABLE D-4: IMPACT OF EXTENDING CONTROLS ON NATURAL GAS PRICES

	1982	1984	1985	1990
GAS PRICES (1980$/mcf)				
Wellhead[1]				
Average Domestic	2.27	2.61	2.91	4.35
New Gas[2]	3.03	3.28	3.41	4.45
Marginal[3]	6.56	6.93	7.13	8.19
Delivered				
Residential	4.31	4.83	5.17	6.79
Industrial	3.15	3.50	3.77	5.06
OIL PRICES[4]				
Crude Oil (1980$/mcf)	5.74	6.08	6.27	7.27
Crude Oil (1980$/bbl.)	32.73	34.72	35.76	41.46
Residual Fuel Oil				
Low Sulfur (.3%)	5.68	6.00	6.17	7.08
High Sulfur (2.0%)	4.65	4.95	5.10	5.95

1. Includes 7% severance and other taxes.

2. The new gas price equals the Section 102 price, plus severance and other taxes.

3. The marginal wellhead price equals the Section 107 deregulated price to 1985 and the deregulated gas price after 1985.

4. Crude oil prices are average refiner acquisition costs.

Source: "A Study on Alternatives to the Natural Gas Policy Act," U.S. Department of Energy, November 1981.

Ending Price Controls before 1985

The most drastic decontrol scenario is the one in which natural gas prices of all categories are decontrolled in 1982. The Department of Energy estimated impact of such a scenario on natural gas prices is depicted in Table D-5. The figures of Table D-5 were derived under the assumption that any existing contract clauses would not inhibit natural gas prices from attaining the free market level. This is a crucial assumption because the majority of contracts for "old" natural gas contain clauses which could escalate natural gas prices to levels well above the free market level. Note that, since all gas prices are deregulated in 1982, the average gas price is equal to the marginal gas price (Table D-5).

Decontrolling of all natural gas prices in 1982 solves some of the potential problems of NGPA -- such as the unequal treatment of interstate and intrastate markets -- but it does not solve the problem of a sudden jump in natural gas prices. Actually, it magnifies the jump while at the same time advances it from 1985 to 1982. The problem of a sudden increase in natural gas prices could be alleviated by considering a phased-in decontrol option in which case the different categories of natural gas are decontrolled during 1982/85, instead of all at once in 1982. A phased-in decontrol scenario would most likely result in different natural gas prices during 1982/85 than the scenario of immediate decontrol in 1982. However, these two scenarios are expected to result in approximately similar natural gas prices after 1985. In other words, as far as the M.I.T. case study is concerned, these scenarios would have the same impact because only the fuel prices in 1985 and thereafter are important for the M.I.T. case study.

TABLE D-5: IMPACT OF IMMEDIATE DECONTROL ON NATURAL GAS PRICES

	1982	1984	1985	1990
GAS PRICES (1980$/mcf)				
Wellhead[1]				
Average Domestic	4.19	4.44	4.65	5.50
New Gas[2]	---	---	----	----
Marginal[3]	4.18	4.43	4.65	5.49
Delivered				
Residential	6.13	6.39	6.62	7.51
Industrial	5.02	5.27	5.47	6.33
OIL PRICES[4]				
Crude Oil (1980$/mcf)	5.74	6.08	6.27	7.27
" " (1980$/bbl.)	32.73	34.72	35.76	41.46
Residual Fuel Oil				
Low Sulfur (.3%)	5.68	6.00	6.17	7.08
High Sulfur (2.0%)	4.65	4.95	5.10	5.95

1. Includes 7% severance and other taxes.

2. The new gas price equals the Section 102 price, plus severance and other taxes.

3. The marginal wellhead price equals the Section 107 deregulated price to 1985 and the deregulated gas price after 1985.

4. Crude oil prices are average refiner acquisition costs.

Source: "A Study of Alternatives to the Natural Gas Policy Act", U.S. Department of Energy, November 1981.

Proponents and Opponents of the NGPA

During the 1980 presidential campaign, President Reagan made statements favoring gas deregulation. During 1981, some Republican Congressional leaders advised the President that a gas deregulation bill could not pass, unless it was coupled with a "windfall profits" tax on decontrolled gas. Some administration officials are in favor of a "windfall profits" tax, because it would decrease the federal deficit. But the President himself promised to veto "with pleasure" a windfall tax on decontrolled gas in a letter to Congressman English from Oklahoma.* Needless to say that Congress is divided on the issue of amending the NGPA. It should be added, that if Congress does not ammend the NGPA, there exist a series of actions which the Federal Energy Regulatory Commission (FERC) can take administratively to increase prices on certain categories of gas in the short-term. These kinds of price increases have been happening lately.

Similarly, the natural gas industry is divided on this issue. Companies with a good competitive position in deep gas are in favor of the NGPA, because this way they can sell their deep gas at double the prices of oil. These companies argue that there is no need to deregulate gas found in shallow formations, because it would merely raise prices without adding any new reserves. However, companies richly endowed with "old" gas reserves are in favor of immediate deregulation on all gas prices. These companies argue that the NGPA distorts the gas market and thereby causing vast amounts of capital to be allocated for the discovery of high-cost and high-risk gas at depths below 15000 feet, while there is

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*See p. 2066, National Journal, November 21, 1981.

still a lot of gas to be found in more shallow depths if the appropriate incentives existed.

The pipelines are also divided on the issue. Interstate pipelines oppose immediate decontrol of "old" gas, because controlling the price of "old" gas provides them with a cushion and enables them to overbid intrastate pipelines on deregulated gas reserves. Of course, intrastate pipelines are opposed to price controls favoring interstate pipelines. Another problem pipelines face is that most of the gas to be decontrolled in 1985 under the NGPA is under contracts that could send gas prices above the price of crude oil because of escalation clauses.
The latter provide for increases in contract prices if the price of competing fuels increases. Pipelines argue that many of the contracts between pipelines and producers tie prices of decontrolled gas to the price of No. 2 fuel oil and not to that of No. 6 fuel oil which is the alternative fuel to gas for most industrial users. In other words, pipelines are afraid that these escalation clauses may price gas out of the industrial market. For this reason, they propose a cap on the wellhead price of deregulated gas equivalent to 70 percent of the average acquisition cost of crude oil by U.S. refiners.

The bottom line of this debate is that there is at stake tens of billions of dollars annually to be distributed among the different participants. For this reason, consumer groups oppose decontrol on natural gas prices, because they will be net losers, at least in the short term.

In addition to politics, the fate of the NGPA will largely depend on the availability of natural gas in the U.S. market, which in turn depends, to a large extent, on the discovery of new reserves. During

1977/81, annual average U.S. reserves additions amounted to approximately 15 Tcf, which is almost double the annual average during 1972/76. As of January 1, 1982, U.S. proven reserves were 198 Tcf and the reserves to production ratio was approximately 10:1. This increase in reserves additions was mainly caused by the surge in exploratory activity during the last five years, which in turn was caused by the higher gas prices. For example, wellhead prices in the interstate market increased from $0.69 per mcf in 1976 to almost $3 for new gas in late 1981.

This improvement in gas reserves additions has made predictions of future domestic production more optimistic as compared to those made in the mid-1970's which predicted that domestic production would decline sharply in the 1980's, and thereafter. Today, estimates of domestic production over the next twenty years are more optimistic, with the majority predicting a small decline in domestic production, but an increase in imports offsetting this decline. For example, during the 1980's, the U.S. Department of Energy expects a decline between 0.5-1.5 tcf in domestic production but an increase of 0.7 Tcf in gas imports. Other estimates are even more optimistic, predicting an actual increase of several Tcf in available gas supplies over the next twenty years.

To summarize, availability of gas over the next twenty years is expected to remain relatively stable or even increase by a small amount. The exact level of gas supplies in the U.S. will depend mainly on federal policy toward natural gas and to a lesser extent on the gas export policies of Canada, Mexico, and Algeria.

D.3 Coal

The United States proven reserves of coal amount to about one-fourth of the world's proven reserves, and the reserves-to-production ratio is about two to three hundred years. This fact has induced some people to refer to coal as "America's ace in the hole." In addition to playing a major role in the electric utility market, coal is expected to play a substantial role in the industrial sector.

U.S. coal is normally categorized as either eastern or western coal, depending on whether it lies east or west of the Mississippi River. Western coal reserves represent about 54 percent by weight and 30 percent by heat content of the total U.S. reserves. Western coal is generally lower in heat and sulfur content by weight than eastern coal, which gives western coal a major advantage in an area where sulfur dioxide emissions are a problem. However, current EPA regulations may diminish most of this advantage. Most of the western coal could be strip-mined because the seams lie within two hundred feet from the surface. Eastern coal is generally extracted by underground mining. Strip mining recovers about 90 percent of the coal in place, while underground mining recovers only about 50 percent. The coal per worker-day recovered with strip mining is about three times higher than with underground mining.

In other words, although eastern coal has a higher heat content than western coal, the latter has a lower cost of recovery and is less polluting in its end uses than the former. If coal becomes a major factor in the future energy mix of the United States, most of the additional coal supplies are expected to be western coal because of its low sulfur content and the facility of production. However, western coal will have to be transported significant distances to where it will ultimately be used.

Coal is shipped by rail (65 percent), and the rest is used by power plants close to the point of extraction. Most of the additional western coal supplies will have to be shipped by rail, unless legislation is introduced soon that will authorize the construction of slurry pipelines.

Slurry pipelines provide an alternative to railroad transportation, especially when large amounts of coal have to be transported long distances. Of course the railroad companies are not willing to lose a large part of their future market to slurry pipeline companies, and they have persistently fought any legislation which would aid in the implementation of the slurry pipeline alternative. In addition to opposition from the railroads, the slurry pipeline companies are facing opposition from users of the West's scarce water resources. A slurry pipeline needs substantial amounts of water to mix with the pulverized coal and then to pump the mixture through the pipeline. In 1978 a slurry pipeline bill was effectively blocked by a coalition made up of the railroad companies, the environmentalists, and the western farmers.

Given the large size of proven coal reserves, no major increase in coal production costs is expected over the next several decades. In other words, no major "cost-push" increase in coal prices is expected over the next two decades. However, there may be an increase in coal prices because of a gap between coal prices and the prices of coal substitutes, as explained below.

