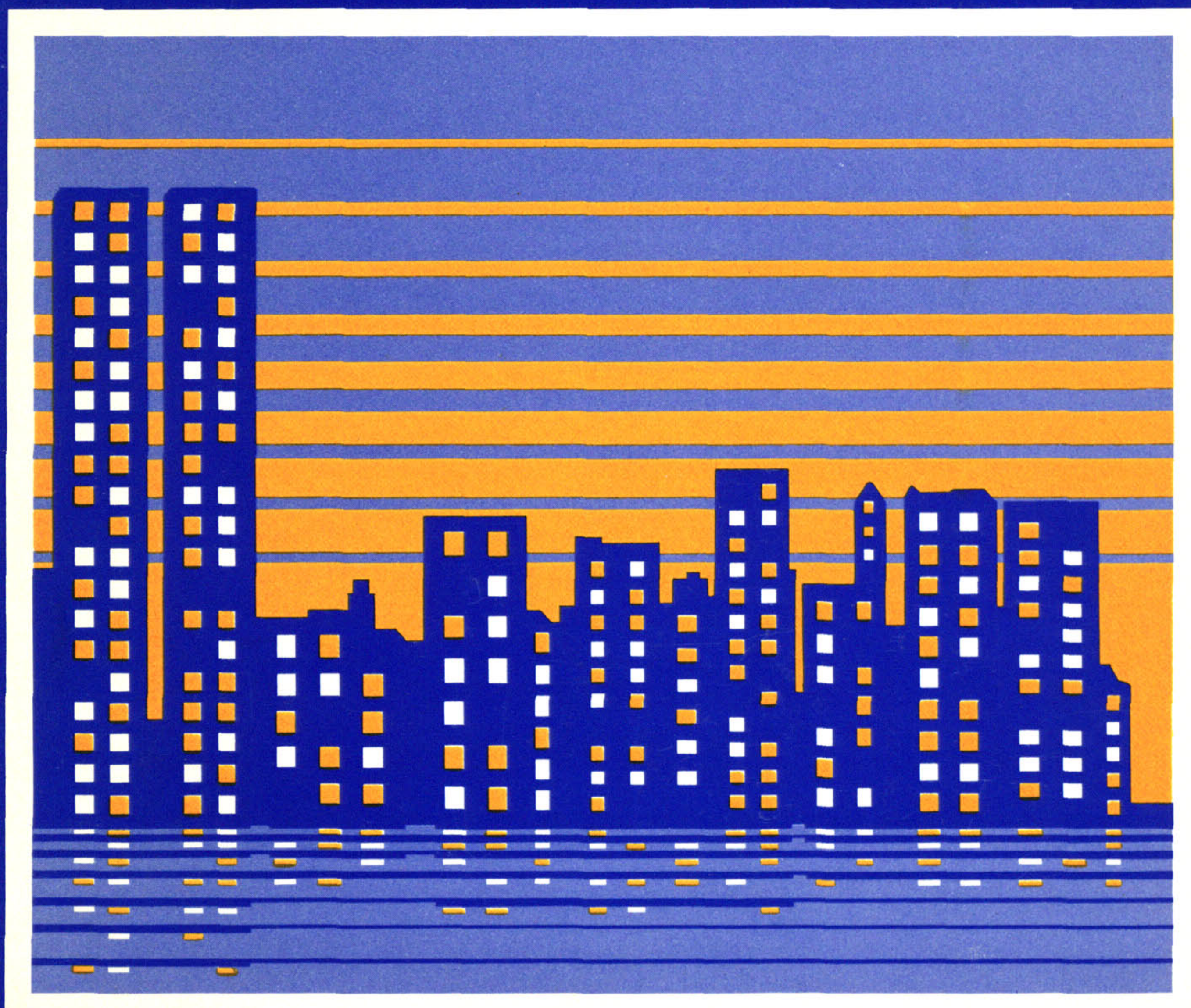
STRATEGIC PLANNING FOR ELECTRIC ENERGY IN THE 1980's

FOR

NEW YORK CITY AND WESTCHESTER COUNTY

An investigation by the Energy Laboratory
Massachusetts Institute of Technology for
Consolidated Edison Company of New York, Inc.

TECHNICAL
REPORT



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FOREWORD

The Energy Laboratory at Massachusetts Institute of Technology (MIT) is pleased to have been invited to conduct this investigation since it presented both an opportunity and a challenge. The opportunity lay in being asked to focus many facets of the diverse, ongoing work within the Energy Laboratory upon technology-related policy issues rather than upon the technology itself. The challenge involved discharging the project responsibility under unusual conditions.

This project was unusual from at least three points of view. First, it is unusual for a business firm to subject one of its major policy decisions to review by an academic institution. Con Edison has made an explicit corporate policy commitment to encourage such interaction in order to facilitate external review of company plans. Second, it is unusual for an academic institution to assemble a diverse interdisciplinary team to work intensely for a prolonged period on one particular applied task. Third, this is the first time the Energy Lab at MIT has addressed a private sector, corporate policy issue.

Successful completion of this project required that a multiple criteria optimization problem with conflicting objectives be subjected to qualitative and quantitative analysis. Moreover, significant developments had to be made simultaneously in both strategic planning methodology for an electric utility as well as in the use of this methodology in a real world, real time situation. An apt analogy might be to invent, build in prototype, learn to ride, and put on a commercial demonstration of a unicycle in one year. And to add additional spice, the policy decision under review rests on the world fuel marketplace which is fraught with uncertainties. Furthermore, these and other uncertainties have created major political, social and regulatory controversy. Much of this uncertainty could not be resolved by research and had instead to be dealt with explicitly within the framework of the logical exposition. Without a particularly high level of dedication and cooperation from everyone involved, this work would have been impossible.

I wish to thank Dr. Peter Likins, member Board of Trustees, Con Edison, for suggesting a collaboration of this type. I would also like to thank Mr. Charles Luce, Chairman, Mr. Arthur Hauspurg, President, and Mr. John E. Deegan, Jr., Vice President of Planning of Con Edison for implementing that suggestion with vigor and firm resolve.

Con Edison commissioned a parallel investigation to this one at Columbia Energy Research Center, Columbia University. Con Edison, MIT, and Columbia felt the need for interested peer review during the development of this project. I am grateful

that the following persons accepted our invitation to serve as an active Advisory Committee, meeting for about eight full days during the year to review and advise: Mr. Robert L. Brugger, Assistant Commissioner of Environmental Planning, New York City Department of Environmental Protection; Mr. Gilbert Cigal, Branch Chief, Field Branch, New York Power Supply and Reliability, who joined the Advisory Committee after its inception; Mr. William Davis, Director of Planning, New York State Energy Office; Mr. John E. Deegan, Jr., Vice President of Planning, Consolidated Edison Company of New York, Inc.; the Honorable Alfred B. DelBello, Westchester County Executive; Mr. Robert J. Hanfling, Deputy Under Secretary, U. S. Department of Energy, later replaced by Dr. Howard Feibus, Director, Division of Direct Coal Combustion, U. S. Department of Energy--Resource Applications; Mr. Robert M. Herzog, Director, New York City Energy Office; Mr. John Honeycomb, Director, Energy Programs, IBM; Dr. Thomas H. Lee, then Staff Executive, Technology Operation Power Systems Sector, General Electric Co., now Professor of Electrical Engineering and Computer Science, MIT; Dr. Peter Likins, then Dean, School of Engineering and Applied Science, now Provost, Columbia University; and Mr. Joel Linsider, Executive Assistant, Public Service Commission of New York, later replaced by Mr. William Schaffer, Chief System Planner, Power Division, Public Service Commission of New York.

I am also grateful to Dr. Burton R. Pierce, President, Energy Strategists, Inc., for directing this project while a Visiting Scientist at the Energy Laboratory.

David C. White, Principal Investigator
Director, Energy Laboratory
Massachusetts Institute of Technology
Cambridge, Massachusetts
April, 1981

ACKNOWLEDGEMENTS

Certain types of research projects can be conducted with minimum collaboration between sponsor and research team. The role of the sponsor on such projects is to provide the question and often research funding; the role of the research team is to determine an answer. This project was different. Its policy orientation, its interdisciplinary nature, and its real time character made close coordination and collaboration between Con Edison and MIT essential. At the same time, however, MIT adopted and maintained the position of independent and intellectually free agent.

I wish to thank Messrs. John E. Deegan, Jr., Vice President of Planning and William A. Harkins, Chief Generation Planning Engineer at Con Edison for their keen appreciation of the type of collaboration required and their diligence in seeing that it occurred. Dr. Peter C. Freudenthal, Director Air and Noise, Environmental Affairs and Mr. Herman C. Bremer, Director Water and Land Use, Environmental Affairs, joined with Bill Harkins on a working committee which met often with members of the MIT team to facilitate the proper transfer of information on the many diverse topics involved in this research. This committee did much to make the project more manageable, and I'm grateful for their help.

Bill Harkins discharged day-to-day operating responsibility for this work in an excellent manner as my counterpart within Con Edison. To Mr. Andrew Vesey, Associate Engineer, fell the often thankless tasks of on-the-scene coordination of frequent meetings, seemingly endless requests for information, questions of procedure, etc. Our sincere thanks, Andy.

The interdisciplinary research team which did this work was composed of individuals drawn from four different organizations: Energy Laboratory, Massachusetts Institute of Technology (MIT), Energy Strategists, Inc. (ESI), Environmental Research and Technology, Inc. (ERT), and Energy Associates (EA). MIT, of course, accepts sole responsibility for performance, but preferred to augment its resident staff in certain technical areas.

I am grateful for the hard work, expertise and high degree of cooperation given to the work by all those involved. The following chart identifies all the individuals on the research team.

	ORGANIZATIONAL AFFILIATION	PROJECT POSITION
Dr. D.G. Aperjis	Visiting Scientist, MIT	Engineering Economist
Mr. C.J. Barberio	Masters Degree Candidate, MIT	Research Assistant
Mr. W.C. Booth	Masters Degree Candidate, MIT	Research Assistant
Mr. B.A. Camenker	Temporary Staff, MIT	Word Processing Operator
Prof. F.J. Evans	Visiting Senior Engineer, MIT. Tyree Professor of Electrical Engineering, The University of New South Wales	Deputy Project Director
Dr. W.D. Hinkle	Managing Director, Energy Laboratory Electric Utility Program, MIT	Technical Specialist
Ms. K.E. Keefe	Secretary, MIT	Administrative Assistant
Mr. S. Krishnamurthy	Masters Degree Candidate, MIT	Research Assistant
Mr. B.A. Latham	Visiting Scientist, MIT	Technical Writer
Dr. H.M. Merrill	Visiting Senior Scientist, MIT	Technical Director
Mr. M.F. Mettler	Technical Assistant, MIT	Computer Analyst
Mr. R.M. Reyes	Technical Assistant, MIT	Technical Assistant, Graphics
Mr. G.N. Smith	Technical Assistant, MIT	Technical Assistant, Information

Dr. J.M. Beer	Professor of Chemical Engineering, MIT	Consultant
Dr. P.J. Drivas	Senior Staff Scientist, Environmental Research and Technology, Inc.	Consultant
Mr. G.F. Hoffnagle	Principal Meteorologist, Environmental Research and Technology, Inc.	Consultant
Dr. W.K. Linvill	Chairman, Department of Engineering Economic Systems, Stanford University	Consultant
Mr. D.B. McKennitt	President, Energy Associates	Consultant
Dr. F.C. Schweppe	Professor of Electrical Engineering and Computer Science and Associate Director, Electric Power Systems Engineering Laboratory, MIT	Consultant
Dr. R.D. Tabors	Principal Research Associate, Energy Laboratory, MIT	Consultant

Dr. William Havens, my counterpart for the parallel investigation at Columbia Energy Research Center, was most helpful in providing ample opportunity for the projects to interact wherever that seemed fruitful.

Dave White, Principal Investigator, and the late Bill Linvill, consultant on project methodology, provided invaluable assistance each time I zigged when I should have zagged.

Burton R. Pierce, Project Director
Visiting Scientist, Energy Laboratory
Massachusetts Institute of Technology
Cambridge, Massachusetts
April, 1981

PREFACE

Background

Triggered by rapid escalation in crude oil prices since 1973, complex and far-reaching changes continue to occur in the U. S. electric utility industry. In 1979 Consolidated Edison Company of New York, Inc. (Con Edison), began a project of sponsored research at the Energy Laboratory of Massachusetts Institute of Technology (MIT). This research was focused on performing a critical review of Con Edison's proposed electric energy strategy for the 1980's. This plan is outlined in the booklet "An Energy Strategy for the 1980's" by Charles F. Luce, Chairman of the Board. (See Appendix A.)

Con Edison sought through the MIT project an independent opinion on technological, economic, and regulatory factors that might affect electric energy planning. The company requested as comprehensive an investigation as could be achieved within the span of approximately one year. It was agreed that, although a high degree of collaboration and cooperation between MIT and Con Edison would be vital to success of the project, MIT would perform an independent analysis, rendering solely its opinions. Further, it was agreed that this report would be a public document.

Con Edison has as its major business the production and procurement of electricity for supply to New York City and Westchester County, the "service area". In addition, it furnishes steam to a significant part of Manhattan through the non-Communist world's largest district heating system. Finally, it is one of the major natural gas utilities for the service area. In response to the manifold changes in the world energy marketplace in the 1970's, Con Edison is proposing sweeping changes in its ways of serving the electric energy needs of its service area. It is upon these proposals that this project is focused.

Study Objectives

Four overall objectives for this investigation were established. These were:

-- identify and evaluate the various considerations relevant to electric energy production and supply decisions in the 1980's;

-- identify and assess electric energy strategy alternatives for the 1980's;

-- evaluate Con Edison's proposed electric energy strategy for the 1980's;

-- provide perspective for strategic planning for electric energy in the 1990's.

Approach and Methodology

In general the approach taken by the MIT investigators has been to:

-- document Con Edison's current energy use profile and proposed strategy;

-- define the company's operating environment and objectives that are relevent for strategic planning purposes;

-- define the options available to management in achieving these objectives;

-- examine quantitatively a wide variety of simulated operating scenarios for the 1980's;

-- assess trends in regulation;

-- define the major electric energy strategy alternatives for the 1980's;

-- critique Con Edison's proposed electric energy strategy for the 1980's;

-- provide perspective on strategic planning for the 1990's.

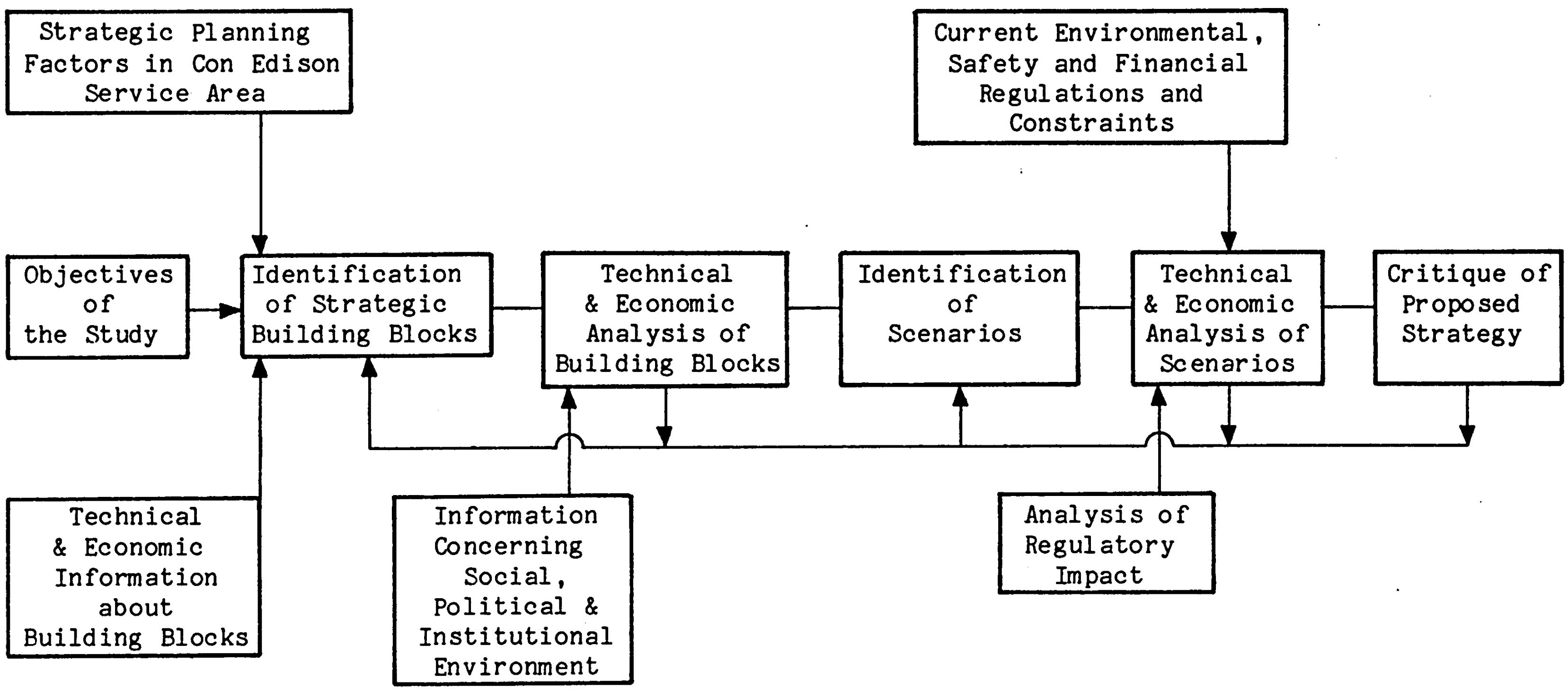
Exhibit P.1 presents the general organization of the major tasks undertaken.

Report Structure

This report is divided into six chapters. Con Edison's electricity energy supply goals and objectives for the next decade are identified and discussed in Chapter One, "Institutional and Socio-Political Factors for Electric Energy Planning Decisions". This chapter places these goals and objectives into a context of the recent history and current operating

Exhibit P.1

MAJOR TASK ORGANIZATION



conditions of the company and the utility industry. This context provides perspective on recent significant economic, environmental or demographic changes this firm must face when planning for its electricity operations in the 1980's. It also discusses the significant public debates which cause uncertainty for implementation of Con Edison's electric energy decisions.

Electric energy strategy building blocks are general ways that Con Edison might use to reach its electric energy goals. Chapter Two, "Technical Options: Electric Energy Strategy Building Blocks", explores these fourteen general areas. The fourteen building blocks touch on all areas of public concern described in Chapter One, and also go beyond that debate to define the full range of technical options available to Con Edison for reaching its goals in the 1980's and 1990's. These fourteen building blocks are classified as primary or secondary for the 1980's or not relevant before the 1990's. Chapter Three contains a detailed discussion of the six building blocks considered primary for the 1980's showing how each is related to Con Edison's current situation and objectives. Details of the building blocks that will not have an impact on Con Edison at least until 1990 are in Chapter Six.

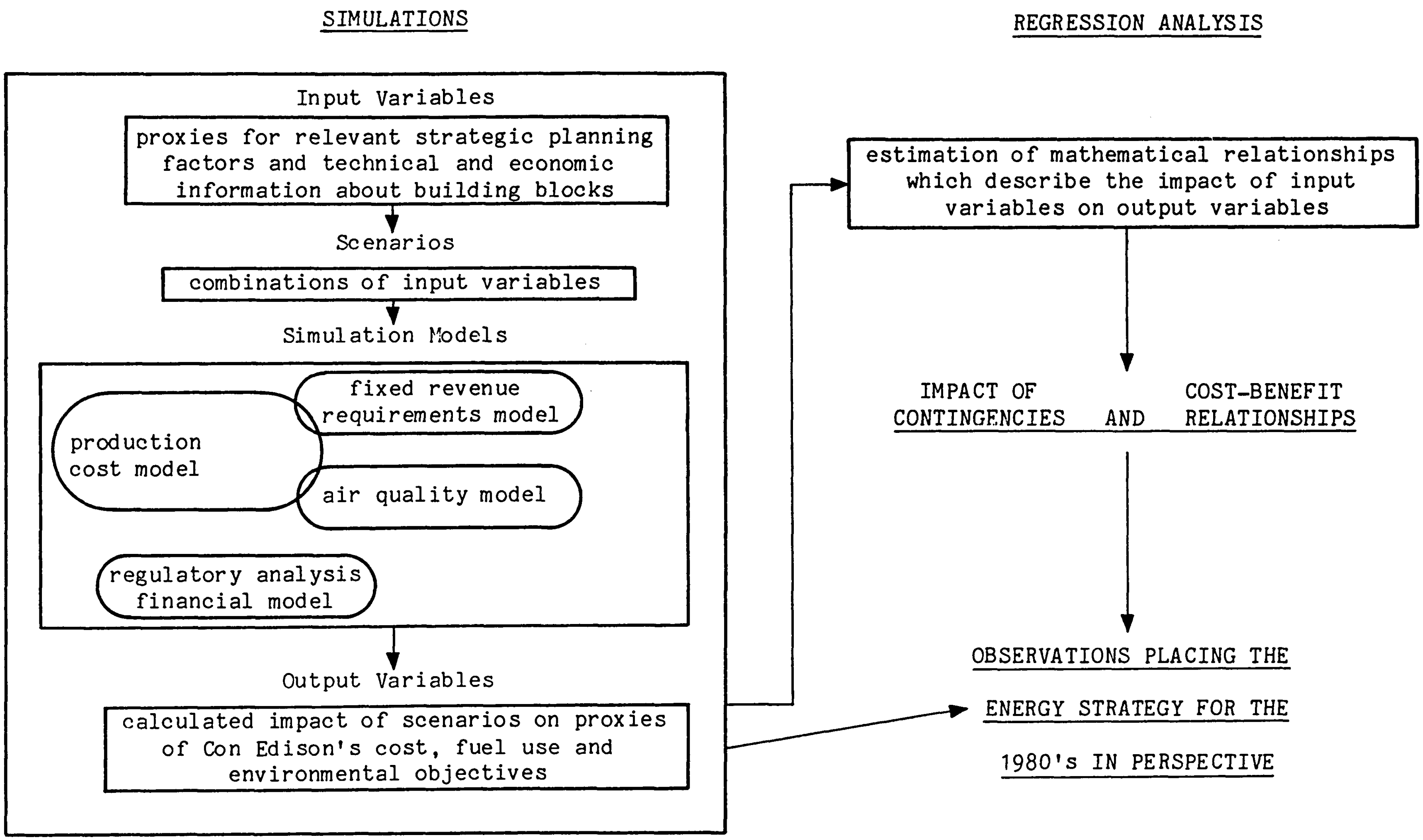
Turning from the generic and static analysis of Chapters Two and Three to a utility system analysis perspective, a comprehensive scenario analysis was performed. Chapter Four discusses the way in which the primary electric energy strategy building blocks for the 1980's plus one secondary one for the 1980's were combined into a quantitative strategic planning model. This scenario analysis permitted quantification of the major impacts which the Con Edison energy strategy for the 1980's would have on the three principal planning parameters; namely, oil usage, total cost of electricity, and air quality. This analysis was predicated on four operational planning models already calibrated to the Con Edison electricity system and in use there.

A wide range of possible strategies was simulated using this strategic planning model. Results of these many simulations were compiled by regression analysis into a small number of mathematical relationships among key variables. These analyses permit the Con Edison plan to be placed in quantitative perspective among the various electric energy strategies which might be chosen.

Exhibit P.2 shows the four major steps of scenario analysis: scenario simulations; regression analysis; cost-benefit trade-offs; and impact of contingencies. Chapter Four deals with the first two of these steps: simulations and regression analysis. The initial results from the simulations and regressions are--like the results of the technical and economic analyses described in Chapters Two and Three--useful for assessing the building blocks. The simulation and regression results are further elucidated in Chapter Five.

Exhibit P.2

MAJOR STEPS IN SCENARIO ANALYSIS



It seems reasonable to ask what is the best plan for Con Edison to follow. This question is discussed in Chapter Five where it is shown that no single answer to this important question is possible. The basic reason that there is no single answer is that at least three criteria of merit are present in this situation, and two of them conflict with one another to some extent. That is, it is inescapable that there are tradeoffs among the cost of electricity, the amount of oil dependence, and the degree of pollution. All three cannot be minimized at once, although that would certainly be a happy circumstance if feasible. Since this best of all strategies is logically impossible, informed judgment by Con Edison, its regulators, and its public needs to enter into the final decision. The MIT study team cannot make these judgments in an informed manner and has not attempted to do so. Rather, it has provided an analysis in which these tradeoffs are displayed in a quantitative way. By doing so, it hopes to aid those with informed judgement as they debate Con Edison's electric energy strategy for the 1980's.

The impacts of possible contingencies on the Con Edison service area are examined in Chapter Five. For purposes of this report a 'contingency' is an event that has a low probability of occurring but a potentially large negative impact. For instance, the OPEC nations could decide once again to stop selling their petroleum products to the U. S., thereby drastically reducing the potential oil supply to Con Edison. Fuel supply uncertainty is a fact of life in the 1980's for Con Edison. As well, continued use of nuclear facilities is uncertain, and this contingency is also uncertain.

It is the combination of observations made from all these analyses--the technical and economic analyses of Chapters Two and Three plus the simulation, regression, cost-benefit and contingency analyses of Chapters Four and Five--which yields the critique of Con Edison's proposed electric energy strategy for the 1980's provided at the end of Chapter Five.

Chapter Six looks ahead to describe briefly the energy technologies which may have their initial impact on Con Edison during the 1990's.

A Word of Caution

This investigation focuses on an evaluation of a major strategic decision by Con Edison in the context of probable futures. Assumptions, forecasts, informed judgments, and best guesses underlie the numbers contained in this report as well as its observations and conclusion. We have tried to qualify and quantify carefully and well, but the process sometimes looks more precise than it is.

In our opinion the results as stated are entirely appropriate for strategic planning purposes. However, detailed analysis, using in some instances more precise tools, is required prior to deciding on implementation programs or regulatory judgements.

OVERVIEW

Background

Consolidated Edison Company of New York, Inc. (Con Edison), is the integrated public utility serving New York City and Westchester County (the "service area") with electricity, natural gas and steam. Electricity is Con Edison's major product, representing about 80% of its revenue. In 1978 Con Edison first announced its energy strategy for supplying electricity in the 1980's. It published a proposed plan and has subsequently made revisions to it. This plan contemplates significant changes in electricity supply arrangements, including some substitution of alternative fuels for oil and larger importation of electric energy. Significant public controversy has developed over many components of this plan, thereby surrounding its implementation with considerable uncertainty. Con Edison began a project of sponsored research at the Energy Laboratory of Massachusetts Institute of Technology (MIT) in late 1979 to obtain an independent review of the plan including evaluation of possible alternatives. This investigation focuses on the revised version of the plan published in early 1980.

Con Edison's plan for the 1980's states two overall goals. It seeks to reduce the Company's dependence on oil as a primary boiler fuel and to moderate the rate of increase in electricity costs to its customers. In addition, the plan's stated objectives are (1) to provide an adequate supply of electric energy to the service area, and (2) to do so in an environmentally acceptable way. The plan sets forth a program of seven specific actions to reach these goals and objectives.

-- Promote strong energy conservation programs in New York City and Westchester County.

-- Convert three Con Edison generating units to burn coal instead of oil, while taking appropriate steps to meet environmental standards.

-- Continue to use nuclear power generated at Indian Point as a principal non-oil source of electricity.

-- Increase imports of hydroelectric power from Canada and other sources.

-- Support the construction of coal-fired and pumped storage hydroelectric plants planned by the Power Authority of the State of New York (PASNY).

-- Use refuse as a fuel to generate steam and electricity.

-- Reduce taxes on energy.

Triggered by rapid escalation in crude oil prices since 1973, complex and far-reaching changes are occuring in the U. S. electric utility industry. Since the time when the rapid increase in crude oil prices began, the prices of Con Edison's electricity have approximately doubled. In 1978 Con Edison supplied electricity for residential use at the highest price among all electric utilities in the continental United States. Con Edison's electricity price also contains the highest tax on electricity in the U.S.

Over half of the electricity produced in the Con Edison service area is fueled by oil or natural gas, both of which recently had sharp price increases. This situation is made more disadvantageous by the high probability of further significant price escalation and supply uncertainty in these fuels. Approximately half of the U. S. electric power industry capacity is coal-fired. However, this cost-advantageous fuel is currently not used to produce electricity in the Con Edison service area. This absence of coal is a fairly recent development. Until the 1970's Con Edison used coal within New York City. This practice was abandoned more than ten years ago when a legal prohibition aimed at environmental protection from this type of coal-burning was enacted.

Analysis

The Con Edison plan represents one course of action from among a number which could be responsive to the stated fuel, cost and environmental protection goals and objectives. Therefore, in order to make an initial assessment of this plan, the MIT investigators defined the entire range of technical and managerial options available to Con Edison over the next two decades. This range was segmented into 14 broad categories representing alternative ways of influencing supply and demand arrangements for electric energy. Thus, these 14 categories constitute all the possible electric energy strategy building blocks for Con Edison at this time. They are:

Oil

Nuclear

Natural Gas

Coal

Purchased Energy

Conservation

Pumped Hydroelectric

Refuse

Coal-Oil Mixtures

Cogeneration (centralized and decentralized)

Load Management Techniques (conventional and developmental)

Synthetic Fuels

Renewable Resources

Developmental Conversion

In MIT's opinion only the first six of these strategy building blocks could have a major impact on Con Edison's electric energy goals in the 1980's. That is: oil, nuclear, natural gas, coal, purchased energy, and conservation are the primary constituents of electric energy strategy development in the 1980's for Con Edison. The next three strategy building blocks listed, pumped hydroelectric, refuse, and coal-oil mixtures can have at most only a secondary role to play in meeting Con Edison's electric energy strategy goals for the 1980's. Decentralized cogeneration and conventional load management techniques may also have a secondary importance for the 1980's. The remaining building blocks, while potentially important in longer-range planning, are irrelevant to operations in the 1980's because they will either not be commercially developed in time, or are not well suited to Con Edison's service area, or both. These are synthetic fuels, renewable resources, developmental conversion, and developmental load management techniques. Centralized cogeneration may also be a building block for the 1990's but is a major feature of overall steam energy strategy rather than electric energy strategy.

Oil

Oil (or gas temporarily made available to Con Edison to displace oil) is the fuel used to generate about 56% of the service area's electricity. It is significantly more expensive than coal and nuclear fuel, and this price gap will in all likelihood widen in the 1980's. Furthermore, oil availability is uncertain due to the unstable political situation surrounding its importation. Imported oil currently forms about 40% of the U. S. oil supply. However, about 90% of Con Edison's oil supply is imported, given market distribution patterns for the type of fuel Con Edison is required to use: low sulfur oil. Unless Con Edison alters its current fuel mix away from oil, it will be vulnerable to almost certain further large increases in cost of oil and possible fuel supply interruption. Furthermore, a decrease in U. S. oil consumption would help meet U. S. economic and security objectives. In 1979, 39,000,000 barrels of oil (and the oil equivalent of gas temporarily made available to displace oil), or 0.6% of the total oil consumed in the U. S., was required for the generation of electricity utilized in the service area.

Nuclear

About 30% of the Con Edison service area electric energy is supplied by nuclear generation. Two plants presently provide almost all of this nuclear-generated electricity: Indian Point units 2 and 3. These plants have the lowest generation cost of any plants on the system, and using them reduces the service area's dependence on oil. Furthermore, by avoiding the use of fossil fuels, these plants protect air quality. However, in the aftermath of the Three Mile Island incident, the Nuclear Regulatory Commission (NRC) is reassessing the safety of continued operation of these and certain other nuclear plants, particularly those in close proximity to large population centers. Thus, the possibility of an NRC-mandated shutdown of the Indian Point plants exists.

No nuclear plants are under construction by Con Edison. The construction of new nuclear plants is not considered in this study because the engineering, licensing and construction takes more than ten years. Con Edison may, however, be able to purchase some additional nuclear capacity from plants presently planned or under construction by other utilities.

Natural Gas

The Powerplant and Industrial Fuel Use Act of 1978 prohibits the use of natural gas as a primary energy source in Con Edison boilers. However, short-term exemptions from this prohibition were granted to Con Edison in 1979 as part of a national oil displacement program. In 1979, natural gas was 12% of the fuel used to generate electricity in the service area.

Continued renewal of the short-term exemption is uncertain. Therefore, Con Edison does not consider natural gas as a planning option for the 1980's. In the opinion of the MIT investigators, the present federal statute limiting natural gas usage by utilities will be modified to liberalize such use. This opinion is based on probable future major upward revisions in domestic gas reserve additions. It was the first of these upward revisions which precipitated the current exemption allowing the burning of gas.

Natural gas, if it continues to be available as a utility boiler fuel, is potentially attractive for several reasons. First, using gas instead of oil reduces oil usage. Second, the price Con Edison pays for boiler fuel gas is currently about half the price of oil. Gas prices are expected to be about 30% less expensive than oil during most of the 1980's, although they are expected to approximately equal oil prices near the end of the decade. On the other hand, gas prices are about 30% higher than coal prices currently. They are expected to rise more rapidly than coal prices throughout the 1980's, and, by the end of the decade, gas prices are expected to be about three times the level of coal prices. Third, many of Con Edison's oil-burning boilers can be gas-fired with no retrofitting. However, gas firing of Ravenswood 3 and Arthur Kill 2 and 3 (those units slated for conversion) would require boiler retrofits and, in the case of Arthur Kill, new gas transmission facilities. Fourth, burning gas in large utility boilers produces less pollution than does burning oil or coal. Fifth, natural gas could be selectively supplied to Con Edison or non-Con Edison sources in New York City to 'offset' the environmental effects of coal-burning by Con Edison. Sixth, natural gas could be supplied to private decentralized cogenerators if that use is deemed desirable. The issue of continued natural gas availability brings a large uncertainty to electricity supply planning in the 1980's.

Coal

The U. S. has abundant domestic coal reserves. Most of Con Edison's current oil-fired generating facilities were originally designed to burn coal, and most of these did so prior to the 1970's. Generally, reconversion of some of these facilities to coal, as planned, would provide the cost and oil reduction benefits of coal-firing more quickly and less expensively than building new coal-fired plants or converting existing plants that were not originally designed for burning coal.

Coal conversion promises a larger potential for electricity cost savings and reduction in oil consumption than does any other operating decision Con Edison could make for the 1980's. Fuel costs are the largest single controllable cost element in production of electricity. In general, increases in the extent of coal conversion tend to decrease the total cost of electricity production as well as the total amount of oil consumption in the Con Edison service area. However, as the coal-fired capacity increases, the additional benefits in cost and oil usage reduction become gradually smaller.

Total cost of electricity produced (as defined in this analysis) would decrease by about 8% if the 1700 MW of coal conversion planned by Con Edison (Arthur Kill 2 and 3 and Ravenswood 3) were completed. This assumes that annual average load growth of 1% (roughly Con Edison's forecast) materializes over the next 15 years. More extensive coal conversion, for instance 2460 MW (Arthur Kill 2 and 3; Ravenswood 1, 2 and 3), would add about one percentage point to this reduction. The amount of oil consumed during the period 1980-1995 would decrease by approximately 35% and 40%, respectively, for the same two levels of coal conversion. Because of the fuel adjustment clause feature of New York electricity rates, these cost savings would be passed through to consumers.

Use of coal as a boiler fuel in these plants could have a greater detrimental effect on the local environment than use of oil, natural gas, or nuclear. Coal is potentially the most polluting among these four fuels. Hence, obtaining permission to convert will depend partially upon actual and perceived effectiveness of the environmental protection controls employed. The available control options are electrostatic precipitators, bag houses, low sulfur coal, cleaned coal, flue gas desulfurization (FGD) equipment and environmentally acceptable coal, ash and sludge handling equipment. Con Edison's plan includes installation of precipitators with an operational efficiency of 99.6% while using 1% sulfur coal. This action will control particulate emissions well within regulated limits and impose no important operating difficulties. (The particulate emissions will be no more than such emissions resulting from low sulfur fuel oil.)

Con Edison's plan includes the use of 1% sulfur coal to limit sulfur dioxide (SO_2) emissions. Implementation of this plan would cause SO_2 emissions to increase over current emissions with the burning of 0.3% sulfur oil. Installation of FGD equipment could prevent this increase in SO_2 emissions. However, installation of these facilities would (1) increase conversion costs substantially, (2) reduce the availability of generating units, (3) cause some deratings, and (4) create a different pollutant as they remove SO_2 unless technologies different from the current commercial FGD system are developed. The current commercial FGD system, the wet scrubber, produces a wet sludge by-product. Proper disposal of this sludge, generated at these in-city New York plant sites, would be necessary. Development work on a regenerative FGD system is timely.

The air quality analysis indicates that Con Edison's coal conversion of 1700 MW as planned (using 1% sulfur coal without FGD facilities) would not cause air quality in New York City to exceed annual average SO_2 ambient air quality standards. In fact, conversion of 2460 MW to coal burning (adding Ravenswood 1 and 2 to the planned conversion) without FGD facilities would not necessarily violate present SO_2 annual average ambient concentration standards. The next most reasonable units after Ravenswood for conversion would be Astoria 3, 4, and 5. Further conversion involving Astoria without FGD equipment would in all likelihood cause air quality levels to exceed SO_2 average annual ambient air quality standards. It is possible to significantly reduce emissions from other sources to achieve reduced ambient SO_2 in the more polluted areas of New York City, perhaps by conversion of low level sources to natural gas.

A ban on coal-firing of large boilers in New York City was adopted by both New York City and New York State in the early 1970's in an effort to control ambient SO_2 concentrations. In order to effect coal conversion, the New York City Air Pollution Code must be revised. Also, a special limitation (variance) must be obtained by Con Edison from the New York State Department of Environmental Conservation. This special limitation is subject to U. S. Environmental Protection Agency (EPA) approval. Therefore, a major aspect of implementation of this planned reconversion to coal at two in-city plants is the removal of these legal prohibitions. As well, a demonstration by Con Edison using acceptable modeling techniques will be needed to show that any increased ambient SO_2 concentrations from coal-burning do not violate standards. Finally, a regulatory decision must be made that this conversion is an acceptable use of the available air quality increment. For example, other electric power plants in New York and New Jersey are contemplating coal conversion with possible increases in SO_2 emissions.

Con Edison is presently conducting a test of the environmental acceptability of burning 1.0% sulfur coal by burning 1.5% sulfur oil which has equivalent SO_2 emissions. Air quality impact studies, using various simulation techniques, are also in progress. Further, any increases in SO_2 emissions may be challenged because of issues such as acid rain. Connecticut and New Jersey have sued to block emission increases in New York City because of potential impacts there.

Other environmental issues related to coal reconversion are less burdensome than the SO_2 air quality issue. Ambient NO_2 ground concentrations would be increased only slightly by coal conversion and would remain well under present standards. Noise and dust from coal-handling can be controlled through use of washed coal and/or through purchase of properly designed equipment. Proper disposal of solid wastes including fly ash, bottom ash and FGD wet sludge (if present) remains to be resolved, but appears capable of resolution. Waste water treatment presents no particular difficulty.

If coal conversions are made at Arthur Kill and Ravenswood, it is likely that coal transportation and handling will pose significant difficulties. Specialized coal transportation and handling techniques will be required. Con Edison plans to keep its oil burning capability intact both in recognition of the coal supply unreliability and to provide the capability to switch to low sulfur oil during air pollution control emergencies. The infrastructure which existed for moving coal about the city in the 1960's has debilitated during disuse, and it will be necessary to upgrade coal transportation and handling facilities within the city.

While Con Edison is focusing its efforts during the 1980's on conversion of existing power plants to coal, PASNY is proceeding with plans to construct a 700 MW plant, the energy from which will be used to supply the service area. This plant is designed to burn coal or coal augmented by up to 20% refuse used as fuel at Travis, on Staten Island, New York. This proposed Travis plant, currently undergoing siting analysis and review, is scheduled for completion in 1987. The Travis plant has several attractive features from the standpoint of helping to meet Con Edison's electric energy goals. First, its primary fuel, coal, is attractive because it reduces oil dependence and moderates cost increases. Second, since the proposed Travis plant may burn up to 20% refuse, it may provide a means for New York City to dispose of a small part of its solid wastes. Third, its impact on regulated emissions when burning coal is expected to be negligible, since it is required to have FGD equipment. The overall attractiveness of Travis with respect to Con Edison electric energy strategy objectives would be large if Con Edison were not permitted to burn coal. However, given the proposed coal conversion, the impact is significant but not as large.

Purchased Energy

Con Edison plans to purchase approximately 68.8 billion kWh of electric energy during 1980-1995. This amount is larger than in the past. Purchasing energy reduces oil usage and air pollution directly, to the extent that it is generated either by hydroelectric or nuclear facilities. However, the projected percentage decrease in total cost of electricity is rather small because the planned purchases represent only a small share of the service area's electricity demand and because most of this energy is currently priced near the cost of energy that it replaces.

The potential for purchasing electric energy, particularly from Hydro Quebec, has recently increased sharply. In the opinion of the MIT investigators, there is a potential to purchase additional energy beyond that now planned on the order of 20-30 billion kWh over the next 15 years. However, transmission system improvements would probably be required at additional capital cost. The desirability of this investment, particularly since the purchased energy may be priced near the cost of energy it replaces, needs to be examined carefully. Also, there could be a negative impact on reliability.

Conservation

Con Edison was one of the first U. S. electric utilities to support and implement conservation programs. Its "Save A Watt" program was begun in 1971, two years before the Arab oil embargo. Conservation has a positive impact on all three electric energy strategy objectives of Con Edison because it reduces total costs of electricity, oil consumption and environmental pollution. It is therefore one of the most attractive building blocks.

However, its potential specific benefits and costs are difficult to quantify.

The rate of electricity load growth in the Con Edison service area fell from its historical level of about 4.5% per year to -0.8% per year from 1973-1979. This decrease was largely caused by increased conservation and by a lower level of local economic activity. Rapid increases in electricity and other energy prices during 1973-1979 were partially responsible for the conservation.

The electric load growth during 1980-1995 will depend both on the effectiveness of conservation efforts and the level of economic activity during this period. Both of these effects are difficult to forecast with precision. Con Edison and PASNY project an annual load growth of 1.0% in the service area from 1980-1995. This projection takes into account several new conservation programs being readied for implementation over the next several years as well as further increases in electricity prices.

There exists substantial additional potential for conservation. This investigation provides some analysis of the benefits associated with realization of this potential. It does not provide a comprehensive analysis of either benefits or costs, nor has it investigated who should bear these costs. Modifications in existing regulations might be required for Con Edison to be able to participate in certain types of conservation programs. Examples are being seen in certain other states.

Additional conservation efforts could further reduce the annual electricity load growth during 1980-1995. For example, if, by 1995, load limiting devices (LLDs) are installed for all commercial peak load customers who could utilize LLDs, and if one-third of master-meter consumption is converted to sub-metering, then annual electricity load growth during 1980-1995 could be further reduced by, say, 0.5 percentage points. Assuming Con Edison's coal conversion plan is implemented, such a decrease would lead to a saving of about 0.5 billion dollars (present value in 1980) in total cost of electricity and to about 20 million barrels less oil consumption during 1980-1995.

The electric load growth during 1980-1995 is uncertain. For this reason, a range of load growth values was chosen by the MIT group instead of a single value. This range includes Con Edison's estimate for load growth during 1980-1995 and, in the opinion of the MIT group, all other reasonable values of load growth during this period.

Pumped Hydroelectric

Pumped hydroelectric facilities are attractive in two circumstances. One such circumstance exists if a utility needs additional peaking capacity, since these facilities often have lower total capital costs than other sources of peaking energy. The other circumstance exists if there is wide variation in costs among various energy sources. In this situation they can help replace generation during the daytime with less expensive generation at night.

PASNY plans to build a pumped hydroelectric facility to serve the Con Edison service area, with a projected in-service date of 1987. Based on this analysis, which considered only three groups of criteria of merit and only the next 15 years, this proposed facility has a negligible impact on Con Edison energy strategy objectives in the 1980's. However, this analysis is too narrow in scope to permit a valid assessment of the value of this facility, which has an expected life of more than 50 years and a variety of possible benefits not analyzed here.

Refuse

If the generating unit which PASNY has proposed for construction at Travis, New York, is built, up to 20% of its fuel may be refuse. Furthermore, several other refuse-burning plants in the Con Edison service area are at various stages of planning for the 1980's. Among the most likely to be built are the Peekskill plant in Westchester County, the Brooklyn Naval Yard steam plant and plants proposed by the Port Authority of New York.

The overall costs of generating electricity with refuse are likely to be higher than the costs of using conventional fossil or nuclear fuels. Potentially significant environmental concerns have been expressed concerning refuse fuel preparation and combustion. The principal potential merit in burning refuse as a fuel is that it might help solve municipal waste disposal problems while producing electricity, a useful by-product. Con Edison's support of research into new ways to use refuse as a fuel is appropriate.

Coal-Oil Mixtures

Coal-oil mixtures (COMs) are suspensions of finely ground coal in oil. Potentially, they are a way to introduce coal into a boiler designed for oil. They might be useful to Con Edison in a limited way. For example, if Con Edison wished to reduce oil usage at the Roseton and Bowline plants, which it owns jointly with other utilities, a conversion to COMs might be feasible.

However, these plants were never intended to burn coal and would require substantial modification to burn COMs. Other applications may offer potential also.

There are uncertainties associated with COMs since they are untested as a large-scale commercial boiler fuel. The Japanese and, closer to home, New England Electric System and Florida Power and Light are each currently undertaking experiments with COMs in large-scale, sustained operations. Con Edison is monitoring these and other COM tests to establish the benefits, if any, which might be gained from the use of coal-oil mixtures for the service area.

Cogeneration

Cogeneration is the production of usable heat (often steam) and electricity within the same generating cycle. If cogeneration is centralized, heat and electricity are produced in large utility-owned generating units. The electricity is then fed to the utility's electrical distribution grid, and the heat is transported via the utility's steam distribution system. By contrast, decentralized cogeneration describes a power generating system which is usually owned and operated by the final consumer and is usually much smaller than a centralized unit. In theory, cogeneration provides a technologically more efficient use of primary energy because of the increased efficiency inherent in joint production of electricity and usable heat.

Centralized cogeneration is a central element in Con Edison's steam system, since about 60% of the steam distributed is cogenerated. However, centralized steam cogeneration is not expected to be important for electricity planning in the 1980's for at least two reasons. First, the electricity currently cogenerated with steam is only about 2% of the dispatched electricity. Second, Con Edison is not planning to add new electric generating capacity.

Decentralized cogeneration now appears attractive to certain large users of electricity and heat in the service area. Several privately-owned, decentralized cogeneration facilities have recently been constructed in Con Edison's service area. Increases in decentralized cogeneration are occurring for several reasons. First, private decentralized cogenerators do not need to pay certain taxes which Con Edison must pay or collect on its energy sales. Second, small cogenerating units are readily available on the commercial market and have proven to be attractive from an economic perspective in certain situations. The Public Utility Regulatory Policies Act (PURPA) has the potential for improving the economics of thermal load following design in these decentralized installations by requiring Con Edison to buy electricity which the decentralized cogenerator may wish to sell.

The move toward private, decentralized cogeneration using diesel engines or gas turbines is a matter of concern to Con Edison. A part of Con Edison's concern stems from the NO_x emissions and low stack heights which are a feature of typical diesel-fired and gas turbine decentralized units. Also, to the extent that these installations are oil-fired, they could be counterproductive to the goal of reducing dependence on oil, notwithstanding their efficient use of primary energy.

Overall Critique of Plan

Con Edison's electric energy strategy for the 1980's takes into account all of the possible primary electric energy strategy building blocks for the 1980's and three of the four secondary building blocks for the 1980's. In addition, in its perspective on the 1990's the plan touches on three of the four building blocks that will have impact during the last decade of this century. From this perspective, the proposed plan is comprehensive.

A moment of reflection confirms that Con Edison is severely constrained in oil replacement possibilities for the 1980's. Barring large-scale access to natural gas, only three options remain: coal, purchased energy, and conservation. Further, natural gas and purchased energy offer little in the way of moderation of cost increases. Conservation, while very attractive, probably cannot replace a significant portion of the oil.

As discussed above, Con Edison has four stated goals and objectives which motivate its electric energy plan for the 1980's. These are (1) reduction in oil usage, (2) moderation of electricity cost increases, (3) adequacy of supply, and (4) environmental acceptability. The plan's attractiveness in terms of Con Edison's objective of supplying an adequate amount of electricity is clear. Furthermore, the plan's choices among fuels are appropriate given the company's goals of reduction in oil usage and moderation of electricity cost increases.

During the 1980's Con Edison has only four potential primary fuels from which to make electricity: oil, nuclear, natural gas, and coal. Maximum possible use of nuclear-generated electricity in the 1980's is contemplated, and hence this component of the plan aims at lower cost electricity and avoidance of oil dependence. The plan centers on rapid conversion of high cost oil-fired capacity to coal, the lowest cost primary fuel. Hence, this component of the plan also aims at lower costs of electricity. Because this conversion reduces oil usage, it is consistent with national policy to reduce oil consumption. In addition to its cost and oil consumption advantages, coal is also the only remaining primary fuel alternative to oil unless future variances to the Powerplant and Industrial Fuel Use Act are granted to allow continued use of gas in Con Edison electric-generating plants. Furthermore, the plan recognizes the positive oil reduction and cost implications of purchased energy. Con Edison expects to purchase energy even though it has adequate reserve capacity to generate all its needs. This is a rational decision.

There is no conflict between the goals of decreasing total cost and decreasing oil consumption if coal is introduced into the Con Edison system. However, the introduction of coal burning--as planned--although possible within environmental standards, would raise the level of SO_2 emissions. To meet the last objective, environmental acceptability, the plan will have to conform to federal ambient air quality standards. Further, a regulatory decision must be made that the conversions under the plan are an acceptable use of part of the available air quality increment in New York City. Con Edison will also have to seek and be successful in obtaining a change in New York City's air pollution control code which effectively bans the burning of coal within New York City. In addition, there is likely to be negative action from environmental interest groups.

The MIT investigators established three criteria of merit for evaluating the Con Edison energy strategy for the 1980's in terms of the partially conflicting goals of moderating the rate of increase of total cost of electricity (compared to the cost path without coal conversion), reducing oil consumption and maintaining acceptable air quality. A broad spectrum of possible alternative programs was constructed and evaluated. All of the alternative programs assume the use of 1% sulfur coal. However, they differ in the amount of coal capacity introduced, the use of FGD equipment, the amount of purchased energy, the availability of Indian Point and the addition of Travis and Prattsville. This entire evaluation was designed to identify only broad trends and major tradeoffs. Detailed engineering analysis would be required before the actual desirability of any of these alternative plans could be established. Based on this broad analytic perspective the following observations emerge.

Con Edison's proposed coal conversions are attractive in terms of the tradeoff they imply between total cost of electricity and SO_2 emissions. Specifically, for the expected SO_2 emission level, Con Edison's conversion program achieves the lowest total cost of electricity (among the alternatives examined), about 8% lower than total cost of electricity assuming no coal is burned in the system. Other possible conversion programs involving the same SO_2 emissions but, for example, different units converted to coal, would yield a higher total cost of electricity.

There are alternative conversion programs, involving more coal-fired capacity without FGD equipment, which would yield a lower total cost of electricity than the Con Edison plan.

However, they would result in higher SO_2 emissions. To achieve more than about an additional one percentage point reduction in total cost of electricity by simply adding more coal capacity appears impossible, because by that point the SO_2 annual average ambient standard is likely to be exceeded.

The current commercially available FGD technology is the wet scrubber, which produces a pollutant wet sludge by-product that requires proper disposal. There are other FGD technologies at various stages of development. Some of these alternative technologies do not produce a pollutant by-product. The SO_2 emissions of the proposed Con Edison conversion program would decrease by about 60% if the conversions are completed as scheduled, and wet scrubbers are added subsequently in 1986-1987. This resultant SO_2 emission level would be essentially the same as in the case of no coal conversion. Despite the added costs of FGD, the proposed Con Edison conversions with subsequent addition of wet scrubbers in 1986-1987 still results in lower total cost of electricity than if no coal conversion occurred. Rather than being 8% lower as contemplated for the proposed conversions, total cost would be 5% lower with subsequent addition of FGD equipment in 1986-1987.

Addition of FGD equipment before beginning the burning of coal would delay conversion even if an FGD technology that is satisfactory to Con Edison and to the regulators can be identified rapidly from the present range of technical options. Even if commercially available non-regenerative wet scrubbers were chosen, a coal burning delay would be experienced relative to the proposed conversion without FGD equipment. This occurs because additional engineering design work, procurement, installation and start-up of the FGD equipment would be required. Any delay in coal burning is costly to consumers. The combined costs associated with FGD equipment as well as delayed coal burning (until 1986-1987) would reduce the cost savings from the proposed conversions to approximately 4% over the period to 1995 rather than 8%. Also, oil consumption would be higher for any delayed coal burning case than for the proposed conversion program.

There are alternative coal conversion programs with FGD equipment that would produce levels of SO_2 emission and total cost of electricity that are comparable to those resulting from Con Edison's conversion program. These programs involve higher levels of coal-fired generating capacity than the Con Edison conversion program. Although these programs do not lead to any further decreases in total cost of electricity or SO_2 emissions, they lead to an additional decrease in oil consumption of up to 15 percent compared to the Con Edison conversion program.

These conclusions regarding the relative merits of the various coal conversion alternatives have been tested for sensitivity to load growth, as might be introduced by strong conservation efforts, as well as to decisions on Prattsville, Travis and amounts of purchased energy. The conclusions are not sensitive to these various uncertainties. Furthermore, it appears that Con Edison's coal conversion program, with or without FGD equipment, should not be financially constraining. Moreover, the construction expenditure levels for this program and alternative programs examined with more extensive coal conversion should be readily financeable given a reasonable regulatory environment.

Oil supplies for the U. S. could be disrupted during the 1980's. Implementation of the proposed Con Edison conversions would reduce the service area's effective dependence on oil from about 56% in the 1979 fuel mix to about 30% by 1990. Additional coal conversion could further reduce Con Edison's dependence on oil. To the extent oil is replaced, Con Edison and its service area are less vulnerable to this contingency.

Should an NRC-mandated shutdown of the Indian Point units occur during the 1980's, oil and perhaps natural gas would have to be substituted. If the proposed Con Edison conversions were implemented, coal could make a small contribution toward replacing this lost electric energy. However, if maximum coal conversion (3500 MW) had taken place, coal could provide up to 35% of the lost nuclear generated electric energy.

Specifically, with regard to Con Edison's seven-step electric energy strategy for the 1980's, we conclude, based on this investigation, that:

-- Existing conservation programs are commendable. Planned conservation programs could be strengthened, but the cost-effectiveness of doing so remains undetermined.

-- Conversion of Ravenswood 3 and Arthur Kill 2 and 3 to coal is the most significant action which Con Edison can take to reduce oil consumption and to moderate the rate of increase in electricity costs to its customers. Our analysis indicates that those conversions (using 1% sulfur coal without FGD facilities) would not cause air quality standards in New York City to exceed annual average SO_2 ambient standards, the most constraining standard. Before the conversions can be undertaken, however, it is necessary that a regulatory decision be made that these conversions are an acceptable use of part of the available air quality increment. Also, the conversions cannot take place as long as the present coal-burning ban stands in New York City. FGD technology, which could be used to limit SO_2 emissions to the same levels as those from the burning of 0.3% sulfur oil, would add substantial capital and operating costs to the coal conversions, but total cost of electricity would still be lower than if no coal conversion had occurred. However, addition of FGD systems as a condition of conversion would delay conversion at least two years relative to conversion without FGD equipment. Rapid conversion, with later addition of FGD, is one possible course of action. A regulatory judgement needs to be made as to whether the emission control benefits of FGD exceed its costs. The choice of the most appropriate FGD technology, if necessary, needs to be made by Con Edison. It would be prudent for Con Edison to develop and have available for installation--if and when required--the FGD technology that it believes appropriate for its plants.

-- Continued use of Indian Point is desirable.

-- Increases in purchased energy, as planned, are desirable. Even larger purchases may be desirable, particularly if terms sufficiently favorable to cover the cost of any necessary transmission improvements can be negotiated. The possible negative impact on system reliability of increases in energy importation has not been investigated.

-- Support for Travis is appropriate. The overall attractiveness of Travis with respect to Con Edison electric energy strategy objectives would be large if Con Edison were not permitted to burn coal. However, given the proposed coal conversion, the impact is significant but not as large. This investigation identified both small advantages and small disadvantages for Prattsville in terms of the stated goals. Since the analysis undertaken for this study is too narrow in scope to permit complete assessment of the value of this facility, we defer on Prattsville.

-- Support of research on refuse as a fuel for electricity generation is appropriate. MIT defers on the matter of the use of refuse as a fuel in the service area until more is known about pollution aspects and possible pollution control technologies.

-- We defer on the matter of tax reduction. The taxation issue is one of social equity, an issue outside the scope of this work.

This analysis strongly supports the implementation of Con Edison's plan. In fact, based on this analysis serious consideration should be given to coal conversion beyond the 1700 MW currently proposed. Such additional coal conversions would likely require the utilization of FGD facilities. Also, in the near term Con Edison's electric energy strategy should take full account of the probability of future upward revisions of domestic gas reserve additions and of the easing of federal statutes which currently limit the burning of natural gas by utilities.

The energy realities of the 1980's may well compel more coal conversion and larger amounts of purchased energy than proposed in the plan. In light of these realities, it is important for this entire plan to be seen as possibly only a first step in re-establishing coal usage in New York City.

Since this first step approaches the limits of coal transportation and handling facilities, SO_2 average annual ambient air quality, and long-distance electricity transmission capability, it is important that Con Edison intensify its investigation into alternative means to accomplish these functions. Furthermore, because so many limits are being reached at the same time, conservation offers a particularly compelling logic even though reserve capacity exists. Additional research to supplement present programs in these areas is needed, as is further research on developmental conversion.

It is unrealistic to assume that technical options forecast to become operational in the 1990's--synthetic fuels, renewable resources, developmental conversion and developmental load management techniques--will make obsolete reconversion to coal scheduled to occur in the 1980's. Only natural gas represents a potentially viable alternative to coal for in-city electricity generation, and even if available, gas will be priced at least on a parity with oil. Greater reliance on nuclear power for the Con Edison service area in the 1990's, while perhaps compelling by economic and, to a lesser extent, environmental logics, will require the endorsement of society. The future societal judgement concerning nuclear power constitutes the largest uncertainty in long-range electric energy planning.

Chapter One

INSTITUTIONAL AND SOCIO-POLITICAL FACTORS FOR ELECTRIC ENERGY PLANNING DECISIONS

Brief Review of Con Edison's Growth and Development

The small steam turbine generating station constructed in 1891 by Thomas Edison at Pearl Street in New York City has grown, through a series of acquisitions and mergers, into what is today Consolidated Edison Company of New York, Incorporated (Con Edison). Con Edison is one of the largest utilities in the U. S. with more than eight million customers spread over an area of 600 square miles. Con Edison's service area includes the Boroughs of Brooklyn, Richmond, Bronx and Manhattan, as well as most of Queens and much of Westchester County. A complex network of underground electric and gas transmission and distribution lines and a large district steam heating system are important parts of this large, integrated utility system serving the service area with electricity, steam, and natural gas. Despite recent transfer of some public sector customers to the Power Authority of the State of New York (PASNY), Con Edison continues to be the primary electricity supplier in New York City and Westchester County. In 1978, Con Edison ranked as the eighth largest electric utility in the U. S. in terms of installed capacity and eleventh largest in terms of total electricity sold (Exhibit 1.1).

In 1978, the Con Edison service area had an installed peak capacity of 11,885 megawatts (MW) of electricity, and in terms of revenue, electricity is by far Con Edison's largest product. Exhibit 1.2 shows that revenue from sales of electricity constituted 81% of the company's total revenue in 1978. Much of this electricity is generated at steam electric power plants located within the city of New York. In addition the company owns and operates nuclear electric power plants at Indian Point, New York. It also is part owner of steam electric power plants in Bowline and Roseton, New York. These last-named three sites are north of New York City along the Hudson River.

Since World War II Con Edison's electricity demand (and electricity generating capacity to meet this demand) have grown by over a factor of three (Exhibit 1.3). Most of this growth occurred during the 1950's and 1960's. In fact, the increase in electricity sales peaked in 1973, declined by about 7% in 1974, and remained at a level approximately 6% below the 1974 level in the next four years (Exhibit 1.3). This decline and stagnation were caused in part by consumer responses to rapid escalation in electricity prices and conservation programs. There are strong indications that continued stagnation or at most relatively small growth in demand will occur in the 1980's.

Exhibit 1.1

RANKING OF THE LARGEST U.S. ELECTRIC UTILITIES
IN TERMS OF INSTALLED CAPACITY
AND TOTAL ELECTRICITY SOLD
(1978)

	Installed Capacity in Megawatts (MW)	Ranking	Total Electricity Sold in Megawatt Hours (MWh)	Ranking
Commonwealth Edison Company	17,285	1	65,221,142	1
Southern California Edison Company	13,055	2	63,344,701	2
Pacific Gas and Electric Company	10,915	7	63,272,563	3
Duke Power	12,670	3	52,609,003	4
Houston Lighting and Power Company	12,022	4	48,533,763	5
Georgia Power Company	11,966	5	46,300,212	6
Florida Power and Light Company	11,728	6	40,711,787	7
The Detroit Edison Company	9,911	9	39,237,914	8
Virginia Electric and Power Company	8,682	10	38,249,592	9
Ohio Power Company	6,921	11	36,615,910	10
Consolidated Edison[1]	10,057	8	33,412,507	11

[1] Both Con Edison and PASNY serve the same service area. Because the operations of these two utilities overlap geographically, this analysis focused upon the entire service area rather than just Con Edison. The installed capacity and total electricity sold for the service area are 11,885 megawatts and 32,596,075 megawatt hours respectively.

Sources: Moody's Public Utility Manual 1979, Moody's Investors Service, Inc., New York, N.Y. and Operating Statistics Yearbook 1978, Generation Planning Department, Consolidated Edison Co. of New York, Inc., New York, N.Y., August, 1979.

Exhibit 1.2

CON EDISON'S TOTAL OPERATING REVENUES
(1978)

	Revenue (Thousands of 1978 Dollars)	Per Cent
Total Electric Sales Revenue	$2,450,726	81%
Total Gas Sales Revenue	337,586	11%
Total Steam Sales Revenue	222,658	8%
TOTAL REVENUE	$3,010,970	100%

Source: Consolidated Edison 1979 Annual Report, Consolidated Edison of New York, Inc., New York, N.Y., February 26, 1980.

Exhibit 1.3

CON EDISON SERVICE AREA INSTALLED CAPACITY AND ELECTRICITY SALES (1950-1978, SELECTED YEARS)

Year	Installed Capacity (MW)	Percentage Change	Electricity Sales (GWh)	Percentage Change
1950	2,915	--	10,431	--
1955	3,696	27%	13,721	32%
1960	4,883	32%	18,894	38%
1965	6,607	35%	24,307	29%
1970	9,420	43%	31,924	31%
1971	9,504	1%	32,499	2%
1972	9,663	2%	33,068	2%
1973	9,694	0%	34,653	5%
1974	11,082	14%	32,206.	- 7%
1975	10,709	- 3%	32,418	1%
1976	11,437	7%	32,630	1%
1977	12,001	5%	32,458	- 1%
1978	11,885	- 2%	32,596	0%

Sources: Operating Statistics Yearbook 1979, Generation Planning Department, Consolidated Edison Co. of New York, Inc., New York, N.Y., November, 1980, and Report of Member Electric Systems of the New York Power Pool and the Empire State Electric Energy Research Corp., Vol. 1, Long-Range Plan 1980, Albany, N.Y., April 1, 1980.

Evolution of Con Edison's Fuel Usage for Electricity Supply

Historically, Con Edison has responded frequently to the economic and environmental factors affecting its fuel mix decisions. Through a series of reasonable responses to the historically slow and small energy marketplace changes, the company evolved from a predominantly coal-dependent utility in the late 1940's to a predominantly oil-dependent one by 1970 (See Exhibit 1.4). Soon after that, sudden and major changes in the factors affecting fuel choice decisions began to confront the U. S. economy in general and electric utilities in particular. It is useful to trace these changes in economic and environmental factors in some detail in order to place current plans in perspective.

During the first half of this century (until the late 1960's), fuel costs were only a small component of total cost for electric utilities. Instead, capital expansion costs dominated the picture. Further, during this period U. S. energy prices were virtually constant or declining in real terms, and relative prices of various fuels remained almost constant. Thus, the use of a fuel in an electric utility was governed primarily by its availability. In the mid-Atlantic states a supply situation associated with eastern coals tipped the choice of fuel in electric utilities in favor of coal. This usage continued despite the then prevailing slight price differential in favor of oil on a per Btu basis. All increases in electricity demand until the early 1950's were met primarily by coal-fired generation, with a small contribution coming from oil.

With the advent in the early 1950's of abundant domestic supplies of natural gas and massive interstate gas pipelines, whose economics required developing large users, natural gas became an attractive boiler fuel. Its ease of use and compatibility with existing boilers further encouraged the use of natural gas by electric utilities.

By the mid-1960's, world oil markets had expanded, largely due to extensive exploration and production activities and the advent of bulk water carriers. Thus, the Great Lakes cities and Atlantic Coast had easy access to supplies of inexpensive imported oil. Coincidentally, coal production and transportation facilities had proven particularly vulnerable to interruption by organized labor. About the same time, social pressures to clean up some of the negative environmental effects of intense industrialization were building up in the U. S. Within large cities air pollution was reaching alarming levels.

New York City air quality, particularly with regard to sulfur dioxide (SO_2) and particulates, was poor by 1965. There

Exhibit 1.4

CON EDISON SERVICE AREA FUEL SOURCE PROFILE*
(1945-1979, SELECTED YEARS)

Year	Each Fuel's Share of Total Amount of Fuel Used to Generate Electricity (Percent)				
	Coal	Oil	Gas	Nuclear	Hydro
1945	94	6	0	0	-
1950	65	35	0	0	-
1955	70	18	12	0	-
1960	63	21	16	0	-
1965	43	37	20	3	-
1970	20	57	19	4	0
1975	3	76	2	17	2
1976	4	75	1	19	1
1977	3	63	0	32	2
1978	3	62	0	30	5
1979	3	44	12	28	13

*Includes fuels used to generate electricity purchased or produced by Con Edison for distribution in the Con Edison service area in the period 1970 to 1979. No fuel source profile data is available for any electricity which may have been purchased by Con Edison prior to 1967.

Sources: Operating Statistics Yearbook 1978, Generation Planning Department, Consolidated Edison Co. of New York, Inc., New York, N.Y., August, 1979, and An Energy Strategy for the 1980's, Charles F. Luce, Chairman of the Board, Consolidated Edison Co. of New York, Inc., New York, N.Y., April, 1980.

had been several 'episodes' of significant air pollution, and action seemed warranted. The major culprit was presumed to be coal burning, both for residential heating and electric generation. Citizen groups, organized to fight for a cleaner environment, were becoming vocal and politically powerful. Demands were made to reduce the use of fuels polluting the atmosphere in New York City.

In 1971 a decision to ban coal-firing of large boilers was adopted by New York City in an effort to control ambient SO_2 concentrations. The ban also required all such fuel burning equipment to use low sulfur fuel oil. (Administrative Code of New York City; Chapter 57, the Air Pollution Control Code.) The New York State Implementation Plan for the New York City Metropolitan Area, adopted in early 1972, also called for an elimination of coal as a boiler fuel. After the city's code was adopted, there was an improvement in SO_2 and particulate air quality due to reduction in these emissions from major combustion sources. Ash was significantly reduced and the coal and ash barges servicing Con Edison's in-city riverside plants were eliminated, further decreasing particulates. The noise associated with coal handling at these sites was also eliminated. After these ordinances were adopted National Ambient Air Quality Standards (NAAQS) were promulgated by the United States Environmental Protection Agency (E.P.A.). Subsequent monitoring in New York City has shown attainment of these standards by a narrow margin.

Within Con Edison's generating system all these events caused a dramatic decline, in a relative sense, of coal as boiler fuel. Coal's share of Btu input into the Con Edison generating system dropped from a high of 94% in 1945 to 3% in 1975 (Exhibit 1.4). (Of course since the ban, coal has not been used to generate electricity in the service area, but about 3% of the electricity dispatched in the service area has been purchased outside of the service area from coal-fired plants owned by other utilities.)

Curtailment of the use of coal in New York City came at a time when Con Edison had recently completed a considerable amount of then-new coal-fired generating capacity. These new coal-fired units were modified to burn oil, as were a number of other plants that were already burning coal. At almost the same time, adequacy of natural gas supplies to the northeast region of the U. S. began to be questioned. This development led to a reduced use of gas in Con Edison's generating system. As a result of the confluence of these trends and events, by 1973 Con Edison was more or less completely dependent on oil for electricity generation.

Beginning a few months after the coal curtailment in New York City, sudden and large oil price increases caused roughly a fivefold increase in Con Edison's oil fuel cost within five years (Exhibit 1.5). The Arab oil embargo of 1973 made clear the possibility of future supply interruptions. Con Edison's

Exhibit 1.5

CON EDISON'S FUEL COSTS
(1945-1979, SELECTED YEARS)

Year	Fuel Costs (¢/MMBtu)			
	Coal	Oil	Gas	Nuclear
1945	23.80	27.37	-	-
1950	34.16	32.82	-	-
1955	35.43	38.04	33.36	-
1960	36.29	35.52	39.12	-
1965	30.64	33.84	36.33	70.04
1970	50.31	42.96	38.49	48.92
1975	-	213.43	107.67	36.26
1976	-	207.62	127.27	43.70
1977	-	234.53	143.24	31.03
1978	-	222.61	137.53	42.63
1979	-	316.74	247.44	48.63

Sources: Operating Statistics Yearbook 1978, Generation Planning Department, Consolidated Edison of New York, Inc., New York, N.Y., August, 1979, and Electric Production Economy Statistics, 1979, Generation Planning Department, Consolidated Edison of New York, Inc., New York, N.Y., January 31, 1980.

vulnerability to fuel price escalation and, more importantly, sensitivity to supply interruptions were, of course, not unique. The entire U. S. economy felt these shocks. However, few electric utilities were as dependent on low sulfur oil as Con Edison.

Shortly thereafter came the U. S. federally mandated entitlements program aimed primarily at reducing the impact of sudden fuel price escalations. This program was effective in keeping the price of oil in U. S. markets at lower levels than those prevailing in other industrialized countries. However, since there was no simultaneous control on the U. S. consumption of oil, this program actually stimulated oil demand. Since domestic oil supply had peaked, this program in fact helped to increase U. S. dependence on imported oil. This dependence reached such alarming proportions that, by 1977, one of the major tenets of U. S. energy policy was to reduce dependence on imported oil. This policy took the shape of the Powerplant and Industrial Fuel Use Act of 1978 (PIFUA) and a Presidential call to reduce oil use by about 50% in electric utilities, beginning with those which could convert to coal most easily. Con Edison moderated its oil dependence by 1977 with the addition of Indian Point nuclear units, but with the continued absence of natural gas, it was still 63% oil dependent (Exhibit 1.4).

This Powerplant and Industrial Fuel Use Act prohibits the use of natural gas as a primary energy source in most Con Edison Boilers. However, short-term exemptions from this prohibition were granted to Con Edison in 1979 as part of a national oil displacement program. This short term natural gas was 12% of the fuel used to generate electricity in the service area that year (Exhibit 1.4).

In the last several years, continued operation of the Indian Point nuclear units has come under question because of their proximity to New York City. Even as this study is underway, Con Edison, various advocacy groups, and the Nuclear Regulatory Commission (NRC) are debating the future of these units. Whereas these debates are a part of nationwide concern regarding nuclear power generation, Con Edison is especially affected by such developments since nuclear energy is at present its only major long term alternative to oil. In 1979 nuclear energy supplied 28% of the fuel used to generate electricity in the Con Edison service area (Exhibit 1.4).

Con Edison's Goals and Objectives

At the most general level, the goals of any electric utility are to meet demand for electricity in a reliable and economic manner while, at the same time, meeting or exceeding environmental protection standards. While these general goals remain constant over the long-term, the specific goals and objectives to achieve them must often undergo change as market and other forces operate. It is such changes that have caused the extensive evolution of fuel usage by Con Edison over the past 30 years and which will shape its fuel decisions in the future.

Con Edison has responded recently to the rapidly changing U.S. fuel and energy markets with a plan for the 1980's which states two overall goals. The actions in the plan seek to reduce the company's dependence on oil as a primary boiler fuel and to moderate the rate of future increases in electricity costs to its customers. In addition, the plan's further stated objectives are to provide an adequate supply of electric energy to the service area, and to do so in an environmentally acceptable way.

Con Edison's Plan for Responding to Recent Events

In 1978 Con Edison first announced its energy strategy for supplying electricity in the 1980's. A somewhat revised plan was published in 1980. This revised plan includes major changes in electric energy supply arrangements and consists of the following seven specific actions:

-- Promote strong energy conservation programs in New York City and Westchester County.

-- Convert three Con Edison in-city generating units to burn coal instead of oil, while taking appropriate steps to meet environmental standards.

-- Continue to use nuclear power generated at Indian Point as a principal non-oil source of electricity.

-- Increase imports of hydroelectric power from Canada and other sources.

-- Support the construction of coal-fired and pumped storage hydroelectric plants planned by the Power Authority of the State of New York (PASNY).

-- Use refuse as a fuel to generate steam and electricity.

-- Reduce taxes on energy.

For a complete statement of this plan as revised in 1980 see Appendix A. The most basic common objective behind all these actions is said to be reduction of oil consumption and, hence, Con Edison's vulnerability to further oil price escalation and supply interruptions.

Legal Constraints on Plan Implementation

A central feature of this proposed plan is in-city coal-firing for electricity generation. In order to effect such coal-firing, the New York City Air Pollution Code must be revised. Also, a special limitation (variance) must be obtained by Con Edison from the New York State Department of Environmental Conservation. This special limitation is subject to U.S. EPA approval. Therefore, a major aspect of implementation of the planned reconversion to coal at two in-city plant sites is the removal of these legal prohibitions. As well, a demonstration by Con Edison using acceptable modeling techniques will be needed to show that any increased ambient SO_2 concentrations from such coal-burning do not violate standards. Finally, a regulatory decision must be made that this conversion is an acceptable use of part of the available air quality increment.

Other electric power plants in New York and New Jersey are contemplating coal conversion with possible increases in SO_2 emissions.

Because Con Edison has proposed coal conversion without Flue Gas Desulfurization (FGD), there would be increases in SO_2 emissions. The company has recognized that a demonstration of the probable impact of these higher SO_2 emissions in New York City will be necessary in order to obtain repeal of the ban. Thus, the company proposed to burn 1.5% sulfur oil (roughly equivalent to burning 1% sulfur coal) at the three units for one year and measure the SO_2 concentrations to see if the standards were still maintained. Included in the proposal was an "offset" of providing natural gas to several large residual oil-burning sources near the City College monitoring station. (This area has had problems meeting the standards in the past.) This test burn required a special limitation from New York State and therefore approval by the U.S.E.P.A. EPA approved the test burn on August 11, 1980. In its federal register notice, the EPA indicated that the test burn approval did not pre-judge its future decision on the proposed coal conversions. Air quality impact studies, using various simulation techniques, are also in progress.

Any increases in SO_2 emissions may be challenged because of issues such as acid rain. Connecticut has sued several times to block emission increases in New York City because of potential impacts there. The test burn is currently progressing, but the existence of major controversy over coal use in New York City has been clearly demonstrated.

Strategic Planning Factors for the Con Edison Area

A strategic planning factor is a basic economic, environmental, or demographic characteristic affecting the production or demand for electricity in the Con Edison service area that must be considered in development of a strategic plan for providing electricity there. (Appendix B provides background information for planning factors discussed below.) The first major strategic planning factor is that service area reserve capacity precludes the need for capacity expansion until the 1990's, if average annual load growth is about 1% per year as forecast. (See Exhibit 1.6.) To maintain reliable service, the New York Power Pool requires its member companies to maintain an 18% capacity reserve margin above anticipated peak load. If the service area peak load of approximately 8020 MW increases about one percent per year, as projected in Con Edison's 1980 plan, the electricity required to meet that peak demand will not need to be withdrawn from the capacity reserve margin until at least 1995.

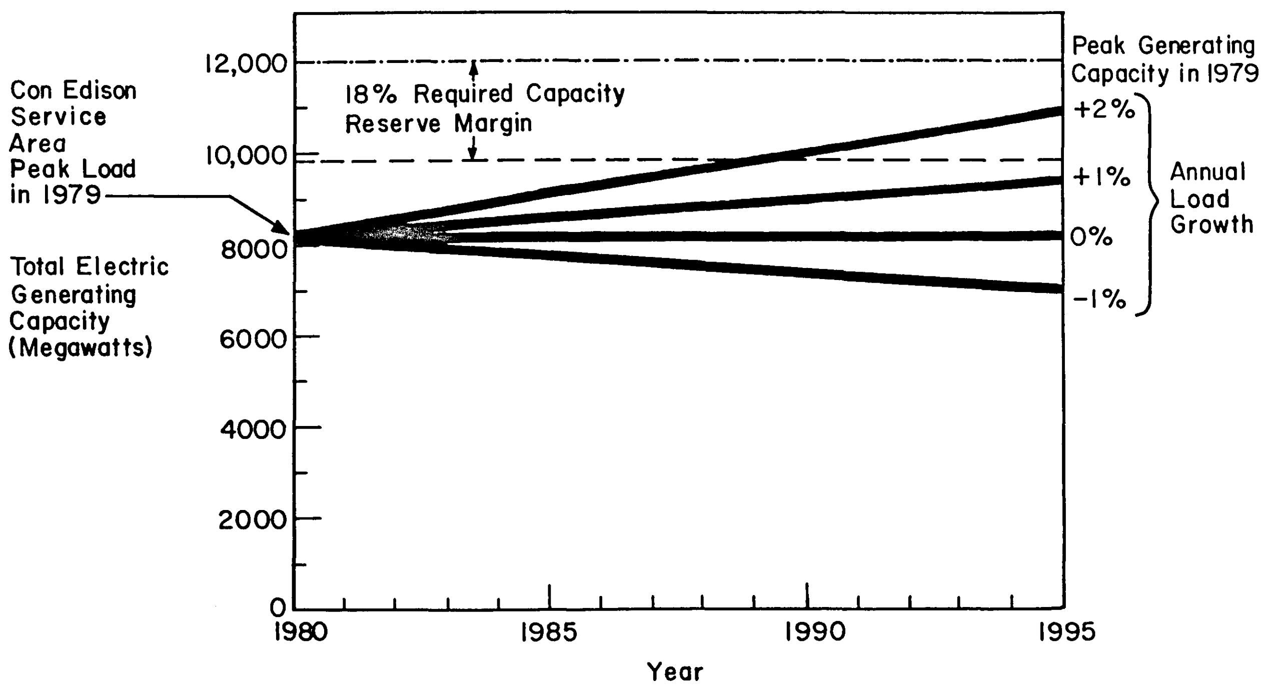
Certain features of the service area which affect this expected match between electricity supply and demand are noteworthy. Unlike most other electric utilities in the U. S., Con Edison operates in an area which is exclusively urban and extremely densely populated. Whereas the average populations per square mile of New York State and the U. S. as a whole are 369 and 62, respectively, New York City has a population density of 24,000 people per square mile. Within the city, Manhattan--with 60,000 persons per square mile--represents a service area with urban compaction unequaled elsewhere in the U. S. As a result of this intense urbanization there is a relative absence of large industrial customers in Con Edison's service area. Consequently, a much greater than industry average percentage of electricity sales is to the commercial market segment. (See Exhibit 1.7.)

Within the residential sector, the per capita electricity consumption in New York City is much lower than the rate prevailing on average elsewhere in the U. S. Furthermore, the differential between the daytime peak and nighttime slack in demand for power is greater than for typical electric utilities since New York City has comparatively few round-the-clock electric consumers and has a large commuter population which leaves at night. As a result of these demand characteristics, as well as the recent slump and subsequent stagnation in demand, the amount of electricity sold by Con Edison, in relation to its installed capacity, stands out as one of the lowest among the major electric utilities, as can be seen from Exhibit 1.1. Reserve capacity at time of system peak in 1978 was 32% (Exhibit 1.8).

A second major planning factor is that Con Edison's price for electricity is high. Since the time when the rapid increase in crude oil price began, the price for the company's electricity has more than doubled (Exhibit 1.9). In 1978 Con Edison supplied electricity for residential use at the highest price among all

Exhibit I. 6

IMPACT OF LOAD GROWTH ON CAPACITY
RESERVE MARGIN (1980-1995)



Assumptions:

Peak generating capacity does not include any proposed additions to capacity or relatively minor scheduled plant retirements.

Exhibit 1.7

RELATIVE SIZE OF MAJOR ELECTRICITY MARKET SEGMENTS FOR LARGEST U.S. UTILITIES*
(1978)

	Percent of Electricity Sales to:			
	Commercial Sector	Industrial Sector	Residential Sector	Percent
Commonwealth Edison Company	28	30	32	90 %
Southern California Edison Company	31	36	29	96 %
Pacific Gas and Electric Company	37	24	34	95 %
Duke Power	31	21	47	99 %
Houston Lighting and Power Company	18	59	23	100 %
Georgia Power Company	25	44	30	99 %
Florida Power and Light Company	36	8	54	98 %
The Detroit Edison Company	29	17	52	98 %
Virginia Electric and Power Company	33	22	45	100 %
Ohio Power Company	10	71	19	100 %
Consolidated Edison of New York, Inc.	57	6	37	100 %
Industry Average	26	41	33	98

* Those utilities which did not sell 100% of their electricity to the above listed sectors also sold electricity to one or more of the following sectors: Public Authorities, Railroads and Internal Departments.

Source: Statistics of Privately Owned Electric Utilities in the United States 1978, Department of Energy, DOE/EIA 0044 (78), Washington, D.C., October, 1979.

Exhibit 1.8

CON EDISON SERVICE AREA RESERVE CAPACITY
(AT TIME OF SYSTEM PEAK)

	1978
Total Capacity Resources (at time of system peak)	11,305,000 (kW)
Peak Requirements	7,698,000 (kW)
Reserve Capacity	3,607,000 (kW)
Reserve Capacity (%)	32%

Source: Consolidated Edison 1979 Annual Report, Consolidated Edison of New York, Inc., New York, N.Y., February 26, 1980.

Exhibit 1.9

CON EDISON RATES CHARGED
FOR ELECTRICITY
(1968-1979)

	Electricity Rates (¢/kWh)
1968	4.0
1969	3.9
1970	3.9
1971	4.2
1972	4.6
1973	5.2
1974	7.6
1975	8.2
1976	8.8
1977	9.6
1978	9.6
1979	10.5*

*Industry average in 1979 was 4.33¢/kWh.

Sources: Ten Year Financial and Operating Statistics: 1968-1978, Consolidated Edison of New York, Inc., New York, N.Y., 1979, and Standard and Poor's Industry Surveys: Utilities--Electric, Basic Analysis, Section 2, New York, N.Y., March 22, 1979.

electric utilities in the continental United States (Exhibit 1.10). In 1979 Con Edison charged 10.5¢/kWh, more than twice the industry average price of 4.33¢/kWh (Exhibit 1.9)[1]. Con Edison's electricity price also contains the highest tax rate on utility supplied electricity in the U.S.

Over half of the fuel used to produce electricity in the Con Edison service area is oil or natural gas (Exhibit 1.11). Both of these fuels have had recent sharp price increases. Nearly half of the fuel used for electricity generation by the U.S. electric power industry is coal. However, this cost-advantageous fuel is not used to produce electricity in the Con Edison service area as discussed above.

This situation of major oil and natural gas dependence is made more disadvantageous by the high probability of further significant supply uncertainty and price escalation. During this decade oil prices are expected to rise about 35% to 50% in real terms. In 1980, natural gas was about half the price of oil. Gas prices are expected to be about 30% less than oil during most of the 1980's, although they are expected to approximately equal oil prices near the end of the decade. Gas prices were about 30% higher than coal prices in 1980. They are expected to rise more rapidly than coal prices throughout the 1980's, and, by the end of the decade, gas prices are expected to be about three times the level of coal prices. (See Exhibit 1.12.)

A third major planning factor concerns Con Edison's financial condition. Financially Con Edison is one of the strongest electric utilities in the country. Since the early 1970's the company has steadily improved its financial condition to a current balance sheet position of nearly one half billion dollars in liquid assets and a 44% common equity ratio. Furthermore, the company's financial condition is expected to improve over the near future. Cash flow from operations is estimated to closely match construction expenditures, and because of the large cash position, no major external financing requirements are expected over the next several years. It is likely, however, that some bond financing will be undertaken in the 1981-1983 period in connection with the proposed coal conversions. No equity financing should be required until at least the late 1980's.

Con Edison's earnings per share and common dividends per share have shown major improvement since 1972, growing approximately 11.8% and 4.4% per year, respectively (Exhibit 1.13).[2]

[1] For a discussion of the reasons for Con Edison's high electricity prices see reference number 83.

[2] These 1972-1978 growth rates are somewhat misleading since 1972 was a particularly poor year financially.

Exhibit 1.10

CON EDISON RESIDENTIAL ELECTRICITY RATES
COMPARED TO OTHER CONTINENTAL U.S. UTILITIES
(1978)

Average Residential Rate per kWh (¢)

Allegheny Power System	3.9	Middle South Utilities	3.4
American Electric Power	3.5	Minnesota Power & Light	4.5
Arizona Public Service Co.	5.0	Montana-Dakota Utilities	4.1
Atlantic City Electric	5.1	Montana Power Co.	2.8
Baltimore Gas & Electric	5.0	Nevada Power Co.	3.0
Boston Edison Co.	5.9	New England Electric System	5.4
Carolina Power & Light	4.1	New England Gas & Electric	5.7
Central Hudson Gas & Electric	5.4	New York State Electric & Gas	4.6
Central Illinois Light	5.2	Niagara Mohawk Power	3.9
Central Illinois Public Serv.	5.3	Northeast Utilities	4.7
Central Louisiana Energy Corp.	4.1	Northern Indiana Public Serv.	5.1
Central Maine Power Co.	3.6	Northern States Power	4.0
Central & South West Corp.	4.0	Ohio Edison Co.	4.8
Cincinnati Gas & Electric	3.8	Oklahoma Gas & Electric	3.5
Cleveland Electric Illum.	5.0	Orange & Rockland Utilities	7.9
Columbus & Southern Ohio	4.9	Pacific Gas & Electric	3.9
Commonwealth Edison	4.7	Pacific Power & Light	2.5
Consolidated Edison of N.Y.	9.6	Pennsylvania Power & Light	4.1
Consumers Power Co.	4.5	Philadelphia Electric Co.	5.5
Dayton Power & Light	4.1	Public Service Co. of Colo.	3.6
Delaware Power & Light	5.3	Public Service Co. of Ind.	3.9
Detroit Edison Co.	4.8	Public Service Co. of N.H.	5.6
Duke Power Co.	3.6	Public Service Co. of N. Mex.	5.1
Duquesne Light Co.	5.9	Public Service Electric & Gas	6.6
El Paso Electric Co.	4.9	Puget Sound Power & Light	1.8
Florida Power Corp.	4.8	Rochester Gas & Electric	4.3
Florida Power & Light	4.1	San Diego Gas & Electric	4.9
General Public Utilities	5.1	Siera Pacific Power Co.	4.8
Gulf States Utilities	3.5	South Carolina Electric & Gas	4.3
Houston Industries	3.4	Southern Calif. Edison Co.	4.6
Idaho Power Co.	2.1	Southern Co.	3.9
Illinois Power Co.	4.2	Southern Ind. Gas & Electric	3.9
Indianapolis Power & Light	3.6	Southwestern Public Serv. Co.	4.4
Interstate Power Co.	4.9	Tampa Electric Co.	4.7
Iowa Electric Light & Power	4.6	Texas Utilities Co.	3.6
Iowa-Illinois Gas & Electric	4.4	Toledo Edison	5.6
Iowa Power & Light	4.1	Tucson Electric Power Co.	5.6
Iowa Public Service Co.	4.6	Union Electric Co.	4.3
Kansas City Power & Light	4.5	United Illuminating Co.	4.9
Kansas Gas & Electric	3.8	Utah Power & Light	4.3
Kansas Power & Light	4.1	Virginia Electric & Power	4.5
Kentucky Utilities Co.	3.5	Washington Water Power	1.5
Long Island Lighting	6.3	Wisconsin Electric Power	3.9
Louisville Gas & Electric	3.5	Wisconsin Public Service	4.5

Source: Standard & Poor's Industry Surveys: Utilities--Electric, Basic Analysis, Section 2, New York City, N.Y., April 17, 1980.

Exhibit 1.11

FUEL MIX PROFILES:
CON EDISON SERVICE AREA
COMPARED TO
U.S. ELECTRIC UTILITY INDUSTRY

	Fuel Mix for Electricity Generated in Con Edison Service Area (1979)	Fuel Mix for Electricity Purchased for Con Edison Service Area (1979)	Fuel Mix for Electricity Supplied to Con Edison Service Area (1979)	Industry Average Fuel Mix (1979)
Coal	0%	3%	3%	46%
Oil	40%	4%	44%	18%
Gas	12%**	0%	12%	14%
Nuclear	26%	2%	28%	12%
Other	0%	13%*	13%	10%
Percent of Total Supplied	78%	22%	100%	100%

*All hydroelectric energy.

**Since this gas portion of the fuel mix is only temporarily permitted to offset use of oil, the service area is effectively dependent on oil for 56% of its electricity.

Sources: Moody's Public Utility Manual 1980, Moody's Investors Service, Inc., New York, N.Y., and An Energy Strategy for the 1980's, Charles F. Luce, Chairman of the Board, Consolidated Edison Co. of New York, Inc., New York, N.Y., April, 1980.

Exhibit 1.12

FUEL PRICE PROJECTIONS 1980-1990
(REAL 1980 DOLLARS)[1]

Year	Projected[2] Oil Prices ($/MMBtu)	Projected[3] Gas Prices ($/MMBtu)	Projected[4] Coal Prices ($/MMBtu)
1980	$ 5.00	$ 2.50	$ 2.00
1981	5.15	2.75	2.02
1982	5.30	3.03	2.04
1983	5.46	3.33	2.06
1984	5.63	3.66	2.08
1985	5.80	4.03	2.10
1986	5.97	4.51	2.12
1987	6.15	5.05	2.14
1988	6.33	5.66	2.17
1989	6.52	6.34	2.19
1990	6.72	6.72	2.21

[1] These projections were made in early 1980.

[2] The base price is for number 6 residual oil containing 0.3% sulfur. The projected annual price escalation rate of oil used here was 3%.

[3] The projected annual price escalation rate of gas is 10% from 1980 to 1985 and 12% from 1985 until the price of gas reaches the price of number 6 residual oil. Then, it was assumed that gas prices and oil prices would remain approximately equal. It was also assumed that natural gas prices would be deregulated in the mid-1980's.

[4] The base price is for 1% sulfur coal. The projected annual price escalation rate of coal used here is 1%.

Exhibit 1.13

CON EDISON FINANCIAL
AND OPERATING STATISTICS
(1968-1979)

Financial Ratios	1968	1969	1970	1971
Return on Average Common Equity (%)	8.5	8.6	7.5	7.4
Earnings per Share ($)	2.57	2.68	2.30	2.35
Dividends per Share ($)	1.80	1.80	1.80	1.80
Payout Ratio (%)	70.0	67.2	78.3	76.6
S.E.C. Interest Coverage (x)*	2.88	2.60	2.02	2.10
Construction Expenditures and Funding				
Construction Expenditures ($mm)	246.3	305.0	400.6	424.6
% of Total Funds Internal (%)	57.2	53.7	36.1	47.1
% of Total Funds External (%)	42.8	46.3	63.4	52.9
Electric Rates and Usage				
Electric Revenues (¢/kWh)	4.0	3.9	3.9	4.2
KWh Use per Customer -- Annual	2736	2950	3180	3355

*This variable measures the ratio of earnings to interest payments. For example, a ratio of 3.0 indicates earnings three times the amount of interest payments.

Exhibit 1.13

Continued

1972	1973	1974	1975	1976	1977	1978	1979
6.6	7.6	8.4	11.1	11.6	11.7	10.5	10.5
2.07	2.34	2.68	3.74	4.18	4.53	4.27	4.51
1.80	1.80	0.85	1.20	1.60	2.00	2.20	2.44
87.0	76.9	31.7	32.1	38.3	44.2	51.3	54.1
2.00	2.07	2.17	2.64	3.20	3.49	3.35	3.45
518.5	685.6	498.4	358.3	300.2	284.2	313.7	316.3
36.5	37.5	48.8	78.3	66.5	99.05	100.0	100.0
63.5	62.5	51.2	21.7	33.5	0.05	0.0	0.0
4.6	5.2	7.6	8.2	8.8	9.6	9.6	10.5
3367	3609	3248	3300	3314	3300	3255	3255

Source: Ten Year Financial and Operating Statistics: 1969-1979, Consolidated Edison Co. of New York, Inc., New York, N.Y., 1980.