Currently, coal prices are about 40 percent of the oil price. In the event that natural gas prices increase and reach the oil price, there will be a lot of economic rent to be captured by the coal suppliers. Given that the coal market is relatively competitive at the minemouth, coal prices at the minemouth are not expected to increase because mine owners cannot take advantage of the gap between the coal prices and the prices of coal substitutes (oil and natural gas). Rather coal prices at the minemouth are expected to remain relatively stable in real terms. However, the same may not hold true with coal prices at the retail level, because the transportation of coal is controlled by the railroads. In other words, the railroads may very well exercise their monopoly power in order to capture some of the available economic rent. They would do this by increasing the transportation rates.

To summarize, delivered coal prices to the industrial user are not expected to decline in real terms. If the industrial user is located relatively close to the mine, coal prices are expected to remain constant in real terms because of the small transportation cost involved. However, if coal has to be transported over long distances, delivered coal prices are expected to increase in real terms by several percentage points annually, because of the monopoly power of the railroads.

The estimates of Data Resource Incorporated (DRI) for future coal prices are depicted in Table D-6. Note that these estimates are in current dollars, which implies that coal prices in the mine mouth will be relatively constant in real terms if the inflation rate ranges at about 7-9 percent annually.

Table D-6

DRI's Estimates of

Marginal Mine-mouth Prices of Coal

(current dollars per ton)

Supply region Sulfur type	1980	1981	1982	1985	1990	1995	2000
North Appalachia							
low sulfur	31.84	35.29	39.71	57.64	98.19	142.2	206.6
medium sulfur	29.13	31.96	35.32	51.89	84.62	121.8	178.1
high sulfur	22.72	24.88	27.26	39.90	64.76	93.80	129.3
South Appalachia							
low sulfur	31.63	34.99	39.40	59.23	103.4	145.7	211.4
medium sulfur	30.07	32.90	36.39	54.43	95.37	135.9	198.4
high sulfur	23.28	25.76	28.31	41.19	69.10	101.7	176.9
Midwest							
low sulfur	30.52	33.31	39.47	63.13	106.0	151.7	226.8
medium sulfur	28.88	31.92	36.04	50.71	80.95	118.7	174.7
high sulfur	25.69	27.62	30.83	42.66	66.78	93.22	129.9
Montana-Wyoming							
low sulfur	9.58	10.26	11.23	15.37	24.07	33.16	45.60
medium sulfur	9.52	10.20	11.24	15.13	23.17	31.59	42.93
high sulfur	9.52	10.20	11.24	15.07	23.01	31.09	42.15
Colorado-Utah							
low sulfur	20.49	21.37	23.86	34.36	58.58	86.33	129.8
medium sulfur	19.27	20.56	23.11	33.73	55.35	79.06	115.8
high sulfur	19.27	19.91	21.90	32.51	53.69	75.95	117.0
Arizon-New Mexico							
low sulfur	19.35	20.55	22.97	33.35	60.24	87.74	152.6
medium sulfur	18.11	19.03	20.95	40.37	56.41	74.71	104.7
high sulfur	18.11	19.03	20.95	74.67	115.7	161.3	223.2

Note: Low sulfur is coal with up to 1.04% sulfur. Medium sulfur is coal with from 1.06% to 2.24% sulfur. High sulfur is coal with 2.25% or more sulfur. Percent change is the compound annual rate of change.

Source: Coal Outlook, Feburary 1, 1982, page 5.

APPENDIX E

FINANCIAL MODEL

E.1 Introduction

The choice of fuels and technologies for energy supply on a corporate level has to be seen in the framework of the company's objectives as well as in its social, institutional, political, and legal environment.

Within private industry it can be assumed that the major objective is some type of "profit maximization". The differences between companies are in their definition of profitability and in their timing. The setting of priorities either to high income (dividends, etc.) today or to a high future value to be obtained by investment.

Whatever the structure and definition of the individual firm's goals may be, their economic criteria are one of the most important factors in evaluating different energy supply strategies.

The Financial Model of the Interfuel Substitution Project evaluates the economic effects of the alternate technology and/or fuel choices such as boilers or cogeneration. The model looks at alternative investments and performs profitability capital budgeting calculations which can then be evaluated (traded off) against other factors such as air pollution effects.

The model is build up in a matrix form, where the time sector is a number of periods (actually 12 years). Each of the matrix's values can be changed separately and can be taken for further computation separately. This makes it possible, for example, to increase prices differently. For this purpose all variables with values which are related to the market (like labor costs, fuel costs, or price of the equipment) can be escalated independently at a rate which differs from year to year.

The Financial Model has been implemented on the M.I.T. Sloan School of Management's Prime Computer using the IFPS (Interactive Financial Planning System) software framework and its simple and transferable programming language.

E.2 Model Use

The financial model, because it has been developed on IFPS allows for both high flexibility in type of analyses run (NPV vs. IRR, etc.) and in changes in basic input data.

As an example, after a first, it is possible to change by either altering some of the input data, building up a different input data file or by using the "What if.." approach.

By using the "goal seeking" approach, it is possible to work through the program from the bottom to the top. An output variable is defined and the break even point is calculated The user defines, for example, goals such as an IRR of 20% in the 12th year and asks how high the fuel costs (oil price) or capital costs may rise to obtain an IRR of 20%.

In addition, it is possible to evaluate the impact that one or more variables has on an output variable. By changing the value of the input variables, the user can see which of the input variables has the largest impact on the specific output variable. This process is equivalent to estimating the partial derivates of the output variable given the different input variables.

Systematic sensitivity analysis offers the simplest means of evaluating uncertainty when there is limited information concerning the probability of individual events. An input variable which is uncertain and has a considerable impact on the profitability can be changed stepwise in percentages.

The Monte Carlo Simulation considers an input variable as a probabilistic distribution. This may be of interest if a variable cannot easily be defined as a given point (e.g., because of historic probabilistic distribution) or if the risk that is involved can be simulated by giving a certain probabilistic distribution to a critical variable. The model then generates a number of cases given the probabilistic distribution and sets of statistical data on desired output variables.

The financial model considers the following probabilistic distributions:

Uniform Distribution

Normal Distribution

Triangular Distribution

Generalized Distribution to be specified by coordinates of a piecewise linear approximation

The number of Monte Carlo simulations to be run can be chosen as well as the desired output (histogram, frequency table, or normal approximation table of percentile values).

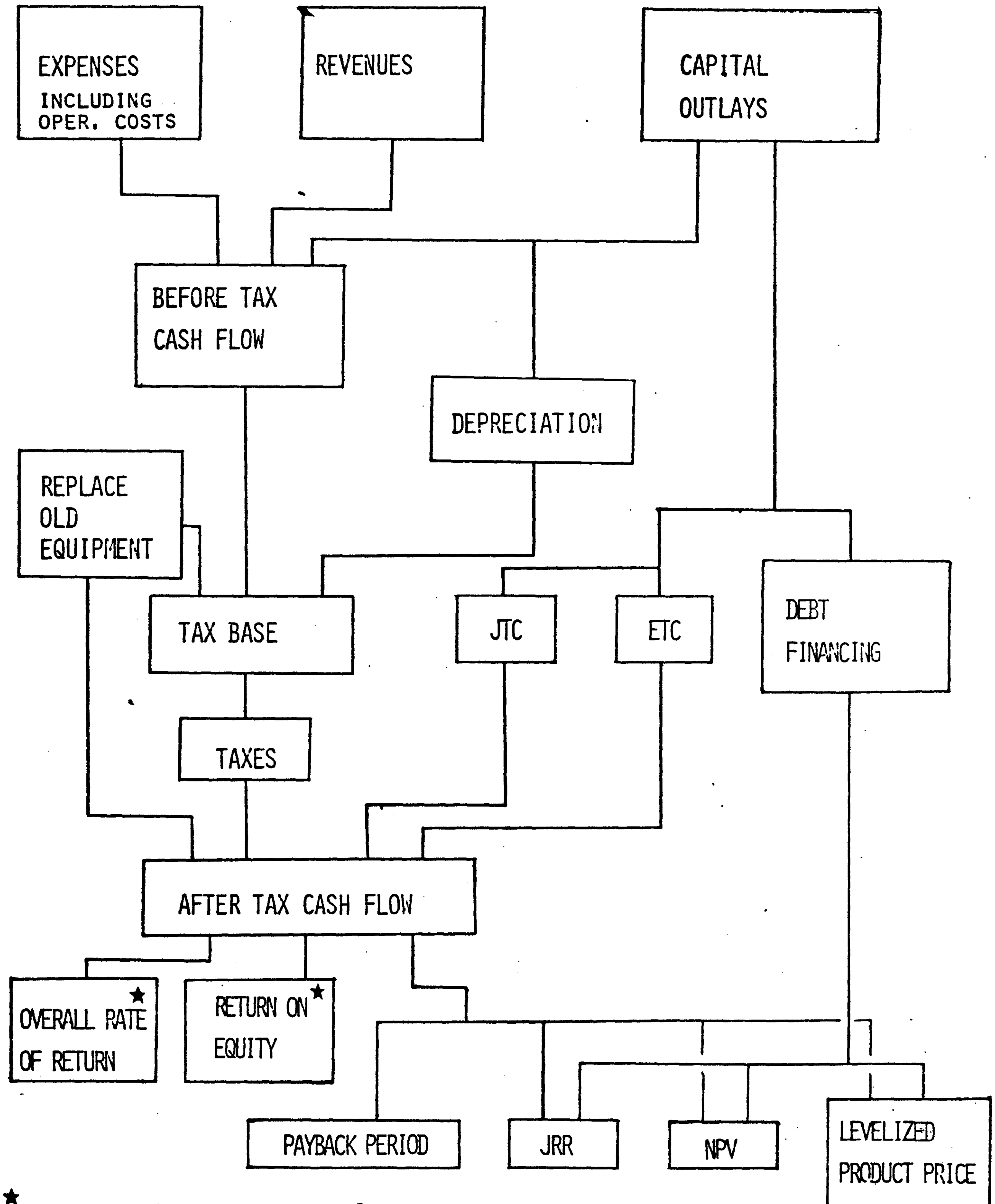
E.3 Structure of the Program

Computation of Net present value

The overall structure of the program that basically calculates the NPV, IRR, and the Payback period can be seen in Figure E-1.