Returns on common equity have also improved. However, Con Edison's rate of return on average common equity in 1979, 10.5%, was below its regulated maximum return of 12.14%. The company's rate of return on common equity was also below the industry average return of 11.3% and below the return earned by other New York utilities, some of which have been granted an allowable maximum return up to 14% (Exhibit 1.14).

A fourth major planning factor concerns Con Edison's overall environmental impact. When the coal burning ban was adopted, Con Edison's in-city power plants constituted the largest single source of coal-fired SO_2 emissions under one management. Since determination of the relative impact of the various coal-burning sources was made based on total emissions, the Con Edison plants were the logical and the actual starting points for replacement of coal with oil in New York City. However, Con Edison's plants had relatively tall stacks, well above the usual for northeastern utilities at that time. If consideration had been given to the actual ambient air quality impact for existing atmospheric dispersion processes, it is probable that the Con Edison coal-burning facilities would have been shown to have significantly less impact on New York City air quality (per ton of SO_2 emissions) than coal-fired space heating boilers with rooftop stacks. At present, the company's contribution to environmental pollution in the New York City area is quite small. It is probable that coal-firing as proposed by Con Edison would have less impact on NYC air quality (per ton of SO_2 emissions) than coal-fired space heating boilers with rooftop stacks.

When the coal burning ban was adopted in New York City, installation of much of the currently available equipment to control environmental impacts from burning coal was not a viable option. This is because the available technology for particulate control, the electrostatic precipitator, was not economic for electricity generation. Furthermore, various control technologies for sulfur dioxide emissions, for instance flue gas desulfurization (FGD) equipment, was not commercially available. Thus, the only control option at that time was to ban coal and to use oil with a much lower sulfur content. These coal-banning ordinances predate most air quality sulfur control technology.

Current Public Debate on Electric Energy Strategy Options

Difficulty in evolving an electric energy plan for the 1980's arises partly because the public is questioning where, and to what extent, the benefits of a particular electric energy alternative outweigh its negative impacts. Public debate is extensive, and dialogue frequently appears in the media. During the course of this project, public debate has focused on several major energy alternatives.

Exhibit 1.14

COMPARATIVE FINANCIAL RATIOS:
CON EDISON AND THE ELECTRIC UTILITY INDUSTRY
(AT END 1979)

Capitalization (%)	Con Edison	Industry
Long Term Debt	44.5	50.4
Preferred Stock	11.4	12.3
Common Stock	44.1	37.3
Return on Average Common Equity (%)	10.5	11.3
Pre-Tax Interest Coverage (x)	3.8	2.7
Dividend Payout Ratio (%)	54.1	73.5
Market Price to Book Value/Share (%)	55.2	70-75
Allowance for Funds Used During Construction (expressed as % of Earnings per Share)	1.3	48.4
Capital Outlays Financed Externally (%)	0	55.2
Revenue/kWh (¢)	10.5	4.33

Sources: Ten Year Financial and Operating Statistics: 1969-1979, Consolidated Edison of New York, Inc., New York, N.Y., 1980, and Standard and Poor's Industry Surveys: Utilities--Electric, Basic Analysis, Section 2, New York, N.Y., April 17, 1980.

The two major questions raised about Con Edison's plan focus on the utility's reconversion of certain plants to coal and continued use of nuclear power. Many residents of New York City might agree that using coal is commendable to the extent that it is a domestic energy source and its mining and transportation employs U. S. workers. However, Con Edison's plan to transport and burn coal is questioned because of potential environmental degradation (particularly SO_2 emissions). Furthermore, analysis of recent newspaper coverage suggests the possibility of additional regulation aimed at controlling acid rain and limiting allowable dust and noise emitted during transportation and handling of coal.

The question of nuclear reactor safety at Indian Point is often raised in New York City because approximately four million people live within 30 miles of Indian Point. Concern about the safety of nuclear power plants in general, or Indian Point specifically, could lead to a shutdown of Indian Point.

Two other energy alternatives which the public discusses are conservation and renewable resources. Questions about these center on the potential size of their contribution to electricity production in the 1980's and the extent to which Con Edison should be active in promoting them. Cogeneration and refuse as a utility fuel also receive some attention in the press. Some people are questioning whether or not decentralized cogeneration might be a good substitute for Con Edison's centralized generation. Electric energy generation from refuse is getting public attention because of its perceived refuse disposal advantages despite its possible negative environmental impacts.

This type of public debate often generates regulatory change. This possible regulatory change, coupled with frequent major changes to national energy policy, in general, and changes to legislation on fuel use by utilities, in particular, increases the uncertainty in electric energy strategic planning and makes it more difficult.

Chapter Two

TECHNICAL OPTIONS:
ELECTRIC ENERGY STRATEGY BUILDING BLOCKS

Identification

Con Edison can move to influence both the supply of and the demand for its electricity in reaching toward its objectives. The company has two basic ways to supply electricity. First, it can generate electricity in its own facilities. Secondly, it can purchase electricity from other utilities located outside the service area and transmit it for use in New York City and Westchester County. Likewise, there are two major ways for Con Edison to affect the demand for its energy: load management[1] and conservation. For purposes of this report, load management techniques are those ways to shift a portion of demand from one time to another. Conservation involves steps that actually reduce the total demand. It is, of course, also possible for a utility to stimulate demand through incentive pricing and other promotion schemes. However, neither Con Edison nor MIT contemplates such a management stance in the next two decades; therefore, this possibility is ignored in this investigation.

Exhibit 2.1 presents these broad areas of management choice conceptually. It is important to realize that they are not mutually exclusive since both demand and supply can be and are usually managed simultaneously. Further, some energy is often purchased while other energy is being generated. Similarly, load management does not preclude conservation. Most electric energy plans blend these two concepts of supply and demand management and the various options they present. However, these broad areas of management choice serve to highlight the fourteen electric energy strategy building blocks available to Con Edison for influencing supply and demand for its electricity. Exhibit 2.2

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[1] Demand for electricity is called the 'load of the utility' or, simply, the 'load'. A utility's load peaks at certain times of the day or certain times of the year. For instance, the Con Edison load is higher in summer months than in winter months because many customers use electric air conditioners for space cooling while few use electricity for space heating. The load is also higher at certain times of the day when industrial and commercial users are demanding their peak amounts of electricity during working hours. During the evening and night, however, demand diminishes. This uneven demand situation causes a management issue because the system must carry a surplus of capacity during off-peak periods to assure that it is able to supply peak demand, and this extra capacity costs money.

Exhibit 2.1

BROAD AREAS OF MANAGEMENT CHOICE

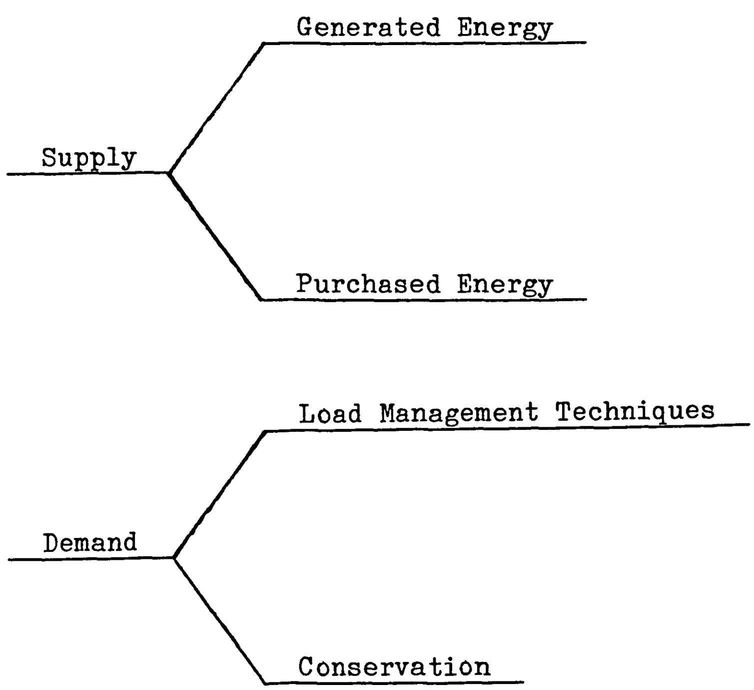

Exhibit 2.2

ELECTRIC ENERGY STRATEGY BUILDING BLOCKS

- Supply
  - Generated Energy
    - Oil
    - Coal
    - Coal-Oil Mixtures
    - Natural Gas
    - Nuclear
    - Refuse
    - Synthetic Fuels
    - Cogeneration (Decentralized and Centralized)
    - Developmental Conversion
    - Renewable Resources
    - Pumped Hydroelectric
  - Purchased Energy
- Demand
  - Load Management Techniques (Conventional and Developmental)
  - Conservation

presents these fourteen electric energy strategy building blocks, and Exhibit 2.3 defines them[2]. Just as the broad areas of management choice are not mutually exclusive, neither are these more specific fourteen building blocks. Several will normally be used at the same time.

Key Observations[3] and Building Block Classification

Oil

Oil (or gas temporarily made available to Con Edison to displace oil) is the fuel used to generate about 56% of the service area's electricity. It is significantly more expensive than coal and nuclear fuel, and this price gap will in all likelihood widen in the 1980's. Furthermore, oil availability is uncertain due to the unstable political situation surrounding its importation. Imported oil currently forms about 40% of the U. S. oil supply. However, about 90% of Con Edison's oil supply is imported due to distribution patterns for the type of fuel the company is required to use, low sulfur oil. Unless Con Edison alters its current fuel mix away from oil, it will be vulnerable to almost certain further large increases in cost and possible fuel supply interruption. Furthermore, a decrease in U. S. oil consumption would help meet U. S. economic and national security objectives. In 1979, 39,000,000 barrels of oil (and the oil equivalent of gas temporarily made available to displace oil), or 0.6% of the total oil consumed in the U. S., was required for the generation of electricity utilized in the service area. However, oil is a primary electric energy strategy building block for the 1980's because it will in all probability be used to generate about half the electric energy generated by Con Edison in this decade even if the proposed plan is implemented.

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[2] This segmentation into fourteen areas is somewhat arbitrary. But this classification scheme provides a basis for analysis and is proposed primarily for that reason. Organization of planning factors and technical information within these fourteen areas is also somewhat arbitrary. Hence it is important to refer to the definitions in Exhibit 2.3.

[3] These key observations on most of the fourteen electric energy strategy building blocks are discussed in more detail elsewhere in this report. Those detailed discussions for building blocks which are primary to electricity energy strategy development in the 1980's are in Chapter Three. Discussions of building blocks not relevant at least until the 1990's may be found in Chapter Six.

Exhibit 2.3

DEFINITION OF ELECTRIC ENERGY STRATEGY BUILDING BLOCKS

OIL	Use of oil as a fuel to generate electricity.
COAL	Use of coal as a fuel to generate electricity. Alternative methods to handle and transport coal and to burn it in an environmentally acceptable way are also included.
COAL-OIL MIXTURES (COMs)	Use of coal and oil mixtures as fuel to generate electricity. Coal-oil mixtures are suspensions of finely crushed coal in oil. Typically these mixtures are made up of coal (30-50%), oil (65-45%), water (4.5%), and a stabilizing additive (0.5%), by weight.
NATURAL GAS	Use of natural gas as a fuel to generate electricity.
NUCLEAR	Use of nuclear processes to generate electricity.
REFUSE	Use of municipal solid waste or refuse derived fuel to generate electricity.
SYNTHETIC FUELS	Use of distantly-prepared liquid or gaseous fuel derived from coal, shale, oil, or other substances, to generate electricity.
COGENERATION	The simultaneous production of usable heat (often steam) and electricity for commercial purposes. Centralized cogeneration is that which is produced in large generating units. Decentralized cogeneration is that which is produced by various small facilities usually owned privately.
DEVELOPMENTAL CONVERSION	Use of new methods of energy conversion and combustion techniques which have improved thermal efficiency and environmental impact as compared to existing commercial technologies. These include new methods of energy conversion such as fuel cells, combined cycle systems and coal gasifiers as well as combustion techniques such as fluidized bed.

Exhibit 2.3 (continued)

RENEWABLE RESOURCES	Use of renewable resources--solar and wind--either directly or as fuels to generate electric power. The four major uses of renewable resources considered are solar hot water heating, solar space heating, plus wind turbine and photovoltaic electricity generation.
PUMPED HYDROELECTRIC	Use of a hydroelectric storage facility pumping water to a higher reservoir at night and on weekends when demand for electricity is low. During peak hours the water is released to generate electricity.
PURCHASED ENERGY	Energy that a utility supplies to its customers but does not generate itself.
LOAD MANAGEMENT TECHNIQUES	A heterogeneous group of techniques used to shift peak load from one time to another. They may involve either voluntary or involuntary action on the part of the consumer and as well may be direct or indirect. Currently available technologies are called conventional while those involving future technological development are called developmental. These developmental techniques may reduce total demand.
CONSERVATION	Tempering demand to reduce total use of electric energy.

Coal

The U. S. has abundant domestic coal reserves. Most of Con Edison's current oil-fired generating facilities were originally designed to burn coal, and most of these did so prior to the 1970's. Generally, reconversion of some of these facilities to coal, as planned, would provide the cost and oil reduction benefits of coal-firing more quickly and less expensively than building new coal-fired plants or converting existing plants that were not originally designed for burning coal.

Use of coal as a fuel is a primary electric energy strategy building block for the 1980's since coal conversion promises a larger potential for electricity cost savings and reduction in oil consumption than does any other operating decision Con Edison could make for the 1980's. Fuel costs are now the largest single controllable cost element in production of electricity.

Use of coal as a boiler fuel in these plants could have a greater detrimental effect on the physical environment than use of oil, natural gas, or nuclear. Coal is potentially the most polluting among these four fuels. Hence, obtaining permission to convert will depend partially upon actual and perceived effectiveness of the environmental protection controls employed. The available control options are electrostatic precipitators, bag houses, low sulfur coal, physically cleaned coal, flue gas desulfurization (FGD) equipment and environmentally acceptable coal, ash and sludge handling equipment. Con Edison's plan includes installation of precipitators with an operational efficiency of 99.6% while using 1% sulfur coal. This action will control particulate emissions well within regulated limits and impose no important operating difficulties. (The particulate emissions will be no more than such emissions using low sulfur fuel oil.)

Con Edison's plan includes the use of 1% sulfur coal to limit sulfur dioxide (SO_2) emissions. Implementation of this plan would cause SO_2 emissions to increase over current emissions with the burning of 0.3% sulfur oil. It may be deemed necessary either to use cleaned coal or install FGD equipment, or both to prevent this increase in SO_2 emissions. While effective in this regard, installation of FGD facilities would (1) increase conversion costs substantially, (2) reduce the availability of generating units, (3) cause some deratings, and (4) create a different pollutant. The current commercial FGD system, the wet scrubber, produces a wet sludge by-product. Proper disposal of this sludge, generated at in-city New York plant sites, would be necessary.

Other environmental issues related to coal conversion are less burdensome than the SO_2 air quality issue. Ambient NO_2

ground concentrations would be increased only slightly by coal conversion and would remain well under present standards. Noise and dust from coal-handling can be controlled through use of washed coal and/or through purchase of properly designed equipment. Proper disposal of solid wastes including fly ash, bottom ash and FGD wet sludge (if present) remains to be resolved, but appears capable of resolution. Waste water treatment presents no particular difficulty.

If coal conversions are made at Arthur Kill and Ravenswood, it is likely that coal transportation and handling will pose significant difficulties. The infrastructure which existed for moving coal about the city in the 1960's has debilitated during disuse, and it will be necessary to upgrade coal transportation and handling facilities within the city if reconversion is implemented. Specialized coal transportation and handling techniques will be required. Con Edison plans to keep its oil burning capability intact both in recognition of possible coal supply unreliability and to provide the capability to switch to low sulfur oil during air pollution control emergencies.

While Con Edison is focusing its efforts during the 1980's on conversion of existing power plants to coal, PASNY is proceeding with plans to construct a 700 MW plant, the energy from which will be used to supply the service area. This plant at Travis, on Staten Island, New York, is designed to burn coal or coal augmented by up to 20% refuse used as fuel. This proposed Travis plant, currently undergoing siting analysis and review, is scheduled for completion in 1987. The Travis plant has several attractive features from the standpoint of helping to meet Con Edison's electric energy goals. First, its primary fuel, coal, is attractive because its use reduces oil dependence and moderates cost increases. Second, since the proposed Travis plant may burn up to 20% refuse, it may provide a means for New York City to dispose of a small part of its solid wastes. Third, its impact on regulated emissions is expected to be negligible, since it is required to have FGD equipment.

The construction of the new plant at Travis would be subject to the New Source Performance Standard (NSPS) promulgated by the U.S.E.P.A. Compliance to existing standards will require installation of FGD equipment. The disposition of the Travis proposal is presently before the New York State Siting Commission which has the power under Article 8 of the Siting Law to override local laws, such as the New York City coal ban. If the commission does not choose to use this power, the burning of coal at Travis would require repeal of the ban. The State's implied coal ban would require a special limitation but this could probably be approved by both the state Department of Environmental Conservation and the U.S.E.P.A. because of the FGD equipment.

Coal-Oil Mixtures

Coal-oil mixtures (COMs) are suspensions of finely ground coal in oil. They are a way to introduce coal into a boiler designed for oil. They might be useful to Con Edison in a limited way. For example, if Con Edison wished to reduce oil usage at the Roseton and Bowline plants, which it owns jointly with other utilities, a conversion to COMs might be considered. However, these plants were never intended to burn coal and would require substantial modification to burn COMs. Other applications for COMs may offer potential.

There are uncertainties associated with COMs since they are untested as a large-scale commercial boiler fuel. The Japanese and, closer to home, New England Electric System and Florida Power and Light are each currently undertaking experiments with COMs in large-scale, sustained operations. Con Edison is monitoring these and other COM tests to establish the benefits, if any, which might be gained from the use of coal-oil mixtures for the New York City service area. Since most Con Edison boilers were designed initially to burn coal, COMs are a secondary electric energy strategy building block for the 1980's.

Natural Gas

The Powerplant and Industrial Fuel Use Act of 1978 prohibits the use of natural gas as a primary energy source in most Con Edison boilers. However, short-term exemptions from this prohibition were granted to Con Edison in 1979 as part of a national oil displacement program. In 1979, natural gas was 12% of the fuel used to generate electricity in the service area.

Continued renewal of the short-term exemption is uncertain. Therefore, Con Edison does not consider natural gas as a planning option for the 1980's. In the opinion of the MIT investigators, the present federal statute limiting natural gas usage by utilities will be modified to liberalize such use. This opinion is based on probable future major upward revisions in domestic gas reserve additions. It was the first of these upward revisions which precipitated the current exemption allowing the burning of gas.

Natural gas, if it continues to be available as a utility boiler fuel, is potentially attractive for several reasons. First, using gas instead of oil reduces oil usage. Second, the price Con Edison pays for boiler fuel gas is currently about half the price of oil. Gas prices are expected to be about 30% less expensive than oil during most of the 1980's, although they are expected to approximately equal oil prices by the end of the decade. On the other hand, gas prices are about 30% higher than coal prices currently. They are expected to rise more rapidly than coal prices throughout the 1980's, and, by the end of the decade, gas prices are expected to be about three times the level of coal prices. Third, many of Con Edison's oil-burning boilers can be gas-fired with no retrofitting. However, gas firing of Ravenswood 3 and Arthur Kill 2 and 3 (those units slated for coal conversion) would require boiler retrofits and, in the case of Arthur Kill, new gas transmission facilities. Fourth, burning gas in large utility boilers produces less pollution than does burning oil or coal. Fifth, natural gas could be selectively supplied to Con Edison or non-Con Edison sources in New York City to 'offset' the environmental effects of coal-burning by Con Edison. Sixth, natural gas could be supplied to private decentralized cogenerators if that use is deemed desirable. The issue of continued natural gas availability brings a large uncertainty to electricity supply planning in the 1980's. Natural gas is a primary electric energy strategy building block for the 1980's since it might displace significant amounts of oil throughout the period.

Nuclear

About 30% of the Con Edison service area electric energy is supplied by nuclear generation. Two plants presently provide almost all of this nuclear-generated electricity: Indian Point units 2 and 3. These plants have the lowest generation cost of any plants on the system, and using them reduces the service area's dependence on oil[4]. Furthermore, by avoiding the use of fossil fuels, these plants protect air quality. However, in the aftermath of the Three Mile Island incident, the Nuclear Regulatory Commission (NRC) is reassessing the safety of continued operation of these and certain other nuclear plants, particularly those in close proximity to large population centers. Thus, the possibility of an NRC-mandated shutdown of the Indian Point plant exists.

No nuclear plants are under construction by Con Edison. The construction of new nuclear plants is not considered in this study because the engineering, licensing and construction takes more than ten years. Con Edison may, however, be able to purchase some additional nuclear capacity from plants presently planned or under construction by other utilities. Continued use of the Indian Point units is therefore a primary building block for the 1980's since they are currently the only long term replacement for oil and would continue to displace oil as baseload plants regardless of coal utilization.

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[4] A full discussion of nuclear energy cost advantages may be found in reference number 88.

Refuse

If the generating unit which PASNY has proposed for construction at Travis, New York, is built, up to 20% of its fuel may be refuse. Furthermore, several other refuse-burning plants in the Con Edison service area are at various stages of planning for the 1980's. Among the most likely to be built are the Peekskill plant in Westchester County, the Brooklyn Naval Yard steam plant and plants proposed by the Port Authority of New York.

The overall costs of generating electricity with refuse are likely to be higher than the costs of using conventional fossil and nuclear fuels. Potentially significant environmental concerns have been expressed about refuse fuel preparation and combustion. The principal potential merit in burning refuse as a fuel is that it might help solve municipal waste disposal problems while producing electricity as a useful by-product. Con Edison's support of research into improved ways to use refuse as a fuel is appropriate. Refuse is a secondary, rather than primary, electric energy strategy building block for the 1980's since, considering its state of development as a boiler fuel, it cannot provide significant amounts of electricity regardless of price.

Synthetic Fuels

Synthetic fuels are not expected to be attractive as a boiler fuel for Con Edison for the 1980's. The availability of synthetic fuels in commercial quantities in the 1980's will be constrained severely by insufficient technological development. Further, synthetic fuels are expected to have relatively high prices. Because continued technological development is expected to make synthetic fuels more attractive, however, they are an electric energy strategy building block for the 1990's.

Cogeneration

Cogeneration is the production of usable heat (often steam) and electricity within the same generating cycle. If cogeneration is centralized, heat and electricity are produced in large utility-owned generating units. The electricity is then fed to the utility's electrical distribution grid, and the heat is transported via the utility's steam distribution system. By contrast, decentralized cogeneration describes a system for heat and electricity production which is usually owned and operated by the final consumer and is much smaller than a centralized unit. In theory, cogeneration provides a more efficient use of primary energy because of the increased efficiency inherent in joint production of electricity and usable heat. In practice this higher efficiency might provide economic advantage to decentralized cogeneration over centralized non cogeneration.

Decentralized cogeneration now appears attractive to certain large users of electricity and heat in the service area. Several privately-owned, decentralized cogeneration facilities have been constructed recently in Con Edison's service area. Increases in decentralized cogeneration are occurring for several reasons. First, private decentralized cogenerators are not required to pay certain taxes which Con Edison must pay or collect on its energy sales. Second, small cogenerating units are readily available on the commercial market and have proven to be attractive from an economic perspective in certain situations. The Public Utility Regulatory Policies Act (PURPA) has the potential for further improving the economics of thermal load following design in these decentralized installations by requiring Con Edison to buy electricity which the decentralized cogenerator may wish to sell.

The move toward private, decentralized cogeneration using diesel engines or gas turbines is a matter of concern to Con Edison. A part of Con Edison's concern stems from the NO_x emissions and low stack heights which are a feature of typical diesel-fired and gas turbine decentralized units. Also, to the extent that these installations are oil-fired, they could be counterproductive to the goal of reducing dependence on oil, notwithstanding their efficient use of primary energy. It is outside the scope of this study to assess Con Edison's position on private decentralized cogeneration.

Decentralized cogeneration is a secondary rather than a primary electric energy strategy building block for the 1980's because the trend toward using this technology is recent and not expected to have large impact during the 1980's, due in part to uncertainties in regulatory and economic incentives. If these uncertainties settle in favor of decentralized cogeneration, however, the amount of central generation load reduction induced could be significant in the 1990's.

Centralized cogeneration is a central element in Con Edison's steam system, since about 60% of the steam distributed is cogenerated. However, centralized steam cogeneration is not expected to be important for electricity planning in the 1980's for at least two reasons. First, the electricity currently cogenerated with steam is only about 2% of the dispatched electricity. Second, Con Edison is not planning to add new electric generating capacity. However, centralized cogeneration is an electric energy strategy building block for the 1990's since about half of Con Edison's steam system will be retired by 1995 and about 90% of it will be retired by 2000.

Developmental Conversion

Developmental conversion includes fuel cells, atmospheric and pressurized fluidized bed combustion, and combined cycle systems. From among these, only combined cycle systems, and possibly fuel cells, will be available for large-scale use in the 1980's. However, such systems are unattractive from an economic point of view for the 1980's assuming that Con Edison undertakes its proposed coal conversion. Con Edison may consider one or several of the developmental conversion technologies for new plants that it brings on-line after 1990 because of their higher thermal efficiencies, lower emissions or both. Consequently, developmental conversion provides an electric energy strategy building block for the 1990's.

Renewable Resources

Renewable resources will have little impact on Con Edison during the 1980's because of insufficient technological development and/or lack of suitablility to Con Edison's densely populated service area. However, renewable resources are an electric energy strategy building block for the 1990's since further developments in the 1980's are expected to make certain renewable technologies applicable then, particularly in those parts of the service area with the lowest population density. Nevertheless, the contribution toward meeting electric energy requirements from renewable resources in the service area even in the 1990's is expected to be small.

Pumped Hydroelectric

Pumped hydroelectric facilities which store energy generated at off peak periods are attractive in two circumstances. One such circumstance exists if a utility needs additional peaking capacity, since these facilities often have lower total capital costs than other sources of peaking energy. The other circumstance exists if there is wide variation in costs among various energy sources. In this situation they may help reduce costs by replacing generation during the daytime with less expensive generation at night. However, in general they return only three units of energy for each four put in and therefore may not be attractive in a particular system application.

Pumped hydroelectric could have some impact in the 1980's since PASNY plans to build a pumped storage system at Prattsville to serve the Con Edison service area. This facility has a projected in-service date of 1987, so has no possible impact until late in this decade. Consequently, pumped hydroelectric is only a secondary building block for the 1980's.

Purchased Energy

Con Edison plans to purchase approximately 68.8 billion kWh of electric energy during 1980-1995. This amount is larger than in the past. Purchasing energy reduces oil usage and air pollution directly, to the extent that it is generated either by hydroelectric or nuclear facilities. The potential for purchasing electric energy, particularly from Hydro Quebec, has recently increased sharply. In the opinion of the MIT investigators, there is a potential to purchase additional energy beyond that now planned on the order of 20-30 billion kWh over the next 15 years. However, transmission system improvements would probably be required at some additional capital cost. Since this purchased energy is presently priced below but near the cost of energy it replaces, more detailed analysis than is provided in this investigation would be necessary to determine the economic desirability of such transmission system improvements. Also, there could be a negative impact on system reliability which has not been assessed. However, the potential for sharply increasing purchases of energy is intriguing. Con Edison may want to consider major strengthening of the transmission network to make significantly larger purchases possible.

In any case, purchased energy is a primary electric energy strategy building block for the 1980's for at least three reasons. First, significant amounts of energy are available at a price that is likely to be less expensive than Con Edison's own energy. Second, using purchased energy helps reduce oil dependence since most such purchased energy is generated without the use of oil. Third, purchased energy has a positive impact on air pollution to the extent that it is hydroelectric and nuclear and does so for New York City regardless of its source.

Load Management Techniques

Conventional load management techniques do not offer significant potential in terms of Con Edison electric energy strategy objectives in the 1980's for two reasons. First, Con Edison's reserve generating capacity is more than sufficient to meet expected peak demand. Second, many conventional load management techniques are not useful to Con Edison because they are designed for use in areas which, unlike the service area, have individual consumers who use a large amount of power. While continued application of load management techniques currently used in the service area is appropriate, conventional load management techniques are at best a secondary electric energy strategy building block for the 1980's.

Developmental load management techniques are an electric energy strategy building block for the 1990's, however, since presently developmental load management techniques with a wide range of applications in the Con Edison service area are likely to be available commercially in the next decade. These include commercial applications of concepts such as spot pricing of electricity, microshedding of electric load and decentralized system dynamic control.

Conservation

Con Edison was one of the first U. S. electric utilities to support and implement conservation programs. Its "Save A Watt" program was begun in 1971, two years before the Arab oil embargo. Conservation has a positive impact on all three electric energy strategy objectives of Con Edison. This is so because, by lowering demand, it reduces total costs of electricity, oil consumption and environmental pollution. Conservation is a primary electric energy strategy building block for the 1980's. However, its potential specific benefits and costs are difficult to quantify.

The rate of electricity load growth in the Con Edison service area fell from its long term historical level of about 4.5% per year to -0.8% per year from 1973-1979. This large decrease was caused mainly by increased conservation and to a lesser extent by a lower level of local economic activity. The rapid increases in electricity prices during 1973-1979 were partially responsible for the conservation. However, Con Edison's conservation programs no doubt further stimulated and facilitated this decrease in demand.

The electric load growth during 1980-1995 will depend on price of electricity, the effectiveness of further conservation efforts and the level of local economic activity. The result of these effects is impossible to forecast with precision. Con Edison and PASNY project an annual load growth of 1.0% in the service area from 1980-1995. This projection takes into account several new conservation programs being readied for implementation over the next several years as well as further increases in electricity prices.

There exists substantial additional potential for conservation in the United States in general and this service area in particular. Con Edison plans programs to further develop this potential. More active programs by Con Edison are possible involving capital investment. Modifications in existing regulations would be required for Con Edison to be able to participate in certain of these conservation programs.
However, examples are being seen in certain other states.

To summarize, in MIT's opinion only six of these electric energy strategy building blocks could have a major impact on Con Edison's electric energy goals in the 1980's. Specifically, oil, nuclear, natural gas, coal, purchased energy, and conservation are the primary constituents of electric energy strategy development in the 1980's for Con Edison. (See Exhibit 2.4.) Four other strategy building blocks, pumped hydroelectric, decentralized cogeneration, refuse, and coal-oil mixtures can have at most only a secondary role to play in meeting Con Edison's electric energy strategy goals for the 1980's. Conventional load management techniques may also have a secondary importance for the 1980's. The remaining building blocks, while potentially important in longer-range planning, are irrelevant to operations in the 1980's because they will either not be commercially developed in time, or are not well suited to Con Edison's service area, or both. These are synthetic fuels, renewable resources, developmental conversion, and developmental load management techniques. Centralized cogeneration may also be a building block for the 1990's, but is a major feature of overall steam energy strategy rather than electric energy strategy.

A moment of reflection on Exhibit 2.4 confirms that Con Edison is severely constrained in oil replacement possibilities for the 1980's. Barring large scale access to natural gas, only three options remain: coal, purchased energy, and conservation. Further, natural gas and purchased energy offer little in the way of moderation of cost increases, although they might, together, replace a significant portion of the oil. Conservation, while attractive, probably cannot replace a significant portion of the oil. The next chapter looks in detail at each primary option.

Exhibit 2.4

CLASSIFICATION OF ELECTRIC ENERGY STRATEGY BUILDING BLOCKS

<u>Primary Electric Energy Strategy Building Blocks for the 1980's:</u>

Oil
Coal
Natural gas
Nuclear
Purchased energy
Conservation

<u>Secondary Electric Energy Strategy Building Blocks for the 1980's:</u>

Pumped hydroelectric
Coal-oil mixtures
Decentralized cogeneration
Refuse
Conventional load management techniques

<u>Electric Energy Strategy Building Blocks for the 1990's:</u>

Developmental load management techniques
Synthetic fuels
Developmental conversion
Renewable resources
Centralized cogeneration

Chapter Three

PRIMARY ELECTRIC ENERGY STRATEGY BUILDING BLOCKS FOR THE 1980's

Oil

In 1979 oil constituted about 44%[1] of the Con Edison service area fuel mix and will continue to be an important fuel throughout the 1980's. In January 1980, the price of oil as delivered to Con Edison was more than double the price of coal and natural gas. During 1980-1995, the oil price is expected to increase at a faster rate than the price of coal, making the 1995 oil price three to four times larger than the 1995 coal price.

Due to political instability in oil-exporting nations, the supply of oil became uncertain during the 1970's. Because political instability is expected to continue in nations which belong to the Organization of Petroleum Exporting Countries (OPEC), the supply of oil is expected to remain uncertain in the future. In response to this instability a decrease in U. S. oil imports has become an objective of the U. S. government. While the U. S. government has yet to adopt a specific policy for reduction of oil imports, it's likely that governmental action, when and if taken, will strongly affect Con Edison. For example, in late 1979 the Carter Administration proposed legislation to Congress that would require electric utilities to reduce their 1979 usage of oil in boilers for the generation of electric power by 50% by 1990.

Given the political instability expected to prevail in the Middle East and the expected relative tightness in the oil market, real oil prices are expected to increase during 1980-1995. They are not expected to increase as fast as they did in the 1970's for several reasons. First, OPEC oil prices in 1980 are closer to prices of possible OPEC oil substitutes than they were in 1970. Second, additional oil price increases could lead to major economic recessions in the economies of OPEC's major customers; thus it is to OPEC's advantage to use restraint in administering future price increases. Third, it is likely that some conservative OPEC countries will try to block large oil price increases as a political concession to the West. Most probably, oil prices will increase at an annual rate of about 3-5% in real terms during 1980-1995. As a matter of comparison, OPEC oil prices increased at an annual average real rate of about 20% per year from 1970-1980 and about 5% from 1974-1980. These

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[1] This number would be 56% if natural gas were not being temporarily supplied to displace oil.

views about future oil prices and oil availability are further discussed below.[2]

Supply Instability

OPEC controls about 90% of the oil traded worldwide, excluding oil from centrally planned economies. There is deep-rooted political instability within each OPEC country as well as in the interactions among OPEC members. Six OPEC members are located in the Middle East, four in Africa, two in Latin America, and one in Southeast Asia. All of these areas have been politically unstable, often characterized by civil wars, coup d'etats, or interregional conflicts. The appearance of a radical leader in one of the conservative Arab monarchies or a repeat of the 1979 Iranian experience in another OPEC country are likely events during 1980-1995. The occurence of such an event or of a new Middle Eastern regional conflict could lead to a drastic reduction of the OPEC oil exports--and consequently of the U. S. oil imports--during 1980-1995.

The Arab radicals--represented by Libya, Algeria, and Iraq--represent a different political alignment than the conservative monarchies of the Persian Gulf--Saudi Arabia, Kuwait, United Arab Emirates, and Qatar. The two groups have major differences on issues such as oil policy and the Arab-Israeli war. Territorial disputes are common in the Gulf, since most states there were created from an area that once all belonged to the Ottoman Empire. For example, Iraq has territorial disputes with both Iran and Kuwait. Recently, Iran occupied an island in the Gulf. In September, 1980, Iran and Iraq began a military conflict. This war was still being waged during final production stages of this report. Lybia has frequent territorial disputes with Egypt.

Since all Gulf Region states are Islamic, the current revival of Islam in Iran threatens sitting governments. While such a revolution is difficult to predict, the events following seizure of the U. S. embassy in Iran suggest that potential for other revolutions remains high.

Soviet influence in the area has increased recently. In 1978 a pro-Soviet government was established in Afghanistan, and Soviet troops were transferred there in late 1979. In addition,

[2] There are many standard references for discussions of oil supply instability and oil price forecasts. They generally support the views summarized above as well as the objective of Con Edison to reduce imported oil dependence during the 1980's. See reference numbers 5, 8 and 9. The discussion which follows here is based directly on reference number 113.

the Soviet Union keeps close ties with Syria, Iraq, and South Yemen. The latter has been a major threat to Saudi Arabia since it has had several conflicts with North Yemen--the most recent being a border war in 1979. Two presidents and one prime minister of North Yemen have been assassinated during the last few years. In 1978 South Yemen helped Ethiopia in its war against Somalia. Soviet troops, as advisors in Ethiopia, South Yemen, Iraq, Syria, and Afghanistan, have created a ring around the most prolific of oil fields of the world. At the same time, the Iranian revolution has substantially decreased U. S. influence in the area.

Half of OPEC's exports (about one-fourth of the world's oil supplies) are carried in tankers passing at the rate of one tanker about every twelve minutes through the narrow Strait of Hormuz. There have been several reports, most recently during the summer of 1979, that Palestinian terrorists would attempt to block the Straits by sinking a tanker. Such an action would have dramatic consequences to non-Communist nations. International insurance companies (such as Lloyds of London) have declared the Gulf a war region for tanker insurance.

The Arab-Israeli conflict has been a major source of friction and instability in the Middle East. There have been four wars in recent years between the Arabs and the Israelis, and all four have had an impact on the international oil market. The 1948 war led to the closing of the Iraqi pipeline in Haifa. The 1956 war led to a short-term closing of the Suez canal. The 1967 war led again to the closing of the Suez canal--this time for seven years. Finally, the 1973 war led to the oil embargo and the quadrupling of oil prices. In the first three cases, the impact on the world oil market was marginal; in the fourth case the impact was major. Eight of the OPEC members are involved in one way or another with the Arab-Israeli conflict. These are the seven Arab states (Saudi Arabia, Iraq, Kuwait, UAE, Qatar, Libya, and Algeria) and Iran. They represent about 85% of OPEC oil production and 92% of OPEC proven reserves. All these countries have made statements about using oil as a weapon to obtain Western political concessions on the Arab-Israeli conflict.

Oil Market Conditions

In the 1970's prices of internationally traded oil increased by 1700% in nominal terms, after having declined in the 1950's and remaining relatively stable in the 1960's. The 1970 oil price breakthrough of Libya, the 400% nominal oil price increases in 1973, and the 100% nominal oil price increases in 1979 were the three major oil price increases during the 1970's.

Despite these large oil price increases, the next 15 years' demand for OPEC oil is not expected to decrease below current levels. This is because oil-importing countries will probably be unable to significantly expand their use of domestic energy due to lack of natural resources and/or necessarily long lead time.

Further, the economies of several OPEC countries have small economic absorptive capacity. The recent oil price increases have made the annual oil revenues of these countries much larger than the revenues needed for their internal economic development. Hence, these countries could significantly reduce their oil production and still be able to satisfy their economic development needs. This ability to reduce their oil production at no real cost enables these countries to keep oil prices from falling, even if the demand for OPEC oil does decrease somewhat.

Coal

Given the current price differential between coal and oil, there is a strong economic incentive for a shift back to the use of coal in the Con Edison service area as well as many other places in the U.S. economy. The 1980 estimated price for coal delivered to New York City was approximately $2/MMBtu. The low sulfur fuel oil burned in Con Edison's in-city plants during 1980 cost approximately $5/MMBtu. This large price differential will in all probability grow even larger in the future. Certainly future rates of price escalation for coal and oil are somewhat uncertain. However, many sources forecast that the price of coal will escalate at a real average annual rate between 0-2%, while oil prices move up at a rate between 3-5% during the 1980-1995 period. The use of coal in the Con Edison service area would be consistent with the national goal to reduce imports of oil. Furthermore, the U. S. has large coal reserves; thus Con Edison would depend more on a politically stable fuel supply. The potential fuel cost savings from burning coal would quickly and directly be passed on to consumers via the fuel adjustment clause in the New York State Public Service Commission (PSC) billing procedure. Thus, consumers have the largest stake in the economic benefits derivable from the use of coal in the Con Edison service area.

Primary Conditions for Coal Conversion

Much of Con Edison's current total generating capacity was originally designed to burn coal and did so prior to the 1970's. Expected load growth and current reserve capacity combine to argue against new plant construction during the 1980's. Returning to the use of coal as a boiler fuel in the service area means reconverting some of these once coal-burning units, rather than more costly conversion of existing plants not originally designed to burn coal or construction of new coal-fired plants.

Based on the analysis below, the Ravenswood, Arthur Kill, and Astoria plants are the most attractive candidates for coal reconversions within the Con Edison generating system. Given the current local air quality and the lower stack heights (due to proximity to LaGuardia Airport) at Astoria, the environmental acceptability of coal conversion at Astoria is limited. Also, Astoria units 1 and 2 have smaller capacity and shorter remaining life than the other units[3]. Because of these factors, it is reasonable to exclude Astoria units 1 and 2 from primary consideration for reconversion.

The boiler shutdown time anticipated to perform the necessary modifications at each of the primary candidate plants is roughly equivalent, about five months[4]. However, lead times for engineering design, regulatory analysis and review, and procurement of major capital equipment are significant. Given the fact that Con Edison is at present actively pursuing coal conversions at Ravenswood 3 and Arthur Kill 2 and 3, these plants could be converted much sooner than the remaining primary candidate plants. Con Edison indicates that the lead time for conversion of Ravenswood units 1 and 2 and Astoria units 3, 4 and 5 is four and a half years,[5] while under an expedited implementation schedule (i.e., prompt government approvals), conversion of Ravenswood unit 3 and Arthur Kill units 3 and 2 can be accomplished as proposed in approximately one, two, and three years, respectively.[6]

Exhibit 3.1 summarizes various factors important in determining the technical and economic feasibility of converting existing oil-fired generating units to coal. As explained below, the degree of modification necessary to resume coal burning at existing Con Edison plants is lowest at Astoria, Ravenswood, and Arthur Kill. The preliminary estimates of conversion costs for these plants are therefore lower than for the remaining plants. The remaining generating units can be grouped into two general categories: relatively older, smaller units originally designed to burn coal, and located in or near Manhattan; and larger, newer units originally designed to burn oil, and located outside New York City.

The first of these two groups of plants includes East River, Waterside, Hudson Avenue, 74th Street, and 59th Street. These plants are located on small sites in highly developed areas.

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[3] Reference number 92.

[4] Reference number 32.

[5] Reference number 32.

[6] Reference number 12.

Exhibit 3.1

FACTORS AFFECTING COAL CONVERSION OF STEAM-ELECTRIC BASE LOAD UNITS CURRENTLY BURNING OIL[1]

Generating Station	Capacity (MW)	Service Date	Designed for Coal-Burning[2]	Relative Degree of Modification Necessary[3]	Preliminary Estimates of Conversion Cost (Millions)[4]
Astoria #1	146	1953	Yes	Moderate to High	$ 10
Astoria #2[5]	161	1954	Yes	Moderate to High	$ 10
Astoria #3[5]	367	1958	Yes	Moderate to High	$ 21
Astoria #4[5]	379	1961	Yes	Moderate to High	$ 21
Astoria #5[5]	359	1962	Yes	Moderate to High	$ 21
Ravenswood #1[5]	385	1963	Yes	Moderate	$ 43
Ravenswood #2[5]	385	1963	Yes	Moderate	$ 43
Ravenswood #3[6]	928	1965	Yes	Low	$ 7
Arthur Kill #2[6]	335	1959	Yes	Moderate	$ 25
Arthur Kill #3[6]	491	1969	Yes	Moderate	$ 27
East River #5	130	1951	Yes	High	$ 92
East River #6	125	1951	Yes	High	$ 92
East River #7	166	1955	Yes	High	$ 92
Waterside	325	1949	Yes	High	$125
Hudson Avenue	419	1932-51	Yes	High	$182
74th Street	159	1956-62	Yes	High	$ 31
59th Street	110	1952-68	Yes	High	$ 23
Bowline Point #1	601	1972	No	High	$750+
Bowline Point #2	601	1974	No	High	
Roseton #1	660	1974	No	High	$770
Roseton #2	660	1974	No	High	

Footnotes on the following page.

Exhibit 3.1
(continued)

Footnotes:

[1] Adapted from Staff Report Recommending the Conversion of Selected Oil Fueled Power Plants to Coal, New York State Department of Public Service, Appendix D, Albany, NY, July 17, 1979.

[2] Per Coal Conversion Testimony of William A. Harkins on behalf of the New York Power Pool member committees before the New York State Planning Board, September 5, 1979.

[3] Involves consideration of coal and ash handling equipment, boiler modification, and precipitators necessary to convert to coal.

[4] Excludes cost of sulfur control. It should be noted that these are preliminary estimates and should only be used to distinguish relative conversion costs of various plants. Updated estimates were used for scenario analysis (Chapters Four and Five).

[5] Designated Priority II Plants by the New York State Department of Public Service; plants recommended for further study prior to coal conversion.

[6] Designated Priority I Plants by the New York State Department of Public Service; plants recommended for immediate coal conversion.

Therefore, there is inadequate space for conventional coal handling equipment, coal storage, and some forms of air pollution control equipment. In addition to these logistical constraints, the relatively small size and short remaining life of these units further reduces the desirability of conversion to coal.

The second group of plants includes Roseton and Bowline Point. These plants, completed in the early 1970's, have large units designed to burn only oil. A detailed engineering study would be required to determine the feasibility of converting these units to coal. It is not clear that these plants can physically be converted to coal at all; and even if conversion is physically feasible, the costs are likely to approach new plant costs. In addition, derating on the order of 40-60% of original design output could be expected[7]. There is only one known successful case of such a conversion: the Kwinana Power Station in Western Australia. This coal conversion required derating from 200 MW to 120 MW, and costs were approximately $300/kW (1980 dollars).

It should be noted that the economic incentive for converting Bowline Point and Roseton to coal would be somewhat reduced if higher sulfur content, lower-priced oil were burned. Similarly, if other plants are converted to coal prior to converting Bowline and Roseton, the capacity factor of the oil-fired Bowline Point and Roseton units will fall, thereby further reducing the economic incentives for converting these plants.

A comparison of the conversion cost assumptions for the primary candidate plants is presented in Exhibit 3.2. The relatively high cost of converting Ravenswood units 1 and 2 is readily apparent. This results from the fact that, although these units were originally sized for coal burning, coal was never actually burned. Therefore, all the ancillary equipment (i.e., coal handling, preparation, and storage equipment, ash handling equipment, and air pollution control equipment) was never installed. The relatively low cost of converting Ravenswood unit 3 results primarily from the fact that only minor modification to electrostatic precipitators and fly ash and bottom ash systems is required, while major modification or replacement of these facilities is required at Arthur Kill and Astoria.

Several previous studies and certain regulatory actions have addressed the subject of the proposed coal reconversions. In 1976-1977 Con Edison undertook a comprehensive study to assess the capital costs of reconverting its boilers to coal (approximately 5300 MW of Con Edison's current total generating capacity of 11,000 MW was originally designed to burn coal). As

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[7] Reference number 60.

Exhibit 3.2

CONVERSION COST ASSUMPTIONS FOR
PRIMARY CANDIDATE PLANTS
(In Millions of 1980 Dollars)

Station	Conversion Cost Assumptions (without FGD)	FGD Equipment Cost Assumptions
Ravenswood:		
1 & 2	$ 220[1]	$ 154[3]
3	27	185[3]
Arthur Kill:		
2 & 3	136	171
Astoria:		
3, 4 & 5	150[2]	186[4]

[1] Updated estimate as of February 1981 is $167.

[2] Updated estimate as of February 1981 is $180.

[3] These figures do not include the potentially necessary costs of purchasing more space for FGD installation.

[4] Updated estimate as of February 1981 is $227.

a result of this study, Arthur Kill units 2 and 3 and Ravenswood unit 3 (about 1700 MW) were targeted for conversion to coal considering such factors as remaining useful life, plant efficiency, capital costs of conversion, the degree of technical and engineering problems involved, and environmental standards. As a result of a statewide study in 1979, the New York Department of Public Service also recommended the conversion of these units while pointing out that significant environmental constraints exist. This study also recommended that conversion of Ravenswood units 1 and 2 and Astoria units 3, 4 and 5 be further evaluated, but that the remainder of Con Edison's coal-capable plants should not undergo conversion to coal. The 1979 New York State Energy Office Master Plan also recommended conversion of Arthur Kill units 2 and 3 and Ravenswood unit 3.

To assist individual utilities in the northeastern U.S. in their coal conversion plans, the DOE is currently coordinating the completion of a regional environmental impact statement to evaluate the cumulative impact of widespread coal conversion. Further, the DOE has been instrumental in advocating coal conversion subsidies. Although legislation has not yet been passed, a recent Senate coal conversion bill provides $3.6 billion in federal loans and grants to pay up to 75% of conversion costs for 80 power plants at 38 utilities. Con Edison's Arthur Kill units 2 and 3 and Ravenswood unit 3 are named in the bill.

Environmental Control

There are two ways to mitigate the potential SO_2 air quality problem: (1) use of coal cleaned to a lower sulfur content than 1%, and (2) flue gas desulfurization (FGD). Various combinations of these two alternatives are also a possibility. If it becomes necessary for Con Edison to further limit SO_2 emissions, the economic and environmental tradeoffs of the various control alternatives will need to be evaluated carefully. Based on a preliminary and mostly generic analysis (see Appendix D) the following general observations can be made about the alternative SO_2 control technologies: (1) If coal is to be cleaned, only physical coal cleaning, which is effective only in removal of inorganic sulfur, is commercially available for the units slated for reconversion. This method has sulfur removal capabilities ranging from approximately 10% for 1% sulfur coal to 40% for higher sulfur content coal. (2) Nonregenerative, wet scrubbers are the predominant technology in operation in the U.S. at this time. Among the various such processes lime/limestone wet slurry scrubbing processes are the dominant systems. These processes are commercially available, but require several years for design, engineering, construction and start-up. Of the wet systems, lime/limestone processes appear to have the lowest capital and operating costs. (3) Although several regenerable wet processes are in bench and pilot scale operation, only the Wellman-Lord and magnesia slurry processes are commercially available. These systems at present appear to require higher capital investment due to the regeneration process. However, operating costs might be offset somewhat should a market value of by-products materialize. (4) The spray dryer/fabric filter FGD process has recently moved from pilot scale to commercial operation. This dry partially regenerative FGD process has both lower capital and operating costs compared with wet processes. (5) FGD systems have certain negative impacts including: boiler derating of up to 5%, solid and liquid wastes requiring proper disposal, and additional land and water.

If FGD equipment is required as a condition for Con Edison's coal conversions, there would be various impacts. Exhibit 3.3 presents the additional capital cost estimates for the installation of FGD at the primary candidate plants and estimated lead time necessary to design and install such equipment. As can be seen, the additional capital costs and project delays are significant. In addition, delays imply decreased fuel cost savings for the consumer, since virtually all fuel savings are passed on directly to consumers via the fuel adjustment clause.

The installation of FGD equipment also entails additional costs in terms of reduced energy conversion efficiency and reliability of the units. Con Edison estimates a 4% reduction in conversion efficiency, a 2% increase in the rate of forced shutdown, and a 3% increase in planned shutdown for maintenance. The FGD equipment also leads to increased operation and maintenance costs, a significant component of which is the stabilization and disposal of fly ash and "scrubber sludge".

It should, however, be noted that the installation of FGD equipment could potentially increase the amount of coal conversion that could be done. For example, it is likely that conversion of Astoria units 3, 4 and 5 without FGD would lead to contravention of the ambient air quality standards for sulfur dioxide. The use of FGD equipment would not affect the background air quality in New York City. However, in general, its use would reduce the incremental air quality impact of coal conversion very substantially. By largely preventing further environmental deterioration, installation of FGD equipment would generally improve the environmental acceptability of utilizing coal within the Con Edison system.

Various studies indicate the possible economic advantage of physical coal cleaning followed by FGD when compared to using FGD alone[8]. For existing plants (i.e., retrofit FGD systems), study assessments indicate a 13% to 14% capital and operating cost savings for combined coal cleaning and FGD relative to FGD alone. The use of cleaned coal has other advantages, including reduced bulk and, therefore, cost in coal transportation;

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[8] Reference numbers 73 and 138.

Exhibit 3.3

ADDITIONAL CAPITAL COST AND LEAD TIME ESTIMATES FOR FGD[1]

Unit	Additional Capital Cost of FGD (Millions of 1980 Dollars)	Conversion Period with FGD (Years)	Conversion Delay Created by FGD Installation (Years)
Ravenswood 3[2]	$185	5[3]	3 1/2
Arthur Kill 2 & 3[2]	$171	4 1/2	2 and 1, Respectively
Ravenswood 1 & 2	$154	5[3]	
Astoria 3, 4, & 5	$186[4]	5	

1 Based on Con Edison Internal Memorandum from Herman C. Bremer to Andrew M. Vesey, May 5, 1980.

2 Ravenswood 3 in 1981, Arthur Kill 2 & 3 in 1982 and 1983, respectively.

3 Does not include the potentially necessary costs of purchasing more space for FGD installation.

4 Updated estimate as of February, 1981, is 227.

decreased fly ash loading in electrostatic precipitators; and a reduced production rate of FGD sludge. Such combined sulfur control systems will need to be evaluated if FGD is required for Con Edison's coal conversions.

The use of dry scrubbing technology, which will be available in the mid-1980's, may have economic and technical advantages relative to wet scrubbing. Advantages include simplicity in engineering design, avoidance of handling high moisture content waste products, and reduced necessity for flue gas reheating. However, removal efficiencies limit the applicability of dry scrubbing technology to low sulfur content coal.

Solid wastes from coal-fired utility plants are primarily identified as fly ash, bottom ash, and FGD sludge. Fly ash is texturally classified as a 'sandy silt' and is primarily composed of glassy spheres. Bottom ash is considerably coarser and would be classified as a 'sandy gravel'. Fly and bottom ash have comparable chemical characteristics, although bottom ash has a higher percentage of nearly insoluble components. The physical and chemical characteristics are widely variable depending upon the coal source, burning process, and ash handling system. Special handling is needed for fly ash transportation and deposition due to its ability to generate dust when dry or to become slippery when wet. Up to 7% of fly ash can be water soluble; therefore, the presence of water can cause fly ash to leach in various concentrations, dependent upon ash compaction, chemical composition and the rate of water infiltration. FGD sludges are composed primarily of calcium salts with varying quantities of fly ash and calcium carbonate. Leaching can also develop from the infiltration of water into FGD sludge.

Con Edison projects that approximately 150 acres, filled to a depth of 60 feet, will be needed over the next 25 years to accommodate the solid wastes expected to be generated from coal firing. The current site near Arthur Kill is not considered adequate for a long-term disposal operation. Means for proper disposal of scrubber sludge by landfill stabilization has not been satisfactorily resolved, in the opinion of Con Edison.

Present long-term ash disposal alternatives include:

(1) sanitary landfill;

(2) ocean disposal;

(3) ash utilization;

(4) barging or railshipping to coal source.

Disposal by sanitary landfilling is the most common present technique. However, in the northeastern U. S. great difficulty in establishing new landfill sites has been experienced due primarily to potential adverse environmental impacts, adverse public reaction from host communities, land availability and value, and circuitous and unsuitable transporation routes. The 'land reclamation' approach, with proper environmental safeguards coupled with an intensive public education and participation, appears to be the most suitable manner in which to establish landfills.

Ocean disposal of ash as a viable disposal alternative depends on the result of existing and future ocean dumping experiments and analysis. The advantages include ease of disposal, negligible commitment of land, and no potential impact on land and ground water resources. However, a potential disadvantage is the impact on marine resources that have not been established in the selected area, as of 1980.

Ash utilization is the subject of interest and efforts by many utilities, researchers, and utility trade organizations. The safe and productive utilization of coal ash waste has economic and environmental benefits as well as easing the difficult problems of land or ocean disposal. It is probable that ash products and the market will improve with increased activity in the field of ash utilization, especially as construction material costs increase and earth resources decrease. In any event, it is increasingly apparent that the supply of ash will exceed the demand, and other disposal techniques must be anticipated.

Barging or railshipping of coal ash back to the source is a disposal option that will require considerably more analysis in the future. The concept involves loading empty coal barges with ash and returning the ash to the pits or mines to fill the voids created by coal extraction. The advantages of returning ash to the coal source include land reclamation at the source and negligible commitment of land for sanitary landfilling in the power plant area. A considerable amount of effort is needed to determine the economics of the concept, especially as it pertains to a handling and transportation system that is currently geared for the one-way flow of coal. In addition, the acceptability of the ash at the host state and community is a significant issue.

In conclusion it is apparent that all present methods for the safe and economic disposal of coal ash waste present significant difficulties requiring a concerted effort to develop a viable disposal option. It is apparent that the long-term disposal problem may be solved by a combination of the techniques over a long period of time.

Coal-fired power plants have more sources of outdoor noise than oil- and gas-fired plants. In 1980 Con Edison contracted with Stone & Webster Engineering Corporation to conduct a detailed study of noise emissions from various types of coal-handling equipment. Based on this work as well as related studies, noise impacts of coal usage at Ravenswood and Arthur Kill plants have been estimated. For both plants, it was found that appropriate equipment and feasible noise mitigation approaches currently exist to allow the conversion to coal without causing significant noise impacts.

Coal Transportation and Handling

Aside from the stack, the only significant sources of air pollutant emissions associated with the use of coal are particulates which escape from coal transportation vehicles, storage piles, conveyor belts, transfer points and loading/unloading operations. The mechanisms for containing and preventing release of these particulates are well established. Washing coal to clean it and remove some sulfur is becoming a widely used practice. Washed coal produces considerably fewer emissions than unwashed coal and merits consideration.

Con Edison can be expected to have little difficulty in suitably controlling fugitive coal dust emissions. Aesthetically, the coal dust emissions will be orders of magnitude less than those experienced when these boilers were coal-fired in the 1960's. Fugitive coal dust control at non-Con Edison transshipment points can be expected to be more difficult because of the age of the existing facilities.

Although Con Edison's planned coal sulfur content of 1% limits the coal source region, sufficient coal of this quality appears to be available in central and southern West Virginia, western Virginia, eastern Kentucky and Tennessee, and western Pennsylvania. Furthermore, the number of different mine operators in these areas ensures effective competition in the coal mining industry. However, competition in the transportation of coal by railroads is significantly less than competition in the mining of coal. Because coal is competing with much higher priced oil, railroad companies have leeway to raise coal hauling rates without reducing coal demand. The strong lobbying efforts of some utilities--not including Con Edison--against recent Congressional efforts to deregulate the railroad industry indicate the utilities' high degree of concern with this situation.

Although the transportation and distribution of coal would be more complicated than for oil, numerous coal transportation and distribution alternatives exist. Rail and rail-vessel systems are the most likely alternatives for the transportation of coal to, and distribution within, New York City. Distribution of coal within New York City might also be accomplished utilizing a rail-conveyor system or, if economically viable, by using a slurry pipeline. In addition, maintaining an ability to receive imported coal from ocean-going vessels would be advantageous in terms of providing added flexibility for coal purchases.

Three major coal-origin railroads (B&O, C&O, and N&W) can provide direct service to rail/marine transfer points in the Norfolk or Baltimore area, and the Conrail system can ship directly to the New York City area. Given the fact that none of these lines appear to hold significant advantage, simultaneous negotiation with the four companies should result in reasonably competitive rates. Other carriers, including BC&G, SC&M, SIRC, WM, L&N, and SRS may also participate through interline movements.

A study commissioned by Con Edison evaluated various alternative transportation systems[9]. The first set of alternatives involves the delivery of all coal directly to Arthur Kill where a stockpile is maintained. Movement of coal to Arthur Kill is accomplished by direct rail transport, by rail delivery to a tidewater port in Virginia or Maryland and subsequent transfer by coastal vessels, or by maintaining dual capability for all rail and rail/coastal vessel transport to Arthur Kill. Ravenswood is served by intraharbor vessel from Arthur Kill. Under these alternatives, Con Edison maintains maximum control of the coal stockpile and trans-shipping operations.

The second set of alternatives evaluated involves the use of a transfer station and stockpile elsewhere in New York Harbor (e.g., Port Reading). Coal is transferred from the New York Harbor transfer station to Ravenswood via intraharbor vessel. Coal transfer to Arthur Kill is accomplished by direct rail service or rail/coastal vessel alternatives.

The railroad system for transporting coal directly to the New York area or to a tidewater port in Maryland or Virginia is generally available to meet Con Edison's January 1981 schedule. Vessels for coastwise shipment of coal from the south may not be available to meet the January 1981 schedule, but such vessels could be constructed within a period of 16-20 months from the time an order is placed. Marine equipment for intraharbor service can probably be located by January 1981 for use on an interim basis until more suitable equipment can be constructed.

Economic evaluation of the various alternative transportation systems discussed above indicate they are all of potential interest. Delivered coal cost estimates range from approximately $42 to $57 per ton, with transportation charges amounting to $8-$17 (1980 dollars), depending on the coal source region. (Intraharbor transfer to Ravenswood is estimated to cost an additional $1.50 per ton.)

Con Edison has been advised to consider ownership of marine vessels and railroad cars to enhance its control over marine and rail operations. Extending the idea of direct control, Con

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[9] Reference number 193.

Edison might also consider ownership of railroad locomotives, thereby ensuring equipment availability and adding to system flexibility.

One potentially troublesome point in the various alternative transportation systems evaluated is the transfer of coal to Ravenswood by intraharbor vessel. To begin, on-site coal storage is limited to a one or two day supply. Further, channel depth and strong tidal currents severely limit the hours available for docking and undocking vessels.[9] Finally, inclement weather and ice floating down the Hudson River during the winter have the potential of disrupting intraharbor delivery of coal to Ravenswood. It might be desirable to provide for coal storage at a site nearer to Ravenswood and the rest of Con Edison's in-city plants. This arrangement would be particularly advantageous should additional plants be converted to coal (e.g., Ravenswood units 1 and 2 and Astoria 3-5); and, hence, may constitute an attractive option.

It also appears feasible to provide unit train service to Long Island via Conrail's Penn Station (New York) yards. A coal unloading terminal could be constructed near Hell Gate bridge with coal storage at Astoria, Hell Gate, or another location in South Bronx or Queens. Coal could then be transported to Ravenswood by intraharbor vessels or, possibly, if coal unloading can be accomplished on the Long Island side of Hell Gate bridge, by an extended conveyor system or barges. Distribution of coal to Ravenswood in the medium- to long-term might also be accomplished via a coal slurry pipeline. The coal slurry option appears more attractive if additional plants are converted to coal (e.g., Ravenswood units 1 and 2). In the longer term the existence of a coal slurry distribution system, perhaps in conjunction with fluidized bed combustion, would greatly improve the feasibility of utilizing coal at steam system plants in Manhattan. The economic desirability of these technical possibilities requires further investigation.

Although all current transportation alternatives for the movement of coal to New York City involve the use of railroads, long distance coal slurry pipelines might be constructed in the future. The last serious attempt at constructing such pipelines to service New York and New Jersey was in 1962. However, opposition at the time by eastern railroads defeated federal legislation granting eminent domain through rail rights of way for coal slurry pipelines.

Nuclear

Two units provide most of the nuclear-generated electricity that is provided to New York City and Westchester County. These are the Indian Point units 2 and 3, located on the Hudson River, about 35 miles north of midtown Manhattan. Both of these units are light-water reactors (LWR) of the pressurized water reactor (PWR) type[10]. Unit 2 is owned by Con Edison and has been in operation since mid-1974; unit 3 is owned by PASNY and has been in operation since 1976. Indian Point units 2 and 3 provide a combined capacity of 1820 MWe, about 16% of the currently available system generating capacity in 1980. When operated as base load plants, they supply about 30% of the total system demand. These units have the lowest generation cost of any plants on the system, and their use reduces dependence on foreign oil. By reducing the use of fossil fuels, they reduce SO_2 emissions. Furthermore, these units provide an important contribution to system capacity and reliability.

In the aftermath of the Three Mile Island incident, however, the NRC is investigating the safety of certain nuclear plants and particularly those in close proximity to a large population. Thus, the possibility of an NRC-mandated shutdown during the early 1980's must be considered.

The concern is that an accident might occur at Indian Point causing release of radioactive material to the environment. Much of the concern relates to the site's proximity to a large population area and the feasibility of evacuation. Approximately 220,000 people live within ten miles of the site and about 4 million people live within 30 miles. The fact that the Indian Point units are close to a large population has always been recognized by the NRC. Consequently, when the units were originally licensed, they were required to have additional safety features to lower the probability of an accident. Because the units were especially designed to prevent such an occurence, the probability of released radioactive material is very small. On the other hand, the consequences could be large (including possible deaths, illness, cancer, and genetic effects).

A shutdown at Indian Point would require Con Edison to supply 30% more of the service area electricity demand from existing oil-fired plants or from other sources outside the

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[10] The only type of nuclear power reactor that is likely to be available for commercial use in the U. S. between now and the year 2000 is the LWR. The LWR derives its name from the fact that ordinary water (the molecules of which predominantly contain the light isotope of hydrogen) is used as the coolant. There are two LWR designs. One is the boiling water reactor (BWR), in which the water is allowed to boil within the reactor. The steam produced is then utilized to turn a turbine. The other is the pressurized water reactor (PWR), in which the water is kept at a pressure sufficient to prevent it from boiling. This pressurized hot water is pumped through a heat exchanger to boil water in a secondary loop. The steam produced in this second loop is then used to turn the turbine.

service area. This is because no new plants except Travis could be brought on-line until the early 1990's. Given present capacity, this arrangement is possible but very expensive and risky. In Chapter Five the possible impacts of an Indian Point shutdown are examined in detail. However, several general impacts of such a shutdown are obvious. First, additional oil-firing used to replace the Indian Point plants would require imported oil unless current regulations were changed to permit use of higher sulfur oil. Second, the Indian Point units provide considerable service area protection in the event of curtailments of oil supply. If such a curtailment were to occur and the Indian Point units were not operating, there might not be enough oil available to operate the existing oil-fired plants. The extent and timing of such a problem would depend on: (1) the amount of coal conversion, if any, which had taken place, (2) the amount of emergency conservation possible, (3) the available stored supply, and (4) the amount of available energy for purchase from other utilities. The last two sources would be small, since very little energy can be stored and the New York Power Pool is 44% dependent on oil. The neighboring power pools (with the exception of Canada) are also highly dependent upon oil.

There would also be environmental effects from a shutdown. This is because the Indian Point units do not produce and emit pollutants such as SO_2 and NO_x to the atmosphere, while the additional oil-fired or coal-fired generation would. Also, since the replacement generation would come primarily from the older, less efficient in-city plants, this additional pollution would be emitted in a location where the existing levels are the largest and the concern for health effects (because of the high population density) is greatest.

Purchased Energy

Con Edison has purchased significant quantities of energy in the past. Most of this energy has been purchased from the New York State Power Pool. This power pool, of which all major electric utilities in the State of New York are members, coordinates the transfer of economy energy purchases among members[11]. In recent years the pool has also been the agent for the purchase and distribution of energy from Canada. Con Edison has been the largest single user of this Canadian energy. A summary of these purchases is provided in Exhibit 3.4.

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[11] Economy energy purchases are sales of surplus energy by a utility on a spot market rather than on a firm contract basis.

Exhibit 3.4

CON EDISON NRI
ENERGY PURCHASES
1968-1978

Year	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978
Net Purchased Energy in MWh x 10^6	1.33	1.95	3.72	4.25	4.46	7.46	4.70	5.74	8.23	2.36	5.06
Purchased from:											
NYPP	1.33	1.95	3.72	4.29	3.69	6.87	2.95	4.19	3.95	0.36	1.31
PASNY	--	--	--	0.04	0.04	--	--	0.65	3.53	2.23	3.98
Ontario Hydro	--	--	--	--	0.73	0.59	0.97	0.16	0.37	*	*
Hydro Quebec	--	--	--	--	--	--	0.78	0.74	0.38	0.43	*
Other	--	--	--	--	--	--	--	--	--	-0.66	-0.23
Purchased Energy as a Percentage of Net System Input	5	6	12	13	13	21	14	17	26	8	19

* Included in 'Other'

Source: Operating Statistics Yearbook 1978, Generation Planning Department, Consolidated Edison of New York, Inc., New York, N.Y., August, 1979.

Con Edison has a firm agreement for 741 MW of energy from Hydro Quebec during the summer season. (PASNY actually holds the contract.) The agreement is for 3 million MWh over the summer season (April-October, gross sendout from Hydro Quebec) on a take-or-pay basis through 1982. In 1982 the agreement is subject to renegotiation. Thereafter, Con Edison may be able to purchase less than 3 million MWh on a firm basis. If Con Edison takes additional energy beyond the agreed amount (up to a total of 3 million MWh), it would be obligated to return the additional energy the following winter. Fortunately, Con Edison has peak need in summer while Hydro Quebec peaks in winter.

There are several incentives for increasing Con Edison's purchases of energy in the 1980's. First, the energy available for purchase is likely to be less expensive than energy produced in Con Edison's own oil-fired generating plants. This is because the present major sources of purchased energy, Hydro Quebec and Ontario Hydro, price their surplus energy at 80% of the cost of the fuel it replaces at Con Edison. Hydro Quebec's energy will be less expensive than Con Edison-generated energy, assuming continuation of the current pricing policy and assuming that transmission costs and losses do not increase on a per unit of energy basis. Other likely sources of purchased energy are also financially attractive; they predominantly use coal-fired plants, which produce energy less expensively than Con Edison's oil-fired ones. Second, since the energy with the most likely availability is produced with coal or hydroelectric generating facilities, increasing energy purchases will help meet the national goal of reducing foreign oil dependence. Third, since purchased energy is produced outside New York City, its use will not increase pollution in New York City. To the extent it is hydroelectric it produces no air pollution.

Three potential sources for major increases in purchased energy for the 1980's have been identified[12]:

> <u>Hydro Quebec</u> - This utility expects to have excess supply of its hydroelectric energy until at least 1987 (Exhibit 3.5). Transmission limitations, which are scheduled for removal by 1983, will temporarily restrict purchases from Hydro Quebec to current levels. However, from about 1984 to 1987 there will be a larger amount of energy available to the New York Power Pool for purchase, perhaps as much as 7000 to 10,000 GWh. After 1987 the prospects are less clear; but if load growth projections continue to decline, there should be

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[12] Since purchased energy is excess energy to the seller, the exact amount available depends upon the gap between the sellers' generating capacity and demand. A significant amount of available purchased energy is expected, however, since the electric load growth projections of Hydro Quebec, Ontario Hydro, and the New York Power Pool have been lowered in the past year.

Exhibit 3.5

HYDRO QUEBEC
ESTIMATED ENERGY SURPLUSES
1980-1995

Annual Year	Surplus Energy in GWh
1980	3,999
1981	2,712
1982	2,089
1983	9,820
1984	16,116
1985	19,036
1986	15,813
1987	6,975
1988	204
1989	-659
1990	-380
1991	392
1992	159
1993	425
1994	345
1995	1,664

Source: Programme Guide 1979-1988, Hydro-Quebec, Division Programme, Quebec, Canada, February 1979.

significant amounts of purchased energy available well into the 1990's.

Ontario Hydro - This utility expects to sell part of its supply from coal-fired generating units until at least 1991.

New York Power Pool - It is likely that Con Edison will be able to purchase economy energy from the power pool's supply of coal-, nuclear-, and oil-fired energy throughout the planning period.

A substantial transmission system now exists in New York State which can transmit a large amount of energy to Con Edison. There is about 3100 MW[13] of transmission capability between the Con Edison service area and the utilities to the north of them in the state[14]. There is about 1300 MW of transmission capability between Quebec and New York State[15]. Hydro Quebec is installing equipment which will increase above these levels the amount of power it can transfer into New York State. This work, plus reinforcement of certain facilities associated with the 765 kW Marcy-Massena Line, which must be done by New York utilities, will allow about 2300 MW to be transferred from Hydro Quebec to the Utica area. (See Exhibit 3.6.)[16]

There are limitations on parts of the northern transmission network for this or any other additional energy obtained from upstate New York or Ontario Hydro. Work is planned or under way to reinforce portions of this network. After about 1982, the transmission network immediately north of the service area between Leeds and Pleasant Valley will have a transfer capability of about 1000 MW above present firm commitments.[17]

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[13] The 3100 MW figure is a gross capability. In summer there are firm commitments for over 2500 MW of northern energy which would use this transmission capability.

[14] Reference number 37.

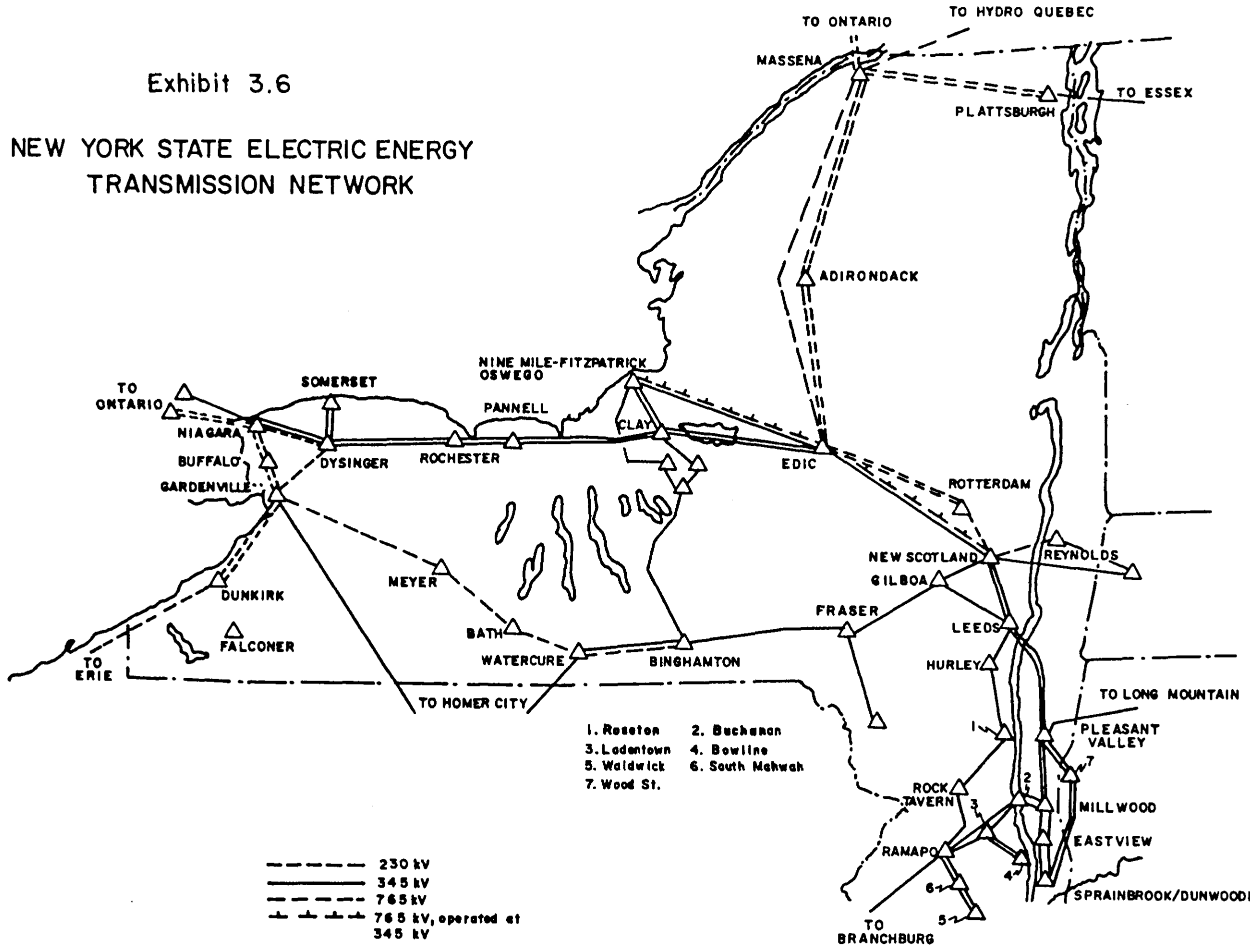
[15] Reference number 35.

[16] Note that protection against thermal overloads in the seconds-to-minutes time frame following the sudden loss of 2300 MW might best be achieved by microshedding. (See discussion of homeostatic control, Chapter Six.)

[17] The 1000 MW figure needs to be tempered by two observations. First, it represents a conservative measure of system capability. Second, much of this apparently "spare" capacity is presently used for economy transfers of energy within New York State, principally to the southeast. Operating experience and engineering studies indicate that under certain conditions, which are not uncommon, the amount of economy energy which can be transferred has been and will continue to be limited by the network.

Exhibit 3.6

NEW YORK STATE ELECTRIC ENERGY TRANSMISSION NETWORK



Source: Adapted from a map provided by Consolidated Edison of New York, Inc. on June 4, 1979.

Thus, the post-1982 network will allow additional energy above present firm commitments to be imported to the Con Edison service area; much of it could eventually come from Hydro Quebec. The weakest link remaining in the transmission network after about 1982 will be the portion between Utica and Leeds which will have a transfer capability of about 1000 MW above present firm commitments.

A well-coordinated plan for electric energy purchases is important. As these decisions are being made, several facts are important to consider. First, the current pricing policy for energy purchased from Hydro Quebec is to price it 20% below the cost of the fuel it replaces. Thus, if a significant portion of the service area's facilities are converted to coal rather than oil and the same pricing policy is maintained, the price of purchased energy would decrease. Second, the price of purchased energy may be further reduced if Con Edison does not negotiate for firm energy purchases. The possible impact of such an agreement on system reliability, however, must be assessed. Third, Hydro Quebec is spilling energy over its dams at certain times and might well be induced to take a lower price than the ones presently quoted.

Conservation

Through normal market operations, future increases in electricity prices are expected to result in a dampening effect on electricity demand and, thus, load growth. For instance, according to Edison Electric Institute statistics, the growth rate in the national demand for electricity recently decreased concurrent with electricity price increases. Specifically, the national annual average growth rate of electricity demand was 7.1% from 1960-1973, but declined to 3.4% from 1973-1977. Electricity prices decreased in real terms at an annual average rate of 1.4% from 1960-1973 and increased 2.6% annually from 1973-1977. Although factors other than prices (such as changes in the level of economic activity and saturation of various electric appliance markets) were operating, the role of price in dampening demand was significant. Conservation stemming directly from such electricity price increases is referred to here as price-elasticity conservation.

Con Edison and PASNY estimate that the service area load will grow at about 1.0% per year from 1980-1995. In developing this forecast, estimates of the future level of market-derived conservation due to price elasticity were incorporated. Con Edison might be able to influence increased conservation and therefore decrease annual load growth (1980-1995) below this forecast by utilizing means other than price elasticity.

Four possible programs to increase conservation are: (1) load limiting devices, (2) operating and maintenance for residential air conditioners, (3) building sub-metering, and (4) upgrading residential end use efficiencies beyond present statutory requirements. By utilizing load limiting devices (LLDs) ranging from manual to computerized controls, it is possible to ensure that a predetermined level of electricity usage is not exceeded in a particular building. Con Edison has already planned an LLD effort that is expected to bring about 75% of the potential target population under LLD control by 1995, and this action is reflected in the current load growth forecast. If this plan could be accelerated to reach 100% of the target by 1995, it is possible that approximately 285 GWh of additional conservation would occur.

Con Edison's current load management program identifies significant energy savings which would result from improved operation and maintenance of room air conditioners in the residential sector (i.e., cleaning filters and condensers and using timing devices to switch air conditioners off in unoccupied apartments). Indications are that approximately 335 GWh of electricity could be saved by 1995, if this program were implemented.

A master-metered building is one where the cost of providing electricity is included in the rent. Various studies have demonstrated that tenants, both commercial and residential, who are made individually responsible for the amount of energy they consume will utilize less energy than tenants living in a master-metered situation. While estimates of the potential energy savings from a sub-metering program need further investigation, it is possible that such a program could reduce electricity used by about 205 GWh by 1995.

The three largest electricity uses in the residential sector are room air conditioners, refrigerators, and lighting. It is possible that approximately 1050 GWh of reduction in residential electric demand could be achieved by improving the energy-efficiency of these domestic amenities. It must be noted that for Con Edison to implement a program to affect directly the end use of energy in the residential sector, modifications to current regulations are required. Such programs, however, have been used in other states with some success.

Exhibit 3.7 indicates that by 1995 the combined impact of these four conservation areas is 1875 GWh. This represents approximately 4.5% of the projected 1995 electric demand in the service area. Achieving this potential would reduce the current projected annual growth during the 1980-1995 period by about 0.4%. Because conservation is a relatively new energy issue, this 0.4% reduction is an indication rather than an estimate of the conservation potential from these areas. It should be noted that this analysis does not represent a conservation plan that should be implemented without further analysis of the costs and benefits involved.

Exhibit 3.7

INDICATION OF CONSERVATION POTENTIAL
IN CON EDISON FRANCHISE AREA

	Cumulative Gigawatt Hours*		
	1985	1990	1995
Accelerated LLD Program	95	190	285
Improved Operation and Maintenance of Residential Air Conditioners	110	225	335
Sub-Metering	70	135	205
Accelerated Upgrading of Selected Residential End Use Efficiencies	350	700	1,050
TOTAL	625	1,250	1,875

* Potentials defined are assumed to occur evenly over the 1980-1995 period.

Market-Derived Conservation in New York City

An estimate of the energy savings realized in response to the 1973 oil embargo's quadrupling of the price of oil was made in a study assessing the conservation potential in New York City commercial office buildings[18]. After adjusting for occupancy/utilization factors and weather conditions, between 1971-1972 and 1974-1975, a 12% energy savings occurred (including electricity, steam, natural gas, distillate, and fuel oil). The raw data indicated a 19% savings. These savings were due largely to simple adjustments in building operating temperatures and lighting practices. They occurred despite the fact that owners and managers, in many instances, had only sparse quantitative information about the energy consumption in their buildings. However, the study also indicates that economic incentive still exists in New York City's commercial sector for significant additional investment in conservation. The raw data for total electric sales in the commercial sector show only a 3% drop between 1973-1979.[19]

Electric consumption data for the residential sector in the Con Edison service area are shown in Exhibit 3.8. As can be seen, residential demand increased at an average annual rate of 5.7% from 1968-1973, and then declined from 1973-1978 at an annual rate of -2.1%. The respective average annual growth rate in real prices during these two periods was 0.0% and 8.4%. The overall decline in average residential consumption between 1973-1978 was 10%. Although other economic factors were operative during this period, real increases in residential electric prices undoubtedly had a dampening effect on demand.

The previous discussion indicates that the market has been effective in bringing about conservation of energy. However, significant market inefficiencies do exist. Recent energy studies have included, in their treatment of conservation, extensive discussions of market inefficiencies in the form of institutional, economic, and political constraints[20]. Those most applicable to the Con Edison service area are discussed here.

First, approximately 70% of New York City's residential units are rental. This situation provides the incentive for the use of cheaper and less energy-efficient appliances in households since landlords purchase them but do not pay electric bills.

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[18] Reference number 87.

[19] Reference number 175.

[20] Reference numbers 5, 8 and 9.

Exhibit 3.8

RESIDENTIAL ELECTRICITY DATA

Year	Annual Per Customer kWh Use	Price Per kWh (Nominal)	Price Per kWh (Real)*
1978	3,255	9.6¢	6.0¢
1977	3,300	9.6¢	6.6¢
1976	3,314	8.8¢	6.2¢
1975	3,300	8.2¢	5.9¢
1974	3,248	7.6¢	5.8¢
1973	3,609	5.2¢	4.0¢
1972	3,367	4.6¢	3.8¢
1971	3,355	4.2¢	3.6¢
1970	3,180	3.9¢	3.4¢
1969	2,950	3.9¢	3.7¢
1968	2,736	4.0¢	4.0¢

* Deflated via the consumer price index for urban wage earners and clerical workers. 1968 is the base year.

Source: Ten Year Financial and Operating Statistics: 1968-1978, Consolidated Edison of New York, Inc., New York, N.Y., 1979.

Second, a significant percentage of customers in the Con Edison service area are master-metered. While this reduces the "first-cost bias" of landlords, it has been demonstrated that removing the direct price signals to consumers by master-metering leads to electric consumption 15-20% higher than in individually metered situations. Third, in both the residential and commercial sectors, consumers generally lack the requisite knowledge concerning energy use and conservation to make fully informed decisions. Finally, market prices of electricity do not reflect marginal or replacement costs; nor do they include the cost of all externalities--pollution cost, national security cost of reliance on foreign oil, etc. Therefore, the market-determined level of conservation will be suboptimal relative to a perfectly efficient market. For all of these reasons conservation programs are of crucial importance.

Conservation Programs

A sectoral breakdown of electric energy sales in the Con Edison service area during 1971-1979 is shown in Exhibit 3.9. Only about 5% of total electric sales in 1979 went to industrial consumers. Therefore, subsequent discussion will be focused on the residential and commercial sectors.

Con Edison's load management plan is primarily aimed at shifting peak demand for electricity[21]. However, some parts of the plan have significant impact on reducing total electric demand. The cornerstone of the program in the commercial sector is installation of LLDs in existing buildings. Con Edison has targeted its LLD effort to over 1500 commercial customers with demand in excess of 300 kW, for a total summer demand of approximately 2200 MW in existing buildings plus an expected load growth of 150 MW and 638 MW by 1985 and 1995, respectively.

The primary targets of the LLDs in reducing demand are the ventilation systems, since they are often in operation more than is necessary. Other systems that are usually included in load limiting efforts are elevators, escalators, pumps, display lighting, and cafeteria operations.

Con Edison has identified 2200 MW of commercial peak load which can utilize LLDs. It estimates a 14% reduction in the summer peak load and approximately a 6% reduction in total energy requirements for loads controlled by LLDs. The potential impact of LLDs in existing buildings is a 1153 GWh reduction in total energy demand. Con Edison currently anticipates that about 75% of the 2200 MW potential will be under LLD control by 1995. If 100% of the potential LLD market is under control by 1995, an

[21] Reference number 20.

Exhibit 3.9

CON EDISON'S ANNUAL ENERGY SALES BY CUSTOMER CLASSIFICATION
1971-1979
(Gigawatt Hours)

	Residential (a)	Residential (b)	Commercial (c)	Industrial (d)	Street Lighting	Railroads	Other Governmental (e)	Total Sales (f)
1971	9,488	197	14,289	2,289	474	2,785	2,977	32,499
1972	9,602	233	14,602	2,232	480	2,693	3,226	33,068
1973	10,318	268	15,252	2,169	493	2,553	3,600	34,653
1974	9,311	362	14,218	1,823	546	2,476	3,470	32,206
1975	9,425	496	14,367	1,617	580	2,406	3,527	32,418
1976 (g)	9,361	614	14,480	1,635	506	2,422	3,612	32,630
1977 (g)	9,252	668	14,528	1,557	519	2,196	3,738	32,458
1978 (g)	9,099	707	14,606	1,648	523	2,172	3,842	32,597
1979 (g)	9,105	684	14,830	1,605	476	2,209	3,851	32,770

(a) Residential excluding electric heating - Service Category #1, 1E, 13 and 8 (excluding Public Authorities).

(b) Residential with electric heating - Service Category #7 and 12 (excluding Public Authorities).

(c) Service Category #2, 3, 4 and 9 (excluding Industrials and Public Authorities).

(d) Large Industrial (SIC Code 20-39). Included in Service Category #4 and 9.

(e) Public Authorities in Service Category #2, 3, 4, 8, 9, 12, NYC Public Bldgs. and World Trade Center.

(f) Excludes Sales to Other Public Utilities.

(g) Data includes Energy supplied to customer by PASNY, transferred from Con Edison beginning on 9/22/76.

Source: Adapted from Report of Member Electric Systems of the New York Power Pool and the Empire State Electric Energy Research Corporation, Vol. 1, Long-Range Plan 1980, Albany, N.Y., April 1, 1980.

additional 285 GWh reduction in total energy demand will result.

Con Edison's load management program also identifies significant energy savings which would result from improved operation and maintenance of room air conditioners in the residential sector (i.e., cleaning filters and condensers and the use of timing devices). Calculations indicate potential energy savings amounting to 335 GWh. These are detailed in Exhibits 3.10, 3.11 and 3.12.

Various studies have demonstrated that tenants who are made individually responsible for energy that they consume will utilize less energy than tenants in a master-meter situation. For electricity, the average savings is approximately 15-20%[22]. Con Edison has residential customers who are master-metered (SC8 and 12) with electric consumption amounting to 1960 GWh in 1979. PASNY supplied an additional 100 GWh in 1979 to Government housing authorities in a master-meter situation. In addition, an unspecified number of Con Edison's SC4 customers are master-metered. If we assume one-third of master-meter consumption can be converted to sub-metering, that sub-metering electric demand is reduced by 20% upon conversion, and that SC4 classification contains 1000 GWh of master-metered demand, then the potential electric savings from master-meter conversions is 205 GWh in the service area.

The New York City Energy Office has performed preliminary analysis of a plan that would accelerate retirement of inefficient residential room air conditioners and refrigerators and promote installation of efficient light bulbs in residences[23]. The plan thus focuses on the three largest end-use components of residential demand. The objective of the plan is to insure that three-quarters of the stock of air conditioners and refrigerators are replaced by more efficient units within 10 years and that 50% of the most frequently used light bulbs in the franchise area are replaced by more efficient bulbs within 10 years. The estimated energy savings from the plan is 2100 GWh. However, a significant turnover of refrigerators and room air conditioners is already anticipated in the Con Edison residential load forecast methodology. Therefore, only about half of the 2100 GWh represents potential savings beyond the current load forecast[24]. In addition, the plan proposes that the refrigerator and air conditioner stock be replaced with units having efficiencies better than the average units available. The potential is thus assumed to be 1050 GWh beyond the current Con Edison load forecast.

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[22] Reference number 62.

[23] Reference numbers 75, 76 and 77.

[24] Reference number 27.

Exhibit 3.10

AVOIDABLE LOSSES FROM RESIDENTIAL ROOM AIR CONDITIONERS

Losses

Filter	--	5% Loss of Efficiency for Dirty Filter
Condenser	--	20% Loss of Efficiency for Dirty Condenser
Timer	--	100% Unnecessary Usage for 8 Hours, Weekday

Potential Energy Savings (in Gigawatt Hours):

Filter	--	1,500,000 Units x 1.15 KW x 5% Loss x 428 hrs	= 35 GWh
Condenser	--	2,500,000 Units x 1.15 KW x 20% Loss x 428 hrs	= 245 GWh
Timer	--	120,000 Units x 1.15 KW x 100% Loss x 40 hrs/wk x 10 wks	= 55 GWh
Total:			335 GWh

Source: Adapted from Load Management Program: 1977-1987, Consolidated Edison Co. of New York, Inc., New York, NY, April 15, 1977.

Exhibit 3.11

VALUE TO CUSTOMER OF IMPROVING OPERATION AND MAINTENANCE OF ROOM AIR CONDITIONERS

<u>Filter</u>

1.15 KW x 428 hrs. x

$0.10/kWh x 5% Efficiency Loss = $2.46/Unit/Summer

<u>Condenser</u>

1.15 KW x 428 hrs. x

$0.10/kWh x 20% Efficiency Loss = $9.84/Unit/Summer

<u>Timer</u>

1.15 KW x 40 hrs/wk x 10 wks x

$0.10/kWh x 100% Efficiency Loss = $46.00/Unit/Summer

Source: Adapted from <u>Load Management Program: 1977-1987</u>, Consolidated Edison Co. of New York, Inc., New York, NY, April 15, 1977.

Exhibit 3.12

CUSTOMER SAVINGS FROM PURCHASE OF A ROOM AIR CONDITIONER

Moderately Efficient Unit (8.0 EER)
Versus
Inefficient Unit (6.5 EER)

First Cost

Premium of $50.00 on Purchase of 8.0 EER Unit Compared with 6.5 EER Unit

Operating Cost

Savings with 8.0 EER Unit:

0.216 KW/Unit x 428 hours/year x $0.10/KWh = $9.24/year

Twelve Year Life:

12 years x $9.24/year = $110.88

Present Worth of $9.24 for 12 years @ 12% = $57.24

Benefits

The present worth of $9.24 per year for 12 years at 12% interest is $57.24. This more than offsets the $50 cost premium for the more efficient unit. The payback period is about 5 years.

Source: Adapted from Load Management Program: 1977-1987, Consolidated Edison Co. of New York, Inc., New York, NY, April 15, 1977.

Natural Gas

The generic discussion of natural gas in Chapter Two is complete except for the following documentation of the MIT opinion concerning probable increased availability of natural gas in the U.S. during the 1980's.

The potential availability of natural gas in the U. S. has improved substantially since 1976. Annual gas reserve additions increased from 7.5 trillion cubic feet (Tcf) in 1976 to 14.3 Tcf in 1979. In addition, gas discoveries in Mexico and Canada have increased the potential for future exports to the U. S. Recent higher gas prices in the U. S. and forecasts of more price increases are expected to lead to a slower growth rate of gas demand in the high priority sectors such as the residential and commercial sectors. This slower growth might make more gas available to the industrial and electric utility sectors. However, according to the Powerplant and Industrial Fuel Use Act of 1978 (PIFUA), natural gas is presently prohibited for burning in new power plants. Furthermore, existing plants cannot burn natural gas after 1990.