For the Expenses, the following definition is used:

Figure E-1.
STRUCTURE OF THE FINANCIAL MODEL



★BASED ON ESCOE

$$\text{Expenses} = \text{Variable Costs} + \text{Semivariable Costs} + \text{Fixed Costs} \tag{1}$$

The terms of Equation (1) are explained in Section II of the main body of the report. As most of the operating costs are variable, this term is broken down to:

$$\text{Variable Costs} = \text{Fuel} + \text{Process material} + \text{Electricity} + \text{Other Utilities} + \text{Labor} + \text{Miscellaneous} \tag{2}$$

with the exception of "Miscellaneous", each of these cost items is structured as:

$$\text{Fuel} = \text{Requirement of Fuel at full capacity} \times \text{Capacity Factor} \times \text{Unit Cost Fuel} \tag{3}$$

where the Capacity Factor is defined as:

$$CF = \frac{\text{Actual annual energy production}}{(\text{Maximum annual capacity}) \times 8760 \text{ hr.}} \tag{4}$$

The "Revenues" are the sum of the revenues from the different products. Each revenue is defined as follows:

$$\text{Revenues} = \sum_{m=1}^{M} (\text{Sales volume}_m \times \text{price}_m) \tag{5}$$

The Investment Expense is the non-capital expenditures that occured mostly during the construction period, whereas later the expense primarily consist of Operating Costs.

$$\text{Total Capital} = \text{Depreciable Capital} + \text{Working Capital} + \text{Nondeprec.Capital} + \text{Investment Expense} \tag{6}$$

$$\text{Depreciable Capital} = \text{Depreciable Capital without Contingencies} + \text{Contingencies} \tag{7}$$

where the Depreciable Capital without Contingencies is, mainly for depreciation purposes, broken down into different items:

Depreciable Capital without Contingencies =

$$\sum_{n=1}^{N} \text{Depreciable Capital}_n \qquad (8)$$

with

$$\text{Depreciable Capital}_n = \text{Equipment}_n + \text{Construction}_n \text{ Material}_n + \text{Construction Labor}_n + \text{Indirect Costs}_n \qquad (9)$$

Capital can be broken down into items that can be depreciated independently considering different Tax Life (e.g., shorter writeoff for environmental equipment) and different depreciation methods.

These methods can be Straight Line Depreciation, Sum of the Years Digits, or Declining Balance Method, where the Salvage, the Acceleration Constant for the decling balance and the choice of switching over to either Straightline or Declining Balance are further options. Before Tax Cash Flow (BTCF) is defined as:

$$\text{BTCF} = \text{Revenues} - \text{Expenses} - \text{Depreciable Capital} - \text{Working Capital} - \text{Nondeprec.Capital} + \text{Salvage} \qquad (10)$$

Where Salvage is the sum of the Liquidation value which is obtained by selling the old equipment that is replaced at the beginning of the investment.

$$\text{Salvage} = \text{Liquidvalold} + \sum_{n+1}^{N} \text{Salvage}_n \qquad (11)$$

From this, the Depreciation has to be subtracted as well as the <u>Loss</u>. The tax base is then derived from the Before Tax Cash Flow:

$$\text{Tax Base} = \text{Revenues} - \text{Expenses} - \text{Depreciation} - \text{Loss} \qquad (12)$$

The loss is the difference between the Bookvalue and the Liquidationvalue of the old equipment. In case of a Liquidvalue being greater than the

Bookvalue the Loss gets a negative sign and adds a "gain" to the Taxbase.

$$\text{Loss} = \text{Bookvalueold} - \text{Liquidvalold} \tag{13}$$

The amount of income tax to be paid is given by the following equation:

$$\text{Taxes} = \text{Tax Base} \times \text{Tax rate} \tag{14}$$

Where the tax rate is the company's overall income tax rate. The investment tax credit is computed:

$$\text{ITC} = \text{ITC rate} \times \text{Depreciable Capital} \tag{15}$$

and the energy tax credit (ETC) as:

$$\text{ETC} = \text{ETC rate} \times \text{Depreciable Capital} \tag{16}$$

The After Tax Cash Flow (ATCF) is then:

$$\text{ATCF} = \text{BTCF} - \text{Taxes} + \text{ITC} + \text{ETC} + \text{Salvage} \tag{17}$$

This ATCF is the base to calculate the net present value (NPV)

$$\text{NPVproj} = \sum_{t=1}^{T} \frac{\text{ATCF}_t}{(1+r)^t} \tag{18}$$

where r is the discount rate that the company uses and the Internal Rate of Return (IRR_{PROJ}) is defined as:

$$IRR_{PROJ} = r \text{ for } NPV_{PROJ} = 0 \tag{19}$$

The Payback period is the time when the cumulated ATCF gets to zero.

Debt Financing

The consideration of <u>debt financing</u> in this kind of investment analysis is a very controversial subject among scholars working in the field. The "purist" approach points out that the Net Present Value and the IRR have to be used as they are defined and no adjustment to the impacts of debt financing can be made. The "practical" approach is of the opinion that the debt financing can change considerably the results of investment analyses. This can be caused by a change in expenditures that may occur if the interest on debt does not equal the opportunity cost for equity capital.

Furthermore there are side effects like issuing costs or the tax shields gained by the fact that interest on debt is tax deductible. These effects can be taken into consideration by adjusting the Net Present Value or the Discount Rate.

The adjustment used in this financial model is in accordance with the theory of Myers (1981).

The Net Present Value of the totally equity financed project has to be adjusted to the effects of the yearly tax shields by adding the present value of the tax shields.

$$NPV = NPVproj + PVTaxshield \qquad (20)$$

$$NPV = \sum_{t=1}^{T} \frac{ATCF_t}{(1+r)^t} + \frac{Tax\ Shield_t}{(1+i)^t} \qquad (21)$$

where i equals the interest rate on debt

$$Tax\ Shield = Tax\ rate \times i \times Debt_{t-1} \qquad (22)$$

Currently there is a discussion under way about whether the tax shields have to be discounted differently assuming that the firm follows a policy of period by period adjustment of its borrowing. The difference, however, is negligible in most of the cases.

With the same approach as for the Adjusted NPV the Adjusted Internal Rate of Return can be calculated. The definition for the IRR is again

0 for NPV = 0

This applies to (20) and (21):

$$0 = \sum_{t=1}^{T} \frac{ATCF_t}{(1+r)^t} + PVTaxshield \qquad (21a)$$

where r has to be determined of

$$\sum_{t=1}^{T} \frac{ATCF_t}{(1+r)^t} = - \text{PVTaxshield} \tag{21b}$$

A different way to consider debt financing is proposed by the Engineering Societies Commission on Energy, Inc (ESCOE, 1979). The ESCOE method avoids the dispute about whether or not it is right to introduce debt financing in the Net Present Value concept. (see Exhibit 2)

Besides required product prices, the ESCOE procedure computes an "overall rate of return" which is a weighted average cost of capital based on a "return on equity" which is an "internal rate of return" where the return is after paying the debt retirement and the interest and therefore only the equity part of the capital is considered. Rewriting the ESCOE definition in terms of the Finacial Model :

$$i_s = \text{Return on Equity for } \sum_{t=1}^{T} \frac{ECF}{(1+i_s)^t} + \text{PVTaxshield} = 0 \tag{23}$$

where ECF is the Equity Cash Flow

A reconciliation with the ESCOE guidelines is briefly given in Exhibit 2.

Levelized Product Price

Given a certain, venture management often wants to know which prices are required to obtain the desired profitability (in terms of return on investment/discount rate) to combine the investment analysis with the market analysis.

The price p has to be found which results in NPV = 0. With Equations (17) and (18) this is:

$$NPV = \sum_{t=1}^{T} \frac{ATCF}{(1+r)^t} + PVTAXSHIELD \tag{24}$$

which has analytically to be solved for the revenues:

$$0 = \sum_{t=1}^{T} \left(\frac{Rev}{(1+r)^t} + \frac{X}{(1+r)^t}\right) + PVTAXSHIELD \tag{25}$$

The computation of X is laid out in Appendix 3.

Equation (22) can be transformed:

$$\sum_{t=1}^{T} \frac{Rev}{(1+r)^t} = \sum_{t=1}^{T} \left(- \frac{X}{(1+r)^t}\right) - PVTAXSHIELD \tag{26}$$

The present value of revenues (PVREV) is defined as:

$$PVREV = \sum_{t=1}^{T} \frac{X}{(1+r)^t} \tag{26a}$$

PVREV has first to be compounded to the startup-year (first year of operation)

$$PVRevStartup = PVRev \quad (1+r)^s \tag{27}$$

As the product price is required to be constant (levelized) the present value of the revenues is annualized:

$$Annual\ Rev = PVRev \quad A \tag{28}$$

$$\text{with } A = \frac{d(r+d)^t}{(r+d)^t - 1}$$

The (levelized) price is then computed as:

$$Price = \frac{Annual\ Rev}{Sales\ Vol} \tag{29}$$

Cost per Unit

For the comparison of different technical systems it may be of interest to compare the unit costs of generating steam or electricity in the case of cogeneration. The concept of this cost calculation is not based on accounting calculation procedures but rather annualizes the capital costs, adds them to the yearly operating expenses and divides that by the production volume.

Annual Capital Cost = Cumulant + Capital Costs * A (30)

Cap.Cost/kwh = Annual Capital Cost/Production Volume Electricity (31)

Cap.Cost/BTU Steam = Annual Capital Cost/Steam Production (32)

Operating Expenses/kwh = Expenses/Prod. Vol. El. (33)

Operating Expenses/BTU Steam = Expenses Steam Production (34)

Fuel Cost/kwh = Fuel Cost/Prod.Vol.El. (35)

Fuel Cost/BTU Steam = Fuel Cost/Steam Production (36)

Costs/kwh = Cap.Cost/kwh + Operating Exp./kwh + Fuel Cost/kwh (37)

Costs/BTU=Cap.Cost/BTU Steam + Operating Exp./BTU Steam + Fuel Cost/BTU Steam (38)

Using this model in the actual form, the following underlying assumptions are involved:

- For the whole Depreciation Model only tax depreciation is used.