Con Edison will be able to burn natural gas if PIFUA is amended or if Con Edison is continuously granted an exemption. In May 1980 the U. S. Senate passed an amendment to PIFUA which would allow gas-burning power plants to continue burning gas until the plants are fully depreciated. This amendment has not yet been considered by the House.

Gas Availability

The future amount of gas available at the national level is expected to be the sum of the gas supplied from the Continental U. S., from Alaska, from various gas exporters, and from producers of synthetic gas. Total gas supply from all these sources is expected to be between 18.8-22.0 trillion cubic feet (Tcf) in 1985, 19.7-22.6 Tcf in 1990, and 18.7-21.6 Tcf by 1995.

The amount of natural gas available to utilities is the total national supply minus the amounts used by the industrial, transportation, and residential-commercial sectors. Gas demand in the residential/commercial, industrial, and transportation sectors is expected to increase from 16.7 Tcf in 1978 to about 18-20.5 Tcf by 1995. Since gas supply is expected to be between 18.7-21.6 Tcf in 1995, there could be up to 3.6 Tcf of gas for electric utilities in 1995.

Exhibit 3.13 depicts estimates of Continental U. S. gas production developed in 1980 by the U. S. Department of Energy (DOE), the Gas Research Institute (GRI), Shell, and Exxon[25]. It can be seen that GRI gave the most optimistic estimates; Shell

Exhibit 3.13

PROJECTED CONTINENTAL U. S. GAS PRODUCTION (Tcf)

	1985	1990	1995
U. S. Department of Energy	17.1	15.7 - 16.1	13.0 - 14.4
Gas Research Institute	16.2 - 18.4	15.6 - 18.9	14.7 - 20.8
Shell	15.5	13.1	n.a.
Exxon	n.a.	14.5 - 14.9	12.2 - 13.0

Sources: See references 92, 147, 50 and 142.

and Exxon gave the most pessimistic; and DOE is in between these two extremes.

Below, the future reserves additions required for two gas production profiles are investigated. Assume first a linear decline in gas production from 20.0 Tcf in 1979 to 17.0 Tcf in 1990 and to 15.0 Tcf in 1995. To support this first production schedule, with a reserves to production ratio of 8 in 1995,[26] the reserves additions would need to be 16 Tcf during 1980-1990 and 12.8 Tcf during 1991-1995. Secondly, if production were to decline linearly from 20.0 Tcf in 1979 to 15 Tcf in 1990, and then to 13 Tcf in 1995, reserves additions would need to be 13.6 Tcf during 1980-1990 and 12.4 Tcf during 1991-1995.

Total U. S. reserves additions amounted to 7.5 Tcf in 1976, 11.7 Tcf in 1977, 10.6 Tcf in 1978, and 14.3 Tcf in 1979. Continental U. S. reserves additions amounted to about 95% of these figures. For example, in 1979 Continental U. S. reserves additions amounted to 13.7 Tcf out of a total 14.3 Tcf. Thus, the second production profile, 15 Tcf in 1990 and 13 Tcf in 1995, appears more probable to be achieved than the first production profile, 17 Tcf in 1990 and 15 Tcf in 1995. However, even the latter could be achieved if the annual reserves additions keep increasing as they have done in the past five years. One way this more optimistic profile could be achieved is by increasing the unconventional gas supply to about 2 Tcf during the first half of the 1990's.

Unconventional gas includes gas from Western tar sands, Devonian shale, and coal seams. GRI claims that by 1995 gas supplies from these sources could reach a level of 1.2 Tcf at a market price of about $3/MBtu (1979 dollars) and today's technology, and a level of 5.3 Tcf at a market price of about $6/MBtu and advanced technology.

The U. S. is expected to import gas during 1980-1995 from Canada and Mexico (through pipelines) and from Algeria and Indonesia (as liquefied natural gas, or LNG). Exhibit 3.14 depicts estimates of gas imports developed by the DOE, GRI, and Exxon. All three studies predict an improvement in the potential for gas imports during 1980-1995. Recent gas discoveries in Mexico and Canada are the major reasons for such an improvement.

Synthetic gas supply estimates are shown in Exhibit 3.15. The GRI gave the most optimistic estimate, while Exxon gave the most pessimistic. For a detailed discussion of synthetic gas, see the section on synthetic fuels in this report.

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[25] Reference numbers 92, 147, 50 and 142 respectively.

[26] Proven gas reserves in the Continental U. S. were 163 Tcf as of January 1, 1980, and the reserves to production ratio was 8.3.

Exhibit 3.14

PROJECTED U. S. GAS IMPORTS (Tcf)

	1985	1990	1995
U. S. Department of Energy			
Canada	0 - 1.3	0 - 1.3	0 - 1.3
Mexico	0 - 1.2	0 - 1.2	0 - 1.2
LNG	0.8 - 1.1	0.8 - 1.1	0.8 - 1.1
Gas Research Institute			
Canada	1.0 - 1.4	1.0 - 1.5	1.5 - 2.0
Mexico	0.3 - 0.7	0.7 - 1.1	
LNG	0.8 - 1.0	1.0	1.0 - 1.5
Exxon			
Canada/Mexico	n.a.	1.8	2.0
LNG	n.a.	0.8	0.8

Sources: See references 92, 147 and 142.

Exhibit 3.15

PROJECTED U. S. SYNTHETIC GAS SUPPLY (Tcf)

	1985	1990	1995
U. S. Department of Energy	0.5	1.1	2.3 - 2.6
High-Btu Gas	0.1	0.4	0.9
Medium-Btu Gas	0	0.3	.01 - 1.3
Naptha + LPG	0.4	0.4	0.4
Gas Research Institute	0.5 - 1.1	0.8 - 2.9	1.2 - 4.2
Fossil Fuels	0 - 0.1	0.3 - 1.7	0.9 - 3.3
Naptha + LPG	0.5 - 1.0	0.5 - 1.0	0.2 - 0.5
Biomass + Wastes	0	0 - 0.2	0.1 - 0.4
Exxon	0.5 - 0.7	0.6 - 1.0	1.3 - 2.1

Sources: See references 92, 147 and 142.

In summary, Continental U. S. gas supplies are expected to decline from 20 Tcf in 1979 to about 15-17 Tcf in 1990 and 13-15 Tcf in 1995 (Exhibit 3.16). Of course these figures might prove optimistic if the recent improved trend in gas reserve additions does not continue during the 1980's.

Gas imports are expected to increase from 1.0 Tcf in 1979 to about 2.8-3.7 Tcf in 1990 and 1995, composed of imports from Canada of 1.0-1.5 Tcf, from Mexico 1.0-1.2 Tcf, and LNG 0.8-1.0 Tcf. The Alaskan gas pipeline will be available in the second half of the 1980's, with a throughput capacity of approximately 0.9 Tcf. Finally, synthetic gas supplies are expected to increase from 0.3 Tcf in 1979 to about 1.0 Tcf in 1990 and 2.0 Tcf in 1995.

Even though projections of future gas supplies for the U. S. have become considerably more optimistic in the last two years, Con Edison may not be the recipient of large future gas allocations because utilities are the lowest priority in the national gas allocation policy and because even the gas which is allocated to utilities may be assigned to other companies.

National Demand for Gas

Exhibit 3.17 depicts actual gas consumption during 1980-1995 based on the DOE and GRI reports. Higher gas prices and gas shortages led to a decrease in gas consumption in all economic sectors during 1972-1978.

In the residential/commercial sector, the DOE forecasts no increase in gas consumption during 1980-1995. DOE assumes that electricity will capture a large share of the increased demand in the residential/commercial sectors. On the contrary, GRI assumes that 60-80% of the new residential/commercial units will be using gas. Consequently, GRI estimates an increase in gas demand of about 25% during 1980-1995. Assuming that about half of the new residential/commercial units will be using gas, gas demand in the residential/commercial sector will be between 7.5-9.0 Tcf in 1995.

In the industrial sector, GRI predicts an increase of up to 60% of gas demand by 1995 because it assumes that most of the energy demand increase in this sector will be used in steam generation and direct heat (intermediate). However, DOE assumes that the energy demand increase in the industrial sector will be captured by electricty, coal, and natural gas. Consequently, DOE predicts a much smaller increase in gas demand by 1995. The assumption of DOE appears more realistic, because coal is expected to capture a significant part of the energy demand increase in the industrial sector--especially the demand increase in steam generation and direct heat. Most probably, gas demand in the industrial sector will increase to about 10-11 Tcf by 1995.

Exhibit 3.16

CURRENT AND PROJECTED TOTAL U. S. GAS SUPPLIES (Tcf)

	1980	1985	1990	1995
Lower 48		16.0 - 18.0	15 - 17	13 - 15
Alaska		0	0.9	0.9
Synthetic Gas		0.5	1.0	2.0
Imports		2.3 - 3.5	2.8 - 3.7	2.8 - 3.7
TOTAL	20.5	18.8 - 22.0	19.7 - 22.6	18.7 - 21.6

Sources: See references 92, 147, 50 and 142.

Exhibit 3.17

HISTORIC AND PROJECTED U.S. GAS DEMAND BY ECONOMIC SECTOR (Tcf)

	Historic		Projected		
	1972	1978	1985	1990	1995
Residential/Commercial	8.0	7.7			
DOE			7.6	7.4 - 7.6	7.3 - 7.7
GRI			8.1 - 8.6	8.5 - 9.2	8.8 - 9.7
Industrial	9.7	8.5			
DOE			7.7 - 7.9	8.5 - 9.8	9.1 - 10.5
GRI			10.7 - 12.6	11.0 - 14.4	11.4 - 15.1
Transportation	0.5	0.5			
DOE			0.5 - 0.6	0.5 - 0.6	0.5 - 0.6
GRI			0.6 - 0.7	0.6 - 0.7	0.6 - 0.7
Electricity Generation	4.4	3.3			
DOE			2.4 - 2.9	2.5 - 3.2	1.7 - 2.2
GRI			2.0 - 3.3	1.2 - 3.3	1.0 - 3.3

Sources: See references 92 and 147.

In summary, natural gas demand is expected to amount to 18-20.5 Tcf in 1995, composed of 7.5-9.0 Tcf from the residential/commercial sector, 10-11 Tcf from the industrial sector, and 0.5 Tcf from the transportation sector. •

Con Edison Demand for Gas

In 1980, Con Edison gas contracts amounted to 160 billion cubic feet of which 86-88 Bcf were to be consumed in centralized generation, and the rest (72-74 Bcf) were to go to Con Edison's customers for direct use. Astoria 1-3, Ravenswood 1-2, and East River 7 are the major units which are capable of burning natural gas in Con Edison's system. Other units can burn natural gas partially, usually for ignition only. Burning natural gas in Astoria 1-3 and Ravenswood 1-2 would require up to 80 Bcf annually. The maximum amount of gas that could be burned in decentralized cogeneration in Con Edison's service area is about 60 Bcf in 1995, corresponding to 1000 MW of capacity at 60% capacity factor.

Thus, Con Edison has three major uses for gas, each requiring a different amount. It can use gas as the primary fuel burned in some of its plants; it can supply gas directly to customers; and it could distribute gas for fuel in decentralized cogenerating units. About 220 billion cubic feet would be needed in 1995 assuming that: Con Edison gas customers used 80 Bcf, decentralized cogeneration required 60 Bcf, and centralized cogeneration required 80 Bcf. The 220 Bcf of gas corresponds to about 1% of the U. S. natural gas supply in 1995. Natural gas supply and demand conditions suggest it is possible this amount will be available, but it is unclear that Con Edison would receive such a large allocation.

Chapter Four

ELECTRICITY SUPPLY SCENARIOS FOR THE 1980'S

Methodology

Exhibit 4.1 shows the major components of scenario simulations and regression analysis. As the arrows of that figure indicate, input variables are created from the relevant planning factors and building block information. These 'proxies' or input variables are then combined to form scenarios which are simulated by four computer-oriented models. The simulation models calculate output variables which are measures of the impacts which planning factor and building block proxies have on the Con Edison objectives. Many of these initial output variables from the simulations are then fed into a regression analysis computer program to estimate the mathematical relationships between input variables and output variables. Each of the major components of scenario simulations and regression analysis is discussed below.

Input Variables

Coal Conversion. Arthur Kill 2 and 3, Ravenswood 1, 2, and 3, and Astoria 3, 4, and 5 have been identified as primary potential candidates for coal conversion. Arthur Kill 2 and 3 and Ravenswood 3 have the lowest conversion costs among those plants, and Arthur Kill is better sited for coal conversion than is the Ravenswood plant. The present plan calls for near-term conversion of Ravenswood 3 and Arthur Kill 2 and 3. To begin putting the plan into quantitative perspective simulations with various amounts of conversion were ran. Further, some scenarios included scrubbers and some did not. The assumed plant capacities and conversion dates are in Exhibit 4.2.

Purchased Energy. Con Edison's prospects for purchasing energy during 1980-1995 have considerably improved in the last two years because Hydro Quebec expects to have energy surpluses during the 1980's which could also be extended into the 1990's. In addition, Con Edison could purchase energy from other sources, especially Ontario Hydro and the New York Power Pool. Four alternative levels of purchased energy were used as input variables: to purchase no energy, or to purchase the low, medium, or high level shown in Exhibit 4.3. (Note: The amount of electric energy purchases planned by Con Edison, for practical purposes, equals the "low" purchased energy case. The high level would probably exceed the transmission network capabilities in some years. The medium level would probably be feasible for the current and planned transmission network.)

Exhibit 4.1

METHODOLOGY FOR SCENARIO SIMULATIONS AND
REGRESSION ANALYSIS

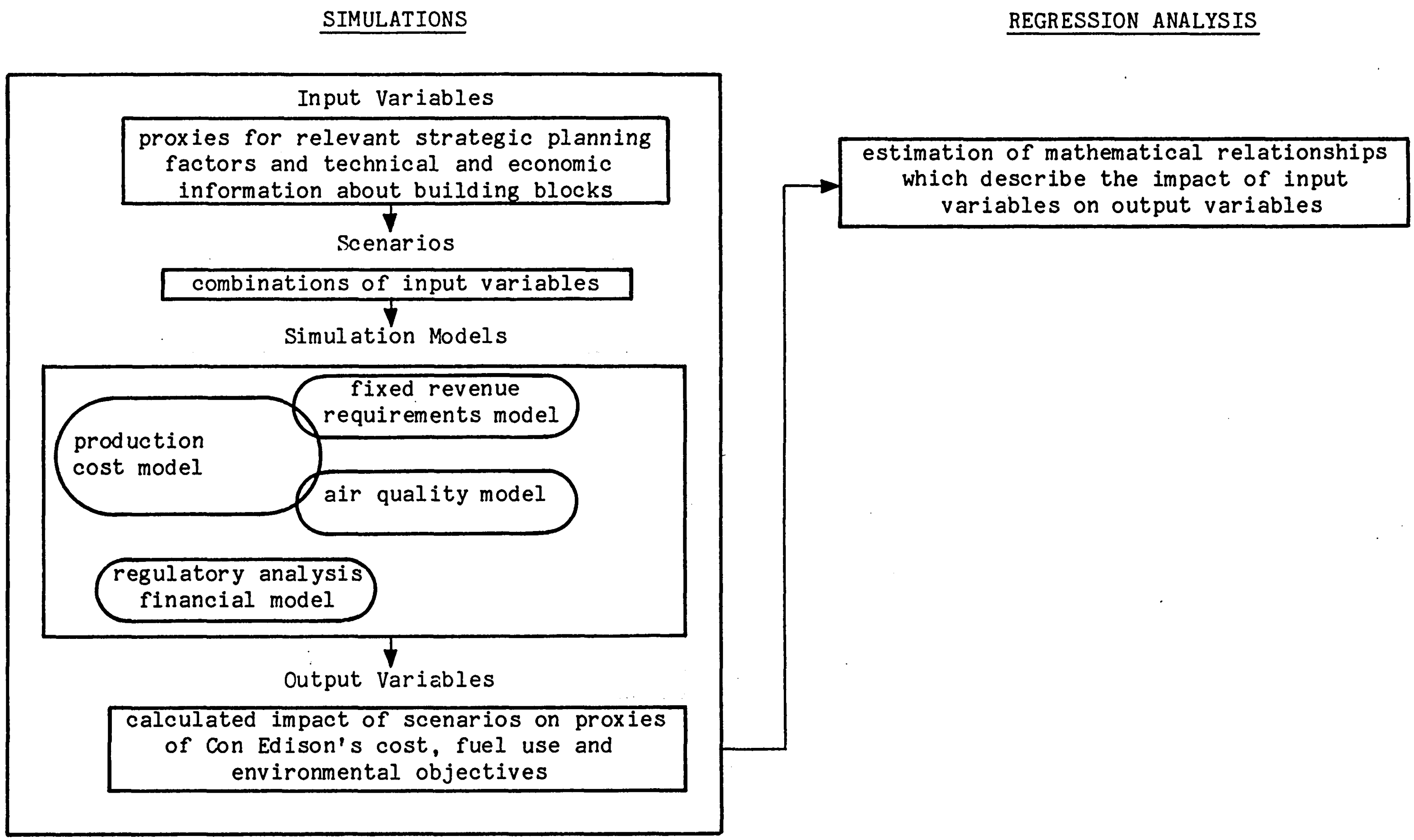


Exhibit 4.2

COAL PLANT CAPACITIES AND
ASSUMED DATE OF CONVERSION OR CONSTRUCTION[1]

	Conversion or Construction Date[2]	Coal-Fired Generating Capacity (Megawatts)[3]	"COALAREA"[4] Megawatt Years
Ravenswood 3	1981	922	13,830
Arthur Kill 2	1982	335	4,690
Arthur Kill 3	1983	461	5,993
Con Edison Conversion Program (without Travis)	--	1718	24,513
Travis	1987	632	5,688
Con Edison Conversion Program (with Travis)	--	2350	30,201
Possible Additional Conversion:			
Ravenswood 1	1985	372	4,092
Ravenswood 2	1985	370	4,070
Astoria 3	1987	328	2,952
Astoria 4	1987	346	3,114
Astoria 5	1988	322	2,576

1 Other conversion timetables were also investigated. See Appendix F.

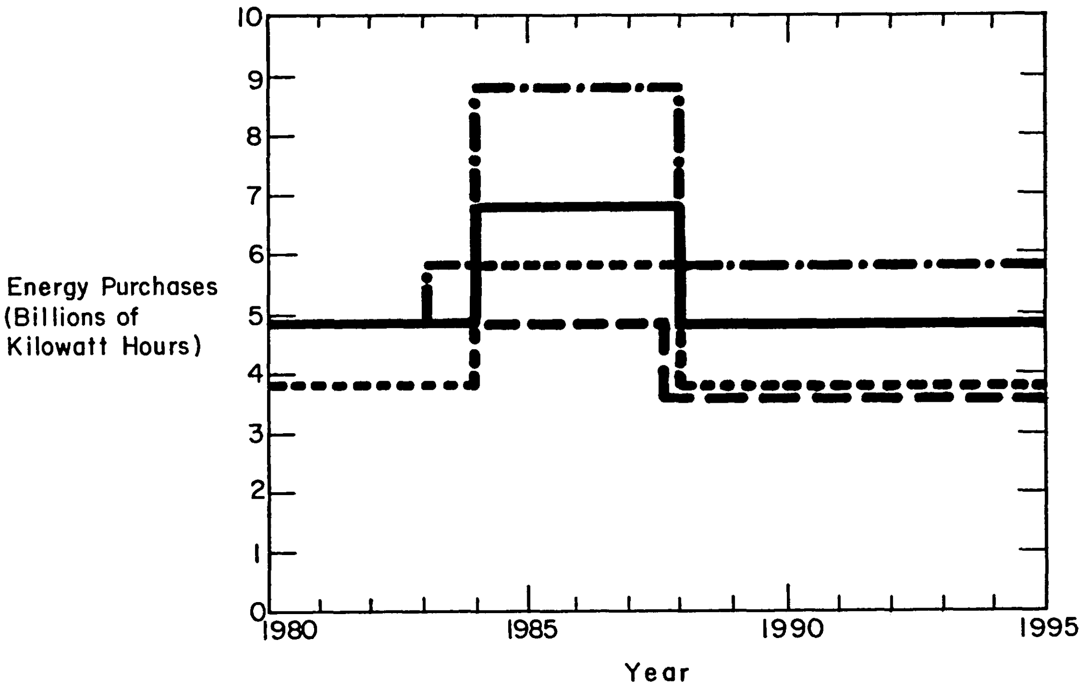
2 Only Travis is new construction. All others are conversion.

3 This input variable measures the amount of coal-fired capacity for each plant for any single year.

4 "COALAREA" is the input variable which measures a plant's total coal-fired generating capacity from time of conversion (or construction) until 1995.

Exhibit 4.3

PURCHASED ENERGY LEVELS
(1980-1995)



<u>Note:</u>

Projected total energy demand for the Con Edison Service Area in 1980 = 36.14 billion kilowatt hours. (9.5 x 1980 Energy Purchases)

<u>Key:</u>

MIT High (cumulative total = 101.8)
MIT Medium (cumulative total = 84.8)
MIT Low (cumulative total = 68.8)
Con Edison Strategy for the 1980's (cumulative total = 65.0)

Additional PASNY Capacity. Construction of a 700 MW coal-fired plant at Travis and a 1000 MW pumped storage plant at Prattsville, both of which would mainly serve the Con Edison service area, is under consideration by PASNY. The input variables used are: the service area uses all of the power generated at the Prattsville facility (beginning in 1987), or the plant is not built; and the service area uses 632 MW of the power generated at Travis (beginning in 1987), or the plant is not built.

Fuel Prices. To estimate trends of fuel prices over the next fifteen years, several recently published studies were utilized. Exhibit 4.4 lists the estimated real fuel prices (as delivered to Con Edison during 1980-1995) used as input variables. (See Appendix B and Chapter Three for discussion surrounding these estimates.)

Electric Load Growth. Con Edison forecasts that the electric load in the service area will grow an an average annual rate of about 1.3% during 1980-1995. Because the load growth is dependent on several uncertain economic factors, the input variables for annual and peak electric load growth rate range from -1% to +2% during 1980-1995.

Scenario Design

Scenarios were created by making combinations of different values of the input variables. While a full list of all 126 scenarios is given in Appendix F, a brief picture of one possible scenario is given here to illustrate the process. One scenario could be created by assuming that Con Edison converted Arthur Kill 2 and 3 to coal and used the low level of purchased energy. Other features of the scenario could be that the annual electric load growth is 1% and that oil and coal prices increase at an annual rate of 3% and 1% respectively. This process was used to design scenarios with all relevant combinations of the input variables.

Simulation Models

The 126 scenarios were simulated using three models: the Production Cost Model; the Fixed Revenue Requirements Model; and the Air Quality Model. As explained later, the Regulatory Analysis Financial Model was also used for a subset of the 126 scenarios since this was sufficient to verify the extent of financial constraints.

Production Cost Model (PROCOS). This simulation program was developed by Systems Control, Inc., of Palo Alto, California, and

Exhibit 4.4

FUEL PRICE ESTIMATES FOR
SCENARIO ANALYSIS INPUT VARIABLES
AS DELIVERED TO CON EDISON (1980-1995)

	1980 Price ($/Million Btu)	Real Annual Growth Rates (1980-1995)
Oil	5.00[1]	0-5%
Coal	2.00[2]	0-2%

[1] The listed figure is the price of No. 6/residual containing 0.3% sulfur. The price of the 1.5% sulfur No. 6/residual is expected to be about $4.40/MMBtu. The price of the No. 2/distillate is expected to be $5.70/MMBtu.

[2] The listed figure is the price of coal containing 1% sulfur.

is presently used at Con Edison. PROCOS estimates the minimum electricity production costs for a specified load given plant ratings, availability factors, and fuel types and cost. PROCOS determines a minimum cost operation schedule for each day throughout the year. Annual totals of cost, fuel consumed for each type of plant, and kWh output for each type of plant are calculated. In these simulations, this process was repeated for each year 1980-1995.

Fixed Revenue Requirements Model (FRRM). This program is used by Con Edison to estimate revenues needed to recover the fixed costs associated with a scenario. The model uses the following inputs: cost of capital (debt, preferred stock, common stock); dispersion pattern of investment depreciation; discount rate; interest during construction; federal income tax; property tax and insurance; gross revenue tax. The model has the following outputs: sum of present values of the components of the revenue requirements for the capital portion of the investment; high, mean, and low non-levelized data (i.e., year-by-year revenue requirements); net plant; high, mean, and low levelized totals.

Air Quality Model (ERTAQ). This simulation program was developed by Environmental Research and Technology, Inc., of Concord, Massachusetts. ERTAQ simulates average emissions and resulting concentrations of three pollutants--SO_2, TSP, and NO_2--from all Con Edison generating facilities within a 40 x 40 km^2 grid. Incremental changes in annual average air quality are computed by modeling incremental emission changes from 1978 baseline emissions. The absolute air quality is assumed to be the sum of the incremental concentrations and 1978 baseline concentrations at each grid point. The incremental and absolute air quality impacts are calculated for the peak SO_2 emission year during 1980-1995 and also for 1995.

The annual average ambient concentrations present the overriding environmental air quality constraints for SO_2, TSP, and to a lesser extent NO_2; therefore, the analysis focused on this annual average impact. Air quality monitoring data indicates that the short-term, 1-24 hour, pollutant levels are not constraining factors in the New York Metropolitan area.

The Regulatory Analysis Financial Model (RAm). RAm was developed by Temple, Barker & Sloane, Inc., of Wellesley Hills, Massachusetts, and is used presently by Con Edison in its planning. The model is used for making financial projections for an electric utility given a set of assumptions or projections of demand, capital expenditures, operating costs, and financial and regulatory policies. RAm utilizes a combination of historical data, input assumptions concerning financial and operating relationships, and regulatory and tax accounting logic in making financial projections.

The output of the RAm model is a comprehensive array of financial statistics. For purposes of this study, however, the focus was to relate various construction expenditure patterns to the amount and type of required external financing and the resulting capital structure and SEC coverage ratios.

Output Variables

Values of output variables are calculated by the four computerized simulation models. These calculated values of output variables change among the various scenarios. As they change, they serve as "proxies" measuring the impacts which input variable values in different combinations have on Con Edison management objectives. Exhibit 4.5 lists the three general categories of output variables: measures of oil dependence; measures of dollar costs; and measures of environmental impact. Some output variables are summations or integrations from 1980-1995. Others are 'snapshots' showing conditions in the year 1995. Key output variables are discussed below.

Total cost of electricity supplied, 1980-1995 (sum of present values, billions of dollars). This measure of electricity cost includes the cost of fuel, the cost of purchased energy, other operation and maintenance costs, the fixed charge revenue requirements associated with existing or new capital facilities, as well as all other costs of doing business. Present value of that cost is used because it permits logical comparisons to be made among costs incurred at different times.

Total annual average SO_2 emissions in 1995 from all in-city power plants (grams per second). Total SO_2 emissions are important as an indicator of environmental impact. A limitation of this measure is that it does not explicitly contain information about the air quality in years prior to 1995. This limitation could be important if 1995 calculations assume scrubbers are added subsequent to the date of coal conversion. For such scenarios, this measure could give a misleading indication of total SO_2 impact from 1980-1995, although a scan of the data indicates few scenarios where this occurs.

Annual average ground level SO_2 concentrations in 1995 at the peak in-city location (micrograms per cubic meter). This measure is important for two major reasons. First, the national and local air quality standards are stated in terms of peak ground level concentrations and must not be exceeded. (There are also 3- and 24-hour SO_2 ambient standards in New York City. However, it is generally agreed that the annual average is the most constraining standard.) Second, this measure is sensitive to differences in stack heights and relative locations of the various SO_2 sources, while SO_2 emission measures are not. A weakness of this measure is that SO_2 ground concentrations in New York City would be dominated by coal conversion at the Astoria

Exhibit 4.5

OUTPUT VARIABLES

	Fuel Use Variables (Oil Dependence)	Cost Variables[1]	Environmental Impact[2] Variables
Summations (1980-1995)	Total coal consumption, millions of tons (TOTCOAL) Total oil consumption, millions of barrels (TOTOIL)	Total fuel cost, millions of dollars, present worthed to 1980 (TFUELC) Total fixed charge revenue requirements for conversion and new construction, millions of dollars, present worthed to 1980 (REVREQ) Total Costs (TFUELC + REVREQ + power plant O&M + cost of purchased energy + all other costs of business), millions of dollars, present worthed to 1980 (TOTCOST)	
Terminal Year (1995)	1995 coal consumption, millions of tons (TERMCOAL) 1995 oil consumption, millions of barrels (TERMOIL)	1995 fuel cost, millions of 1995 dollars (TERMFCST) 1995 fixed charge revenue requirements for conversion and new construction, millions of 1995 dollars (TERMRR) 1995 costs (TERMFCST + TERMRR + power plant O&M + cost of purchased energy + all other costs of business), millions of 1995 dollars (TERMTCST)	[3]Total annual average SO_2 emissions from all in-city sources of electricity, grams per second ($TERMSO_2$) [4]Worst-location-in-city annual average ground level incremental SO_2 concentrations, micrograms per cubic meter ($TERMDSO_2$) Worst-location-in-city annual average ground level total SO_2 concentrations, micrograms per cubic meter ($TERMTSO_2$) Worst-location-in-city annual average ground level total NO_2 concentration, micrograms per cubic meter ($TERMTNO_2$)

Footnotes on following page.

Exhibit 4.5 (continued)

Notes:

[1] In developing the cost variables, it was assumed that inflation between 1980-1995 would continue at an average rate of 7%. The present values of costs, where computed, were derived with a present value factor of 1.1131. The conclusions drawn from the variables are relatively insensitive to these two assumptions. In developing TOTCOST and TERMTCST, it was assumed that purchased energy was priced at 80% of the cost of the fuel replaced.

[2] TSP (particulates) were also modeled and all environmental model simulations indicated that the incremental contribution to ambient particulate levels from electricity production was extremely minor. This is due to the assumption that any coal conversion will include installation or upgrading of precipitators to high levels of efficiency (that is, about 99.6%).

[3] The total annual average SO_2 emissions, $TERMSO_2$, are the total amount of SO_2 which goes up the stacks of all sources of electricity in-city, expressed as an annual average.

[4] Ambient concentrations of SO_2 and NO_2 are expressed in two ways. First is incremental ambient concentrations caused by the difference between 1978 and 1995 emissions at the worst location in the city, $TERMDSO_2$ and $TERMDNO_2$. Second is total ground level concentrations which include the incremental concentration as well as the background concentrations, $TERMTSO_2$ and $TERMTNO_2$. These also measure the concentration levels at the worst location in the city.

Plant. Specifically, because of the stack height at Astoria this measure of SO_2 impact would be highly dominated by coal conversion at the Astoria plant, although it is relatively insensitive to coal conversion at other plants. Furthermore, this measure, like the one above, only indicates 1995 conditions which may differ from conditions in interim years.

Total oil consumption by service area power plants (including Con Edison's share of Bowline and Roseton) 1980-1995 (millions of barrels). This is a measure of the amount of oil consumed in the generation of electricity in the service area, during the entire period of the study. It is the single most important criterion by which Con Edison measures its electric energy strategy.

Regression Analysis

A regression analysis computer program called TROLL was used to estimate relationships indicative of the quantitative impact that particular input variables have on the output variables. The methodology for developing these estimated regression relationships is briefly diagramed in Exhibit 4.6. The entire process and results are described in Appendix G. The creation of these estimated regression relationships permits examination of a much wider range of possible electric energy planning choices than considered in the original list of scenarios.

Several tests were used to investigate the accuracy of the regression analysis (see page 1, Appendix G). In general, the regression analysis gave estimates within ± 5 per cent of the actual simulations. However, in very few cases the regression analysis estimates were within ± 10 per cent of the actual simulations.

Observations Concerning Electric Energy Strategy Choices

Coal

Exhibit 4.7 shows the estimated regression relationship between the total amount of coal-fired generating capacity and the amount of oil burned in the year 1995[1]. Two general observations can be drawn from this regression curve. First, as

[1] A similar relationship between availability of coal-fired generating capacity and total amount of oil burned from 1980-1995 exists (Exhibit 4.11).

Exhibit 4.6

PROCEDURE FOR ESTIMATING REGRESSION RELATIONSHIPS

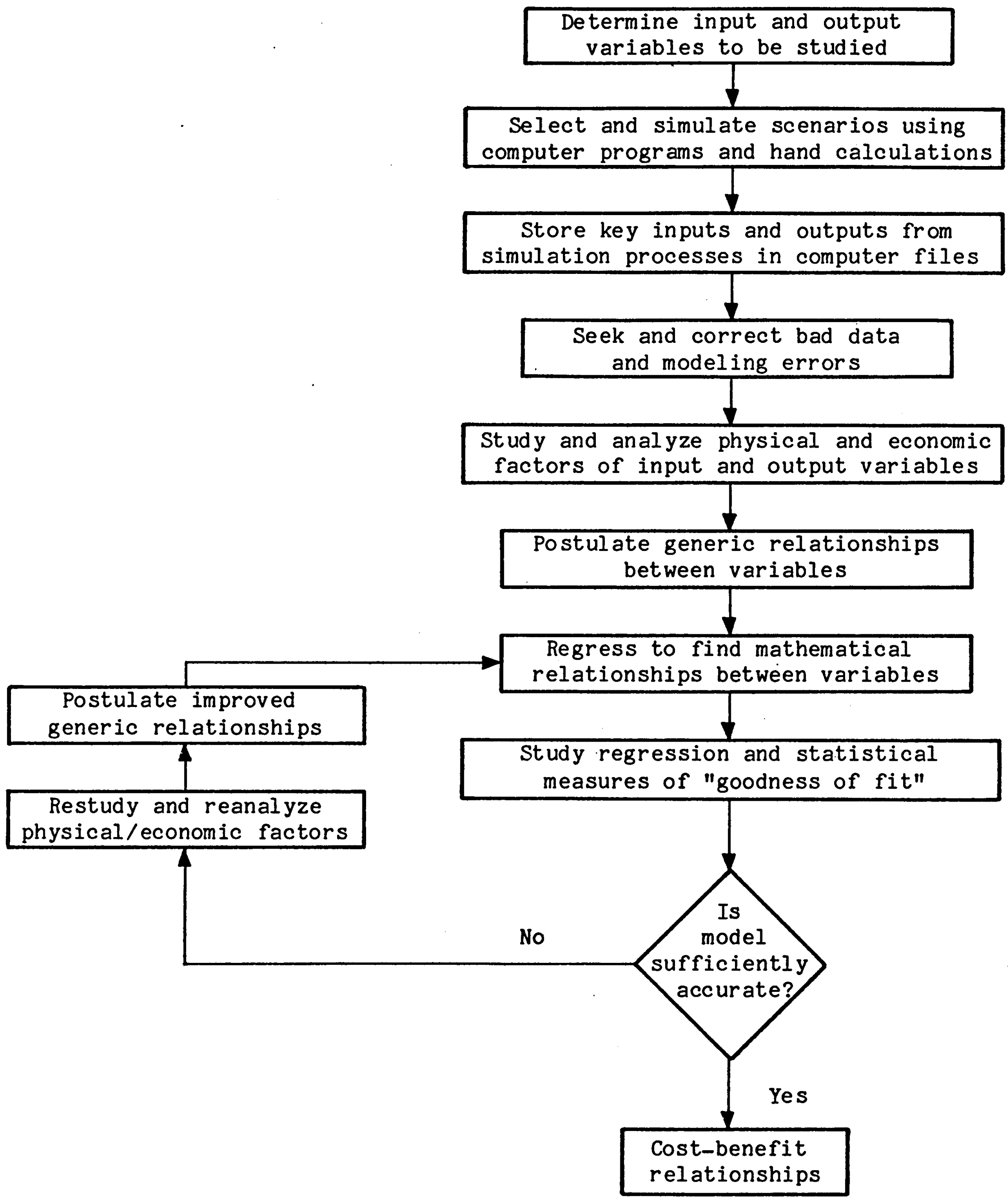
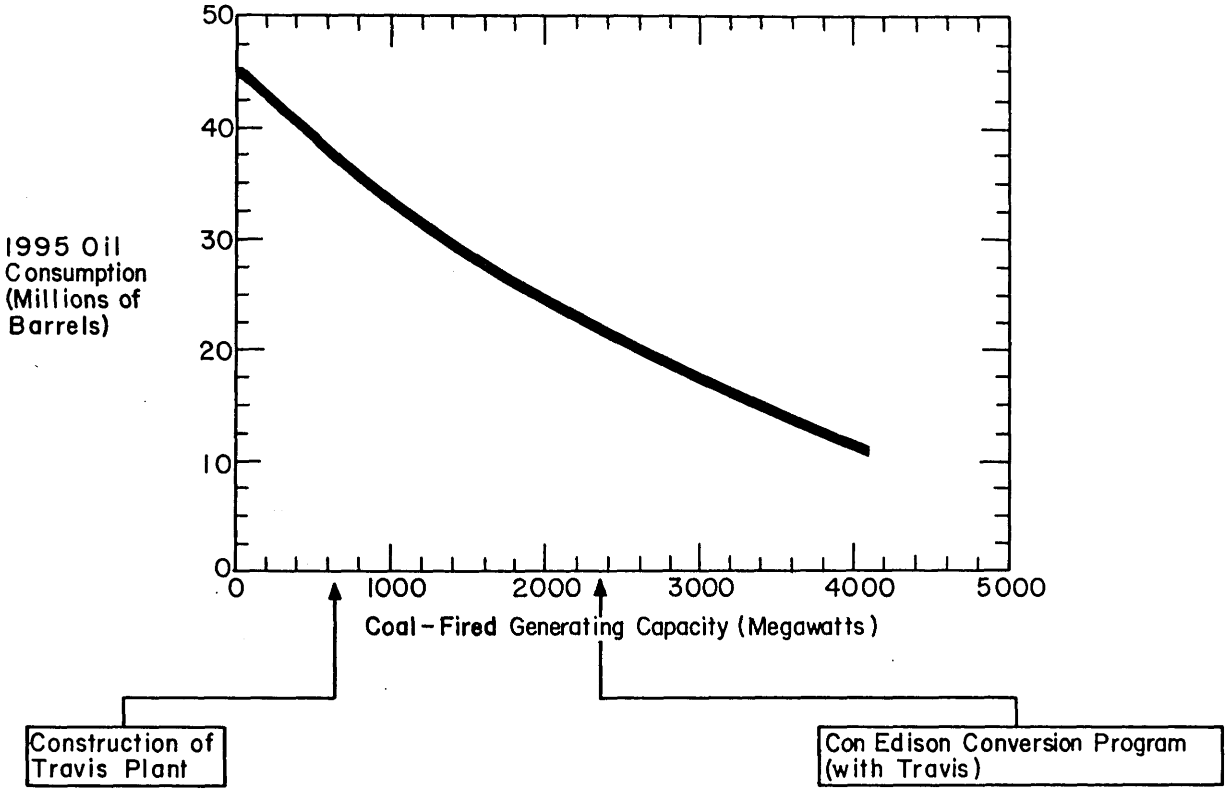


Exhibit 4.7

1995 SERVICE AREA OIL CONSUMPTION
FOR ELECTRICITY PRODUCTION
AS A FUNCTION OF COAL-FIRED GENERATING CAPACITY



Assumptions:

+1% Annual load growth.

Total purchased energy, 1980-1995 = 84.8 billion kilowatt hours.

Indian Point nuclear plant is on-line.

Prattsville pumped storage plant is on-line beginning 1987.

the amount of coal-fired generating capacity increases, the amount of oil consumed by Con Edison in 1995 decreases. Second, there are diminishing benefits in terms of reduced oil use as coal capacity increases[2]. This leveling off in oil reduction is due to the saturation effect of coal-burning shown in Exhibit 4.8: as coal-fired generating capacity increases, the rate of growth in increasing coal consumption in 1995 decreases; that is, coal consumption increases as coal burning capacity increases, but at a smaller and smaller rate. This saturation effect between the amount of coal capacity and the amount of coal burned results from normal operating economics and constraints.[3]

Exhibit 4.9 shows the estimated regression relationship between total fuel costs from 1980-1995 and the amount of coal-fired capacity for those fifteen years. Three general observations can be made from this curve. First, according to this analysis, as the amount of coal conversion increases, total fuel costs (1980-1995) generally decrease. This is due to the lower price of coal relative to the price of oil. Second, the saturation effect shown in Exhibit 4.8 operates so that the rate of cost decrease becomes smaller and smaller as the amount of coal-fired capacity (1980-1995) increases. Third, according to the curves, fuel costs generally increase as the rate of load growth increases. This is so because more fuel must be burned as load increases.[4]

Note that these cost estimates are based on a 7 per cent annual rate of inflation and 3 and 1 per cent annual growth rates in real terms during 1980-1995 for oil and coal prices respectively. If different price growth rates were assumed for oil and coal, the absolute fuel costs and costs of producing electricity would change correspondingly. However, the dispatching of the units and consequently the fuel consumption would remain the same

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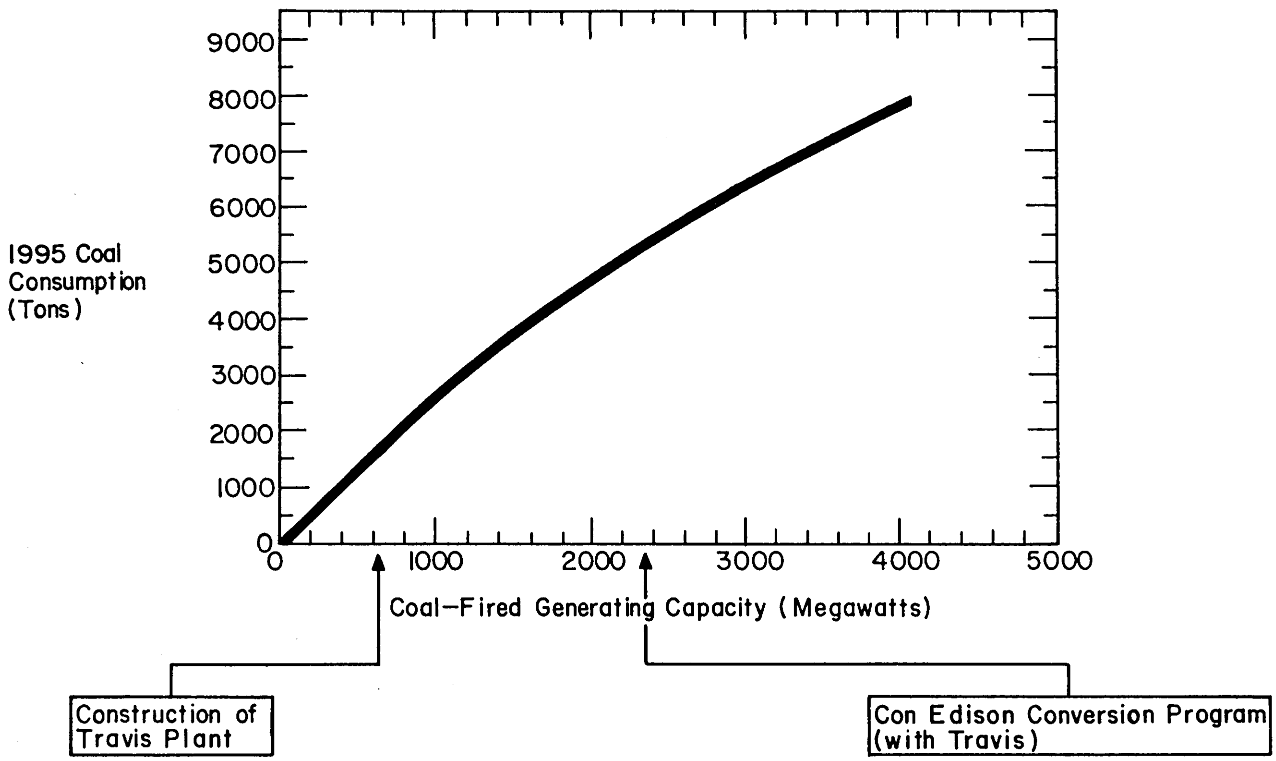
[2] There are no significant differences for strategic planning purposes between a level of coal-fired generating capacity (or COALAREA) which is all conversion and the same level of capacity (or COALAREA) which is newly constructed coal-fired plants such as Travis. Thus, both these general observations would be true for either coal conversion or new construction.

[3] Suppose, for example, that Con Edison were only able to convert one generating unit to coal. Because that unit will be able to produce electricity so much cheaper than oil-fired units, it would be operated at a very high capacity factor and would be heavily loaded, even during off-peak periods. However, if Con Edison were able to convert a large amount of capacity to coal-fired operation, then during off-peak periods the loading on those units will have to be reduced.

[4] The regression relationships between the amount of coal burned and the fuel cost in 1995 show similar behavior.

Exhibit 4.8

1995 SERVICE AREA COAL CONSUMPTION
FOR ELECTRICITY PRODUCTION
AS A FUNCTION OF COAL-FIRED GENERATING CAPACITY



Assumptions:

+1% Annual load growth.

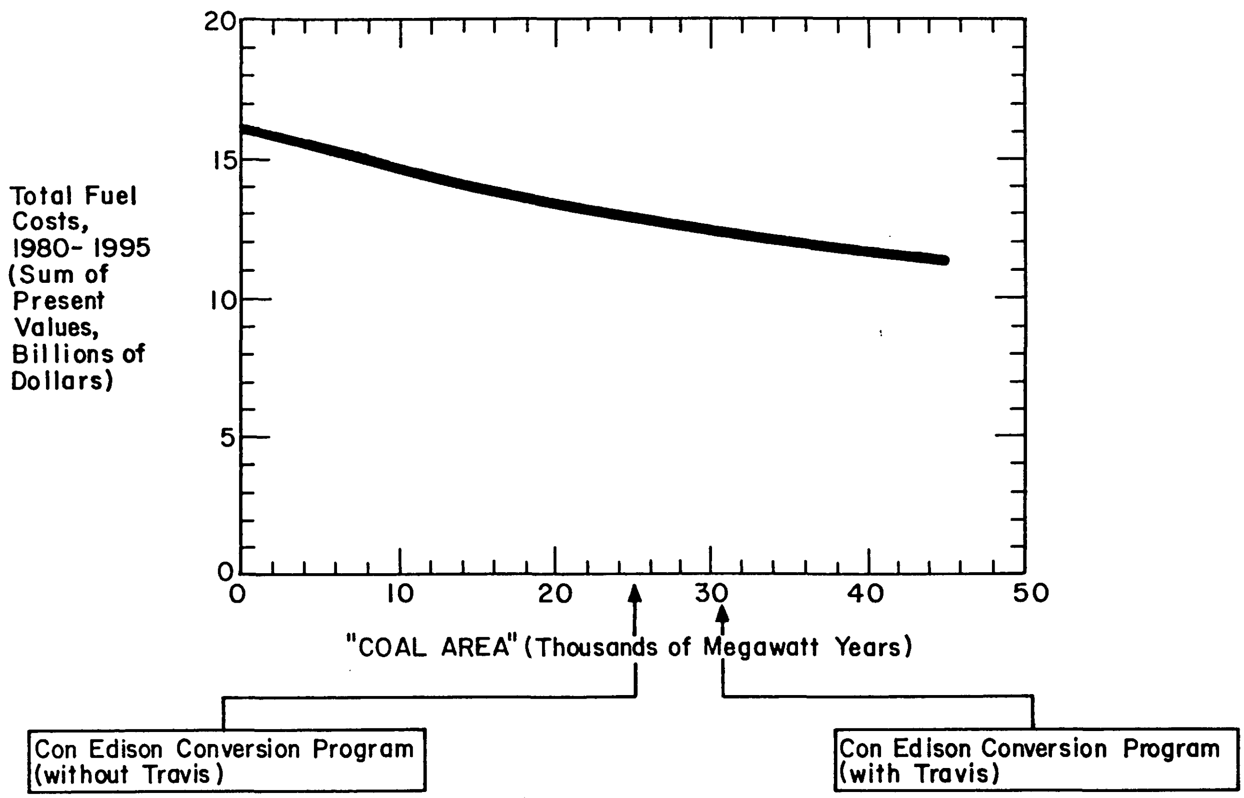
Total purchased energy, 1980–1995 = 84.8 billion kilowatt hours.

Indian Point nuclear plant is on–line.

Prattsville pumped storage plant is on-line beginning 1987.

Exhibit 4.9

TOTAL SERVICE AREA FUEL COST (1980-1995)
FOR ELECTRICITY PRODUCTION
AS A FUNCTION OF TIMING AND AMOUNT OF
COAL-FIRED CAPACITY



Assumptions:

+1% Annual load growth.

Total purchased energy, 1980-1995 = 84.8 billion kilowatt hours.

Indian Point nuclear plant is on-line.

Prattsville pumped storage plant is on-line beginning 1987.

for an oil price growth rate within the range of -2 to 10 per cent and a coal price growth rate of 0 to 5 per cent.

Exhibit 4.10 shows the estimated regression relationship between total cost of electricity supplied (1980-1995) and the 15-year amount of coal-fired capacity for various load growth assumptions. According to this relationship, increases in the amount of coal conversion and decreases in load growth generally imply reductions in total costs of electricity (1980-1995). While the percentage reductions are small, in absolute terms the impacts are large since total costs are here measured in billions of dollars.

Total cost of electricity supplied (as defined in this analysis) would decrease by about 8% if the 1700 MW of coal conversion planned by Con Edison (Arthur Kill 2 and 3 and Ravenswood 3) were completed as scheduled (Exhibit 4.10). This forecast assumes that average annual load growth of 1% (roughly Con Edison's forecast) materializes over the next 15 years. It also assumes the altered sequence of plant dispatch listed in Appendix E. More extensive coal conversion, for instance 2460 MW (Arthur Kill 2 and 3; Ravenswood 1, 2 and 3), would add about one percentage point to this reduction (Exhibit 4.10). The amount of oil consumed during the period 1980-1995 would decrease by approximately 35% and 40% (Exhibit 4.11), respectively, for the same two levels of coal conversion. Because of the fuel adjustment clause feature of New York electricity rates, these cost savings would be passed through to consumers.

Exhibit 4.12 shows, for various load growth assumptions, the estimated regression relationships between changes in the amount of coal-fired generating capacity and the total annual average SO_2 emissions from the in-city power plants in 1995 (excluding Bowline and Roseton). Exhibit 4.13 shows the estimated effect of scrubbers on SO_2 emissions. According to the curves in Exhibit 4.13, the increases in SO_2 emissions--which accompany coal-fired generating capacity increases--are generally smaller as the amount of scrubber capacity increases[5]. Con Edison's plan contemplates the use of 1% sulfur coal to limit SO_2 emissions. Under this plan SO_2 emissions will increase over current emissions with the burning of 0.3% sulfur oil. Installation of FGD equipment could prevent this increase in SO_2 emissions.

Exhibit 4.14 shows the estimated impact of adding various degrees and types of scrubbing on peak annual average ground level SO_2 concentrations in 1995. It was assumed that wet scrubbers remove 80% of the SO_2 from the flue gas. Therefore, on a pounds of SO_2 per kWh basis, burning coal with wet scrubbers is

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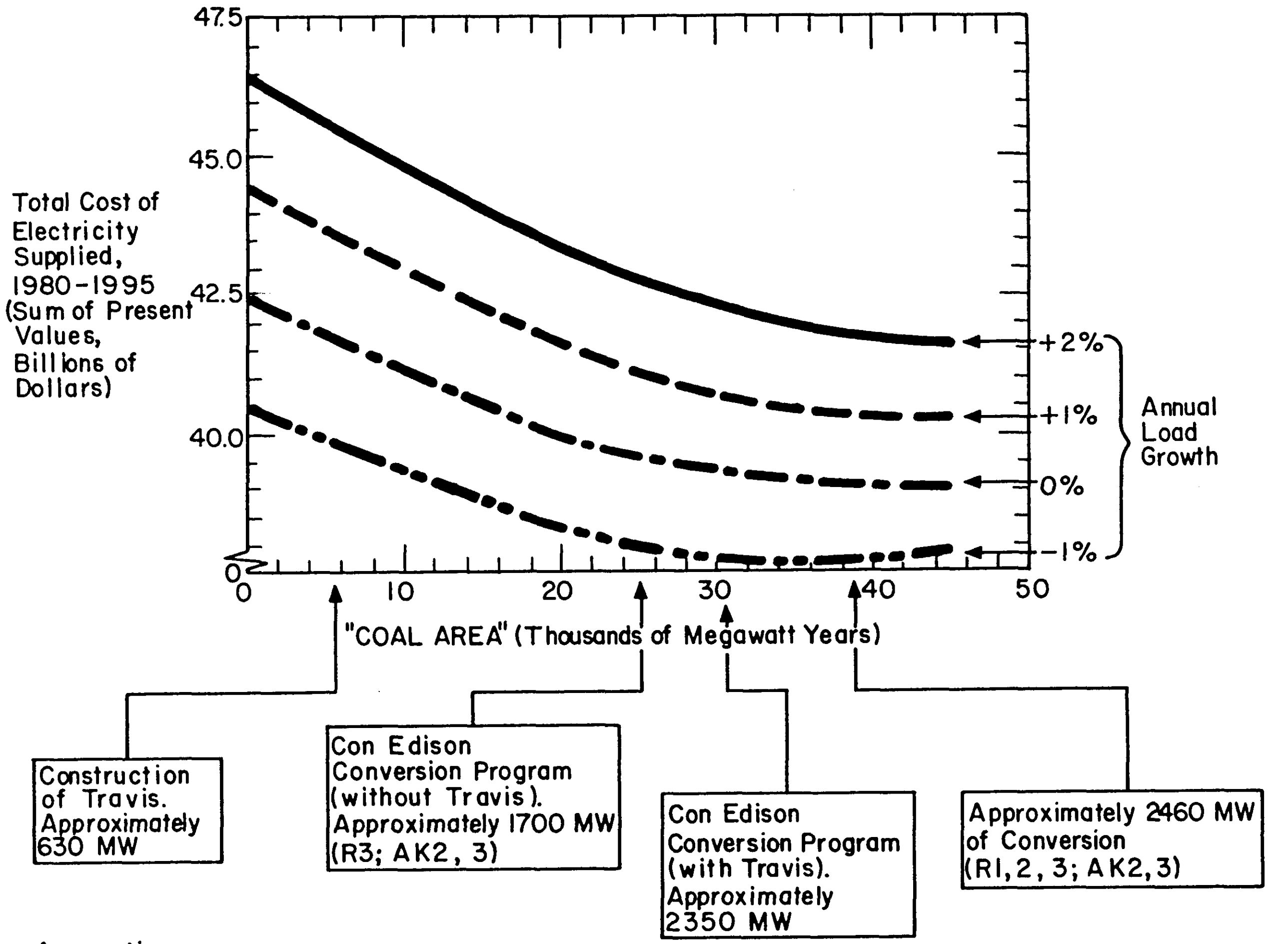
[5] The peaks and troughs of the top two curves are misleading. They are due to the methodological sequence of adding coal-fired generating units into the system.

Exhibit 4.10

EFFECT OF CHANGES IN LOAD GROWTH ON TOTAL SERVICE AREA COST OF ELECTRICITY AS A FUNCTION OF TIMING AND AMOUNT OF COAL-FIRED CAPACITY



Assumptions:

Total purchased energy, 1980–1995 = 84.8 billion kilowatt hours.

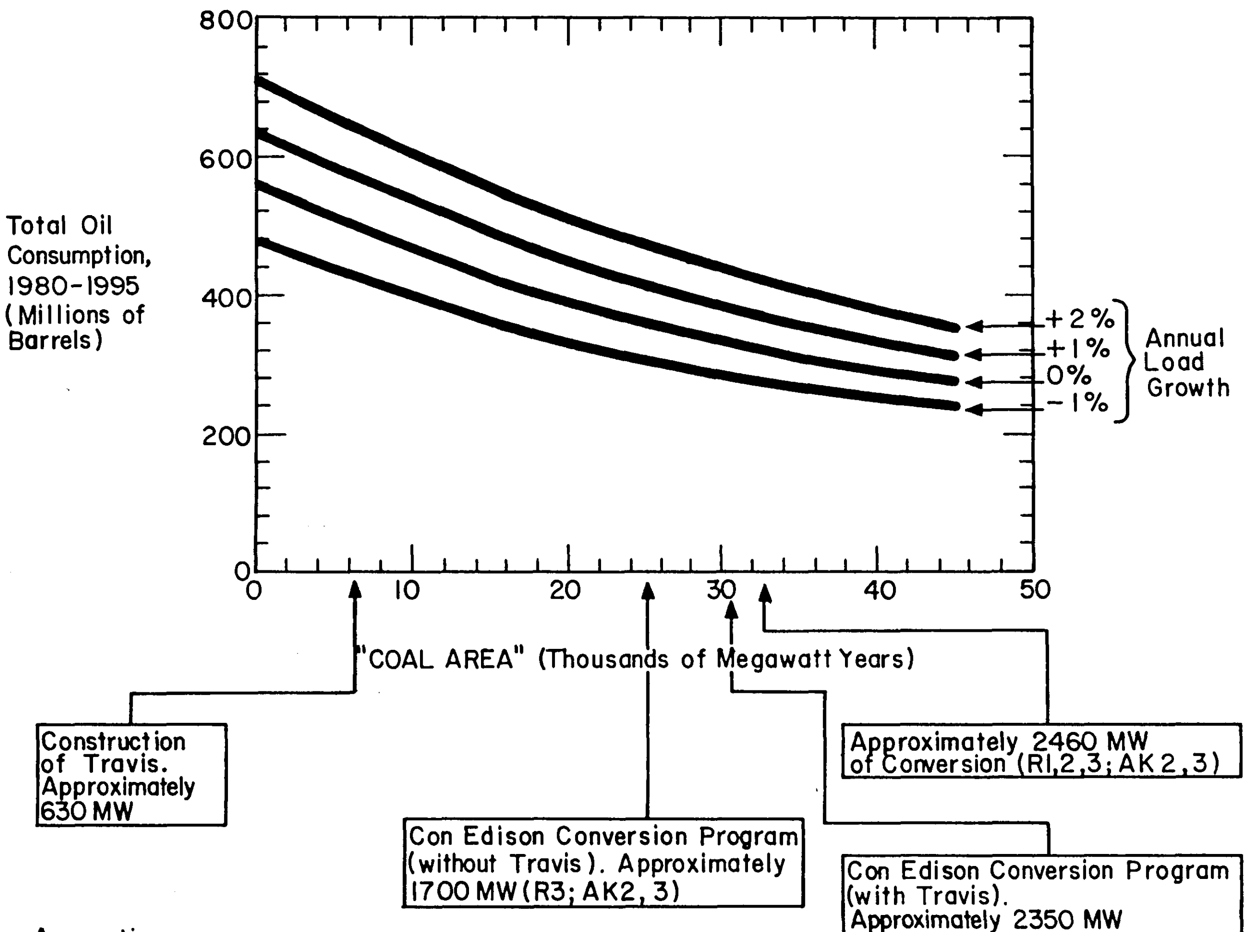
Indian Point nuclear plant is on-line.

Prattsville pumped storage plant is on-line beginning 1987.

No scrubbers except at PASNY Travis Plant.

Exhibit 4.11

EFFECT OF CHANGES IN LOAD GROWTH ON TOTAL OIL CONSUMPTION (1980–1995)



Assumptions:

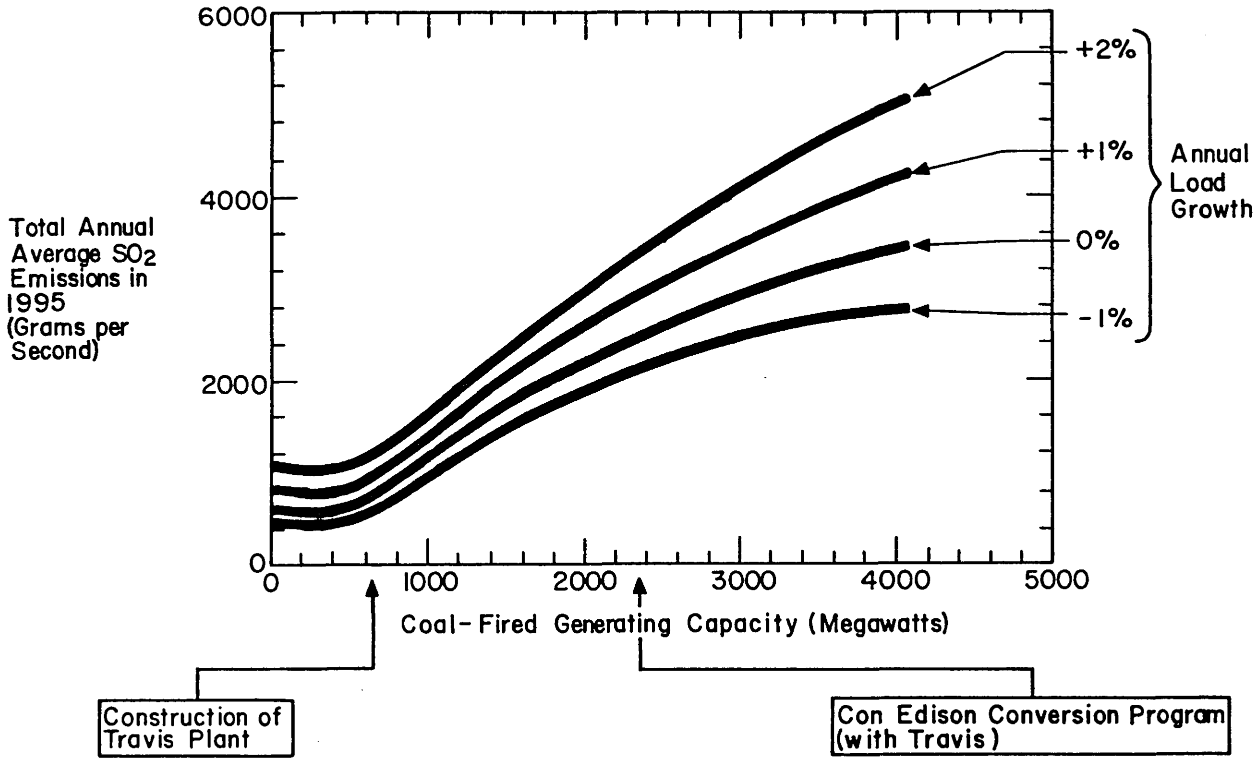
Total purchased energy, 1980–1995 = 84.8 billion kilowatt hours.

Indian Point nuclear plant is on-line.

Prattsville pumped storage plant is on-line beginning 1987.

Exhibit 4.12

EFFECT OF CHANGES IN LOAD GROWTH ON 1995 IN CITY POWER PLANT SO_2 EMISSIONS



Assumptions:

Total purchased energy, 1980-1995 =84.8 billion kilowatt hours.

Indian Point nuclear plant is on-line.

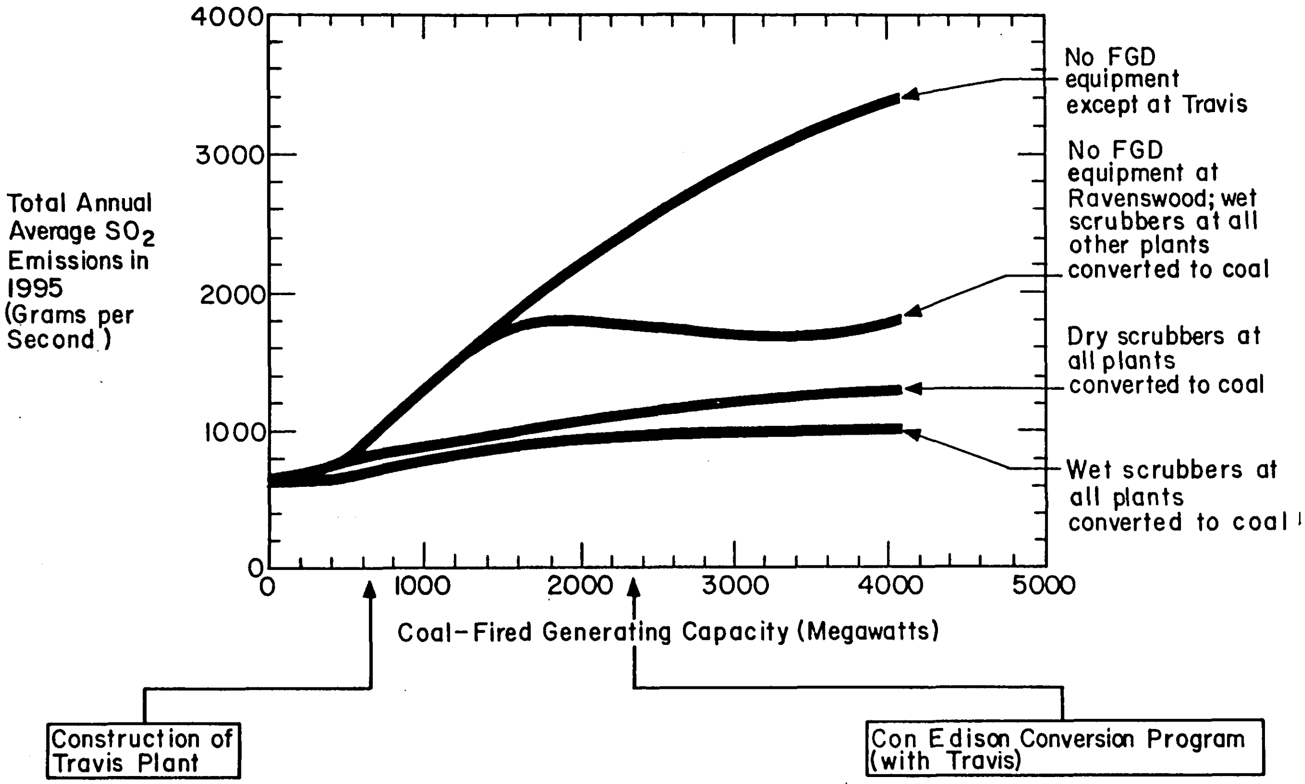
Prattsville pumped storage plant is on-line beginning 1987.

No scrubbers except at PASNY Travis plant.

The irregularity between 0 MW and 650 MW is caused by addition of the Travis plant (with scrubbers).

Exhibit 4.13

EFFECT OF CHANGE IN FLUE GAS DESULFURIZATION (FGD) EQUIPMENT ON 1995 SO_2 EMISSIONS



Assumptions:

0% Annual load growth.

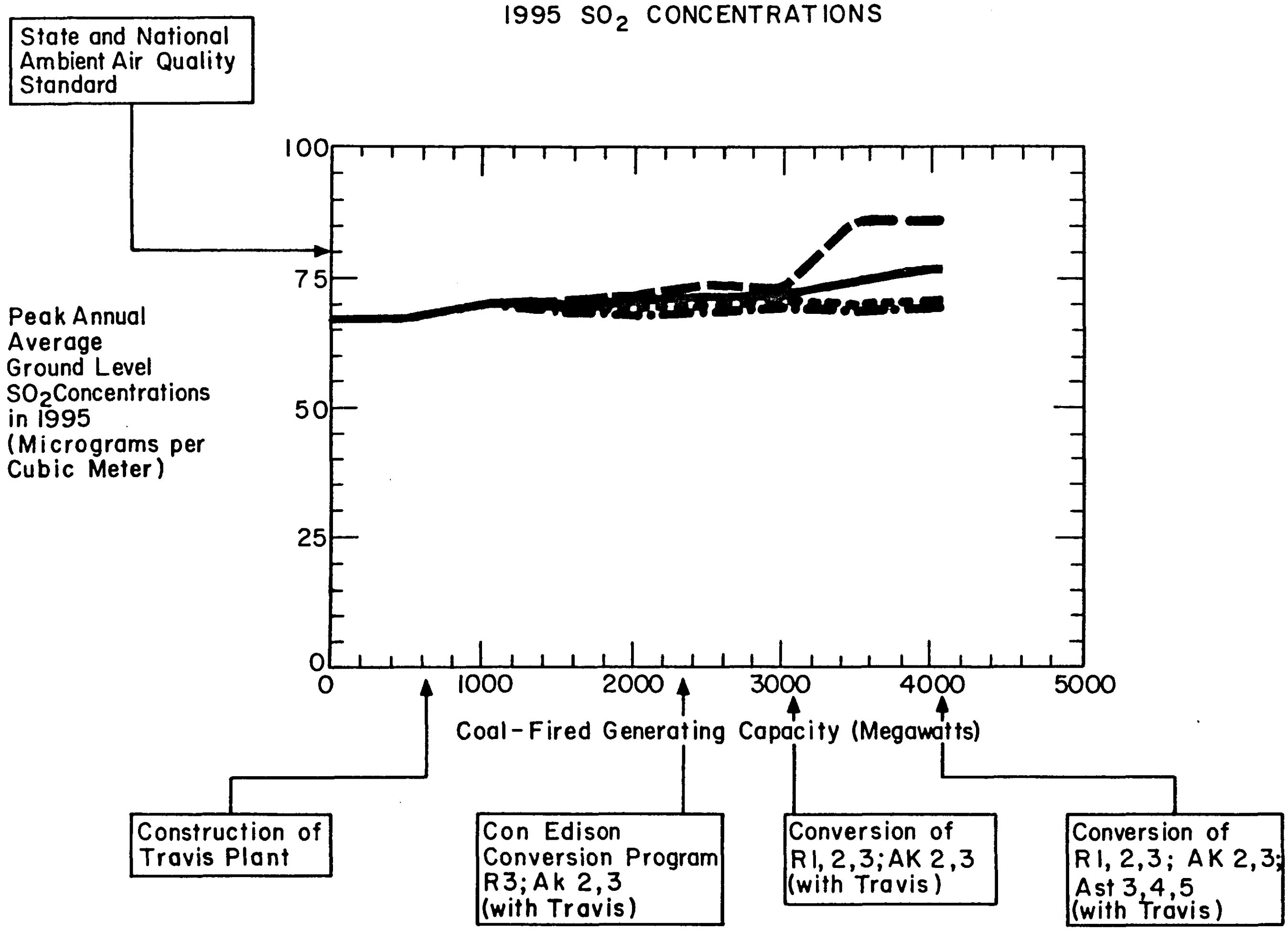
Total purchased energy, 1980 - 1995 = 84.8 billion kilowatt hours.

Indian Point nuclear plant is on-line.

Prattsville pumped storage plant is on-line beginning 1987.

Exhibit 4.14

EFFECT OF CHANGE IN FGD EQUIPMENT ON 1995 SO_2 CONCENTRATIONS



Key:

No FGD equipment except at Travis.

No FGD equipment at Ravenswood; wet scrubbers at all other plants converted to coal.

Dry scrubbers at all plants converted to coal.

Wet scrubbers at all plants converted to coal.

Assumptions:

0% Annual load growth.

Total purchased energy, 1980-1995 = 84.8 billion kilowatt hours.

Indian Point nuclear plant is on-line.

Prattsville pumped storage plant is on-line beginning 1987.

approximately equivalent to burning oil. It was assumed that dry scrubbers remove 70% of the SO_2; hence, use of dry scrubbers implies an amount of SO_2 discharge somewhat greater than that which would be produced by burning oil[6]. The increases in peak annual average ground level SO_2 concentrations in 1995--which accompany coal-fired generating capacity increases--are generally smaller as the amount of scrubber capacity increases.

Air quality analysis suggests that Con Edison's coal conversion of 1700 MW as planned (using 1% sulfur coal without FGD facilities) would not exceed SO_2 annual average ambient air quality standards in New York City (Exhibit 4.14). In fact, conversion of 2460 MW to coal burning (adding Ravenswood 1 and 2 to the planned conversion) without FGD facilities would not necessarily violate present SO_2 annual average ambient concentration standards (Exhibit 4.14). The next most reasonable units after Ravenswood for conversion would be Astoria 3, 4 and 5. Further conversion involving Astoria without FGD equipment would in all likelihood cause air quality levels to exceed SO_2 annual average ambient air quality standards (Exhibit 4.14). Conversion of Astoria plants without FGD facilities is likely to be problematic because their stack heights must be kept low due to their location in LaGuardia airport's flight pattern. It is perhaps possible that significant emission reductions from other sources could be achieved to reduce ambient SO_2 in the more polluted areas of New York City, perhaps by conversion of low level sources to natural gas.

The predicted total NO_2 concentrations are not very sensitive to burning coal in power plants, nor are they expected to present an environmental constraint for coal conversions. Specifically, peak annual average ambient NO_2 concentrations were between 88 and 93 micrograms per cubic meter for all scenarios, and the federal and state primary standard is 100 micrograms per cubic meter. Furthermore, assuming high-efficiency, commercially-available precipitators are used, total suspended particulate (TSP) concentrations are not increased significantly by conversion to coal.

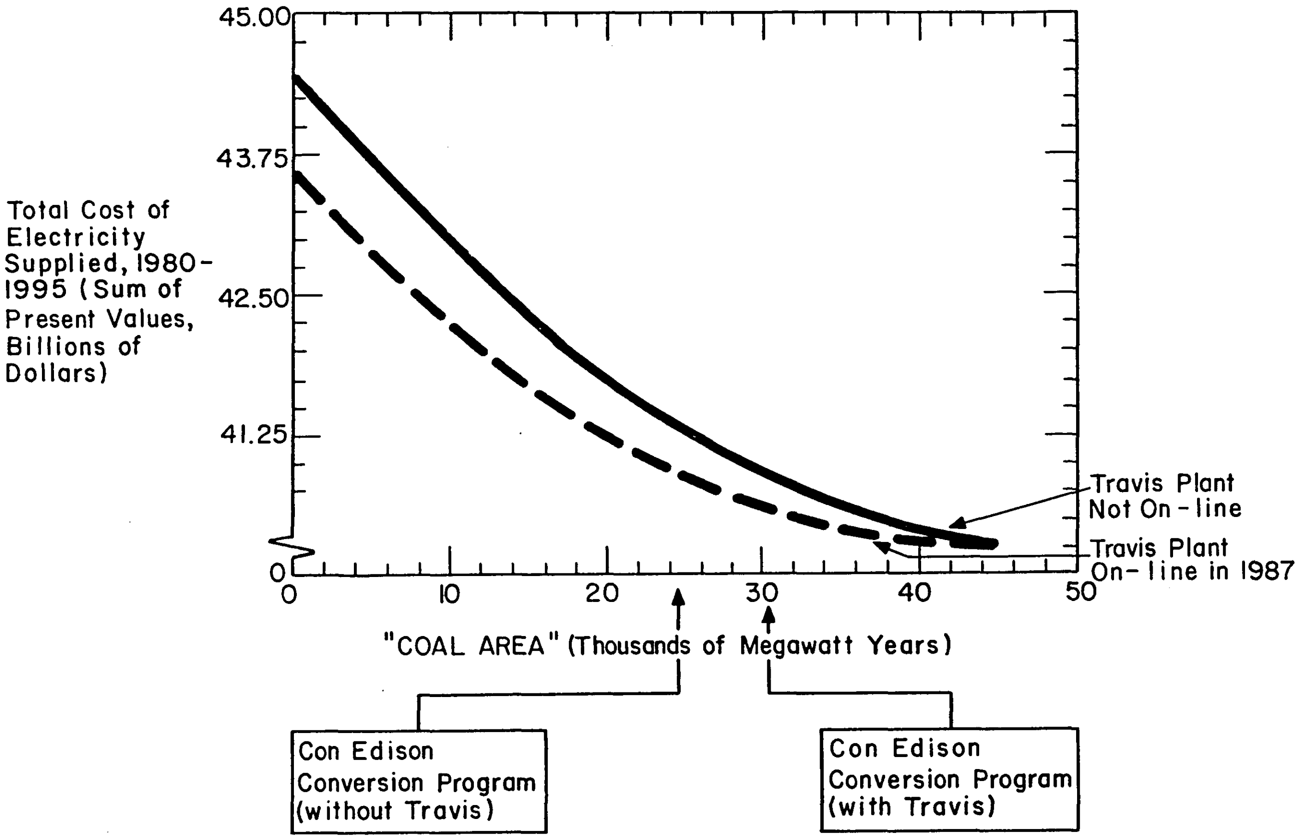
Travis

The overall attractiveness of Travis with respect to Con Edison electric energy strategy objectives would be large if Con Edison were not permitted to convert existing units to burn coal. However, given the proposed coal conversion, the impact is significant but not as large (Exhibits 4.15 and 4.16). This is so due to the saturation effect of coal use (shown in Exhibit

[6] Assuming 1.6 lb. SO_2/MBtu for coal and 0.31 lb. SO_2/MBtu for residual oil.

Exhibit 4.15

EFFECT OF TRAVIS PLANT ON TOTAL COST (1980-1995)



Assumptions:

+1% Annual load growth.

Total purchased energy, 1980-1995 = 84.8 billion kilowatt hours.

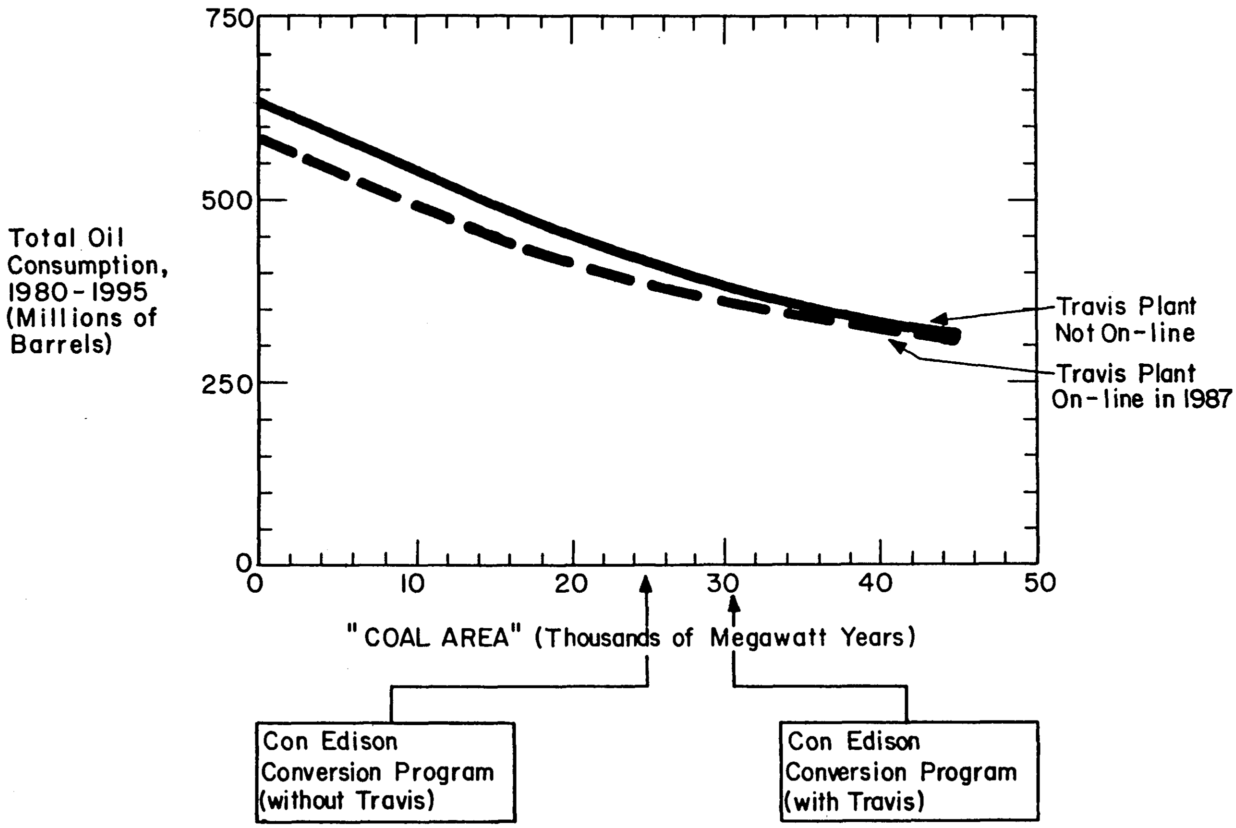
Indian Point nuclear plant is on-line.

Prattsville pumped storage plant is on-line beginning 1987.

No scrubbers except at PASNY Travis plant.

Exhibit 4.16

EFFECT OF TRAVIS PLANT ON TOTAL OIL CONSUMPTION (1980-1995)



Assumptions:

+1% Annual load growth.

Total purchased energy, 1980-1995 = 84.8 billion kilowatt hours.

Indian Point nuclear plant is on-line.

Prattsville pumped storage plant is on-line beginning 1987.

4.8) which causes a decrease in oil and cost benefits as the amount of coal in the system increases. (As a new coal-fired plant, Travis is presently required to have scrubbers. Thus, its impact on SO_2 is expected to be small.)

Purchased Energy

According to the regression curve in Exhibit 4.17, purchase of electric energy by Con Edison would have at best a small impact on the total cost of electricity supplied. This is so because the planned purchases represent only a small share of the service area's electricity demand and because most of this energy is currently priced near the cost of energy that it replaces. However, increased use of purchased energy will decrease oil dependence somewhat and slightly decrease environmental pollution in New York City (Exhibits 4.18 and 4.19). This is because most sources of purchased energy use alternate fuels to generate energy and do so outside of New York City.

Pumped Hydroelectric

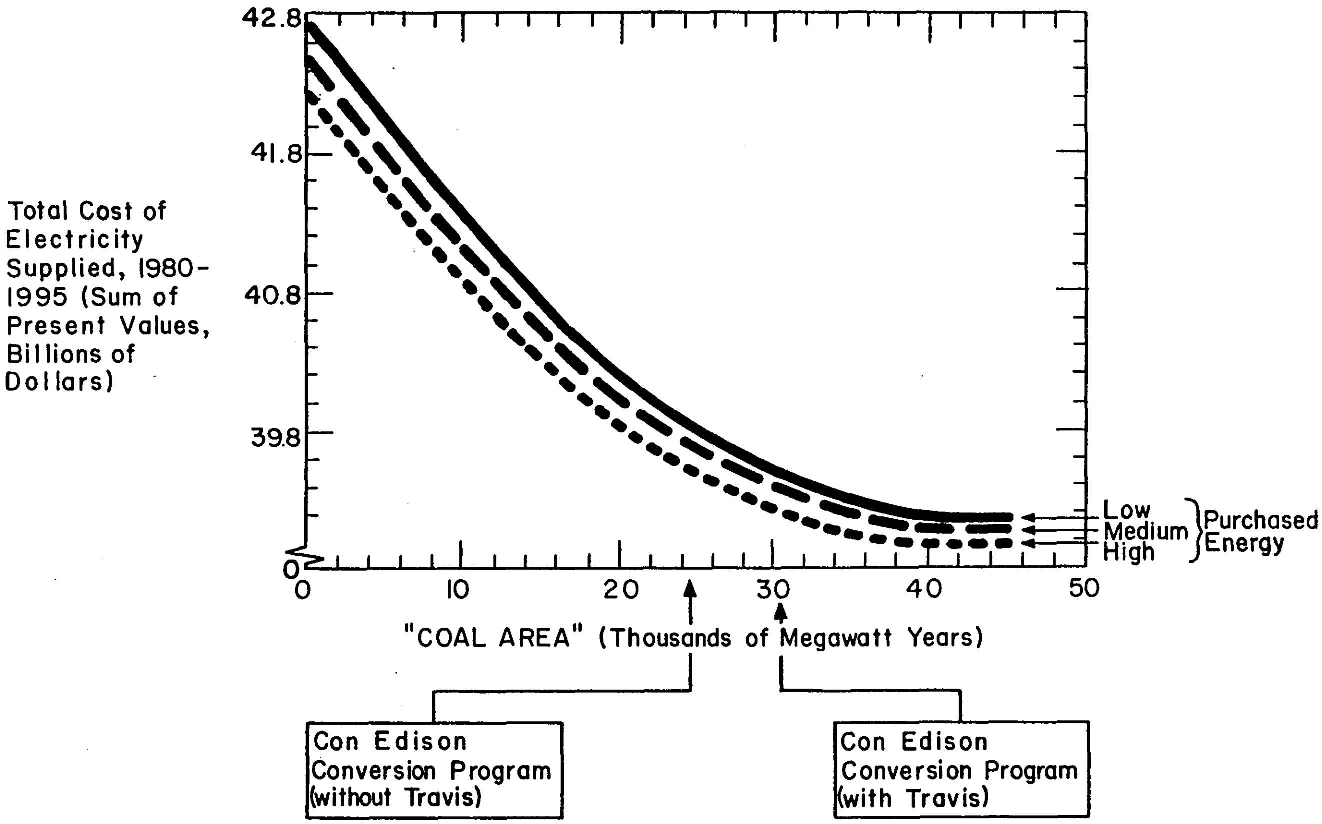
PASNY plans to build a pumped hydroelectric facility to serve the Con Edison service area, with a projected in-service date of 1987. Based on this analysis, which considered only three groups of criteria of merit and only the next 15 years, this proposed facility has a negligible impact on Con Edison energy strategy objectives in the 1980's (Exhibits 4.20 and 4.21). However, this analysis is too narrow in scope to permit a valid assessment of the overall value of this facility, which has an expected life of more than 50 years and a variety of possible benefits not analyzed here.

Conservation

The direct impact of conservation on Con Edison is that it reduces load growth. Exhibits 4.10, 4.11 and 4.12 show the impacts that various annual load growth rates have on total cost of electricity supplied (1980-1995), total oil consumption (1980-1995), and total annual average SO_2 emissions in 1995. According to these regression curves, as the rate of load growth decreases from +2% to -1%, the levels of all three of these output variables decrease. For 25,000 MW years of coal burning, for instance, total costs decrease from approximately $43 billion at +2% load growth to $38 billion at -1% load growth. For 25,000 MW years of coal burning, total oil consumption decreases from approximately 450 million barrels of oil to 300 million barrels of oil. Likewise, for 25,000 MW years of coal burning, annual average SO_2 decreases from approximately 3500 grams per second at 2% load growth to 2200 grams per second at -1% load growth.

Exhibit 4.17

EFFECT OF CHANGE IN PURCHASED ENERGY ON TOTAL COST (1980-1995)



Assumptions:

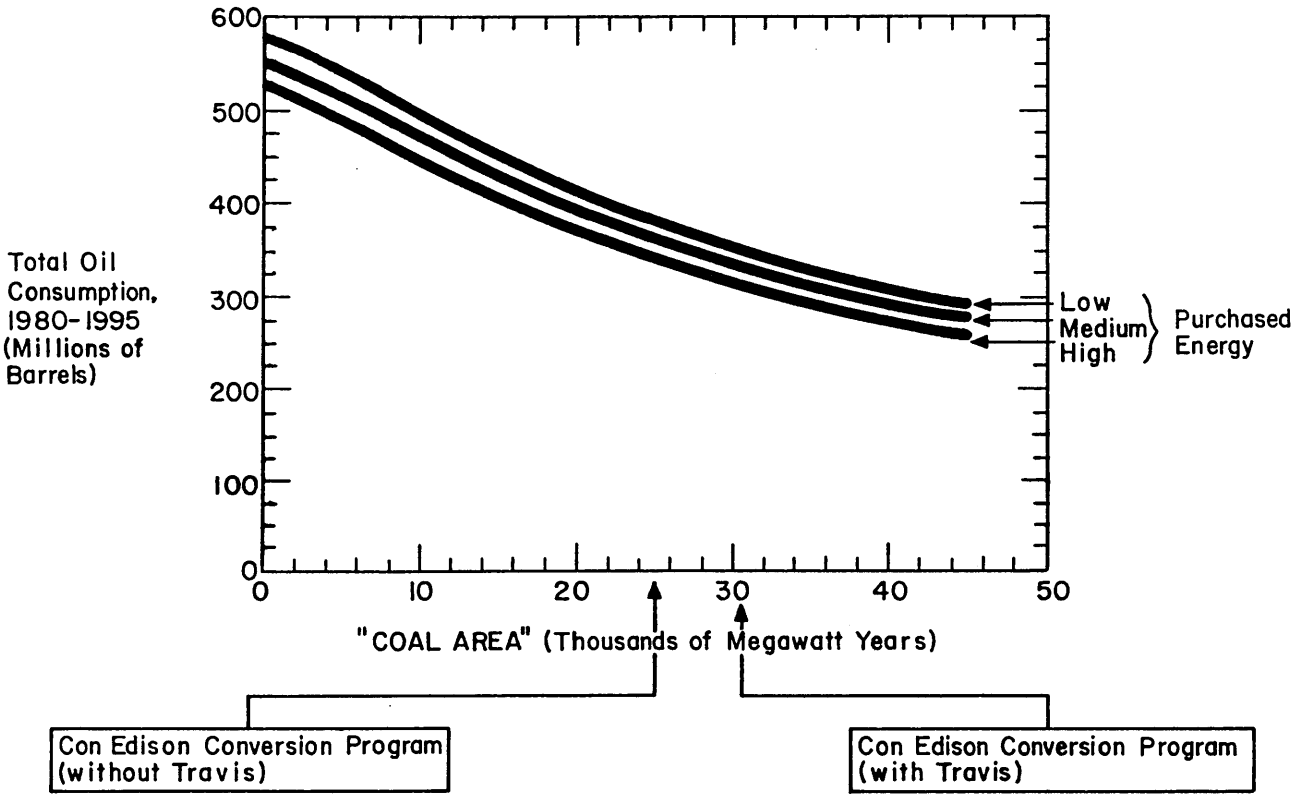
0% Annual load growth.

Indian Point nuclear plant is on-line.

Prattsville pumped storage plant is on-line beginning 1987.

Exhibit 4.18

EFFECT OF CHANGE IN PURCHASED ENERGY ON TOTAL OIL CONSUMPTION (1980-1995)



Assumptions:

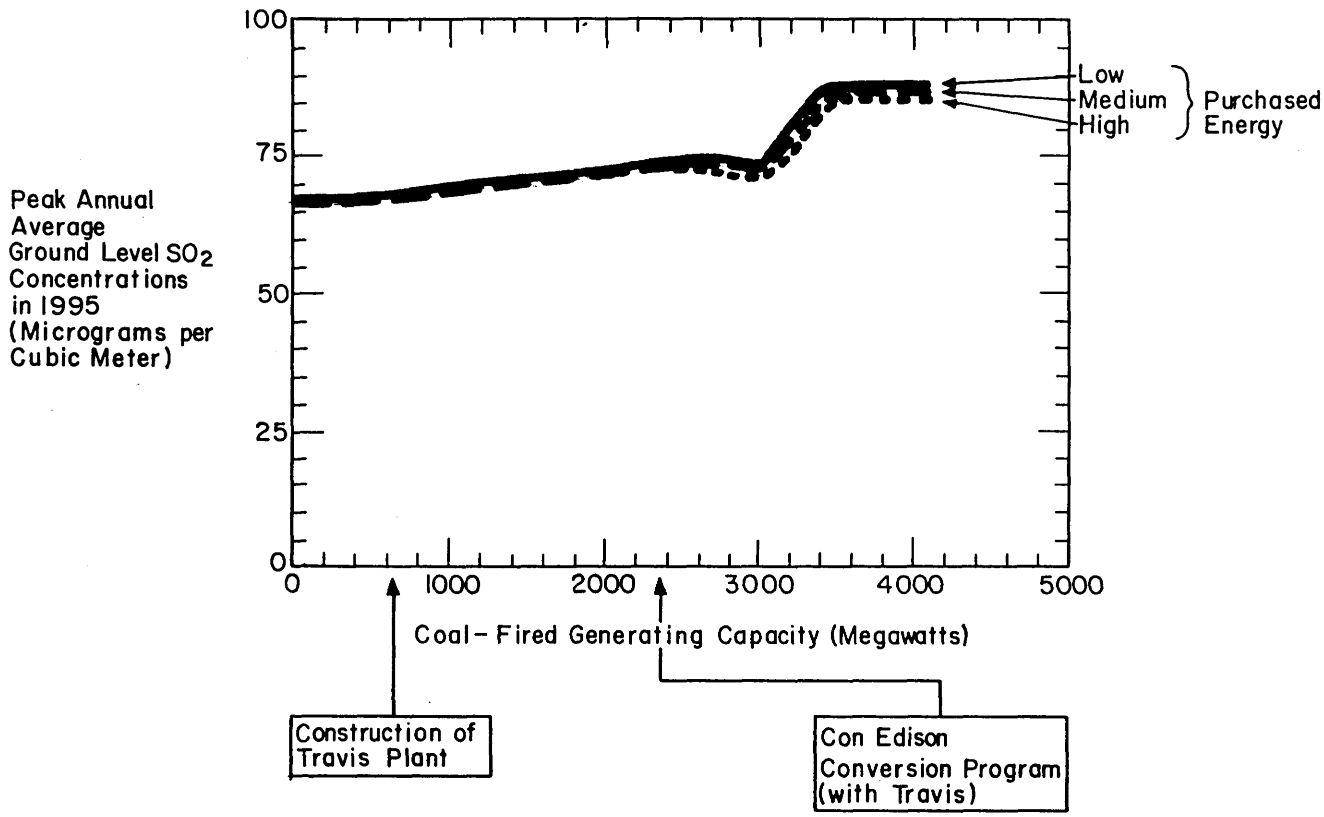
0% Annual Load Growth.

Indian Point nuclear plant is on-line.

Prattsville pumped storage plant is on-line beginning 1987.

Exhibit 4.19

EFFECT OF CHANGE IN PURCHASED ENERGY ON
1995 SO_2 CONCENTRATIONS



Assumptions:

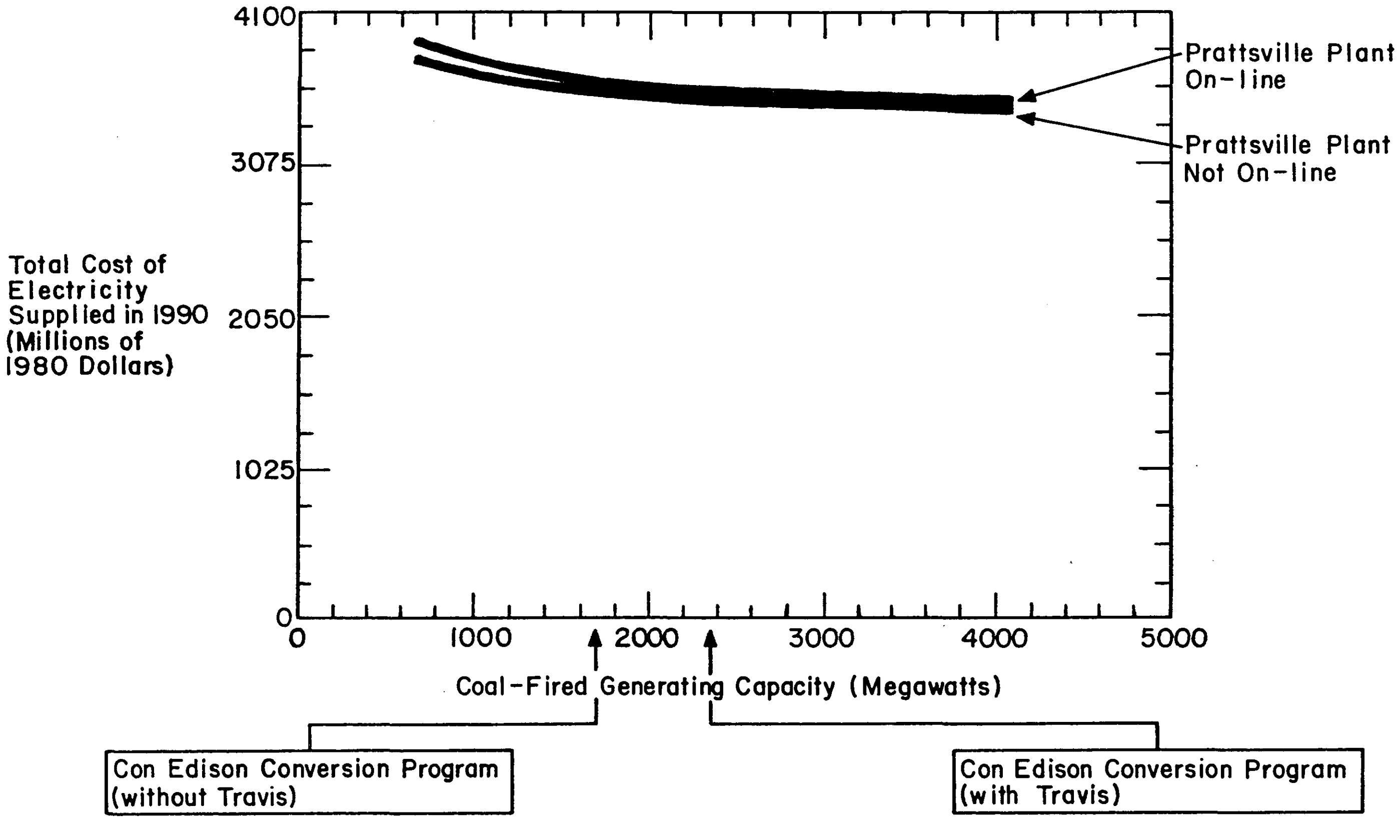
0% Annual load growth.

Indian Point nuclear plant is on-line.

Prattsville pumped storage plant is on-line beginning 1987.

Exhibit 4.20

EFFECT OF PRATTSVILLE PUMPED STORAGE PLANT
ON 1990 TOTAL COSTS



Assumptions:

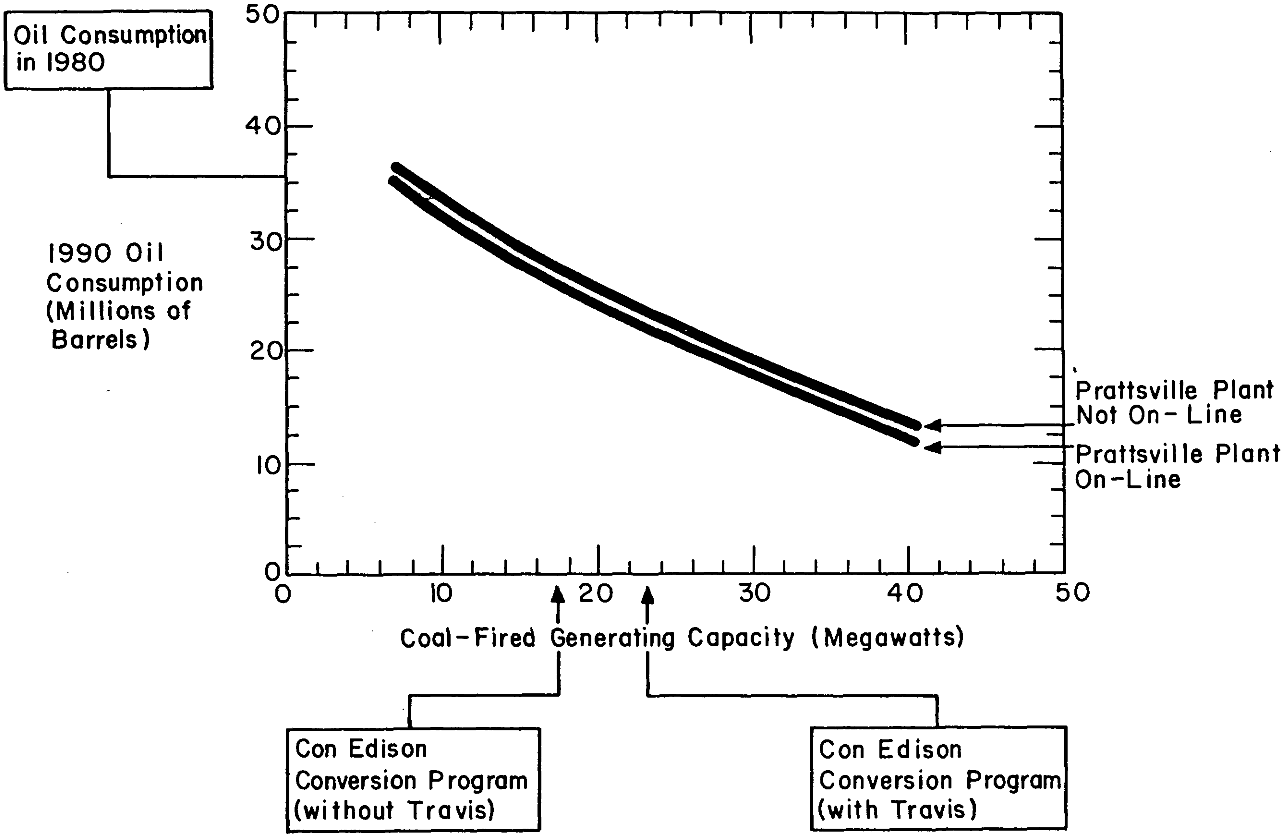
+1% Annual load growth.

Total purchased energy, 1980-1995 = 84.8 billion kilowatt hours.

Indian Point nuclear plant is on-line.

Exhibit 4.21

EFFECT OF PRATTSVILLE PUMPED STORAGE PLANT ON
1990 OIL CONSUMPTION



Assumptions:

0% Annual load growth.

Total purchased energy, 1980-1995 = 84.8 billion kilowatt hours.

Indian Point nuclear plant is on-line.

The electric load growth during 1980-1995 will depend both on the effectiveness of conservation efforts and the level of economic activity during this period. Both of these effects are difficult to forecast with precision. Con Edison and PASNY project an annual load growth of 1.0% in the service area from 1980-1995.

Additional conservation efforts could further reduce the annual electricity load growth during 1980-1995. For example, if, by 1995, load limiting devices (LLDs) are installed for all commercial peak load customers who could utilize LLDs, and if one-third of master-meter consumption is converted to sub-metering, then annual electricity load growth during 1980-1995 could be further reduced by about 0.5%. This may reduce total cost of electricity by approximately 0.5 billion dollars (present value in 1980) and lead to about 20 million barrels less oil consumption during 1980-1995. (This calculation assumes that Con Edison's coal conversion plan is implemented.)

This investigation provides some measure of the benefits associated with realization of this potential. It does not provide a comprehensive analysis of either benefits or costs, nor has it investigated who should bear these costs. Modifications in existing regulations might be required for Con Edison to be able to participate in certain types of conservation programs. Examples are being seen in certain other states.

Financial Impacts

Exhibit 4.22 lists the ten scenarios that were selected from the 126 for RAm model analysis and are therefore called Financial Scenarios. To assure a robust analysis of Con Edison's financing capability, several of the highest-cost scenarios are included in this list even though it is unlikely that they will be implemented. Exhibit 4.23 summarizes the fifteen-year financial impacts of these ten scenarios under the financially conservative assumption that the minimum SEC coverage ratio does not go below 3.25. (If a scenario resulted in a small, temporary violation of this assumption, the violation was considered insignificant.) Exhibit 4.24 summarizes the fifteen-year financial impacts of the ten scenarios when there is no restriction on the minimum SEC coverage ratio, a somewhat less rigorous financial policy.

Estimates of total cumulative construction expenditures for the last eight scenarios range from $10.8 billion for the lowest-cost scenario to $12.4 billion for the highest-cost scenario. These expenditure levels require external financing in the range of $6.4 to $7.6 billion over the period 1980-1994. The equity component of the external financing required varies considerably among the different scenarios. Under a financial policy that targets a minimum SEC coverage of 3.25, the required equity financing level ranges from $1.2 billion to $1.8 billion.

Exhibit 4.22

LIST OF TEN FINANCIAL SCENARIOS

Financial Scenario	1:	This is referred to as the Base Case scenario since it is the current Con Edison strategy for coal conversion: conversion of Ravenswood 3 and Arthur Kill 2 and 3 without scrubbers (Code "ST").
Financial Scenario	2:	Con Edison's "Fuel Strategy for the 1980's" assumes purchases from PASNY's proposed Travis and Prattsville plants, which are expected to be in service in 1987. If construction of these facilities is significantly delayed, Con Edison expects it will have to construct additional generating capacity. This scenario, which would involve expenditures on new company-built generating capacity starting in the mid-1980's, is referred to as the Alternative A case.
Financial Scenario	3:	This is the maximum coal conversion scenario in which Ravenswood 3, Arthur Kill 2 and 3, Ravenswood 1 and 2, and Astoria 3, 4, and 5 are all converted (Code "FT").*
Financial Scenario	4:	This is the same as Financial Scenario 1 but delayed by two years (Code "TD").
Financial Scenario	5:	This is the same as Financial Scenario 1 with wet scrubbers installed at each plant after conversion (Combination of Code "FT" and "SC").
Financial Scenario	6:	This is the conversion of Arthur Kill 2 and 3, and Astoria 3, 4, and 5, no scrubbers (Code "NR").
Financial Scenario	7:	This is the conversion of Arthur Kill 2 and 3 without scrubbers, the conversion of Ravenswood 3 with installation of wet scrubbers at a later date, and the conversion of Ravenswood 1 and 2 and Astoria 3, 4, and 5 with wet scrubbers added at time of conversion (Code "DS").

*A description of each financial scenario can be found in Appendix F, including specific conversion date, and date and type of scrubber installation. The code names on this table refer to the code used in Appendix F to identify the coal conversion plans in various scenarios.

Exhibit 4.22 (continued)

Financial Scenario 8:	This is conversion of all eight plants converted in Financial Scenario 5, plus the addition of a dry or wet scrubber at each plant (Code "DW").
Financial Scenario 9:	This is the conversion of Arthur Kill 2 and 3, plus Ravenswood 3 with scrubbers added at each plant after conversion (Code "DR").
Financial Scenario 10:	This is the conversion of Arthur Kill 2 and 3, plus Ravenswood 3 with a scrubber added after conversion only at Ravenswood 3 (Code "DRA").

Exhibit 4.23

SUMMARY OF 15 YEAR PROJECTED FINANCIAL IMPACT
OF 10 FINANCIAL SCENARIOS
(1980 THROUGH 1994)
RAm MODEL ANALYSIS

Assumption: Minimum SEC Coverage of 3.25

	Financial Scenario 1 Con Edison	Financial Scenario 2 Alt "A"	Financial Scenario 3 "FT"	Financial Scenario 4 "TD"	Financial Scenario 5 "FT"&"SC"	Financial Scenario 6 "NR"
Total Construction Expenditures 1980-1994 ($mm)	10,569	14,160	11,128	11,231	12,334	10,808
Total External Financing Required ($mm)	6,204	10,777	6,559	6,734	7,477	6,397
Total Long Term Debt ($mm)	4,355	6,394	4,499	4,612	4,914	4,434
Total Preferred Stock ($mm)	755	1,329	725	737	821	774
Total Common Stock ($mm)	1,097	3,054	1,335	1,385	1,742	1,189
Year First Common Stock Issued	1991	1989	1988	1988	1987	1991
Minimum SEC Coverage Level*	3.25	3.24	3.26	3.24	3.16	3.19
Year of Minimum SEC Coverage	1994	1991	1994	1988	1987	1991
Minimum Equity Ratio (%)	45.3	45.7	45.7	46.0	45.8	45.3
Year of Minimum Equity Ratio	1991	1994	1992	1994	1990	1991

*This variable measures the ratio of earnings to interest payments; a ratio of 3.0 indicates earnings three times the size of interest payments.

Exhibit 4.23 (continued)

	Financial Scenario 7 "DS"	Financial Scenario 8 "DW"	Financial Scenario 9 "DR"	Financial Scenario 10 "DRA"	Range of Values Scenarios 2-10
Total Construction Expenditures 1980-1994 ($mm)	12,103	12,451	11,245	10,822	10,808 - 12,451
Total External Financing Required ($mm)	7,291	7,609	6,733	6,423	6,397 - 7,609
Total Long Term Debt ($mm)	4,974	4,981	4,589	4,349	4,349 - 4,981
Total Preferred Stock ($mm)	742	836	812	777	725 - 836
Total Common Stock ($mm)	1,575	1,792	1,332	1,297	1,189 - 1,792
Year First Common Stock Issued	1987	1987	1989	1991	1987 - 1991
Minimum SEC Coverage Level*	3.22	3.25	3.23	3.23	3.16 - 3.26
Year of Minimum SEC Coverage	1988	1987	1989	1991	1987 - 1994
Minimum Equity Ratio (%)	45.9	45.9	45.4	45.0	45.3 - 46.0
Year of Minimum Equity Ratio	1990	1990	1990	1990	1990 - 1994

*This variable measures the ratio of earnings to interest payments; a ratio of 3.0 indicates earnings three times the size of interest payments.

Exhibit 4.24

SUMMARY OF 15 YEAR PROJECTED FINANCIAL IMPACT
OF 10 FINANCIAL SCENARIOS
(1980 THROUGH 1994)
RAm MODEL ANALYSIS

Assumption: No Restriction on SEC Coverage Level

	Financial Scenario 1 Con Edison	Financial Scenario 2 Alt "A"	Financial Scenario 3 "FT"	Financial Scenario 4 "TD"	Financial Scenario 5 "FT"&"SC"	Financial Scenario 6 "NR"
Total Construction Expenditures 1980-1994 ($mm)	10,596	14,160	11,128	11,231	12,334	10,808
Total External Financing Required ($mm)	6,207	10,777	6,576	6,754	7,502	6,412
Total Long Term Debt ($mm)	4,355	6,394	4,522	4,577	4,937	4,687
Total Preferred Stock ($mm)	755	1,329	796	809	899	773
Total Common Stock ($mm)	1,097	3,054	1,258	1,368	1,666	952
Year First Common Stock Issued	1991	1989	1991	1989	1987	1991
Minimum SEC Coverage Level*	3.25	3.24	3.12	3.02	2.89	3.03
Year of Minimum SEC Coverage	1994	1991	1991	1989	1989	1992
Minimum Equity Ratio (%)	45.3	45.7	44.6	44.5	44.5	43.6
Year of Minimum Equity Ratio	1991	1994	1990	1990	1990	1991

*This variable measures the ratio of earnings to interest payments; a ratio of 3.0 indicates earnings three times the size of interest payments.

Exhibit 4.24 (continued)

	Financial Scenario 7 "DS"	Financial Scenario 8 "DW"	Financial Scenario 9 "DR"	Financial Scenario 10 "DRA"	Range of Values Scenarios 2-10
Total Construction Expenditures 1980-1994 ($mm)	12,103	12,451	11,245	10,822	10,808 - 12,451
Total External Financing Required ($mm)	7,319	7,637	6,742	6,425	6,412 - 7,637
Total Long Term Debt ($mm)	4,827	5,008	4,586	4,443	4,443 - 5,008
Total Preferred Stock ($mm)	882	915	813	776	773 - 915
Total Common Stock ($mm)	1,565	1,714	1,343	1,206	952 - 1,714
Year First Common Stock Issued	1988	1988	1990	1991	1987 - 1991
Minimum SEC Coverage Level*	2.92	2.89	3.11	3.18	2.89 - 3.18
Year of Minimum SEC Coverage	1989	1989	1991	1991	1989 - 1992
Minimum Equity Ratio (%)	44.5	44.5	44.5	45.3	43.6 - 45.3
Year of Minimum Equity Ratio	1990	1990	1990	1991	1990 - 1991

*This variable measures the ratio of earnings to interest payments; a ratio of 3.0 indicates earnings three times the size of interest payments.

Under the highest-cost scenarios, numbers 5, 7, and 8, equity is required each year beginning in 1987.

With no restriction on SEC coverage level, the SEC coverage drops below 3.0 in only the three highest-cost scenarios and then only to approximately 2.9. Equity is still required in 1987 or 1988. Under the no restriction on SEC coverage assumption, required equity financing drops to a range of $0.9 billion to $1.7 billion. Regardless, according to this simulation, equity is required commencing in the period 1987-1991.

Of the last eight scenarios, cases 5, 7, and 8 involve the heaviest expenditure levels, reflecting the conversion of all eligible plants to coal and the installation of scrubbers on all or most of the plants converted to coal. Even for these cases, only moderate amounts of debt financing are required annually during the first half of the forecast period. The latter half of the forecast period requires some major debt financings of $500 million and above annually, and regular equity offerings as well. All of the cases examined involve heavy external financing, including equity, in the last five years of the forecast period.

The most capital-intensive scenarios (5, 7, and 8) require debt financings in the $500 million range in the closing years of the 1980's. All scenarios studied require debt financing in the over-$600 million range in the final year or two of the study period. In addition, all scenarios analyzed require annual equity offerings up to the $300 to $400 million range during the 1990-1995 period. However, external financings of these magnitudes should be manageable in light of the projected continued financial strength of the company, and such financings would represent a smaller portion of total capital than have some financings in the past.

The expenditure level and financing requirements of the Con Edison Base Case (Financial Scenario 1) fell within the ranges embodied in the first eight cases analyzed. The planned 1980's construction program can be financed with only moderate amounts of long-term debt annually. Major debt financings of $500 million and above annually, and regular equity financings, are not anticipated until the 1990's.

In Financial Scenario 2, significantly higher levels of external financing are required commencing in the late 1980's and escalating sharply through the early 1990's. This scenario is the most financially burdensome of all cases examined, and cumulative construction expenditures aggregate $14.2 billion, nearly $2 billion above the next highest expenditure level examined (Financial Scenario 8). The projected external financing requirement of $10.8 billion is 40% greater than Financial Scenario 8. Although even the external financial requirements of Financial Scenario 2 might be feasible, the requirement for financings---approximately twice the size of those for any other alternative--would be challenging, particularly in the last few years investigated.

These financial projections were made under the assumption that return earned on equity would be 12% for 1982-1989 and 13% for 1990-1994. If these rates are earned, even the more capital-intensive scenarios should not be financially constraining. Since Con Edison's current and expected future financial condition is strong, the construction expenditure levels for any of the last eight scenarios should be readily financeable within a conservative financial profile for the Company. Furthermore, the moderate differences in the financial impacts of the various scenarios suggest that financial considerations need not be a controlling factor in the choice among scenarios.

Chapter Five

COST-BENEFIT TRADEOFFS, IMPACT OF CONTINGENCIES, AND CRITIQUE OF THE PLAN

Purpose of Cost-Benefit Analysis

The measures of desirability used as output variables in the scenario simulations included measures of electricity cost, measures of environmental impact, and measures of oil dependence. Through the creation and use of the regression relationships discussed in Chapter Four, it has been possible to quantify and in many ways compare a large number of alternative ways Con Edison might supply electric energy, including their proposed plan. With this perspective from which to review the plan, one might ask, "Is this the best plan? If not, what is the best way for Con Edison to supply electric energy to the service area?"

It is clear from the analysis in Chapter Four that implementation of the plan would have a significant positive impact on oil dependence and electricity cost. It appears that the plan could be implemented without violating air quality standards. Planned electric energy purchases and conservation efforts are also steps in the right direction. But even more energy purchases, under the right conditions, and more conservation, depending on its cost-benefit and cost allocation aspects, might make the plan better. FGD and other sulfur control technologies might also be used to advantage.

It would be ideal to develop an electric energy strategy which minimized costs, environmental impacts, and dependence on oil. Unfortunately, such a plan is not possible. For instance, decisions which minimize costs do not necessarily minimize environmental impact. Technically speaking, a balance must be struck among partially conflicting criteria of merit. The decisions of where to strike the balance between oil dependence, electricity costs, and environmental impact are the responsibility of Con Edison management and regulatory agencies. In this chapter, MIT quantifies some of the major tradeoffs that are made as these decisions are made. While such information can better inform decision makers about the tradeoffs, the need for good judgement remains. No analysis can remove the need for it.

Methodology

Exhibit 5.2 lists the 22 exploratory scenarios that were analyzed through cost-benefit techniques in order to reach further observations concerning the relative desirability of various electric energy choices that Con Edison could make. By combining each of these 22 exploratory scenarios with various decisions concerning Travis, Prattsville, and purchased energy, a total of 264 cost-benefit cases were studied[1]. Exhibit 5.1 is a sample tradeoff curve relating total cost of electricity supplied (sum of present values, 1980-1995) and the resultant peak annual average ground level SO_2 concentrations in 1995 for each of these 264 cases.

For purposes of understanding other exhibits in this chapter, a few points should be made about this exhibit. First, each point in Exhibit 5.1, represents a cost-benefit case, and all cases displayed have associated values of both SO_2 ambient concentrations and total cost of electricity. Second, the curved line (Curve I) is an 'optimal tradeoff curve'. It connects the 'optimum' cases in the sense that all points on the curve have either a lower cost or a lower value of SO_2 than points not on the curve. Next, the extreme areas on the optimal tradeoff curve are areas P and Q. Area Q represents the cases with the lowest cost of all 264 cases, about $39.5 billion. Area P represents the cases with the lowest SO_2 of all 264 cases, about 68 micrograms/cubic meter.

Further, every case which is on the curve is of potential interest. Specifically, any point on the curve has the lowest cost of all cases which have that same value of SO_2. Similarly, each case on the curve has the lowest SO_2 among all cases which have the same cost. (For instance, all points directly above Point R have approximately 74 micrograms/cubic meter of SO_2, but they all have higher cost than approximately $40.2 billion; all points directly to the right of Point R cost approximately $40.2 billion, but they all have more SO_2 than approximately 74 micrograms/cubic meter.)

Now it is possible to see why, in one sense, there is no 'best' strategy. That is, if clean air is considered significantly more important than lower costs, the best strategy will tend to be a high cost strategy with low levels of SO_2. If costs are considered to be more important than SO_2, the best strategy will have low costs and high SO_2. The "optimal" strategy depends on judgements about the relative significance of electricity cost versus air quality. The current coal burning ban in New York City, for instance, is a legislative expression of a judgement giving air quality strong preference over electricity cost, given today's cost of low sulfur oil.

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[1] The 264 cases included all possible combinations of the 22 alternatives with seven other variables: Travis is or is not constructed; Prattsville is or is not constructed; and purchased energy is either the high, medium, or low amount specified earlier.

Exhibit 5.1

TOTAL COST (1980-1995) VERSUS PEAK 1995 SO_2 CONCENTRATIONS FOR ALL COST-BENEFIT CASES STUDIED

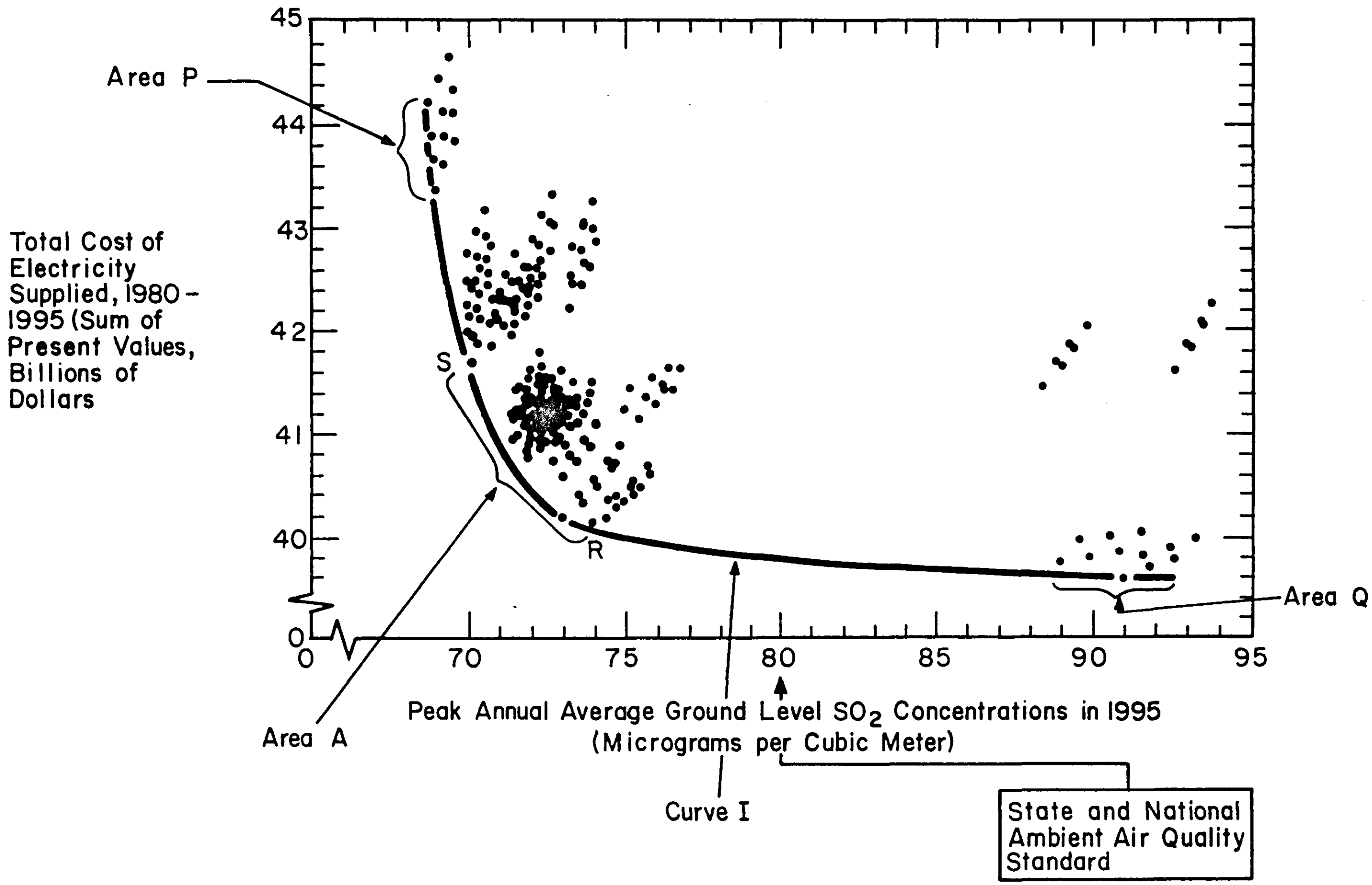

Exhibit 5.2

TWENTY-TWO SCENARIOS EXPLORING EXTENT OF
COAL USAGE AND SO_2 CONTROL OPTIONS

Alternatives with coal conversion amounts
less than the Con Edison strategy:

1. No conversions.

2. AK 2, 3 converted with no scrubbers in 1982 and 1983 respectively.

3. R 3 converted without scrubber (1982); wet scrubber added in 1986.

4. R 3 converted with wet scrubber (1986).

Alternatives with coal conversion amounts
similar to the Con Edison strategy:

5. AK 2, 3 and R 3 converted with no scrubbers in 1982, 1983, and 1981 respectively (Con Edison conversion program).

6. AK 2,3 and R 3 delayed until wet scrubbers are on-line in 1986-1987. (Scrubbers as a condition of coal burning.)

7. AK 2, 3 and R 3 converted with one-year delays without scrubbers; dry scrubbers added in 1989-91 to all units.

8. AK 2, 3 and R 3 converted with one-year delays without scrubbers; dry scrubber added to R 3 in 1991.

9. AK 2, 3 and R 3 converted without scrubbers in 1982, 1983 and 1981 respectively with wet scrubbers on-line in 1986-1987 on all three units. (Con Edison conversion program as scheduled with wet scrubbers added subsequently.)

KEY: AK Arthur Kill
R Ravenswood
AST Astoria

Exhibit 5.2 (continued)

Alternatives with coal conversion amounts
slightly higher than the Con Edison strategy:

10. AK 2, 3 and R 3 converted with one-year delays without scrubbers; dry scrubbers added to all three in 1989-91; R 1 converted with dry scrubber in 1989.

11. AK 2, 3 and R 3 converted with one-year delays; conversion of R 1, 2 in 1985; Scrubbers at no units.

12. Same as 10, plus R 2 converted with dry scrubber in 1989.

13. AK 2, 3 and R 3 converted with one-year delays without scrubbers; wet scrubbers added in 1986-87 at all three units; R 1, 2 converted with wet scrubbers in 1989.

14. AK 2, 3 and R 1, 2, 3 converted with wet scrubbers at all units (beginning 1986).

15. AK 2, 3 and R 3 converted with one-year delays without scrubbers; wet scrubbers added in 1989-91 to all three units; R 1, 2 converted with wet scrubbers in 1989.

16. Conversion of AK 2 (1983), AK 3 (1984), AST 3 and 4 (1987), and AST 5 (1988); scrubbers at no units.

17. AK 2, 3 and R 3 converted with one-year delays without scrubbers; dry scrubbers added in 1989-91 to all three units; AST 5 converted with dry scrubber in 1989.

18. Same as 17, plus AST 3, 4 converted with dry scrubbers (1989-90).

Alternatives with large
amounts of coal conversion:

19. Conversion of AK 2 (1983), AK 3 (1984), R 3 (1982), R 1 and 2 (1985), AST 3 and 4 (1987), and AST 5 (1988); scrubbers at no units.

20. Conversion of AK 2, 3; R 1, 2, 3; and AST 3, 4, 5 with wet scrubbers at time of conversions. Conversions begin in 1985.

21. AK 2, 3 and R 3 converted with one-year delays without scrubbers; wet scrubbers in 1986 at R 3; conversion of R 1, 2, AST 3, 4, 5 with wet scrubbers in 1989-91.

22. AK 2, 3 and R 3 converted with one-year delays without scrubbers; dry scrubbers added in 1989-91 at all three units; conversion of R 1, 2 and AST 3, 4, 5 with wet scrubbers in 1989-91.

Although this tradeoff curve logic cannot point to a "best" strategy it does point out a section of the optimal tradeoff curve which is worth more thought in making this decision, i.e., the area near the knee of the curve (Area A). Notice that moving from point R toward the knee results in relatively dramatic SO_2 decreases with only minor increases in cost. Similarly, moving from point S toward the knee results in relatively dramatic cost decreases with only minor increases in SO_2 concentrations. Thus, the area of most interest for someone making the decision on total cost and SO_2 tradeoffs is in the neighborhood of the knee of this curve. In that area, 'giving up' a little of one 'gets' a lot of the other.

Exhibit 5.2 is a list of the 22 exploratory scenarios which this chapter focuses on in order to summarize the cost- benefit analyses performed[2]. There are four major groups of exploratory scenarios in that exhibit. The groups were formed on the basis of coal conversion quantity. The first group is composed of alternatives with an amount of coal conversion which is lower than the amount planned by Con Edison. The second group includes the Con Edison conversion program plus other alternatives which have about an equal amount of conversion. The third group is composed of alternatives with an amount of coal conversion slightly larger than in the Con Edison conversion program. The last group has alternatives with the largest amount of coal conversion investigated.

Each of the four groups in Exhibit 5.2 contains variations in terms of several characteristics about which there is decision making discretion. First, the conversion dates differ among the alternatives. Second, degree of scrubber utilization, including none, is varied. Third, scrubbers, if installed, vary over wet and dry technologies. And lastly, if scrubbers are installed, they may be added at the date of conversion or at a subsequent date. The amount of variation among the twenty-two exploratory scenarios reflects a fact highlighted earlier; namely, there is a broad range of coal conversion alternatives.

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[2] The cost-benefit tradeoffs of the coal conversion alternatives analyzed are not sensitive to the decisions about Travis, Prattsville, or purchased energy. Thus, decisions among the coal conversion alternatives can be made independently of these decisions on other portions of Con Edison's entire proposed energy strategy for the 1980's. In the balance of the chapter (including the Exhibits), except as otherwise noted, the following assumptions were used: Prattsville pumped storage plant is not on-line; Travis plant is on-line in 1987 with dry scrubbers; the medium amount of purchased energy is used (approximately 84.8 billion kWh, cumulative through 1995); load growth is +1% per year; Indian Point nuclear plant is in service; real oil prices increase at +3% per year; real coal prices increase at +1% per year; and the rate of inflation is +7% per year.

Coal Conversion Alternatives

Exhibits 5.3 through 5.6 show the tradeoff relationship between total cost of electricity supplied (1980-1995) and total annual average SO_2 emissions in 1995. In Exhibit 5.3 the exploratory scenarios involving less coal conversion than the basic Con Edison conversion program are circled. In Exhibit 5.4 exploratory scenarios with an amount of conversion equal to the Con Edison conversion program are circled. In Exhibit 5.5 exploratory scenarios involving somewhat more coal conversion than the basic Con Edison conversion program are circled, and in Exhibit 5.6 exploratory scenarios involving very large amounts of coal conversion are circled. Exhibit 5.4 reveals an important observation: the Con Edison program and most of the exploratory scenarios with about an equal amount of conversion are on the optimal tradeoff curve. This means that in terms of these measures of total cost and SO_2 emissions, the Con Edison conversion program is a well-chosen one. In particular, for its resulting level of SO_2 emissions in 1995, the Con Edison conversion program is the lowest-cost exploratory scenario investigated. For its resulting level of cost, the Con Edison conversion program has the lowest SO_2 emissions of the exploratory scenarios investigated.[3]

Notice, however, that there are scenarios that involve coal conversion beyond the amounts in the Con Edison program which are also on or near the knee of this optimal tradeoff curve. In Exhibits 5.3 through 5.6, there are a number of exploratory scenarios for coal conversion which involve approximately the same 1995 SO_2 impact and the same total cost, 1980-1995 as the Con Edison program. It is reasonable to ask if any of them are better or worse than the basic Con Edison conversion program which is among them.

Exhibits 5.7 and 5.8, which show the relationship between total cost of electricity supplied (1980-1995) and total oil consumption (1980-1995), help to answer this question[4]. In Exhibit 5.7 the several variants of the Con Edison conversion program are circled, and in Exhibit 5.8 other exploratory scenarios which were in the knee of the total cost versus total

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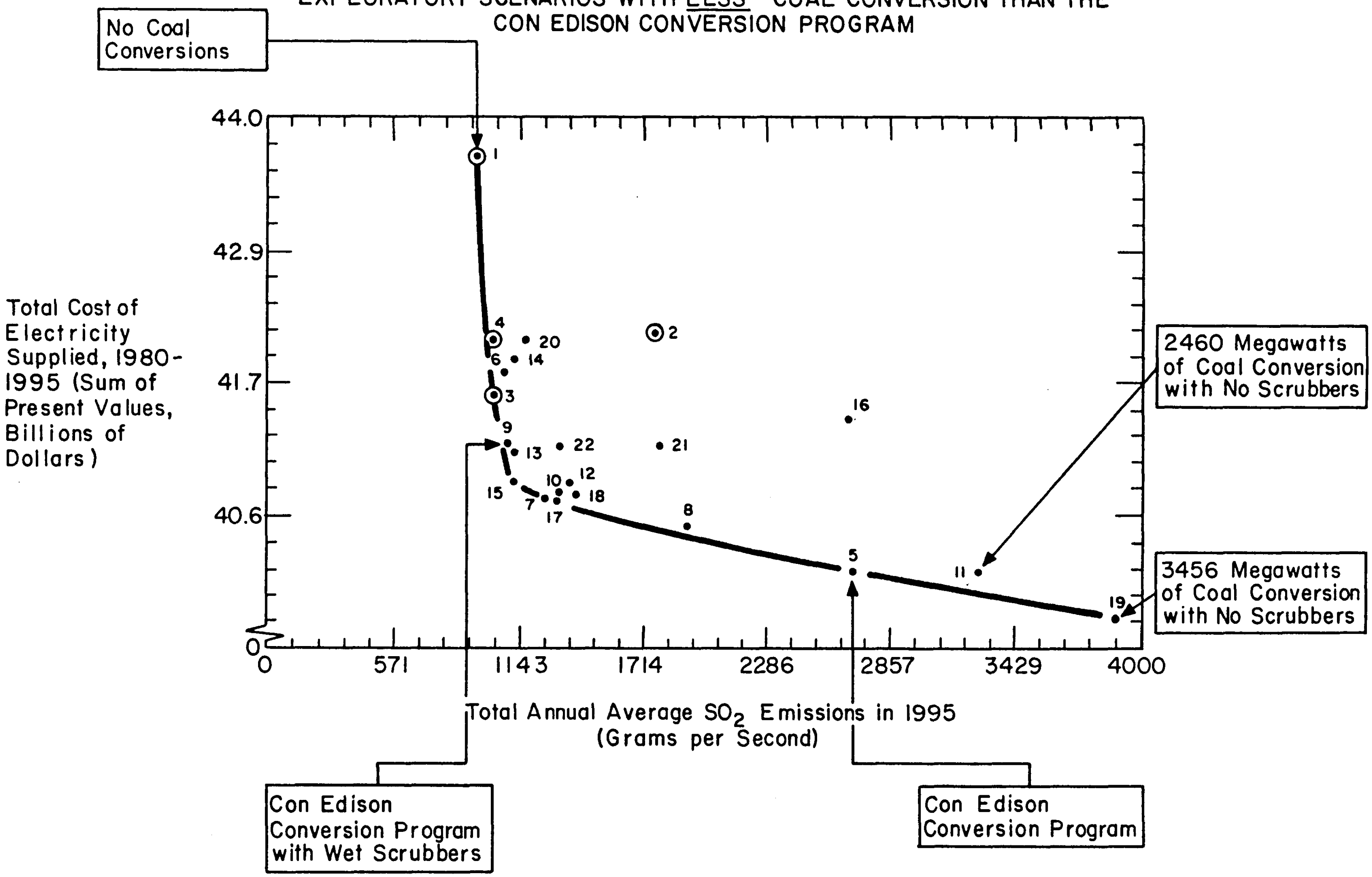
[3] Note that the highest cost coal conversion alternatives generally include those with relatively low amounts of conversion, including the 'do nothing' alternative. This is because the amount of oil displaced by low conversion is small.

[4] Note that there is no conflict or tradeoff between Con Edison's cost and oil consumption objectives; that is, reducing oil consumption reduces costs.

Exhibit 5.3

TOTAL COST (1980-1995) VERSUS 1995 SO_2 EMISSIONS FOR THE FOUR EXPLORATORY SCENARIOS WITH LESS* COAL CONVERSION THAN THE CON EDISON CONVERSION PROGRAM

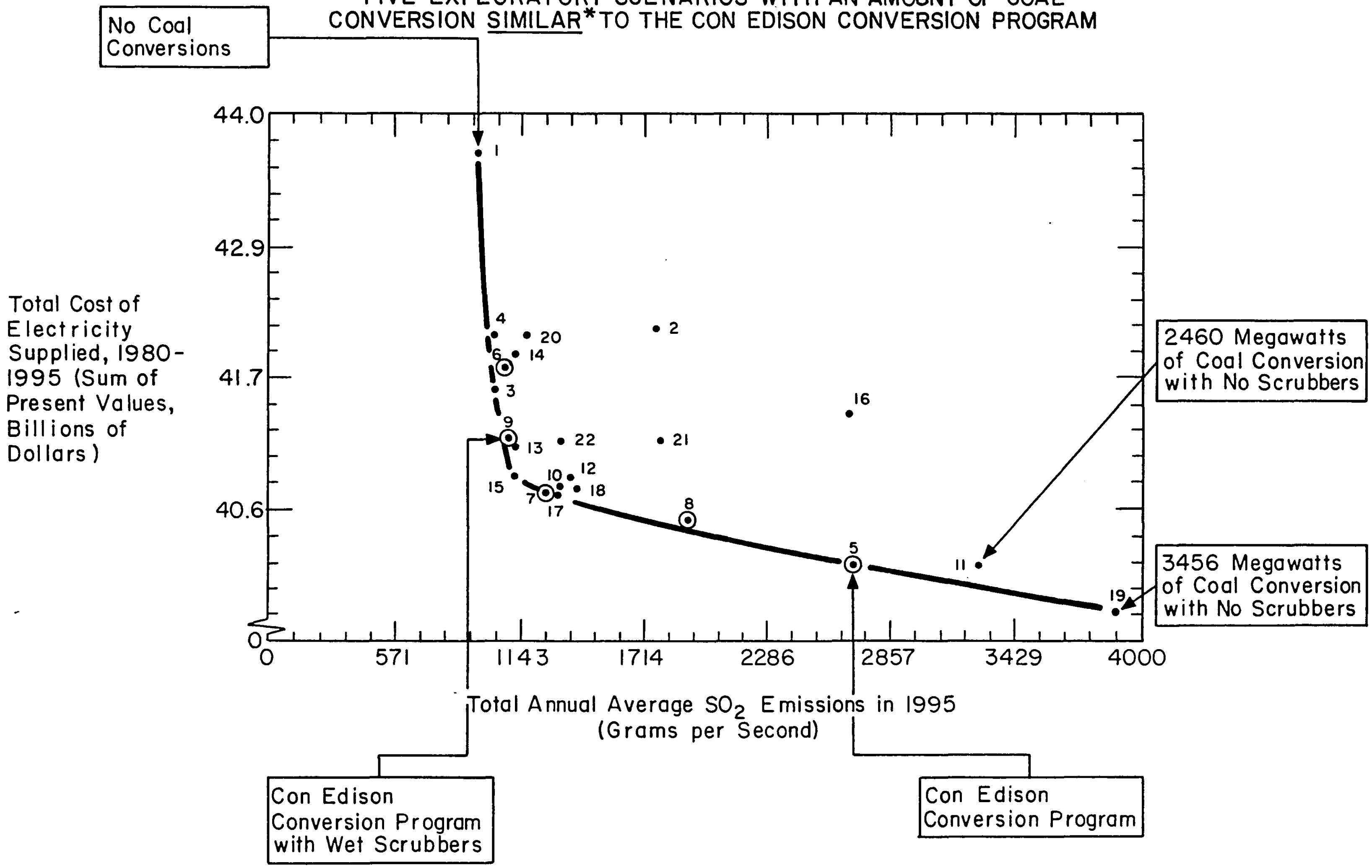


Note:
Numbers refer to scenarios defined in Exhibit 5.2.

* These scenarios are indicated by circles ⊙.

Exhibit 5.4

TOTAL COST (1980-1995) VERSUS 1995 SO_2 EMISSIONS FOR THE FIVE EXPLORATORY SCENARIOS WITH AN AMOUNT OF COAL CONVERSION <u>SIMILAR</u>* TO THE CON EDISON CONVERSION PROGRAM

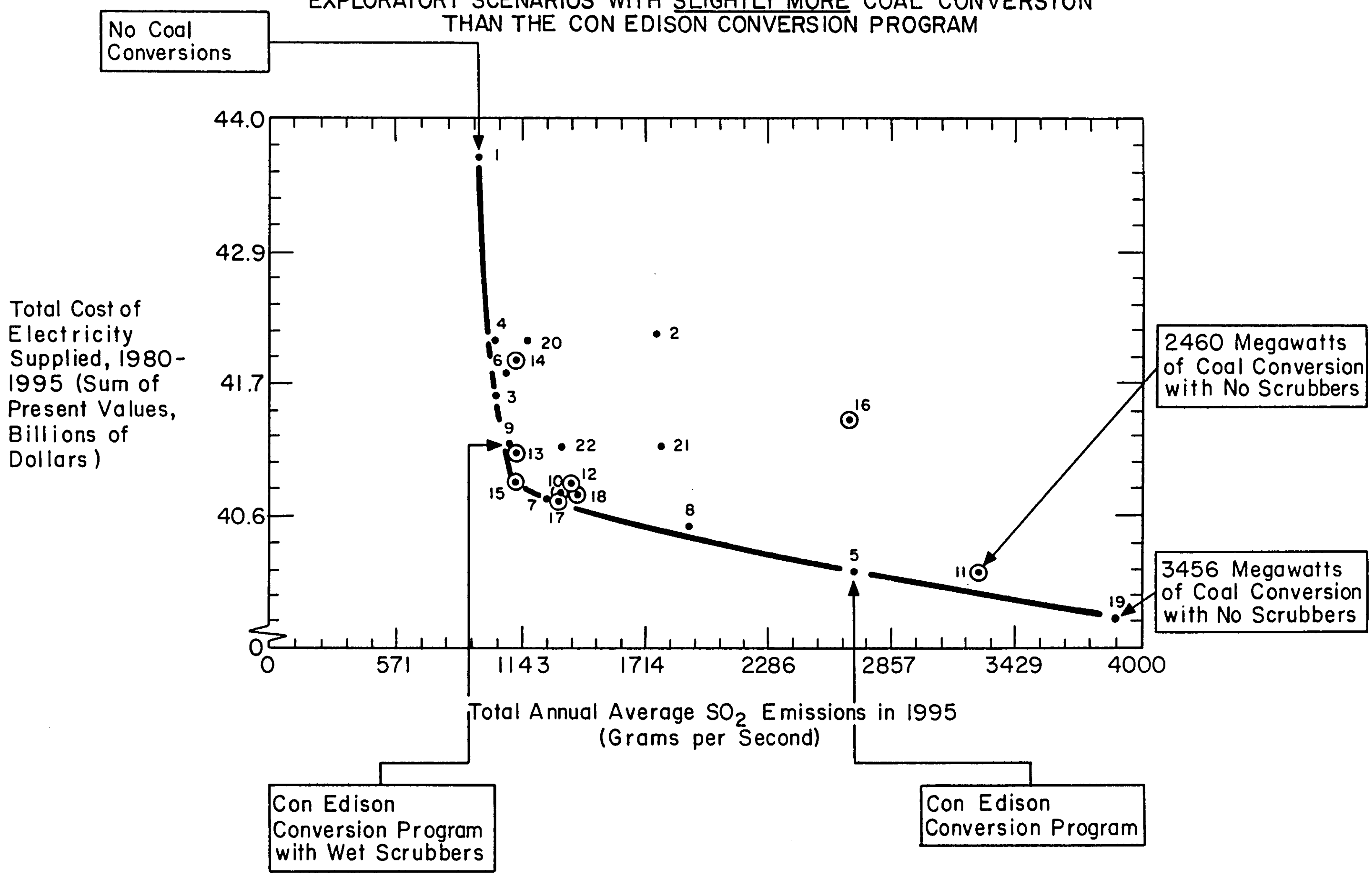


Note:
Numbers refer to scenarios defined in Exhibit 5.2.

* These scenarios are indicated by circles ⊙.

Exhibit 5.5

TOTAL COST (1980-1995) VERSUS 1995 SO_2 EMISSIONS FOR THE NINE EXPLORATORY SCENARIOS WITH SLIGHTLY MORE* COAL CONVERSION THAN THE CON EDISON CONVERSION PROGRAM

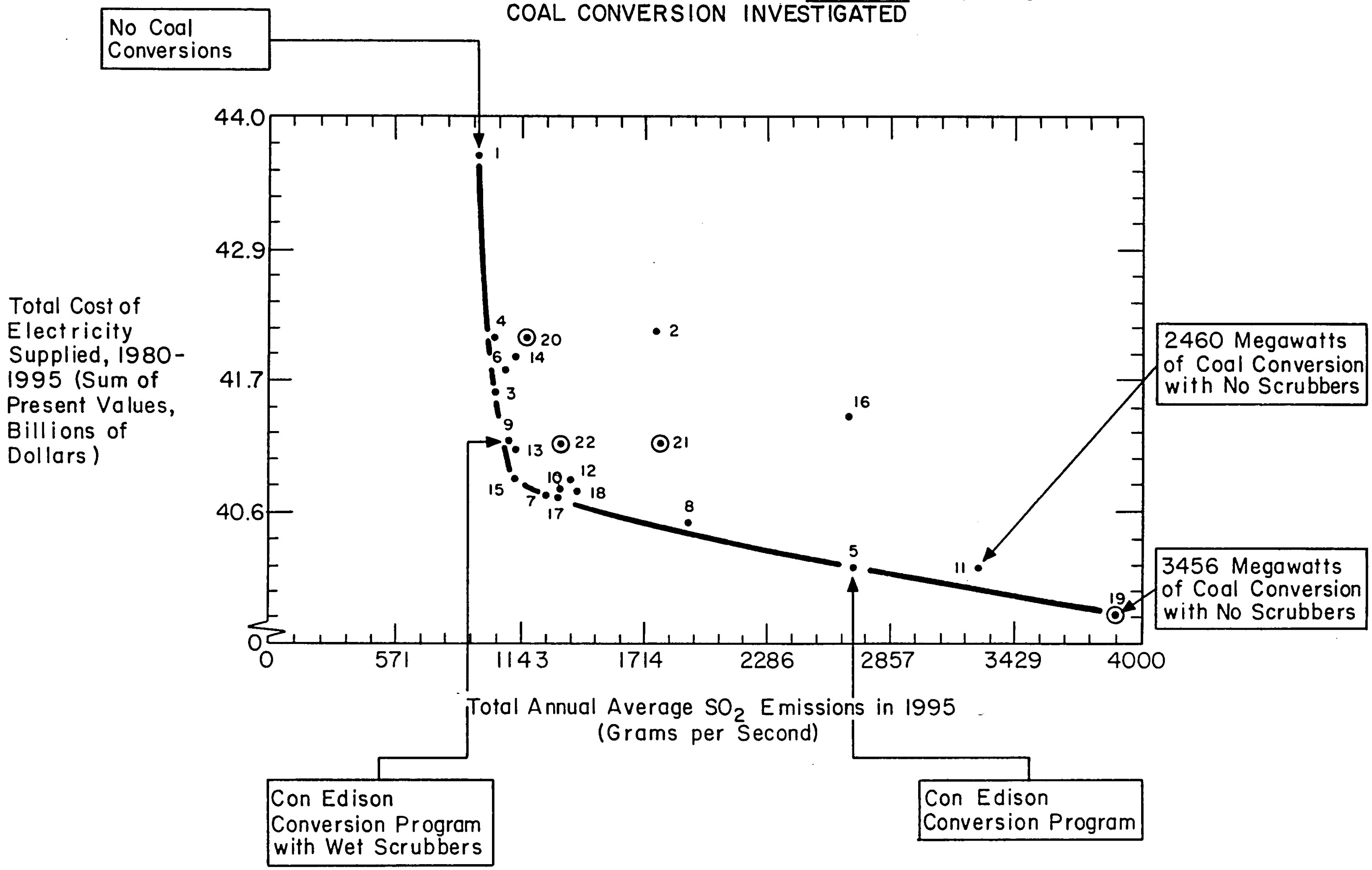


Note:
Numbers refer to scenarios defined in Exhibit 5.2.

* These scenarios are indicated by circles ⊙.

Exhibit 5.6

TOTAL COST (1980-1995) VERSUS 1995 SO_2 EMISSIONS FOR THE FOUR EXPLORATORY SCENARIOS WITH THE MAXIMUM* AMOUNT OF COAL CONVERSION INVESTIGATED

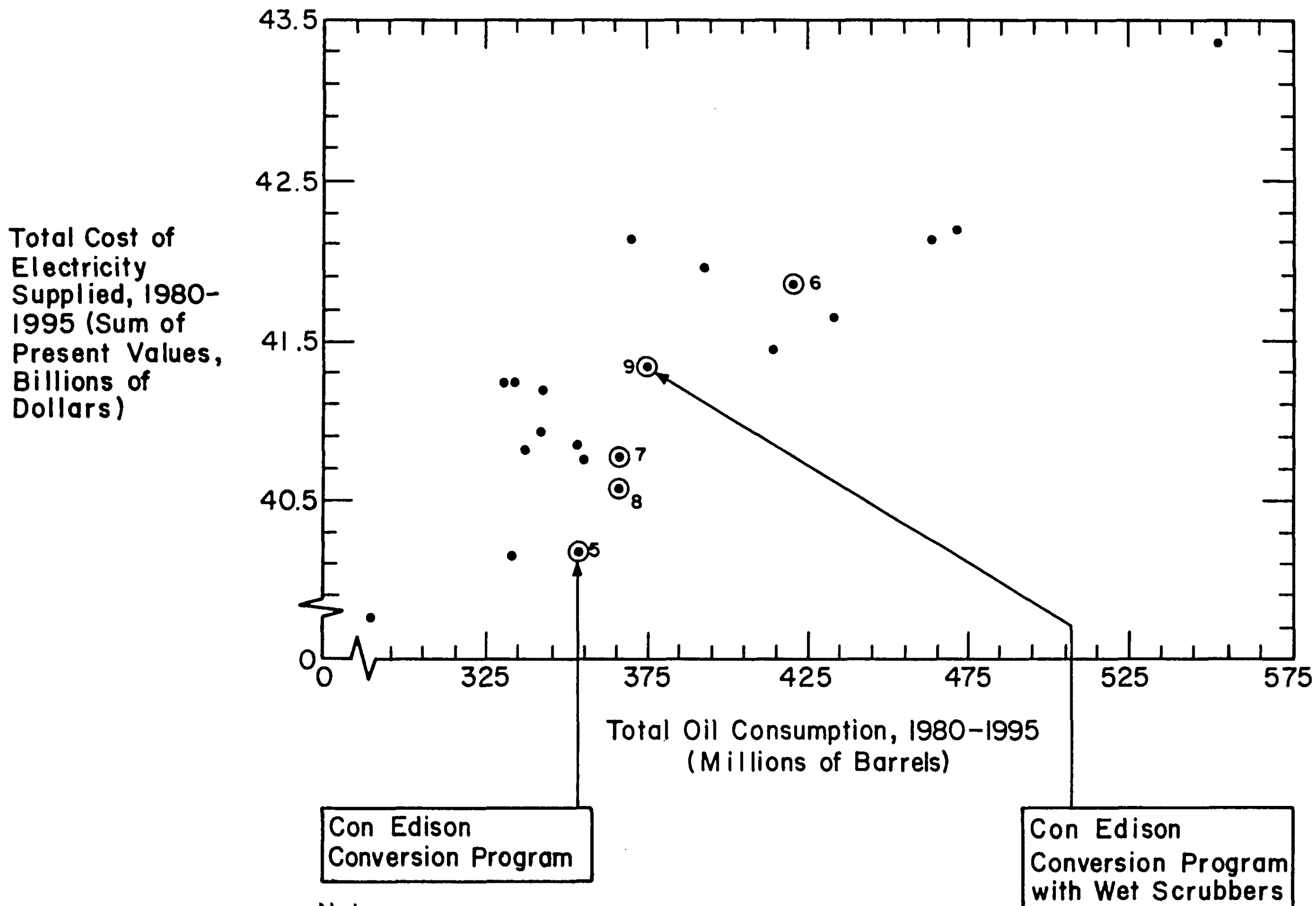


Note:
Numbers refer to scenarios defined in Exhibit 5.2.

* These scenarios are indicated by circles ⊙.

Exhibit 5.7

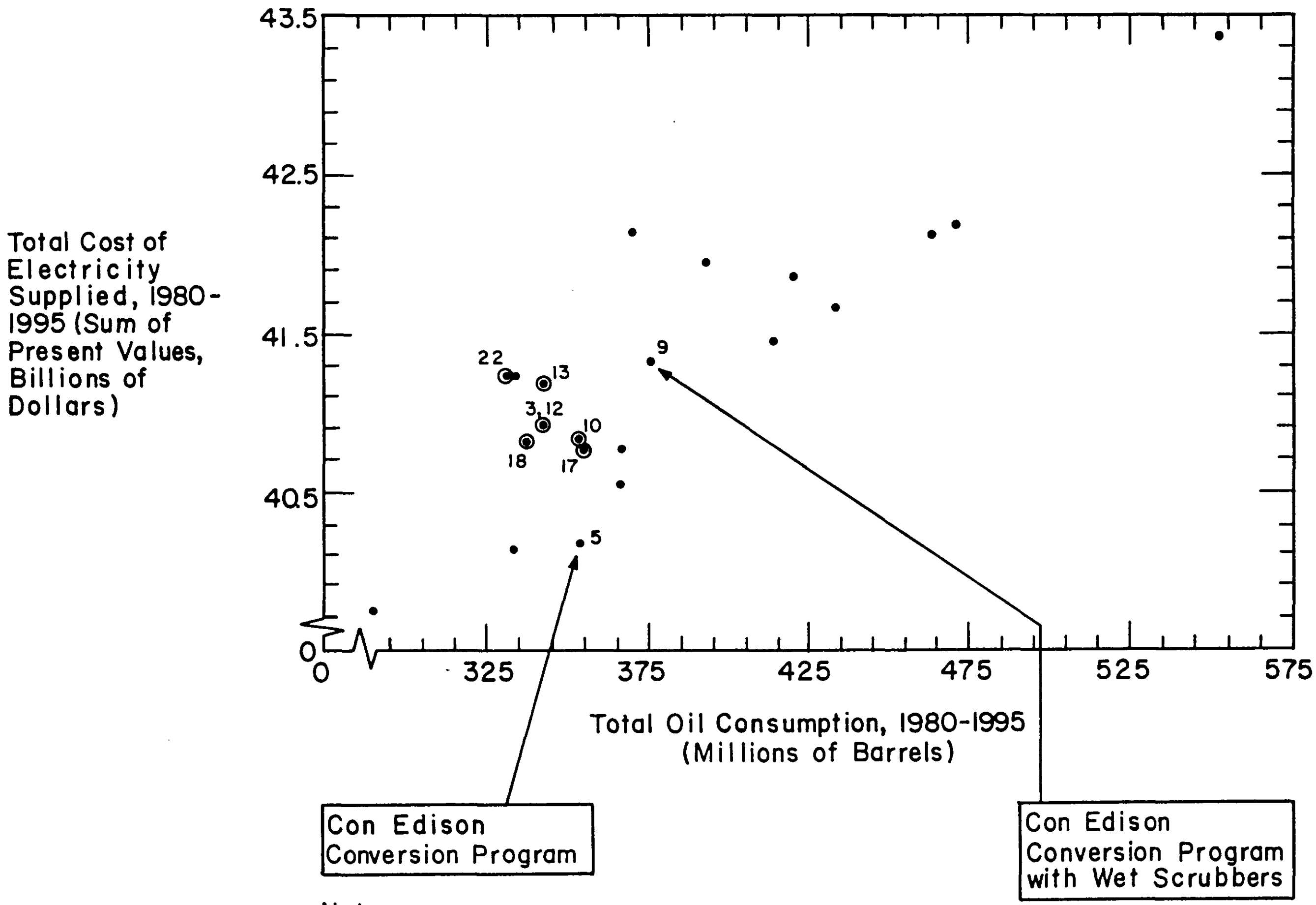
TOTAL COST (1980–1995) VERSUS TOTAL OIL CONSUMPTION (1980–1995) FOR EXPLORATORY SCENARIOS WITH AN AMOUNT OF COAL CONVERSION SIMILAR* TO THE CON EDISON CONVERSION PROGRAM



Note:
Numbers refer to scenarios defined in Exhibit 5.2

* These scenarios are indicated by circles. ⊙

Exhibit 5.8
TOTAL COST (1980-1995) VERSUS TOTAL OIL CONSUMPTION (1980-1995) FOR EXPLORATORY SCENARIOS NEAR THE KNEE* OF THE TOTAL COST (1980-1995) VERSUS 1995 SO_2 EMISSIONS TRADEOFF CURVE (Exhibit 5.3)



Note:
Numbers refer to scenarios defined in Exhibit 5.2.

* These scenarios are indicated by circles. ⊙

SO_2 emissions curve are circled. In both of these exhibits as the amount of conversion increases the amount of oil consumption generally decreases. Con Edison's conversion program, specifically, has less oil consumption than exploratory scenarios with less coal conversion. Notice, however, that the alternatives circled in Exhibit 5.8--which involve more coal conversion than the Con Edison conversion program--have even less oil consumption.

The conclusion, then, is that in terms of cost and SO_2 emission tradeoffs, the Con Edison conversion program is a good alternative, although there are others involving higher levels of coal conversion that are competitive in dollar and pollution costs. If the impact of coal conversion on oil consumption is considered, alternatives involving higher levels of coal conversion, which are competitive with the Con Edison program in terms of cost and SO_2, are more attractive than the proposed program. Stated differently, most of the cost savings that can be derived from coal conversion will accrue from the proposed conversions. Additional coal capacity, however, would further decrease oil dependence.

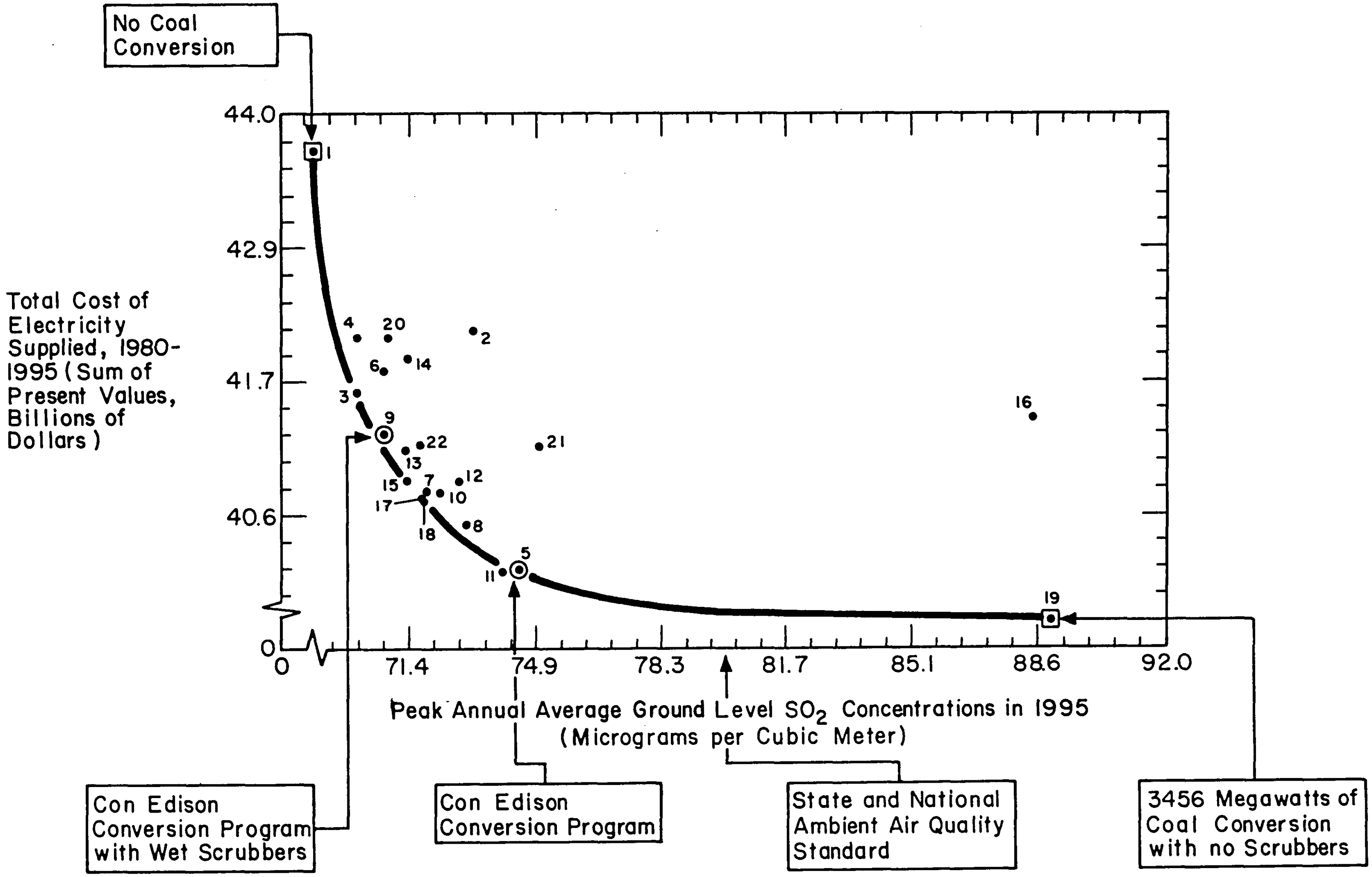
Exhibit 5.9 shows the cost-benefit relationships between total cost of electricity supplied (1980-1995) and peak annual average ground level SO_2 concentration in 1995. The Con Edison conversion program is also attractive in terms of these tradeoffs, and exploratory scenarios with more coal conversion are again more attractive than the proposed conversions, if oil consumption is considered.

In Exhibit 5.10 the optimal tradeoff curves for the 22 exploratory scenarios are shown for +1% load growth and -1% load growth. Alternatives that are on or near the tradeoff curve for 1% load growth are also on or near the tradeoff curve for -1% load growth. This includes the Con Edison conversion program. Thus, the desirability of the Con Edison conversion program, the desirability of most other coal conversion alternatives, and the relative desirability among the alternatives are all insensitive to changes in load growth.

Scrubbers

Many of the 22 exploratory scenarios involve scrubber installation. Dry and wet scrubbers were studied, as were installation of scrubbers as a condition of coal burning and installation at some time subsequent to the date of conversion. Exhibits 5.11 and 5.12 show the probable effects of various scrubber policies on 1995 SO_2 emissions and total cost of electricity supplied (1980-1995) respectively. The SO_2 emissions of the proposed Con Edison conversion program would decrease by about 60% if the conversions are completed as scheduled and wet scrubbers are added subsequently in 1986-1987. This SO_2 emission

Exhibit 5.9
TOTAL COST (1980-1995) VERSUS PEAK 1995 SO_2
CONCENTRATIONS FOR THE EXPLORATORY SCENARIOS

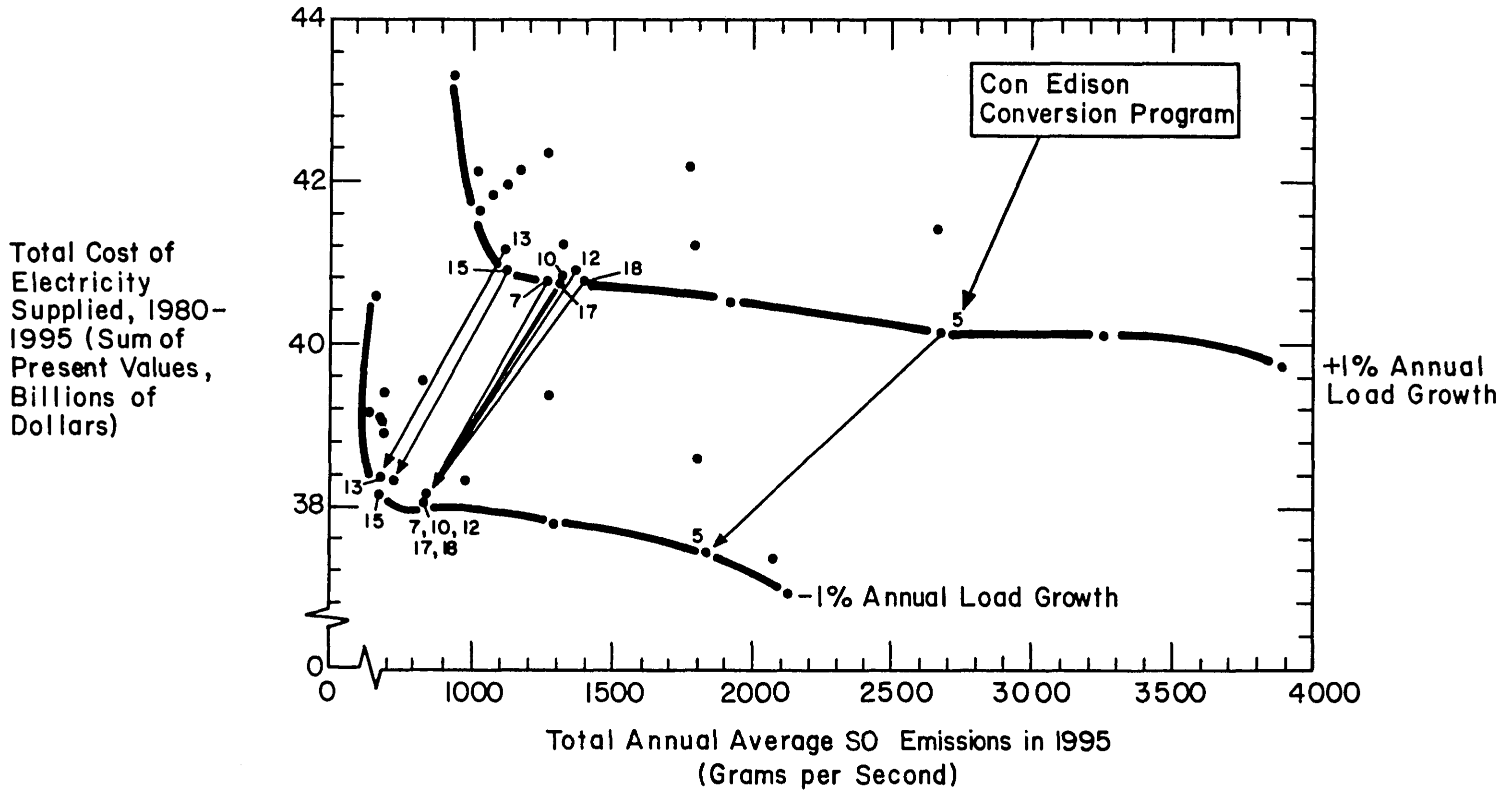


Note:

Numbers refer to scenarios defined in Exhibit 5.2.

Exhibit 5.10

EFFECT OF CHANGE IN LOAD GROWTH ON TOTAL COST (1980-1995) AND 1995 SO_2 EMISSIONS FOR THE EXPLORATORY SCENARIOS



Note:

Numbers refer to scenarios defined in Exhibit 5.2.

Exhibit 5.11

IMPACT OF SCRUBBERS ON SO_2 EMISSIONS

Alternative	Projected Total Annual Average SO_2 Emissions in 1995 (Grams per Second)	Percentage Reduction from Con Edison Conversion Program
No coal conversion (Alternative 1)	1000	--
Con Edison Conversion Program (Alternative 5)	2700	--
Con Edison Conversion Program as scheduled with wet scrubbers added subsequently in 1986-87 (Alternative 9)	1080	60%
Con Edison Conversion Program delayed until wet scrubbers are added in 1986-87 (Alternative 6)	1080	60%

Exhibit 5.12

IMPACT OF SCRUBBERS ON
TOTAL COST OF ELECTRICITY

Alternative	Projected Total Cost of Electricity Supplied, 1980-95 (Sum of Present Values, Billions of Dollars)	Percentage Reduction in Cost from No Coal Conversion
No coal conversion (Alternative 1)	$43.7	--
Con Edison Conversion Program (Alternative 5)	$40.3	8%
Con Edison Conversion Program as scheduled with wet scrubbers added subsequently in 1986-87 (Alternative 9)	$41.3	5%
Con Edison Conversion Program delayed until wet scrubbers are added in 1986-87 (Alternative 6)	$41.8	4%

level would be essentially the same as in the case of no coal conversion. Despite the added costs associated with scrubbers, the proposed Con Edison conversion program with subsequent addition of wet scrubbers in 1986-1987 still results in lower total cost of electricity than if no coal conversion occurred. Rather than being 8% lower as contemplated for the proposed program, total cost would be 5% lower with subsequent addition of wet scrubbers in 1986-1987. That is, the added costs associated with such scrubber installation are less than the savings which result from the use of coal instead of oil. Or, going back to the original problem about the "best" strategy, it is possible to substantially replace oil, to somewhat reduce the cost of electricity, and to maintain Con Edison's impact on New York City's air quality at its current level; namely slightly negative.

Ebasco Services, Inc.[5] concludes that scrubbers are feasible at Arthur Kill at capital costs (1980) in the $200-315 per kW range, depending upon whether the technology used is regenerative or non-regenerative. The costs used by MIT in this investigation, $215 per kW, are in this range. It is clear from the Ebasco report that installing scrubbers at Ravenswood will not be feasible without extraordinary measures. The major difficulty is lack of space. Acquisition of additional property adjacent to the Ravenswood plant, if possible, would seem to be necessary before scrubbers could be utilized. Such extraordinary measures would, no doubt, increase the cost of scrubbers at Ravenswood.

Addition of FGD equipment before beginning the burning of coal would delay conversion even if an FGD technology that is satisfactory to Con Edison and to the regulators could be identified rapidly from the present range of options. Even if commercially available non-regenerative wet scrubbers were chosen, a coal-burning delay would be experienced relative to the proposed conversion without FGD equipment. This is so because additional engineering design work, procurement, installation and startup of FGD equipment would be required. Any coal burning delay would be costly to consumers. For example, the combined increased cost of FGD equipment as well as delayed coal burning (until 1986-1987) would reduce the cost savings from the proposed conversions (over the period 1980 to 1995) to approximately 4% rather than 8%. (See Exhibit 5.12.) Such a coal burning delay would result in the same total average SO_2 emissions in 1955 as converting on schedule with subsequent addition of wet scrubbers. (See Exhibit 5.11.)

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[5] As the present report was in the editing stages, a report was issued by Ebasco on costs and feasibility of scrubbers at Arthur Kill and Ravenswood 3 (reference number 134).

Travis

Exhibit 5.13 shows the 22 exploratory scenarios discussed above with and without the assumption of scheduled construction of Travis. Assuming the amount and timing of coal conversion proposed in Con Edison's program, Travis slightly reduces costs and slightly increases SO_2 emissions. This conclusion holds true for most of the coal conversion alternatives studied, although there are some exceptions. Specifically, construction of Travis actually decreases SO_2 emissions slightly for alternatives involving very large amounts of coal conversion without scrubbers (a perhaps unrealistic alternative). Also, the construction of Travis slightly increases costs under conversion alternatives involving very large amounts of coal conversion (perhaps also unrealistic). Exhibit 5.14 shows the effect of Travis on oil consumption: Travis displaces oil for all coal conversion alternatives, including the Con Edison conversion program.

Prattsville

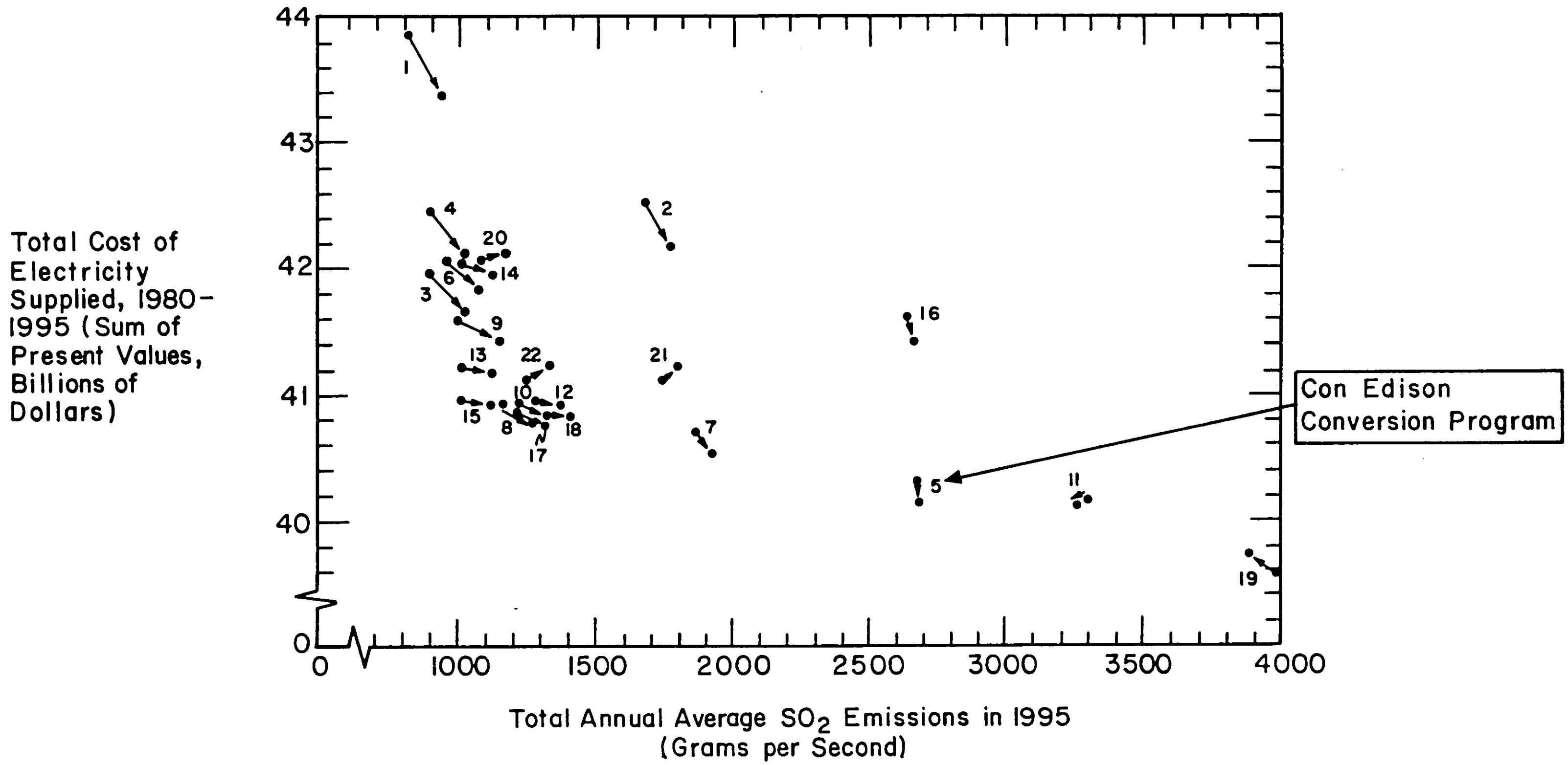
Exhibit 5.15 shows the effect of Prattsville on total cost (1980-1995) and total oil consumption (1980-1995). For the coal conversions in Con Edison's program and for most other conversion alternatives, Prattsville has negligible impacts on oil consumption and cost. Furthermore, Exhibit 5.16 shows that for the Con Edison conversion program and, in general, Prattsville has a negligible impact on 1995 SO_2 emissions.

There is no persuasive reason either to build or not to build Prattsville in terms of the criteria of merit investigated here. However, Prattsville may be attractive in terms of criteria not investigated in this work. First, Prattsville represents additional peaking capacity. While there may be need for additional peaking capacity in the 1990's, additional capacity was not used as a criteria of merit. Second, construction of Prattsville may have a positive impact on system reliability, but this criteria was not investigated. Third, the lifetime of a pumped storage facility may reach 50 or 75 years, but MIT did not study beyond the year 1995.

Purchased Energy

Exhibits 5.17 and 5.18 show the effects of purchased energy on total cost, oil consumption, and 1995 SO_2 emissions. The comparison in those exhibits is between high levels of purchased energy (about 101 billion kWh during the period 1980-1995) and low levels of purchased energy (about 68 billion kWh over the same period). For all coal conversion alternatives, including Con Edison's proposed conversion program, purchasing energy from

Exhibit 5.13
EFFECT OF TRAVIS PLANT ON TOTAL COST (1980-1995)
AND 1995 SO_2 EMISSIONS FOR THE EXPLORATORY SCENARIOS

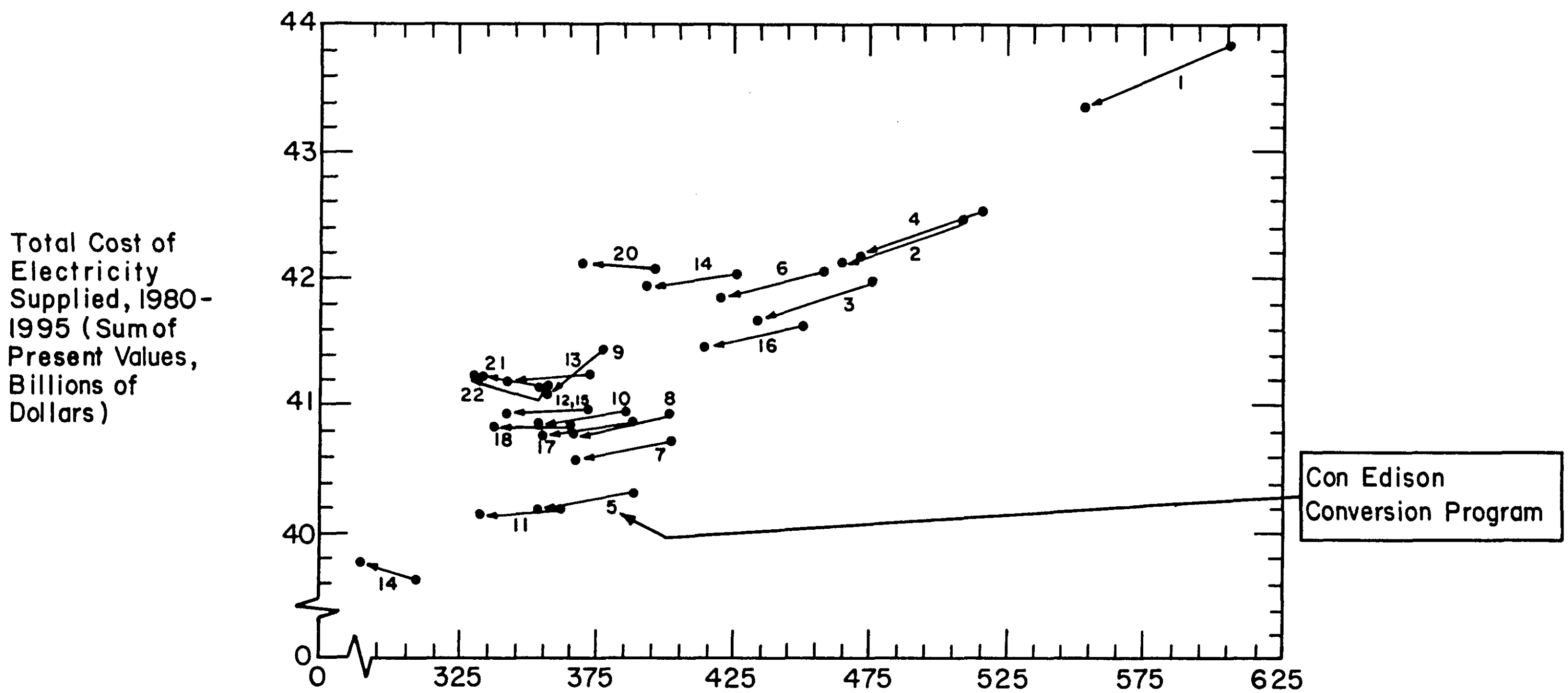


Note:
Numbers refer to scenarios defined in Exhibit 5.2.

Key:
Travis plant not on-line
Travis plant on-line beginning 1987

Exhibit 5.14

EFFECT OF TRAVIS PLANT ON TOTAL COST (1980-1995)
AND TOTAL OIL CONSUMPTION (1980-1995)
FOR THE EXPLORATORY SCENARIOS

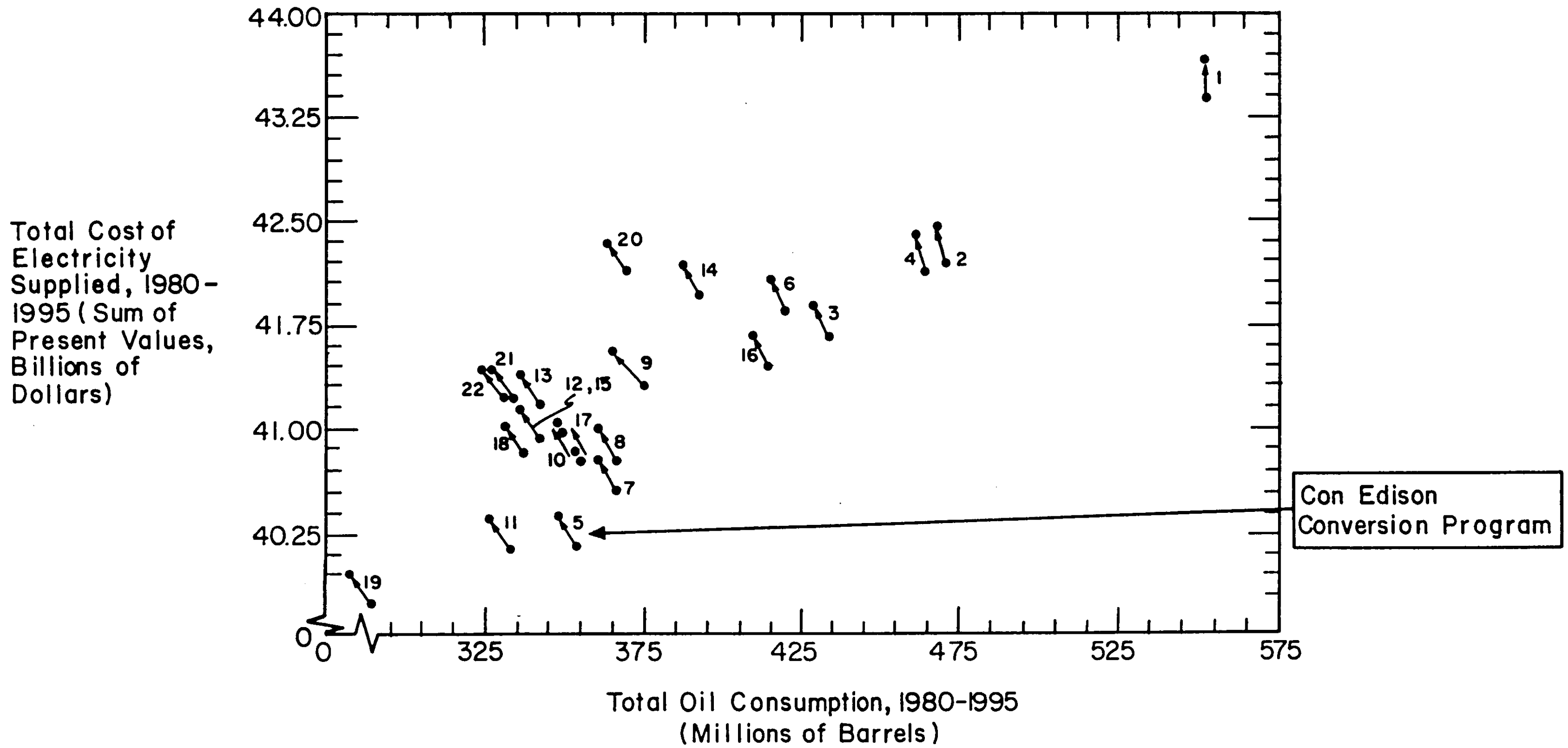


Note:
Numbers refer to scenarios defined in Exhibit 5.2.

Key:
Travis plant not on-line.
Travis plant on-line beginning 1987.

Exhibit 5.15

EFFECT OF PRATTSVILLE PUMPED STORAGE PLANT ON TOTAL COST (1980 — 1995) AND TOTAL OIL CONSUMPTION (1980-1995) FOR THE EXPLORATORY SCENARIOS



Note:

Numbers refer to scenarios defined in Exhibit 5.2.

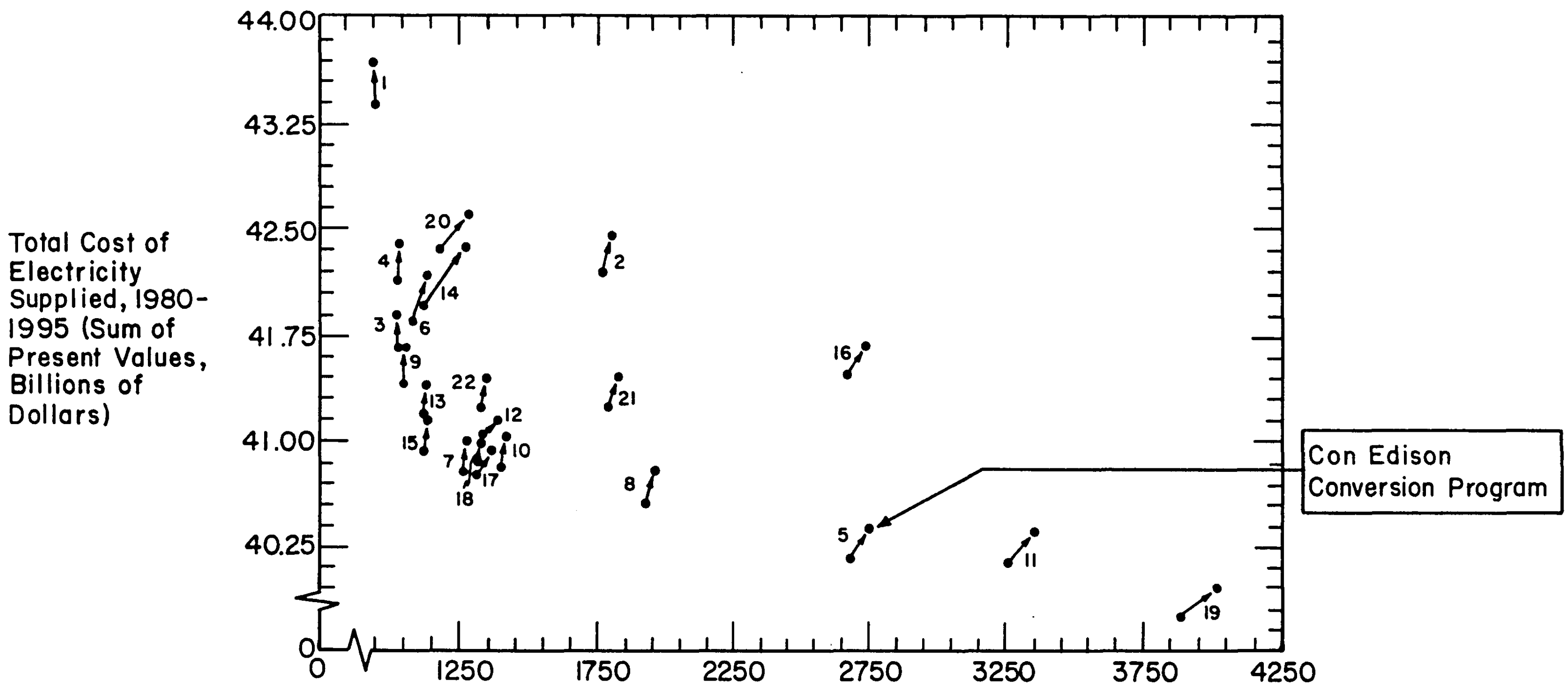
Key:

Prattsville plant on-line beginning 1987

Prattsville plant not on-line

Exhibit 5.16

EFFECT OF PRATTSVILLE PUMPED STORAGE PLANT ON TOTAL COST (1980—1995) AND 1995 SO_2 EMISSIONS FOR THE EXPLORATORY SCENARIOS

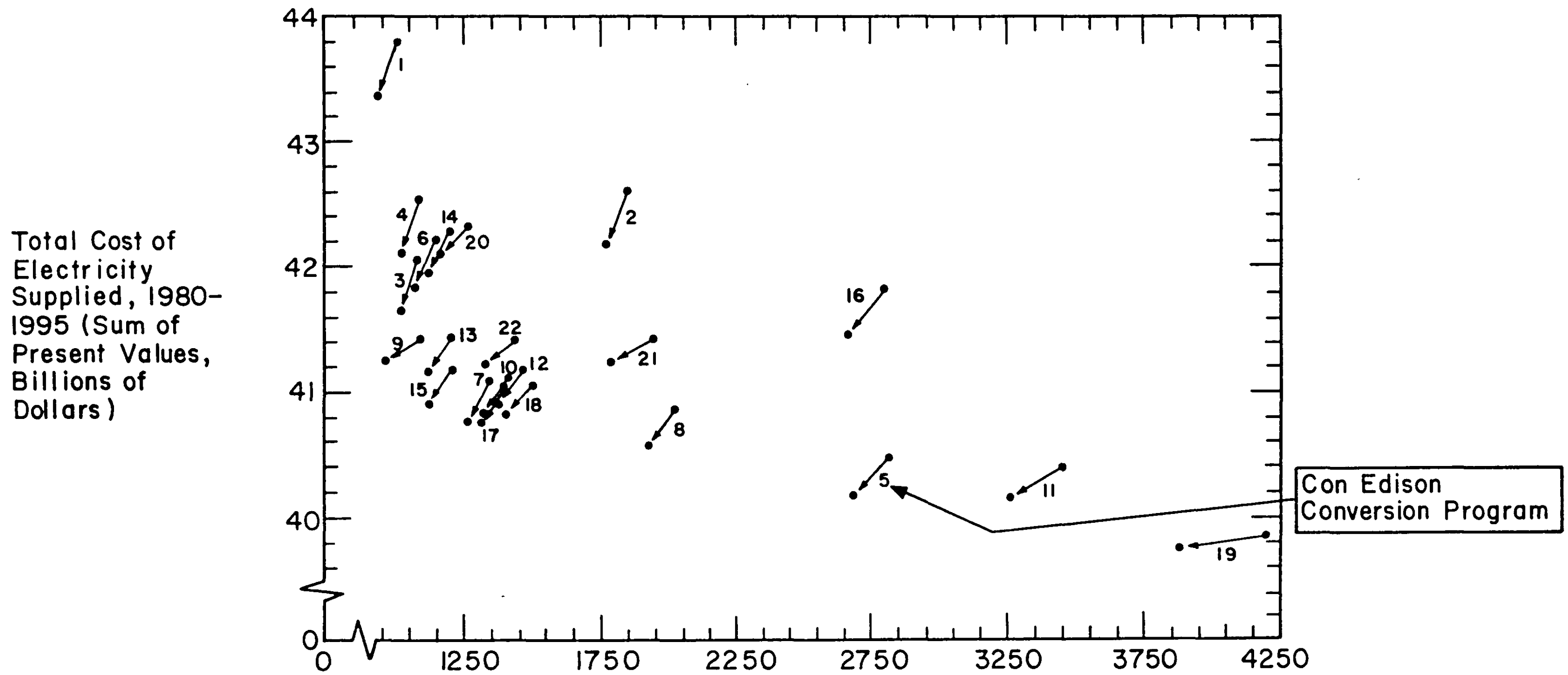


Note:
Numbers refer to scenarios defined in Exhibit 5.2.