- For the Revenues, it is assumed that production rate equals sales volume (stock can be considered as working capital).

- It is assumed that the salvage value equals the book value at the time of replacement.

- The stream of cash flows is discounted to the first year of construction.

- Estimates of all costs and revenue items have to be adjusted to the same base year.

- Each annual account is considered to be discrete end-of-the-year transaction.

- Escalation of prices or cost estimates have to be applied at the full rate to each year's transaction. All cash flow transactions have to be escalated.

E.4 Inputs

For the convenience of the user it is of interest to know that the program accepts inputs on all levels of detail.

These "levels of detail" correspond to the different steps of computation of the program. That means that, for example, the Input can be either Unit Cost of Fuel, Requirement of Fuel and Capacity Factor, or--as a second level--Fuel Cost, or Variable Costs, or even only Expenses.

There is a file of "Default Values" implemented that keeps variables that are not defined "zero" or "1" for the escalation factors, for example.

The value of each variable can be set and changed independently for each year.

For the "Expenses" it should be noted, that it is up to the user to define a given cost item as semi-variable (e.g., maintenance) or fixed (overheads, etc.). Labor would, in most cases, have only a small part to be considered as variable whereas a major part would be fixed costs.

"Depreciable Capital" includes the item "Indirect Costs" which consists of planning and engineering costs, tax or other depreciable costs that are not yet included.

Land costs could be added to other non-depreciable costs as "Contingencies". Contingencies include a reserve for unpredictable costs (cost overruns) that may occur during the life of the project.

For computing the results there are some variables which can be considered as strategic. Whereas the "Life" of the investment is the Tax Life and therefore not a controllable variable, the Discount rate and some assumptions are set up by the user of the model i.e.,a particular company.

In setting up the discount rate, one should first be sure to consider inflation consistently. That means if the expenses and other variables are given in constant dollars the discount rate must exclude inflation. If inflation is considered in the projection of costs and revenues, the discount rate can take into account the "effective" cost of capital which is related to the market.

Furthermore, the discount rate should be set according to the risk the project is considered to include.

When defining the tax rate one has not only to include the local, state and federal income taxes, but it has also to be seen how the project is affecting the company's tax situation. The incremental tax rate can be right but it can also happen that, at least during construction period the company's taxable income is decreased.

A list of Input Variables is attached as Annex E-1.

Annex E-1: LIST OF INPUTS

I. General

-Capacity Factor

-Tax rate

-Discount rate

-Interestrate

-ITC rate

-ETC rate

-Maturity

-Graceperiod

-Debtrate

II. Revenues

1. Revenues 1	1.1 Sales volume 1.	1.2 Price 1.
2. Revenues 2	2.1 Sales volume 2.	2.2 Price 2.
3. Revenues 3	3.1 Sales volume 3.	3.2 Price 3.
4. Revenues 4	4.1 Sales volume 4.	4.2 Price 4.
5. Revenues 5	5.1 Sales volume 5.	5.2 Price 5.

III. Capital Outlay

III. 1 Working Capital

III. 2 Depreciable Capital

2.1 Contingencies

2.2 Depreciable Capital not contingencies

2.2.1 Depreciable Capital 1

2.2.2 Depreciable Capital 2

2.2.3 Depreciable Capital 3

2.2.4 Depreciable Capital 4

2.2.5 Depreciable Capital 5

2.2.1.1 Equipment

2.2.1.2 Construction Material

2.2.1.3 Construction Labor

2.2.1.4 Indirect Costs

2.2.2.1 Equipment 2

2.2.2.2 Construction Material 2

2.2.2.3 Construction Labor 2

2.2.2.4 Indirect Costs 2

2.2.3.1 Equipment 3

2.2.3.2 Construction Material 3

2.2.3.3. Construction Labor 3

2.2.3.4. Indirect Costs 3

3. Non depreciable Capital

IV. Expenses

1. Variable Costs

2. Semi-variable Costs

3. Fixed Costs

1. Variable Costs

1.1 Fuel

1.1.1 Requirement of Fuel at full capacity (Req.Fuel)

1.1.2 Unit Cost Fuel

1.1.3 Capacity Factor

1.2 Process Material

1.2.1 Req. Process Material

1.2.2 Unit Cost Process Material

1.2.3 Capacity Factor

1.3 Electricity

1.3.1 Req. Electricity

1.3.2 Unit Cost Electricity

1.3.3 Capacity Factor

1.4 Other Utilities

1.4.1 Req. Other Utilities

1.4.2 Unit Cost Other Utilities

1.4.3 Capacity Factor

1.5 Labor

1.5.1 Req. Labor

1.5.2 Unit Cost Labor

1.5.3 Capacity Factor

1.6 Miscellaneous

V. <u>Depreciation</u>

V. 1.1 Depreciation Method 1

1.2 Depreciation Method 2

1.3 Depreciation Method 3

1.4 Depreciation Method 4

1.5 Depreciation Method 5

2.1 Tax Life 1

2.2 Tax Life 2

2.3 Tax Life 3

2.4 Tax Life 4

2.5 Tax Life 5

3.1 Salvage 1

3.2 Salvage 2

3.3 Salvage 3

3.4 Salvage 4

3.5 Salvage 5

4.1 Acceleration constant 1

4.2 Acceleration constant 2

4.3 Acceleration constant 3

4.4 Acceleration constant 4

4.5 Acceleration constant 5

5.1 SWITCH OVER 1

5.2 SWITCH OVER 2

5.3 SWITCH OVER 3

5.4 SWITCH OVER 4

5.5 SWITCH OVER 5

VI. Old Equipment

1. Depreciable Capital Old Equipment
2. Liquidation Value Old Equipment
3. Tax Life Old Equipment
4. Salvage Old Equipment

5. Acceleration Constant Old Equipment
6. SWITCH OVER Old Equipment
7. Actual year of life Old Equipment

VII. <u>Escalation Factors</u>

1.1. Escalation Price 1

1.2. Escalation Price 2

1.3. Escalation Price 3

1.4. Escalation Price 4

1.5. Escalation Price 5

2.1. Escalation Working Capital

2.2. Escalation Depreciable Capital

2.1.1. Escalation Depreciable Capital 1

2.1.2. Escalation Depreciable Capital 2

2.1.3. Escalation Depreciable Capital 3

2.1.4. Escalation Depreciable Capital 4

2.1.5. Escalation Depreciable Capital 5

2.2.1.1. Escalation Equipment 1

2.2.1.2. Escalation Equipment 2

2.2.1.3. Escalation Equipment 3

2.2.1.4. Escalation Equipment 4

2.2.1.5. Escalation Equipment 5

2.2.2.1. Escalation Construction Material 1

2.2.2.2. Escalation Construction Material 2

2.2.2.3. Escalation Construction Material 3

2.2.2.4. Escalation Construction Material 4

2.2.2.5. Escalation Construction Material 5

2.2.3.1. Escalation Construction Labor 1

2.2.3.2. Escalation Construction Labor 2

2.2.3.3. Escalation Construction Labor 3

2.2.3.4. Escalation Construction Labor 4

2.2.3.5. Escalation Construction Labor 5

2.2.4.1. Escalation Indirect Costs 1

2.2.4.2. Escalation Indirect Costs 2

2.2.4.3. Escalation Indirect Costs 3

2.2.4.4. Escalation Indirect Costs 4

2.2.4.5. Escalation Indirect Costs 5

3.1. Escalation Fixed Costs

3.2. Escalation Semi-variable Costs

3.3. Escalation Variable Costs

3.3.1. Escalation Fuel

3.3.1.1. Escalation Unit Cost Fuel

3.3.2. Escalation Process Material

3.3.2.1. Escalation Unit Cost Process Material

3.3.3. Escalation Electricity

3.3.3.1. Escalation Unit Cost Electricity

3.3.4. Escalation Other Utilities

3.3.4.1. Escalation Unit Cost Other Utilities

3.3.5. Escalation Miscellaneous

3.3.6. Escalation Labor

3.3.6.1. Escalation Unit Cost Labor

Annex E-2: RECONCILIATION WITH ESCOE

Based on: Guidelines for Economic Evaluation of Coal Conversion Processes, The Engineering Societies Commission on Energy, Inc. Prepared for DOE, April 1979.

The approach used in the Financial Model is based on the principles of the ESCOE guidelines. However, some assumptions are made differently:

The stream of cash flows is discounted to the first year of construction instead of startup point.

The cash flow is viewed from a different point and therefore has opposite signs (outflows are negative, inflows are positive).

An Energy Tax Credit is considered in addition to the Investment Tax Credit.

The ESCOE terminology uses the "Investors balance" (for BAL) as the yearly accumulated investors contribution and interest or Balance.

For the Construction Period the approach is as follows:

$$Z_t = (I_t - K_t) + (B_f - T_t + S_t) + Z_{t-1} \tag{1}$$

B-T+S = Interest on Balance

Z = Investors Balance (BAL in ESCOE)

$$B_t = r_d * i_d * Z_{t-1}: \quad \text{interest on debt} \tag{2}$$

$$T_t = f * r_d * Z_{t-1}: \quad \text{tax credit because of debt} \tag{3}$$

$$S_t = (1-r_d)\ i_s * Z_{t-1}: \quad \text{return on equity} \tag{4}$$

The yearly balance is compounded as:

$$Z_t = Z_{t-1} - \quad Z_t \tag{5}$$

with

$$Z_t = K_t - I_t - r_d i_d Z_{t-1} + f\ r_d\ i_d\ Z_{t-1}$$
$$-(1-r_d)\ i_s\ Z_{t-1} \tag{6}$$

(using (1) through (5))

$$i_p = (1-f)\ r_d\ i_d + (1-r_d)\ i_s \tag{7}$$

combined with (6):

$$Z_t = K_t - I_t - i_p Z_{t-1} \tag{8}$$

If t = 1 is the first year of construction and t = y the startup year (starting production), for the construction period the balance then is:

$$Z_y = \sum_{t-1} (I_t - K_t)(1 + i_p)^{y-t} \tag{9}$$

This balance of an unretired investment is called "total capitalized investment".