Key:
Prattsville plant on-line beginning 1987.
Prattsville plant not on-line.

Exhibit 5.17

EFFECT OF CHANGE IN PURCHASED ENERGY ON TOTAL COST (1980-1995) AND 1995 SO_2 EMISSIONS FOR THE EXPLORATORY SCENARIOS

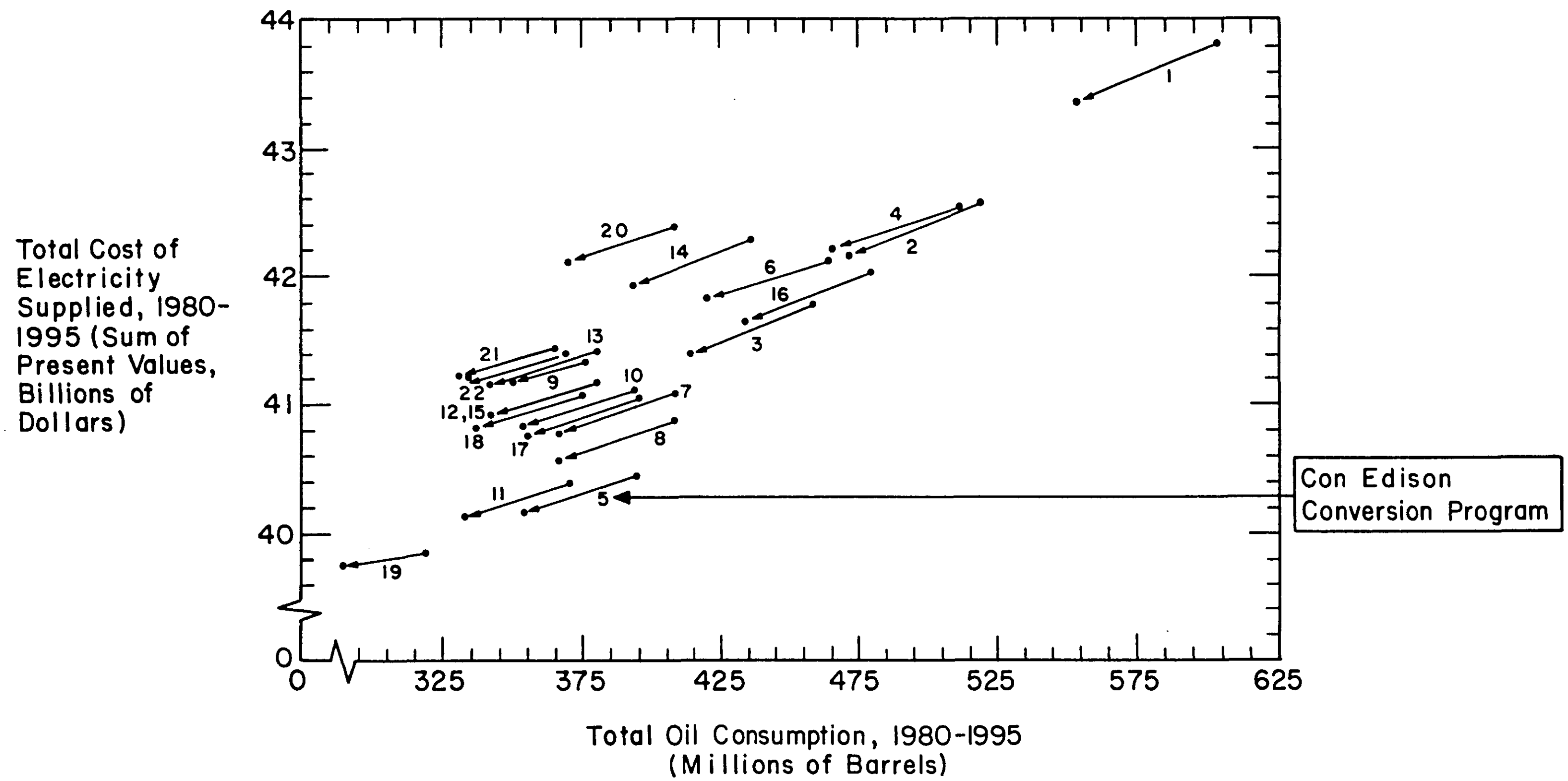


Note:
Numbers refer to scenarios defined in Exhibit 5.2.

Key:
Low energy purchases (68 billion kWh, 1980-1995)
High energy purchases (101 billion kWh, 1980-1995)

Exhibit 5.18

EFFECT OF CHANGE IN PURCHASED ENERGY ON TOTAL COST (1980-1995) AND 1995 SO_2 EMISSIONS FOR THE EXPLORATORY SCENARIOS



Note:
Numbers refer to scenarios defined in Exhibit 5.2.

Low energy purchases (68 billion kWh, 1980-1995)

High energy purchases (101 billion kWh, 1980-1995) outside the system (mainly hydroelectric energy from Hydro Quebec) reduces the consumption of oil in the service area, reduces SO_2 emissions in the service area because less fossil fuel is being burned, and reduces total cost of electricity because the purchased energy was assumed to cost 80% of the cost of the energy that it replaced.

Contingency Analysis

In addition to the regression analysis and the cost-benefit tradeoffs, there is yet another way to look at this coal conversion plan: What can be said about coal conversion under the eventuality of one or more major contingencies impacting Con Edison? A contingency is an event with a low probability of occurring that could have a large negative impact on Con Edison. The expected impact of two such events is explored below.

Contingency Shutdown of Indian Point

Since the Three Mile Island incident, the public controversy concerning nuclear power plants in the U. S. has intensified. The Indian Point nuclear power plants have come under strong attack by the anti-nuclear forces because they are located 36 miles from Manhattan. In 1980, hearings were held on the future of the Indian Point nuclear power plant, indicating that its permanent or temporary shutdown was at least possible.[6]

Exhibit 5.19 shows the unit cost of electricity with and without Indian Point, in 1980 dollars, for the Con Edison strategy with Con Edison's projected load growth. In event of the Indian Point shutdown contingency in 1982, it appears that the cost of electricity would necessarily increase by about 1.5¢/kWh, an increase of approximately 16%. Similarly, if the contingency of an Indian Point shutdown in 1982 occurred, annual oil consumption would increase by about 21 million barrels, an increase of 75% over the amount of oil used in Con Edison's currently proposed strategy for the 1980's (Exhibit 5.20). (This assumes all of the shortfall is made up with oil.)

Exhibit 5.21 shows how coal conversion would still reduce the total cost of electricity supplied (1980-1995), in the case of a shutdown of Indian Point in 1987. Exhibit 5.22 shows the total oil consumed over the period. The hypothetical shutdown of Indian Point in 1987 appears to cause approximately 200 million extra barrels of oil to be consumed from 1980-1995 if there is no

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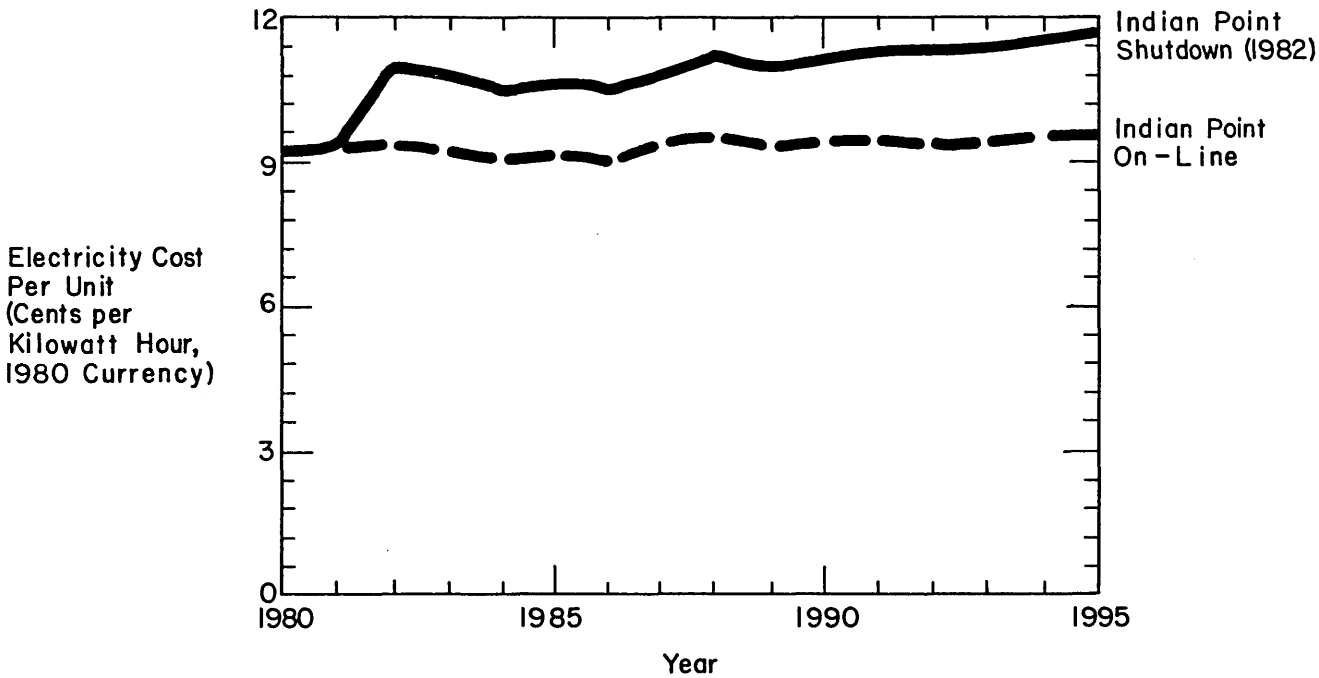
[6] Reference number 88.

Exhibit 5.19

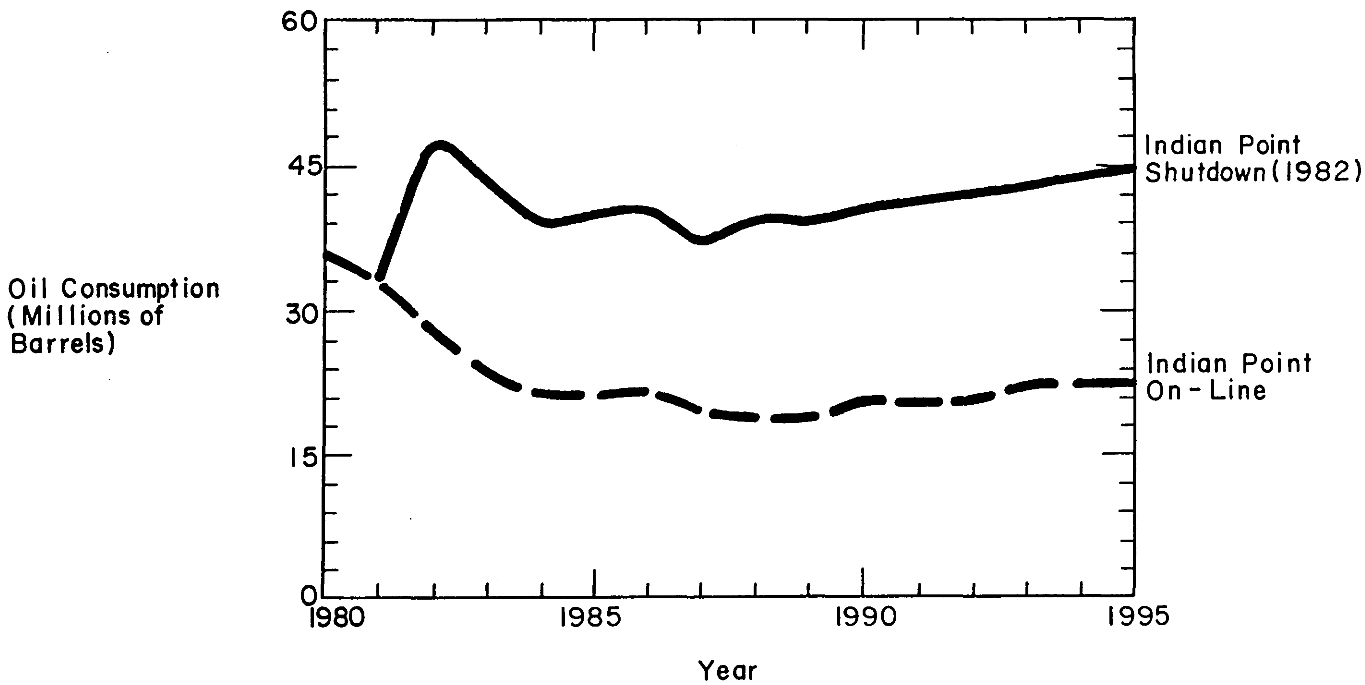
EFFECT OF INDIAN POINT NUCLEAR PLANT
ON ELECTRICITY COST PER UNIT FOR THE
CON EDISON CONVERSION PROGRAM



Note:
Prattsville pumped storage plant
is on-line beginning 1987.

Exhibit 5.20

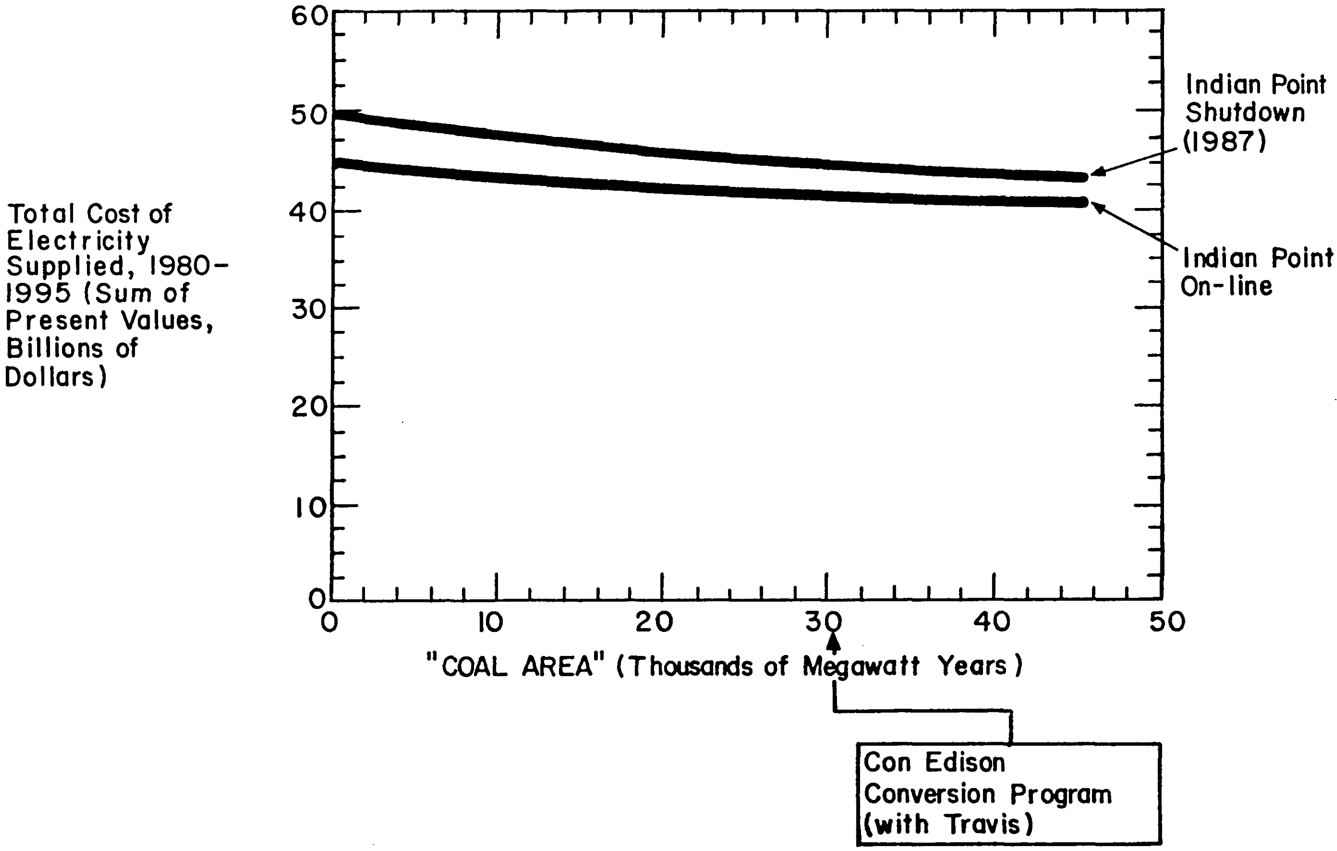
EFFECT OF INDIAN POINT NUCLEAR PLANT ON ANNUAL OIL CONSUMPTION (1980-1995) FOR THE CON EDISON CONVERSION PROGRAM



Note:
Prattsville pumped storage plant is on-line beginning 1987.

Exhibit 5.21

EFFECT OF INDIAN POINT NUCLEAR PLANT ON TOTAL COST
(1980-1995)

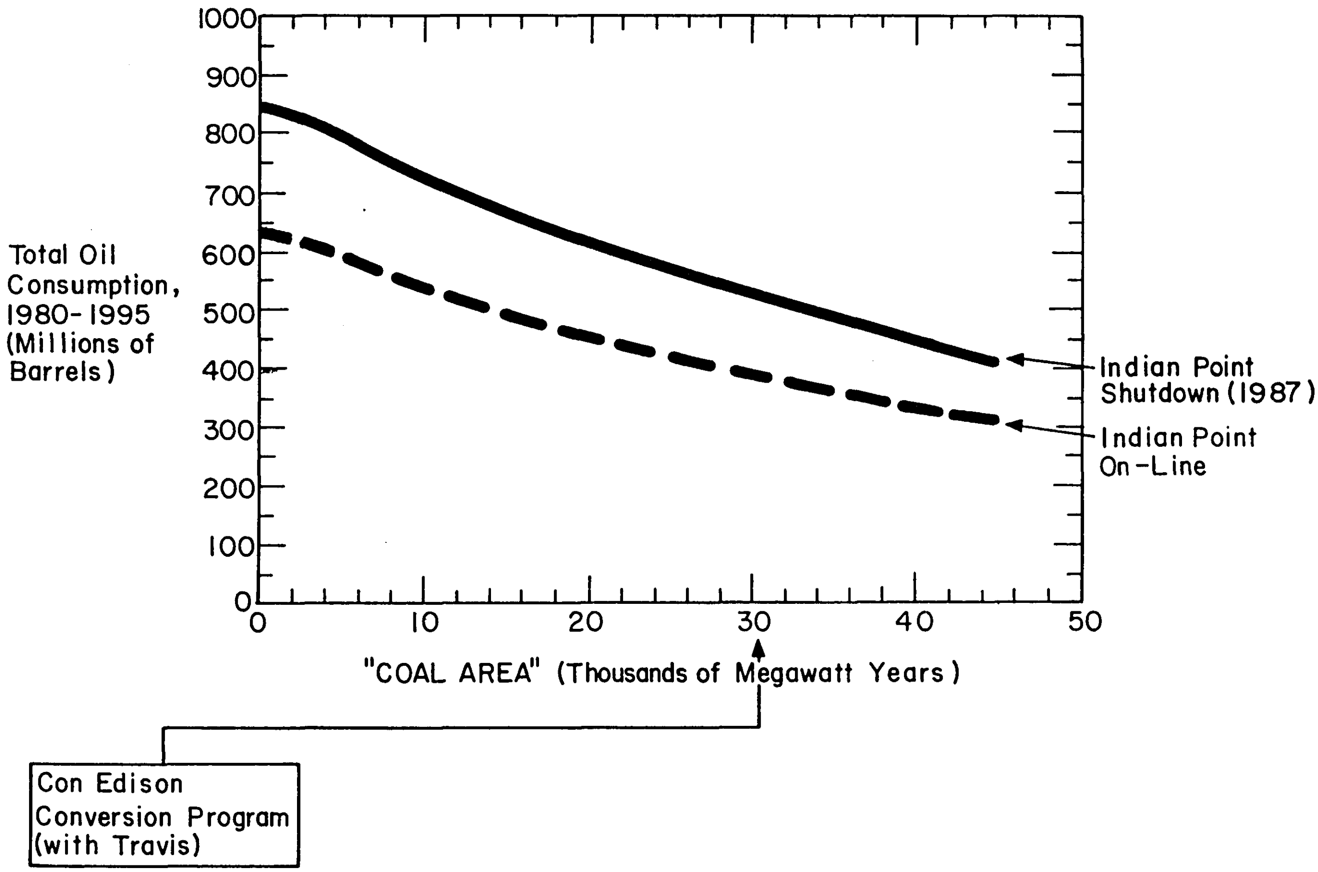


Assumptions:

Prattsville pumped storage plant is on-line beginning 1987.

Exhibit 5.22

EFFECT OF INDIAN POINT NUCLEAR PLANT
ON TOTAL OIL CONSUMPTION (1980-1995)



<u>Note:</u>
Prattsville pumped storage plant
is on-line beginning 1987.

coal conversion. If Indian Point were shut down in 1987, implementing the Con Edison conversion program, with construction of Travis, would save approximately 300 million barrels of oil from 1980-1995. Coal conversion of approximately 3500 MW (all of Ravenswood, Arthur Kill and Astoria) could save 400 million barrels of oil from 1980-1995 if Indian Point were shut down in 1987.

Exhibit 5.23 depicts the 1990 oil consumption of Con Edison as a function of coal-fired generating capacity with and without Indian Point. If Indian Point is shut down, Con Edison's oil consumption in 1990 increases by about 60-100%. Exhibit 5.24 shows that under a contingency shutdown of Indian Point in 1987, total SO_2 emissions in 1995 would increase by 40-60%.

Assuming that some coal conversion occurs, the ability of the Con Edison system to respond with coal to the contingency of a nuclear shutdown increases as the amount of coal burned in the system increases. If the proposed Con Edison conversions were implemented, coal could make a small contribution toward replacing this lost electric energy. However, if maximum coal conversion (3500 MW) had taken place, coal could provide up to approximately 38% of the lost nuclear generated electric energy. (See Exhibit 5.25.)

Contingency of Oil Cutoff

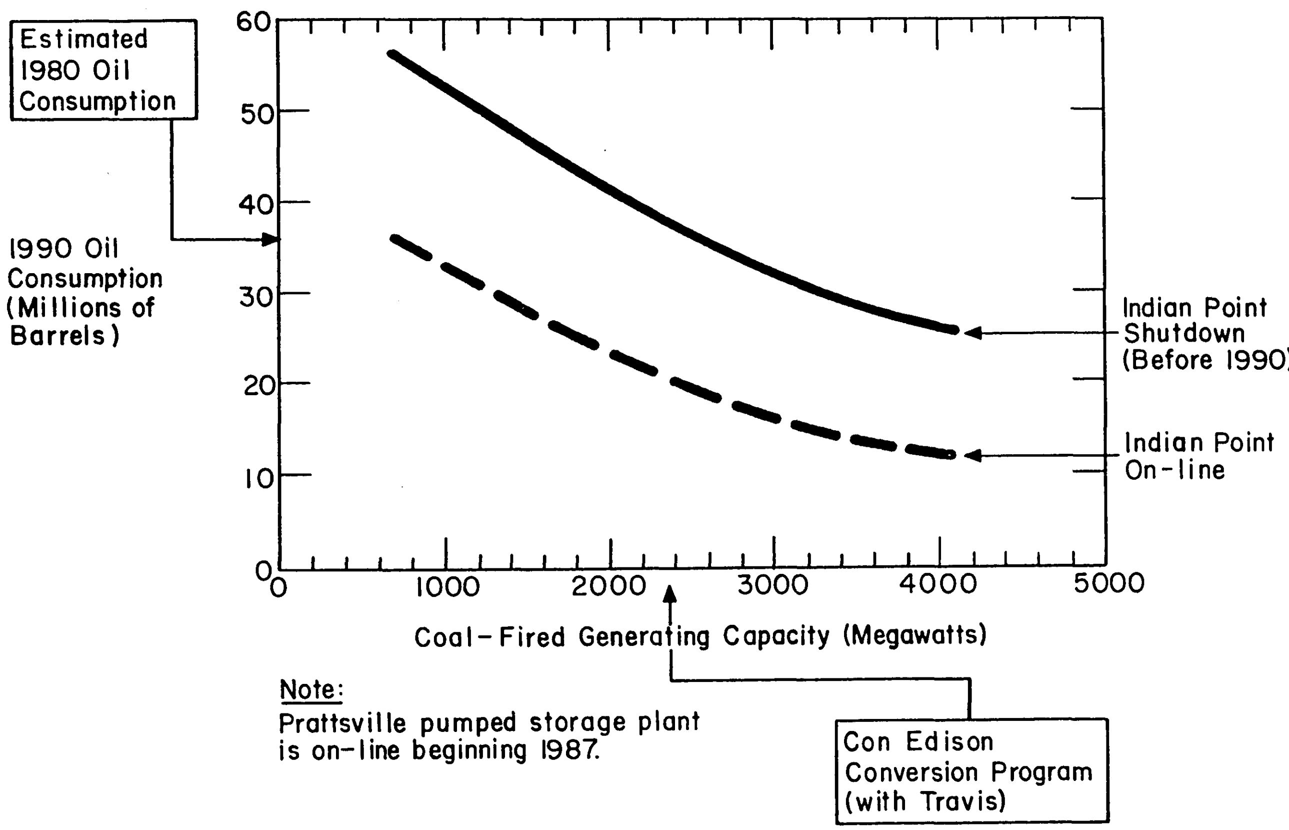
As mentioned in Chapter Two, U. S. oil imports have become uncertain during the last few years and are expected to remain uncertain because of the political instability prevailing in the Middle East. It is possible that sometime during the 1980's U.S. oil imports could be disrupted, perhaps permanently. If so, it is likely that the oil available to Con Edison will be at least partially cut off. The vulnerability of Con Edison to a sudden decrease in oil supply depends mostly on the percentage of its load that is serviced by oil. This, in turn, largely depends on the amount of coal conversion, natural gas availability, and whether the Indian Point nuclear plants continue operations.

Exhibit 5.26 shows how different amounts of coal conversions would affect the percentage of oil used to handle Con Edison's load over the next 15 years. In general, since oil use is reduced by coal conversion, Con Edison's vulnerability to oil cutoffs decreases as amount of coal conversion increases.

Exhibit 5.27 depicts 1990 oil consumption as a function of coal-fired generating capacity for different levels of load growth and purchased energy. An increase in coal-fired generating capacity permits attainment of a reduced level of oil consumption in 1990.

Exhibit 5.23

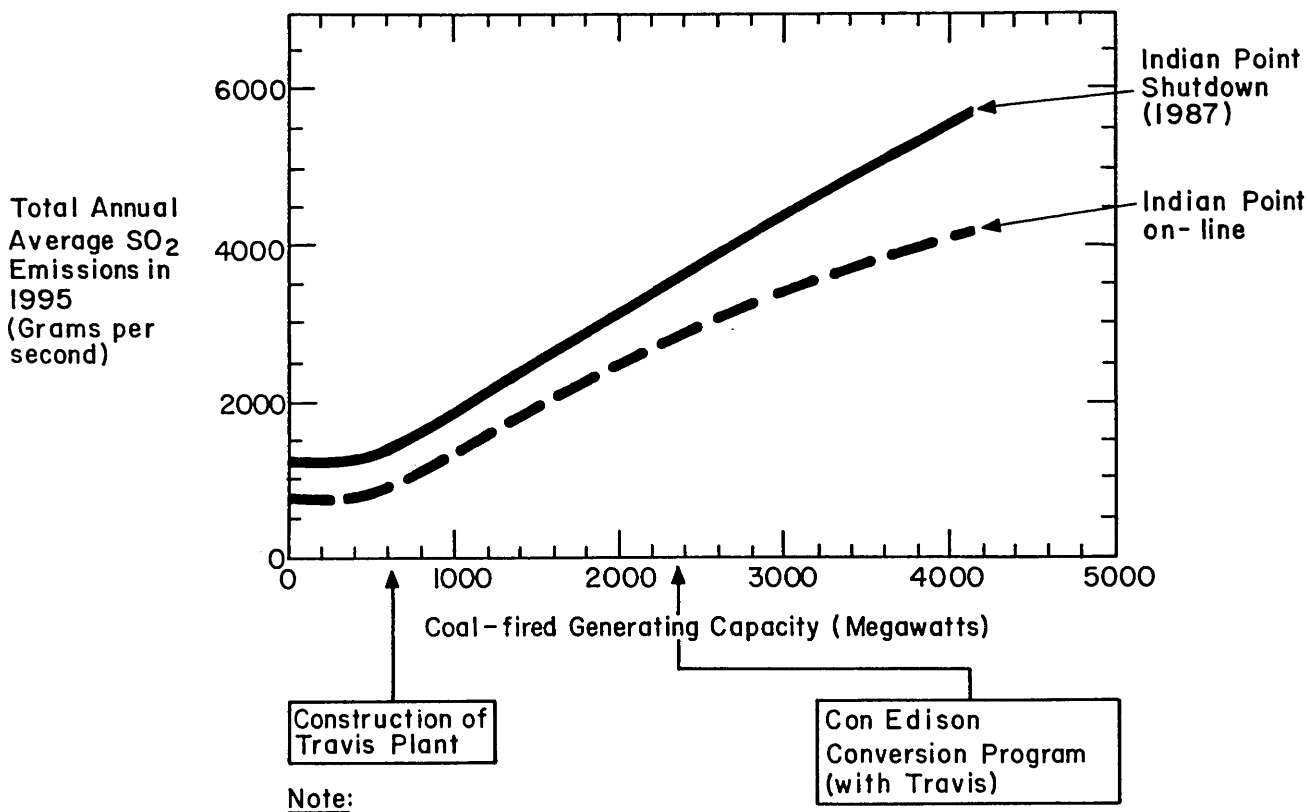
EFFECT OF INDIAN POINT NUCLEAR PLANT ON 1990
OIL CONSUMPTION



Note:
Prattsville pumped storage plant
is on-line beginning 1987.

Exhibit .5.24

EFFECT OF INDIAN POINT NUCLEAR PLANT ON 1995 SO_2 EMISSIONS



Note:
Prattsville pumped storage plant is on-line beginning 1987.

Exhibit 5.25

INDIAN POINT SHUTDOWN CONTINGENCY:
PERCENT OF ELECTRICITY GENERATED AT INDIAN POINT
WHICH WOULD BE REPLACED BY COAL-FIRED GENERATION[1]

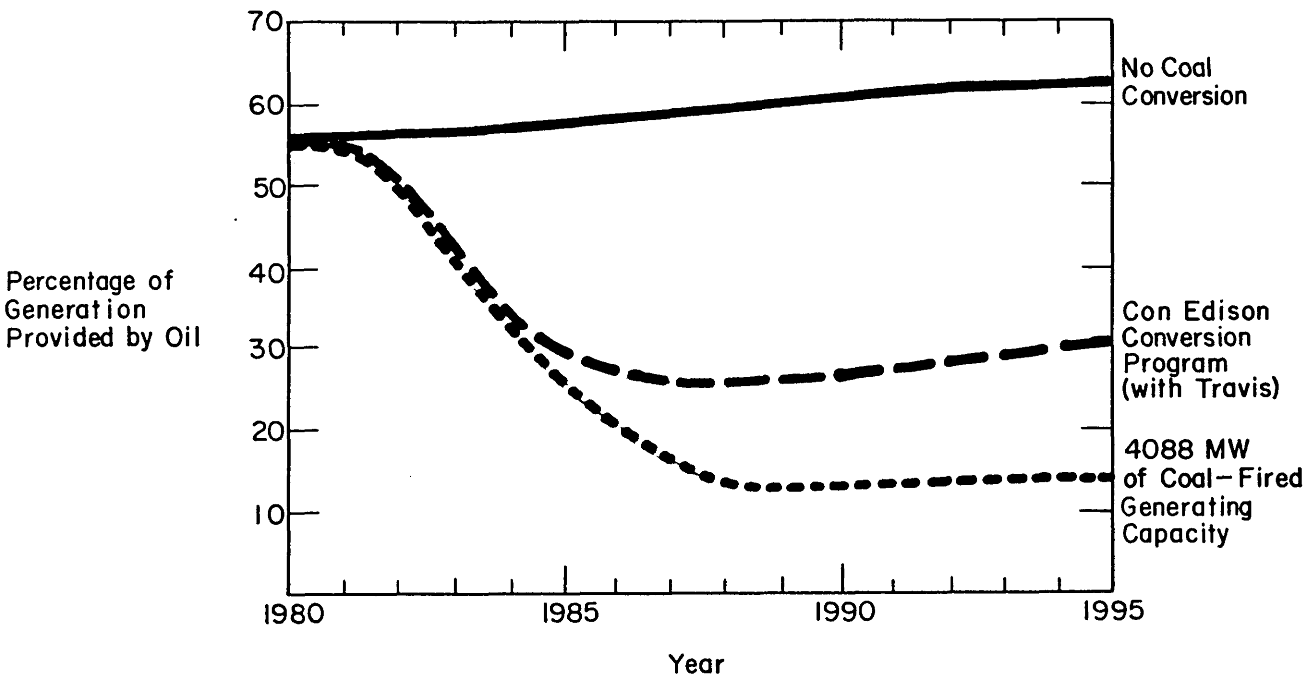
	Amount of Coal-Fired Electricity Generation		
	Indian Point On Line	Indian Point Shutdown in 1982 or 1987	Percent of Coal-Fired Replacement Electricity[2]
Con Edison Conversion Program (1700 MW of Coal Conversion)	13.5 Billion kWh	13.7 Billion kWh	2 %
3500 MW of Coal Conversion (Ravenswood 1,2,3; Arthur Kill 2,3; Astoria 3,4,5)	19 Billion kWh	23.5 Billion kWh	38 %

1 Assuming that coal conversion occurs.

2 Indian Point generates approximately 12 billion kWh of electricity.

Exhibit 5.26

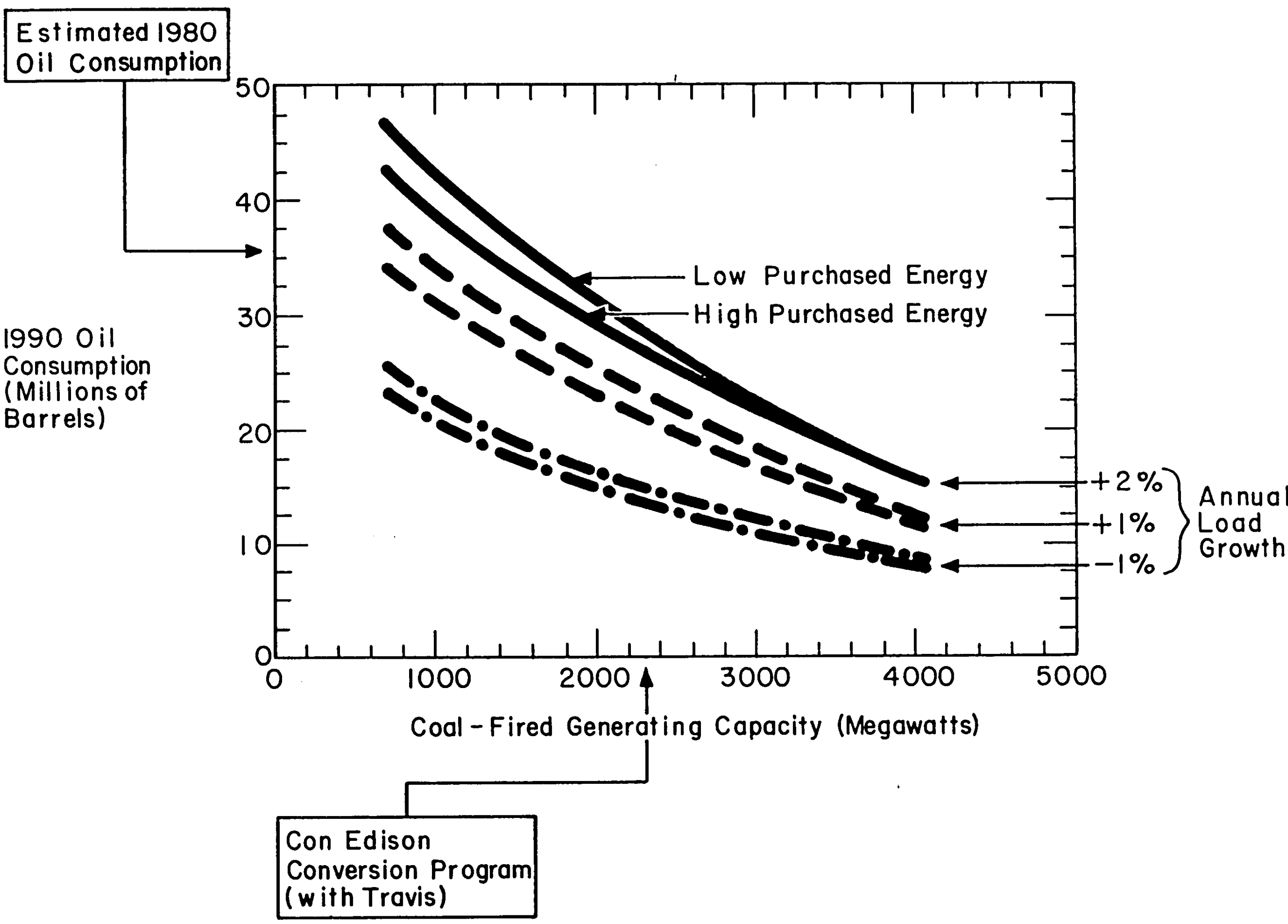
EFFECT OF COAL – FIRED CAPACITY ON ANNUAL PERCENTAGE OF GENERATION PROVIDED BY OIL



Note:
Prattsville pumped storage plant is on-line beginning 1987.

Exhibit 5.27

EFFECT OF CHANGES IN LOAD GROWTH AND PURCHASED ENERGY ON 1990 OIL CONSUMPTION



Note:
Prattsville pumped storage plant is constructed in 1987.

Overall Critique of the Plan

It is now appropriate to synthesize all the various observations drawn about the Con Edison strategy for the 1980's into a concise picture. Con Edison's electric energy strategy for the 1980's takes into account all of the possible primary electric energy strategy building blocks for the 1980's and three of the four secondary building blocks for the 1980's. In addition, in its perspective on the 1990's the plan touches on three of the four building blocks that will have impact during the last decade of this century. From this perspective, the proposed plan is comprehensive.

As discussed in Chapter One, Con Edison has four stated goals and objectives which motivate its electric energy plan for the 1980's. These are (1) reduction in oil usage, (2) moderation of electricity cost increases,(3) adequacy of supply, and (4) environmental acceptability. The plan's attractiveness in terms of Con Edison's objective for supplying an adequate amount of electricity is clear. Furthermore, the plan's choices among fuels are appropriate given the company's goals of reduction in oil usage and moderation of electricity cost increases.

During the 1980's Con Edison has only four potential primary fuels from which to make electricity: oil, nuclear, natural gas, and coal. Maximum possible use of nuclear-generated electricity in the 1980's is contemplated, and hence this component of the plan aims at lower cost electricity and avoidance of oil dependence. The plan centers on rapid conversion of high cost oil-fired capacity to coal, the lowest cost primary fuel. Hence, this component of the plan also aims at lower costs of electricity. Because this conversion reduces oil usage, it is consistent with proposed national policy to reduce oil consumption. In addition to its cost and oil consumption advantages, coal is also the only remaining primary fuel alternative to oil unless future variances to the Powerplant and Industrial Fuel Use Act are granted to allow continued use of gas in Con Edison electric-generating plants. Furthermore, the plan recognizes the positive oil reduction and cost implications of purchased energy. Con Edison expects to purchase energy even though it has adequate reserve capacity to generate all its needs. This is a rational decision.

There is no conflict between the goals of decreasing total cost and decreasing oil consumption if coal is introduced into the Con Edison system. (See Exhibits 5.7 and 5.8.) However, the introduction of coal burning--as planned--although possible within environmental standards, would raise the level of SO_2 emissions. (See Exhibits 4.12, 4.13 and 4.14.) To meet the last objective, environmental acceptability, the plan will have to conform to federal ambient air quality standards. Further, a regulatory decision must be made that the conversions under the plan are an acceptable use of part of the available air quality increment in New York City. Con Edison will also have to seek and be successful in obtaining a change in New York City's air pollution control code which effectively bans the burning of coal within New York City. In addition, there is likely to be negative action from environmental interest groups.

The MIT investigators established three criteria of merit for evaluating the Con Edison energy strategy for the 1980's in terms of the partially conflicting goals of moderating the rate of increase of total cost of electricity (compared to the cost path without coal conversion), reducing oil consumption and maintaining acceptable air quality. A broad spectrum of possible alternative programs was constructed and evaluated. All of the alternative programs assume the use of 1% sulfur coal. However, they differ in the amount of coal capacity introduced, the use of FGD equipment, the amount of purchased energy, the availability of Indian Point and the addition of Travis and Prattsville. This entire evaluation was designed to identify only broad trends and major tradeoffs. Detailed engineering analysis would be required before the actual desirability of any of these alternative plans could be established. Based on this broad analytic perspective, the following observations emerge.

Con Edison's proposed coal conversions are attractive in terms of the tradeoff they imply between total cost of electricity and SO_2 emissions. Specifically, for the expected SO_2 emission level, Con Edison's conversion program achieves the lowest total cost of electricity (among the alternatives examined), about 8% lower than total cost of electricity assuming no coal is burned in the system. Other possible conversion programs involving the same SO_2 emissions but, for example, different units converted to coal, would yield a higher total cost of electricity. (See Exhibits 5.3-5.6.)

There are alternative conversion programs, involving more coal-fired capacity without FGD equipment, which would yield a lower total cost of electricity than the Con Edison plan. However, they would result in higher SO_2 emissions. To achieve more than about an additional one percentage point reduction in total cost of electricity by simply adding more coal capacity appears impossible, because by that point the annual average ambient SO_2 standard is likely to be exceeded. (See Exhibit 5.9.)

The current commercially available FGD technology is the non-regenerative wet scrubber, which produces a polluting wet sludge by-product that must be disposed of properly. There are other FGD technologies at various stages of development. Some of these alternative technologies do not produce a pollutant by-product. Addition of wet scrubbers to the proposed Con Edison conversions would decrease their SO_2 emissions by about 60%. This SO_2 emission level would be essentially the same as in the case of no coal conversion. Despite the added costs, the proposed Con Edison conversions with FGD equipment still result in lower total cost of electricity than if no coal conversion occurred. Rather than being 8% lower as contemplated for the proposed conversions, total cost is 5% lower if FGD equipment is installed. (See Exhibit 5.11 and Exhibit 5.12.)

Addition of FGD equipment as a condition of conversion may delay conversion if an FGD technology that is satisfactory to Con Edison and to the regulators cannot be identified rapidly. Even if wet scrubbers were chosen, a delay of at least two years would be experienced relative to conversion without FGD equipment. This is so because additional engineering design work, procurement, installation and start-up of FGD equipment would be required. Such a conversion delay would be costly. A two-year delay in the coal conversion of Arthur Kill 2 and 3 and Ravenswood 3 experienced due to FGD addition, the regulatory approval process, or any other reason would reduce the cost savings of the proposed Con Edison conversions by about 10% and reduce the oil savings by about 8% over the period of 1980-1995. (See Exhibit 5.12.) Thus, a reduction of approximately 7% of total cost of electricity, rather than the 8% as contemplated for the proposed conversions, would be passed on to consumers through the fuel adjustment price process.

There are alternative coal conversion programs with FGD equipment that would produce levels of SO_2 emissions and total cost of electricity that are comparable to those resulting from Con Edison's conversion program. These programs involve higher levels of coal-fired generating capacity than the Con Edison conversion program. Although these programs do not lead to any further decreases in total cost of electricity or SO_2 emissions, they lead to an additional decrease in oil consumption of up to 15% compared to the Con Edison conversion program. (See Exhibit 5.8.)

These conclusions regarding the relative merits of the various coal conversion alternatives have been tested for sensitivity to load growth, as might be introduced by strong conservation efforts, as well as to decisions on Prattsville, Travis and amounts of purchased energy. The conclusions are not sensitive to these various uncertainties. (See Exhibits 5.10 and 5.13-5.18.) Furthermore, it appears that Con Edison's coal conversion program, with or without FGD equipment, should not be financially constraining. Moreover, the construction expenditure levels for this program and alternative programs examined with more extensive coal conversion should be readily financeable given a reasonable regulatory environment. (See Exhibits 4.22-4.24.)

Oil supplies for the U. S. could be disrupted during the 1980's. Implementation of the proposed Con Edison conversions would reduce the service area's effective dependence on oil from about 56% in the current fuel mix to about 30% by 1990. Additional coal conversion could further reduce Con Edison's dependence on oil (Exhibit 5.26.) To the extent oil is replaced, Con Edison and its service area are less vulnerable to this contingency.

Should an NRC-mandated shutdown of the Indian Point units occur during the 1980's, oil and perhaps natural gas would have to be substituted. If the proposed Con Edison conversions were implemented, coal could make a small contribution toward replacing this lost electric energy. However, if maximum coal conversion (3500 MW) had taken place, coal could provide up to approximately 38% of the lost nuclear generated electric energy. (See Exhibit 5.25.)

Specifically, with regard to Con Edison's seven-step electric energy strategy for the 1980's, we conclude, based on this investigation, that:

-- Existing conservation programs are commendable. Planned conservation programs could be strengthened, but the cost-effectiveness of doing so remains undetermined.

-- Conversion of Ravenswood 3 and Arthur Kill 2 and 3 to coal is the most significant action which Con Edison can take to reduce oil consumption and to moderate the rate of increase in electricity costs to its customers. Our analysis indicates that those conversions (using 1% sulfur coal without FGD facilities) would not cause air quality standards in New York City to exceed annual average ambient SO_2 standards, the most constraining standard. Before the conversions can be undertaken, however, it is necessary that a regulatory decision be made that these conversions are an acceptable use of part of the available air quality increment. Also, the conversions cannot take place as long as the present coal-burning ban stands in New York City. FGD technology, which could be used to limit SO_2 emissions to the same levels as those from the burning of 0.3% sulfur oil, would add substantial capital and operating costs to the coal conversions, but total cost of electricity would still be lower than if no coal conversion had occurred. However, addition of FGD systems as a condition of conversion would delay conversion at least two years relative to conversion without FGD equipment. Rapid conversion, with later addition of FGD, is one possible course of action. A regulatory judgement needs to be made as to whether the emission control benefits of FGD exceed its costs. The choice of the most appropriate FGD technology, if necessary, needs to be made by Con Edison. It would be prudent for Con Edison to develop and have available for installation--if and when required--the FGD technology that it believes appropriate for its plants.

-- Continued use of Indian Point is desirable.

-- Increases in purchased energy, as planned, are desirable. Even larger purchases may be desirable, particularly if terms sufficiently favorable to cover the cost of any necessary transmission improvements can be negotiated. The possible negative impact on system reliability of increases in energy importation has not been investigated.

-- Support for Travis is appropriate. The overall attractiveness of Travis with respect to Con Edison electric energy strategy objectives would be large if Con Edison were not permitted to burn coal. However, given the proposed coal conversion, the impact is significant but not as large. This investigation identified both small advantages and small disadvantages for Prattsville in terms of the stated goals. Since the analysis undertaken for this study is too narrow in scope to permit complete assessment of the value of this facility, we defer on Prattsville.

-- Support of research on refuse as a fuel for electricity generation is appropriate. MIT defers on the matter of the use of refuse as a fuel in the service area until more is known about pollution aspects and possible pollution control technologies.

-- We defer on the matter of tax reduction. The taxation issue is one of social equity, an issue outside the scope of this work.

This analysis strongly supports the implementation of Con Edison's plan. In fact, based on this analysis serious consideration should be given to coal conversion beyond the 1700 MW currently proposed (Exhibits 5.3-5.9). Such additional coal conversions would likely require the utilization of FGD facilities (Exhibit 4.14). Also, in the near term Con Edison's electric energy strategy should take full account of the probability of future upward revisions of domestic gas reserve additions and of the easing of federal statutes which currently limit the burning of natural gas by utilities.

The energy realities of the 1980's may well compel more coal conversion and even larger amounts of purchased energy than the proposed plan. In light of these realities, it is important for the entire plan to be seen as possibly only a first step in re-establishing coal usage in New York City.

Since this first step approaches the limits of coal transportation and handling facilities, annual average ambient SO_2 air quality, and long-distance electricity transmission capability, it is important that Con Edison intensify its investigation into alternative means to accomplish these functions. Furthermore, because so many limits are being reached at the same time, conservation offers a particularly compelling logic even though reserve capacity exists. Additional research to supplement present programs in this area is needed, as is further research on developmental conversion.

It is unrealistic to assume that technical options forecast to become operational in the 1990's--synthetic fuels, renewable resources, developmental conversion and developmental load management techniques--will make obsolete reconversion to coal scheduled to occur in the 1980's.(See Chapter Six.) Only natural gas represents a potentially viable alternative to coal for in-city electricity generation, and even if available, gas will be priced at least on a parity with oil. Greater reliance on nuclear power for the Con Edison service area in the 1990's, while perhaps compelling by economic and, to a lesser extent, environmental logics, will require the endorsement of society. The future societal judgement concerning nuclear power constitutes the largest uncertainty in long-range electric energy planning.

Viewpoint on General Direction of National Energy Planning in the 1980's[7]

The U. S. will continue to fuel the transportation sector of the economy almost exclusively with liquid petroleum. Total transportation fuel demand during the decade is expected to remain roughly constant, since there is potential for fuel efficiency and every indication that liquid petroleum price increases will stimulate that move toward greater efficiency. Interestingly, it would be possible today to satisfy transportation fuel demand by domestic fossil fuel liquids if these liquid fuels were not being used in other sectors of the economy.

This substitution could be accomplished if compensating equal increases in utilization of natural gas and electricity were made where liquid fuels are now used in the residential/commercial sector. It would also be important to make significant efficiency gains in areas in which electric losses are now occurring. In the industrial sector the substitution for liquid fossil fuels could be made directly with coal. Because of the growth of electricity in the residential/commercial sector, the primary fuel for utility generation of this electricity becomes crucial to balancing domestic supply and demand for energy. Either coal or uranium could serve to displace existing supplies of liquid fossil fuels and natural gas while, at the same time, providing for the expected growth. Since uranium appears politically unacceptable in the 1980's, coal can be expected to be the displacing fuel. The result of these changes would be to displace most of the imported liquid fossil fuel by use of domestic coal. That is, the U. S. could become virtually energy self-sufficient in the 1990's by reassignment of its domestic fuel supplies among the competing uses, while at the

[7] Condensed from reference number 199.

same time vigorously pursuing fuel efficiency in the transportation sector.

No attempt has been made in this investigation to forecast the rate at which these various inter-fuel substitutions will take place. Rather, this investigation assumes that the political and regulatory processes will tend toward this type of fuel reallocation, since it will appear over time to be politically expedient to do so.

The movement to make these adjustments is the result of a process of decision making where choices are difficult. Those who must make the choices need to inform themselves of the tradeoffs involved, weigh the alternatives, and then make the decisions in a timely manner. Completing the first two steps without the third is a relatively meaningless exercise. It is difficult to imagine that any significant portion of society affected by these decisions can be benefited by further delays in the decision process.

Chapter Six

PERSPECTIVES FOR ELECTRIC ENERGY STRATEGIC PLANNING IN THE 1990's

In Chapter Two several of Con Edison's options were classified as electric energy strategy building blocks for the 1990's. This chapter explores the future of these developing technologies that will have little or no impact on Con Edison at least until the 1990's.

Synthetic Fuels

The U. S. has very large reserves of certain resources that can be used to produce synthetic fuels (synfuels). For instance, it has supplies of oil shale and coal that could sustain a synthetic fuels industry producing 15 million barrels of fuel per day for about 150-200 years. By 1990, however, the supply of synfuels is expected to be less than 5% of the total U. S. gas and oil used. This low level of availability is partly because only a few synfuel technologies have been proven commercially. Furthermore, it takes about 15 years after a test program to develop a commercial application. Most synfuel processes will be available, at the earliest, in the second half of the 1990's. The most promising technologies are explored below.

Coal Gasification

With this technology, gas of various heat values can be produced from coal. Several coal gasification processes are currently in commercial and/or experimental operations, making it perhaps the most highly developed synfuel technology. Estimates of 1990 gas supplies from coal range from 0.3-1.0 trillion cubic feet (Tcf), equivalent to 2-3.5% of U. S. gas consumption in 1979.[1]

In the gasification process gas is produced from coal by passing air (or oxygen) and steam through a bed of incandescent carbon to form hydrogen and carbon monoxide. If air is used, a low-Btu gas with a heat content of 100-250 Btu per cubic foot is produced. If oxygen is used in the gasification process, a medium-Btu gas with a heat content of 300-500 Btu per cubic foot is produced. The medium-Btu gas can be converted to high-Btu gas

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[1] Reference numbers 50, 64, 92, 142, and 147.

by a methanation process producing a heat content of 900-950 Btu per cubic foot. Low- and medium-Btu gas cannot be transported over long distances. Consequently, gasification plants for such gas must be built close to their final use. On the other hand, high-Btu gas can be transported over long distances through pipeline and, in general, is similar to natural gas.

Several gasification processes are currently in commercial operation, including the Lurgi, the Koppers-Totzek, the Winkler, and the Wellman-Gadusha processes. In addition, there are several processes in the experimental stage, including the *in situ* coal gasification process.

Coal Liquefaction

This technology converts coal into liquids that can be used as fuel or chemical feedstocks. Only one coal liquefaction process is currently available on a commercial level, though others are in experimental stages. Estimates of the 1990 coal liquids supply range from 30,000-200,000 barrels per day.[2]

Coal can be liquefied either directly or indirectly. Direct liquefaction techniques add hydrogen directly to coal. The solvent refined coal (SRC) process is the best known example of direct liquefaction. Indirect techniques first gasify coal and then chemically react the gas into methanol or chemical intermediates that can be upgraded to gasoline.

The Fischer-Tropsch is the only coal liquefaction process available commercially. It is an indirect coal liquefaction process where coal is first converted to gas and, subsequently, to methanol or a number of chemical intermediates that can be further upgraded to gasoline. The Fischer-Tropsch process has been used commercially in South Africa at the SASOL coal liquefaction plant.

Oil Shale

Oil shale is a finely textured rock containing kerogen, an organic substance that is crushed, heated, processed, and then refined into a variety of oil products. Several oil shale processes have been tested and appear ready for scaling up to commercial size. Estimates of shale oil products available in 1990 range from 200,000-400,000 barrels per day.[3]

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[2] Reference numbers 64 and 92.

[3] Reference numbers 64, 92, and 142.

Much effort is currently devoted to developing *in situ* techniques that would process the shale underground and, thus, avoid its mining. Several oil shale retorting processes have been demonstrated successfully at pilot-plant scale and appear ready for scaling up to commercial size. Efforts to develop *in situ* techniques processing the shale underground have not been very successful so far.

Tar Sands

Tar sands are deposits of very heavy oil which cannot be recovered by conventional methods. Because the domestic supply of tar sands is small, the expected future supply is minimal, about 20,000 barrels per day in 1990.[4]

Production and Capital Costs

Exhibit 6.1 depicts predictions of the production cost of synfuels. The capital costs of synfuels are expected to be very large and well above the capital costs of conventional oil and gas (Exhibit 6.2).

Renewable Resources

This building block refers to the use of renewable fuels--solar and wind--either directly or as fuels to generate power with appropriate technology and equipment. The four major uses of renewable resources considered were solar hot water, solar space heating, wind turbines (e.g., modern designs of "windmills"), and photovoltaic energy (energy produced when light (photons) strikes a wafer of specially-prepared, single crystal silicon or other material). While renewable resources may have a major effect on individual electricity consumers in some areas of the country, their impact in the Con Edison service area will be quite limited during the next twenty years.

Solar Hot Water and Space Heating

It is highly unlikely that solar hot water or space heating technologies will have a major impact on Con Edison's load before the end of the century. This is primarily because the relatively

[4] Reference number 64.

Exhibit 6.1

PRODUCTION COSTS OF SYNFUELS
(1980 $/MBtu)

	Cameron Engineers*	Exxon**
Coal Liquids	5.7 - 7.3	5.4 - 9.9
Oil Shale	2.8 - 4.9	4.2 - 4.4
Tar Sands	4.9 - 6.2	n.a.
Coal Gasification	6.6 - 9.9	6.1 - 8.8

* Cameron Engineers figures were converted from 1979 dollars to 1980 dollars by using a 13% inflation rate. A 15% discount rate was assumed by Cameron Engineers.

** Assuming 10% discount rate.

Sources: "Overview of Synthetic Fuels Potential to 1990" in Report by the Subcommittee on Synthetic Fuels, U. S. Senate, Washington, D.C., report prepared by Cameron Engineers, September 27, 1979 and U.S.A.'s Energy Outlook 1980-2000, Exxon Corporation, Public Affairs Department, New York, NY, December 1979.

Exhibit 6.2

CAPITAL COSTS OF SYNFUELS

	Investment: ($/million cubic feet per day)
Coal Gasification	5,700 - 8,700
Alaska Gas	6,200
Onshore Continental U.S.	2,000 - 3,000

	($/barrel per day)
Coal Liquefaction	
SRC II	28,500 - 35,000
Direct Liquefaction	35,000 - 42,000
Indirect Liquefaction	36,500 - 43,000
Shale Oil	16,600 - 25,000
Tar Sands	20,000 - 23,000
North Sea Oil	10,000
Onshore Continental U.S.	3,000 - 5,000

Sources: MIT Study Group and "Overview of Synthetic Fuels Potential to 1990" in Report by the Subcommittee on Synthetic Fuels, U. S. Senate, Washington, DC, report prepared by Cameron Engineers, September 27, 1979.

low energy density of the solar technology has limited potential within New York City. Solar energy falls upon the earth at a rate of 1000 watts per square meter at high noon on a cloudless day. Given the normal conversion factors, which average 10%, it is necessary to have 10 square meters of surface space to collect 1 kW of energy. Even advanced solar technology cannot achieve operating efficiencies required for use in New York City. There is a possibility that solar energy could have a greater impact on the load of Westchester County than on the load of New York City.

Secondarily, the majority of the areas served by Con Edison are built to near capacity. Therefore, solar energy technologies would need to be retrofit systems rather than systems integrated with new construction. The energy potential from retrofit solar systems is lower than that for new construction because few existing buildings have roof areas with correct facing or with sufficient unshaded areas for collectors. Third, the solar hot water heating systems currently being installed are often backed up by electricity. If these systems replace those that use oil or natural gas, they will actually increase electrical demand due to their need for such backup. If they are replacements for units which use electricity, the net impact on the load will be negative.

The solar space heating issue is more complex since there are limited advantages to electric backup for space heating. As a result, new systems have a relatively equal probabilities of having oil, gas, or electric heat for backup (dependent upon availability). In retrofit installations, the heating system used prior to the retrofit is generally used for backup. In either case, there is reason to believe that there will be a net reduction in demand brought about by these technologies, although the amount would be slight.

Further, there has been relatively little past use of solar energy systems within the Con Edison service area. A major impact during the period of the 1980's would imply installation rates more rapid than are expected. While the impacts of solar hot water and space heating in either New York City or Westchester County are expected to be small, in all likelihood their effects will be a net increase in demand for electricity to serve as backup, particularly for hot water heating systems.

Wind Turbines

The use of wind turbines could have more impact in the 1990's than solar technologies. This is so because technological development is expected to make them financially attractive earlier and because the wind energy density problem is somewhat less of a problem than the solar energy density problem. While their precise impact on Con Edison cannot be predicted, wind turbines will probably reduce somewhat the company's load during the 1990's, since they will most likely be operated in a decentralized, privately-owned fashion.

While there are a variety of wind technologies under development, they may be classed as either horizontal or vertical axis machines. Horizontal shaft machines collect wind energy as it blows through a set of blades ranging from two (many of the newer aerodynamic designs) to 'multivaned' (as was the case in many of the older electrical and pumping machines of the midwest). Energy is either transferred directly into electricity in the hub at the top of the machine, or it is transferred mechanically through a gearing arrangement to the base of the machine where it is maintained as mechanical energy or converted into electrical energy. The vertical axis wind machines are simpler in their construction than horizontal axis machines because the heavy generator components can be located at the base of the tower without elaborate gearing, and because the tower itself can be a simpler construction.

The average wind speed for the New York metropolitan region is 13.4 miles per hour in January and 10.6 in July, which would generate between 21,000 kWh and 35,000 kWh of electricity from a 10 kW wind turbine located on the island[5]. It might be argued that the tops of buildings in the downtown Manhattan area are ideal locations for wind turbines since wind speed is high in these locations. However, the amount of space required for the safety of the blade, should it break off, is in excess of that available on the building tops. Vertical axis turbines may be more acceptable in these sites than horizontal axis machines, but additional study and development are required before even these are both reliable and safe. Safety remains a real constraint to placing wind turbines on building tops.

Photovoltaics

The renewable energy source associated with the most rapid future technological advances and consequently with the greatest expected impact on Con Edison in the 1990's is photovoltaic technology. The photovoltaic effect was developed by researchers of the Bell Laboratories in the mid-1950's. It creates a direct current capable, in theory, of converting solar energy to electricity at a total efficiency of 24%. Currently available photovoltaic cells produce electricity at up to 18% efficiency, though losses in the system after encapsulation and transfer of the power from DC to AC generally range from 10-14% of the conversion efficiency.

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[5] Reference number 110. Performance based on a 20 mph rated turbine.

At present, there are few photovoltaic systems on-line and limited potential for equipment production. The majority of the current systems have been funded by the U. S. DOE or the Department of Defense and are experimental. The largest is a portion of the Natural Bridges National Park in Utah, an installation of 125 kW. The first residential application is in Phoenix, Arizona, with a second and third to be completed within the year in Florida and Massachusetts. A number of intermediate applications are also operational. The majority of all current units (excluding Natural Bridges) are interactive with the local utility.

The analysis carried out for photovoltaics relied heavily upon work completed at the MIT Energy Laboratory as part of ongoing research for the DOE on the economics of photovoltaic power systems. That effort has focused on the measurement of the 'worth' of photovoltaic generation equipment to specific owners. In general the analysis has looked at residential, commercial, and utility ownership using simulation techniques in which the potential output of the system is evaluated against the source of alternative energy, generally the utility to which it is connected. The utility analyses which have been undertaken have not looked specifically at Con Edison, but have, rather, utilized the EPRI synthetic utilties 'tuned' to represent northeastern utilities. The load data that has been used in the analyses has been that of Boston Edison, again a utility similar to Con Edison, though clearly not identical. Despite these approximations, the conclusions from the studies were meant to be generalized beyond the specific bounds of the synthetic utility used.

The analyses looked at three generic applications for photovoltaic power systems. These were residential, commercial, and industrial/utility. The analyses focused on the output relative to the load, the ability to sell power back to the utility, and the capital and equity position of the potential owner. There were a number of assumptions which were made concerning the economic and physical conditions within which the systems would be installed. Probably the most important was that the institution or individual installing such a system would, act as an economically rational individual. This meant that the system was worth to them an amount exactly equal to the life cycle cost of the energy displaced, appropriately discounted. Choice of a discount rate and the terms of purchase made a significant difference in the worth of the system to a given user.

Of the three generic applications analyzed, the most attractive (i.e., that which appeared to have the highest worth) was the residential application. The principle reason for this was the favorable tax structure faced by residential consumers when making capital investments. The second most attractive was specific applications in the commercial sector, particularly those in the public sector where the discount rate is lower. The least attractive investments appeared to be in industry and in utilities. In the case of the utility there was an additional need to purchase land for location of the plant and to pay additional taxes which were disadvantages for the photovoltaics.

Photovoltaics are unique among generation technologies since they are nearly scale independent (i.e., small units have nearly the same cost-benefit ratios as large units). Because of this and because of the favorable tax structure that residential consumers face when making capital investments, it is likely that photovoltaics will be used commercially first on a decentralized, but grid interactive, basis. The advent of PL 617, the Public Utility Regulatory Policy Act (PURPA), Section 210, has guaranteed that this type of interaction will be possible between the utility and the small photovoltaic generator.

Developmental Conversion

Several developmental conversion techniques (DCTs) will become interesting for Con Edison to consider in the 1990's, generally because their combustion efficiency and/or pollutant emission rates are superior to those of current technology.

Two major new ways of using DCTs were identified. One is retrofit of existing combustion turbines to combined cycle. The other is to build a new plant which uses a combined cycle system, fluidized bed boiler or fuel cell. Retrofit of existing combustion turbines to combined cycle was considered to be technologically feasible but uneconomic for the 1980's. None of the other technologies will be available on other than a first-of-a-kind or demonstration basis until the late 1980's or the 1990's. Con Edison might want to consider a DCT for new plants scheduled for on-line availabilities after that time because of their higher efficiencies or lower emissions. Thus, DCTs are an electric energy strategy building block for the 1990's.

Because a large part of Con Edison's steam system will be retired in the 1990's, the company could consider new steam/electricity centralized cogenerating facilities for the next decade. Two technologies for new facilities are especially interesting. First is use of combined cycle gas turbines, which would use natural gas or synthetic fuels for steam/electricity cogeneration; second is use of fluidized bed boilers, which would use coal and operate with relatively low environmental impact.

Fluidized Bed

In a fluidized bed boiler a pulverized fuel is mixed with limestone and burned to produce heat. This heat is then used to boil water and produce steam. The fuel can be coal, solid waste, or several other low grade fuels. The mixture is fluidized by continuously forcing air into the boiler from the bottom. Limestone removes SO_2 by trapping it as calcium sulfate, and steam is produced by submerging boiler tubes into the bed as well as locating them in hot flue gases above the bed. The bed can be operated at atmospheric pressure or it can be pressurized. Atmospheric fluidized bed boilers are viewed by many as a simpler and more reliable plant than conventional coal with scrubbers. Further, a fluidized bed has the potential of being able to burn coal in-city with SO_2 and NO_x emissions comparable to those from conventional coal plants using scrubbers. However, atmospheric fluidized bed boiler operations have an associated solid waste problem.

Combined Cycle

In a combined cycle system the exhaust gases exiting from a conventional combustion turbine are passed through a heat recovery boiler which raises steam for a turbine generator set. These units can burn natural gas, oil, or they can burn coal by adding a coal gasifier to the system. This gasifier combined cycle system would have a higher capital cost than a conventional coal-fired plant, but since it can use coal more efficiently, it may have a lower incremental fuel cost. The use of a gasifier might result in siting difficulties due to problems associated with disposal of the conversion waste products. These possible difficulties, however, should not be significantly different from those of a conventional coal-fired plant.

Fuel Cells

A fuel cell generator system has three parts: a fuel processor; a fuel cell stack; and a power inverter. Hydrocarbon fuel and steam (recycled from the fuel cell operation) are first fed into the fuel processor and converted to hydrogen and carbon dioxide. This hydrogen-rich mixture is then fed into the fuel cell stack (where a large number of individual fuel cells are connected electrically in series). In the fuel cell, chemical energy stored in the fuel stored in this mixture is converted directly into DC electricity. This electricity is fed to the power inverter which converts it to AC electricity suitable for utility application. A fuel cell generator can use a variety of liquid and gaseous hydrocarbon fuels, or it can burn coal if it is integrated with a coal gasifier.

The modularity, fuel flexibility, efficiency and emissions characteristics of fuel cells seem to offer many economic, siting, and operating advantages which might make them of interest for the 1990's. Unit capacity would probably be chosen for peaking or decentralized application. Because of their characteristics fuel cells may be of interest for cogeneration. A fuel cell with a gasifier would probably not be of interest for the 1990's because of the higher technical risk.

For each of these DCTs, Exhibits 6.3 - 6.7 summarize: technological availability, potential improvement in efficiency and air pollutant emissions; potential application and types of fuels used; capital costs; operating complexity; and technical risks.

Availability[6]

Oil- or gas-fired combined cycle systems are commercially available now and could be installed during the 1980's. Atmospheric fluidized bed boilers, fuel cells, and combined cycle with a coal gasifier will probably be available by the early 1990's. Other technologies such as pressurized fluidized bed boilers and fuel cells with a coal gasifier will probably not be available until the late 1990's.

Advanced Load Management Techniques

Load management refers to a heterogeneous set of actions used to reduce peak load by shifting it to an off-peak time. The actions fall into a number of categories. They may be either voluntary or involuntary. They may be direct or indirect, and they may be conventional or advanced. Conventional techniques are currently-available methods for a utility with a relatively constant structure. Advanced load management techniques are new methods which can produce a higher level of economic and operating efficiency for utilities in the future.

The communication and computational breakthroughs of microprocessing will allow many utilities to take advantage of advanced load management techniques in the 1990's. The major characteristic of advanced load management techniques is the cooperation between customer and utility to make short-term decisions--conceivably as short as every five minutes--influenced by consumer preferences and by cost and quality of utility operation. This cooperation increases economic and operating efficiency of the utility and increases consumer purchasing information and options.

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[6] On other than a first-of-a-kind basis.

Exhibit 6.3

AVAILABILITY OF DEVELOPMENTAL CONVERSION TECHNIQUES

Technology	Estimated Availability*
Fluidized Bed Boilers	
Atmospheric Fluidized Bed/Steam	1990 - 1995
Pressurized Fluidized Bed/Steam	1995 - 2000
Combined Cycle Systems	
Combined Gas/Steam	1980 - 1985
Combined Gas/Steam with Coal Gasifier	1990 - 1995
Fuel Cells	
Fuel Cell--Naphtha	1990 - 1995
Molten Carbonate Fuel Cell with Coal Gasifier	1995 - 2000

* Estimated earliest date of on-line availability (other than first of a kind basis).

Source: Comparing New Technologies for the Electric Utilities, U. S. Energy Research and Development Association, Draft Final Report (Revision-A), Washington, DC, ERDA 76-141 (Discussion Draft), December 9, 1976.

Exhibit 6.4

EFFICIENCY AND AIR EMISSIONS OF DEVELOPMENTAL CONVERSION TECHNIQUES

Technology	Improvement in Efficiency and Air Emissions
Fluidized Bed Boilers	
Atmospheric Fluidized Bed/Steam	Small improvement in efficiency (0-2%) when compared to conventional coal/steam. Emissions comparable to or less than coal with scrubbers. Can use coal, solid waste, or a number of other low-grade fuels.
Pressurized Fluidized Bed/Steam	Moderate improvement in efficiency (2-5%). About the same emissions as atmospheric fluidized bed.
Combined Cycle Systems	
Combined Gas/Steam	Large improvement in efficiency (10-12%) compared to conventional cycle gas turbines, but emissions about the same.
Combined Gas/Steam with Coal Gasifier	Large improvement in efficiency. About the same as fluidized bed and coal with scrubbers in terms of emissions.
Fuel Cells	
Fuel Cell--Naphtha	Moderate improvement in efficiency (5-6%) and significantly reduced emissions compared to conventional alternatives.
Molten Carbonate Fuel Cell with Coal Gasifier	Large improvement in efficiency (12-15%) compared to conventional coal/steam. Reduced emissions.

Source: Comparing New Technologies for the Electric Utilities, U. S. Energy Research and Development Association, Draft Final Report (Revision-A), Washington, DC, ERDA 76-141 (Discussion Draft), December 9, 1976.

Exhibit 6.5

PROBABLE APPLICATION AND FUEL USED BY DEVELOPMENTAL CONVERSION TECHNIQUES

Technology	Probable Application	Fuel
Fluidized Bed Boilers		
Atmospheric Fluidized Bed/Steam	Base Load	Coal, Refuse, Other Low-Grade Fuels
Pressurized Fluidized Bed/Steam	Base Load	Same as for Atmospheric Fluidized Bed
Combined Cycle Systems		
Combined Gas/Steam	Intermediate (Cycling) Load	Oil or Natural Gas
Combined Gas/Steam with Coal Gasifier	Base Load	Coal
Fuel Cells		
Fuel Cell--Naphtha	Peak/Intermediate Load	Naphtha
Molton Carbonate Fuel Cells with Coal Gasifier	Base Load	Coal

Source: Comparing New Technologies for the Electric Utilities, U. S. Energy Research and Development Association, Draft Final Report (Revision-A), Washington, DC, ERDA 76-141 (Discussion Draft), December 9, 1976.

Exhibit 6.6

CAPITAL COSTS OF CONVENTIONAL AND DEVELOPMENTAL CONVERSION TECHNIQUES

Application	Technology	Capital Cost* (1975 $/kW)
Base Load	Conventional Oil-fired Boiler/Steam Turbine	280 - 365
	Atmospheric Fluidized Bed/Steam	390 - 410
	Conventional Coal-fired Boiler without Scrubbers	295 - 405
	Pressurized Fluidized Bed/Steam	330 - 460
	Molten Carbonate Fuel Cell with Coal Gasifier	335 - 465
	Conventional Coal-fired Boiler with Scrubbers	365 - 475
	Combined Gas/Steam with Coal Gasifier	395 - 555
Intermediate (Cycling) or Peak Load	Combined Gas/Steam	190 - 275
	Fuel Cell--Naphtha	205 - 265

* Capital cost does not include interest during construction or inflation allowance. The capital cost inflation rate for electric generating plants (all steam generation) from 1975 to 1980 was approximately 47%.

Sources: Comparing New Technologies for the Electric Utilities, U. S. Energy Research and Development Association, Draft Final Report (Revision-A), Washington, DC, ERDA 76-141 (Discussion Draft), December 9, 1976, and Handy Whitman Guide to Construction Costs, Handy Whitman, Cost Trends of Electric Utility Companies, North Atlantic Region, Construction and Equipment, 1979.

Exhibit 6.7

OPERATING COMPLEXITY AND TECHNICAL RISK OF DEVELOPMENTAL CONVERSION TECHNIQUES

Technology	Operating Complexity	Technical Risk
Fluidized Bed Boilers		
Atmospheric Fluidized Bed/Steam	Viewed by many as simpler and more reliable than conventional coal with scrubbers.	Low
Pressurized Fluidized Bed/Steam	Same as for atmospheric fluidized bed, except that design for elevated pressure introduces additional technical difficulties.	Medium
Combined Cycle Systems		
Combined Gas/Steam	Combined cycle inherently more complex than conventional, but technology has been demonstrated and is commercially available.	Low
Combined Gas/Steam with Coal Gasifier	More complex than conventional coal with scrubbers. Use of gasifiers and operation of combined cycle inherently complex.	Medium
Fuel Cells		
Fuel Cell--Naphtha	Complexity comparable to or less than conventional technologies.	Low to Medium
Molten Carbonate Fuel Cell with Coal Gasifier	Use of coal gasifier adds complexity.	Medium to High

Source: Comparing New Technologies for the Electric Utilities, U. S. Energy Research and Development Association, Draft Final Report (Revision-A), Washington, DC, ERDA 76-141 (Discussion Draft), December 9, 1976.

Homeostatic Control

There have been a number of proposals for increased efficiency in pricing of electric power that included a 'real time' component. One such proposal has been developed by Professor William Vickery of Columbia University[7]. That proposal is concerned specifically with the operating cost component of the utility system and with short-term marginal costs. A second proposal has been put forth by Derek McKey of the Rand Corporation[8]. That proposal deals with long-term capital allocation in a short-term bargaining environment. The MIT Energy Laboratory and Electric Power Systems Engineering Laboratory have developed a concept entitled homeostatic utility control. Homeostatic control integrates a series of concepts in load management that heretofore have been seen as individual pieces rather than part of a larger structural innovation in electric power. Homeostatic control could be adopted either one piece at a time or in its entirety.

There are three major components of homeostatic control: spot pricing; microshedding; and decentralized dynamic control. Spot pricing refers to techniques which inform customers of the price of electricity as often as every five minutes. Micro-shedding refers to a group of techniques which result in computerized decisions to shut down load. The computerized decisions are based on prior negotiations between utility and consumer which establish consumer preferences for electricity during peak periods or emergencies. Decentralized dynamic control refers to the operation of the previous two techniques, wherein computers with customer preference information use data about the utility to reschedule load that satisfies consumer desires while increasing efficiency, reliability, or integrity of the utility's operation.

Spot pricing is a class of concepts wherein the price of electricity varies every five minutes during the day depending on supply-demand conditions and the cost of supply. Three types of spot prices are:

-- buy rate - price paid by customer to buy firm power from utility;

-- buy-back rate - price paid by utility to buy power from customer;

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[7] Reference number 196.

[8] Reference number 163.

-- interruptible rates - lower buy rates which give utility right to control 'percentage' of customer's demands.

Rates are computed by the Central Utility Controller and transmitted to the Customer Controller as often as every five minutes. All three rates can vary with customer location and voltage class of service. Homeostatic control is not tied to any particular economic pricing philosophy or theory. For example, spot price rates could be based on embedded or replacement costs calculated as average or marginal prices or any other basis.

Spot pricing establishes an open 'energy marketplace' for electric power. Today, utility computers make economic decisions every five minutes, and spot pricing provides customers with the same opportunity. Some customers will prefer less frequent decisions; and longer-range energy contracts are available. The Customer Controller will respond to changing spot prices by considering customer desire for services that are reschedulable and/or non-essential.

Microshedding is a group of concepts which helps the utility implement direct control without becoming involved in customer priorities or decisions. There are two types of decision-making associated with microshedding. The first decisions occur during utility-customer negotiations which result in a spot interruptible contract specifying the amount of demand that is interruptible. Microshedding also introduces the concept of different 'qualities' of power into these negotiations. The buy rate is the spot price for firm power, while the interruptible rates are lower spot prices for less dependable power that is transmitted over the same power line. The customer can choose from different types of interruptible contracts and interruptible rates.

The second type of decision-making involves control. The utility tells the Customer Controller to shed a certain percentage or amount of the customer's load (up to the contracted amount), and the Customer Controller decides which parts of the customer's load to shed. Thus, microshedding provides the utility with flexible control over the load without utility involvement with customer priorities. Most Customer Controllers will probably shut down particular energy usage devices for short time intervals (minutes), since short interruptions have little effect on fulfilling customer desires. For longer time intervals (hours), the reschedulable desires for services will probably be shut down.

Decentralized dynamic control is a class of concepts designed to take advantage of the fact that the power usage of energy type devices can be freely rescheduled (within limits) to improve power system dynamics while still completely fulfilling customer desires for services. This can be done if the Customer Controller considers two types of input information:

-- signal(s) of customer desire service fulfillment (for example: Is the temperature of the building being maintained within desired limits? Is the water level of a tank being maintained between desired limits?).

-- signals of the power system's dynamic behavior (frequency, voltage, or power flows).

The Customer Controller is programmed so that fulfillment of customer desires has high priority, but it reschedules power usage to improve the power system's dynamic behavior within these priorities.

However, the examples of homeostatic control applications in Exhibit 6.8 illustrate how all components of homeostatic control support each other in an overall structure.

Oil Conservation. Spot pricing is the most important homeostatic concept in achieving oil conservation. For most utilities, the high cost of oil means that, whenever possible, oil is not used for base generation. Thus it is often desirable to redistribute electric energy use away from peaks to times of otherwise light loading. One current attempt to do this uses prespecified 'time of use' rates; however, there is a fundamental advantage of using spot prices for this purpose. Time of use rates are prespecified months in advance to correspond to some 'average expected' cost of generation, while spot prices can respond to changes in system conditions such as weather variations, an unexpected shutdown of a large coal or nuclear unit, etc.

Prevention of Blackouts and Brownouts. Spot pricing is also the most important homeostatic concept in the area of preventing intentional brownouts (voltage reductions) and rotating blackouts. However, in the oil conservation example, spot prices are set primarily on the basis of economics. In the case of balckouts and brownouts, the spot prices are set primarily using quality of supply concepts.

The demand for electricity can exceed the supply when there is insufficient installed available capacity or when there is insufficient fuel availability. At present, there are two basic schemes for handling such cases. Voltage reduction (known as a brownout) is a very limited control (perhaps up to 4-5%) which may also reduce system integrity as well as adversely affect the quality of supply. A second procedure is the rotating blackout in which portions of the system load are totally cut off at various times. The rotating blackout provides more utility control but significantly lowers the quality of supply to the customer.

Encourage Conservation. A major impact of the energy marketplace will be a greatly increased customer awareness of how he/she is actually using electricity and its costs. Involvement

Exhibit 6.8

APPLICATIONS OF HOMEOSTATIC CONTROL

Application	Spot Pricing	Micro-shedding	Decentralized Dynamic Control
Prevent Black-Outs or Brown-Outs	X*		
Encourage Conservation	X	X	
Integrate Renewable Resources and Generation into System	X	X	X
Improve Normal Operations	X	X	X
Improve Emergency Operations		X	X
Conserve Oil	X		

*X signifies that a particular component of Homeostatic Control has special importance for a particular application.

with the energy marketplace will condition the customer actively to do something about electricity bills. It can be argued that such awareness and conditioning are key elements to successful conservation. Thus, it is likely that customers who are actively participating in the energy marketplace will start to use energy-efficient devices.

Integrate Renewable Resources and Cogeneration. All three homeostatic control concepts--spot pricing, microshedding, and decentralized dynamic control--play important roles in helping with the integration of solar, wind, and decentrally cogenerated energy into the overall electric power system. Spot pricing is probably the most important single concept. There is ever-growing interest by customers in installing and operating their own solar, wind, or cogeneration units. Obstacles often raised in the path of such customer action involve reliability and unschedulability. As a result, unattractive rates for the utilities to buy back power and charges for utility-provided backup service are often imposed. Such rates can make an otherwise attractive solar, wind, or cogeneration installation uneconomical. Homeostatic control provides a framework which allows such new technologies to compete as equals in an open energy marketplace. Wind-solar generation is paid for at a buy-back rate determined by existing system conditions (recomputed every five minutes). Customer cogeneration scheduling is done by comparing customer generation costs with the spot prices. Concepts such as prespecified demand charges, backup charges, etc., are no longer part of the overall pricing scheme.

The unsteady supply of solar and wind resources has also caused concern in relation to their effects on power system dynamics: need for spinning reserve, etc. Microshedding can provide the needed system response to variations in macroweather conditions. Decentralized dynamic control can provide any needed damping of rapid, localized microweather variation effects.

Normal State Control. Normal state control is another example of an application in which all three classes of concepts play an important role. To simplify the discussion, only two aspects of normal state control will be considered: spinning reserve reduction and economic load following.

Today's electric power systems must always maintain sufficient spinning reserve so the system can respond satisfactorily to unexpected losses of generation and/or transmission. The maintenance of this generation reserve has a direct impact on fuel costs. Homeostatic control provides a totally new source of reliable and controllable spinning reserve: the load itself. This spinning reserve is uniformly distributed throughout the system and is never down for maintenance. Microshedding provides a vehicle which enables the Utility Controller to use the interruptible load as a spinning reserve which can respond to centrally-determined needs.

System frequency is a measurable signal that is a direct indication of the system load/generation balance. Thus, without any specialized communication requirements, the customer can be aware of system conditions for the purposes of energy use rescheduling. Low frequency indicates high load, which would be responded to by delaying energy use. Alternatively, a high frequency condition is an indication of light loading and, thus, the appropriate time to obtain energy. Such frequency-responsive load behavior can act as a replacement for spinning reserve for short periods of time. It can be obtained by microshedding.

Today's electric power systems use the central station power plants to follow normal load variations. Two types of normal load variation of concern are: random fluctuations (seconds to minutes) and morning load pickup (rapid demand rise over minutes to hours). Following such normal variation increases fuel and equipment maintenance costs. Microshedding and spot pricing can be used to reduce the random fluctuations and smooth out the morning load pickup. Thus, under homeostatic control, the central power plants operate under normal state conditions on primarily preprogrammed trajectories which are designed to minimize operating (fuel and maintenance) costs.

<u>Emergency State Control</u>. Microshedding and decentralized dynamic control have the largest impact on the control of electric power systems during emergencies. Load shedding has become a generally accepted 'last ditch' plan for reacting to major system disturbances following large loss of generation and/or transmission. Currently, load shedding is done either manually or via frequency-sensitive relays; both procedures are relatively crude because they cannot be adapted to a particular situation. Microshedding provides a mechanism for highly flexible, finely distributed load shedding because the exact amount (percentage) of load control can be specified by the utility. Of even more importance is the fact that the customer has explicitly contracted for the amount of interruptible power available. Thus, instead of being a 'last ditch' action, load control becomes the prime tool in many emergency conditions. This revolutionizes emergency state control by removing the need for fast, large control actions from the central power plants.

Decentralized dynamic control based on locally measured frequency voltage, power flow, etc., has the potential to yield an overall power system whose responses to frequency and/or voltage swings is much more damped than present. This could greatly simplify the overall emergency state control problem.

In summary, spot pricing can, for example, help to conserve oil by informing customers that electricity prices are increasing because oil units are being used (such as in a peaking period). Spot prices can also help prevent blackouts or brownouts if they inform customers that the quality is about to deteriorate. Similarly, it is likely that spot pricing and microshedding will increase conservation, since they are based on consumer understanding of, and active involvement in, energy billing.

It could be easier to integrate renewable resources and decentralized cogenerating units into the utility system with homeostatic control because the techniques help to solve the pricing, reliability, and unschedulability issues associated with these energy sources. Normal utility operations could be improved through more sophisticated tracking of load variation and partial reduction of spinning reserve. Emergency operations could be revolutionized by finely distributed and previously agreed upon load shedding.

Summary

Con Edison's current involvement in research activities is adequate to keep abreast of evolving electric energy technology. Since a number of new developments show promise for the 1990's, systematic technology assessment procedures leading to implementation decisions are important. However, there is no conflict between coal conversion in the 1980's and new technologies of the 1990's.

Appendix A

AN ENERGY STRATEGY FOR THE 1980s

FOR NEW YORK CITY
AND WESTCHESTER COUNTY

BY
CHARLES F. LUCE
CHAIRMAN OF THE BOARD
CON EDISON

1

FOREWORD

Con Edison seeks changes in energy policy at all levels of government to reduce New York City's and Westchester's dangerous dependence on imported oil for electric generation and to reduce the rate of increase in energy costs.

Since 1978, when Con Edison first outlined its Energy Strategy for the 1980s, some progress has been made. However, consumers in New York City and Westchester County continue to be burdened with an outdated energy policy which evolved in the 1960s as a response to a combination of economic, political and environmental objectives. Simply stated that policy was:

- To convert New York City generating stations that burned coal to the burning of natural gas or low-sulfur imported fuel oil.
- To permit no new major generating stations in New York City.
- To use utility bills as a major source of tax revenues.

By early 1980, the price of a barrel of imported oil which cost a mere $2 as late as the early 1970s had reached $30, with future increases assured and continued supply in question because of political instability in the Middle East.

Also, policies regarding the use of natural gas have changed in recognition of the fact that over the long term natural gas is a limited resource which must be saved for residential and other high-priority uses. Con Edison now burns some natural gas in power plants, but only as a temporary measure to take advantage of a short-term surplus.

The Strategy proposed in this booklet contains specific measures to provide for an adequate supply of electrical energy to New York City and Westchester County in an economical and environmentally acceptable way.

2

ENERGY STRATEGY FOR THE 1980s

Energy independence from the Organization of Petroleum Exporting Countries (OPEC) is an important national goal. The Arab oil embargo in 1973-1974, the shutdown of Iranian oil fields in 1979, and the capricious increases in OPEC prices underscore the dangers of our dependence on foreign countries for fuel supply. The rapidly rising price of imported oil is a major contributor to the nation's inflationary spiral and results in significant balance of payment deficits. And the threat of a cutoff of foreign oil is real.

Replacing oil with domestic energy sources, particularly coal, our nation's most abundant energy resource, must be foremost on the list of energy priorities for our nation and, particularly, for New York City and Westchester County, where oil and gas represent more than half the fuel used to produce electricity.

Oil Prices Rise Steeply

Reducing the rate of increase of energy costs must be a major goal for any energy strategy for New York City and Westchester County. To be successful, any attack on high energy costs must be concentrated on reducing the "big ticket" items. For Con Edison customers these items are fuel and taxes, which together account for almost 60 cents of every dollar of their utility bill. The Strategy proposes to bring these costs down to manageable levels.

The price of fuel oil reached the $30-a-barrel level in early 1980—double the price a year earlier. Fuel and purchased power costs represent 33 cents of every dollar of the Con Edison bill, and oil is the principal component of these fuel costs.

The other major area for cost reduction is taxes. Con Edison customers are taxed at a rate two to ten times higher than customers of other large utilities. Many of these taxes are pegged to fuel costs, and when the price of oil goes up, so do the taxes. Taxes account for 26 cents of every dollar Con Edison customers pay in bills.

Con Edison has had some limited, short-term success in meeting its goals during the two years since the Strategy was first proposed. In 1979, for example, the Company was able to cut by 6 percent its dependence on oil for electric generation, principally as a result of increased coal, nuclear, and hydro-electric power purchases from upstate utilities and Canada. Oil use was cut by an additional 12 percent through the burning of natural gas, under the short-term federal approval which is scheduled to expire in June 1980. When this approval expires, oil will once again have to be used.

These oil-reduction steps in 1979 cut the cost of electricity to Con Edison customers by about $500 million.

In addition, some progress was made in obtaining tax reductions. In part as a result of Con Edison's proposals to lower discriminatory taxes on utility bills, the New York State Legislature reduced the sales tax on electric service for residential use from 4 percent to 3 percent effective January 1979 and to 2.5 percent in January 1980. The tax will be eliminated for residential customers in October 1980. These tax savings to Con Edison customers are expected to amount to $25 million in 1980.