This investors balance has an equity and a debt portion.

$$Z_t = (1-r_d)Z_t + r_d\ Z_t \tag{10}$$

The equity portion (only S_t, B_t, T_t = 0):

$$(1-r_d)Z_t = (1-r_d)(I_t - K_t) + S_t + (1-r_d)Z_{t-1} \tag{1a}$$

$$(1-r_d)Z_t = (1-r_d)(K_t - I_t) - (1-r_d)\ i_s Z_{t-1} \tag{6a}$$

$$(1-r_d)Z_y = (1-r_d) \sum_{t=1} (I_t - K_t)(1+i_s)^{y-t} \tag{9a}$$

For the <u>Production period</u>, the following computations are made:

The "return on equity" defined in the Financial Model is the "Equity Investors Rate of Return". Equity Investors Return is in each year the sum of equity return S_t and equity retirement H_t.

The return on equity was defined as:

$$S_t = (1-r_d)\ i_s\ Z_{t-1} \tag{4}$$

The equity retirement is:

$$H_t = (1-r_d)\ Z \tag{11}$$

The Equity Investors Return is then:

$$S_t + H_t = (1-r_d)(i_s\ Z_{t-1} + Z) \tag{12}$$

with: $Z = Z_{t-1} - Z_t$

Equation (12) transforms to :

$$S_t + H_t = (1-r_d)\ (1+i_s)\ Z_{t-1} - Z_t \qquad (12a)$$

which has to be discounted with i_s to get the equity portion of the Present Value:

$$(1-r_d)\ Z_m = \sum_{t=1} (1-r_d)\ (1+i_s)Z_{t-1} - Z_t\ (1+i_s)^{-t} \qquad (13)$$

The rate of return on equity is i_s if:

$$(1-rd)\ (1+i_s)Z_{t-1} - Z_t\ (1+i_s)^{-t}-(1-r_d)Z_m = 0 \qquad (13a)$$

$t=1$

The Overall Rate of Return is defined as i_p in equation (7). To reconcile ESCOE with the Financial Model one has to be aware that the ESCOE approach is a little different with respect to the generating After Tax Cash Flow ( ). The model takes into account all financial Inflows and Outflows and gives the value of what is left to satisfy the investors. In the ESCOE-approach these capital costs are already included in the Investors balance ( )(eg:(4) $S_t=(1-r_d)i_sZ_{t-1}$). The Return on Equiity is computed as the Balance of the previous period times the equity portion$(1-r_d)$ times the Return on Equity(i_s) which leads to equation (13a). In the Financial Model the Return on Equity is computed by analogy to the IRR:

$$i_s = \text{Return on Equity for } \frac{ECF}{(1 + i_s)^t} + \text{PVTaxshield} = 0 \qquad (23)$$

Where ECF stands for Equity CashFlow, which does not consider of Debt Capital. Accordingly the remaining return is only related to the equity portion of the investment.

ECF= ATCF -Interest -Debtretirement +PVTaxshield

-Debtrate*Investment (24)

The <u>overall rate of return</u> is defined as computed in ESCOE(7):

Overall Rate of Return =(1-T)Debtrate Interestrate

+(1-Debtrate)Return on Equity ( )

<u>List of Variables</u>

A	auxiliary variable	a	
B	debt interest	b	
D	debt retirement	d	debt (subscript)
E	expenses		
		f	effective income tax rate
H	equity retirement		
I	annual investment outlay	i	interest/discount rate
		i_s	return on equity
		i_d	interest rate on debt
		i_p	overall rate of return
		j	inflation rate
K	investment tax credit		
L	revenue		
		m	number of production years
N	net operating cost		
		p	overall (subscript)
R	revenues	r	debt to total investment ratio
S	equity return	s	equity (subscript)
T	income taxes	t	year counter
Z	balance of unretired investment		

Exhibit 3

Computation of X (separating the revenues from ATCF)

$$\text{ATCF} = \text{Revenues} - \text{Investment expenditures} - \text{Expenses} - \text{Taxes} + \text{ITC} + \text{ETC} \quad (7)$$

with equations (8) and (9)

$$\text{ATCF} = (1-T)(\text{Rev} - \text{Expenses}) - \text{Inv. Expense} + T(\text{Depreciation} + \text{Loss}) + \text{ITC} + \text{ETC} \quad (10)$$

where T equals Tax Rate.

$$\text{ATCF} = \text{Rev} - \text{Expenses} - \frac{\text{Inv. Expend.}}{(1-T)} + \frac{T(\text{Depreciation} + \text{Loss}) + \text{ITC} + \text{ETC}}{(1-T)} \quad (10a)$$

According to equation (22) X defines as

$$X = \text{Expenses} - \text{Rev}^{1} + \frac{-\text{Inv. Expend.} + T(\text{Deprec.} + \text{Loss}) + \text{ITC} + \text{ETC}}{(1-T)}$$

so that (23) can be written as:

$$\text{PVREV} = \sum_{t=1}^{T} (\text{Exp.} - (-\text{Inv. Expend.} + T(\text{Deprec.} + \text{Loss}) + \text{ITC} + \text{ETC})/(1-T) \quad (23b)$$

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[1] In case there is a byproduct with fixed prices.

References

1. Brealey, Richard A. and Myers, Stewart C., Principles of Corporate Finance, McGraw-Hill, 1981.

2. Myers, Stewart C., Adjusted Present Value and Adjusted Discount Rates: A Reformulation. First Rough Draft, Sloan School of Management, M.I.T., 1981.

3. The Engineering Societies Commisssion on Energy, Inc.: Guidelines for Economic Evaluation of Coal Conversion Processes, prepared for DOE, April 1979.

4. EXECUCOM Systems Corp.: IFPS Tutorial, Austin 1980.

5. EXECUCOM Systems Corp.: IFPS Users Manual, Austin 1980.

GLOSSARY

Tax Rate: equals the overall tax rate as a composition of federal, local and state income taxes that a corporation has to pay on a taxable income (tax base).

Discount Rate: equals the firm's estimation of the cost of capital to discount the present value of a future cash flow.

Payback Period: equals the time when the cumulative After Tax Cash Flow (ATCF) becomes positive (which indicates that the stream of inflows paid back the investment outlays).

Capacity Factor: equals the ratio of the actual production rate (in physical units) and the maximum capacityon an annual basis.

Escalation Factors: $E = (1 + R)$ The Escalation Factor E is used to adjust dollar variables (X) to price increases:

$X_t = X_{t-1} * E$. R equals the escalation rate as fraction.

NPV (Net Present Value) equals the sum of annual after tax cash flows (ATCF) discounted over a given venture life to a selected time zero.

IRR (Internal Rate of Return or Interest Rate of Return) equals the discount rate at which NPV becomes zero.

BTCF: Before tax cash flow as defined in equation 16.

ATCF: After tax cash flow as defined in equation 17.

The stream of cash flows which serves as a base for the NPV and IRR.

ECF: Equity cash flow as defined in equation 22. Serves as a base for the return on equity.

APPENDIX F

ENVIRONMENTAL MODEL

F.1 Introduction

An important aspect of the interfuel substitution project methodology is the relationship between fuel use and air quality. There would be no need for a study on this subject if the least environmentally harmful fuels were also the least costly fuels. Of course this is not the case and decision makers facing investment choices concerning future fuel use are confronted with environmental/cost trade-offs.

Each fuel/technology case considered in this report has an associated air quality dimension. The vehicle by which this dimension is described and analyzed is the air quality simulation model. In essence what these models do is take data pertaining to what is projected to be emmitted from a stack, incorporate the local meteorology and translate all of this into predicted distributions of pollution across a specified area.

This appendix is structured as follows. The Background section discusses the fundamentals of air pollution processes. The primary aspect covered in this section is meteorology. Next the basis of air pollution simulation models is taken up. The class of models that have been most extensively developed and utilized are the so-called steady-state Gaussian plume models. Of this class of models, the model used in this project, the Climatological Dispersion Model is explained in detail.

F.2 Background*

The process of air pollution can be simply depicted as a system of three basic components:

Figure F-1

```
1--------------------------2------------------------3

Emission               Atmosphere               Receptors
Sources
```

Air pollution originates as an emission source. Pollutants are emitted to the atmosphere which acts as a medium for transport, dilution, and physical and chemical transformation. Pollutants may subsequently be detected by instruments or by human beings, animals, plants, or materials.

Once pollutants become airborne they are subject to the dispersing action of the atmosphere. Occurring simultaneously with transport by the wind (advection), and turbulent mixing (turbulent diffusion), are chemical reactions which transform primary to secondary pollutants.

The atmospheric aspects of air pollution can be divided according to:

1 Atmospheric chemistry

2 Meteorology

3 Transport and dispersion of pollutants.

As mentioned, atmospheric chemistry involves the transformation processes affecting airborne pollutants, processes which may take place on time scales of a few seconds to several weeks. Meteorology concerns the

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*Much of this section and Section F.3, Air Pollution Models, is taken from Ref. [5].

dynamics of the atmosphere, particularly pertaining to momentum and energy. Meteorological scales of motion can be categorized as follows:

1 Macroscale: phenomena occurring on scales of thousands of kilometers.

2 Mesoscale: phenomena occurring on scales of hundreds of kilometers.

3 Microscale: phenomena occurring on scales of less than ten kilometers, such as the meandering and dispersion of a stack plume and the complicated flow regime in the wake of a large building.

Each of these scales of motion plays a role in air pollution, although over different periods of time. For example, micrometeorological effects take place over scales of the order of minutes to hours, whereas mesometeorological phenomena influence transport and dispersal of pollutants over hours to days. Finally, macrometeorological scales of motion have characteristic times of days to weeks.

For our purposes the region of the atmosphere governing transport and dispersion of pollutants is the so-called planetary boundary layer, roughly the lowest 1000 meters. The planetary boundary layer represents the extent of influence of the earth's surface on wind structure in the atmosphere. Within this layer, winds are influenced by prevailing high-level flows and the frictional drag of the surface. With respect to air pollution, the key problem associated with the planetary boundary layer is to predict the variation of wind speed and direction with altitude as a function of surface roughness and temperature profile.