What the Strategy Proposes

For the decade ahead, Con Edison's Strategy goes beyond temporary solutions and proposes specific long-term approaches to meet the twin goals of cutting oil dependence and reducing the rise in future bills for electricity. The proposals are summarized below and detailed in the following pages:

- Promote strong energy conservation programs in New York City and Westchester County.
- Convert three Con Edison generating units to burn coal instead of oil, while taking appropriate steps to meet environmental standards.
- Continue to use nuclear power generated at Indian Point as a principal non-oil source of electricity.
- Increase imports of hydro-electric power from Canada and other sources.
- Support the construction of coal-fired and pumped-storage hydro-electric plants planned by the Power Authority of the State of New York (PASNY).
- Use refuse as a fuel to generate steam and electricity.
- Reduce taxes on energy.

Con Edison customers could save almost $5 billion through 1990 if key elements of the Energy Strategy are implemented. By 1990, fuel oil would make up less than 30 percent of the fuel mix used for power generation in the Company's service area, with further reduction in oil dependence planned in the 1990s.

CONSERVE ENERGY

Conservation is the quickest, most environmentally benign way to reduce oil dependence. Con Edison was a pioneer in promoting energy conservation, and consumers in New York City and Westchester have taken many steps to reduce energy use in their homes and businesses.

Con Edison forecasts minimal growth in the demand for electricity in the 1980s. This low forecast results largely from the conviction that consumers in New York City and Westchester will increase their energy conservation efforts.

Consumers in this area already use less electricity on average than others in the rest of the country. Significant additional conservation can be achieved, however, particularly through proper selection and maintenance of appliances and better building insulation practices.

Led With 'Save A Watt"

Con Edison's widely imitated "Save A Watt" campaign began almost a decade ago, when the Company disbanded its sales force in 1971 and started a wide-ranging consumer education program to encourage the wise use of energy. More recently, Con Edison formed a new Conservation Services department to coordinate and direct the company's increasing conservation activities.

Con Edison's newest energy conservation project—a Conservation Center in midtown Manhattan—was opened in November 1979 by Energy Secretary Charles Duncan. The Center is the most complete energy information outlet in the country for consumers. It contains lively exhibits on energy-efficient ways to heat, cool and light homes and apartments, and shows consumers how to buy and use appliances wisely. Conservation experts at the Center answer visitors' questions about the most up-to-date energy-saving devices.

Other ongoing Con Edison conservation programs include:

- Home Energy Audits—Con Edison performs detailed inspections of customers' homes and recommends, and offers to finance, those energy-saving measures that can pay for themselves through savings within seven years.
- Operation ThermoScan—Through aerial photography with infra-red film, Con Edison specialists identify rooftops and other areas of

homes where heat is escaping because of inadequate insulation or other factors. The photos are explained at neighborhood briefings and, as a result, many customers have taken conservation steps and others have requested full-scale home energy audits.

- Commercial and Industrial Programs—Con Edison load management specialists work with large commercial and industrial customers to help them reduce energy use or to shift their usage to the greatest extent possible to off-peak periods.

As soon as the law permits, Con Edison will contract to install energy-saving improvements for customers who request them.

CONVERT TO COAL

Domestic coal, which in the 1960s cost as much as fuel oil, now costs less than half as much. The price gap can be expected to widen in the future. Equally important, replacement of oil with coal for power generation has finally become national policy.

Con Edison proposes to convert three oil-fired units to coal burning without causing violations of federal air quality standards.

The three units, Ravenswood 3 in Queens and Arthur Kill 2 and 3 on Staten Island, were built to burn coal and in fact burned coal until the early 1970s.

Con Edison plans to upgrade the existing coal-handling and coal-burning facilities at the plants, as well as the pollution control equipment. New or improved soot-removing precipitators would be at least 99.6 percent efficient and the plants' environmental impact would be less than when the Company last burned coal.

Through the combined program of equipment upgrading and the burning of low-sulfur coal, Con Edison's total sulfur dioxide emissions would still be only 30 percent of the levels of the 1960s. Particulate emissions would be one-third of those levels.

Coal burning at the three units would save Con Edison customers more than $300 million a year in fuel costs and related taxes in the period through 1990 and would reduce New York's dependence on imported oil by about 15 million barrels per year.

If prompt government approvals are received, coal conversion can be completed at Ravenswood in 1981, at Arthur Kill 2 in 1982 and at Arthur Kill 3 in 1983.

Test Program

Con Edison now burns oil with a maximum sulfur content of 0.3 percent. As a first step toward coal burning, Con Edison plans a test in which 1.5 percent sulfur oil will be burned at the three units. This oil would produce sulfur dioxide emissions approximately equivalent to the 1 percent sulfur coal the Company proposes to use. During the test, New York City air quality will be constantly monitored from at least 12 stations strategically located throughout the City. Thus without major capital investment, Con Edison could confirm the calculations that show that coal burning would not cause violation of air quality standards and would not significantly affect air quality.

In the unlikely event that an infringement of air quality standards occurs, the Company would revert quickly to lower-sulfur oil or take other measures to bring air quality into compliance.

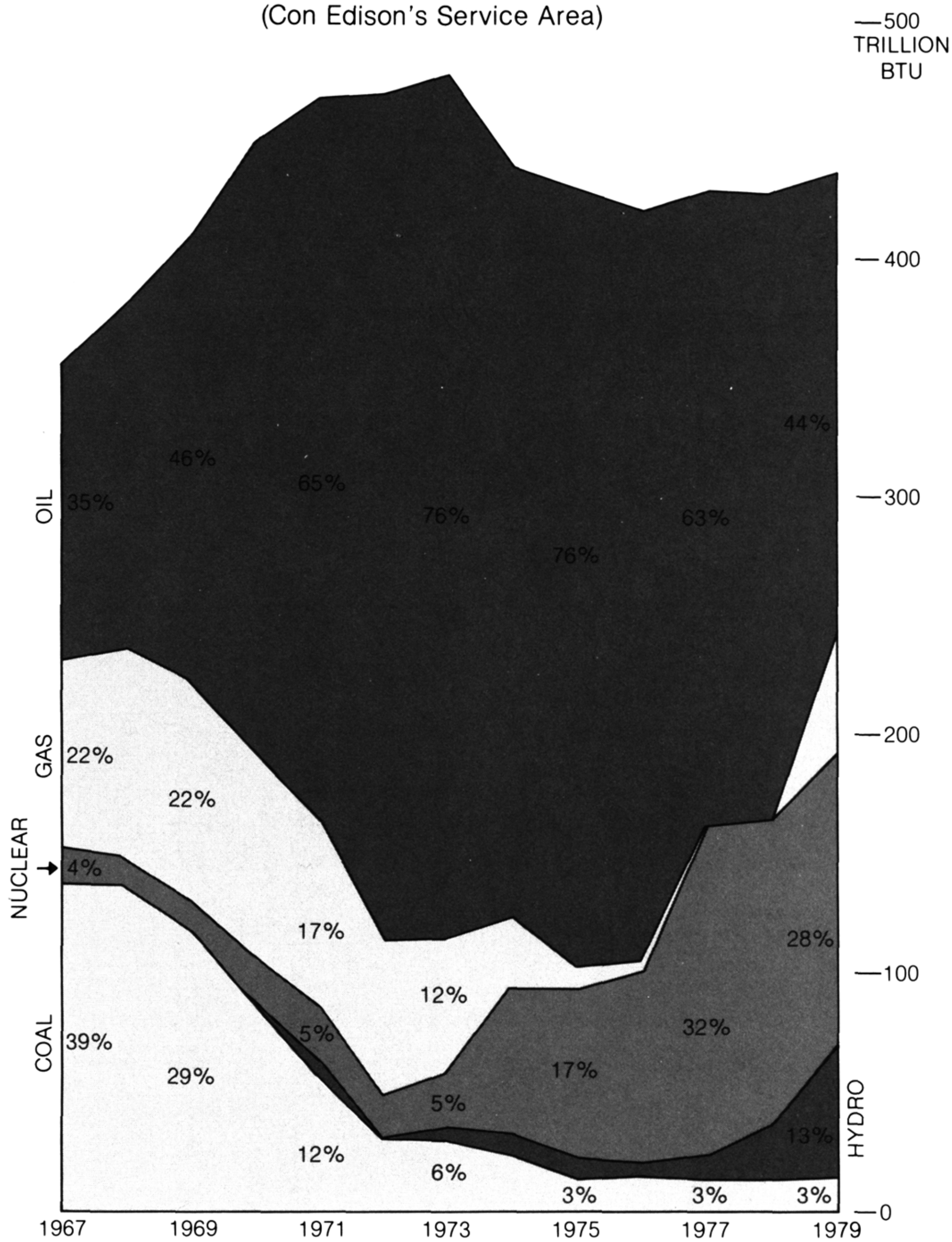
In some localities where compliance with air quality standards is marginal (mostly because of local low-level emissions from sources other than Con Edison) Con Edison, in cooperation with state and local officials, has undertaken to reduce, or "abate," pollution levels. Through the abatement program, Con Edison is assisting owners of some large fuel-burning installations to convert to cleaner fuels or improve the efficiency of their equipment.

Approval for this test was received in 1979 from New York State and New York City. Approval of the U.S. Environmental Protection Agency is needed before the test can start.

(Text continues on page 11.)

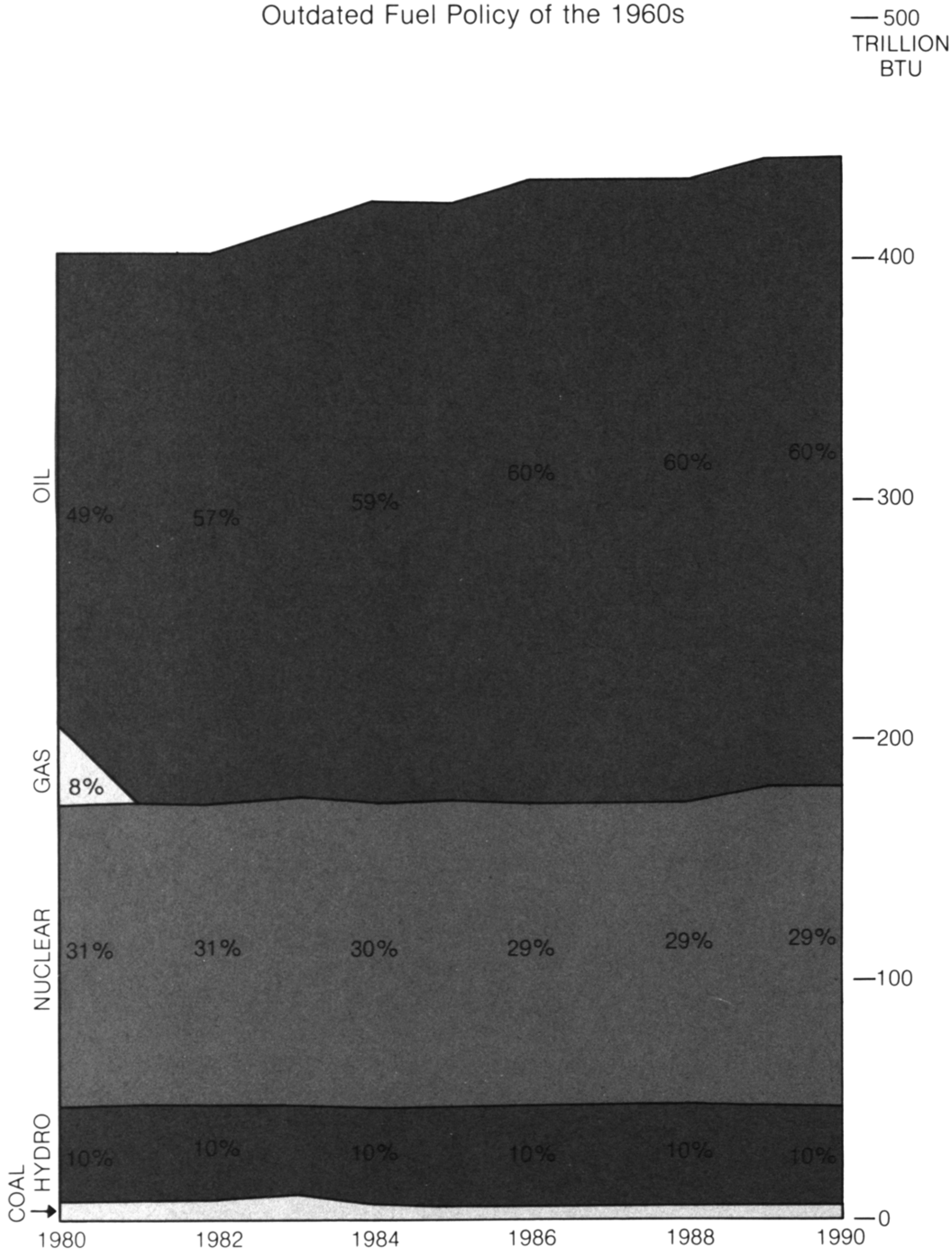
Fuel Used to Generate Electricity 1967-1979

(Con Edison's Service Area)



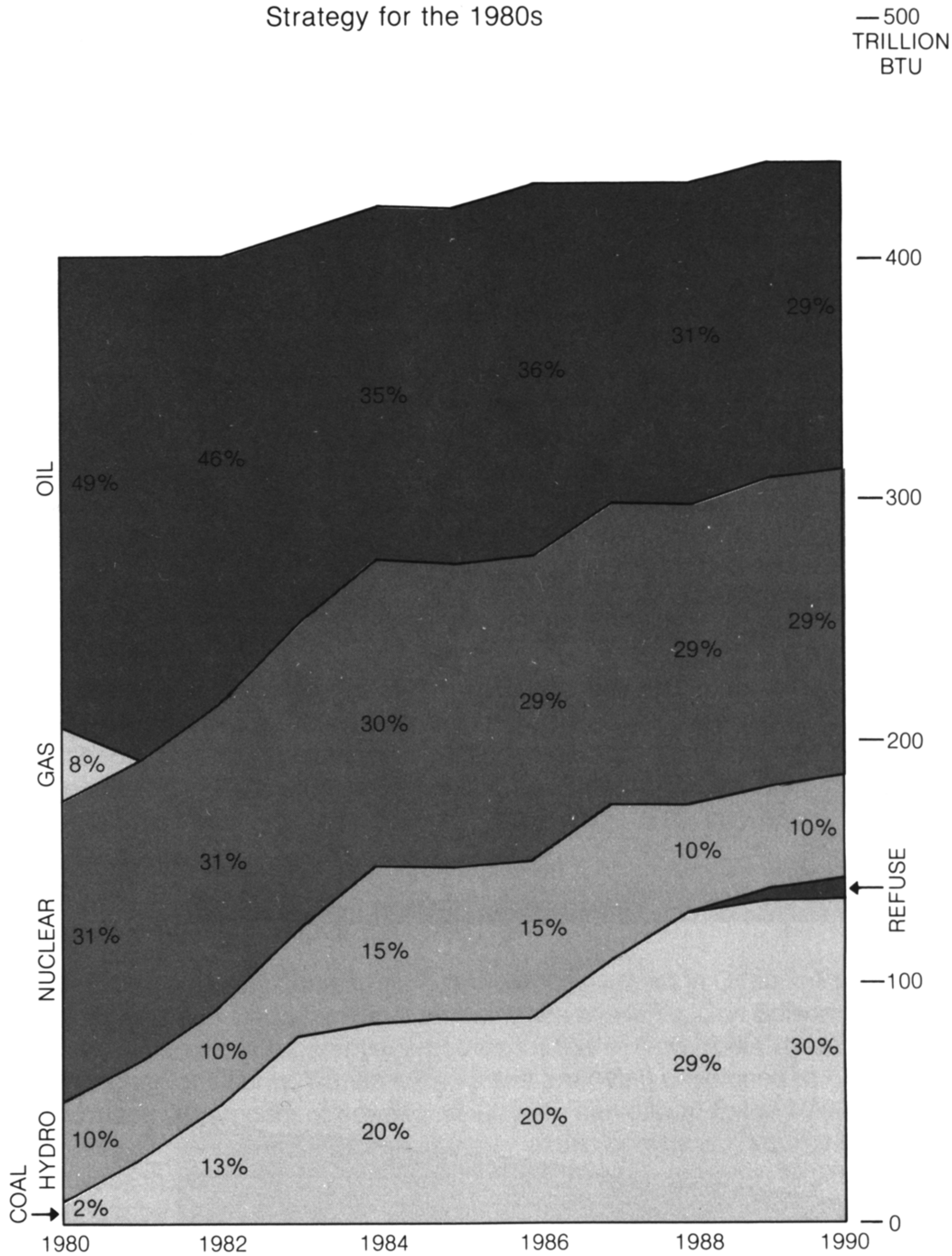
Comparison of Fuel Use Projections 1980-1990

Outdated Fuel Policy of the 1960s

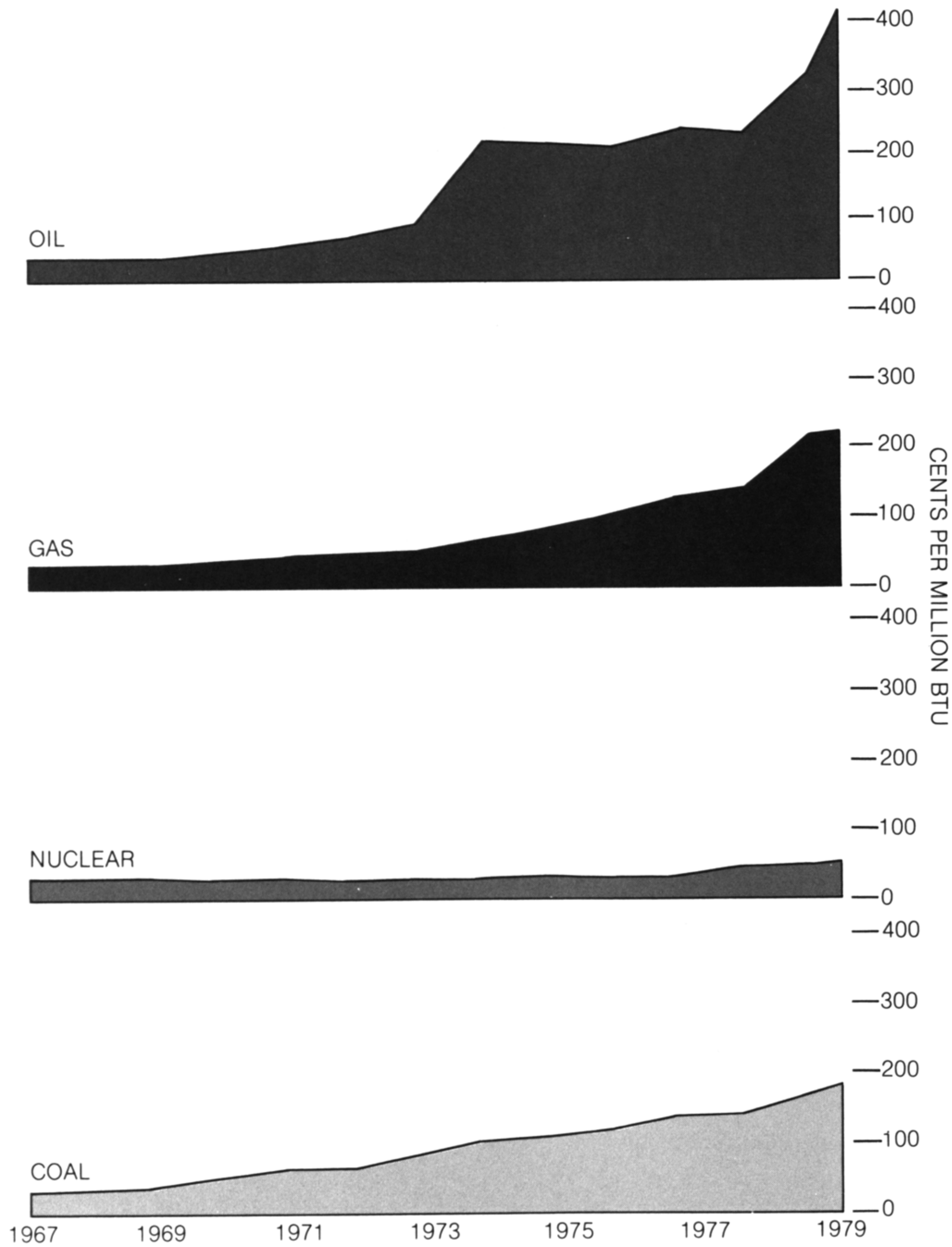


9

Strategy for the 1980s



Cost of Fuel for Electric Generation



11

USE NUCLEAR POWER

Nuclear power generated at Indian Point by Con Edison and by the Power Authority of the State of New York (PASNY) is vital to consumers of electricity in New York and Westchester County. If foreign oil supplies are interrupted or severely curtailed, New York City's and Westchester County's prime defense against possible brownouts or rolling blackouts would be Indian Point.

Since its first unit began operating 18 years ago, Indian Point has had an excellent safety record, and safety continues to be the overriding consideration in operating the nuclear plants.

Nuclear power from Indian Point 2 and 3 provides about 30 percent of the electricity used in New York City and Westchester County and displaces about 20 million barrels of oil per year, resulting in direct savings to customers of more than $600 million per year. Indirect savings also result because demand for low-sulfur oil is reduced, and this tends to hold down oil prices in New York City and the Northeast region as a whole.

INCREASE HYDRO PURCHASES

In 1979 Con Edison started receiving the first full year's allocation of 2.8 billion kilowatthours per year of hydro-electric power from Canada. This power was purchased under a contract the Company negotiated in 1972 with the Quebec Hydro-Electric Commission. Deliveries began as the necessary transmission facilities were completed.

In 1979, Con Edison was able to purchase an additional 1.3 billion kilowatthours of this energy.

As power from the James Bay hydro-electric project in Quebec Province and other Canadian projects becomes available, Con Edison will seek to purchase substantial amounts for use in New York City and Westchester County. Transmission plans are being developed to increase the amount of power that Quebec can export to the New York Power Pool and to permit transfer of this energy to oil-burning utilities in southeastern New York State. These transmission facilities should be licensed and built as quickly as possible.

SUPPORT NEW PASNY PLANTS

The Power Authority of the State of New York is seeking permits to build two non-oil fired plants scheduled for operation in 1987. Recent legislation would allow power from these plants to be sold to Con Edison for the benefit of its customers. Con Edison strongly supports construction of these two plants. One, a 700,000-kilowatt coal and refuse-burning plant proposed for Staten Island, could use refuse-derived fuel for up to 20 percent of its input.

The second proposed plant, a 1 million kilowatt pumped storage hydro-electric plant at Prattsville, New York, about 110 miles northwest of New York City, would be used to generate power during the day, displacing oil-fired generation. At night, when demand for electricity is low, coal, hydro or nuclear power could be used to pump water into a reservoir for the next day's generation.

Full operation of both plants will result in a net reduction in oil use of approximately 6 million barrels a year.

REFUSE TO ENERGY

Burning refuse to generate electricity or steam has two potential benefits: reduction of oil use, and practical refuse disposal in a manner which would provide revenues to offset garbage collection and disposa costs. Con Edison stands ready to participate in the refuse-to-energy programs of New York City and Westchester County by providing a market for the energy that would be produced from refuse.

Two refuse projects are currently being planned.

In Westchester County, Con Edison has proposed to purchase the entire electric output of the County's planned 40,000 kilowatt refuse-burning facility in Peekskill. Con Edison's proposal would provide substantial savings to the residents of Peekskill, as well as a sharing in some of the economic benefits by the Company's other customers.

In New York City, Con Edison has offered to purchase the steam that would be produced by the proposed Brooklyn Navy Yard Resource Recovery Project, for distribution in the Company's steam system.

These two projects represent just a small fraction of the potential for obtaining energy from refuse in Con Edison's service area. The Company encourages further development and believes that an additional 100,000 kilowatts of refuse-to-energy plants could be constructed by 1990. If this occurs, refuse could displace up to 1 million barrels of oil per year by 1990.

REDUCE TAXES

Con Edison is New York City's and Westchester County's largest tax collector. All told, 26 cents out of every dollar Con Edison customers pay in utility bills goes to taxes. As the price of OPEC oil increases, Con Edison customers pay not only the increased cost of oil, but also increased state and local taxes on fuel costs.

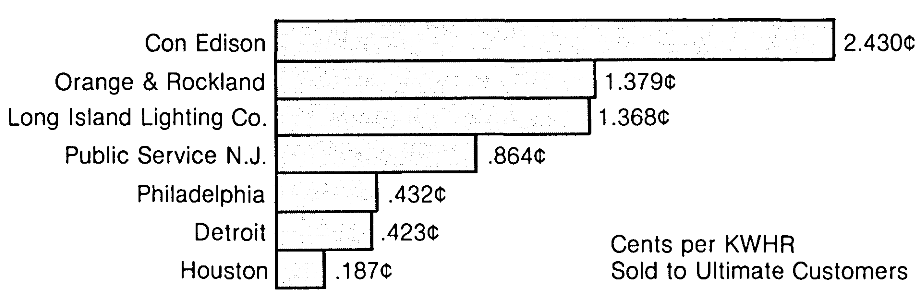
In 1979, Con Edison paid $183 million in revenue taxes from sales of electricity, gas and steam. This was an increase of almost 11 percent over 1978.

Like no other city in the state, New York City imposes a 4 percent sales tax on fuel used to generate electricity and steam. As a first step, this tax should be eliminated. This step alone would save about $600 million through 1990, and these savings would be passed on automatically to Con Edison customers.

Programs to expand business and employment through tax reductions are underway in New York City and Westchester County. Logically, these programs should include steps to reduce the high taxes on energy.

Tax Comparisons—1979

Taxes Other Than Federal Income Taxes
Paid by Customers of Various Utilities.



LOOKING TO THE 1990s

Beyond the 1980s, Con Edison supports construction of new coal-fired generating facilities to displace oil-fired capacity and to meet future energy needs of the New York City-Westchester County area. Con Edison also participates in research programs whose goal is the development of economical and environmentally acceptable synthetic fuels and generating processes using domestic resources, including coal, nuclear power, solar energy, wind systems and other developing technologies.

Additional Coal Plants

The New York State Energy Planning Board has recommended the construction of additional coal-fired generating facilities in the 1990s in the Southeastern New York area to reduce the State's dependence on oil. Two coal plants with a combined capacity of 1.2 million kilowatts could displace 7 million barrels of imported oil in New York City and Westchester.

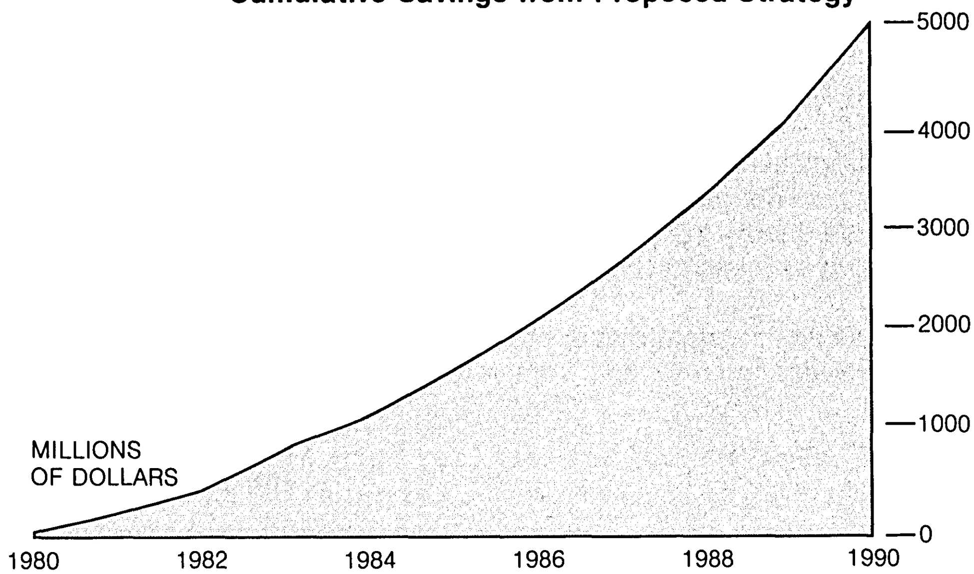
Research and Development Projects

Con Edison's Research and Development projects include:

- A government-industry program to produce a clean-burning liquid fuel from coal. The success of this project would mean that liquid coal could be burned instead of imported oil at generating plants which now burn oil. The first large-scale demonstration test burn of a fuel called SRC-II (solvent-refined coal-II) was made at a Con Edison power plant in 1978. Now, a larger SRC-II production plant is planned. Con Edison has organized a group of oil-burning utilities which will participate by purchasing much of the output of the new plant.
- Construction in Manhattan of a 4,800 kilowatt fuel cell using naphtha as fuel. The fuel cell converts a fuel's chemical energy directly into electrical energy without a burning process. While small, relative to other types of power plants, fuel cells offer great promise of providing power in urban areas because they are quiet and clean, and need relatively small parcels of land. In the future, coal-derived fuels may be used. If this demonstration fuel cell is successful, it could lead to large scale fuel cells in New York City and elsewhere, perhaps as early as the 1990s.

- A solar energy project in Westchester, where Con Edison is testing solar-assisted water heating systems in 19 homes and one public building. Co-sponsor of the project is the New York State Energy Research and Development Authority. As technology advances and solar energy becomes more economical as a supplement or substitute for electric hot water heating in New York City and Westchester County, Con Edison will offer to install and maintain such systems. Con Edison also sponsors a number of solar research projects through the Electric Power Research Institute.
- Development of a coal-oil mixture as a fuel for power generation. Adelphi University is participating in this project. The goal is to develop a coal-oil slurry that could be burned in existing generating plants.
- Feasibility studies of wind conversion systems. The Company participates in a 40 kilowatt windmill project in the South Bronx and has an ongoing study with Manhattan College relating to wind patterns.
- Industry and government-sponsored projects to develop advanced technologies to remove sulfur dioxide from the emissions of coal-fired plants. Technologies under consideration include fluidized bed combustion, which removes sulfur during the burning process, and scrubber systems which remove sulfur pollutants after combustion.

Cumulative Savings from Proposed Strategy



BENEFITS OF THE ENERGY STRATEGY

Con Edison customers can save almost $5 billion through 1990 if the following elements of the Energy Strategy are implemented: conservation; prompt conversion of Ravenswood 3 and Arthur Kill 2 and 3 to coal burning; increased use of hydro-electric power; construction of the Prattsville and Staten Island power plants by PASNY; production of energy from refuse, and elimination of the 4 percent New York City sales tax on fuel burned to generate electricity.

With additional tax reductions, savings would be greater.

If all the steps listed are accomplished, oil would comprise less than 30 percent of the fuel mix used to supply electricity in Con Edison's service area by 1990. Oil use could be further reduced in the 1990s by aggressive development of clean burning synthetic fuels derived from coal and construction of additional non-oil burning power plants.

This *Strategy* evolves from Con Edison's studies on how New York City and Westchester can best, and most economically, meet future energy needs. We have shared our proposals with government officials at the local, state and federal levels.

If you have any suggestions or comments on the *Strategy*, we would like very much to hear from you.

April, 1980

Appendix B

BRIEF DESCRIPTION OF THE CON EDISON UTILITY SYSTEM AND SERVICE AREA

Source: Except as noted, all of the tables, graphs and maps in Appendix B are taken or adapted from the Consolidated Edison Operating Statistics Yearbook, 1977 and 1978, Generation Planning Department, Consolidated Edison of New York, Inc., New York, N.Y., August, 1978 and 1979, respectively.

1978 CON EDISON
OPERATING AND PLANNED PLANTS

Principal Fuel (Alternate Fuel)	Conversion Technology	Site	Unit
Oil	Steam Turbine-Electric Generator	Bowline Point	1,2
		Roseton	1,2
	Steam Turbine-Steam/Electric Generator (Cogeneration)	Hudson Ave.	2,3,5,7,8,10
		Waterside	8,9
		59th St.	13-15
		74th St.	3,9-11
	Steam Generator	East River	
		Kipps Bay	
		Ravenswood	
		Woolworth	
		59th St.	
		60th St.	
		74th St.	
	Combustion Turbine-Electric Generator	Arthur Kill	1
		Astoria	5-13
		Gowanus	1-4
		Hudson Ave.	1-5
		Indian Point	1
		Kent Ave.	2
		Waterside	1
		59th St.	1,2
		74th St.	1,2
		Buchanan	2,3
Oil (Coal)	Steam Turbine-Electric Generator	Arthur Kill	2,3
		Astoria	1,2,3,4,5
		Ravenswood	3
Natural Gas	Steam Turbine-Electric	Waterside	7
	Combustion Turbine-Electric Generator	Astoria	1
		Ravenswood	1

1978 CON EDISON
OPERATING AND PLANNED PLANTS
(continued)

Principal Fuel (Alternate Fuel)	Conversion Technology	Site	Unit
Oil (Natural Gas)	Steam Turbine-Electric Generator	Astoria East River Ravenswood Waterside	2,3,4 6,7 1,2 4,5,6,14,15
	Steam Turbine-Steam/Electric Generator	East River	5
	Combustion Turbine-Electric Generator	Narrows Ravenswood	1,2 2-11
Uranium	Light Water Reactor/Steam Turbine-Electric Generator	Indian Point	2 PASNY 3
Coal/ Refuse	Steam Turbine-Electric Generator	Travis*	PASNY
Refuse		Westchester* County	Brooklyn Navy Yard Resource Recovery Project
Running Water	Pumped Hydro-Electric Generator	Prattsville*	PASNY

* Planned facility.

Sources: The information in this exhibit was obtained from the 1978 Consolidated Edison Operating Statistics yearbook and by direct consultation with Consolidated Edison.

CON EDISON POWER GENERATION AND ENERGY DEMAND BY DISTRICT*
(title of tables on pages four through sixteen, Appendix B)

* In these tables, identification of physical units differs slightly from the rest of the report (i.e., MWH = MWh).

MANHATTAN 1978

ELECTRIC

Base Load Station	Service Date	Capacity MW	Net Generated MWH	Plant Factor %[1]	Heat Rate Btu/Net KWH	Oil Used 1000's Gal	Fuel Cost $/Gal	Fuel Cost ¢/KWH	Total Cost ¢/KWH
East River H. P.	1951-55	421	1,227,827	32.4	12,672	106,837	.33	2.9	3.7
% Base Load Stations		(7.7%)	(79%)			(6.2%)[2]			
Peak Load Stations									
Steam Turbines									
Waterside	1937-49	325	1,198,413	39.3	14,493	116,947	.33	3.2	4.4
74th Street	1915-62	147	276,677	21.5	15,690	29,845	.33	3.6	5.6
59th Street	1918-62	82	313,914	43.7	16,842	36,438	.32	3.9	6.0
Totals		554	1,789,004			183,230			
Gas Turbines									
Waterside		11	1,153	0.9	15,193	130	.39	4.5	6.8
74th Street	1968	34	770	0.2	18,886	108	.38	5.5	40.4
59th Street	1969	34	902	0.3	17,030	113	.38	6.9	11.3
Totals		79	2,825			352			
% Gas Turbines		(5.2%)	(1%)			-			
% Peak Load Stations		(25%)	(81%)			(17%)[2]			

Notes:

1. $$\frac{\text{Annual Kilowatt Hour Generation}}{\text{(Annual Average Hourly Net Capacity)X(8760 hours/year)}}$$

2. This is a percentage of all oil used by Con Edison

M A N H A T T A N (Continued)

STEAM

Steam Stations	Service Date	Steam Sendout MLB	Net Maximum Hour Load MLB	Plant Factor %	Heat Rate Btu/lb.	Oil Used 1000's Gal	Oil Cost $/Gal	Fuel Cost $/MLb	Total Cost $/MLb
Kips Bay		1,340,757	1,345	8.2	1,492	13,797	.32	3.37	5.73
Woolworth		13,772	80	1.3	2,096	199	.35	5.12	8.65
59th Street		381,426	345	11.4	1,454	3,822	.32	3.27	7.57
74th Street		64,151	330	1.0	1,669	737	.35	4.04	5.20
Ravenswood (located in Queens)		2,278,203	961	27.1	1,491	23,355	.33	3.40	4.07
East River South		2,536,226	1,000	22.6	1,448	25,319	.33	3.32	4.47
60th Street		254,343	819	3.8	1,352	2,548	.41	4.15	6.35
Totals		6,868,878	---[3]		67,289				
% Steam Generation		(18%)			(3.9%)				
Electric Stations									
Waterside		13,538,054	2,999	51.5	1,244	113,083	.33	2.86	3.45
59th Street		5,818,891	1,561	46.5	1,394	55,882	.32	3.16	3.80
74th Street		3,824,042	1,140	39.7	1,266	33,264	.33	2.90	3.62
Hudson Avenue (Located in Brooklyn)	1932	5,907,499	2,041	29.3	1,660	67,655	.33	3.82	4.48
East River		3,079,721	1,400	22.1	1,266	26,876	.33	2.94	3.54
Totals		32,168,207	---[3]		296,760[4]				
% Steam Generation		(82%)[5]	---		---				
Leased Plants		45,440	350	1.5	1,707	485,568	.3567	--	--
Total Steam Generation		39,037,085	13,921[6]			849,617			

Notes:
3. Non-coincident loads
4. Primarily waste heat utilization
5. Per Steam System Annual Report, 53% of total steam sendout was first utilized to generate electricity
6. Per Steam System Annual Report, total system capacity available in 1978 was 14,056 MLbs/hr, excluding 1,320 MLbs/hr of capacity bottled due to mains limitations

Basic Steam Sales 1977

Classes	Sales to Customers MLb
General[1]	1,413,725
Annual Power[2]	24,557,346
Apartment House	6,134,172
Public Authority	2,073,138
Interdepartmental sales	148,467
Total Sales	34,326,848
Steam Sendout	40,770,072 (4.4×10^{13} Btu Equivalent)
Efficiency	84.2%

Notes: 1. Applicable to use of service for all purposes and generally small steam consumers.
2. Applicable to use of service for power, or power and heat. Generally a larger consumer than general service.

Basic Electric Sales 1977

Classes	Number of Customers	MW Hours
Residential	455,200	1,218,437
Commercial and Industrial	95,000	9,311,067
Public Authority	800	297,536
Total	551,000	10,817,040 (3.6×10^{13} Btu Equivalent)
% Electric Sales	20%	39.7%

Basic Gas Sales 1977

Classes	Number of Customers	Millions of Cubic Feet
Residential	332,700	6,669
Commercial and Industrial	38,300	11,616
Public Authority	800	1,105
Total	371,810	19,390 (1.9×10^{13} Btu Equivalent)
% Con Gas Sales	35.20%	27.88%

QUEENS 1978

ELECTRIC

Base Load Stations	Service Date	Capacity MW	Net Generated MWH	Plant Factor %[1]	Heat Rate Btu/Net KWH	Oil Used 1000's Gal	Fuel Cost $/Gal	Fuel Cost ¢/KWH	Total Cost ¢/KWH
Astoria	1953-62	1,412	3,758,828	29.8	11,429	294,246	.33	2.62	3.26
Ravenswood	1963-65	1,698	5,307,572	35.3	10,524	382,726	.33	2.40	2.80
Totals		3,110	9,066,400			676,972			
% Total Base Load Stations		(57%)	(52%)			(36.8%)[2]			
Peak Load Stations									
Gas Turbines									
Astoria	1970-71	148	162,509	2.4	14,565	17,278	.38	4.17	6.88
Ravenswood	1967-70	407	34,768	0.8	15,654	3,940	.39	4.56	19.40
Totals		555	197,277			21,218			
% Total Gas Turbine		(36.78%)	(61%)			---			
Total Peak Load Stations		(22%)	(9%)			(1%)[2]			

Notes: 1. $\frac{\text{Annual Kilowatt Hour Generation}}{\text{(Annual Average Hourly Net Capacity)X(8760 hours/year)}}$

2. This is a percentage of all oil used by Con Edison

QUEENS 1977

Basic Electric Sales

Customer Class	Number of Customers	Sales MWH
Residential	572,000	1,977,595
Commercial and Industrial	59,600	2,526,522
Public Authority	400	234,183
Totals	632,000	4,738,300 (1.60×10^{13} Btu Equivalent)
% Total Electric Sales	(23.3%)	(17.4%)

Basic Gas Sales

Customer Class	Number of Customers	Millions of Cubic Feet
Residential	166,500	8,086
Commercial and Industrial	10,700	4,435
Public Authority	400	528
Totals	177,600	13,049 (1.3×10^{13} Btu Equivalent)
% Total Gas Sales	(16.7%)	(16.9%)

B R O O K L Y N 1 9 7 8

ELECTRIC

Base Load Stations	Service Date	Capacity MW	Net Generated MWH	Plant Factor[1] %	Heat Rate Btu/Net KWH	Oil Used 1000's Gal	Fuel Cost $/Gal	Fuel Cost ¢/KWH	Total Cost ¢/KWH
None located in Brooklyn									
Peak Load Stations									
Steam Turbines									
Hudson Avenue	1932	419	99,368	2.4	27,836	38,465	.32	12.8	20.2
Gas Turbines									
Gowanus	1971	456	59,341	1.0	16,863	7,265	.36	4.4	13.1
Hudson Avenue	1968-70	66	3,283	0.5	22,513	544	.37	6.8	15.4
Kent Avenue	1968	9	334	0.3	18,172	45	.38	5.2	27.5
Narrows	1972	272	61,536	1.9	16,823	7,497	.36	4.6	7.6
Totals		803	124,494			15,351			
% Con Edison Total Gas Turbines		(53.2%)	(38%)			(2.9%)[2]			
% Con Edison Peak Load		(48.6%)	(10%)						

Notes:

1. $\frac{\text{Annual Kilowatt Hour Generation}}{\text{(Annual Average Hourly Net Capacity)X(8760 bours/year)}}$
2. This is a percentage of all oil used by Con Edison

BROOKLYN 1977

Basic Electric Sales 1977

Customer Class	Number of Customers	Sales MWH
Residential	672,800	2,027,379
Commercial and Industrial	101,000	2,512,265
Public Authority	800	172,865
Totals	774,600	4,712,509
		(1.6 x 10^{13} Btu Equivalent)
% Total Electric Sales	(28%)	(17.3%)

Basic Gas Sales 1977

Brooklyn not included in Con Edison Franchise Area

BRONX 1978

ELECTRIC

Peak Load Station	Service Date	Capacity MW	
Hellgate	1922-73	35	(not in use since 1973)

Basic Electric Sales

Customer Class	Number of Customers	Sales MWH
Residential	318,100	818,796
Commercial and Industrial	37,400	1,593,238
Public Authority	500	345,399
Totals	356,000	2,757,433 (9.6×10^{12} Btu Equivalent)
% Total Electric Sales	(13%)	(10%)

Basic Gas Sales

Customer Class	Number of Customers	Millions of Cubic Feet
Residential	291,100	8,496
Commercial and Industrial	17,200	5,804
Public Authority	800	1,320
Totals	309,100	15,620 (1.6×10^{13} Btu Equivalent)
% Total Gas Sales	(29.27%)	(22.46%)

RICHMOND 1978

ELECTRIC

Base Load Stations	Service Date	Capacity MW	Net Generated MWH	Plant Factor %[1]	Heat Rate Btu/Net KWH	Oil Used 1000's Gal	Fuel Cost $/Gal	Fuel Cost ¢/KWH	Total Cost ¢/KWH
Arthur Kill	1959	826	2,929,963	39.3	10,383	209,742	.325	2.38	2.7
% Total Base Load Stations		(15%)	(17%)			(11.4%)[2]			
Peak Load Stations									
Gas Turbines									
Arthur Kill	1970	16	1,219	0.8	16,259	143,396	.36	4.24	28.7
% Total Peak Load Stations		(.6%)	(.05%)			(7.8%)[2]			

Notes:

1. $\dfrac{\text{Annual Kilowatt Hour Generation}}{\text{(Annual Average Hourly Net Capacity)X(8760 hours/year)}}$
2. This is a percentage of all oil used by Con Edison

R I C H M O N D

Basic Electric Sales

Customer Class	Number of Customers	Sales MWH
Residential	96,700	478,434
Commercial and Industrial	8,900	325,809
Public Authority	100	82,989
Totals	105,700	896,232
		(3.07×10^9 Btu Equivalent)
% Electric Sales	(3.9%)	(3.28%)

Basic Gas Sales

Richmond is not included in Con Edison's Franchise Area

W E S T C H E S T E R   1 9 7 8

ELECTRIC

Base Load Stations	Service Date	Capacity MW	Net Generated MWH	Plant Factor[1] %	Heat Rate Btu/Net KWH	Oil Used 1000's Gal	Fuel Cost $/Gal	Fuel Cost ¢/KWH	Total Cost ¢/KWH
Indian Point 1	1962	260	(Unit not in service; needs emergency core cooling system; future use doubtful)						
Indian Point 2	1973	873	4,369,315	57.7	11,660	1,799	.315	.490	1.0
Totals		1,133	4,369,315			1,799			
% Total Base Load Stations		(21%)	(25%)			(.09%)[2]			
Peak Load Stations									
Gas Turbines									
Indian Point		56	130	0.1	23,037	21,675	.35	7.584	197.0
% Total Peak Load Stations		(2.2%)	---			(1.2%)[2]			

Notes:

1. $$\frac{\text{Annual Kilowatt Hour Generation}}{\text{(Annual Average Hourly Net Capacity)X(8760 hours/year)}}$$

2. This is a percentage of all oil used by Con Edison

WESTCHESTER

1977

Basic Electric Sales

Customer Class	Number of Customers	Sales MWH
Residential	257,000	1,305,263
Commercial and Industrial	33,400	1,909,977
Public Authority	2,000	145,824
Totals	292,400	3,361,064 (1.13×10^{10} Btu Equivalent)
% Total Electric Sales	(11%)	(12.3%)

Basic Gas Sales

Customer Class	Number of Customers	Millions of Cubic Feet
Residential	183,500	14,821
Commercial and Industrial	13,500	5,879
Public Authority	700	792
Totals	197,700	21,492 (2.2×10^{13} Btu Equivalent)
% Total Gas Sales	(18.72%)	(30.9%)

ADDITIONAL PLANTS

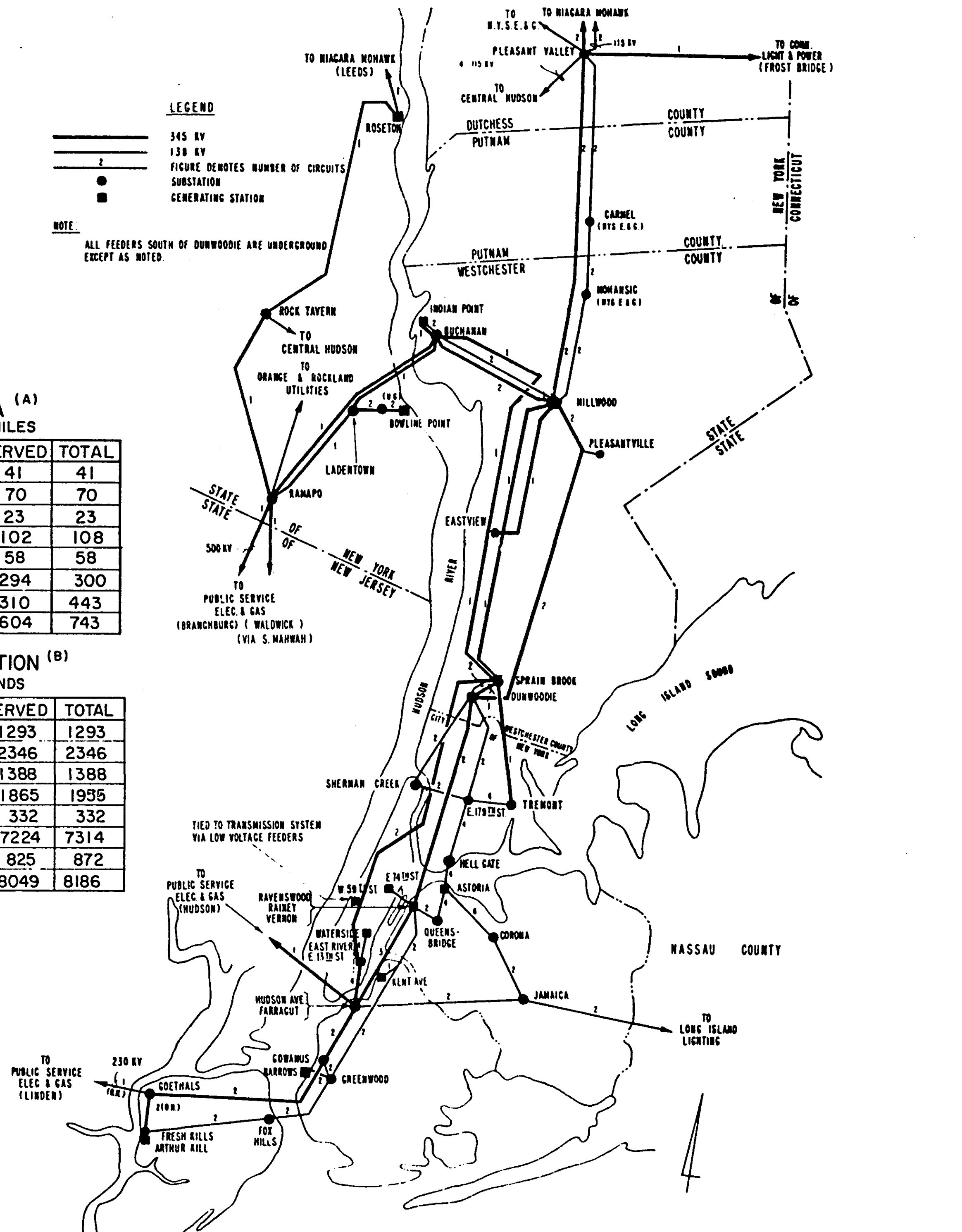
ELECTRIC

	Service Date	Capacity MW	Net Generated MWH	Plant[1] Factor %	Heat Rate Btu/Net KWH	Oil Used 1000's Gal	Fuel Cost $/Gal	Fuel Cost ¢/KWH	Total Cost ¢/KWH
Base Load									
Bowline Point	1972-74	801	3,243,012	46.2	9,857	219,578	.32	2.1	2.2
Roseton	1974	480	2,734,715	65.0	9,560	176,675	.28	1.8	1.8
Totals		1,281	5,477,727			396,253			
% Total Base Load Stations			(23%)			(24%)			

CON EDISON FRANCHISE AREA

(ELECTRIC OPERATING TERRITORY AND PRINCIPAL FACILITIES)

DECEMBER 31, 1978



AREA (A)

SQUARE MILES

	SERVED	TOTAL
BRONX	41	41
BROOKLYN	70	70
MANHATTAN	23	23
QUEENS	102	108
RICHMOND, S.I.	58	58
N.Y. CITY	294	300
WESTCHESTER	310	443
TOTAL	604	743

POPULATION (B)

THOUSANDS

	SERVED	TOTAL
BRONX	1293	1293
BROOKLYN	2346	2346
MANHATTAN	1388	1388
QUEENS	1865	1955
RICHMOND, S. I.	332	332
N.Y. CITY	7224	7314
WESTCHESTER	825	872
TOTAL	8049	8186

(A) SOURCE: BASED ON U.S. CENSUS OF POPULATION - 1970

(B) SOURCE: BASED ON U.S. BUREAU OF THE CENSUS REPORT - NOVEMBER 1978

Net Output
Con Edison Electric System
(Megawatt-hours)

	1977			1978		
	25 CYCLE	60 CYCLE	TOTAL	25 CYCLE	60 CYCLE	TOTAL
NET GENERATION						
STEAM – ASTORIA	–	4 789 167	4 789 167	–	3 758 828	3 758 828
RAVENSWOOD	–	5 962 536	5 962 536	–	5 307 572	5 307 572
ARTHUR KILL	–	2 608 826	2 608 826	–	2 929 963	2 929 963
EAST RIVER	(4 061)	1 124 755	1 120 694	(3 730)	1 231 557	1 227 827
BOWLINE 1 & 2 (I)	–	3 472 659	3 472 659	–	3 243 012	3 243 012
ROSETON 1 & 2 (I)	–	2 335 941	2 335 941	–	2 734 715	2 734 715
BASE LOAD STATIONS	(4 061)	20 293 884	20 289 823	(3 730)	19 205 647	19 201 917
WATERSIDE	21 792	1 169 292	1 191 084	(332)	1 198 745	1 198 413
HUDSON AVE	10 040	102 404	112 444	55 640	43 728	99 368
74TH STREET	274 599	14 821	289 420	269 026	7 651	276 677
59TH STREET	315 858	(20 953)	294 905	339 051	(25 137)	313 914
PEAK LOAD STATIONS	622 289	1 265 564	1 887 853	663 385	1 224 987	1 888 372
TOTAL STEAM STATIONS	618 228	21 559 448	22 177 676	659 655	20 430 633	21 090 288
NUCLEAR – INDIAN POINT NO. 1 (J)	–	(15 010)	(15 010)	–	(11 830)	(11 830)
INDIAN POINT NO. 2	–	5 210 299	5 210 299	–	4 369 315	4 369 315
GAS TURBINES – ARTHUR KILL	–	2 385	2 385	–	1 219	1 219
ASTORIA	–	299 994	299 994	–	162 509	162 509
BUCHANAN	–	2 008	2 008	–	586	586
GOWANUS BAY	–	167 870	167 870	–	59 341	59 341
HUDSON AVE	–	2 949	2 949	–	3 283	3 283
INDIAN POINT	–	479	479	–	130	130
KENT AVE	–	702	702	–	333	333
NARROWS	–	146 482	146 482	–	61 536	61 536
RAVENSWOOD	–	73 871	73 871	–	34 768	34 768
WATERSIDE	–	621	621	–	1 153	1 153
59TH STREET	–	3 143	3 143	–	902	902
74TH STREET	-	1 832	1 832	–	770	770
TOTAL GAS TURBINES	–	702 336	702 336	–	326 530	326 530
TOTAL ALL STATIONS	618 228	27 457 073	28 075 301	659 655	25 114 648	25 774 303
FREQUENCY CHANGED						
25 CYCLE TO 60 CYCLE	(125 716)	125 716	–	(158 541)	158 541	–
60 CYCLE TO 25 CYCLE	386 899	(386 899)	–	(C)	(C)	–
PURCHASED FROM OTHER UTILITIES						
CENTRAL HUDSON	–	9 746	9 746	–	–	–
LONG ISLAND LIGHTING	–	27 129	27 129	–	–	–
MAINE PUBLIC SERVICE	–	–	–	–	–	–
NEW ENGLAND POWER EXCHANGE	–	69 090	69 090	–	–	–
NEW YORK STATE ELECTRIC & GAS	–	4 795	4 795	–	1 200	1 200
NIAGARA MOHAWK	–	47 302	47 302	–	–	–
ONTARIO HYDRO	–	16 510	16 510	–	–	–
ORANGE & ROCKLAND	–	40 134	40 134	–	26 600	26 600
POWER AUTHORITY STATE OF N. Y.	–	3 030 217	3 030 217	–	4 423 300	4 423 300
ROCHESTER GAS & ELEC	–	33 781	33 781	–	–	–
NEW YORK POWER POOL	–	1 625 360	1 625 360	–	2 532 221	2 532 221
HYDRO QUEBEC	–	425 661	425 661	–	310 232	310 232
NORTHEAST UTILITIES	–	55 897	55 897	–	51 948	51 948
TOTAL	–	5 385 622	5 385 622	–	7 345 501	7 345 501
SOLD TO OTHER UTILITIES						
CENTRAL HUDSON	–	4 119	4 119	–	–	–
LONG ISLAND LIGHTING	–	23 102	23 102	–	29	29
NEW ENGLAND POWER EXCHANGE	–	24 730	24 730	–	–	–
NEW YORK STATE ELECTRIC & GAS	–	15 295	15 295	–	–	–
NIAGARA MOHAWK	–	18 578	18 578	–	–	–
ONTARIO HYDRO	–	68 350	68 350	–	–	–
ORANGE & ROCKLAND	–	17 200	17 200	–	–	–
POWER AUTH. STATE OF N. Y.	–	795 984	795 984	164 663	304 467	469 130
ROCHESTER GAS & ELECTRIC	–	330	330	–	–	–
NEW YORK POWER POOL	–	1 170 446	1 170 446	–	1 990 384	1 990 384
NORTHEAST UTILITIES	–	15 150	15 150	–	185 842	185 842
TOTAL	–	2 153 284	2 153 284	164 663	2 480 722	2 645 385
*INTERCHANGE POWER – GENERATION FROM NORTHFIELD MTN.	–	133 995	133 995	–	360 629	360 629
– PUMPING FOR NORTHFIELD MTN.	–	(182 411)	(182 411)	–	(504 394)	(504 394)
TOTAL NET INPUT	879 411	30 379 812	31 259 223	336 451 (D)	29 994 203	30 330 654
SALES TO CUSTOMERS (A)			27 850 286			26 597 009
COMPANY USE			180 647 (B)			153 481 (E)
SUPPLIED FREE (FRANCHISE REQUIREMENTS)			12 371			13 992
TOTAL NET OUTPUT			28 043 304			26 764 482
SYSTEM EFFICIENCY – PERCENT			89.7			88.2

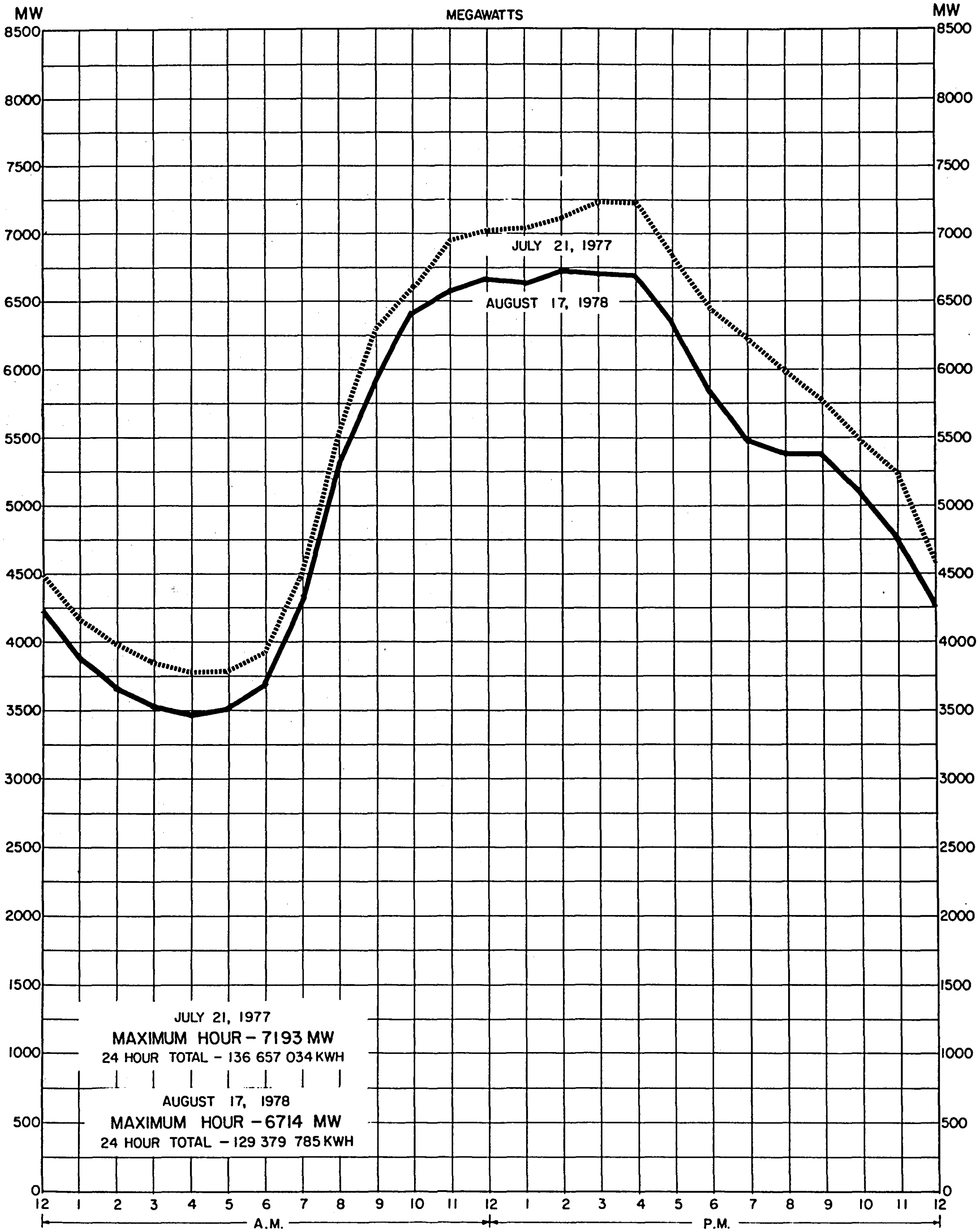
*NORTHFIELD MOUNTAIN PUMPED STORAGE (NORTHEAST UTILITIES)

(A) EXCLUDES SALES TO OTHER UTILITIES AND PASNY GOVERNMENTAL CUSTOMERS IN 1977 AND 1978
(B) INCLUDES 51,941 MWHS SUPPLIED TO PASNY (INDIAN POINT NO. 3 AND ASTORIA NO. 6)
(C) ENERGY TRANSFER FROM 60 CYCLE TO 25 CYCLE IS FOR PASNY CUSTOMERS UNDER THE TERMS OF A SEPARATE AGREEMENT
(D) REFLECTS ELECTRIC GENERATION FROM CON EDISON STEAM-ELECTRIC GENERATING STATIONS AND IS NOT REPRESENTATIVE OF CON EDISON 25 CYCLE SYSTEM SENDOUT
(E) INCLUDES 33,728 MWHS SUPPLIED TO PASNY (INDIAN POINT NO. 3 AND ASTORIA NO. 6)

LOAD CURVES ON DAY OF ELECTRIC SYSTEM MAXIMUM-HOUR NET INPUT

CON EDISON

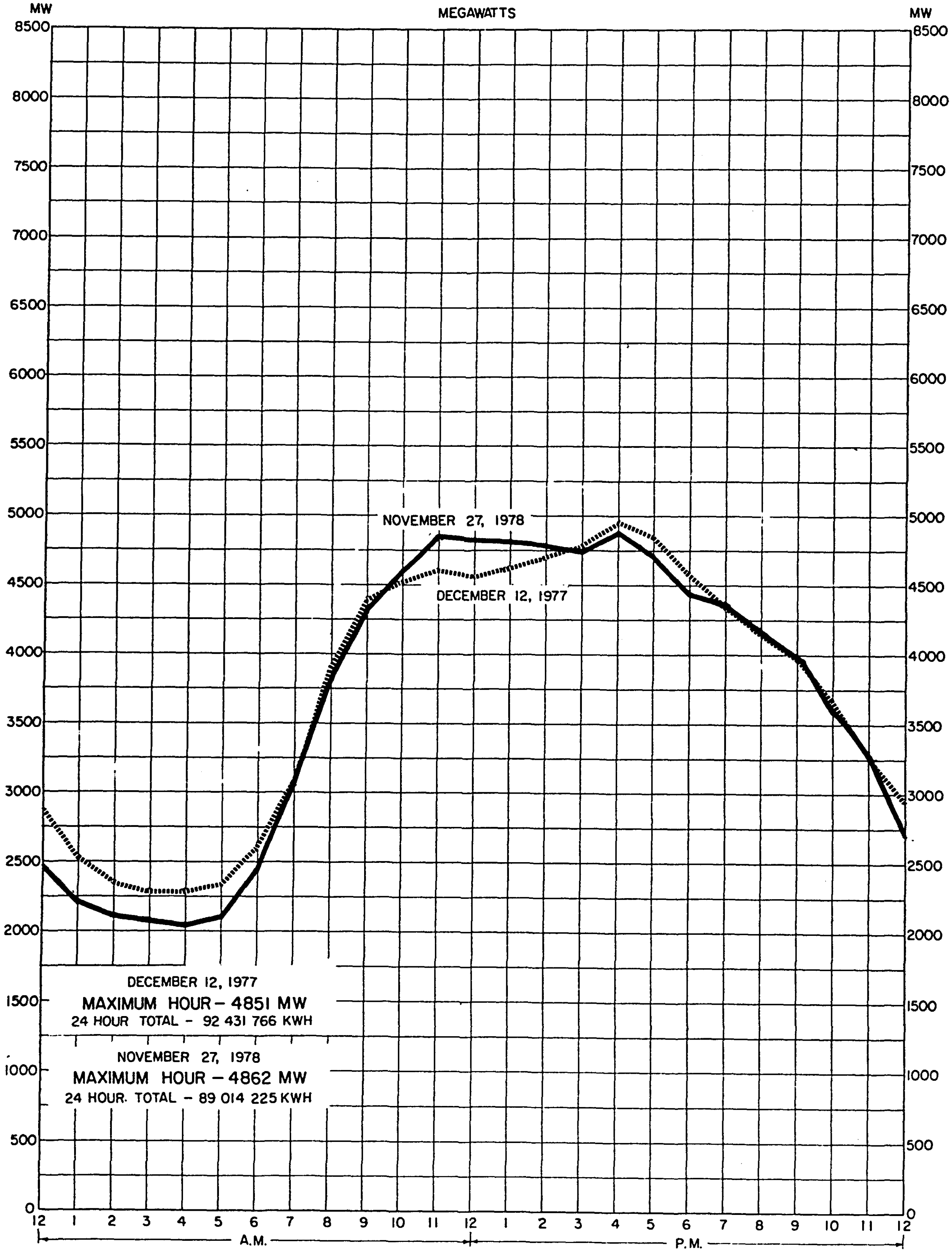
SUMMER SEASON

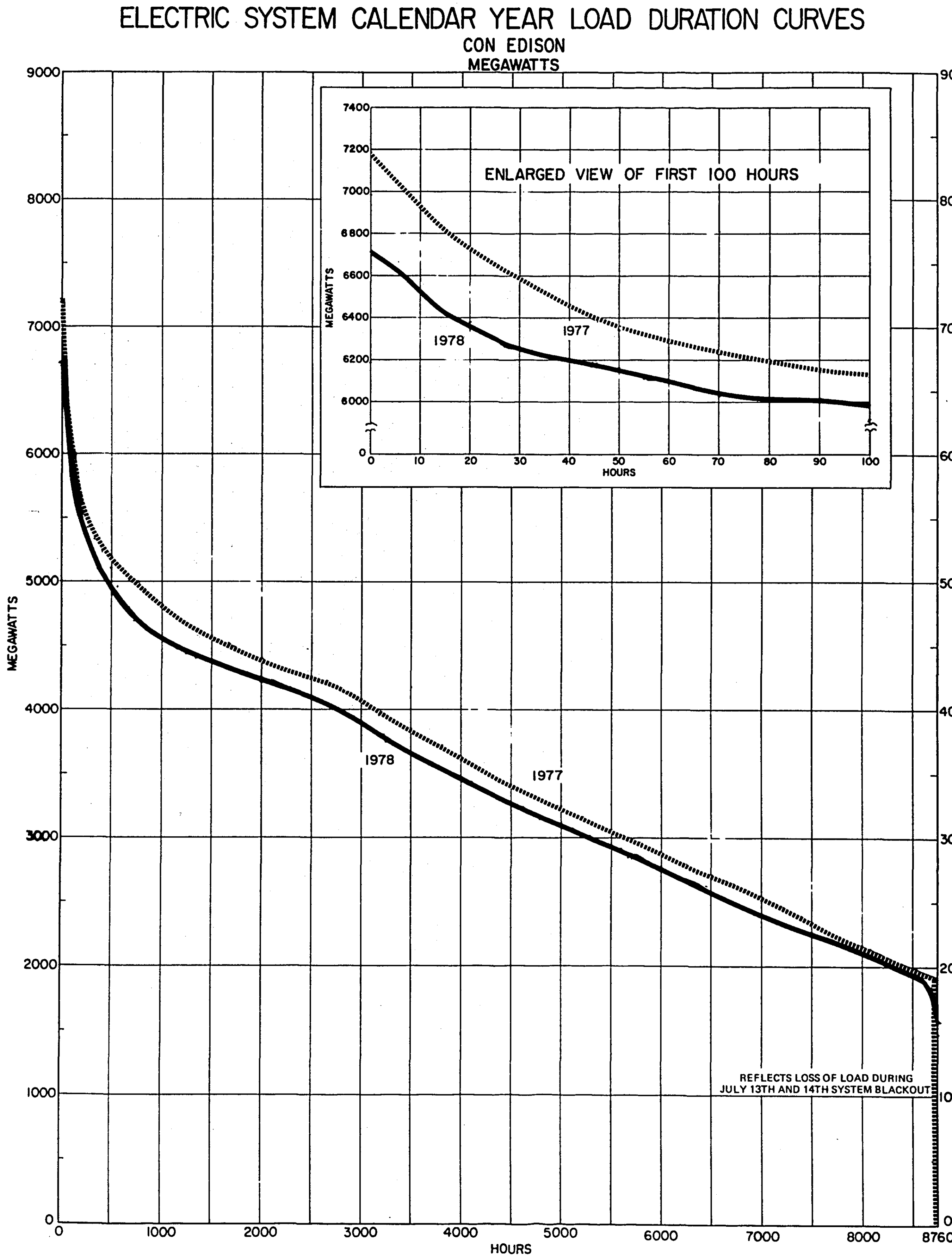


LOAD CURVES ON DAY OF ELECTRIC SYSTEM MAXIMUM HOUR NET INPUT

CON EDISON

WINTER SEASON





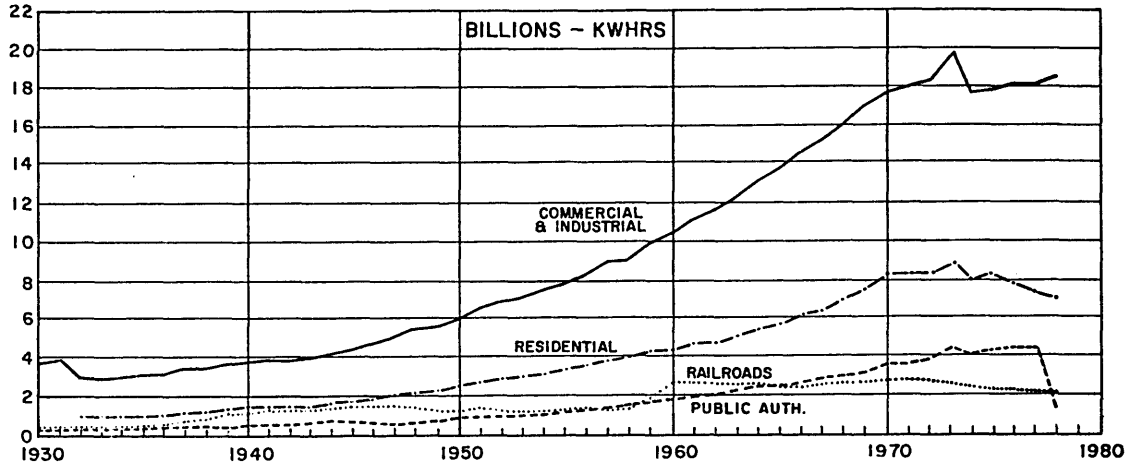
ELECTRIC SYSTEM CALENDAR YEAR LOAD DURATION CURVES
CON EDISON
MEGAWATTS
ENLARGED VIEW OF FIRST 100 HOURS
MEGAWATTS
HOURS
1978
1977
REFLECTS LOSS OF LOAD DURING JULY 13TH AND 14TH SYSTEM BLACKOUT

CON EDISON

SYSTEM ELECTRIC ENERGY SALES BY CLASSES

EXCLUDING SALES TO OTHER UTILITIES

MEGAWATT - HOURS

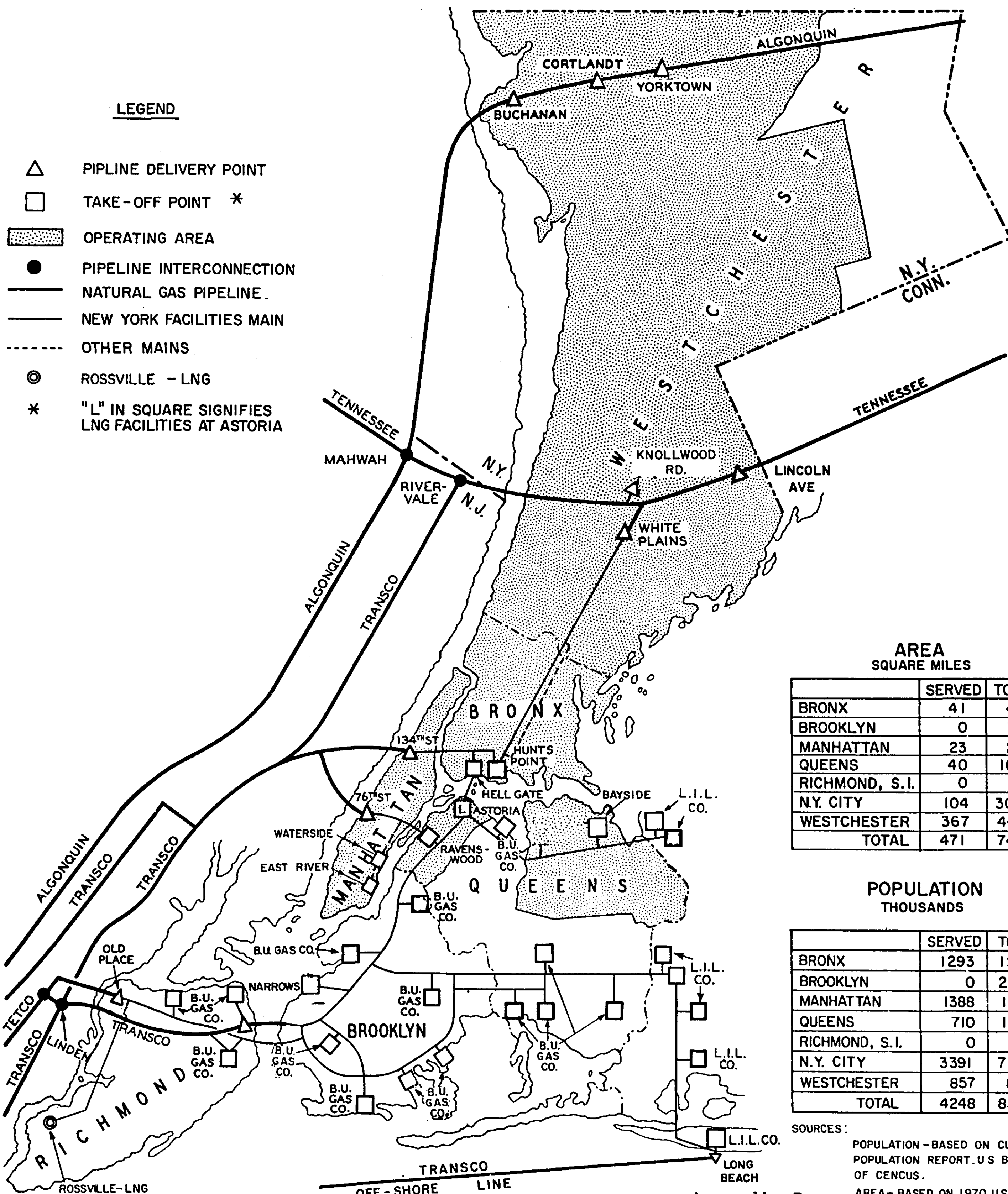


YEAR	TOTAL	RESIDENTIAL	COMM. & IND.	PUBLIC AUTH.	RAILROADS
1915	754 809				
16	880 547				
17	977 334				
18	1 010 935				
19	1 156 387				
1920	1 339 874				
21	1 552 870				
22	1 754 256				
23	2 008 301				
24	2 211 797				
1925	2 487 304				
26	2 825 522				
27	3 171 378				
28	3 568 454				
29	3 972 351				
1930	4 242 459				
31	4 419 306				
32	4 317 976				
33	4 323 842				
34	4 547 369				
1935	4 736 642	927 131	3 017 506	307 051	484 954
36	5 232 160	1 041 510	3 197 044	344 376	649 230
37	5 713 504	1 140 946	3 372 643	362 769	837 146
38	5 874 432	1 204 361	3 367 877	421 502	880 691
39	6 529 633	1 276 288	3 641 144	459 017	1 153 183
1940	6 718 235	1 315 604	3 723 379	498 319	1 180 932
41	6 993 097	1 355 955	3 881 570	531 736	1 223 836
42	6 985 061	1 374 639	3 808 704	525 596	1 276 123
43	7 281 941 (C)	1 359 702	3 941 263 (C)	654 739	1 326 236
44	7 775 176 (D)	1 509 839	4 185 240 (D)	720 415	1 359 682
1945	8 084 151	1 678 941	4 338 158	699 323	1 367 730
46	8 483 170	1 868 726	4 611 556	634 059	1 368 829
47	9 062 206	1 988 730	5 043 987	653 265	1 376 224
48	9 517 318	2 103 357	5 418 094	665 638	1 330 230
49	9 725 051	2 182 942	5 563 127	758 796	1 220 187
1950	10 431 370	2 438 623	5 971 672	805 606	1 215 470
51	11 263 354	2 629 461	6 438 938	875 633	1 319 322
52	11 793 534	2 829 041	6 782 720	936 353	1 245 421
53	12 302 265	2 974 701	7 090 179	1 016 812	1 220 573
54	12 877 602	3 160 713	7 405 911	1 075 606	1 235 371
1955	13 721 299	3 357 914	7 921 782	1 153 631	1 287 972
56	14 496 308	3 543 444	8 353 669	1 267 791	1 331 405
57	15 382 362	3 781 528	8 901 078	1 380 728	1 319 027
58	15 939 584	3 925 882	9 140 960	1 525 457	1 347 286
59	17 601 285 (E)	4 206 881	9 969 842	1 610 738	1 813 826 (E)
1960	18 893 844	4 215 957	10 391 255	1 741 159	2 545 472
61	20 191 370	4 613 371	11 162 515	1 864 261	2 551 222
62	20 789 028	4 675 438	11 589 363	1 983 902	2 540 325
63	21 905 995	4 997 572	12 230 960	2 117 577	2 559 885
64	23 298 011	5 315 483	13 135 787	2 341 968	2 504 773
1965	24 307 375	5 620 921	13 747 162	2 452 577	2 486 715
66	25 436 008	6 044 368	14 411 867	2 592 221	2 387 552
67	26 593 985	6 285 579	15 017 048	2 793 796	2 497 563
68	28 258 080	6 853 691	15 916 113	2 942 565	2 545 712
69	30 075 358	7 372 249	16 920 239	3 197 724	2 585 146
1970	31 923 936	8 208 181	17 633 850	3 406 019	2 675 886
71	32 498 721	8 314 446	17 948 821	3 618 597	2 616 858
72	33 067 716	8 298 887	18 369 747	3 873 811	2 525 271
73	34 653 176	8 916 618	19 090 496	4 269 938	2 376 125
74	32 206 077	8 005 864	17 707 991	4 196 021	2 296 201
1975	32 417 600	8 056 264	17 848 586	4 279 782	2 232 968
76 (A)	32 629 648	7 919 659	18 169 953	4 298 617	2 241 419
77 (A)	32 457 900	7 825 905	18 178 879	4 256 863	2 196 253
78 (A)	32 596 075	7 677 023	18 384 164	4 363 010	2 171 878
76 (B)	31 923 868	7 919 659	18 169 953	3 894 593	1 939 663
77 (B)	27 850 286	7 825 905	18 178 879	1 278 794	566 708
78 (B)	26 597 009	7 677 023	18 384 164	408 712	127 110

(A) CON EDISON FRANCHISE AREA (INCLUDES PASNY SALES)
(B) SALES TO CON EDISON CUSTOMERS ONLY (EXCLUDES PASNY SALES)
(C) EXCLUDE 1 530 920 MWH TO MASPETH ALUMINUM PLANT
(D) EXCLUDE 735 468 MWH TO MASPETH ALUMINUM PLANT
(E) ALL DATA AFTER AUGUST 1, 1959 INCLUDE ADDITIONAL NEW LOAD OF NEW YORK CITY TRANSIT AUTHORITY

GAS OPERATING TERRITORY AND PRINCIPAL FACILITIES

DECEMBER 31, 1978



AREA
SQUARE MILES

	SERVED	TOTAL
BRONX	41	41
BROOKLYN	0	70
MANHATTAN	23	23
QUEENS	40	108
RICHMOND, S.I.	0	58
N.Y. CITY	104	300
WESTCHESTER	367	443
TOTAL	471	743

POPULATION
THOUSANDS

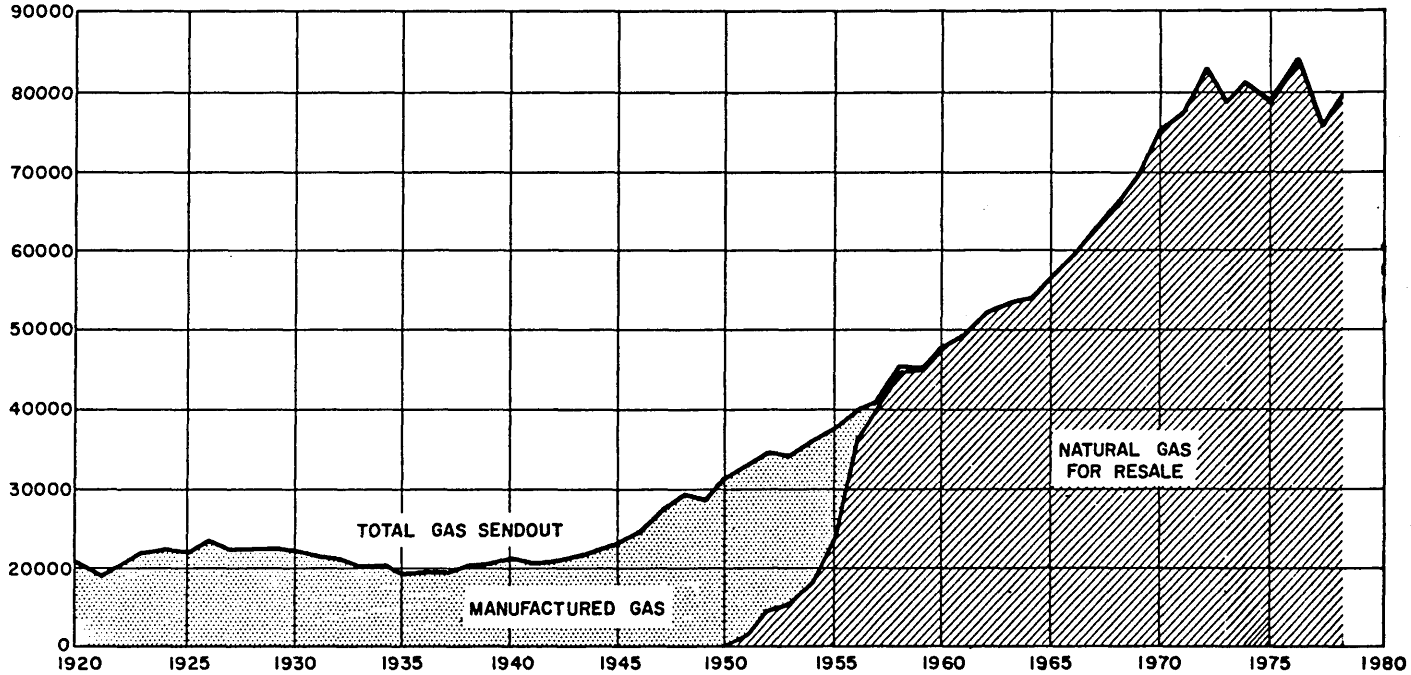
	SERVED	TOTAL
BRONX	1293	1293
BROOKLYN	0	2346
MANHATTAN	1388	1388
QUEENS	710	1955
RICHMOND, S.I.	0	332
N.Y. CITY	3391	7314
WESTCHESTER	857	872
TOTAL	4248	8186

SOURCES:

POPULATION - BASED ON CURRENT POPULATION REPORT. U S BUREAU OF CENCUS.

AREA - BASED ON 1970 U S CENSUS OF POPULATION & CON ED.

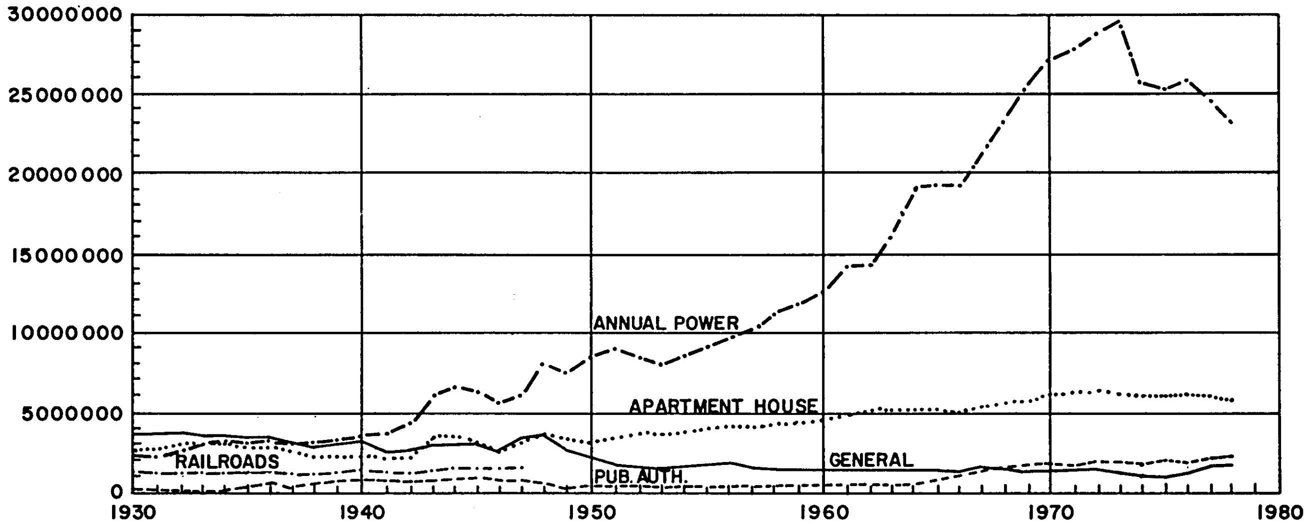
Natural Gas Made and Sent Out
(Millions of Cubic Feet)



	1977		1978	
DELIVERED TO DISTRIBUTION MAINS FROM HOLDER STOCK		–		–
HOLDER STOCK BEGINNING OF YEAR	–		–	
HOLDER STOCK END OF YEAR	–		–	
GAS PURCHASED		82 300.644		80 859.288
ALGONQUIN	884.722		758.905	
TENNESSEE	10 286.412		10 318.621	
TEXAS EASTERN	16 598.801		17 776.544	
TRANSCO	54 530.709		52 005.218	
LONG ISLAND LIGHTING CO.	–		–	
LOWELL GAS CO.	–		–	
EXCHANGE GAS – B.U. CO.	–		–	
EXCHANGE GAS – LILCO	–		–	
BROOKLYN UNION GAS CO.	–		–	
LESS GAS USED BY ELECTRIC DEPARTMENT		(1 041.401)		(963.177)
ASTORIA – CONVENTIONAL	291.408		226.348	
– GAS TURBINE	56.555		40.639	
EAST RIVER	82.543		48.005	
HELL GATE	–		–	
RAVENSWOOD – CONVENTIONAL	237.028		248.930	
– GAS TURBINE	18.541		14.605	
WATERSIDE	345.994		383.355	
59TH STREET	9.332		1.295	
NARROWS – GAS TURBINE	–		–	
LESS GAS USED BY STEAM DEPARTMENT		(367.055)		(430.991)
WATERSIDE	358.804		426.027	
EAST RIVER	6.964		4.243	
EAST 60TH STREET	1.287		.721	
LESS BANK GAS AT BROOKLYN UNION		–		–
LESS GAS STOCKED AT ASTORIA LNG FACILITY		(223.500)		(195.206)
LESS GAS STOCKED AT HONEOYE		(277.180)		174.312
LESS GAS INJECTED INTO GAS FIELD STORAGE		(6 992.814)		(5 297.138)
PLUS GAS TAKEN FROM GSS GAS STORAGE		3 522.828		5 470.113
TOTAL SENDOUT		76 921.552		79 617.201

( ) INDICATES NEGATIVE VALUE

STEAM SALES BY CLASSES
THOUSANDS OF POUNDS



Recent Financial History

The decade of the 1970's reflected a dramatic financial turnaround for Con Edison. During the 1968-1973 period the company experienced a deterioration in its financial condition as indicated by a declining trend in such financial measurements as interest coverage, return on equity, earnings per share, and market price (Exhibit 1.13). By early 1974 Con Edison faced a financial crisis and was forced thereby to omit its second quarter common dividend payment. Common dividends for the final two quarters of 1974 were reduced to $.20 per share from the prior $.45 per share level. Since 1974, the company's financial fortunes have improved steadily, reflecting the sale of two major generating units to PASNY, tight budget controls with respect to the construction and operating budgets and a sharp improvement in earnings following a major rate increase at the end of 1974.

The late 1960's and early 1970's were years of strong growth in demand for Con Edison's services. Unit sales of electricity, gas, and steam from 1968-1973 expanded at an annual rate of 4.2%, 4.8%, and 3.5%, respectively (excluding sales to other utilities). Electricity use per residential customer expanded at a 5.7% annual rate (Exhibit B.1). Meeting the strong demand growth required sharply expanded construction expenditures (Exhibit 1.13). Construction expenditures in 1973 exceeded $685 million, more than 2 3/4 times the 1968 level. During these years internal cash flow fell progressivly behind the expanding expenditure level, giving rise to a growing need for external financing (Exhibit 1.13). Debt financing was undertaken every year from 1968-1974. Long-term debt outstanding rose by more than 57% during this six-year period. Preferred stock was sold in 1968, 1970, and 1972. Common stock was sold in each year 1969-1973 when generally the price of Con Edison stock was below book value. Nevertheless, working capital continued to decline. Return on equity earned and earnings per share were also declining over this period (Exhibit 1.13).

The OPEC-induced fuel cost increases of 1973-1974 led to large increases in Con Edison's operating costs. There was a regulatory lag in the full pass through of these cost increases to consumers. Furthermore, when the cost increases were passed on to customer bills, there was an increase in uncollectable accounts. The combination of these events put such strains on the Company's financial position that it was forced to eliminate its quarterly common dividend in April 1974. Further, the company was forced to reduce the final two dividend payments for the year to $.20/quarter bringing the annual dividend payment down to $.85/share for all of 1974, from the level of $1.80/share in 1973--a level which had been maintained for many years. The payout ratio dropped from 77% to a more manageable 32%.

The 1973-1974 period marked a watershed in the growth of energy usage nationwide. This turnabout was rapidly reflected in

Con Edison's financial situation. Electricity usage by Con Edison customers peaked in 1973 and, after growing at 4.2% annually in the five years 1968-1973, usage declined by 4.3% annually over the six years 1973-1979, in part due to loss of 20% of Con Edison sales to PASNY. Gas and steam sales followed a similar trend. Concurrently, Con Edison's electric rates jumped 46% in 1974, and by 1979 rates were 200% above the 1973 level (Exhibit 1.13).

ELECTRICITY, GAS, AND STEAM COMPOUNDED ANNUAL AVERAGE KILOWATT HOUR GROWTH RATES (1968-1979)

	1968-1973 (5 Years)	1973-1979 (6 Years)
Electric Sales	4.2%	-4.2%*
Gas Sales	4.8%	0.2%
Steam Sales	3.5%	-4.5%

* If delivery to PASNY customers is included, the growth rate from 1973 to 1979 becomes -0.9%.

Source: Ten Year Financial and Operating Statistics: 1968-1978, Consolidated Edison of New York, Inc., New York, N.Y., March 22, 1979.

The turndown in demand eased pressure for construction of new facilities. Of more immediate financial significance, however, was the Company's sale of two partially completed generating plants to PASNY, including Astoria 6 in 1974 and Indian Point 3 in 1975. These sales removed the burden of further expenditure for these plants. In addition, the sales yielded cash proceeds of approximately $600 million over the 1974-1976 period. The combined effect of reduced expenditures, the injection of capital, internal budget procedures, and significant rate relief in 1974 produced a prompt and remarkable financial recovery. Return on common equity, earnings per share,and interest coverage improved dramatically in 1975 (Exhibit 1.13).

No common stock was sold after 1973, and the year 1974 marked the last sale of debt. In 1974, proceeds from the sale of generating units accounted for roughly one-half of the Company's external funding, or 25% of 1974's total financial resources. In

1975-1977, proceeds from the sale of generating units accounted for all external financial input. Since 1975, capital expenditures have been held to a level that could be almost entirely financed from internally generated funds. With no new long-term debt, with some debt maturing, and with retained earnings augmenting common equity, the common/equity ratio has risen sharply during the last five years from 34.6% in 1974 to 44.1% at the end of 1979. With internal cash flow meeting capital requirements, $500 million of the funds received from PASNY in 1974-1976 have remained invested in financial assets.