The atmospheric temperature profile (the variation of temperature with altitude), has an important effect on wind structure and turbulence in the lowest 1000 meters. In the trophoshere (the 10 to 20 kilometers of the atmosphere closest to the ground) the temperature normally decreases with increasing altitude because of the decrease in pressure with height. The temperature profile against which all others are judged is that of a parcel of dry air as it moves upward in a hydrostatically stable atmosphere and expands slowly to lower pressure with no gain or loss of heat. If such a profile exists in the atmosphere, a parcel of air at any height is in neutral equilibrium; that is, it has no tendency either to rise or fall. Actually, the atmosphere is very seldom in such delicate equilibrium; the influence of surface heating and large-scale phenomena usually results in a temperature profile different from the reference profile (also referred to as the adiabatic lapse rate)*.

If the temperature decreases faster with height than the reference profile, air parcels at any height are unstable, that is, if they are displaced either upward of downward, they will continue their movement in the direction in which they were displaced. Such a condition is referred to as unstable. On the other hand, if the temperature decreases more slowly with height than the reference profile (or even increases), air parcels are inhibited from either upward or downward motion and the situation is referred to as stable. The stability condition of the atmosphere plays an important role in determining the rate of dispersal of pollutants.

The phenomenon of direct interest in predicting the dispersion of air

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*This should not be too surprising considering the diurnal variation of solar radiation from above coupled with ground surface absorption/radiation from below acting as inputs to the planetary boundary layer system.

pollutants is turbulent diffusion. This phrase refers to the observed spreading of a cloud of marked particles in a turbulent fluid at a rate many orders of magnitude greater than that from molecular diffusion alone. The spreading is really not due to a "diffusion" phenomenon such as results from molecular collisions but rather is a result of the rapid, irregular motion of macroscopic lumps of fluid (called eddies) in turbulence. Thus, the scales of length in turbulent diffusion are much greater than in molecular diffusion, with the contribution of the latter to the dispersion of pollutants in turbulence being virtually negligible. The level of turbulence in the planetary boundary layer increases with increased wind speed, surface roughness, and instability. Turbulence, therefore arises from both mechanical forces (shear, surface friction) and thermal forces (buoyancy).

F.2 Air Pollution Models

In general mathematical models that attempt to simulate the complex atmospheric processes involved in air pollution are based on the equations of mass conservation for individual pollutant species. Models based solely on the equations of conservation of mass cannot predict variations in the wind velocity field or the temperature field. Wind and temperature information thus must be input as data. What these models can do, however, is relate in a managable set of equations the effects of all the dynamic processes that influence the mass balance on a parcel of air. Ideally these include the transport, turbulent diffusion, and reaction of all pollutant species of interest. The introduction or removal of species can also be treated by such models.

A model based on the equations of conservation of mass requires, as part of its formulation or as data input the following general types of information: emissions, meteorology, and atmospheric chemistry and removal processes. Models may describe the behavior of reactive species, or they may be limited in application to inert species. Furthermore, models may be formulated under the assumption of steady-state behavior, or they may be descriptors of time-varying behavior. Temporal and spatial resolution of models may vary widely. Models may be based on a fixed grid, or they may be formulated so as to trace the variations in concentration in an air parcel moving with the average wind field.

Temporal and Spatial Resolution

The temporal resolution of an ambient air quality model (i.e. the time period over which the predicted concentrations are averaged) may vary from several minutes to one year. For example, a model may predict the 15-minute average pollutant concentration as a function of location in the airshed, or it may predict the yearly average concentration as a function of location. The requirements in implementing a model will be strongly governed by its temporal resolution.

Certain simplifying assumptions involving steady source rates and meteorology form the basis for the most widely used models. These so-called steady-state models can predict the spatial distribution of airborne pollutant concentrations under conditions of time-invariant meteorological and source emission rates. Models of this type are predicated upon the assumption that one meteorological "vector" prevails throughout the region of interest. Hence it is not surprising that steady-state models are not recommended for applications involving distances exceeding 50 kilometers. Steady-state models will be discussed in more detail later.

Apart from temporal aspects there are spatial aspects associated with air pollution modeling. The spatial resolution of an ambient air quality model (i.e. the area over which the predicted concentrations are averaged) may vary from several meters to several thousand kilometers.

F.4 Steady State Gaussian Plume Models

Climatological Dispersion Model (CDM)

The Climatological Dispersion Model (CDM) is one of a set of steady-state Gaussian plume models designated by the Environmental Protection Agency (EPA) as "guideline models" (EPA, 1981). What this means is that assuming the models are used appropriately, the EPA will recognize the results of such models in determining compliance with federal air pollution laws and regulations. CDM is one of EPA's UNAMAP air quality simulation models. UNAMAP is an acronym for User's Network for Applied Modeling of Air Pollution. It contains all guideline models.

No single air quality simulation model is universally superior to all others. Indeed, that is one of the reasons for there being several guideline models. Each model has its own peculiar set of attributes. These include temporal resolution (such as the ability to process hourly meteorological data for the purpose of simulating ground level concentrations for hourly, 3-hour, 24-hour as well as annual averages; all of which are included in EPA's National Ambient Air Quality Standards (NAAQS), see Table F-10).

Terrain adjustment is another attribute. For example, if a major pollution source were located in a valley, the pollutant plume may impinge upon the surrounding hills. Some guideline models provide for point sources and receptors to be designated at different levels thus allowing for such situations to be more accurately modeled.

Although CDM can accommodate numerous point and area sources distributed over a considerable area, some models are capable of handling only a single emission source. There are models that are capable of considering local or microscale situations such as downwash. Downwash occurs when the stack plume dips down immediately on the leeward side of the factory due to the drop in pressure caused by the areodynamic wake of the building. It can be seen that the motive for having a set of guideline models is to cover the myriad of situations that arise in air quality simulation.

The Climatological Dispersion Model is particularly well suited for the type of planning being performed in the Interfuel Substitution Project.* Apart from being a guideline model, CDM's advantages include its ability to accommodate many point and area sources distributed across a wide area.

The Anatomy of CDM

The Climatological Dispersion Model simulates the long-term (seasonal or annual) concentrations at ground level receptors of one or several air pollution sources in a region (Busse and Zimmerman, 1973). Recall that the size of the region should not exceed 50 kilometers in any direction for any steady-state plume model. The CDM uses average emission rates from sources and a joint frequency function of wind direction, wind speed and atmospheric stability for the same period as inputs.

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*A slightly modified version of CDM was used successfully in the MIT Energy Lab long range planning study for Consolidated Edison of New York.

The basic assumptions behind steady-state gaussian plume models are:

1) constant source emission rates
2) constant meteorological state over the entire region for pollutant plumes to reach steady state
3) plume behavior is defined by a bi-variate gaussian distribution as indicated in equation 1.

$$C(x,y,z) = \frac{Q}{2\pi u\sigma_y(x)\sigma_z(x)} \exp[-\frac{1}{2}[(\frac{y}{\sigma_y(x)})^2 + (\frac{z - H}{\sigma_z(x)})^2]] \qquad (1)$$

where

$C(x,y,z)$ = pollutant concentration at a point x,y,z

x = downwind distance from emission source

y = crosswind displacement from plume centerline

z = verticle displacement from plume centerline

Q = emission rate gm/sec

U = mean wind speed

$\sigma_y(x)$ = crosswind dispersion factor

$\sigma_z(x)$ = verticle dispersion factor

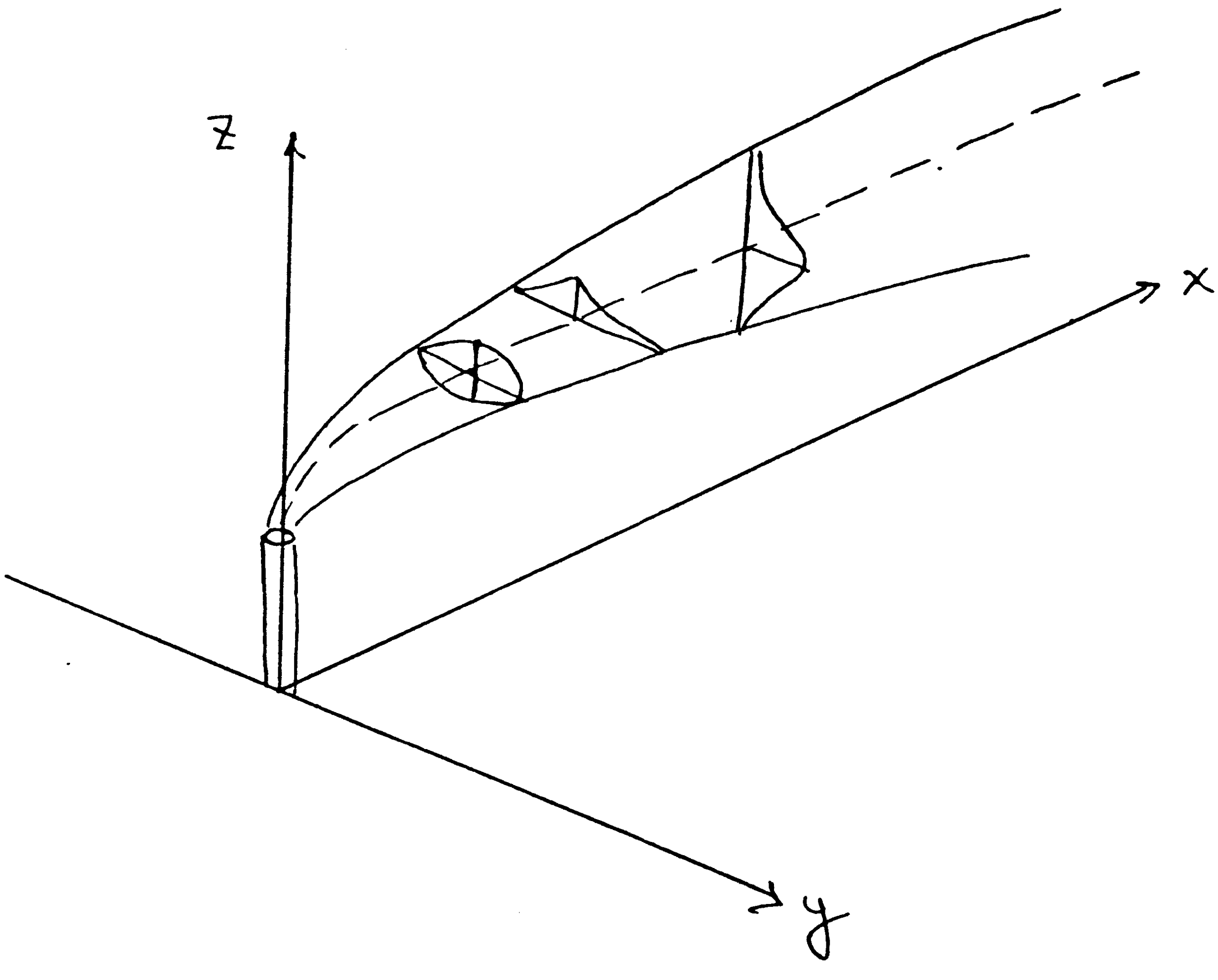
H = virtual stack height (equal to actual stack height + plume rise)

The meteorological input to the CDM is in the form of a joint frequency function $\phi(k,l,m)$. The function gives the joint frequency of occurance of a wind direction sector k, a wind speed class l, and a stability category index m. There are 576 entries in the table for the joint frequency function. This number derives from 16 different wind sectors (22.5 degrees each), 6 wind speed classes and 6 atmospheric stability classes. Information for localities throughout the United States can be obtained from the National Climatic Center.