In addition to the strengthening of the balance sheet, financial efficiency in operations has also showed dramatic improvement. One measure is the ratio of receivables to operating revenue. This ratio was 6.7% in 1979, down from 12.2% in 1974, and a high of 17.0% in 1973. Provision for uncollectables charged to operating expense was $12.7 million in 1977, down some $45 million from its highest level in 1975.

Present and Near-Term Future Financial Condition

Con Edison's current financial condition is strong in every dimension, and the company has one of the strongest balance sheets in the electric utility industry (Exhibit 1.14). At year-end 1979 the Company had--at that one point in time--$493 million of temporary cash investments surplus to current operating needs. Of that total, approximately $180 million was set aside for retirement of bonds and preferred stock through 1982. The company's year-end 1979 common equity ratio of 44.1% was among the highest in the industry, as was its interest coverage of 3.6 times. Current capital outlays can be covered by internal cash generation and cash balances, which is unique in the utility industry. Con Edison's earnings are of high quality in terms of allowance for funds during construction. Taken as a percent of earnings, this measure is among the lowest in the industry. Con Edison's debt is currently A-rated and is highly regarded by bond analysts, some of whom view Con Edison as a double-A.

On the negative side, Con Edison's return on common equity is below the industry average, and the company has the highest electric rates of any utility in the nation. Because average usage is far below national average, actual customer bills are far below the national average. Furthermore, Con Edison's market price to book value ratio is the lowest in the industry, with the exception of General Public Utilities.

The improving financial condition of the last four years is likely to continue during the next several years. It is reasonable to expect that capital spending will remain at relatively low levels during the early 1980's; and, depending on the return on equity earned and payout ratio, most or all of the Company's capital needs could probably be met from internally generated funds and cash balances. The common equity ratio will most likely continue to rise as long-term debt is retired and retained earnings increase equity. The equity ratio could approach the 50% level by the mid-1980's, assuming only modest amounts of new long-term debt financing. Annual dividend increases are anticipated at a rate that will gradually move up the dividend payout ratio toward industry norms. Over the next several years, Con Edison's financial ratios should remain very strong or, as in the case of interest coverage and equity ratio, continue to improve, assuming that adequate rate increases are granted.

Under an optimistic scenario, Con Edison's near-term financing needs are minimal. In an industry where internal generation of required funds is typically 30-40% and sometimes as low as 15-20%, Con Edison's internal generation of funds has been 100% plus in recent years and should be at least 70-80% over the next five years. Thus, there will be some drawdown of financial reserves, followed by some new debt financing. Con Edison anticipates issuing $100 million of pollution control bonds in late 1981 in connection with the conversion to coal of the Ravenswood 3 and Arthur Kill 2 and 3 plants. Prolongation of the test burn program at these plants could, however, delay pollution control financing until 1982. On the other hand, various uncertainties or contingencies could require substantial infusion of new capital in the near term over and above the amounts of expected expenditures.

The Senate Energy Committee recently supported a federal grant to utilities that would cover 25% of the cost of conversion of oil-fired plants to coal. Should such a proposal become law, this would be of major significance to Con Edison in financing its future construction program which consists mainly of coal conversions. With internal generation of funds estimated to cover 70% or more of near-term needs, a 25% subsidy on conversions would stretch out any external financing needs considerably.

Financial Regulatory Environment

Con Edison operates in one of the highest-cost service territories in the industry. Con Edison has the highest electric rates of any utility in the nation.[1] During the last five years, however, Con Edison's average electric rate has risen slower than the industry average.

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[1] Con Edison is also the most heavily taxed utility in the country and is the largest single source of taxes in New York City.

On April 18, 1980, Con Edison filed for a $449 million rate increase which would normally take effect in March of 1981. The requested 15.5% increase in rates is predicated on an overall rate of return of 10.2%, which equates to a return on equity of 14.7%. A breakdown of the revenue requirements follows:

REVENUE REQUIREMENTS FOR A 10.2 PER CENT RATE OF RETURN

Reason	Millions of Dollars
Improve return	150
Offset higher costs	225
Cost of new facilities	74
Total	449

Source: Con Edison Application for a Rate Increase, Public Service Commission case number 27744, Consolidated Edison Co. of New York, Inc., New York, N.Y., April 18, 1980.

In its last electric rate case, decided in April 1979, Con Edison was allowed a 12.1% return on equity. In that case, the Company was awarded a $158.1 million, or 7%, annual increase in revenues, $70 million less than the Company had requested a year earlier in May 1978. On March 7, 1980, the New York Public Service Commission (NYPSC) approved an 8% gas rate increase of $28.8 allowing a 9.5% overall return and a 13.5% return on equity. The authorized increase was approximately 74% of the Company's request.

Other New York electric utilities were granted returns on equity ranging from 13.3% to 14% during 1978 and 1979, while Con Edison was limited to 12.14%. Industry observers have pointed out that Con Edison's financial strength, its high equity ratio, and its high reserve margin, in combination with its high rates, may have negative connotations in terms of regulatory pressures to hold down rate increases. Nevertheless, their return on average equity remains below industry average. In general, the NYPSC is regarded as reasonable; and the regulatory climate and practice in New York is in line with the national average. Con Edison's proposed conversions to coal, which will reduce fuel costs to customers, are viewed constructively in terms of easing the burden of future rate increases generally.

Projected Fuel Prices for 1985

Exhibit 1.12 lists the projected prices for major boiler fuels as delivered to Con Edison from 1980 to 1995. As shown in that exhibit the price of 0.3% sulfur content oil in 1980 is approximately twice the price of natural gas and more than twice the price of 1% sulfur content coal. The price of oil as delivered to Con Edison is expected to remain at least twice as expensive as coal throughout 1980-1995 since the expected real annual price growth rate is higher for oil than for coal. However, it was estimated that the price of natural gas as delivered to Con Edison will grow at least twice as quickly as the price of oil throughout most of the 1980's. Thus, it is expected that the prices of oil and natural gas will be similar by the late 1980's and remain so through 1995.

As further explained in Chapter Three oil prices are expected to increase in real terms during 1980-1995 because of international economic and political reasons. However, they are not expected to increase at a rate higher then 5% because of the concern of some OPEC governments for the well-being of the economies of the oil-importing countries.

Furthermore, coal prices at the minemouth are expected to remain independent from oil prices since the coal mining industry is relatively competitive. However, the transportation of coal is mainly controlled by the railroads; and at high oil prices the railroads are expected to exercise their monopoly power and increase coal transportation rates. It is expected that most of the coal Con Edison burns will come from coal regions in the Eastern United States, if it converts some of its oil-fired plants to coal. If Con Edison does not want to use FGD equipment, however, it might mix some Western U.S. coal with Eastern U.S. coal to achieve a mixture of lower sulfur content. Prices of Eastern coal, as delivered to Con Edison, are expected to remain relatively constant in real terms because of the small transportation cost involved. On the contrary, prices of Western coal, as delivered to Con Edison, could increase in real terms because of the high transportation cost involved. Nevertheless, since Con Edison will not be using large amounts of Western coal, it is expected that real coal prices as delivered to Con Edison will increase at an annual rate between 0-2% during 1980-1995.

The Natural Gas Policy Act of 1978 promulgates that natural gas prices will be deregulated in 1985. Price controls could be reimposed by the Congress or the President until December 21, 1988, when price controls will be removed completely, unless a new law is introduced. In the last five years, the price of gas has been increasing at a rate of about 10% in real terms. it is assumed that the price of natural gas will continue to increase at this rate until deregulation occurs; i.e., until 1985. Thereafter, the price of natural gas is expected to increase at a faster rate (about 11-13%) until it reaches the price of the No.

6/Residual oil sometime in the late 1980's. During 1990-1995 the price of natural gas is expected to increase at the same rate as the price of No. 6/Residual oil; i.e., at an annual rate of 0-5%.

Appendix C

REGULATORY AGENCIES AND REGULATIONS

Federal, State, and Local Environmental Regulatory Agencies

The United States Environmental Protection Agency (EPA) was given principal responsibility for major federal programs dealing with air and water pollution, solid waste disposal, pesticides control, and environmental radiation. As additional environmental laws were passed in the 1970's, the EPA assumed responsibility for new environmental programs, including noise, safe drinking water, and toxic substances control. The majority of the federal environmental laws with the potential to affect Con Edison's fuel strategies are administered by the EPA. Other agencies, such as the U. S. Department of Interior, the U. S. Army Corps of Engineers, and the National Oceanic and Atmospheric Administration, maintain responsibility for specialized environmental programs directly related to their mandated duties.

New York State's environmental authority is concentrated in the Department of Environmental Conservation (DEC), although the Public Service Commission, the Department of Public Health, and the Department of State administer some environmental programs. The Environmental Conservation Law (ECL), administered by the DEC, is the heart of the state's environmental law, with jurisdiction over most environmental contaminants. The following ECL articles, discussed later in the text, are most important to Con Edison's fuel use decisions: Article 8 (Environmental Quality Review), Article 15 (Water Resources), Article 17 (Water Pollution Control), Article 19 (Air Pollution Control), and Article 27 (Refuse and Solid Waste).

Two other state programs have the potential to apply to Con Edison's fuel options, although they are not likely to preclude any of the options. First, the Public Service Law requires "certificates of environmental compatibility and public need" for siting major utility transmission facilities and major steam electric generating facilities. Second, the New York Department of State's Coastal Zone Management Program, presently under revision, contains a draft plan for New York City which could affect waterfront activities (e.g., barge loading dock construction).

Chapter 57 of the New York City Charter establishes the Department of Environmental Protection (DEP) and the Environmental Control Board (ECB), with jurisdiction over numerous activities in the City of New York. Section 1403 of the amended charter defines the powers of the DEP to include: (a) water resources control; (b) sewage control; (c) air resources control; (d) noise pollution control; (e) review of environmental consequences of certain activities; (f) establishment of a resource recovery task force; and, (g) city energy policy development. The ECB, consisting of the heads of DEP divisions and other appointed officials, has the authority to adopt and amend rules regulating or prohibiting air or water pollutant emisisons.

General Environmental Assessment Requirements

Federal Requirements

The landmark National Environmental Policy Act (NEPA)(42 U.S.C. Section 4321 et seq.) was passed by Congress in 1969 and went into effect on January 1, 1970. NEPA consists of a declaration of Congressional purpose plus two titles. Title I, the most conspicuous requirement in NEPA, requires the preparation of an environmental impact statement (EIS). Title II requires the President of the United States to transmit an annual report to Congress that discusses the current status of the major aspects of the environment. The second title also creates the Council on Environmental Quality (CEQ) to advise the President on environmental matters and to aid in the implementation of Title I.

Of the four major parts to Title I, three place certain environmental responsibilities on federal agencies, while the fourth, Section 102(2)(C), actually stipulates that federal agencies prepare an EIS prior to any major action which may significantly affect the quality of the human environment. Section 102(2)(C) imposes on Con Edison a visible public information requirement: an EIS for any major changes to Con Edison's existing combustion facilities or new facility construction that requires federal agency action (other than EPA air and water permits, except National Pollutant Discharge Elimination System (NPDES) permits for 'new' sources).

State Requirements

Following the implementation of NEPA, a number of states adopted environmental protection requirements for state actions; the statutes have come to be called "little NEPAs". These state environmental policy statutes differ widely in their breadth and stringency, but, in general, they require state agencies to heed stated environmental goals in their decision-making on major projects. The State of New York's "little NEPA", the State Environmental Quality Review Act (SEQRA), became Article 8 of the New York Environmental Conservation Law in November 1978. New York's SEQRA provides for a series of State and local government agency reviews for all projects that require State government action, government funding, or a government permit unless the actions are exempt, excluded, or predetermined not to have potentially adverse environmental impacts. Any major plant change by Con Edison is likely to require SEQRA review at some point in time.

Local Requirements

Executive Order No. 91 of the City of New York establishes the city Environmental Quality Review procedure authorized under subdivision 3 of Section 8-0113 of Article 8 of the New York State Environmental Conservation Law. The city environmental review is closely patterned after the State SEQRA program. City agencies must ascertain whether or not their permit applicants must file an additional application for environmental review under Executive Order No. 91. If an application for environmental review is required, the city agency determines whether the project must have an EIS. The substantive EIS requirements are similar to those under the SEQRA regulation; the applicant is responsible for the EIS preparation.

Federal-State Coordination of Environmental Review

Although federal, state, and local jurisdiction have existing EIS requirements, three separate reviews are not likely to be required of a major plant change. In the case of a United States Department of Energy (DOE) prohibition order, the DOE is required to prepare an EIS in its role as the "lead federal agency". The lead agency concept is designed to avoid duplication of EIS reviews for actions involving more than one federal agency. An EIS is not required of any other federal agency.

The state and local agencies are also permitted to defer EIS review to the lead agency rather than prepare separate documents. Although the state or local agencies may request that DOE address certain issues in an EIS it is highly unlikely that a separate review will be conducted.

Air Quality Control

Federal Requirements

Legislative attempts to control air pollution have placed primary responsibility for control of major new air pollution sources with the federal government, although implementation and enforcement authority has been delegated to the states. The Clean Air Act (42 U. S. C. Section 7401 et seq.) directs the EPA to establish minimum national standards for air pollutant emissions as well as to establish minimum national requirements for evaluating and permitting acceptable new or modified air pollution sources. Depending on the extent of source modifications contemplated, Con Edison may be subject to the following federal requirements.

National Ambient Air Quality Standards (NAAQS). The 1970 amendments to the Clean Air Act required the EPA to establish NAAQS for air pollutants which were determined to threaten public health or welfare, based on the latest scientific knowledge as written in EPA 'criteria' documents. (Hence, these pollutants are called 'criteria pollutants'.) Two sets of standards were established: primary standards (the levels deemed appropriate for public health protection) and secondary standards (the levels deemed necessary to protect public welfare). The current short-term NAAQS, shown in Exhibit C.1, are generally not to be exceeded more than once per year.

Areas of the country where monitored air quality does not meet any or all of the NAAQS are considered to be non-attainment areas for a pollutant or pollutants which exceed minimum requirements. New sources and major expansions to existing sources with the potential to emit the non-attained pollutant are subject to strict air quality permit requirements. Areas that do meet the NAAQS are called attainment areas. New or modified sources locating in these areas are subject to regulation under the final Prevention of Significant Deterioration (PSD) rules of August 7, 1980 (45 Fed. Reg. 52676).

Prevention of Significant Deterioration. EPA's final PSD regulations apply to new stationary sources with the "potential to emit"[1] or modifications with "net emissions increases"[2] more than specified "de minimus" levels of any regulated pollutant (Exhibit C.2).

Since portions of New York City are designated "unclassifiable" and others "better than national standards" for all regulated pollutants except ozone, major industrial sources with emissions of any attaining pollutants which are above the de minimis levels will be subject to PSD regulation unless otherwise exempted. Briefly, the regulations require that emissions from major new or modified sources:

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[1] "Potential to emit" is defined as "the capability at maximum design capacity to emit a pollutant after the application of all required air pollution control equipment and after taking into account all federally enforceable requirements restricting the type or amount of source operation.

[2] "Net emissions increase" is calculated as the sum of actual emissions from a modification plus any other increases or decreases in actual emissions which are contemporaneous with the modification in question.

Exhibit C.1

U.S. ENVIRONMENTAL PROTECTION AGENCY
NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS)

Pollutant	Averaging Period	Maximum Permissible Concentration ($\mu g/m^3$)
Carbon Monoxide		
(primary and	8-hour	10,000*
secondary)	1-hour	40,000*
Nonmethane Hydrocarbons**		
(primary and	3-hour	
secondary)	(6-9 a.m.)	160*
Lead		
(primary and	Calendar	
secondary)	Quarter	1.5
Nitrogen Dioxide		
(primary and		
secondary)	Annual	100
Particulate Matter		
(primary)	Annual	75
	24-hour	260*
(secondary)	Annual	60
	24-hour	150*
Ozone		
(primary and		
secondary)	1-hour	235
Sulfur Dioxide		
(primary)	Annual	80
	24-hour	365*
(secondary)	3-hour	1,300*

*Short-term standards are not to be exceeded more than once per year.

**The hydrocarbon standard does not have to be met if the oxidant standard is met; it is a guide for implementation plans to achieve the oxidant standard.

Exhibit C.2

U.S. ENVIRONMENTAL PROTECTION AGENCY
PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENTS
(Micrograms per cubic meter)

		Class I	Class II*	Class III
SO_2				
	Annual	2	20	40
	24-Hour**	5	91	182
	3-Hour**	25	512	700
TSP				
	Annual	5	19	37
	24-Hour**	10	37	75

*Con Edison's facilities would be subject to Class II increment levels.

**All 3-hour and 24-hour values may be exceeded once per year.

-- do not exceed the maximum allowable increases (increments) in total suspended particulates (TSP) and SO_2 concentrations over baseline measurements (Exhibit C.2);

-- do not exceed the NAAQS or any other applicable emission or performance standard;

-- are controlled by the best available control technology for each pollutant regulated by the Clean Air Act; and

-- are analyzed to determine their potential effect on ambient air quality, climate and meteorology, terrain, soils and vegetation, and visibility at the site.

The PSD regulations state that the following will not be considered "major modifications" unless previously limited by enforceable permit conditions: (1) a fuel switch due to an order under the Energy Supply and Environmental Coordination Act of 1974 (ESECA)(or any superseding legislation) or due to a natural gas curtailment plan under the Federal Power Act; (2) a voluntary switch to an alternative fuel or raw material that the source (prior to January 6, 1975) was capable of accommodating; (3) a fuel switch due to an order or rule under Section 125 of the Clean Air Act; and (4) a switch to refuse-derived fuel (RDF) generated from municipal solid waste (MSW).

On the basis of the exemptions described above, it appears that a reconversion of previously coal-fired plants will not constitute a major modification and, thus, will be exempt from review under PSD. EPA, however, will determine on a case-by-case basis whether a source will be exempt from the PSD regulations. Furthermore, even if Con Edison plants are exempt from PSD, they may still be required, either by state or local rule, to meet the incremental and ambient air quality standards.

Stationary Source Emissions Control Requirements. In general, the Clean Air Act as amended in 1977 requires continuous, rather than intermittent, pollution control requirements. To this end, several regulations possibly affecting the cost and design of future Con Edison facilities have been proposed and promulgated, including:

-- New Source Performance Standards (NSPS) for Electric Utility Steam Generating Facilities (promulgated: 44 Fed. Reg. 33580-33629, June 11, 1979, 40 C. F. R. Part 60, Subpart Da); and

-- Stack Height Regulations: Good Engineering Practice Limitations (proposed: 44 Fed. Reg. 2608-2614, January 12, 1979).

The NSPS establish specific emission limitations for SO_2, TSP, and nitrogen dioxide (NO_2), depending on the fuel burned. The NSPS would not, however, apply to existing steam generating facilities which were originally designed for the burning of coal and which are required by prohibition order to convert. The stack height regulations limit the credit given for tall stacks to a height determined by "good engineering practice," hence discouraging the use of dispersion techniques for pollution control.

One additional proposal has the potential to affect the costs and design of Con Edison's fuel options; namely, the EPA decision to list radionuclides as hazardous air pollutants under Section 112 of the Clean Air Act (44 Fed. Reg. 76738-76746, December 27, 1979). The EPA has already targetted coal-fired boiler radionuclides as the most serious health hazard among the 38 source categories projected for radionuclide emissions control. The EPA plans to propose National Emission Standards for Hazardous Air Pollutants (NESHAP) requirements to control radionuclide emissions from both existing and new coal combustion facilities.

State Requirements

Article 19 of the New York State ECL, known as the Air Pollution Control Act, contains the statutory core of New York State's air pollution Control regulations. The regulations, codified in 6 NYCRR Section 200.1-257.10, are administered and enforced by the DEC. They contain several sections specific to New York City and to fuel combustion facilities, in addition to general air quality regulations.

Air Quality Standards. New York State's ambient air quality standards are contained in Part 257 of the DEC Rules and Regulations. In general, the standards are comparable to the NAAQS and are to be exceeded no more than once per year. The DEC does, however, distinguish between suspended and settleable particulates, and has additional standards for fluorides, beryllium, and hydrogen sulfide (Exhibit C.3). In addition, the standards for particulate matter may differ according to an area's potential for social and economic development and pollution, using the following classification system.

-- Level I - predominantly used for timber, agricultural crops, dairy farming, or recreation. Sparse habitation and industry.

-- Level II - predominantly single- and two-family residences, small farms, and limited commercial services and industrial development.

-- Level III - densely populated, primarily commercial office buildings, department stores, and light industries in small and medium metropolitan complexes, or suburban areas of limited commercial and industrial development near large metropolitan complexes.

Exhibit C.3

NEW YORK STATE DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging Period	Maximum Permissible Concentration* (ppm)	Maximum Permissible Concentration** (μg/m^3)
Sulfur Dioxide	Annual (99 percent of 3-hour averages)	0.25	650
	3 hour	0.50	1,300
	Annual (99 percent of 24-hour averages)	0.10	260
	24-hour	0.14	365
	Annual	0.03	80
Fluorides (total, dry weight)	Growing Season	40	
	60-day	60	
	30-day	80	
Fluorides (gaseous)	12-hour	4.5 ppb	3.7
	24-hour	3.5 ppb	2.85
	1 week	2.0 ppb	1.65
	1 month	1.0 ppb	0.8
Beryllium	1 month		0.01
Hydrogen Sulfide	1-hour	0.01	14

*In parts per million (ppm), unless otherwise noted.

**In micrograms per cubic meter (μg/m^3), unless otherwise noted. For the purposes of comparison, some concentrations are expressed in both ppm and μg/m^3.

Exhibit C.3 Continued

Pollutant	Averaging Period	Maximum Permissible Concentration* (ppm)	Maximum Permissible Concentration** ($\mu g/m^3$)
Carbon Monoxide	1-hour	35	40,000
	8-hour	9	10,000
Hydrocarbons (nonmethane)	3-hour (6 to 9 a.m.)	0.24	160
Nitrogen Dioxide	Annual	0.05	100
Suspended Particulates (below 10μ in diameter).	24-hour		250
	Annual: Level I		45
	Level II		55
	Level III		65
	Level IV		75
	30-Day: Level I		80
	Level II		100
	Level III		115
	Level IV		135
	60-day: Level I		70
	Level II		85
	Level III		95
	Level IV		115
	90-Day: Level I		65
	Level II		80
	Level III		90
	Level IV		105
Settleable Particulates (Dustfall) (above 10μ in diameter)	Annual (50 percent of 30-day averages):		
	Level I		0.30 $mg/cm^2/mo$
	Level II		0.30 $mg/cm^2/mo$
	Level III		0.40 $mg/cm^2/mo$
	Level IV		0.60 $mg/cm^2/mo$
	Annual (84 percent of 30-day averages):		
	Level I		0.45 $mg/cm^2/mo$
	Level II		0.45 $mg/cm^2/mo$
	Level III		0.60 $mg/cm^2/mo$
	Level IV		0.90 $mg/cm^2/mo$
Photochemical Oxidants	1-hour	0.08	160

-- Level IV - densely populated, primarily commercial office buildings, department stores, and industries in large metropolitan complexes, or areas of heavy industry (6 NYCRR Section 256.1).

Sulfur-in-Fuel Limitations. The regulations specify the following limitations for sulfur content of fuel used in New York City (6 NYCRR Section 225.1):

-- oil: 0.30 (0.20 for distillate oil) percent sulfur by weight; and

-- solid fuel: 0.20 lbs sulfur per million Btu heat input.

Section 225.1(b) states that "no person who changes from the use of fuel oil or gas to coal in his air contaminant source" may purchase coal exceeding the sulfur content specified above. If the source emissions are projected to violate the NAAQS for SO_2 using these limitations, the sulfur content of the coal must be less than or equal to 55% of the maximum oil sulfur content spcified above. However, if the source has a special limitation for higher sulfur fuel oil, the sulfur content of the coal is not to exceed 55% of that sulfur content limitation [6 NYCRR Section 225.5(b)].

Some exemptions are available from the sulfur content limitations, including fuel shortage conditions (Section 225.3), and certain fuel mixtures [Section 225.5(a)]. In addition, the regulations exempt a source from using the mandated sulfur content fuels if the source achieves an equivalent SO_2 emission rate by: using fuel as a process constituent, installing approved control technology equipment, or retaining a significant portion of the sulfur in the ash [6 NYCRR Section 225.5(b)].

Particulate Emission Limitations. Coal-fired facilities with heat input equal to or exceeding 250 million Btu/hour, for which a construction permit application was submitted to the DEC after August 11, 1972, are not to exceed particulate emissions of 0.10 lb. per million Btu (6 NYCRR Section 227.3).

Nitrogen Dioxide Emission Limitations. Only fossil fuel-fired combustion facilities for which a construction permit application was submitted after August 11, 1972, have specific NO_2 emission limitations. The NO_2 emissions limitation for coal combustion facilities is 0.70 lb. per million Btu heat input (6 NYCRR Section 227.5).

Exemptions from Permit Requirements. Part 231 of the New York State DEC regulations contains the permit review requirements for new source construction and existing source modifications in PSD and non-attainment areas. Only those facilities with an existing emission source, which the federal government ordered to convert to coal, are exempted from the permit application review and analysis procedures and control technology requirements [6 NYCRR Section 231.9(c)(2)]. However, since October 1, 1977, coal use has been allowed at an installation with total rated heat input capacity less than or equal to one million Btu/hour located in New York City or Nassau, Rockland, Suffolk, or Westchester Counties only if the installation has used coal as its regular fuel continuously since December 31, 1967, and the maximum sulfur content of the coal used does not exceed 0.755 per cent by weight at an installation with total rated input capacity greater than or equal to one million Btu/hour. Coal can be used only if coal has been used continuously since December 31, 1967, and the use of such coal is in compliance with a federally approved implementation plan (6 NYCRR Section 225.5(d)).

Local Regulations

Chapter 57, Part II of the Administrative Code of the City of New York establishes the core requirements of the Air Pollution Control Code. The key sections of the Code likely to apply to Con Edison are highlighted below.

Permit Requirements. Several requirements of the City Code are likely to apply to Con Edison's potential coal conversions. First, the New York City DEP requires existing facilities with plans to install or alter equipment or apparatus to apply for a city permit, with the exception of fuel burning installations with heat input less than 350,000 Btu per hour (Section 1403.2 to 5.01). Second, owners of fuel-burning equipment using solid fuel must apply for and receive a city certificate of operation before commencing operations [Section 1403.2 to 5.50(b)(4)]. However, Article 13.03(d) of the New York City Code stipulates that after October 1, 1971, solid fuel containing up to 0.7% sulfur may be burned, at the discretion of the Administrator, provided that there is no extension or increase of use and that a report is submitted setting forth a detailed program for the termination of the use of such fuel. In addition to the standard regulations in the City Code, the DEP issues technical specification regulations requiring certain source categories to comply with the city engineering performance standards.

Emission Standards. The New York City DEP establishes SO_2 and nitrogen oxide (NO_2) emission rates for boilers with a capacity greater than or equal to 500 million Btu per hour, based on when the boiler construction was completed. Most of Con Edison's units were completed before the local law was in effect; hence, the larger emission rate would apply. The rates are based on the volume of undiluted emissions [expressed in parts per million (ppm)] measured at 10% excess air, as follows:

	Sulfur Compounds	Nitrogen Compounds
Before the local law was enacted	200 ppm	150 ppm
After the local law was enacted	100 ppm	100 ppm

Allowable particulate matter emissions vary depending on the actual rate, but are determined by the formula:

$$\text{Allowable Emissions (lb/hr)} = 0.6575\ P^{0.7841}$$

where P is the heat input in Btu/hr.

Section 13.03 of the Code establishes sulfur-in-fuel restrictions for alternative combustion fuels. According to this section, solid fuel up to 0.7% sulfur content by weight may be burned in the City, at the discretion of the DEP Administrator. However, as discussed above, Article 13.03(d) effectively bans the use of coal in New York City.

Memoranda of Understanding. Con Edison has had a history of interaction with both the Mayor's office and the DEP on air pollution matters. In 1966, Con Edison and the Mayor's office agreed in a memorandum of understanding (MOU) that "to the fullest possible extent, power from coal and oil-fired plants should be generated outside city limits and brought into New York City by transmission lines." Con Edison's 1969 proposed addition to Astoria's capacity allegedly violated this agreement, leading the Mayors office to condition its approval of the unit on Con Edison's signing a new MOU, dated August 22, 1970. In the new MOU, Con Edison agreed that:

(1) It would not build any additional fossil-fuel plants in the City;

(2) It would make every reasonable effort to obtain natural gas for use in the new unit and other generating units;

(3) If required of persons burning fuel oil in the City, or when natural gas is unavailable, it would burn low sulfur fuel in its entire system;

(4) It would add stack gas proceses and other emission controls to the new unit to reduce noxious emissions to levels consistent with emission standards established by the City;

(5) It would close down at least 1,100 MW of old units in the City by 1974;

(6) It would develop additional, jointly-owned power plants outside the City and enter into additional contracts for purchase of power from outside sources;

(7) It would spend $4 million for, and devote a site for use in, a joint project to develop a process for removal of noxious emissions resulting from combustion of fossil fuels; and

(8) It would develop long-range plans for power supply for a period of 20 to 25 years and develop a mechanism for joint planning and review with the City.

The City, in return, agreed to support Federal Power Commission Approval of Con Edison's planned 2000 MW pumped storage hydroelectric plant at Storm King Mountain near Cornwall, New York. The City further agreed to support additional natural gas allocations for Con Edison's facilities.

Water Quality and Use

Federal Requirements

The principal federal statutory authority to protect water quality is in the Safe Drinking Water Act (42 U. S. C. Section 201 _et seq_.) and the Federal Water Pollution Control Act as amended in 1977 (33 U. S. C. Section 1251 _et seq_.), commonly referred to as the Clean Water Act.

The Safe Drinking Water Act requires the EPA to establish primary and secondary standards for specific contaminant concentrations in public waters, or to require specific treatment technologies to protect public health and welfare. The EPA has promulgated primary drinking water regulations, to be enforced by the states, which establish limitations for selected microbiological contaminants, inorganic chemicals, organic pesticides, turbidity, and radiation. Since runoff or leachate from coal storage piles and coal combustion waste disposal sites may contain inorganic chemicals regulated by the EPA, Con Edison may be required to install additional contaminant control technologies.

The Clean Water Act establishes a national goal to protect and improve the quality of the nation's waters. In general, this goal is to be achieved by prohibiting the discharge of pollutants to public waters without a permit, and by imposing stringent technological controls on these discharges. Two key program elements will be of interest to Con Edison.

Effluent Standards. The EPA has developed pretreatment standards for new and existing indirect dischargers, as well as several technology-based standards for existing direct dischargers. The latter are more important for Con Edison's purposes, and include Best Practicable Control Technology Currently Available (BPT), Best Available Technology Economically Achievable (BAT), and Best Conventional Technology (BCT). BPT, the average of the best performances by existing plants with common characteristics, should have been achieved by July 1, 1977. BAT and BCT are to be achieved by July 1, 1984, and, in the case of BAT, will represent a much more stringent level of control. BAT is for nonconventional and toxic pollutant discharges, including thermal pollution as well as 65 "priority" pollutants listed in the Act. BAT represents the best economically achievable performance by similar plants, even if not common industry practice. BCT must be met for conventional water quality criteria such as biological oxygen demand, total suspended solids, fecal coliform, pH, oil, grease, and any other guidelines listed by the EPA.

National Pollutant Discharge Elimination System (NPDES). The NPDES permit system requires source owners or operators to disclose the volume and nature of their effluent, to demonstrate capability to meet EPA or State effluent limitations, to establish a compliance schedule, and to monitor and report compliance with the permit requirements. The EPA administers the permit program unless a state has an EPA-approved program, as is the case with New York. Depending on the characteristics of the plant, the administering authority may prescribe additional pollutant controls, including Best Management Practice (BMP), to control spills and runoff from the plant site. In general, the NPDES permit is issued for five years and is renewable. New York's EPA-approved permit program is discussed below.

State Requirements

Article 17 of the New York State ECL contains New York's primary statutory authority over water pollution control. The law itself contains the State Pollutant Discharge Elimination System (SPDES) program authority (ECL Section 17-0801 to 17-0829) and explicitly states that a facility may not increase or alter the content of wastes discharged into State waters by a change in volume or physical, chemical, and biological characteristics without a new SPDES permit (Section 15-0507). Although Con Edison does not anticipate developing new generating facilities during the 1980's, it should be noted that Section 17-0701 of the law requires that new steam electric generating facilities and facilities which increase their generating capacity be granted a permit to ensure that outlet, point source, and disposal systems meet Public Health and Environmental Conservation Laws' standards.

New York's water pollution control regulations are administered by the DEC Division of Water Resources. The Water Classification and Quality Standards (Parts 700-704), authorized by Section 17-0303 of the ECL, specify water quality standards for each class of New York City waters (classification is in 6 NYCRR Section 890.5). Part 703 establishes classifications and standards for ground-water. Part 704 deals specifically with thermal discharges and establishes both general operating criteria governing thermal discharges and special criteria specifying allowable temperature increases in various state waters, with limited exemptions (6 NYCRR Section 704.6).

The SPDES program regulations are contained in Parts 750-757 of the state regulations. In general, an SPDES permit is required for new point source discharges, alterations in the volume discharges, and thermal discharges. Depending on SPDES permit conditions for the existing generating unit, the actual engineering changes or replacement of the boiler, and the pollution control equipment added to the unit (e.g., flue gas desulfurization equipment), Con Edison will likely need to renegotiate their SPDES permit. Although the state has administrative and enforcement authority, the discharges must conform to federal law.

New York's ECL contains several additional articles which supplement Article 17's water pollution control mandate. Article 15 of the law, the Water Resources Law, deals with improvements to or developments of State waters. Title 5 of this article requires that permits be obtained for stream bed disturbances, construction of dams and docks, and proposed dredging or filling of navigable waters. Depending on the mode of transportation chosen for Con Edison's fuel choice (i.e., barge), these permits could be required.

Other articles relating to water include Article 37 (Substances Hazardous to the Environment), Article 24 (Freshwater Wetlands Act), and Article 25 (Tidal Wetlands Act). None of these contain provisions of direct concern to Con Edison at this time, although they may be of interest once the final fuel decision is made.

Local Requirements

Although New York City does have rules relating to water quality control and water supply, there are no obvious limitations on fuel options. Regulatory authority is scattered among several New York City departments, but the Bureau of Water Supply has key responsibility for water quality, with both the DEP and the Health Services Administration contributing to existing Bureau of Water Supply regulations. In general, these regulations are highly specific hardware requirements that would not be of concern to Con Edison.

Solid Waste Disposal

Federal Requirements

The Resource Conservation and Recovery Act (RCRA)(42 U.S.C. Section 6901 et seq.), enacted on October 21, 1976, provides the principal federal statutory authority for the control of solid waste. RCRA completely changed solid waste law and laid the foundation for a national hazardous waste management program. RCRA requires the EPA to prepare guidelines for state solid waste management plans, but the core of the new law is the comprehensive federal regulations for the classification, handling, and disposal of hazardous wastes. Six months after final regulations are adopted, anyone generating, handling, or disposing more than some small amount of hazardous waste per month becomes subject to recordkeeping, operating, and performance standards.

The EPA's original definition of hazardous wastes raised fears that utility waste (fly ash, bottom ash, and scrubber sludge) could be subject to the hazardous waste regulations. Therefore, EPA proposed to consider such high volume, relatively low risk wastes as "special wastes". Special waste disposal facilities would be required only to meet general facility standards, and be exempted from storage, treatment, and disposal standards, until such time as they are determined to be hazardous (43 Fed. Reg. 58991-58992, December 18, 1978).

While the EPA was completing the final version of the regulations for hazardous waste control, Congress was considering amendments to RCRA including an amendment to exempt utility wastes from the EPA's regulations, pending a study on the actual degree of hazard posed by these wastes. The EPA issued its regulations in May 1980 and, in anticipation of passage of the amendment, exempted utility wastes from its jurisdiction under RCRA. At this writing, the amendment is still in conference committee.

In any case, coal-fired power plants are likely to face increased disposal costs in the near- to mid-term and could be required to upgrade existing disposal facilities substantially, depending on the results of the studies. If Con Edison installs scrubbers to control air pollution from coal, dramatically increasing the volume of solid waste generated, additional solid waste control will undoubtedly place some financial and administrative burdens on Con Edison.

State Requirements

Article 27 of the ECL regulates refuse and solid waste management. In 1978 the New York State Legislature amended Article 27 to add the Industrial Hazardous Waste Management Act. In the months following, the Legislature added hazardous and solid waste amendments to New York's Public Health and Public Authorities Laws in attempts to "close the holes" in New York State solid waste law.

Regulations for solid waste management facilities are administered by the DEC and are codified at 6 NYCRR Section 360.1-360.8. Very specific requirements are established for both hazardous and non-hazardous waste facilities; however, these are likely to change to conform to the new requirements. New York has not yet issued final regulations to implement the industrial Hazardous Waste Management Act.

Local Requirements

New York City regulations apply primarily to sewage control, and would have no direct effect on Con Edison. However, any increase in the volume of solid waste or any changes to the characteristics of the waste could be evaluated by DEP officials under the city environmental impact assessment process if there is a requirement for discretionary government action.

Noise Control

Federal Requirements

The Noise Pollution and Abatement Act of 1970 (42 U.S.C. Section 1857 et seq.), the 1972 Noise Act (42 U.S.C. Section 4901 et seq.), and the 1978 Quiet Communities Act (P.L. 95-609) have steadily increased EPA's authority over noise emissions from certain product categories. Local and state authorities retain extensive control over noise emissions from fixed facilities.

The principal effect of federal noise control regulations would be on fuel and byproduct transportation. This will principally affect the coal conversion option because of coal and ash transportation. Sections 17 and 18 of the Act regulate noise emissions from railroad and motor carriers "engaged in interstate commerce" which may not be preempted by state or local authorities. The Quiet Communities Act of 1978 extended the Noise Control Act for one year and provided funds for state and local governments to institute noise control programs.

State Requirements

Although the ECL contains no specific noise control requirements, it contains two sections authorizing the state to establish noise control requirements. Section 3-0301(1)(i) authorizes the DEC Commissioner to control noise, and 27-0503(1) authorizes DEC adoption of noise limitations for solid waste management facilities.

Parts 450-454 of the codified regulations implement noise control requirements of both the ECL and the New York Vehicle and Traffic Law. These laws deal exclusively with motor vehicles and, as such, would be of concern only to Con Edison's transportation requirements. However, the solid waste management facility noise regulations establish property-line noise limits based on the character of the community (rural, suburban, urban) and the time of day (7 a.m. to 10 p.m., 10 p.m. to 7 a.m.) [6 NYCRR Section 360.8(a)(11)]. A "solid waste management facility" is defined as any activity beyond initial solid waste collection, and includes such facilities as rail haul or barge haul facilities, land burial facilities, industrial waste processing or disposal facilities, and any storage areas. Therefore, Con Edison will be subject to these requirements in disposing of its solid wastes [6 NYCRR Section 360.1(c)(29)].

Part 75 of the regulatory requirements to implement the Public Service Law contains requirements to assess the noise impact of new power plants and related facilities (16 NYCRR Section 75.1-75.4). Changes to existing fuel combustion facilities would not be subject to these laws, although any new construction, such as new transmission lines, is likely to be affected by these regulations.

Local Requirements

New York City's Bureau of Noise Abatement in the DEP is responsible for implementing and enforcing rules under Local Law No. 57, the Noise Control Code, which contains the bulk of the regulatory requirements for noise control. The majority of the regulations relate to noise from construction equipment and motor vehicles. However, a recent addition to the Noise Control Code, Local Law No. 64, established ambient noise quality zones with standards as follows:

Ambient Noise Quality Zone	New York City Ambient Noise Standards (L_{eq} measured in any one hour) Day (7 a.m. - 10 p.m.)	(Night 10 p.m. - 7 a.m.)
N-1 (low density residential)	60 dB(A)	50 dB(A)
N-2 (high density residential)	65 dB(A)	55 dB(A)
N-3 (commercial and manufacturing zones)	70 dB(A)	70 dB(A)

These noise levels, to be measured at the property line of the affected site, are to be the basis for the DEP to establish allowable noise levels for specific sources and activities. Given the close proximity of some Con Edison installations to residential areas, the source-specific levels to be established under Section 1403.3-1406.03 of the Administrative Code may affect Con Edison's operations. In addition, new cogeneration units, if diesel-powered, must conform to these noise standards.

Land Use

Virtually every environmental law affecting Con Edison's options carries with it some aspect of land use control. For example, it is widely held that the PSD provisions of the Clean Air Act are effectively land use controls limiting industrial activities at sites where potential air pollution emissions would degrade air quality. Similarly, solid waste landfill sites are restricted to areas with suitable groundwater and soil characteristics. Hence, the Clean Air Act, RCRA, and other laws while intended primarily for single purpose regulation, affect the uses of land in many indirect ways. In addition, there are several laws which explicitly identify land use controls as the primary means of protecting or enhancing environmental quality. Due to the nature of land use legislation, the following sections will divide land use discussion into federal, state, and local requirements.

Coastal Zone Management

The federal Coastal Zone Management Act of 1972 (16 U.S.C. Section 1451 et seq.) delegated to state governments the central role and responsibility for protecting the "national interest in the effective management, beneficial use, protection, and development of the coastal zone." The Act states that the "key to more effective protection and use of the land and other resources of the coastal zone is to encourage the states to exercise their full authority over the lands and waters in the coastal zone by assisting the states...in developing land and water use programs ...including unified policies, criteria, standards, methods, and processes for dealing with land and water use decisions..."

New York State has developed a draft Coastal Zone Management (CZM) plan designed to qualify the State for financial assistance to implement the plan, pending approval by the Office of Coastal Zone Management in the National Oceanic and Atmospheric Administration. The draft plan contains a state coastal boundary, coastal policies and their means of implementation, and program organization and management. The plan describes Geographic Areas of Particular Concern (GAPC) in the State and includes several GAPC management plans. The federal Office of Coastal Zone Management requires two additional elements in New York's proposed draft plan: to identify and regulate development in critical erosion areas; and to give priority to locating water-dependent uses in urban areas. All State agencies are to conform to the policies of the CZM plan, which will be overseen by the Coastal Management Board in the New York Department of State. Coastal cities and towns are also encouraged to prepare local coastal zone management plans to assist in implementing the state program.

In 1978 the New York City Department of City Planning published the New York City Regional Element of the New York State CZM Plant. The City then prepared the New York CZM Program in an effort to further strengthen the City's Regional Element of the State plan. The City CZM plan identifies the critical problems of the New York City waterfront, develops management plans for six GAPC's, and outlines recommendations regarding Critical Access Areas and Erosion/Flooding Hazard Areas. All city agencies are directed to carry out their respective functions, including environmental permitting, in conformance with the management policies put forth in the City CZM plan.

New York State Public Service Law

Among its many provisions, the Public Service Law requires utilities to obtain a certificate of environmental compatibility and public need from the Public Service Commission before constructing certain transmission lines. Sections 120-130 require such a certificate to construct or modify a line of 125 kilovolts (KV) or more extending a mile or more, or a line of 100 KV extending more than ten miles. The certificate application must include a description of environmental studies conducted, the possible alternatives, and the justification for the facility. After certain prescribed notices and hearings, the Public Service Commission may generally grant, deny, condition , or modify the proposal. Its final decision will be based on such considerations as the need for the facility, the environmental impacts versus the economy and reliability of the system, and compliance with local and State laws (except where local restrictions are in conflict with economic factors and the needs of the greater public).

Appendix D

SULFUR DIOXIDE CONTROL TECHNOLOGY OPTIONS

Over the next 15 years there will be several technical options available for control of sulfur dioxide (SO_2) in coal-fired utility boilers. In general the available control methods are: (1) removing the sulfur from coal prior to combustion; (2) relying on ash to retain the sulfur removed from coal during combustion; or (3) removing SO_2 from the flue gas after combustion. The first option may be accomplished by physical coal cleaning, chemical coal cleaning, or solvent refining of coal. The second option, sulfur retention in the ash, cannot be relied on for continuous SO_2 control and has consequently been omitted from this evaluation. The last option requires flue gas desulfurization (FGD). These control options may be used singly or used in combination.

Removing Sulfur Prior to Combustion

The inorganic sulfur in coal, such as pyrite, is present as discrete particles and is thus amenable to physical cleaning. About 40% to 60% of the total sulfur in Appalachian coals is in the form of pyrite, as is about 35% of the sulfur in Western coals. Sulfur in the organic form is chemically bound in the coal. Consequently, more complex and costly chemical cleaning processes are required to remove organic sulfur.

Physical coal cleaning techniques are based on differences in the physical properties of coal and coal 'refuse' such as iron pyrite, gypsum, carbonaceous shale, etc. The most common physical property used is density. The specific gravity of coal is lower than the specific gravities of the refuse materials; thus separation can be achieved through equipment such as hydraulic jigs, laundering tables, cyclones, dense medium vessels, or air classifiers. In wet processes, ground coal is suspended in a fluid, the refuse materials fall to the bottom of the separation unit, and the clean coal is removed from the top. Other techniques include magnetic separation, oil agglomeration, and electrophoretic and electrostatic separation.

The reduction in sulfur that can be achieved through physical coal cleaning varies with the physical characteristics of the coal and with the degree to which the coal is crushed prior to cleaning. Typically, 35% to 50% of the inorganic sulfur, pyrite, can be removed, although only about 10% of the pyrite can be removed from 1% sulfur coal. The mining industry has used physical coal cleaning methods for years, and the processes are reliable. Certain environmental problems exist, however, including disposal of the separated refuse material and contaminated water. Furthermore, the limitation in sulfur reduction imposed by the organic sulfur content of coal makes physical coal cleaning alone sometimes unable to meet current emission standards.

Chemical coal cleaning processes have an advantage over physical methods in that almost all the inorganic sulfur can be removed as well as some of the organic sulfur. A number of different chemical processes have been tested and many more are in developmental stages. The high costs of these processes and the various technical problems that have been encountered do not make this an attractive commercial option at present. None of the processes described below have yet been commercialized. However, these processes may eventually prove cost-effective, especially in light of alternative control costs.

The most highly developed chemical coal cleaning process is the Meyers/TRW process. This process leaches crushed coal with ferric sulfate [fe_2 $(SO_2)_3$] to convert the pyrite to sulfuric acid, ferrous sulfate, and elemental sulfur. However, removal of organic sulfur has not been proven with this process. The waste products of the process--sulfuric acid, ferrous sulfate, and physical cleaning refuse--must be disposed of properly with pH adjustment.

The Battelle hydrothermal chemical coal cleaning process leaches coal with sodium and calcium hydroxide solutions at elevated temperatures and pressures. This process removes up to 99% of the inorganic sulfur and has demonstrated 24% to 72% organic sulfur removal [1]. The capital costs of the system are very high due to the elevated temperature and pressure requirements and the need for leachant regeneration. Hydrogen sulfide (H_2S) is produced in this process and measures must be taken to prevent H_2S leakage both for process and safety reasons.

One totally dry chemical coal cleaning process under development is the Hazen process. In this process, inorganic sulfur is removed from finely ground coal through reaction with gaseous iron pentacarbonyl and magnetic separation. Iron pentacarbonyl, which enhances magnetic susceptibility, is a highly toxic substance and careful monitoring is required. The available magnetic separators can only handle a very finely ground coal which further limits the process for commercialization.

Another chemical cleaning process under development is the production of solvent refined coal (SRC). In this process, pulverized coal is dissolved in a solvent solution; mineral matter (ash), pyrite, and organic sulfur are then removed. The coal is reconstituted by separtating it from the liquid solvents

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[1] Reference number 100.

and allowing it to cool and solidify. The purified solid coal can be burned in a modified pulverized-coal boiler. This process also has not yet been capable of commercialization. The SRC process was developed and patented by two German scientists in 1932. Further developmental work was begun in the U. S. in the 1960's and two pilot plants are now operational in the U. S.--one producing 50 tons per day (tpd) of liquid or solid product SRC and the other 6 tpd of solid product SRC.

The last chemical coal cleaning process which will be discussed here is the KVB process. The KVB process oxidizes the sulfur components of dry, pulverized coal with nitrogen dioxide (NO_2). The sulfur compounds formed during oxidation are then removed through caustic leaching and mixed with lime to regenerate caustic and precipitate gypsum ($CaSO_4$) and iron oxides. A problem with the system is the uptake of nitrogen by the coal, though no information is yet available on the NO_x emissions increase.

Other chemical cleaning processes use more exotic techniques, such as General Electric's (GE) microwave radiation/gasification process and Dynatech's microbial action process.

Removing SO_2 from Flue Gas After Combustion

A large number of chemical process systems exist for removing sulfur compounds from combustion flue gases. These flue gas desulfurization systems (FGD) can be classified as regenerable or non-regenerable processes, and then further divided into wet, dry, or semi-dry processes. Each system has its own set of advantages and disadvantages.

Flue gas desulfurization (FGD) is based on the chemical processes of absorption and adsorption. Absorption processes are seen in liquid or so called "wet" scrubbers and the major driving force is the concentration gradient at the liquid/gas interfaces. Adsorption processes, based on the ability of certain solids to attract gaseous components, are used in dry scrubbers. Wet and "dry" scrubbers can employ either regenerable or non-regenerable processes depending on the materials involved and disposition of by-products.

Regenerable FGD processes remove sulfur dioxide from flue gas and convert it to a marketable product such as sulfuric acid, elemental sulfur, or liquid sulfur dioxide. The production of solid wastes is thus greatly minimized, as is the need for sorbent makeup. The complexity and high energy requirements of these processes, however, may make them more expensive than non-regenerable FGD processes. Currently only two regenerable processes, both wet, are used commercially in the U. S.-- the

Wellman-Lord and the magnesia slurry processes. However, several others are in the developmental or demonstration stages.

Non-regenerable or throwaway processes using lime or limestone in an aqueous slurry (wet scrubbers) have provided the majority of operational experience in the U. S. to date. Lime (CaO) or limestone ($CaCO_3$) in a wet slurry reacts with SO_2 in the flue gas to produce calcium sulfite and calcium sulfate precipitates. Sodium carbonate and dual alkali systems are two other wet, non-regenerable commercial FGD processes currently available from several suppliers.

Wet scrubbing processes can remove both fly ash and sulfur dioxide simultaneously from a gas stream. In practice, however, there may be good reasons for collecting fly ash separately, generally by means of electrostatic precipitators or fabric filters (baghouse). Possible interference with the process reactions is avoided by removing the fly ash upstream of the desulfurizing unit, and erosion of the desulfurization process equipment is reduced. The volume of sludge is also minimized when the fly ash is removed prior to the desulfurization process. In addition, contamination of the reagents and by-products is prevented.

All wet FGD processes cause a considerable cooling of the treated flue gas and an increase in its moisture content. Reheat of the gas prior to discharge may be desirable in certain applications to reduce condensation and corrosion in ducts, fans, and the stack downstream of the scrubber, and to restore the buoyancy of the flue gas entering the stack. Reduction of a visible stack plume (due to condensation) may be an added incentive to reheat the gas. These drawbacks are largely minimized in semi-dry and dry processes. Further, the disposal of solid wastes generated in semi-dry and dry throwaway processes may be easier than the disposal of sludges and liquid wastes.

Dry FGD systems, based on the adsorption principle, have been studied for a number of years. Only non-regenerable dry FGD systems have been used commercially in the U. S., however. The solid reactants involved have been lime, sodium carbonate, or sodium bicarbonate. Regenerable dry processes have not yet been shown to be economically attractive. Carbon adsorption has been tested in Japan, Germany, and the U. S. Copper oxide and catalytic oxidation FGD systems have also been tested in pilot plants.

Three major end products can be produced from flue gas scrubbing: gypsum, sulfur, and sulfuric acid. Attempts are being made to develop other products from sulfur sludge such as fertilizer and building materials [2].

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[2] Reference number 100.

Exhibit D.1 summarizes FGD processes for operational units, those under construction and those planned. As can be seen, lime- and limestone-based processes constitute the majority of present and future FGD systems. The growing utility interest in semi-dry systems is indicated in this Exhibit.

Lime/Limestone Processes

Lime and limestone scrubbing systems are similar in that both use a slurry of suspended alkali as the SO_2 absorption medium. The basic difference is that the lime process employs a lime-slaking process to produce a lime slurry, while the limestone process uses finely ground limestone in the slurry. The SO_2 in the flue gas reacts with the lime (CaO) or limestone ($CaCO_3$) and produces calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$). The solids are continuously separated from the slurry and discharged. The remaining liquor is recycled to the scrubber after fresh limestone or lime has been added. (See Exhibits D.4 and D.5.)

Major process equipment includes the scrubber in which SO_2 is absorbed by the lime or limestone slurry, a mist eliminator for removal of entrained liquid from the clean flue gas, a holding tank where makeup lime/limestone is added and solid product precipitation occur, and a solids separator. Partial reheating of the clean flue gas is usually required to have the necessary buoyancy to exit the stack at the required velocity. A waste sludge handling area is also required. Precollection of particulates is not necessary with these systems but is often desireable to minimize corrosion and scale formation. This has a tendency to reduce availability of the FGD system.

Lime and limestone systems make up the largest portion (greater than 80%) of the current FGD capacity in the U. S. [3]. While early lime or limestone scrubbers experienced several operational problems, the reliability and operability of the newer systems is improving.

Exhibits D.2 and D.3 respectively, show the major (greater than 100 MW) domestic limestone and lime FGD systems currently in operation [4]. Design SO_2 removal efficiencies exceed 90% for several of these installations. The simplicity of these systems makes their operability and reliability quite good, though there are still some problems with scaling, plugging, erosion, and corrosion. Relatively high liquid-to-gas ratios are needed with these systems, with substantial gas pressure drops.

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[3] Reference number 44.

[4] Reference number 101.

EXHIBIT D.1

SUMMARY OF FGD SYSTEMS BY PROCESS

Process	Operational		Under Construction		Planned		Total	
	No.	MW	No.	MW	No.	MW	No.	MW
Limestone	26	10,194	20	8,883	22	12,124	68	31,201
Lime	26	8,260	13	6,593	8	3,271	47	18,124
Sodium Carbonate	4	925	0	0	1	250	5	1,175
Dual Alkali	3	1,181	0	0	2	842	5	2,023
Wellman-Lord	4	1,360	2	714	0	0	6	2,074
Magnesium Oxide	1	120	2	574	2	750	5	1,114
Citrate	1	60	0	0	0	0	1	60
Spray Drying	0	0	3	1,150	5	1,677	8	2,827

SOURCE: Electric Utility Steam Generating Units. Background Information for Proposed SO_2 Standards. Environmental Protection Agency, EPA-450/2-78-007a, Washington, D.C., July 1978.

Exhibit D.2

SELECTED U.S. FGD INSTALLATIONS - LIMESTONE SLURRY

Station	Company	Capacity (Mw)	Start-Up Date	New or Retrofit	Sulfur (%)	Design SO_2 Removal Efficiency (%)
Cholla 1	Arizona Public Service	115	10/73	R	0.5	92
Cholla 2	Arizona Public Service	250	4/78	N	0.5	75
Coronado 1	Salt River Project	350	11/79	N	1.0	82.5
Craig 2	Colorado Ute. Electric	400	8/79	N	0.4	85
Duck Creek 1	Central Illinois Light	378	7/76	N	3.3	85
Jeffery 1	Kansas City Power & Light	680	8/78	N	0.3	80
LaCygne 1	Kansas City Power & Light	820	2/73	N	5.0	80
Lawrence 4	Kansas City Power & Light	125	1/76	R	0.5	73
Lawrence 5	Kansas City Power & Light	400	11/71	R	0.5	52
Martin Lake 1	Texas Utilities	750	4/77	N	1.0	70.5
Martin Lake 2	Texas Utilities	750	5/78	N	1.0	70.5
Marion 4	S. Illinois Power Coop.	160	5/79	N	3.5	89.4
Monticello 3	Texas Utilities	750	5/78	N	1.5	74.0
Petersburg 3	Indiana Power & Light	515	12/77	N	3.2	85
R.D. Morrow	S. Mississippi Electric	180	8/78	N	1.3	85
Sherburne 1	Northern States Power	710	3/76	N	0.8	50
Sherburne 2	Northern States Power	700	4/77	N	0.8	50
Southwest 1	Springfield City	173	4/77	N	3.5	80
Widows Creek 3	TVA	516	5/77	R	3.7	80
Winyah 2	S.C. Public Service	258	7/77	N	1.7	69

SOURCE: EPA Utility FGD Survey: January-March 1980, United States Environmental Protection Agency, EPA-600/7-80-029b, May 1980.

Exhibit D.3

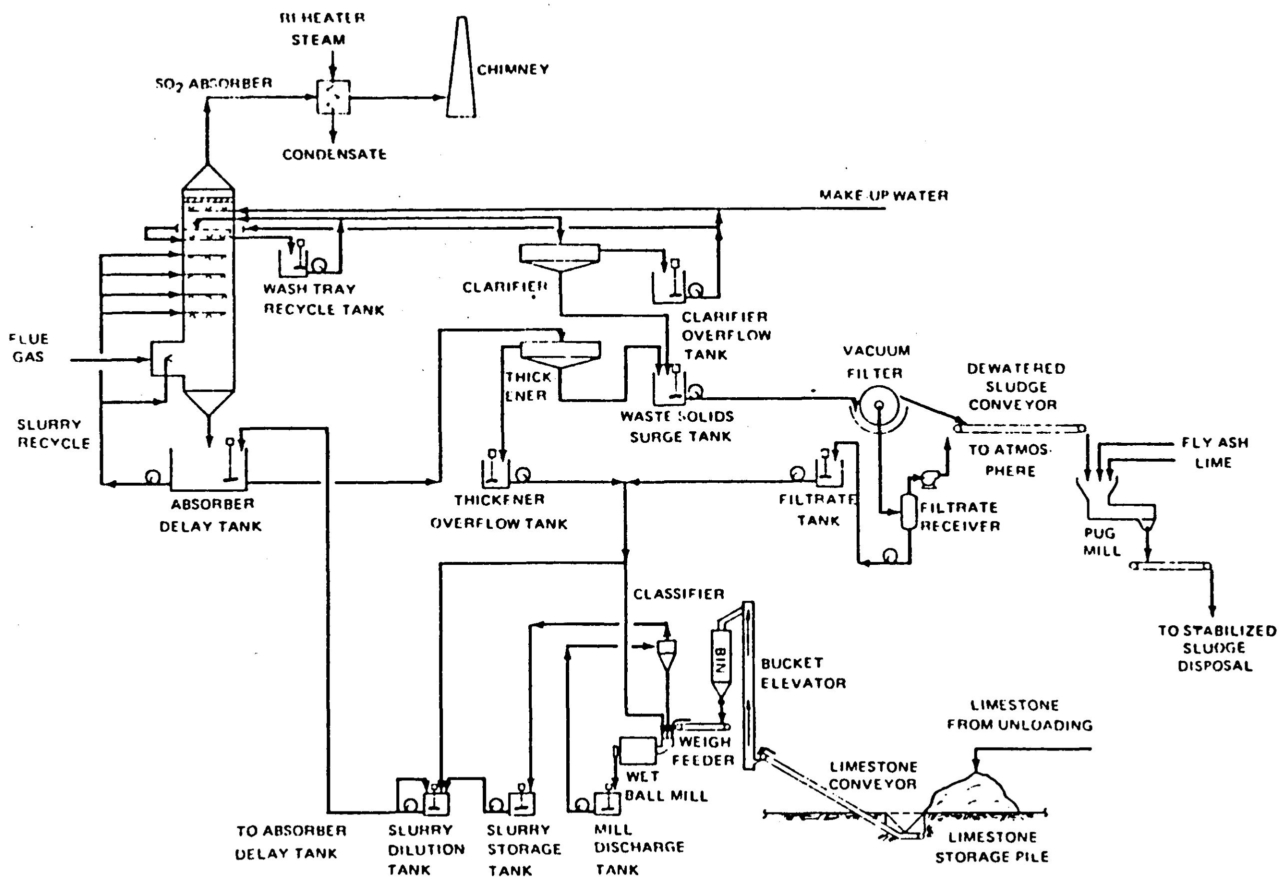
SELECTED U.S. FGD INSTALLATIONS - LIME SLURRY

Station	Company	Capacity (Mw)	Start-Up Date	New or Retrofit	Sulfur (%)	Design SO_2 Removal Efficiency (%)
Bruce Mansfield 1	Penn. Power Co.	825	6/76	N	3.0	92
Bruce Mansfield 2	Penn. Power Co.	825	7/77	N	3.0	92
Cane Run 4	Louisville Gas & Electric	175	8/76	R	3.5-4	85
Cane Run 5	Louisville Gas & Electric	192	12/77	R	3.5-4	85
Coal Creek 1	Coop. Power Ass.	495	8/79	N	0.6	90
Colstrip 1	Montana Power Co.	332	9/75	N	0.8	60
Colstrip 2	Montana Power Co.	332	5/76	N	0.8	60
Conesville 5	Columbus & Southern Ohio	375	1/77	N	4.5-4.9	89.5
Conesville 6	Columbus & Southern Ohio	375	6/78	N	4.5-4.9	89.5
Elmara	Duquesne Light Co.	475	10/75	R	2.2	83
Green 1	Big River Electric	200	12/75	N	3.8	90
Hunker 1	Utah Power & Light	400	5/79	N	0.5	80
Huntington 1	Utah Power & Light	400	5/78	N	0.5	80
Mill Creek 3	Louisville Gas & Electric	420	8/78	N	3.5-4.0	85
M.R. Young 2	Minnekota Power Cooperative	402	9/77	N	0.7	85
Phillips	Duquesne Light Co.	373	7/73	R	2.0	83

SOURCE: EPA Utility FGD Survey: January-March 1980, United States Environmental Protection Agency, EPA-600/7-80-029b, May 1980.

EXHIBIT D.4

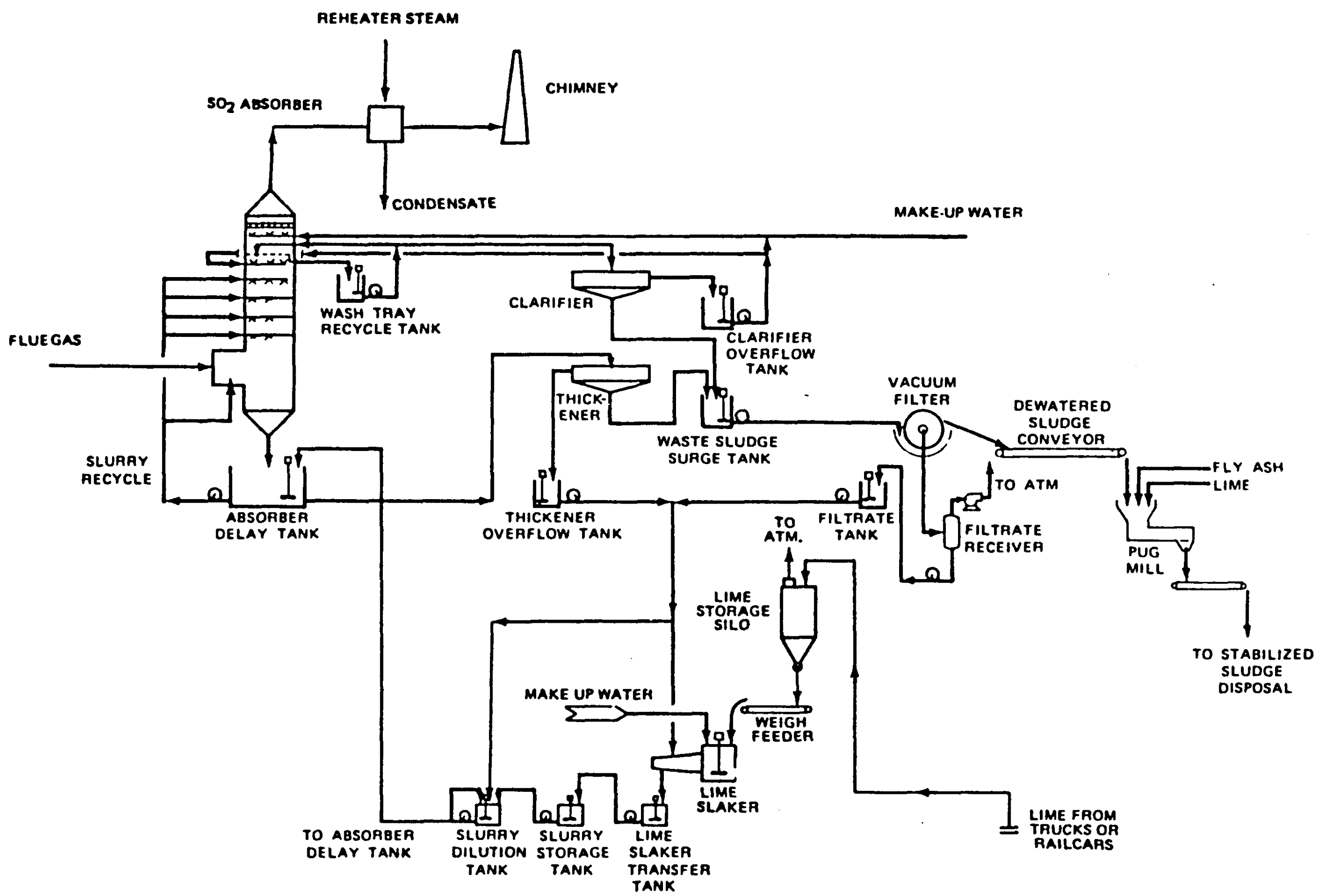
FLOW DIAGRAM OF A LIMESTONE SLURRY FGD SYSTEM



SOURCE: Economic and Design Factors for Flue Gas Desulfurization Technology, Electric Power Research Institute (EPRI), EPRI CS-1428, April 1980.

EXHIBIT D.5

FLOW DIAGRAM OF A LIME SLURRY FGD SYSTEM



SOURCE: Economic and Design Factors for Flue Gas Desulfurization Technology, Electric Power Research Institute (EPRI), EPRI CS-1428, April 1980.

Sodium Carbonate Process

The sodium carbonate process scrubs SO_2 from the flue gas with a clear water solution of sodium carbonate (Na_2Co_3) to form sodium sulfite/bisulfite ($Na_2SO_3/NaHSO_3$). The spent alkali solution, sodium sulfate ($Na_2SO_3/NaHSO_3$), must be purged to maintain a chemical balance in the system. The purge stream must be neutralized with more soda alkali before disposal. Process water and fresh soda makeup are required. Major process equipment includes the scrubber, a soda liquor storage tank, and a waste liquor surge tank.

Three 125 MW coal-fired boilers at Nevada Power Company's Reid Gardner Station are operating sodium carbonate scrubbers. Low sulfur coal (0.5%) is burned at each. Two of the units were retrofitted with the scrubbers in 1974, and the third was a new unit which went on-line in 1976. Design SO_2 removal efficiencies were 85% for the three scrubbers, while actual SO_2 removals have been from about 85 to 90%. Availability and operability for the systems have generally been on the order of 90%. Jim Bridger 4, a 550 MW coal-fired power station newly constructed by Pacific Power & Light, utilizes a sodium carbonate FGD system. The design SO_2 removal efficiency is 91%.

System advantages are process simplicity, high SO_2 removal efficiency, and good system operability and reliability. Minimum corrosion and erosion occurs. Precollection of particulates is not required, but a high efficiency will be seen if particulates are removed prior to SO_2 scrubbing. The major disadvantage of this process is its consumptive use of expensive alkali, either caustic soda or soda ash. This factor tends to limit the system's applicability to small industrial boilers or to utility boilers located near an inexpensive source of the alkali. Disposal of the spent alkali solution may also pose problems and requires careful evaluation.

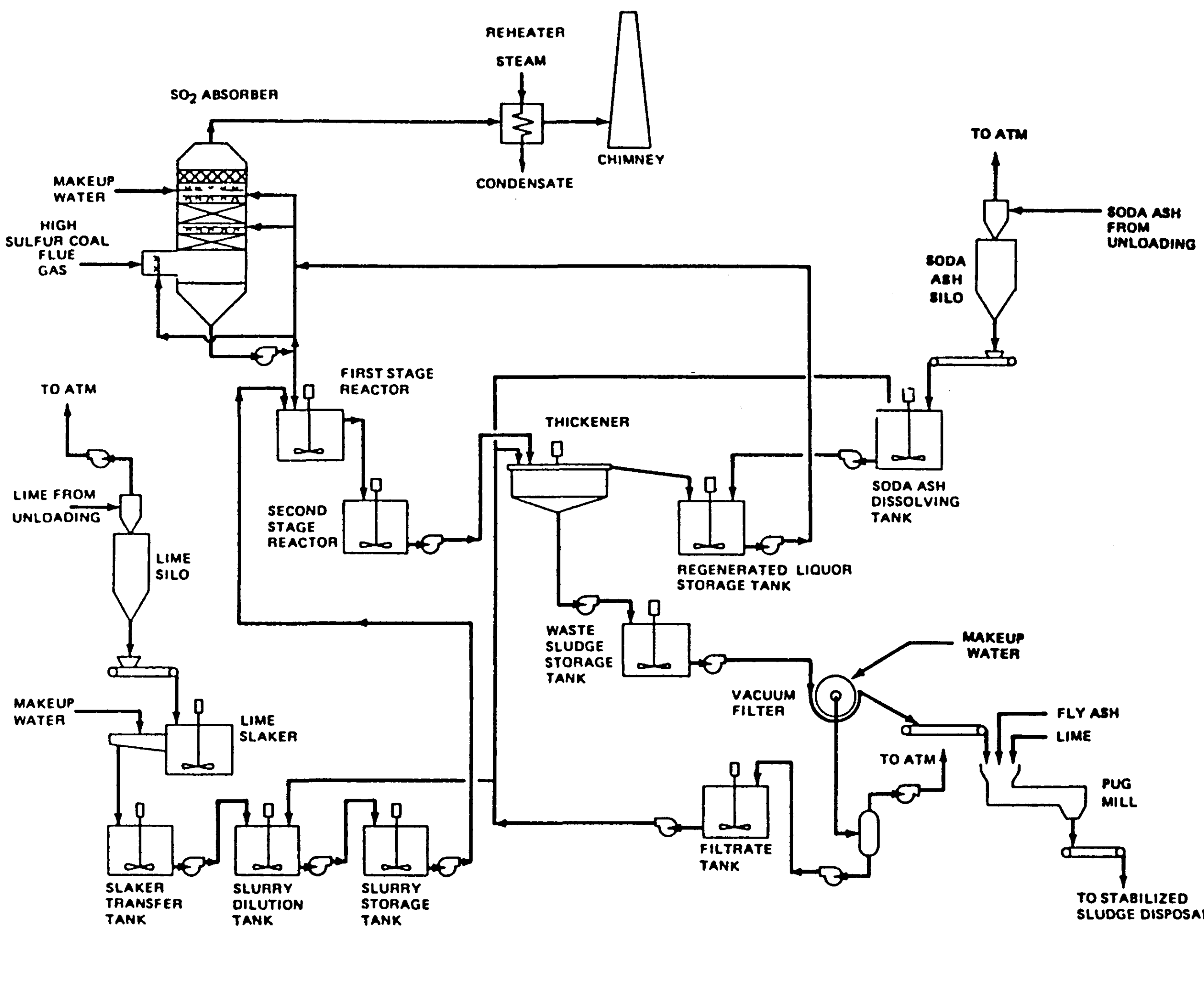
Dual Alkali Process

In the dual alkali process, SO_2 in the flue gas is passed through a wet scrubber and absorbed by a clear sodium sulfite solution to produce sodium bisulfite ($NaHSO_3$). The scrubbing solution is regenerated with lime or limestone, resulting in the precipitation of calcium sulfite ($CaSO_3$) wastes. It is a two-stage process where the absorption and waste production functions are separate and it is often referred to as an 'indirect' lime/limestone process. (See Exhibit D.6.)

Available operating experience to date is based on some twelve industrial boiler installations in the U. S. and Japan, three utility oil-fired boilers in Japan, and a 20 MW prototype coal-fired utility boiler in Florida. Two full-scale dual alkali

EXHIBIT D.6

FLOW DIAGRAM OF A DUAL ALKALI FGD SYSTEM



SOURCE: Economic and Design Factors for Flue Gas Desulfurization Technology, Electric Power Research Institute (EPRI), EPRI CS-1428, April 1980.

systems have recently become operational (Cane Rune 6, Louisville Gas & Electric; A. B. Brown 1, Southern Indiana Gas & Electric) and one is approaching start-up (Newton 1, Central Illinois Public Service). Data are not currently available on these newly operational full-scale systems, but earlier bench-scale, prototype, and pilot plant programs have been successful.

The 20 MW prototype utility boiler is operated by Gulf Power Company in Florida. This unit, Scholz 1, burns coal with 3-5% sulfur. SO_2 removal capabilities of the dual alkali scrubbing system have been up to 90% and greater. Being a demonstration unit, the plant has less spare equipment than would be normal in full-scale applications and, thus, the system's operability is very sensitive to equipment failures. Operability has steadily improved, however, and has reached 90% and above [5].

The dual alkali system was designed to combine desirable properties of other FGD processes. By using a clear liquid scrubbing solution, it minimizes problems with scaling, plugging, and erosion and has a high SO_2 removal efficiency. Regeneration of the scrubbing solution avoids the disposal problems of sodium salt wastes associated with FGD systems such as the sodium carbonate process. Only lime has been used successfully as the alkali source. The major problem of the dual alkali process is the regeneration of sodium sulfate (Na_2SO_4) formed by oxidation in the scrubber system. Sodium sulfate does not react well with lime in the presence of sodium sulfite (Na_2SO_3). This liquid-solid separation system of the dual alkali process is quite complex but has benefited from commercial applications.

Wellman-Lord Process

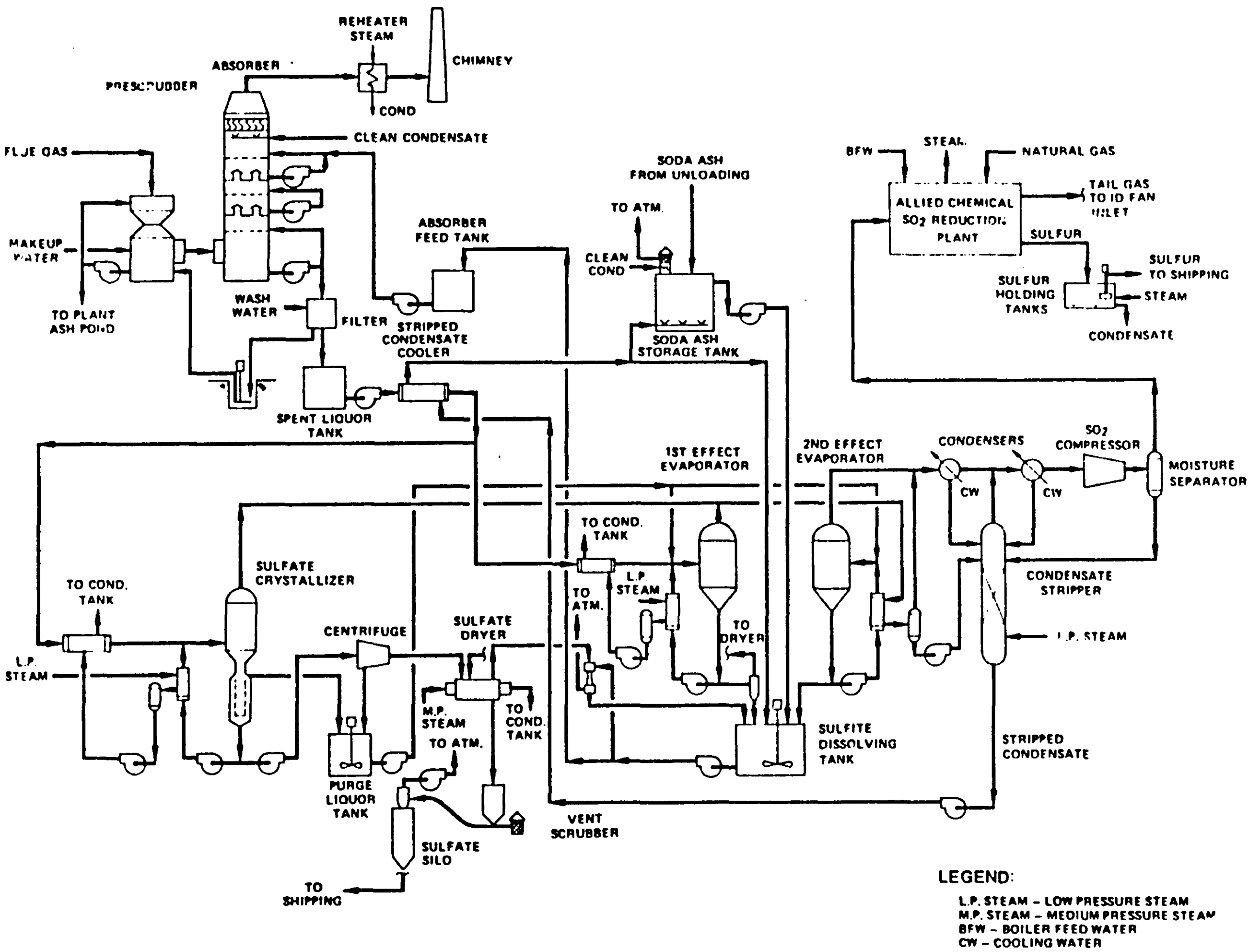
In the sodium sulfite (Wellman-Lord) process, SO_2 is absorbed in a concentrated clear liquid solution of sodium sulfite (Na_2SO_3) to produce sodium bisulfite ($NaHSO_3$). The sodium bisulfite is thermally decomposed to solid sodium sulfite and gaseous SO_2 in a forced-circulation evaporator-crystallizer. Na_2SO_3 solids are separated in a clarifier, redissolved in water, and recycled to the absorber. The concentrated SO_2 is directed to a sulfuric acid or sulfur plant. Sodium sulfate formed by the oxidation of sodium sulfite cannot be decomposed and must be purged from the system. (See Exhibit D.7.)

The Wellman-Lord process was first tested in 1970 on tail gas from a sulfuric acid plant in Paulsboro, New Jersey. Several applications have followed since then on tail gas from sulfur recovery plants in the U. S. and on flue gas from oil-fired boilers in Japan. The first application to a coal-fired boiler

[5] Reference number 100.

EXHIBIT D.7

FLOW DIAGRAM OF A WELLMAN-LORD FGD SYSTEM



SOURCE: <u>Economic and Design Factors for Flue Gas Desulfurization Technology</u>, Electric Power Research Institute (EPRI), EPRI CS-1428, April 1980.

in the U. S. was made on the North Indiana Public Service Company's Dean H. Mitchell Station in Cary, Indiana. The FGD system was retrofitted to a 115 MW unit firing 3.5% sulfur coal. The start-up performance tests were conducted from August to September 1977 and showed an average of 91% SO_2 removal. Operational data to date show SO_2 removals from 87 to 91%. Monthly system operability has reached 99% [6]. Major FGD outages have been attributable to booster fan problems, high silica levels in the boiler (due to a breakthrough in the feed water demineralizer unit), and problems with the guillotine isolation damper.

The Public Service Company of New Mexico retrofitted Wellman-Lord SO_2 absorbers and an Allied Chemical SO_2 Reduction Unit on two power generation units at their San Juan plant in 1978. Each unit is equipped with four (one spare) venturi scrubber/spray tower absorber trains designed to remove 85% of the flue gas SO_2. A third Wellman-Lord system was installed on a new power generating unit in December 1979 with a 90% design SO_2 removal efficiency. The coal contains 0.8% sulfur. Various mechanical problems were experienced during start-up and not all the scrubber modules were yet operational as of the latest utility FGD survey [7]. Problems with the flue gas reheat system are being experienced.

The Wellman-Lord process creates little or no scaling and requires a low liquid/gas ratio in the absorber. Fly ash must be kept out of the system. Expensive materials of construction are required due to the corrosive process environment. The system has high steam consumption and requires a prescrubbing step to remove HCl generated by coal combustion. The oxidation of sodium sulfite to sulfate causes a 5 to 10% loss of the incoming sulfur as soluble sodium sulfate in the purge stream along with a loss of expensive reactant. The lost reactant requires continual addition of soda makeup and the purge stream.

Magnesium Oxide Process

The magnesia or magnesium oxide (MgO) scrubbing process uses a wet slurry (about 10% solids by weight) of MgO and some recycled $MgSO_3$ and $MgSO_4$ to absorb SO_2 from flue gases. The MgO reacts with SO_2 to form hydrated magnesium sulfite/sulfate ($MgSO_3$/$MgSO_4$) crystals. These crystals are withdrawn from the scrubbing cycle in a side stream and are separated by a centrifuge. The separated liquid is recycled to the absorber and the solids are transferred to a dryer. The dried crystals are

[6] Reference number 100.

[7] Reference number 101.

usually sent to an off-site plant where they are converted to MgO and SO_2 by direct fired heating at 815-1090°C in a rotary or fluidized bed calciner. The SO_2 can be used for production of sulfuric acid and the MgO is returned to the scrubber. Major process equipment includes the scrubber, slurry tank, fly ash separator, crystallizer, centrifuge, and dryer. (See Exhibit D.8.)

One demonstration MgO system was recently in service (Eddystone 1, Philadelphia Electric Co.), and two such systems have been operated and terminated (Mystic 6, Boston Edison; Dickerson 3, Potomac Electric & Power). An additional full-scale (600 MW) MgO system is planned for the Tennessee Valley Authority's (TVA) Johnsonville Steam Plant. A brief operating history of the three tested MgO scrubber systems is presented below.

The Mystic 6 MgO scrubber started up in April 1972 and terminated in June 1974. Mystic is a 155 MW facility which burned 2.5% sulfur fuel oil. Average SO_2 removal efficiency over the test period was approximately 91% [8]. The operability of the MgO unit, defined as hours of FGD operation divided by hours of boiler operation for a given period, ranged from less than 15% to about 80% in the last four months. Major problem areas encountered during the operation of this prototype unit included formation of tryhydrate instead of hexahydrate sulfite crystals, which are more difficult to handle; dust problems in the calciner; lack of stack gas reheat which caused condensation in the stack; some erosion of pumps, piping, and centrifuge; and minor ancillary equipment failures.

The 95 MW Dickerson 3 station burned 2.0% sulfur coal and operated from September 1973 to August 1975. An average SO_2 removal efficiency of 88.9% was achieved. Operability here, lower than at Mystic, averaged about 50% and was caused by various mechanical and material failures [9].

The Eddystone 1 station commenced operation in September 1975 and had to suspend operation in January 1976 because the acid plant serving the MgO calciner was closed down. The unit was restarted in June 1977 and treated one-third of the flue gas. This 120 MW facility burns 2.5% sulfur. Design SO_2 removal efficiency for the FGD system was 90%. Performance data show the actual SO_2 removal efficiency to be from 95-97%. Operation of this prototype MgO system was recently terminated. The system is currently being replaced with a similar MgO system designed to treat 100% of the boiler flue gas. The expected start-up date of this new system is December 1982. Philadelphia Electric is retrofitting another three of their units, totalling 726 MW, with

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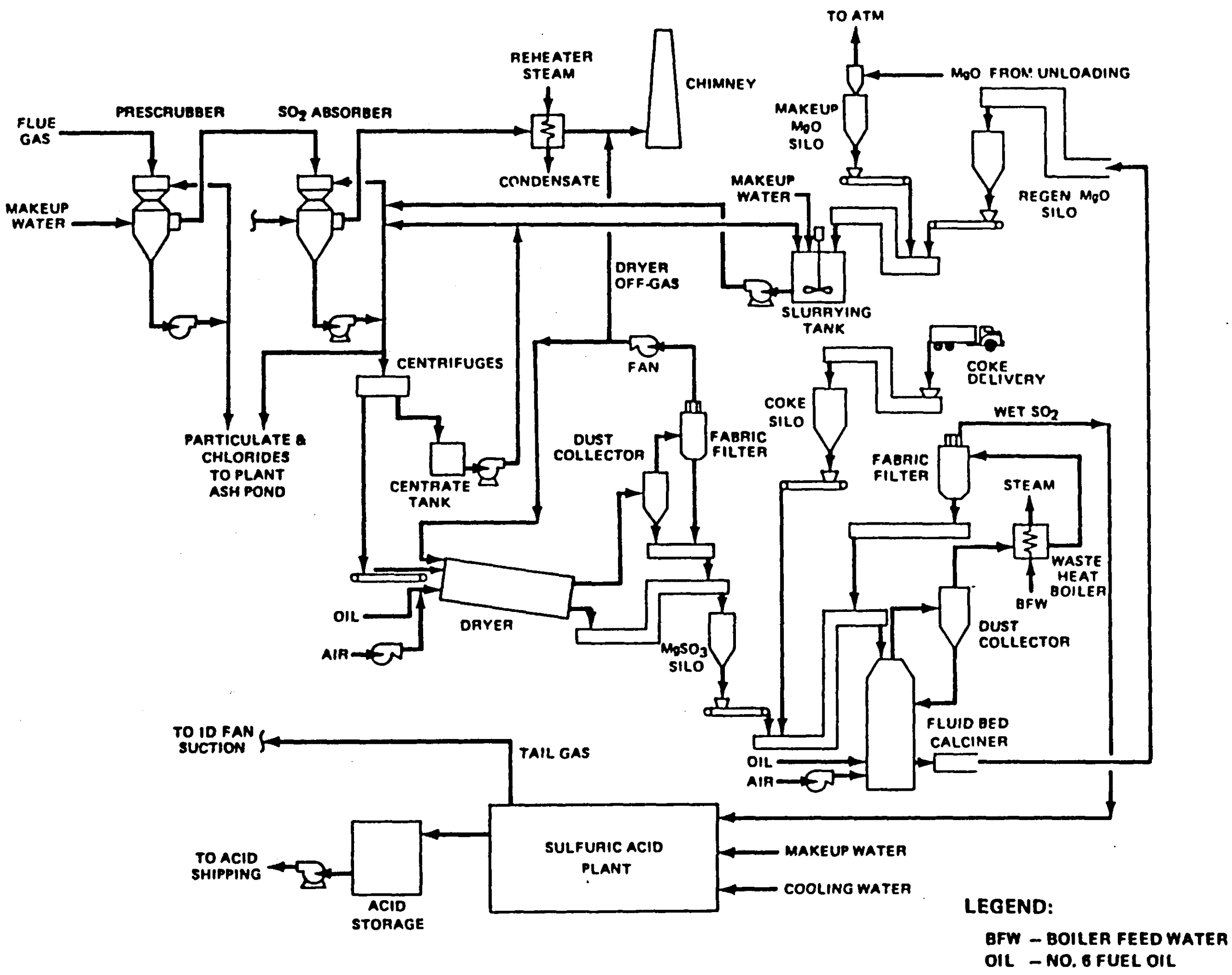
[8] Reference number 100.

[9] Reference number 100.

EXHIBIT D.8

FLOW DIAGRAM OF A MAGNESIA SLURRY FGD SYSTEM



SOURCE: Economic and Design Factors for Flue Gas Desulfurization Technology, Electric Power Research Institute (EPRI), EPRI CS-1428, April 1980.

MgO scrubbers. Operations are scheduled to begin in 1982. Operational data on the Eddystone 1 station showed system availability to steadily improve as experience was gained and system design modifications were incorporated.

The major advantages of MgO scrubbing are that little or no scaling occurs and that a marketable product of sulfur or sulfuric acid is available. Being a closed loop system, minimal waste disposal is required. Some losses and deactivation of MgO may occur by repeated regeneration. Studies have shown that reactivated MgO has a 90% removal efficiency, while that of the virgin absorbent is 95% [10]. The regenerative process requires that particulates be collected prior to the entrance of flue gas in the scrubber. Heat is required for calcining the spent MgO as well as for flue gas reheat. Major problem areas have been with the recovery system.

Citrate Process

This process, under development by the Bureau of Mines, achieves absorption of SO_2 in a solution of sodium citrate, citric acid, and sodium thiosulfate. The flue gas must first be cooled and pretreated to remove particulates, chlorides, and sulfuric acid mist. The absorbed SO_2 is reacted with H_2S to precipitate elemental sulfur and regenerate the citrate solution for recycling. Sulfur is separated from the solution by oil flotation and melting. New H_2S may be obtained by reacting some of the recovered sulfur with natural gas and steam.

Two pilot plant studies were developed to assess the feasibility of this process: the Bunker Hill Company lead smelter in Kellogg, Idaho, and the Pfizer-McKee-Peabody operation in Terre Haute, Indiana. SO_2 removals up to 99% were reported and experience was gained to improve the system's reliability. A 60 MW coal-fired electric power generation plant is now equipped with this FGD system. The plant is owned and operated by the St. Joe Zinc Company of Monaca, Pennsylvania. Preliminary mechanical testing of the demonstration plant and completion of most construction activities were initiated in March 1979. A one-year demonstration testing and performance evaluation program was designed, though no formal evaluation report is available at this time.

Spray Drying (Semi Dry) Processes

Semi-dry processes remove SO_2 in a two-stage system that combines a spray dryer and fabric filter or electrostatic precip-

[10] Reference number 10.

itator. In the first stage the flue gas enters the dryer and flows downward through a finely atomized spray of scrubbing solution containing an alkali slurry. This accomplishes primary SO_2 removal and the solution completely evaporates. The flue gas then leaves the spray dryer by particulate loaders and enters the second stage. The second-stage fabric filter functions as an SO_2 adsorber by reaction with unused sorbent and as a collector of dry reacted alkali and other particulate matter. (See Exhibit D.9.)

SO_2 removal efficiencies vary with the alkali sorbent used, as does the ability to regenerate the spent sorbent. Three sorbents were tested under identical conditions and the following overall SO_2 removal efficiencies were seen: sodium carbonate, 92%; sodium bicarbonate, 74%; and lime, 71% [11]. A full-scale system is scheduled for mid-1981 at Coyote 1, a 440 MW coal-fired unit jointly-owned by five utilities. This unit will burn a low sulfur (less than 1%) lignite. Basin Electric Power Corporation has contracted out the installation of semi-dry scrubbing systems for both their 440 MW Antelope Valley 1 station and their 575 MW Laramie River 3 station. The Niagara Mohawk Power Corporation's C. R. Huntley 6 station has been retrofitted for a spray dryer/ESP FGD system. Both Coyote 1 and C. R. Huntley 6 will be using an aqueous carbonate solution, while Basin Electric will use lime-based slurries. The design SO_2 removal efficiency for the 100 MW C. R. Huntley unit is 90%. This demonstration system will produce end-product sulfur by regenerating the spent sorbent with a solid carbon-reducing agent to produce hydrogen sulfide (H_2S). The H_2S will be converted to sulfur in a Claus plant. Waste products will be landfilled from the three other full-scale plants.

Minimal process development is required for this system as it combines two technologies (spray drying and electrostatic filtration) which have already had wide commercial application. As no liquid is present at the dryer outlet, the use of corrosion resistant material is generally not required. At high SO_2 concentrations (greater than 1000 ppm), however, the sodium carbonate may be prohibitively expensive because of the large amounts of alkali consumed. With no regeneration, a soluble salt waste is produced which will require proper disposal methods to be environmentally acceptable. Exhibit D.10 summarizes the major characteristics of U.S. FGD technologies.