Each "cell" of the joint frequency function has a value anywhere from

FIGURE F.2

GAUSSIAN PLUME



zero to one representing its percentage of the hourly meteorological measurements over a year. The steady-state plumes resulting under each of the 576 possible meteorological situations is then multiplied by the respective frequency of occurrence.

The wind speed U for the various weather bureau classes is taken as the central wind speed of the class. See Table F-1.

Table F-1 Central Wind Speed

Wind Speed Class	Speed Interval Knots	Class Wind Speed m/s
1	0 to 3	1.50
2	4 to 6	2.41
3	7 to 10	4.47
4	11 to 16	6.93
5	17 to 21	9.61
6	greater than 21	12.52

The stability classes 1 through 6 indicate the following stability states:

1 ----- extremely unstable conditions

2 ----- moderately unstable conditions

3 ----- slightly unstable conditions

4 ----- neutral conditions

5 ----- slightly stable conditions

6 ----- moderately stable conditions

To account for an increase of wind with height above a height of 10 meters (anemometer height) to the level of the plume centerline, a power law relation of the following form is used in CDM:

$$U(z) = U_1(z/z_0)^p$$

where

z is vertical height

z_0 is height of reference wind speed U_1.

Table F-2 Exponents for Wind Profile

Stability Class	Exponents (p)
1	0.1
2	0.15
3	0.20
4	0.25
5	0.25
6	0.3

The dispersion functions $\sigma_y(x)$ and $\sigma_z(x)$ depend on the stability class and distance from the emission source. These functions have been empirically estimated and are shown in Figures F-3 and F-4.

The dispersion function $\sigma_z(x)$ used in CDM follows the approximation:

$$\sigma_z(x) = ax^b$$

where a and b are given in Table F-3.

An initial value of the dispersion function $\sigma_z(x)$ is used in CDM to represent the verticle dispersion created by the roughness of the surrounding topography.

Apart from the Gaussian behavior of pollutant streams a major aspect of this model is the establishment of the plume centerline. This is accomplished through a formula describing plume rise. There are several

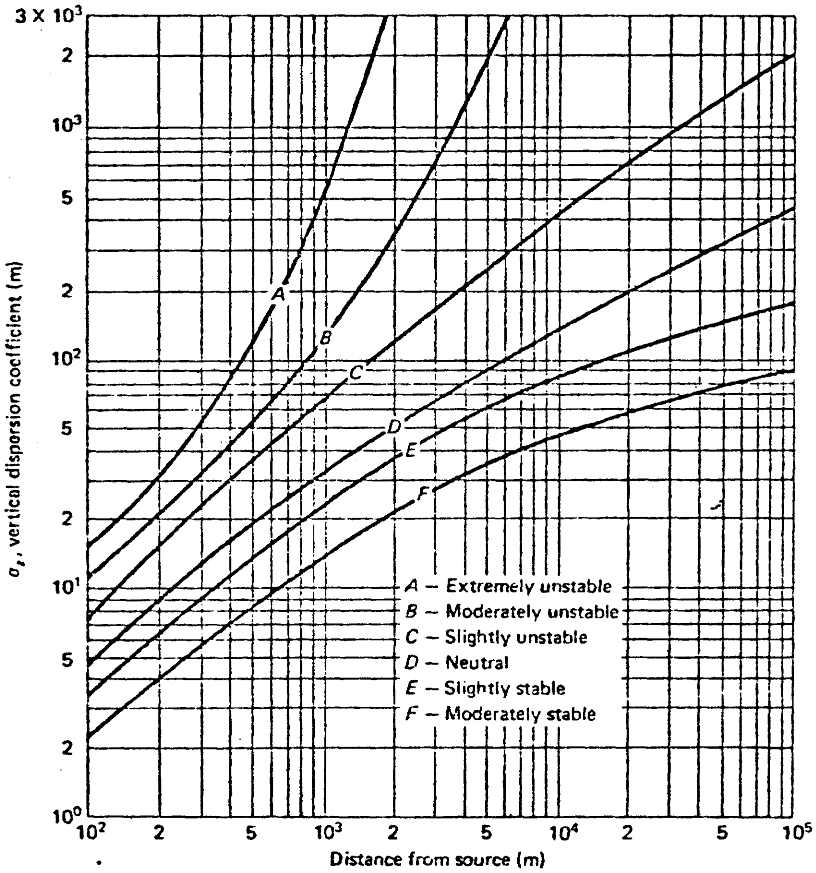


FIGURE F.3
σ_z as a function of downwind distance for the Pasquill-Gifford stability categories.

SOURCE: REF (5)

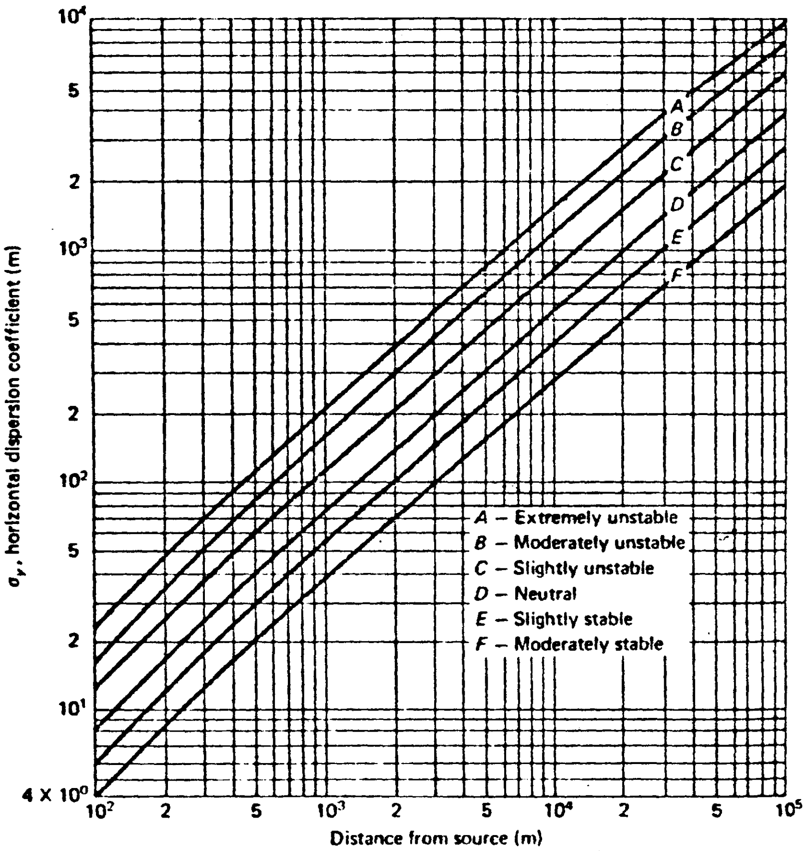


FIGURE F.4
σ_y as a function of downwind distance for the Pasquill-Gifford stability categories.

SOURCE: REF (5)

Table F-3 Parametric Values for $\sigma_z(x)$

Stability Class	100 to 500 a	b	500 to 5000 a	b	5000 to 50,000 a	b
1	0.0383	1.2812	0.254×10^{-3}	2.0886	-	-
2	0.1393	0.9467	0.494×10^{-1}	1.1137	-	-
3	0.1120	0.9100	0.1014	0.9260	0.1154	0.9109
4	0.0856	0.8650	0.2591	0.6869	0.7368	0.5642
5	0.0818	0.8155	0.2527	0.6344	1.2969	0.4421
6	0.0545	0.8124	0.2017	0.6020	1.5763	0.3606

Distance in Meters

such formulae all of which are based on empirical studies. The plume rise formula attributable to Briggs and available in CDM is described below (Briggs, 1971).

$$\text{delta h} = 1.6F^{1/3}U^{-1}X^{2/3} \qquad X \leq 3.5X^*$$

and

$$\text{delta h} = 1.6F^{1/3}U^{-1}(3.5X^*)^{2/3} \qquad X > 3.5X^*$$

$X^* = 14F^{5/8}$ if $F \leq 55$

$X^* = 34F^{2/5}$ if $F > 55$

delta h = plume rise (meters)

$F = gV_sR^2[(T_s-T_a)/T_s]$

g = acceleration due to gravity, m/sec^2

V_s = average exit velocity of gases of plume, m/sec

R = inner radius of stack (meters)

T_s = average temperature of gases in plume, degrees K

T_a = ambient air temperature, degrees K

U = wind speed at stack height, m/sec

X = distance from source to receptor (meters)