Non-regenerable Dry Processes

The two basic versions of non-regenerable dry scrubbing which have emerged over the years involve the direct injection of

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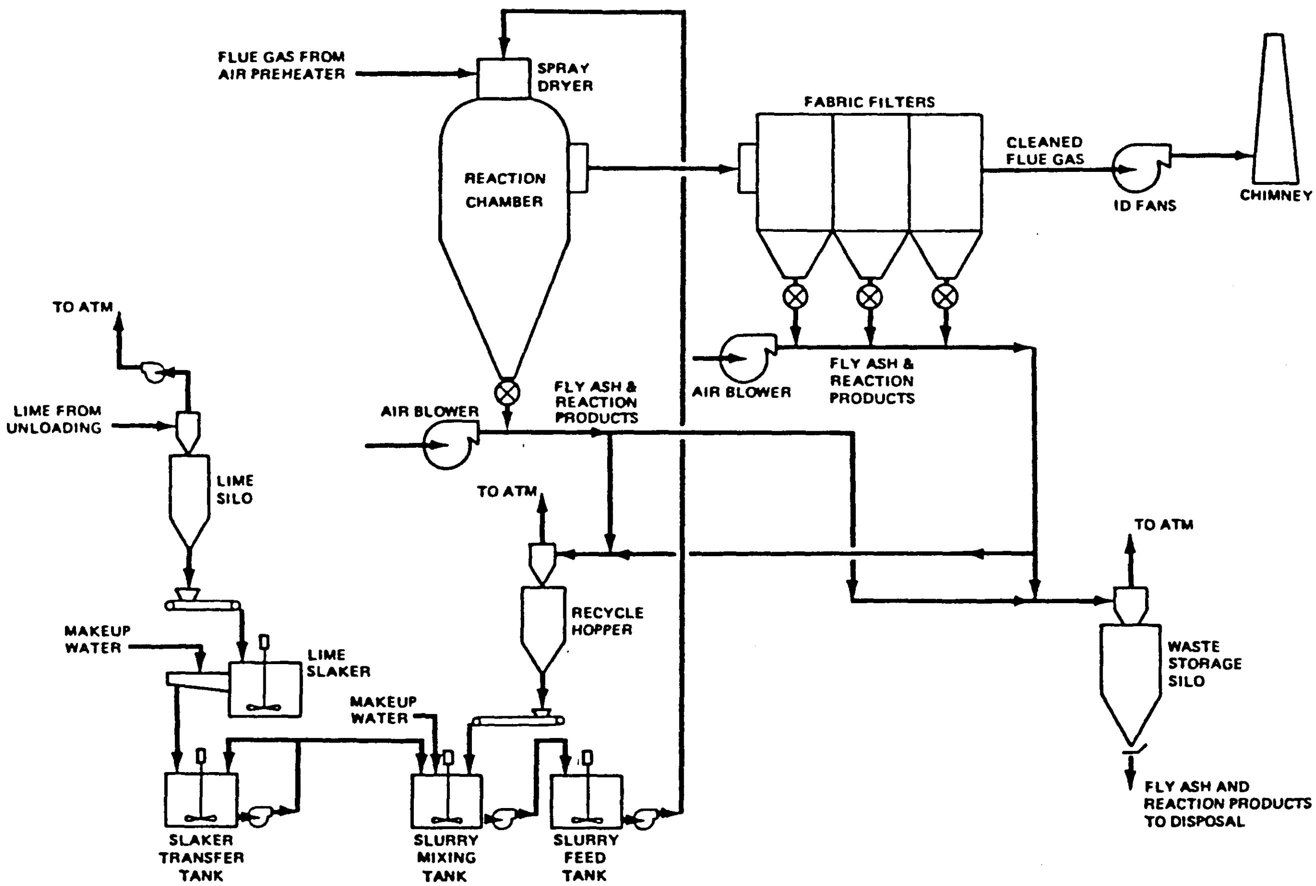
[11] Reference number 100.

EXHIBIT D.9

FLOW DIAGRAM OF A SPRAY DRYER/FABRIC FILTER
LIME BASED FGD SYSTEM



Source: <u>Economic and Design Factors for Flue Gas Desulfurization Technology</u>, Electric Power Research Institute (EPRI), EPRI CS-1428, April 1980.

EXHIBIT D.10

SUMMARY OF FLUE GAS DESULFURIZATION (FGD) TECHNOLOGIES

FGD Process	Sulfur Content of Coal (%)	Efficiency (%)	Capital Cost ($/kW)	Levelized Annual Cost (mills/kWh) O&M	Fixed	Total	Comments
Limestone	3.5 0.8	85-90 70-85	152 116	9.2 4.9	4.5 3.4	13.7 8.3	Currently most popular. Relatively simple process. Some problems with plugging, scaling, erosion and corrosion. Produces large quantities of waste sludge. Requires high liquid to gas (L/G) ratio and/or substantial pressure drops.
Lime	3.5 0.8	85-90 70-85	144 109	10.2 4.3	4.2 3.2	14.4 7.5	Relatively simple process. Some problems with plugging, scaling, erosion, and corrosion. Produces less sludge than limestone process. Requires high L/G ratio and pressure drop. Added cost of lime over limestone offset by lower capital cost.
Dual Alkali	3.5 0.8	90+ 80-90	154 122	8.8 4.6	4.5 3.6	13.3 8.2	Somewhat complex process. Minimal scrubber scaling; low L/G ratio. Disposal of calcium sludge and sodium sulfate purge required. Two to three separate solids handling systems required. Full-scale operation on oil-fired boilers in Japan. Recent full-scale operation on coal-fired boilers in U.S.

EXHIBIT D.10 (continued)

fgd process	Sulfur Content of Coal (%)	Efficiency (%)	Capital Cost ($/kW)	Levelized Annual Cost* (mills/kWh) O&M	Fixed	Total	Comments
Magnesium Oxide	3.5 0.8	90+ 80-90	172 125	7.1 4.3	5.0 3.7	12.1 8.0	Complicated chemical process. No scaling. Must operate acid plant; marketing of acid may be a problem. Fly ash must be kept out of regeneration system. Losses and deactivation of magnesium oxide may occur from repeated regeneration.
Wellman-Lord	3.5 0.8	90+ 90	177 126	7.8 4.6	5.2 3.7	13.0 8.3	Most successful for oil-fired boilers, now being demonstrated on coal. No scaling, low L/G ratio. Corrosive process environment requires expensive materials of construction; high steam consumption. Required soda makeup. Produces sulfuric acid or sulfur plus a small amount of liquid waste.
Spray Dryer/ Fabric Filter	3.5 0.8	80-90 70-80	109 46	5.7 2.3	3.2 1.4	8.9 3.7	Combines two technologies--spray drying and fabric filtration--which have had wide commercial application. Low L/G ratio. Produces dry powder waste with potential regeneration. Lower SO_2 removals with limestone sorbent; high costs with soda ash sorbent.

* Economic data is based on a 500 MW plant with 70% capacity factor. The fixed charge rate is 18% and the levelization factor is 1.886.

Source: Environmental Research and Technology, Inc., Lexington, Massachusetts.

a powered solid reactant either into the flue gas downstream of the baghouse or into the boiler itself along with the coal. Baghouse FGD may also involve application of the sorbent as a precoat to the baghouse. Spray dryers may also be grouped in this category but are discussed separately as a semi-dry process in this report.

Baghouse FGD tests have made use of many sorbents, including: nahcolite, a mineral containing natural sodium bicarbonate ($NaHCO_3$); naturally occuring sodium carbonate (Na_2CO_3); calcium oxide; and calcium hydroxide. The sorbent reacts with SO_2 to form sulfite salts which are collected as particulate matter. Nahcolite achieved impressive results at several installations (Southern California Edison's 320 MW Alamitos Station, Public Service of Indiana's Edwardsport Station, and Public Service Electric & Gas Company of New Jersey's Mercer Station). However, a general lack of nahcolite availability developed due to problems in meeting mining regulations. Lime and other dry alkalis tested were found to be relatively ineffective in a baghouse. Research needs to be done to continue evaluating other sorbents or to find ways to reduce or eliminate the large consumption of nahcolite. Sorbent regeneraton seems a likely consideration but must be proven in pilot-scale testing.

Combustion zone injection FGD using pulverized limestone was investigated by the EPA in the early 1970's. However, boiler fouling caused the program to be terminated. The EPA is continuing investigations now on a staged combustion, low NO_x burner. It is thought the mechanics of combustion in these low NO_x burners may eliminate the boiler fouling. These FGD concepts are still very developmental and commercialization is not seen to be forthcoming in the near future.

Regenerable Dry Processes

The two regenerable dry processes that have been demonstrated on pilot plant or prototype scale are the carbon adsorption and copper oxide processes. These two systems are described below. Neither has been domonstrated on full-scale units.

Carbon adsorption has been demonstrated in the Westvaco activated carbon process on a 50 MW oil-fired boiler. In this system, dry granular-activated carbon in a fluidized bed is contacted with the flue gas at stack gas temperatures. SO_2 removal is accomplished through catalyzed oxidation to SO_3 and subsequent hydrolysis to sulfuric acid. The sulfuric acid (H_2SO_4) remains absorbed in the carbon granules. The H_2SO_4-loaded carbon is then mechanically transported to a second fluidized bed reaction where the H_2SO_4 is reacted with hydrogen sulfide to produce elemental sulfur. Generation of the required hydrogen sulfide (H_2S) and removal of the elemental sulfur for recovery is accomplished in a third fluidized bed reactor fed by cylinder hydrogen. Other carbon adsorption process variations differ in the regeneration cycle.

In one carbon adsorption process, the Foster Wheeler Bergbau-Forshung (FW-BF) process, the H_2S-loaded carbon moves through a regeneration vessel where it comes in contact with hot sand. The H_2S reacts with the sand, releasing sulfur in the form of SO_2. The Chemiebau process, another variation, also reacts the H_2S-loaded carbon with sand, but introduces heat by a hot scavenging gas. The FW-BF process was developed in the early 1960's. A pilot plant in Germany was operated from 1968 to 1970, and a test program was run at the Scholz steam plant in Florida in 1976. Four pilot plants using the Chemiebau process ran from 1967 to 1968. Of these, the largest handled flue gas from a 10 MW boiler [12]. Further development of these processes has been hindered by the high costs associated with equipment and the large amounts of carbon required. Low gas velocities through the carbon bed are required, leading to large scrubber size requirements. Continuous SO_2 removal efficiencies are on the order of 75%, though the Westvaco process has reported removal efficiencies greater than 90%.[13]

The copper oxide scrubbing (Shell process) system contains two or more copper oxide (CuO) reactor units: one serves as an acceptor of incoming flue gas, while the other unit undergoes regeneration. SO_2 in the flue gas is adsorbed by the copper oxide at 400 C forming copper sulfate ($CuSO_4$). When the acceptor CuO bed becomes loaded, it automatically switches operational modes with the other CuO reactor and becomes a regeneration unit. Switching is performed by a timing device. In the regeneration mode, the bed is flushed with a hydrogen-rich gas stream. The hydrogen reacts with the copper sulfate, releasing SO_2 and regenerating copper oxide. The released SO_2 can be processed in an off-gas treatment system for recovery. Small-scale (0.6 MW) pilot testing of this process was conducted at Tampa Electric's Big Bend Station from 1974 to 1976. Results showed that the system is catalytically, mechanically, and physically stable. Removal efficiencies of 90% were achieved in some tests [14]. Equipment and installation costs for the system are high and material cost may also be high due to the hydrogen requirements. The process temperature requirement of 400 C makes this system more attractive for new rather than retrofit installations.

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[12] Reference number 104.

[13] Reference number 102.

[14] Reference number 103.

Appendix E

SCENARIO ANALYSIS ASSUMPTIONS

General Assumptions

Fuel Prices

1980 prices for oil and coal were assumed to be \$5.00/million Btu for No. 6, 0.3% sulfur oil and \$2.00/million Btu for 1% sulfur coal. The real annual rates of increase (1980-95) for oil and coal prices were assumed to be 3% and 1% respectively for all relevant scenarios. To assess sensitivity to these assumptions, the following alternative real annual fuel price growth rates were also investigated:

Oil (%)	Coal (%)
10	5
5	3
0	0
-2	0

Purchased Energy

Three alternative levels of energy purchases were assumed (See Exhibit 4.3).

Load and Energy Growth Rates

Annual Growth Rate 1980-1995	1995 Load (MW)	1995 Energy (Billions of kWh)	Percentage Change in Load (1980-1995)
-1%	6,898	31,830	-14
0%	8,020	36,140	0
+1%*	9,311	41,957	+16
+2%	10,794	48,640	+35

* Projected in Con Edison's Energy Strategy for the 1980's

Procos Assumptions

Operating and Maintenance Costs

Converted Plant	Fixed Cost (1980 $/Week)	Variable Cost (1980 $/MWh)
Ravenswood 3	$ 116,500	1.54
Arthur Kill 2	54,800	1.54
Arthur Kill 3	75,400	1.54
Ravenswood 1	60,800	1.54
Ravenswood 2	60,500	1.54
Astoria 3	53,600	1.54
Astoria 4	56,600	1.54
Astoria 5	52,700	1.54

Dispatching Startup Costs*

Plant	Cost (1980 dollars)
No Conversion	
Astoria 1	3,950
Astoria 2	7,350
East River 5	1,150
East River 6	1,150
East River 7	3,650
Converted Plants	
Astoria 3	12,150
Astoria 4	5,400
Astoria 5	5,400
Ravenswood 1	5,400
Ravenswood 2	10,010

* Escalated at a 7% annual rate.

New Assumed Sequence for Economic Dispatch

New Sequence of Start-up	Old Sequence of Start-up	
1	1	Indian Point 2
2	2	Indian Point 3
3	5	PASNY Travis Plant
4	--	Ravenswood 3 (if coal-fired)
5	--	Arthur Kill 2 (if coal-fired)
6	--	Arthur Kill 3 (if coal-fired)
7	--	Ravenswood 1 (if coal-fired)
8	--	Ravenswood 2 (if coal-fired)
9	--	Astoria 3 (if coal-fired)
10	--	Astoria 4 (if coal-fired)
11	--	Astoria 5 (if coal-fired)
12	3	Ravenswood 3 (if oil-fired)
13	6	Arthur Kill 3 (if oil-fired)
14	15	Arthur Kill 2 (if oil-fired)
15	16	Roseton 1
16	17	Roseton 2
17	7	Bowline 1
18	8	Bowline 2
19	9	Bowline 3
20	4	Astoria 6
21	10	Ravenswood 1 (if oil-fired)
22	11	Ravenswood 2 (if oil-fired)
23	12	Astoria 5 (if oil-fired)
24	13	Astoria 4 (if oil-fired)
25	14	Astoria 3 (if oil-fired)
26	19	East River 7
27	21	East River 5
28	22	East River 6
29	18	Astoria 2
30	20	Astoria 1
31	23	Prattsville Pumped Storage Plant

Coal Conversion Cost Assumptions

	Coal Conversion Costs (Millions of 1980 Dollars)	
	Without Scrubbers	With Scrubbers
Ravenswood 3	27	212
Arthur Kill 2 and 3*	136	307
Ravenswood 1 and 2*	220	374
Astoria 1, 2 and 3*	150	336

* Costs are equally distributed among the different units.

Air Quality Modeling Assumptions

The climatological version of the ERT Air Quality Model (ERTAQ) was used to compute the annual average impact of power generation sources in the New York City vicinity. This model has several unique features which enabled automation of emission data analyses required for this analysis. ERTAQ has recently been submitted to the U.S. EPA for possible acceptance as a guideline model.

The annually averaged concentration calculations were performed using a climatological wind rose from La Guardia Airport surface wind data. The modeling grid consisted of 121 ground level receptors, separated by 4 kilometers, extending from the Bronx to Staten Island, as shown in Exhibit E.1. The receptor grid provides an area-wide coverage of the entire Con Edison impact region but may not be sufficiently dense to determine the exact point of maximum concentration impact.

Baseline Concentrations

The baseline or background concentrations in the New York metropolitan area were determined for 1978 using ambient monitoring data from the New York DEC and New Jersey DEP monitoring networks. The 1978 annual average concentrations of SO_2, TSP, and NO_2 from each monitoring station were plotted on a base map and subjectively analyzed into concentration isopleths (for NO_2 baseline values, 1976 concentrations were used, because 1976 was the latest year with accurate NO_2 annual average data).

Baseline values for the 121 points of the 4 kilometer receptor grid were then interpolated from the base map isopleths. Because the grid points and monitoring sites were not coincident, there was some degree of smoothing which resulted in a slight reduction of peak monitored concentrations (i.e., peak ambient levels fell between two grid points). Exhibits E.2, E.3 and E.4 show the resulting grid-based isopleths of baseline SO_2, NO_2, and TSP concentrations, respectively.

Emission Methodology

For each scenario, yearly fuel use data was provided by PROCOS for 16 years, 1980 to 1995. An algorithm was developed to convert the fuel use data into SO_2, NO_x and TSP emission rates based on fuel Btu and sulfur content. For coal burning, NO_x and TSP emission factors from the EPA 1978 Compilation of Air Pollutant Emission Factors were used assuming a particulate removal efficiency of 99.6%. The NO_x and TSP emission factors for oil burning at Con Edison generating stations were provided

Exhibit E.1

4 KM x 4 KM RECEPTOR GRID FOR AIR QUALITY MODELING

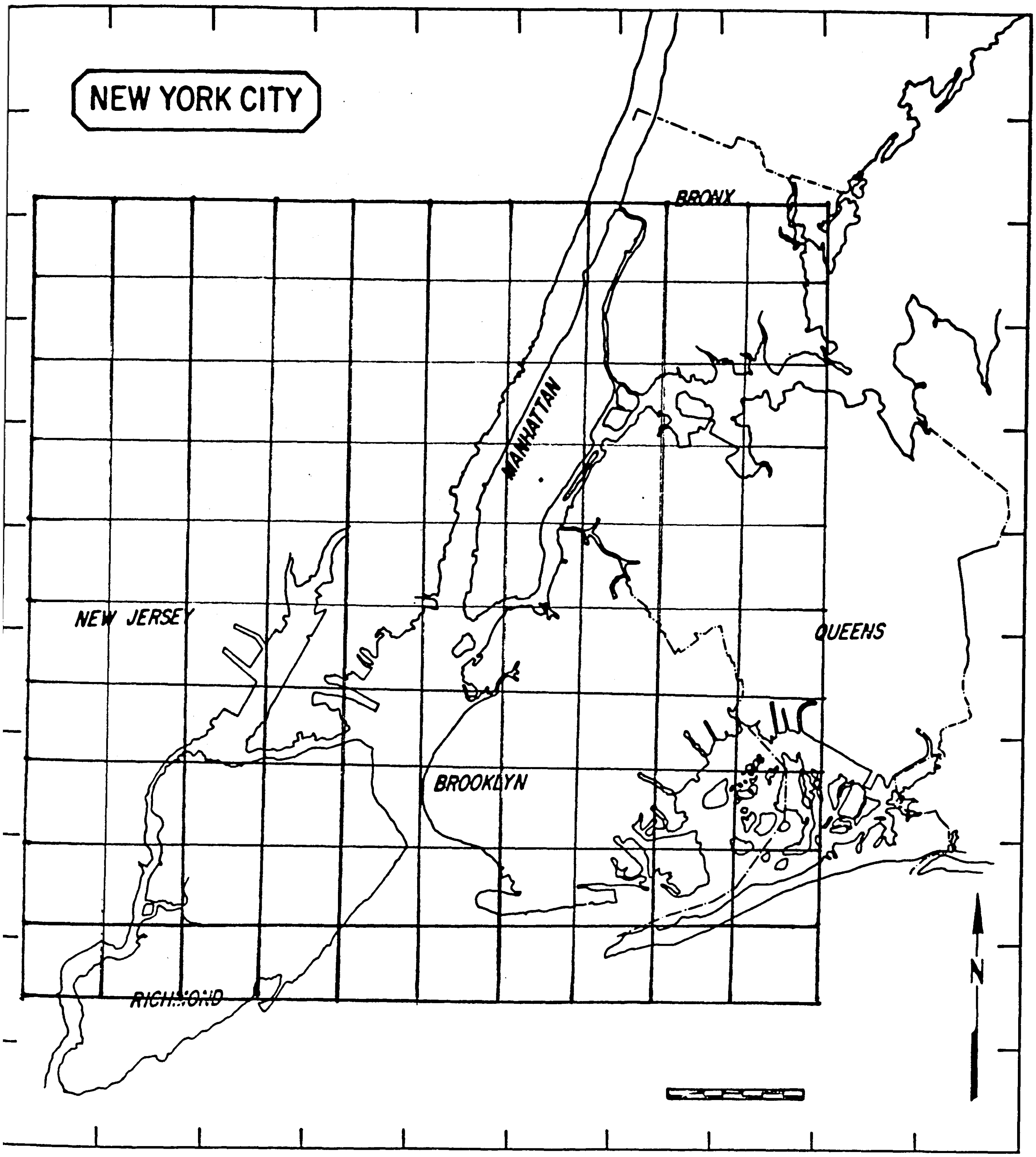

Exhibit E.2

BACKGROUND ANNUAL AVERAGE SO_2 CONCENTRATIONS
(Micrograms per Cubic Meter)

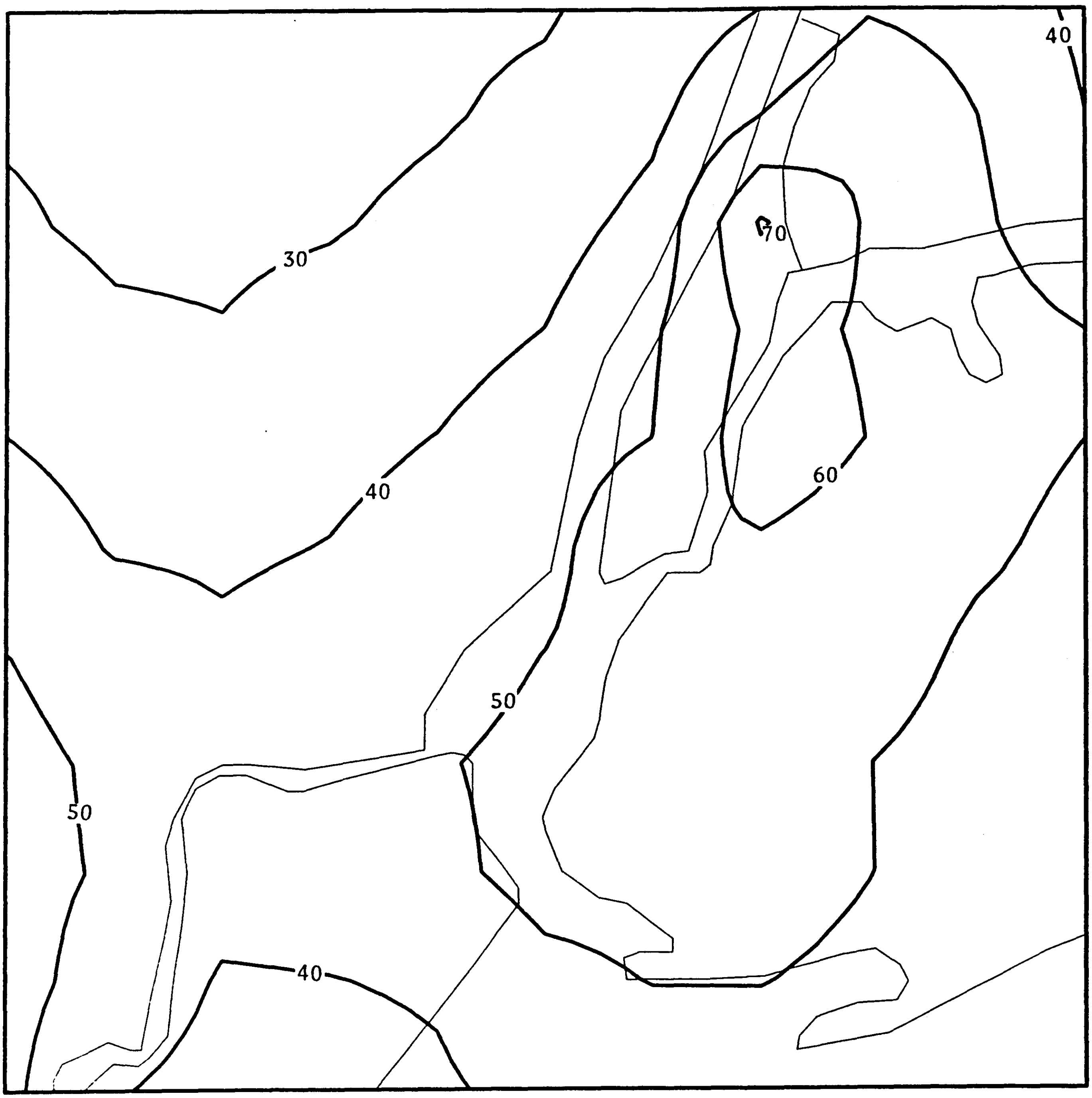

Exhibit E.3

BACKGROUND ANNUAL AVERAGE NO_2 CONCENTRATIONS
(Micrograms per Cubic Meter)

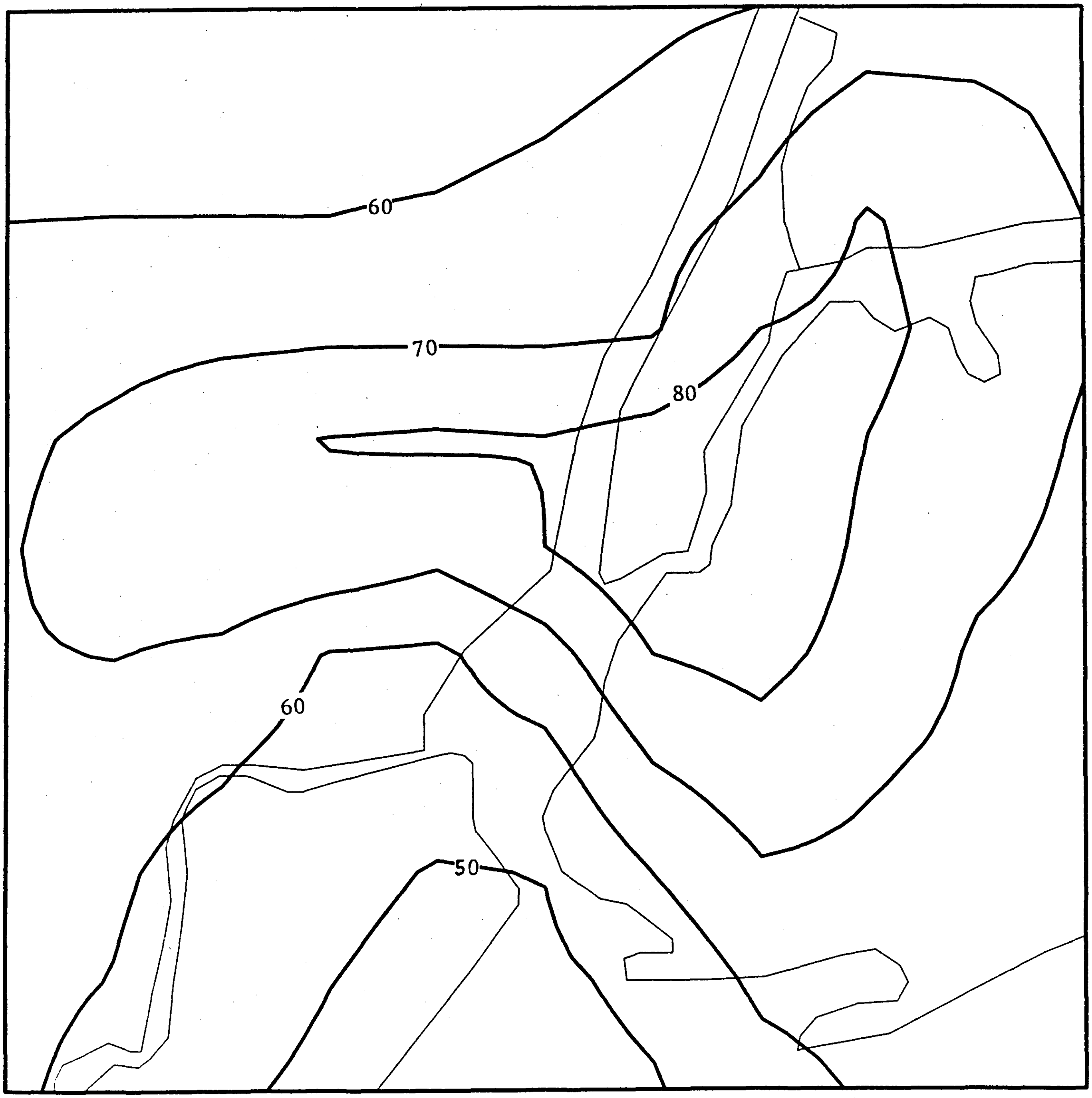

Exhibit E.4

BACKGROUND ANNUAL AVERAGE TSP CONCENTRATIONS
(Micrograms per Cubic Meter)

directly by stack gas sampling results.

Emission factors used are shown in Exhibit E.5. Depending on the scenario and facility, three types of SO_2 control assumptions were employed for coal conversion: (1) no scrubbers (0% removal), (2) dry scrubbers (70% removal), and (3) wet scrubbers (80% removal). It was assumed that 1% sulfur coal was burned and none of these SO_2 mitigation measures had any effect on NO_x or TSP emission rates.

For each fuel use scenario, the year with the greatest total SO_2 emissions was determined. For that peak year and 1995, the change in emissions from 1978 baseline emissions for each Con Edison source was modeled using ERTAQ. This was accomplished by setting up a normalized concentration field due to each source, multiplying by the incremental emission factor, and combining contributions from each source. These incremental concentrations were then added to the 1978 background concentrations to obtain the total predicted concentrations. This methodology implicitly assumes that stack parameters (e.g., temperature and exit gas velocity) do not change with the scenario.[1]

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[1] In fact, operation of FGD equipment does change stack temperatures.

Exhibit E.5

EMISSION FACTORS FOR CON EDISON SOURCES*
(Pounds per Million Btu)

		SO_2	NO_x	TSP
		Coal		
All Units:		1.6	0.70	0.032
		0.48 (Dry Scrubber)		
		0.32 (Wet Scrubber)		
		Residual Oil		
Astoria	1	0.312	0.26	0.021
	2	0.312	0.26	0.021
	3	0.312	0.27	0.043
	4	0.312	0.19	0.027
	5	0.312	0.19	0.027
	6	0.312	0.25	0.025
Ravenswood	1	0.312	0.20	0.030
	2	0.312	0.20	0.030
	3	0.312	0.23	0.032
Arthur Kill	2	0.312	0.25	0.041
	3	0.312	0.25	0.041
East River	5	0.312	0.29	0.040
	6	0.312	0.29	0.040
	7	0.312	0.25	0.024
59th Street	93	0.312	0.26	0.040
	3	0.312	0.22	0.024
	9	0.312	0.22	0.033

Exhibit E.5 (continued)

EMISSION FACTORS FOR CON EDISON SOURCES*
(Pounds per Million Btu)

		SO_2	NO_x	TSP
74th Street	1	0.312	0.20	0.020
	3	0.312	0.20	0.020
	11	0.312	0.20	0.020
Waterside	81	0.312	0.20	0.064
	86	0.312	0.20	0.064
	87	0.312	0.30	0.020
	91	0.312	0.17	0.020
Hudson Ave.	95	0.312	0.27	0.026
	86	0.312	0.27	0.026

* Assumptions:

1. 1% sulfur coal; 12,500 Btu/lb
2. 0.3% sulfur residual oil; 19,250 Btu/lb
3. Electrostatic precipitators, 99.6% efficient
4. Dry scrubbers, 70% efficient
   wet scrubbers, 80% efficient
5. Con Edison peaking plants use:
   #2 heating oil; 134,300 Btu/gal

   SO_2 -- 3.5 lb/10^3 gal
   NO_x -- 67.8 lb/10^3 gal
   TSP -- 5.0 lb/10^3 gal

Source: Compilation of Air Pollutant Emission Factors, United States Environmental Protection Agency, publication No. AP-42, Research Triangle Park, North Carolina, 1978.

RAm Financial Model Assumptions for 15 Year Financing Plan

(1) Minimum SEC coverage of 3.25 times.

(2) Minimum Common Equity ratio 45%.

(3) Maximum combination of Debt and Preferred Stock ratio 55%.

   (a) If increment of debt forced interest coverage constraint to be violated (that is, less than 3.25 times) then we would issue Preferred Stock, as long as the combination of Debt and Preferred were within 55% of Total Capitalization.

(4) Common Stock would be issued when no further Debt and Preferred stock were available to be issued under the above guidelines.

(5) Temporary Cash Investments: minimum level of $200 million through 1994.

(6) All outstanding Preferred stock will be converted into Common over a 3 year period 1980-1982.

(7) Rates of Inflation and Senior Securities

Period	Inflation Rate Per Year	Cost Rate of New Bonds and Preferred Stock Per Year*
1981 - 1983	8.5%	11.5%
1984 - 1987	7.5%	10.5%
1988 - 1991	6.5%	9.5%
1992 - 1994	6.0%	9.0%

* 3% above the annual inflation rate

(8) Return on Equity Actually Earned

1980	8.8% per year
1981	11.0% " "
1982 - 1989	12.0% " "
1990 - 1994	13.0 % " "

(9) Dividend Policy

Common Dividend gradually increases to about 75% payout ratio by 1988.

Appendix F

ENUMERATION OF SCENARIOS AND PRELIMINARY SIMULATION RESULTS

Key to the MIT Scenario Code

Each of the 126 scenarios simulated is listed by computer code name in Exhibit F.1. The code name is made up of 5 fields of information drawn from Tables A through E which follow. An example will serve to make the coding method clear. Consider scenario number 124, NC2LMPTN:

NC	means	no coal conversion (Table A)
2	means	+ 2% annual load growth (Table B)
L	means	low level of purchased energy (Table C)
M	means	oil price real annual growth 3%, coal 1% (Table D)
P	means	Prattsville not on-line within study period of 1980 to 1995 (Table E)
T	means	Travis not on-line within study period of 1980 to 1995 (Table E)
N	means	Indian Point 2 & 3 are shutdown in 1987 (Table E)

Code letters from Table E are optional and more than one may be used.

Exhibit F.1

COMPUTER CODE NAMES OF MIT SCENARIOS 1 THROUGH 126

	Code Name		Code Name		Code Name
1	FT1LM	43	AK9HM	85	DR9MM
2	FT1MM	44	ST1LM	86	DR8MM
3	FT1HM	45	ST1MM	87	NRD1MM
4	FT9LM	46	ST1HM	88	NRD9MM
5	FT9MM	47	ST9LM	89	AKD1MM
6	FT9HM	48	ST9MM	90	AKD9MM
7	NR1LM	49	ST9HM	91	STD1LM
8	NR1MM	50	ST1MMN1	92	FT1LMO
9	NR1HM	51	ST1MMN	93	FT1MMO
10	NR9LM	52	ST9MMN1	94	FT9MMO
11	NR9MM	53	ST9MMN	95	NR1LMO
12	NR9HM	54	FT9MMN1	96	NR1MMO
13	NC1LM	55	FT9MMN	97	NR9MMO
14	NC1MM	56	NR9MMN1	98	NC1LMO
15	NC1HM	57	NR9MMN	99	NC1MMO
16	NC9LM	58	FT2MM	100	NC9MMO
17	NC9MM	59	NR2MM	101	FT1ML
18	NC9HM	60	NC2MM	102	FT1MH
19	TD1MM	61	AK2MM	103	FT1MA
20	TD9MM	62	FT8MM	104	FT1MB
21	FT1MMN	63	NR8MM	105	NR9ML
22	NR1MMN	64	NC8MM	106	NR9MH
23	NR1HMN	65	AK8MM	107	NR9MA
24	NC1MMN	66	FT1NM	108	NR9MB
25	NR1MMNT	67	NR1NM	109	NC1ML
26	NR1MMNP	68	NC1NM	110	NC1MH
27	FT1MMT	69	AK1NM	111	NC1MA
28	NR1MMT	70	FT9NM	112	NC1MB
29	NR1HMT	71	NR9NM	113	FT1MMC
30	NR9MMT	72	NC9NM	114	NR1MMC
31	NC1MMT	73	AK9NM	115	NC1MMC
32	NR1MMTP	74	SC1MM	116	AK1MMC
33	FT1MMP	75	SC1HM	117	ST1MMC
34	NR1MMP	76	SC9MM	118	FT9MMC
35	NR1HMP	77	DS1MM	119	NR9MMC
36	NR9MMP	78	DS9MM	120	NC9MMC
37	NC1MMP	79	DW2MM	121	AK9MMC
38	AK1LM	80	DW1MM	122	ST9MMC
39	AK1MM	81	DW9MM	123	NC1LMPT
40	AK1HM	82	DW8MM	124	NC2LMPTN
41	AK9LM	83	DR2MM	125	DRA1MM
42	AK9MM	84	DR1MM	126	DRA9MM

Table A. Codes for Coal Conversion Plans

1. "FT" represents the maximum coal conversion scenario which is given below.

Plant	Conversion Date	Capacity (Megawatts)
Ravenswood 3	4-1-82	922
Arthur Kill 2	4-1-83	335
Arthur Kill 3	4-1-84	461
Ravenswood 1	4-1-85	372
Ravenswood 2	9-1-85	370
Astoria 3	4-1-87	328
Astoria 4	9-1-87	346
Astoria 5	2-1-88	322
	Total	3456

2. "NR" represents the following coal conversion schedule.

Plant	Conversion Date	Capacity (Megawatts)
Arthur Kill 2	4-1-83	335
Arthur Kill 3	4-1-84	461
Astoria 3	4-1-87	328
Astoria 4	9-1-87	346
Astoria 5	2-1-88	322
	Total	1792

3. "ST" represents the Con Edison strategy for coal conversions which is given by the following schedule.

Plant	Conversion Date	Capacity (Megawatts)
Ravenswood 3	8-1-81	922
Arthur Kill 2	11-1-82	335
Arthur Kill 3	6-1-83	461
	Total	1718

4. "AK" represents the following coal conversion cases.

Plant	Conversion Date	Capacity (Megawatts)
Arthur Kill 2	4-1-83	335
Arthur Kill 3	4-1-84	461
	Total	796

5. "NC" represents the no coal conversion case.

6. "TD represents a coal conversion schedule that is similar to the "FT" schedule but delayed by two years; i.e., "TD" represents the following coal conversion schedule.

Plant	Conversion Date	Capacity (Megawatts)
Ravenswood 3	4-1-84	922
Arthur Kill 2	4-1-85	335
Arthur Kill 3	9-1-85	461
Ravenswood 1	4-1-87	372
Ravenswood 2	9-1-87	370
Astoria 3	4-1-89	328
Astoria 4	9-1-89	346
Astoria 5	2-1-90	322
	Total	3456

7. "NRD" represents a coal conversion schedule that is similar to the "NR" schedule but delayed by two years; i.e., "NRD" represents the following coal conversion schedule.

Plant	Conversion Date	Capacity (Megawatts)
Arthur Kill 2	4-1-85	335
Arthur Kill 3	4-1-86	461
Astoria 3	4-1-89	328
Astoria 4	9-1-89	346
Astoria 5	2-1-90	322
	Total	1792

8. "STD" represents a coal conversion schedule that is similar to the "ST" schedule but delayed by two years; i.e., "STD" represents the following coal conversion schedule.

Plant	Conversion Date	Capacity (Megawatts)
Ravenswood 3	8-1-83	922
Arthur Kill 2	11-1-84	335
Arthur Kill 3	6-1-85	461
	Total	1718

9. "AKD" represents a coal conversion schedule that is similar to "AC" but delayed by two years; i.e., "AKD" represents the following coal conversion schedule.

Plant	Conversion Date	Capacity (Megawatts)
Arthur Kill 2	4-1-85	335
Arthur Kill 3	4-1-86	461
	Total	796

10. "SC" represents the following coal conversion and wet scrubber installation schedule.

Plant	Coal Conversion and Wet Scrubber Installation Date
Ravenswood 3	4-1-86
Arthur Kill 2	4-1-85
Arthur Kill 3	4-1-86
Ravenswood 1	4-1-89
Ravenswood 2	9-1-89
Astoria 3	4-1-91
Astoria 4	9-1-91
Astoria 5	2-1-92

11. "DS" represents the following coal conversion and wet scrubber installation schedule.

Plant	Coal Conversion Date	Wet Scrubber Installation Date
Ravenswood 3	4-1-82	4-1-86
Arthur Kill 2	4-1-83	--
Arthur Kill 3	4-1-84	--
Ravenswood 1	4-1-89	4-1-89
Ravenswood 2	9-1-89	9-1-89
Astoria 3	4-1-91	4-1-91
Astoria 4	9-1-91	9-1-91
Astoria 5	2-1-92	2-1-92

12. "DW" represents the following coal conversion and dry and wet scrubber installation schedule.

Plant	Coal Conversion Date	Scrubber Installation Date
Ravenswood 3	4-1-82	4-1-91, Dry Scrubbers
Arthur Kill 2	4-1-83	4-1-89, Dry Scrubbers
Arthur Kill 3	4-1-84	4-1-90, Dry Scrubbers
Ravenswood 1	4-1-89	4-1-89, Wet Scrubbers
Ravenswood 2	9-1-89	9-1-89, Wet Scrubbers
Astoria 3	4-1-91	4-1-91, Wet Scrubbers
Astoria 4	9-1-92	9-1-92, Wet Scrubbers
Astoria 5	2-1-92	2-1-92, Wet Scrubbers

13. "DR" represents the following coal conversion and dry scrubber installation schedule.

Plant	Coal Conversion Date	Dry Scrubber Installation Date
Ravenswood 3	4-1-82	4-1-91
Arthur Kill 2	4-1-83	4-1-89
Arthur Kill 3	4-1-83	4-1-90

14. "DRA" represents the following coal conversion and dry scrubber installation schedule.

Plant	Coal Conversion Date	Dry Scrubber Installation Date
Ravenswood 3	4-1-82	4-1-91
Arthur Kill 2	4-1-83	--
Arthur Kill 3	4-1-84	--

Table B. Codes for Electric Load Growth

Electric load growth is represented in code by a number following the symbol for coal conversion. The following symbols are used for electric load growth.

Symbol	Annual Electric Load Growth during 1980 to 1995
2	+2
1	+1
9	-1
8	-2

Table C. Codes for Purchased Energy

The amount of purchased energy is represented in code by a letter following the load growth symbol. The following symbols are used for various amounts of purchased energy.

Symbol	MIT Scenario of Purchased Energy
H	High Level (Cumulative total= 101.8 billion kWh, 1980-1995)
M	Medium Level (Cumulative total= 84.8 billion kWh, 1980-1995)
L	Low Level (Cumulative total= 68.8 billion kWh, 1980-1995)
N	No Purchased Energy (Cumulative total= 65.0 billion kWh, 1980-1995)

Table D. Codes for Fuel Prices

Fuel prices are represented in code by a letter following the symbol for purchased energy. The following symbols are used for fuel prices.

	Annual Growth of Fuel Price (%)	
Symbol	Oil	Coal
H	5	3
M	3	1
L	0	0
A	-2	0
B	10	5

Table E. Miscellaneous Codes

The following symbols could follow the fuel price symbol.

Symbol	Explanation
N	Shutdown of Indian Point 2 and 3 in 1987
N1	Shutdown of Indian Point 2 and 3 in 1982
T	The Travis plant is not on-line within the study period (1980-1995)
P	The Prattsville plant is not on-line within the study period (1980-1995)
O	Constraints were introduced in certain oil-fired plants to estimate the maximum amount of electricity produced from coal-fired plants in case of a drastic oil supply decrease
C	All power plants except combustion turbines were assumed to be 'must run' plants

Selected Output of MIT Scenarios

Exhibits F.2 through F.5 list the values of selected output variables for the MIT scenarios. The scenario numbers shown are the same as in Exhibit F.1.

Exhibit F.2

TOTAL INCREMENTAL COST (1980-1995)*
FOR EACH OF THE 126 MIT SCENARIOS
(PRESENT VALUE, IN MILLIONS OF 1980 DOLLARS)

	Cost		Cost		Cost		Cost
1	15307	32	17681	63	13473	95	17508
2	15193	33	15153	64	14758	96	17216
3	15094	34	16800	65	13581	97	13734
4	13155	35	16619	66	16180	98	21204
5	13077	36	14174	67	17986	99	20758
6	13012	37	19063	68	20668	100	16018
7	16987	38	17811	69	18911	101	13796
8	16052	39	17629	70	13784	102	16705
9	16752	40	17494	71	14890	103	13166
10	14331	41	14706	72	17004	104	20340
11	14281	42	14649	73	15397	105	12779
12	14231	43	14602	74	17642	106	15660
13	19478	44	16286	75	17513	107	12017
14	19257	45	16113	76	15229	108	19557
15	19058	46	15986	77	16724	109	16367
16	16117	47	13370	78	14280	110	21668
17	15996	48	13333	79	18573	111	14810
18	15901	49	13285	80	16736	112	29531
19	15793	50	22595	81	14327	113	15904
20	13663	51	19845	82	13457	114	17604
21	18477	52	18310	83	18880	115	19906
22	20606	53	15928	84	16810	116	18389
23	20341	54	17077	85	13965	117	16939
24	23460	55	14713	86	12943	118	13732
25	21436	56	18985	87	17290	119	15083
26	20513	57	16519	88	14611	120	16719
27	15298	58	16799	89	17798	121	15532
28	17114	59	18751	90	14803	122	14246
29	16966	60	21440	91	16734	123	19770
30	14225	61	19711	92	15141	124	26800
31	20051	62	12294	93	14966	125	16524
				94	12367	126	13754

* Incremental cost includes fuel costs, operation and maintenance costs, revenue requirements for coal conversion and new units, and purchased energy costs.

Exhibit F.3

TOTAL OIL CONSUMPTION (1980-1995)
FOR EACH OF THE 126 MIT SCENARIOS
(IN MILLIONS OF BARRELS)

	Oil Usage		Oil Usage		Oil Usage		Oil Usage
1	302	32	475	63	300	95	463
2	288	33	304	64	388	96	437
3	277	34	435	65	323	97	306
4	243	35	417	66	374	98	660
5	231	36	340	67	546	99	628
6	220	37	577	68	717	100	447
7	440	38	508	69	622	101	288
8	422	39	484	70	305	102	288
9	403	40	462	71	421	103	288
10	341	41	379	72	565	104	288
11	328	42	362	73	474	105	328
12	312	43	345	74	375	106	328
13	598	44	387	75	358	107	328
14	573	45	367	76	301	108	328
15	547	46	347	77	334	109	573
16	460	47	277	78	258	110	573
17	438	48	264	79	393	111	573
18	417	49	250	80	326	112	573
19	332	50	649	81	252	113	323
20	274	51	535	82	229	114	454
21	421	52	477	83	438	115	599
22	595	53	377	84	382	116	514
23	568	54	377	85	276	117	404
24	765	55	282	86	242	118	262
25	661	56	533	87	453	119	365
26	600	57	425	88	353	120	468
27	315	58	343	89	499	121	401
28	464	59	499	90	376	122	308
29	442	60	663	91	418	123	657
30	351	61	571	92	289	124	949
31	627	62	213	93	274	125	380
				94	195	126	279

Exhibit F.4

TOTAL COAL CONSUMPTION (1980-1995)
FOR EACH OF THE 126 MIT SCENARIOS
(IN MILLIONS OF TONS)

	Coal Usage		Coal Usage		Coal Usage		Coal Usage
1	88	32	39	63	33	95	54
2	84	33	80	64	11	96	53
3	81	34	48	65	27	97	45
4	67	35	46	66	99	98	12
5	63	36	38	67	55	99	12
6	60	37	12	68	13	100	13
7	53	38	35	69	36	101	84
8	51	39	35	70	79	102	84
9	50	40	34	71	50	103	84
10	43	41	32	72	13	104	84
11	40	42	31	73	36	105	40
12	38	43	29	74	65	106	40
13	13	44	66	75	63	107	40
14	13	45	64	76	48	108	40
15	13	46	62	77	75	109	13
16	12	47	57	78	58	110	13
17	12	48	55	79	83	111	13
18	11	49	52	80	77	112	13
19	73	50	68	81	59	113	81
20	53	51	66	82	50	114	49
21	99	52	67	83	63	115	13
22	55	53	64	84	61	116	34
23	54	54	93	85	52	117	61
24	13	55	80	86	46	118	60
25	42	56	54	87	44	119	36
26	54	57	52	88	34	120	11
27	79	58	93	89	31	121	28
28	41	59	54	90	27	122	50
29	40	60	13	91	58	123	0
30	34	61	35	92	91	124	0
31	0	62	54	93	88	125	61
				94	70	126	52

Exhibit F.5

EFFECT OF CHANGE IN THE DISCOUNT RATE ON
TOTAL COSTS (1980-1995) FOR SELECTED COAL CONVERSION STRATEGIES
(PRESENT VALUE, IN BILLIONS OF 1980 DOLLARS)

	Total Costs (1980-1995)					
	Discount Rate (+ 1% Electric Load Growth)			Discount Rate (- 1% Electric Load Growth)		
Capacity Converted to Coal (MW)	7%	11.31%	15%	7%	11.31%	15%
0	$62.0	$44.4	$34.5	$56.9	$41.2	$32.3
796 (Arthur Kill 2 & 3)	59.6	42.8	33.4	55.1	39.9	31.4
1718 (Con Edison Strategy)	57.7	41.5	32.4	53.6	38.9	30.6
3456 (Arthur Kill 2 & 3; Ravenswood 1, 2, 3; Astoria 3, 4 & 5)	56.9	41.1	32.2	53.9	39.1	30.8

Summary of Air Quality Impacts from Scenario Analysis

The impact of each of the scenarios on SO_2, NO_2 and TSP annual average air quality in New York City was calculated using the climatological version of the ERT Air Quality Model (ERTAQ). The changes in emissions from Con Edison point sources were related to changes in annual average air quality, using the ERTAQ model, for a grid of 121 ground-level receptor points equally spaced every 4 km and covering a 40 km x 40 km area, as shown in Exhibit E.1. Incremental changes in annual average air quality were computed by modeling the incremental emission changes from 1978 baseline emissions. The total air quality at each grid point was then estimated by adding the modeled incremental changes in concentrations to 1978 measured baseline air quality concentrations. Both incremental and total air quality concentrations for SO_2, NO_2 and TSP were calculated for the peak SO_2 emission year during 1980-1995, and also for 1995, for each scenario.

A summary of selected SO_2 and NO_2 results is presented in Exhibits F.6 - F.8. In general, the coal conversion scenarios, without scrubbers, that included Astoria were predicted to exceed SO_2 annual average air quality and PSD increment standards. Coal conversion runs with scrubbers, either dry or wet, produced little SO_2 impact. The Con Edison strategy approached, but was not predicted to exceed, the SO_2 annual average air quality standard. The TSP air quality impact was relatively minor for all scenarios. The air quality impacts for the Con Edison strategy and other selected scenarios are shown in the grid in Exhibits F.9 - F.17.

The air quality modeling analysis was conducted for planning purposes to compare the relative impacts of a large number of fuel use scenarios. The air quality modeling was not intended as a regulatory analysis for any scenario, and modeling results should not be used or extrapolated for regulatory purposes. The basic modeling limitations were as follows:

* A climatological (statistical) air quality modeling technique was used for annual average concentrations; current regulatory practice favors the use of hour-by-hour modeling for every hour in the year.

* Short-term air quality impacts were not examined.

* A relatively coarse 4 km receptor grid spacing was used; it is possible that higher concentrations would result at locations between the modeled grid points.

* A basic modeling assumption was that stack temperatures and exit gas velocities remained constant for all scenarios; a more detailed regulatory analysis would consider the changes in these parameters.

Exhibit F.6

MIT SCENARIOS IN ORDER OF PEAK ANNUAL
AVERAGE SO_2 CONCENTRATION IN 1995

(Air Quality Standard = 80 Micrograms per Cubic Meter)

Code Name	SO_2 Concentration (micrograms/meter^3)	Code Name	SO_2 Concentration (micrograms/meter^3)
FT1MMN	102.81	FT8MM	74.23
FT2MM	99.89	NC2LMPTN	73.71
NR1MMNT	97.68	ST9LM	73.24
NR1MMN	97.33	DW2MM	73.20
NR1HMN	96.98	ST9MM	73.00
NR1MMNP	96.44	NC1MMN	72.98
FT1MMT	96.27	AK2MM	72.95
NR2MM	95.45	DR2MM	72.82
NR1MMT	93.94	ST9HM	72.80
FT1LM	93.75	DS1MM	72.65
FT9MMN	93.62	DRA1MM	72.44
FT9MMN1	93.62	NR8MM	72.42
NR1HMT	92.86	DW1MM	72.33
NR1LM	92.24	AK1LM	72.03
FT1MM	92.09	NC2MM	71.98
NR9MMN	91.79	SC1MM	71.89
NR9MMN1	91.79	AK1MM	71.88
NR1MMTP	91.17	AKD1MM	71.88
TD1MM	90.94	SC1HM	71.75
NRD1MM	90.76	AK1HM	71.75
FT1HM	90.67	DR1MM	71.73
NR1MM	90.64	NC1LMTP	71.51
FT1MMP	89.84	NC1MMT	71.37
NR1HM	89.76	NC1LM	71.15
NR1MMP	87.55	NC1MMP	71.11
NR1HMP	86.47	DS9MM	71.05
NR9MMT	82.12	NC1MM	71.00
NR9LM	78.36	DRA9MM	70.89
ST1MMN	77.06	NC1HM	70.87
ST1MMN1	77.06	DW9MM	70.75
FT9LM	76.97	AK9LM	70.53
NR9MM	76.92	AKD9MM	70.47
FT9MM	76.45	AK9MM	70.44
TD9MM	76.27	SC9MM	70.41
FT9HM	76.01	AK9HM	70.34
NRD9MM	75.83	DR9MM	70.32
NR9HM	75.60	DW8MM	70.20
ST9MMN	75.50	AK8MM	70.07
ST9MMN1	75.50	DR8MM	69.88
ST1LM	75.47	NC9LM	69.73
STD1LM	75.47	NC9MM	69.67
NR9MMP	75.39	NC9HM	69.62
ST1MM	75.27	NC8MM	69.47
ST1HM	75.06		

Exhibit F.7

MIT SCENARIOS IN ORDER OF PEAK ANNUAL
AVERAGE NO_2 CONCENTRATION IN 1995
(Air Quality Standard = 100 Micrograms per Cubic Meter)

Code Name	NO_2 Concentration (micrograms/meter^3)
FT1MMN	94.70
NC2LMPTN	94.19
NR1MMNT	93.50
FT2MM	93.13
DW2MM	93.02
NR1MMNP	92.63
NR1MMN	92.58
NR1HMN	92.38
ST1MMN	92.33
ST1MMN1	92.33
FT1MMT	92.11
FT1LM	91.87
SC1MM	91.76
FT9MMN	91.69
FT9MMN1	91.69
FT1MM	91.65
TD1MM	91.62
FT1MMP	91.61
DW1MM	91.58
SC1HM	91.54
DS1MM	91.47
FT1HM	91.44
NR2MM	91.23
DR2MM	91.01
NC1MMN	90.84
NR1MMTP	90.49
NR1MMT	90.41
NR1LM	90.29
NR1HMT	90.25
NR9MMN	90.17
NR9MMN1	90.17
NRD1MM	90.17
NR1MM	90.14
NR1MMP	90.11
AK2MM	90.07
NR1HM	90.04
NR1HMP	89.99
ST1LM	89.96
STD1LM	89.96
ST9MMN	89.90
ST9MMN1	89.90
ST1MM	89.83
DRA1MM	89.82
DR1MM	89.82
FT9LM	89.79
ST1HM	89.71
NC2MM	89.67
FT9MM	89.64
TD9MM	89.58
SC9MM	89.57
DW9MM	89.55
FT9HM	89.51
DS9MM	89.47
NC1LMTP	89.40
NR9MMT	89.18
NR9LM	89.12
AK1LM	89.08
NC1MMT	89.05
NR9MM	89.02
FT8MM	88.97
AK1MM	88.96
AKD1MM	88.96
NRD9MM	88.96
NR9MMP	88.93
NR9HM	88.93
NC1MMP	88.90
DW8MM	88.86
NC1LM	88.85
AK1HM	88.83
ST9LM	88.80
NR8MM	88.31
NC1MM	88.72
ST9MM	88.70
DR9MM	88.69
DRA9MM	88.66
ST9HM	88.63
NC1HM	88.60
DR8MM	88.30
AK9LM	88.12
AK9MM	88.07
AKD9MM	88.07
AK9HM	88.03
NC9LM	87.96
AK8MM	87.93
NC9MM	87.93
NC9HM	87.91
NC8MM	87.84

Exhibit F.8

MIT SCENARIOS IN ORDER OF PEAK YEAR
ANNUAL AVERAGE SO_2 CONCENTRATION
(Air Quality Standard = 80 Micrograms per Cubic Meter)

Code Name	SO_2 (micrograms/meter^3)	Peak Year	Code Name	SO_2 (micrograms/meter^3)	Peak Year
FT1MMN	103.63	1993	ST1LM	75.47	1995
FT2MM	99.89	1995	STD1LM	75.47	1995
NR1MMNT	99.08	1993	DR2MM	75.47	1989
NR1MMN	98.15	1993	NR8MM	75.39	1988
NR1HMN	97.75	1993	ST1MM	75.31	1993
NR1MMNP	97.09	1993	ST1HM	75.11	1993
FT1MMT	96.93	1993	DR1MM	74.77	1989
FT9MMN	96.41	1988	DS1MM	74.19	1980
FT9MMN1	96.41	1988	FT9MM	73.88	1990
NR2MM	95.96	1993	NC2LMPTN	73.81	1994
NR1MMT	94.82	1993	ST9LM	73.72	1990
NR1HMT	94.32	1993	DW9MM	73.52	1989
FT1LM	94.05	1993	DRA9MM	73.46	1990
NR1LM	93.67	1993	ST9MM	73.44	1990
NR9MMN	93.65	1988	DR9MM	73.43	1989
NR9MMN1	93.53	1988	DS9MM	73.40	1989
NRD1MM	92.56	1993	DR8MM	73.40	1984
NR1MM	92.45	1993	DW8MM	73.39	1984
FT1MM	92.41	1993	ST9HM	73.21	1990
NR1MMTP	92.21	1993	NC1MMN	72.98	1994
NR1HM	91.18	1993	AK2MM	72.95	1985
TD1MM	90.94	1995	AK1LM	72.03	1995
FT1HM	90.73	1993	NC2MM	71.93	1994
FT1MMP	89.84	1995	SC1MM	71.91	1993
NR1MMP	88.77	1973	AKD1MM	71.88	1995
NR1HMP	87.61	1993	SC1HM	71.77	1993
NR9MMT	84.97	1990	AK1MM	71.76	1994
NR9LM	81.59	1988	AK1HM	71.75	1995
NR9MM	80.17	1988	NC1LMTP	71.46	1993
FT9LM	78.64	1990	NC1MMT	71.29	1993
NR9HM	78.64	1988	NC1LM	71.10	1993
NRD9MM	78.17	1990	NC1MMP	71.03	1993
NR9MMP	77.42	1990	NC1MM	70.95	1993
FT9MM	77.37	1990	AK9LM	70.85	1990
TD9MM	77.34	1990	NC1HM	70.85	1990
FT9HM	77.23	1990	AKD9HM	70.81	1993
ST1MMN	77.06	1995	AK9MM	70.75	1990
ST1MMN1	77.06	1995	AK9HM	70.66	1990
DW1MM	76.63	1989	NC8MM	70.58	1980
FT9MM	76.39	1990	NC9MM	70.57	1980
FT8MM	75.99	1988	NC9HM	70.57	1980
ST9MMN1	75.75	1989	SC9MM	70.51	1990
ST9MMN	75.75	1989	AK8MM	70.49	1988
DW2MM	75.69	1989	NC9LM	69.99	1990
DRA1MM	75.51	1990			

Exhibit F.9

INCREMENTAL ANNUAL AVERAGE SO_2 CONCENTRATIONS
FOR PEAK SO_2 EMISSION YEAR
FOR CON EDISON STRATEGY, ST1MM
(Micrograms per Cubic Meter)

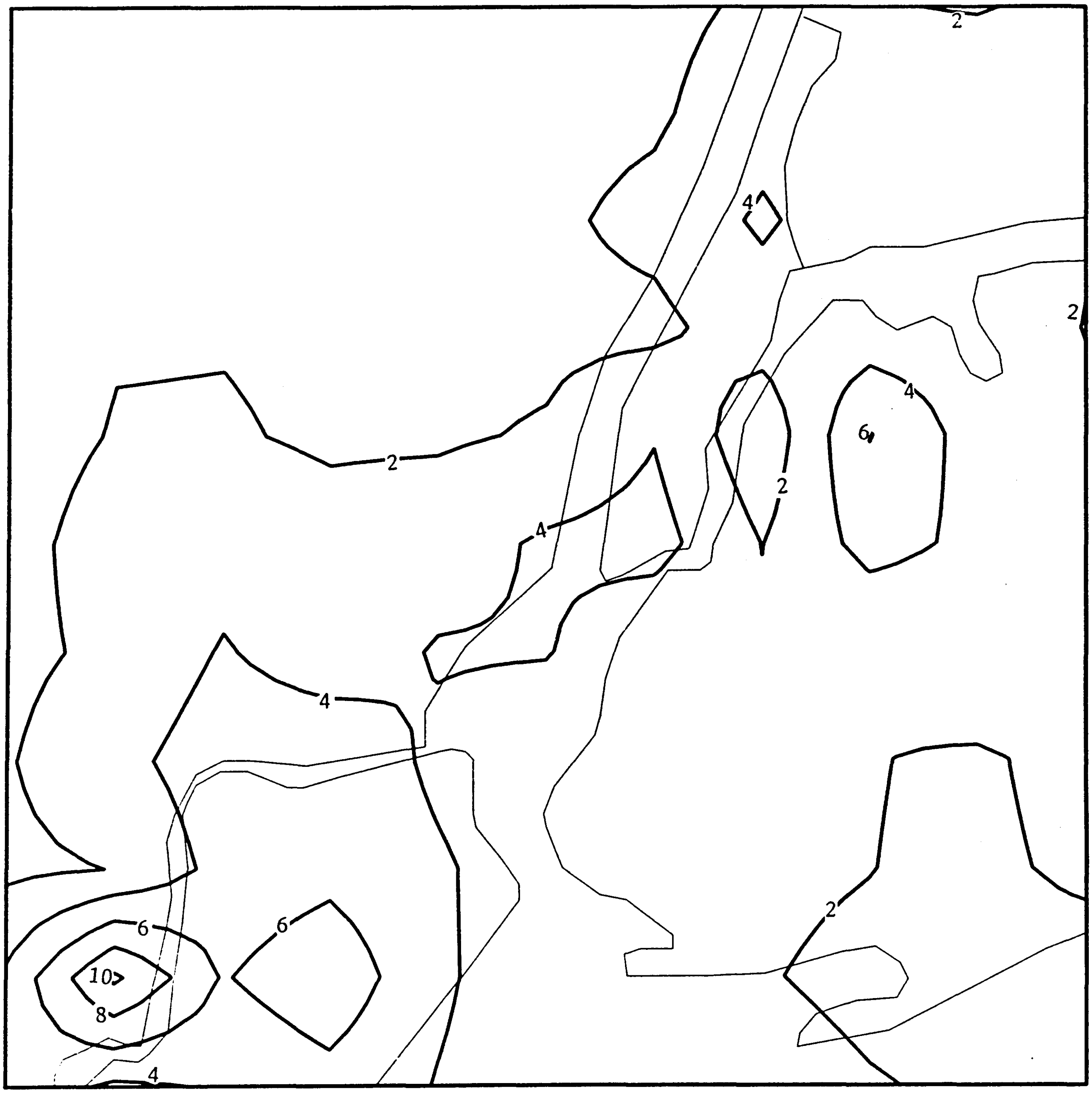


Exhibit F.10

TOTAL ANNUAL AVERAGE SO_2 CONCENTRATIONS
FOR PEAK SO_2 EMISSION YEAR
FOR CON EDISON STRATEGY, ST1MM
(Micrograms per Cubic Meter)

Exhibit F.11

INCREMENTAL ANNUAL AVERAGE SO_2 CONCENTRATIONS
FOR PEAK SO_2 EMISSION YEAR
FOR THE MAXIMUM CONVERSION STRATEGY, FT1MM
(Micrograms per Cubic Meter)

Exhibit F.12

TOTAL ANNUAL AVERAGE SO_2 CONCENTRATIONS
FOR PEAK SO_2 EMISSION YEAR
FOR THE MAXIMUM CONVERSION STRATEGY, FT1MM
(Micrograms per Cubic Meter)

Exhibit F.13

INCREMENTAL ANNUAL AVERAGE NO_2 CONCENTRATIONS
FOR PEAK SO_2 EMISSION YEAR
FOR THE MAXIMUM CONVERSION STRATEGY, FT1MM
(Micrograms per Cubic Meter)

Exhibit F.14

TOTAL ANNUAL AVERAGE NO_2 CONCENTRATIONS
FOR PEAK SO_2 EMISSION YEAR
FOR THE MAXIMUM CONVERSION STRATEGY, FT1MM
(Micrograms per Cubic Meter)

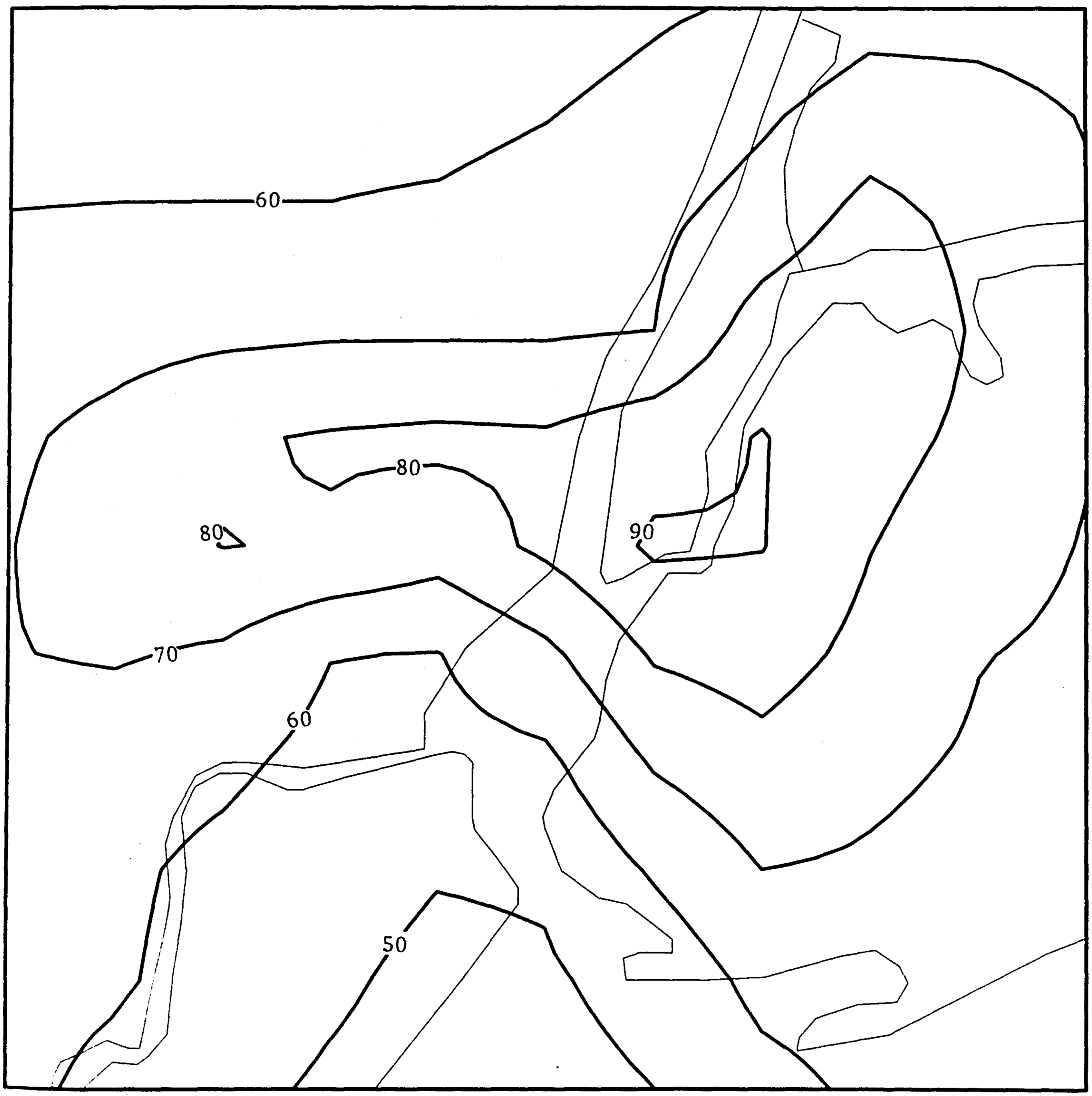


Exhibit F.15

INCREMENTAL ANNUAL AVERAGE TSP CONCENTRATIONS
FOR PEAK SO_2 EMISSION YEAR
FOR THE MAXIMUM CONVERSION STRATEGY, FT1MM
(Micrograms per Cubic Meter)

Exhibit F.16

INCREMENTAL ANNUAL AVERAGE SO_2 CONCENTRATIONS
FOR PEAK SO_2 EMISSION YEAR
FOR A COAL CONVERSION STRATEGY
WITH WET SCRUBBER INSTALLATION, SC1MM
(Micrograms per Cubic Meter)

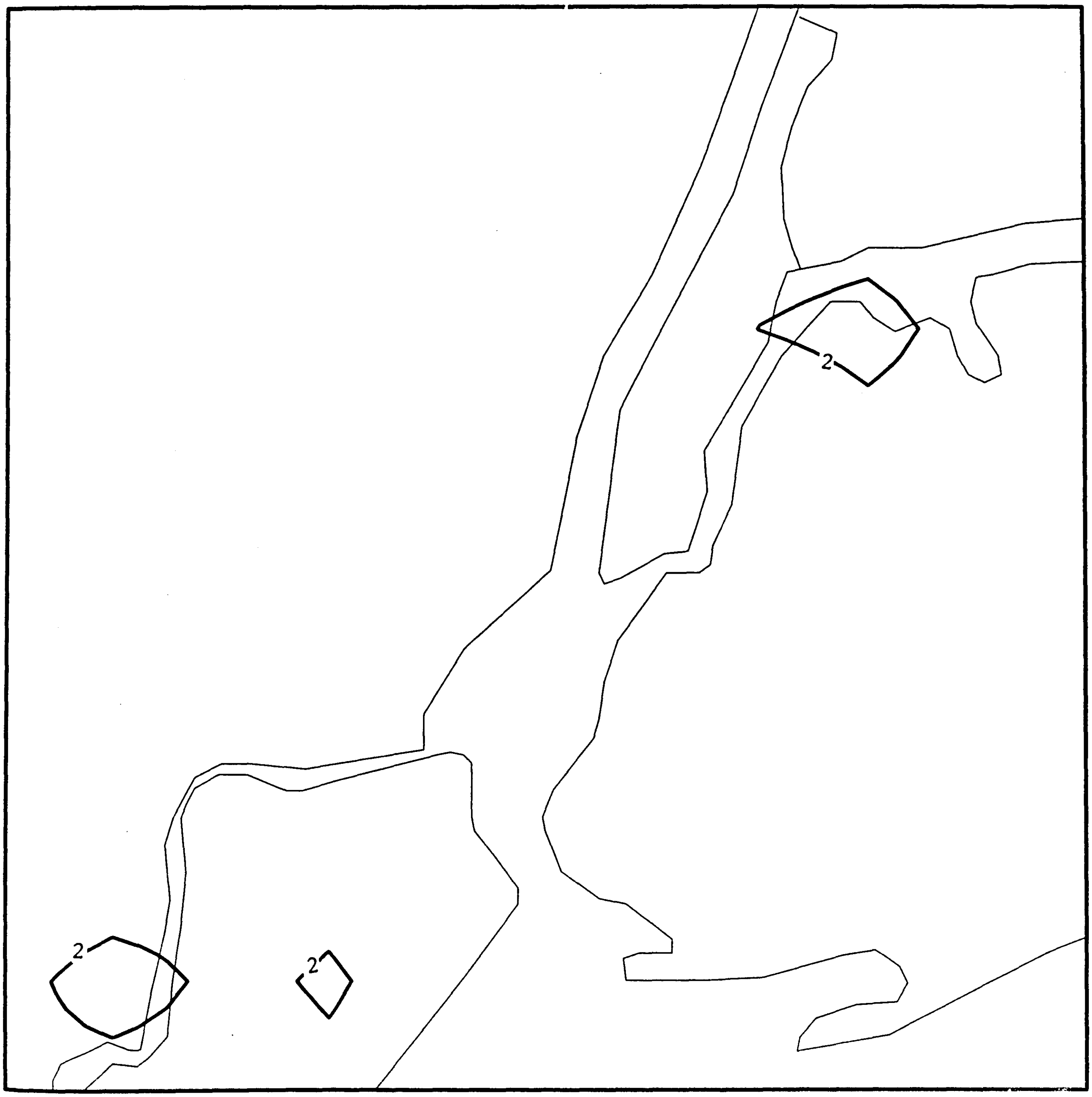
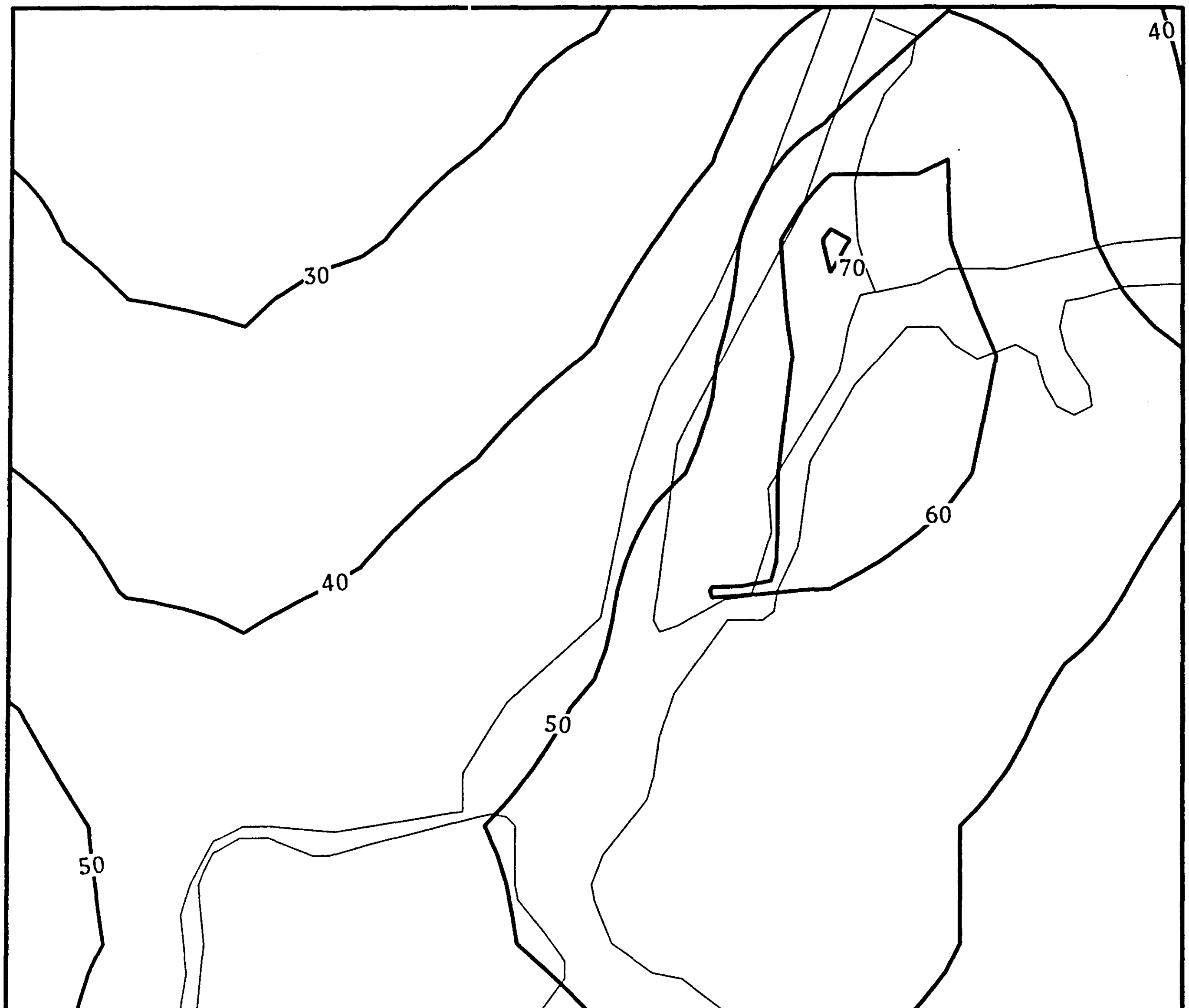


Exhibit F.17

TOTAL ANNUAL AVERAGE SO_2 CONCENTRATIONS
FOR PEAK SO_2 EMISSION YEAR
FOR A COAL CONVERSION STRATEGY
WITH WET SCRUBBER INSTALLATION, SC1MM
(Micrograms per Cubic Meter)



The modeling analysis that was conducted can thus be considered as a screening technique for planning purposes. A more detailed modeling analysis should be conducted for any individual scenario for an environmental impact regulatory review.

Appendix G

REGRESSION ANALYSIS METHODOLOGY AND SELECTED EXAMPLES

Methodology

The procedure for estimating regression relationships between input variables and output variables in scenario analysis was iterative and recursive. As shown in Exhibit 4.6, the first step was to determine which input and output variables were to be related. Once this was determined, scenarios were chosen in an attempt to capture the major effects among the chosen variables. The scenarios were then simulated using the models described in Chapter Four. The output variables from the simulations were then entered into a data base where they could be easily manipulated. At this point an important effort to correct data and modeling errors was undertaken. Next, the physical and economic characteristics of the input and output variables were analyzed, and simple generic relationships between the variables were postulated. Then, regressions were run to calculate the coefficients for the mathematical forms of these relationships. The relationships were further studied by using statistical measures of how well they 'fit' the simulation data. If models were not sufficiently accurate, the physical and economic characteristics were reanalyzed and new generic relationships were postulated. These were then regressed to find the coefficients for mathematical relationships between the variables.

The models did not perfectly fit the simulation data. This is due to two major effects. First, these equations could not capture all details of the extremely complex system. Second, certain features of the system which are unimportant for strategic planning decision-making were not modeled. For example, each of the Indian Point nuclear units is taken out of service about once every 18 months for maintenance and refueling. When this is done the oil or coal consumption and fuel costs increase to account for the nuclear plant unavailability. This short-term increase and similar low-impact system features were not modeled in this project.

Validity

There is no single adequate measure of the precision of regression models. One is the correlation coefficient which measures correlation between simulation data and the model. For almost all models, the coefficients of correlation were above .99, an extremely high correlation. Each coefficient in the models also has associated with it a t-statistic and a standard error. T-statistics greater than 2 imply confidence limits greater than about 97.5%. The t-statistics for the relationships were, with few exceptions, greater than 2. The ultimate test of precision used was a scenario-by-scenario comparison of the simulation data and the model. Almost all of the models were within a few percentage points of the simulation data.

These models are valid for the ranges over which simulation studies were carried out. For instance, they are valid for values of load growth between -1% per year to +2% per year from 1980-1995. They are valid with purchased energy varying between 0 and 100 billion kWh. 1995 variables are valid if the assumed purchased energy in that year is about 6% of the total electric energy purchased during the entire period.

The 1995 output variables are valid for the shutdown of the Indian Point plant at any time prior to 1995. For such variables: DN=1 means Indian Point is operating in 1995; DN=0 means Indian point is shutdown; DN=-.67 is meaningless. For variables of the period 1980-1995 the Indian Point variable, DN, must be equal to 1.0 (no shutdown), -.67 (shutdown in 1982) or 0.0 (shutdown in 1987). The fuel price escalations over which the models are valid follow: oil between -2% and +8% per year, 1980-1995; and coal between 0% and +5% per year, 1980-1995. Further, the price of coal may not increase more than 2 percentage points per year faster than the price of oil. (These escalation rates are in real terms with annual inflation at 7%.)

Model Forms and Coefficients

Exhibit G.1 defines the symbols used for variables in the regression analysis. Exhibit G.2 shows the technical form of the equations for the relationships between input and output variables. Exhibit G.3 lists the coefficients calculated for the relationships of Exhibit G.2.

Examples

Examples of how to estimate the input and output variables is done below for two sample scenarios: the "do nothing" scenario and the Con Edison strategy.

(i) Coal generating capacity in 1995 in MW is referred to as CAPCOAL. In the "do nothing" scenario no coal conversion takes place and no new coal plants are built; thus, CAPCOAL is equal to zero. The Con Edison strategy assumed that Ravenswood 3 and Arthur Kill 2 and 3 are converted to coal and that Travis is

Exhibit G.1

SYMBOLS FOR VARIABLES USED IN REGRESSION ANALYSIS MODELS

CAPCOAL:	Sum of nameplate capacities of all service area coal-fired generation, in 1995, in MW.
COALAREA:	A measure of coal-fired generating capacity from time of conversion (or construction) until 1995.
DN:	Variable for Indian Point. DN = 0 means plant is shut down permanently on December 31, 1986. DN = 1 means Indian Point is operating. DN = -.67 means Indian Point is shut down in 1982 (irrelevant for 1995 variables).
DP:	Binary variable for Prattsville. DP = 0 means facility is not built. DP = 1 means facility goes on line on May 1, 1987. (It is assumed that 990 MW are available for loads in the service area.)
DT:	Binary variable for Travis. DT = 0 means facility is not built. DT = 1 means plant goes on line on May 1, 1987. (It is assumed that 632 MW are available for loads in the service area.)
LG:	Service area load growth in percent.
PPAREA:	Total electric energy purchased from sources outside the service area, 1980-1994, in thousands of GWh (billions of kWh). This excludes energy from Bowline Point, Roseton, and Indian Point 3 and firm purchases from Fitzpatrick (325 MW through February 28, 1989; 0 MW thereafter), which are modeled separately.
REVREQ:	1980 present value of fixed cost revenue requirements for new service area generation facilities (including coal conversion, Travis and Prattsville) in millions of dollars.
TERMCOAL:	Coal consumption by service area plants, in 1995, in millions of tons.
TERMFCST:	Total cost of fuel for service area, 1995, in millions of dollars.
TERMOIL:	Oil consumption by service area plants (including Con Edison's share of Bowline Point and Roseton plants), in 1995, in millions of barrels.

Exhibit G.1
(Continued)

TERMSO$_2$:	Annual average rate of discharge of SO_2 in service area for the year 1995, in grams per second.
TERMTCST:	Incremental total cost of electricity, 1995; that is, TERMFCST plus O&M costs plus fixed charge revenue requirements (for coal conversions, Prattsville, and Travis) plus cost of purchased energy (80% of avoided cost) for service area, 1995, in millions of dollars.
TFUELC:	1980 present value of fuel costs, 1980-1995, in millions of dollars, for service area plants (including Indian Point 3; 325 MW from Fitzpatrick through February 28, 1989; and Con Edison's share of Bowline Point and Roseton).
TOTCOAL:	Total coal consumption by service area plants, 1980-1995, in millions of tons.
TPRODC:	1980 present value of production cost; that is, TFUELC + O&M, for the service area, in millions of dollars.
TOTCOST:	1980 present value of TPRODC + REVREQ + Cost of purchased energy, for the service area, 1980-1995, in millions of dollars.
TOTOIL:	Total oil consumption by service area plants (including Con Edison's share of Bowline Point and Roseton), 1980-1995, in millions of barrels.
DAK, DRV3, DRV, and DAS:	Denotes fraction of, respectively, Arthur Kill, Ravenswood 3, Ravenswood 1 and 2, and Astoria 3, 4, and 5 that is converted to coal. 0 = no conversion. 1.0 = 100% conversion.
DDS:	Denotes fraction of dry scrubbers on coal-converted capacity (i.e., excluding Travis). 0 = no dry scrubbers; 1.0 = 100% dry scrubbers.
ESCOIL and ESCOAL:	Annual price escalations, in current (inflated) dollars, for oil and coal, in percent.

EXHIBIT G.2

EQUATIONS FOR REGRESSION ANALYSIS

Fuel Utilization and Cost Models*

```
X1 == ((1+ESCOIL/100)/1.1131)**7

X2 == ((1+ESCCOAL/100)/1.1131)**7

Y1 == ((1+ESCOIL/100)/1.1131)**15

Y2 == ((1+ESCCOAL/100)/1.1131)**15

LOAD == (1+LG/100)**15

TFUELC = A11*DN+A12*TOTOIL*X1+A13*TOTCOAL*X2

TOTOIL = A29*DP*DN*COALAREA+A218*DP*DN+A219*DP*COALAREA**2+A217*DP*LG*COALAREA+A213*CAPCOAL**2*LOAD+
A21+A22*LG+A23*PPAREA+A24*COALAREA+A25*COALAREA**2+A26*COALAREA**2*LG+A27*COALAREA**2*PPAREA+(A28+
A210*COALAREA)*DN+A211*DP+A214*DRV3*LOAD+A215*DP*LG+A216*DP*COALAREA

TOTCOAL = A316*DP*LG*COALAREA+A315*LG*COALAREA+A312*DRV3*LOAD+A313*DP*LG+A314*DP*COALAREA+A31+A32*
COALAREA+A33*COALAREA**2+A34*COALAREA**2*LG+A35*COALAREA**2*PPAREA+A36*COALAREA**2*DN+A37*DP

TERMOIL = A413*CAPCOAL*LOAD*DP+A421*CAPCOAL*DN*DP+A422*DN*DP+A420*DP*LOAD+A419*DHA+A414*PPAREA*LOAD+
A415*DN+A416*CAPCOAL*DN+A417*CAPCOAL*LOAD*DN+A418*DP+(+A411)*(1-DRV3)*LOAD+A41+A412*LOAD**2*CAPCOAL**
2+A42*CAPCOAL+A43*LOAD+A44*CAPCOAL*LOAD+A45*CAPCOAL*LOAD**2+A46*LOAD*CAPCOAL**2+A47*DP*CAPCOAL**2+A48
*PPAREA*CAPCOAL+A49*DP*CAPCOAL+A410*CAPSCRB**2

TERMCOAL = A512*CAPCOAL*LOAD+A513*CAPCOAL*LOAD*DP+A511*CAPCOAL*DN*DP+A51+A52*CAPCOAL+A53*CAPCOAL**2+
A54*CAPCOAL**2*LOAD+A55*CAPCOAL**2*PPAREA+A56*CAPCOAL**2*DN+A57*DP+A58*DP*CAPCOAL+A59*DP*LOAD+A510*
DRV3*LOAD

REVREQ = A61*COALAREA+A62*DT+A63*DRV3+A64*DP+(+A68)*SCRBAREA+A69*DRV

TERMRR = B611*DDS+B61*CAPCOAL+B62*DT+B63*DRV3+B64*DP+(+B68)*CAPSCRB+B69*DRV+B610*DDS*CAPSCRB

TPRODC = A71*DN+A72*X1*TOTOIL+A73*X2*TOTCOAL+A74*COALAREA

TOTCOST = A81*DN+A82*X1*TOTOIL+A83*X2*TOTCOAL+A84*REVREQ+A85*PPAREA+A86*COALAREA

TERMFCST = A91*DN+A92*TERMOIL*Y1+A93*TERMCOAL*Y2

TERMTCST = B11*DN+B12*Y1*TERMOIL+B13*Y2*TERMCOAL+B14*REVREQ+B15*PPAREA+B16*CAPCOAL
```

EXHIBIT G.2 (continued)

Environmental Impact Models*

```
LOAD == (1+LG/100)**15

CAPDRY == 632*DT+DDS*(CAPSCRB-632*DT)

CAPWET == CAPSCRB-CAPDRY

TERMSO2 = TERMCOAL*(A11*CAPDRY+A12*CAPWET+A13*(CAPCOAL-CAPSCRB))/(CAPCOAL+0.1)+A14*TERMOIL

TERMDSO2 = TERMCOAL*(A21*CAPDRY+A22*CAPWET+A23*(CAPCOAL-CAPSCRB))/(CAPCOAL+0.1)+A24*TERMOIL+A25*DT+
A26*DAK+A27*DAS+A28*DRV+A29*DRV3

TERMTSO2 = TERMCOAL*(A31*CAPDRY+A32*CAPWET+A33*(CAPCOAL-CAPSCRB))/(CAPCOAL+0.1)+A34*TERMOIL+A30+(A35*
DT+A36*DAK+A37*DAS+A38*(922*DRV3+742*DRV))*LOAD

TERMDNO2 = A71+A72*TERMCOAL+A73*TERMOIL+A74*DT+A75*DAS+A76*DRV3

TERMTNO2 = A80+A85*TERMCOAL+A86*TERMOIL
```

* Equations are shown in computer notation.

Key:

Computer Notation	Mathematical Function
+	Addition
-	Subtraction
*	Multiplication
/	Division
**	Exponentiation

EXHIBIT G.3

COEFFICIENTS FOR REGRESSION ANALYSIS

Fuel Utilization and Cost Models

A48	2.147672E-05	A77	-2.09166	A111	-442.044
A110	-0.066586	A19	-7.98389	A18	-62.4213
A17	398.895	A16	-0.144632	A15	-0.756606
A82	-0.165397	A58	-4.386876E-05	A84	0.363832
A81	-0.491987	A83	0.868904	A87	0.480152
A85	0.64295	A86	0.073771	A80	85.4536
A71	-0.607029	A72	1.29078	A73	0.063781
A76	-2.47565	A75	0.624677	A74	-1.82075
A24	0.090172	A23	5.81144	A22	1.62516
A21	3.51147	A25	-5.09655	A26	-3.12623
A29	-8.96897	A28	-4.62684	A27	8.40247
A39	-0.000305	A310	-0.002058	A34	0.189809
A33	4.79799	A31	3.52124	A32	1.82735
A35	-3.89051	A36	-4.47596	A38	-0.00554
A37	8.16274	A30	62.2885	A11	169.769
A12	118.033	A14	19.0797	A13	561.592

EXHIBIT G.3 (continued)

Environmental Impact Models

B23	-1.029379E-16	B33	-3.675787E-14	B21	-7.261191E-07
B22	0.039604	B24	0.03005	B34	0.005053
B32	0.008023	B31	-1.618923E-06	A15	139.062
A514	-1.823366E-11	A515	1.033071E-11	A31	-0.36338
A32	0.002229	A33	-1.540741E-09	A34	4.305619E-09
A36	-8.399059E-09	A35	-9.628079E-11	A37	-0.182494
A310	0.	A39	0.	A38	0.
A311	0.	A312	1.88785	A313	0.200419
A314	0.00017	A315	0.000114	A316	-9.189644E-05
A61	0.022711	A62	36.6133	A63	-222.336
A64	261.731	A68	0.037577	A65	0.099988
A67	44.7122	A66	-54.972	A69	133.722
B68	0.080103	B62	64.8682	B61	0.045398
B63	-45.2932	B64	98.5844	B69	34.4847
B610	0.171472	B67	-39.6009	B66	-207.022
B65	0.110849	B611	-266.217	A41	23.302
A42	-0.006924	A43	50.4632	A44	-0.031759
A45	0.021011	A46	3.215921E-06	A47	-1.176173E-07
A48	1.402314E-05	A410	7.821200E-08	A411	0.981881
A412	-2.231791E-06	A413	-0.004799	A414	-0.091327
A415	-29.5627	A416	0.015661	A417	-0.010213
A49	0.007863	A418	-24.6678	A419	0.725947
A422	4.55257	A420	16.7151	A421	-0.002082
A12	26.9137	A13	43.9699	A14	4.46943
A11	491.037	A81	692.733	A82	28.7729
A83	34.6513	A84	1.13394	A85	25.9558
A87	0.	A86	0.016565	A75	0.
A71	680.505	A72	28.7121	A73	24.8751
A74	0.045873	A94	0.	A93	245.036
A92	151.538	A91	127.529	B16	-0.090888
B15	7.00109	B14	0.631635	B13	241.004
B12	159.859	B11	207.52	B17	0.
A21	949.664	A22	51.2817	A23	-1.5051
A24	-0.012916	A25	1.753261E-08	A26	-9.045095E-09
A27	3.056966E-10	A28	-241.601	A211	-50.592
A210	0.003258	A212	0.	A213	2.781260E-06
A214	-12.3681	A215	23.8331	A216	0.000856
A217	-0.000588	A29	-0.000567	A218	27.6263
A219	2.511688E-09	A51	-0.038565	A52	0.001305
A53	-3.873807E-07	A54	3.935587E-07	A55	-9.912380E-10
A56	-1.429906E-07	A57	0.22987	A510	0.198065
A59	-0.213315	A58	0.000577	A511	1.822985E-05
A513	-0.00044	A512	0.000989		

built. Thus, CAPCOAL is equal to 2350 MW in Con Edison's strategy. The variable CAPSCRB describes the number of megawatts of coal-fired capacity that has scrubbers in 1995. For the Con Edison strategy CAPSCRB is equal to 632 MW. This represents that Travis has scrubbers.

(ii) Availability of coal generating capacity is referred to as COALAREA. COALAREA is calculated by multiplying the capacity of a plant by the number of years it is available at that capacity. For the "do nothing" scenario there is no coal, so COALAREA is zero. For the Con Edison strategy COALAREA is 30,201:

Plant Name	Capacity	Date Converted	No. Years Available*	COALAREA
Ravenswood 3	922	1981	15	13,830
Arthur Kill 2	335	1982	14	4,690
Arthur Kill 3	461	1983	13	5,993
Travis	632	1987	9	5,688
	Total for Con Edison Strategy			30,201

*Since this study covers the period 1980 to 1995, a plant converted in 1983 has 13 operational years before the end of 1995.

To account for scrubbers there is another decision variable (SCRBAREA) which takes into account the amount of time which the plant has scrubbers. For the Con Edison strategy, only Travis has scrubbers; so SCRBAREA is 9 years x 632 MW or 5688 MW.

(iii) The regression models have a number of terms which are binary input variables (0 or 1) (See Exhibit G.1).

Thus, to estimate the output variables (i.e., fuel use, cost, and pollution) of any given scenario, the input variables must be provided as above. Then, using the relationships of Exhibit G.2, the estimated output variables can be calculated.

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