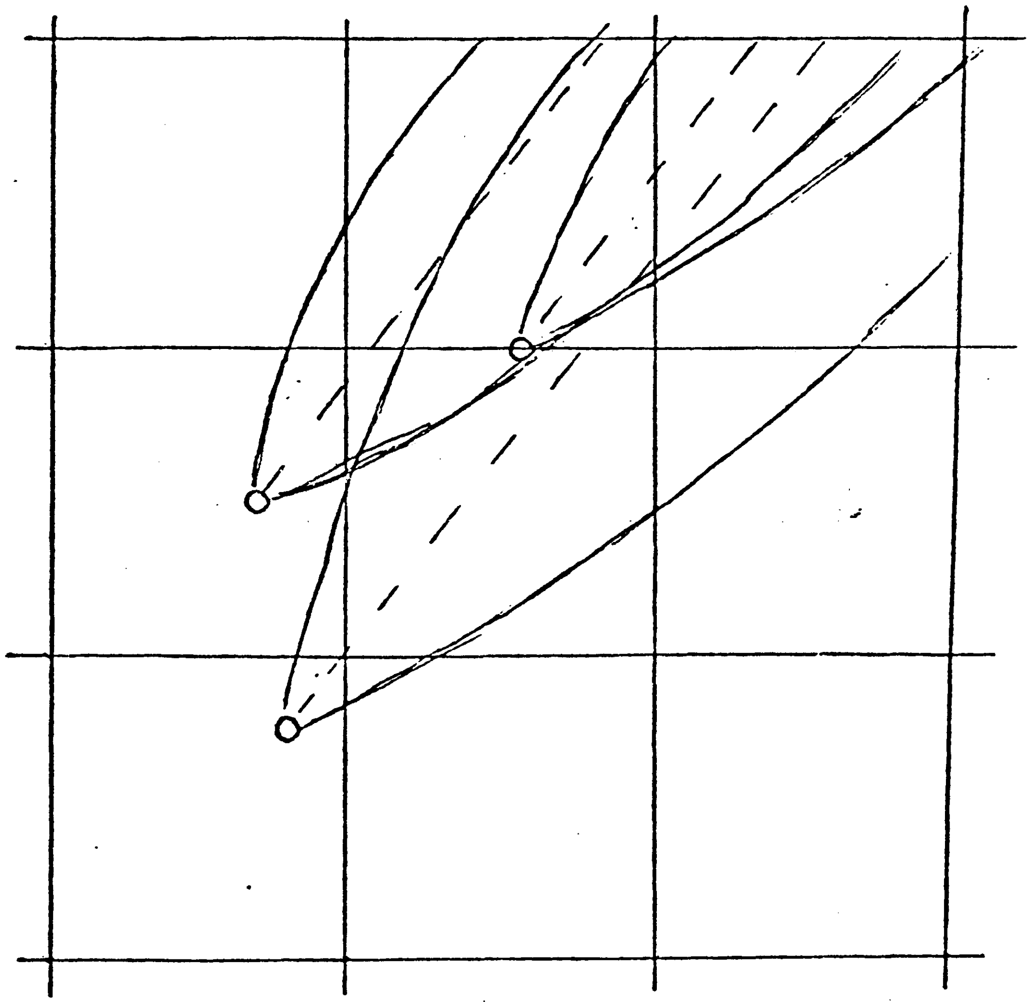
Mixing height is an important component in these models. The mixing height defines the verticle dimension of the volume within which pollutant emissions may be dispersed. The lower the mixing height, the greater will be the levels of pollutant concentrations. Generally these models assume perfect reflection of the plume off the ground and the ceiling of the mixing layer. If the plume rise mechanisms force stack emissions above the mixing height (a situation referred to as "punch-through"), the Climatological Dispersion Model will set ground level concentrations from that source to zero.

Figures F-5 and F-6 show how CDM handles several point sources. Figure F-5 shows the wind direction that results in maximum plume overlap. Figure F-6 shows the wind direction that results in minimum plume overlap. Essentially, a steady-state plume is simulated for each point source under each meteorological situation represented by the 576 cells of the joint frequency function. The ground level concentrations attributable to each plume are sampled and stored for each receptor grid point. If more than one plume crosses a receptor then the individual contributions are simply added.

In this appendix an attempt has been made to acquaint the reader with the basic aspects of air quality simulation models. Towards this goal, the fundamental processses underlying air pollution were introduced as a first step. With this understanding established, the bases for air pollution modelling were explained. Next the class of air quality models known as Guassian steady-state plume models were described. Finally the model from the aforementioned class and used in this methodology, the Climatological Dispersion Model, was explained in detail.

FIGURE F.5

STEADY STATE GAUSSIAN PLUME TRAJECTORY SUPERPOSITION MODEL



STABILITY-WIND FREQUENCY ROSE
16 WIND DIRECTIONS - 22.5°
6 WIND SPEED CLASSES
6 ATMOSPHERIC STABILITY CLASSES

WIND DIRECTION

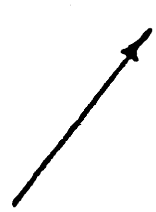
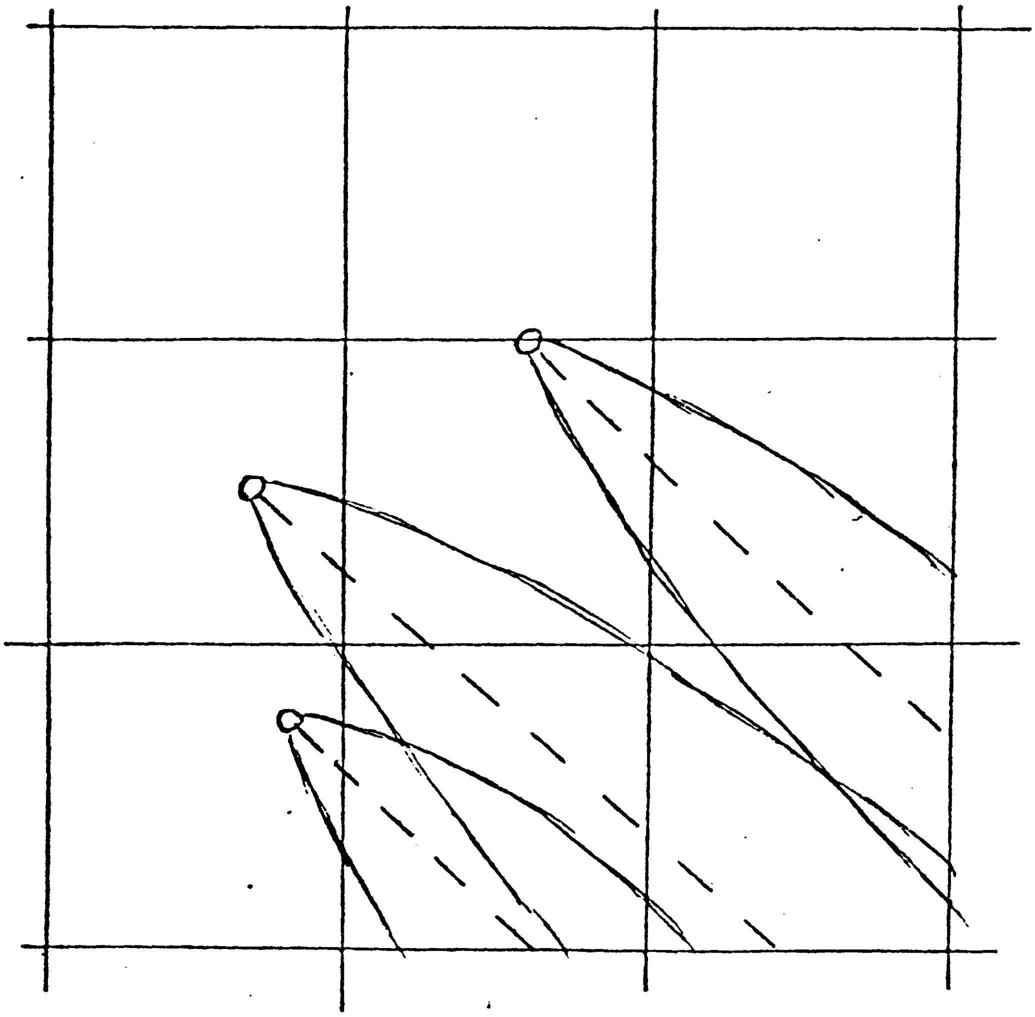


FIGURE F.6

STEADY STATE GAUSSIAN PLUME TRAJECTORY SUPERPOSITION MODEL



STABILITY-WIND FREQUENCY ROSE
16 WIND DIRECTIONS - 22.5°
6 WIND SPEED CLASSES
6 ATMOSPHERIC STABILITY CLASSES

WIND DIRECTION

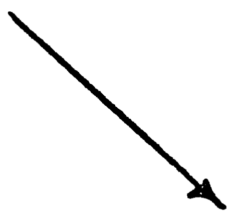


TABLE F.10

NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS)

		Annual Mean microgram/m^3	ppm	24-Hour Mean microgram/m^3	ppm	3-Hour Mean microgram/m^3	ppm
SO_2	Primary	80	0.03	365	0.14	---	---
	Secondary	---	---	---	---	1,300	0.5
TSP	Primary	75	---	260	---	---	---
	Secondary	60	---	150	---	---	---
CO	Primary	---	---	8-hour 10,000	9	1-hour 40,000	35
	Secondary	---	---	"	"	"	"
O_3	Primary	---	---	---	---	1-hour 235	0.12
	Secondary	---	---	---	---	"	"
HC	Primary	---	---	---	---	6 - 9 AM 160	0.24
	Secondary	---	---	---	---	"	"
NO_2	Primary	100	0.05	---	---	---	---
	Secondary	"	"	---	---	---	---
Pb	Primary	3-month mean 1.5	---	---	---	---	---
	Secondary	"	---	---	---	---	---

TABLE F.11

PREVENTION OF SIGNIFICANT DETERIORATION

POLLUTANT		CLASS I	CLASS II
		INCREMENTS (MICROGRAMS/M^3)	
SO_2	3-HOUR	25	512
	24-HOUR	5	91
	ANNUAL	2	20
TSP	24-HOUR	10	37
	ANNUAL	5	19

EXCLUSIONS

A. COAL CONVERSIONS TILL 1984

B. TEMPORARY ACTIVITIES

VARIANCES MAY BE OBTAINED THROUGH "DUE PROCESS"
(GUBERNATORIAL AND/OR PRESIDENTIAL VARIANCES, PUBLIC HEARING)

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